EXHIBIT NO. ___(EMM-3)
DOCKET NO. ____________
2005 POWER COST ONLY RATE CASE
WITNESS: ERIC M. MARKELL

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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

SECOND EXHIBIT TO THE PREFILED DIRECT TESTIMONY OF
ERIC M. MARKELL (NONCONFIDENTIAL)
ON BEHALF OF PUGET SOUND ENERGY, INC.

JUNE 7, 2005

April 30, 2003

Ms. Carole J. Washburn, Executive Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
Olympia, Washington 98504-7250

Re: Puget Sound Energy's 2003 Least Cost Plan

Dear Ms. Washburn,

Enclosed for filing, please find an original and 19 copies of Puget Sound Energy's ("PSE" or "the Company') Least Cost Plan ("LCP"). This document presents information and analysis to comply with both the electric utility least cost planning requirements under WAC 480-100-238 and the natural gas utility least cost planning requirements under WAC 480-90-238. Please note that resource planning is a continual process in what has become a highly dynamic energy industry environment. The Company's LCP should be viewed as a snapshot in time to demonstrate the Company's process, not as a static 20-year resource plan.

During this planning cycle, the Company made a renewed effort to enhance and expand resource planning in light of the recent western energy crisis and its aftermath, which are discussed in the document. This LCP demonstrates application of an extensive, innovative analysis of numerous resource planning issues. These issues include identifying the Company's resource needs, investigating the costs and cost volatility of different planning standards, analyzing the cost and cost volatility of different resource strategies to meet planning standards, and explaining how the Company's judgment is applied to all this information to derive a long-term resource strategy which will be revised over time.

Consultation with WUTC Staff and public participation were important parts of this planning process. Numerous meetings were held with Commission Staff to discuss nearly every aspect of the plan, including details of the analytical approaches that underlie much of the analysis. Feedback provided by Commission Staff was particularly helpful. In addition, the Company received extensive feedback from its Least Cost Planning Advisory Group ("LCPAG"). Many of those comments and suggestions were incorporated into the LCP. PSE is most grateful for the significant commitment made by LCPAG members including WUTC Staff, Public Counsel, Northwest Power Planning Counsel, CTED, Northwest Energy Coalition, and several others. PSE hopes members of the LCPAG share the Company's belief that their contributions to the LCP process will assist the Company in making sound resource decisions in the future.

PSE looks forward to making a formal presentation of the Company's 2003 LCP to the Commission and receiving feedback from the Commission as soon as practical, to help the Company continue to improve and refine its resource planning process. If you have questions regarding the Company's LCP, please contact Charlie Black, PSE's Director of Resource Planning and Analysis, at 425-462-3081, and if I can be of any assistance, please contact me at 425-462-3272.

Sincerely,

George Pohndorf
Director-Regulatory Initiatives

Least Cost Plan

April 30, 2003

PUGET SOUND ENERGY

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 17 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 – Electric Portfolio Analysis Overview
This chapter includes a succinct graphical overview of PSE's Electric Portfolio Analysis, including its electric resource needs and electric resource addition strategy.

Chapter III – Planning Issues
This chapter examines major regional and federal industry issues influencing the resource strategy PSE establishes during its least cost planning process.

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

Chapter IX – 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 X – 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 XI – 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 XII – Electric Resource Analysis Results and Judgment
This chapter presents the results of the electric resource analysis, and the application of company judgment to bridge the gap between the theoretical world of models and real-world behavior.

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

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

Chapter XVI – 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 gas portfolio strategy.

Chapter XVII – Two-Year Action Plan
This chapter updates PSE's previous action plan and provides a new two-year Action Plan for implementing its long-term 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 IV, PSE's Current Situation • Chapter VI, 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 VIII, Existing Electric Resources • Chapter X, 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 XI, Electric Portfolio Analysis • Chapter XII, Electric Analytical Results and Application of 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 XI, Electric Portfolio Analysis • Chapter XII, Electric Analytical Results and Application of 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 XIII, 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 XVII, Two-Year Action Plan
WAC 480-100-238 (4) Progress report that relates the new plan to the previously filed plan.	• Chapter XVII, Two-Year Action Plan

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 VI, 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 XIV, Existing Gas Portfolio Resources • Chapter XV, 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 XV, New Gas Resource Opportunities • Chapter XVI, 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 XVI, 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 XVI, 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 XVII, Two-Year Action Plan
WAC 480-90-238 (4) Progress report that relates the new plan to the previously filed plan.	• Chapter XVII, Two-Year Action Plan

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

LIST OF EXHIBITS

LIST OF EXHIBITS

LIST OF EXHIBITS

LIST OF EXHIBITS

LIST OF EXHIBITS

I. EXECUTIVE SUMMARY

A. Introduction

PSE pursues a Least Cost Plan process as part of its long-term resource strategy development. This document provides a current perspective of this process. Moreover, this document satisfies 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 such factors as price, supply and weather risks, reviews the mix of conservation programs and supply resources that might best meet electric or gas resource needs. This document provides an update of the results of the electric and gas Least Cost Plan analysis process and long-term resource strategic direction. PSE believes its Least Cost Plan meets applicable 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 April 30, 2003, 10 formal Least Cost Plan meetings, in addition to dozens of informal meetings and communications have taken place. A number of stakeholders including WUTC Staff; the Public Counsel; consumer advocates; individual customers from industrial, commercial, and residential classes; conservation and renewable resource advocates; the Northwest Power Planning Council; project developers; capital market participants; 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. Stakeholder suggestions and practical information were invaluable in developing this Least Cost Plan. PSE wishes to express its 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. Use and Relevance of PSE's Least Cost Plan

PSE's Least Cost Plan provides the strategic direction guiding the Company's long-term resource acquisition process. As detailed throughout this document, the Least Cost Plan does not commit PSE to the acquisition of a specific resource type or facility. Nor does the Least Cost Plan preclude PSE from pursuing a particular resource technology or acquisition. Instead, the Least Cost Plan identifies key factors related to various resource decisions and provides a method for evaluating a resource acquisition in terms of cost and risk at the time a decision needs to be made.

The strategic direction articulated in the Least Cost Plan highlights an important feature of least cost planning – its continual, ongoing nature. PSE recognizes that least cost planning is a dynamic process, that must reflect dynamic market forces, and a continually changing regulatory environment. In short, change is constant and the Company must remain flexible. For this reason, PSE's Least Cost Plan provides a strategic direction and goals to guide its long-term decision-making.

PSE's decision to pursue a diversified solutions strategy that includes the inclusion of renewable resources in its electric portfolio provides an example of the use and relevance of the Least Cost Plan. As detailed in its Two-Year Action Plan, PSE has identified a number of issues that must be addressed in order to determine the specific mix of renewable resources. PSE's analysis leads it to believe that certain wind power development would be one suitable renewable resource to contribute toward meeting this strategic goal. As a first step toward greater use of wind power, PSE recently signed a 12-month contract to purchase output from a wind facility, and has committed to studying wind power-related issues such as wind integration. As part of its electric resource strategy, PSE has begun to examine other renewable resource technologies that meet its planning criteria. PSE does not commit to specific amounts of wind power, or biomass, or other renewable resource technologies because the market factors affecting specific development projects are so uncertain. Instead PSE makes a strategic decision to build a diversified supply portfolio that includes a goal to meet five percent of its energy resource needs through renewable resources.

C. 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. PSE has a need for new electric resources due to growing load in its service territory, the loss of existing resources over the next 10 years, reduced hydro and combustion turbine generation, and the expiration of power purchase and NUG contracts. 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 at 16 degrees Fahrenheit. Both energy and capacity resources will be shaped to fill winter deficiencies, while minimizing summer surpluses.

A planning assumption is that PSE will acquire at least 150 aMW of new conservation resources over the next 10 years, to be further updated in August 2003. Following its strategic direction of building a diversified portfolio, PSE has established a goal of serving five percent of its customers' energy needs through renewable resources. Given possible lower-cost alternatives to using SCGTs to back up wind power and the possibility of including other renewable resources in its portfolio, PSE has established a higher target of serving 10 percent of its customers' energy needs through renewable resources. A diverse mix of other resources, including combined cycle gas-fired generation in the near-term, market purchases, and possibly coal later in the decade provide options for meeting the rest of PSE's resource needs. PSE will shape resources to meet two objectives – to balance the portfolio within the year and to avoid the associated risks of being out of balance in certain months of the year. Finally, PSE will continue to monitor the market for opportunistic resource acquisitions and power contracts, but not at the expense of its corporate 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 from the Northwest Power Planning Council 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's Least Cost Plan analysis assumes a 15 aMW and 2.1 million therms conservation savings level per year. As detailed in its Two-Year Action Plan, PSE will

perform an integration analysis to reassess, and possibly revise, these conservation target levels for its August 2003 update.

- ***Renewable Resources*** – PSE will examine wind integration issues for incorporating wind resources into its portfolio, consider releasing an RFP for wind and other renewable resources, and continue to explore ways to attain a target of providing 10 percent of PSE's energy needs through renewable resources.[1]
- ***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 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.

---

[1] Refer to Appendix M for a definition of renewable resources.

D. Key Chapter Highlights

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 having control over one's business through sound resource planning and supply decisions, and the critical importance of well-designed and liquid markets. Other key highlights include[2]:

1. Supply adequacy and price volatility issues remain a regional concern, and PSE's obligation is to balance cost and risk for its ratepayers.
2. Resource adequacy in the Pacific Northwest region continues to mean having enough firm resources that can be counted upon to meet customer needs.
3. 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.
4. Regional interdependencies will continue to affect resource availability and price volatility.
5. Heavy reliance on hydro resources poses unique challenges for planning supply and will continue to present risks to future merchant power development in the region.
6. Merchant power retrenchment may create a window of opportunity for PSE to acquire assets to meet some of its resource needs.
7. The current financial condition of counterparties in the wholesale energy market and PSE's own creditworthiness, limit PSE's ability to manage its existing portfolio and enter into long-term forward power contracts.
8. The future of the wholesale market structure remains uncertain in the West even as FERC continues to move forward with its Standard Market Design.
9. The operations and capital investment decisions of Bonneville Power Administration will continue to heavily impact the region and the Company. Greater investment in the region's electric transmission system will be essential to reduce market volatility and allow new resources to reach the market.

[2] For ease of reference, key highlights are numbered. The numbering in no way implies an order of importance or magnitude.

10. 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.
11. State lawmakers have introduced legislation to stimulate greater investment in renewable resources, 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.

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 risk, while allowing both stakeholders and customers to benefit from its prudent business strategy. Other key conclusions include:

1. PSE's financial policy focuses on one main goal – improving its credit rating so that it has the debt incurrence and credit capacity to economically support its portfolio management and investment requirements.
2. 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. Such PCA limits PSE's financial exposure to power supply costs to an aggregate of $40 Million over a four-year period, and provides for prompt recovery through the return of excess power costs in highly volatile power markets.
3. 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.
4. PSE's ability to execute risk management strategies is constrained by the magnitude of its short and long resource positions, the number and creditworthiness of counterparties, and by its own credit rating and limited access to credit
5. 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.

6. 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 market-driven gas supply costs and “upstream-of-the-city gate” gas transmission and storage resource costs.
7. 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 reduce energy costs to its customers.
8. Increased investment in the gas transmission infrastructure serving the I-5 corridor and in the gas supply basins in Canada and the Rocky Mountains region will be important to constraining gas prices and price volatility.

Stakeholder Interaction

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:

1. As of April 30, 2003, 10 formal Least Cost Plan meetings, in addition to dozens of informal meetings and communications have taken place. A number of stakeholders including WUTC Staff; the Public Counsel; consumer advocates; individual customers from industrial, commercial, and residential classes; conservation and renewable resource advocates; the Northwest Power Planning Council; project developers; capital market participants; and the Washington State Department of Community, Trade and Economic Development have actively participated in meetings.
2. During these meetings, a variety of topics were addressed, including electric sales forecasts and assumptions, PSE resource needs, transmission constraints, conservation, renewable resources, gas and electric distribution planning, natural gas supply and hedging risk, a deferral strategy, emissions considerations, and the AURORA modeling process, among others.
3. 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.

4. 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.
5. PSE has incorporated stakeholder issues of concern into the Least Cost Plan process. The Company has reviewed and revised its assumptions, expanded the depth and robustness of its analysis, examined a wide range of electric resource opportunities, and continued to seek public input.
6. Whenever possible, PSE accommodated suggestions and comments from stakeholders through updating its analysis and assumptions. In addition, PSE included several follow-on activities in its Action Plan as a result of stakeholder comments.

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 key highlights include:

1. Annual real GDP is anticipated to grow at 3.2 percent in the next 20 years.
2. Employment growth in PSE's service territories will likely grow at a slower rate (1.7 percent) than its 30-year historical growth rate, fueled mainly through growth in the service sector.
3. Electric rates (in nominal dollars) are anticipated to grow between 2.4 and 2.7 percent per year over the next twenty years, resulting in declining real electric rates.
4. Gas rates are anticipated to increase at about two percent per year, lower than the long-term rate of inflation.
5. Electric conservation savings are assumed to grow by 15 aMW per year for the next 10 years, in contrast to the rate case settlement, which assumed PSE to achieve 15 aMW

of savings for 2003 only. Gas conservation savings are assumed to be 2.1 million therms per year.

6. PSE's conservation assumptions beyond 2003 will be revisited after further collaborative studies are completed by the third quarter of 2003.
7. 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.
8. The long-term rate of decline in residential use per customer in the Least Cost Plan forecast is higher than in PSE's recent rate case forecast due to different assumptions regarding electric price projections and conservation savings.
9. PSE anticipates a projected growth rate of electric customers at an average annual rate of growth of 1.8 percent per year between 2002-2022, to 1.35 million customers in 2022.
10. Electric peak load forecasts are expected to grow by 1.6 percent in the next 20 years with conservation, and 1.7 percent in the next 20 years without conservation.
11. 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 1,086,575 Mtherms in 2004 to 1,562,567 Mtherms by 2022.
12. PSE anticipates a projected growth rate of natural gas customers at 2.7 percent per year in the next 20 years.
13. 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.

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 include:

1. 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 and investment challenge for both the gas and electric distribution systems.
2. Performance standards regarding safety and reliability form a basis for distribution system planning.
3. 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.

4. 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.
5. Planning alternatives for distribution facilities planning may take one of two paths – building new facilities or making operational adjustments to existing facilities.
6. To improve the overall efficiency of its distribution planning operations, PSE has initiated the use of value-based budgeting.
7. PSE has made additional 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.
8. 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.

Existing Electric Resources

PSE utilizes a 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:

1. PSE currently has approximately 20 conservation programs in place, with nearly 10 more pilot/new programs underway (see Exhibit VIII-3 for program details).
2. PSE has provided conservation services for its electricity customers since 1979, saving 218 aMW (net, cumulative load reduction) through 2001. The Company has invested approximately $310 million in electricity conservation since 1989 and has realized estimated energy savings representing over 11% of PSE's average existing annual electric loads.
3. From September 2002 – December 2003, PSE's conservation programs and services are expected to achieve 15.1 aMW of energy savings.
4. PSE's schedule 150 net metering customers provide a resource of approximately 37 kW.
5. 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.

6. 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 shortfall between PSE's load forecast and projected resources.

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 contractual 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 key highlights include:

1. 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.
2. 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.
3. By 2010, PSE will lose 314 aMW of energy and 755 MW of capacity through the expiration of power supply contracts.
4. PSE's loss of hydro resources by 2012 will decrease its supply sources by 102 aMW.
5. The loss of PSE's leased Whitehorn combustion turbine in 2009 will decrease its load resources by 134 MW.
6. The scheduled expiration of PSE's NUG contracts in 2011-2012 will deplete PSE's resources by 498 aMW.
7. PSE simulated the dispatch of its existing resources to serve the forecast load over the 20-year period to quantify its load resource outlook.
8. 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.
9. 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.
10. For planning purposes, PSE reflects the full baseload capacity of its combined cycle resources.

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 key highlights include:

1. As part of the current effort to develop new conservation resource supply curves, PSE is reviewing new and emerging measures anticipated to become cost-effective over the next 5 to 10 years.
2. Supply resource alternatives include renewable resources such as wind, biomass, solar and geothermal energy, while thermal resources options focus on gas-fired and coal sources.
3. Fuel conversion, the switching of existing electric end-users to gas, represents a potential cost-effective efficiency resource opportunity.
4. 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.
5. Distributed generation consists of several technologies – fuel cells, micro turbines, mini-turbines and reciprocating engines – that provide near-term opportunities for electric resource needs.
6. PSE considers demand-response programs such as time-of-use programs or critical peak pricing products as options for meeting some electric resource needs. Currently, PSE is participating in a collaborative effort to examine time-of-use scenarios and conduct program analysis.
7. 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.
8. The failure to timely expand the region's transmission infrastructure may well increase both costs and volatility to customers.

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 include:

1. In absence of a regional or state regulatory requirement on sufficiency standards for resource planning (i.e., reserve margins), 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.
2. At these planning levels, incremental energy needs in 2004 ranged from 10 to 674 aMW, growing to 1,176 to 1,874 aMW by 2013.
3. For capacity, the needs in 2004 ranged from 307 to 1,558 MW, increasing to 2,156 to 3,562 MW in 2013.
4. 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.
5. 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.
6. PSE developed a dispatch model which provides MWh and variable costs for each resource considered by PSE in order to screen the various portfolios.
7. 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.
8. 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 the meantime, a simplistic analysis of an additional 5 aMW to the current 15 aMW of annual conservation through 2013 yields a gross savings benefit, however, this analysis did not include a cost component. PSE's August 2003 Least Cost Plan update will also include dynamic modeling of both the benefits and costs of incremental conservation.
9. In addition to performing probabilistic risk analysis, PSE modeled three 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.

Electric Resource Analysis Results and Judgment

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

1. PSE modeled expected costs to customers for the eight combinations of energy and capacity levels. Results of this analysis indicated that as the overall level of resource adequacy is increased, including both energy and capacity together, expected costs generally tend to increase as well.
2. Evaluation of increasing energy planning levels (holding the capacity planning level constant) indicates as the energy planning level is increased (i.e., more long-term resources are added), the 20-year Net Present Value (NPV) declines. Acquiring as many long-term baseload energy resources as possible, or an "overbuild" strategy, however, would create power surpluses the Company would have to sell into the wholesale power market.
3. Evaluation of increasing capacity planning levels (holding the energy planning level constant) indicates that expected costs to customers increase with the addition of more peaking resources to meet progressively 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. PSE intends to examine other potentially lower-cost sources of capacity. Further, the Company's obligations to meet reliability requirements and its obligations to serve winter peak needs of its customers also need to be considered.
4. Evaluation of tradeoffs between expected costs to customers and risk (represented as variability of costs) indicates that moving from a lower energy planning level (A1) to higher levels of B1, A2 and B2, the additional costs of the higher capacity levels more than offsets the reduction in cost from the higher energy planning levels. Additionally, these planning levels have a similar risk profile.
5. Thus, a balanced planning level that provides an adequate amount of energy resources to meet each month's expected customer energy needs proves to be attractive on the basis of cost and risk.
6. The use of Joint Ownership for new long-term resources helps balance the portfolio seasonally and thereby mitigate the need to make significant spot energy sales in summer periods. Moreover, by avoiding the reliance on making spot energy sales in the

summer periods, the Joint Ownership approach produces a significant reduction in risk of over 25 percent.[3]

7. PSE's examination of the impacts of Seasonal Forward Capacity Sales of new capacity resources from SCGTs justifies the forward sale of peak capacity resources during the May-October period on the basis of cost and risk.
8. The analysis of the impact of replacing Seasonal Exchanges with a roughly equal amount of long-term resources indicate a reduction in expected costs to customers (on a 20-year NPV) of over $100 Million, in addition to a slight reduction in risk.
9. Analysis of resource portfolios that defer new resource additions until 2008 shows both higher cost and higher risk levels under the deferral strategy for the A1, B1 and B2 planning levels. Moreover, the execution challenges to a deferral strategy, including an illiquid marketplace, the impact on PSE's credit and market purchase risk make this a costly and risky strategy for PSE to pursue.
10. 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:

1. 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.
2. 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 are greatest when the Company's portfolio is significantly out of balance.

[3] For a definition of Joint Ownership, please refer to Section B of Chapter XII.

3. 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.
4. 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. Because no available generating resource technology is clearly superior to all other alternatives, the Company’s preferred resource strategy identifies a mix of resource alternatives.

Electric Resource Strategy

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

1. Energy resources will be adequate to serve each month’s expected customer energy needs under average hydro conditions.
2. Capacity resources will be adequate to meet customer peak loads of 16 degrees Fahrenheit.
3. New energy and new capacity resources will be shaped to fill winter deficiencies, without creating summer surpluses, to the extent feasible.
4. For planning purposes, PSE assumes the acquisition of 150 aMW of new conservation resources over the next 10 years.
5. PSE will pursue a goal of serving five percent of its customers’ energy needs through renewable resources. Given the possible alternatives to using SCGTs to back up wind power and the possibility of including other renewable resources in its portfolio, PSE has

established a higher target of serving 10 percent of its customers' energy needs through renewable resources.

6. A diverse mix of other resources, including combined cycle gas-fired generation in the near-term and possibly coal later in the decade, in addition to seasonal exchanges and other market transactions provide options for meeting the rest of PSE's resource needs.
7. PSE will continue to monitor the market for acquisition opportunities and power contracts, but not at the expense of its corporate commitment to conservation.

Existing Gas Resources

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

1. 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 service expect to achieve 2.9 million therms of cost-effective energy savings, at a utility cost of $3.9 Million.
2. PSE holds a total of 960,330 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, 90,392 Dth/day on PG&E's Gas Transmission Northwest pipeline, and additional upstream capacity on other pipelines.
3. 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.
4. PSE's peaking resources include Liquefied Natural Gas (LNG), Peak Gas Supply Service (PGSS) and vaporized propane-air.
5. 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.
6. PSE has a mix of long-term (+ three years), medium-term (one to three years) and short-term (less than one year) contracts to meet average loads during different months.
7. PSE participates in the gas futures market, primarily through fixed-price physical transactions and fixed-price financial swap transactions. On a going forward basis, PSE

will continue to evaluate the hedging mechanisms available in the market to weight the benefits of each mechanism to determine its applicability in PSE's portfolio.

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:

1. 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.
2. 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.
3. 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.
4. 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.
5. 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.
6. 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.
7. Reserve additions in the basin's tributaries to PSE's firm transportation receipt points indicate growing exploration and production activity.
8. Pipeline and producers have demonstrated a willingness to develop the facilities to bring gas into the Northwest region as necessary.

Gas Resource Analysis and Strategy

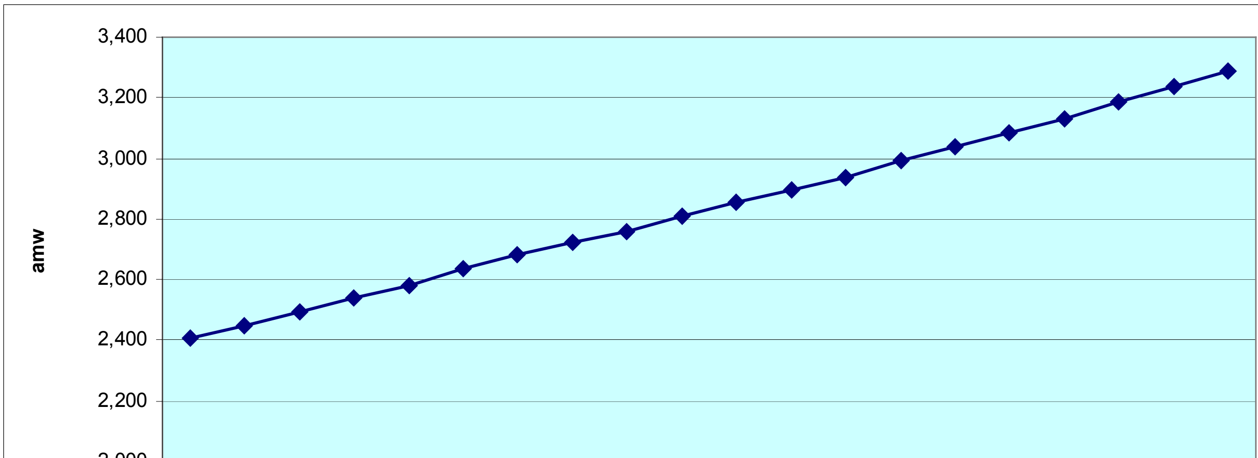
PSE analyzed its resource portfolio in light of expected changes and under a variety of assumptions. This evaluation demonstrated that PSE has developed and maintains a portfolio of gas resources that provides a reliable supply of natural gas to its customers at least cost. Other key highlights include:

1. 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.
2. 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.
3. 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.
4. 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.
5. 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.
6. 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.

Chapter II:
PSE Electric Least Cost Plan Summary

- This chapter provides a graphical overview of PSE's Electric Least Cost Plan analysis and electric resource strategy
- Key components of this chapter include
  1. Load Forecast
  2. Resource Expiration
  3. Load Growth & Resource Expiration
  4. Energy Need – Level B
  5. Load-Resource Balance: 2004
  6. Load-Resource Balance: 2013
  7. Peak Loads & Resources
  8. New Resource Characteristics
  9. Levelized Resource Cost Summary
  10. Ten-year Electric Resource Addition Strategy
  11. Ten-year Trend of Increased Supply Diversity

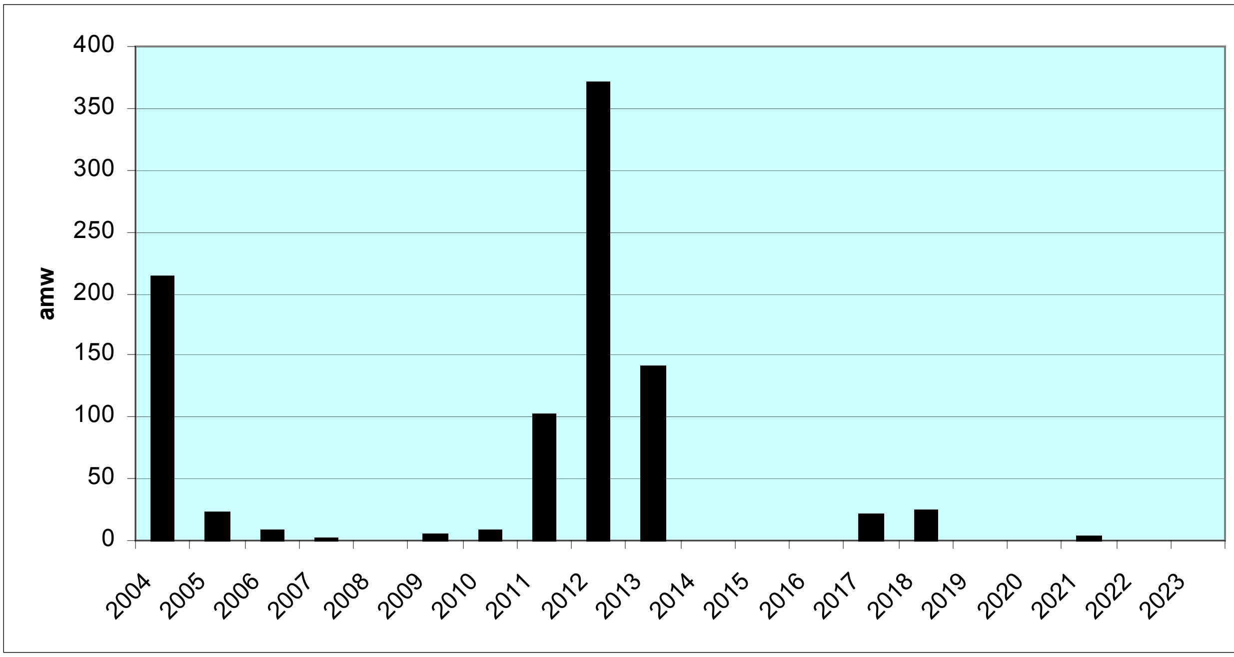
Exhibit II-1
Load Forecast



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Load	2,405	2,447	2,492	2,539	2,580	2,638	2,680	2,724	2,759	2,808	2,853	2,898	2,936	2,991	3,038	3,087	3,129	3,186	3,237	3,288

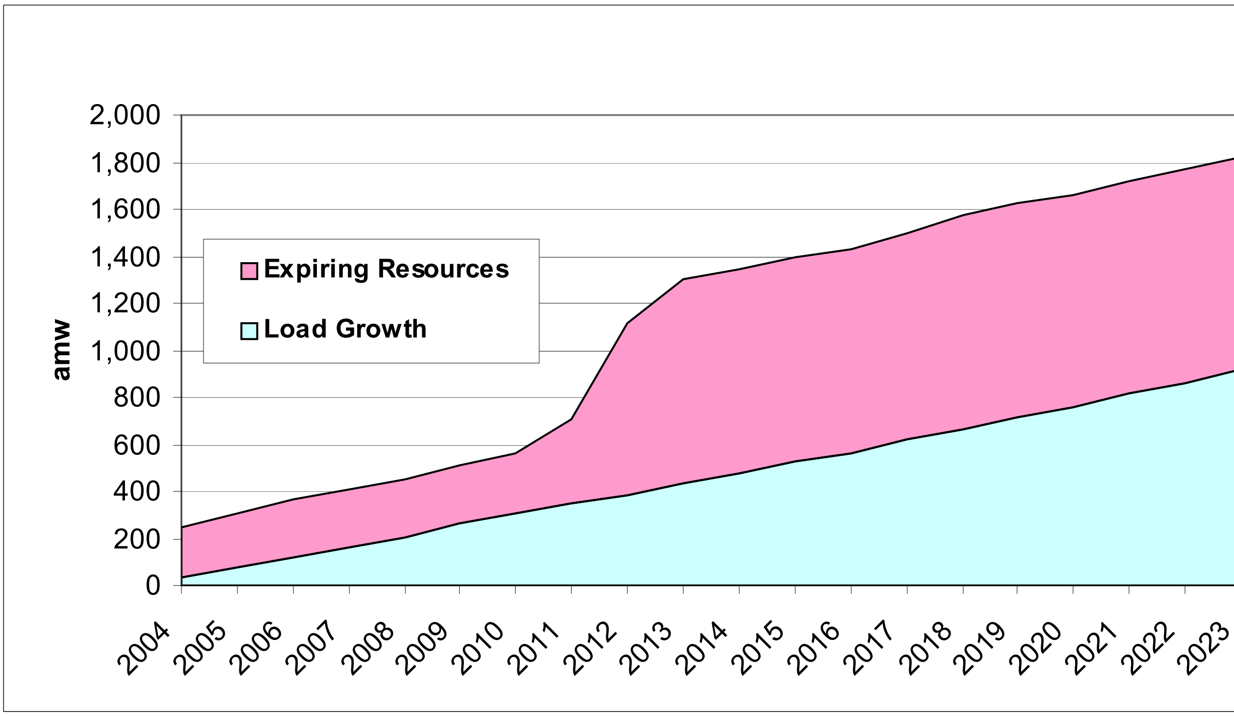
- From 2004 to 2013, PSE load grows at 1.2 percent, from 2,405 aMW to 2,808 aMW in 2013.
- From 2013 to 2023, PSE load grows at 1.4 percent, from 2,808 aMW in 2013 to 3,288 aMW in 2023.
- The load forecast in Exhibit II-1 is net of conservation implemented prior to 2003 and does not include new conservation.
- Chapter VI provides more detail on PSE's load forecast.

Exhibit II-2
Resource Expirations



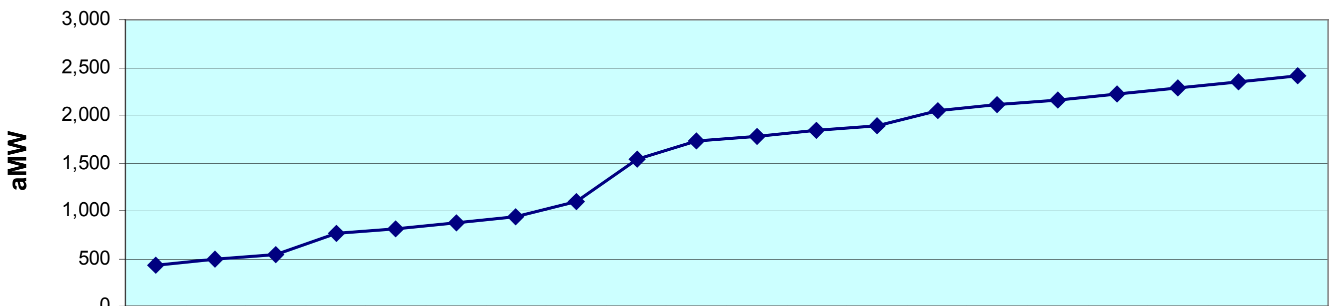
- The 214 aMW amount shown for 2004 includes the following resource expirations - the 75 aMW Avista contract (2002), the 19 aMW Columbia Storage Power Exchange contract (2003) and & the 120 aMW PacifiCorp contract (2003).
- Resources expiring from 2011-2013 include several NUG contracts (March Point I & II, Tenaska & Sumas) and the Colstrip contract with Northwestern Energy.
- Chapter IX provides more detail on resource expirations.

Exhibit II-3
Load Growth & Resource Expirations



- Exhibit II-3 combines PSE's anticipated load growth and its expiring resources.
- This exhibit illustrates that PSE's need for resources – including in the near-term – is driven more by resource expirations than load growth.
- The amounts shown in this exhibit are annual averages and do not indicate seasonal variations within each year.
- Chapter VI provides more detail on load growth and Chapter IX provides information on resource expiration.

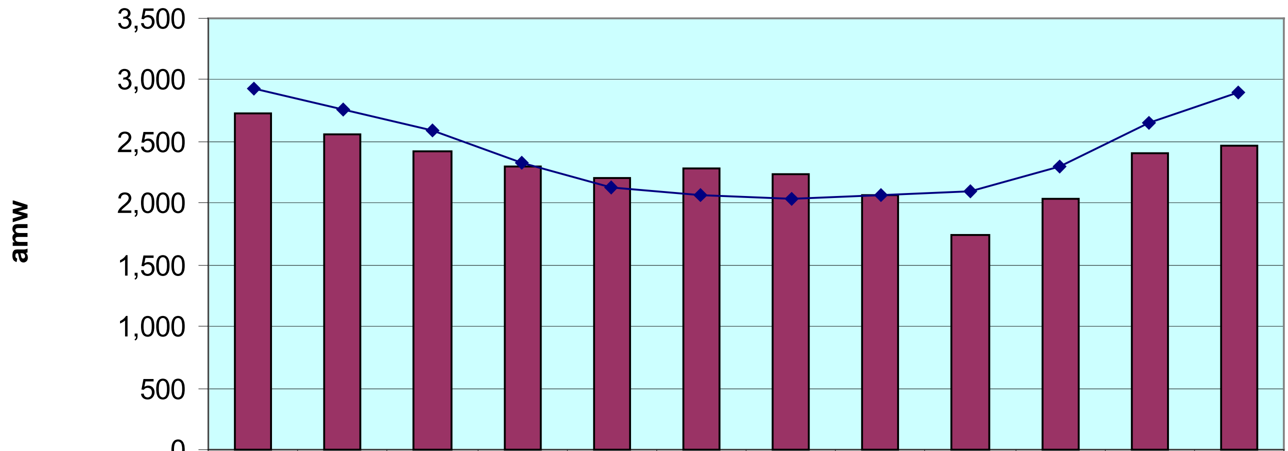
Exhibit II-4
Energy Need – Level B



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Level B Need	427	486	541	760	817	877	943	1,099	1,543	1,729	1,782	1,836	1,892	2,051	2,107	2,166	2,226	2,285	2,346	2,407

- Exhibit II-4 illustrates PSE's energy need (before new conservation) at a Level B planning standard over the 20-year planning period.
- The Level B standard requires adequate energy resources to meet the needs of every month in a year.
- A significant jump in the need for energy occurs in 2011 – the same year in which PSE's large NUG contracts are scheduled to begin expiring.
- Chapter XII provides more detail on PSE's need for energy.

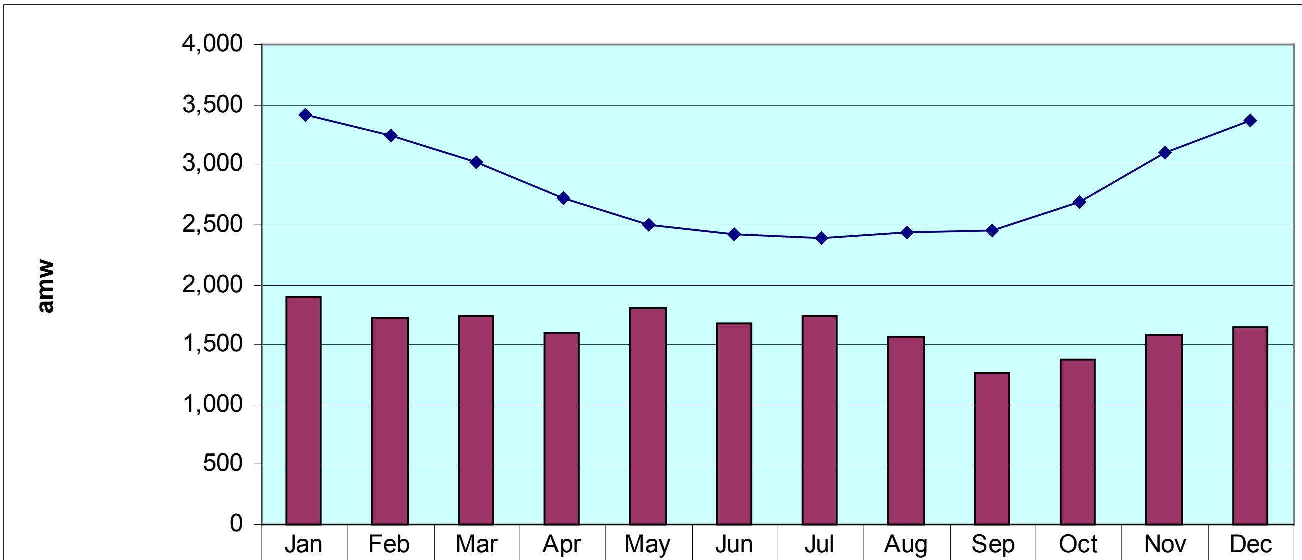
Exhibit II-5
Load-Resource Balance: 2004



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Resources	2,736	2,555	2,418	2,293	2,206	2,281	2,240	2,071	1,745	2,040	2,403	2,469
Load	2,933	2,766	2,590	2,325	2,132	2,068	2,039	2,072	2,099	2,294	2,653	2,896

- Whereas Exhibit II-3 provided the annual average load-resource balance during the planning period, Exhibit II-5 provides the monthly balance of loads and resources for 2004.
- Due to the seasonal shape of PSE's energy needs, PSE experiences the greatest shortfall in need during the winter months, specifically December.
- Chapter IX provides more information on PSE's load-resource balance for 2004.

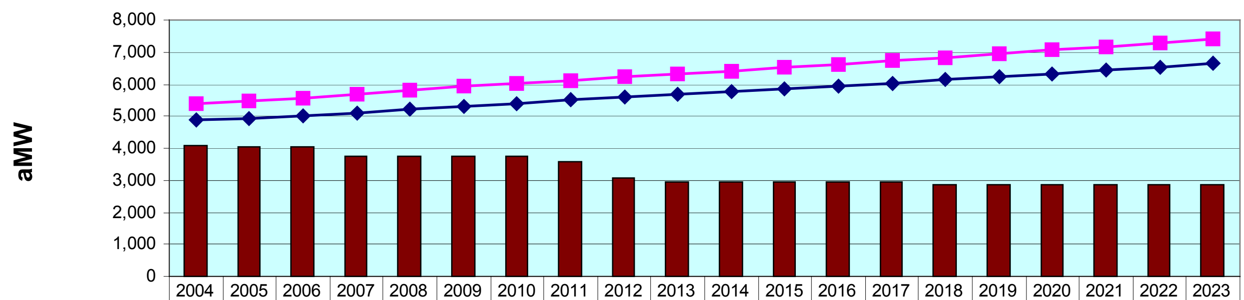
Exhibit II-6
Load-Resource Balance: 2013



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Resources	1,899	1,717	1,734	1,599	1,795	1,671	1,735	1,570	1,262	1,383	1,585	1,641
Load	3,414	3,235	3,024	2,712	2,500	2,422	2,380	2,433	2,455	2,683	3,095	3,369

- By 2013, the load-resource outlook increases and becomes year-round; not only does PSE have a significant deficit during the winter, now there is a significant deficit during the summer as well.
- In any given month, PSE has a gap between its resource balance and load needs.
- Chapter IX provides more information on PSE’s load-resource balance for 2013.

Exhibit II-7
Peak Loads and Resources



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Peaking Resources	4,083	4,038	4,027	3,733	3,733	3,733	3,731	3,597	3,061	2,929	2,929	2,929	2,929	2,929	2,847	2,847	2,847	2,847	2,847	2,847
Expected Peak-23F	4,874	4,942	5,024	5,116	5,216	5,325	5,409	5,501	5,590	5,675	5,764	5,853	5,945	6,039	6,134	6,232	6,333	6,433	6,535	6,639
Peak-16F	5,393	5,469	5,561	5,683	5,795	5,917	6,010	6,122	6,220	6,316	6,415	6,514	6,616	6,720	6,832	6,941	7,053	7,165	7,279	7,394

- In addition to energy needs, PSE has capacity needs to meet winter peak loads.
- Peak loads shown in Exhibit II-7 do not include reserves.
- The 23 degree minimum hour temperature expected peak has a 50 percent probability of occurring.
- This plan selects the peak at a 16 degree minimum hour temperature as the planning standard.
- Under both scenarios, PSE has a gap between its peak loads & resources.
- Chapter IX provides more information on PSE’s peak loads and resources.

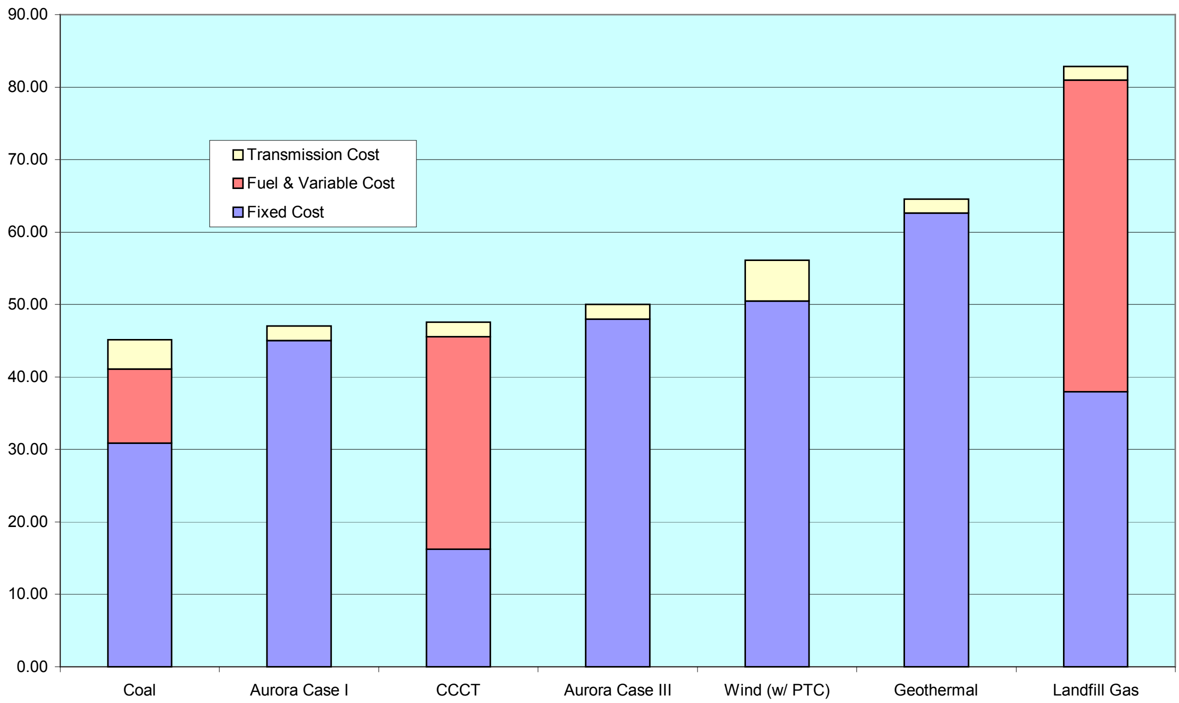
Exhibit II-8
New Resource Characteristics

Technology	Capacity (mw)	Heat Rate (btu/kwh)	All-In Cost ($/kw)	Fixed O&M ($/kw-yr)	Fixed Fuel ($/kw)	Variable O&M ($/mwh)
CCGT	516	6,900	645	11	15.55	2
SCGT	168	11,700	441	3	15.74	2
Coal	900	9,425	1,500	20	0	2
Wind	100	0	1,003	26.1	0	0
* Solar	20	0	6,000	15	0	0.8
* Landfill Gas	5	11,100	1240	114	0	1
* Geothermal	200		2922	86	0	7.9

** These resource technology types were not modeled.*

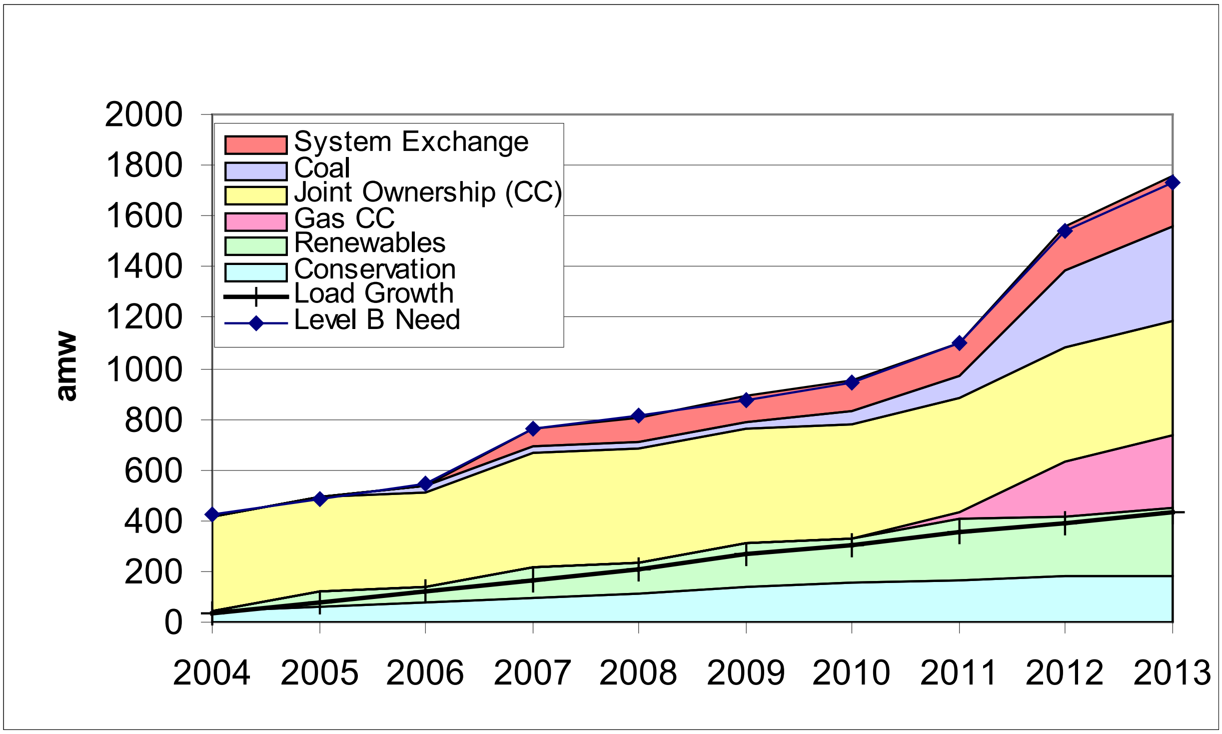
- The modeling analysis for both the AURORA market power price forecasts and PSE's portfolio analysis reflects the assumptions in Exhibit II-8.
- The combined cycle gas turbine (CCGT) plant represents a relatively efficient base load plant; while the simple cycle gas turbine (SCGT) plant represents a less efficient and less expensive turbine used to meet peak capacity need.
- Chapter X provides more information on new resource characteristics.

Exhibit II-9
Levelized Resource Cost Summary



- Key assumptions in this exhibit include a weighted after tax cost of capital is 7.61%, and a Wind Production Tax Credit (PTC) of $18/MWh for the first 10 years.
- The levelized cost of new resources range from $45-68/MWh, depending on the resource type.
- PSE believes opportunities may materialize to acquire renewable resources within its service territory which are economic and help attain its renewable resources goal.
- Appendix K provides more detail on the levelized resource cost summary.

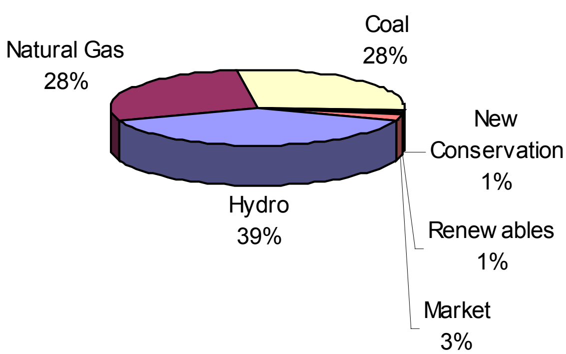
Exhibit II-10
Ten-year Electric Resource Addition Strategy



- This exhibit illustrates the long-run level-B planning need being met using a mix of conservation, renewable resources, fossil fuel-based resources and system exchanges.
- Load Growth can be met through conservation at 15 aMW/year and renewable resources which grow to 10 percent in 10 years.
- Chapter XIII provides more detail on PSE's 10-year electric resource addition strategy.

Exhibit II-11
Ten-Year Trend of Increased Supply Diversity

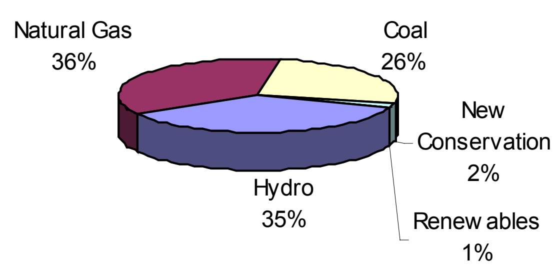
Estimated Annual Energy Resource Mix, 2003



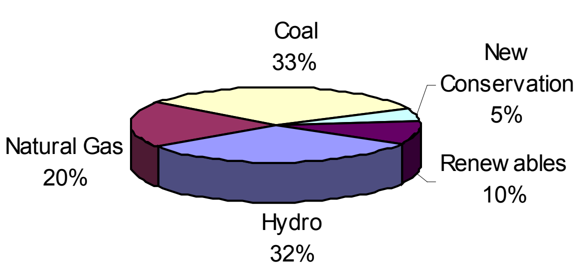
- PSE's current energy resource mix is comprised primarily of hydro, natural gas and coal.
- Market represents the annual energy shortfall.

- PSE's 2004 energy mix is slightly less dependent on hydro and slightly more on natural gas.
- New conservation shows the cumulative total over two years.

Estimated Annual Energy Resource Mix, 2004



Estimated Annual Energy Resource Mix, 2013



- By 2013, expiration of some existing resources and new resource additions significantly change PSE's annual energy mix.
- Renewable resources are estimated to become 10 percent of the mix, conservation 5 percent, with hydro and natural gas becoming smaller proportions than 2004.

- Chapter XIII provides more information on PSE's electric resource strategy.

III. PLANNING ISSUES

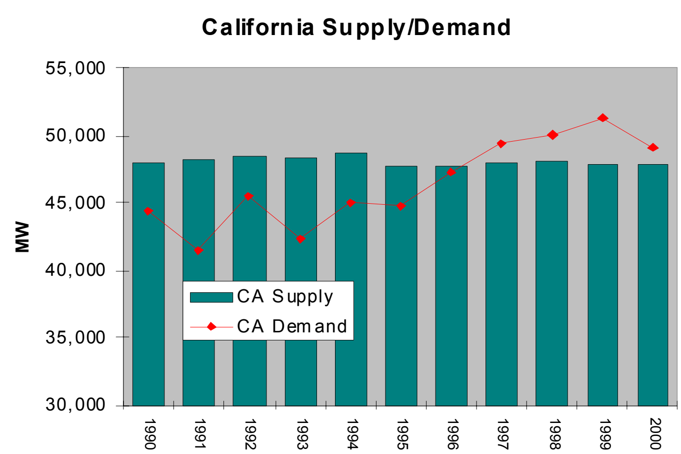
This chapter provides insight into major industry and Company issues which may impact PSE's resource choices. As mentioned in the preface, PSE continually pursues a Least Cost Plan process, with the current Least Cost Plan filing offering a snapshot of this process. To fully understand the factors compelling 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 III-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 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 III-2 and III-3 illustrate, market prices for electricity and gas began to

Exhibit III-1



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 III-2

CA PX Prices

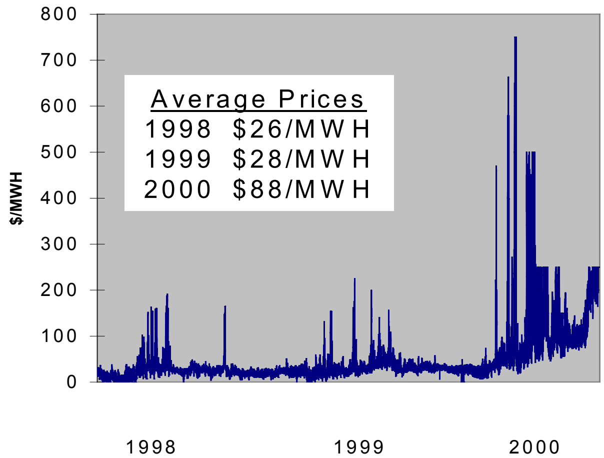
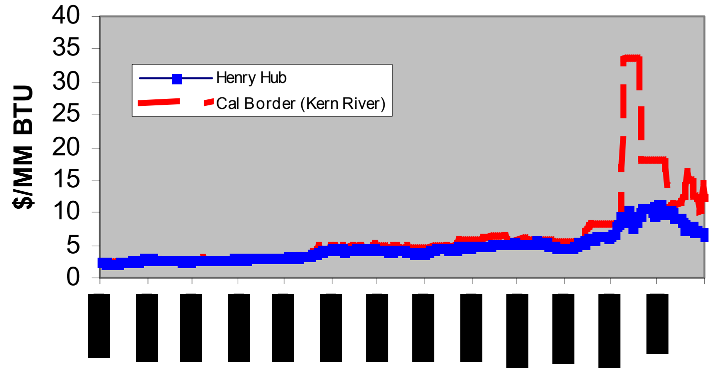


Exhibit III-3

California Gas Prices (2000-2001)

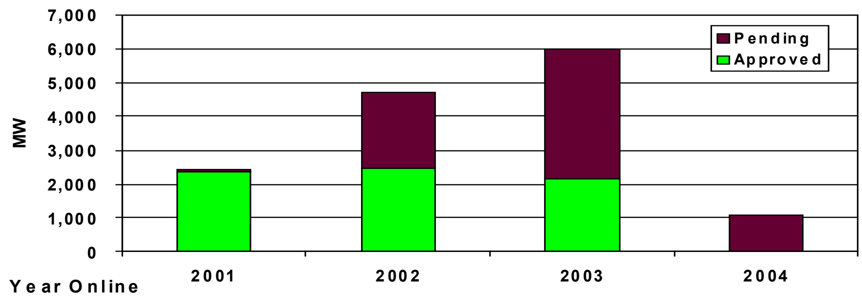


The energy crisis had significant financial impacts on California's largest utilities. The California utilities, unable to pass through to customers skyrocketing costs of spot market purchases, quickly became cash strapped and illiquid in the face of rising prices on the Power Exchange (PX), from which 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 III-4). The State of California 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 restructure the state 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 III-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 IV, 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

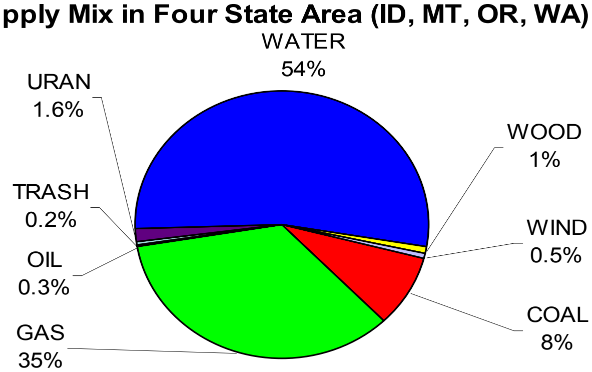
Current Supply Mix

As of 2001, the four-state region of Idaho, Montana, Oregon and Washington had nearly 68,000 MW of installed capacity (See Exhibit III-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 III-5

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

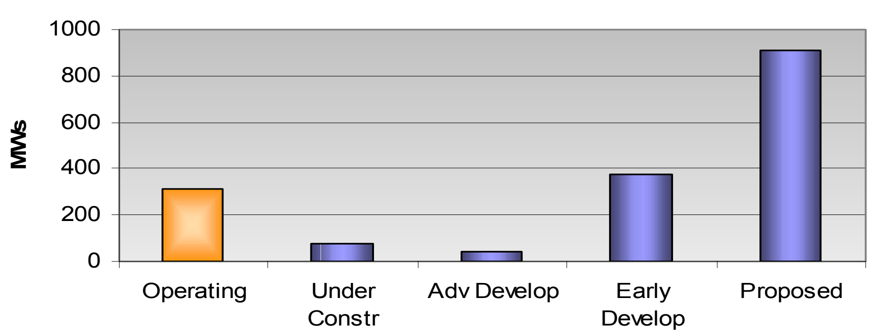


	Installed Capacity (MW)
WATER	36,235
GAS	23,516
COAL	5,772
URAN	1,107
WOOD	650
WIND	324
OIL	182
TRASH	140
Total	67,926

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 yet to improve transmission service to plants located east of the Cascades, creating additional challenges to further coal development.

Exhibit III-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 renewable resources such as wind power. As Exhibit III-6 illustrates, more than 1,400 MW of wind power capacity, comprising 16 independent wind power 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 power resource is approximately one-third of its installed capacity, thus it is necessary to divide the total installed wind power 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 aMW 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 spark spreads, will not lead to significant new capacity additions in the region.

C. Merchant Generation Retrenchment

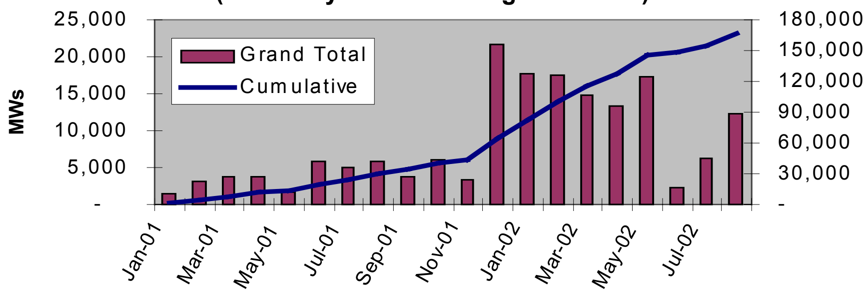
National Picture

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 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 III-7). Lenders and equity

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

investors have pulled back their support for new development projects as they reconsider the business and financial models guiding merchant power markets.

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



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.

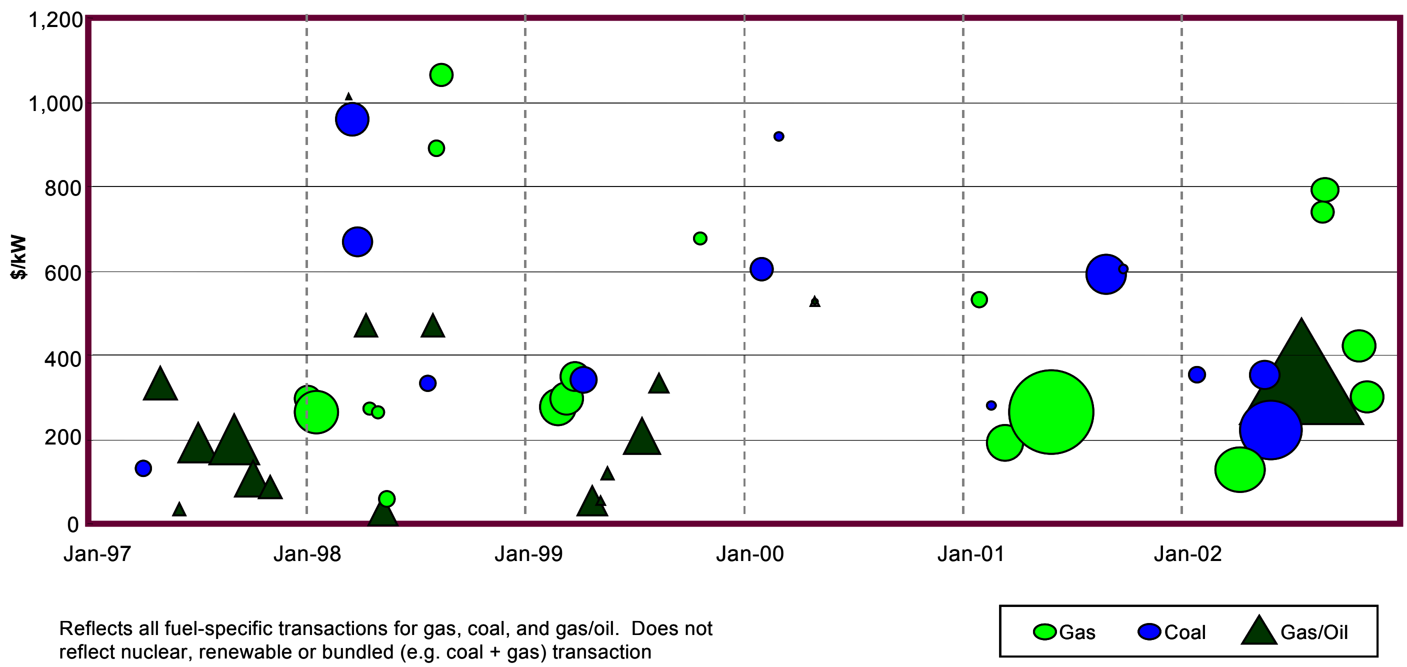
The inability to access capital runs counter to the business model of many merchant generators, who assumed a continued access to capital. Merchant generators have increasingly been forced to retrench from development plans, and instead to focus on strengthening their balance sheets, refinancing outstanding 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 III-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 III-8

Generation Asset Transaction History 1997-2002



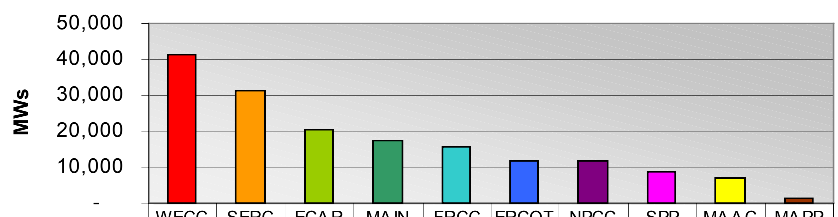
Reflects all fuel-specific transactions for gas, coal, and gas/oil. Does not reflect nuclear, renewable or bundled (e.g. coal + gas) transaction

Implications for PSE – the Buy vs. Build Decision

As discussed earlier in this chapter, the merchant generation retrenchment trend has been a significant factor in the Northwest region. As Exhibit III-9 illustrates, over 40,000 MW of proposed new generation capacity has been tabled or

Exhibit III-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

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 existing plant is part of the resource planning process. From a buy perspective, restructuring trends in the merchant industry may 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 perhaps 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 limited promise as many possible partners for PSE have left the energy marketing business or have unacceptable credit ratings and PSE itself has little unused capacity to support mark-to-market collateral calls.

For more information on regional 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. And, Duke Energy Trading and Marketing has announced its exit from speculative trading.

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. When coupled with the 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

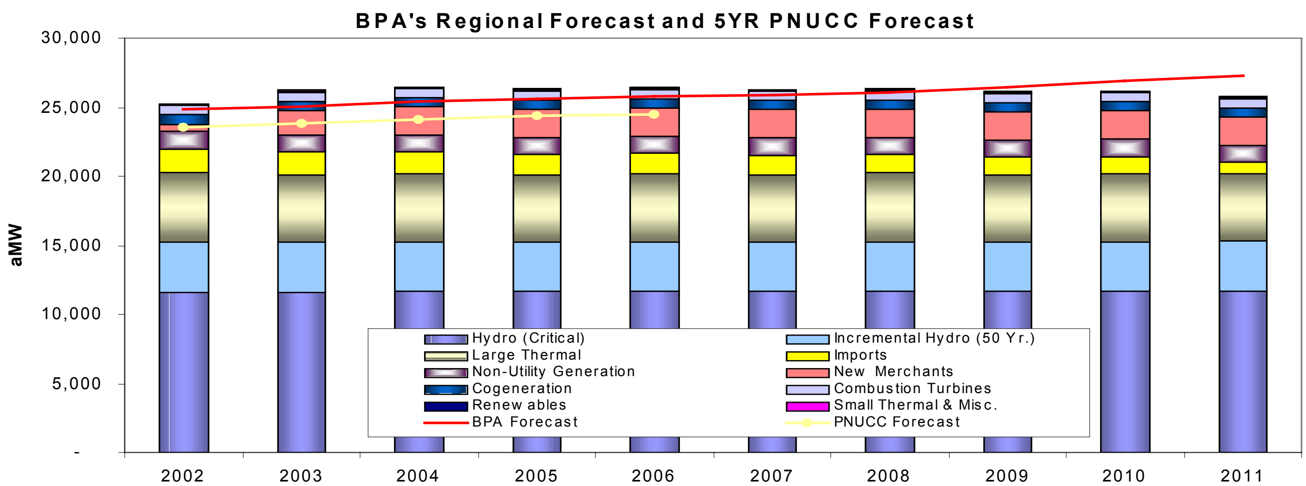
The decline in wholesale energy commodity trading market activity impacts PSE's resource planning options. The decline in counterparty credit has decreased the number of entities PSE can transact with, and in combination with constraints imposed by PSE's own weak credit standing, significantly limited 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 for its needs. However, as Exhibit III-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 III-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 III-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 III-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 • Pacific Northwest transmission constraints 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)

STATE	ISSUES/CONDITIONS
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 XII, 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 remains 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 resource 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 Production Tax Credit (PTC). The PTC, 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 power 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 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. For more information on *Clear Skies,* refer to Appendix L.

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 power resource proposals from Northwest wind power 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 Western Energy Crisis, the Washington State Legislature initiated a review of the State Energy Strategy, which was last published in 1993. The Department of Community, Trade and Economic Development 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. Themes focusing on system enhancements/reliability and environmental protection are 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, renewable resources, 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 renewable resources 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 renewable resources, 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 creates 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. H.B. 2119 establishes the framework for emissions inventories and verification of amounts and reductions of emissions. If the program becomes 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. HB 1050 also allows for the periodic formation of the task force to review the state energy strategy.

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 having control over one's business through sound resource planning and supply decisions, and the critical importance of well-designed and liquid markets. Other key highlights include:

1. Supply adequacy and cost volatility issues remain a regional concern, and PSE's obligation is to balance cost and risk for its ratepayers.
2. Resource adequacy in the Pacific Northwest region continues to mean having enough firm resources that can be counted upon to meet customer needs.
3. 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.

4. Regional interdependencies will continue to affect resource availability and price volatility.
5. Heavy reliance on hydro resources poses unique challenges for planning supply and will continue to present risks to future merchant power development in the region.
6. Merchant power retrenchment may create a window of opportunity for PSE to acquire assets to meet some of its resource needs.
7. The current financial condition of counterparties in the wholesale energy market and PSE's own creditworthiness, limit PSE's ability to manage its existing portfolio and enter into long-term forward power contracts.
8. The future of the wholesale market structure remains uncertain in the West even as FERC continues to move forward with its Standard Market Design.
9. The operations and capital investment decisions of Bonneville Power Administration will continue to heavily impact the region and the Company. Greater investment in the region's electric transmission system will be essential to reduce market volatility and allow new resources to reach the market.
10. 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.
11. State lawmakers have introduced legislation to stimulate greater investment in renewable resources, 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.

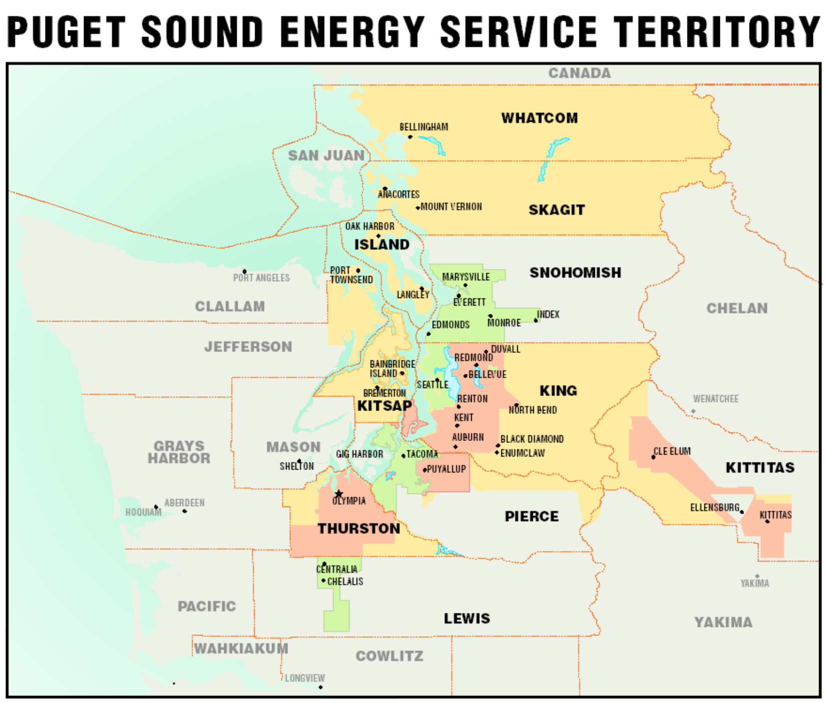
IV. PSE'S CURRENT SITUATION

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 addresses 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 IV-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, and 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

Exhibit IV-1



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.

rates of 1.8 percent and 2.6 percent in its electric and gas customer bases, respectively.

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 IV-2 and IV-3 provide a breakdown of numbers of customers receiving electric or gas service from PSE, and Exhibits IV-4 and IV-5 detail PSE's retail revenue attributed to different customer groups. Exhibits IV-6 and IV-7 illustrate PSE's electric and gas load by customer type.

Exhibit IV-2
PSE Electric Customers by Customer Type

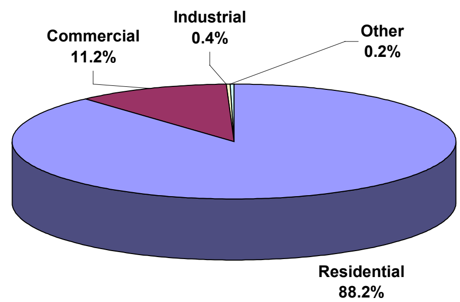


Exhibit IV-3
PSE's Gas Customers by Customer Type

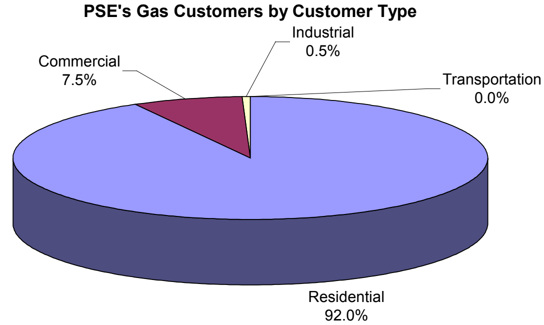


Exhibit IV-4
PSE Electric Retail Revenue by Customer Type

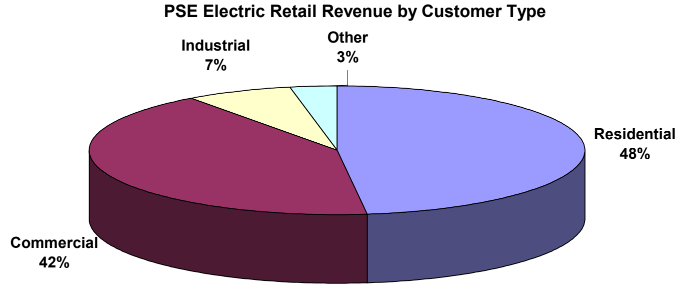


Exhibit IV-5
PSE Gas Retail Revenue by Customer Type

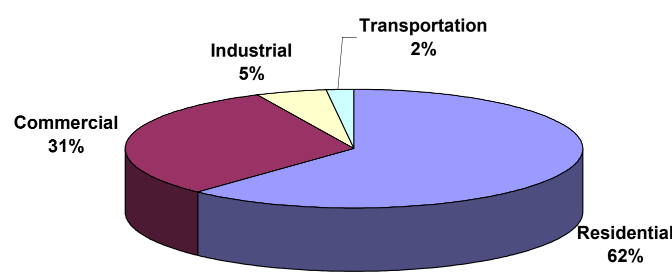


Exhibit IV-6
PSE 2002 Electric Load by Customer Type

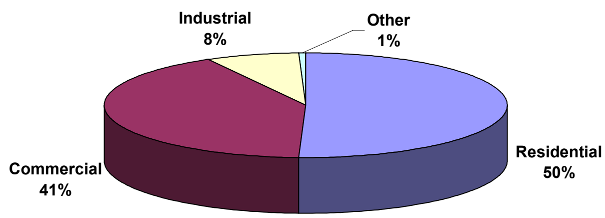
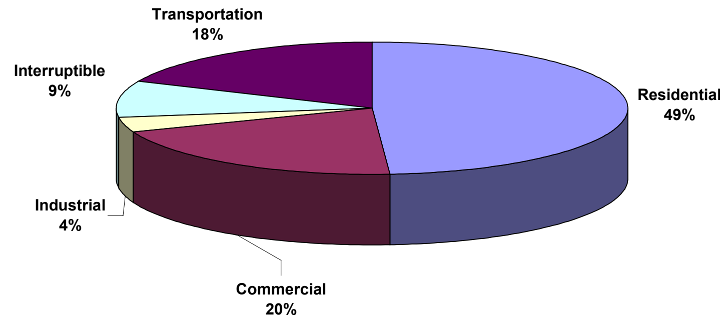


Exhibit IV-7
PSE 2002 Gas Load by Customer Type



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 on 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 the 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 enable 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 IV-8
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 it 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.

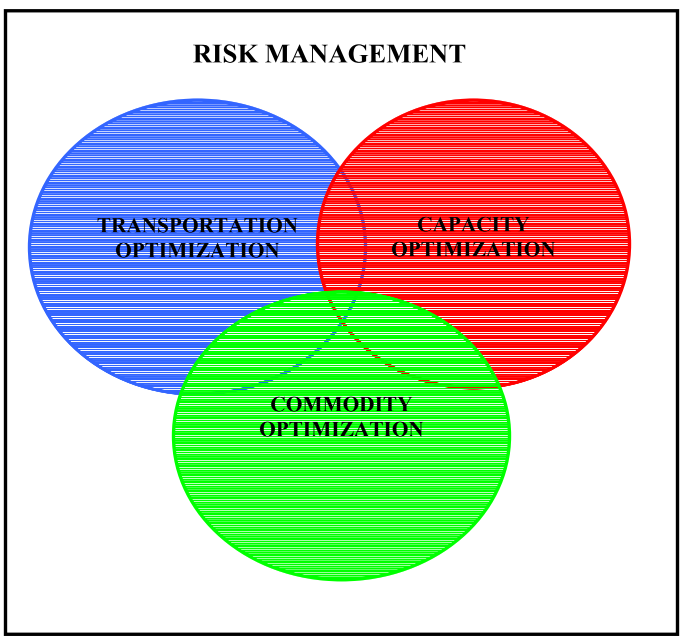
Periodically, usually every 6-12 months, PSE requests authorization from the WUTC to begin refunding over-collected gas costs or recovery of under-collected gas costs through a separate PGA Tracker unit rate. After audit of the deferred gas cost amounts by the WUTC, the PGA Tracker unit rates are approved to allow “amortization” of the over- or under-recovered amounts, generally over a period of less than 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-9

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.

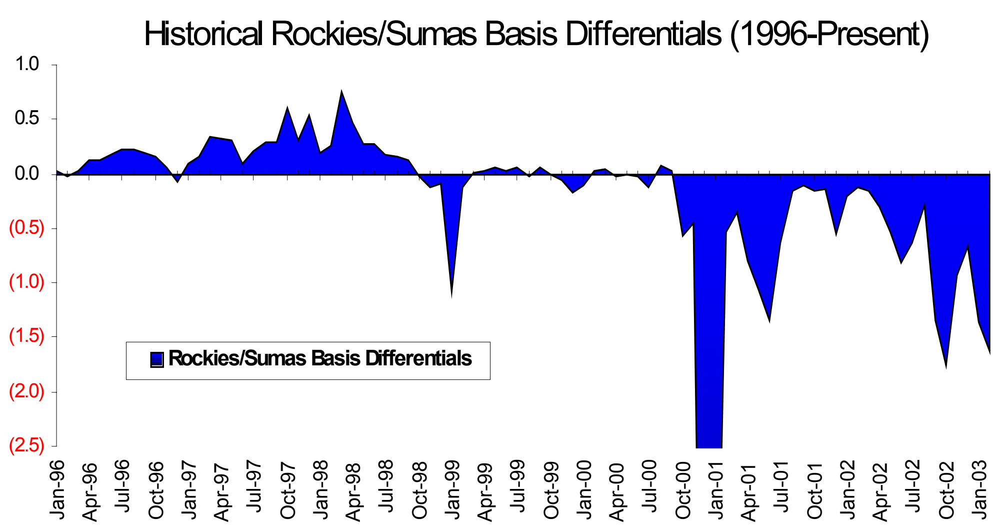
Capacity Release. PSE also captures the value of geographic price differences by releasing temporarily unused transportation capacity to other pipeline shippers. PSE estimates its available capacity for release on a daily, monthly, and annual basis, with the open market determining the value of the capacity. 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 IV-10 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 IV-10



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 section 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, thus 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 impact 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 clause 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 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 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. Increased investment in the gas transmission infrastructure serving the I-5 corridor and in the gas supply basins in Canada and the Rocky Mountains region will be important to constraining gas prices and price volatility. Throughout the procurement decision process, PSE takes into account fundamental supply and demand information, including these factors to guide the Company 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 risk, while allowing both stakeholders and customers to benefit from its prudent business strategy. Other key conclusions include:

1. PSE's financial policy focuses on one main goal – improving its credit rating so that it has the debt incurrence and credit capacity to economically support its portfolio management and investment requirements.
2. 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. Such PCA limits PSE's financial exposure to power supply costs to an aggregate of $40 Million over a four-year period, and provides for prompt recovery through the return of excess power costs in highly volatile power markets.
3. 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.
4. PSE's ability to execute risk management strategies is constrained by the magnitude of its short and long resource positions, the number and creditworthiness of counterparties, and by its own credit rating and limited access to credit.
5. 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.
6. 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 market-driven gas supply costs and "upstream-of-the-city gate" gas transmission and storage resource costs.
7. 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 reduce energy costs to its customers.

8. Increased investment in the gas transmission infrastructure serving the I-5 corridor and in the gas supply basins in Canada and the Rocky Mountains region will be important to constraining gas prices and price volatility.

V. STAKEHOLDER INTERACTION

Chapter V 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 April 30, 2003, 10 formal Least Cost Plan meetings, in addition to dozens of informal meetings and communications have taken place. A number of stakeholders including WUTC Staff; the Public Counsel; consumer advocates; individual customers from industrial, commercial, and residential classes; conservation and renewable resource advocates; the Northwest Power Planning Council; project developers; capital market participants; and the Washington State Department of Community, Trade and Economic Development have actively participated in meetings. The stakeholder meetings provided an avenue for constructive feedback and useful information to guide the Least Cost Plan process. Stakeholder suggestions and practical information were invaluable in developing this Least Cost Plan. 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 April 30, 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

PSE enlisted several outside experts to present information regarding renewable resource opportunities and development issues. Specific presentations and discussions focused on wind power, 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. In addition, 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 the decision-making process which will guide its analysis 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.

Least Cost Plan Technical Meeting: April 4, 2003

PSE held a Least Cost Plan technical meeting to address questions related to PSE's analytical process and assumptions. A wide range of topics were discussed, including model impacts and assumptions, the modeling process, emissions considerations, modeled portfolios and PSE's preferred planning levels. In terms of model inputs and assumptions, PSE discussed its gas price forecast, new resource technology efficiency improvements, residential load growth and conservation impacts, discount rates and cost of capital, and wind power assumptions. PSE provided a schematic of the modeling elements. Emissions considerations related to SO_2 and CO_2 were discussed, and PSE agreed to show explicit results by portfolio for its April 30 Least Cost Plan. The meeting ended with a discussion of PSE's use of a B2 planning level.

Least Cost Plan Advisory Meeting: April 8, 2003

PSE held a Least Cost Plan Advisory Group Meeting to receive initial feedback on its March 31 Draft Least Cost Plan. The meeting participants set the discussion agenda, raising a host of issues including the linkage between PSE's analysis and strategy, carbon and mercury issues, wind power pricing and assumptions, hydro re-licensing, PSE's renewable resources policy statement, the Least Cost Plan action plan for the August 2003 update, peak load management, expiration of existing resources and PSE's load portfolio. In addition to providing oral comments during this Advisory Group Meeting, participants indicated they would be submitting written comments on PSE's Least Cost Plan during April.

Least Cost Plan Technical Meeting: April 22, 2003

PSE held a technical meeting on the Least Cost Plan to highlight some changes in the analysis for the April 30 Least Cost Plan filing. The meeting focused on three main topics: an update of PSE's deferral analysis; an overview of the execution/implementation challenges associated with a deferral strategy; and a preview of the CO_2 analysis results.

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 V-1 references the WUTC expectations to chapters within the Least Cost Plan where a discussion of the topic can be found.

Exhibit V-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 IV, 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 III, Planning Issues • Appendix B, Portfolio Management Perspectives
p. 3: PSE should integrate DSM into the planning for other types of supply.	• Chapter X, New Electric Resource Opportunities • Chapter XVII, Two-Year Action Plan

AUGUST 28, 2001, LETTER	CHAPTER
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 X, New Electric Resource Opportunities • Chapter XVII, Two-Year 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 XI, Electric Portfolio Analysis • Chapter XVII, Two-Year 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 XI, Electric Portfolio Analysis • Chapter XVII, Two-Year 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 relatively small sample of weather observations.	• Chapter VI, Load Forecasting • Chapter XI, Electric Portfolio Analysis
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 XI, Electric Portfolio Analysis • Chapter XII, Analytical Results and Application of Judgment • Chapter XVI, 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 XI, 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 X, New Electric Resource Opportunities • Chapter XVII, Two-Year 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:

- 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 questioned 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, utilizing its CT's and Encogen purchase more, or making more market purchases. 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 XI details PSE's analytical process, while Appendix K details PSE's updated assumptions driving its analysis. Chapter XII 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 E 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 XI 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 power, 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 XVII, 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 XI describes, in lieu of the existence of a prescribed regulatory standard, PSE evaluated eight different planning levels and assessed the trade-off between costs and risks to customers. As detailed in Chapter XII, 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:

1. As of April 30, 2003, 10 formal Least Cost Plan meetings, in addition to dozens of informal meetings and communications have taken place. A number of stakeholders including WUTC Staff; the Public Counsel; consumer advocates; individual customers

from industrial, commercial, and residential classes; conservation and renewable resource advocates; the Northwest Power Planning Council; project developers; capital market participants; and the Washington State Department of Community, Trade and Economic Development have actively participated in meetings.

2. During these meetings, a variety of topics were addressed, including electric sales forecasts and assumptions, PSE resource needs, transmission constraints, conservation, renewable resources, gas and electric distribution planning, natural gas supply and hedging risk, a deferral strategy, emissions considerations, and the AURORA modeling process, among others.
3. 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.
4. 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.
5. PSE has incorporated stakeholder issues of concern into the Least Cost Plan process. The Company has reviewed and revised its assumptions, expanded the depth and robustness of its analysis, examined a wide range of electric resource opportunities, and continued to seek public input.
6. Whenever possible, PSE accommodated suggestions and comments from stakeholders through updating its analysis and assumptions. In addition, PSE included several follow-on activities in its Action Plan as a result of stakeholder comments.

VI. LOAD FORECASTING

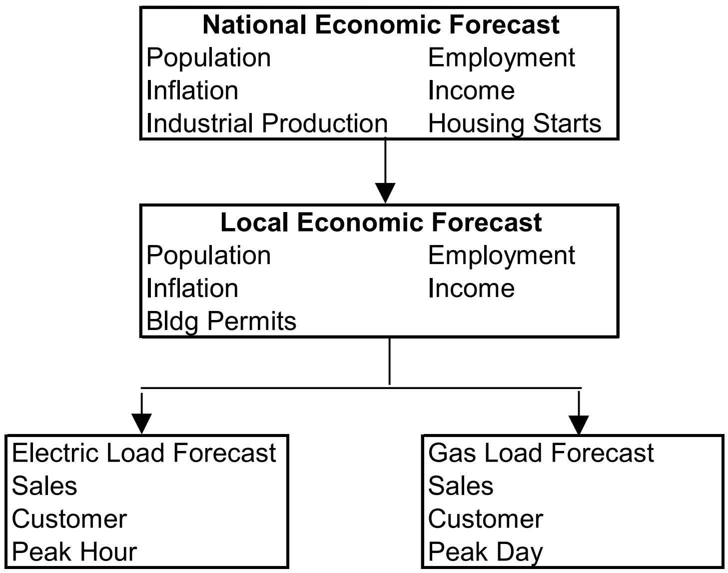
Each year, PSE develops a 20-year forecast of customers, energy sales and peak demand for its electric and gas service territories. PSE utilizes the forecast for short-term planning activities such as the annual revenue forecast, marketing and operations plans, as well as in various long-term planning 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 VI-1 provides an illustration of the forecasting model.

Exhibit VI-1
PSE Forecasting Model Overview

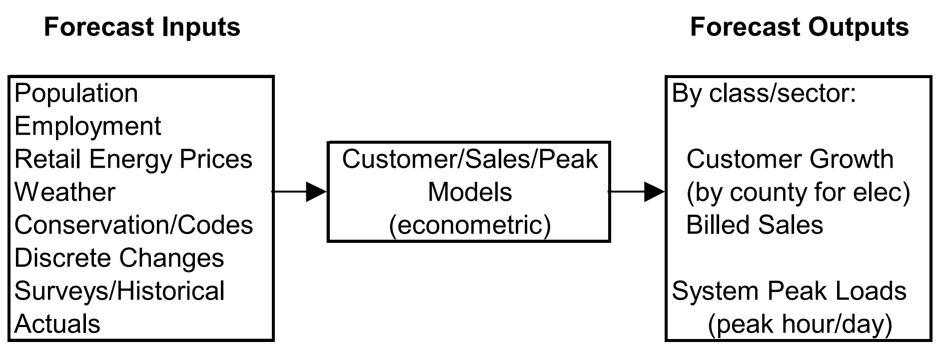


PSE used a mixed end-use and econometric model to develop its long-term billed sales forecasts in its previous Least Cost Plan. Specifically, electric sales forecasts from the residential and commercial sectors were developed by using end-use models (RHEDMS and CEDMS, respectively), while those in the 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 VI-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 VI-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 VI-3 summarizes the national economic forecasts used an inputs to the model.

Exhibit VI-3
National U.S. Economic Outlook

	2004	2005	2010	2015	2020	aarg
GDP (96$B)	$10,280.1	$10,569.3	$12,300.0	$144,450.8	$16,895.1	3.2%
Employment (mill)	136.5	138.4	146.4	154.8	161.9	1.1%
Population (mill)	283.6	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 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 (1.7 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 VI-4 summarizes the employment and population data used as inputs.

Exhibit VI-4
Electric Service Area Economic Growth Assumptions

	2004	**2005**	**2010**	**2015**	**2020**	**aarg**
Electric Service Area						
Employment (thousands)	1,757.9	1,795.6	1,972.9	2,124.2	2,277.2	1.7%
Population (thousands)	3,402.2	3,438.7	3,659.1	3,859.5	4,078.9	1.1%
Gas Service Area						
Employment (thousands)	1,748.5	1,788.9	1,969.9	2,120.5	2,276.1	1.7%
Population (thousands)	3,383.5	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 VI-5 provides forecasts of retail rates for electric and gas for the three major customer classes.

Exhibit VI-5
Retail Rate Forecasts

(nominal)	2004	2005	2010	2015	2020	aarg
Residential						
Electric, cents/kwh	6.18	6.18	7.36	8.36	9.72	2.7%
Natural gas, cents/therm	71	71	74	83	93	1.8%
Commercial						
Electric, cents/kwh	6.65	6.65	7.38	8.38	9.75	2.4%
Natural gas, cents/therm	64	65	65	73	82	1.8%
Industrial						
Electric, cents/kwh	6.14	6.14	6.82	7.74	9.01	2.4%
Natural gas, cents/therm	60	61	63	70	79	2.0%

The forecast of electric rates 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 VI-5 illustrated that electric rates growing between 2.4 percent and 2.7 percent in the next twenty years, meaning that real electric rates will decline given an inflation rate of about 3 percent.

From 2004 to 2020, gas rates are expected to increase from 1.8 to 2.0 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.[1] 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.

Exhibit VI-6 illustrates the relative effects of a MW of conservation savings from each of the customer classes by month. For example, one MW of conservation savings in January for a residential customer would reduce on-peak demand by 1.45 aMW, whereas one MW of conservation savings in January for a commercial customer would reduce peak by 1.16 aMW.

Exhibit VI-6
Assumed On-Peak Contributions per aMW of Conservation by End-Use Sector

Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	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

[1] This forecast is based upon 2002-2003 tariffed programs. The breakout of kwh savings to be achieved include 18% residential, 62% commercial and 21% industrial, for an overall savings of 132,686 MWh.

Other Key Assumptions

- ***Data Center Loads*** – Given the current economic background for high technology 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 this 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 2,224 aMW in 2004 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 VI-7
2002 Electric Sales by Class in aMW

Base with Conservation	
Total	2,186
Residential	1,104
Commercial	910
Industrial	162
Others	10

Exhibit VI-8
Electric Sales Forecasts by Class in aMW

	2004	2005	2010	2015	2020	2022	aarg
Base with Conservation							
Total	2,224	2,243	2,390	2,574	2,798	2,891	1.4%
Residential	1,126	1,135	1,230	1,334	1,445	1,493	1.5%
Commercial	921	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	3.7%
Base without Conservation							
Total	2,257	2,291	2,508	2,713	2,936	3,030	1.6%
Residential	1,132	1,144	1,251	1,354	1,466	1,514	1.6%
Commercial	941	959	1,061	1,158	1,265	1,309	1.9%
Industrial	172	176	181	182	184	184	0.5%
Others	11	13	15	18	21	23	3.7%

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 2004 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 2004 to 51.5 percent in 2022.

Exhibit VI-9 compares the trends in residential use per customer in the rate case forecast versus the Least Cost Plan forecast. Note that the long term rate of decline in residential use per customer is 0.3% per year in the Least Cost Plan forecast, but only about 0.1% per year in the rate case forecast. The differences arise due to the different assumptions about electric price projections and conservation savings. In the rate case forecast, PSE assumed electric prices to be flat nominal after rising by 22 percent from 2002 to 2003, whereas electric prices were assumed to grow about 2.5 percent per year on a nominal basis in the Least Cost Plan forecast, after accounting for the general rate case increase of 6.5 percent between 2002 and 2003 and changes in the BPA exchange credit which effectively raise rates near-term (2003-2006) but lower it slightly in the long-term (2007 and beyond). The net effect is that long-term residential rates are still expected to be higher in the Least Cost Plan forecast than in the rate case forecast. This causes the use per customer to decline faster in the Least Cost Plan forecast due to price elasticity effects. Secondly, a small residential conservation savings was assumed in the rate case forecast (0.5 aMW flat over the next 20 years), but a more significant amount is assumed in the Least Cost Plan forecast (3 aMW), going away at the end of measure life. Hence, the reduction in use per customer in the Least Cost Plan forecast is higher near-term than in the longer-term. While PEM savings were also included in the rate case forecast but not in the LCP forecast, its effects were also higher in the near-term than in the long-term since this constitutes a one-time savings assumed to persist over time.

Exhibit VI-9
Comparison of Residential Normalized Electric Use per Customer in KWh

							aarg	
	1996	2002	2005	2010	2015	2020	2020	2002-2020
Rate Case	12,197	11,500	11,312	11,281	11,300	11,330	-0.80%	-0.10%
LCP	12,211	11,584	11,257	11,184	11,120	11,054	-0.90%	-0.30%

Base Case Electric Customer Forecasts

PSE expects electric customer numbers to grow at an average annual rate of growth of 1.8 percent per year between 2004 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, at about 1.7 percent per year, consistent with the pattern of growth in population and employment. The long-term projected growth rate of 1.8 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 VI-10
Electric Customer Count Forecasts by Class (Year End)

	2004	2005	2010	2015	2020	2022	aarg
Total	990,272	1,006,365	1,100,176	1,199,495	1,308,581	1,354,784	1.8%
Residential	876,870	890,981	972,659	1,060,085	1,155,907	1,196,599	1.7%
Commercial	107,254	109,049	120,475	131,602	143,872	148,920	1.8%
Industrial	3,895	3,946	4,069	4,083	4,129	4,146	0.4%
Others	2,253	2,389	2,973	3,725	4,673	5,119	4.7%

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. Exhibit VI-11 provides information on the 2002 electric peak.

Exhibit VI-11
2002 Electric Peak Day

Peak	3,817 MW
Date	1/28/02
Time	7:00 PM
Temperature	30 degrees F

Exhibit VI-12
Electric Peak Forecast in MWs

	2004	2005	2010	2015	2020	2022	aarg
Normal Peak Load w/Conservation	4,819	4,862	5,251	5,702	6,182	6,384	1.6%
Normal Peak Load wo /Conservation	4,874	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. The annual normal peak load is assumed to occur at 23 degrees, in January. These loads are also adjusted 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

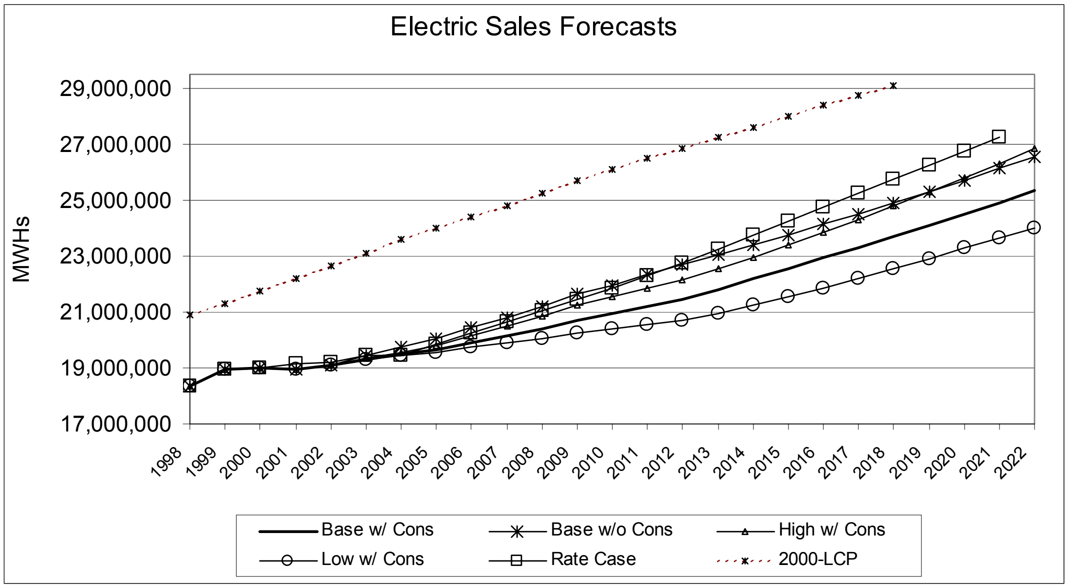
Any forecast carries a degree of risk. The base case long-term sales forecast assumes that the economy grows smoothly over time, with no major shocks or disruptions to the economy. In order to capture the range of economic possibilities in the forecast of billed sales, high and low sales forecast scenarios 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 VI-13 and VI-14 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-13
Electric Sales Forecast Scenarios in aMW

	2004	2005	2010	2015	2020	2022	aarg
Scenarios							
Base case with conservation	2,224	2,243	2,390	2,574	2,798	2,891	1.4%
High case with conservation	2,234	2,260	2,459	2,672	2,945	3,063	1.7%
Low case with conservation	2,221	2,233	2,329	2,458	2,659	2,737	1.1%
Base Case - no conservation	2,257	2,291	2,508	2,713	2,936	3,030	1.6%
F2001 - rate case	2,219	2,268	2,497	2,766	3,054		1.9%
2000 LCP	2,692	2,739	2,981	3,198			1.6%

Exhibit VI-14



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 1,086,575 Mtherms in 2004 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 VI-15
2002 Gas Sales in Therms (000s)

Total - Base With Conservation	1,028,722
Residential	493,938
Commercial	206,325
Industrial	37,671
Interruptibles	87,542
Transportation	203,246

Exhibit VI-16
Gas Sales Forecast in Therms (000s)

	2004	2005	2010	2015	2020	2022	aarg
Total - Base with Conservation	1,086,575	1,120,050	1,266,701	1,384,504	1,511,788	1,562,567	2.1%
Residential	528,780	538,819	620,839	697,900	779,054	813,192	2.4%
Commercial	211,262	216,043	240,917	264,362	286,922	295,623	1.8%
Industrial	39,813	39,626	43,539	44,173	45,455	45,967	0.9%
Interruptibles	90,386	95,864	115,999	132,717	146,974	152,276	3.1%
Transportation	215,884	229,698	245,407	245,362	253,383	255,509	1.1%

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-17
Gas Customer Count Forecasts by Class (Year End)

	2004	2005	2010	2015	2020	2022	aarg
Total - Base with Conservation	653,522	669,443	772,626	881,470	1,003,158	1,056,030	2.7%
Residential	602,429	617,591	717,141	822,613	941,176	992,864	2.9%
Commercial	47,507	48,304	51,947	55,331	58,465	59,653	1.4%
Industrial	2,832	2,806	2,840	2,861	2,882	2,889	0.4%
Interruptibles	643	632	586	552	521	511	-1.4%
Transportation	110	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 2.9 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 six percent of total customer base, PSE also expects the commercial sector to grow slightly, at approximately 1.4 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 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 VI-18
2002 Gas Peak Day

Peak	4,961,050 therms
Date	1/28/02
Temperature	31.6 degrees F
HDD65	33.4

Exhibit VI-19
Gas Peak Day Forecast in Therms (000s)

	2004	2005	2010	2015	2020	2022	aarg
Peak Day Load Total	8,168,417	8,350,742	9,372,901	10,500,329	11,674,861	12,184,509	2.2%
Residential	5,967,621	6,110,857	6,963,176	7,922,978	8,939,900	9,387,111	2.5%
Commercial	1,836,807	1,866,821	2,011,599	2,150,361	2,279,200	2,329,364	1.3%
Industrial	283,114	290,384	305,324	323,026	340,167	347,396	1.3%
Losses	80,875	82,681	92,801	103,964	115,593	120,639	2.2%

Gas Sales Forecast Scenarios

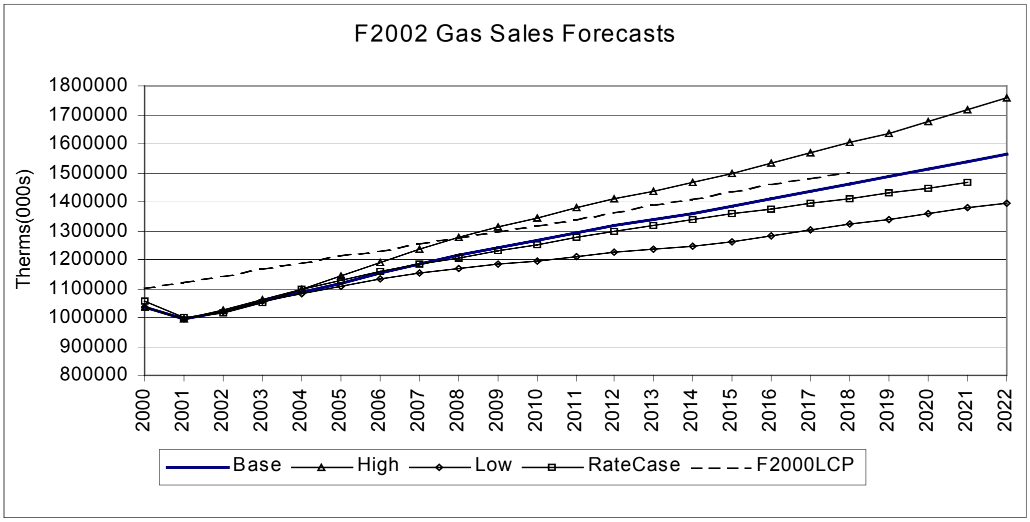
The high and low case economic scenarios were developed using the same methodology used in electric demand forecast to derive the high and low case scenarios for population and employment for the gas service territory. Exhibits VI-20 and VI-21 provide a comparison between the current forecasts and the forecasts generated for the rate case and the 2000 Least Cost Plan.

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

Exhibit VI-20
Gas Sales Forecast in Therms (000s)

	2004	2005	2010	2015	2020	2022	aarg
Scenarios							
Base case	1,086,575	1,120,050	1,266,701	1,384,504	1,511,788	1,562,567	2.1%
High case	1,099,503	1,142,161	1,344,884	1,498,239	1,677,649	1,757,849	2.7%
Low case	1,081,308	1,106,939	1,197,388	1,262,506	1,359,810	1,394,458	1.5%
F2001 - rate case	1,099,544	1,129,211	1,253,504	1,356,868	1,448,403		2.0%
2000 LCP	1,192,055	1,213,489	1,318,724	1,435,792			1.8%

Exhibit VI-21



The 2000 Least Cost Plan forecast initially starts higher 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 key highlights include:

1. Annual real GDP is anticipated to grow at 3.2 percent in the next 20 years.
2. Employment growth in PSE's service territories will likely grow at a slower rate (1.7 percent) than its 30-year historical growth rate, fueled mainly through growth in the service sector.
3. Electric rates (in nominal dollars) are anticipated to grow between 2.4 and 2.7 percent per year over the next twenty years, resulting in declining real electric rates.
4. Gas rates are anticipated to increase at about two percent per year, lower than the long-term rate of inflation.
5. Electric conservation savings are assumed to grow by 15 aMW per year for the next 10 years, in contrast to the rate case settlement, which assumed PSE to achieve 15 aMW of savings for 2003 only. Gas conservation savings are assumed to be 2.1 million therms per year.
6. PSE's conservation assumptions beyond 2003 will be revisited after further collaborative studies are completed by the third quarter of 2003.
7. 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.
8. The long-term rate of decline in residential use per customer in the Least Cost Plan forecast is higher than in PSE's recent rate case forecast due to different assumptions regarding electric price projections and conservation savings.
9. PSE anticipates a projected growth rate of electric customers at an average annual rate of growth of 1.8 percent per year between 2002-2022, to 1.35 million customers in 2022.

10. Electric peak load forecasts are expected to grow by 1.6 percent in the next 20 years with conservation, and 1.7 percent in the next 20 years without conservation.
11. 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 1,086,575 Mtherms in 2004 to 1,562,567 Mtherms by 2022.
12. PSE anticipates a projected growth rate of natural gas customers at 2.7 percent per year in the next 20 years.
13. 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.

VII. 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

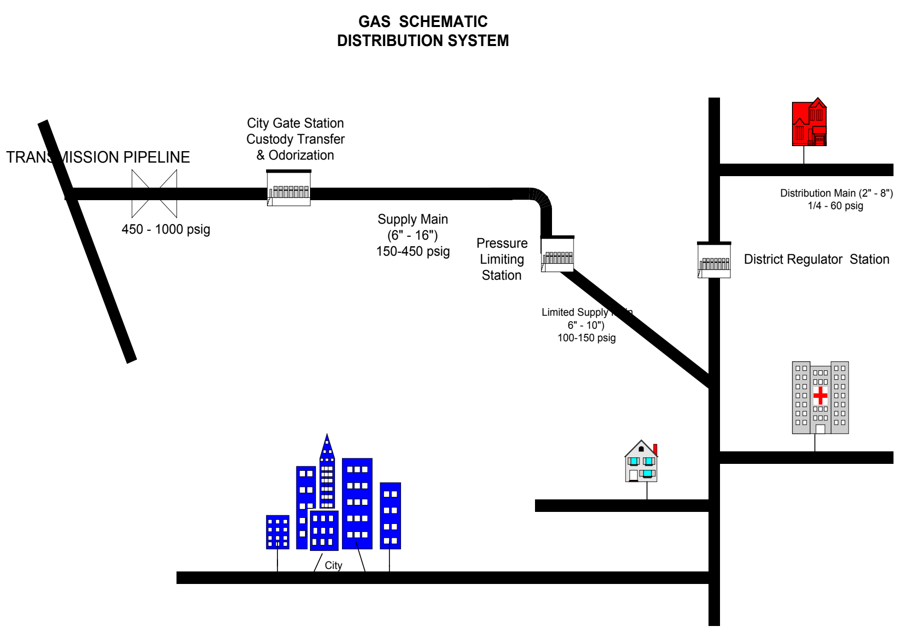
Gas Delivery System

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 VII-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 VII-1
Gas Schematic Distribution System



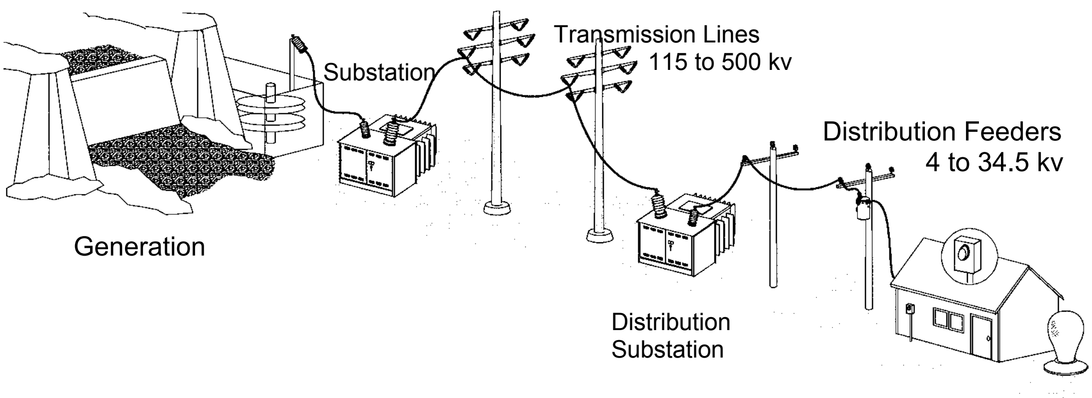
Electric Energy Delivery System

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 VII-2 provides a schematic view of the electric distribution system.

Exhibit VII-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 societal role of energy, 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 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 X). Each of these has a variety of operating characteristics, which create 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

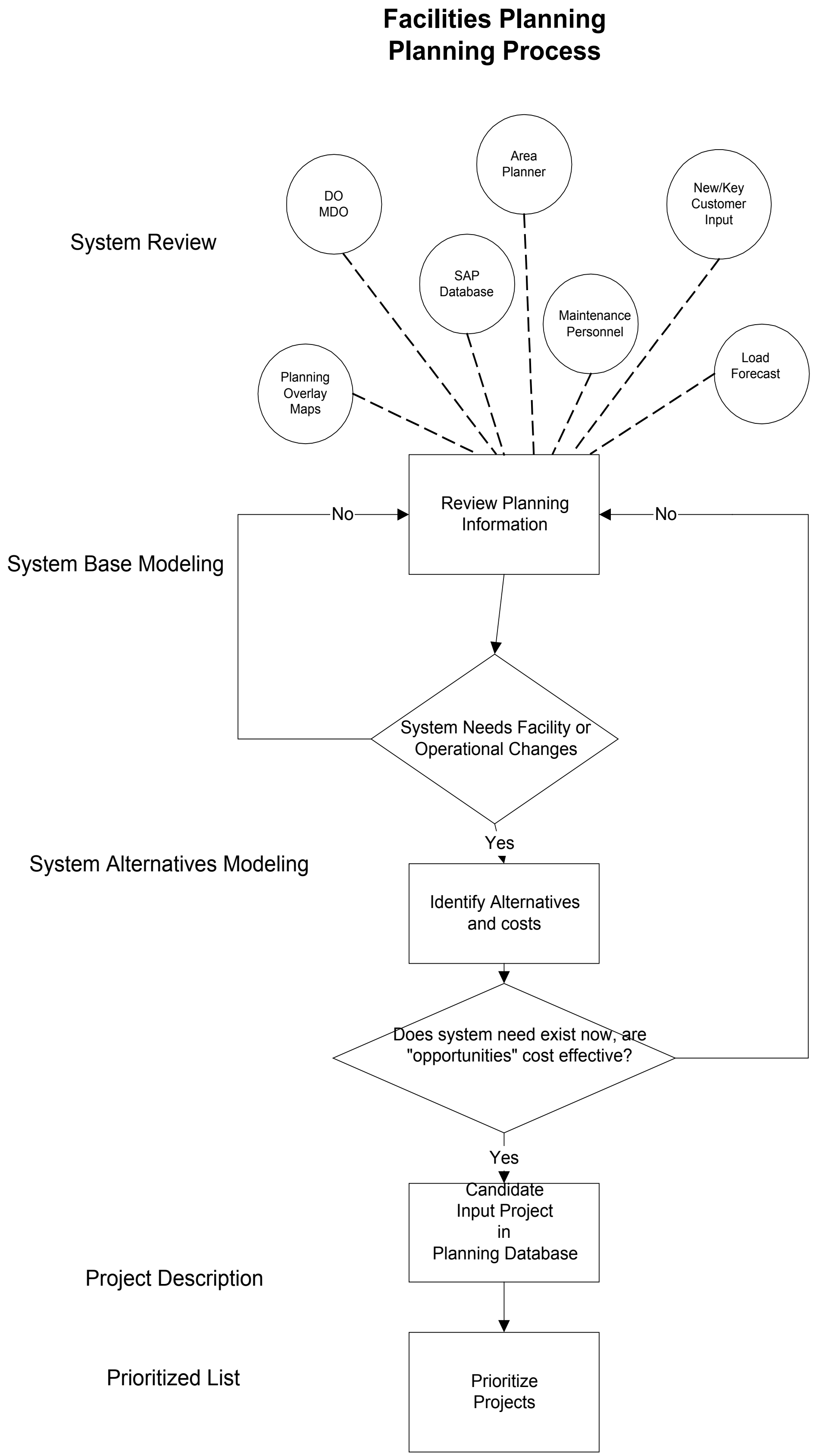
"Asset management" comprises an important part of the distribution planning process. Asset management seeks to assure the full utilization of existing facilities before adding new facilities, unless the cost advantage of early installation offsets the cost of having the new facility at a low level of 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 from 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 VI, 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 VII-3 provides a view of this process.

Exhibit VII-3



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:

Gas

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

Electric

- 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 VI, 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 conjunction 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 being served. DG is not a new concept, dating 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 years 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 a 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 X, 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 XVII.

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 distribution system facilities. Other key highlights include:

1. 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 and investment challenge for both the gas and electric distribution systems.
2. Performance standards regarding safety and reliability form a basis for distribution system planning.
3. 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.
4. 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.
5. Planning alternatives for distribution facilities planning may take one of two paths – building new facilities or making operational adjustments to existing facilities.
6. To improve the overall efficiency of its distribution planning operations, PSE has initiated the use of value-based budgeting.
7. PSE has made additional 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.
8. 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.

VIII. EXISTING ELECTRIC RESOURCES

Chapter VIII 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 1,908,288 MWh (net, cumulative, annual) or 218 aMW (net, 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 included significant input 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 15.1 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 the Northwest

Energy Efficiency Alliance (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 VIII-1 provides an overview of current PSE conservation programs. For a more detailed description of these programs, please refer to Appendix D.

Exhibit VIII-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 VIII-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

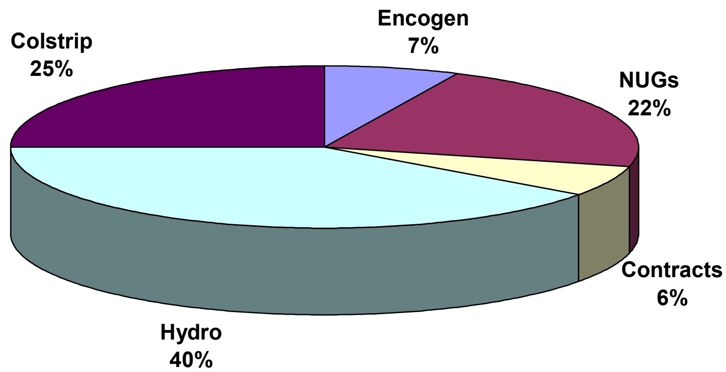
B. Schedule 150 Net Metering Customers

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 power project.

C. Generation Supply

PSE's generation portfolio currently consists of 2,287 aMW, comprised of a balanced portfolio of assets. 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 VIII-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[1].

Exhibit VIII-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 plants & contract capacity, & energy estimates may differ slightly from information included in PSE's March 2003 SEC Form 10-K Filing & 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 the Mid-Columbia 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 VIII-3 lists the PSE hydro resources.

Exhibit VIII-3
PSE Existing Hydro Resources

PLANT	OWNER	PSE SHARE %	ENERGY (AMW)	EXPIRATION DATE
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	3/31/18
Rocky Reach	Chelan Co. PUD	38.9	285	11/1/11
Rock Island I & II	Chelan Co. PUD	65.0	204	6/7/12
Wanapum	Grant Co. PUD	10.8	48	TBD
Priest Rapids	Grant Co. PUD	8.0	34	TBD
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 VIII-4 lists the capacity and planned energy output from Colstrip and Encogen.

Exhibit VIII-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 VIII-5 provides additional detail on PSE's CTs.

Exhibit VIII-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 VIII-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 VIII-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 Cogeneration) –*** 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 VIII-7 lists PSE's long-term contracts with QF's and Exhibit VIII-8 lists PSE's non-QF long-term contracts.

Exhibit VIII-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 VIII-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 northwestern 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, 2004.) 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 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:

1. PSE currently has approximately 20 conservation programs in place, with nearly 10 more pilot/new programs underway.
2. PSE has provided conservation services for its electricity customers since 1979, saving 218 aMW (net, cumulative load reduction) through 2001. The Company has invested approximately $310 million in electricity conservation since 1989 and has realized estimated energy savings representing over 11% of PSE's average existing annual electric loads.
3. From September 2002 – December 2003, PSE's conservation programs and services are expected to achieve 15.1 aMW of energy savings.
4. PSE's schedule 150 net metering customers provide a resource of approximately 37 kW.
5. 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.
6. 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 shortfall between PSE's load forecast and projected resources.

IX. ELECTRIC LOAD-RESOURCE OUTLOOK

Chapter IX 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 VI. 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 IX-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 IX-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 IX-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 IX-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 IX-3 details, PSE will lose 314 aMW of energy and 755 MW of capacity by 2010 due to the expiration of current power supply contracts.

Exhibit IX-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 IX-4 provides details on PSE's expiring NUG contracts.

Exhibit IX-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 power 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 the 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 Section 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 IX-5 provides the fuel efficiency of PSE's SCGTs and Exhibit IX-6 provides the fuel efficiency of PSE's cogeneration resources.

Exhibit IX-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%

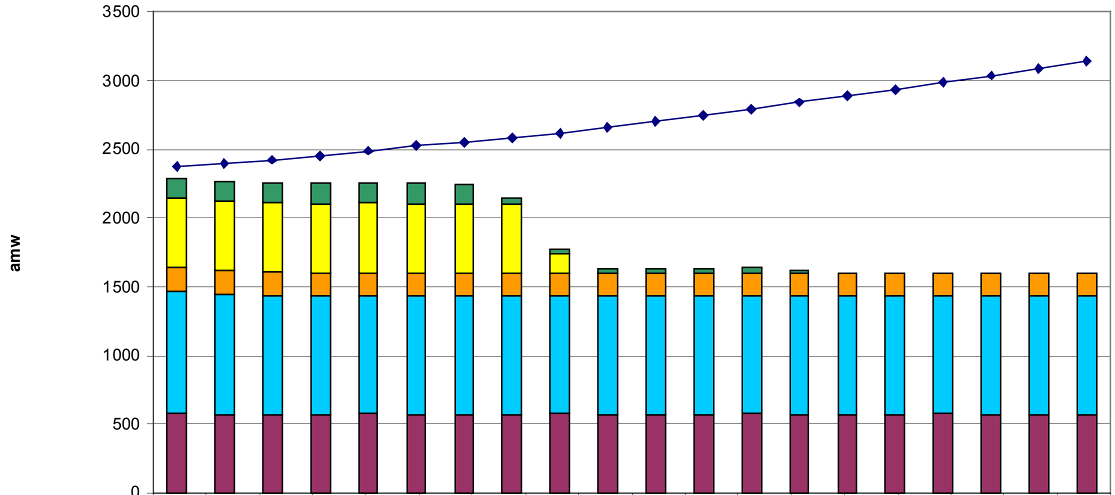
Exhibit IX-6
Fuel Efficiency of PSE's Cogeneration Resources

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

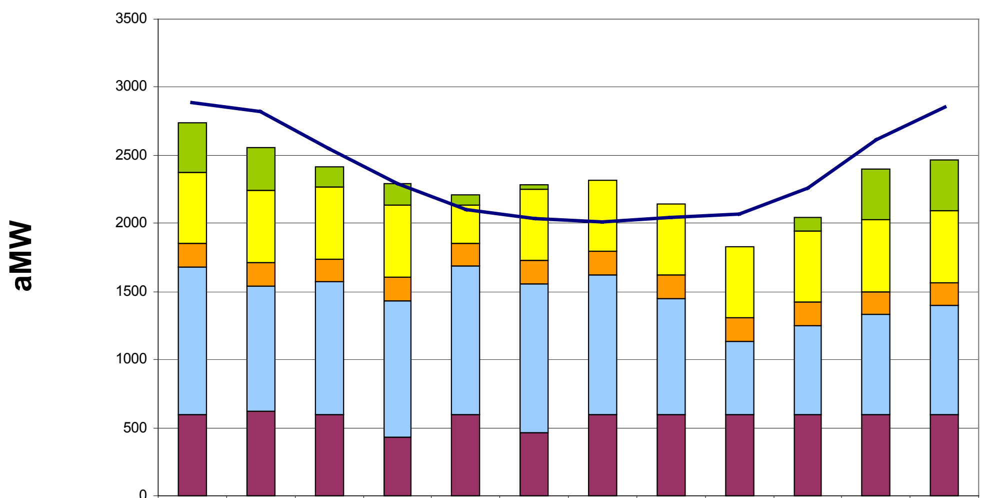
Exhibit IX-7 provides PSE's annual energy load-resource balance from 2004-2023. Exhibits IX-8 and IX-9 provide a monthly view of PSE's energy needs in 2004 and 2013. On an annual basis, PSE has an existing gap of 90 aMW between its load forecast and existing resources. As illustrated by Exhibit IX-8, 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 IX-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 IX-7
Annual Load-Resource Outlook



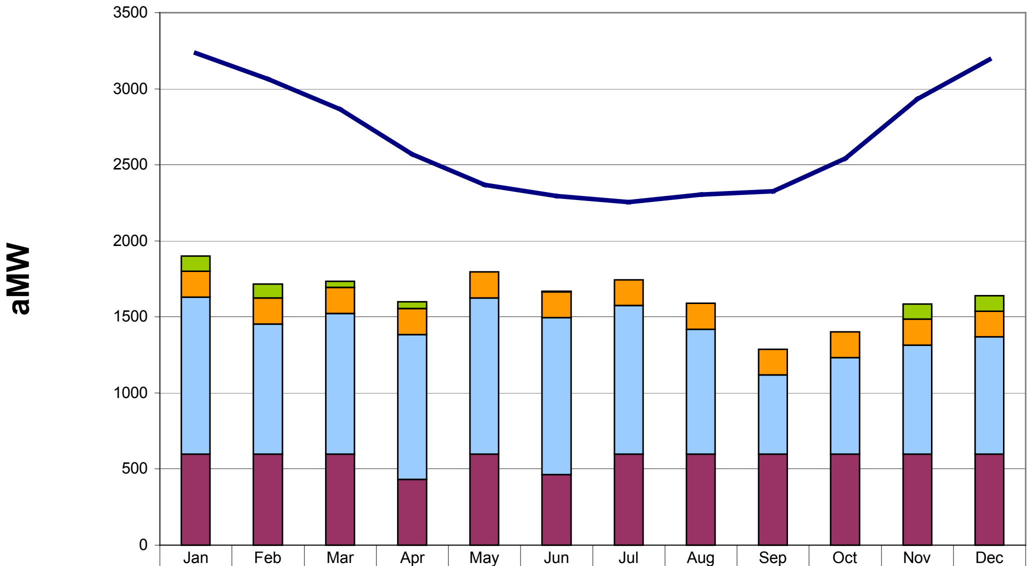
	2004	2005	2006	2007	2008	2010	2011	2012	2013	2014	2015	2016	2017	2018	2020	2021	2022	2023
Contracts	139.8	140.4	144.3	150	150.9	142.1	40.16	38.26	33.6	33.42	32.99	33.55	16.8	-8.12	-8.005	-7.919	-7.849	-7.778
NUGs	505.2	505.2	505.2	505.2	505.2	505.2	505.2	133	0	0	0	0	0	0	0	0	0	0
Encogen	170	170	170	170	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 IX-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 IX-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

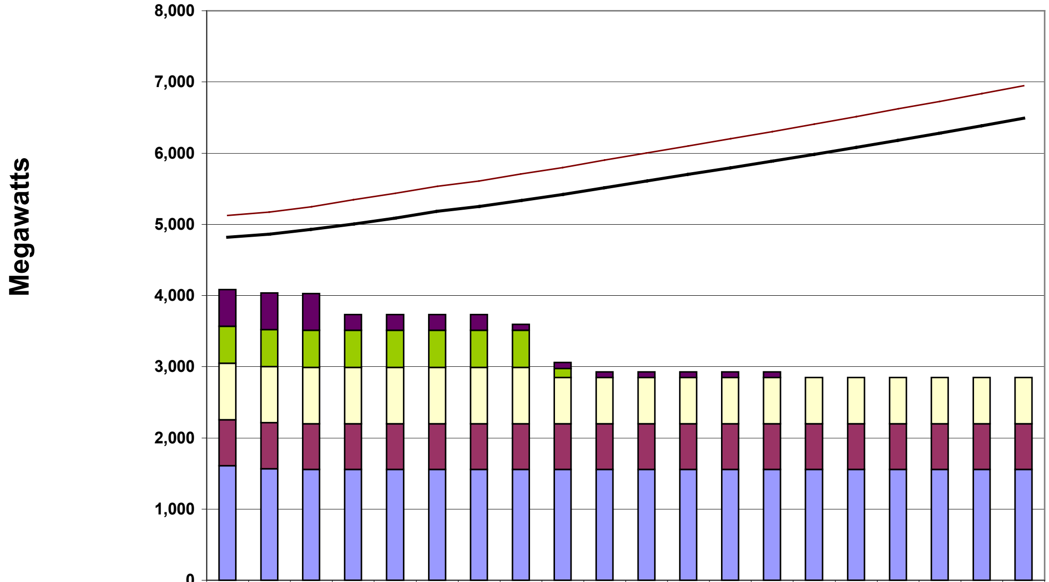
There is currently a deficit between PSE's existing capacity and its expected peak load. As the power supply and NUG contracts expire, this situation intensifies. Exhibit IX-10 provides PSE's annual capacity balance for 2002-2023.

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 contractual 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 key highlights include:

1. 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.
2. 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 IX-10
PSE's Annual Winter Peak Load and Resources (2004-2023)



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Contracts	515	515	515	221	221	221	219	85	85	80	80	80	80	80	-2	-2	-2	-2	-2	-2
NUGs	520	520	520	520	520	520	520	520	127	0	0	0	0	0	0	0	0	0	0	0
Encogen + CTs	793	793	793	793	793	793	793	793	650	650	650	650	650	650	650	650	650	650	650	650
Colstrip	646	646	646	646	646	646	646	646	646	646	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	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.	5,126	5,172	5,244	5,345	5,436	5,536	5,610	5,709	5,800	5,901	6,001	6,101	6,200	6,300	6,408	6,513	6,620	6,728	6,837	6,951
Expected Peak Load	4,819	4,862	4,929	5,004	5,089	5,182	5,251	5,336	5,421	5,514	5,608	5,702	5,794	5,888	5,983	6,081	6,182	6,282	6,384	6,490

3. By 2010, PSE will lose 314 aMW of energy and 755 MW of capacity through the expiration of power supply contracts.
4. PSE's loss of hydro resources by 2012 will decrease its supply sources by 102 aMW.
5. The loss of PSE's leased Whitehorn combustion turbine in 2009 will decrease its load resources by 134 MW.
6. The scheduled expiration of PSE's NUG contracts in 2011-2012 will deplete PSE's resources by 498 aMW.
7. PSE simulated the dispatch of its existing resources to serve the forecast load over the 20-year period to quantify its load resource outlook.
8. 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 power resources.

9. 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.
10. For planning purposes, PSE reflects the full baseload capacity of its combined cycle resources.

X. NEW ELECTRIC RESOURCE OPPORTUNITIES

Chapter VIII provided an overview of PSE's existing resources – including existing conservation and efficiency programs and generation supply resources. Chapter X looks forward by examining resource opportunities, beginning with new possible conservation and efficiency initiatives. This chapter also 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 Power

A wind power 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 MW, however, based on recent project proposals, turbines of 2 MW and greater have been introduced. Wind power's primary economic benefit stems from its avoidance of the volatility characterizing the fuel market. However, wind power availability often proves volatile. Typical average capacity for a wind power project is 30-35 percent, with a range of output from zero to 100 percent. Raw wind power energy needs to be either small enough to be absorbed into the control area without adversely affecting operations, or have firming from a dispatchable resource.

Wind power 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-Columbia 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 power 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 resource 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 geothermal 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 powered 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. These plants primarily need 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 initial 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. Additional assessments are underway and will be included in updates to this Least Cost Plan.

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 its 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.

- ***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 pleased 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 examining 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.

---

[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.

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 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 customers 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 either be a gas to 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 VII).

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 power 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, 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 have been varied, and expected near-term cost reductions have not been realized. A continuing need exists to understand manufacturer 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.

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 XVII, 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,

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

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

PSE owns transmission facilities in its control area and, in connection with the Colstrip generating facility, in Montana. PSE'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 PSE'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 PSE's control area without new construction by BPA or PSE. PSE'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*** – PSE 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*** **–** PSE 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 PSE 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 PSE's 115 kV lines causing them to reach their thermal limits. Furthermore, PSE 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*** **–** PSE has a 230 kV line and a 115 kV line running between the Mid-Columbia and Puget Sound areas. BPA has agreed with PSE that the two lines have a combined capacity of 450 MW. However, due to the amount of output from generation resources that PSE has under contract in the Mid-Columbia area and elsewhere, PSE has its transmission capacity on the two lines already fully utilized. PSE has had to contract with BPA for an additional 1,136 MW of transmission capacity between these two areas.

- ***Internal King County*** – Power transfers to and from Canada affect PSE's 230 and 115 kV system through King County. Outages on BPA's system could result in overloads on PSE and BPA's system to such an extent that the transfers from and to Canada must be curtailed below the full ratings. PSE 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 –*** PSE 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 PSE's load and the U.S. Navy's load in Kitsap County, the remaining two transmission lines could be overloaded. Finally, PSE 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 –*** PSE 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 –*** PSE'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, Washington 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 two to three 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 2003/2004 were 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. Contemplated delays in construction may time the additions to coincide with generating plant construction. Surplus pipeline capacity may be available until the construction of the contemplated power plants.

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 key highlights include:

1. As part of the current effort to develop new conservation resource supply curves, PSE is reviewing new and emerging measures anticipated to become cost-effective over the next 5 to 10 years.
2. Supply resource alternatives include renewable resources such as wind power, biomass, solar and geothermal energy, while thermal resources options focus on gas-fired and coal sources.
3. Fuel conversion, the switching of existing electric end-users to gas, represents a potential cost-effective efficiency resource opportunity.
4. 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.

5. Distributed generation consists of several technologies – fuel cells, micro turbines, mini-turbines and reciprocating engines – that provide near-term opportunities for electric resource needs.
6. PSE considers demand-response programs such as time-of-use programs or critical peak pricing products as options for meeting some electric resource needs. Currently, PSE is participating in a collaborative effort to examine time-of-use scenarios and conduct program analysis.
7. 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.
8. The failure to timely expand the region's transmission infrastructure may well increase both costs and volatility to customers.

XI. ELECTRIC PORTFOLIO ANALYSIS

Chapter XI 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 power Production Tax Credit. The chapter ends with the results of a preliminary simplistic analysis of the benefits of adding five aMW of incremental conservation to PSE's analysis.

A. Portfolio Planning Levels

As will be discussed more fully in Chapter XII, 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 XI-1 illustrates, PSE examined eight different planning levels, ranging from a "do nothing" level to an extremely conservative level.

Exhibit XI-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 generally occurring 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.

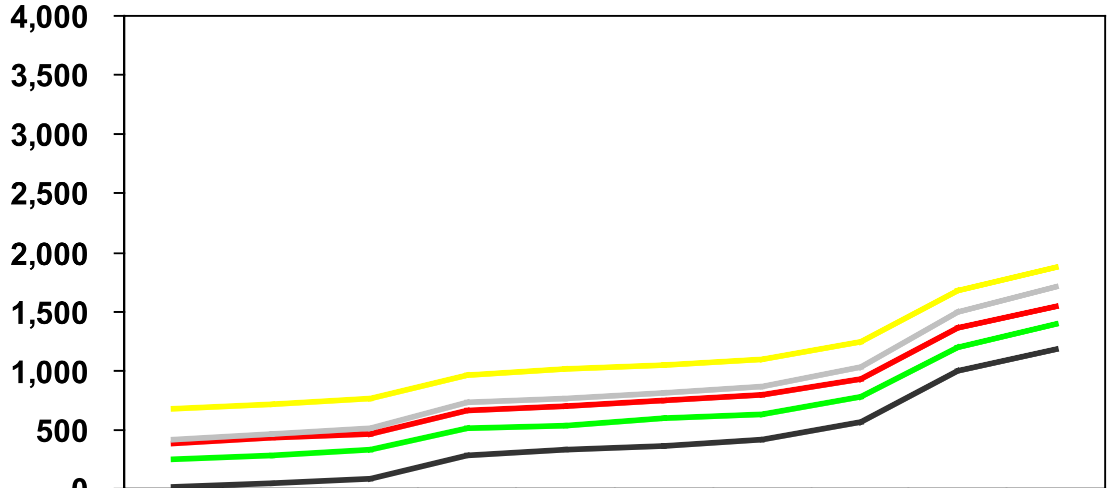
PSE also examines four different capacity planning levels. These various levels of capacity meet needs based on weather observed at the Seattle-Tacoma International Airport (SEA-TAC). These four levels include:

- 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 XI-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 XI-2
Energy Planning Level Impact (aMW)

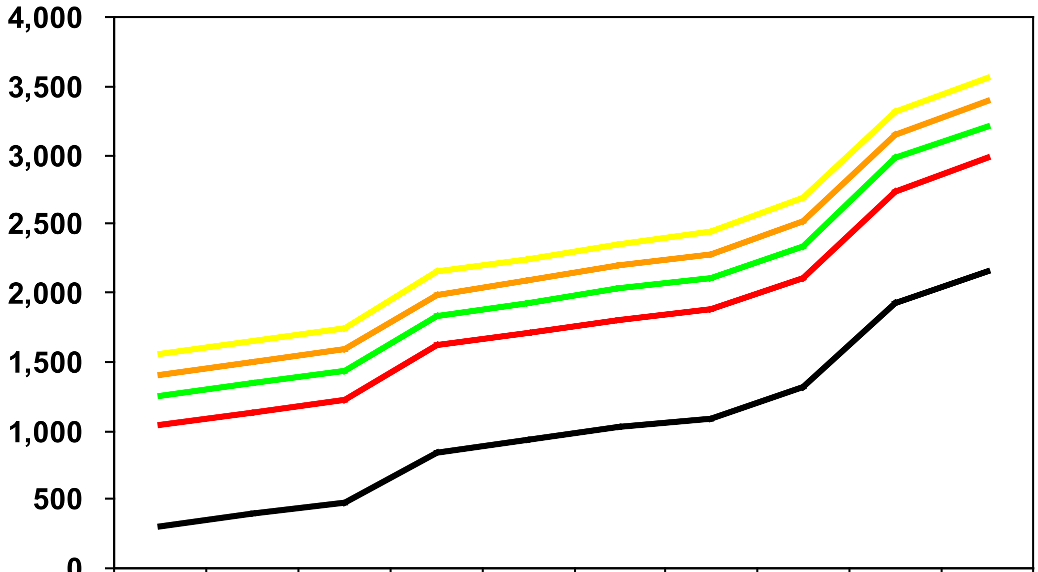


	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Status Quo	10	50	88	287	327	369	416	558	991	1,176
Level A1, 2	255	283	330	512	536	592	630	772	1,196	1,395
Level B1, 2	385	425	462	662	701	743	791	933	1,365	1,551
Level C1	423	468	509	728	772	818	870	1,026	1,502	1,706
Level C2	674	717	757	961	1,004	1,050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

Exhibit XI-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 XI-3
Capacity Planning Level Impact (MW)



	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. Appendix I provides an overview of the 92 portfolio cases created, including the new resources, the resulting 2013 portfolio mix and analytical results for each case.

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 power. The Company assumed the wind power resources to be those described in the Cascades & Inland profile developed by the NPCC. PSE considered several other technologies, including many discussed in Chapter X, but excluded these resources for a variety of reasons. Although PSE considered solar power, the high capital cost associated with the 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 power 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 power 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 power 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 power 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 power 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 power 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 power resources are added until 2005.*** Given the state of various projects in the region, PSE finds it improbable that wind power could be brought online prior to

2005. When meeting the technology mix wind power standards (two percent, five 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 exchanges.

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 eight 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. Appendix J provides a more detailed overview of PSE's modeling process.

Analytical Process Objectives

Since its previous Least Cost Plan, PSE significantly revised and updated its Least cost Plan analytical process. 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 XI-4.

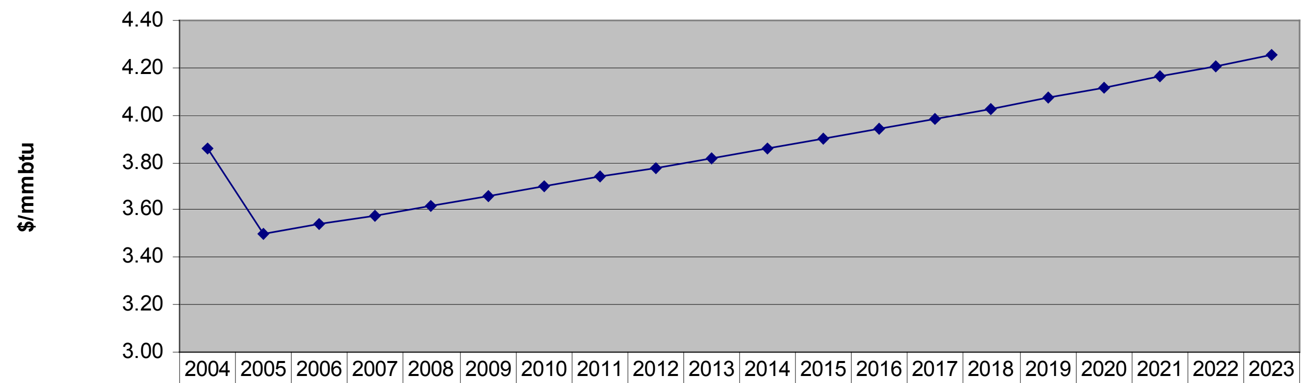
Exhibit XI-4
Major Stages in the Least Cost Plan Analytical Process

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 VI 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 VIII discusses PSE's existing electric resources and Chapter X 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 XI-5 and Exhibit XI-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 XI-5
Natural Gas Price Forecast: Sumas (nominal $)



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
PIRA 1/17/03	3.86	3.50	3.54	3.58	3.62	3.66	3.70	3.74	3.78	3.82	3.86	3.90	3.94	3.99	4.03	4.07	4.12	4.16	4.21	4.25

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

YEAR	PIRA 9/13/02	PIRA 1/17/03	NPPC 3/02
2004	3.70	3.86	3.44
2005	3.70	3.50	3.41
2006	3.75	3.54	3.54
2007	3.80	3.58	3.63
2008	3.85	3.62	3.72
2009	3.90	3.66	3.82
2010	3.95	3.70	3.91
2011	4.01	3.74	4.05
2012	4.07	3.78	4.20
2013	4.13	3.82	4.34
2014	4.19	3.86	4.50
2015	4.25	3.90	4.66
2016	4.31	3.94	4.79
2017	4.37	3.99	4.92
2018	4.43	4.03	5.06
2019	4.49	4.07	5.21
2020	4.55	4.12	5.36
2021	4.62	4.16	5.53
2022	4.68	4.21	5.70
2023	4.75	4.25	5.88

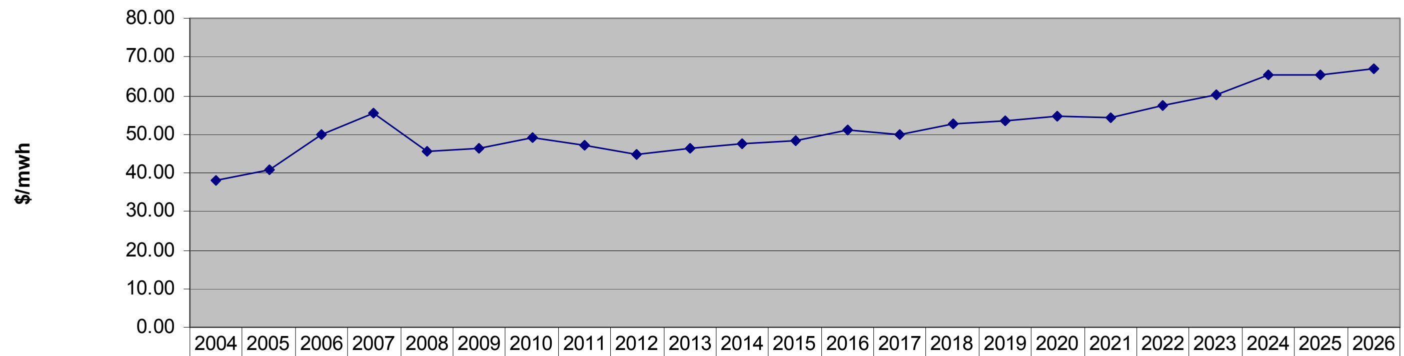
- ***Wholesale Electric Market Prices –*** Input assumptions about market prices for wholesale electric supplies represents another key variable for the resource analysis. Stage Two of the analytical process addresses the preparation of the market electricity price forecast.

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 K provides further detail about these assumptions. Exhibits XI-7 and XI-8 summarize results from the forecast of Mid-Columbia power supply prices.

Exhibit XI-7
Forecast of Annual Average Mid-Columbia Wholesale Power Price
(Nominal Dollars per MWH)



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
3/13/2003	38.04	40.85	49.91	55.26	45.54	46.20	49.20	47.01	44.60	46.25	47.49	48.46	50.98	50.01	52.60	53.64	54.57	54.21	57.54	60.26	65.22	65.44	66.91

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

YEAR	1/28/2003	2/21/2003	3/13/2003
2004	36.75	37.89	38.04
2005	37.75	41.01	40.85
2006	38.76	48.19	49.91
2007	39.42	52.16	55.26
2008	39.44	51.24	45.54
2009	40.37	49.49	46.20
2010	41.87	50.86	49.20
2011	43.26	53.97	47.01
2012	44.30	56.56	44.60
2013	47.74	57.57	46.25
2014	48.98	61.35	47.49
2015	52.60	62.83	48.46
2016	52.11	61.38	50.98
2017	54.38	56.64	50.01
2018	55.58	65.61	52.60
2019	55.80	63.20	53.64
2020	54.51	69.83	54.57
2021	58.76	70.97	54.21
2022	59.71	70.60	57.54
2023	63.53	73.71	60.26
2024	62.90	75.23	65.22

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.

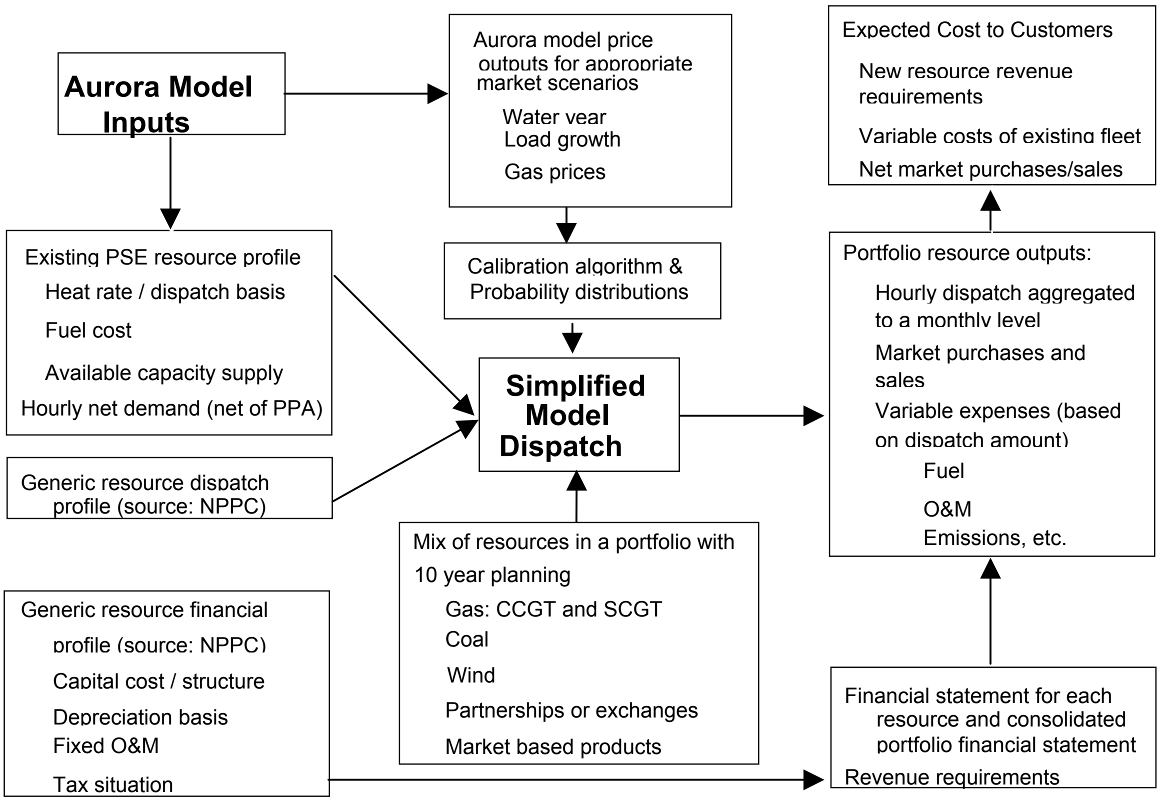
  It is important to note that the AURORA model results to determine PSE's need for new energy resources include projections of energy produced on an economic basis from PSE's existing co-generation and simple-cycle combustion turbine facilities (i.e., during periods when market prices for power are higher 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 XII provides analysis results – including the planning level guiding 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 XI-9 provides a schematic view of PSE's portfolio screening model.

Exhibit XI-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 XVII, 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 included 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:

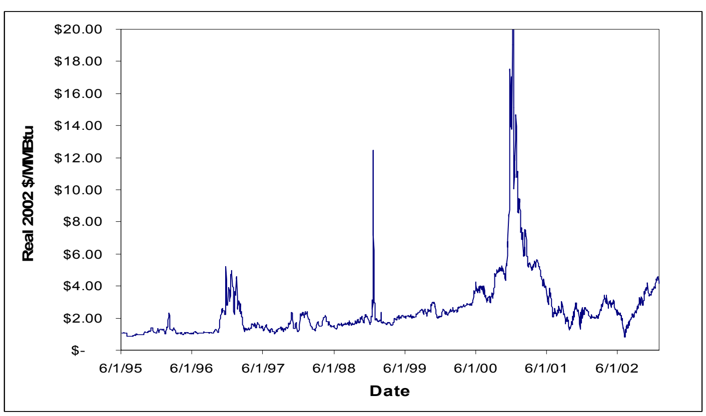
- Market prices for natural gas
- Market prices for power
- Hydroelectric generation availability

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 XI-10 illustrates the Sumas index data set used for natural gas prices.

Exhibit XI-10
Historical Sumas Daily Gas Prices

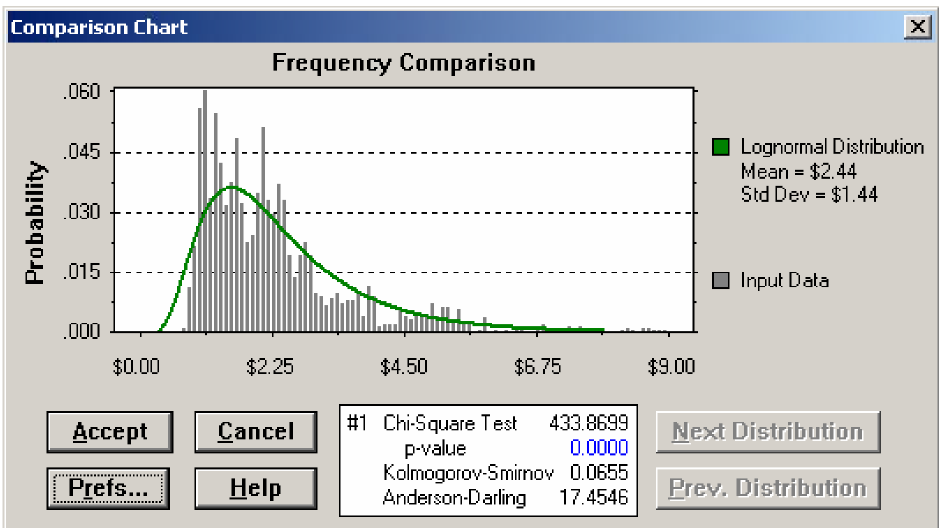


Source: Gas Daily

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 XI-11.

Exhibit XI-11
Historical Sumas Daily Gas Price Distribution



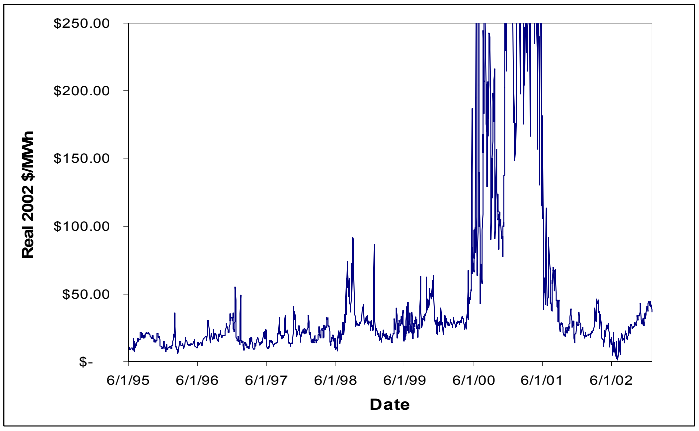
The mean of this data set is $2.44/MMBtu (real 2002$), with a standard deviation of $1.44/MMBtu. These values translate to a coefficient of variability of 59 percent (standard deviation as a percent of the mean). PSE applied this measure of gas price volatility to the gas prices in the screening model 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 XI-12 provides the data set used for power prices, with the Mid-Columbia hub as the index.

Exhibit XI-12

Historical Mid-Columbia Power Prices

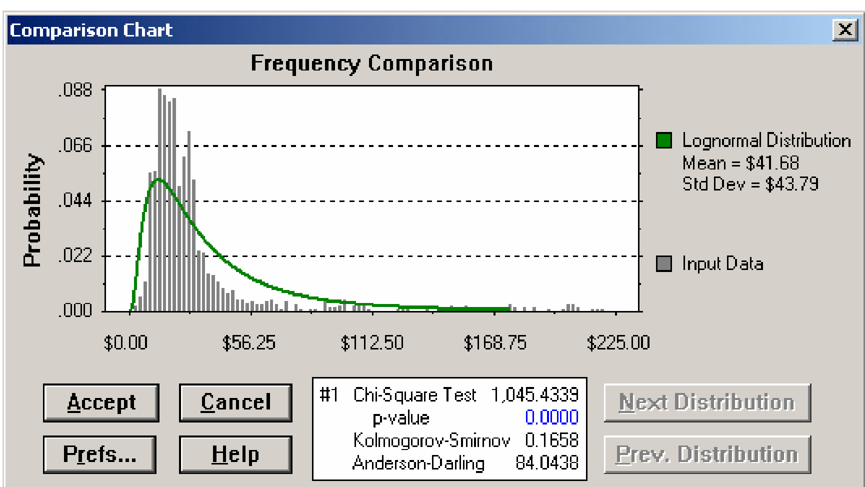


Source: MegaWatt Daily

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 XI-13 displays lognormal distribution which ranked highest.

Exhibit XI-13
Historical Mid-Columbia 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 XI-14 and XI-15 illustrate these facilities, their associated capacity, and coefficient of variability.

Exhibit XI-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 XI-15
Columbia River Hydroelectric System

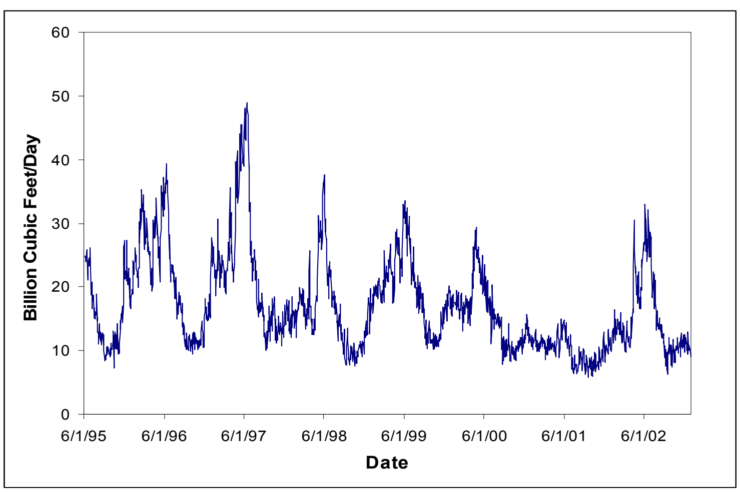
Plant	40-year SD (% of mean)	MW
Wells	9.9%	262.92
Rocky Reach	9.9%	492.67
Rock Island 1	4.5%	163.08
Wanapum	4.5%	106.49
Priest Rapids	7.8%	72.96
Rock Island 2	7.8%	173.95
Weighted Avg SD	8.3%	

As Exhibits XI-14 and XI-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 do 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 XI-16.

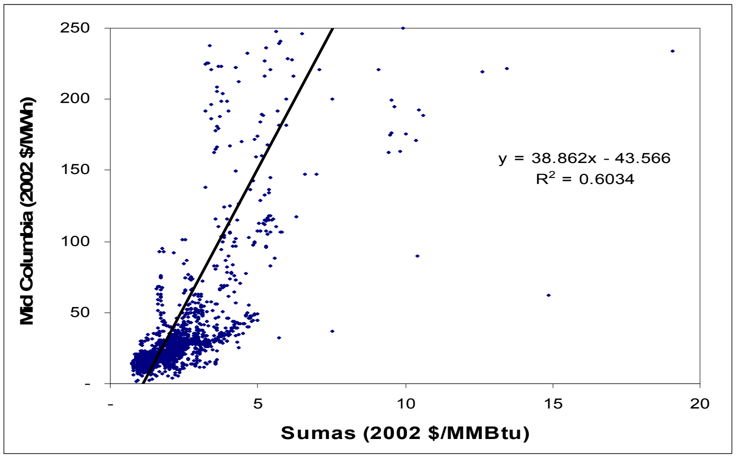
Exhibit XI-16
Volumetric River Flow at The Dalles



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 XI-17 illustrates this relationship and demonstrates a coefficient of determination (R-squared) of close to 60 percent.

Exhibit XI-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 XI-18 and XI-19 portray this relationship.

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

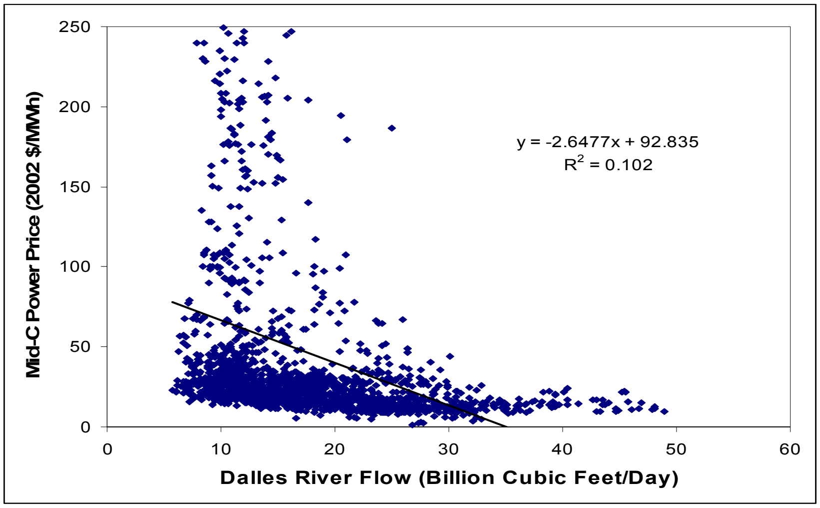
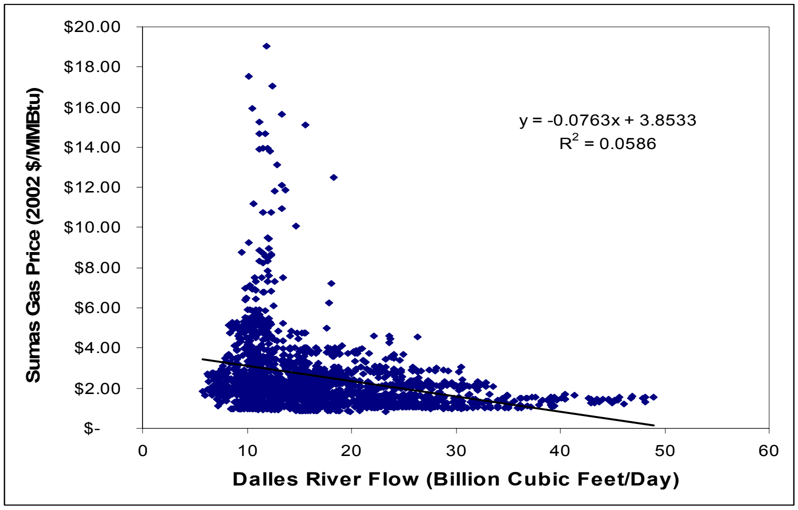


Exhibit XI-19
Gas Price as a Function of Dalles River Flow



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 XI-20 shows the results of these calculations.

Exhibit XI-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 variables.

F. Other Uncertainties

In addition to performing probabilistic risk analysis, PSE examined other uncertainties impacting the modeling process. PSE examined market price uncertainty through the use of scenario analysis. In addition, PSE examined retail load growth scenarios; emissions such as sulfur dioxide, nitrous oxides and carbon dioxide; and the wind power Production Tax Credit (PTC).

Market Price Uncertainty

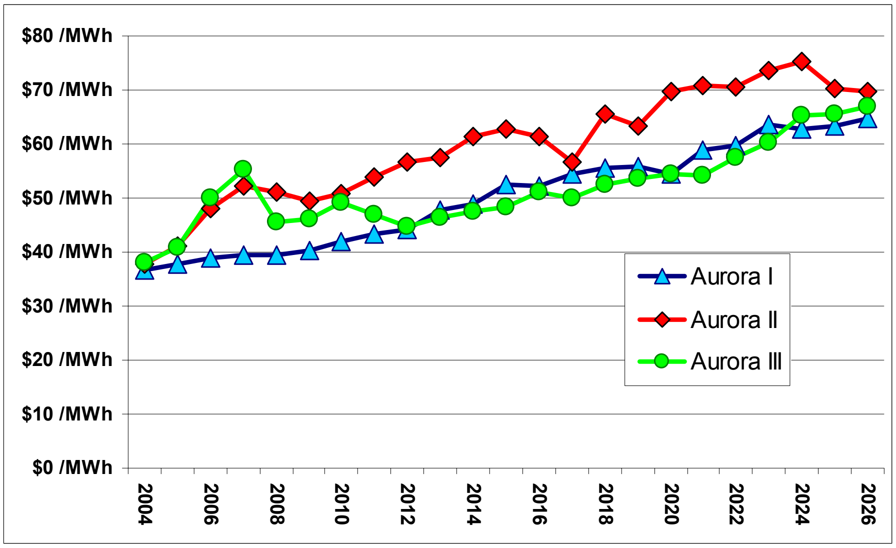
As detailed earlier, PSE performed the initial AURORA run ("AURORA I") using input assumptions similar to those used by the Northwest Power Planning Council (NWPPC). The NWPPC assumes fairly low cost-of-capital, especially considering the current financial state of many IPP's and regional utilities. 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 XI-21 provides an overview of market prices under the three scenarios.

Exhibit XI-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 percent long-term average annual growth rate. The high growth rate considered is 1.7 percent while the low growth rate is 1.1 percent 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 percent 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 XI-22 provides the model emission rate assumptions for the existing PSE fleet and for new resources.

Exhibit XI-22
Screening Model Emission Rate Assumptions

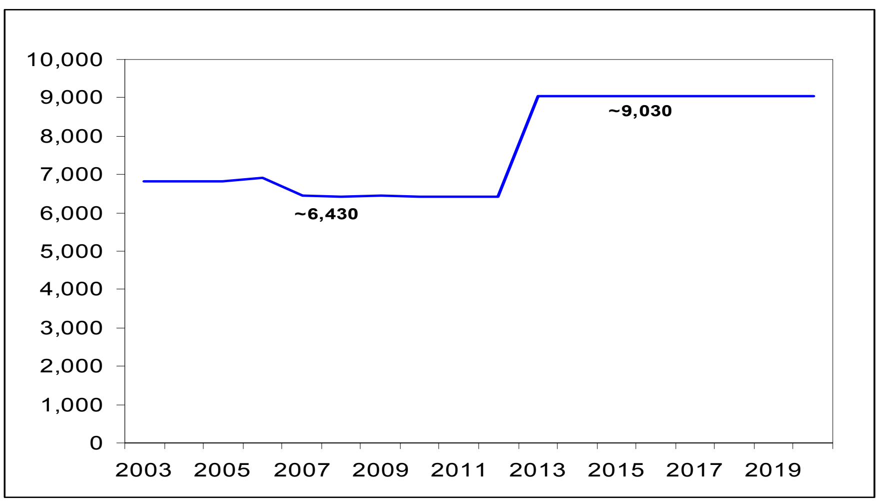
Emission rate (T/GWh)	SO2	NOX	CO2	Source
Fredonia 1&2	-	0.00002	582.00	PSE
Frederickson 1&2	0.00080	0.03900	582.00	NPPC Generic
Fredonia 3&4	0.00080	0.03900	582.00	PSE
Whitehorn 2&3	0.000003	0.00002	582.00	PSE
Colstrip 1&2	2.27613	2.09048	1,119.24	EPA
Colstrip 3&4	0.50220	2.19521	1,097.69	EPA
Encogen (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. Under the regulatory framework, the Company receives a certain allocation of allowances. Exhibit XI-23 details the total allowances issued to PSE through 2020.

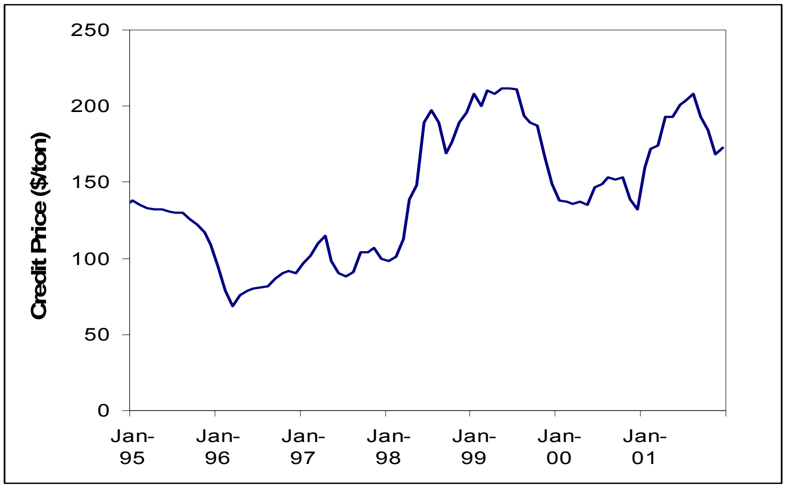
Exhibit XI-23
PSE SO_2 Allowances



Source: EPA

A forward market exists for SO_2 credits. As a simplification, the screening model assumes SO_2 credits cost \$200/ton and escalate at the assumed rate of inflation (2.5%) going forward. Exhibit XI-24 provides an overview of the market for SO_2 credits.

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



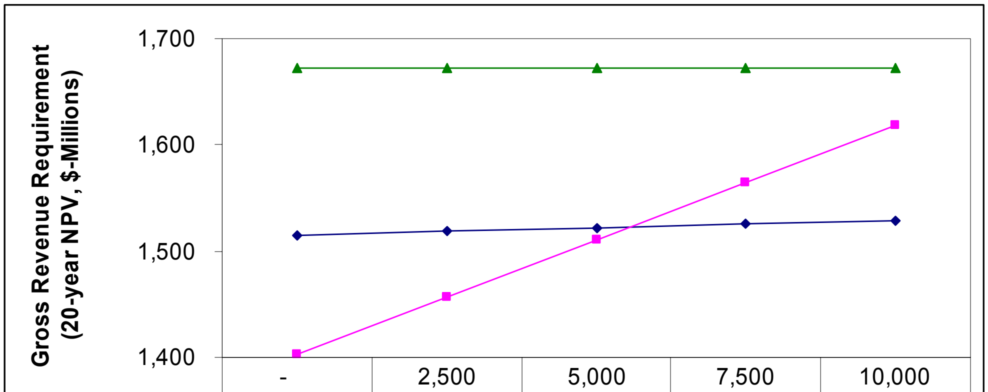
Source: EPA

As referenced in Chapter III, Planning Issues, and provided in more detail in Appendix L, Emissions Considerations and Wind Production Tax Credit, 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 L provides a 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 XI-25 shows the impact of a range of NO_X credit prices on the relative cost of wind power, coal and CCGT resources.

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



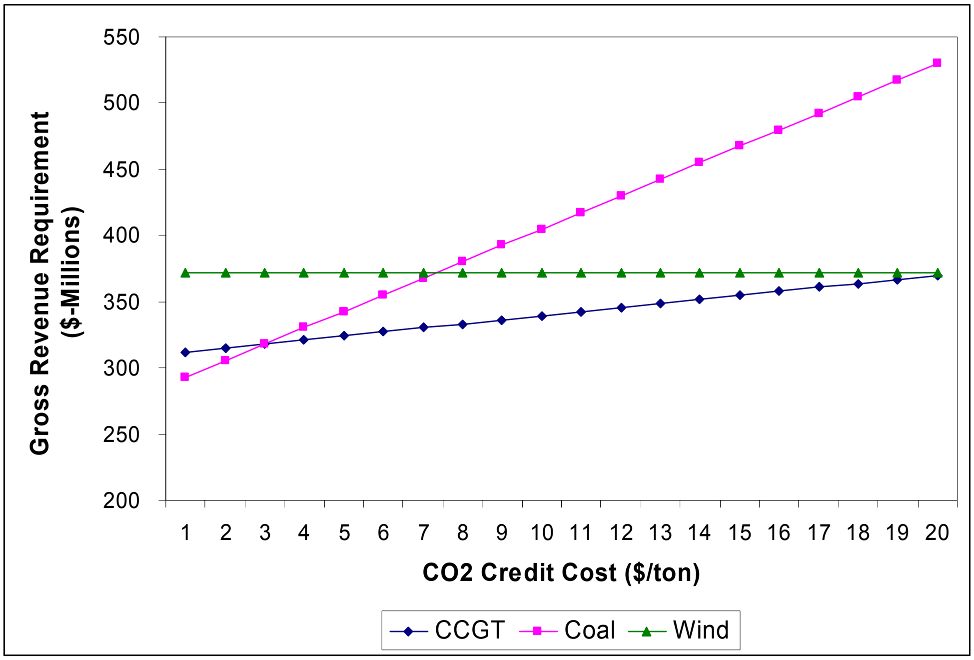
	-	2,500	5,000	7,500	10,000
CCGT	1,515	1,518	1,522	1,525	1,529
Coal	1,402	1,456	1,510	1,564	1,618
Wind	1,673	1,673	1,673	1,673	1,673

The analysis in Exhibit XI-25 assumes that 500 MW (energy equivalent for wind power) 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. It is important to note that this analysis is done in complete isolation, all other assumptions are held constant.

- ***Carbon Dioxide Legislation.*** Currently, power plants in the U.S. are not subject to CO_2 regulations. However, as detailed in Appendix L, 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 XI-26 shows the impact of CO_2 reduction regulations that would employ a cap-and-trade system.

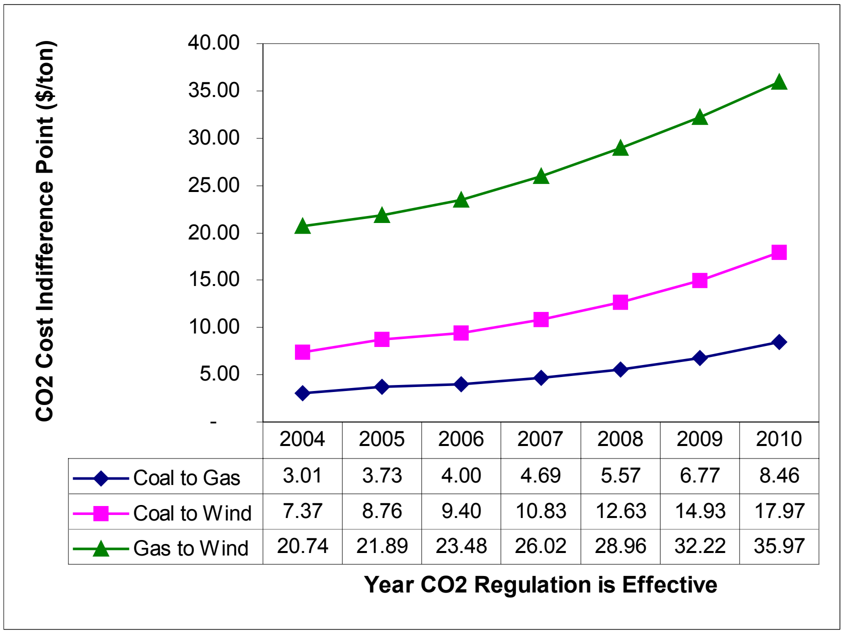
Exhibit XI-26
Impact of CO_2 Credit Prices on Generation Technologies



The analysis in Exhibit XI-26 assumes that 100 MW (energy/capacity equivalent for wind power) of each technology is installed in 2004, with CO_2 regulations also becoming effective in 2004. In order to make wind power equivalent on an energy basis, PSE adds 333 MW of capacity on a nameplate basis (wind power is assumed to have a capacity factor of 30 percent on an annual basis). To put wind power on an equal capacity footing as the coal and gas, 100 MW of simple cycle gas turbine is added. The comparison metric is a 20-year NPV of the gross revenue requirements including all fixed and variable expenses, plus a return. It is important to note that PSE did this analysis in complete isolation, with all other variables held constant.

The results depicted in Exhibit XI-26 indicate that at a CO_2 cost of approximately $3/ton, CCGT and coal are economically equivalent, all else being equal. Similarly, coal and wind power become economically equivalent at a little over $8/ton, while CCGT and wind power become equivalent at a little over $20/ton. These indifference points can be plotted for different CO_2 implementation dates. Exhibit XI-27 illustrates these indifference points for implementation dates ranging from 2004-2010.

Exhibit XI-27
CO_2 Credit Price Indifference Points by Switching Scenario



	2004	2005	2006	2007	2008	2009	2010
Coal to Gas	3.01	3.73	4.00	4.69	5.57	6.77	8.46
Coal to Wind	7.37	8.76	9.40	10.83	12.63	14.93	17.97
Gas to Wind	20.74	21.89	23.48	26.02	28.96	32.22	35.97

- ***Mercury.*** As Exhibit XI-22 illustrated, PSE does not include emission assumptions regarding mercury for its screening model. As detailed further in Appendix L, 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

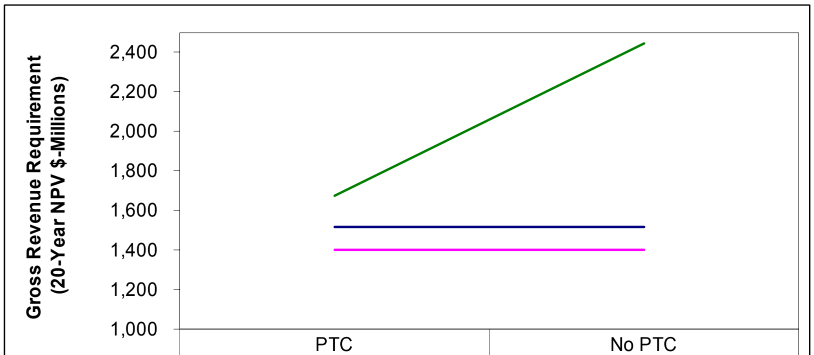
In 1992, Congress signed the Energy Policy Act into law, which included enactment of a Production Tax Credit (PTC) under Section 45 of the Internal Revenue Code of 1986. This credit was available to corporate entities building new renewable energy production facilities such as solar, biomass, wood chip, 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 power, 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 power developments would be highly uncertain, especially in relation to wind power 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 power into the Company's portfolio under conditions with and without the PTC beyond December 2003. While the PTC makes wind power 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 power 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. Exhibit XI-28 provides an analysis of the effect of the PTC on wind power economics. For the purposes of the Least Cost Plan, PSE assumed that for any new wind power 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 L

Exhibit XI-28
Impact of PTC on Wind Power Economics

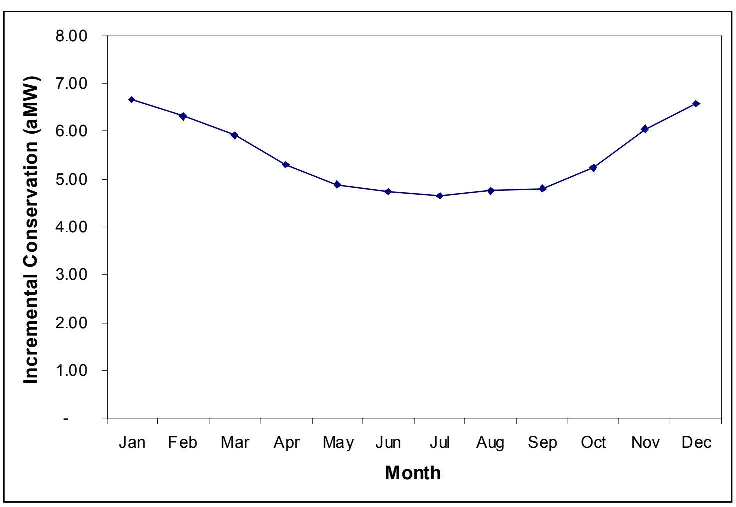


	PTC	No PTC
CCGT	1,515	1,515
Coal	1,402	1,402
Wind	1,673	2,442

G. Potential Benefits of Incremental Conservation

In response to suggestions from the Least Cost Plan Advisory Group, PSE developed an analysis to quantify the benefit of increasing conservation by 5 aMW. The current analysis includes 15 aMW of conservation per year on a cumulative basis for 10 years, totaling 150 aMW by the year 2013. From here, the analysis considers an additional 5 aMW of conservation per year through 2013, providing an overall total of 20 aMW per year on a cumulative basis, for 200 aMW by the year 2013. Exhibit XI-29 provides the monthly profile of the incremental aMW conserved in 2005.

Exhibit XI-29
Monthly Energy Impact of Incremental 5 aMW Conservation (2005)

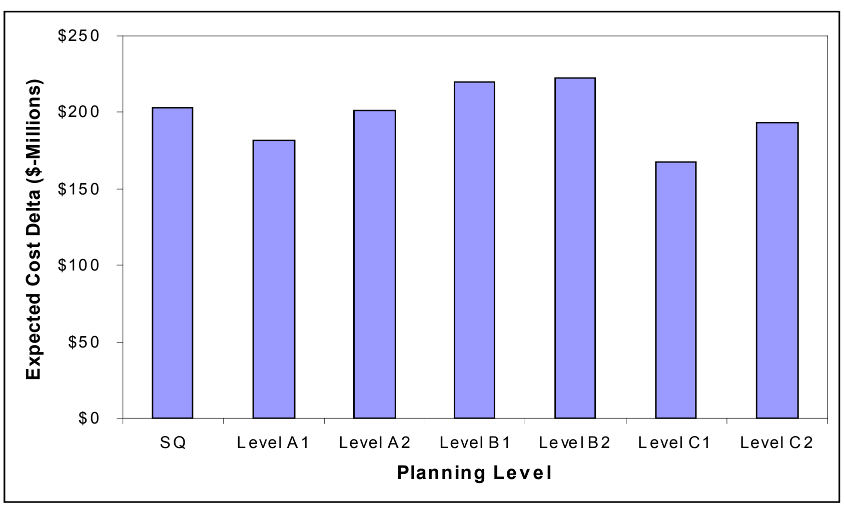


The additional conservation was first applied at the sales forecast level. Then, PSE converted the forecast incorporating the additional conservation from billed sales to actual load, commonly called GPI for generation, purchase and interchange. (See Appendix C for further discussion.) The annual billed sales forecast was first increased to account for the transmission and distribution losses, and then shaped among the 12 months. The load was shaped hourly based on recent historical loads developed in the last General Rate Case. Since the load was shaped hourly it results in the incremental conservation being shaped to take into account seasonal differences and peak capacity needs.

PSE incorporated the decremented load forecast into the portfolio screening model. This lead to a reduction in the quantity of new baseload resources required to meet energy needs from the base case which resulted in a lower capital expenditure. This also reduced the level of additional peaking resources, relatively greater than the base load.

Exhibit XI-30 provides the gross savings from the incremental 5 aMW.

Exhibit XI-30
Gross Savings Impact From 5 aMW Incremental Conservation (20-year NPV)



The gross savings benefit averages out to approximately $200 Million on a 20-year Net Present Value (NPV) basis. The gross savings equals the Expected Cost difference on a 20-year NPV basis between the 15 aMW conservation case and the 20 aMW conservation case. The gross savings presented in Exhibit XI-30 does not include a cost component resulting from the incremental 5 aMW of conservation, but is indicative of the level of cost that would be supported by such an increase in conservation. As PSE develops the conservation supply and cost curves for the detailed conservation study, this simplified analysis will become far more robust. The August 2003 Least Cost Plan update will include dynamic modeling of both the benefits and costs of incremental conservation.

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 include:

1. In absence of a regional or state regulatory requirement on sufficiency standards for resource planning (i.e., reserve margins), 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.
2. At these planning levels, incremental energy needs in 2004 ranged from 10 to 674 aMW, growing to 1,176 to 1,874 aMW by 2013.
3. For capacity, the needs in 2004 ranged from 307 to 1,558 MW, increasing to 2,156 to 3,562 MW in 2013.
4. PSE constructed portfolios consisting of a mix of gas, coal and wind power. 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.
5. 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.
6. PSE developed a dispatch model which provides MWh and variable costs for each resource considered by PSE in order to screen the various portfolios.
7. 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.

8. 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 the meantime, a simplistic analysis of an additional 5 aMW to the current 15 aMW of annual conservation through 2013 yields a gross savings benefit, however, this analysis did not include a cost component. PSE's August 2003 Least Cost Plan update will also include dynamic modeling of both the benefits and costs of incremental conservation.
9. In addition to performing probabilistic risk analysis, PSE modeled three 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.

XII. ANALYTICAL RESULTS AND APPLICATION OF JUDGMENT

This chapter details the electric portfolio analytical results, describes the judgment that PSE has applied to interpret the results and incorporate additional considerations, and creates a roadmap for the electric resource strategy that PSE is adopting with this Least Cost Plan. The analytical results, including analysis of cost and risk, support balancing the portfolio with enough firm resources that can be counted upon to meet retail customer energy needs on an "expected" monthly basis. "Expected" is a lower standard than one that would meet energy loads under all circumstances. Shortfalls on such extreme peak days, would still be met by purchases from the marketplace at the prevailing market prices. For peak capacity planning, the plan addresses resource adequacy in terms of customer needs, and in terms of meeting those needs in the least-cost manner available. For a detailed description of the portfolios and analytical results refer to Appendix I.

PSE reached a major conclusion that the Company should plan to meet its customers' needs for new energy and capacity resources with a diversified portfolio that includes conservation, renewable resources and thermal generation. This chapter presents additional analytical results and conclusions for several topics, including shaping new electric energy and capacity resources to match the seasonal profile of the need, and risks associated with deferring the addition of new resources.

A. Analysis of Planning Levels

The first major area of analytical results focuses on identifying the level of resource adequacy the Company should plan upon to meet its customers' electric energy needs at least cost and within an acceptable degree of risk. As described in Chapter XI, the Company analyzed this topic by identifying and evaluating a wide range of planning levels for both energy and peak capacity.

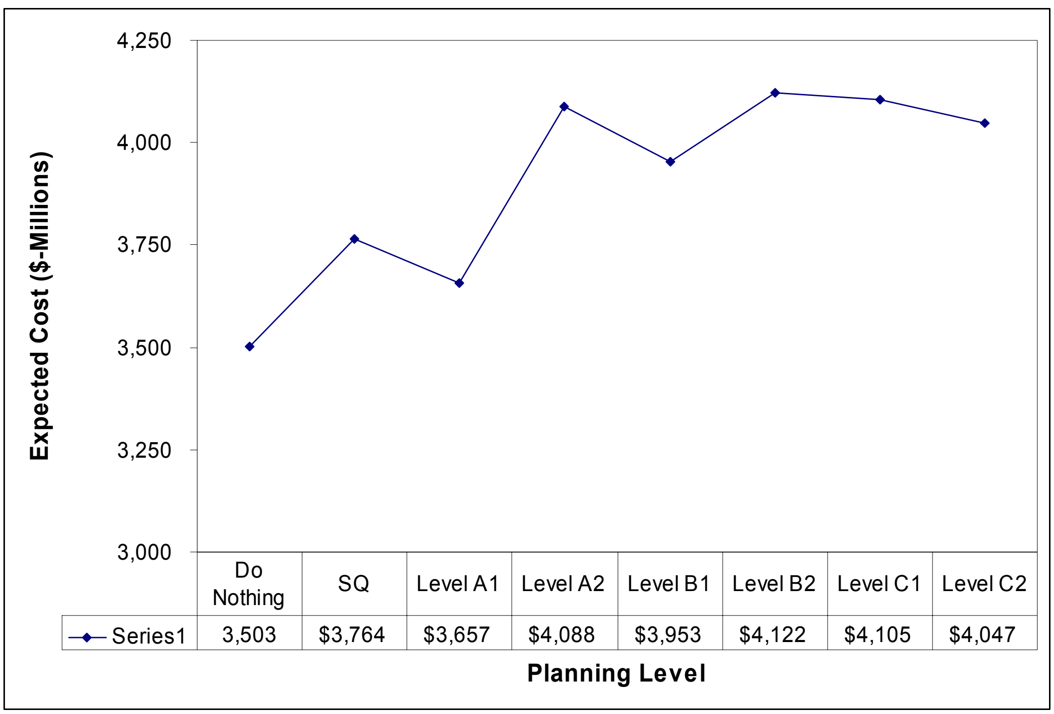
Combined Energy and Capacity Planning Levels

PSE considered a total of eight planning levels, including (in addition to Do Nothing and Status Quo cases), six combinations of different levels of energy resource adequacy and peak capacity adequacy.

Three key considerations should be noted regarding the eight planning levels considered in this stage of the analysis. First, each planning level consists of a planning level for energy and a planning level for capacity. Second, moving from lower planning levels to higher planning levels generally, but not uniformly, involves moving from lower to higher levels of resource adequacy for energy and higher levels of resource adequacy for capacity. Third, the eight planning levels do not include all combinations of the five energy planning levels and the five capacity levels.

In the analytical process, the Company modeled expected costs to customers for the eight combinations of energy and capacity levels. Exhibit XII-1 provides the results of this expected cost analysis for the eight planning levels (see Exhibit XI-1 for a detailed description of the eight planning levels).

Exhibit XII-1
Expected Cost to Customer by Planning Level



The Expected Costs shown in Exhibit XII-1 apply to the average of four different mixes of electric resource technologies at each planning level: (1) All Gas; (2) Gas and Coal; (3) 5% Wind Plus Gas and Coal; and (4) 10% Wind Plus Gas and Coal.

These results illustrate that as the overall level of resource adequacy is increased, including both energy and capacity together, expected costs generally tend to increase as well. However, since the eight planning levels considered at this stage of the analysis reflected combinations of energy planning levels and capacity planning levels, the analysis then turned to a distinct evaluation of energy planning levels (holding the capacity planning level constant), and a distinct evaluation of capacity planning levels (holding the energy planning level constant). The following sub-section discusses the expected cost results for the five energy planning levels, followed by results of the evaluation of five capacity planning levels.

Energy Planning Levels

Exhibit XII-2 presents expected cost results for five different levels of energy resource adequacy, holding capacity resource adequacy constant at the A1, or Status Quo capacity planning level.

Exhibit XII-2
Expected Cost Across Energy Levels Holding Capacity Levels Fixed

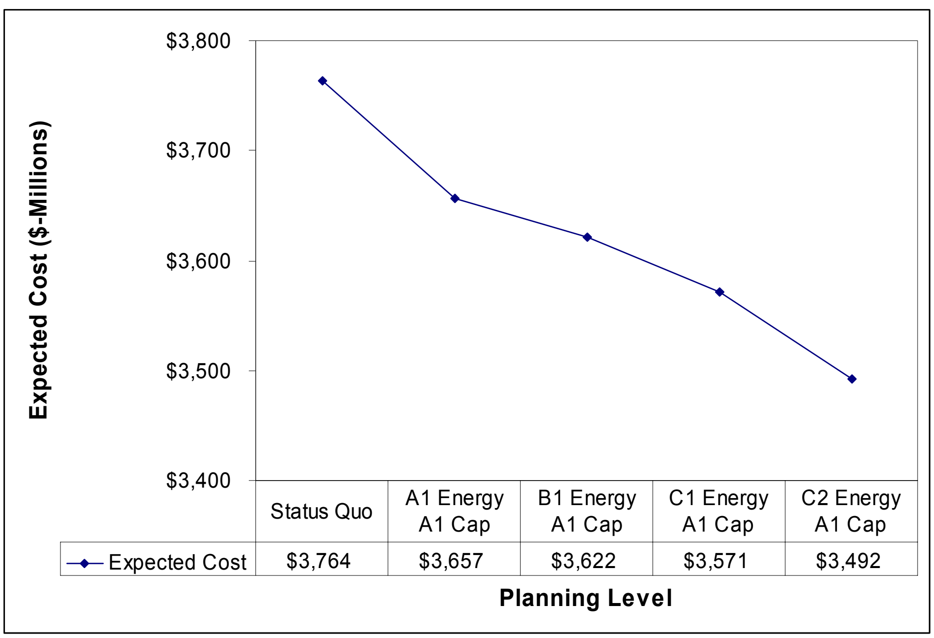


Exhibit XII-2 indicates that as the energy planning level is increased (i.e., as more long-term resources are added), the 20-year net present value cost to customers declines. At first glance, this exhibit might imply that on a purely expected cost basis, the Company should acquire as many long-term baseload energy resources as possible, even to the point of acquiring more resources than needed to serve its retail customers' needs. However, such an 'over-build' resource strategy would create power surpluses that the Company would have to sell into the wholesale power market. The revenue volatility associated with market sales of this surplus energy would cause the Company and its customers to take on a risk profile more akin to a merchant than a vertically-integrated utility.

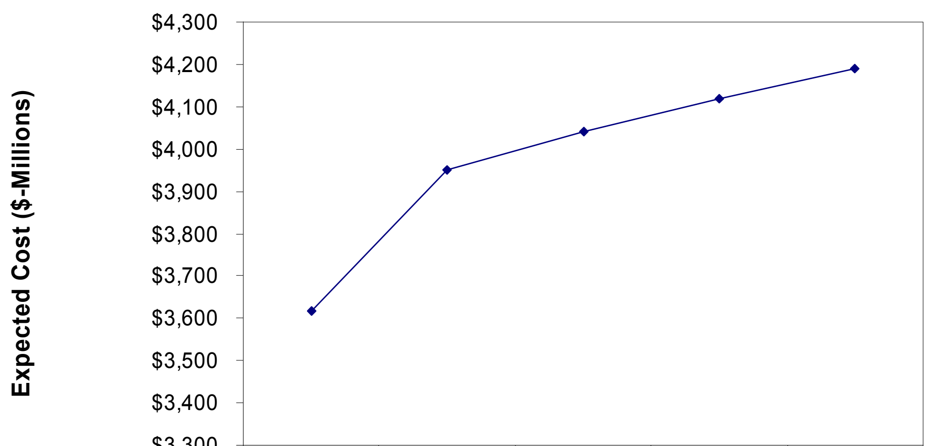
Accordingly, consideration of costs and risks points toward adopting a balanced energy planning level, or one that includes enough long-term firm resources to meet each month's expected customer needs. Specifically, this consideration points to the B energy planning level.

Capacity Planning Levels

Planning to meet peak capacity needs proves more challenging than planning to meet customer energy needs. The process must consider more than just expected costs, as resource capacity needs relate to the Company's obligations to serve customer peak electric needs during cold winter weather periods. The character of the Company's temperature-dependent loads further complicates the analysis, since PSE must plan for winter needle peaks that may occur only for comparatively short periods of times (during one day up to several days). Further, these temperature-dependent loads may not reach extreme peak levels during years when severe winter cold conditions do not materialize. In other words, capacity resources may only be needed for relatively brief periods of time, and may or may not be fully needed in any given winter. As a result, tradeoffs exist between (1) the costs of acquiring and keeping long-term capacity resources ready to meet peak loads, and (2) consequences (i.e., prices, supply shortfalls, possible curtailments) of not being able to fully serve extreme peak loads when they do occur.

Keeping these considerations in mind, PSE performed an analysis of the expected cost to meet various capacity planning levels while holding the energy planning level constant. The expected cost to customer results of this analysis for five capacity planning levels at the "B" energy planning level are shown in Exhibit XII-3. This exhibit shows that the expected cost to customers increases with the addition of more peaking resources to meet progressively higher capacity planning levels.

Exhibit XII-3
Expected Cost Across Capacity Levels Holding Energy Levels Fixed



	B1 Energy-Status Quo Capacity	B1 Energy-23 Deg Capacity	B1 Energy-19 Deg Capacity	B1 Energy-16 Deg Capacity	B1 Energy-13 Deg Capacity
Expected Cost	$3,618	$3,951	$4,041	$4,118	$4,189

In large part, the increased costs at higher capacity planning levels reflect the generic nature of the Least Cost Plan analysis, which typically identifies SCGT generation as the primary, extensively-available resource technology available to meet such loads. However, SCGTs may be a high-cost solution, particularly given the short and infrequent amount of time that they would be needed to meet winter peak load requirements.

While Exhibit XII-3 indicates increasing costs to meet higher capacity planning levels, the Company also recognizes that its analysis has not yet fully considered potential winter peaking power supply contracts or demand-side alternatives that might be used to help meet these needs in a more cost-effective manner than by adding only SCGTs. Accordingly, the Action Plan in Chapter XVII lays out a commitment to further explore a broader range potential resource alternatives to meet these capacity needs.

Further, peaking capacity needs also relate to issues of regional resource adequacy. In January 2003, the Northwest Power Planning Council, the Northwest Power Pool, representatives of regional utilities and representatives of state regulatory commissions began a process to investigate this topic, including possible development of a regional resource adequacy standard. Accordingly, PSE intends to actively participate in this regional process.

However, given the assumptions used for this analysis, the conclusion remains that meeting increasing capacity needs for a given energy need is an increasingly costly requirement, but one that also reflects the Company's obligations to meet its customers' peak demands on cold winter days.

Risk Analysis of Combined Energy and Capacity Planning Levels

Cost and risk tradeoffs for each of the eight portfolio planning portfolios were also assessed. Exhibit XII-4 provides a scatter plot of expected cost versus risk (measured as standard deviation of expected cost) for each of the planning levels.

Exhibit XII-4
Expected Cost vs. Risk

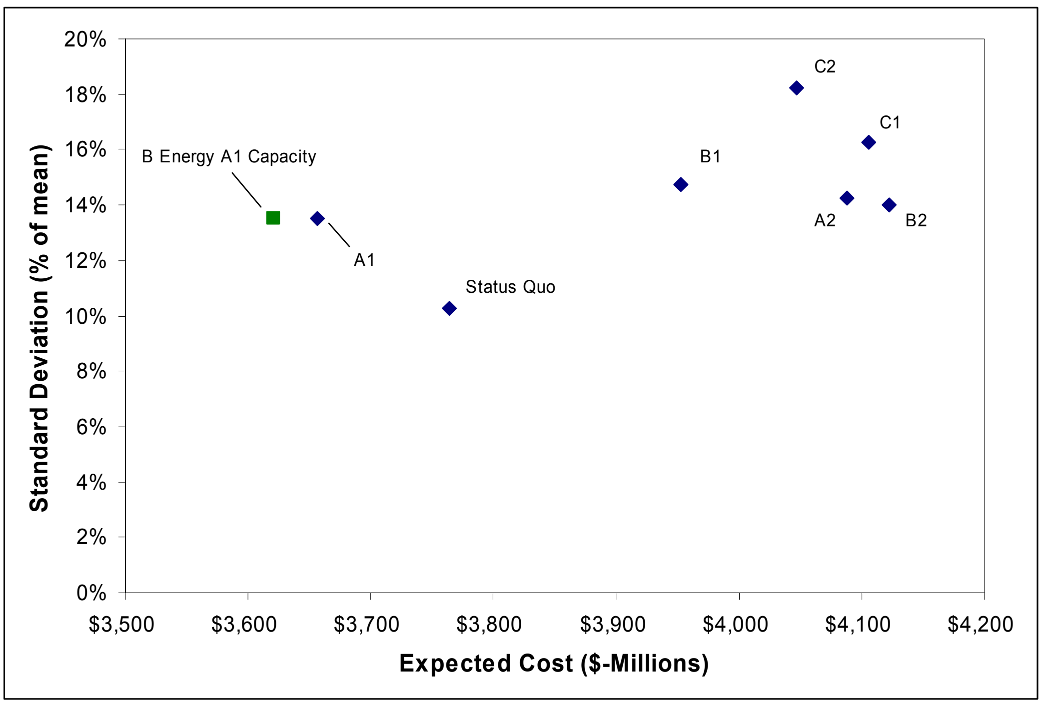


Exhibit XII-4 shows that moving from the A1 planning level to higher levels of B1, A2 and B2, the additional costs of the higher capacity planning levels more than offsets the reduction in cost from the higher energy planning levels. Additionally, these planning levels have a similar risk profile.

Exhibit XII-4 also illustrates that further increases in energy for planning levels C1 and C2 lead to increased risk as the portfolios become surplus and exposed to market price risks associated with dependence on revenue from market sales that would need to be made to dispose of such surplus power.

Lastly, Exhibit XII-4 illustrates the results of an analysis of the impact of combining the B planning level energy with the A1 capacity level. This result indicates a small reduction in expected cost from the higher amount of energy and a negligible change in risk. This leads to a major conclusion that a balanced planning level that provides an adequate amount of energy resources to meet each month's expected customer energy needs proves to be attractive on the basis of cost and risk.

B. Portfolio Shaping Results

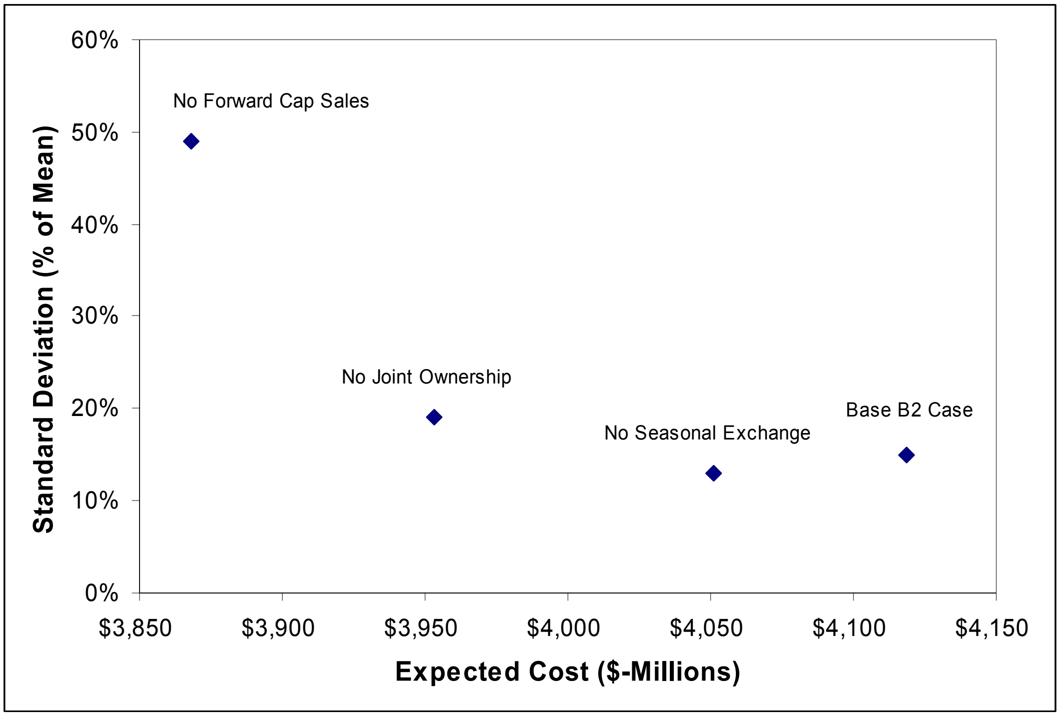
Chapter XI provided a detailed description of the techniques used to seasonally shape both energy and capacity resources to balance the portfolio within each year. The techniques described in Chapter XI include:

1. "Joint Ownership" of base load resources[1]
2. Forward Capacity sales of new Single Cycle Gas Turbines (SCGTs)
3. Seasonal Exchanges

Exhibit XII-5 summarizes an the impact of these three shaping techniques individually under the B2 planning standard and using the AURORA Case III market price forecast. The point labeled Base B2 Case includes the utilization of all three techniques – joint ownership of base load resources, forward capacity sales and seasonal exchanges.

[1] Joint Ownership means functionally shared facility use. Such arrangements could be literally joint ownership or other functional near equivalent commercial relationships. The model currently assumes PSE ownership for September-April, with ownership by another entity for May-November.

Exhibit XII-5
Impact of Shaping Techniques on the B2 Planning Level



The use of Joint Ownership for new long-term resources provides two major results. First, as discussed earlier, PSE's resource portfolio generally does not need energy in the summer months. The result of using a Joint Ownership approach will be to help balance the portfolio seasonally (i.e., by avoiding creation of summer surpluses) and thereby mitigate the need to make significant spot energy sales in summer periods to reduce certain costs. However, the AURORA Case III market price forecast underlying the analysis indicates the highest spot market power prices occurring during the summer months. Expected cost to customers, therefore, is increased by about $150 million (on a 20-year net present value basis), due to the foregoing of revenues from sales of surplus energy into the spot market in the summer months. The second impact involves risk. By avoiding the reliance on making spot energy sales in the summer periods, the use of a Joint Ownership approach produces a significant reduction in risk of over 25 percent. PSE's consideration of this tradeoff between expected costs and risks leads it to conclude the strategy of shaping new long-term resource acquisitions using Joint Ownership arrangements is merited. In other words, comparing the Base B Case and the No

Joint Ownership points, the risks associated with holding summer surplus energy for sale into the spot market outweighs the potential upside in revenues from such a strategy.

Exhibit XII-5 also demonstrates the impact of seasonal Forward Capacity Sales of new capacity resources from SCGTs. The forward sale period (May-October) will return fixed revenues to approximately equal to the carrying cost of an SCGT. The cost difference between the case where SCGT capacity is sold forward and the case where PSE retains and uses SCGT capacity for spot market sales is large due to off-system sales in the peak summer months (similar to Joint Ownership). A significant difference exists in terms of risk exposure. The volatility of power prices can cause wide differences in the amount of economic dispatch the new SCGT resources experience from a probabilistic perspective. The risk associated with exposure to variability in revenue from spot sales is over triple that in the case where PSE sells capacity forward at a fixed price. (It is important to note that this effect is muted at lower capacity planning levels and magnified at higher capacity planning levels.) Therefore, comparing the Base B2 Case and the Forward Cap Sales points, the analysis justifies the forward sale of peaking capacity resources during the May-October period on the basis of risk.

Lastly, Exhibit XII-5 demonstrates the impact of Seasonal Exchanges. Under the AURORA Case III market price forecast, adding baseload energy resources (with Joint Ownership) has a lower cost than the forecasted cost of purchasing power from the spot market. PSE evaluated this by creating a portfolios that removed System Exchanges and replaced them with a roughly equal amount of long-term resources instead. As shown on Exhibit XII-5, replacement of Seasonal Exchanges with a combination of seasonally shaped long-term firm resources and year-round ownership of resources reduces expected cost to customers (on a 20-year net present value basis) by over $100 million. In comparing the Base B2 Case and No Seasonal Exchanges points, the removal of System Exchanges produces a slight reduction in risk. Different from Joint Ownership, System Exchanges allow for far greater flexibility in terms of month to month shaping. This flexibility is attractive especially in shaping the energy needs near the monthly peaks. PSE intends to hold the option open to utilize System Exchanges to a limited extent in the future based on this flexibility and depending on the prevailing market conditions at the time.

PSE's portfolio analysis concluded the need to meet a Level B2 planning standard. Level B2 meets the energy needs of the highest deficit month (for example, 375 aMW in December

2004). The addition of resources in 2004 includes shaping of the 375 aMW, thus no additions are made in the four summer months. As it is, PSE already begins with a long position in the summer and will remain in this position until toward the end of the decade. As conservation and renewable resources are added year round, these additions expand PSE's long position in the summer. The Company currently hedges its summer long position and could continue to do so in the future. Therefore, the analysis results in a portfolio that is long on an annual average basis. Given the month to month variability in PSE's need for energy, and the long-term nature of the analysis, this approximation of portfolio balance is reasonable.

C. Deferral of Long-Term Resource Acquisitions

PSE also analyzed the issue of deferring acquisition of new long-term firm resources. To explore the impact of deferring the acquisition of long-term firm resources, the Company evaluated costs and risks for two sets of resource portfolios:

(1) portfolios composed of various technology mixes, with energy and capacity needs met starting in 2004 using long-term firm resources; and

(2) Portfolios that include the same resource technology mixes as in the first set, but that defer resource acquisitions until 2009. For these deferral portfolios, PSE assumes that energy and capacity needs during 2004-2008 will be met with power purchase contracts. The capacity contract is a five-year contract with a fixed component equal to the carrying cost of a SCGT and a tolling arrangement on the gas. The energy contract is at spot market prices.

Exhibit XII-6 presents the analysis result with the AURORA Case III market price forecast.

Exhibit XII-6
Deferral Analysis

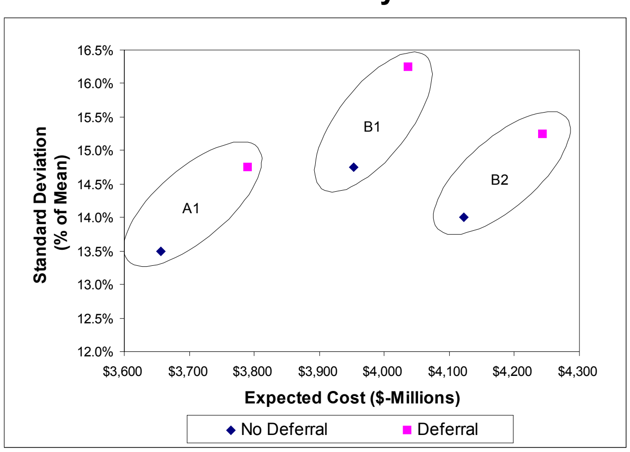


Exhibit XII-6 shows both higher cost and higher risk levels under the deferral strategy for the A1, B1 and B2 planning levels. The higher cost of the deferral strategy stems from two sources. First, market power has a significantly higher levelized cost than that of hard assets during the deferral period. As described in Chapter XI, Section F, the AURORA Case III shows prices increasing above Case I for several years, before returning to equilibrium. The fixed commitment associated with of the capacity contract employed in the deferral strategy provides another cost impact. Standard & Poors (S&P), as well as the other rating agencies treat long-term contractual obligations, such as fixed price power purchase contracts as a liability on the balance sheet. S&P will impute debt to the balance sheet equivalent to the Net Present Value of the fixed cost portion of the contract multiplied by a factor based on the type of contract and the company's entire contractual position (the current factor for PSE is 40 percent). In order to maintain an equivalent capital structure from a coverage ratio perspective, equity must be issued to offset the imputed debt. The return on this equity must be added to the cost of the contract.

The exposure to spot market prices in the energy contract results in the higher risk associated with the deferral strategy. The energy contract could be "firmed up" using fixed price take-or-pay type arrangement. The result of this strategy would be to reduce the risk profile, but it would also further increase the cost by introducing more imputed debt and the associated equity offset.

Conservation as a Deferral Strategy– Execution Challenges

In considering a deferral strategy, one question to consider is whether accelerating conservation acquisition over the next couple of years would allow PSE to meet the majority of its 375 aMW gap beginning in 2004. Currently, PSE is in the process of assessing the conservation potential available in its service territory with preliminary information to be available in the next six weeks. While PSE can not prejudge that analysis at this point, the Company has received comments from some stakeholders that it may be possible that the Company's need for generation acquisitions could be forestalled for some time through significantly accelerated conservation acquisition in the immediate term. For instance, one quite optimistic assumption might be acquisition of 25-30 aMW in conservation per year over the next few years. At such a level, it would be expected that very substantial increases would be made to residential, commercial and industrial programs. Corresponding increases to rider funding would occur under such an effort.

If a level of conservation acquisition such as this were potentially available and the Company were to seek to attempt to acquire it in the immediate term, PSE would need to address whether and how this conservation could be achieved in a least-cost manner. The major obstacles involve the time and resources needed to ramp up programs, and strong preference of market players (i.e. the market place infrastructure necessary to support the marketing and implementation of conservation measures) to maintain consistent levels of conservation acquisition as opposed to ramping-up and ramping down in successive years. As a point of reference, PSE achieved its largest annual amounts of conservation to date in 1992 and 1993 respectively. Nearly 27.9 aMW and 29.7 aMW were achieved in those years, respectively, at a cost of $58.5 M and $64 Million. Since that time, significant improvements have been made in energy codes effecting new construction and major retrofits, and further saturations of efficiency measures has taken place in buildings and homes. Conservation savings are only credited for savings beyond code-required efficiency levels. In the residential sector, there has also been increasing activity in conversions to natural gas in the residential single-family sector.

In order to achieve targets of this magnitude in the next couple of years, a number of market factors would need to work in the program's favor. First, the economy of the region would need to improve to allow for more customer investments in efficiency, particularly for commercial and industrial sectors, and for an increase in building starts. Even if this were the case, PSE may need to further increase incentive levels to accelerate the customers' decisions to go forward on projects. Some of these projects may otherwise be undertaken at lower cost to PSE, however they may take more time to bring on board. With a significant ramp up, program experience has shown the need for long lead times, especially for commercial and industrial projects and for new construction. PSE staff would need to begin laying the groundwork soon.

Residential goals depend heavily on the availability and selection of qualifying products. For example, the region may be beginning to reach saturation levels sufficient to constitute market transformation with compact fluorescent lamps. A shift to CFL-dedicated fixtures would mean greater choice and volumes of fixtures would have to become widely available. A result of this shift from the utility perspective is that the first cost for the first-year savings achieved for fixtures would be higher than for a bulb program. New Energy Star appliances currently have limited selection, and a premium price. It is anticipated that prices will drop over time. It has also been PSE's program experience that a more gradual introduction of certain measures often allows for higher quality, improved reliability and broader applications in the product design develops over time. It should also be noted that the optimum timing to "capture" customers is at the normal replacement cycle for appliances, and only a limited number of appliance turnovers occur in any given year.

Further costs would be incurred on promoting program participation in many sectors. None of those dollars are spent on hardware or equipment to generate savings, although they represent necessary costs to increase awareness, education and to encourage participation. Greater costs would be incurred to educate customers on the need for energy efficiency, particularly if the ramp up occurs absent a major "energy crisis". Similarly, if significant price signals do not motivate customers, it may be more difficult to convince customers to justify making investments in energy efficiency over other, alternative investments they may choose to make.

Sufficient time and resources would be needed to recruit and train the network of suppliers and contractors familiar with the programs in order to achieve larger volumes of participation. Significant risks threaten the long-term viability of programs if they are rapidly ramped-up, and then, a few years later, they ramp down. Trade allies – equipment manufacturers, vendors, designers, architects, and engineering firms, contractors, installers and retail outlets of products and services – are extremely reluctant to invest business resources or marketing to support utility efforts unless they acknowledge some level of longer-term stability to the utility programs. Alternatively, they will charge much higher prices to operate short-term.

In addition to the time and resource challenges, a significant increase in conservation acquisition could significantly exacerbate lost revenue issues. The greater the conservation savings achieved, absent any regulatory mechanism to address lost revenues, the greater the potential financial disincentives to the Company of implementing such a strategy. Such financial disincentives may pose difficulties in implementing potentially least-cost resource strategies and would need to be addressed.

Portfolio Management as a Deferral Strategy – Execution Challenges

Several factors related to the implementation of a Deferral Strategy, with respect to wholesale energy portfolio management, must be considered. The issues of market illiquidity and growing credit concerns create hedging risks associated either with a strategy designed around short-term market purchases or a strategy to procure multi-year contracts with either fixed price power or tolling capacity terms.

The Pacific Northwest wholesale power market has experienced a significant reduction in market liquidity during the last 9-15 months. This has resulted in fewer market participants transacting in wholesale power markets. As described elsewhere in this document, the decision by energy firms to exit the speculative trading business has resulted in a market comprised more of local utilities and a handful of wholesale power marketers. Several of the merchant players who own completed or partially completed merchant power facilities have announced plans to exit 'speculative' trading and focus on trading or optimization around assets. With the future of their assets in the region unknown, it remains unclear which of these marketers will continue to participate in the regional market. Other merchant power producers have substantial credit constraints and may find continuing wholesale power marketing operations to be challenging.

In the future, fellow utility companies will likely make up the majority of PSE's Pacific Northwest counterparty list. It is unlikely these companies will have large trading and marketing positions. Therefore, they may be sellers or buyers of power depending upon their net positions, and only when they need to hedge. Since they have similar load-serving needs as PSE (same seasonal peak), at the time that PSE needs energy and capacity, many of these entities may have similar needs. To rely upon the "market," one would need to assume the regional utilities would have surplus power in the future. With many of the investor-owned utilities filing Least Cost Plans that propose a reduction of current deficit positions, they would need to cover their deficit positions *and* build a surplus into their portfolios for PSE to be able to purchase their surplus.

Market "illiquidity" translates into a widening "bid/ask" spread in the market. Whereas in the past, parties offering to sell and parties offering to purchase may have been only $.25 per MWh apart in their wish prices, that spread has widened significantly to $.50 to $1.50, depending upon the time frame. This widening "bid/ask" is most notable in forward markets, with fewer market participants and less depth to the volume on both the buy and sell side. As the "bid/ask" spread widens, it increases transaction costs for entities. Instead of being able to transact at a mid-market level, in a wider "bid/ask" market, the party wishing to transact will need to raise or lower its price to the level at which the counterparty is willing to transact. This translates into higher costs for energy procurement.

As a result of the Enron bankruptcy and the severe deterioration of many major energy firms' credit ratings, the industry has become extremely concerned about credit risks. This affects PSE in two ways. First, as PSE evaluates counterparty performance risk, it must make some assessments about another company's ability to perform contractual obligations. The other side to credit risk is the manner in which counterparties evaluate PSE. Due to recent events in the industry, market participants are cautious about credit issues. As a result, PSE has limited open credit with its counterparties.

As market conditions have eroded over the last year, PSE's group of counterparties has changed. In addition, the importance of credit considerations has caused many industry players to promote new credit terms (in the form of credit annexes to master agreements). Whereas credit used to be more of a concern to parties engaged in financial derivative markets (under the ISDA agreement and its associated credit annex), the credit issues have now spread to physical agreements.

In the form proposed most often, the credit annex provides that the parties agree bilaterally to establish a credit matrix based upon credit ratings. The higher the rating, the greater amount of open credit for that counterparty. An imbalance can develop if one company has a significantly different credit rating from the other. In PSE's case, this occurs since PSE is just above investment grade, but the parties with whom it feels comfortable transacting are BBB+ or higher rated (S&P ratings).

With respect to deferring a resource acquisition and relying on short-term markets, several concerns must be considered. First, the liquidity and credit reasons described above make the practice of short-term hedging less easy than even one to two years ago. Second, with fewer market participants, PSE has concerns that, all other things being equal, PSE will not be offered competitive prices. Third, while current prices may look attractive next to the combined fixed and variable cost of an asset, no guarantee exists that prices will remain at current levels. In the event short-term prices rose, PSE has limited capacity to step out and forward hedge the projected deficit position in short-term markets. Fourth, there is no guarantee that the resource acquisition will be available to purchase at lower prices than today. If short-term prices were to go up, it is possible a new resource cost would go up in a corollary fashion. The resource price would not rise as much as spot market prices, for the resource valuation would take into account both short-term price trends and longer-term valuation.

With respect to deferring a resource acquisition and attempting to enter into long-term fixed price or tolling agreements, PSE also faces several hurdles. In a fixed price arrangement, the buyer would have less opportunity to optimize the facility, than if it owned the facility. When an asset operator/owner is not the same as the party managing the economic dispatching of a facility, inefficiencies can arise. Instead of fully coordinating activities, there might be some value seepage as the owner mitigates costs and the contracting party (PSE) seeks to maximize commercial value. In contrast, when a party owns a resource, the operations and commercial teams can work on a coordinated fashion to optimize the facility.

The limited number of parties offering long-term supply also concerns PSE. In addition, the credit considerations (from both perspectives of credit issued and credit terms received) are much larger for long-term contracts, and long-term contracts exacerbate the credit problems described above. The amount of potential collateral in the event of a negative market move or a potential downgrade can be quite large. Of potential sellers, only a few companies with A-rated credit and assets exist. PSE could potentially purchase from merchant power producers, but the performance risks are potentially much greater due to many companies' struggle for financing, debt-reduction challenges, and efforts to mitigate exposures and costs associated with leaving the trading and marketing business.

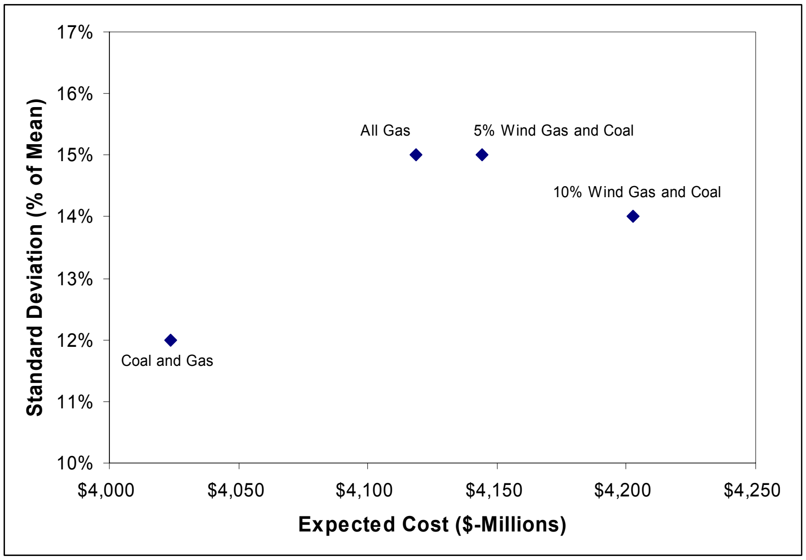
Several benefits may be realized by shifting from purchasing power to purchasing fuel supply for an asset. As a starting point, the total dollars needed to purchase fuel would be a smaller amount than what would be required to purchase power. The benefit would be a smaller utilization of a limited resource, namely credit. Within the overall energy world, the gas producer sector is financially stronger than pipeline, utility, and merchant power sectors. This represents an important consideration from the perspective of counterparty risk of default. Finally, on a historical basis, natural gas prices have experienced lower volatility than power prices, even with factoring out power and gas pricing excursions in western energy markets in 2000-2001.

D. Analysis of Portfolio Diversification

Section B of this chapter discusses the use of Joint Ownership of baseload resources and forward summer-season sales of peaking capacity resources to help mitigate risks. Another important approach to managing risk involves diversification across multiple resource technologies. Each resource technology, including gas, wind power and coal, has its own set of critical drawbacks and uncertainties. Relatively severe price volatilities, oftentimes showing a high correlation with the petroleum/distillate market, impact gas resources. Coal facilities, which would likely be Montana-based, must contend with transmission constraints across the BPA system as well as legislative uncertainty regarding emissions control standards and costs for NO_X, SO_2 and CO_2. Wind power facilities require significant amounts of capital and currently prove to be uneconomic without the Production Tax Credits and reasonable transmission costs. However, the Company's preliminary analysis suggests that wind projects that directly interconnect with its system and that can be timely completed to secure "bonus MACRS" benefits could well be economic. Together these resource-specific issues – the volatility of gas prices, the economic cost of emissions under various regulatory paradigms and the level and/or continuation of wind Production Tax Credits – create an uncertain future, calling for a need for portfolio diversification and a proactive approach to portfolio construction. This section summarizes results of the analysis of resource portfolio diversification across various generating resource technology alternatives.

As described in Chapter XI, the Company evaluated resource portfolios with various combinations of resource technologies. All of these portfolios included 150 aMW of conservation resource acquisition. Exhibit XII-7 illustrates the different cost and risk profiles for four generating resource technology mixes at the B2 planning level.

Exhibit XII-7
Impact of Technology Mix on Expected Cost and Risk



Under an assumption of no CO_2 costs, these results indicate that a portfolio composed of gas-fired generation and coal-fired generation is attractive on the basis of both cost and risk. Other resource technology mixes have higher expected costs and higher risk.

A similar pattern can be seen at the other planning levels evaluated. The All Gas portfolios typically have the highest risk portfolios, due to their increased exposure to volatility in market prices for natural gas. Adding coal to the portfolio technology mix both lowers cost and risk. (Coal fuel prices are assumed to have no volatility in PSE's analysis.) From a cost perspective, the higher capital cost of coal is more than offset by lower fuel costs and higher economic dispatch relative to gas resources. As PSE adds wind power to the coal and gas mix, cost and risk go back up. Two factors drive the increase in cost – higher capital costs for wind power and the assumed need for additional SCGT capacity to back up the wind power energy with capacity. This additional SCGT capacity also leads to the slight increase in the risk profile, initially offsetting the benefit of adding an energy resource with no fuel price volatility. Notice that in the 10 percent wind power case that while the cost goes up as expected, the risk is slightly lower.

There are several additional factors that need to be brought into an analysis of the appropriate mix of resource technologies. The primary factors that PSE considered were emissions associated with fossil-fueled generation, Production Tax Credits for wind power and market price volatility for natural gas. Under new emissions regulations for NOx and/or CO_2, coal and to a lesser extent gas resources could become far less competitive than implied under the assumption of no new costs for NOx or CO_2. (See Chapter XI for a full analysis of the impact of potential emissions regulations on coal and gas-fired assets). Also, as demonstrated in Chapter XI, without the Production Tax Credit, wind power would become far less competitive on the basis of cost. Lastly, significant volatility impacts market prices for natural gas. Gas prices are subject to a number of influences, including changes in crude oil prices. Thus, gas prices may introduce sources of risk that do not currently affect a major base load portion of PSE's existing resource portfolio. Consideration of these factors, in conjunction with the economic and risk characteristics of the technologies, points toward a diversified portfolio strategy. This not only avoids putting "all the eggs in one basket", but allows flexibility for mid-course corrections should one or more of the factors above change.

E. Application of Company Judgment

This section addresses several additional considerations that the Company has factored into development of its Least Cost Plan and the resource strategy in particular. The section begins by noting several relevant guiding principles as stated in the recent Washington State Energy Strategy update. A discussion of the Company's role in contributing to regional load-resource balance follows. Then, the capabilities and limitations of using economic dispatch models for load-resource analysis are described. Next, this section discusses the need to be aware for inconsistencies that may be created when input assumptions to the load-resource analysis assume overall market equilibrium (i.e., 'perfect' resource adequacy at the macro level), but the results of such load-resource analysis indicate taking actions that could lead to different market outcomes (i.e., shortages that could result from insufficient resource development). Finally, the section closes with a discussion of additional judgmental factors that the Company considered in its identification of a diversified resource strategy that includes a mix of various electric resources.

Washington 2003 Biennial State Energy Strategy

In February 2003, the State of Washington issued its biennial update to the State Energy Strategy (SES). The SES addresses a number of the same topics that are also addressed in this Least Cost Plan. The SES also sets forth 13 Guiding Principles as developed by the SES Advisory Committee. Several of these Guiding Principles are directly relevant to PSE's Least

Cost Plan, including the following three principles that focus on utility obligations regarding provision of resource adequacy and protection of customers from market price volatility and other risks.

Guiding Principle	Detailed Annotation
#1 Encourage all load-serving entities to adopt and implement resource plans to ensure they have adequate resources to meet their obligation to serve their customers' projected long term energy and capacity needs	"…underscore the continuing obligation that the state's utilities have to serve their customers' load requirements and to acquire the resources necessary to do so." "…Recognize that current and future electricity markets are likely to experience greater price volatility, and supply risk than has historically occurred prior to 2000. "
#2 Encourage the development of a balanced, cost-effective and environmentally sound resource portfolio that includes conservation, renewables (e.g., wind, geo, hydro, biomass and solar) and least-cost conventional resources.	
#4 Preserve and promote Washington's cost-based energy system to benefit the end use consumer by providing reliable power and reduce the 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	"…Washington continues to be extremely cautious about increasing its reliance on market forces to provide for its electric supply……the main question for Washington is the extent to which our load-serving utilities rely on market purchases or their own resources to serve their loads."

These three Guiding Principles send a clear message that load-serving entities, including PSE, have significant obligations and responsibilities to plan and acquire resources to meet their customers' needs reliably, cost-effectively and without excessive exposure to risks of supply shortage and market price volatility. PSE recognizes these obligations and responsibilities and has factored them into the development of the resource strategy identified in this Least Cost Plan. In particular, PSE has factored them into its consideration of the results of its analysis of energy and capacity planning levels.

PSE Contribution to Regional Load-Resource Balance

Historically, regulators in many states have defined utility obligations to maintain sufficient capacity reserves to meet extreme peaks. Reliability organizations such as NERC also prescribed regional reliability standards. However, recent events in California and other areas that have attempted regulatory restructuring have underscored the dangers of a load-serving entity not having access to sufficient resources to meet customer needs in a deregulated market where prices are free to rise to meet what is essentially an inelastic demand. While price caps can dampen these impacts to a limited extent, the consequences of resource inadequacy have proven to be much more severe than was anticipated when deregulation models were being developed.

A company can not assume that market forces alone will ensure the availability of timely, sufficient, cost-effective electric resources and that the goals set in the SES Guiding Principles described above will be achieved through such an approach. In other words, a utility cannot assume that it would be able fall back upon the regional market at any time to correct imbalances in the utility's portfolio without exposing itself and its customers to substantial price risk and potential impacts on reliability.

Therefore, it has become very important for PSE to consider its load-resource balance in the context of the regional load-resource situation. The interactions between PSE's load resource balance with the Pacific Northwest region as a whole can be seen in Exhibit XII-8.

Exhibit XII-8
PSE and Regional Load Resource Balance

Exhibit XII-8 illustrates that the greatest adverse consequence to PSE and its customers would occur with an out-of-balance resource portfolio in which the Company must either purchase power from the regional market to cover shortfalls in its own resources, or sell power into the regional market to dispose of resources surplus to its customers' needs. While it may be tempting to try to "time" the market by staying short during periods when the regional market appears to be surplus, or by going long during periods when the regional market appears to be deficit, this is highly risky, both in terms of execution and in terms of potential consequences. Accordingly, PSE believes that a more robust strategy is to plan adequate electric resources to meet its customers' needs without excessive reliance on the regional market. Again, this supplements the results of the Company's analysis of energy and capacity planning levels. In addition, it further validates the analytical results that indicate significant risks would be associated with deliberately delaying acquisition of new resources.

Evaluating Energy and Capacity Needs with Economic Dispatch Models

The utility industry has developed various resource planning models to evaluate and select preferred resource strategies to meet a utility's projected loads. These models provide the analytical capability to evaluate resources and alternatives under a variety of assumptions. They also provide a useful perspective of the future under a market that is often assumed to continuously remain in equilibrium over the long run. The models assume that when adequate existing resources to serve loads no longer exist, and market prices begin to increase, unspecified market participants will anticipate this change and respond by constructing new generation facilities in time to mitigate the tightened conditions. As a result of this modeling approach, most dispatch models focus on the evaluation of the energy component of a utility's resource planning decision and will tend to undervalue the expected value of the utility's capacity resources. Due to this underlying assumption of a well-functioning market that always remains in equilibrium, extreme peak demand-supply imbalances will not occur in the model.

However, recent experience has shown that extreme variability impacts energy markets. The merchant generation and marketing sector observed the magnitude of market price spikes that can be caused by capacity constrained conditions and soon modified their use of dispatch models based on equilibrium assumptions. Many merchants and marketers shifted to use of option valuation models that explicitly reflect the impacts of market price volatility under market disequilibrium conditions. While such models are perhaps a better reflection of the dynamics of price volatility in deregulated markets, they also highlight the potential disconnect that can be created by basing a utility's resource plan on a fundamental assumption that the regional marketplace will continuously remain in equilibrium over the long-run. This disconnect is addressed further below.

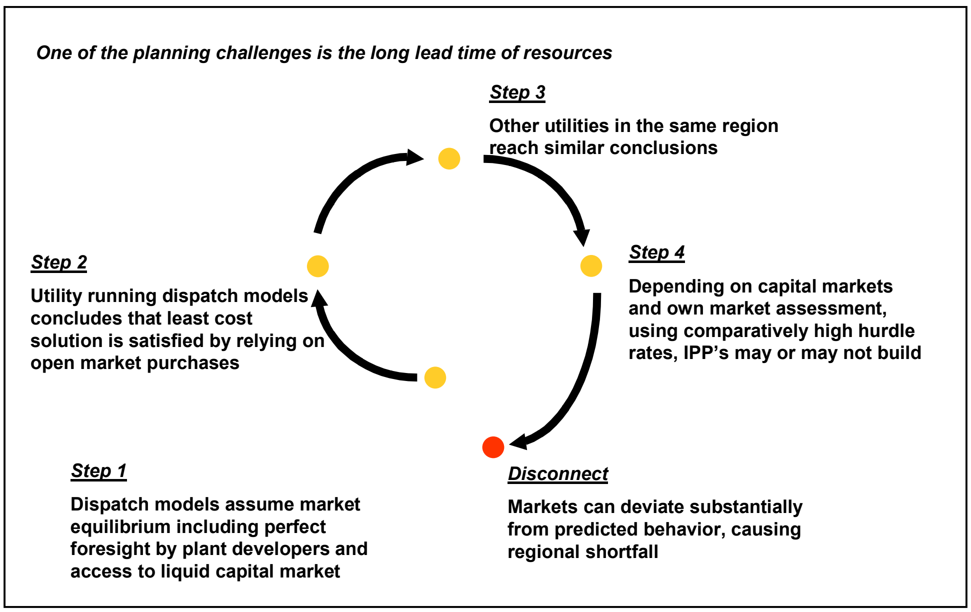
Bridging the Disconnect in Dispatch Models' Analysis

It was noted earlier that economic dispatch models assume a long-run equilibrium condition in which extreme supply-demand imbalances do not occur in the model. In the real world however, capacity shortfalls can and do occur. They can result from below-normal hydroelectric conditions, unforeseen outages at large generating facilities, inadequate transmission facilities, transmission line outages, or a variety of other reasons. When capacity shortfalls do occur, a "disconnect" can be created between a dispatch model's view of long-run equilibrium market prices, and the impacts of market price spikes that can occur if market equilibrium is disturbed.

This same type of disconnect can occur in what the model assumes for the industry's and the region's response to long-term market price signals and other conditions. In the real world, if market price projections are perceived by developers to be too low, with constrained access to capital to finance new resources, then market participants will not build new facilities.

Meanwhile, if utilities assume that other entities will develop new resources to maintain balance in the regional market where the utility is planning to buy power to meet its customers' needs, this can lead to an actual outcome of regional supply shortfalls and higher market prices. This potential disconnect obligates utility planners to increase the importance of resource capacity adequacy beyond what might be indicated by a strict interpretation of dispatch model results that are based on an assumption of market equilibrium. The cycle that could result from this disconnect is shown Exhibit XII-9.

Exhibit XII-9
Disconnect in Dispatch Models' Analysis



Regulators have also recognized that capacity can be undervalued in competitive markets and therefore have attempted to develop mechanisms such as installed capacity (ICAP) pricing to assign an explicit premium to those assets needed to meet capacity needs in order to encourage their development. FERC has recognized the impact of this disconnect in its development of its Standard Market Design (SMD) where it states:

> …Some market participants depend on government intervention during severe shortages as an alternative to paying their share of the cost of developing adequate regional resources. ***As long as regional reserves are made available to all, a load-***

> ***serving entity can reduce its own reserve resource costs and rely on the resources of others. The result is that all load-serving entities will tend to follow this strategy, leading to a systematic under-investment in resources needed for reliability***. …….
>
> …..This is the well-known "free rider" problem for public goods, those for which consumption cannot be limited to those who paid for them (such as parks and national defense) and that are available to all users even if only some users pay for them. See, e.g., Lee S. Friedman, The Microeconomic of Public Policy Analysis, Princeton University Press (Princeton, NJ 2002), which states at pages 597-598: If their provision were left to the marketplace, public goods would be under-allocated. The reason is that individuals would have incentives to understate their own preferences in order to avoid paying and free-ride on the demands of others. Thus, public goods provide one of the strongest arguments for government intervention in the marketplace: not only does the market fail, but it can fail miserably.
>
> ***emphasis added***

The requirement for PSE to apply judgment to its analytical results leads to the development of a resource strategy that balances the Company's responsibility to minimize the cost of meeting its customer's needs with its responsibilities to contribute to maintaining regional load-resource balance and not become a "free rider" dependent upon other market participants during peak demand periods. This consideration further supplements the results of the Company's analysis of energy and capacity planning levels and supports a resource strategy that maintains a balanced portfolio to meet customer needs for both energy and winter peak capacity.

PSE has seen how dispatch models based on inputs that assume continuous market equilibrium tend to undervalue capacity resources. It has also been seen how the current analysis and assumptions considered a limited set of available capacity resources, which can be quite expensive when only used for those rare, extreme peak periods. This has led to identification of a need for more analysis and research by the Company to develop additional supply- and demand-side resource solutions to help meet extreme winter peaks.

As also discussed earlier in this chapter, the Company has a significant role in contributing to the regional load-resource balance for energy and capacity. PSE intends to actively participate in regional efforts that have recently been initiated to address this topic. Utility obligations, as well as the methods and criteria that they use to balance tradeoffs between costs and risks, represent important elements of the overall topic of regional resource adequacy. In addition, opportunities to consider regional load diversity, and to develop collaborative regional approaches merit serious review and appear to offer considerable potential.

Additional Judgmental Factors Supporting A Diversified Resource Mix

As discussed in Section D, each major resource technology type has a unique combination of favorable features, as well as risks and uncertainties. For example, coal-fired generating resources offer potential benefits of comparatively low and stable costs, but they also produce emissions that raise environmental concerns and may become subject to increased costs (e.g., CO_2). Natural gas-fired resources are currently the predominant source of new generation in the region and nation, but they involve risks associated with volatility of market prices for natural gas. Wind power generation produces no air emissions and is not subject to market fuel price risks, but its economic viability is highly dependent on extension of federal production tax credits.

In other words, no single electric resource technology has a clear and obvious advantage in meeting all of the Company's need for new resources. Further, it is not possible to predict with any degree of certainty the future outcomes of the particular uncertainties associated with each of the generating resources discussed above. In recognition of this, PSE is committed to the use of conservation and renewable resources. In addition, the Company has concluded that a diversified long-term resource strategy that identifies several forms of generating resource technologies provides an effective way to spread out and mitigate the risks associated with each specific technology type.

F. Analytical Conclusions

PSE's Least Cost Plan is designed to identify the best long-term resource strategy to meet its retail customers' needs at least cost consistent with acceptable risk. To accomplish this, the Company has reached the following conclusions on the basis of its analysis and its application of judgment:

1. The Company will plan to acquire long-term firm energy resources sufficient to ensure that customer energy needs are met on an expected monthly basis.
2. To meet its customers' winter peak demands, the Company will plan to maintain adequate capacity resources to meet its obligations to serve peak loads, contribute to regional load-resource adequacy and do so at least cost. The Company plans to meet a capacity planning level associated with loads at a minimum hour temperature of 16

degrees F and will seek lower-cost approaches than relying only on SCGTs to meet this capacity planning level.

3. The Company will develop a diversified portfolio of multiple resource technologies to meet its customers' future energy and capacity needs, including the establishment of a goal based on the assumptions used in this analysis (e.g., the modeling focused on wind power backed by SCGTs) to meet five percent of its customers' energy needs by 2013 through the use of renewable resources. PSE believes there may be cost-effective ways to increase its use of renewable resources and sets a higher target to meet 10 percent of its customer energy needs through renewable resources, including wind power and other technology types.

Each of these conclusions is described in greater detail below.

Energy

To meet its energy needs, the earlier discussion demonstrated that adding long-term, firm resources is the least cost approach. The analysis also shows that beyond a certain amount of new resource additions, the overall portfolio would become surplus to customer needs and the Company would become more exposed to market price risk as a seller and would take on a risk profile more like a merchant. Energy level "A" meets the average November-February energy needs, but relies on market purchases to meet some remaining monthly needs. Energy level "B" meets the expected deficit needs for each month of the year, while energy level "C" provides additional energy needs above the highest deficit month. The Company's selected planning level is therefore "B", which meets the highest deficit month. The Company also plans to pursue Joint Ownership for new resources to dispose of energy in those parts of the year when it does not have resource needs, so as to reduce its overall exposure to market price risks. The "B" energy level involves adding 375 aMW energy in 2004, growing to 1,600 aMW in 2013.

Capacity

To meet its capacity needs, the Company must balance the increased costs of adding new capacity with the obligation to meet customer peak needs without imprudently relying on non-specific market resources to meet future needs. The "A" planning levels would appear to be less expensive under strict evaluation of base case assumptions. However, there is considerable risk exposure to a regional under-build scenario and the resultant high prices which would put the Company in the same situation the region recently experienced during the Western Energy

Crisis. Furthermore, the Company has a responsibility to avoid a “free-rider strategy”. Instead, it recognizes that by planning adequate capacity resources to meet its customers’ needs, it can also help maintain resource adequacy in the Northwest region. Therefore, an increase beyond the “A” capacity level is warranted.

The B1 and B2 planning levels both provide the improved level of reliability that the Company and its customers require. However, the analysis conducted during this least cost planning process has indicated that current planning assumptions make the ”B” capacity planning levels a higher cost option. This is largely a result of the assumed use of SCGT’s as the primary resource technology to meet the higher peak demand levels. Even with seasonal shaping transactions to lower the net costs of SCGT resources, the Company recognizes that it still needs to find lower cost options to meet capacity needs at the B1 or B2 level. The primary areas that appear to offer the most potential would be greater use of winter capacity purchase agreements and greater use of demand-response programs oriented toward extreme peak circumstances. Moving to the higher “C” capacity levels would meet the peak demand requirements, but would also entail an inordinate cost and would not be cost-justified, given current results of analysis. Therefore, the Company has selected planning level “B2”, with a commitment to identify lower cost options than just adding SCGTs. The B2 capacity level involves adding approximately 1,050 MW of capacity resource in 2004, growing to 1,887 MW in 2013.

Technology Mix

The analysis of alternative resource technologies demonstrates that diversified portfolios can offer reduced exposure to major uncertainty factors. There are a variety of uncertainties associated with each of the available resource technologies, ranging from emissions costs for thermal resources to extension of Production Tax Credits for wind power. Exposures to these risks can be mitigated by diversifying the portfolio of new resources across technology types. The analysis also demonstrates the benefits of a portfolio that would include renewable resources to meet a portion of customer energy needs. Portfolios with higher amounts of renewable resources (modeled as wind power energy) indicate higher costs however, which is primarily a result of the Company’s assumption that wind power would need to be backed with SCGTs for firming requirements.

The Company is adopting a policy that incorporates renewable resources into its portfolio where possible. The Company has committed to performing further work to identify more effective approaches to integrate wind power and other renewable resources into its portfolio. PSE also intends to seek specific resource acquisition opportunities for other types of renewable resources beyond just wind power. On this basis, PSE has established a goal of meeting five percent of its customers' energy needs with renewable resources by 2013, and has set a higher target of serving 10 percent of its customer energy through the use of renewable resources by 2013.

G. Summary

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

1. PSE modeled expected costs to customers for the eight combinations of energy and capacity levels. Results of this analysis indicated that as the overall level of resource adequacy is increased, including both energy and capacity together, expected costs generally tend to increase as well.
2. Evaluation of increasing energy planning levels (holding the capacity planning level constant) indicates as the energy planning level is increased (i.e., more long-term resources are added), the 20-year Net Present Value (NPV) declines. Acquiring as many long-term baseload energy resources beyond the needs of PSE's customers, or an "overbuild" strategy, however, would create power surpluses the Company would have to sell into the wholesale power market.
3. Evaluation of increasing capacity planning levels (holding the energy planning level constant) indicates that expected costs to customers increase with the addition of more peaking resources to meet progressively 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. PSE intends to examine other potentially lower-cost sources of capacity. Further, the Company's obligations to meet reliability requirements and its obligations to serve winter peak needs of its customers also need to be considered.
4. Evaluation of tradeoffs between expected costs to customers and risk (represented as variability of costs) indicates that moving from a lower energy planning level (A1) to higher levels of B1, A2 and B2, the additional costs of the higher capacity levels more than offsets the reduction in cost from the higher energy planning levels. Additionally, these planning levels have a similar risk profile.

5. Thus, a balanced planning level that provides an adequate amount of energy resources to meet each month's expected customer energy needs proves to be attractive on the basis of cost and risk.
6. The use of Joint Ownership for new long-term resources helps balance the portfolio seasonally and thereby mitigate the need to make significant spot energy sales in summer periods. Moreover, by avoiding the reliance on making spot energy sales in the summer periods, the Joint Ownership approach produces a significant reduction in risk of over 25 percent.
7. PSE's examination of the impacts of Seasonal Forward Capacity Sales of new capacity resources from SCGTs justifies the forward sale of peak capacity resources during the May-October period on the basis of cost and risk.
8. The analysis of the impact of replacing Seasonal Exchanges with a roughly equal amount of long-term resources indicate a reduction in expected costs to customers (on a 20-year NPV) of over $100 Million, in addition to a slight reduction in risk.
9. Analysis of resource portfolios that defer new resource additions until 2008 shows both higher cost and higher risk levels under the deferral strategy for the A1, B1 and B2 planning levels. Moreover, the execution challenges to a deferral strategy, including an illiquid marketplace, the impact on PSE's credit and market purchase risk make this a costly and risky strategy for PSE to pursue.
10. 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:

1. 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 and to diversify across resource technologies. These Guiding Principles further support the Company's selection of a

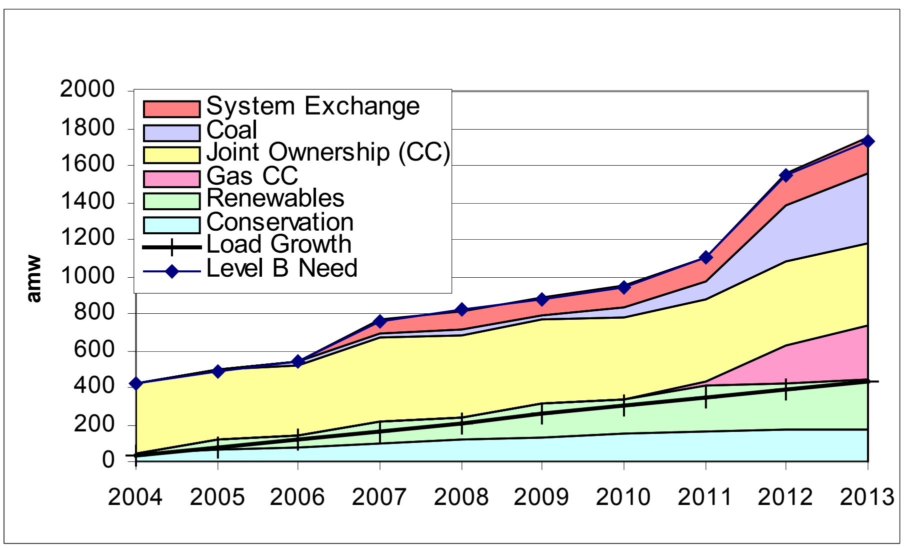
diversified and balanced resource strategy including energy and capacity planning levels that provide adequate resource to meet expected customer needs.

2. 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 are greatest when the Company's portfolio is significantly out of balance.
3. 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.
4. 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. Because no available generating resource technology is clearly superior to all other alternatives, the Company's preferred resource strategy identifies a mix of resource alternatives.

XIII. ELECTRIC RESOURCE STRATEGY

Chapter XIII presents PSE's long-term electric resource strategy. PSE recognizes an opportunity to establish a balanced long-term resource strategy that meets customers needs, while keeping rates low and protecting customers against market and price risks. To realize this vision, PSE has established a goal of serving five percent of its customers' needs through the use of renewable resources by 2013. The resource strategy also includes the model assumption of acquiring 150 aMW of new conservation resources over the next 10 years, possibly updating this commitment based on the outcome of the region's current collaborative developing new conservation potential assessments. To meet the rest of its need over the planning period, PSE will look to a diverse mix of other resources, including combined cycle gas-fired generation, coal-fired generation, market purchases, Joint Ownership or other seasonal resource shaping approaches, and winter peaking resources. Exhibit XIII-1 presents a graphical view of PSE's 10-year energy resource addition strategy.

Exhibit XIII-1
Ten-Year Electric Resource Addition Strategy
(Based on 10% Renewable Resource Target)



A. Conclusions Supporting PSE's Electric Resource Strategy

As mentioned in Chapter XII, PSE's analysis demonstrates that diversified portfolios offer customers reduced exposure to various risks, including gas price volatility and potential emissions impacts and costs. PSE acknowledges this factor, and has adopted the objective of maintaining a balanced portfolio of firm resources to meet its retail customer needs. To serve customer energy needs, PSE will plan adequate long-term firm resources to serve each month's energy load under average hydro conditions. In order to ensure that PSE meets its winter energy deficit, without creating summer energy surpluses, PSE will seasonally shape its new energy resources. To serve customer capacity needs, PSE has established a goal of adequate resources to serve retail load during winter peaks at temperatures as low as 16 degrees Fahrenheit. Again, PSE seeks to fill its winter capacity deficit, without exacerbating summer resource surpluses. To reach this goal, PSE will seasonally shape its capacity resources and also seek lower-cost resource alternatives than relying exclusively on new SCGTs.

B. Conservation

PSE recognizes the significant value of conservation in a long-term electric resource strategy. For planning purposes, PSE assumes 150 aMW of new conservation over the next 10 years. In the analysis for this Least Cost Plan, PSE assumes the conservation savings will be proportional to the seasonal shape of customer loads. In August 2003, PSE will incorporate results from the regional conservation resource potential analysis into an update of its April Least Cost Plan. At that time, PSE will revisit its 150 aMW assumption and may revise this number.

It is important to note that other elements of PSE's long-term resource strategy do not "preempt" further commitments to conservation. As detailed in Chapter X, PSE there are adequate avenues for further conservation initiatives. As detailed in PSE's two-year Action Plan in Chapter XVII, PSE has made commitments to further explore conservation and demand response opportunities. A decision by PSE to acquire a new generation resource will not come at the expense of its corporate commitment to conservation.

C. Renewable Resources

As a result of its electric resource portfolio modeling analysis, PSE has established a goal of serving five percent (133 aMW) of its customers' energy needs by 2013 through the use of renewable resources. For this Least Cost Plan, PSE's portfolio modeling analysis focused on one renewable resource technology – wind power, and assumed that new simple cycle combustion turbines (SCGTs) would be used to back up intermittent energy output from wind power. PSE recognizes that this may be an overly conservative assumption. By applying its judgment to this assumption and the associated analytical results, PSE believes it may be possible to find less expensive ways to incorporate wind power into its electric resource portfolio.

Accordingly, during 2003 PSE intends to more thoroughly investigate impacts and approaches for adding potentially significant amounts of wind power into its electric resource portfolio. This follow-on effort will address the intermittent nature of wind generation, including its interaction with other types of resources and the impacts on costs and reliability for the Company’s overall resource portfolio. Other factors that will be addressed include reserve requirements, generation imbalance costs and transmission for wind power.

PSE also recognizes that other renewable resource technologies in addition to wind power may fit into the Company’s long-term resource portfolio. Therefore, during 2003 PSE will also expand the scope of its resource analysis to examine other renewables, including biomass and geothermal resources.

Given the possible alternatives to using SCGTs to back up wind power and the possibility of also including other renewable resource technologies into its portfolio, PSE has established a higher target of serving 10 percent (266 aMW) of its customer energy needs through the use of renewable resources.

PSE's draft renewable policy statement in Appendix M illustrates the corporate commitment that PSE is making to renewable energy resources. In addition, the two-year Action Plan for this Least Cost Plan describes initial steps PSE will take in an effort to make this 10 percent target more attainable. Meanwhile, PSE is already taking actions to increase the amount of renewable resources in its portfolio. PSE is currently evaluating several wind resource proposals that it received in response to solicitations for new resources that the Company issued in 2002. PSE is also considering pursuing a more targeted approach for the acquisition of renewable resources.

D. Diversified Mix of Other Resources

PSE’s existing resources – including hydro, coal, gas, and both power supply and NUG contracts – will continue to play an important role in meeting PSE’s resource needs. As loss of a portion of these resources occurs, and power supply contracts expire, PSE will not only look to conservation and renewable resource opportunities, but also to a diversified mix of other resources. Combined cycle gas-fired generation and coal-fired generation both have potential roles. PSE will include combined cycle generation in its near-term mix, and will shape this resource to meet monthly energy needs. New coal-fired generation will not be included in PSE's near-term resource mix, however, PSE will monitor development and acquisition opportunities. While coal may not be the first fuel of choice for PSE, the Company recognizes this technology offers benefits in terms of long-term costs and mitigating gas and market price risk. However, the environmental costs of coal must be taken into consideration as well. As such, PSE will monitor opportunities for coal, but makes no near-term commitment to this resource.

PSE also plans to seasonally shape new baseload generating resources and acquire winter peaking resources to meet its growing needs.

E. Other Considerations

PSE's Least Cost Plan focuses mainly on "generic" resource technologies. Currently, PSE is monitoring the market for attractive resource acquisition opportunities, considering both asset ownership and power contracts as possibilities. New conservation resource potential assessments will be available in May 2003, serving as the basis for PSE's August 31, 2003 update. PSE will continue to investigate seasonal shaping techniques and wind integration issues, as outlined in its two-year Action Plan in Chapter XVII.

F. Summary

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

1. Energy resources will be adequate to serve each month's expected customer energy needs under average hydro conditions.
2. Capacity resources will be adequate to meet customer peak loads of 16 degrees Fahrenheit.
3. New energy and new capacity resources will be shaped to fill winter deficiencies, without creating summer surpluses, to the extent feasible.
4. For planning purposes, PSE assumes the acquisition of at least 150 aMW of new conservation over the next 10 years.
5. PSE will pursue a goal of serving five percent of its customers' energy needs through renewable resources. Given the possible alternatives to using SCGTs to back up wind

power and the possibility of including other renewable resources in its portfolio, PSE has established a higher target of serving 10 percent of its customers' energy needs through renewable resources.

6. A diverse mix of other resources, including combined cycle gas-fired generation in the near-term and possibly coal later in the decade, in addition to seasonal exchanges and other market transactions provide options for meeting the rest of PSE's resource needs.
7. PSE will continue to monitor the market for acquisition opportunities and power contracts, but not at the expense of its corporate commitment to conservation.

XIV. EXISTING GAS PORTFOLIO RESOURCES

Chapter XIV provides an overview of PSE's existing gas resource portfolio. The chapter begins with background on PSE's gas conservation and efficiency approach, providing details on specific conservation and efficiency programs. Next, this chapter turns to the supply side and details PSE's pipeline capacity, storage capacity, other capacity resources and gas supplies. The chapter ends with an assessment of PSE's existing gas supply/demand balance.

A. Conservation and Efficiency

Overview

PSE has provided conservation services for natural gas customers since 1993, saving approximately 5,916,258 therms (cumulative) through 2002. These energy savings were captured through energy-efficiency programs primarily serving residential and low-income customers from 1993 through 1998. Beginning in 1999, PSE recognized nearly three-quarters of the energy savings from commercial and industrial customer facilities. In terms of investments in energy efficiency, the Company has invested close to $6 million in natural gas conservation. 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 heating equipment measures, while certain water heating measures may have shorter measure lives.

As discussed previously in Chapter VIII, PSE recently increased its commitment to conservation by doubling its annual conservation targets in August 2002. When PSE filed new conservation tariffs with the WUTC, 11 programs were expanded, three new programs were added and three pilot projects were initiated. The scope and size of programs received significant input 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 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.

Current PSE Natural Gas 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.

PSE funds these programs through natural gas “tracker” funds collected from all customers. The scale and scope of PSE’s natural gas programs have been smaller than its electric programs. The variety of applicable natural gas end-uses primarily include space, water and process heating – a list of measures more limited than those available to electric customers. Within PSE’s joint electric and gas service territories, the Company offers customers all applicable conservation programs – including both electric and gas. Since the natural gas territory has significant overlap with neighboring electric utilities which offer their own programs for electric savings, PSE carefully tracks these programs to avoid PSE electric offerings for those non-PSE electric customers. Conversely, in areas of the service territory where another utility serves natural gas, PSE will only offer programs according to the electric rate schedule which it serves at a given location.

Exhibit XIV-1 provides an overview of current PSE’s current gas conservation and efficiency programs. See Appendix E for more detailed information on these programs.

Exhibit XIV-1
PSE Existing Gas Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
Energy Efficiency Information Services – Personal / Business Energy Profile	• Free energy audit survey, analysis, & report providing customers with specific & customized energy efficiency recommendations.	• No energy savings currently credited
Energy Efficiency Information Services – Personal Energy Advisors	• Phone representatives provide customers direct access to PSE's energy efficiency services & programs through a toll-free number.	• No energy savings currently credited
Energy Efficiency Information Services – Energy Efficiency Brochures	• Brochures on program participation guidelines & how-to guides on energy efficiency opportunities.	• No energy savings currently credited
Energy Efficiency Information Services – On Line Services	• Sections of PSE's web site dedicated to energy efficiency & energy management information, program details & application instructions.	• No energy savings currently credited
Efficient Natural Gas Water Heater	• $25 rebate towards purchase of an energy-efficient gas water heater served with PSE natural gas.	• 170,667 therms • 7-year resource
High-Efficiency Gas Furnace	• $150 rebate toward the purchase of a high-efficiency gas furnace, offered to residential customers for existing homes & new construction.	• 224,667 therms • 15-year resource
Energy Efficient Manufactured Housing	• $150 rebate to the buyers of qualifying Natural Choice/ Energy Star labeled manufactured homes with natural gas heat.	• 12,720 therms • 20-year resource
Small Business Energy Efficiency Programs	• Rebates for energy-efficient upgrades & programmable thermostats.	• 93,308 therms • 10-year resource
Commercial & Industrial Retrofit Program	• Incentives to commercial and industrial customers for cost-effective energy-efficient upgrades.	• 1,406,033 therms • 15-year resource
Commercial & Industrial New Construction Efficiency	• Incentives to commercial & industrial customers for cost-effective energy-efficient building components or systems.	• 100,000 therms • 20-year resource

Exhibit XIV-1
PSE Existing Gas Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
Resource Conservation Manager (RCM) Program	• PCM to implement low-cost/no-cost energy saving activities with building occupants & facility maintenance staff.	• 266,667 therms • 3-year resource
PILOT Programs – Residential Duct Systems Pilot	• Participating customers receive the duct diagnostic measurement services & sealing services from the certified contractor at no cost.	• 10,667 therms • 10-year resource
PILOT Programs – Commercial & Industrial Boiler Tune-up Pilot	• Pilot provides incentives of 50% of the cost of the tune-up for customers to have older boilers tuned up for the first time.	• 377,000 therms • 1-year resource
Public Purpose Programs – Energy Education 6-9th Grade Environmental	• Conservation education program funded by PSE, along with 26 other utilities, cities, and agencies responsible for energy, water, & environmental programs in the Puget Sound area.	• 80,756 therms • 10-year resource life
Public Purpose Programs – Residential Low-Income Retrofit	• Funding for installation of home weatherization measures for low-income gas & electric heat customers.	• 120,800 therms • 20-year resource life

B. Pipeline Capacity

Puget holds 456,381 Dth/day and 413,557 Dth/day of firm TF-1 and TF-2 transportation capacity, respectively, on the Northwest Pipeline (NWP). PSE also holds 90,392 Dth/day on PG&E's Gas Transmission Northwest (GTN) in order to deliver gas received at Kingsgate, British Columbia, to NWP in eastern Washington. PSE has recently acquired capacity on Duke Transmission (formerly Westcoast) from Station 2 to Huntingdon / Sumas in British Columbia. A further discussion of this acquisition appears in Section D of Chapter XV, Upstream Pipeline Capacity. Exhibit XIV-2 provides a summary of PSE's pipeline capacity position.

Exhibit XIV-2
PSE Pipeline Capacity Position
(Dth/Day)

	TOTAL	**EXPIRATION DATE**		
		2004	**2008**	**Other**
Pipeline/Receipt Point				
NWP – Sumas TF-1	196,705	128,705	58,000	10,000 (in 2016)
NWP – GTN Interconnect	75,936	75,936	-	-
NWP – Rockies TF-1	183,740	131,836	43,848	8,056 (in 2016)
Total TF-1	***456,381***	***336,477***	***101,848***	***18,056***
NWP – Jackson Prairie TF-2	343,057	343,057	-	-
NWP – Plymouth LNG TF-2	70,500	70,500	-	-
Total TF-2	***413,557***	***413,557***	***-***	***-***
Total Capacity to City-Gate	***869,938***	***750,034***	***101,848***	***18,056***
GTN – Kingsgate to Starr Road	75,936	-	-	75,936 (in 2023)
GTN – Kingsgate to Stanfield	14,456	-	-	14,456 (in 2023)
Duke Transmission to Sumas (beginning 11/03)	40,000	-	-	25,000 (in 2014) 15,000 (in 2019)

Note: all NWP and GTN contracts have automatic renewal provisions, but can be canceled by PSE upon one year's prior notice. The Duke contract contains a right of first refusal upon expiry.

Firm pipeline transportation capacity carries the right, but not the obligation, to transport up to a maximum daily quantity (MDQ) of gas from one or more receipt points to one or more delivery points.[1] This transportation activity is conducted in accordance with the pipeline's published tariff, as approved by the Federal Energy Regulatory Commission (FERC). The tariff defines the scope of service, which includes the number of days that the transportation service is available, along with the rates and other operating terms and conditions.

The NWP TF-1, and GTN and Duke transportation contracts are firm contracts, available for use 365 days each year. The NWP TF-2 firm transportation contracts have annual contract quantities (ACQ) that correspond to the storage capacity held by the shipper. While the annual contract term limits TF-2 service to a quantity equal to the storage ACQ, the cost of this service proves to be significantly lower than holding firm pipeline capacity for the entire year.

PSE may also use interruptible transportation, sometimes referred to as "best-efforts" agreements, from NWP under rate schedule TI-1. This service allows NWP to provide a transportation service that is subordinate to the rights of the shippers holding and using firm transportation capacity. To the extent that the firm shippers do not use their pipeline capacity, they may receive interruptible capacity. Since TI-1 transportation service can be interrupted, PSE does not rely upon it to meet peak demand, thus it serves a limited role in PSE's gas resource portfolio.

Additionally, firm transportation capacity on NWP and GTN may be "released" and remarketed to third parties under the FERC-approved pipeline tariffs. PSE aggressively releases capacity during time periods when it has identified surplus capacity. The capacity release market can also provide PSE with access to additional firm capacity, when available.

Consistent with the pipeline's service obligation, the rate for firm transportation capacity requires a fixed payment, regardless of whether or not PSE uses the capacity. The rate for interruptible capacity is negotiable, and typically billed as a variable charge.

C. Storage Capacity

PSE' s natural gas storage represents an important and cost-effective component of its capacity portfolio due to the many advantages it offers. Primarily, storage offers an immediate and controllable source of firm gas supply. Storage also proves advantageous as it can be used as a

---

[1] From a risk management perspective, pipeline capacity can be viewed as an option that provides the contract holder with the right, but not the obligation, to buy gas at one location and sell it at another.

pooling point for the quantities of gas purchased, but not consumed during off-peak seasons, or times of the year when gas prices tend to be less expensive. PSE can achieve significant commodity price savings by buying gas during the relatively low demand period of the summer. In addition, coupling the market area storage and peaking facility located near PSE's system (Jackson Prairie and Plymouth LNG) with the TF-2 transportation service, allows PSE to purchase less year-round pipeline capacity than it might otherwise need.

Further, storage allows PSE to use its annual transportation and gas supply contracts at a higher load factor, minimizing the average cost of gas to its customers. Operationally, PSE uses underground storage for daily balancing on the interstate pipeline. If PSE's loads run higher or lower than the forecasted amount, PSE will use its storage to handle operational imbalances throughout the day, and minimize any balancing or scheduling penalties.

PSE also uses storage to balance its city-gate gas receipts with actual loads of its Gas Transport customers. The industrial and commercial customers who elect gas transport service (as an alternative to gas sales service) make nominations directly or through marketer-agents to move city-gate gas deliveries to the their respective meters. The customers, or marketer providing services to customers, often have daily imbalances since their scheduled gas deliveries do not match their actual gas consumption. On a daily basis, PSE provides balancing services in connection with its transportation tariff, and relies quite heavily upon storage to manage these imbalances.

PSE has contractual access to two storage projects, each of which serves a different purpose in PSE's resource portfolio. Jackson Prairie storage is an aquifer storage field that has been designed to deliver large quantities of gas over a relatively short period of time. PSE's other storage facility, Clay Basin – a depleted reservoir storage field – provides supply area storage and a winter gas supply. PSE has 343,057 Dth/day of TF-2 transport capacity to deliver gas from Jackson Prairie and can use its Rockies-originated TF-1 transport capacity from Clay Basin. Exhibit XIV-3 provides more details on PSE's storage capacity.

Exhibit XIV-3
PSE Gas Storage Position

	STORAGE CAPACITY (DTH)	INJECTION CAPACITY (DTH/DAY)	WITHDRAWAL CAPACITY (DTH/DAY)	EXPIRATION DATE
Jackson Prairie – Owned	6,344,000	144,600	289,216	N/A
Jackson Prairie – NWP SGS-2F[2]	1,181,021	26,900	53,841	2004
Clay Basin	13,419,000	55,900	111,825	2013/19
Total	**20,944,021**		**454,882**	

Located in PSE's market area in Chehalis, Washington, PSE uses Jackson Prairie and the associated NWP TF-2 transportation capacity to meet seasonal load requirements, and eliminate the need to contract for year-round pipeline capacity to meet winter-only demand. PSE primarily uses Jackson Prairie to meet the intermediate peaking requirements of core customers.

PSE operates and owns one-third (with NWP and Avista Utilities) of the Jackson Prairie storage facility. PSE currently holds firm daily deliverability of 343,057 Dth and firm seasonal capacity of 7,525,021 Dth – of which PSE owns 6,344,000 Dth and holds the right under the contract for SGS-2F storage service from NWP to 1,181,021 Dth until October 2004. PSE holds the unilateral right to this contracted capacity. PSE has access to best efforts withdrawal rights of up to 82,000 Dth, and interruptible transportation service from Jackson Prairie.

Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This depleted gas reservoir was developed to allow gas to be stored during the summer and withdrawn all winter. PSE holds the right, under two contracts, to store up to 13,419,000 Dth, and withdraw up to 111,825 Dth/day. FERC regulates the terms and conditions, including rates, of this agreement.

---

[2] Jackson Prairie leased contract has an auto-renewal provision, but can be cancelled by PSE upon one year's prior written notice.

PSE also uses Clay Basin as a pooling point for purchasing gas, and as a partial supply backup in the case of well freeze-offs, or other supply disruptions in the Rocky Mountains during the winter.[3] As such, gas stored at Clay Basin provides a reliable source of available gas throughout the winter, including on-peak day. Gas withdrawn from Clay Basin is delivered to PSE's system, and to other markets directly or indirectly, using firm, TF-1 transportation. Similar to firm pipeline capacity, firm storage arrangements require that a fixed charge be paid regardless of whether or not the storage service is used. PSE pays a variable charge for gas injected or withdrawn from storage.

D. Peaking Capacity Resources

PSE has firm access to other resources that provide capacity and gas supplies to meet peaking requirements or short-term operational needs. Liquefied natural gas (LNG), Peak Gas Supply Service (PGSS), and vaporized propane-air (LP-Air) provide firm gas supplies on short notice for relatively short periods of time. PSE typically uses these sources to meet extreme peak demand during the coldest few hours or days, and generally only as the supply of last resort due to their relatively higher variable cost. LNG, PGSS, and LP-Air do not afford all of the flexibility of other supply sources. Exhibit XIV-4 provides an overview of PSE's peaking gas capacity resources.

Exhibit XIV-4
PSE Peaking Gas Resources

	STORAGE CAPACITY (DTH)	INJECTION CAPACITY (DTH/DAY)	WITHDRAWAL CAPACITY (DTH/DAY)	TRANSPORT TARIFF
Plymouth LNG	241,700	1,208	70,500	TF-2
Swarr LP-Air	128,440	16,680[4]	30,000	On-system
PGSS	NA	NA	48,000	City-gate delivered
Total	370,140		148,500	

[3] From a risk management perspective, Clay Basin provides value as an arbitrage tool, and serves as a partial hedge to price spikes in the Rockies supply basins.
[4] Swarr holds 1.24 million gallons. At a refill rate of 111 gallons/minute, it takes 7.7 days to refill Swarr. This equates to 16,680 Dth/day.

NWP owns and operates an LNG facility located in Plymouth, Washington, and provides a gas liquefaction, storage, and vaporization service under its LS-1 tariff. PSE holds a long-term contract that provides for seasonal storage with an ACQ of 241,700 Dth, liquefaction with an MDQ of 1,208, and a withdrawal MDQ of 70,500 Dth. The ratio of injection and withdrawal rates to the storage capacity means that it can take PSE over 200 days to fill the capacity, but only three and one-half days to empty it. Due to these operating characteristics, PSE uses the LS-1 service to meet its needle-peak demands, with LS-1 gas delivered to PSE's city-gate using firm TF-2 transportation.

Under its PGSS agreements, PSE has the contractual right to call on third party gas supplies for a limited duration during peak periods. Currently, PSE has the right to purchase up to 48,000 Dth/day at a price tied to the replacement cost of distillate oil for up to twelve days during the winter season.[5]

PSE maintains an LP-Air facility with a net storage capacity of 128,440 Dth equivalent, and has the ability to vaporize approximately 30,000 Dth per day. At the maximum vaporization capacity, this provides a little over four days of supply. Since the propane air facilities connect to PSE's distribution system, PSE requires no upstream pipeline capacity. PSE typically uses this LP-Air facility to meet extreme hourly or daily peak demand, or to supplement distribution pressures in the event of a pressure decline on NWP. Some of PSE's peak shaving resources require that a fixed charge be paid regardless of whether or not the resource is used. The LNG service is billed to PSE pursuant to a FERC-approved tariff, while the cost of service associated with the on-system LP-Air plant is recovered from customers through base rates. PSE pays a variable charge on gas injected or withdrawn from LNG storage.

E. Gas Supplies

By maintaining pipeline capacity to various supply basins, PSE gains access to supplies of natural gas. Gas supply contracts tend to have a shorter duration than transportation contracts. The price and delivery terms across supply basins tend to be very similar, although the price levels from one day to the next can vary significantly. While the gas supply contract terms ensure the gas suppliers' performance, PSE's firm transportation capacity grants access to supply basins that offer the greater likelihood of availability and liquidity. In the event of a

[5] In essence, this is a call option with a variable strike price equal to the then-current, delivered price of distillate oil.

supplier default, PSE can always use its pipeline capacity to buy gas from other suppliers or marketers at market locations along the pipeline. PSE primarily focuses on the reliability of its pipeline delivery capacity and the long-term outlook for natural gas.

PSE has a mix of long-term (+three years), medium-term (one to three years) and short-term gas supply contracts (less than one year) to meet average loads during different months. Long-term contracts and medium-term contracts are typically baseload supplies delivered ratably over the year. Additionally, PSE can contract for seasonal baseload firm supply, typically for the winter months. The company enters into forward month transactions to supplement the baseload transactions, particularly for the months of November-March. During “bid week” – the week prior to the beginning of the upcoming delivery month – PSE estimates the average load requirements for the upcoming month and enters into month-long transactions to balance load. On a daily basis, the company does not plan to be long or short going into any day, but instead balances the position using storage and day ahead purchases and sales transactions. During the gas day, the company uses its Jackson Prairies storage for balancing. Exhibit XIV-5 provides an example of the weighting between different contract terms in 2002.

Exhibit XIV-5
Percentage Mix of Winter Supplies for 2002-2003

TERM	PERCENTAGE
Long-term (+3 years)	15%
Medium-term (1-3 years)	26%
Short-term (less than 1 year, includes storage)	54%
Bid Week	5%
Total	100%

Due to the number of long-term contracts expiring in the next few years, the weighting in Exhibit XIV-5 may change if PSE elects to change the ratio of long-term, medium-term and short-term supply. PSE will consider both costs and reliability issues when developing the portfolio strategy.

PSE also has a contract with King County - Metro (“Metro”) to purchase the gas produced by Metro as the byproduct of its water pollution abatement processes. The gas is delivered directly into PSE's distribution system. The agreement has a remaining term of approximately three years.

PSE Participation in the Gas Futures Market

The Company commenced hedging in its core gas portfolio as of September 2002. The Company utilizes hedge instruments such as fixed-price physical transactions and fixed-price financial swap transactions. These were determined to be the most effective means of hedging at the time. In its power portfolio, the company has entered into similar transactions for natural gas hedging.

The Henry Hub futures market has a delivery point at the Henry Hub, Louisiana. There can be a significant price dislocation between Henry Hub and the physical locations from which PSE sources its physical supply (from the Rockies, British Columbia and Alberta). In order for a futures hedge to be fully effective, PSE would need to enter into an Exchange for Physical (EFP) basis transaction with another counterparty to effectuate local delivery. In this way, PSE could enter into a fixed price hedge that transpired into physical delivery.

A futures account necessitates opening an account with a clearing firm and establishing commercial relationships with floor brokers who can execute transactions for its customers on the New York Mercantile Exchange (NYMEX). The clearing firm would require PSE to post a margin call, and there would be a daily settlement into and out of the PSE account, depending upon the size of PSE’s futures position and the daily direction of futures prices. Then, with respect to entering into an EFP, PSE would enter into a transaction with a counterparty who would agree to physical delivery at the agreed upon location, and the two parties would exchange futures at the NYMEX as part of the EFP transaction. The level at which the futures are exchanged, combined with the basis price of the EFP contract, sets the price for the physical delivered gas.

While the EFP mechanism provides a viable means to hedge, PSE has been able to enter into fixed price physical agreements directly with regional suppliers. These transactions prove to be far more simple and remove the need for opening and managing a futures account with a clearing firm engaging in futures trades and then entering into an EFP with a regional supplier.

In addition, a liquid market has developed for the over-the-counter financial derivatives for fixed price and basis transactions. These transactions are similar to entering into futures trades and EFP's from a pricing perspective, but requires a simpler process as transactions do not require the intermediary of clearing firms, floor brokers and the NYMEX. A master agreement, or an ISDA agreement, governs these transactions, and the parties negotiate a range of contractual items including credit, netting and cross-collateral terms. These transactions have worked well for PSE since they can be combined with physical index purchases. Moreover, many of PSE's long-term and medium-term contracts are index-based contracts, thus the financial derivatives work well within the company's portfolio.

On a going forward basis, the company will continue to evaluate the hedging mechanisms available in the market to weigh the benefits of each mechanism to determine its applicability in PSE's portfolio.

F. PSE Gas Supply/Demand Balance

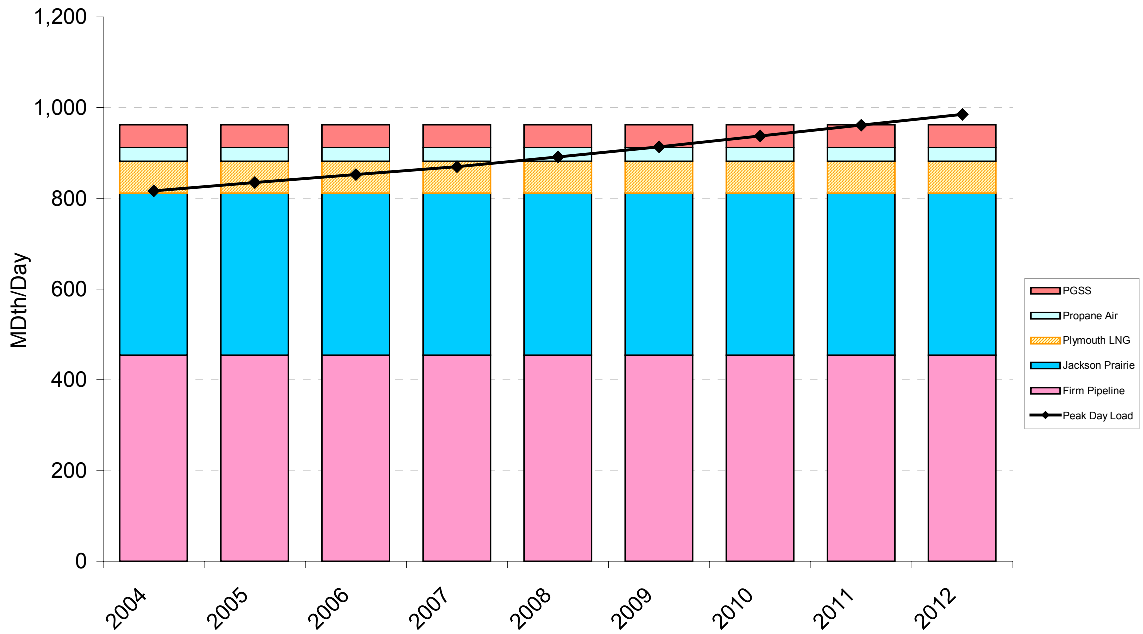
PSE holds firm pipeline transportation and vaporization capacity that allows it to transport or otherwise deliver gas, on a firm basis, from points of receipt to its customers. This capacity ensures that PSE can provide its customers with reliable and cost-effective gas supplies during the coldest expected weather, and over a range of expected scenarios. In addition, PSE maintains on-system resources that assist in meeting peak demands and contribute to the reliability of the distribution system.

Based on the current base case forecast, PSE does not anticipate requiring additional firm capacity until around 2010. Until that time, PSE has adequate capacity to meet the expected requirements of its firm customers. Exhibit XIV-6 summarizes PSE's capacity position.

Exhibit XIV-6

Summary of PSE's Gas Capacity Position

(Dth per Day)



G. Summary

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

1. 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 service expect to achieve 2.9 million therms of cost-effective energy savings, at a utility cost of $3.9 Million.
2. PSE holds a total of 960,330 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, 90,392 Dth/day on PG&E's Gas Transmission Northwest pipeline, and additional upstream capacity on other pipelines.
3. 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.

4. PSE's peaking resources include Liquefied Natural Gas (LNG), Peak Gas Supply Service (PGSS) and vaporized propane-air.
5. 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.
6. PSE has a mix of long-term (+ three years), medium-term (one to three years) and short-term (less than one year) contracts to meet average loads during different months.
7. PSE participates in the gas futures market, primarily through fixed-price physical transactions and fixed-price financial swap transactions. On a going forward basis, PSE will continue to evaluate the hedging mechanisms available in the market to weight the benefits of each mechanism to determine its applicability in PSE's portfolio.

XV. NEW GAS RESOURCE OPPORTUNITIES

Chapter XIV provided an overview of PSE's existing natural gas resources including conservation and efficiency, and supply portfolio resources. This chapter examines potential new gas resource opportunities for PSE. Gas resource portfolio opportunities exist when PSE can vary the structure of its existing capacity resource portfolio. These opportunities arise either when capacity contracts expire or additional capacity opportunities become available. Under some situations, it might also be desirable for PSE to buy out of an existing capacity contract in order to meet PSE's least cost objectives. Over the forecast period, PSE has a number of opportunities to modify the structure of its gas resource portfolio.[1] The NWP transportation contracts expire over the next 13 years, sponsors are considering new pipeline projects, underground storage expansions are proceeding, conservation continues, and peak shaving resources could be expanded. This chapter not only describes natural gas conservation and efficiency opportunities, but also these other supply-side opportunities.

A. Conservation and Efficiency

The amount of conservation and efficiency in the Company's gas 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 more emphasis on high-efficiency heating appliances, duct sealing, better controls and potentially higher-efficiency windows. Space heating primarily drives gas energy use in the commercial sector, with water heating loads significant only in certain business segments. Higher-efficiency equipment, better control schemes, demand controlled ventilation, and more attention to commissioning and O&M represent major potential for space heat savings. Certain measures, such as variable speed devices, will yield both electric and gas savings at facilities. These become more cost-effective for PSE customers when PSE serves both fuels at the site; thus PSE has sought to co-fund measures with neighboring utilities which serve electricity to a PSE gas customer. Industrial process heating improvements tend to be site-specific, and primarily include waste heat recovery.

[1] These opportunities are permanent capacity changes, as opposed to capacity optimization techniques such as capacity release, interruptible sales, off system sales, and other portfolio management activities used by PSE to minimize the average cost of gas to its customers.

The settlement agreement stemming from PSE's rate case in 2002 established a framework for future natural gas conservation programs beyond 2003. Data collection for natural gas measures to be used in development of the natural gas conservation supply curves will be complete in May 2003. Energy efficient natural gas end-use technologies will be compared with those being used by other gas and dual-fuel utilities in the region, and will focus on space, water and process heating applications. The gas supply curve, outlining cost-effective gas energy savings achievable in PSE customers' facilities, will be developed by early summer 2003. At this time, PSE anticipates adapting the models it uses for electric supply curves for use with natural gas. PSE will evaluate new measures using natural gas avoided cost forecasts developed through this Least Cost Plan process. The effectiveness of PSE's latest conservation initiatives, market research findings and the conservation potential will be tools for developing new program offerings and targets, and the best strategies for achieving gas energy efficiencies going forward.

B. Pipeline Capacity

PSE has a number of opportunities to modify its capacity position on interstate pipelines. As detailed in Chapter XIV, a number of the NWP contracts expire in 2004, 2008, and 2016. PSE retains the unilateral right to cancel these contracts upon one year's notice, otherwise the contracts renew automatically. In essence, the pending expirations coupled with PSE's renewal rights, create opportunities, at those points in time, for PSE to make alternative resource decisions.

While NWP is the only pipeline that directly connects to PSE's city-gates, other pipeline projects have developed initial plans to offer transportation alternatives, some of which might connect directly with PSE. To date, those pipeline projects have not aggregated enough anchor tenants to make a project feasible. However, PSE continues to monitor their progress toward aggregating load, since, as stated earlier, the Company has some flexibility with respect to the expiration of transportation contracts with NWP and the roll-over terms of those contracts.

New pipeline capacity tends to be more expensive than existing capacity. For example, NWP's current Evergreen expansion is expected to cost approximately $0.42 per dth/day versus NWP's existing rate of $0.32. PSE will evaluate the cost of incremental capacity, weighing other transportation alternatives from a cost and reliability perspective, with diversity benefits from access to other supply basins. To the extent that core loads and/or incremental capacity costs change, PSE believes it important to maintain this analytical perspective in order to structure its gas resource portfolio on a least cost basis.

C. Storage Capacity

PSE has a number of opportunities to modify its storage capacity positions over the next eight years. As detailed in Chapter XIV, the Jackson Prairie lease expires in 2004. The Clay Basin contract continues through 2013 and 2020.

A capacity expansion is currently underway at Jackson Prairie, anticipated to add an additional 1,750,000 Dth of storage capacity to the facility every summer (April – October) for six summers, eventually expanding the total capacity by 10,500,000 Dth. Of this capacity, 40 percent will be cushion gas – gas that is injected and used to prevent ground water from seeping into the storage space. The remaining 60 percent – or 1,050,000 Dth each year for a total of 6,300,000 Dth – will be used to provide working storage capacity. PSE holds the right to use one-third of this working capacity, or 2,100,000 Dth (350,000 each of six years). While the exact time frame for completing the Jackson Prairie expansion has not yet been determined, PSE anticipates the owners will elect to expand the deliverability of the project by 300,000 dth/day of delivery (100,000 dth/day for PSE) for the next decade. Jackson Prairie may well represent the least cost way of meeting this firm load requirement.

D. Gas Supplies

The Company manages its supply portfolio to maintain supply diversity, and the pricing terms reflect at least three regional markets: the U.S. Rockies, British Columbia, and Alberta. Over long periods of time, a tendency exists toward equilibrium pricing among the three regions. Over shorter-time frames, however, one basin will be lower cost than the others – a difference that can be more pronounced on a daily basis. PSE's capacity rights on NWP allow it some flexibility in buying from the lowest cost basin. This arbitrage opportunity can mitigate the price volatility and serves to mediate prices between the various supply basins.

PSE has always purchased its supply at market hubs or pooling points. In the Rockies, the transportation receipt point is Opal but alternate points such as gathering system interconnects with NWP allow for some purchases directly from producers as well as from gathering & processing firms. In fact, the Company has a number of supply arrangements in the Rockies with major producers. Thus, the Company has the ability to purchase supply at or close 'to the wellhead' or point of production.

With respect to Canadian supply, NWP's receipt points interconnect with upstream pipelines (Duke Transmission at Sumas / Huntingdon, BC) or at a lateral (GTN at Starr Road). The Company's upstream GTN transportation capacity allows PSE to source supply at the Kingsgate British Columbia interconnect with Alberta Natural Gas (ANG). In British Columbia, the Company has entered into an agreement with Duke Transmission to hold firm transportation from Station 2 to the Sumas market (called T-south capacity). Station 2 is a pooling point, and producers move their gas supply from the wellhead and gas processing facilities to the Station 2 pooling point. The upstream transportation arrangements are explained in more detail later in this chapter.

From a supply-planning perspective, continued diversification of its natural gas purchases among the three supply basins provides some measure of reliability and price protection for PSE by avoiding a concentration in any single market. PSE expects to maintain this approach to contracting for gas supplies in the Rockies, British Columbia and Alberta.

Pipeline projects add capacity in stepwise fashion, while load growth and production increases tend to happen more gradually. New pipeline projects can suddenly increase the take-away capacity from one supply basin, shifting the supply-demand dynamic across the network. As a result, large price shifts can result from a pipeline expansion project. While the pricing data illustrate the relative equilibrium among the western basins, the imbalance lies between these basins and the market areas. When that differential becomes large enough and persists over time, new pipeline capacity is proposed to re-balance the market. Rockies prices are relatively depressed in comparison to other production basins, however, the price differentials between the Rockies and Sumas areas have grown more pronounced. New pipeline projects such as the Kern River expansion (summer 2003) will tend to narrow these price differentials.

With respect to planning future gas purchases by basin, PSE will diversify its portfolio to match the transportation take-way capacity it holds at the primary receipt points in its long-term pipeline transportation contracts. Over time, as the market differentials spur pipeline capacity expansions, PSE could have an opportunity to diversify to other supply basins. However, the expansions might also serve to bring prices closer together.

Outlook for Future Natural Gas Supplies

Natural gas reserves in the United States and Canada are estimated to be 2,189 trillion cubic feet (Tcf). This estimate includes gas reserves that are proved (236 Tcf) and unproved (1,953 Tcf). Proved reserves are those estimated to be commercially recoverable, with reasonable certainty, under current geologic, commercial and technical conditions. Unproved reserves include all other reserves, including those calculated to exist, but not yet discovered. Under these definitions, the level of gas reserves depends, in part, on the expected price of gas. At higher expected gas prices, the potential quantity of recoverable gas also increases.

Since 1994, US gas reserve additions have exceeded production in all years except 1998[2]. While Canada has seen a gradual decline in proved reserves, continued exploration and development of natural gas reserves in the U.S. Rockies, British Columbia and Alberta will provide production adequate to meet most of the projected demand. Increasingly, the development and re-opening and expansion of LNG import projects will likely play a role in meeting incremental capacity and gas supply requirements in certain regions of the United States.

Over longer periods of time, as reserve and gas production levels change, the development of gas reserves in other regions might take on greater significance to PSE. Given the continued development of gas reserves accessible from Duke Transmission, GTN, and NWP, PSE does not expect shifting purchases to other supply areas to be a material consideration in the foreseeable future.

U.S. Reserves

As noted earlier, additions to natural gas reserves in the U.S. have exceeded production in every year but one prior to 2001. Existing gas reserves in the lower-48 are estimated to be 183 Tcf. At current production levels, these reserves will be adequate to supply approximately nine years of gas demand at current consumption levels. As with Canada, significant amounts of gas reserves remain unproved. 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. See Exhibit O-1 in Appendix O for more details.

[2] According to the EIA, this year [1998] was characterized by extremely low energy prices and accounting adjustments that affected reserve calculations.

Canadian Reserves

Canada is a major producer of natural gas and oil, and the largest exporter of natural gas to the United States. In 2001, Canada produced 17.4 Bcf per day (6.4 Tcf per year) of gas, with year-end, proved reserves at 60.1 Tcf. Exports to the United States were 10.6 Bcf per day (3.9 Tcf per year).

Alberta, the largest natural gas producer in Canada, produces almost 5 Tcf (13.6 Bcfd) in 2001. Estimated, proved reserves at year-end 2001 stood at 40.5 – 45.2 Tcf. British Columbia produced a little over one Tcf (2.9 Bcfd) in 2001, the second largest gas producer in Canada behind Alberta. Gas reserves are concentrated in the northeastern part of the province, with a recent, significant find (Greater Sierra - 2002) estimated to contain five Tcf. As the frontier gas development progresses, new pipelines (from Alaska, Mackenzie Delta, or both) will likely tie into existing systems in Alberta, finding a ready market for the gas at the AECO Hub for markets south and east. PSE's capacity position on PGT provides strategic access to current and future gas supplies from Alberta and points north. For more details on Canadian reserves, please see Appendix O.

Reserve Growth

When evaluating published accounts of gas reserves, it is important to note that a significant portion of reserve growth comes from the re-evaluation and continued development of existing reserves. The USGS observes that " … reserve growth is expected to contribute at least twice as much oil and natural gas to the Nation's reserves as new discoveries."[3] For PSE, this implies that gas reserves currently accessed by their transportation contracts should be expected to grow. And given the relative early development stage of the gas reserves in British Columbia and Rockies, the potential for reserve growth could be substantial. Further, applying the same logic to Alberta's reserves suggests that additional gas reserves await further development.

In summary, the pipeline transportation contracts held by PSE position it well to maintain access to adequate gas supplies in producing areas well-positioned for further development. These supplies will likely remain price competitive due to the focus on development of these reserves.

[3] See USGS Fact Sheet FS-119-00, October 2000.

PSE finds itself in a strong position to seek additional pipeline capacity when needed to meet incremental load requirements with reliable and economical gas supplies.

Upstream Pipeline Capacity

In some cases, a trade off exists between buying gas at one point or buying capacity to enable gas to be purchased at another upstream point, closer to the supply basin. PSE faces this situation with its purchase of gas at Sumas and Kingsgate. Many of its Canadian supply arrangements have upstream transportation values embedded in the contract price. At Sumas, upstream transportation values from Station 2 on Duke Transmission are embedded in the gas supply pricing PSE has in several, long-term contracts expiring in 2003. Moreover, owning upstream capacity can help insulate the Company and its customers from price volatility at the downstream location (in this case, Sumas).

PSE initiated this strategy by acquiring 40,000 Dth/d of capacity on Duke Transmission from Station 2 to Huntindon, BC starting November 2003. PSE can take advantage of a growing re-seller market at Station 2 with this transportation capacity, minimizing its cost and risk by contracting for a portion of this upstream transportation, and serving as a hedge against potential price spikes at the Sumas market. PSE will continue to evaluate its upstream transportation, and re-evaluate its position to ensure a balance of market diversity, liquidity, volatility and least cost.

PSE also holds GTN capacity from Kingsgate (Canadian border) south to NWP. The Company has had a long-term supply arrangement, through aggregators, with the Alberta Pool at Kingsgate. Transportation costs for upstream pipelines ANG and Nova are included in the pricing formula. Since that supply contract will soon be up for renewal, the Company will seek to explore both supply arrangements at Kingsgate and upstream at AECO, providing upstream transportation capacity on ANG and Nova if available. If capacity on ANG and Nova is available so that PSE could transport gas from AECO to its city-gates, then this would open opportunities to procure gas supplies directly at AECO. Therefore the Company will review options to renew the contract at Kingsgate, procure gas from alternate suppliers at Kingsgate, and evaluate the possibility of holding upstream transportation and purchasing from AECO suppliers.

With respect to making those decisions, the Company will review a host of factors including price risk, currency risk, pricing and other contract conditions, fixed cost exposure, market liquidity, security of supply issues, other transaction costs, and counter-party creditworthiness.

E. Summary

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:

1. 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.
2. 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.
3. 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.
4. 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.
5. 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.
6. 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.
7. Reserve additions in the basin's tributaries to PSE's firm transportation receipt points indicate growing exploration and production activity.
8. Pipeline and producers have demonstrated a willingness to develop the facilities to bring gas into the Northwest region as necessary.

XVI. GAS RESOURCE ANALYSIS AND STRATEGY

Chapter XVI focuses on the analysis process used by PSE to develop its gas Least Cost Plan. The chapter begins by stating the objectives guiding PSE's gas Least Cost analysis. Next, this chapter details the steps taken in the analytical process. The chapter ends with a presentation of the resource analysis results and a discussion of the implications of the results. Specific actions for the recommended long-term gas resource strategy can be found in PSE's two-year Action Plan in Chapter XVII.

A. Analytical Process Overview

PSE's gas portfolio analysis seeks to identify the combination of gas resources that minimizes the average cost of gas to firm customers over time, under a given set of assumptions and constraints. While mainly quantitative in nature, the analysis has a strong qualitative dimension. It relies on forecasts of annual and peak day gas demand; projected costs for gas capacity and commodity; contract quantities, terms and conditions; and other known or expected operating constraints.

This process also identifies those points in time when changes to the portfolio can or must be made, evaluates the costs or benefits of making those changes, and assists PSE in re-structuring its portfolio to select the appropriate resource mix. Finally, PSE conducted and evaluated various sensitivities.

PSE evaluated three portfolios that correspond to three demand scenarios – Base Case, High Growth and Low Growth. The sensitivity of the Base Case portfolio to hypothetical changes in gas prices was also evaluated and there were two scenarios with different gas commodity price assumptions – High Gas and Low Gas. In all, five different model runs were conducted and evaluated. The three different growth scenarios produced different portfolio structures, while the price scenarios tested the sensitivity of the Base Case scenario at two alternative hypothetical price levels.

Once the optimal portfolio structure has been selected, it remains the same. However, managing the portfolio to minimize cost and price volatility constitutes a dynamic and continuous activity as discussed in Chapter IV. PSE's assessments of the potential opportunities to enhance the value of the portfolio comprise a significant part of the qualitative dimension of the gas portfolio analysis process. These include assessments of the potential risks associated with various resource selections when making portfolio restructuring decisions, including risks associated with supply reliability, price, and resource diversity.

As detailed in Chapter V, meetings with stakeholders, and public input only enhances the analytical process. PSE believes its portfolio analysis process supports its ability to design and manage a gas resource portfolio that meets the objective of providing customers with a reliable, least-cost supply of natural gas.

B. Analytical Process Stages

The analytical process consisted of the following six stages.

1. Defining and validating all data inputs (e.g., demand forecasts, contract quantities, gas costs and transportation rates, etc.);
2. Identifying those gas resources that can be varied and when;
3. Pre-screening resources to streamline modeling time;
4. Running the planning model to evaluate various resource configurations, under Base Case, Low, and High gas demand scenarios;
5. Running the Base Case demand scenarios under High Price and Low Price scenarios; and
6. Evaluating the model results.

Data Validation

PSE considered a combination of available and potential capacity and commodity, and their respective costs. Capacity includes pipeline transportation capacity; supplemental (LNG and LP-Air) vaporization capacity; injection, storage, and withdrawal capacities of storage facilities; conservation measures; and firm, third-party delivered gas. Commodity includes the gas supplies available or avoided due to holding the capacity positions. Each of these resources has one or more costs associated with it and those costs can be fixed and/or variable. Further, the costs and capacities can also change over time and as a function of other inputs. All of these data, plus the demand data, must be verified and input into the model.

In the base case, PSE used the same forecast of gas prices as used in the electric analysis. It is important to note that the costs used by PSE in its analyses reflect its long-term view of the magnitude and direction of natural gas commodity costs, and may be lower than the costs currently seen in the market. PSE believes that the current market volatility reflects short-term factors that will dissipate over time and does not believe it appropriate to evaluate long-term resource decisions in light of short-term market aberrations.[1]

Identifying Gas Resources to Vary

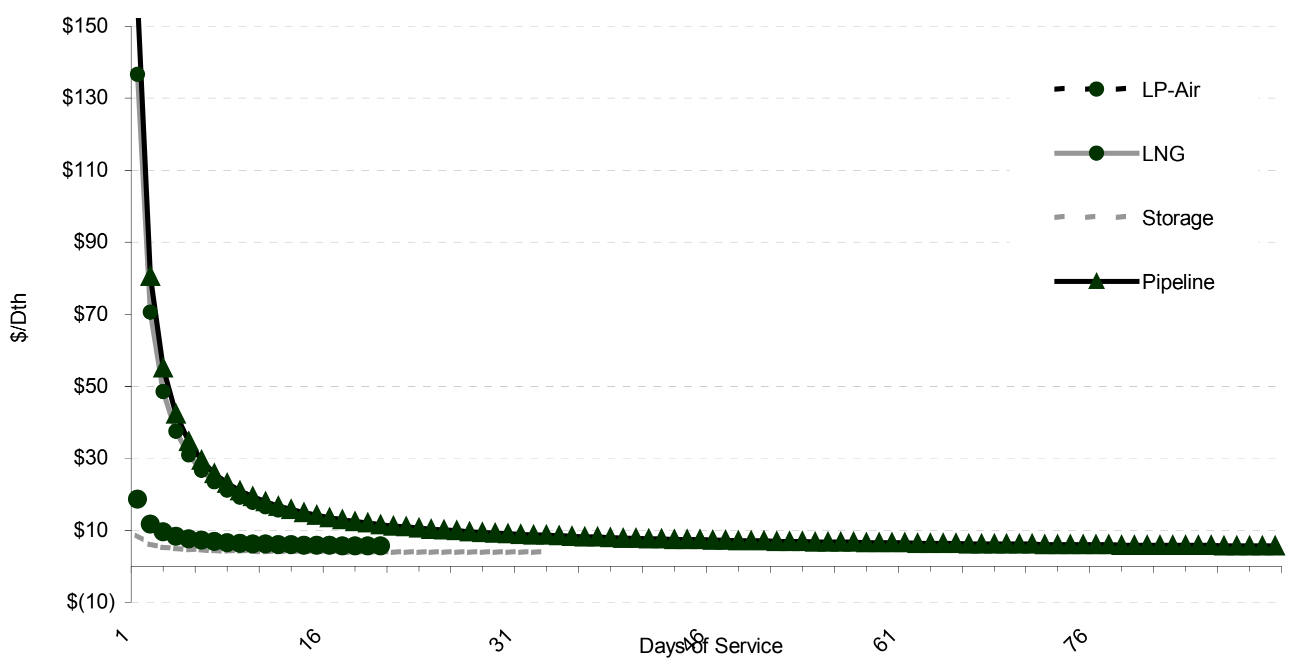
The structure of the portfolio can change only when a capacity resource can be changed. Capacity contracts that have renewal dates, incremental capacity requirements, and options to increase or decrease capacity positions all represent examples of changes that can affect the portfolio structure. Some of these changes may prove to be material and require more detailed analysis, others occur so far into the future obviating the need for a decision, while some are obvious to the point of requiring minimal analysis.

The decision whether to meet incremental demand with new pipeline capacity, storage capacity, conservation, supplemental capacity, or a combination of all four requires a complex analysis. The fact that capacity additions occur in large, discrete quantities, available only at certain points in time, and not necessarily available year-round further complicates this decision. Since modeling all of the possible combinations can be time-consuming and redundant, screening the various resources prior to the modeling activity allows for a more efficient selection of the resources to analyze. Exhibit XVI-1 illustrates how the screening process could quickly identify that storage and LP-Air should be included in an analysis of how best to meet a 30-day gas requirement, while pipeline and conservation resources seem better suited to meet demands of longer duration. The analysis also illustrates how LNG competes with pipeline capacity as a resource to meet short duration, peak winter demands. Each resource faces limits, however, due to operational constraints such as the available amount of storage capacity, injection and withdrawal rates, interchangeability limits on LP-Air injections, or the difficulty in siting a new LNG facility. Of course, this represents only a snapshot, and aids in refining the resource selection process. This approach does not substitute for the long-term, least-cost modeling of the resource portfolio, nor does it reflect the best resource selection over time. The long-term modeling effort described below provides greater insight to addressing that issue.

[1] The host of factors pushing up gas prices this year include sustained cold weather in the eastern U.S.; larger-than-normal storage withdrawals; high storage refill demand; growing evidence of low hydro levels in the West and Northwest; projected warmer-than-normal temperatures for the Southwest; oil prices pushed high due to the instability in the Middle East; and trading activity by fund mangers in commodity markets.

Exhibit XVI-1

Preliminary Resource Screening
Average Cost per Dth Over 90 Days of Service
($/Dth)



While the existing NWP capacity contracts could be varied, they are maintained in this analysis because the existing TF-1 contract is approximately $0.10 per Dth per day less expensive than a new firm transportation contract. Accordingly, PSE recognizes that it has the contract cancellation options available but models its existing NWP contracts as being available for the forecast period because it simplifies the modeling process and does not compromise the results.

Gas Resource Portfolio Model

PSE used a least-cost planning model (Uplan-G Resource Planning Model) that calculated the net present value (NPV) of the costs of the gas resources selected to meet specified load requirements under the terms of the various capacity and commodity contracts. The model uses a time period of twenty years beginning in 2004 and a discount rate of 8.95 percent. The Uplan-G model specification for this Least Cost Plan used the data, described above, as inputs to a network representation of the systems that supply natural gas to PSE.[2] The model then ran daily dispatches for 20 years including a planning criteria peak day each year to calculate the annual cost of serving PSE's firm load under the Base Case, Low Case, and High Case demand scenarios.

PSE has the option of using Uplan-G to minimize either the variable costs of its portfolio or the total costs.[3] For the purposes of its long-term plan, PSE used the model in the mode of minimizing total costs. In this mode, the analysis took into account the complete life-cycle costs of contracts for gas supply, storage, pipeline, and LP-Air capacity, minimizing the fixed costs, as well as the variable costs. Given the planned expansion of the Jackson Prairie storage field, this storage capacity was modeled to be available at assumed points of time that varied by scenario.

From this analysis, PSE identified that mix and timing of gas resource additions that would be expected to minimize the cost of gas to its customers under the given sets of price and load forecasts, and capacity assumptions.

Evaluating Model Results

The model results were evaluated to ensure the following:

- All of the firm customers' requirements were met each year over the planning period.
- The model dispatched resources in a least-cost fashion.
- What, and if, any resource decisions were required.

The year-to-year changes in gas costs, as calculated by the model, also were examined for continuity and reasonableness to understand the timing effect of resource changes.

C. Modeling Approach and Results

In developing its current Gas Least Cost Plan, PSE analyzed three portfolio configurations and two additional price scenarios, generating five model runs.[4] The three portfolio configurations corresponded to Base Case, High Growth and Low Growth demand scenarios. Since each of these scenarios had different projections of gas demand, Uplan-G identified a different optimal

---

[2] Consistent with accepted modeling practice, Uplan-G is configured to provide an abstract representation of PSE's resource portfolio and supply system.

[3] PSE regularly uses the variable cost optimization mode of Uplan-G for calculating its PGA.

[4] One model run included both Base Case load growth and Base Case price forecasts.

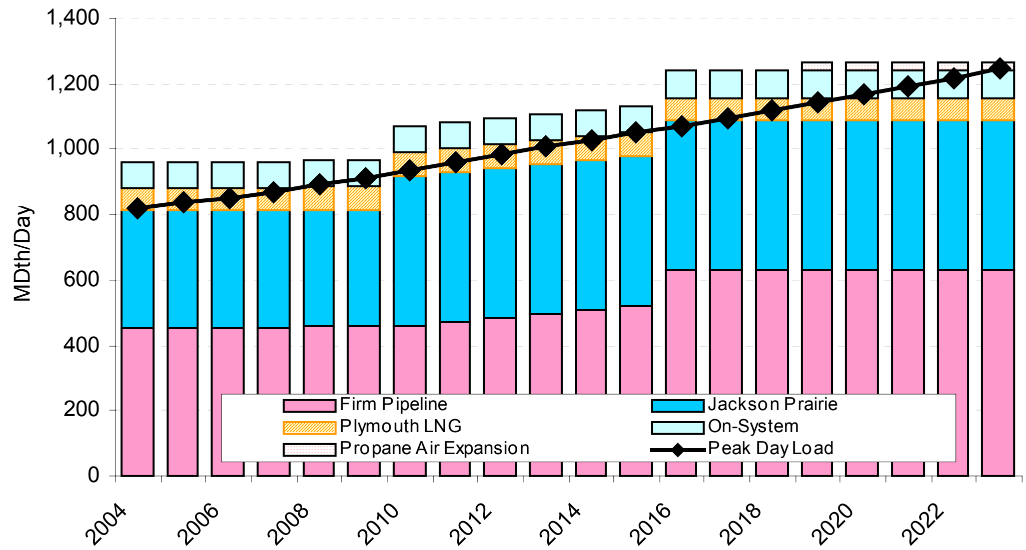
mix of resources, or portfolios, for each scenario. To understand the impact of different gas price levels on the Base Case portfolio, PSE ran it against two hypothetical price scenarios, generating High Price and Low Price scenarios. In these two price analyses, the resource mix did not change from the Base Case but the impact on the average cost of gas under different price levels was calculated. In all of the analyses, there was a need to add resources, however the mix and timing varied. More importantly, the timing of the required resource additions indicated that PSE would not have to make a resource acquisition decision at this time. The results of each of these runs are discussed below.

Base Case

Exhibit XVI-2 illustrates the current gas resource portfolio has sufficient resources to meet the expected Base Case demands of PSE's firm customers through 2009. Additional underground storage deliverability is assumed to be available in 2010. After that point in time, pipeline capacity is added from 2011 through 2016, and propane air capacity in 2019. While the model identifies the need for relatively small, annual additions of pipeline capacity, in practice the required capacity would be added in larger amounts but less frequently. Contemporaneously, the peak day demand is expected to grow at an annual rate of 2.27 percent, moving from 817 MMBtu in 2004 to 1,246 MMBtu in 2023. The total load served over the 20-year forecast period is 2.2 Tcf.

Exhibit XVI-2

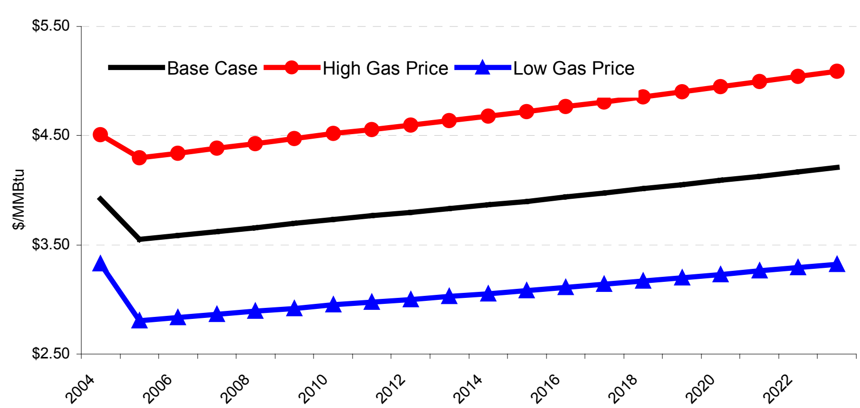
**PSE Peak Day Load and Delivery Capacity
Base Case Load and All Price Scenarios**



The High Gas Price and Low Gas Price scenarios used hypothetical price forecasts for gas purchased at Sumas, AECO Hub, and the Rockies to evaluate the sensitivity of the Base Case portfolio to changes in gas prices. Exhibit XVI-3 illustrates the different price levels. These different gas commodity prices flow through the models, affecting the costs used for storage gas and Plymouth LNG. As will be seen later, the impact of different gas prices on the average costs of the various portfolios is larger than changes in capacity.

Exhibit XVI-3

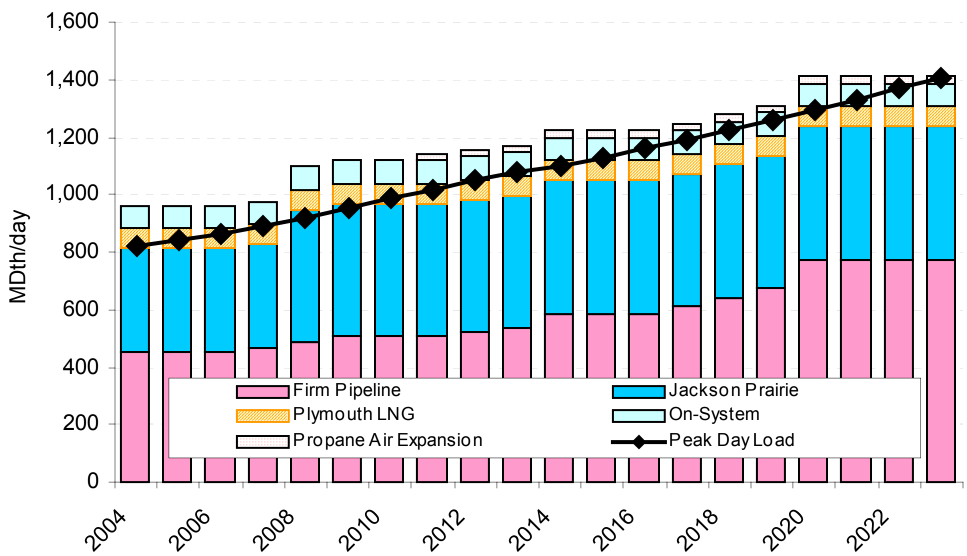
PSE Natural Gas Price Scenarios



High Growth

Exhibit XVI-4 illustrates the current gas resource portfolio has sufficient resources to meet the expected needs of PSE's firm customers through 2007. Due to the higher growth rate, additional storage deliverability is assumed to be available in 2008. After that point in time, pipeline capacity is added from 2008 through 2020, and LP- Air capacity in 2011. At the same time, the peak day demand is expected to grow at an annual rate of 2.89 percent, moving from 819 MMBtu in 2004 to 1,408 MMBtu in 2023. The total load served by this portfolio over the forecast period is 2.4 Tcf.

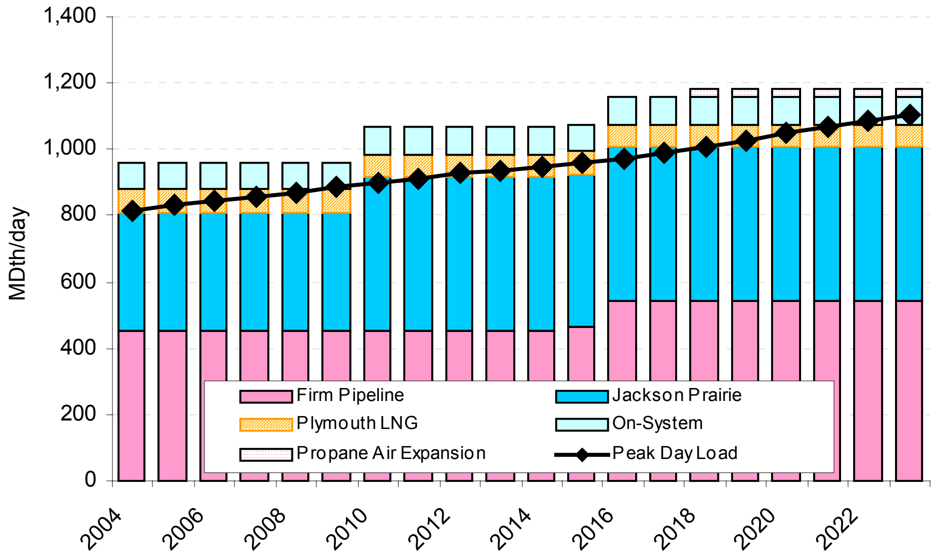
Exhibit XVI-4
PSE Peak Day Load and Delivery Capacity
High Load Growth



Low Growth

The Low Growth scenario models a significantly lower growth in annual and peak day gas demand. Exhibit XVI-5 illustrates that the lower growth pushes out the time when additional capacity would have to be added. As modeled, the current portfolio has sufficient resources to meet the expected needs of PSE's firm customers through 2009. Reflecting the lower growth rate, storage deliverability was assumed to be available in 2010. After that point in time, pipeline capacity is added in 2015 and 2016, and LPAir capacity in 2018. Under this scenario, the peak day demand is expected to grow at an annual rate of 1.60 percent, moving from 816 MMBtu in 2004 to 1,404 MMBtu in 2023. The total load served by this portfolio over the forecast period is 2.1 Tcf.

Exhibit XVI-5
PSE Peak Day Load and Delivery Capacity
Low Load Growth



D. Analysis of Model Results

The model results were reported and compared in terms of the net present value (NPV) of each portfolio. To standardize for the different sales quantities under the three different growth scenarios, an average cost of gas ($/Dth) was calculated for each growth and price scenario. To understand these results, they were evaluated from an investment perspective and an expense perspective by using discount rates of 8.76 percent and 3.00 percent, respectively. The 8.76 percent rate represents PSE's weighted average cost of capital. The first discount rate represents a portfolio evaluation from the perspective of an investor in PSE. The second discount rate characterizes the effect that may be experienced by a PSE firm customer. Viewing the results through these two perspectives allowed PSE to ensure that the results did not differ materially from either perspective. Exhibits XVI-6 and XVI-7 summarize these results.

Exhibit XVI-6
Summary of Portfolio Analysis Results at 8.76 Percent

MODEL RUN	FIRM DTH (MM)	NPV ($MM)	$/DTH
P1 – Base Case	2,215.8	$4,645	$2.10
P2 – High Growth	2,386.1	$4,972	$2.08
P3 – Low Growth	2,055.5	$4,362	$2.12
P1 – High Gas Price	2,215.8	$4,384	$2.18
P1 – Low Gas price	2,215.8	$3,858	$1.74

Exhibit XVI-7
Summary of Portfolio Analysis Results at 3.00 Percent

MODEL RUN	FIRM DTH (MM)	NPV ($MM)	$/DTH
P1 – Base Case	2,215.8	$7,846	$3.55
P2 – High Growth	2,386.1	$8,519	$3.57
P3 – Low Growth	2,055.5	$7,291	$3.55
P1 – High Gas Price	2,215.8	$8,195	$3.70
P1 – Low Gas price	2,215.8	$6,519	$2.94

These model results were compared to determine which portfolio had the lower NPV, the lower average cost per Dth, and the likely lower level of risk. The first two steps required straightforward calculations, while the latter relied upon more qualitative and subjective analysis.

To approximate the sensitivity of the average cost of gas to changes in firm requirements (for any one portfolio), PSE calculated the cost per Dth by dividing the NPVs from the Base Case, Low Case and High Case by their respective demand quantities. This resulted in average costs per Dth that varied by $0.04 per Dth and $0.02 per Dth using the respective 8.76 and 3.00 percent discount rates. The High Gas Price and Low Gas Price scenarios illustrated that the average costs per Dth were more sensitive to changes in commodity gas costs than to changes in the fixed costs, portfolio structure, or the level of gas demand.[5] This also underscored the important role played by portfolio optimization in minimizing the average cost of gas.

Under the 8.76 percent discount rate, the results indicated that the High Growth portfolio resulted in an average cost that was lower than the Base Case portfolio by $0.02 per Dth. From the 3.00 percent perspective, the average costs under the Base Case and Low Growth scenarios were equal, and lower than the High Growth Scenario by $0.02 per Dth. This

[5] Generally, this holds true as long as the (variable cost) > (unit fixed costs)/(firm load factor).

comparison demonstrated two points. First, the low disparity in the average costs of the portfolios illustrates relatively stable portfolios. Second, the change in the relative order of the average costs suggested that the timing of resource additions could have an effect on the average cost of gas. Accordingly, PSE evaluated the average cost of the portfolios over time.

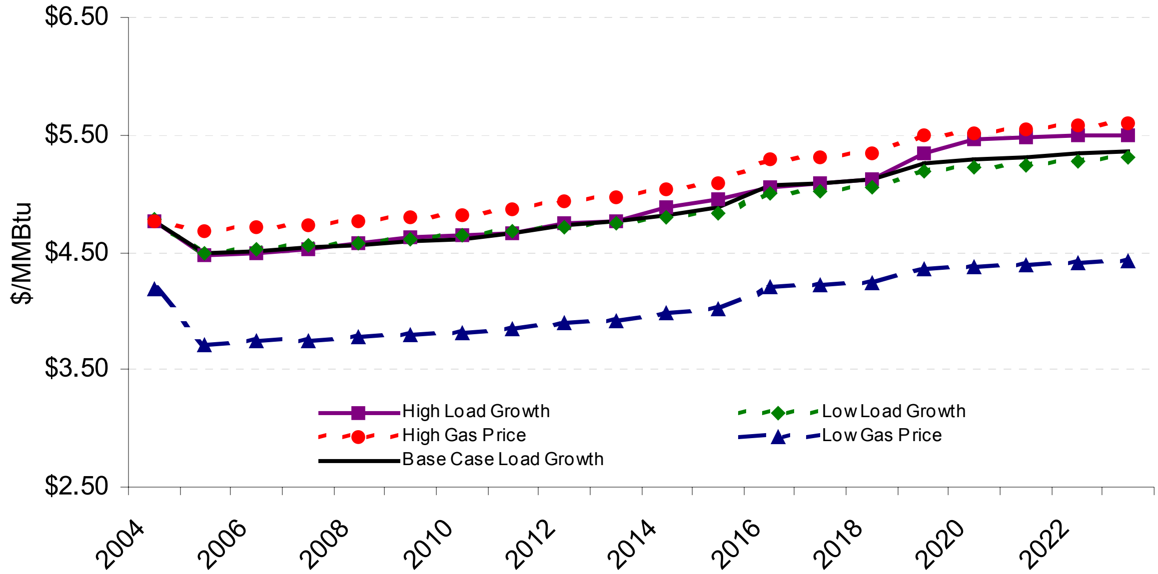
Exhibit XVI-8 illustrates the average cost paths over time for each model run. Exhibit XVI-9 shows the percent deviation of the average costs under each model run from the average cost under the Base Case. The average costs under the three different growth scenarios track closely until 2011, when the average costs under the High Load Growth and Low Load Growth scenarios begin to diverge. Prior to that point in time, the High Growth Scenario results in a lower average cost than the average costs under the Low Growth Scenario, and, in some years, the Base Case.

This pattern illustrates two key points. First, the higher growth results in the existing portfolio being used at a higher load factor during the earlier years, lowering the average cost of gas. As new capacity is added in the later years, the average cost begins to increase. Second, the average cost under the lower load growth portfolio is higher than the average cost under the Base Case portfolio until 2012. These two points illustrate the following:

- PSE faces little risk from growing as expected or more quickly over the next four to eight years.
- The resource additions having the greatest impact on the average cost of gas are expected to be required around 2012.
- Since average costs in the short-term are not very sensitive to the structure of the portfolio, the larger benefit to firm customers will come from optimizing the existing portfolio.

This temporal analysis also identified the point in time that resource additions would be expected to have a larger effect on average gas costs.

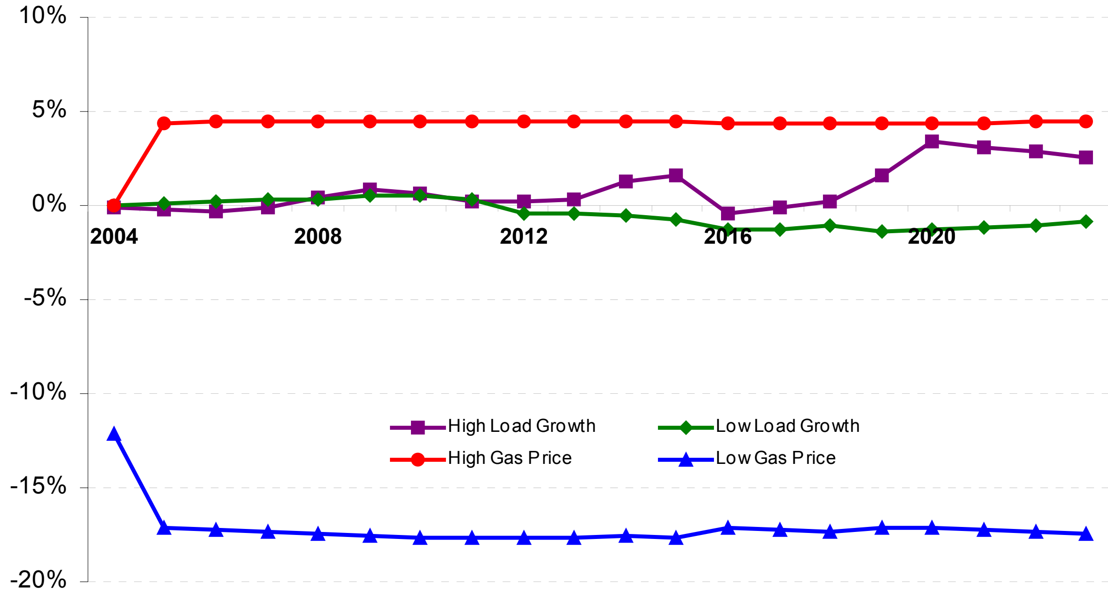
Exhibit XVI-8
Comparison of Average Cost of Gas
Under the Various Portfolios



Exhibits XVI-9 and XVI-10 illustrate that the average cost of the portfolio is more sensitive to market forces than to structural changes. Due to the fixed cost component of gas resource portfolios, PSE expected this result since average costs are much more sensitive to changes in variable rather than fixed costs. This also illustrates and confirms the earlier conclusion that optimizing the portfolio on a day-to-day basis will more likely have a greater impact in the near-term, pending the more significant resource decisions required toward the end of the decade.

Taken together, these two graphs also illustrate that PSE currently holds and manages a least-cost gas resource portfolio. They further illustrate that PSE could optimize the value of this portfolio through growth (or capacity release/optimization) in the short-term and the addition of selected resources around 2010. Since PSE faces no compelling capacity resource decisions in the next few years, PSE did not evaluate the portfolio with the lowest NPV in 2010. Over the next few years, PSE has the opportunity to carefully evaluate and select those resources that will contribute to the least cost portfolio in the latter part of this decade.

Exhibit XVI-9
Percent Deviation of Average Cost of Gas
Under the Various Portfolios
From the Base Case Average Gas Cost



To evaluate the sensitivity of these various portfolios to different assumptions, PSE used the model results to develop relative comparisons. PSE did this for the results across the growth scenarios and then the price scenarios. While this analytical approach tends to overstate the near-term risk and understate the long-term risk, it proves useful for illustrating the portfolio sensitivities.[6] Exhibit XVI-10 illustrates the variability in the model results for the three growth scenarios using the estimated upper and lower bounds for the projected results.[7] Exhibit XVI-11 contains the corresponding illustration for the gas price scenarios. Not surprisingly, PSE found the sensitivity of the average cost in the growth scenarios to be relatively lower than that for the price scenarios.[8]

---

[6] There were insufficient data points to make calculating standard deviations meaningful, so the total results for the three portfolios were combined.

[7] These bounds were determined for each year as: Base Case $/MMBtu +/- 1.96(Std. Dev.)

[8] The standard deviations of the average costs of gas for the growth and price scenarios were $0.315/MMBtu and $0.605/MMBtu, respectively.

Exhibit XVI-10
Sensitivity of the Average Cost of Gas Under
Base Case, High Growth, and Low Growth Scenarios

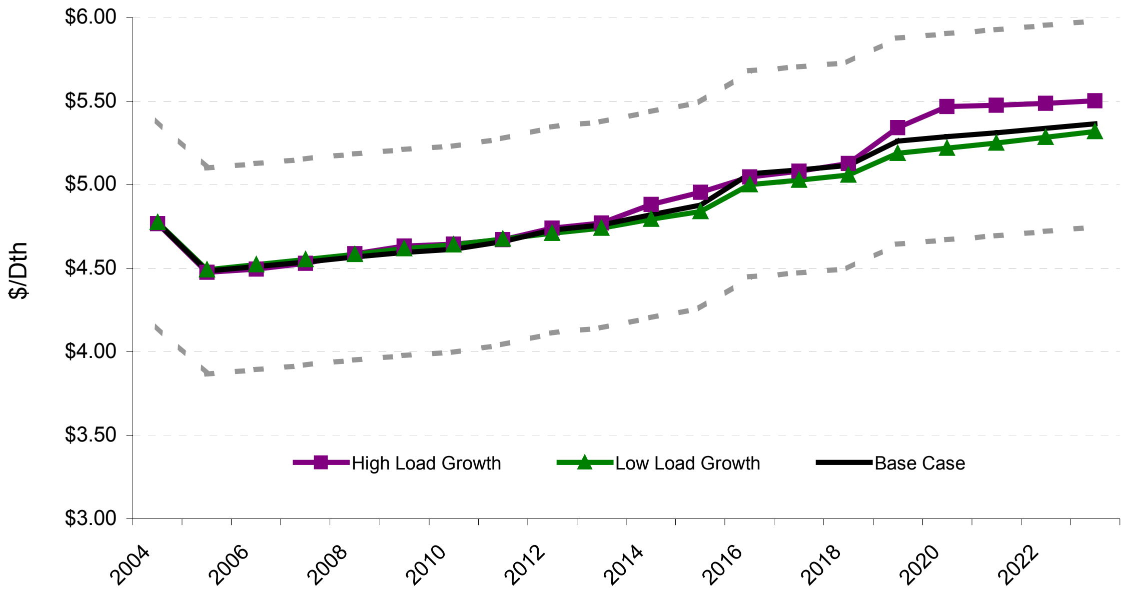
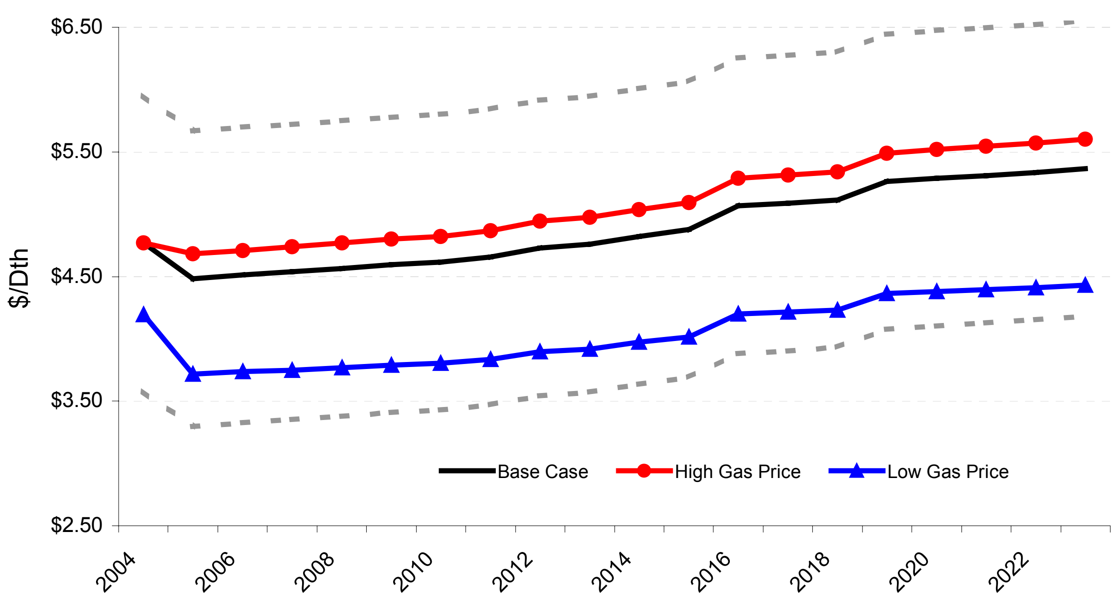


Exhibit XVI-11
Sensitivity of the Average Cost of Gas Under
Base Case, High Price, and Low Price Scenarios



D. Summary

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:

1. 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.
2. 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.
3. 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.
4. 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.
5. 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.
6. 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.

XVII. TWO-YEAR ACTION PLAN

Chapter XVII addresses PSE's two-year Action Plans, including a review of the Action Plan from its previous Least Cost Plan, and its new two-year Action Plan. The chapter begins with a progress report on PSE's previous two-year Action Plan, providing a status of efforts to date on each of the implementation items identified in the 2000-2001 Gas and Electric Least Cost Plan. Next, PSE provides a two-year Action Plan to implement the recommended resource strategies found in this current Least Cost Plan.

A. Progress Report of Previous Action Plans

The Least Cost Plan submitted by PSE in 1999 included short-term Action Plans. The following provides a review of PSE's efforts related to previous Action Plan items. The statements in boldface font style are from the Least Cost Plan filed in 1999.

I. Energy Demand Forecasting

- **Refine the weather adjustment methodology for billed sales to further distinguish temperature sensitivities within the year.**
  The econometric models used to develop forecasts for the current Least Cost Plan account for differences in the effects of weather by season in the case of electric, and by month in the case of gas. This equation specification holds true for residential electric only, and for all gas sectors. Seasonal variation in temperature sensitivity for commercial electric was tested, but the results did not show significant improvement in the equation.

- **Complete the analysis of gas load research data to refine peak day equations.**
  The gas load research data collection process was interrupted by the installation of AMR meters, and the resources devoted to the data collection process were later needed to address general rate case issues. As a result, the gas load research data were not used in refining the gas peak day equations. However, the gas peak day equation was tested for accuracy using more recent observations, and demonstrated that the percent error was within +/- two percent, about equal to the tolerable meter error in pipeline tariffs.

- **Develop a forecasting module for transportation to account for the effects of business cycles and for the effects of known schedule switching.**
  This task is postponed because the Company's billing system was changed from the Oasis Data Extract Mechanism (ODEM) to Consumer LinX (CLX). Historic billing data

are not readily retrievable. Accordingly, PSE decided to wait until the CLX system is completed and new means of extracting data from CLX is developed using the new Client Data Analysis and Retrieval System (CDARS).

- **Implement a database to track large customer consumption and observed fuel or rate schedule switching.**

  This task is postponed because the Company's billing system was changed from the Oasis Data Extract Mechanism (ODEM) to Consumer LinX (CLX). Historic billing data are not readily retrievable. Accordingly, PSE decided to wait until the CLX system is completed and new means of extracting data from CLX is developed using the new Client Data Analysis and Retrieval System (CDARS).

II. Demand Side Management

- **Investigate the use of technology and real-time pricing to enable market-based conservation and load management.**

  PSE's Time-of-Use rate program began in May of 2001 for approximately 300,000 residential customers, and expanded to include 20,000 business customers (primarily on Rate Schedule 24, less than 50 kW demand) in the fall of 2001. PSE terminated the program in the fall of 2002 when recent changes in the program resulted in many Time-of-Use customers paying slightly more in energy bills than they would have on flat rates. Further details on PSE's Time-of-Use program may be found in Chapter X.

- **Implement the 3-year conservation plan as described in PSE's March 1999 conservation filing.**

  In 1999, PSE submitted a three-year, joint electric and gas conservation program and received Commission approval in April 1999. The program was extended beyond March 31, 2002 for an additional period during the course of the General Rate Case. Three-year savings and costs for that program were 33 aMW and 5,645,085 therms, for a combined electricity and natural gas cost of $37,281,352.

Exhibit XVII-1
Energy Efficiency Services Program Results

Year/period	Kwh	Therms
1999	35,896,091	916,494
2000	63,863,530	1,785,874
2001	149,452,752	2,381,651
Jan-Aug 2002	42,623,632	561,066
Total	**291,836,005**	**5,645,085**

Few accurately predicted the events and electricity wholesale price escalations of 2000 and 2001. The period of extremely low market prices that initially resulted from deregulation in California gave way in 2000-2001 to extremely high prices, volatility, shortages and blackouts. With close interties with California, an “energy crisis” for the Pacific Northwest also emerged. BPA and many of the region’s utilities immediately sought to raise rates, and quickly imposed significant rate increases. This included the three large public utilities adjoining PSE’s service territory. Rate increases of this magnitude, particularly hitting in the middle of winter (peak load periods for the Northwest), were packaged with significant near-term increases to utility conservation efforts to help manage utility and customer costs.

More broadly, a policy need developed to heavily encourage conservation to help manage energy costs throughout the region. PSE, while not raising electric rates, joined others to ramp up its conservation efforts. One of PSE’s most successful tactics was a “time-limited”, 10 percent bonus available on commercial conservation grants. This effort in conjunction with daily news headlines of the energy situation no doubt aided customer readiness to adopt efficiency measures during the 2001 period, resulting in a marked, corresponding rise in natural gas efficiency investments.

PSE instituted another company-wide program for five months in 2001. Customers who converted or adapted efficiency measures such that their monthly use was 10 percent less than energy use for the same monthly period in the prior year were offered an incentive of five cents per kwh beyond the 10 percent saved. As the crisis began to moderate, the Commission approved termination of the program.

- **Continue to pursue "fuel-blind" cost-effective conservation programs.**

  PSE, with regulatory support, continues to serve customers by proactively addressing their questions and concerns on energy efficiency and energy management. Customers, whether receiving electricity or natural gas, benefit from a one-stop, comprehensive conservation service. When a customer receives both electric and natural gas service from PSE, the Company informs the customer of eligibility for efficiency services and potential funding for both electric and natural gas end-uses, as appropriate.

- **Continue to support market developments of energy efficiency products and services, to promote customer-driven energy efficiency.**

  PSE routinely reviews findings of the Northwest Energy Efficiency Alliance's Market Research Reports and Baseline Characteristic Studies to help with designing delivery of its local energy efficiency programs. Most recently, PSE has incorporated findings into its lighting, appliances, manufactured housing and new construction offerings. PSE is supplementing funding of the Commercial Sector Baseline Study now underway in the region, with additional sampling underway from commercial buildings in PSE service territory.

  PSE has worked with Northwest Energy Efficiency Council (NEEC) to investigate potential savings from improved maintenance on unitary roof-top systems in medium size commercial facilities. NEEC's membership is comprised largely of mechanical contracting firms interested in promoting energy efficiency to its clients. Three firms expressed interest in participating in a pilot to develop standards, test procedures and demonstrate savings from improved maintenance practices to be offered as a "premium" level service contract. PSE is continuing its investigation in 2003, and comparing its approach with the Alliance's Small Commercial HVAC O&M service Pilot program.

- **Conduct evaluations for conservation programs as appropriate. Support broader-based conservation evaluation, for example at the regional level.**

  Two surveys of Personal Energy Profile participants were completed in March of 2002. Results were consistent with previous findings that found significant numbers of participants were pursuing energy conservation actions. These included energy- efficient behavior (e.g. shorter showers), installing low-cost measures (e.g. compact fluorescent lamps) and using energy efficiency as a purchase criterion for appliances (e.g. clothes washers) and/or home remodeling (e.g. insulation). This survey was conducted during the time PSE's Time-of-Use pilot was in operation and nearly half of the respondents reported shifting energy use to off-peak periods as well as conserving energy use.

PSE conducts follow-up feedback phone surveys for Energy Efficiency Hotline callers and customer feedback continues to qualitatively measure high customer satisfaction with the program. The surveys also enable PSE to make process improvements, specifically to identify additional training for hotline staff. In addition, PSE routinely asks commercial and industrial customers receiving grant funding for Commercial/Industrial Retrofit conservation measures to provide feedback on their satisfaction with the retrofit program, and on the level of service received. PSE's decision in 2002 to significantly increase incentive levels for small business lighting rebates resulted directly from customer and contractor feedback.

PSE supports regional evaluation work by the Northwest Energy Efficiency Alliance, and has used evaluation findings to help assess the energy savings impacts of select measures and market transformation activities. Examples include evaluations of Building Operator Certification, Motor Management, Energy Star Products, EZSim, Magna Drive and the Lighting Design Lab. The Company is represented on the Regional Technical Forum and has adopted many of the regionally developed findings regarding conservation measure energy savings.

- **In cooperation with the Puget Sound Clean Air Agency, investigate benefits of fuel-conversion from wood-burning appliances to natural gas.**
  PSE explored options for offering this program, and presented information to Least Cost Plan stakeholders early in 1999. This program was not pursued.

- **Expand customer access to energy-efficiency information using PSE's web site.**
  PSE's web site has significantly increased the amount of content regarding energy efficiency and energy management. The site includes an online version of the Personal and Business Energy Profile, calculator tools and brochures. Energy Efficiency Libraries for both residential and for business customers have been added. PSE periodically

updates the energy efficiency pages to add additional programs, rebate forms and information. Moreover, PSE plans to enhance navigation and links within the web site.

Additional electronic services include both a quarterly residential (8,000 subscribers) and bi-monthly business (1,100 subscribers) e-newsletters. PSE maintains an email box, energyefficiency@pse.com for customer questions, providing response within 24 hours. PSE provides links from a customer's Personal Energy Management information/graphs to energy efficiency tips and ideas.

III. Energy Supply – Electric

- **Continue to move, incrementally, toward more market responsive market supply.**

  Since no new long-term resources were added during the period, PSE had a defacto reliance upon short-term markets. Out of necessity, the Company entered into short-term purchases and sales to balance its portfolio. Relying on the short-term market provided some flexibility and had lower costs than purchasing long-term supplies since long-term supplies carried a premium to current market pricing.

  Prior to 2002, the "market" was more robust, made up of numerous creditworthy counterparties offering an array energy instruments. During this time, new forward market hedge products were being introduced, and there was market liquidity (ability to forward transact 3 to 18 months in the future).

  During this time frame, the Company entered into both market-sensitive contracts and fixed price/cap contracts. PSE purchased market-responsive energy supply under index pricing arrangements for winter delivery period to supplement its portfolio. These index contracts were matched specifically with financial hedge instruments to protect against an extreme winter temperature event causing a price spike. Coupling index-related physical supply with financial price caps allowed PSE to have physical supply on hand to serve customers as well as price insurance of the financial hedges.

  PSE combined index-priced physical natural gas purchase contracts with financial derivatives to pair financial hedges and physical contracts that use the same index as a benchmark price. By separating the physical supply from the financial supply, the company was able to purchase the financial hedge from one party and the physical supply from another. That allowed the company to enter into agreements at the same or at different times, and to purchase from the best supplier in each respective market.

Following the bankruptcy of Enron in late winter 2001 and other developments, there has been significant retrenchment of the “market” as numerous marketers and merchant power producer companies have either gone out of business, or ceased to transact in the Pacific Northwest regional markets. Since then, market liquidity has suffered significantly. PSE’s weak credit rating combined with the credit issues of remaining market participants make entering into forward commitments to purchase extremely challenging for PSE. As a result, reliance upon the short-term market, with a growing short position and limited ability to forward hedge, leaves the company and its customers vulnerable to short-term price volatility. As part of this Least Cost Plan, the Company has highlighted the degree of the company’s deficit position and explored the benefits of procuring supply for its deficit positions using long-term power purchase agreements and acquisition of resources with much less cost volatility.

- **Continue to develop risk analysis of PSE portfolio management.**

  In 2002, PSE implemented a portfolio screening-testing tool – KW 3000, which is now used to help the Company identify risk exposure in its portfolio. This risk management tool allows the Company to enhance its portfolio analysis. The risk management system is integrated with PSE’s physical trade capture and scheduling systems for power and natural gas.

  The risk management group uses this system for numerous portfolio management purposes. Outside of risk control needs for deal capture, credit risk management, billing and position reporting, the staff has developed the portfolio management capability of the system so that dynamic position and exposure reports can be generated. The risk system allows PSE to develop a “probabilistic” base case, using certain percentage probabilities and correlations that are inputs to the model. PSE can test its portfolio, not only in a base case environment, but also in scenarios driven by variability unique to its portfolio and the region.

  In order to fully model the portfolio, PSE has integrated external models incorporating hydro risks, wholesale price variability, load changes, plant outage risks, flexible supply contacts, and heat rate valuations of combustion turbines and cogeneration plants. These new models, developed in 2002, give the Company additional tools to test hypotheses and explore the impact of volumetric and market price changes on different parts of its portfolio.

The integration of KW 3000 with the scheduling systems greatly reduces manual data entry, and provides a more stable reporting platform for physical and financial volumetric and price risks.

- **Develop production costing capability in AURORA or another model**
  PSE continues to use AURORA for electric portfolio production costing. AURORA was used to estimate portfolio power costs for the 2001-02 General Rate Case (GRC). A number of enhancements were added during the GRC to the AURORA software and associated databases to extend the ability of AURORA to accurately represent PSE's resource portfolio. These capabilities were used and extended during the preparation of this LCP. The more significant modeling enhancements include: 1) development of software and databases to model PSE's hydro resources under the 60 years of record for the Northwest Power Pool's hydroelectric regulations; 2) added logic to model power purchase agreements unique to PSE; 3) developed data to allow hourly shaping of PSE's power purchase agreements and generating resources; and 4) developed databases and capability to do risk analyses of PSE's resource portfolio.

- **Continue to pursue economic FERC (re)licensing of PSE-owned hydro projects.**
  PSE is currently pursuing the relicensing of three of its hydroelectric projects. The "uneconomic" relicense issued for the White River project has been stayed at PSE's request, and the Company is conducting a collaborative project to identify possible solutions to the economic, recreational and fisheries aspect of the project. PSE has begun a relicensing effort around its Baker River projects utilizing FERC's alternative/collaborative process, and expects to file its license application in 2004.

- **Pursue re-negotiation of Mid-Columbia resource agreements.**

  Late in 2001, PSE finalized new long-term agreements for cost-based purchases of power from the Priest Rapids and Wanapum projects, operated by Grant PUD. These agreements extend PSE's rights to purchase of power to the end of any new FERC license. PSE's current Priest Rapids and Wanapum purchase rights expire in 2005 and 2009, respectively. PSE is discussing with Douglas and Chelan PUDs whether and when it will be appropriate to begin negotiations for renewing/extending the power purchase arrangements with these utilities.

- **Continue to pursue opportunities to reduce costs of existing resource commitments.**

  PSE continues to evaluate its long-term supply contracts to determine cost reduction opportunities in its existing supply commitments. PSE is currently renegotiating a price re-opener in the fuel supply for Colstrip Units 1 & 2 to provide long-term fuel stability and operational cost reductions for these units.

IV. Energy Supply – Gas

- **Investigate increased use of financial instruments for portfolio management.**

  PSE uses financial instruments for gas hedging in both the power and natural gas core portfolios. The most common instrument that PSE enters into is a fixed-price financial swap for the physical location that approximates the receipt points under the Company's pipeline transportation contracts. As an example, the Company entered into fixed price hedges for the period of November 2002-October 2003 for the natural gas core portfolio. The hedges were both fixed-price physical transactions and fixed-price financial swap transactions.

  At times there is not a fixed-price financial swap available as a single instrument for the geographical location PSE seeks to hedge. In this case, the Company will enter into a fixed-price financial swap at Henry Hub, and a basis swap contract to lock in the basis for the Pacific Northwest region. Combined, they simulate a fixed-price financial swap.

  Additionally, the Company has entered into some daily price options struck at the first of the month index price, using its storage as a backstop to reduce price exposure. The

Company has also entered into basis swaps at two locations to act as a hedge for off-system stales that lock in transportation values for the gas portfolio.

- **Explore city-gate delivery service.**

  There are very few occasions when PSE can release capacity and procure city-gate gas supplies from a third party at a cost savings to using its transportation capacity to move supply from supply source to city-gate. However, there are occasions when PSE can enter into an economically attractive exchange agreement to supply a third party at their requested city-gate while that party supplies PSE at its city-gate. PSE has been able to earn a premium for providing baseload supplies (using secondary transport rights), while the counterparty has made baseload deliveries of the same service to one of PSE's system city-gates.

  Some holders of long-term NWP capacity have offered end-users and LDCs a fully bundled service of supply, capacity and delivery to the city-gate for limited periods in the winter months. In the future, the option of city-gate delivery service may be a least cost alternative for meeting peak requirements relative to acquiring more storage and/or pipeline capacity assuming consistent availability over time. PSE will continue to evaluate all resource options and select those that meet the Company's least cost and reliability criteria.

- **Perform feasibility study for expanded capacity of Jackson Prairie storage.**

  PSE and other Jackson Prairie owners completed a feasibility study, and have embarked on a further expansion of the storage capacity of Jackson Prairie by removing additional water from the aquifer storage field. This storage capacity expansion is expected to be developed over a period of approximately seven years. The owners are also evaluating the feasibility, economics and timing of further increasing the gas injection/withdrawal capability of Jackson Prairie. (see Chapter XIV for more details on Jackson Prairie).

- **Increase number and scope of business relationships with suppliers, customers, other LDC's and NUG's.**

  PSE seeks to expand its group of gas physical and financial counterparties. In 2001, the Company added 12 counterparties to its list of suppliers for physical and financial gas transactions. In 2002, there have been significant changes in the gas marketing and trading sector in which PSE dropped 10 of its counterparties due to weak financial conditions, and the net number of counterparties added in 2002 totaled 21, increasing PSE's total number of gas physical and financial counterparties to 54. The large number of counterparties is due to the fact that in each discrete region, there are utilities, merchant power producers and NUGs, producers, aggregators, marketers, and gathering and processing companies. Only some of PSE's counterparties transact in all regions and for all products.

- **Conduct feasibility study of increased LNG capacity for peak load needs.**
  PSE has monitored LNG capacity in wholesale markets but there are no projects currently in Washington, Oregon or British Columbia expected to be placed in service anytime soon.

  For its distribution system, PSE is installing LNG capacity during 2003 at Gig Harbor to increase pressures and delivered volumes to PSE's customers during peak periods. Additionally, the Company has installed compressed natural gas (CNG) to relieve constraints on its system. Approximately 35 sites exist throughout Snohomish, King, Pierce, Thurston and Lewis Counties. PSE can utilize 13 of these sites during a peaking event.

V. Integrated Resource Modeling

- **Continue on-going process of evaluating new gas resource options and alternative resource strategies to meet customer needs.**
  As discussed earlier in this LCP, PSE has continued to review pipeline expansions as well as gas storage and propane-air alternatives to meet future needs. However, since PSE currently has sufficient capacity to meet forecasted needs for several years no new developments are recommended.

- **Continue development of AURORA model databases to better assess the impacts of alternative gas price scenarios, resource costs, and load forecasts on PSE's resource portfolio.**

  As discussed earlier in Section III of this chapter, a number of enhancements have been developed for the AURORA software and the associated data bases to extend the ability of AURORA to accurately represent PSE's resource portfolio.

- **Continue working with AURORA and Uplan-G software developers to better address PSE's resource and policy options.**

  An update of UPLAN-G Version 5.01 was provided by LCG Consulting, the software developers, in March 2002. This update corrected some "bugs" in the software. PSE staff have discussed the possibility of extending the risk analysis capabilities of UPLAN-G but no firm plans have been made.

VI. Distribution Facilities Planning

- **Continue to evaluate opportunities for lower cost, innovative solutions, which facilitate an appropriate level of system performance at the best long-term cost (such as the TreeWatch and Silicone Injection initiatives).**

  PSE continues to evaluate opportunities for low-cost solutions that facilitate system performance. For example, PSE has recently piloted a cost-effective method to reduce animal-related distribution outages in targeted areas.

- **Develop methods for cross-energy solution sets, including cost participation by the beneficiary of the system improvement (off-loading a critical substation by expanding gas usage within the affected area).**

  PSE continues to evaluate fuel switching of customers to address capacity constraints as part of its total energy system planning process. As a long-term strategy where possible, PSE locates new gas and electric facilities nearby to facilitate future fuel switching and distributed generation opportunities.

- **Continue to evaluate distributed resources technologies and consider their impact to both gas and electric plant.**
  As discussed in Chapter VII, PSE has continued to evaluate distributed resources and has developed distributed resource screening tools that identify those projects that facilitate deferral of capital expenditures in a least cost manner.

- **Continue to evaluate historic design conditions and their impact on facility additions.**
  PSE continues to review the historic and continued loading on equipment under design conditions. PSE has begun to review a plan for an increase in facility additions due the impact of loading under design conditions on the aging equipment.

- **Continue to develop system models and other technologies which facilitate more accurate, customer and time-sensitive system evaluations regarding system performance (i.e. Stoner SynerGEE implementation, SCADA, AMR).**
  As discussed in Chapter VII, PSE utilizes distribution system models for both its gas and electric delivery system. PSE has a mature gas system model that is regularly updated to reflect system changes and new customer additions. PSE's electric system model has been recently created and models the distribution feeder system.

B. Two-Year Action Plan

The following is PSE's two-year "Action Plan" organized by topic area. This lists the steps to be taken over the next two years to implement PSE's recommended long-term resource strategy.

I. August 2003 Update

- Modify Northwest Power Planning Council models and run with PSE data assumptions.
- Provide a detailed measure-by-measure summary of results.
- Assess the practicality of pursuing specific cost-effective measures based on the analysis.
- Incorporate the above results into a revised integrated analysis of supply and demand-side resource alternatives.
- Update PSE resource strategy accordingly.

II. Conservation and Efficiency

- Achieve average annual target of 15 aMW and 2.1 million therms of conservation savings per year through 2006.
- Achieve an additional 2.5 aMW electricity savings from residential and farm customers, supported by Conservation & Renewable Discount (C&RD) credits to electricity supply-side purchases from BPA.
- Assess the impact of conservation programs on peak load and losses.
- Promote information, education and training efforts for energy efficiency products, services and practices, in order to support customer decision-making in selecting, purchasing, maintaining and efficiently using equipment, which consumes electricity and natural gas.
- Support local energy efficiency market infrastructure in the communities PSE serves, in addition to continuing support for activities at the regional level through the Northwest Energy Efficiency Alliance.

III. Demand Response Management

- Conduct a fuel-conversion pilot to investigate the cost-effectiveness of residential space and water heating conversions from electric resistance units to high-efficiency natural gas, in order to defer the need for electric distribution system capacity upgrades.
- Investigate the use of natural gas for multi-family units.

- Provide an assessment of the current status and of the potential future of the role of price responsiveness efforts as a demand-side resource option. This work will build upon the efforts of the existing Time-of-Use Collaborative once the group has completed its assessment of the Company's Time-of-Use program per the commitment in the prior General Rate Case. The August 2003 Least Cost Plan update will include the results of this assessment.
- Participate in the Regional CVR pilot program as a demonstration utility, to examine cost-effectiveness of energy savings benefits for the customer and the utility, as well as other impacts.

IV. Renewable Resources

- Continue to study the issues associated with integrating wind resources into PSE's distribution system. In particular, identify and evaluate lower-cost alternatives to the use of new SCGTs to back up intermittent wind generation.
- Explore the feasibility of other renewable resources such as biomass, solar and geothermal energy.

V. Peaking Resources

- Look for lower-cost alternatives to simple-cycle gas turbines (SCGTs), including peaking power supply contracts; and peak-oriented demand response programs.
- Actively participate in regional processes focusing on electric resource adequacy.

VI. Supply-Side Resource Acquisition

- Continue to monitor market opportunities for acquisition of generation assets or power contracts.
- Issue RFP for supply from a large-scale, commercially feasible renewable resources.

VII. Energy Supply – Gas

- Perform detailed analysis of expected long-term supply basin pricing differentials to assist in determination of preferred pipeline alternatives.
- Develop further refinement of the Propane Air options and cost estimates.
- Analyze specific new pipeline projects.
- Explore additional storage options.
- Evaluate the cost and benefits of upstream pipeline capacity.

- Perform feasibility study on expandability of Jackson Prairie storage capacity and deliverability (beyond the current project).
- Examine feasibility of gas reserve ownership as an alternative or supplement to fixed price hedges.

VIII. Energy Demand Forecasting

- Develop more detailed load shape and duration data to facilitate greater optimization of resources and potential for further gas/electric synergies.
- Analyze results of electric to gas conversion pilot program to determine impacts on gas and electric load, and implication for regulatory policy.

IX. Distribution Facilities Planning

- Participate with other EEI utilities in the FERC NOPR process for distributed generation. The FERC NOPR for distributed generation will be issued in the spring of 2003.
- Seek opportunities to deploy distributed generation for least cost capacity deferral.
- Continue the collaboration with the DOE/NREL/GE Universal Interconnect project.
- Track distributed generation technologies and applications that can impact and improve the distribution gas and electric planning process.

X. Integrated Resource Modeling

- Continue on-going process of evaluating new gas and electricity resource alternatives and development of integrated resource strategies to meet customer needs.
- Continue development of databases to support modeling and better assess the impacts of alternative gas price scenarios, resource costs, and loads forecasts on PSE's resource portfolio.
- Continue working with software developers of resource planning models to better address PSE's resource planning issues, resource alternatives and policy options.

APPENDIX A
REGIONAL GENERATION PROJECT DEVELOPMENT

In spite of the financial duress currently impacting the merchant sector, a few developers continue to complete projects. Many projects have been put on hold and several have been tabled or cancelled. As part of its overall least cost resource planning efforts, PSE has examined a variety of supply alternatives, including the acquisition of a physical unit operating or under development by a merchant.

Exhibit A-1 provides an alphabetical list of merchant projects proposed in the State of Washington over the next several years. Assuming all of these projects moved forward, they would provide over 10,000 MW. As has been witnessed over the past year, the pace of development project tabling and cancellation has continued, so PSE fully expects that additional projects on this list will fall by the wayside over the next 12 to 24 months. PSE notes that this project list neither represents facilities of interest to PSE nor all the facilities from which it has collected information, rather it represents an inventory of projects around the state in various stages of development, provided by RDI. With respect to asset acquisitions, PSE has evaluated both in-state and out-of-state alternatives, as well as investigating possible Purchased Power Agreements (“PPAs”).

In addition to the development projects, a number of facilities have come on-line over the past 24 months. As illustrated in Exhibit A-2, in 2002, over 1,100 MW of additional capacity has become operational in the State of Washington. Gas-fired capacity comprises a majority of the newly installed capacity.

Exhibit A-3 lists the three plants currently under construction with their expected commercial operation dates.

Exhibit A-1
Proposed Generation Projects in Washington

Facility	Developer	Facility Type	Size (MW)
Bickleton	PacifiCorp Power Marketing, Inc.	Wind	200
Big Horn	PacifiCorp Power Marketing, Inc.	Wind	200
BP Cherry Point Refinery	BP Cherry Point Refinery	CC/Cogen	720
Columbia River 1	Nordic Electric, Llc	Combust Turb	100
Columbia River 2	Nordic Electric, Llc	Combust Turb	100
Cowlitz Cogneration	Weyerhaeuser Co.	CC/Cogen	405
Darrington	National Energy Systems Co.	Boiler/Cogen	15
Everett Delta Power Project	FPL Energy, Inc.	Comb Cycle	248
Frederickson (USGECO)	PG&E Generating Co.	Combust Turb	100
Frederickson (Tahoma)	Tahoma Energy	Comb Cycle	270
Frederickson 2	EPCOR	Comb Cycle	290
Goldendale Smelter	Westward Energy Llc	Comb Cycle	300
Horse Heavan	Washington Winds Inc.	Wind	150
King County Fuel Cell Plant	Fuel Cell Energy Inc	Other	1
Kittitas Valley	Zilkha Renewable Energy	Wind	250
Klickitat	Columbia Wind Power	Waste	80
Longview (MIR)	Mirant Corp.	Comb Cycle	286
Mercer Ranch	Cogentrix, Inc.	Comb Cycle	850
Moses Lake	National Energy Systems Co.	CC/Cogen	306
Plymouth Energy LLC	Plymouth Energy Llc	Comb Cycle	306
Port Of Washington	Continental Energy Services, Inc.	Combust Turb	290
Rainier	National Energy Systems Co.	Comb Cycle	306
Richland (COMPOW)	Composite Power Corp.	Combust Turb	2600
Roosevelt (SEENGR)	SeaWest Energy Group, Inc.	Wind	150
Roosevelt Landfill	PUD No. 1 of Klickitat County	Intern Combust	13
Satsop Combined Cycle	Duke Energy North America	Comb Cycle	530
Satsop Combined Cycle	Duke Energy North America	Duct Firing	120
Seattle (Globaltex)	Globaltex Industries Inc.	Coal	249
Six Prong	SeaWest Energy Group, Inc.	Wind	150
Stateline Wind Project [Wa]	FPL Energy, Inc.	Wind	40
Sumas Energy 2, Inc.	Sumas Energy 2, Inc.	Comb Cycle	530
Sumas Energy 2, Inc.	Sumas Energy 2, Inc.	Duct Firing	130
Sumner (PG&E)	PG&E Dispersed Generating Co.,	Combust Turb	87
Tacoma (Mscg)	Morgan Stanley Capital Group, Inc	Combust Turb	324
Underwood	PacifiCorp Power Marketing, Inc.	Wind	70
Waitsburg	SeaWest Energy Group, Inc.	Wind	50
Wallula	Newport Northwest	Comb Cycle	1000
Wallula	Newport Northwest	Duct Firing	300
Washington (Elcap)	El Cap I	Combust Turb	10

Exhibit A-2
Washington/Oregon Generation Facilities Online in 2002

Facility	Developer	Facility Type	Size (MW)	On-Line Date
Boulder Park	Avista Corp	Intern Combust	25	5/31/2002
Centralia (TRAENE)	TransAlta Energy Corp.	Comb Cycle	248	8/12/2002
Frederickson Power	Frederickson Power (EPCOR)	Comb Cycle	248	8/19/2002
Hermiston	Calpine	Comb Cycle	630	6/1/2002
Klondike	Northwest Wind Power	Wind	25	4/30/2002
Nine Canyon Wind Project	Energy Northwest	Wind	50	9/25/2002

Exhibit A-3
Washington Generation Facilities Currently Under Construction

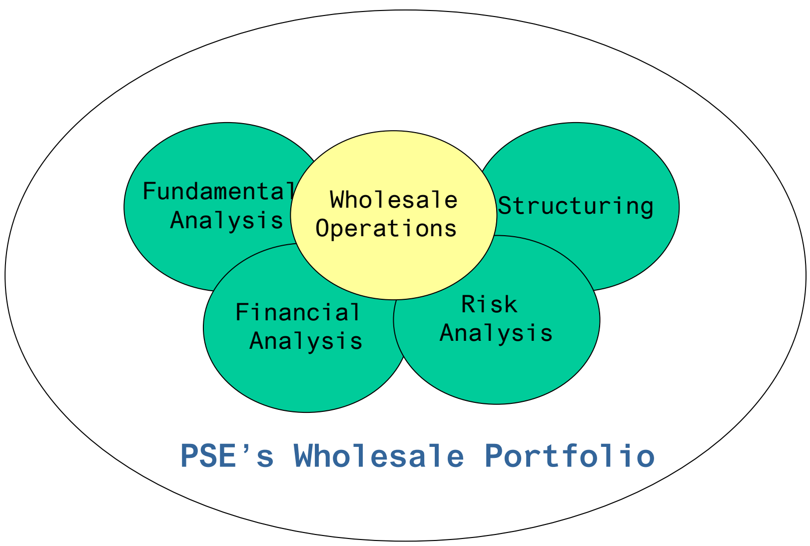
Facility	Developer	Facility Type	Size (MW)	On-Line Date
Chehalis Power Station	Tractebel Power, Inc.	Comb Cycle	520	Q3/2003
Coyote Springs 2	Avista	Comb Cycle	260	Q3/2003
Goldendale	Calpine Corp.	Comb Cycle	248	Q2/2004

APPENDIX B
PORTFOLIO MANAGEMENT PERSPECTIVES

Once PSE has configured its portfolio with a mix of long-term resources, the focus of activity shifts toward the task of near-term operation of the portfolio. These near-term operational functions include portfolio hedging and optimization of the Company's resources. This appendix describes PSE's portfolio management activities more in detail.

Within Energy Risk Management, the Company employs several analytical disciplines to cover different facets of portfolio management. It is important that the various functions inter-relate to ensure a coordinated overall effort with the consistent use of models and theories for multiple purposes. Exhibit B-1 illustrates this dynamic.

Exhibit B-1
Portfolio Management Perspectives



Fundamental analysis pertains to the study of supply and demand factors that influence the price of energy in a given market for a certain time frame. PSE applies both a top-down and bottoms-up approach to fundamental analysis. The Company uses some tools such as stacking models to replicate market behavior. This provides both a base expectation, as well as other scenarios that might result in different market prices. Having a range of possible outcomes enables the risk management group to get a sense for potential risks, and to identify the single largest uncertainty factors.

Commoditization Of Energy Markets

Supply/demand fundamentals primarily drive commodity prices. Over the last 5 to 10 years, natural gas and electric markets have become 'commoditized' through FERC deregulation of the natural gas pipeline industry and electric power sector. Factors indicating the commoditization of power and natural gas markets include:

- Price discovery through numerous market buyers and sellers electronic exchanges and broker markets.
- Development of liquid pricing locations at central trading hubs such as Mid-Columbia for power and Sumas, WA for natural gas.
- Standardization of contractual terms for physical power, natural gas and associated financial derivatives.
- Development of parallel financial markets and new structured products around physical power and natural gas markets.

Power Market Drivers

With respect to understanding the underlying supply/demand factors, the Company looks at a number of leading indicators. In power, the key variables in the Pacific Northwest include weather (temperature and precipitation), economic conditions, fuel costs, plant heat rates, plant availability, transmission and intertie capacity, hydro energy and storage, biological opinion affecting flows on the river system and spill requirements, new generation capacity and other neighboring regional power market dynamics.

As Exhibit B-2 illustrates, hydro energy comprises the largest share of power generation in the Pacific Northwest, making hydro energy availability the single largest source of variability in PSE's energy portfolio. The cost of hydro energy is extremely low, relative to market-based replacement power. The percentage change in any given year from normal hydro output provides a meaningful number for PSE's portfolio (between 5,600,000 and 9,800,000 MWh). As a result, hydro analysis proves important. However, forecasting energy out of the hydro system is highly complex. As a result, PSE conducts analysis internally, and supplements the analysis with two outside consultants. PSE gathers information on precipitation at critical locations that mimic the Company's West Side hydro facilities and which correspond to the rainfall into the federal river system.

Exhibit B-2
Northwest Power Pool Area (U.S. Systems) Capacity By Fuel

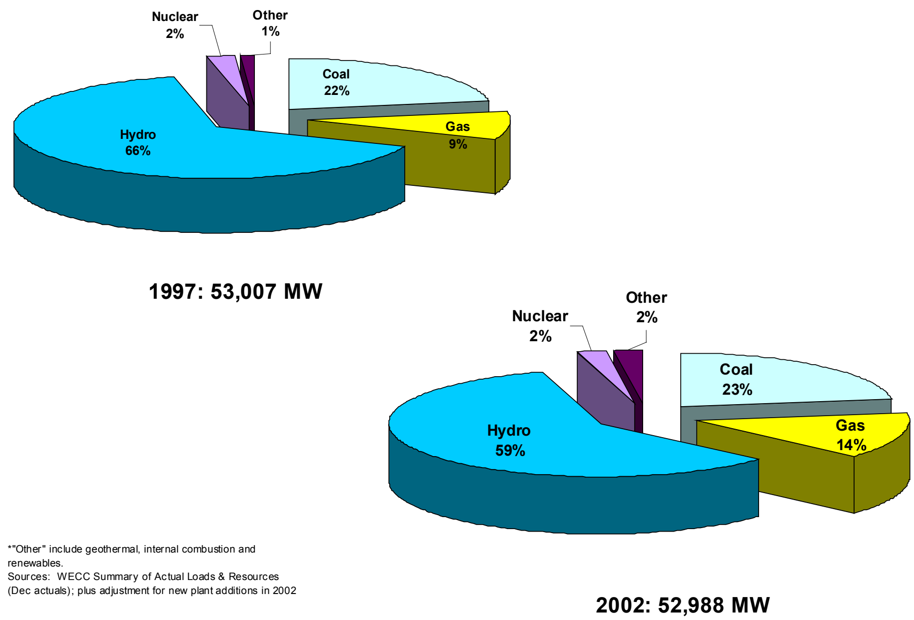
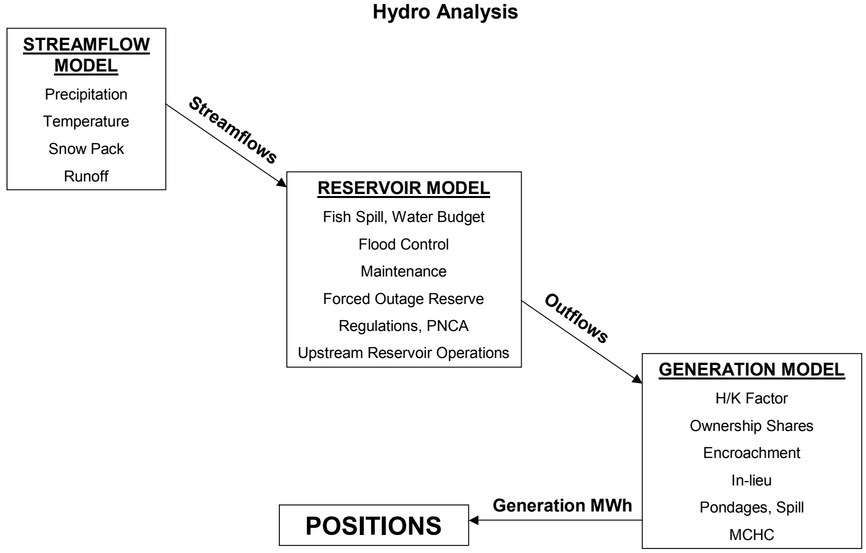


Exhibit B-3 illustrates PSE's hydro modeling process. The precipitation information feeds a "Streamflow Model" which feeds a "Reservoir Model" that subsequently models fish spill, flood control, forced outages, regulation and other factors affecting outflows of water. The Generation Model – the last piece of the modeling effort – allows PSE to forecast available energy for the

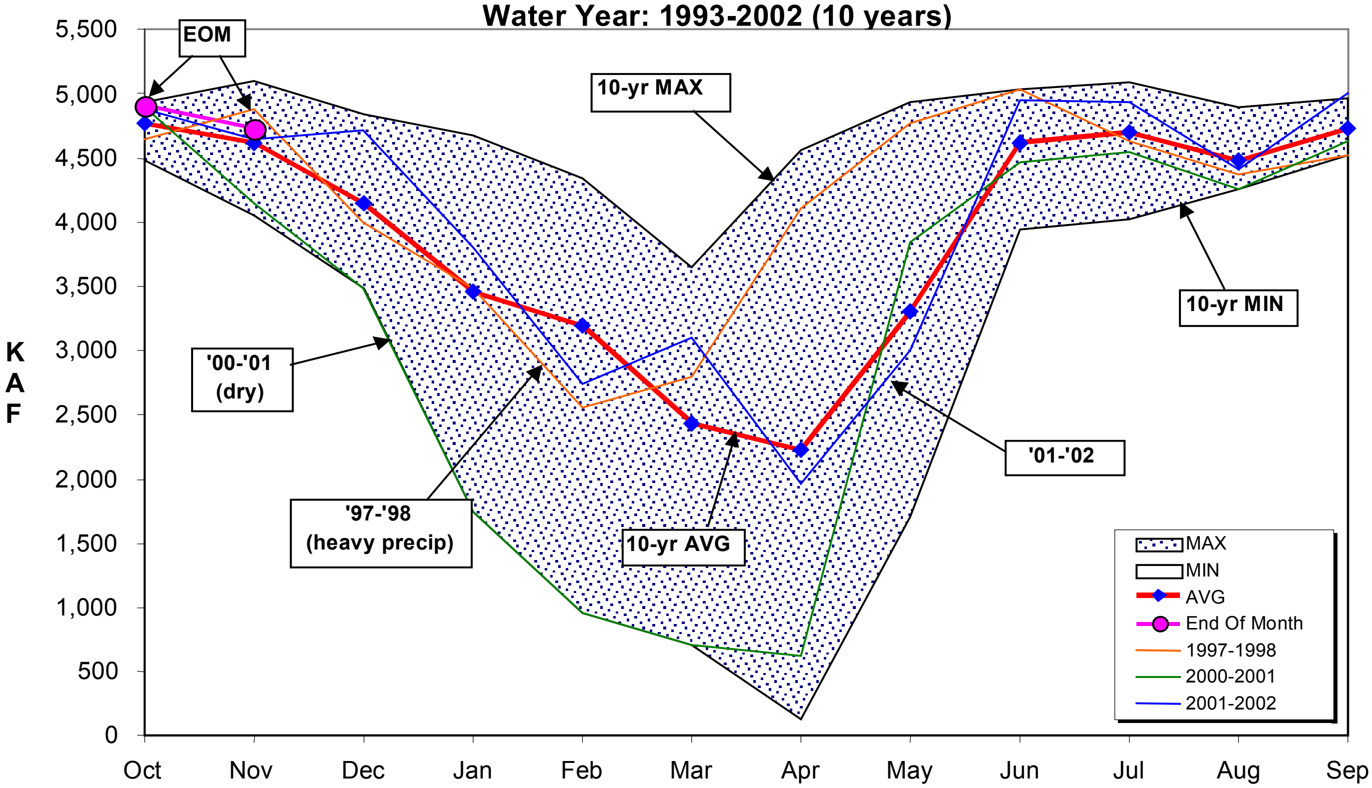
Exhibit B-3
Hydro Analysis



base case position. The final stage, which the Company is just now completing, involves taking the base case forecast and running scenario tests based upon historical years. This allows the Energy Risk Management group to project a range of possible energy outcomes as a result of the scenario testing.

Hydro reservoir storage provides a short-term market indicator, in addition to elevation levels on the federal system above Grand Coulee dam, and MAF (million acre-feet) streamflow levels. These factors, in addition to plant outages, weather reports, and spot fuel prices enable PSE to understand what energy comes into the market, and the relative changes by day and through the current month of energy costs. Exhibit B-4 illustrates historical reservoir levels.

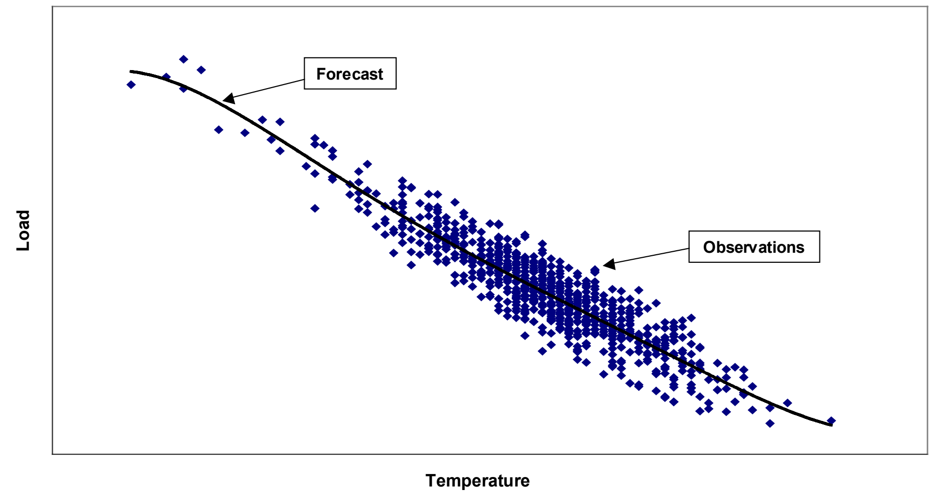
Exhibit B-4
End-Of-Month Grand Coulee Reservoir Storage (KAF)
Water Year: 1993-2002 (10 years)



Source: USBR

Load, driven by customer count, temperature and economic conditions, represents the next largest source of variability in PSE's Power portfolio. The Energy Risk Management group models expected average load, and then develops a forecast range for necessary minimum and maximum loads to model variability for exposure testing. PSE's challenge focuses on having enough energy to serve the peak loads, but to have some flexibility to back down supplies in off-peak periods in order to mitigate costs.

Exhibit B-5
Load Versus Temperature Relationship



PSE's load has an hourly variability, as well as diurnal and seasonal variability. At any given time, the Company must plan to meet that load, especially in an extreme winter peak condition. The double peak of PSE's load profile further complicates hourly management of its load profile.

Exhibit B-6
Peak Load Analysis and Planning

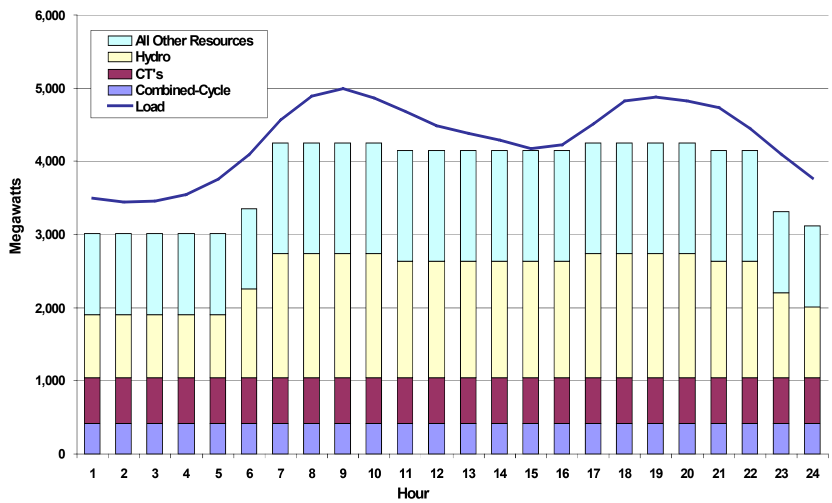
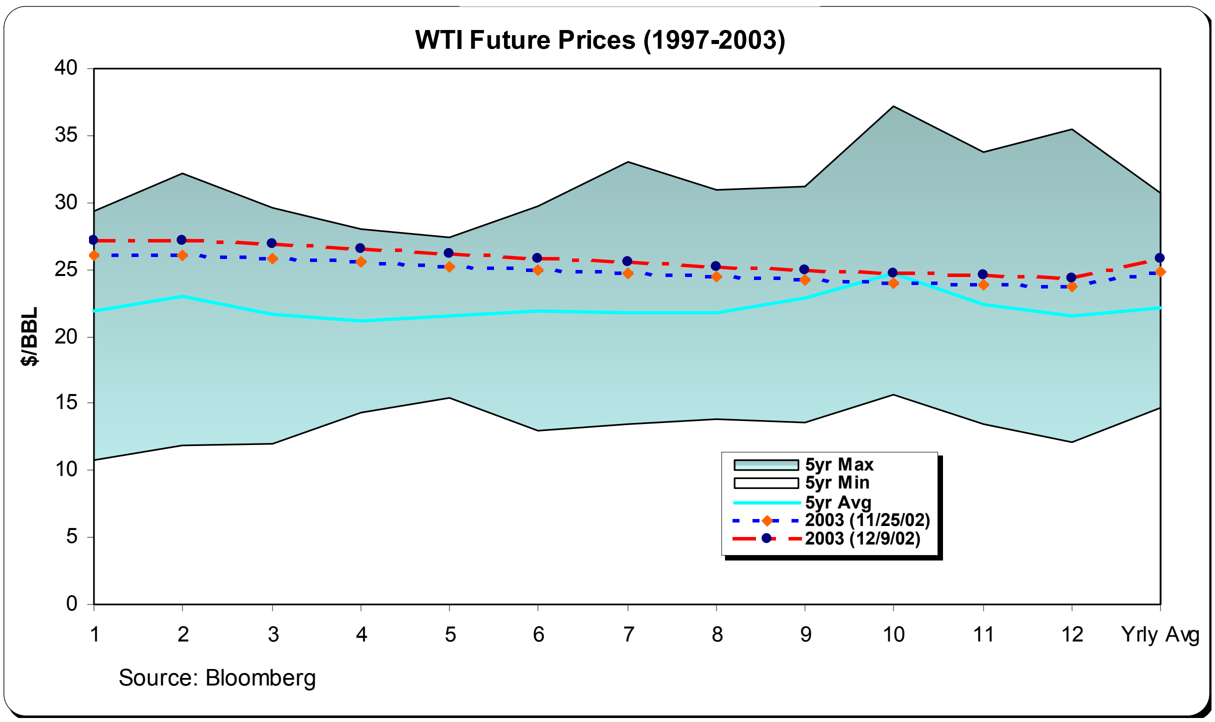


Exhibit B-6 illustrates a typical load picture over a 24-hour period. PSE's hydro storage provides a critical resource for balancing the resource and loads on a short-term basis. The Company has storage both at its Baker facilities and through its Mid-Columbia contracts.

Natural Gas Market Drivers

Natural gas represents a growing part of the generation mix in the Pacific Northwest, with similar market drivers as the power market. Therefore power market factors, particularly the relative surplus or deficit of hydro energy, can have a large impact on regional natural gas demand. Significant movements in natural gas market prices will also affect power prices.

Exhibit B-7



As Exhibit B-7 illustrates, oil prices are strongly linked to natural gas prices. This occurs for a couple of reasons. In the fuel consumption area, natural gas competes with two refined products, residual fuel and distillate fuel which are burned in older fossil fuel plants as an alternate fuel to natural gas. In the exploration and production sector, natural gas and crude oil are sometimes found together ("associated oil"), or at times have to compete for exploration budgets. An indicator of natural gas drilling activity is 'rig counts', with an 8- to 18-month lag time between drilling and gas coming to market. PSE tracks rig counts to monitor the longer term increasing or decreasing supply trends.

Storage inventories provide an important gauge to natural gas supply/demand imbalances. The natural gas industry uses salt caverns and depleted oil wells as underground storage facilities. The relative level of inventory acts as an important determinant of relative surplus or deficit in the short-term markets. PSE tracks the weekly and monthly storage inventory levels nationally, as well as in the western US and Canada.

As with power markets, weather and economic factors also serve as important determinants in price volatility. PSE's gas load is predominantly heating-load based, with extreme sensitivity to variations in load on account of changing weather patterns. PSE monitors weather patterns from several sources including local weather stations, the national weather service and through a weather subscription with Weatherbank.

Credit Risk Management

PSE faces significant constraints executing wholesale transactions in short-term and medium-term power and gas markets, due to several factors. One, the markets have become less liquid with fewer parties transacting, and the forward time frame shrinking to shorter-term delivery periods. Two, default risk has become a concern, given the recent bankruptcy filing of Enron, NRG, and TXU Europe. Therefore credit requirements have risen dramatically. Three, the higher rated companies command a "premium" in their power and natural gas prices to transact with them. This increases operating costs significantly for PSE since its credit rating is only just above investment grade.

In both power and gas markets, there has been a huge decline in forward market activity by traditional investor-owned utilities and municipal load serving entities. Moreover, the large energy marketing companies have either exited the Pacific Northwest markets, scaled back for strategic purposes, stopped trading altogether in North America (Aquila, Dynegy), or simply cannot transact because of their weak credit rating. This liquidity situation has several implications. Forward hedging becomes much more difficult, with PSE being in an uncomfortable position of having to ration credit across multiple needs and activities (power, gas, weather derivatives, peaking capacity, regional exchanges to improve reliability). In Core Gas, PSE has ample storage and pipeline capacity, but because of market illiquidity, the Company cannot optimize its assets fully, but must hold open capacity or inventory for significant changes in load. PSE faces challenges in displacing and dispatching its generation units to respond to all price opportunities due to the market liquidity problem.

In addition to liquidity concerns that hamper hedging, short-term balancing and asset optimization, PSE faces serious credit concerns from counterparties. Entities who would have transacted with PSE a year ago, now have concerns over PSE's credit rating. By example, a surprising number of natural gas producers are reluctant to sell at a fixed price to PSE due to concerns over PSE's credit rating.

Tools And Methods

Portfolio Management

PSE utilizes an energy transaction capture and risk management system ("system") to capture, monitor, manage, and control physical positions, exposures and variances. The system monitors volumetric positions, and financial exposures and variability. Additionally, PSE uses proprietary models to conduct portfolio and scenario financial analysis of the energy supply portfolio. These models are analytical applications incorporating industry models and third party software. The Energy Risk Management and Risk Control groups perform specific analyses to quantify volumetric and financial exposures with internal written procedures. Risk Control is responsible for deal capture, data integrity and reporting from the system. Exhibit B-8 provides the KWI explanation for the Risk Analysis module.

Exhibit B-8

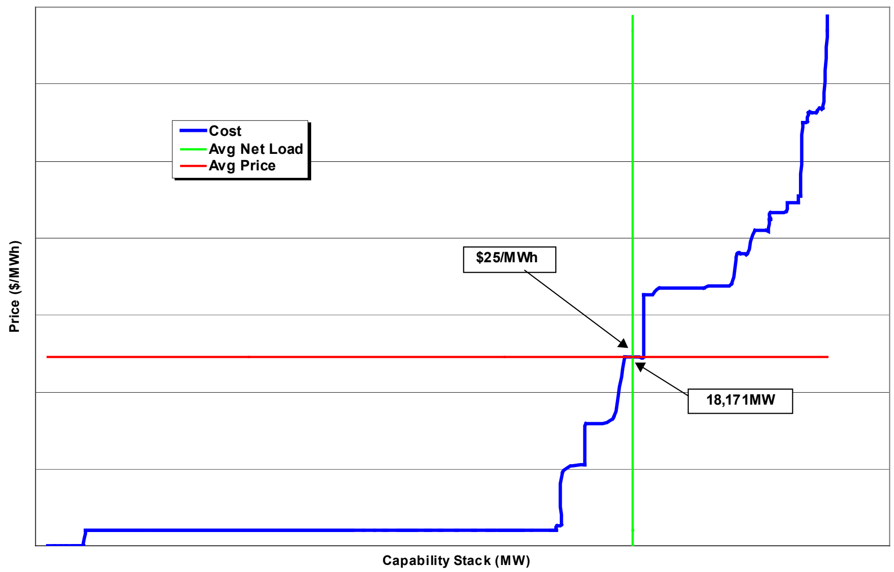
Risk Analysis Model

Module Name
Risk Analysis
kWRiskAnalysis.exe
The objective in using this module is to find a strategy that best improves the profit/risk trade-off in a portfolio or sub-portfolio of the Company. In this module the Risk Manager (or similar person) can carry out detailed risk analysis to ascertain the expected profitability of the total portfolio or any part of the portfolio in the potential profit at risk. Risk managers can see the effect of adding a new trade or trades and then can assess how their position relates to a variety of categories such as Production, Bilateral purchases, Futures (or Standard Product) purchase, Spot purchases, End user sales, etc. These data can also be viewed in a graphical manner. Risk managers are then able to perform sensitivity analysis in order to evaluate the impact on ratio between profit and risk of any trading, production or sales strategies. This is used to develop hedging strategies that create a portfolio including physical assets (such as generation plant and retail customers) that is robust to changes in the market.

Fundamental Analysis Tools

To model the Pacific Northwest region's power supply/demand dynamics, the Company utilizes the AURORA model. Energy Risk Management staff have adapted the long-term forecasting tool to simulate economic dispatch throughout the region in short-term market scenarios.

Exhibit B-9
Fundamental Analysis Example:
Forecasting Regional Supply and Demand



The intersection of projected load and the resource stack produces the theoretical market-clearing price. PSE does not use the model as much for a point estimate for price, but more as a tool to give an indication of market price direction, and the scale of that potential market price move, given changes to inputs in the model. This tool is used to give a sense of relative change in market prices given different assumptions for regional load and estimated generation availability.

To model its natural gas portfolio, PSE utilizes a model called “U Plan G”. This model enables the energy risk management staff to simulate the gas portfolio using estimated loads and capacity utilization. The model includes assumptions about estimated load, transportation requirements, storage requirements and an estimated market value for unused capacity.

PSE Approach To Managing Price Risk

Risk management is the process of using financial tools to manage price volatility, and volumetric risks in power and natural gas profiles. Risk management tools can also be used to bring certainty to a given outcome, or “hedge.” PSE bases the decision to hedge, and evaluation of a hedge, on the information known at the time that the hedge was put on, not on the market conditions that might exist when the hedge was recognized. In fact, existing market conditions when the hedge was recognized prove to be irrelevant because the desired outcome was achieved, with some other party bearing the market risk. When combined with its least cost planning process, PSE’s risk management efforts stabilize the average cost of gas to its firm customers, but there is a cost incurred in managing the risk.

PSE uses risk management to enhance the value of the physical, portfolio optimization transactions, and those transactions used to supply its firm customers, within a defined risk framework, however, it does not maintain any speculative positions. All of the financial risk management transactions correspond to underlying physical transactions. The risk management transactions require PSE to buy and sell power and natural gas and basis positions on various exchanges or in over-the-counter (OTC) markets. For example, fixed and forward prices are used to lock in the value of storage injections or future gas purchases. PSE primarily uses fixed/floating swaps to manage the value of index-based gas sales or purchases.

PSE's goals in hedging and managing price risks in the power and gas portfolios include:

- Providing price certainty and locking down risks
- Keeping prices stable and minimizing costs

PSE has internal risk management processes to help bring focus and order to the energy risk management function. For power, Energy Risk Management staff develop position reports based upon probabilities load, generation output and unit availability. The probabilities position is driven by several important inputs. First, the analysis centers on current market prices for fuel and power, and price dispersion around those base prices. Next, each plant's operating characteristics are modeled, with a resulting fuel need and estimated power output results. Plants with lower heat rates (better conversion costs of fuel to power) will typically be economically dispatched more often in the models feeding the position, whereas, peaking units have less impact and contribution to position. Lastly, dispatchable contracts are modeled to be fully optimized for a given set of price assumptions and load/resource balances.

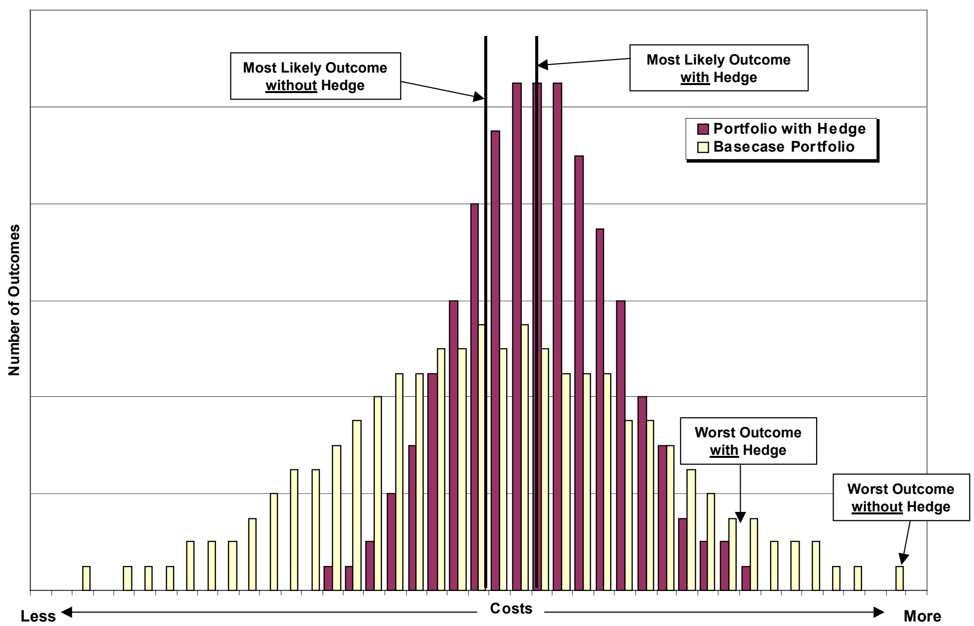
This information results in a position report that illustrates the net open position for every month for power and natural gas. The positions are generated for 12-24 months out in time. Next, the energy risk management staff evaluate the forward positions, and explore which of them have significant forward risks associated with them. There is a prioritization process of focusing on these items that can be hedged, and which have the greatest risk associated with them.

Hedge strategies are developed through evaluating a wide range of deal structures. The hedge might be a straightforward fixed price purchase or sale of fuel or power. It might be a seasonal exchange, or a buy/sell at different locations. Still other common instruments include options, such as a call (option to purchase) or a put (option to sell). Calls and puts can be valuable instruments, *depending upon their cost,* to offset the risks PSE has in a load that is highly weather-related.

Strategies are tested, not only against the current probalistic position, but also for the portfolio in numerous other market scenarios (different hydro, load, energy prices, etc.). PSE seeks to identify a strategy not only for the base case, but also for other scenarios. Sometimes the "winning" strategy proves not to be the immediately obvious strategy, but one that takes significant risks out of the portfolio under a range of conditions.

PSE has just begun to utilize the new KW 3000 tool to measure how hedging strategies minimize risks in different scenarios. Exhibit B-10 shows a histogram of what a hedge strategy ideally does in terms of reducing outlier risks and not moving expected outcome (the mean) too much as a result of the hedged cost.

Exhibit B-10
Portfolio Risk Analysis
Measuring cost of Hedging versus Risk Reduction



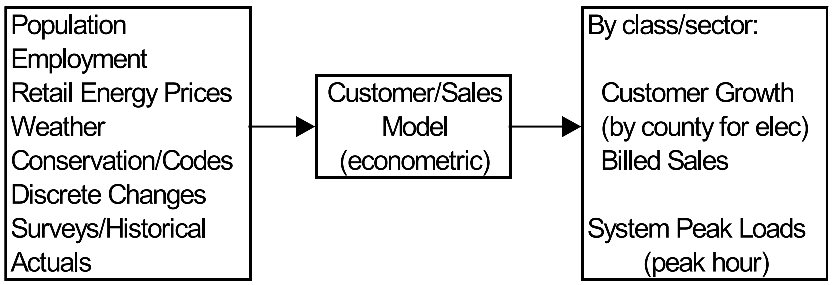
PSE monitors how the hedge costs affect the bottom line costs. PSE sets a budget for power costs at the beginning of the year. This includes hedging costs, as well as operating costs. Hedge costs need to be taken into consideration so the hedge costs do not move the expected value or outcome too much in a negative fashion.

APPENDIX C
LOAD FORECASTING METHODOLOGY

Billed Sales and Customer Count Forecast Methodology

Exhibit C-1
PSE Econometric Forecasting Model

Forecast Inputs **Forecast Outputs**



The estimated equations have the following forms:

- **Use per Customer by Class** = f (Weather, Prices, Economic/Demographic Variables)
- **Customer Count by Class** = f (Economic/Demographic Variables)

  where: *Use per Customer* = monthly billed sales/customers

  *Weathe*r = cycle adjusted HDDs (base 60,45,35 for electric, base 65 for gas) and CDDs (base 75 for electric); cycle adjusted HDDs/CDDs are created to fit consumption period implied by the billing cycles

  Prices = $/kwh for electric or $/therm for gas (constant 2000$, or the relative gas to electric price)

  Econ/Demo Variables = Income, Household Size, Population, Employment Levels/Growth, Building Permits

  (variables entered depend on class and whether it is use/customer or customer counts equation and by class)

- **Billed Sales** = Use per customer, multiplied by customer counts

Different functional forms were used depending on the customer class. For the electric residential use per customer equation, a semi-log form was used with the explanatory variables (prices and demographic variables) entering in polynomial distributed lagged form. The length of the lag depends on the customer class equation with residential having the longest lags. A double log form was used for the other sectors, again with explanatory variables entering in a lagged form. Use of lagged explanatory variables in the equations account for changes in prices or economic variables that have both short-term and long-term effects on energy consumption. For gas, most of the use per customer equations have a linear form with prices or economic variables entering in polynomial distribution lagged form again.

The equations were estimated using historical data from January 1993 to March 2002, depending on the sector and fuel type. Electric billed sales from the data centers in the commercial sector were not included in the commercial equations. The forecast of electric billed sales from the data center was based on discussions with the customers and their planned capacity additions in the next few years. The electric industrial equations were estimated using data from January 1996 to March 2002. Note that the industrial use per customer and customer count equations pertain only to industrial customers which did not go to Schedule 449 or 459 (transportation or “retail wheeling” schedules). It was only possible to go back to January 1996 to isolate the electric billed sales of these customers from the total industrial billed sales. However, a separate equation was used to forecast billed sales for the non-core Schedule 449/459 customers using manufacturing employment and Mid-Columbia prices as explanatory variables. The forecast for electric resale also accounted for the Seatac airport leaving the system.

Exhibit C-2, based on the estimated coefficients for the retail prices in the use per customer equations, provides the computed long-term price elasticities for the major customer classes for electric and gas.

Exhibit C-2
Long-Term Price Elasticity For Major Customer Classes

	Electric	Gas
Residential	-0.19	-0.14
Commercial	-0.21	-0.21
Industrial	-0.17	-0.24

All of the estimated price coefficients are also statistically significant.

Electric customer forecasts by county were also generated by estimating an equation relating customer counts by class/county and population or employment levels in that county. The adding up restriction was imposed so that the sum of forecasted customers across all counties equaled the total service area customer counts forecast. This projection also serves as an input into the distribution planning process.

The billed sales forecast was further adjusted for discrete additions and deletions not accounted for in the forecast equations. These adjustments include the company's forecast of new programmatic conservation savings for each customer class, known large additions/deletions or fuel switching, and schedule switching. Finally, total system loads were obtained after accounting for own use and losses from transmission and distribution.

Electric Peak Hour Forecast

PSE obtains normal and extreme peak load forecasts through the use of an econometric equation relating observed hourly system peak loads in the month with weather sensitive sales from both residential and non-residential sectors, with deviations from normal peak temperature for the month, and with unique weather irregularities such as El Nino. Since the historical data includes periods when large industrial customers left the system, the equation also accounts for this change in historical series. Finally, PSE allows the impact of peak temperature on peak loads to vary by season. This specification allows for different effects of residential and non-residential loads on peak demand by season, with and without conservation. The functional form of the equation is displayed below:

Peak MW = *a**Resid aMW + *b**Non-Resid aMW
+ *c**(Deviation from Normal Peak Temp)*(Weather Sensitive aMW)*SeasonDummy
+ *d**Sched48Dummy + *e**ElNinoDummy

where a,b,c,d,e are coefficients to be estimated.

PSE estimated the equation using monthly data from 1991 to 2001 resulting in coefficients which are statistically significant from zero and an R-Squared of 0.96. The standard error is about 2.9 percent of the forecast. To obtain the normal and extreme peak load forecasts, PSE factors the appropriate design temperatures into the equation for either condition. For PSE, these design temperatures are 23 degrees for normal peak and 13 degrees for extreme peak, both occurring in January.

Gas Peak Day Forecast

PSE uses the following equation to represent peak day firm requirements:

Peak Requirements = Number of Customers x [Base Load per Customer + Heating Load per Customer per Degree Day x Design Day Heating Degree Days]

- **Base Load** is defined in "Therms per Day" or "Therms per Month" per customer for daily and annual estimates. The Base Load may or may not be significantly temperature-sensitive depending on the sector, and is generally considered to be related to water heating, cooking or other gas appliances.
- **Heating Load** is defined as "Therms per Customer per Heating Degree Day." This load is usually due to heating or air conditioning of the ambient air temperature.
- **Heating Degree Days** (HDDs) are determined by deducting the daily average temperature from 65°F.
- The **number of customers** by class is based on the forecast of customers by class as presented in the previous section.

The design peak day requirements for this forecast are based 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).

PSE determined the peak day requirements for the year by applying the above equation to the design, peak day degree days in January. The heating load per customer per degree day was derived from regression analysis of the actual billed sales per customer per degree day by customer class for the five winter months (November—March) over the last five years versus the respective monthly heating degree days. This resulted in regression equation coefficients that describe the relationship of use to monthly heating degree days for each of the major firm class customers. The estimated coefficients were statistically significant while the R-squared were greater than 0.95. The estimated standard error is about 3.2 percent of the forecast in January for all firm classes. Previous non-base load methodologies focused on a single HDD series. This provided an annual average temperature response, likely over-estimating shoulder periods and under-estimating peak periods. This method was not consistent with declining annual per customer consumption. The newer approach focuses on isolating responses attributable to each month. Hence, 12 HDD series have been implemented, one for each month. In this approach, January has the largest temperature coefficient, the greatest temperature sensitivity and therefore more likely to experience the design day. This also allows PSE to evaluate if there appears to be any changing temperature sensitivity over time due to conservation or other factors, observed in the peak month. There does appear to be a declining trend in heat sensitive loads for residential customers, but not other customer groups at this time.

Base loads have been estimated using econometric equations, rather than being estimated from a simple average of the last five Augusts. This allowed identification of slight temperature sensitivities in August. It also allowed estimation of trends for each of the three core classes. Base loads were estimated with zero HDD and then subtracted from all months. The remaining daily demands were then attributable to temperature. All three core sectors tend to have base loads with increasing trends.

Large volume customer daily contract demand was estimated from January, rather than from August. These data tend to have a seasonal shape, with interruptible customers taking more in January. The per customer January 2002 value is simply held constant over the forecast horizon, and multiplied by customers to form large volume peak demand. These data are added with their respective category, either commercial core or industrial core.

Conversion Of Monthly Billed Sales Forecast To Loads (Gpi)

Historically, the Financial Planning department at PSE has produced an annual KWh (and more recently a monthly KWh) forecast of Billed Sales. This Billed Sales forecast needs to be converted into a monthly total Generated, Purchased and Interchanged amount (“GPI”) in order to be used in Power Supply related load/resource models.

Summary of Methodology

Monthly GPI is forecast through a system of hourly multivariate regressions utilizing historical temperatures and GPI loads. This method does not convert or allocate Billed Sales forecasts to GPI; it forecasts monthly GPI “from scratch” using real GPI loads. The statistical techniques are similar to the process for forecasting Billed Sales. To capture conservation and load growth assumptions the GPI forecasts are adjusted to match up with annual forecasted Billed Sales.

Input Data and Assumptions

- An annual Billed Sales forecast for the upcoming calendar year.
- Seven years of historical, hourly actual (i.e. non-temperature normalized) loads.
- Historical hourly Sea-Tac temperatures.
- An assumed annual distribution loss factor.

Validity of Methodology

Stationarity of the GPI load data:

- *Stationarity* ensures that the data generating process for the series is itself not dependent on time.
    - Measurement of the variance of GPI load data reveals no significant change over the sample period. Thus the series is stationary in variance.
    - Although the raw GPI load data clearly exhibit trends over time (customer growth) the data have been de-trended to allow accurate specification through the addition of a linear trend variable (Equation Details).

Alternative methodology - temperature splines:

- It is common to use splines to help identify the separate relations between temperature and load depending on the level of temperature. For the calculation of this model the inclusion of splines was rejected in favor of the quadratic equation form. This was done for two reasons:

    1) Temperature splines require arbitrarily chosen temperatures to act as boundaries (e.g. <60 F to 60 F , 61 F to 70 F , >71 F). With the changing energy demands of our customers (air conditioning load) over recent years the arbitrary selection of spline boundaries and the linearities they impose on the model would serve to reduce its explanatory power vis-à-vis the quadratic specification. This is particularly true with hourly data.

    2) To assist with a generalized format across all hourly equations, the quadratic format is superior to the use of temperature splines as the equation is able to self-select the appropriate balance point between heating and cooling for every hour of the day.

Equation Details

$aMW_h = a_w + \beta_1(aMW_{h-i}) + \beta_2(\Sigma(aMW_{h-i})/3) + \beta_3((Month_m)Temp_h) + \beta_4((Month_m)Temp_h^2) + \beta_5(Holiday) + \beta_6(Trend)$

where: h=1-24 (hour)

w=1-7 (weekday)

i= 2-4 (lagged hours)

j= 1-12 (months)

Holiday includes all NERC holidays. Trend is a linear function $y=\alpha + x$.

Discussion of Load Forecasts

To determine the amount of power that needs to be generated to supply the forecasted billed sales, the billed sales forecast must be increased to account for transmission and distribution losses (6.4 percent of generation) and the time lag associated with the billing cycle. For example, assuming a monthly billing cycle, power bills reflect the power consumed and generated in the previous month.

To do this the annual billed sales forecast is first increased to account for the transmission and distribution losses and then shaped or allocated among the 12 months based upon the methodology outlined above. The base, low and high load forecasts are shown in Exhibit C-3.

Exhibit C-3
PSE Load Forecasts (MWh/year)

	Base	Low	High
2003	20,623,609	20,616,264	20,663,433
2004	20,818,940	20,782,992	20,907,983
2005	20,994,755	20,900,232	21,154,277
2006	21,252,369	21,082,274	21,524,529
2007	21,527,009	21,260,599	21,909,439
2008	21,816,085	21,445,549	22,297,612
2009	22,128,117	21,658,193	22,697,310
2010	22,365,522	21,793,254	23,012,717
2011	22,650,883	21,958,722	23,362,312
2012	22,937,946	22,124,724	23,686,149
2013	23,303,207	22,390,372	24,092,860
2014	23,694,736	22,689,911	24,543,722
2015	24,088,851	23,004,458	25,003,781
2016	24,493,362	23,357,857	25,485,107
2017	24,900,901	23,727,627	25,986,039
2018	25,312,603	24,096,313	26,488,900
2019	25,741,711	24,483,757	27,010,223
2020	26,183,871	24,882,072	27,559,282
2021	26,616,016	25,250,955	28,102,829
2022	27,058,693	25,615,816	28,662,113
2023	27,508,734	25,985,949	29,232,527

Peak Capacity Forecast for Resource Planning

The econometric equations discussed above in the load forecasting section are utilized to forecast peak loads (on a GPI basis).

PSE uses the expected peak load for long-term capacity planning. The expected peak load is the maximum hourly load expected to occur when the hourly temperature during the winter months (November through February) is 23 degrees at SeaTac Airport. Based on historical temperature data at SeaTac, there is a 50 percent probability of the minimum hourly temperature during the winter months being 23 degrees or lower. The maximum expected peak load for the year is expected to occur in January of each year given PSE customer use profiles.

PSE's expected peak loads for the 2003 through 2023 time period are in Exhibit C-4. The peak loads are forecasted to increase over time as the number of customers increase. As discussed earlier, the growth in the peaks (about 1.6 percent per year) is slightly higher than the growth in energy (about 1.4 percent per year) since residential energy load is growing faster than non-residential energy loads and the residential sector has a larger contribution to peak.

Exhibit C-4
Expected Peak Load (MW)

2003	4,773
2004	4,819
2005	4,862
2006	4,929
2007	5,004
2008	5,089
2009	5,182
2010	5,251
2011	5,336
2012	5,421
2013	5,514
2014	5,608
2015	5,702
2016	5,794
2017	5,888
2018	5,983
2019	6,081
2020	6,182
2021	6,282
2022	6,384
2023	6,490

APPENDIX D
CONSERVATION AND EFFICIENCY

PSE has been offering energy efficiency programs to customers for over 20 years. Utilities throughout the Pacific Northwest have a unique legacy. Despite some of the lowest electricity rates in the country, PSE and others in the region have invested heavily in conservation programs, encouraging efficiency use by customers. Utility new construction programs of the 1980's largely resulted in Washington State's current energy codes, among the country's strongest for encouraging energy efficiency in housing and the commercial building stock. PSE has consistently offered programs targeted to its low-income customers, and over the years has developed a strong working partnership with the Community Action Agencies in the communities it serves.

Recent History

During the mid-1990s, utilities invested less in demand-side resources due to uncertainty over future deregulation in the electricity industry. Electric and gas avoided costs were significantly lower than they had been up until that time, with many anticipating restructured electricity markets to produce lower prices. Most conservation incentives for residential end-uses were no longer cost-effective, and residential programs came to rely primarily on information, education and referral services to encourage efficiency. PSE grants and rebates, in addition to information and technical services, continued for the more cost-effective commercial and industrial sector programs. At the same time, Energy Service Companies (ESCOs) were beginning to actively target the commercial building sector. These independent contractors could package services and equipment together with favorable financing by using the energy bill savings generated by the project. Of particular note, the Washington State General Administration Office promoted ESCO financing for public facilities, and the State Treasurer's office made low-interest financing available for public projects. The largest industrial customers were pursuing the option to purchase power on the open market in regulatory and legislative forums. A period of uncertainty ensued wherein the future requirements for utilities to acquire resources for some customer classes might be changed through legislative or regulatory actions.

At the same time, improved energy codes were adopted in Washington State, making new construction and major remodels more energy efficient from the beginning, thus requiring less future investment for retrofits to homes and buildings.

While national interests were promoting deregulation of the electric industry, the governors of the four Pacific Northwest States convened the Comprehensive Review of Northwest Energy System. Business interests – particularly of large consumers who viewed deregulation as a way to lower energy costs for their “bulk” purchases – were influential. The Review committee addressed “public purpose” issues, including conservation, low-income assistance and renewable resources. From this committee’s recommendations, the idea of “market transformation”(MT) emerged as another potential cost-effective method to get customers to invest in efficiency on their own. The philosophy driving market transformation held that through undertaking MT activities now, market prices of efficiency equipment or practices could drop in the future, making them more rapidly attractive for end-use consumers. Regional utilities created the Northwest Energy Efficiency Alliance (“Alliance”), with PSE as a major funding provider. The Alliance has pursued notable recent efforts such as accelerating consumer adoption of compact fluorescent lamps and horizontal-axis washing machines.

The PSPL merger with WNG in 1997 provided PSE the opportunity to offer “fuel-blind” conservation/energy efficiency programs. Instead of being sent to the “other” company, customers now benefit from a one-stop, comprehensive conservation service. PSE is indifferent to whether a customer upgrades efficiency of an electric heating system or converts to natural gas.

Initially, Puget’s cost-recovery of cost-effective conservation resources were added to rate base, and amortized over 10 years. Rates allowed for a premium of plus two percent on the allowed rate of return for all unamortized conservation balances. To an industry facing deregulation, this financing method, which often created outstanding debt, could be an obstacle. Washington State passed legislation to allow conservation investments to be financed using bonds, and in 1995 PSE became the first utility to issue and obtain favorable financing terms for over $200 Million in conservation bonds. Two years later, PSE offered a second bond offering of $35 Million. WNG, by comparison, relied on a “tracker” mechanism; whereby costs spent on conservation were collected as an expense in the year following the year of expenditure. After the merger, PSE retained the “tracker” mechanism for gas conservation and added a similar “rider” mechanism to allow for cost-recovery of electric conservation. The rider recovers costs for conservation in the same year as expended.

In 1999, PSE submitted a three-year, joint electric and gas conservation program. The Commission approved the program effective April 1 of that year. The program was extended beyond March 31, 2002 for an additional period during the course of the General Rate Case. Three-year savings and costs for that program were 31.6 aMW and 5,084,019 therms, for a combined electricity and natural gas cost of $30,484,713.

No one accurately predicted the events and electricity wholesale price escalations of 2000. Price impacts hit the recently deregulated California market, complete with rolling blackouts. The Pacific Northwest had close electricity interties with California, making a regional energy crisis inevitable. BPA and many of the region’s utilities immediately sought to raise rates, and quickly imposed significant rate increases, mostly in the form of surcharges. This included the three large public utilities adjoining PSE’s service territory. Rate increases of this magnitude, particularly hitting in the middle of winter (peak load periods for the Northwest), were packaged with dramatic near-term increases to conservation efforts to help manage utility and customer costs. More broadly, a societal need existed to heavily encourage conservation as a means to manage energy costs throughout the region, and PSE joined others to ramp up its efforts. One of the most successful efforts was a broadly promoted, time-limited 10 percent bonus to commercial conservation grants. This effort in conjunction with daily news headlines of the energy situation no doubt aided customer readiness to adopt efficiency measures.

PSE had another tool at its disposal. Having installed new metering throughout the service territory, and with a new billing system in place, the Company worked with the Commission to launch a Time-of-Use pilot program to over 300,000 residential customers. Subsequently, an additional 20,000 business customers were added to the pilot. While the program set out to reward customers who used energy efficiently, the Company determined in fall 2002 that further analysis and restructuring of the program was needed to enhance customer value. The WUTC recently approved PSE’s request to terminate the program.

Exhibit D-1 provides a detailed look at PSE’s existing electric conservation programs and Exhibit D-2 provides a list of gas conservation programs.

Exhibit D-1
Current Electric Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
Energy Efficiency Information Services – Personal / Business Energy Profile	• Free energy audit survey, analysis, and report providing customers with specific and customized energy efficiency recommendations. • Identifies current energy costs and consumption by end-use, and provides a list of specific recommendations for energy efficiency opportunities with savings estimates. • Home version is available as a mail-in booklet. Home and business versions are available online at pse.com.	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. • Information programs cannot exceed 10% of the total conservation program budget.
Energy Efficiency Information Services – Personal Energy Advisors	• Specially trained and dedicated phone representatives provide customers of all sectors direct access to PSE's array of energy efficiency services and programs through a toll-free number. • Discuss the potential benefits of various conservation programs and related products and services including contractor referrals. • Answer 3,000 customer inquires per month, including 150 e-mail messages.	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. • Information programs cannot exceed 10% of the total conservation program budget.
Energy Efficiency Information Services – Energy Efficiency Brochures	• Brochures on program participation guidelines and how-to guides on energy efficiency opportunities, including behavioral and low-cost measures, weatherization measures, appliance and equipment upgrades. • Includes investment and savings estimates as appropriate. • Available in hard-copy through mail, at trade show and publicity events; available for download at www.pse.com.	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. • Information programs cannot exceed 10% of the total conservation program budget.
Energy Efficiency Information Services – On Line Services	• Sections of PSE's web site are dedicated to energy efficiency and energy management information, program details and application instructions. • Online Personal and Business Energy Profile energy audits, calculator "tools", and energy libraries are available for registered PSE customers.	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. • Information programs cannot

Exhibit D-1
Current Electric Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
	• Free, periodic PSE energy efficiency e-newsletters for residential and business subscribers. • An Energy Efficiency e-mail box is available for customer questions, featuring maximum 24-hour turn around.	exceed 10% of the total conservation program budget.
Residential Energy Efficient Lighting Program (includes a portion of C&RD funding)	• *Retail Incentive Program* – Participating retailers and lighting showrooms (approximately 350 retail stores) deduct $3 from the cost of Energy Star CFL bulbs or $10 from a qualifying Energy Star fixture at the time of purchase, when presented with a PSE coupon. Customers receive coupons with their bill and may request additional coupons through the energy Hotline. Coop promotion with Home Depot, Costco, Bartells and others. • *New Construction/Remodelers* – Builders receive rebates on qualifying Energy Star CF fixtures installed in new single-family and multi-family residences, indoor and outdoor fixtures. • *Cross Promotional/WEB Incentive* –Rebates (e.g. CFL bulb) to encourage participation in programs such as online energy-use analysis tools.	• 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. • Unmetered traffic-signal accounts must document all connected load at the intersection to request a bill adjustment. • Partner with Association of Washington Cities.	• 2,027 MWh (0.2 aMW) • 6-year resource
Small Business Energy Efficiency Programs	• Rebates for energy-efficient fluorescent lighting upgrades and conversions, lighting controls, programmable thermostats, and vending machine controllers. • Streamlined incentives for small usage commercial businesses receiving electricity under Rate Schedule 24 (<50kW demand).	• 3,333 MWh (0.4 aMW) • 10-year resource
Commercial & Industrial Retrofit Program	• Incentives in the form of grants to commercial and industrial customers are available for cost-effective energy-efficient upgrades including HVAC, water heating and refrigeration equipment, controls, process efficiency improvements, lighting upgrades, and building thermal improvements. • PSE engineers work with customers to assess energy savings	• 73,063 MWh (8.3 aMW) • 12-year resource

Exhibit D-1
Current Electric Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
	opportunities, approve project proposals, recommend bid specifications, review contractor bids and verify installations prior to grant payment. • Includes an HVAC Premium Service project, using specially trained maintenance contractors to optimize efficiency of packaged roof-top HVAC equipment. • Also for electric customers, provide grants for farm motors and processes, with funding support from CR&D.	
Commercial & Industrial New Construction Efficiency	• Incentives in the form of grants to commercial and industrial customers are available for cost-effective energy-efficient building components or systems, including HVAC, lighting, water heating, process and refrigeration equipment, controls, building design and thermal improvements, which exceed requirements of the Washington State Energy Code (NREC) by 10% or more. • Also provides funding toward cost of building commissioning beyond code requirements. • PSE Energy Management Engineers work with designers, developers, commissioning agents, owners and tenants (when available) of new C/I facilities, or major remodels, to propose cost-effective energy efficiency measures. • Funding may be provided using a prescriptive measure approach or a whole building approach.	• 1,333 MWh (0.2 aMW) • 20-year resource
Large Power User Self-Directed Program	• Incentives up to 87% of the Sch. 120 Conservation Rider revenues contributed to PSE's Conservation Program, for eligible C/I customers receiving high-voltage electrical service under Schedules 46, 49, or 449. • Projects are conceived, developed, and implemented by customers for their facilities, with PSE engineering staff evaluating proposals for cost-effectiveness.	• 20,000 MWh (2.3 aMW) • 12-year resource
Resource Conservation Manager (RCM) Program	• PSE supports customers who employ a RCM to implement low-cost/no cost energy saving activities with building occupants and facility maintenance staff. • Responsibilities include detailed accounting of resource consumption	• 26,667 MWh (3 aMW) • 3-year resource

Exhibit D-1
Current Electric Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
	(electricity, gas, water, sewer, recycling, etc.), costs and savings estimates. • PSE provides training, accounting tools, network meetings, review of reports and electronic data downloads.	
PILOT Programs – Fuel Switching Pilot	• Incentives toward the cost of converting electric space and/or water heating equipment to equipment fueled by natural gas. • PSE determines residential customers eligibility by targeting geographic areas where the cost of adding electric infrastructure would exceed making natural gas available to the residence.	• 4,600 MWh (.5 aMW) • 20-year resource
PILOT Programs – Residential Duct Systems Pilot	• Participating customers receive the duct diagnostic measurement services and sealing services from the certified contractor at no cost. Targets residences with central forced air electric or gas heating systems • As this technique is new to the industry, this program provides technical support, contractor training and marketing assistance to contractors.	• 353 MWh (<0.1aMW) • 10-year resource
Market Transformation Programs – NW Energy Efficiency Alliance	• PSE is a major financial supporter of the Northwest Energy Efficiency Alliance, and serves on NEEA's Board of Directors. • The primary function of NEEA 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 • Electrical energy savings acquired at the Regional level, allocated to individual utility service territories. Most activities expected to transform market behavior, providing significantly longer efficiency impacts.
Market Transformation Programs – Local Infrastructure & Market Transformation & Research	• PSE funds specific energy-efficiency initiatives and/or organizations committed to accelerating the adoption of energy efficiency in the marketplace, including research activities for which PSE may not have a related program in place.	• 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 responsible for energy, water, and environmental programs in the Puget Sound area. • Currently, in 70 schools with a reach of over 12,000 students 6th-9th	• 1,773 MWh • 0.2 aMW

Exhibit D-1
Current Electric Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
	grade students. • Provides comprehensive energy and environmental curriculum, teaching students how to apply principles and make informed choices on energy, air quality, water and solid waste.	
Public Purpose Programs – Residential Low-Income Retrofit	• Funding (up to 100% where cost-effective) for installation of home weatherization measures for low-income gas and electric heat customers. • Customers in single family, multifamily, and mobile home residences are qualified by local community action agencies, using federal income guidelines. • Also includes structure audits and energy use education.	• 2,608 MWh • 0.3 aMW
C&RD Programs – Green Power	• All customers can purchase green power directly on their monthly energy bill at $2 per 100 kWh block, with a two-block minimum purchase. • Recommended purchase is 10% of energy bill, representing $6 per month, or 3 blocks for typical residential user. Business customers can use purchases to help offset other environmental impacts.	• 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 for qualifying Energy Star light fixtures are under development, and 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 ($35) and Energy Star dishwashers ($20) for customers who purchase electricity from PSE; customers may also purchase natural gas. • Additional rebates may be available from customer's water utility. • Rebates offered at 140 participating retailers.	• 2,092 MWh (.2 aMW) • 12-year resource
Energy Efficient Manufactured Housing	• $300 rebate to the buyers of qualifying Super Good Cents/Energy Star labeled manufactured homes with electric heat, sited in PSE electric service territory. • Parallel with regional programs (NEEA), Washington Manufactured Housing Association.	• 1,456 MWH (0.2 aMW) • 30-year resource

Exhibit D-2
Current Gas Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
Energy Efficiency Information Services – Personal / Business Energy Profile	• Free energy audit survey, analysis, and report providing customers with specific and customized energy efficiency recommendations. • Identifies current energy costs and consumption by end-use, and provides a list of specific recommendations for energy efficiency opportunities with savings estimates. • Home version is available as a mail-in booklet. Home and business versions are available online at pse.com.	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. Information programs cannot exceed 10% of the total conservation program budget.
Energy Efficiency Information Services – Personal Energy Advisors	• Specially trained and dedicated phone representatives provide customers of all sectors direct access to PSE's array of energy efficiency services and programs through a toll-free number. • Discuss the potential benefits of various conservation programs and related products and services including contractor referrals. • Answer 3,000 customer inquiries per month, including 150 e-mail messages.	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. Information programs cannot exceed 10% of the total conservation program budget.
Energy Efficiency Information Services – Energy Efficiency Brochures	• Brochures on program participation guidelines and how-to guides on energy efficiency opportunities, including behavioral and low-cost measures, weatherization measures, appliance and equipment upgrades. Includes investment and savings estimates as appropriate. • Available hard-copy through mail, at trade show and publicity events; available for download at www.pse.com.	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. Information programs cannot exceed 10% of the total conservation program budget.
Energy Efficiency Information Services – On Line Services	• Sections of PSE's web site are dedicated to energy efficiency and energy management information, program details and application instructions. • Online Personal and Business Energy Profile energy audits, calculator "tools", energy libraries are available for registered PSE	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. Information

Exhibit D-2
Current Gas Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
	customers. • Free, periodic PSE energy efficiency e-newsletters for residential and business subscribers. • An Energy Efficiency e-mail box is available for customer questions, featuring maximum 24-hour turn around.	programs cannot exceed 10% of the total conservation program budget.
Efficient Natural Gas Water Heater	• \$25 rebate towards purchase of an energy-efficient gas water heater (EF>=.6), served with PSE natural gas.	• 170,667 therms • 7-year resource
High-Efficiency Gas Furnace	• \$150 rebate towards the purchase of a high-efficiency gas furnace (AFUE>=.9),offered to PSE residential customers, for existing homes and new construction. • Rebates not available for conversion from electricity unless installing the high-efficiency furnace.	• 224,667 therms • 15-year resource
Energy Efficient Manufactured Housing	• \$150 rebate to the buyers of qualifying Natural Choice/ Energy Star labeled manufactured homes with natural gas heat, sited in PSE natural gas service territory. • Parallel with regional programs.	• 12,720 therms • 20-year resource
Small Business Energy Efficiency Programs	• Rebates for energy-efficient fluorescent lighting upgrades and conversions, lighting controls, programmable thermostats, and vending machine controllers. • Streamlined incentives for small usage commercial businesses receiving electricity under Rate Schedule 24 (<50kW demand) and Schedule 8, (or natural gas under Rate Schedule 31.	• 93,308 therms • 10-year resource
Commercial & Industrial Retrofit Program	• Incentives in the form of grants to commercial and industrial customers, are available for cost-effective energy-efficient upgrades including HVAC, water heating and refrigeration equipment, controls, process efficiency improvements, lighting upgrades, and building thermal improvements. • PSE engineers work with customers to assess energy savings opportunities, approve project proposals, recommend bid specifications, review contractor bids and verify installations prior to grant payment. • Includes an HVAC Premium Service project, using specially trained maintenance contractors to optimize efficiency of packaged roof-top	• 1,406,033 therms • 15-year resource

Exhibit D-2
Current Gas Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
	HVAC equipment.	
Commercial & Industrial New Construction Efficiency	• Incentives in the form of grants to commercial and industrial customers, are available for cost-effective energy-efficient building components or systems, including HVAC, lighting, water heating, process and refrigeration equipment, controls, building design and thermal improvements, which exceed requirements of the Washington State Energy Code (NREC) by 10% or more. Also funding toward cost of building commissioning beyond code requirements. • PSE Energy Management Engineers work with designers, developers, commissioning agents, owners and tenants (when available) of new C/I facilities, or major remodels, to propose cost-effective energy efficiency measures. • Funding may be provided using a prescriptive measure approach or a whole building approach.	• 100,000 therms • 20-year resource
Resource Conservation Manager (RCM) Program	• PSE supports customers who employ a RCM to implement low-cost/no cost energy saving activities with building occupants and facility maintenance staff. • Responsibilities include detailed accounting of resource consumption (electricity, gas, water, sewer, recycling, etc.), costs and savings estimates. • PSE provides training, accounting tools, network meetings, review of reports and electronic data downloads.	• 266,667 therms • 3-year resource
PILOT Programs – Residential Duct Systems Pilot	• Participating customers receive the duct diagnostic measurement services and sealing services from the certified contractor at no cost. Targets residences with central forced air electric or gas heating systems. • Because this is a new technique in the industry, this program provides technical support, contractor training and marketing assistance to contractors.	• 10,667 therms • 10-year resource
PILOT Programs – Commercial & Industrial Boiler Tune-up Pilot	• Pilot provides incentives of 50% of the cost of the tune-up, up to $300 per boiler, for customers to have older boilers tuned up for the first time.	• 377,000 therms • One-year resource

Exhibit D-2
Current Gas Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
Public Purpose Programs – Energy Education 6-9th Grade Environmental	• Conservation education program funded by PSE, along with 26 other utilities, cities, and agencies responsible for energy, water, and environmental programs in the Puget Sound area, for over 70 schools with a reach of over 12,000 students. • Provides comprehensive energy and environmental curriculum, teaching students how to apply principles and make informed choices related to energy use, air quality, water conservation, and solid waste.	• 80,756 therms • 10-year resource life
Public Purpose Programs – Residential Low-Income Retrofit	• Funding for installation of home weatherization measures for low-income gas and electric heat customers. • Customers in single family, multifamily, and mobile home residences are qualified by local community action agencies, using federal income guidelines. • Also includes structure audits and energy use education.	• 120,800 therms • 20-year resource life

APPENDIX E
OPERATIONAL CONSIDERATIONS FOR EXISTING SINGLE-CYCLE CTs

Some stakeholders have questioned whether PSE should consider operating its simple-cycle Combustion Turbines (SCGTs) to satisfy baseload energy requirements as a substitute for acquiring new baseload resources. A number of factors must be carefully weighed prior to committing to such a strategy – CT plant design, staffing and spare parts inventories, heat rate and economics, emissions and environmental factors, transmission constraints, and alternative peaking needs.

This appendix provides a preliminary discussion of those factors and offers general information and insight into the implications of changing the duty cycle of PSE's SCGTs.

General Information

Puget Sound Energy (PSE) operates four dual-fuel combustion turbine plants at sites located in Whatcom, Skagit and Pierce counties. One of the combustion turbine plants is in combined-cycle operation, with the others configured as simple-cycle plants. Exhibit E-1 provides basic plant information.

Exhibit E-1
CT Performance By Plant

PLANT NAME	LOCATION	CAPACITY (MW)	HEAT RATE (BTU/KWH)	CYCLE
Encogen	Whatcom County	170	8,700	Combined
Frederickson	Pierce County	150	12,500	Simple
Fredonia 1&2	Skagit County	210	12,500	Simple
Fredonia 3&4	Skagit County	108	10,500	Simple
Whitehorn	Whatcom County	150	12,500	Simple

Encogen Combustion Turbine

Lone Star Energy installed the Encogen NW combined cycle plant in 1993, operating it as a qualifying cogeneration facility until the assets of Encogen NW, LLP were purchased by PSE in November 1999. Encogen consists of three General Electric heavy frame CTs of 42 MW each and one General Electric steam turbine rated at 44 MW. The on-site management, administrative, technical, and operating staff numbers 24.

The CTs may be fueled with natural gas or distillate oil, and the fuel source may be alternated during operation. Operating hours on distillate fuel are restricted in the air operating permit to limited tests periods or times when the natural gas fuel supply has been curtailed. As a result, the plant has operated almost entirely on natural gas fuel since installation.

Encogen consumes approximately 35,000 million Btus of natural gas per day and supplies an average net output of 165 Mw of electrical energy to PSE, and 55,000 pounds of steam and 150,000 gallons of warm water per hour to the Georgia-Pacific mill in Bellingham.

Encogen employs various techniques to control pollutants generated by the turbines during the combustion process. Nitrogen Oxides (NO_x) are controlled by injection of steam into turbine combustors and the use of a Selective Catalytic Reduction (SCR) system. Steam injection limits peak combustion temperatures thereby limiting the formation of additional NO_x and the SCR reacts the remaining NO_x with ammonia to form elemental nitrogen and water. PSE controls ammonia emissions by carefully regulating the amount of ammonia added to the SCR system. Sulfur Dioxide (SO_2) emissions are controlled by use of natural gas as the primary fuel and "road-spec" distillate fuel for the rare occasions of liquid fuel operation.

In addition to the CTs, three above-ground storage tanks of 11,000 barrels (465,000 gallons) capacity were installed. The tanks have a conventional cone roof design and store only distillate oil. This plant already operates in baseload operation and no duty cycle change is anticipated. This general information is included only for reference.

Frederickson Combustion Turbine

Frederickson 1&2 were installed in 1981, each consisting of a General Electric heavy frame CT of 75 MW capacity each. The CT may be fueled with natural gas or distillate fuel, with fuel changes possible while the turbine is in operation. The Frederickson 1&2 turbines may be ramped from start to full load in 20 minutes. Recent operations have been made almost entirely on natural gas. Onsite staffing includes one technician and two servicemen.

In addition to the CTs, one above-ground storage tank of 100,000 barrels (4,300,000 gallons) capacity was installed. The tank has a conventional cone roof design and stores only distillate fuel.

To control the formation of harmful NO_X during combustion, PSE injects demineralized water directly into the turbine combustor with the fuel supply. The water demineralizer system at Frederickson can produce 75 gallons per minute of pure water for use in the turbine, or storage in the adjacent 300,000-gallon water storage tank.

Fredonia 1&2 Combustion Turbine

Fredonia 1&2 were installed in 1984, each consisting of a Westinghouse heavy frame CT of 105 MW capacity. The CTs may be fueled with natural gas or distillate fuel, with fuel changes possible while the turbine is in operation. The Fredonia 1&2 turbines may be ramped from start to full load in 50 minutes. Recent operations have been made almost entirely on natural gas. Onsite staffing includes the CT service manager (for all simple-cycle CT plants), administrative assistant, one technician and four servicemen.

In addition to the CTs, one above-ground storage tank of 100,000 barrels (4,300,000 gallons) capacity was installed. The tank has a conventional cone roof design and stores only distillate fuel.

To control the formation of harmful NO_X during combustion, PSE injects demineralized water directly into the turbine combustor with the fuel supply. The water demineralizer system at Fredonia can produce 150 gallons per minute of pure water for use in the turbine, or storage in the adjacent 500,000 gallon water storage tank.

Fredonia 3&4 Combustion Turbine

Fredonia 3&4 were installed in 2001, each consisting of a Pratt & Whitney aeroderivative CT of 54 MW capacity each. The CTs may be fueled with natural gas and distillate fuel. The Fredonia 3&4 turbines may be ramped from start to full load in under 10 minutes. Recent operations have been largely on natural gas.

To control the formation of harmful NO_X during combustion, PSE injects demineralized water directly into the turbine combustor with the fuel supply. In addition, NO_x emissions are further controlled by use of a SCR system. CO emissions are controlled with an oxidation catalyst.

Whitehorn 2&3 Combustion Turbines

Whitehorn 2&3 were installed in 1980, each consisting of a General Electric heavy frame CT of 75 MW capacity each. The CTs may be fueled with natural gas and distillate fuel. The Whitehorn 2&3 turbines may be ramped from start to full load in 20 minutes. Recent operations have been made almost entirely on natural gas. Onsite staffing includes one technician and two servicemen.

In addition to the CTs, one above-ground storage tank of 100,000 barrels (4,300,000 gallons) capacity was installed. The tank has a conventional cone roof design and stores only distillate fuel.

To control the formation of harmful nitrous oxides during combustion, PSE injects demineralized water directly into the turbine combustor with the fuel supply. The water demineralizer system at Whitehorn can produce 100 gallons per minute of pure water for use in the turbine, or storage in the adjacent 500,000-gallon water storage tank.

Duty Cycle

The duty classification of a combustion turbine plant has important implications since it indicates the mission anticipated for the plant as part of PSE's energy supplies, and the associated capital and maintenance expenditures planned over its lifetime. Duty cycle also represents an important element in the original design and installation of the facility. The anticipated duty cycle impacts the basic plant layout; connection to external infrastructure; permitting, operation & maintenance strategy; and economics.

The mission, or duty classification, of a combustion turbine depends on the number of service hours and is defined by EPRI as follows:

- ***Standby Duty*** – less than 1 percent capacity factor
- ***Peaking Duty –*** between 1 percent and 10 percent capacity factor
- ***Cycling Duty*** – between 10 percent and 50 percent capacity factor
- ***Baseload Duty*** – between 50 percent and 90 percent capacity factor
- **Continuous Duty –** greater than 90 percent capacity factor

Cost Implications

PSE's heavy-frame combustion turbine plants were designed and installed in the 1980s to be used as peaking resources with relatively limited operation. The Powerplant and Industrial Fuel Use Act of 1978 governed the original permitting of these plants. PSE applied for and received an emergency peaking exemption to the Act which allowed powerplant operations up to 1,500 hours per year. As a result, the balance-of-plant equipment, staffing, anticipated spare parts and service, and emissions permits were all planned based on this operational limitation. At no time was operation as a baseload facility contemplated during the design and installation of these plants.

Economics

While the thermodynamics of energy conversion can be extremely complex, the economics of energy conversion are simple and driven by the efficiency of the thermodynamics. The thermal efficiency of a state-of-the-art combined cycle powerplant can be over 55 percent. This means that 55 percent of the energy available in the fuel source is converted to electrical energy. Compared with <30 percent thermal efficiency typical of PSE's simple-cycle plants, the modern combined-cycle plant is much less expensive to operate as it uses less fuel for a given electrical output. This high thermal efficiency is an important consideration for conserving limited natural resources and reducing the production of greenhouse gases.

In addition to the obvious economic issues of operating electrical generating plants at a loss, the following issues should be considered before changing the duty cycle of PSE's SCGTs:

Staffing

The O&M staff performs all preventive maintenance tasks for the turbines, generators and balance-of-plant equipment located at the plant site. In addition, during operation of the facility, the staff takes data readings, monitors the proper operation of the equipment, troubleshoots malfunctions, documents fuel and water consumption, operates the water treatment system, and performs fire-watch and safety checks during startup and shutdown of the equipment.

The simple-cycle CT plants have historically been staffed to support a peaking duty cycle of 0 to 1,500 hours per year. In the years since these facilities were originally installed, operations have typically been limited to periodic exercise and testing, or responding to occasional summer or winter load peaks.

Extending the duty cycle to a baseload operation would require hiring additional staff sufficient to support round-the-clock operations, to provide for safety pairing, and to allow for normal sick days and vacations.

Spares

The simple-cycle CT plants all inventory spare parts and consumables appropriate to the peaking duty cycle. Spares include hot gas path parts, thermocouples, fuel nozzles, control cards, batteries, indicator lamps, bearings, pumps, and other equipment typically needed for anticipated operations. Parts currently inventoried are those which experience has shown to be needed frequently or those with very long production or repair lead times. Peaking operations entail relatively short periods of operating activities and long idle periods when maintenance can be performed without staff overtime or material expediting costs. To support baseload operations, additional spares would be required to support limited maintenance time lines, higher criticality of forced outage spares and the additional importance of plant reliability for baseload energy.

Balance of Plant

In addition to the turbine-generators, other plant systems, collectively known as the “Balance of Plant,” work to supply needed electrical power and control, supply demineralized water for emission control, provide instrument air service, handle process waste products and disposal, etc. These systems, too, have been designed, sized and installed to support an anticipated peaking duty cycle. For example, water treatment systems were sized to provide demineralized water service for turbine NO_x emission controls, provided that the turbines had frequent downtime between runs. The water tank capacity, treatment system throughput capacity, and process automation levels are insufficient to support continuous duty operations. Concurrent with the water system, waste handling and disposal would also require substantial revision. In some cases it would be necessary to purchase additional public water or sanitary sewer capacity to support increased operation. No attempt has been made to quantify these costs, but they are expected to be substantial.

Emissions Issues

Various emissions limits apply to PSE’s simple-cycle combustion turbine plants which restrict total annual operating hours. Operating hours would be further restricted if the turbines were to be fired on distillate fuel. PSE must keep detailed records of fuel usage and operating hours to monitor emissions and to verify compliance with all permit limits.

NO_x

To reduce NO_x emissions from PSE's simple-cycle combustion turbines, PSE injects demineralized water into the combustion flame to reduce its peak temperature. Water injection effectively lowers NO_x emissions, but at the expense of gas turbine efficiency, more costly maintenance and higher CO emissions. It is not the preferred NO_x emission control strategy for continuous duty operations.

Operating Restrictions

Several combustion turbine units have limits on the total quantity of certain pollutants that can be emitted over a 12-month period – a rolling year mass limit. These mass limits would prevent continuous duty operations of Fredonia Unit #1 and restrict operations of both Frederickson units to less than 80 percent.

In addition, the Whitehorn units may be restricted from continuous duty operations by the equipment lease agreement. The lease agreement for Fredonia 3&4 should be reviewed for potential restrictions on operation.

Greenhouse Gases

The quantity of fuel burned and the carbon content of the fuel directly impacts the production of greenhouse gases. PSE has restated its commitment to energy conservation programs in both the residential and commercial sectors to reduce the pressure on developing new resources. When new resources are needed, every effort should be made to develop renewable resources and/or resources with high thermal efficiency. Serious efforts to reduce greenhouse gas emissions and to preserve limited natural resources should not include the operation of simple-cycle combustion turbines for baseload energy needs.

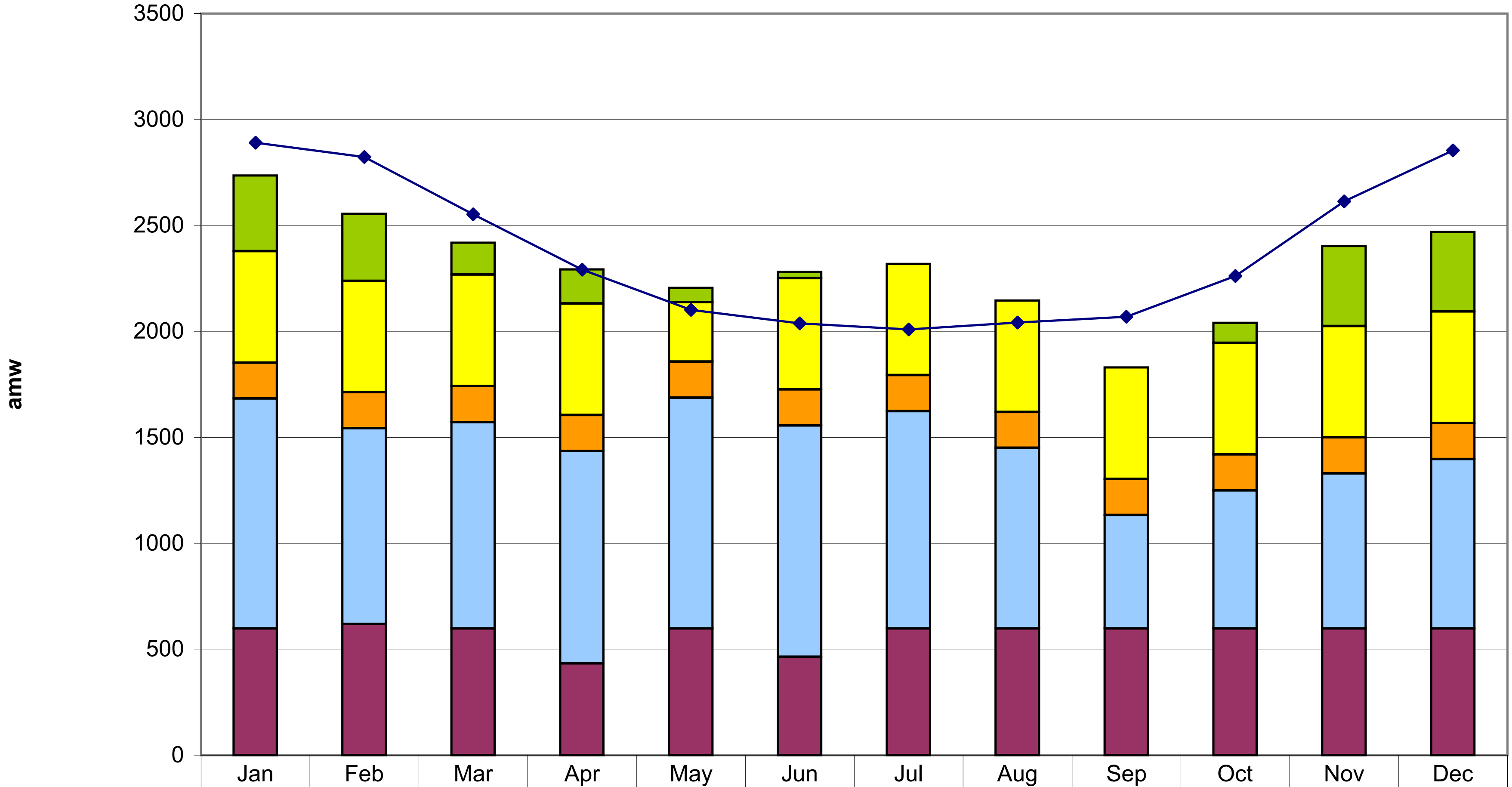
Transmission Constraints

The PSE transmission system has several congestion points in its electrical transmission system. This issue would require considerable study before committing to continuous duty operations of the simple-cycle CTs and may add substantial expense for system upgrades and improvements.

Peak Load Requirement

PSE's peak load requirements have been well-served over the years by the simple-cycle combustion turbines. If these turbines were converted to continuous duty operations, in spite of the disadvantages to doing so, other peaking resources would have to be acquired to serve the peaking mission. In that event, PSE would have investments in both sub-optimal continuous duty resources and new peaking resources. Neither would be as efficient, clean, or as cost-effective as procuring high-efficiency continuous duty equipment and using the older equipment in a peaking role with limited operations.

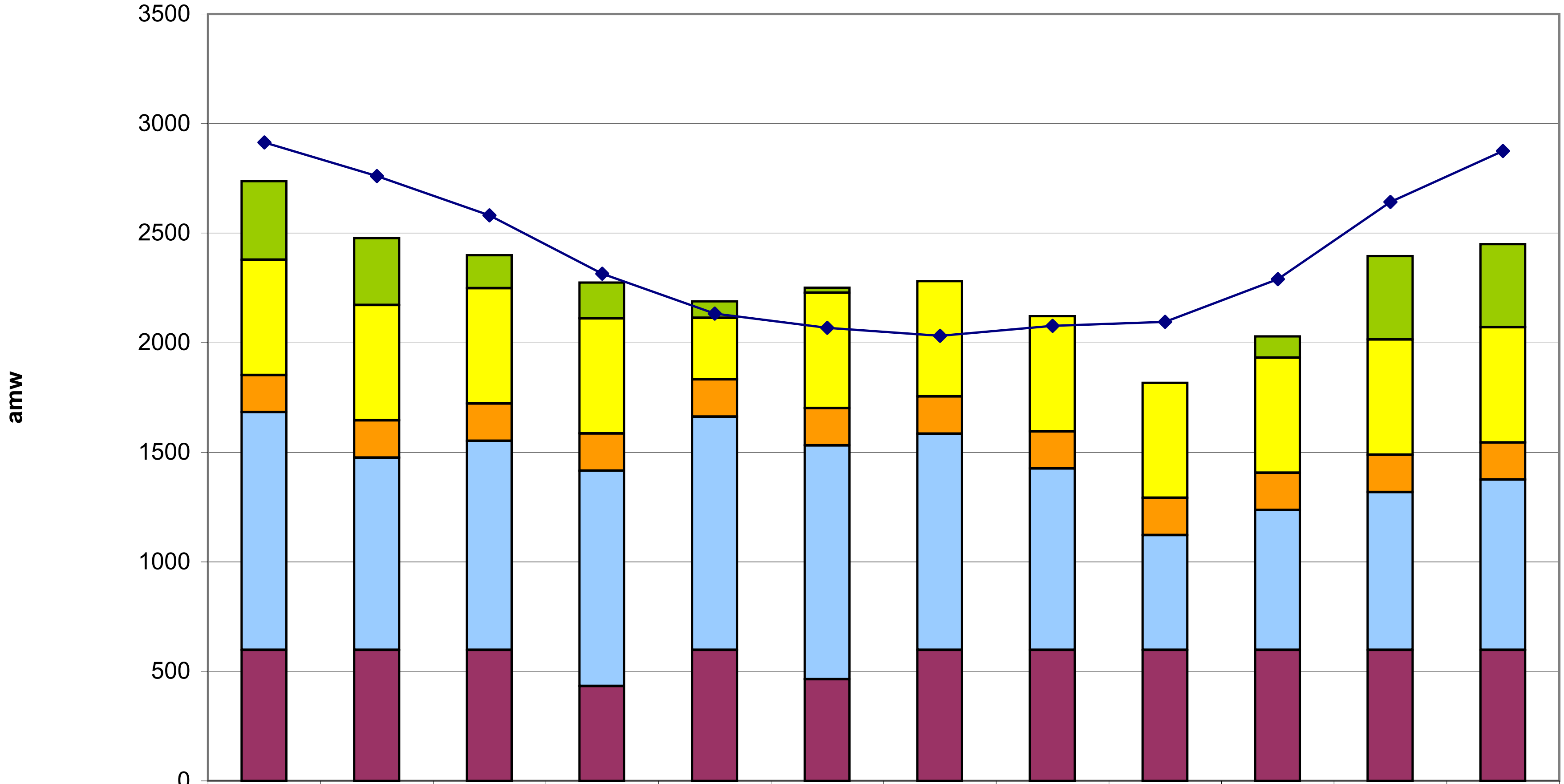
Exhibit F-1
2004 Monthly Energy Load-Resource Outlook



	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

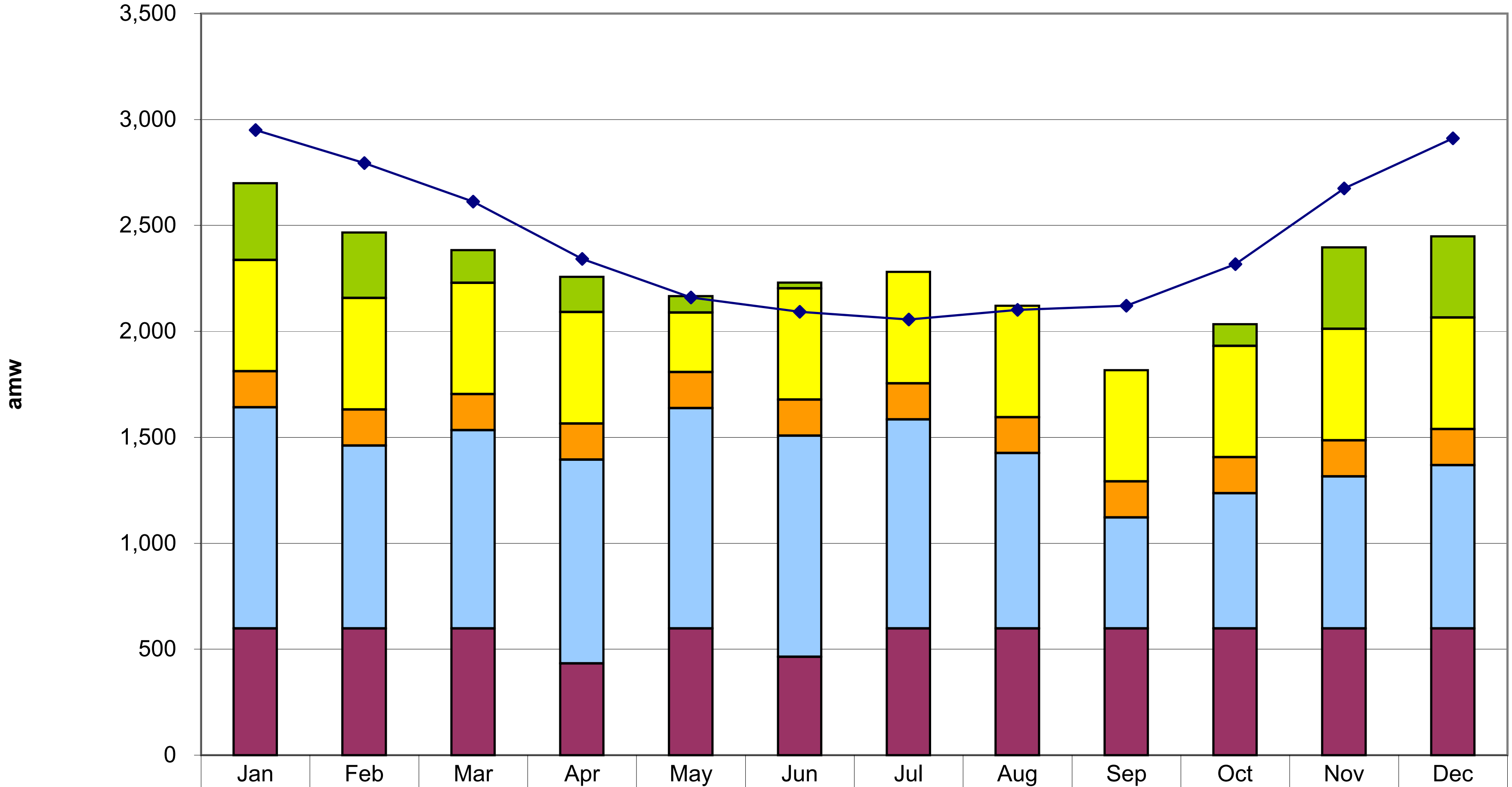
Exhibit No. ___(EMM-3)
Page 339 of 529

Exhibit F-2
2005 Monthly Energy Load-Resource Outlook



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	358	306	151	163	75	23	(78)	(74)	(83)	96	381	379
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	878	955	982	1,065	1,068	987	828	524	638	721	777
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Load	2,914	2,761	2,581	2,314	2,133	2,067	2,032	2,076	2,095	2,290	2,642	2,875

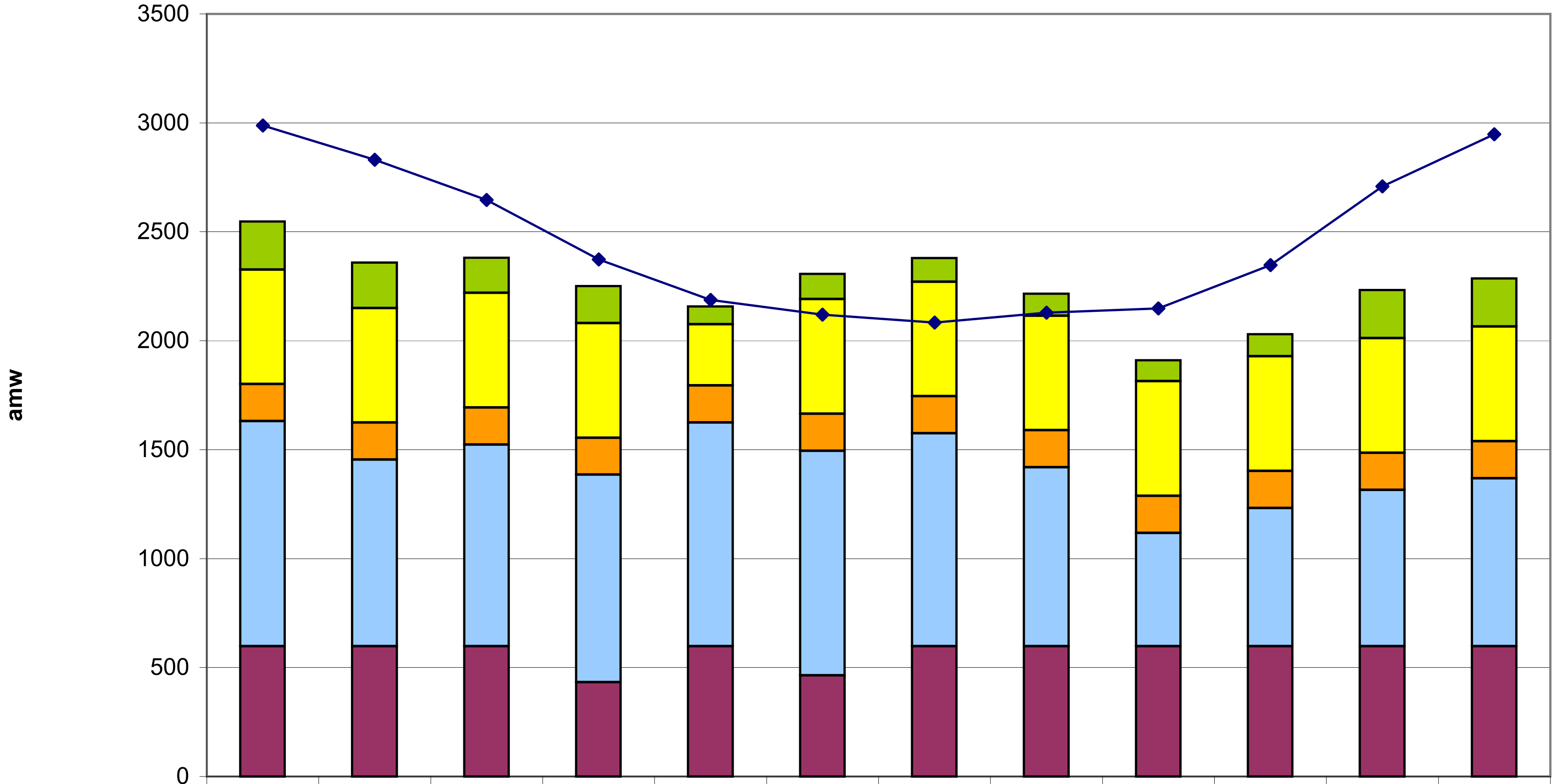
Exhibit F-3
2006 Monthly Energy Load-Resource Outlook



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	362	309	155	167	78	26	(75)	(71)	(77)	102	385	383
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	1,044	864	936	962	1,040	1,043	987	828	524	638	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Load	2,950	2,795	2,612	2,343	2,159	2,093	2,056	2,102	2,121	2,318	2,674	2,911

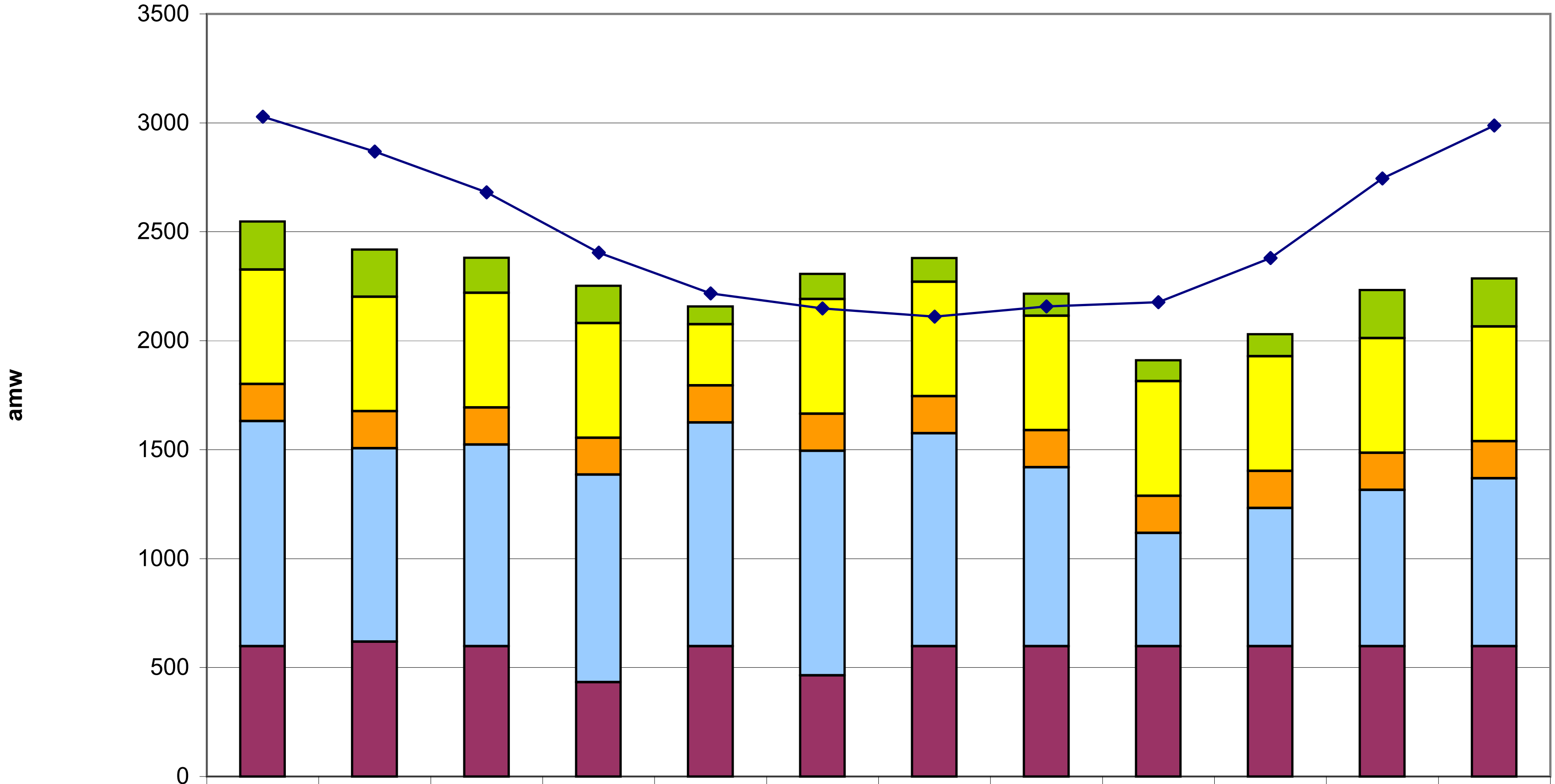
Exhibit No. ___(EMM-3)
Page 341 of 529

Exhibit F-4
2007 Monthly Energy Load-Resource Outlook



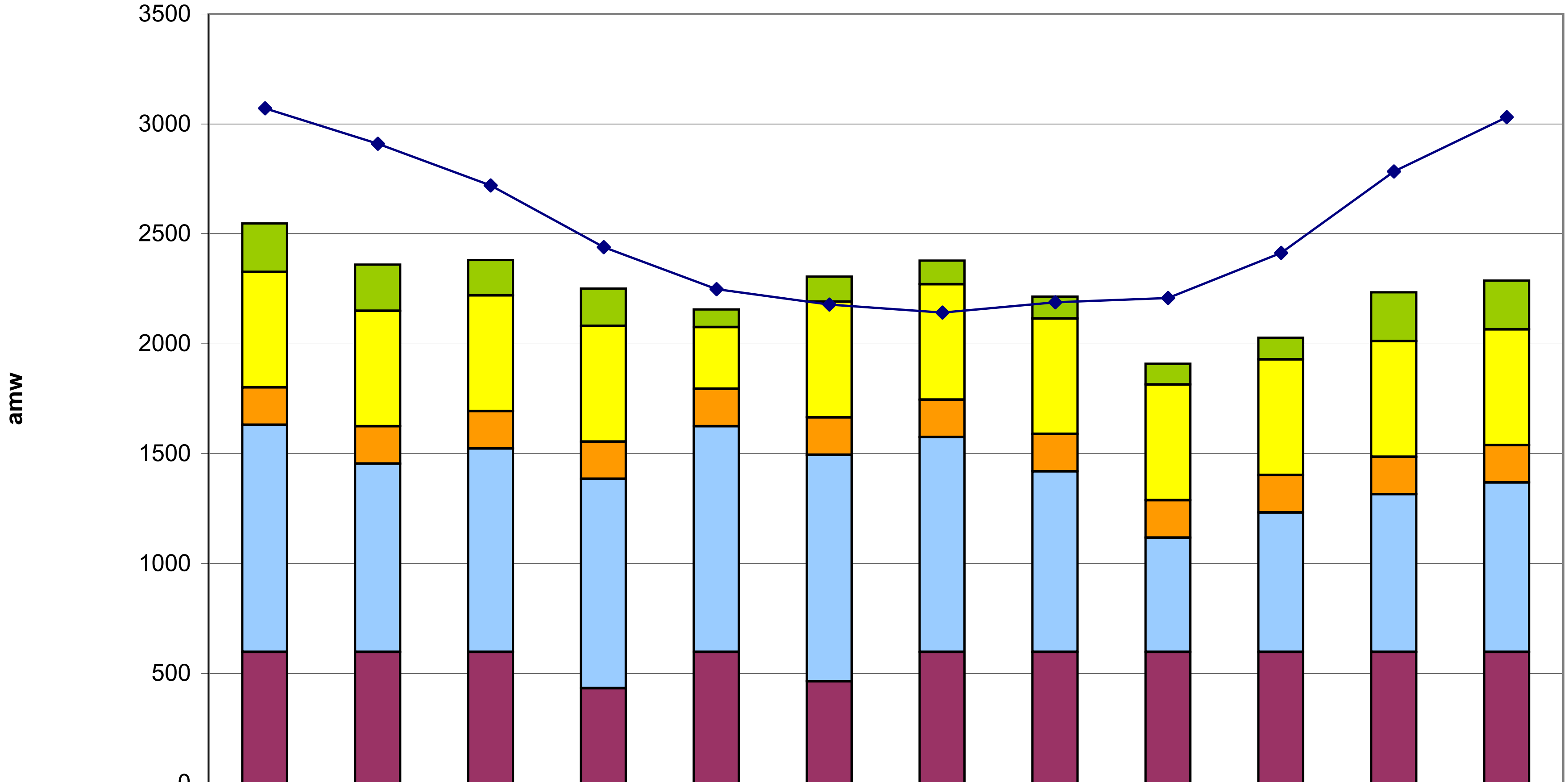
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	220	209	161	171	81	115	108	101	96	101	222	221
NUGs	526	526	526	526	281	526	526	526	526	526	526	526
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	1,033	857	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Load	2,988	2,831	2,646	2,373	2,187	2,120	2,083	2,129	2,149	2,348	2,709	2,948

Exhibit F-5
2008 Monthly Energy Load-Resource Outlook



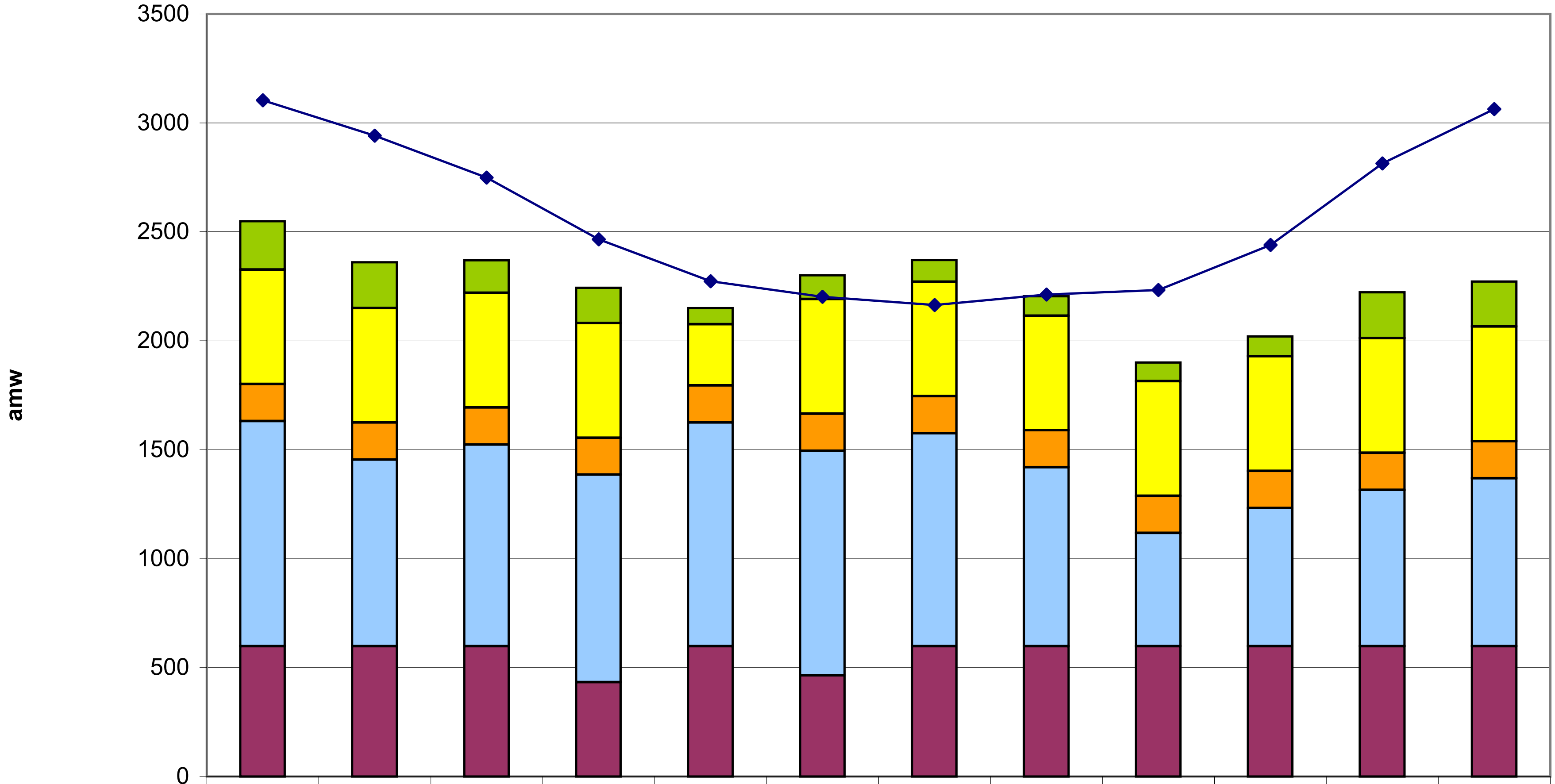
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	221	217	161	171	81	116	109	101	96	101	222	222
NUGs	526	526	526	526	281	526	526	526	526	526	526	526
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	1,033	887	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	619	598	433	598	464	598	598	598	598	598	598
Load	3,028	2,869	2,682	2,405	2,217	2,148	2,111	2,158	2,177	2,379	2,745	2,988

Exhibit F-6
2009 Monthly Energy Load-Resource Outlook



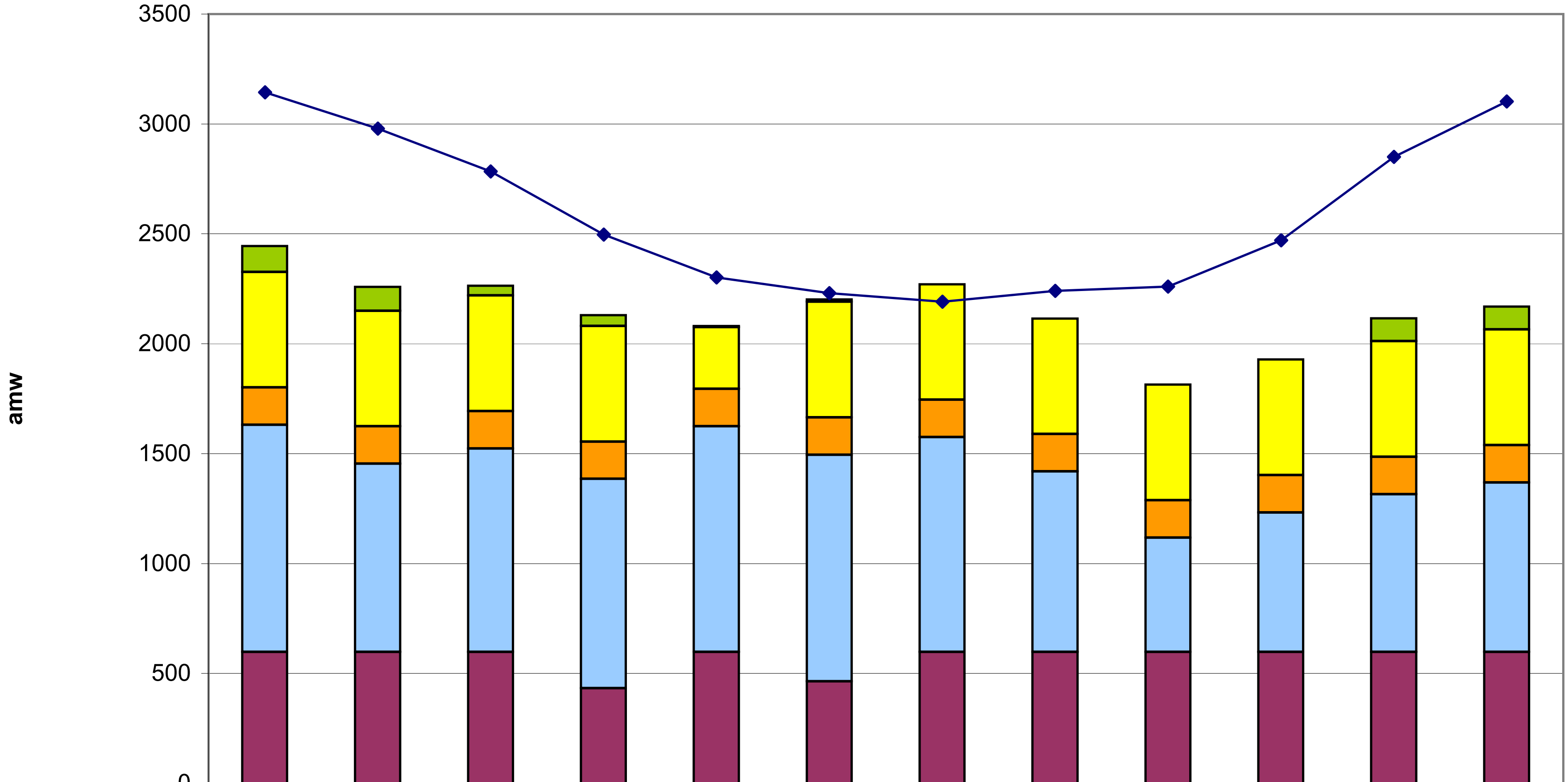
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	221	210	161	170	80	114	107	99	94	99	222	222
NUGs	526	526	526	526	281	526	526	526	526	526	526	526
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	1,033	857	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Load	3,071	2,910	2,720	2,439	2,248	2,179	2,141	2,188	2,209	2,413	2,784	3,031

Exhibit F-7
2010 Monthly Energy Load-Resource Outlook



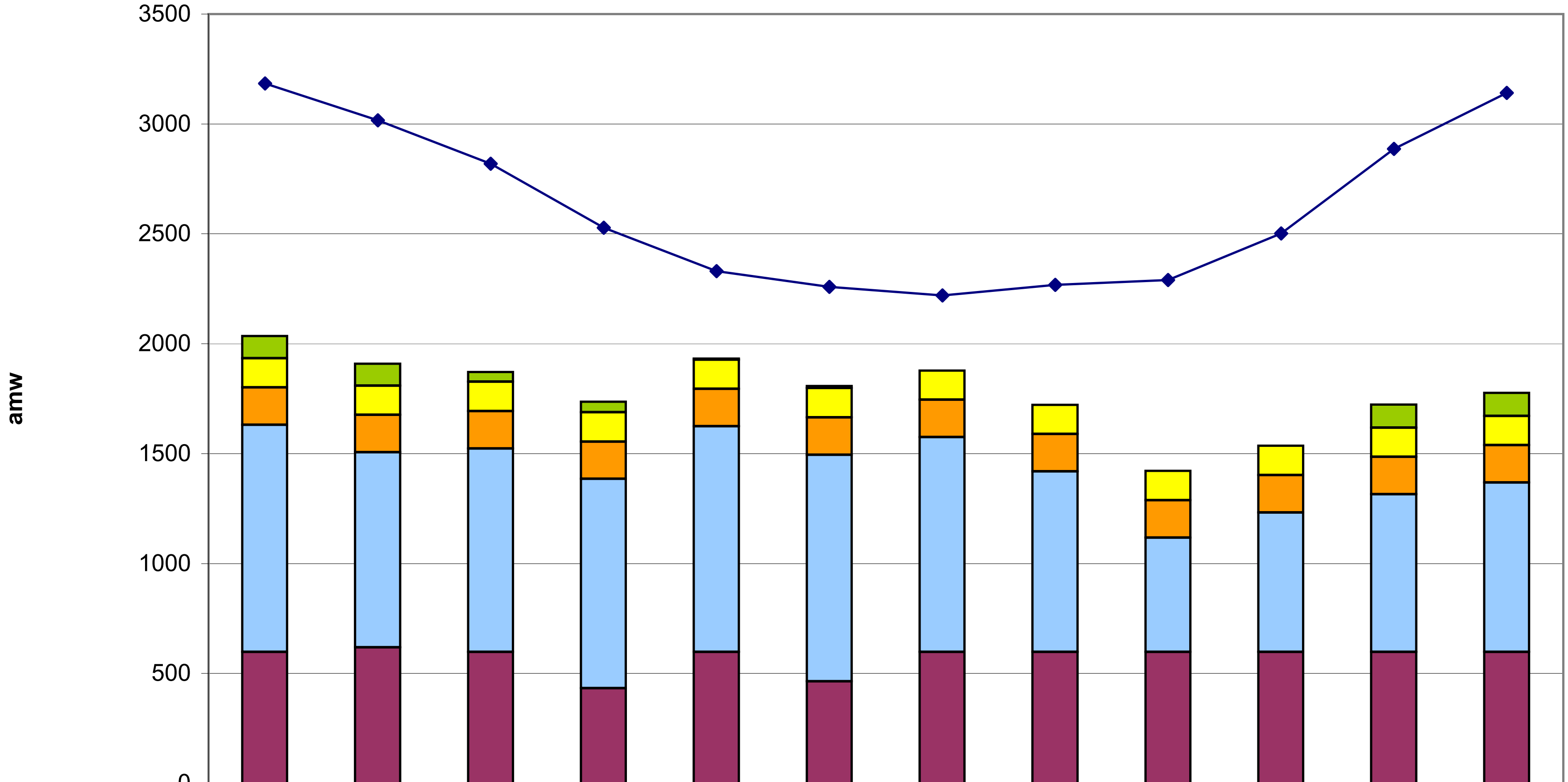
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	222	210	150	162	74	109	100	89	86	91	211	207
NUGs	526	526	526	526	281	526	526	526	526	526	526	526
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	1,033	857	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Load	3,104	2,941	2,749	2,465	2,273	2,202	2,164	2,212	2,232	2,439	2,814	3,063

Exhibit F-8
2011 Monthly Energy Load-Resource Outlook



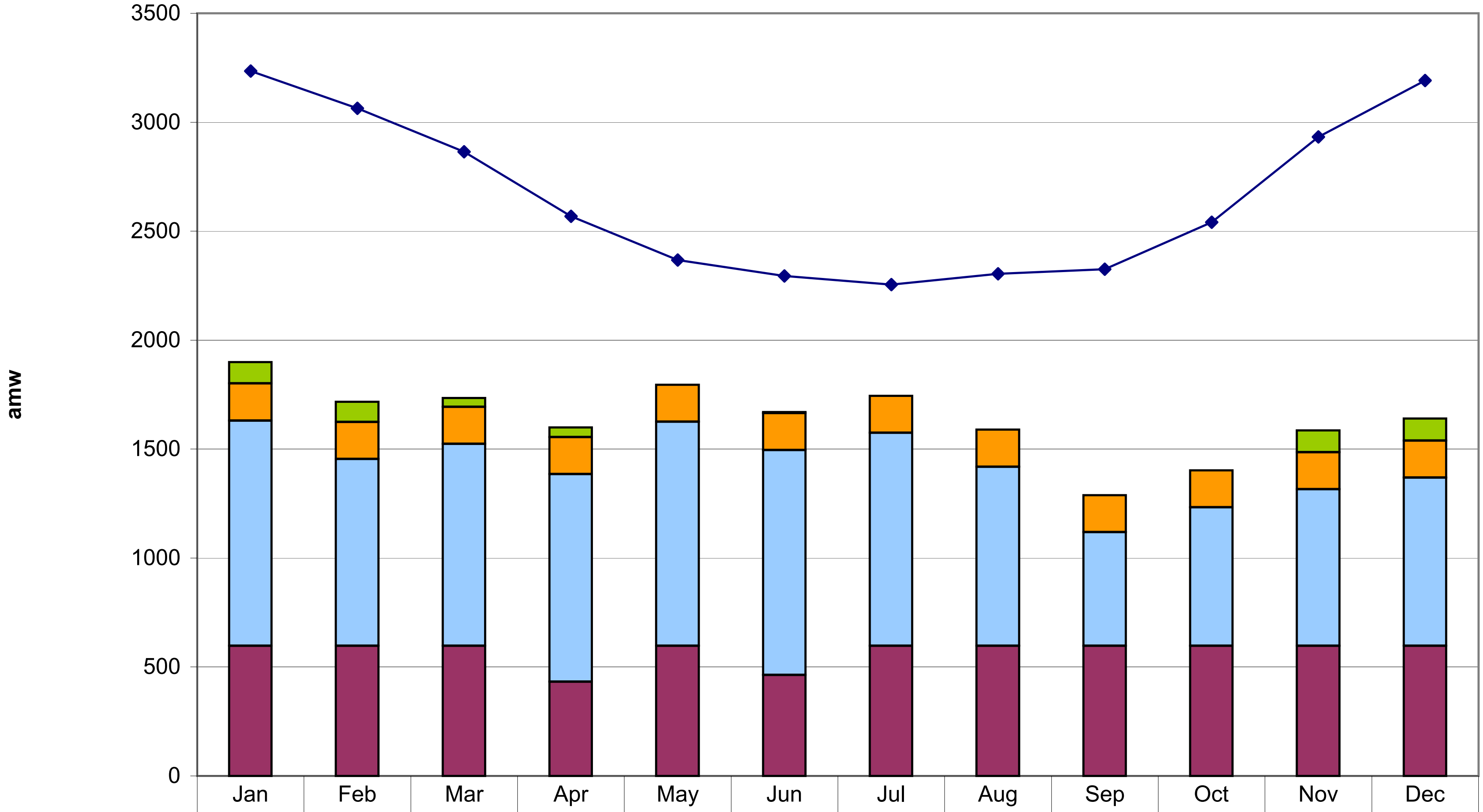
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	118	108	45	49	5	10	(5)	(17)	(18)	(15)	104	104
NUGs	526	526	526	526	281	526	526	526	526	526	526	526
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	1,033	857	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Load	3,144	2,979	2,784	2,497	2,302	2,230	2,192	2,240	2,261	2,470	2,850	3,102

Exhibit F-9
2012 Monthly Energy Load-Resource Outlook



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	102	101	45	49	5	10	(5)	(17)	(18)	(15)	105	104
NUGs	133	133	133	133	133	133	133	133	133	133	133	133
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	1,033	887	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	619	598	433	598	464	598	598	598	598	598	598
Load	3,184	3,016	2,819	2,528	2,331	2,259	2,220	2,268	2,289	2,501	2,886	3,142

Exhibit F-10
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

APPENDIX G
DETAILED RESOURCE TYPE DESCRIPTIONS

OVERVIEW OF GEOTHERMAL TECHNOLOGIES

Introduction

Geothermal energy, the natural heat within the earth, arises from the ancient heat remaining in the Earth's core, from friction where continental plates slide beneath each other, and from the decay of radioactive elements that occur naturally in small amounts in all rocks.

For thousands of years, people have benefited from hot springs and steam vents, using them for bathing, cooking, and heating. During this century, technological advances have made it possible and economic to locate and drill into hydrothermal reservoirs, pipe the steam or hot water to the surface, and use the heat directly (for space heating, aquaculture, and industrial processes) or to convert the heat into electricity.

The amount of geothermal energy is enormous. Scientists estimate that just 1 percent of the heat contained in just the uppermost 10 kilometers of the earth's crust is equivalent to 500 times the energy contained in all of the earth's oil and gas resources [1].

Hydrothermal and Hot Dry Rock

This document characterizes electric power generation technology for two distinct categories of geothermal resources.

Hydrothermal resources are the "here-and-now" resources for commercial geothermal electricity production. They are relatively shallow (from a few hundred to about 3,000 meters). They contain hot water, steam, or a combination of the two. They are inherently permeable, which means that fluids can flow from one part of the reservoir to other parts of the reservoir, and into and from wells that penetrate the reservoir. In hydrothermal reservoirs, water descends to considerable depth in the crust, becomes heated and then rises buoyantly until it either becomes trapped beneath impermeable strata, forming a bounded reservoir, or reaches the surface as hot springs or steam vents. The water convects substantial amounts of heat from depths to relatively near the surface.

Hot Dry Rock (HDR) resources, on the other hand, are relatively deep masses of rock that contain little or no steam or water, and are not very permeable. They exist where geothermal gradients (the vertical profile of changing temperature) are well above average (>50°C/km). The rock temperature reaches commercial usefulness at depths of about 4,000 meters or more. To exploit hot dry rock, a permeable reservoir must be created by hydraulic fracturing, and water from the surface must be pumped through the fractures to extract heat from the rock.

There are both strong similarities and large differences between hydrothermal and HDR geothermal resources and exploitation systems. Most of the component technologies, i.e., the power plant and well drilling methods, are very similar for both systems. The most important differences are that: (a) Hydrothermal systems are commercial today, while HDR systems are not, whereas (b) HDR resources are enormously larger (between 3,170,000 EJ and 17,940,000 EJ of accessible energy in the U.S.) than hydrothermal resources (on the order of 1,060 EJ to 5,300 EJ of accessible energy) [2]. By way of comparison, in 1995 the U.S. used about 95 EJ of primary energy. U.S. hydrothermal sources could supply that amount for 10 to 50 years. But U.S. Hot Dry Rock resources could supply that amount for somewhere between 30,000 and 500,000 years.

Because of these differences, the general strategic approach of national geothermal R&D programs (including that of the U.S.) has been to try to lower costs in the hydrothermal commercial arena today and, by so doing, to improve generic "geothermal" technology enough to make HDR exploitation economically feasible in the not-too-distant future.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF GEOTHERMAL TECHNOLOGIES

Hydrothermal Features

Hydrothermal resources are categorized as dry steam (vapor dominated) or hot water resources, depending on the predominant phase of the fluid in the reservoir. Although the technology is similar for both, dry steam technology is not included in this Technology Characterization because dry steam resources are relatively rare. Hot water resources are further categorized as being high temperature (>200°C/392°F), moderate temperature (between 100°C/212°F and 200°C/392°F), and low temperature (<100°C/212°F). Only the high and moderate temperature resources are adequate for commercial power generation.

Two separate power generation technologies, flash and binary, are characterized. The boiling temperature of water depends on its pressure, so as the pressure of the high temperature geothermal fluid is lowered in the plant, a portion (about 10 to 20% of it, depending on temperature and pressure) "flashes" to steam, which is used to drive a turbine to produce electricity. For moderate temperature resources, binary technology is more efficient. It is termed "binary" because the heat is transferred from the geothermal fluid to a secondary working fluid with a lower boiling temperature than water. The secondary fluid, vaporized by the heat, drives the turbine.

Beginning commercially in the 1950s, hydrothermal electric power generation has grown into an active and healthy, albeit not large, industry. About 7,000 MW of electric generation capacity have been developed worldwide, including about 2,800 MW in the U.S. [3]. Supply and demand forces and anticipated restructuring in the U.S. electric markets have resulted in very low demand for new geothermal capacity since 1990. However, geothermal energy is competing very well in markets outside the U.S., especially in Indonesia and the Philippines, where demand is high, geothermal resources are plentiful, and government policy is favorable. Approximately 2,000 additional MW will likely be developed worldwide in 1996 through 2000, with the majority of this being in Asia.

Hot Dry Rock Features

Flash or binary technology could be used with HDR resources depending on the temperature. However, because of the constraints imposed by high well costs, a larger portion of the accessible HDR resource will produce well-head fluids in the moderate temperature range. Therefore, binary technology is characterized for HDR resources.

To date, HDR resources have not been developed commercially for two reasons. Well costs increase exponentially with depth, and since HDR resources are much deeper than hydrothermal resources, they are much more expensive to develop. Also, although the technical feasibility of creating HDR reservoirs has been demonstrated at experimental sites in the U.S., Europe, and Japan, operational uncertainties regarding impedance (resistance of the reservoir to flow), thermal drawdown over time, and water loss make commercial development too risky.

Resource Details

In the U.S., the higher quality geothermal resources (both hydrothermal and HDR) are predominately located in the western states, including Alaska and Hawaii, as shown in the map below. Development of hydrothermal resources for electric power generation has been limited to California, Nevada, Utah, and Hawaii. Most of the western U.S. contains HDR resources, with the highest grade resources probably located in California and Nevada.

Scientists have made various estimates of the geothermal resource in the U.S. The U.S. Geologic Survey (USGS) completed the nation's most comprehensive assessment of geothermal resources, documented in USGS Circular 790, published in 1978 [2]. Circular 790 estimated the known, accessible hydrothermal resource to be about 23,000 MW

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF GEOTHERMAL TECHNOLOGIES

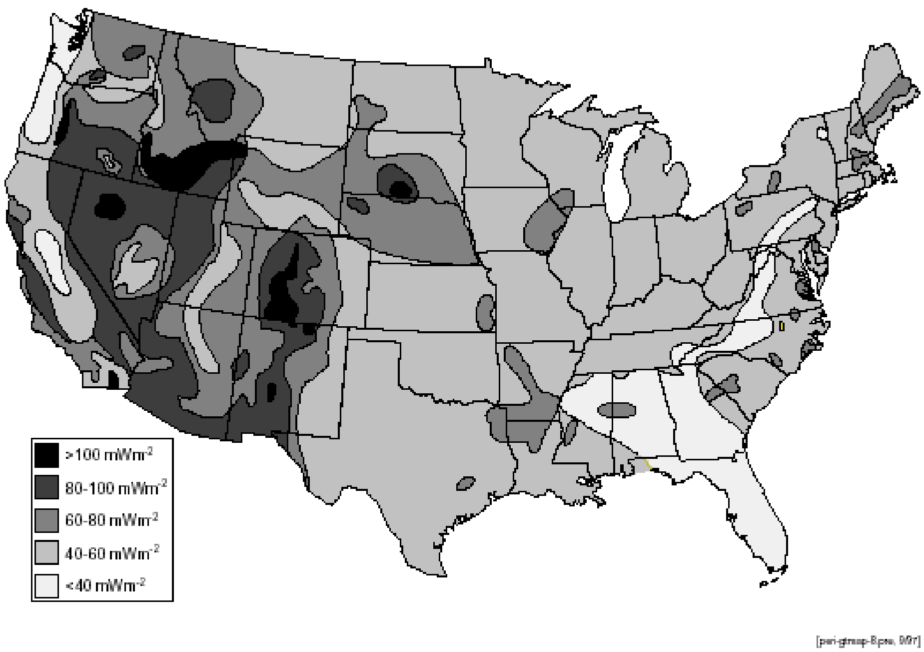


Figure 1. Geothermal resource quality in the United States.

of electric capacity for 30 years, and the as yet undiscovered accessible hydrothermal resource to be 95,000 to 150,000 MW of electric capacity for 30 years. It should be noted that the accessible resource is that which is accessible with current technology, but not necessarily economic. Considerable geothermal exploration and development in the U.S. since the mid 1950s has identified and characterized (moderately well) about 3,000 to 5,000 MW of hot water hydrothermal resources. Exploration work in the Cascade Mountains of Oregon in the 1990s seems to preclude the existence of the significant hydrothermal resource once estimated for that area.

An unpublished study by the University of Utah Research Institute in 1991 estimated about 5,000 MW of electric capacity for 30 years would be available at a cost of 5.5¢/kWh [4]. Recent preliminary analyses by the authors of the geothermal TCs suggest that for Hydrothermal electricity in 1997, no capacity would be available at ≤2¢/kWh, about 5,000 MW would be available at ≤3¢/kWh, and about 10,000 MW available at ≤5¢/kWh. If the predicted technology improvements for 2020 hold true, then 6,000 MW would be available at ≤2¢/kWh, about 10,000 MW available at ≤3¢/kWh, and about 19,000 MW available at ≤5¢/kWh. (These prices are levelized in constant dollars, using the "GenCo" financing assumptions described in Chapter 7.) Also note that the lowest prices given here are lower than the price calculated for the characterized geothermal flash power plant because the characterized plant is for a "typical" rather than "least expensive" geothermal high-temperature reservoir.

Although the potential of the nation's HDR resource has been studied less and is less well understood, it is believed to be very much larger than that of the hydrothermal resource. Tester and Herzog estimated the U.S. high grade HDR resource to have the potential of generating 2,800,000 MW at a cost ≤8.7¢/kWh (1996$) using 1990 technology [5]. For the year 2020 technology projected in the Hot Dry Rock TC, the current authors estimate that about 2,000,000 MW would be available from very high quality resource regions at ≤5¢/kWh, and that as much as 17,000,000 MW (about

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF GEOTHERMAL TECHNOLOGIES

24 times the current installed electric capacity in the U.S.) of HDR would be available at $\leq$6¢/kWh. (The economic assumptions here are the same as stated in the paragraph above.)

Aspects of Cost Estimates

The current state of many aspects of geothermal technology is fairly well documented. Indeed, the timing of this characterization of geothermal technologies is opportune in that it follows the first major engineering analysis of the cost and performance of geothermal power plants in 15 years. The "Next Generation Geothermal Power Plants" study (NGGPP), published in 1996, characterizes current flash and binary technology and evaluates new technologies proposed for the next generation of geothermal power plants [6]. Prior to this study, it has been difficult to obtain current cost and performance data for geothermal power plants because of the proprietary nature of this information.

The Hydrothermal and Hot Dry Rock TCs incorporate much data from the NGGPP. However, the characterization of Hydrothermal Flash reflects decreased flash plant capital costs (approximately 40% less than those documented in the NGGPP) due to intense competition. As of mid-1997, capital costs for binary plants appear to have been unaffected by these factors.

The HDR technology characterization depends on the NGGPP for binary power plant cost and performance data. The NGGPP includes an analysis of HDR technology that some believe is too conservative. The current HDR characterization is based on a higher grade HDR resource than that in the NGGPP. The NGGPP HDR well cost (including fracturing) estimates were about 30% higher than the TC HDR well costs, which were estimated by an experienced geothermal drilling engineer based on the costs of deep geothermal wells drilled recently in Nevada. The costs of creating the HDR reservoir, as well as its performance, are based on estimates of HDR scientists at Los Alamos National Laboratory, where HDR has been studied for the last 20 years.

Projections of Technology Improvements

For geothermal, as for other renewable energy electric supply technologies, the "accuracy" of projections of improvements in cost effectiveness are very important because in many instances, use of the technologies at specific locations will not be cost effective until the technologies are improved somewhat. The projections for improvements in the cost and performance of hydrothermal and HDR technologies are a synthesis of what various experts believe is possible.

The projections for improvements in hydrothermal technology are based on trends in performance and cost since about 1985 when U.S. firms first started constructing many hydrothermal power systems. It has been apparent that for both wells and power plants, the earliest forms of the technologies -- borrowed more or less wholly from other industries and uses -- have been constantly analyzed, rethought, and improved. The past five years especially have seen much new attention focused on how to improve the cost effectiveness of power plants, through changes in the underlying process cycles and conditions used to convert heat to electricity.

The single major exception to this ten-year (1985-1995) trend of apparent improvements has been in the area of industry's ability to locate and target, in many reservoirs, high-permeability zones for fluid collection and delivery. But here too, constant theoretical progress is being made, that is soon likely to engender practical progress.

The estimates for current and projected HDR cost and performance are more speculative than those for hydrothermal technology since HDR technology is much less mature and has not been applied commercially. Therefore, there is greater uncertainty in the HDR technology estimates. With HDR technology, the stated estimates are for the best cost

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

and performance that is reasonably possible; the estimated uncertainty values reflect the possibility of lower performance and less improvement in the technology.

The projections are predicated on various assumptions about factors that will affect the timing and extent of improvements in the technologies. These include the levels of funding for hydrothermal and HDR R&D in several countries, as well as fossil fuel drilling and well completion R&D, supply and demand in electricity markets, supply and demand in petroleum markets (this greatly influences drilling costs and private funding of drilling research), public policy (especially regarding energy and the environment) in several countries, currency fluctuations, and technological progress in other electric supply technologies.

References

1. Duffield, W.A., J.H. Sass, and M.L. Sorey, "Tapping the Earth's Natural Heat," U.S. Geological Survey Circular 1125, 1994.

2. Muffler, L.J.P, ed., "Assessment of Geothermal Resource of the United States -- 1978," U.S. Geologic Survey Circular 790, 1979.

3. U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook 1996, DOE/EIA-0603(96), August 1996.

4. U.S. Department of Energy, Energy Information Administration, Geothermal Energy in the Western United States and Hawaii: Resources and Projected Electricity Generation Supplies, U.S. Department of Energy, DOE/EIA-0544, September 1991.

5. Tester, J.W., and H.J. Herzog, Economic Predictions for Heat Mining: A Review and Analysis of Hot Dry rock (HDR) Geothermal Energy Technology, Massachusetts Institute of Technology: July 1990.

6. Brugman, J., Hattar, M., Nichols, K., and Y. Esaki, Next Generation Geothermal Power Plants, Electric Power Research Institute: February 1996. Report EPRI TR-106223.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF PHOTOVOLTAIC TECHNOLOGIES

Introduction

Solar photovoltaic modules, called "photovoltaics" or "PV", are solid-state semiconductor devices with no moving parts that convert sunlight into direct-current electricity. Although based on science that began with Alexandre Edmond Becquerel's discovery of light-induced voltage in electrolytic cells over 150 years ago, significant development really began following Bell Labs' invention of the silicon solar cell in 1954. PV's first major application was to power man-made earth satellites in the late 1950s, an application where simplicity and reliability were paramount and cost was nearly ignored. Enormous progress in PV performance and cost reduction, driven at first by the U.S. space program's needs, has been made over the last 40-plus years. Since the early 1970s, private/public sector collaborative efforts in the U.S., Europe, and Japan have been the primary technology drivers. Today, annual global module production is over 100 MW, which roughly translates into a $1billion/year business. In addition to PV's ongoing use in space, its present-day cost and performance also make it suitable for many grid-isolated applications in both developed and developing parts of the world, and the technology stands on the threshold of major energy-significant applications worldwide.

PV enjoys so many advantages that, as its comparatively high initial cost is brought down another order of magnitude, it is very easy to imagine its becoming nearly ubiquitous late in the 21st century. PV would then likely be employed on many scales in vastly differing environments, from microscopic cells integrated into and powering diamond-based optoelectronic devices in kilometers-deep wells to 100-MW or larger 'central station' generating plants covering square kilometers on the earth's surface and in space. The technical and economic driving forces favoring PV's use in these widely diverse applications will be equally diverse. However, common among them will be PV's durability, high efficiency, low cost, and lack of moving parts, which combine to give an economic power source with minimum maintenance and unmatched reliability. In short, PV's simplicity, versatility, reliability, low environmental impact, and—ultimately—low cost, should help it to become an important source of economical premium-quality power within the next 50 years.

It is easy to foresee PV's 21st-century preeminence, but the task of this chapter is a difficult one of accurately predicting PV's development trajectory toward that time. The three applications described here (Residential PV; Utility-Scale, Flat-Plate Thin Film PV; and Concentrating PV) illustrate highly feasible elements of that trajectory. These applications likely will blossom at different rates and may not all develop as forecasted. Furthermore, they are not the only major applications likely to emerge. Nevertheless, the three scenarios presented serve to give a sense of the time scale in which PV is likely to evolve from its present-day state, to the pervasive low-priced appliance of the latter half of the next century. During the time period covered by these characterizations, PV will evolve from a technology serving niche markets, to one entering and then playing an important and growing role in the world's energy markets. Up to 10% of U.S. capacity could be PV by 2030, and significant PV will be used worldwide as global demand for electricity grows.

Economic Evolution

Empirical progress in manufacturing processes is frequently displayed by means of a "learning" or "experience" curve. Conventionally, such curves are plotted using logarithmic axes, to show per-unit cost versus cumulative production volume. Most often, such a plot will produce a straight line over a very large range of actual production volumes and unit costs. The slope of that line, expressed as the percent of cost remaining after each doubling in volume, is called the "progress ratio." (Since a progress ratio of 100% would represent no learning —i.e., zero cost reduction—it would perhaps be better called a "lack-of-progress ratio.") Most manufactured goods are found to yield progress ratios between 70% and 90%, but there appears to be no generally applicable rule for assigning *a priori* expectations of progress ratios for a given process.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF PHOTOVOLTAIC TECHNOLOGIES

Figure 1 shows the experience curve over the past 20-some years for PV module prices versus total sales. Price and total sales are used as proxies for cost and manufactured volume because the actual cost and production information for the entire industry is not available. Note that, although the plotted data comprise a number of technologies, the dominant technology—crystalline silicon—has set the pace for the price-volume relation. Therefore, this figure most closely represents an experience curve for crystalline silicon PV, and this curve was used within the Technology Characterization for Residential PV systems. The 82% value falls within the range typical for manufactured goods, and the projections of crystalline-silicon module sales and prices provided within that TC are further supported by a "bottom up" analysis of the industry.

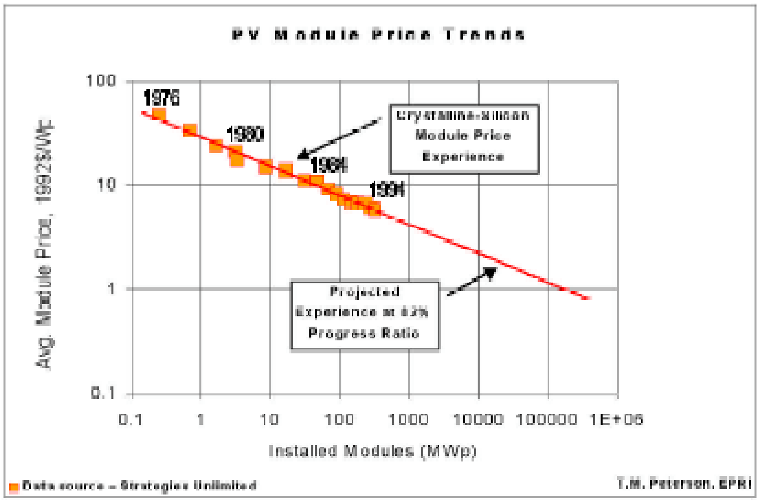


Figure 1. Learning curve for crystalline-silicon PV.

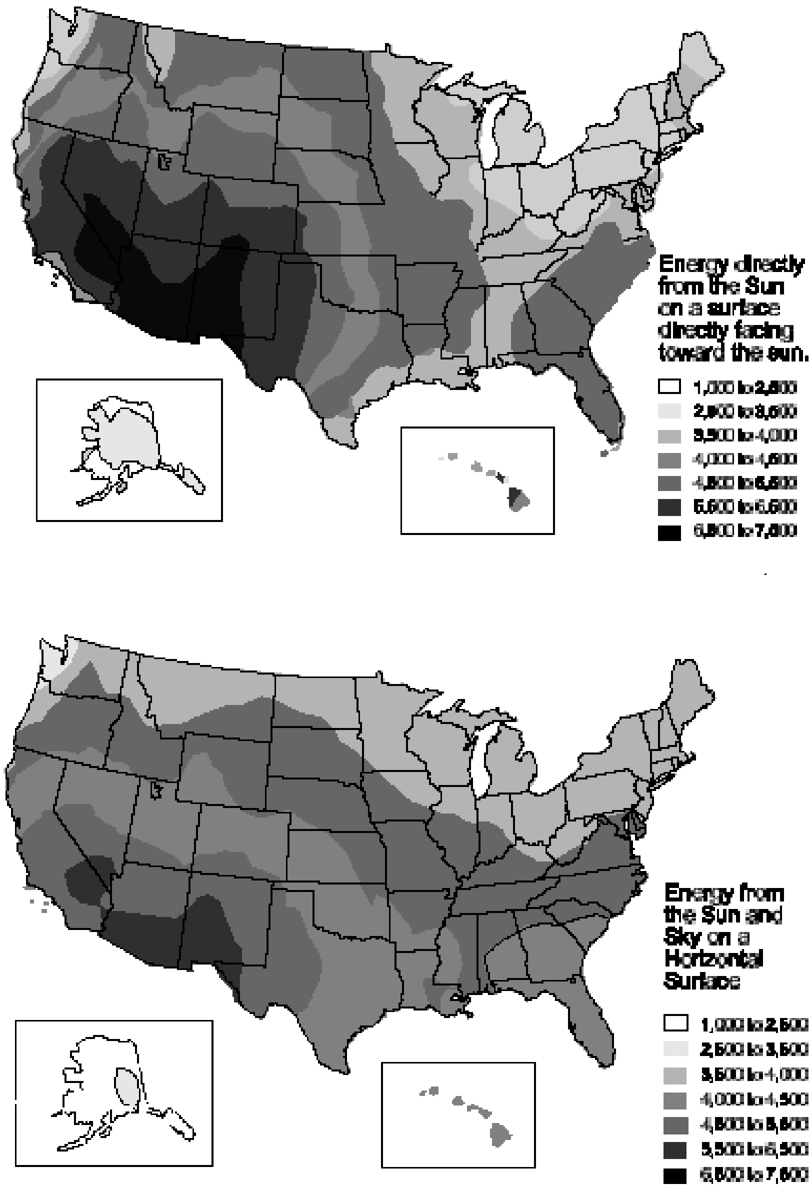
A major departure from the historical trend could be caused by emergence of a fundamentally new technology where the learning process would need to begin anew. Both thin-film and concentrator PV are likely candidates for just such a fundamental technology shift. Because historical data are not available, a great deal of uncertainty exists regarding the future costs of thin-film and concentrator PV systems which are so dependent on R&D funding and for which much industry data is proprietary.

Technology Comparison

Solar Resource: One significant difference between concentrating and other PV systems pertains to the solar resource used. Concentrating PV systems use sunlight which is incident perpendicular to the active materials (direct normal insolation). Other PV systems utilize both direct and indirect (diffuse) solar radiation. Provided in Figure 2, below, are two maps; the first is a map of direct normal insolation, the second is a map depicting global insolation for the U.S.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF PHOTOVOLTAIC TECHNOLOGIES



Reproduced from data provided by
NREL Renewable Energy Resource Information & Analysis Center
in support of the
DOE Resource Assessment Program
Solar Radiation Resource Assessment Project

Figure 2. Direct normal insolation resource for concentrator PV (above) and global insolation resource for crystalline-silicon and thin film PV systems (below).

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF PHOTOVOLTAIC TECHNOLOGIES

The main consequence of this difference is that concentrator systems should be deployed in regions that are predominantly cloud free. While other PV systems do not have this requirement, total solar resource quality does of course influence system performance. The PV Technology Characterizations take resource quality into consideration by providing performance estimates based on average and high solar resource assumptions.

Deployment: The deployment needs of the two utility scale applications described in this report are similar. Medium and large-scale deployments have significant land requirements. However, it is important to note that concentrator systems are less appropriate for very small-scale deployments (less than a few tens of kilowatts) due to their costs and complexity. Customer (building) sited PV have no land requirements, however several structural requirements are important (i.e. roof integrity and orientation, shading, pitch, etc.).

Application: The PV systems characterized here all provide distributed benefits. Residential PV systems either feed power into the grid and/or reduce customer demand for grid power. Medium and larger scale systems add capacity incrementally, and to the extent that they match load patterns, may reduce the need for major capital investments in central generation.

Modularity: PV generating systems are easily scaled to meet demand. PV systems can be constructed using one or more modules, producing from a few tens of watts to megawatts. For example, the residential PV systems characterized in this report are a few kW in size, while the concentrating and utility scale thin film PV systems are multi-megawatt applications.

Low-cost operation and maintenance: PV systems have few moving parts. Flat-plate types without tracking have no moving parts, and even two-axis tracking requires only a relatively small number of low-speed moving parts. This tends to keep operation and maintenance costs down. Indeed, some early kilowatt-scale first-of-a-kind plants demonstrated O&M costs around $0.005/kWh.

Summary

The PV applications described here are both competitive and mutually supportive at the same time. They are competitive because successful pursuit of one application will divert enthusiasm and resources from the others to some degree; but supportive, because technology and marketing advances fueled by any one of them will also somewhat aid the rest. They do compete to some extent for common markets, but they each serve sufficiently distinct needs to expect their respective niches to persist indefinitely, despite the likelihood that a single one of them may dominate the overall market.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF BIOMASS TECHNOLOGIES

Situation Analysis

Biopower (biomass-to-electricity power generation) is a proven electricity-generating option in the United States. With about 10 GW of installed capacity, biopower is the single largest source of non-hydro renewable electricity. This installed capacity consists of about 7 GW derived from forest-product-industry and agricultural-industry residues, about 2.5 GW of municipal solid waste (MSW) generating capacity, and 0.5 GW of other capacity such as landfill gas-based production. The electricity production from biomass is being used, and is expected to continue to be used, as base load power in the existing electric-power system.

In the U.S., biopower experienced dramatic growth after the Public Utilities Regulatory Policy Act (PURPA) of 1978 guaranteed small electricity producers (less than 80 MW) that utilities would purchase their surplus electricity at a price equal to the utilities' avoided-cost of producing electricity. From less than 200 MW in 1979, biopower capacity grew to 6 GW in 1989 and to today's capacity of 7 GW. In 1989 alone, 1.84 GW of capacity was added. The present low buyback rates from utilities, combined with uncertainties about industry restructuring, have slowed industry growth and led to the closure of a number of facilities in recent years.

The 7 GW of traditional biomass capacity represents about 1% of total electricity generating capacity and about 8% of all non-utility generating capacity. More than 500 facilities around the country are currently using wood or wood waste to generate electricity. Fewer than 20 facilities are owned and operated by investor-owned or publicly-owned electric utilities. The majority of the capacity is produced in Combined Heat and Power (CHP) facilities in the industrial sector, primarily in pulp and paper mills and paperboard manufacturers. Some of these CHP facilities have buyback agreements with local utilities to purchase net excess generation. Additionally, a moderate percentage of biomass power facilities are owned and operated by non-utility generators, such as independent power producers, that have power purchase agreements with local utilities. The number of such facilities is decreasing somewhat as utilities buy back existing contracts. To generate electricity, the stand-alone power production facilities largely use non-captive residues, including wood waste purchased from forest products industries and urban wood waste streams, used wood pallets, some waste wood from construction and demolition, and some agricultural residues from pruning, harvesting, and processing. In most instances, the generation of biomass power by these facilities also reduces local and regional waste streams.

All of today's capacity is based on mature, direct-combustion boiler/steam turbine technology. The average size of existing biopower plants is 20 MW (the largest approaches 75 MW) and the average biomass-to-electricity efficiency of the industry is 20%. These small plant sizes lead to higher capital cost per kilowatt of installed capacity and to high operating costs as fewer kilowatt-hours are produced per employee. These factors, combined with low efficiencies which increase sensitivity to fluctuations in feedstock price, have led to electricity costs in the 8-12¢/kWh range.

The next generation of stand-alone biopower production will substantially reduce the high costs and efficiency disadvantages of today's industry. The industry is expected to dramatically improve process efficiency through the use of co-firing of biomass in existing coal-fired power stations, through the introduction of high-efficiency gasification-combined-cycle systems, and through efficiency improvements in direct-combustion systems made possible by the addition of fuel drying and higher performance steam cycles at larger scales of operation. Technologies presently at the research and development stage, such as Whole Tree Energy™ integrated gasification fuel cell systems, and modular systems, are expected to be competitive in the future.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF BIOMASS TECHNOLOGIES

Technology Alternatives

The nearest term low-cost option for the use of biomass is co-firing with coal in existing boilers. Co-firing refers to the practice of introducing biomass as a supplementary energy source in high efficiency boilers. Co-firing has been practiced, tested, or evaluated for a variety of boiler technologies, including pulverized coal boilers of both wall-fired and tangentially-fired designs, coal-fired cyclone boilers, fluidized-bed boilers, and spreader stokers. The current coal-fired power generating system presents an opportunity for carbon mitigation by substituting biomass-based renewable carbon for fossil carbon. Extensive demonstrations and trials have shown that effective substitutions of biomass energy can be made in the range of 10-15% of the total energy input with little more than burner and feed intake system modifications to existing stations. One preliminary test reached 40% of the energy from biomass. Within the current 310 GW of installed coal capacity, plant sizes range from 100 MW to 1.3 GW. Therefore, the biomass potential in a single boiler ranges from 15 MW to 130 MW. Preparation of biomass for co-firing involves well known and commercial technologies. After "tuning" the boiler's combustion output, there is very little loss in total efficiency. Since biomass in general has much less sulfur than coal, there is an SO_2 benefit, and early test results suggest that there is also a NO_x reduction potential of up to 30% with woody biomass co-fired in the 10-15% range. Investment levels are very site-specific and are affected by the available space for yarding and storing biomass, installation of size reduction and drying facilities, and the nature of the boiler burner modifications. Investments are expected to be $100-700/kW of biomass capacity, with a median in the $180-200/kW range. Note that these values are per kW of biomass, so, at 10% co-fire, $100/kW adds $10/kW to the total, coal plus biomass, capacity costs.

Another potentially attractive biopower option is gasification. Gasification for power production involves the devolatilization and conversion of biomass in an atmosphere of steam or air to produce a medium-or low-calorific gas. This "biogas" is then used as fuel in a combined cycle power generation plant that includes a gas turbine topping cycle and a steam turbine bottoming cycle. A large number of variables influence gasifier design, including gasification medium (oxygen or no oxygen), gasifier operating pressure, and gasifier type. Advanced biomass power systems based on gasification benefit from the substantial investments made in coal-based gasification combined cycle (GCC) systems in the areas of hot gas particulate removal and synthesis gas combustion. They also leverage investments made in the Clean Coal Technology Program (commercial demonstration cleanup and utilization technologies) and in those made as part of DOE's Advanced Turbine Systems (ATS) Program. Biomass gasification systems will also be appropriate to provide fuel to fuel cell and hybrid fuel-cell/gas-turbine systems, particularly in developing or rural areas without cheap fossil fuels or having a problematic transmission infrastructure. The first generation of biomass GCC systems would have efficiencies nearly double that of direct-combustion systems (e.g., 37% vs. 20%). In cogeneration applications, total plant efficiencies could exceed 80%. This technology is very near to commercial availability with one small (9MW equivalent) plant operating in Sweden. Costs of a first-of-a-kind biomass GCC plant are estimated to be in the $1,800-2,000/kW range, with the cost dropping rapidly to the $1,400/kW range for a mature plant in the 2010 time frame.

Direct-fired combustion technologies are another option, especially with retrofits of existing facilities to improve process efficiency. Direct combustion involves the oxidation of biomass with excess air, producing hot flue gases which produce steam in the heat exchange sections of boilers. The steam is used to produce electricity in a Rankine cycle. In an electricity-only process, all of the steam is condensed in the turbine cycle while, in CHP operation, a portion of the steam is extracted to provide process heat. Today's biomass-fired steam cycle plants typically use single pass steam turbines. In the past decade, however, efficiency and design features found previously in large-scale steam turbine generators have been transferred to smaller capacity units. These designs include multi-pressure, reheat and regenerative steam turbine cycles, as well as supercritical steam turbines. The two common boiler designs used for steam generation with biomass are stationary and traveling-grate combustors (stokers) and atmospheric fluid-bed combustors. The addition of drying processes and incorporation of higher performance steam cycles is expected to raise the efficiency of direct-combustion systems by about 10% over today's best direct-combustion systems, and to lower the capital investment from the present $2,000/kW to about $1,300/kW or below.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF BIOMASS TECHNOLOGIES

The three technologies discussed in the detailed technology characterizations are all at either the commercial or commercial-prototype stage. There are additional technologies that are at the conceptual or research and development stage and thus do not warrant development of a comparable technology characterization at this time. However, these options are potentially attractive from a performance and cost perspective and therefore do merit discussion. These technologies include the Whole Tree Energy™ process, biomass gasification fuel cell processes, and small modular systems such as biomass gasification Stirling engines.

The Whole Tree Energy™ process is under development by Energy Performance Systems, with the support of EPRI and DOE, for application to large-scale energy crop production and power generation facilities, with generating capacities above 100 MW. To improve thermal efficiency, a 16.64 MPa/538 .
Whole trees are to be harvested by cutting the trees at the base, then transported by truck to the power plant, stacked in a drying building for about 30 days, dried by air heated in the second stage of the air heater downstream of the boiler, and burned under starved-air conditions in a deep-bed combustor at the bottom of the furnace. A portion of the moisture in the flue gas will be condensed in the second stage of the air heater and collected along with the fly ash in a wet particulate scrubber. The remainder of the plant is similar to a stoker plant. Elements of the process have been tested, but the system has not been tested on an integrated basis.

Gasification fuel cell systems hold the promise of high efficiency and low cost at a variety of scales. The benefits may be particularly pronounced at scales previously associated with high cost and low efficiency (i.e., from < 1MW to 20 MW). Fuel cell-based power systems are likely to be particularly suitable as part of distributed power generation strategies in the U.S. and abroad. Extensive development of molten carbonate fuel cell (MCFC) technology has been conducted under DOE and EPRI's sponsorship, largely with natural gas as a test fuel. Several demonstration projects are underway in the U.S. for long-term testing of these cells. A limited amount of testing was also done with MCFC technology on synthesis gas from a coal gasifier at Dow Energy Systems' (DESTEC) facility in Plaquamine, LA. The results from this test were quite promising.

No fuel cell testing has been done to-date with biomass-derived gases despite the several advantages that biomass has over coal in this application. Biomass' primary advantage is its very low sulfur content. Sulfur-containing species are a major concern in fossil fuel-based fuel cell systems since fuel cells are very sensitive to this contaminant. An additional biomass advantage is its high reactivity. This allows biomass gasifiers to operate at lower temperatures and pressures while maintaining throughput levels comparable to their fossil-fueled counterparts. These relatively mild operating conditions and a high throughput should permit economic construction of gasifiers of a relatively small scale that are compatible with planned fuel cell system sizes. Additionally, the operating temperature and pressure of MCFC units may allow a high degree of thermal integration over the entire gasifier/fuel cell system. Despite these obvious system advantages, it is still necessary for actual test data to be obtained and market assessments performed to stimulate commercial development and deployment of fuel cell systems.

The Stirling engine is designed to use any heat source, and any convenient working gas, to generate energy, in this case electricity. The basic components of the Stirling engine include a compression space and an expansion space, with a heater, regenerator, and cooler in between. Heat is supplied to the working gas at a higher temperature by the heater and is rejected at a lower temperature in the cooler. The regenerator provides a means for storing heat deposited by the hot gas in one stage of the cycle, and releasing it to heat the cool gas in a subsequent stage. Stirling engine systems using biomass are ideal for remote applications, stand-alone or cogeneration applications, or as backup power systems. Since the Stirling engine is an external combustion system, it requires less fuel-gas cleanup than gas turbines. A feasibility test of biomass gasification Stirling engine generation has been performed by Stirling Thermal Motors using a 25 kW engine connected to a small Chiptec updraft gasifier. While the results were encouraging, further demonstration of the concept is required.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF BIOMASS TECHNOLOGIES

Markets

Biopower systems encompass the entire cycle -- growing and harvesting the resource, converting and delivering electricity, and recycling carbon dioxide during growth of additional biomass. Biomass feedstocks can be of many types from diverse sources. This diversity creates technical and economic challenges for biopower plant operators because each feedstock has different physical and thermochemical characteristics and delivered costs. Increased feedstock flexibility and smaller scales relative to fossil-fuel power plants present opportunities for biopower market penetration. Feedstock type and availability, proximity to users or transmission stations, and markets for potential byproducts will influence which biomass conversion technology is selected and its scale of operation. A number of competing biopower technologies, such as those discussed previously, will likely be available. These will provide a variety of advantages for the U. S. economy, from creating jobs in rural areas to increasing manufacturing jobs.

The near-term domestic opportunity for GCC technology is in the forest products industry. A majority of its power boilers will reach the end of their useful life in the next 10-15 years. This industry is already familiar with use of its low-cost residues ("hog" fuel and even a waste product called "black liquor") for generation of electricity and heat for its processing needs. The higher efficiency of gasification-based systems would bolster this self-generation (offsetting the need for increased electricity purchases from the grid) and perhaps allow sales of electricity to the grid. The industry is also investigating the use of black liquor gasification in combined cycles to replace the aging fleet of kraft recovery boilers.

An even more near-term and low-cost option for the use of biomass is co-firing with coal in existing boilers. Co-firing biomass with coal has the potential to produce 10 to 20 GW in the next twenty years. Though the current substitution rate is negligible, a rapid expansion is possible using wood residues (urban wood, pallets, secondary manufacturing products) and dedicated feedstock supply systems such as willow, poplar and switchgrass.

Resource Issues

Nationally, there appears to be a generous fuel supply. However, the lack of an infrastructure to obtain fuels and the current lack of demonstrated technology to combust or gasify new fuels currently prevents utilization of much of this supply. According to researchers at Princeton University, of the total U.S. biomass residues available, half could be economically used as fuel. They estimate that of the 5 exajoules (4.75 quads) of recoverable residues per year, one third are made up of agricultural wastes and two thirds composed of forestry products industry residues (60% of which are mill residues). Urban wood and paper waste, recoverable in the amount of 0.56 EJ per year, will also be an important source. Pre-consumer biomass waste is also of increasing interest to urban utilities seeking fuels for co-firing, and such use also provides a useful service to the waste producer.

In the Southeast, biomass resources are plentiful, with 91.8 Tg of biomass fuel produced annually according to a study done in the mid-1980s by the Southeast Regional Biomass Energy Program. This translates to an estimated potential of 2.3 EJ of annual energy. North Carolina and Virginia are the biggest wood fuel producers (10.4 and 10.1 Tg, respectively). These residues come primarily from logging applications, culls and surplus growth, and are in the form of whole tree chips. In the western U.S., California is another major user of biomass energy. The California biomass market grew from about 0.45 Tg in 1980 to about 5 Tg in the early 1990s. Feedstocks include mill residues, in-forest residues, agricultural wastes and urban wood waste.

Worldwide, biomass ranks fourth as an energy resource, providing approximately 14% of the world's energy needs. In developing countries, biomass accounts for approximately 35% of the energy used, and in the rural areas of these nations, biomass is often the only accessible and affordable source of energy [1,2]. There is much optimism that biomass will continue to play a significant, and probably increasing, role in the world's future energy mix. The basis

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF BIOMASS TECHNOLOGIES

for this optimism stems from: (1) the photosynthetic productivity of biomass (conservatively an order of magnitude greater than the world's total energy consumption); (2) the fact that bioenergy can be produced and used in a clean and sustainable manner; and (3) continuing advancements in biomass conversion technologies along several fronts. Increased bioenergy use, especially in industrialized countries, will depend on greater exploitation of existing biomass stocks (particularly residues) and the development of dedicated feedstock supply systems.

Because the future supply of biomass fuels and their prices can be volatile, many believe that the best way to ensure future fuel supply is through the development of dedicated feedstocks. Large-scale dedicated feedstock supply systems designed solely for use in biomass power plants do not exist in the U.S. today on a commercial basis. The DOE Biomass Power Program (BPP) recognizes this fact, and a major part of the commercial demonstration program directly addresses dedicated feedstock supply issues. The 'Biomass Power for Rural Development' projects in New York (willow), Iowa (switchgrass), and Minnesota (alfalfa) are developing the commercial feedstock infrastructure for dedicated feedstocks. The Minnesota Valley alfalfa producers project will involve the production of 700,000 tons/yr of alfalfa on 101,000 hectares (250,000 acres) of land. Unused agricultural lands in the U.S. (31.6 million ha in 1988) are primary candidates for tree plantations or herbaceous energy crops. About 4% of the land within an 80 km radius could supply a 100 MW plant operating at 70% capacity. Although, there are requirements for water, soil type and climate that will restrict certain species to certain areas, an assured regional fuel supply can reduce variability in prices.

Oak Ridge National Laboratory also has an extensive feedstock development and resource assessment program that is closely integrated with the DOE BPP. ORNL is responsible for development and testing of the switchgrass and hybrid poplar species that are receiving intense interest by not only the commercial power project developers, but also the forest products industry.

Although not directly applicable, there are numerous examples in the agriculture and pulp and paper industries that serve to illustrate the feasible size of sustainable commercial biomass operations. There are over fifty pulp and paper mills in the U.S. that produce more than 500,000 tons/yr of product [3]. The feed into such plants is at least one third higher than the product output, with the additional increment being used for internal power and heat generation. The sugarcane industry also routinely harvests, transports, and processes large quantities of biomass. In the U.S. alone, more than a dozen sugar mills each process more than 1.3 million tons of cane per year, including four plants in Florida that process more than 2.25 million tons/yr [4]. Sweden and the other Scandinavian countries have long been leaders in the biomass energy arena. Currently, Sweden has over 16,500 hectares of farmland planted in willow for energy use. The market for woody biomass for energy in Sweden has experienced strong growth, with a steady increase equivalent to 3-4 TWh extra each year for the last five years. This equals one nuclear power station in aggregate every two years. Additionally, Denmark annually produces roughly 7 million tons of wheat straw that cannot, by law, be burned in-field. This straw is increasingly being used for energy production. Thus, there is ample evidence that agricultural, harvest, transport, and management technologies exist to support power plants of the size contemplated.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF BIOMASS TECHNOLOGIES

Environmental Issues

Two primary issues that could create a tremendous opportunity for biomass are: (1) global climate change and (2) the implementation of Phase II of Title IV of the Clean Air Act Amendments of 1990 (CAAA). Biomass offers the benefit of reducing NO_x, SO_2, and CO_2 emissions. The environmental benefits of biomass technologies are among its greatest assets. The first issue, global climate change, is gaining greater salience in the scientific community. There now appears to be a consensus among the world's leading environmental scientists and informed individuals in the energy and environmental communities that there is a discernable human influence on the climate, and that there is a link between the concentration of carbon dioxide (i.e., greenhouse gases) and the increase in global temperatures. The recognition of this link is what led to the signing of the Global Climate Change treaty. Co-firing biomass with fossil fuels and the use of integrated biomass-gasification combined cycle systems can be an effective strategy for electric utilities to reduce their emissions of greenhouse gases.

The second issue, the arrival of Phase II emission requirements, could also create a number of new opportunities for biomass to be used more widely in industrial facilities and electric power generating units. The key determinant will be whether biomass fuels offer the least expensive option for a company when compared to the installation of pollution control equipment or switching to a "cleaner" fossil fuel.

The second, and more restrictive, phase of the CAAA goes into effect in 2000. CAAA is designed to reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x), that make up acid rain, and are primarily emitted by fossil-fuel powered generating stations. The first phase of CAAA affects the largest emitters of SO_2 and NO_x, while the second phase will place tighter restrictions on emissions not only from these facilities, but also from almost all fossil-fuel powered electric generators of 25 MW or greater, utilities and non-utilities alike. The impact of Phase II will be tempered by the fact that most of the utilities that had to comply with Phase I chose to over comply, thereby creating a surplus of allowances for Phase II use. The planned strategies for compliance by utilities suggest that fuel switching will be the compliance of choice. Fuel switching will be primarily to low sulfur coal. Other strategies include co-firing with natural gas, purchasing of allowances, installing scrubbers, repowering of existing capacity, and retirement of existing capacity. An opportunity exists for biomass, especially if credit is given for simultaneous reduction in greenhouse gases.

Use of biomass crops also has the potential to mitigate water pollution. Since many dedicated crops under consideration are perennial, soil disturbance, and thus erosion can be substantially reduced. The need for agricultural chemicals is often lower for dedicated energy crops as well leading to lower stream and river pollution by agri-chemical runoff.

References

1. McGowan, F., "Controlling the Greenhouse Effect--the Role of Renewables," Energy Policy, March 1991, p. 111-118.

2. Hall, D.O., F. Rosillo-Calle, and P. de Groot, "Biomass Energy--Lessons from Case Studies in Developing Countries," Energy Policy, January 1992, p. 62-73.

3. Pulp and Paper 1996 North American Fact Book, Miller Freeman, San Francisco, CA, 1995. ISBN10-87930-4219.

4. Gilmore Sugar Manual, 1994/95, Sugar Publications, Fargo, ND, 1994.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

Northwest Power Planning Council
New Resource Characterization for the Fifth Power Plan

Wind Power Plants

August 27, 2002

This paper describes the technical characteristics and cost and performance assumptions to be used by the Northwest Power Planning Council for new wind power plants. The intent is to characterize a typical facility, recognizing that actual facilities can differ from these assumptions. This is particularly true of wind power projects. Energy production is sensitive to the quality of the wind resource and costs are sensitive to location and size of a wind farm. The value of energy from a wind power plant is a function of the seasonal and daily variations of the wind. The assumptions that follow will be used in our price forecasting and system reliability models and in the Council's periodic assessments of system reliability. The Council may also use these assumptions in the assessment of other issues where generic information concerning wind power plants is needed. Others may use the Council's technology characterizations for their own purposes.

Wind energy is converted to electricity by wind turbine generators. A wind turbine generator is a tower-mounted electric generator driven by rotating airfoils. Because of the low energy density of wind, bulk electricity production from wind power requires tens or hundreds of wind turbine generators arrayed in a wind power plant. A wind power plant (often called a "wind farm") includes meteorological towers, strings of wind turbine generators, turbine service roads, a control system interconnecting individual turbines with a central control station (often remote), a voltage transformation and transmission system connecting the individual turbines to a central substation, a substation to step up voltage for long-distance transmission and an electrical interconnection to the main transmission grid. On-site service buildings may be provided.

The typical wind turbine generator being installed in commercial-scale projects is a horizontal axis machine of 600 to 1500 kilowatts capacity with a three-bladed rotor 150 to 250 feet in diameter. The machines are mounted on tubular towers currently ranging to over 250 feet in height. Trends in machine design include improved airfoils; larger machines; taller towers and improved controls. Improved airfoils increase energy capture. Larger machines provide economies of manufacturing, installation and operation. Because wind speed generally increases with elevation above the surface, taller towers and larger machines intercept more energy. Turbine size has increased rapidly in recent years and multi-megawatt (2000 - 2750kW) machines are being introduced. These machines are likely to see initial service in European offshore applications.

Many of the issues that formerly impeded the development of wind power have been resolved in recent years, clearing the way for the significant development that has occurred in the Northwest. Concerns regarding avian mortality, aesthetic and cultural impacts have been alleviated by the choice of dry land agricultural areas for project development. The resulting land rent revenue has also garnered political support from the agricultural community. The impact of wind machines on birds, which has been significant at certain wind development sites has been reduced by better understanding of the interrelationship of birds, habitat and wind turbines. The resulting improvements in turbine design (e.g., tubular towers), choice of project locations and siting of individual turbines have resulted in low rates of avian mortality at recently developed projects.

Though per-kilowatt installed costs of wind power plants have not greatly declined in recent years, turbine performance, reliability, site selection and turbine micro-siting have improved. This has increased the efficiency of energy conversion and thereby reduced energy production costs. The resulting busbar energy production costs at the better sites are in the range of **4 to 5** cents per kilowatt-hour. However, because wind is an intermittent resource, to these costs must be added the costs of shaping and firming, and, if the site is remote from load centers, the cost of long-distance transmission, which can be especially high for wind because of its relatively low capacity factor.

Though the cost of energy from wind power plants is not yet economically competitive with the average energy production costs of gas-fired combined-cycle plants, wind power has benefited from a variety of economic incentives, leading to unprecedented development of wind power in certain regions, notably Minnesota, Texas and the Pacific Northwest. The most important incentive is the federal production tax credit, currently about $18/MWh, available for the first ten years of project operation. Complementing the production tax credit have been energy premiums resulting from the robust market for “green” power that has developed in recent years. This market is driven by retail green power offerings, utility efforts to diversify and “green up” resource portfolios, green power acquisition mandates imposed by public utility commissions as a condition of utility acquisitions, renewable portfolio standards and system benefits funds established in conjunction with industry restructuring.

In spite of the recent wind power development activity, issues affecting continued development of the resource remain. Wholesale power costs are currently low and are anticipated to remain so for several years. The cost of firming and shaping wind farm output to serve load are not well understood and can be substantial. While it appears possible that several hundred megawatts of wind power can be shaped at relatively low cost using the Northwest hydropower system, the cost of firming and shaping additional amounts of wind energy are uncertain, pending further operating experience and analysis. In addition, wind power, because of its intermittency, has been subject to generation imbalance penalties intended to constrain gaming by operators of schedulable thermal resources. The Bonneville Power Administration has recently exempted wind power from imbalance penalties for a period of one year. The issue has received considerable publicity and is likely to be addressed in federal energy legislation and discussions of future transmission management. Northwest wind development to date has not required expansion of transmission capacity, which can be expensive for wind because of its relatively low capacity factor. However, the availability of prime sites with easily accessible surplus transmission capacity is limited. Finally, the competitive position of wind power remains dependent upon the federal production tax credit

The first commercial-scale wind plant in the Northwest using contemporary technology is the 25 MW Vansycle project in Umatilla County, Oregon. Since Vansycle entered service in late 1998, four additional wind projects have been placed in service or are under construction. Now in operation or under construction within the region are 412 megawatts of wind capacity, producing about 130 average megawatts of energy. In addition, Northwest utilities have contracted for 110 megawatts of capacity, producing about 44 megawatts of energy from the Rock River and Foote

Creek projects in Wyoming. Northwest wind farms range from 25 to 265 megawatts capacity. These projects are comprised of 16 to nearly 400 machines, ranging in size from 600 to 1500 kilowatts capacity. Several of the project sites are capable of expansion and additional sites have been proposed for development.

Northwest Power Planning Council
New Resource Characterization for the Fifth Power Plan

Coal-fired Power Plants

August 19, 2002

This paper describes the technical characteristics, cost and performance assumptions used by the Northwest Power Planning Council for new coal-fired power plants. The intent is to characterize a reasonably typical facility, recognizing that any actual new plant could differ from these assumptions in many respects. These assumptions will be used in our price forecasting and system reliability models and in the Council's periodic assessments of system reliability. The Council may also use these assumptions in the assessment of other issues where generic information concerning coal-fired power plants is needed. Others use the Council's technology characterizations for their own purposes.

Coal-fired steam-electric power plants are a mature technology in use for over a century. Coal-fired power plants are the major source of power in the east and the second largest power supply component of the western grid. Currently, over 36,000 megawatts of coal steam-electric power plants are in service on the western electricity grid, comprising about 23% of generating capacity. In recent years the economic and environmental advantages of combined-cycle gas turbines, low load growth and promise of advanced coal-based technologies with superior efficiency and environmental characteristics eclipsed coal-fired steam-electric technology for new resource development in North America. Since 1990, less than 500 megawatts of coal-fired steam electric plant entered service on the western grid.

The future prospects for coal-fired steam-electric power plants may be changing. The economic and environmental characteristics of coal-fired steam-electric power plants have greatly improved and show evidence of continuing evolutionary potential for improvement. These factors, combined with the prospect of stable or declining coal prices may reinvigorate the competition between coal and natural gas and lessen the near-term prospects for revolutionary coal-based technologies.

The capital cost of coal-fired steam-electric plants has declined about 25% in constant dollars since the early 1990s with little or no sacrifice to thermal efficiency or reliability. Environmental performance has improved. This reduction in cost is attributable to plant performance improvements, automation and reliability improvements, equipment cost reduction, reduced construction schedule, and increased market competition (DOE, 1999). Coal prices also have declined during this period as a result of stagnant demand and productivity improvements in mining and transportation. By way of comparison, the Council's 1991 power plan estimated the overnight capital cost of a new coal-fired steam-electric plant to be $1775/kW and the cost of Powder River coal at $0.68/MMBtu (year 2000 dollars). The comparable capital and fuel costs proposed for the Fifth Power Plan are $1230/kW and $0.71/MMBtu, respectively.

Though the economics have improved, many issues associated with development of coal-fired power plants remain. The issues cited in the Fourth Power Plan - air quality impacts, carbon dioxide production, water impacts, solid waste production, site availability, coal transportation, electric power transmission and impacts of coal mining and transportation - remain significant

A conventional steam-electric coal-fired power plant consists of coal handling equipment, a steam generator, a steam turbine-generator, flue gas treatment equipment and stack, ash handling system, condenser cooling system, switchyard and transmission interconnection. Typically, two to four units of similar design will be located at a site to take advantage of economies of design, construction and operation. In the west, coal-fired plants have generally been sited near the mine-mouth, or at intermediate locations between mine-mouth and load centers having good rail and transmission access.

The proposed reference plant is a 400 megawatt pulverized coal-fired unit of subcritical steam cycle design, co-located with several similar units. The plant would be equipped with low-NOx burners and selective catalytic reduction for control of nitrogen oxides. The plant would also be equipped with flue gas desulfurization, fabric filter particulate control and activated charcoal injection for additional reduction of mercury emissions. Because the Council forecasts delivered coal prices for specific geographic areas, some of which could host mine-mouth plants and others that would require rail delivery of coal, the base case does not distinguish between fuel supply methods. The estimated costs include a shared local switchyard and transmission interconnection, but do not include dedicated long-distance transmission facilities that might be required for some plant sites (the cost of long-distance transmission is captured elsewhere in the Council's models).

The base case plant uses evaporative (wet) condenser cooling. Dry cooling uses less water, and other factors equal, might be more suitable for arid areas of the West where new coal-fired power plants might be located. But dry cooling reduces the thermal efficiency of a steam-electric plant by about 10 percent, and proportionally increases per-kilowatt air emissions and carbon dioxide production. The effect is about three times greater for steam-electric plants than for gas turbine combined-cycle power plants, where recent proposals have trended toward dry condenser cooling. For this reason, we assume that the majority of new coal-fired power plants, if developed, would be located in areas where water availability is not critical and would use evaporative cooling.

Specific proposals for new coal-fired power plants could differ substantially from this case. These differences can significantly affect the cost and performance. Important variables include the steam cycle, method of condenser cooling, transmission interconnection, the level of equipment redundancy and reliability desired, unit number and size, level of air emission control, the type of coal used and method of delivery.

Advanced coal technologies, including supercritical steam cycles, atmospheric fluidized bed combustion, pressurized fluidized bed combustion and coal gasification offer higher thermal efficiency, improved control of air emissions and reduced water consumption. Supercritical units are widely used in Europe and Japan. Many were installed in North America in the 1960s and 70s but more recent installations are uncommon because of low coal costs and poor reliability associated with early units. Recent European and Japanese experience has been satisfactory (World Bank, 1999). Atmospheric fluidized bed technology is in commercial use, but has been generally limited to smaller units using waste or low-grade coal. Coal gasification has been commercially employed in the petrochemical industry, but electric power applications are in the demonstration phase. Both coal gasification and pressurized fluidized bed combustion designs would offer the benefits of highly-efficient gas turbine combined-cycle technology, but to date have been limited by lack of cost-effective and reliable product gas cleanup technology. The generally superior competitive position of natural gas has been a major factor impeding more widespread adoption of advanced coal technologies. If more aggressive attempts at reducing carbon dioxide production are made, advanced coal technologies will be increasingly attractive because of superior energy conversion efficiency.

References

DOE (1999): US Department of Energy. *Market-based Advanced Coal Power Systems*. March 1999.

EIA (2001): US Department of Energy, Energy Information Administration. *Assumptions to the Annual Energy Outlook 2002*. December 2001.

Kitto (1996): Kitto, J. B. Developments in Pulverized Coal-fired Boiler Technology. Babcock & Wilcox, April 1996.

UN (2002): United Nations Environmental Programme. Global Mercury Assessment Report (1st Draft). April 2002.

World Bank (1998): Technologies for Reducing Emissions in Coal-fired Power Plants. *Energy Issues* No 14, August 1998.

World Bank (1999): Supercritical Coal-fired Power Plants. *Energy Issues* No 19, April 1999.

Northwest Power Planning Council
New Resource Characterization for the Fifth Power Plan

Natural Gas Combined-cycle Gas Turbine Power Plants

August 27, 2002

This paper describes the technical characteristics and cost and performance assumptions to be used by the Northwest Power Planning Council for new natural gas combined-cycle gas turbine power plants. The intent is to characterize a facility typical of those likely to be constructed in the Western Electricity Coordinating Council (WECC) region over the next several years, recognizing that each plant is unique and that actual projects may differ from these assumptions. These assumptions will be used in our price forecasting and system reliability models and in the Council's periodic assessments of system reliability. The Council may also use these assumptions in the assessment of other issues where generic information concerning natural gas combined-cycle power plants is needed. Others may use the Council's technology characterizations for their own purposes.

A combined-cycle gas turbine power plant consists of one or more gas turbine generators equipped with heat recovery steam generators to capture heat from the gas turbine exhaust. Steam produced in the heat recovery steam generators powers a steam turbine generator to produce additional electric power. Use of the otherwise wasted heat in the turbine exhaust gas results in high thermal efficiency compared to other combustion-based technologies. Combined-cycle plants currently entering service can convert about 50 percent of the chemical energy of natural gas into electricity (HHV basis[1]). Additional efficiency can be gained in combined heat and power (CHP) applications (cogeneration), by bleeding steam from the steam generator, steam turbine or turbine exhaust to serve direct thermal loads[2].

A single-train combined-cycle plant consists of one gas turbine generator, a heat recovery steam generator (HSRG) and a steam turbine generator ("1 x 1" configuration). Using "FA-class" combustion turbines - the most common technology in use for large combined-cycle plants - this configuration can produce about 270 megawatts of capacity at reference ISO conditions[3]. Increasingly common are plants using two or even three gas turbine generators and heat recovery steam generators feeding a single, proportionally larger steam turbine generator. Larger plant sizes result in economies of scale for construction and operation, and designs using multiple combustion turbines provide improved part-load efficiency. A 2 x 1 configuration using FA-class technology will produce about 540 megawatts of capacity at ISO conditions. Other plant components include a switchyard for electrical interconnection, cooling towers for

[1] The energy content of natural gas can be expressed on a higher heating value or lower heating value basis. Higher heating value includes the heat of vaporization of water formed as a product of combustion, whereas lower heating value does not. While it is customary for manufacturers to rate equipment on a lower heating value basis, fuel is generally purchased on the basis of higher heating value. Higher heating value is used as a convention in Council documents unless otherwise stated.
[2] Though increasing overall thermal efficiency, steam bleed for CHP applications will reduce the electrical output of the plant.
[3] International Organization for Standardization reference ambient conditions: 14.7 psia, 59^{o} F, 60% relative humidity.

cooling the steam turbine condenser, a water treatment facility and control and maintenance facilities.

Additional peaking capacity can be obtained by use of various power augmentation features, including inlet air chilling and duct firing (direct combustion of natural gas in the heat recovery steam generator). For example, an additional 20 to 50 megawatts can be gained from a single-train plant by use of duct firing. Though the incremental thermal efficiency of duct firing is lower than that of the base combined-cycle plant, the incremental cost is low and the additional electrical output can be valuable during peak load periods.

Gas turbines can operate on either gaseous or liquid fuels. Pipeline natural gas is the fuel of choice because of historically low and relatively stable prices, deliverability and low air emissions. Distillate fuel oil can be used as a backup fuel, however, its use for this purpose has become less common in recent years because of additional emissions of sulfur oxides, deleterious effects on catalysts for the control of nitrogen oxides and carbon monoxide, the periodic testing required to ensure proper operation on fuel oil and increased turbine maintenance associated with fuel oil operation. It is now more common to ensure fuel availability by securing firm gas transportation.

The principal environmental concerns associated with gas-fired combined-cycle gas turbines are emissions of nitrogen oxides (NOx) and carbon monoxide (CO). Fuel oil operation may produce sulfur dioxide. Nitrogen oxide abatement is accomplished by use of “dry low-NOx” combustors and a selective catalytic reduction system within the HSRG. Limited quantities of ammonia are released by operation of the NOx SCR system. CO emissions are typically controlled by use of an oxidation catalyst within the HSRG. No special controls for particulates and sulfur oxides are used since only trace amounts are produced when operating on natural gas. Fairly significant quantities of water are required for cooling the steam condenser and may be an issue in arid areas. Water consumption can be reduced by use of dry (closed-cycle) cooling, though with cost and efficiency penalties. Gas-fired combined-cycle plants produce less carbon dioxide per unit energy output than other fossil fuel technologies because of the relatively high thermal efficiency of the technology and the high hydrogen-carbon ratio of methane (the primary constituent of natural gas).

Because of high thermal efficiency, low initial cost, high reliability, relatively low gas prices and low air emissions, combined-cycle gas turbines have been the new resource of choice for bulk power generation for well over a decade. Other attractive features include significant operational flexibility, the availability of relatively inexpensive power augmentation for peak period operation and relatively low carbon dioxide production. Combined-cycle power plants are an increasingly important element of the Northwest power system, comprising about 87 percent of generating capacity currently under construction. Completion of plants under construction will increase the fraction of gas-fired combined-cycle capacity from 6 to about 11 percent of total regional generating capacity.

Proximity to natural gas mainlines and high voltage transmission is the key factor affecting the siting of new combined-cycle plants. Secondary factors include water availability, ambient air quality and elevation. Initial development during the current construction cycle was located largely in eastern Washington and Oregon with particular focus on the Hermiston, Oregon crossing of the two major regional gas pipelines. Development activity has shifted to the I-5 corridor, perhaps as a response to east-west transmission constraints and improving air emission controls.

Issues associated with the development of additional combined-cycle capacity include uncertainties regarding the continued availability and price of natural gas, volatility of natural gas prices, water consumption and carbon dioxide production. A secondary issue has been the ecological and aesthetic impacts of natural gas exploration and production. Though there is some evidence of a decline in the productivity of North American gas fields, the continental supply appears adequate to meet needs at reasonable price for at least the 20-year period of the Council's power plan. Importation of liquefied natural gas from the abundant resources of the Middle East and the former Soviet states and could enhance North American supplies and cap domestic prices. The Council forecasts that US wellhead gas prices will escalate at an annual rate of about 0.9% (real) over the period 2002 - 21. Though expected to remain low, on average, natural gas prices have demonstrated both significant short-term volatility and longer-term, three to four year price cycles. Both effects are expected to continue. Additional discussion of natural gas availability and price is provided in the Council issue paper Draft Fuel Price Forecasts for the Fifth Power Plan (Document 2002-07). The conclusions of the paper with respect to natural gas prices are summarized in Appendix A of this document.

Water consumption for power plant condenser cooling appears to be an issue of increasing importance in the west. As of this writing, water permits for two proposed combined-cycle projects in northern Idaho have been recently denied, and the water requirement of a proposed central Oregon project is highly controversial. Significant reduction in plant water consumption can be achieved by the use of closed-cycle (dry) cooling, but at a cost and performance penalty. Over time it appears likely that an increasing number of new combined-cycle projects will use dry cooling.

Carbon dioxide, a greenhouse gas, is an unavoidable product of combustion of any power generation technology using fossil fuel. The carbon dioxide production of a gas-fired combined-cycle plant on a unit output basis is much lower than that of other fossil fuel technologies. The reference plant, described below, would produce about 0.8 lb CO_2 per kilowatt-hour output, whereas a new coal-fired power plant would produce about 2 lb CO_2 per kilowatt-hour. To the extent that new combined-cycle plants substitute for existing coal capacity, they can substantially reduce average per-kilowatt-hour CO_2 production.

The proposed reference plant is based on the General Electric 7FA gas turbine generator in 2 x 1 combined-cycle configuration. The baseload capacity is 540 megawatts and the plant includes an additional 70 MW of power augmentation using duct burners. The plant is fuelled with pipeline natural gas using a firm gas transportation contract with capacity release provision. No backup fuel is provided. Air emission controls include dry low-NOx combustors and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC control. Condenser cooling is wet mechanical draft.

Northwest Power Planning Council
New Resource Characterization for the Fifth Power Plan

Natural Gas Simple-cycle Gas Turbine Power Plants

August 27, 2002

This paper describes the technical characteristics and cost and performance assumptions to be used by the Northwest Power Planning Council for new natural gas simple-cycle gas turbine power plants. The intent is to characterize a typical facility, recognizing that actual facilities will likely differ from these assumptions in the particulars. These assumptions will be used in our price forecasting and system reliability models and in the Council's periodic assessments of system reliability. The Council may also use these assumptions in the assessment of other issues where generic information concerning natural gas simple-cycle power plants is needed. The Council's technology characterizations are available to others for their own purposes.

A simple-cycle gas turbine generator set consists of a gas compressor, fuel combustors and a gas turbine. Air is compressed in the gas compressor. Energy is added to the compressed air by combusting liquid or gaseous fuel in the combustor and the hot, compressed air is expanded through the gas turbine. The gas turbine drives both the compressor and an electric power generator.

Gas turbine power plants are available as heavy-duty "frame" machines specifically designed for stationary applications, or as aeroderivative machines - aircraft engines adapted to stationary applications. Because of higher rotor speeds and pressure (compression) ratios, aeroderivative machines are more efficient and compact than frame machines, but are more costly to purchase than frame machines. Aeroderivative machines exhibit excellent operational flexibility with superior black start capability, short run-up periods, capability for overpower operation (at a shortening of maintenance intervals, however) and ability to trade off higher power operation at low ambient temperatures for overpower operation at high ambient temperatures (constant power operation). Aeroderivative machines are highly modular and major maintenance is often accomplished by swapping out the engine for a replacement, shortening maintenance outages. Both frame and aeroderivative stationary gas turbine technology development is strongly driven by developments in military and aerospace gas turbine applications.

A typical simple-cycle gas turbine power plant consists of one to several gas turbine generator sets. The generator sets are typically equipped with inlet air filters and exhaust silencers. Water or steam injection, intercooling or inlet air cooling can be used to increase power output. Steam injection requires a heat recovery steam generator. Increasingly, exhaust gas catalysts are used to reduce nitrogen oxide and carbon monoxide production. Other plant components may include a switchyard for electrical interconnection, fuel gas compressors (if line pressure is inadequate for the gas turbine generator) a water treatment facility (if units are equipped with water or steam injection) and control and maintenance facilities. Simple-cycle gas turbine generators are often co-located with gas-fired combined-cycle plants to take advantage of shared site infrastructure and operating crew.

Gas turbines can operate on either gaseous or liquid fuels, however pipeline natural gas is the fuel of choice because of historically low and relatively stable prices and low air emissions. Though still occasionally used, distillate fuel oil is has become less common as backup fuel in recent years because of environmental concerns, the periodic turbine testing required to ensure proper operation on fuel oil and increased maintenance associated with fuel oil operation. It is now more common to ensure fuel availability by securing firm gas transportation. A few plants have used propane as backup fuel.

The principal environmental concerns associated with simple-cycle gas turbines are emissions of nitrogen oxides (NOx) and carbon monoxide (CO). Noise has been a concern at sites near residential and commercial areas. Fuel oil operation may produce sulfur dioxide. Within the past decade, the commercial introduction of “low-NOx” combustors and high temperature selective catalytic controls for NOx and CO, has enabled the control of NOx and CO emissions from simple-cycle gas turbines to levels comparable to combined-cycle power plants. Water is required for water or steam injection but is not usually an issue for simple-cycle machines because of relatively low consumption. Gas-fired simple-cycle plants produce moderate levels of carbon dioxide per unit energy output because of the moderate thermal efficiency of the technology and the high hydrogen-carbon ratio of methane (the primary constituent of natural gas).

Because of the ability of the Northwest hydropower system to supply short-term peaking capacity, simple-cycle gas turbines have been a minor element of the regional power system. As of January 2000, about 900 megawatts of simple-cycle gas turbine capacity were installed in the Northwest, comprising less than 2% of system capacity. The power price excursions, threats of shortages and abnormally poor hydro conditions of 2000 and 2001 sparked a renewed interest in simple-cycle turbines as a hedge against high power prices, shortages and poor water. About 360 megawatts of simple-cycle gas turbine capacity has been installed in the region since 2000, primarily by large industrial consumers exposed to wholesale power prices and by utilities with direct exposure to hydropower uncertainty (including Bonneville “Slice” customers).

The proposed reference plant is generally based on a large aeroderivative gas turbine generator such as the General Electric LM6000, Pratt & Whitney FT-8 or Rolls-Royce RB211. The rated capacity of these machines ranges [up to] 48 megawatts. Recently-developed simple-cycle projects in the Northwest have tended to use smaller machines, though this is believed to be an artifact of machine availability and permitting requirements. Fuel is assumed to be pipeline natural gas. A firm gas transportation contract with capacity release capability is assumed, in lieu of backup fuel. Air emission controls include dry low-emissions combustors plus selective catalytic reduction for NOx control and an oxidation catalyst for CO control. Costs are representative of a machine located at an existing gas-fired power plant site, or two or more machines located at a greenfield site. Fuel gas delivery pressure is assumed to sufficient to not require additional compression.

References:

GE (2000): General Electric Power Systems. *GE Aeroderivative Gas Turbines - Design*.

APPENDIX H

PUGET SOUND ENERGY

FINAL REPORT

Assessment and Report on Self-Build Generation Alternative for Puget Sound Energy's 2002-2003 Least Cost Plan

Prepared by Tenaska, Inc.
Omaha, Nebraska

March 2003

Tenaska, Inc.
Assessment and Report on Self-Build Generation Alternative for Puget Sound Energy's 2002-2003 Least Cost Plan

Table of Contents

Disclaimer

Section 1 – Introduction

Tenaska, Inc. (Tenaska) is pleased to provide this document for use in Puget Sound Energy's (PSE's) 2002-2003 Least Cost Plan. As part of its resource planning process, PSE retained Tenaska to prepare an assessment and report on alternatives for generation project self-development by PSE. Tenaska has extensive knowledge and experience as a developer of new electric generating facilities, including siting, permitting, design, major equipment procurement, and construction management for over 9,000 megawatts (MW) of project capacity. Tenaska also provides operations and maintenance services for all six of its domestic, operating projects and will provide similar services for three more domestic projects which are currently under construction. This experience includes development, ownership and operation of a combined-cycle facility near Ferndale, WA.

Natural gas-fired, combined-cycle combustion turbine technology is the most common type of new electric generation resource now being developed in North America. PSE could potentially acquire long-term power supplies from this type of resource under several alternative mechanisms, including: (a) self-building a project at a greenfield site; (b) purchasing and completing a project that is partially-developed; or (c) purchasing power output from a project that is owned by a third party. Comparison of the advantages and disadvantages of these three alternative resource acquisition methods is beyond the scope of this report. However, information provided in this report may be useful for comparing the self-build alternative with other methods of acquiring power from natural gas-fired, combined-cycle resources.

Following this Introduction, the discussion provides more detailed information on various aspects of self-development including project design, siting, permitting, equipment procurement, project construction, startup, operation and maintenance. Estimates of project development costs and time schedules are also provided. A brief overview of current market conditions affecting the price and availability of combustion turbines and other prime mover equipment, as well as similar information for EPC (engineering, procurement and construction) contractor services is also provided.

Section 2 – Report Approach

Tenaska's assignment for this report can be summarized as follows:

- identify and screen a range of potential sites;
- narrow the potential sites to a short list of leading candidates;
- describe possible project configurations;
- estimate project permitting and construction costs and schedules;
- estimate non-fuel project operating costs; and

- finally integrate all project performance and cost characteristics to estimate total resource costs of a hypothetical self build option.

For costing purposes, the primary focus of this report is to identify representative “reference” costs under market conditions that are relatively stable. Tenaska also discusses recent industry events that have caused actual EPC and equipment prices to vary from “equilibrium” levels. The report uses a bottom-up approach to develop cost estimates, including breakout of costs into major categories. A standardized format, or “template” is used to present the cost estimates for “generic” plants. Actual costs are very project-specific; we have used our experience and judgment to customize these generic estimates to several project configurations for two PSE sites possibilities. This template can then be used to evaluate specific self-build project development opportunities in a systematic, consistent fashion as such opportunities arise in PSE’s ongoing resource identification and evaluation process.

The focus for this report is to develop estimates of capital costs and non-fuel operating and maintenance costs for the self-build alternative. Topics such as capital structures that might be used to finance a self-build project and forecasts of costs for natural gas supply to fuel a project do not receive extensive attention in this report. While total power, or PSE “resource,” costs are estimated at several points, many financial, macro economic and energy market parameters need to be consistent with those used in the analysis of other PSE resource alternatives before final least cost comparisons can be reached.

Finally, this report does not draw conclusions about which site or sites PSE might actually select to construct a generating project. Instead, the purpose of this report is to assess and develop reasonable estimates of costs, permitting, schedules and other project development considerations. Any decision to proceed with self-build development of a generation project by PSE would require more specific and detailed analysis. As indicated above, such a project would also have to be shown to be consistent with PSE’s least cost electric resource plan and preferable to other available alternatives.

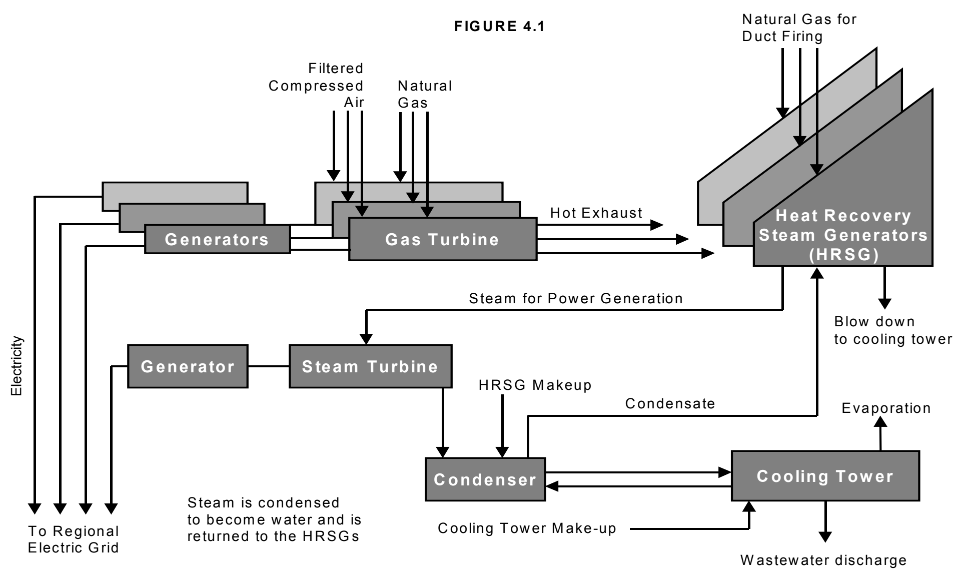
Section 3 – Basic Project Configurations

Gas-fired power plants can be separated into two basic types depending on their intended market service. "Peaking units" operate and produce electricity only during periods of high electricity demand. These peak demand periods generally occur during the extreme hot spells of summer and extreme cold spells in the winter. "Baseload units," on the other hand, generally operate full time. For gas turbine (GT) power plants, peaking units are usually comprised of simple cycle GT’s and baseload units are usually comprised of GT’s operating in combined cycle with one or more steam turbines (ST’s).

A simple cycle gas turbine is a combustion engine with three major parts: an air compressor, burner(s), and power turbine. In the air compressor, a series of bladed rotors compresses the incoming air from the atmosphere. A portion of this compressed air is then diverted through the burners (also called combustors), where fuel (usually natural gas at pressures of 325 to 500 psig) is burned raising the temperature of the compressed air. This very hot gas is mixed with the rest of the compressed air and directed to the power turbine at temperatures up to 2350°F. In the power turbines, the force of the hot compressed air as it expands pushes another series of blades, rotating a shaft. Greater than 60 percent of the mechanical energy produced by the power turbine is consumed to drive the air compressor. The balance of the mechanical energy turns a generator and makes electricity. The cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is typically in the 30 to 35 percent range.

The difference between simple cycle and combined cycle is that in combined cycle, the hot exhaust gases from the GT do not directly go to the atmosphere. Instead, the hot exhaust gases, which are typically above 1000°F, are ducted through a waste heat boiler (a heat recovery steam generator, or “HRSG”) to generate steam. This steam is then used to drive a steam turbine generator (or “ST”) to make additional electricity. The recovery of the heat energy in the exhaust of a gas turbine in this manner can increase the cycle efficiency of a combined cycle plant to 50 percent or more. The additional electricity that can be produced by a combined cycle installation is accompanied by additional capital costs for the HRSG, ST and a cooling system. However, the operating cost per unit of electricity produced is usually lower compared to that of simple cycle turbines due to the higher energy recovery. Figure 4.1 illustrates the basic components of a combined cycle facility.

FIGURE 4.1



Because it appears that a portion of PSE's need for new resources could be met with base load generation, Tenaska focused on combined cycle plant designs, or "configurations." The cost and performance of combined cycle plants is very dependent on the size and number of the basic GT unit(s) around which the overall plant is designed. These plants are commonly referred to by the number of gas turbines and steam turbines they feature. A "one by one" (1 X 1), for example, represents one gas turbine, paired with one steam turbine/HRSG. Larger plants can be designed as "3 X 1" (three GT's and three HRSG's paired with one larger ST), "4 X 2," and so on.

Initial Results

In June of 2002, Tenaska provided basic performance and cost information for five generic or "reference" combined cycle plants based on two standard General Electric (GE) frame gas turbines (FA's and EA's). Refer to Table 4.1. As indicated, these five plants cover a range of combined cycle capacity from 146 MW (1 X 1 EA) to 893 MW (3 X 1 FA).

The capital and operating costs associated with these plants were our first estimates and feature only very high-level detail. The initial estimates were based on Tenaska's experience with similar projects. The capital and operating costs were "inputs" to an economic model which also added the various financial parameters and assumptions necessary to determine an all-in cost of electricity expressed in $/MWh. PSE provided many of the financial assumptions such that the results reflect a utility's analytic approach and determination of total project cost and revenue requirement rather than that of an IPP developer. The all-in costs shown on Table 3.1 represent the price of electricity needed per MWh, assuming 7884 annual operating hours , to cover fuel, all fixed and variable operating costs, debt service and to earn a return on invested equity. A summary of the results follows:

Table 3.1

Gas Turbine Type	Configuration	MW	Total Capital MM$	Total Capital $/kW	All-In Cost $/MWh
GE 7FA	1 X 1	294	216.4	735	43.07
	2 X 1	593	367.8	620	40.25
	3 X 1	893	490.4	549	38.81
GE 7 EA	1 X 1	146	158.0	1081	53.73
	2 X 1	295	234.4	794	46.91

Figures 4.2 and 4.3 graphically show the results from this high level analysis for all five generic plant configurations. These graphs clearly show how project size impacts cost. Capital costs range from about $1100/kW for the smallest EA-based plant (about 146 MW) to under $600/kW for the largest FA-based plant (about 893 MW). All-in costs in $/MWh range from about $54 to about $38, respectively, over the same range (using common financial assumptions and fuel cost). FA-

FIGURE 4.2
Generic Combined Cycle Plants - All In Cost
June 2002 Results

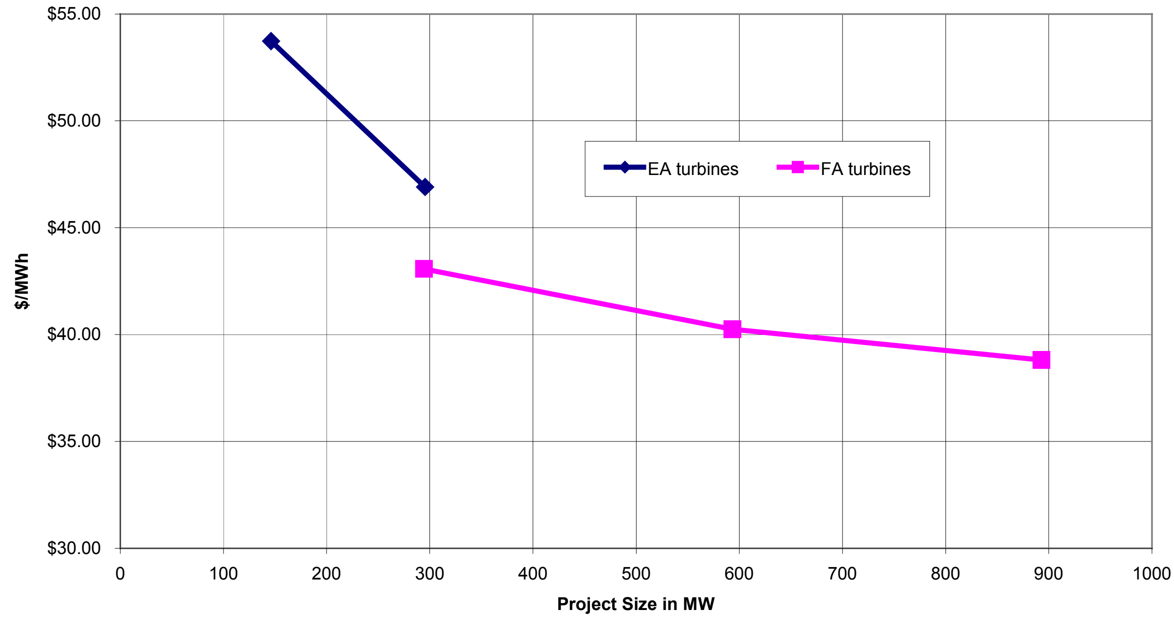
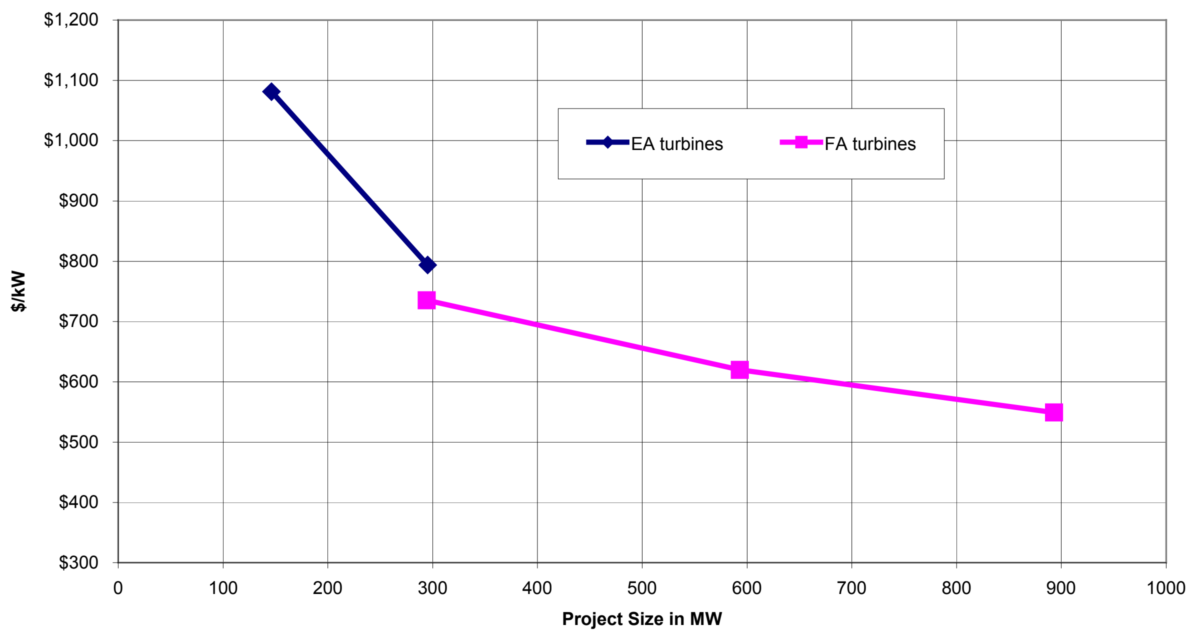


FIGURE 4.3
Generic Combined Cycle Plants - Capital Cost
June 2002 Results



based plants are also clearly more economic than EA technology if resource requirements match this plant size.

Revised and Updated Results

These high level results formed the basis for more detailed analysis of PSE's self-build options and some of the plant design trade-offs which need to be considered. Subsequent to Tenaska's initial work for PSE, which was highlighted above, we increased the level of technical and cost detail for the five original generic plants during a second phase of our assignment which was conducted in November and December of 2002. This analysis includes more detail on the components of capital and operating costs and indicates many of the physical requirements of each generic configuration (fuel use, water requirements, site size, etc.). Once again this data was combined with the requisite economic parameters in a financial model to estimate all-in project costs and revenue requirements, the results of which are discussed in later sections.

Two design issues should be mentioned at least briefly. First is cooling. Refer back to Figure 4.1. When steam exits the steam turbine it is condensed back into water and further cooled to be recirculated through the steam cycle or discharged. "Wet" cooling uses large open towers and evaporation to cool process water while "dry" or "air" cooling condenses steam and passes hot water through large radiator-like facilities in a closed system. Wet cooling has a large raw water requirement, approximately 2 million gallons per day for a generic 1 X 1 on Table 3.1 depending on climatic conditions and technical configuration. Typically more than 80% or so of this raw water is "consumed" due to evaporation. For the same 1X1, dry cooling uses only a small fraction of the daily raw water volume of wet cooling, typically less than 10%, but suffers two disadvantages: efficiency is lower (hence project capacity is reduced by 2-3% or about 6-8 MW at summer conditions) and capital costs are higher (15% more EPC cost or about $10MM). Dry cooling can be an important option, however, if water is not physically available in the quantities required or if environmental or community circumstances restrict its use. Municipal wastewater, if available, is another source of make-up water for a wet cooling system. Additional pretreatment may be required and typically more wastewater is produced also due to the lower quality raw feedwater. The fact that this water is often very low cost (often free), usually offsets the incremental treating and wastewater discharge costs.

The second design issue is duct firing. When ambient temperatures increase, gas turbine output and overall plant output decrease. This loss of output can be more than offset by adding supplemental firing, via "duct burners," to the hot gases passing through the HRSG's into the steam turbine. Typically, combined cycle steam turbines are "over-sized" to accommodate duct firing during such ambient conditions. Over-sized steam turbines do suggest a small cost and efficiency penalty when duct firing is available but not in use. The overriding benefit, however, is that although duct firing adds capital cost, the cost per incremental MW added is quite attractive. For a generic 7FA 1 X 1 on Table 3.1, duct firing adds 38 MW of capacity from 256

MW to 294 MW) and about $6MM, or about $150/kW. Simple cycle peaking plants typically cost about twice this per kW. The incremental heat rate for duct firing is also much lower than the simple cycle peaking alternative (say 9,200 btu/kWh versus 11,000 to 12,000).

Additional output over and above duct firing can also be derived on hot days by inlet air cooling either by evaporative cooling or mechanical refrigeration. Evaporative cooling (or fogging) is the most cost effective technique but gas turbine compressor inlet temperatures are of course limited to the ambient wet bulb temperature. Typically inlet cooling is not placed in service unless ambient dry bulb temperatures exceed 59 degrees F.

Section 4 – Current Status of Equipment and EPC Markets

The largest portion of a combined cycle plant's capital cost is the EPC contract (Engineering, Procurement and Construction) and the cost of the major equipment components. Contracting practices obviously vary by project and from developer to developer, but a common approach is to negotiate a single EPC contract with one construction firm to serve as the "general contractor" and to provide all construction materials, labor and supervision and all "balance of plant" components. Developers/owners often independently provide the major equipment components and "turnkey" contracts for the interconnects (power, fuel and water). Some or all of these latter items can also be assigned to the EPC contractor contractually. Contractor fees vary depending the scope of services and materials provided and the amount of project risk, both in terms of schedule and dollar budget, the EPC contractor takes on.

EPC costs and fees and equipment prices vary with market conditions. In general, both have fallen with the 2002 down-turn in the energy sector. Making generalizations can be difficult because both can be very project-specific; however, we observed a change in EPC and equipment costs during 2002 between our initial (June) and final (December) work based on Tenaska's judgment and conversations with industry sources, contractors and equipment vendors. EPC differences are the most difficult to determine because so few new contracts have been announced or awarded recently. The reduction has generally been 5 to 10%. Appropriately scaling these changes up or down with project size is also project specific. EPC costs have fallen; this reflects a revision in our scaling factor for smaller projects not an increase in price.

Changes in equipment prices are much easier to observe. Gas turbines have a high degree of interchangeability and hence a "secondary" market exists were GT's are bought and resold. The price of gas turbines rose quickly in the late 1990's and early 2000's with the surge in gas-fired plant development. Waiting periods for delivery reached "years." The opposite has occurred this year. FA turbines peaked at about

$40MM each in early to mid 2001. Today's manufacturer price is perhaps $30MM; prices on the secondary market are perhaps $20MM. Steam turbines and HRSG's are less "commodity-like" and a larger number of manufacturers exist than for GT's. Hence prices have not been as volatile as prices for GT's, but in our view some softening has occurred.

Occasionally, very distressed pricing can be observed in the secondary market, usually through equipment brokers which protect the identity of the actual owner/seller. The lowest price Tenaska has observed has been a package of three 1 X 1 FA power islands for about $70MM (a GT, ST and HRSG). We do not recommend basing an investment decision in a resource planning context on such numbers. Availability of this pricing on an ongoing basis is very uncertain and such sales are "as is, where is." Significant costs can be associated with relocating and reusing such equipment components.

Section 5 – Potential Sites

Selection of a suitable site is a major step in the development of a new power generation facility. A number of site-specific factors can significantly influence a particular location's feasibility and attractiveness. Some factors are 'knockout' factors, such as when zoning for a prospective site would prohibit its use for power generation. Other factors influence the cost of development, including availability or accessibility of electric transmission.

It should be noted that discussion of potential sites in this report is primarily for the purpose of illustrating various factors that need to be considered and estimating representative costs associated with particular sites. Nothing in this report should be interpreted to mean that a particular site has been selected for development, or that other sites would be excluded from future consideration.

In the site review, transmission constraints and regulatory uncertainties, as discussed elsewhere in this document, were of primary concern. Early in the process it was determined that the company should avoid building new generation in locations where the ability to deliver the power to the company's retail loads was uncertain. This first meant that new generation sites should focus on west of the Cascades as there are already trans-Cascades constraints on the regional transmission system. West of the Cascades, there are some south-north constraints as well, which removed Whatcom and Skagit counties from consideration. After eliminating some geographic areas, the search focused on PSE's service territory in King, Pierce and Thurston counties.

Map A-6-1 shows the location of twenty-four sites that were considered. None of the sites were perfect in every aspect. For example, some substation sites were large enough, but they were not close to a gas supply line, while other sites had become encumbered with suburban growth. For a first cut, it was determined to remove the sites with non-economic constraints: zoning and public acceptance. A group of PSE municipal land planners reviewed the sites and identified a “short list” of sites which could provide the appropriate zoning environment (Map A-6-2). The process led to a fundamental paradox: the further a site was located from its customers, the greater the cost for gas, transmission and water.

PSE personnel and Tenaska conducted on-site inspections of the short list properties before initiating financial analyses. The on-site inspections allowed for discovery of developments and other locational issues that did not show up on inspection of maps. These issues were further investigated by direct contact with local authorities, and PSE personnel who were knowledgeable of specific sites and processes.

The financial analysis will focus on two sites: Dieringer, which is a substation near the White River hydro plant; and Frederickson, which currently holds two gas turbine peakers. The Dieringer site could contain a “one-on-one” 250+ megawatt combined cycle turbine with a steam generator as it is limited by size. The Frederickson site has more room for expansion and could be used for either a ”one-on-one” or a ”two-on-one” (250+ mw and 500+ mw, respectively).

The evaluations of these sites by Tenaska included many important issues such as power system upgrades and fuel and water availability and costs. Nevertheless, this report is still a rough cut to be used as a benchmark for comparison with other alternatives. A detailed analysis would still require engineering reports for construction, OASIS-based transmission upgrade studies, and negotiations with municipalities for services and taxes

Section 6 – Site Specific Project Description and Cost Estimates

Table 6.1, based on the technical characteristics of the generic combined cycle plants detailed on Table 3.1 and the specific attributes of PSE’s two main site alternatives listed on Table 6.1, summarizes Tenaska’s view of the capital cost of a 1 X 1 and a 2 X 1 project at Frederickson and a 1 X 1 project at Dieringer. Two scenarios are provided for each configuration to highlight the impact of possible equipment price differences. As discussed previously for the initial June results, these capital costs were added to an economic model that calculated “soft costs” and then total installed project cost. A summary follows using “Base” equipment pricing:

Table 6.1

	Units	Frederickson 1 X 1	Frederickson 2 X 1	Dieringer 1 X 1
Capacity	MW	294	593	294
EPC Cost	MM$	76.0	137.4	75.6
Equipment (GT, ST & HRSG's)	MM$	54.8	102.5	53.6
Interconnects	MM$	31.2	75.3	14.4
Soft Cost	MM$	68.3	105.7	65.4
Total Cost	MM$	230.4	420.8	209.0
	$/kW	784	710	711

The economies of scale associated with larger plants usually suggest declining capital cost per kW as plant size increases as is evident with the two Frederickson cases ($784/kW falling to $710/kW using higher equipment pricing). Notice that the Dieringer 1 X 1 shows about the same capital cost per kW as the Frederickson 2 X 1. Interconnect costs at Frederickson are a significant issue. This location may have offsetting system benefits to PSE, but all other things equal, Frederickson appears to be a higher cost site.

Section 7 – Project Permitting

The construction and operation of a new project will require approvals from certain federal, state, and local authorities. The following information characterizes the process of obtaining these approvals and the costs and schedule associated with completion of the permitting process.

Requirements

PSE would need to self-certify under the requirements of the Power Plant and Industrial Fuel Use Act of 1978. A Certificate of Compliance would be filed with the Office of Fuels Programs, Department of Energy. Publication of a Public Notice by the Department of Energy would also be required.

Stationary thermal power plants to be sited in Washington with a net electrical generating capacity greater than 350 MW are included within the definition of Major Energy Facilities and subject to licensing review by the Washington State Energy Facility Site Evaluation Council (EFSEC or Council) and case-by-case approval by the governor. The state's energy facility license is obtained in the form of a Site Certification Agreement. The licensing process includes application to the Council, evaluation of the application, and recommendation by the Council to the governor to approve and sign a Site Certification Agreement. The Council will apply its regulatory standards to subject facilities, and is currently in the process or reviewing those standards.

Smaller projects (i.e., less than 350 MW) that do not meet the definition of a Major Energy Facility do not require a Site Certification Agreement or governor approval, but are subject to applicable state and local permitting requirements, including federal air quality and water quality reviews that are delegated by the United States Environmental Protection Agency (USEPA) to the State of Washington or local jurisdictions. Such requirements include air quality permits, wastewater discharge or pretreatment permits, and local land use or zoning and building construction permits.

The State Environmental Policy Act (SEPA) process provides broad interdisciplinary environmental review and will be lead by EFSEC for Major Energy Facilities or by other state or local agencies for smaller projects. In the event that there is a material federal environmental review required by the National Environmental Policy Act (NEPA), the lead agency under SEPA may conduct a coordinated review with federal agencies whose action with respect to the Project is subject to NEPA.

Notable federal jurisdiction is that of the U.S. Army Corps of Engineers (USACE) over certain construction activities in waterways and wetlands. If such construction is necessary, including interconnecting water, gas, and electrical infrastructure, some form of permit may be required from the USACE. Review of permit applicability and compliance by the USACE also includes review of cultural resource issues under the requirements of the National Historic Preservation Act as well as review of potential impacts to threatened and endangered species required by the Endangered Species Act. The USACE will coordinate the reviews of state and federal agencies with expertise in these areas, or coordination will be provided by the lead agency under NEPA. A detailed delineation of wetlands and other waters of the United States must be developed to help avoid jurisdictional waters and to determine potential USACE requirements.

The potential site alternatives include discharge of cooling water and minor volumes of other process effluents to the collection systems of publicly owned wastewater treatment works. Storm water drainage, retention, and discharge facilities will also comply with the treatment requirements and approvals established by local ordinances, State of Washington regulations, and the National Pollutant Discharge Elimination System.

Given available emissions control technology, combined cycle combustion turbine projects subject to EFSEC are also likely to be subject to federal new source review or Prevention of Significant Deterioration (PSD) permit requirements. Smaller project alternatives may not necessarily be subject to PSD depending on final equipment and emissions control selection decisions. Federal land management agencies, such as the National Park Service and U.S. Forest Service, must be consulted in the PSD permitting process with respect to air quality impacts on certain public lands that they administer, such as national parks and wilderness areas. Detailed air quality modeling, potentially including emissions from other sources as well as the Project, may be required to address federal land manager concerns.

The air quality permitting process includes a review of applicable construction standards, assessment of potential project impacts to ambient air quality, and a determination of best available control technology. An air quality construction permit will establish operating and emission limits for project equipment, requirements for initial emissions testing, as well as monitoring and reporting requirements.

New projects must also apply for a permit under the Clean Air Act acid rain prevention program at least 24 months prior to the date when electricity is first provided to the grid system. The acid rain prevention program includes additional monitoring requirements for emissions of sulfur dioxide, oxides of nitrogen, and carbon dioxide. Projects must certify and operate a continuous emissions monitoring system in accordance with the requirements of the acid rain prevention program.

After completion of construction, projects will also apply for an operating permit. When issued, the operating permit will identify applicable regulatory requirements including a requirement to regularly certify compliance with all applicable air quality regulations and conditions of the operating permit. The acid rain permit is issued as one part of the operating permit.

Unless site conditions dictate otherwise, new projects generally will not require hazardous waste transfer, storage, or disposal permits or underground storage tank registration (no underground storage tanks are included). Projects will be required to submit to the USEPA and Ecology a Facility Response Plan detailing contingency plans for oil spills and a Risk Management Plan governing hazardous materials contingencies.

Estimated Costs

Budgetary cost estimates for permitting range from $0.8 to $1.7 million exclusive of preliminary design engineering that may be required to support permitting efforts. In addition to costs directly associated with project permitting, new EFSEC global warming mitigation costs could be imposed as a result of currently ongoing regulatory rulemaking. One of the regulatory options for such mitigation is based upon Oregon Energy Facility Siting Council (EFSC) requirements. Under the Oregon program, these mitigation costs are paid lump-sum prior to commercial operation (i.e. the fee would be treated as another up-front capital cost). For the size range of projects Tenaska evaluated for PSE, the fee would range from about $4MM for a small 146 MW project to over $14MM for a 3 X 1. Given the status of the debate on this subject, however, no mitigation costs have been included in Tenaska’s project cost estimates.

Schedule

EFSEC's web site provides a generalized siting process timeline. EFSEC suggests a potential schedule involving four to eight months of preliminary site study plus an additional 14 months for the various other steps for development of air and water permits and the Site Certification Agreement as well as public hearings and other procedural steps. A smaller project not subject to Council requirements could anticipate a permitting timeline of 10 to 14 months, depending upon procedural options selected by the lead SEPA agency and assuming no significant federal involvement.

Section 8 – Project Construction

As an example, Table 8.1 lists the major components of the cost to construct a 1 X 1 at the Frederickson site. At this level of detail, construction costs (often called total installed cost) are highly site-specific. The EPC contract reflects all balance of plant requirements (i.e. non-equipment requirements) such as buildings, cooling towers, site preparation and excavation, footings and foundations, installing utilities and all piping, fans and control systems. The EPC contract also includes the contractor's fees and profit and is reflective of the amount of risk the contractor assumes. One important risk is related to labor (both hours and wage rates). With fully loaded wage rates of $50/hour and 600,000 total man-hours the Frederickson 1 X 1 would have about $30MM of labor cost, or almost 40% of the total EPC contract. Typically EPC contracts also contain premium/penalty provisions that set out the cost or benefit of achieving or missing key schedule milestones and/or equipment performance.

Table 8.1

Example of Total Installed Project Costs ($2002)		
	000 $	Percent of Total
EPC contract	$ 76,000	33.0%
Equipment	$ 54,840	23.8%
Interconnects	$ 31,190	13.5%
Subtotal	$ 162,030	70.3%
Interest During Construction	$ 11,479	5.0%
Contingency	$ 10,238	4.4%
Sales Tax	$ 9,512	4.1%
Development Costs	$ 7,000	3.0%
LTSA-related and Spares	$ 5,782	2.5%
Startup Including Fuel	$ 5,639	2.4%
Project Management	$ 5,500	2.4%
Lender-related	$ 5,472	2.4%
Insurance-related	$ 2,900	1.3%
Land- related	$ 2,500	1.1%

Working Capital	$ 1,750	0.8%
All Other	$ 591	0.3%
Subtotal	$ 68,363	29.7%
Total Installed Cost	$ 230,393	100.0%

This example suggests that costs other than EPC, equipment and interconnects (commonly called "soft costs") comprise about 30% of total installed costs. These costs are very dependent on what type of company sponsors and builds a project (regulated utility or independent power producer) and how it is financed. The costs related to bank financing (interest during construction and lender-related fees and reimbursables) total about $17MM. The philosophy on contingency and spare parts also varies from sponsor to sponsor and may be dependent upon lender requirements.

A schedule should reflect site and project specific characteristics, but in Tenaska's experience a general rule of thumb for a 3 X 1 configuration is 24 months. 2 X 1's and 1 X 1's might be one month less each (i.e. 23 months and 22 months). This particular schedule also assumes a two or three month "Limited Notice To Proceed (LNTP)" during which the contractor and sometimes subcontractors get a "head start" on certain site-preparation and engineering items. The permitting and construction timelines, of course, are additive. The following table summarizes the total timeline for a new gas-fired project. 1 X 1's might range from 33 to 39 months; 2 X 1's might range from 40 to 48 months. Some of the individual activities can be accomplished concurrently. In our experience the regulatory process is highly uncertain; it is critically important to gain local community support and communicate regularly with all of a project's stakeholders.

Table 8.2

Configuration	Site Study Permit Preparation	EFSEC?	Regulatory Approvals	Construction
1 X 1	2 – 4 mos	No	10 – 14 mos	21 mos
2 X 1	4 – 8 mos	Yes	14 – 18 mos	22 mos

Section 9 – Operating and Maintenance Requirements and Cost Estimates

Non-fuel operating and maintenance ("O&M") costs are typically broken into two categories. The first category, "fixed" costs, generally does not vary with a plant's level of output. Fixed costs include plant labor, ongoing utilities and building/grounds upkeep, usually some allocated corporate overhead and fees paid to the operator. Operator fees of course are eliminated if Puget self operates.

Variable costs generally change with a plant's annual hours of operations. Water treatment, chemicals, environmental controls and catalyst replacement, etc. all are directly related to hours of operation. The largest single item in the variable category is major maintenance of the gas and steam turbines. Scheduled, routine maintenance occurs on a very carefully managed timeline related to annual hours and the number of starts per year, typically as follows:

Table 9.1

Activity	Operating Hours Between Each Activity	Starts Between Each Activity
Combustion Inspection	8,000	400
Hot Gas Path Inspection	24,000	800
Major Overhaul	48,000	2,400

Although some plant owners/operators manage and conduct these major maintenance activities themselves, others opt to contract with third parties for these services, frequently with the manufacturer of the equipment. In such cases Long Term Service Agreements (LTSA's) describe these maintenance practices and include all the parts and labor needed. LTSA's usually levelize annual maintenance costs using a charge per fired hour with an annual fixed minimum fee ($450 to $500/fired hour for a 1 X 1, for example). In this fashion, the manufacturer assumes most of the risks associated with parts availability, premature wear, etc. and some equipment performance issues.

Section 10 – Summary of Results

As discussed in previous sections, Tenaska looked at two Puget self-build site alternatives for Frederickson (1 X1 and 2 X 1) and one for Dieringer (1 X 1). Table 10.1 integrates all of these estimates for plant performance, capital and operating cost, permitting and construction schedules as well as all of the necessary financial modeling assumptions to calculate total installed capital cost (in MM$ and $/kW) and all-in power costs (in $/MWh). Capacity cost in $/kW-month estimates the fixed payment that a plant owner needs to receive to support the full cost of new capacity. This payment covers all fixed costs including repayment of debt and earns the project owner a minimum "profit." The capacity payment is independent of hours of operation (i.e. it's "take or pay"). The all-in cost in $/MWh covers the capacity payment as well as fuel and all variable costs (i.e. all of the costs which are incurred based on hours operated). The all-in cost is clearly very dependent on the assumption about annual hours of operation. A summary of the results using "Base" equipment pricing follows:

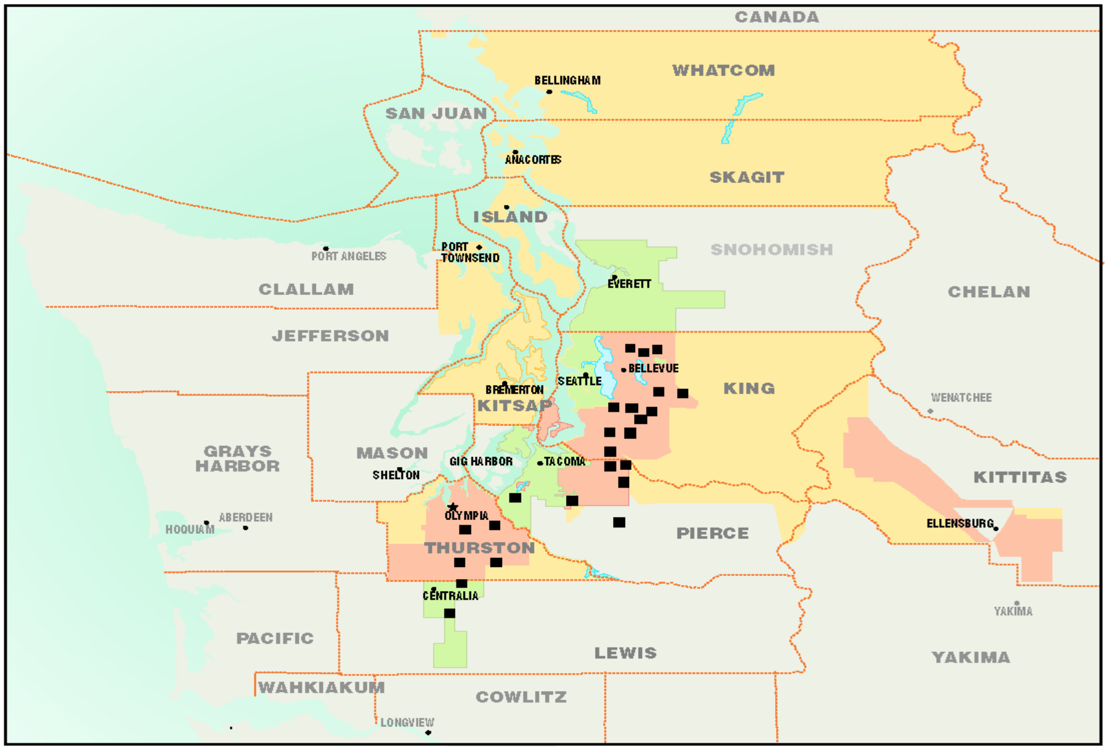
Table 10.1

	Units	Frederickson 1 X 1	Frederickson 2 X 1	Dieringer 1 X 1
Capacity	MW	294	593	294
Capital Cost	MM$	230.4	420.9	209.0
	$/kW	784	710	711
Capacity Cost	$/kW-mon	8.36	7.17	7.68
All-In Cost	$/MWh			
Capacity Factor	60%	52.33	49.34	51.01
	70%	49.17	46.29	47.77
	80%	46.54	43.98	45.32
	90%	44.48	42.18	43.41

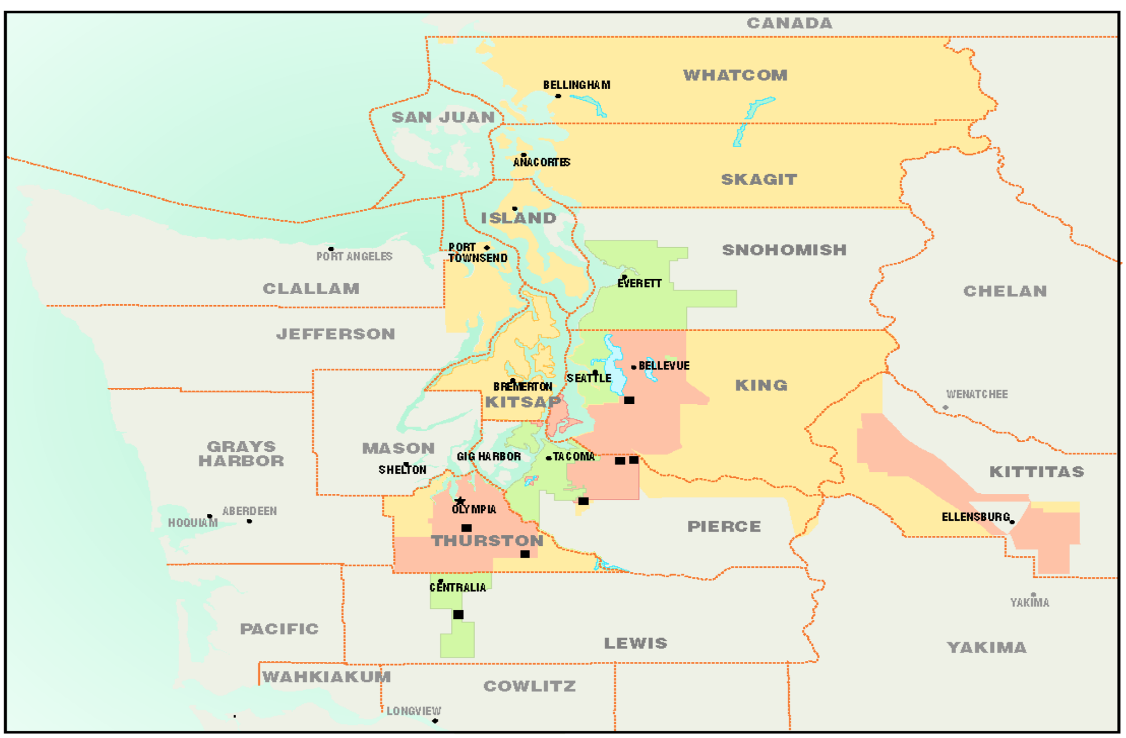
Capital costs for the 1 X 1's range from $711/kW at Dieringer to $784/kW at Frederickson. Interconnect costs account for the vast majority of the difference. Notice that interconnect costs for a Frederickson 2 X 1 are substantially higher than for a 1 X 1, but the scale of a larger plant offsets the increase. If lower priced equipment is available, capital costs for the lower cost sites fall to about $660/kW. The only difference in non-fuel operating costs is water and wastewater cost at Dieringer (less cycles of cooling concentration due to water quality). All-in costs, based on $3.63/mmbtu fuel, and other financial assumptions, range from about $42/MWh for a Frederickson 2 X 1 with a capacity factor of 90% to about $52.33/MWh for a Frederickson 1 X 1 with a capacity factor of 60%. Lower equipment prices and hence capital cost push the all-in costs down about $.80/mWh.

Maps A-6-1, A-6-2

PUGET SOUND ENERGY SERVICE TERRITORY



PUGET SOUND ENERGY SERVICE TERRITORY



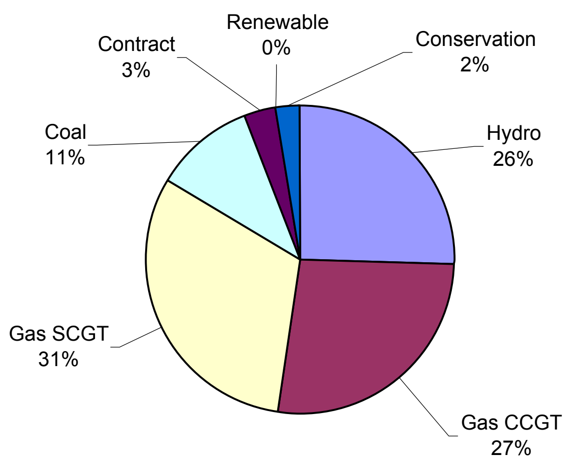
Appendix I - Portfolios and Analysis Results

Case Number 1
Case Name Level B1 all Gas

Capacity Standard: Meets 23 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	75	-	25	50	50	100	425	175	900	28%
SCGT	625	75	-	175	75	25	-	125	150	-	1,250	39%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	54	-	10	24	3	7	7	14	57	24	199	6%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	175	-	-	-	-	-	-	575	18%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,331	3,299
Market Sales Revenue:	(1,352)	(1,065)
Market Purchase Expense:	484	500
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	52	56
Expected Cost:	3,969	4,099
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	16%	
Standard Deviation:	635	
+ 2 sigma	5,239	
- 2 sigma	2,699	

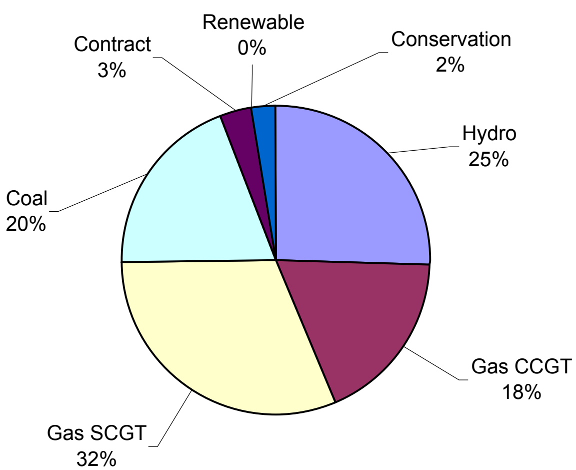
Appendix I - Portfolios and Analysis Results

Case Number 2
Case Name Level B1 Coal & Gas

Capacity Standard: Meets 23 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	25	-	-	50	200	100	375	12%
SCGT	625	75	25	175	75	25	-	125	200	-	1,325	41%
Coal	-	-	75	-	-	50	50	50	225	100	550	17%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	54	-	-	24	3	-	-	7	27	14	128	4%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	175	-	-	-	-	-	-	575	18%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

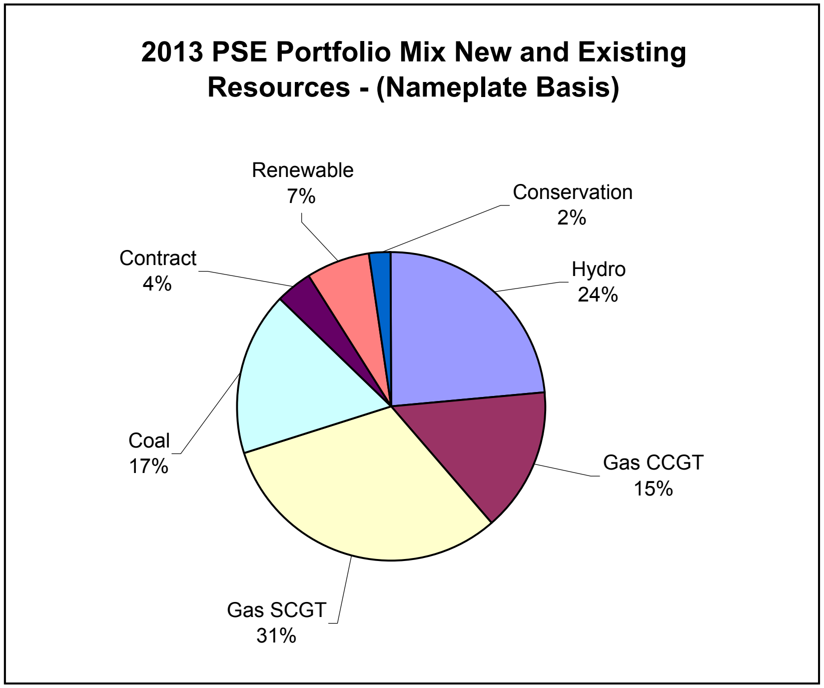
Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,282	3,246
Market Sales Revenue:	(1,309)	(1,023)
Market Purchase Expense:	411	435
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	19	20
Expected Cost:	3,856	3,988
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	13%	
Standard Deviation:	501	
+ 2 sigma	4,859	
- 2 sigma	2,854	

Appendix I - Portfolios and Analysis Results

Case Number 3
Case Name Level B1 Wind (5%) Gas and Coal

Capacity Standard: Meets 23 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	50	-	-	25	200	75	350	9%
SCGT	625	75	50	225	50	75	-	175	175	50	1,500	41%
Coal	-	-	50	-	-	-	50	50	225	100	475	13%
Wind	-	100	-	100	-	100	-	100	-	50	450	12%
Duct Fired	54	-	-	10	7	-	-	3	27	10	111	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	75	-	-	-	-	-	-	475	13%
System Exchange	-	-	-	75	-	25	25	-	25	25	175	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,307	3,290
Market Sales Revenue:	(1,292)	(1,012)
Market Purchase Expense:	420	429
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	62	64
Expected Cost:	3,951	4,079
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	17%	
Standard Deviation:	672	
+ 2 sigma	5,294	
- 2 sigma	2,607	

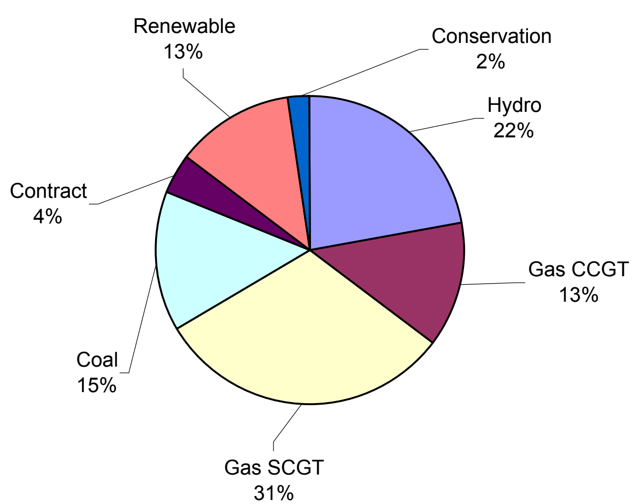
Appendix I - Portfolios and Analysis Results

Case Number 4
Case Name Level B1 Wind (10%) and Gas and Coal

Capacity Standard: Meets 23 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	25	200	75	300	7%
SCGT	625	100	75	225	75	125	25	150	175	50	1,625	39%
Coal	-	-	25	-	-	-	25	50	225	75	400	10%
Wind	-	200	-	200	-	200	-	200	-	100	900	22%
Duct Fired	51	-	-	10	-	-	-	3	27	10	101	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	375	-	-	75	-	-	-	-	-	-	450	11%
System Exchange	-	-	-	75	25	-	25	-	50	25	200	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,357	3,347
Market Sales Revenue:	(1,295)	(1,018)
Market Purchase Expense:	421	419
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	97	99
Expected Cost:	4,035	4,155
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	13%	
Standard Deviation:	525	
+ 2 sigma	5,084	
- 2 sigma	2,986	

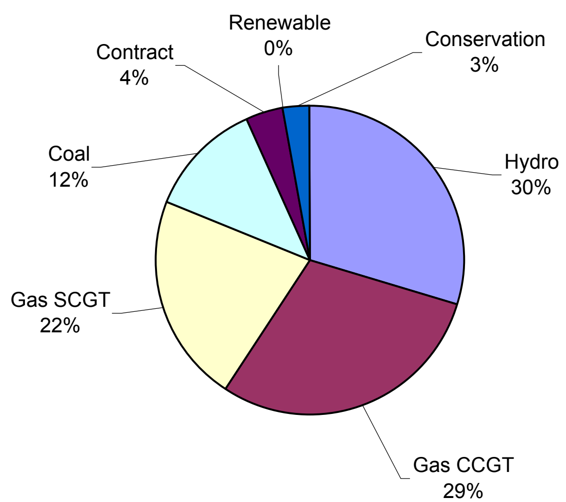
Appendix I - Portfolios and Analysis Results

Case Number 5
Case Name Level A1 all Gas

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	50	-	50	50	50	125	425	200	950	40%
SCGT	-	75	25	150	50	-	-	75	150	-	525	22%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	-	7	24	7	7	7	17	57	-	165	7%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	275	-	-	175	-	-	-	-	-	-	450	19%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,809	2,805
Market Sales Revenue:	(1,129)	(889)
Market Purchase Expense:	559	575
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(9)	(6)
Expected Cost:	3,685	3,794
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	15%	
Standard Deviation:	553	
+ 2 sigma	4,790	
- 2 sigma	2,579	

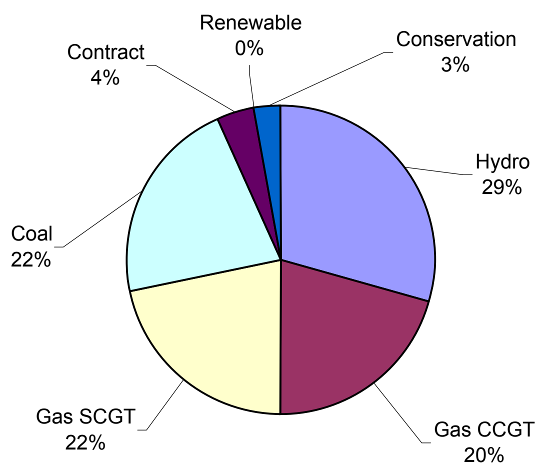
Appendix I - Portfolios and Analysis Results

Case Number 6
Case Name Level A1 Coal & Gas

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	50	-	50	50	225	100	475	20%
SCGT	-	75	50	150	25	25	-	75	150	25	575	24%
Coal	-	-	50	-	-	50	-	75	225	100	500	21%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	-	-	24	7	-	7	7	30	-	114	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	275	-	-	175	-	-	-	-	-	-	450	19%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,787	2,770
Market Sales Revenue:	(1,106)	(867)
Market Purchase Expense:	489	514
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(42)	(41)
Expected Cost:	3,582	3,685
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	13%	
Standard Deviation:	466	
+ 2 sigma	4,513	
- 2 sigma	2,651	

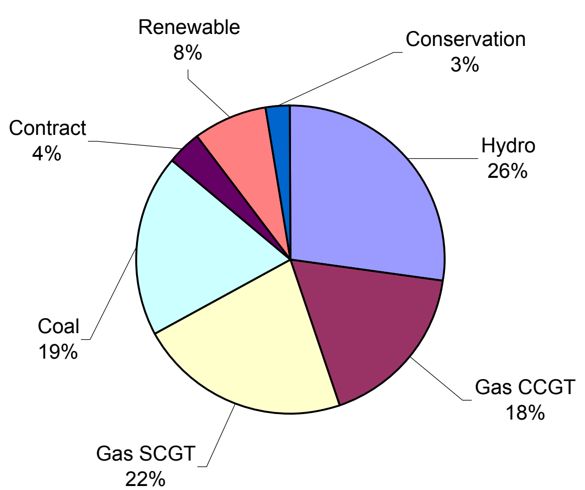
Appendix I - Portfolios and Analysis Results

Case Number 7
Case Name Level A1 Wind (5%) Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	25	-	25	75	200	100	425	15%
SCGT	-	75	75	175	50	50	25	75	175	-	700	25%
Coal	-	-	25	-	-	25	-	75	225	100	450	16%
Wind	-	100	-	100	-	100	-	100	-	50	450	16%
Duct Fired	40	-	-	20	3	-	3	10	27	-	104	4%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	275	-	-	150	-	-	-	-	-	-	425	15%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,893	2,881
Market Sales Revenue:	(1,143)	(899)
Market Purchase Expense:	465	490
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(9)	(8)
Expected Cost:	3,661	3,772
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	13%	
Standard Deviation:	476	
+ 2 sigma	4,612	
- 2 sigma	2,709	

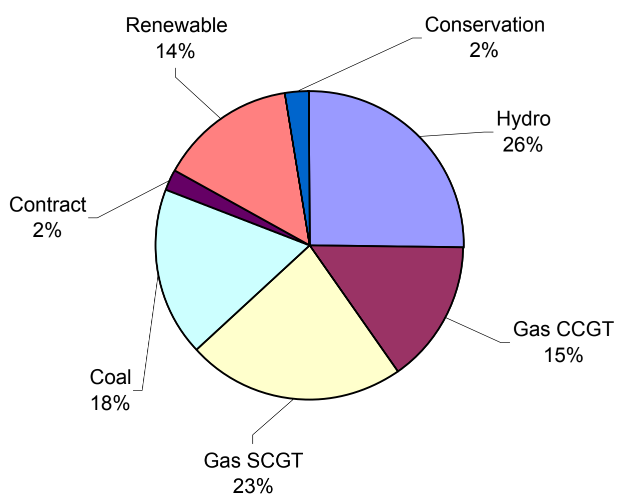
Appendix I - Portfolios and Analysis Results

Case Number 8
Case Name Level A1 Wind (10%) and Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	25	-	25	50	225	75	400	12%
SCGT	25	75	50	225	50	75	25	125	150	25	825	25%
Coal	-	-	50	-	-	25	-	50	225	100	450	14%
Wind	-	200	-	200	-	200	-	200	-	100	900	27%
Duct Fired	40	-	-	17	3	-	3	7	30	-	101	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	250	-	-	125	-	-	-	-	-	-	375	11%
System Exchange	-	-	-	-	-	-	25	-	25	25	75	2%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,114	3,091
Market Sales Revenue:	(1,306)	(1,041)
Market Purchase Expense:	422	450
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	15	17
Expected Cost:	3,699	3,825
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	13%	
Standard Deviation:	481	
+ 2 sigma	4,660	
- 2 sigma	2,737	

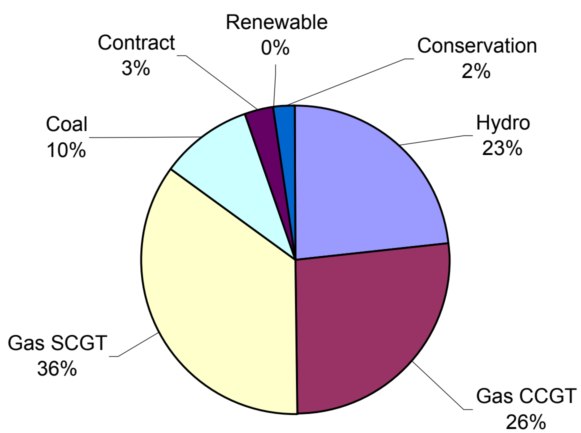
Appendix I - Portfolios and Analysis Results

Case Number 9
Case Name Level C1 all Gas

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: Meets the highest deficit month plus 10% of the deficit

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	25	50	-	50	25	75	125	450	200	1,000	26%
SCGT	1,125	50	50	175	50	50	-	100	100	50	1,750	46%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	7	7	24	7	3	10	17	61	-	175	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	425	25	-	175	-	-	-	-	-	-	625	16%
System Exchange	-	-	-	25	-	25	25	-	50	-	125	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,760	3,727
Market Sales Revenue:	(1,553)	(1,252)
Market Purchase Expense:	429	445
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	86	90
Expected Cost:	4,175	4,319
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	19%	
Standard Deviation:	793	
+ 2 sigma	5,762	
- 2 sigma	2,589	

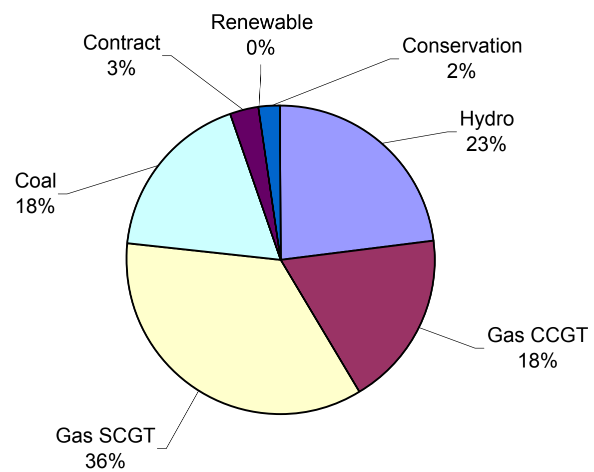
Appendix I - Portfolios and Analysis Results

Case Number 10
Case Name Level C1 Coal & Gas

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: Meets the highest deficit month plus 10% of the deficit

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	25	-	-	-	50	-	50	225	100	450	12%
SCGT	1,125	50	50	175	75	50	25	75	150	25	1,800	47%
Coal	-	-	50	-	50	-	50	75	225	125	575	15%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	7	-	24	-	7	-	7	30	-	114	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	425	25	-	175	-	-	-	-	-	-	625	16%
System Exchange	-	-	-	25	-	-	-	50	50	-	125	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,720	3,676
Market Sales Revenue:	(1,517)	(1,215)
Market Purchase Expense:	349	376
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	47	49
Expected Cost:	4,053	4,195
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	16%	
Standard Deviation:	648	
+ 2 sigma	5,350	
- 2 sigma	2,756	

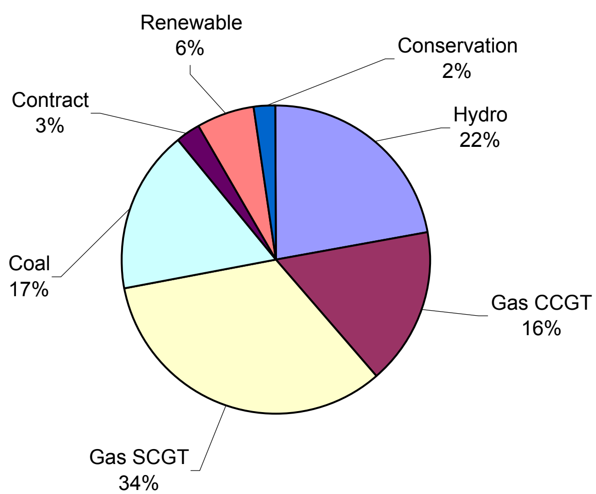
Appendix I - Portfolios and Analysis Results

Case Number 11
Case Name Level C1 Wind (5%) Gas and Coal

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: Meets the highest deficit month plus 10% of the deficit

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	25	-	50	225	100	400	10%
SCGT	1,125	50	50	175	75	50	25	75	150	25	1,800	43%
Coal	-	-	50	-	50	-	50	50	225	125	550	13%
Wind	-	100	-	100	-	100	-	100	-	50	450	11%
Duct Fired	40	-	-	24	-	3	-	7	30	-	104	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	425	-	-	175	-	-	-	-	-	-	600	14%
System Exchange	-	-	-	25	-	-	-	25	50	-	100	2%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,809	3,765
Market Sales Revenue:	(1,575)	(1,270)
Market Purchase Expense:	323	346
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	63	65
Expected Cost:	4,074	4,213
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	16%	
Standard Deviation:	652	
+ 2 sigma	5,378	
- 2 sigma	2,770	

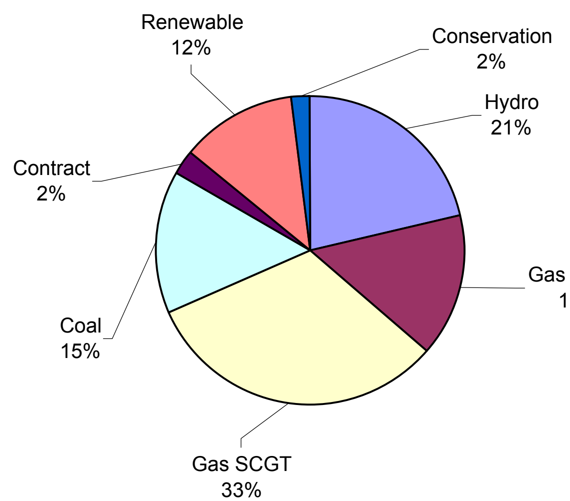
Appendix I - Portfolios and Analysis Results

Case Number 12
Case Name Level C1 Wind (10%) Gas and Coal

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: Meets the highest deficit month plus 10% of the deficit

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	50	225	100	375	8%
SCGT	1,125	50	50	175	75	50	25	75	150	25	1,800	40%
Coal	-	-	25	-	25	-	50	25	225	100	450	10%
Wind	-	200	-	200	-	200	-	200	-	100	900	20%
Duct Fired	40	-	-	20	-	-	-	7	30	-	97	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	425	-	-	150	-	-	-	-	-	-	575	13%
System Exchange	-	-	-	25	-	-	-	25	50	-	100	2%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	3%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

	Case III	Case I
Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,853	3,788
Market Sales Revenue:	(1,593)	(1,283)
Market Purchase Expense:	317	337
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	88	89
Expected Cost:	4,119	4,241
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	14%	
Standard Deviation:	577	
+ 2 sigma	5,272	
- 2 sigma	2,965	

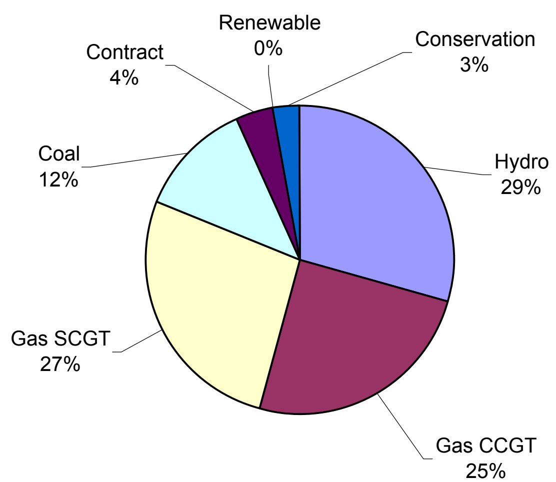
Appendix I - Portfolios and Analysis Results

Case Number 13
Case Name Status Quo all Gas

Capacity Standard: 2003 deficit level maintained
Energy Standard: 2003 deficit level maintained

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	25	50	-	25	25	25	150	425	200	925	39%
SCGT	200	50	50	200	50	50	25	50	125	25	825	35%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	14	3	7	17	3	3	3	20	57	-	128	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	100	-	-	125	-	-	-	-	-	-	225	9%
System Exchange	-	-	-	25	-	25	25	-	50	-	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

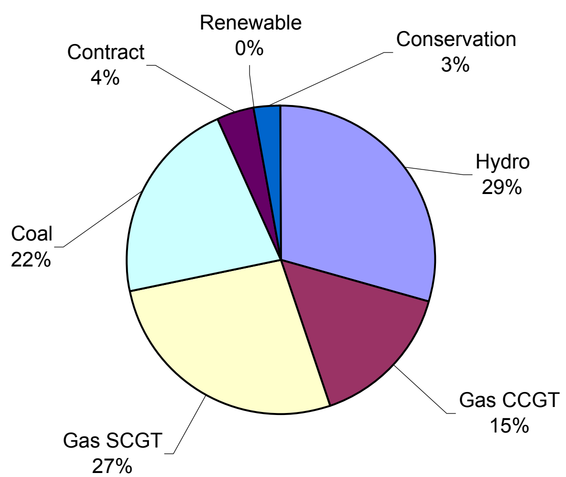
Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,339	2,353
Market Sales Revenue:	(804)	(598)
Market Purchase Expense:	779	793
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	23	27
Expected Cost:	3,790	3,883
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	12%	
Standard Deviation:	455	
+ 2 sigma	4,700	
- 2 sigma	2,880	

Appendix I - Portfolios and Analysis Results

Case Number 14
Case Name Status Quo Coal & Gas

Capacity Standard: 2003 deficit level maintained
Energy Standard: 2003 deficit level maintained

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	25	-	-	-	25	-	75	200	100	425	18%
SCGT	200	75	25	200	75	50	-	75	150	50	900	38%
Coal	-	-	50	-	25	-	25	75	225	100	500	21%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	14	3	-	17	-	3	-	10	27	-	74	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	100	-	-	125	-	-	-	-	-	-	225	9%
System Exchange	-	-	-	25	-	25	25	-	50	-	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	6%



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,282	2,286
Market Sales Revenue:	(765)	(560)
Market Purchase Expense:	729	754
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(5)	(3)
Expected Cost:	3,694	3,786
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	10%	
Standard Deviation:	369	
+ 2 sigma	4,433	
- 2 sigma	2,956	

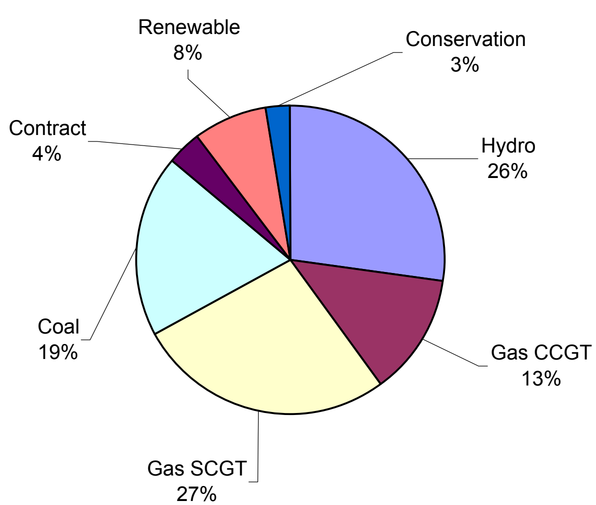
Appendix I - Portfolios and Analysis Results

Case Number 15
Case Name Status Quo Wind (5%) Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: 2003 deficit level maintained

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	25	-	50	200	100	375	13%
SCGT	200	100	25	250	75	50	25	125	150	25	1,025	36%
Coal	-	-	50	-	-	-	25	50	225	100	450	16%
Wind	-	100	-	100	-	100	-	100	-	50	450	16%
Duct Fired	14	-	-	14	-	3	-	7	27	-	64	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	100	-	-	100	-	-	-	-	-	-	200	7%
System Exchange	-	-	-	25	-	25	25	-	50	-	125	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

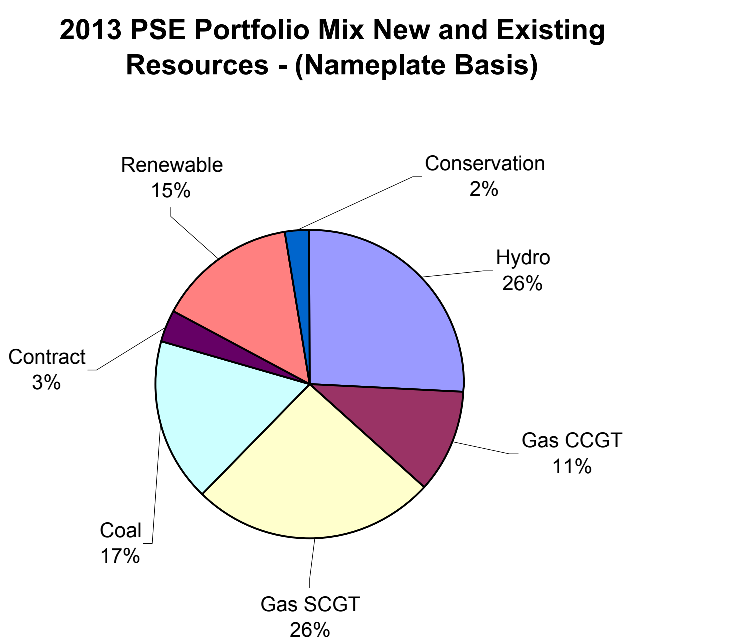
Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,389	2,389
Market Sales Revenue:	(804)	(593)
Market Purchase Expense:	703	725
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	27	30
Expected Cost:	3,769	3,859
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	11%	
Standard Deviation:	415	
+ 2 sigma	4,598	
- 2 sigma	2,940	

Appendix I - Portfolios and Analysis Results

Case Number 16
Case Name Status Quo Wind (10%) and Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: 2003 deficit level maintained

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	50	200	75	325	10%
SCGT	200	100	25	250	75	50	25	125	150	25	1,025	32%
Coal	-	-	25	-	-	-	-	50	225	100	400	13%
Wind	-	200	-	200	-	200	-	200	-	100	900	29%
Duct Fired	14	-	-	10	-	-	-	7	27	-	57	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	100	-	-	75	-	-	-	-	-	-	175	6%
System Exchange	-	-	-	25	-	25	25	-	50	-	125	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,481	2,462
Market Sales Revenue:	(858)	(639)
Market Purchase Expense:	677	696
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	46	49
Expected Cost:	3,800	3,876
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	8%	
Standard Deviation:	304	
+ 2 sigma	4,408	
- 2 sigma	3,192	

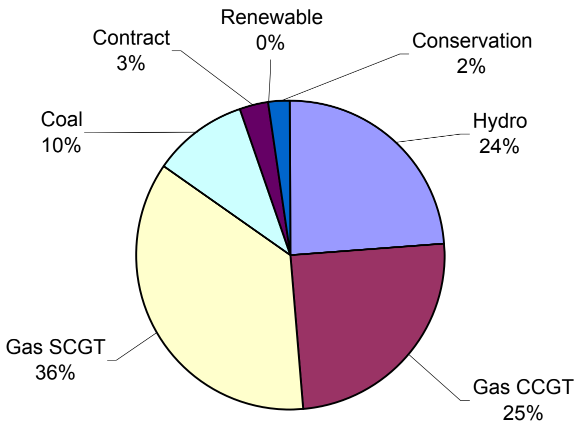
Appendix I - Portfolios and Analysis Results

Case Number 17
Case Name Level B2 all Gas

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	75	-	25	50	50	100	425	175	900	25%
SCGT	975	100	25	175	75	25	-	150	150	25	1,700	47%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	54	-	10	24	3	7	7	14	57	24	199	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	175	-	-	-	-	-	-	575	16%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

	Case III	Case I
Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,490	3,451
Market Sales Revenue:	(1,375)	(1,078)
Market Purchase Expense:	484	500
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	90	95
Expected Cost:	4,144	4,276
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	15%	
Standard Deviation:	622	
+ 2 sigma	5,387	
- 2 sigma	2,901	

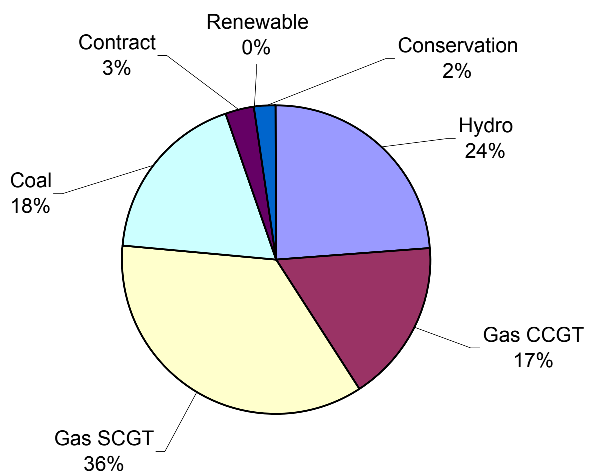
Appendix I - Portfolios and Analysis Results

Case Number 18
Case Name Level B2 Coal & Gas

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	25	-	-	50	200	100	375	10%
SCGT	975	100	25	200	75	25	-	150	200	-	1,750	48%
Coal	-	-	75	-	-	50	50	50	225	100	550	15%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	54	-	-	24	3	-	-	7	27	14	128	4%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	175	-	-	-	-	-	-	575	16%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,436	3,393
Market Sales Revenue:	(1,331)	(1,036)
Market Purchase Expense:	411	435
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	54	56
Expected Cost:	4,024	4,157
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	12%	
Standard Deviation:	483	
+ 2 sigma	4,989	
- 2 sigma	3,058	

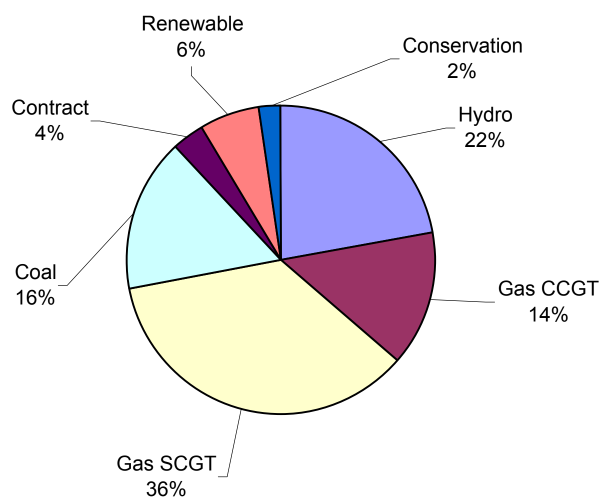
Appendix I - Portfolios and Analysis Results

Case Number 19
Case Name Level B2 Wind (5%) Gas and Coal

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	50	-	-	25	200	75	350	9%
SCGT	975	100	50	250	50	75	25	175	175	50	1,925	47%
Coal	-	-	50	-	-	-	50	50	225	100	475	12%
Wind	-	100	-	100	-	100	-	100	-	50	450	11%
Duct Fired	54	-	-	10	7	-	-	3	27	10	111	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	75	-	-	-	-	-	-	475	12%
System Exchange	-	-	-	75	-	25	25	-	25	25	175	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,462	3,437
Market Sales Revenue:	(1,314)	(1,025)
Market Purchase Expense:	420	429
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	97	99
Expected Cost:	4,118	4,249
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	15%	
Standard Deviation:	618	
+ 2 sigma	5,354	
- 2 sigma	2,883	

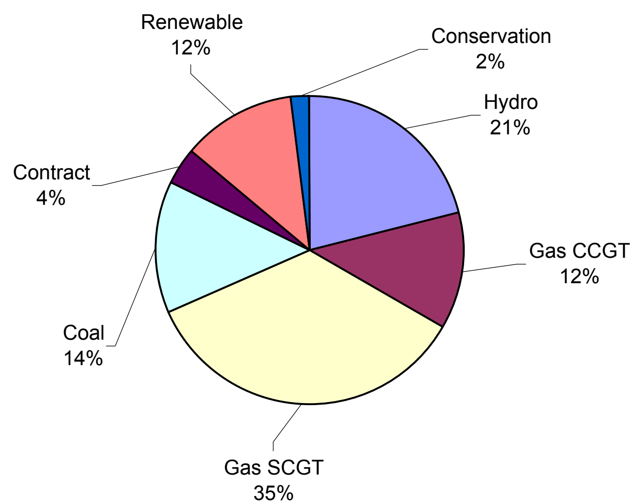
Appendix I - Portfolios and Analysis Results

Case Number 20
Case Name Level B2 Wind (10%) and Gas and Coal

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	25	200	75	300	7%
SCGT	1,025	100	50	250	75	125	25	175	150	75	2,050	45%
Coal	-	-	25	-	-	-	25	50	225	75	400	9%
Wind	-	200	-	200	-	200	-	200	-	100	900	20%
Duct Fired	51	-	-	10	-	-	-	3	27	10	101	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	375	-	-	75	-	-	-	-	-	-	450	10%
System Exchange	-	-	-	75	25	-	25	-	50	25	200	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	3%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

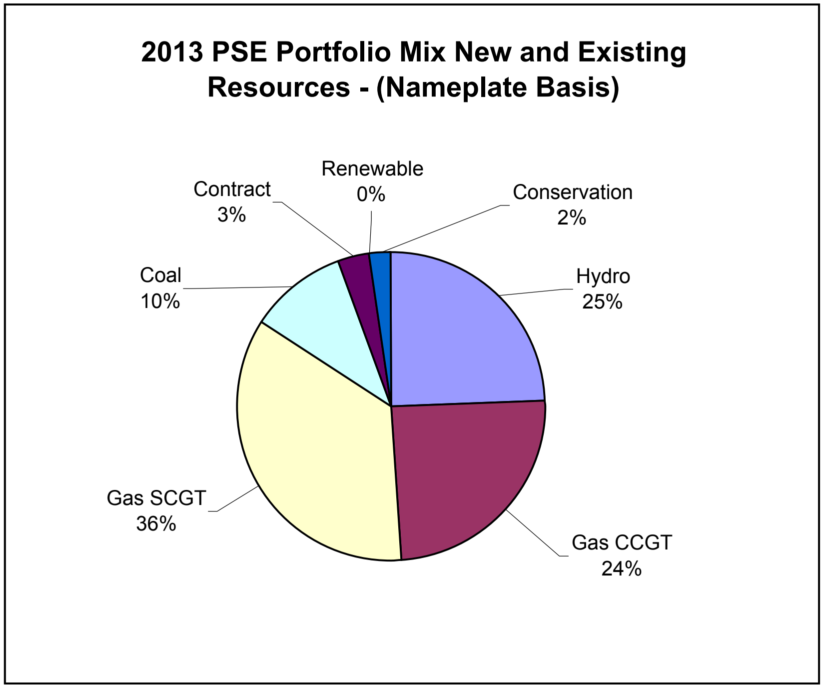
Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,512	3,494
Market Sales Revenue:	(1,317)	(1,032)
Market Purchase Expense:	421	419
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	132	135
Expected Cost:	4,203	4,324
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	14%	
Standard Deviation:	588	
+ 2 sigma	5,379	
- 2 sigma	3,026	

Appendix I - Portfolios and Analysis Results

Case Number 21
Case Name Level A2 all Gas

Capacity Standard: Meets 19 Degree F hour at SEA-TAC
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	50	-	50	50	50	125	425	200	950	27%
SCGT	975	100	25	175	50	25	-	100	150	25	1,625	47%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	-	7	24	7	7	7	17	57	-	165	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	275	-	-	175	-	-	-	-	-	-	450	13%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,210	3,187
Market Sales Revenue:	(1,184)	(922)
Market Purchase Expense:	557	573
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	82	86
Expected Cost:	4,119	4,233
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	12%	
Standard Deviation:	494	
+ 2 sigma	5,107	
- 2 sigma	3,130	

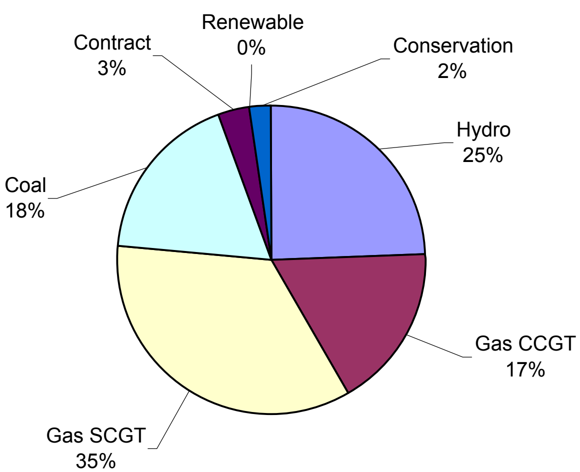
Appendix I - Portfolios and Analysis Results

Case Number 22
Case Name Level A2 Coal & Gas

Capacity Standard: Meets 19 Degree F hour at SEA-TAC
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	50	-	50	50	225	100	475	14%
SCGT	975	100	25	200	25	50	-	100	175	-	1,650	48%
Coal	-	-	50	-	-	50	-	75	225	100	500	14%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	-	-	24	7	-	7	7	30	-	114	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	275	-	-	175	-	-	-	-	-	-	450	13%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,184	3,147
Market Sales Revenue:	(1,160)	(899)
Market Purchase Expense:	486	513
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	45	47
Expected Cost:	4,008	4,116
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	15%	
Standard Deviation:	601	
+ 2 sigma	5,211	
- 2 sigma	2,806	

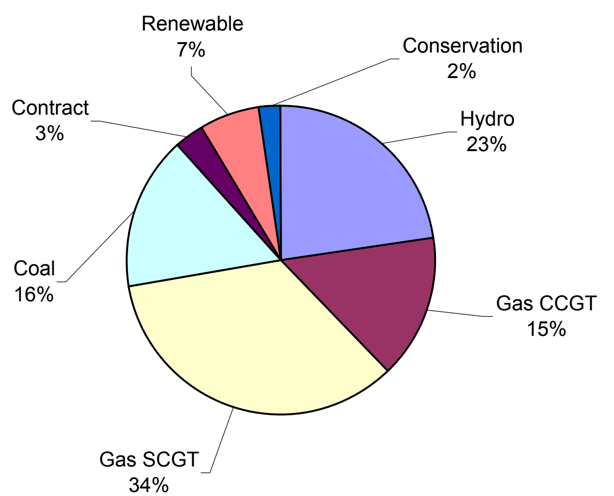
Appendix I - Portfolios and Analysis Results

Case Number 23
Case Name Level A2 Wind (5%) Gas and Coal

Capacity Standard: Meets 19 Degree F hour at SEA-TAC
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	25	-	25	75	200	100	425	11%
SCGT	975	100	50	225	50	75	25	75	200	25	1,800	46%
Coal	-	-	25	-	-	25	-	75	225	100	450	11%
Wind	-	100	-	100	-	100	-	100	-	50	450	11%
Duct Fired	40	-	-	20	3	-	3	10	27	-	104	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	275	-	-	150	-	-	-	-	-	-	425	11%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,293	3,261
Market Sales Revenue:	(1,198)	(932)
Market Purchase Expense:	464	488
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	81	84
Expected Cost:	4,094	4,209
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	14%	
Standard Deviation:	573	
+ 2 sigma	5,240	
- 2 sigma	2,948	

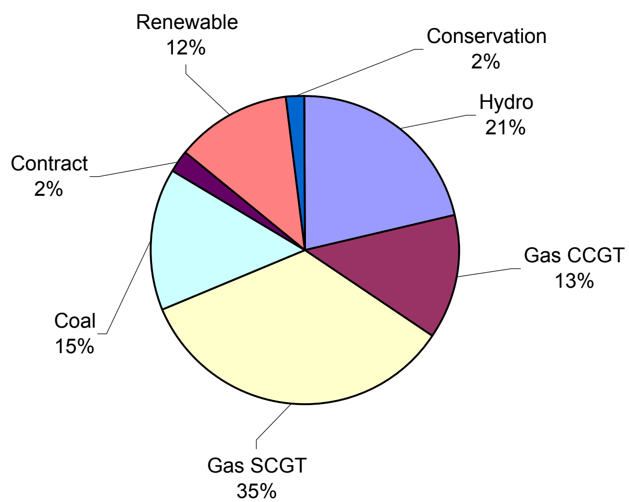
Appendix I - Portfolios and Analysis Results

Case Number 24
Case Name Level A2 Wind (10%) and Gas and Coal

Capacity Standard: Meets 19 Degree F hour at SEA-TAC
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	25	-	25	50	225	75	400	9%
SCGT	1,000	100	25	275	75	75	25	150	150	50	1,925	44%
Coal	-	-	50	-	-	25	-	50	225	100	450	10%
Wind	-	200	-	200	-	200	-	200	-	100	900	21%
Duct Fired	40	-	-	17	3	-	3	7	30	-	101	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	250	-	-	125	-	-	-	-	-	-	375	9%
System Exchange	-	-	-	-	-	-	25	-	25	25	75	2%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	3%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,515	3,472
Market Sales Revenue:	(1,362)	(1,075)
Market Purchase Expense:	420	449
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	106	109
Expected Cost:	4,133	4,263
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	16%	
Standard Deviation:	661	
+ 2 sigma	5,455	
- 2 sigma	2,810	

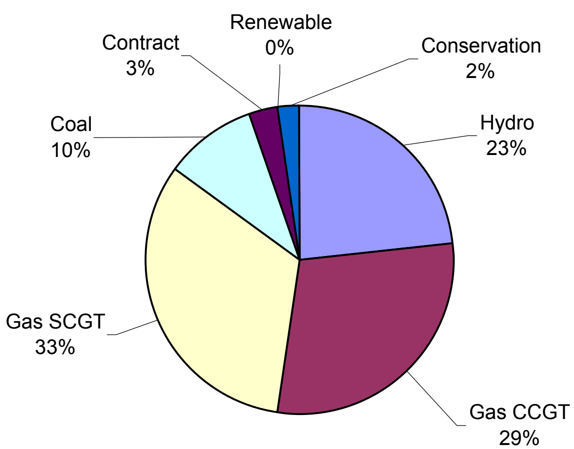
Appendix I - Portfolios and Analysis Results

Case Number 25
Case Name Level C2 all Gas

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: All months are at least 110% of the total monthly load

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	175	75	25	25	50	50	50	100	425	175	1,150	30%
SCGT	875	-	50	225	50	50	-	125	125	75	1,575	41%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	14	3	20	7	7	7	14	57	-	168	4%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	500	25	-	125	-	-	-	-	-	-	650	17%
System Exchange	-	-	-	25	-	-	50	-	50	-	125	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	4,325	4,269
Market Sales Revenue:	(2,124)	(1,738)
Market Purchase Expense:	335	351
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	70	74
Expected Cost:	4,060	4,264
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	21%	
Standard Deviation:	853	
+ 2 sigma	5,766	
- 2 sigma	2,355	

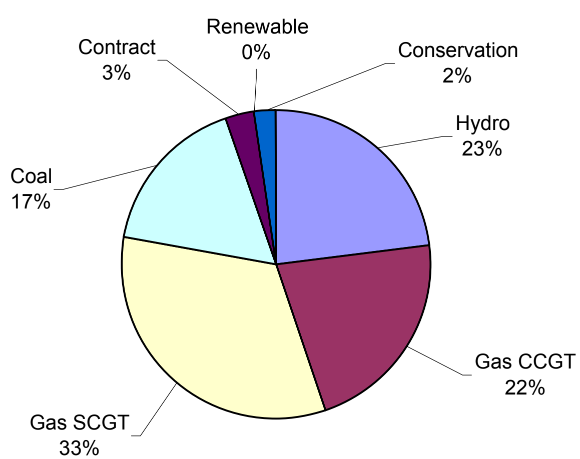
Appendix I - Portfolios and Analysis Results

Case Number 26
Case Name Level C2 Coal & Gas

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: All months are at least 110% of the total monthly load

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	175	75	-	25	-	50	-	50	200	75	650	17%
SCGT	875	-	75	200	50	75	-	125	175	75	1,650	43%
Coal	-	-	25	-	50	-	50	50	225	100	500	13%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	14	-	20	-	7	-	7	27	-	114	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	500	25	-	125	-	-	-	-	-	-	650	17%
System Exchange	-	-	-	25	-	-	50	-	50	-	125	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	4,274	4,206
Market Sales Revenue:	(2,067)	(1,678)
Market Purchase Expense:	266	291
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	41	44
Expected Cost:	3,968	4,170
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	16%	
Standard Deviation:	635	
+ 2 sigma	5,238	
- 2 sigma	2,698	

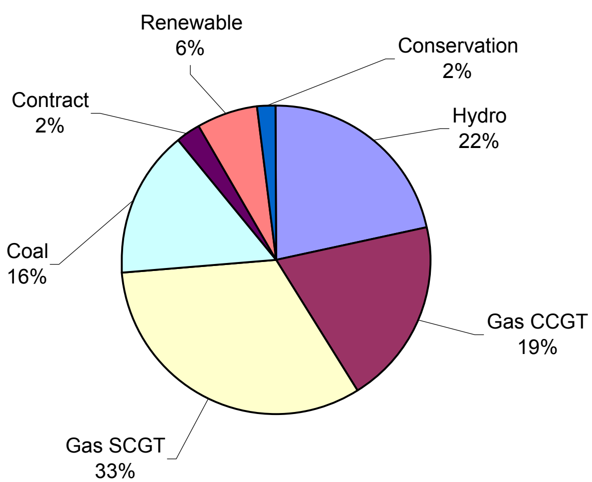
Appendix I - Portfolios and Analysis Results

Case Number 27
Case Name Level C2 Wind (5%) Gas and Coal

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: All months are at least 110% of the total monthly load

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	175	50	-	-	-	25	-	50	200	75	575	13%
SCGT	875	25	75	250	75	75	25	125	175	75	1,775	41%
Coal	-	-	25	-	25	-	50	50	225	100	475	11%
Wind	-	100	-	100	-	100	-	100	-	50	450	11%
Duct Fired	40	10	-	17	-	3	-	7	27	-	104	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	500	25	-	125	-	-	-	-	-	-	650	15%
System Exchange	-	-	-	25	-	-	25	-	50	-	100	2%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	4,377	4,312
Market Sales Revenue:	(2,103)	(1,714)
Market Purchase Expense:	242	265
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	72	74
Expected Cost:	4,043	4,244
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	21%	
Standard Deviation:	849	
+ 2 sigma	5,740	
- 2 sigma	2,345	

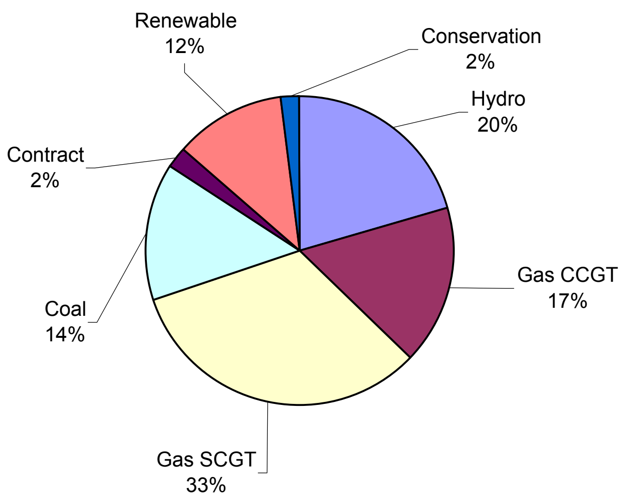
Appendix I - Portfolios and Analysis Results

Case Number 28
Case Name Level C2 Wind (10%) Gas and Coal

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: All months are at least 110% of the total monthly load

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	175	-	-	-	-	-	-	50	200	75	500	11%
SCGT	875	75	75	275	50	125	25	150	200	75	1,925	41%
Coal	-	-	25	-	50	-	25	50	200	100	450	9%
Wind	-	200	-	200	-	200	-	200	-	100	900	19%
Duct Fired	40	3	-	14	-	-	-	7	27	-	91	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	500	25	-	100	-	-	-	-	-	-	625	13%
System Exchange	-	-	-	25	-	-	25	-	50	-	100	2%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	3%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	4,465	4,404
Market Sales Revenue:	(2,130)	(1,744)
Market Purchase Expense:	223	243
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	105	107
Expected Cost:	4,118	4,319
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	15%	
Standard Deviation:	618	
+ 2 sigma	5,353	
- 2 sigma	2,883	

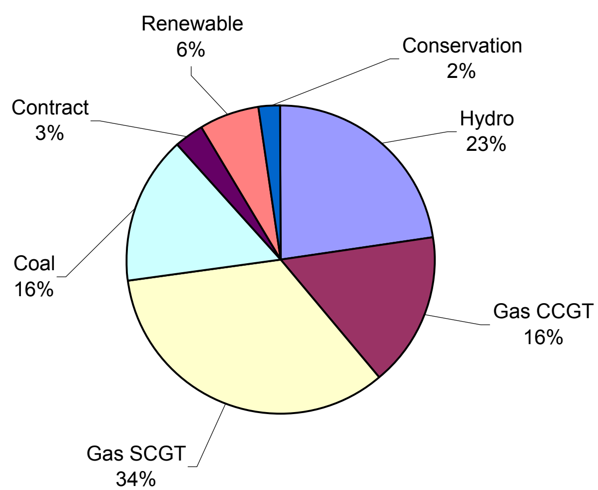
Appendix I - Portfolios and Analysis Results

Case Number 29
Case Name 033103 B2 No JO 5% G&C

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	400	-	-	175	25	-	-	50	225	75	950	24%
SCGT	975	100	25	200	75	25	-	150	200	-	1,750	44%
Coal	-	-	50	-	-	-	25	50	225	75	425	11%
Wind	-	100	-	100	-	100	-	100	-	50	450	11%
Duct Fired	54	-	-	24	3	-	-	7	30	10	128	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	-	-	-	-	-	-	-	-	-	-	0	0%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	4,016	3,958
Market Sales Revenue:	(1,934)	(1,538)
Market Purchase Expense:	365	381
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	52	58
Expected Cost:	3,953	4,168
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	19%	
Standard Deviation:	751	
+ 2 sigma	5,455	
- 2 sigma	2,451	

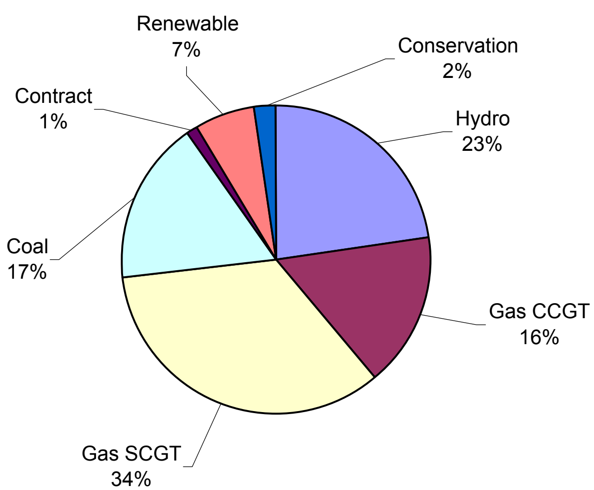
Appendix I - Portfolios and Analysis Results

Case Number 30
Case Name 033103 B2 No Seasonal Exch 5% G&C

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	25	-	-	50	225	75	375	9%
SCGT	975	100	25	200	75	25	-	150	200	-	1,750	44%
Coal	-	-	50	-	-	25	50	75	225	100	525	13%
Wind	-	100	-	100	-	100	-	100	-	50	450	11%
Duct Fired	54	-	-	20	7	-	-	7	30	10	128	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	150	25	-	-	-	-	-	575	15%
System Exchange	-	-	-	-	-	-	-	-	-	-	0	0%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,634	3,579
Market Sales Revenue:	(1,475)	(1,168)
Market Purchase Expense:	372	401
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	66	68
Expected Cost:	4,051	4,189
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	13%	
Standard Deviation:	527	
+ 2 sigma	5,104	
- 2 sigma	2,998	

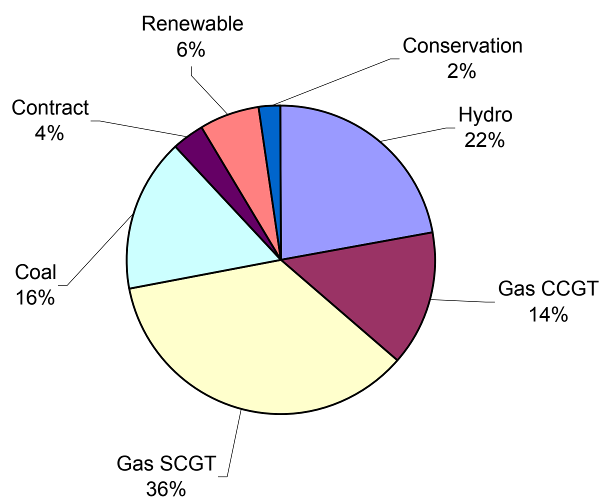
Appendix I - Portfolios and Analysis Results

Case Number 31
Case Name 033103 B2 No SCGT Shaping 5% G&C

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	50	-	-	25	200	75	350	9%
SCGT	975	100	50	250	50	75	25	175	175	50	1,925	47%
Coal	-	-	50	-	-	-	50	50	225	100	475	12%
Wind	-	100	-	100	-	100	-	100	-	50	450	11%
Duct Fired	54	-	-	10	7	-	-	3	27	10	111	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	75	-	-	-	-	-	-	475	12%
System Exchange	-	-	-	75	-	25	25	-	25	25	175	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	4,696	4,502
Market Sales Revenue:	(2,721)	(2,048)
Market Purchase Expense:	386	417
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	53	84
Expected Cost:	3,868	4,263
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	49%	
Standard Deviation:	1,895	
+ 2 sigma	7,659	
- 2 sigma	77	

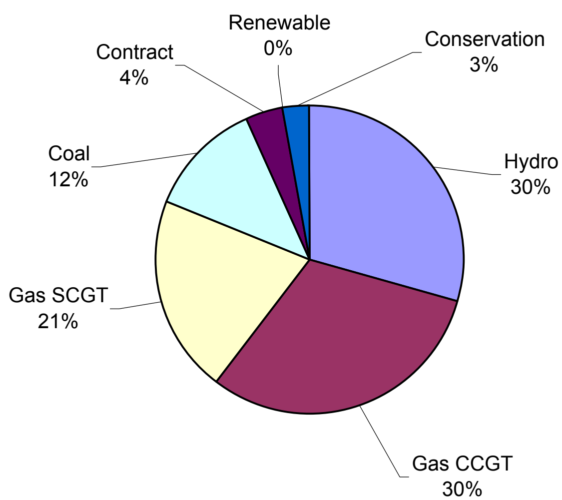
Appendix I - Portfolios and Analysis Results

Case Number 32
Case Name B1 Energy A1 Cap All Gas

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	75	-	25	50	50	100	425	175	900	38%
SCGT	-	-	-	75	75	-	-	125	125	25	425	18%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	-	-	10	75	3	7	7	14	57	24	196	8%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	175	-	-	-	-	-	-	575	24%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,001	2,989
Market Sales Revenue:	(1,286)	(1,024)
Market Purchase Expense:	492	506
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(16)	(14)
Expected Cost:	3,645	3,767
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

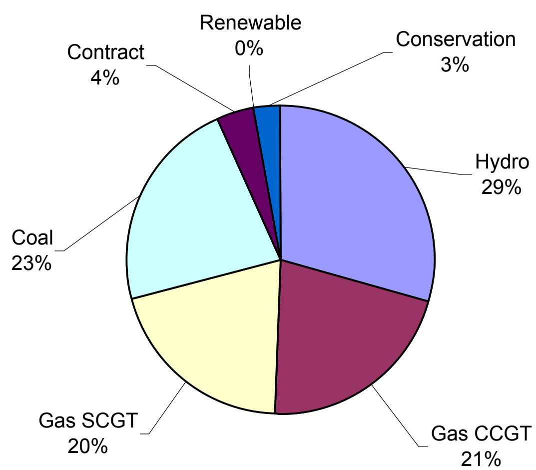
Appendix I - Portfolios and Analysis Results

Case Number 33
Case Name B1 Energy A1 Cap Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	25	-	-	50	200	100	375	16%
SCGT	-	-	-	100	50	25	-	125	175	-	475	20%
Coal	-	-	75	-	-	50	50	50	225	100	550	23%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	-	-	-	75	3	-	-	7	27	14	126	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	175	-	-	-	-	-	-	575	24%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,947	2,931
Market Sales Revenue:	(1,242)	(982)
Market Purchase Expense:	418	442
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(53)	(52)
Expected Cost:	3,524	3,648
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

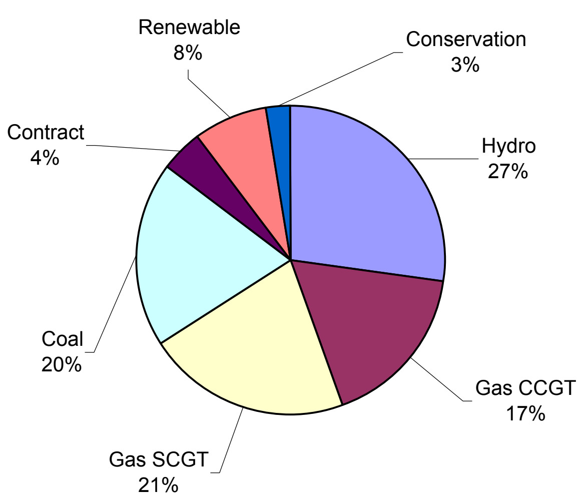
Appendix I - Portfolios and Analysis Results

Case Number 34
Case Name B1 Energy A1 Cap Wind 5% Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	50	-	-	25	200	75	350	12%
SCGT	-	-	-	200	25	75	-	150	175	25	650	23%
Coal	-	-	50	-	-	-	50	50	225	100	475	17%
Wind	-	100	-	100	-	100	-	100	-	50	450	16%
Duct Fired	-	-	25	35	7	-	-	3	27	10	107	4%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	75	-	-	-	-	-	-	475	17%
System Exchange	-	-	-	75	-	25	25	-	25	25	175	6%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,977	2,978
Market Sales Revenue:	(1,229)	(971)
Market Purchase Expense:	427	435
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(10)	(9)
Expected Cost:	3,619	3,741
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

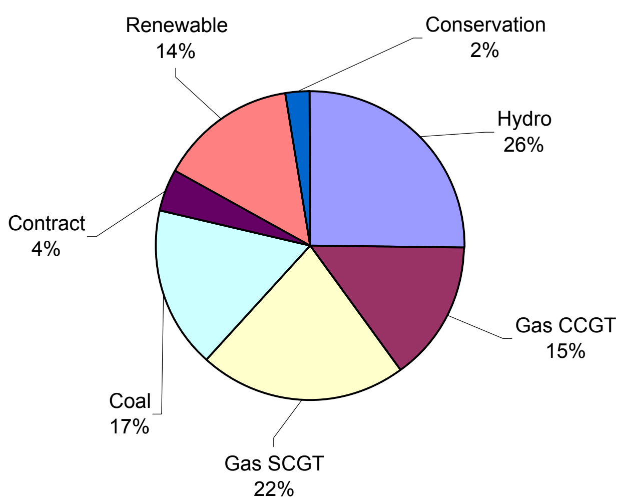
Appendix I - Portfolios and Analysis Results

Case Number 35
Case Name B1 Energy A1 Cap Wind 10% Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	25	200	75	300	9%
SCGT	-	-	26	225	50	100	25	150	150	50	776	24%
Coal	-	-	25	-	-	-	25	50	225	75	400	12%
Wind	-	200	-	200	-	200	-	200	-	100	900	27%
Duct Fired	-	25	25	10	-	-	-	3	27	10	101	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	375	-	-	75	-	-	-	-	-	-	450	14%
System Exchange	-	-	-	75	25	-	25	-	50	25	200	6%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,041	3,047
Market Sales Revenue:	(1,247)	(988)
Market Purchase Expense:	424	421
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	26	27
Expected Cost:	3,699	3,816
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

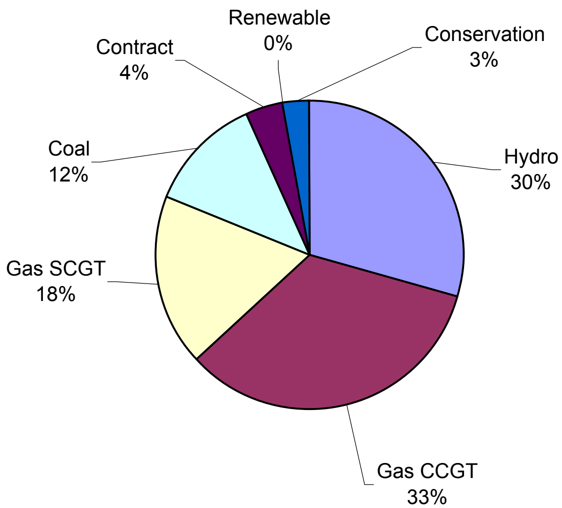
Appendix I - Portfolios and Analysis Results

Case Number 36
Case Name C1 Energy A1 Cap All Gas

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets the highest deficit month plus 10% of the deficit

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	25	50	-	50	25	75	125	450	200	1,000	42%
SCGT	-	-	-	50	25	50	-	50	75	50	300	13%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	7	7	24	7	3	10	17	61	-	175	7%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	425	25	-	175	-	-	-	-	-	-	625	26%
System Exchange	-	-	-	25	-	25	25	-	50	-	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

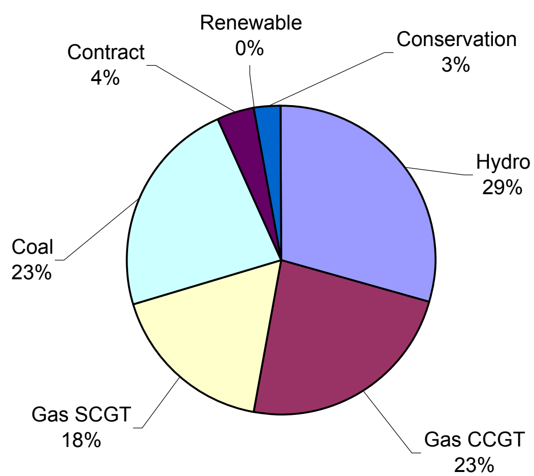
	Aurora Case:	Case III	Case I
Static Analysis			
	Gross Revenue Requirement:	3,239	3,232
	Market Sales Revenue:	(1,482)	(1,209)
	Market Purchase Expense:	431	447
	Existing Fleet Variable Costs:	1,454	1,308
	End Effects:	(35)	(33)
	Expected Cost:	3,607	3,745
Probabilistic Analysis			
	Iterations:	-	
	Coefficient of Variability:	0%	
	Standard Deviation:	-	
	+ 2 sigma	-	
	- 2 sigma	-	

Appendix I - Portfolios and Analysis Results

Case Number 37
Case Name C1 Energy A1 Cap Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets the highest deficit month plus 10% of the deficit

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	25	-	-	-	50	-	50	225	100	450	19%
SCGT	-	-	-	50	50	25	25	50	125	25	350	15%
Coal	-	-	50	-	50	-	50	75	225	125	575	24%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	7	-	24	-	7	-	7	30	-	114	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	425	25	-	175	-	-	-	-	-	-	625	26%
System Exchange	-	-	-	25	-	-	-	50	50	-	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	6%



Analytical Results ($'s in millions)

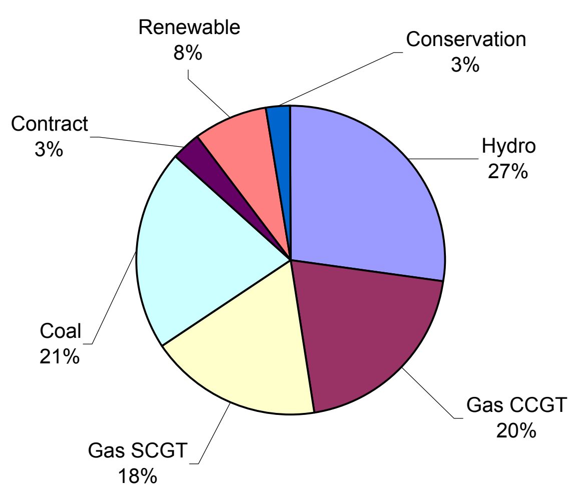
Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,199	3,180
Market Sales Revenue:	(1,446)	(1,172)
Market Purchase Expense:	351	377
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(74)	(74)
Expected Cost:	3,484	3,620
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

Appendix I - Portfolios and Analysis Results

Case Number 38
Case Name C1 Energy A1 Cap Wind 5% Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets the highest deficit month plus 10% of the deficit

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	25	-	50	225	100	400	14%
SCGT	-	-	-	100	50	75	25	100	125	-	475	17%
Coal	-	-	50	-	50	-	50	50	225	125	550	19%
Wind	-	100	-	100	-	100	-	100	-	50	450	16%
Duct Fired	40	-	-	24	-	3	-	7	30	-	104	4%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	425	-	-	175	-	-	-	-	-	-	600	21%
System Exchange	-	-	-	25	-	-	-	25	50	-	100	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,322	3,302
Market Sales Revenue:	(1,507)	(1,230)
Market Purchase Expense:	325	347
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(45)	(45)
Expected Cost:	3,549	3,683
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

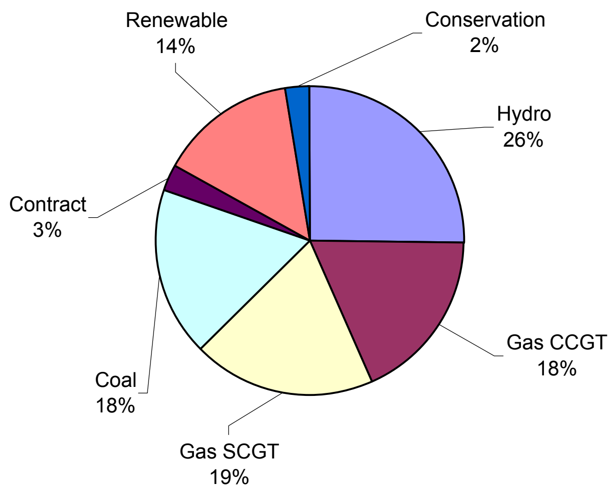
Appendix I - Portfolios and Analysis Results

Case Number 39
Case Name C1 Energy A1 Cap Wind 10% Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets the highest deficit month plus 10% of the deficit

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	50	225	100	375	11%
SCGT	-	-	-	175	50	100	25	125	125	25	625	19%
Coal	-	-	25	-	25	-	50	25	225	100	450	14%
Wind	-	200	-	200	-	200	-	200	-	100	900	28%
Duct Fired	40	-	-	20	-	-	-	7	30	-	97	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	425	-	-	150	-	-	-	-	-	-	575	18%
System Exchange	-	-	-	25	-	-	-	25	50	-	100	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,405	3,364
Market Sales Revenue:	(1,529)	(1,246)
Market Purchase Expense:	318	338
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(3)	(2)
Expected Cost:	3,645	3,763
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

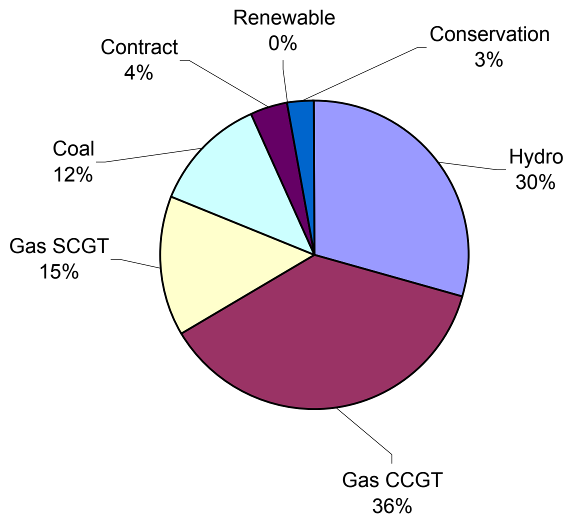
Appendix I - Portfolios and Analysis Results

Case Number 40
Case Name C2 Energy A1 Cap All Gas

Capacity Standard: 2003 deficit level maintained
Energy Standard: All months are at least 110% of the total monthly load

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	175	75	25	25	50	50	50	100	425	175	1,150	49%
SCGT	-	-	-	-	-	-	-	-	75	50	125	5%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	14	3	20	7	7	7	14	57	-	168	7%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	500	25	-	125	-	-	-	-	-	-	650	27%
System Exchange	-	-	-	25	-	-	50	-	50	-	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,842	3,806
Market Sales Revenue:	(2,061)	(1,697)
Market Purchase Expense:	337	353
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(63)	(61)
Expected Cost:	3,510	3,709
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

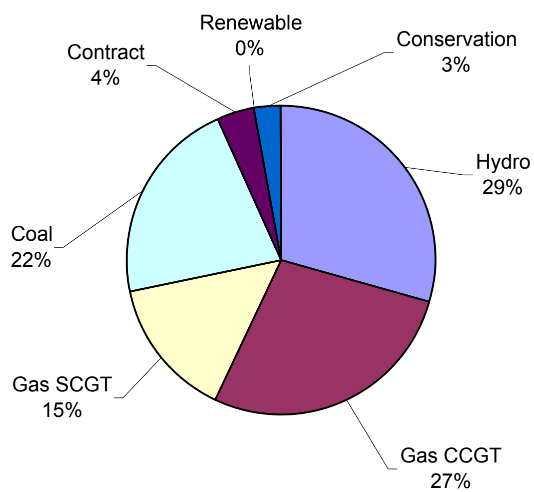
Appendix I - Portfolios and Analysis Results

Case Number 41
Case Name C2 Energy A1 Cap Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: All months are at least 110% of the total monthly load

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	175	75	-	25	-	50	-	50	200	75	650	27%
SCGT	-	-	-	-	-	-	-	-	125	75	200	8%
Coal	-	-	25	-	50	-	50	50	225	100	500	21%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	14	-	20	-	7	-	7	27	-	114	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	500	25	-	125	-	-	-	-	-	-	650	27%
System Exchange	-	-	-	25	-	-	50	-	50	-	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,788	3,741
Market Sales Revenue:	(2,003)	(1,637)
Market Purchase Expense:	268	292
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(91)	(90)
Expected Cost:	3,416	3,613
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

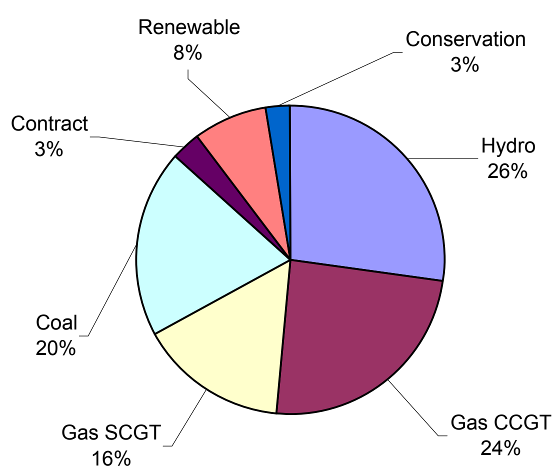
Appendix I - Portfolios and Analysis Results

Case Number 42
Case Name C2 Energy A1 Cap Wind 5% Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: All months are at least 110% of the total monthly load

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	175	50	-	-	-	25	-	50	200	75	575	20%
SCGT	-	-	-	-	-	-	-	125	125	75	325	11%
Coal	-	-	25	-	25	-	50	50	225	100	475	17%
Wind	-	100	-	100	-	100	-	100	-	50	450	16%
Duct Fired	40	10	-	17	-	3	-	7	27	-	104	4%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	500	25	-	125	-	-	-	-	-	-	650	23%
System Exchange	-	-	-	25	-	-	25	-	50	-	100	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,881	3,837
Market Sales Revenue:	(2,037)	(1,672)
Market Purchase Expense:	244	266
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(58)	(57)
Expected Cost:	3,485	3,681
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

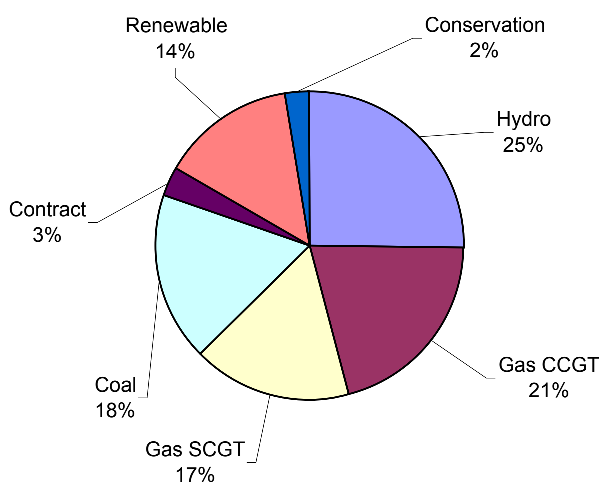
Appendix I - Portfolios and Analysis Results

Case Number 43
Case Name C2 Energy A1 Cap Wind 10% Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: All months are at least 110% of the total monthly load

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	175	-	-	-	-	-	-	50	200	75	500	15%
SCGT	-	-	-	-	-	75	25	125	175	75	475	14%
Coal	-	-	25	-	50	-	25	50	200	100	450	14%
Wind	-	200	-	200	-	200	-	200	-	100	900	27%
Duct Fired	40	3	-	14	-	-	-	7	27	-	91	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	500	25	-	100	-	-	-	-	-	-	625	19%
System Exchange	-	-	-	25	-	-	25	-	50	-	100	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,961	3,923
Market Sales Revenue:	(2,061)	(1,701)
Market Purchase Expense:	224	244
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(22)	(22)
Expected Cost:	3,557	3,752
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

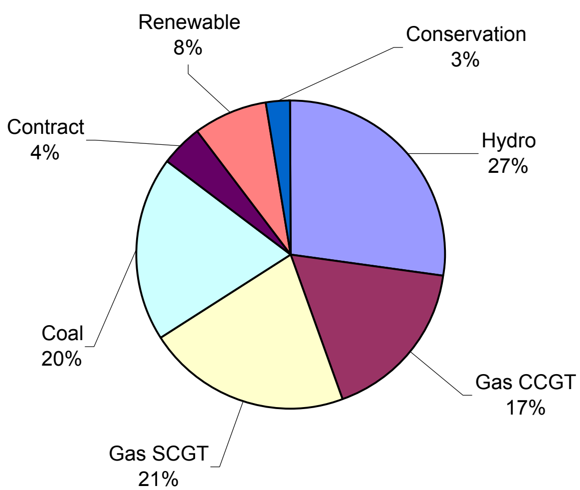
Appendix I - Portfolios and Analysis Results

Case Number 44
Case Name B1 Energy-SQ Cap Wind (5%) G&C

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	50	-	-	25	200	75	350	12%
SCGT	-	-	-	200	25	75	-	150	175	25	650	23%
Coal	-	-	50	-	-	-	50	50	225	100	475	17%
Wind	-	100	-	100	-	100	-	100	-	50	450	16%
Duct Fired	54	-	-	10	7	-	-	3	27	10	111	4%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	75	-	-	-	-	-	-	475	17%
System Exchange	-	-	-	75	-	25	25	-	25	25	175	6%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,003	3,000
Market Sales Revenue:	(1,251)	(987)
Market Purchase Expense:	422	430
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(10)	(9)
Expected Cost:	3,618	3,743
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

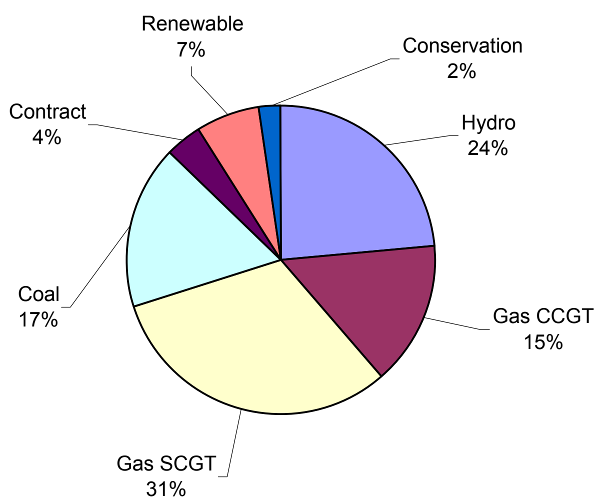
Appendix I - Portfolios and Analysis Results

Case Number 45
Case Name B1 Energy-B1 Cap Wind (5%) G&C

Capacity Standard: Meets 23 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	50	-	-	25	200	75	350	9%
SCGT	625	75	50	225	50	75	-	175	175	50	1,500	41%
Coal	-	-	50	-	-	-	50	50	225	100	475	13%
Wind	-	100	-	100	-	100	-	100	-	50	450	12%
Duct Fired	54	-	-	10	7	-	-	3	27	10	111	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	75	-	-	-	-	-	-	475	13%
System Exchange	-	-	-	75	-	25	25	-	25	25	175	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,307	3,290
Market Sales Revenue:	(1,292)	(1,012)
Market Purchase Expense:	420	429
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	62	64
Expected Cost:	3,951	4,079
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

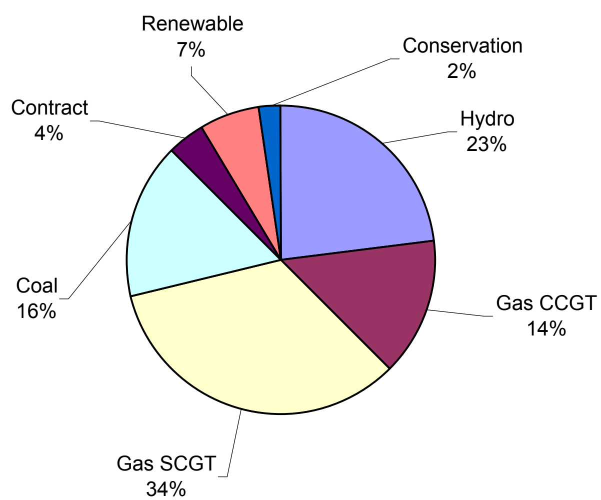
Appendix I - Portfolios and Analysis Results

Case Number 46
Case Name B1 Energy-A2 Cap Wind (5%) G&C

Capacity Standard: Meets 19 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	50	-	-	25	200	75	350	9%
SCGT	825	100	50	225	50	75	25	150	200	25	1,725	44%
Coal	-	-	50	-	-	-	50	50	225	100	475	12%
Wind	-	100	-	100	-	100	-	100	-	50	450	12%
Duct Fired	54	-	-	10	7	-	-	3	27	10	111	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	75	-	-	-	-	-	-	475	12%
System Exchange	-	-	-	75	-	25	25	-	25	25	175	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,393	3,371
Market Sales Revenue:	(1,305)	(1,019)
Market Purchase Expense:	420	429
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	79	81
Expected Cost:	4,041	4,171
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

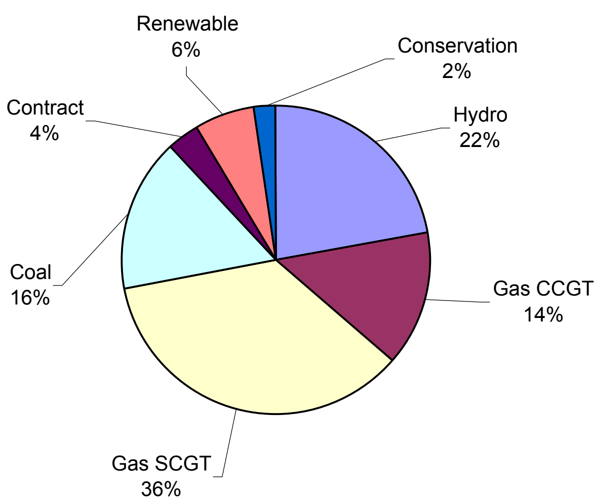
Appendix I - Portfolios and Analysis Results

Case Number 47
Case Name B1 Energy-B2 Cap Wind (5%) G&C

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	50	-	-	25	200	75	350	9%
SCGT	975	100	50	250	50	75	25	175	175	50	1,925	47%
Coal	-	-	50	-	-	-	50	50	225	100	475	12%
Wind	-	100	-	100	-	100	-	100	-	50	450	11%
Duct Fired	54	-	-	10	7	-	-	3	27	10	111	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	75	-	-	-	-	-	-	475	12%
System Exchange	-	-	-	75	-	25	25	-	25	25	175	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,462	3,437
Market Sales Revenue:	(1,314)	(1,025)
Market Purchase Expense:	420	429
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	97	99
Expected Cost:	4,118	4,249
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

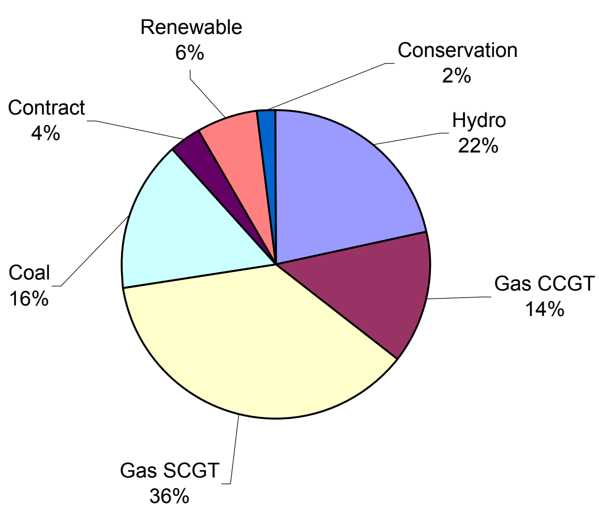
Appendix I - Portfolios and Analysis Results

Case Number 48
Case Name B1 Energy-C Cap Wind (5%) G&C

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	50	-	-	25	200	75	350	8%
SCGT	1,150	100	50	250	50	75	25	175	175	50	2,100	49%
Coal	-	-	50	-	-	-	50	50	225	100	475	11%
Wind	-	100	-	100	-	100	-	100	-	50	450	10%
Duct Fired	54	-	-	10	7	-	-	3	27	10	111	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	75	-	-	-	-	-	-	475	11%
System Exchange	-	-	-	75	-	25	25	-	25	25	175	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	3%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,528	3,500
Market Sales Revenue:	(1,324)	(1,031)
Market Purchase Expense:	420	429
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	110	113
Expected Cost:	4,189	4,319
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

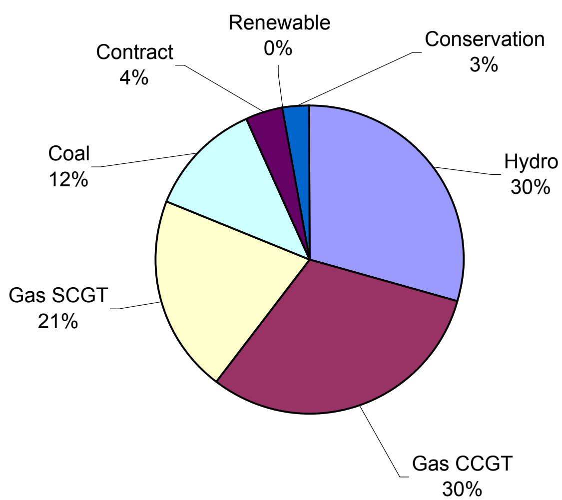
Appendix I - Portfolios and Analysis Results

Case Number 49
Case Name B1 Energy - SQ Cap all Gas

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	75	-	25	50	50	100	425	175	900	38%
SCGT	-	-	-	75	75	-	-	125	125	25	425	18%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	54	-	10	24	3	7	7	14	57	24	199	8%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	175	-	-	-	-	-	-	575	24%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,030	3,013
Market Sales Revenue:	(1,312)	(1,041)
Market Purchase Expense:	487	502
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(16)	(13)
Expected Cost:	3,643	3,770
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	14%	
Standard Deviation:	510	
+ 2 sigma	4,663	
- 2 sigma	2,623	

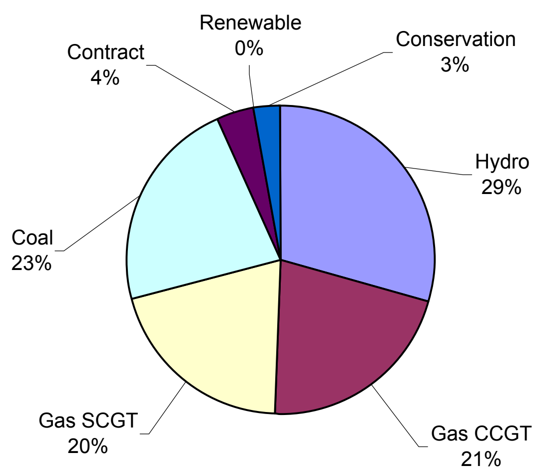
Appendix I - Portfolios and Analysis Results

Case Number 50
Case Name B1 Energy - SQ Cap C&G

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	25	-	-	50	200	100	375	16%
SCGT	-	-	-	100	50	25	-	125	175	-	475	20%
Coal	-	-	75	-	-	50	50	50	225	100	550	23%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	54	-	-	24	3	-	-	7	27	14	128	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	175	-	-	-	-	-	-	575	24%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

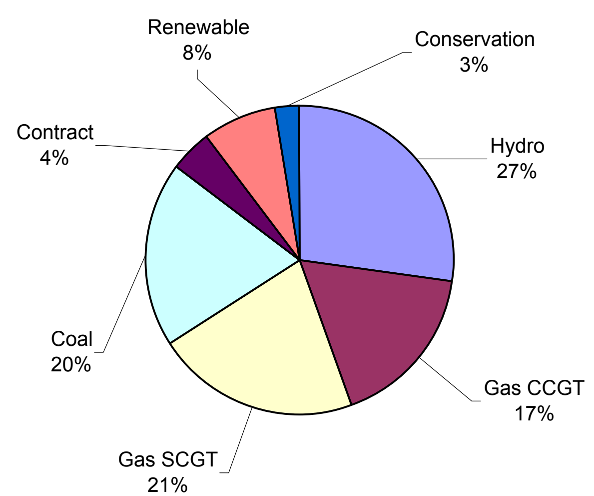
Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,975	2,955
Market Sales Revenue:	(1,268)	(998)
Market Purchase Expense:	413	437
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(53)	(52)
Expected Cost:	3,522	3,650
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	15%	
Standard Deviation:	528	
+ 2 sigma	4,578	
- 2 sigma	2,465	

Appendix I - Portfolios and Analysis Results

Case Number 51
Case Name B1 Energy - SQ Cap Wind 5% G&C

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	50	-	-	25	200	75	350	12%
SCGT	-	-	-	200	25	75	-	150	175	25	650	23%
Coal	-	-	50	-	-	-	50	50	225	100	475	17%
Wind	-	100	-	100	-	100	-	100	-	50	450	16%
Duct Fired	54	-	-	10	7	-	-	3	27	10	111	4%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	75	-	-	-	-	-	-	475	17%
System Exchange	-	-	-	75	-	25	25	-	25	25	175	6%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%



Analytical Results ($'s in millions)

	Aurora Case:	Case III	Case I
Static Analysis			
	Gross Revenue Requirement:	3,003	3,000
	Market Sales Revenue:	(1,251)	(987)
	Market Purchase Expense:	422	430
	Existing Fleet Variable Costs:	1,454	1,308
	End Effects:	(10)	(9)
	Expected Cost:	3,618	3,743
Probabilistic Analysis			
	Iterations:	100	
	Coefficient of Variability:	12%	
	Standard Deviation:	434	
	+ 2 sigma	4,486	
	- 2 sigma	2,749	

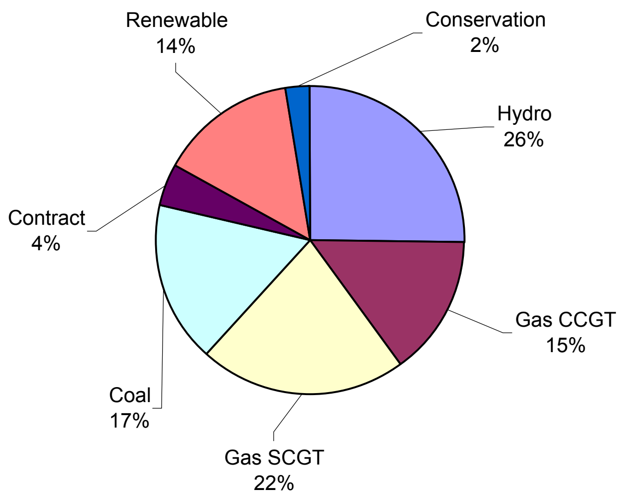
Appendix I - Portfolios and Analysis Results

Case Number 52
Case Name B1 Energy - SQ Cap Wind 10% G&C

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	25	200	75	300	9%
SCGT	-	-	25	225	50	100	25	150	150	50	775	24%
Coal	-	-	25	-	-	-	25	50	225	75	400	12%
Wind	-	200	-	200	-	200	-	200	-	100	900	27%
Duct Fired	51	-	-	10	-	-	-	3	27	10	101	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	375	-	-	75	-	-	-	-	-	-	450	14%
System Exchange	-	-	-	75	25	-	25	-	50	25	200	6%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

	Aurora Case:	Case III	Case I
Static Analysis			
	Gross Revenue Requirement:	3,050	3,054
	Market Sales Revenue:	(1,253)	(993)
	Market Purchase Expense:	422	419
	Existing Fleet Variable Costs:	1,454	1,308
	End Effects:	26	27
	Expected Cost:	3,700	3,817
Probabilistic Analysis			
	Iterations:	100	
	Coefficient of Variability:	13%	
	Standard Deviation:	481	
	+ 2 sigma	4,662	
	- 2 sigma	2,738	

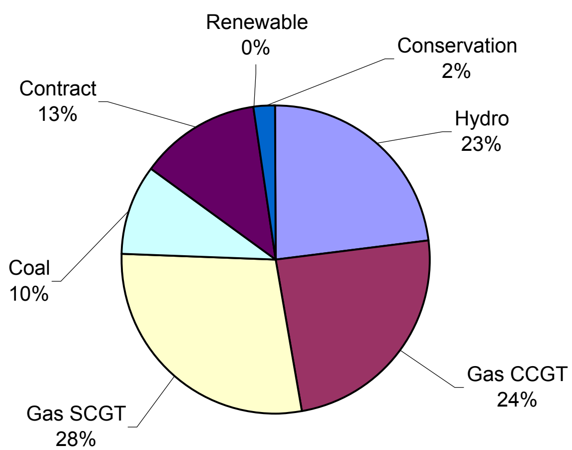
Appendix I - Portfolios and Analysis Results

Case Number 53
Case Name B1 all Gas with Deferral

Capacity Standard: Meets 23 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	100	25	150	425	175	875	22%
SCGT	-	-	-	-	-	1,000	25	75	150	-	1,250	32%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	-	-	-	-	-	98	3	20	57	24	203	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	-	-	-	-	-	625	-	-	-	-	625	16%
System Exchange	400	25	25	200	50	25	25	-	25	25	800	20%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,447	3,653
Market Sales Revenue:	(1,302)	(1,630)
Market Purchase Expense:	433	757
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	84	87
Expected Cost:	4,117	4,177
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	19%	
Standard Deviation:	782	
+ 2 sigma	5,681	
- 2 sigma	2,552	

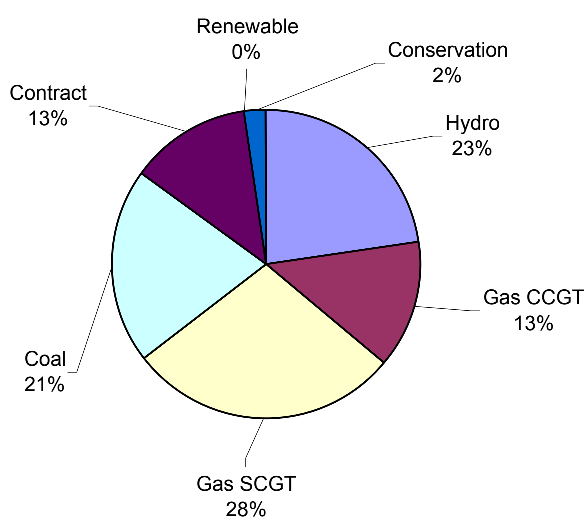
Appendix I - Portfolios and Analysis Results

Case Number 54
Case Name B1 Coal & Gas with Deferral

Capacity Standard: Meets 23 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	75	200	100	375	9%
SCGT	-	-	-	-	-	1,050	25	75	200	25	1,375	35%
Coal	-	-	-	-	-	375	25	75	225	75	775	20%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	-	-	-	-	-	51	-	10	27	14	101	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	-	-	-	-	-	375	-	-	-	-	375	9%
System Exchange	400	25	25	200	50	25	25	-	25	25	800	20%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,534	3,725
Market Sales Revenue:	(1,405)	(1,636)
Market Purchase Expense:	319	567
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	24	27
Expected Cost:	3,926	3,992
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	16%	
Standard Deviation:	628	
+ 2 sigma	5,182	
- 2 sigma	2,670	

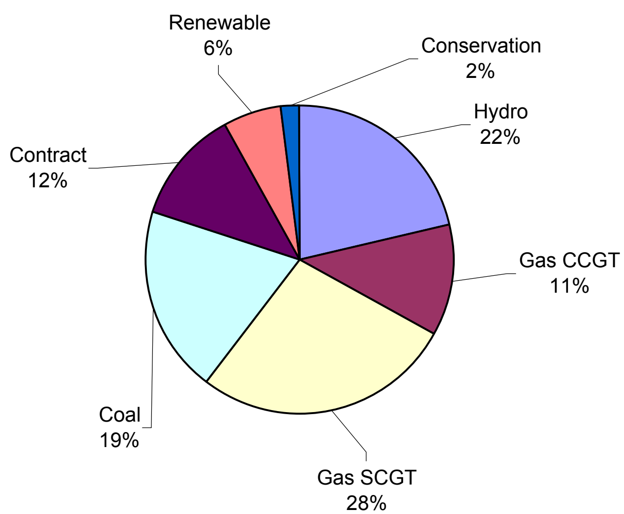
Appendix I - Portfolios and Analysis Results

Case Number 55
Case Name B1 Wind (5%) Gas and Coal with Deferral

Capacity Standard: Meets 23 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	25	200	75	300	7%
SCGT	-	-	-	-	-	1,075	-	150	200	25	1,450	33%
Coal	-	-	-	-	-	350	50	50	225	100	775	18%
Wind	-	-	-	-	-	100	100	100	100	50	450	10%
Duct Fired	-	-	-	-	-	51	-	3	27	10	91	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	-	-	-	-	-	375	-	-	-	-	375	9%
System Exchange	400	25	25	200	50	25	25	-	25	25	800	18%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	3%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,688	3,876
Market Sales Revenue:	(1,494)	(1,705)
Market Purchase Expense:	286	518
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	54	56
Expected Cost:	3,988	4,054
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	15%	
Standard Deviation:	598	
+ 2 sigma	5,184	
- 2 sigma	2,792	

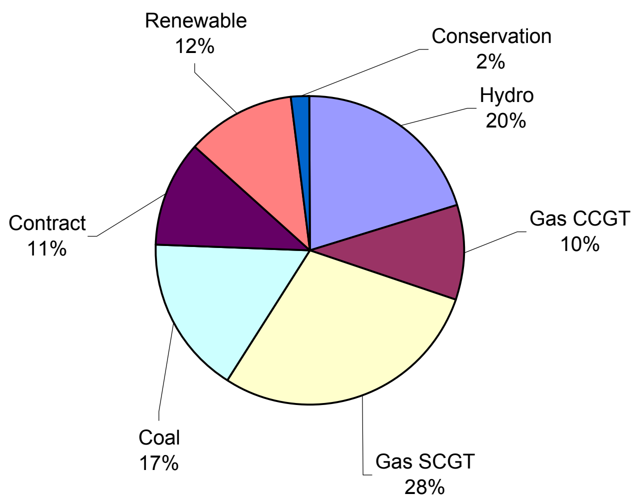
Appendix I - Portfolios and Analysis Results

Case Number 56
Case Name B1 Wind (10%) and Gas and Coal with deferral

Capacity Standard: Meets 23 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	25	175	50	250	5%
SCGT	-	-	-	-	-	1,100	75	150	225	100	1,650	34%
Coal	-	-	-	-	-	350	-	50	175	75	650	13%
Wind	-	-	-	-	-	200	200	200	200	100	900	19%
Duct Fired	-	-	-	-	-	51	-	3	24	7	84	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	-	-	-	-	-	375	-	-	-	-	375	8%
System Exchange	400	25	25	200	50	-	-	-	50	25	775	16%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	3%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,718	3,904
Market Sales Revenue:	(1,479)	(1,651)
Market Purchase Expense:	305	505
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	116	118
Expected Cost:	4,115	4,184
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	15%	
Standard Deviation:	617	
+ 2 sigma	5,349	
- 2 sigma	2,880	

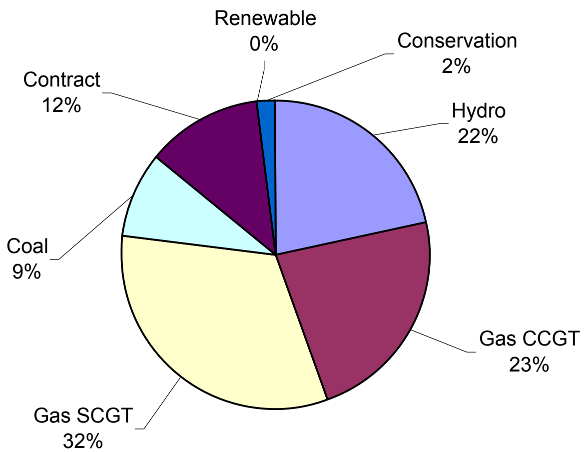
Appendix I - Portfolios and Analysis Results

Case Number 57
Case Name B2 all Gas with Deferral

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	375	25	100	425	175	1,100	25%
SCGT	-	-	-	-	-	1,375	50	100	150	25	1,700	39%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	-	-	-	-	-	101	3	17	57	24	203	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	-	-	-	-	-	375	-	25	-	-	400	9%
System Exchange	400	25	25	200	50	25	25	-	25	25	800	18%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	3%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,777	3,974
Market Sales Revenue:	(1,469)	(1,673)
Market Purchase Expense:	416	634
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	125	130
Expected Cost:	4,302	4,373
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	17%	
Standard Deviation:	731	
+ 2 sigma	5,765	
- 2 sigma	2,839	

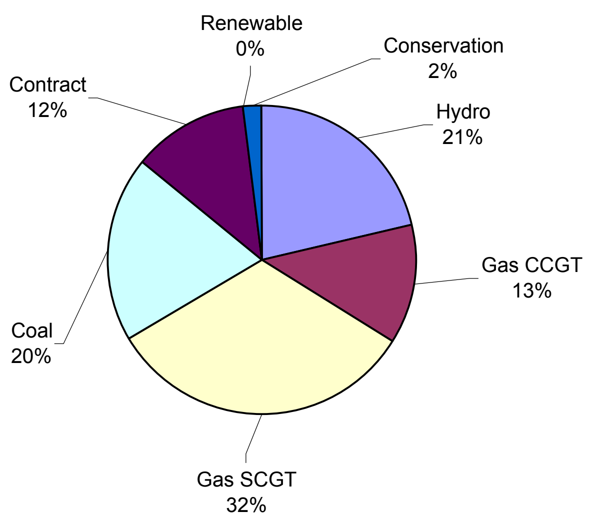
Appendix I - Portfolios and Analysis Results

Case Number 58
Case Name B2 Coal & Gas with deferral

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	75	200	100	375	9%
SCGT	-	-	-	-	-	1,450	25	100	175	50	1,800	41%
Coal	-	-	-	-	-	375	25	75	225	75	775	18%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	-	-	-	-	-	51	-	10	27	14	101	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	-	-	-	-	-	375	-	-	-	-	375	9%
System Exchange	400	25	25	200	50	25	25	-	25	25	800	18%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	3%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

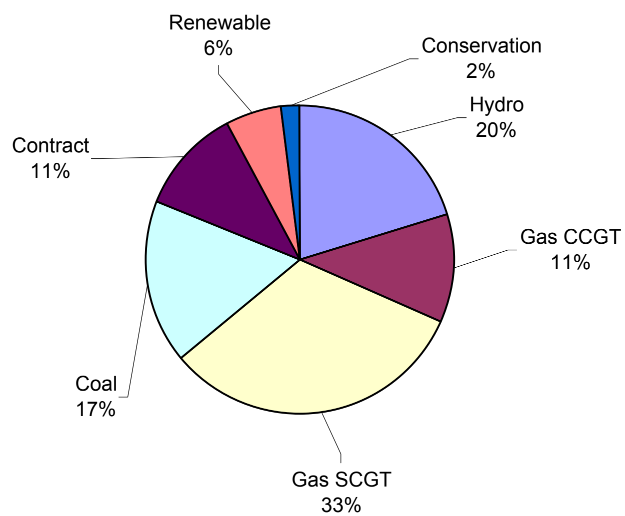
	Case III	Case I
Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,719	3,902
Market Sales Revenue:	(1,428)	(1,649)
Market Purchase Expense:	319	567
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	74	77
Expected Cost:	4,138	4,206
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	16%	
Standard Deviation:	662	
+ 2 sigma	5,462	
- 2 sigma	2,814	

Appendix I - Portfolios and Analysis Results

Case Number 59
Case Name B2 Wind (5%) Gas and Coal with deferral

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	50	200	75	325	7%
SCGT	-	-	-	-	-	1,500	50	125	200	50	1,925	40%
Coal	-	-	-	-	-	325	-	50	200	100	675	14%
Wind	-	-	-	-	-	100	100	100	100	50	450	9%
Duct Fired	-	-	-	-	-	51	-	10	27	10	98	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	-	-	-	-	-	375	-	25	-	-	400	8%
System Exchange	400	25	25	200	50	25	25	-	25	25	800	17%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	3%



Analytical Results ($'s in millions)

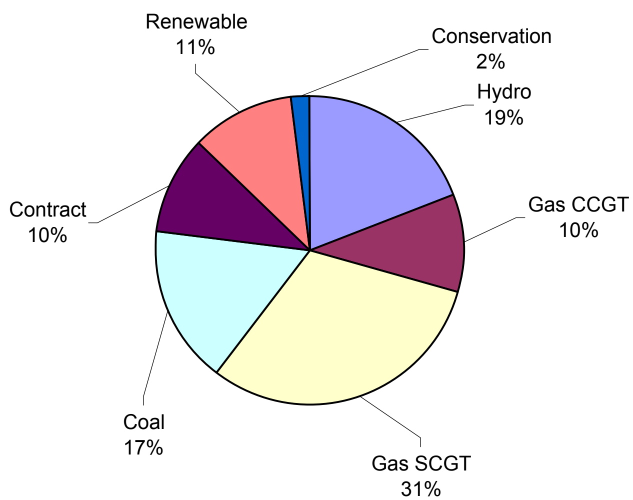
Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,790	3,972
Market Sales Revenue:	(1,430)	(1,652)
Market Purchase Expense:	312	561
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	122	125
Expected Cost:	4,248	4,315
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	15%	
Standard Deviation:	637	
+ 2 sigma	5,522	
- 2 sigma	2,974	

Case Number 60
Case Name B2 Wind (10%) and Gas and Coal with Deferral

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	25	200	75	300	6%
SCGT	-	-	-	-	-	1,500	75	175	150	75	1,975	38%
Coal	-	-	-	-	-	350	-	50	225	75	700	13%
Wind	-	-	-	-	-	200	200	200	200	100	900	17%
Duct Fired	-	-	-	-	-	51	-	3	27	10	91	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	-	-	-	-	-	375	-	-	-	-	375	7%
System Exchange	400	25	25	200	50	-	-	-	50	25	775	15%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	3%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	4,027	4,207
Market Sales Revenue:	(1,607)	(1,767)
Market Purchase Expense:	271	461
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	141	144
Expected Cost:	4,286	4,354
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	13%	
Standard Deviation:	557	
+ 2 sigma	5,401	
- 2 sigma	3,172	

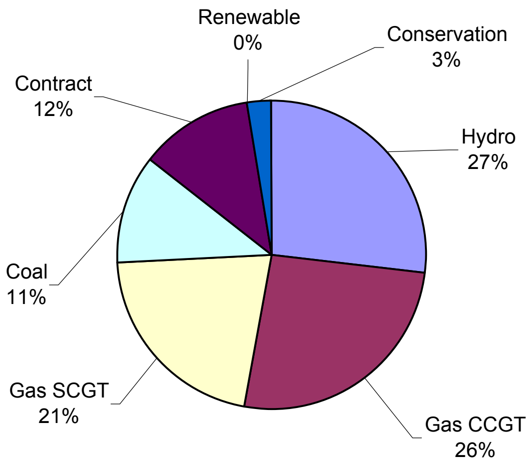
Appendix I - Portfolios and Analysis Results

Case Number 61
Case Name A1 all Gas with Deferral

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	100	25	100	425	200	850	29%
SCGT	-	-	-	-	-	325	25	125	125	25	625	22%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	-	-	-	-	-	81	3	14	57	-	155	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	-	-	-	-	-	500	-	-	-	-	500	17%
System Exchange	275	-	50	175	25	25	25	-	25	25	625	22%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

	Aurora Case:	Case III	Case I
Static Analysis			
	Gross Revenue Requirement:	2,826	2,993
	Market Sales Revenue:	(1,004)	(1,113)
	Market Purchase Expense:	563	705
	Existing Fleet Variable Costs:	1,454	1,308
	End Effects:	18	20
	Expected Cost:	3,856	3,914
Probabilistic Analysis			
	Iterations:	100	
	Coefficient of Variability:	16%	
	Standard Deviation:	617	
	+ 2 sigma	5,091	
	- 2 sigma	2,622	

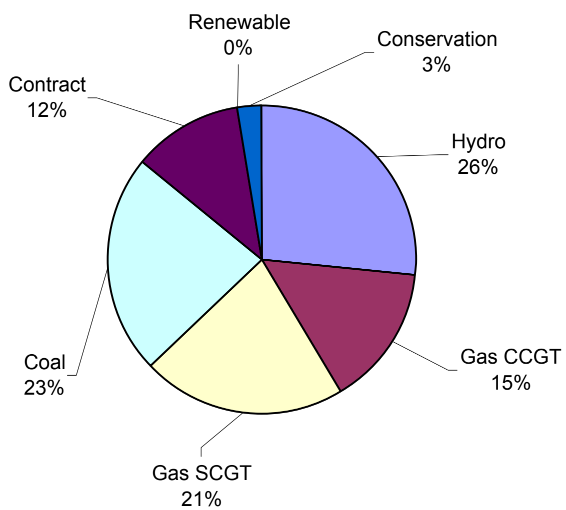
Appendix I - Portfolios and Analysis Results

Case Number 62
Case Name A1 Coal & Gas with Deferral

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	25	50	225	100	400	14%
SCGT	-	-	-	-	-	400	25	75	175	25	700	24%
Coal	-	-	-	-	-	300	-	75	225	100	700	24%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	-	-	-	-	-	41	3	7	30	-	81	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	-	-	-	-	-	300	-	-	-	-	300	10%
System Exchange	275	-	50	175	25	25	-	25	-	25	600	20%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,921	3,074
Market Sales Revenue:	(1,104)	(1,130)
Market Purchase Expense:	454	531
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(43)	(41)
Expected Cost:	3,682	3,742
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	16%	
Standard Deviation:	589	
+ 2 sigma	4,860	
- 2 sigma	2,504	

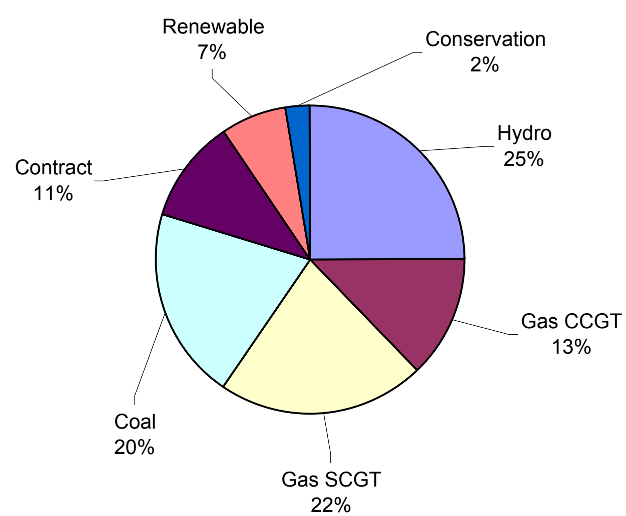
Appendix I - Portfolios and Analysis Results

Case Number 63
Case Name A1 Wind (5%) Gas and Coal with Deferral

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	50	200	100	350	10%
SCGT	-	-	-	-	-	425	50	100	225	25	825	24%
Coal	-	-	-	-	-	275	-	75	200	75	625	19%
Wind	-	-	-	-	-	100	100	100	100	50	450	13%
Duct Fired	-	-	-	-	-	41	-	7	27	-	74	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	-	-	-	-	-	300	-	-	-	-	300	9%
System Exchange	275	-	50	175	25	25	-	-	25	25	600	18%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,014	3,167
Market Sales Revenue:	(1,135)	(1,151)
Market Purchase Expense:	440	508
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	2	3
Expected Cost:	3,775	3,836
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	14%	
Standard Deviation:	529	
+ 2 sigma	4,833	
- 2 sigma	2,718	

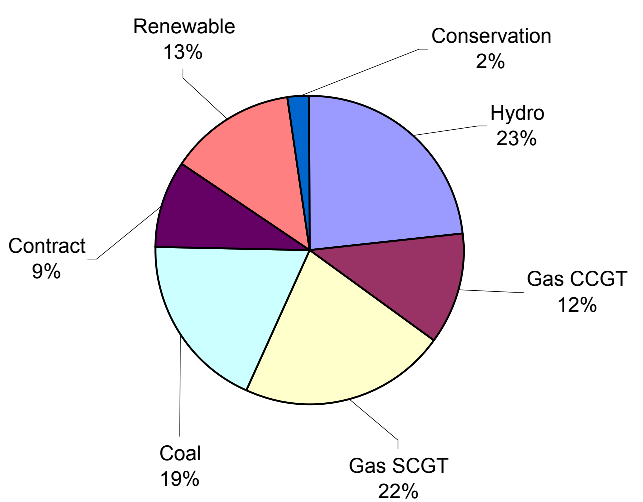
Appendix I - Portfolios and Analysis Results

Case Number 64
Case Name A1 Wind (10%) and Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	50	200	75	325	8%
SCGT	-	-	-	-	-	450	75	100	225	75	925	24%
Coal	-	-	-	-	-	275	-	50	200	75	600	16%
Wind	-	-	-	-	-	200	200	200	200	100	900	24%
Duct Fired	-	-	-	-	-	41	-	7	27	-	74	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	-	-	-	-	-	300	-	-	-	-	300	8%
System Exchange	275	-	50	175	25	-	-	-	-	25	550	14%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	15	15	15	15	15	15	15	15	15	15	150	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

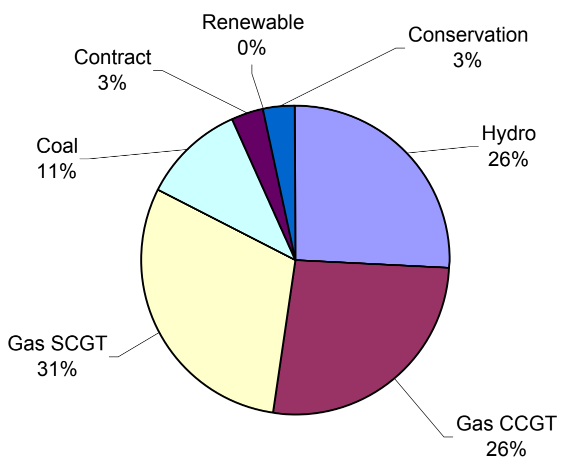
Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,206	3,357
Market Sales Revenue:	(1,259)	(1,232)
Market Purchase Expense:	411	439
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	34	36
Expected Cost:	3,847	3,908
Probabilistic Analysis		
Iterations:	100	
Coefficient of Variability:	13%	
Standard Deviation:	500	
+ 2 sigma	4,847	
- 2 sigma	2,847	

Case Number 65
Case Name 20 MW Conservation B1 all Gas

Capacity Standard: Meets 23 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	50	-	25	50	50	100	400	175	850	27%
SCGT	600	75	25	175	25	-	-	100	175	-	1,175	38%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	54	-	7	24	3	7	7	14	54	24	192	6%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	175	-	-	-	-	-	-	575	18%
System Exchange	-	-	-	-	25	25	25	-	25	25	125	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,210	3,176
Market Sales Revenue:	(1,408)	(1,108)
Market Purchase Expense:	448	469
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	47	51
Expected Cost:	3,751	3,895
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

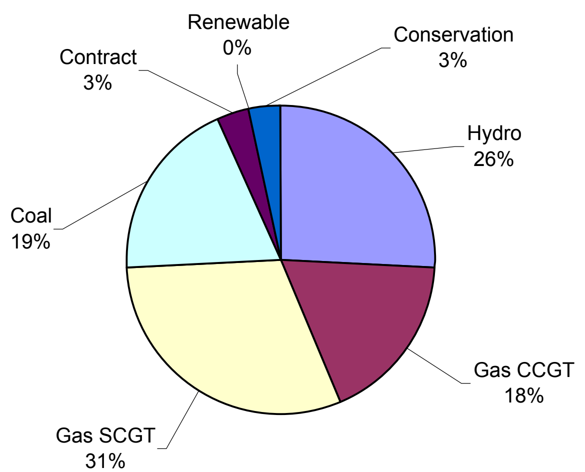
Appendix I - Portfolios and Analysis Results

Case Number 66
Case Name 20 MW Conservation B1 Coal & Gas

Capacity Standard: Meets 23 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	25	-	-	50	175	100	350	11%
SCGT	600	75	25	200	25	-	-	125	200	-	1,250	40%
Coal	-	-	50	-	-	50	50	50	225	100	525	17%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	54	-	-	24	3	-	-	7	24	14	125	4%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	175	-	-	-	-	-	-	575	18%
System Exchange	-	-	-	-	25	25	25	-	25	25	125	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,168	3,124
Market Sales Revenue:	(1,368)	(1,069)
Market Purchase Expense:	375	406
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	16	18
Expected Cost:	3,646	3,787
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

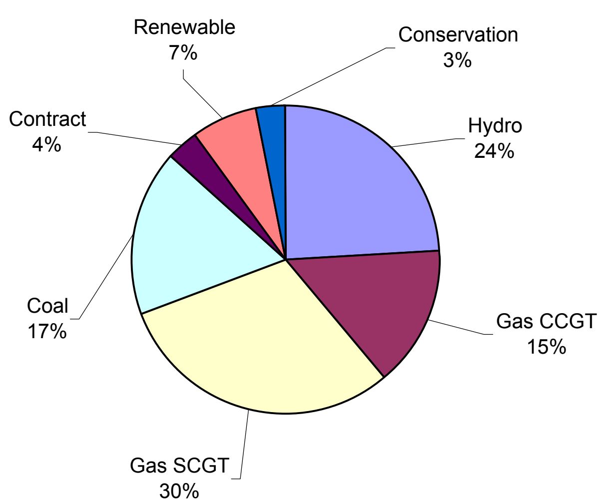
Appendix I - Portfolios and Analysis Results

Case Number 67
Case Name 20 MW Conservation B1 Wind (5%) Gas and Coal

Capacity Standard: Meets 23 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	50	-	-	25	200	75	350	10%
SCGT	625	75	25	225	25	100	-	150	150	25	1,400	39%
Coal	-	-	50	-	-	-	50	50	225	100	475	13%
Wind	-	100	-	100	-	100	-	100	-	50	450	13%
Duct Fired	51	-	-	10	7	-	-	3	27	10	108	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	375	-	-	75	-	-	-	-	-	-	450	13%
System Exchange	-	-	-	75	-	-	-	25	25	25	150	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,235	3,190
Market Sales Revenue:	(1,385)	(1,084)
Market Purchase Expense:	362	390
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	50	52
Expected Cost:	3,717	3,856
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

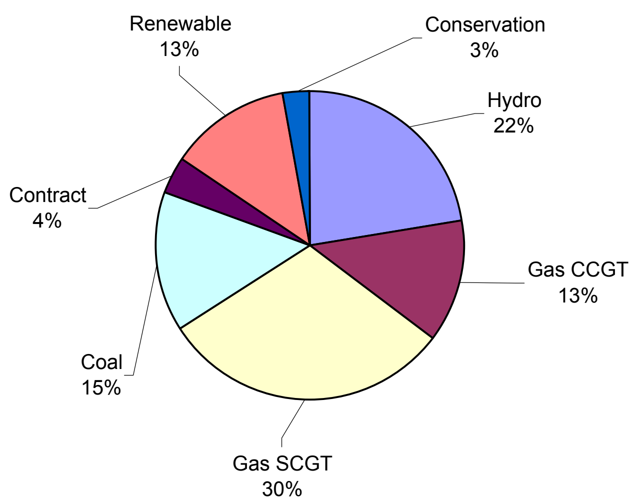
Appendix I - Portfolios and Analysis Results

Case Number 68
Case Name 20 MW Conservation B1 Wind (10%) and Gas and Coal

Capacity Standard: Meets 23 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	25	200	75	300	7%
SCGT	650	100	25	225	75	75	50	150	175	50	1,575	39%
Coal	-	-	25	-	-	-	25	50	200	75	375	9%
Wind	-	200	-	200	-	200	-	200	-	100	900	22%
Duct Fired	47	-	-	10	-	-	-	3	27	10	98	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	350	-	-	75	-	-	-	-	-	-	425	10%
System Exchange	-	-	-	75	25	-	-	-	50	25	175	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,274	3,230
Market Sales Revenue:	(1,369)	(1,067)
Market Purchase Expense:	363	389
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	96	98
Expected Cost:	3,818	3,959
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

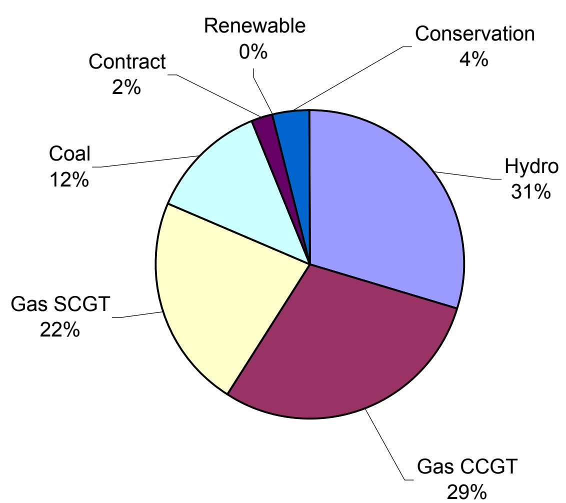
Appendix I - Portfolios and Analysis Results

Case Number 69
Case Name 20 MW Conservation A1 all Gas

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	25	-	25	75	25	125	400	250	925	40%
SCGT	-	75	25	150	25	-	-	100	175	-	550	24%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	-	3	24	3	10	3	17	54	-	155	7%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	275	-	-	175	-	-	-	-	-	-	450	19%
System Exchange	-	-	-	25	-	25	-	-	-	-	50	2%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	9%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,694	2,684
Market Sales Revenue:	(1,166)	(918)
Market Purchase Expense:	528	550
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(3)	0
Expected Cost:	3,507	3,625
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

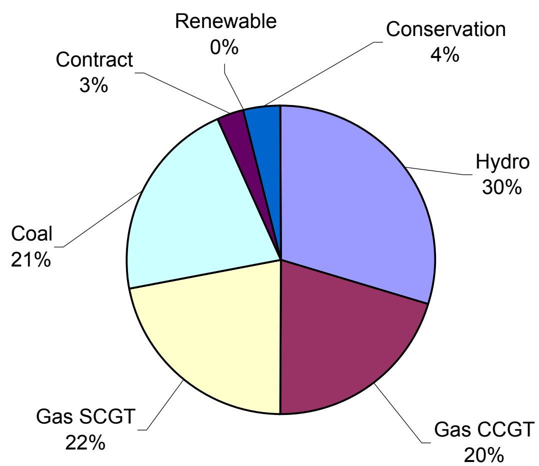
Appendix I - Portfolios and Analysis Results

Case Number 70
Case Name 20 MW Conservation A1 Coal & Gas

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	25	25	25	50	200	125	450	19%
SCGT	-	75	25	150	25	-	25	75	200	-	575	25%
Coal	-	-	25	-	-	50	-	75	200	125	475	20%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	-	-	24	3	3	3	7	27	-	108	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	275	-	-	175	-	-	-	-	-	-	450	19%
System Exchange	-	-	-	25	-	25	-	-	25	-	75	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	9%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,648	2,626
Market Sales Revenue:	(1,128)	(879)
Market Purchase Expense:	464	497
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(36)	(34)
Expected Cost:	3,402	3,518
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

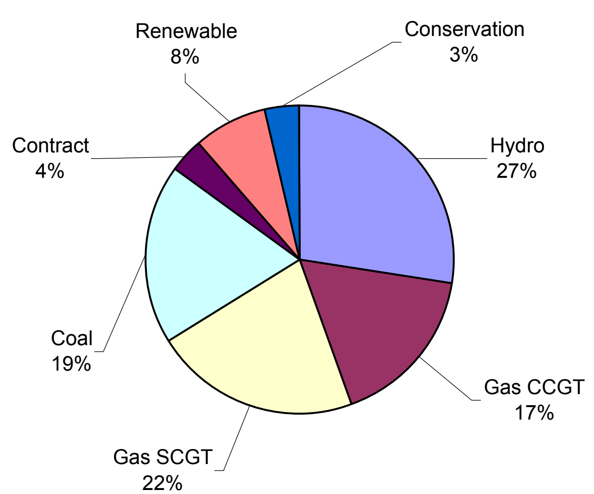
Appendix I - Portfolios and Analysis Results

Case Number 71
Case Name 20 MW Conservation A1 Wind (5%) Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	25	50	200	100	375	14%
SCGT	-	75	50	175	75	25	-	100	150	25	675	24%
Coal	-	-	-	-	-	25	-	75	225	100	425	15%
Wind	-	100	-	100	-	100	-	100	-	50	450	16%
Duct Fired	40	-	-	20	-	-	3	7	27	-	97	4%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	275	-	-	150	-	-	-	-	-	-	425	15%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	7%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,732	2,709
Market Sales Revenue:	(1,148)	(897)
Market Purchase Expense:	437	470
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(5)	(4)
Expected Cost:	3,470	3,588
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

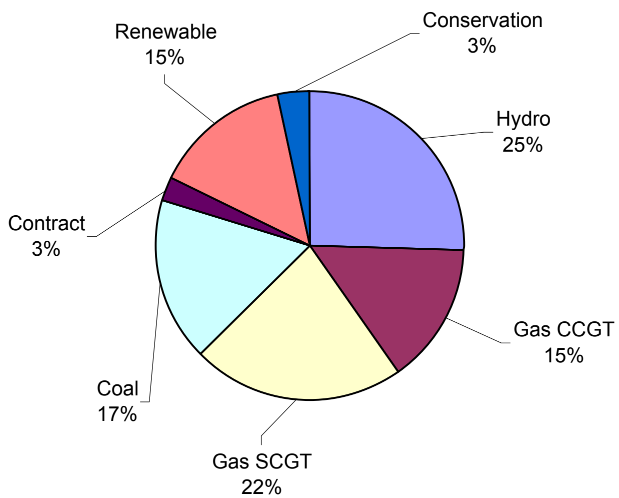
Appendix I - Portfolios and Analysis Results

Case Number 72
Case Name 20 MW Conservation A1 Wind (10%) and Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	25	50	200	100	375	12%
SCGT	25	75	50	200	75	75	-	100	200	-	800	25%
Coal	-	-	-	25	-	25	-	50	200	100	400	12%
Wind	-	200	-	200	-	200	-	200	-	100	900	28%
Duct Fired	40	-	-	17	-	-	3	7	27	-	94	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	250	-	-	125	-	-	-	-	-	-	375	12%
System Exchange	-	-	-	-	-	-	25	-	25	25	75	2%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,942	2,925
Market Sales Revenue:	(1,301)	(1,033)
Market Purchase Expense:	404	431
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	21	23
Expected Cost:	3,520	3,655
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

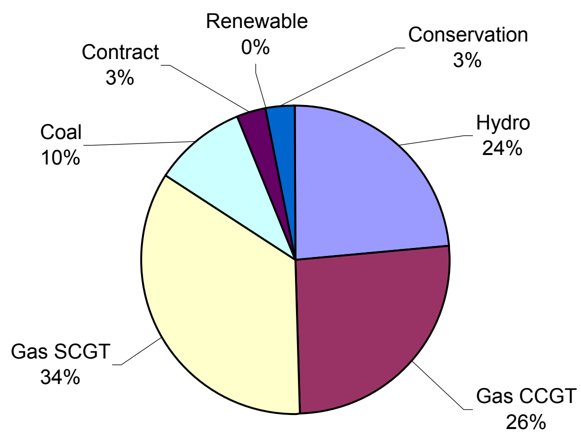
Appendix I - Portfolios and Analysis Results

Case Number 73
Case Name 20 MW Conservation C1 all Gas

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: Meets the highest deficit month plus 10% of the deficit

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	25	25	-	25	50	50	100	450	200	925	25%
SCGT	1,125	25	50	175	50	-	-	125	100	25	1,675	45%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	7	3	24	3	7	7	14	61	-	165	4%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	425	25	-	175	-	-	-	-	-	-	625	17%
System Exchange	-	-	-	25	-	25	25	-	50	-	125	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

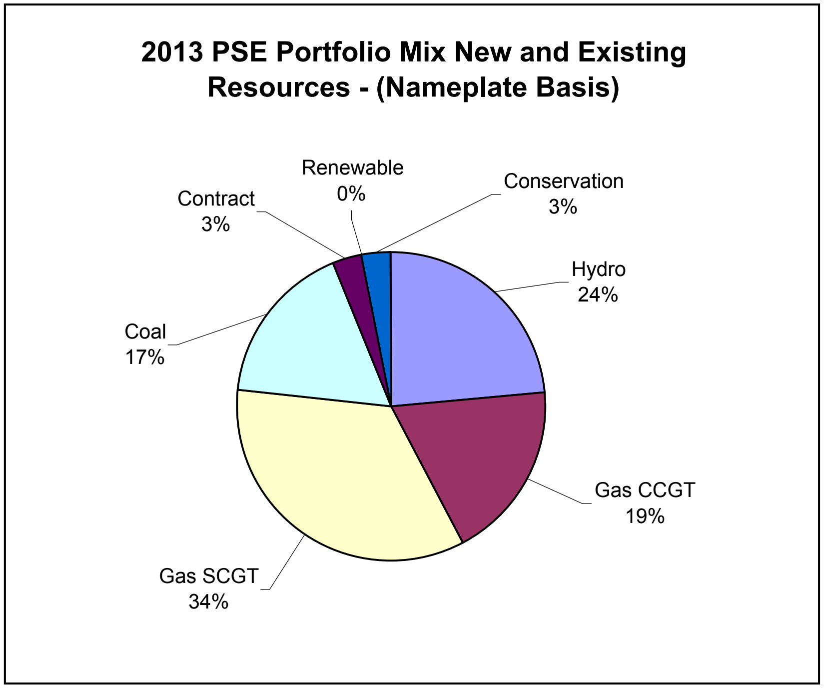
Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,586	3,541
Market Sales Revenue:	(1,567)	(1,254)
Market Purchase Expense:	406	427
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	83	87
Expected Cost:	3,963	4,109
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

Appendix I - Portfolios and Analysis Results

Case Number 74
Case Name 20 MW Conservation C1 Coal & Gas

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: Meets the highest deficit month plus 10% of the deficit

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	25	-	-	-	50	-	50	225	100	450	12%
SCGT	1,125	25	50	175	50	50	25	50	175	-	1,725	46%
Coal	-	-	25	-	25	-	50	75	225	100	500	13%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	7	-	24	-	7	-	7	30	-	114	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	425	25	-	175	-	-	-	-	-	-	625	17%
System Exchange	-	-	-	25	-	-	-	50	50	-	125	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	5%



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,567	3,511
Market Sales Revenue:	(1,544)	(1,230)
Market Purchase Expense:	334	365
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	49	51
Expected Cost:	3,861	4,006
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

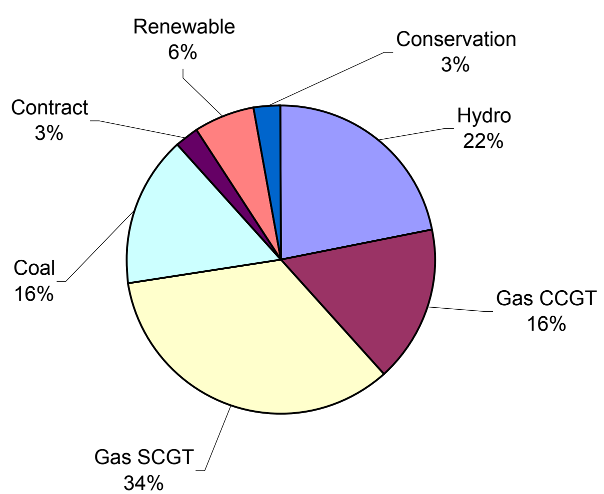
Appendix I - Portfolios and Analysis Results

Case Number 75
Case Name 20 MW Conservation C1 Wind (5%) Gas and Coal

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: Meets the highest deficit month plus 10% of the deficit

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	25	-	50	225	100	400	10%
SCGT	1,125	74	50	175	75	50	25	100	125	50	1,849	44%
Coal	-	-	25	-	25	-	50	50	225	100	475	11%
Wind	-	100	-	100	-	100	-	100	-	50	450	11%
Duct Fired	40	-	-	24	-	3	-	7	30	-	104	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	425	-	-	175	-	-	-	-	-	-	600	14%
System Exchange	-	-	-	25	-	-	-	25	50	-	100	2%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,689	3,636
Market Sales Revenue:	(1,603)	(1,286)
Market Purchase Expense:	304	333
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	79	81
Expected Cost:	3,924	4,072
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

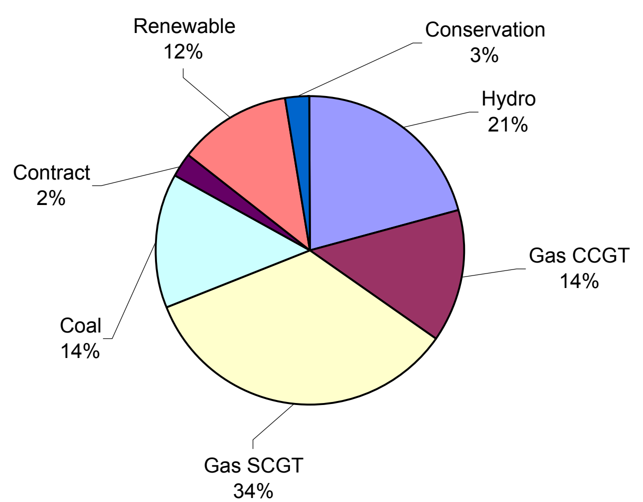
Appendix I - Portfolios and Analysis Results

Case Number 76
Case Name 20 MW Conservation C1 Wind (10%) Gas and Coal

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: Meets the highest deficit month plus 10% of the deficit

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	50	225	75	350	8%
SCGT	1,125	100	50	225	50	100	25	150	125	75	2,025	44%
Coal	-	-	25	-	25	-	25	25	225	100	425	9%
Wind	-	200	-	200	-	200	-	200	-	100	900	19%
Duct Fired	40	-	-	20	-	-	-	7	30	-	97	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	150	-	-	-	-	-	-	550	12%
System Exchange	-	-	-	-	25	-	-	25	50	-	100	2%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,792	3,740
Market Sales Revenue:	(1,653)	(1,326)
Market Purchase Expense:	292	318
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	119	121
Expected Cost:	4,003	4,161
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

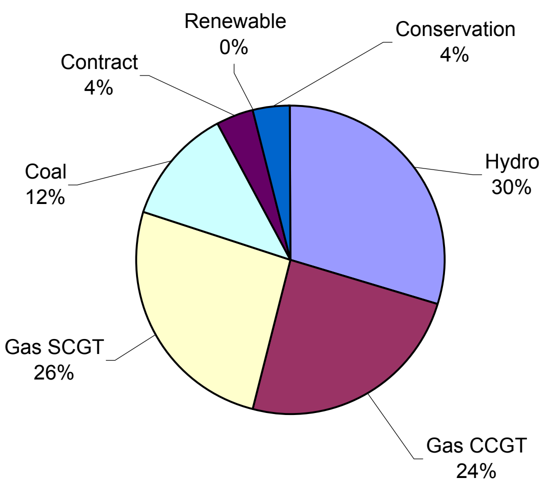
Appendix I - Portfolios and Analysis Results

Case Number 77
Case Name 20 MW Conservation Status Quo all Gas

Capacity Standard: 2003 deficit level maintained
Energy Standard: 2003 deficit level maintained

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	25	25	50	-	25	150	425	200	900	39%
SCGT	225	50	-	225	25	50	25	25	125	25	775	33%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	10	3	7	14	7	-	3	20	57	-	122	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	75	25	25	75	-	-	-	-	-	-	200	9%
System Exchange	-	-	-	25	-	25	25	-	50	-	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	9%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,216	2,220
Market Sales Revenue:	(832)	(626)
Market Purchase Expense:	727	753
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	18	22
Expected Cost:	3,584	3,677
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

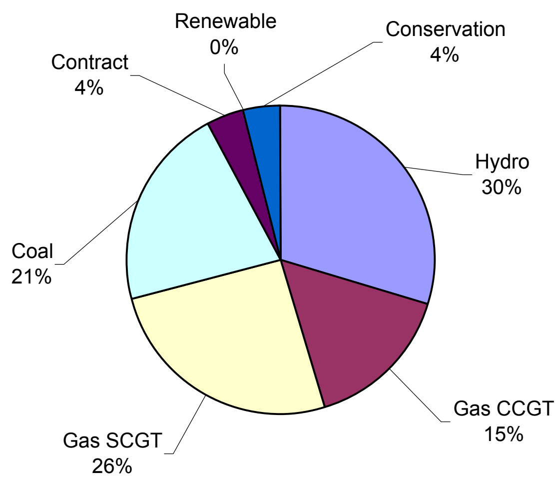
Appendix I - Portfolios and Analysis Results

Case Number 78
Case Name 20 MW Conservation Status Quo Coal & Gas

Capacity Standard: 2003 deficit level maintained
Energy Standard: 2003 deficit level maintained

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	25	-	-	-	-	-	75	225	100	425	18%
SCGT	225	25	50	200	25	75	-	50	125	25	800	34%
Coal	-	-	25	-	25	-	25	75	225	100	475	20%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	10	7	-	17	-	-	-	10	30	-	74	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	75	25	-	125	-	-	-	-	-	-	225	10%
System Exchange	-	-	-	-	25	25	25	-	50	-	125	5%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	9%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,190	2,181
Market Sales Revenue:	(810)	(602)
Market Purchase Expense:	662	700
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	(15)	(12)
Expected Cost:	3,482	3,574
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

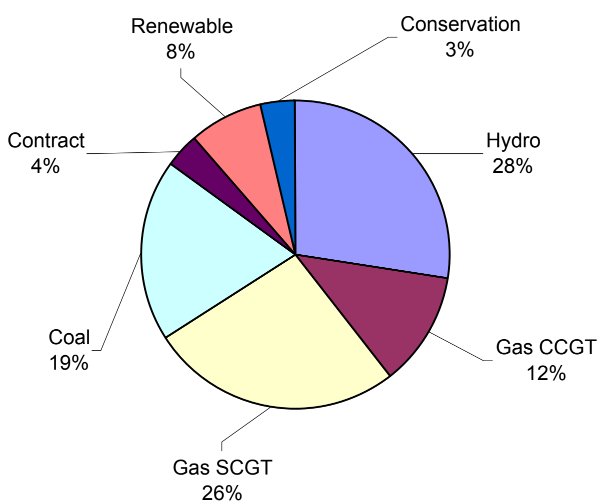
Appendix I - Portfolios and Analysis Results

Case Number 79
Case Name 20 MW Conservation Status Quo Wind (5%) Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: 2003 deficit level maintained

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	50	200	100	350	13%
SCGT	225	75	50	225	25	50	25	125	125	50	975	35%
Coal	-	-	25	-	50	-	-	50	225	100	450	16%
Wind	-	100	-	100	-	100	-	100	-	50	450	16%
Duct Fired	10	-	-	14	-	-	-	7	27	-	57	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	75	-	-	100	-	-	-	-	-	-	175	6%
System Exchange	-	-	-	25	-	25	25	-	50	-	125	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	7%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,270	2,262
Market Sales Revenue:	(838)	(626)
Market Purchase Expense:	646	681
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	23	26
Expected Cost:	3,555	3,651
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

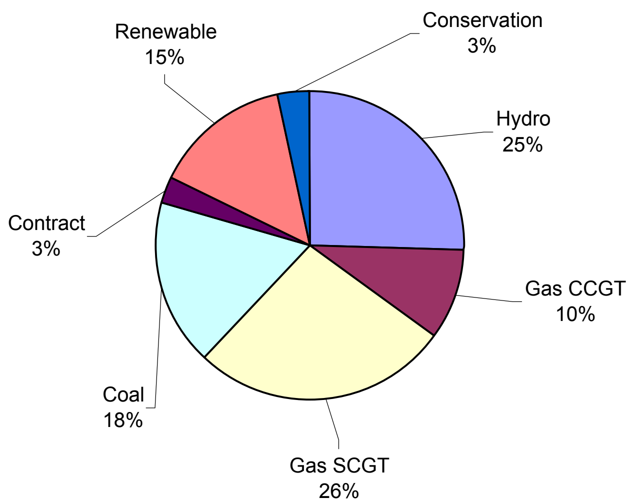
Appendix I - Portfolios and Analysis Results

Case Number 80
Case Name 20 MW Conservation Status Quo Wind (10%) and Gas and Coal

Capacity Standard: 2003 deficit level maintained
Energy Standard: 2003 deficit level maintained

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	25	200	75	300	9%
SCGT	250	75	50	225	75	100	25	125	150	50	1,125	35%
Coal	-	-	25	25	-	-	-	50	225	100	425	13%
Wind	-	200	-	200	-	200	-	200	-	100	900	28%
Duct Fired	7	-	-	10	-	-	-	3	27	-	47	1%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	50	-	-	75	-	-	-	-	-	-	125	4%
System Exchange	-	-	-	25	-	-	25	-	50	-	100	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	2,394	2,388
Market Sales Revenue:	(917)	(692)
Market Purchase Expense:	635	666
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	56	59
Expected Cost:	3,622	3,729
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

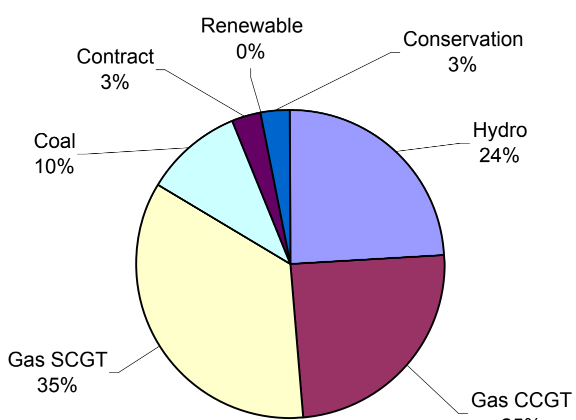
Appendix I - Portfolios and Analysis Results

Case Number 81
Case Name 20 MW Conservation B2 all Gas

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	50	-	25	50	50	100	400	175	850	24%
SCGT	975	75	25	200	25	-	-	125	150	25	1,600	45%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	54	-	7	24	3	7	7	14	54	24	192	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	175	-	-	-	-	-	-	575	16%
System Exchange	-	-	-	-	25	25	25	-	25	25	125	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,364	3,322
Market Sales Revenue:	(1,430)	(1,122)
Market Purchase Expense:	448	469
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	83	86
Expected Cost:	3,918	4,064
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

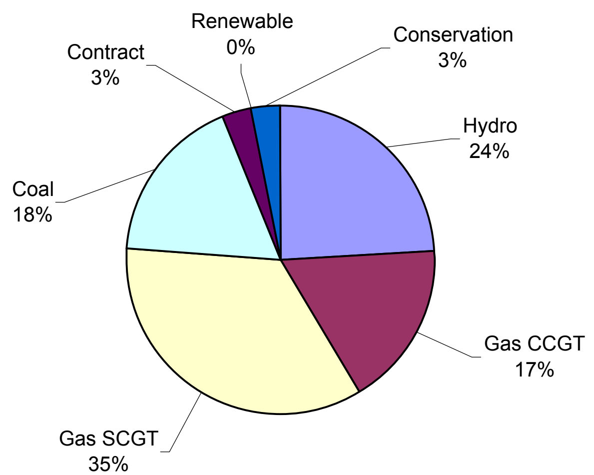
Appendix I - Portfolios and Analysis Results

Case Number 82
Case Name 20 MW Conservation B2 Coal & Gas

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	25	-	-	50	200	100	375	11%
SCGT	975	75	25	200	25	25	-	125	200	-	1,650	46%
Coal	-	-	50	-	-	50	50	50	200	100	500	14%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	54	-	-	24	3	-	-	7	27	14	128	4%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	400	-	-	175	-	-	-	-	-	-	575	16%
System Exchange	-	-	-	-	25	25	25	-	25	25	125	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,320	3,268
Market Sales Revenue:	(1,391)	(1,084)
Market Purchase Expense:	377	407
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	50	52
Expected Cost:	3,810	3,953
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

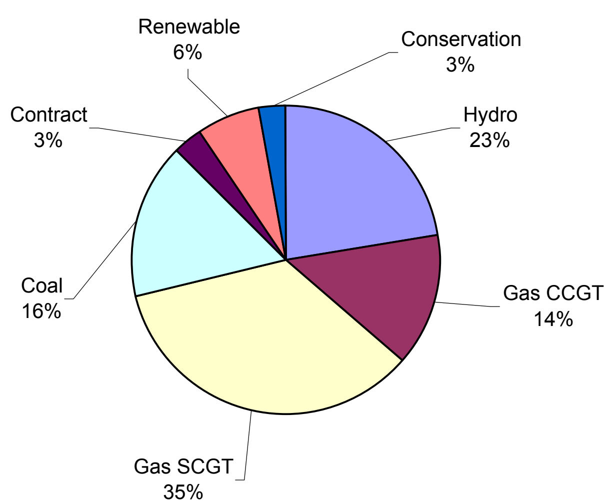
Appendix I - Portfolios and Analysis Results

Case Number 83
Case Name 20 MW Conservation B2 Wind (5%) Gas and Coal

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	50	-	-	25	200	75	350	9%
SCGT	1,000	100	-	250	25	100	-	150	175	25	1,825	46%
Coal	-	-	50	-	-	-	50	50	225	100	475	12%
Wind	-	100	-	100	-	100	-	100	-	50	450	11%
Duct Fired	51	-	-	10	7	-	-	3	27	10	108	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	375	-	-	75	-	-	-	-	-	-	450	11%
System Exchange	-	-	-	75	-	-	-	25	25	25	150	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

	Case III	Case I
Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,390	3,337
Market Sales Revenue:	(1,407)	(1,098)
Market Purchase Expense:	362	390
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	85	87
Expected Cost:	3,884	4,025
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

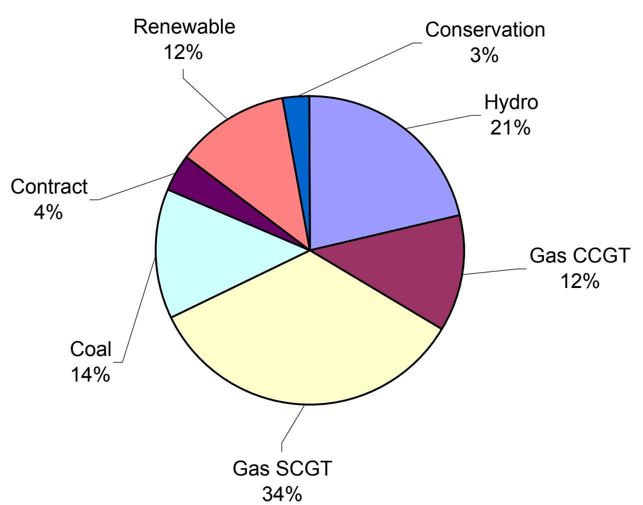
Appendix I - Portfolios and Analysis Results

Case Number 84
Case Name 20 MW Conservation B2 Wind (10%) and Gas and Coal

Capacity Standard: Meets 16 Degree F hour at SEA-TAC
Energy Standard: Meets highest deficit month

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	-	25	200	75	300	7%
SCGT	1,000	100	50	250	50	100	25	175	175	25	1,950	44%
Coal	-	-	-	-	-	-	-	50	200	100	350	8%
Wind	-	200	-	200	-	200	-	200	-	100	900	20%
Duct Fired	51	-	-	10	-	-	-	3	27	10	101	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	375	-	-	75	-	-	-	-	-	-	450	10%
System Exchange	-	-	-	75	25	-	25	-	50	25	200	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,418	3,364
Market Sales Revenue:	(1,374)	(1,067)
Market Purchase Expense:	361	390
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	128	131
Expected Cost:	3,988	4,126
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

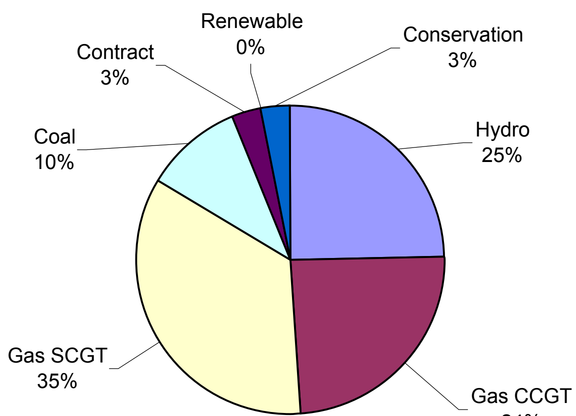
Appendix I - Portfolios and Analysis Results

Case Number 85
Case Name 20 MW Conservation A2 all Gas

Capacity Standard: Meets 19 Degree F hour at SEA-TAC
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	25	-	25	75	25	125	400	225	900	27%
SCGT	950	100	25	175	50	-	25	100	150	-	1,575	47%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	-	3	24	3	10	3	17	54	-	155	5%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	275	-	-	175	-	-	-	-	-	-	450	13%
System Exchange	-	-	-	25	-	25	-	-	25	25	100	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,065	3,036
Market Sales Revenue:	(1,207)	(937)
Market Purchase Expense:	523	546
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	80	84
Expected Cost:	3,915	4,038
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

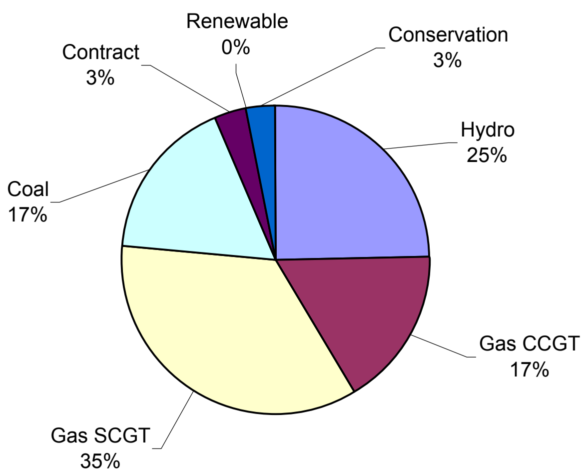
Appendix I - Portfolios and Analysis Results

Case Number 86
Case Name 20 MW Conservation A2 Coal & Gas

Capacity Standard: Meets 19 Degree F hour at SEA-TAC
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	25	25	50	50	200	100	450	13%
SCGT	975	100	25	200	25	50	-	100	175	-	1,650	48%
Coal	-	-	25	-	-	50	-	50	200	125	450	13%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	-	-	24	3	3	7	7	27	-	111	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	275	-	-	175	-	-	-	-	-	-	450	13%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	4%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	6%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,048	3,005
Market Sales Revenue:	(1,181)	(908)
Market Purchase Expense:	460	494
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	54	56
Expected Cost:	3,835	3,955
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

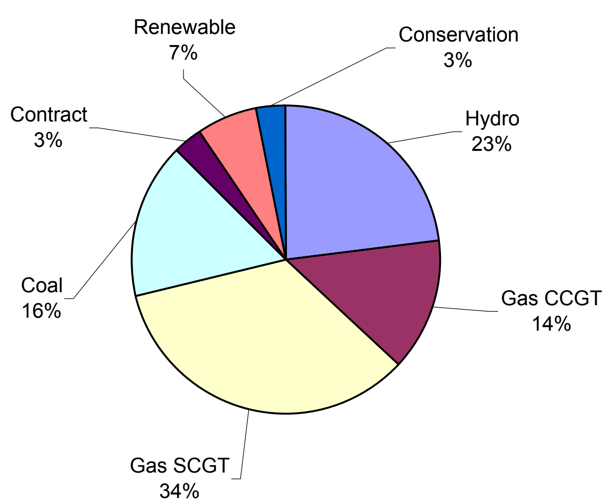
Appendix I - Portfolios and Analysis Results

Case Number 87
Case Name 20 MW Conservation A2 Wind (5%) Gas and Coal

Capacity Standard: Meets 19 Degree F hour at SEA-TAC
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	25	-	50	200	100	375	10%
SCGT	975	100	50	175	75	25	50	100	175	25	1,750	45%
Coal	-	-	25	-	-	25	-	75	225	100	450	12%
Wind	-	100	-	100	-	100	-	100	-	50	450	12%
Duct Fired	40	-	-	20	-	3	-	7	27	-	97	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	250	-	-	150	-	-	-	-	-	-	400	10%
System Exchange	-	-	-	25	-	25	25	-	25	25	125	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,138	3,097
Market Sales Revenue:	(1,226)	(949)
Market Purchase Expense:	432	464
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	80	82
Expected Cost:	3,877	4,002
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

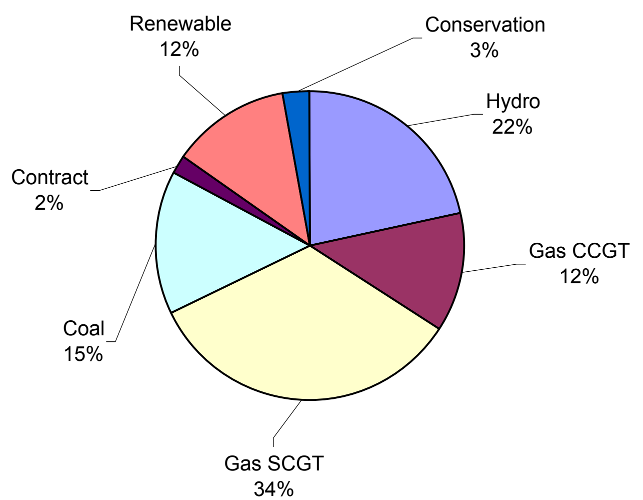
Appendix I - Portfolios and Analysis Results

Case Number 88
Case Name 20 MW Conservation A2 Wind (10%) and Gas and Coal

Capacity Standard: Meets 19 Degree F hour at SEA-TAC
Energy Standard: Meets Nov-Feb avg. customer needs

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	-	-	-	-	-	-	25	50	200	100	375	9%
SCGT	1,000	100	25	250	75	75	-	125	200	25	1,875	44%
Coal	-	-	50	-	-	25	-	50	200	100	425	10%
Wind	-	200	-	200	-	200	-	200	-	100	900	21%
Duct Fired	40	-	-	17	-	-	3	7	27	-	94	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	225	-	-	125	-	-	-	-	-	-	350	8%
System Exchange	-	-	-	-	-	-	25	-	25	25	75	2%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	3,348	3,312
Market Sales Revenue:	(1,384)	(1,088)
Market Purchase Expense:	401	427
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	106	109
Expected Cost:	3,925	4,068
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

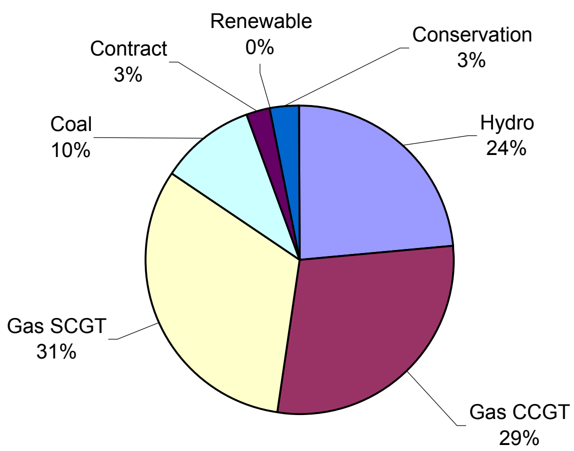
Appendix I - Portfolios and Analysis Results

Case Number 89
Case Name 20 MW Conservation C2 all Gas

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: All months are at least 110% of the total monthly load

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	175	50	25	-	50	50	50	100	425	175	1,100	29%
SCGT	875	-	50	225	25	25	-	100	150	75	1,525	41%
Coal	-	-	-	-	-	-	-	-	-	-	0	0%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	10	3	17	7	7	7	14	57	-	162	4%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	500	25	-	125	-	-	-	-	-	-	650	17%
System Exchange	-	-	-	25	-	-	50	-	-	25	100	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	4,185	4,118
Market Sales Revenue:	(2,151)	(1,758)
Market Purchase Expense:	317	334
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	68	71
Expected Cost:	3,873	4,075
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

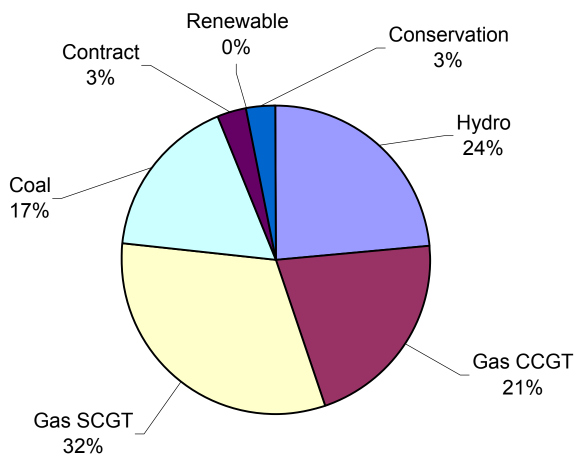
Appendix I - Portfolios and Analysis Results

Case Number 90
Case Name 20 MW Conservation C2 Coal & Gas

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: All months are at least 110% of the total monthly load

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	175	50	-	-	-	50	-	50	200	75	600	16%
SCGT	875	-	50	225	50	25	-	100	150	75	1,550	42%
Coal	-	-	25	-	50	-	50	50	225	100	500	13%
Wind	-	-	-	-	-	-	-	-	-	-	0	0%
Duct Fired	40	10	-	17	-	7	-	7	27	-	108	3%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	500	25	-	125	-	-	-	-	-	-	650	17%
System Exchange	-	-	-	25	-	-	50	-	50	-	125	3%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	4,129	4,051
Market Sales Revenue:	(2,102)	(1,707)
Market Purchase Expense:	244	271
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	33	34
Expected Cost:	3,758	3,958
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

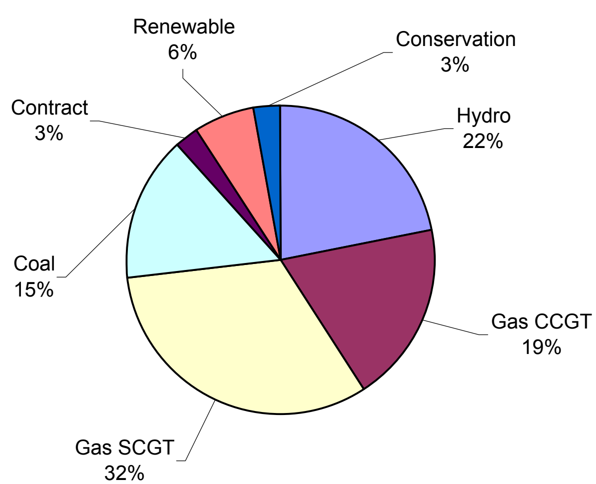
Appendix I - Portfolios and Analysis Results

Case Number 91
Case Name 20 MW Conservation C2 Wind (5%) Gas and Coal

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: All months are at least 110% of the total monthly load

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	175	25	-	-	-	25	-	50	200	75	550	13%
SCGT	875	25	50	250	75	75	-	150	150	75	1,725	41%
Coal	-	-	25	-	25	-	25	50	225	100	450	11%
Wind	-	100	-	100	-	100	-	100	-	50	450	11%
Duct Fired	40	7	-	14	-	3	-	7	27	-	97	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	500	25	-	100	-	-	-	-	-	-	625	15%
System Exchange	-	-	-	25	-	-	25	-	50	-	100	2%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	5%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

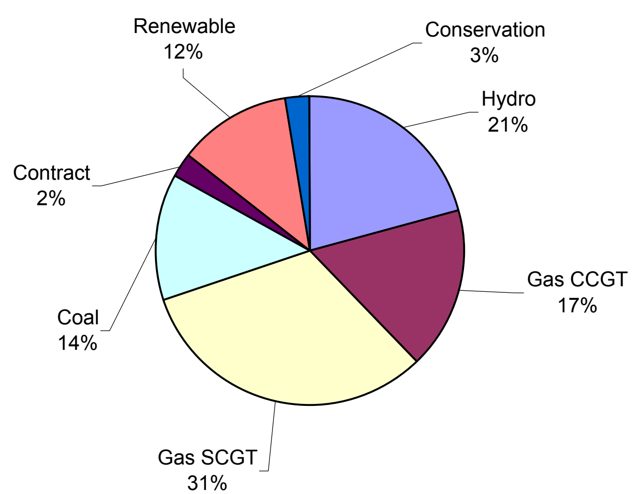
Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	4,216	4,140
Market Sales Revenue:	(2,119)	(1,723)
Market Purchase Expense:	227	253
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	72	73
Expected Cost:	3,850	4,052
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

Case Number 92
Case Name 20 MW Conservation C2 Wind (10%) Gas and Coal

Capacity Standard: Meets 13 Degree F hour at SEA-TAC
Energy Standard: All months are at least 110% of the total monthly load

New Resources	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	Percent
CCGT	175	-	-	-	-	-	-	50	200	75	500	11%
SCGT	875	50	75	250	75	100	25	150	175	75	1,850	40%
Coal	-	-	-	-	25	-	-	50	200	100	375	8%
Wind	-	200	-	200	-	200	-	200	-	100	900	19%
Duct Fired	40	3	-	14	-	-	-	7	27	-	91	2%
Geothermal	-	-	-	-	-	-	-	-	-	-	0	0%
Joint Ownership	500	25	-	100	-	-	-	-	-	-	625	13%
System Exchange	-	-	-	25	-	-	25	-	50	-	100	2%
LT PPA	-	-	-	-	-	-	-	-	-	-	0	0%
Conservation	20	20	20	20	20	20	20	20	20	20	200	4%

2013 PSE Portfolio Mix New and Existing Resources - (Nameplate Basis)



Analytical Results ($'s in millions)

Aurora Case:	Case III	Case I
Static Analysis		
Gross Revenue Requirement:	4,306	4,232
Market Sales Revenue:	(2,146)	(1,749)
Market Purchase Expense:	212	236
Existing Fleet Variable Costs:	1,454	1,308
End Effects:	108	110
Expected Cost:	3,935	4,138
Probabilistic Analysis		
Iterations:	-	
Coefficient of Variability:	0%	
Standard Deviation:	-	
+ 2 sigma	-	
- 2 sigma	-	

Navigant
CONSULTING, INC.

www.navigantconsulting.com

Appendix J

LCP Portfolio Screening

Assumptions, Methodology, & Results

April 2003

PUGET SOUND ENERGY

Summary of Portfolios Constructed and Analysis Summary

	Status Quo	Level A1	Level A2	Level B1	Level B2	Level C1	Level C2	Deferral (Level B1)	Joint Ownership	Forward Capacity Sales	System Exchange
All Gas	X	X	X	X	X	X	X	X	X	X	X
All Coal		X		X		X		X			
All Wind		X		X		X		X			
Gas & Coal	X	X	X	X	X	X	X	X	X	X	X
5% Wind $ Gas & Coal Mix	X	X	X	X	X	X	X	X	X	X	X
2% Wind & Gas		X		X		X		X	X		
5% Wind & Gas		X		X		X		X	X		
10%Wind & Gas		X		X		X		X	X		
10%Wind & Gas & Coal	X	X	X	X	X	X	X	X	X	X	X

Exhibit No. ___(EMM-3)
Page 487 of 529

Analysis Summary Continued

Porffolio Mix	Aurora Case 1		Aurora Case 2		Aurora Case 3	
	Static	Volatility	Static	Volatility	Static	Volatility
All Gas	X	X	X		X	X
All Coal	X	X	X		X	
All Wind	X	X	X		X	
Gas & Coal	X	X	X		X	X
5% Wind Gas & Coal	X		X		X	X
10% Wind Gas & Coal	X		X		X	X
2% Wind & Gas	X	X	X		X	
5% Wind & Gas	X	X	X		X	
10% Wind & Gas	X	X	X		X	

Exhibit No. ___(EMM-3)
Page 488 of 529

LCP Portfolio Screening Tool - Overview

The Portfolio Screening Tool is composed of two main parts:

- Dispatch Model Calculation
  - Dispatches PSE fleet and potential new resources against hourly power prices from AURORA for WA/OR region
  - Utilizes the same inputs to AURORA for plant profiles and demand
  - Uses Crystal Ball Monte Carlo simulation to achieve probability weighted results
  - Output from dispatch model includes MWh for the PSE fleet and an assumed portfolio of new resources and their associated variable (or incremental) costs (fuel, O&M, etc.)

- Financial Summary and Expected Cost to Customer Calculation
  - MWhs produced and variable cost data from the dispatch model is used in conjunction with fixed cost assumptions to derive a 'bottom up' revenue requirement for each new resource being considered
  - A financial summary is generated for each new resource technology that includes an income statement, cash flow summary and an approximation of regulatory asset base
  - Financial data from each new resource are then consolidated
  - The comparative incremental cost to customers for a particular resource portfolio is developed by combining the variable cost of dispatch from the existing dispatchable PSE fleet, the variable emission cost from the existing PSE fleet, the cost of market purchases, and the revenue from market sales with the revenue requirements from the new resource portfolio over a 20-year period
  - The NPV of the 20-year strip of incremental costs to customers is then calculated at the pre-tax WACC
  - The NPV of the Expected Cost to Customers are for comparative purposes only

LCP Screening Tool Modeling Process Flow Chart

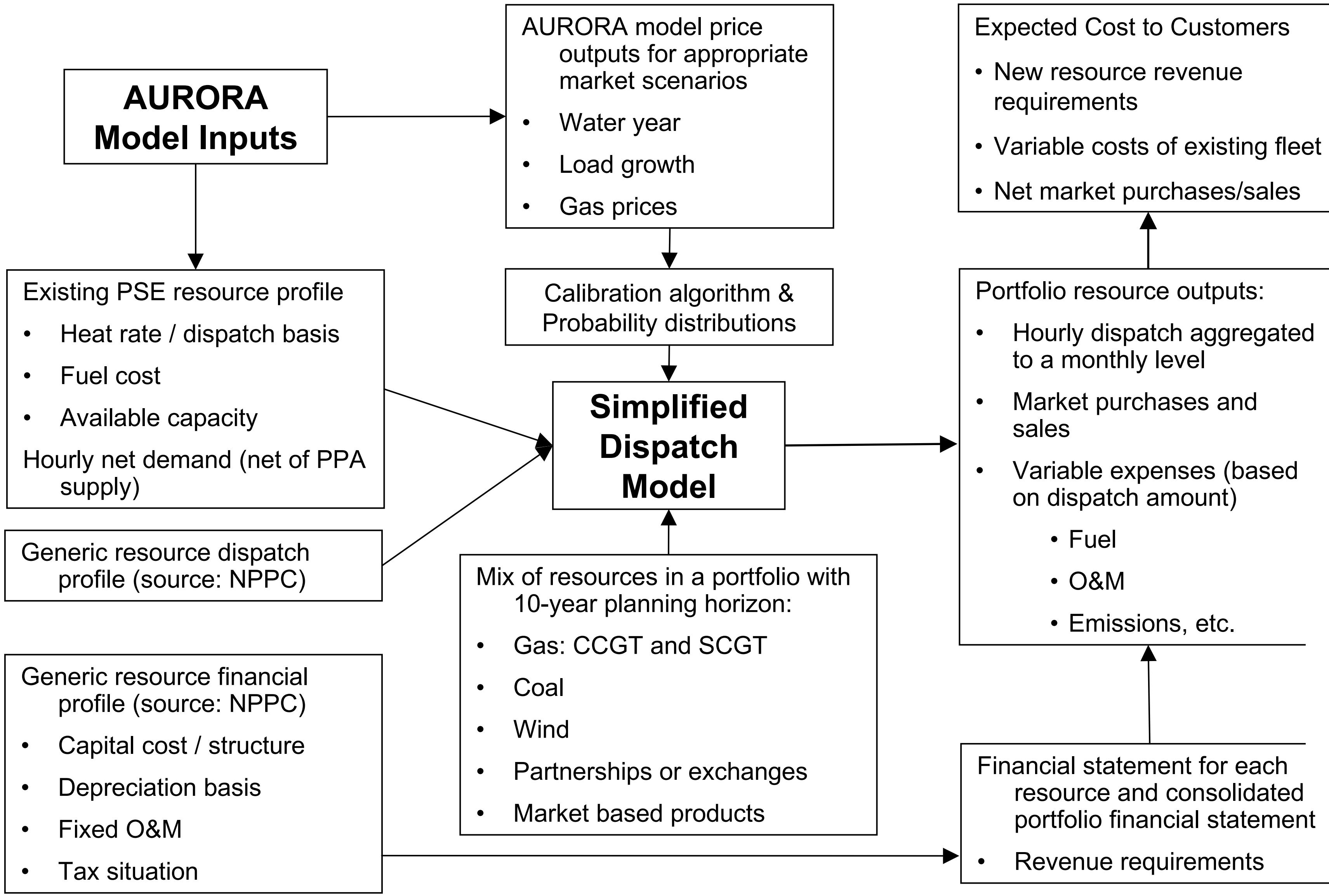


Exhibit No. ___(EMM-3)
Page 490 of 529

Net Demand Development

- Monthly demand and resource summaries extracted from AURORA for the forecast period (see 2003 example below) are used to develop Net Demand

Energy (aMW)	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Hydro	2003	1,106	906	993	1,022	1,114	1,116	1,026	852	536	652	732	800	905
Colstrip	2003	598	598	598	432	598	464	598	598	598	598	598	598	573
Encogen & CTs	2003	99	61	82	79	48	59	143	339	320	183	116	113	137
NUGs	2003	586	252	357	272	97	86	473	524	528	508	498	504	392
Contracts Purch/(Sale)	2003	504	478	299	247	149	136	72	44	33	210	363	390	242
Market Purchases	2003	96	419	291	251	135	193	14	18	197	232	301	498	219
Market Sales	2003	(135)	(8)	(71)	(79)	(70)	(52)	(348)	(291)	(141)	(52)	(53)	(22)	(111)
Total Demand	2003	2,853	2,705	2,548	2,224	2,071	2,001	1,977	2,084	2,071	2,330	2,555	2,879	2,357
Contracts	2003	504	478	299	247	149	136	72	44	33	210	363	390	242
Net Demand	2003	2,349	2,227	2,250	1,978	1,922	1,866	1,905	2,039	2,038	2,120	2,191	2,490	2,115

- The monthly Net Demand is derived by taking the total demand and subtracting contract purchases/(sales)
- The monthly Net Demand is converted to hourly Net Demand through the following process:
  - The 2003 hourly demand forecast is the basis for the load shape for all forecast years
  - An average demand is calculated for each month in 2003 and then an actual/average factor is calculated for each hour (demand in each hour in a month is divided by the monthly average)
  - These factors for each hour are then applied to the monthly Net Demand to create 8760 Net Demand profiles for each forecast period
  - The 2003 base year begins on Wed, the 2003 shape is applied to each forecast year beginning on the day the forecast year starts (e.g. Thursday in 2004, Saturday in 2005, etc.) (same as AURORA methodology)

Dispatchable Resources

- The dispatchable plants are:
  - PSE owned: Fredonia1&2, Fredonia 3&4, Frederickson 1&2, Whitehorn 2&3, Colstrip 1&2, Colstrip 3&4 and Encogen (dispatchable)
  - NUG's: March Point 1&2 (dispatchable), Sumas, and Tenaska
  - New resources: CCGT (including structured deals), SCGT, and coal
- There are two primary data inputs to the dispatch logic from the dispatchable plants:
  - Dispatch Basis: This is the marginal cost of dispatch and is sum of variable O&M, fuel cost (calculated by running a "burner tip" $/MMBtu fuel cost through the plants heat rate to arrive at $/MWh), and any other incremental costs (e.g. emissions, transmission, etc.)
  - Dispatchable Capacity: The dispatchable capacity adjusts the net capacity for an asset by a forced outage rate applied evenly over all periods, and a planned outage rate applied when the outage is expected

Plant	Net Capacity (MW)	Heat Rate (Btu/KWh)	Forced Outage Rate (%)	VOM ($/MWh)	Fuel Cost (Note/$/MMBtu)	Planned Outage Period (Approx.)
Fredonia 1&2	202.1	11,569	16.87	2.12	Sumas + trans.	1 week in May
Fredonia 3&4	108.0	10,540	5.00	2.12	Sumas + trans.	1 week in May
Frederickson 1&2	141.0	12,450	14.26	2.12	Sumas + trans.	1 week in April
Whitehorn 2&3	134.4	11,987	13.23	2.12	Sumas + trans.	1 week in April
Colstrip 1&2	298.6	10,889	10.38	Inc. in fuel	0.45	2 weeks in May
Colstrip 3&4	359.9	10,695	8.29	Inc. in fuel	0.60	2 weeks in June
Encogen - Disp.	120.0	9,032	1.97	Inc. in fuel	Sumas + trans.	Inc. in FOR
March Point 1 - Disp.	0.0	8,500	0.20	Inc. in fuel	Sumas	Inc. in FOR
March Point 2 - Disp.	13.0	12,000	0.20	Inc. in fuel	Sumas	Inc. in FOR
Sumas	133.0	8,200	1.80	Inc. in fuel	Sumas	Inc. in FOR
Tenaska	245.0	8,700	0.30	Inc. in fuel	Sumas	Inc. in FOR
CCGT - Generic	NA	7,030	5.00	2.80	Sumas	1 week
SCGT - Generic	NA	9,960	3.60	8.00	Sumas	1 week
Coal - Generic	NA	9,550	7.00	1.75	0.73	2 weeks/yr

Source: 2002 Rate Case with some updates

Must Run and Renewable Resources

- The Must Run plants are:
  - PSE Owned: All hydro plants, and Encogen MR
  - NUG's: March Point 1&2 MR
  - New resources: Wind
- The Must Run plants have only have Dispatchable Capacity as input to the dispatch logic
  - The must run portions of Encogen and March Point calculate the Dispatchable Capacity in the same fashion as the dispatchable portions of those plants
  - The wind units have their nominal capacity adjusted for monthly availability based on seasonal variations in wind patterns (the proxy is currently for wind located in the Basin & Range region of OR and ID)
  - The hydro unit Dispatchable Capacity is based on the monthly availability for the average water year in the 40-year hydro data set from NWPP and the hourly dispatch shape for a 2003 base year in AURORA
    - ✓ The hourly shape adjusts the monthly average in a similar fashion as the Net Demand

Plant	Net Capacity (MW)	Heat Rate (Btu/KWh)	Forced Outage Rate (%)	VOM ($/MWh)	Fuel Cost (Note/$/MMBtu)	Planned Outage Period (Approx.)
Encogen - MR	51.0	9,830	1.97	Inc. in fuel	Sumas + trans.	Inc. in FOR
March Point 1 - MR	85.0	8,500	0.20	Inc. in fuel	Sumas	Inc. in FOR
March Point 2 - MR	50.0	8,500	0.20	Inc. in fuel	Sumas	Inc. in FOR
Wind	NA	NA	72%	1.00	NA	NA

Source: 2002 Rate Case with some updates

Must Run and Renewable Resources Continued

Hydro Plants

Plant	Nominal Capacity (MW)	Monthly Availability Factor Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Upper Baker	104.9	28%	26%	21%	27%	47%	21%	57%	62%	13%	45%	65%	35%
Lower Baker	79.0	67%	52%	39%	55%	68%	43%	60%	79%	22%	66%	82%	74%
White River	62.5	69%	53%	46%	53%	65%	69%	45%	55%	6%	22%	64%	32%
Puget Small Plants	69.7	74%	76%	74%	82%	88%	87%	72%	53%	34%	41%	74%	77%
Wells	262.9	67%	54%	62%	65%	72%	73%	65%	53%	36%	36%	36%	45%
Rocky Beach	492.7	69%	56%	64%	67%	72%	78%	69%	55%	37%	38%	38%	47%
Rock Island 1	163.1	68%	69%	66%	65%	61%	61%	64%	66%	64%	64%	68%	65%
Wanapum	106.5	68%	55%	59%	46%	37%	45%	44%	32%	34%	35%	36%	46%
Priest Rapids	73.0	75%	63%	66%	41%	17%	33%	41%	32%	43%	44%	44%	55%
Rock Island 2	174.0	95%	65%	88%	92%	100%	100%	89%	57%	28%	31%	26%	52%

The hydro availability is based on the mean of the 40-year data set

Must Run and Renewable Resources Continued

Month	Basin & Range	Cascades & Inland	Northern California	Northwest coast	Rockies & Plains	Southern California
January	119%	103%	22%	119%	161%	68%
February	139%	90%	28%	157%	157%	66%
March	107%	107%	69%	107%	102%	97%
April	105%	107%	113%	86%	84%	128%
May	94%	121%	181%	84%	77%	175%
June	71%	107%	188%	84%	73%	133%
July	56%	111%	210%	101%	35%	147%
August	61%	107%	185%	54%	42%	95%
September	72%	94%	96%	66%	52%	87%
October	74%	73%	65%	80%	100%	82%
November	159%	85%	24%	140%	130%	65%
December	143%	96%	18%	121%	188%	57%
FOR	72%	70%	69%	70%	64%	69%

- PSE is currently using the Cascade & Inland profile in the calculations
  - Appears to be the location of the most promising near-term projects

Exhibit No. ___(EMM-3)
Page 495 of 529

Emissions 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	0.00200	0.03900	411.00	NPPC Generic
SCGT	0.00080	0.05523	582.00	NPPC Generic
Coal	0.38200	0.35000	1,012.00	NPPC Generic
Escalation	-	-	-	
Base Cost/Ton	200.00	-	-	

Exhibit No. ___(EMM-3)
Page 496 of 529

Equity Partnerships

- The equity partnership or Joint Ownership resource is characterized by entering into a transaction with a developer or other party for partial ownership of a generating resource asset and partial rights to output
  - The Screening Tool allows specification of which months PSE would claim rights to output from the facility
  - The capital cost of the facility (whether it is for completion of a project, construction of a new project or partial purchase of an existing facility) is split between the two parties on a market price weighted basis
    - ✓ The price weighted calculation ratios the average market prices of the respective output ownership rights
    - ✓ The price-weighted split of capital cost assumes both parties have the same view of market prices going forward and there is no discount or premium for either party

Dispatch Logic

- The hourly dispatch of the PSE fleet and the new resources considered in the planning portfolio is done on a month by month basis (this is due to size constraints within Excel)
- The dispatch logic is as follows:
  - For each hour, the Dispatch Basis for each dispatchable plant is compared to the market price for that hour, if the Dispatch Basis is less than the market price, then the plant generates its Dispatchable Capacity for that hour, else, it does not dispatch that hour
  - The total generation from the dispatchable plants is summed for each hour
  - The total generation from the must run plants is added to the total generation from the dispatchable plants
  - The grand total of plant generation (dispatchable and must run) is compared to the Net Demand for each hour, if the amount generated is less than the Net Demand, then that amount represents a market purchase, if the amount generated is greater than Net Demand, than that amount represents a market sale
  - For every hour where there is a market sale or purchase, the market price at that hour is used to calculate the financial impact of the purchase or sale
- The major simplification from the dispatch logic in AURORA is that there is no provision for unit minimum run times, ramp rates, minimum dispatch levels, etc.

End Effects Implementation in the Screening Model

- The issue of end effects arises because PSE has a 20-year evaluation period for assets with a 30-year life, this is compounded by the fact that PSE's portfolio planning horizon allows asset additions to occur through year 10, effectively creating a 40-year horizon for asset life
- To deal with years 21-40 in the analysis, PSE uses the following methodology:
  - Forecast the free cash flows (100% equity basis) from the assets for years 21 to 40
  - NPV the free cash flows to year 20 at the after-tax WACC
  - Compare the NPV at year 20 to the remaining book value at year 20
  - NPV the difference to year one at the after tax WACC
  - Subtract the year one value from the Total Cost to Customer
- The free cash flow are estimated using the following assumptions:
  - ***Revenue***: The revenue from year 17-20 is averaged and escalated at 2.5%
  - ***Fuel and VOM***: The fuel and VOM from year 17-20 is averaged and escalated at 2.5%
  - ***Capacity Factor***: The capacity factor from year 17-20 is averaged and held constant for year 21-40
  - ***FOM***: The FOM continues to be escalated as in years 1-20
  - ***Property Tax***: The property tax is trended down from year 17-20 (follows the trend down in rate base)
  - ***Insurance***: The insurance is trended down from year 17-20 (follows the trend down in rate base)
  - ***Depreciation***: The tax depreciation is run out normally for all assets past year 20
- The impact of the end effects are relatively small in comparison to the Total Cost to Customer, on the order of 2% of the total

Financial Summary and Revenue Requirement Calculation - *Assumptions and Methodologies*

- Dates used for analysis period
  - Planning horizon for resource acquisition is 10 years beginning Jan. 1, 2004
  - Model assumes 'financial close' date of 12/31/2003 as basis for the model starting point
  - Analysis period is 20 years

- Expense / Capital escalation rates
  - Both fixed and variable O&M currently assume a 2 ½% annual escalation factor
  - Both periodic and acquisition capex assume a 2 ½% annual escalation factor
    - ✓ Methodology – The model assumes two kinds of additional capex: 'incremental capex' and 'acquisition capex.' 'Incremental capex' are capital expenditures (plant) acquired on an annual basis using a $/Kwh valuation. The current model assumes that 'incremental capex' is funded through available cash rather than by debt. Alternatively, the model assumes that 'acquisition capex', or capital expenditures related to acquiring new generation MW during the 10-year planning horizon, are financed using the debt to equity ratio supplied by PSE (60% debt to 40% equity).

- Capital Costs (New Acquisition Capex in $/kw)

	All in Cost ($/kw)
CCGT	$645
SCGT	$441
Coal	$1,500
Wind	$1,003
Duct Fired	$150
Joint Ownership	$423

Exhibit No. ___(EMM-3)
Page 500 of 529

Financial Summary and Revenue Requirement Calculation - *Assumptions and Methodologies - continued*

- O&M Costs (Table below outlining Fixed rates in $/kw-yr and Variable O&M rates in $/MWh)

	CCGT	SCGT	Coal	Wind	Duct Fired	Joint Ownership
FOM ($/kw-yr)	$41.43	$18.74	$49.76	$40.98	$30.43	$27.14
VOM ($/MWh)	$2.00	$2.00	$2.00	$1.00	$2.00	$2.00
Fuel Basis Differential ($/MWh)	$3.45	$5.85	$0.00		$4.55	$3.45
Total VOM ($/MWh)	$5.45	$7.85	$2.00	$1.00	$6.55	$5.45

- Finance and Regulatory assumptions
  - Cost of equity and debt (used for both the WACC and debt amortization calculations) – 11.0% and 7.24% respectively
  - Pre / After Tax WACC – 8.95% and 7.61% respectively
  - Conversion Factor (gross-up factor used in revenue requirement calculation) – 62.02%
    - ✓ Roughly equivalent to (1- Federal tax rate and miscellaneous regulatory fees)

- Heat Rate and Forced Outage Rates

	CCGT	SCGT	Coal	Wind	Duct Fired	Joint Ownership
Heat Rates	6,900	11,700	9,425		9,100	6,900
Forced Outage Rates	5%	4%	7%	70%	0%	5%

Exhibit No. ___(EMM-3)
Page 501 of 529

Financial Summary and Revenue Requirement Calculation - *Calculation Detail*

The revenue requirement for a specified portfolio utilizes a 'bottom-up' approach where total fixed and variable costs are used to back solve for the appropriate revenue stream that would yield an operating income stream sufficient to provide a desired regulated rate of return. The following discussion outlines how individual components of fixed and variable expenses are calculated:

- Variable Costs – Fuel and Variable O&M
  - Fuel expense is calculated by multiplying the calculated number of MWh dispatched or generated each month, times the heat rate of the plant times the appropriate fuel curve (i.e. gas or coal)
  - Variable O&M is calculated by taking the appropriate VOM factor (as provided by PSE and illustrated on the previous slide), applying the VOM escalation percentage adjusted for time, and multiplying the resulting inflation adjusted VOM factor (in $/Kwh) times the number of Kwh produced for the selected technology
- Fixed Costs – Fixed O&M
  - The FOM Factor provided by PSE includes all categories of fixed costs associated with the various technologies under consideration
  - The fixed cost calculation is similar to that of Variable O&M in that the FOM factor (quoted in $/Kw) provided by PSE is inflation-adjusted using the escalation factor illustrated on the previous slide and multiplied times the plant capacity (rather than the number of Kwh produced)
- Depreciation - Book and Tax
  - Book – Modeled value assumes 30-year recovery on all capital additions (Wind 25 years)
  - Tax – The portfolio model contains flexibility to select from 5, 10, 15 and 20 year MACRS (half-year convention)
    - ✓ The current test cases utilize 5-year MACRS for 'green' resources, 15-year MACRS for simple and combined cycle gas and 20-year MACRS for coal-fired resources.

Financial Summary and Revenue Requirement Calculation - *Calculation Detail - continued*

- Debt Service – Interest
  - The interest is calculated as a function of Rate Base
  - The long-term capital structure assumes 52.57% debt
  - The interest rate is assumed to be 7.4%

- Tax – Current and Deferred
  - Current taxes are computed on taxable income calculated using tax depreciation rates previously discussed
  - Differences between book and tax depreciation are the only items considered to generate book/tax differences that give rise to deferred taxes
  - Currently, the model assumes a 37.98% effective marginal rate (from the 2002 Rate Case)

Financial Summary and Revenue Requirement Calculation - *Expected Cost to Customer*

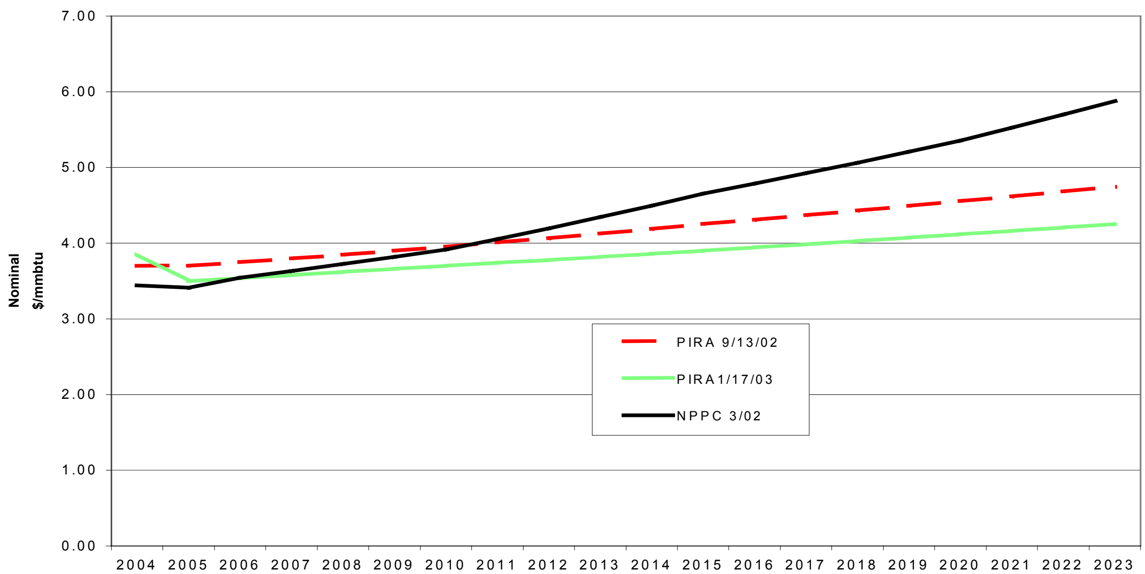
- Expected Cost to Customer is the point at which various alternative portfolios will be measured
- Expected Cost to Customer in the portfolio model is calculated as follows:
  - The comparative incremental cost to customers for a particular resource portfolio is developed by combining the variable cost of dispatch from the existing dispatchable PSE fleet, the variable emission cost from the existing PSE fleet, the cost of market purchases, and the revenue from market sales with the revenue requirements from the new resource portfolio over a 20-year period
  - The NPV of the 20-year strip of incremental costs to customers is then calculated at the pre-tax WACC
  - The NPV of the Expected Cost to Customers are for comparative purposes only

APPENDIX K
KEY ASSUMPTIONS FOR AURORA MARKET POWER PRICE FORECAST

Gas Prices

PIRA Energy Group forecasts for the primary hubs were updated in January 2003, replacing the September 2002 PIRA forecast which was an input for the December 2002 Draft LCP. An alternative forecast, published in March 2002, was available through NPPC. The PIRA forecast for the Sumas hub more closely tracks the current forward market and has a less steep escalator than the NPPC forecast

Exhibit K-1
Natural Gas Forecast: Sumas

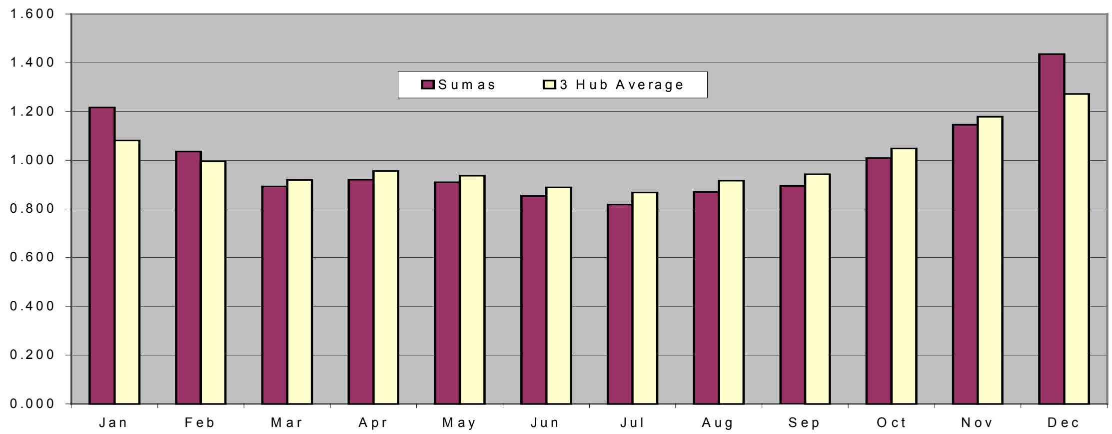


The PIRA forecast includes monthly estimates for 2004, then annual values for 2005, 2010 and 2015. The gas prices for the other years, up to 2023, are estimated with arithmetic interpolation and geometric extrapolation.

Each annual price requires that a monthly shape factor be applied to generate 12 monthly prices. The monthly shape factors are the average of the three Northwest hubs, Sumas, AECO and Rockies, for the years 1991-1999. More recent data do not have any consistent pattern and the prices show extreme volatility and randomness.

Exhibit K-2 illustrates the traditional pattern of higher prices in the winter and lower in the summer. The three-hub average was applied to all eight hubs in the model other than Henry Hub which has its own monthly shaping.

Exhibit K-2
Monthly Shaping



Electricity Demand

AURORA divides the WECC into 13 subregions with individual growth rates. Exhibit K-3 lists the regions along with the new and previously assumed long-run regional growth rates. The new growth rates were adopted from the NPPC, "Draft Forecast of Electricity Demand of the 5th Pacific Northwest Conservation and Electric Power Plan," August 2, 2002. Short-run demand was adjusted downward to take into account the current recession, following the assumptions in the NPPC's 5th Draft of Wholesale Electric Price Forecast. Intermediate-term growth rates were increased so that the long-run growth rate was unchanged.

Exhibit K-3
Regional New and Previous Demand Rates

Region	New Demand (%)	Previous (%)
OR / WA / No. ID	1.50	1.53
No. California	1.71	1.63
So. California	1.87	1.63
British Columbia	1.53	1.53
Idaho South	1.71	1.53
Montana	0.90	1.53
Wyoming	0.23	2.37

Region	New Demand (%)	Previous (%)
Colorado	1.22	2.37
New Mexico	2.43	2.45
Arizona / So. Nevada	1.39	2.45
Utah	2.32	1.53
No. Nevada	1.65	1.53
Alberta	1.53	1.53

New Northwest Resources

In 2002 there were over 8,000 MW of new resources under development; however, most of the proposals did not make it beyond the planning stage. PSE currently assumes that 2,055 MW of new natural gas-fired resources will be available in the region. Presently three plants have been completed, with three under construction to be on line by mid-2004. Exhibit K-4 lists those plants.

Exhibit K-4
New Natural Gas-Fired Resources

Plant	Owner/Developer	Capacity MW)	Online Date
Coyote Springs II	Avista-Mirant	260	Q2/03
Hermiston	Calpine	530	Online
Goldendale	Calpine	248	Q2/04
Big Hanaford	TransAlta	248	Online
Frederickson I	EPCOR	249	Online
Chehalis	Tractebel	520	Q3/03

Other well known gas-fired resources that once were expected to be developed, such as the Duke Grays Harbor plant, have not been assumed into the model. Wind resources that could be built in 2003, or later, were not assumed to be built. The AURORA database includes 473 MW of wind generation which their developers listed as going online in 2002.

New Resources

Three aspects of new resource costs need to be considered – the debt/equity ratio and their corresponding costs; assumptions about who will be building plants in the future; and the fixed and variable costs for each technology. To reflect the current market difficulties of merchant companies (IPP's), new projects will have to be financed with a mix of private equity and fairly high-yielding debt. However, it could be expected that this period of comparatively expensive cost of capital will give way to a long-term equilibrium with lower cost of capital assumptions.

Cost of Capital

Exhibit K-5 presents the cost of capital assumptions for PSE. The company expects that the spread between the return for debt and equity for the IOU's should be four to five percent, consistent with recent practice. The debt/equity ratio and the corresponding rates of return were used to determine a weighted cost of capital for each developer segment. For the IPP's the model uses the higher rates for years 2004 and 2005.

Exhibit K-5
PSE Cost of Capital Assumptions

Cost of Capital			
Return %	Public	IOU's	IPP's
Debt	6.5	7.5	10 to 8.5
Equity	0	11.5	30 to 17
Debt/Equity Ratio			
Debt	100	55	40
Equity	0	45	60
Total Cost (%)			
Weighted	6.5	9.3	22.0 to 14

New Resource Development

The second set of assumptions focus on which entities will be building new generation for each technology over the next 20 years. PSE used the developer mix assumptions made by the NPPC listed in Exhibit K-6.

Table K-6
NPPC Developer Mix Assumptions

	Developer Mix (%)			**Mix Weighted Cost of Capital**
Technology	Public	IOUs	IPPs	PSE
CCCT	15	15	70	**17.8 to 11.9**
SCCT	40	40	20	**10.7 to 9.0**

	Developer Mix (%)			Mix Weighted Cost of Capital
Wind	20	20	60	**16.4 to 11.3**
Coal	25	25	50	**15.0 to 10.8**
Solar	50	25	25	**11.1 to 9.0**

The developer mix percentages were applied to the weighted cost of capital for each developer segment (i.e. 6.5 percent, 9.3 percent, 13.6 percent) to produce a mix weighted cost of capital (values in bold font under PSE in Exhibit K-5) for each technology. The mix-weighted cost of capital was then applied to the investment costs discussed in the following section.

Timing of New Resource Development

In AURORA, new plants are brought online at the optimal time without regard to planning horizons. To replicate realistic planning needs, the higher overall cost of new resources was extended for additional years based on construction lead time. Simple cycle turbines and wind generation can be brought online in a year so the higher cost was extended through 2006. For combined cycle the higher cost is extended for an additional year through 2007. For coal, with it long lead time, the higher development cost is included through 2010 with a significant price drop in 2011.

Cost of Various Technologies

The AURORA model selects new resources for addition from a set of generic resources which will result in lowest overall cost. The cost and performance characteristics were provided by Tenaska for the combined cycle and simple cycle gas plants, as well as the coal plant. The wind data were provided by Navigant Consulting, Inc. and confirmed by other sources, while the solar data are from the NPPC.

The capacity of most new generation resources (i.e., the capacity of individual projects in MWs) can be scaled to meet the specific needs of the developer; hence there is not one correct size or correct estimate for each technology. Furthermore, with shared ownership, even greater flexibility of capacity can be achieved for a utility. PSE, in collaboration with Tenaska, selected a representative plant for each gas and coal technology based both on economies of scale and current development practices. Exhibit K-7 provides a list of the primary characteristics.

Exhibit K-7
Cost and Performance Characteristics

Technology	Capacity (mw)	Heat Rate (btu/kwh)	All-In Cost ($/kw)	Fixed O&M ($/kw)	Fixed Fuel ($/kw)	Variable O&M ($/mwh)
CCCT	516	6,900	645	11.00	15.55	2.00
SCCT	168	11,700	441	3.00	15.74	2.00
Coal	900	9,425	1,500	20.0	0	2.00
Wind	100	0	1,003	26.10	0	0
Solar	20	0	6,000	15.00	0	0.80

The CCCT represents a two-by-one configuration – two turbines with a heat recovery system. These plants are typically scaled by increments of about 250 MW, with variations around those figures depending on specific configurations.

The SCCT represents a lower-cost traditional peak using "frame" FA or EA gas turbines in simple cycle. More expensive aero-derivative plants are available which have a better heat rate at a much higher cost. Throughout the industry and its literature, one can find a wide variety of capacities, heat rates and costs for the numerous simple cycle options. The least-cost option is site and application dependent. The costs provided by Tenaska are based on the same assumptions as the combined cycle and coal plants which allows for a fair comparison between the technologies. For example, the SCCT listed starts with an EPC cost (engineering, procurement and construction) of $327/kw before taking into account "soft" costs such as insurance, contingencies, and costs related to financing, startup and spares etc. before arriving at a total installed capacity cost of $441/kW.

The coal plant represents a new site with a supercritical boiler design. An alternative would be a plant with two percent to four percent lower costs but with a two percent to four percent higher heat rate. Again the least-cost option depends upon the site and application.

The wind plant is based on the assumption that 100 MW is necessary to achieve economies of scale.

APPENDIX L
EMISSIONS CONSIDERATIONS AND WIND PRODUCTION TAX CREDIT

Emissions

Sulfur Dioxide

Currently SO_2 regulations apply to existing and future PSE plants. Title IV of the Clean Air Act set a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. To achieve these reductions, the law required a two-phase implementation of the SO_2 regulations applicable to fossil fuel-fired power plants.

Phase I began in 1995 and affected 263 units at 110 mostly coal-burning electric utility plants located in 21 eastern and Midwestern states. An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total of Phase I affected units to 445. Emissions data indicate that 1995 SO_2 emission at these units nationwide were reduced almost 40 percent below their required level.

Phase II, which began in 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also set restrictions on smaller, cleaner plants fired by coal, oil and gas, encompassing a total of 2,000 units. The program affects existing utility units serving generators with an output capacity of greater than 25 MW and all new utility units.

A market-based allowance trading system was established to implement the regulations. Affected utility units receive allowance allocations 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, the utility must retire one allowance. Allowances may be bought, sold or banked. Anyone may acquire allowances and participate in the trading system. However, regardless of the number of allowances a source holds, it may not emit at levels that would violate federal or state limits set under Title I of the Clean Air Act to protect public health. During Phase II of the program, the Act set a permanent ceiling (or cap) of 8.95 million allowances for total annual SO_2 allowance allocations to utilities.

Nitrous Oxide (NO_X)

PSE is currently not subject to NO_X mitigation regulations. However, other portions of the country are subject to NO_X mitigation regulations. These regulations could be a proxy for what may eventually apply to the western United States.

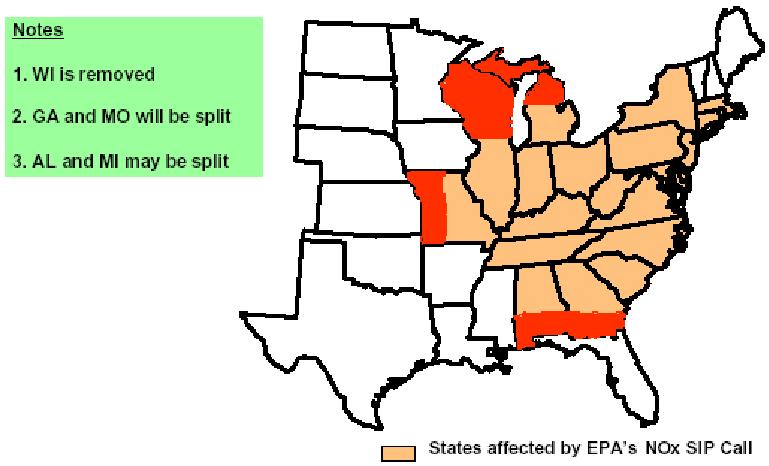
Section 126 of the Clean Air Act allows states to petition the EPA for a finding that sources from upwind states contribute significantly to non-attainment, or interfere with maintenance of national ambient air standards in the state. If a source receives such a finding, the source must either shut down in three months, or comply within three years with emission schedules set by the EPA. Through 1998, eleven states (CT, DE, MA, MD, ME, NH, NJ, NY, PA, RI and VT) and the District of Columbia have petitioned EPA to find that certain major stationary sources in upwind States emit NO_X emissions in violation of the Clean Air Act's prohibition on amounts of emissions that contribute significantly to ozone non-attainment or maintenance problems in the petitioning State.

These petitions eventually led to the 1998 "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone" (the "NO_X SIP Call"). Nineteen states and the District of Columbia were required to submit rules for implementation of Phase I by 10/2002. Phase I is expected to achieve 90 percent of the required reductions. Exhibit L-1 identifies the NO_X SIP Call area.

On December 17, 1999 the EPA finalized the Findings of Significant Contribution and Rulemaking on Section 126 Petitions for Purposes of Reducing Regional transport of Ozone (commonly referred to as the Section 126 final action). As a result of this action, each affected facility will participate in a federal NO_X emissions cap-and-trade program, aimed at reducing interstate ozone transport. Compliance is mandated by May 1, 2003.

Exhibit L-1

States Required to Submit Under SIP Call



Source: EPA

Clear Skies Act of 2003

H.R. 999 was introduced in the U.S. House of Representatives and S.B. 485 in the U.S. Senate in February 2003 to implement the tenets of the Bush Administration's Clear Skies Initiative. Clear Skies would require mandatory reductions and cap emissions of sulfur dioxide SO_2, NO_X, and mercury from electric power generation nation-wide. A mandatory, market-based cap and trade program for power generators would build upon the Clean Air Act to facilitate achievement of the initiative's goals. Exhibit L-2 outlines the goals of the Clear Skies Initiative.

Exhibit L-2
Clear Skies Initiative Goals

	Actual Emissions in 2000	Clear Skies Emissions Caps		Total Reduction
		First Phase of Reductions	Second Phase of Reductions	
SO2	11.2 million tons	4.5 million tons in 2010	3 million tons in 2018	73%
NOX	5.1 million tons	2.1 million tons in 2008	1.7 million tons in 2018	67%
Mercury	48 tons	26 tons in 2010	15 tons in 2018	69%

Source: EPA

The western portion of the U.S. would be included in all three reduction programs, introducing NO_X regulations for the first time in the region.

Carbon Dioxide Legislation

In response to the introduction of the Clear Skies Act of 2002, Senators James M. Jeffords (I-VT) and Joseph I. Lieberman (D-CT) requested the EPA to analyze the impact of reducing CO_2 emission levels to 1990 levels – the same level proposed in the Kyoto Protocol to the United Nations Framework Convention On Climate Change. Senator Lieberman and John McCain (R-AZ) introduced legislation in January 2003 modeled after the acid rain trading program of the 1990 Clean Air Act Amendments. This legislation seeks to return to 2000 carbon dioxide emission levels by 2010.

Many states are also pursuing state-level CO_2 mitigation programs. In June 1997, Oregon adopted a CO_2 standard for new energy facilities. The enabling legislation authorized the state's Energy Facility Siting Council to establish CO_2 standards for base load natural gas plants, non-base load power plants (all fuels), and non-generating energy facilities (all fuels). Pursuant to the legislation, the Council set up the rules to implement the standard in March of 1999. As an example of the implementation of these rules, the Hermiston Power Project is expected to have gross CO_2 emissions (i.e., over 30 years) of 50.2 million metric tons (MMT) (13.7 MTCE). The CO_2 standard offsets required for this project are 5.5 MMT CO_2 (1.5 MMTCE) and will be met through a monetary path offset value of $3.6 million.

California has also pursued CO_2 mitigation initiatives. On July 22, 2002, Governor Gray Davis signed into law a bill that provides authority to the California Air Resources Board (CARB) to consider CO_2 in their regulation of air emissions. Other governors have indicated an interest in considering similar legislation.

Production Tax Credit

In 1992, the Energy Policy Act was signed into law and 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 was $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 equipment operation. The current PTC rate is approximately $0.019 per kWh.

The credit is available 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, the President 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 energy bills being considered at the federal level propose extensions of the PTC beyond 2003. Until the future of the PTC is resolved, 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 dampened relative to wind facilities leveraging the PTC as well as other conventional resource options.

The congressional tax committees originally sponsored the PTC legislation in order to encourage the development and utilization of wind energy with the intent that the PTC would enable wind energy to compete with conventional energy resources. Some have argued that an extension of the PTC through December 31, 2006 is necessary to provide wind developers with a level of certainty and stability that would allow the technology to further mature. Moreover, supporters agree the extension would stimulate the wind industry to achieve greater economies of scale, as well as enhancing wind's ability to compete with conventional alternatives.

Recent Legislative Activity

During the 107th Congress, a comprehensive energy bill passed the House and Senate, and went before a conference committee. Negotiations over the bill broke down, and the legislation died in Committee at the end of 2002. The energy legislation passed by the House and Senate would have extended the renewable energy production tax credit for an additional two years.

During the current Congress, Sen. Gordon Smith (R-Ore.) introduced a bill in January 2003 to extend the PTC through January 1, 2014. A similar bill introduced in the House by Representative Mark Foley (R-Fla.) seeks a five-year extension. Energy legislation will be addressed by this Congress and most speculate the PTC extension would be a component of any comprehensive legislation.

APPENDIX M

April 30, 2003

Puget Sound Energy

Policy Statement Regarding the Promotion and Use of Renewable Energy Resources

Definition of Renewable Energy

For purposes of this Policy Statement, "renewable energy" means the electricity, gas or mechanical energy produced from facilities that are fueled by: (a) wind, (b) solar energy, (c) geothermal energy, (d) landfill gas, (e) municipal solid waste, (f) gas recovered from waste treatment facilities, (g) biomass, (h) wave or tidal action and, (i) qualified hydropower (as defined in RCW 19.29A.090). However, the Company believes it must remain flexible and open to advances in technology and the best thinking about technology applications.

Our Policy

Puget Sound Energy ("Company") believes that renewable energy resources can and should play a role in meeting the incremental needs of its customers and become an important part of its resource supply portfolio beginning in 2004. Cost-effective renewable energy resources can diversify fuel sources, enhance fuel price stability, provide location related benefits on the electric grid, reduce incremental air emissions, provide economic solutions to the disposal of various waste streams and stimulate local economic development.

The Company believes it should encourage the use of renewable energy resources by: a) using such resources to help meet its own-use requirements, b) encouraging its employees to use renewable energy resources at home, c) promoting appropriate renewable energy development and use by its customers, d) promoting the use of renewable energy resources in appropriate community applications through targeted education and demonstration projects, and (e) promoting the commercialization of cost effective renewable energy projects.

Many renewable energy resource applications are of a relatively small-scale with unit economies that may not compare favorably with the unit economies large conventional central generating plant alternatives. Accordingly, the scale and rate of their adoption and deployment by the Company must include consideration of the ultimate price impact upon the Company's retail prices and its customers. Further, some important renewable resource opportunities depend upon special federal tax depreciation and financing incentives for their commercial viability. Viable renewable energy projects that can be permitted, financed, constructed and reliably operated on a timely basis are of particular interest to the Company.

The Company's acquisition plan for renewable resources will include exploration of direct ownership through development and acquisition, use of bilateral contracts, and general solicitations. Any and all such means will be evaluated to secure appropriate renewable resources that complement the Company's goals of fuel diversity, price stability and supply reliability. Opportunities to pursue the integration of renewable resources into the Company's supply portfolio will be sought with the goal of gaining direct experience with managing and relying upon such resources to meet its customers' energy needs.

For small-scale customer side renewable energy applications, the Company supports the net metering standards adopted in 1998 that facilitate renewable energy development within the Company's customer base as well as across Washington. Further, the Company proposes to increase to 50 kw from the current 25 kw the size of the machine permitted under its net metering tariff. Net metering allows customers' electric meters that have generating facilities to "turn backward" when their generators are producing energy in excess of their demand, and would enable customers to use their own renewable generation to offset the cost of their own consumption at retail rates over a billing period. Such an approach involves customers more directly in renewable energy utilization, but also yields specific benefits to the Company including potential improvements to system load factors and additional energy resources within the service area.

Our Goals

- ***Electric Resource Portfolio Goals***. The results of the Company's current least cost planning efforts indicate that wind resources (or its equal) could serve at least five percent of its retail electric customers' energy needs with renewable resources by the year 2013. Higher standards of reliable energy supply described in the Least Cost Plan suggest that renewable energy could be targeted at the ten percent planning level. Such targets would necessitate acquiring approximately 125 and 250 average megawatts of renewable resources, respectively, for the Company's electric resource portfolio during the next ten years. The Company is continuing to consider renewable resources on the basis of cost and risk in its Least Cost Plan. Further assessment will include investigation of strategies and specific transactions to integrate renewable resources into the overall supply portfolio to meet 10 percent of retail electric customer energy needs by 2013.

- ***Own-Use Goals.*** Beginning in 2004, the Company will acquire renewable energy for 50 percent of its own-use/own service territory requirements and will acquire 100 percent of such requirements beginning in 2006. The Company's estimated own-use annual load is approximately 28 million kwhr's.[1]

- ***Employee Goals.*** The Company will set goals and develop a five-year plan for the use of renewable resources by its employees.

- ***Customer Goals.*** The Company will set goals for renewable energy use by its customers. Such goals may include, but not limited to, use of green pricing programs, adoption of net metering technology, additions of renewable resources to its overall supply portfolio and creation of programs to involve customers in the demonstration and adoption of renewable resources for their own direct use.

Action Plan

The Company will organize managerial and financial resources to identify and utilize or acquire renewable resource projects appropriate to its energy needs, cost considerations and customer and community interests. Additionally, the Company will encourage entrepreneurial initiatives in its service territory to identify and implement appropriate renewable resource projects that are intended either as merchant power, customer end-use consumption with net metering options, and purchase power alternatives.

The Company realizes that the opportunity to economically obtain renewable resources can vary greatly over time. Such opportunities are impacted by shifts in technology, transmission constraints, capital markets, federal and state tax policy, wholesale power markets, markets for various waste products, environmental regulations and public acceptance of the impacts such

[1] Own-use annual load includes PSE's metered owned and leased facilities within its service territory.

resources have on local communities and the environment. The Company recognizes that many renewable resource projects have unusual and even unique market and siting attributes. The Company notes its concern that there may be a dearth of specific, commercial scale renewable energy development opportunities in its service territory that are economically attractive and readily able to be permitted. Accordingly, it is the intent of the Company to become knowledgeable about renewable resource opportunities and to obtain such resources by proactively engaging in both development and acquisition transactions. In pursuing such development opportunities and/or making such acquisitions, the Company will consider not only cost criteria, but also the ancillary benefits of appropriate scale and local impacts, reduced price volatility, customer and community needs.

Annual Policy Review

This policy shall be reviewed not less than annually by the Company and shall be considered in each Least Cost Plan the Company creates in connection with its obligations under various laws and regulations of the State of Washington.

APPENDIX N
WIND RESOURCE INTEGRATION ISSUES

Wind As a Resource Option

PSE's electric resource strategy includes a goal of meeting five percent (133 aMW) of its customer energy loads through renewable resources. In order to meet this goal, and strive for a higher target of meeting 10 percent of its electric customers' needs from renewable resources, PSE must address issues related to integrating wind into its portfolio. Recently, wind energy has been attracting greater interest among developers, utilities and consumers alike as a viable resource. The drivers of this interest include the continuing improvement in the competitiveness of wind energy economics, the recent increase in natural gas prices along with increased price volatility, and the growing consumer interest in green pricing programs and renewable energy in general

For PSE, the attractive aspects of wind include immunity to fuel price volatility, absence of emissions, opportunity to diversify the supply portfolio, ability to offer a green product directly to customers, and the potentially favorable economics. In the short-term, PSE has signed a 12-month contract to purchase output from a wind facility in order to gain first-hand experience with dispatching this technology within the Company's portfolio. Critical to the further integration of this technology is gaining a better understanding of the implications of integrating wind and relying upon it as a part of the Company's supply portfolio. To do this effectively, PSE needs to consider a number of issues as it evaluates available options. These issues include:

- The intermittency of wind resources
- Balancing system reliability with wind interconnection
- Understanding the match between wind resources and PSE's system peak
- Accessing the best wind resources in the region

The remainder of this appendix examines each of these issues along with addressing preliminary potential solutions that PSE can exercise to integrate wind into its supply portfolio.

Intermittency of Wind

At the forefront of its efforts to integrate wind into its portfolio, PSE must consider the issue of wind intermittency. This issue refers to the simple fact that when the wind does not blow, power is not generated. In addition, it is difficult to accurately predict output from a wind facility on an hour-to-hour and on a day-to-day basis due to the variability of wind resource availability. This characteristic of wind facilities poses specific challenges for PSE in considering how best to integrate it with the other resources that it operates and dispatches in meeting customer loads on a daily and hourly basis.

The issue of predictability itself has several dimensions such as hour-to-hour, day-to-day, and matching supply to load. Under each set of circumstances, wind exhibits different attributes. As PSE continues to assess the best applications for wind, its predictability attributes will reflect the particular circumstances being considered. In the first case of hour-to-hour predictability, wind tends to have relatively predictable performance levels. The practice of utilities scheduling supplies on an hourly basis, and the fact that wind performance becomes more predictable the closer to the hour of need, supports the wind integration concept. It has been claimed by some that within two hours, the prediction of wind availability can be made with a high degree of confidence with variability of +/-10 percent. As you get further away from the hour of need, the predictability declines.

In the second case of day-to-day predictability, PSE pre-schedules on a day-ahead basis to establish its resource commitments. Day-ahead forecasts function to provide an operator such as PSE with a sense of available generation for the next day. In the case of wind, the fact that the predictability is less on a day-ahead basis than hour-to-hour does present additional challenges for incorporating wind resources. However, the predictability of wind during the summer is better (when winds are strongly correlated with rising temperatures) than during the winter (when wind resources are driven by storms). From PSE's perspective this creates an additional consideration when looking at the best applications for wind as it relates to the Company's integrated portfolio of resources. For most resources that the Company relies upon, both owned assets and purchased power, PSE schedules on a day-ahead basis thus the issue for PSE is one of blending wind's predictability attributes over the year with the rest of the resources in its mix.

Balancing System Reliability

Beyond the hour-ahead and day-ahead predictability of actual wind resource availability, PSE must also consider the issue of load variability and potential imbalances. Based on wind resource availability studies prepared in the region, no correlation exists between wind variations and load variations. Although this fact makes it highly unlikely that wind can be relied upon as a load following resource, it does not preclude the use of wind as a forward planning resource. PSE recognizes that reliance on wind power will have different probabilities associated with it than other resources and that the probabilities will change from season to season.

The effects of wind on other resource planning and operation activities differ in the long-and short-term and vary in how they affect PSE's resource planning, acquisition, and operation efforts. In the long-term, wind resources can be viewed as a consistent resource providing needed energy on an annual basis. One could argue that wind has more consistency in terms of the energy contribution from year to year than hydro resources. However, challenges arise when taking into account the timing of availability in the near-term (day-to-day), which is more consistent with hydro than wind. Nevertheless, PSE views wind resources as a potentially viable energy resource for use in meeting its annual energy needs. As noted above, wind resource availability on a season-to-season basis may not be consistent, however, the summer months tend to be more consistent for wind than the winter months.

Match Between Wind and System Peak

In the short-term, resource operation issues for wind are more pervasive than the planning and acquisition activities, due to the increased importance of resource predictability. The shorter the horizon, the more PSE has to ensure the availability of the appropriate mix of resources for meeting projected loads. The system operator will ramp up and dispatch resources and rebalance the portfolio on a real-time basis to optimize the Company's operational costs in parallel with reliably meeting customer end-use loads. An intermittent resource can potentially impose additional costs on an operator as a result of unanticipated changes in resource output.

In terms of resource adequacy, or reliability, wind does impose some unique challenges that can result in cost implications for PSE. As a control area operator, PSE has responsibilities to meet reserve margin targets. Intermittent resources such as wind, which like load can contribute to the need for maintaining a higher reserve margin requirement, cannot be relied upon to meet these reserve margin requirements and could subject the Company to penalty exposure. Consequently, PSE must either acquire additional resources to meet its needs or hold some of its existing resources in reserve. While wind can certainly satisfy average annual energy requirements, it cannot be counted on to satisfy regional reserve margin targets. The other cost implication of wind resource reliability is in the area of off-system sales. The less reliable the resource, the less the Company can rely on that resource (as part of an integrated portfolio) to market excess capacity and/or energy when PSE system loads are lower than the resources available in the portfolio. Shortfalls in resource availability have to be covered by other resources in the portfolio, which diminishes the off-system sales opportunities that could be pursued.

Best Regional Wind Resources

For purposes of the Least Cost Plan, PSE assumed a reliance upon wind resources within the Northwest region versus other adjacent states that may have better wind resources, but would be subject to large wheeling charges. PSE is cognizant that most of the best wind resources are not close to either existing high-voltage transmission or major load centers. In spite of this limit, a number of developers have identified potentially workable sites, with proximity to transmission lines and locations within the PSE system. PSE must determine its transmission capabilities in these areas and determine whether they require capital improvements and/or additional wheeling rights.

Given its intermittent nature and its dependence on the location of the resource, wind facilities are often at a competitive disadvantage to power generating facilities relying on traditional resources such as coal, gas and nuclear. Transmission scheduling policies are geared toward dispatchable facilities whereby one knows on a day-ahead basis how much and how long capacity will be needed, with a fairly high degree of confidence as to whether it will be used. Wind variability makes the proportional impact of transmission costs relative to actual utilization much higher than for the conventional facilities, due to the take or pay nature of firm service. Transmission operators rely on schedules and reservations to optimize the utilization of the system for all users. Deviations from these result in costs that must be allocated among the users. Typically, the allocation of these costs is done based on who was responsible for the deviation.

Facility Interconnection

The point of interconnection for a wind facility, and the turbine/generator technology employed play important roles in determining the impact that facility will have on the system. Strong interconnected transmission or distribution systems have greater voltage stability, and are not as impacted by the voltage response of non-synchronous wind generators to faults, switching actions, and load changes. Depending on the turbine/generator technology, strong transmission and distribution system can absorb significant amounts of intermittent wind generation with relatively modest impacts on the quality of power. A weak, voltage limited system, on the other hand, will not be able to as easily absorb these intermittent flows, and the generators may be susceptible to remote faults, and switching actions due to voltage instability. Where voltage support is weak and at remote parts of the PSE system, considerations for wind resources will include their intermittent output during peak loads, voltage instability, and their susceptibility to faults on weak systems. Future opportunities to integrate wind will be considered at both the transmission and distribution levels.

Potential Solutions for Integrating Wind

Although PSE recognizes the challenges to integrating wind into its portfolio, the Company realizes the advantages such a strategy offers. PSE's recent contract to take delivery of wind-generated electricity will provide the Company with valuable experience addressing the intermittency and other issues. PSE also acknowledges that having pre-defined interconnection requirements provide a particularly important component necessary to facilitate the development of wind within the control area. For developers, this would send a clear signal of PSE's confidence in its ability to manage the integration of wind resources into the region's supply mix while managing its interconnection with the transmission system. Having responsibility for maintaining the safety and reliability of the grid, PSE has continued to maintain strict control over the terms and conditions for interconnection to the grid by non-utility generators. Gaining first hand experience with a small amount of wind generation, either owned by a third party or by PSE, would give PSE first-hand empirical data regarding the issues raised by the intermittence of wind. This would enable PSE to more effectively integrate more wind into its portfolio.

As detailed in PSE's Two-Year Action Plan in Chapter XVII, PSE has a commitment to study wind integration issues. This Appendix not only offers PSE's preliminary thoughts on the challenges it faces, but also serves to demonstrate PSE's commitment to identify, address and develop solutions to the challenges of integrating wind into its system.

APPENDIX O
GAS RESERVE BACKGROUND

The data in this table were combined from a number of sources in order to construct a picture of the overall reserve position in the United States and Canada.[1] Particular focus is given to those gas production areas that are expected to affect PSE directly.

Since 1994, US gas reserve additions have exceeded production in all years except 1998.[2] Canada, however, has seen a decline in proved reserves. Continued exploration and development of natural gas reserves will provide adequate production to meet most of the projected demand. Over longer periods of time, as reserve and gas production levels change, the development of gas reserves in other regions might take on greater significance to PSE. But, given the continued development of gas reserves accessible from Duke Transmission, GTN, and NWP, PSE does not expect shifting purchases to other supply areas to be a material consideration in the foreseeable future. Exhibit O-1 provides a summary of North American reserves.

US Reserves

Additions to natural gas reserves in the US have exceeded production in every year but one prior to 2001. Existing gas reserves in the lower-48 are estimated to be 183 Tcf. At current production levels, these reserves will be adequate to supply approximately nine years of gas demand at current consumption levels. As with Canada, significant amounts of gas reserves remain unproved.

[1] While some liberty was taken with combining these data from different sources, the scale and relative allocation of the gas reserves was maintained.
[2] According to the EIA, this year [1998] was characterized by extremely low energy prices and accounting adjustments that affected reserve calculations.

Exhibit O-1
Summary of North American Gas Reserves

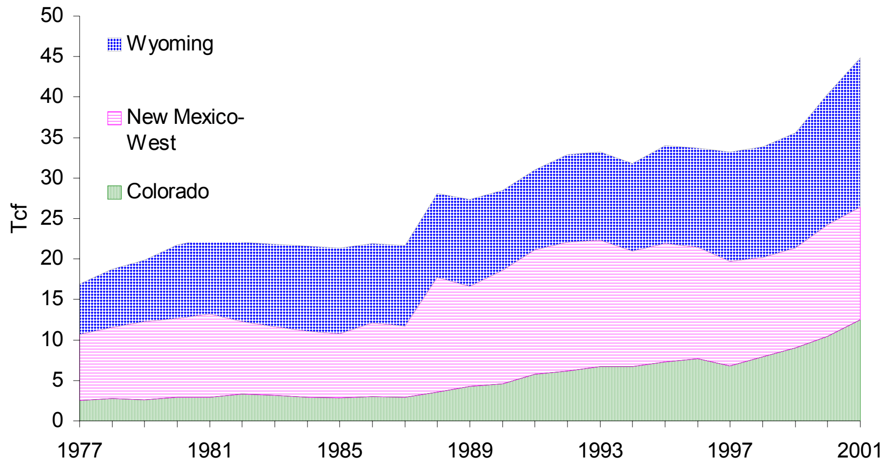
	ENERGY INFORMATION ADMINISTRATION	NATIONAL PETROLEUM COUNCIL	POTENTIAL GAS COMMITTEE	CANADA	TOTALS & AVERAGES
Lower – 48 Proved	183	157	157		
Lower – 48 Unproved	1,073	1,309	738.76		
Total Lower – 48	**1,256**	**1,466**	**895.76**		
Alaska Proved	10	10	10		
Alaska Unproved	32.32	303	183.83		
Total Alaska	**42.32**	**313**	**193.83**		
Total U.S. Proved	193	167	167		**175.67**
Total U.S. Unproved	1,105.32	1,612	922.59		**1,213.3**
Total U.S. Reserves	**1,298.32**	**1,779**	**1,089.59**		**1,388.97**
Alberta Proved				42	**42**
Alberta Unproved				158	**158**
Total Alberta				**200**	**200**
British Columbia Proved				8.9	**8.9**
British Columbia Unproved				111.25	**111.25**
Total British Columbia				**120.15**	**120.15**
Mackenzie Proved				0.5	**0.5**
Mackenzie Unproved				12.3	**12.3**
Total Mackenzie				**12.8**	**12.88**
Other Canada Proved				8.7	**8.7**
Other Canada Unproved				458.35	**458.35**
Total Other Canada				**467.05**	**467.05**
Total Other Canada Proved				60.1	**60.1**
Total Other Canada Unproved				739.9	**739.9**
Total Canada				**800**	**800**
Total NA Proved					**235.77**
Total NA Unproved					**1,953.2**
Total NA Reserves					**2,188.97**

Notes

- *Exhibit does not include Mexico. Data covers estimates from 1999-2001. Highlighted areas include derived or estimated values.*
- *Data sources include National Gas Supply Association; Canadian Association of Petroleum Producers; U.S. Geological Survey, Province of Alberta, EUG Statistical Surveys, Province of British Columbia, Energy and Mines; Energy Information Administration, Natural Gas Outlook*

The northern Rockies and Wyoming basins have emerged as the fastest growing gas-producing region in the U.S. Shallow gas formations, low drilling costs, and IRS Section 29 tax credits[3] for coal bed methane have spurred a rapid development pace in this area. However, development of pipeline capacity adequate to transport this gas market has lagged behind gas production. Accordingly, gas supplies in these areas (and other regions, such as the San Juan Basin) are generally lower priced than those in other areas as they compete to gain access to the available capacity. Exhibit O-2 provides an overview of natural gas reserves in the Rockies, San Juan and Powder River Basin.

Exhibit O-2
Natural Gas Reserves in the Rockies, San Juan Basin, and Powder River Basin
1977 – 2001



Recently, the United States Geological Service (USGS)[4] revised its estimates for undiscovered natural gas reserves in these areas. In the case of the Powder River, and San Juan Basins, these revisions resulted in upward estimates of the amount of undiscovered gas in these regions. With its capacity positions on the Northwest system, PSE is well-positioned to access these growing gas reserves and participate in facilities expansions. Exhibit O-3 details these revised estimates.

---

[3] These tax credits expired on December 31, 2002, resulting in a drop in the gas exploration activity. Expectations are that the resumption of these credits will be re-visited in the next Energy Bill.
[4] These revisions were published by the USGS between December 2002 and January 2003.

Exhibit O-3
Summary of Gas Reserves Accessible to PSE

GEOLOGIC AREA	MEAN ESTIMATE (TCF)	PERCENT CONVENTIONAL	PERCENT UNCONVENTIONAL	BASE YEAR OF ESTIMATE
Montana Thrust Belt	8.6	99.0	1.0	2002
South-western Wyoming	84.6	3.0	97.0	2002
Uinta and Piceance Basins	21.0	~1.0	~99.0*	2002
Powder River Basin	16.5	6.0	94.0	2002
San Juan Province	50.6	0.1	99.9	2002
Total	***181.3***	***6.8***	***93.2***	

** Characterized as "nearly all".*

The potential for increased gas reserves, relatively low field prices, and high market prices make new pipelines and pipeline expansions attractive for these areas. A number of new pipeline projects are in the works to move gas East, West, and South from these regions to existing markets and pipeline systems. The Cheyenne Plains project (El Paso) plans to move gas from eastern Wyoming to existing pipeline systems in Kansas to support declining reserves/production from older gas reserves. Kinder-Morgan and Transwestern have both proposed to build new pipelines into Phoenix, Arizona, and on to interconnect with El Paso's southern system and deliver additional gas into southern California. Kern River has recently completed expansions into southern California, and plans to expand further.

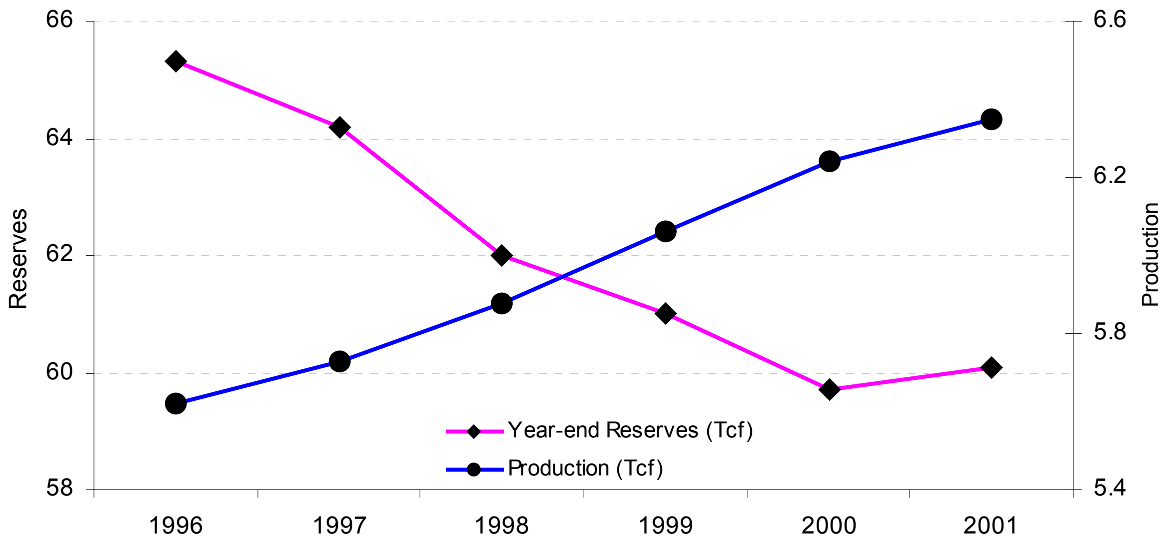
Canadian Reserves

Alberta, the largest natural gas producer in Canada, produces almost 5 Tcf (13.6 Bcfd) in 2001. Estimated, proved reserves at year-end 2001 stood at 40.5 – 45.2 Tcf. These reserve estimates do not consider coal bed methane (CBM) gas reserves, which are thought to be significant. Additional, remaining reserves are estimated at approximately 155 Tcf, more than three times the estimate of proved reserves. Most of the recent gas drilling activity has been centered on shallow formations in the southeastern part of the Province. Over time, development activity will likely shift to wells with smaller pools and higher declining rates. Developmental drilling continues on the Ladyfern field, a major discovery in the northwestern part of the province.

Nonetheless, Alberta projects that beginning in 2005, gas production will begin to decline two percent per year.

British Columbia produced a little over one Tcf (2.9 Bcfd) in 2001, the second largest gas producer in Canada behind Alberta. Gas reserves are concentrated in the northeastern part of the province, with a recent, significant find (Greater Sierra - 2002) estimated to contain five Tcf. Since 1991, the estimated remaining, marketable gas for British Columbia has hovered around 240,000,000 e3m3 (8.56 Tcf) – the same in 2001 as it was in 1991. Against this backdrop of stable reserve estimates, annual production in British Columbia almost doubled between 1991 and 2001, moving from 15.8 e9m3 (1.5 Bcfd) to 29.9 e9m3 (2.9 Bcfd day).

Exhibit O-4
Canadian Natural Gas Proved Reserves and Production



Preliminary estimates for the reserves in Mackenzie Delta region are modest at 0.5 Tcf, but the potential gas reserves are expected to be significant. Debate over the best pipeline route to move natural gas from this region, and other reserves further west in Alaska, has heated up recently as higher gas prices have made production from these areas more attractive.

As the frontier gas development progresses, the new pipelines (from Alaska, Mackenzie Delta, or both) will likely tie into existing systems in Alberta, finding a ready market for the gas at the AECO Hub for markets south and east. PSE's capacity position on PGT provides strategic access to current and future gas supplies from Alberta and points north.