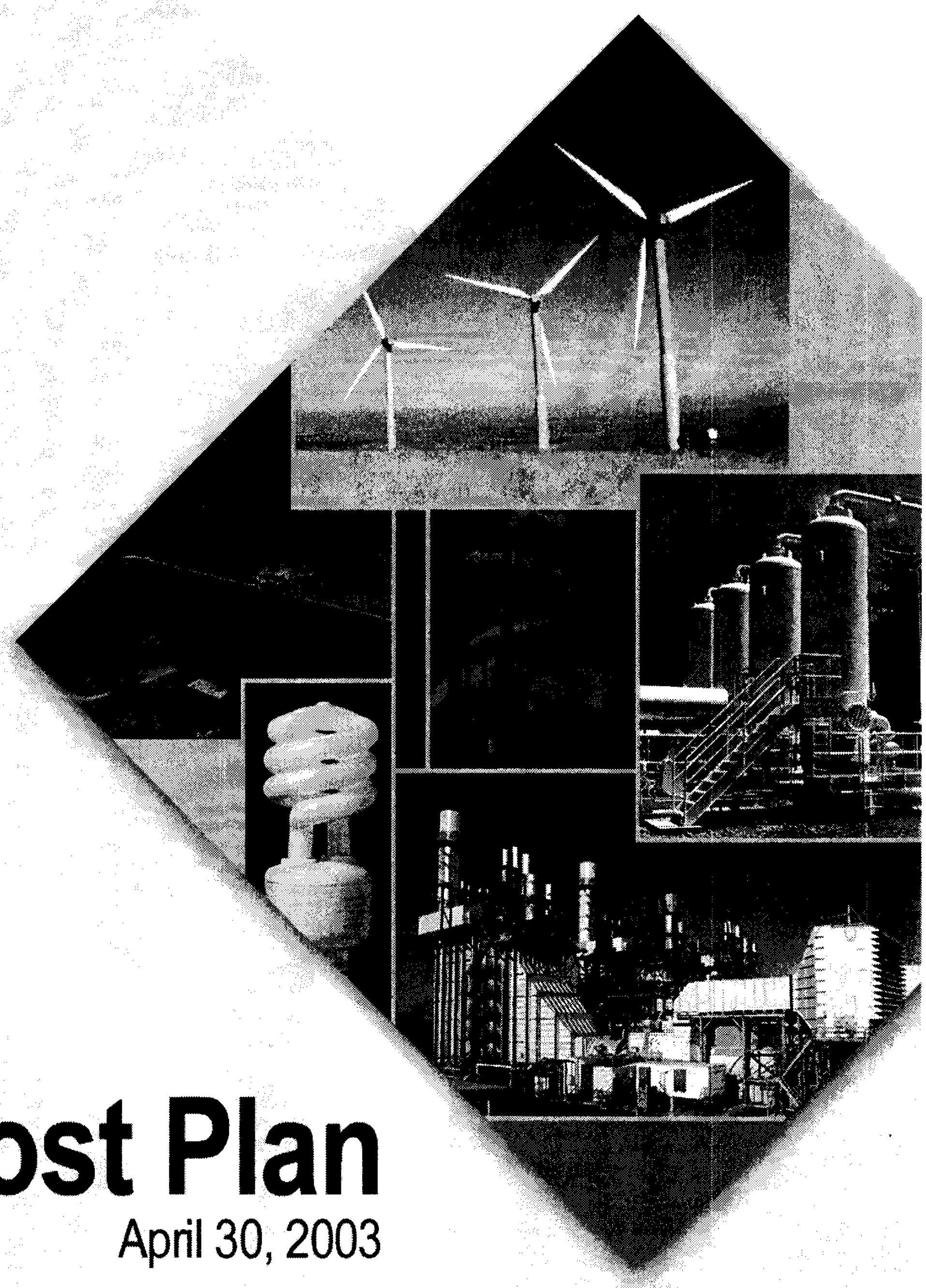
EXHIBIT NO. ___(JAH-16)
DOCKET NO. UG-040640, *et al.* (consolidated)
2004 PSE GENERAL RATE CASE
WITNESS: JAMES A. HEIDELL

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UG-040640** **Docket No. UE-040641** **(*consolidated*)**
In the Matter of the Petition of **PUGET SOUND ENERGY, INC.** **For an Order Regarding the Accounting Treatment for Certain Costs of the Company's Power Cost Only Rate Filing.**	**Docket No. UE-031471 (*consolidated*)**
In the Matter of the Petition of **PUGET SOUND ENERGY, INC.** **For an Accounting Order Authorizing Deferral and Recovery of the Investment and Costs Related to the White River Hydroelectric Project.**	**Docket No. UE-032043 (*consolidated*)**

SECOND EXHIBIT TO THE
PREFILED REBUTTAL TESTIMONY OF
JAMES A. HEIDELL (NONCONFIDENTIAL)
ON BEHALF OF PUGET SOUND ENERGY, INC.

NOVEMBER 3, 2004



Least Cost Plan

April 30, 2003

PUGET SOUND ENERGY

VI. LOAD FORECASTING

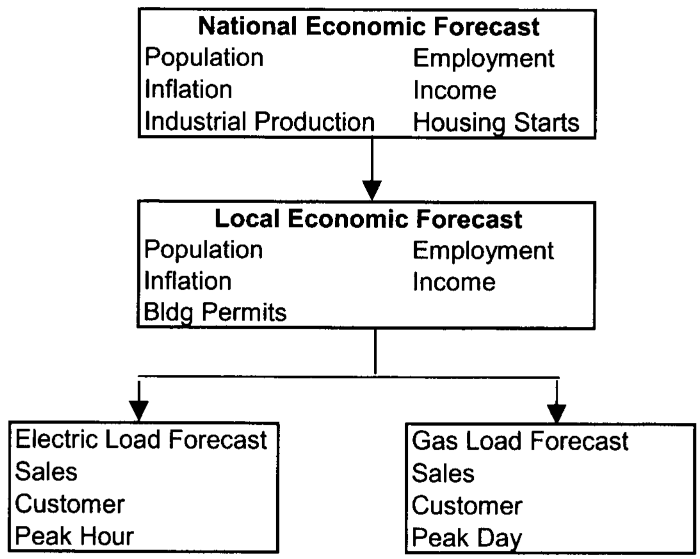
Each year, PSE develops a 20-year forecast of customers, energy sales and peak demand for its electric and gas service territories. PSE utilizes the forecast for short-term planning activities such as the annual revenue forecast, marketing and operations plans, as well as in various long-term planning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

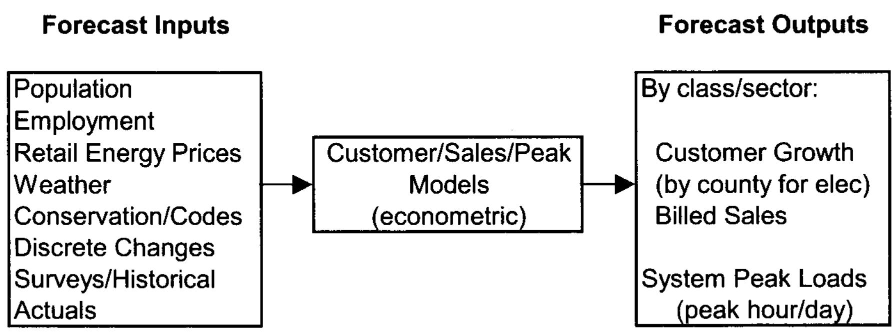


PSE used a mixed end-use and econometric model to develop its long-term billed sales forecasts in its previous Least Cost Plan. Specifically, electric sales forecasts from the residential and commercial sectors were developed by using end-use models (RHEDMS and CEDMS, respectively), while those in the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

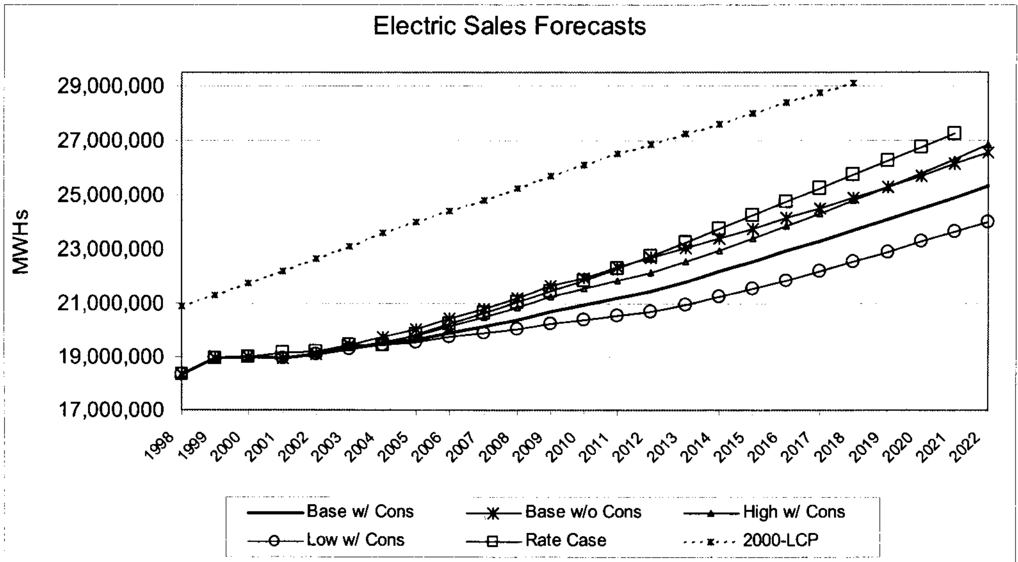
Any forecast carries a degree of risk. The base case long-term sales forecast assumes that the economy grows smoothly over time, with no major shocks or disruptions to the economy. In order to capture the range of economic possibilities in the forecast of billed sales, high and low sales forecast scenarios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

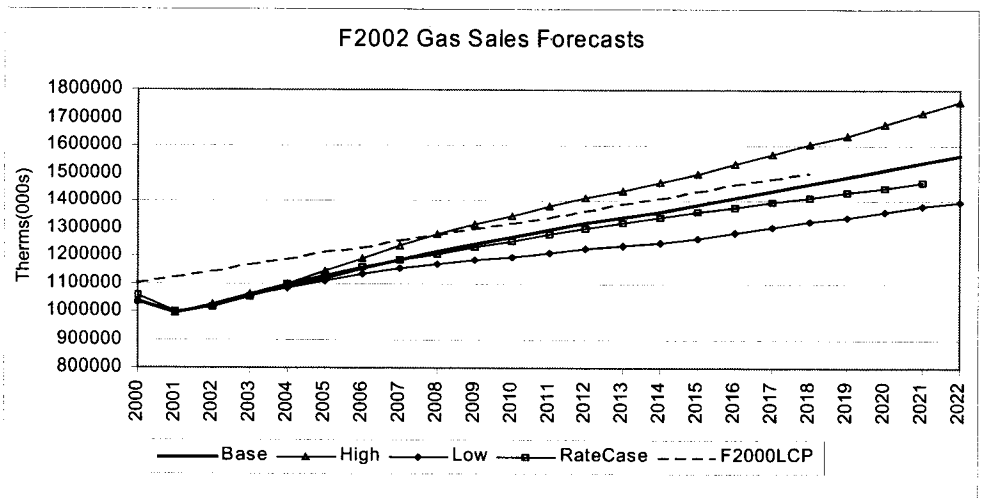
The high and low case economic scenarios were developed using the same methodology used in electric demand forecast to derive the high and low case scenarios for population and employment for the gas service territory. Exhibits VI-20 and VI-21 provide a comparison between the current forecasts and the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

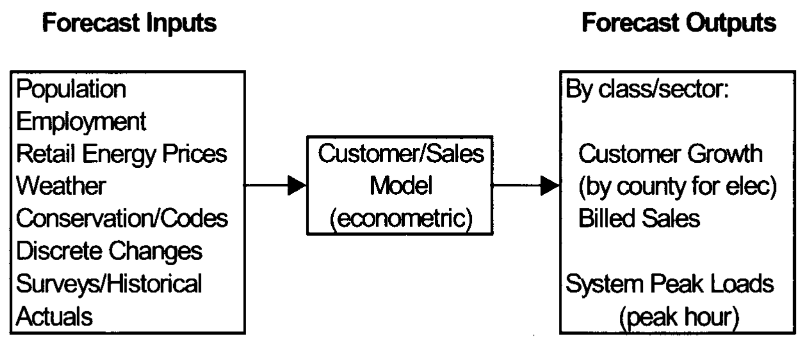
1. Annual real GDP is anticipated to grow at 3.2 percent in the next 20 years.
2. Employment growth in PSE's service territories will likely grow at a slower rate (1.7 percent) than its 30-year historical growth rate, fueled mainly through growth in the service sector.
3. Electric rates (in nominal dollars) 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.

APPENDIX C
LOAD FORECASTING METHODOLOGY

Billed Sales and Customer Count Forecast Methodology

Exhibit C-1
PSE Econometric Forecasting Model



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

  Weather = 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

PREFACE

As part of its long-term resource strategy development, Puget Sound Energy pursues a Least Cost Plan process. The primary purpose of this Least Cost Plan Update is to provide the results of a detailed assessment of the long-term conservation resource potential available to PSE, along with an updated load resource portfolio analysis that incorporates the results of the conservation resource assessment. The August 2003 Least Cost Plan Update, developed in consultation with Commission staff and with public input, is organized into 10 chapters:

Chapter I – Executive Summary
This chapter explains the purpose and goals of the Least Cost Plan Update and presents major findings and conclusions.

Chapter II – Conceptual Overview of Electric Resource Analysis
This chapter provides an overview of the electric resource portfolio analysis approach that PSE has used to prepare the August 2003 Least Cost Plan Update.

Chapter III – Forecasts
This chapter updates the electric-load, gas-price, and AURORA assumptions that were provided in PSE's April 2003 Least Cost Plan.

Chapter IV – Electric and Natural Gas Conservation Potential Assessment
This chapter summarizes the results of an assessment of technical and achievable electricity and natural gas conservation potential in PSE's service area for the 2004-2023 planning horizon.

Chapter V – Determination of Need for New Electric Resources
This chapter provides an update to the levels of need for electric energy and capacity that were identified in the April 30 Least Cost Plan.

Chapter VI – Demand Response
This chapter examines one form of demand-response program to help determine whether peak-oriented demand-response programs could be a more cost-effective alternative than single-cycle combustion turbines.

Chapter VII – Electric Portfolio Analysis and Results
This chapter details the approach, assumptions, and methodology used in the electric portfolio analysis, and summarizes the analysis results.

Chapter VIII – Conservation Implementation Issues
This chapter examines the unique implementation issues associated with acquiring conservation resources as part of a long-term resource strategy.

Chapter IX – Long-Term Electric Resource Strategy
This chapter presents PSE's updated long-term electric resource strategy, based on the integrated load resource portfolio analysis.

CHAPTER III. FORECASTS

Since the April 2003 Least Cost Plan was submitted, PSE has made numerous and significant changes to its long-term forecasting, discussed below. First, the load forecast has been updated to reflect a reduction in both energy and peak capacity. Second, the gas-price forecast has been improved with the consideration of a range of forecasts and scenarios. Third, the long-run Aurora optimization modeling was updated with these load- and gas-price forecasts, along with new assumptions about new plant-financing costs.

A. Energy-Load Forecasts

Electric-Load Forecasts

PSE's policy is to continually update its forecasts based on the latest available information. To that end, the April 2003 Least Cost Plan's forecasts of energy sales and peak loads for electricity have been revised for the August 2003 LCP Update. Similar revisions and updates will continue until a final forecast is produced in fall 2003. Hence the forecast used for the August 2003 LCP Update should be considered an interim forecast.

For the August 2003 LCP update, the billed-sales forecasts for electricity were revised for the following inputs:

- forecasts of regional population and employment, which call for slower growth and a longer recovery period;
- forecast of retail electric rates to account for expected rate changes stemming from changes in the BPA residential-exchange credit, from anticipated power-cost and purchased-gas adjustments, and from a new, long-term rate projection of retail electric rates for the region; and finally
- Calibration of the billed-sales forecasts to account for actual, weather-adjusted billed sales this year.

Economic and Demographic Assumptions

Because the Northwest economy is closely linked to the national economy, PSE forecasts of service-area population and employment are affected by the performance of the national economy. Global Insight (formerly DRI-WEFA) has revised its short- and long-term outlooks of the national economy to account for the most current information. The latest national economic forecast is based on Global Insight's March 2003 25-Year Macroeconomic Forecasts. Based on the new outlook for the national economy, Dick Conway and Associates also has updated PSE's electric-service-territory forecasts for employment and population. Conway's forecast of regional employment and population reflects Washington state's latest benchmarked employment data (for 2002), as well as revised county-population data from the U.S. Census Bureau. Exhibits III-1 and III-2 provide comparisons of the national and regional economic forecasts used in the April 2003 LCP and the August 2003 LCP Update.

Exhibit III-1
National Economic Outlook

	2004	2005	2010	2015	2020	aarg
April LCP						
GDP (BILS. $96)	$10,280.1	$10,569.3	$12,300.0	$14,450.8	$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%
August LCP Update						
GDP (BILS. $96)	$10,060.7	$10,390.0	$12,149.8	$14,163.9	$16,239.7	3.0%
EMPLOYMENT (MILL.)	133.0	135.4	144.6	153.3	160.8	1.2%
POPULATION (MILL.)	294.2	296.8	309.3	322.0	334.7	0.8%

Compared to the previous forecast, the new outlook calls for a slightly slower growth rate in national economic output, but a slightly higher growth rate in employment. This is driven by an assumption of a slightly lower growth rate in productivity, and a slightly lower inflation rate coupled with stimulative fiscal and monetary policies. Lower personal and corporate income-tax rates and a monetary policy that ensures stable growth in credit are expected to continue to ensure that the national economy recovers from a slow growth mode.

Exhibit III-2
Electric Service-Area Economic Growth Assumptions

	2004	2005	2010	2015	2020	aarg
April LCP						
EMPLOYMENT (THOUS.)	1,757.9	1,795.8	1,972.9	2,124.2	2,277.2	1.6%
POPULATION (THOUS.)	3,402.2	3,438.7	3,659.1	3,859.5	4,078.9	1.1%
August LCP Update						
EMPLOYMENT (THOUS.)	1,718.3	1,749.9	1,924.8	2,066.8	2,203.6	1.6%
POPULATION (THOUS.)	3,419.3	3,450.2	3,636.3	3,805.9	3,980.4	1.0%

While the expected growth *rates* in employment and population are the same in both the August 2003 LCP Update and the April 2003 LCP, the actual levels are not the same. Employment is lower in the August LCP Update, primarily because of a deeper employment reduction in 2002 and a slower recovery in 2003. As a result, the employment peaks experienced by the region in 2000 are not expected to be reached again until late 2005 or early 2006. Population is higher initially, however, because of higher revised final estimates for 2000 from the Census Bureau. In the long run, population growth is expected to be lower than previously forecasted because of slower economic growth. Hence, population totals in the long run are also lower.

Retail Energy-Price Assumptions

This interim forecast also revises PSE's retail electric-price forecast assumptions to account in the near term for an expected reduction in the BPA residential-exchange credit between October 2003 and October 2006, and expected rate adjustments due to increases in power and natural-gas costs. The August 2003 LCP Update also accounts for the long-term changes in Global Insight's forecast of retail electric rates for the entire region. These changes imply an overall increase in retail rates for all customer classes, both in the short and long term.

The retail-rates forecast in the April 2003 LCP assumed no changes in rates in the near term and growth rates of less than 2% per year in the long term. Near term (2004-2005), the August 2003 forecast of residential electric rates is higher by about 5%-10% because of the lower BPA residential-exchange credit, while commercial and industrial electric rates are higher by 1%-5% compared to the near-term forecast of rates in the April 2003 LCP. Longer term (beyond 2006), the new forecast projects PSE electric rates to grow by about 3% per year, while the April LCP forecast predicted a growth rate of about 2.5%. This change arises from a higher forecast of gas prices in the new forecast. The newly updated retail-rate forecasts are preliminary and are based on current information. These forecasts are likely to change again, over time, as the forecasted price of gas changes and as critical decisions are made within the company.

Changes in Other Assumptions

- **New Normal Annual Heating or Cooling Degree Days** – Because the definition of normal heating or cooling degree days is the average of degree days over the most recent 30 years, degree days in 2002 were added to the August 2003 LCP Update calculations while degree days from 1972 were deleted. Since 2002 was slightly warmer than 1972, the new figure for normal annual heating degree-days is slightly lower (4852 vs. 4858). This also implies slightly lower normalized loads.

- **Adjustment in Annual Savings for Ramp-Up and Conversion from Delivered to Billed Savings** – First-year annual savings were adjusted to allow for ramp-up. The effect is that only about half of the targeted savings in the first year is actually realized when a ramp-up based on historical data is imposed. Further, the delivered savings are converted to billed savings by assuming that approximately half of the delivered savings in the current month plus half of the delivered savings in the previous month are billed savings in the current month.

- **Load Losses** from the closure of a Weyerhaeuser lumber mill and the Miller brewery in Tumwater combined for about 4.5 aMW, near term.

As part of the company's ongoing load-forecast updates, more revisions are anticipated in some of the forecasts of inputs discussed above, along with other inputs such as weather-adjustment coefficients and monthly allocation factors.

Electric Sales and Customer Forecasts

Given the revised inputs, PSE expects billed sales (*without* conservation savings) to grow from 2,233 aMW in 2004 to 2,957 aMW in 2022, a growth rate of approximately 1.6 percent per year over the next 20 years. The billed sales forecast with conservation will use the projected conservation savings identified in Chapter VII. Exhibit III-3 shows the sales forecast by class for the August 2003 LCP Update.

Exhibit III-3

Electric-Sales Forecast by Class in aMW

	2004	2005	2010	2015	2020
August LCP Update without Conservation					
Total	2,232	2,252	2,407	2,628	2,857
Residential	1,113	1,118	1,172	1,289	1,414
Commercial	951	966	1,057	1,155	1,253
Industrial	156	157	163	166	169

The growth pattern is such that the growth rate in the next 10 years is slightly lower than the growth rate in the following 10 years. This is a result of the assumption that retail prices will have slightly higher growth rates in the first 10 years than in the second 10 years. Compared to the April 2003 LCP, these growth rates are slightly lower. Exhibits III-4 provides a comparisons of the total billed-sales forecasts for the April 2003 LCP and the August 2003 LCP Update.

Exhibit III-4

Electric Billed-Sales Forecast Comparison

	2004	2005	2010	2015	2020	2022	aarg
April LCP w/o Conserv	2,257	2,291	2,508	2,713	2,936	3,030	1.6%
August LCP Update w/o Conserv	2,232	2,252	2,407	2,628	2,857	2,957	1.6%

The August 2003 LCP forecasts are about 2.9% lower than in the April 2003 LCP, on average, over the next 20 years. The differences in the next two years are less than 1.5%, however, because the changes in employment are not magnified until a few years later, and because of the lag effect (about a year or more) of price changes on consumption.

Electric Customer Counts (Year-End)

Customer-count forecasts also changed as a result of the changes in inputs. The change is consistent with the revisions in population growth, where the population level in the new forecast is slightly higher than the April LCP forecast in the near term but lower in the long term. For the August 2003 LCP Update, PSE's electric-customer count is expected to grow by about 1.7% per year, compared to 1.8% in the April 2003 LCP forecast. Exhibit III-5 shows a comparison of the April LCP and the August LCP Update forecasts of year-end customer counts.

Exhibit III-5

Electric-Customer Counts (Year-End)

	2004	2005	2010	2015	2020	2022	aarg
April LCP	990,281	1,006,365	1,100,176	1,199,495	1,308,581	1,354,784	1.8%
August Update LCP	994,312	1,011,067	1,100,658	1,197,158	1,299,160	1,342,730	1.7%

Electric Peak-Load Forecasts

Based on further evaluation of the electric peak-load forecast, the peak-load equation was re-calculated using an expanded estimation period. This is expected to make the contribution of non-weather-sensitive loads to peaks more accurate because the data will have more observations where the transportation loads are excluded. The re-calculation further tested for the effects of consecutive cold-snap days, non-linearity in the temperature sensitivity in the extreme cold events, and whether there is a difference between morning versus afternoon/evening peaks. The final form of the re-calculated peak-load equation is as shown below:

Peak MW = a*(Resid aMW) + b*(Non-Resid aMW)
+ c*(Normal Temp for Month – Peak Hour Temp)*(Weather Sensitive aMW)
*Season Dummy
+ d*(Sched 48 Dummy) + e*(El Niño Dummy + f*(2-Day Consec Cold Snap)

- a, b, c, d, e, and f are coefficients to be estimated
- Resid aMW – residential delivered sales in the month
- Non-Resid aMW – commercial + industrial delivered sales in the month
- Weather Sensitive aMW – residential + 80% of commercial delivered sales
- Season Dummy – equals 1 if season is winter, zero otherwise; same for summer and shoulder months
- Sched 48 Dummy – equals 1 if year is 2001 and beyond
- El Niño Dummy – equals 1 if month is identified as El Niño month based on NOAA data

The only difference between this equation and the equation used in the April 2003 LCP is the addition of the 2-Day Consecutive Cold-Snap variable. This variable is a binary variable that equals 1 if the month's peak load is preceded by two consecutive cold-snap days in which peak loads exceeded 4,000 MWs. One-day and three-day consecutive cold days also were examined, but only the two-day consecutive cold days showed a statistically significant coefficient. Further, non-linearity in temperature sensitivity in the extreme cold events and introduction of a binary variable that distinguishes morning versus afternoon or early evening peaks were tested, but both tests resulted in non-statistically significant coefficients. Finally, this equation was estimated using data from January 1991 to March 2003, compared to the April 2003 LCP equation, which used data from January 1991 to December 2001. The re-estimation lowered the coefficient associated with non-residential loads, which was expected because there were more observations (from January 2002 to March 2003) in which the non-residential load was free of the transportation loads. There was only a gradual reduction of the transportation loads in 2001.

The table below provides a comparison of the estimated coefficients between the April 2003 LCP forecast and the August 2003 LCP Update forecast for the winter season-only case.

Exhibit III-6

Coefficients for Peak-Load Equations, Winter Case

Estimated Parameter	April LCP Equation	August LCP Equation
a	2.1590	2.2250
b	1.1520	0.9370
c	0.0212	0.0196
d	-0.2370	-0.2240
e	-122.0400	-185.1220
f		229.1160
RSqr	0.962	0.964

All the estimated parameters shown above are also statistically significant. Using the updated equation, the August 2003 LCP Update provides a forecast of normal January peak-hour load based on the following assumptions: 23 degrees Fahrenheit; a new forecast of sales; no El Niño; and a frequency of 2-day consecutive cold snaps matching the historical average of .04. The exhibits below show comparisons of the peak-load forecasts contained in the April 2003 LCP and the August 2003 Update.

Exhibit III-7

Electric-Peak Forecasts in MWs

	2004	2005	2010	2015	2020	2022	aarg
Normal Peak Load Without Conservation							
April LCP	4,874	4,942	5,409	5,853	6,333	6,535	1.6%
August LCP Update	4,508	4,538	4,785	5,250	5,734	5,948	1.6%

The average difference in forecasts between the April 2003 LCP and the August 2003 LCP Update is about 10% over the 20-year forecast period. The reduction in peaks is due to a lower projection of residential and non-residential loads, and a smaller projected contribution of non-residential loads to peaks based on the re-estimated equation.