# Demand Forecasts

Contents



*Demand forecasts are an estimate of how much energy customers will use in the future. When demand forecasts are compared with an assessment of the company's existing resources, the gap between the two identifies "resource need."*

## 1. Methodology

The demand forecast PSE develops for the IRP is an estimate of energy sales, customer counts, and peak demand over a 20-year period. These estimates are designed for use in long-term planning for resources and delivery systems. The 20-year horizon helps us anticipate needs so we can develop timely responses. Updates based on the most current information are used in developing near-term annual revenue forecasts and operational plans.

To produce forecasts of energy demand and customer growth, PSE employs econometric models that use historical data to explain changes in energy use per customer and customer counts. Significant inputs include information about regional and national economic growth, demographic changes, weather, prices, seasonality, and other customer usage and behavior factors. Known large load additions or deletions are also included.

In the forecast models, electricity and gas are assumed as inputs into the production of various economic activities. For residential customers, typical energy uses include space heating, water heating, lighting, cooking, refrigeration, dish washing, laundry washing, televisions, computers, and various other plug loads. Commercial and industrial customers use energy for production processes, space heating, ventilation, and air conditioning (HVAC), lighting, computers and other office equipment.

To forecast energy sales and customer counts, customers are divided into classes and service levels that use energy for similar purposes and at comparable retail rates. The different classes are modeled separately using variables specific to their usage patterns.

- Electric customer classes include residential, commercial, industrial, streetlights, resale, and transportation.
- Gas customer classes include firm (residential, commercial, industrial, commercial large volume, and industrial large volume), interruptible (commercial and industrial interruptible), and transportation (commercial firm, commercial interruptible, industrial firm, and industrial interruptible).

Peak load forecasts are developed using econometric equations that relate observed monthly peak loads to weather-sensitive delivered loads for both residential and nonresidential sectors. They account for deviations of actual peak hour temperature from normal peak temperature for the month, day of the week effects, and unique weather events such as a cold snap or an El Nino season.

For a detailed description of electric and gas peak models, and the methodology used to produce the annual energy and hourly electric forecasts, see Appendix E, Load Forecasting Models.

# 2. Key Assumptions

Economic activity has a significant effect on energy demand. During this 2-year planning cycle, it has been particularly challenging to develop assumptions about national and regional economic trends due to continually changing conditions throughout the period. These included a series of abrupt declines throughout the second half of 2008, and an uncertain and slow recovery process during 2009 and early 2010.

## A. Economic Growth

Because the Puget Sound region is a major commercial and manufacturing center with strong links to the national and state economies, the performance of these economies has a direct affect on the industries in our service territory and the businesses that support them. For this reason, PSE's service area forecast begins with assumptions about what is happening in the broader U.S. economy. PSE relies on Moody's Analytics U.S. Macroeconomic Forecast, a long-term forecast of the U.S. economy, for this information. Ultimately, PSE forecasts economic and demographic conditions for each county in the service territory using a system of econometric equations that relates national to regional economic conditions.

### *National Economic Outlook*

For the purpose of creating the baseline load forecast used in this IRP, PSE used the March 2010 Moody's Analytics U.S. Macroeconomic Forecast. Moody's predicted the recovery would not be firmly under way until 2011, when real GDP was expected to be rising at 4 percent and unemployment would finally be on a sustainable path downward, though still averaging over 9.5 percent for the year. As the economy reaches a sustainable path of expansion, Moody's expects the Federal Reserve to begin raising interest rates, and that inflation will return to target levels.

Short-term risks to the economy include a weaker housing market as foreclosures increase, reduced consumer spending as households reduce debt, and persistently high unemployment that causes further deterioration in workforce skills. Long-term concerns exist over federal fiscal policy and the budget when considering the costs of Medicare, Medicaid, and Social Security in combination with the retirement of the baby boomer generation.

Globally, the dollar is expected to strengthen against the euro and other currencies in the near term, and to strengthen against the yuan over a longer period, as policymakers in China allow it to revalue more naturally.

### *Regional Economic Outlook*

PSE's regional economic and demographic forecast is prepared internally using econometric models whose primary input is a macroeconomic forecast of the United States. Although the Puget Sound region has its own economic and demographic characteristics, it is part of a national and global economy and its pattern of growth is highly correlated with that of the rest of the nation. As mentioned above, the baseline analysis in the current IRP is based on a regional economic forecast derived using the March 2010 Moody's Analytics U.S. Macroeconomic Forecast, with other sources providing input and context where appropriate. The assumptions from this regional forecast were used to create the forecast scenario identified as the 2010 Base Case.

According to PSE's regional forecast model base case, the projected employment in the electric service territory is expected to grow at an annual rate of 1.4 percent between 2009 and 2029, compared to the prior 15-year historical rate of 1.1 percent. The main factor contributing to the slightly faster long-term growth in employment is recovery from the effects of the latest recession that depress the end point of the historical sample. Overall long-term regional growth is moderated by slower national employment growth due to lower national population growth, lower regional population growth resulting from space constraints, and the expectation that The Boeing Company's strong historical employment growth will not necessarily persist into the future. Manufacturing employment is expected to decline at a 0.8 percent annual rate of change in this scenario. The base case scenario projects that local employers will create more than 560,000 jobs between 2009 and 2029 and that an inflow of more than 920,000 new residents will increase the population of PSE's electric service territory to almost 4.6 million by 2029.

Four alternate scenarios were developed for the analysis, two based on business cycle variations ( "Cyclical" Alternate Low and High) and two based on population growth variations ( "Structural" Alternate Low and High).

The "Cyclical" Alternate Low and High scenarios were developed using varied assumptions provided by Moody's Analytics. "Cyclical" is used as a descriptor in this case because Moody's alternative scenarios are based in large part on assumptions about near-term business cycles in the national economy. To derive the Low assumptions, PSE calculated the ratio between Moody's baseline and pessimistic outlooks for each major national economic variable (such as total U.S. employment). These ratios were then used to scale down the equivalent regional variable (such as regional employment). Then these sets of revised variables were used to calculate the Cyclical Low scenario load forecast. A similar approach was taken to calculate the Cyclical High scenario load forecast, with a ratio calculated between Moody's optimistic and baseline projections for each economic variable.

"Structural" Alternate Low and High scenarios were developed using variations on long-term population growth provided by the Washington state Office of Financial Management. "Structural" is used in this case as a descriptor to indicate that the scenarios are based on alternative assumptions of long-term regional population growth, rather than business cycles. The regional forecast model was used to determine how other related economic variables would change given the adjusted population growth. The final set of variables related to both the high and low population estimates were then used to calculate the Structural Low load forecast and the Structural High load forecast.

# *B. Energy Prices*

Retail energy prices—what customers pay for energy—are included as explanatory variables in the demand forecast models because they affect the efficiency level of newly acquired appliances, their frequency and level of use, and the type of energy source used to power them. The energy price forecasts draw on information obtained from internal and external sources.

## *Electricity*

PSE projects that over the next 20 years, nominal retail electric rates will experience an increase of between 3.7 percent and 6.2 percent annually through 2014. Following a decline in the rate of increase, nominal long-term annual growth rates level off between 2.1 percent and 2.6 percent. In the near term, the retail price forecast assumes rate increases resulting from PSE's General Rate Cases and from Power Cost Only Rate Cases. For long-term retail rates, each usage class's annual retail rate growth is estimated using Seattle's consumer price index based on PSE's regional economic and demographic forecast.

### Natural Gas

PSE expects the rise in nominal retail gas rates to be slightly higher than the long-term rate of inflation: approximately 2.2 percent per year over the next 20 years. Two components make up gas retail rates: the cost of gas and the cost of distribution, known as the distribution margin. The near-term forecast of gas rates includes PSE's purchased gas adjustment and General Rate Case considerations. Forecasted gas costs reflect Kiodex gas prices for the 2010-2014 period and inflation projections beyond that. The distribution margin is based on PSE's projection for the near term and inflation projections for the longer term.

## C. Other Assumptions

### Weather

The billed sales forecast is based on normal weather defined as the average monthly weather using a historical time period of 30 years, ending in 2009.

### Loss Factors

Based on updated analysis, the electric loss factor was adjusted from 6.7 to 6.8, while the gas loss factor remains at 0.8 percent.

### Major Accounts

The 2010 Base Case forecast assumed that several large corporations and entities within PSE's service area planned to add facilities starting in 2010, which would eventually increase electric consumption by approximately 15 aMW.

# 3. Electric and Gas Demand Forecasts

Demand forecasts starting in 2010 serve as the basis for establishing resource need in this IRP. The charts and tables included herein incorporate demand-side resources implemented through March 2010 (primarily energy efficiency), but do not include anticipated additional demand-side resources thereafter. PSE analyzed the five scenarios described below in order to capture a range of possible economic futures.

2010 base case. This scenario assumes that the U.S. economy grows over time at an average annual real GDP growth rate of 2.5 percent from 2009 to 2029, with no major shocks or disruptions. It projects employment in the electric service territory to grow at an annual rate of 1.4 percent, and manufacturing employment growth to decline by an annual rate of 0.8 percent. With a faster rate of growth than the 15-year historical rate of 1.1 percent, it projects that local employers will create more than 560,000 jobs between 2009 and 2029, and that the inflow of more than 920,000 new residents will increase the population of our service territory to almost 4.6 million.

**2010 "cyclical" alternate low** assumes a double-dip recession and lower short-term growth. This scenario is based on pessimistic assumptions of the current business cycle. Long-term growth is almost identical to the 2010 Base Case scenario and the scenario differences occur primarily during the 2010- 2017 period. For PSE's service territory, this scenario projects that employment will be 5.2 percent lower than the 2010 Base Case scenario in 2012, with most of the recovery to the 2010 Base Case scenario complete by 2016. Unemployment will peak at 11.8 percent in 2012 in this scenario, and personal income, households, and housing permits assumptions are also lower than in the 2010 Base Case.

**2010 "cyclical" alternate high** assumes a 2 percent faster national GDP growth rate during 2010 and an earlier return to the pre-recession GDP growth rates. For PSE, this scenario includes an increase in the rate of employment growth through 2015 and a more aggressive return to pre-recession housing permit rates. In addition, upward adjustments were made to assumptions about personal income growth and the speed of the unemployment rate's decline.

**2010 "structural" alternate low** assumes lower long-term population growth and determines the subsequent effect on customer growth and other parameters instead of modeling near-term differences in the business cycle. Final population in 2029 is approximately 9 percent lower than the 2010 Base Scenario, leading to substantially reduced levels of employment and total personal income.

**2010 "structural" alternate high** assumes higher long-term population growth and determines the subsequent effect on customer growth and other parameters instead of modeling a shorter business cycle forecast process. Final population in 2029 is just over 10 percent higher than the 2010 Base Scenario, leading to substantially increased levels of employment and total personal income.

**Figure H-1**

**Forecast of Electric Service Area Household Growth Rate by Scenario**

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|
| Scenario | | | | | | | | |
| 2010 Baseline | 1.0% | 1.1% | 1.2% | 1.3% | 1.4% | 1.4% | 1.3% | 1.3% |
| 2010 "Cyclical" Alternate Low | 0.9% | 0.8% | 1.0% | 1.1% | 1.3% | 1.4% | 1.4% | 1.3% |
| 2010 "Cyclical" Alternate High | 1.1% | 1.3% | 1.2% | 1.3% | 1.4% | 1.4% | 1.3% | 1.3% |
| 2010 "Structural" Alternate Low | 0.8% | 0.7% | 0.7% | 0.8% | 0.9% | 0.9% | 0.9% | 0.9% |
| 2010 "Structural" Alternate High | 1.3% | 1.6% | 1.7% | 1.8% | 1.9% | 1.8% | 1.8% | 1.8% |

**Figure H-2**

**Forecast of Electric Service Area Unemployment Rate by Scenario**

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|
| Scenario | | | | | | | | |
| 2010 Baseline | 9.2% | 8.5% | 7.0% | 6.0% | 5.7% | 5.6% | 5.6% | 5.6% |
| 2010 "Cyclical" Alternate Low | 10.2% | 11.8% | 11.1% | 10.0% | 8.7% | 6.8% | 5.7% | 5.6% |
| 2010 "Cyclical" Alternate High | 8.5% | 7.1% | 6.5% | 6.0% | 5.7% | 5.6% | 5.6% | 5.6% |
| 2010 "Structural" Alternate Low | 9.3% | 8.7% | 7.2% | 6.2% | 6.0% | 5.9% | 6.0% | 6.1% |
| 2010 "Structural" Alternate High | 9.2% | 8.5% | 6.9% | 5.9% | 5.5% | 5.4% | 5.3% | 5.3% |

## *A. Electric Forecast*

Figures H-3 and H-4 show electric sales and peak growth forecasts for all five scenarios over the first 10 years of the planning horizon. Highlights with reference to the 2010 Base Case scenario are discussed on the following pages.

**Figure H-3**
**Annual Electric Load Forecasts 2010-2019**

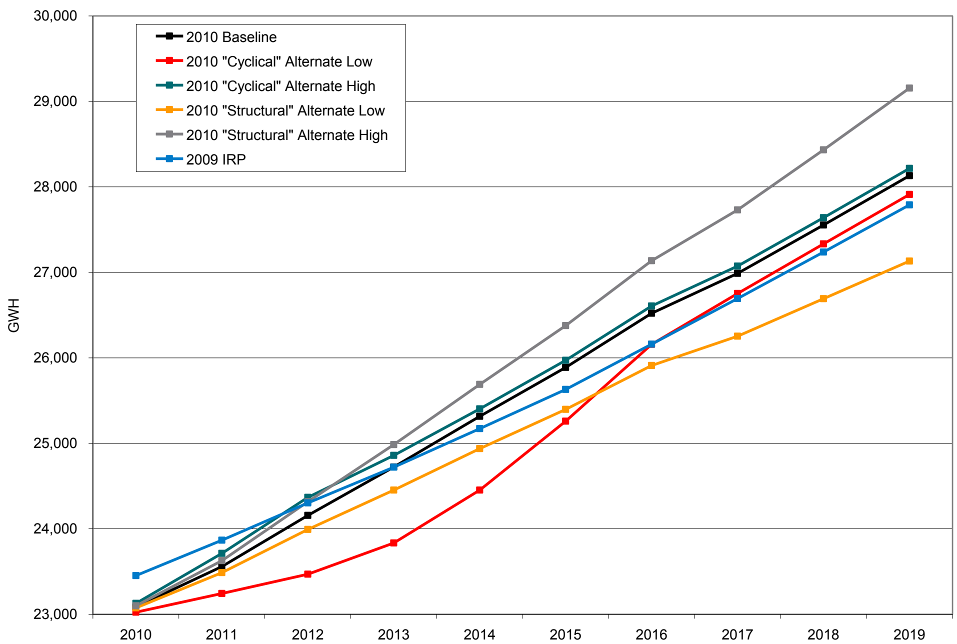
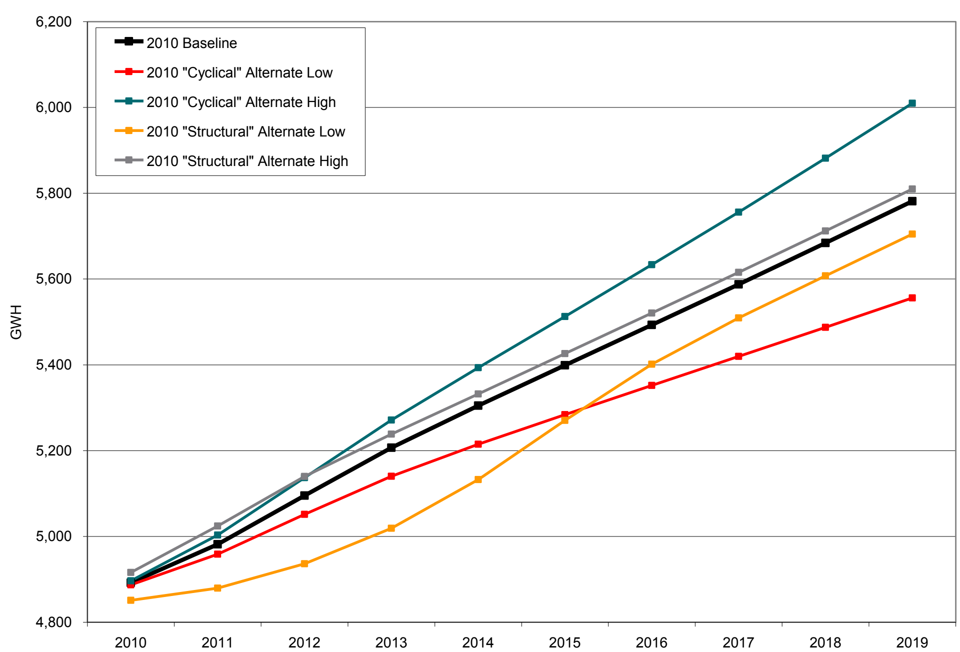



**Figure H-4**
**Electric Peak (Normal: 23°F) Forecast 2010-2019**



## *Electric Forecast Highlights (2010 Base Case)*

**1. Average electric firm loads are expected to grow at an average annual rate of 2 percent per year, from 2,455 aMW in 2009 to 3,642 aMW by 2029.**

The average annual growth rate is projected to be approximately 1.9 percent between 2009 and 2014 due to reduced near-term economic growth. The long-term growth rate of sales returns to slightly above 2 percent per year for the remainder of the period, 2014-2029.

**2. Commercial loads are expected to grow faster than residential loads, increasing from 44 percent of total loads in 2009 to 48 percent of total loads in 2029.**

Commercial loads related to nonmanufacturing employment are expected to grow the fastest in the future, while industrial loads are expected to continue to decline gradually.

Slower growth in residential loads is caused by several factors: a projected increase in the rate of construction of multifamily housing, which uses less energy per customer compared to single-family housing; the use of more efficient appliances; the expectation that new single-family homes are likely to use gas for space and water heating; and increases in the retail rate. These factors are expected to combine to create a relatively flat average residential use per customer during the forecast period. Residential loads as a percentage of total sales are projected to decline from 51 percent in 2009 to 49 percent in 2029.

**3. The number of electric customers is predicted to grow at an average rate of 1.7 percent per year, reaching approximately 1.5 million by 2029.**

Even though commercial customer growth rates are higher, the residential sector is expected to account for the majority of customer growth in absolute numbers. Multi-family residential housing units, which have a lower number of persons per household than single family units, are expected to be constructed at a higher rate in the future. Since multi-family units tend to have a lower average number of persons per household, this leads to a customer growth rate that is higher than the population growth rate. As of December 2009, residential customers accounted for 88 percent of PSE's total customer base.

**4. Peak hourly loads for electric are expected to grow by 1.6 percent per year over the next 20 years to 6,746 MW from 4,905 MW, slower than the growth in billed energy.**

Peak load growth is projected to grow more slowly than total energy use because residential sales (which place the most upward pressure on temperature-driven peak load events) are growing more slowly than commercial sales.

In general, compared to the 2009 IRP, the 2010 Base Case forecast of energy load is higher by about 278 aMW by 2027. The load forecast has a lower starting point for 2010 due to the impacts of the recession. Changes to the way PSE accounts for how historical investments in programmatic demand-side resources have reduced historical load growth have led to a slightly higher forecast of future load growth, prior to the impact of new programmatic demand side-resources.

The following tables summarize electric demand forecast results.

## Figure H-5[1]

### Electric Load Forecast Scenarios in aMW

| | 2010 | 2011 | 2012 | 2017 | 2022 | 2027 | 2029 | AARG |
|---|---|---|---|---|---|---|---|---|
| Scenario | | | | | | | | |
| 2010 Baseline | 2,456 | 2,507 | 2,570 | 2,871 | 3,182 | 3,507 | 3,642 | 2.1% |
| 2010 "Cyclical" Alternate Low | 2,450 | 2,473 | 2,497 | 2,846 | 3,158 | 3,480 | 3,615 | 2.1% |
| 2010 "Cyclical" Alternate High | 2,461 | 2,523 | 2,593 | 2,880 | 3,191 | 3,517 | 3,653 | 2.1% |
| 2010 "Structural" Alternate Low | 2,455 | 2,499 | 2,553 | 2,793 | 3,029 | 3,264 | 3,358 | 1.7% |
| 2010 "Structural" Alternate High | 2,458 | 2,514 | 2,587 | 2,950 | 3,343 | 3,773 | 3,958 | 2.5% |
| 2009 IRP | 2,542 | 2,591 | 2,639 | 2,905 | 3,222 | 3,570 | NA | 2.0% |

## Figure H-6[1]

### Electric Load Forecasts by Class in aMW (2010 Base Scenario)

| | 2010 | 2011 | 2012 | 2017 | 2022 | 2027 | 2029 | AARG |
|---|---|---|---|---|---|---|---|---|
| 2010 Base Scenario | | | | | | | | |
| Total | 2,456 | 2,507 | 2,570 | 2,871 | 3,182 | 3,507 | 3,642 | 2.1% |
| Residential | 1,233 | 1,254 | 1,289 | 1,432 | 1,574 | 1,714 | 1,770 | 1.9% |
| Commercial | 1,080 | 1,106 | 1,136 | 1,302 | 1,472 | 1,659 | 1,739 | 2.5% |
| Industrial | 132 | 135 | 133 | 123 | 119 | 114 | 113 | -0.8% |
| Other | 12 | 12 | 13 | 15 | 17 | 19 | 20 | 2.9% |

## Figure H-7[1]

### Annual Average Electric Customer Count Forecast by Class (2010 Base Case)

| | 2010 | 2011 | 2012 | 2017 | 2022 | 2027 | 2029 | AARG |
|---|---|---|---|---|---|---|---|---|
| 2010 Base Scenario | | | | | | | | |
| Total | 1,079,475 | 1,089,860 | 1,105,021 | 1,212,168 | 1,325,430 | 1,443,843 | 1,492,208 | 1.7% |
| Residential | 953,237 | 961,872 | 974,476 | 1,066,523 | 1,164,222 | 1,265,622 | 1,306,748 | 1.7% |
| Commercial | 119,104 | 120,659 | 122,990 | 136,945 | 151,421 | 167,172 | 173,855 | 2.0% |
| Industrial | 3,673 | 3,664 | 3,655 | 3,589 | 3,519 | 3,449 | 3,421 | -0.4% |
| Other | 3,461 | 3,665 | 3,900 | 5,111 | 6,268 | 7,600 | 8,184 | 4.6% |

## Figure H-8[1]

### Annual Electric Peak Forecast (2010 Base Case)

| | 2010 | 2011 | 2012 | 2017 | 2022 | 2027 | 2029 | AARG |
|---|---|---|---|---|---|---|---|---|
| 2010 Base Scenario | | | | | | | | |
| Normal | 4,892 | 4,982 | 5,095 | 5,588 | 6,073 | 6,552 | 6,746 | 1.7% |
| Extreme | 5,313 | 5,411 | 5,537 | 6,083 | 6,623 | 7,159 | 7,375 | 1.7% |
| 2009 IRP | 4,987 | 5,067 | 5,149 | 5,628 | 6,165 | 6,747 | NA | 1.8% |

## Figure H-9[1]

### Residential Electric Use per Customer in MWh,

### Current IRP (2010 Base Case) compared to 2009 IRP (Base Case)

| | 2010 | 2011 | 2012 | 2017 | 2022 | 2027 | 2029 | AARG |
|---|---|---|---|---|---|---|---|---|
| Current IRP | 11.327 | 11.416 | 11.589 | 11.762 | 11.845 | 11.863 | 11.868 | 0.2% |
| 2009 IRP | 11.019 | 10.991 | 10.974 | 11.008 | 11.029 | 11.044 | NA | 0.0% |

1 AARG means average annual rate of growth.

## B. Gas Forecasts

Figures H-10 and H-11 map the gas forecasts for all five scenarios to show load and peak day forecasts, excluding demand-side resources, for the first 10 years of the planning horizon. Highlights are discussed on the following pages.

**Figure H-10**
**Annual Gas Load Forecast Scenarios, 2010-2019**

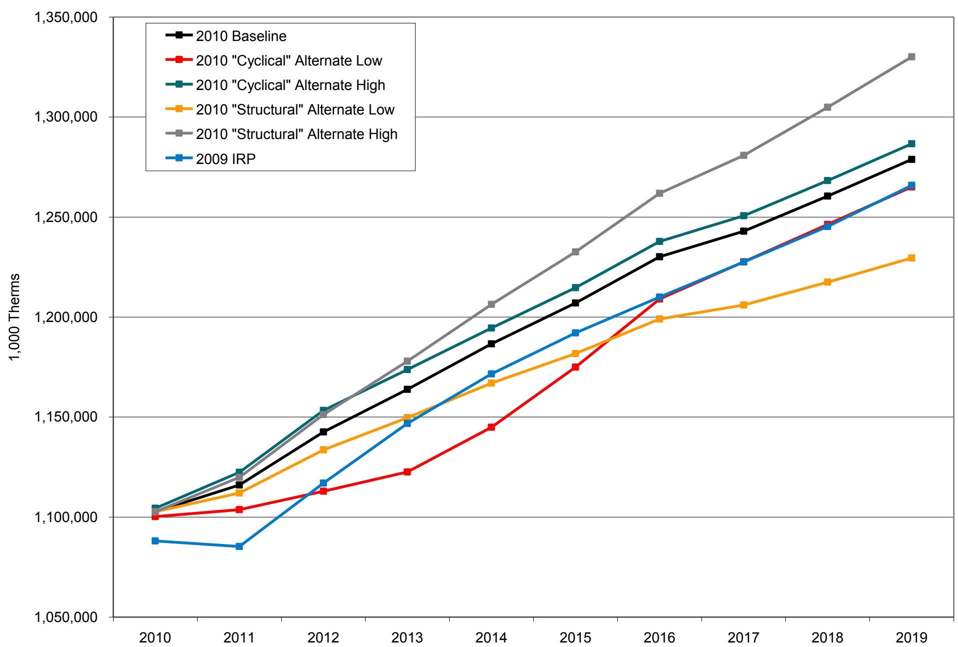
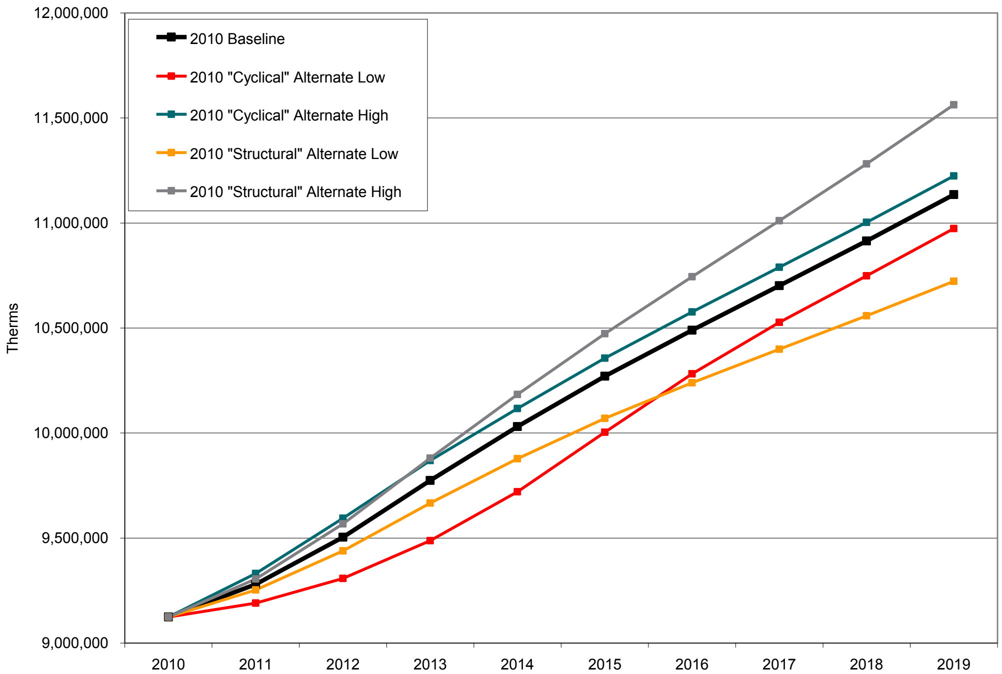


**Figure H-11**
**Firm Gas Peak Day Forecast Scenarios 2010-2019**



## *Gas Forecast Highlights (2010 Base Case)*

**1. Natural gas load is expected to grow at an average rate of 1.5 percent per year over the next 20 years, from 1.1 billion therms in 2009 to just under 1.5 billion therms in 2029.**

For 2010-2013, we expect a lower growth rate in gas load due to a lower rate of customer growth. Customer growth is expected to be weak in the near term due to lower household formation stemming from high unemployment and a weak housing market. As long-term gas retail rates approach the rate of inflation and economic conditions normalize, load is expected to grow at a long-term rate of 1.5 percent per year.

While overall sales volume will increase over the long term, some sectors (industrial, interruptible, and transportation) are expected to decline slightly, continuing more than a decade-long trend of slowing manufacturing employment and increasing retail prices. In the residential class, a slight decline in use per customer caused by more efficient equipment, a projected increase in multifamily housing, and energy efficiency, is expected to be offset by a steady increase in the number of customers due to population growth and conversion from electric to gas.

**2. The gas customer count is expected to increase at a rate of 2.1 percent per year over the next 20 years, reaching approximately 1.1 million by 2029.**

This forecast reflects slower population growth (hence slower demand for housing), an increase in the percentage of multifamily units, and a declining pool of potential conversion customers. This leads to a forecast that is lower compared to the 10-year historical growth rate of 2.8 percent.

Residential accounts are expected to increase at a rate of just over 2.1 percent per year over the next 20 years, and to represent 92.8 percent of our total customer base in 2029, up 1.3 percent from 91.5 percent in 2009.

While the number of potential conversion customers is expected to decline, this is expected to be partially offset by increasing penetration of gas into multifamily buildings (townhomes and condominiums) and new single-family homes.

Commercial sector accounts are expected to grow at an average annual rate of approximately 1.9 percent per year during the next two decades, and to account for roughly 7.0 percent of the overall customer base in 2029.

**3. Peak day firm gas requirements are expected to increase at an average rate of 1.9 percent per year over the next 20 years, from 9.3 million therms in 2009 to 13.5 million therms in 2029.**

Gas peak day growth rates are slightly higher than those for total load because faster growth is predicted for the weather-sensitive residential and commercial sectors. The primary drivers of peak growth across all sectors are an expanding customer base and changes in use per customer. Rising base loads are contributing to peak demand because gas is increasingly being used for purposes other than heating (such as cooking, clothes drying, and fireplaces). This effect is slightly offset by higher appliance efficiencies, and by the increasing use of gas in multifamily housing, where per-customer use is lower.

The residential sector accounts for about 70 percent of the peak daily requirement; the commercial and industrial sectors account for 28 percent and 2 percent, respectively. Large-volume commercial and industrial customers are included in this forecast.

Compared to the gas peak day forecast from the 2009 IRP, this forecast is lower during the 20-year forecast. This reduction is caused by a lower residential billed sales forecast, the primary driver of the peak day forecast, which is slightly lower due to a reduced customer growth forecast, as well as slightly lower use per customer due to weaker economic conditions and a slightly higher retail rate.

The tables below summarize gas demand forecast results.

### Figure H-12

### Gas Sendout Forecast Scenarios

| (in 1,000 Therms) | 2010 | 2011 | 2012 | 2017 | 2022 | 2027 | 2029 | AARG |
|---|---|---|---|---|---|---|---|---|
| Scenario | | | | | | | | |
| 2010 Baseline | 1,093,884 | 1,107,154 | 1,133,382 | 1,232,994 | 1,325,897 | 1,426,027 | 1,465,196 | 1.6% |
| 2010 "Cyclical" Alternate Low | 1,091,416 | 1,094,866 | 1,104,059 | 1,217,850 | 1,311,987 | 1,411,341 | 1,450,258 | 1.5% |
| 2010 "Cyclical" Alternate High | 1,095,541 | 1,113,410 | 1,144,079 | 1,240,649 | 1,334,061 | 1,434,913 | 1,474,361 | 1.6% |
| 2010 "Structural" Alternate Low | 1,093,884 | 1,103,197 | 1,124,539 | 1,196,356 | 1,257,430 | 1,320,987 | 1,344,306 | 1.1% |
| 2010 "Structural" Alternate High | 1,093,884 | 1,110,951 | 1,142,047 | 1,270,592 | 1,398,806 | 1,542,217 | 1,601,009 | 2.0% |
| 2009 IRP | 1,124,345 | 1,129,982 | 1,145,530 | 1,248,410 | 1,363,660 | 1,486,884 | NA | 1.7% |

### Figure H-13

### Gas Sendout Forecast by Class (2010 Base Case)

| (in 1,000 Therms) | 2010 | 2011 | 2012 | 2017 | 2022 | 2027 | 2029 | AARG |
|---|---|---|---|---|---|---|---|---|
| 2010 Base Scenario | | | | | | | | |
| Total | 1,093,884 | 1,107,154 | 1,133,382 | 1,232,994 | 1,325,897 | 1,426,027 | 1,465,196 | 1.6% |
| Residential | 556,123 | 565,367 | 580,645 | 647,522 | 713,823 | 782,901 | 809,757 | 2.0% |
| Commercial | 249,477 | 253,240 | 260,313 | 295,505 | 327,997 | 364,576 | 379,122 | 2.2% |
| Industrial | 31,698 | 32,249 | 32,965 | 31,618 | 30,225 | 28,916 | 28,398 | -0.6% |
| Interruptible | 53,664 | 52,700 | 53,465 | 55,103 | 54,636 | 54,292 | 54,072 | 0.0% |
| Transportation | 202,923 | 203,598 | 205,994 | 203,246 | 199,215 | 195,343 | 193,848 | -0.2% |

### Figure H-14

### Annual Average Gas Customer Count Forecasts by Class (2010 Base Case)

| | 2010 | 2011 | 2012 | 2017 | 2022 | 2027 | 2029 | AARG |
|---|---|---|---|---|---|---|---|---|
| 2010 Base Scenario | | | | | | | | |
| Total | 752,143 | 762,590 | 777,625 | 875,176 | 975,401 | 1,080,067 | 1,123,064 | 2.1% |
| Residential | 695,007 | 704,577 | 718,375 | 809,276 | 903,445 | 1,001,598 | 1,041,853 | 2.2% |
| Commercial | 54,106 | 55,011 | 56,273 | 63,041 | 69,203 | 75,811 | 78,588 | 2.0% |
| Industrial | 2,493 | 2,476 | 2,462 | 2,389 | 2,316 | 2,245 | 2,217 | -0.6% |
| Interruptible | 387 | 377 | 366 | 320 | 288 | 263 | 255 | -2.2% |
| Transportation | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 0.0% |

### Figure H-15

### Firm Gas Peak Day Forecast by Class (2010 Base Case)

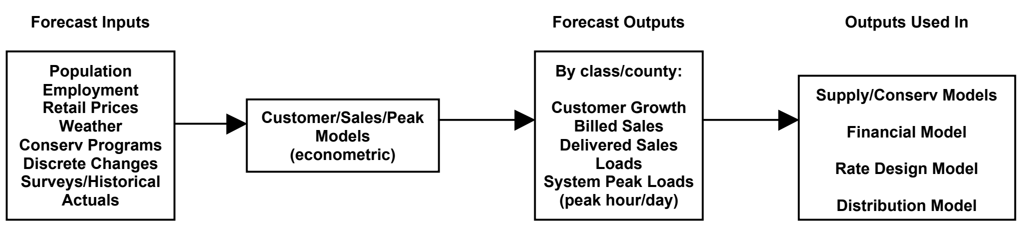
| (in Therms) | 2010 | 2011 | 2012 | 2017 | 2022 | 2027 | 2029 | AARG |
|---|---|---|---|---|---|---|---|---|
| 2010 Base Scenario | | | | | | | | |
| Total | 9,124,134 | 9,279,897 | 9,504,391 | 10,701,876 | 11,820,710 | 13,019,355 | 13,489,001 | 2.1% |
| Residential | 6,300,341 | 6,409,224 | 6,560,566 | 7,376,794 | 8,160,947 | 8,981,746 | 9,300,773 | 2.1% |
| Commercial | 2,480,041 | 2,521,199 | 2,586,143 | 2,967,120 | 3,304,528 | 3,685,120 | 3,836,516 | 2.3% |
| Industrial | 270,759 | 275,235 | 281,647 | 272,347 | 261,091 | 250,431 | 246,195 | -0.5% |
| Losses | 72,993 | 74,239 | 76,035 | 85,615 | 94,566 | 104,155 | 107,912 | 2.1% |
| 2009 IRP | 9,449,453 | 9,655,477 | 9,894,575 | 11,140,841 | 12,453,514 | 13,867,904 | NA | 2.3% |

# 4. Load Forecasting Models

This section provides a more detailed technical description of the four econometric methodologies used to forecast (a) billed energy sales, (b) customer counts, (c) system peak loads for electricity and natural gas, and (d) hourly distribution of electric loads.

For the 2010 load forecast used in this IRP, the company updated our key forecast driver assumptions and re-estimated the main equations. The diagram below shows the overall structure of the analysis.

**Figure H-16**
**Econometric Model for Forecasts of Energy Sales, Customer Counts,**




**and Peak Loads**

## *A. Electric and Gas Billed Sales and Customer Counts*

PSE estimated the following use-per-customer (UPC) and customer count equations using varied sample dates from within a historical monthly data series from January 1989 to December 2009, depending on sector or class and fuel type.  The billed sales forecast is based on the estimated equations, normal weather assumptions, rate forecasts, and forecast of various economic and demographic inputs.  The variable "t" denotes a month within the sample, and is therefore unique.  However, when we restrict a given month to be 1, 2,…,12 it is to be understood that we are talking about which monthly equivalence class it belongs to.

The UPC and customer count equations are defined as follows:

$$UPC_{c,t} = f(UPC_{c,t(k)}, RR_{c,t(k)}, W_{c,t}, ED_{c,t(k)}, MD_m)$$

$$CC_{c,t} = f(CC_{c,t(k)}, ED_{c,t(k)}, MD_m)$$

$$MD_i = \begin{cases} 1, Month = i \\ 0, Month \neq i \end{cases} \quad i \in \{1,2,\ldots 12\}$$

$UPC_{c,t}$ = use (billed sales) per customer for class “c”, month “t”

$CC_{c,t}$ = customer counts for class “c”, month “t”

$\_\__{t(k)}$ = the subscript $t(k)$ denotes either a lag of “k” periods from “t” or a polynomial distributed lag form in “k” periods from month “t”

$RR_{c,t(k)}$ = effective real retail rates for class “c”

$W_{c,t}$ = class-appropriate weather variable; cycle-adjusted HDD/CDD using base temperatures of 65, 60, 45, 35 for HDD and 65 and 75 for CDD; cycle-adjusted HDDs/CDDs are created to fit consumption period implied by the class billing cycles

$ED_{c,t(k)}$ = class-appropriate economic and demographic variables; variables include income, household size, population, employment levels or growth, and building permits

$MD_i$ = monthly dummy variable that is 1 when the month is equal to “i”, and zero otherwise for “i” from 1 to 12

UPC is forecast at a class level using several explanatory variables including weather, retail rates, monthly effects, and various economic and demographic variables such as income, household size, and employment levels. Some of the variables, such as retail rates and economic variables, are added to the equation in a lagged, or polynomial lagged form to account for both short-term and long-term effects of changes in these variables on energy consumption. Finally, we use a lagged form of the dependent variable in many of the UPC equations. This lagged form could be as simple as a one month lag, or could be a more sophisticated time-series model, such as an ARIMA(p,q) model. This imposes a realistic covariant structure to the forecast equation.

Similar to UPC, PSE forecasts the customer count equations on a class level using several explanatory variables such as household population, total employment, manufacturing employment, or the retail rate. Some of the variables are also implemented in a lagged or polynomial distributed lag form to allow the impact of the variable to vary with time. Many of the customer equations use monthly growth as the dependent variable, rather than totals, to more accurately measure the impact of economic and demographic variables on growth, and to allow the forecast to grow from the last recorded actual value.

We generate customer forecasts by county by estimating an equation relating customer counts by class and county to population or employment levels in that county. Once the customer counts for each county are estimated, adjustments are made proportionally so that the total of all customer counts is scaled to the original service area forecast.

The billed sales forecast for each customer class is the product of the class UPC forecast and the forecasted number of customers in that class, as defined below.

$$Billed\ Sales_{c,t} = UPC_{c,t} \times CC_{c,t}$$

The billed sales and customer forecast is adjusted for discrete additions and subtractions not accounted for in the forecast equations, such as major changes in energy usage by large customers. These adjustments may also include fuel and schedule switching by large customers. Total billed sales in a given month are calculated as the sum of the billed sales across all customer classes:

$$Total\ Billed\ Sales_t = \sum_c Billed\ Sales_{c,t}$$

PSE estimates total system delivered loads by distributing monthly billed sales into each billing cycle for the month, then allocating the billing cycle sales into the appropriate calendar months using degree days as weights, and adjusting each delivered sales for losses from transmission and distribution. This approach also enables computation of the unbilled sales each month.

# B. Peak Load Forecasting

## *Electric Peak-hour Load Forecast*

Based on the forecast delivered loads, we use hourly regressions to estimate a set of monthly peak loads for both residential and nonresidential sectors based on three specific design temperatures: “Normal,” “Power Supply Operations” (PSO), and “Extreme.” The “Normal” peak is based on the average temperature at the monthly peak during the historical time period, currently the past 30 years. The winter peaks are set at the highest Normal peak which is currently the December peak of 23 degrees Fahrenheit.

We estimated the PSO peak design temperatures to be a 1-in-20 year probability of exceedance. These temperatures were established by examining the minimum temperatures of each winter month. A function relating the monthly minimum temperature and the return probability was established. The analysis revealed the following design temperatures: 15 degrees Fahrenheit for January and February, 17 degrees Fahrenheit for November, and 13 degrees Fahrenheit for December. Finally, the “Extreme” peak design temperatures are estimated at 13 degrees Fahrenheit for all winter months.

Weather dependent loads are accounted for by the major peak load forecast explanatory variable, the difference between actual peak hour temperature and the average monthly temperature multiplied by residential loads and commercial loads. The equations allow the impact of peak design temperature on peak loads to vary by month. This permits the weather-dependent effects of residential and nonresidential delivered loads on peak demand to vary by season. The sample period for this forecast utilized monthly data from January 1991 to December 2009.

In addition to the effect of temperature, the peak load is estimated by accounting for the effects of several other variables. A variable is used to account for the portion of monthly residential and nonresidential delivered loads which are non-weather dependent and affect the peak load. The peak forecast also depends on a number of other variables such as a dummy variable accounting for large customer changes, a day of the week variable, and a cold snap variable to account for when the peak day occurs following several cold days.

The functional form of the electric peak-hour equation is

$$PkMW_t = \vec{\alpha}_{1,m} R_t + \vec{\alpha}_{2,m} NR_t + \vec{\alpha}_{3,m} \chi_1 \cdot \Delta T \cdot Ws + \vec{\alpha}_{4,m} \chi_2 \cdot \Delta T \cdot C + \alpha_{5,m} S48 + \vec{\beta}_d \cdot DD_d + \alpha_{6,m} CSnp$$

where:

$$\chi_1 = \begin{cases} 1, & Month \neq 7,8 \\ 0, & Month = 7,8 \end{cases}$$

$$\chi_2 = \begin{cases} 1, & Month = 7,8 \\ 0, & Month \neq 7,8 \end{cases}$$

$PkMW_t$ = monthly system peak-hour load in MW

$R_t$ = residential delivered loads in the month in aMW

$NR_t$ = commercial plus industrial delivered loads in the month in aMW

$\Delta T$ = deviation of actual peak-hour temperature from monthly normal temperature

$Ws$ = residential plus a % of commercial delivered loads

$C$ **=** monthly delivered loads for the commercial class.

$S48$ = dummy variable for when customers in schedule 48 switched to transportation customers

$DD_d$ = day of the week dummy

$CSnp$ = 1 if the minimum temperature the day before peak day is less than 32 degrees Fahrenheit

$\chi_1, \chi_2$ = dummy variables used to put special emphasis on summer months to reflect growing summer peaks.

To clarify the equation above, when forecasting we allow the coefficients for loads to vary by month to reflect the seasonal pattern of usage. However, in order to conserve space, we have employed vector notation. The Greek letters $\alpha_m$ and $\beta_d$ are used to denote coefficient vectors; $\alpha_m$ denotes a monthly coefficient vector (12 coefficients) and $\beta_d$ denotes a coefficient for the day of the week (seven coefficients). The difference between $\alpha_m$ and $\vec{\alpha}_m$ is that all values in $\alpha_m$ are constant, whereas $\vec{\alpha}_m$ can have unique values by month. That is to say, all “January” months will have the same coefficient. There are also two indicator variables that use a weather-sensitive combination of residential and some commercial loads for all months except for July and August, which use only commercial loads, to reflect the growing summer usage caused by increased saturation of air conditioning.

### Gas Peak-day Load Forecast

Similar to the electric peaks, the gas peak day is assumed to be a function of weather-sensitive delivered sales, the deviation of actual peak-day average temperature from monthly normal average temperature, and other weather events. The following equation used monthly data from October 1993 to June 2009 to represent peak day firm requirements:

$$PkDThm_t = \vec{\alpha}_{1,m} Fr_t + \vec{\alpha}_{2,m} \Delta T_g \cdot Fr_t + \alpha_{3,m} EN + \alpha_{4,m} Win + \alpha_{5,m} Smr + \alpha_{6,m} Csnp$$

where:

$$Win = \begin{cases} 1, & Month = 1,2,11,12 \\ 0, & Month \neq 1,2,11,12 \end{cases}$$

$$Smr = \begin{cases} 1, & Month = 6,7,8,9 \\ 0, & Month \neq 6,7,8,9 \end{cases}$$

$PkDThm_t$ = monthly system gas peak day load in dekatherms
$Fr_t$ = monthly delivered loads by firm customers
$\Delta T_g$ = deviation of actual gas peak-day average daily temperature from monthly normal temperature
$EN$ = dummy for when El Nino is present during the winter
$Win, Sum$ = winter or summer dummy variable to account for seasonal effects
$CSnp$ = indicator variable for when the peak occurred within a cold snap period lasting more than one day, multiplied by the minimum temperatures for the day

As before, the Greek letters are coefficient vectors as defined in the Electric Peak section above.

This formula uses forecasted billed sales as an explanatory variable, and the estimated model weighs this variable heavily in terms of significance. Therefore, the peak day equation will follow a similar trend as that of the billed sales forecast with minor deviations based on the impact of other explanatory variables. An advantage of this process is the ability to account for the effects of conservation on peak loads by using billed sales with conservation included as the forecast variable. It also helps estimate the contribution of distinct customer classes to peak loads.

The design peak day used in the gas peak-day forecast is a 52 heating degree day (13 degrees Fahrenheit average temperature for the day), based on the costs and benefits of meeting a higher or lower design day temperature. In the 2003 LCP, PSE changed the gas supply peak-day planning standard from 55 heating degree days (HDD), which is equivalent to 10 degrees Fahrenheit or a coldest day on record standard, to 51 HDD, which is equivalent to 14 degrees Fahrenheit or a coldest day in 20 years standard. The Washington Utilities and Transportation Commission (WUTC) responded to the 2003 plan with an acceptance letter directing PSE to "analyze" the benefits and costs of this change and to "defend" the new planning standard in the 2005 LCP.

As discussed in Appendix I of the 2005 LCP, PSE completed a detailed, stochastic cost-benefit analysis that considered both the value customers place on reliability of service and the incremental costs of the resources necessary to provide that reliability at various temperatures. This analysis determined that it would be appropriate to increase our planning standard from 51 HDD (14 degrees Fahrenheit) to 52 HDD (13 degrees Fahrenheit). PSE's gas planning standard relies on the value our natural gas customers attribute to reliability and covers 98 percent of historical peak events. As such, it is unique to our customer base, our service territory, and the chosen form of energy. Thus, we use projected delivered loads by class and this design temperature to estimate gas peak-day load.

## C. Hourly Electric Demand Profile

Because temporarily storing large amounts of electricity is costly, the minute-by-minute interaction between electricity production and consumption is very important. For this reason, and for purposes of analyzing the effectiveness of different electric generating resources, an hourly profile of PSE electric demand is required.

We use our hourly (8,760 hours) load profile of electric demand for the IRP, for our power cost calculation, and for other AURORA analyses. The estimated hourly distribution is built using statistical models relating actual observed temperatures, recent load data, and the latest customer counts.

### *Data*

PSE developed a representative distribution of hourly temperatures based on data from Jan. 1, 1950 to Dec. 31, 2009. Actual hourly delivered electric loads between Jan. 1, 1994 and Dec. 16, 2009 were used to develop the statistical relationship between temperatures and loads for estimating hourly electric demand based on a representative distribution of hourly temperatures.

### *Methodology for Distribution of Hourly Temperatures*

The above temperature data were sorted and ranked to provide two separate data sets:

- For each year, a ranking of hourly temperatures by month, coldest to warmest, over 60 years was used to calculate average monthly temperature.
- A ranking of the times when these temperatures occurred by month, coldest to warmest; these rankings were averaged to provide an expected time of occurrence.

Next PSE found the hours most likely to have the coldest temperatures (based on observed averages of coldest-to-warmest hour times) and matched them with average coldest-to-warmest temperatures by month. Sorting this information into a traditional time series then provides a representative hourly profile of temperature.

### *Methodology for Hourly Distribution of Load*

For the time period Jan. 1, 1994 to Dec. 31, 2009, PSE used the statistical hourly regression equation:

$$\hat{L}_h = \vec{\beta}_{1,d} \cdot DD_d + \alpha_1 L_{h-1} + \alpha_2 \left( \frac{L_{h-2} + L_{h-3} + L_{h-4}}{3} \right) + \left( \vec{\alpha}_{3,m} T_h + \vec{\alpha}_{4,m} T_h^2 \right) + \vec{\beta}_{2,d} Hol + \alpha_5 P^{(1)}(h)$$

for h from one to 24 to calculate load shape from the representative hourly temperature profile.  This means that a separate equation is estimated for each hour of the day.

$\hat{L}_h$ = Estimated hourly load at hour "h"
$L_h$ = Load at hour "h"
$L_{h-k}$ = Load "k" hours before hour "h"
$T_h$ = Temperature at time "h"
$T_h^2$ = Squared hourly temperature at time "h"
$P^{(1)}(h)$ = 1st degree polynomial
$Hol$ = NERC holiday dummy variables

All Greek letters again denote coefficient vectors.