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Chapter 8 Need for Power

8.0 Introduction

In 10 CFR 51.45(c), the NRC requires that the COLA environmental report include consideration of the benefits of the construction and operation of the proposed action. One of the primary benefits of a nuclear power plant is supplying electrical power. Therefore, this chapter addresses the need for the power that construction and operation of the proposed VCS Units 1 and 2 would satisfy.

The electric utility industry in Texas was deregulated in 2002. In Texas, Exelon is a merchant generator and does not have a specific service area. Therefore, Exelon has defined the relevant service area as the region served by the Electric Reliability Council of Texas (ERCOT). ERCOT is the independent system operator for most of Texas, including the area of the proposed VCS site. Subsequent discussions of reliability, supply, and demand will be specific to the ERCOT region unless otherwise noted.

As provided in NUREG-1555, the NRC will rely on a need-for-power evaluation prepared by a state or regional body if the evaluation is systematic, comprehensive, subject to confirmation, and responsive to forecasting uncertainty. ERCOT has prepared an evaluation of the need for power in the ERCOT region. In this chapter, Exelon summarizes the ERCOT process for evaluating the need for power, and Section 8.4.3 demonstrates that the ERCOT evaluation satisfies the criteria in NUREG-1555.

The following sections discuss regional need-for-power evaluations as follows:

- Description of Power System (Section 8.1)
- Power Demand (Section 8.2)
- Power Supply (Section 8.3)
- Assessment of Need for Power (Section 8.4)

The following ERCOT studies were used for this evaluation:

- The Report on Existing and Potential Electric System Constraints and Needs (ERCOT Dec 2007a) identifies and analyzes existing and potential constraints in the ERCOT transmission system that could either pose reliability concerns or increase costs to the electric power market and Texas consumers. This report is used in Section 8.1.
- The Long-Term Forecast Model is used in the Long-Term Hourly Peak Demand and Energy Forecast (ERCOT May 2007a) to predict the peak hourly power demand and energy consumption for each of the next 10 years. Some of the calculations are extrapolated to 2025. The forecast is based on the latest hourly peak demands for the region and adjusted for economic and weather variables. This report is described more completely in Section 8.2.
- The Report on the Capacity, Demand, and Reserves (ERCOT May 2007b) is developed from data provided by the market participants as part of the annual load data request, the generation asset registrations, and from data collected for the annual U.S. DOE Coordinated Bulk Power

Supply Program Report. The working paper is a series of spreadsheets that compares demand load forecasts from other ERCOT analyses with the generation resources reported to be available by market participants, and calculates reserve margins. This report and its Summer Assessment Update (ERCOT Dec 2007b) are the bases for Sections 8.3 and 8.4.

- The last report is the ERCOT Long Term System Assessment (ERCOT Dec 2006), which uses available data to predict the type and general location of new generation that the market may find economic to construct. ERCOT recognizes in the report that it cannot control these decisions, but the ERCOT estimation of market behavior provides a reasonable basis on which to assess longer-term transmission needs under a range of scenarios.

8.0.1 References

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8.1 Description of Power System

8.1.1 Project Description and Owner

Exelon would own and operate VCS Units 1 and 2. Exelon is one of the largest electric wholesale and retail power generation companies in the United States. It operates 17 nuclear generating units that produced 131.4 million net MWh of electricity in 2006, and its fleet had an average capacity factor of 93.9%. In addition, Exelon has 113 fossil and hydroelectric units with a combined capacity of approximately 8000 MWe. Exelon's wholesale market is focused in Texas, the Mid-Atlantic, the Midwest, the Northeast, and the Southwest; its retail electric and gas market is focused in the Midwest through ComEd and the Northeast through PECO. (Exelon 2007)

Exelon is proposing the construction and operation of two ESBWR units: VCS Unit 1 would begin commercial operation in December 2015 and VCS Unit 2 would begin commercial operation in June 2017. Each unit would generate 1535 MWe net for a combined total of 3070 MWe net. The VCS units would serve as merchant generation plants in the Electric Reliability Council of Texas' (ERCOT) deregulated market. Accordingly, Exelon would sell the electricity generated at VCS to the wholesale market in bilateral transactions with wholesale purchasers of electric power and on the wholesale spot market. As discussed in Subsection 2.2.2, new transmission lines would be constructed from the VCS switchyard to termination points at Hillje, Cholla, Coleto Creek, Blessing, White Point and the South Texas Project in order to connect VCS to the ERCOT grid.

8.1.2 Relevant Service Area

The region of interest (ROI) is the region that VCS would supply. Because the two proposed VCS units will be merchant plants operating in a deregulated market, the ROI includes the entire ERCOT region. As shown in Figure 8.1-1, the ERCOT region lies entirely within Texas' state boundary and includes 75% of Texas' land area (200,000 square miles), but excludes most of the Panhandle, the extreme west, and parts of the east. Each of these excluded areas falls under the jurisdiction of other reliability councils.

ERCOT manages the flow of electric power to approximately 20 million customers, representing 85% of Texas' electric load (ERCOT Jun 2007). According to the Energy Information Administration, 2006 retail electric power sales in the ERCOT region were: residential sales 116.8 terawatt-hours[1] (TWh); commercial sales 92.2 TWh; industrial sales 81.7 TWh; and transportation sales 1.6 TWh (EIA Feb 2007). The average hourly peak demand for 2006 was 62,339 MWe and, based on a 2.31% growth rate, the hourly peak demand in ERCOT for 2017 would be 78,694 MWe and the hourly peak demand in 2022 would be 87,335 MWe (ERCOT May 2007a; ERCOT May 2007b).

ERCOT estimates that the region had a 2007 population of 21 million people and predicts that population in the region could increase to 24.3 million in 2015 (ERCOT May 2007a). A longer-term forecast by the Texas State Data Center indicates that the total population for the counties comprising

1. A terawatt-hour (TWh) is equal to one million MWh.

the ERCOT region could further expand to 25 million people in 2020 (TSDC Oct 2006). As shown in Figure 8.1-2, major population centers in the ERCOT region are located in the Dallas-Ft. Worth, Houston, and San Antonio metropolitan areas.

8.1.3 Public Utility Commission and Electric Reliability Council of Texas

In 1975, Texas became the last state in the country to provide for statewide comprehensive regulation of electric utilities by creating the Public Utility Commission of Texas (PUCT). For approximately the first 20 years of the PUCT's existence, its primary role was traditional regulation of electric and telecommunications utilities. Significant legislation enacted by the Texas legislature in 1995 dramatically changed this role by creating a competitive electric wholesale market. In 1999, the Legislature provided for restructuring of the electric utility industry, further changing the PUCT mission and focus (PUCT Jul 2006).

Although the PUCT's traditional regulatory functions have decreased since 1999, many of those functions have been replaced by other, more challenging responsibilities. The PUCT's responsibilities under the Public Utilities Regulatory Act include the following (PUCT Jul 2006):

- Issuing certificates of convenience and necessity for proposed transmission lines.
- Licensing REPs.
- Registering power generation companies and aggregators.
- Overseeing competitive wholesale and retail markets.
- Resolving customer complaints, using informal processes whenever possible.
- Implementing a customer education program for retail electric choice.
- Regulating vertically-integrated, investor-owned utilities outside ERCOT.
- Providing jurisdiction over ratemaking, quality of transmission service, and distribution utilities within ERCOT.
- Establishing wholesale transmission rates for investor-owned utilities, cooperatives, and municipally owned utilities within ERCOT.

ERCOT is a membership-based, nonprofit corporation governed by a board of directors and subject to oversight by the PUCT and the Texas legislature. ERCOT members include retail consumers, investor- and municipally owned utilities, rural electric cooperatives, river authorities, independent generators, power marketers, and retail electric providers. (ERCOT Jun 2007)

The ERCOT board of directors is made up of independent members, consumers, and representatives from each of ERCOT's electric market segments. The board of directors appoints officers to direct and manage day-to-day operations, accompanied by a team of executives and managers responsible for critical components of ERCOT operations areas. (ERCOT Undated a).

As the independent system operator for the region, ERCOT schedules power on an electric grid that connects 38,000 miles of high-voltage transmission lines with more than 500 generating units. ERCOT

also manages financial settlements for the competitive wholesale bulk power market and administers customer switching for 5.9 million Texans in competitive choice areas (ERCOT Jun 2007). Figure 8.1-1 shows the major load centers in the ERCOT region and Figure 8.1-3 depicts the ERCOT electric grid.

ERCOT performs three main roles in managing the electric power grid and marketplace (ERCOT 2005):

- Monitors schedules submitted by wholesale buyers and sellers for the next day's electricity supply. ERCOT ensures the system can accommodate those schedules and, if necessary, creates a new market to fill the gap.
- Ensures electricity transmission reliability by managing the incoming and outgoing supply of electricity over the grid. ERCOT monitors the flow of power and issues instructions to generation and transmission companies to maintain balance.
- Serves as the central hub for retail transactions. When a consumer chooses a retail electric provider, ERCOT ensures the information related to that transaction is conveyed to the appropriate companies in a timely manner.

The ERCOT region is almost entirely isolated from other areas. At the beginning of World War II, several electric utilities in Texas banded together as the Texas Interconnected System to support the war effort. They sent their excess power generation to industrial manufacturing companies on the Gulf Coast to provide reliable supplies of electricity for energy-intensive aluminum smelting. Recognizing the reliability advantages of remaining interconnected, the Texas Interconnected System members continued to use and develop the interconnected grid. Texas Interconnected System members adopted official operating guides for their interconnected power system and established two monitoring centers within the control centers of two utilities, one in North Texas and one in South Texas. Texas Interconnected System formed ERCOT in 1970 to comply with North American Electric Reliability Corporation (NERC) requirements (ERCOT Undated b). The goal of Texas Interconnected System, and later ERCOT, was not to create ties with the rest of the country, but to ensure that the Texas grid was reliable through interconnection.

Even today, there are only five asynchronous ties that go outside of the ERCOT region with a total capacity of approximately 1100 MW. The locations of these ties are shown in Figure 8.1-3. There are also approximately 2880 MW of "switchable" generation resources that can be connected to either the ERCOT transmission grid or a grid outside the ERCOT region (ERCOT Dec 2007b). While this means that ERCOT can only export a very small amount of power, it also means that ERCOT cannot import significant amounts of power. This becomes an important fact when considering the need for power in the ERCOT region. Essentially, all power required to supply the ERCOT region loads must be generated within the ERCOT region.

On December 29, 2006, Entergy Gulf States Inc. filed a transition plan with the PUCT to join ERCOT. If the plan is approved, Entergy Gulf States Inc. would construct synchronous ties with ERCOT and disconnect its synchronous ties with the Eastern Interconnection. In order to serve existing load obligations, they would also construct three asynchronous ties with a total capacity of 1050 MW

between ERCOT and the Eastern Interconnection (EGSI Dec 2006). While these new ties would effectively double the amount of power that could be imported from other regions, the total ERCOT import capacity would remain insignificant.

Representatives of all segments of ERCOT's market participants collaboratively created the ERCOT Protocols, which is the governing document adopted by ERCOT that contains the scheduling, operating, planning, reliability, and settlement policies, rules, guidelines, procedures, standards, and criteria of ERCOT. These Protocols were approved by the PUCT and amendments are subject to PUCT review and modification. The Protocols are intended to implement ERCOT's functions as the Independent Organization for the ERCOT Region as certified by the PUCT. The ERCOT Board, Technical Advisory Committee, and other ERCOT subcommittees authorized by the Board or the Committee, may develop procedures, forms, and applications for the implementation of and operation under the Protocols. ERCOT and its market participants must abide by the Protocols (ERCOT Jan 2008).

Since deregulation of the electric supply market in the ERCOT region, utilities no longer perform the comprehensive analysis and planning functions they once did. The central planning organization under the new Texas market is ERCOT, the independent system operator. State law assigns these obligations to ERCOT under the oversight of the PUCT. The analyses, reports, system planning processes, and criteria development from ERCOT are the key measures for determining resource needs in the state [e.g., Tex. Util. Code Ann. §§ 39.155(b) and 39.904(k)].

8.1.4 Deregulation of the Texas Electric Utility Industry

The traditional discussion of the need for power, including a description of the power system, service areas, regional relationships, power pool agreements, electrical transfer capabilities, diversity interchange agreements, wheeling contracts, types of customers, and major electrical load centers, generally does not apply in the case of the proposed VCS because the electrical utility industry in Texas has been deregulated. In 1995, the Texas legislature passed Senate Bill 373 introducing wholesale competition into Texas' intrastate markets. Under what is now Chapter 35 of the Public Utilities Regulatory Act, prior bilateral transactions addressing use of the interconnected transmission systems of vertically-integrated utilities in ERCOT were replaced by PUCT-regulated open access requirements and a methodology for placement of new merchant generation. Senate Bill 373 directed the PUCT to adopt rules requiring all transmission system owners to make their transmission systems available for use by others at prices and on terms comparable to each respective owner's use of its system for its own wholesale transactions. The PUCT implemented its initial transmission open access rules in January 1997.

During the 1999 legislative session, the Texas legislature enacted Senate Bill 7 (SB 7), providing for retail electric open competition that began in 2002. SB 7 continued electric transmission wholesale open access and fundamentally redefined and restructured the Texas electric industry. SB 7 allowed

retail customers of investor-owned utilities (IOUs) to choose their electric energy supplier (San Antonio Jan 2007).

SB 7 allowed municipally-owned utilities and electric cooperatives to remain non-opt-in entities (NOIEs) until they choose to enter competition. Most have elected to remain NOIEs. Therefore, the customers within the service areas of most electric cooperatives and municipally owned utilities are not able to choose their electric energy supplier. Under the terms of SB 7, NOIEs may remain vertically integrated electric utilities offering generation, transmission, and distribution services. However, SB 7 required IOUs to separate their retail energy service activities from regulated utility activities and to unbundle their generation, transmission/distribution, and retail electric sales functions into separate units. An IOU could choose to sell one or more of its lines of business to independent entities, or it could create separate but affiliated companies, and possibly operating divisions. These separate companies or operating divisions could be owned by a common holding company, but must operate independently of each other subject to code of conduct restrictions under PUCT rules. The services offered by transmission entities had to be available to other parties on a nondiscriminatory basis (San Antonio Jan 2007).

IOUs and independent power producers owning generation assets must be registered as power generation companies with the PUCT and must comply with certain rules that are intended to protect consumers, but they are otherwise unregulated and may sell electricity in private bilateral transactions and at market prices (San Antonio Jan 2007).

IOU owners of transmission and/or distribution facilities, or transmission service providers, are fully regulated by the PUCT. IOU service providers, municipal utilities, electric co-ops, and other entities providing transmission and distribution service are obligated to deliver the electricity to retail customers. These utilities are also required to transport power to wholesale buyers. Transmission service providers are required to provide access to both their transmission and distribution systems on a nondiscriminatory basis to all eligible customers (San Antonio Jan 2007).

Retail sales activities in the IOU service areas are performed by retail electric providers (REPs) on a “customer choice” basis. These are the only entities authorized to sell electricity to retail customers. REPs must register with the PUCT, demonstrate financial capabilities, and comply with certain customer protection requirements. REPs buy electricity from power generation companies, power marketers, or other parties and may resell that electricity to retail customers at any location in Texas other than within the service areas of municipal utilities and electric co-ops (San Antonio Jan 2007).

8.1.5 Market Economic Forces

Beyond compliance with operational procedures, ERCOT does not have authority over the business activities of its market participants. The economic forces of the market and signed agreements by the market participants provide the cooperative atmosphere in which the ERCOT system functions. Figures 8.1-4 and 8.1-5 demonstrate the market economic forces at work (ERCOT Dec 2007a). Since 1999, ERCOT market participants have made the economic decision to decommission 107 units with a

total generation capacity of 5099 MW (Figure 8.1-4). These decisions were based on economic parameters such as unit efficiency, age, capacity, cost of operation, outage frequency, outage duration, and fuel cost. Similarly, since 1999, the ERCOT market participants have made the economic decision to add 239 new units and to upgrade two units for a total generation capacity of 29,531 MW (Figure 8.1-5). These decisions were based on the same economic parameters that led to decommissioning the older units. Figures 8.1-4 and 8.1-5 show that on a county-by-county basis, in accordance with the market economic forces, the decommissioned units were sometimes replaced by new units and sometimes not replaced.

By law, ERCOT must perform extensive annual and semiannual studies, issue reports, make recommendations for transmission system needs and resource adequacy, and make legislative recommendations to further those objectives [e.g., Tex. Util. Code Ann. §§ 39.155(b) and 39.904(k)]. ERCOT analyzes the region in the context of the competitive ERCOT market using load growth scenarios, industrial growth projections, regional transmission topology, subregional modeling, and new generation characteristics. The development of these reports is subject to vigorous market participant stakeholder input and review. ERCOT only forecasts the generation and transmission capacity that may be necessary to meet the forecast load. The market economic forces drive the market participants' decisions to increase or decrease their generation and transmission capacity.

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TSDC Oct 2006. Texas State Data Center, *Projections of the Population of Texas and Counties in Texas by Age, Sex and Race/Ethnicity for 2000-2040,* October 2006, Table 12, “Total Population and Population by Race/Ethnicity in 2000 and Projected Population and Percent Population Change 2000-2040 Under Alternative Assumptions of Age, Sex and Race/Ethnicity-Specific Net Migration for Counties in Texas - Ranked by Total Population Size in 2000,” available at http://txsdc.utsa.edu/tpepp/2006projections/summary/desctab.php, accessed March 25, 2008.

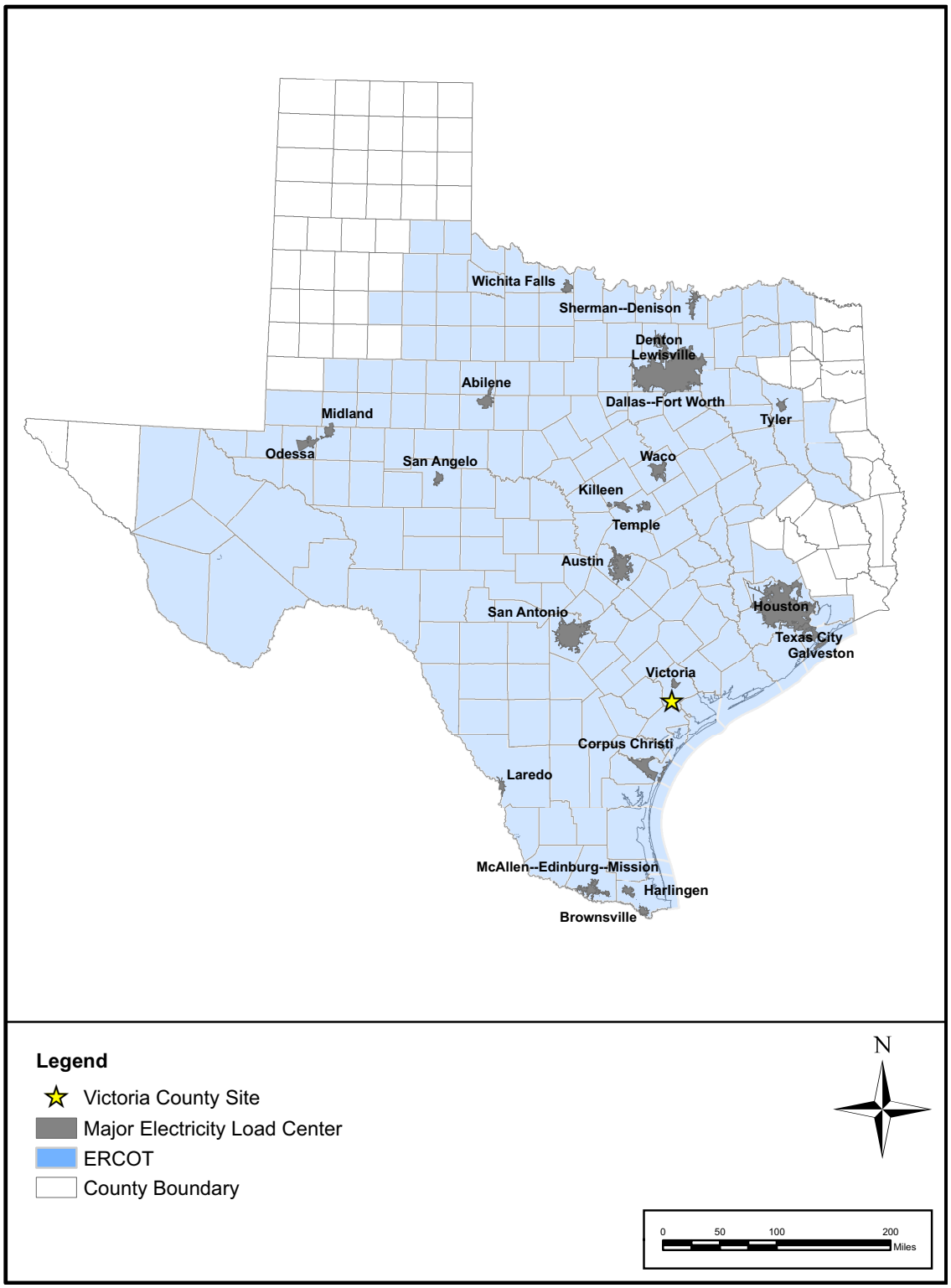


Figure 8.1-1 ERCOT Boundary with Major Load Centers, 2007

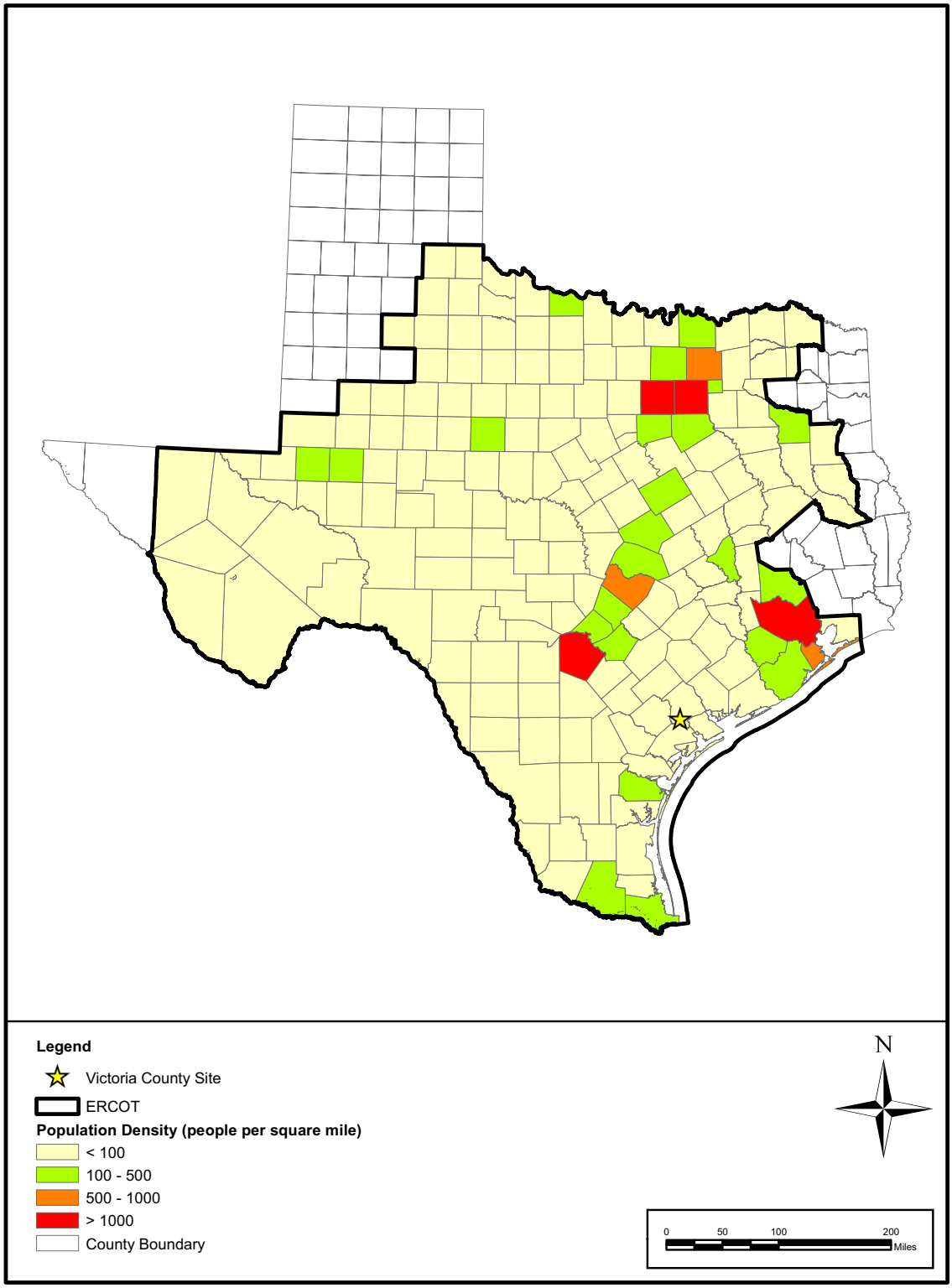


Figure 8.1-2 Year 2000 Population Density for Counties within the ERCOT Region

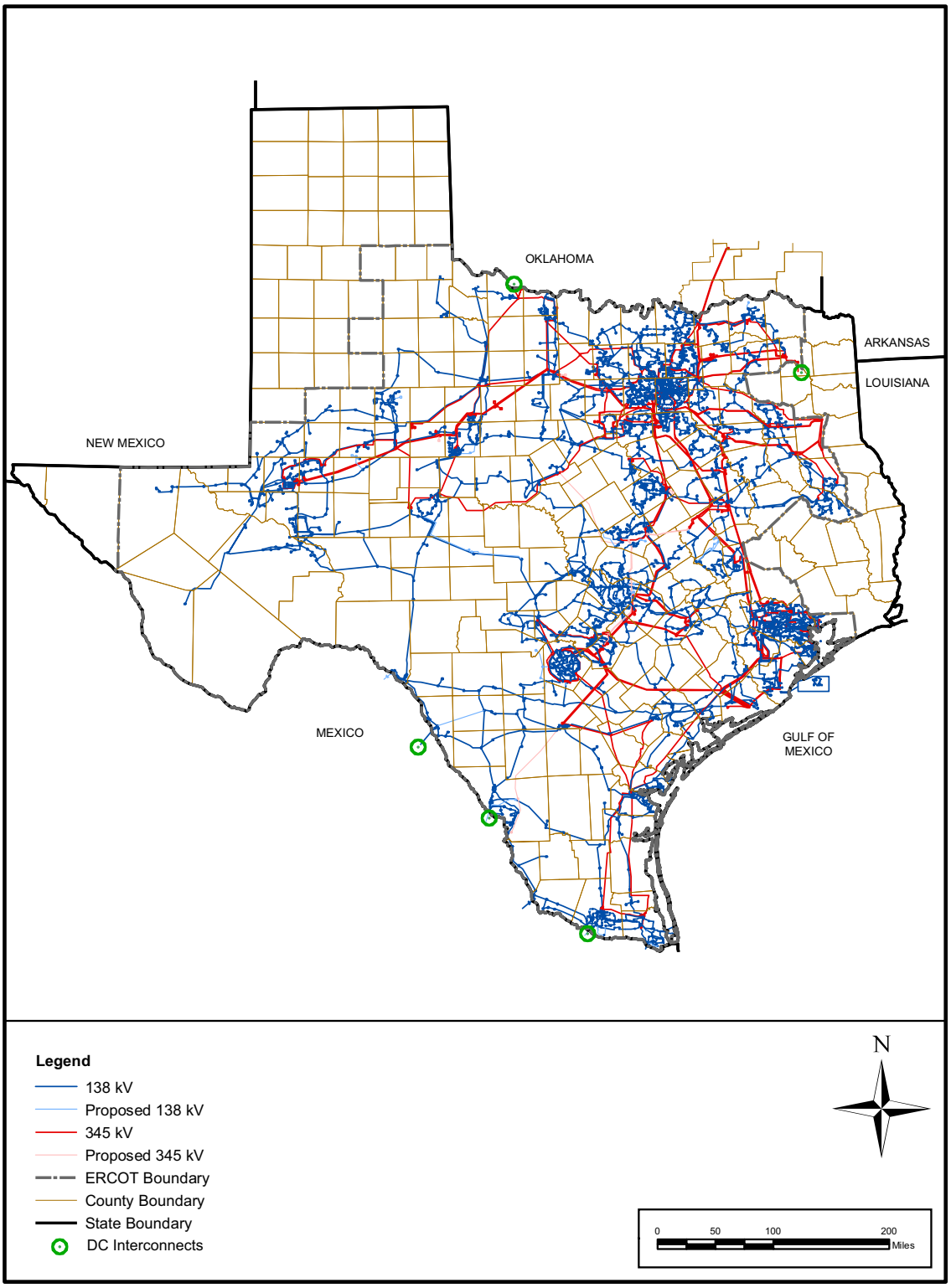
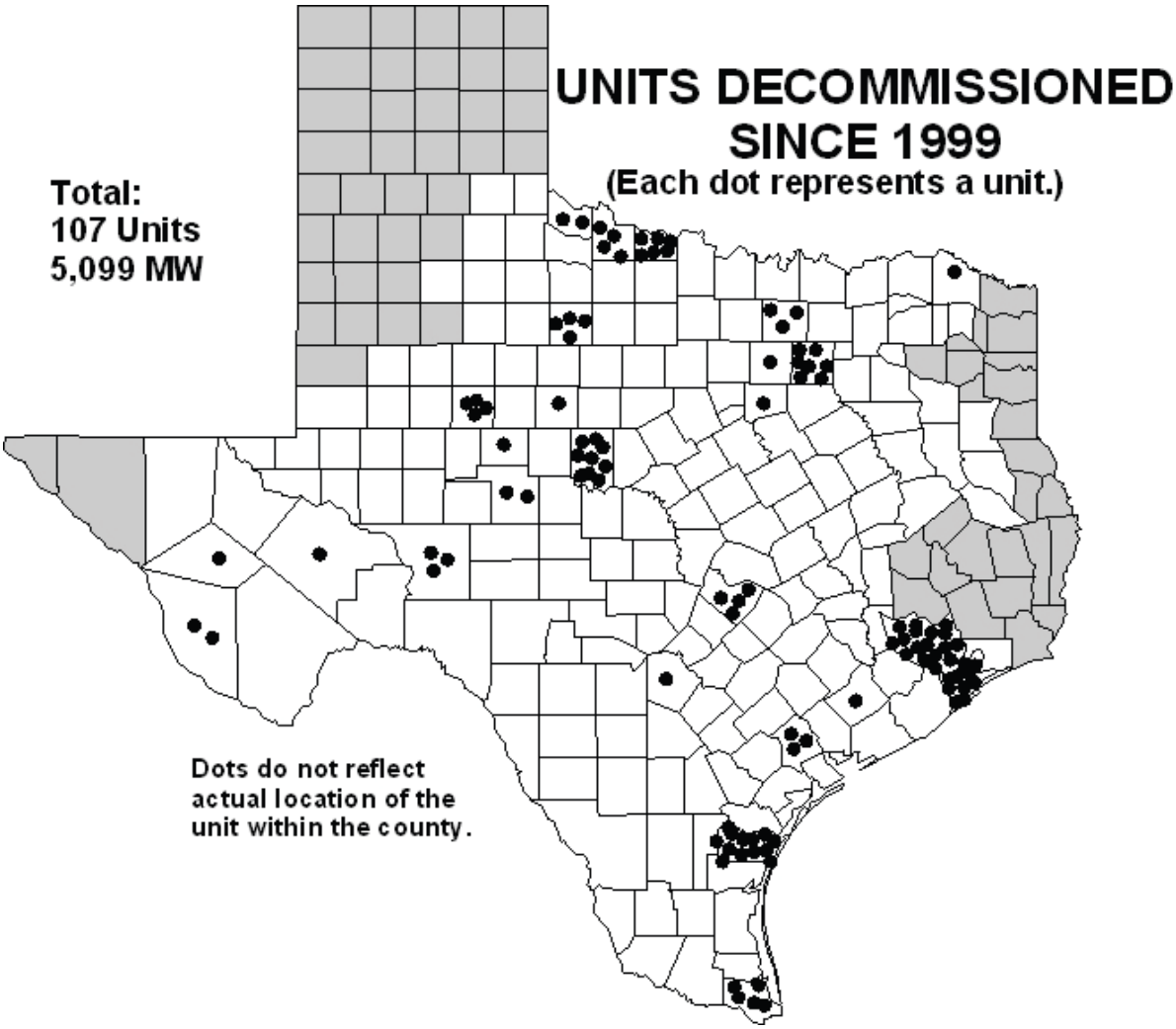
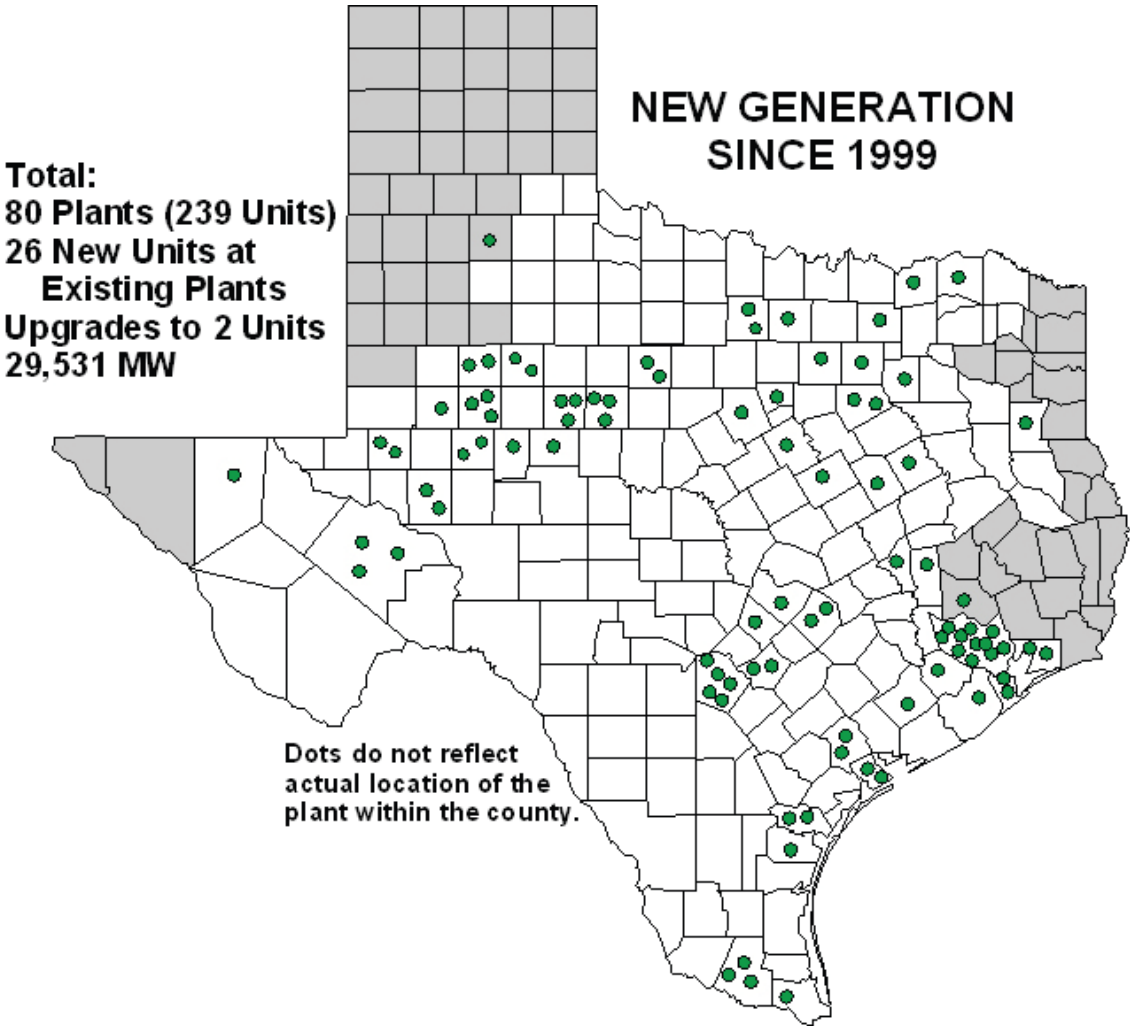


Figure 8.1-3 ERCOT Transmission Lines and System



Note: Counties which are part of the ERCOT service region are shown in white.
Source: ERCOT Dec 2007b

Figure 8.1-4 Units Decommissioned Since 1999



Note: Counties which are part of the ERCOT service region are shown in white.

Source: ERCOT Dec 2007b

Figure 8.1-5 New ERCOT Generation Since 1999

8.2 Power Demand

This section describes and analyzes peak load and electrical energy demand forecasts, methodologies and underlying assumptions, as well as the soundness of the forecasts. A historical perspective of the load growth in the Electric Reliability Council of Texas (ERCOT) region is provided, and growth factors including weather, economic, and demographic data are analyzed. In short, it addresses the demand side of the demand/supply equation.

8.2.1 ERCOT Historical Trends

Figure 8.2-1 provides the average hourly load and the annual system peak hour load from 1997 to 2006. The average hourly load growth is almost constant. The historical annual peak demand for 1997–2006 is included in Figure 8.2-2 and the historical energy consumption for the same period is included in Figure 8.2-3. Table 8.2-1 provides the historical annual growth percentage of the average hourly load, peak demand, and energy consumption for the period of 1998–2006. Figure 8.2-4 provides the three annual growth percentages graphically.

8.2.2 ERCOT Forecast of Long-Term Demand and Energy

This subsection provides a high-level overview of the 2007 ERCOT Long-Term Demand and Energy Forecast (ERCOT May 2007). All of the tables, figures, and data in this subsection are taken from the forecast.

The long-term load forecast covers a period from 1 to 15 years using a process and tools developed internally by ERCOT. The forecast is used for:

- Annual budget development (energy)
- System planning studies
- Resource adequacy assessments
- Annual capacity, demand, and reserves report
- Seasonal and long-term assessments
- Weekly forecast for outage coordination
- Statement of opportunities report
- PUCT/NERC/DOE/FERC reporting methodology (ERCOT Jan 2007)

The econometric forecasting process centers on a regression analysis, i.e., the development of an equation or set of equations that describes the historical load as a function of independent variables. The regression analysis is used to calculate the appropriate coefficients for each variable and to choose the best equations for describing historical patterns (ERCOT Jan 2007). The forecasting process is shown in Figure 8.2-5. Refer to Appendix 3 of the 2007 ERCOT Long-Term Demand and Energy Forecast (ERCOT May 2007) for a detailed description of the model and methodology.

The long-term forecast was produced with a set of econometric models that use weather, economic, and demographic data to capture and project the long-term trends from the past 5 years of historical data. Each of these factors is discussed below.

Weather Data

Weather drives most of the variation in electric demand in the short term. Because weather also affects the variation in the electric demand in the long run, long-term forecasting uses historical average weather profiles to indicate the future variation in weather. There are eight defined weather zones in ERCOT. The largest metropolitan statistical areas are located in the North Central, South Central, and Coastal zones:

- North Central (Dallas-Ft. Worth)
- South Central (Austin-San Antonio)
- Coastal (Houston)

Twelve years of weather data was available from WeatherBank for 20 ERCOT weather stations. These weather stations were used to develop weighted hourly weather profiles for each of the eight weather zones. These profiles were used in the load shape models. Monthly cooling degree days and heating degree days were used in the monthly energy models.

A representative hourly load shape by weather zone was forecasted using an average weather profile of temperatures, cooling degree hours, and heating degree hours obtained from historical data. Seasonal daily, weekly, monthly, and yearly load variations and holiday events were considered, in addition to various interactions such as weather, weekends, and weekdays. This hourly load shape only describes the hourly load fluctuations within the year and in itself does not reflect the long-term trend.

The long-term trend was provided by the energy consumption forecast. The monthly energy consumption forecast models by weather zones used cooling degree days and heating degree days to project the monthly energy for the next 19 years (2007–2025).

One measure of the uncertainty associated with extreme weather impacts on the peak demand can be obtained by using a more extreme weather profile to obtain the forecasts. ERCOT developed weather profiles that rank at the 90th percentiles of all the temperatures in its hourly temperature database and did the same to develop profiles with the 10th percentile of all temperatures. These are not confidence bands in the statistical sense, but this term has commonly been used to refer to the results. More appropriate terms would be “scenarios associated with the 90th percentile temperature distribution” or “90th percentile scenario forecasts.” ERCOT has also run Monte Carlo simulations to assess the impact of extreme temperatures on the peak demands. Subsection 8.2.3 provides the results of the analysis for both normal and extreme weather patterns.

Economic and Demographic Data

Economic and demographic changes can affect the characteristics of electrical demand in the medium to long run. Economic and demographic data at the county level were obtained on a monthly basis from Moody's Economy.com. The data were used as input to the monthly energy consumption models.

The regional economic outlook for Texas is projected to outperform the United States as a whole. Three of its major metropolitan areas—Houston, Dallas, and Austin—which are among the top 50 metropolitan areas in the United States, are leading the south. Employment growth in Texas shows a stronger performance for the Dallas-Forth Worth area and the Austin-San Antonio area, relative to the Houston area. The Houston area is expanding, but is expected to lose some momentum due to a slowdown in the energy industry.

Some of the indicators that were used in the forecast are economic and demographic drivers such as real per capita personal income, population, employment in the financial services, nonfarm employment, and total employed. These are presented in Figures 8.2-6 through 8.2-10.

As discussed in Subsection 8.4.2, actions to reduce the demand for power (i.e., demand-side management or conservation) are taken into account in determining the reserve margin.

8.2.3 Results of ERCOT Long-Term Demand and Energy Forecast

The forecast energy consumption for 2007–2017 using the normal weather scenario is included in Figure 8.2-3. Figure 8.2-11 provides the forecast average hourly load for 2007–2017 using the normal weather scenario. Figure 8.2-12 shows the historic (2002–2006) and forecast (2007–2012) hourly load shapes.

Figure 8.2-13 shows the forecast peak demand scenarios for 2007–2017 using the extreme weather profiles described above. The red dashed line on the top is a plot of the system peak demand forecast using temperatures above 90% of the historical temperatures (90th percentile) experienced during the last 12 years. This extreme forecast is referred to in Figure 8.2-13 as the High Hourly Forecast 90-10. The middle line is the normal weather scenario (Base 50-50).

The Low Hourly Forecast 10-90 refers to the forecast obtained by using temperatures above 10% of all temperatures during the last 12 years.

The historical peak demand for 2002–2006 and the forecast peak demand for 2007–2015 for the eight weather zones are shown in Table 8.2-2. The forecasts for the three major zones (North Central, South Central, and Coastal) show stable, strong growth. The forecasts for the smaller zones show an average or below-average trend in growth.

A summary of the long-term forecast model results for 2007–2025 peak demand and energy consumption is provided in Table 8.2-3. Table 8.2-4 provides the forecast growth percentages for average hourly load, peak demand, and energy consumption. Figure 8.2-4 provides the three annual growth percentages graphically.

Difference between the 2006 and 2007 Forecasts

In the long-term, the 2007 forecast is very similar to the 2006 forecast for the same forecasted period. The energy forecast from 2007 to 2015 is 0.06% higher than the 2006 forecast. A one-time adjustment due to economic revisions and other factors, such as Hurricane Katrina, contributed to the growth from the actual energy consumption in 2006 to the forecast for 2007. One of the key factors driving the long-term higher energy consumption is an improvement in the outlook of the overall health of the economy. This is captured by economic indicators such as the real per capita personal income, population, and various employment measures including non-farm employment and total employment. If income is growing at a faster rate than population, the average person expects to enjoy an overall higher standard of living. A higher standard of living generally translates into improvements in comfort, which in many cases directly translates into increases in electricity consumption.

The energy consumption forecast scenarios show a slight degree of variability between the 90-10 high weather forecasts and the median (50-50) base case. The same holds true for the 10-90 low weather forecast scenario. Figure 8.2-14 shows the difference between the two forecasts of peak demand for the period of 2007–2015.

Accuracy of the Long-Term Forecast

Comparisons of the historical and forecasted peak demand (Figure 8.2-15) and of the historical and forecasted energy consumption (Figure 8.2-16) show that ERCOT long-term forecasts have been within ±5% of the actual demand and consumption since 1999. Since 2003, the accuracy of the energy consumption forecast has been very close to ±1% (ERCOT Jan 2007).

8.2.4 References

ERCOT Jan 2007. Electric Reliability Council of Texas, *Long Term Demand and Energy Forecasting – Planning,* January 24, 2007.

ERCOT May 2007. Electric Reliability Council of Texas, 2007 *ERCOT Planning Long-Term Hourly Peak Demand and Energy Forecast*, May 8, 2007.

Table 8.2-1
ERCOT Historical Annual Growth of Average Hourly Load, Peak Demand, and Energy Consumption, 1998–2006

Year	Average Load (MW)	Load Growth (MW)	Load Growth (%)	Peak Demand (MW)	Peak Growth (MW)	Peak Growth (%)	Energy Consumption (TWh)	Energy Growth (TWh)	Energy Growth (%)
1998	30,475	1986	6.97%	53,691	3326	6.60%	270	16	6.30%
1999	30,336	–139	–0.46%	54,980	1289	2.40%	269	–1	–0.37%
2000	32,488	2152	7.09%	57,981	3001	5.46%	289	20	7.43%
2001	31,623	–865	–2.66%	55,214	–2767	–4.77%	278	–11	–3.81%
2002	32,052	429	1.36%	56,086	872	1.58%	281	3	1.08%
2003	32,533	481	1.50%	60,037	3951	7.04%	285	4	1.42%
2004	32,917	384	1.18%	58,506	–1531	–2.55%	289	4	1.40%
2005	34,161	1244	3.78%	60,214	1708	2.92%	299	10	3.46%
2006	34,899	738	2.16%	62,339	2125	3.53%	306	7	2.34%

Source: ERCOT May 2007

Table 8.2-2
Yearly Coincident Peak Demands by Weather Zone (MW)

Year	North	North Central	East	Far West	West	South Central	Coast	South	System Load
Historical									
2002	1904	20,527	2175	1830	1595	9492	14,578	3985	56,086
2003	2070	22,303	2319	1805	1675	10,016	15,823	4025	60,037
2004	2047	20,749	2265	1658	1562	9619	16,611	3996	58,506
2005	2080	21,975	2351	1661	1542	10,162	16,282	4159	60,214
2006	2361	22,687	2432	1598	1612	10,718	16,739	4191	62,339
Forecast									
2007	2086	23,782	2251	1412	1638	11,329	17,174	4123	63,794
2008	2117	24,059	2363	1415	1683	11,708	17,631	4158	65,135
2009	2145	24,472	2323	1429	1725	12,075	18,112	4227	66,508
2010	2183	24,914	2353	1435	1770	12,475	18,554	4271	67,955
2011	2229	25,365	2382	1441	1820	12,901	19,002	4317	69,456
2012	2263	25,743	2402	1442	1863	13,292	19,377	4351	70,733
2013	2325	26,267	2517	1448	1914	13,725	19,794	4405	72,394
2014	2377	26,788	2462	1509	1964	14,111	20,312	4474	73,998
2015	2447	27,360	2484	1461	2022	14,570	20,727	4525	75,596

Source: ERCOT May 2007

Table 8.2-3
2007 ERCOT Long-Term Forecast Model Results

Year	Forecast Energy Consumption (MWh)	Historical Energy Consumption (MWh)	Peak (MW)
Historical			
2002	281,930,582	280,772,959	56,086
2003	284,207,211	284,983,916	60,037
2004	287,569,872	289,140,984	58,506
2005	300,553,020	299,253,971	60,214
2006	305,552,884	305,687,145	62,339
Forecast			
2007	313,027,658		63,794
2008	319,688,988		65,135
2009	325,408,664		66,508
2010	332,578,515		67,955
2011	340,089,254		69,456
2012	347,087,436		70,733
2013	354,122,426		72,394
2014	361,232,831		73,998
2015	369,322,241		75,596
2016	377,330,064		77,024
2017	384,606,172		78,694
2018	391,597,067		80,161
2019	398,301,224		81,622
2020	404,587,586		82,871
2021	411,162,342		84,363
2022	417,594,564		85,681
2023	423,892,847		87,015
2024	430,373.659		88,180
2025	436,287,512		89,883

Source: ERCOT May 2007

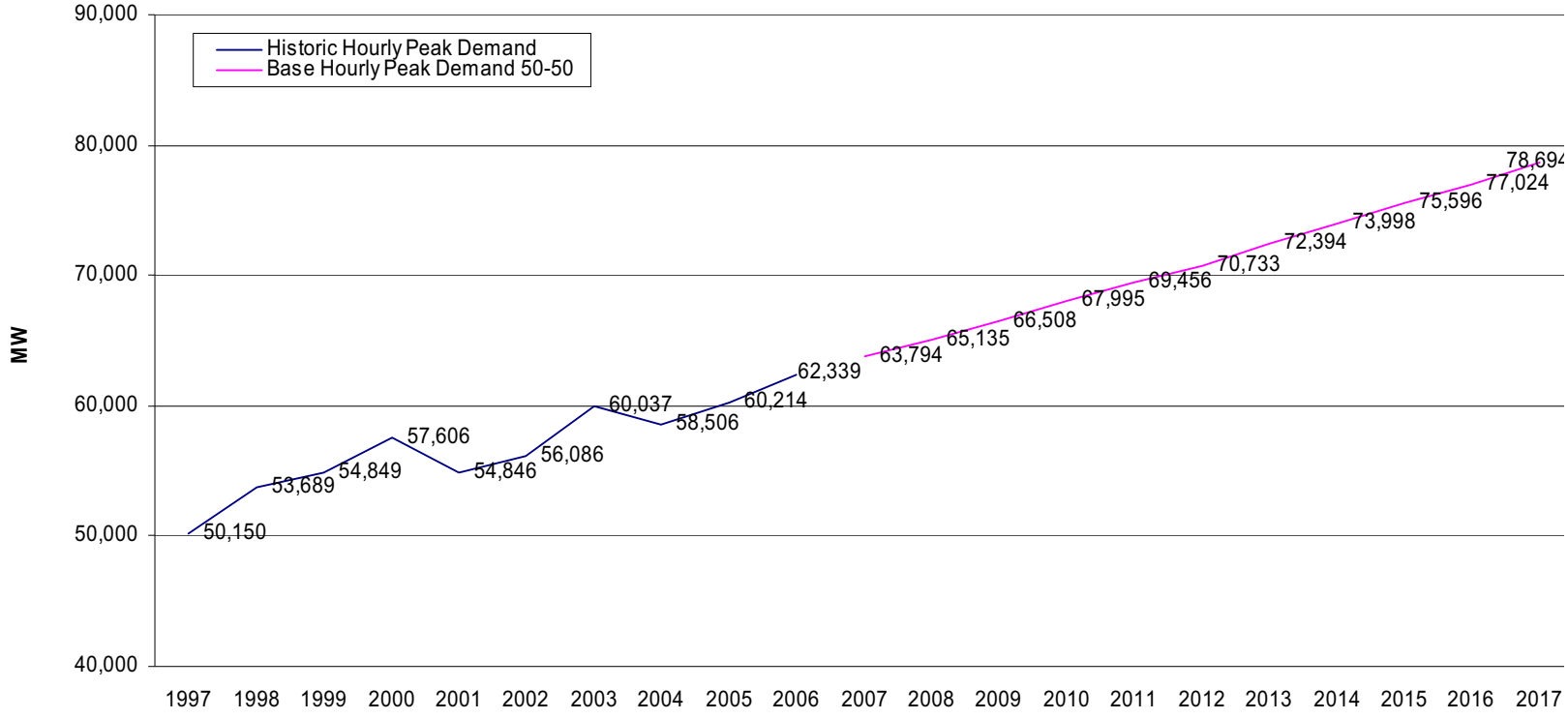
Table 8.2-4
ERCOT Forecast Annual Growth of Average Hourly Load, Peak Demand, and Energy Consumption, 2007–2017

Year	Average Load (MW)	Load Growth (MW)	Load Growth (%)	Peak Demand (MW)	Peak Growth (MW)	Peak Growth (%)	Energy Consumption (TWh)	Energy Growth (TWh)	Energy Growth (%)
2007	35,734	835	2.39%	63,794	1455	2.33%	313	7	2.29%
2008	36,395	661	1.85%	65,135	1341	2.10%	320	7	2.24%
2009	37,147	752	2.07%	66,508	1373	2.11%	325	5	1.56%
2010	37,966	819	2.20%	67,955	1447	2.18%	333	8	2.46%
2011	38,823	857	2.26%	69,456	1501	2.21%	340	7	2.10%
2012	39,513	690	1.78%	70,733	1277	1.84%	347	7	2.06%
2013	40,425	912	2.31%	72,394	1661	2.35%	354	7	2.02%
2014	41,237	812	2.01%	73,998	1604	2.22%	361	7	1.98%
2015	42,159	922	2.24%	75,596	1598	2.16%	369	8	2.22%
2016	42,957	798	1.89%	77,024	1428	1.89%	377	8	2.17%
2017	43,905	948	2.21%	78,694	1670	2.17%	385	8	2.12%

Source: ERCOT May 2007

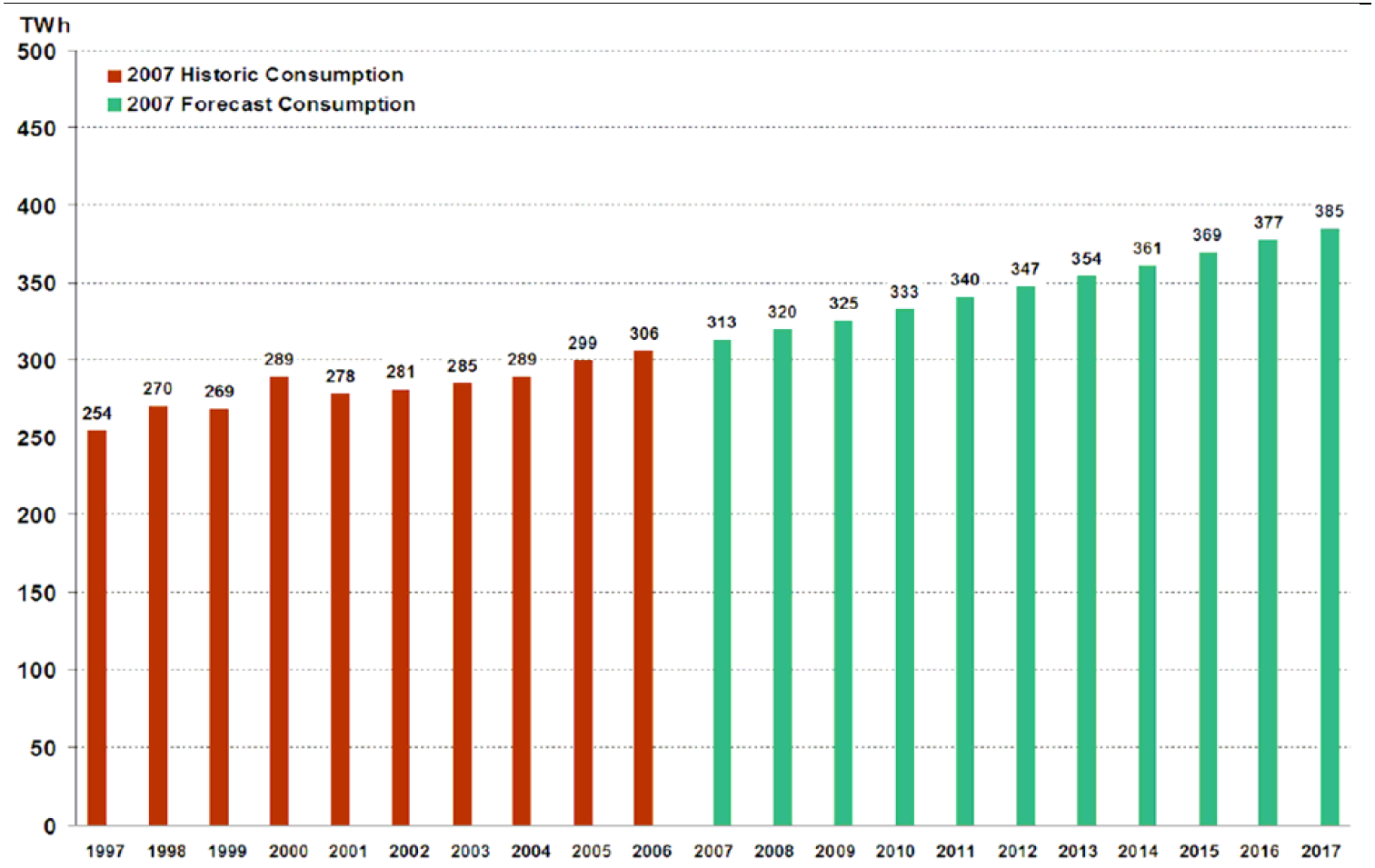
Source: ERCOT May 2007

Figure 8.2-1 ERCOT Historical Average Load and System Peak Load



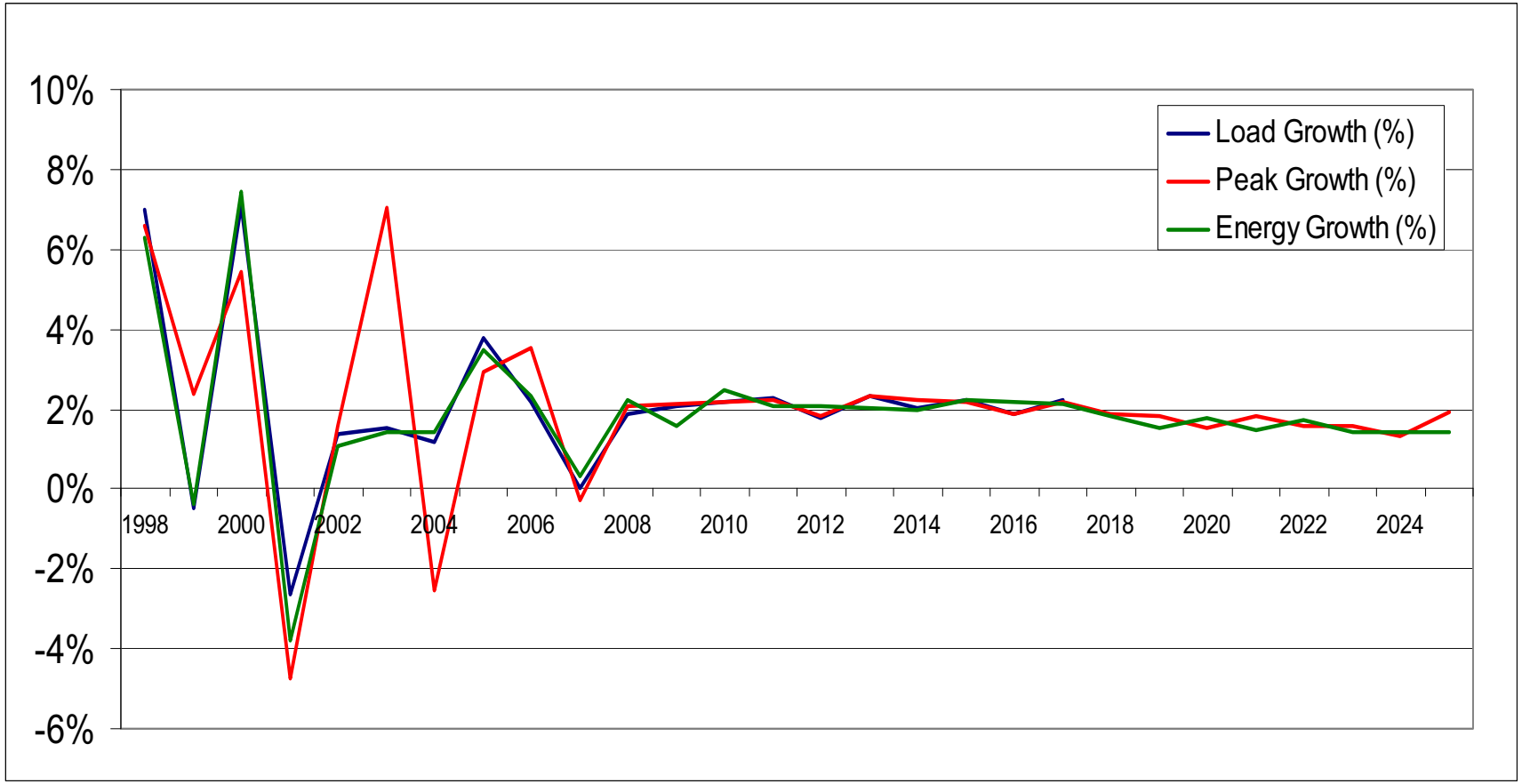
Source: ERCOT May 2007

Figure 8.2-2 Historical and Forecast Hourly Peak Demands



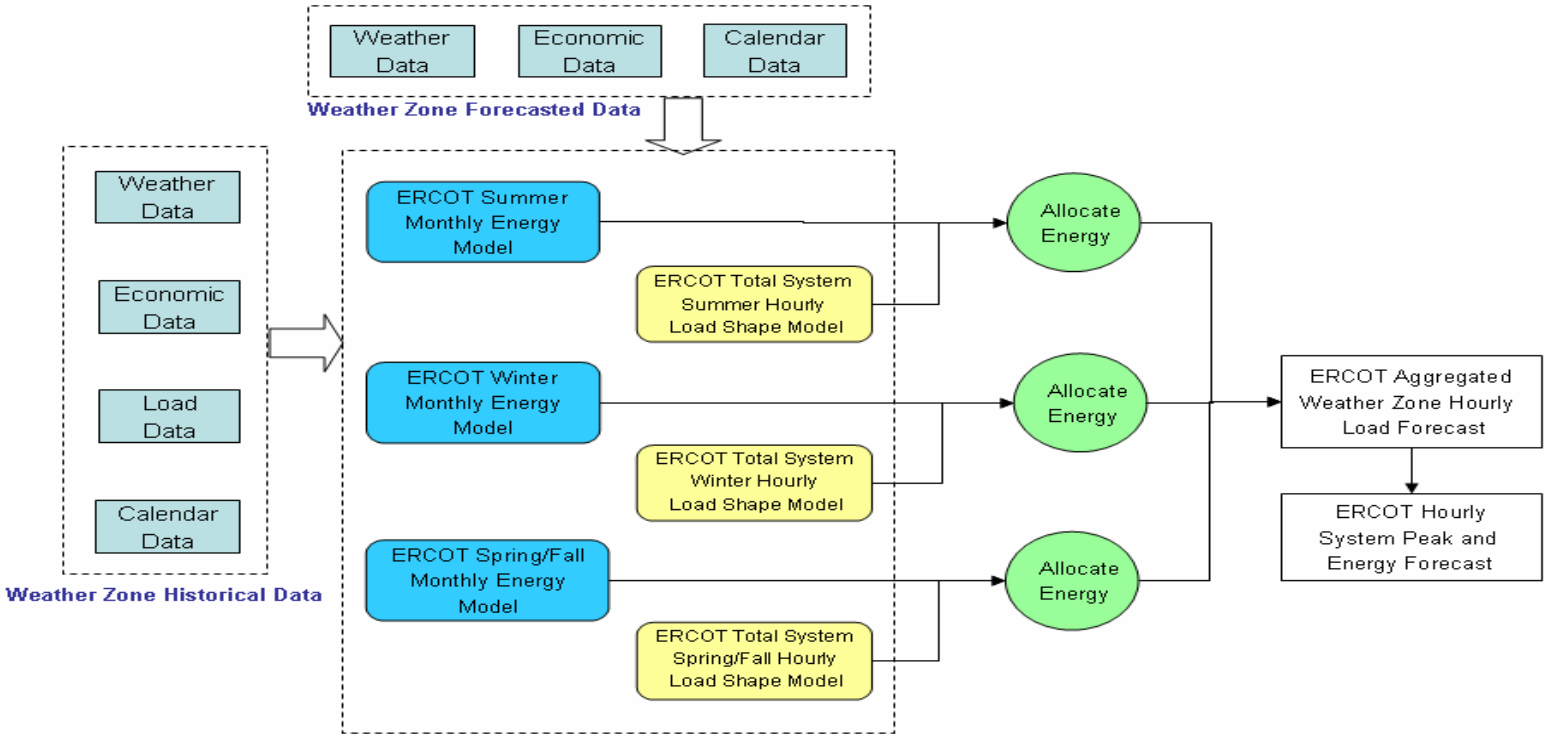
Source: ERCOT May 2007
Note: Annual consumption forecasts through the year 2025 are provided in Table 8.2-3.

Figure 8.2-3 Historical and Forecast Energy Consumption



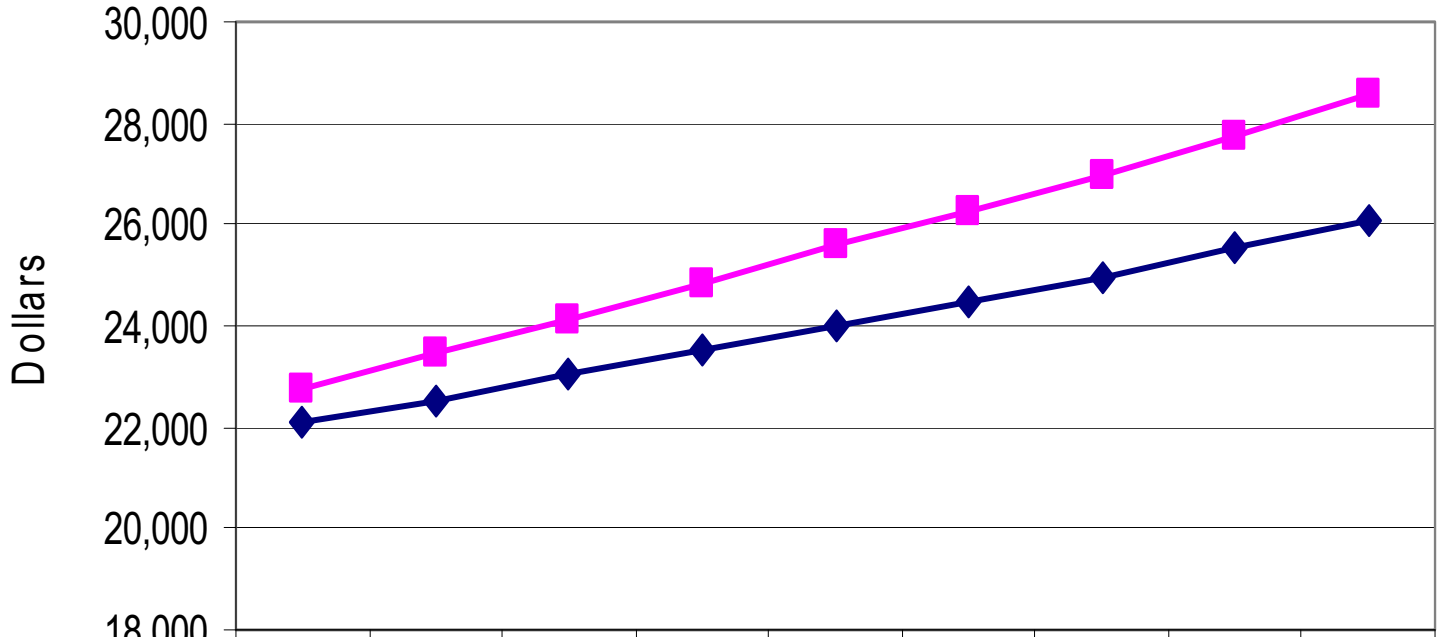
Compiled from ERCOT May 2007

Figure 8.2-4 Annual Percentage Growth of Average Hourly Load, Peak Demand, and Energy Consumption



Source: ERCOT May 2007

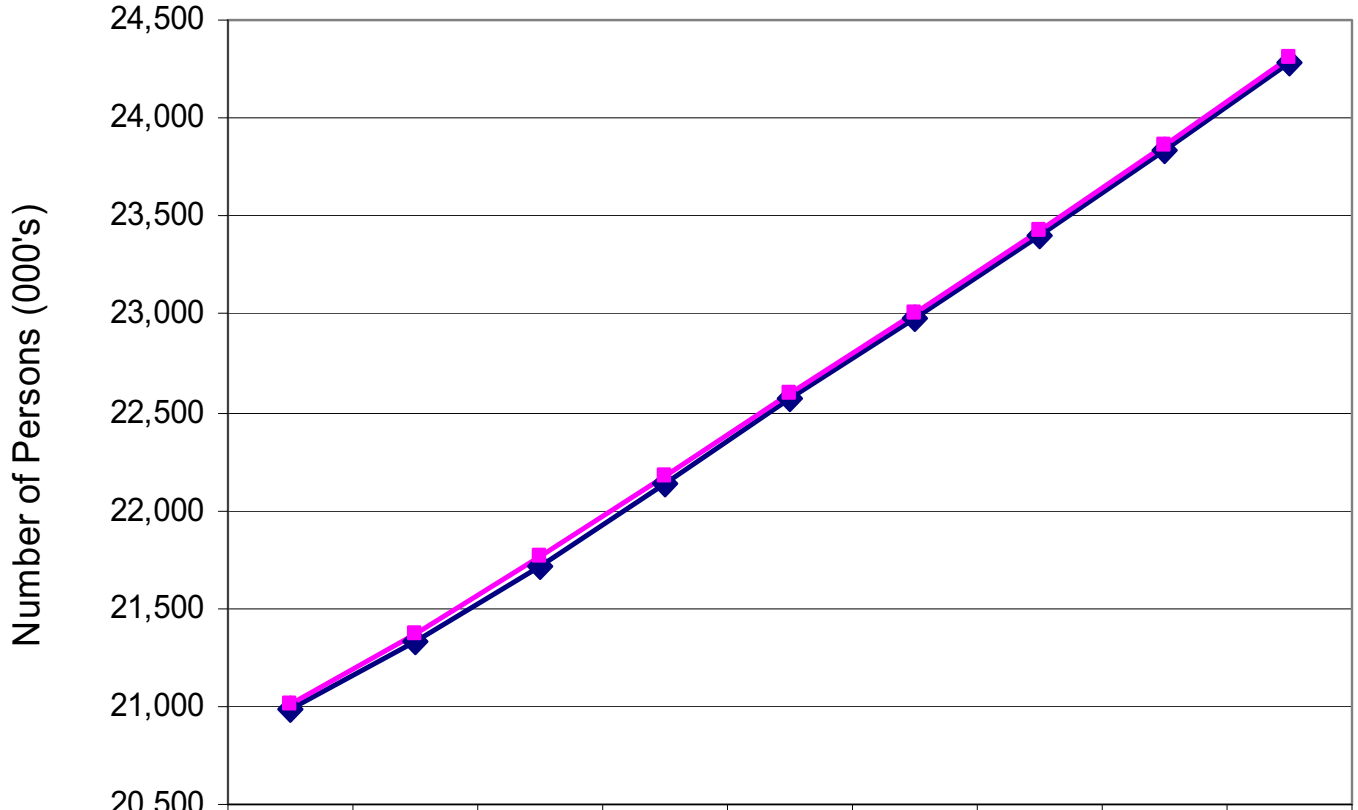
Figure 8.2-5 ERCOT Long-Term Forecasting Process



	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006 Forecast	22,092	22,518	23,035	23,533	24,015	24,480	24,978	25,515	26,078
2007 Forecast	22,776	23,445	24,132	24,847	25,600	26,282	26,961	27,736	28,547

Source: ERCOT May 2007

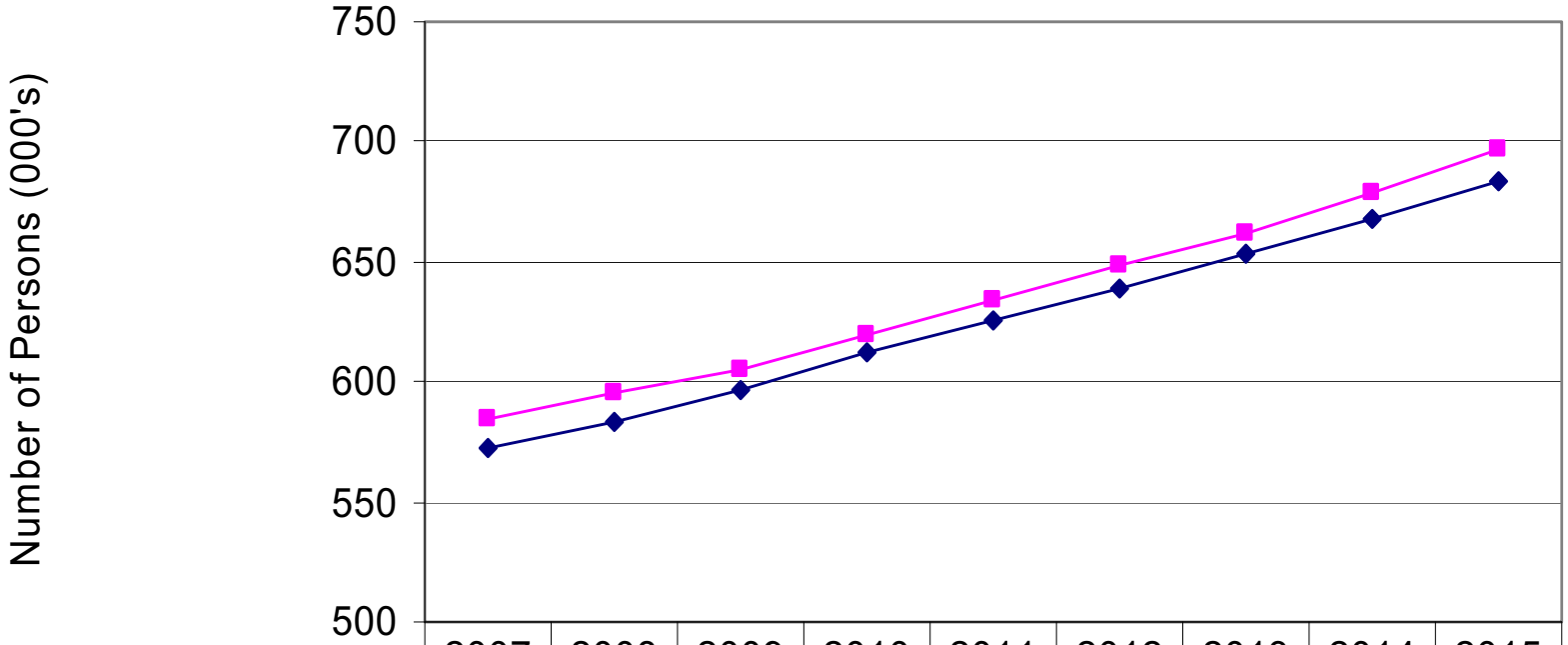
Figure 8.2-6 Real Personal Per-Capita Income



	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006 Forecast	20,986	21,327	21,713	22,137	22,566	22,981	23,398	23,837	24,282
2007 Forecast	21,015	21,372	21,759	22,175	22,602	23,011	23,425	23,862	24,309

Source: ERCOT May 2007

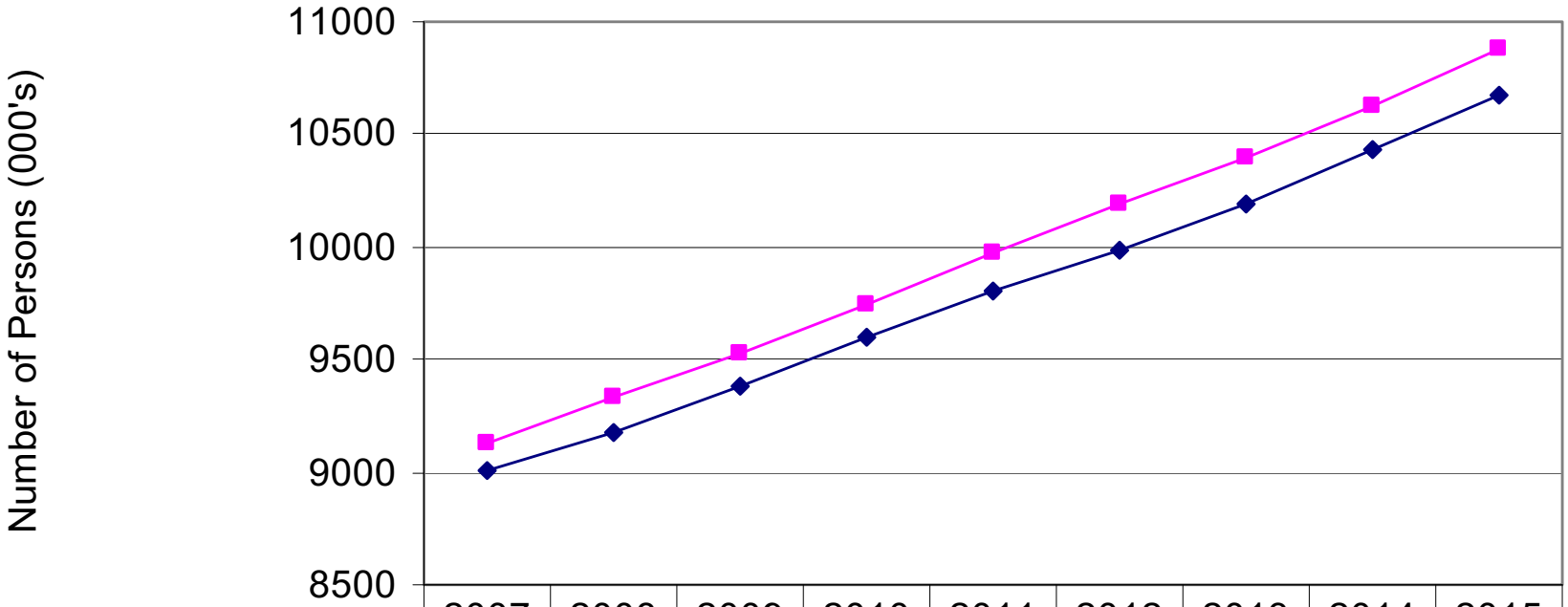
Figure 8.2-7 Population in the ERCOT Region



	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006 Forecast	572	583	597	612	626	639	653	668	684
2007 Forecast	584	595	605	620	634	648	662	679	697

Source: ERCOT May 2007

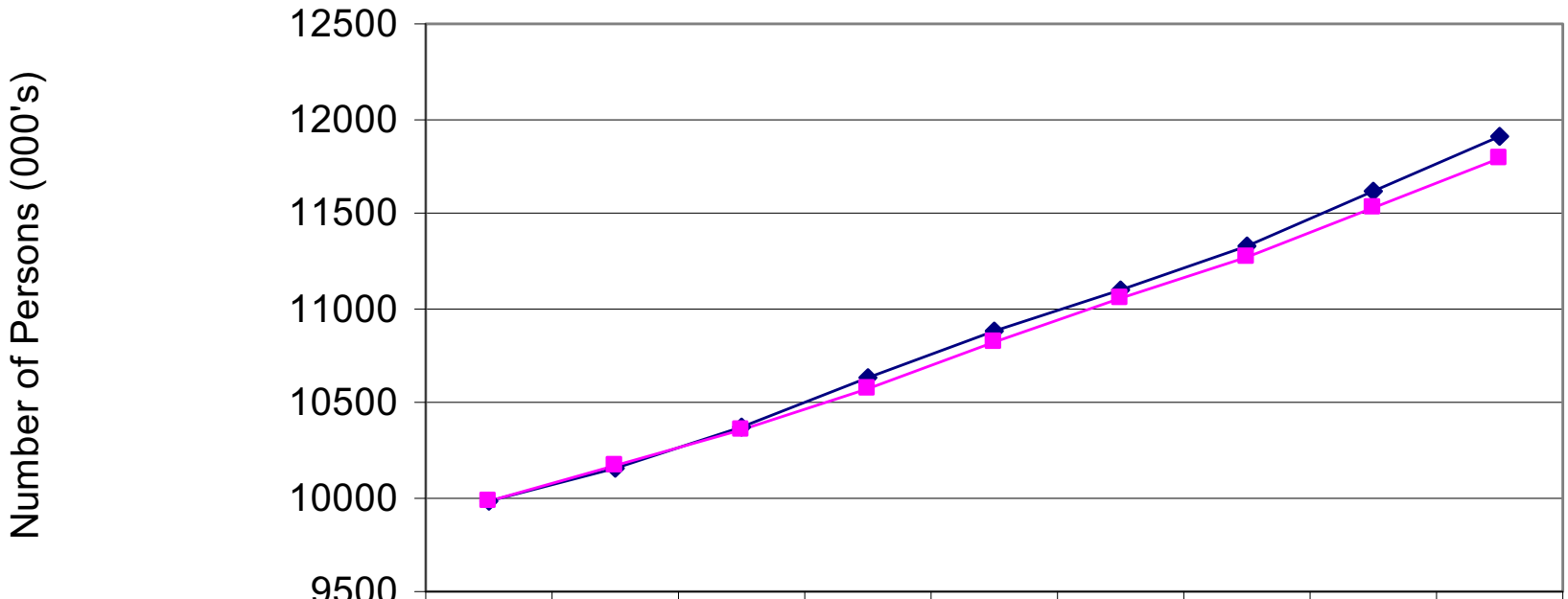
Figure 8.2-8 Employment in Financial Services



	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006 Forecast	9003	9173	9377	9597	9801	9983	10,191	10,429	10,675
2007 Forecast	9123	9328	9526	9749	9975	10,187	10,399	10,628	10,877

Source: ERCOT May 2007

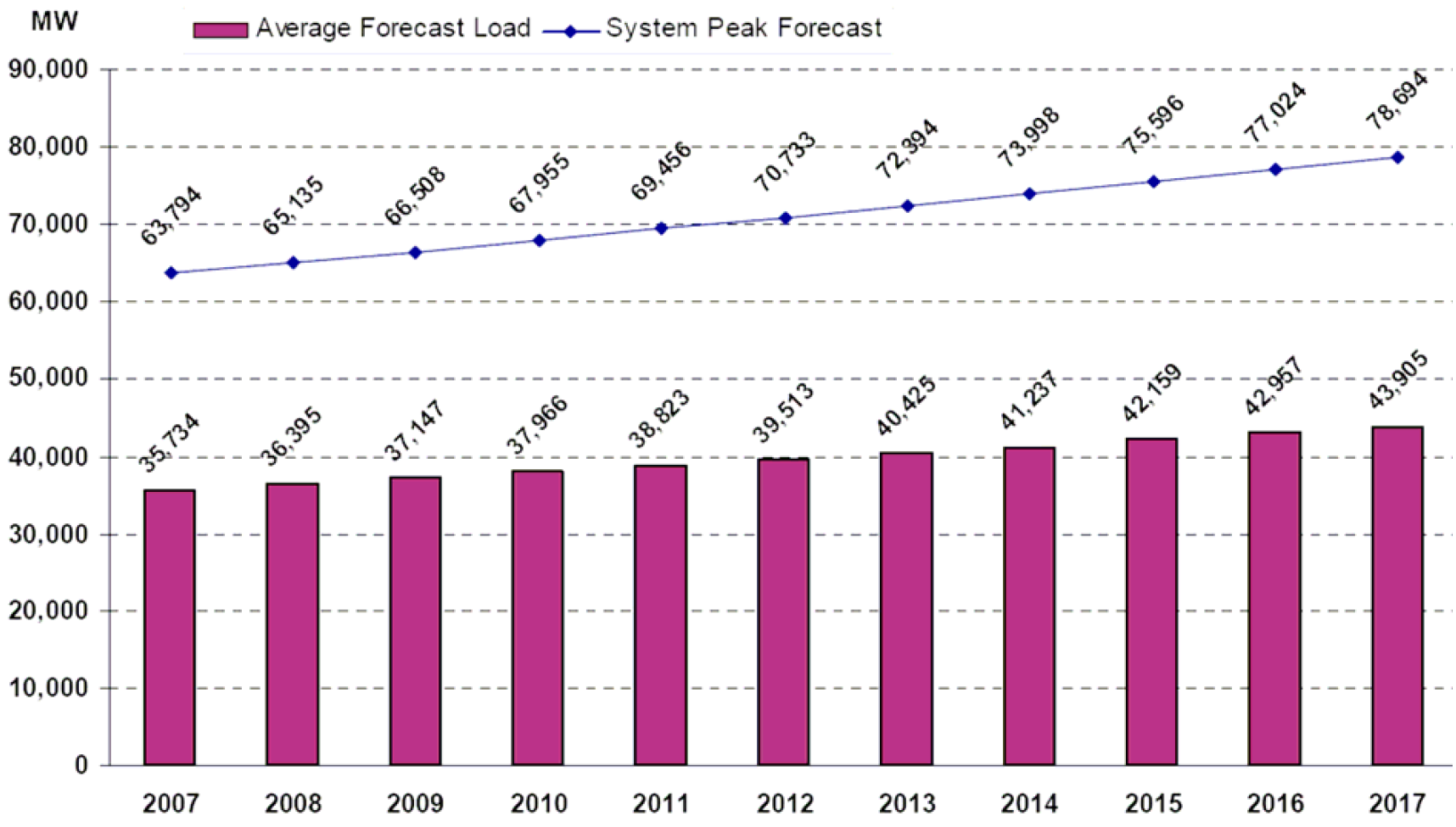
Figure 8.2-9 Total Non-Farm Employment



	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006 Forecast	9975	10,158	10,370	10,633	10,875	11,089	11,333	11,617	11,911
2007 Forecast	9985	10,160	10,348	10,577	10,818	11,044	11,271	11,522	11,797

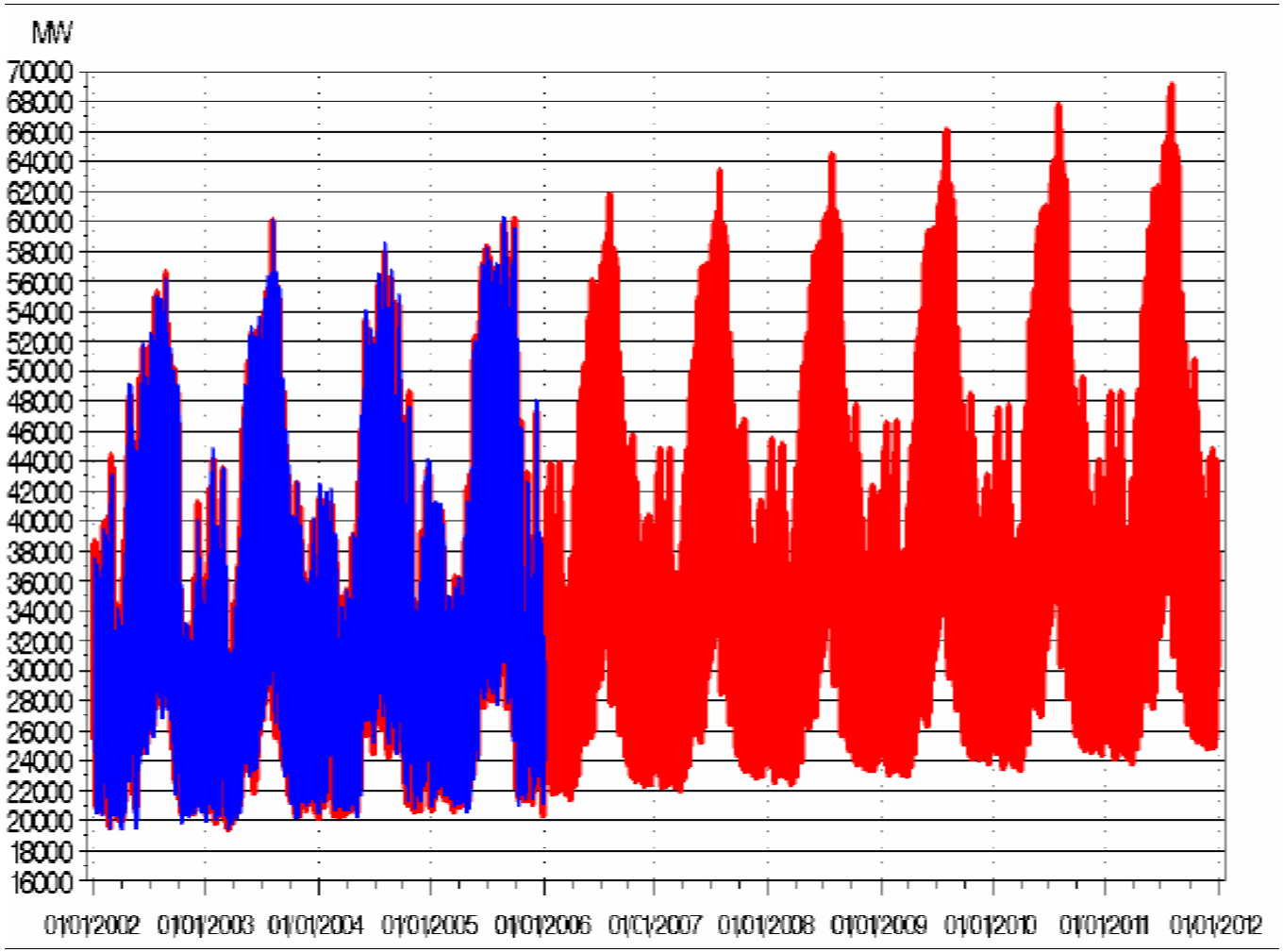
Source: ERCOT May 2007

Figure 8.2-10 Total Persons Employed



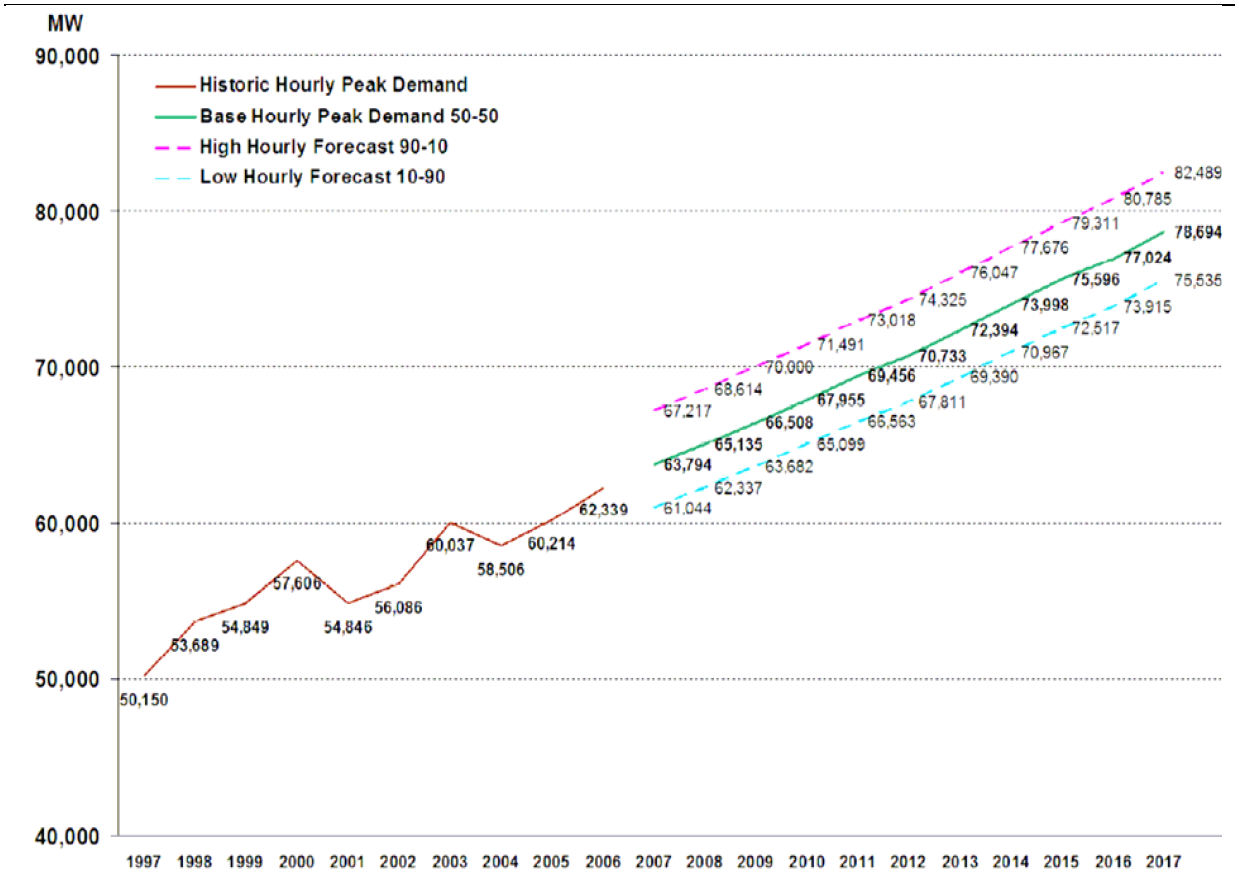
Source: ERCOT May 2007
Note: Annual peak demand forecasts through the year 2025 are provided in Table 8.2-3.

Figure 8.2-11 Forecast Average Load versus Forecast System Peak



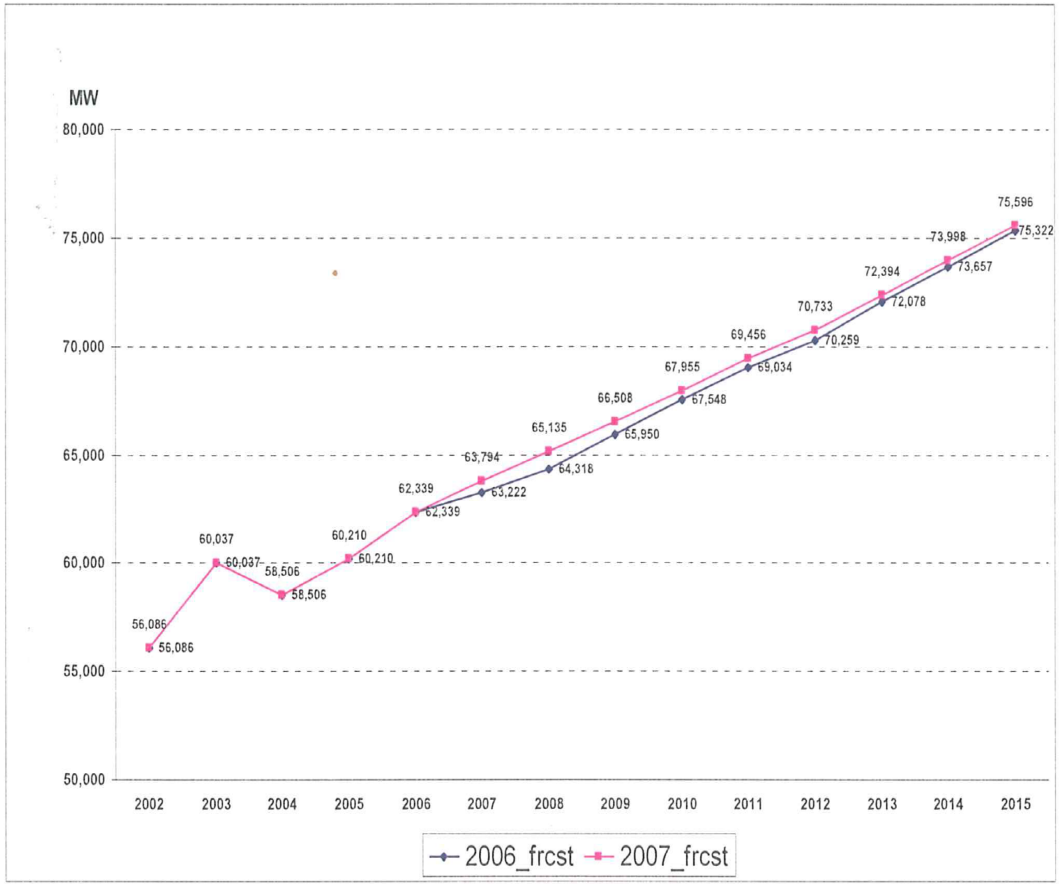
Source: ERCOT May 2007

Figure 8.2-12 ERCOT Hourly Load Shape Historic (2002-2006) and Forecasts (2007-2012)



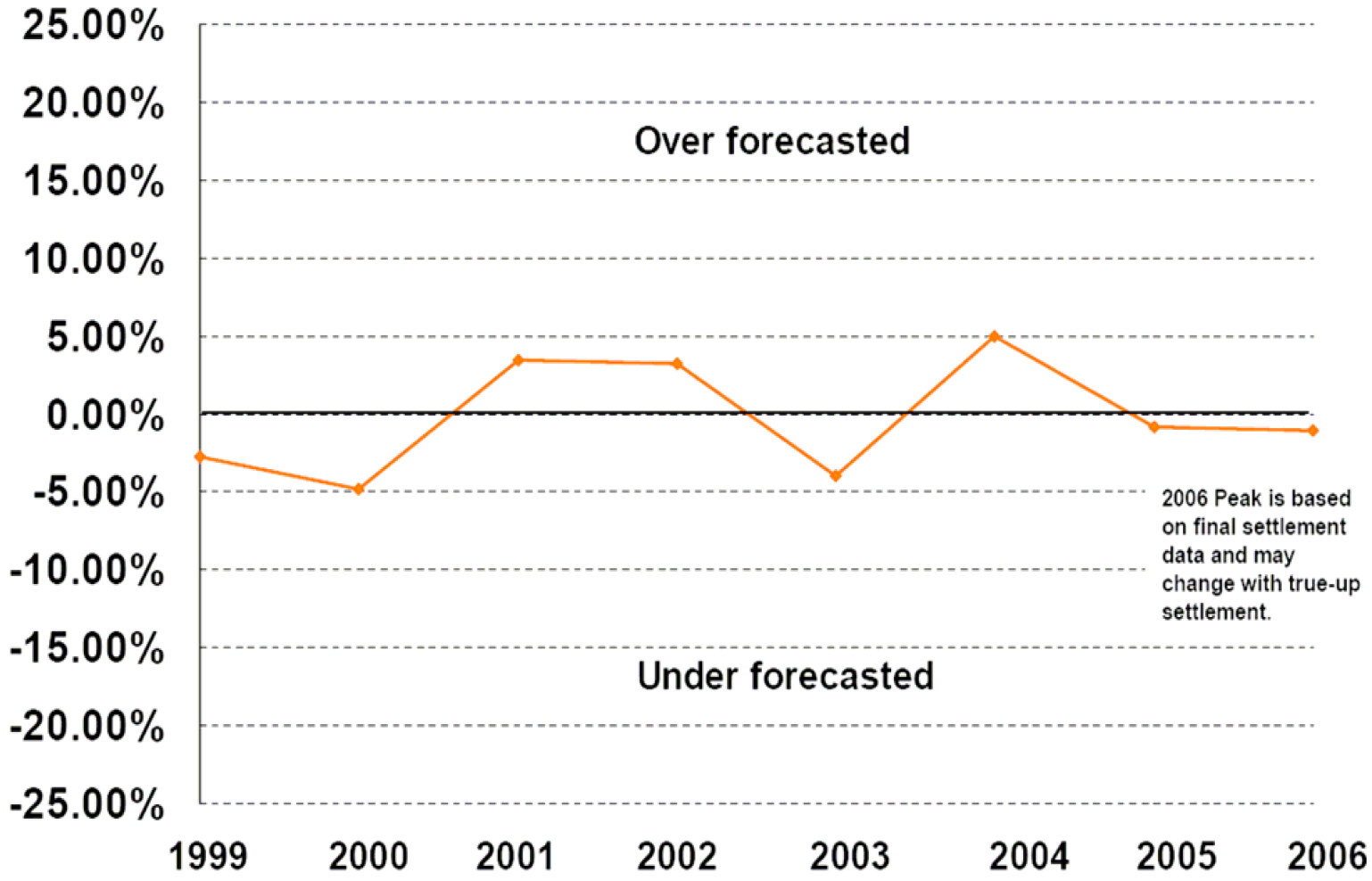
Source: ERCOT May 2007
Note: Annual peak demand 50-50 forecasts through the year 2025 are provided in Table 8.2-3.

Figure 8.2-13 Historical and Forecast Hourly Peak Demand



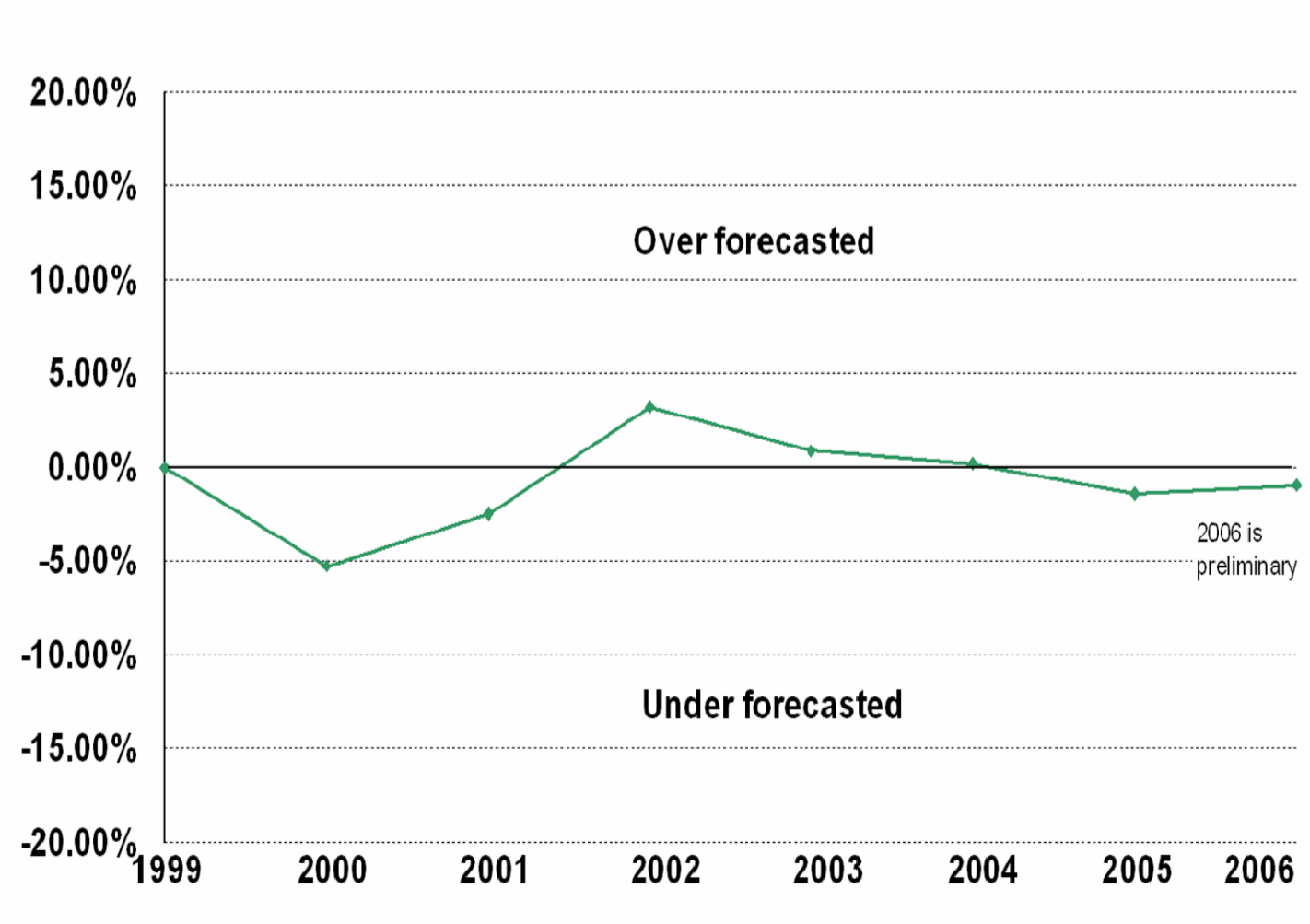
Source: ERCOT May 2007

Figure 8.2-14 Comparison of 2006 and 2007 Peak Demand Forecast



Source: ERCOT Jan 2007

Figure 8.2-15 Historical Accuracy of Peak Demand Forecasts



Source: ERCOT Jan 2007

Figure 8.2-16 Historical Accuracy of Energy Consumption Forecasts

8.3 Power Supply

This section addresses the supply side of the demand/supply equation by projecting supplies as well as looking at potential market competitors and describes the existing and planned generating capacity in the relevant service area. Based on Electric Reliability Council of Texas (ERCOT) projections, the effects of Exelon's proposed start of commercial operation in 2015 for Unit 1 and 2017 for Unit 2 would most likely coincide with a growing gap between supply and demand (Figure 8.3-1).

8.3.1 Present Generation Capacity

Installed generation capacity in the ERCOT region is approximately 81,000 MW, which includes 5000 MW of "mothballed" natural gas-fired generation capacity, that is, units that have suspended operations from the grid for more than 6 months (ERCOT Dec 2007a).

Although not a formal definition, ERCOT considers the cost of operation as the identifier of baseload generation units. Currently, ERCOT considers the larger solid fuel units (nuclear and coal greater than 550 MW) to be the baseload generation units. As shown in Table 8.3-3, approximately 25.9% of the installed generation capacity is provided by baseload generation units. ERCOT would consider the two proposed VCS units to be baseload generation units.

8.3.2 Generation Capacity Forecast

ERCOT prepares an annual working paper known as the Capacity, Demand, and Resources Report (CDR) (ERCOT May 2007b). It is developed from data provided by the market participants as part of the annual load data request, the generation asset registrations, and from data collected for the annual U.S. DOE Coordinated Bulk Power Supply Program Report. The working paper calculates the generation resources reported to be available by market participants.

The CDR considers all of the generation resources in the ERCOT region including coal, natural gas, nuclear, wind, landfill gas, water, petroleum coke, diesel, waste heat, generation available from private networks, the asynchronous ties, and switchable resources. There are several constraints on which resources are listed as available in the CDR. Those most important to this discussion are:

- Only those new generation resources for which the owners have signed generation interconnection agreements with ERCOT are included as planned generation.
- If an air permit is required for a new generation unit, the unit must have received that permit before it is included as planned generation.

All the new generation resources that were included in the May 2007 CDR and in the December 2007 Update (ERCOT Dec 2007b) would be on line by 2012. VCS was not included in the CDR because Exelon has not signed a generation interconnection agreement with ERCOT.

Table 8.3-1 provides the complete summary of the resources expected to be available each summer from 2008–2013 and establishes the extent of the CDR analysis from the December 2007 Update of the CDR (ERCOT Dec 2007b). The focus is on the summer, because the loads in ERCOT are substantially

higher in the summer than the winter, given the climate of the region. Table 8.3-2 is the list of generating units with a capacity of 100 MWe or greater that are included in the resource summary in Table 8.3-1. Table 8.3-3 concentrates on the contribution of baseload generation units to meeting the forecast summer peak demand. Table 8.3-4 is the list of generating units considered to be the baseload units used to develop Table 8.3-3.

Figure 8.3-2 is contained in the CDR and provides the ERCOT generation capacity projections for 2012–2027. The computer program that develops the projection curves takes many factors into consideration:

- Units aging, which may lead to inefficiency, increased outage time, or reduced output capacity.
- New units being connected to the grid (capacity and date) based on market participants' reported plans.
- Units being decommissioned (capacity and date) in accordance with market participants' reported plans.
- Units being mothballed (capacity and date) based on market participants' reported plans.
- Units being taken out of mothballed status and reconnected to the grid (capacity and date) based on market participants' reported plans.

Figure 8.3-2 provides three possible capacity scenarios based on the aging of existing units to assist the market participants in making sound economic decisions. Based on company operating experience and specific economic constraints, some market participants may choose not to operate their units past 30 years, 40 years, or 50 years. The three aging scenarios allow the market participants to understand the forecast generation capacity with and without units of various ages. This provides the market participants flexibility in their economic decisions.

ERCOT does not dictate which units should be mothballed, when mothballed units should be returned to the grid, when new units should be planned and constructed, or when older units decommissioned. ERCOT relies on market economic forces to provide the market participants with the impetus to make such economic decisions. ERCOT simply provides as much information as possible to assist the market participants in making economic decisions that will benefit the whole ERCOT region.

8.3.3 References

ERCOT Dec 2007a. Electric Reliability Council of Texas, *ERCOT Report on Existing and Potential Electric System Constraints and Needs*, December 2007.

ERCOT Dec 2007b. Electric Reliability Council of Texas, *Report on the Capacity, Demand, and Reserves in the ERCOT Region — Summer Assessment Update*, December 2007.

ERCOT May 2007b. Electric Reliability Council of Texas, *Report on the Capacity, Demand, and Reserves in the ERCOT Region*, May 2007.

Table 8.3-1
Forecast Summer Resources for 2008–2013

Resources:	2008	2009	2010	2011	2012	2013
Installed Capacity, MW	61,722	61,722	61,722	61,722	61,722	61,722
Capacity from Private Networks, MW	6405	6405	6405	6405	6405	6405
Effective Load Carrying Capability of Wind Generation, MW	497	497	497	497	497	497
Reliability Must-Run Units under Contract, MW	169	169	169	0	0	0
Operational Generation, MW	68,793	68,793	68,793	68,624	68,624	68,624
50% of Non-Synchronous Ties, MW	553	553	553	553	553	553
Switchable Units, MW	2877	2877	2877	2877	2877	2877
Available Mothballed Generation, MW	510	419	594	558	522	522
Planned Units (not wind) with Signed Interconnection Agreement and Air Permit, MW	0	836	3296	3296	4221	4221
Effective Load Carrying Capability of Planned Wind Units with Signed Interconnection Agreement, MW	0	148	153	153	153	153
Total Resources, MW	72,733	73,625	76,266	76,061	76,950	76,950
Less Switchable Units Unavailable to ERCOT, MW	317	317	0	0	0	0
Less Retiring Units, MW	0	0	65	65	65	65
Resources, MW	72,416	73,308	76,201	75,996	76,885	76,885

Table 8.3-2 (Sheet 1 of 8)
Generation Units with Capacity Greater Than 100 MWe Included in Summer Capacity Forecast

		Summer Capacity, MWe					
Unit Name	**Fuel**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
A von Rosenberg 1-CT1	Natural Gas	155	155	155	155	155	155
A von Rosenberg 1-CT2	Natural Gas	155	155	155	155	155	155
A von Rosenberg 1-ST1	Natural Gas	174	174	174	174	174	174
AES Deepwater 1	Petroleum Coke	138	138	138	138	138	138
Airtricity Champion Wind Farm	Wind	126	126	126	126	126	126
Airtricity Panther Creek Wind Farm 1	Wind	150	150	150	150	150	150
B M Davis 1	Natural Gas	339	339	339	339	339	339
B M Davis 2	Natural Gas	340	340	340	340	340	340
Barton Chapel Wind Farm 1	Wind	120	120	120	120	120	120
Bastrop Energy Center 1	Natural Gas	147	147	147	147	147	147
Bastrop Energy Center 2	Natural Gas	150	150	150	150	150	150
Bastrop Energy Center 3	Natural Gas	233	233	233	233	233	233
Big Brown 1	Coal	618	618	618	618	618	618
Big Brown 2	Coal	589	589	589	589	589	589
Bosque 1	Natural Gas	156	156	156	156	156	156
Bosque 2	Natural Gas	151	151	151	151	151	151
Bosque 3	Natural Gas	150	150	150	150	150	150
Brazos Valley 1	Natural Gas	168	168	168	168	168	168
Brazos Valley 2	Natural Gas	166	166	166	166	166	166
Brazos Valley 3	Natural Gas	252	252	252	252	252	252
Buffalo Gap Wind Farm 1	Wind	120	120	120	120	120	120
Buffalo Gap Wind Farm 2	Wind	233	233	233	233	233	233
Callahan Divide Wind Farm (FPL)	Wind	114	114	114	114	114	114
Camp Springs Energy Center 1	Wind	134	134	134	134	134	134
Capricorn Ridge Wind Project 1	Wind	200	200	200	200	200	200
Capricorn Ridge Wind Project 2	Wind	150	150	150	150	150	150
Cedar Bayou 1	Natural Gas	744	744	744	744	744	744
Cedar Bayou 2	Natural Gas	746	746	746	746	746	746
Coleto Creek 1	Coal	633	633	633	633	633	633
Colorado Bend Energy Center I	Natural Gas	105	105	105	105	105	105
Colorado Bend Energy Center II	Natural Gas	275	275	275	275	275	275
Comanche Peak 1	Nuclear	1159	1159	1159	1159	1159	1159
Comanche Peak 2	Nuclear	1159	1159	1159	1159	1159	1159

Table 8.3-2 (Sheet 2 of 8)
Generation Units with Capacity Greater Than 100 MWe Included in Summer Capacity Forecast

		Summer Capacity, MWe					
Unit Name	**Fuel**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Dansby 1	Natural Gas	105	105	105	105	105	105
Decker Creek 1	Natural Gas	321	321	321	321	321	321
Decker Creek 2	Natural Gas	427	427	427	427	427	427
DeCordova 1	Natural Gas	779	779	779	779	779	779
Ennis Power Station 1	Natural Gas	196	196	196	196	196	196
Ennis Power Station 2	Natural Gas	116	116	116	116	116	116
Fayette Power Project 1	Coal	604	604	604	604	604	604
Fayette Power Project 2	Coal	613	613	613	613	613	613
Fayette Power Project 3	Coal	444	444	444	444	444	444
Forest Creek 1	Wind	124	124	124	124	124	124
Forney Energy Center GT11	Natural Gas	161	161	161	161	161	161
Forney Energy Center GT12	Natural Gas	164	164	164	164	164	164
Forney Energy Center GT13	Natural Gas	164	164	164	164	164	164
Forney Energy Center GT21	Natural Gas	162	162	162	162	162	162
Forney Energy Center GT22	Natural Gas	161	161	161	161	161	161
Forney Energy Center GT23	Natural Gas	163	163	163	163	163	163
Forney Energy Center STG 10	Natural Gas	414	414	414	414	414	414
Forney Energy Center STG 20	Natural Gas	415	415	415	415	415	415
Freestone Energy Center 1	Natural Gas	151	151	151	151	151	151
Freestone Energy Center 2	Natural Gas	151	151	151	151	151	151
Freestone Energy Center 3	Natural Gas	177	177	177	177	177	177
Freestone Energy Center 4	Natural Gas	152	152	152	152	152	152
Freestone Energy Center 5	Natural Gas	157	157	157	157	157	157
Freestone Energy Center 6	Natural Gas	178	178	178	178	178	178
Frontera 1	Natural Gas	142	142	142	142	142	142
Frontera 2	Natural Gas	148	148	148	148	148	148
Frontera 3	Natural Gas	173	173	173	173	173	173
Gibbons Creek 1	Coal	463	463	463	463	463	463
Goat Wind 1	Wind	150	150	150	150	150	150
Graham 1	Natural Gas	231	231	231	231	231	231
Graham 2	Natural Gas	366	366	366	366	366	366
Greens Bayou 5	Natural Gas	388	388	388	388	388	388
Guadalupe Power Partners 1	Natural Gas	147	147	147	147	147	147
Guadalupe Power Partners 2	Natural Gas	138	138	138	138	138	138

Table 8.3-2 (Sheet 3 of 8)
Generation Units with Capacity Greater Than 100 MWe Included in Summer Capacity Forecast

		Summer Capacity, MWe					
Unit Name	**Fuel**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Guadalupe Power Partners 3	Natural Gas	146	146	146	146	146	146
Guadalupe Power Partners 4	Natural Gas	138	138	138	138	138	138
Guadalupe Power Partners 5	Natural Gas	182	182	182	182	182	182
Guadalupe Power Partners 6	Natural Gas	203	203	203	203	203	203
Handley 3	Natural Gas	395	395	395	395	395	395
Handley 4	Natural Gas	435	435	435	435	435	435
Handley 5	Natural Gas	435	435	435	435	435	435
Hays Energy Facility 1	Natural Gas	224	224	224	224	224	224
Hays Energy Facility 2	Natural Gas	225	225	225	225	225	225
Hays Energy Facility 3	Natural Gas	225	225	225	225	225	225
Hays Energy Facility 4	Natural Gas	227	227	227	227	227	227
Hidalgo 1	Natural Gas	145	145	145	145	145	145
Hidalgo 2	Natural Gas	144	144	144	144	144	144
Hidalgo 3	Natural Gas	172	172	172	172	172	172
Horse Hollow Wind Farm 1	Wind	220	220	220	220	220	220
Horse Hollow Wind Farm 2	Wind	186	186	186	186	186	186
Horse Hollow Wind Farm 3	Wind	223	223	223	223	223	223
Horse Hollow Wind Farm 4	Wind	115	115	115	115	115	115
J K Spruce 1	Coal	560	560	560	560	560	560
J T Deely 1	Coal	385	385	385	385	385	385
J T Deely 2	Coal	385	385	385	385	385	385
Jack County Generation Facility 1	Natural Gas	160	160	160	160	160	160
Jack County Generation Facility 2	Natural Gas	160	160	160	160	160	160
Jack County Generation Facility 3	Natural Gas	300	300	300	300	300	300
Johnson County Generation Facility 1	Natural Gas	158	158	158	158	158	158
Johnson County Generation Facility 2	Natural Gas	100	100	100	100	100	100
Lake Creek 2	Natural Gas	227	227	227	227	227	227
Lake Hubbard 1	Natural Gas	382	382	382	382	382	382
Lake Hubbard 2	Natural Gas	516	516	516	516	516	516
Lamar Power Project CT11	Natural Gas	160	160	160	160	160	160
Lamar Power Project CT12	Natural Gas	156	156	156	156	156	156
Lamar Power Project CT21	Natural Gas	156	156	156	156	156	156
Lamar Power Project CT22	Natural Gas	157	157	157	157	157	157
Lamar Power Project STG1	Natural Gas	196	196	196	196	196	196

Table 8.3-2 (Sheet 4 of 8)
Generation Units with Capacity Greater Than 100 MWe Included in Summer Capacity Forecast

		Summer Capacity, MWe					
Unit Name	**Fuel**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Lamar Power Project STG2	Natural Gas	198	198	198	198	198	198
Limestone 1	Coal	827	827	827	827	827	827
Limestone 2	Coal	849	849	849	849	849	849
Lost Pines 1	Natural Gas	165	165	165	165	165	165
Lost Pines 2	Natural Gas	161	161	161	161	161	161
Lost Pines 3	Natural Gas	181	181	181	181	181	181
Louis (Buffalo Gap 3)	Wind	138	138	138	138	138	138
Magic Valley 1	Natural Gas	217	217	217	217	217	217
Magic Valley 2	Natural Gas	217	217	217	217	217	217
Magic Valley 3	Natural Gas	250	250	250	250	250	250
Martin Lake 1	Coal	790	790	790	790	790	790
Martin Lake 2	Coal	809	809	809	809	809	809
Martin Lake 3	Coal	795	795	795	795	795	795
Mesquite Wind Farm 1	Wind	200	200	200	200	200	200
Midlothian 1	Natural Gas	216	216	216	216	216	216
Midlothian 2	Natural Gas	216	216	216	216	216	216
Midlothian 3	Natural Gas	212	212	212	212	212	212
Midlothian 4	Natural Gas	211	211	211	211	211	211
Midlothian 5	Natural Gas	224	224	224	224	224	224
Midlothian 6	Natural Gas	226	226	226	226	226	226
Monticello 1	Coal	558	558	558	558	558	558
Monticello 2	Coal	553	553	553	553	553	553
Monticello 3	Coal	770	770	770	770	770	770
Morgan Creek 5	Natural Gas	137	137	137	137	137	137
Mountain Creek 6	Natural Gas	118	118	118	118	118	118
Mountain Creek 7	Natural Gas	115	115	115	115	115	115
Mountain Creek 8	Natural Gas	571	571	571	571	571	571
North Lake 1	Natural Gas	169	169	169	169	169	169
North Lake 2	Natural Gas	175	175	175	175	175	175
North Lake 3	Natural Gas	389	389	389	389	389	389
O W Sommers 1	Natural Gas	418	418	418	418	418	418
O W Sommers 2	Natural Gas	400	400	400	400	400	400
Odessa-Ector C11	Natural Gas	145	145	145	145	145	145
Odessa-Ector C12	Natural Gas	132	132	132	132	132	132

Table 8.3-2 (Sheet 5 of 8)
Generation Units with Capacity Greater Than 100 MWe Included in Summer Capacity Forecast

		Summer Capacity, MWe					
Unit Name	**Fuel**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Odessa-Ector C21	Natural Gas	137	137	137	137	137	137
Odessa-Ector C22	Natural Gas	147	147	147	147	147	147
Odessa-Ector ST1	Natural Gas	208	208	208	208	208	208
Odessa-Ector ST2	Natural Gas	213	213	213	213	213	213
Oklaunion 1	Coal	650	650	650	650	650	650
Permian Basin 5	Natural Gas	114	114	114	114	114	114
Permian Basin 6	Natural Gas	524	524	524	524	524	524
Post Oak Wind 1	Wind	200	200	200	200	200	200
Quail Run Energy Center II	Natural Gas	275	275	275	275	275	275
R W Miller 2	Natural Gas	113	113	113	113	113	113
R W Miller 3	Natural Gas	210	210	210	210	210	210
R W Miller 4	Natural Gas	102	102	102	102	102	102
R W Miller 5	Natural Gas	101	101	101	101	101	101
Ray Olinger 2	Natural Gas	107	107	107	107	107	107
Ray Olinger 3	Natural Gas	146	146	146	146	146	146
Rio Nogales 1	Natural Gas	148	148	148	148	148	148
Rio Nogales 2	Natural Gas	148	148	148	148	148	148
Rio Nogales 3	Natural Gas	154	154	154	154	154	154
Rio Nogales 4	Natural Gas	284	284	284	284	284	284
Roscoe 1	Wind	209	209	209	209	209	209
Sam Bertron 3	Natural Gas	213	213	213	213	213	213
Sam Bertron 4	Natural Gas	228	228	228	228	228	228
Sam Bertron ST1	Natural Gas	167	167	167	167	167	167
Sam Bertron ST2	Natural Gas	176	176	176	176	176	176
San Miguel 1	Coal	396	396	396	396	396	396
Sandhill Energy Center 5A	Natural Gas	159	159	159	159	159	159
Sim Gideon 1	Natural Gas	132	132	132	132	132	132
Sim Gideon 2	Natural Gas	133	133	133	133	133	133
Sim Gideon 3	Natural Gas	329	329	329	329	329	329
South Texas 1	Nuclear	1333	1333	1333	1333	1333	1333
South Texas 2	Nuclear	1332	1332	1332	1332	1332	1332
Stanton Wind Energy 1	Wind	101	101	101	101	101	101
Stryker Creek 1	Natural Gas	182	182	182	182	182	182
Stryker Creek 2	Natural Gas	495	495	495	495	495	495

Table 8.3-2 (Sheet 6 of 8)
Generation Units with Capacity Greater Than 100 MWe Included in Summer Capacity Forecast

		Summer Capacity, MWe					
Unit Name	**Fuel**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Sweetwater Wind 3	Wind	129	129	129	129	129	129
Sweetwater Wind 4	Wind	300	300	300	300	300	300
T H Wharton 3	Natural Gas	107	107	107	107	107	107
T H Wharton 4	Natural Gas	108	108	108	108	108	108
Texas City 1	Natural Gas	100	100	100	100	100	100
Texas City 3	Natural Gas	103	103	103	103	103	103
Texas City 4	Natural Gas	130	130	130	130	130	130
Thomas C Ferguson 1	Natural Gas	423	423	423	423	423	423
Tradinghouse 1	Natural Gas	537	537	537	537	537	537
Tradinghouse 2	Natural Gas	807	807	807	807	807	807
Trent Mesa Wind Farm 1	Wind	150	150	150	150	150	150
Trinidad 6	Natural Gas	226	226	226	226	226	226
Twin Oaks 1	Coal	152	152	152	152	152	152
Twin Oaks 2	Coal	153	153	153	153	153	153
V H Braunig 1	Natural Gas	206	206	206	206	206	206
V H Braunig 2	Natural Gas	220	220	220	220	220	220
V H Braunig 3	Natural Gas	397	397	397	397	397	397
Valley 1	Natural Gas	170	170	170	170	170	170
Valley 2	Natural Gas	520	520	520	520	520	520
Valley 3	Natural Gas	375	375	375	375	375	375
W A Parish 1	Natural Gas	166	166	166	166	166	166
W A Parish 2	Natural Gas	166	166	166	166	166	166
W A Parish 3	Natural Gas	248	248	248	248	248	248
W A Parish 4	Natural Gas	544	544	544	544	544	544
W A Parish 5	Coal	654	654	654	654	654	654
W A Parish 6	Coal	656	656	656	656	656	656
W A Parish 7	Coal	565	565	565	565	565	565
W A Parish 8	Coal	595	595	595	595	595	595
W B Tuttle 4	Natural Gas	154	154	154	154	154	154
Wild Horse Wind Farm 1	Wind	126	126	126	126	126	126
Wise County Power Proj. 1	Natural Gas	204	204	204	204	204	204
Wise County Power Proj. 2	Natural Gas	204	204	204	204	204	204
Wise County Power Proj. 3	Natural Gas	241	241	241	241	241	241
Wolf Hollow Power Proj. 1	Natural Gas	217	217	217	217	217	217

Table 8.3-2 (Sheet 7 of 8)
Generation Units with Capacity Greater Than 100 MWe Included in Summer Capacity Forecast

		Summer Capacity, MWe					
Unit Name	**Fuel**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Wolf Hollow Power Proj. 2	Natural Gas	216	216	216	216	216	216
Wolf Hollow Power Proj. 3	Natural Gas	272	272	272	272	272	272
Wolf Ridge Wind Farm	Wind	201	201	201	201	201	201
Airtricity Inadale	Wind	0	212	212	212	212	212
Airtricity LaMesa Wind Plant	Wind	0	183	183	183	183	183
Airtricity Pyron Wind Farm	Wind	0	303	303	303	303	303
Bosque Expansion	Natural Gas	0	255	255	255	255	255
Buffalo Gap 4	Wind	0	378	378	378	378	378
Bull Creek Wind Plant	Wind	0	180	180	180	180	180
Gray Wind Project	Wind	0	141	141	141	141	141
Gulf Wind 1	Wind	0	187	187	187	187	187
Gunsight Energy Center	Wind	0	200	200	200	200	200
Hackberry Wind Farm	Wind	0	165	165	165	165	165
Lenorah Project	Wind	0	350	350	350	350	350
M Bar Wind	Wind	0	194	194	194	194	194
McAdoo Energy Center II	Wind	0	500	500	500	500	500
Notrees-1	Wind	0	151	151	151	151	151
Penascal Wind Farm 1	Wind	0	202	202	202	202	202
Pistol Hill Energy Center	Wind	0	300	300	300	300	300
Sandow 5	Coal	0	581	581	581	581	581
South Trent Wind Farm	Wind	0	101	101	101	101	101
Sterling Energy Center	Wind	0	300	300	300	300	300
Turkey Track Energy Center	Wind	0	300	300	300	300	300
V H Braunig 6	Natural Gas	0	185	185	185	185	185
Wild Horse Mountain	Wind	0	120	120	120	120	120
Winchester Peaking Plant	Natural Gas	0	200	200	200	200	200
Wind Tex Energy Stephens Wind Farm	Wind	0	141	141	141	141	141
Camp Springs Energy Center III	Wind	0	0	350	350	350	350
Cobisa-Greenville	Natural Gas	0	0	1750	1750	1750	1750
Comanche Peak 1&2 Uprate	Nuclear	0	0	86	86	86	86
Gatesville Wind Farm	Wind	0	0	200	200	200	200
Gulf Wind 2	Wind	0	0	400	400	400	400
J K Spruce 2	Coal	0	0	750	750	750	750
Oak Grove 1	Coal	0	0	855	855	855	855

Table 8.3-2 (Sheet 8 of 8)
Generation Units with Capacity Greater Than 100 MWe Included in Summer Capacity Forecast

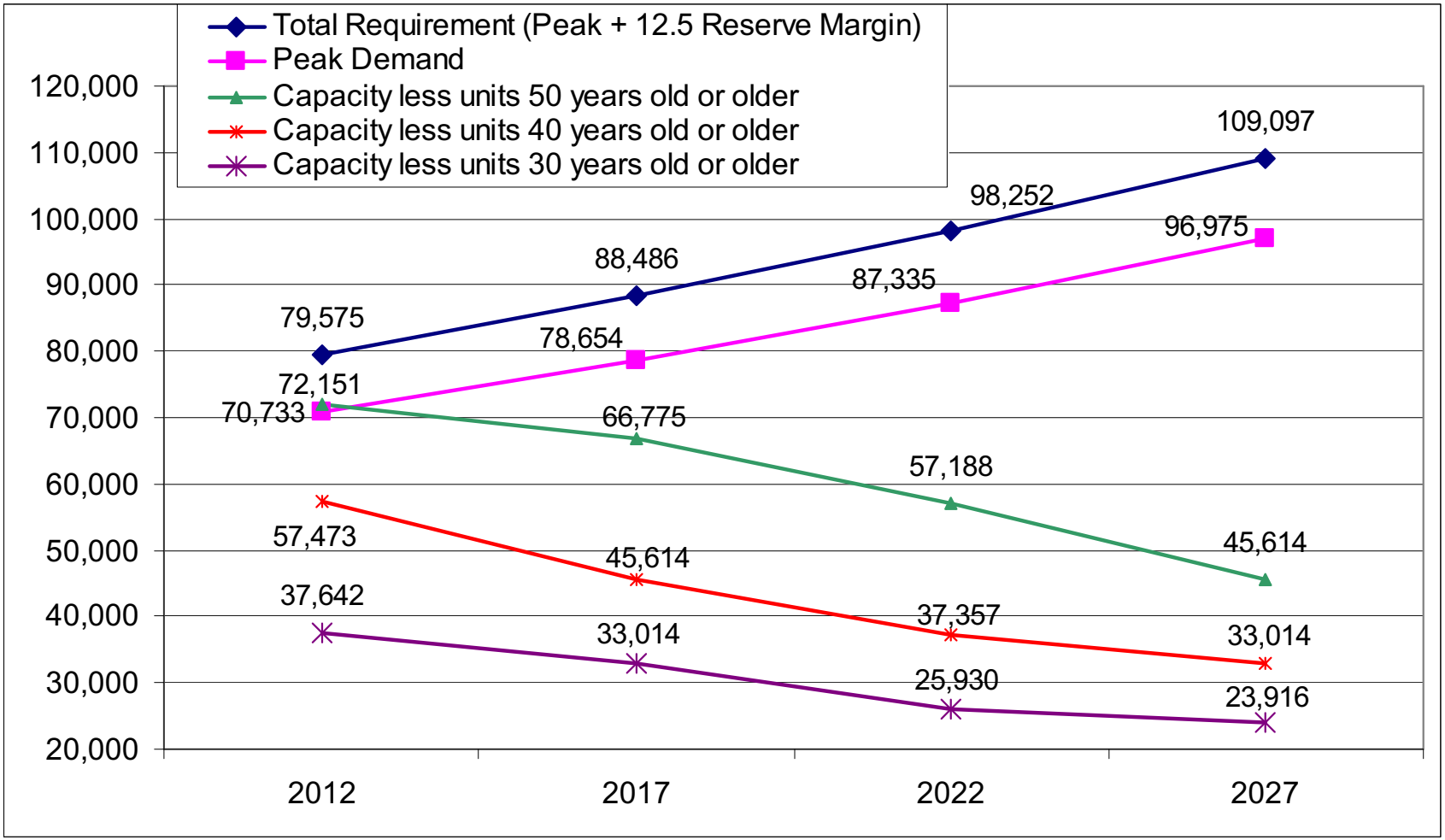
		Summer Capacity, MWe					
Unit Name	**Fuel**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Oak Grove 2	Coal	0	0	855	855	855	855
Gulf Wind 3	Wind	0	0	0	400	400	400
Mountain Creek	Natural Gas	0	0	0	700	700	700
Thockmorton Wind Farm	Wind	0	0	0	400	400	400
Twin Oaks 3	Coal	0	0	0	630	630	630
B&B Panhandle Wind	Wind	0	0	0	0	1001	1001
Fort Concho Wind Farm	Wind	0	0	0	0	400	400
Pampa Energy Center	Natural Gas	0	0	0	0	165	165
Sandy Creek 1	Coal	0	0	0	0	925	925

Table 8.3-3
Forecast Summer Capacity, Baseload Generation Units Only

	Summer Capacity, MWe					
	2008	**2009**	**2010**	**2011**	**2012**	**2013**
Resources, MW	72,416	73,308	76,201	75,996	76,885	76,885
Baseload Generation, MW	18,786	19,367	21,913	22,543	23,468	23,468
Percent of Resources that are Baseload Generation	25.9%	26.4%	28.8%	29.7%	30.5%	30.5%

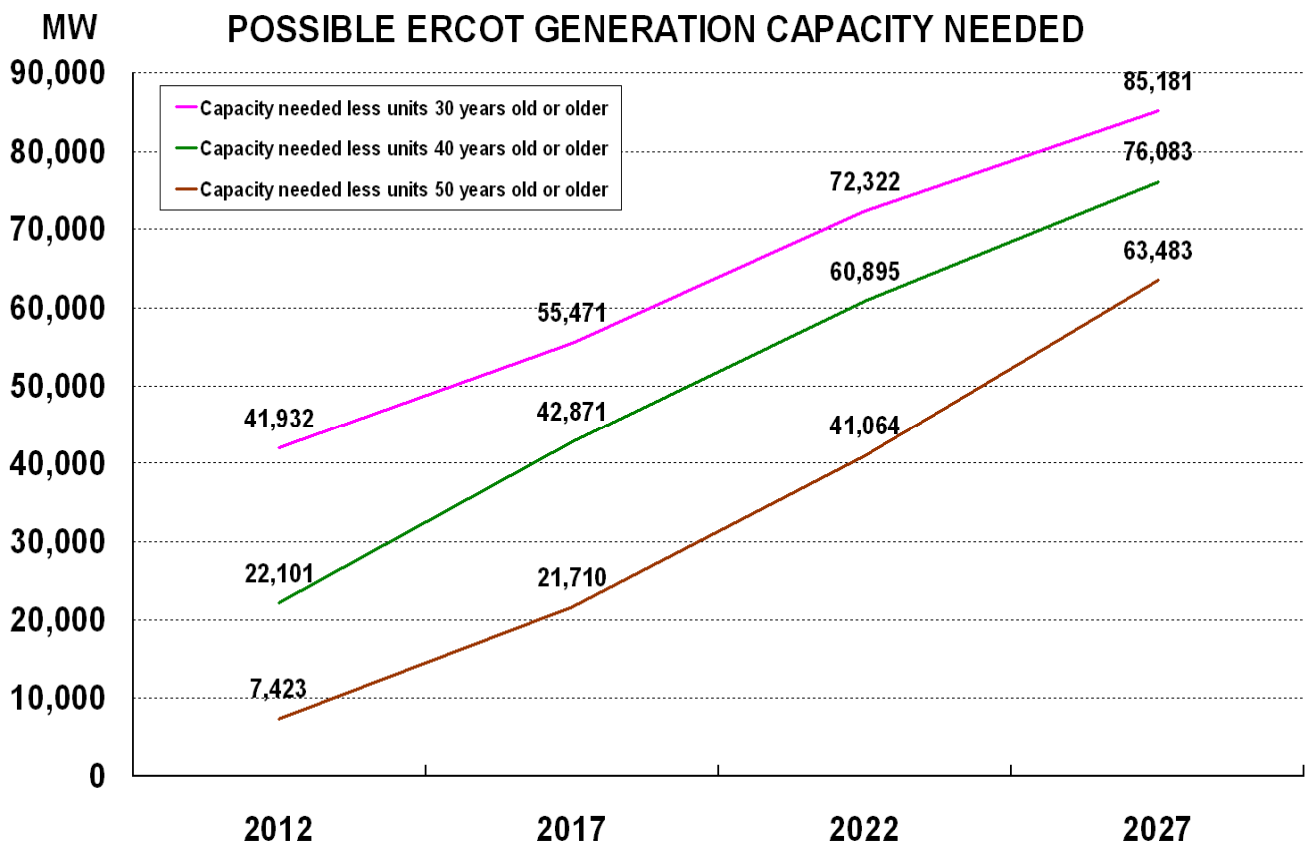
Table 8.3-4
Baseload Generation Units for Summer Capacity Forecast

	Summer Capacity, MWe					
Unit Name	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Big Brown 1	618	618	618	618	618	618
Big Brown 2	589	589	589	589	589	589
Coleto Creek 1	633	633	633	633	633	633
Comanche Peak 1	1159	1159	1159	1159	1159	1159
Comanche Peak 2	1159	1159	1159	1159	1159	1159
Fayette Power Project 1	604	604	604	604	604	604
Fayette Power Project 2	613	613	613	613	613	613
J K Spruce 1	560	560	560	560	560	560
Limestone 1	827	827	827	827	827	827
Limestone 2	849	849	849	849	849	849
Martin Lake 1	790	790	790	790	790	790
Martin Lake 2	809	809	809	809	809	809
Martin Lake 3	795	795	795	795	795	795
Monticello 1	558	558	558	558	558	558
Monticello 2	553	553	553	553	553	553
Monticello 3	770	770	770	770	770	770
Mountain Creek 8	571	571	571	571	571	571
Oklaunion 1	650	650	650	650	650	650
W A Parish 4	544	544	544	544	544	544
W A Parish 5	654	654	654	654	654	654
W A Parish 6	656	656	656	656	656	656
W A Parish 7	565	565	565	565	565	565
W A Parish 8	595	595	595	595	595	595
South Texas Project 1	1333	1333	1333	1333	1333	1333
South Texas Project 2	1332	1332	1332	1332	1332	1332
J K Spruce 2	0	0	750	750	750	750
Oak Grove 1	0	0	855	855	855	855
Oak Grove 2	0	0	855	855	855	855
Sandow 5	0	581	581	581	581	581
Sandy Creek 1	0	0	0	0	925	925
Twin Oaks 3	0	0	0	630	630	630
Comanche Peak 1&2 Uprate	0	0	86	86	86	86
	18,786	19,367	21,913	22,543	23,468	23,468



Source: ERCOT May 2007

Figure 8.3-1 ERCOT Generation Capacity Projections



Source: ERCOT May 2007

Figure 8.3-2 Possible ERCOT Generation Capacity Needed (MWe)

8.4 Assessment of Need for Power

8.4.1 ERCOT Reserve Margin Calculation Methodology

In determining the need for power, the Electric Reliability Council of Texas (ERCOT) considers the reserve margin needed to ensure reliable system operation and supply of power. The reserve margin helps ensure that there will be sufficient generating resources available to meet the load, while providing allowance for generating facilities that may be unavailable due to planned or forced outages. The reserve margin is the percent by which the generating capacity exceeds the peak demand and is defined as:

$$\frac{\text{Available Resources — Firm Load}}{\text{Firm Load}}$$

The current generation reserve margin requirement for the ERCOT region is 12.5%, as approved by the ERCOT Board in August 2002. The following is a brief summary of the methodology for the reserve margin calculation (ERCOT May 2005). The terms used in the discussion are defined below.

Firm Load equals Long-Term Forecast Model total summer peak demand

- Minus loads acting as resources (LaaRs) serving as responsive reserve.
- Minus LaaRs serving as non-spinning reserve.
- Minus balancing up loads (BULs).

Available resources equals installed capacity using the summer net dependable capability (SNDC) pursuant to ERCOT testing requirements (excluding wind generation).

- Plus capacity from private networks.
- Plus effective load-carrying capability (ELCC) of wind (i.e., 8.7% of name plate generation).
- Plus reliability must run (RMR) units under contract.
- Plus 50% of non-synchronous ties.
- Plus SNDC of available switchable capacity as reported by the owners.
- Plus available “mothballed” generation.
- Plus planned generation with a signed generation interconnection agreement and a Texas Commission on Environmental Quality air permit, if required.
- Plus ELCC of planned wind generation with a signed generation interconnection agreement.
- Minus retiring units.

LaaRs are capable of reducing or increasing the need for electrical energy or providing ancillary services such as responsive reserve service or non-spinning reserve service. LaaRs must be registered and qualified by ERCOT and are scheduled by a qualified scheduling entity (ERCOT Mar 2008).

Responsive reserve service is provided by operating reserves that ERCOT maintains to restore the frequency of the ERCOT system within the first few minutes of an event that causes a significant deviation from the standard frequency. These resources are online, capable of reducing or increasing consumption under dispatch control, and immediately respond proportionally to frequency changes. The amount of capacity from unloaded generation resources or direct current tie response is limited to the amount that can be deployed within 15 seconds.

Non-spinning reserve service is provided by LaaRs that can be interrupted within 30 minutes and that can run or be interrupted at a specified output level for at least 1 hour.

BULs are also capable of reducing the need for electrical energy when providing balancing up load energy service, but are not considered resources as defined by the ERCOT Protocols (ERCOT Mar 2008). Refer to Subsection 8.4.2.

SNDC is the maximum sustainable capability of a generation resource as demonstrated by a performance test lasting 168 hours (ERCOT May 2007b).

A private network is an electric network connected to the ERCOT transmission grid that contains loads that are not directly metered by ERCOT (i.e., loads that are typically netted with internal generation) (ERCOT May 2007b).

ERCOT selected Global Energy Decisions, Inc. (GED) to complete a new target reserve margin study to estimate wind generation capacity, which is measured by the effective load carrying capability (ELCC). This study was published in January 2007. GED used their unit commitment and dispatch software, MarketSym, to analyze the impact of load volatility, wind generation, unit maintenance, and unit forced outages on expected un-served energy, loss of load probability, and loss of load events. GED ran the model with the base set of generating units and a generic thermal generator (550 MW) and determined the expected un-served energy. GED removed the generic thermal generator and added new wind generation until the same expected un-served energy was achieved. It was found that 6300 MW of wind had the same load carrying capacity as 550 MW of thermal generation. Thus, the ELCC of wind is 8.7%(ERCOT Jan 2007b).

RMR service is provided under agreements for capacity and energy from resources that otherwise would not operate and that are necessary to provide voltage support, stability, or management of localized transmission constraints under first contingency criteria (ERCOT Mar 2008)

Switchable capacity is defined as a generating unit that can operate in either the ERCOT market or the Southwest Power Pool market, but not simultaneously. These switchable generating units are situated close to the transmission facilities of both ERCOT and the Southwest Power Pool market, which allows them to switch from one market to the other when it is economically appropriate.

Mothballed capacity includes generation resources for which generation entities have submitted a Notification of Suspension of Operations and for which ERCOT has declined to execute an RMR agreement. Available mothballed generation is the probability that a mothballed unit will return to

service provided by the owner multiplied by the capacity of the unit. Return probabilities are considered protected information under the ERCOT Protocols (ERCOT May 2007b).

Planned generation capacity is based on the interconnection study phase. A generation developer must go through a set procedure to connect new generation to the ERCOT grid. The first step is a high-level screening study to determine the effects on the transmission system of adding the new generation. The second step is the full interconnection study, which is a detailed study performed by transmission owners to determine the effects of the new generation (ERCOT May 2007b). A full interconnection study for the proposed VCS Units 1 and 2 was completed in May 2008; however, this study is being considered an interim at this point because an interconnection agreement has not yet been signed. Once the agreement has been signed and construction timelines are finalized, the study will be revised.

There is uncertainty associated with a number of the inputs to the ERCOT reserve margin calculation. The methodology considers these uncertainties to the extent possible in a formulaic approach, attempting to produce an equation to calculate an ERCOT reserve margin forecast that produces a reasonable estimate of such reserve margins while not being overly cumbersome or complex. It is not possible to create an equation that can capture all of the impacts of market prices on capacity reserves. However, ERCOT believes that the methodology represents an accurate calculation of reserve margin (ERCOT May 2005).

The reserve margins reported in the 2007 CDR (ERCOT May 2007a) and summarized in Table 8.3-2 were calculated using the methodology described above. As shown in Table 8.3-2 and Figure 8.3-1, through 2008 ERCOT's reserve margin remains above the 12.5% requirement set by the ERCOT Board of Directors. However, ERCOT predicts the reserve margin will fall below 12.5% in 2009.

ERCOT cannot order new capacity to be installed to keep the reserve margin from falling below the required 12.5%, but publication of the various ERCOT reports and continuous collaboration between ERCOT and the market participants ensure that they are aware of the demand and capacity situation. If the power generation companies do not voluntarily react to market economic forces and add generation capacity, the reserve margin is likely to fall below the required minimum in the very near future.

8.4.2 ERCOT Demand Side Working Group

The ERCOT Demand Side Working Group was created in 2001 as a task force by a directive of the PUCT and was converted to a permanent working group in 2002. A broad range of commercial and industrial consumers, transmission/distribution service providers, load serving entities, REPs, and power generation companies participate in the Demand Side Working Group meetings and initiatives. Their mission is to identify and promote opportunities for demand-side resources to participate in ERCOT markets and to recommend adoption of protocols and protocol revisions that foster optimum load participation in all markets. The current ERCOT market rules allow demand-side participation under three general classes of services: voluntary load response, qualified balancing upload, and load acting as a resource. (ERCOT Sep 2006)

Voluntary load response refers to a customer's independent decision to reduce consumption from its scheduled or anticipated level in response to a price signal. This applies to situations in which the customer has not formally offered this response to the market. The practice has also been known as "passive load response" and sometimes as "self-directed load response."

Voluntary loads gain financially from the ERCOT markets by reducing consumption when prices are high. However, a load's ability to receive extra financial compensation depends entirely on its contractual relationship with its REP and qualified scheduling entity (QSE). Any advanced metering, communication, or curtailment infrastructure required for load participation is a contractual matter between the load and its REP and does not involve ERCOT. The QSE and REP are reimbursed by ERCOT only for the energy imbalance (e.g., hourly mismatches between the scheduled delivery and the actual delivery of energy to a load located within a control area) and do not receive capacity payments. Because the load is not recognized by ERCOT as a resource, it is not subject to being curtailed involuntarily during emergency situations.

BULs refer to loads that contract with a QSE to submit offers formally to ERCOT to provide balancing energy (by reducing their energy use). BULs are paid only if they actually deploy (reduce energy use) in response to selection by ERCOT. If deployed, they receive two separate forms of compensation: a payment for actual load reduction based on prevailing market clearing price for energy and a capacity payment based on the market clearing price for capacity in the non-spinning reserves market. The latter is an additional reward to the BULs for submitting bids into the balancing energy market, even though they are not actually providing non-spinning reserves. Payments are made to a BUL's QSE, who may pass the value on to its REP, who may, in turn, pass the value along to the BUL.

Many variations in REP products are available and the load customer has choices on how it may receive value for its interruptible load. Customers with interruptible loads that can meet certain performance requirements may be qualified to provide operating reserves under the LaaR program.

In eligible ancillary services markets, the value of the LaaR load reduction is equal to that of an increase in generation by a generating plant. In addition, any provider of operating reserves selected through an ERCOT ancillary services market is eligible for a capacity payment, regardless of whether the demand-side resource is actually curtailed. To participate in the ERCOT market as a LaaR, a customer must register each individual LaaR asset and also register with ERCOT as a resource entity (ERCOT 2008).

As described above, the reserve margin calculation methodology subtracts the LaaRs and BULs from the load forecast, which reduced the load forecast for 2007–2012 by 1125 MW per year.

8.4.3 Comparison of ERCOT Studies with NRC Criteria

Exelon is relying on the ERCOT need for power evaluation to demonstrate the benefit associated with the proposed VCS Units 1 and 2.

Sections 8.0 through 8.4 describe several ERCOT studies and reports on which Exelon has relied for the need for power evaluation. The tables and figures in these sections have been taken from, or been generated from, the ERCOT studies and reports. The NRC has indicated that an independent evaluation of the need for power may not be needed if it determines that the state- or region-prepared evaluation is (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. Each of these criteria is addressed below with respect to the collective ERCOT reports.

Systematic — ERCOT is required by the PUCT to provide extensive studies, issue reports, make recommendations for transmission system needs and resource adequacy, and even make legislative recommendations to further those objectives. Analysis is pursued in the context of the competitive ERCOT market using load growth scenarios, industrial growth projections, regional transmission topology, subregional modeling, and new generation characteristics. The development of these reports is subject to a rigorous stakeholder input process that includes ERCOT and market participants. The output of the Long-Term Forecast Model (ERCOT May 2007b) is used as input to the CDR (ERCOT May 2007b). There is an orderly and efficient progression of data and calculation results.

Comprehensive — ERCOT's planning responsibilities are broad. For example, the Long-Term System Assessment (ERCOT Dec 2006) uses projections and variations in scenarios such as fuel prices, load growth, and environmental regulations. The study looks forward 10 years and includes high-, low-, and base-case assumptions for a variety of factors. The CDR accounts for each resource in the ERCOT region and accurately designates its status.

Subject to Confirmation — The analyses and reports benefit from extensive stakeholder input and stakeholder scrutiny in the ERCOT stakeholder process, as well as review by the PUCT, which has the ultimate responsibility for market oversight in ERCOT. Both the Long-Term Peak Demand Study and the CDR look at historical information, as a check on past forecasting performance. From 1999 to 2006, the ERCOT peak demand and energy consumption forecasts have been within ±5% of the actual demand and consumption. (ERCOT Jan 2007a)

Responsive to Forecasting Uncertainty – The Long-Term Forecasting Model resolves one measure of the uncertainty associated with extreme weather impacts on peak demands by using a more extreme weather profile to obtain the forecasts. It then uses a 90th and 10th percentile "confidence band" to bound contingencies. From 1999 to 2006, the ERCOT peak demand and energy consumption forecasts have been within ±5% of the actual demand and consumption. Also, the reserve margin calculation methodology has been revised several times since 2005 to reduce the uncertainties associated with the inputs to the calculation.

The need for power studies performed by ERCOT satisfy the four NRC criteria and obviate any need for further Exelon or NRC independent evaluation.

8.4.4 Conclusions

ERCOT has concluded that a significant amount of new generation will be needed to meet the demand projected for 2016 and to maintain the 12.5% reserve margin needed for system reliability, regardless of which load scenario is under consideration (ERCOT Dec 2006).

Figure 8.3-1 provides the ERCOT generation capacity and demand projections for 2012–2027, which demonstrates a steady divergence between demand and capacity for the period. Figure 8.3-2 provides the potential ERCOT generation capacity needed from 2012–2027. Baseload generation capacity currently provides approximately 25.9% of the peak demand and is forecasted to provide approximately 30.5% by 2013, as shown in Table 8.3-3.

The ERCOT studies did not include the generation capacity that would be provided by the proposed VCS project. It is anticipated that 1535 MWe (net) from VCS Unit 1 would be available in December 2015 and 1535 MWe (net) from VCS Unit 2 would be available in June 2017. At that time, the need for new capacity in Texas is predicted to be between 21,710 to 55,471 MWe as shown in Figure 8.3-2. Thus, the need for new capacity in ERCOT in 2016–2017 is substantially greater than the new capacity to be provided by VCS. As a result, not only will there be a need for power from VCS, there will be a need for a substantial amount of other new generating capacity.

In this regard, a number of companies have announced their intentions to build new generating capacity in the ERCOT region, including new nuclear plants at South Texas Project and Comanche Peak.

Additionally, other companies have announced their intentions to construct other types of generation capacity, including fossil-fueled facilities. However, only 550 MW of new gas-fired generation capacity (in 2008), 750 MW of coal-fired generation capacity (in 2011), and 800 MW of coal-fired generation capacity (in 2012) were included in the 2007 CDR resources forecast. None of the announced nuclear capacity is included in the resources forecast.

In summary, the ERCOT studies have forecast a shrinking reserve margin that ceases to satisfy ERCOT system reliability goals by 2009. By the time both the proposed VCS units are projected to enter commercial operation in 2015–2017, there will be a substantial need for power not only from VCS, but from other new generating plants as well.

8.4.5 References

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