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8.0 Need for Power

The electric utility industry in the State of Texas was deregulated in 2002. One of the principal owners of STP 3 & 4 is a merchant generator that does not have a specific service area and the other owner sells excess capacity in the Electric Reliability Council of Texas (ERCOT) wholesale market. Therefore, STP Nuclear Operating Company (STPNOC) has defined the region of interest for evaluating the need for power and alternative sites (Section 9.3) as the entire area served by ERCOT, which is the independent system operator for the electric grid for most of Texas. STPNOC is relying upon several studies performed for or by ERCOT for its need for power evaluation.

This chapter provides an evaluation of the need for power. According to NUREG-1555, an NRC independent evaluation may not be needed if the NRC determines that the State/region-prepared evaluation is (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. As discussed in more detail below, the ERCOT studies related to need for power satisfy these four criteria and provide an appropriate basis for the need for power evaluation for STP 3 & 4.

The following ERCOT studies were used for this evaluation:

- The Report on Existing and Potential Electric System Constraints and Needs (Reference 8.0-1) 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 (LTFM) is used in the Long-Term Hourly Peak Demand and Energy Forecast (Reference 8.0-2) to predict the peak hourly power demand and energy consumption for each of the next ten 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 (Reference 8.0-3) 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. Department of Energy 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 is the basis for Sections 8.3 and 8.4.
- The last report is the ERCOT Long Term System Assessment (Reference 8.0-4), 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.

Subsection 8.4.2 demonstrates that these reports satisfy the criteria in NUREG-1555 for a reliable independent evaluation of the need for power.

As described in Section 8.1, the owners of STP 3 & 4 are NINA and CPS Energy, who are both market participants in the ERCOT system. As such, they recognize ERCOT's legal responsibilities under Public Utility Commission of Texas (PUCT) oversight, and support ERCOT in achieving its vision and mission through the open and collaborative process involving electric industry members, customers, and regulators. NINA and CPS Energy endorse the ERCOT studies that were prepared to inform the PUCT, the Texas Legislature, the public, and the market participants. They accept the assumptions made in the studies and believe that ERCOT is providing valuable and accurate assessments of the ERCOT system for the benefit of all ERCOT members. One of the benefits of deregulation was to consolidate regional planning under a single entity with the expertise and resources necessary to accurately and efficiently ensure that the entire region was proceeding on a course that benefits everyone.

The remainder of this chapter provides the following information:

- A description of the project owners (Section 8.1)
- A description of the PUCT and ERCOT (Section 8.1)
- A discussion of the deregulation of electric generation in the State of Texas and associated market forces (Section 8.1)
- A description of the ERCOT studies and a discussion of the forecast for demand for power provided in those studies (including reserve margins specified by ERCOT) (Section 8.2)
- A discussion of the generation capacity in the ERCOT region (Section 8.3)
- Conclusions related to the need for power from STP 3&4 (Section 8.4)

8.0.1 References

8.0-1 ERCOT Report on Existing and Potential Electric System Constraints and Needs, December 2006, available at http://www.ercot.com/news/presentations/2006/2006_ERCOT_Reports_Transmission_Constraints_and_Needs.pdf.

8.0-2 2007 ERCOT Planning Long-Term Hourly Peak Demand and Energy Forecast – May 8, 2007, available at http://www.ercot.com/news/presentations/2007/2007_ERCOT_Planning_Long_Term_Hourly_Demand_Energy_Forecast_.pdf.

8.0-3 Report on the Capacity, Demand, and Reserves in the ERCOT Region, May 2007, available at http://www.ercot.com/news/presentations/2007/07CDR05172007-final.xls.

8.0-4 Long Term System Assessment for the ERCOT Region, December 2006, available at http://www.ercot.com/news/presentations/2006/Attch_A_-_Long_Term_System_Assessment_ERCOT_Region_December_.pdf.

8.1 Description of Power System

8.1.1 Project Description and Owners

South Texas Project Unit 3 will be owned by NINA Texas 3 LLC and the City of San Antonio, Texas, acting by and through the City Public Service Board (CPS or CPS Energy). South Texas Project Unit 4 will be owned by NINA Texas 4 LLC and CPS Energy. Once licensed and built, STP 3 & 4 will be operated by STP Nuclear Operating Company. STP 3 & 4 each utilizes the GE Advanced Boiling Water Reactor (ABWR) light water reactor design rated at approximately 1370 MWe (gross). Initial commercial operation for STP 3 & 4 is expected to be June 2015 and July 2016, respectively.

NINA Texas 3 LLC and NINA Texas 4 LLC are indirectly majority-owned and controlled by NRG Energy, Inc. (NRG Energy). In this discussion, "NRG" is used when referring to NRG Energy, the parent, or to one of the NINA Texas LLCs. Further detail regarding the ownership of the NRG LLCs is provided in Part 1 of the COLA. NRG is a wholesale power generation company, primarily engaged in the ownership and operation of power generation facilities and the sale of energy, capacity and related products in the United States and internationally. NRG has a diverse portfolio of electric generation facilities in terms of geography, fuel type, and dispatch levels. NRG does not meet the definition of an electric utility in 10 CFR 50.2. NRG is a merchant generator that will sell its share of the electricity generated at STP 3 & 4 to the wholesale market in bilateral transactions with wholesale purchasers of electric power and at market prices. As such, NRG does not have a specific service area in the traditional sense of pre-deregulation utilities. The area of Texas that is served by the Electric Reliability Council of Texas (ERCOT) is the area in which NRG intends to sell its power.

As a municipal utility, CPS Energy meets the definition of an electric utility in 10 CFR 50.2, that provides retail power to its service area around San Antonio, which is within the ERCOT region, and sells excess capacity to wholesale buyers anywhere within the ERCOT system. The CPS Energy electric system serves a territory consisting of substantially all of Bexar County and small portions of the adjacent counties. Certification of this service area has been approved by the Public Utility Commission of Texas (PUCT). CPS Energy is currently the exclusive provider of electric service within this service area. Until and unless the San Antonio City Council and the CPS Energy Board exercise the option to opt-in to retail electric competition, CPS Energy has the sole right to provide retail electric services in its service area (Reference 8.1-1). The ERCOT studies being relied upon for the need for power evaluation include the CPS Energy electric system.

In addition to the area served at retail rates, CPS Energy currently has wholesale supply agreements to sell wholesale electricity to the Floresville Electric Light & Power System, the City of Hondo, and the City of Castroville. These three wholesale supply agreements have remaining terms ranging from less than one to ten years, although all of the agreements provide for extensions. Discussions are ongoing with all three entities to renew their respective long-term wholesale power agreements. Additionally, CPS Energy has recently entered into several one-year wholesale supply agreements with various other municipalities and cooperatives. CPS Energy will seek additional opportunities to enter into long-term wholesale electric power agreements in the future.

The requirements under the existing and any new wholesale agreements would be firm energy obligations of CPS Energy (Reference 8.1-1). In any event, because the need for power evaluation for STP 3 & 4 is based on the need for power in the entire ERCOT region, these supply agreements are not material to the need for power from STP 3 & 4 or the need for CPS Energy to develop additional generation to meet the needs of the growing customer base within its certificated service area.

8.1.2 Public Utility Commission and Electric Reliability Council of Texas

In 1975, Texas became the last state in the country to provide for state-wide 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's mission and focus (Reference 8.1-2).

Although the PUCT's traditional regulatory functions have decreased since 1999, many of those functions have been replaced by other, more challenging responsibilities. Restructuring of the utility industry is not simply elimination of regulation. Effective oversight of competitive wholesale and retail markets is necessary to ensure that customers receive the benefits of competition. The PUCT's responsibilities under the Public Utilities Regulatory Act (PURA) include the following (Reference 8.1-2):

- Issuance of certificates of convenience and necessity for proposed transmission lines
- Licensing of retail electric providers
- Registration of power generation companies and aggregators
- Oversight of competitive wholesale and retail markets
- Resolution of customer complaints, using informal processes whenever possible
- Implementation of a customer education program for retail electric choice
- Regulation of vertically integrated investor owned utilities outside ERCOT
- Jurisdiction over ratemaking and quality of service of transmission 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 501(c)(6) nonprofit corporation governed by a board of directors and subject to oversight by the PUCT and the Texas Legislature. ERCOT's members include retail consumers, investor- and municipally-owned utilities, rural electric cooperatives, river authorities, independent generators, power marketers, and retail electric providers (Reference 8.1-3). 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 ERCOT's officers to direct and manage ERCOT's day-to-day operations, accompanied by a team of executives and managers responsible for critical components of ERCOT's operations areas (Reference 8.1-4).

ERCOT manages the flow of electric power to approximately 20 million Texas customers, representing 85% of the state's electric load and 75% of the state's land area (approximately 200,000 square miles). Figure 8.1-1 depicts the ERCOT region. As the independent system operator (ISO) for the region, ERCOT schedules power on an electric grid that connects 38,000 miles of high-voltage transmission lines and more than 500 generation 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 (Reference 8.1-3).

ERCOT performs three main roles in managing the electric power grid and marketplace (Reference 8.1-5):

- Monitor 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.
- Ensure 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.
- Serve 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 (TIS) 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 TIS members continued to use and develop the interconnected grid. TIS 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. TIS formed ERCOT in 1970 to comply with North American Reliability Council (NERC) requirements (Reference 8.1-6). The goal of TIS, and later ERCOT, was not to create ties with the rest of the country, but to assure that the Texas grid was reliable through interconnection. Even today, there are only a few asynchronous ties that go outside of the ERCOT region with a total capacity of approximately 1100 MW. There are also approximately 2,850 MW of "switchable" generation resources that can be connected to either the ERCOT transmission grid or a grid outside the ERCOT region. There is currently no indication of plans to increase either the asynchronous MW or the switchable resources (Reference 8.1-7). 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.

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 (TAC), and other ERCOT subcommittees authorized by the Board or the TAC, 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 (Reference 8.1-8).

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 the ERCOT ISO. 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 [*See e. g.*, Tex. Util. Code Ann. §§ 39.155(b) and 39.904(k)].

8.1.3 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 STP 3 & 4 because the electrical utility industry in Texas has been deregulated.

In 1995, the Texas Legislature passed Senate Bill 373 (SB 373) introducing wholesale competition into Texas' intrastate markets. Under what is now Chapter 35 of the PURA, prior bilateral transactions addressing use of the interconnected transmission systems of vertically integrated utilities within ERCOT were replaced by PUCT-regulated open access requirements and a methodology for placement of new merchant generation. SB 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 (Reference 8.1-1). 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, that could be owned by a common holding company, but which must operate largely independent 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 non-discriminatory basis (Reference 8.1-1).

IOUs and independent power producers owning generation assets must be registered as Power Generation Companies (PGCs) 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 (Reference 8.1-1).

IOU owners of transmission and/or distribution facilities, or Transmission Service Providers (TSPs), are fully regulated by the PUCT. IOU TSPs, 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. TSPs are required to provide access to both their transmission and distribution systems on a non-discriminatory basis to all eligible customers (Reference 8.1-1).

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 PGCs, 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 (Reference 8.1-1).

8.1.4 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 8.1-2 and 8.1-3 demonstrate the market economic forces at work. Since 1999, ERCOT market participants have made the economic decision to decommission 95 units with a total generation capacity of 3,536 MW (Figure 8.1-2). 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 205 new units and to upgrade 2 units for a total generation capacity of 25,372 MW (Figure 8.1-3). These decisions were based on the same economic parameters that led to decommissioning the 95 older units. Figures 8.1-2 and 8.1-3 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 they were not replaced by new units.

By law, ERCOT must perform extensive annual and semi-annual studies, issue reports, make recommendations for transmission system needs and resource adequacy, and make legislative recommendations to further those objectives [See 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, sub-regional 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.

8.1.5 References

8.1-1 Official Statement, City of San Antonio, Texas Electric and Gas Systems Revenue Funding Bonds, New Series 206B, dated January 10, 2007, available at http://www.cpsenergy.com/files/financial_data/Bonds_New_Series_2006B_OS.pdf, accessed on July 11, 2007

8.1-2 “Public Utility Commission of Texas Agency Strategic Plan For the Fiscal Years 2007-2011 Period,” available at http://www.puc.state.tx.us/about/stratplan/stratplan.pdf, accessed on July 11, 2007.

8.1-3 “ERCOT Company Profile,” available at http://www.ercot.com/about/profile/index.html, accessed on June 30, 2007.

8.1-4 “ERCOT Governance,” available at http://www.ercot.com/about/governance/index.html, accessed on June 30, 2007.

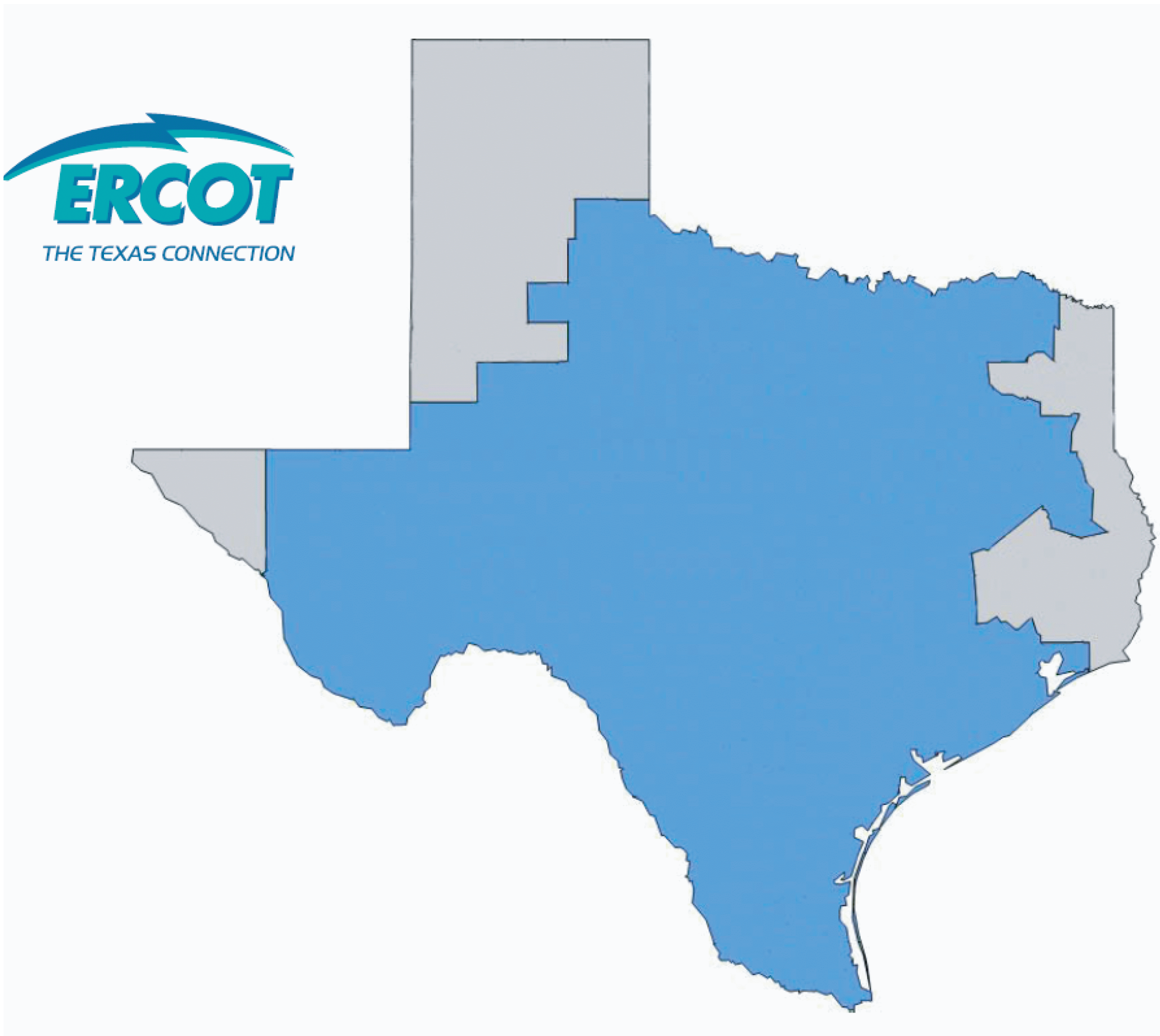
8.1-5 “ERCOT’s Role,” available at http://www.ercot.com/about/ercotrole.html, accessed on June 30, 2007.

8.1-6 “ERCOT History,” available at http://www.ercot.com/about/profile/history/index.html, accessed on June 30, 2007.

8.1-7 Report on the Capacity, Demand, and Reserves in the ERCOT Region, May 2007, available at http://www.ercot.com/news/presentations/2007/07CDR05172007-final.xls.

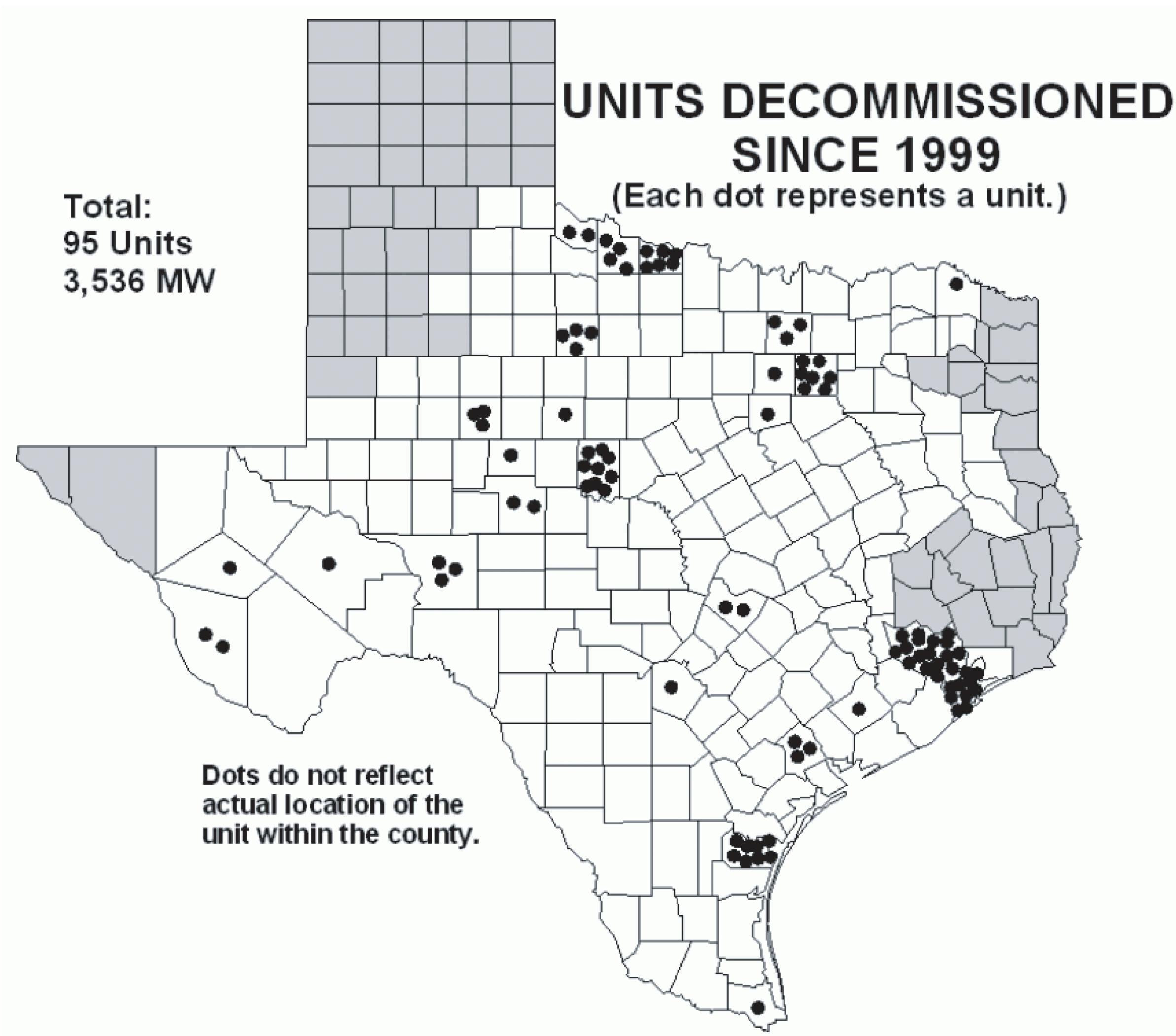
8.1-8 “ERCOT Protocols, Section 1: Overview,” available at http://www.ercot.com/mktrules/protocols/current/01-050107.doc, accessed on July 10, 2007.

8.1-9 ERCOT Report on Existing and Potential Electric System Constraints and Needs, December 2006, available at http://www.ercot.com/news/presentations/2006/2006_ERCOT_Reports_Transmission_Constraints_and_Needs.pdf.



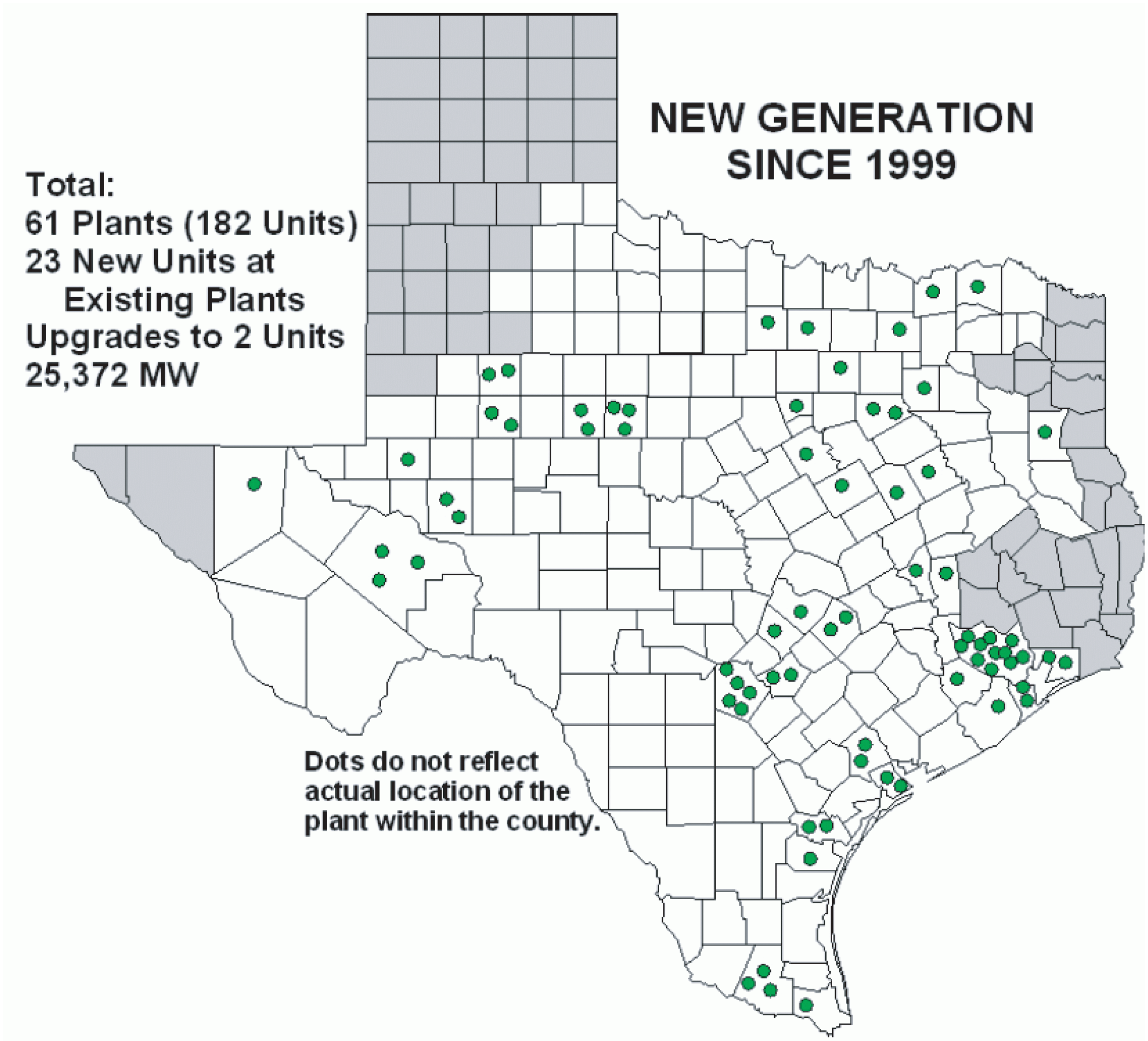
Reference 8.1-9

Figure 8.1-1 ERCOT Region



Reference 8.1-9

Figure 8.1-2 Units Decommissioned Since 1999



Reference 8.1-9

Figure 8.1-3 New ERCOT Generation Since 1999

8.2 Power Demand

This section provides a high-level overview of the 2007 ERCOT Long-Term Demand and Energy Forecast (Reference 8.2-1) and all of the tables, figures, and data are taken from the Forecast. The methodology is briefly described, highlighting the major aspects involved in producing the forecast, including the data input used in the process. An historical perspective of the load growth in the ERCOT region is provided, and final results of the forecast peak demands and energy consumption are presented in a graphical form and summarized in table. A discussion of the major drivers of peak demands and energy consumption is included, along with the uncertainties associated with the forecast, and the differences from last year's forecast. A more detailed explanation of the econometric forecasting methodology used by ERCOT is described in Appendix 3 of Reference 8.2-1.

8.2.1 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

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 (Reference 8.2-2):

- 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

The econometric forecasting basics center 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 describing historical patterns (Reference 8.2-2). The forecasting process is shown in Figure 8.2-5. Refer to Appendix 3 of Reference 8.2-1 for a detailed description of the model and methodology.

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

Weather

Weather drives most of the variation in electric demand in the short-run. 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 were 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 data 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 is forecast 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 nineteen 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. Strictly speaking these are not confidence bands in the statistical sense, but this term has commonly been used to refer to the results. A more appropriate term would be to use 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 provided 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 the 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 U.S. as a whole. Three of its major metropolitan areas, Houston, Dallas, and Austin, which are among the top 50 in the U.S., are leading the South. Employment growth in Texas shows a stronger performance for the Dallas-Fort Worth area and the Austin-San Antonio 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, non-farm employment, and total employed. These are presented in Figures 8.2-6 through 8.2-10. As discussed in Subsection 8.4.1, 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 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 twelve years. This extreme forecast is referred to in the figure 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 twelve 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 a stable and 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 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 as 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 an improvement in comfort, which in many cases directly translates into increases in electricity consumption.

The energy consumption forecast scenarios show a rather 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 8.2-13 shows the difference between the two forecasts of peak demand for the period of 2007-2015.

Accuracy of the Long-Term Forecast

A comparison of the historical actual and forecast peak demand (Figure 8.2-14) and a comparison of the historical actual and forecast energy consumption (Figure 8.2-15) show that since 1999 ERCOT long-term forecasts have been within ± 5% of the actuals. Since 2003 the accuracy of the energy consumption forecast has been very close to ± 1% (Reference 8.2-2).

8.2.4 References

8.2-1 “2007 ERCOT Planning Long-Term Hourly Peak Demand and Energy Forecast - May 8, 2007” available at http://www.ercot.com/news/presentations/2007/2007_ERCOT_Planning_Long_Term_Hourly_Demand_Energy_Forecast_.pdf, accessed on July 13, 2007.

8.2-2 “Long Term Demand and Energy Forecasting – Planning,” available at www.ercot.com/meetings/other/keywords/2007/0124-LoadForecast/KDonohoo_ERCOTLongTermDemandEnergForecastingPlanning01242007.ppt, accessed on June 2, 2007.

Table 8.2-1 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	1,986	6.97%	53,691	3,326	6.60%	270	16	6.30%
1999	30,336	-139	0.46%	54,980	1,289	2.40%	269	-1	-0.37%
2000	32,488	2,152	7.09%	57,981	3,001	5.46%	289	20	7.43%
2001	31,623	-865	-2.66%	55,214	-2,767	-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	3,951	7.04%	285	4	1.42%
2004	32,917	384	1.18%	58,506	-1,531	-2.55%	289	4	1.40%
2005	34,161	1,244	3.78%	60,214	1,708	2.92%	299	10	3.46%
2006	34,899	738	2.16%	62,339	2,125	3.53%	306	7	2.34%

Compiled from Reference 8.2-1

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	1,904	20,527	2,175	1,830	1,595	9,492	14,578	3,985	56,086
2003	2,070	22,303	2,319	1,805	1,675	10,016	15,823	4,025	60,037
2004	2,047	20,749	2,265	1,658	1,562	9,619	16,611	3,996	58,506
2005	2,080	21,975	2,351	1,661	1,542	10,162	16,282	4,159	60,214
2006	2,361	22,687	2,432	1,598	1,612	10,718	16,739	4,191	62,339
Forecast									
2007	2,086	23,782	2,251	1,412	1,638	11,329	17,174	4,123	63,794
2008	2,117	24,059	2,363	1,415	1,683	11,708	17,631	4,158	65,135
2009	2,145	24,472	2,323	1,429	1,725	12,075	18,112	4,227	66,508
2010	2,183	24,914	2,353	1,435	1,770	12,475	18,554	4,271	67,955
2011	2,229	25,365	2,382	1,441	1,820	12,901	19,002	4,317	69,456
2012	2,263	25,743	2,402	1,442	1,863	13,292	19,377	4,351	70,733
2013	2,325	26,267	2,517	1,448	1,914	13,725	19,794	4,405	72,394
2014	2,377	26,788	2,462	1,509	1,964	14,111	20,312	4,474	73,998
2015	2,447	27,360	2,484	1,461	2,022	14,570	20,727	4,525	75,596

Compiled from Reference 8.2-1

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

Compiled from Reference 8.2-1

Table 8.2-4 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	1,455	2.33%	313	7	2.29%
2008	36,395	661	1.85%	65,135	1,341	2.10%	320	7	2.24%
2009	37,147	752	2.07%	66,508	1,373	2.11%	325	5	1.56%
2010	37,966	819	2.20%	67,955	1,447	2.18%	333	8	2.46%
2011	38,823	857	2.26%	69,456	1,501	2.21%	340	7	2.10%
2012	39,513	690	1.78%	70,733	1,277	1.84%	347	7	2.06%
2013	40,425	912	2.31%	72,394	1,661	2.35%	354	7	2.02%
2014	41,237	812	2.01%	73,998	1,604	2.22%	361	7	1.98%
2015	42,159	922	2.24%	75,596	1,598	2.16%	369	8	2.22%
2016	42,957	798	1.89%	77,024	1,428	1.89%	377	8	2.17%
2017	43,905	948	2.21%	78,694	1,670	2.17%	385	8	2.12%

Compiled from Reference 8.2-1

Figure 8.2-1 Historical Average Load and System Peak Load

Compiled from Reference 8.2-1

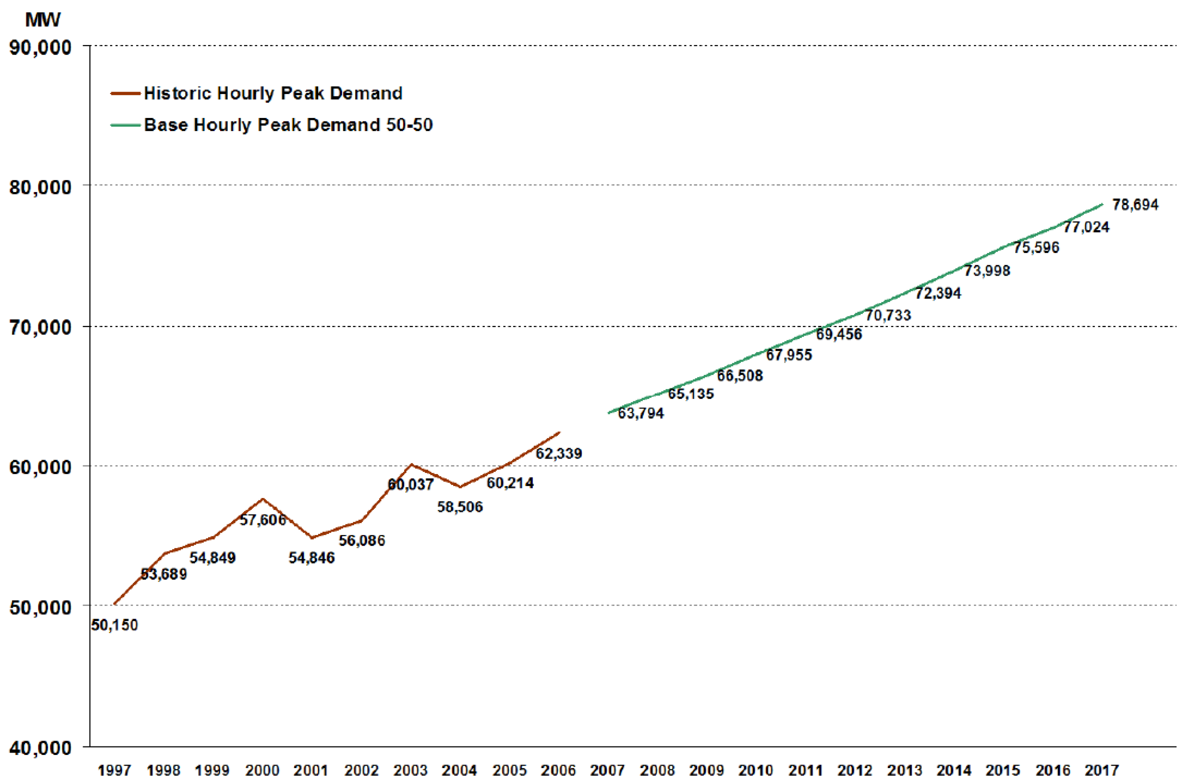
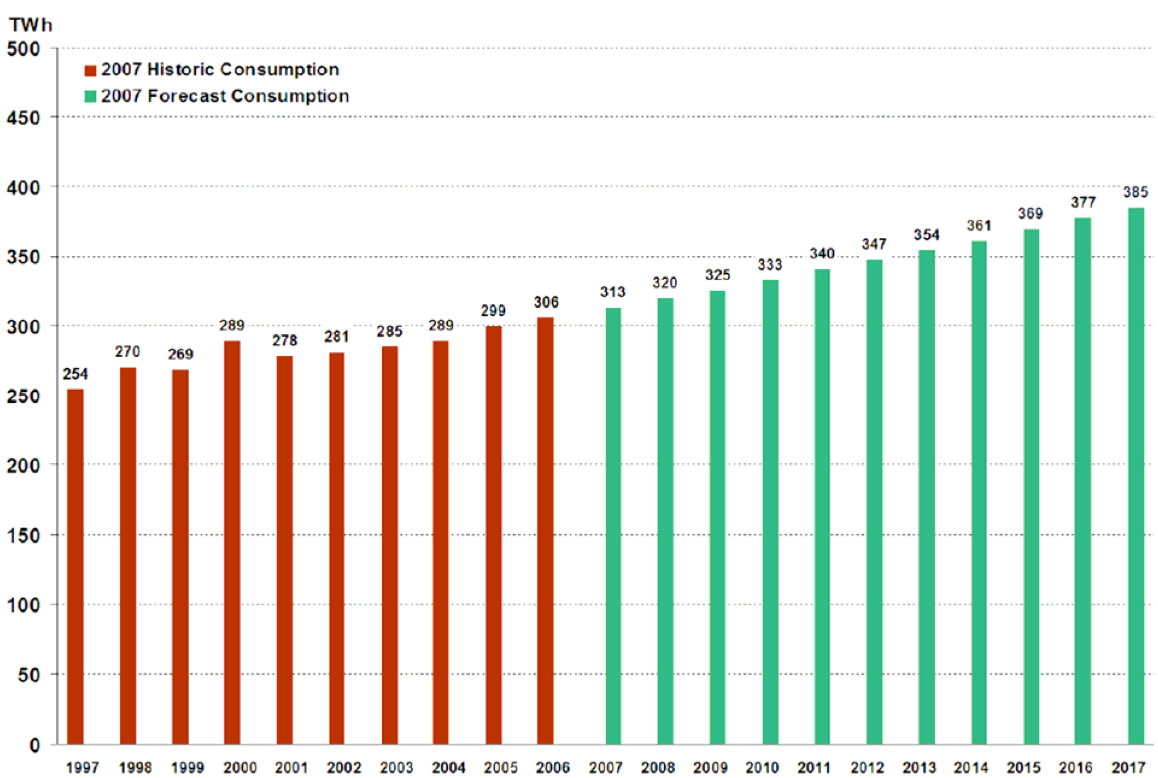


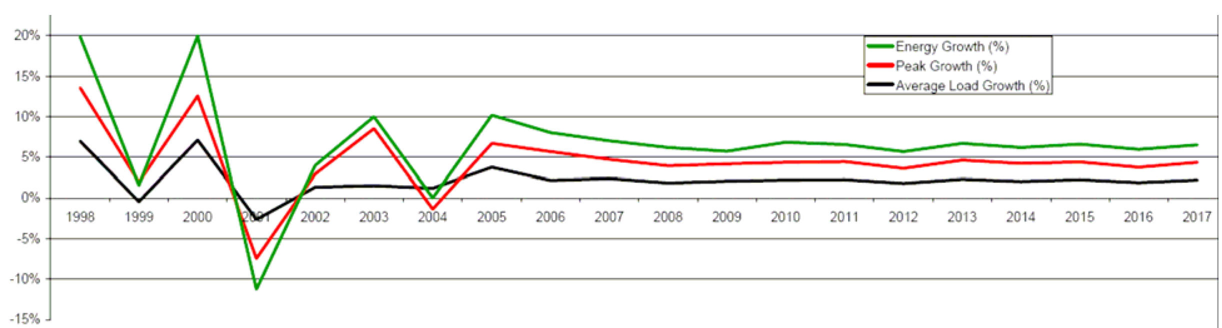
Figure 8.2-2 Historical and Forecast Hourly Peak Demands

Reference 8.2-1



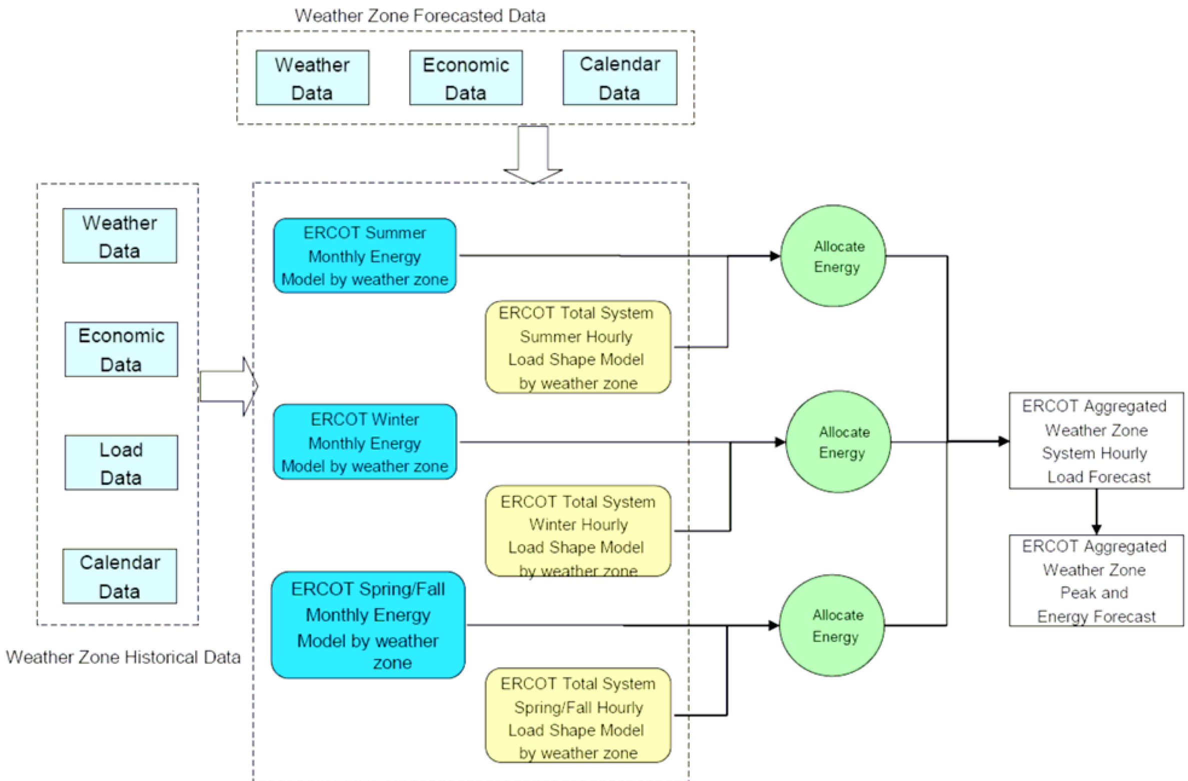
Reference 8.2-1

Figure 8.2-3 Historical and Forecast Energy Consumption



Compiled from Reference 8.2-1

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



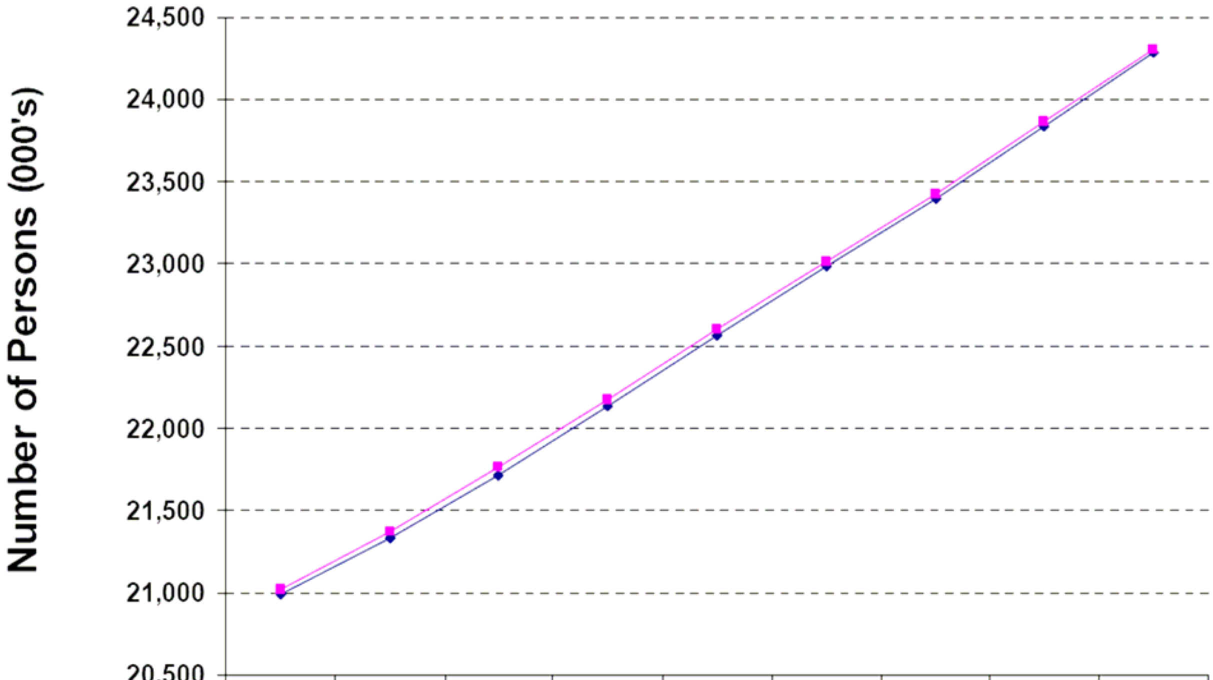
Reference 8.2-1

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

Reference 8.2-1

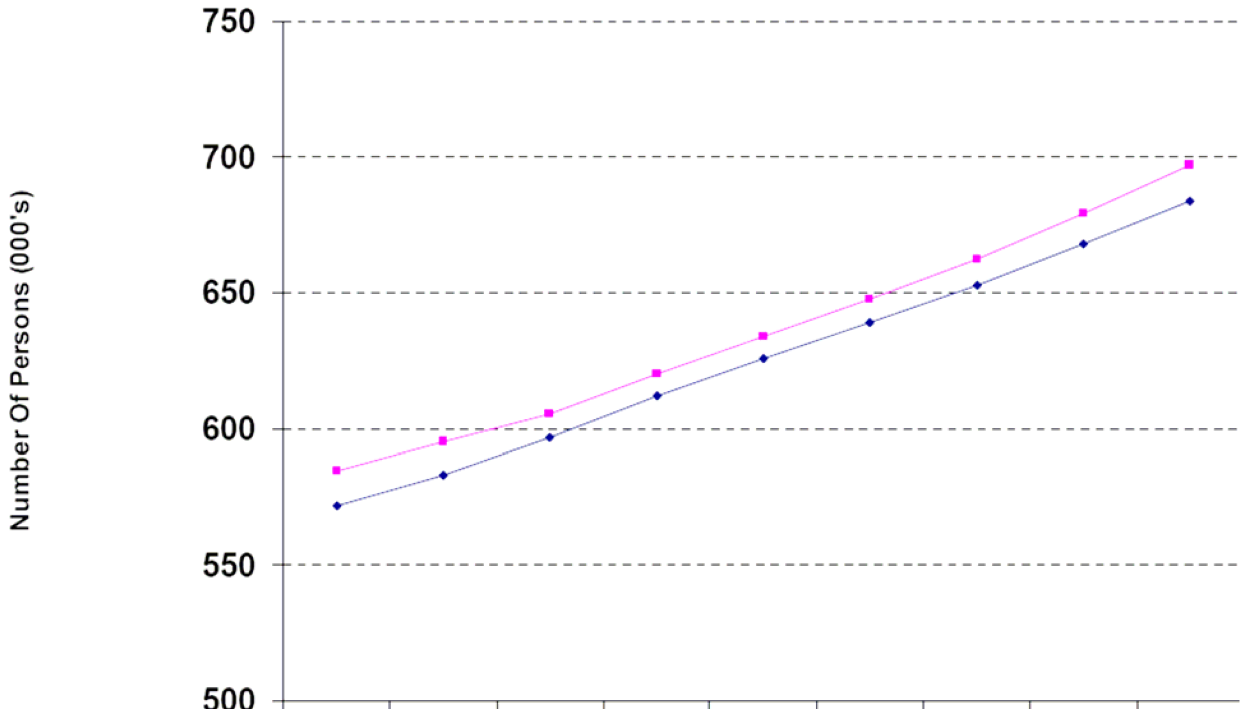
Figure 8.2-6 Real Personal Per-Capita Income



	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

Reference 8.2-1

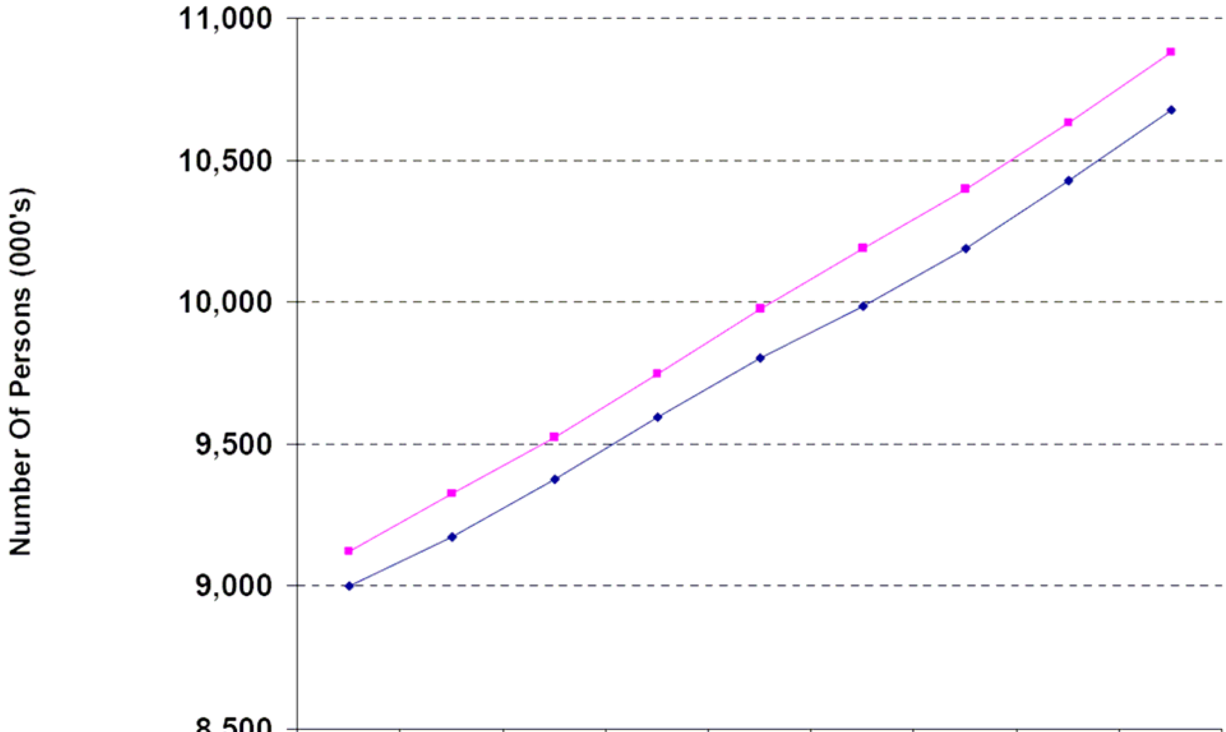
Figure 8.2-7 Population in the ERCOT Region



	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

Reference 8.2-1

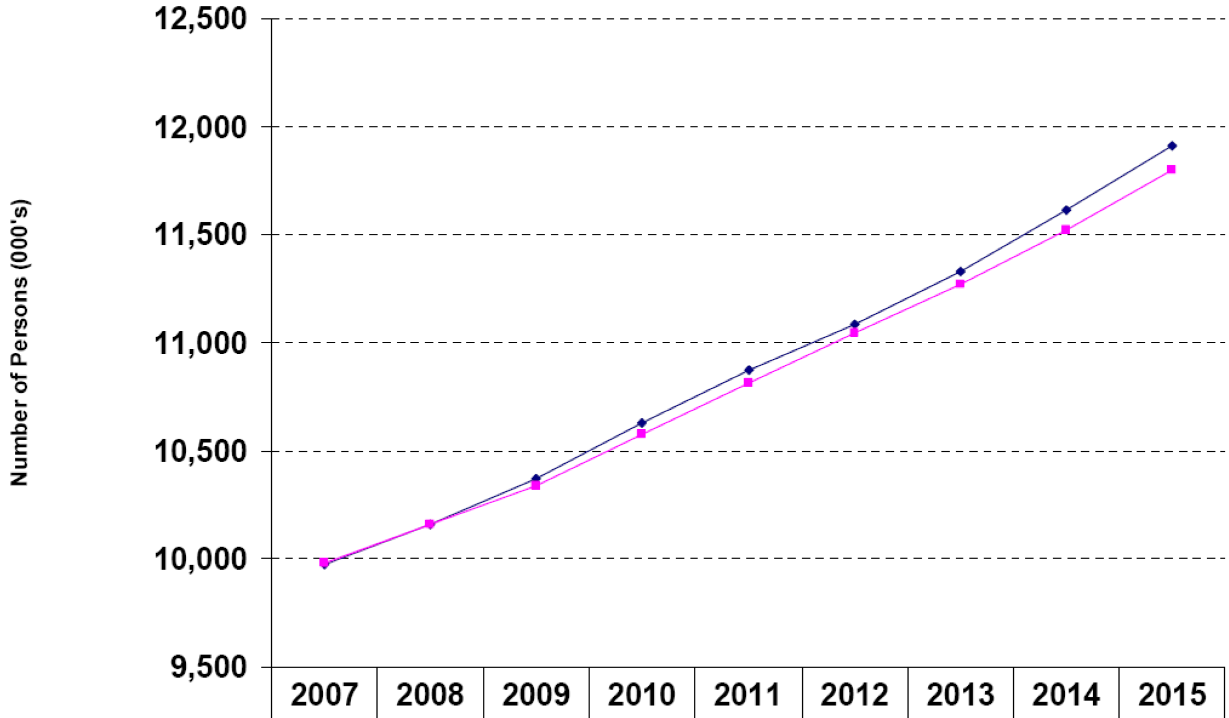
Figure 8.2-8 Employment in Financial Services



	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006 Forecast	9,003	9,173	9,377	9,597	9,801	9,983	10,191	10,429	10,675
2007 Forecast	9,123	9,328	9,526	9,749	9,975	10,187	10,399	10,628	10,877

Reference 8.2-1

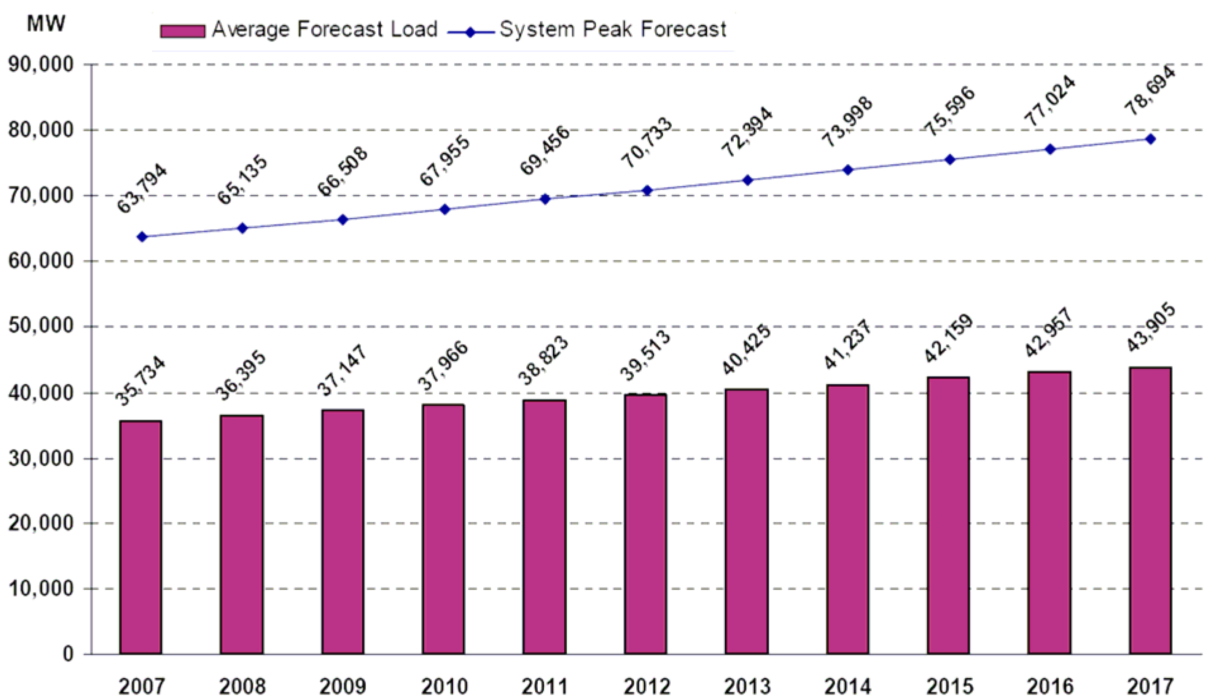
Figure 8.2-9 Total Non-Farm Employment



	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006 Forecast	9,975	10,158	10,370	10,633	10,875	11,089	11,333	11,617	11,911
2007 Forecast	9,985	10,160	10,338	10,577	10,818	11,044	11,271	11,522	11,797

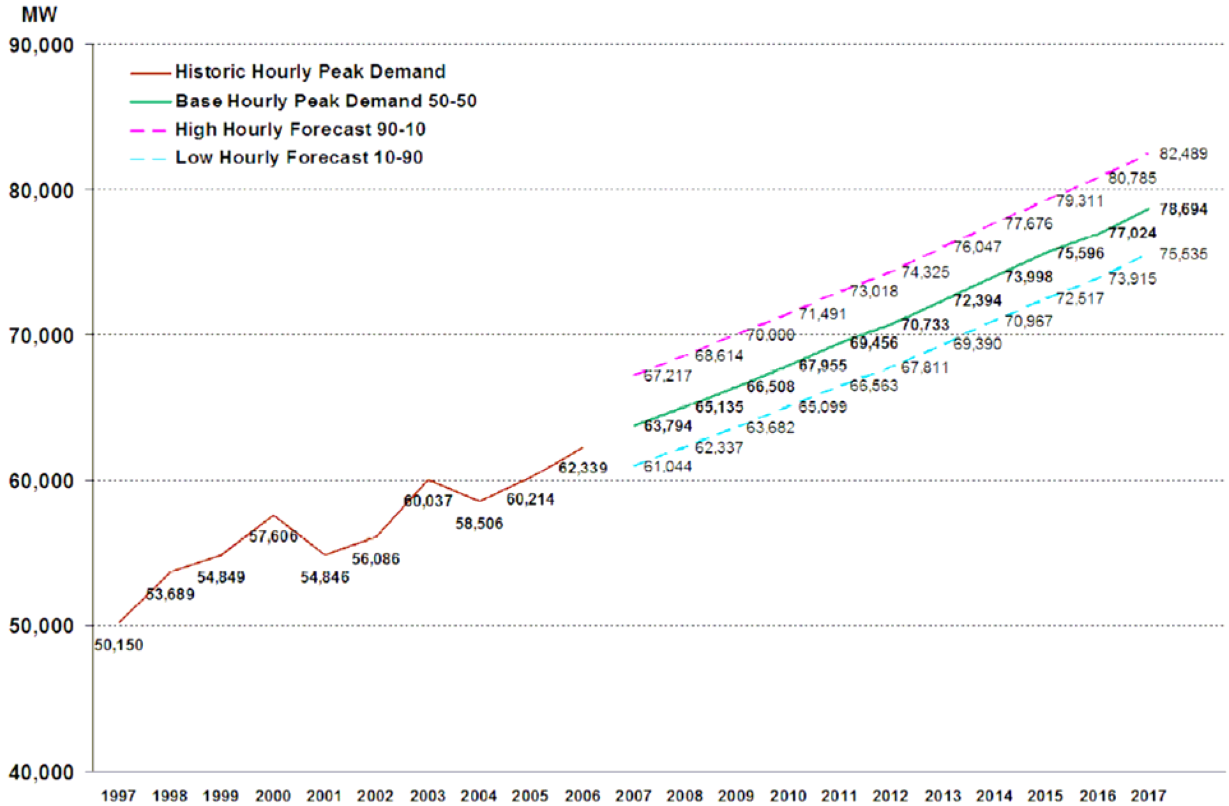
Reference 8.2-1

Figure 8.2-10 Total Persons Employed



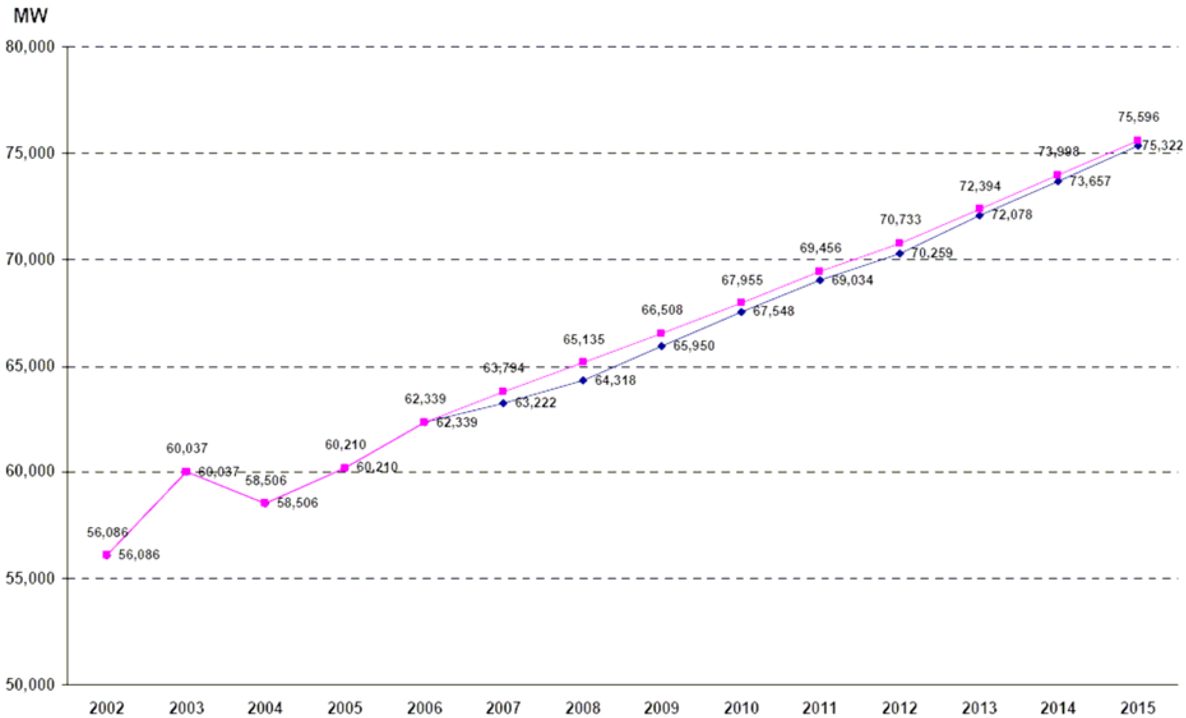
Reference 8.2-1

Figure 8.2-11 Forecast Average Load versus Forecast System Peak



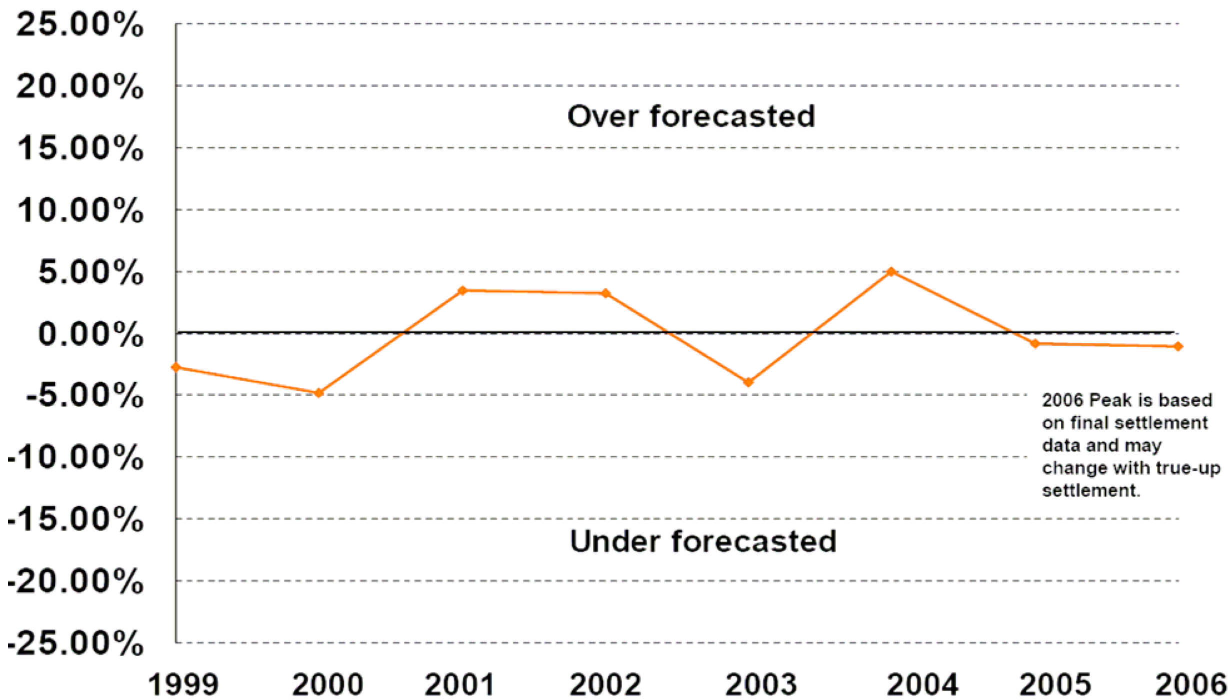
Reference 8.2-1

Figure 8.2-12 Historical and Forecast Hourly Peak Demand



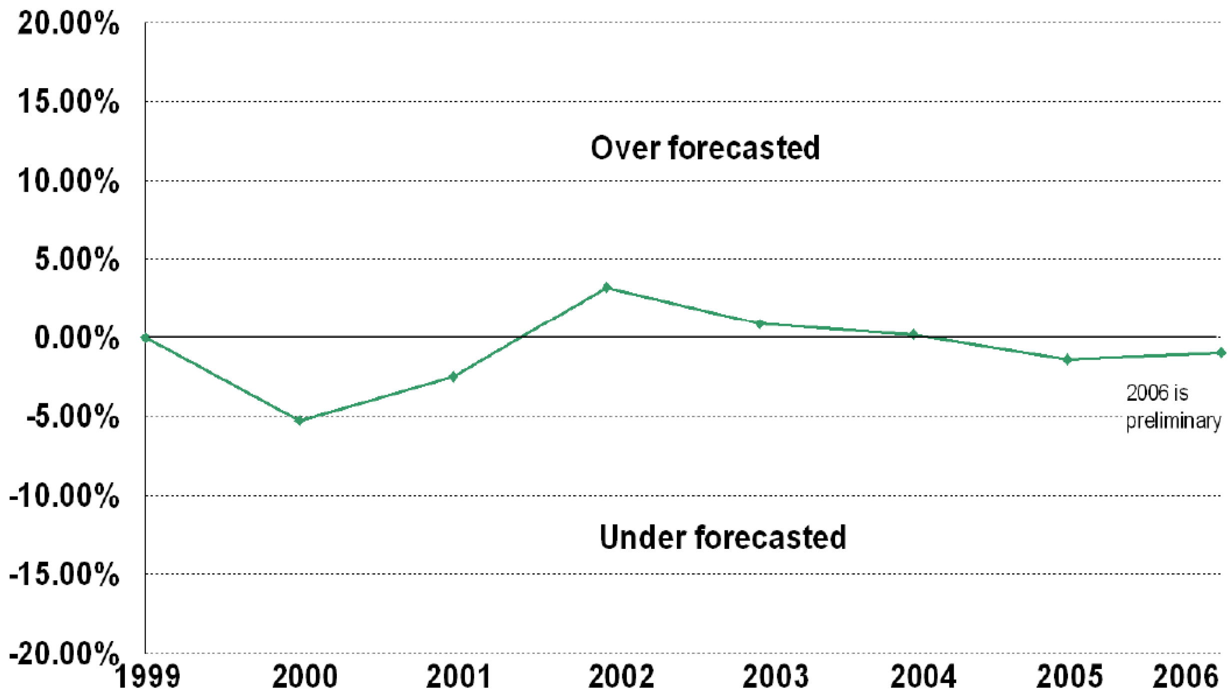
Reference 8.2-1

Figure 8.2-13 Comparison of 2006 and 2007 Peak Demand Forecast



Reference 8.2-2

Figure 8.2-14 Historical Accuracy of Peak Demand Forecasts



Reference 8.2-2

Figure 8.2-15 Historical Accuracy of Energy Consumption Forecasts

8.3 Power Supply

8.3.1 Present Generation Capacity

Installed generation capacity in the ERCOT region is approximately 81,000 MW, which includes 7,260 MW of “mothballed” natural gas-fired generation capacity, that is, units that have suspended operations from the grid for more than six months (Reference 8.3-1).

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 (nuclear and coal ≥ 550 MW) units to be the baseload generation units. Approximately 22% of the currently installed generation capacity is provided by baseload generation units. ERCOT would consider STP 3 & 4 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 or CDR (Reference 8.3-2). 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. Department of Energy 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 initiated full transmission interconnection study requests through 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.

Thus, the May 2007 CDR did not include STP 3 & 4, because the owners had not filed a full transmission interconnection study request with ERCOT.

Table 8.3-1 provides the complete summary from the CDR of the resources expected to be available each summer from 2007-2012. The focus is on the summer, because the loads in ERCOT are substantially higher in the summer than the winter. Table 8.3-1 establishes the extent of the CDR analysis. Table 8.3-2 concentrates on the contribution of baseload generation units to meeting the forecast summer peak demand. Table 8.3-3 is a list of generation units considered to be the baseload units used to develop Table 8.3-2.

Figure 8.3-1 is contained in the CDR and provides the ERCOT generation capacity projections for 2012-2027. The program that develops the curves takes many factors into consideration:

- Increasing age of generation units, 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

The figure 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 to not operate their units past thirty years, some past forty years, or some past fifty 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 to the market participants which units should be mothballed, or when mothballed units should be returned to the grid, or when new units should be planned and constructed. 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 good economic decisions that will benefit the whole ERCOT region.

8.3.3 References

8.3-1 ERCOT Report on Existing and Potential Electric System Constraints and Needs, December 2006, available at http://www.ercot.com/news/presentations/2006/2006_ERCOT_Reports_Transmission_Constraints_and_Needs.pdf.

8.3-2 Report on the Capacity, Demand, and Reserves in the ERCOT Region, May 2007, available at http://www.ercot.com/news/presentations/2007/07CDR05172007-final.xls.

Table 8.3-1 Forecast Summer Resources for 2007-2012

Resources:		2007	2008	2009	2010	2011	2012
	Installed Capacity, MW	61,424	61,424	61,424	61,424	61,424	61,424
	Capacity from Private Networks, MW	6,513	6,217	6,217	6,217	6,217	6,217
	Effective Load-Carrying Capability (ELCC) of Wind Generation, MW	298	298	298	298	298	298
	RMR Units under Contract, MW	169	169	169	169	0	0
	Operational Generation, MW	**68,404**	**68,108**	**68,108**	**68,108**	**67,939**	**67,939**
	50 % of Non-Syncronous Ties, MW	553	553	553	553	553	553
	Switchable Units, MW	2,848	2,848	2,848	2,848	2,848	2,848
	Available Mothballed Generation, MW	165	510	419	594	558	522
	Planned Units (not wind) with Signed IA and Air Permit, MW	0	550	550	550	1,300	2,100
	ELCC of Planned Wind Units with Signed IA, MW	0	171	174	174	174	174
	Total Resources, MW	**71,970**	**72,740**	**72,652**	**72,827**	**73,372**	**74,136**
	less Switchable Units Unavaialble to ERCOT, MW	158	317	317	0	0	0
	less Retiring Units, MW	0	375	375	433	433	433
	Resources, MW	**71,812**	**72,048**	**71,960**	**72,394**	**72,939**	**73,703**

Reference 8.3-2

Table 8.3-2 Forecast Summer Capacity, Baseload Generation Units Only

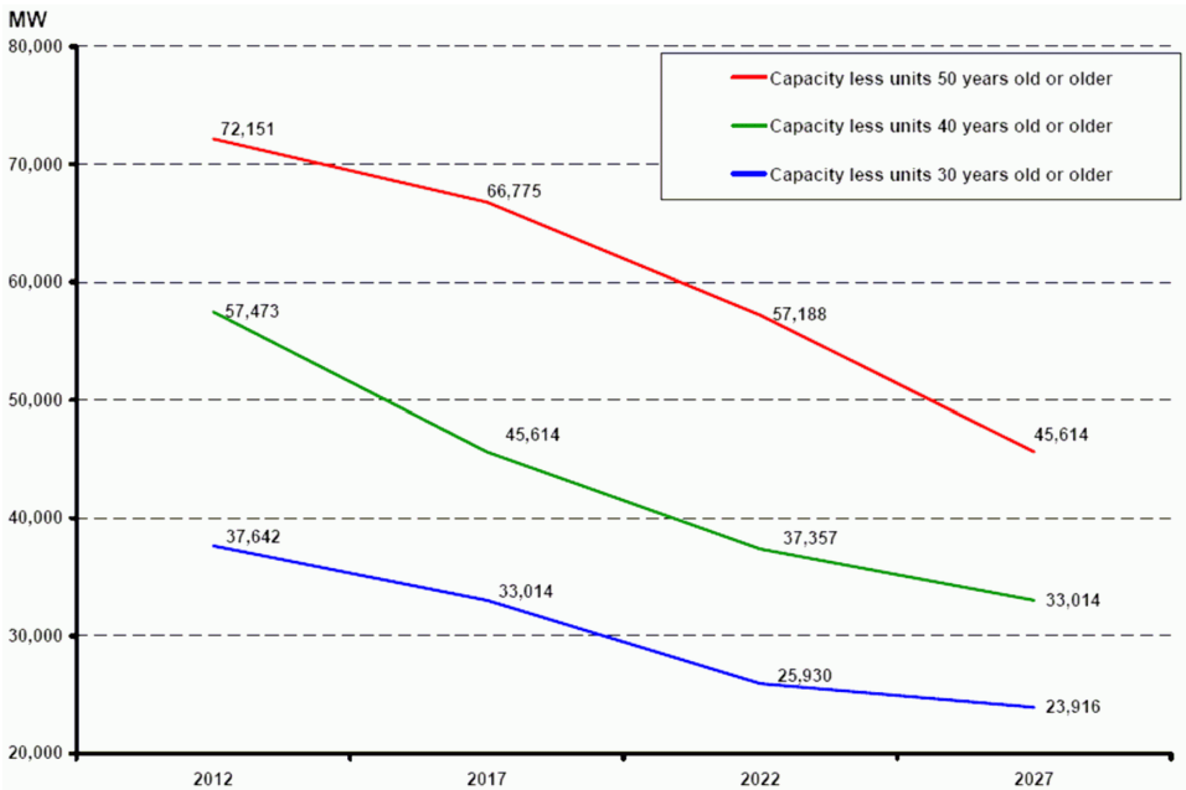
	2007	2008	2009	2010	2011	2012
Resources, MW	71,812	72,048	71,960	72,394	72,939	73,703
Baseload Generation, MW	17,621	17,621	19,057	19,998	21,378	22,178
% of Resources that are Baseload Generation	24.5%	24.5%	26.5%	27.6%	29.3%	30.1%

Compiled from Reference 8.3-2

Table 8.3-3 Baseload Generation Units for Summer Capacity Forecast

	Summer Capacity, MW					
Unit Name	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Big Brown 1	597	597	597	597	597	597
Big Brown 2	610	610	610	610	610	610
Coleto Creek 1	633	633	633	633	633	633
Comanche Peak 1	1,164	1,164	1,164	1,164	1,164	1,164
Comanche Peak 2	1,164	1,164	1,164	1,164	1,164	1,164
Fayette Power Project 1	596	596	596	596	596	596
Fayette Power Project 2	608	608	608	608	608	608
J K Spruce 1	560	560	560	560	560	560
Limestone 1	826	826	826	826	826	826
Limestone 2	853	853	853	853	853	853
Martin Lake 1	799	799	799	799	799	799
Martin Lake 2	795	795	795	795	795	795
Martin Lake 3	804	804	804	804	804	804
Monticello 1	560	560	560	560	560	560
Monticello 2	579	579	579	579	579	579
Monticello 3	808	808	808	808	808	808
Oklaunion 1	629	629	629	629	629	629
South Texas 1	1,282	1,282	1,282	1,282	1,282	1,282
South Texas 2	1,282	1,282	1,282	1,282	1,282	1,282
W A Parish 5	657	657	657	657	657	657
W A Parish 6	645	645	645	645	645	645
W A Parish 7	567	567	567	567	567	567
W A Parish 8	603	603	603	603	603	603
Oak Grove 1			855	855	855	855
Sandow 5			581	581	581	581
Oak Grove 2				855	855	855
Comanche Peak 1&2 Upgrade				86	86	86
J K Spruce 2					750	750
Twin Oaks 3					630	630
Sandy Creek 1						800
	17,621	**17,621**	**19,057**	**19,998**	**21,378**	**22,178**

Compiled from Reference 8.3-2



Compiled from Reference 8.3-2

Figure 8.3-1 ERCOT Generation Capacity Projections (MW)

8.4 Assessment of Need for Power

8.4.1 Reserve Margin Calculation Methodology

In determining the need for power, 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:

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

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 (Reference 8.4-1). The terms used here 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 (SGIA) and a TCEQ air permit, if required
- plus ELCC of planned wind generation with SGIA

- minus retiring units

Loads acting as resources (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 will be scheduled by a qualified scheduling entity (Reference 8.4-2).

- 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 unloaded generation resources are online, capable of controllably reducing or increasing consumption under dispatch control and that immediately respond proportionally to frequency changes. The amount of capacity from unloaded generation resources or DC tie response is limited to the amount that can be deployed within 15 seconds.

- Non-spinning reserve service is provided by LaaRs that are capable of being interrupted within 30 minutes and that are capable of running or being interrupted at a specified output level for at least 1 hour.

Balancing up Loads (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 (Reference 8.4-2). Refer to Subsection 8.4.2.

Summer Net Dependable Capability is the maximum sustainable capability of a generation resource as demonstrated by a performance test lasting 168 hours (Reference 8.4-3).

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) (Reference 8.4-3).

Effective Load Carrying Capability – ERCOT selected Global Energy Decisions, Inc. (GED) to complete a new target reserve margin study. 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 unserved 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 unserved energy. GED removed the generic thermal generator and added new wind generation until the same expected unserved energy was achieved. The amount of new wind generation will have the same effective load-carrying capability as the 550 MW thermal generator. It was found that 6,300 MW of wind had the same load carrying capacity as 550 MW of thermal generation. Thus, the effective load carrying capacity (ELCC) of wind is 8.7% (Reference 8.4-4).

Reliability must run service is provided under agreements for capacity and energy from resources which otherwise would not operate and which are necessary to provide voltage support, stability or management of localized transmission constraints under first contingency criteria (Reference 8.4-2)

Switchable capacity is defined as a generating unit that can operate in either the ERCOT market or the Southwest Power Pool (SPP) market, but not simultaneously. These switchable generating units are situated in close proximity to the transmission facilities of both ERCOT and SPP, 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 (Reference 8.4-3).

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 done by transmission owners to determine the effects of the new generation (Reference 8.4-3). The owners of STP 3 & 4 have requested the screening study and it has been completed by ERCOT. The full interconnection study will not be requested for several years.

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 while attempting to produce an equation to calculate an ERCOT reserve margin forecast that produces a reasonable estimate of such reserve margins and 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 approved methodology represents an accurate calculation of reserve margin (Reference 8.4-1).

The reserve margins reported in the 2007 CDR (Reference 8.4-3) and summarized in Table 8.4-1 were calculated using the methodology described above. As shown in that table and Figure 8.4-1, through 2008, ERCOT's reserve margin remains above the 12.5% requirement set by the ERCOT Board of Directors. However, ERCOT predicts that by 2009, the reserve margin will fall below 12.5%.

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. Figure 8.4-1 was compiled from the reserve margin forecasts from 1999 – 2007 and compares specifically the forecasts from the 2005, 2006, and 2007 CDRs. If the PGCs do not voluntarily react to market economic forces and add generation capacity, the reserve margin could fall below the required minimum in the very near future.

8.4.2 ERCOT Demand Side Working Group

The ERCOT Demand Side Working Group (DSWG) was created in 2001 as a task force by a directive of the Public Utility Commission of Texas (PUCT) and was converted to a permanent working group in 2002. A broad range of commercial and industrial consumers, load serving entities and retail electric providers (REPs), transmission/distribution service providers, and power generation companies participate in the DSWG 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 up load, and load acting as a resource. (Reference 8.4-5)

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, but 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 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.

Balancing up loads (BULs) refer to loads that contract with a QSE to formally submit offers 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, but if deployed, they receive two separate forms of compensation. They receive a payment for actual load reduction based on prevailing Market Clearing Price for Energy. They also receive a capacity payment based on the Market Clearing Price for Capacity in the non-spinning reserves market. This is an additional reward for the BULs 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 products offered by REPs 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 Load Acting as a Resource (LaaR) program. In eligible ancillary services (AS) 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 AS 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 (Reference 8.4-6).

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 1,125 MW per year. Voluntary load responses are not included in the CDR.

8.4.3 Comparison of ERCOT Studies with NUREG-1555 Criteria

Sections 8.0 through 8.4 have described several ERCOT studies and reports on which STPNOC has relied for the need for power evaluation. The tables and figures in these sections have been taken from, or been generated from the data in, the ERCOT studies and reports. According to NUREG-1555, an NRC independent evaluation of the need for power may not be needed if the NRC determines that the State/region-prepared evaluation is (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. Each of the NUREG-1555 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, sub-regional modeling, and new generation characteristics. The development of these reports is subject to a vigorous stakeholder input process. The output of the Long-Term Forecast Model or LTFM (Reference 8.4-7) is used as input to the CDR (Reference 8.4-3). There is an orderly and efficient progression of data and calculation results.

Comprehensive – ERCOT's planning responsibilities are broad. The Long Term System Assessment (Reference 8.4-8), for example, uses projections and variations in scenarios such as fuel prices, load growth, and environmental regulations. The study looks forward ten years and includes high-, low-, and base-case assumptions for a variety of factors. The CDR accounts for every resource in the entire 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, who has the ultimate responsibility for market oversight in ERCOT. Both the Long-Term Peak Demand study (Reference 8.4-7) 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 actuals. (Reference 8.4-9)

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 actuals. 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 studies performed by ERCOT regarding need for power collectively satisfy the four criteria in NUREG-1555 and obviate any need for further 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 along with maintaining the 12.5% reserve margin that is needed to maintain system reliability, regardless of which load scenario is under consideration (Reference 8.4-8).

Figure 8.4-2 provides the ERCOT generation capacity and demand projections for 2012-2027, which demonstrates a steady divergence between demand and capacity for the period. Figure 8.4-3 provides the potential ERCOT generation capacity needed from 2012-2027. Baseload generation capacity currently provides approximately 24.5% of the peak demand and is forecast to provide approximately 30.1% by 2012.

The ERCOT studies did not include the generation capacity that will be provided by STP 3 & 4. It is anticipated that the 1370 MWe (gross) from STP 3 will be available in 2015 and 1370 MWe from STP 4 will be available in 2016. At that time, the need for new capacity in Texas is predicted to be between 20,000 to 50,000 MWe as shown in Figure 8.4-3. Thus, the need for new capacity in ERCOT in 2015-2016 is substantially greater than the new capacity to be provided by STP 3 & 4. As a result, not only will there be a need for power from STP 3 & 4, 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 by Exelon and TXU. 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 does not satisfy ERCOT goals to maintain system reliability by 2009. By the time STP 3 & 4 are projected to enter commercial operation in 2015-2016, there will be a substantial need for power not only from STP 3 & 4, but from other new generating plants as well.

8.4.5 References

8.4-1 Memo from Read Comstock, TAC Chair to ERCOT Board of Directors, “Methodology for Reserve Margin Calculation,” available at http://www.ercot.com/meetings/board/keydocs/2005/0517/Item_11b_-_Reserve_Margin_Calculation.pdf, accessed on June 20, 2007.

8.4-2 “ERCOT Protocols, Section 6: Ancillary Services,” available at http://www.ercot.com/mktrules/protocols/current/06-080107.doc, accessed on August 2, 2007.

8.4-3 “Report on the Capacity, Demand, and Reserves in the ERCOT Region, May 2007,” available at http://www.ercot.com/news/presentations/2007/07CDR05172007-final.xls.

8.4-4 “Analysis of Target Reserve Margin for ERCOT, Warren Lasher, January 12, 2007,” available at http://www.ercot.com/meetings/gatf/keydocs/2007/20070112-GATF/GATF_LOLP_Presentation_1_12_07_as_presented.ppt#360,15,Generic Coal Additions, accessed on August 2, 2007.

8.4-5 “ERCOT Demand Side Working Group,” available at http://www.ercot.com/services/programs/load/DSWG_Presentation_to_PUCT_Workshop_9_15_06.ppt, accessed on July 22, 2007.

8.4-6 “Load Acting as a Resource,” available at http://www.ercot.com/services/programs/load/laar/index.html, accessed on July 24, 2007.

8.4-7 “2007 ERCOT Planning Long-Term Hourly Peak Demand and Energy Forecast – May 8, 2007” available at http://www.ercot.com/news/presentations/2007/2007_ERCOT_Planning_Long_Term_Hourly_Demand_Energy_Forecast_.pdf, accessed on July 13, 2007.

8.4-8 “Long Term System Assessment for the ERCOT Region, December 2006,” available at http://www.ercot.com/news/presentations/2006/Attch_A_-_Long_Term_System_Assessment_ERCOT_Region_December_.pdf.

8.4-9 “Long Term Demand and Energy Forecasting – Planning,” available at www.ercot.com/meetings/other/keywords/2007/0124-LoadForecast/KDonohoo_ERCOTLongTermDemandEnergForecastingPlanning01242007.ppt, accessed on June 2, 2007.

Table 8.4-1 Forecast Summer Capacity, Baseload Generation Units Only

	2007	2008	2009	2010	2011	2012
Firm Load Forecast	62,669	64,010	65,383	66,830	68,331	69,608
Resources, MW	71,812	72,048	71,960	72,394	72,939	73,703
Reserve Margin	14.6%	12.6%	10.1%	8.3%	6.7%	5.9%
Baseload Generation, MW	17,621	17,621	19,057	19,998	21,378	22,178
% of Resources that are Baseload Generation	24.5%	24.5%	26.5%	27.6%	29.3%	30.1%

Compiled from Reference 8.4-3

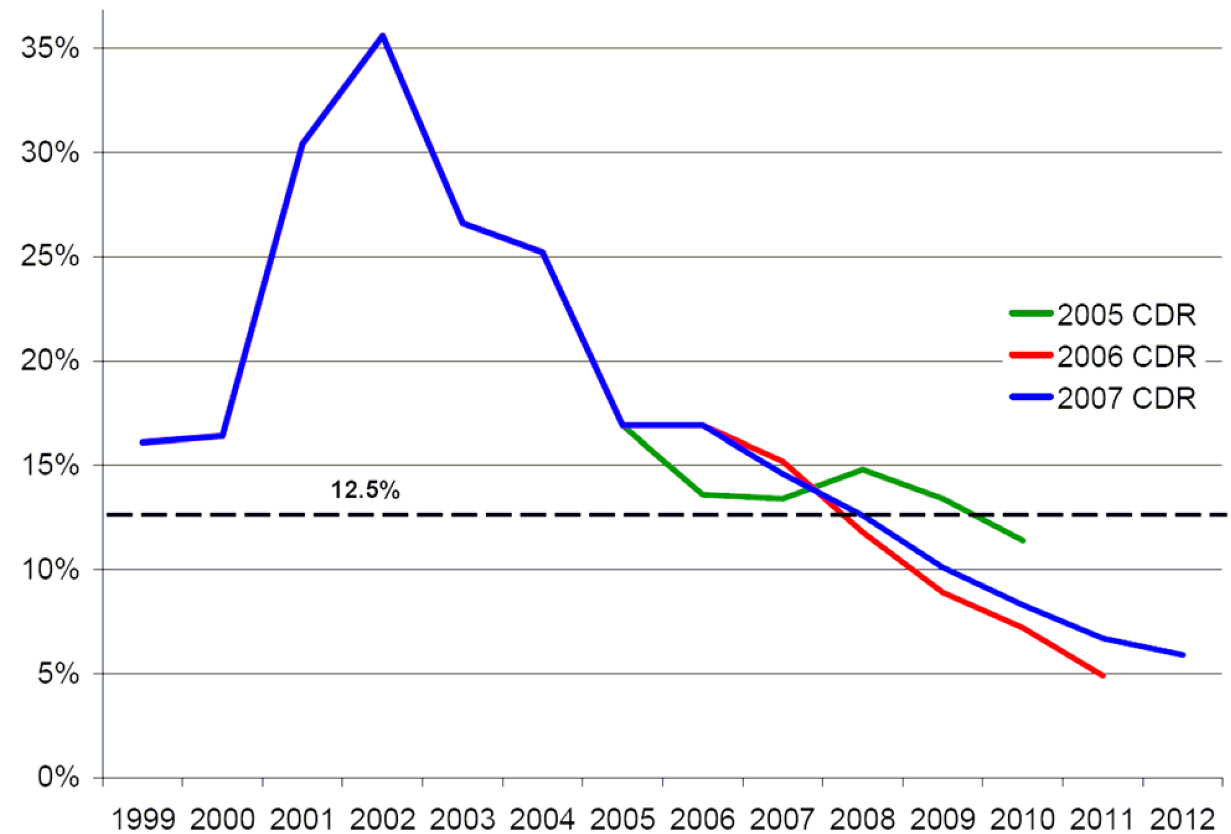


Figure 8.4-1 ERCOT Reserve Margin Forecasts, 1999-2012

Compiled from 2005 CDR, 2006 CDR, and 2007 CDR

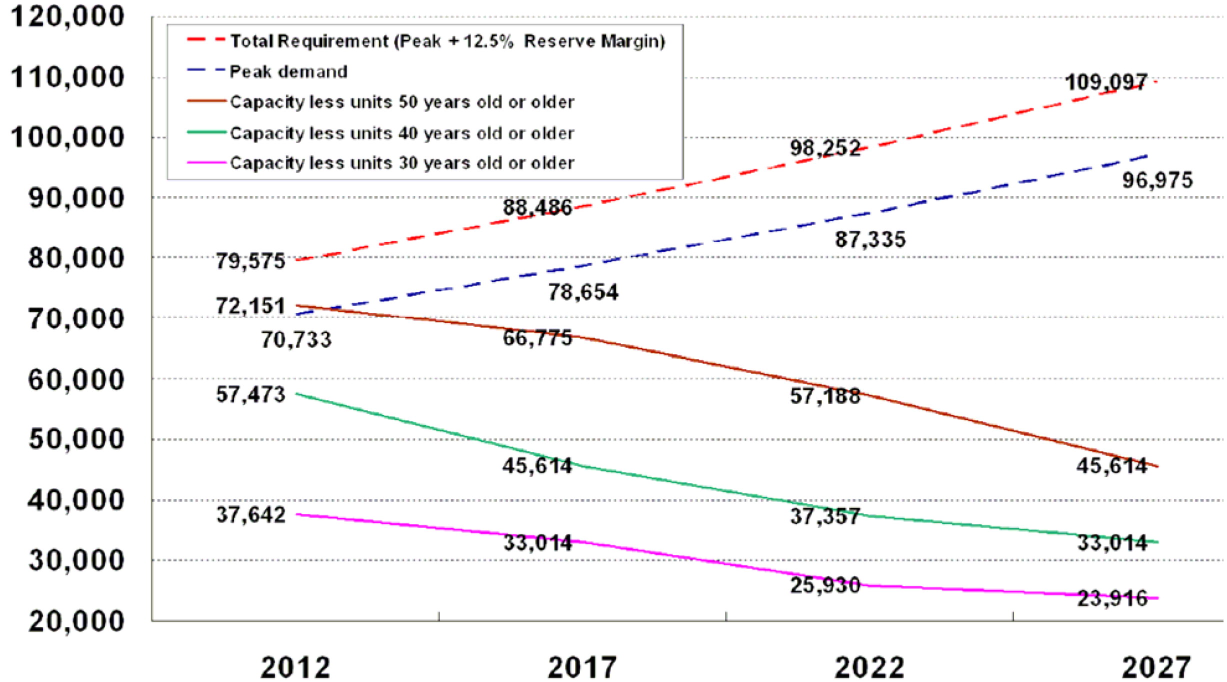


Figure 8.4-2 ERCOT Generation Capacity and Demand Projections (MW)

Reference 8.4-3

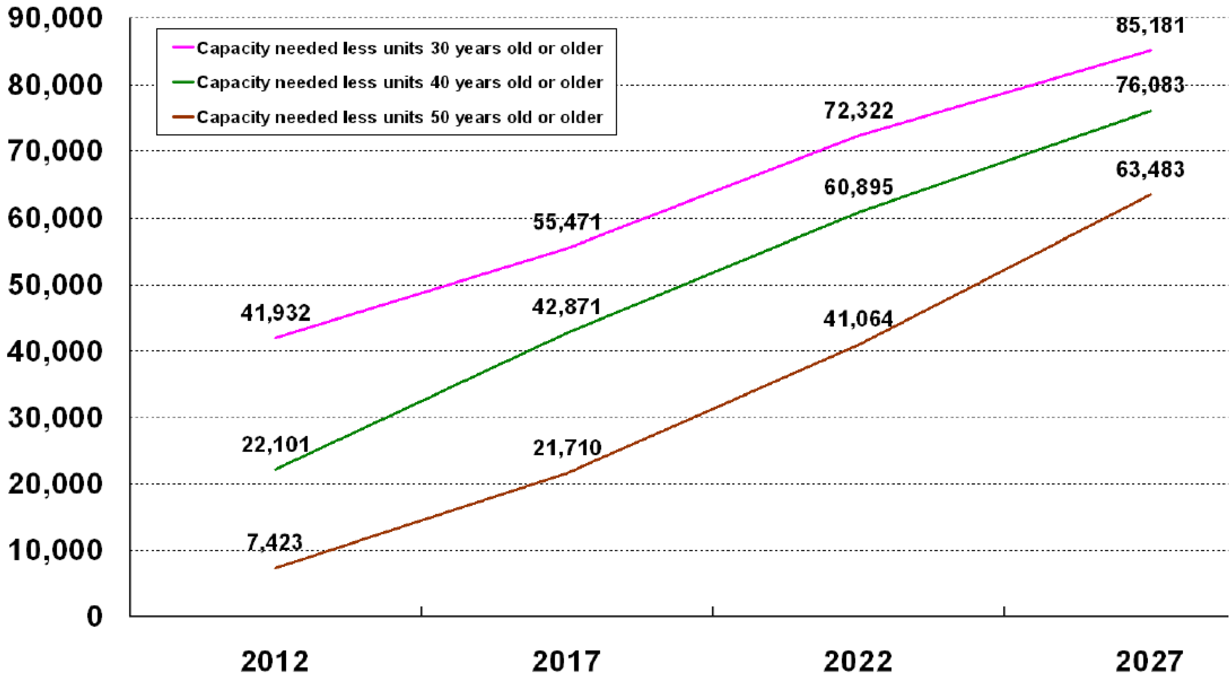


Figure 8.4-3 Potential ERCOT Generation Needed (MW)

Reference 8.4-3