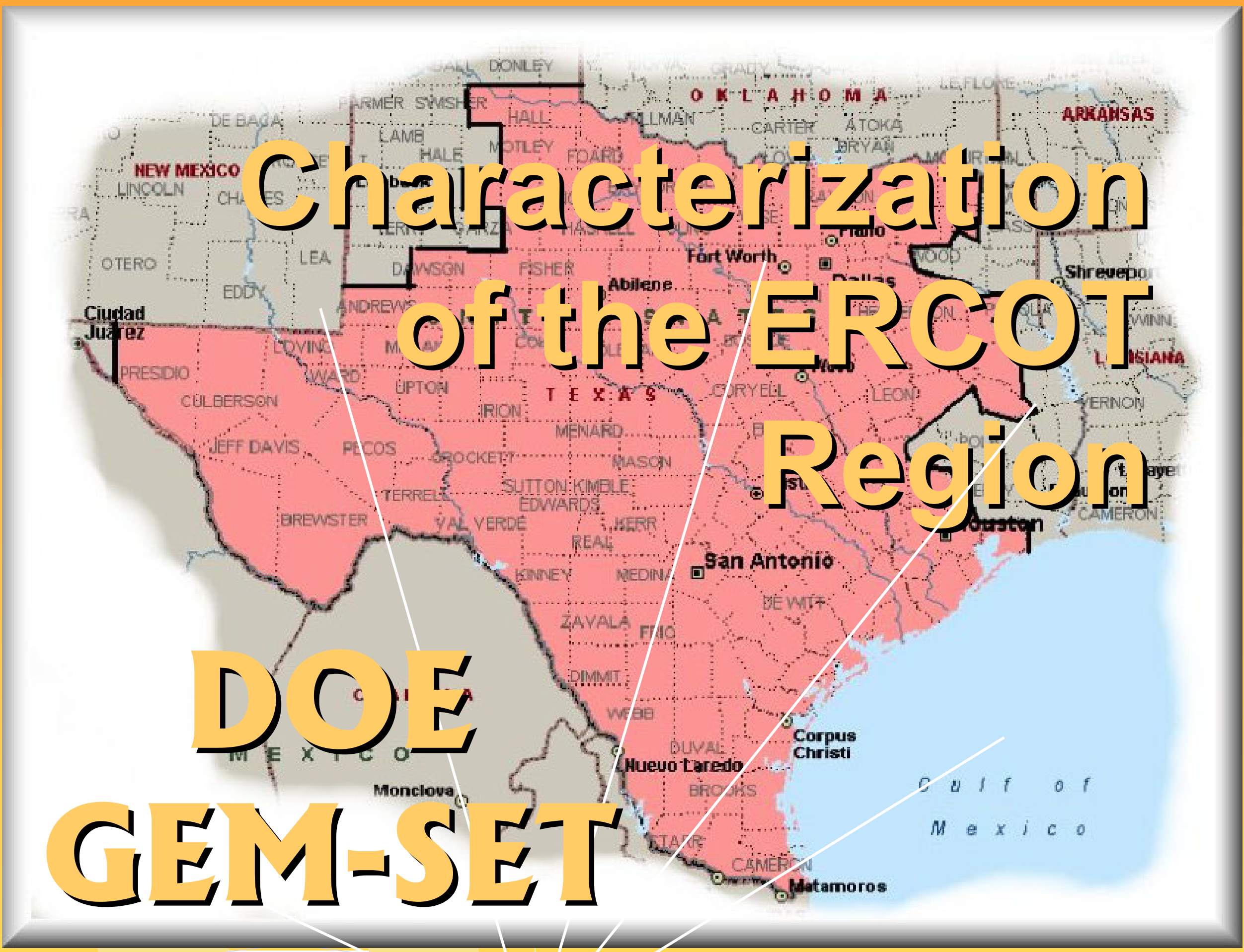
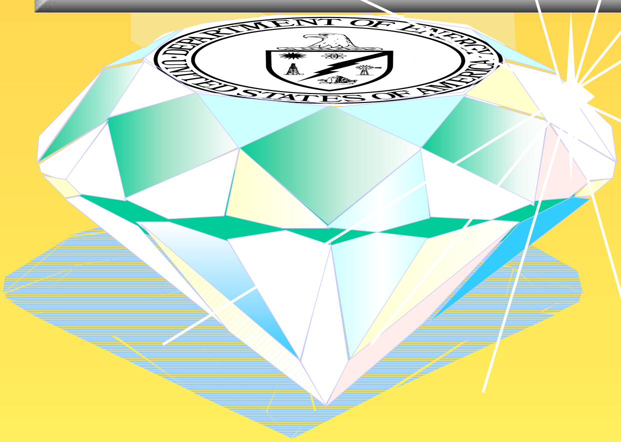
Report No. EJ-2002-08
October 2002



Characterization of the ERCOT Region

DOE GEM-SET



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PARSONS

Prepared for the United States Department of Energy
National Energy Technology Laboratory

Parsons Report No. **EJ-2002-08**
DOE Contract Number DE-AM26-99FT40465 / Task 50901: Market and Environmental Analysis
Parsons Job / WBS: 736223 / 00100

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Final Report

GEMSET Regional Segmentation Analysis:

2002 Characterization of the Electric Reliability Council of Texas

October 2002

Prepared for:
The United States Department of Energy
National Energy Technology Laboratory

DOE Project Manager:
Patricia A. Rawls

Prepared by:
PARSONS
1 Meridian Boulevard, Wyomissing, Pennsylvania 19610-3200 USA

Principal Investigators:
James J. Lowe
Christopher Wiederspahn
Albert A. Herman, Jr.

Task Manager:
Richard E. Weinstein, P.E.

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Technical Report Abstract

Parsons Infrastructure & Technology Group Inc.

System & Policy Support

EJ-2002-08

Characterizing the Electric Reliability Council of Texas

Key Services

- Characterize current ERCOT electric sale prices, and potential return to generating unit owners from operation within ERCOT
- Estimate ERCOT demand growth, the existing units in the State of Texas, and the generating units planned over the next ten years for construction to meet demand growth
- Evaluate the fuel price history and prospects for the ERCOT region
- Provide the historical base of information needed to evaluate the economic merits of new generation projects for consideration in ERCOT

Study Region

State of Texas (85%)

Client

U.S. Department of Energy
National Energy Technology Laboratory

Client Contact

Patricia A. Rawls
P.O. Box 10940
Pittsburgh, PA 15236-0940
Tel: (412) 386-5882 / Fax: (412) 386-4818
Email: Rawls@netl.doe.gov

Task Manager

Richard E. Weinstein, P.E.

Dates

July 2001-June 2002

Contract / Job Numbers

DE-AM26-99FT40465 - Task 50901
Parsons: 736223 / 00100

Project Description

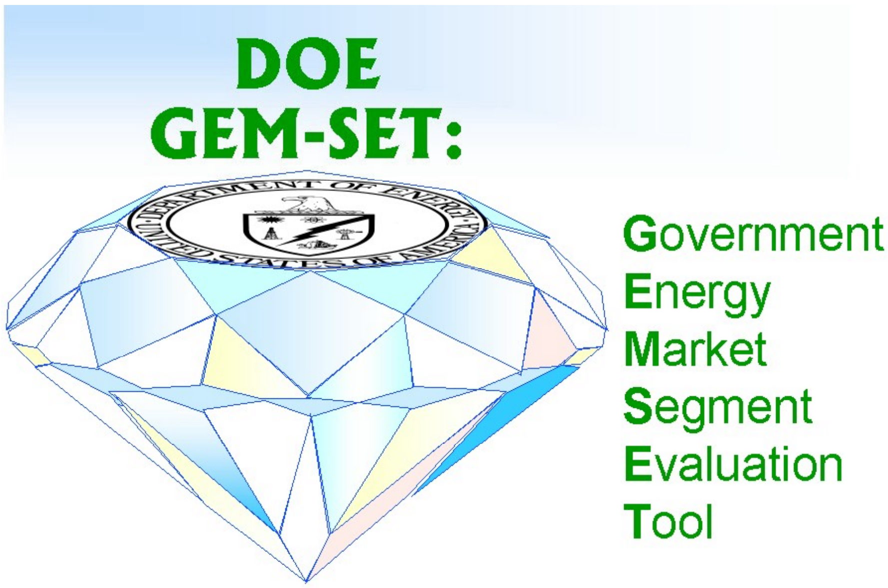
Electric Power Market Condition Evaluation in a Competitive Electric Market Region

ERCOT is one of 10 electric reliability regions in North America operating under the safety standards set by the National Electric Reliability Council (NERC). ERCOT oversees more than 85% of the electric market in the state of Texas includes approximately 72,000 megawatts of generation and 37,000 miles of transmission lines. Texas is one of the fastest growing states in the US, and is now the second largest in terms of population with over 21 million residents. Parsons evaluated the competitive market conditions that exist in the ERCOT region. Some features of this study include the following:

- Electric demands were characterized hour-by-hour for each of the utilities, and summarized for the entire ERCOT region.
- The future expectation of ERCOT's demand growth is discussed, and the list of planned units that might meet that demand growth, are identified.
- A data base is developed that characterizes ERCOT utility cost of generation and load demand that allows ease of evaluation of the potential return to units having different production costs.
- Fuel prices within the region were assessed and projected for future evaluations.
- The units operating in the region are identified.

Key project team members:

- Richard E. Weinstein, P.E.
- Albert A. Herman, Jr.
- James J. Lowe
- Christopher Wiederspahn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The reader should check with the DOE project manager, Patricia Rawls, to see if there is a more recent issue of this report, or to discuss any related information that might be available about the region, or about the GEMSET project data.

Ms. Patricia A. Rawls
Project Manager, Office of System & Policy Support

U.S. Department of Energy
National Energy Technology Laboratory
Mail Stop 920-L
P.O. Box 10940
Pittsburgh, PA 15236-0940
Phone: **(412) 386-5882**
Fax: (412) 386-4818
e-mail: Rawls@NETL.DOE.GOV

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List of Exhibits

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Patricia A. Rawls, *Project Manager*

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Charles J. Drummond

This report was prepared by the following **Parsons** personnel:

PARSONS

Task Manager:
Richard E. Weinstein, P.E.
Lead Economist:
Albert A. Herman, Jr.

Project Support:
James J. Lowe
Christopher Wiederspahn
Nancy S. Lewis

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Abbreviations and Acronyms

Term	Meaning
AAGC	average automatic generation control
ACAP	available capacity (as in PJM West)
AEO1999	EIA Annual Energy Outlook 1999
AEO2000	EIA Annual Energy Outlook 2000
AEO2001	EIA Annual Energy Outlook 2001
AEO2002	EIA Annual Energy Outlook 2002
AEP	American Electric Power
AGC	automatic generation control
ALM	Active Load Management
ASCC	Alaska Systems Coordinating Council
AVR	automatic voltage regulator
Bcf	billion cubic feet, that is, 10^9 cubic feet
Block Forwards Market	a continuously traded standardized product for month-ahead on-peak energy in blocks of 1 or 25 MW
BME	balancing market evaluation
CAISO	California Independent System Operator
CalPX	California Power Exchange (no longer operating)
Capacity Resource	Generator qualifying as PJM capacity
CARL DATA	control area resource and load data submitted by Control Area Resources to the ISO
CDR	Capacity Deficiency Rate
COE	the cost of electricity, the levelized busbar cost of electric production including amortized capital, operating, and maintenance costs
combustion turbine, CT	a synonym for gas turbine, used interchangeably
ComEd	Commonwealth Edison
CP&L	a Progress Energy company
CR	competitive retailer
CSC	commercially significant constraint
DAM	day-ahead market
Day-Ahead Market	functions as a physical forwards market and establishes the supply and demand for electric power in California one day in advance of delivery
Day-Of Market	provides for three auction periods daily, 6 a.m., noon, and 4 p.m.
DCA	Department of Community Affairs
DEP	Department of Environmental Protection

DMNC..dependable maximum net capability
DNI...desired net interchange
DOE...United States Department of Energy
DSM...demand side management
ECAR..East Central Area Reliability Coordination Agreement, a NERC region
EDC...Electric Distribution Company
EFORd......................................demand equivalent forced outage rate
eGADS......................................electronic generating availability data system; an electronic data system allowing the posting of data regarding a generating unit's availability record
EIA..the Energy Information Administration of the DOE
EPA...U.S. Environmental Protection Agency
EPAct..Energy Policy Act of 1992
EPRI..Electric Power Research Institute
ERCOT.....................................Electric Reliability Council of Texas, a NERC region
ERO...industry self-regulatory electric reliability organization
EUE...expected unserved energy
FERC...Federal Energy Regulatory Commission
FGD...flue gas desulfurization, a sulfur emission control device
FGT...Florida Gas Transmission, a natural gas transportation pipeline company
FLOASIS..................................Peninsular Florida's OASIS
FPC..Florida Power, a Progress Energy company
FPL..Florida Power & Light Company
FPSC...Florida Public Service Commission
FRCC..Florida Reliability Coordinating Council, a NERC region
FTR...Financial Transmission Right
GADS..generating availability data system; see "eGADS"
gas turbine, GT.........................a synonym for combustion turbine, used interchangeably
GEMSET..................................government energy market segment evaluation tool
GNP...gross national product
GT..gas turbine (a synonym for combustion turbine)
GTCC..natural gas fueled gas turbine combined cycle
HAM..hour-ahead market
HHV..higher heating value of a fuel including the heat released if all of the water vapor in the combustion products were condensed
HRSG..heat recovery steam generator
ICAP..installed capacity requirement
IOU..investor-owned utility
IPD..implicit price deflator
IPM..the EPA's integrated planning model

IPP .... an independent power producer, an unregulated electric generating company
IRM .... installed reserve margin
IRP.. integrated resource plan
ISO.. independent system operator; a regulated body that dispatches all competitive electric generation on the high voltage transmission grid within its service region; they operate the grid, administer the power pools power transfers, select the lower cost generation bid into the pool according to the pool's operating rules, and maintain the integrity of the electric transmission grid
ISONE .... New England ISO
ITC .... Independent Transmission Company
JEA .... Jacksonville Electric Authority
KUA... Kissimmee Utility Authority
LAK... City of Lakeland
LBMP .... locational-based marginal pricing
LCC .... local control center
LHV .... lower heating value of a fuel, the heat released if all of the water vapor in the combustion products remained as steam
LMP... locational marginal price
LOC... lost opportunity cost
LOLE .... loss of load expectation
LOLP... loss of load probability
LSE .... load-serving entity
MAAC .... Mid-Atlantic Area Council, a reliability council, a NERC region
MAIN .... Mid-America Interconnected Network, a NERC region
MAPP .... Mid-Continent Area Power Pool, a NERC region
MCP .... market clearing price
MCPC .... market clearing price for capacity
MCPE.. market clearing price for energy
MCR.. maximum continuous rating
MISO... Midwest Independent System Operator
MMC .... market monitoring committee
MMU .... Market Monitoring Unit
MOU.. Memorandum of Understanding
MVA .... megavolt amperes
MVAR .... megavolt-ampere-reactive
MWe .... electrical megawatts
MWth .... thermal megawatts
NAERO .... the North American Electric Reliability Organization; NERC is in the process of transforming itself into NAERO, whose principal mission will

be to develop, implement, and enforce standards for a reliable North American bulk electric system. (NERC has no enforcement capability.)

NEL .... net energy for load

NEMS .... the EIA's national energy modeling system

NERC .... North American Electric Reliability Council; soon, NERC, without enforcement authority, will become NAERO with that authority

NERTO .... North East Regional Transmission Owner

NETL .... the U.S. Department of Energy's National Energy Technology Laboratory

NOIE .... Non-Opt-In Entity

NOPR .... notice of proposed rulemaking

NOx .... nitrogen oxides, types of air pollutant, mainly NO and NO_2

NPCC .... Northeast Power Coordinating Council, a NERC region

NUG .... non-utility generator, a competitive, unregulated independent electric power producer

NYCA .... New York Control Area

NYISO .... the New York State independent system operator, a NERC region

NYMEX .... New York Mercantile Exchange

NYPA .... New York Power Authority

NYPP .... New York Power Pool

NYSRC .... New York State Reliability Council

O&M .... operation and maintenance

OASIS .... open-access same-time information system

OATT .... open access transmission tariff

OI .... PJM Office of the Interconnection, LLC

OTAG .... Ozone Transport Assessment Group

OTR .... Northeast Ozone Transport Region

OUC .... Orlando Utilities Commission

P.E. .... licensed professional engineer

PCD .... particulate emission control device

PECO .... Philadelphia Electric Company

PJM .... Pennsylvania, New Jersey, Maryland, or PJM Interconnection LLC, an ISO/RTO

PPL .... Pennsylvania Power & Light Company

PRL .... price responsive load

PSC .... local state Public Service Commission

PSE&G .... Public Service Electric & Gas Company

PUCT .... Public Utility Commission of Texas

PUHCA .... Public Utilities Holding Company Act

PURA .... Public Utility Regulatory Act

PURPA .... Public Utility Regulatory Policy Act of 1978

RACT .... reasonably available control technology (pollution control)
RAG... Reliability Assessment Group
REP .... retail electric provider
RMCP .... regulation market clearing price
RTEM .... real-time energy marketplace
RTO... regional transmission operator
RWG .... Resource Working Group
SAS .... Statement on Auditing Standards
SCD .... security-constrained dispatch
SCNG .... Strategic Center for Natural Gas
SCUC... security-constrained utility commitment
SERC... Southeast Electric Reliability Council, a NERC region
SMCP .... spinning market clearing price
SMD... FERC's Standard Market Design for competitive electric markets
SOx .... sulfur oxides, types of air pollutant, mainly SO_2
SPP .... Southwest Power Pool, a NERC region
SRE.. supplemental resources evaluation
State Estimator......................... PJM system model
SWG .... Stability Working Group
TAC .... Technical Advisory Council
TCC .... Transmission Congestion Contracts
TCR... Transmission Congestion Right
TDSP .... Transmission and/or Distribution Service Provider
TECO .... Tampa Electric Company
TIS .... Texas Interconnected System
TWG.. Transmission Working Group
TYSP .... 10-year site plan
UDI .... Utility Data Institute
VAR... volt-ampere-reactive
WECC .... Western Electricity Coordinating Council (formerly WSCC), a NERC region

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1. Summary of Electric Reliability Council of Texas (ERCOT)

1.1 Overview

ERCOT is one of 10 electric reliability regions in North America operating under the reliability and safety standards set by the North American Electric Reliability Council (NERC). As a NERC member, ERCOT's primary responsibility is to facilitate reliable power grid operations in the ERCOT region by working with the area's electricity industry organizations. The Public Utility Council of Texas (PUCT) has primary jurisdictional authority over ERCOT to ensure the adequacy and reliability of electricity across the state's main interconnected power grid. An independent Board of Directors comprised of electric Market Participants governs ERCOT.

Since 1970, ERCOT's primary role has been to ensure electricity transmission reliability and to schedule electric power transfers among competitive wholesale providers and users. Several times since its origin, ERCOT's duties have expanded to accommodate the changing needs of Texas' electricity industry. Today ERCOT is also charged with overseeing the transactions related to the January 1, 2002, restructuring of the electric industry – including the development and effective operation of the majority of Texas' competitive retail market. In that role, ERCOT is the central controller of the majority of the energy market's activities, including power scheduling and troubleshooting. When required, ERCOT steps in to ensure that the appropriate reliability standards are met with mandated sales from other utilities when a shortage is experienced.

Given the recent situation in California (where the California competitive market has proven unstable at best), Texas believes that its competitive market is much more likely to succeed than the one structured for California. Below are listed some of the reasons that ERCOT assumes that its market will be more responsive to the public needs:

- Although Texas and California have similarly sized electric grids and similar growth in power demand, Texas has put more than eight times the capacity on line between 1996 and 1999 than California added.

- Texas has a lead-time of 2 to 3 years to construct new power plants, while California's lead time is approximately 7 years. Since 1995, 47 new power plants were built or are being built in Texas, representing one-fourth of all power plants being built in the nation. California has built only two power plants since 1995.

- The new plant construction in ERCOT will allow power generators to easily meet the needs of residential and non-residential power users in Texas.

- Texas imports less than 1% of its power during peak power demand, compared to California, which imports at least 25% of its load during peak demand.

- Long-term wholesale market contracts in Texas shield customers from price volatility. In Texas, power generators and Retail Electric Providers (REPs) are able to negotiate wholesale power purchases for the lowest price, which will benefit customers.

- While California is now struggling to fix its flawed system, circumstances prior to the state's takeover of the electric market need to be contrasted here. In particular, the California power system left the door open to price spikes during peak demand periods. Thus, utilities and customers were exposed to volatile spot market prices, forcing them to pay unnaturally high prices.

- Texas enacted strong measures to protect customers during the transition to a fully competitive retail electric market. ERCOT feels that these measures will keep a lid on electric rates so that Texas electric customers will not see their electric bill double or triple, as happened last summer in the San Diego area.

This report includes the following discussions in subsequent sections:

- Section 2 describes the ERCOT region.

- Section 3 discusses the specifics of the ERCOT operations in terms of planning, reliability considerations and external factors affecting ERCOT.

- Section 4 describes historical information on generation, demands, and the energy prices experienced by the ISO in its balancing function

- Section 5 presents the generation identified in ERCOT by the GEMSET Team, and the generation planned for the future.

- Section 6 gives ERCOT's forecasts and projections on demand growth, and on the fuel prices forecasted for the region by the GEMSET Team.

These data are dynamic, and what is reported here represents only a "snapshot" of information that existed a month prior to this report's issue date, October 2002. Periodically, the ERCOT region will be revisited, and this report revised.

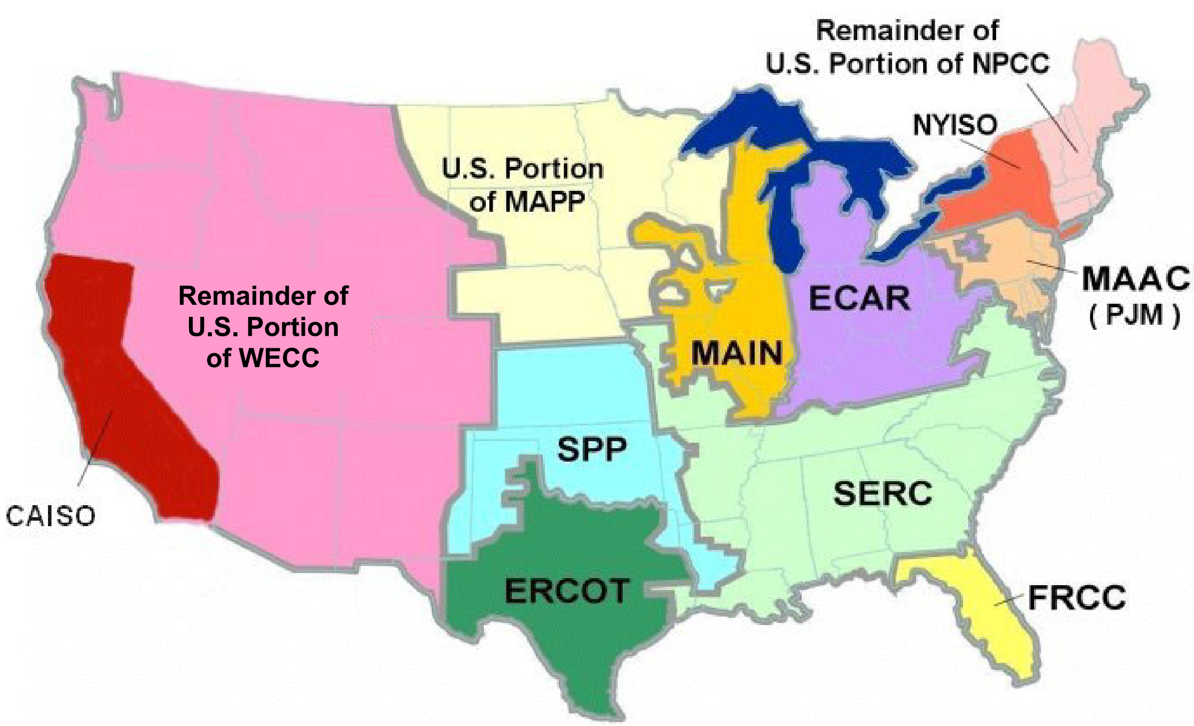
1.2 The Other GEMSET Regions

This report is one of a series describing the market conditions that exist, and that are forecast as part of the Department of Energy's (DOE) government energy market segment evaluation tool (GEMSET) project. Others in the series describe other regions, both competitive and regulated.

GEMSET forecasts for the ERCOT and other areas will be presented in future reports in the series. Future reports on the ERCOT will be issued where the GEMSET evaluation team makes reasoned conjecture of what might occur in the electric power market in this region in the future under a range of possible future energy prices and economic circumstances.

This is one of 12 regional assessments. The GEMSET regional characterizations generally follow the U.S. portions of the North American Reliability Council (NERC) regions, excepting the Alaska Systems Coordinating Council (ASCC) and Hawaii, which are not modeled. Two of the NERC regions are broken into parts, to separate out California and New York State. The 12 GEMSET regions, and their associated NERC region are shown in Exhibit 1-1.

Exhibit 1-1 The GEMSET Regions



The 12 GEMSET regions are:

- **CAISO** - The California Independent System Operator, a portion of the NERC's Western Electricity Coordinating Council (WECC).
- **East Central** - East Central Area Reliability Coordination Agreement (ECAR).
- **Florida** - Florida Reliability Coordinating Council (ERCOT).
- **Mid-America** - Mid-America Interconnected Network (MAIN).
- **Mid-Continent** - the U.S. portion of the Mid-Continent Area Power Pool (MAPP).
- **Northeast** - the U.S. portion of NERC's Northeast Power Coordinating Council (NPCC), excluding New York
- **NYISO** - The New York ISO, a portion of NERC's Northeast Power Coordinating Council (NPCC).
- **PJM** - the Pennsylvania, New Jersey, Maryland Interconnect, which comprises the NERC's Mid Atlantic Area Council (MAAC).
- **Southeast** - Southeast Electric Reliability Council (SERC).
- **Southwest** - Southwest Power Pool (SPP).
- **Texas** - Electric Reliability Council of Texas (ERCOT).
- **Western** - the U.S. portion of the NERC's Western Electricity Coordinating Council (WECC), excluding California.

2. The ERCOT Region

2.1 ERCOT Overview

ERCOT is an Independent Organization certified by the PUCT to perform certain functions for the ERCOT Region. Its operations are defined by provisions of the ERCOT Protocols, a set of rules designed by collaboration between stakeholders from all segments of Market Participants. A description of the ERCOT Protocols can be found on the Internet website: www.TexasChoiceProgram.com. According to Section 3 of the ERCOT Protocols, the ERCOT functions are to:

(1) Ensure access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms;

(2) Ensure the reliability and adequacy of the ERCOT Transmission Grid;

(3) Ensure that information relating to a Customer's choice of Retail Electric Provider in the state of Texas is conveyed in a timely manner to the persons who need that information; and

(4) Ensure that electricity production and delivery are accurately accounted for among the Generation Resources and wholesale buyers and sellers in the ERCOT Region.

ERCOT also functions as the PUCT-appointed Program Administrator of the Renewable Energy Credits Program, and helps market participants effectively plan and implement their competitive market operations by providing timely information like ancillary service requirements and forecasts of weather, load, and losses.

To understand how ERCOT monitors the traffic over Texas' main power grid for multiple competitive power companies and their customers, it is useful to think of an airport. Airports maintain their runways, air traffic controllers, and facilities for use by multiple, competing airlines and their customers, safely and equitably monitoring the incoming and outgoing airplanes. Similarly, ERCOT must manage the incoming and outgoing supply of electricity over the grid. While doing so, ERCOT's team of professionals ensure that access to the grid is fairly and safely accessed among all market participants, who then distribute it to their customers. ERCOT's members include retail consumers, investor and municipally owned electric utilities, rural electric co-ops, river authorities, independent power producers, competitive retailers, and power marketers. However, unlike an airport, ERCOT is a not-for-profit organization, with no financial stake in the industry it serves. As an Independent System Operator (ISO), ERCOT maintains an impartial role as it maintains the reliability of the power transmission system, and facilitates an open, competitive electric marketplace within its appointed reliability region.

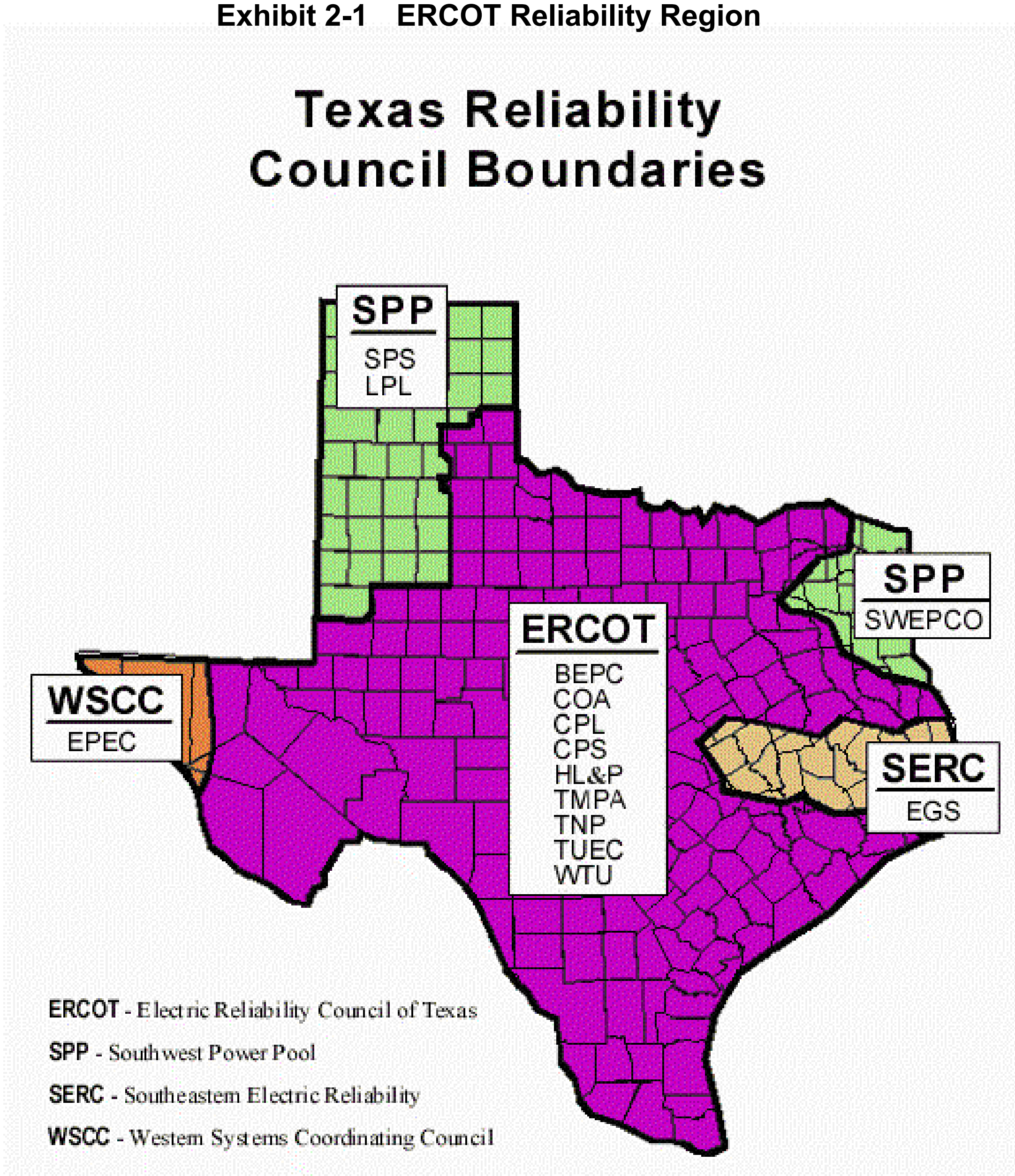
ERCOT acts only as an agent on behalf of the various Market Participants. ERCOT does not take title to any energy or Ancillary Services or to require Transmission and/or Distribution Service Providers (TDSPs) or Resources to transfer any control of their Facilities to ERCOT. In the exercise of its sole discretion under the Protocols, ERCOT is required to act in a reasonable, non-discriminatory manner.

Market Participants pay for use of the ERCOT scheduling, settlement, registration and other related systems and equipment. The ERCOT Board has the power to adopt additional fees and charges as they deem necessary to cover additional costs of those systems and services.

2.2 ERCOT's Reliability Region

The ERCOT reliability region serves about 85% of the electrical load in Texas (covering about 75% of the land area in the state) and has an overall generating capacity of approximately 75,479 MW (2002 Summer Capacity). ERCOT is the only reliability region in North America that is located completely within the borders of a single state, and it is one of two reliability regions that are also ISOs (the other being PJM East). Exhibit 2-1 illustrates the ERCOT control area, as well as the other Texas Reliability Councils.

Exhibit 2-1 ERCOT Reliability Region



2.3 Background and History of ERCOT

At the beginning of World War II, a number of electric utilities in Texas banded together to support the war effort. They sent their excess power generation to industrial manufacturing companies located along the Gulf coast, in particular, to provide reliable supplies of electricity for energy-intensive aluminum smelting. This group became known as the Texas Interconnected System (TIS). From this experience, TIS members realized the reliability advantages of remaining interconnected. They continued to use and develop the interconnected grid as their electrical loads grew and larger generating units were installed.

TIS members adopted official operating guides for their interconnected power system. To monitor security control functions, they also established two monitoring centers within the control centers of two utilities, one in North and one in South Texas. This system consisted of an operator with telephone lines to each of the control areas.

The National Electric Reliability Council (NERC) was established as an industry overseer of reliable electric service throughout North America in the 1960s.

TIS formed the Electric Reliability Council of Texas (ERCOT) to comply with the formation of NERC's organizational structure in the 1970s. In 1981 TIS' members voted to transfer all of its operating functions to ERCOT

In 1995 a major step toward a competitive market in the ERCOT region was taken when the Texas Legislature amended Public Utility Regulatory Act (PURA) to deregulate the wholesale generation market. This legislation authorized ERCOT to expand its scope to facilitate wholesale competition through the efficient use of the electric transmission system by all market participants. On August 21, 1996, the PUCT endorsed an ERCOT joint industry task force filing and created the ERCOT Independent System Operator (ISO). Then, on September 11, 1996 the ERCOT Board of Directors officially restructured its organization and initiated operations as a not-for-profit ISO

In 1997, the Texas Legislature debated whether to introduce competition to the retail electric market, but ultimately failed to adopt a bill. However, in anticipation of the passage of deregulation in 1999, the ERCOT ISO Board of Directors charged its Technical Advisory Committee (TAC) to begin investigation of how the ISO might need to change in order to support retail choice. As part of this investigation process, the TAC initiated voluntary and open public workgroups comprised of existing and potential market participants, generically labeled "stakeholders." These stakeholder workgroups were formed on a number of issues. One stakeholder work group summarized the findings and recommendations of the different workgroups. This committee was called "Ad Hoc Committee on Possible Impacts of Future Electric Market Changes on the Independent System Operator."

- In December 1998, this stakeholder group issued a significant report to the TAC on ERCOT's role to facilitate an orderly transition to a competitive retail market.

In early 1996, the Public Utility Council of Texas (PUCT) issued revised rules to incorporate the legislative changes in PURA. Parallel to the PUCT's implementation, a broad-based industry task force spent several months preparing and outlining recommendations. These recommendations included making ERCOT an Independent System Operator (ISO), amending ERCOT's Articles of Incorporation and Bylaws to allow various segments of the industry to join and be represented on the Board, creating a new ERCOT membership and funding agreement, developing an ISO functions document, and adopting OASIS (Open Access Same-time Information System) requirements. The proposals outlined three major areas of responsibility for ERCOT to enable these changes: (1) generation of the security activities of the region's bulk electric system, (2) facilitation of the efficient use of the electric transmission system by all market participants, and (3) coordination of future transmission planning

On August 21, 1996, the PUCT endorsed an ERCOT joint industry task force filing and created an ISO. On September 11, 1996, this change was officially implemented when the ERCOT Board of Directors restructured its organization and initiated operations as a not-for-profit ISO. ERCOT was the first electricity utility industry ISO created in the U.S.

2.4 State Senate Bill 7

The Texas State Legislature passed Senate Bill 7 (SB7) in 1999, which changed how both wholesale and retail electric operations in the state would be changed. Under SB7 Texas' electric industry within the ERCOT region reorganization incorporated the following key changes:

- Investor-owned electrical utility services were unbundled. On January 1, 2002 all investor-owned utilities unbundled their services into three service areas: generation, transmission and/or distribution, and retail functions. This created three new separate entities: a Power Generation Company, a Transmission and/or Distribution Service Provider, and a Retail Electric Provider.

- Retail customers of the investor-owned utilities who did not choose a new retail provider by January 1, 2002, automatically received service from the new Retail Electric Provider created by their existing utility.

- Transmission and/or Distribution Service Providers will continue to be regulated by the Public Utility Commission of Texas. Their meter reading functions, however, were open to retail competition beginning January 1, 2004.

- Power Generation Company's electrical capacity ownership is limited. After January 1, 2002, no Power Generation Company was allowed to own more than 20% of the generation capacity in the ERCOT region, or in any other power region in Texas. In addition, each Power Generation Company affiliated with an electric wires company must auction entitlements to at least 15% of its generation capacity for five years or until 40% of the customers in the wires company's service area switch to non-affiliated Retailers Electric Providers.

- New competitive Retail Electric Providers must establish a "price to beat." Retail Electric Providers affiliated with pre-existing investor-owned utilities are required to offer residential and small commercial customers in its former service area a "price to beat." This is a price that is 6% lower than the rate charged by its affiliated electric utility on January 1, 1999. The Retail Electric Provider cannot adjust this price until either (a) 36 months after retail competition is introduced or (b) 40% of the customers in its affiliated Transmission and/or Distribution Service Provider area have switched to another retailer.

- No-opt provision for municipally owned utilities or cooperatives. Municipally owned utilities and electric cooperatives can decide whether or not to participate in retail competition. If they do not opt-in, they will retain their existing service territories. Even if they do choose to opt-in and participate as a Competitive Retailer, they are not required to functionally unbundle their organizations. They may choose to opt-in to retail competition at any time, but once they opt-in to participate, they cannot reverse their decisions.

SB7 milestones include:

- September 1, 1999 through January 1, 2002 – (Frozen Rates) – Freeze on existing retail base rate tariffs.

- January 10, 2000 – (Separation of Business Activities) – Each electric utility files a plan with the PUCT to implement the unbundling of its business activities into power generation, retail electric provider and transmission.

- April 1, 2000 – (Transmission and Distribution Tariffs) – Utilities file proposed tariffs for transmission and distribution services and other charges.

- December 31, 2000 – (Market Power Mitigation) – Participating utilities controlling more than 20% of generation capacity in a power region must file market power mitigation plans to sell, auction, or otherwise mitigate capacity over 20% in a region.

- June 1, 2001 – (Retail Pilot Programs) – Start of mandatory pilot projects offering customer choice to 5% of a participating utility's combined load.

- November 1, 2001 – (Capacity Auction) – 15% capacity to be auctioned for participating utilities' installed generation at least 60 days prior to the date for customer choice to begin.

- January 1, 2002 – (Customer Choice Begins – Price to Beat) – Customer choice begins. Each participating utility's affiliated retail electric provider will make available to residential and small commercial customers rates that are 6% below the incumbent's January 1, 1999 tariffed residential and small commercial customer rates.

Following the Texas Senate's approval of SB7, and in anticipation of similar legislation passing in the Texas House, the TAC initiated voluntary and open public work groups comprised of existing and potential market participants, called stakeholders. Work groups were formed to address a number of issues including scope of responsibilities, control areas, scheduling, ancillary services, and load profiling. One work group committee, called the "Ad Hoc Committee on Possible Impacts of Future Electric Market Changes on the Independent System Operator," was responsible for assimilating the findings and recommendations. From this process, the group created the initial document that laid the groundwork for the scope and organization of ERCOT's new role under the complete industry restructuring to a competitive wholesale and retail electricity market environment.

The group's findings made recommendations for ERCOT that would ensure a smooth transition for the environment created by future market changes. Among its findings were the conclusions that ERCOT would need to expand and enhance its operations to accommodate the increased numbers and types of transactions that it would oversee. In addition, staffing and funding requirements would increase. The report also found that:

- ERCOT should be financially neutral in its operations.
- Multiple control areas would be unnecessarily complex. A single control area would be advisable.
- Balancing services would need to be addressed, including a real-time balancing market to provide Load Servicing Entities with necessary resource to balance load requirements.
- Settlement of energy balancing and some ancillary services to be supplied in a competitive retail market. For purposes of settlement, ERCOT must develop and implement a procedure to ensure that the energy supplied by each Load Serving Entity is properly reconciled against load actually served.
- Profiles would be required by Load Servicing Entities for determining load responsibilities for customers without real time meters.
- Ancillary services accounting would be ERCOT's responsibility and ERCOT's role in providing ancillary services was evaluated under a number of scenarios.

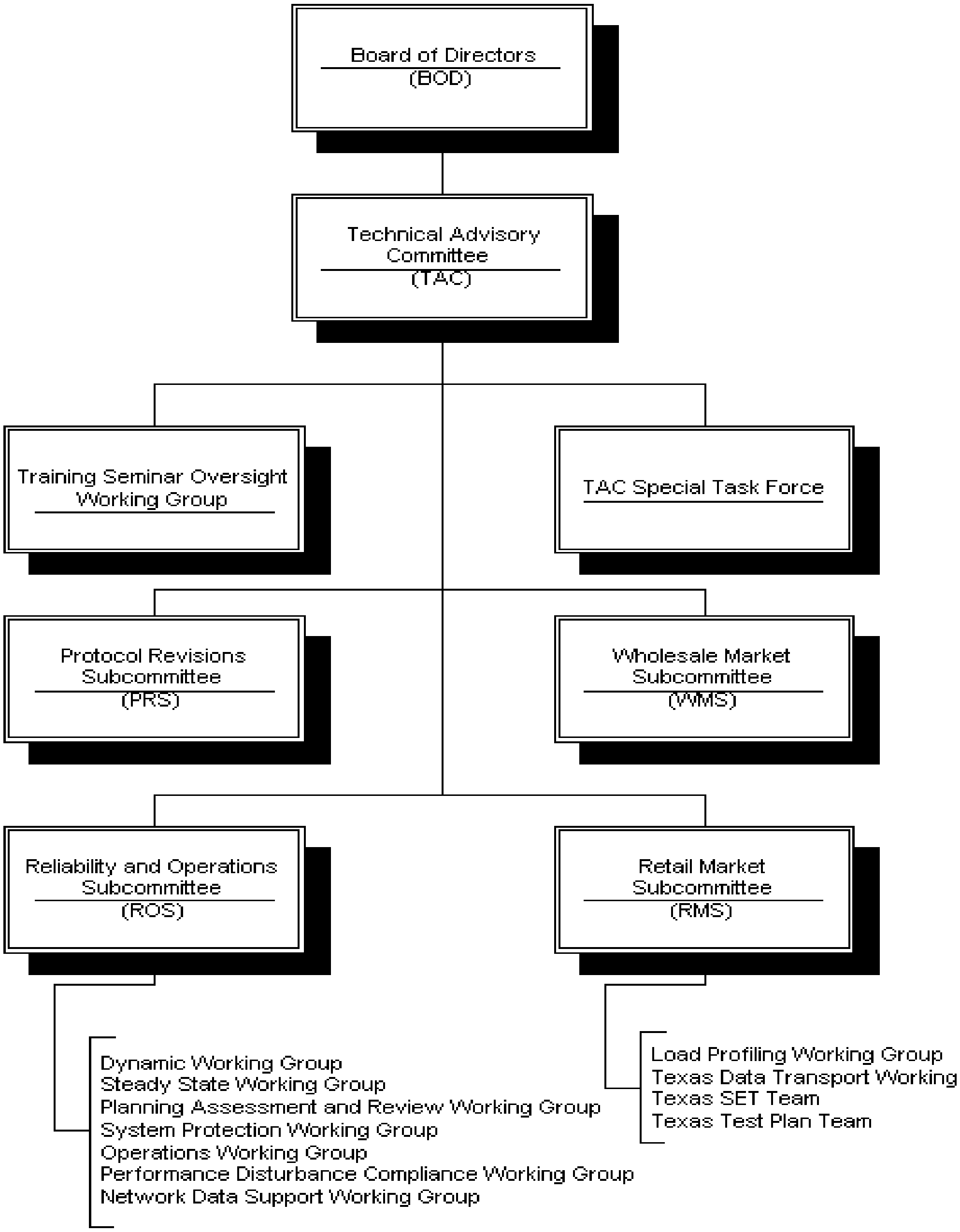
2.5 ERCOT's Governance

Because ERCOT is located entirely within Texas, the Public Utility Commission of Texas (PUCT) is ERCOT's principal regulatory authority. The Texas State Legislature establishes the laws related to the electric utility industry. A balanced Board of Directors, made up of members from each of ERCOT's electricity market groups, governs ERCOT. A Technical Advisory Committee (TAC) consisting of members from each market group makes policy recommendations to the Board of Directors. Four Subcommittees, a Working Group, and Task Force assist TAC. These include:

- The Protocol Revisions Subcommittee,
- The Reliability and Operations Subcommittee,
- The Retail Market Subcommittee,
- The Wholesale Market Subcommittee,
- The Training Seminar Oversight Working Group, and
- The TAC Special Task Force.

These committees are assisted by numerous workgroups and task forces. The Board of Directors hires the CEO and also appoints ERCOT's officers. These executives direct and manage ERCOT's day-to-day operations. This organization is shown in Exhibit 2-2.

Exhibit 2-2 ERCOT Organization



2.6 ERCOT Market Participants

ERCOT's members include Market Participants in the ERCOT region electric industry. They include participants from Cooperatives and River Authorities, Municipals, Investor-Owned Utilities, Independent Power Marketers, Independent Retail Electric Providers, Independent Generators, and Consumers. As of July 10, 2002, ERCOT's Membership included 144 voting and non-voting Members. The Member groups are comprised of 43 Cooperatives and River Authorities, 22 Municipals, 13 Investor Owned Utilities, 20 Independent Power Marketers, 15 Independent Generators, 14 Independent Retail Electric Providers, 15 Consumers, as well as 2 Adjunct Members. These members are shown in Exhibit 2-3.

Exhibit 2-3 ERCOT Members

C = Corporate S = Associate D = Adjunct

ACN ENERGY C
AEP TX COMMERCIAL & INDUSTRIAL RETAIL LIMIT. PARTN S
AES DEEPWATER, INC. S
AES NEWENERGY, INC. C
AIR LIQUIDE AMERICA CORPORATION C
AIR PRODUCTS & CHEMICALS C
ALCOA, INC. S
AMERICAN ELECTRIC POWER SVC. CORPORATION C
AMERICAN NATIONAL POWER C
AQUILA ENERGY MARKETING CORPORATION C
AUSTIN ENERGY C
BARTLETT ELECTRIC COOPERATIVE, INC. C
BASTROP POWER & LIGHT S
BELFALLS ELECTRIC COOPERATIVE, INC. C
BIG COUNTRY ELECTRIC COOPERATIVE, INC. C
BLUEBONNET ELECTRIC COOPERATIVE, INC. C
BP ENERGY COMPANY C
BRAZOS ELECTRIC POWER COOPERATIVE, INC. C
BRAZOS RIVER AUTHORITY - POSSUM KINGDOM s
BROWNSVILLE PUBLIC UTILITIES BOARD C
BRUBAKER & ASSOCIATES, INC. S
BRYAN TEXAS UTILITIES C
CALPINE CORPORATION C
CALPINE ENERGY SERVICES S
CAP ROCK ELECTRIC COOPERATIVE S
CARGILL-ALLIANT, LLC. C
CARTER & BURGESS, INC. S
CHEROKEE COUNTY ELECTRIC COOPERATIVE ASSN. C
CIELO WIND POWER, LLC C
CIRRO GROUP S
CITY OF COLLEGE STATION C
CITY OF CUERO C
CITY OF GONZALES S
CITY OF GRANBURY S
CITY OF HEARNE C
CITY OF LAMPASAS/ELECTRIC UTILITY C
CITY OF SAN MARCOS C
CITY OF SCHULENBURG S
CITY PUBLIC SERVICE C
COLEMAN COUNTY ELECTRIC COOPERATIVE, INC. C
COMANCHE ELECTRIC COOPERATIVE C
COMMONWEALTH ENERGY CORPORATION C
CONCHO VALLEY ELECTRIC COOPERATIVE, INC. C
CONOCO GAS & POWER MKT (A DIVSN. OF CONOCO, INC. S
CONSTELLATION POWER SOURCE C
COOKE COUNTY ELECTRIC COOPERATIVE ASSN., INC. C
CORAL POWER, LLC. C
COSERV ELECTRIC C
DEEP EAST TEXAS ELECTRIC COOPERATIVE, INC. C
DENTON MUNICIPAL ELECTRIC C
DUKE ENERGY NORTH AMERICA C
DYNEGY POWER CORP. C
ENCANA ENERGY SERVICES, INC. C
ENTERGY SOLUTIONS LTD. C
EXELON GENERATION COMPANY, LLC. (ExGen) C
EXELON GENERATION COMPANY, LLC. (ExGen) S
EXXONMOBIL GLOBAL SERVICES CO. C
FAYETTE ELECTRIC COOPERATIVE, INC. C
FIRST CHOICE POWER, INC. C
FLINT HILLS RESOURCES, L.P. C
FLORESVILLE ELECTRIC LIGHT & POWER SYSTEM C
FORMOSA PLASTICS CORP., TEXAS C
FORT BELKNAP ELECTRIC COOPERATIVE, INC. C
FPL ENERGY C
GARLAND POWER & LIGHT C
GEORGETOWN UTILITY SYSTEMS C
GREEN MOUNTAIN ENERGY CO. C
GEUS C
GEXA ENERGY S
GREGORY POWER PARTNERS, L.P. C
GUADALUPE-BLANCO RIVER AUTHORITY S
GUADALUPE VALLEY ELECTRIC COOP., INC. C
HALLIBURTON COMPANY C
HAMILTON COUNTY COOPERATIVE, INC. C
J-A-C ELECTRIC COOPERATIVE, INC. C
JACKSON ELECTRIC COOPERATIVE, INC. C
JASPER-NEWTON ELECTRIC COOPERATIVE, INC. C
KARNES ELECTRIC COOPERATIVE, INC. C
KERRVILLE PUBLIC UTILITY BOARD C
LONGHORN POWER, L.P. C
LOWER COLORADO RIVER AUTHORITY C
M&S ENERGY S

MAGIC VALLEY ELECTRIC COOPERATIVE, INC.   C
MARATHON ASHLAND PETROLEUM, LLC.   S
MARATHON OIL COMPANY   C
MCLENNAN COUNTY ELECTRIC COOPERATIVE, INC.   C
MEDINA ELECTRIC COOPERATIVE, INC.   C
MID-SOUTH ELECTRIC COOPERATIVE ASSOC.   C
MIRANT AMERICAS ENERGY MARKETING, L.P.   C
MIRANT TEXAS, L.P.   S
MORGAN STANLEY CAPITAL GROUP, INC.   C
MUTUAL ENERGY CPL, L.P.   S
MUTUAL ENERGY SWEPCO, L.P.   S
MUTUAL ENERGY WTU, L.P.   S
NAVARRO COUNTY ELECTRIC COOPERATIVE, INC.   C
NEW BRAUNFELS UTILITIES   C
NRG POWER MARKETING, INC.   C
NUCOR CORPORATION   C
NUECES ELECTRIC COOPERATIVE, INC.   C
OCCIDENTAL CHEMICAL CORPORATION   C
PEDERNALES ELECTRIC COOPERATIVE, INC.   C
PEDERNALES ELECTRIC COOP. RETAIL ELECT. PROVIDER   S
PG&E NATIONAL ENERGY GROUP   C
RELIANT ENERGY, INC.   C
RELIANT RESOURCES, INC.   S
REPUBLIC POWER, L.P.   C
RES NORTH AMERICA, LLC   C
RIDGE ENERGY STORAGE & GRID SERVICES   D
RIO GRANDE ELECTRIC COOPERATIVE, INC.   C
RWE TRADING AMERICAS, INC.   C
SAM HOUSTON ELECTRIC COOPERATIVE, INC.   C
SAN BERNARD ELECTRIC COOPERATIVE, INC.   S
SAN PATRICIO ELECTRIC COOPERATIVE   C
SEMPRA ENERGY SERVICES   C
SHARYLAND UTILITIES, L.P.   C
SMI- TEXAS, INC.   C
SOUTH PLAINS ELECTRIC COOPERATIVE, INC.   C
SOUTH TEXAS ELECTRIC COOP., INC.   C
SOUTHWEST TEXAS ELECTRIC COOPERATIVE, INC.   C
STRATEGIC ENERGY, LLC.   C
TAYLOR ELECTRIC COOPERATIVE, INC.   C
TECO POWER SERVICES   C
TENASKA ENERGY, INC.   C
TENASKA POWER SERVICES CO.   S
TEXAS INDEPENDENT ENERGY, L.P.   C
TEXAS INDUSTRIES, INC.   C
TEXAS-NEW MEXICO POWER COMPANY   S
TEX-LA ELECTRIC COOPERATIVE OF TEXAS, INC.   D
THE DOW CHEMICAL COMPANY   C
THE ENERGY AUTHORITY, INC.   S
THE NEW POWER COMPANY   C
TRACTEBEL ENERGY SERVICES, INC.   S
TRI-COUNTY ELECTRIC COOPERATIVE, INC.   C
TXU ELECTRIC   C
TXU ENERGY SERVICES   S
TXU ENERGY TRADING   S
UBS AG, LONDON BRANCH   C
UNITED COOPERATIVE SERVICE   C
UTILITY CHOICE ELECTRIC   C
VALERO REFINING-TEXAS, L.P.   C
VICTORIA ELECTRIC COOPERATIVE, INC.   C
WEATHERFORD MUNICIPAL UTILITY SYSTEM   C
WHARTON COUNTY ELECTRIC COOP., INC.   C
WILLIAMS ENERGY MARKETING & TRADING COMPANY INC.   C
WISE ELECTRIC COOPERATIVE, INC. C
WOOD COUNTY ELECTRIC COOP., INC. C

2.6.1 ERCOT Generation Sector

Various types of entities can produce and/or sell electricity to utilities at wholesale, such as independent power producers, qualifying facilities, cogenerators, exempt wholesale generators, and power marketers. The first four of these generate electricity, but power marketers only buy and sell electricity. Some non-utility entities are affiliate with regulated utilities. ERCOT's generation sector members are comprised of both utility and non-utility entities, as shown in Exhibit 2-4.

Exhibit 2-4 ERCOT Generation Sector

Independent Generator

Corporate Members
- American National Power
- Calpine Corporation
- Cielo Wind Power, LLC
- Dynegy Power Corp.
- Formosa Plastics Corp., Texas
- FPL Energy
- Gregory Power Partners, LP
- Sempra Energy Resources
- Teco Power Services
- Tenaska Energy, Inc.
- RES North America, LLC
- Texas Independent Energy, LP

Associate Members
- AES Deepwater, Inc.
- Exelon Generation Company, LLC
- Mirant Texas, LP

Investor Owned Utility

Corporate Members
- Reliant Energy, Incorporated

Associate Members
- TXU Energy Trading

Municipal

Corporate Members
- Bryan Texas Utilities
- City Public Service
- GEUS

Associate Members
- Brazos River Authority - Possum Kingdom
- Guadalupe-Blanco River Authority

3. ERCOT Operations

Beginning with the phased-in competitive retail market Pilot Program on June 1, 2001, ERCOT's duties are now categorized into four primary operations: Production Operations, Market Operations, Financial Operations, and Registration.

- **Production Operations**. This task involves system security, planning, and market support. These technical responsibilities include supporting resource and obligation scheduling, real time operations, operations analysis, system planning, analysis and data collection. In performing its responsibilities, ERCOT monitors and analyzes all of the electricity transmission components within the ERCOT region every two to four seconds for status, load, and output to maintain the reliable transmission of electricity at every moment. To support this responsibility, ERCOT has a sophisticated new technological infrastructure, called the Energy Management System, and an expanding engineering staff that monitors the balance between power generation and power demand. In this capacity, ERCOT will also keep an eye on Texas's future transmission requirements.

- **Market Operations**. This includes monitoring the intricate balance between forecasted electricity power generation schedules and actual electricity demands among all competing market participants. In this process, ERCOT conducts detailed studies of the estimated electricity generation and demand requirements of the marketplace for every 15-minute interval of every day. Plus, ERCOT assesses the ancillary services required to maintain reliable electricity production for the actual demand at any moment. Then it procures extra ancillary services to be on standby to ensure electric reliability when there are gaps between forecasted and actual electricity usage.

- **Financial Operations**. This duty includes client relations, meter acquisition and data aggregation, settlements, billing, business rules, registration, load profiling, and renewable energy credit program management.

- **Registration**. ERCOT is the centralized registration agent for both retail premises and market participants for the entire state of Texas.

3.1 Market Participants

There are six major subdivisions of Market Participants in the ERCOT region:

3.1.1 Qualified Scheduling Entities (QSEs)

QSEs are market participants that are qualified by ERCOT to submit balanced schedules and Ancillary Services bids and settle payments with ERCOT. They play a key role in the competitive retail market. QSEs are the main information interface with ERCOT to support market operations. All scheduling of energy or bidding for ancillary services must be done through a QSE. The schedules that QSEs submit must be "balanced" in terms of loads and their corresponding Resources. For example, a schedule that indicates a load of 2 MW but corresponding Resources of only 1 MW will not be balanced because there are insufficient resources for the load. For every Settlement Interval, which lasts 15 minutes, ERCOT will accept balanced schedules from QSEs that identify the source and destination of contracted power flows, as well as their amount and timing. ERCOT will compare the sum of these schedules to its own load forecasts, to determine balancing energy and ancillary services requirements.

ERCOT and QSEs work closely to provide the ancillary needed to ensure system reliability services through a series of markets that ERCOT operates. Each day and during the operating day, ERCOT sends instructions, including regulation signals, balancing instructions, and accepted bid information to the QSEs. QSEs then relay these instructions to the appropriate market participants as required. If QSE-submitted schedules result in congestion of the transmission system, ERCOT may need to re-dispatch system Resources out of merit order in order to resolve the congestion. Market Participants pay for the costs of such re-dispatch, also known as congestion costs. QSEs can bid into the balancing energy market and other ancillary services markets based upon the availability of Resources in their portfolio. If ERCOT selects the bid, they reimburse the QSE at the Market Clearing Price.

According to the ERCOT Market Guide V 1.2, "The financial settlement for balancing energy and ancillary services used by ERCOT takes place between QSEs and ERCOT. Settlement of the balancing energy is based on the load imbalance and Resource imbalances from each QSE. The load imbalance is the difference between the scheduled load and actual load from each QSE. Resource imbalance is the difference between the scheduled energy and actual energy for each QSE. The actual load and energy amounts are derived from the load and resource meter readings. For example, when a QSE's actual energy supplied from its resources it represents is insufficient to match the scheduled energy in the balanced schedule it provided to ERCOT, that QSE would be required to reimburse ERCOT for the balancing energy ERCOT procured, at the Market Clearing Price. On the other hand, if ERCOT accepts a balancing energy bid by a QSE from the ancillary services market, ERCOT will pay the QSE as appropriate at the Market Clearing Price.

"In order to settle with QSEs, ERCOT will aggregate load and resource data for every settlement interval. ERCOT will then calculate the load imbalance as the difference between scheduled and the aggregated load data, to issue the appropriate credits and/or debits to QSEs. The same comparison is made between aggregated energy supplied from the resources provided by the QSE and the scheduled energy to allocate the appropriate debits and/or credits due to the resource imbalance."

3.1.2 Resources

Resources are either generation owners or entities controlling load that can be interrupted on demand. They trade their energy privately with other market participants and must report the resulting schedules to ERCOT through their QSEs.

3.1.3 Load Serving Entities (LSEs)

Load-Serving Entities, or LSEs, are either: (1) Competitive Retailers (CRs) which are the only entities allowed to sell retail electricity to customers that have customer choice, or (2) Non Opt-in Municipal Utilities or Cooperatives. CRs may either be Retail Electric Providers (REPs) or Opt-in Municipal Utilities or Cooperatives. LSEs forecast their customer load and negotiate privately with Market Participants like Resources or power marketers to purchase, and then adivse ERCOT as to the resulting schedules through a QSE.

ERCOT operates a central customer facility (premise) registration system that supports the customer switching process by communicating requests to switch and meter consumption data between CRs and TDSPs. ERCOT also keeps track of the relationship between premises and load serving entities.

3.1.4 Transmission and/or Distribution Service Providers (TDSPs)

TDSPs provide and maintain the electric system infrastructure and work together with ERCOT to manage the transmission system. TDSPs are responsible for load and resource meter installation as well as submitting data for all metered loads and resource not polled directly polled by ERCOT. TDSPs must also perform meter management and meter reading activities until those services are opened to competition in 2004.

ERCOT needs TDSPs to provide meter reading and consumption information in order to correctly settle the balancing energy and ancillary service markets. Consumption information for each LSE determines whether schedules submitted by its QSE match the actual load. If not, the difference will be settled with QSEs at the Balancing Energy Market Clearing Price.

Currently the majority of end-use customer meters only yield data once a month, when they are read. Yet energy consumption information for each 15-minute interval is vital to properly perform 15-minute settlement. To overcome this issue, ERCOT uses standard load profiles to estimate how monthly consumption breaks down into 15-minute intervals for different customer segments. Over time advanced meters, which can measure usage in 15-minute intervals will be installed at more customer locations, thus reducing or eliminating the need for this estimation process.

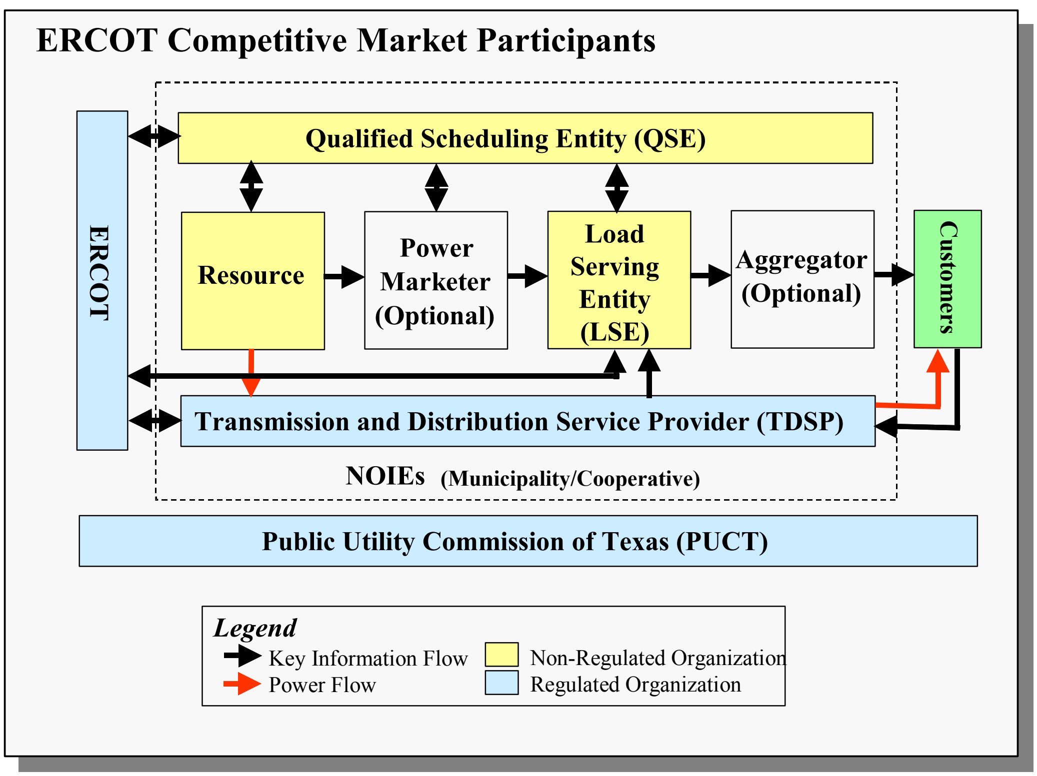
3.1.5 Non-Opt-In Entities (NOIEs)

Municipalities and Cooperatives may choose to remain functionally bundled organizations, and will not need to submit switching requests to ERCOT because their customers will not have a choice of electric retailer. However, these entities will continue to participate wholesale competitive market transactions, including acquiring energy bilaterally and submitting balanced schedules for energy to ERCOT.

3.1.6 Other Participants

Other Participants that may operate in the ERCOT market are Power Marketers, who buy and sell blocks of energy, and Aggregators, who acquire groups of retail customers. Power Marketers will need to schedule their power through a QSE. The PUCT retains oversight on these entities and monitors market activity to stem potential market abuses and/or gaming.

Exhibit 3-1 ERCOT Market Participants



Source: The ERCOT Market Guide Version 1.2

3.2 Market Fundamentals in ERCOT

3.2.1 Bilateral Market

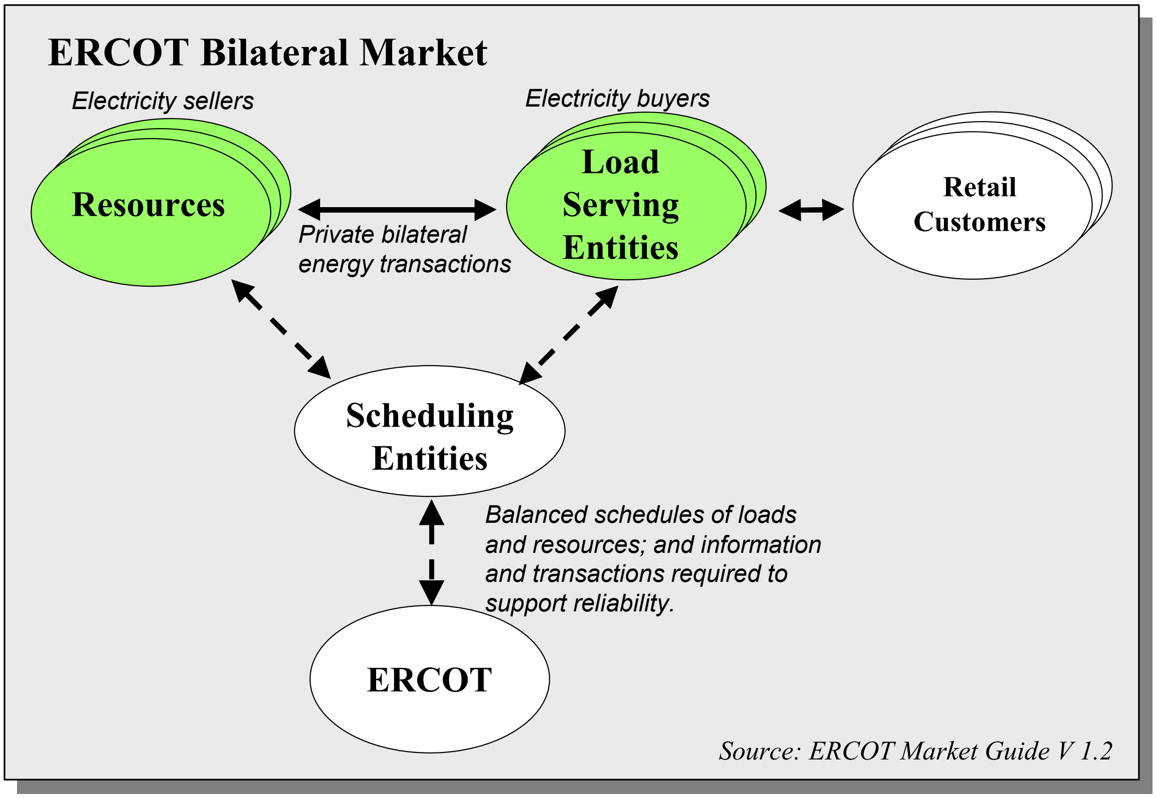
A key feature of the ERCOT competitive retail electricity market is that it will be based on "bilateral" transactions between buyers and sellers of energy, as shown in Exhibit 3-2. The Bilateral Market makes up 90 to 95% of the electrical power market in the ERCOT Region. The price is established based on contracts and are not known by ERCOT.

QSEs must to turn balanced energy schedules of load and energy required to serve the load in to ERCOT. These schedules are largely comprised of bilateral trades between load and Resource entities. ERCOT only operates the electricity markets needed to address energy imbalances that occur because differences exist between the real time system requirements and the system loading anticipated in the balanced schedules. This is different than other markets, where power generating companies sell electricity into a "pool" and LSEs purchase from the same "pool" in an open exchange where demand and supply sets market prices for buyers and sellers. There are also no markets for a separate "installed capacity" or ICAP commodity in ERCOT such as those that exist in PJM.

As indicated in ERCOT's Market Guide Version 1.2, "LSEs buying energy and Resources selling energy will communicate operational information such as their bilaterally arranged balanced schedules of loads and resources to ERCOT through their QSEs. ERCOT will ensure that the power grid can accommodate the schedules that were generated by the bilateral market.

"ERCOT makes an assessment of the ancillary services needed to accommodate the bilateral schedules and the QSEs are asked to either provide their share of these services from their own resources or let ERCOT purchase these services from the market on their behalf. Market Participants may self provide all or part of their share of ancillary services. ERCOT is uniquely positioned to identify the ancillary services needed to resolve system conditions like capacity inadequacy and congestion, and to maintain reliability."

Exhibit 3-2 ERCOT Bilateral Market



3.2.2 Balancing Market

The Balancing Market makes up the difference between the total ERCOT electricity requirements and the sum of the Base Energy Schedules. This market totals 5 to 10% of the total electricity market in the ERCOT Region. This market is also used to control transmission congestion through zonal procurement of the Balancing Market electricity. This energy is procured from the market every 15 minutes based on bids submitted to ERCOT. The quantity required is established based on the total system forecasted requirement. Bids are accepted from the lowest price and continuing higher until the requirement is satisfied. The highest price paid to satisfy the last required quantity sets the Market Clearing Price of Energy (MCPE) for that 15-minute interval. This is the price paid for all Balancing Market electricity purchased during that 15-minute interval. This purchasing is done on a zonal basis to balance transmission within the system if there is transmission congestion. Therefore the MCPE can be different in each zone during any 15-minute period.

3.3 Ancillary Services

ERCOT relies on the availability of generation capacity to provide balancing energy to maintain the electric system within prescribed reliability limits. Generating Resources that can be on standby and available to be dispatched to provide energy or loads that are available to be interrupted may provide these services, known collectively as "Ancillary Services." Ancillary Services are procured on a continuing basis to assure capacity reserved as backup for reliability and security of the system. Ancillary services are arranged for in day-ahead markets and deployed in real time during the operating day. Responsibility for payment of these services is allocated to the Load Serving Entities (LSE's) based on proportional load. LSE's can self-arrange some or all of their responsibility for most services with bilateral agreements. There are several categories of Ancillary Services, but the two types that are most important to a discussion of the ERCOT markets are:

- **Capacity** – or generation reserve available to be used if needed to provide balancing energy or loads available to be interrupted reducing the need for additional capacity.

- **Balancing Energy** – or energy deployed to ensure that supply and demand are in balance or loads interrupted to avoid the need for additional energy.

3.3.1 Ancillary Services – Capacity

ERCOT continuously monitors the available reserve capacity across the system to prepare against the impact of unforeseen events, ranging from imbalances between scheduled and actual demand to the catastrophic loss of a large generator or transmission facility. ERCOT obtains any amount that is not self-arranged through bids and the market clearing price process for each hour of the following day. The result is the Market Clearing Price of Capacity (MCPC).

The first three services listed below are the first ancillary services that ERCOT procures each day. They are required in amounts specified by ERCOT (which are re-determined annually), independent of the scheduled amounts of generation and load. These Capacity Ancillary Services that are procured include:

3.3.1.1 Regulation Reserve (Up and Down)

This is generating capacity that can follow instantaneous load changes to maintain system frequency. It provides energy in response to electronic signals sent by ERCOT. The current system requires 1800 MW up or down.

3.3.1.2 Responsive Reserve

This represents generating capacity or interruptible load that can be deployed within 10 minutes and either produce energy or quit using energy when frequency drops due to a system disturbance (i.e., a unit trip). The current and historical requirement is 2300 MW.

3.3.1.3 Non-Spinning Reserve

This is offline or unloaded generation or interruptible load that can produce energy or quit using energy within 30 minutes upon ERCOT request. It is used to get Responsive Reserve back to 2300 MW if it is used or if Balancing Energy is almost depleted. The requirement is 1250 MW when needed.

3.3.1.4 Replacement Reserve

The fourth and last type of Ancillary Services-Capacity that ERCOT may procure, Replacement Reserve, *is* dependent on the scheduled amounts of generation and load. This is generating capacity (or interruptible load) that is not planned to be available for the next day that ERCOT sees is needed to provide Balancing Energy for a system deficiency or congestion management. This ancillary service is only arranged by ERCOT. The quantity is dependent on forecast conditions and/or resource plans provide by the Qualified Scheduling Entities (QSEs).

3.3.2 Ancillary Services – Balancing Energy

Balancing Energy, like Replacement Reserve, is procured and deployed based upon ERCOT's assessment of its need on an interval-by-interval basis to keep the system in balance and minimize the net energy needed in real time from regulation service providers.

As ERCOT moves even closer to the real-time interval in which the energy will actually be delivered, it constantly is fed additional information that improves its ability to forecast system electric requirements. As the day-ahead energy schedules are finalized for a given 24-hour period, QSEs submit Resource Plans for generators that indicate the amounts of generation capacity that is readily available if needed but not planned to be delivered to the grid, and energy that will be generated to serve the generators' contracted amounts of load.

After evaluating forecasted loads, schedules, transmission system conditions and resource plans, ERCOT procures balancing energy approximately ten minutes before the time of actual power flow, by which time the amount needed can be very accurately predicted using short-term forecasting tools. Replacement Reserve Ancillary Service providers submit Balancing Energy bids at the same time they submit their Replacement Reserve capacity bids. These Balancing Energy bids are included in the bid stacks for the hours in which their Replacement Reserve bids were awarded. Ancillary service providers may not bid the capacity that they have sold to ERCOT into the market for other capacity services.

3.3.3 Transmission Congestion Rights (TCRs)

Congestion occurs when electric generation must be dispatched out of economic merit order because local transmission system safety limits have been reached. This means that the cost for energy is greater over the constrained path than that along unconstrained paths. In the past, ERCOT assigned the additional cost of what ERCOT calls Commercially Significant Constraints (a path or point on the transmission grid that is found to result in congestion that limits the flow of energy to a commercially significant degree) or CSCs to QSEs based on the proportion of their load to the total load they served. This was by far the simplest solution, but created no incentive to relieve congestion as those entities that were creating the problem paid the same as those that were not. However, the ERCOT Protocols provided that ERCOT must convert to a more direct assignment of congestion costs at the earlier of May 1, 2004 or within six months after the costs of clearing congestion during a twelve month period reaches $20 million.

ERCOT's best information indicates that the $20 million threshold was reached on or about August 14, 2001, thereby requiring best efforts to implement a TCR auction and direct assignment of CSC Congestion costs. Therefore, a new method of zonal congestion cost allocation was instituted earlier this year, and a TCR auction process conducted in late January 2002.

Under the zonal method of assigning congestion costs, each QSE's impact on specific CSCs is calculated. Groups of CSCs sharing similar constraint patterns are aggregated into zones (determined each year). There are currently four such aggregated CSC zones; ERCOT West, ERCOT South, ERCOT Houston, and ERCOT North. QSEs are charged their portion of the "shadow cost" or difference between the constrained and unconstrained MCPE in each zone times their load for each interval.

TCRs are financial instruments that enable QSEs to hedge against the risk of incurring CSC congestion charges. Each MW of transmission capacity on each CSC is equal to 1 TCR for that constraint. These congestion rights are now auctioned to the highest bidder, and are applicable for a defined period, typically one year or one month. The owner of a TCR can use it to avoid the congestion charges for a corresponding constraint, for the period in which the rights are valid.

TCRs are:

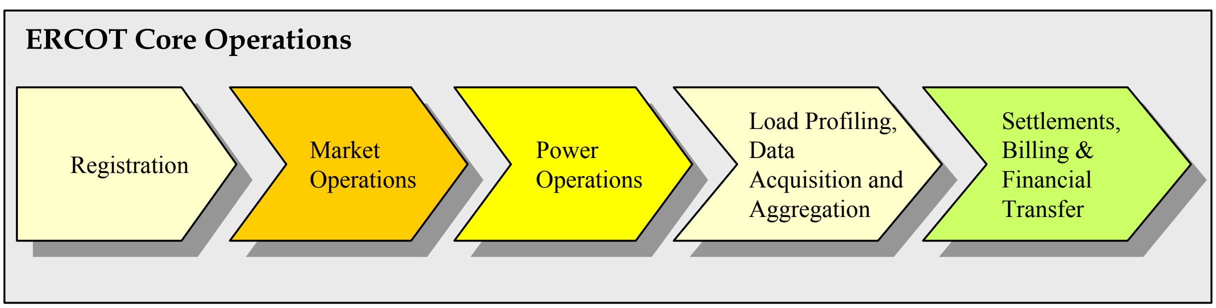
- A financial option, not an obligation.
- Directional in nature.
- A financial instrument whose owner is entitled to receive its value independent of use.

- Available in Annual or Monthly auctions.
- Determined by ERCOT based on ongoing analysis.
- Are expected to be settled on an intrazonal basis, as well as zonal, in the future

3.4 ERCOT Core Processes

This section describes ERCOT's Core Processes and is taken mostly from ERCOT's Market Guide Version 1.2. ERCOT is continuously performing five major processes to support the competitive retail market:

- Registration
- Market Operations
- Power Operations
- Load Profiling, Data Acquisition & Aggregation
- Settlements, Billing & Financial Transfer



Source: ERCOT Market Guide V 1.2.

3.4.1 Registration

The ability for customers to switch competitive retailers (CRs) is fundamental to supporting retail competition. ERCOT is the registration agent for the entire state of Texas. It uses a centralized registration system to register retail premises and market participants alike. ERCOT is responsible for the registration of:

- Market participant **organizations**, and the people within those organizations who are authorized to access ERCOT computer systems. Each time an organization joins the ERCOT market, it will provide this information.

- Market participant **assets,** which are resources that participate in the supply of energy and ancillary services, including both generating units and loads acting as resources.

- Metered and un-metered retail **premises** of customers who are in the competitive market. This information is sent to the ERCOT database by the TDSPs that serve those retail customers.

The ERCOT centralized registration database contains the minimal information that ERCOT needs to facilitate the process of a customer switching CRs. Additional information on retail premises such as customer names and telephone numbers is not stored by ERCOT.

When ERCOT receives a switch request from a customer's New CR, it verifies that the New CR is certified by the PUCT, registered with ERCOT, and authorized to serve the customer's premise area. ERCOT notifies the customer and both CRs about the impending switch. ERCOT also notifies the Transmission and/or Distribution Service Provider (TDSP) so it can send detailed premise data, like historical usage, the rate class and meter type. This information is sent from the TDSP to ERCOT, which forwards it to the New CR. The New CR needs this data in order to prepare for the switch.

When the TDSP reads the customer's meter, it sends the reading data to ERCOT, which forwards it to both CRs and finalizes the switch. The CRs need this meter reading information in order to determine when the customer stops being billed by the Current CR and starts being billed by the New CR.

3.4.2 Market Operations

In this process ERCOT assesses the amount of ancillary services required to support the reliable operation of the grid, and procures those services. The market operations process contains four major sets of activities: Day-Ahead Market, Adjustment Period, Hour-Ahead Period, and the Real Time Balancing Energy Market Clearing as discussed in Section 3.5.

3.4.3 Power Operations

The power operations process runs continuously as power flows, to ensure reliability of the grid. ERCOT operates the power grid in accordance with market rules, monitors all network generators and bulk transmission line loading and voltage, as well as the current status of all network generators and bulk transmission facilities, and manages frequency through deployment of Regulation, balancing energy or deployment of other ancillary services.

An Energy Management System that is configured for the ERCOT region enables the power operations process to perform an analysis of reliability every 2 to 4 seconds. The Energy Management System is essential for maintaining system reliability, and frequency at 60 Hertz. Deviations from this frequency are detected by the system, which then sends requests for small increases or decreases in generation to QSEs.

The energy management systems used by the QSEs to control their generation resources respond to ERCOT signals and provide the increases and decreases in output, which are required to restore system frequency.

The power operations process also includes a series of activities to ensure system reliability in the longer term. ERCOT analyzes the changing energy consumption patterns of the ERCOT region and provides load forecasts several years into the future. Market participants and the Public Utility Commission of Texas (PUCT) use this data to evaluate the need for transmission and generation.

3.4.4 Load Profiling, Data Acquisition and Aggregation

3.4.4.1 Load Profiling

In order for ERCOT to determine the load obligations of each QSE during each 15-minute period of each settlement day, it is necessary to allocate energy consumption data collected from the TDSPs into 15-minute intervals. Interval data recorders (IDRs), which collect consumption data in 15-minute intervals, are required to be installed at large commercial and industrial load exceeding 1000 kW of demand. Even though IDRs are installed at some utilities below the 1000 kW level, cumulative (non-IDR) meters will continue to be used at most residential and small commercial loads due to the higher cost of IDRs. Some loads such as streetlights will also continue to be unmetered.

Meter data from cumulative meters and estimated consumption from unlettered loads is allocated into 15-minute intervals through the process of Load Profiling. This process uses load profile models or energy consumption patterns to allocate cumulative meter readings into estimated 15-minute consumption values. Load profiles are patterns of energy consumption at various hours of each day that are developed by studying groups of loads with similar consumption patterns

ERCOT develops and maintains load profile models for residential, small commercial and unmetered loads in the ERCOT region. Load research data from utilities was used to create load profile models and identify the profile zones and classes. These profile models are adjusted daily using actual weather and calendar data, for use in the aggregation processes. ERCOT gives market participants a description of the profile models so they can forecast their own loads and better manage their costs and revenues.

Proper allocation of load obligations at different times during the day using Load Profiling is important to market participants because energy prices are more costly during periods of high demand.

Load profiling has been used in many markets to enable the participation of residential and small commercial loads without incurring the higher cost of IDRs. The process of estimating interval consumption data from cumulative meter data through Load Profiling can introduce inaccuracies for premises whose energy consumption patterns may not be adequately represented by the profile models. Competitive Retailers who want to ensure that their load obligations for each settlement interval are calculated using actual interval data can install IDRs.

3.4.4.2 Data Acquisition and Aggregation

Data Acquisition is the process of receiving and processing energy consumption and production data from TDSPs. It also supports the retrieving, validating, editing and estimating of energy production and consumption data from ERCOT polled settlement meter points. This process provides the necessary meter data for the ERCOT data aggregation process. Data Aggregation is the process of:

- Receiving, retrieving and estimating energy production and consumption data from all points within ERCOT.
- Grouping the data by responsible entity.
- Applying load profiles, appropriate loss factors and allocation mechanisms (UFE).
- Providing the necessary billing determinants to settle the market for each 15-minute interval on a daily basis.

The centralized aggregation of data by ERCOT has a number of benefits:

- Provides a central data repository that allows for ESI-level validation of data completeness.
- Standardizes methods for estimation, application of profiles and aggregation.
- Facilitates changes to market (e.g., zonal changes, profile methodology, utility unbundling, etc).
- Is consistent with centralized registration and load profiling.

3.5 Market Timeline

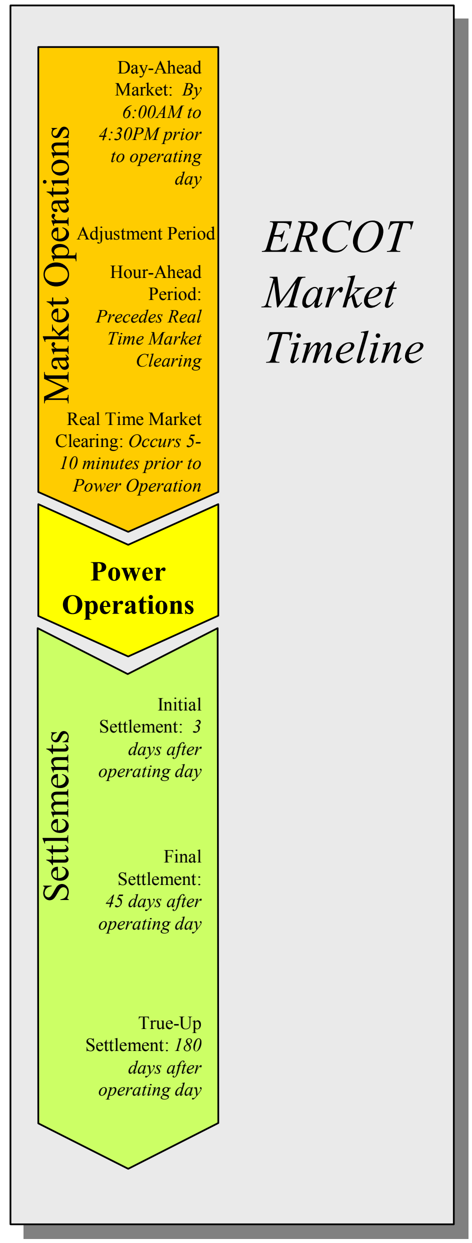
This description of the ERCOT Market Timeline comes from the ERCOT Market Guide Version 1.2. The market timeline combines the operations processes from the preceding section with the settlements process. Market operations enable a competitive ancillary services market. Power operations support the reliability of the grid. Settlements allocate the resulting costs among QSEs.

3.5.1 Market Operations

Day-Ahead Market occurs from 6 a.m. to 4:30 p.m. on the day prior to the operating day. QSEs submit balanced schedules and ancillary services bids based on operation forecasts. Ancillary services for Regulation, Responsive, Non-Spinning and Replacement Reserve capacity markets clear, and ERCOT publishes the results.

Adjustment Period happens in the time between the Day-Ahead Market and Hour-Ahead Period. QSEs may modify their schedules and outstanding bids. ERCOT may procure additional ancillary services as needed, based on its analysis of changed schedules, resource plans, load forecasts, and other system conditions.

Operating Period includes the Operating hour and the hour prior to Operating hour. During the Operating period, ERCOT performs look-ahead analysis of the physical system and identifies operational constraints. If necessary, ERCOT requests unit-specific energy bids, as well as Out-of-Merit Energy, Reliability-Must-Run units, or Non-Spinning Reserve energy. 10 minutes prior to the Settlement Interval, ERCOT clears the balancing energy market, and instructs those QSEs whose bids were selected to provide balancing energy for the Settlement Interval.



Source: ERCOT Market Guide V 1.2

3.5.2 Power Operations

Power Operations run continuously. ERCOT operates the grid according to market rules. The ERCOT power operations system monitors and analyzes all grid components every 2 to 4 seconds for status, loading and output. In conjunction with the transmission control centers of the TDSPs in the ERCOT region, ERCOT supports the safe and reliable operation of the power system.

3.5.3 Settlements

Initial Settlement: 3 days after the operating day, ERCOT runs the settlement program for the Settlement Intervals in that day. For most premises this settlement is based on estimated consumption using average daily usage from previous months.

Final Settlement: 45 days after the operating day, ERCOT runs the final settlement program for the Settlement Intervals, and incorporates any revised results. This settlement is based on actual premise consumption.

True-Up Settlement: In 6 months ERCOT issues this statement to reconcile any late or final metering information, and resolve any outstanding disputes.

Resettlement: ERCOT may run a resettlement as needed if disputes or data error result in an impact greater than 2% of the ERCOT Operating Day market transaction dollars, excluding bilateral transactions.

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4. GENERATION & TRANSMISSION IN ERCOT

ERCOT is historically a summer-peaking Region. The summer season for ERCOT is considered to be June, July, and August. Most of the peaks occur in August but a few have occurred during July. Peaking during the other seasons occurs most commonly in December for winter, May for spring, and September for the fall season. The projected annual net peak demand for ERCOT for the next five years is projected to increase yearly at 4% in 2004 and an average 2.7% in 2005 through 2007. In 2007 this total to an estimated peak of 68,715 MW less 176 MW of summer interruptible load resulting in a Firm Peak Demand of 68,539 MW.

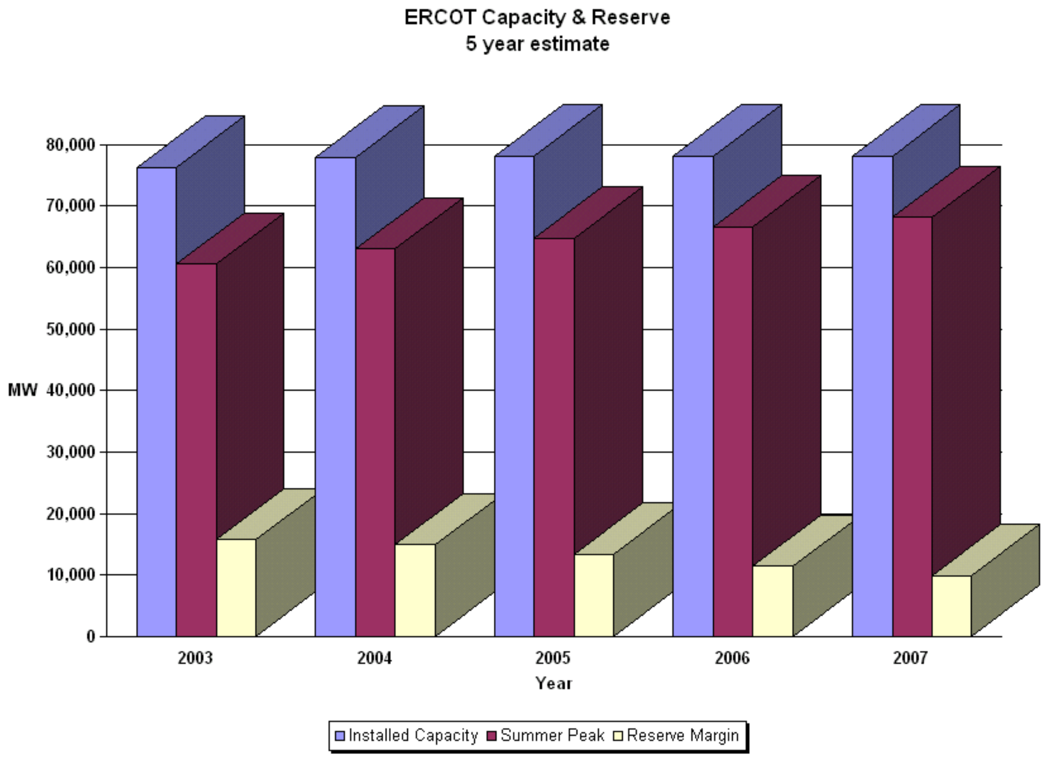
4.1 Resource Assessment

The reserve margins for the five-year assessment period (2003–2007) are at or above the ERCOT reserve margin standard of 15% until 2007 when they show a 14.6% reserve margin. The Steady State Working Group (SSWG) working under the direction of the Reliability and Operations Subcommittee (ROS), as part of its overall assessment of resource adequacy, determines the most restrictive load flows base cases for both each of the operating seasons. The Reserve Margin is determined by utilizing the net of the total peak demand (which includes the projected effects of conservation) minus the effects of exercising load management and interruptible loads during the peak demand periods.

ERCOT members are projecting the net addition (i.e., additions less removals) of 27,416 MW of new capacity over the next four years. Based on the system planning forecast, this will satisfy the 15% reserve margin required through the year 2006. Of the proposed new plants under development most are gas fire combined cycle, gas fired combustion turbine or wind power units.

The increased reliance on generation that requires a short build time, such as combined cycle and combustion turbine units that burn natural gas, is evident in the assessment. This technology gives the demand serving entities considerable flexibility in reacting to a dynamic marketplace in today's changing and competitive environment. This changing environment will continue to place more emphasis on increased efficiency of existing units. Exhibit 4-1 indicates the reserve situation in ERCOT over the next 5 years as described above. Installed capacity against the forecasted peak requirement indicates sufficient reserves through this time period.

Exhibit 4-1 Forecasted Reserve Margin



4.2 Adding New Generation Capacity in ERCOT

This section discusses the ERCOT approval process required of a generating company owner planning to add any interconnected generation in the region. Adding new capacity with the deregulation of the electric market has become a marketplace function. Generation interconnection information and data are treated as proprietary and market sensitive. This information is not released to the public until appropriate authorization is received. The information is sensitive in a competitive market. It is not to be released until transmission providers' reviews are completed and the generator has made a public commitment to construct. As of July 2002, there were 16 applications before ERCOT for new power plant interconnection studies. These projects represented more than 7,500 MW. The type of plant, its fuel supply, size, and location are determined by market conditions and the objectives of private developers.

4.3 Approval Process for of a New Interconnection

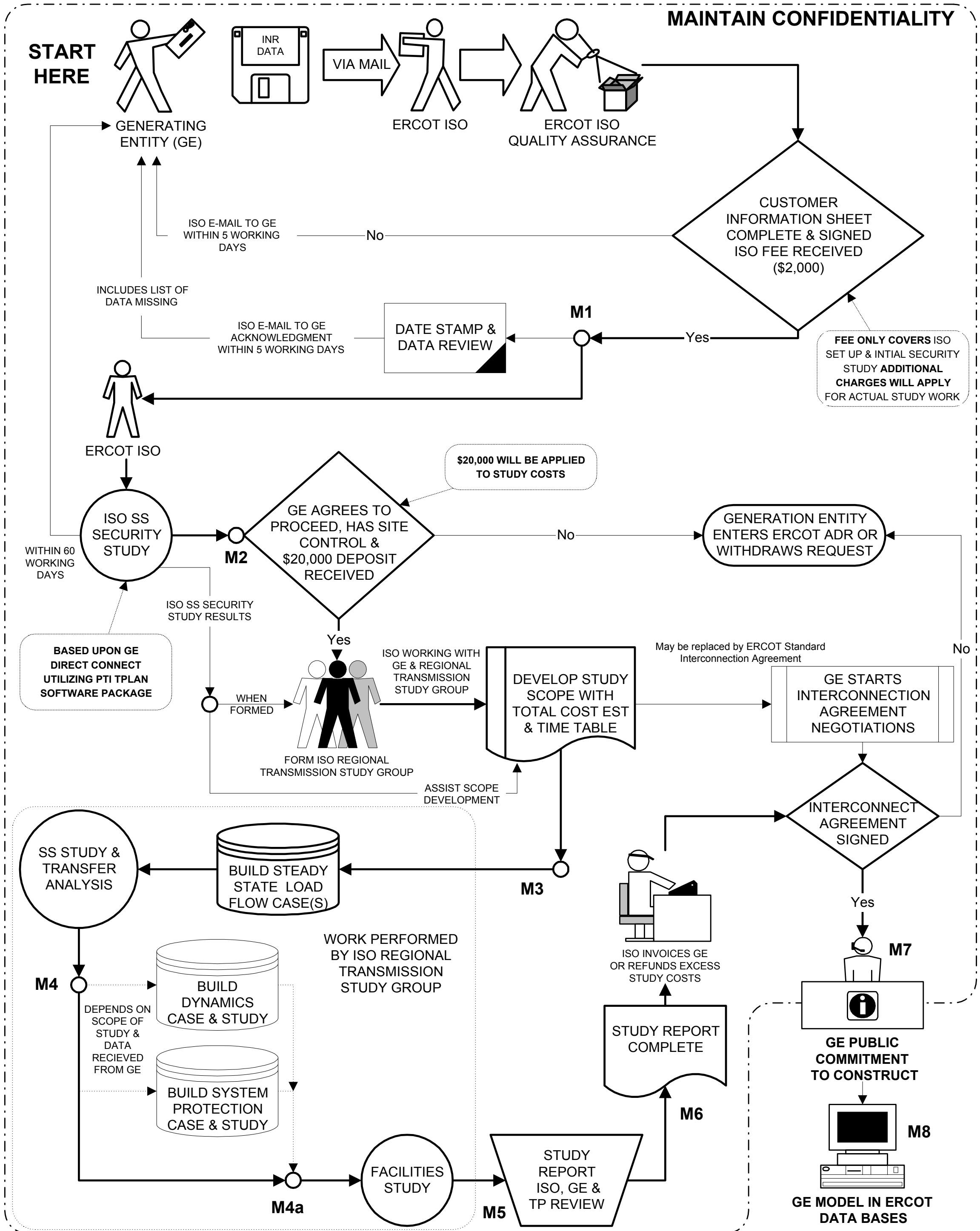
For the purpose of determining whether a proposed generation is to be approved ERCOT completes a study of the proposal. After ERCOT reviews and acknowledges the request for an interconnection, they perform a Steady State Security Study. Upon completion of this the Generating Entity (GE) then agrees to proceed and submits a deposit ($20,000) and Site Control Documentation. This is followed by the formation of an ERCOT study group that proceeds to develop a Study Scope. This study scope includes:

- Steady State and Transfer Analysis Study
- Dynamics Analysis
- System Protection Analysis
- Facilities Study

Upon completion of the study a report is issued for review.

Though the interconnection request is submitted to ERCOT, the interconnection agreement is negotiated separately with the Transmission Service Provider (TSP). As part of the study process a new interconnection project that is obligated to satisfy the queuing and reliability impact study requirements of ERCOT, the following factors will apply:

Exhibit 4-2   ERCOT Generation Interconnection Process



4.4 Steady-State Analysis Study

This is a load flow, power flow, transfer analysis. The ISO shall use existing SSTF Analyses as a base case to begin this study. The base case is updated to reflect changes required due to unspecified resource or additional resources from prior Generation Interconnection Requests. Contingency analyses are completed as outlined in ERCOT Planning Criteria. From this Transmission Facility Additions are identified that would be required to ensure expected system performance.

4.5 Transient Analyses Study

Transient stability studies will be performed where stability concerns exist. These studies will include all existing or committed generation in the area operating at full output. Again these studies are performed based on the latest SSTF Base Case for the area. These studies are performed in accordance with requirements of the ERCOT Planning Criteria and shall identify additional transmission facilities or other actions necessary to ensure conformance to that standard. Other types of studies such as voltage stability, subsynchronous resonance studies, etc. will be defined in the study scope as warranted.

4.6 System Protection Study

This study will specify where short circuit fault duties will be calculated and documented. The ISO along with the TSP determines if the interconnection of the generating plant and associated transmission system modifications cause any transmission facility to violate the TSP short circuit criteria. System improvements if any to address violations are determined. Also the available fault currents at the interconnection substation are determined for relay setting purposes.

4.7 Study Schedule

ERCOT establishes and completes studies of Generation Interconnection Requests on a schedule mutually agreeable to the GE and the study group.

4.8 Committed ERCOT Capacity Additions

ERCOT has responsibility for Regional Transmission Expansion Planning and oversees the process of adding new generation resources to the ERCOT region. ERCOT created a procedure for analyzing the impact of new electric generation interconnection requests. Generators in ERCOT may:

- Sell generation directly into Balancing Market.
- Sell capacity bilaterally.
- Sell Regulation into the Ancillary Services Markets.
- Sell energy from their unit to areas outside of ERCOT.
- Self-schedule their generation to serve their load obligation.

4.9 Existing & Planned Units in ERCOT

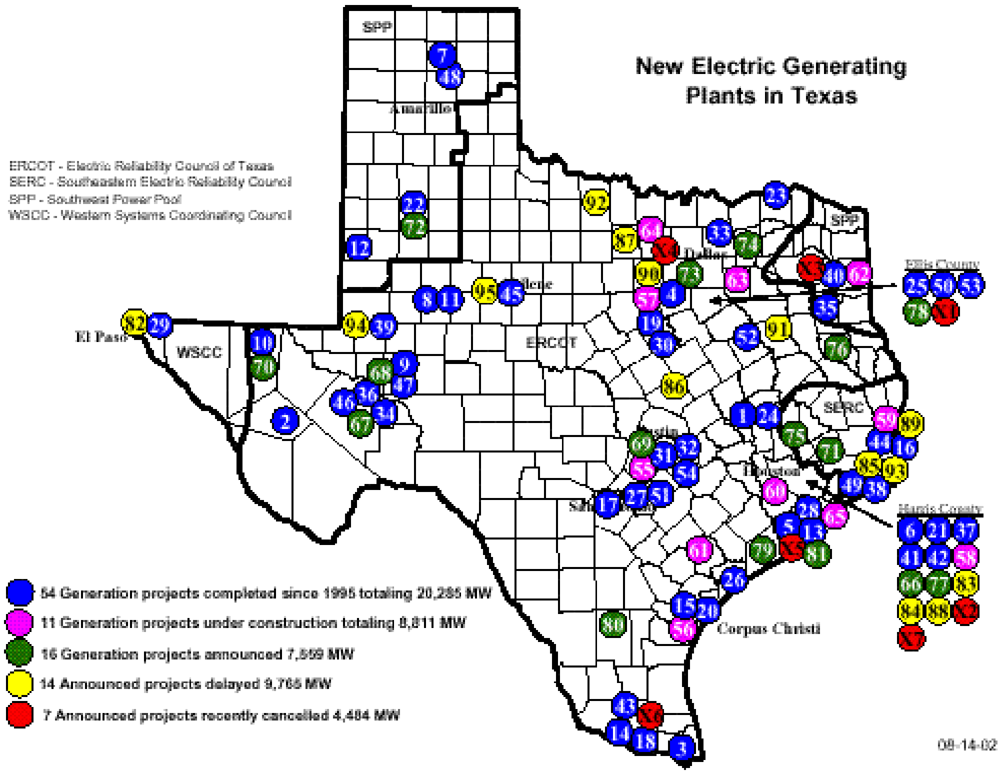
As part of the regional characterizations, the GEMSET Team collects data on each generating unit in a particular region. In Appendix A of this characterization are all of the identified units currently in the ERCOT. This information will be utilized to develop pricing and other information when evaluating future plans in this region.

In the following sections, descriptions will be provided that are part of that planning process. The next section will discuss the plans of the various suppliers in meeting the needs of their consumers.

4.10 Planned Generation

Based on the approved demand and energy forecasts by the state's utilities, various additions to the generation fleet have been approved by ERCOT. The following map, shown as Exhibit 4-3 and titled, "New Electric Generating Plants in Texas," and the three tables that follow it provide the recent history since 1995 and the future plans for expansion of capacity in the state of Texas. The third table in the series reflects those projects that have been delayed or cancelled which is an indicator of the health of the industry in the state.

Exhibit 4-3 New Generating Plants in Texas



www.puc.tx.us/electric/reports/gentable.pdf

Generation Projects Under Construction in Texas

Map No.	Company	Facility	City (County)	Capacity (MW)	Cogen Host (MW)	Date in Service	Intercon-nection	Region
55	ANP	Hays Station	San Marcos (Hays)	550 550		Aug-02 Complete	LCRA	ERCOT
56	Calpine-Citgo	Corpus Christi Energy Center	Corpus Christi (Nueces)	520	110	Aug-02	CPL	ERCOT
57	AES[8]	Wolf Hollow Power Plant	Granbury (Hood)	730		Oct-02	TXU	ERCOT
58	Calpine-Shell	Deer Park Energy Center	Deer Park (Harris)	166 169 438	190	Feb-03 Aug-03 Jun-04	Reliant	ERCOT
59	InterGen	Cottonwood Energy Project	Deweyville (Newton)	1200		Apr-03	EGS	SERC
60	NRG Energy	Brazos Valley Energy	Thompsons (Fort Bend)	633		May-03	Reliant	ERCOT
61	South Texas Electric Co-op		Nursery (Victoria)	185		Jun-03	STEC	ERCOT
62	Entergy/NTEC[9]	Harrison County Gen Station	(Harrison)	550		Jun-03	SWEPCO	SPP
63	FPL/Cobisa	Forney	Forney (Kaufman)	1750		3Q-03	TXU	ERCOT
64	Tractebel	Wise County Power Project	Bridgeport (Wise)	800		Jan-04	TXU	ERCOT
65	BP/Cinergy	Texas City	Texas City (Galveston)	570	NA	Spring-04	TNMP	ERCOT
	11 Under Construction		***Total Capacity***	***8,811***	***300***			

Announced Generation Projects in Texas

Map No.	Company	Facility	City (County)	Capacity (MW)	Expected Construction Date	Expected Date In Service	Region
66	Reliant/Jenbacher		Humble (Harris)[10]	24 8	Sum-02	Dec-02 Mar-03	ERCOT
67	Cielo/Renewable Energy (wind)	Capital Hill Wind Ranch	(Pecos)	100	Nov-02	Feb-03	ERCOT
68	TXU Energy/Cielo Wind (wind)	Noelke Hill Wind Ranch	McCamey (Upton)	240	Dec-02	Sep -03	ERCOT
69	Austin Energy	Sand Hill	Del Valle (Travis)	300 250	2002	Oct-03 Sum-07	ERCOT
70	Orion Energy (wind)		(Culberson)	175[11]	2002	2003	ERCOT
71	Sempra Energy Resources	Cedar Power Project	Dayton (Liberty)	600	Spring-03	Spring-05	ERCOT/SERC
72	Cielo Wind Power/LPL (wind)	Llano Estacado at Lubbock	Lubbock (Lubbock)	2	Jun-03	Jun-03	SPP
73	DFW Airport		(Tarrant/Dallas)	55 55	2003 2005	2005 2007	ERCOT
74	Cobisa	Greenville	Greenville (Hunt)	1750	Spring-04	Spring-06	ERCOT
75	Sempra Energy Resources	MC Energy Partners	Dobbin (Montgomery)	600	Apr-04	Apr-06	ERCOT/SERC
76	Steag Power	Sterne	(Nacogdoches)	950	2Q-04	2Q-06	ERCOT/SPP
77	Texas Petrochemicals		Houston (Harris)	900	2004	2006	ERCOT
78	Tractebel	Ennis-Tractebel II	Ennis (Ellis)	800	NA	Jun-04	ERCOT
79	Ridge Energy Storage[12]	Markham Energy Storage Center	(Matagorda)	270	NA	3Q-04	ERCOT
80	CCNG Inc[13]		San Diego (Duval)	310	NA	2Q-05	ERCOT
81	Dow Chemical		Freeport (Brazoria)	170	NA	Dec-05	ERCOT
	16 Projects Announced		*Total Capacity*	*7,559*			

Delayed Generation Projects[14]

Map No.	Company	Facility	City (County)	Capacity (MW)	Expected Construction Date	Expected Date In Service	Region
82	ANP		El Paso (El Paso)	450	NA	NA	WSCC
83	ANP		Houston (Harris)	2150	NA	NA	ERCOT
84	Calpine	Channel Energy Center exp.	Houston (Harris)	180	NA	NA	ERCOT
85	Calpine	Amelia Energy Center	Beaumont (Jefferson)	800	NA	NA	SERC
86	Duke Energy		(Bell)	500	NA	NA	ERCOT
87	Duke Energy		(Jack)	500	NA	NA	ERCOT
88	Dynegy		Lyondell expansion (Harris)	155	NA	NA	ERCOT
89	Hartburg Power		Deweyville (Newton)	800	NA	NA	SERC
90	Mirant		Weatherford (Parker)	650	NA	NA	ERCOT
91	Newport Generation[15]	Palestine Power Project	Palestine (Anderson)	1600	NA	NA	ERCOT
92	Texas Independent Energy	Archer Power Partners	Holliday (Archer)	500[16]	NA	NA	ERCOT
93	Sabine Power I/Port of Port Arthur		Port Arthur (Jefferson)[17]	1000	NA	NA	SERC
94	York Research Group (wind)	Notrees Wind Farm	(Ector, Winkler)	80	NA	NA	ERCOT
95	Enron Wind[18]		Sweetwater (Nolan)	400	NA	NA	ERCOT
	14 Projects Delayed		*Total Capacity*	*9,765*			

4.10.1 Natural Gas

The Public Utility Commission of Texas (commission) proposed a new rule §25.172 relating to Goal for Natural Gas. The proposed new rule implements a provision of Senate Bill 7, 76th Legislature, Regular Session (1999) that will be codified as Texas Utilities Code, §39.9044. The proposed new rule establishes a natural gas energy credit (NGEC) trading program to meet the legislative goal that 50% of the electric generating capacity installed in this state after January 1, 2000, use natural gas. As of July 2002, 62% of the capacity in ERCOT is fueled by natural gas.

4.11 Transmission Assessment

The transmission network is the highway system for the delivery of electricity, and as the economy grows this network needs to grow. The strong growth in the demand for electricity in Texas and the large number of new power plants that have been built or are planned represent a significant challenge to the ISO in planning the transmission network and to the utilities in building new facilities. New transmission facilities will be needed to meet the growth in demand and to permit new generating facilities to deliver their output to customers. Landowners on or near projected transmission rights of way typically do not want new transmission lines near their land. Opposition to new transmission facilities can be particularly acute in urban areas, if the right of way is adjacent to residential areas. PURA establishes a process for the Commission to review new transmission projects and for landowners and other affected persons to contest projects.

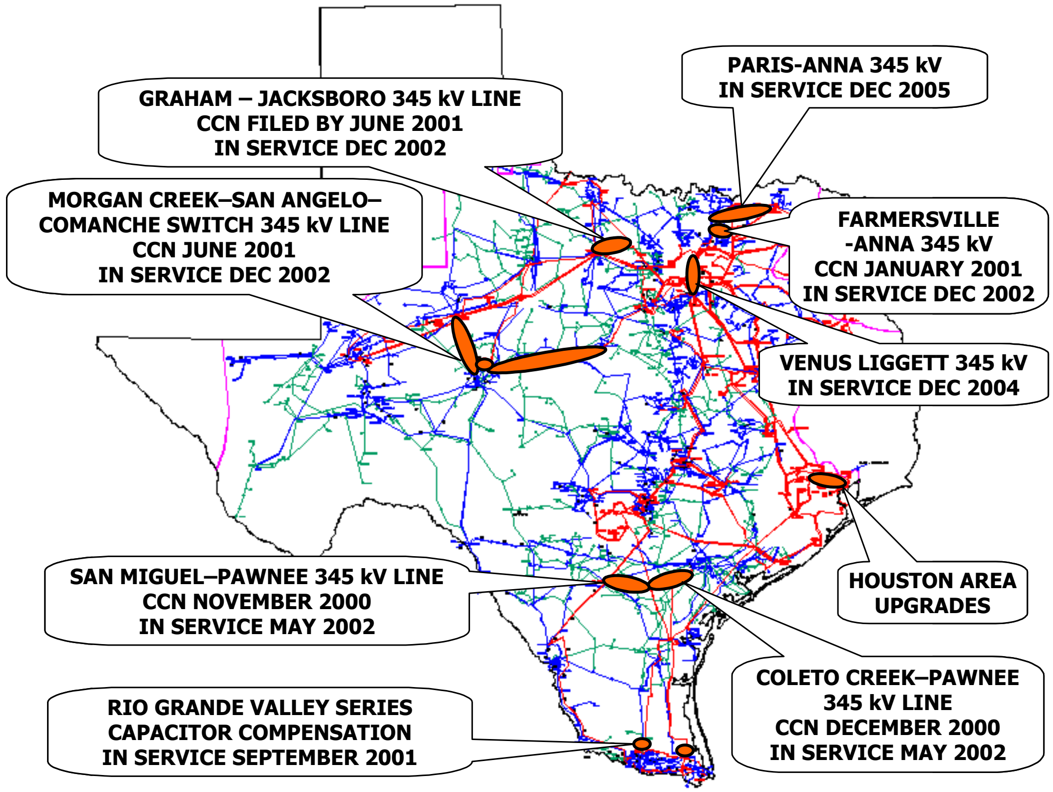
The PUCT has also assigned the ISO responsibility for planning the regional transmission network, and the ISO has developed a process for determining regional transmission needs. In its first transmission report, the ISO identified several transmission constraints that could affect the reliability and competitiveness of the wholesale market.

The current major ERCOT transmission constraints are:

- South Texas to North Texas
- To and from West Texas
- To and from South Texas and the Rio Grande Valley
- To Dallas, Denton, Collin and Tarrant counties
- From Northeast Texas

The Commission granted an amendment of TXU Electric Company's certificate of convenience and necessity (CCN) for a transmission project to alleviate a Houston-DFW constraint, and construction is under way. Central Power & Light Company is also constructing new facilities in the first phase of a project to increase the transmission capacity to the RGV, and the Commission recently approved CCN amendments for additional transmission facilities to alleviate this constraint. Exhibit 4-4 shows these major transmission projects underway:

Exhibit 4-4 Major Transmission Projects Approved or Underway



Source: Existing & Potential Electric System Constraints & Needs, page 51

Exhibit 4-5 lists the approved (including approval with conditions) transmission projects. As required by PUCT Substantive Rule 25.101, ERCOT reviewed these projects using methodologies consistent with good utility practice including NERC Planning Standards and ERCOT Planning Criteria. These transmission projects have been approved as required to reliably supply electricity within ERCOT.

Exhibit 4-5 Approved Transmission Improvement Projects

Project Name	Projected Completion Date	Mileage	Voltage	TSP	Regional Approval Date(s)	Approval Status
Reconductor Midkiff - Spraberry 138 kV Line	06/03	23.0	138kV	TXU	West-04/16/01	Approved (pending Rio Pecos area wind)
Reconductor Crane-Odessa EHV 138kV Line	06/03	31.9	138kV	TXU	West-04/16/01	Approved (pending Rio Pecos area wind)
Convert Crane - Midkiff 69kV Line to 138kV	06/02	34.3	138kV	TXU	West-04/16/01	Approved (pending Rio Pecos area wind)
New Series Reactor on Crane-Odessa N. 69 kV	06/03	N/A	69kV	TXU	West-04/16/01	Approved (pending Rio Pecos area wind)

Project Name	Projected Completion Date	Mileage	Voltage	TSP	Regional Approval Date(s)	Approval Status
Marion– GPI– Loop 337– Comal 138 kV	06/02	12.1	138kV	LCRA	Central-04/11/01	Approved
New Tap line from STEC's Mathis-Sandia line to CPL's Mathis 69kV line	05/02	1.96	69kV	STEC/AEP	South-05/08/01	Approved
New Ft. Lancaster-Friend Ranch 138kV line	09/05	40.0	138kV	AEP	West-04/16/01	Approved
New 138/69kV autotransformer at Crane	03/03	N/A	138kV	AEP	West-04/16/01	Approved
Convert McCamey-Crane 69kV line to 138kV and double-circuit McElroy-Crane	09/05		138kV	AEP	West-04/16/01	Approved
Convert Spudder Flat 69kV substation to 138kV	09/07	N/A	138kV	AEP	West-04/16/01	Approved
Reconductor King Mnt West Tap-Crane 138kV	09/07	11.5	138kV	AEP	West-04/16/01	Approved
Reconductor SW Mesa-King Mnt East 138kV	03/04	3.85	138kV	AEP	West-04/16/01	Approved
Reconductor SW Mesa – N McCamey 138kV	03/04	2.0	138kV	AEP	West-04/16/01	Approved
Reconductor SW Mesa – Big Lake 138kV line	09/07	40.9	138kV	AEP	West-04/16/01	Approved
New West Yates 138kV Station includes moved N McCamey 138/69kV autotransformer	09/03	N/A	138kV	AEP	West-04/16/01	Approved
New Mesa View 138kV Switching Station	09/03	N/A	138kV	AEP	West-04/16/01	Approved
Convert McCamey 69kV substation to 138kV	09/03	N/A	138kV	AEP	West-04/16/01	Approved
Convert Tippet 69kV substation to 138kV	09/03	N/A	138kV	AEP	West-04/16/01	Approved
Rebuild Mesa View – Mesa View Switch 138kV	09/05	5.57	138kV	AEP	West-04/16/01	Approved
Convert Tippet – West Yates 69kV to 138kV	09/03	9.98	138kV	AEP	West-04/16/01	Approved
New Yates Pump – Mesa View 138kV line	09/03	1.0	138kV	AEP	West-04/16/01	Approved
Convert W Yates- Yates Pump 69kV to 138kV	09/03	4.23	138kV	AEP	West-04/16/01	Approved
Convert Yates Pump 69kV substation to 138kV	09/03	N/A	138kV	AEP	West-04/16/01	Approved
Rebuild N McCamey – Tippet 69kV to 138kV	08/03	30.0	138kV	AEP	West-04/16/01	Approved
Convert Rio Pecos-WTU Crane 69kV to 138kV	09/07	22.98	138kV	AEP	West-04/16/01	Approved

Project Name	Projected Completion Date	Mileage	Voltage	TSP	Regional Approval Date(s)	Approval Status
New Friend Ranch – Twin Buttes 138kV line	07/05	70.0	138kV	AEP	West-04/16/01	Approved
Reconductor Rio Pecos – N McCamey 138kV	09/03	9.67	138kV	AEP	West-04/16/01	Approved
New Rio Pecos 138kV 25MVAR Capacitor	03/03	N/A	138kV	AEP	West-04/16/01	Approved
Reconductor Rio Pecos – Mesa View SS 138kV	12/05	27.13	138kV	AEP	West-04/16/01	Approved
Reconductor Mesa View – Ft. Lancaster 138kV	12/06	19.8	138kV	AEP	West-04/16/01	Approved
New West Yates 138kV 25MVAR Capacitors	09/03	N/A	138kV	AEP	West-04/16/01	Approved
New Mesa View 138kV 25MVAR Capacitors	09/03	N/A	138kV	AEP	West-04/16/01	Approved
New Ft. Lancaster 69kV 10MVAR Capacitors	03/03	N/A	138kV	AEP	West-04/16/01	Approved
New Lewisville Switch 138 kV 105.6 MVAR Capacitor	06/02	N/A	138kV	BEC	North-05/03/01	Approved
Reconductor Coppell – Lewisville 138kV	12/02	6.7	138kV	BEC	North-05/23/01	Approved
New 345/138 kV autotransformer at Lewisville Switch	06/03	N/A	345kV	BEC	North-07/30/01	Approved
Aubrey – Sanger 69kV to 138kV conversion	06/02	11.24	138kV	BEC	North-07/30/01	Approved
New Paris – Anna 345 kV line	2004-05	70	345kV	TXU	North-04/23/01	Approved
Venus-Liggett 2nd 345 kV line	05/04	29	345kV	TXU	North-06/21/01	Approved
2nd 345/138kV autotransformer at Liggett	05/04	N/A	345kV	TXU	North-06/21/01	Approved
Upgrades for Constellation plant	10/02	N/A	138 & 345	TXU	North-04/13/01	Approved
Upgrades for Newport plant	05/03	N/A	345kV	TXU	North-04/13/01	Approved
Upgrades for Ennis Tractabel	05/04	N/A	345kV	TXU	North-08/15/01	Approved
Upgrades for Texas City BP/AMOCO Units	03/04	N/A	138kV	TNMP/RHLP	Houston-09/14/01	Approved
New Macedonia-Hockley 138kV line	02/04	13	138kV	LCRA/RHLP	Central-06/20/01	Approved
New Whitney autotransformer138/69kV	10/02	N/A	138kV	BEC	North-10/09/01	Approved

Project Name	Projected Completion Date	Mileage	Voltage	TSP	Regional Approval Date(s)	Approval Status
Convert Reno to Rhome 69kV to 138 kV	10/02	1.8	138kV	BEC	North-10/09/01	Approved
Rebuild North Texas to Cottondale Switch from 69kV to 138 kV	06/03	26.8	138kV	BEC	North-10/10/01	Approved
Rebuild Woodbine to Redmond Switch to Gainsville from 69kV to 138 kV	10/02	6.72	138kV	BEC	North-10/10/01	Approved
Rebuild Granbury loop from 69kV to 138 kV	06/03	12	138kV	BEC	North-10/10/01	Approved
Rebuild Grandview to Lillian Switch from 69 to 138 kV & rebuild Conley sub for 138 kV	04/03	9.8	138kV	BEC	North-10/10/01	Approved
Rebuild Lillian to Sardis 69 to 138 kV	10/02	21.3	138kV	BEC	North-10/10/01	Approved
New Bell County Switching Station 138 kV	06/03	N/A	138kV	BEC	North-10/23/01	Approved
New Morris Sheppard capacitors 69 kV	06/02	N/A	69kV	BEC	North-10/29/01	Approved
New Keeter capacitors 69 kV	06/02	N/A	69kV	BEC	North-11/08/01	Approved
New Carlton capacitors 69 kV	06/02	N/A	69kV	BEC	North-11/08/01	Approved
New autotransformer at Olney 138/69 kV	06/03	N/A	138/69kV	BEC	North-11/08/01	Approved
Convert Leander-Andice to 138 kV & new 138 kV from Andice to Glasscock	05/04	22.6	138kV	LCRA	North-11/01/01	Approved
Reconfigure Ties between TNMP,TXU, and BEC	09/03	0.4	138kV	TNMP TXU, BEC	North-01/04/02	Approved
New 2nd circuit Watermill to Cedar Hill	05/04	17.3	345 kV	TXU	North-01/10/02	Approved
Rebuild East to Iola from 69 kV to 138 kV	04/04	20.3	138kV	BEC	North-02/20/02	Approved
Hickory Forest – New Berlin	12/03	13	69kV	LCRA	South – 04/02/02	Approved

4.12 Operations Assessment

ERCOT has both a Security Coordinator and an Operations Planning Coordinator who monitor system conditions and evaluate near-term operating conditions. ERCOT has a detailed Security Process that gives the Security Coordinator the authority to direct actions to ensure the real-time security of the bulk electric system in the Region.

The Security Coordinator uses a Region-wide Security Analysis Program and a "Look-Ahead" Program to evaluate current system conditions. These programs use databases that are updated with data from operating members on an as-needed basis throughout the day. The procedures in the Security Process are being evaluated and updated on an ongoing basis to ensure Regional reliability, conformance to ERCOT procedures, and adherence to NERC Standards and Policies.

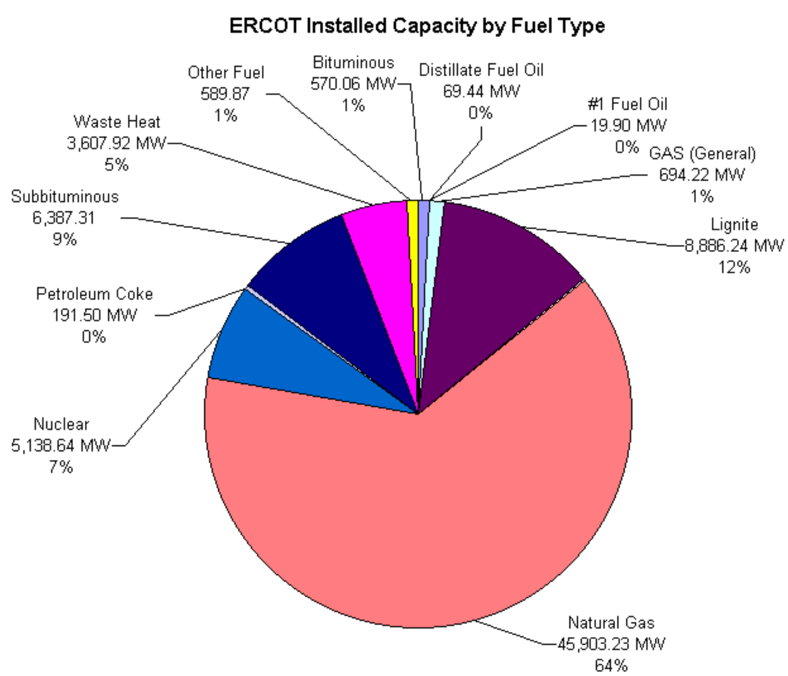
5. Historical Data

These data represent the latest available data as of September 2002, when this characterization was last revised. This historical information serves as a basis for understanding the existing mix of generation, the demand and energy requirements for each of the utilities, and the ERCOT region as a whole.

5.1 Generation Mix

Within the ERCOT region there are currently 655 operational electric generating units representing approximately 72,500 MW of nameplate capacity. The installed capacity in the region by fuel type is summarized in Exhibit 5-1 below. A complete listing of all identified operating units in ERCOT is provided in Appendix A

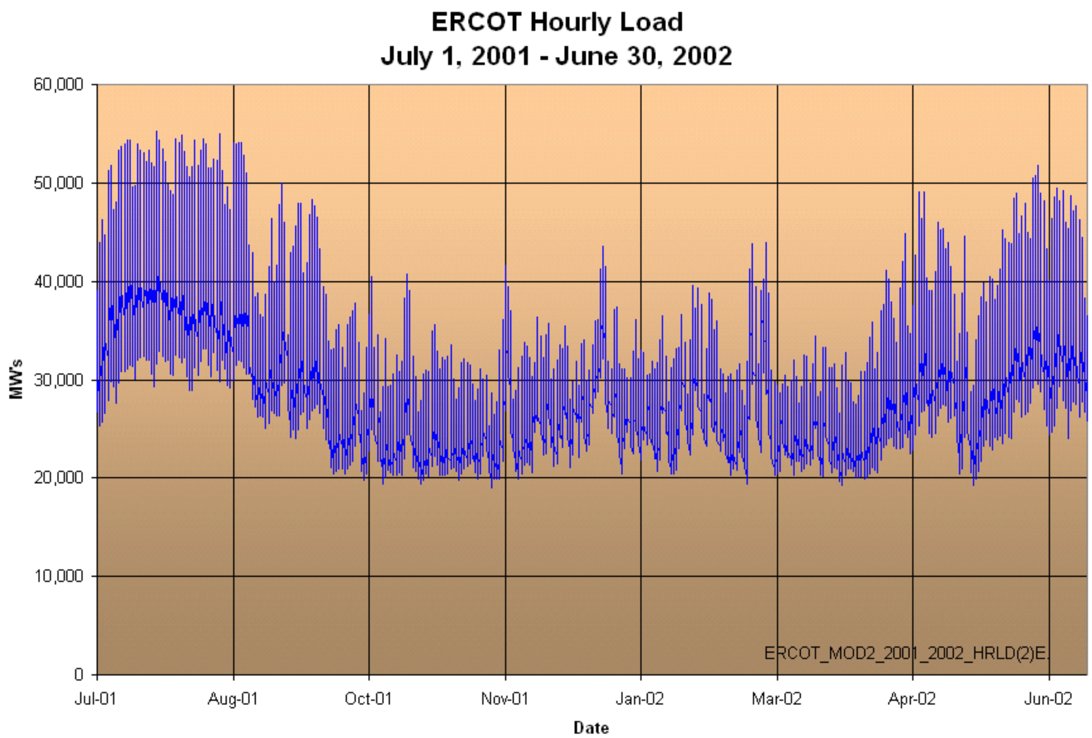
Exhibit 5-1 ERCOT Installed Capacity by Fuel Type



5.2 Demands

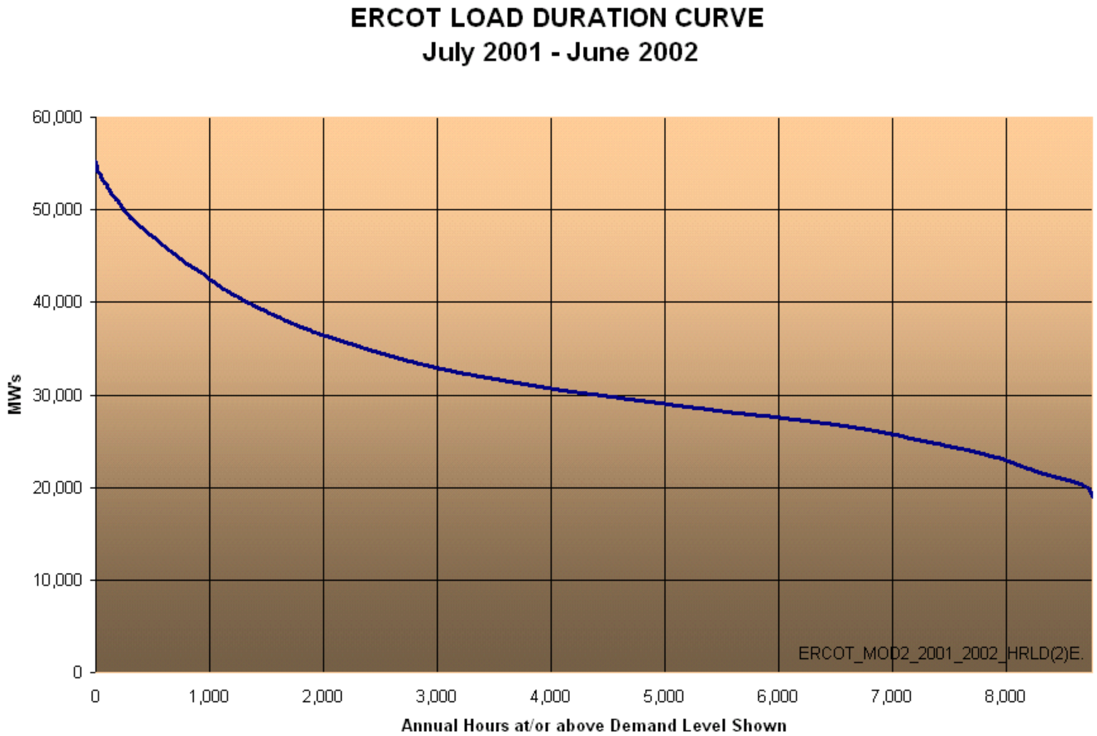
In Exhibit 5-2, the latest hourly loads for the ERCOT region are shown. This is the latest available data on hourly loads from the utilities and the regulatory bodies. As indicated in the following chart, the peak loads occur and are frequent during the months of June through September. There are peaks during the other months including the winter but generally they are infrequent and lower that those experienced during the summer period.

Exhibit 5-2 Hourly Demands July 1, 2001 through June 30, 2002



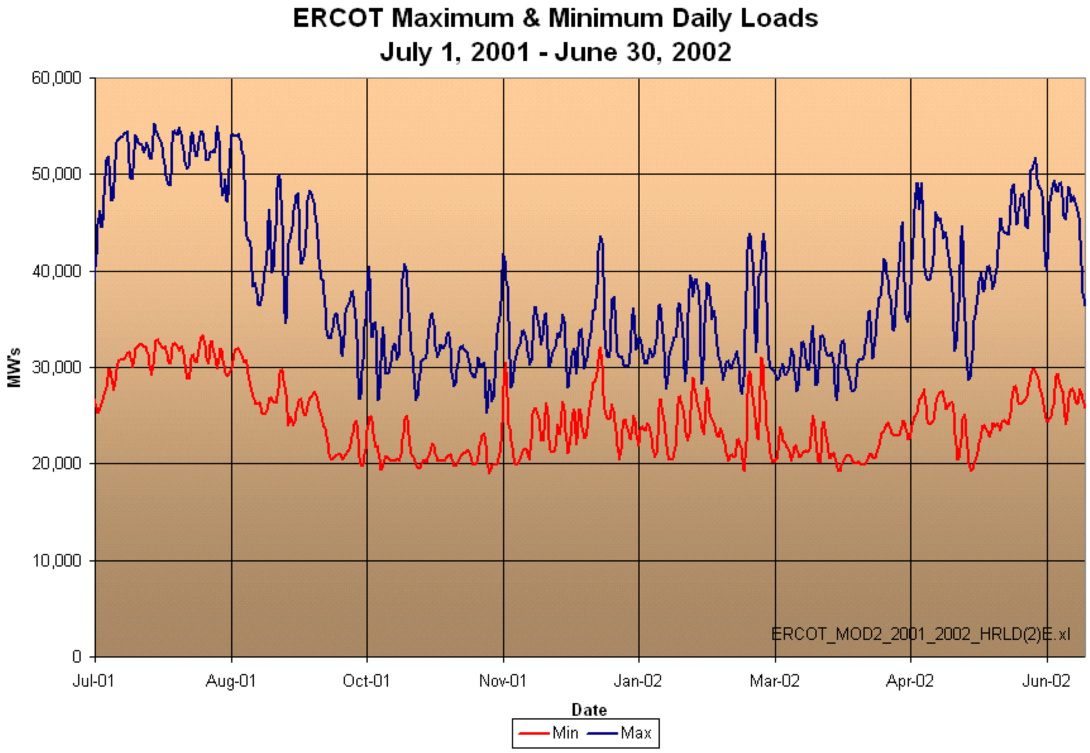
The load duration curve for the ERCOT Region is presented in Exhibit 5-3 below.

Exhibit 5-3 Load Duration Curve for July 2001 through June 2002



In addition to the hourly loads shown above, the maximum and minimum loads for each day during the yearly time period were also calculated and shown graphically in Exhibit 5-4. As shown, there are some significant differences in daily loads during the warmer months, while the winter periods are much closer in terms of diversity of hourly loads.

Exhibit 5-4 Maximum & Minimum Loads – ERCOT



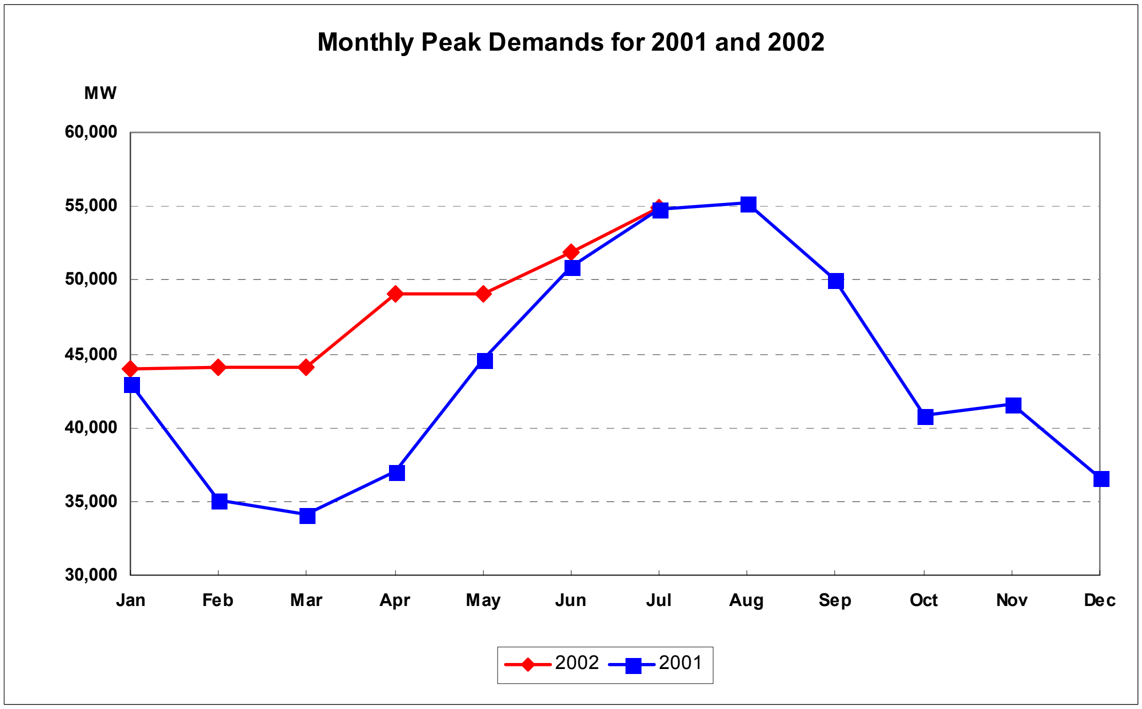
5.2.1 Baseload

As shown by the data listing the various units, there is over 21,000 MW of nuclear and lignite/bituminous-fired generation on the ERCOT system, and almost 46,000 MW of gas-fired generation. The remaining MWs consist of a variety of fuels including hydro, wastes and other types of fuels used primarily as energy producers, including waste heat from cogeneration and other industrial applications. Given that the minimum load on the system is about 19,000 MW during the last year, the typical daily requirement for baseload power will range around 30,000 to 35,000 MW during the summer months, and 20,000 to 25,000 MW during the winter months. This baseload should be covered by the four primary types of generation.

5.2.2 Peaking

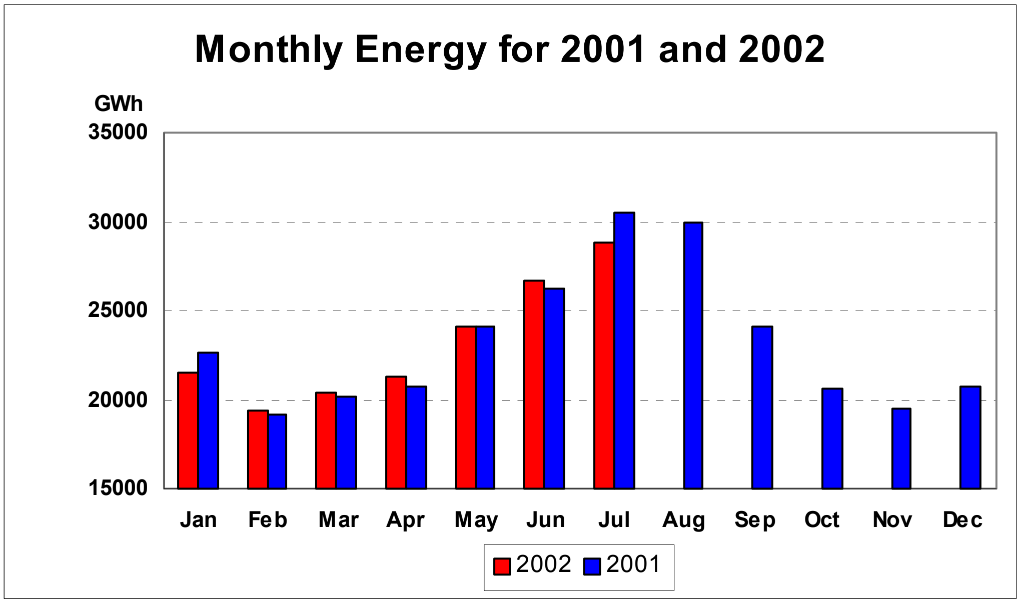
For the last 18 months, Exhibit 5-5 shows the peak demands for the period January 2001 through July 2002.

Exhibit 5-5 Monthly Peak Demands Comparison Jan. 2001 through July 2002



As shown, the peaks in the summer months of June through September indicate ERCOT is a summer peaking region. Also it can be seen that through the first 5 months of 2002, the peaks were significantly higher than those experienced in 2001. This trend to increased demand is verified in the following chart which shows increased energy demand during 2002 in the months of February through May as compared the same months in 2001.

Exhibit 5-6 Monthly Energy Comparison Jan. 2001 through July 2002



5.3 Price Duration

A composite of the month-by-month data was assembled that gives thirteen months worth of price data in ERCOT. This is the full amount of Balancing Energy prices available since the beginning of the competitive market in Texas. The balancing energy represents less than 5% of the total energy sold in the ERCOT market. Exhibit 5-7 indicates the small percentage of the balancing energy versus the daily loads in ERCOT. Exhibit 5-8 just shows the levels of the balancing energy, both up and down.

Exhibit 5-9 shows the weighted average daily prices of both the up and down balancing energy. As indicated, the balancing up prices are never below zero, while the balancing down prices can fluctuate above and below zero. Exhibit 5-10 indicates the maximum and minimum daily prices for balancing energy over the 13-month period. Exhibit 5-11 and Exhibit 5-12 are price duration curves, indicating the weighted average daily price and the maximum and minimum duration curves.

Given the limited amount of energy actually traded on the ERCOT market, the price is almost insignificant in the actual market for energy. With bilateral arrangements being the norm for suppliers, it is almost like a regulated market in ERCOT.

Exhibit 5-7 Balancing Energy Vs. Total Load

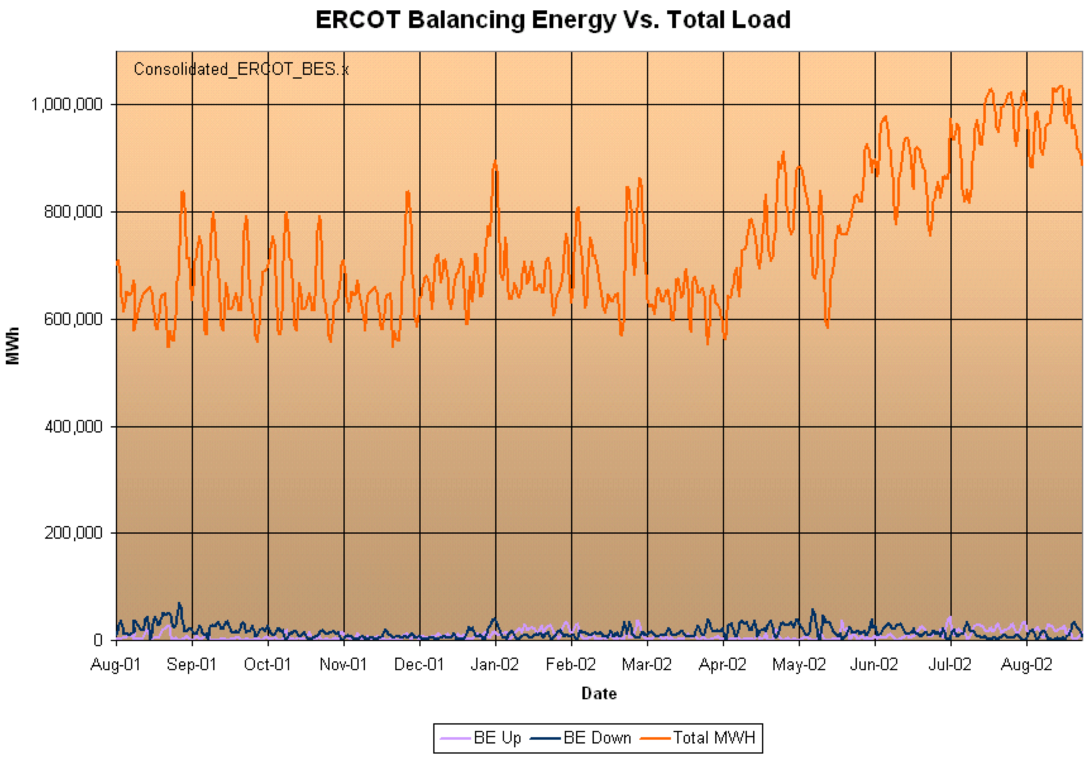


Exhibit 5-8 Balancing Energy (Up and Down)

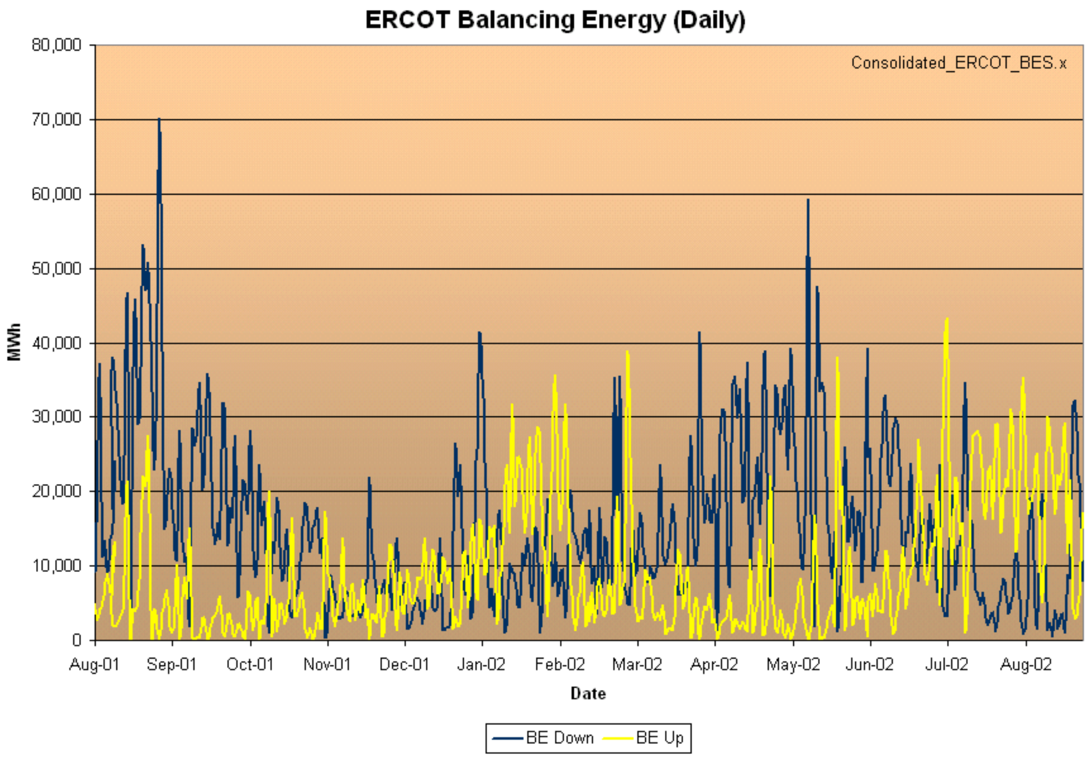


Exhibit 5-9   Weighted Average BE Daily Price (Up & Down)

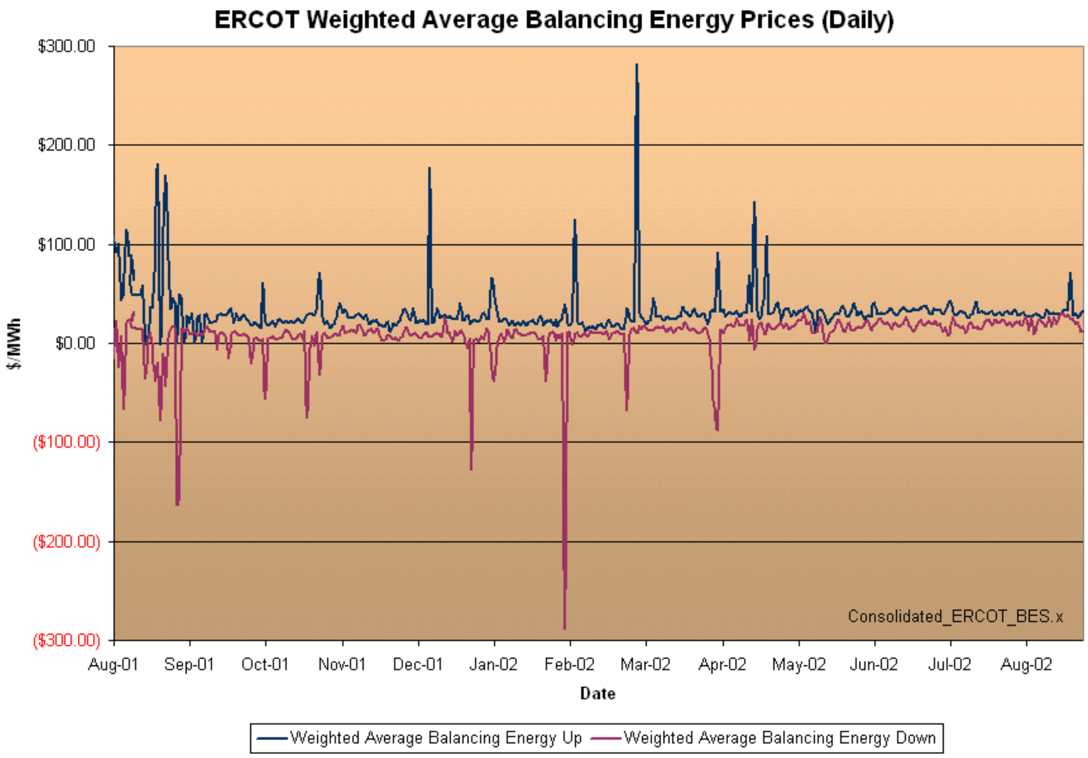


Exhibit 5-10 Max-Min Daily Prices

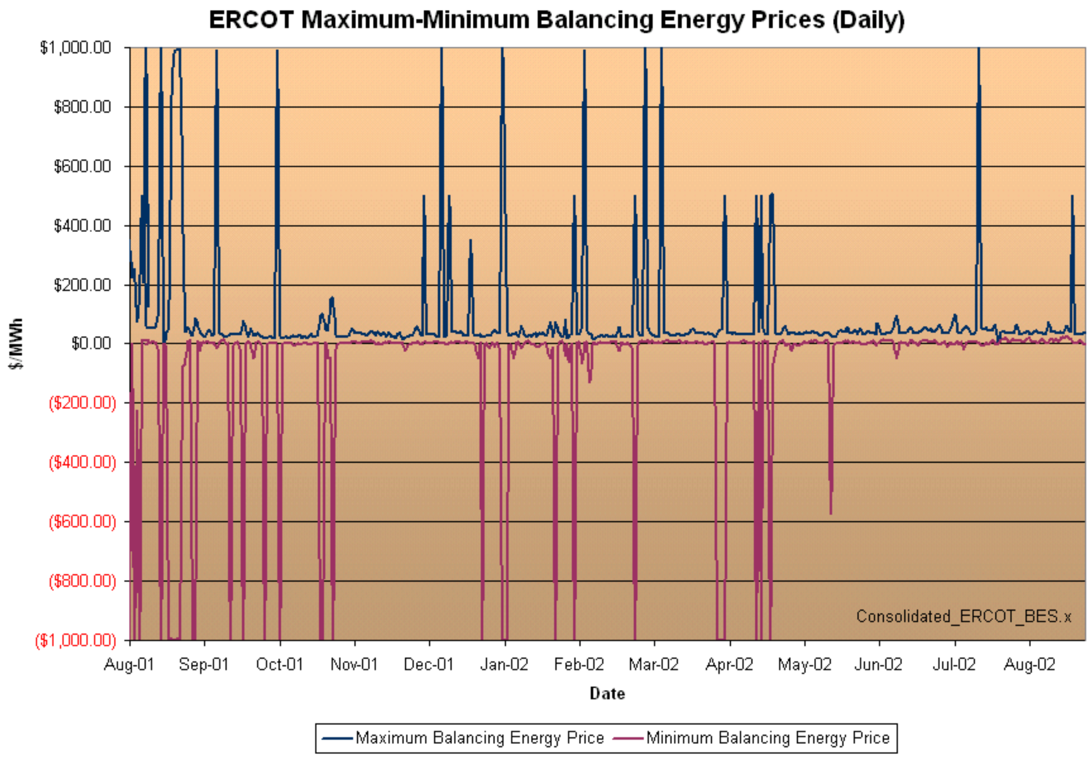


Exhibit 5-11 Weighted Daily Average Price Curve

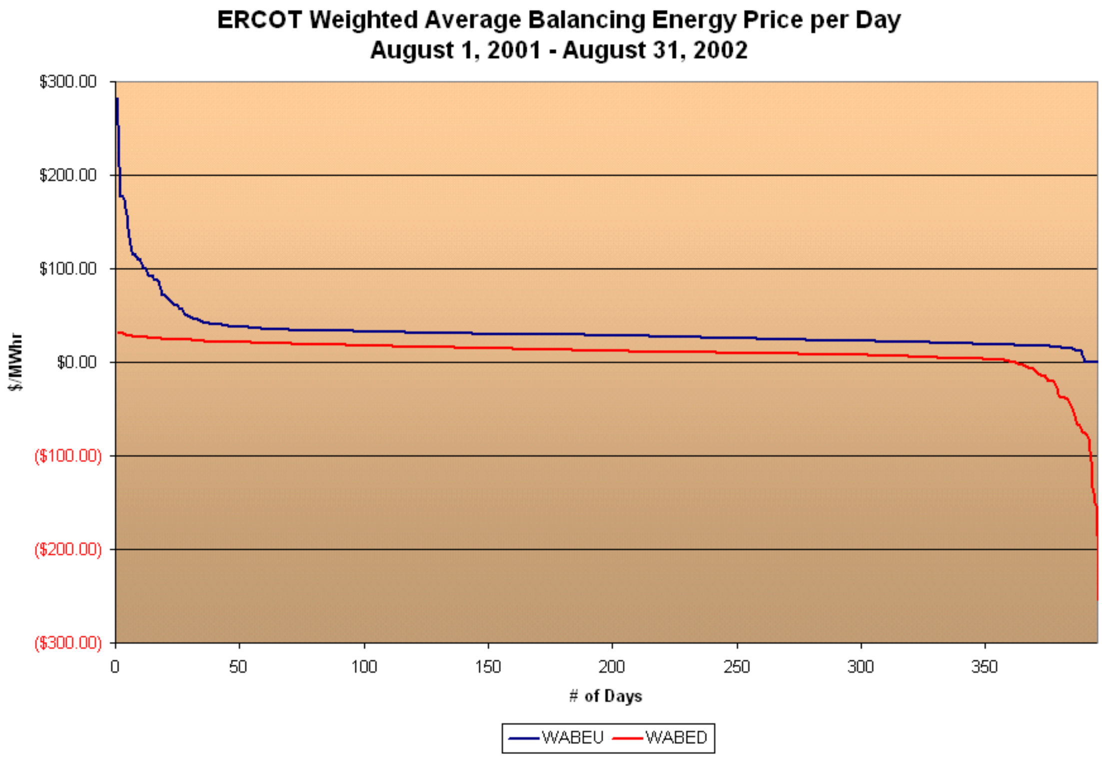
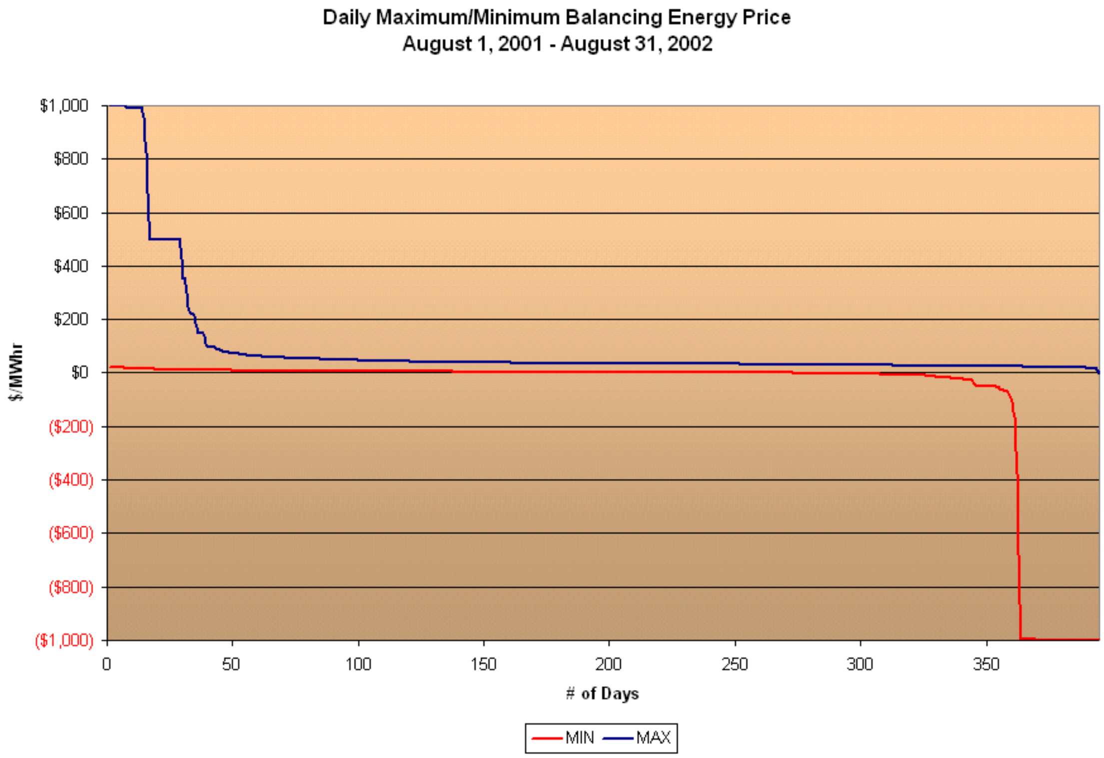


Exhibit 5-12 Max-Min Price Duration Curve



6. ERCOT Demand, Energy, and Fuel Price Projections

This section describes ERCOT's assessment about how the region's load is projected through 2010. This projection is based on the current planning reported by ERCOT. These ERCOT data are assessed, and used as the basis for the region's forecast that will be utilized by the GEMSET team. This section covers the following subjects:

- Section 6.1 gives ERCOT demand and energy growth projections for the region.
- Section 6.2 documents ERCOT's historical and forecast fuel prices for generation.

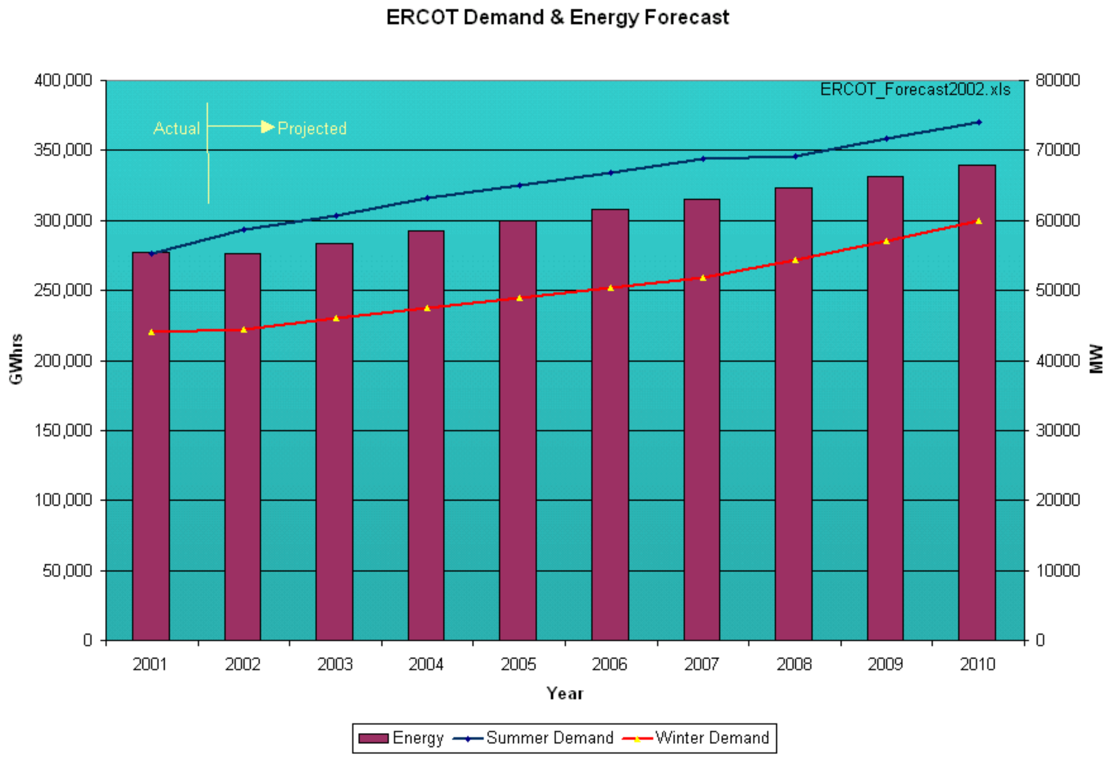
6.1 Demand and Energy Growth Projection

Exhibit 6-1 shows the growth trend in energy. It shows last year's actual demand and energy and the forecasted annual energy usage in ERCOT. For the forecasted energy two scenerios are shown, each derived from different data and with differing long-term results. The 2002 through 2007 data are from the ERCOT Capacity Demand & Reserve (CDR) Working Papers as of May 7, 2002, while the remaining several years come from the 10-year forecast put out by ERCOT in 2000.

It is clear that ERCOT is a summer-peaking system, due to hot weather with a high saturation of air conditioning, and usually has the lowest peaks in the spring and fall. The month with the lowest peak is February, and that peak is 60.4% of the summer peak. Except for the summer months, the minimum demands hover around 20,000 MW

The GEMSET team for any analysis required in that region will utilize these projections in ERCOT. Overall, the ERCOT region is projecting rather robust growth in electric requirements over the decade. Summer peak is expected to go from around 57,000 MW in 2000, to almost 73,000 MW in 2010. Energy is likewise expected to grow at a similar rate.

Exhibit 6-1 ERCOT Demand & Energy Forecast



6.2 Fuels Forecast for the ERCOT Region

Region 1 – New England

Region 2 – Mid-Atlantic

Region 3 – East North Central

Region 4 – West North Central

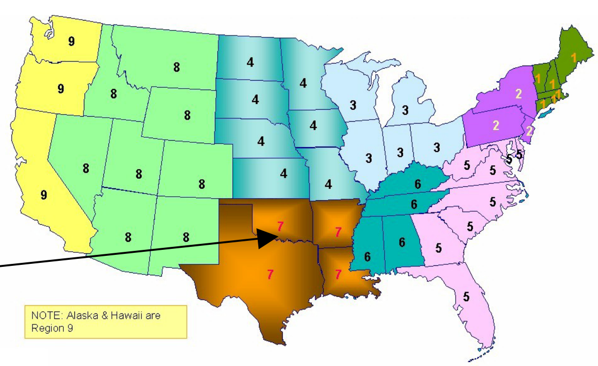
Region 5 – South Atlantic

Region 6 – East South Central

Region 7 – West South Central

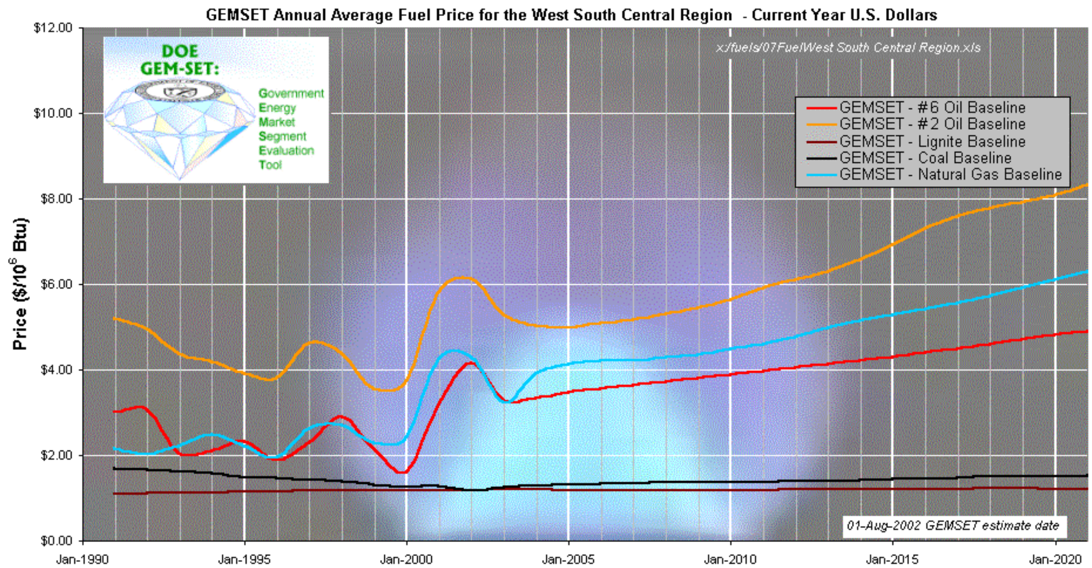
Region 8 – Mountain

Region 9 - Pacific



This section discusses the fuel prices that existed in the region and describes the forecast expectations for the region. Region 7 is made up of the following states as reported by FERC: Texas, Louisiana, Arkansas, and Oklahoma. All data are contained in tables available in the Fuels Characterization prepared by the GEMSET Team.[1] Exhibit 6-2 demonstrates the comparative cost of fuels (historic and projected) within the region for a 30-year period beginning in 1990.

Exhibit 6-2 GEMSET Comparison Showing Baseline Fuel Prices & Projections for the West South Central Region in Current Year U.S. Dollars



6.2.1 Natural Gas Prices

The delivered natural gas prices to generating company owners in the region are reported on FERC Form 423. Recent gas price historical and projected data for the region are shown in Exhibit 6-3 and Exhibit 6-4. These data are reported on a monthly basis with a 6-month lag in the reports. The charts reflect the expectation of a continuing increase in the price of gas over the period. With current 2002 prices in the range of \$2 to \$3 per 10^6 Btu, the charts project a price of over \$6 per 10^6 Btu (in current U.S. dollars) by the year 2020.

Exhibit 6-3 GEMSET Baseline Natural Gas Price Projection for the West South Central Region in Current Year U.S. Dollars Compared to the Data Sources Used for the Projections

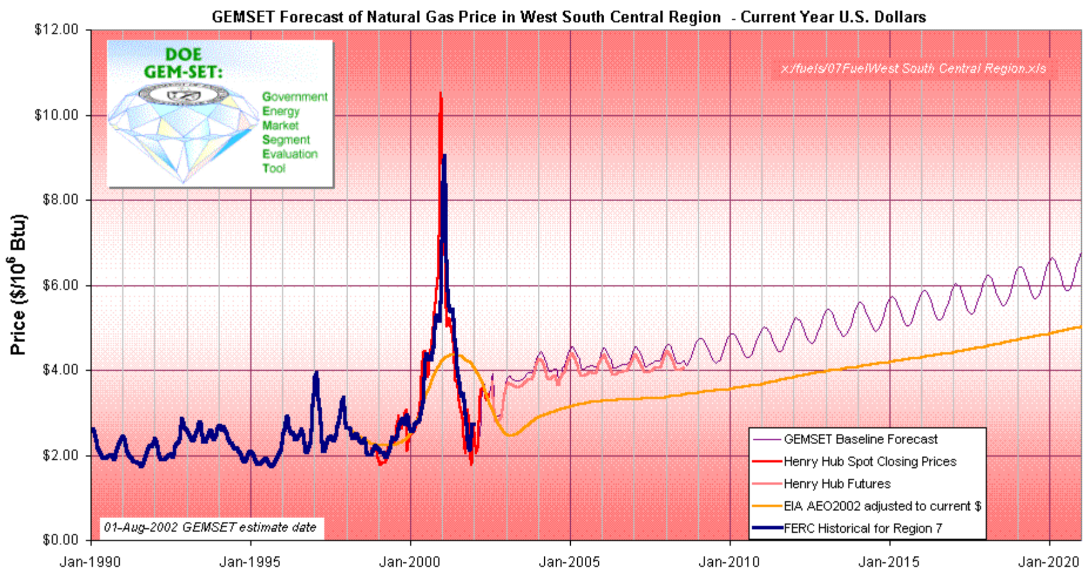
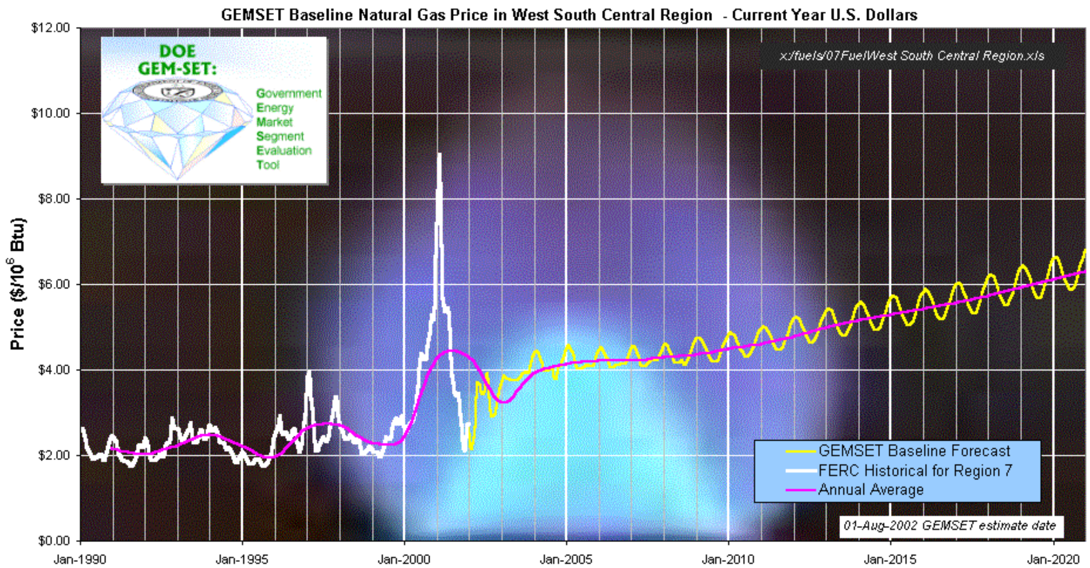


Exhibit 6-4 GEMSET Baseline Natural Gas Price Projection for the West South Central Region in Current Year U.S. Dollars

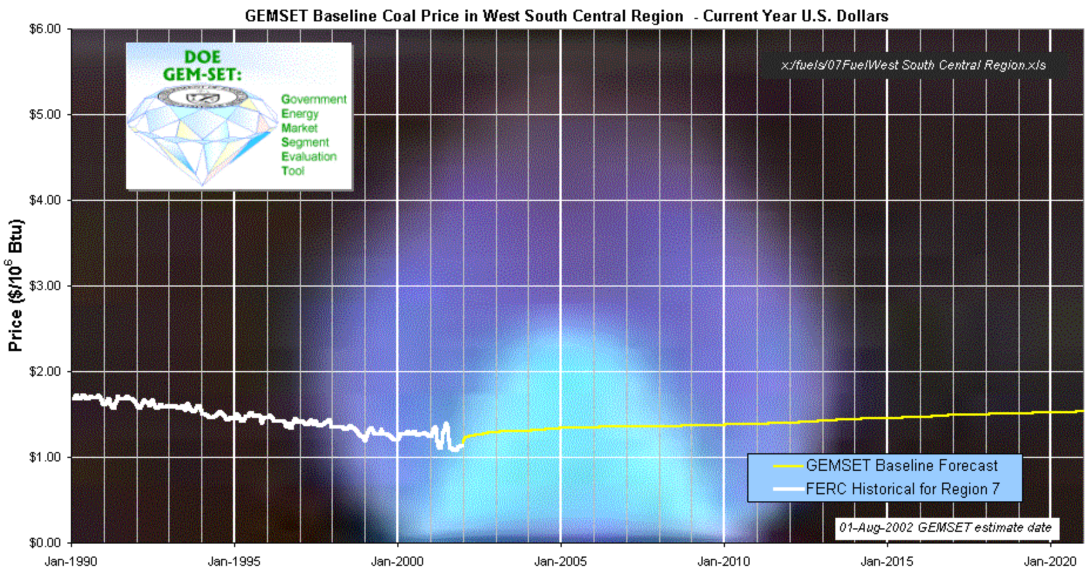


Periodically, these data will be revised to reflect changes in actual prices, and to adjust the forecasts to gas futures market changes, and changes in the NEMS economic modeling.

6.2.2 Coal Price in West South Central Region

The historical coal price in the West South Central Region has slightly declined over the last 12 years, going from approximately \$1.75 per 10^6 Btu to approximately \$1.15 per 10^6 Btu in 2002. This price is projected to return to and mild inflationary trend reaching approximate \$1.53 per 10^6 Btu in today's dollars by year-end 2020.

Exhibit 6-5 GEMSET Baseline Coal Price Projection for the West South Central Region in Current Year U.S. Dollars



6.2.3 Oil Prices in the West South Central Region

Exhibit 6-6 and Exhibit 6-7 below indicate the historical and projected prices for No. 2 and No. 6 fuel oil in the region. As with all of the regions, there are individual ratios developed for each fuel based on the historical relationship on a national basis versus the regional prices. Those ratios are presented in the analysis itself. The charts below reflect the volatility of oil prices over the last 12 years. The projection, shown in the charts and compared to average prices for these fuels in the previous 12 years, is for a continued increase in prices over the period commencing in 2020. No. 6 oil priced at \$3.28 per 10^6 Btu in July 2002 is projected to rise to \$4.96 per 10^6 Btu (in today's dollars) year-end 2020. No. 2 fuel oil at \$5.27 per 10^6 Btu in July 2002 is projected at \$8.43 per 10^6 Btu (in today's dollars) year-end 2020.

Exhibit 6-6 No. 2 Oil Price in the West South Central Region

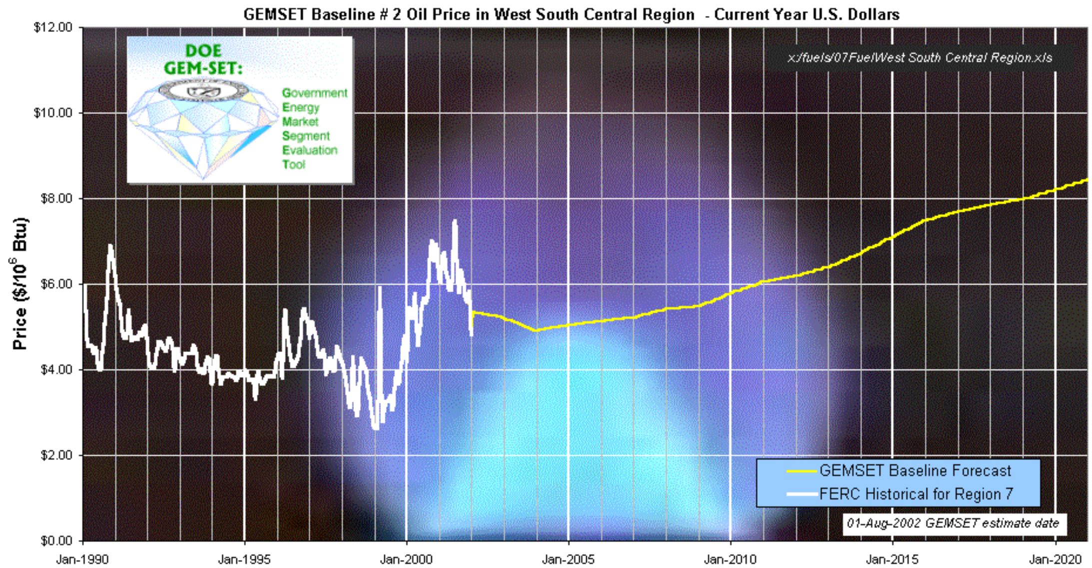
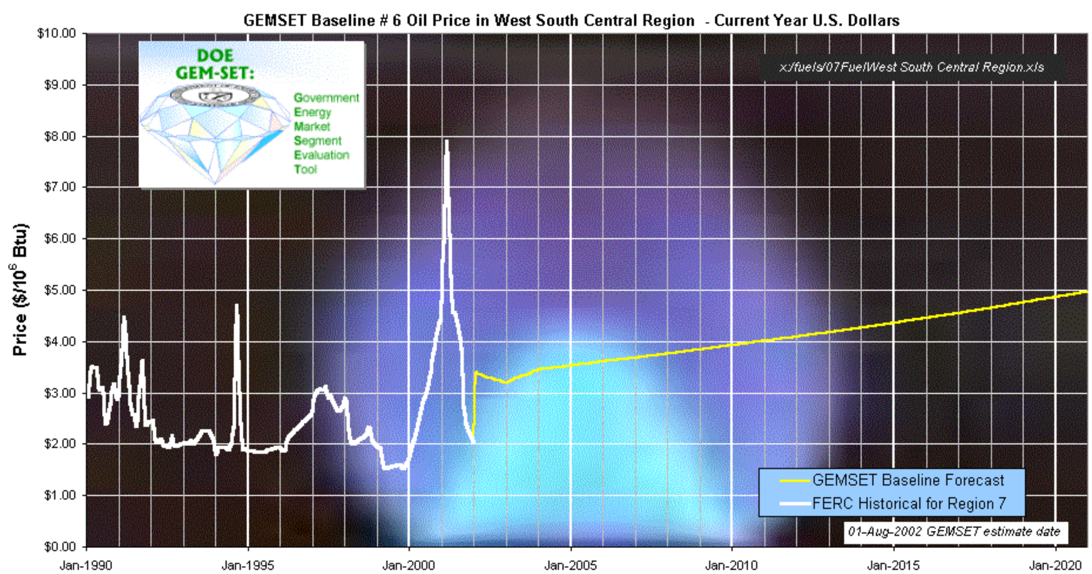


Exhibit 6-7 No. 6 Oil in the West South Central Region



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7. References

[1] Weinstein, R.E., Herman, A.A., and Lowe, J.J. GEMSET Assessment: Fuels Characterization. Parsons Report No. EJ-2002-04. September 2002.

Appendix A – ERCOT Stack

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
Texas-New Mexico Power Co	DFW Gas Recovery	GT	LFG	3000	3
Texas-New Mexico Power Co	DFW Gas Recovery	GT	LFG	3000	6
TXU Electric Co	Village Creek Wastewater Treatment Plant	IC	OBG	1150	7
TXU Electric Co	Village Creek Wastewater Treatment Plant	IC	OBG	1150	8
Central Power & Light Co	Seadrift Coke LP	ST	OG	7600	16
Central Power & Light Co	Valero Refinery	OT	OG	12000	28
Central Power & Light Co	Valero Refinery	ST	OG	28600	57
Central Power & Light Co	Valero Refinery	ST	OG	28600	85
Austin Energy	Decker Creek	PV	SUN	300	85
Lower Colorado River Authority	Delaware Mountain Windfarm	WT	WND	30000	115
Lower Colorado River Authority	West Texas Windplant	WT	WND	33600	149
TXU Electric Co	Big Spring Wind Power Facility	WT	WND	34320	183
West Texas Utilities Co	Fort Davis	PV	SUN	1000	184
West Texas Utilities Co	West Texas Wind Energy LLC	WT	WND	75000	259
Austin Energy	Central Utility Plant	ST	WH	2300	262
Austin Energy	University of Texas at Austin	CA	WH	7617	269
Austin Energy	University of Texas at Austin	CA	WH	6000	275
Austin Energy	University of Texas at Austin	CA	WH	28800	304
Brazos Electric Power Coop Inc	Tenaska IV Texas Partners Ltd Cleburne Cogen	CA	WH	104400	408
Central Power & Light Co	BP Chemicals Green Lake Plant	ST	WH	23800	432
Central Power & Light Co	BP Chemicals Green Lake Plant	ST	WH	15000	447
Central Power & Light Co	Celanese Engineering Resin Inc	OT	WH	1492	449
Central Power & Light Co	Celanese Engineering Resin Inc	OT	WH	1492	450
Central Power & Light Co	Celanese Engineering Resin Inc	OT	WH	1678	452
Central Power & Light Co	Celanese Engineering Resin Inc	CA	WH	8200	460
Central Power & Light Co	Formosa Utility Venture Ltd	CA	WH	66300	526
Central Power & Light Co	Formosa Utility Venture Ltd	CA	WH	33500	560
Central Power & Light Co	Frontera Generation Facility	CA	WH	183000	743
Central Power & Light Co	Gregory Power Facility	CA	WH	100000	843
Central Power & Light Co	Hidalgo Energy Center	CA	WH	175400	1,018
Central Power & Light Co	Pt Comfort Operations	ST	WH	15100	1,033
Central Power & Light Co	Pt Comfort Operations	ST	WH	16000	1,049
Central Power & Light Co	Pt Comfort Operations	ST	WH	16000	1,065
Central Power & Light Co	Pt Comfort Operations	ST	WH	16000	1,081
Central Power & Light Co	Reynolds Metals Co Sherwin Plant	CA	WH	6000	1,087
Central Power & Light Co	Reynolds Metals Co Sherwin Plant	CA	WH	6000	1,093
Central Power & Light Co	Reynolds Metals Co Sherwin Plant	CA	WH	6000	1,099
Central Power & Light Co	Reynolds Metals Co Sherwin Plant	CA	WH	6000	1,105
Central Power & Light Co	Seadrift Plant Union Carbide Corp	CA	WH	15000	1,120
Central Power & Light Co	Seadrift Plant Union Carbide Corp	CA	WH	15000	1,135
Central Power & Light Co	Seadrift Plant Union Carbide Corp	CA	WH	6000	1,141

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
Central Power & Light Co	Seadrift Plant Union Carbide Corp	CA	WH	15000	1,156
Lower Colorado River Authority	Guadalupe Generating Station	CA	WH	201900	1,358
Lower Colorado River Authority	Guadalupe Generating Station	CA	WH	201900	1,560
Reliant Energy HL&P	Chocolate Bayou Plant	ST	WH	6000	1,566
Reliant Energy HL&P	Chocolate Bayou Plant	ST	WH	2000	1,568
Reliant Energy HL&P	Chocolate Bayou Plant	ST	WH	1200	1,569
Reliant Energy HL&P	Chocolate Bayou Plant	ST	WH	46100	1,615
Reliant Energy HL&P	CoGen Lyondell Inc	CA	WH	115000	1,730
Reliant Energy HL&P	Deer Park Plant	CA	WH	10000	1,740
Reliant Energy HL&P	Deer Park Plant	CA	WH	10000	1,750
Reliant Energy HL&P	Deer Park Plant	CA	WH	10000	1,760
Reliant Energy HL&P	Exxon Mobil Co USA Baytown PP3 PP4	ST	WH	7500	1,768
Reliant Energy HL&P	Exxon Mobil Co USA Baytown PP3 PP4	ST	WH	7500	1,775
Reliant Energy HL&P	Freeport	CA	WH	11700	1,787
Reliant Energy HL&P	Houston Chemical Complex Battleground Site	CA	WH	52000	1,839
Reliant Energy HL&P	Newgulf	CA	WH	12500	1,852
Reliant Energy HL&P	Oyster Creek Unit VIII	CA	WH	200970	2,053
Reliant Energy HL&P	Pasadena Cogeneration LP	CA	WH	87500	2,140
Reliant Energy HL&P	Pasadena Cogeneration LP	CA	WH	150000	2,290
Reliant Energy HL&P	Pasadena Cogeneration LP	CA	WH	175000	2,465
Reliant Energy HL&P	T H Wharton	CA	WH	113100	2,569
Reliant Energy HL&P	T H Wharton	CA	WH	113100	2,673
San Antonio Public Service Bd	A Von Rosenberg	CA	WH	200250	2,865
Texas-New Mexico Power Co	Power Station 3	CA	WH	22059	2,887
Texas-New Mexico Power Co	Power Station 3	CA	WH	22059	2,909
Texas-New Mexico Power Co	Power Station 3	CA	WH	22059	2,931
Texas-New Mexico Power Co	Power Station 4	CA	WH	34703	2,966
Texas-New Mexico Power Co	Texas City Cogeneration LP	CA	WH	141000	3,107
Texas-New Mexico Power Co	Texas City Plant Union Carbide Corp	CA	WH	56000	3,163
TXU Electric Co	Big Spring Texas Refinery	ST	WH	1500	3,164
TXU Electric Co	C R Wing Cogeneration Plant	CA	WH	75000	3,239
TXU Electric Co	Encogen One	CA	WH	87200	3,327
TXU Electric Co	Lamar Power Project	CA	WH	202020	3,529
TXU Electric Co	Lamar Power Project	CA	WH	202020	3,731
TXU Electric Co	Southern Energy Wichita Falls LP	CA	WH	20000	3,751
TXU Electric Co	Tenaska III Texas Partners	CA	WH	90000	3,841
Brazos River Authority	Morris Sheppard	HY	WAT	12500	3,853
Brazos River Authority	Morris Sheppard	HY	WAT	12500	3,865
Central Power & Light Co	Eagle Pass	HY	WAT	4000	3,867
Central Power & Light Co	Eagle Pass	HY	WAT	4000	3,869
Central Power & Light Co	Eagle Pass	HY	WAT	4000	3,871
Central Power & Light Co	Small Hydro of Texas Inc	HY	WAT	589	3,871
Central Power & Light Co	Small Hydro of Texas Inc	HY	WAT	589	3,872
Central Power & Light Co	Small Hydro of Texas Inc	HY	WAT	589	3,873
Denton City of	Lewisville	HY	WAT	2800	3,875

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
Denton City of	Ray Roberts	HY	WAT	1200	3,877
Gonzales City of	Gonzales Hydro Plant	HY	WAT	500	3,877
Gonzales City of	Gonzales Hydro Plant	HY	WAT	500	3,877
Gonzales City of	Gonzales Hydro Plant	HY	WAT	500	3,878
Guadalupe Blanco River Auth	Abbott TP 3	HY	WAT	1400	3,879
Guadalupe Blanco River Auth	Abbott TP 3	HY	WAT	1400	3,880
Guadalupe Blanco River Auth	Canyon	HY	WAT	3000	3,883
Guadalupe Blanco River Auth	Canyon	HY	WAT	3000	3,886
Guadalupe Blanco River Auth	Dunlap TP 1	HY	WAT	1800	3,888
Guadalupe Blanco River Auth	Dunlap TP 1	HY	WAT	1800	3,890
Guadalupe Blanco River Auth	H 4	HY	WAT	2400	3,892
Guadalupe Blanco River Auth	H 5	HY	WAT	2400	3,895
Guadalupe Blanco River Auth	Nolte	HY	WAT	1200	3,896
Guadalupe Blanco River Auth	Nolte	HY	WAT	1200	3,897
Guadalupe Blanco River Auth	TP 4	HY	WAT	2400	3,900
Lower Colorado River Authority	Austin	HY	WAT	8068	3,908
Lower Colorado River Authority	Austin	HY	WAT	8068	3,917
Lower Colorado River Authority	Buchanan	HY	WAT	18300	3,934
Lower Colorado River Authority	Buchanan	HY	WAT	11250	3,949
Lower Colorado River Authority	Buchanan	HY	WAT	18300	3,966
Lower Colorado River Authority	Granite Shoals	HY	WAT	22500	3,994
Lower Colorado River Authority	Granite Shoals	HY	WAT	22500	4,022
Lower Colorado River Authority	Inks	HY	WAT	15000	4,036
Lower Colorado River Authority	Marble Falls	HY	WAT	15000	4,054
Lower Colorado River Authority	Marble Falls	HY	WAT	15000	4,072
Lower Colorado River Authority	Marshall Ford	HY	WAT	34000	4,108
Lower Colorado River Authority	Marshall Ford	HY	WAT	34545	4,143
Lower Colorado River Authority	Marshall Ford	HY	WAT	34000	4,179
Seguin City of	Seguin	HY	WAT	250	4,179
Reliant Energy HL&P	AES Deepwater Inc	ST	PC	184000	4,363
Central Power & Light Co	Valero Refinery	ST	PC	7500	4,371
Central Power & Light Co	Rio Grande Valley Sugar Growers Inc	ST	AB	2500	4,373
Central Power & Light Co	Rio Grande Valley Sugar Growers Inc	ST	AB	2500	4,376
Central Power & Light Co	Rio Grande Valley Sugar Growers Inc	ST	AB	2500	4,378
San Antonio Public Service Bd	J K Spruce	ST	SUB	546000	4,933
Reliant Energy HL&P	Limestone	ST	LIG	813400	5,699
Reliant Energy HL&P	Limestone	ST	LIG	813400	6,465
Lower Colorado River Authority	Fayette Power Prj	ST	SUB	615000	7,053
West Texas Utilities Co	Oklaunion	ST	SUB	663943	7,743
TXU Electric Co	Big Brown	ST	LIG	593400	8,318
Lower Colorado River Authority	Fayette Power Prj	ST	SUB	615000	8,906
TXU Electric Co	Big Brown	ST	LIG	593400	9,481
Reliant Energy HL&P	W A Parish	ST	SUB	734100	10,131
TXU Electric Co	Monticello	ST	LIG	593400	10,701
Lower Colorado River Authority	Fayette Power Prj	ST	SUB	460000	11,151
Texas-New Mexico Power Co	TNP ONE	ST	LIG	174600	11,303

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
TXU Electric Co	Martin Lake	ST	LIG	793250	12,053
San Antonio Public Service Bd	J T Deely	ST	SUB	446000	12,468
Reliant Energy HL&P	W A Parish	ST	SUB	614600	13,068
Reliant Energy HL&P	W A Parish	ST	SUB	614600	13,623
San Antonio Public Service Bd	J T Deely	ST	SUB	446000	14,038
Reliant Energy HL&P	W A Parish	ST	SUB	734100	14,688
TXU Electric Co	Monticello	ST	LIG	593400	15,253
Texas-New Mexico Power Co	TNP ONE	ST	LIG	174600	15,405
TXU Electric Co	Martin Lake	ST	LIG	793250	16,155
TXU Electric Co	Monticello	ST	LIG	793250	16,905
TXU Electric Co	Sandow	ST	LIG	590640	17,349
TXU Electric Co	Martin Lake	ST	LIG	793250	18,099
Reliant Energy HL&P	South Texas	ST	NUC	1354320	19,349
San Miguel Electric Coop Inc	San Miguel	ST	LIG	410000	19,740
Reliant Energy HL&P	South Texas	ST	NUC	1354320	20,990
TXU Electric Co	Comanche Peak	ST	NUC	1215000	22,140
TXU Electric Co	Comanche Peak	ST	NUC	1215000	23,290
Central Power & Light Co	Coleto Creek	ST	BIT	570057	23,922
TXU Electric Co	Sandow	ST	LIG	121000	24,043
TXU Electric Co	Sandow	ST	LIG	121000	24,164
TXU Electric Co	Sandow	ST	LIG	121000	24,285
Texas Municipal Power Agency	Gibbons Creek	ST	SUB	443970	24,705
TXU Electric Co	Midlothian Energy Facility	CS	NG	289000	24,994
TXU Electric Co	Midlothian Energy Facility	CS	NG	289000	25,283
TXU Electric Co	Midlothian Energy Facility	CS	NG	289000	25,572
TXU Electric Co	Midlothian Energy Facility	CS	NG	289000	25,861
Central Power & Light Co	Ingleside Cogeneration	CA	GAS	208000	26,069
Lower Colorado River Authority	Guadalupe Generating Station	CT	NG	184600	26,254
Lower Colorado River Authority	Guadalupe Generating Station	CT	NG	184600	26,438
Lower Colorado River Authority	Guadalupe Generating Station	CT	NG	184600	26,623
Lower Colorado River Authority	Guadalupe Generating Station	CT	NG	184600	26,807
Central Power & Light Co	Gregory Power Facility	CT	NG	182000	26,989
Central Power & Light Co	Gregory Power Facility	CT	NG	182000	27,171
Brazos Electric Power Coop Inc	Tenaska IV Texas Partners Ltd Cleburne Cogen	CT	NG	178200	27,350
Reliant Energy HL&P	Pasadena Cogeneration LP	CT	NG	175000	27,525
San Antonio Public Service Bd	A Von Rosenberg	CT	NG	174690	27,699
San Antonio Public Service Bd	A Von Rosenberg	CT	NG	174690	27,873
Reliant Energy HL&P	Pasadena Cogeneration LP	CT	NG	173400	28,046
TXU Electric Co	Lamar Power Project	CT	NG	171700	28,218
TXU Electric Co	Lamar Power Project	CT	NG	171700	28,389
TXU Electric Co	Lamar Power Project	CT	NG	171700	28,561
TXU Electric Co	Lamar Power Project	CT	NG	171700	28,733
Brazos Electric Power Coop Inc	Mirant Texas LP Bosque County Plant	CT	NG	170000	28,903
Brazos Electric Power Coop Inc	Mirant Texas LP Bosque County Plant	CT	NG	170000	29,073
Central Power & Light Co	Frontera Generation Facility	CT	NG	164000	29,237

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
Central Power & Light Co	Frontera Generation Facility	CT	NG	164000	29,401
Central Power & Light Co	Hidalgo Energy Center	CT	NG	162300	29,563
Central Power & Light Co	Hidalgo Energy Center	CT	NG	162300	29,725
Central Power & Light Co	Ingleside Cogeneration	CT	NG	160000	29,885
Central Power & Light Co	Ingleside Cogeneration	CT	NG	160000	30,045
Texas-New Mexico Power Co	Sweeny Cogeneration Facility	GT	NG	115000	30,160
Texas-New Mexico Power Co	Sweeny Cogeneration Facility	GT	NG	115000	30,275
Texas-New Mexico Power Co	Sweeny Cogeneration Facility	GT	NG	115000	30,390
Texas-New Mexico Power Co	Sweeny Cogeneration Facility	GT	NG	115000	30,505
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CT	NG	119000	30,624
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CT	NG	119000	30,743
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CT	NG	119000	30,862
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CT	NG	119000	30,981
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CT	NG	119000	31,100
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CA	NG	111350	31,212
Reliant Energy HL&P	Clear Lake Cogeneration Ltd	CT	NG	103670	31,315
Reliant Energy HL&P	Clear Lake Cogeneration Ltd	CT	NG	103670	31,419
Reliant Energy HL&P	Clear Lake Cogeneration Ltd	CT	NG	103670	31,523
Central Power & Light Co	Formosa Utility Venture Ltd	CT	NG	103000	31,626
Central Power & Light Co	Formosa Utility Venture Ltd	CT	NG	103000	31,729
Central Power & Light Co	Formosa Utility Venture Ltd	CT	NG	103000	31,832
Central Power & Light Co	Formosa Utility Venture Ltd	CT	NG	103000	31,935
Central Power & Light Co	Formosa Utility Venture Ltd	CT	NG	103000	32,038
Texas-New Mexico Power Co	Texas City Cogeneration LP	CT	NG	103000	32,141
Texas-New Mexico Power Co	Texas City Cogeneration LP	CT	NG	103000	32,244
Texas-New Mexico Power Co	Texas City Cogeneration LP	CT	NG	103000	32,347
Robstown City of	Robstown	IC	NG	5000	32,351
Reliant Energy HL&P	Cedar Bayou	ST	NG	765000	33,111
West Texas Utilities Co	San Angelo	CT	NG	25000	33,132
West Texas Utilities Co	San Angelo	CA	NG	85000	33,235
TXU Electric Co	DeCordova	ST	NG	799200	34,053
TXU Electric Co	Tradinghouse	ST	NG	580500	34,628
Reliant Energy HL&P	P H Robinson	ST	NG	484500	35,089
Reliant Energy HL&P	P H Robinson	ST	NG	484500	35,550
Brazos Electric Power Coop Inc	R W Miller	ST	NG	100000	35,670
TXU Electric Co	Graham	ST	NG	247775	35,913
Central Power & Light Co	Nueces Bay	ST	NG	323694	36,281
TXU Electric Co	Morgan Creek	ST	NG	517500	36,801
Lower Colorado River Authority	Thomas C Ferguson	ST	NG	446000	37,221
Brazos Electric Power Coop Inc	R W Miller	ST	NG	200000	37,429
Robstown City of	Robstown	IC	NG	2450	37,431
Robstown City of	Robstown	IC	NG	2615	37,433
Robstown City of	Robstown	IC	NG	2428	37,435
Robstown City of	Robstown	IC	NG	2428	37,437
Reliant Energy HL&P	W A Parish	ST	NG	580500	37,989
TXU Electric Co	Graham	ST	NG	387000	38,391

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
Central Power & Light Co	Barney M Davis	ST	NG	323449	38,735
Reliant Energy HL&P	P H Robinson	ST	NG	765000	39,474
Reliant Energy HL&P	Sam Bertron	ST	NG	225300	39,704
Coleman City of	Coleman	IC	NG	1500	39,705
San Antonio Public Service Bd	O W Sommers	ST	NG	446000	40,150
TXU Electric Co	Handley	ST	NG	404800	40,550
Reliant Energy HL&P	P H Robinson	ST	NG	580500	41,102
TXU Electric Co	Valley	ST	NG	580500	41,660
TXU Electric Co	Tradinghouse	ST	NG	799200	42,478
San Antonio Public Service Bd	O W Sommers	ST	NG	446000	42,913
Whitesboro City of	Whitesboro	IC	NG	1250	42,916
Whitesboro City of	Whitesboro	IC	NG	1250	42,918
Central Power & Light Co	Barney M Davis	ST	NG	323694	43,271
San Antonio Public Service Bd	V H Braunig	ST	NG	417000	43,671
San Antonio Public Service Bd	V H Braunig	ST	NG	225000	43,896
TXU Electric Co	Lake Hubbard	ST	NG	531000	44,424
TXU Electric Co	Mountain Creek	ST	NG	580500	44,974
TXU Electric Co	Permian Basin	ST	NG	535500	45,523
TXU Electric Co	Trinidad	ST	NG	239360	45,767
Whitesboro City of	Whitesboro	IC	NG	500	45,768
TXU Electric Co	Lake Creek	ST	NG	236000	46,004
TXU Electric Co	Morgan Creek	ST	NG	170455	46,188
Austin Energy	Decker Creek	ST	NG	321000	46,520
Austin Energy	Decker Creek	ST	NG	405000	46,952
Coleman City of	Coleman	IC	NG	1360	46,953
Robstown City of	Robstown	IC	NG	1000	46,954
Robstown City of	Robstown	IC	NG	1000	46,955
Weatherford Mun Utility System	Weatherford	IC	NG	1360	46,956
Weatherford Mun Utility System	Weatherford	IC	NG	1360	46,957
Reliant Energy HL&P	Cedar Bayou	ST	NG	765000	47,707
Reliant Energy HL&P	Baytown Turbine Generator Project	GT	NG	100000	47,807
Reliant Energy HL&P	Oyster Creek Unit VIII	CT	NG	99025	47,906
Reliant Energy HL&P	Oyster Creek Unit VIII	CT	NG	99025	48,005
Reliant Energy HL&P	Oyster Creek Unit VIII	CT	NG	99025	48,104
TXU Electric Co	Stryker Creek	ST	NG	526680	48,614
Lower Colorado River Authority	Sim Gideon	ST	NG	351000	48,957
TXU Electric Co	Valley	ST	NG	198990	49,139
Central Power & Light Co	Lon C Hill	ST	NG	234874	49,386
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CT	NG	94563	49,481
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CT	NG	94563	49,575
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CT	NG	94563	49,670
Reliant Energy HL&P	Webster	ST	NG	410040	50,044
San Antonio Public Service Bd	V H Braunig	ST	NG	252000	50,284
Central Power & Light Co	Nueces Bay	ST	NG	160000	50,445
TXU Electric Co	North Lake	ST	NG	361350	50,816
Reliant Energy HL&P	Deer Park Plant	CT	NG	81060	50,897

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
Reliant Energy HL&P	Freeport	CT	NG	81000	50,978
Reliant Energy HL&P	San Jacinto SES	GT	NG	88200	51,059
Reliant Energy HL&P	San Jacinto SES	GT	NG	88200	51,140
Reliant Energy HL&P	W A Parish	ST	NG	299200	51,418
Central Power & Light Co	Victoria Texas Plant	GT	NG	80000	51,498
TXU Electric Co	Tenaska III Texas Partners	CT	NG	80000	51,578
TXU Electric Co	Tenaska III Texas Partners	CT	NG	80000	51,658
Garland City of	Ray Olinger	ST	NG	113400	51,768
Reliant Energy HL&P	CoGen Lyondell Inc	CT	NG	79000	51,847
Reliant Energy HL&P	Newgulf	CT	NG	78750	51,926
West Texas Utilities Co	Oak Creek	ST	NG	75000	52,011
TXU Electric Co	North Lake	ST	NG	170455	52,187
Texas-New Mexico Power Co	Power Station 4	CT	NG	78210	52,265
Texas-New Mexico Power Co	Power Station 4	CT	NG	78210	52,343
Reliant Energy HL&P	Cedar Bayou	ST	NG	765000	53,093
TXU Electric Co	C R Wing Cogeneration Plant	CT	NG	77540	53,171
TXU Electric Co	C R Wing Cogeneration Plant	CT	NG	77540	53,248
San Antonio Public Service Bd	W B Tuttle	ST	NG	192000	53,408
Reliant Energy HL&P	Greens Bayou	ST	NG	446400	53,814
Reliant Energy HL&P	Sam Bertron	ST	NG	225300	54,044
Reliant Energy HL&P	Bayou Cogeneration Plant	GT	NG	75000	54,119
Reliant Energy HL&P	Bayou Cogeneration Plant	GT	NG	75000	54,194
Reliant Energy HL&P	Bayou Cogeneration Plant	GT	NG	75000	54,269
Reliant Energy HL&P	Bayou Cogeneration Plant	GT	NG	75000	54,344
Reliant Energy HL&P	Shell Deer Park	GT	NG	75000	54,419
Reliant Energy HL&P	Shell Deer Park	GT	NG	75000	54,494
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CT	NG	75000	54,569
West Texas Utilities Co	Fort Phantom	ST	NG	190862	54,773
Reliant Energy HL&P	CoGen Lyondell Inc	CT	NG	74000	54,847
Reliant Energy HL&P	CoGen Lyondell Inc	CT	NG	74000	54,921
Reliant Energy HL&P	CoGen Lyondell Inc	CT	NG	74000	54,995
Reliant Energy HL&P	CoGen Lyondell Inc	CT	NG	74000	55,069
Reliant Energy HL&P	CoGen Lyondell Inc	CT	NG	74000	55,143
Reliant Energy HL&P	Houston Chemical Complex Battleground Site	CT	NG	74000	55,217
Reliant Energy HL&P	Houston Chemical Complex Battleground Site	CT	NG	74000	55,291
TXU Electric Co	Encogen One	CT	NG	72760	55,364
TXU Electric Co	Encogen One	CT	NG	72760	55,437
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CT	GAS	71400	55,508
Reliant Energy HL&P	Deepwater	ST	NG	187850	55,686
TXU Electric Co	Eagle Mountain	ST	NG	187500	55,864
Central Power & Light Co	E S Joslin	ST	NG	234874	56,113
Central Power & Light Co	La Palma	ST	NG	153225	56,269
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CA	NG	64800	56,334
Coleman City of	Coleman	IC	NG	4000	56,338

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
Reliant Energy HL&P	T H Wharton	ST	NG	247800	56,567
Lower Colorado River Authority	Sim Gideon	ST	NG	144000	56,711
San Antonio Public Service Bd	W B Tuttle	ST	NG	114000	56,811
Lower Colorado River Authority	Sim Gideon	ST	NG	144000	56,955
West Texas Utilities Co	Fort Phantom	ST	NG	146460	57,113
West Texas Utilities Co	Rio Pecos	ST	NG	88968	57,211
Reliant Energy HL&P	Sam Bertron	ST	NG	187850	57,385
Austin Energy	Holly Street	ST	NG	193000	57,576
Austin Energy	Holly Street	ST	NG	100000	57,676
Coleman City of	Coleman	IC	NG	1500	57,677
Coleman City of	Coleman	IC	NG	1500	57,679
Robstown City of	Robstown	IC	NG	4150	57,682
Texas-New Mexico Power Co	S&L Cogeneration	GT	NG	55000	57,737
Central Power & Light Co	J L Bates	ST	NG	100000	57,847
Central Power & Light Co	Lon C Hill	ST	NG	150000	58,003
Brownsville Public Utils Board	Si Ray	GT	NG	53000	58,055
TXU Electric Co	Stryker Creek	ST	NG	176800	58,238
Reliant Energy HL&P	W A Parish	ST	NG	187850	58,416
Reliant Energy HL&P	Clear Lake Cogeneration Ltd	CA	GAS	51937	58,468
West Texas Utilities Co	Paint Creek	ST	NG	105145	58,586
Austin Energy	University of Texas at Austin	CT	NG	48510	58,635
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CA	GAS	50000	58,685
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CA	GAS	50000	58,735
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CA	GAS	50000	58,785
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CA	GAS	50000	58,835
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CA	GAS	50000	58,885
Reliant Energy HL&P	The Dow Chemical Co Texas Operations	CA	GAS	49000	58,934
San Antonio Public Service Bd	Mission Road	ST	NG	114000	59,034
Central Power & Light Co	Corpus Christi Plant	GT	NG	45176	59,079
Garland City of	Ray Olinger	ST	NG	156600	59,229
Central Power & Light Co	Victoria	ST	NG	234874	59,479
Brazos Electric Power Coop Inc	R W Miller	ST	NG	66000	59,554
Reliant Energy HL&P	Sam Bertron	ST	NG	187850	59,728
Reliant Energy HL&P	Chocolate Bayou Works	GT	NG	41000	59,769
Austin Energy	Holly Street	ST	NG	100000	59,868
Austin Energy	Holly Street	ST	NG	165000	60,056
Texas-New Mexico Power Co	Texas City Plant Union Carbide Corp	CT	NG	40000	60,096
TXU Electric Co	Permian Basin	ST	NG	114954	60,211
San Antonio Public Service Bd	W B Tuttle	ST	NG	114000	60,306
Bryan City of	Dansby	ST	NG	105000	60,416
Whitesboro City of	Whitesboro	IC	NG	900	60,417
Central Power & Light Co	Formosa Utility Venture Ltd	GT	NG	37400	60,454
Reliant Energy HL&P	Baytown Turbine Generator Project	GT	NG	37334	60,492
Reliant Energy HL&P	Baytown Turbine Generator Project	GT	NG	37333	60,529
Reliant Energy HL&P	Baytown Turbine Generator Project	GT	NG	37333	60,566
Reliant Energy HL&P	Exxon Mobil Co USA Baytown PP3 PP4	GT	NG	36500	60,603

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
Reliant Energy HL&P	Exxon Mobil Co USA Baytown PP3 PP4	GT	NG	36500	60,639
San Antonio Public Service Bd	Leon Creek	ST	NG	114000	60,734
TXU Electric Co	North Lake	ST	NG	176800	60,910
Central Power & Light Co	Celanese Engineering Resin Inc	CT	NG	35540	60,946
Central Power & Light Co	Seadrift Plant Union Carbide Corp	CT	NG	35000	60,981
Central Power & Light Co	Seadrift Plant Union Carbide Corp	CT	NG	35000	61,016
Central Power & Light Co	Seadrift Plant Union Carbide Corp	CT	NG	35000	61,051
TXU Electric Co	Mountain Creek	ST	NG	136000	61,181
TXU Electric Co	Encogen One	CT	NG	33250	61,214
TXU Electric Co	Permian Basin	GT	NG	89478	61,294
TXU Electric Co	Collin	ST	NG	156250	61,447
Reliant Energy HL&P	W A Parish	ST	NG	187850	61,625
Coleman City of	Coleman	IC	NG	2500	61,627
Coleman City of	Coleman	IC	NG	1300	61,629
Coleman City of	Coleman	IC	NG	2200	61,631
Coleman City of	Coleman	IC	NG	1000	61,632
TXU Electric Co	Permian Basin	GT	NG	89478	61,712
TXU Electric Co	Lake Creek	ST	NG	79625	61,802
TXU Electric Co	Lake Hubbard	ST	NG	396519	62,195
TXU Electric Co	Parkdale	ST	NG	125000	62,310
Central Power & Light Co	Laredo	ST	NG	105290	62,415
Brazos Electric Power Coop Inc	North Texas	ST	NG	38000	62,455
West Texas Utilities Co	Paint Creek	ST	NG	50000	62,509
Central Power & Light Co	Victoria	ST	NG	160000	62,681
TXU Electric Co	Valley	ST	NG	396000	63,075
Texas-New Mexico Power Co	Power Station 3	CT	NG	20750	63,095
Central Power & Light Co	Corpus Christi Refinery	GT	NG	20000	63,115
Central Power & Light Co	Corpus Christi Refinery	GT	NG	20000	63,135
Reliant Energy HL&P	Exxon Mobil Co USA Baytown PP3 PP4	GT	NG	20000	63,155
Reliant Energy HL&P	Exxon Mobil Co USA Baytown PP3 PP4	GT	NG	20000	63,175
Reliant Energy HL&P	Exxon Mobil Co USA Baytown PP3 PP4	GT	NG	20000	63,195
Reliant Energy HL&P	Exxon Mobil Co USA Baytown PP3 PP4	GT	NG	20000	63,215
TXU Electric Co	Southern Energy Wichita Falls LP	CT	NG	20000	63,235
TXU Electric Co	Southern Energy Wichita Falls LP	CT	NG	20000	63,255
TXU Electric Co	Southern Energy Wichita Falls LP	CT	NG	20000	63,275
TXU Electric Co	DeCordova	GT	NG	89478	63,355
Reliant Energy HL&P	Sheldon Texas	GT	GAS	18000	63,373
Reliant Energy HL&P	Sheldon Texas	GT	NG	18000	63,391
Reliant Energy HL&P	Exxon Mobil Co USA Baytown PP3 PP4	GT	NG	17250	63,409
Bryan City of	Bryan	ST	NG	54000	63,459
Medina Electric Coop Inc	Pearsall	ST	NG	22000	63,484
Medina Electric Coop Inc	Pearsall	ST	NG	22000	63,509
Medina Electric Coop Inc	Pearsall	ST	NG	22000	63,534
Reliant Energy HL&P	Valero Refining Co Texas Houston Refinery	GT	NG	17148	63,551
Reliant Energy HL&P	Valero Refining Co Texas Houston	GT	NG	17148	63,568

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
	Refinery				
TXU Electric Co	DeCordova	GT	NG	89478	63,648
Texas-New Mexico Power Co	Valero Refining Co Texas City Refinery	GT	NG	16200	63,664
Texas-New Mexico Power Co	Valero Refining Co Texas City Refinery	GT	NG	16200	63,680
TXU Electric Co	Parkdale	ST	NG	136000	63,808
TXU Electric Co	DeCordova	GT	NG	89478	63,888
Texas-New Mexico Power Co	Power Station 3	CT	NG	15600	63,904
Texas-New Mexico Power Co	Power Station 3	CT	NG	15600	63,919
Reliant Energy HL&P	Exxon Mobil Co USA Baytown PP3 PP4	GT	NG	15250	63,935
Denton City of	Spencer	ST	NG	65483	64,001
TXU Electric Co	Mountain Creek	ST	NG	135779	64,120
Reliant Energy HL&P	Exxon Mobil Co USA Baytown PP3 PP4	GT	NG	14500	64,134
West Texas Utilities Co	Paint Creek	ST	NG	33000	64,167
Reliant Energy HL&P	Clear Lake Cogeneration Ltd	CA	GAS	14053	64,181
Garland City of	Ray Olinger	ST	NG	75000	64,256
TXU Electric Co	Handley	ST	NG	455000	64,714
TXU Electric Co	River Crest	ST	NG	112500	64,824
Greenville Electric Util Sys	Powerlane Plant	ST	NG	43200	64,866
TXU Electric Co	DeCordova	GT	NG	89478	64,946
Reliant Energy HL&P	Shell Deer Park	ST	NG	50000	64,996
Reliant Energy HL&P	Shell Deer Park	ST	NG	50000	65,046
Austin Energy	University of Texas at Austin	CT	NG	12500	65,059
TXU Electric Co	Eagle Mountain	ST	NG	396150	65,434
West Texas Utilities Co	Rio Pecos	CT	NG	5000	65,439
Central Power & Light Co	Seadrift Plant Union Carbide Corp	CT	NG	12000	65,451
Reliant Energy HL&P	Sheldon Texas	ST	NG	46250	65,497
West Texas Utilities Co	Rio Pecos	CA	NG	33000	65,535
TXU Electric Co	Morgan Creek	ST	NG	18400	65,557
TXU Electric Co	Permian Basin	GT	NG	89478	65,637
TXU Electric Co	Morgan Creek	GT	NG	89478	65,717
TXU Electric Co	Handley	ST	NG	455000	66,175
TXU Electric Co	Parkdale	ST	NG	79625	66,262
TXU Electric Co	Morgan Creek	GT	NG	89478	66,342
TXU Electric Co	Permian Basin	GT	NG	89478	66,422
TXU Electric Co	Eagle Mountain	ST	NG	122500	66,543
TXU Electric Co	Morgan Creek	GT	NG	89478	66,623
TXU Electric Co	Morgan Creek	GT	NG	89478	66,703
Reliant Energy HL&P	Texas Petrochemicals Corp	ST	NG	35000	66,738
TXU Electric Co	Mountain Creek	ST	NG	31213	66,771
Denton City of	Spencer	ST	NG	61162	66,831
TXU Electric Co	Morgan Creek	GT	NG	89478	66,911
TXU Electric Co	Morgan Creek	GT	NG	89478	66,991
Reliant Energy HL&P	Sheldon Texas	ST	NG	33000	67,024
Central Power & Light Co	Reynolds Metals Co Sherwin Plant	CT	NG	7500	67,031
Central Power & Light Co	Reynolds Metals Co Sherwin Plant	CT	NG	7500	67,039
Garland City of	C E Newman	ST	NG	18750	67,056

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
Texas-New Mexico Power Co	Chino Mines Co	ST	NG	30000	67,086
Texas-New Mexico Power Co	Valero Refining Co Texas City Refinery	GT	NG	7160	67,093
Denton City of	Spencer	ST	NG	22000	67,120
Central Power & Light Co	Victoria	ST	NG	66000	67,180
Central Power & Light Co	J L Bates	ST	NG	66000	67,252
Garland City of	C E Newman	ST	NG	18750	67,270
Garland City of	C E Newman	ST	NG	44000	67,311
West Texas Utilities Co	Lake Pauline	ST	NG	20000	67,337
Bryan City of	Bryan	ST	NG	25000	67,362
TXU Electric Co	Permian Basin	GT	NG	89478	67,442
Reliant Energy HL&P	T H Wharton	GT	NG	85000	67,500
Central Power & Light Co	Lon C Hill	ST	NG	66000	67,571
Reliant Energy HL&P	T H Wharton	CT	NG	56700	67,628
Brazos Electric Power Coop Inc	North Texas	ST	NG	16500	67,646
Brazos Electric Power Coop Inc	North Texas	ST	NG	16500	67,664
TXU Electric Co	Mountain Creek	ST	NG	74999	67,734
Reliant Energy HL&P	T H Wharton	CT	NG	56700	67,791
TXU Electric Co	Lufkin Texas	ST	NG	21176	67,812
Austin Energy	Decker Creek	GT	NG	51570	67,856
Austin Energy	Decker Creek	GT	NG	51570	67,900
Austin Energy	Decker Creek	GT	NG	51570	67,944
Austin Energy	Decker Creek	GT	NG	51570	67,986
Greenville Electric Util Sys	Powerlane Plant	ST	NG	16500	68,007
Central Power & Light Co	Laredo	ST	NG	30000	68,042
San Antonio Public Service Bd	Leon Creek	ST	NG	75000	68,107
San Antonio Public Service Bd	W B Tuttle	ST	NG	75000	68,172
Central Power & Light Co	Nueces Bay	ST	NG	30000	68,202
Greenville Electric Util Sys	Powerlane Plant	ST	NG	25000	68,228
TXU Electric Co	Handley	ST	NG	74800	68,308
Reliant Energy HL&P	Pasadena	GT	NG	4000	68,312
Reliant Energy HL&P	Rice University	GT	NG	3937	68,316
Texas-New Mexico Power Co	Chino Mines Co	ST	NG	16500	68,333
Central Power & Light Co	Lon C Hill	ST	NG	60000	68,404
Reliant Energy HL&P	T H Wharton	CT	NG	51300	68,461
TXU Electric Co	North Main	ST	NG	81250	68,541
Reliant Energy HL&P	Westhollow Technology Center	GT	NG	3725	68,544
Brazos Electric Power Coop Inc	R W Miller	GT	NG	118818	68,648
Brazos Electric Power Coop Inc	R W Miller	GT	NG	118818	68,752
TXU Electric Co	Lufkin Texas	ST	NG	15625	68,768
TXU Electric Co	Lufkin Texas	ST	NG	15625	68,784
TXU Electric Co	Morgan Creek	ST	NG	75000	68,858
Central Power & Light Co	Laredo	ST	NG	33000	68,892
Reliant Energy HL&P	Enterprise Products Operating LP	GT	NG	3500	68,895
Reliant Energy HL&P	Enterprise Products Operating LP	GT	NG	3500	68,899
Reliant Energy HL&P	Enterprise Products Operating LP	GT	NG	3500	68,902
TXU Electric Co	Baylor University Cogeneration	GT	NG	3447	68,906

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
Reliant Energy HL&P	Enterprise Products Operating LP	GT	NG	3400	68,909
Reliant Energy HL&P	Enterprise Products Operating LP	GT	NG	3400	68,912
Reliant Energy HL&P	Enterprise Products Operating LP	GT	NG	3400	68,916
Reliant Energy HL&P	T H Wharton	GT	NG	85000	68,974
Reliant Energy HL&P	Rice University	GT	NG	3169	68,977
Bryan City of	Bryan	ST	NG	24000	68,999
TXU Electric Co	Lufkin Texas	ST	NG	12500	69,011
TXU Electric Co	Lufkin Texas	ST	NG	12500	69,024
TXU Electric Co	Yates Gas Plant	GT	NG	2800	69,027
TXU Electric Co	Yates Gas Plant	GT	NG	2800	69,029
Reliant Energy HL&P	T H Wharton	CT	NG	51300	69,086
TXU Electric Co	Morgan Creek	ST	NG	46000	69,130
Reliant Energy HL&P	T H Wharton	GT	NG	85000	69,188
Central Power & Light Co	La Palma	GT	NG	49100	69,236
Reliant Energy HL&P	Enterprise Products Operating LP	GT	NG	2500	69,239
Reliant Energy HL&P	Enterprise Products Operating LP	GT	NG	2500	69,241
Denton City of	Spencer	ST	NG	12650	69,254
Denton City of	Spencer	ST	NG	12650	69,267
Reliant Energy HL&P	T H Wharton	CT	NG	51300	69,324
Reliant Energy HL&P	T H Wharton	CT	NG	51300	69,381
Bryan City of	Bryan	GT	NG	22000	69,402
Reliant Energy HL&P	Pasadena Paper Company	ST	GAS	10000	69,412
Reliant Energy HL&P	T H Wharton	CT	NG	51300	69,469
Reliant Energy HL&P	T H Wharton	GT	NG	85000	69,527
West Texas Utilities Co	Paint Creek	ST	NG	30000	69,560
Reliant Energy HL&P	T H Wharton	GT	NG	85000	69,618
TXU Electric Co	Lufkin Texas	ST	NG	7500	69,626
TXU Electric Co	Handley	ST	NG	43750	69,671
Reliant Energy HL&P	T H Wharton	CT	NG	51300	69,728
Reliant Energy HL&P	T H Wharton	GT	NG	85000	69,786
South Texas Electric Coop Inc	Sam Rayburn	ST	NG	22000	69,811
Central Power & Light Co	La Palma	ST	NG	20000	69,836
Central Power & Light Co	La Palma	ST	NG	20000	69,861
Reliant Energy HL&P	Rhodia Inc Houston Plant	ST	GAS	5000	69,866
Reliant Energy HL&P	Shell Deer Park	ST	GAS	5000	69,871
Austin Energy	Austin State Hospital	GT	NG	1000	69,872
Brownsville Public Utils Board	Si Ray	ST	NG	22000	69,892
Reliant Energy HL&P	Pasadena Paper Company	ST	GAS	4000	69,896
Brownsville Public Utils Board	Si Ray	GT	NG	45000	69,948
Brownsville Public Utils Board	Si Ray	ST	NG	25000	69,966
Reliant Energy HL&P	Greens Bayou	GT	NG	72000	70,030
Reliant Energy HL&P	Greens Bayou	GT	NG	72000	70,094
Reliant Energy HL&P	Greens Bayou	GT	NG	72000	70,158
Reliant Energy HL&P	Greens Bayou	GT	NG	72000	70,212
Reliant Energy HL&P	Greens Bayou	GT	NG	72000	70,266
Reliant Energy HL&P	Greens Bayou	GT	NG	72000	70,320

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
Reliant Energy HL&P	Fort Bend Utilities Co	ST	NG	3000	70,323
San Antonio Public Service Bd	University of Texas at San Antonio	IC	NG	3470	70,326
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3100	70,330
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3000	70,333
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3000	70,336
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3000	70,339
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3000	70,342
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3000	70,345
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3100	70,348
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3000	70,351
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3100	70,354
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3000	70,357
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3000	70,360
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3000	70,363
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3100	70,366
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3000	70,369
Texas-New Mexico Power Co	Phelps Dodge Tyrone Inc	IC	NG	3000	70,372
TXU Electric Co	Benedum Plant	IC	NG	1000	70,373
TXU Electric Co	Benedum Plant	IC	NG	1000	70,374
TXU Electric Co	East Vealmoor Gas Plant	IC	GAS	275	70,374
TXU Electric Co	East Vealmoor Gas Plant	IC	NG	270	70,374
TXU Electric Co	East Vealmoor Gas Plant	IC	NG	280	70,375
TXU Electric Co	East Vealmoor Gas Plant	IC	NG	280	70,375
TXU Electric Co	East Vealmoor Gas Plant	IC	NG	300	70,375
TXU Electric Co	East Vealmoor Gas Plant	IC	NG	265	70,376
TXU Electric Co	East Vealmoor Gas Plant	IC	NG	265	70,376
TXU Electric Co	East Vealmoor Gas Plant	IC	NG	265	70,376
TXU Electric Co	Fullerton Plant	IC	NG	500	70,377
TXU Electric Co	Fullerton Plant	IC	NG	500	70,377
TXU Electric Co	Fullerton Plant	IC	NG	500	70,378
TXU Electric Co	Fullerton Plant	IC	NG	500	70,378
TXU Electric Co	Fullerton Plant	IC	NG	500	70,379
TXU Electric Co	Fullerton Plant	IC	NG	500	70,379
TXU Electric Co	University of Texas at Dallas	IC	NG	3500	70,383
TXU Electric Co	Village Creek Wastewater Treatment Plant	IC	NG	850	70,383
TXU Electric Co	Village Creek Wastewater Treatment Plant	IC	NG	850	70,384
West Texas Utilities Co	Jameson Gas Processing Plant	IC	GAS	550	70,385
West Texas Utilities Co	Jameson Gas Processing Plant	IC	NG	550	70,385
West Texas Utilities Co	Jameson Gas Processing Plant	IC	NG	350	70,386
West Texas Utilities Co	Jameson Gas Processing Plant	IC	NG	350	70,386
Austin Energy	University of Texas at Austin	ST	GAS	2500	70,389
West Texas Utilities Co	Abilene	ST	NG	15000	70,407
Reliant Energy HL&P	Fort Bend Utilities Co	ST	NG	2000	70,409
Garland City of	C E Newman	ST	NG	7500	70,417

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
Garland City of	C E Newman	ST	NG	7500	70,425
Austin Energy	University of Texas at Austin	ST	GAS	1500	70,426
Austin Energy	University of Texas at Austin	ST	GAS	1500	70,428
Reliant Energy HL&P	Rhodia Inc Houston Plant	ST	GAS	1500	70,429
Electra City of	Electra	IC	NG	1250	70,430
Electra City of	Electra	IC	NG	1500	70,432
Electra City of	Electra	IC	NG	500	70,432
Electra City of	Electra	IC	NG	240	70,432
Electra City of	Electra	IC	NG	500	70,433
Electra City of	Electra	IC	NG	240	70,433
Bryan City of	Bryan	ST	NG	13000	70,445
Weatherford Mun Utility System	Weatherford	IC	DFO	1400	70,446
Weatherford Mun Utility System	Weatherford	IC	DFO	840	70,447
Reliant Energy HL&P	Fort Bend Utilities Co	ST	NG	1000	70,448
Reliant Energy HL&P	Hiram Clarke	GT	NG	16000	70,461
Reliant Energy HL&P	Hiram Clarke	GT	NG	16000	70,474
Reliant Energy HL&P	Hiram Clarke	GT	NG	16000	70,487
Reliant Energy HL&P	Hiram Clarke	GT	NG	16000	70,500
Reliant Energy HL&P	Hiram Clarke	GT	NG	16000	70,513
Reliant Energy HL&P	Hiram Clarke	GT	NG	16000	70,526
Reliant Energy HL&P	Sam Bertron	GT	NG	32640	70,549
Reliant Energy HL&P	Sam Bertron	GT	NG	16320	70,562
Reliant Energy HL&P	T H Wharton	GT	NG	16320	70,575
Reliant Energy HL&P	W A Parish	GT	NG	16320	70,588
Reliant Energy HL&P	Webster	GT	NG	16320	70,601
South Texas Electric Coop Inc	Sam Rayburn	IC	DFO	1600	70,603
South Texas Electric Coop Inc	Sam Rayburn	IC	DFO	1600	70,604
South Texas Electric Coop Inc	Sam Rayburn	GT	NG	11250	70,615
South Texas Electric Coop Inc	Sam Rayburn	GT	NG	11250	70,629
West Texas Utilities Co	Vernon	IC	DFO	2460	70,631
West Texas Utilities Co	Vernon	IC	DFO	2000	70,632
TXU Electric Co	Lake Creek	IC	DFO	2000	70,634
TXU Electric Co	Lake Creek	IC	DFO	2000	70,636
TXU Electric Co	Lake Creek	IC	DFO	2000	70,638
TXU Electric Co	Stryker Creek	IC	DFO	2000	70,640
TXU Electric Co	Stryker Creek	IC	DFO	2000	70,642
TXU Electric Co	Stryker Creek	IC	DFO	2000	70,644
TXU Electric Co	Stryker Creek	IC	DFO	2000	70,646
TXU Electric Co	Stryker Creek	IC	DFO	2000	70,648
TXU Electric Co	Trinidad	IC	DFO	2000	70,650
TXU Electric Co	Trinidad	IC	DFO	2000	70,652
West Texas Utilities Co	Lake Pauline	ST	NG	20000	70,671
Weatherford Mun Utility System	Weatherford	IC	DFO	300	70,671
Weatherford Mun Utility System	Weatherford	IC	DFO	300	70,672
Weatherford Mun Utility System	Weatherford	IC	DFO	300	70,672
West Texas Utilities Co	Vernon	IC	DFO	1360	70,673

Utility	Plant Name	Unit Type	Fuel	Name plate	Cumulative MW
West Texas Utilities Co	Vernon	IC	DFO	1360	70,674
West Texas Utilities Co	Vernon	IC	DFO	4100	70,678
West Texas Utilities Co	Fort Stockton	GT	NG	5000	70,683
Texas-New Mexico Power Co	Chino Mines Co	ST	FO1	10000	70,693
Seguin City of	Seguin	IC	DFO	250	70,693
Texas-New Mexico Power Co	Chino Mines Co	ST	FO1	7500	70,701
West Texas Utilities Co	Presidio	IC	DFO	1136	70,702
West Texas Utilities Co	Presidio	IC	DFO	1136	70,703
Austin Energy	Central Utility Plant	IC	DFO	6080	70,709
Austin Energy	Central Utility Plant	IC	DFO	6080	70,715
Reliant Energy HL&P	Fort Bend Utilities Co	IC	DFO	155	70,715
Texas-New Mexico Power Co	Phelps Dodge Cobre Mining Co	IC	FO1	800	70,716
Texas-New Mexico Power Co	Phelps Dodge Cobre Mining Co	IC	FO1	800	70,717
Texas-New Mexico Power Co	Phelps Dodge Cobre Mining Co	IC	FO1	800	70,717
TXU Electric Co	PPG Industries Inc Works 4	IC	DFO	2000	70,719
TXU Electric Co	PPG Industries Inc Works 4	IC	DFO	1100	70,720
TXU Electric Co	PPG Industries Inc Works 4	IC	DFO	2000	70,722
TXU Electric Co	PPG Industries Inc Works 4	IC	DFO	930	70,723
TXU Electric Co	State Farm Ins Co ISC Central	IC	DFO	1825	70,725
TXU Electric Co	State Farm Ins Co ISC Central	IC	DFO	1825	70,727
TXU Electric Co	State Farm Ins Co ISC Central	IC	DFO	1825	70,729
TXU Electric Co	State Farm Ins Co ISC Central	IC	DFO	1825	70,731
TXU Electric Co	State Farm Ins Co ISC Central	IC	DFO	1825	70,733
TXU Electric Co	State Farm Ins Co ISC Central	IC	DFO	1825	70,734