# Transmission Issues Associated with Renewable Energy in Texas

## Informal White Paper For the Texas Legislature, 2005

March 28, 2005

Produced in a joint effort between the industry and
the Electric Reliability Council of Texas Independent System Operator

**CONTENTS**

*Fact Sheet* .......... 3-5
*Questions & Answers*
Future Electricity Needs .......... 6-7
Impact of Different Renewable Bills .......... 7
Comparison of Different Generation Types .......... 8
Wholesale Electricity Prices vs. Natural Gas Prices .......... 9
Transmission Line Loading .......... 9
Transmission System Impacts and Cost Estimates .......... 10
Transmission Cost Recovery .......... 11
Renewable Potential in Non-ERCOT Areas of Texas .......... 12
*Terminology* .......... 13
*Background Information & Supporting Tables* .......... 14-20
Transmission & System Planning Responsibilities
Transmission Planning Process
Generation Adequacy
Energy & Demand Forecasts
Fuel Source Analysis
Peak Demand by Month
Electric Capacity Breakdown

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**QUALIFICATIONS & DISCLAIMERS:**

This document was developed by an informal stakeholder group in an effort to provide factual data for consideration by legislators in evaluating bills to expand Texas renewable energy standards. The stakeholders represent a range of interests with differing positions on the subject of renewable energy standards.

After an initial meeting on March 2, 2005, organized at the request of Rep. David Swinford, ERCOT agreed to facilitate follow-up communications and to develop the initial draft of this document.

Data to support the estimates and projections contained in this document were drawn from numerous sources provided voluntarily by the stakeholders in the group and from reports prepared by ERCOT in its role as the independent system operator and planning supervisor. Unless specifically attributed, **none of the estimates or projections in this document should be considered to be the result of an in-depth ERCOT engineering study**.

This document is intended to provide a source of facts and best estimates, and is not intended to advocate for or against any particular bill or position.

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The Electric Reliability Council of Texas (ERCOT) is the independent organization in Texas charged with ensuring the reliability of the electricity grid in its region, which encompasses 75 percent of Texas area and 85 percent of Texas load. ERCOT is the supervisor of the transmission planning process in its area, and is a neutral source of facts and information. ERCOT does not advocate for or against policy positions, except in cases where electric grid reliability may be affected. ERCOT is an independent, nonprofit corporation fully regulated by the Public Utility Commission of Texas.

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**FACT SHEET**

**Analysis of Renewable Energy Legislation in the 79th Texas Legislature**

The renewable portfolio standards in this chart apply to renewable energy built after the passage of Senate Bill 7 in 1999.

- 2,367 MW of post-SB7 renewables are anticipated to be online by the end of 2005 (this number counts toward the standards in the table).
- An additional 880 MW of renewables were counted as already online in Texas prior to SB7.

| Year | HB 1671 (Hunter)<br>SB 533 (Fraser) | HB 1798 (Swinford)<br>SB 836 (Duncan) | HB 2692 (Gallego)<br>SB 1075 (Zaffirini) |
|---|---|---|---|
| **2015** | **5,000 MW**<br>Existing:<br>-- ERCOT 2127 MW<br>-- SPP 240 MW<br>New 2633 MW includes 500 MW Non-wind | **10,000 MW**<br>Existing:<br>-- ERCOT 2127 MW<br>-- SPP 240 MW<br>New 7633 MW includes 500 MW Distributed Renewable Generation | **10,000 MW**<br>Existing:<br>-- ERCOT 2127 MW<br>-- SPP 240 MW<br>New 7633 MW includes 500 MW Distributed Renewable Generation |
| **2020** | | | **20% of Energy**<br>(Equates to **26,659 MW** of capacity)*<br>Existing:<br>-- ERCOT 2127 MW<br>-- SPP 240 MW<br>New 24,532 MW includes 500 MW Distributed Renewable Generation |
| **2025** | **10,000 MW**<br>Existing:<br>-- ERCOT 2127 MW<br>-- SPP 240 MW<br>New 7633 MW includes 500 MW Non-wind | | |

* Based on 40% capacity factor and projection of 467,121 GWh energy.

**Texas Transmission System Overview**

- Most of Texas is within the ERCOT power region, which is under the sole jurisdiction of the Public Utility Commission of Texas (PUC).
- The Panhandle is connected to the Southwest Power Pool (SPP), whose transmission system is primarily under the joint jurisdiction of the PUC and the Federal Energy Regulatory Commission (FERC).
- The El Paso area is connected to the Western Systems Coordinating Council (WSCC), which is also jointly PUC and FERC-jurisdictional.
- Two sections of East Texas are in the Southeastern Electric Reliability Council (SERC) and SPP, and are also jointly PUC and FERC-jurisdictional.

**Transmission and Grid Operations: Facts Related to Wind Energy**

- Completion of upgrades to the 138kV transmission network in the McCamey area (Oct. 2005) is expected to enable export of up to 650 MW of wind energy from that region, based on AEP analysis.

    - ERCOT is continuing to perform studies to determine how to fully accommodate the total installed generation in the area (755 MW).
- A preliminary ERCOT study has scoped a series of major upgrades to the 345kV transmission network in West Texas that would support a total of 5,000 MW of wind power from that region, assuming clustered development in three principal areas (McCamey, Sweetwater, Abilene).
    - Some of these identified upgrades, particularly projects near the DFW metroplex, will be necessary regardless of whether there is major wind expansion in West Texas.
    - Additional upgrades (138kV and 69kV) will be required to integrate wind power
    - ERCOT has not conducted engineering studies for transmission to support West Texas wind capacity beyond 5,000 MW.
- SPP indicated additional transmission will be required to support any substantial wind generation additions above the 240 MW in the Panhandle that has already been connected to the transmission system or is currently under construction.
- A preliminary ERCOT study indicates that between 100 and 300 MW of new energy could be injected at each of three points (total of 300-900 MW) along the Texas Gulf Coast without requiring significant transmission infrastructure additions.
- Wind production is an intermittent resource and is not always fully available. In order to ensure reliable electric service to customers, substantial wind development must be accompanied by development of comparable capacities of other generation resources that can be called upon when the wind is not blowing.
    - In West Texas, wind produces more power during low load times than during high load times.
    - In coastal areas, wind may produce more power on-peak than off-peak.
- Wind energy can be expected to increase the amount of generation reserves needed to operate the system reliably. The costs of such “ancillary services” are assessed on all energy scheduled in the ERCOT market. The magnitude of any increase in ancillary service costs depends on a number of variables that are not known at this time. Estimates range widely. Diversity of locations and installed amounts over a wide area may help this situation.

**Potential Distribution of Renewables by Zone**

| Zone | Existing 12/04 | Adds for 5000 MW Proposal | Adds for 10000 MW Proposal | TOTALS |
|---|---|---|---|---|
| Panhandle (Amarillo) | 84 | 236 | 2000 | 2320 |
| South Plains (Lubbock) | 0 | 80 | 1000 | 1080 |
| Far West (Guadalupe) | 75 | 0 | 200 | 275 |
| McCamey | 750 | 750 | 500 | 2000 |
| Morgan/Sweetwater | 250 | 1100 | 300 | 1650 |
| Abilene | 200 | 1175 | 300 | 1675 |
| Vernon | 0 | 0 | 200 | 200 |
| South Coast | 0 | 300 | 500 | 800 |
| | | | | |
| TOTAL | 1359 | 3641 | 5000 | 10000 |

*Projections provided by Wind Coalition for rough planning purposes only. Each value (in MW) represents the total amount of wind capacity in the zone. Additions in 2005 are included in the "Adds for 5000 MW" column. Some reasonable variation in these numbers is expected. Transmission cost estimates below are based upon these amounts and will vary if these amounts and locations change.*

**Transmission System Cost Estimates**

| | |
|---|---|
| 345kV transmission lines (per mile) | $1 million |
| 345 kV transformation station (each) | $15-30 million |
| 765kV transmission lines (per mile) | $1.2 million |
| 765kV transformation station (each) | $40-75 million |
| | |
| 345kV option to support 5,000 MW (incremental increase of 3,600 MW) of renewable based on zones as shown above | $1.0 billion |
| 345kV option to support 10,000 MW (incremental increase of 8,600 MW) of renewable based on zones as shown above. Includes 345kV loop Vernon-Amarillo-Lubbock-Big Spring plus necessary upgrades to connect ERCOT grid to the Panhandle (SPP) via DC Ties or switchable facilities. | $1.7 - 2.1 billion |
| 765kV/345kV option to support 10,000 MW (incremental increase of 8,600 MW) of renewable based on zones as shown above | $2.5 - 3.0 billion |
| 765kV/345kV option to support 25,000 MW (incremental increase of 23,600 MW) 10,000 MW location not identified | $5.0 - 7.0 billion |

*A small percentage of these totals, particularly related to projects in the west DFW metroplex, will be necessary regardless of whether major new renewable development occurs in West Texas.*

**Impact on Consumers (residential with 1100 kWh/month consumption)**
Current average monthly bill: $105.00
Transmission component of average monthly bill: $5.68

Each $1 billion of new transmission investment would increase a typical residential bill (1100 kWh) by an estimated 73 to 85 cents per month, or between 0.7% and 0.8%. This is based on an incremental addition to the system of $1 billion using 2004 system data.

## Questions & Answers

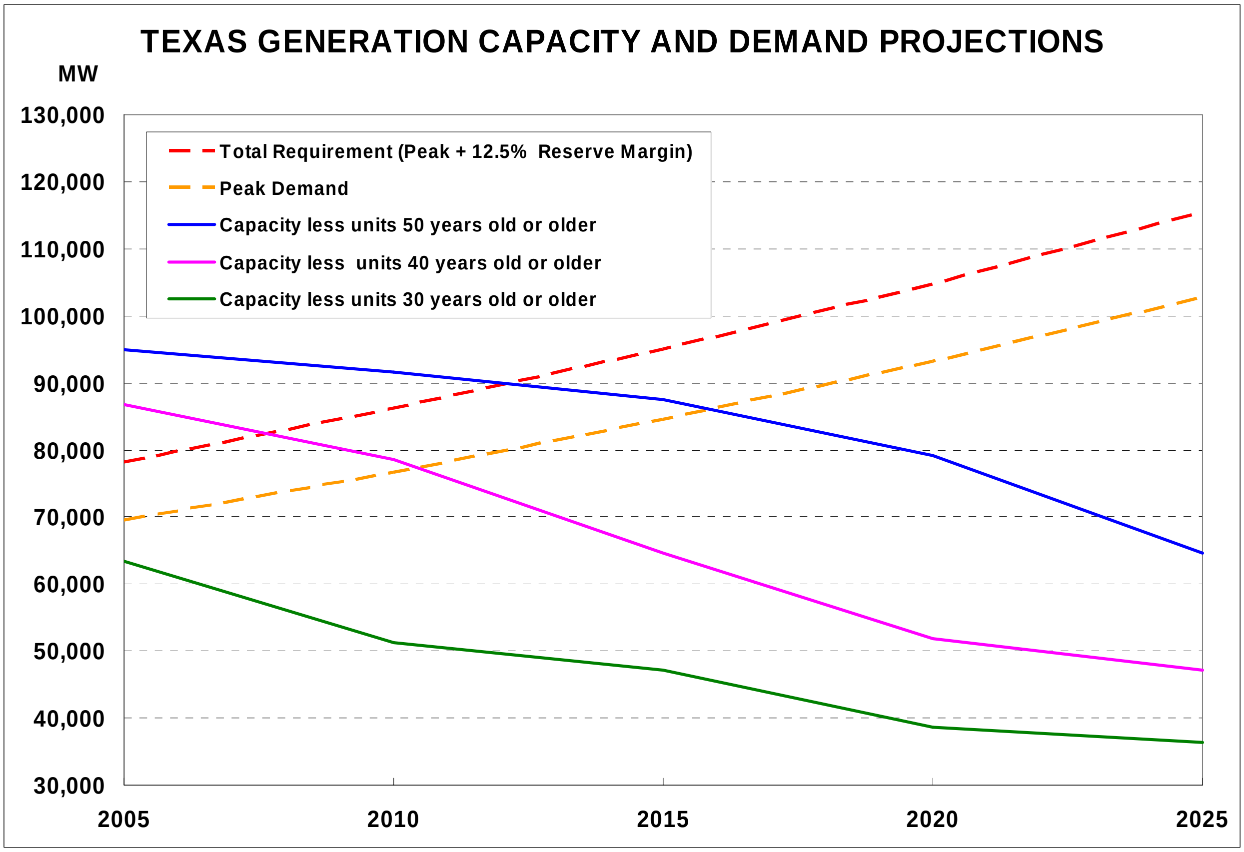
*These questions were posed to the stakeholder group by Rep. David Swinford.*

**1) How much additional electricity will Texas need in the next 10 years? Next 20 years?**
Assuming current growth rates continue, Texas will require 21% more electric energy production in the next decade, and 47% more production by 2025. The following chart assumes an annual incremental growth rate of 2%.

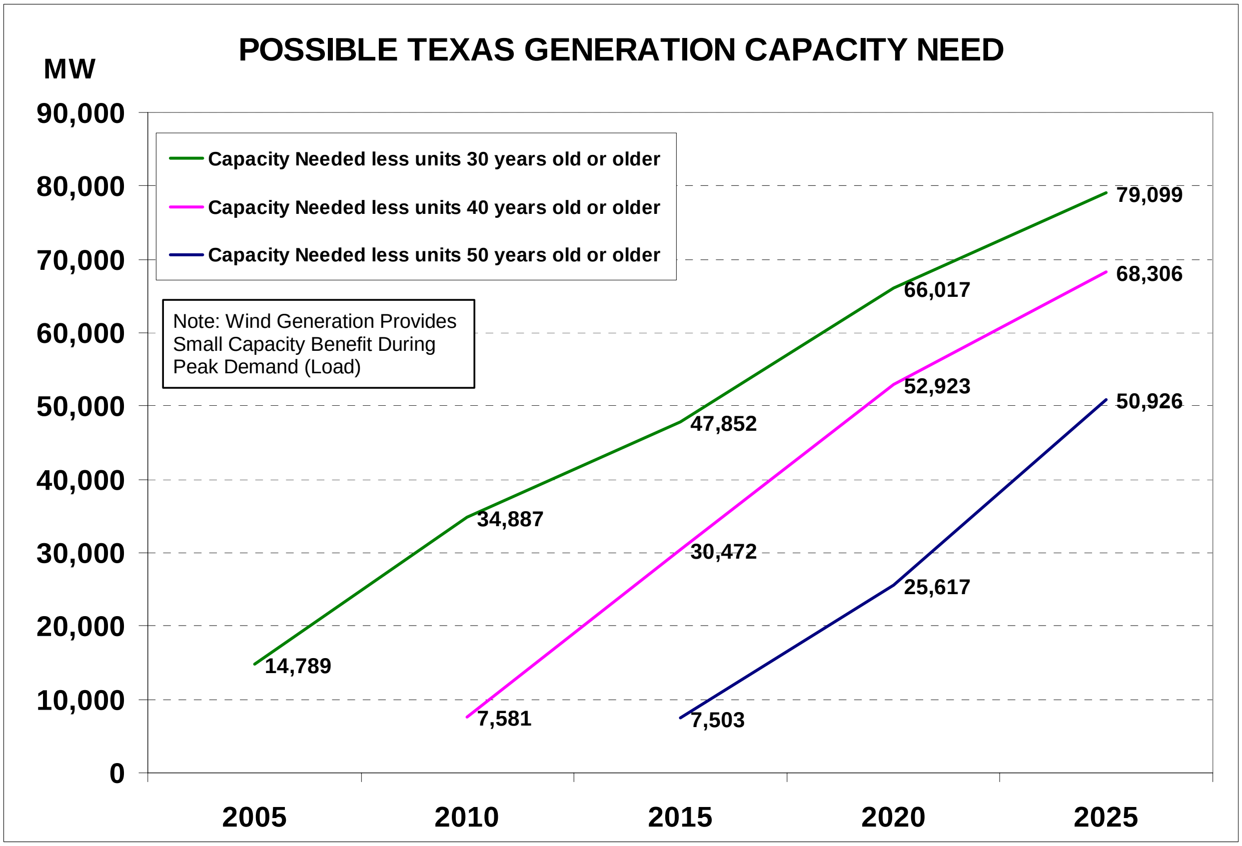
| TEXAS | 2015 | | 2025 | |
|---|---|---|---|---|
| ***Incremental additions*** | **Growth from 2005** | **% Increase from 2005** | **Growth from 2005** | **% Increase from 2005** |
| Peak Demand MW | 14,965 | 22% | 33,146 | 48% |
| Energy GWH | 74,715 | 21% | 165,515 | 47% |
| Installed Capacity MW* | 16,836 | 22% | 37,824 | 48% |

** 112.5% of Peak Demand (based on ERCOT's minimum reserve margin of 12.5%)*

The following graph illustrates the need within the ERCOT region for new capacity when possible retirements of older plants are factored in (based upon currently installed as of December 2004).



The following graph shows the difference between what is needed and what is currently installed as of December 2004, assuming possible plant retirements based upon age as shown above.




Based on growth and possible retirement of plants based upon age, Texas is going to need about:

- 7,000 to 48,000 MW of new peak generating capacity by 2015
- 25,000 to 66,000 MW of new peak generating capacity by 2020
- 50,000 to 79,000 MW of new peak generating capacity by 2025

**2) Under each of the three RPS proposals, how much of the state's electric growth would be met with renewables and how much from non-renewables?**

This chart projects the percentage of growth in energy (GWh) that would be met by new renewables (built after 2005) under the standards proposed (assumes 40% capacity factor). The balance of the growth would be met by non-renewables.

| ***Energy Growth*** | **2015** | **2020** | **2025** |
|---|---|---|---|
| *Growth in GWh from 2005* | *74,715* | *117,886* | *165,515* |
| HB 1671 (Hunter) | 13.5% | | 16% |
| HB 1798 (Swinford) | 37% | | |
| HB 2692 (Gallego) | 37% | 72% | |

In addition to meeting the state's energy needs (MWh), the electric system must also meet expected peak demand (MW). Generation resources other than wind will be needed to meet most of the projected growth in peak demand, as maximum output from wind resources does not correspond to system peak demand. ERCOT currently assigns 10% of the installed capacity of wind turbines to its calculation of the ERCOT peak capacity reserve margin. Based on a review of historical data of actual wind turbine generation during ERCOT system peaks (from 4 p.m. to 6 p.m. in July and August), the average output for wind turbines was 16.8% of capacity. However, the data also showed that for any hour during these months, the output of the wind turbines could range from 0% of installed capacity to 49% of installed capacity. Stakeholders comprising the ERCOT Generation Adequacy Task Group have expressed concern that use of an average number (i.e., 16.8%) was too optimistic because it fails to adequately recognize the intermittency of wind generation. Accordingly, the group is working to assign a peak capacity value for wind using an appropriate "confidence factor." While the group has not yet formally made a recommendation to the ERCOT Technical Advisory Committee, it is currently considering recommending a wind capacity value of 2%. In summary, in order to reliably meet system peak demand, dispatchable resources (such as gas, coal, biomass) would be required to replace the wind resources when wind is not blowing.

3) **Summarize the power options for meeting future electric needs, including coal, gas, nuclear, wind, solar, biomass and anything else that may be viable.**
4) **Estimate the cost and benefits of new generating resource options.**

*The following chart, developed by ERCOT staff with stakeholder input, is intended as a point of reference only and does not represent a comprehensive survey or analysis.*

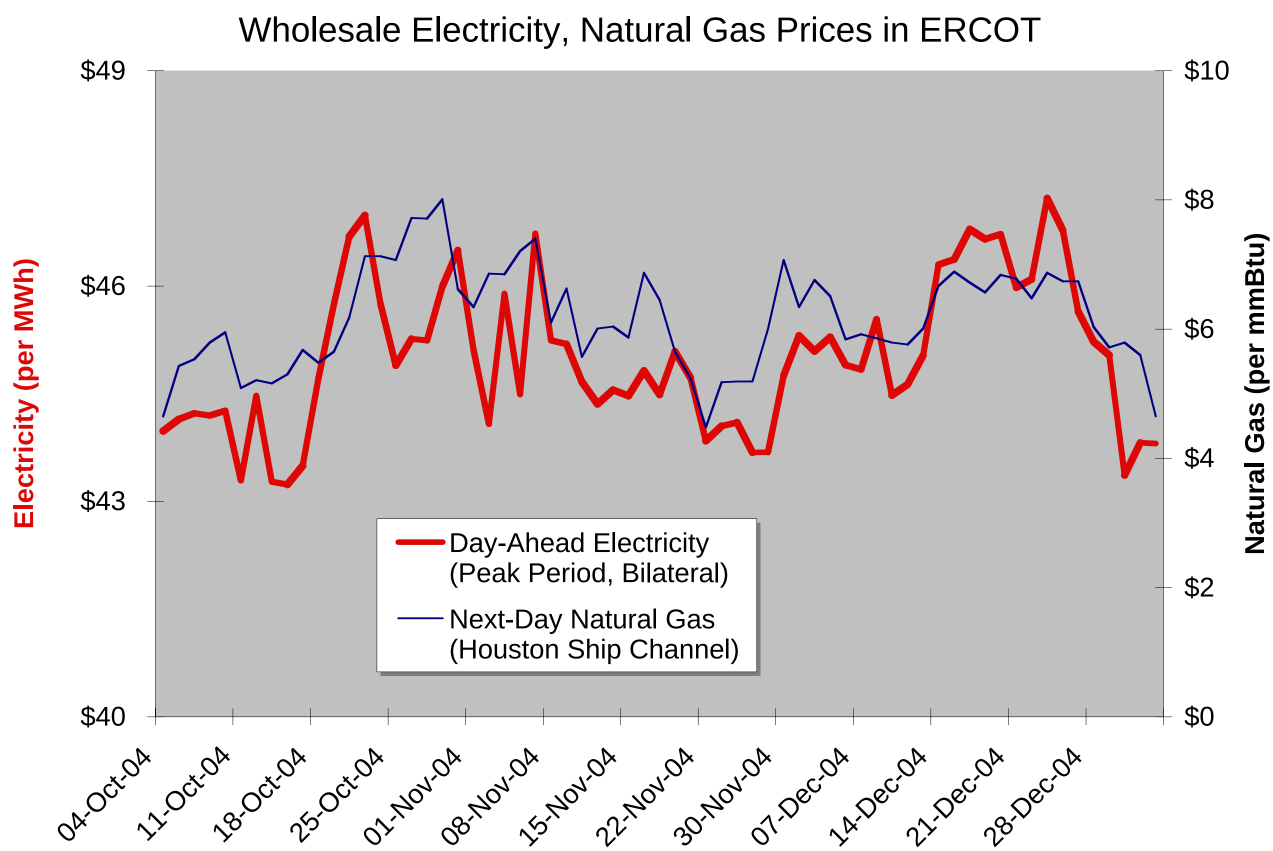
| Resource | Cost / MWh[1] | Characteristic | Benefits | Drawbacks |
|---|---|---|---|---|
| Coal | $36-40 | Base load | Stable fuel cost<br>Stable cost<br>Slow Responsive | Emissions<br>Long lead time<br>High up-front cost |
| Nat. Gas C.C.[2] | $52-69 | Base load | Short lead time<br>Responsive | Volatile fuel cost |
| Nat. Gas C.T.[3] | $74-115 | Peak load | Short lead time<br>Quick start<br>Very Responsive | Volatile fuel cost |
| Nuclear | $36-42 | Base load | Stable fuel cost<br>No emissions<br>Slow Responsive | Permitting/lead time<br>Security<br>Spent fuel disposal |
| Wind | $39 (4) - $53 (5) | Intermittent | No emissions<br>No fuel costs<br>Stable cost<br>Low operating cost | Not dispatchable<br>Not responsive<br>Transmission needs<br>Low peak value |
| Landfill Gas | $40 | Base load | Low fuel cost | Limited # landfills<br>Small facilities |
| Biomass | $48 | Base load | Low fuel cost<br>Reduce solid waste | Small facilities |
| Solar Photovoltaic | $314 | Intermittent | No emissions<br>No fuel cost<br>Offsets summer peak load | High upfront cost<br>Not responsive |
| Solar Thermal | $169 | Intermittent | No emissions<br>No fuel cost<br>Offsets summer peak load | High upfront cost<br>Not responsive |

1 Approximate generation cost averages with many variable factors including capital costs, life expectancy, O&M, capacity factor and fuel costs. Excludes ancillary services costs and transmission impacts.
2 Combined-cycle gas plants convert combustion heat into steam to generate additional electricity.
3 Single-cycle combustion turbines.
4 Based on 40% capacity factor.
5 Based on 30% capacity factor. The cost of wind energy is also subject to other variables including the federal Production Tax Credit and the state Renewable Energy Credit requirement.

**5) What has been the average cost of generation from natural gas, wind and other power plants added in Texas since 1999? How do these compare to spot market wholesale prices?**

The previous table (Questions 3-4) shows approximate generation costs associated with various technologies. The following chart tracks aggregated bilateral energy prices from ERCOT's day-ahead markets, as compared to the price of natural gas. The day-ahead electricity price tends to comprise a constant component of $40 per MWh, plus a variable component of about 87 cents per MWh for every dollar in the price of natural gas.

The Wind Coalition reports that average wind energy prices are about $30 per MWh, plus the cost of Renewable Energy Credits and backup energy costs.




**6) What is the average loading on transmission lines in Texas? How do you select what lines to upgrade or when new lines are needed?**

Average line loading data is not collected as part of normal industry operations. Transmission systems are studied as a network and not individually line by line. Historically, the industry has built infrastructure to meet reliability needs — that is, the most efficient and economical solution to ensure the lights stay on — as opposed to addressing issues related to average loading of individual lines. Facilities are analyzed and upgraded to meet normal conditions and, importantly, contingency conditions — that is, keeping the lights on in the event of an unforeseen event affecting the grid (transmission line outage, major generation outage, severe weather, terror attack, etc.). Transmission planning processes also factor in reductions in the cost of producing electricity in determining whether to recommend construction of specific facilities.

7) **Explain how new renewable and non-renewable generation options impact overall electric reliability and transmission cost. What would be the total cost for each of the three RPS proposals?**

New generation is needed to continue to reliably meet peak demand (load) and serve customer energy requirements in future years. The specific characteristics of different types of generation have different impacts on system reliability, and the electric industry continues to learn as new types of generation are added and improvements are made to each type. For example, nuclear generation has very specific requirements, and the industry is still learning about the personality and operation of combined cycle natural gas-fired power plants. Early wind generation technology presented new reliability challenges when introduced to the grid. Newer technology wind generation is greatly improved and continues to change to better meet the needs of the system. Benefits and drawbacks of major types of generation are illustrated in the table shown as part of the answer to questions 3 and 4.

Transmission costs are incurred to support load growth and any time new generation is added to or removed from the system. Since 1996 in the ERCOT region:

- Over 26,000 MW of new generation capacity has been added;
- Over 2,800 MW of generation capacity has been decommissioned (retired);
- Peak demand has increased by over 12,000 MW;
- As a result of these changes, almost $2 billion in transmission additions have been made over the past six years and the total transmission plant investment has grown to almost $6.8 billion.
- Over 27% of the total transmission plant investment has been added to rate base over the past six years;
- While these investments require significant capital, transmission costs currently make up between 4%-6% percent of the average retail consumer's electric bill;
- Based on the current assessment of existing needs, and in support of ongoing generation and demand growth, ERCOT is tracking a series of new projects over the next several years with an estimated cost of approximately $2.8 billion
- The average level of future transmission investment estimates in ERCOT appears to be consistent with the past six years.

**Transmission Cost Estimates (from Fact Sheet):**

- 345kV option to support 5,000 MW (incremental increase of 3,600 MW) of renewable based on Potential Distribution of Renewables by Zone shown above is $1.0 billion
- 345kV option to support 10,000 MW (incremental increase of 8,600 MW) of renewable based on Potential Distribution of Renewables by Zone (see Fact Sheet) is $ 1.7 - 2.1 billion.
    - Includes 345kV loop Vernon-Amarillo-Lubbock-Big Spring plus necessary upgrades to connect ERCOT grid to the Panhandle (SPP) via DC Ties or switchable facilities.
- 765kV/345kV option to support 10,000 MW (incremental increase of 8,600 MW) of renewable based on Potential Distribution of Renewables by Zone (see Fact Sheet) is $ 2.5 - 3.0 billion
- 765kV/345kV option to support 25,000 MW (incremental increase of 23,600 MW) in locations not identified is $5.0 - 7.0 billion.

**Would defining corridors to support multiple new generation resources be a more effective means of building transmission than reacting to individual generation requests?**
Yes. Having defined locations and amounts of future generation additions (e.g., corridors or zones), along with measured incremental renewable energy requirements, supports planning and construction of new transmission facilities. In the absence of specified corridors, either customers or developers of renewable generation would bear the costs associated with the difficulty of coordinating generation and transmission siting.

8) **How is transmission paid for today? Among the major customer types (large industrial, residential, etc.) who pays and how much (per kWh and total)? What portion of customers' bills are transmission costs?**
The consumer's electric bill contains rate elements covering the three main components of electrical infrastructure costs – generation, transmission and distribution. Generation costs come from the capital costs of power plant equipment, operation and maintenance expenses, and the cost of the fuel used by the plants to produce electricity. Transmission and distribution costs come from the capital costs for transmission and distribution equipment, plus operation and maintenance expenses.

**Within ERCOT**
All customers across ERCOT pay equally for transmission services based on their share of summer peak demand. For the vast majority of customers, transmission costs typically equate to between 4% and 6% of their overall bills. The customer's "load factor" (ratio of energy used versus peak demand) affects the transmission cost per kWH paid by the customer. The higher the load factor, the lower transmission cost per kWh consumed.

**Utilities' Cost Recovery of Incremental Investments**
To the extent that a transmission utility within ERCOT builds new facilities after their rate year, the PUC permits expedited recovery of the investment through allowing the transmission utility to adjust their rates on an annual basis to reflect the additional investment without a full rate case (an interim update of rates). Increases in wholesale rates that result from the interim updates are passed through to retail customers through adders (called a Transmission Cost Recovery Factor (TCRF)) on the transmission portion of the customers' bill. The interim updates provide incentives for Transmission Providers to adequately invest in large transmission projects. Periodic "true-up" rate case proceedings are conducted by the PUC to ensure that the customers' interests are protected.

**Outside of ERCOT**
Electric utilities outside of ERCOT do not have a similar mechanism for an interim update of rates to recover costs of transmission investments. Any new facilities built to comply with an increased RPS may not recoverable until the next full rate case unless an expedited cost recovery mechanism is adopted. H.B. 989 introduced by Representative Chisum proposes to authorize the PUC to establish an expedited cost-recovery mechanism for non-ERCOT utilities.

9) **Summarize cost trends in customer electric bills with percentage breakdown of costs by component. What are the reasons customer bills are going up? What are the major cost items that need to be addressed by the Legislature?**

The 35% increase in average retail electricity prices (based on Price to Beat) since the launch of competitive choice in 2002 can be attributed largely to increases in the price of natural gas. Natural gas-fired facilities accounts for 73% of electric generation capacity in ERCOT. Senate Bill 7 permits the regulated Price to Beat rate for small customers to be adjusted up to twice a year based on the future price of gas. Many competitive providers' price offerings have increased as the Price to Beat has increased.

The portion of the customer's electric bill related to transmission costs is also increasing as new transmission is added to the grid. Significant transmission additions have been made to meet reliability requirements, support load growth, incorporate new generation, and decommission generation from the system. PUC calculations indicate transmission costs have risen by 20% since 2002. Proportionately, if transmission constitutes 6% of a customer's electric bill, a 20% increase in transmission rates results in a 1.2% increase in the overall bill. Transmission costs can be expected to increase as new transmission is added to the grid.

***Additional questions:***

- **Without new transmission, what are the approximate additional amounts of wind energy that can be added without congestion in West Texas, South Texas and the Panhandle?**
  WEST: Additional transmission will be required to support any new wind generation above what is already in place, under construction, or approved.
  SOUTH (Coastal): A preliminary ERCOT study indicates that between 100 and 300 MW of new energy could be injected at each of three points along the Gulf Coast (Galveston, South Corpus Christi, Brownsville) without requiring significant transmission infrastructure additions.
  PANHANDLE: No more than 75 MW of new capacity can realistically be added in the Panhandle, in large part due to the current lack of a 345kV circuit between Amarillo and Lubbock.

- **From a technical perspective, what are the options for using wind power in the Panhandle to serve load in Dallas and Houston?**
  - Would require lateral lines to extend the ERCOT grid into the Southwest Power Pool grid (Eastern Interconnection). Logical extension points would be:
    - Vernon (Oklaunion), west of Wichita Falls.
    - Big Spring.
  - Would require the construction of a significant 345kV circuit in the Panhandle and South Plains (example: Vernon-Amarillo-Lubbock-Big Spring).
    - Based on estimated average costs of 345kV construction, such a project is estimated to cost approximately $400-$450 million (total of approximately 350 miles of line plus station costs, voltage control, etc.).
    - Hub and spoke system (i.e., 138kV or 69kV) could potentially accommodate injection from other resources away from the 345kV loop.
  - Would require additional upgrades to the system from Oklaunion to Dallas-Ft. Worth
  - Would require the power to be transferred between grids via switchable facilities or multiple DC ties.
    - Consultation and regulatory groundwork with FERC would be necessary to ensure ERCOT remains solely PUCT jurisdictional.

## TERMINOLOGY

***Capacity*** represents a calculation of total available generation, expressed in Megawatts (MW).
***Capacity factor*** represents the percentage of total available output that is actually produced.

- *Wind capacity factor* correlates directly to how much the wind blows. (In this document, wind capacity factor does not include any adjustments for congestion management reductions.)

***Peak demand*** represents the amount of energy required to serve consumers at the time of maximum consumption during a period, expressed in MW.
***Energy*** represents actual consumption of electricity, expressed in Megawatt-hours (MWh).

***Demand and Energy***

When you turn on an electric appliance, a “demand” for power is created. This instantaneous amount of electricity demand is measured in watts (kilowatts, megawatts or gigawatts).

A 100-watt light bulb demands 100 watts of electricity when it is turned on. Ten 100-watt light bulbs would demand 1,000 watts, or 1 kilowatt (kW). If this 1-kilowatt load is operated for one hour, 1 kilowatt-hour (kWh) of electricity is used. Kilowatt-hours measure the quantity of electric energy used over a period of time. If it is operated for 30 minutes, ½ kWH of electricity is used. If operated for three hours, 3 kWH of electricity is used.

One way to remember the relationship between demand and energy is to use the analogy of the speedometer and odometer in a car. The measure of demand (kW) or the rate at which energy is used is analogous to the speedometer, which indicates miles per hour. The measure of energy (kWh) is analogous to the odometer, which indicates miles driven.

## BACKGROUND INFORMATION and SUPPORTING TABLES

### Responsibilities for Transmission & System Planning

Reliability councils such as ERCOT along with Transmission and Distribution Service Providers (TDSPs) have a duty and responsibility to operate, maintain, plan, and expand the power system to meet the needs of all users dependent upon it.

Our priorities are to:

- Serve the needs of customers and communities reliably and efficiently,
- Conduct work openly, fairly, and honestly, and
- Solicit a diversity of opinions and ideas to achieve better results.

Customers depend on the reliability councils and the TDSPs to deliver power where and when it is needed. Communities count on us to have the infrastructure in place to meet the electric needs of their residents and businesses and to support economic growth initiatives. System operators expertly monitor and manage the electric system around the clock, while transmission planners continually evaluate future electric needs and make recommendations for improving the reliability and adequacy of the system for customers and communities. Because of years of careful planning and operation of the grid, Texas enjoys one of the most reliable systems in North America.

The transmission system is the principal means for achieving a reliable electric supply. It ties together the major electric system facilities, generation resources, and customer demand centers. This system must be planned, designed, constructed and maintained to operate reliably within thermal, voltage, and stability limits while achieving its major purposes. Its purposes are to:

**Deliver Electric Power to Areas of Customer Demand —** The transmission system provides for the integration of electric generation resources and electric system facilities to ensure the reliable delivery of electric power to meet continuously changing customer demands under a wide variety of system operating conditions.

**Allow Economic and Competitive Exchange of Electric Power Among Systems —** The transmission system allows for the economic and competitive exchange of electric power among all systems and industry participants. Such transfers help to reduce the cost of electric supply to customers and provide a liquid market.

**Provide Flexibility for Changing System Conditions —** Transmission capacity must be available on the interconnected transmission systems to provide the flexibility needed to handle a shift in facility loadings caused by the maintenance of generation and transmission equipment, the forced outages of such equipment, and a wide range of other system variable conditions, such as construction delays, higher than expected customer demands, and generating unit fuel shortages.

Competition is changing the available generation infrastructure. Recent announcements of construction of new generation capacity and retirement of older, less efficient units demonstrate the market is working effectively.

- New participants enter the market, exit the market, or consolidate their operations, thus changing the players and their contractual supply arrangements.

- New technology must be incorporated. The introduction of large, remote wind developments reduce dependence on limited fossil fuel reserves but also place new challenges on the existing transmission grid.

- Retirement of older plants near metropolitan areas due to economics or environmental restrictions requires a careful assessment of the reliability needs and the transmission alternatives to must-run contracts.

Electric systems must be planned to withstand probable forced and maintenance outages at projected customer demand and anticipated electricity transfer levels.

**Transmission and System Planning in ERCOT**

Through its planning authority role, all significant projects are independently studied by ERCOT in an open and non-discriminatory manner. ERCOT leads three regional planning groups (RPGs): North, South, and West. ERCOT staff facilitates the consideration and review of proposed projects to address transmission constraints and other system needs. ERCOT has recently adopted computer simulation tools and developed processes to project congestion costs based on wholesale market fundamentals. These new tools and processes are being applied to determine the cost effectiveness of major transmission additions in the RPG process. Where there is a need, ERCOT recommends and the TDSPs build transmission infrastructure that has been fully analyzed through the open RPG process. We emphasize fairness and openness with stakeholders that may be impacted by these facilities – balancing their concerns with the need to keep the lights on for millions of people. Participation in these regional planning groups is required of all TDSPs and is open to all market participants/stakeholders, consumers, and Public Utility Commission of Texas (PUCT) staff.

**Planning Outside of ERCOT**

Transmission planning occurs in different ways in different parts of the country. In most regions, transmission utilities undertake their own planning studies, sometimes in coordination with one another. In a vertically integrated utility setting, utility planning usually determines the need for specific facilities to be built – including both transmission and generation.

SPP as an RTO is responsible for the planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service. SPP coordinates such efforts with the appropriate state authorities.

SPP, SERC and ERCOT perform coordinated planning studies on a periodic basis. SPP and ERCOT are initiating a new long-range assessment in April 2005 to investigate mutually beneficial expansion opportunities to their systems.

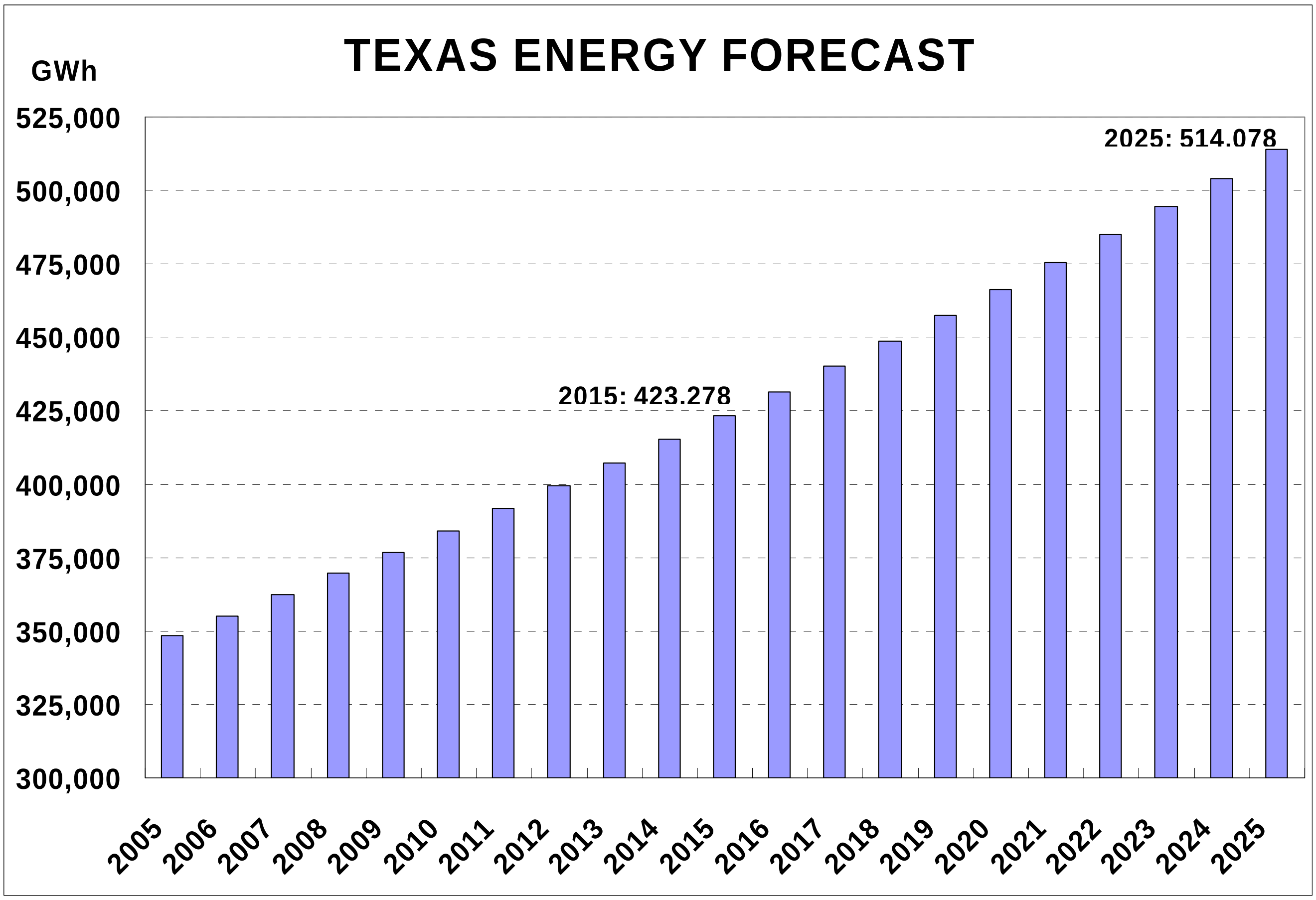
**Generation Adequacy (Reserve Margin)**

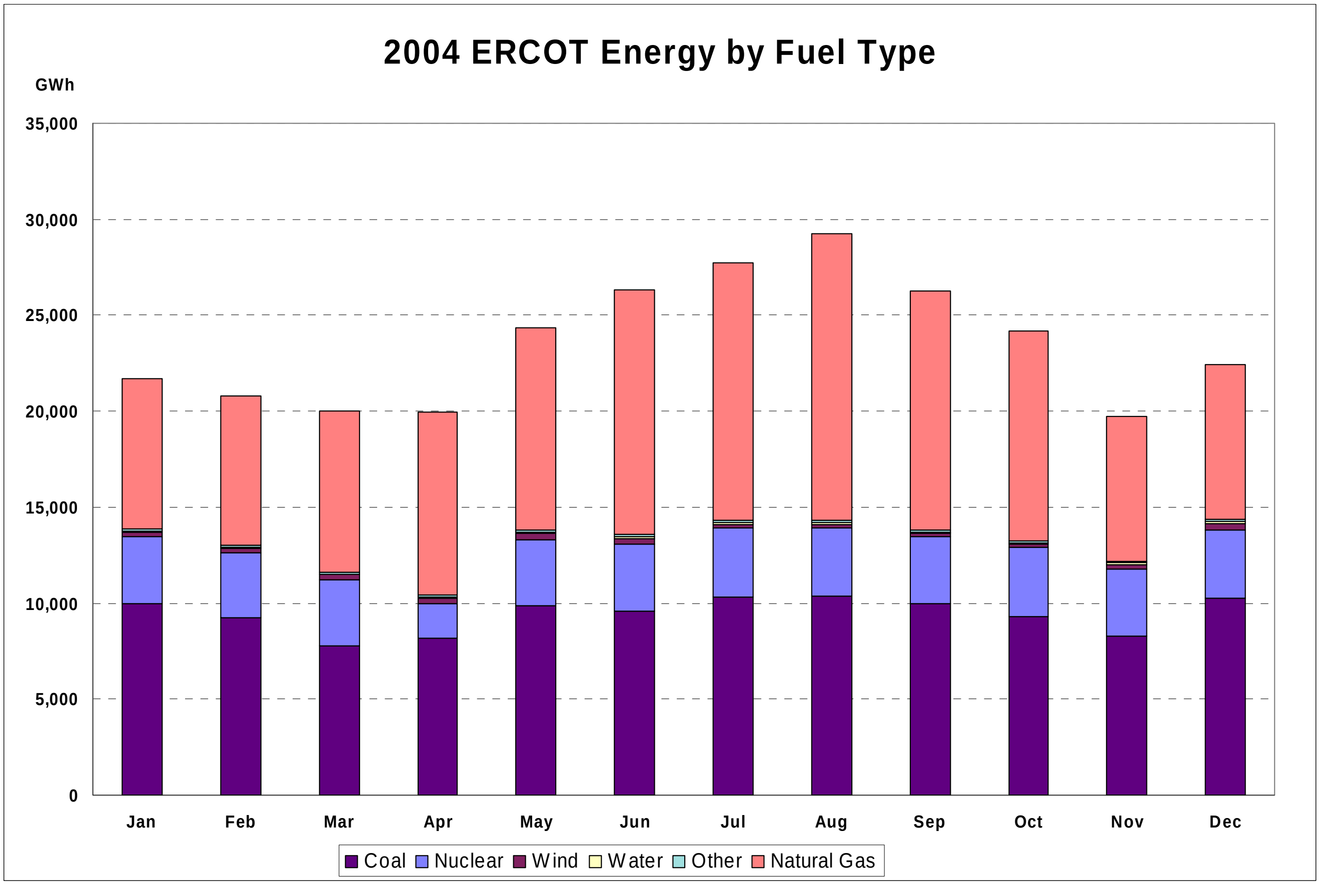
Thanks to a generation construction boom triggered by deregulation of the wholesale and retail markets in Texas, the ERCOT region until very recently enjoyed a healthy reserve margin — the difference between operating generation capacity and peak demand. Recent announcements by various generation companies of their intentions to mothball or decommission certain facilities have affected this margin, and have led ERCOT staff and stakeholders to take a new look at how the reserve margin is calculated, with an emphasis on how to treat mothballed facilities of various ages. For purposes of calculating reserve margin, the ERCOT formula as approved by its Technical Advisory Committee has limited the contribution of wind generation to 10% of the wind farms' total capacity. This number, a reflection of the lack of controllability of the resource and the tendency of the wind in West Texas to blow more consistently off peak than on-peak, is under new review by an ERCOT task force.

## Electric Energy Forecast for Texas

| Energy (GWh) | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ERCOT | 294,939 | 300,838 | 306,855 | 312,992 | 319,251 | 325,636 | 332,149 | 338,792 | 345,568 | 352,479 | 359,529 |
| Non-ERCOT | 53,624 | 54,236 | 55,385 | 56,597 | 57,574 | 58,557 | 59,555 | 60,566 | 61,609 | 62,661 | 63,749 |
| **Total Texas** | **348,563** | **355,073** | **362,239** | **369,588** | **376,826** | **384,194** | **391,704** | **399,358** | **407,177** | **415,141** | **423,278** |

| | | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ERCOT | | 366,720 | 374,054 | 381,535 | 389,166 | 396,949 | 404,888 | 412,986 | 421,246 | 429,670 | 438,264 |
| Non-ERCOT | | 64,857 | 65,985 | 67,135 | 68,307 | 69,500 | 70,716 | 71,955 | 73,217 | 74,503 | 75,814 |
| **Total Texas** | | **431,576** | **440,039** | **448,670** | **457,472** | **466,449** | **475,604** | **484,941** | **494,463** | **504,174** | **514,078** |






**ERCOT ENERGY BY FUEL TYPE, MWh**

| *Fuel Types* | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Natural Gas | 7,849,313 | 7,813,021 | 8,374,002 | 9,522,593 | 10,501,338 | 12,760,416 | 13,412,389 | 14,940,139 | 12,421,762 | 10,931,919 | 7,505,148 | 8,068,226 | 124,100,266 |
| Coal | 9,968,034 | 9,263,412 | 7,758,555 | 8,185,649 | 9,848,789 | 9,597,047 | 10,321,098 | 10,361,705 | 9,995,322 | 9,280,970 | 8,257,738 | 10,229,656 | 113,067,975 |
| Nuclear | 3,490,286 | 3,371,425 | 3,433,959 | 1,783,872 | 3,427,892 | 3,480,190 | 3,579,790 | 3,584,319 | 3,475,015 | 3,608,165 | 3,507,830 | 3,600,115 | 40,342,858 |
| Wind | 243,831 | 240,052 | 283,263 | 294,934 | 377,854 | 280,574 | 215,740 | 149,816 | 194,599 | 200,259 | 225,748 | 300,424 | 3,007,094 |
| Water | 27,902 | 27,223 | 30,024 | 44,588 | 55,196 | 108,187 | 84,792 | 91,183 | 56,755 | 40,670 | 109,080 | 128,243 | 803,843 |
| Other | 121,892 | 90,055 | 110,382 | 115,189 | 113,920 | 106,267 | 112,719 | 118,759 | 114,588 | 113,986 | 96,742 | 115,175 | 1,329,674 |
| Diesel | 0 | 0 | 0 | 0 | 0 |  | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 21,701,258 | 20,805,188 | 19,990,185 | 19,946,825 | 24,324,989 | 26,332,681 | 27,726,528 | 29,245,921 | 26,258,041 | 24,175,969 | 19,702,286 | 22,441,839 | 282,651,710 |

**ERCOT ENERGY BY FUEL TYPE, PERCENTAGE**

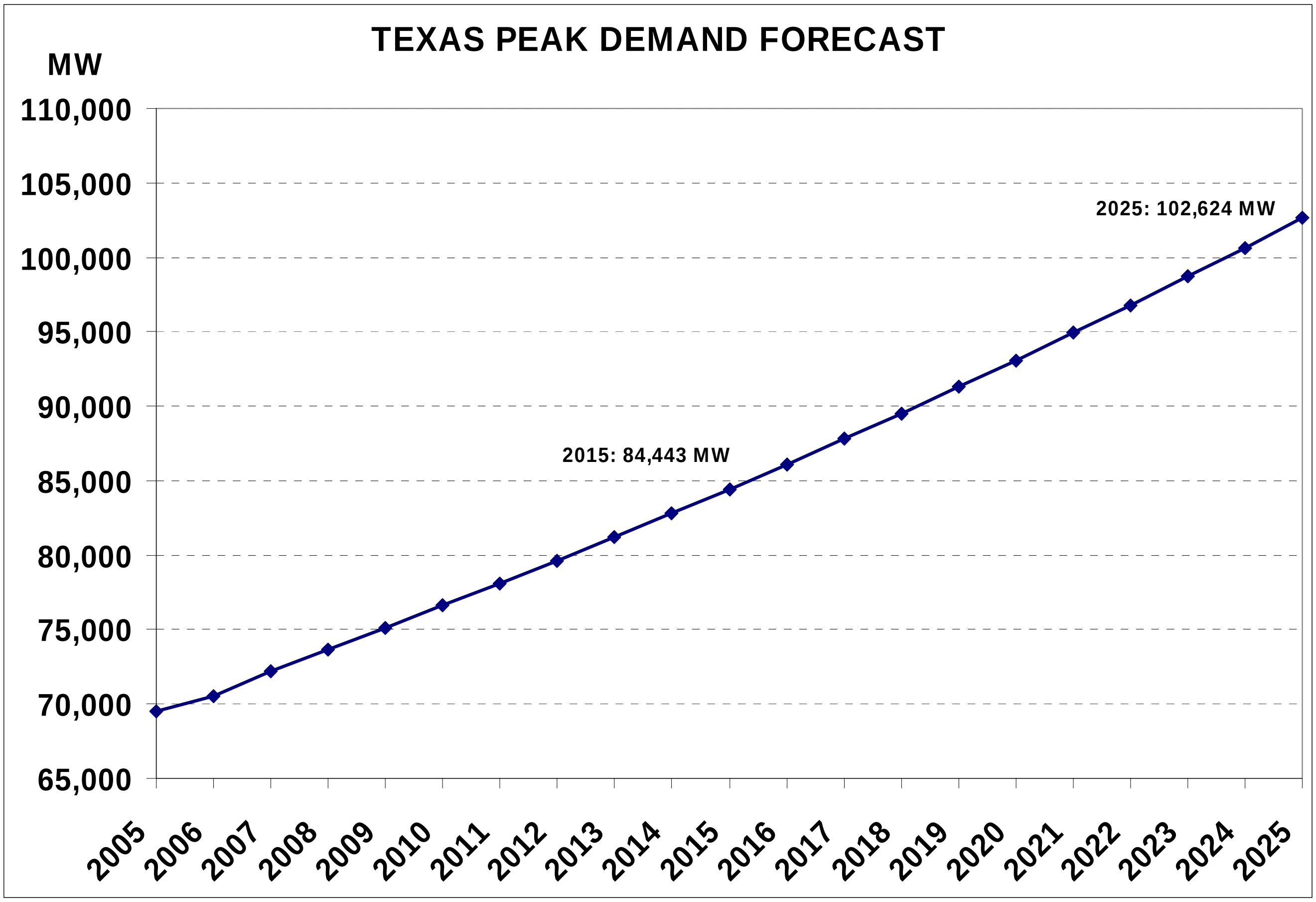
| *Fuel Types* | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Natural Gas | 36.2% | 37.6% | 41.9% | 47.7% | 43.2% | 48.5% | 48.4% | 51.1% | 47.3% | 45.2% | 38.1% | 36.0% | 43.9% |
| Coal | 45.9% | 44.5% | 38.8% | 41.0% | 40.5% | 36.4% | 37.2% | 35.4% | 38.1% | 38.4% | 41.9% | 45.6% | 40.0% |
| Nuclear | 16.1% | 16.2% | 17.2% | 8.9% | 14.1% | 13.2% | 12.9% | 12.3% | 13.2% | 14.9% | 17.8% | 16.0% | 14.3% |
| Wind | 1.1% | 1.2% | 1.4% | 1.5% | 1.6% | 1.1% | 0.8% | 0.5% | 0.7% | 0.8% | 1.1% | 1.3% | 1.1% |
| Water | 0.1% | 0.1% | 0.2% | 0.2% | 0.2% | 0.4% | 0.3% | 0.3% | 0.2% | 0.2% | 0.6% | 0.6% | 0.3% |
| Other | 0.6% | 0.4% | 0.6% | 0.6% | 0.5% | 0.4% | 0.4% | 0.4% | 0.4% | 0.5% | 0.5% | 0.5% | 0.5% |
| Diesel | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Total | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |

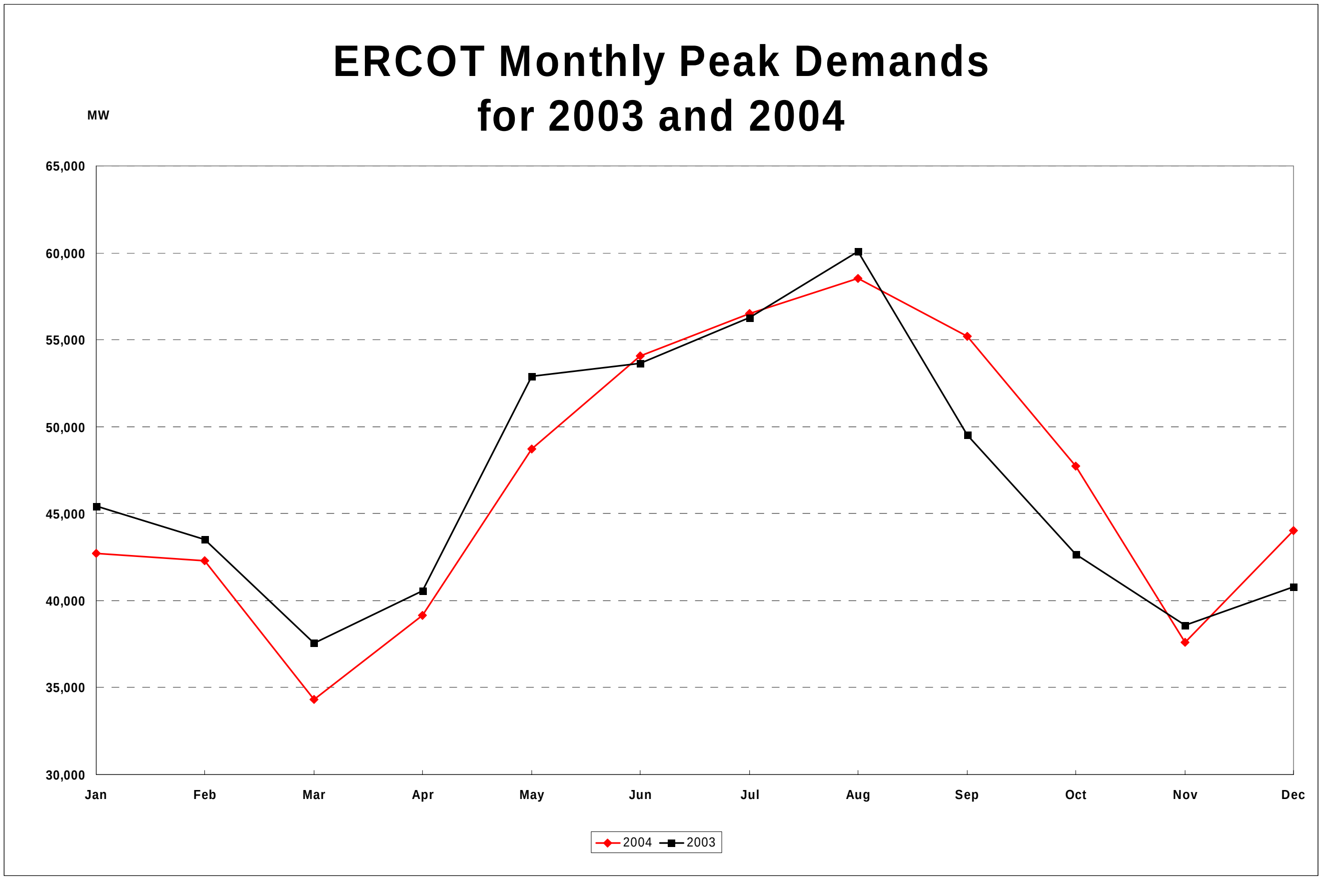
"Other" includes petroleum coke, landfill gas, biomass solids, biomas gases, and any unknown fuel.

## Peak Demand Forecast for Texas

| Demand (MW) | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ERCOT | 59,701 | 60,895 | 62,113 | 63,355 | 64,622 | 65,915 | 67,233 | 68,578 | 69,949 | 71,348 | 72,775 |
| Non-ERCOT | 9,777 | 9,642 | 10,112 | 10,324 | 10,512 | 10,696 | 10,885 | 11,067 | 11,268 | 11,465 | 11,668 |
| **Total Texas** | **69,478** | **70,537** | **72,224** | **73,680** | **75,134** | **76,611** | **78,118** | **79,645** | **81,217** | **82,814** | **84,443** |

| | | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ERCOT | | 74,231 | 75,715 | 77,230 | 78,774 | 80,350 | 81,957 | 83,596 | 85,268 | 86,973 | 88,713 |
| Non-ERCOT | | 11,874 | 12,084 | 12,298 | 12,516 | 12,738 | 12,964 | 13,194 | 13,429 | 13,668 | 13,911 |
| **Total Texas** | | **86,105** | **87,800** | **89,528** | **91,290** | **93,088** | **94,921** | **96,790** | **98,697** | **100,641** | **102,624** |






**ERCOT Peak Demand, MW**

| | 2004 | 2003 |
|---|---|---|
| Jan | 42,698 | 45,433 |
| Feb | 42,301 | 43,514 |
| Mar | 34,321 | 37,554 |
| Apr | 39,131 | 40,579 |
| May | 48,702 | 52,909 |
| Jun | 54,061 | 53,638 |
| Jul | 56,488 | 56,251 |
| Aug | 58,531 | 60,095 |
| Sep | 55,179 | 49,506 |
| Oct | 47,714 | 42,651 |
| Nov | 37,599 | 38,609 |
| Dec | 44,010 | 40,789 |

## TEXAS 2004 INSTALLED CAPACITY

# Electricity Capacity in Texas

| Type of Unit | ERCOT | Outside ERCOT | Texas |
|---|---|---|---|
| | MW | MW | MW |
| Generating Companies | 80,965 | 13,570 | 94,535 |
| Private Network | 5,827 | 989 | 6,816 |
| **Total** | **86,792** | **14,559** | **101,351** |

Source: EIA-860 as of 1/1/2004

Caution: Amount from the private network units that is available for the grid is not known.

# Texas Capacity by Fuel Type

| Fuel | ERCOT | | Outside ERCOT | | Texas | |
|---|---|---|---|---|---|---|
| | Generating Companies, MW | Private Networks, MW | Generating Companies, MW | Private Networks, MW | Generating Companies, MW | Private Networks, MW |
| Natural gas | 58,411 | 5,249 | 8905 | 653 | 67,316 | 5,902 |
| Coal | 15,352 | 363 | 4336 | 2 | 19,688 | 365 |
| Nuclear | 4,768 | 0 | 0 | 0 | 4,768 | 0 |
| Water | 478 | 0 | 221 | 0 | 699 | 0 |
| Wind | 1,201 | 0 | 84 | 0 | 1,285 | 0 |
| Other | 755 | 215 | 24 | 334 | 779 | 549 |
| **Total** | **80,965** | **5,827** | **13,570** | **989** | **94,535** | **6,816** |

"Other" includes diesel, agriculture byproducts, black liquor, biomass gases, biomass solids, other gas (butane, coal processes, methanol, etc.), petroleum coke, purchased steam,