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Need for Transmission and Generation Capacity in Texas; Renewable Energy Implementation and Costs

Public Utility Commission of Texas
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PUBLIC UTILITY COMMISSION OF TEXAS REPORT CONCERNING NEED FOR TRANSMISSION AND GENERATION CAPACITY IN TEXAS AND RENEWABLE ENERGY IMPLEMENTATION AND COSTS

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The Legislature amended the Public Utility Regulatory Act (PURA) during 2005 to require the Public Utility Commission to provide biennial reports on its implementation of new legislation that directs it to establish Competitive Renewable Energy Zones (CREZ) and related issues concerning renewable energy and on the need for increased transmission and generation facilities in Texas.[1] This report addresses the Commission's progress in designating CREZs and other renewable energy issues and the need for transmission and generation facilities. Separate sections deal with transmission and generation needs within the Electric Reliability Council of Texas (ERCOT) region and outside of the ERCOT region.

ELECTRIC TRANSMISSION AND GENERATION NEEDS FOR THE ERCOT REGION

The decision to plan, site, and construct new generation facilities within the Electric Reliability Council of Texas (ERCOT) is, for the most part, a competitive matter for generating companies. Power generation companies assess the level of demand for electricity, current and projected wholesale prices, the existing fleet of generators that supply electricity, available generation technologies, costs of fuel, and other factors in deciding whether to develop a new generation project, the technology to use, and where to site a plant or plants. Municipal utilities and electric cooperatives consider these matters and also assess the needs of their customers and the sources of power available in the market, in making decisions about whether to build new generation facilities or buy power from others in the market, if additional supply is needed for their customers. Transmission, on the other hand, is regulated by the Commission. The Commission has directed ERCOT to plan improvements to the bulk transmission system and coordinate the planning efforts of the utilities in the region. Utilities' plans to develop new transmission facilities are subject to Commission review, with certain exceptions, if they involve the construction of transmission lines on new rights of way. One of the challenges that the industry has faced with the introduction of competition is coordinating the development of generation and transmission.

Power generation companies (PGCs) that plan to build new generation facilities or discontinue the operation of facilities in ERCOT must notify ERCOT of their decision. This notification permits ERCOT to assess whether the electrical system can operate reliably without a facility that is planned for retirement or whether the system can reliably accommodate a new facility of the kind and at the location identified by the PGC. ERCOT publishes information concerning the retirement or mothballing of generation facilities and about plans to build new facilities. As a part of its transmission planning, ERCOT makes projections of the growth in demand in the region. It uses the load information and the information provided by PGCs in various reports, including reports on the expected level of generation and load and the resulting expected reserve margins.

[1] The reports are required by PURA §39.904(j) and (k), which were enacted as a part of Senate Bill 20.

Near-term Generation Projections

ERCOT has projected that load will grow in the region at about 2.3% per year for the period 2007-2011. ERCOT's official forecast indicates that the region will have sufficient generation facilities in 2007 to meet the required 12.5% reserve margin.[2] Its official forecast for 2008 indicates that the reserve margin will fall slightly below the 12.5% level, but an unofficial or snapshot forecast prepared late in 2006 indicates that the reserve margin in 2008 will exceed 12.5%.[3] Planned additions of generation, other than wind projects, are modest in 2007 and 2008. Maintaining an adequate reserve margin in 2008 depends on whether mothballed generating units are available for service during the years and on the development of additional load reduction programs that can be used when supplies are tight. Demand-reduction programs are under development, and PGCs have indicated that some generating plants that have been mothballed are returning to service for 2007 and 2008. Based on the return of mothballed generation to service, ERCOT's unofficial projection, as of December 2006, is that reserve margins will be above the minimum requirement in 2008. The adequacy of generation in 2009 and beyond is dependent upon the plans for the construction of new coal-fired generation facilities that several PGCs have announced.

While there is a significant level of new wind generation that has been announced for completion in 2007 and 2008, wind generation contributes only fractionally to the adequacy of service when measured by the standard measure of resource adequacy. Resource adequacy is assessed as the capability of generation and demand resources to meet peak demand. In Texas, peak demand is associated with the high air conditioning demand that occurs in summer. Historically, wind generation has on average supplied only 2.6% of its rated capacity during summer peaks. The wind additions will, therefore, have minimal impact on the adequacy of generation sources to meet peak demand. The table below summarizes ERCOT's official 2006 assessment of loads, resources, and reserve margins. As is noted above, recent changes to capacity, including the expected return to service of approximately 1,900 MW of mothballed generation, are expected to raise the projected 2008 reserve margin slightly above the 12.5% target level.

ERCOT Reserve Margin Projection, 2007 - 2011

	2007	2008	2009	2010	2011
Firm Load (MW)	62,110	63,206	64,838	66,436	67,922
Capacity Resources (MW)	71,577	70,693	70,632	71,208	71,245
Projected Reserve Margin	15.2%	11.8%	8.9%	7.2%	4.9%
Reserve Margin with Publicly Announced Thermal Units	15.4%	12.0%	20.0%	24.9%	23.9%

Source: ERCOT Capacity, Demand, Reserve Report (June 2006)

The table below summarizes the generation projects that have notified ERCOT of plans for operating in the region, where the related transmission studies have been completed

[2] ERCOT 2006 Report on Capacity, Demand and Reserves, available at http://www.ercot.com/news/presentations/2006/ERCOT06CDR06192006.xls.
[3] ERCOT CDR Update 11152006, Email from Ken Donohoo, Nov. 16, 2006.

and agreements to interconnect the projects to the transmission system have been signed. The resource totals in the table below also include other generation projects that are under development, where the owners have notified ERCOT that the fact that project is under development is not confidential. In addition to the nearly 17,000 megawatts of capacity shown in the table below, there is over 50,000 megawatts of capacity in earlier stages of development where the name of the developer and location of the project are confidential.

Publicly Announced Generation in ERCOT in MW, 2007 - 2011

Energy Source	2007	2008	2009	2010	2011	Total
Wind	1,361	439	400	400		2,600
Natural Gas	550		1,750			2,300
Coal			8,301	1,608	1,930	11,839
Total	1,911	439	10,451	2,008	1,930	16,739

Near-term Transmission Projections

On an annual basis ERCOT conducts a study of transmission needs over a five-year planning horizon. The purpose of this study is to identify transmission facilities that are needed to maintain the reliability of the electric network and improve the economics of the operation of the network. The study notes that past transmission improvements have been instrumental in reducing the congestion cost of operating the electric network. The study indicates that an investment of $3.1 billion will be needed to meet transmission needs of the region over the period 2007-2011. Many of the projects that are identified in the study are projects that increase the capability of the transmission system to deliver power to fast-growing areas of the State, particularly the Dallas-Fort Worth and Houston areas, Central Texas, and Laredo. The need for transmission facilities to serve Dallas-Fort Worth and Houston is related not only to load growth but also to the retirement of older generation facilities in these areas.

Long-term Generation and Transmission Projections

ERCOT conducted a study of generation needs over a ten-year planning horizon, with the objective of assessing the transmission needs that would result from generation decisions made by PGCs, municipal utilities, and electric cooperatives.[4] The need for new bulk transmission is driven in large part by changes in generation, either the construction of new generation facilities or the mothballing or retirement of existing facilities. With the restructuring of the electric industry in Texas, decisions about investing in and siting new generation resources are now made independently by power generation companies, municipal utilities, and electric cooperatives. Because of the competitive nature of this generation market, the developers' plans for adding or retiring generation capacity are typically closely guarded. The developer of a power plant is required to notify ERCOT of its plans so that ERCOT can determine the impact that a new plant will have on the

[4] *Electric Reliability Council Of Texas, Inc.'s Long Term Assessment Report (December, 2006)*, Project No. 33577.

transmission system and whether new transmission facilities will be required to interconnect the plant to the transmission system safely and reliably. In addition, the owner of a power plant that intends to retire it from service (permanently or temporarily) is required to notify ERCOT of its plans, so that ERCOT can determine whether the plant is needed to ensure the reliable operation of the system.[5]

Another important factor in transmission planning is load growth. When load growth in an area causes the need for transmission-system improvements, the selection of which particular transmission project is preferable may be affected by developers' decisions on whether and where to build new generation and the size of the generation facility. The competitive nature of generation has created some uncertainty in transmission planning, and in recent years transmission planning has tended to be more reactive and to operate with a horizon of no more than five years. Some generation technologies can be added quickly: in the case of wind generation, in as little as six months. According to the public plans of at least one generation developer, even coal generation can be added in as little as three to four years. On the other hand, a transmission line addition requiring new right-of-way is typically requires at least four years from the decision to construct the line until the line is placed into service.[6]

ERCOT reports that many stakeholders believe that a longer-term view of the needs of the ERCOT power system could result in more efficient development of the transmission network. ERCOT provided a Long Term System Assessment that is intended to provide such a longer-term view. Its Assessment includes the following elements:

- an analysis of different load growth scenarios;
- development of an assessment of the type and general locations of the new generation that the market might build by 2016, based on an economic analysis, for several scenarios of key drivers of those decisions;
- an evaluation of the need for new transmission under each of these load and generation scenarios; and
- identification of projects and general conclusions that are common across the different scenarios and can be used to provide guidance to nearer-term transmission plans.

The ERCOT study on which this report is based uses available data to predict the type (i.e., coal, nuclear, gas-fired, wind, etc.) and general location of new generation that the market may find economic to construct. Neither ERCOT nor the Commission can control these decisions, but the assessment of market behavior through a planning model provides a reasonable basis on which to assess longer-term transmission needs under a range of scenarios. The specific new generation indicated through this analysis may not be what is ultimately constructed, and thus the exact transmission lines that are eventually built may vary from the specific lines indicated in this analysis. However, this approach

[5] If ERCOT determines that the plant needs to operate for reliability purposes, it will enter into a Reliability Must-Run (RMR) contract to keep the unit in operation while ERCOT explores other economic alternatives.

[6] Typically, a year is required for route evaluation and preparation of an application for a certificate of convenience and necessity (CCN), a year for the Commission's consideration of the CCN, a year for design, acquisition of right of way, and procurement of equipment, and a year for construction. Any of these stages could take longer, depending on the circumstances.

should facilitate the development of general guidance and transmission project concepts that can guide nearer-term decisions.

The ERCOT study is based upon a 10-year horizon instead of a longer 15- or 20-year timeframe. A longer view of the system may not provide useful guidance to nearer-term decisions because of uncertainties in future generation patterns and the variables that highly influence load growth, such as population, electricity prices, economic activities, advances in generation and transmission technology and in the efficiency of devices that use electricity, and changes in weather patterns. It is difficult to incorporate those uncertainties in a very-long-term study with any level of confidence. ERCOT intends to consider timeframes longer than ten years in future assessments.

Conclusions

The ERCOT study concludes that new generation and transmission infrastructure is essential to system reliability, to accommodate load growth in the ERCOT region, and to offset probable retirements of older units. Specific conclusions with respect to transmission are noted below.

At least one additional 345-kilovolt (kV) bulk circuit will be needed into the Houston and Dallas-Fort Worth (DFW) areas for reliability, and additional circuits may be economically justified.[7]

Significant additional upgrades of the 138 and 69-kV system and additional 345-kV support (particularly in DFW, Houston and along the IH-35 cities from the west) will be required in years 6-10, even with moderate 2% annual load growth.

Installation of switching stations at points where existing 345-kV circuits intersect, at Singleton (east of Bryan), Zenith (northwest of Houston), Navarro (south of Dallas) and Paint Creek (north of Abilene), may result in better distribution of power and increased transfer capacities utilizing existing lines.

The total investment in lower-voltage upgrades for the five year period between 2011 and 2016 is roughly estimated to be $2 billion and the investment in 345-kV upgrades is expected to be $1 billion (not including CREZ-related lines), for a total of $3 billion. This is similar to the $3.1 billion currently expected for the five-year period 2007-2011.

Only one 765-kV transmission corridor (in Central Texas) was cost effective, that is, it resulted in lower system costs. At the same time, the 765-kV transmission alternative was more expensive than 345-kV alternatives. A longer term look might provide a different result for the 765-kV options. ERCOT intends to investigate this option in future assessments.

Load growth, natural gas prices and environmental regulations were considered by ERCOT and stakeholders to be the factors that fundamentally influence the type of new generation added.

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7 Transmission lines operating at 345 kV are the highest voltage lines with the largest structures in ERCOT.

The current generation interconnection requests for new fossil fuel generation in ERCOT are consistent, in type and location, with the results of ERCOT's analysis in all cases, except for the lowest natural gas price scenarios studied.

If natural gas prices remain high, they will likely induce more coal and wind generation additions, which are likely to be built in areas at greater distances from load centers in major metropolitan areas, requiring more bulk transmission lines to transfer power from generation to load.

Low natural gas prices, namely in the range of $4 per million British thermal units (MMBtu), may result in marginally-adequate reserve margins, because there would be little economic incentive to overbuild; conversely, higher natural gas prices (for example, $7 to $10/MMBtu) may result in higher reserve margins, as there is sufficient economic incentive to displace higher-priced gas generation with lower-cost solid-fueled generation.

New nuclear power plant additions were not evaluated in this year's assessment because of the lengthy expected licensing and construction timeline. Based on recent announcements and generation interconnection requests, new nuclear plants should be analyzed in the 2008 assessment.

Methodology for Long-term Study

ERCOT used an integrated transmission and generation dispatch model to simulate the dispatch of system generation to serve system load for each hour in year 2016. To assess the longer term transmission needs of the system, a reasonable set of new generation additions were developed for each scenario. Two wind scenarios were developed, one with 6,000 MW and one with 12,000 MW of installed wind generation. This model was used to determine the type and regional location of generation additions that were most profitable for each scenario's set of input assumptions and the existing transmission network.

Many of the factors driving the needs of the system for generation and transmission become increasingly uncertain with time. The further into the future one projects electric demand requirements, the higher the number of scenarios needed to be analyzed to plan those needs, due to the greater range of uncertainty of key variables. ERCOT stakeholders regularly assess these uncertainties as a part of their ongoing business, and ERCOT worked with these stakeholders, through the ERCOT Regional Planning Groups, to identify a set of key drivers of generation decisions that could be used for the purposes of the assessment, as well as a reasonable range for each driver. The table below shows the identified drivers and the ranges used for each.

Key Drivers Used in Planning Model

Gas Prices	Environmental Regulations	Load Growth
High Price Case: Delivered natural gas price $10/MMBtu[8]	Current: No change from regulations currently being implemented	Base Case: Peak and Energy Growth of 2%/year from 2006
Medium Price Case: Delivered natural gas price $7/MMBtu	Low Carbon Case: Current Case regulations plus $8.00/ton allowance cost for CO_2	High Growth Case: Peak and Energy Growth of 4%/year from 2006
Low Price Case: Delivered natural gas price $4/MMBtu	High Carbon Case: Current Case regulations plus $16.00/ton allowance cost for CO_2	High Energy Case: Peak Growth of 2%/year from 2006 and Energy Growth of 3%/year from 2006

ERCOT used the planning model to assess the results of four composite scenarios that used combinations of the key drivers outlined in the table above.

- Scenario 1 consisted of the low natural gas price assumption, the base load growth assumption and low-carbon environmental regulations.
- Scenario 2 consisted of high natural gas prices, high load growth and current carbon-related environmental regulations.
- Scenario 3 consisted of medium natural gas prices, high load growth, and high carbon regulation.
- Scenario 4 consisted of medium natural gas prices, the base load growth assumption, and current carbon-related environmental regulations.

Projected Generation and Transmission

The resulting set of generation additions for the four scenarios identified above is shown in the table below.

8 All dollar amounts are nominal.

New Generation Additions by 2016 (with 12,000 MW installed wind)

Scenario	Coal	Combined-cycle CT[9]	Simple-cycle CT	Total	Reserve Margin
1		13,570	4,500	18,070	12.0%
2	30,000		8,700	38,700	14.2%
3	24,000		600	24,600	19.6%
4	18,000		2,700	20,700	15.1%

The profitability of the existing generation that is included in the reserve margin calculation in the table above, and thus its likelihood of retirement, was not assessed. However, it was noted that many older natural gas units run very little in scenarios 2, 3 and 4. In other words, the modeling looked primarily at the economics of adding resources, not at the economics of retiring generating resources.

In the next phase of the study, the need for transmission system improvements to meet the reliability and economic needs of the system were assessed. All characteristics of the transmission system, including all planned additions through the year 2011 (based on the plans of transmission owners as of March 2006), were used to evaluate transmission constraints on the system. Elements of the transmission system that must be upgraded to maintain the reliability of the network, given the expected load level in 2016, were identified for each generation scenario. Specific transmission system improvements were not identified to solve the portion of these upgrade needs that were attributable to elements at 138 kV or below; it was assumed for the purposes of this study that these elements, which are generally local in nature, could either be upgraded or an equivalent upgrade could be implemented at the appropriate time. However, specific improvements were identified where 345-kV elements were of concern, because these elements generally require a longer lead time to be implemented and are more likely to impact the selection of preferred, near-term upgrades.

Next, with all these reliability improvements modeled, a simulation of the hourly system dispatch was performed for 2016 for scenarios 1, 3 and 4. (The 4% load growth scenario, scenario 2, was dropped from the transmission analysis because of time limitations and the relatively low likelihood of this scenario.) The elements of the system that caused higher-cost generation to run to maintain reliability were identified. Specific transmission solutions were identified for any 345-kV transmission elements if the solution was lower in cost than continuing to run the higher cost generation to meet reliability requirements. Once this transmission analysis had been performed for all three scenarios, common needs were identified across scenarios. A list of 345-kV transmission projects that were found to be either economic or needed for reliability in one or multiple scenarios is included in the table below. (The term “Pass” indicates that a project provides economic benefits.)

[9] Combustion turbine.

345-kV Projects by Scenario

Name	Type	S1	S3	S4
Reliability Projects				
Navarro Station	Substation	Yes	Yes	Yes
T House - Navarro	New Lines	Yes	Yes	Yes
Collin - Anna	New Lines	Yes	Yes	Yes
Singleton Station	Substation	Yes	Yes	Yes
Zenith Station	Substation	Yes	Yes	Yes
Fayette to O'Brien	New Lines	Yes	Yes	Yes
Rio Grande Valley[10]	New Lines		Yes	
Economic Projects				
Bosque-Everman	New Lines		Pass	Pass
Lufkin-Cedar Bayou	New Lines	Pass	Pass	Pass
Big Brown-Lufkin	New Lines	Pass	Pass	Pass
Oasis-PH Robinson	Terminal Equipment	Pass	Pass	Pass
Bellaire-Smith/WA Parish	Terminal Equipment	Pass	Pass	Pass
Killeen-Kendall	New Lines	Pass	Pass	Pass
TNP-Sandow	New Lines		Pass	Pass
Holman-Coleto	New Lines		Pass	Pass
Moses-Martin Lake	New Lines		Pass	

ELECTRIC TRANSMISSION AND GENERATION NEEDS FOR THE NON-ERCOT REGION

The non-ERCOT utilities continue to operate as bundled electric utilities responsible for both power supply and transmission. Additional power generation needs are driven by customer growth in the respective service areas. The projected load growth ranges from 1.4 to 3.1 percent for the next 10 years in the non-ERCOT regions. Several of the utilities have issued requests for proposals (RFPs) for peaking, intermediate, and base load generation. Natural gas and coal generation appear to be the most likely sources for the additional supply. Purchase power will also be an important part of the supply mix if the transmission is available to move the power into the utility service area.

Two utilities have progressed to the power supply selection stage in the process to acquire new resources. Southwestern Electric Power Company (SWEPCO), which serves Northeast Texas and portions of Arkansas and Oklahoma, has decided to build 480 MW of natural gas combustion turbines for a peaking facility in northwestern Arkansas.[11] Also, SWEPCO plans to build a 480-MW intermediate combined-cycle facility in

[10] Lobo – Rio Bravo – Frontera – North Edinburg.

[11] SWEPCO's application for a certificate of convenience and necessity (CCN) for this project is pending, *Application of Southwestern Electric Power Company for a Certificate of Convenience and Necessity Authorization for Power Plant in Arkansas*, Docket No. 32918.

northwest Louisiana.[12] SWEPCO has also proposed 600-MW coal-fired plant for Arkansas.

Southwestern Public Service Company, which serves the Texas Panhandle and portions of Eastern New Mexico has issued several RFPs for thermal-based, dispatchable resources over the 2005/2006 timeframe. These RFPs were issued for resources with specific capacity size, purchase duration, and/or technology type (*i.e.*, combined cycle or coal facilities). Two resources were acquired in these RFPs, a 200-MW contract with Exelon for delivery from a combined-cycle facility for a period of five years, and a 604-MW contract with CEM/Lea Power Partners for delivery from a combined-cycle facility for a period of 25 years.

The Southwest Power Pool performs the regional transmission planning process for the utilities and cooperatives (East Texas cooperatives, Southwestern Electric Power Company, and Southwestern Public Service Company) in an area that includes Northeast Texas and the Panhandle. A Transmission Expansion Planning Study with a 10-year planning horizon is conducted each year. SPP and ERCOT are conducting joint studies on SPP-ERCOT integration by looking at additional points of potential interconnection, using high-voltage DC interconnections between the two grids.

The El Paso Electric Company system is in the Western Electricity Coordinating Council and is heavily dependent upon transmission lines to move power into the utility service area from Arizona and New Mexico. Expansion of the 345/115-kV auto-transformer capacity has been identified as a means to increase its ability to use new generation resources. El Paso Electric expects significant growth in demand in its service area, related to the expansion of Fort Bliss, and it is preparing to issue a solicitation for new generation resources.

Entergy Gulf States Inc. (EGSI) performs an annual transmission expansion process which includes near-term and long-term planning horizons. An important issue for EGSI in acquiring new generation and transmission facilities is the decision that the Commission makes in the Transition to Competition proceeding that it is required to file no later than January 1, 2007.[13]

Electric Cooperatives in East and West Texas areas outside of ERCOT are also experiencing load growth and need to acquire new resources to meet their customers' needs. These cooperatives face challenges in acquiring new resources. In many cases, a part of their requirements are served by investor-owned utilities that are growing and may not be able to continue supplying them. In addition, they are usually dependent on transmission service that is provided by investor-owned utilities under open-access tariffs approved by the Federal Energy Regulatory Commission, and may have to finance transmission enhancements to bring power to their customers. The Cooperatives in

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[12] SWEPCO's application for a CCN for this project is pending, *Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization for a Combined Cycle Power Plant in Louisiana,* Docket No. 33048.

[13] HB 1667, enacted by the 79th Legislature, requires EGSI to file a proceeding to determine how it may transition to competition. One of the options that EGSI will include in the plan is the incorporation of its Texas service area into ERCOT, which will require the construction of transmission facilities to integrate the ERCOT and EGSI electric systems. EGSI also serves customers in Southeast Louisiana.

Southeast Texas face the additional uncertainty about the possible integration of Entergy into ERCOT.

RENEWABLE ENERGY IN TEXAS

Texas achieved two significant renewable energy milestones in 2006. First, the state exceeded the 2,880-MW goal for renewable energy that had been established in 1999 by Senate Bill 7, a goal that the Legislature had mandated be reached by 2009. Second, Texas surpassed California as the state with the greatest amount of installed wind power. Most of the new wind capacity added in the last two years has been in the Abilene-Sweetwater area.

Developers have made substantial progress with respect to new wind projects that are expected to be completed in the next three years. Nearly 2,000 MW of resources have had studies conducted of their impact on the transmission system and have signed agreements with utilities to interconnect to the transmission system. The additional wind resources that have signed such agreements and the projected dates that they will begin operating are shown in the table below. Another 1200 MW of wind projects have been announced but have not signed interconnection agreements.

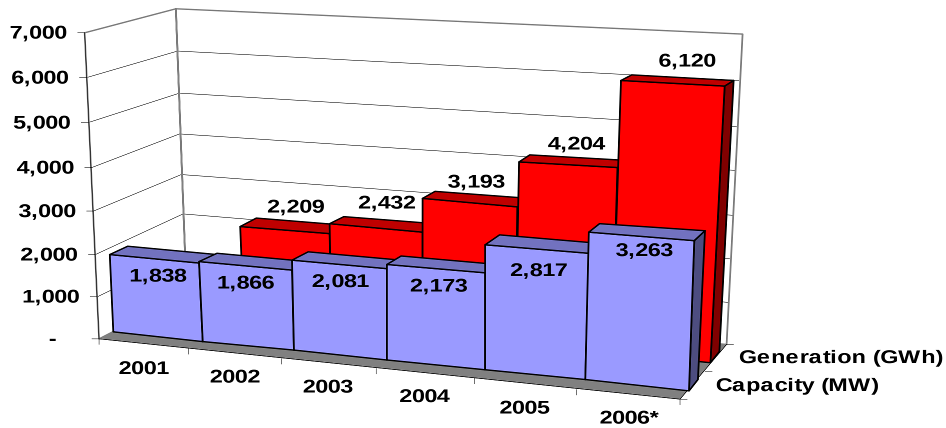
If the projects scheduled for completion in 2007 are completed, the level of renewable capacity in Texas will be roughly 5,240 MW by the end of 2007, an amount that is just 640 MW short of the revised 2015 renewable energy goal of 5,880 MW that the Legislature established in enacting SB 20 in 2005.[14] In addition to the publicly-announced wind projects, ERCOT has reported that another 15,000 MW of wind resources are in earlier stages of development.

Wind-powered resources account for 78% of the state's 3,263 MW of installed renewable capacity, and 97% of the 2,462 MW of capacity installed since the enactment of Senate Bill 7. About 2.1% of the electricity generated in Texas during 2006 came from renewable energy resources, up from 1.5% for all of 2005.[15] Within the ERCOT power region, renewable resources provided 2.0% of the power generated in 2006 through the month of June, up from 1.3% for all of 2005. The figure below illustrates the growth both in installed renewable capacity and in electricity production from renewable resources since 2002.

[14] Senate Bill 20 amended PURA 39.904(a), establishing cumulative goals for installed renewable capacity of 2,280 MW by January 1, 2007, 3,272 MW by January 1, 2009, 4,264 MW by January 1, 2011, 5,256 MW by January 1, 2013, and 5,880 MW by January 1, 2015. SB 20 also established a target of 10,000 MW of renewable capacity by January 1, 2025.

[15] *Electric Power Monthly*, Energy Information Administration (Mar. 2006 and Aug. 2006).

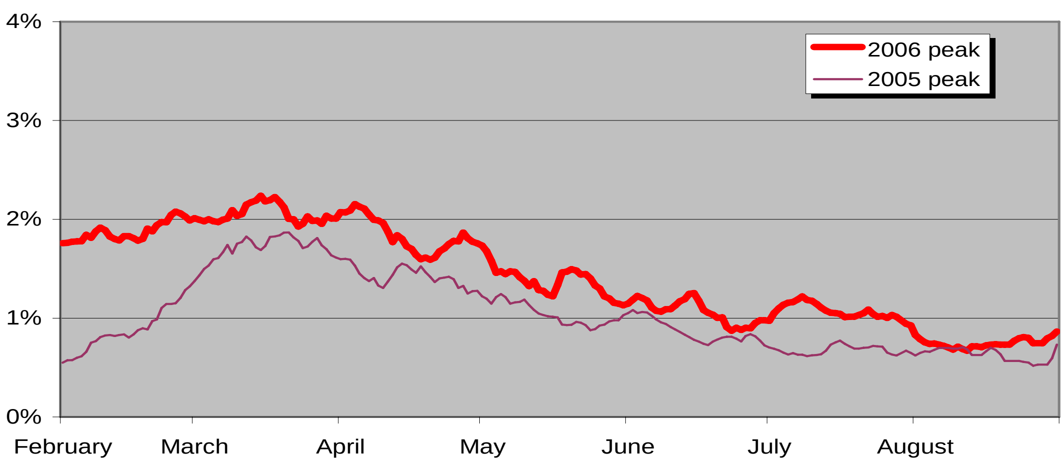
Growth in Renewable Energy Generation and Capacity Since 2001



* Projected

While a significant level of new wind generation has been completed or announced for completion in 2007 and 2008, wind generation does not provide a significant contribution to meeting summer peak demand. Historically, wind generation has supplied on average only 2.6% of its rated capacity during summer peaks, and the table below shows that wind production is significantly lower in the summer than in the spring and has supplied about one percent of the ERCOT peak demand during August.

ERCOT Electricity Demand Met by Renewable Resources



There are three sources of value for the developer of a wind generation facility: Renewable Energy Credits (RECs), Production Tax Credits (PTCs), and the value of the energy produced. RECs are the incentive mechanism that the Legislature established to support meeting the renewable energy goals in state law. PTCs are income-tax credits that have been provided by the federal government. As additional renewable generation has begun operating, the value of RECs has fallen. The value of PTCs is fixed but escalates with inflation. As the value of RECs has fallen, higher natural gas prices have provided a new stimulus for wind energy. The wind turbines that are being installed today can produce electricity at about four cents/kilowatt hour (taking into account the federal production tax credit), so that wind turbines can provide energy at a cost that is competitive with a combined-cycle combustion turbine that is burning natural gas, based on current natural gas prices. The opportunity to compete in a market that is dominated by natural gas generation has made Texas (and particularly ERCOT) an attractive location for new wind generation projects.

Competitive Renewable Energy Zones

A new rule adopted by the Commission in December 2006 establishes a procedure to designate competitive renewable energy zones (CREZs) in Texas.[16] The concept of CREZs was included in Senate Bill 20, with the expectation that by establishing such zones, the Commission would:

- ensure that sufficient transmission infrastructure is built to meet the State's goal for renewable energy;
- improve the coordination between the construction of transmission facilities and renewable generation facilities; and
- avoid duplication of issues in determining the need for new transmission facilities (under SB 20, the need for transmission upgrades to serve a CREZ would be determined by the Commission in the CREZ proceeding and would not be an issue in a subsequent transmission licensing case).

The CREZ rule will expedite the process by which new transmission projects serving renewable energy resources may be approved by the Commission and reduce the risk that a utility's construction of transmission to serve a potential wind zone might be challenged as not providing benefit to the utility's customers. The identification of CREZs will also reduce the development risks for renewable generation.

Senate Bill 7 established the State's goal for renewable energy in 1999 but made no special provisions for transmission to interconnect renewable resources. The rapid development of wind power in West Texas since 2001 has shown that wind farms can be built more quickly than transmission, however. This timing difference poses a dilemma for planning: it is difficult to know whether a new transmission line will be needed if the generation facilities do not yet exist, but a wind farm is difficult to finance if there is no certainty that sufficient transmission will be available. Senate Bill 20 is an effort to solve this dilemma by authorizing the Commission to identify areas with sufficient renewable energy potential, identify the transmission facilities that could serve the area, and establish the need for new transmission facilities serving the area, even if no specific renewable generation projects exist or are under construction. One of the factors that the Commission would consider in designating CREZs would be the financial commitments of wind project developers to building in the zone, and the rule includes mechanisms to minimize the risk that transmission facilities built to serve CREZs would be under-utilized.

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[16] *PUC Rulemaking Related to Renewable Energy Goal Amendments*, Project No. 31852.

The rule does not designate any CREZ. Rather, it establishes the procedure for the contested dockets in which designations will be made and establishes what will be considered a financial commitment. The rule requires ERCOT to study the wind energy production potential statewide and establishes criteria for designating CREZs.

The Commission anticipates issuing its first order in late spring 2007. Once the CREZ order is entered, the affected transmission utilities will have one year to prepare their applications for Certificates of Convenience and Necessity (CCNs). The CCN proceeding is expected to take six months, after which construction would take another one to two years. As a result, transmission from the first group of CREZs is expected to be available by 2010 or 2011.

The Cost and Benefit of Integrating New Renewable Facilities

In preparing this report to the Legislature, the Commission has relied on ERCOT's report on prospective wind zones and the estimated cost of transmission facilities that would be needed to serve areas that are likely to be candidates for designation as a CREZ.[17] ERCOT's evaluation was based on the work of a consultant with expertise in wind characteristics, its own transmission planning staff, and the input of market participants, including both companies that are interested in developing wind projects and utilities that are familiar with transmission planning. The study identified areas with high wind potential, evaluated the capacity of the transmission system as it is expected to be configured in 2009, and studied various scenarios for adding new wind generation at various locations in West and South Texas that could be considered potential CREZs.[18] The study of these scenarios included evaluating transmission alternatives that would allow the energy produced in the potential CREZs to be transmitted to urban areas in East and Central Texas and estimating the costs of new transmission that would be required.

The primary areas of study in the ERCOT report were:

- the Gulf Coast south of Corpus Christi,
- the McCamey area, south of Odessa,
- Central Texas areas around Abilene and Sweetwater, and
- the Texas Panhandle.

The factors that are important in determining the desirability of an area for wind development are the quality of the wind and the availability of transmission service in the area. Where new transmission facilities are needed to provide transmission service, the cost of transmission depends on the configuration of the existing transmission network, whether any transmission in the area is congested, and the distance of the area from urban areas where the energy could be used. Other factors that ERCOT evaluated were variations of wind velocities during the day and year and the degree to which the wind patterns in different areas were similar. Because energy has a higher value during hours and months in which energy consumption is high, wind areas that better match consumption peaks would be more desirable, if other factors were equal. Similarly, there

[17] *Electric Reliability Council Of Texas, Inc.'s Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas*, Project No. 33577.

[18] The information on wind generation potential was based on computer models that included meteorological and geophysical programs.

is a value in having diverse wind patterns, so that when climate and weather conditions result in low wind-energy production in one area, other areas might have high-energy production. The report also considered synergies between wind-related transmission needs and other factors that affect the construction of new transmission facilities. For example, the report indicates that additional transmission facilities are likely to be needed in and to the west of the Temple to San Antonio corridor, as economic development continues along IH-35 and in the Hill Country. Transmission facilities from the Abilene-Sweetwater area to the Temple, Austin, or San Antonio area might serve the dual purpose of improving the reliability and capability of the transmission system in the IH-35 corridor and the Hill Country and allowing power to be imported from CREZs in West Texas to the Austin-San Antonio area.

The ERCOT report evaluated transmission costs and the hypothetical savings to energy consumers that would result if wind generation displaces other sources of energy, primarily natural gas-fired generation. The ERCOT report is not a definitive report of the costs involved in providing transmission service. Because of time constraints, some issues related to adding new wind generation in West or South Texas were not addressed, such as ancillary service costs and the impact of dynamic response on the electric system. The following table summarizes the transmission cost estimates that ERCOT developed for various levels of wind generation in these areas.

Transmission Costs for Wind-Generation Scenarios

Area	**Wind Capacity**	**Transmission Cost (million $)**	**Production Cost Savings (million $/yr)**	**Generator Revenue Reductions (million $/yr)**	**Wind Utilization Factor[19]**
Coast	1000	15	129	221	38.3
Coast	2000	75	262	437	37.1
Coast	3000	320	383	713	37.0
Central	2000	376	276	464	40.1
Central	3000	723	406	727	39.0
Central	3800	1019	495	963	39.3
McCamey	1500	320	198	406	40.5
McCamey	3800	861	506	1069	41.0
Panhandle	800	265	112	247	43.2
Panhandle	1800	645	249	474	43.3
Panhandle	2400	715	297	620	42.8
Panhandle	4600	1515	587	1250	42.5

Finally, ERCOT presented the results of several combination scenarios, providing estimates of transmission costs of development in more than one area. The table below shows the results for two scenarios involving development in Central Texas and McCamey and one involving Central Texas, McCamey and the Coast. Scenario 1 is for

[19] The wind utilization factor is a measure of the output of a generator over the course of a year, compared to its output at its rated capacity. The primary factor affecting the utilization factor is the quality of the wind in the area where a project is located.

2000 MW in Central Texas and 1250 MW in McCamey; Scenario 2 is for 3000 MW in Central Texas and 1000 MW in McCamey; and Scenario 3 is for 2000 MW in the Coastal area, 2000 MW Central Texas, and 1250 MW in McCamey.

Transmission Costs for Combination Wind-Generation Scenarios

Scenario	Wind Capacity	Transmission Cost (million $)	Production Cost Savings (million $/yr)	Generator Revenue Reductions (million $/yr)	Wind Utilization Factor
Scenario 1	3250	863	443	796	39.8
Scenario 2	4000	1159	520	996	39.0
Scenario 3	5250	938	705	1278	38.8

The ERCOT Report will be an important source of information in the CREZ proceeding, which will be initiated in January 2007. Developers and other persons who have an interest in obtaining CREZ status for particular areas will be able to participate in this proceeding.