# Long-Term System Assessment

# for the ERCOT Region

# December, 2008

# ERCOT Long Term System Assessment

## Executive Summary

Senate Bill 20 requires that the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas, Inc. (ERCOT) study the need for increased transmission and generation capacity throughout the state of Texas and report on these needs to the Legislature. A report documenting this study must be filed with the legislature each even-numbered year.

In order to meet this requirement, ERCOT completes a Long-Term System Assessment (LTSA) every other year. The LTSA provides a 10-year-out assessment of transmission needs. This assessment is not conducted to provide specific recommendations for transmission projects. Rather it is used to inform the five-year planning process in two ways. First, the 10-year plan provides a longer term view of system reliability needs. Whereas in the five-year planning horizon a small transmission improvement may appear to be sufficient, the 10-year planning horizon may indicate that a larger project will be required. In this case the larger project may be more cost-effective than multiple smaller projects, each being recommended in consecutive Five-Year Plans. Second, the 10-year plan can indicate system needs that require solutions that will take longer than 5 years to implement. In such cases, it is desirable to incorporate these projects into the 5-year evaluation process as early as possible.

The ERCOT 2008 LTSA is based on the most recently completed ERCOT Five-Year Plan. It incorporates all generation currently in operation (and expected to remain so) and all generation for which there is a signed interconnection agreement. The base transmission topology also includes the transmission improvements ordered by the Public Utility Commission of Texas (PUCT) in August 2008 as part of the designation of Competitive Renewable Energy Zones (CREZ), along with the wind generation facilities for which the CREZ transmission improvements were designed. Other input parameters, such as natural gas price and emissions allowance costs, were modified by scenario in order to determine their impact on the model results.

The study consisted of three parts. The first was an analysis of steady-state peak-load system conditions, using AC contingency analysis, to evaluate import needs into four regions of Texas (Dallas/Fort Worth; San Antonio/Austin, Houston/Galveston, and the Valley). The second was an analysis of local system needs using a system dispatch model. The third was an evaluation of the cost-effectiveness of potential economic projects using scenario analysis.

This analysis leads to the following conclusions:

- As with the LTSA completed in 2006, this assessment indicates a need for additional future import capacity into Houston. Although an import pathway into Houston from the west, such as from the Fayette to the Zenith substations, was generally cost-effective across a range of scenarios included in this study, the intent of the LTSA is to inform the ERCOT five-year study process, and the specific pathway should be reviewed and selected as part of that process. This study did not indicate an additional need for a new import pathway into the Dallas/Fort Worth area as was shown in the previous LTSA. This change may be the result of the additional import capacity into Dallas/Fort Worth from the west resulting from the new transmission lines ordered by the Public Utility Commission of Texas as part of the transmission plan to serve Competitive Renewable Energy Zones.
- Load growth in two areas (north of Dallas in Cooke and Grayson County and in western Williamson County) may result in the need for long-lead time transmission projects in the next ten years. Any transmission project evaluated for these areas in the five-year planning process should be compared to projects evaluated in this LTSA for long-term cost-effectiveness.
- The economic benefits from most transmission projects were dependent on the location of new sources of generation, fuel costs, and emissions allowance costs. Few projects were cost-effective across a range of different potential future scenarios. Given the uncertainty associated with future development of base-load generation, it is not reasonable to plan large inter-zonal projects at this time.
- Large inter-zonal projects are generally not economic in scenarios that include several new nuclear units. This is due to the fact that the likely locations of new nuclear units are close enough to major load centers that additional inter-zonal projects are not required. An additional connection from Comanche Peak towards the south will likely be economic if two new units are constructed at this location.
- Large inter-zonal projects are economic if new coal units are built in the general areas considered in this study and gas prices are consistently at the high levels seen earlier in 2008. These projects would be required to transport energy from expected, remote coal plant locations to major load centers, especially Houston.
- The pathways from Fayette to Zenith (west of Houston) and from Valley View to Valley South (through Cooke and Grayson Counties) were economically justified in many of the scenarios evaluated. These projects should be considered in the next Five-Year Plan to determine if they can be included in the recommended projects based on existing system conditions.

- No system improvements beyond the planned CREZ facilities are likely to be needed to incorporate up to 1,800 MW of solar generation capacity in the McCamey area. With up to 4,600 MW of solar generation capacity, the only identified transmission projects are located in and around the McCamey area. System dispatch model results indicate that increasing amounts of solar generation in these scenarios primarily offset gas generation.
- The implementation of a carbon tax is not likely to have a significant impact on transmission system needs unless carbon emission allowance prices are above $50/ton. Above this amount, the variable cost of gas generation could become competitive with that of coal generation, resulting in significant changes in generating unit dispatch.
- Compressed Air Energy Storage can have a beneficial impact on deliverability of wind energy from West Texas by storing wind energy when wind is abundant and releasing that energy back to the grid when the transmission system is not congested. The value of these projects is more likely to be derived from market prices rather than from overall system production cost savings.
- Plug-In Hybrid Electric Vehicles are not likely to have a significant impact on system transmission needs in the near future, although these devices may have an impact on local transmission needs and on distribution system requirements in the next ten years.

The above conclusions, and this report in general, are based on high level assumptions and are intended to inform the five-year planning process, which provides a more detailed review of specific transmission projects. The technologies and locations of generation projects assumed in the analyses that support the above conclusions may not reflect all issues that necessarily must be considered and/or affect generation development decisions. Accordingly, this report is intended to provide guidance to ERCOT and ERCOT market participants in evaluating system needs, and is not intended to suggest changes to market policy or support changes to market activities.

# ERCOT Long Term System Assessment

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# I. Introduction

Section 39.904(k) to the Public Utility Regulatory Act (PURA) requires the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas, Inc. (ERCOT) to study the need for increased transmission and generation capacity throughout the state of Texas and report to the Legislature the results of the study and any recommendations for legislation. The report must be filed with the legislature not later than December 31 of each even-numbered year.

Two reports have been prepared to meet this requirement:

- Annual Report on Constraints and Needs in the ERCOT Region – this report provides an assessment of the need for increased transmission and generation capacity for the next five years (2009 - 2013) and provides a summary of the ERCOT Five-Year Transmission Plan to meet those needs.
- Long Term System Assessment (LTSA) for the ERCOT Region – this report provides an analysis of the system needs in the tenth year, in order to provide a longer-term view to guide near-term decisions made in the Five-Year Plan.

Together, these reports provide an overall assessment of the needs of the ERCOT system over the next ten years.

The LTSA is intended to provide general guidance to near-term planning and is not intended to provide actual recommendations for specific transmission projects. The LTSA analysis was based on projections of certain factors that drive decisions on generation investment and system needs, such as the price of natural gas and environmental regulations. These projections drove the assumptions of the number and locations of new generation units that would be built to meet the projected increase in demand. The exact placement and size of these new generators together with the growth and location of the load has a significant effect on the transmission needs of the system. All projections are less certain the farther into the future they are based. Thus, any decisions to recommend specific transmission projects for implementation will be made through the Five-Year Plan process and Regional Planning Group review of specific projects.

# II. Methodology

This study is designed to complement the annual Five-Year Plan developed for the ERCOT region. In the Five-Year Planning horizon, the location, size and variable cost of new generation is relatively well-known, and the growth of customer demand can be predicted with limited error. As such, the benefits of transmission improvements can be estimated through modeling. In the ten-year planning horizon, the size, technology and locations of new generation are not known. As an example, it would have been hard to predict in 1998 that by 2008 there would be over 8,000 MW of installed wind generation capacity in ERCOT. Load growth may also be difficult to forecast, as economic growth and customer demand patterns can change over time.

Long-term load forecasting provides uncertainty for transmission planning. From a system standpoint, overall economic growth, technology improvement, energy consumption efficiency and weather all affect electricity consumption. Further, in transmission planning, the load at each substation (including new substations built in areas of growth) must be projected in order to develop a meaningful transmission plan.

In the deregulated market, forecasting future generation development provides another source of uncertainty in transmission planning. Transmission planners have to analyze transmission needs without knowing where, when and what type of generation is going to be built. Since the restructuring of the Texas wholesale electric market in 1999, transmission planners have generally adopted the approach of considering new generation in the transmission planning process only when an interconnection agreement is signed.

New generation can be added to the system in as little as six to nine months, while additional transmission lines requiring new right-of-way typically take three to five years from the time a decision is made to build the line to the time it is placed into service. This has led to increasingly shorter planning horizons and uneconomic congestion being experienced on the system (or dependence on special protection systems) in the interim period between the completion of the generation and transmission. To some extent, this transmission-planning difficulty is unavoidable in a deregulated market; the flexibility in supply decisions that causes a market to be more efficient than regulated decision-making limits the information that is available for long-term transmission planning.

The LTSA does not intend to impose generation type and siting decisions on the market, nor does it propose that transmission construction that would be justified by new generation be made in advance of firm siting decisions. It does, however, attempt to look proactively at the needs of the system by making a reasonable assessment of what type, amount and location of the future generation may be built by the market, with the intent of guiding nearer-term decisions toward what are reasonably expected to be the longer term needs of the system and shortening the timeframe required to study the bulk transmission needs due to firm new generation by anticipating what those needs may be.

Although the LTSA does not recommend specific transmission improvements, it is used to inform the five-year planning process in two ways. First, the LTSA provides a longer term view of system reliability needs. Whereas in the five-year planning horizon a small transmission improvement may appear to be sufficient, the 10-year planning horizon may indicate that a larger project will be required. In this case the larger project may be more cost-effective than multiple smaller projects, each being recommended in consecutive Five-Year Plans. Second, the LTSA can indicate system needs that require solutions that might be expected to take longer than 5 years to implement. In such cases, it is desirable to incorporate these projects into the five-year evaluation process as early as possible.

As the focus of the LTSA is on large, long-lead time projects, smaller projects that are more appropriately analyzed in the five-year planning process are not being recommended. However, in order to develop the LTSA, smaller projects must be evaluated, both in order to determine overall system needs and to determine if larger projects are cost-effective.

## A. Input Assumptions

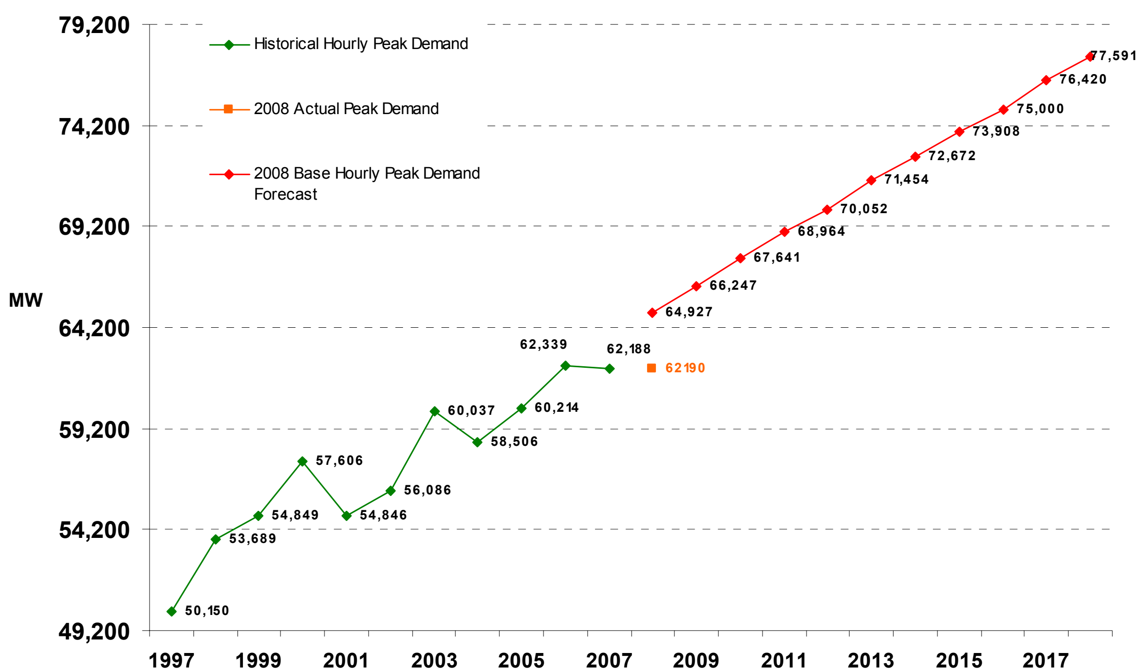
This study has been developed using the latest year of the most recent Five-Year Plan as the base case. All recommended transmission projects as of July 1, 2008, are included in this model, as are all generating units either currently operational (and expected to remain in-service) or with signed interconnection agreements as of July 1, 2008. This base case was modified to include the transmission improvements ordered by the Public Utility Commission of Texas (PUCT) as part of Docket No. 33672, Commission Staff's Petition for Designation of Competitive Renewable Energy Zones (CREZ), and the additional wind generation for which these transmission improvements have been designed. For more information on the proposed CREZ transmission improvements, see the ERCOT report: Competitive Renewable Energy Zones (CREZ) Transmission Optimization Study, dated April 2, 2008. A map of the CREZ set of improvements is provided as Figure 1.

The costs for new transmission equipment are based on planning-grade estimates developed as part of recent ERCOT transmission studies. These costs on a per unit basis are provided in Appendix 1.

The load forecast for 2018 is derived from the ERCOT Long-Term Demand and Energy forecast. This forecast is produced with a set of econometric models that use weather, economic and demographic data, and calendar variables to capture and project the long-term trends in the historical load data for the past six years.

To develop this forecast, a representative hourly load shape by weather zone is forecasted using an average weather profile of temperatures, Cooling Degree Hours (CDH) and Heating Degree Hours (HDH) obtained from historical data. Other factors, such as seasonal daily, weekly, monthly and yearly load variations and holidays, as well as interactions between variables such as weather, weekends, and weekdays are also considered. This hourly ERCOT Load Shape describes the hourly load fluctuations within the year, but does not reflect the long-term trend.

The long-term trend is provided by the energy forecast. The monthly energy forecast models by weather zone use Cooling Degree Days (CDD) and Heating Degree Days (HDD), economic and demographic data, and monthly indicator variables to project the monthly energy for the next eleven years (2008 - 2018). Below is a graph of the historical system peak demands and the forecasted system peak demands.




Bus-level load growth assumptions were obtained from the most recent library of Steady-State Working Group (SSWG) base cases as of July 1, 2008. Bus-level load growth rates were analyzed and extrapolated to 2018 to match the peak load forecast shown above. Self-serve loads that are included in the SSWG cases, but are not included in the forecast shown above, were then added to the starting case.

Other input assumptions are varied by scenario in order to determine the impact of these assumptions on model results, and to determine if any transmission solutions are effective across multiple scenarios. The natural gas price forecast is adjusted by scenario, as is the cost of emissions (carbon allowance prices). Beyond those generating units for which there are signed interconnection agreements, the location, size, technology and efficiency of future generating units is not known. As some generation will need to be developed in order to serve the forecasted load in 2018, the characteristics of future generation have been selected to match the input assumptions by scenario. These generation scenarios are discussed in Section V.

## B. Analysis

Reliability needs of the system were analyzed using two methodologies. The first type of analysis was conducted using steady-state A/C contingency analysis performed on a model of the system expected at the time of the 2018 peak load. The main focus of this analysis was on projects that will be required to relieve import constraints in order to serve load growth in large urban centers. This analysis is described in Section III.

In addition to the reliability needs of large urban areas, load growth in smaller regions can lead to requirements for transmission improvements to allow customer load to be served reliably. As the starting case for this analysis was developed based on expected loads in 2012, numerous load-serving transmission projects were required for the system to be able to reliably serve loads expected in 2018. Unlike the import needs of large urban centers, these localized system needs are harder to identify and require the use of different modeling tools. Using a system dispatch model that simulates the security-constrained unit commitment and economic-dispatch of the generating units in the ERCOT system across a year of hourly customer demand levels, areas where customer load would not be served reliably without transmission improvements regardless of unit commitment and dispatch were noted. Based on modeling results and further study using power-flow software, potential transmission improvements were added to the base case so that all customer demand across the year could be served reliably.

Most of the local load-growth-driven system needs indicated in this analysis will likely be resolved through upgrades to existing facilities, particularly upgrades to existing 138-kV circuits. These types of upgrades are typically best handled through the five-year transmission planning process. However, numerous upgrades of existing circuits in an area could be an indication that a more significant system improvement in that area is justified. For the purposes of this study, upgrades of the existing system required to reinforce the starting case so that 2018 loads could be served reliably were grouped by location, and the results were compared to analyses from recent Five-Year Plans. Alternate upgrades were developed for areas with multiple projects, and the results were evaluated for cost-effectiveness. This analysis is described in Section IV.

Reliability transmission projects are required in order to meet customer demand while adhering to applicable NERC and ERCOT reliability standards. These projects are required because there is no possible dispatch of generating units with which customer demand can be served reliably. In other situations, there are feasible combinations of generating unit output levels that can be used to reliably serve load, but in order to do so, high-variable-cost generation must be utilized in the place of low-variable-cost generation. The displacement of low-cost generation with high-cost generation in order to respect transmission system limits is called transmission congestion. This displacement leads to system inefficiencies and nodal price disparities. In some cases, transmission improvements that are not required in order to reliably serve load can increase system efficiency to such an extent that the reduction in the annual cost to serve load is greater than the annual carrying cost of the transmission improvement. System improvements that meet these criteria can be recommended as economic projects.

Although economic projects are not required to maintain system reliability, they provide significant system benefits by allowing the most efficient generation to serve load. New economic transmission projects are often the result of the development of low-variable-cost generation. However, as has been noted, the size, location, technology and efficiency of much of the generation that will be developed over the next ten years are unknown at this time. In order to evaluate potential future economic projects, the possibilities for future generation development were evaluated. The evaluation of generation expansion alternatives and economic transmission projects is described in Section V.

# III. A/C Contingency Analysis

Steady-state contingency analysis was used to evaluate the need for additional import capacity into large urban areas in ERCOT by the year 2018. The system was analyzed under peak-load conditions in order to simulate the most severe system deficiencies. Including the self-serve loads, the modeled aggregate peak-demand was 83,500 MW.

This contingency analysis was performed in accordance with the minimum voltage standards (presented in Appendix 2). The system-wide maximum voltage performance standard under all conditions is 105% of nominal.

In order to study the import constraints into urban areas likely to develop by 2018, four distinct transmission regions were created. These areas enclose the large metropolitan areas in ERCOT and the corresponding high load concentration zones. The west region was not separated into a zone for import constraint analysis because load growth rates in this part of ERCOT are low and there is significant generation development, mostly from new wind generation facilities throughout west Texas, with more planned as part of the CREZ process. Also, the planned transmission improvements ordered by the PUCT to serve the CREZ wind generation should provide sufficient 345-kV transmission to solve any load-serving reliability import needs in this part of the system.

Contingency analysis was performed to analyze major transmission reliability needs in the four areas. The study involved steady-state analyses of selected generation dispatch scenarios, developed to show moderate to extreme thermal and voltage stresses on key transmission pathways within the study regions and on the interfaces with the adjacent regions. For the purposes of this study, the modeled output of hydroelectric generation resources was set to zero, in order to reflect their potential unavailability during peak-load conditions.

The steady-state analysis focused on contingency analysis of generators, single and multiple transmission elements. Automatically switched shunt devices, synchronous machines and load tap changing transformers that operate to regulate voltage were permitted to adjust, within capability, to maintain schedules under both normal and post-contingency conditions. Branch or transformer post-contingency loading in excess of long-time emergency (LTE) or short-time emergency (STE) ratings was acceptable if the overload could be alleviated within the stipulated time frame using post-contingency adjustment of phase-shifting transformers.

Individual and multiple generator outages were modeled for study by selecting participating generators for reasons including unit age, full-load capacity and location. Generator unavailability rates in the import-constrained areas were assumed to be no more than 10% of installed capacity in the study area. Generation unavailability modeling for export areas was devised to establish the requisite stresses on the area's transmission network by targeting generators deemed to wield some degree of influence on the study area by virtue of capacity and location, and involved adjustments to generation schedules outside of the area of study to produce the desired stresses. General outlines of generation dispatch specifics for the four study areas are presented in the tables included in the discussions by zone below.

Widespread thermal and voltage inadequacies were observed on the 138-kV and 69-kV transmission facilities serving load pockets within the much larger study areas. From the standpoint of identifying and assessing the bulk transfer requirements and limitations for the four defined study areas, the specific focus of this analysis was on evaluating constraints on imports arising from a lack of adequate 345-kV transmission capacity.

## A. Northeast Study Region

The northeast study area as developed for this study is a fifty-five county region with the densely populated Dallas-Forth Worth metro and environs at its hub. It is outlined by the northeast quadrant of the ERCOT transmission footprint with a western boundary defined along the Montague, Jack, Palo Pinto, Erath, Comanche and Brown counties. The southern border of this region is defined by Angelina, Houston, Madison, Grimes, Brazos, Robertson, Falls, Bell, Lampasas and San Saba counties. The 600-MW asynchronous connection between ERCOT and the Eastern Interconnection is located in the northeastern section of this area. The summer peak forecast load for this region in 2018 is approximately 32,600 MW, and the corresponding estimated installed generation capacity, including the Kiamichi plant in Oklahoma, is approximately 33,000 MW. A geographic layout of the region is shown in Figure 2.

Unit unavailability was simulated using the generation outages listed in the following table. The numbers provided in the second column represent the amount of generation capacity unavailable at the specified location.

| Dispatch | Unavailable generators (MW) | Approx. Net Area Import (MW) |
|---|---|---|
| D1 | Powerlane (46); RWMiller (75); N. TX (74); Spencer (60); Olinger (185); Valley (1055); Monticello (580) | 1,700 |
| D2 | Bosque (535); Monticello (808); Forney (900) | 1,855 |
| D3 | Powerlane (46); N. Texas (74); Wise (240); Martin Lake (804); Str. Crk. (665); Tenaska Gateway (828) | 2,180 |
| D4 | Johnson, N. Texas (295); Spencer (60); Wise (650); Wolf Hollow (705); Decordova (779); Handley (392) | 2,550 |

Based on this analysis, it does not appear that there is a reliability need for additional import capacity into the northeastern region as defined. Imports are limited by generators on the outskirts of the defined region; when these units are unavailable, additional power can be imported along the pathways these units occupy. Sufficient transmission capacity exists to import power into the immediate Dallas/Ft. Worth area. This analysis also indicates that there are limitations on import into the Dallas/Ft. Worth region from the generation-rich area in the extreme northeastern corner of ERCOT.

## B. Houston Study Region

The aggregate 2018 summer forecast load for this southeastern region, which includes Chambers, Galveston, Harris, Montgomery, Fort Bend, Brazoria and Waller counties, is approximately 24,385 MW. This region is dominated by large industrial facilities and Houston's fast-growing residential loads. The installed generation capacity in this area, which is expected to be at least 18,800 MW by summer of 2018, is predominantly gas-fired with coal plants contributing about 2,500 MW. This area covers a significantly smaller land area than the northeast study region and is shown in Figure 3.

Unit unavailability was simulated using the generation outages listed in the following table:

| Dispatch | Unavailable generators (MW) | Approx. Net Area Import (MW) |
|---|---|---|
| H1 | None | 5,570 |
| H2 | Deer Park Energy Center (970) | 6,530 |
| H3 | THWharton (390); W.A. Parish (820) | 6,760 |
| H4 | Cedar Bayou (745); Shell Deer Park (70); Sam Bertron (175); W. A. Parish (165) | 6,760 |

Based on this analysis, the difference between installed generation capacity and the peak load in 2018 in the Houston area is expected to result in the need for about 5,600 MW of imported power at a minimum to fulfill the area's peak-load needs, not counting the need to hold some generation in reserve for real-time operational emergencies. Given these import needs, without the benefit of installation of a substantial amount of new generation resources, the Houston area will require additional high-voltage transmission infrastructure in place by the beginning of the 2018 summer period.

This analysis indicates that in 2018 import capacity is likely to be restricted from both the south and the north. Both the capacity along the W. A. Parish-Bellaire 345-kV transmission corridor, and the corridor heading south from the Singleton switching station to the north will begin to pose power transfer limitations if import needs are elevated to the 6,350-MW to 6,400-MW range. Voltage performance on the 345-kV network appears to be marginally acceptable, in general, but will need to be monitored closely since thermal import limits could be undercut by voltage performance under highly stressed system conditions.

## C. South-Central Study Region

This region includes the area in south-central Texas on both sides of Interstate Highway 35 extending from Frio County in the south as far north as Williamson County. The region spreads as far east as Colorado and Austin counties and is bounded by Llano, Gillespie and Kerr counties to the west (depicted in Figure 4). The major load centers of this region are found in the Austin and San Antonio metro areas and the fast-growing Hill Country area. The 2018 summer peak load for this area is projected to reach 7,350 MW, with expected installed generation of about 9,900 MW.

Unit unavailability was simulated using the generation outages listed in the following table:

| Dispatch | Unavailable generators (MW) | Approx. Net Area Import (MW) |
|---|---|---|
| S1 | None; [Combined with high Houston-Matagorda generation] | n/a |
| S2 | None; [Combined with high Northeast and western ERCOT generation] | n/a |
| S3 | Leon Creek (95); Fayette (608); [combined with high Houston generation] | n/a |
| S4 | Leon Creek (95); J. T. Deely (405); J. K. Spruce (560); W. B. Tuttle (247); Fayette (608) | n/a |
| S5 | San Miguel (396); Hays (450); Decker (750) | n/a |

This analysis indicates that the 345-kV infrastructure within this area appears to be adequate under the analyzed generation dispatch scenarios. However, the San Antonio import capability could be improved by alleviating limitations along the Marion-Skyline and Marion-Hill County 345-kV corridors to take advantage of generation in the zone between the Austin and San Antonio metro areas.

## D. Valley Study Region

This region encompasses the south Texas region stretching from Matagorda county along the Gulf coast down to Cameron county and then northwest along the Rio Grande valley to Val Verde county. The largest cities in this region are Corpus Christi, Victoria, Laredo and the Brownsville-McAllen area. The installed generation capacity for the area will be about 11,050 MW with an expected total 2018 summer load of 7,800 MW. Generation in this region is predominantly fueled by natural gas, with a 2,560 MW contribution from two nuclear plants in Matagorda County. Hydroelectric capacity makes up only 100 MW of this region's total. The bulk of the installed generation is concentrated in the Calhoun, Matagorda, and Victoria county areas, and this generation is connected to the major cities along the Rio Grande Valley by a small number of long 345-kV and 138-kV transmission lines. The generation rich area of this region is excluded for study purposes from the net import area which is demarcated by the black and the blue lines in Figure 5.

Unit unavailability was simulated using the generation outages listed in the following table:

| Dispatch | Unavailable generators (MW) | Approx. Net Area Import (MW) |
|---|---|---|
| V1 | None; no import from CFE | 1,725 |
| V2 | Barney Davis (680) | 2,405 |
| V3 | Magic Valley (685); Silas Ray (34); Nueces Bay #7 (330) | 2,750 |
| V4 | Silas Ray (34); Magic Valley (216). | 1,900 |

This analysis indicates that, although a new source of import capacity into the Valley region is not needed in 2018, it will likely be needed soon thereafter. Without an alternative supply source in the form of new generation resources or additional transmission support by the summer of 2018, imports over the current service interconnections to CFE will again become critical to the reliability of service for the Laredo load pocket to avoid voltage collapse. The key limiting situation is the contingency loss of the 345-kV San Miguel-Lobo line. With about 100 MW of support from CFE, and if some internal load serving concerns in the east Valley area are addressed, the greater Valley area as a whole can sustain up to about 2,000 MW of import before the import capacity provided by the pair of existing 345-kV north-south lines from Lon Hill in the east Valley are fully utilized for that purpose. Above this level, power transfer capability will have to be boosted to allow delivery of power to the major load centers along the Rio Grande. Voltage performance is otherwise observed to be generally adequate for power transfer.

# IV.System Dispatch Analysis

As was described in Section II, numerous system upgrades were added to the system dispatch simulation model in order to develop a base case in which all 8760 hourly customer demand could be served in accordance with applicable NERC and ERCOT reliability standards. These projects are listed in Appendix 3. Most of these projects reflect increased local system needs due to increased load by the study year of 2018, above and beyond the projects that were included in the 2012 reliability models from which the starting case was derived. Many of these local system needs are best met using local projects, and it is not appropriate for these types of solutions to be proposed as part of the LTSA. Local system projects are more likely to meet system needs if they are developed in the context of the five-year transmission planning process. However, in some areas, multiple projects were required in order to adequately reinforce the local grid; in these instances it is possible that the cost-effective solution may be to develop a single, long-lead time project that solves all of the local needs, rather than develop several small solutions.

Based on this analysis, three areas were identified in which local system upgrades indicate a potential need for a long-lead time project.

## A. Import Constraints into Houston

As was noted in the A/C Contingency analysis, growing load in the Houston area is likely to require additional import capacity within the next ten years. Several projects that might be reasonable solutions to this need were identified and evaluated. These projects include:

- A new right-of-way connecting the Fayette and Zenith substations
- A new right-of-way connecting the Salem and Zenith substations
- A new right of way connecting the Lufkin and Canal substations. The Canal substation would be a new substation located along the 345-kV line connecting the Cedar and N Belt substations on Ckt # 99 northeast of Houston.
- A new right-of-way from south of Houston, perhaps from the Hillje substation, to either the W. A. Parish, Zenith or O'Brien substations

Based on this evaluation, it is not clear at this time which of these solutions would be the most cost-effective. The determination of which project to recommend will likely depend on generation development over the next several years. As an example, the last of these solutions would likely be preferred if significant new base-load generation is developed south of Houston (such as the proposed South Texas Project or Victoria nuclear facilities). These Houston import projects are discussed further in the economic analysis in Section V.

## B. Western Williamson County

Reliability analysis using the system dispatch simulation model indicated several 138-kV circuits that are limiting power flows in the western Williamson County and Hill Country areas. The new right-of-way connecting the Kendall, Gillespie, and Newton substations, included in the CREZ plan designated by the PUCT, will provide potential solutions for many of these issues. In near-peak-load hours, in the vicinity of Leander, in western Williamson County, several 138-kV lines were limiting power-flows required to reliably serve load. One potential solution was developed for this region:

- Install a new 345-kV to 138-kV autotransformer at the Lampasas substation;
- Upgrade the 138-kV circuits from Lampasas to Burnet13 to a conductor rating of 393 MVA;
- Install a new 138-kV right-of-way from Burnet13 to Leander.

## C. Cooke and Grayson Counties

Several system upgrades were required in the development of the reliable system dispatch simulation model base case in the area north of Dallas in Cooke and Grayson counties (near the border between Texas and Oklahoma). This area is west of the Valley substation, but there is no 345-kV service in this region. One potential solution would be a new 345-kV east-west connection starting from a tap in the new CREZ line connecting Oklaunion and West Krum, near the Valley View substation, and terminating at the Valley South substation. From this line, new 345-kV substations could be created and connected to the underlying 138-kV system. Potential locations for new 345-kV/138-kV autotransformers include the Valley View and Payne substations. Evaluations of this project in the system dispatch simulation model also indicated potential improvements in overall system efficiency.

In addition, the following three areas were evaluated due to local congestion and system conditions.

## D. Brenham Area

The Brenham area is generally served radially from the Fayette substation, and load growth in this area may result in a need for an additional 345-kV connection. One potential solution could be to network the Salem substation, possibly by creating a new 345-kV right-of-way to the Sandow or to the Zenith substations. The new right-of-way from Salem to Sandow would also provide an outlet pathway for generation from the new coal facility (Sandow 5) at that location. Due to recent load reductions and generation additions at Sandow, additional transmission outlet from this area might be helpful. An additional benefit of a new right-of-way from Salem to Zenith is that it would provide a new import pathway into the Houston area. Adding a 345-kV substation and 345-kv/138-kv autotransformer at the Bellso13 substation could also support system needs in the Bellville area. These alternatives are evaluated further in the discussion of the economic analysis portion of the study (Section V).

## E. Columbus Area

The results of the system dispatch simulation analysis also showed significant congestion in the area around Columbus due to the local 69-kV network there providing a parallel pathway to flows on higher-voltage circuits. One potential solution for this would be to convert the 69-kV network from Blessing to Columbus via El Campo and Altair to 138-kV. By itself, this project showed limited benefits in the system dispatch simulation results, but from a load-flow point of view, converting a long, weak, networked 69-kV line to 138-kV and adding some 138-kV/69-kV autotransformers would likely improve local voltage support and reliability. However, if a significant amount of new base-load generation is developed south of the Columbus area, as would be the case if either the new nuclear units at South Texas Project or Victoria are built, then this 138-kV pathway would present a parallel pathway for flows on new higher voltage circuits. In this case, a better approach for the Columbus area would likely be to reinforce the area from the two ends, disconnect it in the middle, and add capacitor banks for reactive support.

## F. West of Waco

Continued development along the west side of Waco will cause increasing congestion resulting from constraints in the 138-kV and 69-kV systems in McLennan, Bosque, and Coryell counties. One possible solution is to develop a new right-of-way connecting the Comanche Peak substation with the new Newton substation, which is part of the CREZ transmission plan recently ordered by the PUCT. From this new right-of-way, a new 345-138kV substation could be developed in northern Coryell County, with an approximately 40-mile 138-kV line to the existing 138-kV substation Waco_W1_ (bus 3436). Reliability benefits were also noted from an additional line connecting the new circuit from Comanche Peak to Newton with the Elm Mott substation. This circuit could use the existing open position of the right-of-way from Elm Mott and Whitney.

# V. Economic Analysis

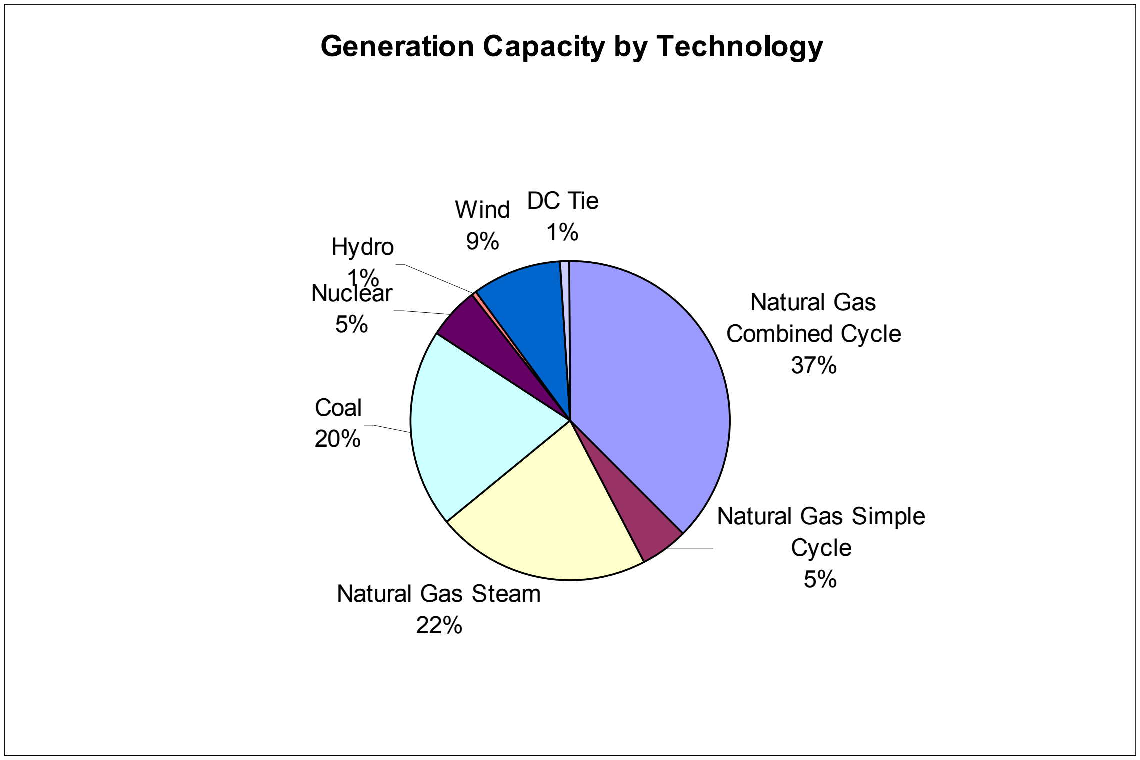
In order to evaluate future potential economic transmission projects in ERCOT, incremental generation over the relevant ten-year planning horizon must be added to the system dispatch simulation input database. This is necessary because the additional generation will be required to reliably serve customer demand, yet the generation component of the ERCOT market structure will impact the economic potential of future transmission projects. The size, technology, efficiency, and location of these generation units will have an effect on the benefits derived from potential transmission projects. As a result, it is necessary to make generation addition assumptions in order to evaluate the economic benefits of transmission projects over the relevant time period.

The following section describes the generation expansion methodology used in this analysis. This methodology is designed to provide sufficient information for the purposes of developing generation scenarios to evaluate the potential economic benefits of transmission projects. This analysis is based on a specific and limited set of assumptions and is not intended to reflect every issue that affects generation investment decisions by the market. Accordingly, it is neither designed, nor intended, to suggest specific generation market opportunities or market structures. Rather, it is only intended to create a necessary input to the analysis used to evaluate the potential economic impact of certain transmission projects over the relevant ten-year planning horizon.

## A. Generation Development Alternatives

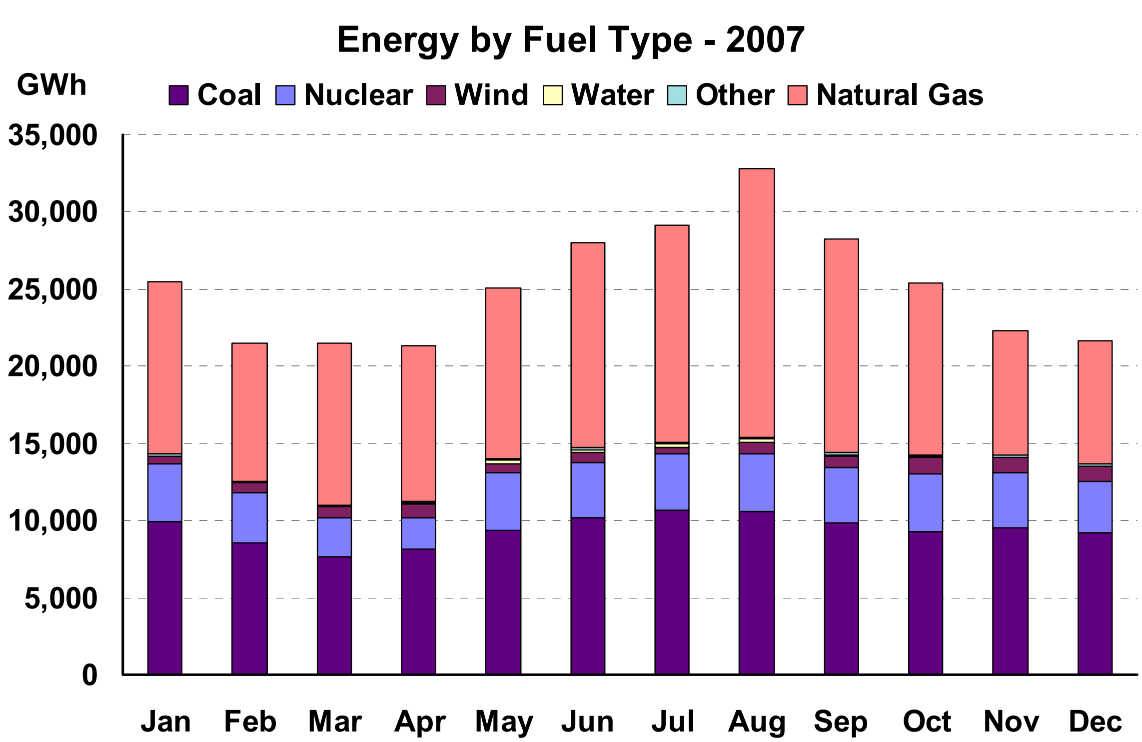
ERCOT has a target reserve margin, an amount of generation capacity above forecasted peak load, so that load can be served reliably given the potential for extreme weather, load forecast error, generation outages, and other factors. This target reserve margin is currently 12.5%. For the economic analysis portion of this Long-Term System Assessment, it is assumed that generation development will result in the ERCOT region maintaining at least this reserve margin through the study year. Given this assumption, the types of generation development for each scenario must be determined.

The following chart shows the generation capacity in ERCOT broken down by technology from the starting case for this LTSA. A breakdown of the actual energy provided by fuel type in ERCOT for 2007 is provided in the next chart. These charts indicate that ERCOT is dominated by natural gas generation, and much of this natural gas generation is combined-cycle technology. This type of generation is called intermediate generation, because it is neither base-loaded, nor is it designed to serve only in peaking conditions. There is relatively little quick-start peaking generation, most notably combustion turbine technology, in the ERCOT system. Given the amount of intermediate generation on the system, it is likely that much of the generation development over the next ten years will either




be designed for peaking operation (either quick-start combustion turbine or very flexible combined-cycle technology) or base-load generation.

In a deregulated generation market, generation alternatives that offer the best balance between

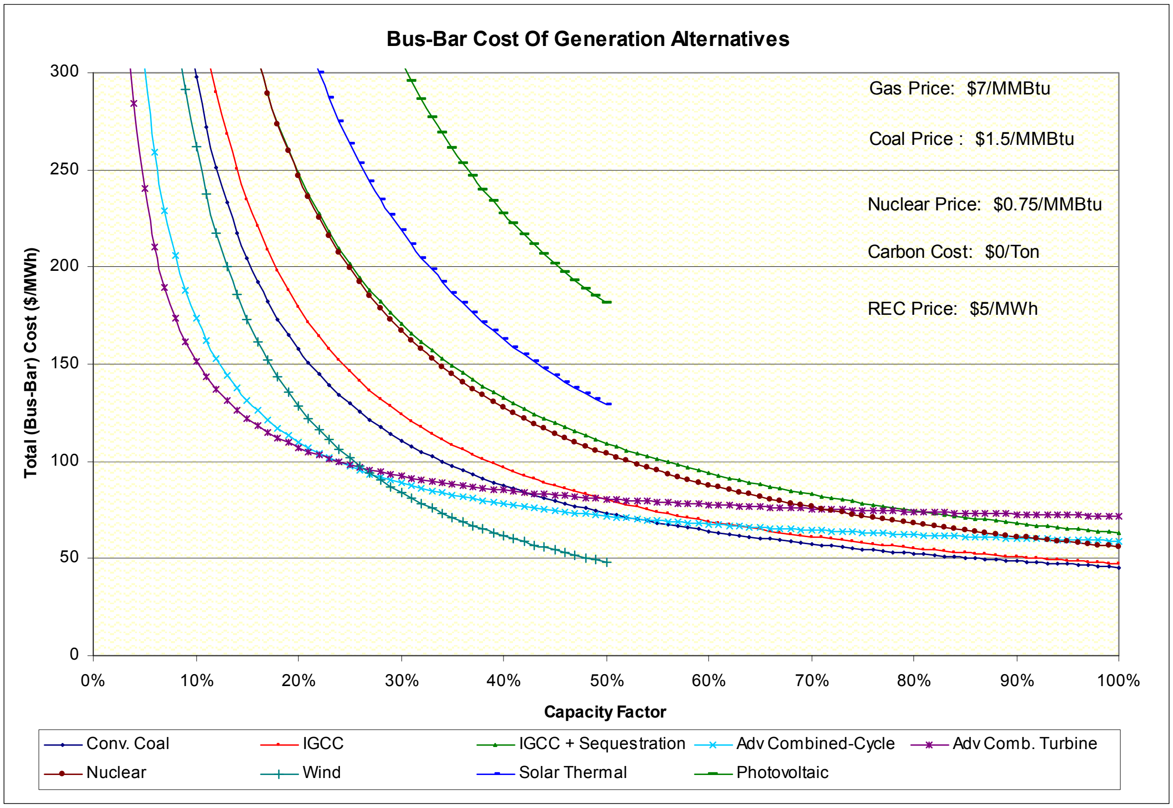


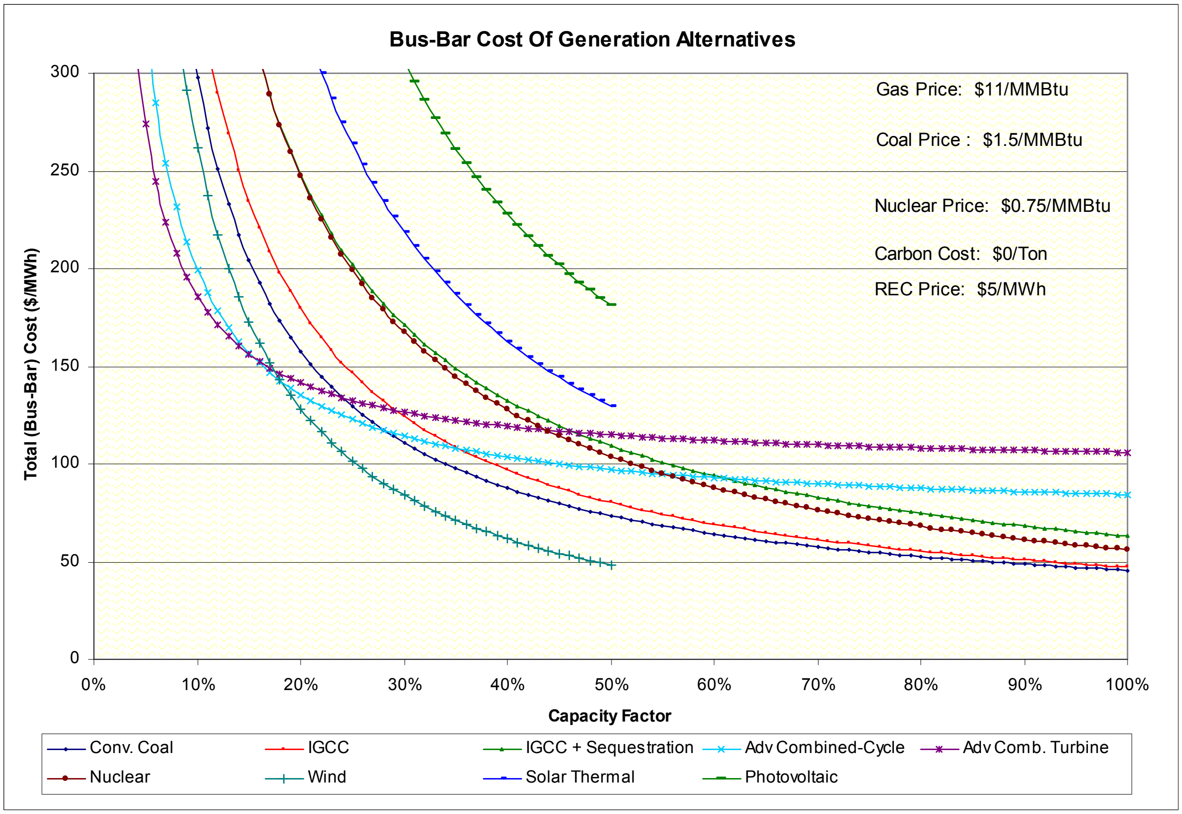
return on capital investment and risk are likely to be developed. Assuming that market prices will not be affected by individual development decisions, profit can be maximized by developing the lowest overall-cost generation technology. Overall costs are made up of construction costs, capital expenses, on-going fixed charges, and variable costs. As such, a bus-bar (or all-in cost) analysis of generation alternatives can provide a reasonable assessment of the profit-potential from different technologies.

The risks associated with generation development result from inaccurate forecasts of future conditions. Fuel price forecasts can affect variable costs of a specific unit, or market prices in general. Changing environmental regulations can lead to increased capital and variable costs. Load forecast errors can lead to reduced demand for energy. Inaccurate expectations of the potential for future technologies may lead to an investment in a technology that is not competitive in the marketplace.

Documentation from the Electricity Market Module of the 2008 Energy Information Agency Annual Energy Outlook provides near-term generation technology options and costs. These options range from established technologies (like scrubbed pulverized coal generation) to new technologies (such as advanced combined cycle and solar thermal) to future technologies (such as integrated gasification and combined cycle with carbon sequestration). Overnight costs, fixed costs, variable costs and unit efficiency estimates are provided. Based on this information, the options for base-load generation in the next ten years are scrubbed pulverized coal, integrated coal-gasification and combined cycle (IGCC), and advanced nuclear. Representative bus-bar charts, indicating the relative all-inclusive costs for the available technologies, are provided below for three different set of input cost assumptions. These charts indicate that at very low capacity factors (below approximately 10%, as viewed along the x-axis), low capital cost units such as combustion turbines are the most economic, i.e., they have the lowest total cost per megawatt-hour. However, at higher capacity factors, the high capital costs of base-load generation are outweighed by their low variable cost, and technologies such as nuclear, pulverized coal, and integrated-gasification combined cycle become the most economically viable.

The amount of base-load generation that is likely to be developed depends on the potential for return on capital investment. In the ERCOT energy-only market, return on investment is derived from energy sales, and the price of these sales is determined by the marginal fuel. Given the current generating fleet in ERCOT, the marginal fuel is typically natural gas, with combined-cycle units setting the marginal cost in most hours, and combustion-turbines or natural gas steam units setting the marginal cost in peak hours. However, with increasing amounts of wind generation being developed, new coal plants being constructed, and several new nuclear plants being planned and designed, it is possible that in the future natural gas will be the marginal fuel in significantly fewer hours than it is today. If this is the case, base-load generation might be earning less revenue in energy sales than they are today.


Bus-Bar Cost Of Generation Alternatives
Gas Price: $7/MMBtu
Coal Price : $1.5/MMBtu
Nuclear Price: $0.75/MMBtu
Carbon Cost: $0/Ton
REC Price: $5/MWh
Total (Bus-Bar) Cost ($/MWh)
300
250
200
150
100
50
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Capacity Factor
Conv. Coal
IGCC
IGCC + Sequestration
Adv Combined-Cycle
Adv Comb. Turbine
Nuclear
Wind
Solar Thermal
Photovoltaic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Gas Price: $11/MMBtu
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Nuclear Price: $0.75/MMBtu
Carbon Cost: $0/Ton
REC Price: $5/MWh
Total (Bus-Bar) Cost ($/MWh)
300
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100
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0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
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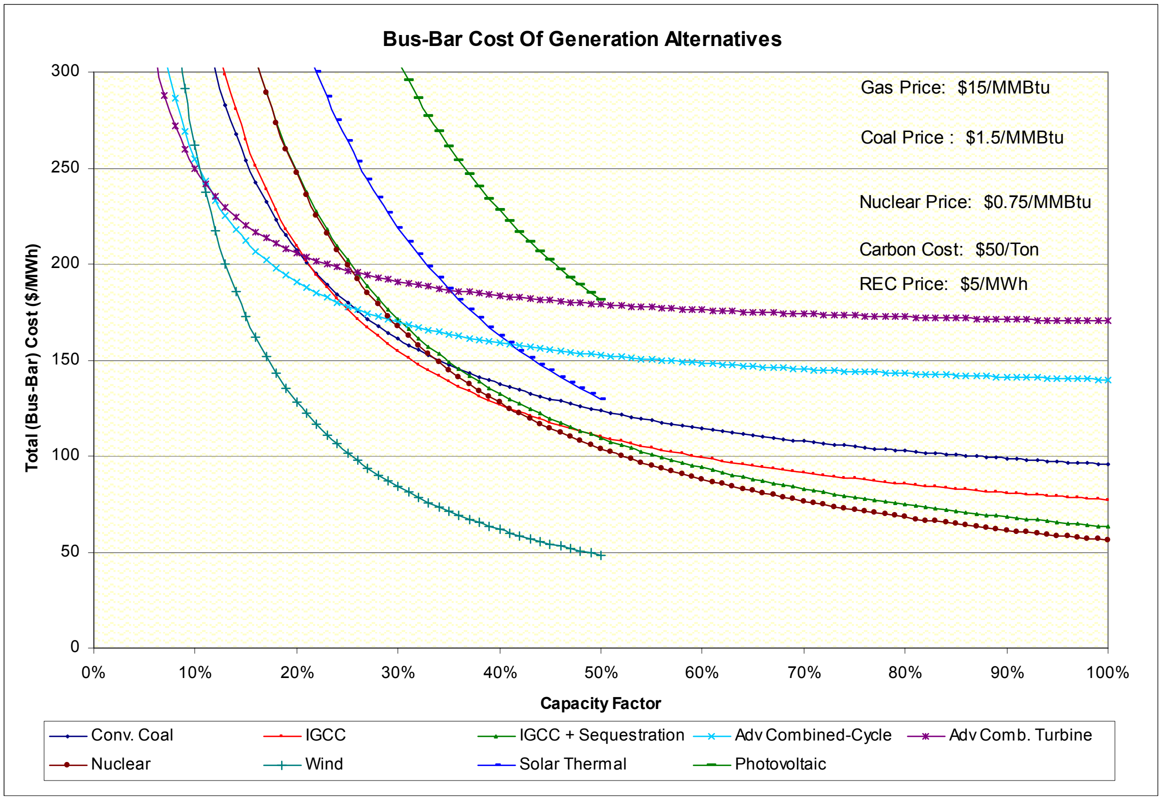
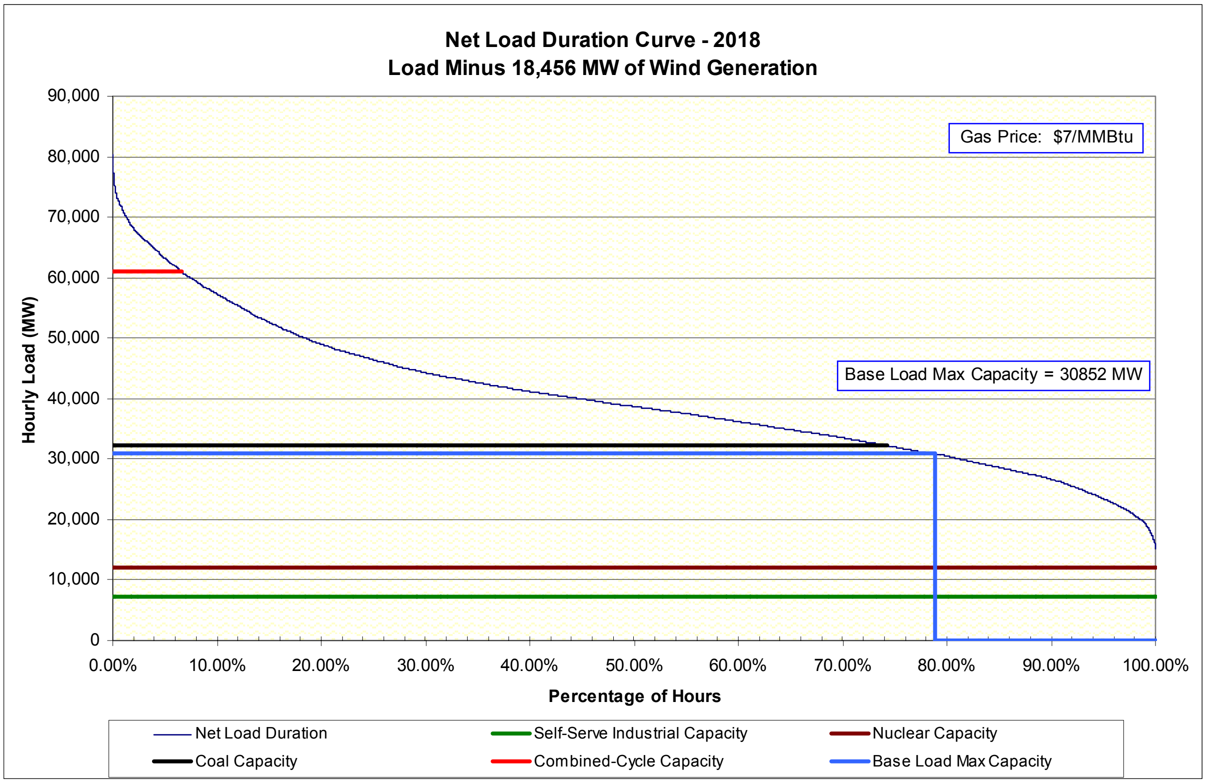
Solar Thermal
Photovoltaic



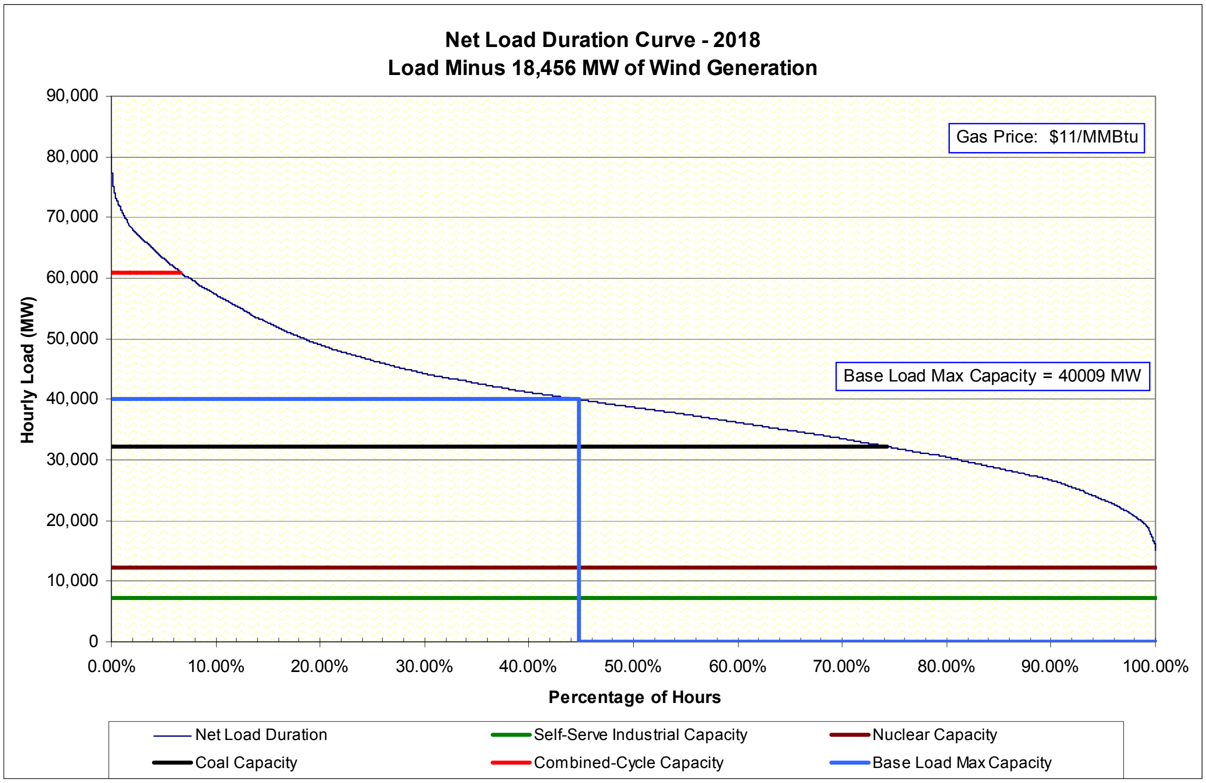

Given a forecast for the price of natural gas and an estimate of the capital cost of new base-load generation, it is possible to calculate the number of hours in which natural gas would have to be the marginal fuel in order for new base-load generation to make an adequate return on investment for that set of conditions. This number of hours can then be plotted on a load duration curve to determine the amount of base-load generation that can be developed and earn a satisfactory return on investment. Examples of these load duration curves are provided in the following charts.

The first of these charts shows the stacked amount of self-serve industrial, nuclear, and coal generation capacity, compared to the load duration curve for 2018 minus representative hourly wind levels (assuming the amount of wind included in CREZ Scenario 2, as ordered by the PUCT). Reducing the load by the hourly wind energy, with its low variable cost, illustrates the load that non-wind generation, with higher variable costs, would be dispatched to serve. With a forecasted $7/MMBtu gas price, this analysis indicates that little, if any, new base-load generation would likely be developed in this scenario. This result is primarily due to the impact of wind reducing the net load levels, and reducing the number of hours in which gas-fired generation is setting the marginal cost of power.




The next chart shows the same load duration curve, but the amount of potential base-load generation is now higher due to the assumed $11/MMBtu gas price. This chart indicates that with a natural gas price of $11/MMBtu and other factors being the same, approximately 8,000 MW of additional base-load generation could potentially be developed.

Assuming the energy-only market will provide sufficient generation capacity to meet the target reserve margin, this process of analyzing the profitability of base-load generation can be used to determine how much prospective generation is likely to be base-load, and the remainder can be assumed to be quick-starting combustion turbine capacity.




It is important to note that any analysis of generation expansion using hourly production-cost models will underestimate the value of combustion turbine technologies. This is especially true in areas that have high penetrations of uncontrolled generation resources such as wind generation. Combustion turbine units can provide increased revenue through bidding into ancillary service markets, such as non-spin service. Also, the amount of wind generation in ERCOT may lead to increased diurnal energy price swings: when wind generation is abundant, low (even negative) energy bids by wind generators will lead to depressed spot energy prices. When wind energy falls off, energy prices are likely to escalate significantly, as generators that remained on-line must make their return in fewer hours, or, in extreme conditions, when on-line generation is inadequate to reliably serve loads. Quick-start technologies can take advantage of these price swings and maximize revenues in a highly variable spot energy market.

## B. Economic Criteria

Transmission projects that significantly reduce congestion will result in improvements in system efficiency (defined as reductions in overall system production costs). By analyzing system efficiency with and without proposed transmission projects, the benefits of these projects can be compared to the estimated project costs. Projects that are expected to result in greater system efficiency gains than the resulting increase in annual transmission revenue requirements charged to consumers are considered to be cost-effective. Based on previous analysis, average first-year revenue requirements charges for transmission projects in ERCOT are approximately 16.5% of the project's estimated capital cost. As such, a transmission project is considered economic and will be recommended by ERCOT if the expected annual reduction in system production costs (i.e., increase in system efficiency) is greater than 16.5% or 1/6 of the capital cost of the project.

## C. Scenario Analysis

The purpose of scenario analysis is to evaluate potential future conditions to determine system transmission needs. The choice of scenarios is based on a need to view a range of potential future conditions (in essence to bound the possibilities), and also to analyze possible future conditions that seem more likely than others to occur. With this in mind, the following scenarios have been analyzed as part of this study:

Nuclear Generation Development

> In this scenario, the impact of additional base-load nuclear capacity on system needs is evaluated. Nuclear additions present unique transmission needs because of the amount of new, very low variable cost generation that is concentrated in specific locations. Locations selected for these nuclear units are based on publicly announced projects currently in the permitting process.

Natural Gas Prices ($7, $11, $15/MMBtu)/Additional Coal Generation

> In these scenarios, the transmission impacts of changes in the price of natural gas are evaluated. Over the last 5 years, the spot and forward prices of natural gas have been more volatile than other generation fuel commodities. Due to the dominance of natural gas generation in the ERCOT market, increased gas prices do not alter unit dispatch significantly. However, increased gas prices are likely to lead to additional development of base-load generation, as the increased gas price is likely to lead to increased electricity prices, and increased return on investments made in new, low-variable-cost generation. Given that additional nuclear generation development is being analyzed in a separate scenario, these higher natural gas prices are assumed to result in new development of coal generation, specifically integrated-gasification combined-cycle (IGCC) generation.

Additional Renewable Generation (Wind, Solar)

> Scenarios were evaluated with additional wind resources (up to the level of wind considered as Scenario 3 in the recent Competitive Renewable Energy Zone study) and for additional solar resources in the McCamey area. Based on a review of available maps of solar resources in the State of Texas, the McCamey area was found to present the greatest potential for solar thermal development.

Imposition of Carbon Constraints

Carbon constraints are analyzed in the context of several of the scenarios listed here. Carbon allowance prices up to $100/ton are evaluated for their impact on transmission congestion and system needs.

Development of Energy Storage and Plug-In Hybrids

The incorporation of compressed air energy storage in West Texas and the use of plug-in hybrids are evaluated for their impact on transmission needs.

In each of these scenarios, transmission congestion reports were analyzed to determine the potential locations for system upgrades. Based on this review of system congestion, potential projects were developed and included in the model to determine the impact on generating unit operating costs. Also, projects that were identified in both the A/C Contingency Analysis and in the system dispatch analysis were evaluated for economic benefits. The results are discussed in the following sections. The transmission projects described are depicted in Figures 6 – 10.

## D. Nuclear Generation

### 1. Scenario Development

The nuclear development scenario was created by adding six nuclear plants to the economic base case. The six units consisted of Comanche Peak 3 and 4, South Texas Project 3 and 4, and the Victoria City Nuclear Plant, all of which are publicly announced potential future generation projects for the ERCOT region. The capacity and the location of each unit are shown in the following table:

| Unit Name | Capacity (MW) | County | Region |
|---|---|---|---|
| Comanche Peak 3 | 1,600 | Somervell | North |
| Comanche Peak 4 | 1,600 | Somervell | North |
| South Texas Project 3 | 1,362 | Matagorda | South |
| South Texas Project 4 | 1,362 | Matagorda | South |
| Victoria City Nuclear 1 | 1,531 | Victoria | South |
| Victoria City Nuclear 2 | 1,531 | Victoria | South |

The total capacity of the nuclear plants added was 8,986 MW, and these additions increased the size of the generation fleet to 111,807 MW. This amount corresponds to a total summer-peak capacity of

96,056 MW after the application of the appropriate monthly capacity factor multiplier and adjusting the capacity of wind to 8.7% of its nameplate rating. This generation capacity provides a reserve margin in August 2018 of 16.5%. For this scenario, the natural gas price was set to $7/MMBtu.

The initial stage of the scenario analysis included the identification and implementation of the necessary upgrades for the reliable export of electric power from the added plants. Several 345-kV lines in the immediate vicinity of the proposed nuclear units had to be upgraded in order to enable the units to export their power throughout the year. These upgrades are representative of the transmission upgrades that will be developed as part of the interconnection studies for these units. Integrating the Victoria City nuclear units required the construction of two new substations and a number of 345-kV lines in the surrounding area in order to make the power deliverable. The South Texas Project units were connected to the system through 345-kV transmission lines to the existing Hillje and the new Victoria City substations. In addition, several of the 345-kV circuits that transfer power towards Houston had to be upgraded in order for the units to be able to export their power.

A number of projects were considered for economic evaluation. These projects were selected based on the locations of the new nuclear units and an evaluation of congestion reports from the system dispatch model. These projects are discussed in the following sections.

### 2. Comanche Peak to Newton 345-kV Circuit

The 95-mile 345-kV double-circuit transmission line connecting Comanche Peak to Newton was evaluated as a possible additional pathway for power from the new Comanche Peak units. This project would provide a new path for power to flow towards the southern and central parts of the ERCOT system and is estimated to cost $180 million. Production cost savings from this line were $120 million per year with all four nuclear units in-service at Comanche Peak. However, when only two or three units were present at Comanche Peak (i.e., when none or only one of the new nuclear units were included in the case) the annual production cost savings were $15 million and $21 million respectively, indicating that the benefits from this project are dependent upon the development of both of the new nuclear units at Comanche Peak.

### 3. Lampasas to Leander Circuit

This project is discussed in Section IV as a possible solution for system reliability needs in western Williamson County. The 138-kV upgrades and additional circuit from Burnet13 to Leander were added to the case with the circuit from Comanche Peak to Newton in order to determine the impact of the additional 2 nuclear units at Comanche Peak on the effectiveness of these upgrades. The addition of these circuits reduced production costs by an additional $24.5 million. Given the estimated construction cost for these projects of $41 million, the production cost savings noted in this scenario are likely to be sufficient to justify the Lampasas to Leander circuits as economic projects. As these projects may also be the most cost-effective solution for solving reliability needs in the western Williamson County area, these production cost savings would be incremental to the reliability benefits noted in Section IV.

### 4. Victoria Switch to Zenith 345-kV Circuit

In order to integrate the proposed Victoria nuclear units into the ERCOT system, a new substation was created in the model along the existing circuits from Elm Creek to Hillje (Victoria Switch). To evaluate the economic benefits from an additional pathway north from this new substation, a 110-mile 345-kV single-circuit transmission line was modeled to the Zenith substation, located west of Houston. Such a line was expected to provide benefits by establishing a new path for power to be imported from the nuclear facilities to Houston, while at the same time providing relief to the high loading observed on the lines from Hillje to O'Brien and Hillje to W.A. Parish. The production cost savings from this addition was $23 million. Given the estimated cost of this project ($165 million), this project was not considered economic.

### 5. Houston Import

Two other options for additional import pathways into Houston were modeled in this scenario. The first of these was a new 167-mile 345-kV single-circuit transmission line from Lufkin to Canal, where Canal is a proposed substation tapping the 345-kV line connecting the Cedar and N Belt substations on Ckt # 99 in the northeastern portion of the CenterPoint service territory. Adding this circuit to the case resulted in production cost savings of only $8.5 million. As this circuit is estimated to cost $300 million, this option was not considered economic in this scenario.

The second option evaluated was a 65-mile 345-kV single-circuit structure from Fayette to Zenith. This option resulted in only $5.4 million in production cost savings. Given the cost of this project, approximately $105 million, it is also not considered economic in this scenario. The reason these two projects resulted in so little production cost savings is likely due to the improvements required in order to integrate the South Texas Project and Victoria nuclear units. By upgrading lines heading north from these facilities (upgrades that are representative of what will likely be included in the interconnection projects for these units), the import needs of Houston were met. Additional import capacity into Houston was therefore not needed.

### 6. Cooke and Grayson Counties

The proposed new 345-kV right-of-way from Valley-View to Valley South in Cooke and Grayson County discussed in Section IV was evaluated in this scenario for cost-effectiveness. This project is estimated to cost approximately $107 million, and its inclusion in this scenario reduced annual production costs by $30 million. As such, this project would be considered economic in this scenario.

## 7. Inter-zonal Low Impedance Circuits

The potential economic value of a low-impedance backbone between the North and Houston zones was evaluated by modeling 765-kV single-circuit transmission lines connecting the Navarro and Hillje substations (North to South) and the Fayette and Zenith substations (West to East). The production cost savings from these lines was $37 million. These savings are not sufficient to justify a 765-kV project of this magnitude, and they indicate the value of additional North – South transmission capacity. A likely reason for the low production-cost savings is the placement of large, low-variable-cost generating plants close to the major load centers (Dallas, Houston and San Antonio), reducing the need for power transfers between ERCOT congestion zones.

Another low impedance backbone was evaluated by modeling a 765-kV transmission line connecting Comanche Peak to Victoria Switch. This path consisted of a 765-kV single-circuit connecting the following buses: Comanche Peak to Newton, Newton to Zenith and Zenith to the Victoria Switch described above. The estimated cost of this project is $1,316 million. The total production cost savings from this option was $166 million. This amount is significantly larger than the result for the connection from Navarro to Hillje and from Fayette to Zenith. However, much of this production cost savings results from just one of these circuits: the Comanche Peak to Newton line accounts for $125 million of the $166 million savings. Since these benefits are only slightly higher than those provided by the 345-kV transmission line from Comanche Peak to Newton discussed above ($120 million), the use of 765-kV for this portion of the circuit is not justified. The remaining portions of this circuit (from Newton to Zenith, and then to the Victoria Switch) only result in $45 million of production cost savings, indicating that they are not economic.

## 8. Carbon Allowance Analysis

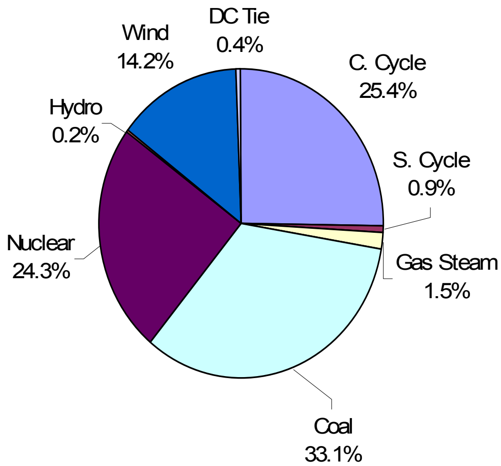
Four different carbon emission scenarios were evaluated in conjunction with this nuclear scenario. Carbon allowance costs of $10, $25, $50 and $100 per ton were included in model runs to determine the impacts on transmission congestion and system needs. These increases in carbon allowance prices did not lead to identification of any new economic transmission projects except for the line from Fayette to Zenith, which is a potential source of new import capacity into Houston. With a carbon allowance price of $100, this project resulted in a production cost savings of $54 million.

The following table shows the changes in production costs savings that result from the Fayette to Zenith project and the Hillje to Navarro and Fayette to Zenith projects with increasing costs for carbon allowances.

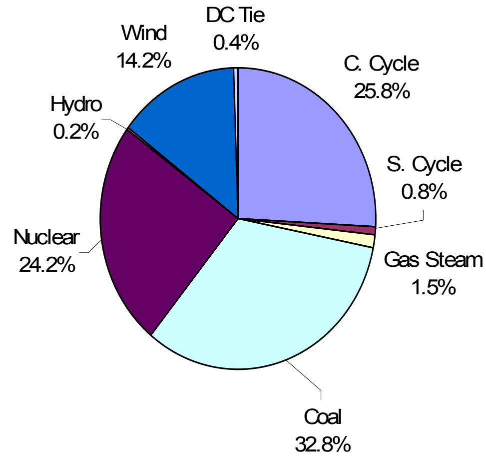
| Production Cost Savings ($ Million) | | |
|---|---|---|
| **Carbon Tax ($/ton)** | **Fayette to Zenith** | **Hillje – Navarro; Fayette - Zenith** |
| **0** | 4 | 37 |
| **10** | 7 | 42 |
| **25** | 16 | 27 |
| **50** | 7 | 23 |
| **100** | 54 | 55 |

In addition, the charts on the following page depict the energy produced by technology for these levels of carbon allowance prices. These charts indicate that only 1.5% of the annual energy production is shifted from coal plants to other technologies when the carbon tax is increased to $25 per ton. A more dramatic shift is noted when the allowance price is increased to $100 per ton; in this scenario the energy production from coal plants is cut by one-half.

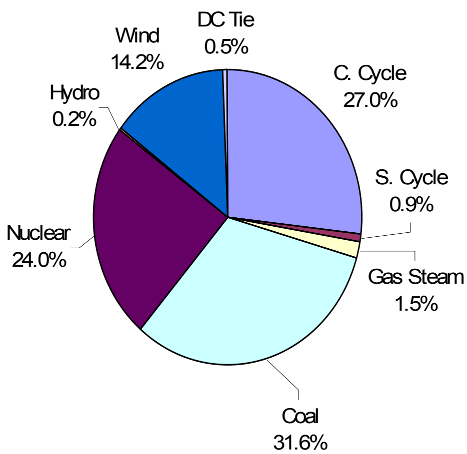
These reductions are consistent with the fact that as the carbon allowance price is raised by $1/ton, the cost of energy produced using conventional coal will increase by approximately $1/MWh, and the cost of energy produced using gas-fired combined-cycle units will increase by approximately $0.60/MWh. So the difference between the price of coal-produced energy and the price of gas-fired combined cycle produced energy will be reduced by approximately $0.40/MWh for every $1/ton increase in the carbon emission allowance price. With a natural gas price of $7/MMBtu, the difference in the variable cost of coal-produced energy and gas-fired combined cycle energy is approximately $30/MWh, so, in this scenario, a carbon allowance price of greater than $75/ton is required to make the variable cost of gas-fired generation competitive with that of coal-fired generation. At that price or above, depending on the relative spot prices of delivered coal and natural gas, changes in system dispatch are likely to result in changes in transmission congestion, and thus changes in the economic value of transmission projects designed to relieve congestion.



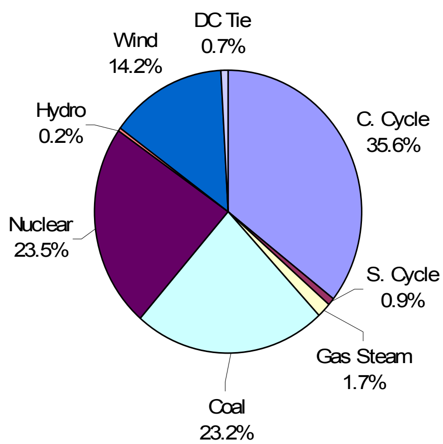

Percentage of Total Annual Generation by Unit Type: Carbon Allowance Cost: $0/Ton



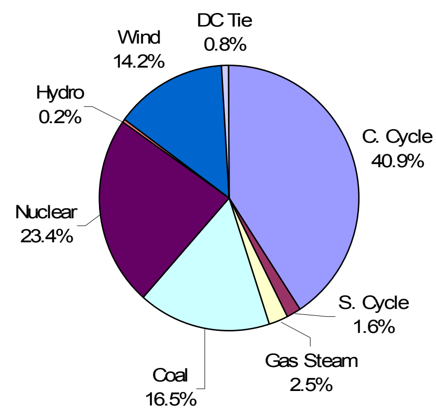

Percentage of Total Annual Generation by Unit Type: Carbon Allowance Cost: $10/Ton




Percentage of Total Annual Generation by Unit Type: Carbon Allowance Cost: $25/Ton




Percentage of Total Annual Generation by Unit Type: Carbon Allowance Cost: $50/Ton




Percentage of Total Annual Generation by Unit Type: Carbon Allowance Cost: $100/Ton

## E. Gas Price Scenarios/Additional Coal Generation

### 1. Scenario Development

The impact of natural gas prices on transmission system needs was evaluated by modeling scenarios with gas prices of $7/MMBtu, $11/MMBtu and $15/MMBtu. As gas-fired generation is more expensive than the other dominant sources of energy in ERCOT (coal and nuclear), increasing the price of natural gas does not affect the ranking of variable costs of these technologies. Rather, the main impact of increases in natural gas prices is to change the profitability of base-load (solid-fuel) generation. As natural gas prices increase, it is reasonable to expect that more solid-fuel generation will be developed. The analysis conducted to determine how much solid-fuel generation will be developed was presented in Section V(A). Since nuclear generation additions were analyzed in their own scenario, much of the solid-fuel generation additions in this scenario were assumed to be coal-fired. Also, given the public resistance to conventional pulverized-coal technology following recent announcements of new pulverized coal plants in ERCOT, the new coal plants in this scenario were assumed to be integrated-gasification combined cycle (IGCC) plants. This technology uses a gasification process to extract a combustible gas from coal. The combustible gas is then used to fire a combined-cycle generating plant. IGCC plants are expected to be more efficient than pulverized-coal plants, and thus will produce energy at a lower variable cost. However, the plants themselves are likely to be more expensive to build. The bus-bar charts provided in Section V(A) show that the all-in or total costs of the two technologies per megawatt of generation are very similar at high capacity factors.

Without adding any generation to the base case, the capacity reserve margin would be lower than ERCOT target reserve margin of 12.5%. At a natural gas price of $7/MMBtu, the analysis described in Section V(A) indicates that no additional base-load generation is likely to be developed. For this scenario, 2,800 MW of combustion turbine generation capacity were added at several locations throughout the system where there are existing generation resources to achieve an acceptable level of generation capacity. For the $11/MMBtu scenario, 11,000 MW of new base-load generation was added to the case. This generation consisted of two new nuclear units (at the South Texas Project facility) and 14 600-MW IGCC units, connected to substations either in the lignite belt or at locations with existing coal generation facilities. For the $15/MMBtu scenario, three additional 600-MW IGCC units were added.

Numerous transmission projects were evaluated in these scenarios to find cost-effective solutions to the congestion created by the additional base-load generation. These projects were selected based on the system dispatch model output and based on system needs as indicated by the reliability analysis and other scenarios.

## 2. Lufkin to Canal

This project consists of a new 167-mile 345-kV single-circuit transmission line from Lufkin to Canal, where Canal is a proposed substation tapping the 345-kV line connecting the Cedar and N Belt substations on Ckt # 99 in the northeastern portion of the CenterPoint service territory. Adding this circuit to the $7/MMBtu case resulted in production cost savings of $39 million. This circuit is estimated to cost approximately $300 million, so in this scenario this project would not be considered economic. However, in the $11/MMBtu scenario this project resulted in $86 million in production cost savings, and in the $15/MMBtu scenario this project resulted in $231 million in production cost savings. This project becomes economic as natural gas prices increase and additional coal-fired generation is added to the system.

3. Fayette to Zenith

This project consists of a new 65-mile 345-kV single-circuit structure from Fayette to Zenith, with an estimated cost of $105 million. In the $7/MMBtu scenario, this project resulted in $28 million in economic benefits, making it cost-effective. However, in the $11/MMBtu scenario, this project only saved $16 million in production cost savings, making it slightly below the current ERCOT criteria for economic projects. In the $15/MMBtu scenario, this project resulted in $71 million in production cost savings, making it economic.

## 3. Salem to Twin Oak

This project would provide additional transmission capacity for the new coal resources located in the lignite belt south of Dallas in the $11/MMBtu and $15/MMBtu scenarios. This approximately 90-mile project is estimated to cost $153 million. In the $7/MMBtu scenario, this project resulted in $17 million in production cost savings, indicating it would not be cost-effective. However, in the $11/MMBtu scenario, this project resulted in $82 million in production cost savings, and in $174 million in the $15/MMBtu scenario, making it economic in both.

Based on these results, an additional circuit from Salem to Zenith was added to this project. The circuit from Salem to Zenith is approximately 50 miles of new 345-kV right-of-way, at a cost of approximately $80 million. With this project, production cost savings were $68 million and $167 million in the $11/MMBtu and $15/MMBtu scenarios, respectively. This additional project would be economic in both of these scenarios.

## 4. Inter-zonal Low Impedance Circuits

The benefits of a low-impedance pathway from the coal areas of North Texas to the Houston area was evaluated by modeling a 765-kV line from the Navarro substation south of Dallas connecting to the Fayette to Zenith circuit described above. The Navarro substation is a project designated in the CREZ order that will join the 345-kV circuits that run from Big Brown to Venus with the line that run from Limestone to Watermill. A new CREZ line will also terminate at this substation. As such, this substation provides a solid connection for power generation in the area south of Dallas.

Production cost savings from this project were $109 million and $165 million for the $11/MMBtu, and $15/MMBtu scenarios, respectively. These savings are sufficient to justify this project, estimated to cost $670 million, given these forecasted fuel prices. In order to determine the benefits of having a stronger connection between new base-load generation and a low-impedance backbone transmission project, two of the 600-MW IGCC plants were relocated to the Navarro bus. With this change, production cost savings became $208 million, and $472 million in the $11/MMBtu, and $15/MMBtu scenarios, respectively. These increased savings clearly indicate the benefits of establishing strong direct connections between new base-load generation and new transmission capacity.

## 5. Carbon Allowance Analysis

To provide an assessment of the change in economic benefits from some of the projects above due to increased carbon allowance prices, four changes cases were developed from the case with $11/MMBtu natural gas price, with escalating prices for carbon allowances. For each of these cases, the Lufkin to Canal project, the Fayette to Zenith project, and the Salem to Twin Oak project were modeled. The results are provided in the following table.

| Production Cost Savings ($ Million) | | | |
|---|---|---|---|
| **Carbon tax / $/ton** | **Lufkin to Canal** | **Fayette to Zenith** | **Twin Oak to Salem** |
| **0** | 86 | 16 | 82 |
| **10** | 121 | 46 | 93 |
| **25** | 112 | 40 | 85 |
| **50** | 117 | 20 | 105 |
| **100** | 145 | 68 | 81 |

These results do not show a clear trend as carbon allowance prices increase.

## F. High Wind Generation Case

### 1. Scenario Development

The LTSA High Wind Generation case was constructed by increasing the amount of wind energy in the CREZ zones to match the levels specified for CREZ Scenario 3 by the PUCT. Overall, 6,403 MW of new wind capacity was added to bring the total installed wind capacity of the High Wind Case to 24,622 MW. To achieve the target reserve margin for ERCOT, two nuclear units totaling 2,724 MW at the South Texas Project were added, as were 3,295 MW of combustion gas turbines at buses across the system, mostly at sites with existing thermal plants and at new CREZ buses in west Texas.

Several transmission projects were evaluated as part of this analysis, based on system needs as determined through the reliability analysis and through other economic scenarios, and based on model output. These projects are discussed in the following sections.

### 2. Lufkin to Canal

As in the other scenarios, this project consists of a new 167-mile 345-kV single-circuit transmission line from Lufkin to Canal, where Canal is a proposed substation tapping the 345-kV line connecting the Cedar and N Belt substations on Ckt # 99 in the northeastern portion of the CenterPoint service territory. This circuit is estimated to cost approximately $300 million. The production cost savings from this line were $32 million, indicating that it would not be cost-effective.

### 3. HVDC Connecting CREZ Central A and Zenith

The design specifications of this line were obtained from the transmission plan for CREZ Scenario 3 submitted by ERCOT in the PUCT docket No. 33672. This line was modeled as a 3,000 MW high-voltage direct current line connecting the CREZ Central A substation located near the existing Tonkawa bus to the Zenith substation west of Houston. Such a line would provide bulk power transfers from the West zone directly to the Houston zone. The flow on this line was set by the system dispatch model on an hourly basis, based on the relative cost of power available in the west versus the cost of power near Houston.

Production cost savings resulting from this line were $52 million. The cost of this project is over $950 million, indicating that it is not economically justified.

### 4. Fayette to Zenith

The 65-mile 345-kV single-circuit line from Fayette to Zenith was modeled in this scenario. The cost of this project is approximately $105 million. As this project resulted in $21 million in annual production cost savings, it would be considered economically justified in this scenario.

## 5. Inter-zonal Low Impedance Circuits

To see the value of a low-impedance circuit between the North, South and Houston zones, a 765-kV project connecting the Navarro and Hillje buses (North and South) with the Fayette and Zenith buses, was modeled. This scenario also required small upgrades near the termination points to relieve congestion. These projects have an aggregated cost greater than $1,100 million. Adding this project resulted in production cost savings of $109 million, indicating that it was not justified.

This low-impedance circuit provides an indication of the maximum benefits that may be available from projects that provide additional transfer capacity between the North, South, and or Houston zones in this scenario. Less expensive inter-zonal projects, such as those constructed using 345-kV, would likely result in lower production cost savings due to the higher impedance of the conductors.

## 6. Carbon Allowance Scenarios

To determine the impact of potential carbon regulations on the benefits provided by transmission improvements in this scenario, escalating carbon allowance prices were modeled. The results of these are provided in the following table.

| Production Cost Savings ($ Million) | | | |
|---|---|---|---|
| **Carbon Tax ($/ton)** | **Lufkin to Canal** | **Fayette to Zenith** | **Hillje – Navarro; Fayette - Zenith** |
| **0** | 32 | 22 | 110 |
| **10** | 42 | 26 | 120 |
| **25** | 67 | 49 | 143 |
| **50** | 80 | 84 | 127 |
| **100** | 48 | 29 | 186 |

These results do not indicate a trend as carbon allowance prices increase. It is possible that the reason that the production cost benefits from the Lufkin to Canal and Fayette to Zenith projects drop when the carbon allowance price is raised to $100/ton is that at this price the combined cycle facilities become competitive with the coal units and start to run as base-load units. As a result, the coal units are more likely to be called upon to dispatch following daily wind generation patterns, resulting in less value for projects that are specifically designed to offset gas generation in the Houston area.

## G. Solar Generation

As of November 30, 2008, there were 863 megawatts of solar projects in the ERCOT interconnection process. To determine the potential transmission system resulting from development of solar projects on the system, scenarios with various levels of solar thermal projects were modeled.

Far West Texas has the best conditions for solar projects within ERCOT, with solar irradiance generally increasing as you travel south and west across Texas. As such, the proposed CREZ substations McCamey A and McCamey C were selected for new solar thermal unit locations in these scenarios. Cases were developed by adding the following amounts of solar energy at the substations: 1.8 GW, 2.7 GW, 3.6 GW, and 4.5 GW. The energy profiles for the solar-thermal plants were developed using 2006 historical direct normal solar radiation measurements obtained from UT-Austin. These radiation measurements were smoothed to simulate a solar thermal plant's thermal inertia. Generally, the plants produced energy from 9 AM to 7 PM, with the bulk of energy being produced from 11 AM to 5 PM. Because the data came from historical measurements, production varied according to weather and time of year. Like the wind plants, the solar plants were modeled with zero variable cost, and the output could also be curtailed if necessary to ensure reliability.

The first phase of the analysis for this scenario was to determine the potential requirements for upgrades in the McCamey area in order to provide adequate local transmission capacity for the additional solar thermal generation. This analysis indicates that no transmission upgrades are required up to a solar thermal capacity of approximately 1,800 MW. This result is caused by the lack of correlation between wind generation and the solar thermal resources in the area. Much of the wind generation occurs in the early morning hours, when solar thermal units would not be generating. As solar thermal generation is increased beyond 1,800 MW, transmission upgrades would likely be recommended. The upgrades that were selected as part of this study are described as follows:

- 1.8 GW Scenario: None.
- 2.7 GW Scenario: Add a single circuit 2-1590 ACSR 345-kV from CREZ substation McCamey C to CREZ substation Central E. The estimated cost of this project is $96 million; the production cost savings is $19 million.
- 3.6 GW: Add a second circuit McCamey A – McCamey C – McCamey D on existing CREZ structures using 345-kV 2-1590 ACSR. Add a single circuit 345-kV 2-959 ACSS from CREZ substation McCamey C to CREZ substation Central E. The estimated cost of these projects is $130 million; the production cost savings is $63 million.
- 4.5 GW: Add a second circuit from McCamey A – McCamey C – McCamey D on existing CREZ structures using 345-kV 2-1590 ACSR. Add a double circuit 345-kV 2-1590 ACSR from CREZ substation McCamey C to CREZ substation Central E. Add a second circuit on existing structures from McCamey C – Central E – Central D – L_Divide and from Twin Buttes – McCamey D. The estimated cost of these projects is $207 million; the production cost savings is $124 million.

The production costs savings values specified above compare the cases with and without the transmission upgrades included in the description. In each of these cases, with the upgrades listed in place, between 93% and 95% of the energy scheduled in the model for the solar thermal plants was used to serve load. The charts on the following page indicate that, to a large extent, the solar generation in these scenarios is replacing natural gas generation.

In the second phase of this analysis, selected transmission projects were evaluated for the case with 1,800 MW of solar projects, to determine the impact of these solar resources on system needs. The results of these analyses are described in the following sections.

### 1. Lufkin to Canal

As in the other scenarios, this project consists of a new 167-mile 345-kV single-circuit transmission line from Lufkin to Canal, where Canal is a proposed substation tapping the 345-kV line connecting the Cedar and N Belt substations on Ckt # 99 in the northeastern portion of the CenterPoint service territory. This circuit is estimated to cost approximately $300 million. The production cost savings from this line were $24 million, indicating that it would not be cost-effective.

### 2. Fayette to Zenith

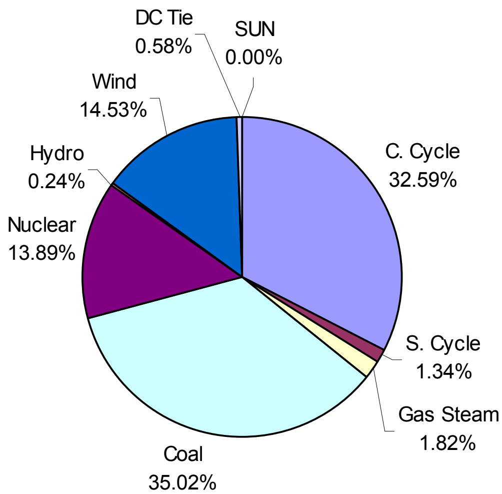
This 65-mile 345-kV single-circuit from Fayette to Zenith is estimated to cost approximately $105 million. Model results indicate that in this scenario this project saves $23 million in annual production costs; as such, it would be considered economic.

### 3. Cooke and Grayson Counties

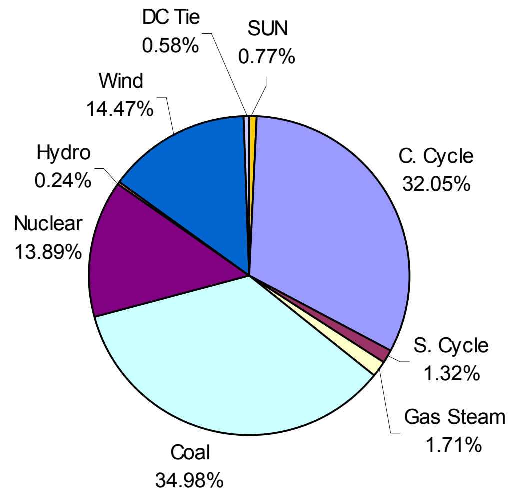
The proposed new 345-kV right-of-way in Cooke and Grayson County discussed in Section IV was evaluated in this scenario for cost-effectiveness. This project is estimated to cost approximately $107 million, and its inclusion in this scenario reduced annual production costs by $5.7 million. As such, this project would not be considered economic in this scenario.

### 4. Inter-zonal Low Impedance Circuits

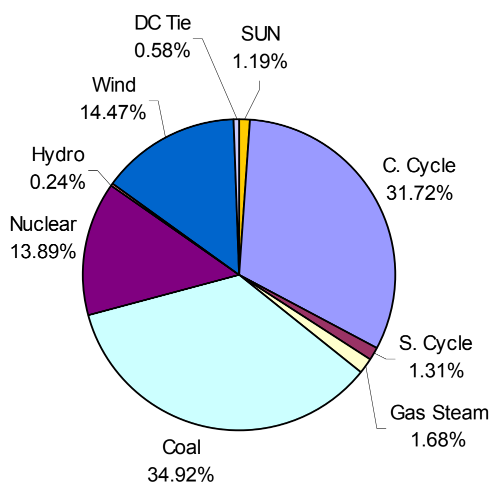
This solution was evaluated to determine the value of a low-impedance circuit between the North, South and Houston zones, a 765-kV project connecting the Navarro and Hillje buses (North and South) with the Fayette and Zenith buses, was modeled. These circuits were modeled the same as in the previous scenario (High-Wind Evaluation). Adding these projects resulted in production cost savings of $91 million, indicating that it was not justified.



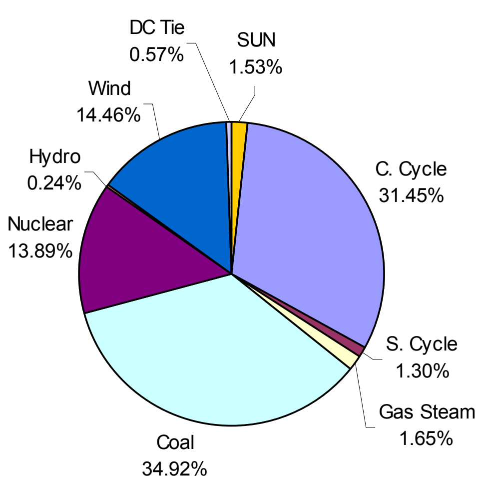

Percentage of Total Annual Generation by Unit Type: 0 MW Solar Generation Capacity



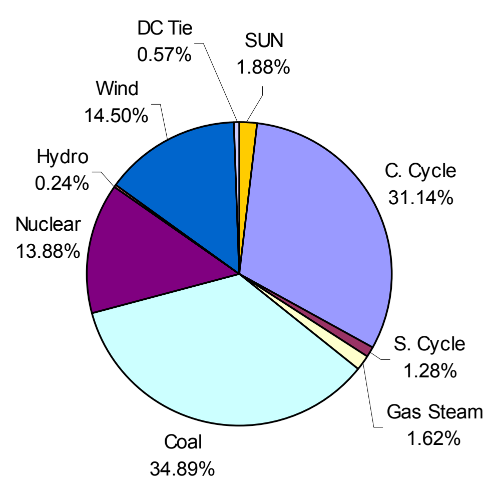

Percentage of Total Annual Generation by Unit Type: 1,800 MW Solar Generation Capacity




Percentage of Total Annual Generation by Unit Type: 2,700 MW Solar Generation Capacity




Percentage of Total Annual Generation by Unit Type: 3,600 MW Solar Generation Capacity




Percentage of Total Annual Generation by Unit Type: 4,500 MW Solar Generation Capacity

5. Carbon Scenario Summary

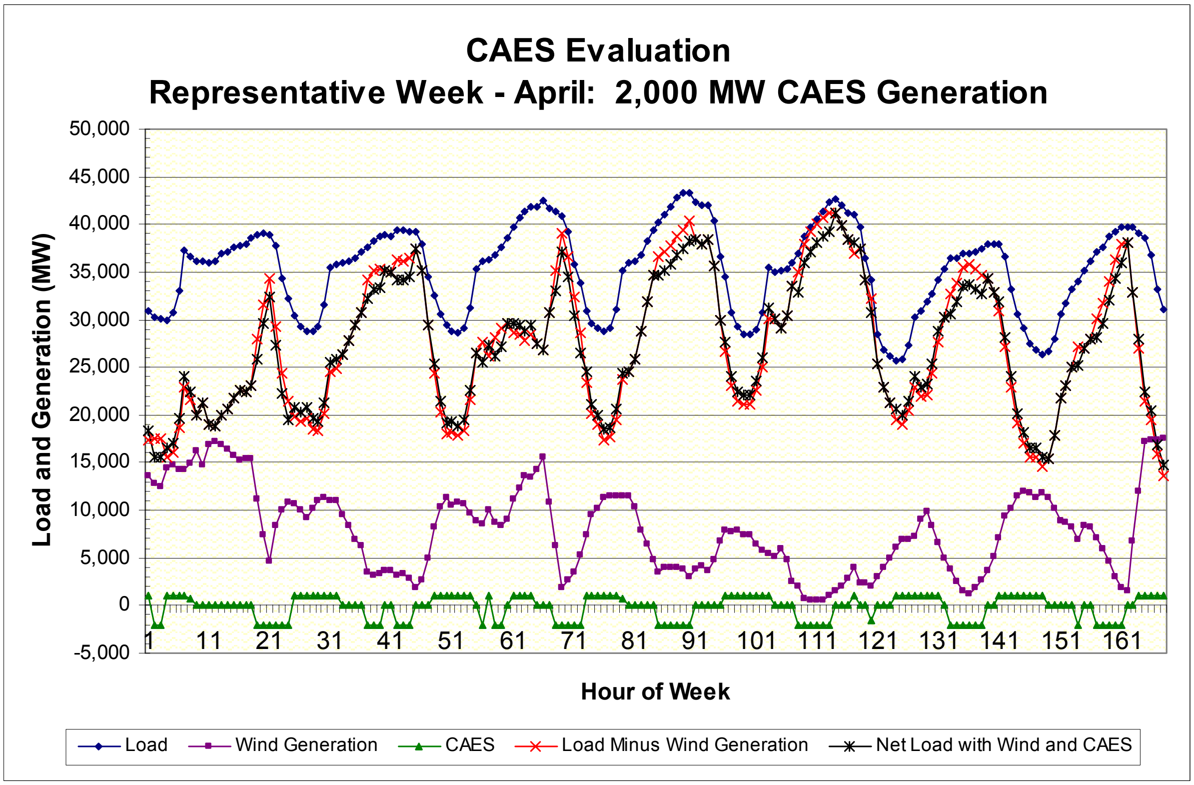
To evaluate the impacts of carbon allowance costs on some of the solutions evaluated in this scenario, the simulation was run with four levels of escalation carbon fees. The results of these are provided in the following table.

| Production Cost Savings ($ Million) | | | |
|---|---|---|---|
| **Carbon Tax ($/ton)** | **Lufkin to Canal** | **Fayette to Zenith** | **Hillje – Navarro; Fayette - Zenith** |
| **0** | 24 | 23 | 91 |
| **10** | 26 | 24 | 90 |
| **25** | 31 | 37 | 97 |
| **50** | 42 | 49 | 73 |
| **100** | 81 | 93 | 221 |

These results indicate that these projects generally increase in value as carbon allowance prices increase.

## H. Compressed Air Energy Storage

Conventional compressed air energy storage (CAES) units were modeled in the system dispatch model to determine to what extent these units will reduce the need for large transmission improvements resulting from wind generation development in west Texas. Two CAES scenarios were evaluated: one with two 250-MW CAES units, and one with four 500-MW CAES units. In the model, these CAES units were located at new CREZ substations in West Texas. Both of these scenarios were evaluated with the amount of wind included in the recent CREZ ruling by the PUCT (18,456 MW) and with approximately the amount of wind in the higher scenario 3 included in the development of CREZ plans by ERCOT (24,000 MW). Based on information made available by EPRI and other institutions, 0.69 MWh of energy is required to be stored in CAES for each 1 MWh of generation. The heat rate of the CAES turbine was assumed to be 3,995 Btu/Kwh. The CAES units were scheduled to charge and discharge every day, with the daily schedule optimized based on the wind generation forecast. The compressor units were sized to reach full storage in 8 hours, and this storage provided 6 hours of generation at maximum capacity. The sizing of the compressor, storage, and generator are typically optimized for every project. These generic values were selected to allow an initial evaluation. A typical week of loads and CAES operation are depicted in the following chart.




With CREZ Scenario 2 levels of wind, comparing the case with no CAES units with the case containing 2,000 MW of CAES generation, wind generation curtailment was reduced by 0.4% (i.e., 0.4% more of the total amount of potential wind generation available was utilized by the system dispatch model). This represents an increase of 246 GWh of wind generation. However, in this case wind generation curtailment was already very low, due to the presence of the CREZ transmission upgrades as well as the 2018 loads (as compared to 2012 loads which were utilized in the CREZ Transmission Optimization Study).

With CREZ Scenario 3 wind levels (approximately 24,000 MW of wind generation capacity) and the base case transmission system, wind generation curtailment is significantly higher (approximately 9.1%) with no CAES generation. The inclusion of 500 MW of CAES generation resulted in 200 GWh of additional wind generation (a reduction in wind generation curtailment of 0.24%). With 2,000 MW of CAES generation, wind generation curtailment was reduced to 8.14%, an increase of 830 GWh of wind generation.

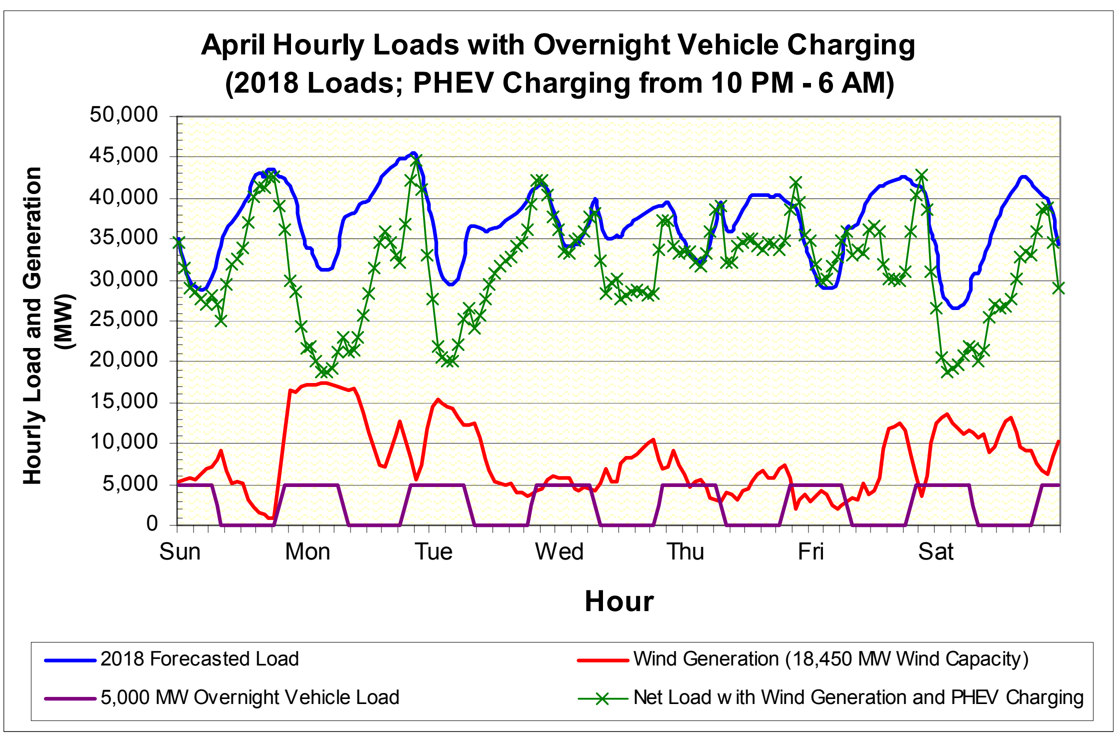
## I. Plug-In Electric Vehicle Impacts

The potential impact of the increased use of plug-in hybrid cars or plug-in electric vehicles (PHEV) was evaluated as part of this study. Current typical PHEV systems store approximately 10 KWh of energy. It is not known how long it will take each of these cars to fully recharge. If they are designed to recharge in 4 hours, then each PHEV will increase system load by 2.5 KW. Four hundred of these vehicles would increase load, if they were all charging at the same time, by 1 MW.

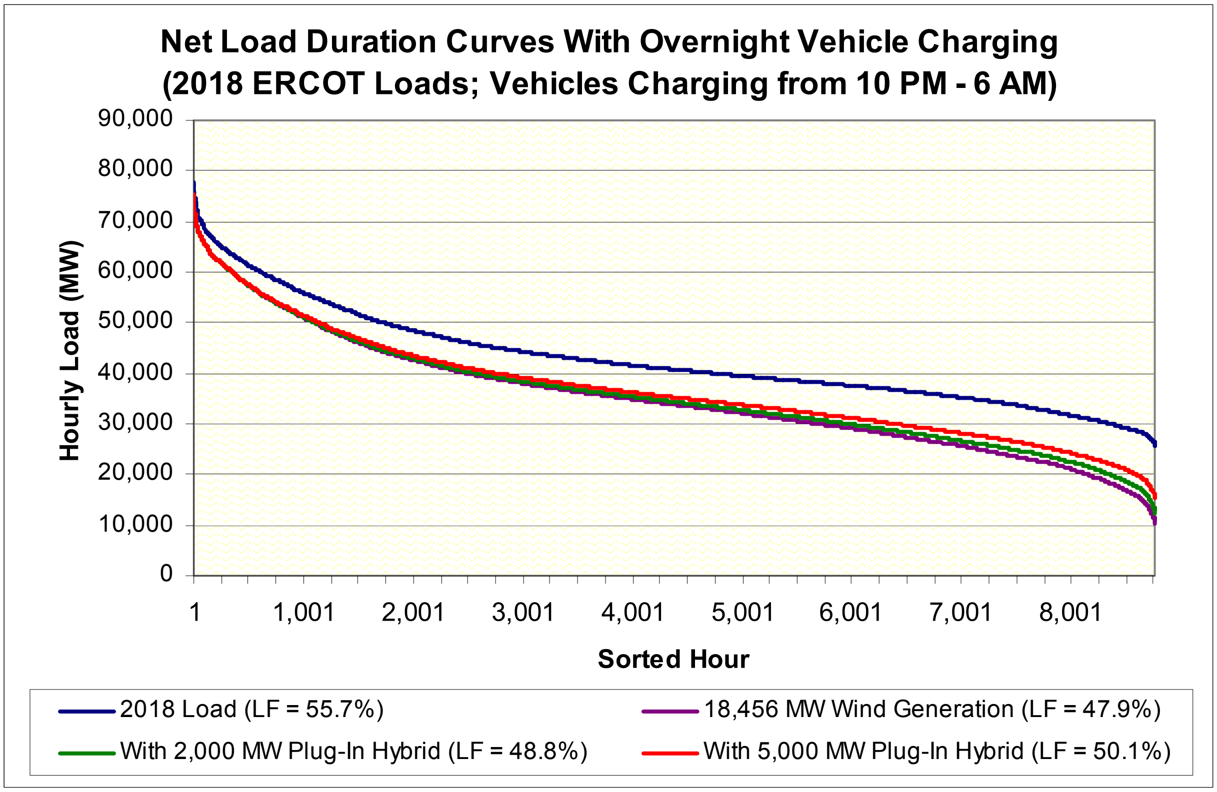
One way to reduce the impact of these vehicles on system load would be to establish a schedule such that vehicles charging at night do not all charge at once. Spreading the overnight charging across eight hours would significantly reduce the impact of PHEV (in this example reducing the average impact of each vehicle to only 1.25 KW). With such a system in place, 1.6 million PHEV would result in an increased overnight load of 2,000 MW, and 4 million PHEV (approximately 20% of all vehicles in Texas) would increase overnight loads by 5,000 MW.

Following this example, the next two charts depict the potential impact of PHEV on system loads. The first chart shows the potential hourly impact of PHEV on system load. This chart depicts one week of hourly system loads as forecasted for April 2018. The blue line represents the hourly load forecast; the red line depicts a typical wind generation pattern for April (based on the installation of 18,450 MW of wind generation capacity); the purple line represents the load from overnight charging of 4 million PHEVs; and the green line shows the net of the first three. This chart shows that even with 4 million PHEV, the impact on system loads appears to be manageable.

The second chart depicts four sorted load-duration curves. The top line, in blue, represents the 2018 ERCOT load forecast; the bottom line, in purple, represents the sorted load-duration curve for the load forecast minus the expected wind generation from 18,450 MW of wind generation capacity. The two inner lines, in green and red, represent the sorted load duration curves for the load forecast minus the



wind generation forecast, plus the impact of 2,000 MW of PHEV load and 5,000 MW of PHEV load, respectively.




The above chart also provides the load factor for each curve. The load factor is the percentage of the total demand compared to the peak hour times 8,760 hours in a year. Scheduling the PHEV load so that it is highly correlated with wind generation could further reduce the impact on net load.

One potential impact from the increased use of plug-in hybrid vehicles would be increased loading on distribution transformers. By increasing the off-peak loading on distribution transformers, it is possible that the peak rating of these devices may be affected. This potential impact will require further study by ERCOT Distribution Service Providers.

# VI. Conclusions

The following conclusions can be made from the study of system transmission needs as analyzed for the year 2018, as described in this report:

- As with the LTSA completed in 2006, this assessment indicates a need for additional future import capacity into Houston. Although an import pathway into Houston from the west, such as from the Fayette to the Zenith substations, was generally cost-effective across a range of scenarios included in this study, the intent of the LTSA is to inform the ERCOT five-year study process, and the specific pathway should be reviewed and selected as part of that process. This study did not indicate an additional need for a new import pathway into the Dallas/Fort Worth area as was shown in the previous LTSA. This change may be the result of the additional import capacity into Dallas/Fort Worth from the west resulting from the new transmission lines ordered by the Public Utility Commission of Texas as part of the transmission plan to serve Competitive Renewable Energy Zones.
- Load growth in two areas (north of Dallas in Cooke and Grayson County and in western Williamson County) may result in the need for long-lead time transmission projects in the next ten years. Any transmission project evaluated for these areas in the five-year planning process should be compared to projects evaluated in this LTSA for long-term cost-effectiveness.
- The economic benefits from most transmission projects were dependent on the location of new sources of generation, fuel costs, and emissions allowance costs. Few projects were cost-effective across a range of different potential future scenarios. Given the uncertainty associated with future development of base-load generation, it is not reasonable to plan large inter-zonal projects at this time.
- Large inter-zonal projects are generally not economic in scenarios that include several new nuclear units. This is due to the fact that the likely locations of new nuclear units are close enough to major load centers that additional inter-zonal projects are not required. An additional connection from Comanche Peak towards the south will likely be economic if two new units are constructed at this location.
- Large inter-zonal projects are economic if new coal units are built in the general areas considered in this study and gas prices are consistently at the high levels seen earlier in 2008. These projects would be required to transport energy from expected, remote coal plant locations to major load centers, especially Houston.
- The pathways from Fayette to Zenith (west of Houston) and from Valley View to Valley South (through Cooke and Grayson Counties) were economically justified in many of the scenarios

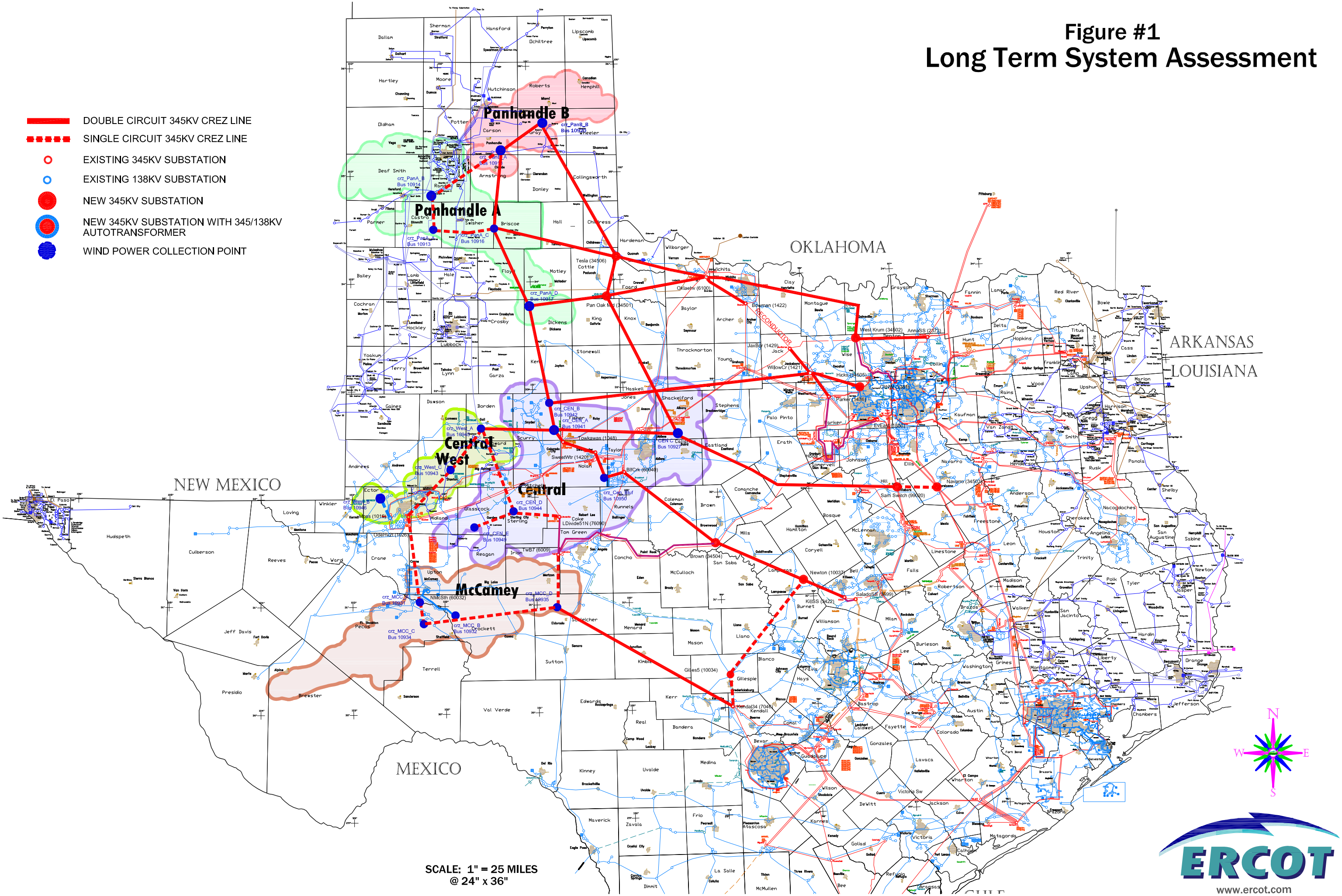
evaluated. These projects should be considered in the next Five-Year Plan to determine if they can be included in the recommended projects based on existing system conditions.

- No system improvements beyond the planned CREZ facilities are likely to be needed to incorporate up to 1,800 MW of solar generation capacity in the McCamey area. With up to 4,600 MW of solar generation capacity, the only identified transmission projects are located in and around the McCamey area. System dispatch model results indicate that increasing amounts of solar generation in these scenarios primarily offset gas generation.
- The implementation of a carbon tax is not likely to have a significant impact on transmission system needs unless carbon emission allowance prices are above $50/ton. Above this amount, the variable cost of gas generation could become competitive with that of coal generation, resulting in significant changes in generating unit dispatch.
- Compressed Air Energy Storage can have a beneficial impact on deliverability of wind energy from West Texas by storing wind energy when wind is abundant and releasing that energy back to the grid when the transmission system is not congested. The value of these projects is more likely to be derived from market prices rather than from overall system production cost savings.
- Plug-In Hybrid Electric Vehicles are not likely to have a significant impact on system transmission needs in the near future, although these devices may have an impact on local transmission needs and on distribution system requirements in the next ten years.

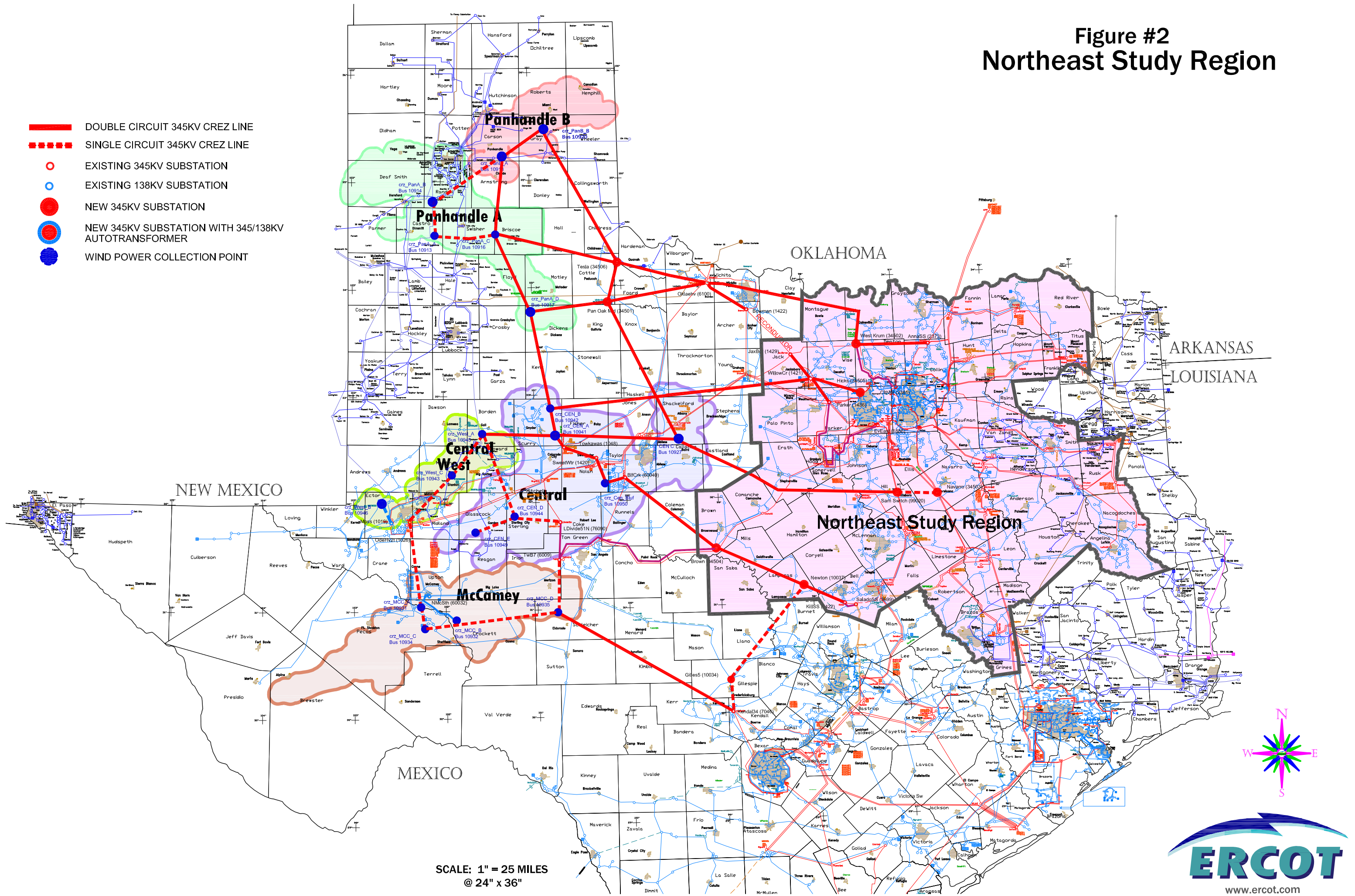
The above conclusions, and this report in general, are based on high level assumptions and are intended to inform the five-year planning process, which provides a more detailed review of specific transmission projects. The technologies and locations of generation projects assumed in the analyses that support the above conclusions may not reflect all issues that necessarily must be considered and/or affect generation development decisions. Accordingly, this report is intended to provide guidance to ERCOT and ERCOT market participants in evaluating system needs, and is not intended to suggest changes to market policy or support changes to market activities.

# Figures

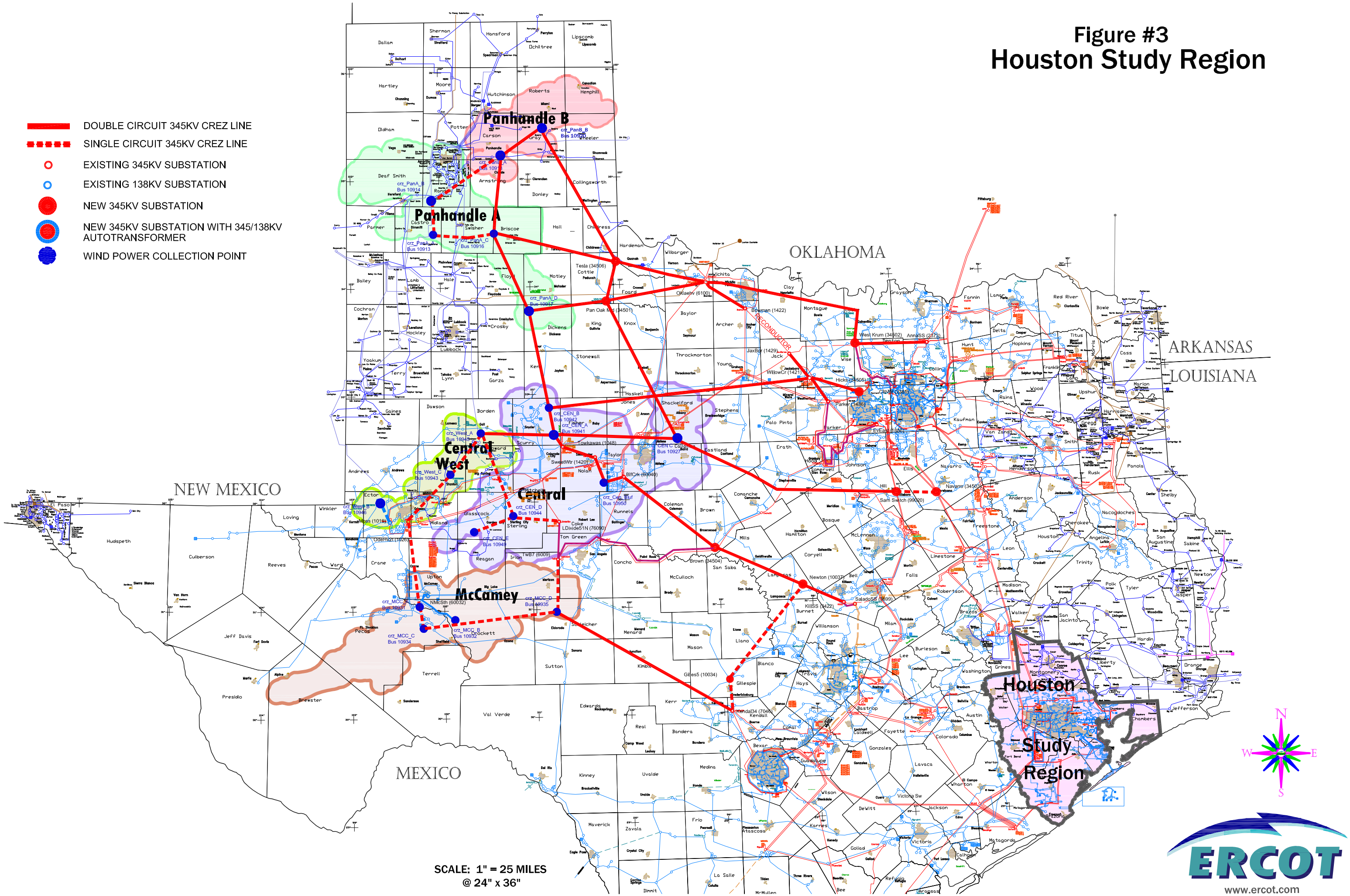
# Figure #1
# Long Term System Assessment



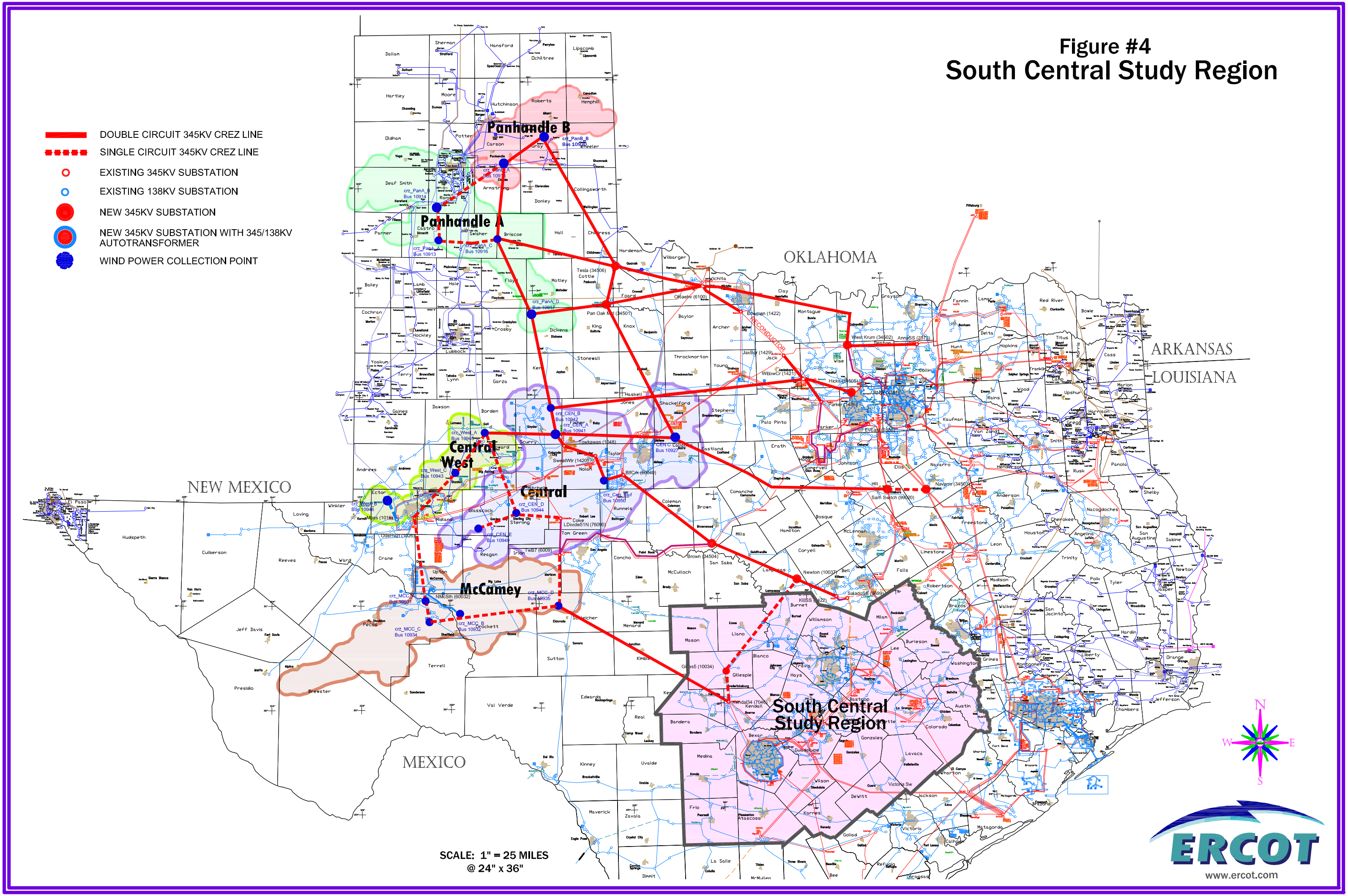
# Figure #2
## Northeast Study Region

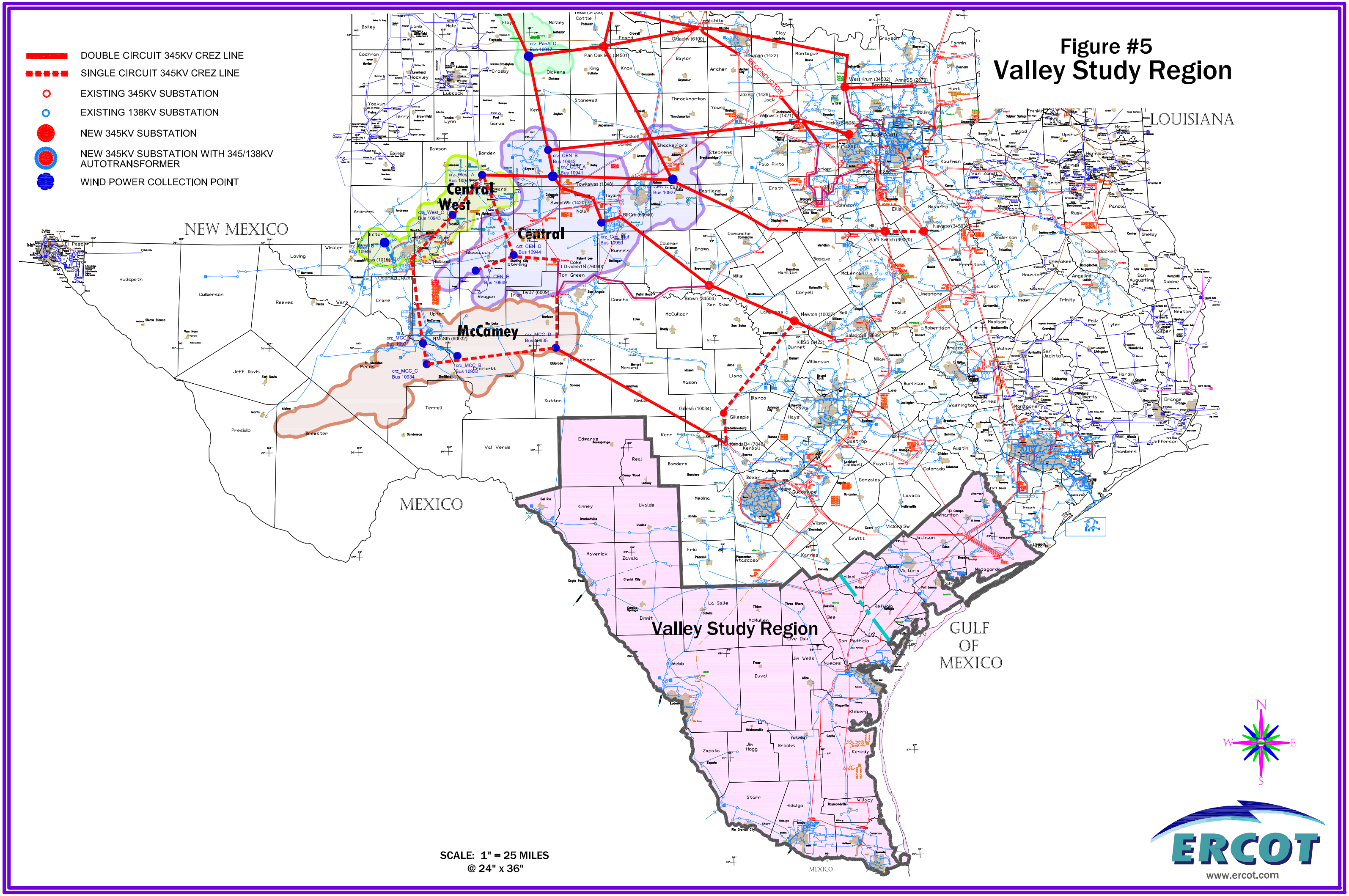


# Figure #3
# Houston Study Region



## Figure #4
# South Central Study Region






# Figure #5
## Valley Study Region

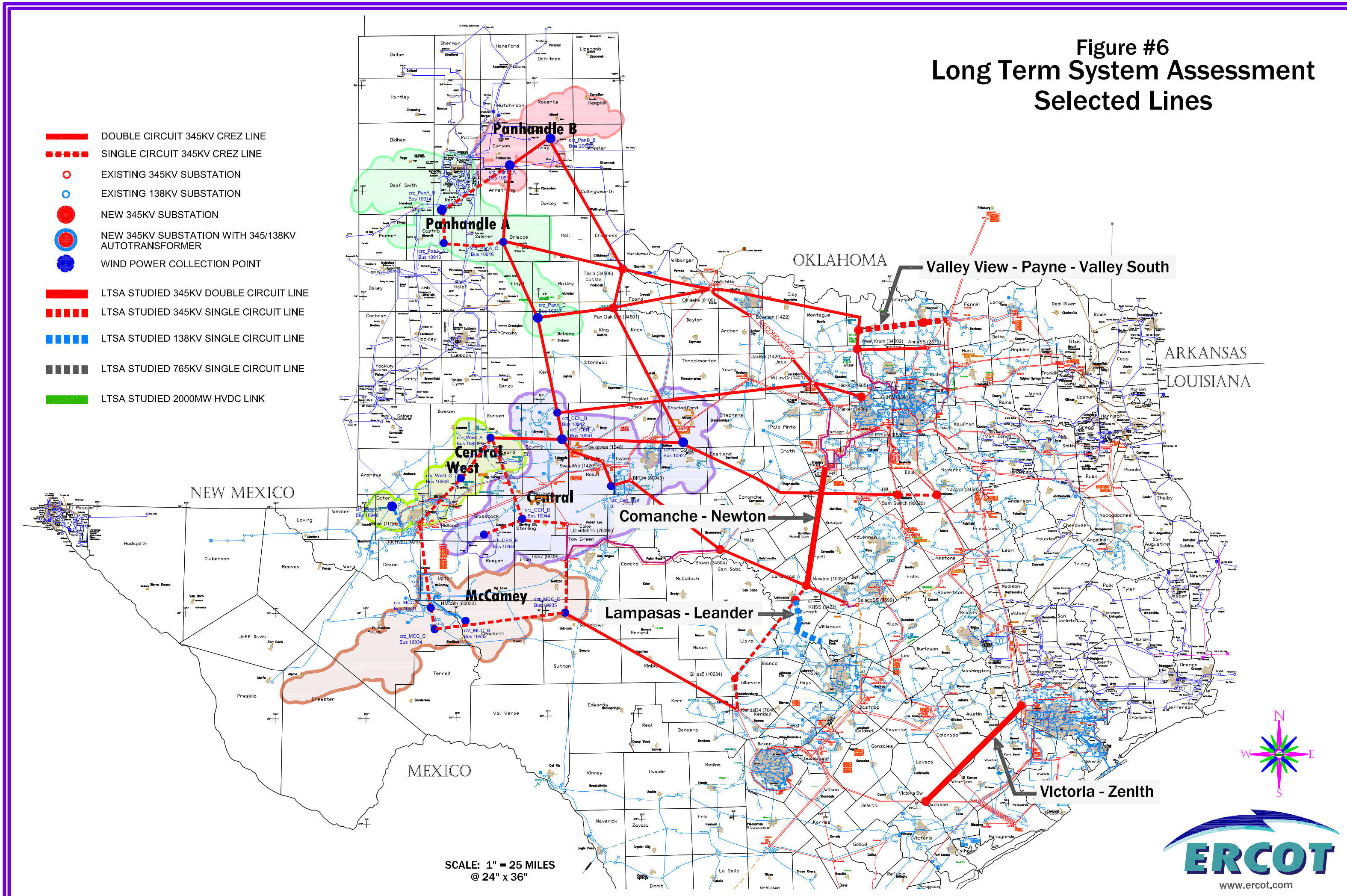
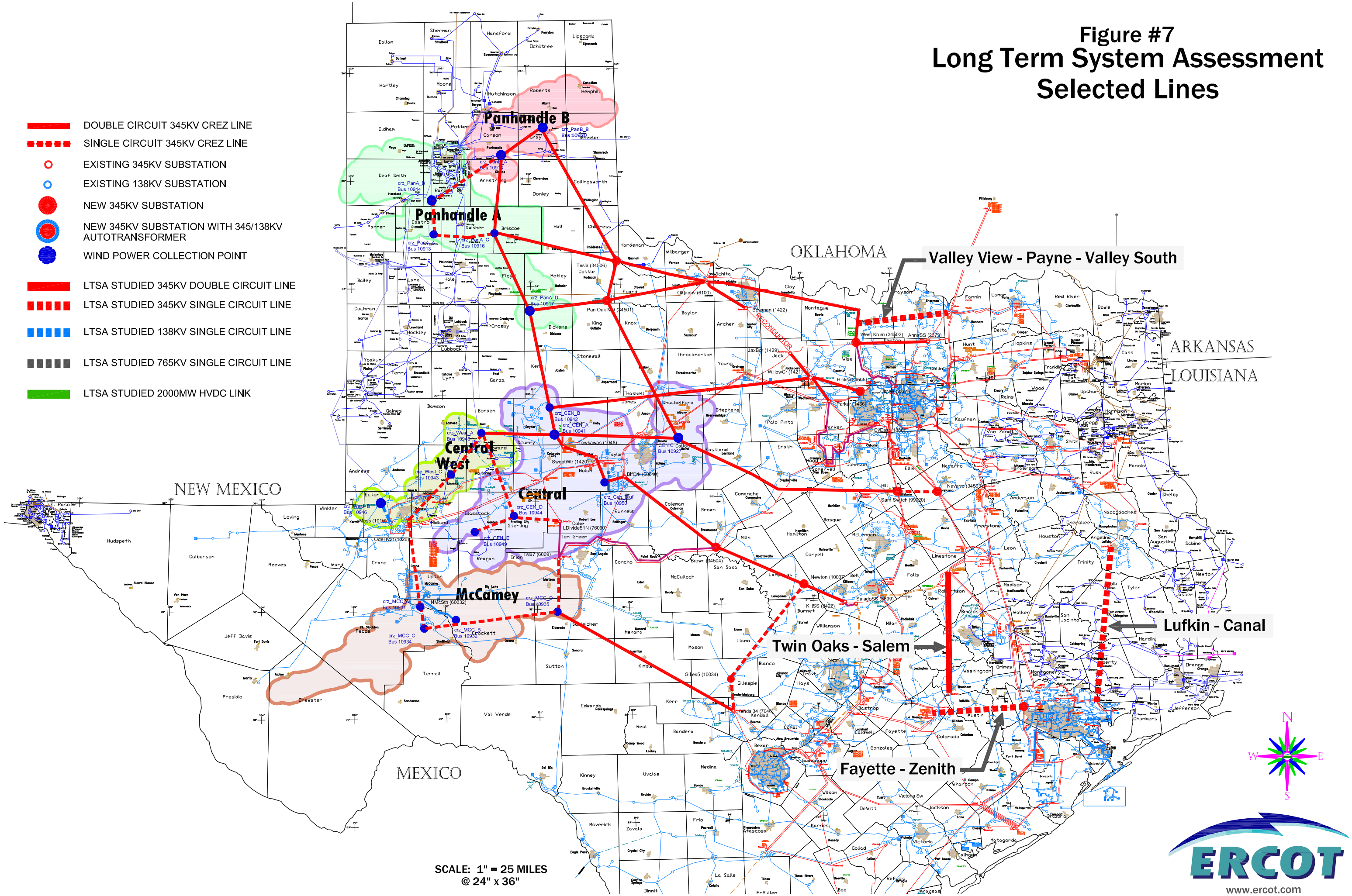


Figure #6
Long Term System Assessment
Selected Lines
DOUBLE CIRCUIT 345KV CREZ LINE
SINGLE CIRCUIT 345KV CREZ LINE
EXISTING 345KV SUBSTATION
EXISTING 138KV SUBSTATION
NEW 345KV SUBSTATION
NEW 345KV SUBSTATION WITH 345/138KV AUTOTRANSFORMER
WIND POWER COLLECTION POINT
LTSA STUDIED 345KV DOUBLE CIRCUIT LINE
LTSA STUDIED 345KV SINGLE CIRCUIT LINE
LTSA STUDIED 138KV SINGLE CIRCUIT LINE
LTSA STUDIED 765KV SINGLE CIRCUIT LINE
LTSA STUDIED 2000MW HVDC LINK
Panhandle B
Panhandle A
Central West
Central
McCamey
Valley View - Payne - Valley South
Comanche - Newton
Lampasas - Leander
Victoria - Zenith
OKLAHOMA
ARKANSAS
LOUISIANA
NEW MEXICO
MEXICO
SCALE: 1" = 25 MILES
@ 24" x 36"
ERCOT
www.ercot.com

# Figure #7
## Long Term System Assessment Selected Lines



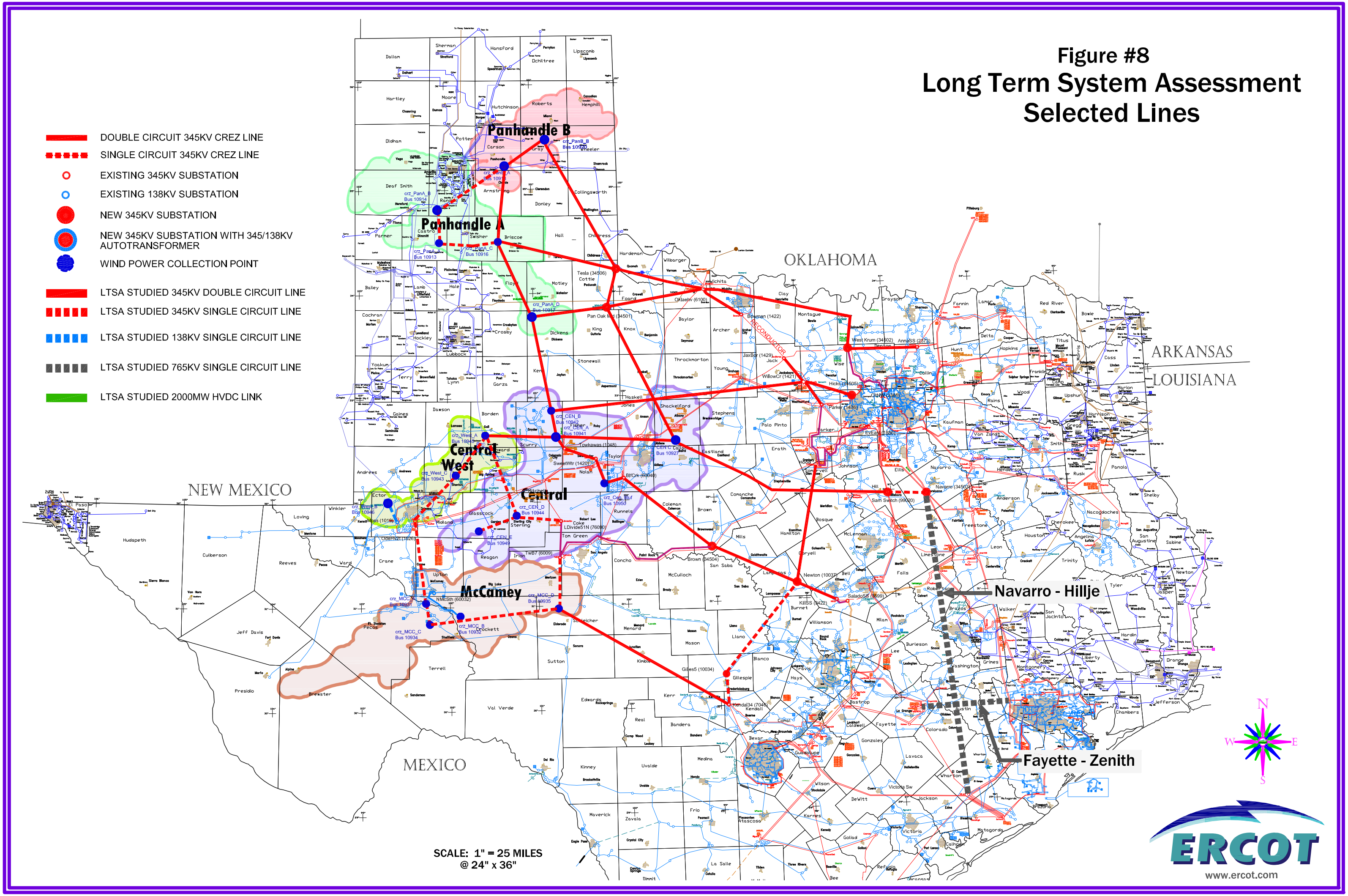
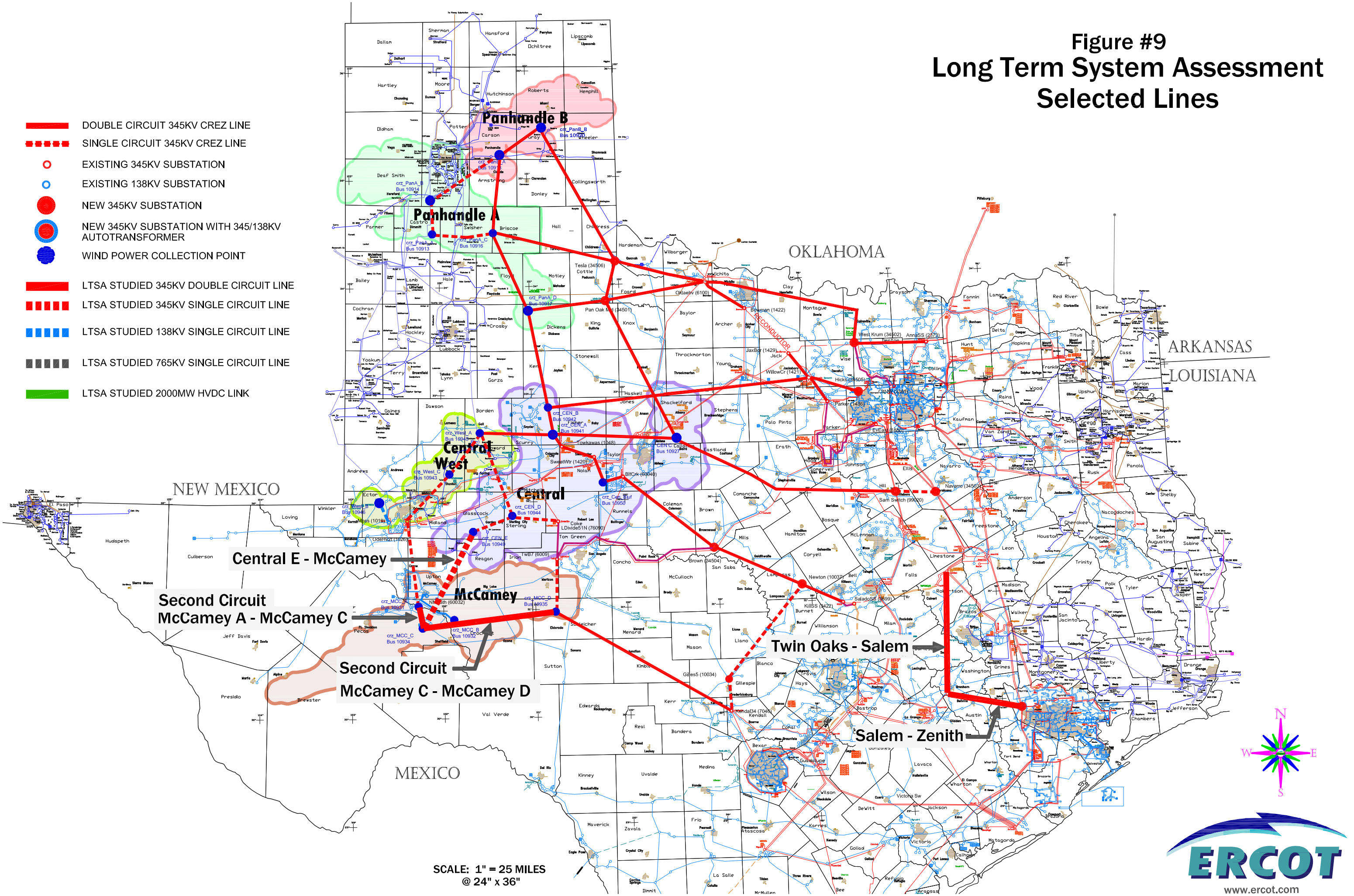
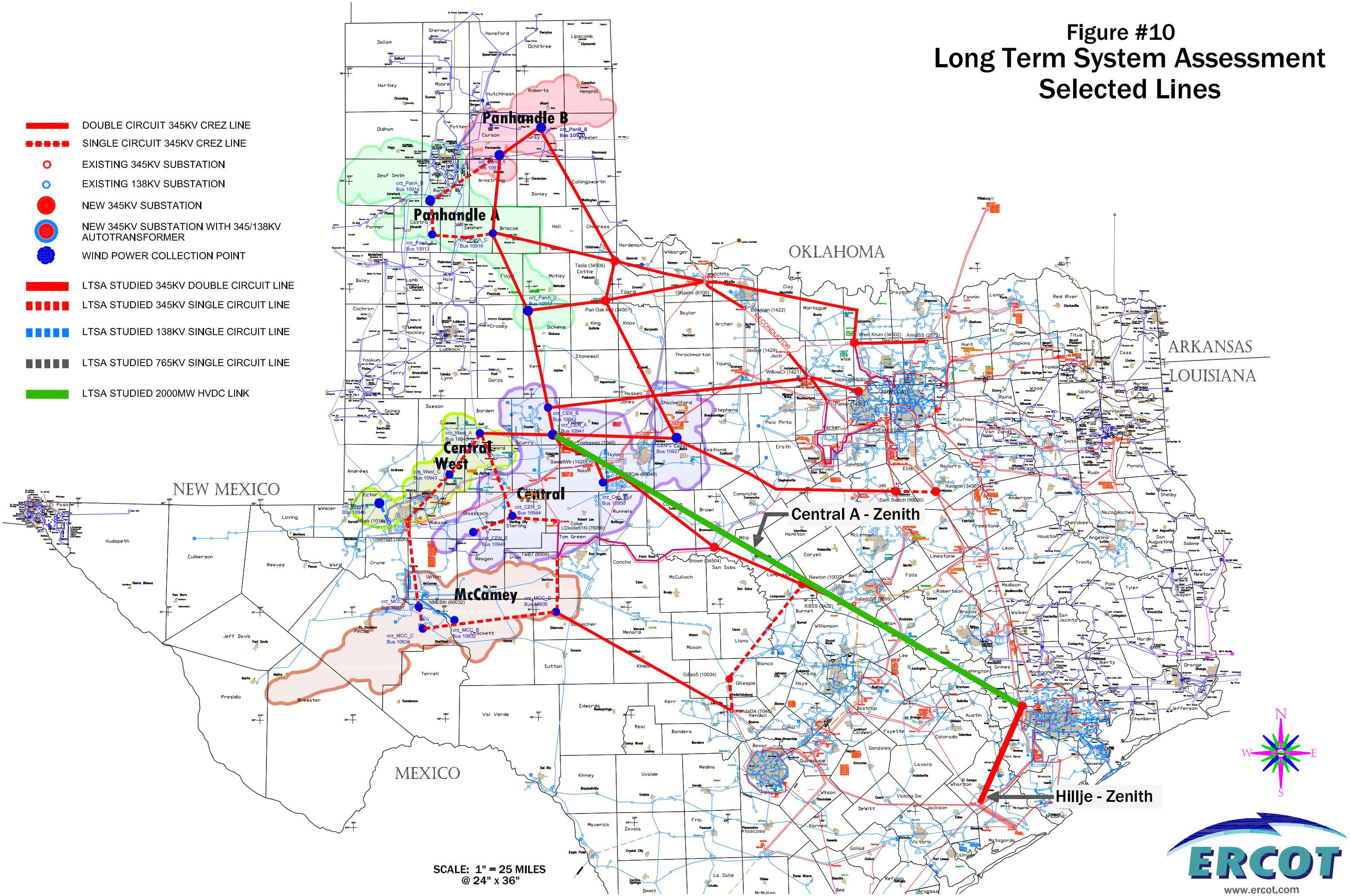


Figure #8
Long Term System Assessment
Selected Lines
DOUBLE CIRCUIT 345KV CREZ LINE
SINGLE CIRCUIT 345KV CREZ LINE
EXISTING 345KV SUBSTATION
EXISTING 138KV SUBSTATION
NEW 345KV SUBSTATION
NEW 345KV SUBSTATION WITH 345/138KV AUTOTRANSFORMER
WIND POWER COLLECTION POINT
LTSA STUDIED 345KV DOUBLE CIRCUIT LINE
LTSA STUDIED 345KV SINGLE CIRCUIT LINE
LTSA STUDIED 138KV SINGLE CIRCUIT LINE
LTSA STUDIED 765KV SINGLE CIRCUIT LINE
LTSA STUDIED 2000MW HVDC LINK
Panhandle B
Panhandle A
Central West
Central
McCamey
OKLAHOMA
ARKANSAS
LOUISIANA
NEW MEXICO
MEXICO
Navarro - Hillje
Fayette - Zenith
RECONDUCTOR
SCALE: 1" = 25 MILES
@ 24" x 36"
ERCOT
www.ercot.com

## Figure #9
## Long Term System Assessment Selected Lines



# Figure #10
# Long Term System Assessment Selected Lines



# Appendix 1

# Per Unit Transmission Cost Estimates

| Component | Cost ($ Million) |
|---|---|
| **138-KV EQUIPMENT COSTS:** | |
| 138-KV NEW CKT./MILE | 1.0 |
| 138-KV SECOND CKT./MILE | 0.25 |
| 138-KV RECONDUCTOR/MILE | 0.30 |
| 138-KV SUBSTATION | 10.0 |
| **345-KV EQUIPMENT COSTS:** | |
| 2-1433 ACSS 345KV SINGLE CKT. ON DOUBLE CKT. TOWERS/MILE | 1.5 |
| 2-1433 ACSS 345KV DOUBLE CKT. ON DOUBLE CKT. TOWERS/MILE | 1.88 |
| 2-1590 ACSR 345KV SINGLE CKT. ON DOUBLE CKT. TOWERS/MILE | 1.4 |
| 2-1590 ACSR 345KV DOUBLE CKT. ON DOUBLE CKT. TOWERS/MILE | 1.68 |
| 2-959 ACSS/TW 345KV SINGLE CKT. ON DOUBLE CKT. TOWERS/MILE | 1.3 |
| 2-959 ACSS/TW 345KV DOUBLE CKT. ON DOUBLE CKT. TOWERS/MILE | 1.56 |
| 345-KV SECOND CKT./MILE | 0.4 |
| 345-KV RECONDUCTOR/MILE | 0.5 |
| SERIES COMP > 100 MILES | 30.0 |
| SERIES COMP < 100 MILES | 25.0 |
| 150-MVAR SHUNT CAPACITOR | 6.0 |
| 345/138-KV 600MVA AUTO TRANSFORMER | 8.0 |
| 345/138-KV 800MVA AUTO TRANSFORMER | 9.0 |
| Substation - RING BUS 6 - LINE TERMINALS | 15.0 |
| Substation - BREAKER & 1/2 > 6 - LINE TERMINALS | 25.0 |
| **765KV EQUIPMENT COSTS:** | |
| 765-KV CKT. COST/MILE | 2.6 |
| 765-KV COST/SUBSTATION | 40.0 |
| 765/345-KV AUTO TRANSFORMER | 20.0 |
| **HVDC COSTS:** | |
| 2 x 3,000-MW CONVERTER STATIONS | 525.0 |
| 345-KV HVDC CKT. COST/MILE | 1.05 |

# Appendix 2

# Voltage Criteria

| Entity | Normal (or pre-contingency) | Emergency (or post-contingency) |
|---|---|---|
| AEP | 0.95pu | 0.90pu |
| AEN | 0.95pu | 0.90pu |
| CNP | 0.95pu<br>1.01pu (STP) | 0.95pu (Category B)<br>0.92pu (Category C)<br>1.01pu (STP) |
| CPS | 0.95pu | 0.93pu (probable disturbances)<br>0.90pu (extreme disturbances) |
| TNMP | .95pu | .90pu |
| TXU | 0.95pu (345-kV buses)<br>0.94pu (138-kV and 69-kV buses)<br>0.99pu (Comanche Peak nuclear) | -5% ?voltage from normal (345-kV)<br>-5% ?voltage from normal (69 & 138)<br>0.98pu (Comanche Peak nuclear) |
| ERCOT | 0.95pu | 0.95pu |

# Appendix 3

# System Dispatch Model Development Projects

| Start Bus | Bus No. | End Bus | Bus No. | Weather Zone | Voltage (kV) | Length (mi) | Action |
|---|---|---|---|---|---|---|---|
| SEATON9 | 131 | TXUPOAG_ | 3635 | North Central | 69 | 11.9 | Upgrade |
| W_DENT_8 | 986 | ARGYLE1_ | 1984 | North Central | 138 | 8.0 | Add |
| MOSS_8 | 1019 | AMOCNCTA | 1143 | Far West | 138 | 12.9 | Upgrade |
| MRGNCRK_ | 1032 | MRGNCRK_ | 1033 | West | 345/138 | 0.0 | Add |
| MRGNCRK_ | 1033 | COLOCITY | 1378 | West | 69 | 8.6 | Upgrade |
| ODESSANO | 1122 | AMOSFOST | 1130 | Far West | 138 | 4.3 | Upgrade |
| HOLTSS_9 | 1142 | EMMATAP_ | 1262 | Far West | 69 | 6.2 | Upgrade |
| COLOCITY | 1378 | LORAINE_ | 1379 | West | 69 | 7.8 | Upgrade |
| BOWMAN_B | 1424 | WFALLS_S | 1464 | North | 138 | 7.2 | Upgrade |
| FISHRDSS | 1426 | FISHERRD | 1427 | North | 138 | 0.0 | Upgrade |
| FISHRDSS | 1426 | CITYVIEW | 1483 | North | 138 | 9.8 | Upgrade |
| LKWICHIT | 1446 | WFALLS_S | 1464 | North | 138 | 3.3 | Upgrade |
| LKWICHIT | 1447 | WCHTFLLS | 1449 | North | 69 | 6.3 | Upgrade |
| LKWICHIT | 1447 | HOLLIDAY | 1527 | North | 69 | 10.2 | Upgrade |
| WCHTFLLS | 1448 | WCHTFLLS | 1449 | North | 138/69 | 0.0 | Add |
| WFALLS_N | 1503 | WFLSNBYP | 1504 | North | 69 | 0.9 | Upgrade |
| SHPFIELD | 1507 | WFLLSBSN | 1508 | North | 69 | 2.3 | Upgrade |
| HOLLIDAY | 1527 | KMA_T9 | 1536 | North | 69 | 10.1 | Upgrade |
| VALLYSES | 1691 | DENISN_N | 1743 | North | 138 | 17.1 | Upgrade |
| PARIS_SW | 1693 | PARIS_8 | 1777 | North | 138 | 1.2 | Upgrade |

| Start Bus | Bus No. | End Bus | Bus No. | Weather Zone | Voltage (kV) | Length (mi) | Action |
|---|---|---|---|---|---|---|---|
| SHER_NW_ | 1732 | SHER_W_8 | 1756 | North | 138 | 3.5 | Upgrade |
| DENISN_W | 1737 | TEXOMA_T | 1742 | North | 138 | 0.7 | Upgrade |
| DENISND_ | 1739 | TEXOMA_T | 1742 | North | 138 | 3.4 | Upgrade |
| DENISND_ | 1739 | DENISN_N | 1743 | North | 138 | 2.0 | Upgrade |
| SHER_W_8 | 1756 | PAYNE1_8 | 1758 | North | 138 | 2.0 | Upgrade |
| PAYNE1_9 | 1759 | PAYNE1_8 | 1758 | North | 138/69 | 0.0 | Add |
| RIVERCST | 1781 | RIVERCST | 1783 | North | 69 | 0.6 | Upgrade |
| COMMERCE | 1821 | COMMERCE | 1820 | North Central | 138/69 | 0.0 | Add |
| EAGLEMNT | 1860 | BLUEMD1_ | 2071 | North Central | 138 | 10.4 | Upgrade |
| WLEVEE1_ | 2398 | WLEVEE_2 | 2480 | North Central | 345/138 | 0.0 | Upgrade |
| ELGIN_SS | 3650 | SAND_TXU | 13430 | South Central | 138 | 22.8 | Upgrade |
| RNDROCK1 | 3668 | RNDRCKNE | 3670 | South Central | 138 | 3.8 | Upgrade |
| HUTTOSS_ | 3696 | HUTTOSS1 | 3666 | South Central | 345/138 | 0.0 | Add |
| CAGNON_5 | 5056 | CAGNON_8 | 5055 | South Central | 345/138 | 0.0 | Add |
| JT DEELY | 5110 | SKYLIN_N | 5369 | South Central | 138 | 20.8 | Open |
| JT DEELY | 5110 | FRATT | 5165 | South Central | 138 | 29.0 | Add |
| FRATT | 5165 | KIRBY | 5250 | South Central | 138 | 7.1 | Open |
| KIRBY2 | 5249 | KIRBY | 5250 | South Central | 138 | 1.5 | Upgrade |
| RANDOLPH | 5360 | TUTTLE | 5435 | South Central | 138 | 10.2 | Open |
| RANDOLPH | 5360 | KIRBY | 5250 | South Central | 138 | 10.0 | Add |

| Start Bus | Bus No. | End Bus | Bus No. | Weather Zone | Voltage (kV) | Length (mi) | Action |
|---|---|---|---|---|---|---|---|
| SKYLIN_N | 5369 | TUTTLE | 5435 | South Central | 138 | 5.0 | Add |
| PLAINVIE | 5540 | DANEVANG | 5544 | Coast | 69 | 4.8 | Upgrade |
| PLAINVIE | 5540 | INDSTRLP | 5543 | Coast | 69 | 5.4 | Upgrade |
| PAUL2A | 6048 | CHLC2A | 6057 | North | 69 | 11.4 | Upgrade |
| CHLC_VER | 6056 | CHLC2A | 6057 | North | 69 | 14.4 | Upgrade |
| CHLC_VER | 6056 | VERN2A | 6058 | North | 69 | 4.3 | Upgrade |
| VERN2A | 6058 | VERN4A | 6060 | North | 138/69 | 0.0 | Add |
| MUND2A | 6107 | MUNDAY | 764 | North | 69 | 3.6 | Upgrade |
| GILL2A | 6112 | KNXC2A | 6113 | North | 69 | 3.0 | Upgrade |
| GILL2A | 6112 | MUNDAY | 764 | North | 69 | 7.4 | Upgrade |
| ABMB4A | 6287 | ABIP4A | 6772 | West | 138 | 4.1 | Upgrade |
| SACO2A | 6450 | SACO4A | 6452 | West | 138/69 | 0.0 | Add |
| SONR4A | 6515 | CTHR4A | 8259 | West | 138 | 19.0 | Upgrade |
| ALMC2A | 6678 | ALMC4A | 6680 | Far West | 138/69 | 0.0 | Add |
| L_CORONA | 7087 | L_CORONA | 7093 | West | 138/69 | 0.0 | Add |
| L_BUCHAN | 7092 | L_CORONA | 7093 | West | 69 | 0.1 | Upgrade |
| L_BUCHAN | 7092 | L_BURNET | 7097 | West/South Central | 69 | 11.5 | Upgrade |
| L_BUCHAN | 7092 | L_CTECBU | 7101 | West | 69 | 2.8 | Upgrade |
| L_BUCHAN | 7092 | L_INKSDA | 7094 | West/South Central | 69 | 2.3 | Upgrade |
| L_WIRTZ_ | 7104 | L_FERGUS | 7126 | South Central/West | 138 | 4.0 | Upgrade |

| Start Bus | Bus No. | End Bus | Bus No. | Weather Zone | Voltage (kV) | Length (mi) | Action |
|---|---|---|---|---|---|---|---|
| L_WIRTZ_ | 7104 | L_FERGUS | 7126 | South Central/West | 138 | 4.0 | Upgrade |
| L_WIRTZ_ | 7104 | L_FLATRO | 7111 | South Central | 138 | 9.2 | Upgrade |
| L_FLATRO | 7111 | L_PALEPE | 7477 | South Central | 138 | 8.1 | Upgrade |
| L_FERGUS | 7126 | L_GRANMO | 7474 | West/South Central | 138 | 9.4 | Upgrade |
| L_GILLES | 7130 | L_GILLES | 7132 | West | 138/69 | 0.0 | Upgrade |
| L_FREDER | 7149 | L_FREDER | 7415 | West | 138/69 | 0.0 | Upgrade |
| L_COMFOR | 7155 | L_RAYMBA | 7158 | South Central/West | 138 | 11.5 | Upgrade |
| L_HENNE_ | 7172 | L_MCCALA | 7184 | South Central | 138 | 6.5 | Upgrade |
| L_ZORN__ | 7180 | L_SEGUIN | 7228 | South Central | 138 | 13.0 | Upgrade |
| L_ZORN__ | 7180 | L_MCCALA | 7182 | South Central | 138 | 8.4 | Add |
| L_GLIDDE | 7257 | L_BERNAR | 7654 | South Central | 69 | 11.3 | Upgrade |
| L_MARSFO | 7356 | L_PALEPE | 7477 | South Central | 138 | 15.6 | Upgrade |
| L_BANDER | 7438 | L_BANDER | 7439 | South Central | 138/69 | 0.0 | Add |
| L_BLANCO | 7482 | L_DEVIHI | 7484 | South Central | 69 | 11.3 | Upgrade |
| L_DEVIHI | 7484 | L_DEVIHI | 7493 | South Central | 138/69 | 0.0 | Upgrade |
| L_WHITES | 7529 | L_BUTTER | 7531 | South Central | 138 | 2.3 | Upgrade |
| L_GERONI | 7604 | L_MCQUEE | 7606 | South Central | 138 | 7.0 | Add |
| L_NIXOGV | 7616 | L_NIXON1 | 7617 | South Central | 69 | 2.0 | Upgrade |
| UVALDE2A | 8231 | UVALDE4A | 8234 | West | 138/69 | 0.0 | Upgrade |
| UVALDE2A | 8231 | CAMPWOOD | 8633 | West | 69 | 37.0 | Upgrade |

| Start Bus | Bus No. | End Bus | Bus No. | Weather Zone | Voltage (kV) | Length (mi) | Action |
|---|---|---|---|---|---|---|---|
| HAMILTN4 | 8255 | HAMIL_P4 | 8257 | West | 138 | 0.0 | Open |
| HAMILTN4 | 8255 | CTHR4A | 8259 | West | 138 | 72.0 | Upgrade |
| NIXONLCR | 8582 | L_NIXON1 | 7617 | South Central | 69 | 0.0 | Upgrade |
| DUNLAP8 | 9045 | DECK_MB1 | 9187 | South Central | 138 | 1.5 | Add |
| GILLE138 | 9054 | GILLE345 | 9053 | South Central | 345/138 | 0.0 | Upgrade |
| AMD | 9151 | GROVE | 9200 | South Central | 138 | 0.9 | Upgrade |
| SUMMITN | 9279 | WILIAMSN | 9295 | South Central | 138 | 3.5 | Upgrade |
| GILLES5 | 10034 | NEWTON | 10037 | West | 345 | 83.0 | Open |
| GILLES5 | 10034 | LAMPSAS5 | 10035 | West | 345 | 68.5 | Add |
| LAMPSAS5 | 10035 | L_LAMPAS | 7064 | West | 345/138 | 0.0 | Add |
| LAMPSAS5 | 10035 | NEWTON | 10037 | West | 345 | 14.5 | Add |
| TNSAINT_ | 37370 | ST_JO_P9 | 1716 | North | 69 | 2.6 | Upgrade |
| EXTER___ | 42600 | LAMARQ__ | 42860 | Coast | 69 | 13.5 | Upgrade |
| GALVES__ | 42670 | TIKIS___ | 43355 | Coast | 138 | 6.9 | Upgrade |
| HITCOK__ | 42800 | W_GALV__ | 43400 | Coast | 138 | 15.8 | Upgrade |
| LAMARQ__ | 42861 | STEWRT__ | 43290 | Coast | 138 | 15.8 | Upgrade |
| CAPEMUT3 | 42862 | TIKIS___ | 43355 | Coast | 138 | 5.9 | Upgrade |
| CAPEMUT3 | 42862 | WEBSTR__ | 43500 | Coast | 138 | 15.9 | Upgrade |
| DUNLVY__ | 47580 | HIGHTS__ | 47680 | Coast | 69 | 2.3 | Upgrade |