ERCOT System Planning:

2016 Long-Term System Assessment for the ERCOT Region

Version 1.0

Document Revisions

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Executive Summary

Section 39.904(k)[1] of the Public Utility Regulatory Act 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 and report on these needs to the Texas Legislature. A report documenting this study must be filed with the Legislature each even-numbered year.

By definition, the bulk transmission network within ERCOT consists of the 69-kilovolt (kV), 138-kV, and 345-kV transmission lines and associated equipment. In planning for both the additions and upgrades to this infrastructure, ERCOT conducts a variety of forward-looking reviews to help ensure continued system reliability and efficiency.

ERCOT's planning process covers several time horizons to identify and endorse new transmission investments. The near-term needs are assessed in the six-year planning horizon through the development of the Regional Transmission Plan (RTP). The Long-Term System Assessment (LTSA) provides an evaluation of the potential needs of ERCOT's extra-high voltage (345-kV) system in the 10- to 15-year planning horizon.

The LTSA guides the six-year planning process by providing a longer term view of system reliability and economic needs. Whereas in the six-year planning horizon a small transmission improvement may appear to be sufficient, the LTSA planning horizon may reveal that a larger project could be required. A larger project may also be more cost-effective than multiple smaller projects — each being recommended in successive RTPs.

ERCOT studies different scenarios in its long-term transmission planning process to account for the inherent uncertainty of planning the system beyond the next six years. The goal of using scenarios in the LTSA is to identify upgrades that are robust across a range of scenarios or might be more economical than the upgrades that would be determined considering only near-term needs.

Members of the ERCOT Regional Planning Group (RPG) developed a set of eight different future scenarios through a series of stakeholder-driven scenario development workshops. Using the assumptions and guidelines set by stakeholders in the scenario descriptions, ERCOT prepared eight different load forecasts.

Planning for transmission 10 and 15 years in the future requires ERCOT to make assumptions regarding what types of new resources could be developed. ERCOT conducted generation expansion analysis for the eight stakeholder-developed scenarios using the guidelines set in the scenario descriptions.

ERCOT and stakeholders used the results from the load forecast and generation expansion analyses to select three of the eight scenarios for transmission planning

[1]Section 39.904(k) of the Public Utility Regulatory Act states that the commission and the independent organization certified for ERCOT shall study the need for increased transmission and generation capacity throughout this state 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.

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analysis. The scenarios selected for transmission planning analysis were the Current Trends, High Energy Efficiency/ Distributed Generation, and Environmental Mandate scenarios.

Based on the results of the analyses that went into the 2016 LTSA, ERCOT identified the following key findings:

- Load continued to grow in ERCOT in seven of the eight scenarios.
- All scenarios showed a significant amount of solar generation additions and the retirement of coal and natural gas generation.
- There may be generation capacity challenges during the summer in the 8-9 p.m. (20:00-21:00) hours in scenarios with a large amount of solar generation.
- The combination of high amounts of solar generation additions in the west and generation retirement in the east will result in a significant increase in west-to-east power flows on the transmission network. This will result in the need for transmission system improvements to reliably accommodate these flows. This result was seen in all of the scenarios selected for transmission needs analysis, including the High Energy Efficiency/ Distributed Generation scenario which had negative load growth.
- Expected continued generation additions in the Panhandle will necessitate transmission improvements in the area. Addition of two 175-MVAR synchronous condensers at Windmill substation were economically justified across all the scenarios studied. In addition, a new 345-kV transmission path out of the Panhandle was found to be economically justified in the Environmental Mandate scenario.

The only scenario that showed load decreasing was the High Energy Efficiency/ Distributed Generation scenario, which assumed aggressive energy efficiency programs and a significant amount of distributed generation would be added in ERCOT. The expected strength of the Texas economy resulted in all other scenarios seeing moderate to strong load growth.

In all eight scenarios, solar generation additions by far represented the largest resource capacity change on the system. As seen in Figure ES.1, total solar generation capacity additions ranged from 14,500 megawatts (MW) to 28,100 MW in the eight scenarios. Conversely, all eight scenarios had varying levels of coal generation retirements, and seven of the eight scenarios had natural gas generation retirements. The retirement capacity by scenario is shown in Figure ES.2

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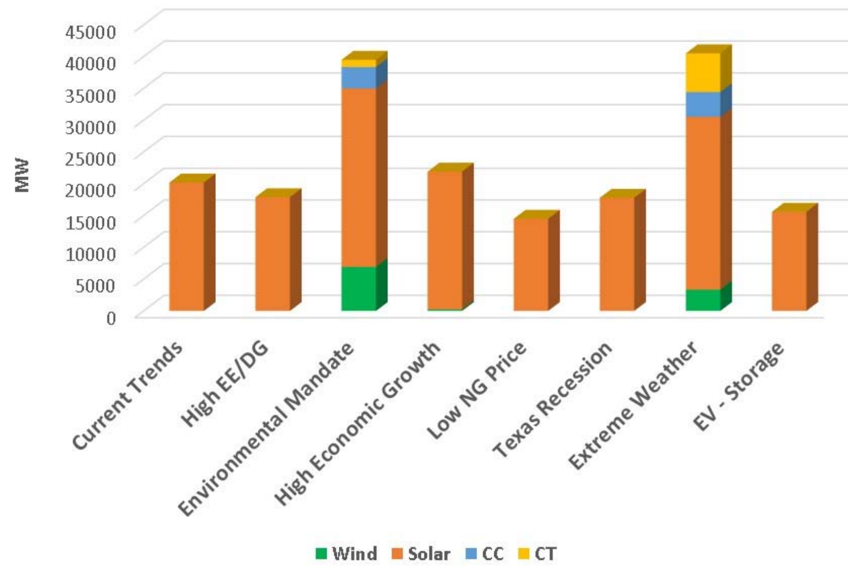

Figure ES.1: Capacity additions across all scenarios

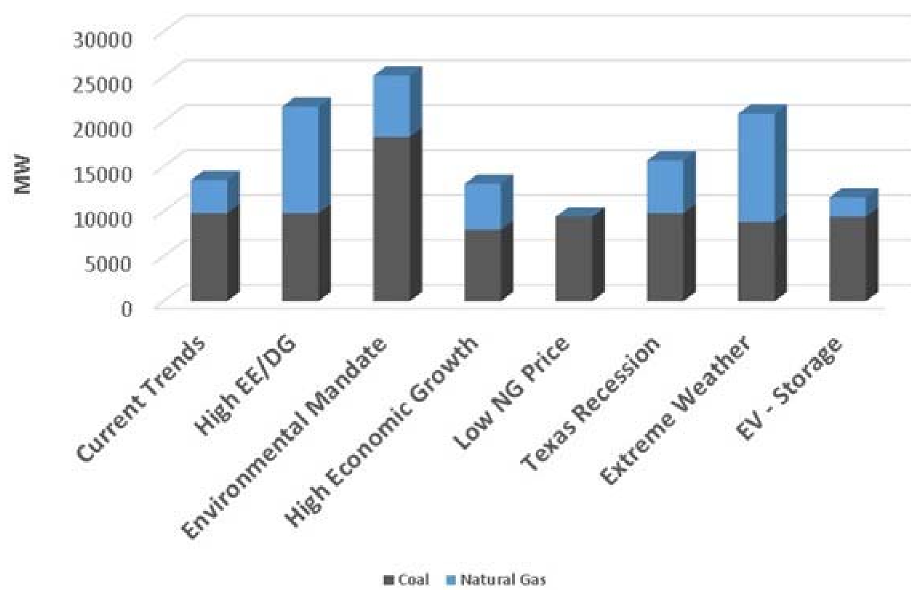

Figure ES.1: Generation retirements across all scenarios

One potential challenge identified in the study is the need for additional generation resources to offset the drop in solar production in late evening hours of the summer. With the amount of solar resources noted in many of the scenarios in this study, the loss of solar output in the late evening while air conditioning load remains high could lead to extreme system ramping conditions, or possibly insufficient generation capacity to serve load (especially on days when there is little to no wind generation output). On some days the model simulation output indicated limited amounts of unserved energy. Figure ES.3 shows this potential result for a summer peak evening in 2031 from the Current Trends

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scenario. Results from this study indicate that if a significant amount of solar generation and/or additional wind generation is developed in ERCOT both resource adequacy and transmission planning studies will need to be adjusted to incorporate an assessment of system reliability under peak load and net peak load conditions.

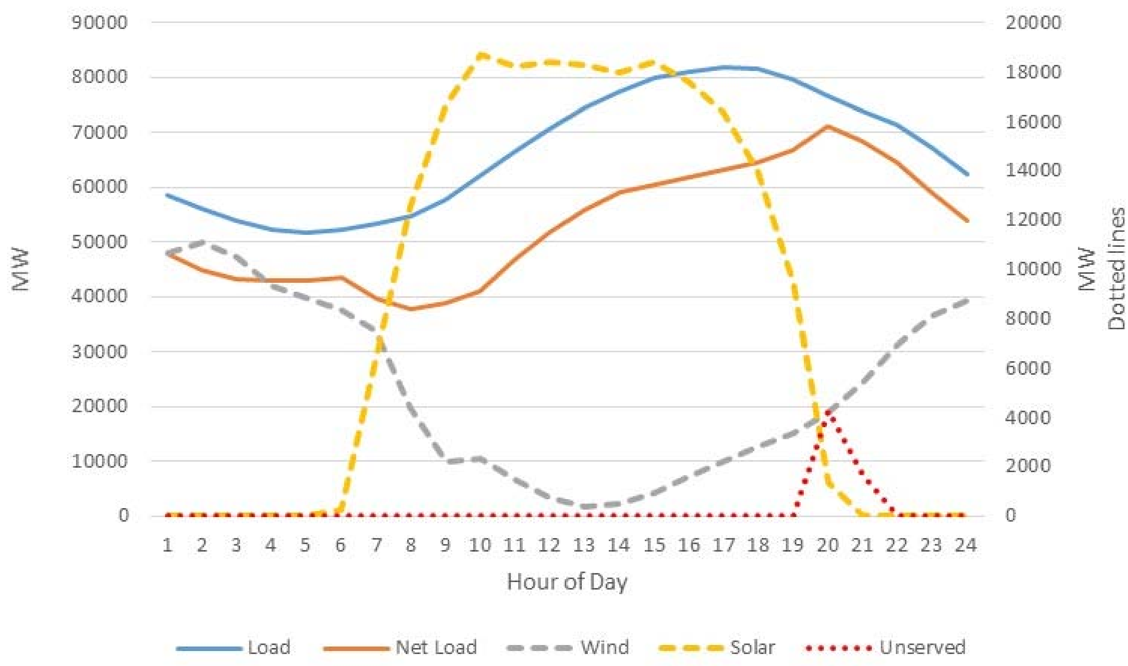

Figure ES.2: Net peak load challenge

The addition of solar generation in the western part of the state coupled with the retirement of coal and natural gas generation in the eastern part of the state could result in significant increases in west-to-east power flows on the transmission system. This outcome was noted in all scenarios studied for transmission analysis. Figure ES.4 illustrates the change in generation capacity across the three scenarios that were used for the transmission analysis. The warm colors on the map indicate the location and magnitude of generation capacity that were added in a particular scenario, whereas the cool colors on the map show the loss of generation capacity on the system.

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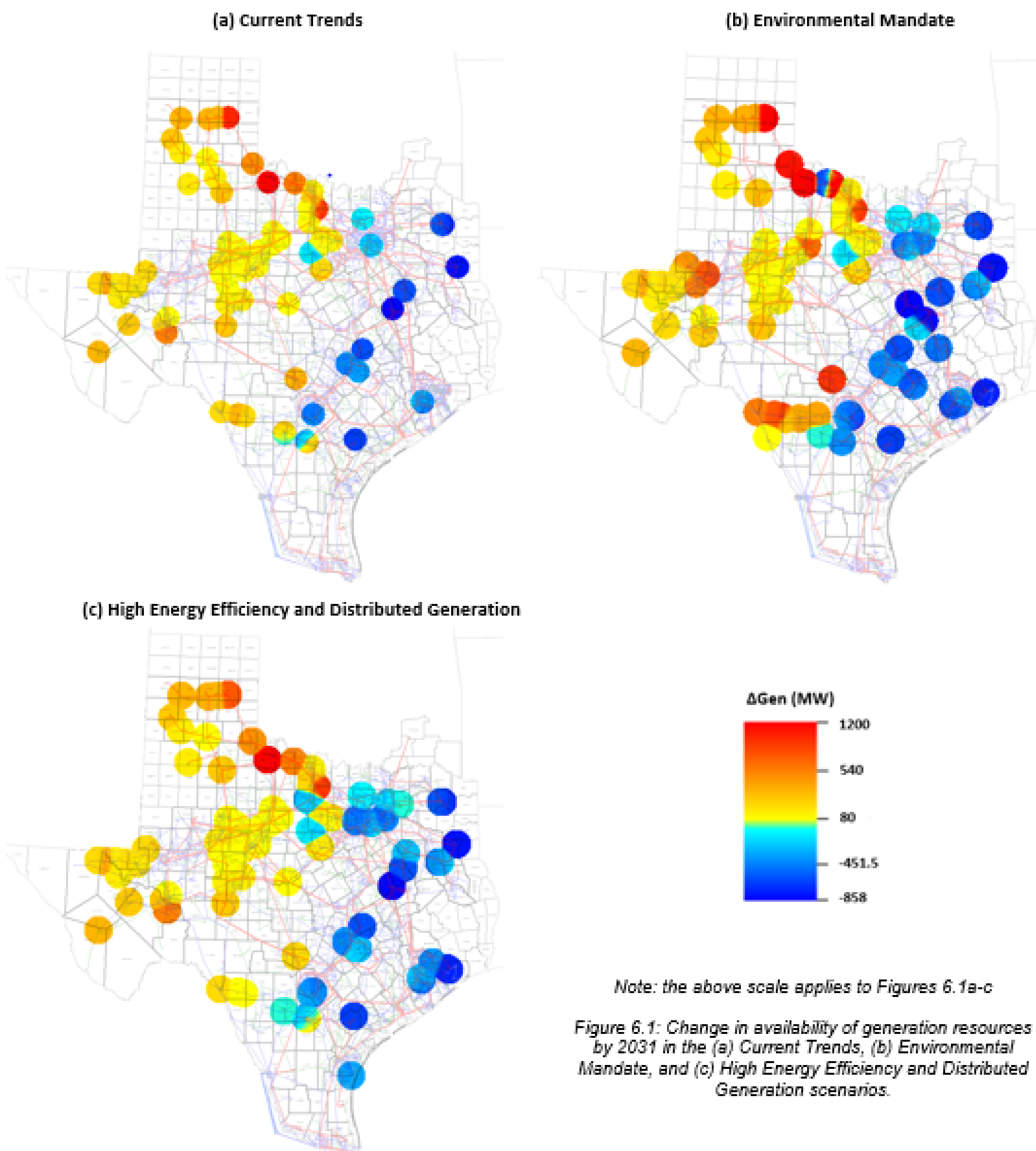

Figure ES.3: Change in generation capacity across different scenarios

The observed west-to-east power flows resulted in the need for transmission system improvements including existing 345-kV upgrades and new extra high voltage paths in order to reliably deliver power to the load centers. Even the High Energy Efficiency/ Distributed Generation scenario, which had a decreasing peak load, required substantial transmission improvements due to the increase in west-to-east power flows resulting from the change in generation mix. Figure ES.5 highlights some of the significant transmission improvements found to be needed in the Current Trends scenario.

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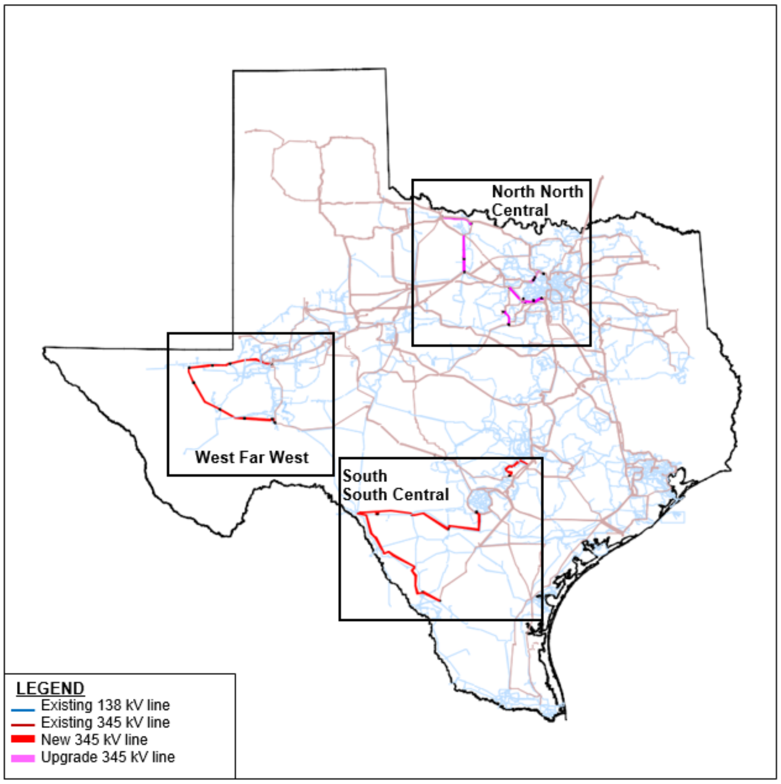

Figure ES.4: Transmission improvements in the Current Trends scenario

The Panhandle was found in all studied scenarios to have a significant amount of congestion due to generation additions in the region. Annual congestion rent in year 2031 ranged from $353 million to $866 million. ERCOT analyzed an additional export transmission path from the Panhandle and found that a new 345-kV line from the Ogallala substation to the Long Draw substation would meet the ERCOT economic criteria in the Environmental Mandate scenario. This finding was in line with the ERCOT 2014 Panhandle Study which identified a similar improvement as being necessary as generation capacity in the Panhandle increased.

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Chapter 1. Introduction

The Electric Reliability Council of Texas (ERCOT) is a membership-based 501(c)(4) nonprofit corporation, subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. In 1999, the Texas Legislature restructured the Texas electric market and assigned ERCOT the responsibilities of maintaining system reliability through both operations and planning activities, ensuring open access to transmission, processing retail switching to enable customer choice, and conducting wholesale market settlement for electricity production and delivery.

In fulfilling these responsibilities, ERCOT manages the flow of electric power to 24 million Texas customers — representing about 90 percent of the state's electricity use. ERCOT schedules power on an electric grid that connects 46,500 miles of transmission lines and more than 550 generation units. ERCOT also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for customers in competitive choice areas.

As part of its responsibility to adequately plan the transmission system, ERCOT must develop a biennial assessment of needed transmission infrastructure. Specifically, Section 39.904(k) of the Public Utility Regulatory Act (PURA) requires the Public Utility Commission of Texas (PUCT) and 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 no later than Dec. 31 of each even-numbered year.

ERCOT develops two reports 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 six years (2017 through 2022) and provides a summary of the ERCOT Regional Transmission Plan to meet those needs (provided under separate cover).
- Long Term System Assessment (LTSA) for the ERCOT Region: This report provides an analysis of the system needs in the 10th year and beyond. The longer-term view in this analysis is designed to guide near-term decisions.

Together, these reports provide an assessment of the needs of the ERCOT System through the next ten years and beyond.

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Chapter 2. Transmission Planning Overview

The process of planning a reliable and efficient transmission system for the ERCOT Region is composed of several complementary activities and studies. The ERCOT-administered System Planning activities comprise near term studies, including the Regional Transmission Plan, Regional Planning Group submissions and review, and ongoing long-range studies, which are documented in the Long-Term System Assessment. In addition to these activities, transmission service providers (TSPs) conduct analysis of local transmission needs supplemental to the ERCOT planning process.

ERCOT performs its planning function in coordination with TSPs, ERCOT market participants, and other interested stakeholders. ERCOT primarily works with two market stakeholder groups in fulfilling its planning responsibilities:

- The Regional Planning Group (RPG) is responsible for reviewing and providing comments on new transmission projects in the ERCOT Region. Per ERCOT Protocol section 3.11.3, participation in the RPG is required of all TSPs and is open to all market participants, consumers, other stakeholders, and PUCT staff.
- The Planning Working Group (PLWG) reviews the Planning Guides to identify any needed improvements to planning criteria, processes and data provision requirements as well as to maintain alignment with North American Electric Reliability Corporation (NERC) Reliability Standards requirements and recommend appropriate Regional Standard Authorization Requests, Planning Guide Revision Requests, or Nodal Protocol Revision Requests as needed.

The LTSA process is based upon scenario analysis techniques to assess the potential needs of the ERCOT System up to 15 years into the future. Due to the degree of uncertainty associated with the amount and location of loads and resources in the 10- to 15-year timeframe, the role of the LTSA is not to recommend the construction of specific system upgrades. Instead, the role of the LTSA is to evaluate the system upgrades that are indicated under each of a wide variety of scenarios in order to identify upgrades that are robust across a range of scenarios or might be more economic than the upgrades that would be determined considering only near-term needs in the RTP development.

The LTSA guides analysis in the near-term study horizon through scenario-based assessment of divergent future outcomes. As future study assumptions become more certain, the RTP supports actionable plans to meet near-term economic- and reliability-driven system needs. In support of stakeholder-identified or ERCOT-assessed projects, the RPG review process leads to the endorsement of individual projects that maintain reliability or increase system economy. Collectively, these activities create a robust planning process to ensure the reliability and efficiency of the ERCOT transmission system for the foreseeable future.

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2.1 2016 LTSA Scenario-Development Process

The LTSA is a composite study made up of various processes and analyses such as scenario development, generation expansion analysis, load forecasting analysis, and transmission expansion analysis. Figure 2.1 summarizes the LTSA processes.

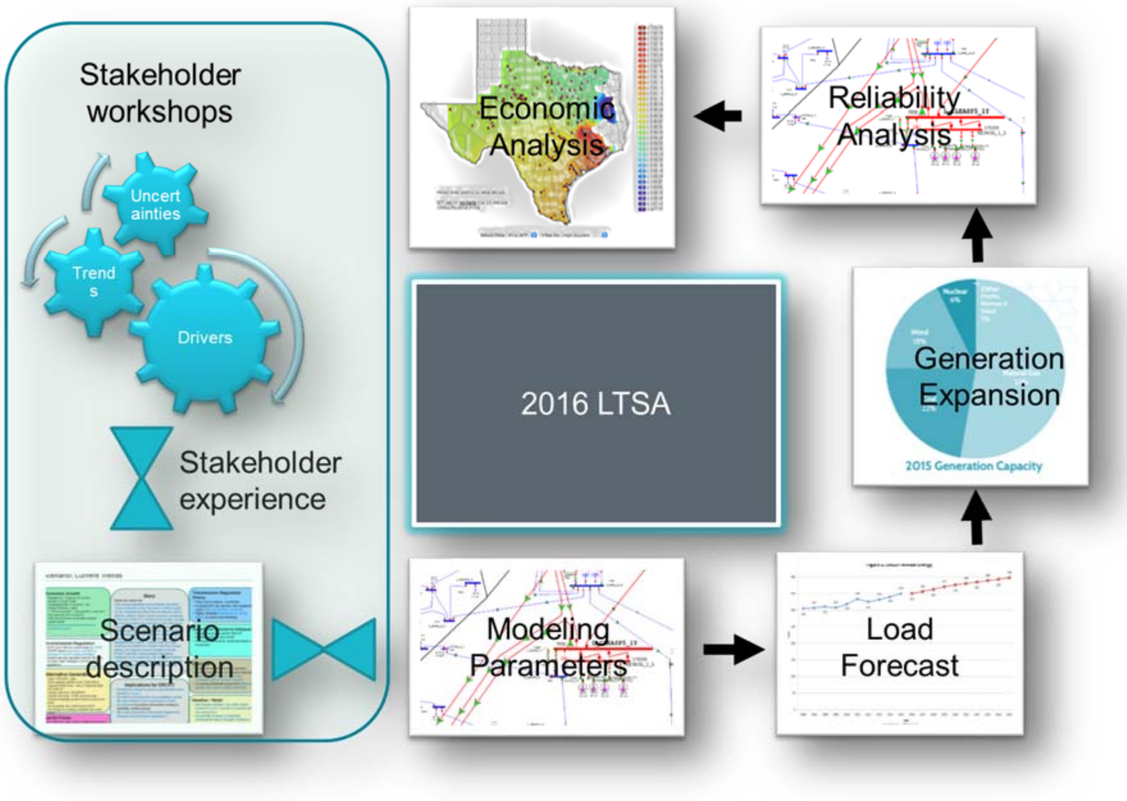

Figure 2.1: 2016 Long-Term System Assessment Process

The 2016 LTSA scenario development process followed a methodology similar to the one used for the 2014 LTSA. The scenario-based planning approach provided a structured way for participants/stakeholders to identify the most critical trends, drivers, and uncertainties for the upcoming ten- to fifteen-year period. Scenario-based planning considers sufficiently different, yet plausible futures and is used to evaluate transmission plans across multiple future states.

The scenario-development process was organized in the following major segments:

- ERCOT and stakeholders conducted a joint review of the drivers, scenarios, and results from the 2014 LTSA. Objectives of this review were to identify scenarios that should be developed further in this LTSA, to identify new drivers that were not considered in the previous LTSA, to identify drivers that would benefit from updated information, and to identify potential topics for expert presentations.

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- Industry expert presentations describing industry trends, drivers, and uncertainties impacting the electric sector were organized for the scenario-development workshops. All interested stakeholders were urged to participate in these workshops.
- With the expert presentations and lessons learned from previous LTSAs as a background, the stakeholders and ERCOT staff finalized the list of key drivers and potential scenarios that were important to the future of ERCOT's transmission system. The list of scenarios and a brief description can be found in Table 2.1. The scenarios were defined by the outcome of either a single key driver or a set of interrelated key drivers. ERCOT stakeholders identified which drivers could play a major role in creating distinctly different scenarios in the future that should be considered in the planning process.
- Stakeholders worked in teams to develop comprehensive descriptions of each scenario. Each team comprised a mix of members representing generation, transmission, ERCOT staff, and other stakeholders. Teams were encouraged to provide detailed future possibilities on various variables such as economic growth, environmental regulations/policy, alternative generation, oil and gas prices, transmission regulations/policy, resource adequacy, technological changes, end-use/new markets, and weather/water. Each scenario was then summarized with a high-level narrative describing the future state and its implications for ERCOT. Appendix A provides a summary of the scenario development workshop and includes a list of the presenters and topics discussed, and a list of drivers and scenarios shortlisted for the 2016 LTSA.

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Table 2.1: *Scenarios Studied in the 2016 LTSA*

Scenario	Description
Current Trends	Trajectory of what we know and is knowable today (e.g., LNG export terminals, Texas growth, low natural gas and oil prices)
High Economic Growth	Significant population and economic growth from all sectors of the economy (affecting load from residential, commercial and industrial)
Texas Recession	Significant reduction in economic activity in Texas
Environmental Mandate	On top of current regulations, aggressive action on mitigating environmental impacts in the energy sector has occurred. Federal or higher Texas renewable standards
High Efficiency/High DG	Reduced *net* demand growth due to increase in distributed solar and higher building and efficiency standards
Extended Extreme Weather	Extreme weather conditions exist for an extended period impacting water-intensive generating resources.
Sustained Low Natural Gas Prices	Low domestic gas prices continue for the entire period.
Storage/Electric Vehicle Adoption	High penetration of electric vehicles and large amounts of residential and utility-scale storage

2.2 Load Forecasting

One key component to any long-term transmission plan is an appropriate forecast of the electric load. Changes in electricity consumption contribute to future transmission needs as do new generation technologies, generator obsolescence, economic, commercial, and policy factors. Transmission plans study the reliable movement of electricity from generation sources to consuming load locations; therefore, planners need to know which resources can provide electricity as well as how much electricity will be needed and

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where. The uncertainty in many of these factors can be significant; as such, load forecasters often prepare several forecasts that reflect different possible futures and circumstances so transmission planners can study load, generation, and transmission needs for those various futures and conditions.

For this long-term plan, ERCOT developed scenario-based forecasts for the region. ERCOT based these forecasts on a set of neural-network models that provide the hourly load in the region as a function of certain economic and weather variables. Vendors under contract with ERCOT provided the data used as input variables to the energy, demand, and premise forecast models. County-level economic and demographic data were obtained on a monthly basis from Moody's Analytics, Inc. Twelve years of weather data were provided by Telvent for 20 weather stations in ERCOT.

Eight different forecasts were created for years 2026 and 2031 to support the scenarios included in this study. These forecasts used different values for a set of input variables that were consistent with the scenario-specific assumptions.

2.3 Resource Expansion Analysis

To provide a reference point for the selection of other future scenarios, market participants created a Current Trends scenario as the first scenario. This Current Trends scenario is based on the assumption that current policies, regulations and market conditions will persist, and that no new policies will be introduced.

Trends in capital costs for new expansion technologies generally increased at GDP in this analysis except for wind and solar PV technologies which were forecasted to decline through the early part of the study period. Commodity prices for natural gas were set as the average of the EIA AEO 2015 Reference Case and High Oil and Gas Production Case.

The technologies included for generation expansion in this LTSA were current and advanced natural gas-fired combined cycles and combustion turbines, solar, geothermal, compressed air energy storage (CAES), biomass, coal, coal with carbon capture and sequestration (CCS), Integrated Gasification Combined Cycle (IGCC), IGCC with CCS, nuclear and demand response (DR) programs. The solar technology evaluated in the generation expansion process was utility scale photovoltaic (PV) single axis tracking.

Additionally, the continuation of the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) was included in all scenarios for renewable generation.

As many older units are located in or near major load centers, (many of which are non-attainment zones under the National Ambient Air Quality Standards) redevelopment of these sites with new generation was considered unlikely.

The implementation of the Regional Haze FIP, included in all scenarios, had a direct impact on some coal-fired units. The FIP, as finalized, requires that the SO_2 scrubbers

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on seven coal-fired units in ERCOT be upgraded by February 2019, and that new SO_2 scrubbers be installed on five units by February 2021. On December 2, 2016, the EPA filed a motion seeking a "voluntary remand" of the FIP for Texas after the rule was stayed by the 5th Circuit of the U.S. Court of Appeals on July 15, 2016. The development of assumptions and generation expansion modeling for this analysis had already been completed prior to the stay of the rule by the 5th Circuit. As a result, it was not possible to remove the Regional Haze FIP from the assumptions included in these scenarios.

Initial analyses indicated that two groups of coal units, would be likely to retire across all scenarios if the Regional Haze FIP were implemented as designed: coal units required to retrofit with new scrubbers, and coal units that were required to upgrade their current scrubbers and which were located in a county proposed for nonattainment with the 2010 sulfur dioxide (SO_2) National Ambient Air Quality Standard (NAAQS).[2] As a result, nine coal units in the ERCOT region, totaling 6,278 MW, were assumed to retire on the Regional Haze FIP compliance dates mentioned above.

The remaining units in this LTSA were considered for retirement based on individual unit economics. Using model output, if a unit's fixed and variable costs were greater than the unit's total revenue, the unit was retired in the next model year run.

In July 2015, ERCOT procured new hourly wind generation patterns based on actual weather data from the previous 15 years. These wind patterns include new hourly wind output patterns for 130 hypothetical future wind generation units and were developed using power generation curves consistent with the most recent wind turbine technologies. The 130 profiles were distributed throughout Texas. Each profile is representative of the historical wind output in a specific county. These wind profiles were incorporated in all scenarios.

In March 2013, ERCOT procured new hourly solar generation patterns based on actual weather data for the previous 15 years. These patterns contained profiles representative of 254 Texas counties for four different types of solar technologies: single axis tracking, fixed tilt, solar thermal, and residential. ERCOT selected the single axis tracking and residential profiles for inclusion in this LTSA.

The resource expansion analysis was conducted using PLEXOS, an hourly economic dispatch model. Additionally, PLEXOS was used to determine the timing, approximate location of wind and solar resources, and capacity of new entrants (generating units) likely to participate in the competitive electric energy market along with units that may be economically retired. A major aspect of the expansion decision process is capital cost recovery. Using the specified capital costs, recovery period, inflation rate, and cost of capital, the model calculates a repayment that is paid in equal installments over the capital recovery period. The inflation rate ensures that units that are added in the future

[2] At the time these assumptions were developed, EPA had proposed to designate several counties in Texas in nonattainment with the 2010 SO_2 NAAQS based on modeled emissions from coal units located in those areas. On November 29, 2016, the EPA finalized these designations under the 2010 SO_2 NAAQS.

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have their capital costs appropriately adjusted for inflation providing consistency with the other specified costs.

The amount of renewable generation included in the scenarios is partially a result of the use of an hourly system dispatch model to develop the resource expansion plan. This type of model does not take into account intra-hour balancing requirements and the need for commitment of additional resources to limit the impact of variable generation forecasting error consistent with increased levels of renewable generation integration. Separate analysis is being conducted to determine the need for additional system dispatch capability to integrate levels of renewable resources seen in this analysis.

2.4 Transmission Expansion Analysis

Transmission expansion analysis in the LTSA involves evaluating the potential needs for the ERCOT grid under different load and generation assumptions as developed during in the load forecasting and generation expansion planning stages of the LTSA. The scenario-development workshops identified eight different scenarios with internally consistent planning assumptions as documented in Section 2.1 above. Load forecasting and generation expansion were performed on each of these scenarios using the guidelines and assumptions captured in the scenario-development process. Transmission expansion analysis was conducted for three of the eight scenarios. These three scenarios were selected based on a combination of the diversity of results from the generation expansion and load forecasting analyses, stakeholder interest, and their expected impacts on the transmission system. The following graphic describes the transmission analysis process applied in the 2016 LTSA.

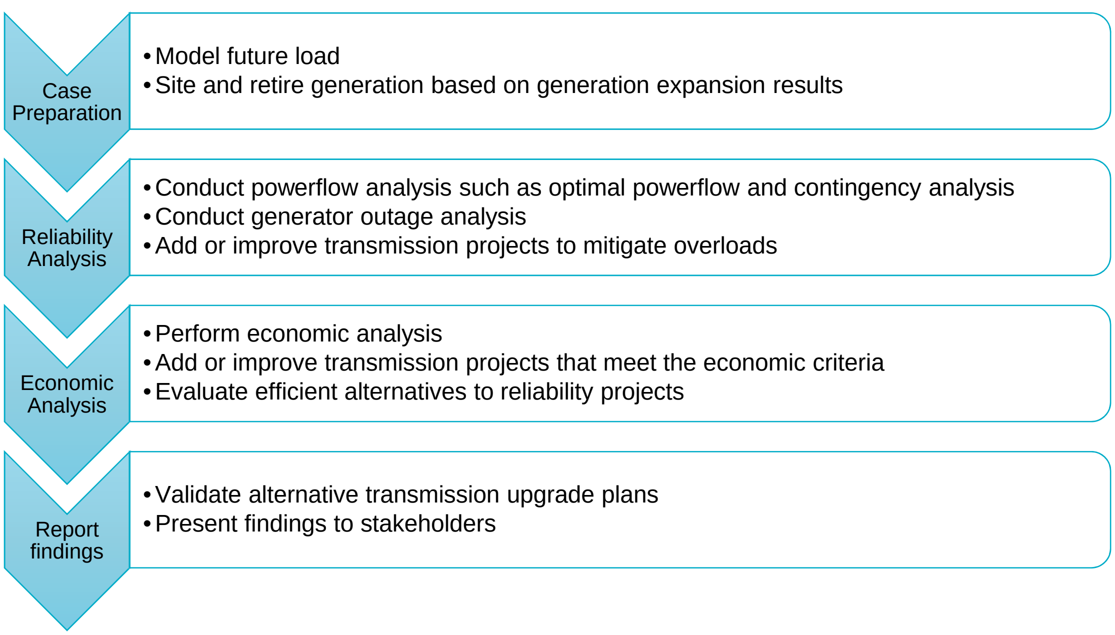

Figure 2.2: LTSA Transmission Expansion Process

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Chapter 3. Key Findings

The development of the 2016 LTSA has led to the following key findings:

- Load continued to grow in ERCOT in seven of the eight scenarios.
- All scenarios showed a significant amount of solar generation additions and the retirement of coal and natural gas generation.
- There may be generation scarcity challenges during the summer in the 8-9 p.m. (20:00-21:00) hours in scenarios with a large amount of solar generation.
- A combination of high amounts of solar generation additions in the west and generation retirements in the east could result in a significant increase in west-to-east power flows on the transmission network. This change will result in the need for transmission system improvements in order to reliably accommodate these power flows. This result was seen in all of the studied scenarios, including the High Energy Efficiency/ Distributed Generation scenario, which also saw negative load growth.
- Expected continued generation additions in the Panhandle will necessitate transmission improvements in the area. Two 175-MVAR synchronous condensers at Windmill substation were economically justified across all the scenarios studied. In addition, a new 345-kV transmission path out of the Panhandle was found to be economically justified in the Environmental Mandate scenario.

These findings are expanded upon in the following sections.

3.1 Load Growth Continues

In all but one of the eight scenarios, load continued to grow in the ERCOT region. This result can be attributed to the expected strong economic growth in the Texas economy.

The only scenario that included reduced customer demand was the High Energy Efficiency/Distributed Generation scenario, which assumed aggressive energy efficiency programs and a significant amount of distributed generation would be added in ERCOT. The High Energy Efficiency/Distributed Generation scenario forecast assumed that energy efficiency would increase from 1% of the summer peak in 2017 to 15.0% of the summer peak in 2031. These changes resulted in the energy efficiency summer peak value increasing from 700 MW in 2017 to 12,200 MW in 2031. Incremental load forecast adjustments were performed for rooftop solar as 6,100 MW were added by 2031. The load forecast for that scenario was 67,541 MW in 2031, which represents a -0.3% annual average compound rate of growth.

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3.2 Changing Generation Mix

The most significant finding from the generation expansion analysis was that solar generation could increasingly displace older coal and natural gas generation in ERCOT in the future. All of the scenarios showed that there would be a substantial amount of solar generation capacity added to the ERCOT grid over the next 10 to 15 years. However, natural gas was found to remain the primary fuel used to meet ERCOT load. As noted in Section 2.3, Resource Expansion Analysis, it should be noted that the 2016 LTSA assumed that the Regional Haze FIP for Texas would be implemented. The recent remand of this rule was not included in these study results.

Coal generation output declined in most scenarios. This reduction was greatest in the Environmental Mandate scenario, in which approximately 91% of the coal fleet capacity was retired and coal resources provided almost no energy by 2031. Figure 3.1 shows the percent of the energy generated by fuel type in 2031 for all modeled scenarios. Figures 3.2 and 3.3 show the amount of capacity retired and added to each scenario, respectively.

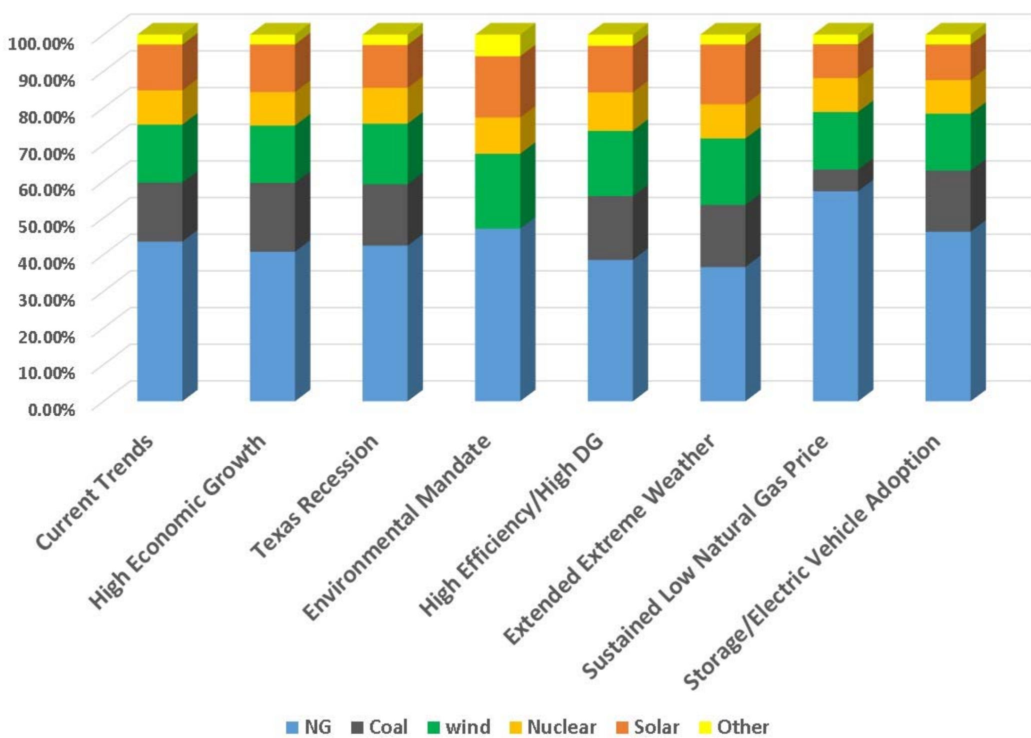

Figure 3.1: Total Generation by Fuel Type in 2031

Generation retirements were limited to coal and natural gas units. Total retirements varied by scenario; from a low of 9,417 MW in the Low Natural Gas Price scenario to a high of 25,112 MW in the Environmental Mandate scenario. A description of the generation expansion and retirement results for each of the scenarios evaluated in this LTSA are provided in Appendix C.

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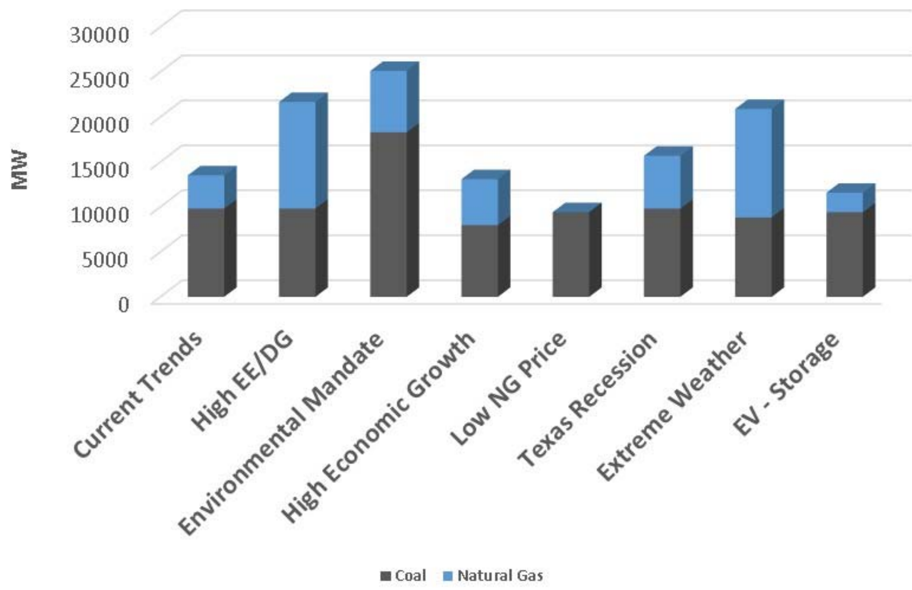

Figure 3.2: Scenario Capacity Retirements

Capacity additions also varied by a scenario: from a low of 14,500 MW in the Low Natural Gas Price scenario to a high of 40,532 MW in the Extreme Weather Scenario. Solar generation dominated capacity additions in all scenarios, ranging from a low of 14,500 MW to a high of 28,100 MW.

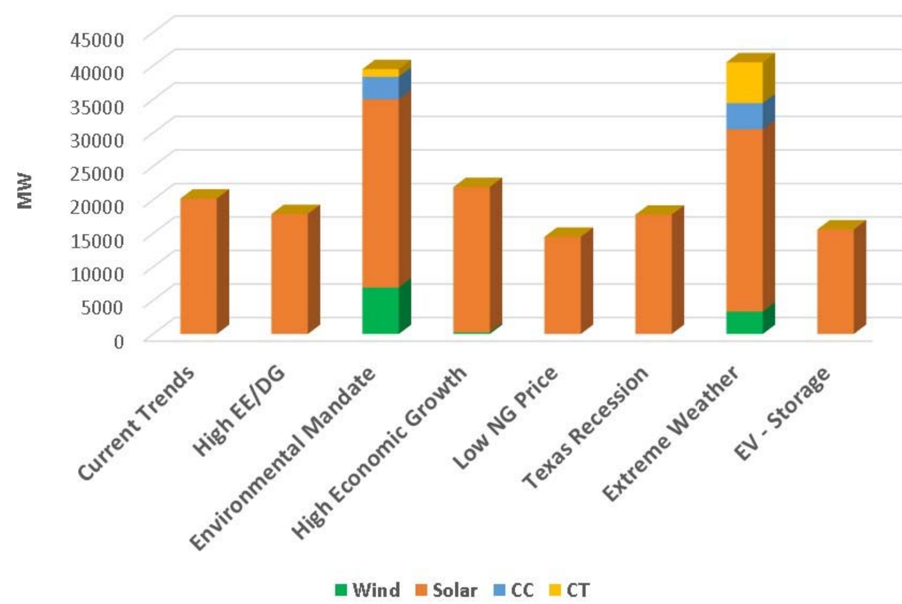

Figure 3.3: Scenario Capacity Additions

Total natural gas burned in each scenario varied from a low of 1,223,729 GBtu in the high EE/DG scenario to a high in the Low Natural Gas Price scenario of 2,037,633 GBtu.

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The consistency of natural gas use across most scenarios is intuitive in that any natural gas units retired were older gas steam units that had very low annual capacity factors (in the 1% to 2% range). The obvious exception from this result was the Low Natural Gas Price scenario. These results are shown in Figure 3.4.

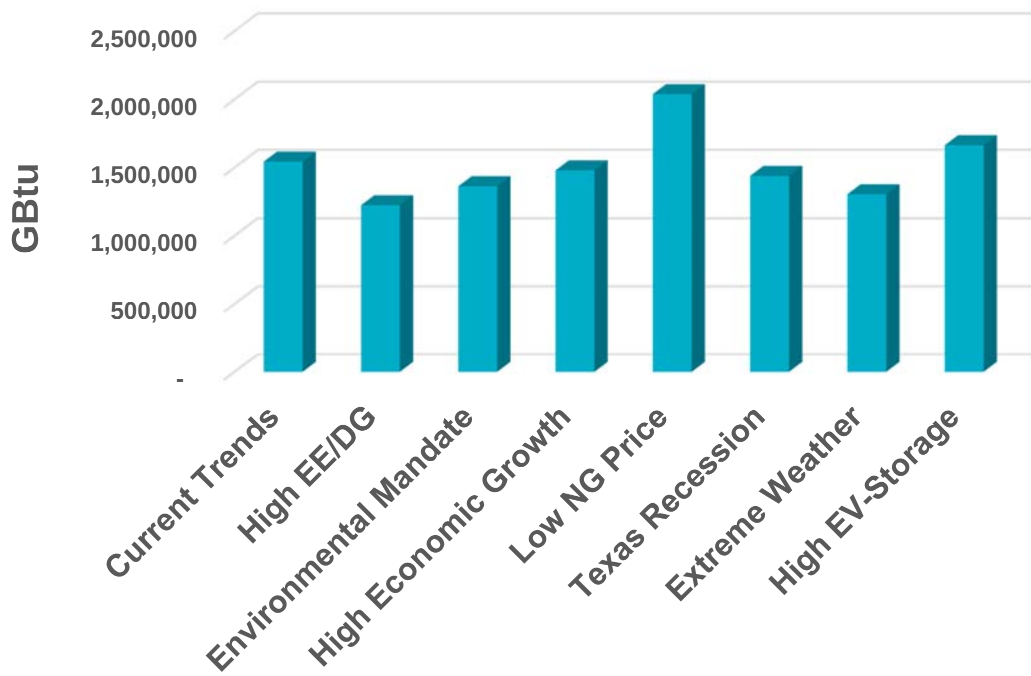

Figure 3.4: 2031 Natural Gas Burned

3.3 Net-Load Challenge

Net load is the total electric demand on the system minus variable (i.e., wind and solar) generation. Figure 3.5 shows customer demand and net load for a sample hot summer day in 2031 from the Current Trends scenario (similar results were noted in all scenarios with significant wind and solar development). This graphic shows the possibility of scarcity conditions, not at the hour of peak demand, but rather later in the evening in the hour of peak net load. With significant additions of solar and wind resources, as solar resources decline due to the setting sun, on days with low wind generation, the system could experience resource scarcity in the late evening hours, well after peak load conditions. It should be noted that the process used to develop the generation expansion for the scenarios in this study did not include consideration of ancillary (reliability) services revenue. These revenues may be sufficient in the future to result in the development of additional resources which could reduce the risk of these scarcity conditions. The hourly model also did not include consideration of intra-hour system reliability needs. Regardless, these results point to a need to incorporate additional system operating conditions into both resource adequacy and transmission planning studies to ensure reliable grid operations.

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Resource adequacy analyses traditionally have focused on comparing expected available resources to system peak demands, with deterministic assumptions regarding availability of variable generation. With increasing amounts of variable generation, an equally important consideration may be the likelihood of relatively high customer demand during periods of low variable generation output.

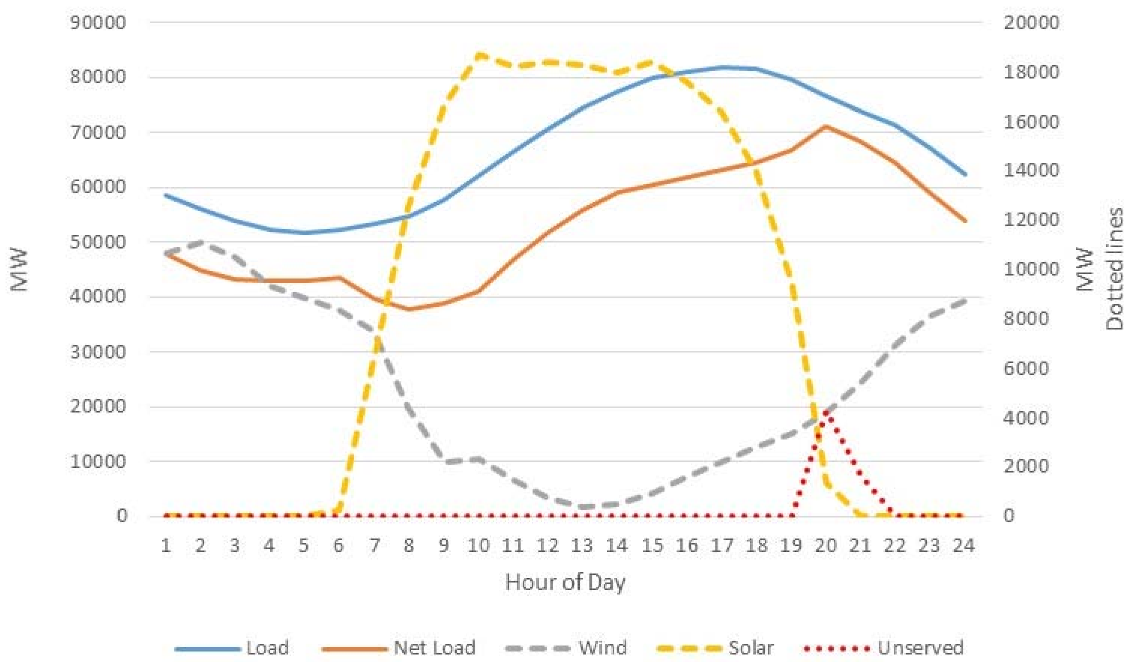

Figure 3.5: Net-peak Load

An indication of the possibility for new technologies to change this outcome was seen in the High Storage/Electric Vehicle Adoption scenario. Results from this scenario indicate that battery storage operated during periods of high solar ramping can reduce the energy shortage during the period of high net-load conditions by the amount of the installed battery capacity.

To analyze the potential for different transmission system needs under peak load and peak net load conditions, ERCOT performed a Net Peak Load Sensitivity Study. Built on the framework of the 2031 Current Trends Summer Peak reliability transmission case, (with 13,505 MW of conventional generation retirements and 20,200 MW of added solar generation), additional system adjustments were made to simulate the net peak load conditions occurring in the late evening hours. Table 3.1 provides the major changes between the Peak Load case and the Net Peak Load Sensitivity Study.

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Table 3.1: Summary of the Differences in Net-peak and Peak Load Conditions

	Current Trends Summer Peak	Current Trends Net Peak	Delta
Wind (MW)	4,089	5,247	**+1,158**
Solar (MW)	17,392	504	**-16,888**
Load (MW)	86,109	74,555	**-11,154**
Losses (MW)	2,506	1,338	**-1,168**
Reserves (MW)	2,499	-542	**-3,041**
Generation Added[3] (MW)	0	3,600	**+3600**

The results of the reliability analyses under the net-peak load conditions indicate that existing and planned transmission infrastructure was adequate to move the power from the online conventional resources to the load. A more detailed description of the transmission results is included in the next section.

3.4 Increased West-to-East Power Flows

The key factors that drive the need for transmission projects are the availability and location of generation resources, the magnitude and concentration of load growth, and the transmission network which connects the two. Appendix D includes maps depicting generator additions and retirements for each of the scenarios studied. In order to understand the results of the transmission analysis and the resulting projects, it is important to understand the changes in the generation fleet and load growth that were modeled in the LTSA. Figures 3.6 through 3.8 depict a common theme in a diverse set of futures: each shows that generation closer to the load centers (i.e., in East, North Central, and South Central regions) were retired and replaced by renewable generation in remote locations (i.e., North, West and Far West regions). This change in generation resulted in increased West-to-East power flows during peak load hours.

[3] 3600 MW of generation was added to address the unserved energy noted in earlier in this section.

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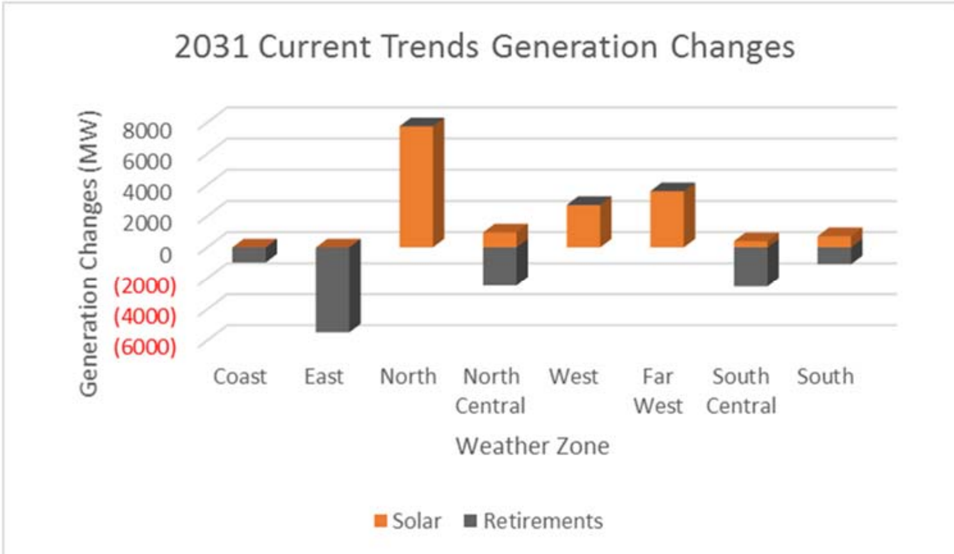

Figure 3.6: Generation Changes in Current Trends Scenario in 2031

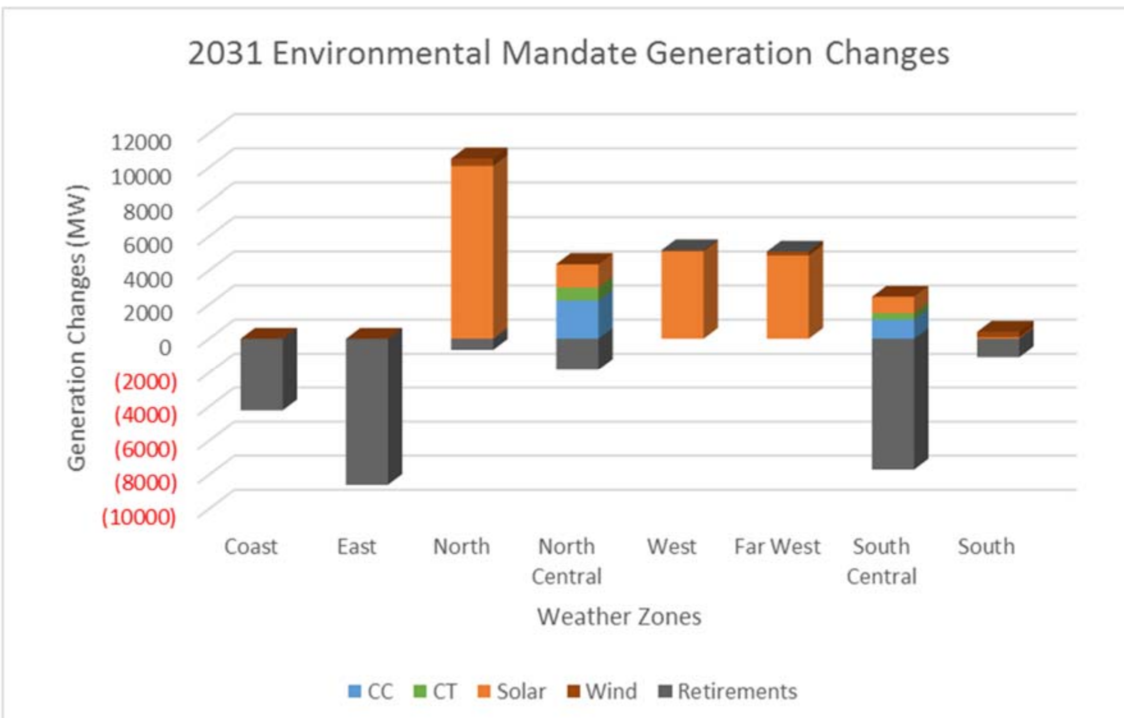

Figure 3.7: Generation Changes in the Environmental Mandate Scenario in 2031

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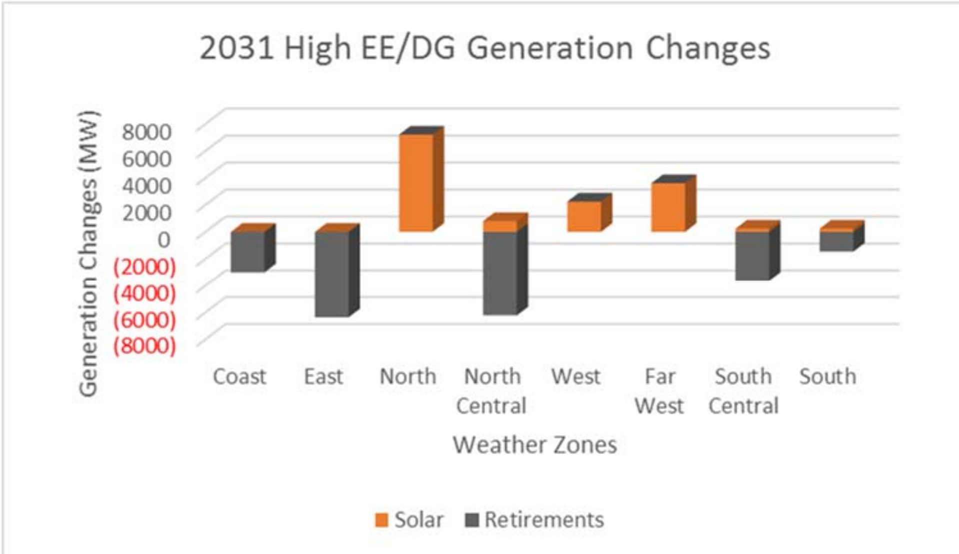

Figure 3.8: Generation Changes in High Energy Efficiency/Distributed Generation Scenario in 2031

Figure 3.9 illustrates the change in generation availability across the three scenarios that were selected for the transmission analysis. The warm colors on the map indicate the location and magnitude of generation capacity that was added in a particular scenario, whereas the cool colors on the map show the loss of generation capacity on the system.

Two common themes that were consistent across all scenarios were the retirements in the eastern portion of Texas and the addition of renewable resources in the Panhandle and the western portion of the state — though the magnitudes differed from scenario to scenario.

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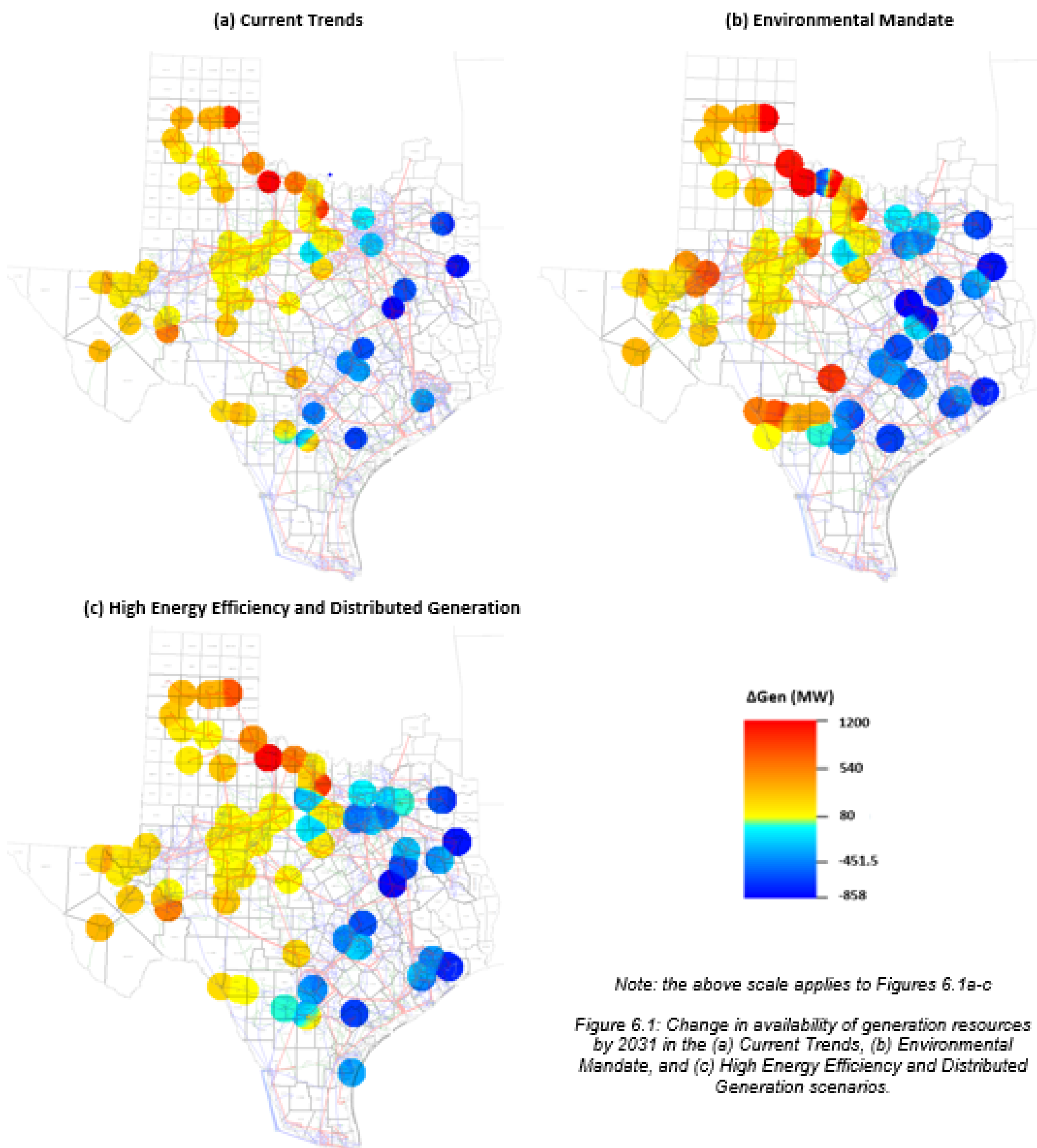

Figure 3.9: Change in Generation Availability by 2031

As the resources closer to the urban centers were retired and new generation resources appeared farther away from the load pockets, the need for new or further reinforcement of existing inter-regional transmission paths increased. This trend was seen previously in the 2014 LTSA Stringent Environmental scenario, in which fossil fuel generation closer to the load centers was replaced by renewable sources primarily sited in West Texas. In this analysis, both the Current Trends and Environmental Mandate scenarios included significant additions of solar generation in the West Texas region. This new generation displaced aging conventional generation closer to the load centers.

This trend also explains why a significant amount of transmission was needed in the High Energy Efficiency/ Distributed Generation scenario. Even though load growth was

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essentially flat in this scenario, the combination of generation retirements and additions caused power flows to change, necessitating the addition of transmission system improvements.

In the 2016 LTSA, many of the selected transmission projects facilitated delivering solar and wind generation from West Texas to Dallas-Fort Worth and the Central Texas region. Studies showed a need for new 345-kV hubs to collect and transfer power from the new solar generators into the 345-kV transmission network feeding load centers to the east.

Transmission analysis indicates that the retirement of conventional generation in the North Central, East, and Coast weather zones could result in the need for upgrades in the West-to-North and West-to-South paths of the transmission interfaces that serve the Dallas-Fort Worth and Central Texas regions, respectively. Figures 3.10 and 3.11 show new enhancements considered in the reliability analysis of Current Trends and Environmental Mandate scenario, respectively. The transmission plan in the Environmental Mandate included the upgrades and additions identified in the Current Trends scenario. It should be noted that the Environmental Mandate scenario also showed a need for transmission improvements resulting from increased import of power into the Houston region.

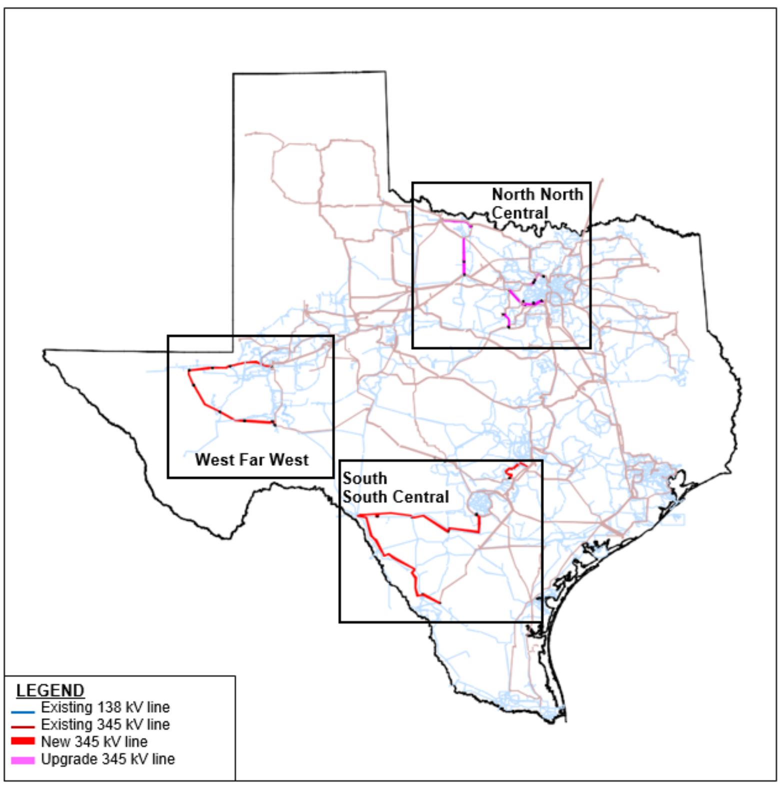

Figure 3.10: Transmission projects in Current Trends scenario (2031)

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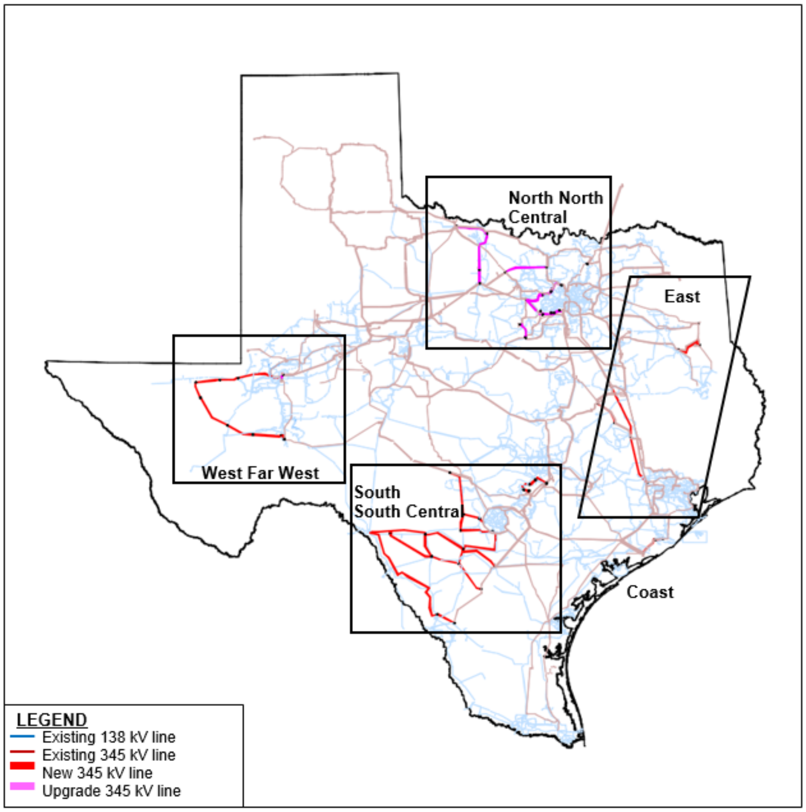

Figure 3.11: Transmission projects in the Environmental Mandate scenario (2031)

In addition to the increased West-to-East power flows observed for summer peak, the Current Trends Net Peak study discussed in Section 3.3 showed some noteworthy results. As seen in Figure 3.12 below, there was a noticeable difference in system flows between the Current Trends Summer Peak and Current Trends Net Peak cases. In Summer Peak, with all solar resources available, there was a substantial West-to-East system flow caused by the added West and Far West solar units serving the load pockets of Houston, and to a greater degree, Dallas-Fort Worth, because of the higher amount of retirements in the North, North Central, and East weather zones. In the Net Peak case, with solar generation declining due to the sun setting, West-to-East power flows were significantly reduced. In fact, in the circled areas below, the Net Peak case showed there would be a reversal of flow in certain areas, changing to East-to-West.

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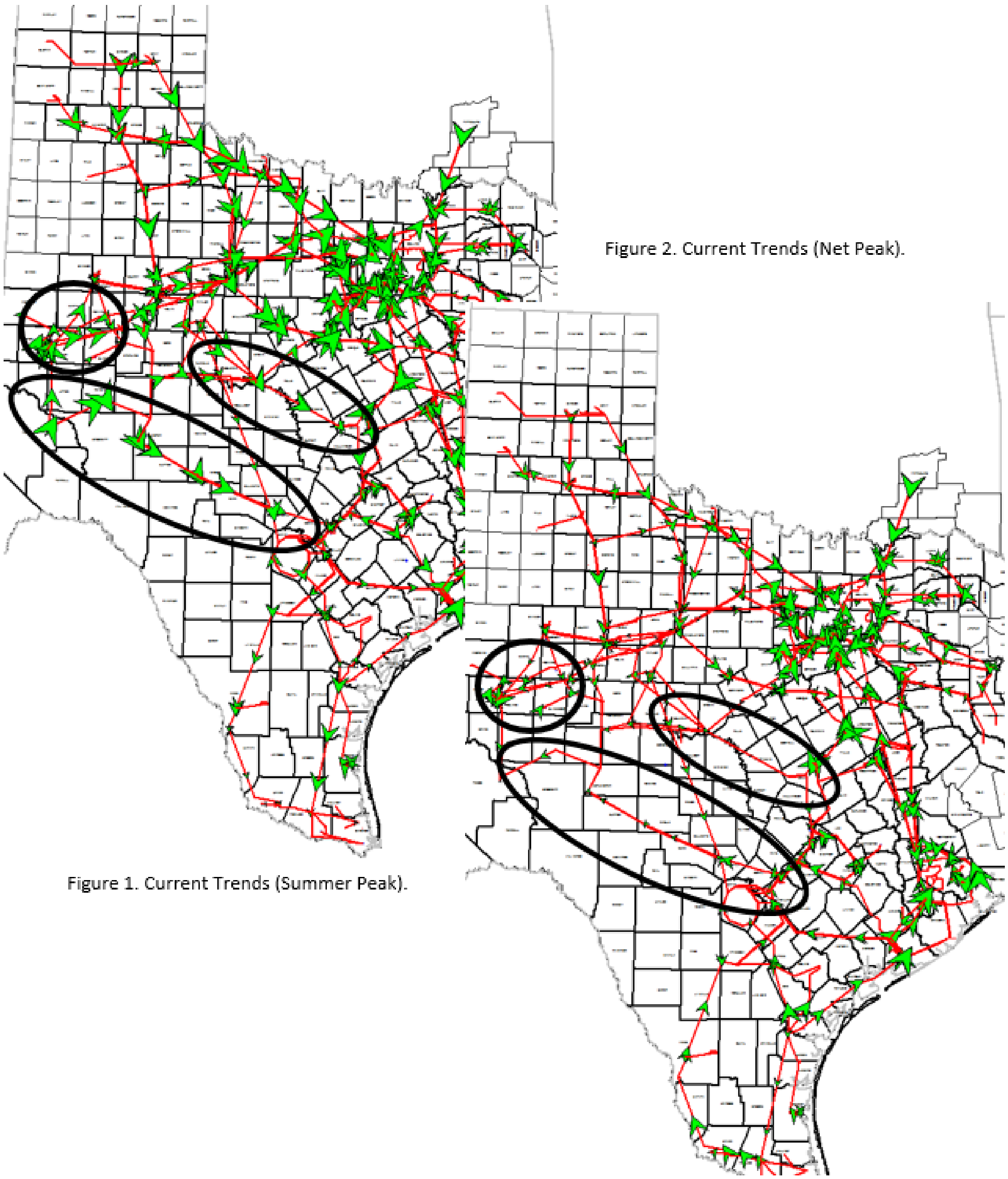

Figure 3.12: Flow Reversal During the Net-peak Load Conditions

Additionally, low voltage issues seen in the Summer Peak case were no longer seen in the Net Peak case. In the Summer Peak case, the North Central load pocket was served primarily by the solar in the West and Far West because of generation retirements in the North, North Central, and East weather zones. The loss of the voltage support from these retired local units, coupled with the transmission losses from power flowing from the West and Far West solar resources, resulted in low voltage conditions at some substations in

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the North Central weather zone in the Summer Peak case. However, the Net Peak case did not indicate these low voltage conditions.

All of the issues discussed above indicate the need to review and update planning processes if large amounts of solar are added to the system in Far West Texas. Current processes are sufficient to study conditions at a specific peak hour and with an assumption that power typically flows in a certain set direction. With a growing number of renewables interconnected in a remote section of the grid, it will be necessary to establish a more flexible planning process to address the larger variety of dispatch patterns and demand levels.

3.5 Panhandle Area Improvements

ERCOT's Panhandle region has experienced significant wind generation additions in recent years. Based on the results from the generation expansion analysis the total amount of the wind and solar generation sited in the Panhandle region increased to 10,275 MW and 13,185 MW in the Current Trends and Environmental Mandate scenarios, respectively. However, the transmission system used to export power from the area is stability limited.

A Panhandle export interface limit of 3,611 MW was enforced on the 345-kV double circuit interface defined by the Gray to Tesla, Tule Canyon to Tesla, Cottonwood to Edith Clarke and Cottonwood to Dermott substations while conducting economic analysis. The limit was based on previous studies assuming existing planned transmission improvements in the area[4]. This limit also assumed a 10% operating margin.

It should be noted that the generation expansion and siting for the 2016 LTSA also included a significant amount of solar generation addition in and around the region. Thus, the existing Panhandle interface definition and the limit may need to be revised to better reflect future generation additions. A detailed dynamic simulation with updated model data would be required to identify the actual Panhandle interface definition and limit. This type of detailed dynamic simulation was not performed as part of this analysis but will be performed as part of future studies.

Economic congestion analysis was performed for the Current Trends, Environmental Mandate, and High Energy Efficiency/ Distributed Generation scenarios. The results showed a large amount of congestion on the Panhandle interface for all scenarios studied. The table below shows the amount of congestion by year under each scenario.

[4] This limit is based on an update at the September Regional Planning Group Meeting (http://www.ercot.com/content/wcm/key_documents_lists/77742/Panhandle_Interface_Limit-Update_RPG_09202016.pptx)

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Table 3.2: Congestion Rent on Panhandle Interface

Year	Current Trends	Environmental Mandate	High EE/DG
2026	$241mm	$661mm	$241mm
2031	$446mm	$866mm	$353mm

The addition of two 175-MVAR synchronous condensers at Windmill substation was economically justified across all the scenarios studied. In addition, ERCOT tested the addition of a new 345-kV transmission line from the Ogallala substation in Castro County in the Panhandle to the Long Draw substation in Bordon County (via the Abernathy substation) in order to relieve the congestion. The results found that this transmission improvement met the ERCOT economic criteria in the Environmental Mandate scenario.

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Chapter 4. Appendices

Appendix A. Scenario Development Workshop

Table A.1: Speakers at 2016 LTSA Workshop

Category	Speaker	Topic
Technology	Michael Goggin, AWEA	Cost and capabilities of future wind technologies
	Colin Meehan, First Solar	Solar growth trends
End Use	Michele Allen, Walmart	Demand side management at big retail stores
	Dr. Varun Rai, Lyndon B. Johnson School of Public Affairs	Adoption of residential rooftop PV
	Mike Legatt, ERCOT	Impact of growth in Electric vehicle on the price of storage
Environmental Regulations	Susana Hildebrand, EFH	Environmental regulations: Overview
	Dana Lazarus, ERCOT	Environmental regulations impacting ERCOT region
Oil and Gas	Gurcan Gulen-Bureau of Economic Geology	Oil and gas growth — impact on other industries
Modeling in LTSA	Doug Murray, ERCOT	Modeling data and sources currently available to ERCOT
	Calvin Opheim, ERCOT	Load forecasting for LTSA Scenarios
Texas Economy	Tom Currah, Texas Comptroller of Public Accounts	Texas Economy

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Table A.2: Drivers Used in 2016 LTSA Workshop

Drivers	Brief description
Economic Conditions	The US and Texas economy, regional and state-wide population, oil & gas, and industrial growth, LNG export terminals, urban/suburban shifts, financial market conditions and business environment
Environmental Regulations and Energy Policies	Environmental regulations including air emissions standards (e.g., ozone, MATS, CSAPR), GHG regulations, water regulations (e.g., 316b), and nuclear safety standards; energy policies include renewable standards and incentives (incl. taxes/financing), mandated fuel mix, solar mandate, and nuclear relicensing.
Alternative Generation Resources	Capital cost trends for renewables (solar and the wind), technological improvements affecting wind capacity factors, caps on annual capacity additions, storage costs, other DG costs, and financing methods.
Natural Gas and Oil Prices	Gas prices are a function of total gas production, well productivity, LNG exports, industrial gas demand growth, and oil prices. Oil prices are dependent on global supply and demand balance, the spread of horizontal drilling technologies. Oil and gas prices will affect drilling locations within Texas.
Government Regulations/Policy/Mandates	New policies around resource adequacy, transmission buildout, interconnections to neighboring regions and cost recovery
Technology	Improvements in technologies resulting in more efficient turbines, or higher capacity factor intermittent resources
End-Use/New Markets	End-use technologies, efficiency standards and incentives, demand response, changes in consumer choices, DG growth, increase interest in microgrids
Weather and Water Conditions	May affect load growth, environmental regulations and policies, technology mix, average summer temperatures, frequency of extreme weather events, water costs

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Appendix B. Load Forecasting

Load Forecast Study Adjustments

ERCOT's load forecasts include losses, which were removed before adjusting load because the software packages used for both reliability and economic analyses account for losses separately from the load. Also, the load forecasts do not include self-served load. The self-served loads were left unchanged from the reliability and economic base cases while the load forecasts (net of losses) were distributed to all other loads in the cases on a by-weather-zone basis. Figure B.1 shows the ninetieth-percentile summer peak load forecasts, calculated as the sum of each weather zone's non-coincident peak used for reliability analysis.

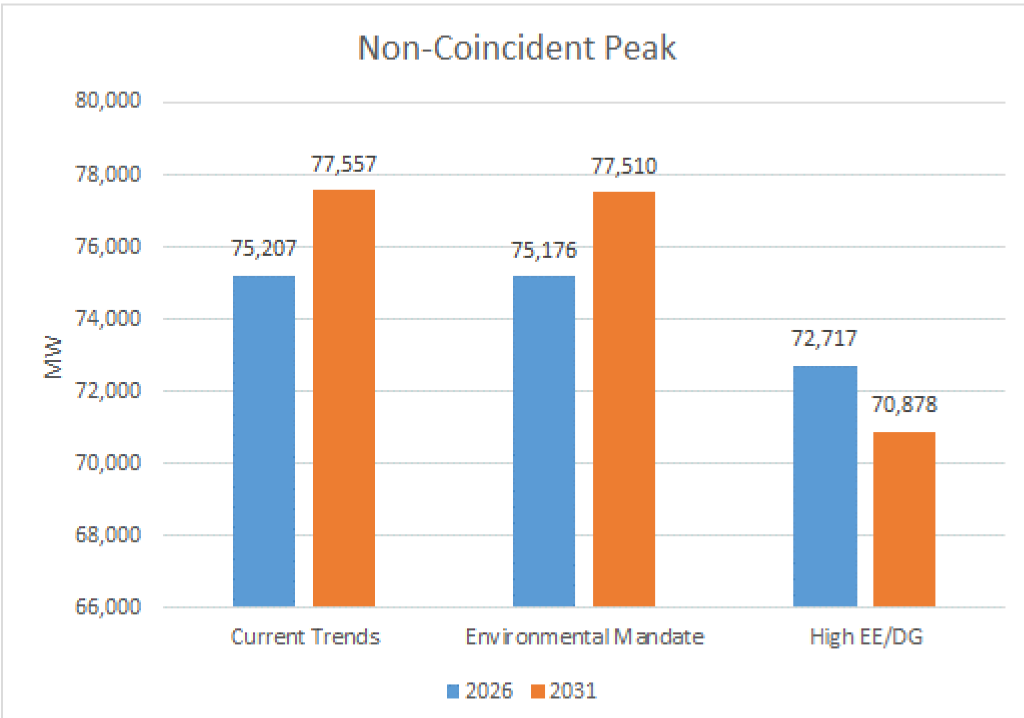

Figure B.1: ERCOT 90th Percentile Peak Loads[5]

Forecast Development

The load forecasts combined econometric input and scenario-specific assumptions as input into forecast models to describe the hourly load in the region. Factors considered included certain economic measures (e.g., nonfarm payroll employment, housing stock, population, number of premises) and weather variables (e.g., heating and cooling degree days, temperature, cloud cover, dew point, and wind speed). A county-level forecast of economic and demographic data was obtained from Moody's. Thirteen years of historical weather data were provided by Schneider Electric for 20 weather stations in ERCOT.

[5] 90th percentile forecast was developed for scenarios selected for transmission expansion analysis

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Detailed documentation on ERCOT's Long-Term Load Forecast can be found on the Long-term load forecast page on the ERCOT website[6].

Load Modeling

ERCOT consists of eight distinct weather zones. Each of these weather zones[7] represents a geographic region within which all areas have similar climatological trends and characteristics. To reflect the unique weather and load characteristics of each weather zone, separate load forecasting models were developed for each of the weather zones. The ERCOT forecast is the sum of all of the weather zone forecasts. A map of weather zones is shown in Figure B.2.

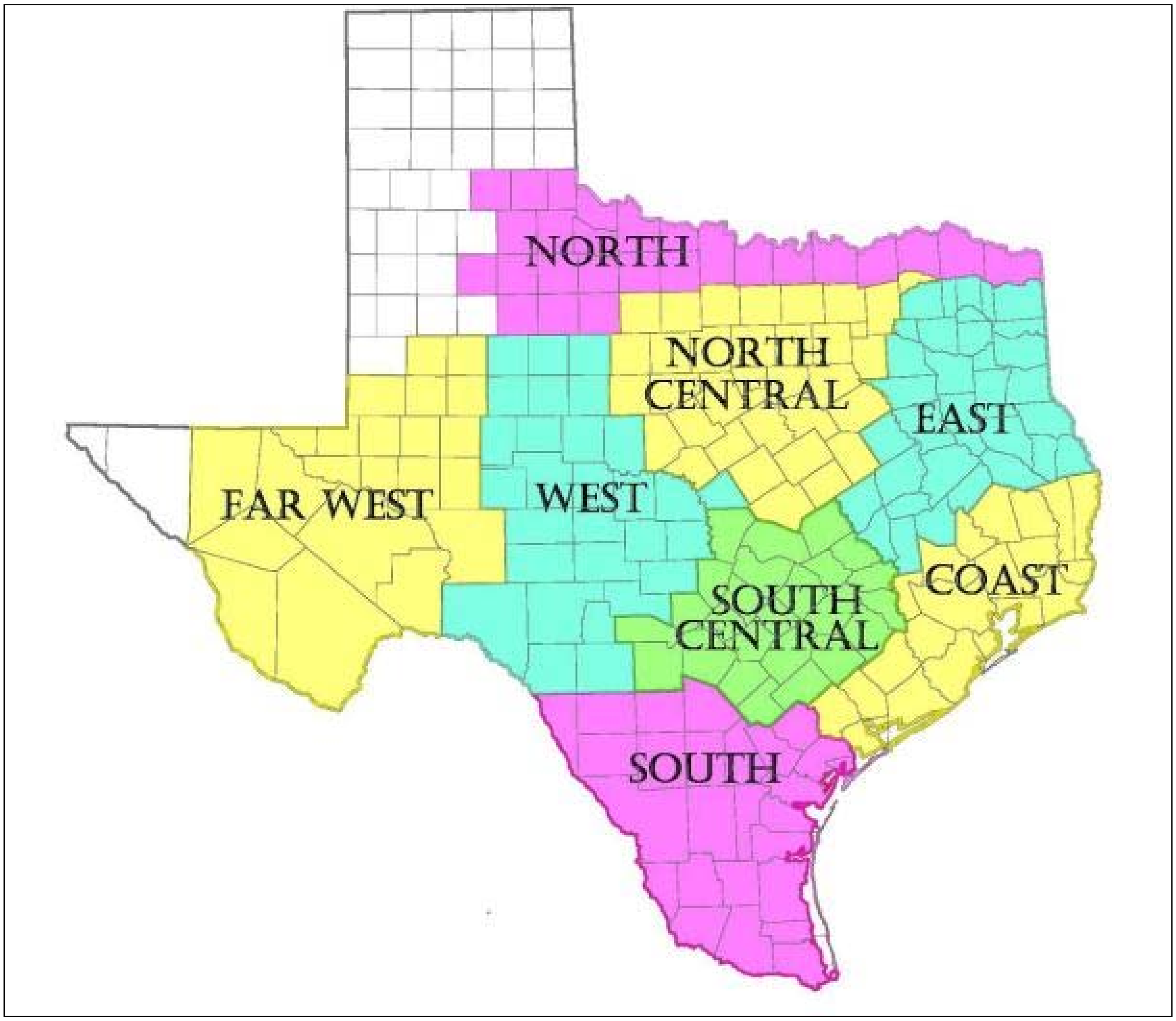

Figure B.2: ERCOT Weather Zones

[6] http://www.ercot.com/gridinfo/load/forecast/index.html
[7] See ERCOT Nodal Protocols, Section 2.

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Model Forecasting

These scenario-specific forecasts used models that combine weather, economic data, and calendar variables to capture and project the long-term trends extracted from the historical load data. The models were developed using historical data from 2009 through the summer of 2015.

Premises were separated into three different customer classes for modeling purposes: residential, business, and industrial. The premise count models consider changes in population, housing stock, and non-farm employment. An autoregressive model (AR1) was used for all premise models.

Hourly Energy Models

The long-term trend in hourly energy was modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable, hourly energy and the following:

1. Month,
2. Day Type (day of week, holiday)
3. Weather Variables,
    a. Cooling Degree Hours[8](base 65),
    b. Heating Degree Hours (base 65),
    c. Lag Cooling Degree Hours (1,2, 3, 24, 48, or 72 previous hours),
    d. Lag Heating Degree Hours (1,2, 3, 24, 48, or 72 previous hours),
    e. Lag Cooling Degree Days[9] (1,2, or 3 previous days),
    f. Lag Heating Degree Days (1,2, or 3 previous days),
    g. Lag Cooling Degree Days from the previous day, and
    h. Temperature,
    i. Lag Temperature (1,2, 3, 24, 48, or 72 previous hours),
    j. Temperature Squared,
    k. Lag Temperature Squared,
    l. Cloud Cover, and
    m. Wind Speed.
4. Interactions
    a. Hour and Day of Week,
    b. Hour and Temperature,
    c. Hour and Cooling Degree Hours,
    d. Hour and Heating Degree Hours,
    e. Premise and Temperature,
    f. Premise and Cooling Degree Hours, and
    g. Premise and Heating Degree Hours.
5. Number of premises[10]

[8] *All Degree Hour variables are calculated versus 65 deg F.*
[9] *All Degree Day variables are calculated versus 65 deg F.*
[10] *Used in Coast, East, North Central, South, and South Central weather zones.*

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6. Non-Farm Employment/Housing Stock/Population[11]

All of the variables listed above are used to identify the best candidates for inclusion in the forecast model and to provide details on the types of variables that were evaluated in the creation of the model. Not every variable listed above was included in each model. Unique models were created for each weather zone to account for the different load characteristics for each area.

Normal Weather (50th-percentile) Forecast

The 2016 LTSA generation expansion and transmission economic analyses use the normal weather (50th-percentile) hourly load forecast. The 2006 weather year was used to represent the 50th percentile in this study.

Ninetieth-Percentile Forecast

The 2016 LTSA transmission reliability analysis uses the 90th-percentile summer peak load forecast. A representation of 90th-percentile weather (weather conditions expected to be seen only once every 10 years) is based on a statistical analysis of peak demand forecasts derived using historical weather patterns from 2002 through 2015.

Premise Forecast

Another key input is the forecast of the number of premises in each customer class. Premise forecasts are developed using historical premise count data and various economic variables, such as non-farm employment, housing stock, and population. ERCOT extracted the historical premise data from its internal settlement databases. The current condition of the United States economy and its future direction is an element of great uncertainty. Thus far, the recent economic downturn has not affected Texas to the same extent as the rest of the United States. This has led to Texas having somewhat stronger economic growth than most of the rest of the nation. Since May of 2010, there has been a reasonably close agreement between actual non-farm employment in Texas and Moody's base economic forecast. Given this trend, ERCOT used the Moody's base economic forecast of non-farm employment in these forecasts. Separate premise forecast models were developed for each weather zone. As required for each scenario, ERCOT adjusted these premise count forecasts to reflect different anticipated load growth. The premises were separated into three different groups for modeling purposes:

1. Residential (including street lighting),
2. Business or small commercial, and
3. Industrial (premises that are required by protocol to have an interval data recorder meter).[12]

Residential Premise Forecast

Residential premise counts were modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable (residential premises) and the following:

[11] *Used in Far West, North, and West weather zones.*
[12] See ERCOT Nodal Protocols, Section 18.6.1.

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1. Housing Stock and
2. Population.

Business Premise Forecast

Business premise counts were modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable (business premises) and the following:

1. Housing Stock,
2. Population, and
3. Non-Farm employment.

Industrial Premise Forecast

Industrial premise counts were modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable (industrial premises), and the following:

1. Housing Stock,
2. Population, and
3. Non-Farm employment.

Premise Model Issues

During the review process for the previously mentioned premise models, two problems were identified.

The first problem, which was noted in the Far West and West weather zones, was that during the historical timeframe used to create the models, there was a significant increase in the number of premises in the middle of 2014. This increase was due to an entity opting in to ERCOT's competitive market and due to an expansion of ERCOT's service territory.

The second problem, which affected the North weather zone, was that premise counts were relatively flat, which made it difficult to be modeled using economic data.

As a result of these two problems, premise forecast models were not appropriate for the Far West, West, and North weather zones. For these three weather zones, ERCOT used economic variables as the key driver in the forecasted growth of demand and energy.

B.1 Forecast Scenarios

Current Trends Forecast

The Current Trends forecast was the base (50th-percentile) forecast used for the analysis. The Current Trends scenario assumed that the Freeport LNG terminals had come online adding 235 MW by summer of 2018 and 706 MW by summer of 2019. Additionally, the Current Trends forecast assumed that energy efficiency would increase from 1% of the summer peak in 2017 to 3.5% of the summer peak in 2031. These changes resulted in the energy efficiency summer peak value increasing from 700 MW in 2017 to

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2,800 MW in 2031. Incremental load forecast adjustments were performed for rooftop solar as 3,500 MW were added by 2031. The Current Trends forecast showed 0.7% average peak load growth through 2031 when it reached a system peak of 77,218 MW.

The Environmental Mandate Scenario Forecast

The Environmental Mandate forecast assumed that the Freeport LNG terminals had come online thus adding 235 MW by summer of 2018 and 706 MW by summer of 2019. Additionally, it was assumed that energy efficiency would increase from 1% of the summer peak in 2017 to 7% of the summer peak in 2031. These changes resulted in the energy efficiency summer peak value increasing from 700 MW in 2017 to 5,600 MW in 2031. Incremental load forecast adjustments were performed for rooftop solar as 6,100 MW were added by 2031. The Environmental Mandate forecast peak demand grew at a 0.4% annual average. Peak demand in the Environmental Mandate forecast reached 74,080 MW in 2031, roughly 3,000 MW lower than the Current Trends forecast.

High Energy Efficiency (EE) & Distributed Generation (DG) Forecast

The High EE/DG forecast assumed that the Freeport LNG terminals had come online thus adding 235 MW by summer of 2018 and 706 MW by summer of 2019. Additionally, it was assumed that energy efficiency would increase from 1% of the summer peak in 2017 to 15% of the summer peak in 2031. These changes resulted in the energy efficiency summer peak value increasing from 700 MW in 2017 to 12,200 MW in 2031. Incremental load forecast adjustments were performed for rooftop solar as 6,100 MW were added by 2031. The High EE/DG forecast provided the lowest peak demand growth scenario for the study. The forecast was 67,541 MW in 2031, which represents a -0.3% annual average compound rate of growth.

High Storage / Electric Vehicle Adoption

The High Storage/Electric Vehicle forecast assumed that the Freeport LNG terminals had come online thus adding 235 MW by summer of 2018 and 706 MW by summer of 2019. Additionally, it was assumed that energy efficiency would increase from 1% of the summer peak in 2017 to 4% of the summer peak in 2031. These changes resulted in the energy efficiency summer peak value increasing from 700 MW in 2017 to 3,250 MW in 2031. Incremental load forecast adjustments were performed for rooftop solar as 3,400 MW were added by 2031. The forecast was 77,618 MW in 2031, which represents a 0.7% annual average compound rate of growth.

Texas Recession

The Texas Recession forecast assumed that the Freeport LNG terminals had come online thus adding 235 MW by summer of 2018 and 706 MW by summer of 2019. Additionally, it was assumed that a recession would occur in 2022. It also assumed that energy efficiency would increase from 1% of the summer peak in 2017 to 3.5% of the summer peak in 2031. These changes resulted in the energy efficiency summer peak value increasing from 700 MW in 2017 to 2,600 MW in 2031. Incremental load forecast adjustments were performed for rooftop solar as 1,200 MW were added by 2031. The

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forecast was 73,576 MW in 2031, which represents a 0.4% annual average compound rate of growth.

High Economic Growth

The High Economic Growth forecast assumed that the Freeport LNG terminals had come online thus adding 235 MW by summer of 2018 and 706 MW by summer of 2019. Additionally, it was assumed included additional LNG facilities in the South with 300 MW added in 2020, 150 MW added in 2021, and 150 MW added in 2022. It also assumed that energy efficiency would increase from 1% of the summer peak in 2017 to 3.5% of the summer peak in 2031. These changes resulted in the energy efficiency summer peak value increasing from 700 MW in 2017 to 2,800 MW in 2031. Incremental load forecast adjustments were performed for rooftop solar as 3,400 MW were added by 2031. The forecast was 78,688 MW in 2031, which represents a 0.8% annual average compound rate of growth.

Sustained Low Natural Gas Price

The Sustained Low Natural Gas Price forecast assumed that the Freeport LNG terminals had come online thus adding 235 MW by summer of 2018 and 706 MW by summer of 2019. Additionally, it was assumed that energy efficiency would increase from 1% of the summer peak in 2017 to 3.5% of the summer peak in 2031. These changes resulted in the energy efficiency summer peak value increasing from 700 MW in 2017 to 2,800 MW in 2031. Incremental load forecast adjustments were performed for rooftop solar as 3,400 MW were added by 2031. The forecast was 77,797 MW in 2031, which represents a 0.8% annual average compound rate of growth.

Extended Extreme Weather

The Extended Extreme Weather forecast was based on weather from 2011. This forecast assumed that the Freeport LNG terminals had come online thus adding 235 MW by summer of 2018 and 706 MW by summer of 2019. Additionally, it was assumed that energy efficiency would increase from 1% of the summer peak in 2017 to 3.5% of the summer peak in 2031. These changes resulted in the energy efficiency summer peak value increasing from 700 MW in 2017 to 2,700 MW in 2031. Incremental load forecast adjustments were performed for rooftop solar as 3,500 MW were added by 2031. The forecast was 82,465 MW in 2031, which represents a 0.7% annual average compound rate of growth.

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Appendix C. Generation Expansion Results

C.1 Current Trends

This scenario is designed to simulate today's market conditions, extended 15 years into the future. One important assumption was the inclusion of the Regional Haze FIP for Texas, which requires certain coal-burning units in ERCOT to retrofit with new scrubbers or upgrade existing scrubbers. Capital costs for wind and solar continued to decline into the middle of the study period and the PTC and ITC extensions were assumed to continue. There was no required reserved margin (excess resources above forecasted peak demand) in this scenario.

Final results for the Current Trends scenario include the addition of 20,200 MW of new solar and 13,505 MW of total retirements. Generation from coal units is down to 16% of total system generation by 2031.

An effect of the large amounts of the wind and solar generation can be seen in the following graph, which shows the potential for scarcity conditions during an evening as solar resources decline due to sunset and wind resources are producing a small percentage of their nameplate capacity. These conditions result in a shortage of capacity in the hour between 8-9 p.m. (20:00-21:00) hours.

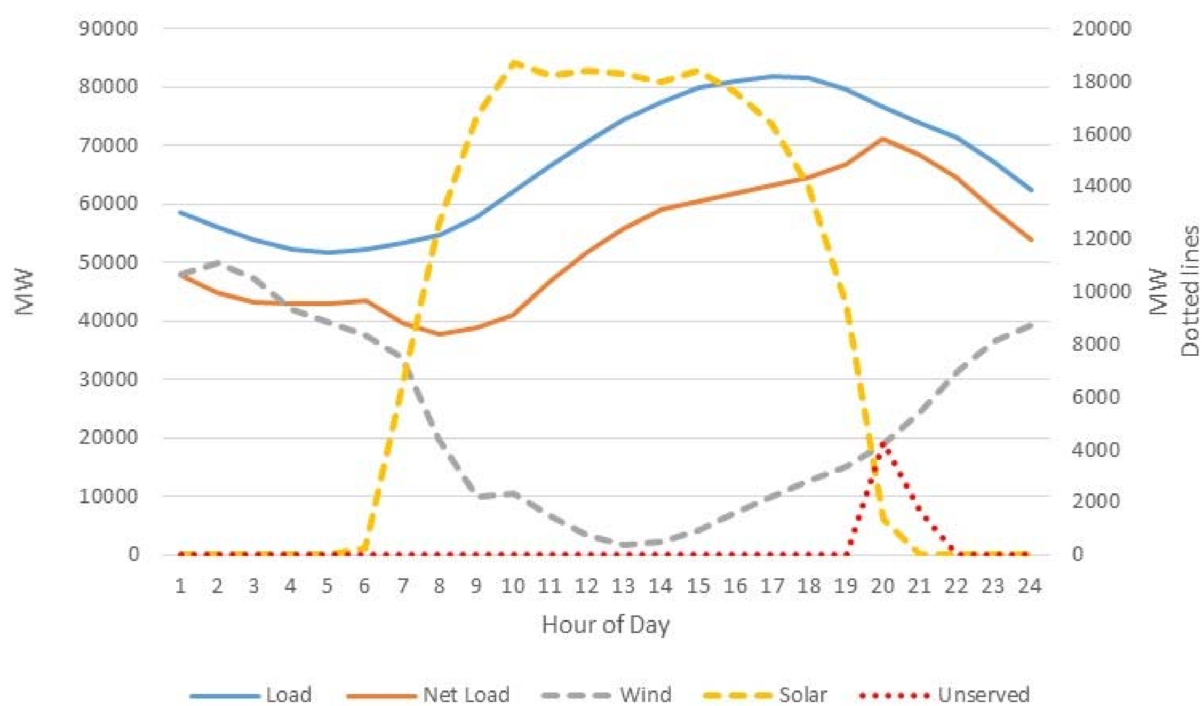

Figure C.1: Net-Load Issue in Current Trends scenario

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This result occurs in all scenarios in the evening hours with high penetrations of the wind and solar.

The following table provides a summary of the generation expansion results for the Current Trends scenario:

Description	Units	2017	2022	2026	2031
CC Adds	MW	-		-	-
CT Adds	MW	-	-	-	-
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	-	-	-
Geothermal Adds	MW	-	-	-	-
Solar Adds	MW	1,100	7,500	4,900	6,700
Wind Adds	MW	-	-	-	-
Annual Capacity Additions	MW	1,100	7,500	4,900	6,700
Cumulative Capacity Additions	MW	1,100	8,600	13,500	20,200
Economic Retirements	MW	721	3,010	3,867	6,377
Retirements due to Regional Haze	MW	-	6,278	-	-
Other Retirements	MW	-	850	-	-
Residential Demand Response	MW	293	328	356	391
Industrial Demand Response	MW	1,172	1,312	1,425	1,565
Reserve Margin	%	22.8	15.9	16.9	10.4
Coincident Peak	MW	74,552	77,284	79,125	81,787
Average LMP	$/MWh	31.26	42.45	52.08	90.38
Natural Gas Price	$/mmbtu	3.74	4.69	5.45	6.28
Average Market Heat Rate	MMbtu/MWh	8.36	9.05	9.56	14.39
Natural Gas Generation	%	39.4	47.1	45.5	43.6
Coal Generation	%	28.1	16.8	16.8	16.1
Wind Generation	%	17.7	17.2	16.5	15.8
Solar Generation	%	1.6	6.2	9.0	12.5
Scarcity Hours	HRS	-	-	3.0	30.0
Unserved Energy	GWhs	-	-	2.1	51.9
SO2	Tons	297,934	88,867	88,040	87,439
CO2	(k) Tons	202,042	178,395	180,669	180,038
NOx	Tons	100,620	74,372	75,355	75,440

Figure C.2: Current Trends Results

C.2 Texas Recession

This scenario is generally marked by a slowdown in all areas of the Texas economy. Load growth slowed with a larger impact felt in counties with economies based on oil and gas exploration. In this scenario subsidies are assumed to continue for wind and solar expansion.

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Results for this scenario provided in the table below indicate that upwards of 17,800 MW of solar could be built while 15,675 MW of retirements is possible. Other than retirements due to the Regional Haze rule most units that retired were older gas-steam driven facilities with operations generally limited to peak system hours.

Description	Units	2017	2022	2026	2031
CC Adds	MW	-		-	-
CT Adds	MW	-	-	-	-
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	-	-	-
Geothermal Adds	MW	-	-	-	-
Solar Adds	MW	1,100	6,100	4,400	6,200
Wind Adds	MW	-	-	-	-
Annual Capacity Additions	MW	1,100	6,100	4,400	6,200
Cumulative Capacity Additions	MW	1,100	7,200	11,600	17,800
Economic Retirements	MW	721	4,087	6,377	8,547
Retirements due to Regional Haze	MW	-	6,278	-	-
Other Retirements	MW	-	850	-	-
Residential Demand Response	MW	293	328	356	391
Industrial Demand Response	MW	1,172	1,312	1,425	1,565
Reserve Margin	%	22.8	18.7	17.4	10.4
Coincident Peak	MW	74,552	73,647	75,450	78,145
Average LMP	$/MWh	31.35	34.94	46.93	73.80
Natural Gas Price	$/mmbtu	3.74	4.69	5.45	6.28
Average Market Heat Rate	MMbtu/MWh	8.38	7.45	8.61	11.75
Natural Gas Generation	%	39.4	45.8	44.3	42.4
Coal Generation	%	28.1	17.3	17.4	16.8
Wind Generation	%	17.1	18.0	17.3	16.5
Solar Generation	%	1.6	5.7	8.3	11.7
Scarcity Hours	HRS	-	-	-	16.0
Unserved Energy	GWhs	-	-	-	24.2
SO2	Tons	297,932	86,321	87,590	87,219
CO2	(k) Tons	202,053	169,832	172,911	172,862
NOx	Tons	100,637	70,911	72,413	72,650

Figure C.3: Texas Recession Results

C.3 High Economic Growth

The High Economic Growth scenario reflects a future in which a large portion of the Texas economy is operating at a high level, mostly driven by the oil and gas sector and related

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upstream and downstream industries. This scenario also included higher natural gas price than in the Current Trends scenario as well as the inclusion of the PTC and ITC for further wind and solar expansion.

As shown in the table below, retirements in this scenario were less than in some other scenarios due to the increase in system demand and energy. Retirements totaled 13,071 MW while added generation totaled 21,921 MW of solar and wind capacity.

Description	Units	2017	2022	2026	2031
CC Adds	MW	-		-	-
CT Adds	MW	-	-	-	-
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	-	-	-
Geothermal Adds	MW	-	-	-	-
Solar Adds	MW	1,300	7,400	5,500	7,500
Wind Adds	MW	-	-	100	121
Annual Capacity Additions	MW	1,300	7,400	5,600	7,621
Cumulative Capacity Additions	MW	1,300	8,700	14,300	21,921
Economic Retirements	MW	-	1,552	2,766	5,943
Retirements due to Regional Haze	MW	-	6,278	-	-
Other Retirements	MW	-	850	-	-
Residential Demand Response	MW	293	328	356	391
Industrial Demand Response	MW	1,172	1,312	1,425	1,565
Reserve Margin	%	22.8	15.8	16.9	13.8
Coincident Peak	MW	75,251	78,640	80,528	83,258
Average LMP	$/MWh	32.68	52.31	67.43	114.03
Natural Gas Price	$/mmbtu	3.74	4.69	5.45	6.28
Average Market Heat Rate	MMbtu/MWh	8.74	11.15	12.37	18.16
Natural Gas Generation	%	37.0	44.2	42.9	40.8
Coal Generation	%	30.6	20.4	19.8	18.8
Wind Generation	%	17.6	16.8	16.2	15.6
Solar Generation	%	1.8	6.2	9.2	13.0
Scarcity Hours	HRS	-	-	5.0	40.0
Unserved Energy	GWhs	-	-	3.5	77.60
SO2	Tons	318,033	102,623	103,261	102,162
CO2	(k) Tons	209,949	191,991	192,643	190,357
NOx	Tons	106,012	84,903	85,183	84,667

Figure C.4: High Economic Growth Results

C.4 High Energy Efficiency / Distributed Generation

The High EE / DG scenario is similar to the Current Trends scenario except for the inclusion of additional amounts energy efficiency, demand response and distributed

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generation (EE/DG). In this scenario, by 2031 EE/DG will account for 15% of ERCOT load and an additional 250 MW of new demand response was added. The model added 17,900 MW of new solar generation and retired 21,654 MW of existing capacity.

The reserve margin in this scenario was 11.6% in 2031 resulting in 22 scarcity hours, which occur mostly in the evening hours similar to the Current Trends scenario results.

Description	Units	2017	2022	2026	2031
CC Adds	MW	-		-	-
CT Adds	MW	-	-	-	-
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	-	-	-
Geothermal Adds	MW	-	-	-	-
Solar Adds	MW	1,100	7,100	4,600	5,100
Wind Adds	MW	-	-	-	-
Annual Capacity Additions	MW	1,100	7,100	4,600	5,100
Cumulative Capacity Additions	MW	1,100	8,200	12,800	17,900
Economic Retirements	MW	721	3,010	6,194	14,526
Retirements due to Regional Haze	MW	-	6,278	-	-
Other Retirements		-	850	-	-
Residential Demand Response	MW	322	361	392	430
Industrial Demand Response	MW	1,289	1,443	1,566	1,720
Reserve Margin	%	23.0	16.9	17.6	11.6
Coincident Peak	MW	74,549	76,463	76,361	72,111
Average LMP	$/MWh	31.23	40.51	49.76	77.41
Natural Gas Price	$/mmbtu	3.74	4.69	5.45	6.28
Average Market Heat Rate	MMbtu/MWh	8.35	8.64	9.13	12.33
Natural Gas Generation	%	39.4	46.8	44.2	38.6
Coal Generation	%	28.1	16.9	17.2	17.4
Wind Generation	%	17.7	17.3	17.1	17.8
Solar Generation	%	1.6	6.1	8.9	10.5
Scarcity Hours	HRS	-	-	2.0	22.0
Unserved Energy	GWhs	-	-	0.8	37.7
SO2	Tons	297,845	88,613	87,571	84,766
CO2	(k) Tons	202,028	176,583	173,835	155,494
NOx	Tons	100,593	73,655	72,763	66,864

Figure C.5: High Energy Efficiency/Distributed Generation Results

C.5 Sustained Low Natural Gas Price

The Sustained Low Natural Gas Price scenario has an natural gas price that remains below $4.00/Mbtu (in nominal dollars) for the entire planning horizon. This low natural gas price would be expected to decrease gas exploration in western Texas while at the same

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time may increase downstream industrial growth. The net effect could be a slightly higher load growth.

The generation expansion is reflective of this low gas price with the lowest amount of new generation built and the lowest amount of retirements. Solar generation accounts for all new capacity, while economic retirements in this scenario were much less than in other scenarios with a total of only 2,289 MW above those due to the Regional Haze rule.

As mentioned earlier a low natural gas price would lead to a decreased dispatch cost for all existing gas units. A low natural gas price would also decrease LMPs, which averaged just over $47 in 2031.

Description	Units	2017	2022	2026	2031
CC Adds	MW	-		-	-
CT Adds	MW	-	-	-	-
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	-	-	-
Geothermal Adds	MW	-	-	-	-
Solar Adds	MW	500	6,800	3,500	3,700
Wind Adds	MW	-	-	-	-
Annual Capacity Additions	MW	500	6,800	3,500	3,700
Cumulative Capacity Additions	MW	500	7,300	10,800	14,500
Economic Retirements	MW	2,289	-	-	-
Retirements due to Regional Haze	MW	-	6,278	-	-
Other Retirements	MW	-	850	-	-
Residential Demand Response	MW	293	328	356	391
Industrial Demand Response	MW	1,172	1,312	1,425	1,565
Reserve Margin	%	21.5	13.5	14.8	8.7
Coincident Peak	MW	74,551	77,875	79,712	82,367
Average LMP	$/MWh	29.81	35.13	38.90	47.35
Natural Gas Price	$/mmbtu	3.37	3.59	3.77	4.00
Average Market Heat Rate	MMbtu/MWh	8.85	9.79	10.32	11.84
Natural Gas Generation	%	52.3	57.2	57.4	57.3
Coal Generation	%	15.7	7.9	6.9	5.9
Wind Generation	%	17.7	17.0	16.4	15.7
Solar Generation	%	1.3	5.4	7.3	9.2
Scarcity Hours	HRS	-	-	3.0	7.0
Unserved Energy	GWhs	-	-	0.4	9.5
SO2	Tons	161,656	48,077	42,731	38,800
CO2	(k) Tons	174,830	161,716	162,955	164,629
NOx	Tons	73,150	59,935	59,873	60,755

Figure C.6: Sustained Low Natural Gas Price Results

C.6 Environmental Mandate

This scenario is meant to depict a future in which aggressive action on mitigating environmental impacts in the energy sector has occurred. In addition to the implementation of the Regional Haze FIP, which was included in all scenarios, this

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scenario also assumed a price on carbon dioxide (CO_2) starting at $5 in 2017 and increasing to $50 in 2031. The combination of continuation of the Production Tax Credit (PTC) and Investment Tax Credit (ITC) and increasing CO_2 costs in this scenario resulted in a large amount of renewable resources being built. While some natural gas generation continues to be built (3,351 MW combined cycles, and 1,140 MW of combustion turbines) the majority of the new generation was from solar and wind, 28,100 MW and 6,924 MW respectively. This results in a total of more than 50,000 MW of variable generation resources on the ERCOT system.

Added to these results is the retirement of more than 25,000 MW of existing ERCOT resources. These retired resources include many of ERCOT's steam gas units as well as most of the coal fleet. The total percent of ERCOT generation from the remaining coal units in 2031 is close to 0%, down from approximately 30% today.

The amount of renewable generation included in this scenario is partially a result of the use of an hourly system dispatch model to develop the resource expansion plan. This type of model does not consider intra-hour balancing requirements and the need for commitment of additional resources to limit the impact of variable generation forecasting error consistent with increased levels of renewable generation integration. Separate studies are being conducted to assess the need for additional system dispatch capability to integrate increasing levels of renewable resources.

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Description	Units	2017	2022	2026	2031
CC Adds	MW	-		1,117	2,234
CT Adds	MW	-	-	190	950
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	-	-	-
Geothermal Adds	MW	-	-	-	-
Solar Adds	MW	1,900	10,000	7,400	8,800
Wind Adds	MW	1,855	-	3,530	1,539
Annual Capacity Additions	MW	3,755	10,000	12,237	13,523
Cumulative Capacity Additions	MW	3,755	13,755	25,992	39,515
Economic Retirements	MW	6,084	8,218	13,313	17,984
Retirements due to Regional Haze	MW	-	6,278	-	-
Other Retirements	MW	-	850	-	-
Residential Demand Response	MW	293	328	356	391
Industrial Demand Response	MW	1,172	1,312	1,425	1,565
Reserve Margin	%	15.7	11.6	15.9	12.9
Coincident Peak	MW	74,549	76,933	78,077	78,650
Average LMP	$/MWh	31.17	69.77	104.80	120.61
Natural Gas Price	$/mmbtu	3.74	4.69	5.45	6.28
Average Market Heat Rate	MMbtu/MWh	8.33	14.88	19.23	19.21
Natural Gas Generation	%	46.8	53.7	51.4	47.1
Coal Generation	%	1.3	4.2	0.1	-
Wind Generation	%	18.2	17.6	19.9	20.4
Solar Generation	%	2.1	7.9	11.9	16.7
Scarcity Hours	HRS	-	10.0	31.0	38.0
Unserved Energy	GWhs	-	8.4	60.0	95.1
SO2	Tons	192,131	30,801	3,319	1,030
CO2	(k) Tons	178,218	143,605	125,067	111,377
NOx	Tons	74,798	51,308	44,300	39,845

Figure C.7: Environmental Mandate Results

C.7 High Storage / Electric Vehicle Adoption

This represents a new scenario for the generation expansion and analysis process. In this scenario, utility and residential storage systems, along with the adoption of large amounts of electric vehicles are incorporated as base assumptions. At the transmission system level, 500 MW of batteries and 500 MW of Compressed Air Energy Storage (CAES) were added. Residential battery additions totaled 1,000 MW. Electric vehicle penetration was assumed to be 20% of the approximately 8 million passenger vehicles on Texas roads today. Using potential charging patterns and assuming that vehicle charging would be controlled primarily by local utilities, the resulting impact to system demand would be approximately 3,000 MW. With most of this charging occurring overnight, an additional 3,000 MW did not represent a significant impact to the ERCOT system.

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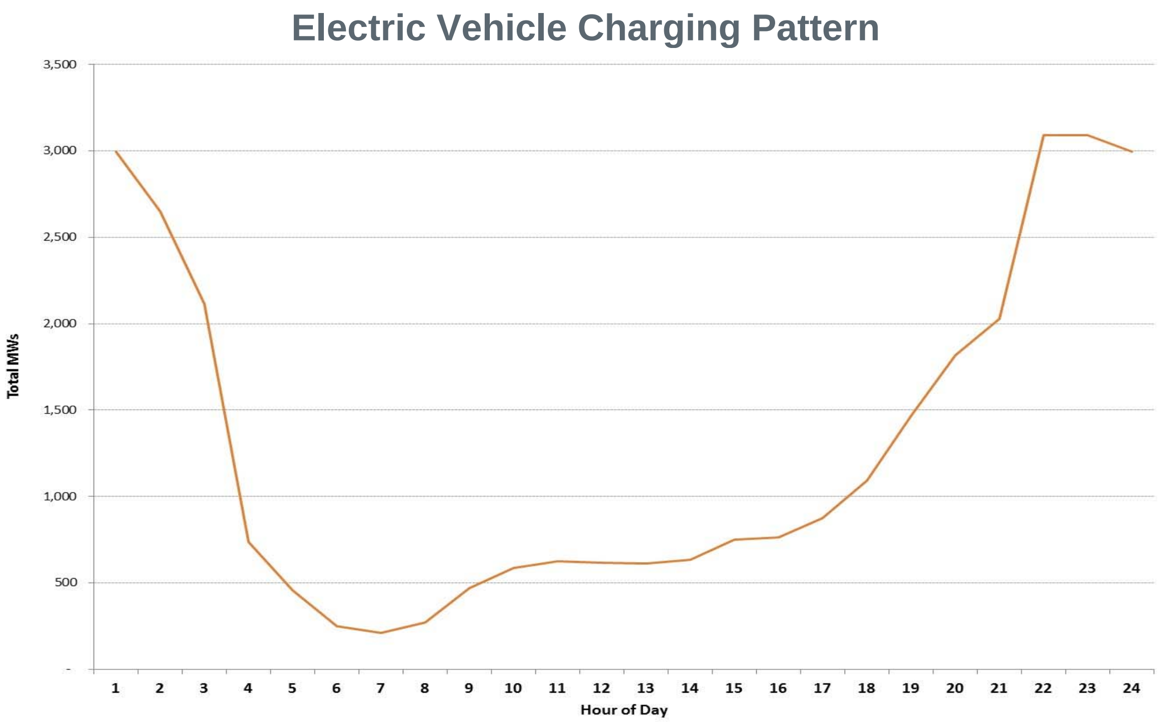

Figure C.8: Aggregate Electric vehicle charging pattern

The scenario results indicate that the combination of solar and storage could reduce system generation needs in the future. Storage operation was primarily seen during periods of high solar ramping in the early morning and late evening. The generation expansion process in this scenario resulted in 15,600 MW of solar being added while retirements totaled 11,571 MW.

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Description	Units	2017	2022	2026	2031
CC Adds	MW	-		-	-
CT Adds	MW	-	-	-	-
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	-	-	-
Battery Adds	MW	-	-	-	40
Solar Adds	MW	1,100	7,100	4,800	2,600
Wind Adds	MW	-	-	-	-
Annual Capacity Additions	MW	1,100	7,100	4,800	2,640
Cumulative Capacity Additions	MW	1,100	8,200	13,000	15,640
Economic Retirements	MW	978	3,267	4,223	4,443
Retirements due to Regional Haze	MW	-	6,278	-	-
Other Retirements	MW	-	850	-	-
Residential Demand Response	MW	293	328	356	391
Industrial Demand Response	MW	1,172	1,312	1,425	1,565
Reserve Margin	%	24.2	16.8	17.5	9.4
Coincident Peak	MW	74,551	77,291	79,219	81,187
Average LMP	$/MWh	31.49	41.94	53.11	73.70
Natural Gas Price	$/mmbtu	3.74	4.69	5.45	6.28
Average Market Heat Rate	MMbtu/MWh	8.42	8.94	9.74	11.74
Natural Gas Generation	%	38.9	47.2	45.9	46.3
Coal Generation	%	28.6	17.0	17.0	16.6
Wind Generation	%	17.7	17.1	16.3	15.5
Solar Generation	%	1.6	6.0	8.6	9.7
Scarcity Hours	HRS	-	-	3.0	12.0
Unserved Energy	GWhs	-	-	2.0	16.5
SO2	Tons	304,635	89,720	92,130	95,094
CO2	(k) Tons	203,186	180,380	184,915	192,939
NOx	Tons	101,608	74,996	77,384	80,978

Figure C.9: Electric Storage/Electric Vehicle Adoption Results

C.8 Extended Extreme Weather

In 2011, Texas had its driest summer on record, an event that was widely publicized in the news media and was a concern for many water users, including power generators. From October 2010 through May 2015, drought conditions persisted throughout the state of Texas. This period was, on average, the second-worst drought in Texas, after the 1950 – 1957 drought, which remains the drought of record for planning purposes in Texas. Previous studies[13] of drought in the ERCOT region have indicated that, while short-term drought conditions could affect generation operations, multi-year droughts may pose a greater risk, due to the potential for multiple years of drought conditions gradually draining reservoir storage.

[13]Argonne National Laboratory. *Impact of Future Climate Variability on ERCOT Thermoelectric Power Generation*, January 2013. Available at http://www.ipd.anl.gov/anlpubs/2013/03/75723.pdf.
Black & Veatch. *Water Use and Availability in the ERCOT Region -Drought Analysis*, December 2013.Available at http://www.ercot.com/content/committees/other/lts/keydocs/2013/ERCOT_Water_Use_and_Availablility_-_DrtRpt_1DF.pdf.

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ERCOT stakeholders included the extreme weather scenario in the LTSA to represent an extended period of extreme weather conditions, in which sustained water stress conditions affect the availability of thermal and hydro generation. In this scenario, ERCOT assumed a six-year drought would occur between the years 2022 and 2027. To develop a set of assumptions about possible generating unit derations and outages resulting from these conditions, ERCOT considered three types of water-related generating unit impacts: thermal unit outages due to water supply availability, thermal unit derations due to water temperatures approaching permit limits, and hydro unit derations and outages. Generation technology types considered for potential water-related impacts included nuclear, coal, natural gas steam turbines, natural gas combined cycles, and hydro.

A set of assumptions about generating units potentially affected by water supply availability during the simulated drought was developed using the ERCOT drought risk prediction tool. This tool screens for potential drought-related impacts to generation resources based on generator information, current reservoir and lake levels, and historical trends in water use.[14] Based on the tool predictions, a subset of generating units was assumed to be derated and subsequently to be put on extended forced outage during the latter years of the simulated drought.

Additionally, most power plants have temperature limits in their water discharge permits. Drought conditions, which typically correspond to high temperatures in the summer months, may result in water discharge temperatures approaching these limits, which could result in outages or derations for affected units. For this study, ERCOT assumed that a small number of generating units would be derated between 1 and 10% of nameplate capacity during summer afternoons during the years of the drought.

Finally, the extreme weather scenario assumed that all hydro generating units would be derated in the early years of the drought and would be unavailable in the latter years of the drought. This assumption was based on ERCOT's experience during the 2010-2015 drought, during which generation from hydro units was significantly reduced, especially in the latter years of the drought.

These impacts, when combined, resulted in aggregate generation unit derations and outages ranging from 200 MW in 2022 (the first year of simulated drought conditions) to 13,000 MW by 2027 (the sixth and final year of simulated drought conditions). All assumptions about unit derations and outages were removed at the conclusion of the drought in 2028.

[14] More information about ERCOT's drought risk analysis reports and reservoir prediction methodology is available at http://www.ercot.com/gridinfo/resource.

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Description	Units	2017	2022	2026	2031
CC Adds	MW	-		3,900	-
CT Adds	MW	-	950	5,138	-
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	-	-	-
Geothermal Adds	MW	-	-	-	-
Solar Adds	MW	1,700	10,000	8,000	7,500
Wind Adds	MW	969	307	2,068	-
Annual Capacity Additions	MW	2,669	11,257	19,106	7,500
Cumulative Capacity Additions	MW	2,669	13,926	33,032	40,532
Economic Retirements	MW	979	4,034	4,034	13,745
Retirements due to Regional Haze	MW	-	6,278	-	-
Other Retirements	MW	-	850	-	-
Residential Demand Response	MW	293	328	356	391
Industrial Demand Response	MW	1,172	1,312	1,425	1,565
Reserve Margin	%	23.6	10.9	9.8	16.8
Coincident Peak	MW	74,551	81,040	84,312	81,825
Average LMP	$/MWh	32.41	82.74	102.42	75.90
Natural Gas Price	$/mmbtu	3.74	4.69	5.45	6.28
Average Market Heat Rate	MMbtu/MWh	8.67	17.64	18.79	12.09
Natural Gas Generation	%	36.0	44.3	42.6	36.6
Coal Generation	%	30.5	18.4	15.7	16.9
Wind Generation	%	18.4	17.2	18.2	18.1
Solar Generation	%	2.0	7.8	11.9	16.3
Scarcity Hours	HRS	-	24.0	34.0	14.0
Unserved Energy	GWhs	-	30.0	57.8	23.7
SO2	Tons	315,476	99,663	93,456	95,242
CO2	(k) Tons	205,466	187,510	174,429	167,134
NOx	Tons	104,289	80,449	66,633	71,195

Figure C.10: Extended Extreme Weather Results

The results of this scenario may seem counterintuitive. With the reduction in capacity for most thermal units for the period of the drought, the average LMPs rose to greater than $100, allowing sufficient revenue to prevent retirement of older resources. Also during this period large amounts of solar, wind, along with air- cooled combined cycles and combustion turbines were developed to meet the increased load. At the end of the drought period load returned to normal levels, all capacity that was reduced due to lack of water returned to service causing retirements to spike, and annual average LMPs returned to $75 by 2031. By the end of the study period, 40,532 MWs of new capacity had been added and 20,873 MW of capacity retired, with a large amount occurring in the final few years of the planning period. Additionally, wind and solar generation in 2031 provided 18.1% and 16.3%, respectively, of total system load.

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Appendix D. Transmission Expansion Analysis

D.1 Base Case Creation

For the three scenarios selected for transmission needs analysis, the 2021 case from the 2015 RTP was used as the starting point for the transmission reliability analysis portion of this study. This case included the transmission upgrades that were recommended as a result of the reliability and economic analyses from the 2015 RTP.

To prepare the LTSA transmission reliability cases, a 90th-percentile, scenario-specific summer-peak load forecast by weather zone was used for the 2026 and 2031 loads in the models.

Scenario-specific portfolios of incremental generation resources were also added to the transmission base case to support anticipated load growth. Table D.1 shows a summary of the base cases used for 2016 LTSA reliability analysis.

Table D.1: Summary of Reliability Analysis Base Case

	Current Trends		Environmental Mandate		High EE and DG	
	2026	2031	2026	2031	2026	2031
CC Adds	-	-	1117	3351	-	-
CT Adds	-	-	190	1140	-	-
Net Solar Adds [a]	10800	16160	15440	22480	10240	14320
Net Wind Adds [b]	-	-	733	1077	-	-
Net Gen Additions	10800	16160	17480	28048	10240	14320
Gen Retirements	9981	12469	19388	24045	12288	20680
Net Generation Change	819	3691	-1908	4003	-2048	-6360
DC Tie Adds	-	-	2000	2000	-	-
SVCs Added (MVAr)	400	1147	1965	4920	0	200
Load (90th Percentile) [c]	83980	86055	83788	85351	75605	73805
Losses	2.49%	2.89%	4.12%	5.53%	2.22%	2.75%

The location of the new generation resources was determined based on the limitations of the technology; certain technologies such as combustion turbines are more flexible and can be built in many areas across the state, whereas solar and wind resources are limited

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by the availability of the natural resources. Figures D.1, D.2, and D.3 show the results of generation siting in the three scenarios considered for transmission expansion analysis. The resources were modeled in the cases at the appropriate buses as outlined in the guidelines from the generation siting methodology.

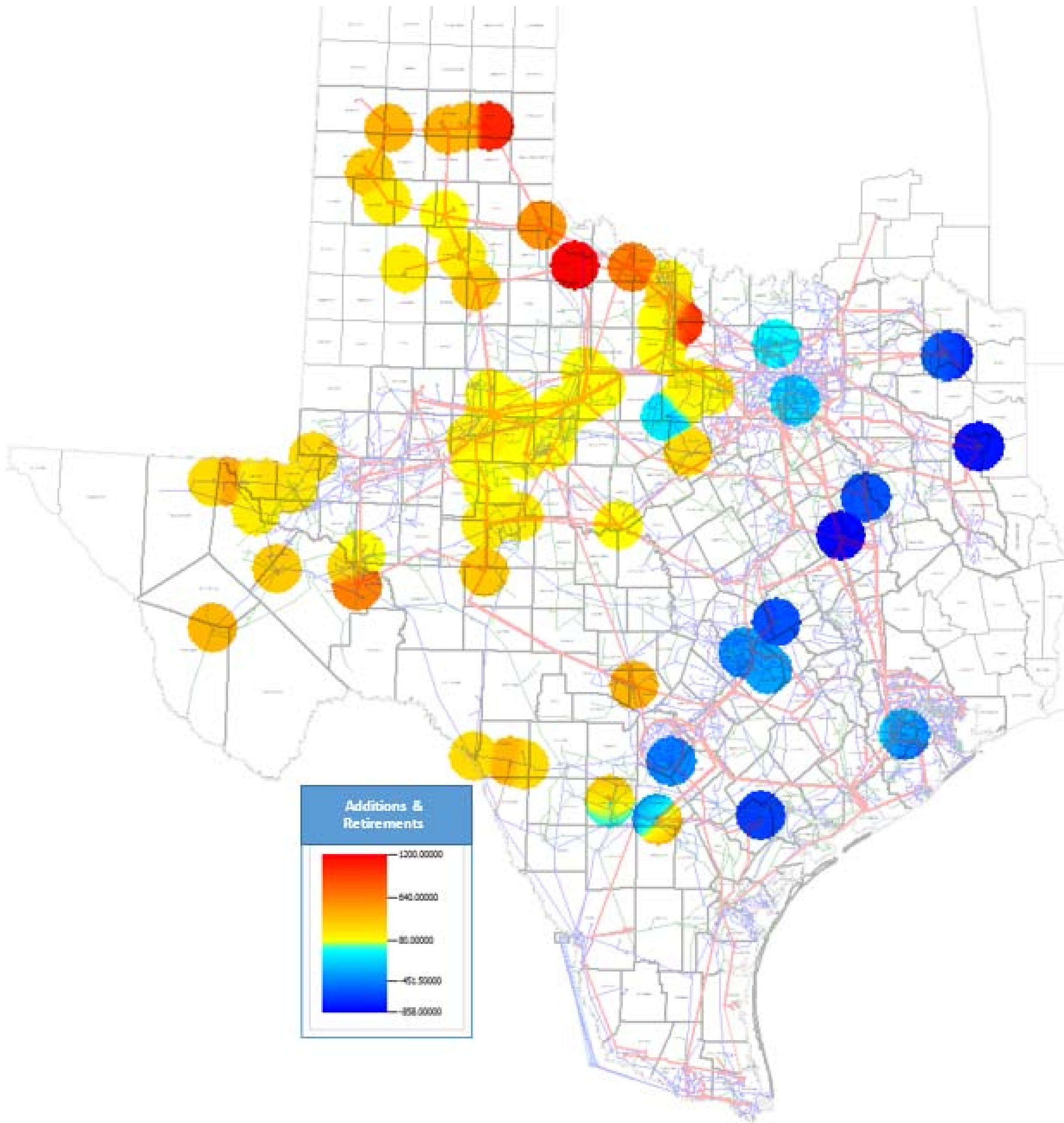

Figure D.1: Generation Additions and Retirements in 2031 Current Trends Case

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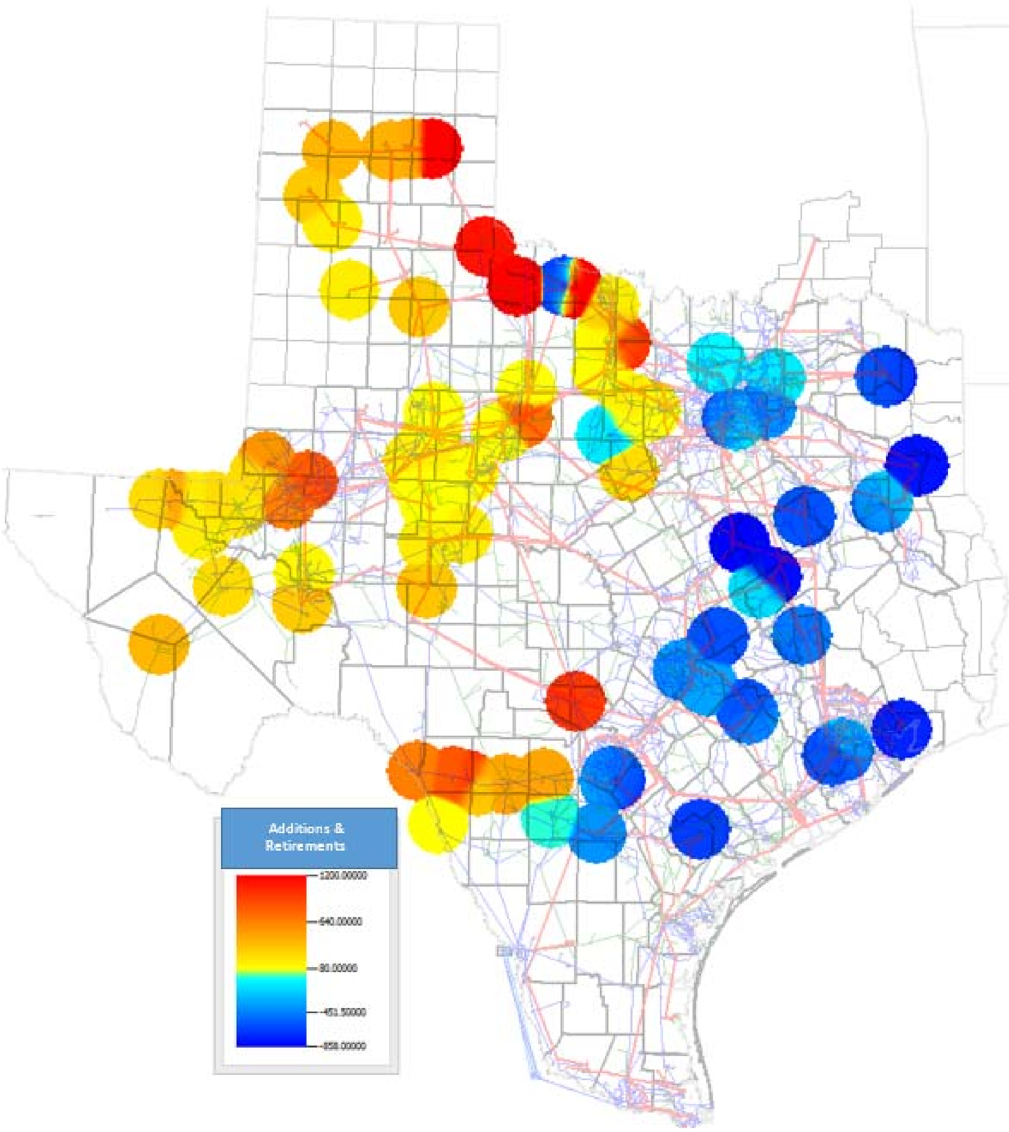

Figure D.2: Generation Addition and Retirement in Environmental Mandate Case

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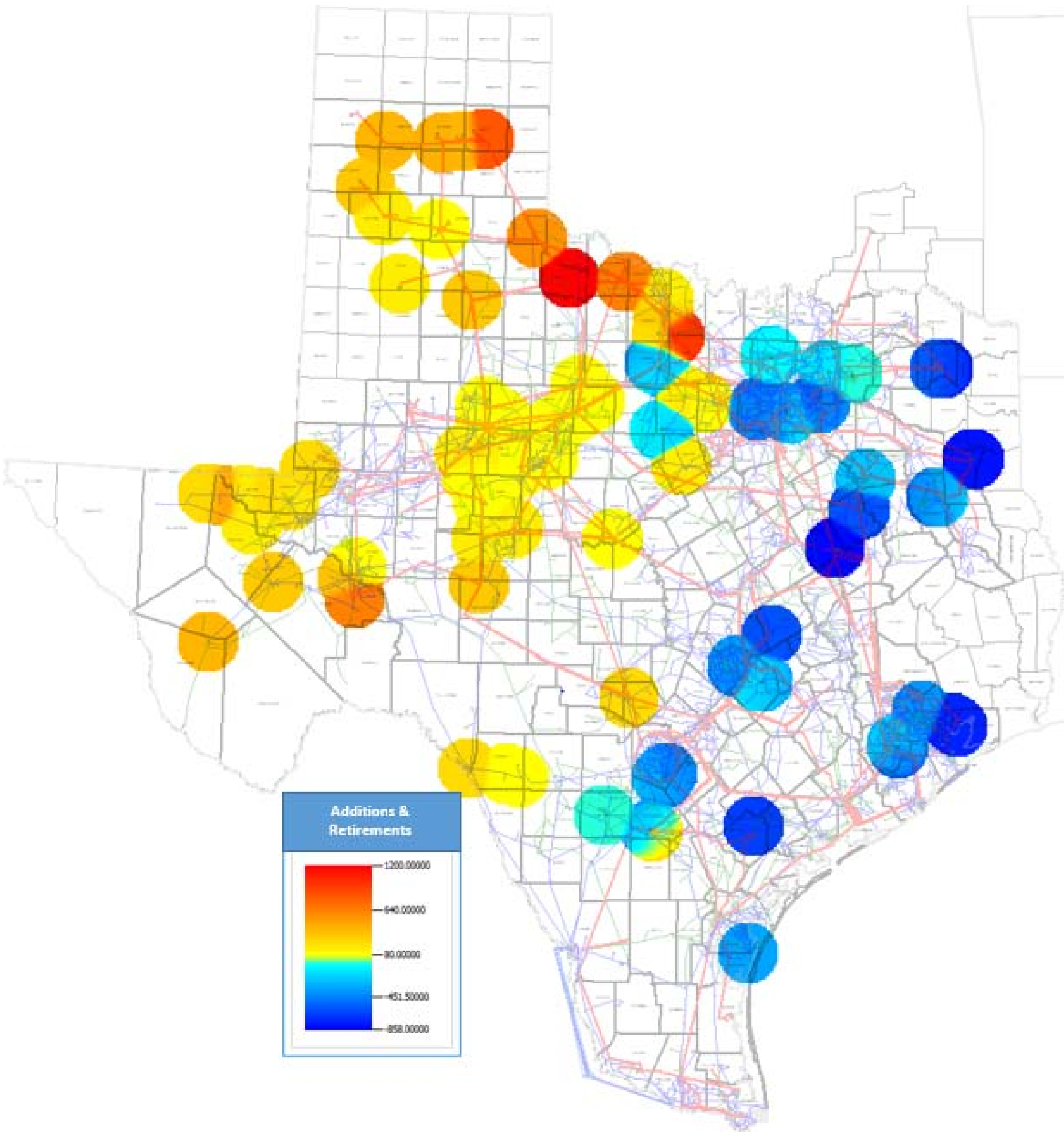

Figure D.3: Generation Additions and Retirements High Energy Efficiency and Distributed Generation Case

In addition to the load and generation updates, any near-term transmission projects that had not been endorsed by ERCOT RPG review process at the time of this study were removed from the case. Similarly, generating units were retired consistent with the resource expansion results.

The transmission reliability analysis was performed for summer peak conditions, per the guidelines set in the LTSA Scope document. Consistent with the RTP, ERCOT used a 90th-percentile load forecast to represent the critical weather conditions during the summer peak timeframe.

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D.2 Reliability Analysis

ERCOT conducted reliability analysis on each of the scenario-appropriate base cases created for 2026 and 2031 to determine the potential transmission needs of the system. ERCOT studied NERC TPL-001-4 Planning Events (P0, P1, and P7), which include the loss of a generator, a transmission circuit, transformer, or a shunt device. The P7 planning events also included the loss of double circuit lines that share towers for more than half a mile. In addition to above contingencies, certain P3 planning events (specifically the loss of a large generation resource followed by another contingency) were also included in the evaluation.

Contingencies at all voltage levels were evaluated while only criteria violations on the 345-kV network were monitored, as any needed 138-kV and 69-kV network upgrades will likely be addressed through the near-term planning process. Overloaded 345-kV elements requiring upgrades regardless of system dispatch were addressed and documented as reliability upgrades. In a later part of the study, reliability upgrades were compared to other project alternatives that resolved the same issues to identify lowest total cost options.

ERCOT worked with associated TSPs to develop potential long-term upgrades for the overloaded elements identified in the reliability analysis.

Findings from Reliability Analysis

Reliability analysis was conducted with a focus on 345-kV network. The following sections describe the findings from reliability analysis in further detail.

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South and South Central upgrades

Figures D.4 through D.6 depict major projects noted in the reliability transmission analysis for the South and South Central weather zones.

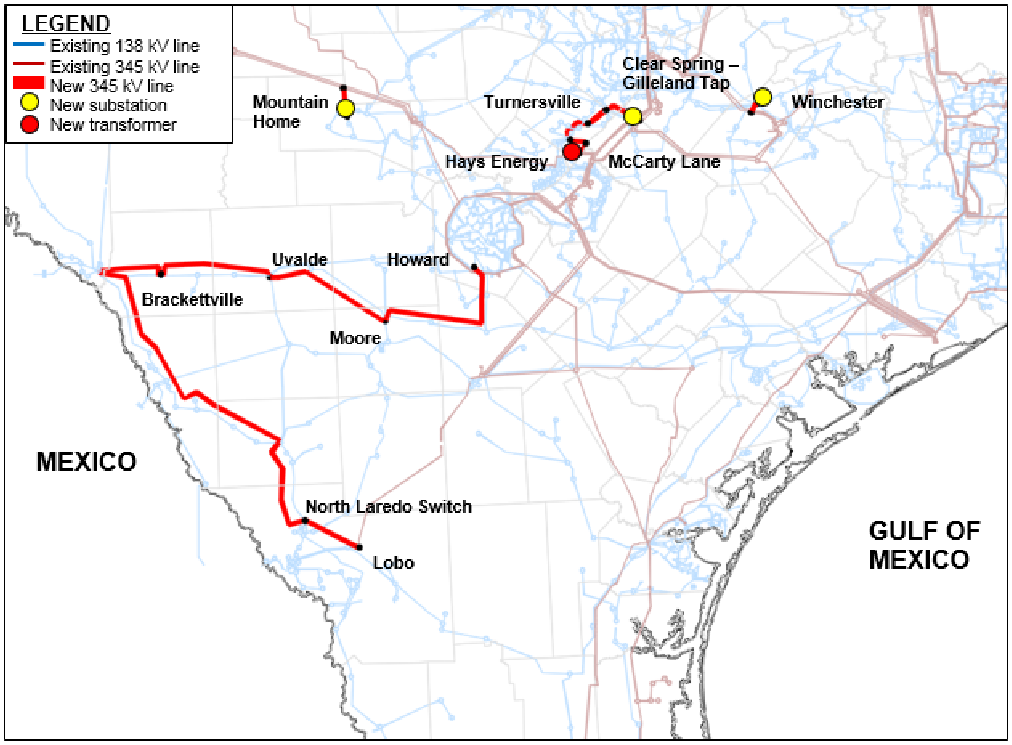

Figure D.4: Current Trends 2031-South and South Central Region Upgrades

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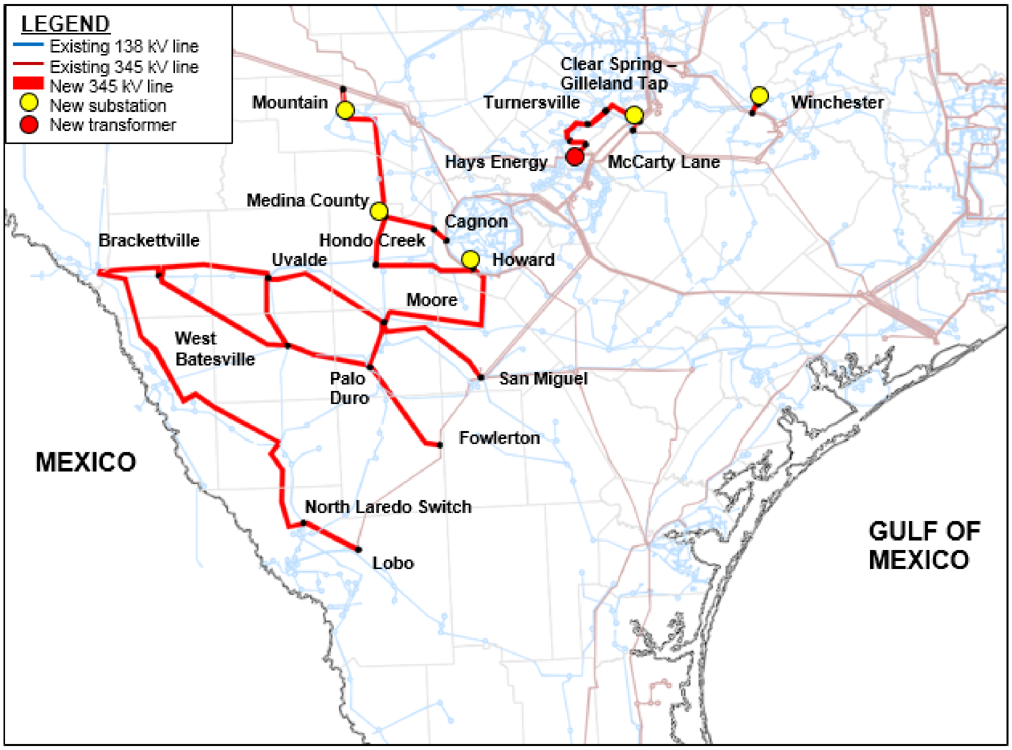

Figure D.5: Environmental Mandate 2031-South and South Central Region Upgrades

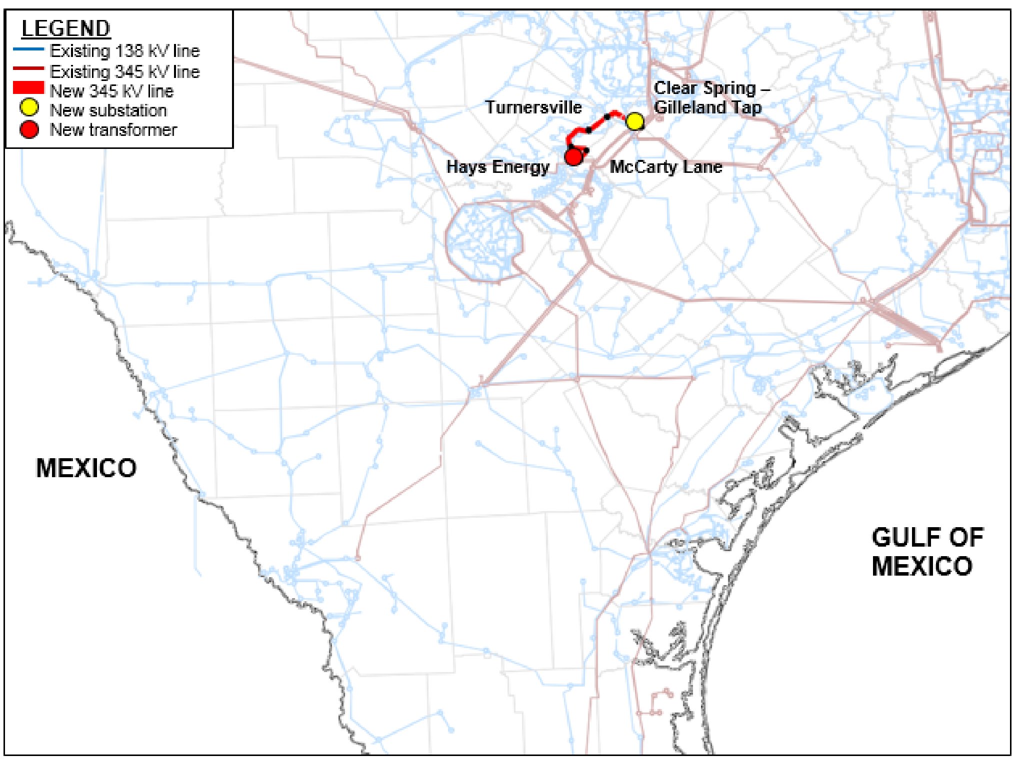

Figure D.6: High EE/DG 2031-South and South Central Region Upgrades

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Renewables West of San Antonio Project:

During the LTSA reliability studies, a number of thermal violations were observed when renewable generation was added to the existing 138-kV system in the area west of San Antonio. This area had solar additions of approximately 2 GW in the Current Trends Scenario, 3.5 GW in the Environmental Mandate Scenario, and 0.5 GW in the High EE/DG Scenario. In addition to the thermal violations, there were power losses as the power flowed over the 138-kV system to the load centers. The projects described below facilitated the additional renewable generation by tapping both of the 345-kV lines between Cagnon and Von Rose/Spruce substations in Bexar County and adding a 345-kV substation at Howard in Bexar County. Then 345-kV lines were added in a path from this new 345-kV substation at Howard to Brackettville substation in Kinney County and Lobo substation in Webb County. Additionally, the connection points for the new 345-kV lines were chosen so that a number of the 138-kV lines could be rebuilt at the same time assuming the towers were double circuit-capable.

Project Description:

- Alternative 1: A new 345-kV path from Howard to Lobo via the Moore, Uvalde, Brackettville, Asherton and North Laredo Switch substations. The routing of the new 345-kV lines could allow a number of the 138-kV lines to be rebuilt at the same time if the towers are double-circuit capable.
- Alternative 2: Instead of connecting the new 345-kV path at Howard, the line connecting to the CPS system could be Moore to Cagnon.
- Alternative 3: Instead of connecting the new 345-kV path at Howard, the line connecting to CPS could be Moore to Cagnon. Also, another 345-kV line could be added from San Miguel to Howard.
- Alternative 4: Instead of connecting the new 345-kV path at Howard, the line connecting to CPS could be Moore to Cagnon. Also, additional 345-kV lines could be added from Moore to San Miguel to Howard.
- Alternative 5: If relatively high amounts of renewable generation are added to this area, as seen in the Environmental Mandate Scenario, then additional 345-kV lines may be justified. Potential 345-kV circuits could connect the Brackettville and Fowlerton substations through West Batesville and Palo Duro, as well as San Miguel to Palo Duro through the Moore substation.
- Alternative 6: If relatively low amounts of renewable generation are added to this area, as seen in the High Energy Efficiency and Distributed Generation Scenario, then improvements to the existing 138-kV system could be sufficient. Likely candidates for upgrades would include: the path from Hamilton to Maverick to Eagle Highway Tap to Escondido to Rosita Creek to Pueblo to West Conoco to Dimmit to Bevo to Asherton. Another 138-kV path that would need to be rebuilt is Hamilton to Brackettville to Odlaw Switchyard to Asphalt Mines to Uvalde to West Batesville to Asherton.

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New 345-kV Lines from Hays Energy to Turnersville to a New Substation East of Turnersville:

In the LTSA cases, solar generation was added in the west, and a number of conventional generators were retired in the east. This increased the west-to-east power flow into the Central Texas region. As a result, the double-circuit 345-kV lines from Hays Energy substation in Hays County to Zorn Substation in Guadalupe County were overloaded when one of the lines was taken as a contingency. To mitigate this violation, a new 345-kV path was added from Hays Energy to Turnersville to a new substation east of Turnersville in Hays County. Depending on the amount of powerflow to the area, new 345/138-kV transformers were added to Hays Energy, Turnersville, and McCarty Lane. Also, a new 345-kV line was added from the new substation east of Turnersville to Lytton in the cases it was necessary. These new facilities also reduced loading on the Kendall to Cagnon 345-kV line during the contingency of the double-circuit 345-kV lines from Hays Energy to Zorn. Also, a new 345-kV path in this area facilitated load growth between Austin and San Antonio.

As shown below, there were project alternatives that proved effective to maintain reliability as power flowed from the west into the Central Texas region. Note that projects were added to Alternative 1 as needed to implement Alternative 2.

Project Description:

- Alternative 1:
    - Hays Energy (7043) - McCarty Lane - Canyon - Turnersville - new substation east of Turnersville 345-kV line additions.
    - At the new substation east of Turnersville, tap the Gilleland Creek to Clear Springs 345-kV line.
    - Existing 138-kV line between Turnersville and Lytton can be reconfigured to operate as 345-kV.
    - 138-kV line rebuilds can be done at the same time as the 345-kV line additions if double circuit 345/138-kV towers are used where possible.
- Alternative 2:
    - Hays Energy (7043) - McCarty Lane - Canyon - Turnersville - new substation east of Turnersville to Lytton 345-kV line additions.
    - At the new substation east of Turnersville, tap both the Hutto to Zorn and the Gilleland Creek to Clear Springs 345-kV lines.
    - Existing 138-kV line between Turnersville and Lytton can be reconfigured to operate as 345-kV.
    - Add Turnersville 345/138-kV transformer.
    - 138-kV line rebuilds can be done at the same time as the 345-kV line additions if double circuit 345/138-kV towers are used where possible.

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New 345-kV Lines West of the Existing Kendall to Cagnon 345-kV Line:
The west-to-east power flows in the Environmental Mandate case for year 2031 were high enough to necessitate a new 345-kV path from a new substation west of Kendall (Mountain Home or Kerrville) to Medina County (a new substation west of San Antonio) to Hondo Creek to Howard. The new substation west of Kendall was a tap of one of the Edison to Kendall 345-kV lines. Also, a new line was required from Medina County to Cagnon. Also note that double-circuit tower construction was utilized so that various underlying 138-kV facilities could be upgraded at the same time as new 345-kV lines were added.

As shown below, the project alternatives are different depending on where the new substation is placed west of Kendall.

Project description:

- Alternative 1:
  - Mountain Home (new substation) - Medina County (new substation) - Cagnon and Medina County (new substation) - Hondo Creek (new substation) - Howard (new substation) 345-kV line additions.
  - Depending on the routing and impedance of these new lines, adding series reactors and series capacitors at Medina County should be considered to balance the flows between the two new paths.
  - If double circuit tower construction is utilized, and depending on the routing of the new 345-kV lines, various underlying 138-kV facilities can be upgraded.
- Alternative 2:
  - Kerrville (new substation) - Medina County (new substation) - Cagnon and Medina County (new substation) - Hondo Creek (new substation) - Howard (new substation) 345-kV line additions
  - Depending on the routing and impedance of these new lines, adding series reactors and series capacitors at Medina County should be considered to balance the flows between the two new paths.
  - If double circuit tower construction is utilized, and depending on the routing of the new 345-kV lines, various underlying 138-kV facilities can be upgraded.

Projects involving 138-kV facilities
Many potential upgrades studied as part of the LTSA were designed to resolve constraints on the EHV network. In addition to projects involving the EHV network, the study analysis also identified the following potential grid improvements involving 138-kV facilities:

The Cico to Comfort 138-kV rebuild:

- Rebuild the 138-kV line from Cico - Comfort in Kendall County such that its new emergency rating is at least 441 MVA

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The Wirtz area 138-kV line rebuilds:

- Wirtz to Flatrock to Paleface to Marshall Ford 138-kV line rebuilds
- Starke to Paleface to Bee Creek 138-kV line rebuilds

Addition of a 345/138-kV transformer West of Kendall:

- Alternative 1: Mountain Home 345/138-kV transformer addition. Additional projects that may be necessary are a new 138-kV line from Mountain Home to Harper Hill and an upgrade of the Kendall to Comfort line.
- Alternative 2: Kerrville 345/138-kV transformer addition. An upgrade of the Harper Hill to Jack Furman line might also be necessary.
- Alternative 3: Add Kendall 345/138-kV transformer #3 addition and Multiple 138-kV line upgrades (Kendall to Kerrville, Kendall to Comfort to Raymond Barker)

Addition of a 345/138-kV transformer in the area near Fayetteville:

- Alternative 1:
    - Add a Winchester 345-kV substation, tapping one of the 345-kV lines from Lost Pines to Fayetteville
    - Add one or two 345/138-kV transformers at Winchester
    - Rebuild the Winchester to Fayetteville 138-kV line
- Alternative 2:
    - Add Fayetteville 345/138-kV transformer #2

North Central Upgrades:

Figures D.7 through D.9 depict reliability transmission upgrades evaluated for the North Central weather zone.

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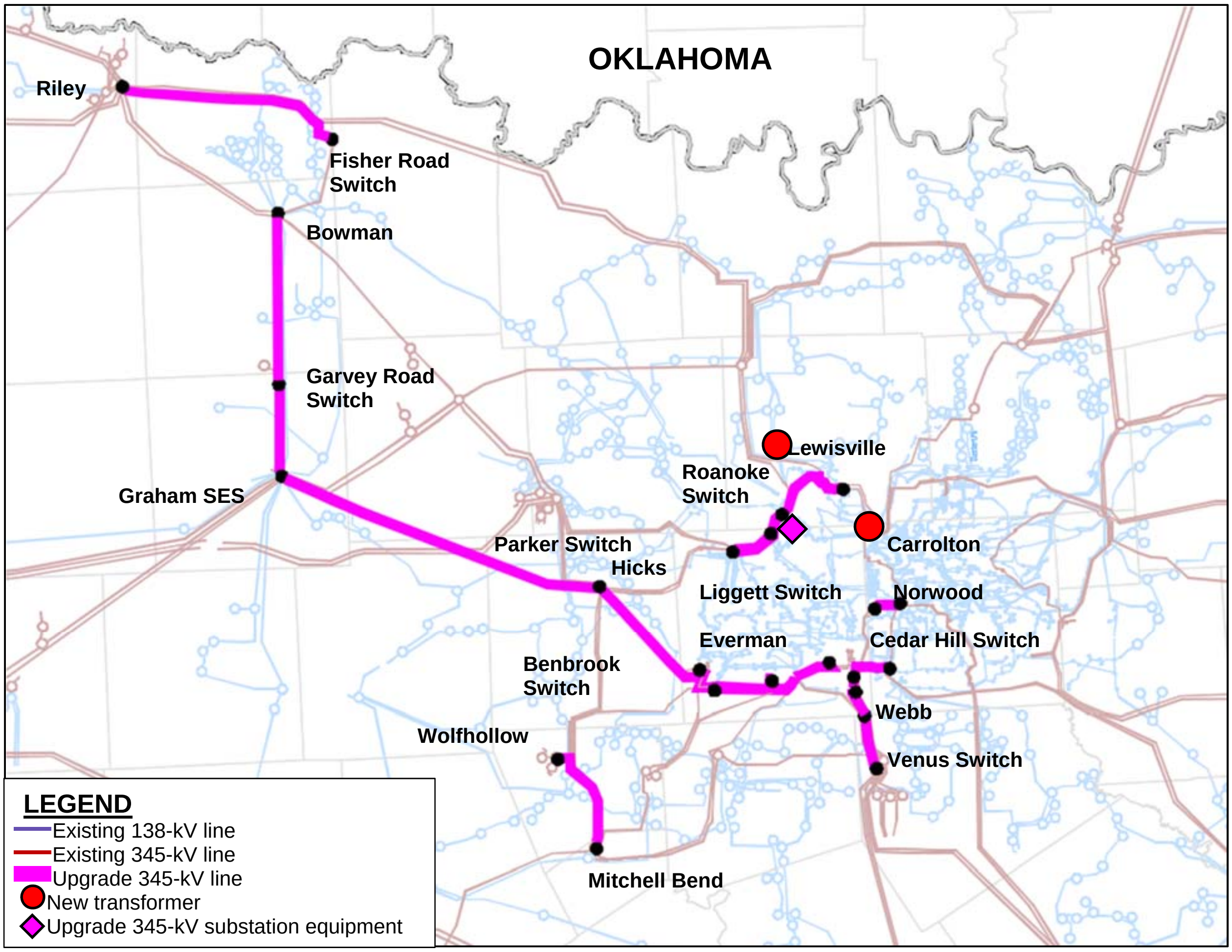

Figure D.7: North/North Central Reliability Projects Identified in the 2016 LTSA Current Trends Scenario

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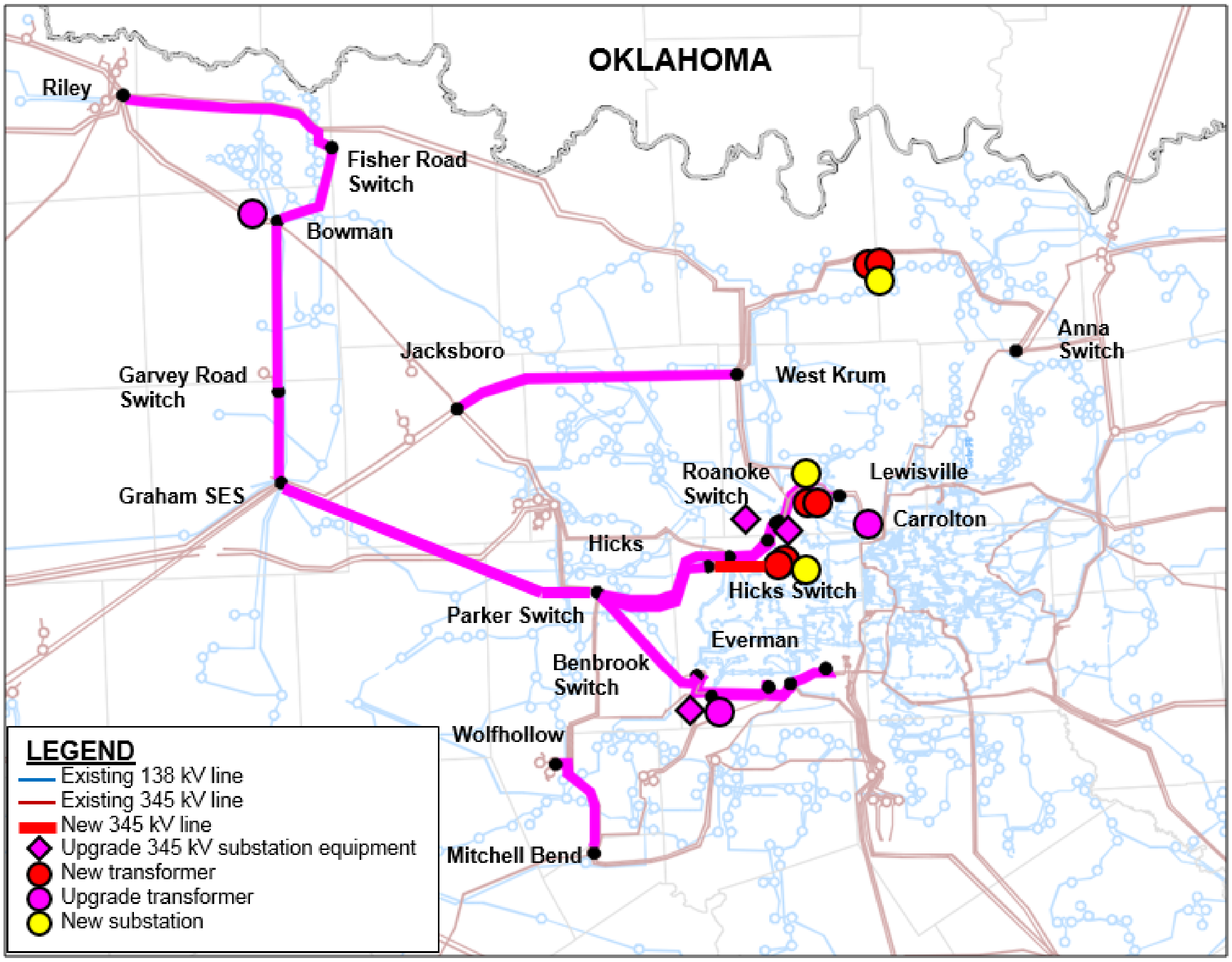

Figure D.8: North/North Central Reliability Projects Identified in 2016 LTSA Environmental Mandate Scenario

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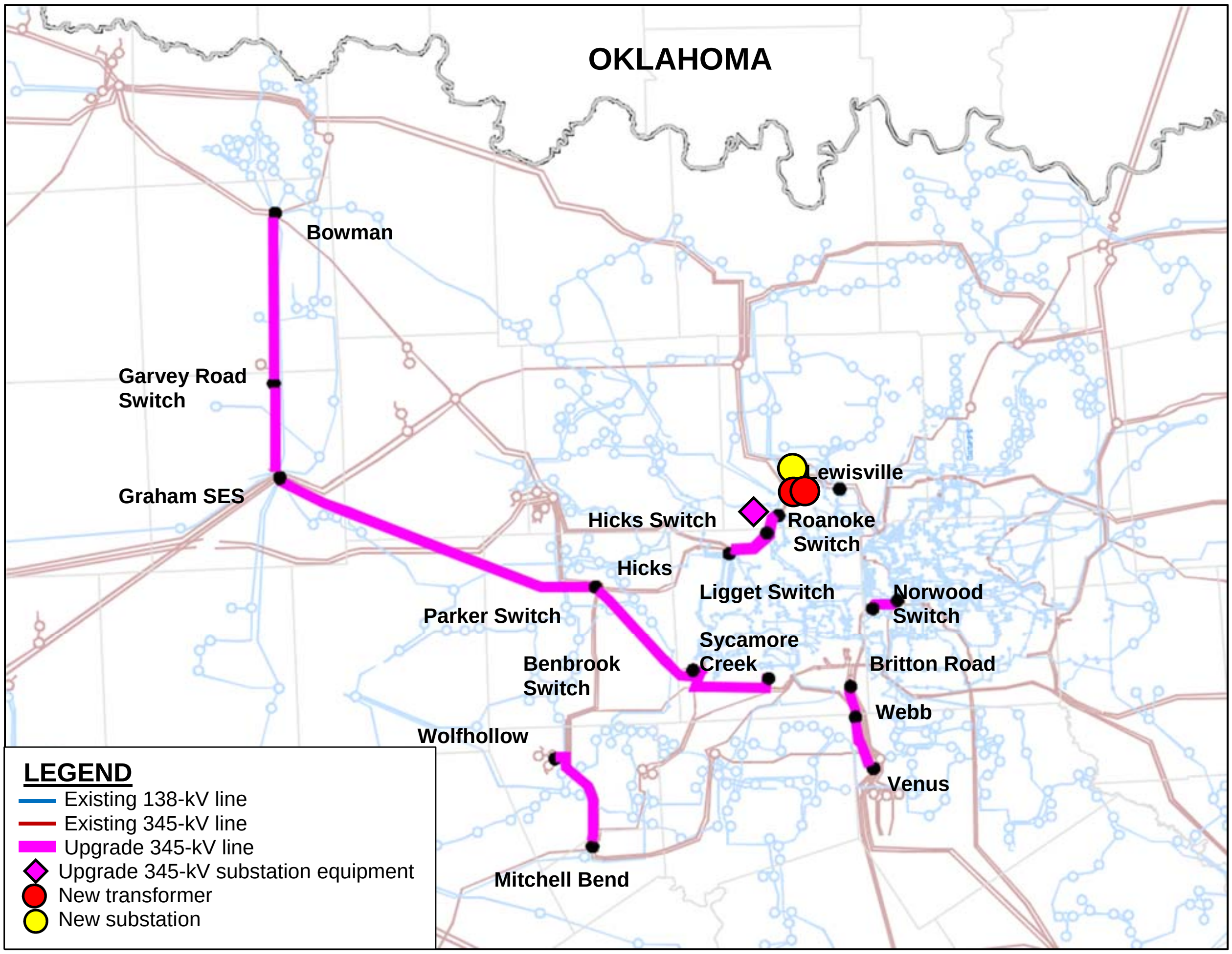

Figure D.9: North/North Central Reliability Projects Identified in the 2016 LTSA High Energy Efficiency and Distributed Generation Scenario

The North Central weather zone has a retirement of 2,449 MW of conventional generators in Current Trends, 2,794 MW in Environmental Mandate and 6,219 MW High Energy Efficiency and Distributed Generation scenario. The continued load growth projected in Denton, Dallas and Tarrant counties combined with the retirements in the East and North Central weather zones increased the overall flow into the region from the north. The line section extending from Bowman to Parker Switch is overloaded in peak conditions due to the flow from North to North-Central. The LTSA studies evaluated the upgrade of the line section from Bowman to Parker Switch for all the scenarios. Also, the scenarios studied indicated reduced voltage support in many 345-kV substations in the North Central zone. There may be need for additional reactive support devices in the North-Central area to account for the losses along the transmission path from North to North Central.

West Roanoke project:

The retirement of the Mountain Creek units in Dallas County with an increase of more than 4% of the load in the Environmental Mandate and Current Trends scenario caused the Hicks substation in Tarrant County with two 345/138-kV transformers to be a primary

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conduit of powerflow from Willow Creek and Parker Switch. The flow was directed along the Willow Creek – Hicks 345-kV double circuit line and the Parker – Hicks 345-kV line, which ultimately directed the flow through the Hicks and Roanoke transformers.

The existing Hicks transformers experienced heavy loading in the year 2026 and 2031 in both the Current Trends and Environment Mandate scenarios.

The following LTSA project included the addition of a new 345-kV bus and two 345/138-kV transformers at the West Roanoke substation, and a new 345-kV line from Hicks to West Roanoke.

The study results showed that this new Hicks – West Roanoke 345-kV line and the transformers at West Roanoke provided a new source diverting the flow from the west (Willow Creek and Parker Switch) and alleviated the loading on the Hicks and Roanoke transformers.

Project Description:

- Add two 345/138-kV transformers rated at least 750 MVA at West Roanoke
- Build a new 345-kV line with an emergency rating of at least 2987 MVA from Hicks to West Roanoke

Alternatively, the existing Hicks transformers could be upgraded or a third transformer added into the station. This alternative can have some siting issues at the current Hicks substation due to space restrictions.

Brazos/Oncor Project:

The existing Denton transformers in Denton County experience heavy loading in the year 2031 for the Environmental Mandate scenario. The Denton transformers were a primary receive point of power flow from several 345-kV circuits from Riley and Graham to the 138-kV load pocket in Denton County.

A new tap at Anna Switch to West Krum 345-kV can be used as a new source to serve the 138-kV load pocket in Denton County. The 2016 LTSA studies evaluated the Brazos/Oncor project that would tap the existing 345-kV double circuit line from West Krum to Anna Switch and would connect to a new tap between Collin-Arco 138-kV double circuit with two 345/138-kV transformers. This project diverts the flow from the Denton and Collins transformer and provides a new source to the 138-kV load in Denton County.

Project Description:

- Tap the existing Anna – West Krum 345-kV and Collin-Arco 138-kV double circuit.
- Add two 345/138-kV transformers rated at least 750 MVA connecting the taps at 345-kV and 138- kV.

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Alternatively, the existing Denton transformers can be upgraded to a higher MVA capacity, or a third auto can be added into the substation to resolve the loading issues. This alternative might have some siting issues due to space constraints in the existing substation.

Highland Tap project:

The Lewisville Switch transformers experienced heavy loading in 2026 and 2031 for the following scenarios: Current Trends and Environment Mandate. The Lewisville Switch transformers are a primary receive point of power flow from several 345-kV circuits from West Krum and Roanoke (North-West).

In the 2016 LTSA Current Trends scenario, the existing West Krum-Lewisville 345-kV line was tapped to add a new 345-kV switching station at existing Highland station and one 345/138-kV transformer was added at the Highland station. This project provides a new source into the 138-kV load pocket diverting the flow in Lewisville transformers. The Lewisville transformers were more stressed in the Environmental Mandate scenario due to increased generation retirements in the South and East weather zones. The Environmental Mandate scenario analysis included an evaluation of a tap at the existing Lewisville Switch – Roanoke Switch 345-kV line, along with a new 345-kV bus and two 345/138-kV transformers at Highland station. However, there might be some Right-Of-Way (ROW) and permitting issues with addition of a new switching station and transformers at Highland substation.

This results from the study showed that the project ultimately reduces loading on the Lewisville transformers and diverts the flow in the direction along the Highland Tap 138-kV path.

Project Description:

- Build a 345/138-kV switching station at Highland Station
- Tap the existing Lewisville Switch – Roanoke Switch 345-kV circuit near the existing West Roanoke 138-kV substation and add two 345/138-kV transformers rated at least 750 MVA at Highland Station (Environmental mandate)
- Tap the existing West Krum –Lewisville Switch – Roanoke Switch 345-kV circuit near the existing West Roanoke 138-kV substation and add one 345/138-kV autotransformer rated at least 750 MVA at Highland (Current Trends)

West and Far West Upgrades:

Figures D.10 and D.11 depict projects evaluated for the West and Far West weather zones.

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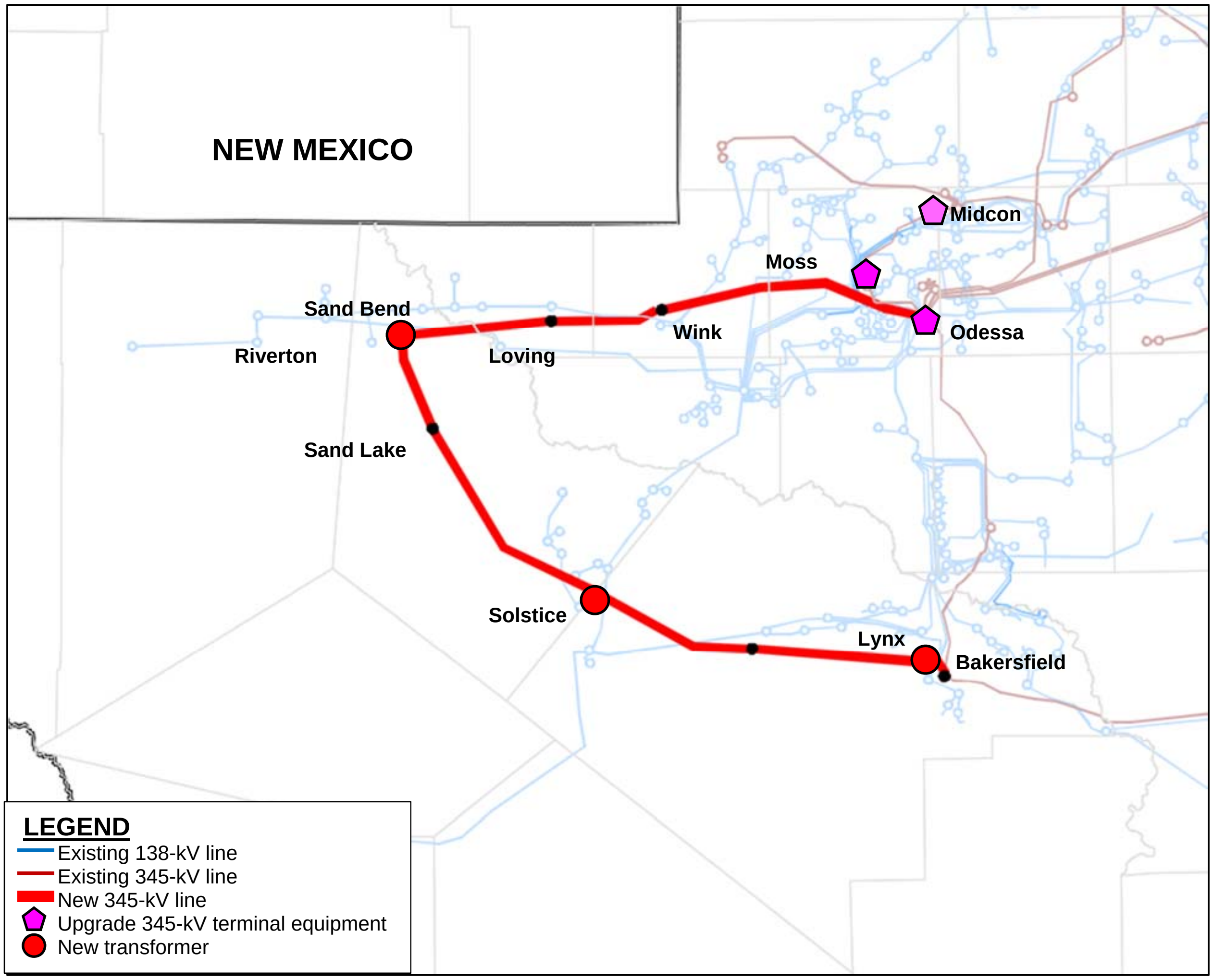

Figure D.10: WFW Current Trends 345-kV Projects

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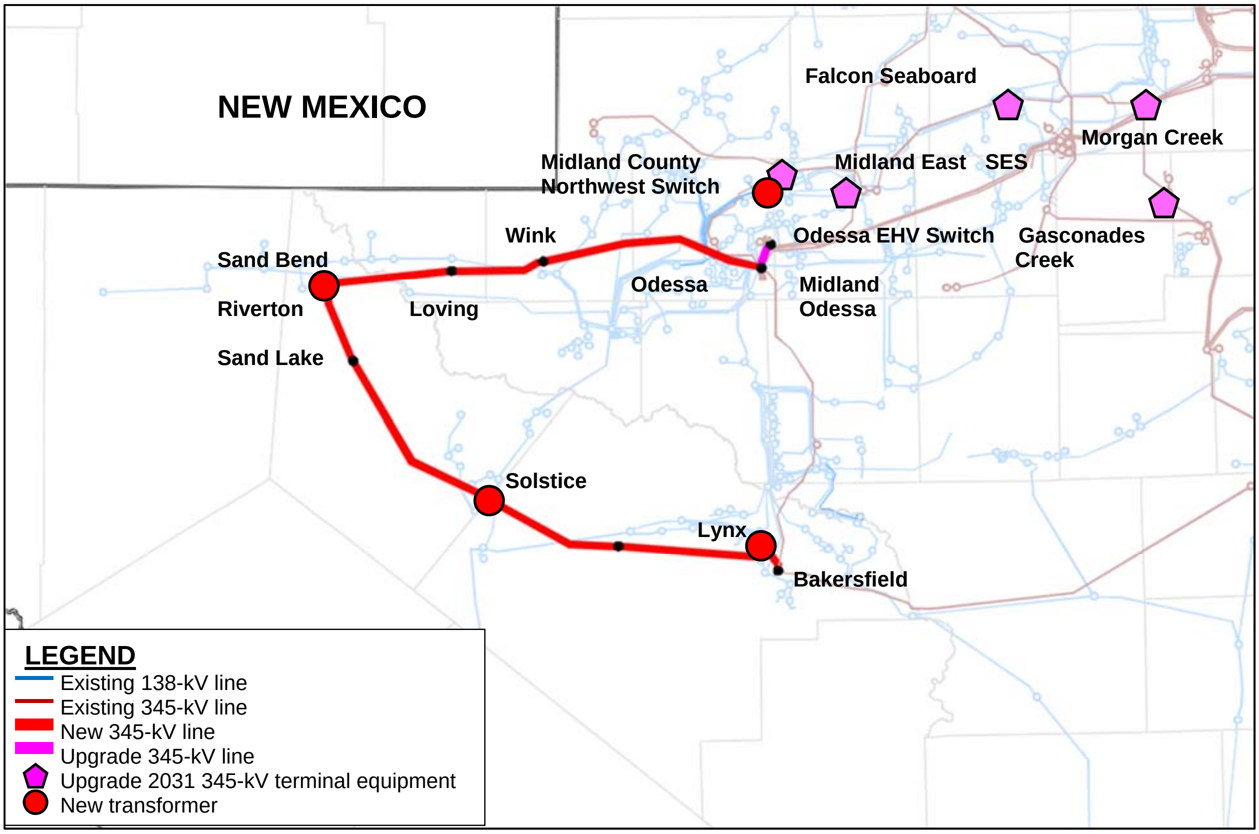

Figure D.11: WFW Environmental Mandate 345-kV Project Map

The Far West area of Texas, which includes Culberson, Reeves, Pecos, Crane, Winkler and Ward Counties, is currently only served by 138-kV and 69-kV facilities. The Far West Texas Project, which would add a 345-kV loop starting at the Odessa substation in Midland County, through the Riverton/Mason substation in Reeves County and the Solstice substation and terminating at the Bakersfield substation in Pecos County, is currently under review at the RPG.

The LTSA scenarios forecasted up to 3.1 GW of new solar generation in 2031 on the existing 138-kV network in this area. These additions resulted in several basecase and post-contingency overloads on existing 138-kV circuits in the area. The Far West Texas project was studied as a solution to provide a 345-kV hub for the new solar generation in this region. The study result showed that this new 345-kV loop alleviated most of the overloads in the area. The project also helped to deliver the new solar generation from the very Far West of Texas area into ERCOT load centers.

Project Description:

- Build approximately 240 miles long of 345-kV transmission line connecting Odessa substation in Midland County to Sand Bend POI substation in Culberson County to Solstice, to Lynx and finally to Bakersfield Switchyard substation in Pecos County.

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- Add 3 new 345/138-kV transformers at Sand Bend POI, Solstice and Lynx substations.
- Interconnect new solar generations at new 345-kV Sand Bend POI and Solstice substations.
- Tap this 345-kV loop at several locations such as Wink in Winkler County, Loving in Loving County, and Sand Lake in Reeves County to interconnect more new solar generation to the 345-kV loop.

By 2031 in the LTSA Current Trends and the Environmental Mandate scenario, approximately 500 MW of new solar generation was added at the Alamito Creek 138-kV substation. The total generation in this area exceeded the Far West Alamito Creek loop capability. As a result, the entire 138-kV and 69-kV loops from Solstice to Alamito Creek to Paisano to Alpine to TNP Belding to Conoco Comp Station and Fort Stockton substation in Pecos, Presidio, and Brewster counties was upgraded. The 69-kV substations and transmission lines on this loop were converted to 138-kV.

The Environmental Mandate scenario added approximately 3.2 GW and 3.6 GW of new solar and wind generation in 2026 and 2031 respectively in the West and Far West zones. The 345-kV circuit from Midland-Odessa in Midland County to Odessa EHV Switch substation in Ector County would need to be upgraded. To resolve the same issue the following substations would need a terminal upgrade: Midland East and Midland County Northwest Switch in Midland County, Falcon Seaboard in Howard County, Morgan Creek SES in Mitchell County, and Gasconades Creek in Sterling County.

By 2031, the Current Trends scenario required a terminal equipment upgrade at the following 345-kV substations: Moss and Odessa (in Ector County), and Midland County Northwest Switch (in Midland County).

Coast and East Zone Upgrades:

Figure D.12 depicts projects evaluated for the Coast and East weather zones.

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Coast and East upgrades

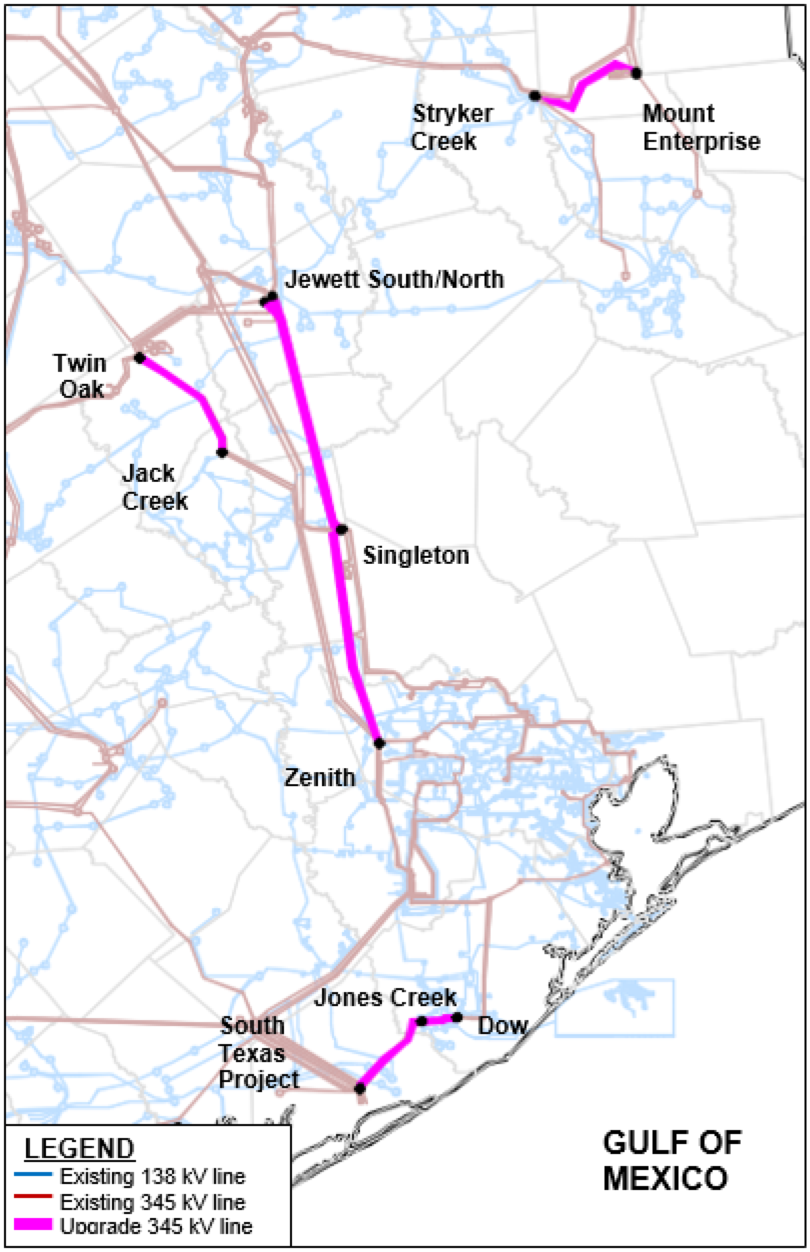

Figure D.12: Environmental Mandate 345-kV Projects Map for East and Coast

Table D.2: Mothballed and Retired Generation in East and Coast Weather Zones

Weather Zone	Retired in 2026	Mothballed in 2026	Retired in 2031	Mothballed in 2031
East	7761	-	8586	-
Coast	3467	-	4216	-
Coast	-	759	-	759

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As shown in Table D.2, in the year 2031, LTSA Environmental Mandate scenario assumed a total of approximately 13 GW of generation would be retired in the East and Coast weather zones of which almost 4,216 MW were located in the Houston area. Also, a total of 759 MW units, including the Amoco Oil Cogen unit 5 and the entire Sam Bertron plant were mothballed in the Houston area. This retirement of local generation coupled with load growth resulted in the increase in power import into Houston. This increase led to several 345-kV transmission lines to be pre and post-contingency overload and hence these lines were upgraded.

G-1 + N-1 contingency studies identified more reliability projects needed especially when one of the South Texas Project units was assumed to be on outage.

Projects list:

1. South Texas Project (in Matagorda County) to Dow / Jones Creek (in Brazoria County) 345-kV double-circuit line upgrade to new emergency rating of 2812 MVA
2. Singleton (in Grimes County) to Zenith (in Harris County) 345-kV double-circuit line upgrade to new emergency rating of 2812 MVA
3. Jewett (in Leon County) to Singleton (in Grimes county) 345-kV line upgrade to new emergency rating of 2812 MVA
4. Twin Oak (in Robertson County) to Jack Creek (in Brazos County) 345-kV line upgrade to new emergency rating of 2812 MVA

With the retirement of both Stryker Creek unit 1 and 2 in 2031, the Stryker Creek 345/138-kV transformer will draw more power from the 138-kV side causing a post-contingency overload. Hence this transformer was upgraded.

5. Upgrade the Stryker Creek 345/138-kV Transformer (in Cherokee County) to 700 MVA

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D.3 Economic Analysis

ERCOT used the final economic case for the year 2019 from the 2015 RTP as a starting point for the 2016 LTSA economic analysis for all scenarios. The cases were modified with the necessary generation fleet changes and load adjustments to represent the different scenarios and years included in the transmission analysis. After completing the analysis to determine upgrades necessary to maintain system reliability for each of the years and scenarios, ERCOT added the resulting projects to the corresponding economic start cases. ERCOT used the scenario-specific 50^{th}-percentile hourly load forecast, in addition to the self-served load, to model the system demand for each transmission scenario. The resource profile, including the profile for DR, as developed in the generation expansion planning process, was used to model the generation build for each scenario.

Each scenario that was evaluated for transmission reliability needs was also evaluated for economic project opportunities. As explained in the reliability analysis section, this economic analysis was also focused on resolving the congestion on the 345-kV network. The study began in areas of high congestion where conceptual projects were studied in an attempt to reduce system production costs sufficiently to offset each project’s total cost to customers. ERCOT used the economic planning criteria from ERCOT Protocol section 3.11.2(5) to evaluate the studied projects.

Reliability-driven projects and economic alternatives or supplements were documented separately for consideration in subsequent shorter-term study horizons. Near-term planning studies (e.g. the RTP) will reference long-term reliability constraints when proposing projects in the same geographical area.

Cost estimates for potential transmission projects used in this study do not reflect routing considerations, including geographic obstacles, physical constraints, or public preferences. Detailed routing considerations can lead to significant project cost increases.

Findings from Economic Analysis

The Table D.3 shows a list of constrained paths observed in one or more of the scenarios studied. Tables D.4 – D.6 show the list of constrained paths in the individual scenarios. As mentioned earlier, the Panhandle interface showed consistently high amounts of congestion across the three scenarios. Significant congestion was also seen on the Cagnon to Kendall and the Killeen Switch to Salado Switch circuits. Transmission projects were evaluated to address some of the highly congested elements. Table D.7 lists some of the transmission projects evaluated for LTSA.

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Table D.3: Top Congested elements in one or more scenarios

Scenario	Current Trends		Environmental Mandate		High EE/DG	
Constrained Element	**2026**	**2031**	**2026**	**2031**	**2026**	**2031**
Killeen Switch - Salado Switch	Medium	High	High	High		
Cagnon – Kendall	Medium	High	High	High	High	High
Panhandle Interface	High	High	High	High	High	High
Parker Switch - Benbrook Switch	High				Medium	
Jacksboro Switching - Burwick Switching Station		Medium	Medium	Medium		
Hutto Switch 345/138-kV Transformer	Medium	Medium	Medium	Low		
Graham SES - Burwick Switching Station		Low	Low	Medium		
Wolf Hollow 345 Switch - Comanche Peak SES		Low	Medium	Medium		
Knob Creek Switch - Temple Switch	Low	Low	Medium	Low		
North McCamey 345/138 Transformer				Medium		Low
Zorn - Hays Energy	Low		Low	Medium		
South Texas Project - Jones Creek	Medium	Medium			Medium	Medium
WA Parish - Jeanetta	Medium	Medium	Low	Medium	Medium	Medium
Morgan Creek SES - Tonkawa Switch	Low	Medium	Medium	Medium		Low
Riverton 345/138-kV Transformer		Medium				
Graham SES - Parker Switch	Low					High
Benbrook Switch - Sycamore Creek	Medium				Low	
Kendall 345/138-kV Transformer	Low				Medium	Medium

High	Medium	Low

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Table D.4: Top congested elements in Current Trends Scenario

Constrained Element	2026	2031
Panhandle Interface		
Cagnon - Kendall		
Killeen Switch - Salado Switch		
Parker Switch - Benbrook Switch		
Hutto Switch 345/138-kV Transformer		
South Texas Project - Jones Creek		
WA Parish - Jeanetta		
Jacksboro Switching - Burwick Switching Station		
Riverton 345/138-kV Transformer		
Benbrook Switch - Sycamore Creek		
Morgan Creek SES - Tonkawa Switch		

Table D.5: Top Congested Elements for High Energy Efficiency/Distributed Generation

Constrained Element	2026	2031
Cagnon - Kendall		
Panhandle Interface		
Graham SES - Garvey Road Switch		
Rocky Creek - Everman Switch		
Graham SES - Parker Switch		
South Texas Project - Jones Creek		
WA Parish - Jeanetta		
Alliance - Hicks Switch		
Comanche Peak SES - Mitchell Bend		
Parker Switch - Benbrook Switch		
Kendall 345/138-kV Transformer		

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Table D.6: Top congested elements in Environmental Mandate

Constrained Element	2026	2031
Killeen Switch - Salado Switch		
Cagnon - Kendall		
Panhandle Interface		
Edith Clarke - Gauss		
Hicks Switch 345/138-kV Transformer		
Holman - Hillje		
Lewisville Switch - Carrollton Northwest		
Roanoke Switch Bus Tie		
Hays Energy - Kendall		
West Denton - Roanoke Switch		
Jacksboro Switching - Burwick Switching Station		
Wolf Hollow 345 Switch - Comanche Peak SES		
Morgan Creek SES - Tonkawa Switch		
Big Brown SES - Jewett		
Bakersfield Switchyard - Big Hill		
Fayette Plant 2 - Holman		
Hays Energy 345/138-kV Transformer		
Medina County - Kerr Street		
Midland East - Midland County Northwest Switch		
Oasis - Wa Parish		
Richland Chambers - Big Brown SES		
South Texas Project - WA Parish		
Trinidad - Watermill Switch		
West Bates - Poloduro		
Orsted Series Capacitor		
Hutto Switch 345/138-kV Transformer		
Graham SES - Burwick Switching Station		
Knob Creek Switch - Temple Switch		
North McCamey 345/138 Transformer		
Zorn - Hays Energy		
WA Parish - Jeanetta		

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Table D.7: List of economic projects evaluated in 2016 LTSA

Projects Evaluated	Current Trends		Environmental Mandate		High EE/DG	
	Economic Criteria Met?	In-Service Year	Economic Criteria Met?	In-Service Year	Economic Criteria Met?	In-Service Year
Panhandle upgrade: 350 MVAR sync condenser at Windmill	Yes	2026	Yes	2026	Yes	2026
Panhandle upgrade: Ogallala to Long Draw single circuit with 175 MVAR sync condenser at Windmill	No	-	Yes	2031	No	-
Panhandle upgrade: Ogallala to Long Draw double circuit with 350 MVAR sync condenser at Windmill	No	-	Yes	2031	No	-
Kendall - Cagnon 345-kV Line Terminal Equipment Upgrade	Yes	2026	Yes	2026	Yes	2026
Kendall - Cagnon 345-kV Line Rebuild	No	-	-	-	Yes	2031
Kendall - Hays Energy 345-kV Line Rebuild	No	-	Yes	2031	Yes	2031
Kerrville - Fowlerton New 345-kV Line	No	-	-	-	-	-
Bakersfield - Brackett New 345-kV Line	No	-	No	-	-	-
Kendall 345/138-kV Transformer Addition	-	-	-	-	Yes	2026
Kerrville 345/138-kV Transformer Addition	-	-	-	-	Yes	2026
Lewisville - Carrollton NW 345-kV Line Upgrade	-	-	Yes	2031	-	-
Rocky Creek - Everman Switch 345-kV Line Upgrade	-	-	-	-	Yes	2031
Killeen - Salado 345-kV Line Upgrade	Yes	2031	Yes	2026	-	-
Hutto 345/138-kV Transformer Addition	Yes	2031	-	-	-	-
Riverton 345/138-kV Transformer Addition	Yes	2031	-	-	-	-
South Texas Project - Dow / Jones Creek 345-kV Line Reconductor	No	-	-	-	No	-
Graham SES – Garvey Road Switch 345-kV Line Upgrade	-	-	-	-	Yes	2026

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