ERCOT System Planning:

2020 Long-Term System Assessment for the ERCOT Region

December 2020

Executive Summary

Section 39.904(k) of the Public Utility Regulatory Act (PURA) requires that the Public Utility Commission of Texas (PUCT) and Electric Reliability Council of Texas, Inc. (ERCOT) study the need for increased transmission and generation capacity and report such 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 60-kilovolt (kV) and higher transmission lines and associated equipment. In planning for both 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. While a small transmission improvement may appear to be sufficient in the six-year planning horizon, the LTSA planning horizon may reveal that a more extensive 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 planning process to account for the inherent uncertainty of planning the system beyond six years. The goal of using scenarios in the LTSA is to identify upgrades that are robust across a range of scenarios or more economical than the upgrades that would be determined considering only near-term needs.

The following set of future scenarios was developed considering stakeholder feedback received via survey and at Regional Planning Group (RPG) meetings:

- Current Trends
- Renewable Mandate
- High Battery Energy Storage
- High Industrial Load
- Existing Transmission Constraints

Using the assumptions and guidelines in the scenario descriptions, ERCOT prepared different demand forecasts.

Planning for transmission 10 and 15 years into the future requires ERCOT to make assumptions regarding what types of new resources can be developed. ERCOT conducted capacity expansion and retirement analysis for the five future scenarios using the guidelines in the scenario descriptions. ERCOT also conducted transmission expansion analysis for the Current Trends and Renewable Mandate scenarios. Two iterations of capacity expansion and retirement analysis, and transmission expansion analysis were conducted for the Current Trends scenario. The first iteration did not consider any transmission limitations for the capacity expansion and retirement analysis, whereas the second iteration of capacity expansion and retirement analysis considered potential interface limits identified in the first iteration of transmission expansion analysis.

Based on the results of the analyses that went into the 2020 LTSA, ERCOT identified the following key findings:

- Significant growth in solar and wind resources was found across all five scenarios.
- Growth in renewable resources and electric vehicle adoption lead to a shift in scarcity hours to later in the day in both summer and winter months.
- The scale and location of wind and solar generation additions are dependent upon sufficient transmission capacity between resource-rich regions and demand centers.
- Holistic solutions addressing both regional transfer limits and local constraints closer to urban demand centers are required to accommodate large-scale renewable generation transfers.

In all five scenarios, a mix of solar, wind, and natural gas generation, and battery energy storage was added to the system to serve growing demand and replace retired capacity. Wind generation additions represented the largest resource capacity change on the system throughout the five scenarios. As seen in Figure 1, total wind generation capacity additions ranged from 35,000 MW to 44,800 MW in the five scenarios. Solar generation capacity additions were also significant, ranging from 22,200 MW to 35,300 MW across all scenarios. Conversely, more than 21,000 MW of existing coal and natural gas generation capacity was retired by 2035 in all scenarios. The timing of specific unit retirements prior to 2035 varied somewhat across scenarios.

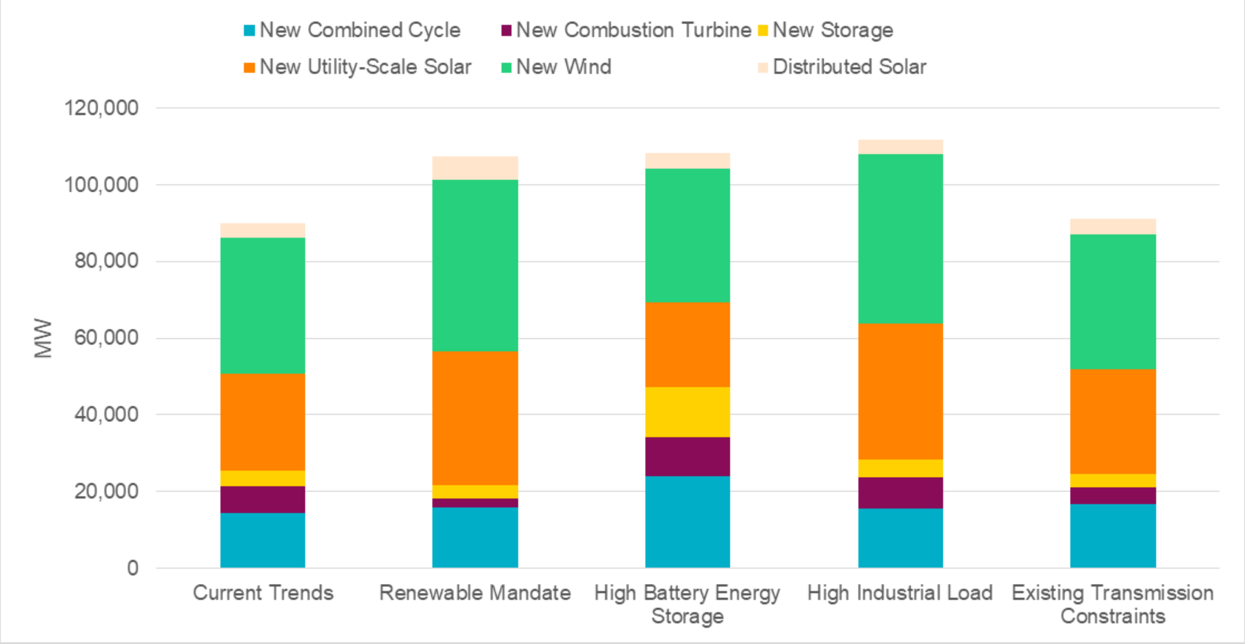


Figure 1: Capacity Additions Across All Scenarios

Retired coal and natural gas generation was replaced by solar, wind, and new natural gas generation, and battery energy storage. The share of demand served by wind and solar generation increased in each of the five scenarios studied. These results indicate the possibility that there may be hours when demand could theoretically be served entirely by wind and solar resources. Thermal and stability constraints on the transmission system, as well as operational considerations such as ramping limitations and maintaining a minimum level of system inertia, will need to be assessed further to ensure reliability under high renewable penetration.

The study results also showed a shift in scarcity hours to later in the day across all five scenarios, driven primarily by an assumed increase in electric vehicle adoption rates and the amount of new solar generation added. The High Battery Energy Storage scenario saw the most significant shift, with scarcity hours extending until 11 p.m. in both summer and winter months. Stressed system conditions were observed at various times of day and in various days throughout the year. As renewable penetration on the ERCOT system continues to increase, possible system conditions outside of summer peak, including peak net load conditions, need to be included in planning studies.

Capacity expansion and retirement analysis results for the Current Trends, Renewable Mandate, and Existing Transmission Constraints scenarios provided insight into the potential impacts of transmission limitations on new generation development. Transmission limitations could lead to the construction of less wind and solar generation capacity as well as a shift in new wind and solar generation away from more resource-rich regions in West and North Texas to sites closer to major urban demand centers. The resource shift observed to result from the consideration of transmission limitations could reduce the amount of ERCOT demand that can be served by renewable resources.

Similar to the 2018 LTSA, 2020 LTSA transmission expansion analysis results identified the need for additional transmission paths from West Texas to demand centers. However, 2020 LTSA results also indicated that the benefit of additional transfer paths cannot be fully realized without also addressing local constraints closer to urban demand centers. It was observed that adding new transmission circuits to increase the West Texas export transfer limit could result in increased congestion into the Dallas-Fort Worth, San Antonio, and Houston and Freeport areas.

Holistic solutions addressing both regional transfer limits and local constraints are required if large-scale renewable generation transfers are to be accommodated. The need for holistic solutions is driven by both the changing resource mix and trends in customer demand growth. Figure 2 and

Table 1 highlight the potential transmission improvements identified for the Current Trends scenario.

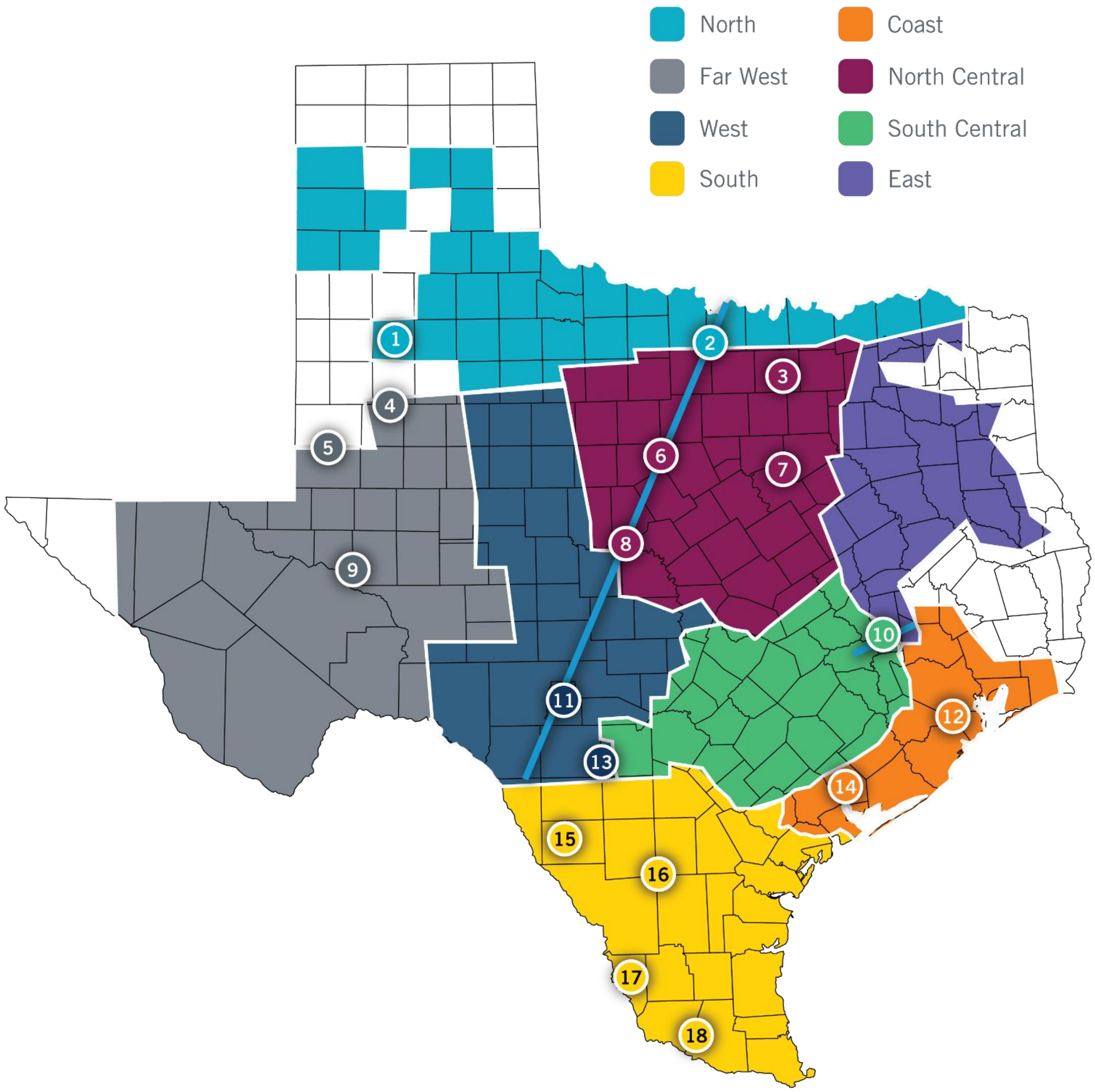


Figure 2: Current Trends Potential Transmission Improvements

Table 1: Current Trends Transmission Improvement Descriptions

Map Index	Transmission Improvement Description	Date of Potential Need[1]
1	Lubbock Loop	2030
2	Panhandle to Dallas-Fort Worth	2030
3	Dallas-Fort Worth Area Improvements	2030
4	Lamesa Area Improvements	2030
5	Lamesa to Andrews County	2030
6	West Shackelford to Comanche Peak	2035
7	Sam Switch to Venus Switch	2030
8	Brown Switch to Bell County East	2030
9	Rio Pecos to Crane	2030
10	North Houston Import	2030
11	Bakersfield to Big Hill to Uvalde	2030
12	Houston / Freeport Area Improvements	2030
13	San Antonio Import	2030
14	South Houston / Freeport Import	2030
15	Southwest Improvements	2030
16	Fowlerton to Del Sol	2030
17	Del Sol to Lobo Second Circuit	2035
18	Frontera Import	2030

[1] Projects may be comprised of multiple parts with varied dates of potential need. The dates provided are the earliest study year for which any portion of a project was identified, and could be earlier or later depending upon future system conditions.

Chapter 1. Introduction

ERCOT manages the flow of electric power to more than 26 million Texas customers—representing about 90 percent of the state's electric demand. ERCOT schedules power on an electric grid that connects over 46,500 miles of transmission lines and more than 680 generation units.

As part of its responsibility to adequately plan the transmission system, ERCOT must develop a biennial assessment of needed transmission infrastructure. PURA § 39.904(k) requires the 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 December 31 of each even-numbered year. ERCOT has developed this 2020 Long-Term System Assessment (LTSA) in satisfaction of that requirement.

The LTSA includes analysis of system needs for the long-term 10- to 15-year planning horizon and is designed to guide near-term transmission planning decisions. Given the long-term nature of the LTSA study horizon, the findings and observations from the LTSA are based on analysis of multiple scenarios. Such scenarios are developed through collaborative effort between ERCOT and stakeholders and are based on projections of certain key assumptions. The LTSA projections, specifically demand, generation, and transmission expansion plans, are outcomes of these scenario-specific studies, and should not be considered ERCOT's official forecasts for the long-term horizon.

The findings and observations from the LTSA are intended to provide information for ERCOT stakeholders and policymakers to consider in their decision-making, and are based upon complex analysis of multiple possible, but not necessarily probable futures. Key limitations of the 2020 LTSA analysis should also be considered by interested parties, including the following:

- Hourly simulations used for economic analysis in both capacity expansion and transmission expansion studies may not fully capture the intra-hour revenue and potential benefits of resources. Conducting intra-hour simulations was not feasible for the 2020 LTSA.
- The profiles used to select and site wind and solar resources do not fully capture all of the considerations used by developers when selecting generation sites.
- While the scenarios selected are meant to investigate the boundaries of potential futures, they do not represent the entirety of possible future outcomes. Future conditions may deviate from those studied in the 2020 LTSA.
- Demand side management included in the 2020 LTSA analysis may not be fully representative of increasingly complex and evolving customer behavior.

Chapter 2. LTSA Process

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 RTP and Regional Planning Group (RPG) projects, and ongoing long-range studies, which are documented in the LTSA. In addition to these activities, transmission service providers (TSPs) conduct analyses of local transmission needs supplemental to the ERCOT planning process.

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.

The LTSA is a composite study made up of various processes and analyses such as scenario development, demand forecasting, capacity expansion and retirement analysis, and transmission expansion analysis. ERCOT uses a scenario-based approach to perform the LTSA. The purpose of the scenario-based approach is to provide a structured format for stakeholders and ERCOT to identify the most critical trends, drivers, and uncertainties over a ten- to fifteen-year period. Scenarios developed in collaboration with stakeholders provided high level guidelines for preparing cases to be used in the LTSA. The scenario descriptions were converted to modeling assumptions using available reference data. In addition, for each scenario, a scenario-specific demand forecast was created using inputs from the scenario descriptions.

The demand forecast and other scenario-specific generation input assumptions such as capital costs, operations and maintenance costs, emission costs, etc. were used to create each capacity expansion and retirement plan. These plans describe the total amount of generation additions by technology. The plans also identify any retirements required as a result of the scenario descriptions. The generation additions were later added to transmission study models using the generation siting process as documented in the generation siting methodology[2]. The LTSA culminated in a transmission expansion analysis which involved evaluating the potential needs for the ERCOT grid under different demand and generation assumptions as developed during the demand forecasting and capacity expansion and retirement planning stages. Figure 3 provides a summary of the LTSA process. A detailed description of analyses and studies that went into the LTSA can be found in Appendix I.

[2] The LTSA Generation Siting Methodology is attached in Appendix II

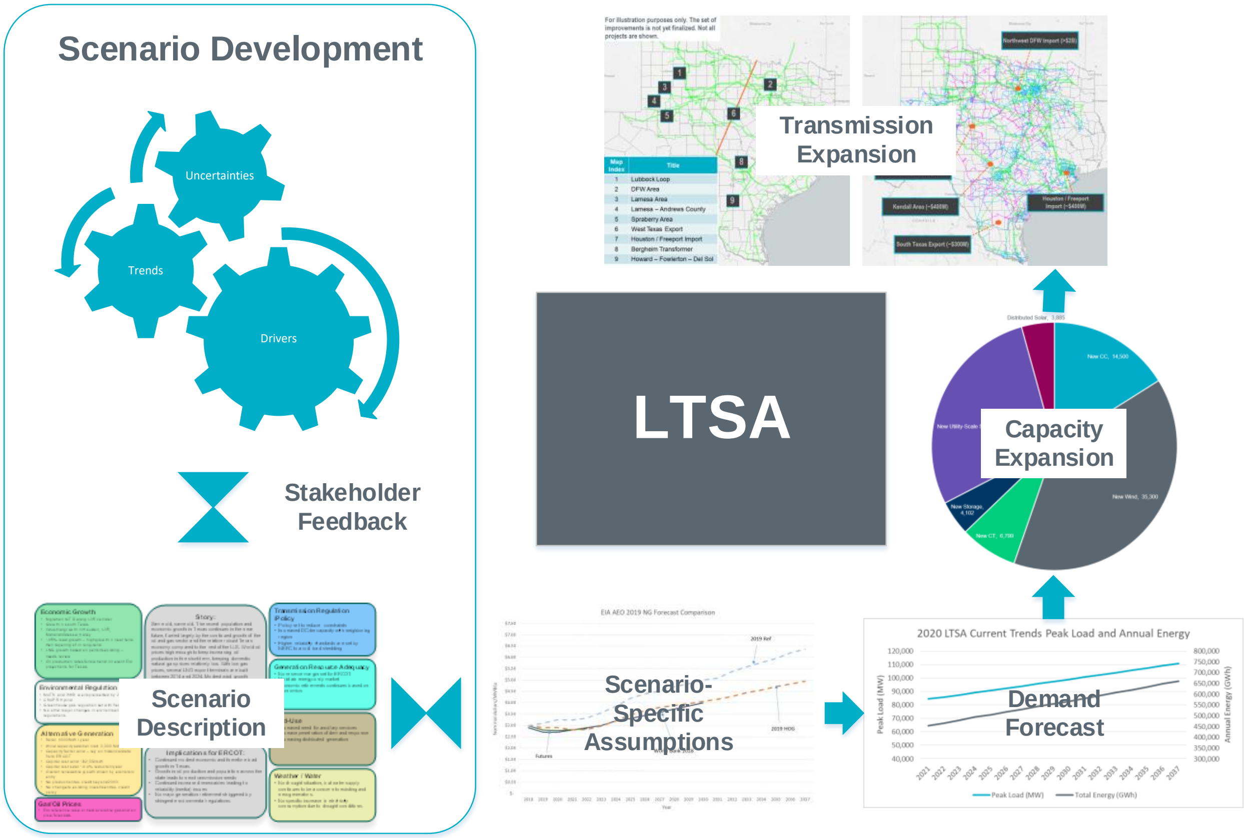


Figure 3: 2020 Long-Term System Assessment Process

Five scenarios were included in the 2020 LTSA. Table 2 provides a summary of each scenario.

Table 2: Scenarios Developed for the 2020 LTSA

Scenario	Description
Current Trends	The Current Trends scenario was designed to study a future trajectory consistent with what is known and knowable today (e.g., demand growth, economic trends, fuel prices, etc.). Two significant changes were made in the assumptions and methodology for the Current Trends scenario in the 2020 LTSA compared with previous LTSAs: • Electric vehicle adoption assumptions were included in the demand forecast. • An iterative process was adopted to co-optimize capacity expansion and transmission expansion.
Renewable Mandate	The Renewable Mandate scenario assumed that favorable regulatory policies and the resolution of major infrastructure-related hurdles would further incentivize the development of renewable resources on the ERCOT system. Scenario-specific assumptions included extension of the ITC and PTC through 2035, higher levels of distributed solar[3] adoption, and the implementation of a carbon tax.
High Battery Energy Storage	The High Battery Energy Storage scenario was developed to study the impacts of the integration of large amounts of battery energy storage. Lower battery costs, higher electric vehicle adoption across all sectors (e.g., cars, light-duty trucks, and heavy-duty trucks), and co-location of battery energy storage with solar builds were assumed for the scenario.
High Industrial Load	The High Industrial Load scenario investigated the impact of continued robust growth of large industrial loads in parts of the ERCOT system. Higher demand growth in the Delaware Basin, as well as an increase in LNG load were assumed.
Existing Transmission Constraints	The Existing Transmission Constraints scenario studied the potential impacts on resource mix and geographic distribution if no new large-scale transmission were developed to address currently identified transfer-related transmission constraints on the ERCOT system. Unlike other scenarios, a zonal model was used to represent existing transmission constraints in the initial capacity expansion.

[3] Distributed solar refers to photovoltaic solar power installed at customer locations, such as homes or businesses, and may also be referred to as rooftop solar or rooftop PV.

Chapter 3. Key Findings

The 2020 LTSA includes a study of five different scenarios. Key findings from the study include:

1. Significant growth in solar and wind resources was found across all five scenarios.
2. Growth in renewable resources and electric vehicle adoption lead to a shift in scarcity hours to later in the day in both summer and winter months.
3. The scale and location of wind and solar generation additions are dependent upon sufficient transmission capacity between resource-rich regions and demand centers.
4. Holistic solutions addressing both regional transfer limits and local constraints closer to urban demand centers are required to accommodate large-scale renewable generation transfers.

Key Finding 1: Significant growth in solar and wind resources was found across all five scenarios

The capacity expansion analysis found that retired coal and natural gas generation was replaced by wind, solar, battery energy storage, and more efficient natural gas generation technologies. The total installed capacities of wind, solar, and battery energy storage increased in all scenarios. These findings are generally consistent with the results from the 2018 LTSA, but much more new capacity was added in the 2020 LTSA.

The primary reason that more new capacity was added in the 2020 LTSA is the inclusion of an input assumption that generating units would be retired at a predetermined age. The total amount of these fixed-age retirements was approximately 21 GW by 2035. These fixed-age retirements were replaced by new capacity to serve the assumed increasing demand. The secondary reason is that there was higher demand growth in the 2020 LTSA compared to the 2018 LTSA. Summer peak demand increased by approximately 23 GW in the 15-year study period in the 2020 LTSA, while it only increased by approximately 16 GW in the 2018 LTSA. Therefore, more new capacity was needed to serve the additional demand in the 2020 LTSA.

Capacity Additions

Total capacity added by the capacity expansion analysis varied from 86,100 MW in the Current Trends scenario to 108,000 MW in the High Industrial Load scenario. Utility-scale solar capacity additions ranged from 22,200 MW to 35,300 MW across the scenarios. The amount of distributed solar generation added in each scenario was a model input rather than a result of economic analysis. The assumed distributed solar adoption varied from 3,900 MW to 6,100 MW.

New wind and solar resources comprised the majority of capacity additions in all scenarios, because the assumed capital cost of wind and solar generation was low enough such that the investment could be recovered by energy prices. Since wind and solar resources have different diurnal generation patterns, they complement each other to serve demand throughout the day. Therefore, if the model added more wind capacity, it added more solar capacity as well, and vice versa. The model added the most combined cycle capacity in the High Battery Energy Storage scenario since this scenario included a significant amount of electric vehicle charging at night, which biased the model to select resources that are available at night. The High Battery Energy Storage scenario also had the most new battery energy storage capacity because a low battery energy storage capital cost was assumed and new battery energy storage was assumed to be co-located with the majority of new solar farms in this scenario. For this scenario the capacity of the co-located battery energy storage was assumed to be 50% of the co-located solar capacity. Figure 4 shows the amount of capacity added by technology in each scenario.

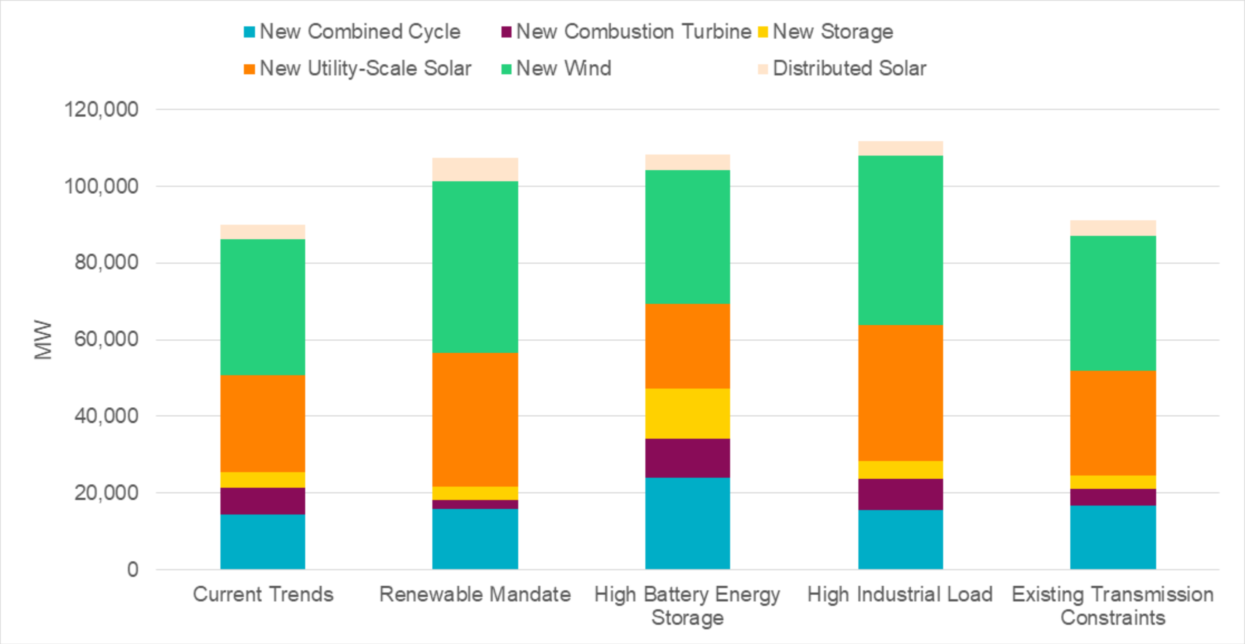


Figure 4: Capacity Additions by Scenario by 2035

Generation Retirements

The retirement process for the 2020 LTSA had two distinct parts. First, a group of fixed-age retirements was determined for use in all scenarios. These fixed-age retirements were determined by the age of an existing unit. Natural gas units were retired after 60 years of operation, and coal units were retired after 45 years of service. The second part of the retirement process considered economics as the criterion for retirement. Based on economic simulations, 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 studied. By 2035, the total fixed-age retirements by capacity type, as described above by age, were 9,982 MW of coal and 10,965 MW of natural gas. The list of affected units and dates of retirement are provided in Appendix III.

The capacity expansion model did not retire any additional capacity based on economics, but did accelerate retirement dates of some fixed-age retirements. Comparatively, in the 2018 LTSA, the model only retired those generators that could not recover their variable and fixed costs. As a result, the total retirements in the 2018 LTSA varied from 0 MW to 5,610 MW across the scenarios, which was much lower than the total retirements in the 2020 LTSA.

Changing Resource Mix

The share of demand served by coal and natural gas generation declined throughout the 15 years in each of the five scenarios due to coal and natural gas generation retirements and demand growth over the study period. Retired coal and natural gas generation was replaced by solar, wind, and new natural gas generation, and battery energy storage. The share of wind and solar generation increased in all five scenarios, driven by solar and wind capacity additions.

Natural gas remained the primary fuel used to serve ERCOT demand in three out of the five scenarios. The two exceptions were that wind generation replaced natural gas generation to become the primary technology from 2030 through 2035 in the High Renewable Mandate scenario and by 2035 in the High Industrial Load scenario. Figure 5 shows the percent of total energy generated by fuel type in 2035 for all scenarios.

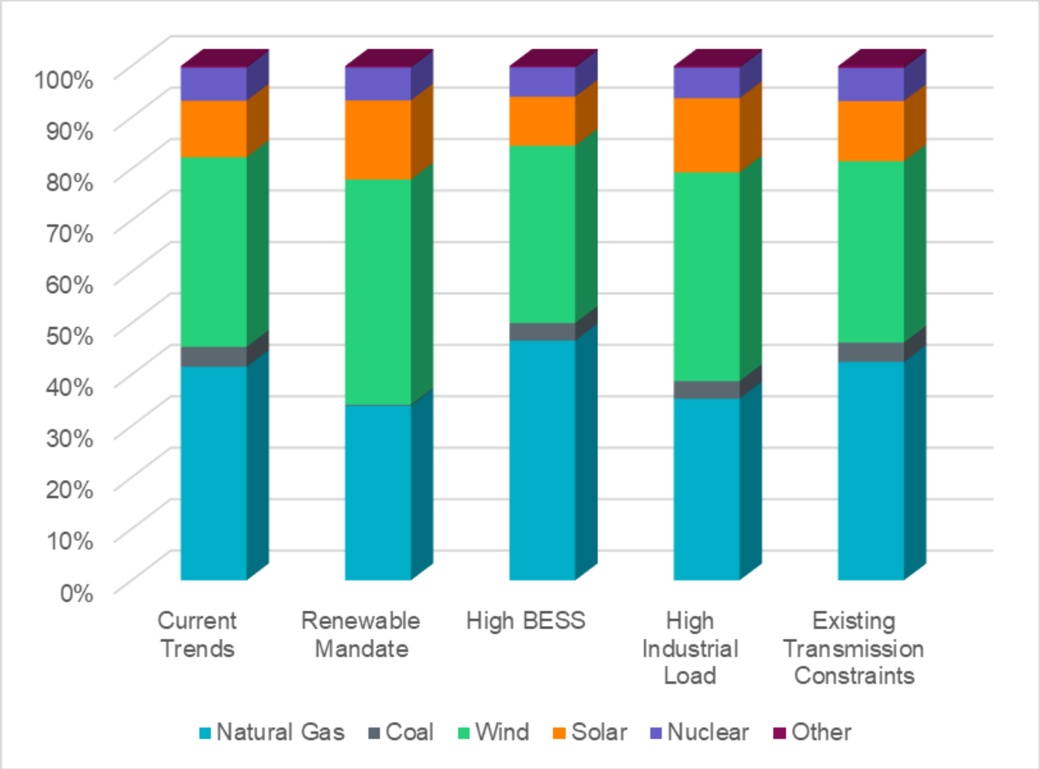


Figure 5: Generation by Fuel Type for 2035

Figure 6 provides a comparison of historical renewable penetration[4] experienced in 2019 to that seen in the Current Trends scenario. It is expected that the number of hours during which the majority of demand could be served by intermittent renewable resources will increase as more wind and solar capacity is integrated into the ERCOT system. Given the amount of renewable generation added in these scenarios, it appears possible that there may be hours when all ERCOT demand could theoretically be served by wind and solar resources. However, thermal and stability constraints on the transmission system and unit commitment limitations caused the grid simulation software to curtail available wind and solar output. In addition, operational considerations, such as ramping limitations and maintaining a minimum level of system inertia, would need to be assessed further in order to ensure reliability under high renewable penetration conditions.

[4] Renewable penetration is defined as the total amount of demand at any given time that is being served by solar and wind generation.

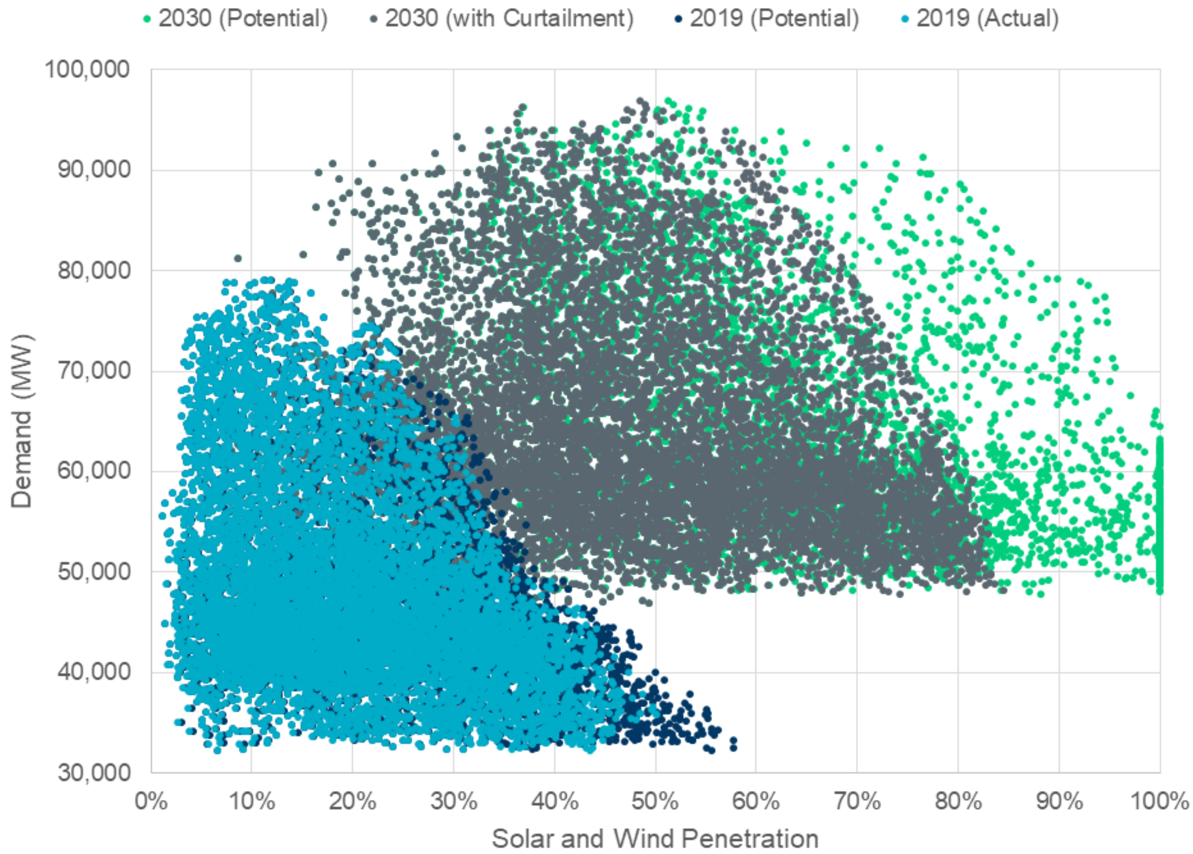


Figure 6: Renewable Penetration Trends

Key Finding 2: Growth in renewable resources and electric vehicle adoption lead to a shift in scarcity hours to later in the day in both summer and winter months

Scarcity hours shifted to later in the day across all five scenarios. The Current Trends, Renewable Mandate, and High Industrial Load scenarios saw scarcity hours from 7-10pm in both summer and winter months by 2035, while the High Battery Energy Storage scenario experienced an extension of scarcity hours until 11pm in the same timeframe. Factors influencing the shift in scarcity hours include:

- Increased adoption of electric vehicles could result in a significant shift in hourly demand profiles. This observation was also noted in the 2018 LTSA.
- The drop in solar production experienced in late evening hours can result in a high ramping rate for net load[5]. High net load ramping conditions will likely become more frequent and severe as solar penetration increases.

Peak Day Load Shape

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 and winter seasons. 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 demand remains high could lead to extreme system ramping conditions, or possibly insufficient generation to serve demand (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 7 shows this potential result for a summer peak evening in 2035 from the Current Trends scenario. The dashed lines are plotted on the secondary vertical axis while the solid lines are plotted on the primary vertical axis.

[5] Customer demand minus aggregate wind and solar output. Net load is representative of the portion of demand not served by wind or solar generation.

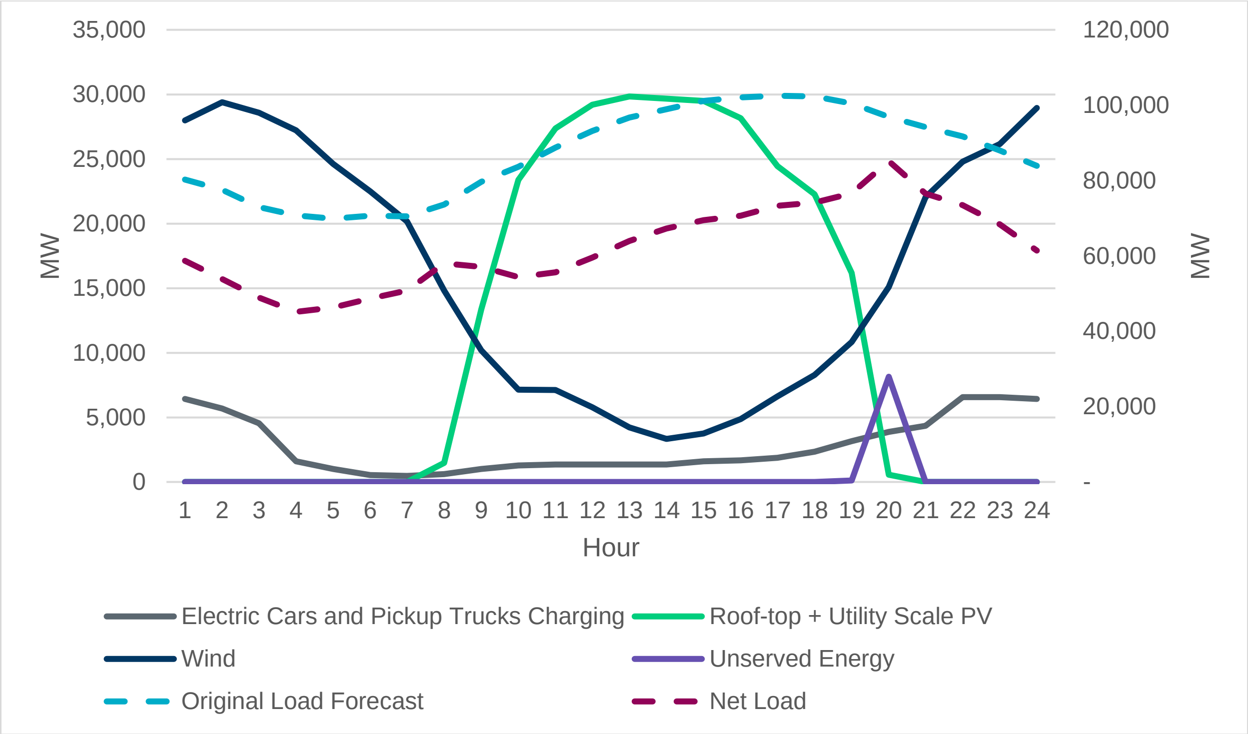


Figure 7: Peak Net Load Challenge on Hot Summer Day in 2035

Historically, the most stressed system conditions – from both resource scarcity and transmission security standpoints – have been during summer afternoons. In all five scenarios, stressed system conditions were observed at other times of day and in days throughout the year. As wind and solar penetration on the ERCOT system continue to increase, transmission planning studies need to consider other possible system conditions outside of summer peak, including peak net load conditions.

Peak Net Load

A comparison of net load and conventional demand from the Current Trends scenario in year 2035 is shown below in Figure 8. The net load curve is the part of ERCOT demand that will be served after intermittent renewable resources (i.e., wind and solar) are utilized. The peak load portion of the net load duration curve is steeper than the conventional load duration curve. The net load peak occurs in a relatively small number of hours, and therefore, investors in conventional peaking generation capacity (e.g., combustion turbines) may not be able to recover investment costs to meet the net peak demand, and other resources will be necessary to serve the net peak demand requirement. Such resources will require suitable availability and ramping capabilities.

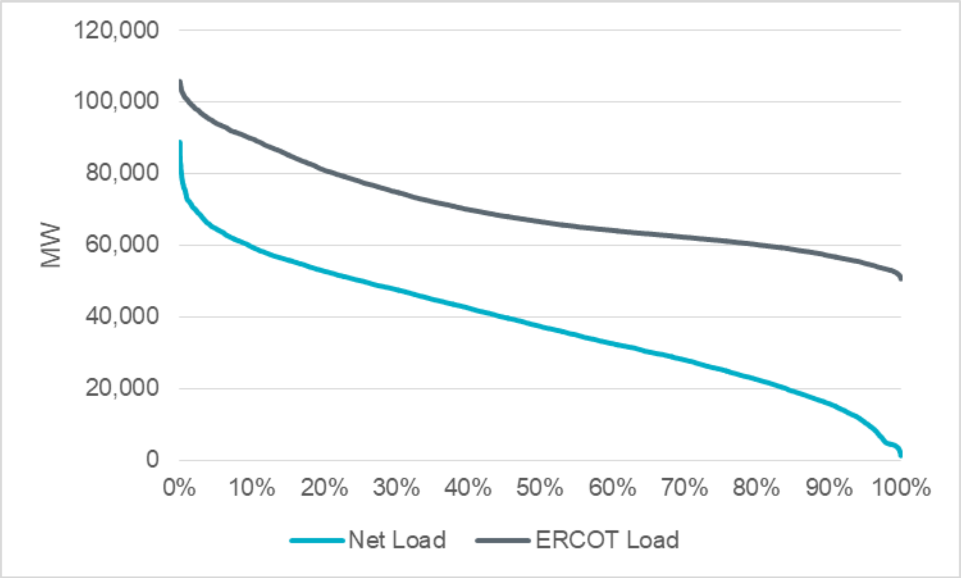


Figure 8: Load vs Net Load for Current Trends Scenario for 2035

The need for increased flexibility, as well as accurate forecasting for demand, wind, and solar, is further illustrated in Figure 9, which compares maximum net load ramp rates by hour of the day for historical data from 2019 and the Current Trends scenario in 2030. As more solar capacity is interconnected to the ERCOT system, net load ramping conditions can increase. The highest net load ramp rates were observed in the morning and in the evening, corresponding to the diurnal patterns of both solar generation and aggregate customer demand.

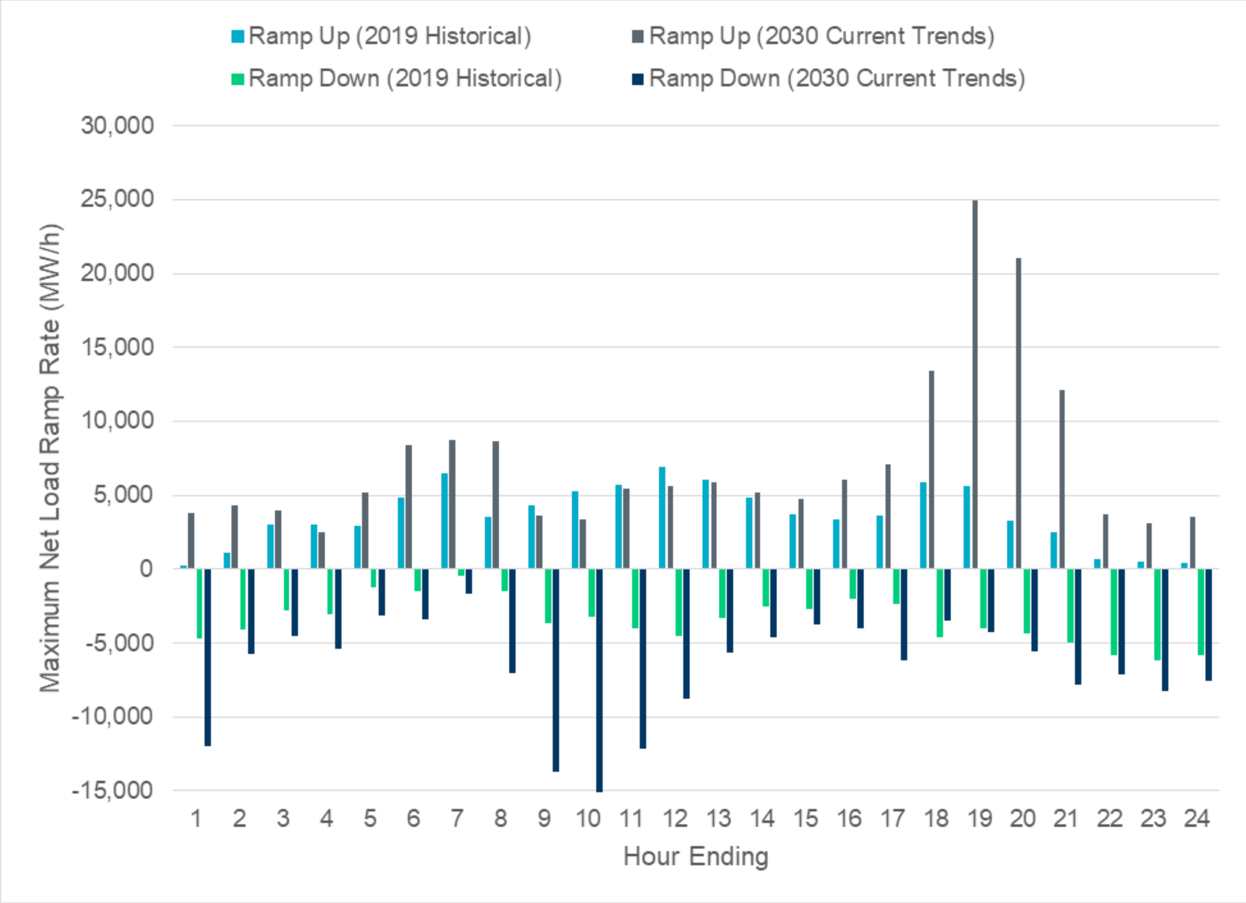


Figure 9: Net Load Ramp Rate Trends

Future net load conditions may also be impacted by increased development of battery energy storage. A peak summer day for the High Battery Energy Storage scenario, which included 12,911 MW of battery energy storage, is shown in Figure 10. Examples of times when battery energy storage charging increased system demand, and when discharging helped to serve demand are indicated in the figure. As indicated in these results, battery energy storage could serve to flatten net load peaks.

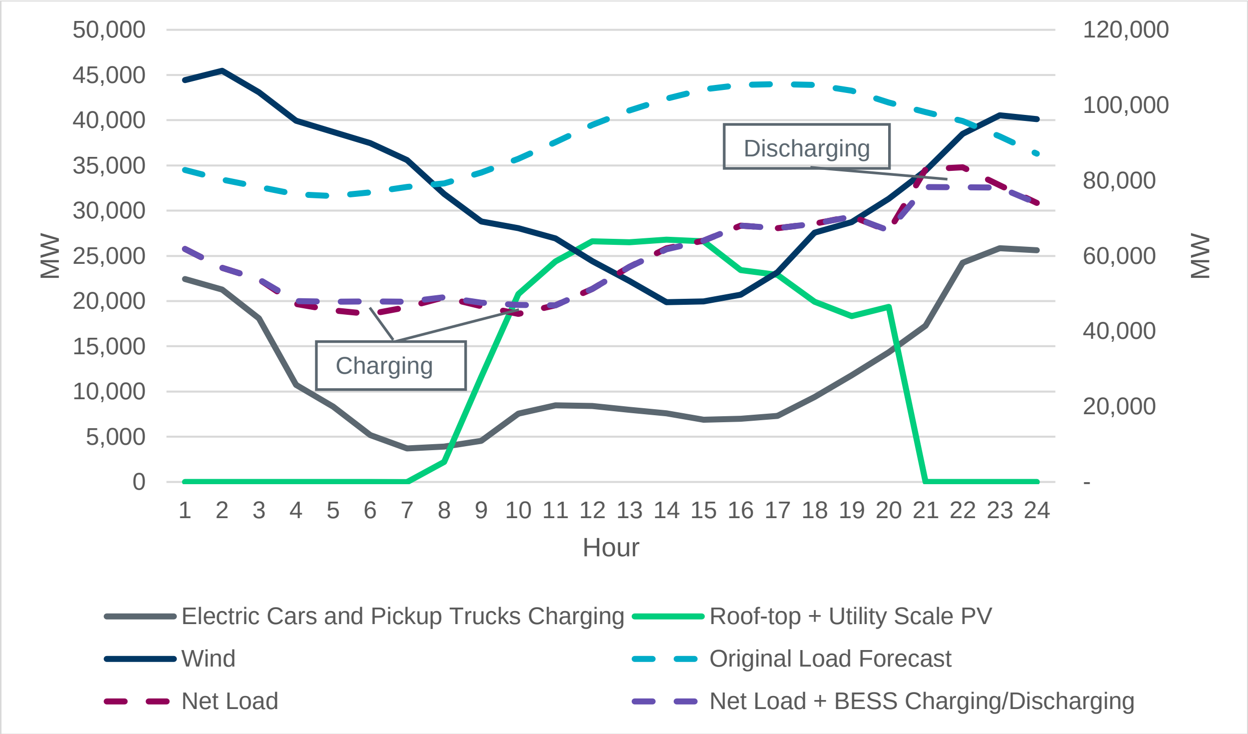


Figure 10: Impact of Battery Energy Storage on Net Load

Key Finding 3: The scale and location of wind and solar generation additions are dependent upon sufficient transmission capacity between resource-rich regions and demand centers

Comparing the results of capacity expansion and retirement analysis for two iterations of the Current Trends scenario, the Renewable Mandate scenario, and the Existing Transmission Constraints scenario provided insight into the potential impacts of transmission limitations on new generation development.

Two iterations of capacity expansion and retirement analysis, and transmission expansion analysis were conducted for the Current Trends scenario. Figure 11 illustrates the iterative process for capacity and transmission expansion. The purpose of the iterative process was to account for the impacts of:

- transmission constraints on the timing, location, and capacity of new resources
- resource siting on the need for transmission improvements

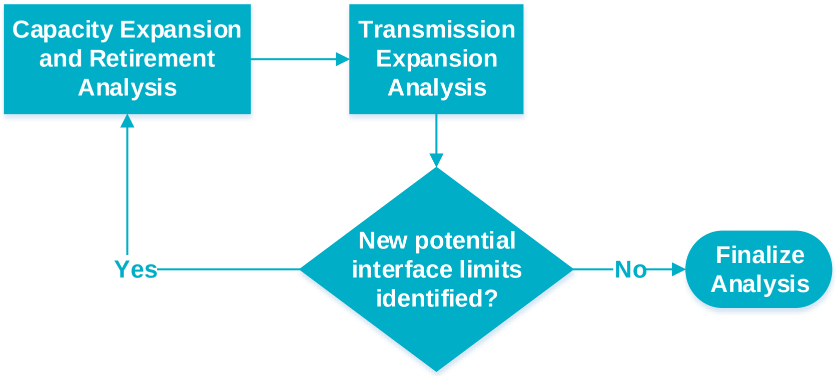


Figure 11: Iterative Process for Capacity and Transmission Expansion

The first iteration of Current Trends capacity expansion and retirement analysis used a single zone model and, as such, did not consider any transmission limitations. The second iteration utilized a four-zone model (Panhandle, West, Valley, and the Other ERCOT Regions) and included West Texas export, Valley import, and Valley export interfaces. Figure 12 shows the relationships between the four zones and their interfaces. Further detail on the four-zone model is included in Appendix IV.

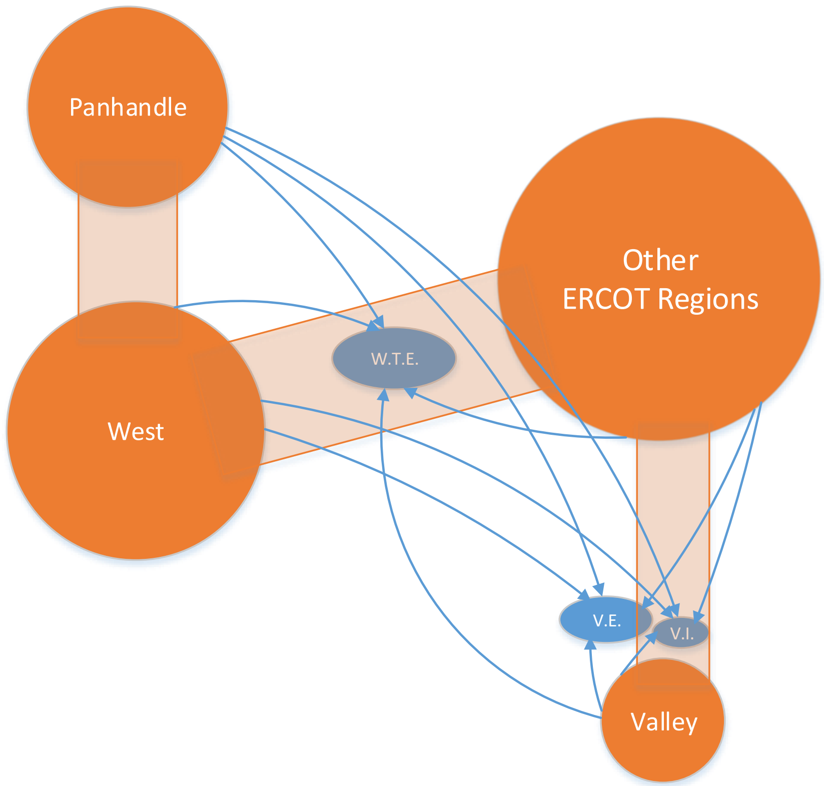


Figure 12: Four-zone Model with Interfaces

The transfer limits and associated zonal shift factors used for the second iteration of capacity expansion and retirement analysis were determined from the first iteration of transmission expansion analysis. The final transmission expansion analysis was performed using the second iteration capacity expansion plan. The interface limits by study year for the second iteration are shown in Table 3.

Table 3: Interface Limits by Study Year[6]

Study Year	West Texas Export Limit[7] (MW)	Valley Import Limit (MW)	Valley Export Limit (MW)
2025 and before	11,500	1,865	3,737
2026 and 2027	13,500	1,865	3,737
2028 and after	15,500	1,865	3,737

[6] The limits used for the 2020 LTSA were assumptions developed for the purpose of the study and should not be construed as representing any current or future operational limits.

[7] A 1 GW increase in the West Texas export transfer limit was assumed for each 345-kV double-circuit line added by the first iteration of transmission expansion analysis. That assumption was not based on stability analysis conducted for the 2020 LTSA, but rather on experience gained from previous stability assessments that analyzed the West Texas export stability constraint.

The Renewable Mandate scenario included additional incentives for wind and solar resources and a single zone model without transmission constraints for capacity expansion and retirement analysis. The Existing Transmission Constraints scenario included an assumption that currently identified transfer limits persist into the foreseeable future. The four-zone model and interface limits used for Existing Transmission Constraints were the same as those used for the second iteration of Current Trends for before 2025. As a result of these input assumptions, the Renewable Mandate and Existing Transmission Constraints scenarios can be considered "bookends" for wind and solar generation development in this LTSA.

Resource Shift

A geographic comparison of wind and solar capacity additions for the Current Trends, Renewable Mandate, and Existing Transmission Constraints scenarios is shown in Figure 13. The inclusion of transmission constraints in capacity expansion and retirement analysis led to a shift in wind and solar resources away from the more resource-rich regions in west and north Texas to sites closer to major demand centers. The primary cause of this shift was the inclusion of the West Texas export stability limit which was a binding constraint in many hours.

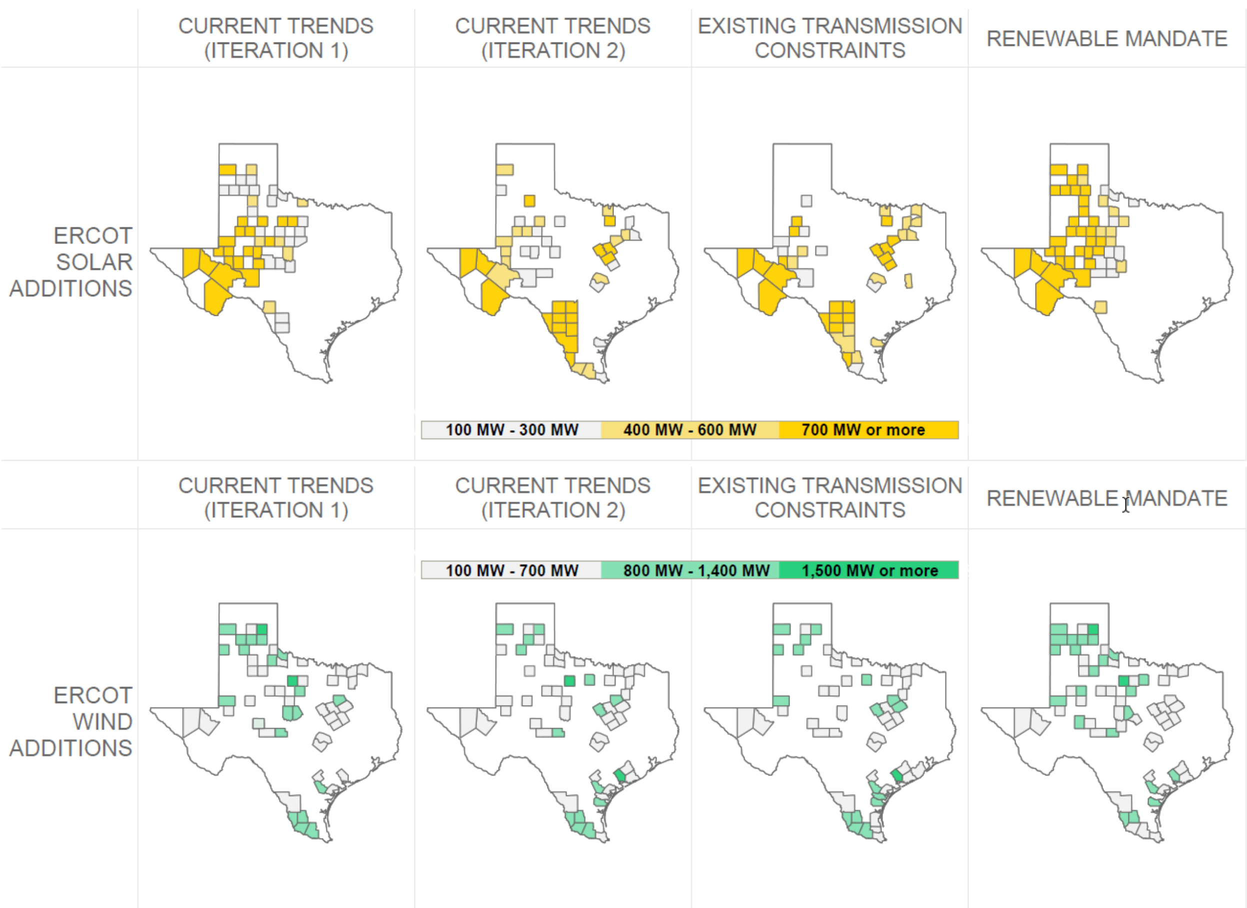


Figure 13: Impact of Transmission Constraints on Wind and Solar Locations

Capacity expansion and retirement analysis for the first iteration of the Current Trends scenario and the Renewable Mandate scenario resulted in solar generation additions almost entirely in the West

Texas and Panhandle regions of ERCOT. However, the inclusion of transmission limitations in the second iteration of the Current Trends scenario and the Existing Transmission Constraints scenario resulted in very little new solar capacity in the Panhandle region. The inclusion of transmission constraints resulted in insufficient revenue for new solar generation in the Panhandle region to be selected by the model.

Additionally, a significant increase in solar capacity additions in the counties southwest of San Antonio was observed for the two scenarios that considered transmission limitations for capacity expansion and retirement analysis. Those counties are located just outside of the West Texas export interface and have reasonably good solar resources. However, there is very little extra-high voltage (EHV) transmission in that area, which could present a challenge to generation development without transmission improvements in the area.

A comparison of capacity expansion results for the Current Trends, Existing Transmission Constraints, and Renewable Mandate scenarios is provided in

Table 4[8]. Scenarios that included transmission limitations not only had fewer wind and solar capacity additions overall, but also experienced less maximum annual wind and solar energy production per megawatt of new generation added. This is due to the fact that new wind and solar sites located closer to major urban demand centers also tend to have lower resource potential. Transmission limitations could reduce the amount of ERCOT demand that can be served by renewable resources.

Another potential impact of transmission limitations is an increase in total production costs. A comparison of the Current Trends and Existing Transmission Constraints scenarios showed that system-wide production costs increased as the portion of demand served by renewable resources with lower marginal costs decreased. Total production costs for the Renewable Mandate scenario were higher due to the inclusion of carbon pricing.

Total emissions (carbon dioxide, nitrogen oxides, and sulfur dioxide) were also observed to increase in scenarios for which transmission limitations were considered for capacity expansion and retirement analysis. The increase in emissions was due to the fact that those scenarios had a higher proportion of demand served by fossil-fueled generation, corresponding to the previously noted reductions in both total wind and solar generation additions and maximum annual capacity factors for wind and solar resources.

[8] Capacity expansion results were not derived from models that utilize the full transmission topology.

Table 4: Capacity Expansion Results Comparison for 2035

	Current Trends (Iteration 1)	Current Trends (Iteration 2)	Existing Transmission Constraints	Renewable Mandate
Cumulative Wind Capacity Additions (GW)	40.2	35.3	35.2	44.8
Cumulative Solar Capacity Additions (GW)	27.7	25.4	27.5	35
Cumulative Total Capacity Additions (GW)	90.7	86.1	87.1	101.4
Total Production Costs ($B)	13.5	15.0	15.2	22.7
Total Potential Annual Wind Capacity Factor (%)	49.6	48.0	47.2	49.6
Total Potential Annual Solar Capacity Factor (%)	30.1	27.8	27.5	30.2
Total CO_2 Emissions (Megaton)	122.6	140.0	142.8	93.5
Total NO_x Emissions (Kiloton)	76.3	83.2	89.9	31.2
Total SO_2 Emissions (Kiloton)	82.7	86.2	98.7	5.1

Interdependence of Resource Siting and Transmission Needs

The impact that resource siting can have on transmission needs is illustrated in Figure 14. The left map shows potential new extra-high voltage (EHV) transmission pathways identified for 2030 in the first iteration of the Current Trends scenario whereas the right map includes potential new EHV transmission needs for the same year in the second iteration of the Current Trends scenario.

As previously shown in Figure 13, the second iteration of Current Trends capacity expansion and retirement analysis showed a shift in solar capacity additions towards counties southwest of San Antonio that have relatively good solar resource but were not constrained by the West Texas export interface limit modeled in that scenario. The need for new EHV transmission through the southwest portion of the ERCOT system was observed as a result of the solar resource sites selected by the model. While future resources may not necessarily be sited in the same locations, this finding illustrates the interdependent relationship between sites selected for new generation and future transmission needs.

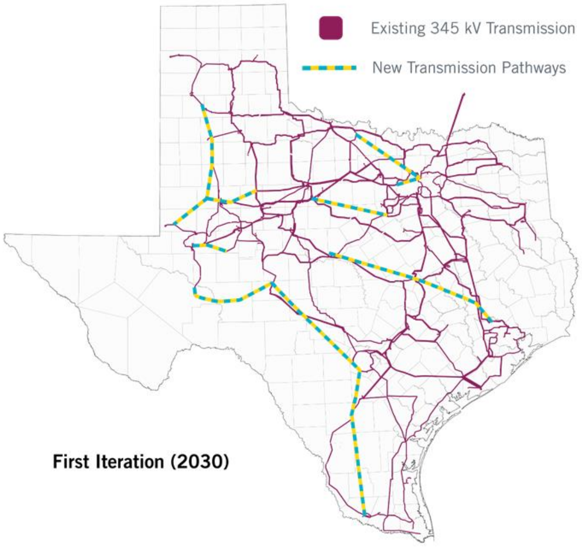


Figure 14: Impact of Resource Siting on Transmission Needs

Increased power transfer from the south into the Houston and Freeport areas was also observed in the second iteration of the Current Trends scenario due to the increased number of resources sited in the southwest portion of the ERCOT system. New EHV transmission pathways from the south into the Houston and Freeport areas may be needed in scenarios where significant new generation resources are sited south of San Antonio.

Key Finding 4: Holistic solutions addressing both regional transfer limits and local constraints closer to urban demand centers are required to accommodate large-scale renewable generation transfers.

Similar to findings from the 2018 LTSA, ERCOT identified the need for additional transmission paths from West Texas to demand centers. However, it was also observed that the full benefit of additional transfer paths cannot be realized without also addressing local constraints closer to customer demand. For example, adding new transmission circuits to increase the West Texas export transfer limit can result in increased congestion into the Dallas-Fort Worth, northwestern San Antonio, and Houston and Freeport areas. Holistic solutions addressing both regional transfer limits and local constraints are required if large-scale renewable generation transfers are to be accommodated.

The need for holistic solutions is driven by both a changing resource mix and trends in customer demand growth. Not only does power need to be transferred across the system, but it must also be delivered to customers. Large industrial load additions are, and are projected to continue, occurring in both rural and urban areas. The time of use and flexibility of customer demand are also shifting as new technologies are adopted.

Figure 15 and Figure 16 show the top constraints observed in 2030 for the Current Trends and Renewable Mandate scenarios, respectively. The sizes of the bubbles indicate the relative amount of congestion rent experienced by each transmission element prior to the addition of any potential transmission improvements.

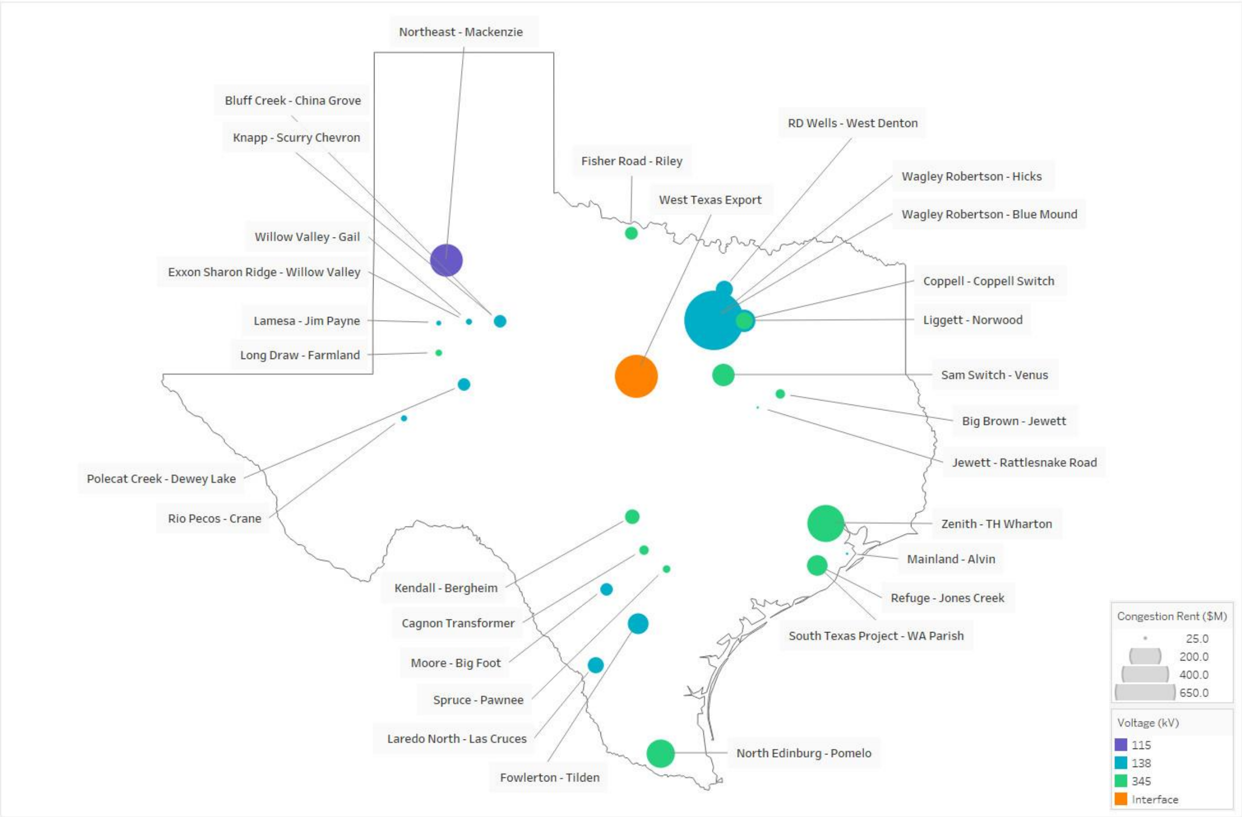


Figure 15: Top Constraints for Current Trends (2030)

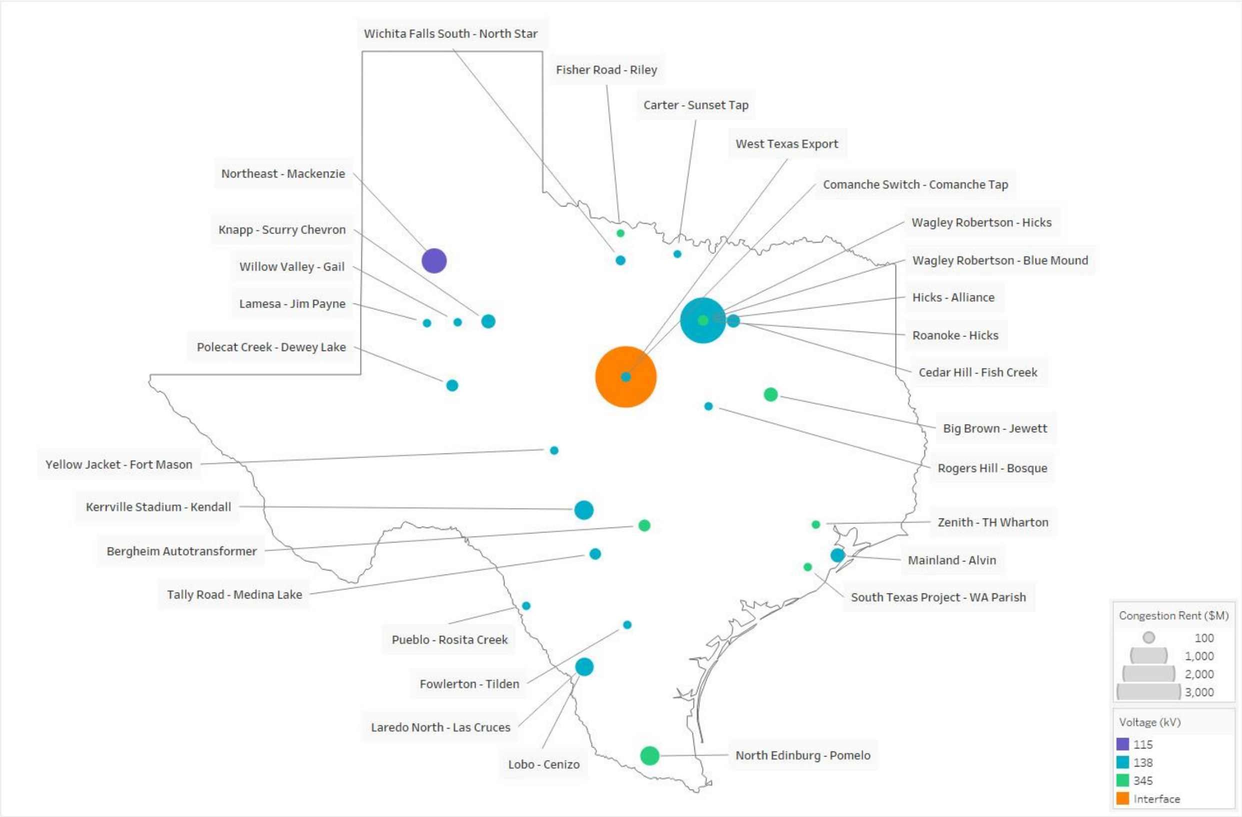


Figure 16: Top Constraints for Renewable Mandate (2030)

The Dallas-Fort Worth area was highly congested in both the Current Trends and Renewable Mandate scenarios, driven by both generation additions to the northwest of the area and load growth within the area. This observation is consistent with both the findings of the 2018 LTSA and near-term needs identified by the 2020 RTP. In the Current Trends scenario, both local improvements (e.g., 138-kV upgrades near Eagle Mountain, Hicks Switch, and Carrollton Northwest) and a new 345-kV line from northwest Dallas-Fort Worth to the central part of the area showed significant production cost savings.

The West Texas export interface also experienced high congestion in both the Current Trends and Renewable Mandate scenarios. Transmission expansion analysis for the Current Trends scenario identified four new EHV transfer pathways that resulted in significant production cost savings and reduced congestion on the interface. Results from the Renewable Mandate scenario indicate that additional transfer pathways beyond the four identified for the Current Trends scenario may be justifiable if sufficient new generation is added to the west of the interface.

Potential EHV transmission pathways identified to relieve congestion on the West Texas export interface for the Current Trends scenario also serve as import pathways to urban demand centers in the Dallas-Fort Worth, San Antonio, and Houston areas. The path from the Panhandle to Dallas-Fort Worth helped to reduce some of the congestion observed in the northwest Dallas-Fort Worth area in conjunction with local Dallas-Fort Worth area improvements. Similarly, the new lines from Bakersfield to Big Hill to Uvalde provided part of an import pathway into San Antonio that relieves some of the congestion observed in the Kendall area northwest of San Antonio. Congestion on transmission lines from the north into Houston was reduced by extending the new path from Brown Switch to Bell County East further south into the Houston area.

The West Shackelford to Comanche Peak and Bakersfield to Big Hill to Uvalde paths experienced significant east-to-west power flow during some hours in the Current Trends scenario. This observation indicates that those potential transmission pathways not only serve to help export power from West Texas to urban demand centers further east, but also import power to serve growing demand in West Texas under some system conditions.

The 115-kV network in the Lubbock region experienced significant congestion in both the Current Trends and Renewable Mandate scenarios. Closing the loop around the Lubbock system with new 345-kV transmission paths alleviated this congestion. The Lubbock Loop project in combination with the Lamesa Area Improvements and Lamesa to Andrews County projects also provided an additional pathway for generation in the Panhandle region to serve demand in Far West Texas.

A list of potential transmission improvements identified for the Current Trends scenario are available in Figure 17 and

Table 5. Figure 18 shows the potential new EHV transmission identified by the transmission expansion analysis conducted for the Current Trends scenario.

Full project descriptions for the Current Trends scenario are available in Appendix IV. All identified projects are conceptual in nature. Routing feasibility and other considerations were not considered in this assessment as the purpose of the analysis was to inform stakeholders of potential transmission solutions to address needs seen in the study. More detailed analysis would be required to design necessary transmission additions and upgrades.

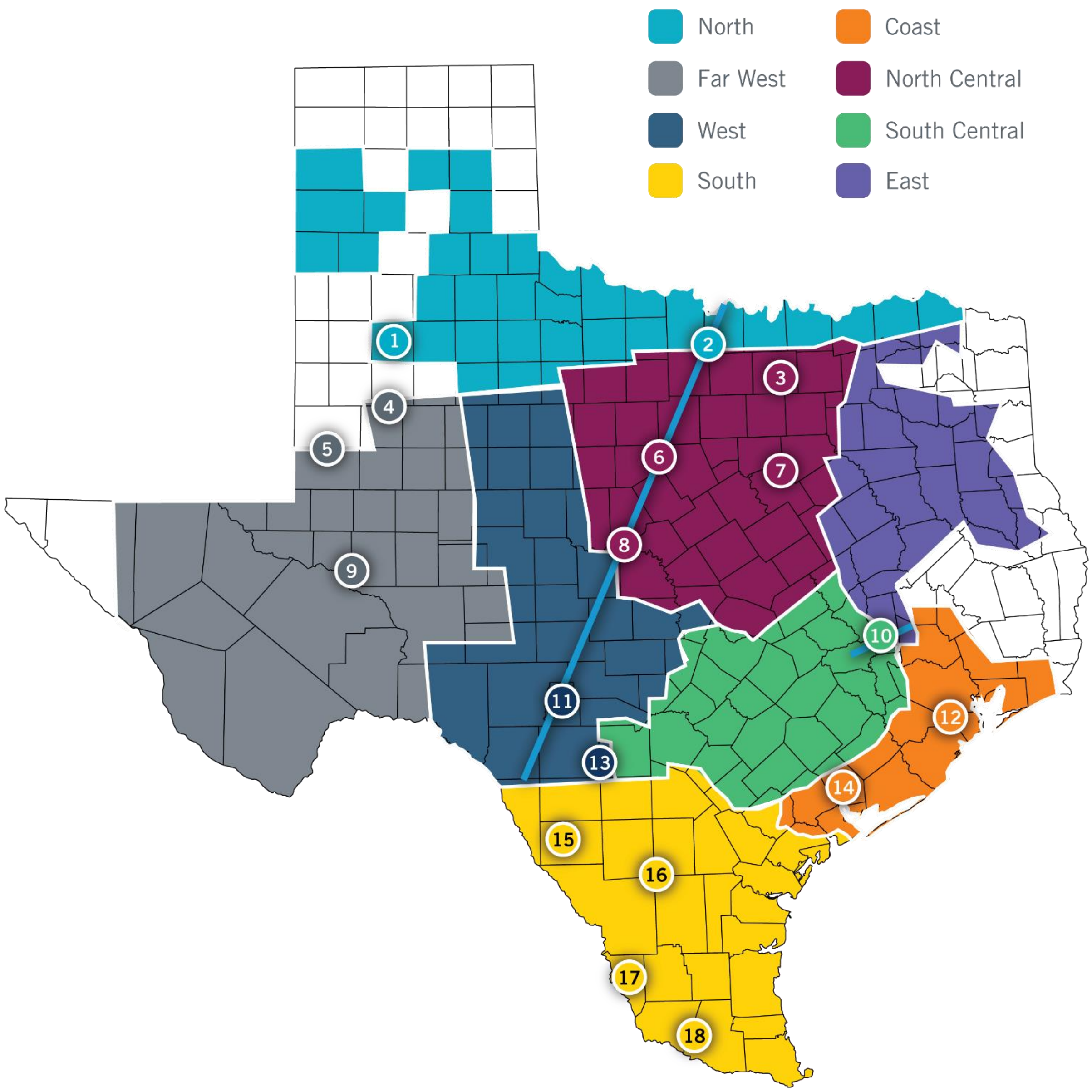


Figure 17: Current Trends Potential Transmission Improvements

Table 5: Current Trends Transmission Improvement Descriptions

Map Index	Transmission Improvement Description	Date of Potential Need[9]
1	Lubbock Loop	2030
2	Panhandle to Dallas-Fort Worth	2030
3	Dallas-Fort Worth Area Improvements	2030
4	Lamesa Area Improvements	2030
5	Lamesa to Andrews County	2030
6	West Shackelford to Comanche Peak	2035
7	Sam Switch to Venus Switch	2030
8	Brown Switch to Bell County East	2030
9	Rio Pecos to Crane	2030
10	North Houston Import	2030
11	Bakersfield to Big Hill to Uvalde	2030
12	Houston / Freeport Area Improvements	2030
13	San Antonio Import	2030
14	South Houston / Freeport Import	2030
15	Southwest Improvements	2030
16	Fowlerton to Del Sol	2030
17	Del Sol to Lobo Second Circuit	2035
18	Frontera Import	2030

[9] Projects may be comprised of multiple parts with varied dates of potential need. The dates provided in the table are the earliest date identified for any portion of a project.

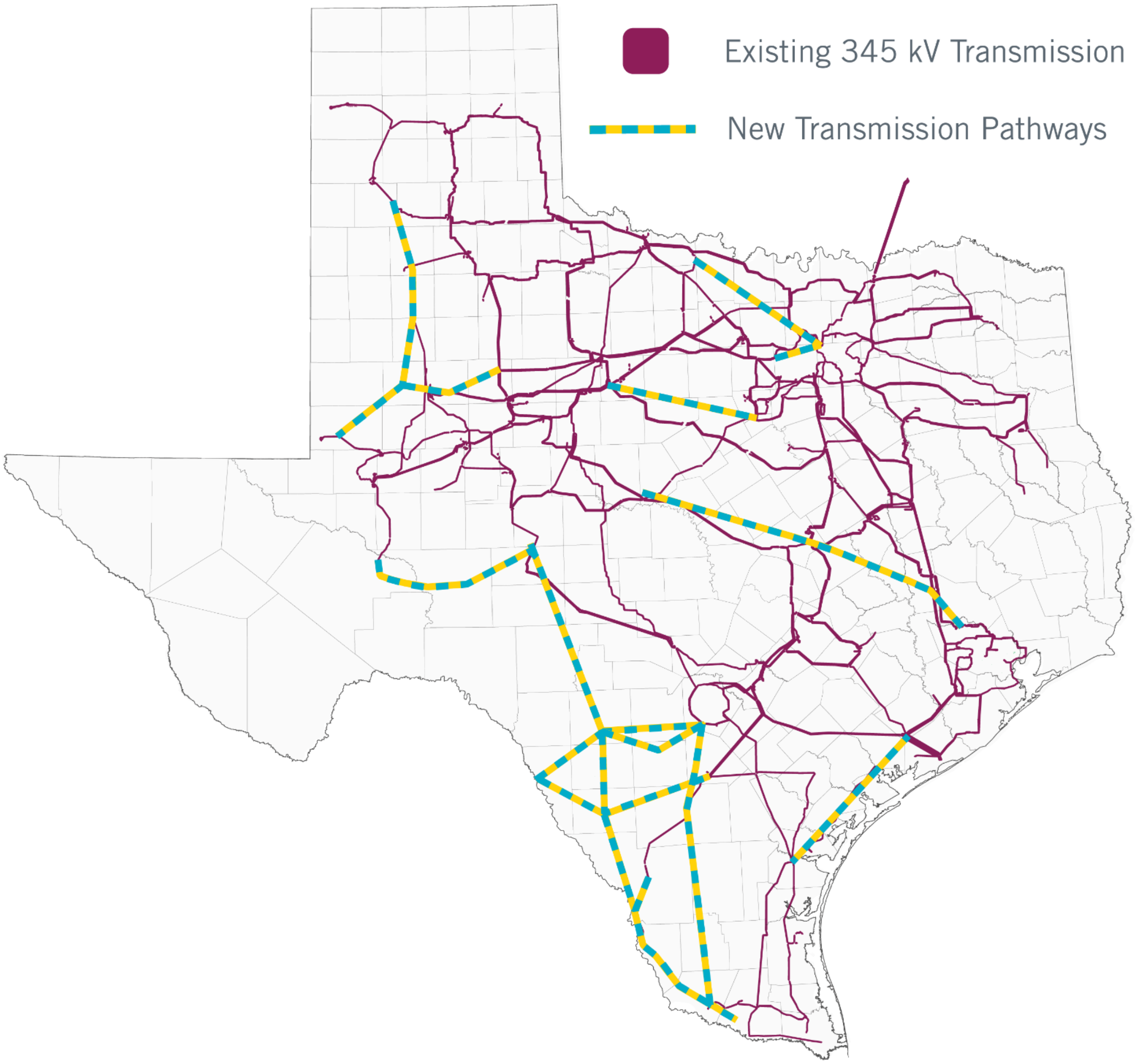


Figure 18: Potential New EHV Transmission (Current Trends, 2035)

Appendices

Appendix I: LTSA Process

LTSA Scenario Development

The 2020 LTSA scenario development process focused on stakeholder feedback received via survey and Regional Planning Group (RPG) meetings. The scenario-based planning approach provided a structured way for stakeholders to identify the most critical trends, drivers, and uncertainties for the upcoming ten- to fifteen-year period. Scenario-based planning considered sufficiently different, yet plausible futures and was used to evaluate transmission plans across multiple future states. Some of the noteworthy drivers considered in the LTSA can be seen in Table 6 below.

Table 6: Key Drivers Considered in the 2020 LTSA

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 the 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.
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, and increased interest in microgrids.
Weather and Water Conditions	May affect demand growth, environmental regulations and policies, technology mix, average summer temperatures, the frequency of extreme weather events, and water costs.

ERCOT presented initial input assumptions and preliminary results for the 2020 LTSA at the May, 2019 RPG meeting. Stakeholder feedback on input assumptions for the Current Trends scenario, as well as important drivers and potential scenarios, was solicited via an online survey following that meeting. A broad range of stakeholder perspectives – including those representing municipal utilities, electric cooperatives, investor-owned utilities, generators, retail electric providers, consumers, and interest groups – were included in survey responses.

A summary of the survey results is illustrated in Figure 19 and Figure 20 using boxplots. The lower and upper edges of the boxes represent the first and third quartiles of the rankings for each item, respectively, while the blue bar inside of the boxes represent the median rank. The maroon dots represent the average ranking and the ends of the line segments represent the minimum and maximum ranks for each item.

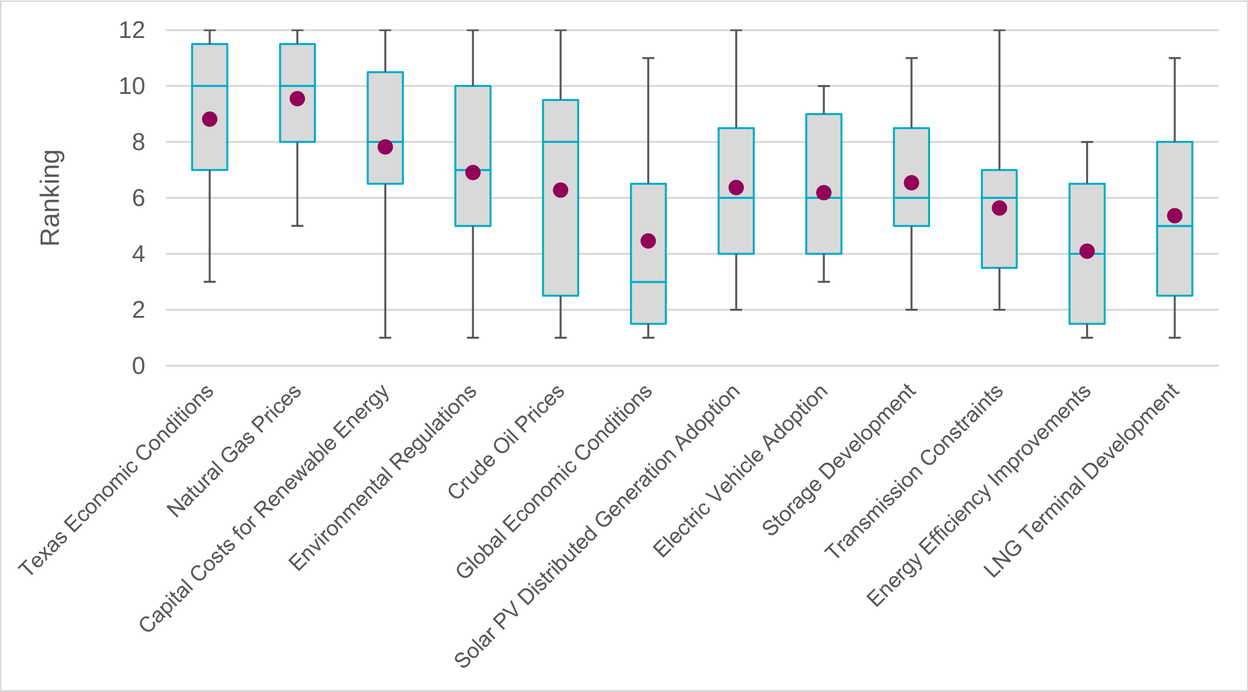


Figure 19. Key Driver Rankings from 2020 LTSA Stakeholder Survey

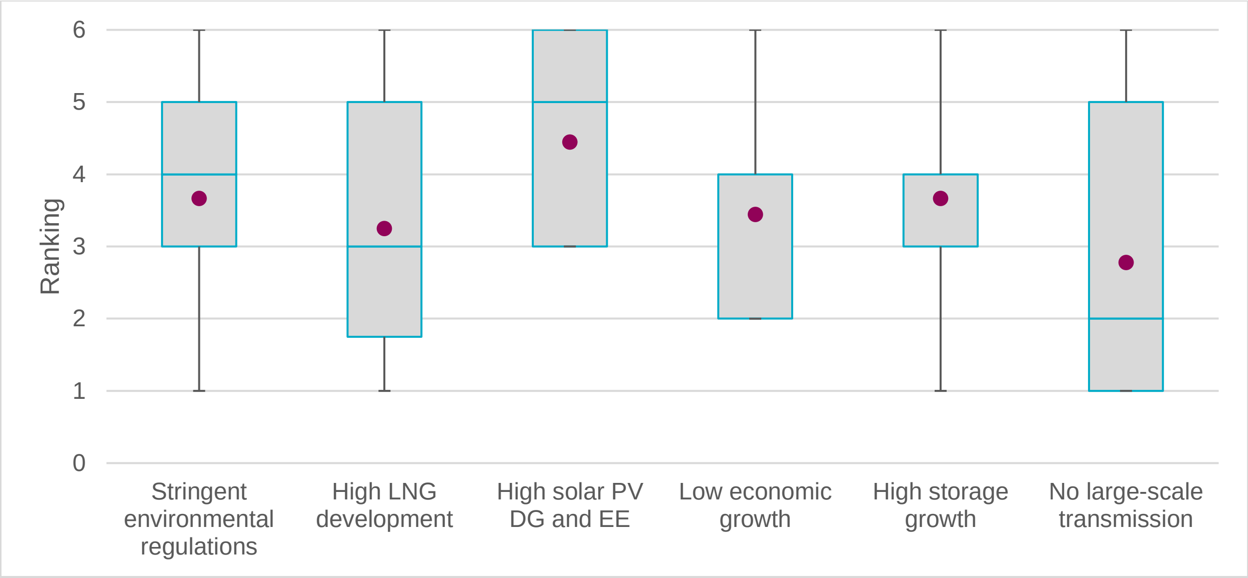


Figure 20. Ranking of Potential Scenario Concepts from 2020 LTSA Stakeholder Survey

ERCOT considered stakeholder feedback received from the online survey, and during RPG meetings, to develop a proposal for additional scenarios. The scenario proposal and draft assumptions for proposed scenarios were presented to stakeholders at the November, 2019 RPG meeting. Further stakeholder feedback received following that scenario proposal led to the final development of the scenarios considered for the 2020 LTSA.

Table 7 summarizes the unique elements of each scenario.

Table 7: Scenarios Studied in the 2020 LTSA

Scenario	Description
Current Trends	The trajectory of what we know and is knowable today (e.g., demand growth, economic trends, fuel prices, etc.). Unlike the 2018 LTSA, electric vehicle adoption was included in the assumptions for the Current Trends scenario in the 2020 LTSA.
Renewable Mandate	Favorable regulatory policies and the resolution of major infrastructure-related hurdles further incentivize the development of renewable resources on the ERCOT system. This scenario assumed that the ITC and PTC were extended through 2035, increased distributed solar adoption, and the inclusion of a carbon tax.
High Battery Energy Storage	A scenario designed to study the impacts of integrating large amounts of battery energy storage into the ERCOT system. Lower battery costs, higher electric vehicle adoption across all sectors (e.g., cars, light-duty trucks, and heavy-duty trucks), and co-location of battery energy storage with solar builds were assumed for the scenario.
High Industrial Load	A scenario designed to investigate the impact of continued robust growth of large industrial loads in parts of the ERCOT system. Higher demand growth in the Delaware Basin, as well as an increase in LNG load were assumed.
Existing Transmission Constraints	A scenario designed to study the potential impacts on resource mix and siting if no new large-scale transmission were developed to address currently identified transfer-related transmission constraints on the ERCOT system.

The final input assumptions used in creating 2020 LTSA study are documented in Table 8.

Table 8: 2020 LTSA Input Assumptions

	Demand				Generation			
Scenario	**Demand and Energy Forecast**	**Electric Vehicle Assumptions**	**Additional LNG Assumptions**	**Distributed Solar Assumptions**	**Renewable Incentives (ITC/PTC)**	**Carbon Pricing**	**Renewable Annual Capacity Addition Limit**	**Natural Gas Prices**
Current Trends	ERCOT Long-Term Demand and Energy Forecast based on the 2013 weather year	Approximately 4 million cars and 800,000 pickup trucks by 2035	No additional demand beyond that included in the ERCOT Long-Term Demand and Energy Forecast	3.9 GW by 2035	Current schedule for retirement	None	Wind: 3,000 MW Solar: 4000 MW	2019 AEO Reference Case
Renewable Mandate	Same as Current Trends	Approximately 6 million cars, 1.3 million pickup trucks, and 77% of miles driven by heavy trucks by 2035	Same as Current Trends	6.1 GW by 2035	Extended through 2035	Carbon price of $40/ton in 2021, increasing by 4.5% per year	Same as Current Trends	Same as Current Trends
High Battery Energy Storage	Same as Current Trends	Same as Current Trends	Same as Current Trends	Same as Current Trends	Same as Current Trends	Same as Current Trends	Same as Current Trends	Same as Current Trends
High Industrial Load	Current Trends demand forecast plus an additional 3,560 MW of industrial load growth in the Delaware Basin by 2035	Same as Current Trends	An additional 778 MW at Corpus Christi and 1,245 MW at Brownsville by 2035	Same as Current Trends	Same as Current Trends	Same as Current Trends	Same as Current Trends	Same as Current Trends
Existing Transmission Constraints	Same as Current Trends	Same as Current Trends	Same as Current Trends	Same as Current Trends	Same as Current Trends	Same as Current Trends	Same as Current Trends	Same as Current Trends

Demand Forecasting

One key component to any long-term transmission plan is an appropriate forecast of the electric demand. Changes in electricity consumption contribute to future transmission needs as do new generation technologies, generator obsolescence, and economic, commercial, and policy factors. Transmission plans study the reliable movement of electricity from generation sources to consumer demand locations; therefore, planners need to know which resources can provide electricity as well as how much electricity will be required and where. The uncertainty in many of these factors can be significant; as such, demand forecasters often prepare several forecasts that reflect different possible futures and circumstances so transmission planners can study demand, generation, and transmission needs for those various futures and conditions.

Two different forecasts were created for the years between 2021 and 2035 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.

The demand forecasts combined econometric input and scenario-specific assumptions as input into forecast models to describe the hourly demand 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). Detailed documentation on ERCOT's Long-Term Hourly Peak Demand and Energy Forecast can be found on the long-term load forecast page on the ERCOT website[10].

ERCOT consists of eight distinct weather zones. Each of these weather zones represents a geographic region within which all areas have similar climatological trends and characteristics. The ERCOT forecast is the sum of all of the weather zone forecasts. A map of weather zones is shown in Figure 21.

[10] http://www.ercot.com/gridinfo/load/forecast

Figure 21: ERCOT Weather Zones

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 demand data. The models were developed using historical data from 2013 through the summer of 2018.

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.

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:

- Month,
- Season,
- Day Type (day of the week, holiday),

Weather Variables,

- Temperature,
- Temperature Squared,
- Temperature Cubed,
- Dew Point,
- Cloud Cover,

- Wind Speed,
- Cooling Degree Days (base 65),
- Heating Degree Days (base 65),
- Lag Cooling Degree Days (1,2, or 3 previous days),
- Lag Heating Degree Days (1,2, or 3 previous days), and
- Lag Temperature (1, 2, and 3, 24, 48, or 72 previous hours).

Interactions

- Hour and Day of Week,
- Hour and Temperature,
- Hour and Dew Point,
- Temperature and Dew Point, and,
- Hour and Temperature and Dew Point.
- Number of premises[11], and
- Non-Farm Employment/Housing Stock/Population

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 demand characteristics for each area.

Another key input is the forecast for 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. 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. The premises were separated into three different groups for modeling purposes namely, Residential (including street lighting), Business or small commercial, and Industrial (premises that are required by protocol to have an interval data recorder meter).

- 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:
    - Housing Stock and
    - 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:
    - Housing Stock,
    - Population, and
- Non-Farm employment.

[11] Used in Coast, East, North Central, South, and South Central weather zones.

- 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
    - Housing Stock,
    - Population, and
    - Non-Farm employment.

The 2020 LTSA capacity expansion and retirement and transmission economic analyses used an 8760-hour demand forecast. This base demand forecast before adjustments for four of the five scenarios was based on the 2013 weather year. These scenarios include the Current Trends, Renewable Mandate, High Battery Energy Storage, and Existing Transmission Constraints scenarios. The High Industrial Load scenario used the base forecast plus an additional 3,560 MW of industrial load in the Delaware Basin, 778 MW of LNG load at Corpus Christi, and 1245 MW of LNG load at Brownsville by 2035.

ERCOT's demand forecasts include losses, which were removed before adjusting demand because the software packages used for both reliability and economic analyses account for losses separately from the demand. Furthermore, scenario-specific demand adjustments were also applied based on the input assumptions.

For instance, distributed solar was assumed to be concentrated in the urban demand centers and was modeled based on residential (distributed solar) generation profiles. 3,885 MW of distributed solar was considered in the Current Trends, High Battery Energy Storage, High Industrial Load, and Existing Transmission Constraints scenarios, while 6,083 MW of distributed solar was assumed to be in the Renewable Mandate scenario.

EV charging patterns for cars, short-haul trucks and buses and long-haul trucks were used to model the effect of EV adoption. Details for EV charging patterns can be found in Appendix IV of this report.

Also, the demand forecasts did not include self-served load. The self-served loads were left unchanged from the base cases used for transmission expansion while the demand forecasts (net of losses) were distributed to all other loads in the cases on a by-weather-zone basis.

Capacity Expansion and Retirement Analysis

Capacity expansion analysis is used to estimate the types and amount of new generation resources to be added, and the existing generation resources to be retired for every scenario. To provide a reference point for the selection of other future scenarios, a Current Trends scenario is developed as the first scenario. The primary input assumptions for all scenarios were the capital cost, new technology types, incentives, and wind and solar locations and profiles. The long-term capacity expansion and retirement concept is depicted in Figure 22.

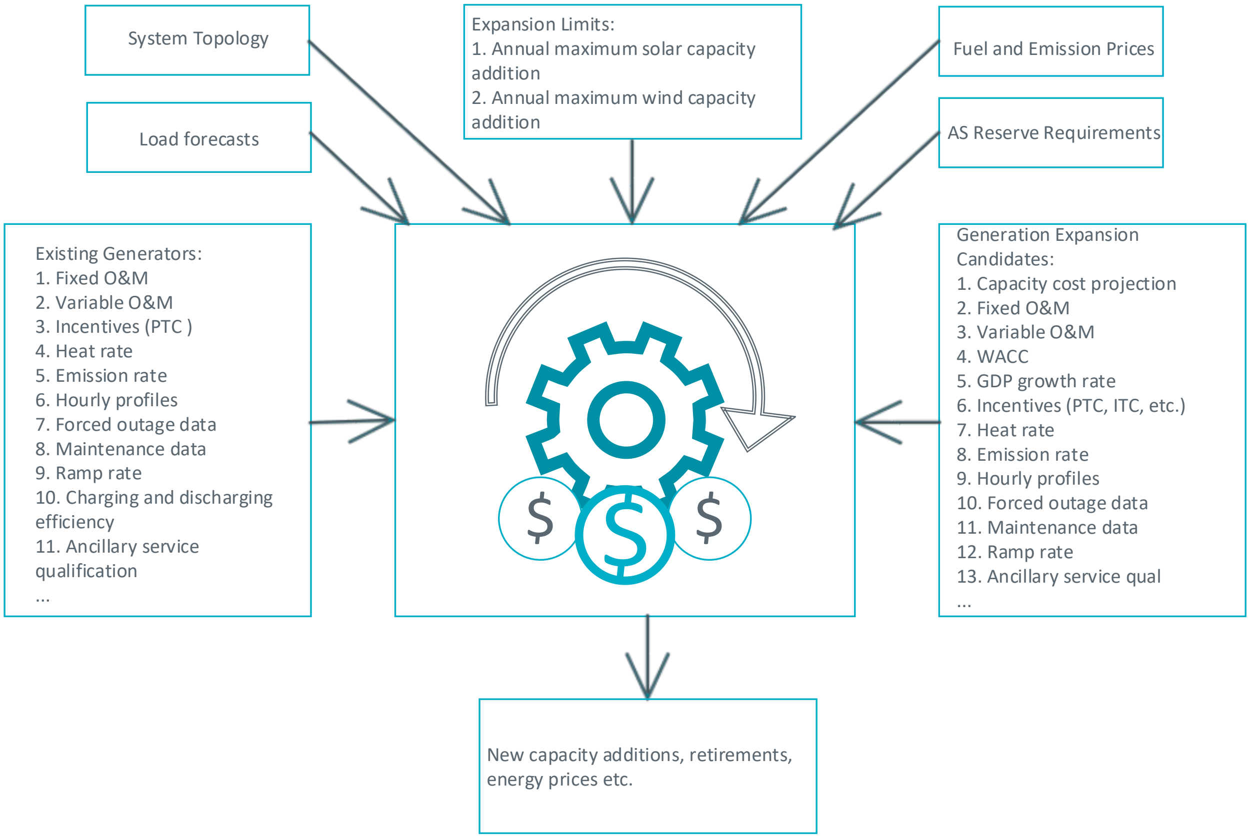


Figure 22: Long-Term Capacity Expansion and Retirement Concept

Trends in capital costs for new expansion technologies generally increased at an assumed GDP growth rate in this analysis except for the wind, utility-scale solar, and battery energy storage technologies which were forecasted to decline rapidly through the early part of the study period. Commodity prices for gas were set as the EIA AEO 2019 Reference Case.

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

Additionally, the 2017 extension[12] of the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) was included in four of the five scenarios for renewable generation. These scenarios include the Current Trends scenario, the High Industrial Load scenario, the High Battery Energy Storage scenario and the Existing Transmission Constraints scenario. For the Renewable Mandate scenario, the PTC and ITC were not assumed to be phased down or expired throughout the study period.

In 2020, ERCOT procured hourly wind generation patterns based on actual weather data for the previous 40 years (1980-2019). These wind patterns include hourly wind output patterns for 148 hypothetical future wind generation units and were developed using power generation curves consistent with the most recent wind turbine technologies. The 148 profiles were distributed throughout Texas. Each profile is representative of the historical wind output in a specific county if there is existing wind farm in the county. These wind profiles were incorporated in all scenarios.

In 2020, ERCOT also procured new hourly solar generation patterns based on actual weather data for the previous 40 years. These patterns contained profiles representative of the west and panhandle Texas counties for two different types of solar technologies: single-axis and dual-axis tracking. Four distributed solar profiles have been developed for four urban demand centers including Dallas Fort Worth, Austin, Houston, San Antonio, and rural areas. ERCOT selected the single-axis tracking and residential profiles for inclusion in this LTSA.

A significant 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 calculated a repayment that was paid in equal installments over the capital recovery period. The inflation rate ensures that units that were added in the future have their capital costs appropriately adjusted for inflation providing consistency with the other specified costs. In addition, the modeled ancillary service prices were much lower than historical ancillary service prices. Average ancillary service prices based on the past three years (2016-2018) were used in the decision-making process of new capacity additions and existing generator retirements. A summary of this analysis can be found in Appendix IV.

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 capacity expansion plan. This type of model does not simulate intra-hour balancing reserve deployment 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 needs to be conducted to determine the need for additional system flexibility to integrate levels of renewable resources seen in this analysis.

[12] https://www.energy.gov/savings/renewable-electricity-production-tax-credit-ptc; https://www.energy.gov/savings/business-energy-investment-tax-credit-itc

Transmission Expansion Analysis

Transmission expansion analysis in the LTSA involves evaluating the potential needs for the ERCOT grid under different demand and generation assumptions as developed during the demand forecasting and capacity expansion and retirement planning stages. Transmission expansion analysis was conducted for the Current Trends and Renewable Mandate scenarios. The Transmission expansion analysis was focused on analyzing congestion on ERCOT's 345-kV and 138-kV network and identifying long-range transmission upgrades and additions to its 345-kV network.

ERCOT used the UPLAN NPM model to perform transmission expansion analysis. ERCOT used the final case for the year 2024 from the 2019 RTP economic analysis as a starting point for the Current Trends and Renewable Mandate scenarios. This case was first updated to incorporate status changes for existing and planned generation, which occurred before the start of this study, as well as status changes to near-term transmission projects.

For each scenario and each study year, the case was then modified with the scenario-specific generation fleet changes and demand adjustments, which resulted from the inputs from the scenario development. ERCOT used the resource profile, including generation retirements, generation additions, and profiles for demand response, as developed by capacity expansion and retirement analysis, to model capacity additions for each scenario and study year. The locations of new 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 the availability of the natural resources limits solar and wind resource locations. Figure 23 and Figure 24 show the results of generation siting in the Current Trends and Renewable Mandate scenarios, respectively, considered for transmission expansion analysis. The resources were modeled in the cases at the appropriate buses as outlined in the guidelines from the resource siting methodology provided as Appendix II. Similarly, generating units were retired consistent with the resource expansion results. Detailed information for generation retirements is included in Appendix III.

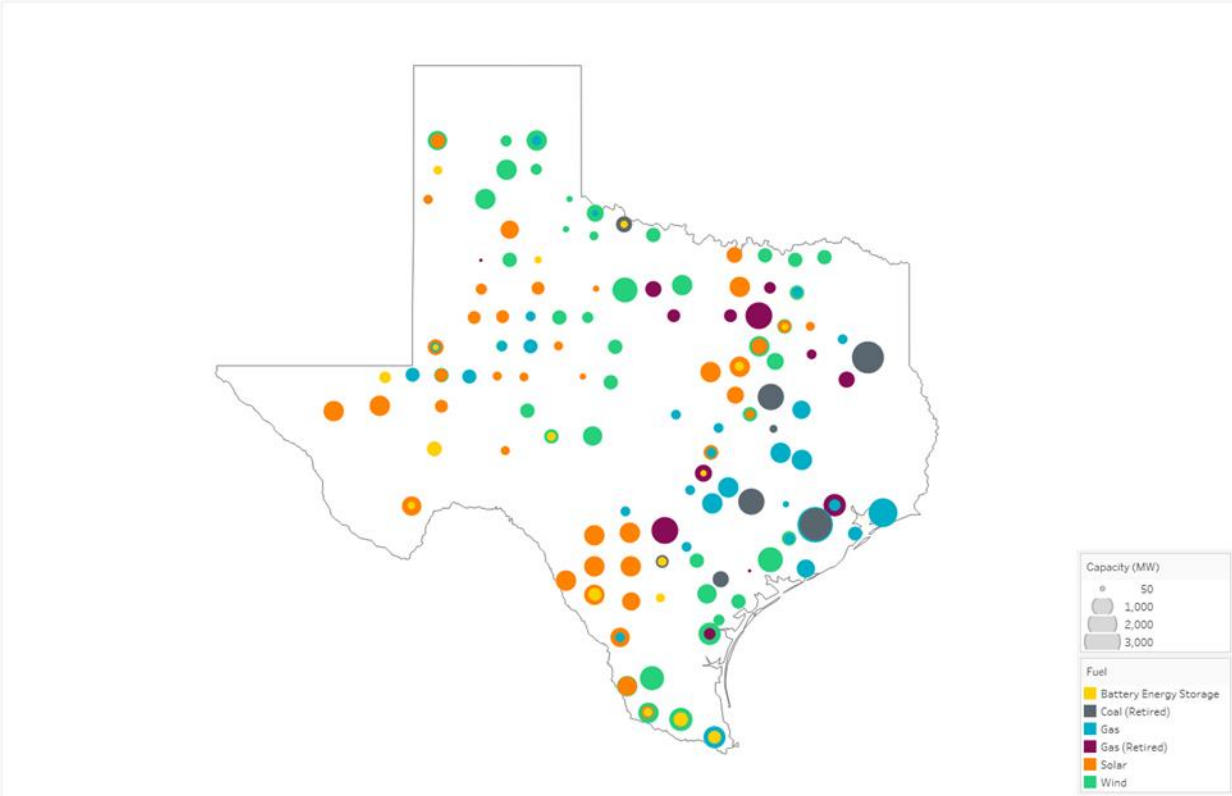


Figure 23: Generation Additions and Retirements in Current Trends (2035)

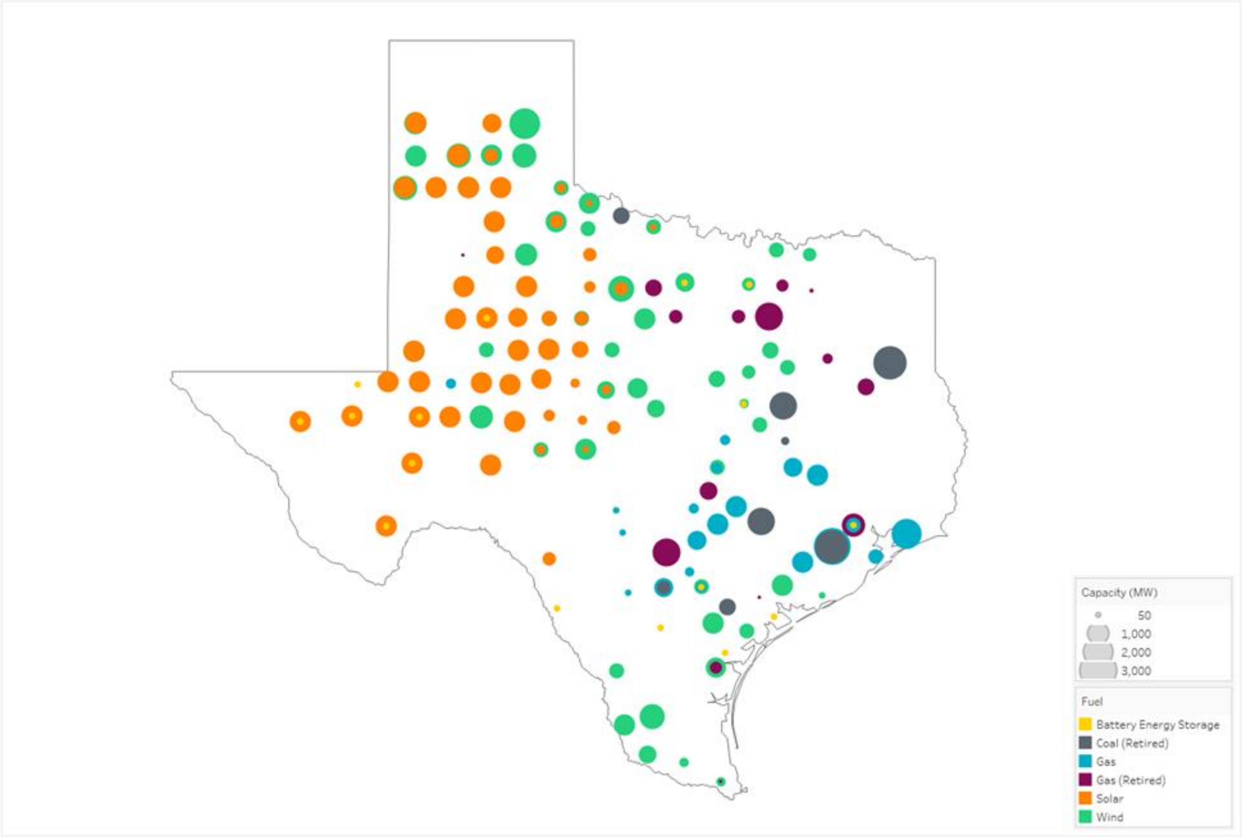


Figure 24: Generation Additions and Retirements in Renewable Mandate (2035)

ERCOT analyzed each of the scenario-appropriate base cases created for 2030 and 2035 to determine the potential transmission needs of the system. ERCOT studied NERC TPL-001-4 Planning Events P0, P1, and P7, which included the loss of a generator, a transmission circuit, transformer, or a shunt device. ERCOT's P7 planning events also included the loss of double circuit lines that share towers for more than half a mile. In addition to the above contingencies, ERCOT included generator maintenance outages in this evaluation.

ERCOT evaluated the contingencies at all voltage levels, but mainly addressed violations and congestion on the network connected at 100-kV and above, as the needs to resolve violations and congestion on the 69-kV network were assumed to be addressed through the RTP process and/or other near-term planning processes. To reveal the potential violations and congestion on the 345-kV network, ERCOT added transmission upgrades due to identified local needs to facilitate generation addition and demand growth in the corresponding start cases and did not monitor the 69-kV transmission elements.

ERCOT developed long-range transmission solutions to address reliability and congestion needs of the system for the Current Trends scenario. Cost estimates for potential transmission projects used in this study do not reflect routing considerations, such as geographic obstacles, physical constraints, or public preferences. Detailed routing considerations can lead to project cost increases. A summary of this analysis can be found in Appendix IV below.

Appendix II: Resource Siting Methodology

The Long-Term System Assessment Resource Siting Methodology is included in a separate document attached with the report.

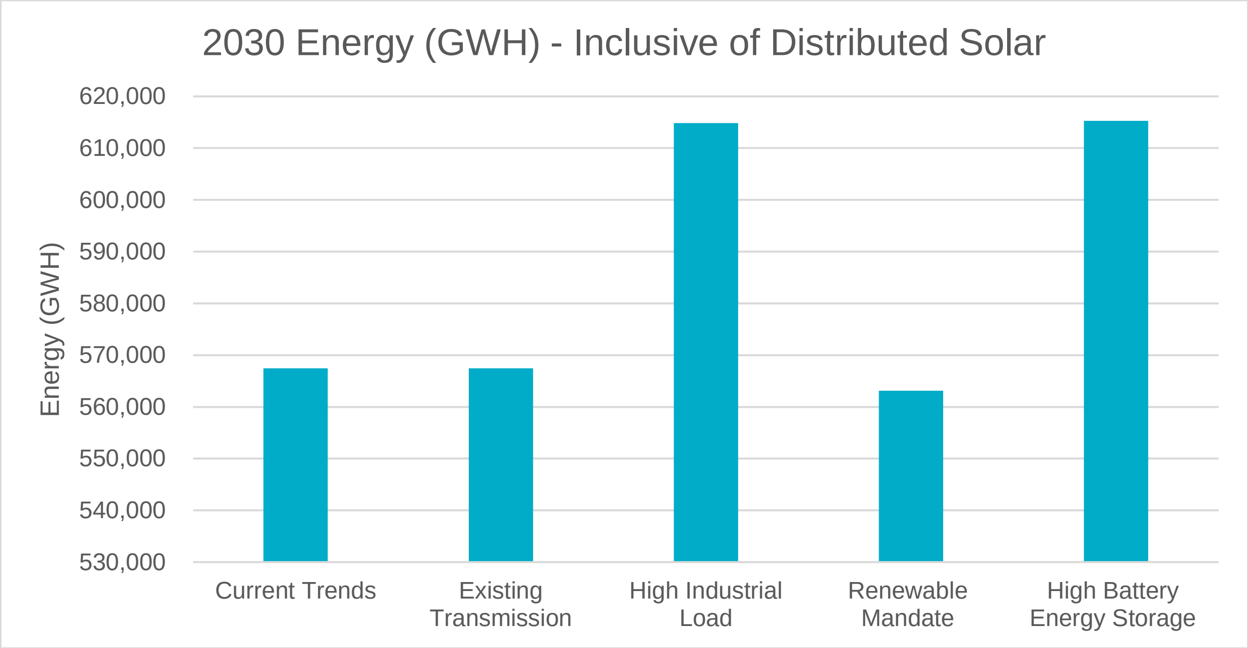
Appendix III: Generation Retirements

UNIT NAME	UNIT CODE	COUNTY	FUEL	ZONE	IN SERVICE	WINTER CAPACITY	RETIREMENT DATE
COLETO CREEK	COLETO_COLETOG1	GOLIAD	COAL	SOUTH	1980	655	12/31/2025
FAYETTE POWER U1	FPPYD1_FPP_G1	FAYETTE	COAL	SOUTH	1979	603	12/31/2024
FAYETTE POWER U2	FPPYD1_FPP_G2	FAYETTE	COAL	SOUTH	1980	605	12/31/2025
FAYETTE POWER U3	FPPYD2_FPP_G3	FAYETTE	COAL	SOUTH	1988	449	12/31/2033
LIMESTONE U1	LEG_LEG_G1	LIMESTONE	COAL	NORTH	1985	824	12/31/2030
LIMESTONE U2	LEG_LEG_G2	LIMESTONE	COAL	NORTH	1986	836	12/31/2031
MARTIN LAKE U1	MLSES_UNIT1	RUSK	COAL	NORTH	1977	815	12/31/2022
MARTIN LAKE U2	MLSES_UNIT2	RUSK	COAL	NORTH	1978	820	12/31/2023
MARTIN LAKE U3	MLSES_UNIT3	RUSK	COAL	NORTH	1979	820	12/31/2024
SAN MIGUEL U1	SANMIGL_G1	ATASCOSA	COAL	SOUTH	1982	391	12/31/2027
W A PARISH U5	WAP_WAP_G5	FT. BEND	COAL	HOUSTON	1977	664	12/31/2022
W A PARISH U6	WAP_WAP_G6	FT. BEND	COAL	HOUSTON	1978	663	12/31/2023
W A PARISH U7	WAP_WAP_G7	FT. BEND	COAL	HOUSTON	1980	577	12/31/2025
W A PARISH U8	WAP_WAP_G8	FT. BEND	COAL	HOUSTON	1982	610	12/31/2027
R MASSENGALE ST7 (LP&L)	R_MASSENGALE_7	LUBBOCK	GAS	PANHANDLE	1959	18	12/31/2019
SILAS RAY POWER STG 6	SILASRAY_SILAS_6	CAMERON	GAS	COASTAL	1962	21	12/31/2022
T H WHARTON POWER CTG 31	THW_THWGT31	HARRIS	GAS	HOUSTON	1972	69	12/31/2032
T H WHARTON POWER CTG 32	THW_THWGT32	HARRIS	GAS	HOUSTON	1972	69	12/31/2032
T H WHARTON POWER CTG 33	THW_THWGT33	HARRIS	GAS	HOUSTON	1972	69	12/31/2032
T H WHARTON POWER CTG 34	THW_THWGT34	HARRIS	GAS	HOUSTON	1972	69	12/31/2032
T H WHARTON POWER STG 3	THW_THWST_3	HARRIS	GAS	HOUSTON	1974	110	12/31/2034
T H WHARTON POWER CTG 41	THW_THWGT41	HARRIS	GAS	HOUSTON	1972	69	12/31/2032
T H WHARTON POWER CTG 42	THW_THWGT42	HARRIS	GAS	HOUSTON	1972	69	12/31/2032
T H WHARTON POWER CTG 43	THW_THWGT43	HARRIS	GAS	HOUSTON	1974	69	12/31/2034
T H WHARTON POWER CTG 44	THW_THWGT44	HARRIS	GAS	HOUSTON	1974	69	12/31/2034
T H WHARTON POWER STG 4	THW_THWST_4	HARRIS	GAS	HOUSTON	1974	110	12/31/2034
ATKINS CTG 7	ATKINS_ATKINSG7	BRAZOS	GAS	NORTH	1973	20	12/31/2033
SAM RAYBURN CTG 1	RAYBURN_RAYBURG1	VICTORIA	GAS	SOUTH	1963	13.5	12/31/2023
SAM RAYBURN CTG 2	RAYBURN_RAYBURG2	VICTORIA	GAS	SOUTH	1963	13.5	12/31/2023
T H WHARTON CTG G1	THW_THWGT_1	HARRIS	GAS	HOUSTON	1967	13	12/31/2027
W A PARISH CTG 1	WAP_WAPGT_1	FT. BEND	GAS	HOUSTON	1967	13	12/31/2027
B M DAVIS STG U1	B_DAVIS_B_DAVIG1	NUECES	GAS	COASTAL	1974	330	12/31/2034
CEDAR BAYOU STG U1	CBY_CBY_G1	CHAMBERS	GAS	HOUSTON	1970	745	12/31/2030
CEDAR BAYOU STG U2	CBY_CBY_G2	CHAMBERS	GAS	HOUSTON	1972	749	12/31/2032
GRAHAM STG U1	GRSES_UNIT1	YOUNG	GAS	WEST	1960	234	12/31/2020
GRAHAM STG U2	GRSES_UNIT2	YOUNG	GAS	WEST	1969	390	12/31/2029
HANDLEY STG U3	HLSES_UNIT3	TARRANT	GAS	NORTH	1963	395	12/31/2023
LAKE HUBBARD STG U1	LHSES_UNIT1	DALLAS	GAS	NORTH	1970	392	12/31/2030
LAKE HUBBARD STG U2	LHSES_UNIT2A	DALLAS	GAS	NORTH	1973	523	12/31/2033
MOUNTAIN CREEK STG U6	MCSES_UNIT6	DALLAS	GAS	NORTH	1956	122	12/31/2016
MOUNTAIN CREEK STG U7	MCSES_UNIT7	DALLAS	GAS	NORTH	1958	118	12/31/2018
MOUNTAIN CREEK STG U8	MCSES_UNIT8	DALLAS	GAS	NORTH	1967	568	12/31/2027
O W SOMMERS STG U1	CALAVERS_OWS1	BEXAR	GAS	SOUTH	1972	420	12/31/2032
O W SOMMERS STG U2	CALAVERS_OWS2	BEXAR	GAS	SOUTH	1974	410	12/31/2034
POWERLANE PLANT STG U1	STEAM1A_STEAM_1	HUNT	GAS	NORTH	1966	17.5	12/31/2026
POWERLANE PLANT STG U2	STEAM_STEAM_2	HUNT	GAS	NORTH	1967	23.5	12/31/2027
R W MILLER STG U1	MIL_MILLERG1	PALO PINTO	GAS	NORTH	1968	75	12/31/2028
R W MILLER STG U2	MIL_MILLERG2	PALO PINTO	GAS	NORTH	1972	120	12/31/2032
RAY OLINGER STG U1	OLINGR_OLING_1	COLLIN	GAS	NORTH	1967	78	12/31/2027
RAY OLINGER STG U2	OLINGR_OLING_2	COLLIN	GAS	NORTH	1971	107	12/31/2031
SIM GIDEON STG U1	GIDEON_GIDEONG1	BASTROP	GAS	SOUTH	1965	130	12/31/2025
SIM GIDEON STG U2	GIDEON_GIDEONG2	BASTROP	GAS	SOUTH	1968	135	12/31/2028
SIM GIDEON STG U3	GIDEON_GIDEONG3	BASTROP	GAS	SOUTH	1972	340	12/31/2032
STRYKER CREEK STG U1	SCSES_UNIT1A	CHEROKEE	GAS	NORTH	1958	167	12/31/2018
STRYKER CREEK STG U2	SCSES_UNIT2	CHEROKEE	GAS	NORTH	1965	502	12/31/2025
TRINIDAD STG U6	TRSES_UNIT6	HENDERSON	GAS	NORTH	1965	235	12/31/2025
V H BRAUNIG STG U1	BRAUNIG_VHB1	BEXAR	GAS	SOUTH	1966	217	12/31/2026
V H BRAUNIG STG U2	BRAUNIG_VHB2	BEXAR	GAS	SOUTH	1968	230	12/31/2028
V H BRAUNIG STG U3	BRAUNIG_VHB3	BEXAR	GAS	SOUTH	1970	412	12/31/2030
W A PARISH STG U1	WAP_WAP_G1	FT. BEND	GAS	HOUSTON	1958	169	12/31/2018
W A PARISH STG U2	WAP_WAP_G2	FT. BEND	GAS	HOUSTON	1958	169	12/31/2018
W A PARISH STG U3	WAP_WAP_G3	FT. BEND	GAS	HOUSTON	1961	258	12/31/2021
W A PARISH STG U4	WAP_WAP_G4	FT. BEND	GAS	HOUSTON	1968	552	12/31/2028
OKLAUNION U1*	OKLA_OKLA_G1	WILBARGER	COAL	WEST	1986	650	12/31/2020
DECKER CREEK STG U1*	DECKER_DPG1	TRAVIS	GAS	SOUTH	1971	320	12/31/2020
DECKER CREEK STG U2*	DECKER_DPG2	TRAVIS	GAS	SOUTH	1978	428	12/31/2021

Note *: The three units at the end of the above table were unconfirmed retirements when the Current Trends scenario was finalized.

Appendix IV: Scenario Results Summary

Demand Forecasts



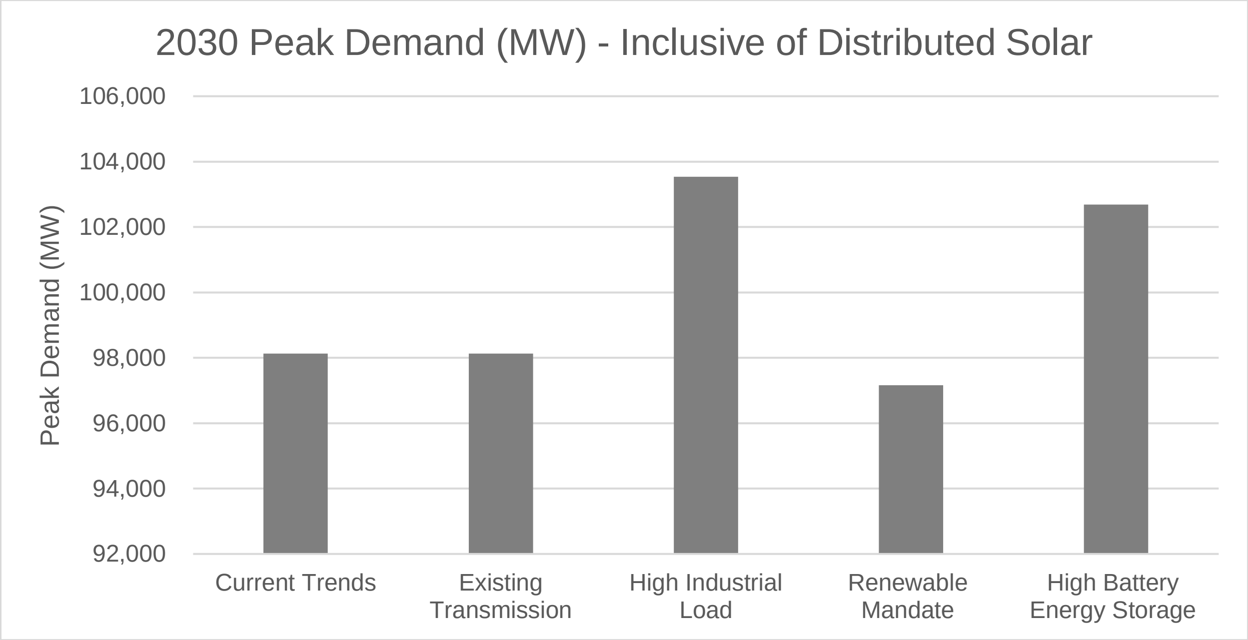
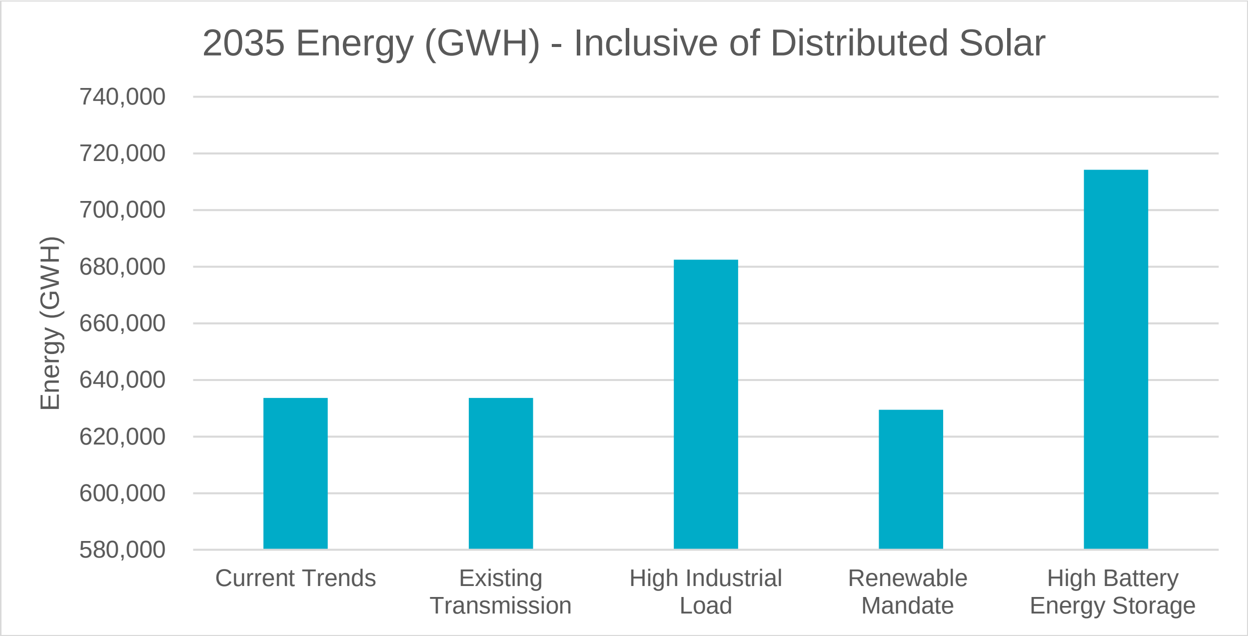


Figure 25: Energy and Peak Demand for 2030



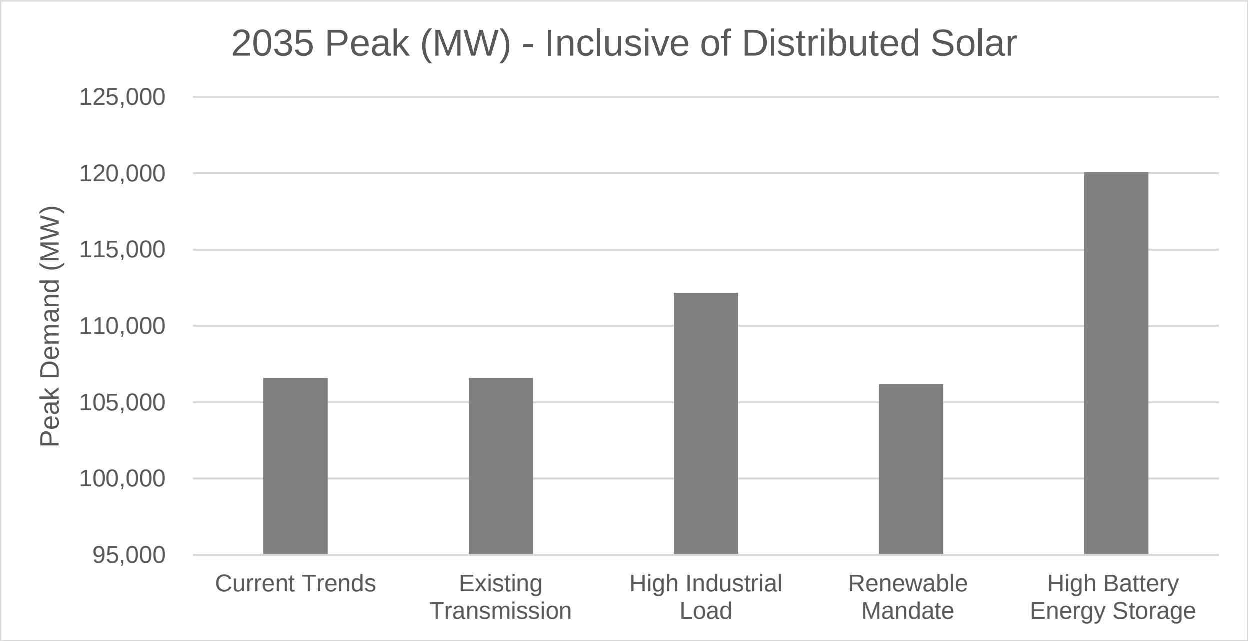


Figure 26: Energy and Peak Demand for 2035

Current Trends

The Current Trends scenario is designed to simulate current market conditions extended 15 years into the future. Since developers usually propose new generation projects where transmission capacity is available, an iterative approach was adopted for this scenario to guide the capacity expansion analysis. Figure 27 illustrates the iterative process for capacity and transmission expansion. Two iterations of capacity expansion and retirement analysis, and transmission expansion analysis were conducted for the Current Trends scenario. The purpose of the iterative process was to account for the impacts of:

- transmission constraints on the timing, location, and capacity of new resources
- resource siting on the need for transmission improvements

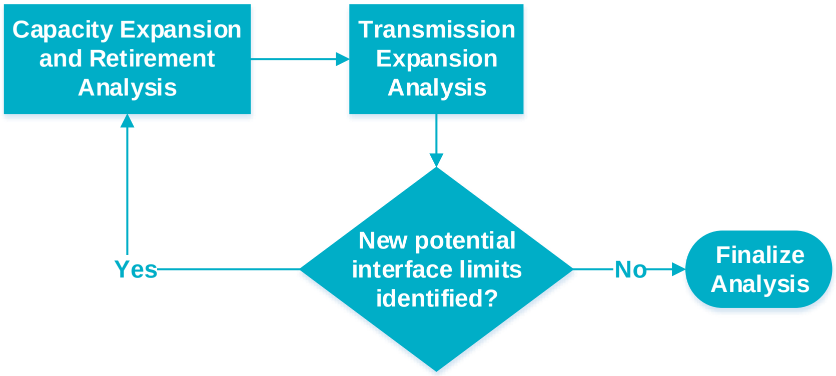


Figure 27: Iterative Process of Capacity Expansion and Transmission Analysis

An electric vehicle adoption assumption based on an electric light-duty vehicle outlook from Bloomberg New Energy Finance[13] was included in this scenario as shown in Figure 28. Transportation electrification was assumed to start slowly but grow exponentially after reaching a certain level when charging infrastructure becomes more established.

[13] https://about.bnef.com/electric-vehicle-outlook/#toc-download

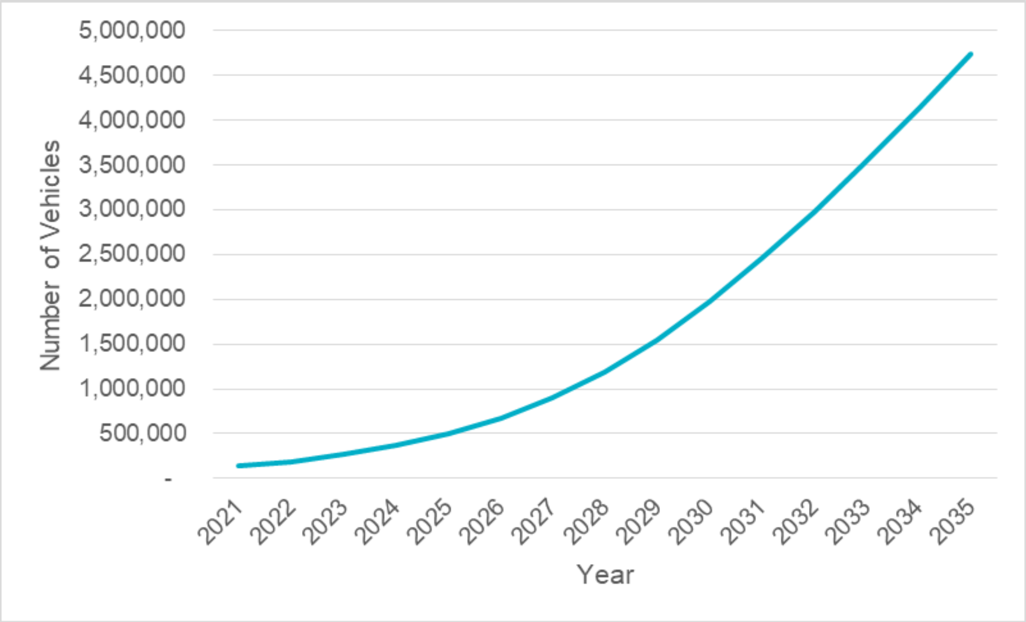


Figure 28: Adoption of Light-Duty Electric Vehicles

The charging patterns and demand flexibility would likely vary among different types of electric vehicles. For this study, most light-duty vehicles were assumed to charge overnight so that they would be fully charged before 5am. Figure 29 shows the assumed normalized average hourly charging pattern of light-duty electric vehicles.

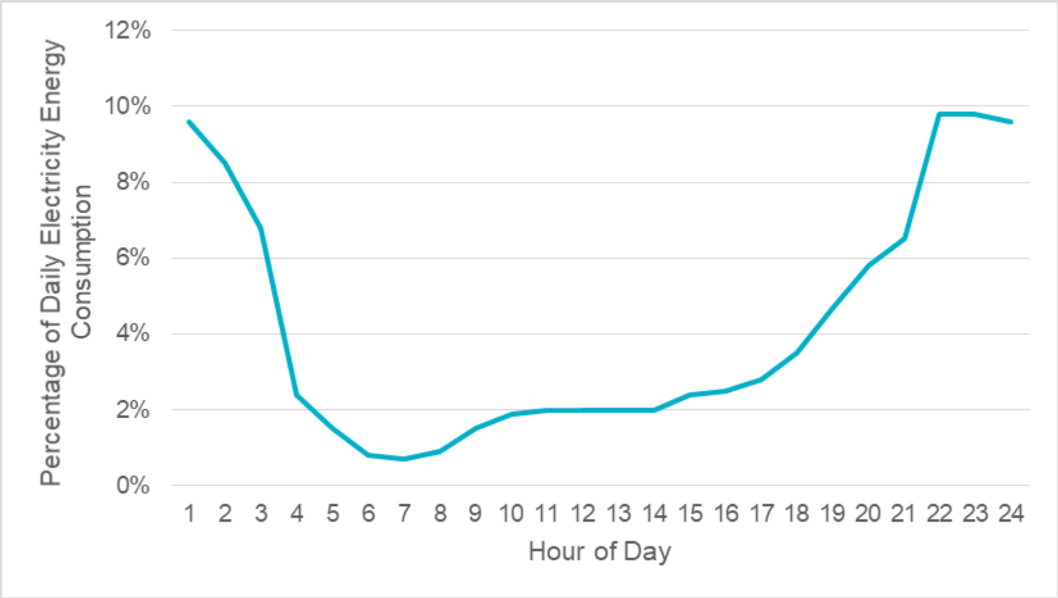


Figure 29: Assumed Hourly Charging Pattern for Light-Duty Electric Vehicles

For 2035, the total peak charging demand was estimated to be over 6,500 MW at midnight. Approximately 1,700 to 2,300 MW of charging demand was expected during hours ending between 4pm and 6pm. In this scenario, peak electric vehicle demand was assumed to occur at approximately 9pm. Figure 4 shows the aggregated charging demand of light-duty vehicles.

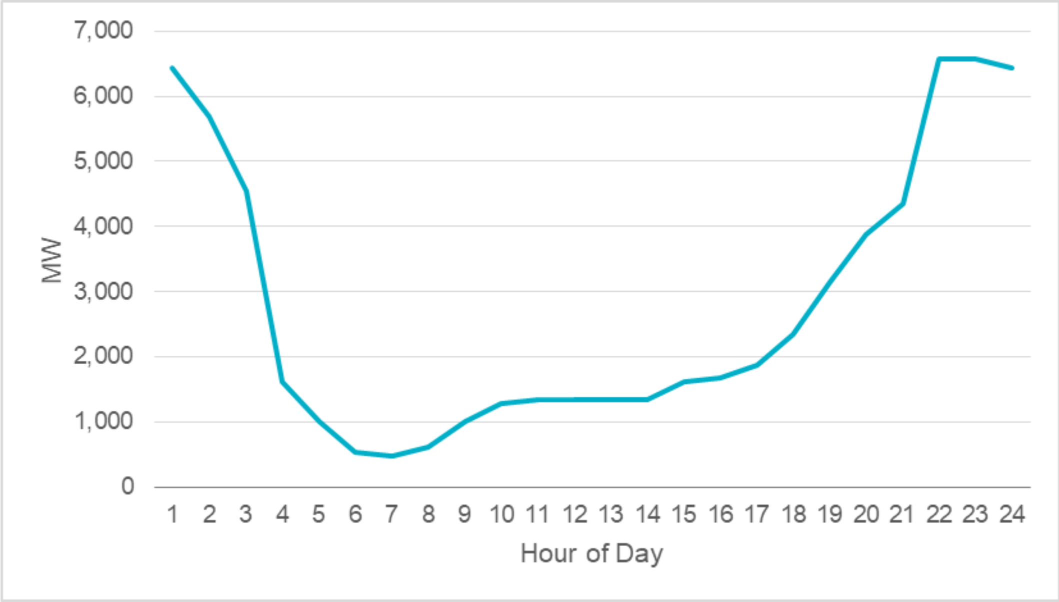


Figure 30: Estimated Total Charging Demand of Light-Duty Electric Vehicles in 2035

Distributed solar adoption was assumed to follow an S-curve pattern. The maximum distributed solar potential in four urban areas was estimated by AWS Truepower in a solar site screening analysis[14]. The market saturation rate was assumed to be 20%, fast growth was assumed to start in 2019, and the takeover time was assumed to be six years. Figure 31 shows assumed distributed solar adoption by year.

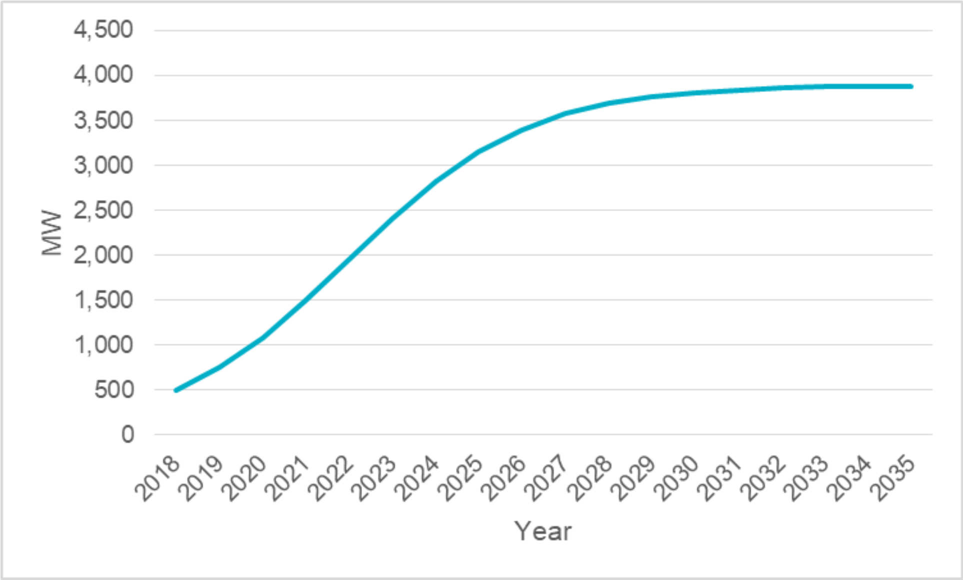


Figure 31: Distributed Solar Adoption by Year

The generation retirement process for the Current Trends scenario had two distinct parts. First, a group of fixed-age retirements were determined for use in all scenarios. These fixed-age retirements

[14] http://www.ercot.com/content/wcm/lists/114800/ERCOT_Solar_SiteScreenHrlyProfiles_Jan2017.pdf

were determined by the age of an existing unit. Natural gas units were retired after 60 years of operation, and coal units were retired after 45 years of service. The second part of the generation retirement process considered economics as the criterion for retirement. Based on economic simulations, 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 studied. Total fixed-age retirements were 9,982 MW of coal generation and 10,965 MW of natural gas generation by 2035.

The first iteration of capacity expansion and retirement analysis resulted in the addition of 13,750 MW of combined cycle capacity, 7,073 MW of simple cycle combustion turbine capacity, 27,700 MW of utility-scale solar capacity and 40,200 MW of wind capacity. 1,211 MW of fixed-aged retirements were accelerated based on economic analysis. Compared to the Current Trends scenario from the 2018 LTSA, much more generation capacity was added in the 2020 LTSA due to the fixed-age retirements. More solar generation capacity was added in the 2020 LTSA compared to the 2018 LTSA because the solar capacity addition annual cap was increased from 1,500 MW to 4,000 MW based on stakeholder feedback. A summary of the capacity expansion results for the first iteration of the Current Trends scenario is shown in Table 9.

Table 9: Capacity Expansion Results for Current Trends (First Iteration)

Description	Units	2021	2025	2030	2035
CC Adds	MW	-	-	6,500	7,250
CT Adds	MW	-	-	-	7,073
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	606	997	420
Solar Adds	MW	4,000	15,200	5,400	3,100
Wind Adds	MW	3,000	12,000	15,000	10,200
Annual Capacity Additions	MW	7,000	27,806	27,897	28,043
Cumulative Capacity Additions	MW	7,000	34,806	62,703	90,746
Economic Retirements	MW	-	1,211	-	-
Cumulative Economic Retirements	MW	-	1,211	1,211	1,211
Reserve Margin	%	11	12	11	12
Coincident Peak	MW	83,594	89,989	98,129	106,579
Annual Energy	GWhs	454,288	505,245	567,464	633,575
Average LMP	$/MWh	43.22	61.76	72.84	85.39
Natural Gas Price	$/mmbtu	3.24	4.20	5.00	5.95
Average Market Heat Rate	MMbtu/MWh	13.33	14.69	14.57	14.34
Natural Gas Generation	%	53.87	38.95	35.17	35.45
Coal Generation	%	7.88	8.20	5.47	3.74
Wind Generation	%	24.44	32.52	39.16	41.43
Solar Generation	%	4.24	11.63	12.77	12.65
Scarcity Hours	HRS	9	24	29	35
Unserved Energy	GWhs	7.64	46.58	90.91	114.60

Transmission expansion analysis was performed based on the results of the first iteration of capacity expansion and retirement analysis. Based on transmission constraints observed in the transmission expansion analysis, three zonal interface limits were recommended for the second iteration of capacity expansion and retirement analysis. A four-zone model was developed to represent the transmission network. The four zones were Panhandle, West, Valley, and Other ERCOT Regions. Interface limits were modeled for West Texas export, Valley import, and Valley export. Though no limit was considered for the interface between the Panhandle zone and the West zone, Panhandle was modeled as a separate zone because injection shift factors for the Panhandle were different from those of West Texas. Figure 32 illustrates the four-zone model and Table 10 shows the interface limits by study year.

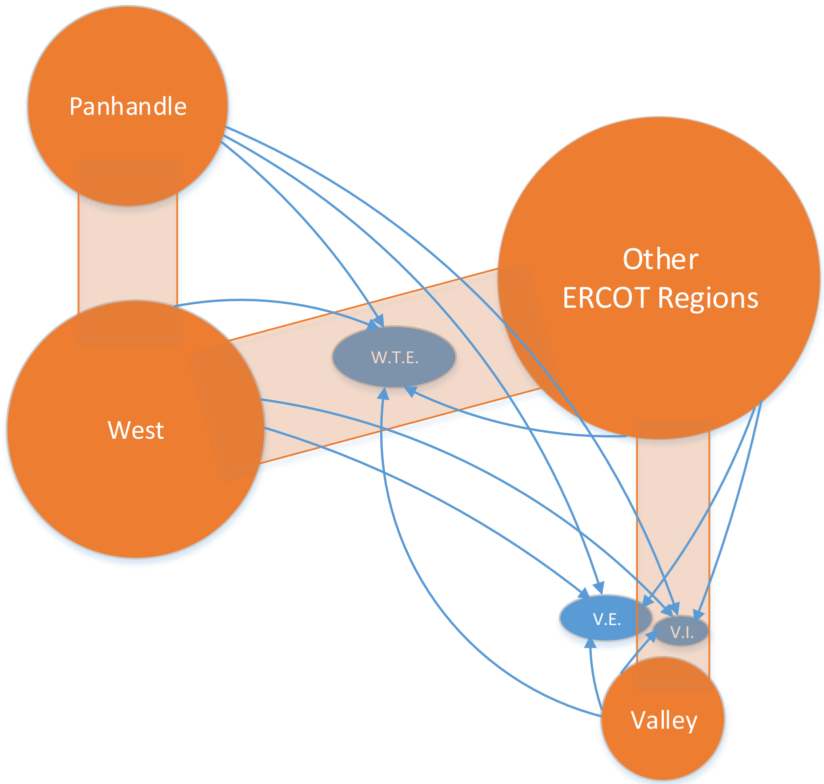


Figure 32: Four-Zone Model with Interfaces

Table 10: Interface Limits by Study Year

Study Year	West Texas Export Limit	Valley Import Limit	Valley Export Limit
2025 and before	11,500 MW	1,865 MW	3,737 MW
2026 and 2027	13,500 MW	1,865 MW	3,737 MW
2028 and after	15,500 MW	1,865 MW	3,737 MW

Enforcing the zonal interface limits resulted in a shift of new wind and solar resources from the West zone to the Other ERCOT Regions zone. The primary cause of this shift was the inclusion of the West Texas export stability limit which was a binding constraint in many hours.

Additionally, compared to the results of the first iteration, wind and solar capacity additions decreased by 4,900 MW and 2,300 MW, respectively, by 2035 because wind and solar resources in the Other ERCOT Regions zone were not as competitive as those in the Panhandle and West zones. However, combined cycle and battery capacity additions increased by 750 MW and 2,079 MW, respectively, by 2035. A comparison of new wind and solar resources geographical distributions between the first and second iteration is shown in Figure 33. The capacity expansion results for the second iteration are summarized in Table 11. Differences in the capacity expansion results between the first and second iterations are shown in Figure 34.

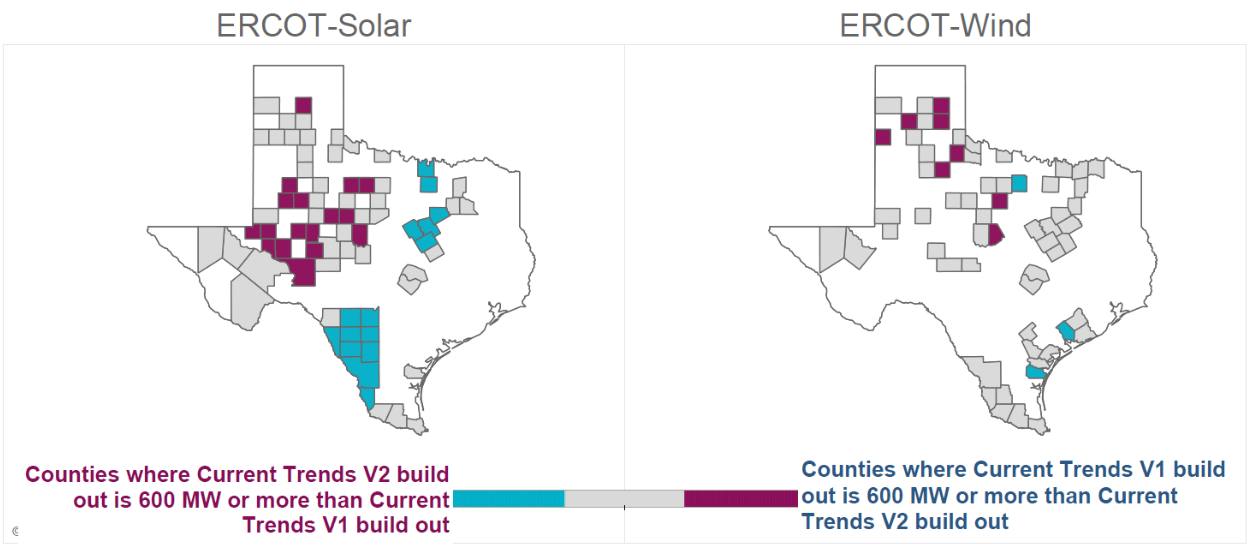


Figure 33: Comparison of Wind and Solar Capacity Addition for Current Trends

Table 11: Generation Expansion Results for Current Trends (Second Iteration)

Description	Units	2021	2025	2030	2035
CC Adds	MW	-	-	6,000	8,500
CT Adds	MW	-	-	2,707	4,092
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	800	1,360	1,942
Solar Adds	MW	4,000	12,600	7,900	900
Wind Adds	MW	3,000	11,200	14,500	6,600
Annual Capacity Additions	MW	7,000	24,600	32,467	22,034
Cumulative Capacity Additions	MW	7,000	31,600	64,067	86,101
Economic Retirements	MW	-	1,874	-	-
Cumulative Economic Retirements	MW	-	1,874	1,874	1,874
Reserve Margin	%	11	10	13	11
Coincident Peak	MW	83,594	89,989	98,129	106,579
Annual Energy	GWhs	454,288	505,245	567,464	633,575
Average LMP	$/MWh	31.49	47.65	51.44	82.18
Natural Gas Price	$/mmbtu	3.24	4.20	5.00	5.95
Average Market Heat Rate	MMbtu/MWh	9.71	11.34	10.29	13.80
Natural Gas Generation	%	54.40	42.88	38.20	41.53
Coal Generation	%	7.89	8.53	5.51	3.87
Wind Generation	%	23.98	27.14	36.92	36.88
Solar Generation	%	4.16	12.68	11.88	10.97
Scarcity Hours	HRS	-	9	7	21
Unserved Energy	GWhs	-	13.67	24.58	66.80

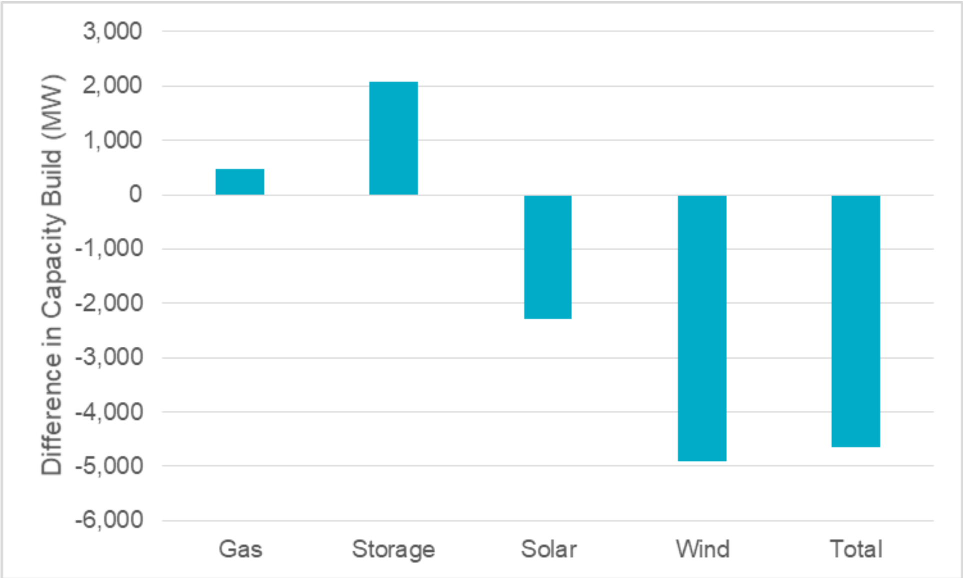


Figure 34: Difference in Capacity Additions Between Current Trends First and Second Iterations

As described in Appendix I, ERCOT used the UPLAN NPM model to perform transmission expansion analysis. Any recently approved RPG projects and local 138-kV upgrades and additions were included in the start cases. Figure 35 shows a map of Texas with the top congested elements connected at levels 100-kV and higher for the 2030 study year. The size of each bubble indicates the amount of annual congestion rent. Several large, inter-regional transmission upgrades were evaluated using ERCOT's economic planning criteria. Transmission upgrades or additions that provided sufficient production cost savings while addressing reliability and economic needs of the system were included in the final LTSA transmission plan.

The potential transmission improvements identified for the Current Trends scenario collectively resulted in approximately $1,136M in production cost savings and an approximately $1,864M reduction in congestion rent. Figure 36 and Figure 37 show the remaining congestion on the system for the 2030 and 2035 study years, respectively. Figure 38 and Table 12 provide details on the set of potential transmission improvements identified for the Current Trends scenario.

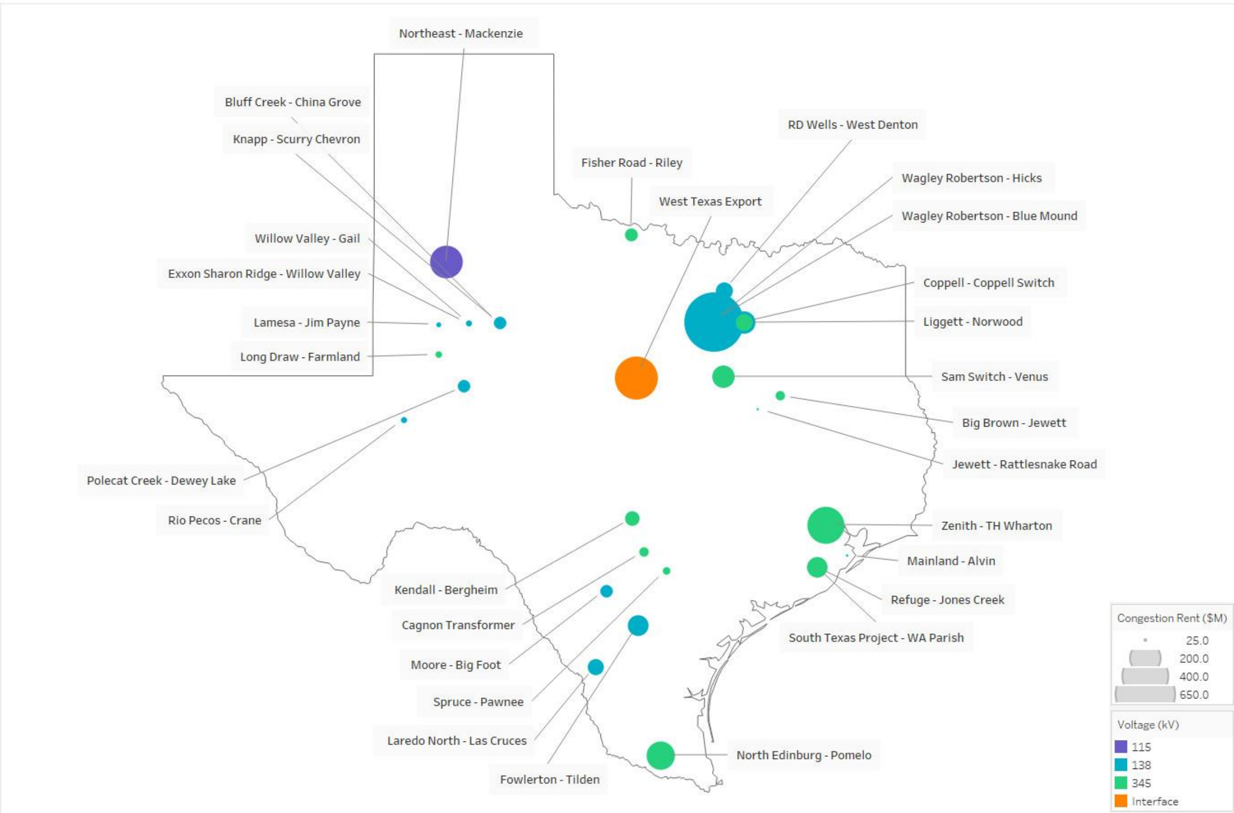


Figure 35: Top Constraints for Current Trends (2030)

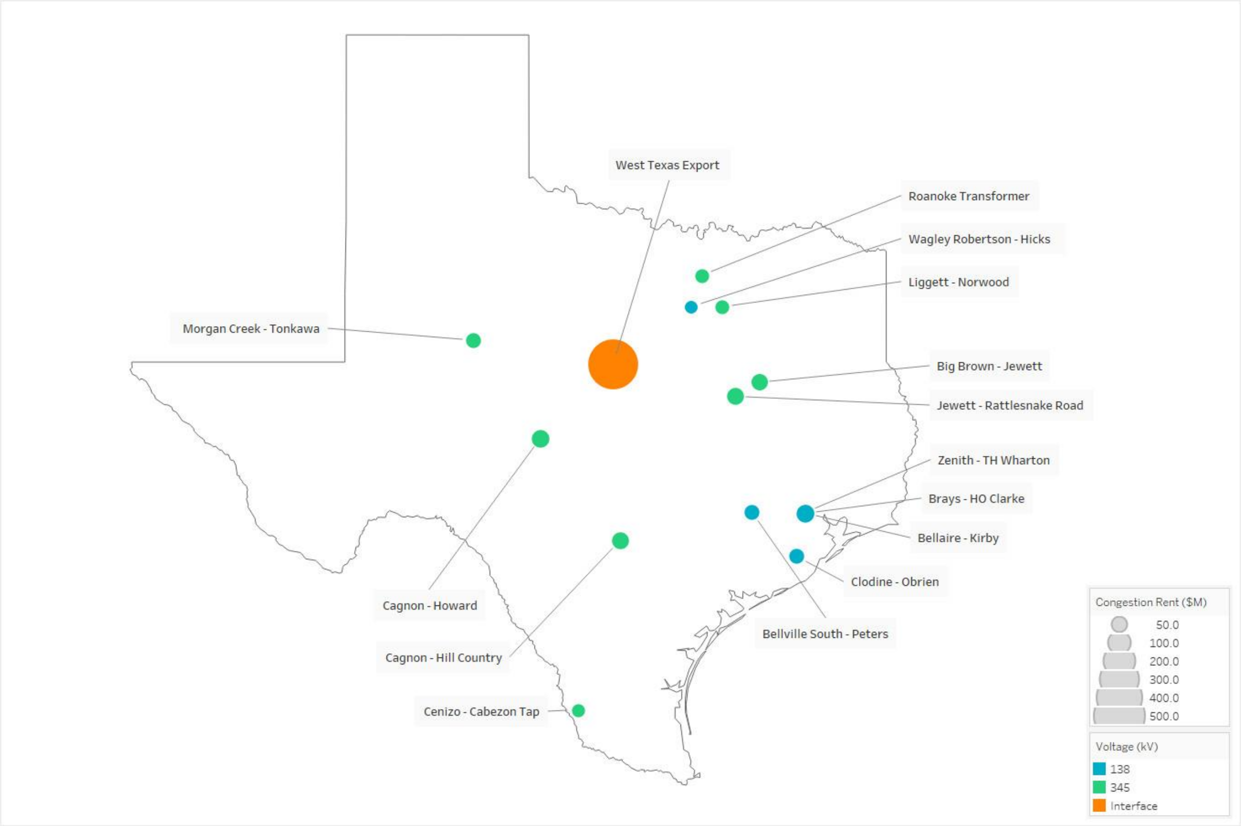


Figure 36: Top Final Congested Elements in 2030 for Current Trends

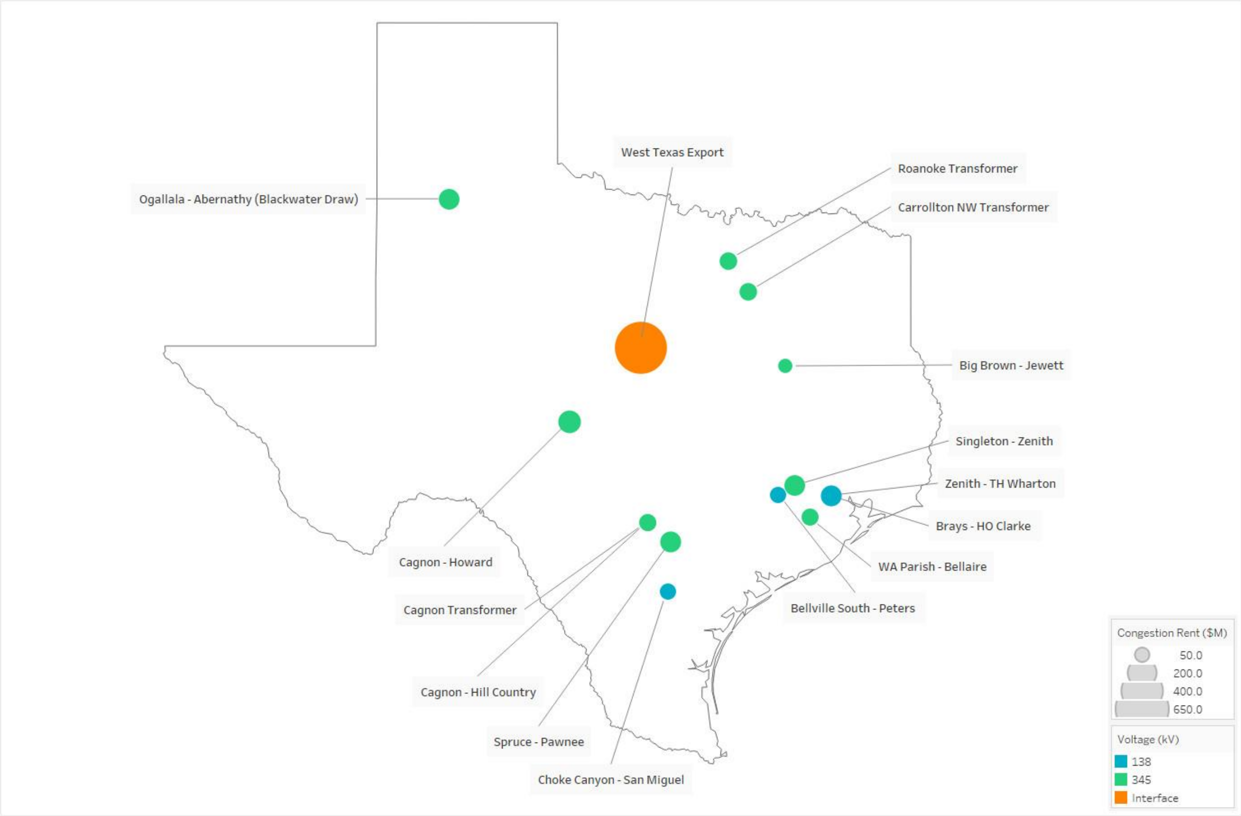


Figure 37: Top Final Congested Elements in 2035 for Current Trends

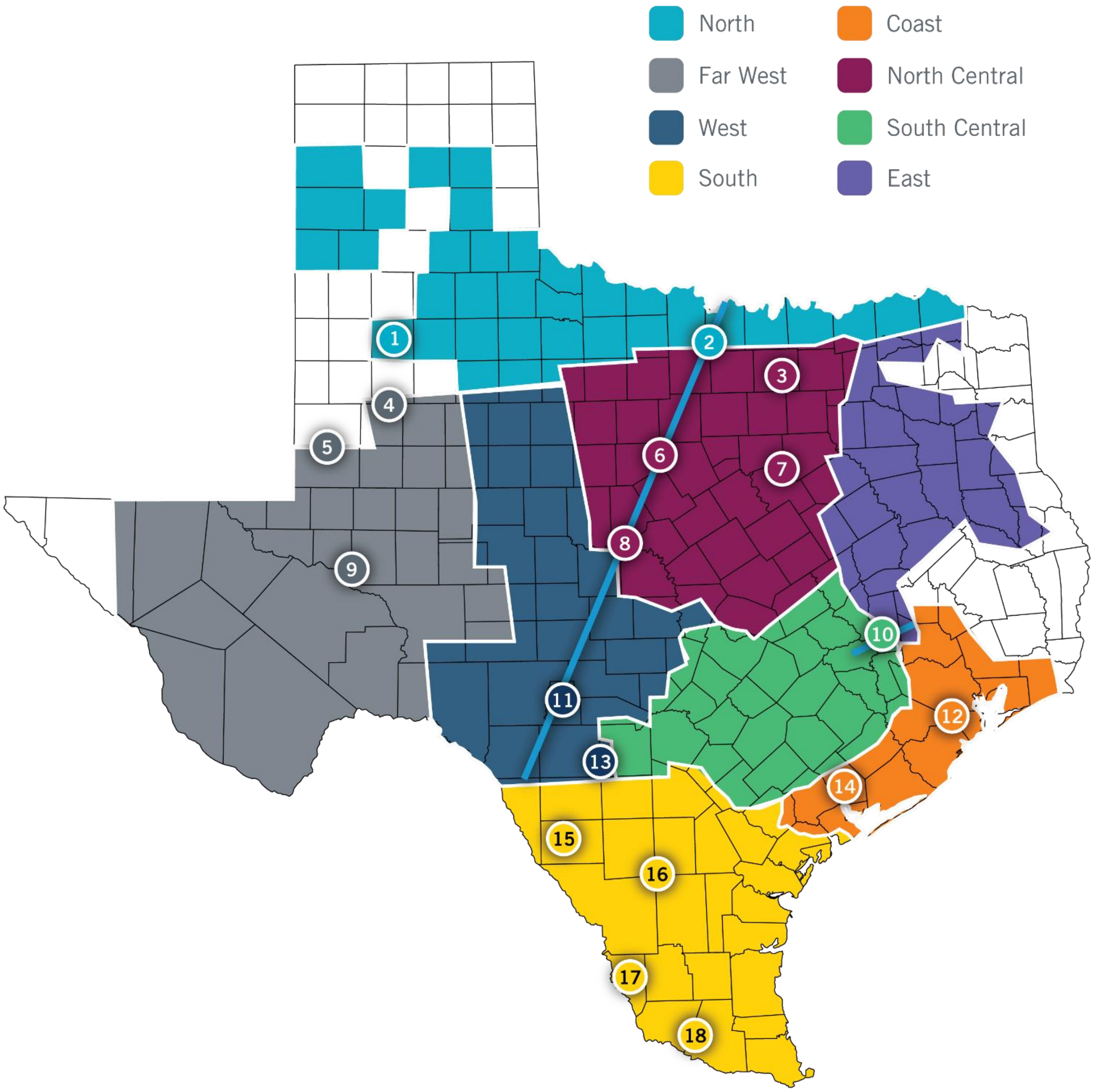


Figure 38: Current Trends Potential Transmission Improvements

Table 12: Potential Transmission Improvements for Current Trends

Map Index	Title	Description	Date of Potential Need	Approximate Break-Even Capital Cost (2030 $M)
1	Lubbock Loop	Add a new 345-kV line from North to Oliver; Upgrade the 345-kV line from Long Draw to Farmland	2030	1,153
2	Panhandle to Dallas-Fort Worth	Upgrade the 345-kV lines from Riley to Fisher Road to Wichita Falls to Bowman Switch; Add a new 345-kV double-circuit line from Fisher Road to Carrollton Northwest	2030	939
3	Dallas-Fort Worth Area Improvements	Upgrade the West Denton to RD Well 138-kV line; Upgrade the Lincoln – Arco 138-kV line	2030	142
		Upgrade the 138-kV double-circuit lines from Eagle Mountain to Hicks Switch to Wagley Robertson to Blue Mound to Saginaw Switch	2030	492
		Add a second 345/138-kV transformer at Carrollton Northwest; Upgrade the 138-kV lines from Carrolton Northwest to Carrollton Josey Lane to Addison; Upgrade the 138-kV line from Carrolton Tarpley Road to Addison	2030	634
		Upgrade the 138-kV line form Coppell to Coppell Switch	2030	204
		Add a new 345-kV line from Hicks Switch to Carrolton Northwest	2035	241
4	Lamesa Area Improvements	Loop the second 345-kV circuit from Long Draw to Scurry County into Faraday; Add a new 345-kV line from Faraday to Dermott; Add a new 345-kV line from Faraday to Lamesa; Add a new 345-kV line from Oliver to Lamesa; Move the 345/138-kV transformer at Willow Creek to Lamesa; Add a second 345/138-kV transformer at Lamesa; Upgrade the 138-kV lines from Lamesa to Jim Payne to Paul Davis	2030	758
5	Lamesa to Andrews County	Add a new 345-kV line from Lamesa to Andrews County	2030	313
6	West Shackelford to Comanche Peak	Add a new 345-kV double-circuit line from West Shackelford to Comanche Peak	2035	498
7	Sam Switch to Venus Switch	Upgrade the 345-kV double-circuit line from Sam Switch to Venus Switch	2030	182

Map Index	Title	Description	Date of Potential Need	Approximate Break-Even Capital Cost (2030 $M)
8	Brown Switch to Bell County East	Add a new 345-kV double-circuit line from Brown Switch to Bell County East	2030	477
9	Rio Pecos to Crane	Upgrade the 138-kV line from Rio Pecos to Crane	2030	76
10	North Houston Import	Add new 345-kV double-circuit lines from Bell County East to Gibbons Creek to Rothwood; Upgrade the 138-kV line from Louetta to Rothwood; Upgrade the 138-kV terminal equipment at North Belt	2030	527
11	Bakersfield to Big Hill to Uvalde	Add a second 345-kV circuit from Bakersfield to Big Hill (cutting in at Schneeman Draw, Noelke, and Cedar Canyon); Add a new 345-kV double-circuit line from Big Hill to Uvalde	2030	459
12	Houston / Freeport Area Improvements	Upgrade the 138-kV lines from Freeway Park to Mainland to Alvin	2030	412
		Upgrade the 345/138-kV transformer at TH Wharton	2035	43
13	San Antonio Import	Add a new 345-kV line from Uvalde to Howard; Add new 345-kV lines from Uvalde to Moore to Howard; Add a new 345-kV line from Howard to Fowlerton; Add two new 345/138-kV transformers at Howard; Loop the 345-kV line from Cagnon to Von Rose into Howard; Loop the 345-kV line from Cagnon to Spruce into Howard; Upgrade the 138-kV line form Howard to Leon Creek; Upgrade the 138-kV line from Medinabs to 36th Street; Upgrade the 138-kV line from Cagnon to VLSI	2030	2,239

Map Index	Title	Description	Date of Potential Need	Approximate Break-Even Capital Cost (2030 $M)
14	South Houston / Freeport Import	Upgrade the 345-kV line from STP to WA Parish; Upgrade the 345-kV double-circuit line from STP to Jones Creek to Dow; Upgrade the 138-kV line from Lolita to Blessing	2030	1,341
		Add a new 345-kV line from Lon Hill to Hillje	2030	243
15	Southwest Improvements	Add a new 345-kV line from Cenizo to Asherton; Add a new 345-kV line from Asherton to San Miguel; Add a new 345-kV line from Asherton to Uvalde; Add a new 345-kV line from Escondido to Uvalde; Add two new 345/138-kV transformers at Uvalde; Add two new 345/138-kV transformers at Asherton; Add two new 345/138-kV transformers at Escondido; Upgrade the 138-kV lines from Uvalde to Downie to Moore; Upgrade the 138-kV lines from Moore to Big Foot to Pleasonton; Upgrade the 138-kV lines from Asherton to Big Well to Dilley; Add a new 138-kV line from Moore to Leon Creek	2030	1,582
16	Fowlerton to Del Sol	Add a new 345-kV line from Fowlerton to Del Sol	2030	447
17	Del Sol to Lobo Second Circuit	Add a second 345-kV circuit from Del Sol to Cabezon to Cenizo to Lobo; Bypass the series capacitors at Del Sol and Cenizo	2035	91
18	Frontera Import	Add a new 345-kV line from Del Sol to Frontera; Add two new 345/138-kV transformers at Frontera	2030	275

Renewable Mandate

The Renewable Mandate scenario assumed that favorable regulatory policies and the resolution of major infrastructure-related hurdles would further incentivize the development of renewable resources on the ERCOT system. The ITC and PTC were assumed to extend through 2035 and, based on a CO_2 tax bill introduced in the U.S. Congress during 2019, a $40/ton CO_2 tax was assumed to start in 2021 and escalate annually at 2.5% above the assumed inflation rate of 2%. Additionally, higher distributed solar assumptions were used compared to those utilized for the Current Trends Scenario. The S-Curve used for the aggressive penetration of distributed solar[15] as a demand modifier for the Renewable Mandate scenario is shown in Figure 39.

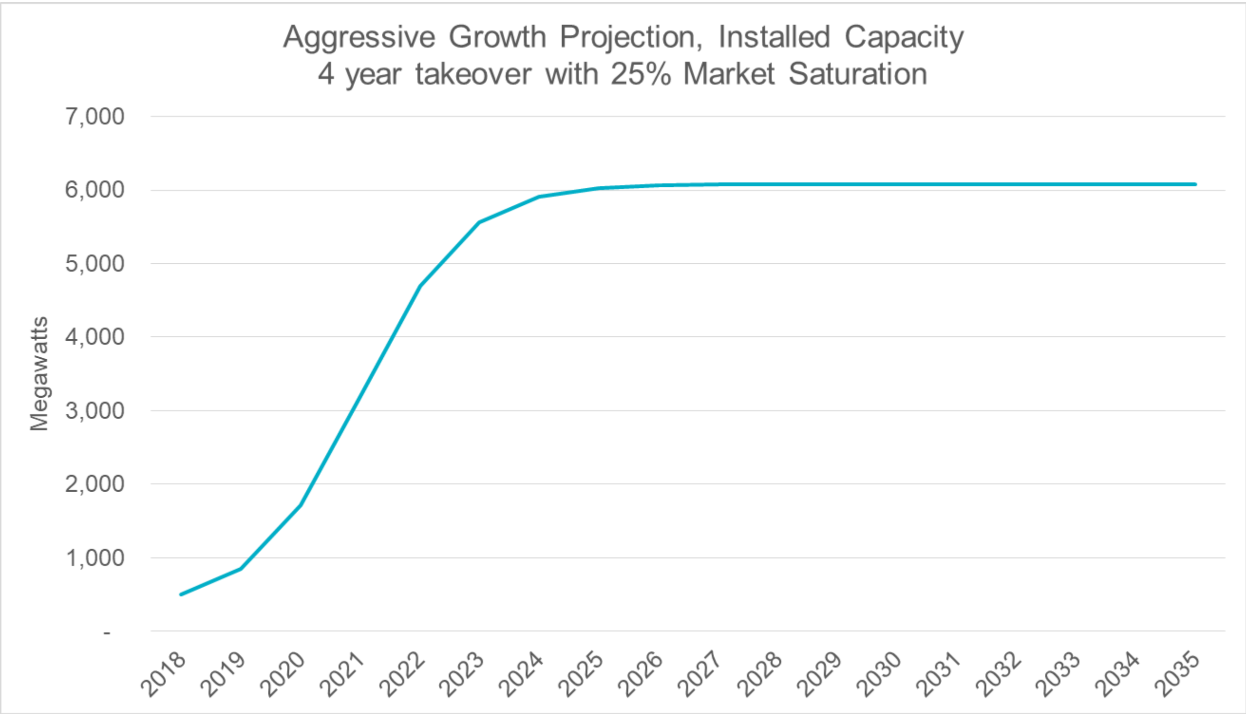


Figure 39: S-Curve for Aggressive Growth Projection of Distributed Solar

The inclusion of carbon pricing in capacity expansion and retirement analysis resulted in 3,056 MW of accelerated fixed-age generation retirements – a value 1,182 MW greater than that found in the Current Trends scenario. Total capacity additions for the Renewable Mandate scenario were 101,391 MW, including 44,800 MW of wind, 35,000 MW of solar, and 3,445 MW of battery energy storage. The model also added 18,146 MW of new natural gas generation to replace some accelerated coal retirements resulting from the CO_2 tax when new solar and wind new capacity additions reached their annual caps in earlier years. A comparison of the capacity expansion results of the Renewable Mandate and Current Trends scenarios is shown in Figure 40.

[15]http://www.ercot.com/content/wcm/key_documents_lists/172749/SAWG__Meeting_12-13-2019_Solar_PV_Forecast_Discussion.pptx

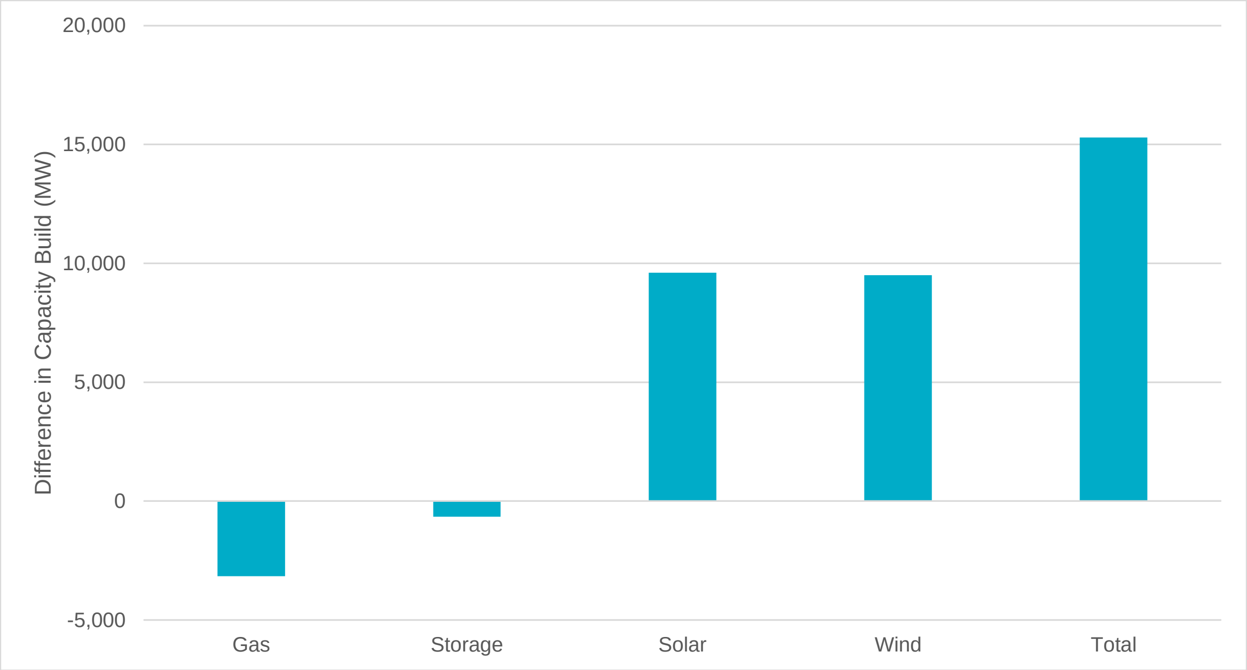


Figure 40: Difference in Capacity Additions Between Current Trends and Renewable Mandate

A summary of the capacity expansion and retirement analysis results for the Renewable Mandate scenario is provided in Table 13. The reserve margin for the Renewable Mandate scenario was 17% by 2035. Compared to the Current Trends scenario, the proportion of demand served by natural gas generation decreased to 33.9% from 41.5% and the proportion of demand served by wind and solar generation increased to 59.2% from 47.8% by 2035 in the Renewable Mandate scenario.

Table 13: Summary of Capacity Expansion and Retirement for Renewable Mandate

Description	Units	2021	2025	2030	2035
CC Adds	MW	-	1,000	6,500	8,250
CT Adds	MW	-	-	100	2,296
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	1,108	1,951	387
Solar Adds	MW	4,000	16,000	15,000	-
Wind Adds	MW	3,000	12,000	15,000	14,800
Annual Capacity Additions	MW	7,000	30,108	38,551	25,733
Cumulative Capacity Additions	MW	7,000	37,108	75,658	101,391
Economic Retirements	MW	-	3,056	-	-
Cumulative Economic Retirements	MW	-	3,056	3,056	3,056
Reserve Margin	%	12	14	21	17
Coincident Peak	MW	82,817	88,897	97,160	106,189
Annual Energy	GWhs	451,026	499,771	563,141	629,391
Average LMP	$/MWh	56.00	71.76	85.62	125.41
Natural Gas Price	$/mmbtu	3.24	4.20	5.00	5.95
Average Market Heat Rate	MMbtu/MWh	17.27	17.07	17.13	21.06
Natural Gas Generation	%	59.78	45.47	35.73	33.96
Coal Generation	%	1.64	0.63	0.28	0.20
Wind Generation	%	24.55	32.77	39.37	43.79
Solar Generation	%	4.35	12.23	17.17	15.37
Scarcity Hours	HRS	-	4	5	20
Unserved Energy	GWhs	-	9.06	16.95	71.13

Partial transmission expansion analysis was conducted for the Renewable Mandate scenario in order to identify top constraints and to provide a comparison of potential needs relative to the Current Trends scenario. Figure 41 shows a map of Texas with the top congested elements connected at levels 100-kV and higher for the 2030 study year. The size of each bubble indicates the amount of annual congestion rent. A complete list of potential transmission improvements was not identified as part of the transmission expansion analysis conducted for the Renewable Mandate scenario.

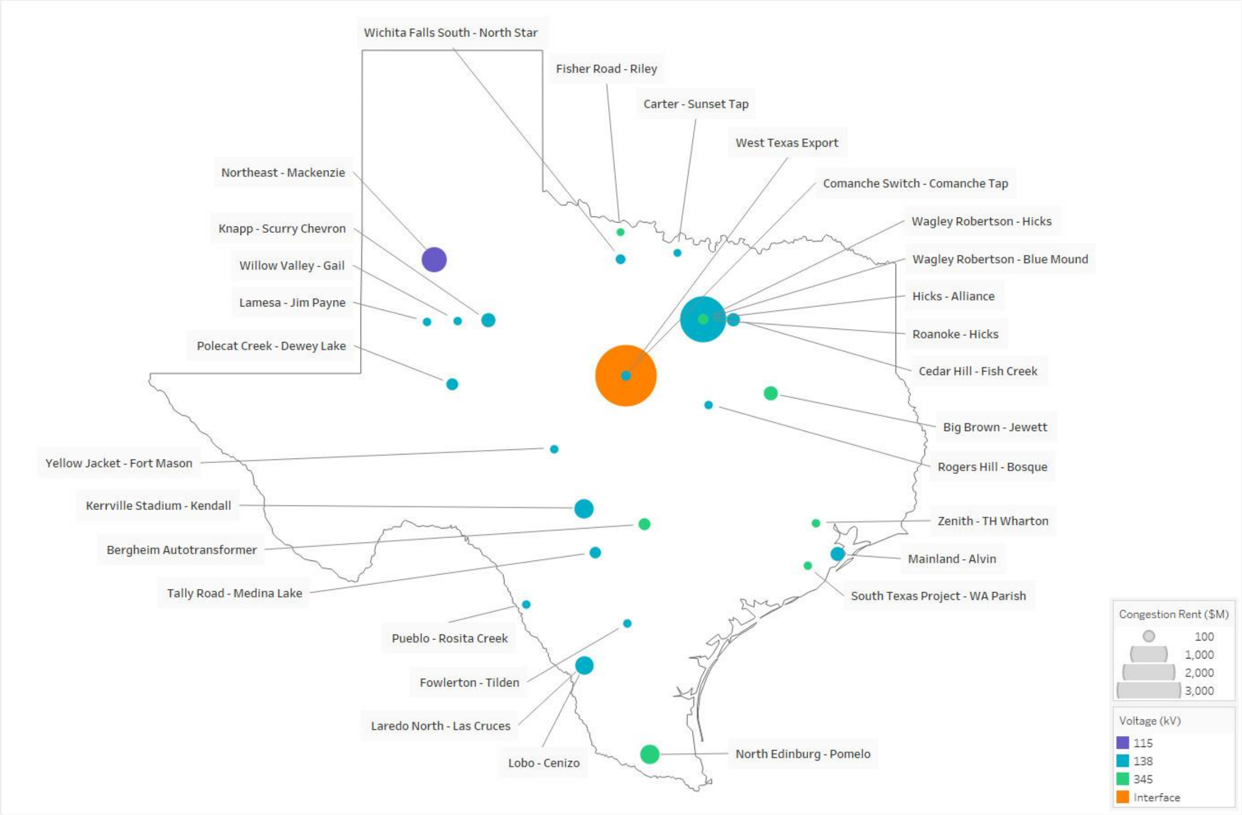


Figure 41: Top Constraints for Renewable Mandate (2030)

High Battery Energy Storage

This scenario was designed to investigate the impacts that high amounts of battery energy storage may have on the ERCOT system and future capacity builds. The capacity expansion results for the Current Trends scenario showed included less new battery energy storage capacity than what was reflected in the monthly Generation Interconnection Status (GIS) report[16]. In this scenario more battery energy storage capacity was fixed in the model to better reflect the trend present in the GIS report. Some of the key assumptions for this scenario were aggressive adoption of electric vehicles and low battery capital cost projections from the National Renewable Energy Laboratory (NREL). 7.5 million light-duty electric vehicles were assumed to be adopted by 2035. Additionally, 77% of the miles driven by buses and heavy trucks were assumed to be electric by 2035. Figure 42 shows the charging pattern of electric vehicles used in the High Battery Energy Storage scenario. The capital costs of battery energy storage assumed for this scenario were 30 to 60 percent lower than those used for the Current Trends scenario.

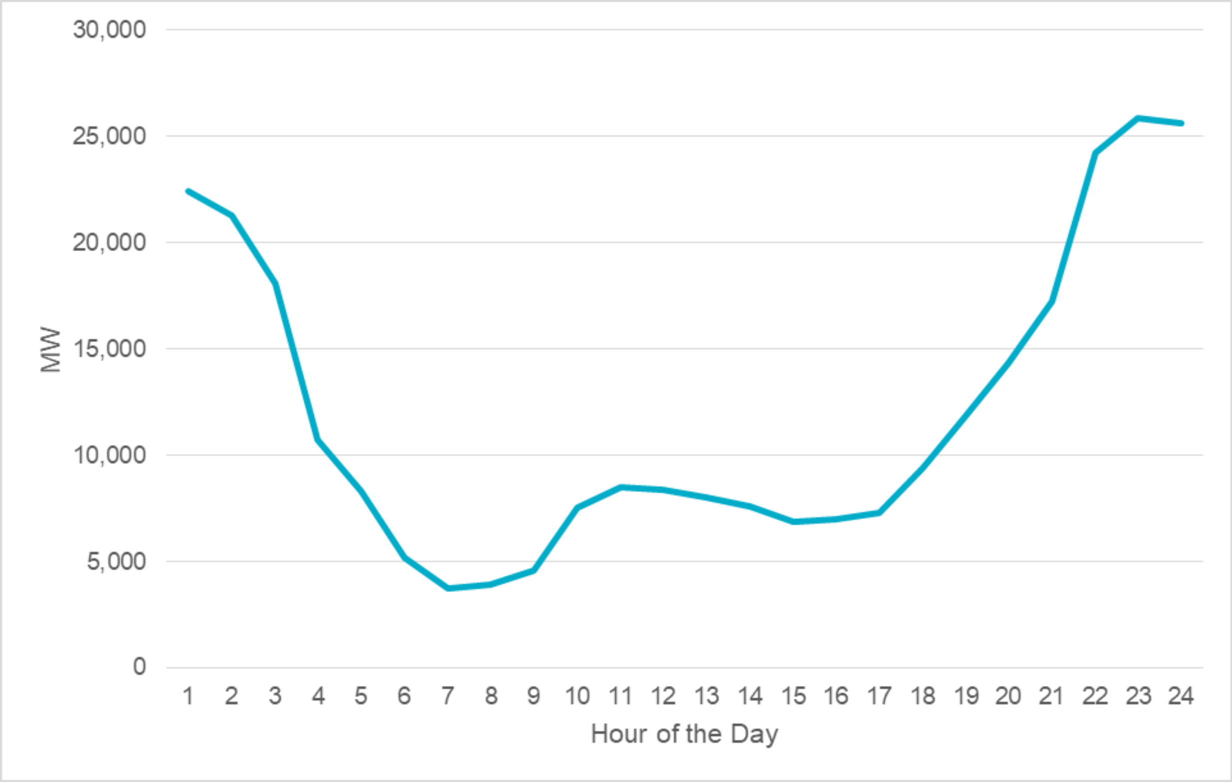


Figure 42: Charging Pattern of Electric Vehicles for High Battery Energy Storage Scenario in 2035

The high level of battery energy storage in this scenario was accomplished by identifying an initial set of solar and battery energy storage capacity additions resulting from the capacity expansion model. Co-located battery energy storage was then added to each solar site identified in that initial capacity expansion plan, and the resulting battery energy and storage sites were fixed in the model for a second iteration of capacity expansion and retirement analysis. The added co-located battery energy storage capacity was assumed to be 50% of the corresponding co-located solar capacity. In total, 21,000 MW

[16] Monthly GIS reports can be found at http://www.ercot.com/gridinfo/resource.

of solar, 10,850 MW of co-located battery energy storage, and 2,000 MW of standalone battery energy storage were fixed in the model for a second run to optimize additional capacity expansion needs around the fixed and existing resources. The difference in capacity additions between the final High Battery Energy Storage scenario and the Current Trends scenario is shown in Figure 43.

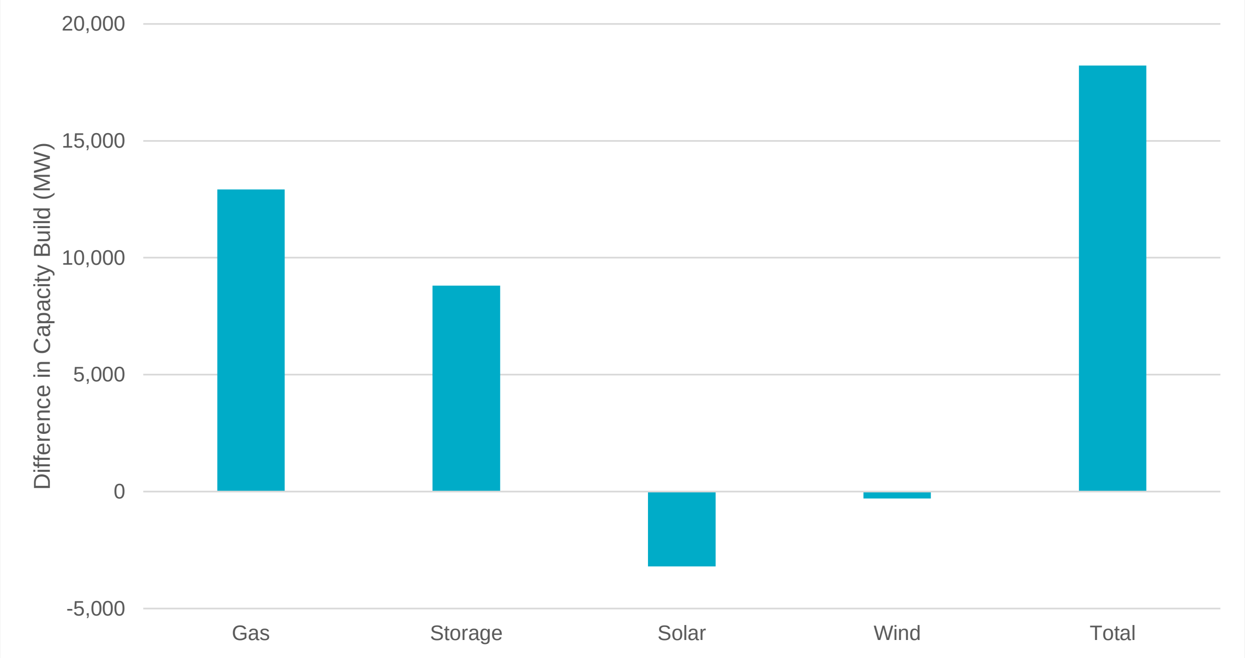


Figure 43: Difference in Capacity Additions Between Current Trends and High Battery Energy Storage

Capacity additions in the High Battery Energy Storage scenario totaled 104,328 MW, including 34,217 MW of natural gas generation, 35,000 MW of wind generation, 22,200 MW of solar generation, and 12,911 MW of battery energy storage. More combined cycle capacity was added to this scenario compared to the Current Trends scenario due to high electric vehicle charging demand at night. Since these combined cycle units can serve demand during daytime as well, less solar capacity was added compared to the Current Trends scenario. Less wind was added compared to the Current Trends scenario because co-located battery energy storage units charged by solar generation during daytime, discharged at night and reduced potential revenue for new wind resources. The summary of capacity expansion and retirement analysis results for the High Battery Energy Storage scenario is shown in Table 14.

Table 14: Summary of Capacity Expansion and Retirements Results for High Battery Energy Storage

Description	Units	2021	2025	2030	2035
CC Adds	MW	-	-	9,000	15,000
CT Adds	MW	-	-	3,181	7,036
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	1,850	8,050	2,150	861
Solar Adds	MW	4,000	14,300	3,400	500
Wind Adds	MW	3,000	12,000	15,000	5,000
Annual Capacity Additions	MW	8,850	34,350	32,731	28,397
Cumulative Capacity Additions	MW	8,850	43,200	75,931	104,328
Economic Retirements	MW	-	2,266	75	-
Cumulative Economic Retirements	MW	-	2,266	2,341	2,341
Reserve Margin	%	10	9	9	6
Coincident Peak	MW	83,787	91,024	102,686	120,057
Annual Energy	GWhs	457,573	517,290	615,279	714,240
Average LMP	$/MWh	29.25	36.43	64.62	94.68
Natural Gas Price	$/mmbtu	3.24	4.20	5.00	5.95
Average Market Heat Rate	MMbtu/MWh	9.02	8.67	12.93	15.90
Natural Gas Generation	%	54.15	40.26	40.31	46.60
Coal Generation	%	7.92	8.07	5.22	3.44
Wind Generation	%	24.21	32.10	36.84	34.46
Solar Generation	%	4.22	11.05	10.73	9.53
Scarcity Hours	HRS	-	-	12	21
Unserved Energy	GWhs	-	-	24.53	67.21

High Industrial Load

The High Industrial Load scenario was designed to study the impact of higher-than-expected growth in industrial load in some areas such as the Delaware Basin and Corpus Christi. This was accomplished by adding 778 MW and 1,245 MW of LNG facilities at Corpus Christi and Brownsville, respectively. An additional 3,560 MW of industrial load was also added in the Delaware Basin by 2035. These additions to industrial loads increased the peak demand by 5,583 MW by 2035 compared to the Current Trends scenario. A comparison of peak demand and energy for the High Industrial Load and Current Trends scenarios is shown in Table 15.

Table 15: Peak Demand and Energy Comparison for Current Trends and High Industrial Load

Year	Peak Demand (MW)			Energy (GWh)		
	Current Trends	High Industrial Load	% Difference	Current Trends	High Industrial Load	% Difference
2021	83,594	84,847	1.5	454,288	465,263	2.4
2025	89,989	95,235	5.8	505,245	550,296	8.9
2030	98,129	103,540	5.5	567,464	614,861	8.4
2035	106,579	112,162	5.2	633,575	682,486	7.7

Capacity expansion and retirement analysis for the High Industrial Load scenario resulted in the acceleration of 511 MW of fixed-age generation retirements, which was 1,363 MW less than the results for the Current Trends scenario. This scenario also resulted in more capacity additions for every resource type compare to the Current Trends scenario. The difference between the total capacity additions of the High Industrial Load and Current Trends scenarios is shown in Figure 44.

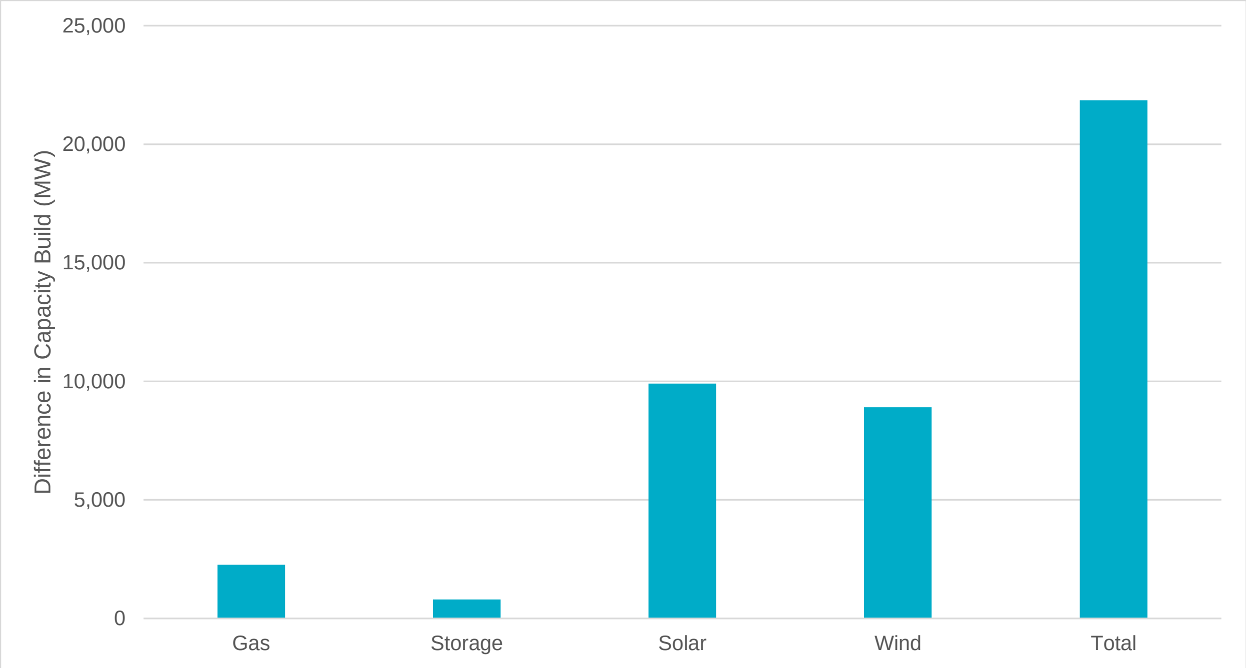


Figure 44: Difference in Capacity Additions Between Current Trends and High Industrial Load

The High Industrial Load scenario resulted in the most capacity additions of any scenario studied in this LTSA. 107,958 MW of total capacity was added by 2035, including 23,558 MW of natural gas generation, 35,300 MW of solar generation, 44,200 MW of wind generation, and 4,900 MW of battery energy storage. Combined cycle capacity was added in early years to serve additional industrial load when both new solar and wind resources reached their annual caps. Because industrial load generally consists of 24/7 demand, and much more wind and solar capacity was added in this scenario compared to the Current Trends scenario, more battery energy storage was needed to firm up variable wind and solar generation. The reserve margin for the High Industrial Load scenario in 2035 was 15%. A summary of the capacity expansion and retirement analysis results for the High Industrial Load scenario is shown in Table 16.

Table 16: Summary of Capacity Expansion and Retirement for High Industrial Load

Description	Units	2021	2025	2030	2035
CC Adds	MW	1,000	3,000	6,000	5,500
CT Adds	MW	-	-	948	7,110
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	1,600	2,100	1,200
Solar Adds	MW	4,000	15,800	4,700	10,800
Wind Adds	MW	3,000	12,000	15,000	14,200
Annual Capacity Additions	MW	8,000	32,400	28,748	38,810
Cumulative Capacity Additions	MW	8,000	40,400	69,148	107,958
Economic Retirements	MW	-	-	391	120
Cumulative Economic Retirements	MW	-	-	391	511
Reserve Margin	%	10	11	9	15
Coincident Peak	MW	84,847	95,235	103,540	112,162
Annual Energy	GWhs	465,263	550,296	614,861	682,486
Average LMP	$/MWh	33.44	45.17	65.00	81.94
Natural Gas Price	$/mmbtu	3.24	4.20	5.00	5.95
Average Market Heat Rate	MMbtu/MWh	10.31	10.75	13.00	13.76
Natural Gas Generation	%	58.07	43.40	39.69	35.32
Coal Generation	%	7.73	7.77	5.20	3.44
Wind Generation	%	21.49	29.82	36.40	40.56
Solar Generation	%	3.46	10.97	11.79	14.43
Scarcity Hours	HRS	1	4	12	21
Unserved Energy	GWhs	0.17	9.32	39.11	77.69

Existing Transmission Constraints

A four-zone model was used to incorporate existing transmission constraints into the capacity expansion and retirement analysis for the Existing Transmission Constraints scenario. The zones were Panhandle, West, Valley, and Other ERCOT Regions. The interface limits enforced in the model included West Texas export, Valley import, and Valley export. Zonal shift factors were utilized to capture the relationship between zonal injections and interface flows. The four-zone model with interface limits is shown in Figure 45.

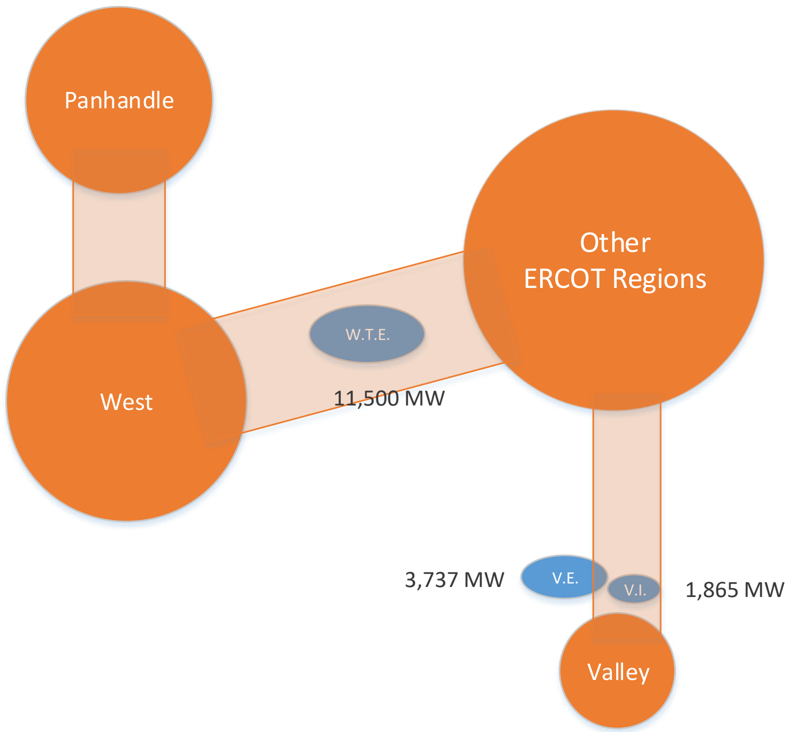


Figure 45: Four-Zone Model with Interface Limits

The West Texas export interface limit was binding approximately 7% of time in 2021, but increased to 35% by 2035. The Valley export interface limit began to bind in some hours after 2025 and the Valley import interface limit was only binding in a few hours through 2035. The difference between the total capacity additions in the Existing Transmission Constraints Current Trends scenarios is shown in Figure 46.

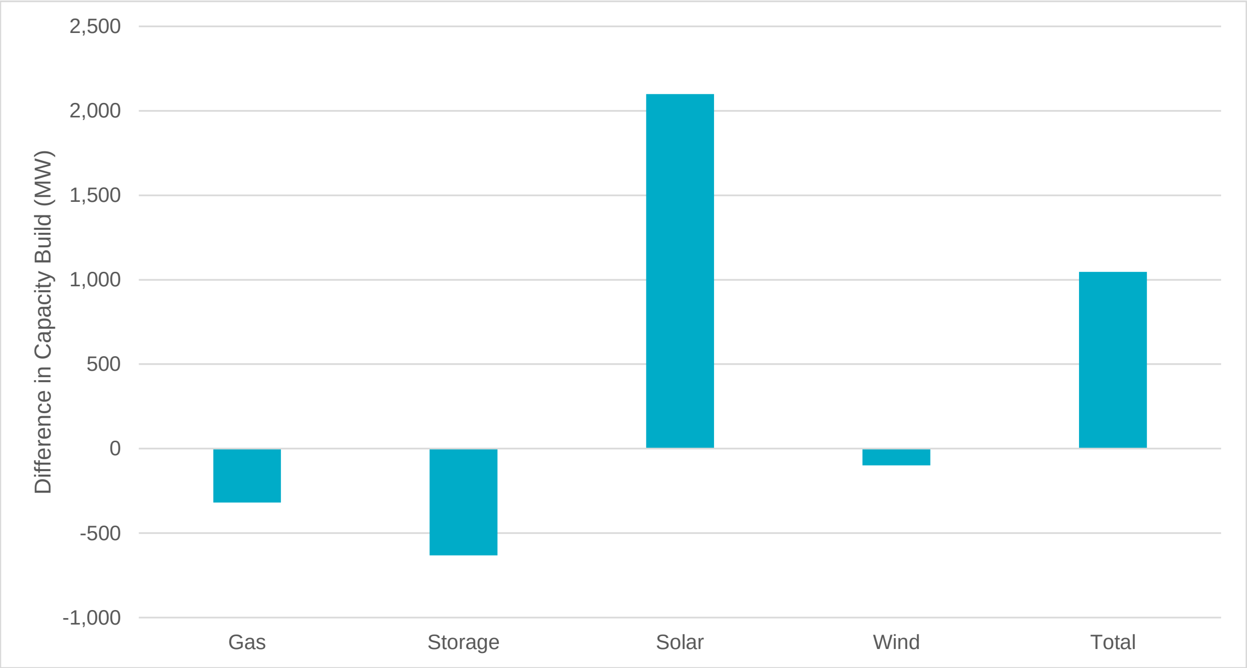


Figure 46: Difference in Capacity Additions Between Current Trends and Existing Transmission

Total capacity additions in this scenario were 87,148 MW, including 35,200 MW of wind, 27,500 MW of solar, 3,469 MW of battery energy storage, and 20,979 MW of natural gas generation by 2035. All new combined cycle capacity, 56% of new wind capacity, and 69% of new solar capacity were added in the Other ERCOT Regions zone. A summary of the capacity expansion and retirement results for the Existing Transmission Constraints scenario is included in Table 17.

Table 17: Summary of Capacity Expansion and Retirement for Existing Transmission Constraints

Description	Units	2021	2025	2030	2035
CC Adds	MW	-	1,000	8,000	7,750
CT Adds	MW	-	-	237	3,992
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	100	1,072	1,411	886
Solar Adds	MW	4,000	10,900	9,600	3,000
Wind Adds	MW	3,000	10,600	12,100	9,500
Annual Capacity Additions	MW	7,100	23,572	31,348	25,128
Cumulative Capacity Additions	MW	7,100	30,672	62,020	87,148
Economic Retirements	MW	-	1,874	-	-
Cumulative Economic Retirements	MW	-	1,874	1,874	1,874
Reserve Margin	%	11	9	13	12
Coincident Peak	MW	83,594	89,989	98,129	106,579
Annual Energy	GWhs	454,288	505,245	567,464	633,575
Average LMP	$/MWh	31.25	45.23	58.14	79.69
Natural Gas Price	$/mmbtu	3.24	4.20	5.00	5.95
Average Market Heat Rate	MMbtu/MWh	9.64	10.76	11.63	13.38
Natural Gas Generation	%	54.44	44.11	41.17	42.46
Coal Generation	%	7.89	8.42	5.43	3.78
Wind Generation	%	23.97	29.73	34.02	35.25
Solar Generation	%	4.13	8.99	11.92	11.70
Scarcity Hours	HRS	-	6	11	23
Unserved Energy	GWhs	-	6.58	28.06	83.59