



# 2024 Long-Term System Assessment for the ERCOT Region

December 2024

## Executive Summary

Section 39.9112 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. A report documenting this study must be submitted to the Texas Legislature each even-numbered year by December 31.

The bulk transmission network within the ERCOT Region consists of 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 annual development of the Regional Transmission Plan (RTP). The Long-Term System Assessment (LTSA) provides an evaluation of the potential needs of ERCOT's transmission system in the 10- to 15-year planning horizon.

Unprecedented load growth was observed in the 2024 Regional Transmission Plan (RTP) due to continued interest in connecting large loads to the ERCOT System. This unprecedented load growth prompted discussions about introducing the 765-kV voltage class to the ERCOT Transmission Grid. In July 2024, ERCOT filed the Permian Basin Reliability Plan Study<sup>1</sup> with the PUCT, which included both a plan with the traditional 345-kV import path and a plan with the 765-kV import path to the Permian Basin area. The PUCT approved the Permian Basin Reliability Plan in October 2024, irrespective of the voltage level, and is anticipated to make a determination on the use of the 765-kV voltage class by May 1, 2025. To facilitate the PUCT's discussion, the 2024 RTP developed two plans to address the reliability needs: the traditional 345-kV plan and the 765-kV plan. The 765-kV system may be part of future considerations in the LTSA pending PUCT decisions on the adoption of the 765-kV voltage class.

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's longer planning horizon typically reveals whether a more extensive project could be needed. 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 a variety of scenarios in the LTSA is to identify transmission upgrades that are robust across a range of potential outcomes or more economical than the upgrades that would be determined considering only near-term needs.

The ERCOT Region is forecasted to experience tremendous electric demand growth in the next five to seven years, which is driving the need for ERCOT to adapt and plan differently for the future. ERCOT's new era of planning focuses on ensuring all areas of system planning—from generation development and load interconnections to transmission plan development—can adapt to better serve

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<sup>1</sup> *Reliability Plan for the Permian Basin under PURA § 39.167*, PUCT Project No. 55718, ERCOT Permian Basin Reliability Plan Study (July 25, 2024).

the needs of the rapidly growing Texas economy.<sup>2</sup> Both the resource mix and transmission buildout needed to support the new era of planning must be carefully evaluated. The 2024 LTSA provides insights on these new challenges that the ERCOT Region is experiencing.

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

1. Current Trends
2. High Large Load Adoption
3. High Load Growth and Environmental Regulations

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

Planning for transmission 10 and 15 years into the future requires ERCOT to make assumptions about the types of new resources that may be developed. As a biennial study process, the 2024 LTSA process started in 2023 and used the 2023 RTP final reliability cases as the start case to develop the LTSA study cases for years 2034 and 2039. It did not incorporate the additional large loads included in the 2024 RTP because the reliability projects (345-kV plan or 765-kV plan) needed to reliably supply such a significant amount of large load additions were not available at the time the 2024 LTSA was initiated in 2023. As a result, neither 2024 unprecedented load growth nor the associated the 345-kV plan or the 765-kV plan from the 2024 RTP was included in the final study cases developed for the 2024 LTSA. Development of the 2026 LTSA will begin in 2025, which will use the 2024 RTP final reliability cases as the start case. The 2026 LTSA will incorporate the 765-kV plan in the transmission needs evaluation if the PUC decides to introduce the 765-kV voltage class into the ERCOT Region.

ERCOT conducted capacity expansion and retirement analyses for each of the three future scenarios, following the guidelines in the scenario descriptions. ERCOT also conducted a transmission expansion analysis for the Current Trends scenario. Two iterations were conducted for that scenario: the first iteration of capacity expansion and retirement analysis assumed no transmission limitations, whereas the second iteration of capacity expansion and retirement analysis included potential interface limits identified in the first iteration of transmission expansion analysis.

The analyses conducted for the 2024 LTSA resulted in the following key findings:

- Significant growth in wind, solar, natural gas, and battery energy storage resource types was found across all scenarios to replace retired coal and natural gas generation capacity and meet rising demand.
- Renewable resources were found to constitute a large portion of available capacity across all scenarios, introducing elevated operational risks due to the increase in intermittency.
- Battery energy storage and combustion turbines resources were found to be critical in managing increased net load ramping challenges.
- The scale and geographic distribution of wind and solar generation additions depend on sufficient transmission capacity between resource-rich regions and demand centers.
- Transmission challenges were identified for both the export from the renewable-resource-rich regions and the import into the demand centers.

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<sup>2</sup> <https://www.ercot.com/files/docs/2024/04/24/5%20CEO%20Update%20REVISED.pdf>

In all three scenarios, a mix of solar, wind, natural gas, and battery energy storage resource types was added to the system to serve growing demand and replace retired capacity. As shown in Figure 1 below the following nameplate capacities were: net total wind capacity ranged from 55,071 MW to 83,771 MW, the net total solar capacity ranged from 62,052 MW to 158,620 MW, and the net total battery capacity ranged from 26,372 MW to 88,165 MW in the three scenarios. The net total combined cycle capacity ranged from 53,625 MW to 66,621 MW and the net total combustion turbine capacity ranged from 21,719 MW to 112,730 MW across all three scenarios. Conversely, more than 25,000 MW of existing coal and natural gas capacity was retired by 2039 in all scenarios, although the timing of specific retirements varied.

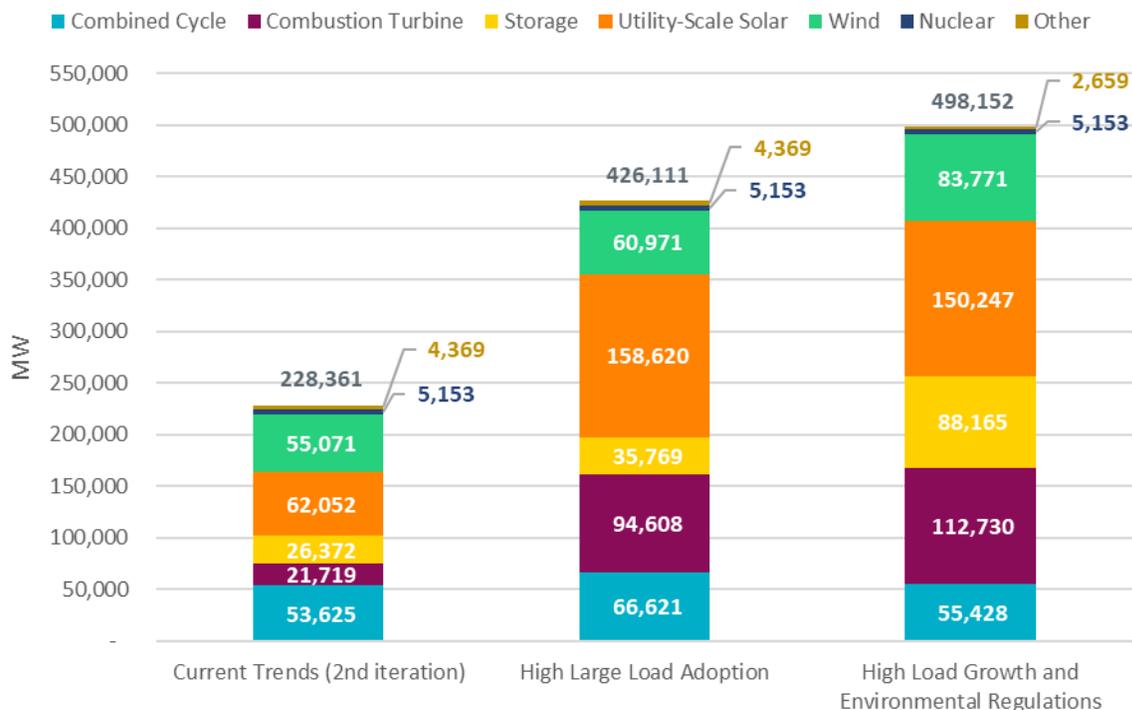


Figure 1: Total Net Nameplate Capacities Across All Scenarios

Renewable resources were projected to comprise a large portion of the resource capacity to serve the demand across all three scenarios. This resource mix change was expected to introduce elevated operational risks. Thermal and stability constraints on the transmission system, as well as operational considerations such as ramping limitations and minimum system inertia needs, should be assessed further to ensure reliability under high renewable penetration. The study results showed a significant increase in the ramping needs across all scenarios, driven primarily by the amount of new solar generation added. Notably, scarcity hours in summer will shift to later in the day, similar to previous LTSAs. However, 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 and winter peak conditions, must be included in planning studies.

The increased development of battery energy storage and combustion turbines became increasingly important in managing the increased variability in generation and demand. The storage resources will be likely to charge when low-cost, surplus renewable generation is available and to discharge during

peak net load periods, providing fast response ramping services and firming up generation. Traditionally, combustion turbines were only running for a small fraction of time. However, in both the High Large Load Adoption and the High Load Growth and Environmental Regulations scenarios, combustion turbines were required to be online more frequently, especially during night hours, to compensate for the rapid changes of the net load.

Capacity expansion and retirement analysis results for iteration 1 and iteration 2 of the Current Trends scenario provided insight into the potential impacts of transmission limitations on new generation development. The inclusion of transmission constraints in capacity expansion and retirement analyses led to a shift of wind and solar resources away from the resource-rich regions in West and North Texas to areas closer to major demand centers. The primary cause of this shift was the inclusion of the West Texas Export and Panhandle interface limits, which were binding constraints during many hours. Transmission challenges were identified for both the export from the renewable-resource-rich regions and the import into the demand center.

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## Chapter 1. Introduction

Electric Reliability Council of Texas, Inc. (ERCOT) manages the flow of electric power to more than 27 million Texas customers — representing about 90 percent of the state’s electric demand. ERCOT schedules power on an electric grid that connects over 54,100 miles of transmission lines and more than 1,250 generation units.<sup>3</sup>

As part of its responsibility to adequately plan the transmission system, ERCOT must develop a biennial assessment of needed transmission infrastructure. Public Utility Regulatory Act (PURA) § 39.9112 requires the (Public Utility Commission of Texas (PUCT) and ERCOT to study the need for increased transmission and generation capacity throughout the state of Texas, and report to the Legislature the results of the study and any recommendations for legislation. The report must be filed with the Legislature no later than December 31 of each even-numbered year. ERCOT has developed this 2024 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 2024 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 2024 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 future outcomes, they do not represent the entirety of possible future outcomes. Future conditions may deviate from those studied in the 2024 LTSA.

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<sup>3</sup> [https://www.ercot.com/files/docs/2022/02/08/ERCOT\\_Fact\\_Sheet.pdf](https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf).

## 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<sup>4</sup>. 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 2 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.

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<sup>4</sup> The LTSA Generation Siting Methodology is attached in Appendix II.

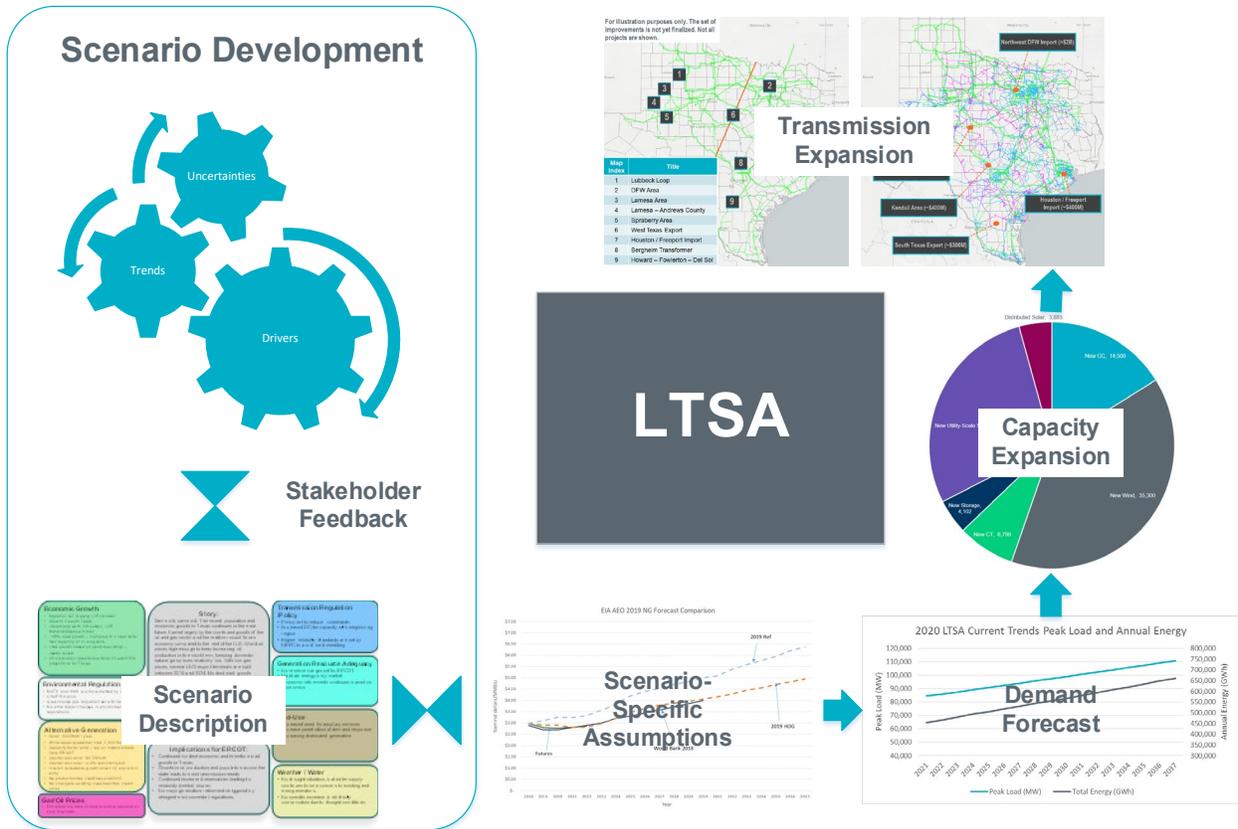


Figure 2: 2024 Long-Term System Assessment Process

Three scenarios were included in the 2024 LTSA. Table 1 provides a summary of each scenario.

Table 1: Scenarios Developed for 2024 LTSA

Scenario	Description
<b>Current Trends</b>	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.). Similar to the 2020 LTSA, an iterative process was adopted to co-optimize capacity expansion and transmission expansion. The Current Trends scenario did not incorporate the additional large loads included in the 2024 RTP from the implementation of HB5066 because the reliability projects (345-kV plan or 765-kV plan) needed to reliably supply such a significant amount of large load additions were not available at the time the 2024 LTSA was performed. The peak load for the Current Trends scenario in 2039 is 115,734 MW.
<b>High Large Load Adoption</b>	The High Large Load Adoption scenario was developed to study the impacts of the significant large load adoptions as provided by the TSPs in the ERCOT region. The peak load for the High Large Load Adoption scenario in 2039 is 191,100 MW.
<b>High Load Growth and Environmental Regulations</b>	High Load Growth and Environmental Regulations scenario assumed the high load growth with the 2011 weather condition and the addition of significant amount of large loads as provided by the TSPs in the ERCOT region, and the environment regulations impacting the development of dispatchable resources in the ERCOT System. The peak load for the High Load Growth and Environmental Regulations scenario in 2039 is 195,976 MW.

## Chapter 3. Key Findings

The 2024 LTSA includes a study of three different scenarios. Key findings from the study include:

1. Significant growth in wind, solar, natural gas, and battery energy storage resource types was found across all scenarios to replace retired coal and natural gas generation capacity and meet rising demand.
2. Renewable resources were found to constitute a large portion of available capacity across all scenarios, introducing elevated operational risks due to the increase in intermittency.
3. Battery energy storage and combustion turbines resources were found to be critical in managing increased net load ramping challenges.
4. The scale and geographic distribution of wind and solar generation additions depend on sufficient transmission capacity between resource-rich regions and demand centers.
5. Transmission challenges were identified for both the export from the renewable resource-rich region and the import into the demand centers.

**Key Finding 1: Significant growth in wind, solar, natural gas, and battery energy storage resource types was found across all scenarios to replace retired coal and natural gas generation capacity and meet rising demand.**

The capacity expansion analysis revealed 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 across all scenarios. These findings are generally consistent with the results from the 2022 LTSA, but the 2024 LTSA shows substantially higher level of new capacity additions.

This increase in capacity additions in the 2024 LTSA is mainly due to two factors:

- an additional 5 to 7 GW of fixed age and economic retirements compared to the previous LTSA; and
- the high load growth, especially the continued interest in connecting large loads to the ERCOT System.

By 2039, the total capacity retired based on the fixed-age assumption was 24.8 GW. The 2024 LTSA also reflected higher demand growth compared to the 2022 LTSA. In the Current Trends scenario, summer peak demand increased by about 18 GW over the 15-year study period compared to 2022 LTSA. In the High Load Growth and Environmental Regulations scenario, demand growth was even more significant, with an increase of 98 GW over the same 15-year period compared to 2022 LTSA. The High Large Load Adoption showed an increase of 94 GW compared to 2022 LTSA. As a result, all scenarios in the 2024 LTSA required higher levels of new capacity to meet the increased demand.

***Capacity Additions***

The total capacity added by 2039 was 87.7 GW for the Current Trends scenario, 285.8 GW for the High Large Load Adoption scenario, and 359.2 GW for the High Load Growth and Environmental Regulations scenario. In each scenario, distributed solar generation capacity additions were set as a model input rather than based on economic analysis, with projected adoption ranging from 4,030 MW in 2025 to 6,011 MW by 2039.

As shown in Figure 3 , the High Load Growth and Environmental Regulations scenario had the highest inverter-based resource capacity additions, with 162 GW of solar and wind and 79.3 GW of battery energy storage by 2039. This scenario had restrictions on new natural gas developments due to stricter environmental regulations, which require new combined cycle plants to install carbon capture and storage. This constraint makes such plants economically unviable until after 2035. Additionally, all new combustion turbines in this scenario were limited to a 20% annual capacity factor due to stricter environmental regulations, prompting the model to add much more combustion turbines compared to the other scenarios. In contrast, the High Large Load Adoption scenario had 147.6 GW of solar and wind additions and 26.9 GW of battery capacity additions by 2039. Figure 4 illustrates the total net capacity by technology type across each scenario. Compared to the Current Trends scenario, the High Large Load Adoption scenario added an additional 198 GW of resources to meet the additional load increase, while the High Load Growth and Environmental Regulations scenario added an additional 270 GW of new resources due to the modeled environmental regulations.

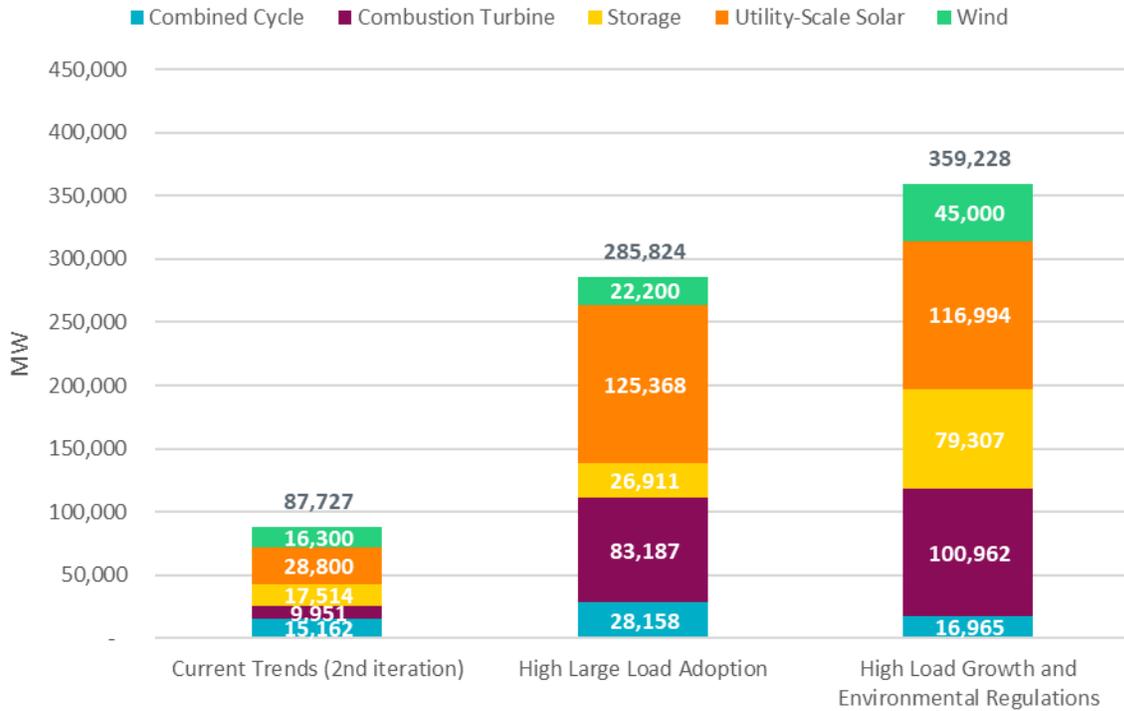


Figure 3: New Capacity Additions Across All Scenarios by 2039

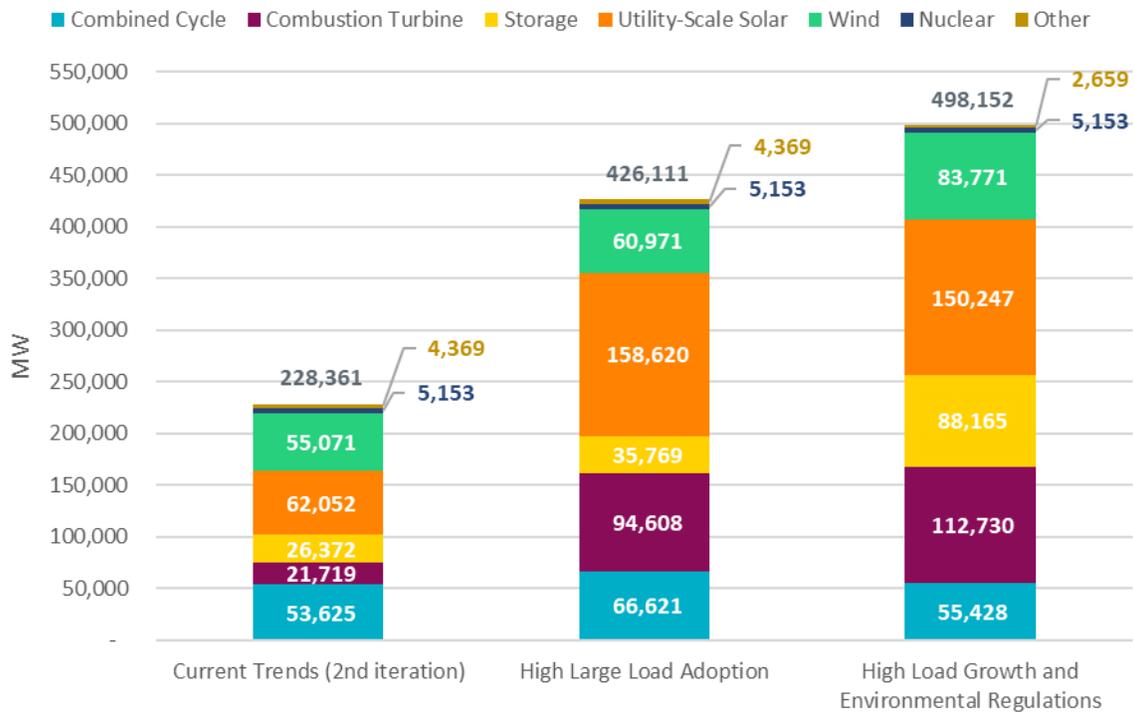


Figure 4: Total Net Capacities Across All Scenarios by 2039

### ***Generation Retirements***

The retirement process for the 2024 LTSA had three 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. Lastly, generation units can potentially retire due to more strict environmental regulations. The generation retirement results were based on the assumptions used in the analysis.

By 2039, the total fixed-age retirements by capacity type, as described above by age, were 10,987 MW of coal and 13,857 MW of natural gas. The list of affected units and dates of retirement are provided in Appendix III. In the High Load and Environmental Regulations scenario, an additional 1,710 MW of coal units retired because of the assumption that all the coal units except Sandy Creek 1 will retire by 2035.

The Current Trends and High Load Growth and Environmental Regulations scenarios showed 105 MW of retirements based on economics criterion, while the High Large Load Adoption scenario had 452 MW of economic retirement.

### ***Changing Resource Mix***

The share of demand served by coal units declined throughout the 15 years in each of the three scenarios due to coal retirements. Retired coal and natural gas generation was replaced by solar, wind, new natural gas generation, and battery energy storage. The share of wind and solar generation increased in all three scenarios, driven by solar and wind capacity additions. The High Large Load Adoption scenario showed the lowest wind generation share in the mix because of the growth in solar and natural gas capacities in this scenario.

Natural gas remained the primary fuel used to serve ERCOT demand in all three scenarios. In the Current Trends and High Load Growth and Environmental Regulations scenarios, the generation from solar and wind provided more than 50% of the generation mix. In the High Large Load Adoption scenario, natural gas and solar units produced close to 77% of the total energy in 2039. Figure 5: shows the percentage of total energy generated by fuel type in 2039 for all scenarios.

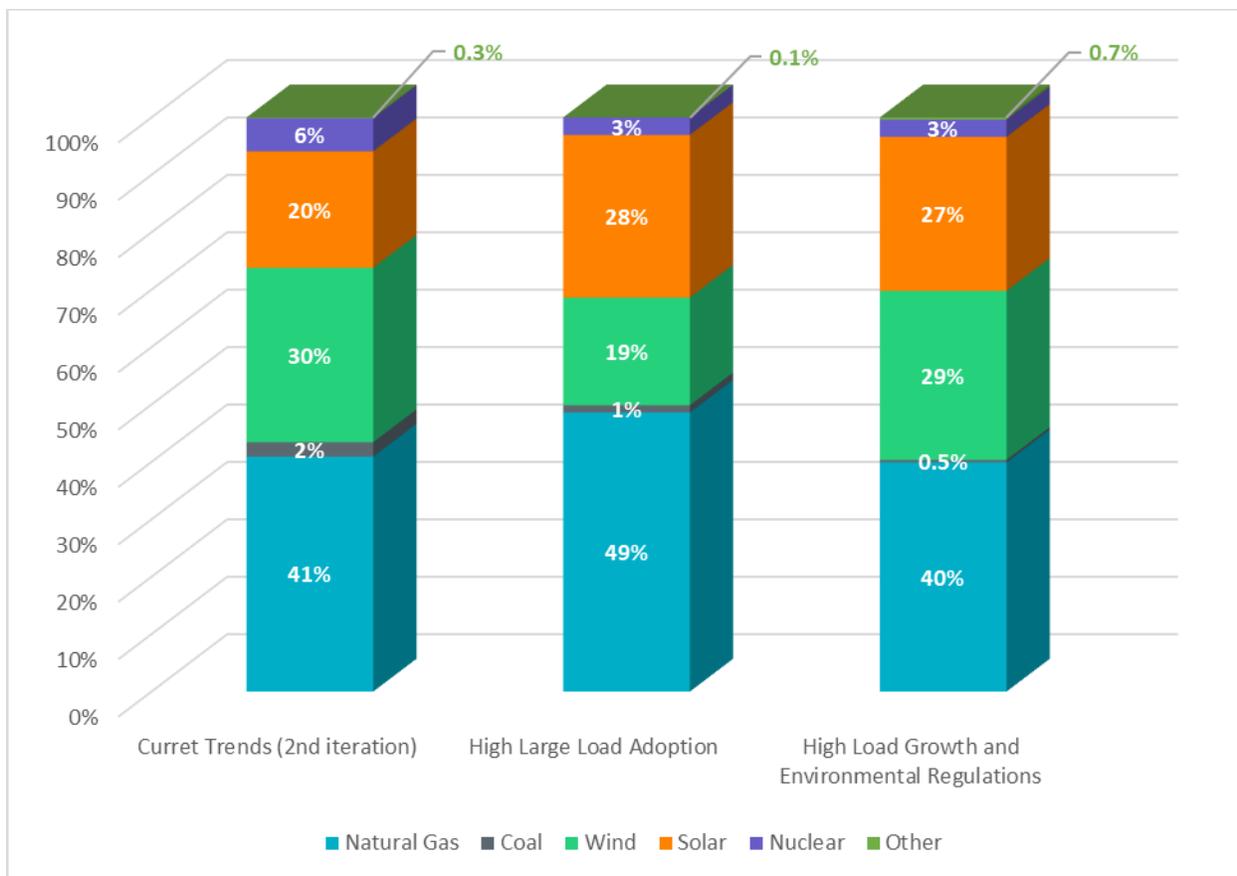


Figure 5: Generation by Fuel Type for 2039

**Key Finding 2: Renewable resources were found to constitute a large portion of available capacity across all scenarios, introducing elevated operational risks due to the increase in intermittency.**

Renewable resources are projected to comprise a large portion of the resource capacity to serve the demand. This resource mix change is expected to introduce elevated operational risks. Notably, scarcity hours in summer will shift to later in the day, similar to previous LTSAs. Additionally, both summer and winter seasons are anticipated to see very high peak net load by 2039.

**Peak Day Load Shape**

One potential challenge identified in the study is the need for additional generation resources to offset reduced solar production in late evening hours during both summer and winter seasons. With significant solar capacity in all scenarios, the decrease in solar output in the evenings, when air conditioning demand remains high, could create extreme ramping challenges, or even insufficient generation to meet demand (especially on days with minimal wind output). Simulation results showed instances of very tight grid conditions that might necessitate firm load shedding to maintain grid reliability. Figure 6 illustrates this risk in the Current Trends scenario on a hot summer day in 2039.

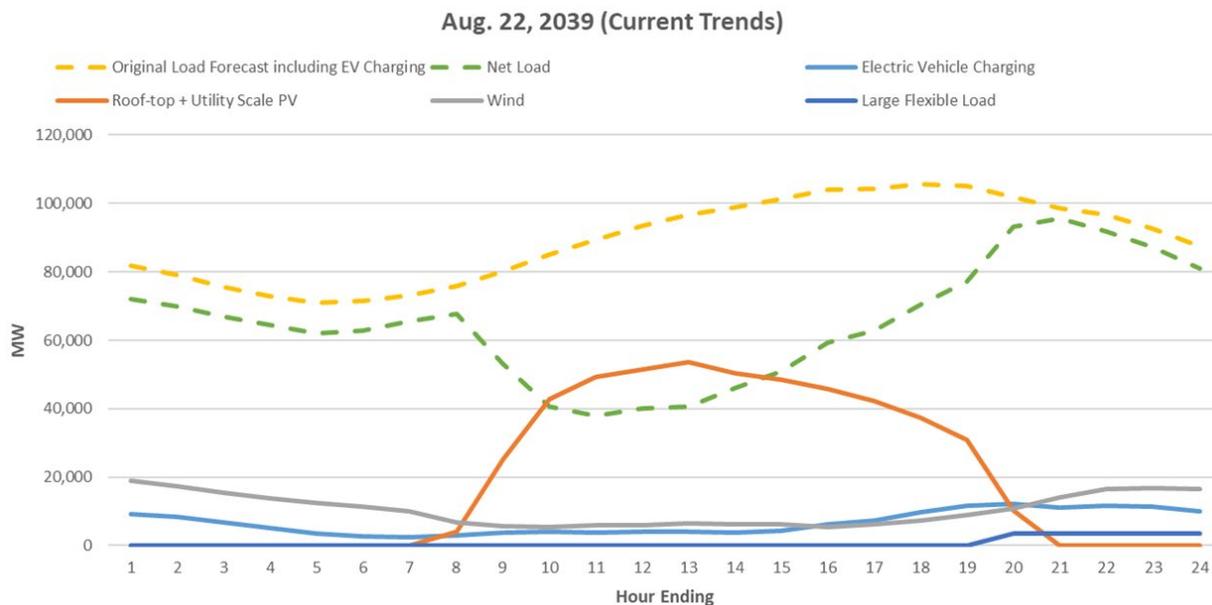


Figure 6: Peak Net Load Challenges on a Hot Summer Day in 2039

Historically, the most stressed system conditions – from both resource scarcity and transmission security standpoints – have occurred during summer afternoons. However, in all three scenarios, stressed system conditions were observed at other times of day and throughout the year. As wind and solar penetration in the ERCOT System increases, transmission planning studies need to consider other possible system conditions beyond traditional summer peak hours, including peak net load conditions.

**Peak Net Load**

Figure 7: compares net load and conventional demand for 2039 across all three scenarios with the actual 2023 load. The net load curve represents the part of ERCOT demand to be met by non-intermittent resources (excluding wind and solar). The peak 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.

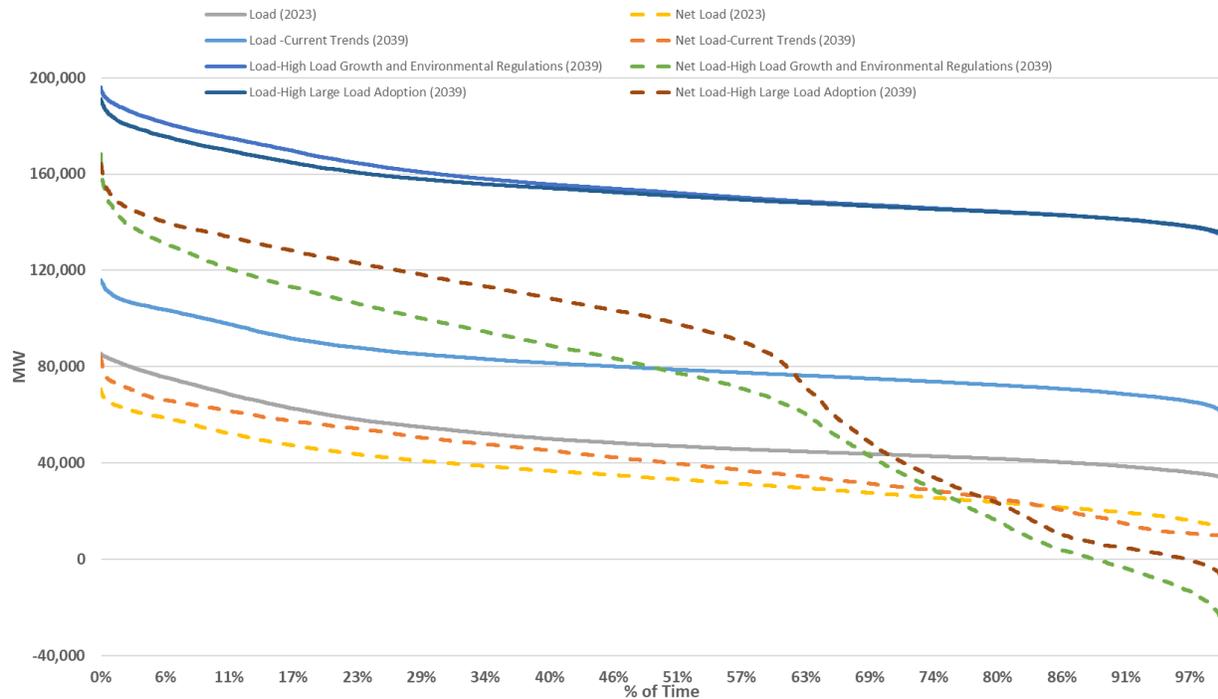


Figure 7: Load vs. Net Load Duration Curve for Current Trends Scenario in 2039

**Minimum Net Load**

Figure 7 also shows that the shape of net load duration curves changes dramatically for the High Large Load Adoption and High Load Growth and Environmental Regulations scenarios when the net load is low or even moving into negative values. When net load is extremely low, dispatchable resources may need to be turned off, creating low system inertia conditions. The sudden drop in the net load for the High Large Load Adoption and High Load Growth and Environmental Regulations scenarios is indicative of the high renewable penetration and their impact on the minimum net load, which warrants further analysis of its broad impacts over the system stability and grid operations.

**Ramping Requirement**

The need for increased flexibility, as well as accurate forecasting for demand, wind, and solar, is further illustrated in Figure 8 and 9, which compares the maximum 1-hour net load ramp rates by hour of the day between historical data from 2023 and all three scenarios for years 2034 and 2039. As more solar generation resources are interconnected to the ERCOT System, 1-hour net load ramping rate can increase dramatically. The highest net load ramp rates were observed in the evening, corresponding to the diurnal patterns of both solar generation and aggregate customer demand. The highest 1-hour ramp rates for the High Load Growth and Environmental Regulations scenario occurred in hour ending of 19 for both 2034 and 2039 with the corresponding values of 73,500 MW/hour and 87,100 MW/hour.

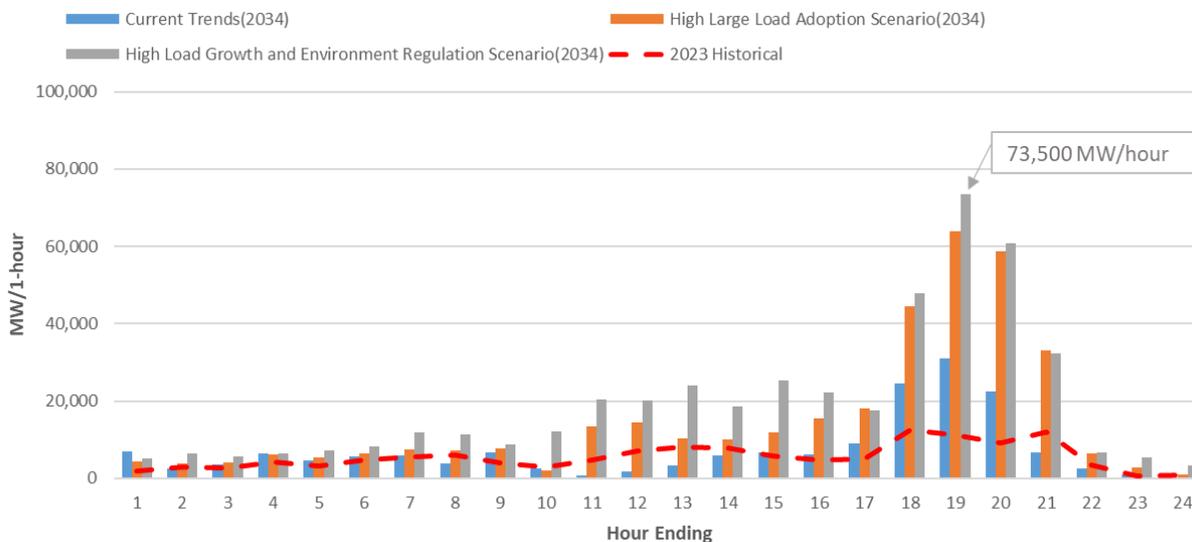


Figure 8: Maximum 1-hour Net Load Ramp Rate Trends for 2034

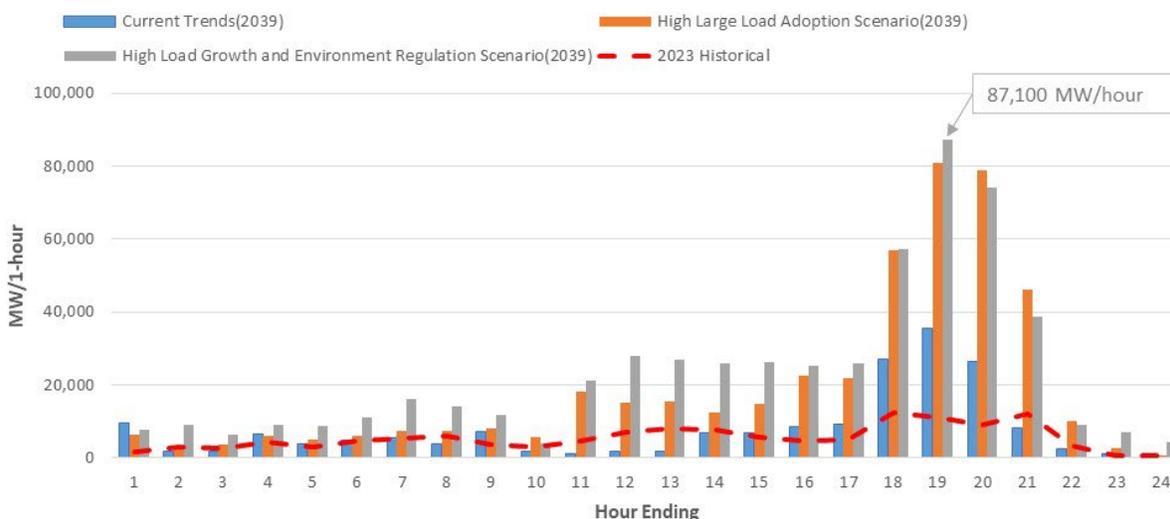


Figure 9: Maximum 1-hour Net Load Ramp Rate Trends for 2039

**Summer and Winter Peak net load**

Figure 10 shows the peak net load by month for 2039. Across all scenarios, winter peak net load surpasses the summer peak net load. Thus, ensuring the summer-weather and winter-weather readiness of the generation resources and transmission equipment is critical to maintain the reliability of a future ERCOT System.

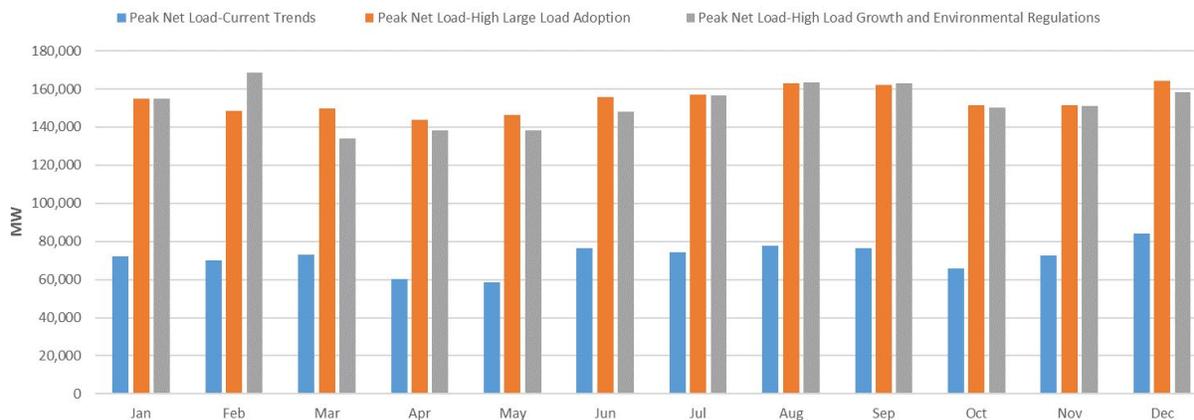


Figure 10: Monthly Peak Net Load for 2039

**Key Finding 3: Battery energy storage and combustion turbines resources were found to be critical in managing increased net load ramping challenges.**

Future net load conditions will be impacted by increased development of battery energy storage. A peak summer day for the Current Trends scenario, which included 26,372 MW installed capacity of battery energy storage, is shown in Figure 11. The figure shows examples of battery energy storage charging during low net load hours and discharging to level out net load peaks when system demand rises.

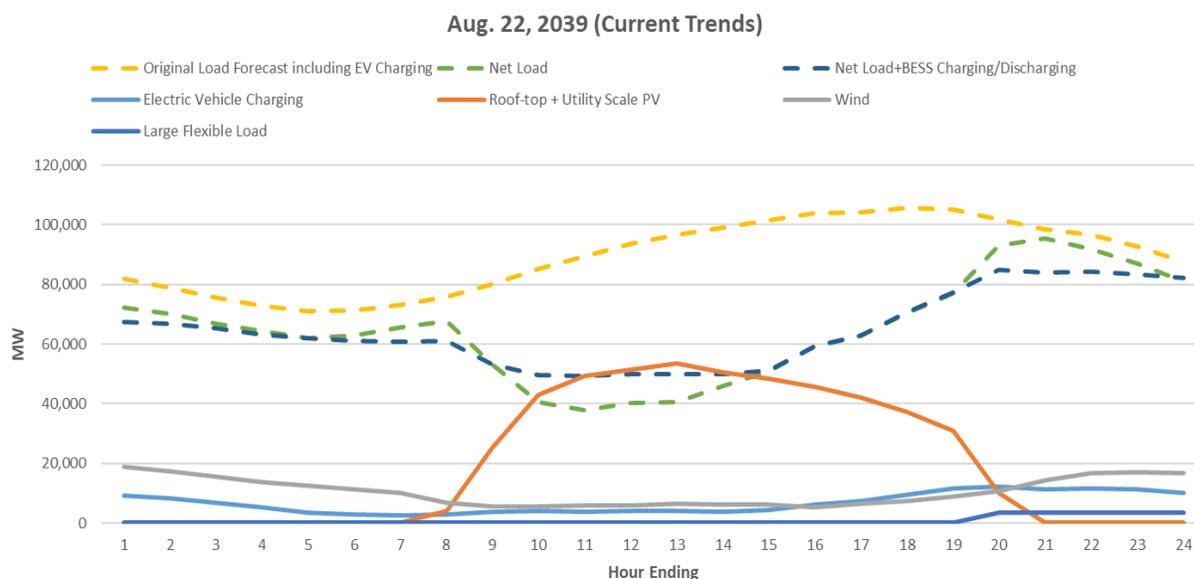


Figure 11: Impact of Battery Energy Storage on Net Load

The operation of the battery energy storage shows that storage resources will be likely to charge when low-cost, surplus renewable generation is available and to discharge during peak net load periods, providing fast response ramping services and firming up generation. Figure 12, 13, and 14 respectively show the daily averaged charging/discharging patterns of the battery energy storage for summer season for all three scenarios for both 2034 and 2039. The numbers in the boxes on each graph

provide the total battery installed capacities for each scenario. The batteries charge during the time when the low-cost surplus of solar energy is available and discharge in the early morning or late afternoon when solar output declines or load rises. The maximum discharge of battery energy storage typically occurs in the late afternoon during peak net load hours.

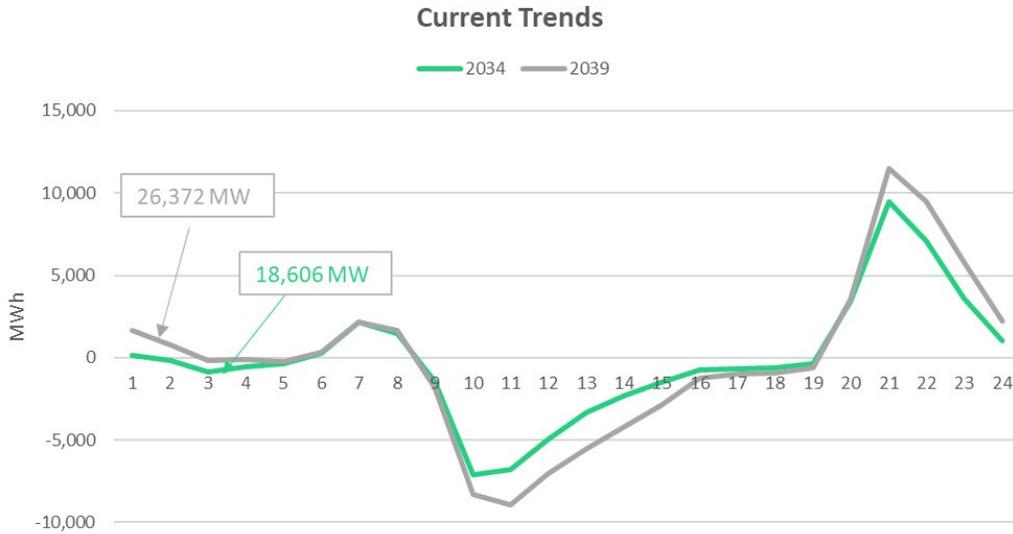


Figure 12: Daily Pattern of Charging and Discharging for Battery Energy Storage in Summer for Current Trends Scenario

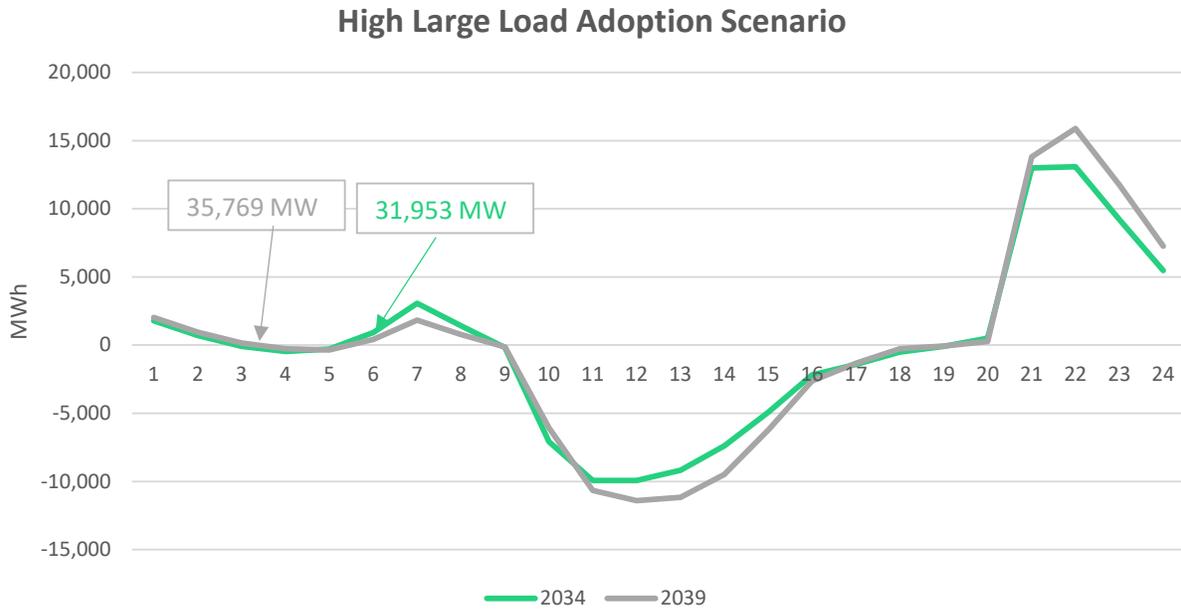


Figure 13: Daily Pattern of Charging and Discharging for Battery Energy Storage in Summer for High Large Load Adoption Scenario

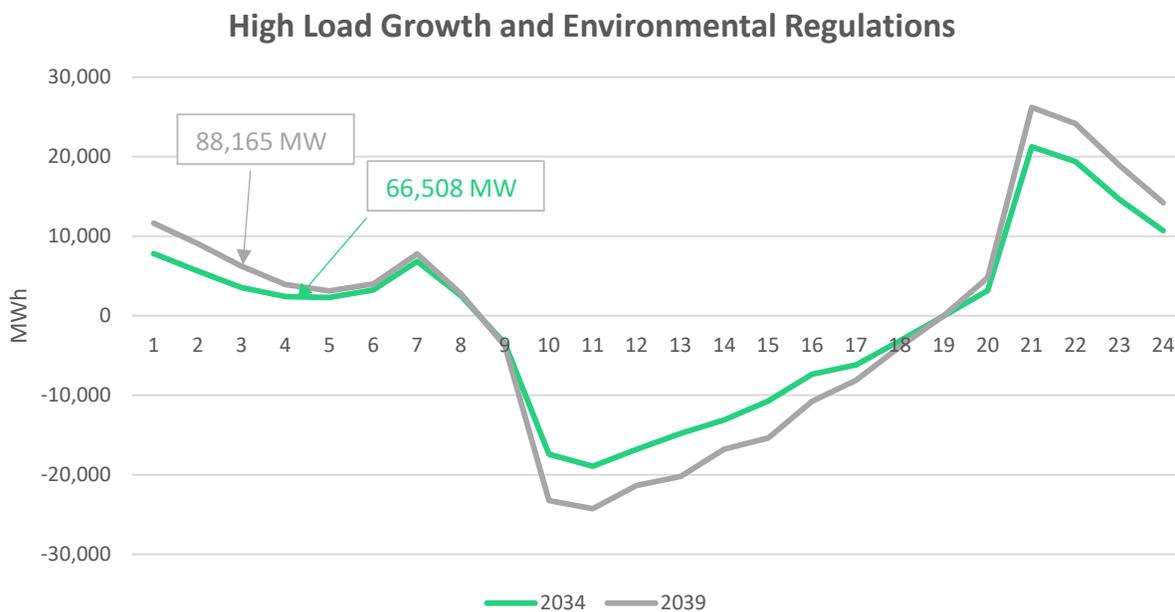


Figure 14: Daily Pattern of Charging and Discharging for Battery Energy Storage in Summer for High Load Growth and Environmental Regulations Scenario

In 2039, daily average battery discharging energy is projected at 40,652 MWh for the Current Trends scenario, 56,324 MWh for the High Large Load Adoption scenario, and 126,189 MWh for the High Load Growth and Environmental Regulations scenario. Figure 15, 16, and 17 respectively show the charging and discharging energy associated with battery energy storage for the three scenarios.

For the High Load Growth and Environmental Regulations scenario, the extreme weather conditions of 2011 weather year and high load modeled in this scenario have a significant impact on the battery energy charging and discharging patterns and can be clearly seen in January and December, as shown in Figure 17. To better illustrate this, Figure 18 shows the charging and discharging of battery energy storage and net load for December of 2039. The high demand combined with very low renewable generation modeled for 2011 weather year causes high net load levels throughout multiple days, for example, December 9<sup>th</sup> to 13<sup>th</sup>, resulting in insufficient energy to charge battery energy storage and low availability of battery energy storage. This presents a challenge when there is a great need for battery energy storage to provide capacity and energy support for an extended period in the winter. Further analysis will be needed to increase the efficiency of the operations of battery energy storage in winter seasons.

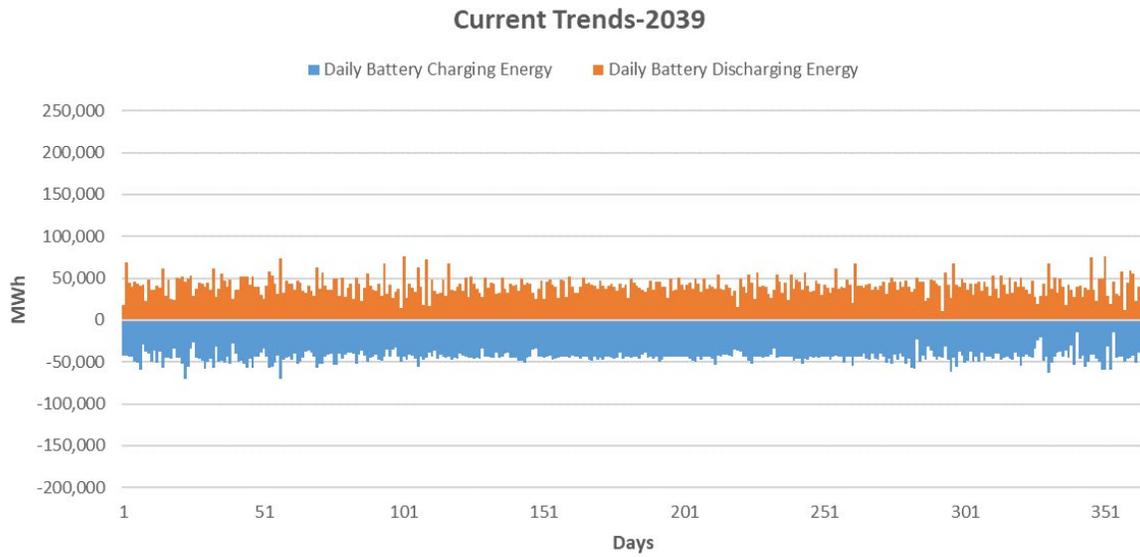


Figure 15: Charging and Discharging of Battery Energy Storage for Current Trends Scenario in 2039

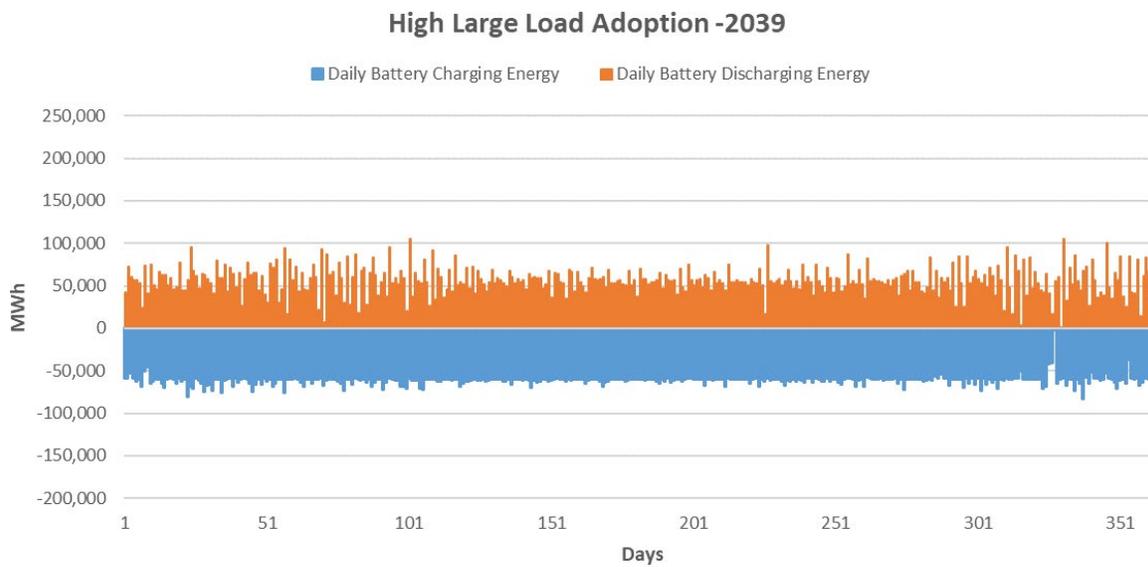


Figure 16: Charging and Discharging of Battery Energy Storage for High Large Load Adoption Scenario in 2039

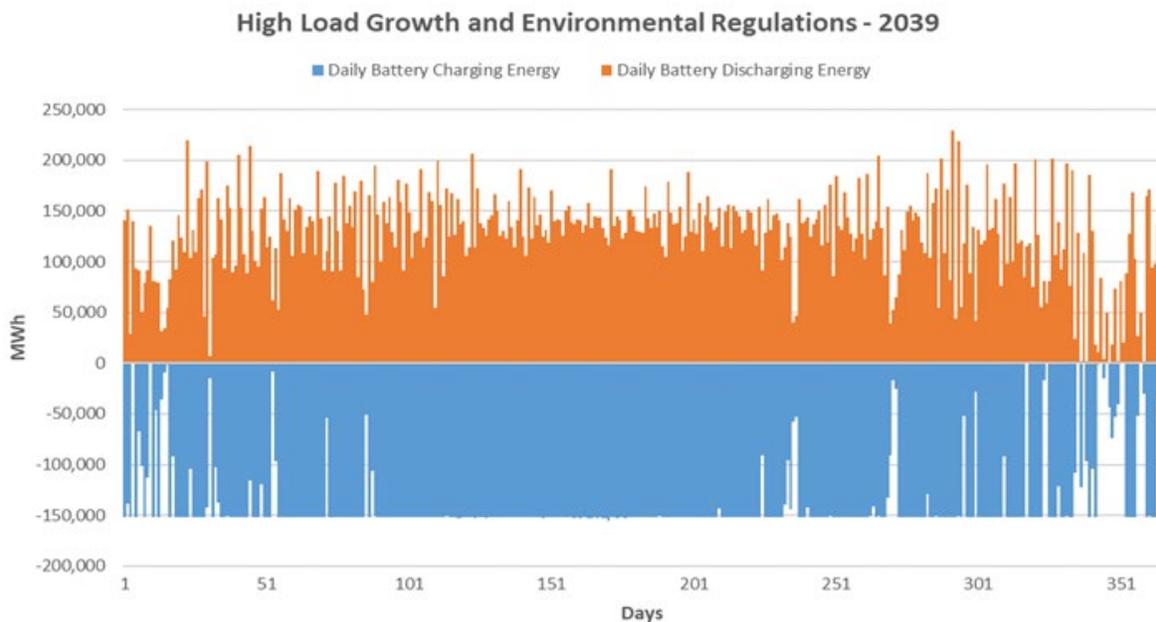


Figure 17: Charging and Discharging of Battery Energy Storage for High Load Growth and Environmental Regulations Scenario in 2039

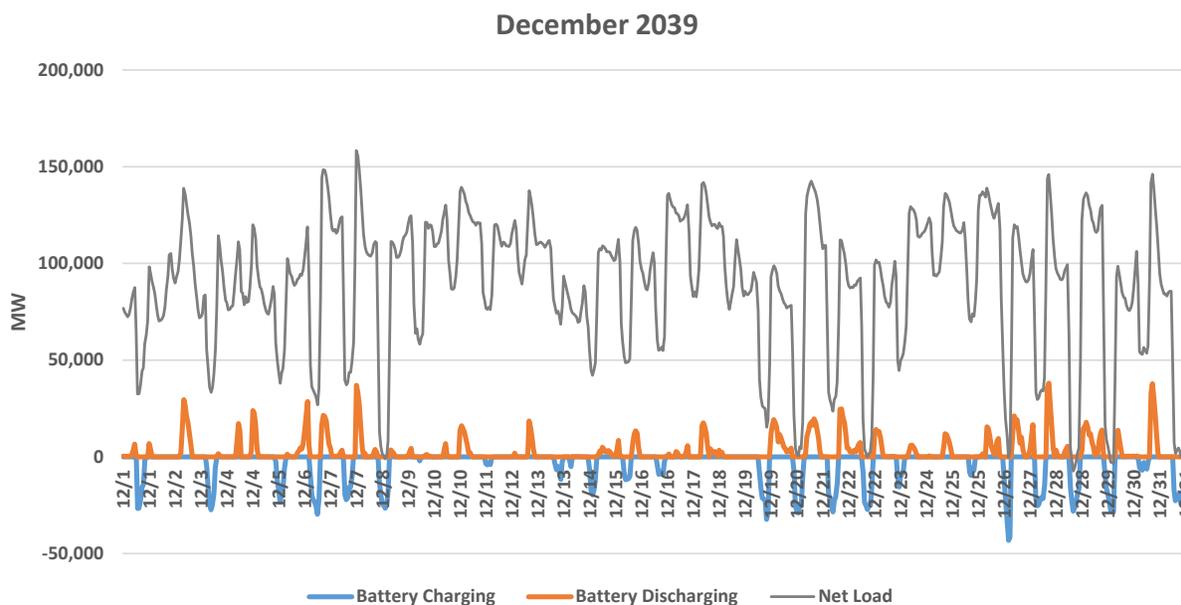


Figure 18: Charging and Discharging of Battery Energy Storage and Net Load for High Load Growth and Environmental Regulations Scenario for December 2039

Traditionally, combustion turbines were only running for a small fraction of time. However, for High Large Load Adoption and High Load Growth and Environmental Regulations scenarios, combustion turbines were required to be online more frequently, especially during nighttime hours, to compensate for the rapid changes of net load, as shown in Figure 19. If the environmental regulations were in

effect, the new combustion turbines were limited to only 20% annual capacity factor so they were running less frequently, as shown in Figure 20.

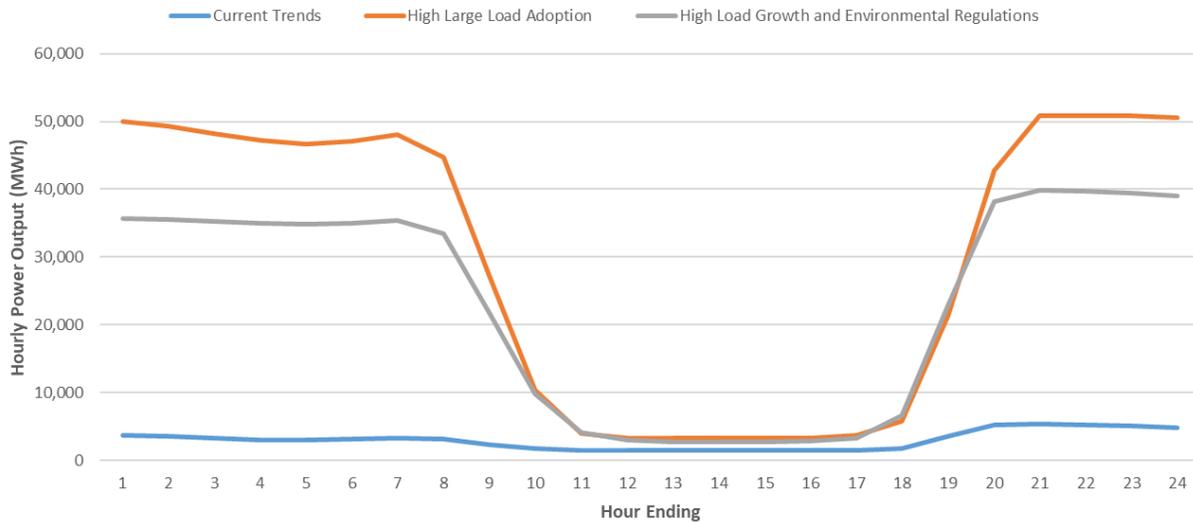


Figure 19: Daily Operational Pattern of Combustion Turbines in 2039

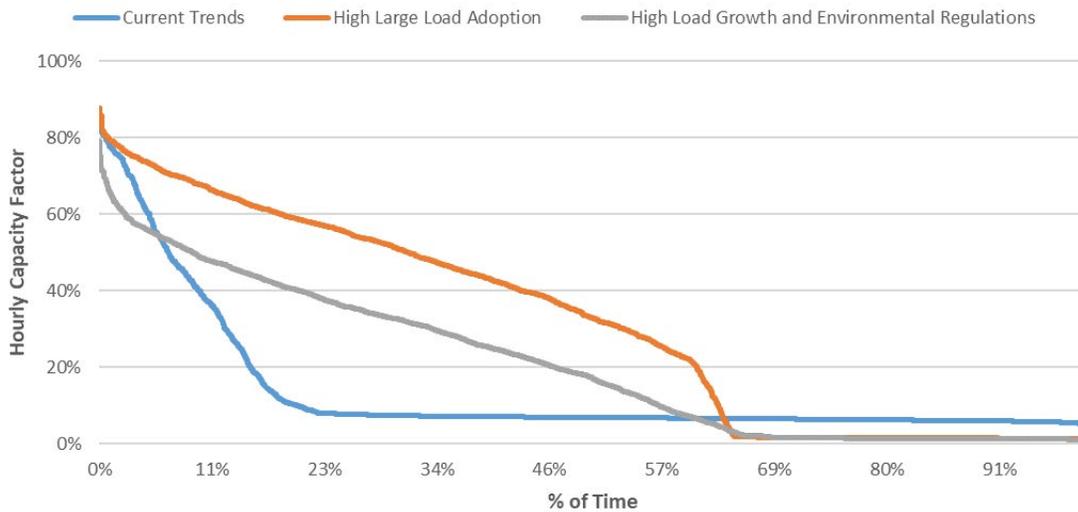


Figure 20: Combustion Turbine Capacity Factor Duration Curve in 2039

**Key Finding 4: The scale and geographic distribution of wind and solar generation additions depend on sufficient transmission capacity between resource-rich regions and demand centers.**

**Resource Shift**

A geographic comparison of wind and solar capacity additions for the Current Trends scenario iterations 1 and 2 is shown in Figure 21. 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 and Panhandle interface limits which were binding constraints during many hours.

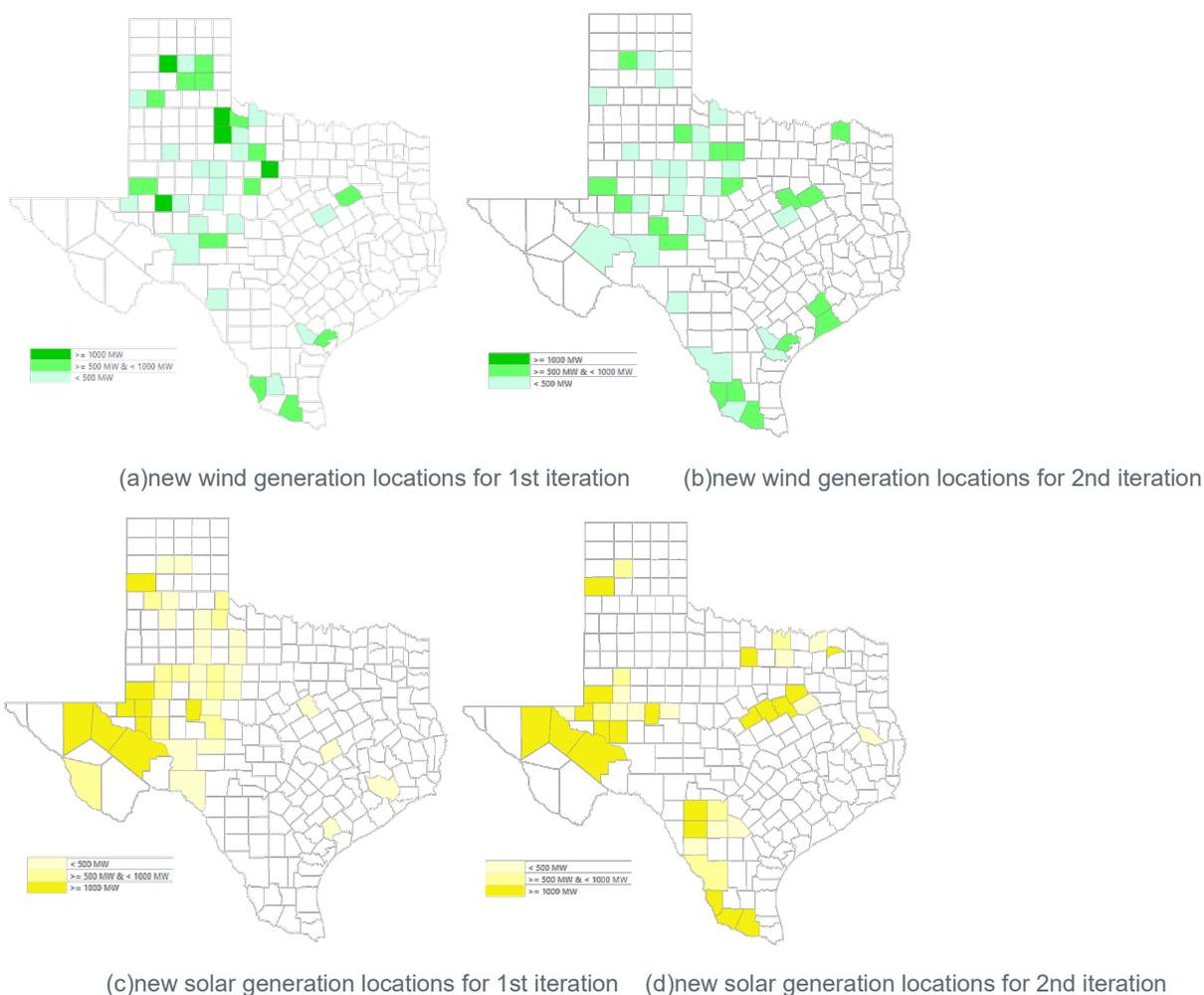


Figure 21: Impact of Transmission Constraints on Wind and Solar Locations for Current Trends Scenario

Capacity expansion and retirement analysis for the first iteration of the Current Trends 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 moved a large portion of new solar capacity outside of the Panhandle region. This is

because 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 second iteration of the Current Trends scenario. 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 the annual capacity factors of different technologies for the Current Trends, High Load Growth and Environmental Regulations, and High Large Load Adoption scenarios is provided in Table 2.<sup>5</sup> Scenarios that included transmission limitations 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.

Table 2: Annual Capacity Factor Comparison for 2039

	Capacity Factor comparison - 2039			
	Curret Trends (1st iteration)	Curret Trends (2nd iteration)	High Load Growth and Environmental Regulations	High Large Load Adoption
Battery	7%	7%	6%	7%
Coal	77%	77%	77%	74%
Combined Cycle	60%	59%	73%	69%
Simple Cycle Turbine & Gas Steam	18%	14%	21%	32%
Solar	27%	27%	28%	27%
Wind	47%	45%	55%	47%

### Key Finding 5: Transmission challenges were identified for both the export from the renewable resource-rich region and the import into the demand centers.

ERCOT identified the need for additional transmission paths to relieve the heavy congestions for both the export from the renewable resource-rich region and the import into the demand centers. In total, the congestion rent for 2034 and 2039 is \$2.2 billion and \$3.3 billion, respectively, with the West Texas Export interface experiencing the most severe congestion. The increase in the west-to-east power flows on the transmission network is attributed to a combination of high amounts of renewable generation additions in the west and generation retirement in the east. To effectively alleviate those congestions from the renewable resource-rich regions to the demand centers, holistic solutions are needed. ERCOT will continue to evaluate the future transmission needs in future LTSA studies to accommodate large-scale renewable generation additions and large load growth which are projected to continue at a fast pace at ERCOT. Table 3 and Figure 22 show the top constraints observed for the second iteration of Current Trends scenario.

<sup>5</sup> Capacity expansion results were not derived from models that utilize the full transmission topology.

The West Texas Export interface experienced extremely high congestion, with a congestion rent of \$556 million and \$821 million for 2034 and 2039, respectively. This was mainly driven by the increased capacity of renewable resources in West and Far West Texas. The Panhandle interface limit also had a profound impact over the congestion cost as more renewable resources were expected to commission in the Panhandle region in the future years. Over \$140 million of congestion rent was observed over the Panhandle interface for both 2034 and 2039. To effectively alleviate congestion on the West Texas Export interface and/or Panhandle interface, the long-distance high voltage or direct current (DC) transmission lines are more favorable. However, these options are also expensive. Those options will be continuously analyzed in the future RTP and LTSA studies.

Table 3: Top 10 Constraints for Current Trends Scenario (2nd iteration)

<i>Index</i>	<i>Constraint</i>	<i>Congestion Rent in 2034 (\$M)</i>	<i>Congestion Rent in 2039 (\$M)</i>
1	West Texas Export Interface	556	821
2	Farmland - Wett Long Draw 345-kV Line	134	233
3	Meadow - PH Robinson 345-kV Line	162	155
4	Bell County East Switch - Sandow Switch 345-kV Line	121	153
5	South Texas Project - Jones Creek 345-kV Line	55	143
6	Panhandle Interface	142	140
7	Refuge - Jones Creek 345-kV Line	49	112
8	North - Houston Interface	60	108
9	Kendall - Welfare 138-kV Line	15	81
10	MacKenzie Substation - Northeast Substation 115 kV Line	55	79

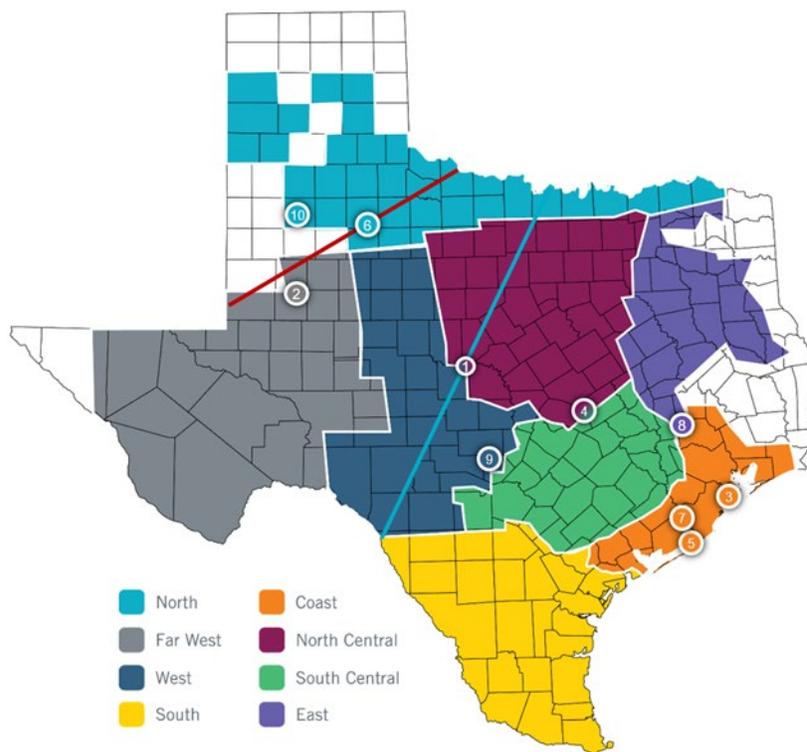


Figure 22: Top Constraints for Current Trends Scenario (2<sup>nd</sup> iteration)

The addition of the renewable generation in the North Central and South Weather Zones and the load growth in Houston area leads to the heavy congestions in the Coast Weather Zone and over the North to Houston interface. The congestion over Meadow to PH Robinson 345-kV line incurred a congestion rent of over \$150 million in 2034 and 2039, while South Texas Project to Jones Creek 345-kV line and Refuge to Jones Creek 345-kV line were more severely congested in 2039. The congestion rent for North to Houston interface reached \$108 million in 2039. Additionally, the load growth in Central Texas contributes to significant congestion rent over the Bell County East Switch to Sandow Switch 345-kV line and the Kendall to Welfare 138 kV line. The aggregated congestion rent for these two constraints was \$136 million and \$234 million in 2034 and 2039, respectively. This indicated the need of improved import path to accommodate the load growth in the Central Texas area.

A list of transmission improvements for the Current Trends scenario are available in Table 4 and Figure 23. Figure 23 shows the potential new EHV transmission identified by the transmission expansion analysis conducted for the Current Trends scenario (2<sup>nd</sup> iteration). Full project descriptions for the Current Trends scenario are available in Appendix IV. The economic savings of the proposed transmission improvements were evaluated using both the production cost saving test and the generator revenue reduction test. Table 5 lists the break-even capital cost and the expected in-service date for those projects which pass either the production cost saving test or the generator revenue reduction test based on the generic cost estimate. 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.

Table 4: Transmission Improvement for Current Trends (2<sup>nd</sup> iteration)

Index	Project Name	Break-even Capital Cost (\$M)	Expected In-Service Date
1	Farmland – Long Draw and Fiddlewood Switch – Farmland 345-kV line upgrades	277	2034
2	STP – Bailey and Bailey – PH Robinson 345-kV line additions	584	2034
3	Hill Country – Kendall 345-kV line addition	289	2034
4	Bell County East Switch – Sandow Switch double-circuit 345-kV line and Temple Switch – Tin Roof Pod 138-kV line upgrades	776	2034

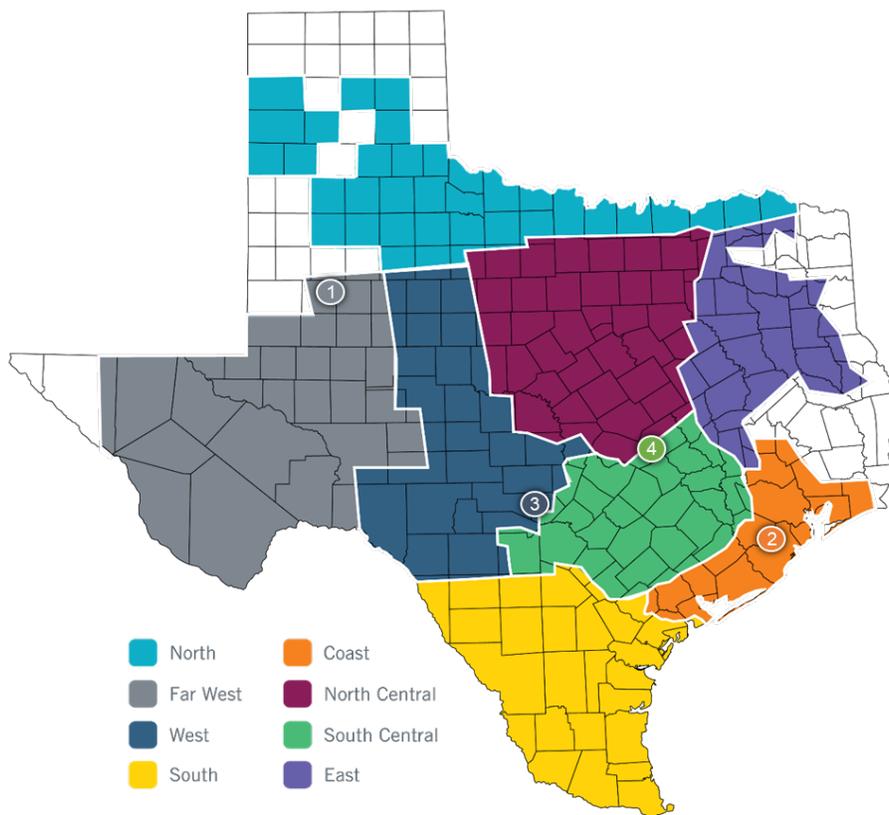


Figure 23: Transmission Improvements for Current Trends (2<sup>nd</sup> iteration)

## Appendices

### Appendix I: LTSA Process

#### LTSA Scenario Development

The 2024 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 5 below.

Table 5: Key Drivers Considered in 2024 LTSA

Drivers	Brief description
<b>Economic Conditions</b>	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.
<b>Gas and Oil Prices</b>	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.
<b>Capital Costs for Renewable Energy</b>	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.
<b>Environmental Regulations</b>	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.
<b>Large Load Growth</b>	Continued interests in connecting large load to the system, and further electrification of oil and gas processes in the Permian Basin.
<b>Weather Conditions</b>	May affect demand growth, environmental regulations and policies, technology mix, average summer temperatures, and the frequency of extreme weather events.

ERCOT presented initial input assumptions and preliminary results for the 2024 LTSA at the May 2023 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 24 and Figure 25 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 dots represent the average ranking and the ends of the line segments represent the minimum and maximum ranks for each item.

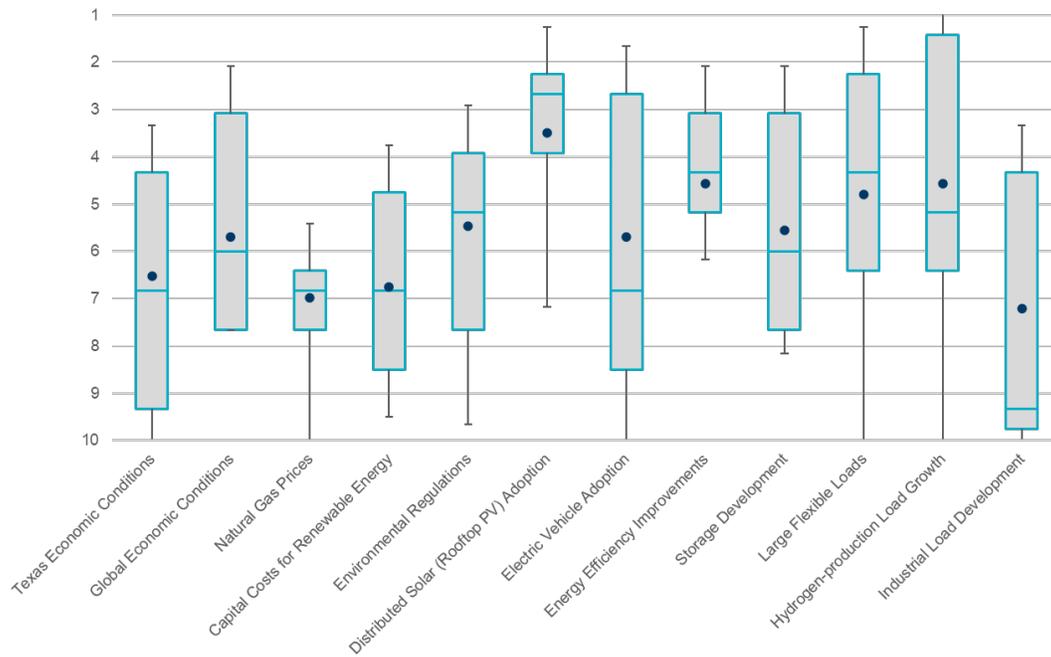


Figure 24: Key Driver Rankings from 2024 LTSA Stakeholder Survey<sup>6</sup>

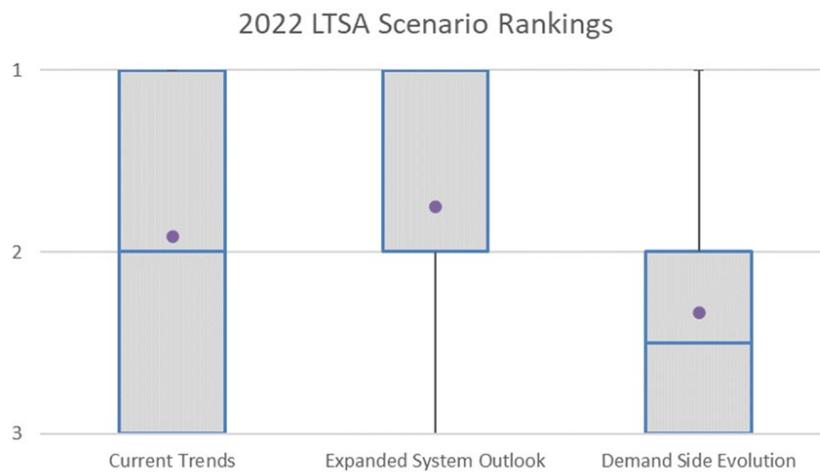


Figure 25: Ranking of Potential Scenario Concepts from 2024 LTSA Stakeholder Survey<sup>7</sup>

<sup>6</sup> 1 being the highest impact and 10 being the lowest impact.

<sup>7</sup> 1 being the highest rank and 3 being the lowest rank.

ERCOT considered stakeholder feedback received from the online survey. The scenario proposal and draft assumptions for proposed scenarios were presented to stakeholders at the September 2023, June 2024, and August 2024 RPG meetings. Further stakeholder feedback received following that scenario proposal led to the final development of the scenarios considered for the 2024 LTSA.

Table 6 summarizes the unique elements of each scenario.

*Table 6: Scenarios Studied in the 2024 LTSA*

Scenario	Description
<b>Current Trends</b>	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.). Similar to the 2020 LTSA, an iterative process was adopted to co-optimize capacity expansion and transmission expansion. The Current Trends scenario did not incorporate the additional large loads included in the 2024 RTP from the implementation of HB5066 because the reliability projects (345-kV plan or 765-kV plan) needed to reliably supply such a significant amount of large load additions were not available at the time the 2024 LTSA was performed. The peak load for the Current Trends scenario in 2039 is 115,734 MW.
<b>High Large Load Adoption</b>	The High Large Load Adoption scenario was developed to study the impacts of the significant large load adoptions as provided by the TSPs in the ERCOT region. The peak load for the High Large Load Adoption scenario in 2039 is 191,100 MW.
<b>High Load Growth and Environmental Regulations</b>	High Load Growth and Environmental Regulations scenario assumed the high load growth with the 2011 weather condition and the addition of significant amount of large loads as provided by the TSPs in the ERCOT region, and the environment regulations impacting the development of dispatchable resources in the ERCOT System. The peak load for the High Load Growth and Environmental Regulations scenario in 2039 is 195,976 MW.

The final input assumptions used in creating 2024 LTSA study are documented in Table 7.

Table 7: 2024 LTSA Input Assumptions

2039		Current Trends	High Load Growth and Environment Regulation	High Large Load Adoption
Gross Load	Weather Condition	2013 weather condition (96,959 MW Peak Demand/563,841 GWh Annual Energy)	2011 weather condition (99,900 MW Peak Demand/581,012 GWh Annual Energy)	2013 weather condition (96,959 MW Peak Demand/563,841 GWh Annual Energy)
	Adjusted for IHS Load in Far West	None	Applied	Applied
	Gross Peak Demand/Annual Energy After IHS Load Adjustment	96,959 MW/563,841 GWh	104,106 MW/615,329 GWh	100,792 MW/595,639 GWh
Roof-top PV/EV/LFL/Flat Load	Roof-top PV	6,011 MW	6,011 MW	6,011 MW
	EV (LDV) Annual Energy	21,228 GWh	26,012 GWh	26,012 GWh
	EV (MHDV) Annual Energy	24,844 GWh	32,387 GWh	32,387 GWh
	Price-responsive Load (LFL)	4,479 MW <sup>8</sup> +2,881 MW <sup>9</sup>	4,479 MW <sup>1</sup> + 4,050 MW <sup>10</sup>	4,479 MW <sup>1</sup> + 4,050 MW
	Additional Flat Load from TSPs Load Projection	0 MW	66,223 MW	66,223 MW
Peak Demand/Annual Energy <sup>7</sup>		115,734 MW/711,078 GWh	195,976 MW/1,363,494 GWh	191,100 MW/1,346,200 GWh
Environment Rules	Carbon Price	0\$/ton	0\$/ton	0\$/ton
	Impact of Environmental Protection Agency (EPA) Rules for Gas Units	None	1) CCS <sup>11</sup> needed for new CCs 2) existing CCs (>300 MW/unit) capacity factor < 50% <sup>12</sup> 3) new CTs capacity factor < 20%	None
	Coal Retirement	10,228 MW coal retirement by 2032 and 10,987 MW by 2038 <sup>13</sup>	12,697 MW coal retirement before 2035	10,228 MW coal retirement by 2032 and 10,987 MW by 2038

<sup>8</sup> In operation as of Feb. 2024.

<sup>9</sup> Estimated new LFL.

<sup>10</sup> From TSP load projection.

<sup>11</sup> Carbon capture and storage (CCS).

<sup>12</sup> Only two existing CCs impacted.

<sup>13</sup> 951 MW of retirement due to economics.

### ***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.

Three different forecasts were created for the years between 2025 and 2039 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<sup>14</sup>.

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 26.

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<sup>14</sup> <http://www.ercot.com/gridinfo/load/forecast>.

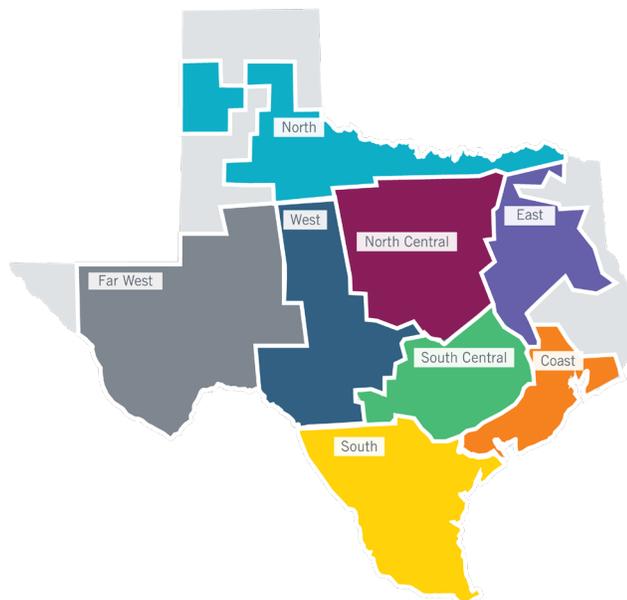


Figure 26: ERCOT Weather Zones

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 2008 through 2022.

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<sup>15</sup>, 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.
- 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 2024 LTSA capacity expansion and retirement and transmission economic analyses used an 8760-hour demand forecast. The base demand forecast for the Current Trends and the High Large

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<sup>15</sup> Used in Coast, East, North Central, South, and South Central Weather Zones.

Load Adoption scenarios was based on the 2013 weather year and then adjusted before included into 2024 LTSA scenarios. The base demand forecast for the High Load Growth and Environmental Regulations scenario was based on the 2011 weather year.

The Current Trends scenario did not incorporate the additional large loads included in the 2024 RTP from the implementation of HB5066 because the reliability projects (345-kV plan or 765-kV plan) that would be needed to reliably supply such a significant amount of large load additions were not available at the time the 2024 LTSA was performed. To assess and evaluate impacts of high large load growth in ERCOT region, ERCOT obtained a list of the loads seeking interconnections from the TSPs that have not signed an interconnection agreement but are likely to be connected in the next 10 to 15 years. TSPs projected a total of 70,273 MW additional load<sup>16</sup> in the next 10 to 15 years, which has not been included in Current Trends scenario. This additional load demand was then added to the base demand forecast for the High Large Load Adoption and High Load Growth and Environmental Regulations scenarios.

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. 6,011 MW of distributed solar was considered in the Current Trends, High Large Load Adoption, and High Load Growth and Environmental Regulations scenarios.

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.

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<sup>16</sup> Price Responsive Load: 4,050 MW, Flat Load: 66,223 MW.

### 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 27.

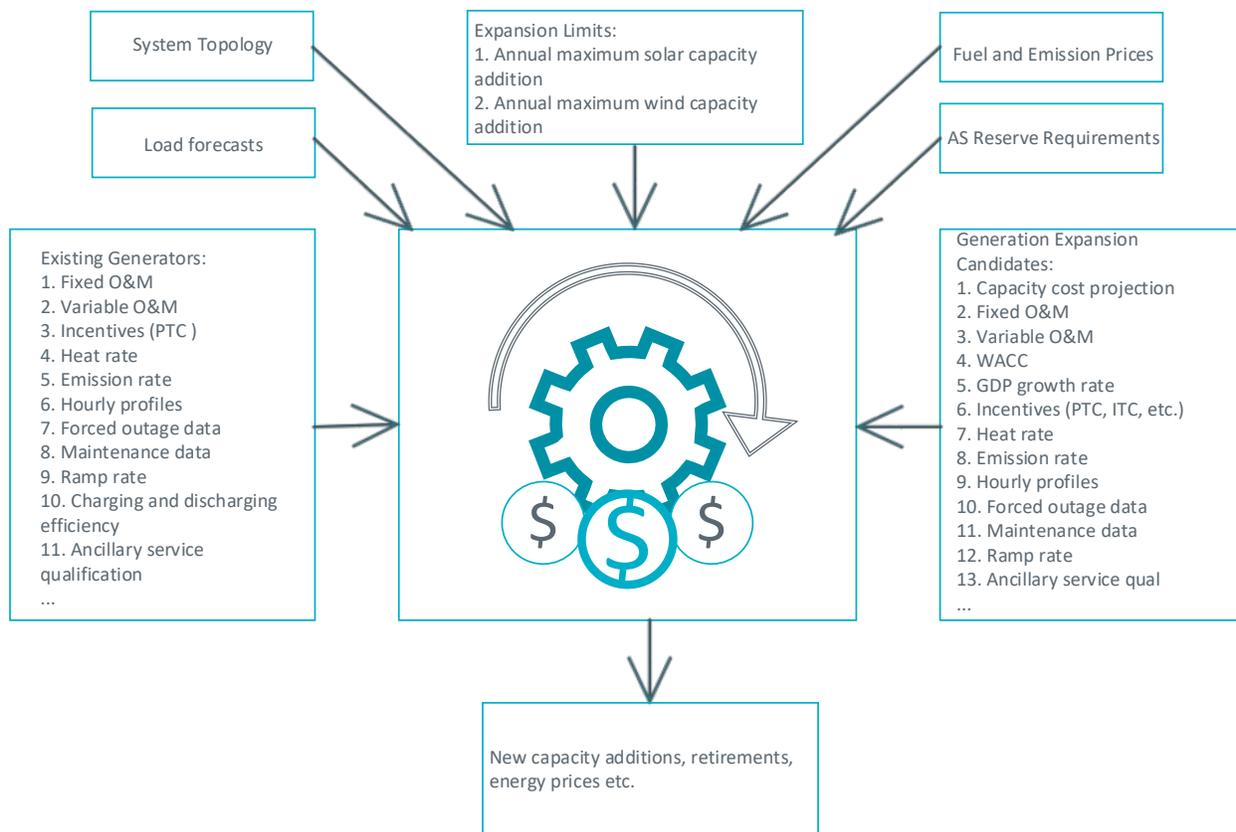


Figure 27: Long-Term Capacity Expansion and Retirement Concept

Trends in capital costs for new expansion technologies generally increased at an assumed GDP growth rate in this analysis except for the 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 U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2023 Reference Case.

The technologies included for capacity expansion in this LTSA were current and advanced gas-fired combined cycles and combustion turbines, combined cycles with carbon capture and storage (CCS), solar, wind and Li-ion battery energy storage. The solar technology evaluated in the capacity expansion process was utility-scale solar single-axis tracking. In the High Large Load Adoption and High Load Growth and Environmental Scenarios, small modular reactors were considered in the capacity expansion analysis. However, since they were found uneconomical under current market

conditions and without subsidies, none was added. In 2023, PUCT created the Texas Advanced Nuclear Reactor Working Group (TANRWG) to evaluate advanced nuclear reactors to determine whether if they can provide safe, reliable, and affordable power to the grid. The TANRWG report was released in November 2024, which “highlights key recommendation, opportunities, and strategies to position Texas as No.1 in the advanced nuclear industry”.<sup>17</sup> .

Additionally, the extension<sup>18</sup> of the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) by the Inflation Reduction Act was included in all three scenarios for renewable generation and battery energy storage.

In 2023, ERCOT procured hourly wind generation patterns based on actual weather data for the previous 43 years (1980-2022). These wind patterns include hourly wind output patterns for 138 hypothetical future wind generation units and were developed using power generation curves consistent with the most recent wind turbine technologies. The 138 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 2023, ERCOT also procured new hourly solar generation patterns based on actual weather data for the previous 43 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 (2020-2022) 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.

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<sup>17</sup> [https://gov.texas.gov/uploads/files/press/TANRWG\\_Advanced\\_Nuclear\\_Report\\_v11.17.24c\\_.pdf](https://gov.texas.gov/uploads/files/press/TANRWG_Advanced_Nuclear_Report_v11.17.24c_.pdf)

<sup>18</sup> <https://www.congress.gov/117/bills/hr5376/BILLS-117hr5376enr.pdf>.

### ***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 scenario in the 2024 LTSA study. 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 2028 from the 2023 RTP economic analysis as a starting point for the Current Trends scenario. 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.

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.

ERCOT analyzed each of the scenario-appropriate base cases created for 2034 and 2039 to determine the potential transmission needs of the system. ERCOT studied NERC TPL-001-5.1 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: Resource Fixed-Age Retirements

Table 9 summarizes the retirement of those resources determined by comparing the age of an existing unit and the fixed-age retirement requirement. 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. Total fixed-age retirements by 2039 were 24,844 MW, 10,987 MW were coal and 13,857 MW were natural gas resources. The list of affected units and dates of retirement are provided in Table 8.

Table 8: Resource Fixed-Age Retirements <sup>19</sup>

Unit Name	CDR Unit ID	Unit Type	Capacity MW	In Service Year	Retirement Year
MOUNTAIN CREEK 6	MCSES_UNIT6	Gas	122	1956	2016
SPENCER 4	SPNCER_SPNCE_4	Gas	57	1966	2018
SPENCER 5	SPNCER_SPNCE_5	Gas	61	1973	2018
MOUNTAIN CREEK 7	MCSES_UNIT7	Gas	118	1958	2018
STRYKER CREEK 1	SCSES_UNIT1A	Gas	167	1958	2018
W A PARISH 1	WAP_WAP_G1	Gas	169	1958	2018
W A PARISH 2	WAP_WAP_G2	Gas	169	1958	2018
GRAHAM 1	GRSES_UNIT1	Gas	239	1960	2020
W A PARISH 3	WAP_WAP_G3	Gas	258	1961	2021
RAY OLINGER 1	OLINGR_OLING_1	Gas	78	1967	2022
SILAS RAY STG 6	SILASRAY_SILAS_6	Gas	70	1962	2022
MARTIN LAKE 1	MLSES_UNIT1	Coal	815	1977	2022
W A PARISH 5	WAP_WAP_G5	Coal	664	1977	2022
R Massengale	21INR0202	Gas	74	2021	2023
Brandon	BRANDON_UNIT1	Gas	20	2021	2023
TY COOKE (LP&L)	TY_COOKE_GT2	Gas	31	2021	2023
MARTIN LAKE 2	MLSES_UNIT2	Coal	820	1978	2023
W A PARISH 6	WAP_WAP_G6	Coal	663	1978	2023
HANDLEY 3	HLSES_UNIT3	Gas	375	1963	2023
FAYETTE POWER PROJECT 1	FPFYD1_FPP_G1	Coal	603	1979	2024
MARTIN LAKE 3	MLSES_UNIT3	Coal	820	1979	2024
V H BRAUNIG 1	BRAUNIG_VHB1	Gas	217	1966	2025
V H BRAUNIG 2	BRAUNIG_VHB2	Gas	230	1968	2025
V H BRAUNIG 3	BRAUNIG_VHB3	Gas	412	1970	2025
COLETO CREEK	COLETO_COLETOG1	Coal	655	1980	2025
FAYETTE POWER PROJECT 2	FPFYD1_FPP_G2	Coal	605	1980	2025
W A PARISH 7	WAP_WAP_G7	Coal	577	1980	2025
SIM GIDEON 1	GIDEON_GIDEONG1	Gas	130	1965	2025
STRYKER CREEK 2	SCSES_UNIT2	Gas	502	1965	2025
TRINIDAD 6	TRSES_UNIT6	Gas	235	1965	2025
POWERLANE PLANT 1	STEAM1a_STEAM_1	Gas	18	1966	2026
O W SOMMERS 1	CALAVERS_OWS1	Gas	420	1972	2027
J K SPRUCE 2	CALAVERS_JKS2	Coal	785	2010	2027
SAN MIGUEL 1	SANMIGL_G1	Coal	391	1982	2027
W A PARISH 8	WAP_WAP_G8	Coal	610	1982	2027
T H WHARTON G1	THW_THWGT_1	Gas	16	1967	2027
W A PARISH T1	WAP_WAPGT_1	Gas	13	1967	2027
MOUNTAIN CREEK 8	MCSES_UNIT8	Gas	568	1967	2027
POWERLANE PLANT 2	STEAM_STEAM_2	Gas	22	1967	2027
J K SPRUCE 1	CALAVERS_JKS1	Coal	560	1992	2028
R W MILLER 1	MIL_MILLERG1	Gas	75	1968	2028
SIM GIDEON 2	GIDEON_GIDEONG2	Gas	135	1968	2028
W A PARISH 4	WAP_WAP_G4	Gas	552	1968	2028
O W SOMMERS 2	CALAVERS_OWS2	Gas	410	1974	2029
GRAHAM 2	GRSES_UNIT2	Gas	390	1969	2029
LIMESTONE 1	LEG_LEG_G1	Coal	824	1985	2030
CEDAR BAYOU 1	CBY_CBY_G1	Gas	745	1970	2030
LAKE HUBBARD 1	LHSES_UNIT1	Gas	392	1970	2030
LIMESTONE 2	LEG_LEG_G2	Coal	836	1986	2031
RAY OLINGER 2	OLINGR_OLING_2	Gas	107	1971	2031
NUECES BAY STG 7	NUECES_B_NUECESG7	Gas	589	1972	2032
CEDAR BAYOU 2	CBY_CBY_G2	Gas	749	1972	2032
R W MILLER 2	MIL_MILLERG2	Gas	120	1972	2032
SIM GIDEON 3	GIDEON_GIDEONG3	Gas	340	1972	2032
NUECES BAY STG 7_DB	NUECES_B_NUECESG7_DB	Gas	66	1972	2032
FAYETTE POWER PROJECT 3	FPFYD2_FPP_G3	Coal	449	1988	2033
ATKINS 7	ATKINS_ATKINSG7	Gas	20	1973	2033
LAKE HUBBARD 2	LHSES_UNIT2A	Gas	523	1973	2033
T H WHARTON STG 3	THW_THWST_3	Gas	386	1974	2034
T H WHARTON STG 4	THW_THWST_4	Gas	386	1974	2034
B M DAVIS 1	B_DAVIS_B_DAVIG1	Gas	292	1974	2034
TWIN OAKS 1	TNP_ONE_TNP_O_1	Coal	155	1990	2035
T H WHARTON 51	THW_THWGT51	Gas	65	1975	2035
T H WHARTON 52	THW_THWGT52	Gas	65	1975	2035
T H WHARTON 53	THW_THWGT53	Gas	65	1975	2035
T H WHARTON 54	THW_THWGT54	Gas	65	1975	2035
T H WHARTON 55	THW_THWGT55	Gas	65	1975	2035
T H WHARTON 56	THW_THWGT56	Gas	65	1975	2035
R W MILLER 3	MIL_MILLERG3	Gas	208	1975	2035
RAY OLINGER 3	OLINGR_OLING_3	Gas	146	1975	2035
B M DAVIS STG 2	B_DAVIS_B_DAVIG2	Gas	637	1976	2036
TWIN OAKS 2	TNP_ONE_TNP_O_2	Coal	155	1991	2036
GREENS BAYOU 73	GBY_GBYGT73	Gas	65	1976	2036
GREENS BAYOU 74	GBY_GBYGT74	Gas	65	1976	2036
GREENS BAYOU 81	GBY_GBYGT81	Gas	65	1976	2036
GREENS BAYOU 82	GBY_GBYGT82	Gas	50	1976	2036
GREENS BAYOU 83	GBY_GBYGT83	Gas	65	1976	2036
GREENS BAYOU 84	GBY_GBYGT84	Gas	65	1976	2036
HANDLEY 4	HLSES_UNIT4	Gas	435	1976	2036
B M DAVIS STG 2_DB	B_DAVIS_B_DAVIG2_DB	Gas	18	1976	2036
HANDLEY 5	HLSES_UNIT5	Gas	435	1977	2037
DANSBY 1	DANSBY_DANSBYG1	Gas	110	1978	2038
POWERLANE PLANT 3	STEAM_STEAM_3	Gas	36	1978	2038

<sup>19</sup> Retirements include permanent mothballed units and unconfirmed retirement capacities from May 2023 Capacity, Demand, & Reserves (CDR) Report.

### Appendix IV: Scenario Results Summary

Figure 28 shows the peak demand projection with years for all of three scenarios in 2024 LTSA. This peak demand includes the base demand forecast, any adjustment if applicable, roof-top PV output at the time of base demand peak, large loads, electric vehicle (EV) charging load and self-served load. Figure 29 shows the annual energy consumption for all of three scenarios.

#### Demand Forecasts

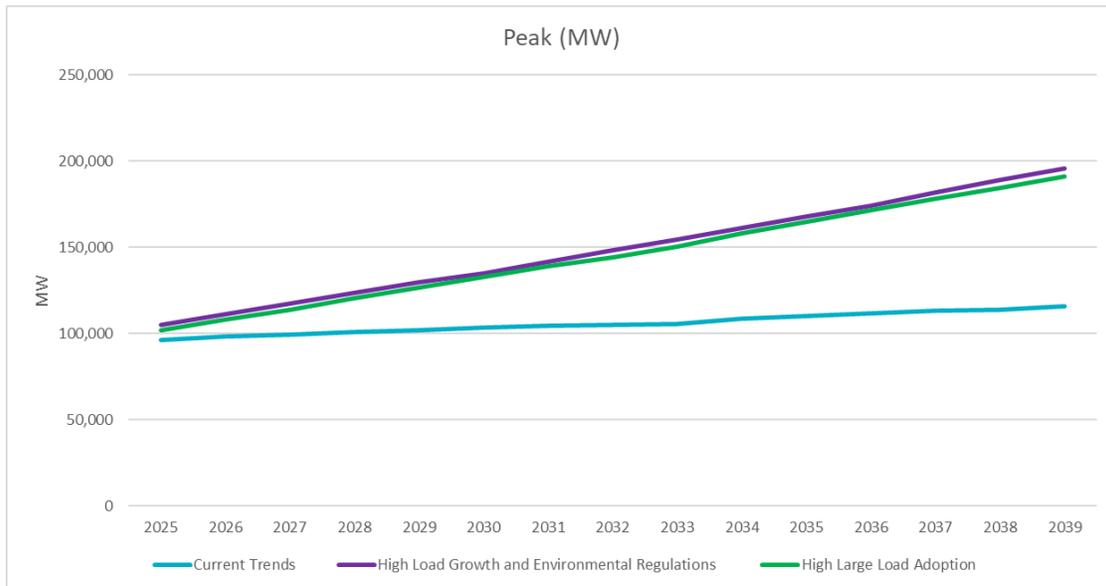


Figure 28: Peak Demand for 2024 LTSA Scenarios

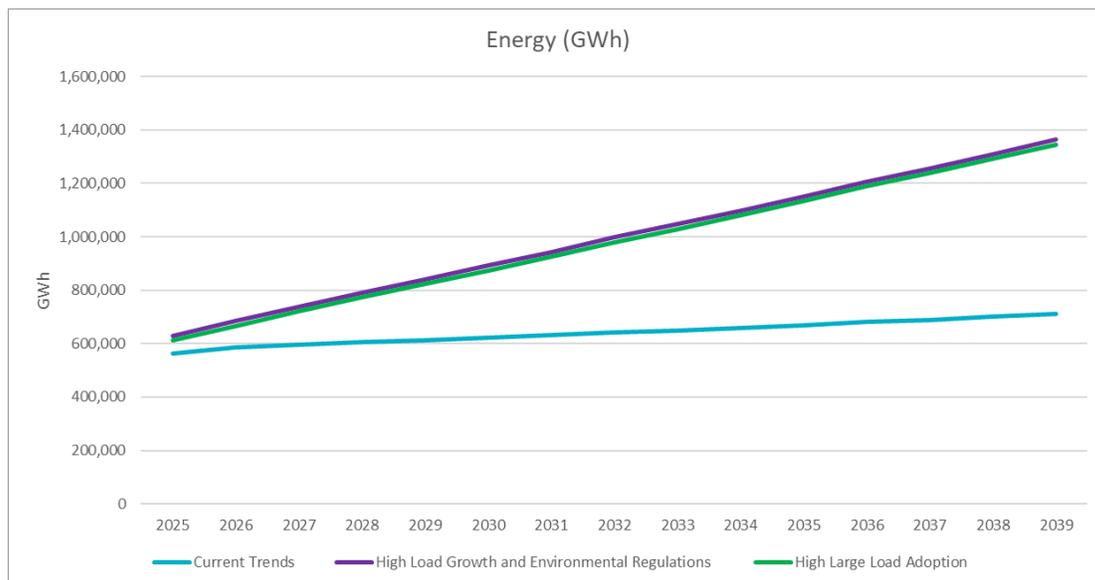


Figure 29: Energy for 2024 LTSA Scenarios

### 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 30 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:

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

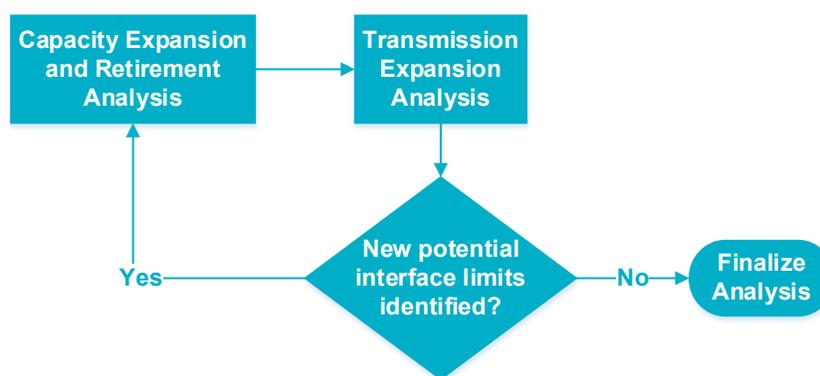


Figure 30: Iterative Process of Capacity Expansion and Transmission Analysis

An EV adoption assumption based on light-duty and medium and heavy-duty vehicles outlook using the model developed by Brattle Group was included in this scenario as shown in Figure 31 and Figure 32. Transportation electrification was assumed to start slowly but grow exponentially after reaching a certain level when charging infrastructure becomes more established.

By 2039 the total number of EV is estimated to be 6.44 million with the total energy consumption of 46 terawatt hours (TWh) for Current Trends scenario. In contrast, the total number of EV is estimated to be 8.42 million with the total energy consumption of 58 TWh by 2039 for the High Large Load Adoption and High Load Growth and Environment Regulation scenarios.

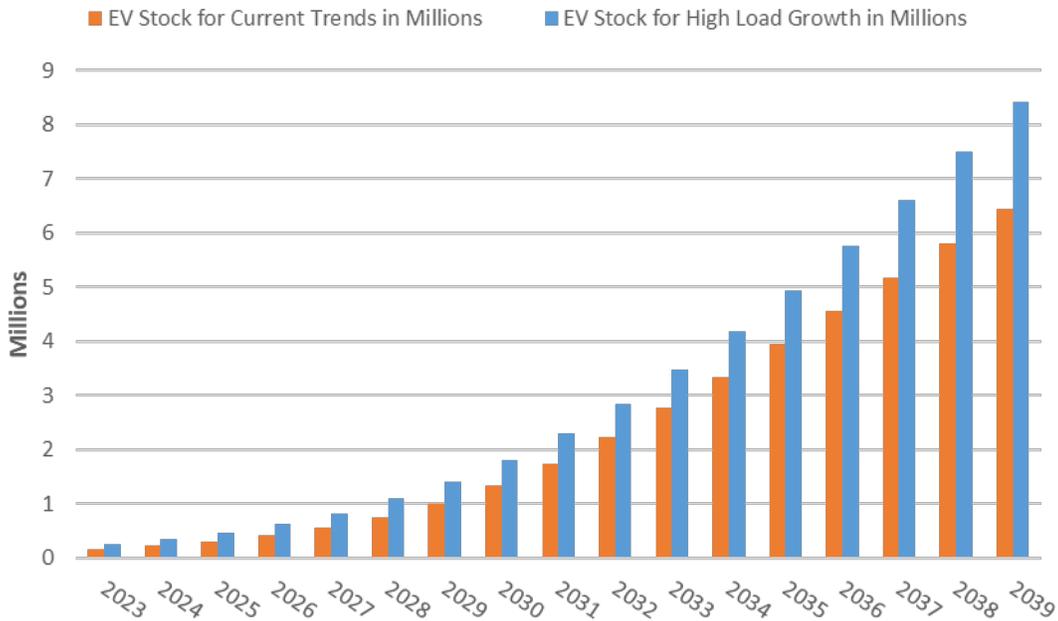


Figure 31: Projected Annual Number of EVs

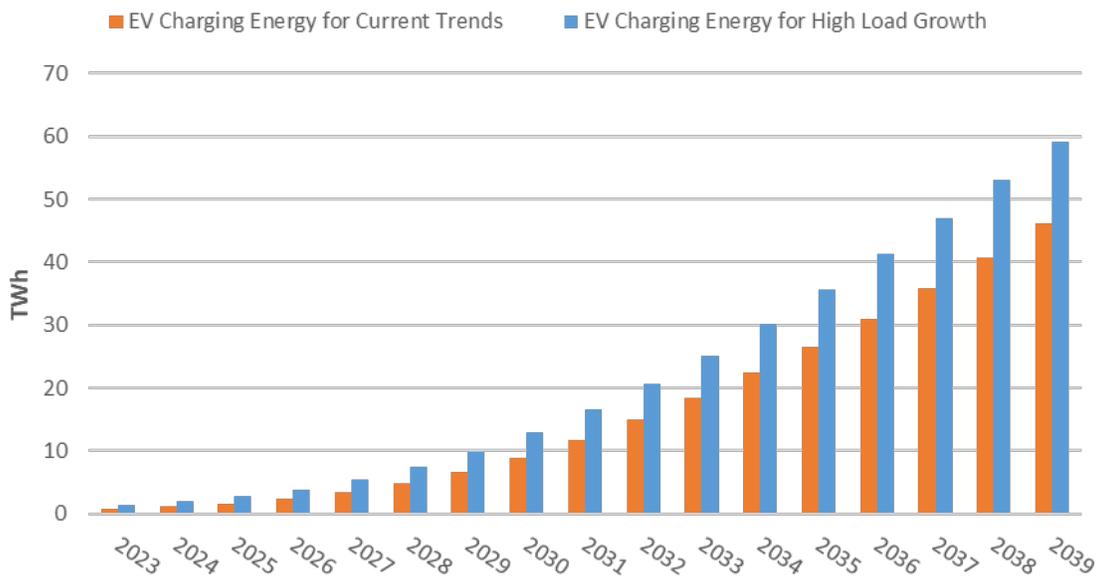


Figure 32: Projected Annual Charging Energy Due to EVs

Distributed solar adoption was assumed to follow an S-curve pattern. The maximum distributed solar potential in four urban areas was estimated by Underwriters Laboratories (UL) in a screening analysis.

<sup>20</sup> The market saturation rate was assumed to be 20%, fast growth was assumed to start in 2019, and

<sup>20</sup> [https://www.ercot.com/files/docs/2020/07/31/ERCOT\\_SolarPVProfiles\\_1980-2019.zip](https://www.ercot.com/files/docs/2020/07/31/ERCOT_SolarPVProfiles_1980-2019.zip).

the takeover time was assumed to be seven years. Figure 33 shows assumed distributed solar adoption by year. The distributed solar adoption varied from 4,030 MW in 2025 to 6,011 MW by 2039.

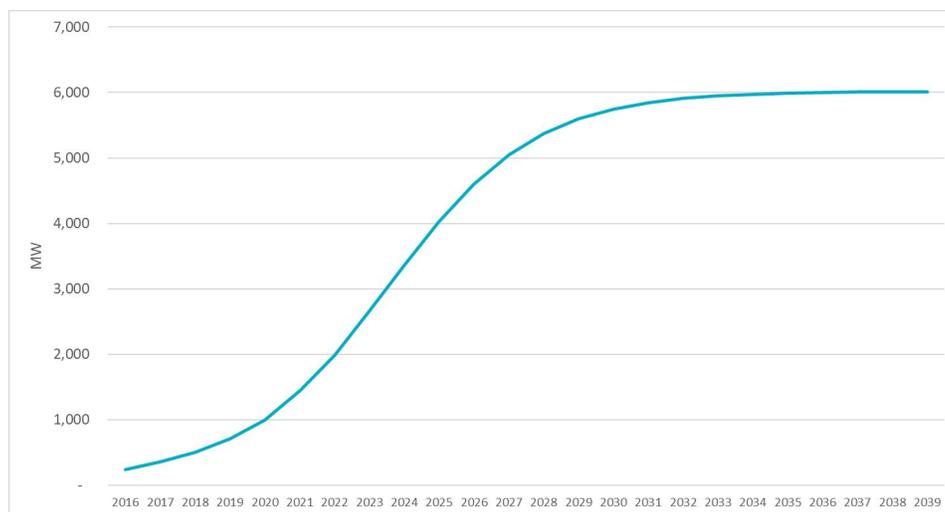


Figure 33: Distributed Solar Adoption by Year

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 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 by 2039 were 24,844 MW, 10,987 MW were coal and 13,857 MW were natural gas resources. In the first iteration of Current Trends there were an additional 2,572 MW of economic retirements resulting in the total retirement of 27,416 MW.

The first iteration of capacity expansion and retirement analysis for the Current Trends scenario resulted in additions of 14,079 MW of combined cycle, 9,243 MW of simple cycle combustion turbine, 22,217 MW of utility-scale solar, 17,100 MW of wind, and 9,032 MW of battery energy storage, with a total capacity expansion addition of 71,671 MW. Table 9 shows the starting capacity mix, retirements, and capacity-expansion additions for the first iteration of Current Trends scenario for the 15-year study period. The total resources in this scenario were 209,838 MW.

A summary of the study results for the first iteration of Current Trends scenario for the selected four study years are shown in Table 10. The first iteration of Current Trends scenario showed only one hour of scarcity in 2039 totaling in 1.9 gigawatt hours (GWh) of unserved energy. The large flexible load curtailment hours ranged from 99 to 336 hours with the total curtailed energy of 287 to 1,007 GWh respectively. The average market price ranged from 31.06 \$/MWh to 52.88 \$/MWh. The share of the coal generation units is reduced over time from 9.6% to 2.5% because of the retirements while the solar and wind generation units are increasing because of the capacity expansion additions.

Table 9: Summary of Retirements and Capacity Additions for First Iteration of Current Trends Scenario

	2024LTSA - Current Trends (MW)					
	Operational Resources	Planned Resources	Retirements	Net Total Starting Capacity	Capacity Expansion	Total Capacity Mix
Battery	2,335	6,523	-	8,858	9,032	17,890
Combined Cycle	40,138	551	4,352	36,337	14,079	50,416
CT & IC	11,733	900	1,206	11,427	9,243	20,670
Gas Steam	11,155	60	10,766	449	-	449
Solar	9,940	23,312	-	33,252	22,217	55,469
Wind	31,495	7,276	-	38,771	17,100	55,871
Coal	13,630	-	10,987	2,643	-	2,643
Hydro	593	-	-	593	-	593
Nuclear	5,153	-	-	5,153	-	5,153
Other	790	-	105	685	-	685
<b>Total</b>	<b>126,961</b>	<b>38,622</b>	<b>27,416</b>	<b>138,168</b>	<b>71,671</b>	<b>209,838</b>

Table 10: Summary of Study Results for First Iteration of Current Trends Scenario

Description	Units	2025	2029	2034	2039	Total
CC Adds	MW	-	3,249	5,415	5,415	14,079
CT Adds	MW	-	2,133	3,555	3,555	9,243
Storage Adds	MW	-	3,895	1,412	3,724	9,032
Solar Adds	MW	800	4,900	11,400	5,117	22,217
Wind Adds	MW	1,800	6,300	4,800	4,200	17,100
Annual Capacity Additions	MW	2,600	20,477	26,582	22,011	
Cumulative Capacity Additions	MW	2,600	23,077	49,660	71,671	
Retirements	MW	11,992	3,241	7,259	4,924	
Cumulative Retirements	MW	11,992	15,233	22,492	27,416	
Coincident Peak	MW	96,122	102,055	108,811	115,734	
Peak Net Load (1)	MW	70,871	74,453	79,955	86,884	
Minimum Net load (1)	MW	10,794	9,176	9,734	9,415	
Annual Energy	GWh	561,975	613,690	659,772	711,078	
Average LMP	\$/MWh	32.28	31.06	40.49	52.88	
Natural Gas Price	\$/MMbtu	3.80	3.35	4.75	5.64	
Average Market Heat Rate	MMbtu/MWh	8.49	9.26	8.52	9.38	
Natural Gas Generation	%	42.0	44.3	40.7	40.6	
Coal Generation	%	9.6	3.3	2.9	2.5	
Wind Generation	%	27.0	30.2	31.6	32.2	
Solar Generation	%	13.6	15.2	18.3	18.6	
Scarcity Hours	HRS	-	-	-	1	
Unserved Energy	GWhs	-	-	-	1.9	
Large Flexible Load Curtailment Hours	Hours	131	99	144	336	
Large Flexible Load Curtailment Energy	GWhs	310	287	432	1,007	

(1) Hourly Net Load = Total Demand – Hourly Wind Output – Hourly Solar Output

Transmission expansion analysis was performed based on the results of the capacity expansion and retirement analysis. Based on transmission constraints observed in the 1<sup>st</sup> iteration of transmission

expansion analysis, three zonal interface limits were recommended for the second iteration of capacity expansion and retirement analysis. This three-zone model was developed to represent the transmission network constraints expected for the future. The three zones were Panhandle, West/Far West and other ERCOT Regions. Interface limits were modeled for West Texas Export and Panhandle interface. Figure 34 illustrates the three-zone model and Table 11 shows the interface limits by study years.

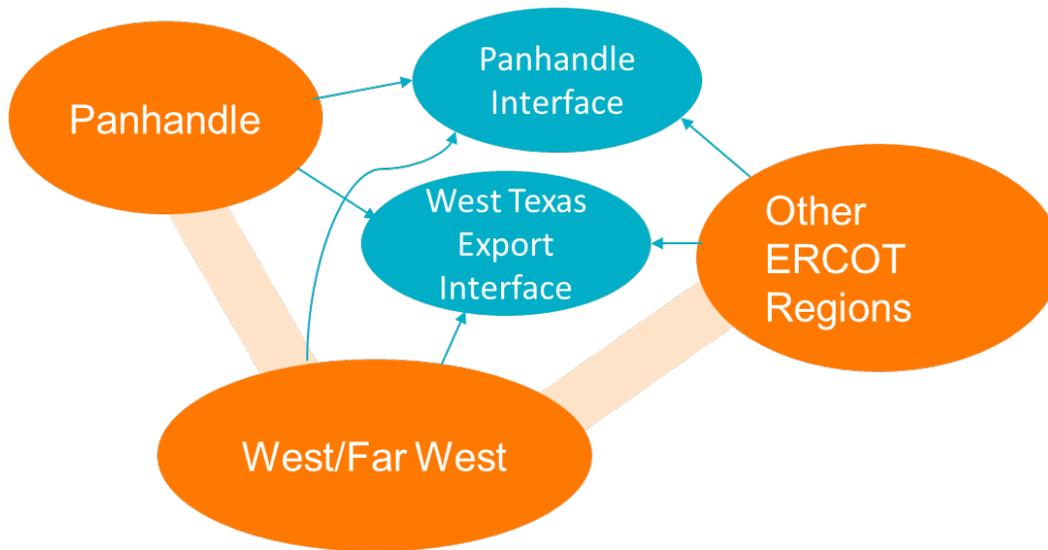


Figure 34: Three-Zone Model with Interfaces

Table 11: Interface Limits by Study Years

	Interface Limit (2025-2033)	Interface Limit (2034-2039)
West Texas Export (MW)	12,240	14,110
Panhandle (MW)	3,810	5,249

Enforcing the zonal interface limits resulted in a shift of new wind and solar resources from the Far West/West and Panhandle zones to the other ERCOT regions in the second iteration of the Current Trends. The primary cause of this shift was the inclusion of the West Texas Export and Panhandle interface limit which was a binding constraint in many hours. The comparison of first iteration versus second iteration capacity expansion results for Current Trends scenario shows an additional 8,482 MW of battery, 1,083 MW of combined cycles, 708 MW of gas turbines, and 6,583 MW of solar while the wind addition capacity is reduced by 800 MW. In the second iteration of Current Trends scenario, there were 2,467 MW less retirements. The total net capacity addition increased by 18,523 MW to 228,361 MW compared to the first iteration of the Current Trends scenario. In the second iteration of the Current Trends scenario because of the interface limits, the solar capacity expansion additions were distributed to other ERCOT regions with lower capacity factor instead of being concentrated in

the Panhandle and West zones compared to the first iteration of Current Trends. The comparison of the Current Trends first iteration and second iteration capacity mix is shown in Table 12.

Table 12: Summary of Retirements and Capacity Additions for Second Iteration of Current Trends Scenario

	Total Starting Capacity Mix	2024LTSA - Current Trends (MW)			2024LTSA - Second Iteration of Current Trends (MW)		
		Retirements	Capacity Expansion	Net Total	Retirements	Capacity Expansion	Net Total
Battery	8,858	-	9,032	17,890	-	17,514	26,372
Combined Cycle	40,689	4,352	14,079	50,416	2,226	15,162	53,625
CT & IC	12,633	1,206	9,243	20,670	865	9,951	21,719
Gas Steam	11,215	10,766	-	449	10,766	-	449
Solar	33,252	-	22,217	55,469	-	28,800	62,052
Wind	38,771	-	17,100	55,871	-	16,300	55,071
Coal	13,630	10,987	-	2,643	10,987	-	2,643
Hydro	593	-	-	593	-	-	593
Nuclear	5,153	-	-	5,153	-	-	5,153
Other	790	105	-	685	105	-	685
Total	165,583	27,416	71,671	209,838	24,949	87,727	228,361

The study results for the second iteration of the Current Trends scenario are summarized in Table 13. No unserved energy was observed for the study years. The large flexible load curtailment hours ranged from 64 to 195 hours with the total curtailed energy of 51 to 247 GWh respectively. The average market price ranged from 29.55 \$/MWh to 41.32 \$/MWh. Reduced large flexible load curtailment and lower average market price are due to the higher addition of new resources driven by zonal transmission constraints.

Table 13: Summary of Study Results for Second Iteration of Current Trends

Description	Units	2025	2029	2034	2039	Total
CC Adds	MW	-	4,332	5,415	5,415	15,162
CT Adds	MW	-	2,607	3,555	3,789	9,951
Storage Adds	MW	3,375	2,923	3,450	7,766	17,514
Solar Adds	MW	1,396	4,371	14,184	8,849	28,800
Wind Adds	MW	400	4,500	7,400	4,000	16,300
Annual Capacity Additions	MW	5,171	18,733	34,004	29,819	
Cumulative Capacity Additions	MW	5,171	23,904	57,908	87,727	
Retirements	MW	11,319	3,993	6,676	2,961	
Cumulative Retirements	MW	11,319	15,312	21,988	24,949	
Coincident Peak	MW	96,122	102,055	108,811	115,734	
Annual Energy	GWh	561,975	613,690	659,772	711,078	
Peak Net Load (1)	MW	69,772	75,121	78,073	84,171	
Minimum Net load (1)	MW	9,801	9,371	9,676	9,168	
Average Market Price	\$/MWh	31.80	29.55	36.76	41.32	
Natural Gas Price	\$/MMbtu	3.80	3.35	4.75	5.64	
Natural Gas Generation	%	43.4	47.6	41.4	40.9	
Coal Generation	%	9.6	3.3	2.8	2.5	
Wind Generation	%	25.4	27.0	30.4	30.4	
Solar Generation	%	13.8	15.1	18.8	20.3	
Scarcity Hours	HRS	-	-	-	-	
Unserved Energy	GWhs	-	-	-	-	
Large Flexible Load Curtailment Hours	Hours	64	139	131	195	
Large Flexible Load Curtailment Energy	GWhs	51	185	174	247	

(1) Hourly Net Load = Total Demand – Hourly Wind Output – Hourly Solar Output

As described in Appendix I, ERCOT used the UPLAN Network Power Model (NPM) to perform transmission expansion analysis. Any recently approved RPG projects and local 138-kV upgrades and additions were included in the start cases. 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 \$1,839 million in production cost savings and an approximately \$2,558 million of congestion rent reduction. Figure 35 show the major congestion on the system. Figure 36 and Table 14 provide details on the set of potential transmission improvements identified for the Current Trends scenario. The break-even capital cost (BECC) for the projects, if applicable, was provided in Table 15.

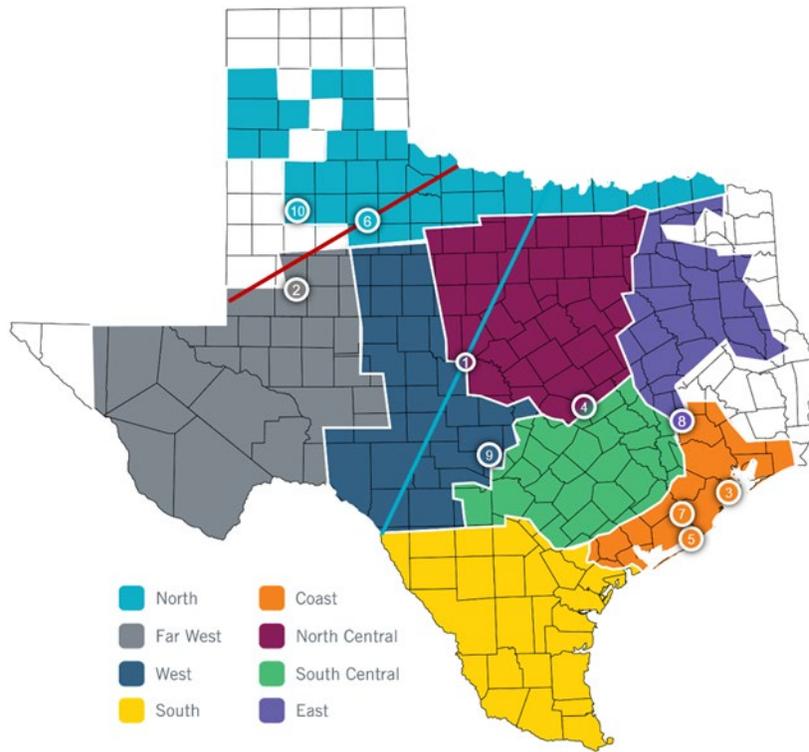


Figure 35: Top Constraints for Current Trends Scenario (2<sup>nd</sup> iteration)

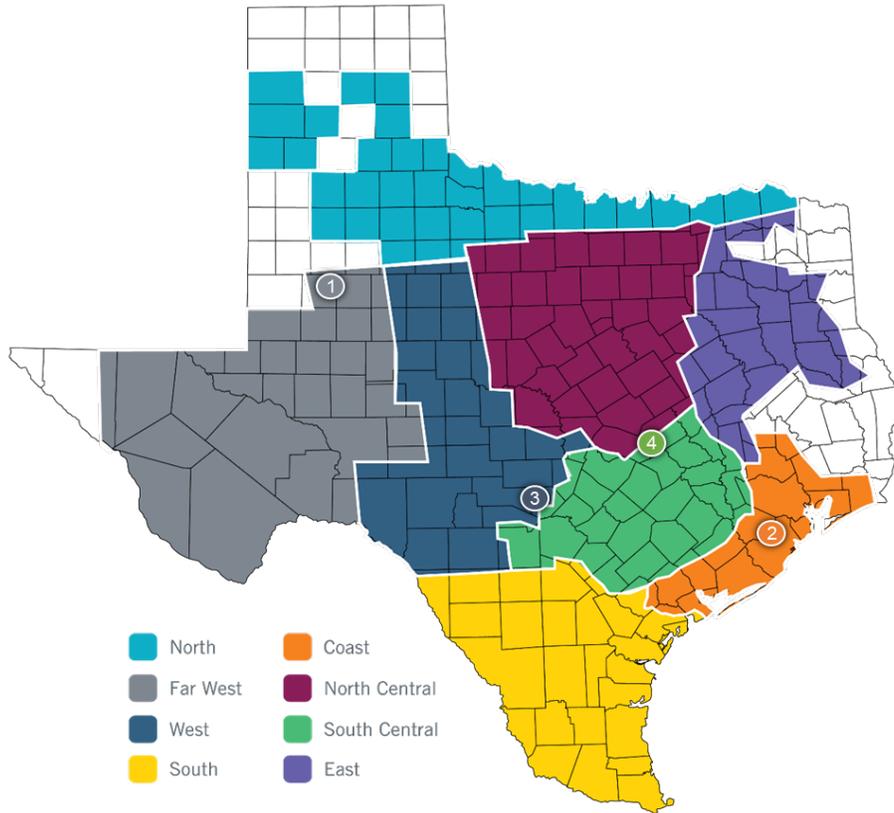


Figure 36: Potential Transmission Improvements for Current Trends (2<sup>nd</sup> iteration)

Table 14: Potential Transmission Improvements for Current Trends

	<b>Project Name</b>	<b>Description</b>
<b>Project 1</b>	Farmland – Long Draw and Fiddlewood Switch – Farmland 345-kV Upgrades	Upgrade Farmland – Long Draw and Fiddlewood – Farmland 345 kV lines
<b>Project 2</b>	New STP – Bailey and Bailey – PH Robinson 345-kV lines	New STP – Bailey and Bailey – Ph Robinson 345 kV line
<b>Project 3</b>	New Hill Country – Kendall 345-kV line	New HILL CITY to KENDAL 345 kV line
<b>Project 4</b>	Upgrade Bell County East Switch – Sandow Switch DCKT 345-kV line and upgrade Temple Switch – Tin Roof Pod 138-kV line	Upgrade Bell County East Switch – Sandow Switch 345 kV DCKT line and upgrade Temple Switch – Tin Roof Pod 138-kV line

Table 15: Break-even Capital Cost (BECC)

Index	Project Name	BECC for production cost savings test (\$M)	BECC for generator revenue reduction test (\$M)	BECC for total consumer energy cost reduction test (\$M)
1	Farmland – Long Draw and Fiddlewood Switch – Farmland 345-kV upgrades	\$277.48	-	-
2	New STP – Bailey and Bailey – PH Robinson 345-kV lines	\$583.98	-	-
3	New Hill Country – Kendall 345-kV line	\$236.76	\$289.00	\$962.82
4	Upgrade Bell County East Switch – Sandow Switch DCKT 345-kV line and upgrade Temple Switch – Tin Roof Pod 138-kV line	\$204.15	\$776.23	\$1,517.39

**High Load Growth and Environmental Regulations Scenario**

In addition to the Current Trends scenario, the High Load Growth and Environmental Regulations scenario was developed to assess the impact of high load growth and environmental regulations on future grid reliability. Additional 70,273 MW of load including 4,050 MW of price responsive load and 66,223 MW of flat load, which has not been captured by the long-term load forecast used for the Current Trends scenario, was included. Figure 28 and Figure 29 compare the peak demand and energy for this scenario against Current Trends. This scenario also considers potentially more restrictive 2024 Green House Gas (GHG) Rule environmental regulations.<sup>21</sup>

The load forecast and environmental rule assumptions for this scenario are outlined below.

**Load Forecast Assumptions:**

1. The projected peak load is 195 GW by 2039, almost 80 GW higher than the Current Trends scenario.
2. 2011 weather year, reflecting extreme weather conditions, was used for this scenario, compared to the 2013 average weather year used for Current Trends.
3. Assumed aggressive EV adoption.
4. Large flexible load amount was 8.5 GW by 2039, up from 7.36 GW in Current Trends.
5. The same amount of roof-top PV was adopted as Current Trends.

**Environmental Rule Assumptions:**

- All new combined cycle Units were required to include carbon capture and storage (CCS) technology, assumed to be available by 2030.
- New combustion turbines are limited to a 20% annual capacity factor.
- Nearly all coal units, totaling 12,697 MW, were retired by 2035, except Sandy Creek 1. Sandy Creek 1, a newer coal unit, was assumed to be retrofitted with CCS. Existing combined cycles over 300 MW per unit were limited to a 50% annual capacity factor, affecting only two units (COLORADO BEND II and WOLF HOLLOW 2).

The comparison of the scenario assumptions for Current Trends and High Load Growth and Environmental Regulations scenarios are shown in Table 16.

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<sup>21</sup> <https://www.epa.gov/newsreleases/epa-proposes-new-carbon-pollution-standards-fossil-fuel-fired-power-plants-tackle>.

Table 16: Input Assumption Comparisons for Current Trends and High Load Growth and Environmental Regulations Scenario

15 Year Input Assumptions (2025-2039)		Current Trends	High Load Growth and Environment Regulation Scenario
Gross Load	Weather Condition	2013 weather condition (96,959 MW Peak Demand/563,841 GWh Annual Energy)	2011 weather condition (99,900 MW Peak Demand/581,012 GWh Annual Energy)
	Adjusted for IHS Load in Far West	None	Applied
	Gross Peak Demand /Annual Energy After IHS Load Adjustment	96,959 MW/563,841 GWh	104,106 MW/615,329 GWh
Roof-top PV/EV/LFL/Flat Load	Roof-top PV	6,011 MW	6,011 MW
	EV (LDV) Annual Energy	21,228 GWh	26,012 GWh
	EV (MHDV) Annual Energy	24,844 GWh	32,387 GWh
	Price-responsive Load (LFL)	4,479 MW <sup>1</sup> + 2,881 MW <sup>5</sup>	4,479 MW <sup>1</sup> + 4,050 MW <sup>6</sup>
	Additional Flat Load from TSPs Load Projection	0 MW	66,223 MW
Peak Demand/Annual Energy <sup>7</sup>		115,734 MW/711,078 GWh	195,976 MW/1,363,494 GWh
Environment Rules	Carbon Price	0\$/ton	0\$/ton
	Impact of EPA Rules for Gas Units	None	1) CCS <sup>2</sup> needed for new CCs 2) existing CCs (>300 MW/unit) capacity factor < 50% <sup>3</sup> 3) new CTs capacity factor < 20%
	Coal Retirement	10,228 MW coal retirement by 2032 and 10,987 MW by 2039 <sup>4</sup>	12,697 MW coal retirement before 2035

(1) in operation as of Feb. 2024, (2) carbon capture and storage (CCS), (3) only two existing CCs impacted, (4) 951 MW of retirement due to economics, (5) estimated new LFL, (6) from TSP load projection

The starting capacity mix for this scenario was the same as Current Trends with total capacity of 165,583 MW. The total retirements for this scenario were 26,659 MW, which included an additional 1,710 MW of coal retirements compared to Current Trends, while 2,126 MW more of combined cycle units remained operational. This scenario required the large-scale buildout of solar, battery and combustion turbines to serve the load. The new combustion turbines were limited to a 20% annual capacity factor, leading to the addition of 100,962 MW to meet demand. The model also added 116,994 MW of solar, 45,000 MW of wind, and 79,307 MW of battery storage. Combined cycles with carbon capture and storage were not economically viable as determined by the model until 2037, resulting in a total addition of 16,965 MW. The total capacity expansion additions were 359,228 MW and this resulted in the total capacity of 498,152 MW for this scenario. The results of the starting capacity mix, retirements, capacity expansion additions and net total capacity are shown in Table 17.

Table 17: Summary of the Retirements and Capacity Additions for High Load Growth and Environmental Regulations Scenario

	Total Starting Capacity Mix	2024LTSA - Current Trends (MW)			High Load Growth and Environmental Regulations Scenario (MW)		
		Retirements	Capacity Expansion	Net Total	Retirements	Capacity Expansion	Net Total
Battery	8,858	-	9,032	17,890	-	79,307	88,165
Combined Cycle	40,689	4,352	14,079	50,416	2,226	16,965	55,428
CT & IC	12,633	1,206	9,243	20,670	865	100,962	112,730
Gas Steam	11,215	10,766	-	449	10,766	-	449
Solar	33,252	-	22,217	55,469	-	116,994	150,247
Wind	38,771	-	17,100	55,871	-	45,000	83,771
Coal	13,630	10,987	-	2,643	12,697	-	933
Hydro	593	-	-	593	-	-	593
Nuclear	5,153	-	-	5,153	-	-	5,153
Other	790	105	-	685	105	-	685
<b>Total</b>	<b>165,583</b>	<b>27,416</b>	<b>71,671</b>	<b>209,838</b>	<b>26,659</b>	<b>359,228</b>	<b>498,152</b>

The battery additions for this scenario included 78,951 MW of 2-hour batteries and 356 MW of 8-hour batteries. The model built both co-located and standalone batteries and solar. The co-located batteries and solar were 19,330 MW. The standalone batteries were 59,977 MW and 97,664 MW of standalone solar were added by the model. In this scenario, Small Modular Reactors were considered in the capacity expansion analysis. However, since they were found uneconomical under current market conditions and without subsidies, none was added.

The results for the four study years for the High Load Growth and Environmental Regulations scenario are summarized in Table 18. The results showed 14 hours of unserved energy for the first few years until the model added enough resources to meet the load demand and offset retirements. The large flexible load curtailment hours ranged from 124 to 1,612 hours, with a total curtailed energy between 452 and 9,110 GWh. The average market price ranged from 44.4 \$/MWh to 70.5 \$/MWh. The coal's share in the generation mix declined from 8.9% to 0.5% over time because of the retirements, while the shares of solar and wind generation in the mix increased.

Table 18: Summary of Results for High Load Growth and Environmental Regulations Scenario

Description	Units	2025	2029	2034	2039	Total
CC Adds	MW	-	-	-	16,965	16,965
CT Adds	MW	4,740	24,411	45,267	26,544	100,962
Storage Adds	MW	10,228	18,116	29,306	21,657	79,307
Solar Adds	MW	8,890	34,957	50,491	22,655	116,994
Wind Adds	MW	3,000	12,000	15,000	15,000	45,000
Annual Capacity Additions	MW	26,858	89,484	140,065	102,822	
Cumulative Capacity Additions	MW	26,858	116,342	256,407	359,228	
Retirements	MW	12,287	3,775	7,703	2,895	
Cumulative Retirements	MW	12,287	16,061	23,764	26,659	
Coincident Peak	MW	105,112	129,604	161,266	195,976	
Annual Energy	GWh	630,376	840,089	1,099,024	1,363,494	
Peak Net Load (1)	MW	88,607	102,956	119,968	145,535	
Minimum Net load (1)	MW	9,648	9,078	9,414	9,486	
Average Market Price	\$/MWh	44.4	55.4	70.5	65.5	
Natural Gas Price	\$/MMbtu	3.80	3.35	4.75	5.64	
Natural Gas Generation	%	41.3	40.4	37.0	39.9	
Coal Generation	%	8.9	3.3	1.7	0.5	
Wind Generation	%	26.5	27.9	28.7	29.4	
Solar Generation	%	16.2	23.0	27.8	26.8	
Scarcity Hours	HRS	14	14	-	-	
Unserved Energy	GWhs	82	115	-	-	
Large Flexible Load Curtailment Hours	Hours	124	695	1,612	804	
Large Flexible Load Curtailment Energy	GWhs	452	2,904	9,110	5,612	

(1) Hourly Net Load = Total Demand – Hourly Wind Output – Hourly Solar Output

### High Large Load Adoption Scenario

Similar to the High Load Growth and Environmental Regulations scenario, a total additional load of 70,273 MW, was included in the High Large Load Adoption scenario. Figure 28 and Figure 29 compare the peak demand and energy for this scenario against Current Trends.

Table 19 presents a comparison of assumptions between Current Trends and High Large Load Adoption scenario. In the High Large Load Adoption scenario, as in Current Trends, the 2013 weather year data was used. Environmental Protection Agency (EPA) environmental regulations were not factored into this study, resulting in total coal retirements of 10,987 MW by 2039.

Table 19: Input Assumption Comparisons between Current Trends and High Large Load Adoption Scenario

2039		Current Trends	High Large Load Adoption
Gross Load	Weather Condition	2013 weather condition (96,959 MW Peak Demand/563,841 GWh Annual Energy)	2013 weather condition (96,959 MW Peak Demand/563,841 GWh Annual Energy)
	Adjusted for IHS Load in Far West	None	Applied
	Gross Peak Demand /Annual Energy After IHS Load Adjustment	96,959 MW/563,841 GWh	100,792 MW/595,639 GWh
Roof-top PV/EV/LFL/Flat Load	Roof-top PV	6,011 MW	6,011 MW
	EV (LDV) Annual Energy	21,228 GWh	26,012 GWh
	EV (MHDV) Annual Energy	24,844 GWh	32,387 GWh
	Price-responsive Load (LFL)	4,479 MW <sup>1</sup> + 2,881 MW <sup>3</sup>	4,479 MW <sup>1</sup> + 4,050 MW <sup>4</sup>
	Additional Flat Load from TSPs Load Projection	0 MW	66,223 MW
Peak Demand/Annual Energy <sup>7</sup>		115,734 MW/711,078 GWh	191,100 MW/1,346,200 GWh
Environment Rules	Carbon Price	0\$/ton	0\$/ton
	Impact of EPA Rules for Gas Units	None	None
	Coal Retirement	10,228 MW coal retirement by 2032 and 10,987 MW by 2038 <sup>2</sup>	10,228 MW coal retirement by 2032 and 10,987 MW by 2038

<sup>1</sup> In operation as of Feb. 2024.

<sup>2</sup> 951 MW of retirement due to economics.

<sup>3</sup> Estimated new LFL.

<sup>4</sup> From TSP load projection.

The starting capacity mix for this scenario was consistent with the Current Trends scenario, totaling 165,583 MW. Total retirements in this scenario reached 25,296 MW with 2,126 MW fewer economic retirements of combined cycles, allowing more combined cycles to remain operational. This scenario required large-scale buildouts of solar, battery and gas resources to serve the load. The model added 28,158 MW of combined cycles and 83,187 MW of combustion turbines, along with 125,368 MW of solar, 22,200 MW of wind, and 26,911 MW of battery storage. The capacity expansion totaled 285,824 MW, resulting in a total capacity of 426,111 MW. The results of the starting capacity mix, retirements, capacity expansion additions and net total capacity are shown in Table 20.

All battery storage additions for this scenario were those with 2-hour energy duration, with a mix of co-located and standalone installations. The model added 13,868 MW of co-located batteries and solar capacity and 13,043 MW of standalone batteries, along with 111,500 MW of standalone solar generation. Small Modular Reactors were also considered in the capacity expansion analysis. However, they were found to be uneconomic under current market conditions and if no subsidies were provided.

The results for the four study years for the High Large Load Adoption scenario are summarized in Table 21. The results show no unserved energy. Large flexible load curtailment hours ranged from 161 hours in 2025 to 9 hours in 2039, with the curtailed energy decreased from 491 GWh to 5 GWh. The average market prices ranged from 33.0 \$/MWh to 47.2 \$/MWh. The share of the coal generation mix declined over time from 9.3% to 1.3% due to retirements, while the solar and natural gas generation mix increased. Although wind capacity and generation increased, its share in the generation mix decreased from 24.5% in 2025 to 18.8% in 2039 as more solar and natural gas resources were added.

Table 20: Summary of Retirements and Capacity Additions for High Large Load Adoption Scenario

	Total Starting Capacity Mix	2024LTSA - Current Trends (MW)			2024LTSA - High Large Load Adoption (MW)		
		Retirements	Capacity Expansion	Net Total	Retirements	Capacity Expansion	Net Total
Battery	8,858	-	9,032	17,890	-	26,911	35,769
Combined Cycle	40,689	4,352	14,079	50,416	2,226	28,158	66,621
CT & IC	12,633	1,206	9,243	20,670	1,212	83,187	94,608
Gas Steam	11,215	10,766	-	449	10,766	-	449
Solar	33,252	-	22,217	55,469	-	125,368	158,620
Wind	38,771	-	17,100	55,871	-	22,200	60,971
Coal	13,630	10,987	-	2,643	10,987	-	2,643
Hydro	593	-	-	593	-	-	593
Nuclear	5,153	-	-	5,153	-	-	5,153
Other	790	105	-	685	105	-	685
<b>Total</b>	<b>165,583</b>	<b>27,416</b>	<b>71,671</b>	<b>209,838</b>	<b>25,296</b>	<b>285,824</b>	<b>426,111</b>

Table 21: Summary of Results for High Large Load Adoption Scenario

Description	Units	2025	2029	2034	2039	Total
CC Adds	MW	-	6,498	10,830	10,830	28,158
CT Adds	MW	1,896	22,752	27,492	31,047	83,187
Storage Adds	MW	1,976	4,727	16,392	3,816	26,911
Solar Adds	MW	2,676	25,700	55,681	41,312	125,368
Wind Adds	MW	1,400	7,200	11,800	1,800	22,200
Annual Capacity Additions	MW	7,947	66,877	122,194	88,805	
Cumulative Capacity Additions	MW	7,947	74,825	197,019	285,824	
Retirements	MW	9,956	6,997	6,613	1,730	
Cumulative Retirements	MW	9,956	16,953	23,566	25,296	
Coincident Peak	MW	102,214	126,524	158,118	191,100	
Annual Energy	GWh	613,065	822,784	1,081,723	1,346,200	
Peak Net Load (1)	MW	75,381	97,265	123,370	153,456	
Minimum Net load (1)	MW	9,642	9,143	9,478	9,080	
Average Market Price	\$/MWh	36.3	33.0	40.9	47.2	
Natural Gas Price	\$/MMbtu	3.80	3.35	4.75	5.64	
Natural Gas Generation	%	45.7	50.2	45.6	48.6	
Coal Generation	%	9.3	3.5	1.8	1.3	
Wind Generation	%	24.5	23.0	22.7	18.8	
Solar Generation	%	13.3	18.1	26.0	28.3	
Scarcity Hours	HRS	-	-	-	-	
Unserved Energy	GWhs	-	-	-	-	
Large Flexible Load Curtailment Hours	Hours	161	49	3	9	
Large Flexible Load Curtailment Energy	GWhs	491	136	8	5	

(1) Hourly Net Load = Total Demand – Hourly Wind Output – Hourly Solar Output