

**2024 ERCOT System Planning**

**Long-Term Hourly Peak Demand and Energy Forecast**

**January 11, 2024**

**Executive Summary**

The 2024 Long-Term Demand and Energy Forecast (LTDEF) for the ERCOT region is presented in this report, which includes information about the methodology, assumptions, and data used to create the forecast. This forecast is based on a set of econometric models describing the hourly load in the region as a function of the number of premises in various customer classes (e.g., residential, business, and industrial), weather variables (e.g., various temperature values), and calendar variables (e.g., day of week and holidays). The premise forecasts that drive growth in the LTDEF are created using a set of econometric autoregressive models (AR1) and are based on certain economic (e.g., non-farm payroll employment, housing stock, and population) data. A county-level forecast of economic and demographic data was obtained from Moody’s.

As shown in Figure 1, the 2024 LTDEF depicts system peak demand increasing at an average annual growth rate (AAGR) of approximately 1.5% from 2024-2033. This forecast assumes Large Flexible Loads (LFL) reduce consumption during summer peak hours to 15% of their normal consumption.

**Figure 1: ERCOT Summer Peak Demand Forecast**

As shown in Figure 3, historical annual energy for the calendar years 2014-2022 grew at an AAGR of 3.1%. The forecasted AAGR for energy from 2024-2033 is 2.5%.

**Figure 2: ERCOT Annual Energy Forecast**

**Introduction**

This report gives a high-level overview of the 2024 LTDEF. The forecast methodology is described, highlighting its major conceptual and statistical underpinnings. The waterfall methodology is used for the LTDEF to exhibit the breakdown of the four major components of the forecast: base load, rooftop PV, electric vehicles, and large industrial loads. The methodologies used for rooftop PV, electric vehicles, and large industrial loads are described. Finally, an examination is presented describing the five major sources of forecast uncertainty: weather, economics, energy efficiency, price responsive loads, and large industrial loads.

**Modeling Framework**

The 2024 LTDEF was produced with a set of linear regression models that combine weather, premise data, and calendar variables to capture and project the long-term trends extracted from the historical load data. Premise forecasts were also developed.

All model descriptions included in this document should be understood as referring to weather zones. The ERCOT forecast is calculated as the sum of all weather zone forecasts.

ERCOT consists of eight distinct weather zones (Figure 3). Weather zones[[1]](#footnote-1) represent a geographic region in which climatological characteristics are similar. Each weather zone has two or three weather stations that provide data for the assigned weather zone. To reflect the unique weather and load characteristics of each zone, separate load forecasting models were developed for each of the weather zones.

**Premise Forecast Models**

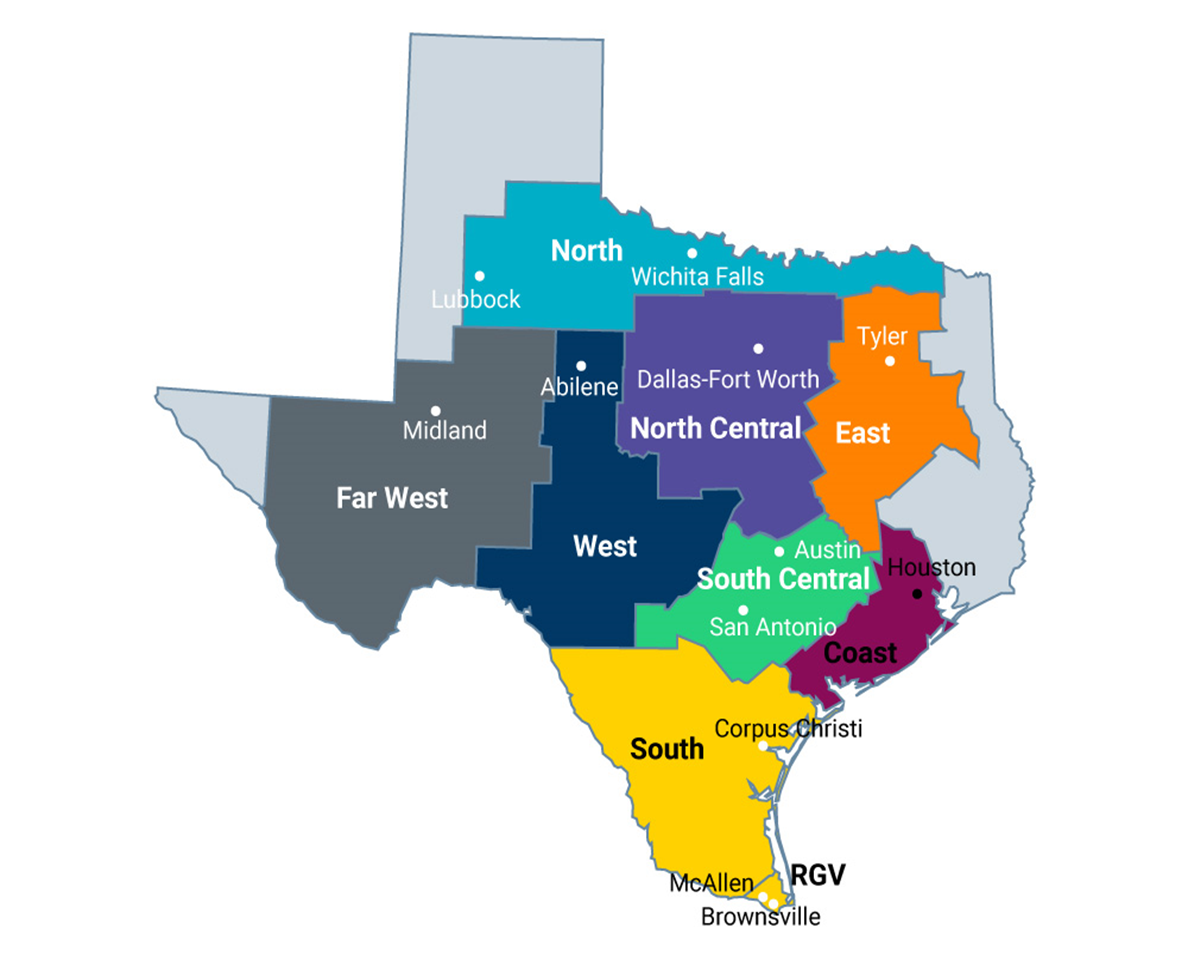
The key driver of the forecasted growth of demand and energy is the number of premises. County-level economic data was used to capture and project the long-term trends extracted from the historical premise data. County-level data was mapped into the weather zones (Figure 3).

Premises were separated into three different customer classes for modeling purposes:

1. Residential (including lighting),
2. Business (small commercial), and
3. Industrial (premises which are required to have an IDR meter[[2]](#footnote-2)).

All premise models were developed using historical data from January 2018 through May 2023. An autoregressive model (AR1) was used for all premise forecasts.

**Figure 3: ERCOT Weather Zones**



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:

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

Business Premise Forecast

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

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

Industrial Premise Forecast

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

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

**Waterfall Methodology**

The method used to create the ERCOT net forecast is a waterfall approach that sequentially combines individual components of the forecast. The purpose of using the waterfall approach is to allow the ability to provide forecasts for many scenarios. The waterfall method allows discovery and insight on changes to the ERCOT system by examining individual components. Reconstitution was also used for rooftop PV to avoid double counting load which is possible using the waterfall method by adding historical PV output back to the native load before modeling occurs. The gross forecast is the weather zone normal hourly forecast and the ERCOT System (the sum of all the weather zone normal forecasts) before any additional forecasts are added. Figure 4 on page 10 demonstrates the waterfall method by appending the four major forecasts one at a time to create the ERCOT Winter Coincident Net Forecast.

As shown in the following formula, LTDEF net forecast is the sum of base load, electric vehicle load, and large flexible load forecasts less the rooftop PV forecast.

**Hourly Demand Models**

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

1. Month,
2. Day of Week,
3. Hour,
4. Weather Variables,
   1. Temperature including various lagged values,
   2. Temperature squared including various lagged values,
   3. Temperature cubed including various lagged values,
5. Interactions,
   1. Day of Week and Temperature variables,
   2. Hour and Day of Week,
   3. Hour and Temperature variables,
   4. Month and Temperature variables, and
6. Number of premises.

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

Model Building Process

The model building data set was comprised of a randomly selected 60% of the data from January 1, 2018 through May 31, 2023, with the remaining 40% of the data withheld. The model building data set was used to create various forecast models. The model building process was an iterative process that was conducted multiple times.

The validation data set consisted of a randomly selected 30% of data from January 1, 2018 through May 31, 2023 timeframe. The data in the validation data set was withheld from the model building data set. After model building was complete, the validation data set was used to determine the accuracy of the various forecast models. Each model’s performance was calculated based on its forecasting performance on the validation data set. The most accurate models were selected based on their performance.

The remaining randomly selected 10% of the data from January 1, 2018 through May 31, 2023 made up the test data set. After the most accurate models were selected based on their performance on the validation dataset, those models were run on the test data set to verify that the models performed well at predicting data they had not seen.

Using only five years of historical data and as much of the current year’s data as possible enables the model to reflect recent appliance stock, energy efficiency measures, price responsive load impacts, etc.

Weather Zone Load Forecast Scenarios

Actual weather data from calendar years 2008 through 2022 was used to create each weather zone’s forecast by applying the weather data from each historical year one-by-one to the load forecasting model. The process began by using actual weather data from 2008 as weather input into the model for all forecasted years (2024-2033). The actual weather data from all days in 2008 was copied into the same day and hour for each of the forecasted years (2024-2033). For example, the actual weather data for 1/1/2008 was copied into 1/1/2024, 1/1/2025, …, and 1/1/2033. Using 2008’s weather as input into each weather zone’s forecast model results in what is referred to as the 2008 weather load forecast scenario. The 2008 weather load forecast scenario is a forecast that assumes 2008’s weather would occur for each forecasted calendar year (2024-2033). This process was completed for each of the historical weather years (2008-2022) individually and resulted in fifteen weather load forecast scenarios for each weather zone for each of the forecasted years 2024-2033. It should be noted that the premise and economic forecasts are the same in each of these fifteen weather scenarios.

Weather Zone Normal Weather Hourly Forecast

The fifteen weather zone load forecast scenarios are used as the basis for creating the weather zone normal weather hourly forecast. Each of the fifteen hourly weather zone load forecast scenarios were separated into individual calendar year forecasts (covering calendar years 2024-2033). The calendar year forecasts were then divided by calendar month. Forecasted hourly values for each individual calendar month were ordered from the highest value to the lowest value. Then, for each ordered value, the average was calculated. This process is commonly referred to as the Rank and Average methodology.

For example, to determine the normal weather forecasted peak value for August 2024, take the highest forecasted value from each of the fifteen weather load forecast scenarios for August 2024 and average them. To determine the second highest value for August 2024, take the second highest forecasted value for each of the fifteen weather load forecast scenarios for August 2024 and average them. Repeat this process for all hours in August 2024. See Table 1 (below) for a summary of these calculations.

After this process has been completed for all hours in August, a forecast will have been created for all 744 hours of August. At this point, the forecast is ordered from the highest value (indicated as rank 1) to the lowest value (indicated as rank 744). Note that the forecasted values have not yet been assigned to a day or hour. The values associated with a rank of 1 are the monthly forecasted peak demand values. The forecasted monthly peak values for August and January, however, are subject to an adjustment which is covered in the two sections immediately below.

Weather Zone Normal Weather Summer Peak Demand Forecast

The fifteen weather load forecast scenarios are used as the basis for creating the weather zone normal weather summer peak forecast. Each of the fifteen hourly weather load forecast scenarios are separated into individual calendar year forecasts (covering calendar years 2024-2033). The maximum forecasted hourly value occurring during the summer season (defined as June through September) is determined for each individual calendar year.

The summer peak demand values from the fifteen weather scenarios for a particular calendar year are averaged to determine the normal weather forecasted summer peak value. For example, to determine the normal weather forecasted summer peak value for calendar year 2024, take the highest forecasted value in months June through September from each of the fifteen weather load forecast scenarios for calendar year 2024 and average them. The forecasted summer peak demand is then assigned to August and replaces the previously calculated peak (rank 1) forecasted value for the month of August.

Example:

Table 1 (below) shows the forecasted summer peak demand for the Coast weather zone for 2024 based on the historical weather years of 2008-2022. The forecasted gross summer peak demand for Coast is 21,637 MW.

**Table 1: Coast Weather Zone August 2024 Forecast Scenarios**

**Historical Weather Year**

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Rank** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **Average** |
| 1 | 21,396 | 21,651 | 21,719 | 22,387 | 21,777 | 21,471 | 21,445 | 22,193 | 21,536 | 21,015 | 21,437 | 21,834 | 21,681 | 21,400 | 21,612 | 21,637 |
| 2 | 21,178 | 21,492 | 21,662 | 22,352 | 21,763 | 21,464 | 21,370 | 22,037 | 21,505 | 21,011 | 21,349 | 21,834 | 21,557 | 21,325 | 21,590 | 21,566 |
| 3 | 21,111 | 21,411 | 21,652 | 22,088 | 21,595 | 21,445 | 21,292 | 21,853 | 21,461 | 20,932 | 21,275 | 21,794 | 21,495 | 21,261 | 21,569 | 21,482 |
| 4 | 21,081 | 21,403 | 21,650 | 22,043 | 21,574 | 21,436 | 21,198 | 21,737 | 21,428 | 20,920 | 21,248 | 21,785 | 21,488 | 21,253 | 21,518 | 21,451 |
| 5 | 20,991 | 21,400 | 21,613 | 22,025 | 21,407 | 21,427 | 21,125 | 21,690 | 21,417 | 20,909 | 21,246 | 21,748 | 21,448 | 21,225 | 21,517 | 21,413 |
|  | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . |
|  | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . |
|  | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . |
| 740 | 12,134 | 12,455 | 12,504 | 13,248 | 12,424 | 12,244 | 11,962 | 11,964 | 12,268 | 11,785 | 12,439 | 12,992 | 12,305 | 12,640 | 12,761 | 12,408 |
| 741 | 12,133 | 12,439 | 12,478 | 13,188 | 12,408 | 11,997 | 11,817 | 11,836 | 12,195 | 11,750 | 12,374 | 12,974 | 12,294 | 12,618 | 12,745 | 12,350 |
| 742 | 12,103 | 12,411 | 12,461 | 13,151 | 12,395 | 11,868 | 11,783 | 11,831 | 12,129 | 11,731 | 12,273 | 12,967 | 12,264 | 12,596 | 12,706 | 12,311 |
| 743 | 12,099 | 12,400 | 12,377 | 13,106 | 12,297 | 11,778 | 11,773 | 11,809 | 12,120 | 11,686 | 12,217 | 12,928 | 12,225 | 12,573 | 12,675 | 12,271 |
| 744 | 12,084 | 12,330 | 12,360 | 12,985 | 12,137 | 11,749 | 11,764 | 11,803 | 12,107 | 11,638 | 12,184 | 12,878 | 12,190 | 12,459 | 12,566 | 12,216 |

Weather Zone Normal Weather Winter Peak Demand Forecast

The fifteen weather load forecast scenarios are used as the basis for creating the weather zone normal weather winter peak forecast. Each of the fifteen hourly weather load forecast scenarios are separated into individual calendar year forecasts (covering calendar years 2024-2033). The maximum forecasted hourly value occurring during the winter season (defined as December through March) is determined for each year. The winter peak

demand values from each weather scenario for a particular year are averaged to determine the normal weather forecasted winter peak value. For example, to determine the normal weather forecasted winter peak value for 2024, take the highest forecasted value from each of the fifteen weather load forecast scenarios for December 2023 – March 2024 and average them. The forecasted winter peak demand is then assigned to January and replaces the previously calculated peak (rank 1) forecasted value for the month of January. The weather zone normal weather winter peak demand forecast is then summed with electric vehicle, rooftop PV, and large flexible load forecasts.

Example:

Table 3 (below) shows the forecasted winter peak demand for the Coast weather zone for the winter of 2024 based on the historical weather years of 2008-2022. The forecasted net winter peak demand for Coast is 17,082 MW.

**Figure 4: ERCOT Winter Coincident Peak**

Weather Zone Normal Weather Hourly Forecast Mapping to Calendar

The next step is to map the weather zone average hourly forecasts into a representative calendar. Remember that the average hourly forecast is ranked from highest to lowest value within each forecasted month. The sorted hourly forecasted values need to be mapped into a representative time-sequenced shape. This was accomplished by looking at historical load data from calendar years 2008-2022. For each month in each historical year, the rank of all of the observations for each day and hour was determined. Then, the corresponding forecasted average hourly values were mapped to the day and hour from the historical year with the same month and the same rank.

Example:

The Coast Gross Summer Peak Forecast for 2024 is 21,462 MW. Also remember that the forecasted summer peak value is assigned to the month of August. In 2016, Coast’s Summer Peak occurred on 8/09/2016 @ 1600. Using the 2016 mapping ranking, the Coast Summer Peak value is assigned to 8/09 @ 1600 for all forecasted years (2024-2033). This means that the Coast Summer Peak will always occur on 8/09 @ 1600 for all forecasted years that are mapped to 2016.

Example:

In 2015, Coast’s Summer Peak occurred on 8/11/2015 @ 1600. Using the 2015 mapping ranking, the Coast Summer Peak value is assigned to 8/11 @ 1600 for all forecasted years (2024-2033). This means that the Coast Summer Peak will always occur on 8/11 @ 1600 for all forecasted years that are mapped to 2015.

**Historical Weather Year**

**Table 2: Coast Weather Zone 2024 Summer Peak Forecast Scenarios**

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Rank** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **Average** |
| 1 | 21,396 | 21,651 | 21,719 | 22,387 | 21,777 | 21,471 | 21,445 | 22,193 | 21,536 | 21,015 | 21,437 | 21,834 | 21,681 | 21,400 | 21,612 | 21,637 |
| 2 | 21,178 | 21,492 | 21,662 | 22,352 | 21,763 | 21,464 | 21,370 | 22,037 | 21,505 | 21,011 | 21,349 | 21,834 | 21,557 | 21,325 | 21,590 | 21,566 |
| 3 | 21,111 | 21,411 | 21,652 | 22,088 | 21,595 | 21,445 | 21,292 | 21,853 | 21,461 | 20,932 | 21,275 | 21,794 | 21,495 | 21,261 | 21,569 | 21,482 |
| 4 | 21,081 | 21,403 | 21,650 | 22,043 | 21,574 | 21,436 | 21,198 | 21,737 | 21,428 | 20,920 | 21,248 | 21,785 | 21,488 | 21,253 | 21,518 | 21,451 |
| 5 | 20,991 | 21,400 | 21,613 | 22,025 | 21,407 | 21,427 | 21,125 | 21,690 | 21,417 | 20,909 | 21,246 | 21,748 | 21,448 | 21,225 | 21,517 | 21,413 |
|  | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . |
|  | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . |
|  | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . |
| 740 | 12,134 | 12,455 | 12,504 | 13,248 | 12,424 | 12,244 | 11,962 | 11,964 | 12,268 | 11,785 | 12,439 | 12,992 | 12,305 | 12,640 | 12,761 | 12,408 |
| 741 | 12,133 | 12,439 | 12,478 | 13,188 | 12,408 | 11,997 | 11,817 | 11,836 | 12,195 | 11,750 | 12,374 | 12,974 | 12,294 | 12,618 | 12,745 | 12,350 |
| 742 | 12,103 | 12,411 | 12,461 | 13,151 | 12,395 | 11,868 | 11,783 | 11,831 | 12,129 | 11,731 | 12,273 | 12,967 | 12,264 | 12,596 | 12,706 | 12,311 |
| 743 | 12,099 | 12,400 | 12,377 | 13,106 | 12,297 | 11,778 | 11,773 | 11,809 | 12,120 | 11,686 | 12,217 | 12,928 | 12,225 | 12,573 | 12,675 | 12,271 |
| 744 | 12,084 | 12,330 | 12,360 | 12,985 | 12,137 | 11,749 | 11,764 | 11,803 | 12,107 | 11,638 | 12,184 | 12,878 | 12,190 | 12,459 | 12,566 | 12,216 |

**Historical Weather Year**

**Table 3: Coast Weather Zone 2024 -2025 Winter Peak Forecast Scenarios**

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Rank** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **Average** |
| 1 | 16,477 | 16.503 | 18.119 | 18,113 | 15,633 | 16,240 | 17,711 | 16,570 | 15,450 | 16,912 | 18,841 | 15,636 | 14,973 | 20,373 | 17,726 | 17,019 |

In the current LTDEF, Far West, North Central, South, and South Central have shifted summer peak hours from the mapping year peak due to large flexible load and rooftop PV growth impact on the net forecast. As shown in

Figure 5: North Central peaks at hour ending 19, after the sun set, in 2028 and 2029 because the growth rate of rooftop PV is increasing more than base load.

**Figure 5: NCENT NCP Summer Forecast**

This mapping process was completed using calendar years 2008-2022. This produced fifteen different hourly forecasts one based on each calendar year. Note, though, that the monthly peak demand and monthly energy

values are the same in each of the fifteen hourly weather zone forecasts. The only difference is the day and time that the forecasted hourly values occur when mapped to the different historical years.

Example:

There are 744 (31 days times 24 hours per day) hourly forecasted demand values for the Coast weather zone for August. They are mapped into a day and time (in August) based on the historical ranking of actual load values from August 2008, August 2009, August 2010, ..., August 2021, and August 2022. Each forecasted value was assigned a day and hour based on the historical ranking. But the monthly peak demand and monthly energy values are the same no matter which historical mapping year is used.

ERCOT Zone Normal Weather (P50) Hourly Forecast

Each of the fifteen different mapped hourly forecasts based on the historical calendar years of 2008-2022 for each weather zone are summed for each forecasted year, month, day, and hour. This results in fifteen different ERCOT hourly coincident forecasts. The differences among these forecasts are caused by the different timing of weather conditions across the ERCOT region. It bears repeating that all of the underlying weather zone load forecasts have the same exact monthly peak demand and energy values.

To determine which hourly ERCOT coincident forecast to use as the primary and official ERCOT coincident forecast, an analysis was performed on these fifteen different hourly coincident forecasts. The distribution of ERCOT summer peak demand was determined. Seeing that it is very difficult to determine how weather conditions will align or not at the time of ERCOT’s summer peak, the forecast using historical factors from 2008 was deemed the ERCOT official forecast. Using the 2008 historical factors resulted in the least amount of diversity between weather zone demand and ERCOT-wide demand at the time of ERCOT’s summer peak. As shown in Figure 6: ERCOT summer coincident peak shifts from 5:00 PM to 10:00 PM starting in 2028.

**Figure 6: ERCOT Coincident Peak Summer Forecast**

Load Forecast Scenarios (ERCOT system)

The weather zone load forecast scenarios are used as the basis for creating load forecast scenarios for the ERCOT system. The hourly values from each weather zone are summed for each year, month, day, and hour to get the ERCOT total forecasted hourly demand.

Weather Zone 90th Percentile Summer Peak Demand Forecast

Another forecast of interest is the 90th percentile (denoted as P90) weather zone summer peak demand forecast. The process for determining the 90th percentile weather zone summer peak demand forecast is identical to the process used for calculating the base forecast, except that instead of using the average of the fifteen-weather year load forecast scenarios, the 90th percentile of the values is used. This is the methodology for the 90th percentile forecast for planning purposes, the operational 90th percentile forecast is subject to be changed to reflect seasonal conditions.

Weather Zone (P90) Summer Peak Demand Forecast for Far West

Although using weather variation from fifteen historical weather years to derive percentiles works well for most weather zones where load is highly dependent on weather, using weather to derive percentiles does not work

well for Far West, where the load is relatively consistent across weather variations. Instead, economic variation, in particular the Moody’s high economic scenario, was used to derive a 90th Percentile forecast for Far West.

ERCOT Electric Vehicle Forecast

ERCOT’s EV forecast is summarized as follows:

1. Approximately 998,000 Light Duty Vehicles (LDVs) and 103,000 Medium/Heavy Duty Vehicles (MHDVs) are projected to be electric by 2029 in Texas, representing about 4% of the LDV stock and 4% of MHDV stock and therefore 4% of all vehicles on the road. Approximately 96% of electrified LDVs and 93% of MHDVs will be registered in ERCOT’s service territory.

2. The total EV charging load in 2029 is approximately 6 TWh, adding 1.25% of load to ERCOT’s electric load forecast in 2029 up from 0.2% in 2023

Table 4 shows the forecasted EV demand at the time of summer peak, by year.

**Table 4: EV Load at Summer Peak**

|  |  |
| --- | --- |
| **EV Load (MW) at Summer Peak** |  |
| **Year** | **EV Load (MW) at Summer Peak** |
| 2024 | 91 |
| 2025 | 195 |
| 2026 | 278 |
| 2027 | 393 |
| 2028 | 970 |
| 2029 | 747 |

Rooftop PV Forecast

The rooftop solar load forecast was generated by customer class (Residential or Business) at the weather zone level. Usage per customer was modeled to create a typical profile of rooftop solar using weather and calendar drivers, specifically solar irradiance because it captures solar generation well. The modeling dataset contains historical weather and calendar data from January 2012 to July 2023. Recent growth rates that decline over time were used to generate the customer class forecast. The installed capacity in 2029 is 7,392 MWh and the forecasted PV Max is 6,128 MW

**Table 5: Rooftop PV Scenarios**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Year** | **PV Max** | **PV on Summer Peak** |  |  |
| 2024 | (1,467) | (1,061) |  |  |
| 2025 | (2,021) | (1,472) |  |  |
| 2026 | (2,743) | (1,996) |  |  |
| 2027 | (3,658) | (2,649) |  |  |
| 2028 | (4,784) | 0 |  |  |
| 2029 | (6,128) | 0 |  |  |

Large Flexible Loads (LFLs)

Large Flexible Loads are a new type of load that has been growing rapidly in the ERCOT service territory. This load commonly includes crypto miners. This load can come online quickly and is very responsive to real time prices. Large flexible loads are categorized as:

1. Co-located meaning that the load is behind existing generation and

2. Non co-located meaning that the load is not behind existing generation.

There is approximately 1,500 MWs of LFLs on the ERCOT system. The 2024 LTDEF includes a LFL forecast derived by historical Figure 9 load and seasonal variables. The demand contribution of LFLs at the time of ERCOT’s Summer Peak was assumed to be 15% of their total demand based on observed historical summer response.

Other Forecast Adjustments

A portion of the load in the city of Lubbock was moved into the ERCOT Region in 2021, and the entire load was moved into ERCOT by the end of 2023. An hourly forecast was created for Lubbock based on Lubbock Power and Light’s (LP&L) peak forecast of its own growth. This separate forecast for Lubbock was added to the ERCOT forecast from LP&P’s projected integration date onward. LP&P’s forecasted load was added to the North weather zone.

Additional Rayburn Country Electric Cooperative (RCEC) load was included in the East weather zone. This load was initially added to the East weather zone in January 2020. A forecast was created based on data included from RCEC’s PUCT filing.

Winter Weather Scenarios: Uri and Elliott

Weather zone normal weather hourly forecasts from the 2024 LTDEF were used to anticipate the impacts of future winter storms to the ERCOT system. February 2021 weather was used to create forecasts that simulate the historical weather from Uri and reflect the economic growth in the region. Winter Storm Elliott (December 2022) was also used to create a weather scenario for future planning. Tables 4 and 5 show the winter peaks using the two weather scenarios described above.

**Table 6: February 2021 Winter Weather Scenario**

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| 89,580 | 91,958 | 94,047 | 96,087 | 97,937 | 99,684 | 101,412 |

**Table 7: December 2022 Winter Weather Scenario**

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| 81,392 | 83,472 | 85,508 | 87,552 | 89,304 | 91,034 | 92,740 |

**Load Forecast Uncertainty**

A long-term load forecast can be influenced by a number of factors. The volatility of these factors can have a major impact on the accuracy of the forecast. This document will cover the following five areas:

1. Weather,
2. Economics,
3. Energy Efficiency,
4. Price Responsive Loads,
5. Large Industrial Loads

Weather Uncertainty

Figure 7 (page 17) suggests the significant impact of weather in forecasting. This figure shows what the 2024 forecasted peak demand would be using the actual weather from each of the past fifteen years as input into the model. As shown, there is considerable variability ranging from 78,594 MW using 2021’s weather to 85,006 MW using 2011’s weather. This equates to approximately an 8% difference in the forecast based on historical weather volatility. This variation is due to differences in weather and calendar factors between the fifteen historical weather years.

Figure 8 (page 18) depicts weather volatility out to 2029. Assuming 2021 weather (identified as the mild weather scenario) in 2029, would result in an expected peak of 84,126 MW. Assuming 2011 weather (identified as the extreme weather scenario) in 2029, results in a forecasted peak demand of 90,001 MW. This equates to approximately a 7% difference in the forecast based on weather extremes.

Economic Uncertainty

Economic uncertainty impacts the premise forecasts. Stated differently, significant changes in economic forecasts will have impacts on the premise forecasts which, in turn, will be reflected in the peak demand and energy forecasts. A recent example was the impact COVID-19 had on economic forecasts. Premise forecasts were created using the base economic scenario from Moody’s Analytics.

**Figure 7: 2024 Summer Peak Demand Scenarios**

Energy Efficiency

Energy efficiency is another source of uncertainty. First, it must be recognized that the 2024 LTDEF was a “frozen efficiency” forecast. That means the forecast model employs statistical techniques that estimate the relationships between load, weather, and economics based on historical data from January 2018 through May 2022. The implicit assumption in the forecast is that there will be no significant change in the level of energy efficiency during the forecasted timeframe when compared to what occurred during the historical period used in the model building process. This means that the models assume the thermal characteristics of the housing stock and the characteristics of the mix of appliances will remain relatively the same throughout the forecast horizon.

Price Responsive Loads

Price responsive load programs are another area of uncertainty. Determining the impact of these programs is challenging, especially when you consider that ERCOT’s price caps have increased from $1,000/MWh to $9,000/MWh followed by cut to $5,000/MWh. There have typically been few times with very high prices. This makes forecasting their impacts difficult due to a scarcity of data. There remains much uncertainty as to what future levels these programs may achieve.

Like Energy Efficiency, it must be recognized that the 2022 LTDEF is a “frozen” forecast with respect to price responsive loads. Price responsive loads are reflected in the forecast at the level that was observed

during the historical period of January 2018 – May 2022. In the future, ERCOT may create price responsive load scenarios, which would adjust the forecasted peak demands.

**Figure 8: Summer Peak Forecast Uncertainty Due to Weather**

Large Industrial Loads

A key challenge in creating a load forecast is to determine if the model is adequately capturing the impact of future large industrial loads. Examples include liquefied natural gas facilities, oil and gas exploration, chemical processing plants, hydrogen production facilities, etc. In addition, ERCOT had discussions with Transmission Service Providers (TSPs) and gathered information on the expected growth of industrial load within their service territories. ERCOT carefully reviews the historical performance of long-term load forecasts to determine how well large industrial growth has been captured. Based on the results of this evaluation and on data gathered from the TSPs, ERCOT may use this information to adjust the long-term load forecast.

**Appendix A**

**Peak Demand and Energy Forecast Summary**

|  |  |  |
| --- | --- | --- |
| Year | Summer Peak Demand (MW) | Energy (TWh) |
| 2024 | 82,239 | 472 |
| 2025 | 83,291 | 488 |
| 2026 | 84,172 | 505 |
| 2027 | 84,962 | 522 |
| 2028 | 86,623 | 537 |
| 2029 | 88,141 | 549 |
| 2030 | 89,114 | 556 |
| 2031 | 90,797 | 566 |
| 2032 | 92,449 | 578 |
| 2033 | 94,072 | 587 |

1. *See ERCOT Nodal Protocols, Section 2.* [↑](#footnote-ref-1)
2. *See ERCOT Nodal Protocols, Section 18.6.1.* [↑](#footnote-ref-2)