2021 ERCOT System Planning

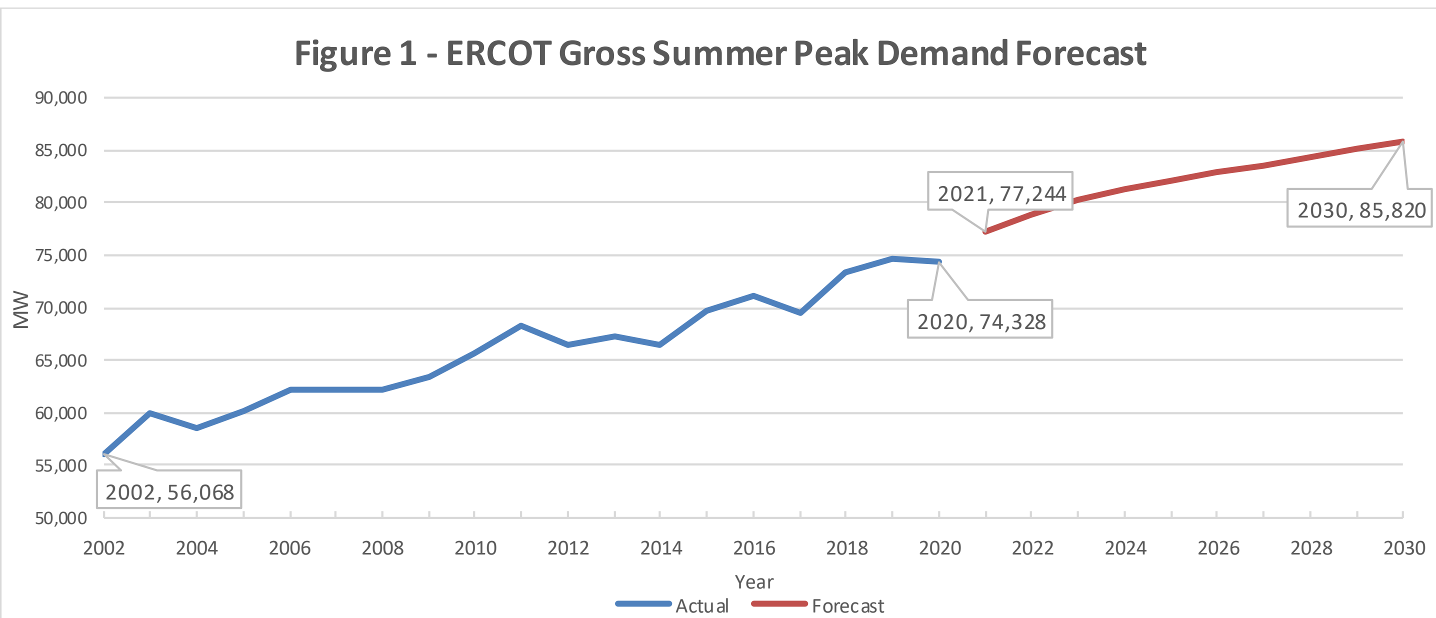
Long-Term Hourly Peak Demand and Energy Forecast

January 8, 2021

Executive Summary

The 2021 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., temperature, heating and cooling degree days, cloud cover, and wind speed), 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. Fifteen years of historical weather data was provided by Schneider Electric/DTN for 20 weather stations.

As shown in Figure 1, the 2021 LTDEF depicts system peak demand increasing at an average annual growth rate (AAGR) of approximately 1.2% from 2021-2030. Historically, summer peak demand has grown at an AAGR of 0.9% from 2011-2020.



As shown in Figure 2, historical annual energy for the calendar years 2011-2020 grew at an AAGR of 1.5%. The forecasted AAGR for energy from 2021-2030 is 2.0%.

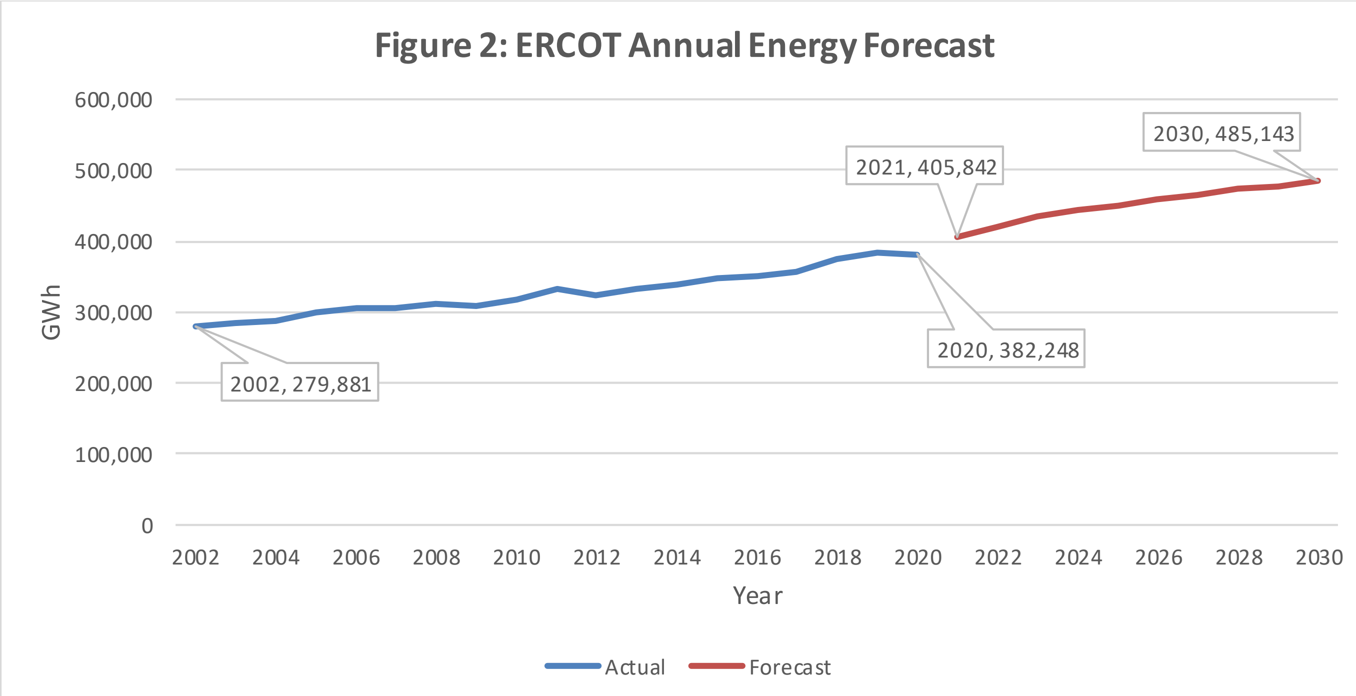


Figure 2: ERCOT Annual Energy Forecast
600,000
500,000
400,000
300,000
200,000
100,000
0
GWh
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
Year
2002, 279,881
2020, 382,248
2021, 405,842
2030, 485,143
Actual
Forecast

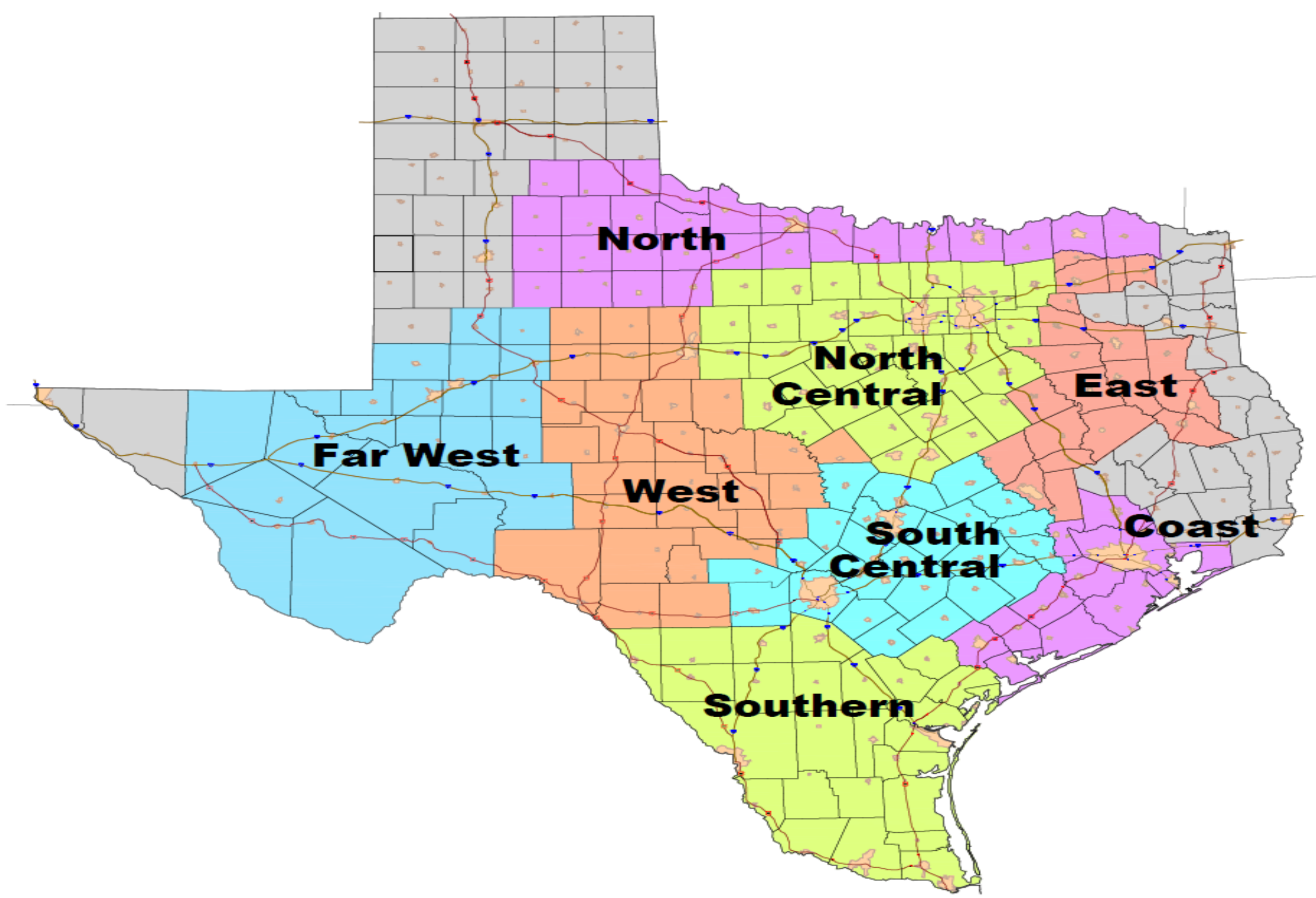
Introduction

This report gives a high-level overview of the 2021 LTDEF. The forecast methodology is described, highlighting its major conceptual and statistical underpinnings. The 2021 forecast results are presented in a manner comparing them to the 2020 LTDEF to allow for a direct comparison of results. This year ERCOT created a rooftop PV forecast. The rooftop PV forecast methodology is also described. Finally, an examination is presented describing the six major sources of forecast uncertainty: weather, economics, energy efficiency, demand response, on-site distributed generation, and electric vehicles.

Modeling Framework

ERCOT consists of eight distinct weather zones (Figure 3). Weather zones[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. In order to reflect the unique weather and load characteristics of each zone, separate load forecasting models were developed for each of the weather zones.

Figure 3: ERCOT Weather Zones



[1] *See ERCOT Nodal Protocols, Section 2.*

The 2021 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 of the model descriptions included in this document should be understood as referring to weather zones. The ERCOT forecast is calculated as the sum of all of the weather zone forecasts.

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]).

All premise models were developed using historical data from January 2015 through August 2020. An autoregressive model (AR1) was used for all premise models.

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.

[2] *See ERCOT Nodal Protocols, Section 18.6.1.*

Industrial Premise Forecast

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

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

Premise Model Issues

During the historical timeframe used to create the models, in the Far West and West weather zones, there was a significant increase in the number of premises. This increase was due to an entity opting into ERCOT's competitive market in those two regions in the middle of 2014 and due to an expansion of ERCOT's service territory.

As a result, it was problematic to create accurate premise forecast models for the Far West and West weather zones. These two weather zones instead used economic variables as the key driver of forecasted growth of demand and energy.

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,
    a. Temperature,
    b. Temperature Squared,
    c. Temperature Cubed,
    d. Dew Point,
    e. Cloud Cover,
    f. Wind Speed,
    g. Cooling Degree Days[3] (base 65),
    h. Heating Degree Days[3] (base 65),
    i. Lag Cooling Degree Days[3] (1, 2, or 3 previous days),
    j. Lag Heating Degree Days[3] (1, 2, or 3 previous days), and
    k. Lag Temperature (1, 2, 3, 24, 48, or 72 previous hours).
5. Interactions,
    a. Hour and Day of Week,
    b. Hour and Temperature,

[3] *All Degree Day variables are calculated versus 65 degrees F.*

   c. Hour and Dew Point,
   d. Temperature and Dew Point, and
   e. Hour and Temperature and Dew Point,
6. Number of premises[4], and
7. Non-Farm Employment / Housing Stock / Population[5]

All of 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 area.

Model Building Process

The model building data set was comprised of a randomly selected 60% of the data from January 1, 2015 through August 31, 2020, 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, 2015 through August 31, 2020 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, 2015 through August 31, 2020 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 been 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 2005 through 2019 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 2005 as weather input into the model for all forecasted years (2021-2030). The actual weather data from all days in 2005 was copied into the same day and hour for each of the forecasted years (2021-2030). For example, the actual weather data for 1/1/2005 was copied into 1/1/2021, 1/1/2022, …, and 1/1/2030. Using 2005's weather as input into each weather zone's forecast model results in

[4] *For Coast, East, North, North Central, South, and South Central weather zones.*
[5] *For Far West and West weather zones.*

what is referred to as the 2005 weather load forecast scenario. The 2005 weather load forecast scenario is a forecast that assumes 2005's weather would occur for each forecasted calendar year (2021-2030). This process was completed for each of the historical weather years (2005-2019) individually and resulted in fifteen weather load forecast scenarios for each weather zone for each of the forecasted years 2021-2030. It should be noted that the premise and economic forecasts are the same in each of these fifteen weather scenarios.

The following notation can be used to denote the weather load forecast scenarios:

$HF_{(x,y,z)}$

Where:
HF = hourly demand forecast,
x = weather zone (Coast, East, Far West, North, North Central, South, South Central, and West),
y = historical weather date and time, and
z = forecast date and time.

For example, $HF_{(West,\ 7/24/2008\ 1700,\ 7/24/2021\ 1700)}$, would denote the forecast for 7/24/2021 at 5:00 pm, based on weather from 7/24/2008 at 5:00 pm, for the West weather zone.

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 2021-2030). 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 2021, take the highest forecasted value from each of the fifteen weather load forecast scenarios for August 2021 and average them. To determine the second highest value for August 2021, take the second highest forecasted value for each of the fifteen weather load forecast scenarios for August 2021 and average them. Repeat this process for all hours in August 2021. 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.

Table 1: Coast Weather Zone August 2021 Forecast Scenarios

	Historical Weather Year															
Rank	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Average**
1	21,157	21,103	21,600	21,091	21,968	21,539	22,344	22,793	21,628	21,167	22,157	21,745	21,049	21,289	22,044	21,645
2	20,532	20,936	21,472	20,728	21,374	21,425	22,312	21,321	21,281	21,131	22,091	21,452	21,029	21,231	21,973	21,353
3	20,431	20,864	21,426	20,716	21,311	21,258	22,287	21,261	21,251	21,089	21,659	21,391	20,847	21,151	21,922	21,258
4	20,411	20,583	21,374	20,627	21,254	21,257	22,170	21,197	21,213	20,993	21,615	21,367	20,810	21,105	21,909	21,192
5	20,401	20,546	21,316	20,617	21,199	21,204	22,119	21,169	21,202	20,990	21,570	21,301	20,807	21,072	21,892	21,160
.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
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.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
740	11,762	11,667	11,511	11,315	11,748	11,760	12,945	11,678	11,324	11,140	11,172	11,390	10,757	11,685	12,462	11,621
741	11,707	11,601	11,504	11,271	11,748	11,749	12,916	11,642	11,243	11,046	11,140	11,368	10,757	11,529	12,410	11,575
742	11,705	11,336	11,488	11,232	11,694	11,716	12,792	11,572	11,146	10,947	11,027	11,330	10,721	11,507	12,372	11,506
743	11,702	11,111	11,456	11,127	11,639	11,668	12,777	11,544	10,967	10,936	11,018	11,287	10,663	11,449	12,274	11,441
744	11,620	11,054	11,360	11,121	11,595	11,553	12,764	11,491	10,964	10,908	10,930	11,272	10,587	11,437	12,174	11,389

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 2021-2030). 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 all of 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 2021, take the highest forecasted value in months June through September from each of the fifteen weather load forecast scenarios for calendar year 2021 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 2 (below) shows the forecasted summer peak demand for the Coast weather zone for 2021 based on the historical weather years of 2005-2019. The forecasted summer peak demand for Coast is 21,645 MW.

Table 2: Coast Weather Zone 2021 Summer Peak Forecast Scenarios

	Historical Weather Year																
Rank	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Average**	**90th**
1	21,157	21,103	21,600	21,091	21,968	21,539	22,344	22,793	21,628	21,167	22,157	21,745	21,049	21,289	22,044	21,645	22,524

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 2021-2030). 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 2022, take the highest forecasted value from each of the fifteen weather load forecast scenarios for December 2021 – March 2022 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.

Example:
Table 3 (below) shows the forecasted winter peak demand for the Coast weather zone for the winter of 2022 based on the historical weather years of 2005-2019. The forecasted winter peak demand for Coast is 16,624 MW.

Table 3: Coast Weather Zone 2021 Winter Peak Forecast Scenarios

	Historical Weather Year															
Rank	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Average**
1	15,240	15,516	16,649	16,255	15,944	17,950	17,846	15,798	16,337	17,302	16,744	15,702	17,074	18,456	16,543	16,624

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 2007-2019. 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 Summer Peak Forecast for 2021 is 21,645 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 factors, the Coast Summer Peak value is assigned to 8/09 @ 1600 for all forecasted years (2021-2030). 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 factors, the Coast Summer Peak value is assigned to 8/11 @ 1600 for all forecasted years (2021-2030). This means that the Coast Summer Peak will always occur on 8/11 @ 1600 for all forecasted years that are mapped to 2015.

This mapping process was completed using calendar years 2007-2019. This produced thirteen different hourly forecasts based on calendar years 2007-2019. Note, though, that the monthly peak demand and monthly energy values are exactly the same in each of the thirteen 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 2007, August 2008, August 2009, ... , August 2018, and August 2019. 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 thirteen different mapped hourly forecasts based on the historical calendar years of 2007-2019 for each weather zone are summed for each forecasted year, month, day, and hour. This results in thirteen 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.

In order to determine which hourly ERCOT coincident forecast to use as our primary and official ERCOT coincident forecast, an analysis was performed on these thirteen 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. Stated differently, using the 2008 historical factors resulted in the highest ERCOT coincident summer peak forecast. Figure 4 (below) shows the ranges of ERCOT Summer Peak demands based on using different historical diversity factors.

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.

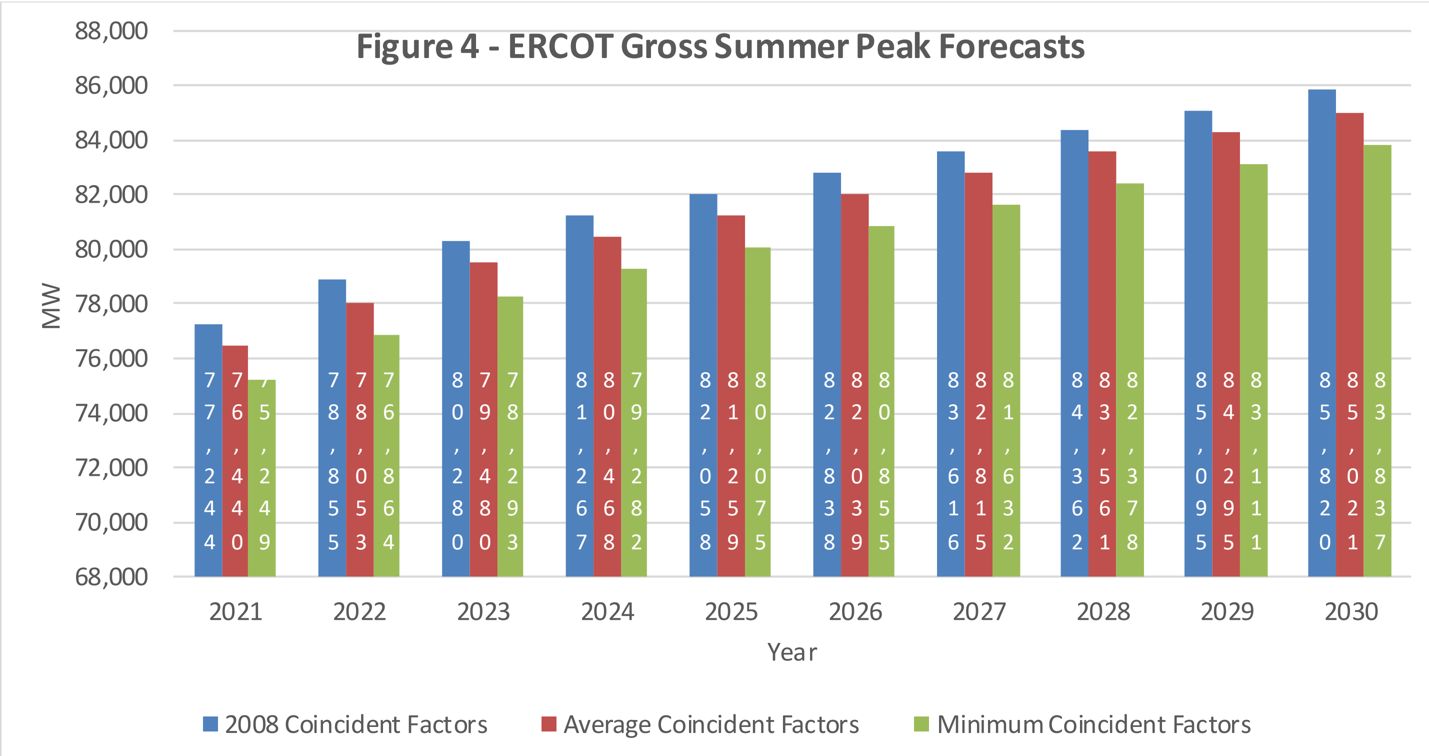


Figure 4 - ERCOT Gross Summer Peak Forecasts

The following notation can be used to denote ERCOT system weather load forecast scenarios:

$$\sum_{x=1}^{8} HF_{(y,z)}$$

Where:
HF = hourly demand forecast,
y = historical weather date and time, and
z = forecast date and time.

For example, $HF_{(7/24/2008\ 1700,\ 7/24/2021\ 1700)}$, would denote the forecast for 7/24/2021 at 5:00 pm, which was based on weather from 7/24/2008 at 5:00 pm, for the ERCOT system.

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 forecast, except that instead of using the average of the fifteen weather year load forecast scenarios, the 90th percentile of the values is used.

Example:
Table 2 (above) shows the forecasted summer peak demand for the Coast weather zone for 2020 based on historical weather years of 2005-2019. The P90 column is the 90th percentile of the fifteen forecasts. The P90 forecasted summer peak demand for the Coast weather zone in 2021 is 22,524 MW.

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 all other 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 fairly 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.

Forecast Adjustments

There are multiple large industrial facilities projected to be operational in the South weather zone during the forecasted years 2021 – 2030. Additions of 75 - 930 MW were made to the South load forecast based on the estimated loads of these large industrial facilities. The assumptions regarding these loads are as follows:

1) The loads will be served by ERCOT (i.e., these loads will not be self-served).
2) The loads will not be price responsive (i.e., these loads will not actively be reduced to avoid transmission charges as part of ERCOT's four Coincident Peak calculations, high price intervals, etc.).
3) The loads will come online on the currently projected integration dates.

A large industrial facility is projected to be operational in the South Central weather zone during the forecasted years of 2021 – 2030. Additions of 24 - 480 MW were made to the load forecast based on the estimated loads of this large industrial facility. The assumptions regarding this load are:

1) The load will be served by ERCOT (i.e., load will not be self-served).
2) The load may be price responsive (i.e., load could actively be reduced to avoid transmission charges as part of ERCOT's four Coincident Peak calculations, high price intervals, etc.).
3) The load will come online on the currently projected integration dates.

Lubbock is joining ERCOT in 2021. An hourly forecast was created for Lubbock based on Lubbock's Peak Forecast of its own growth. This separate forecast for Lubbock was added to the ERCOT forecast from Lubbock's projected integration date onward. Lubbock's forecasted load was added to the North weather zone.

Additional Rayburn 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 the PUCT filing.

Load Forecast Comparison

Figure 5 presents the ERCOT summer peak demand forecasts for 2021-2030 from the 2020 LTDEF and the 2021 LTDEF. Similarly, Figure 6 presents the ERCOT annual energy forecasts for 2021-2030 from the same forecasts.

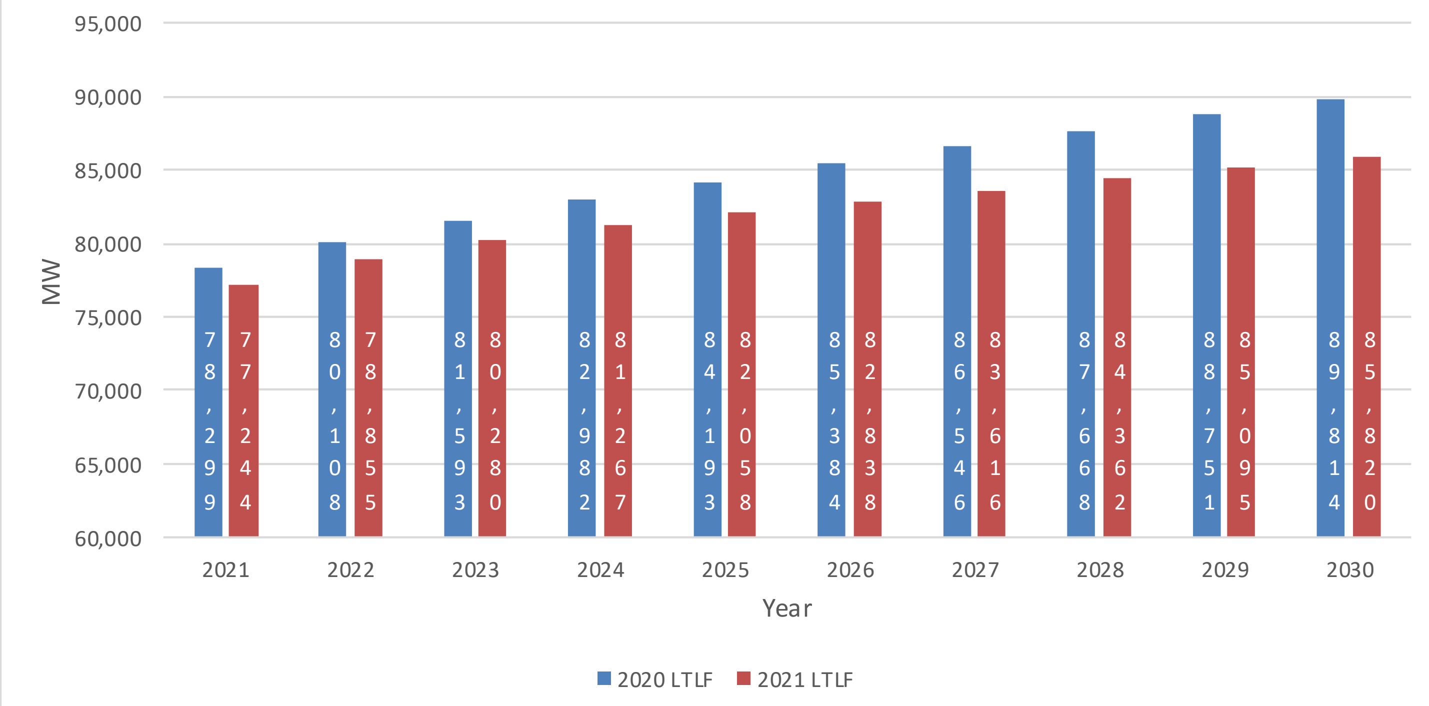


Figure 5 - ERCOT Gross Summer Peak Demand Forecasts

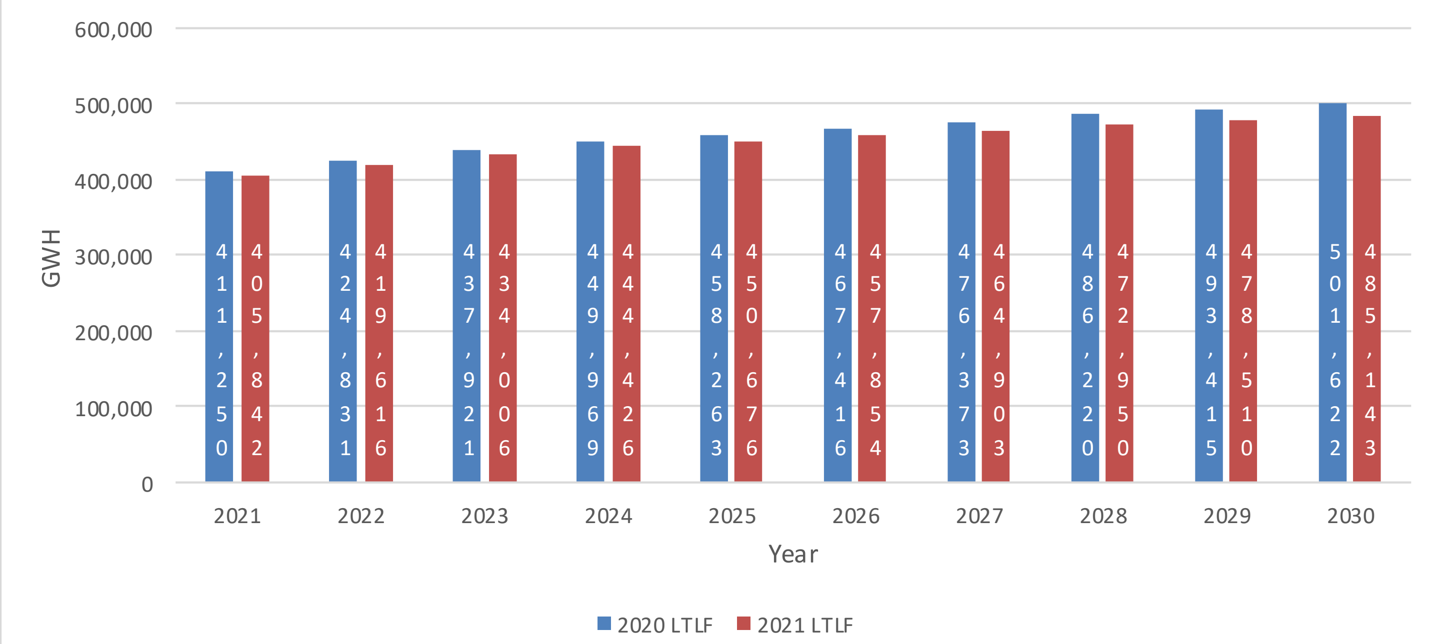
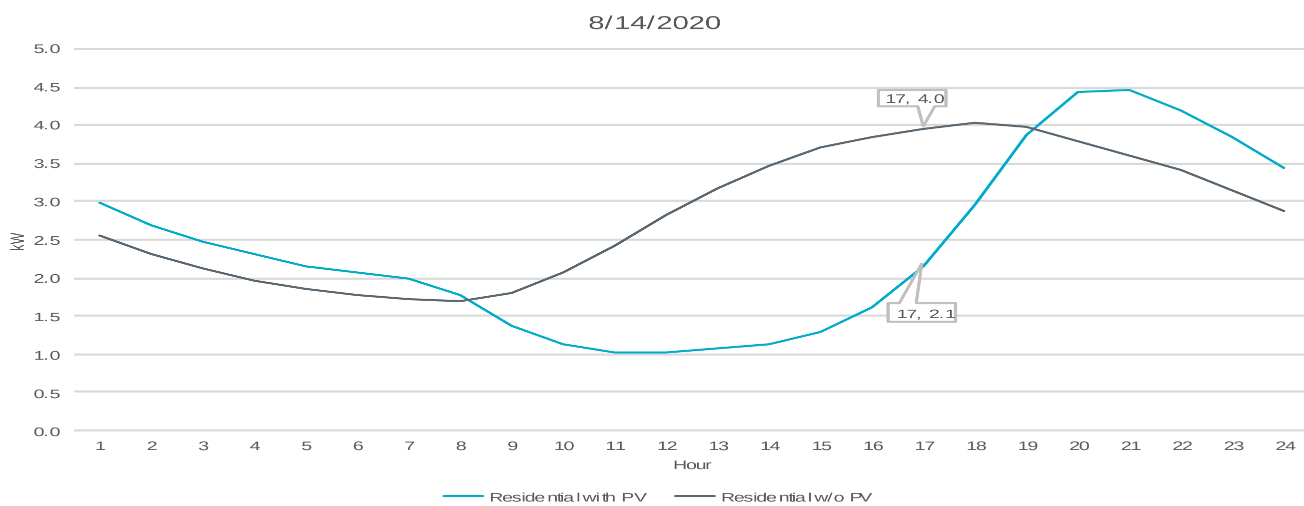


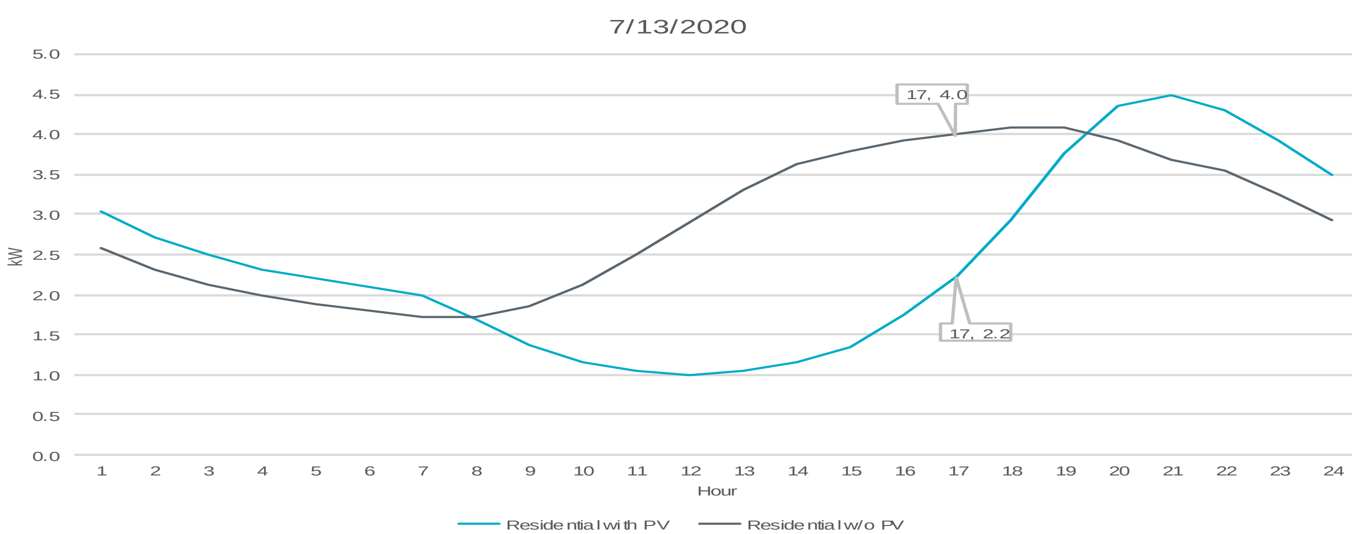
Figure 6 - ERCOT Annual Energy Forecasts

Rooftop PV Forecast

To create the Rooftop PV forecast, data from all ESIDs was used. The 15-minute ESIID usage data was separated into two groups, those with rooftop PV and those without PV. This was determined by the load profile assigned. The monthly peak days from July (7/13/2020) and August (8/14/2020) were used to determine the average hourly kw per ESIID for each group. The difference between the groups represents the average amount of load reduction from the PV group. For the peak hour (5 pm), there was a 46% reduction in load for the ESIIDs that had rooftop PV based on these two days (see Figure 7 below). This percentage reduction was multiplied times the total installed capacity for this summer (approximately 700 MW) to arrive at the total estimated load reduction for the ESIIDs with rooftop PV of 322 MW during the 2020 summer peak. The total installed capacity of rooftop PV is forecasted to grow to approximately 2,100 MW by the summer of 2030. This represents over 640 MW of additional load reduction at the time of ERCOT's summer peak in 2030.

Figure 7 – Comparison of Residential ESIIDs with and without Rooftop PV





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 eight areas.

1. Weather,
2. Economics,
3. Energy Efficiency,
4. Price Responsive Loads,
5. On-site Distributed Generation,
6. Electric Vehicles.
7. Large Industrial Loads, and
8. Change in ERCOT's Service Territory.

Weather Uncertainty

Figure 8 suggests the significant impact of weather in forecasting. This figure shows what the 2021 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 75,045 MW using 2017's weather to 80,178 MW using 2011's weather. This equates to approximately a 7% difference in the forecast based on historical weather volatility. The variation seen in the figure below is due to differences in weather and calendar factors between the fifteen historical weather years.

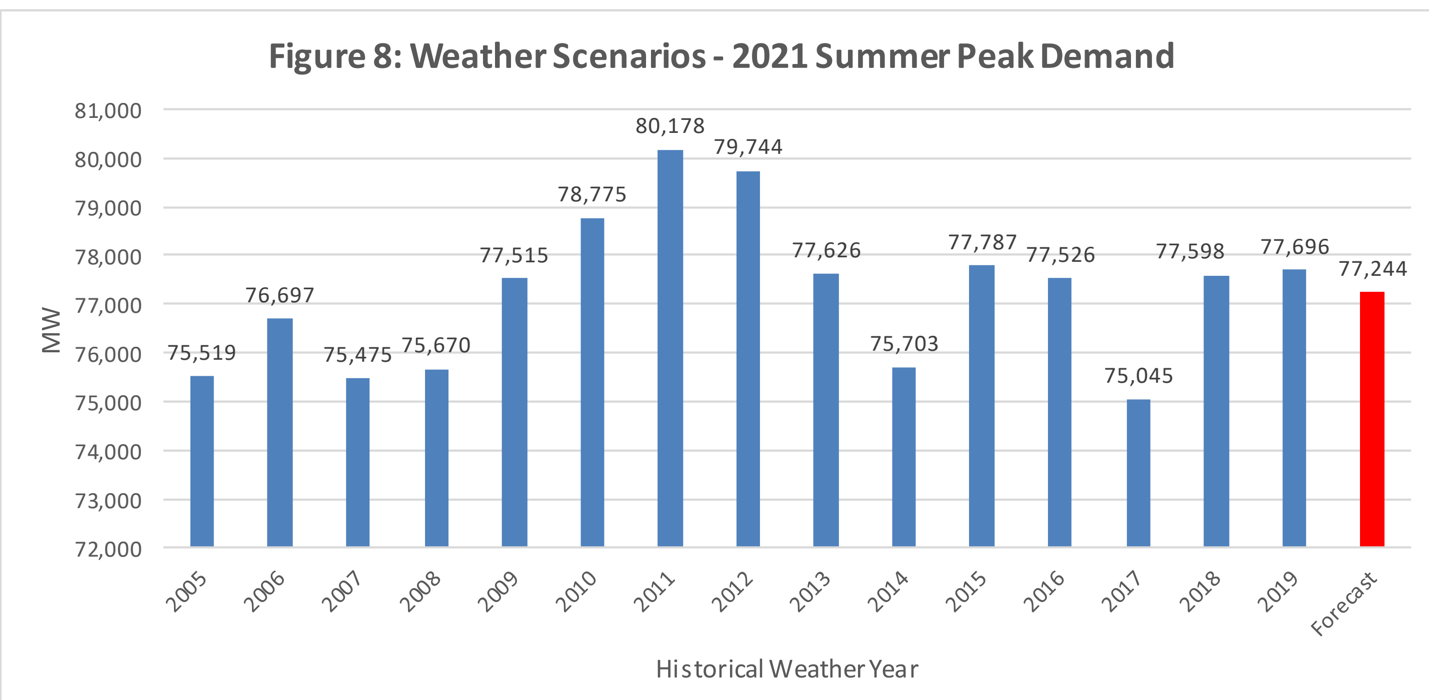
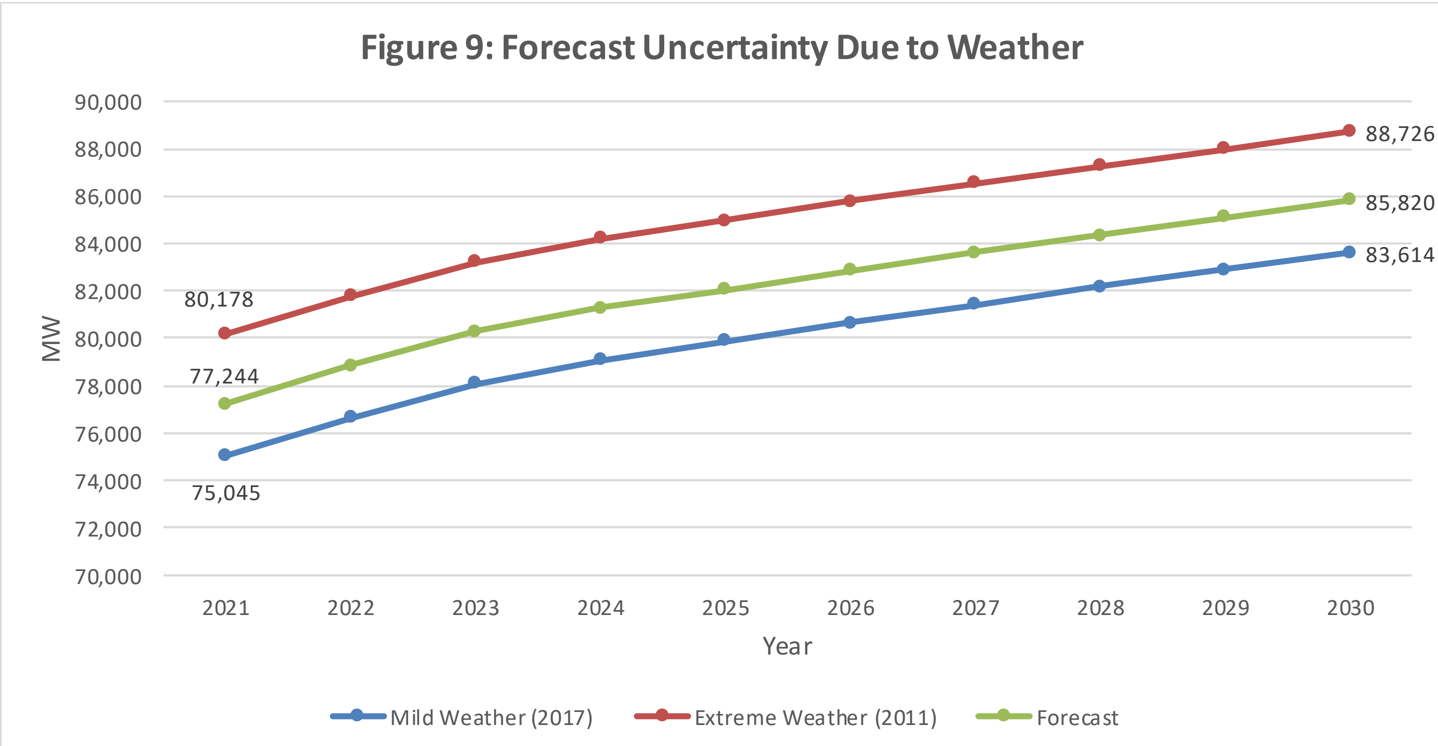


Figure 9 depicts weather volatility out to 2031. Assuming 2017 weather (identified as the mild weather scenario) in 2031, we would expect a peak of 83,614 MW. Assuming 2011 weather (identified as the extreme weather scenario) in 2031, results in a forecasted peak demand of 88,726 MW. This equates to approximately a 6% 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. Premise forecasts were based on the base economic scenario from Moody's Analytics.

Energy Efficiency

Energy efficiency is another source of uncertainty. First, it must be recognized that the 2021 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 2015 through August 2020. 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. Such an assumption has significant implications. Among other things, it 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. If thirty percent of the residential central air conditioners in the South Central weather zone had Seasonal Energy Efficiency Ratios (SEER—a measure of heat extraction efficiency) of twelve during the historical time period, then the model assumes that same proportion in all forecasted years.

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 over the last few years, ERCOT's price caps have increased from $1,000/MWh to $9,000/MWh. There have also 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. Similar to Energy Efficiency, it must be recognized that the 2021 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 2015 – August 2020. In the future, ERCOT may create price responsive load scenarios, which would adjust the forecasted peak demands.

On-site Distributed Generation (DG) excluding Rooftop PV

Another area of uncertainty is on-site distributed generation. Included are technologies such as the following:

1. Distributed Generation (non-renewable),
2. Distributed On-site Wind, and
3. Solar Water Heating.

On-site distributed generation technologies are also characterized by much uncertainty about what future levels may be achieved. The 2020 LTDEF was a "frozen" forecast with respect to on-site renewable generation technologies. On-site renewable generation technologies are reflected in the forecast at the level that was observed during the historical period of January 2015 – August 2020.

Electric Vehicles Uncertainty

The growth of Electric Vehicles (EVs) has been accelerating. As an example, industry forecasts indicate that the number of electric vehicles in Texas will significantly increase by 2030 with estimates ranging from several hundred thousand to one million personal vehicles. This does not include the electrification of mass transit, large trucks, etc. The 2021 LTDEF was a "frozen" forecast with respect to EVs. EVs are reflected in the forecast at the level that was observed during the historical period of January 2015 - August 2020 which was used to build the 2020 LTDEF models. ERCOT plans on developing an Electric Vehicle forecast by the end of 2021.

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, 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. The 2021 LTDEF was adjusted for large industrial loads in the South and South Central weather zones.

Change in ERCOT's Service Territory

Another challenge in creating a load forecast is the potential for ERCOT's service territory to change. As an example, the City of Lubbock is joining ERCOT in 2021. Lubbock's peak load is approximately 500 MW. The 2021 LTDEF includes an hourly forecast for Lubbock (based on the City of Lubbock's forecast of its growth) which was added to the North weather zone forecast. The addition of Rayburn to ERCOT's service territory also necessitated an adjustment to the 2021 LTDEF and it was added to the East weather zone forecast.

Looking Ahead

As more information becomes available and additional data analysis is performed on each of these highlighted areas of forecast uncertainty, ERCOT will begin developing models which quantify their impacts on future long-term demand and energy forecasts. These themes will likely be revisited in the 2022 LTDEF.

Appendix A
Peak Demand and Energy Forecast Summary

Year	Summer Peak Demand (MW)	Energy (TWh)
2021	77,244	406
2022	78,855	420
2023	80,280	434
2024	81,267	444
2025	82,058	451
2026	82,838	458
2027	83,616	465
2028	84,362	473
2029	85,095	479
2030	85,820	485