FEBRUARY 2021

2021 ERCOT ELECTRICITY MARKET OUTLOOK

LCG CONSULTING

4962 El Camino Real, Suite 112
Los Altos, CA 94022
Tel: 650-962-9670
www.EnergyOnline.com

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. INTRODUCTION

February's winter weather has brought a new level of uncertainty to the Texas grid, on top of rapid renewables growth and hot summer weather. Not only did the blackouts solidify the need to plan for extreme weather in winter and summer, but they also brought Texas residents, the governor, and the legislature into a public conversation about demand-supply planning.

Freezing temperatures lead to a new record winter peak demand of 69,222 MW on the evening of February 14. A few hours later, at 12:15 a.m., ERCOT declared emergency conditions and began shedding load. At the worst point, an astonishing 48.6 percent of generation was forced out: more than 52,000 MW. The emergency conditions were resolved February 19, after five days of weather that did not go above 40 F in much of Texas.

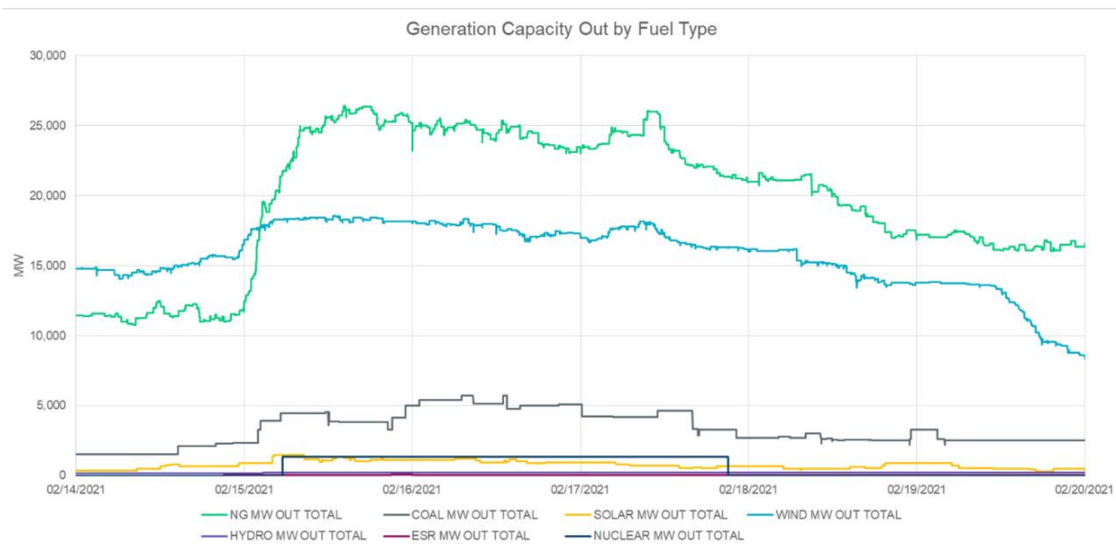


Figure 1 Generation capacity outage by fuel type. Source: ERCOT.

The events lead to widespread blackouts and hearings with legislators. Changes may be coming to several aspects of electricity management in Texas, for example to resource adequacy, ancillary services procurement, and making planned outages contingent on weather.

Now more than ever, Texas stakeholders need to plan carefully and understand each aspect of demand and supply.

This report was prepared with data that took none of these weather events into account. The modeling was done under normal conditions, as our Outlooks have always reflected. However, UPLAN's flexibility allows us to rewrite conditions to model ERCOT under any imaginable future conditions, with outages of any desired number of plants and transmission lines, along any timeframe. We expect to reinvestigate our findings after the Public Utilities Commission of Texas and legislature meet and make any changes, probably by mid-summer. Please contact us for details.

1.1 METHODOLOGY AND ASSUMPTIONS

The nodal market simulations for this study were performed using LCG's proprietary UPLAN Network Power Model (NPM) and PLATO-ERCOT data model utilizing hourly dispatch. UPLAN-NPM is a full network model designed for electricity market simulation. It replicates the engineering protocols and market procedures of any system operator. It also captures the commercial activities, such as bidding, trading, hedging, and contracting, of all players in a deregulated nodal power market. The model performs coordinated marginal (opportunity) cost-based energy and ancillary service procurement, congestion management, full-fledged contingency analysis with Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) replicating those used by the ERCOT ISO. The model prepares a rolling, hourly unit commitment and hourly dispatch while integrating generators' economic and operating characteristics, the SSWG summer network for 2020 published in October 2019, and ERCOT standard planning contingencies. An overview on the UPLAN-NPM and PLATO data model can be found at http://energyonline.com/Products/Uplane.aspx and http://energyonline.com/Products/Plato.aspx.

Generation expansion and retirement assumptions were based on ERCOT publications. In addition, ERCOT publications and other public and private data sources provided electricity demand and transmission network topology assumptions including transmission upgrades, list of contingencies analyzed, list of monitored elements, interface definitions and limits.

LCG's 2021 ERCOT hourly load shapes are based on hourly weather zone load profiles from the 2013 weather year published by ERCOT's Regional Transmission Plan (RTP) Group and modified monthly peak forecasts for each weather zone based on the 50-50 load forecast published by ERCOT in January 2021. Electricity market modeling incorporated above 900 generators, including existing facilities – based on the ERCOT Capacity Demand and Reserves report – and future units that have a Standard Generation Interconnection Agreement – using ERCOT Monthly System Planning reports and LCG assumptions. LCG produces proprietary natural gas price forecasts, as well as sub-bituminous and lignite coal prices, with data from EIA's 2020 Annual Energy Outlook. The study used the SSWG Summer Peak Power Flow Case for 2021 published December 2020 by ERCOT SSWG group for the transmission network. Detailed input assumptions are discussed below in Section 3.

1.2 ANNUAL AVERAGE LOCATIONAL MARGINAL PRICES

Figure 2 below shows a heat map of annual average LMPs in the ERCOT region for 2021. The annual average zonal prices are in general the highest in the Houston zone followed by the South, North, and West zones.

Source: LCG Consulting ERCOT Simulation Results

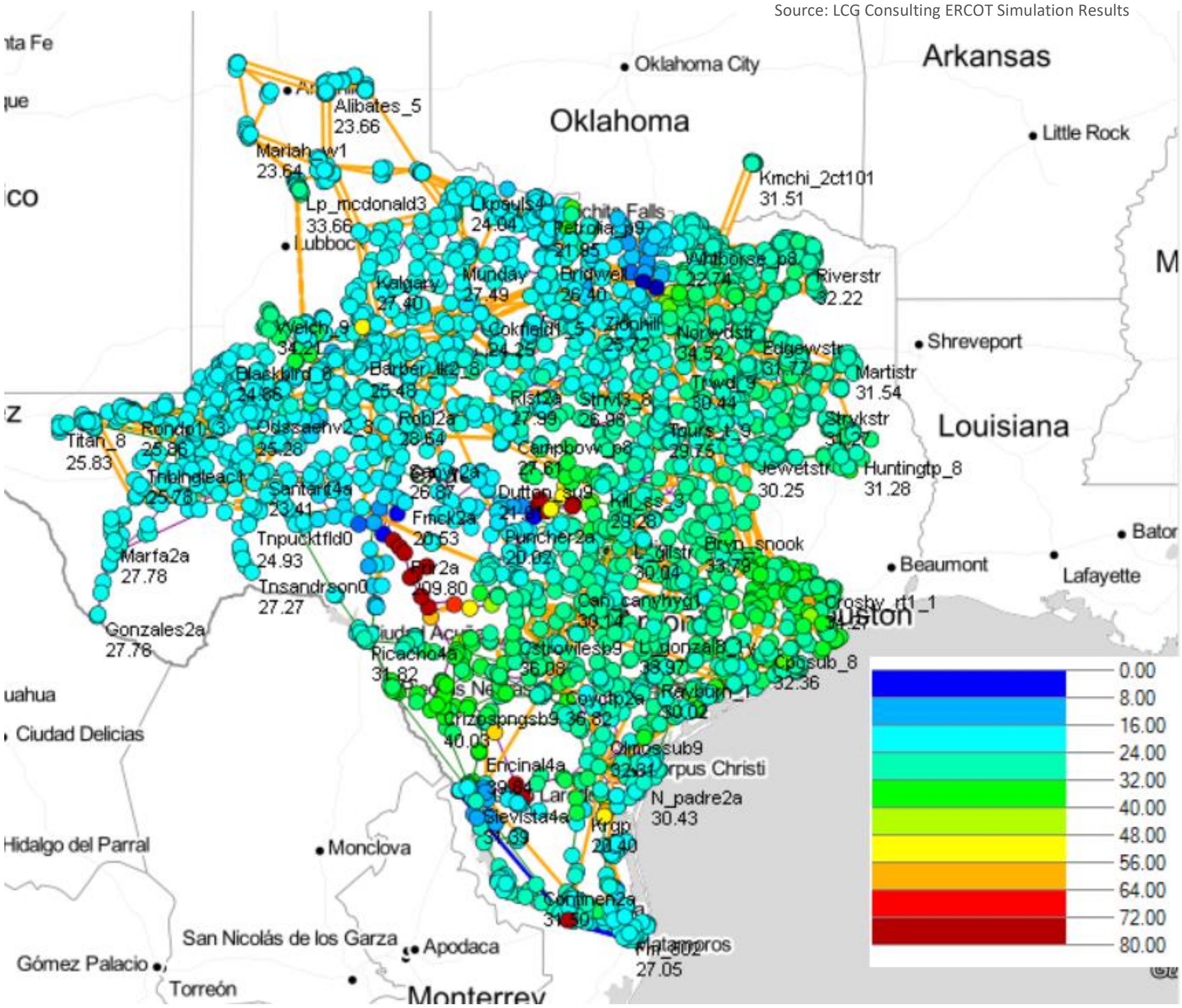


Figure 2 Annual Average Nodal Price Heat Map

2. SIMULATION RESULTS

2.1 GENERATION

In the 2021 simulation, energy in ERCOT continues to come primarily from fossil fuel sources. The rapid increase in wind generation offsets some natural gas and coal generation, but natural gas remains the dominant fuel in ERCOT, accounting for 44.3% of generation. Coal generation is expected to continue to reduce its share of total generation in ERCOT, falling to 14.1% of total generation in 2021, down from 18.0% in 2020[1]. Solar generation doubled from 1.0% in 2019[2] to 2.3% in 2020[3], and is expected to grow to 3.9% in 2021. Wind development continues to grow in ERCOT, bringing wind generation to 26.7% of total generation in 2021, from 22.9% in 2020[4].

Figure 3 shows the annual production by fuel in LCG's 2021 simulation.

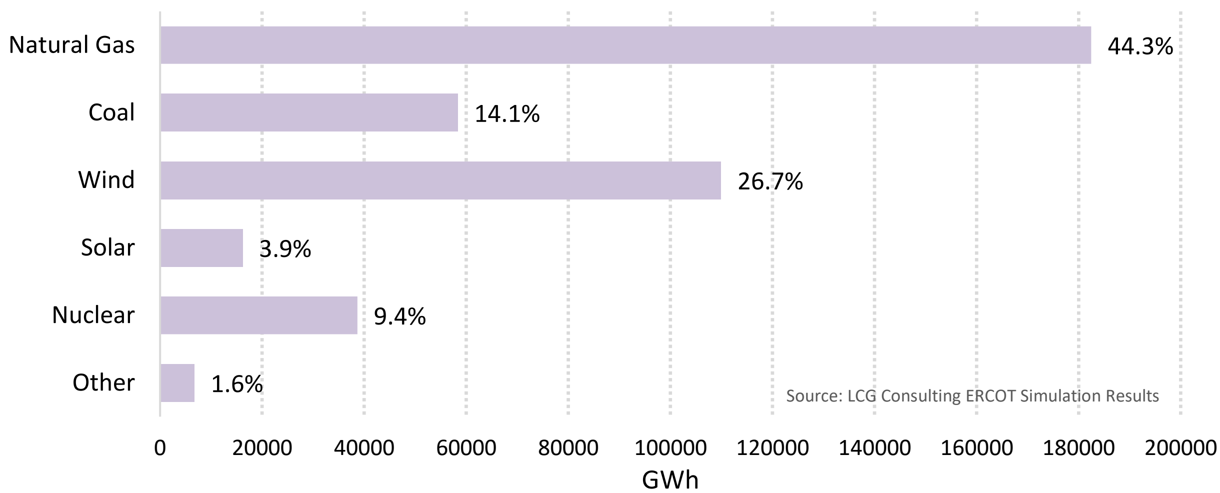


Figure 3 Annual Energy Production by Fuel Type (GWh)[5]

1 2020 ERCOT Demand and Energy report.
2 2019 ERCOT Demand and Energy report.
3 Ibid.
4 Ibid.
5 Contributions from other fuel types including hydro are considered under "Other" fuel type.

The fuel mix varies by season in ERCOT, particularly because summer's experience higher demand and wind resource availability is lower in the summer months when thermal resource generation increases to meet the higher demand. Monthly generation results from the ERCOT 2021 simulation is shown in Figure 4.

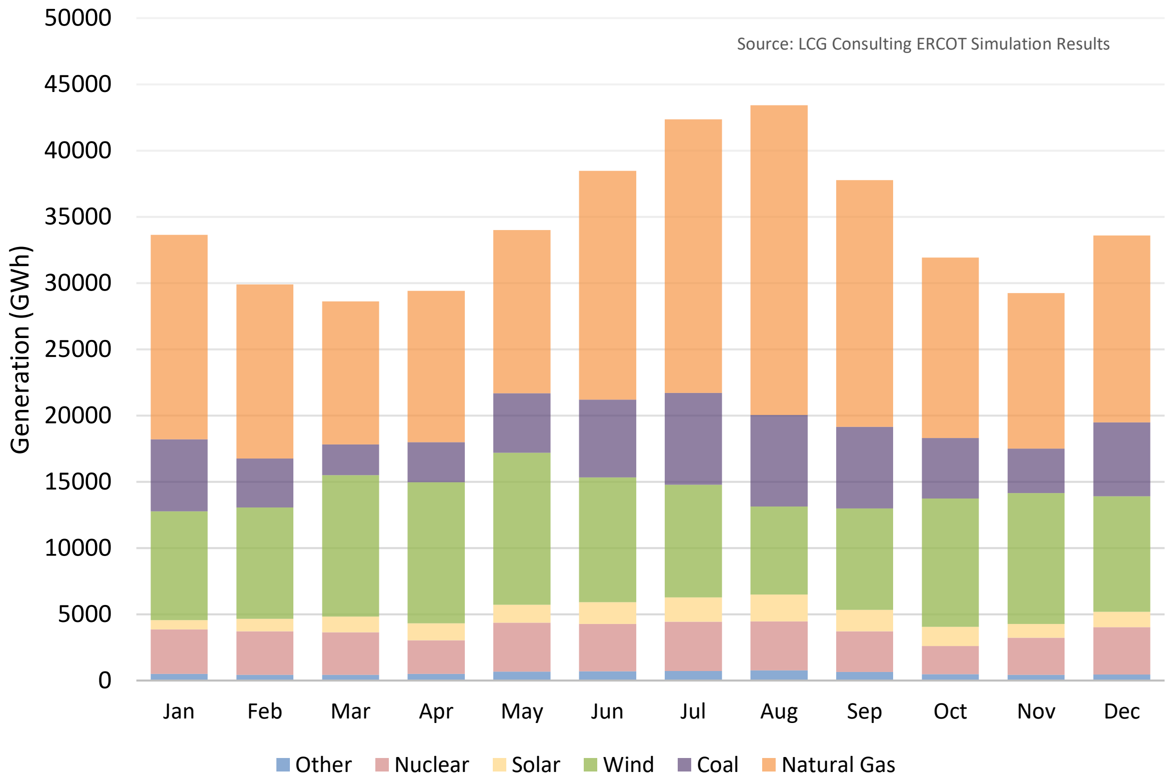


Figure 4 Monthly Generation by Fuel Type – 2021 [6]

For 2021, wind generation is 109,924 GWh, contributing 26.7% of ERCOT's generation portfolio. Figure 5 shows how the projected wind generation for 2021 compared to ERCOT's historical wind generation for prior years. The annual curtailment of wind resources is 4.2% with the lowest average wind output during peak hours of the high demand months (especially in August).

6 Contributions from other fuel types including hydro are considered under "Other" fuel type.

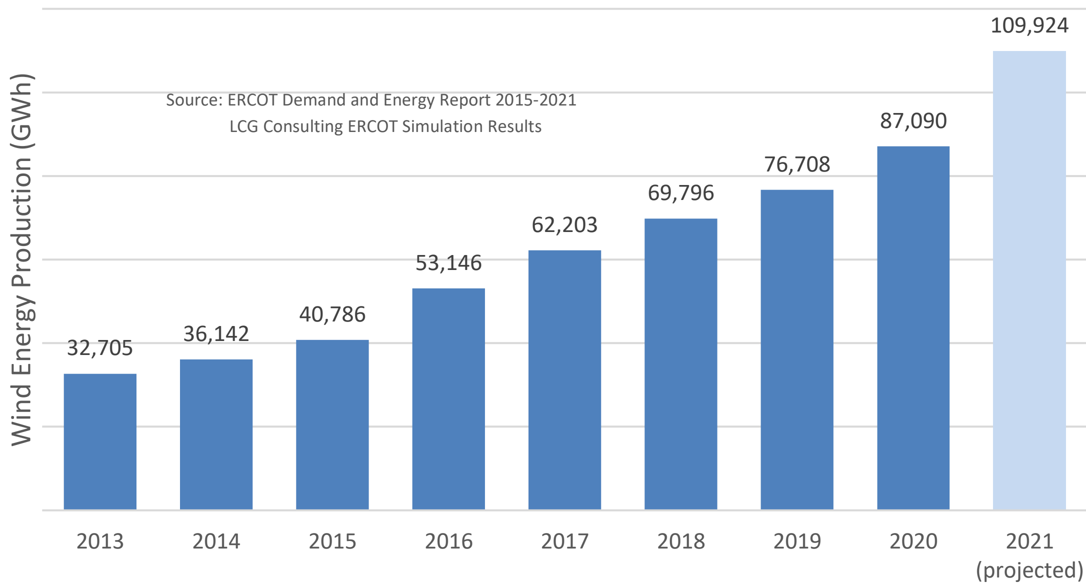


Figure 5 ERCOT Historical and Projected Wind Generation (GWh)

Lower wind output, coupled with higher electricity demand in the hottest summer months, requires more expensive units to come online to serve load at these times, elevating summer prices. With the notable exception of units on the coast, wind units in Texas tend to generate more electricity in the late evening and early morning hours, rather than during high demand hours. Figure 6 below shows the average peak and off-peak system-wide wind output in the 2021 simulation. Curtailment is also outlined in Figure 6. As can be seen here, lowest average wind output coincides with the peak hours of the high demand months.

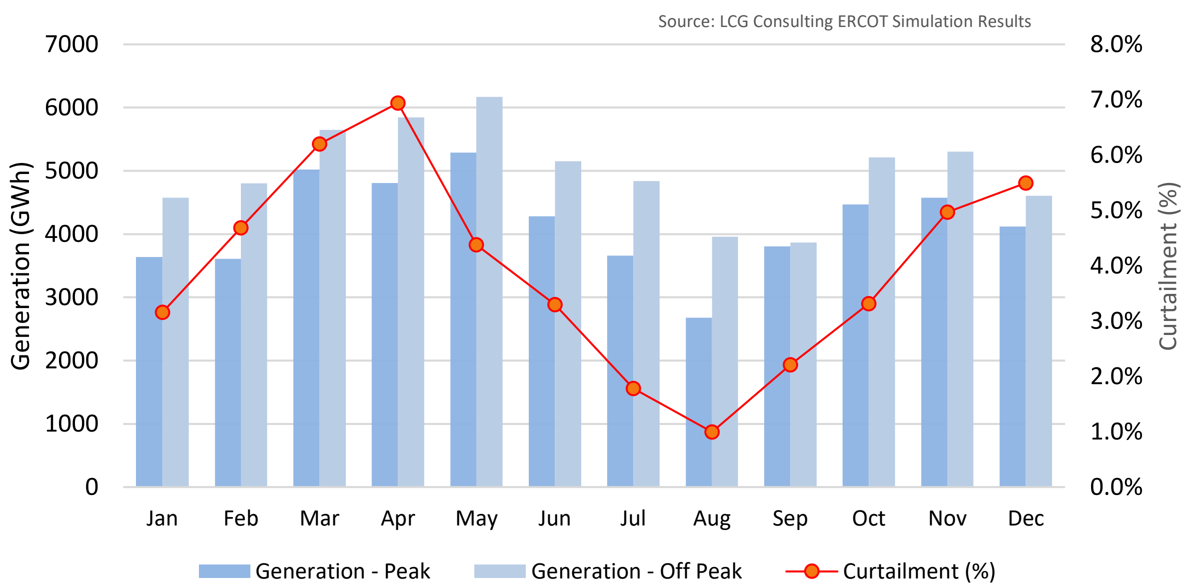


Figure 6 Monthly Average Peak and Off-Peak Wind Generation & Monthly Wind Curtailment – 2021

2.2 CONGESTION

Significant congestion risk exists for certain elements in the system. Table 1 below shows a list of the top congested elements in 2021. The lines are listed in order of their congestion rent, from highest to lowest. Certain elements shown here have been highly congested in recent years and are expected to continue to experience congestion in 2021.

Table 1 ERCOT Annual Congestion – 2021

Map Index	Line Name	Direction F:Forward R:Reverse	Voltage (kV)	Zone
1	SOUTH MCALLEN TO BENTSEN	F	138	SOUTH
2	WEST TNP TO TI TNP	F	138	NORTH
3	NORTH TO HOUSTON GTC	F		NORTH - HOUSTON
4	NORTH EDINBURG TO LOBO GTC	F		SOUTH
5	SONORA TO BONDROAD	F	69	WEST
6	SOUTH TEXAS PROJECT TO WA PARISH CKT 39	F	345	SOUTH - HOUSTON
7	SANDY CREEK TO SUNRISE BEACH	F	69	LCRA
8	BRUNI SUB TRANSFORMER	R	138/69	SOUTH
9	LAS CRUCES TO LAREDO VFT NORTH	R	138	SOUTH
10	BURNS SUB TO RIO HONDO	R	138	SOUTH
11	GUNSIGHT SWITCH TO HOWDEN POD	F	138	WEST
12	CARTERVILLE TO EINSTEIN	R	138	WEST
13	TALL CITY TO TELEPHONE ROAD	R	138	WEST
14	JEFFERSON TO SOUTH CHANNEL	F	138	HOUSTON
15	KENDALL TO BERGHEIM	F	345	SOUTH

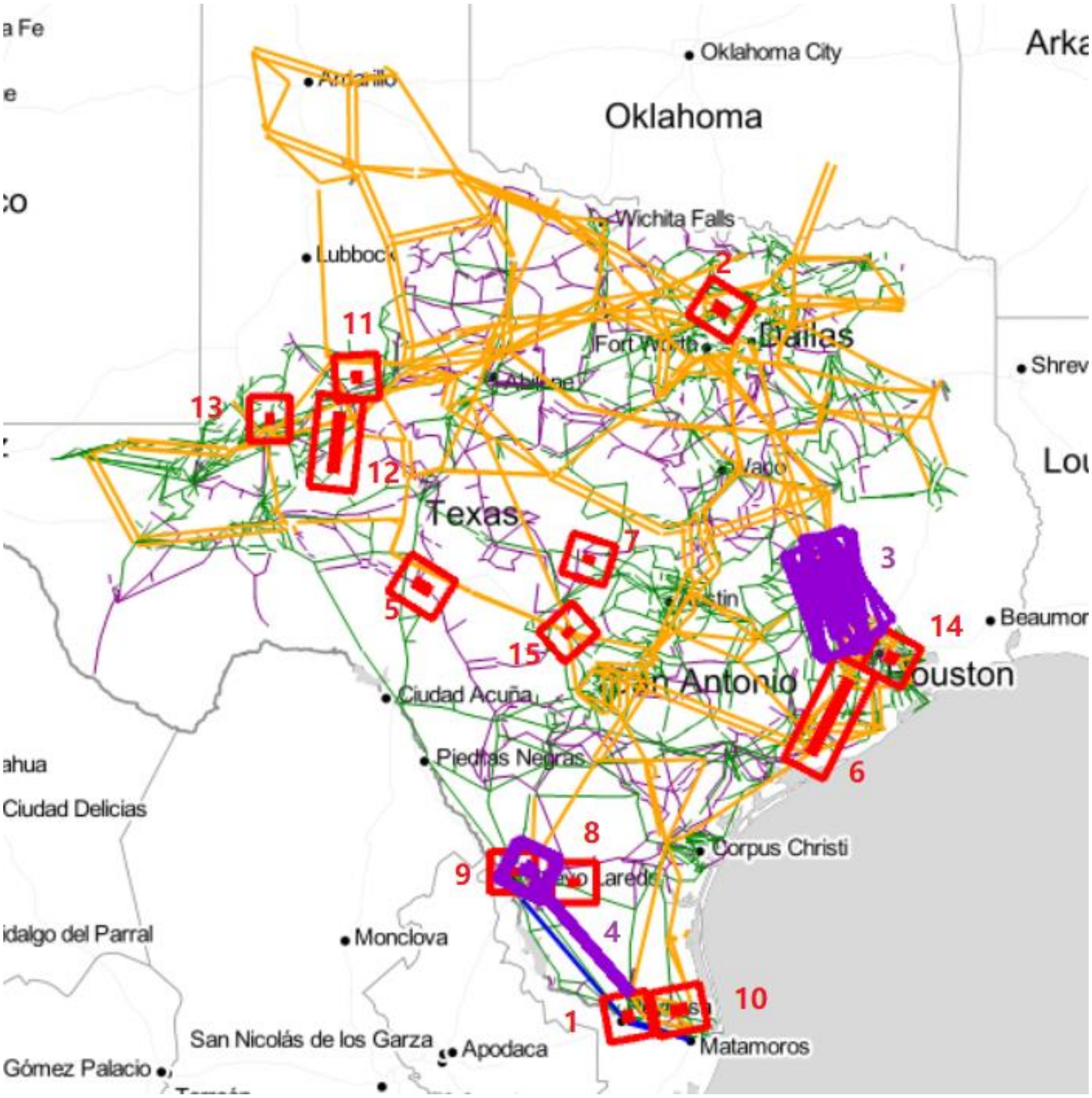
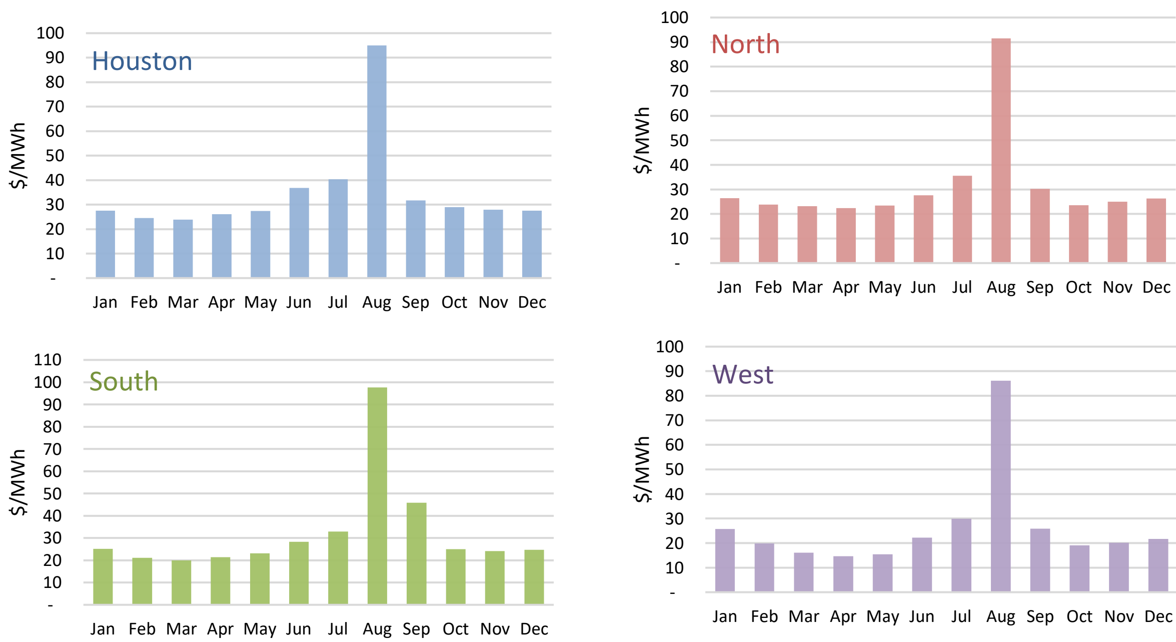


Figure 7 Congested elements on ERCOT map

2.3 LOAD ZONE PRICES

The average price for the West load zone is the lowest and the Houston load zone is the highest for 2021. Figure 8 shows the load-weighted, monthly average prices by load zone. In all four zones, a high price is observed around August in summer compared to other months. These high prices are caused when the spin and non-spin reserve capacities plummet, resulting in a very high ORDC penalty across the system for those hours.



Source: LCG Consulting ERCOT Simulation Results

Figure 8 Monthly Load-Weighted Average Prices ($/MWh) by Load Zone – 2021

Annual average zonal prices shown in Figure 9 are highest in the Houston zone followed by South, North and West zones.

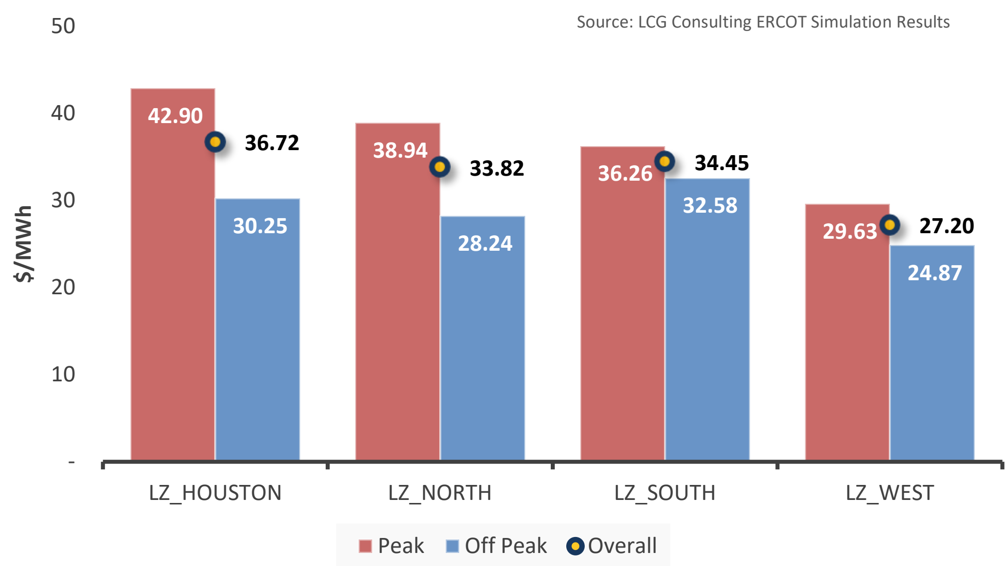


Figure 9 Annual Load-Weighted Average Load Zone Prices ($/MWh) – 2021

Implied heat rate is the electric price divided by the natural gas price. Only a natural gas generator with an operating heat rate (measure of unit efficiency) below the implied heat rate value can make money by burning natural gas to generate power. The lowest implied heat rate happens in April in the West load zone. During non-summer months, the implied heat rate averages around 9 MMBtu/MWh. Monthly implied heat rate is shown in Figure 10.

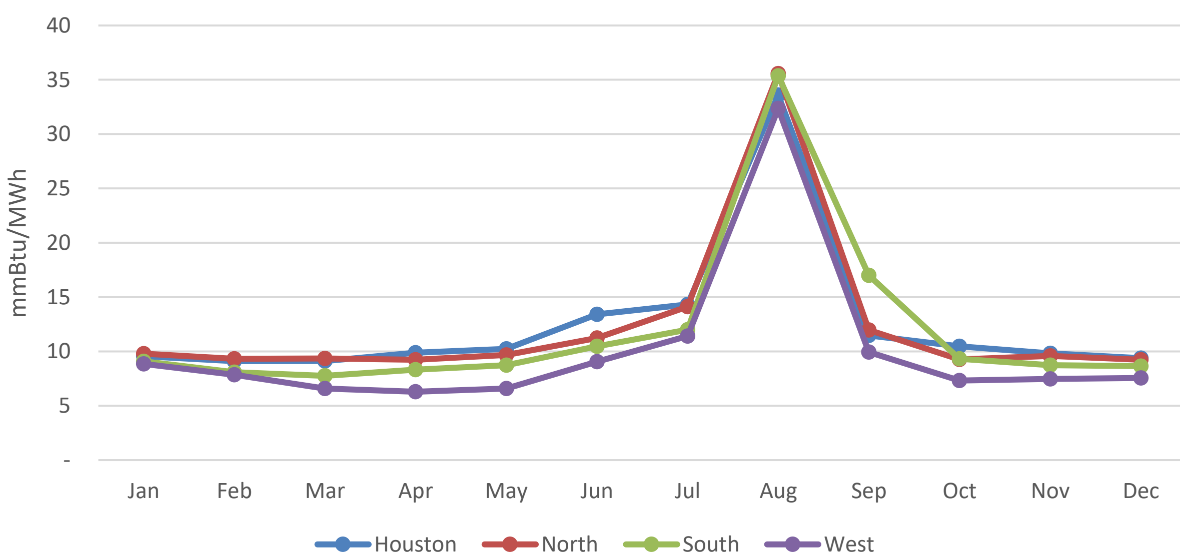


Figure 10 Monthly Implied Heat Rate (IHR) by load zone

2.4 HUB PRICES

ERCOT has defined seven hubs for calculating average LMPs and assisting transactions between hubs, zones and individual buses. Houston: 20 buses; North: 75 buses; South: 31 buses; West: 17 buses; ERCOT Bus average: 143 buses; and ERCOT Hub average: 143 buses. A Panhandle Hub was created on 2019 which includes 12 buses. This Panhandle Hub is excluded from the existing ERCOT Bus average and Hub average.

The most competitive average hub price is observed in the West hub, with progressively more expensive prices experienced in South, North and Houston hubs. The hub price averages are higher during the summer months of June, July and August, with significantly high prices in August, a trend similar to load zone prices. Monthly average prices in 2021 at Houston, North, South and West hubs are shown below in Figure 11.

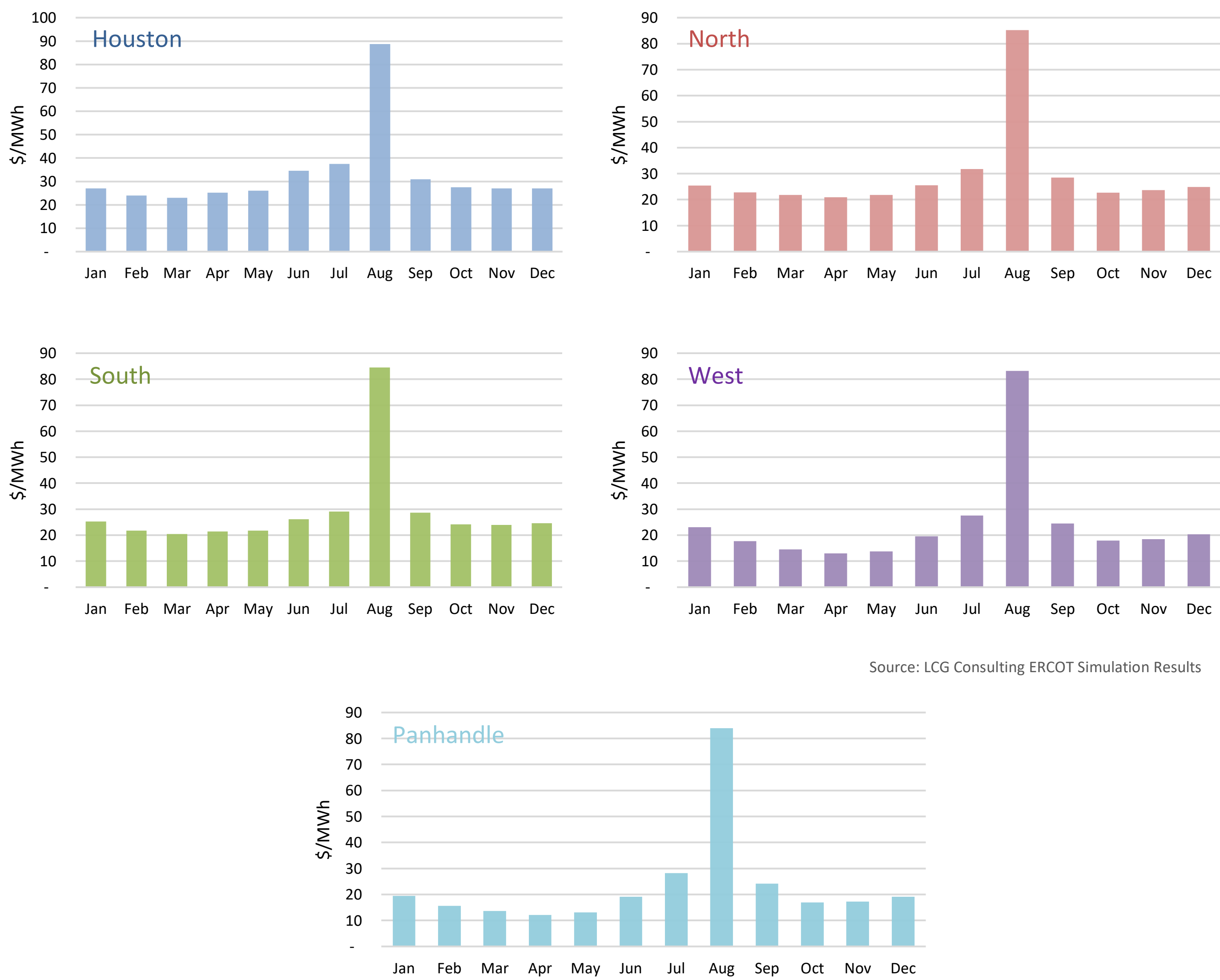


Figure 11 Monthly Average Prices ($/MWh) by Trading Hub – 2021

The highest average hub prices are at the Houston hub, with decreasing electricity prices forecasted at the South, North and West hubs, as shown in Figure 12.

Figure 12 Annual Average Hub Prices ($/MWh) – 2021

3. KEY INPUT ASSUMPTIONS

Simulation of the ERCOT nodal market required detailed, hourly, node-specific information about generation, transmission, loads, and many other economic and engineering parameters. A brief overview of the key inputs for 2021 is provided in this section.

3.1 ELECTRICITY DEMAND

The study uses hourly weather zone load profiles (based on 2013 weather year) published by ERCOT's Regional Transmission Plan (RTP) Group in December 2020. Although the base year for the shape is 2013, the hourly load profile was shifted to 2021 so that when using a historical curve for the future, the weekends line up. Monthly peak forecasts for each weather zone were modified based on ERCOT's 50-50 load forecast published in January 2021. Zonal level loads were then distributed to each load bus using Load Distribution Factors (LDFs) derived from the seasonal SSWG power flow cases, published October 2020. Table 2 shows the forecasted annual peak load and energy demand for 2021 in each weather zone.

Table 2 Annual Peak (MW) and Energy (GWh) Demand by Weather Zone – 2021

Weather Zone	Annual Peak (MW)	Annual Energy (GWh)
COAST	16581	72693
EAST	2515	11271
FAR_WEST	1543	8038
NON CONFORMING (FLAT)	12131	105983
NORTH	1830	8079
NORTH_C	25389	113181
SOUTH_C	12339	57210
SOUTHERN	5122	25786
WEST	1841	9397
ERCOT (NON-COINCIDENTAL)	**77244**	**405842**

3.2 INSTALLED CAPACITY

Over 900 generators are included in this study. Existing facilities relied on the ERCOT's historical SCED data and the Capacity, Demand and Reserve (CDR) Report published in May 2020. Expansion units expected to start service in 2021 originates from the ERCOT Monthly Generation Interconnection Report published in December 2020. Only units that have Signed Interconnection Agreement (IA) with Posted Financial security and Notice to proceed provided were modeled. All generation details are methodically characterized in LCG's proprietary PLATO-ERCOT data model and incorporated into the UPLAN electricity market simulations.

Natural gas-powered generators account for the majority of installed capacity followed by wind and coal resources in 2021. Wind energy plays an important role in the capacity mix with a total nameplate wind capacity of 34,397 MW. This number is not adjusted for Effective Load Carrying Capability (ELCC).

Figure 13 and Figure 14 show installed capacity by zone and fuel type respectively, as modeled in UPLAN simulations.

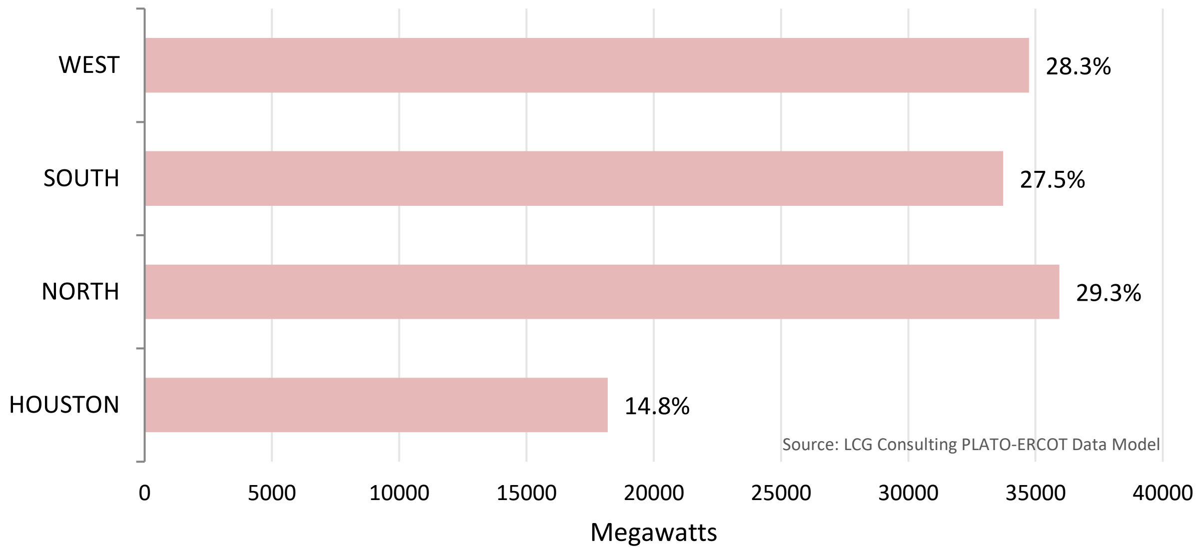


Figure 13 ERCOT Installed Capacity by Zone (MW) – 2021

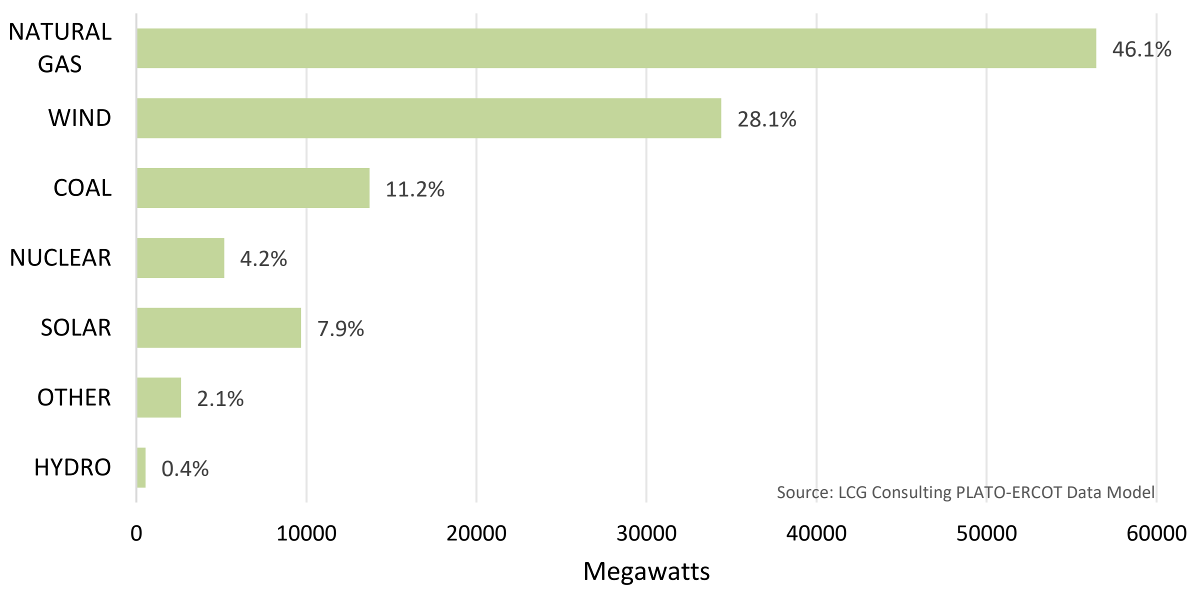


Figure 14 ERCOT Installed Capacity by Fuel Type (MW) – 2021

UPLAN has taken into account approximately 12GW of new capacity in the simulation. Generation expansion capacity by fuel and zone can be seen below in Table 3. Note that these figures include all units with installation date on or after January 1, 2021.

Table 3 Capacity Expansion (MW) by Fuel Type and Zone by 2021

Zone	Wind	Natural Gas	Solar	Battery
HOUSTON	-	11	882	202
NORTH	784	112	1332	152
SOUTH	1108	100	1604	509
WEST	2587	-	3087	143
TOTAL	**4,478**	**223**	**6,905**	**1,006**

LCG's generation retirement data is based ERCOT Approved and Announced retirements. About 250 MW of gas and 150 MW wind unit has been approved to be retired in 2021.

3.3 FUEL PRICES

Monthly gas prices used in the annual simulations for 2021 are based on ICE future prices, published January 2021. Figure 15 shows the 2021 monthly average zonal NG price projections.

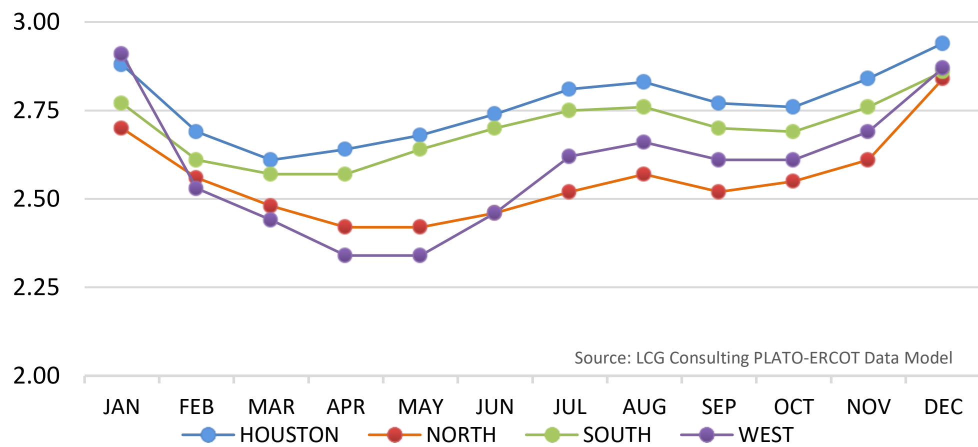


Figure 15 Monthly Natural Gas Price by Zone ($/MMBtu) – 2021

Coal price forecasts are based on the mine mouth prices and transportation rates from the 2020 EIA Annual Energy Outlook published February 2020 and is given in Table 4.

Table 4 Annual Coal Price ($/MMBtu) – 2021

Coal Forecast	Price ($/MMBtu)
Lignite	1.20
Sub-Bituminous	2.50

3.4 TRANSMISSION NETWORK

The base transmission network and its characteristics used in the study come from SSWG seasonal power flow cases for 2021 published by ERCOT in October 2020. Lubbock Power & Light (LP&L) is expected to be join ERCOT starting June 2021 and is therefore included in the simulation for Q3 and Q4. The list of contingencies relies on the ERCOT published Standard contingency list and 2020 RTP Economic cases. All special protection schemes (SPS's) that are in-service and approved by ERCOT have been included. Generic Transmission Constraint (GTC) limits were modeled based on definitions and limits published by ERCOT in December 2020. Table 5 gives an overview of the modeled ERCOT transmission footprint.

Table 5 Transmission Network Characteristics for 2021

Elements	Count
No. of Buses	8,918
No. of Branches	11,298
No. of N-1 Contingencies	6,349
No. of N-X Contingencies	10,107

4. MARKET CONDITIONS AND BACKGROUND

The ERCOT market has experienced dramatic changes since the implementation of the nodal market at the end of 2010: load growth in Texas, integration of renewables, fossil fuel price fluctuations, and changes in protocols, among others. This section provides background on recent developments and trends to consider in the region.

4.1 ERCOT MARKET LANDSCAPE

Transmission infrastructure additions, generation expansion, oil and gas price movements, rapid wind development, and changes in ERCOT market protocols along with evolving federal and state energy policy regimes have all contributed to a changing landscape in the ERCOT market.

As the population of Texas has grown steadily, ERCOT's annual energy demand and peak energy demand have generally increased from 2006 to 2020 with a few notable exceptions like in 2012. Despite the COVID-19 pandemic affecting the country since March 2020, it didn't have huge impact on ERCOT in terms of peak load and energy demand.

Total peak demand in ERCOT has risen from 62,115 MW in 2007 to 74,328 MW in 2020, an increase of about 20% over the thirteen-year period, or an average annual growth rate of approximately 1.4%. As peak load continues to increase in ERCOT, new resources will be necessary to maintain grid stability. According to ERCOT's long term load forecast, summer coincident peak demand is projected to reach 85,820 MW by 2030, indicating an average annual growth rate of 1.4%.

Total annual energy has also risen over the 2007-2020 time period, from 307 TWh in 2007 to 382 TWh in 2020. Growing at an annual average rate of 1.7% from 2007 through 2020, annual energy in the ERCOT footprint is projected to continue growing at an annual average rate of 2.4% through 2030, reaching 485 TWh in that year. Figure 16 below shows the historical and forecasted annual energy, and summer peak demand from 2007 through 2030.

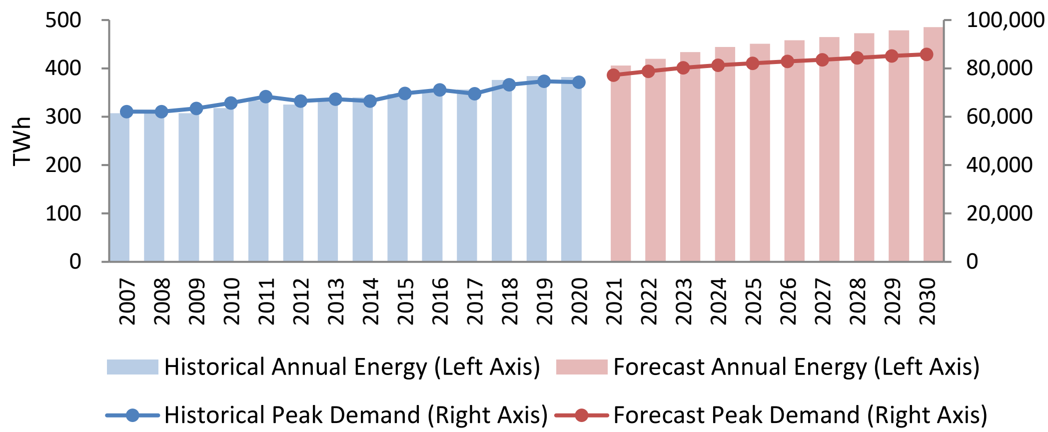


Figure 16 Historical and Forecasted Annual Energy (TWh) and Summer Peak Demand (MW) [7]

4.2 DEMAND AND GENERATION

Despite recent rapid growth in wind power development in ERCOT, generation remains dominated by natural gas resources, with 44.3% of generation coming from natural gas resources in 2020. Coal unit retirements in 2020 brought coal generation from 37% in 2013 to 18% of generation in 2020. Wind generation has grown from 10% in 2013 to 23% in 2020. Figure 17 shows the annual fuel mix percentage in ERCOT's generation portfolio from 2013 through 2020.

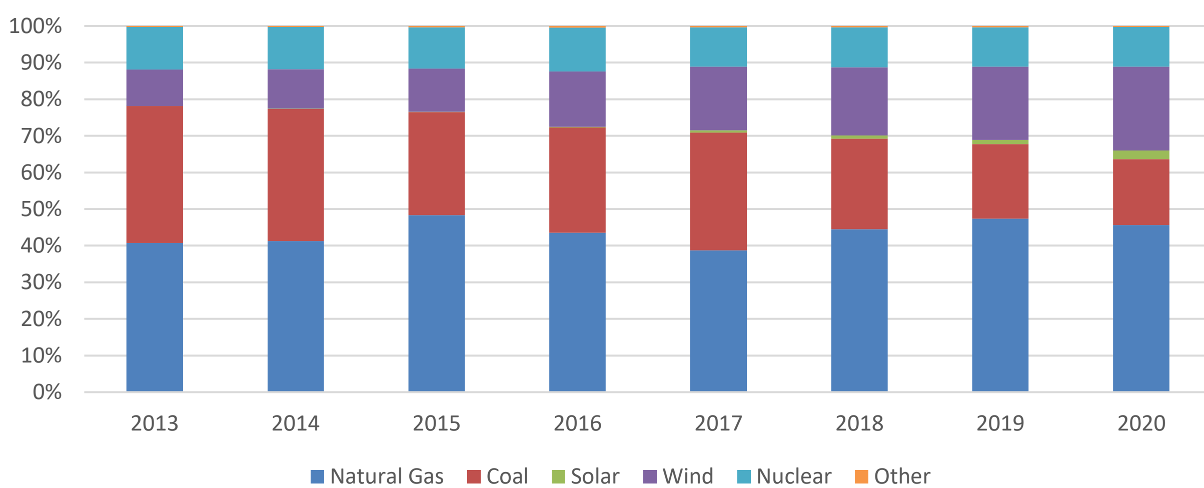


Figure 17 Generation Fuel Mix as Percentage of Total Generation (2013 through 2020) [8 9]

7 2021 ERCOT System Planning Long-Term Hourly Peak Demand and Energy Forecast. December 2020.
8 ERCOT Demand and Energy Report.
9 Contributions from other fuel types including solar and hydro are considered under "Other" fuel type.

The planning reserve margin for summer 2021 is forecasted to be 15.5%, based on resource updates provided to ERCOT from generation developers and an updated peak demand forecast. It is 4.9% higher than the 10.6% reserve margin ERCOT reported in the summer 2020 peak demand season.[10]

Due to strong load growth in Far West Texas and along the coast where the new industrial facilities are being constructed, the peak electricity demand is having above-normal growth.

4.3 LP&L INTEGRATION

The entry of Lubbock Power & Light (LP&L) to the ERCOT was approved in March 2018. LP&L is working with ONCOR to build the transmission facilities to interconnect LP&L's system to ERCOT. The new transmission line projects are:

- Blackwater Draw to Ogallala 345 kV Line
- Blackwater Draw to Folsom Point 345 kV Line
- Blackwater Draw to Double Mountain 345 kV Line
- Double Mountain to Fiddlewood to Farmland 345 kV Line

Benefits expected from integrating LP&L into the ERCOT are:

- Balances ERCOT's panhandle transmission system, and creates greater transmission capacity
- Increases generation deliverability with load addition and new 345 kV transmission lines, for the constrained panhandle region and the ERCOT in general
- Improves economies of scale

LP&L is expected to join the ERCOT grid on June 1, 2021.

4.4 HISTORICAL ENERGY PRICES

Real-time monthly average ERCOT load zone prices from 2018 to 2020 are shown below in Figure 18. Average load zone prices in 2020 is the lowest in recent years, on average around 35% lower, possibly due to lower fuel prices caused by weaker demand.

10 Capacity, Demand and Reserves Report December 2020

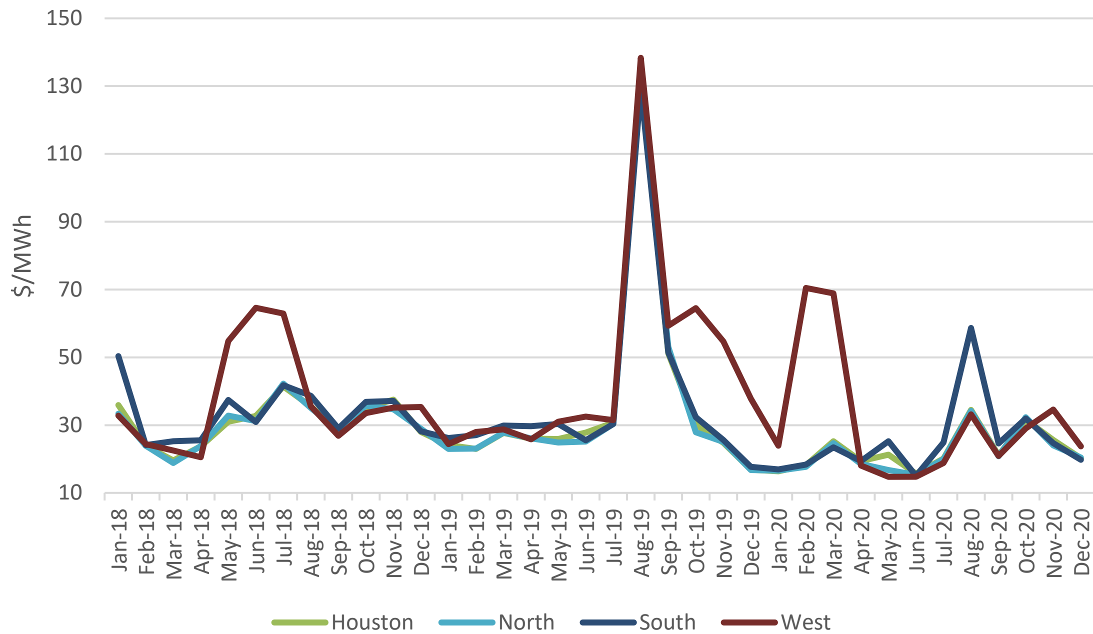


Figure 18 Historical load zone prices