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2020 ERCOT ELECTRICITY MARKET OUTLOOK

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EXECUTIVE SUMMARY

This report presents our view on ERCOT under "business as usual" conditions for 2020. However, 2020 is not usual, and the conditions have been evolving daily resulting from the COVID-19 pandemic and federal, local and state responses. Since the publication of this report, there have been many changes to gas demand, electricity usage, and general economic activities. As of March 2, energy consumption has decreased by 2 percent and the morning load has decreased by approximately 10 percent, according to ERCOT. LCG is preparing a supplement to this "business as usual" report incorporating the near-term impact of the economic downturn.

The Business as usual (BAU) simulation discussed in this report relies on the analysis performed before February 2020 and does not include the impact of COVID 19 on expected demand growth, the makeup of active generation capacity, transmission infrastructure and market operation. It also does not capture any regulatory changes that may occur. In addition to the COVID-19 supplemental report, a report updating the current analysis will be published in the second half of 2020.

According to our BAU case, Texas wind energy production grows in 2020 and will continue growth through the year. New import and export capabilities are on the horizon, such as through the integration of Lubbock Power & Light and the possible Southern Cross transmission project. Currently, there are $6.07 billion of future transmission improvement projects that are expected to be put in service between 2020 and the end of 2025. Financial and physical operations of the entire grid under the ERCOT nodal market protocols were simulated to forecast the future market operation. This report summarizes the modeling methodology, input assumptions, and results of hourly simulations of the 2020 ERCOT nodal market including Locational Marginal Prices (LMPs), load zone prices, hub prices and expected congestion. Tailored analysis for individualized generator performance, hourly prices at the nodal level, and congested elements can be acquired upon request.

All nodal market simulations were performed using LCG's proprietary UPLAN Network Power Model (NPM) and PLATO-ERCOT data model. UPLAN simulations provide a realistic projection of future physical and financial operations in any electricity market and have been used extensively to model ERCOT. Some key findings from the ERCOT 2020 BAU simulation include:

- Wind growth is expected to continue to increase its share of overall generation, reaching 22.3% or 96,009 GWh in 2020.
- Wind curtailment is expected to increase from a monthly average of 1.84% to 3.49%. A significant uptick in curtailment is expected from February to April and November.
- Fossil fuel sources will continue to be the primary source of generation in ERCOT's portfolio for 2020, with the contribution of natural gas and coal generation amounting to 52.8% and 12.2% of the total generation respectively.
- The annual average zonal prices are highest in the West zone followed by the South, Houston, and North zones. The highest average hub prices are at the Houston hub followed by the South, North and West hubs.
- The DOLLARHIDE – NO TREES SWITCH causes price spikes in the west zone, and is worth paying attention especially because of expected far west load growth.

1. INTRODUCTION

Texas energy industry and ERCOT market continue to undergo unprecedented transformation. With record wind production in 2020, ERCOT remains a worldwide leader in wind power generation. More than $1.4 billion was spent for upgrading transmission system in 2017. ERCOT Board endorsed the West Texas Transmission project, at an estimated cost of $336 million, to address future reliability concerns over load growth in Far West Texas. The $246.7 million Freeport area transmission upgrade to address the oil and gas activities was also endorsed by ERCOT Board in 2017. The integration of Lubbock Power and Light in 2021 is expected to improve the ability to export generation from the Panhandle region.

These conditions intensify the challenge to model the system, especially considering unknowns in transmission development, intermittent resources, and a greater focus on ancillary services. At the same time, and for the same reasons, getting a good picture of 2020 and beyond is increasingly important to all ERCOT stakeholders.

Financial and physical operations of the entire grid under the ERCOT nodal market protocols were simulated to forecast the future operation of the ERCOT nodal market. This report summarizes the modeling methodology, input assumptions, and results of hourly nodal network simulations of the 2020 ERCOT nodal market performed by LCG Consulting (LCG). More detailed input assumption data and output results can be acquired upon request.

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 a 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 2020 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 2020. Electricity market modeling incorporated almost 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 2019 Annual Energy Outlook. The study used the SSWG Summer Peak Power Flow Case for 2020 published December 2019 by ERCOT SSWG group for the transmission network. Detailed input assumptions are discussed below in Section 3.

1.2 ANNUAL AVERAGE LOCAATIONAL MARGINAL PRICES

Figure 1 below shows a heat map of annual average LMPs in the ERCOT region for 2020.

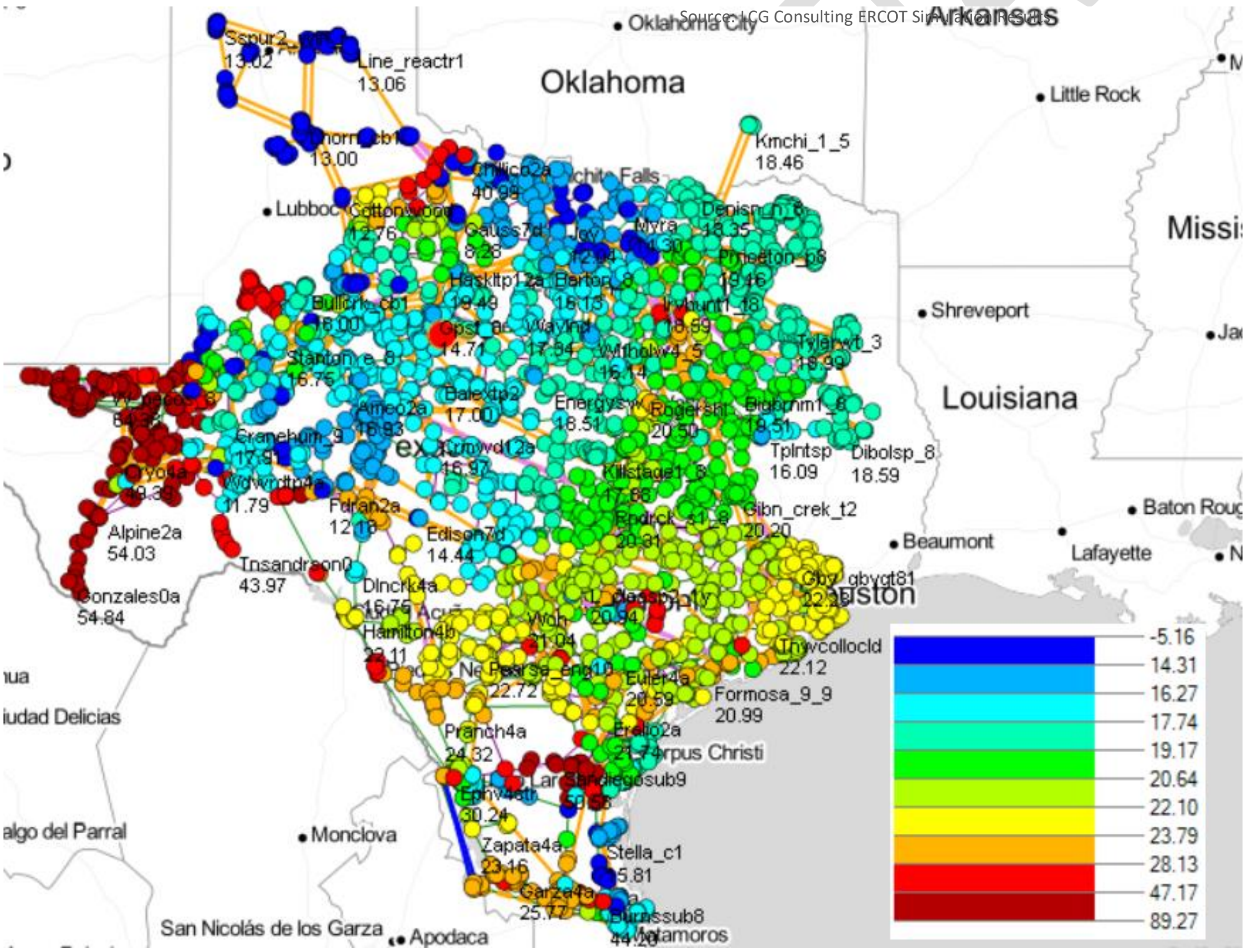


Figure 1 Annual Average Nodal LMP Heat Map – 2020 ERCOT BAU Case

The annual average zonal prices are highest in the West zone followed by the South, Houston, and North zones. The highest average hub prices are at the Houston hub followed by the South, North and West hubs.

2. SIMULATION RESULTS

2.1 GENERATIO

In the 2020 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 52.8% of generation. Coal generation is expected to continue to reduce its share of total generation in ERCOT, falling to 12.2% of total generation in 2020, down from 20.3% in 2019[1]. Wind development continues to grow in ERCOT, bringing wind generation to 22.3% of total generation in 2020, from 20% in 2019[2].

Figure 2 shows the annual production by fuel in 2020 BAU simulation.

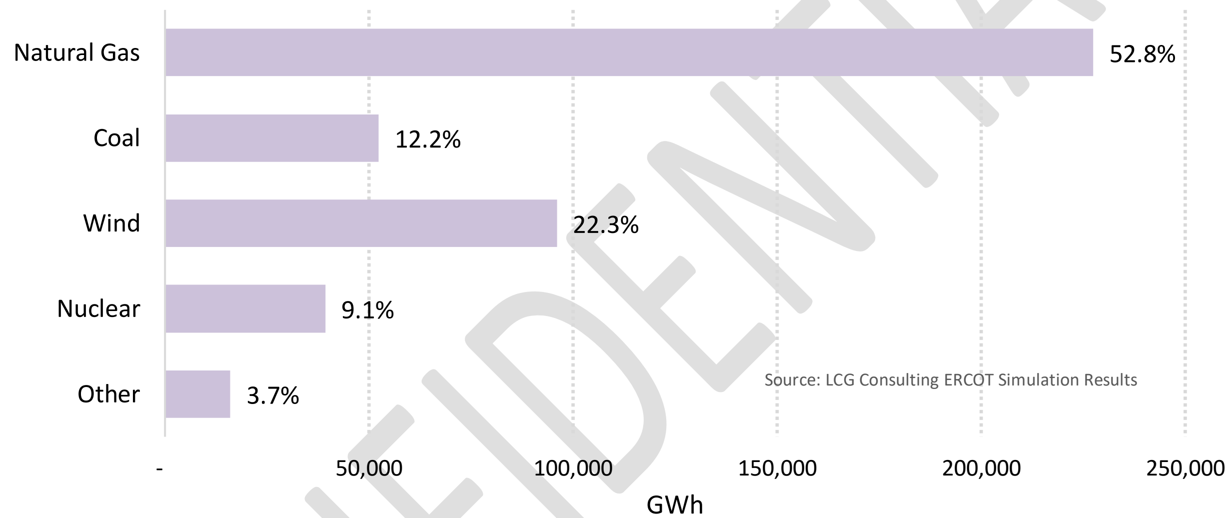


Figure 2 Annual Energy Production by Fuel Type (GWh)[3]

1 2019 ERCOT Demand and Energy report.
2 2019 ERCOT Demand and Energy report.
3 Contributions from other fuel types including solar and 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 2020 simulation is shown in Figure 3.

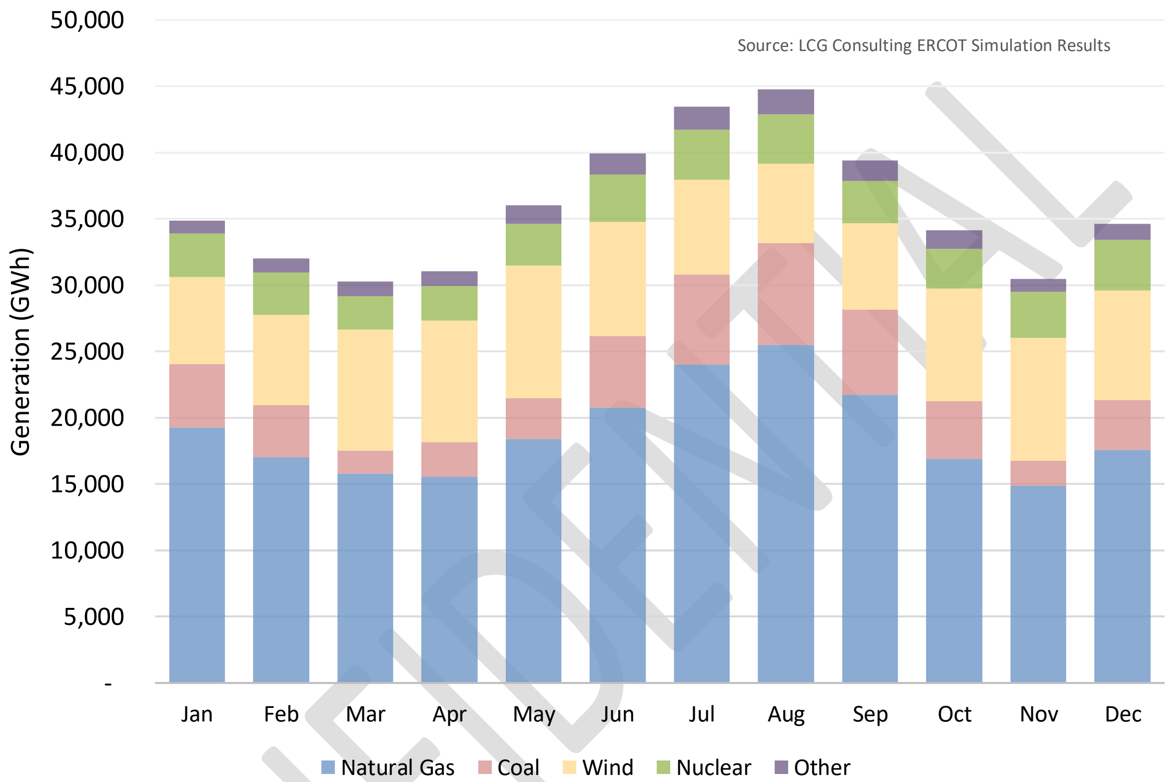


Figure 3 Monthly Generation by Fuel Type – 2020 [4]

4 Contributions from other fuel types including solar and hydro are considered under "Other" fuel type.

For 2020, wind generation is 96,009 GWh, contributing 22.3% of ERCOT's generation portfolio. Figure 4 shows how the projected wind generation for 2020 compared to ERCOT's historical wind generation for prior years. The annual curtailment of wind resources is 3.49% with the lowest average wind output during peak hours of the high demand months.

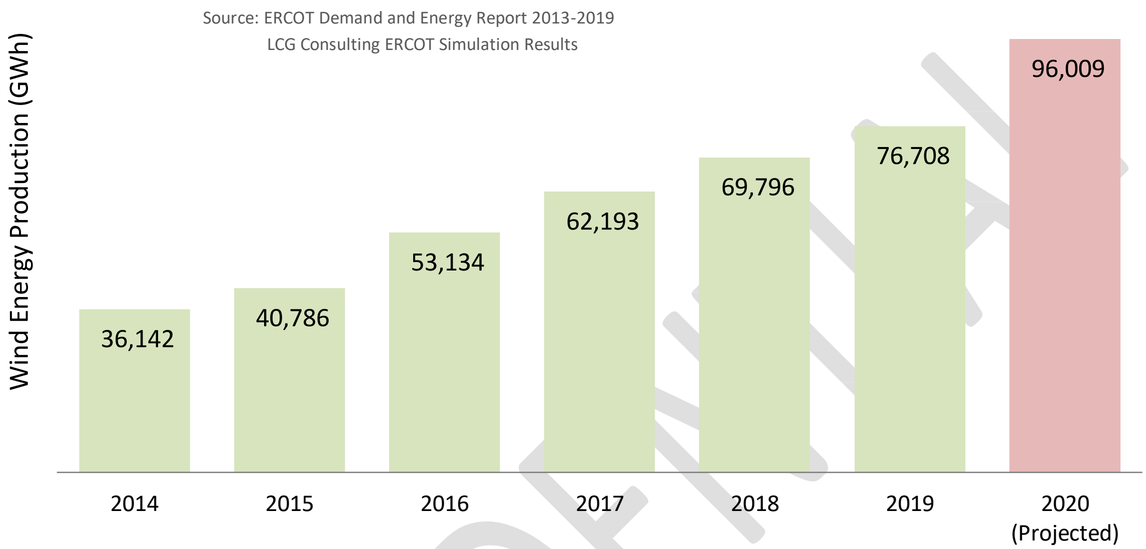


Figure 4 ERCOT Historical and Projected Wind Generation (GWh)

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 5 below shows the average peak and off-peak system-wide wind output in the 2020 simulation. Curtailment is also outlined in Figure 5. As can be seen here, lowest average wind output coincides with the peak hours of the high demand months.

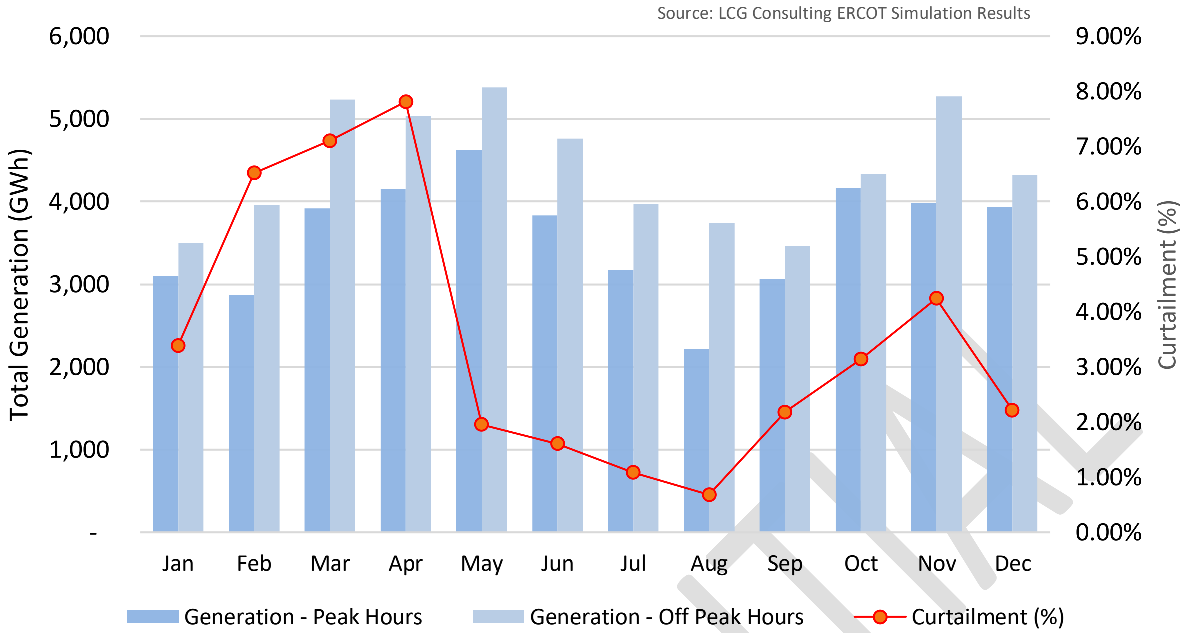


Figure 5 Monthly Average Peak and Off-Peak Wind Generation & Monthly Wind Curtailment – 2020

2.2 CONGESTION

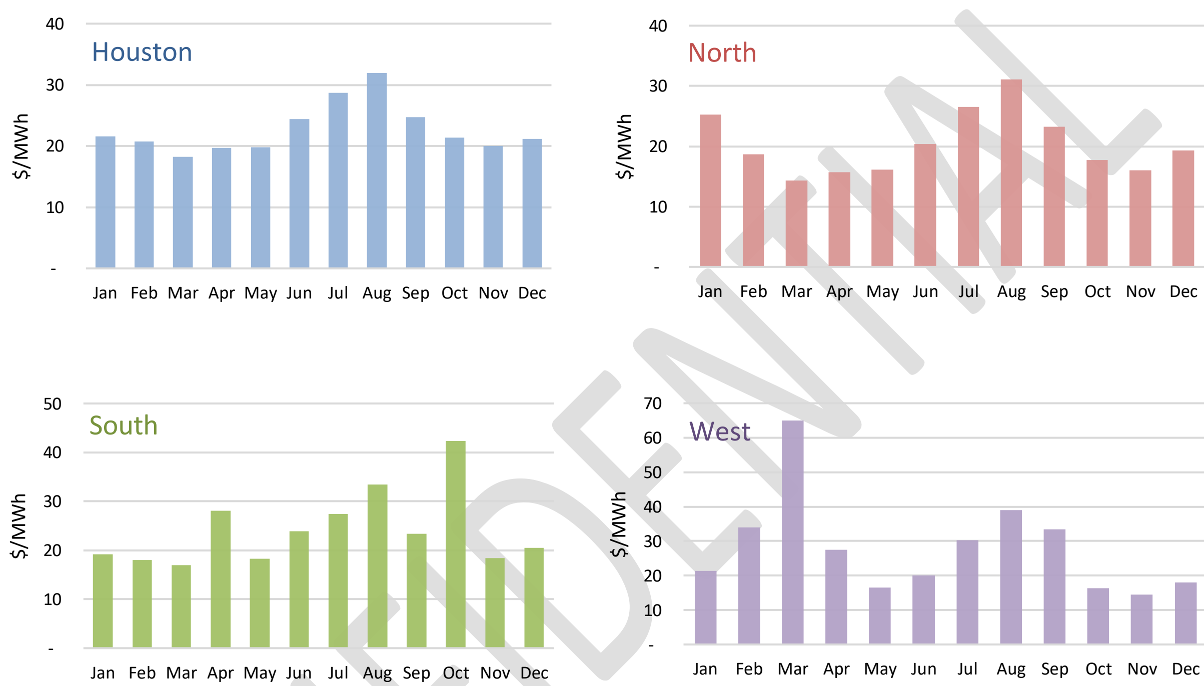
Significant congestion risk exists for certain elements in the system. Table 1 below shows a list of the top congested elements in 2020. The lines are ranked based on their congestion rent, from highest to lowest. Certain elements shown here have been highly congested in recent years and are expected to continue to experience congestion in 2020.

Table 1 ERCOT Annual Congestion – 2020

Line Name	Voltage (kV)	Zone
DOLLARHIDE - NO TREES SWITCH	138	WEST
AROYA SWITCH - YUCCA DRIVE SWITCH	138	WEST
SOUTH TEXAS PROJECT - WA PARISH	345	SOUTH/ HOUSTON
NORTH - HOUSTON IMPORT INTERFACE		NORTH
KENDALL - BERGHEIM	345	LCRA
DOLLARHIDE - AMOCO THREE BAR TAP – ANDREWS COUNTY	138	WEST
BURNS SUB - RIO HONDO	138	SOUTH
WEST TNP - TI TNP	138	NORTH
NORTH EDINBERG 138/69 kV TRANSFORMER	138	SOUTH
KNAPP - SCURRY CHEVRON	138	WEST

2.3 LOAD ZONE PRICES

The average price for West load zone is the highest followed by South and Houston load zones for 2020. Figure 6 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 6 Monthly Load-Weighted Average Prices ($/MWh) by Load Zone – 2020

Annual average zonal prices shown in Figure 7 are highest in West zone followed by South, Houston and North zones.

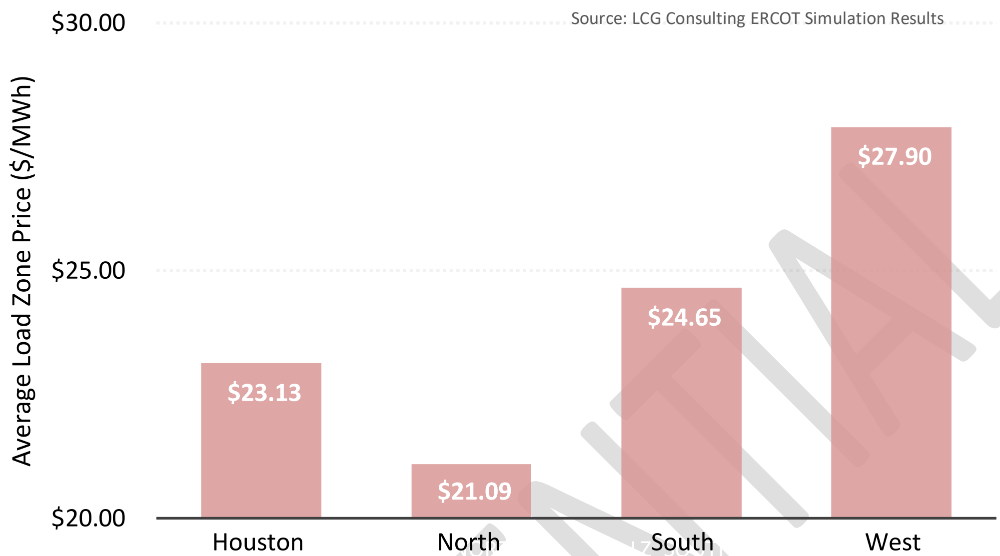


Figure 7 Annual Load-Weighted Average Load Zone Prices ($/MWh) – 2020

2.4 HUB PRICES

ERCOT has defined six 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.

The most competitive average hub price is observed in the Houston hub, with progressively more expensive prices experienced in South, North and West 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 2020 at Houston, North, South and West hubs are shown below in Figure 8.

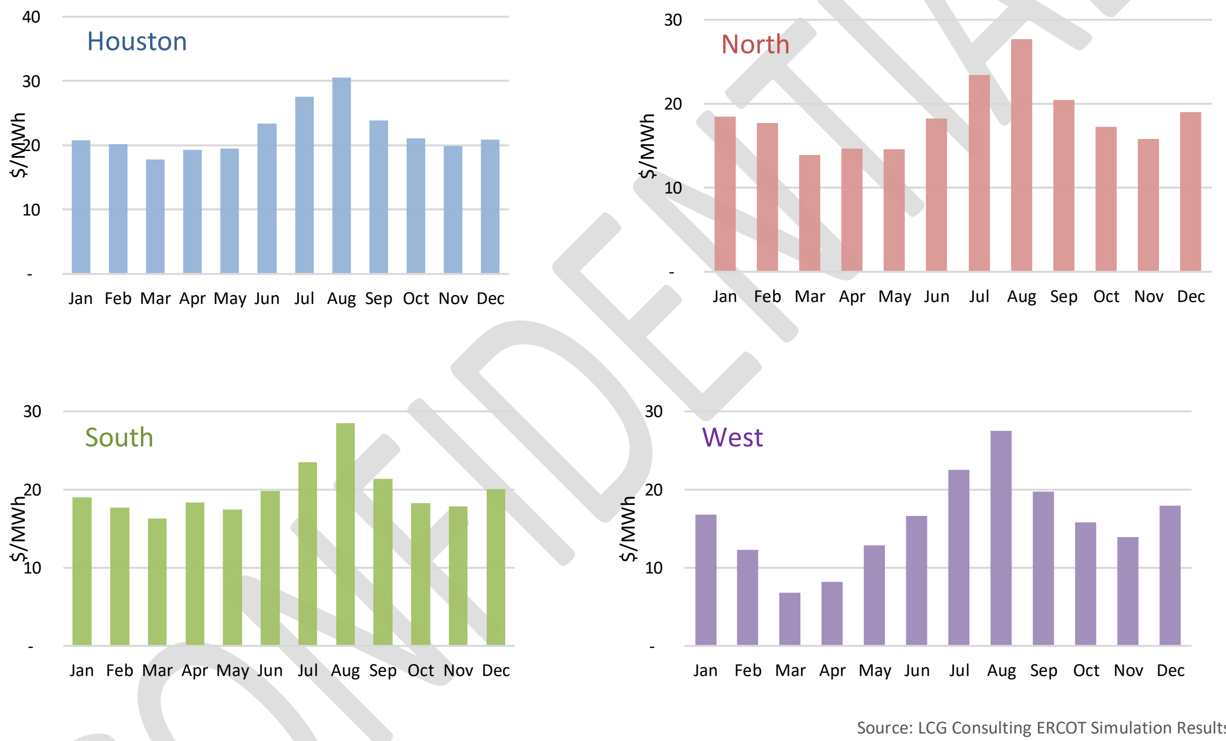


Figure 8 Monthly Average Prices ($/MWh) by Trading Hub – 2020

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 9.

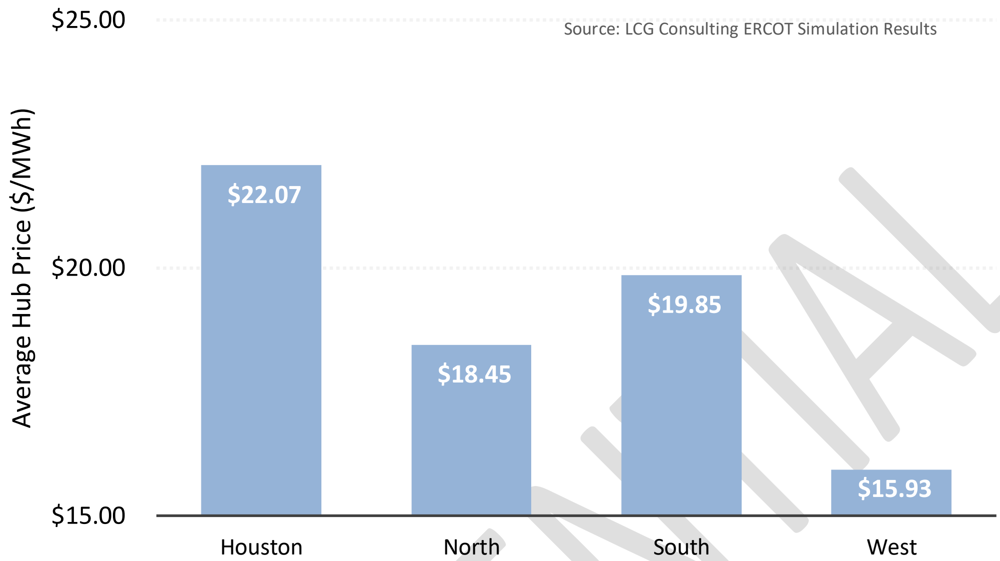


Figure 9 Annual Average Hub Prices ($/MWh) – 2020

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 2020 is provided in this section.

3.1 ELECTRICITY DEMAND

The study uses 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 2020. Table 2 shows the forecasted annual peak load and energy demand for 2020 in each weather zone.

Table 2 Annual Peak (MW) and Energy (GWh) Demand by Weather Zone – 2020

Weather Zone	Annual Peak (MW)	Annual Energy (GWh)
COAST	17,390	96,330
EAST	2,420	12,221
FAR_WEST	2,591	17,213
NON SELF SERVE (FLAT)	9,586	81,645
NORTH	1,390	7,088
NORTH_C	25,021	117,782
SOUTH_C	12,468	59,921
SOUTHERN	5,084	27,954
WEST	1,868	10,179
ERCOT 50-50	**77,064**	**430,332**

3.2 INSTALLED CAPACITY

Almost 900 generators are included in this study. Existing facilities relied on the *Report on Capacity Demand and Reserves in the ERCOT Region*. Future units that have a Standard Generation Interconnection Agreement originate from the ERCOT Monthly System Planning reports and LCG assumptions. 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 for the simulation time horizon, followed by wind and coal resources in 2020. Wind energy plays an important role in the capacity mix with a total nameplate wind capacity of 32,467 MW. This number is not adjusted for Effective Load Carrying Capability (ELCC).

Figure 10 and

Figure 11 show installed capacity by zone and fuel type respectively, as modeled in UPLAN simulations.

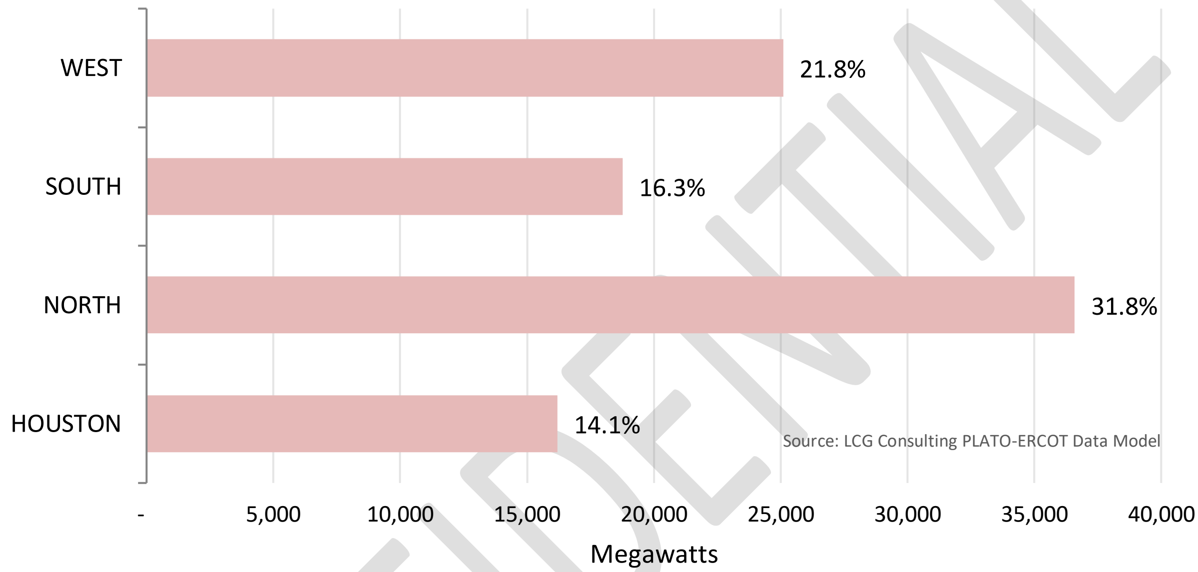


Figure 10 ERCOT Generation Capacity by Zone (MW) – 2020

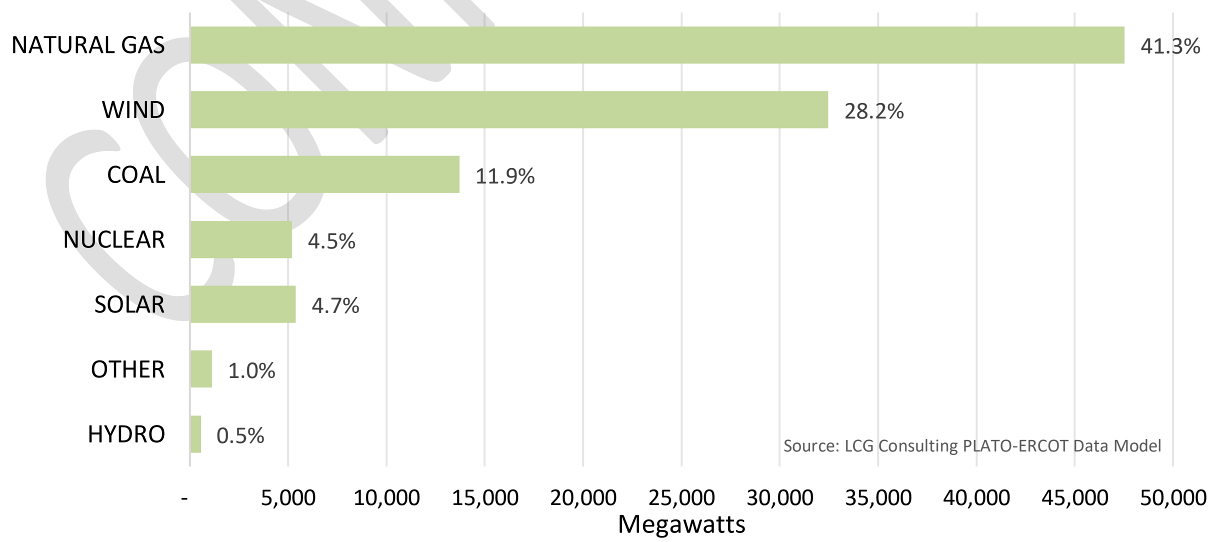


Figure 11 ERCOT Generation Capacity by Fuel Type (MW) – 2020

UPLAN has taken into account approximately 10,330 MW of new generating resources in the simulation, based on the generator expansion assumptions in the ERCOT System Planning Monthly Report and LCG projections. 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, 2020.

Table 3 Capacity Expansion (MW) by Fuel Type and Zone by 2020

Zone	Battery	Wind	Natural Gas	Solar
HOUSTON		151	151	120
NORTH	200	300		199
SOUTH		1909	58	294
WEST		4821		2127
Total	**200**	**7181**	**209**	**2740**

3.3 FUEL PRICES

Monthly gas prices used in the annual simulations for 2020 originate from LCG's proprietary projections for natural gas prices is given in Figure 12. The price projections are based on NYMEX Henry Hub futures settlement prices and EIA 2019 Annual Energy Outlook published February 2019. Average coal price ($/MMBtu) applied for 2020 is given in Table 4.

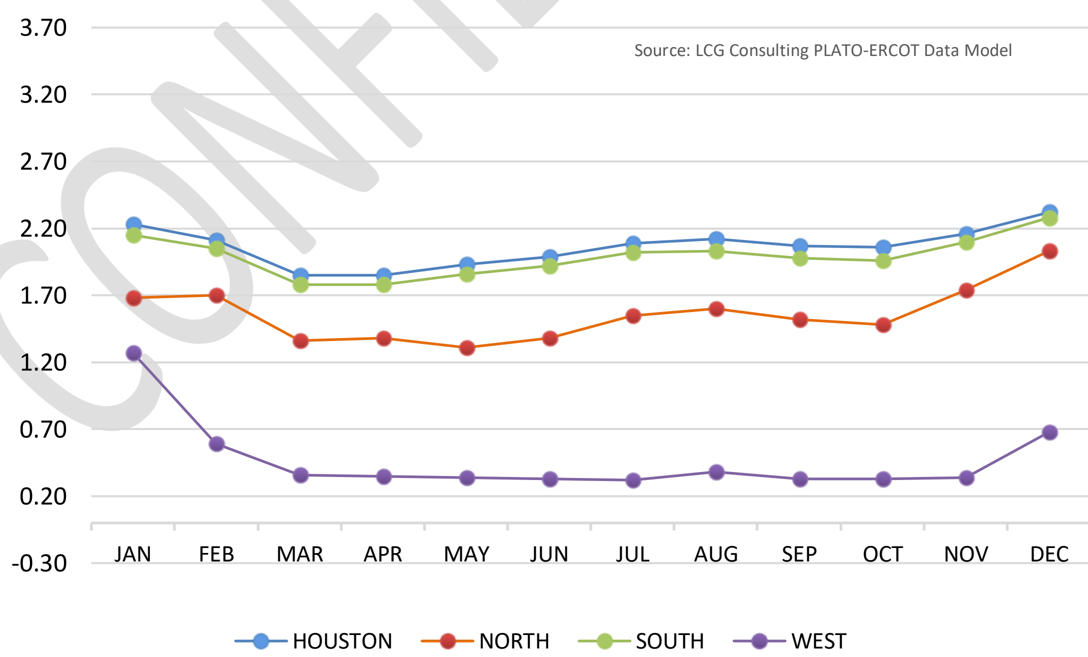


Figure 12 Monthly Natural Gas Price by Zone ($/MMBtu) – 2020

Table 4 Average Coal Price ($/MMBtu) – 2020

Coal Forecast	Price ($/MMBtu)
Lignite	1.39
Sub-Bituminous	2.00

3.4 TRANSMISSION NETWORK

The base transmission network and its characteristics used in the study come from SSWG summer peak power flow cases published by ERCOT in October 2019. The list of contingencies relies on the ERCOT published Standard list. About 1400 approved and accepted transmission outages as of February 2020 were also included. 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 February, 2020. Table 5 gives an overview of the modeled ERCOT transmission footprint.

Table 5 Transmission Network Characteristics for 2020

Description	Count
Buses	8,500
Branches	10,809
N-1 Contingencies	2,998
N-2 Contingencies	966
N-3 Contingencies	627
N-4 Contingencies	266
N-5 Contingencies	175
N-6 Contingencies	111
N-7 Contingencies	82
N-8 Contingencies	63
N-9 Contingencies	52
N-10 Contingencies	40
N-11 Contingencies	27
N-12 Contingencies	15
N-13 Contingencies	12
N-14 Contingencies	8
>=N-15 Contingencies	46

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.

Total peak demand in ERCOT has risen from 62,203 MW in 2006 to 74,666 MW in 2019, 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 88,751 MW by 2029, indicating an average annual growth rate of 1.7%.

Total annual energy has also risen over the 2006-2019 time period, from 305 TWh in 2006 to 385 TWh in 2019. Growing at an annual average rate of 1.7% from 2006 through 2019, annual energy in the ERCOT footprint is projected to continue growing at an annual average rate of 2.5% through 2029, reaching 493 TWh in that year. Figure 13 below shows the historical and forecasted annual energy, and summer peak demand from 2006 through 2029.

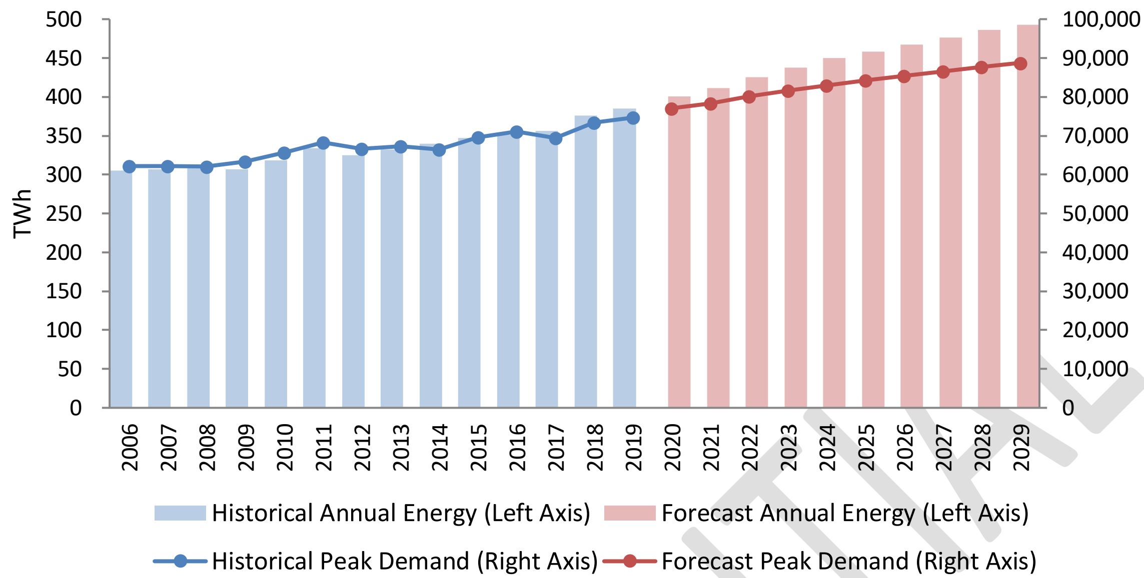


Figure 13 Historical and Forecasted Annual Energy (TWh) and Summer Peak Demand (MW) [5]

4.2 DEMAND AND GENERATION

Despite recent rapid growth in wind power development in ERCOT, generation remains dominated by natural gas resources, with 47% of generation coming from natural gas resources in 2019. Coal unit retirements in 2019 brought coal generation from 37% in 2013 to 20% of generation in 2019. Wind generation has grown from 10% in 2013 to 20% in 2019. Figure 14 shows the annual fuel mix percentage in ERCOT's generation portfolio from 2013 through 2019.

5 2020 ERCOT System Planning Long-Term Hourly Peak Demand and Energy Forecast. December 2019.

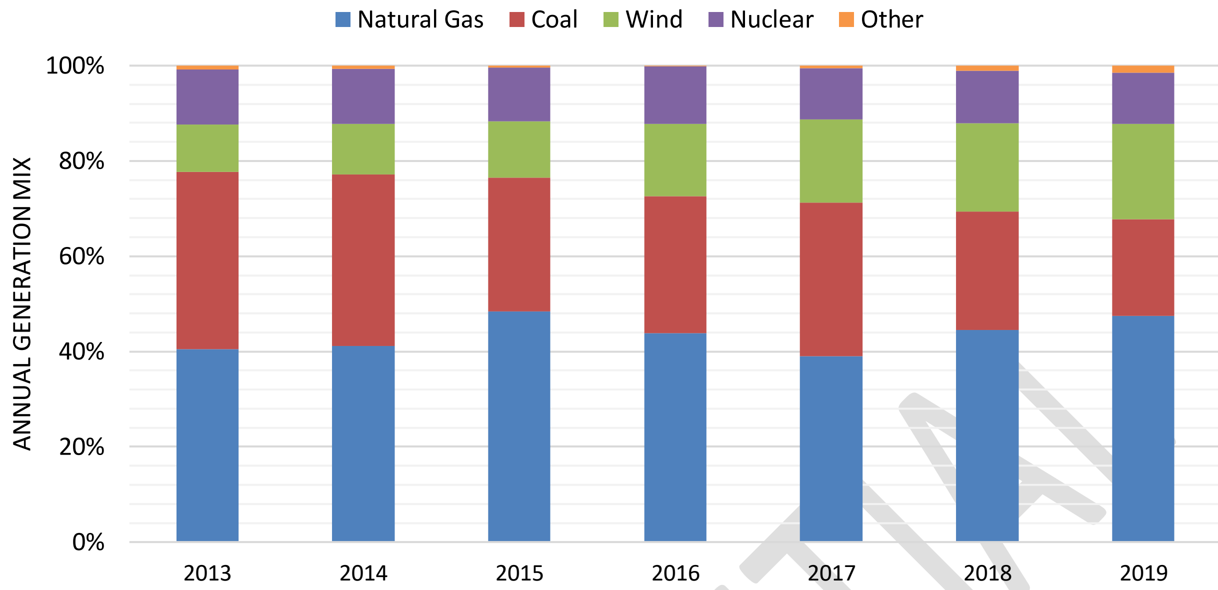


Figure 14 Generation Fuel Mix as Percentage of Total Generation (2013 through 2019) [6 7]

The planning reserve margin for summer 2020 is forecasted to be 10.6%, based on resource updates provided to ERCOT from generation developers and an updated peak demand forecast. It is 2% higher than the 8.6% reserve margin ERCOT reported in the summer 2019 peak demand season.[8]

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 FAR WEST LOAD GROWTH

Much higher than ERCOT average peak load growth in the Far West weather zone has been recorded, mainly due to the oil and gas activity. The peak demand in the Far West weather zone has more than doubled since 2010. In June 2019, load exceeded 4,000 MW for the first time in the region, and it is anticipated that the upward trend will continue. The strong load growth is concentrated in Culberson, Reeves, Loving, Winkler and Ward counties. The transmission lines form a loop in this area, and are known as the Culberson Loop.

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6 ERCOT Demand and Energy Report.
7 Contributions from other fuel types including solar and hydro are considered under "Other" fuel type.

[8] Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2020-2029

In 2016 and 2017, ERCOT endorsed almost $600 million of major transmission projects, and 2 additional projects in 2018 that also helps to reduce congestion in this region. Several transmission projects are underway to address the congestion. Four new 345-kV power lines will create a double-circuit loop, as well as three new 138-kV power lines that will be double-circuit capable. These lines together will span about 272 miles. Figure 15 shows the improvements on a map.

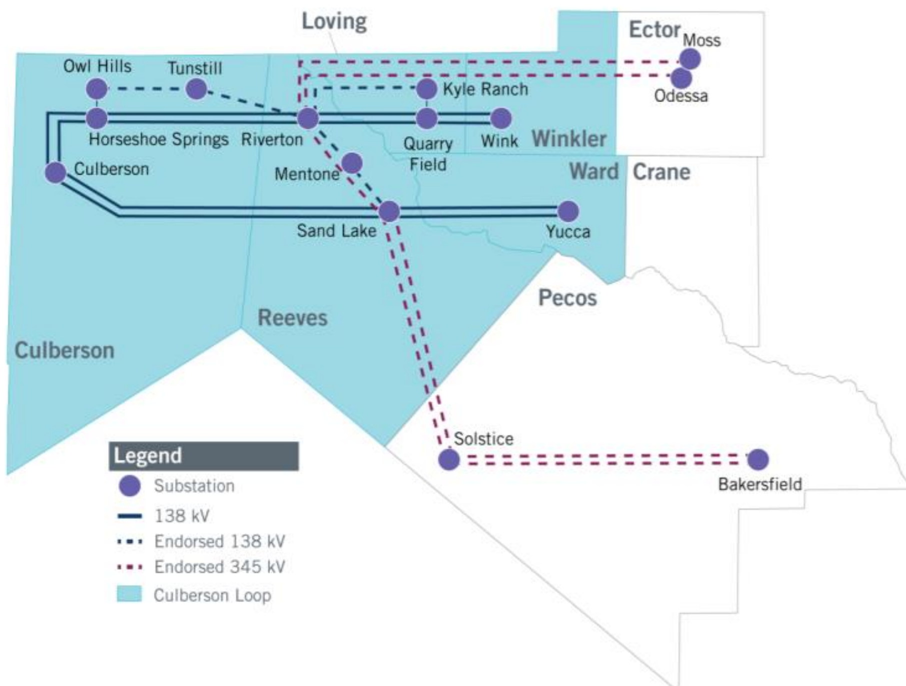

Figure 15 Far West Transmission Improvements

4.4 TRENDS IN ENERGY PRICES

Real-time monthly average ERCOT load zone prices from 2017 to 2020 (simulated) are shown below in Figure 16. Average load zone prices in 2019 have increased from 2018, with significant increase in the West load zone prices of 24%.

The simple average of monthly average load zone prices rose to $39.47 in December 2019, an 18% increase from the previous year. Increase in natural gas price is one of the key drivers for the average increase of 18% from 2016 to 2017. Increased Panhandle congestion raised the load zone prices in the west, thereby increasing the average load zone price in 2018.

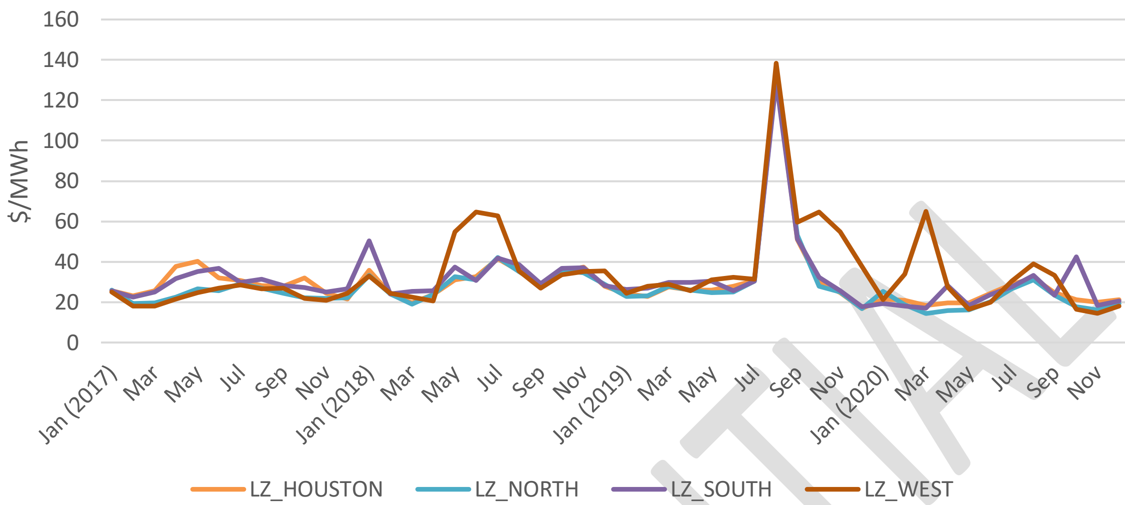

Figure 16 Monthly Average Real-Time and Predicted Load Zone Prices ($/MWh)