2021 SUMMER RESOURCE ADEQUACY IN THE ERCOT REGION

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ACRONYMS AND ABBREVIATIONS

CDR	Capacity, Demand and Reserves
CO_2	Carbon dioxide
CONE	Cost of new entry
COVID-19	Coronavirus disease 2019
CREZ	Competitive Renewable Energy Zone(s)
DAH	Day Ahead
DC	Direct current
DOE	Department of Energy
EEA	Energy Emergency Alert
EIA	Energy Information Administration
EORM	Economically optimal reserve margin
ERCOT	Electric Reliability Council of Texas
ERS	Emergency Response Service
GW	Gigawatt
Hz	Hertz
IA	Interconnection agreement
IMM	Independent market monitor
ISO	Independent system operator
ITC	Investment Tax Credit
kV	Kilovolt
kWh	Kilowatt-hour
lb	Pounds
LMP	Locational marginal price
LOLE	Loss of load expectation
LOLH	Loss of load hours
LOLP	Loss of load probability
Mcf	Million cubic feet
MERM	Market equilibrium reserve margin
mins	Minutes
MMBtu	Million British thermal unit
MW	Megawatt
MWh	Megawatt hour
NERC	North American Electricity Reliability Corporation
NETL	National Energy Technology Laboratory
NG	Natural gas
NOx	Nitrogen oxides
ORDC	Operating Reserve Demand Curve
PJM	PJM Interconnection
PRC	Physical responsive capability
PTC	Production tax credit
PUCT	Public Utility Commission of Texas
RE	Reliability Entity
RTM	Real-time market
RTO	Regional transmission organization
SARA	Seasonal Assessment of Resource Adequacy
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
TDSP	Transmission and/or Distribution Service Provider
TWh	Terawatt hour
U.S.	United States
VOLL	Value of lost load
VRE	Variable renewable energy

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EXECUTIVE SUMMARY

This report is an update to the NETL report on the same topic that examined the potential system performance of the Electric Reliability Council of Texas (ERCOT) system during the summer of 2020. Anticipated reserve margins in ERCOT have risen year-over-year from the 10.7 percent reported in ERCOT's Final Seasonal Assessment of Resource Adequacy (SARA) for Summer 2020 to 15.7 percent for Summer 2021 in ERCOT's Capacity, Demand and Reserves [CDR] report published in December 2020 and 2021 Summer Preliminary SARA published in March 2021. [1] [2] [3] This is above current minimum target reserve margin of 13.75 percent set by the ERCOT Board of Directors [4], and above the 12.25 percent market equilibrium reserve margin (MERM), and 11.0 percent economically optimal reserve margin (EORM) levels identified by the Astrapé Consulting study done for ERCOT in late 2018. [5] Despite tight operating conditions, ERCOT was able to maintain the system with no load shedding events over 2019 and 2020. [6]

Using data from ERCOT's 2021 Summer SARA, CDR, and historical performance data, six economic dispatch scenarios using PROMOD were developed to assess the risk to ERCOT of a load shedding event for Summer 2021. The results suggest that ERCOT could make it through the summer season without a loss of load event, as long as the weather remains normal, even though ERCOT will be well below its minimum reserve margin target. However, if demand reaches previous growth adjusted historical peak levels, ERCOT is likely to find itself operating in emergency conditions during the summer peak, which is usually the end of July through mid-August. Under these conditions, ERCOT will need to call on its operating tools to maintain reliability and continue serving load, and those measures alone may not be sufficient to avert a shedding of load.

1 HISTORIC RESOURCE ADEQUACY IN ERCOT

In 2012, Electric Reliability Council of Texas (ERCOT), working with the Public Utility Commission of Texas (PUCT), commissioned The Brattle Group ("Brattle") to investigate the question of whether ERCOT's market design could sufficiently maintain resource adequacy. Unlike other independent system operators (ISOs) and regional transmission organizations (RTOs) that operate capacity, energy, and ancillary service markets, ERCOT operates only energy and ancillary service markets. When Brattle's study, "ERCOT Investment Incentives and Resource Adequacy," was published, ERCOT was struggling to attract investment in new generation projects, and reserve margins were predicted to fall below 10 percent. [7]

The Brattle study determined that if ERCOT maintained only a 10 percent reserve margin, this would, on average, "result in approximately one load-shed event per year with an expected duration of two-and-a-half hours, and thirteen such events in a year with a heat wave as severe as the one in 2011."[a] [7] In 2011, Texas experienced both extreme cold weather, with a record winter peak demand in February, and unusually hot weather, with June–August temperatures that were the hottest on record. The average 24-hour statewide temperature from June through August was 86.8 degrees Fahrenheit, the hottest three months on record. [8] Dallas experienced 70 days where temperatures hit 100 degrees Fahrenheit that summer. [9] In August of that year, ERCOT was forced to trigger emergency operating procedures six times. [7]

An Astrapé Consulting study, "Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024," [5] was completed in 2021 as an update to the 2018 Brattle study "Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region." [10] In this report, the market equilibrium reserve margin (MERM) and the economically optimal reserve margin (EORM) of ERCOT's wholesale electric market were estimated. [5] The MERM describes the reserve margin that the market can be expected to support in equilibrium, as investment in new supply resources responds to expected market conditions, where a marginal unit's revenue and cost of a new entry (CONE) intersect. The EORM represents a balance between increased capital costs and decreased reliability-related operating costs and provides a gauge for evaluating the expected MERM. Under projected 2024 market conditions, the suggested EORM is 11.00 percent, and the MERM is 12.25 percent. At the given MERM value, the system could expect to experience 0.5 events per year loss of load expectation (LOLE),[b] and 0.84 LOLE events per year at the EORM value. [10]

To address the absence of the capacity market to attract new resources for the market, ERCOT implemented the Operating Reserve Demand Curve (ORDC) on June 1, 2014. The ORDC is used to create a real-time reserve price adder, to reflect the value of reserves in the real-time market, based on the probability that reserves for the ERCOT system fall below a minimum level of

[a] For reference, the traditional 1 day-in-10 years reliability planning criteria used by industry equates to 2.4 hours per year.

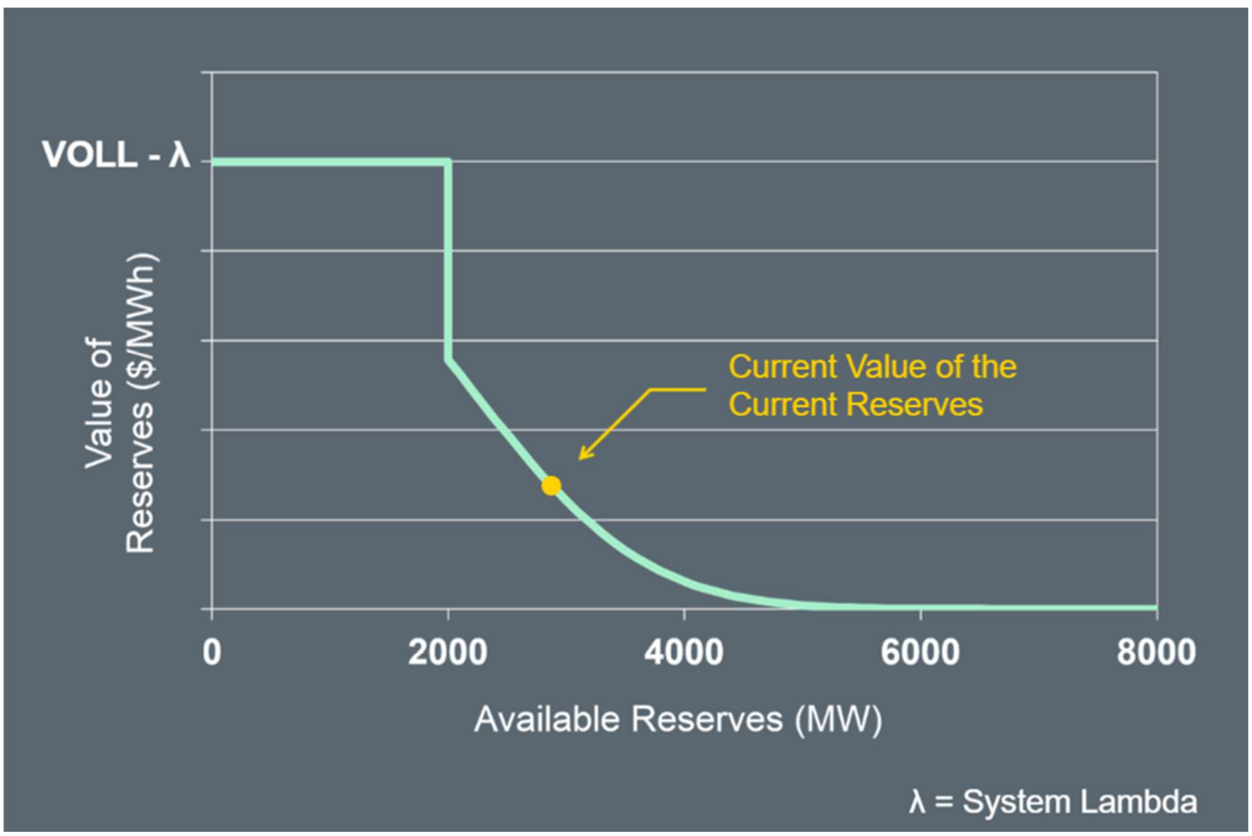
[b] LOLE is defined as the expected number of days in which the available generation capacity is insufficient to serve the demand at least once per day. LOLE counts the days meeting this criterion, regardless of the number of consecutive or nonconsecutive hours in the day. [61] For reference, the traditional 1 day-in-10-years reliability planning criteria used in industry is reflected on an LOLE basis. On loss of load hours (LOLH) basis; this is equivalent to 2.4 hours per year. Both are unconcerned with the magnitude or number of outages. [59]

2,000 megawatts (MW). The ORDC curve is constructed by value of lost load (VOLL), system lambda (λ), and loss of load probability (LOLP), as shown in the following equation:

$$ORDC = (VOLL - \lambda) \times LOLP$$

Where VOLL is set to be equal to the system-wide offer cap, which is currently $9,000/megawatt hour (MWh); λ is the price of matching generation and demand at the reference bus; and LOLP is calculated by a normal distribution built from the historical difference between hour ahead reserve and real-time reserve.[c] A typical example ORDC graph is shown in Exhibit 1-1. ORDC automatically increases when the reserves get tighter and reaches the maximum when reserves drop below 2,000 MW. Note that different LOLPs and ORDCs are constructed and utilized for different seasons and daily hour ranges. For example, the ORDC used in hour ending (HE)15 to HE18 for the summer will be different for the ORDC used in HE7 to HE10 in winter. The curve depends on historical data for that season and particular daily hour range.

Exhibit 1-1. Graph of ORDC



Used with permission from ERCOT [11]

ERCOT then uses the ORDC to calculate two price adders: *real-time on-line reserve price adder* for all resources that could be available to dispatch within 30 minutes and *real-time off-line*

[c] More detailed mathematical discussion for the ORDC and LOLP can be found in an ERCOT online course and training. [11] [62]

reserve price adder for all other resources that could be available to dispatch within an hour. These two price adders are then incorporated into the ERCOT real-time energy market to pay resources for their value of reserves and energy. Note that ORDC and its associate price adders are only used in the ERCOT real-time energy market; they are not included in the ERCOT day-ahead energy market.

In response to low reserve margins in recent years, the PUCT directed ERCOT to shift the ORDC based on the standard deviation of the hour-ahead operating reserve forecast error's distribution. The normal distribution will shift at 0.25 standard deviation (to the right) for Summer 2019, and again shift another 0.25 standard deviation in Spring 2020. [12] This change for LOLP makes energy prices rise faster when reserve is low. Generation groups like Vistra Energy support this change; they believe ERCOT should have proper price signals to support generation investment for maintaining resource adequacy during periods of peak demand. [13] After adjusting its market design to attract new generation investment and maintaining higher reserve margins for several years, ERCOT began to realize the problem predicted by Brattle for 2014. In early Fall 2017, ERCOT was notified of the retirements of 9 coal-fired generating units between 2018 and 2020, which constituted the bulk of the retiring 5,622 MW, which is around 6 percent of the total current system generation resource capacity. This resulted in a projected reserve margin of 10.62 percent in Summer 2018, 8.36 percent in Summer 2019, and 10.7 in Summer 2020, which were all below the region's planning reference margin level at 13.75 percent set by the ERCOT Board of Directors. [14] Going into Summer 2021, with an addition of 3.3 gigawatts (GW) from solar generation and 1.9 GW from wind generation (after effective load carry capacity adjustment), the predicted reserve margin increases to 15.7 percent. While the reserve margin is above planning reference margin, higher renewables in ERCOT pose risk for tight conditions during low wind or during early evening hours when solar comes offline. While summer is traditionally seen as the peak demand season in ERCOT, extreme winter weather can cause strain on the system, as seen in the rolling blackouts that occurred in February 2021 and the April 2021 maintenance event. These events are discussed in Section 2.

Comparing the forecast in the Summer 2021 Final Seasonal Assessment of Resource Adequacy (SARA) to the Summer 2020 Final SARA, the adjusted peak demand increased from 75,200 MW to 77,144 MW.[d] This peak demand forecast number would be a new system-wide peak demand for ERCOT region (previous record in Summer 2019 at 74,820 MW). This load increase comes from continued economic and population growth with expected hot and dry summer conditions.

Total resource capacity increased from 82,119 MW to 86,862 MW. The majority of this capacity increase came from solar with a 3,250 MW increase from 2020, followed by 1,925 MW of new wind capacity. Note that the final 15.7 percent reserve margin considers demand response programs under ERCOT's control, which include registered load resources that provide operating reserves in the day-ahead ancillary service market, Energy Response Service (ERS) (discussed in detail later in this section), behind the meter rooftop solar panels, and utility-offered load management programs triggered during summer-season Energy Emergency Alerts (EEAs)

[d] Note that the peak demand in Summer 2019 was 74,820 MW, which was very close to the 2019 Summer SARA forecast value.

declared by ERCOT. These programs account for more than 2 GW according to 2020 December CDR. [15] Besides generation and demand resources, ERCOT also anticipates some peak mitigation impacts from energy storage units. Although energy storage is not counted in final SARA's resources, ERCOT has 537 MW of energy storage capacity based on its Capacity Changes by Fuel Type report on April 6. Another 735 MW storage capacity are expected to have interconnection agreements (IAs) signed and financial security posted by August 2021. [16] Additionally, ERCOT announces plans to review selected plant's summer weatherization plans This will be first-time summer weatherization plans visited by ERCOT.

In Summer 2020, there were several days with tight conditions, but no EEAs were declared.[e] The peak demand occurred on August 13, with 74,328 MW between 4 and 5 pm central time while July peak demand was set at 74,311 MW on July 13. While ERCOT states there is no significant impact to the summer peak demand due to the coronavirus disease 2019 (COVID-19), the forecast peak demand from 2020 Summer preliminary SARA is 76,696 MW, which was published on March 5, 2020, and did not consider the impact of COVID-19. The 2,385 MW difference between forecast and actual peak demand can be considered COVID-19 impact, considering ERCOT has underestimated the summer peak demand for the last 10 years except 2017.

On the peak demand day (August 13, 2020), ERCOT had lower than expected demand, higher wind contribution, higher solar contribution, and fewer generation outages. Therefore, the available operating reserve on the peak day was 5,935 MW, much higher than 2,300 MW, which is the level that triggers ERCOT to declare EEA 1. The detail resources, demand, and reserve on the peak day compared to the estimation numbers from the 2020 Summer Final SARA are shown in Exhibit 1-2. [17]

Exhibit 1-2. Forecast vs. actual 2020 summer peak days resource adequacy values

Resources, Demand, and Reserve (MW)	2020 Actual Peak Demand Hour (MW)	Final 2020 Summer SARA Forecast (MW)	Difference (MW)	Actual Compared to Forecast (%)
Total Resources	83,809	82,199	1,610	102.0%
Thermal and Hydro	65,531	65,797	-267	99.6%
Private Use Networks, Net to Grid	3,011	3,176	-165	94.8%
Switchable Generation Resources	3,027	2,756	271	109.8%
Wind Capacity Contribution	8,055	6,641	1,414	121.3%
Solar Capacity Contribution	3,620	2,979	641	121.5%
Non-Synchronous Ties	565	850	-285	66.5%
Peak Demand	74,328	75,200	-872	98.8%
Reserve Capacity	9,481	6,999	2,482	135.5%
Total Outages	3,546	4,069	-523	87.1%

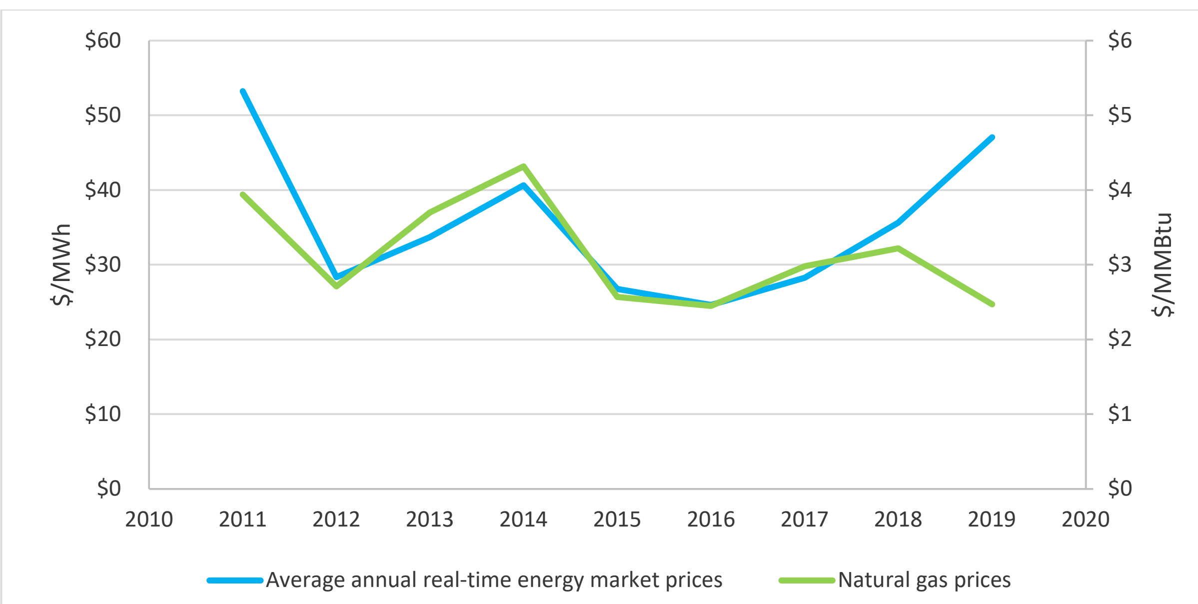
[e] More detail about ERCOT EEA definition can be found in Exhibit 1-12.

Capacity Available for Operating Reserves	5,935	2,930	3,005	202.6%

A July 2020 paper from the Institute for Energy Economics and Financial Analysis predicts that solar installations will soon cause much of the remaining coal-fired generation in ERCOT to retire. Due to the low cost of solar and wind, coal will lose market share as these technologies become more prolific. The paper cited an 8.6 million MWh decrease in coal-fired generation in January 2020, while wind and solar increased by 8.5 million MWh. This is an almost 21 percent increase in solar and wind production. The rise in solar capacity poses a nascent daytime threat to coal-fired generation and will increase in coming years. [18]

An October 2017 article in *Power* magazine points to a roughly 50 percent drop in wholesale power prices in ERCOT's energy market since 2011 as the primary driver of the recent plant retirements. [19] In 2016, average annual real-time energy market prices in ERCOT were $24.62, down from $53.23 in 2011, although they increased slightly in 2017 to $28.25, as seen in Exhibit 1-3. [20] The *Power* article posits that coal and nuclear units in ERCOT are becoming unprofitable, and the retirements announced in Fall 2017 were economic decisions by generator owners who determined that the plants were unable to earn a profit under existing market conditions. [19] In 2020, AEP Texas retired Oklaunion, a 650-MW coal-fired power plant due to unfavorable market condition. AEP Texas stated that the cost to generate energy from Oklaunion[f] is no longer competitive in ERCOT. [21] Note that in Exhibit 1-3, the ERCOT real-time energy market price in 2019 jumped to $47.06/MWh, a 32 percent increase from 2018.[g] This was due to the combination of shortage pricing in August and September 2019 where prices approached $9,000/MWh for a total of more than two hours. [22]

Exhibit 1-3. Average annual real-time energy market and natural gas prices [22]

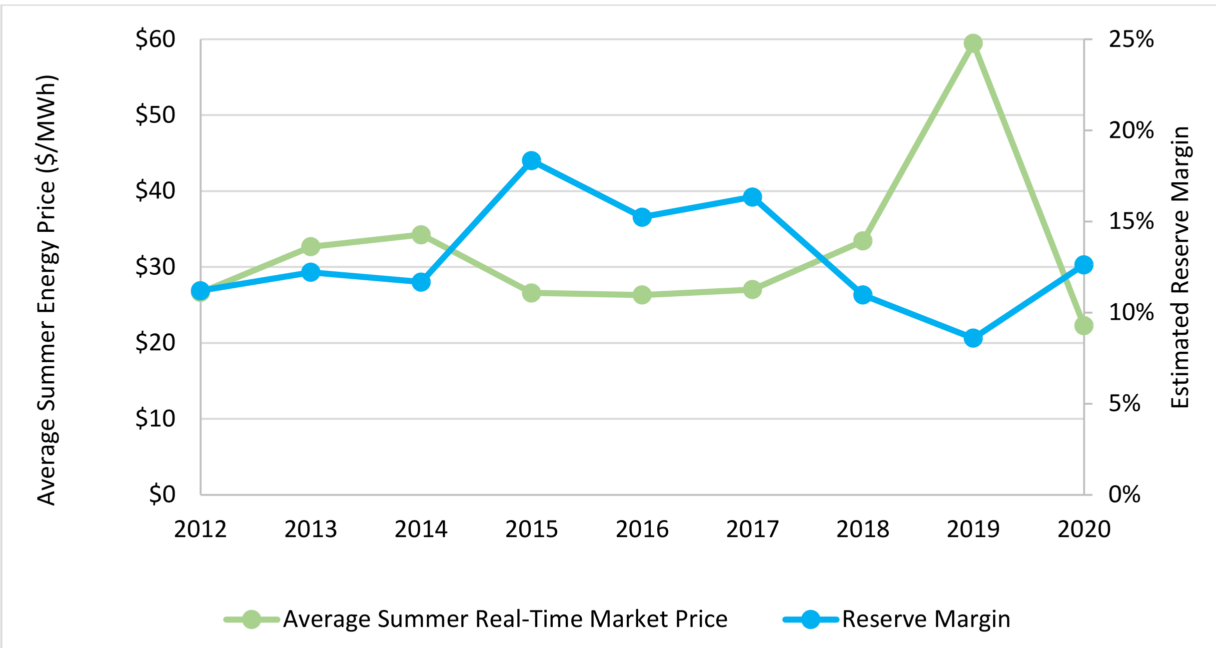


[f] Oklaunion is in the process of being converted to natural gas. [60]

[g] The ERCOT 2020 State of the Market Report has not yet been released as of the date of this publication.

The recent thermal plant retirements resulted in a lower summer reserve margin for these years, especially for 2019. The lower reserve margin is a major factor causing higher summer energy prices (real-time market hub average price), as shown in Exhibit 1-4. The reserve margins are the estimated values from SARA and CDR reports published by ERCOT each year, not the operating reserves from summer peak days. As seen in Exhibit 1-4, the reserve margin has dropped 55.5 percent from 19.34 percent to 8.61 percent from 2015 to 2019, while the average summer energy price increased from $26.59/MWh to $59.48/MWh from 2015 to 2019. The energy prices are from ERCOT's real-time energy market average hub prices in June, July, August, and September. [23] In 2020, due to the lower-than-expected demand and higher reserve margin, the average summer energy price decreases to $22.27 per MWh, which is the lowest summer energy price in ERCOT for past 10 years.

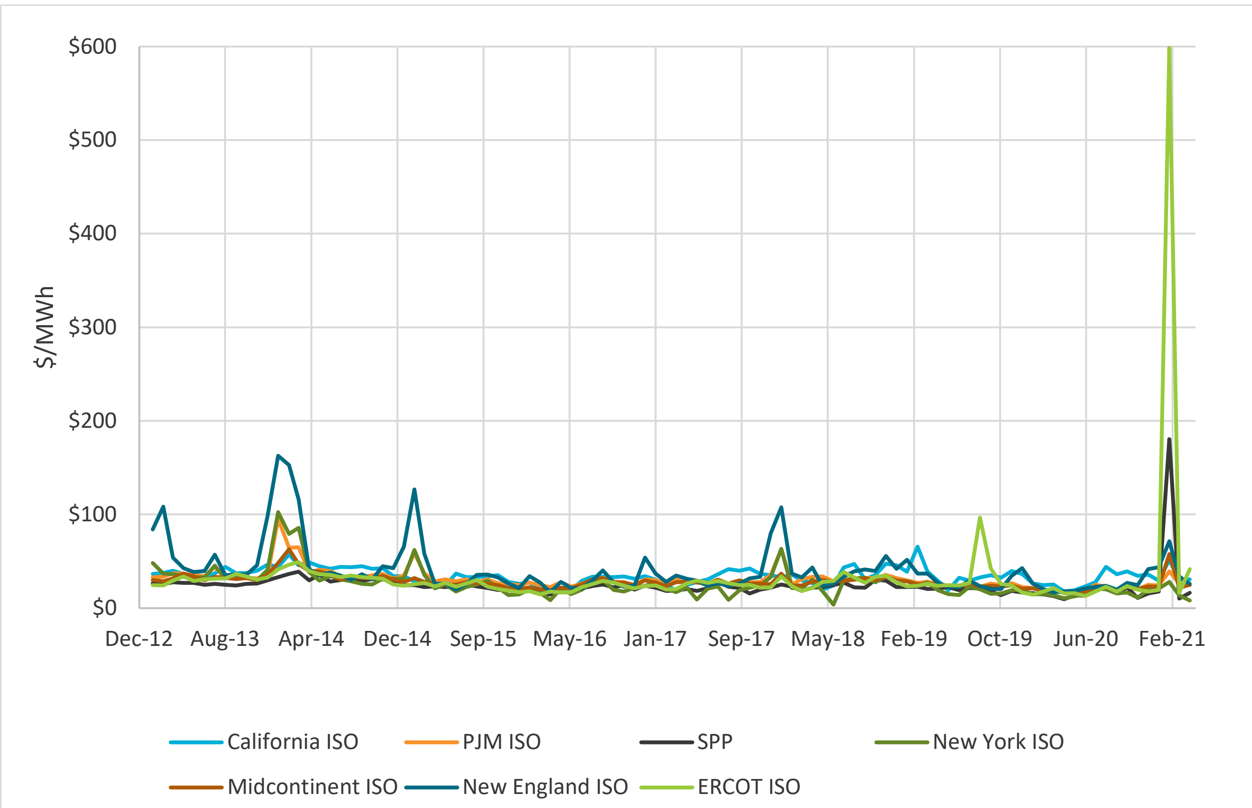
Exhibit 1-4. ERCOT estimated summer reserve margin and average energy market price from 2012 to 2019 [23]



A lower reserve margin not only causes higher average energy market price in summer, but also results in higher price fluctuations. Exhibit 1-5 shows the monthly hub average real-time energy prices in ERCOT compared with those for other ISOs/RTOs in the United States (U.S.) over the last seven years. While the overall energy price is relatively low in ERCOT, energy price spikes occur in winter and summer, when demands are highest and wind resources reach their lowest seasonal output levels. Energy price ranges from $15 to $97 per MWh in ERCOT, which is a large swing range compared to other ISOs/RTOs except ISO New England and ISO New York, which experienced wider swings of $145 and $99 during the 2014 Polar Vortex and 2018 Bomb Cyclone respectively. Price spikes in ERCOT are significantly higher in Summer 2019 than previous years. On August 13, 2019, real-time energy price even reached the market price cap of $9,000/MWh, [24] showing the resource adequacy problem ERCOT is facing as a result of low reserves.

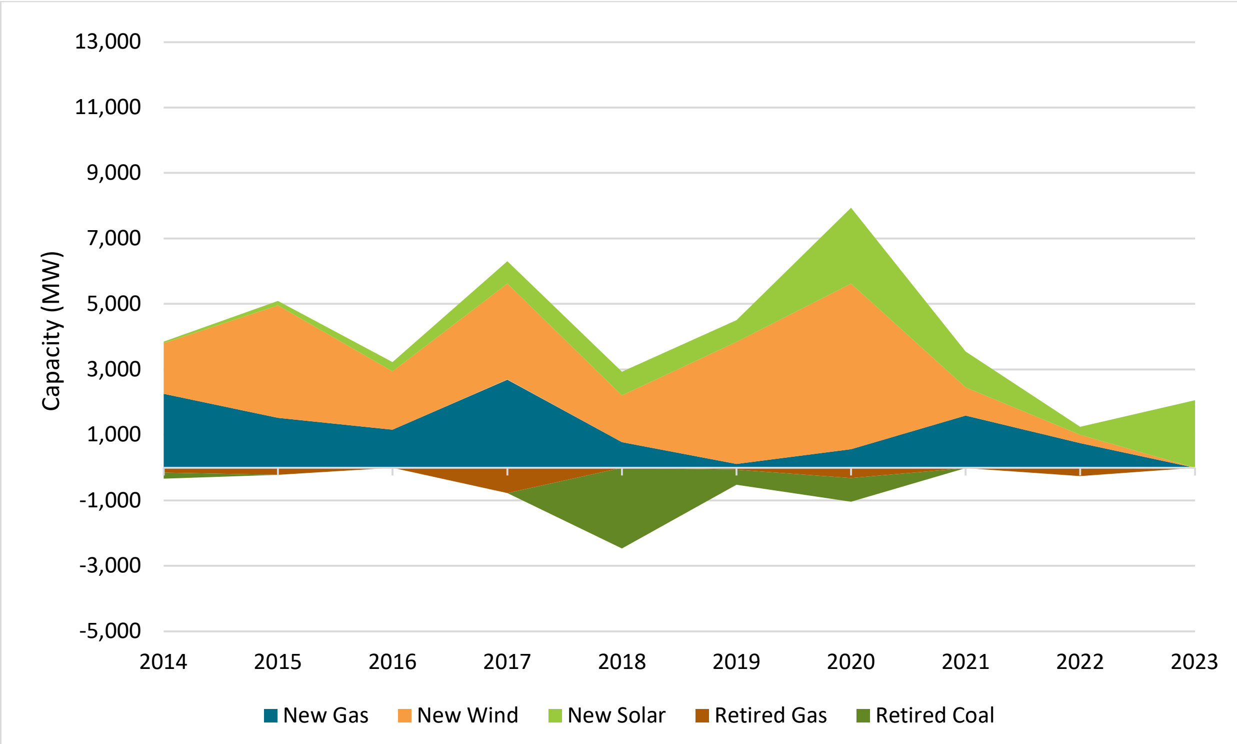
2020 was a relatively calm year, with the real-time energy price reaching $1,040/MWh during a brief period in May 2020. To date, 2021 has not been as calm. In February, the much chronicled extreme cold weather event that struck the midsection of the US leading to extended periods of rolling blackouts in ERCOT, SPP, and MISO pushed the ERCOT average monthly LMP up to nearly $600/MWh, with the real-time energy price reaching the market price cap of $9,000/MWh for a sustained period during the energy emergency from February 15 through 19. While April 2021 saw average prices near $40/MWh, prices rose to between $1,200 and $1,630/MWh on April 13 due to maintenance outages and increased demand from unseasonably high temperatures. [25, 26] This event saw a demand of nearly 49 GW and available supply of 50 GW. This event only lasted a few hours as opposed to the February 2021 event that was several days in duration.

Exhibit 1-5. ISO/RTO averaged monthly average real-time energy market price ($/MWh) [26]



The generation capacity changes to date and projected changes within ERCOT from 2014 to 2022 are shown in Exhibit 1-6. Wind and natural gas capacity compose the majority of new generating capacity in ERCOT, while solar generation saw steady relative growth. In 2017, ERCOT added more than 5 GW of new capacity, with 57 percent coming from variable renewable energy (VRE) sources. In 2020, more than 13 GW of new capacity will be added with more than 93 percent being VRE. Coal has been the largest fuel type resource that has been retired to date with 650 MW of coal-fired capacity retired since the publication of the 2020 version of this report. Apart from coal, about 1.2 GW of natural gas has also retired from 2014 to 2019 with almost 600 MW of natural gas-fired capacity currently scheduled to be retired by 2022.

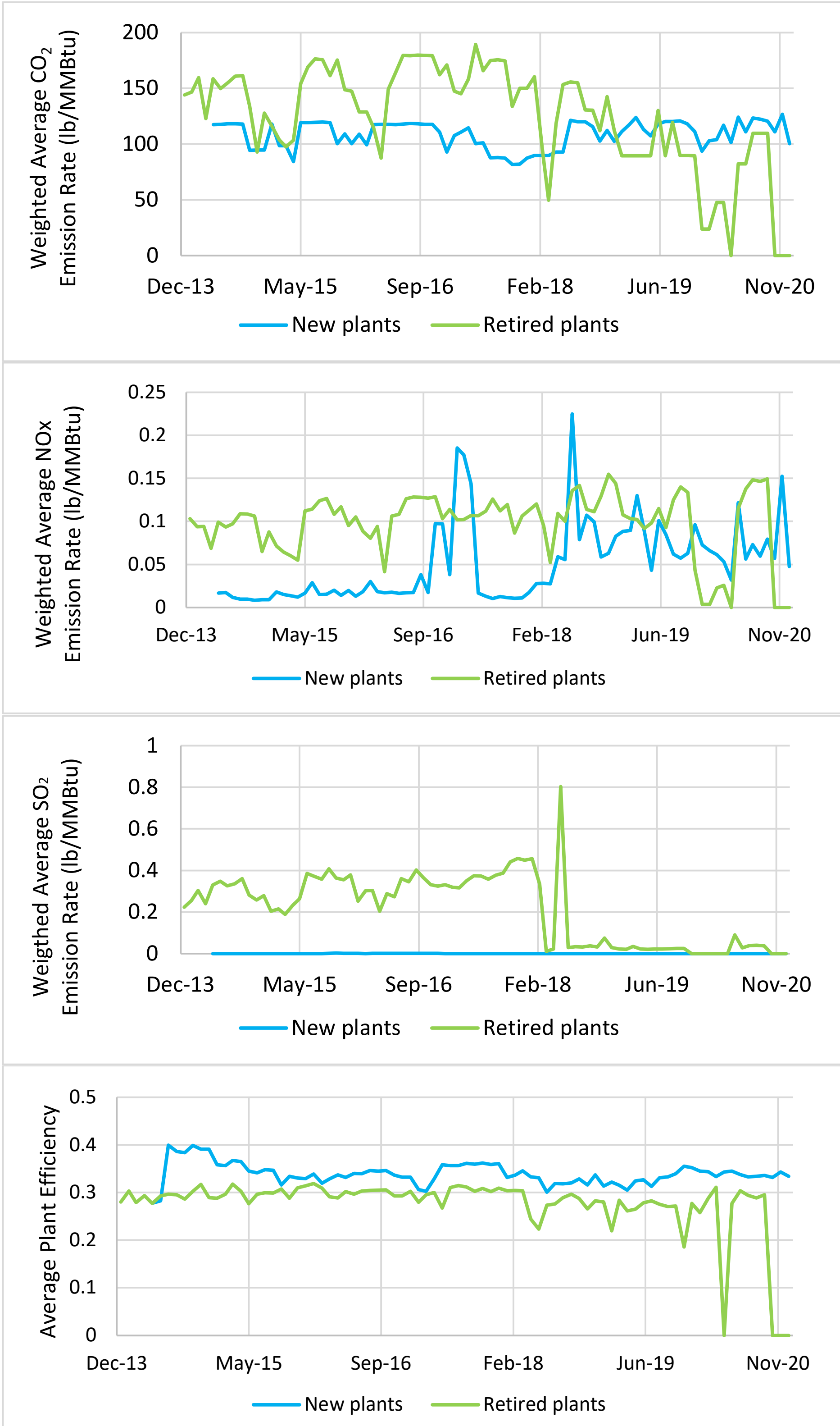
Exhibit 1-6. ERCOT generation capacity changes and projection changes from 2014 to 2022 [26]



Note: Negative capacity indicates retirement, while positive capacity indicates addition

Exhibit 1-7 further compares the fossil fired generation fleet between the new generation on-line and retired generation within the last five years. The top three plots of Exhibit 1-7 show that newly added natural gas capacity emission rates are much less than that of the retired capacity. The newly added generators have a zero-emission rate for sulfur dioxide (SO_2) for most months since 2014. With higher emission rate capacity retiring and lower emission rate natural gas capacity and VRE coming on-line, overall emissions in ERCOT are declining. The very bottom plot of Exhibit 1-7 shows the efficiency comparison between newly added and retired generation in ERCOT. Newly added generators have a higher average efficiency than retired generators from July 2014 to December 2019.

Exhibit 1-7. ERCOT new (online after 2013) vs recently retired (retired between 2014 and 2021) thermal generation plant emission performance and efficiency [26]

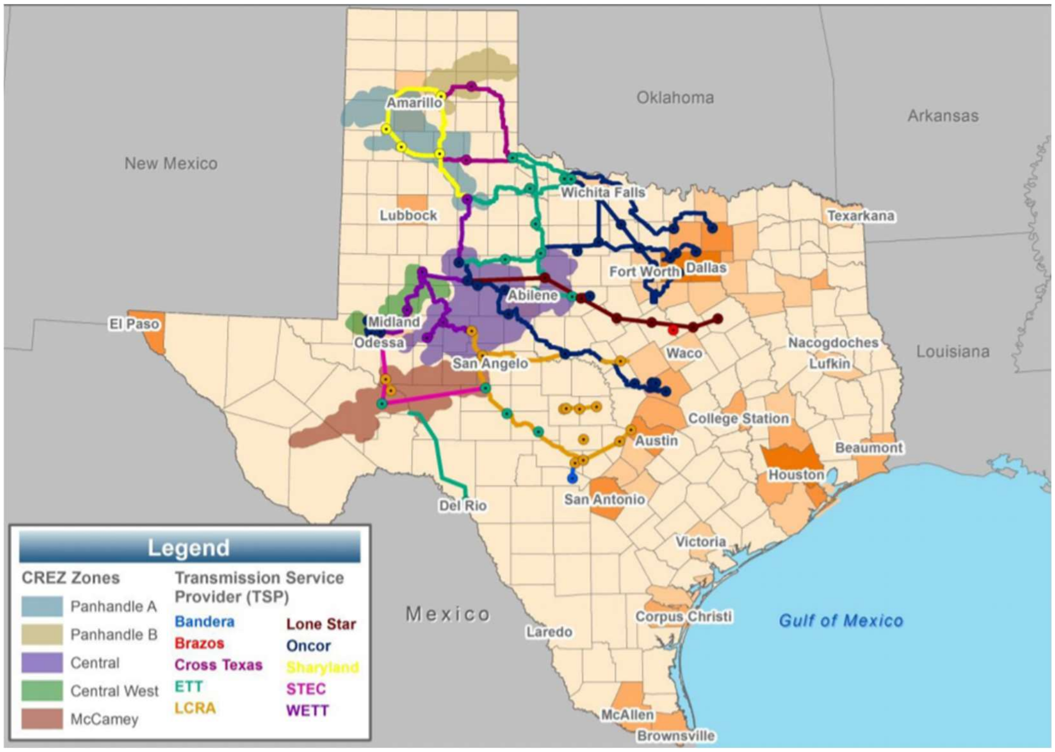


Since the majority of new generation in ERCOT is wind (4.7 of 4.9 GW added generation in 2019), as discussed above, the decline in wholesale power prices is being driven by competition from low-cost renewables. [19] In the view of ERCOT's independent market monitor (IMM), Potomac Economics, the higher real-time energy price increase of 32 percent in 2019 was a competitive outcome resulting from significant shortages during the year. Outside of the shortage events in August and September 2019, the real-time prices correlated with the lower natural gas prices, indicative of a well-functioning competitive market. [19, 22]

A 2017 report by IHS Markit offers a different assessment of the state of ERCOT's energy market. IHS Markit asserts that subsidizing the cost of renewable generation is distorting the market, causing the share of wind generation to exceed its cost-effective level. [29] The study argues that wind output is disproportional to the ERCOT demand curve, which means wind generates more power while demand and market clearing prices are lower. With subsidies, it distorts the wholesale energy prices and even causes negative prices in ERCOT. On the other hand, major transmission projects have been built to transmit renewable-generated power, and the cost of those projects is not accounted for in wholesale energy prices.

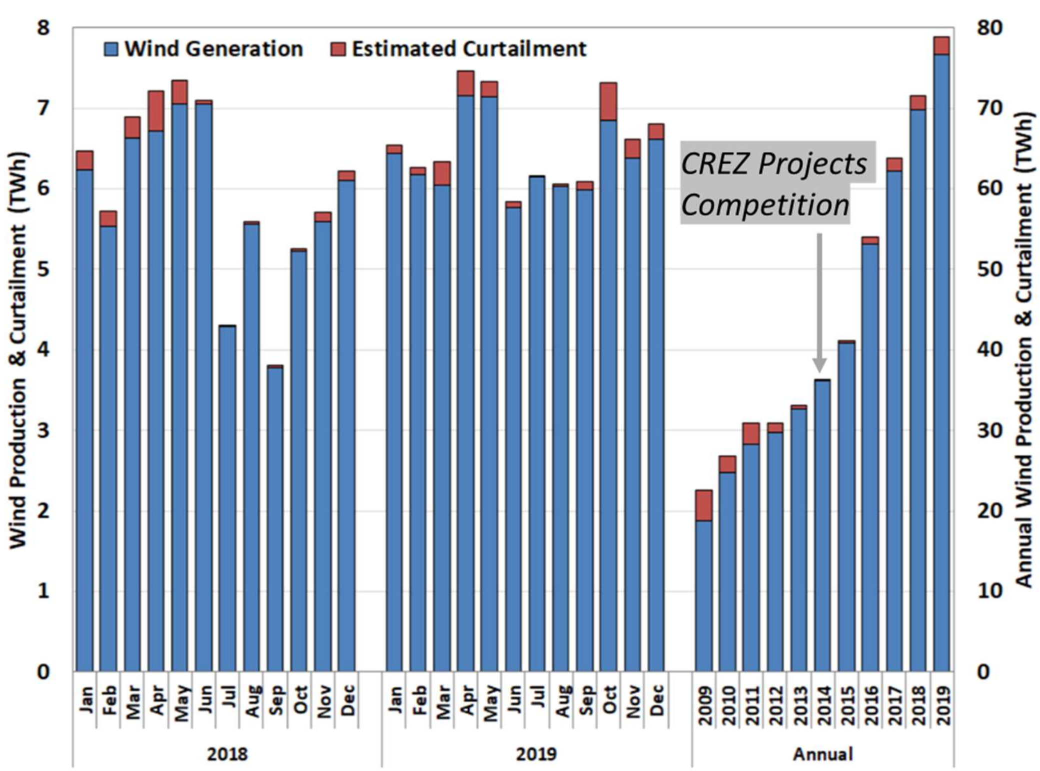
One of the largest transmission investment projects in Texas was the establishment of Competitive Renewable Energy Zones (CREZ). In 2005, Texas Senate Bill 20 was passed requiring the design of a transmission plan to deliver wind generation from windy, but less populated CREZ in West Texas, to end-users in Texas demand centers (Exhibit 1-8). The intent of CREZ transmission projects was to relieve wind congestion and lower energy prices. The projects were completed in 2014 and are able to accommodate 18.5 GW of electricity flow with approximately 3,600 circuit miles of 345-kilovolt (kV) transmission lines. The total project cost was around $6.9 billion. [30] After the completion of the CREZ transmission projects in January 2014, wind curtailment dropped to 0.5 percent from 17 percent back in 2009, but with additional wind and solar brought online since the CREZ project's completion, and proposed wind and solar generation projects in the queue, congestion has returned due to transmission constraint. Exhibit shows the wind curtailment is gradually increasing since 2014. Around 2 TWh of wind generation was curtailed in 2019, mostly in spring and fall seasons. [22] Nevertheless, benefiting from federal and state subsidies, including the wind production tax credit (PTC), an additional total of about 13,865 MW of wind capacity has been proposed, with more than 1.2 GW of wind generation having signed IAs and slated to come online in 2021, shown in Exhibit 1-10. [31] This continued growth of VRE and the increasing demand from oil and gas extraction activities can cause system congestion keep increasing into the future.

Exhibit 1-8. CREZ and projects (2014)



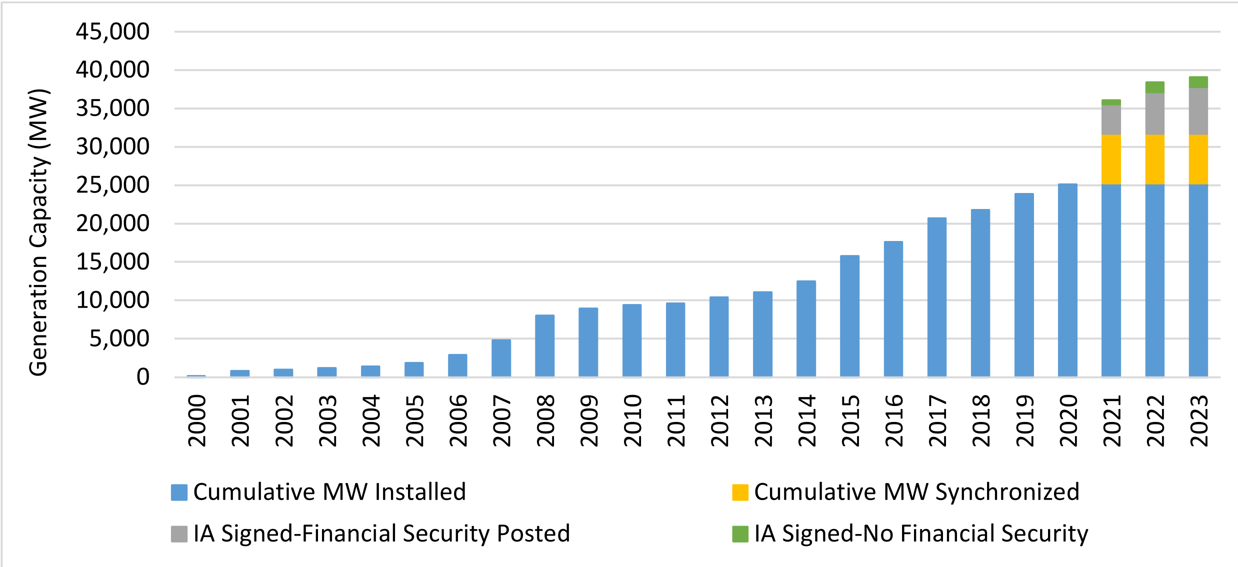
Used with permission from ERCOT [32] [30]

Exhibit 1-9. ERCOT wind generation and curtailment



Permission pending from Potomac Economics

Exhibit 1-10. ERCOT wind generation cumulative and proposed capacity (MW) with IA signed (as of January 8, 2020) [33]



PTC is a production-based credit for the first 10 years of a wind generation project's operation. It was set at 1.5 cents per kilowatt-hour (kWh) in 1992 and is indexed to inflation so it is now worth 2.5 cents per kWh pre-tax in 2019. [34] This is even higher than the ERCOT 2020 real-time market hub average summer price shows in Exhibit 1-4. The Department of the Treasury has estimated PTC to be the most expensive energy-related tax credit, and 47th most expensive overall, under the U.S. tax code, with a total more than $33 billion from 2020 to 2029.[h] [35, 36] Wind capacity beginning construction after 2016 will only receive a percentage decreased PTC by 20 percent per year from 2017 through 2019 due to the phase-out and sunset provision set by Congress in late 2015. However, with PTC extensions set by Congress in 2019 and 2020, wind generation that begins construction during 2020 or 2021 also qualifies to claim 60 percent of PTC. [37] Currently, wind generation starting construction after 2021 will not be qualified for PTC.

While traditional generation resources receive some federal subsidies, they are not as substantial as the PTC. With the PTC, wind generation is able to bid into the market at prices lower than its true cost, thereby undercutting other forms of generation. IHS Markit estimates that without subsidized wind, the market clearing price during peak periods would have been about one-third higher in 2014. Although IHS Markit does not state that wind subsidies are the cause of plant retirements in ERCOT, this price change would be large enough to change the economic calculation for recently retired coal- and gas-fired generating units. [29]

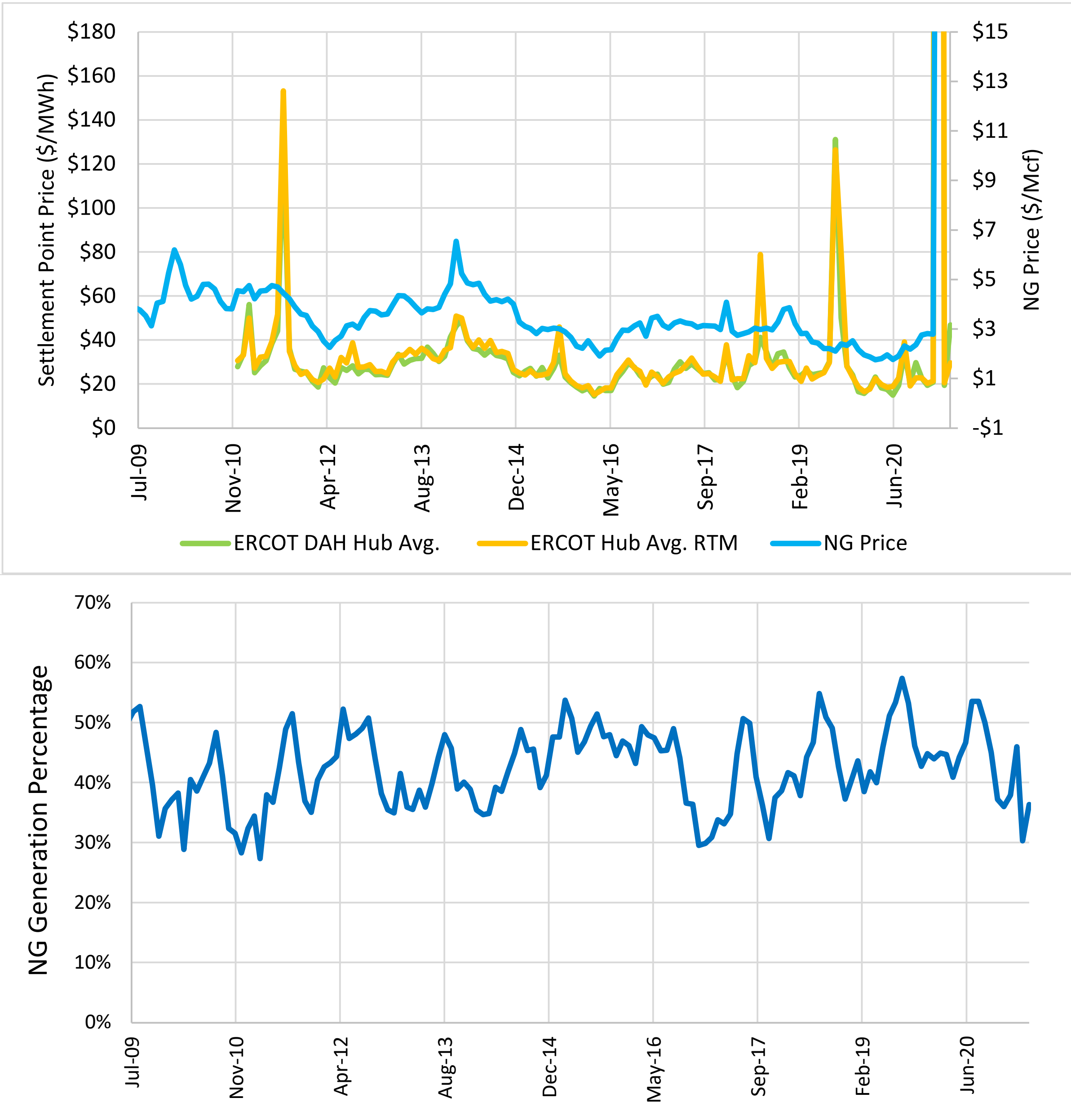
For solar energy, the Solar Investment Tax Credit (ITC) is a significant subsidy to support the growth of solar energy in the United States. The ITC was created and enacted in 2006 with the passage of the Energy Policy Act of 2005. Since then, solar energy has grown rapidly, with

[h] For comparison, the much more politicized and publicly visible Earned Income Tax Credit and Student Loan Interest deductions are projected at $49 billion and $22 billion, respectively, over the same period.

average annual growth of 50 percent over last decade. After the multi-year extension passed by Congress in 2015, ITC provides a 30 percent tax credit for investment in an eligible solar residential or commercial property that began construction by 2019. Commercial solar projects that begin construction in 2020, 2021, 2022, 2023, or 2024 will get a 26, 26, 26, 22, or 10 percent tax credit, respectively. For residential solar projects, the same tax credits apply for projects that begin construction before 2024. [38] The Department of the Treasury has estimated that the ITC will provide a total of almost $27 billion in credit from 2019 to 2029. [35] Note that wind generation owners can also claim the ITC in lieu of PTC. For offshore wind generation projects that begin construction between 2022 through 2025, while they are not eligible for any PTC anymore, they qualify for 30 percent of ITC. [39]

Low natural gas price is also a major driver for the decreasing wholesale power price ERCOT. The top plot of Exhibit 1-11 shows the correlation between natural gas price, day ahead, and real-time LMP in ERCOT. The natural gas price curves and LMP curves have similar trends and fluctuations except for a few LMP summer spikes. The bottom plot of Exhibit 1-11 shows the monthly natural gas generation percentage, on a MWh basis as a percentage of all energy generated in ERCOT in each month. As seen in the plot, ERCOT relies heavily on natural gas-fired electricity generation, with more than 50 percent of natural gas in summer. ERCOT's IMM, Potomac Economics, also points out that natural gas prices have and will continue to be a primary driver for the electricity prices. [20] With coal plants retirement and new natural gas plants added in the ERCOT power grid, the electricity price in ERCOT might become more volatile and experience larger price fluctuation. This is because coal prices are historically more stable than natural gas, and natural gas price fluctuations can lead to unstable LMP prices. The high LMP spike is already shown in ERCOT since 2018. [24]

Exhibit 1-11. ERCOT monthly natural gas price compares to monthly hub average real-time and day ahead market LMP (top) and ERCOT monthly natural gas generation percentage (bottom) [26]



Source: S&P Global and Energy Information Administration (EIA)

Not everyone shares IHS Markit's perspective on the impact these price distortions have on ERCOT's market. A Greentech Media article published in June 2018 argues that ERCOT has saved customers billions by not developing a capacity market, while also maintaining resource adequacy and transitioning to cheaper sources of electricity. [40] The article acknowledged that ERCOT would be operating with tight reserves in Summer 2018, but maintained that ERCOT had enough operating tools to manage a situation where peak load might come close to exceeding available capacity. In fact, Texas did not suffer from any energy emergency events during Summer 2018 and 2020. And in 2019, only two EEA1 events occurred on August 13 and 15.

ERCOT has defined EEA levels and procedures to utilize operational tools and send out alert communications when reserve is low to maintain system reliability. ERCOT uses physical responsive capability (PRC) as a trigger for EEA. [41] [42] PRC represents the grid's response time to disturbances from online generating and load resources. The real-time PRC is published on the ERCOT System Ancillary Service Capacity Monitor page.[i] The EEA trigger criteria and corresponding operation for each level are shown in Exhibit 1-12. In Summer 2011, with the severe heat wave, ERCOT issued EEA1 six times and EEA2 twice. As stated in the previous section, ERCOT issued EEA1 twice in Summer 2019.

Exhibit 1-12. ERCOT EEA matrix

Emergency Level	Trigger Criteria	Grid Operation	Other Operation
Control Room Watch	PRC < 2,500 MW with no expectation to recover within 30 minutes (mins)	• Issue "Watch" to ERCOT Market Participants • Release non-spinning reserves	• Notify PUCT and Texas RE • Provide update to ERCOT board
EEA1 – Power Watch	PRC < 2,300 MW with no expectation to recover within 30 mins	• Issue EEA 1 to ERCOT Market Participants • Import energy from DC tie • Implement 30-minute ERS • Deploy responsive reserve • Launch TDSP load management program	• Contact utility • Update grid condition on social media and update app status • Release news if appropriate
EEA2 – Power Warning	PRC < 1,750 MW with no expectation to recover within 30 mins or frequency below 59.91 Hz for more than 15 mins	• Issue EEA 2 to ERCOT Market Participants • Deploy demand response resource • Deploy remaining ERS • Instruct transmission service provider to use voltage reduction • Begin block load transfer to other grids	Same as above
EEA3 – Power Emergency	PRC < 1,000 MW with no expectation to recover within 30 mins or frequency below 59.91 Hz for more than 15 mins	• Issue EEA 3 "Rotating Outages" to ERCOT Market Participants • Instruct transmission operators for load shedding	Same as above

In addition to internal generation resources, ERCOT can utilize direct current (DC) ties to import energy from neighboring systems. There are two DC ties between ERCOT and the Southwest Power Pool (SPP) and two DC ties between ERCOT and Mexico's state-owned electric utility, Comisión Federal de Electricidad. The combined DC ties allow the import of up to 1,220 MW to help ERCOT manage tight reserves. [43] There are also switchable generation units on the border of the ERCOT grid that can provide electricity to ERCOT, if needed. These switchable

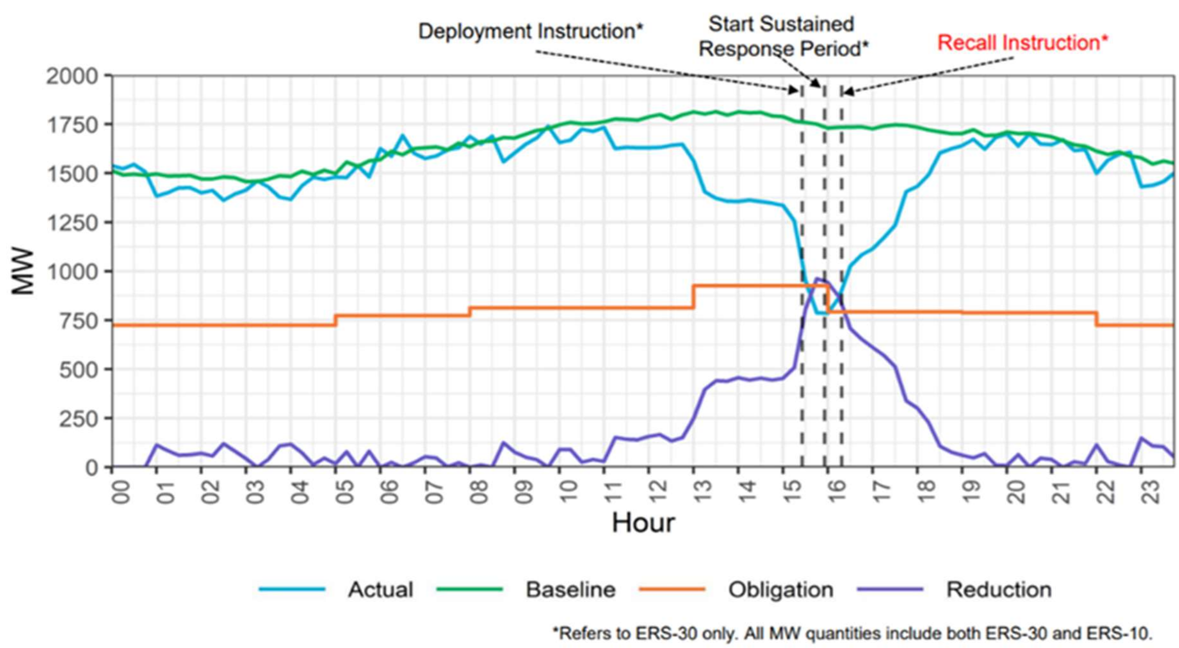
[i] http://www.ercot.com/content/cdr/html/as_capacity_monitor.html

units serve customers in SPP or the Midcontinent ISO but maintain an operating agreement with ERCOT allowing ERCOT to request assistance from these units during an energy emergency.

ERCOT procures ERS three times annually (for four-month service) to help avoid load shedding during a grid emergency. Qualified loads and generators can offer to provide ERS to ERCOT through their qualified scheduling entities. ERCOT publishes the procurement results on their website.[j] As an example, for Time Period 4 (17:00 to 19:00) from February 1 to May 31, 2021, ERCOT procured 1,009.7 MW of non-weather sensitive 30-minutes response time ERS from 455 load resources and 43 generation resources. [44]. These generation and demand response resources can help ERCOT avoid a load shedding event during energy emergency situations.

Demand response is an ability from the load side to reduce or shift electricity consumption when the price is high or when the reliability of the grid is endangered. Customers who are capable of demand response can participant in ERCOT's market in three ways. The first is to become an ERCOT Load Resource to participate in ERCOT's day-ahead energy market, real-time energy market, or ancillary service market. The second is to participate in ERCOT ERS (as described above). The last method is to opt into the transmission or distribution utility's demand response program. On August 13, 2019, the ERCOT EEA1 announcement day, ERS were deployed as shown in Exhibit 1-13 to ease the emergency condition. ERCOT did not report on ERS deployment during Summer 2020 since there were no tight resource situations. In February 2021, ERCOT also deployed all types of ERS starting from 00:17 on February 15. As a result, ERS provided more than 1,000 MW in total the morning of February 15. [45] This event is discussed in Section 2.

Exhibit 1-13. ERCOT ERS deployment on August 13, 2019



Used with permission from ERCOT [46]

j http://www.ercot.com/services/programs/load/eils/

In ERCOT, price responsive load may not receive proper price benefit of their load shifting action because the load zone settlement point prices are the average of 5-minute bus locational marginal prices (LMP) during the 15-minute period. The payment of retail load is to multiply 15-minute energy by the 15-minute settlement point price. This calculation will cause disconnection when load demand's response action is based on 5-minute price. For example, Exhibit 1-14 lays out a theoretical example of price responsive and non-price responsive load scenarios with identical total electricity usage. With the current ERCOT settlement calculation, the options result in the exact same amount of electricity cost during this 15-minute period, indicating there is no benefit for demand response. In the demand response scenario, load should be paying only $15,000 (300 kWh times $50/kWh), which is half of the cost shown in Exhibit 1-14.

Exhibit 1-14. Demand response scenarios and calculations

Scenario	0–5-minute ($125/kWh)	5–15-minute ($125/kWh)	10–15-minute ($50/kWh)	15-minute (kWh)	Price	Cost
Demand Response	0 kWh	0 kWh	300 kWh	300 kWh	$100/kWh	$30,000
Flat Demand	100 kWh	100 kWh	100 kWh	300 kWh	$100/kWh	$30,000

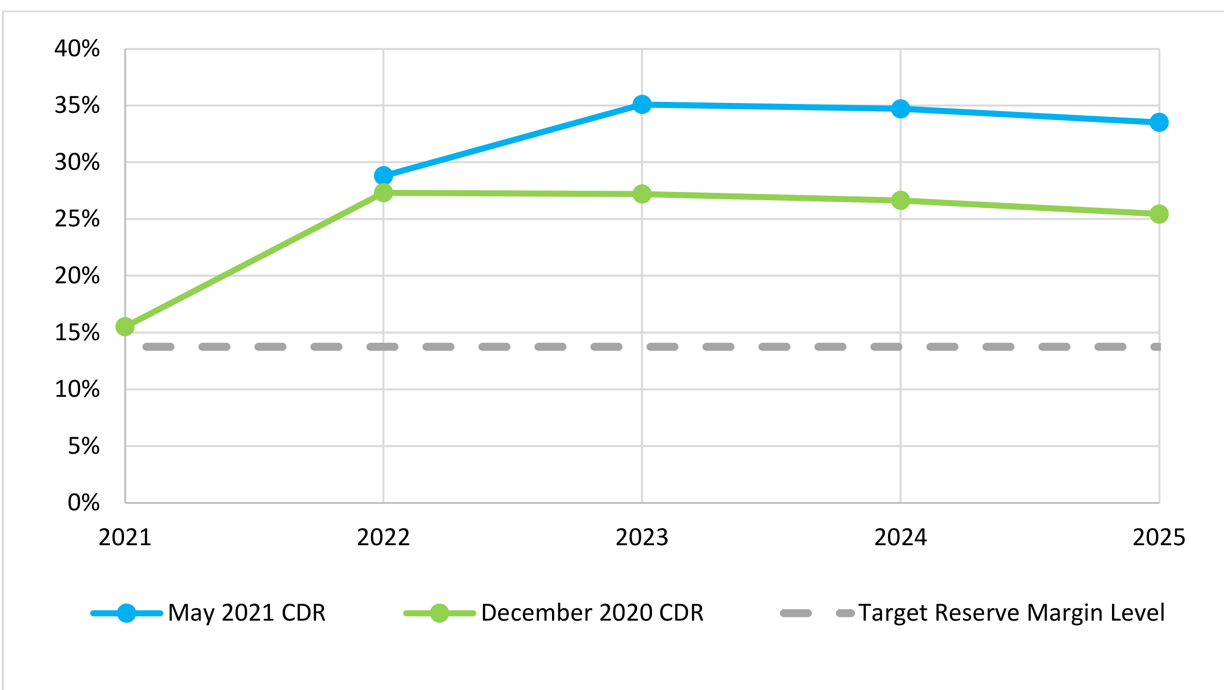
ERCOT realized that demand response load is not receiving proper benefits and planned to address it by integrating telemetry signals for 5-minute energy usage data. An extra credit or charge would be created by multiplying 5-minute energy by 5-minute LMP. This credit or charge would be applied to an ERCOT Balancing Account. By fixing this problem, it helps to attract more responsive loads and the current responsive loads to respond better to real-time market price. [47]

Another point made by the Greentech Media article is that there is uncertainty around the correct reserve margin. [40] Utility standard for decades has been to plan to a one day in ten years' LOLE. However, LOLE events are rare enough that it is difficult to determine what level of reserves are necessary to prevent such an event. This is especially true now that transmission operators have increasingly sophisticated tools at their disposal for managing load, including demand response and interruptible load. A 2014 paper by Brattle suggested that to plan for the 1-in-10 LOLE standard, ERCOT needed a reserve margin of 14.1 percent, although in its consideration, the economically optimal reserve margin was 10.2 percent. [48] Under the 10.2 percent reserve margin scenario, ERCOT could still meet a 24-hours in 10 years LOLH standard (e.g., 2.4 hours in a given year). Under such a standard, an LOLE event is unlikely to be a sustained system-wide blackout, but controlled rolling outages that leave individual customers without power. [48]

Although the reserve margin is higher than target level 13.75 percent, there is still potential for EEA events in ERCOT during Summer 2021 due to higher renewable penetration. Based on the Summer 2021 Final SARA, wind generation accounts for 10 percent of total resources while solar generation accounts for 7 percent of total resources. ERCOT has a risk for tight reserve during low wind condition or during early evening when solar comes offline. The SARAs describe these risks in their extreme scenarios for Low Wind Output Adjust and Low Solar Output Adjust, which will be further modeled and studied in Section 2. ERCOT plans to utilize its operational tools and ask consumers for voluntary conservation to manage the operation during these EEA events. Once all resources are deployed, ERCOT can instruct transmission or distribution providers to initiate rotating outages to protect the entire grid. However, it is not clear whether these tools will be sufficient.

Exhibit 1-15 shows the summer reserve margin forecast beyond 2021 based on ERCOT CDR. [15] The reserve margins will keep increasing in 2021 (around 5 percent in 2022 to 27 percent and 28 percent in 2022, and then increase again to 35 percent in 2023 from May 2021 CDR. The increases in 2022 and 2023 are caused by new planned resources. The majority of those resources are renewable—about 12.3 GW of solar and 2.9 GW of wind are expected to be online for Summer 2022. In 2023, solar will have another 6 GW increase while 0.5 GW of wind also plan to come online. After the generation surge in 2023, there are few capacity increases but steady load growth, which results in reserve margin decline. However, additional generation resource announcement, delay, or cancellation might occur, which is the reason for difference between the two CDR curves in Exhibit 1-15. If ERCOT generation resources act according to the plan in in May 2021 CDR, they will stay much higher than the North American Electricity Reliability Corporation (NERC) reserve margin level of 13.75 percent. Note that it is typical for generation developers to submit interconnection requests up to two to four years before the plan in-service dates. Therefore, CDRs will report little planned capacity beyond four years, and planning reserve margin will always decrease as long as load growth is positive.

Exhibit 1-15. Reserve margin estimation by ERCOT CDR from 2020 to 2024 [14]



2 2021 EVENTS

Historically, ERCOT has seen system stress in summer months, as detailed in Section 1. However, stress has occurred during winter months several times in the past, notably in 1989, 2011, and 2021. These events caused rolling blackouts for portions of the ERCOT system. Weatherization procedures recommended after the 2011 were not mandatory, and many units experienced outages due to weather-related issues. [49]

Extreme system stress was seen during February 2021. Winter Storm Uri, which broke several records for temperature and snowfall, caused rotating outages in ERCOT February 14–19. [50]

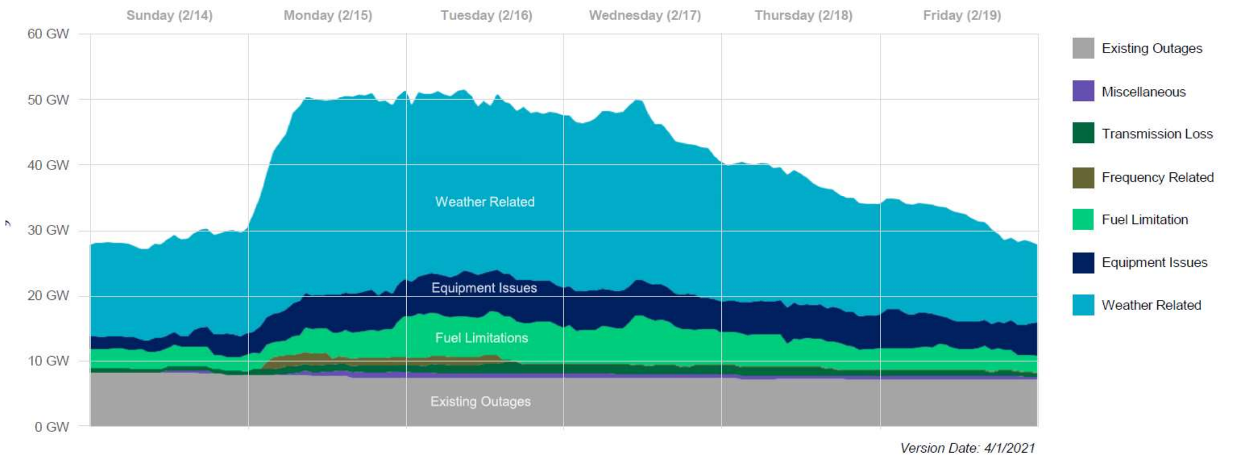
Outages from just under 30 GW to a high of 51.2 GW total occurred across the ERCOT system. These outages include derates of equipment as well as outages, of which 54 percent were attributed to weather-related issues, as seen in in Exhibit 2-1. [51, 52]

Exhibit 2-1. Outage causes by percent

Cause	Percent of Reported Outages	Additional Information
Existing outages	15%	Outages or derates that started prior to the storm preparation
Fuel limitations	12%	
Weather related	54%	Frozen equipment, ice accumulation on wind turbines, ice/snow cover on solar panels, exceedance of low temp limits for wind turbines, flooded equipment due to ice/snow melt, and others
Equipment issues	14%	
Transmission loss	2%	
Frequency related	2%	
Other	1%	Includes outages where the cause is not yet known

Exhibit 2-2 illustrates the causes of the outages as reported by Qualified Scheduling Entities in ERCOT during the period of highest capacity unavailability, which occurred around 8 am on February 16.

Exhibit 2-2. Net generation outages and derates by cause [52]



Net generator outages at the beginning of each hour on February 14-19, 2021, by cause category.

ERCOT reported these values based on the nameplate capacity of the generating unit. It should be noted that there is a distinct difference between operating capacity and nameplate capacity. While the operational capacity of dispatchable thermal resources may change slightly with weather and equipment conditions and fuel quality, the operational capacity of variable energy resources varies significantly with operating capacities well below nameplate capacities, meaning that the outage amount may exceed what would be available under normal circumstances.[k] [51, 52] Outages range from near 30 GW to over 50 GW for the duration of the event.

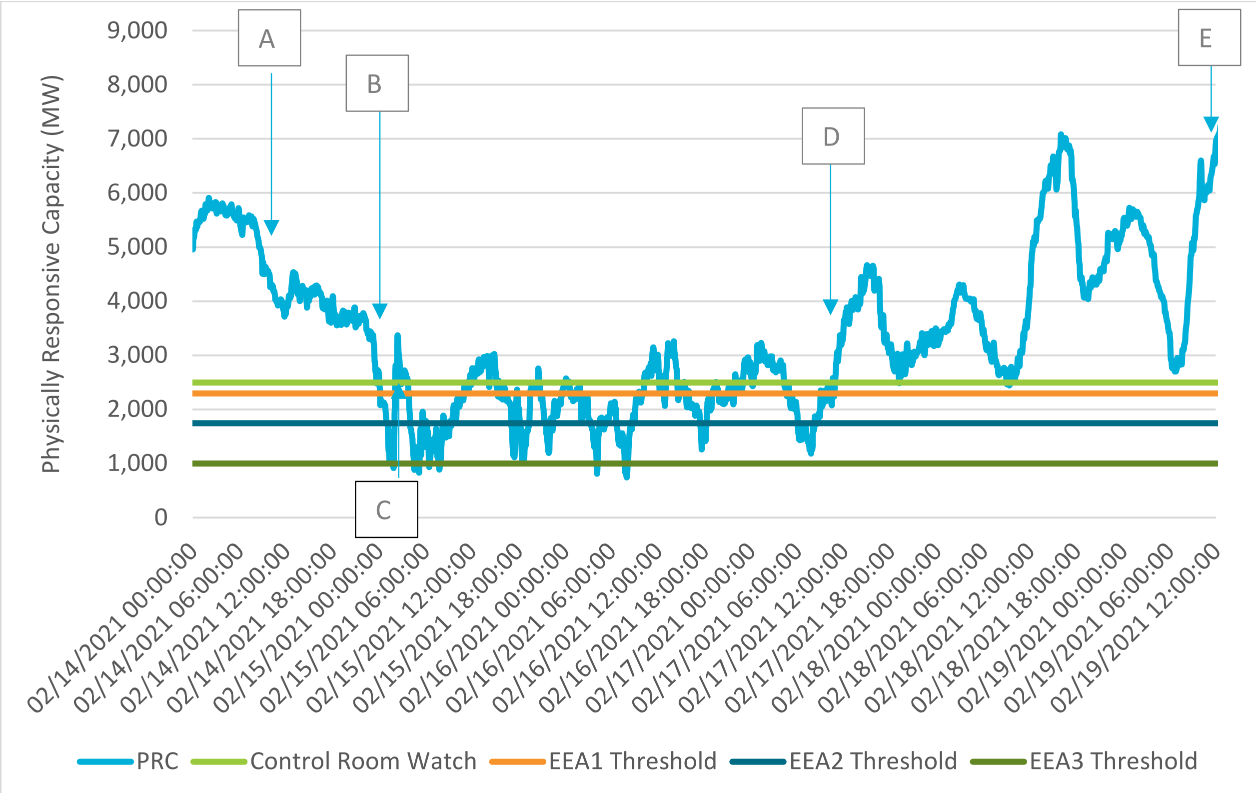
According to Hitachi-ABB Velocity Suite, the installed nameplate capacity available in February 2021 was 110,403 MW. [26] Exhibit 2-3 shows the demand, demand forecast and net generation from EIA for February. [53] Lines were added to show the winter capacity at varying levels of outages. The levels are existing outages (the 15 percent that were started before storm preparatory measures were instituted), 30 GW offline, 40 GW offline, and 50 GW offline. Around the end of the day February 14, the demand was very close to the 50 GW offline point. Rolling blackouts were stared near midnight on February 15.

[k] For dispatchable thermal resources, nameplate capacity is the maximum rated output of the unit under specific conditions designated by the manufacturer, while operating capacity represents the maximum rated output based on deviations from those manufacturer specifications. For variable energy resources, the nameplate capacity is the maximum theoretical output level under ideal conditions. i.e. perfect weather conditions and perfect equipment performance.

Exhibit 2-3. Demand and available capacity in ERCOT, February 2021

The NETL report "2020 Summer Reliability ERCOT" indicated that an extreme weather event could push demand to a level where the reserve margin was less than 1 percent (total capacity available 84,657 MW, demand 83,979 MW). [54] As seen in Exhibit 2-4, with reduced capacity of 40–50 GW, the net combined effect of outages and increased load created effective conditions exceeding those previously studied. Additionally, the 2020 report predicted that in the case of extreme weather, EEA1, EEA2, and EEA3 days would occur. On February 15, 2021, an EEA1 notice was issued just after midnight. This escalated to an EEA3 by 1:30 am. The system began recovering on February 19 just after 9 am when the EEA level lowered from 3 to 2. The system was declared normal by 11 am on the 19. [55] For more than four days the system was under an EEA notice. The EEA threshold levels and reported levels of physically responsive capacity are shown in Exhibit 2-4. Significant events are included in the accompanying table.

Exhibit 2-4. Physically responsive capacity during the February outage



Point	Event
A	Temperatures begin to decline statewide
B	Multiple generating units begin tripping offline
C	Rolling blackouts initiated
D	System restoration begins
E	System fully restored

The 2020 ERCOT study showed that extreme weather in the summer could push physically responsive capacity availability to less than 1,000 MW for multiple-day periods. Winter storm Uri in February 2021 and the event in August 2019 showed that ERCOT faces extreme weather challenges in both winter and summer seasons.

On April 13, 2021, ERCOT issued advisories regarding low physical responsive capability (<2,500 MW available) for the evening. [56] This event did not result in blackouts, but illustrated the tight conditions caused by maintenance and weather events. The April event was attributed to generating units undergoing maintenance from the February event and high demand due to high temperatures in parts of the state. [25] Additional strain on the system could have led to an EEA event. Additionally, responsive reserves were deployed, and real-time LMPs rose to between $1,200 and $1,630/MWh for the 5 pm and 6 pm hours. [26, 56]

3 ERCOT Summer Scenarios

ERCOT releases several resource adequacy assessments throughout the year, with the primary assessments being the SARA and the CDR. SARA releases are seasonal, with the Final Summer 2021 SARA released in May. [57] The Summer 2021 SARA includes scenarios with a range of potential risks, including typical maintenance and forced thermal outages, extreme forced outages, low wind output, low solar output, and a peak load adjustment accounting for extreme weather. In order to evaluate these scenarios, data was evaluated from a variety of sources, including the Final Summer SARA, the most recent CDR, and ERCOT performance data from 2020. The SARA predicts a peak demand of 77,244 MW. This prediction is based on normal weather conditions and does not account for higher-than-average temperatures. [58] Data from ERCOT performance during Summer 2020 was used to develop wind and solar generation profiles. The Summer SARA includes 7 risk scenarios; 4 scenarios exploring outages, increased load, and low wind output; and 3 cumulative extreme scenarios involving cumulative forced outages, peak load, and low wind output, low solar output, and an extreme scenario involving low wind, solar, and extreme outages, and peak load adjustments.

Using this data, six scenarios were developed using ABB's PROMOD IV to assess the LOLE event risk to ERCOT for Summer 2021, as shown in Exhibit 3-1. Generation in the model was updated using the generation available in the May 2021 SARA.[l] Model peak loads were updated to match information in the SARA. Each scenario involves cumulative additions of risks identified in the SARA. The Base scenario uses the Summer 2021 SARA peak load estimate and the expected thermal forced outages. The Thermal Forced Outages ("Outages") scenario adds the high thermal forced outages in the SARA to peak load and typical forced outages.[m] Unlike maintenance outages, forced outages are not planned and cannot be postponed under an emergency situation. This scenario gives a picture of the expected change between available capacity (shown in Exhibit 3-2) and peak load under normal weather conditions. The High Weather Seasonal Load ("High Weather") scenario assumes an extreme weather event similar to what happened in 2011 in the ERCOT region. High weather increased peak load is added to the base load, and typical and high forced outages. The Past Wind scenario substituted 2020 ERCOT summer hourly wind generation for the wind generation profiles in PROMOD and uses the same peak load from the high weather scenario. These new wind generation profiles were used when calculating dispatch using the High Weather scenario peak loads, to provide a picture of generation performance with wind generation experienced in 2020. The use of the 2020 ERCOT summer hourly wind profile, in place of the existing wind profiles in PROMOD results in wind generation on the same scale, with different periods of high and low production. The result is the frequency of these shifts from high to low is slightly lower in the 2020 ERCOT data, compared to the existing wind profiles. The lower frequency of shifts results in slightly longer periods of high and low production, with some of those low points being significantly

[l] PROMOD model data is created using provided ABB interconnection model and updated using available information from regulatory filings and other sources. Model thermal and renewable generation was updated to match summer as closely as possible using available information.

[m] Since specific generator forced outages cannot be predicted and a random selection would impact the network congestion component of the dispatch, the outage totals were added to the demand side, since a shift in the overall supply curve or a shift in the demand curve have the same net effect toward obtaining the marginal generation cost.

lower than the output using the existing profiles by 5 GW, while the average hourly output for the study period remains within close in each scenario. The Past Solar scenario substitutes 2020 ERCOT summer hourly solar generation for the solar generation profiles in PROMOD and uses the same peak load from the high weather scenario. The final scenario is an Extreme Conditions scenario, using past wind and solar generation profiles, and adds typical, high, and extreme forced outages, and extreme weather peak load increases. These six scenarios are used in PROMOD to provide a simulation of generation and load for the summer season.[n] PROMOD uses the updated peak loads, along with past hourly demand, to generate future hourly demand estimates. Historic renewable production data and data from National Renewable Energy Laboratory is used by ABB to provide the profiles used to estimate wind and solar generation on an hourly basis. These factors combine to create an hourly estimate of available capacity in the model.

[n] June 1 through September 30.

Exhibit 3-1. Peak load under scenarios

Scenario Name	Description	Peak Demand (MW)	Normal Forced Outages (MW)	High Forced Outages (MW)	High Peak Load (MW)	Extreme Peak Load	Extreme Forced Outages	Historic Wind	Historic Solar	Net Effective Peak Load
1	Base Case (Normal Conditions)	77,244	3,617							80,861
2	Base case + High Forced Outages	77,244	3,617	2,601						83,462
3	Base case + High Forced Outages + High Peak Load	77,244	3,617	2,601	2,934					86,396
4	Base case + High Forced Outages + High Peak Load + Historic Wind	77,244	3,617	2,601	2,934			x		86,396
5	Base case + High Forced Outages + High Peak Load + Historic Wind + Historic Solar	77,244	3,617	2,601	2,934			x	x	86,396
6	Base case + Extreme Forced Outages + Extreme Peak Load + Historic Wind + Historic Solar	77,244	3,617	2,601		4,911	4,535	x	x	92,908

Exhibit 3-2. Available generating capacity

Category	Capacity (MW)
Thermal*	**71,395**
Hydro (Derated)	462
Wind (Derated)	7,704
Solar (Derated)	6,256
Storage	853
DC Ties (Derated)	**849**
Interruptible Loads	**2,251**
Total Capacity	**89,770**

*Includes switchable units

As seen in Exhibit 3-1 and Exhibit 3-2, available on-peak reserve generating capacity, including DC ties and interruptible loads called in emergency situations, exceeds load in the high weather scenario by only 3,374 MW, and in the Extreme Conditions scenario, load exceeds generation by 3,138 MW. The exhibits below show the on-peak reserve capacity of each day compared against the minimum target reserve margin of 13.75 percent. The reserve capacity is the available capacity at each hour, minus the total load at that hour. Exhibit 3-3 through Exhibit 3-8 show the results of the PROMOD runs. Exhibit 3-9 shows the number of days on-peak reserve capacity fell below Reference margins and EEA event thresholds in each scenario. In only the first three scenarios, ERCOT is expected to have sufficient reserves capacity to meet peak load. In the Past Wind and Past Solar scenarios on-peak reserve capacity dips below zero for five days. In the Extreme Conditions scenario, on-peak reserve capacity dips below zero for 12 days during the end of July and beginning of August. The magnitude of the shortfall in August is over 10 GW. This indicates a predicted LOLE of five days in the Past Wind and Past Solar scenarios, and 12 days in the Extreme Conditions scenarios.

Exhibit 3-3. Scenario 1 (80,861 MW peak)

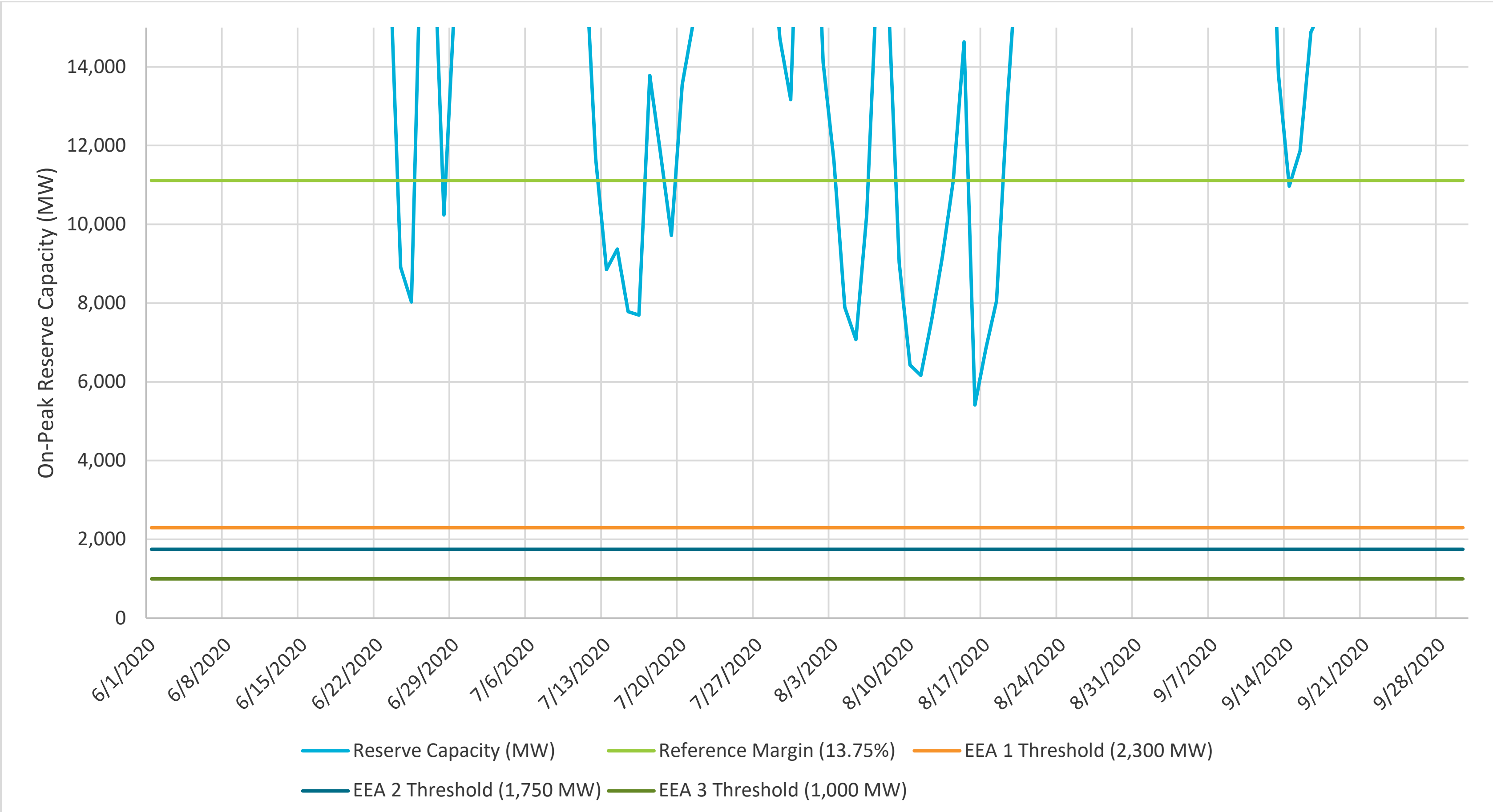


Exhibit 3-4. Scenario 2 (83,462 MW peak)

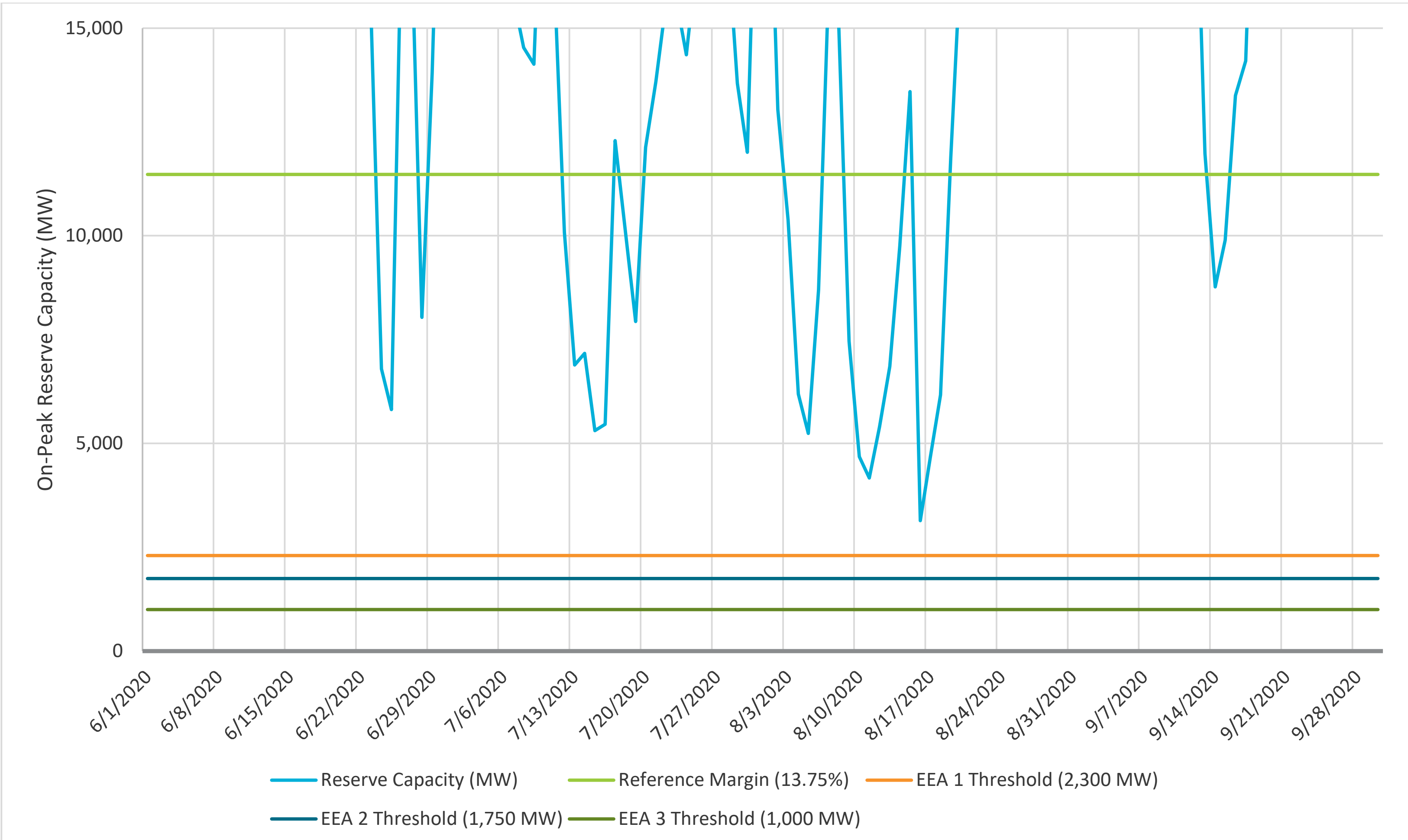


Exhibit 3-5. Scenario 3 (86,396 MW peak)

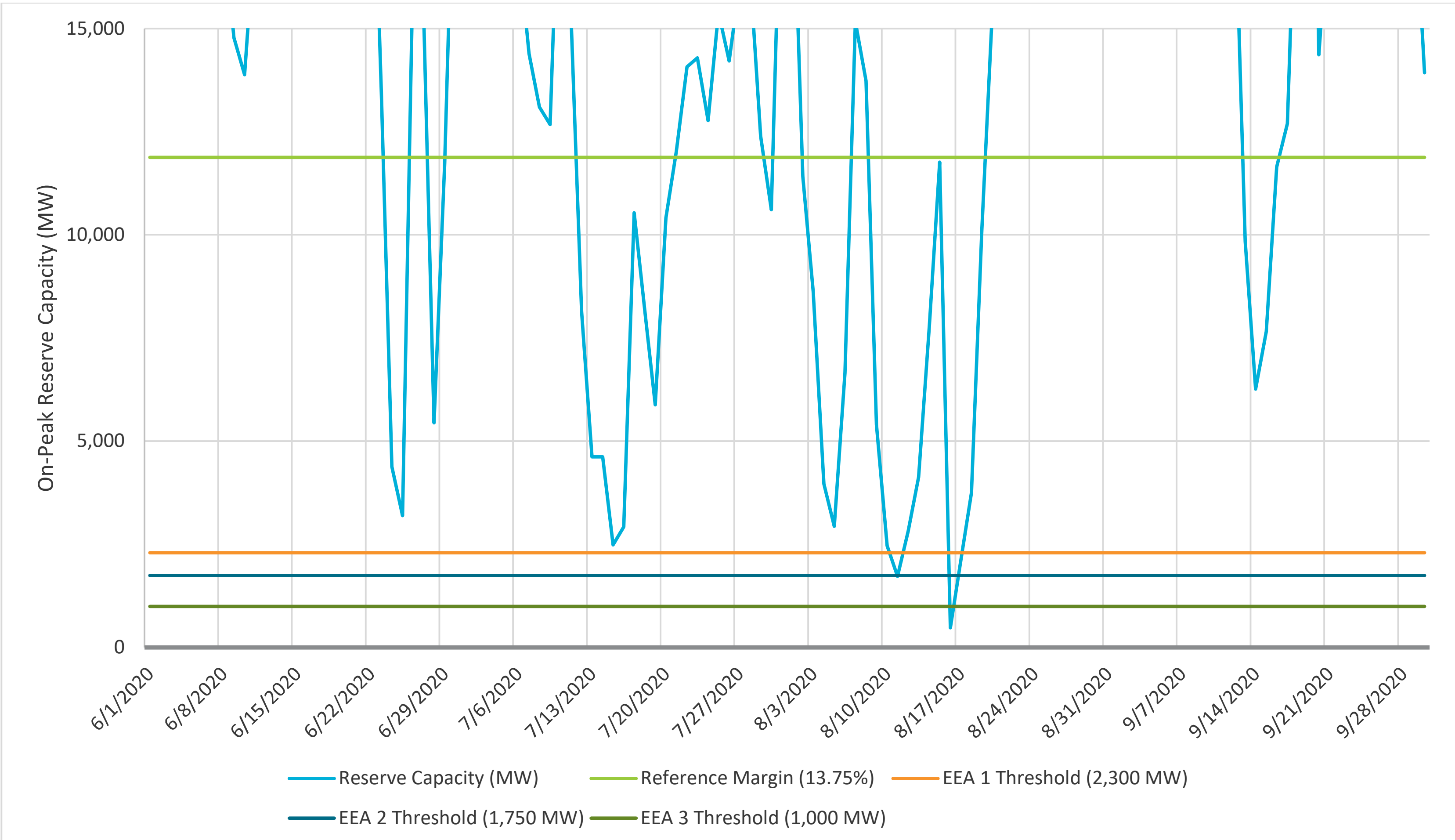


Exhibit 3-6. Scenario 4 (86,396 MW peak)

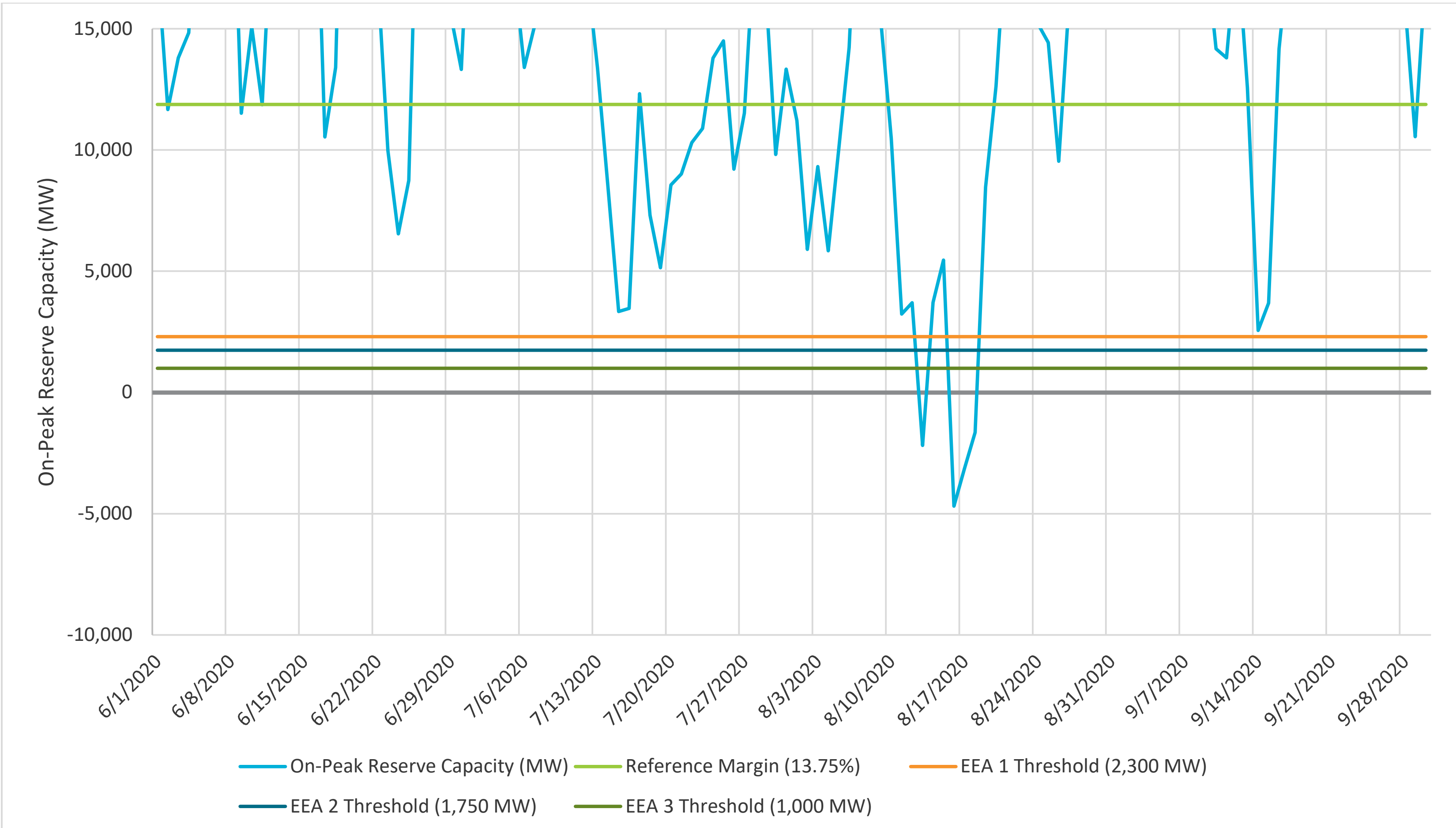


Exhibit 3-7. Scenario 5 (86,396 MW peak)

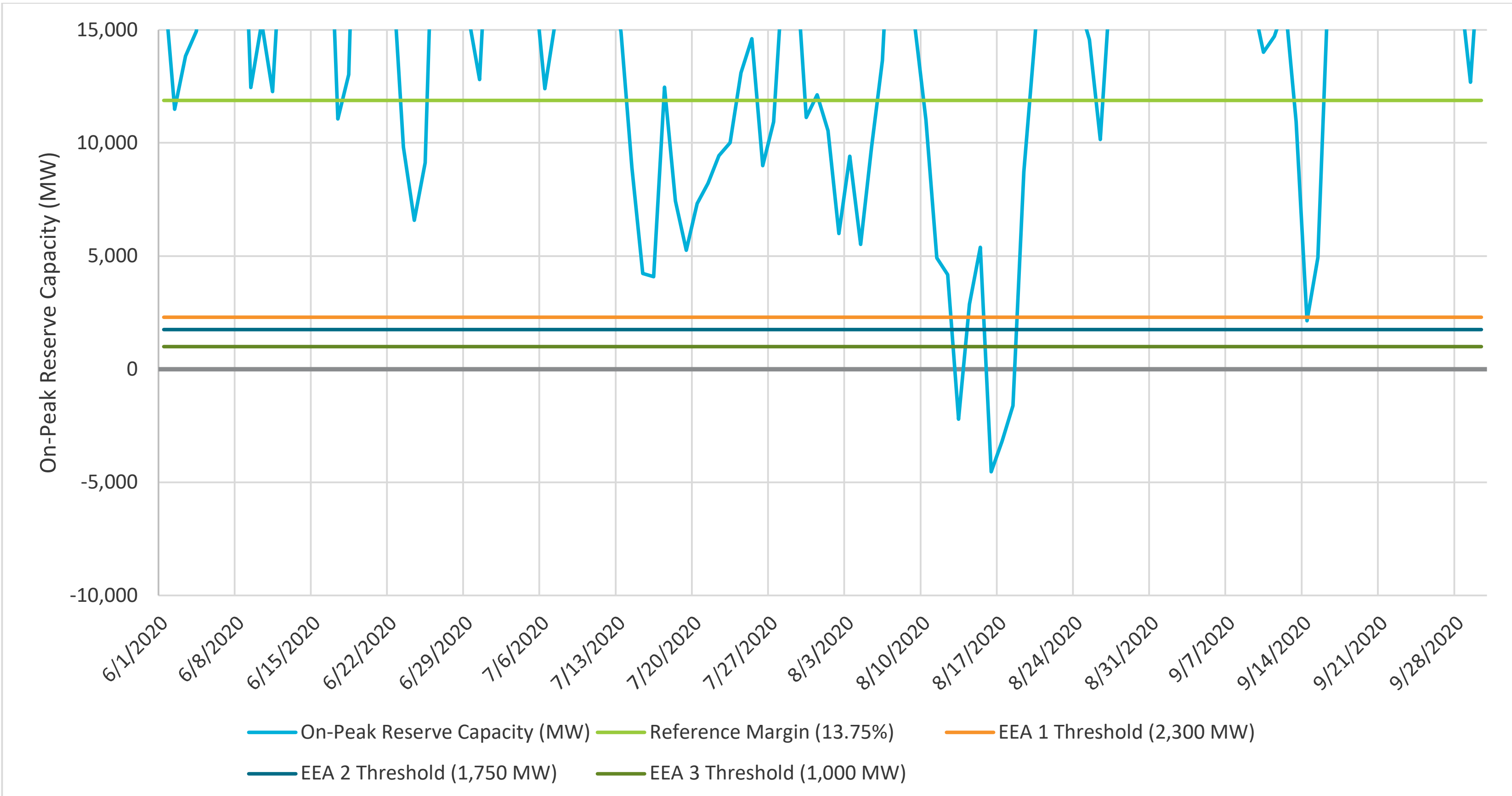


Exhibit 3-8. Scenario 6 (92,908 MW peak)

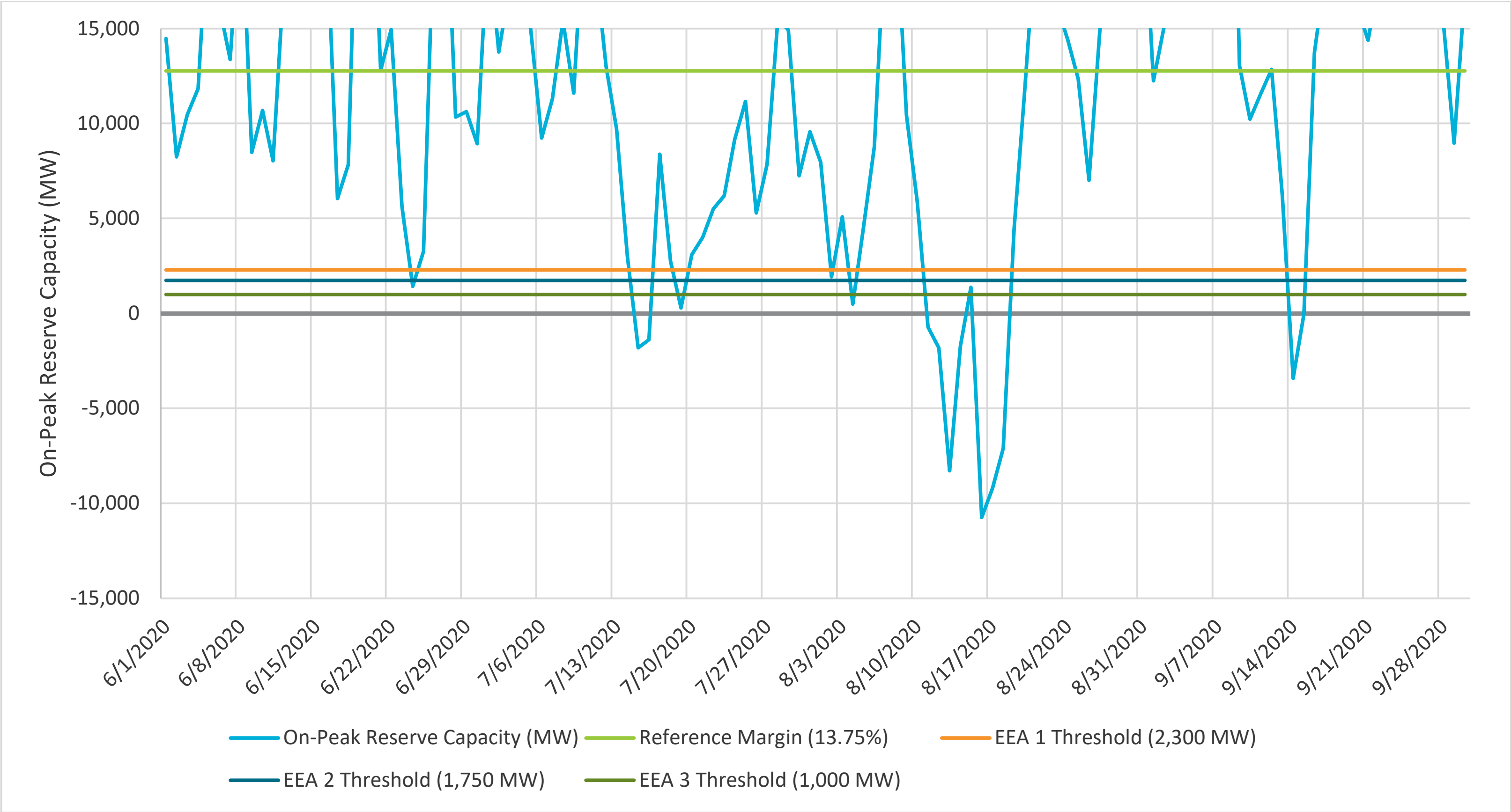


Exhibit 3-9. Number of days with reserve shortfall under six modeled scenarios

Scenario	Description	Reference Margin	EEA 1	EEA 2	EEA 3
1	Base Case (Normal Conditions)	21	0	0	0
2	Base case + High Forced Outages	25	0	0	0
3	Base case + High Forced Outages + High Peak Load	34	3	2	1
4	Base case + High Forced Outages + High Peak Load + Historic Wind	38	4	4	4
5	Base case + High Forced Outages + High Peak Load + Historic Wind + Historic Solar	36	5	4	4
6	Base case + Extreme Forced Outages + Extreme Peak Load + Historic Wind + Historic Solar	61	16	15	13

4 SUMMARY

ERCOT is continuing to face a test of both its operating system and its energy-only market. As discussed in Section 1, the ERCOT market has successfully functioned to date. While annualized wholesale prices have declined and emissions have decreased, summer seasonal prices have increased and with higher price spikes. Going into Summer 2021, however, the energy-only market is contending with a low reserve margin, caused by a number of generating capacity retirements in 2017, delays in new capacity projects coming online since 2018, and continued strong load growth in West Texas and other areas in the ERCOT region. ERCOT will have to rely on other tools until the reserve margin returns to levels where there is less risk of EEA. Even with those tools, the market construct implemented by ERCOT runs the risk of higher energy prices and situations that trigger more EEAs for Summer 2021.

The PROMOD scenarios described in Section 3 suggest that ERCOT could make it through the summer season without an LOLE event, as long as the weather remains normal, even though ERCOT will be well below its minimum target reserve margin. If demand in the region reaches potential peak levels, escalated for extreme weather, problems could arise in the system. ERCOT could then find itself operating in emergency conditions during the height of the summer peak demand season, which is usually the end of July through mid-August. Should these conditions occur, ERCOT will need to call on its operating tools to maintain reliability and continue serving load, and those measures alone may not be sufficient to avert a shedding of load. More extreme situations where wind production is reduced could lead to significant load shedding and the system (theoretically) dropping below 0 MW. The energy-only market, combined with subsidized renewables and cheap natural gas prices driving out other forms of generation may result in lower wholesale energy prices than other market models that pay for capacity, but it may also be taking greater reliability risks.

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