2022 SUMMER RESOURCE ADEQUACY IN THE ERCOT REGION

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Disclaimer

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ACRONYMS AND ABBREVIATIONS

CDR	Capacity, Demand and Reserves
CO_2	Carbon dioxide
DC	Direct current
DEC	Dispatchable Energy Credit
DOE	Department of Energy
EEA	Energy Emergency Alert
EORM	Economically optimal reserve margin
ERCOT	Electric Reliability Council of Texas
ERS	Emergency Response Service
GW	Gigawatt
HCAP	High system-wide offer cap
HE	Hour ending
Hz	Hertz
IMM	Independent market monitor
LOLE	Loss of load expectation
LOLP	Loss of load probability
LSE	Load Serving Entity
MCL	Minimum Contingency Level
MERM	Market equilibrium reserve margin
mins	Minutes
MMBtu	Million British thermal units
MW	Megawatt
MWh	Megawatt hour
NETL	National Energy Technology Laboratory
ORDC	Operating Reserve Demand Curve
PRC	Physical responsive capability
PUCT	Public Utility Commission of Texas
RTOFFCAP	Real-Time Off-Line Reserve Capacity
RTOFFPA	Real-Time Off-Line Reserve Adder
RTOLCAP	Real-Time On-Line Reserve Capacity
RTORPA	Real-Time Online Reserve Price Adder
RUC	Reliability Unit Commitment
SARA	Seasonal Assessment of Resource Adequacy
RRC	Railroad Commission of Texas
U.S.	United States
VOLL	Value of lost load
VRE	Variable renewable energy

EXECUTIVE SUMMARY

This report is a 2022 update to the National Energy Technology Laboratory (NETL) report [1] that examined the potential system performance of the Electric Reliability Council of Texas (ERCOT) system during the summer of 2021. Anticipated summer reserve margins in ERCOT have risen year-over-year from the 15.7 percent reported in ERCOT's Final Seasonal Assessment of Resource Adequacy (SARA) for Summer 2021 to 22.8 percent in the Final SARA for Summer 2022, driven mostly by increases in wind and solar generation. [2] [3] This is well above the current minimum target reference reserve margin of 13.75 percent of peak electricity demand 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 early 2021. [5]

In the wake of Winter Storm Uri in February 2021, several regulatory and legislative changes have been implemented with the goal of increasing the resilience of the Texas grid including operational changes for generators, transmission operators, and changes to the ERCOT energy market. Several changes to ERCOT's energy market have already been made, including updates to the system-wide offer cap on electricity prices, while other changes, such as changes to the Emergency Response Service and Dependable Energy Credit program, are still under review by ERCOT and the Texas Public Utility Commission. These changes are intended to send stronger price signals to invest in capacity and ensure resource adequacy. [6]

ERCOT is also facing changing demand patterns and increasing congestion on the transmission system related to variable renewable energy (VRE) generation growth in rural areas. [7] ERCOT recorded a record for demand (74,997 MW) on June 12, 2022, nearly two months prior to historical peak demand times. [8] Given the 48 percent planned VRE capacity increase between 2021 and 2022, the following report will assess the likelihood of a loss of load expectation (LOLE) during the 2022 summer season. The LOLE metric was chosen for this analysis to be consistent with prior NETL reports and to compare to past reports by The Brattle Group commissioned by ERCOT.

Using data from ERCOT's 2022 Summer SARA, Capacity, Demand and Reserves (CDR) reports, and historical performance data obtained from ERCOT and Hitachi Energy Velocity Suite, six economic dispatch scenarios using PROMOD were developed to assess the risk to ERCOT of a load shedding event for Summer 2022. The scenarios and results are summarized in Exhibit ES-1. The results suggest that ERCOT may be facing a very tight resource adequacy situation, with the potential for a serious shortfall during the summer peak, usually the end of July through mid-August, if demand and generator outage rates significantly exceed peak levels. Under these conditions, ERCOT will need to call on its operating tools, including Energy Emergency Alerts (EEA) and calls to conserve electricity, to maintain reliability and continue serving load. Those measures alone may not be sufficient to avert a shedding of load.

Exhibit ES-1. Overview of PROMOD analysis results

Scenario Name	Description	Net Effective Peak Load	Count of Days with Capacity Shortfalls				
			<13.75% Reserve	EEA 1	EEA 2	EEA 3	<0% Reserve
1	Base Case	81,989	9	0	0	0	0
2	Base case + High Forced Outages	85,974	38	11	10	10	8
3	Base case + High Forced Outages + High Peak Load	87,896	47	18	16	14	11
4	Base case + High Forced Outages + High Peak Load + Historic Low Wind	87,896	46	10	9	8	7
5	Base case + High Forced Outages + High Peak Load + Historic Low Wind + Historic Low Solar	87,896	44	10	8	7	6
6	Base case + Extreme Forced Outages + Extreme Peak Load + Historic Low Wind + Historic Low Solar	95,834	66	20	19	17	16

Note: The results count the days when the reserve margin was below 13.75 percent targeted reserve, EEA1, EEA2 and EEA3 limit, and negative.

1 HISTORIC RESOURCE ADEQUACY IN ERCOT

As discussed in the National Energy Technology Laboratory (NETL) report, *2021 Summer Resource Adequacy in the ERCOT Region,* the Electric Reliability Council of Texas (ERCOT), working with the Public Utility Commission of Texas (PUCT), commissioned The Brattle Group ("Brattle") to assess ERCOT's energy-only market design and its ability to maintain resource adequacy and reliability in 2012. In contrast to other independent system operators and regional transmission organizations that operate capacity, energy, and ancillary service markets, ERCOT operates only energy and ancillary service markets without a resource adequacy reliability standard or reserve margin requirement. Instead, ERCOT uses the concepts of an economically optimal reserve margin (EORM) and a market equilibrium reserve margin (MERM) to assess resource adequacy on the system (as discussed in detail later in this section.) [5] When the Brattle study, "ERCOT Investment Incentives and Resource Adequacy," was published in 2012, ERCOT was struggling to attract investment in new generation projects, and reserve margins were predicted to fall below 10 percent. The 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] [9]

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] The Astrapé Consulting study estimated the MERM and the EORM of ERCOT's wholesale electric market. [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 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 MERM is 12.25 percent and the EORM is 11.00 percent. At the given MERM value, the system could expect to experience 0.5 events per year loss of load expectation (LOLE)[b] [11] and 0.84 LOLE events per year at the EORM value. [10]

To address the absence of the capacity market and to attract new resources, ERCOT implemented the Operating Reserve Demand Curve (ORDC) on June 1, 2014. The ORDC is used to create a real-time reserve price adder and reflects 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 capacity measured in megawatts (MW). This minimum contingency level was originally set to 2,000 MW and currently set to 3,000 MW. [12] The accuracy of the ORDC to value the avoiding

[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. [11] For reference, the traditional 1-day-in-10-years reliability planning criteria used in industry is reflected on a LOLE basis. On a loss of load hours basis, this is equivalent to 2.4 hours per year. Both are unconcerned with the magnitude or number of outages. [58]

load shed event is dependent on the accuracy of the loss of load probability (LOLP) calculation, where LOLP "for a given level of available Real-Time reserves is the probability of an [load shed] event/ disturbance that can exceed the level of available real-time reserves." [13]

As reported in the NETL report, *2021 Summer Resource Adequacy in the ERCOT Region*, The ORDC curve is constructed by value of lost load (VOLL), system lambda (λ), and LOLP distribution, as shown in the following equation:

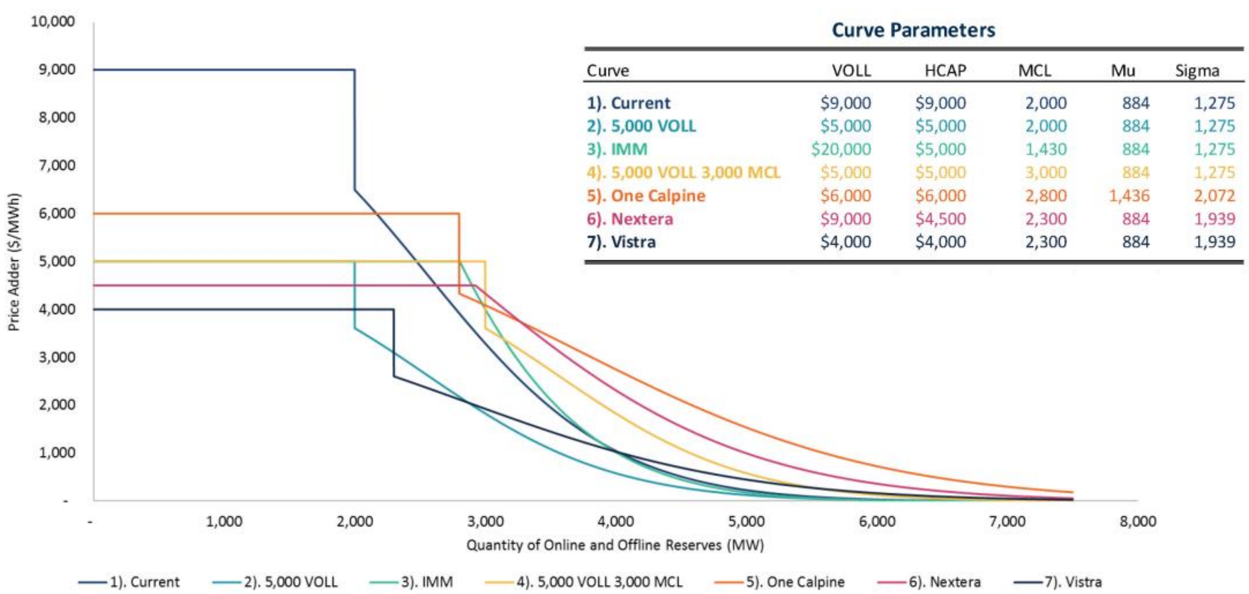
$$ORDC = (VOLL - \lambda) \times LOLP$$

Equation 1: ORDC curve

The VOLL is set to be equal to ERCOT's offer cap, which is $5,000/megawatt hour (MWh) as of January 1, 2022. [14] λ is the price of matching generation and demand at the reference bus; and LOLP is calculated as one minus the cumulative distribution function built from the historical difference between hour ahead reserve and real-time reserve. [1]

Exhibit 1-1 shows the ORDC from 2021, labeled current in the curve parameters table, and the 2022 ORDC, labeled 5,000 VOLL 3,000 Minimum Contingency Level (MCL). The ORDC automatically increases when the reserves get tighter and reaches the maximum when reserves drop below 3,000 MW. To more accurately determine the probability of an event, the LOLPs and ORDCs are constructed and utilized for different seasons and daily hour ranges to adjust for peak demands when event probabilities increase. Specifically, the ORDC uses the peak demand hour ending (HE) for ERCOT summer (HE15–HE18) and the peak demand for winter (HE7–HE10). The curve depends on historical data for that season and particular daily hour range.

Exhibit 1-1. Actual versus example ERCOT ORDC curves



Permission pending from PUCT [15]

ERCOT then uses the ORDC to calculate separate price adders for the Real-Time On-Line Reserve Capacity (RTOLCAP)—immediately available following an event—and the Real-Time Off-Line Reserve Capacity (RTOFFCAP)—capacity available in 30 minutes of the event. According to a

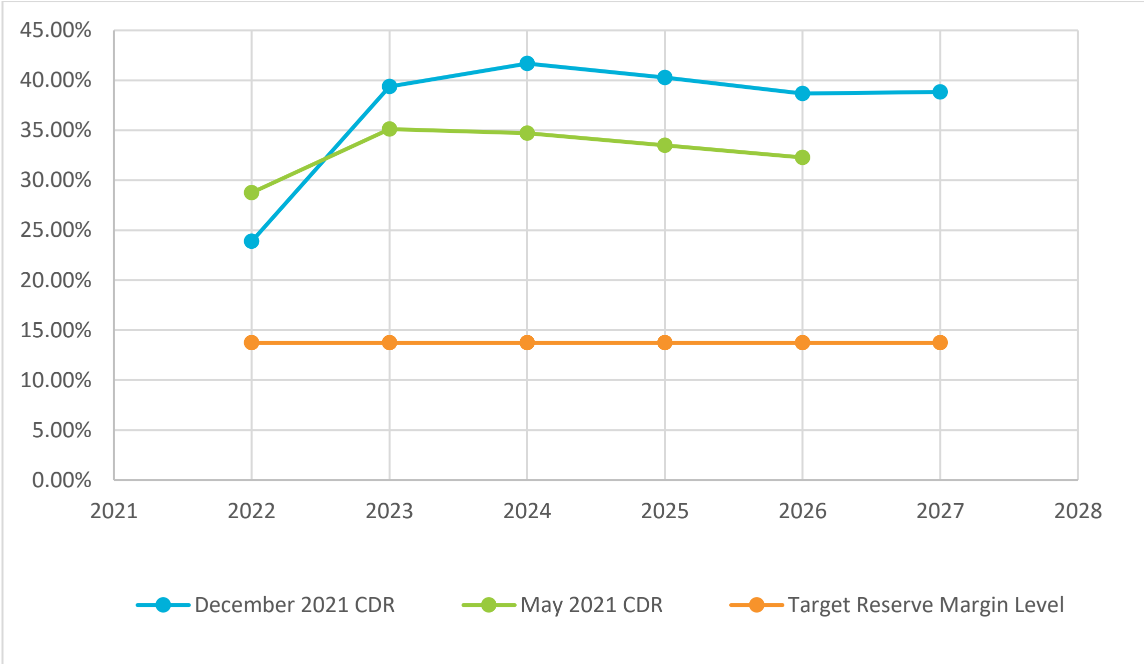
2018 ERCOT presentation on the ORDC, the Real-Time Off-Line Reserve Adder (RTOFFPA) is based on the probability of the sum of the RTOFFCAP and RTOLCAP "falling below a minimum contingency level over an hour given the amount of reserves available in the latter 30 minutes of the hour." [13] The calculated value is then multiplied by 0.5 x (VOLL-λ), to indicate that the RTOFFCAP is only available for half of the hour. [13] The Real-Time Online Reserve Price Adder (RTORPA) is calculated using the probability of reserves falling below the minimum contingency level over 30 minutes based on the total amount of RTOLCAP available in the first 30 minutes of the hour, i.e., when the offline reserves are unavailable. The probability is then again multiplied by 0 .5 x (VOLL-λ) to indicate the 30-minute availability, the product is added to the RTOFFPA to produce the final RTORPA. [13] The RTOPRA and the RTOFFPA are ultimately used in ERCOT's real-time energy market to pay resources for the value of their reserves and available 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.

1.1 COMPARISON OF HISTORIC PRICES AND RESERVE MARGINS

Although the current reserve margin of 22.8 percent is higher than the target level of 13.75 percent, there is still potential for EEA events in ERCOT during Summer 2022 due to higher renewable penetration. [3] For example, wind resources alone accounted for 24 percent of total generation in 2021. [16] The SARAs describe these risks in their extreme scenarios for Low Wind Output Adjustments and Low Solar Output Adjustments, which will be further modeled and studied in Section 2. ERCOT plans to utilize its operational tools and issue public appeals to conserve electricity 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 still not clear whether these tools will be sufficient.

Exhibit 1-2 shows the summer reserve margin forecast beyond 2022 based on ERCOT's Capacity, Demand and Reserves (CDR) reports. [17] [18] The December 2021 CDR states, "the Planning Reserve Margin for summer 2022 is forecasted to be 23.9 percent. This is 4.9 percentage points lower than the 28.8 percent margin for summer 2022 reported in the May 2021 CDR report. This decrease is due mainly to delays of planned projects that were previously expected to be in service by July 1, 2022." [17] Beyond 2022, the reserve margin is expected to rise to a peak of 41.7 percent in 2024 driven largely by new solar generation. Of the planned resources to be in service in 2024, 18,688 MW are solar, 1,564 MW are wind, and 822 MW are non-variable renewable energy (VRE) resources. After 2024, there are no planned capacity increases paired with continued load growth, which leads to a smaller reserve margin. [17] If ERCOT generation resources act according to the plan in December 2021 CDR, they will stay much higher than the current minimum reference reserve margin of 13.75 percent set by the ERCOT Board of Directors. [4] Note that it is typical for generation developers to submit interconnection requests up to two to four years before the plan(ned)? 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 1-2. Reserve margin estimation by ERCOT CDR, 2022–2027 [19] [18]



While the reserve margin is above the 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 discussed in Section 1.3.

Comparing the forecast in the Summer 2022 Final Seasonal Assessment of Resource Adequacy (SARA)[c] to the Summer 2021 Final SARA, the adjusted peak demand increased from 77,144 MW to 77,317 MW. The true peak demand in Summer 2021 was 73,475 MW, or 3,769 MW less than the 2021 Summer SARA forecast value. [20] If the 2022 peak demand forecast is accurate, it will set a new system-wide peak demand for the 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 estimated resource capacity increased from 86,862 MW in 2021 to 91,392 MW in 2022. ERCOT predicted capacity availability would be sufficient to maintain reliability under normal and most risk scenarios with a planning reserve margin of 22.8 percent. [3] As discussed previously, these capacity reserves are slightly lower than what ERCOT had predicted in prior CDRs likely due to delays of in-service dates for planned capacity cited in the December 2021 CDR report. [17] ERCOT stated that it expects 1,323 MW, mostly solar, of new capacity to be added before Summer 2022 peak demand. [3] Additional capacity increases are from planned gas-fired capacity. While not included in ERCOT's capacity increase estimate, 2,035 MW of

[c] The 2022 Summer SARA defines the summer season as June through September. [3] ERCOT releases seasonal reports annually with a Winter SARA covering December through February and a Spring SARA covering March through May. [59] [60]

battery storage is anticipated to be operational by Summer 2022; however, ERCOT's December 2021 CDR states that "[storage capacity is] assumed to provide grid reliability services (Ancillary Services) for short periods of time rather than to support customer demand on a sustained basis during peak demand hours." [17]

Exhibit 1-3 shows the historic trend of the estimated summer reserve margins and electricity prices over the last 10 years. 2022 is expected to have the highest planning reserve margin since before the extreme events in 2011 due to new gas-fired and utility-scale solar and wind resources. Of the 91,392 MW of total capacity ERCOT plans to have online by the summer, on-peak adjusted wind and solar resources account for 18,622 MW. [3]

***Exhibit 1-3**. ERCOT summer reserve margin and average summer electricity prices, 2012–2021*

Note: the reserve margin is calculated based on the annual reserve margin estimate given in the Summer SARA and adjusted based on the available capacity listed in that year's CDR

The 2021 NETL report, *2021 Summer Resource Adequacy in the ERCOT Region*, provided an independent assessment of resource adequacy conditions in ERCOT for the 2021 summer season. Based on the economic dispatch analysis performed for Summer 2021, the report stated, "ERCOT could make it through the [2021] summer season without a [loss of load 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." [1] This prediction turned out to be very accurate, although the most extreme event of 2021 occurred in the winter as opposed to the summer.

According to a June 2021 Potomac Economics report to ERCOT, Winter Storm Uri had a significant impact on the markets for both electricity and natural gas (see Exhibit 1-5). After the storm, ERCOT significantly increased the use of its reliability tools to ensure sufficient capacity reserves for summer operations, as discussed in more detail in Section 1.4. Overall hourly average load in ERCOT increased by an average of 1,300 MW while approximately 8,800 MW of capacity was added in 2021 including 730 MW of gas generation. Transmission congestion rents also increased by 46 percent to $2.1 billion in 2021 driven partly by the increases in both generation and load. [16] Between 2018 and 2021, ERCOT also retired over 6 gigawatts (GW) of coal and natural gas generation. [7] These operating statistics are consistent with the predictions laid out in the prior NETL report, *2021 Summer Resource Adequacy in the ERCOT Region.*

Exhibit 1-4 shows the 2021 peak demand hour values compared to the 2021 Summer SARA. [21] On the peak demand day (August 31, 2021), ERCOT had lower than expected demand, higher wind contribution, higher solar contribution, and higher generation outages. [22] Based on available reserve data for August 2021 obtained from Velocity Suite, ERCOT is estimated to have had 19,107 MW of operating reserves available on the 2021 peak demand day, much higher than the 5,935 MW of operating reserves estimated for the 2020 peak demand day in the prior NETL report, *2021 Summer Resource Adequacy in the ERCOT Region.*

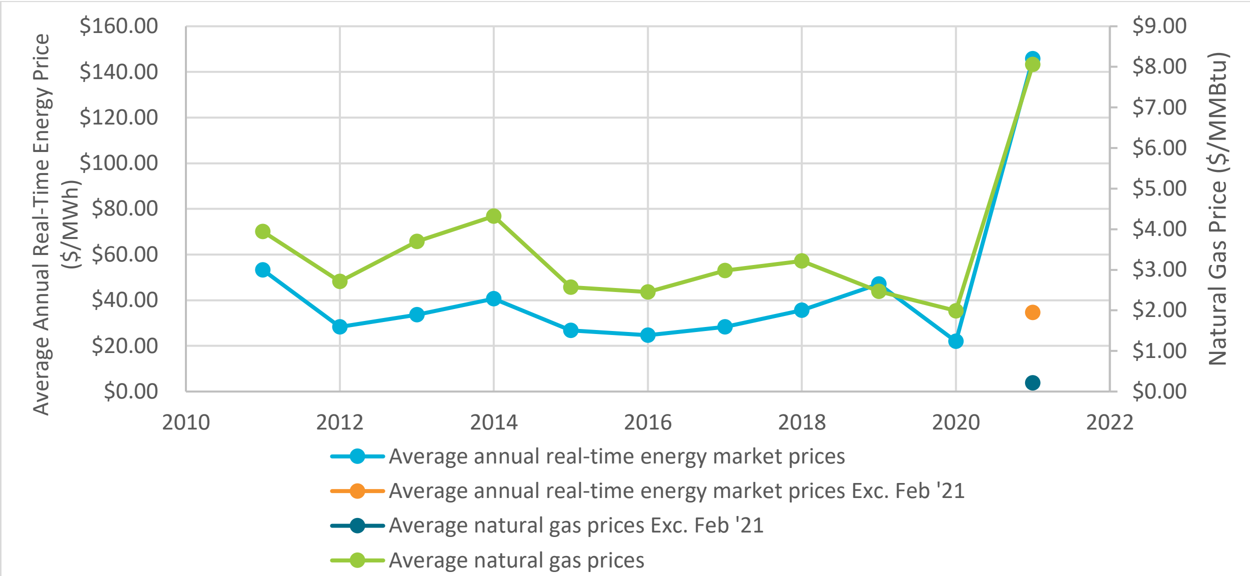
Exhibit 1-4. Forecast vs. 2021 summer peak days resource adequacy values

Resources, Demand, and Reserve (MW)	2021 Reported Peak Hour (MW)	Final 2021 Summer SARA Forecast (MW)	Difference (MW)	Actual Estimate Compared to Forecast (%)
Total Resources	97,159	86,908	+10,251	10.55
Thermal and Hydro	80,281*	63,657	+16,624	20.71
Wind Capacity Contribution	10,704	8,566	+2,138	19.97
Solar Capacity Contribution	6,174	6,086	+88	1.43
Peak Demand	73,475	77,144	-3,669	-4.99
Reserve Capacity	23,684	9,764	+13,920	58.77
Total Outages	4,577	3,578	+999	21.83
Capacity Available for Operating Reserves	19,107	6,160	+12,947	67.76

* The available thermal and hydro capacity available to ERCOT on August 31, 2021, was estimated based on the Velocity Suite dataset 'generating unit capacity - monthly history.' The actual available capacity is likely less than the 80,281 MW shown in Exhibit 1-3 since it does not account for maintenance outages or derates that may have been in place. The Capacity Available for Operating Reserves is, therefore, listed as estimated since actual hourly values could not be obtained for the available thermal and hydro capacities as well as the non-synchronous tie flows.

Exhibit 1-5 shows the trend in both average real-time electricity prices and natural gas prices during the last 11 years, as well as the 2021 prices excluding February. It is observed that there is a strong correlation between the price of electricity and natural gas. Without the influence of the winter storm, natural gas prices would have been slightly higher than the 2011–2020 average of about $3.82/MMBtu. Meanwhile average annual electricity prices would have remained near the 2011–2020 average price of $34.62/MWh.

Exhibit 1-5. Average annual real-time energy market and natural gas prices

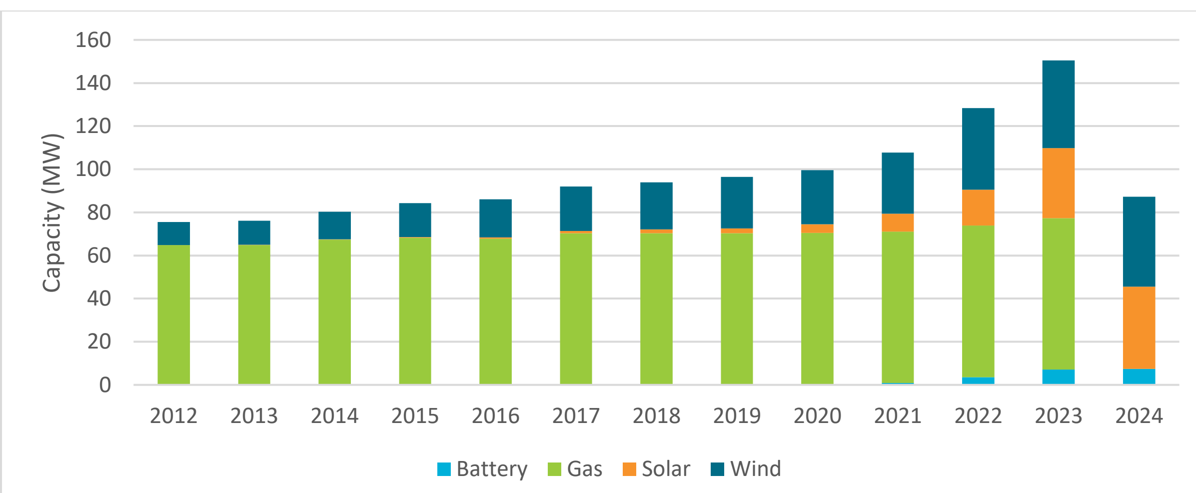


Aside from Winter Storm Uri, Texas experienced several major electricity price spikes over $1,000/MWh in the last few years including in August 2019 and May 2022. [23] [24] These high prices were driven in part by significant transmission congestion, a rapid transition to renewable energy, and significant retirements of thermal generating units, as well as strong load growth in industrials, data centers, and cryptocurrency mining. [7]

1.2 Resources

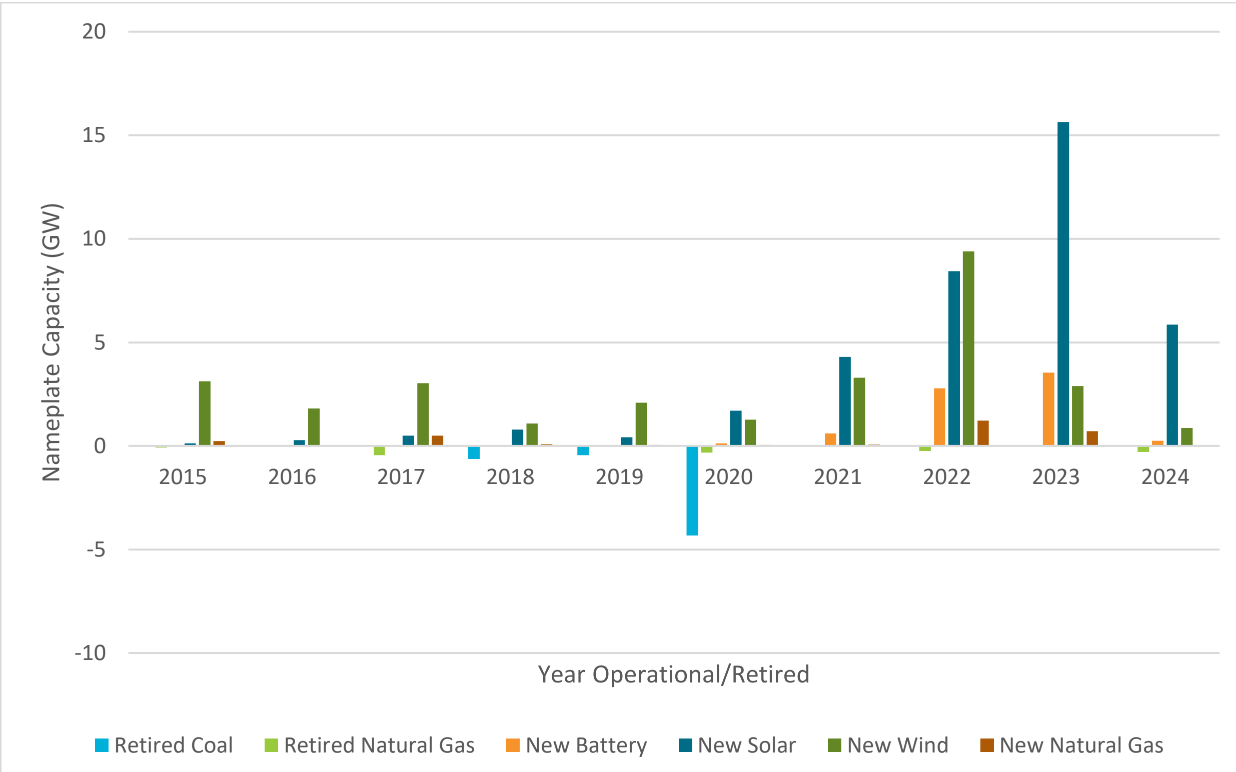
The generation capacity additions to date and projected changes within ERCOT from 2012–2024 are shown in Exhibit 1-6. Wind and natural gas capacity composed the majority of new and planned generating capacity in ERCOT through 2023, after which no new natural gas investments are currently proposed. [25]

Exhibit 1-6. ERCOT capacity additions by fuel type as of May 2022 [26]



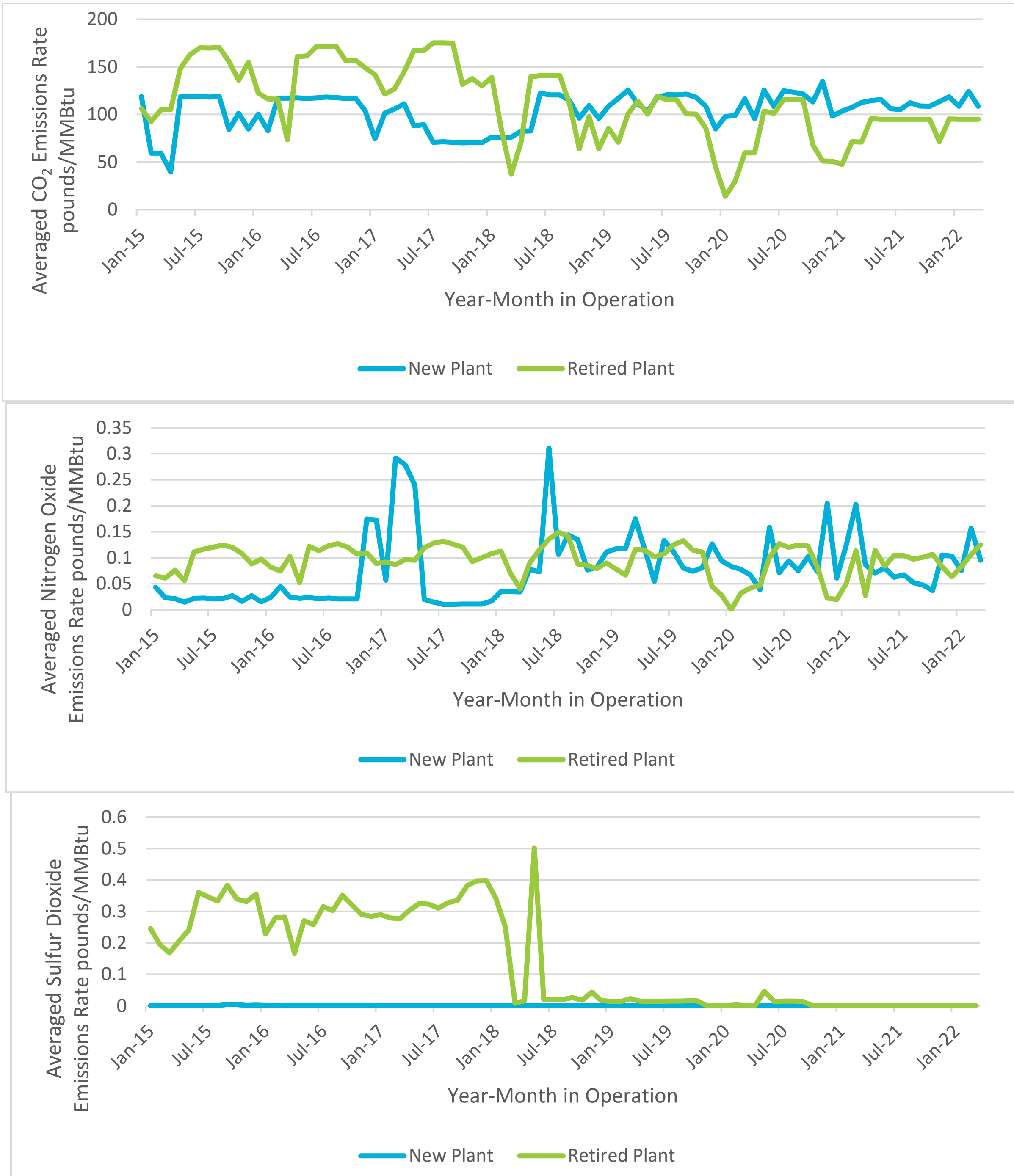
In 2023, ERCOT is expected to add 2.2 GW of new capacity, with 84 percent coming from VRE sources, as shown in Exhibit 1-7. There are no reported new coal plants and coal has been the largest fuel type resource retired as of May 2022. Approximately 848 MW of natural gas was also retired from 2015 to 2021 and 538 MW is currently scheduled to be retired between 2022 and 2024.

Exhibit 1-7. New and retired capacity in ERCOT, 2015–2021 [27]



To highlight the emissions impacts of changes in ERCOT's energy market, Exhibit 1-8 compares 8 years of weighted averaged emissions rates for new fossil fuel generation on-line after 2015—100 percent natural gas—to the mix of coal and natural gas generation retiring in 2015–2024. The three graphs in Exhibit 1-8 indicate that, on average, the newly added natural gas capacity emission rates are lower than the retired capacity rates. The newly added generators produce 0.0016–0.07 ounces/million British thermal units (MMBtu) of sulfur dioxide while retiring plants have an produce an average of 0.0032–ounces/MMBtu. In terms of carbon dioxide (CO_2) emissions rates, new generators produce 39–134 pounds/MMBtu of CO_2 while retiring plants have an average CO_2production ranging from 14–175 pounds/MMBtu. Lastly, nitrogen oxide emissions rates ranged 0.16–1.12 ounces/MMBtu for new generators and 0.304–2.384 ounces/MMBtu for retiring plants. Overall emissions in ERCOT are declining due to the retirements of higher emitting fossil plants and the increased efficiency in the new natural gas fleet in addition to added VRE capacity.

Exhibit 1-8. ERCOT new (online after 2015) vs recently retired (retired 2015–2024) thermal generation plant emission performance [28]



Note: Values are an average of the weighted daily average emissions rate of each plant type by month

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 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. [29] There are also switchable generation units on the border of the ERCOT grid that can provide electricity to ERCOT, if needed. These switchable units serve customers in Southwest Power Pool or the Midcontinent Independent System Operator but maintain an operating agreement with ERCOT allowing ERCOT to request assistance from these units during an energy emergency.

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. ERCOT procures demand response through two programs administered by ERCOT: [30]

- Emergency Response Service (ERS)
- Load Resource Participation in ERCOT's Ancillary Services and Real-Time energy market.

There are also four categories of demand response not administered by ERCOT: [30]

- Transmission and Distribution Service Providers' Load Management Programs
- 4-Coincident Peak Load Reduction
- Price-responsive Demand response
- Distributed Generation Price Response

Load Resource Participation in ERCOT's Ancillary Services and Real-Time energy market includes 6 controllable load resources with approximately 300 MW of registered capacity and approximately 600 non-controllable load resources with approximately 7,000 MW of registered capacity. According to ERCOT, about 1,380 MW of this capacity actually participates. [30]

ERCOT procures ERS four times annually (change effective December 2021) to help avoid load shedding during a grid emergency. [30] Qualified loads and generators can offer to provide ERS to ERCOT through their qualified scheduling entities. ERCOT publishes the procurement results on their website.[d] As an example, for Time Period 4 (17:00–19:00) from April 1 to May 31, 2022, ERCOT procured 25 MW of non-weather sensitive response time ERS from one resource at a clearing price of $4.44/MWh. According to ERCOT, about 1,000 MW of ERS capacity typically participates. [31]

These generation and demand response resources can help ERCOT avoid a load shedding event during energy emergency situations. Customers who are capable of demand response can participate in ERCOT's market in three ways: 1) become an ERCOT Load Resource to participate in ERCOT's day-ahead energy market, real-time energy market, or ancillary service market; 2) participate in ERCOT ERS (as described above); 3) opt into one of the four demand response categories not administered by ERCOT as described above.

1.3 Extreme Events

This report is primarily focused on power system stress during summer months. Increasingly extreme weather events have caused stress during both spring and winter months. Major winter events, notably in 1989, 2011, and 2021, caused rolling blackouts and damage to power

[d] http://www.ercot.com/services/programs/load/eils/

infrastructure. In recent years, ERCOT experienced disruptions during spring months when power plants typically perform maintenance ahead of the high-demand summer season. [32] To understand the impacts of these events on summer grid operations, this section will briefly describe selected extreme events.

When reserves are tight, 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. [33] [34] 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.[e] The EEA trigger criteria and corresponding operation for each level are shown in Exhibit 1-9. [35] In Summer 2011, with the severe heat wave, ERCOT issued EEA1 six times and EEA2 twice. ERCOT also issued EEA1 twice in Summer 2019.

During February 2021, Winter Storm Uri blanketed Texas with record-breaking freezing temperatures and snowfall resulting in rotating outages and significant damage to energy infrastructure. [36] Despite a similar winter event in 2011, many generators and natural gas producers neglected to properly winterize their equipment, which was recommended but not required. [37] The storm resulted in generation outages and derates ranging from near 30 GW to over 50 GW for the duration of the event. [38] The storm resulted in over 4 million power outages, over 200 deaths, and the system remained under an EEA for over 4 days, including a significant period under EEA3, which signifies load-shed conditions.

The damage to battery energy storage equipment led to tight resource adequacy conditions and calls to conserve power in April 2021 as many power plants damaged in the February freeze were offline for maintenance and demand was higher than expected due to higher temperatures. According to reporting from The Texas Tribune, the available reserve capacity available Tuesday, April 12, 2021, at 5 pm was approximately 1,000 MW with approximately 32,000 MW of generation offline for maintenance. [39] When generating units are not given the opportunity to perform permanent repairs, often during the spring, this creates a risk that those units will experience forced outages during summer peak demand, and in turn, increase the risk of a LOLE.[f] In this instance, no EEAs were reported during the second half of 2021.

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

[f] 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. [11] For reference, the traditional 1-day-in-10-years reliability planning criteria used in industry is reflected on a LOLE basis. On a loss of load hours basis, this is equivalent to 2.4 hours per year. Both are unconcerned with the magnitude or number of outages. [58]

Exhibit 1-9. ERCOT EEA criteria

Emergency Level	Trigger Criteria	Grid Operation	Other Operation
Control Room Watch	Operating Reserves < 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 Reliability Entity • Provide update to ERCOT board
EEA1 – Power Watch	Operating Reserves < 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 emergency response service • Deploy responsive reserve • Launch transmission and/or distribution service provider load management program	• Contact utility • Update grid condition on social media and update app status • Release news if appropriate
EEA2 – Power Warning	Operating Reserves < 1,750 MW with no expectation to recover within 30 mins or frequency below 59.91 hertz for more than 15 mins	• Issue EEA 2 to ERCOT Market Participants • Deploy demand response resource • Deploy remaining emergency response service • Instruct transmission service provider to use voltage reduction • Begin block load transfer to other grids	• Contact utility • Update grid condition on social media and update app status • Release news if appropriate
EEA3 – Power Emergency	Operating Reserves < 1,000 MW with no expectation to recover within 30 mins or frequency below 59.91 hertz for more than 15 mins	• Issue EEA 3 "Rotating Outages" to ERCOT Market Participants • Instruct transmission operators for load shedding	• Contact utility • Update grid condition on social media and update app status • Release news if appropriate

On May 13, 2022, ERCOT asked Texans to conserve power[g] after six generation facilities tripped offline. This request lasted through May 15. There were multiple reasons that ERCOT asked Texans to conserve power: hot weather increased demand, 20,000 MW of transmission lines were down for scheduled maintenance through May 15, and 6 generators tripped offline on May 13. The first site tripped offline around noon on Friday, May 13, and the sixth site tripped offline around 4 pm local time. The request for citizens to conserve power went out around 5 pm local time; however, ERCOT did not reach alert status over the weekend. ERCOT's Interim Chief Executive Officer Brad Jones said after the weekend of conservation that ERCOT has about

[g] ERCOT may issue a public appeal to conserve electricity as the first step in mitigating tight supply conditions. [42] If conditions do not improve, ERCOT will initiate Energy Emergency Alerts.

22 percent reserves for this summer compared to 15–16 percent last summer. He conveyed confidence in the ERCOT grid and ability to keep the lights on in Texas. [40] Leading up to the weekend of May 13, power plants were asked to postpone outages so that all available capacity could be available. Before May 13, ERCOT was projecting a record demand of 70,459 MW, which is higher than the peak demand during Winter Storm Uri (70,000 MW) and previous May records (67,000 MW). Many factors contributed to the record demand including population growth and a lack of energy efficiency across the state. Texas currently ranks 36th (of 50) in energy efficiency spending as a percentage of utility revenue and 38th (of 50) in terms of energy efficiency savings as a percentage of electric consumption. Adding energy efficient systems to the ERCOT grid, such as programs to improve heating, ventilation, and air-conditioning in commercial and industrial buildings, would reduce consumer demand and allow for more operating margins during extreme events. [41] [25]

The May 2022 event highlights the balance that must be maintained between ensuring that there are sufficient generating resources to meet rising demand versus scheduling sufficient time for generators to perform maintenance. However, ERCOT has recently asked some generators to delay planned maintenance to ensure that firm capacity would be available during the unusually warm May temperatures. [42] This tight spring maintenance situation has the potential to complicate summer operations if less firm capacity is available due to unplanned outages, especially if temperatures surge above seasonal averages. Winter Storm Uri also provides an example of how a major winter event can create a backlog of maintenance issues and lead to a reduction in available summer capacity.

1.4 Summary of Regulatory Updates

After the storm in February 2021, the PUCT voted in December 2021 to enact major changes to the state's wholesale energy market to ensure reliability. [43] These sweeping changes include modifying the ORDC to help enhance regular market operations and avoid capacity shortfalls by improving price signaling, increasing the minimum contingency level from 2,000 MW to 3,000 MW, increasing market incentives for demand response, upgrading the ERS from an emergency-only demand response service to a mechanism to avoid emergency conditions, and decreasing the high system-wide offer cap for electricity to $5,000/MWh. [44]

ERCOT changed its system-wide offer cap numerous times in the past to incentivize new capacity. The PUCT stated in an October 2012 filing that, "raising the [system-wide offer cap] in the manner provided for in the proposed rule is an economically efficient means of supporting resource adequacy and should therefore be done regardless of any additional measures the commission takes to support resource adequacy." [45] This rule change increased the system-wide offer to $5,000 in 2013, to $7,000 in 2014, and $9,000 in 2015. The report further states that the PUCT felt that acting quickly to incentivize investment was the best way forward given the long lead times for both conventional and demand response resources to be developed. [45]

By changing the ORDC and system-wide offer cap, ERCOT attempted to send stronger price signals to invest in capacity, since the high $9,000/MWh price cap implemented in 2015 had not prevented massive load shed during Winter Storm Uri. According to a November 2021 analysis of potential ORDC changes by Brattle, a wider ORDC curve could limit exposure to maximum prices by allocating scarcity pricing to a greater number of hours as well as increasing demand for reserve capacity in real time, consistent with day-ahead procurement of ancillary services. The analysis showed that the $5,000/MWh VOLL and 3,000 MW minimum contingency level curve (Summer 2022 ORDC) yielded $5,000/MWh when reserves met the minimum contingency level of 3,000 MW. This is important since the market will be sent the strongest signal to install capacity before the criteria for ERCOT to issue a Control Room Watch at 2,500 MW of reserves. The analysis also showed Summer 2022 ORDC will include a $10/MWh adder deemed sufficient to incentivize combustion turbines to self-commit and cover their start-up costs. [15]

A comparison of the old ORDC and the updated curve are shown in Exhibit 1-1. Some of these measures, such as changes to the ORDC and system-wide offer cap, are already in place. Other measures, such as a firm fuel supply service,[h] will take months or years to implement according to ERCOT, which pointed to staffing and funding limitations on the number of projects that can be executed simultaneously. [46]

PUCT commissioners also voted to develop additional market tools by February 2022, after which the commissioners would vote on implementation. These new proposals include requiring power providers to procure sufficient resources to meet their share of peak load, creating dispatchable energy credits similar to Texas's renewable energy credit system, and a firm fuel supply service where ERCOT would procure energy from generators in a scarcity event where market prices hit the system cap of $5,000/MWh as an insurance policy against emergency conditions. [6] In a February 2022 filing by ERCOT responding to PUCT's Phase II market re-design, ERCOT stated, "the goal of a load-side reliability mechanism is to provide economic incentive to ensure there is sufficient dispatchable supply to meet system demand within ERCOT. This would be accomplished through some manner of requirement on Load Serving Entities (LSEs) in the ERCOT market design. In the case of an LSE Obligation program, this would come in the form of an obligation on the LSE to contract with accredited grid resources to cover some proportion of their expected demand. In the case of a Dispatchable Energy Credit (DEC) program, the form would be a requirement for LSEs to purchase DECs and clear or retire those DECs through arrangements with eligible grid resources." [47] As of June 24, 2022, the PUCT and ERCOT continue to file proposals to revise the new market design rules. [48]

ERCOT also made significant efforts in response to Winter Storm Uri to ensure reliability throughout the remainder of 2021. [43] These included increased procurement of responsive spinning reserve services and non-spinning reserve services—a significant increase in the use of Reliability Unit Commitments (RUCs). [49] RUCs are a tool ERCOT may call upon to ensure sufficient reserves by calling up a thermal unit out-of-merit and paying for the unit to idle online so that it can be immediately called upon to mitigate a reliability issue. ERCOT called approximately 3,850 effective RUC resource hours in 2021 (with the majority being called in July) compared to only 220 hours in 2020. [12] ERCOT made these calls as needed to maintain

[h] Firm Fuel Supply Service is an ancillary service designed to meet specific reliability needs not met by ERCOT's real-time and ancillary service markets during periods of high uncertainty. [14]

5,500–5,800 MW of online reserves. [15] According to a London Economics analysis on the impacts of these changes on electricity prices, 96 percent of 2021 RUC hours were instructed only to maintain reserves as opposed to resolving local issues. Based on this analysis, new proposed changes to the RUC offer floor would move the RUC capacity offers down the dispatch stack and depress the new ORDC adders by undercutting offers made by self-committed resources and distorting the energy market. [50] Changes to the ORDC have been opposed by renewable energy groups who argue that the new rules would unfairly benefit thermal resources at the expense of variable renewable generation. [6]

In the wake of Winter Storm Uri, the Texas State Legislature passed reforms aimed at ensuring the damage to bulk-power system[i] infrastructure was repaired and mitigating the effects of future cold weather events. Required equipment changes for generators and transmission service providers include adequate heat tracing on pipes, insulation of critical components, and thermal enclosures and windbreaks around sensitive equipment. Generation and transmission service providers must also provide training on winter weather preparation and operations and provide a notarized attestation that all equipment damaged during Winter Storm Uri has been repaired. The legislation also gives ERCOT the authority to inspect generation and transmission sites to confirm compliance with the new law. [51] As discussed in Section 1.3, a backlog of winter maintenance issues can create a risk to summer operations if spring temperatures are above normal, thus risking forced outages on dispatchable capacity units during summer operations.

The Railroad Commission of Texas (RRC), which regulates the natural gas industry in that state, also introduced new rules for natural gas suppliers to prevent catastrophic loss of power. The new rules establish the criteria and process by which natural gas providers are designated as critical gas suppliers or critical customers during an energy emergency to prevent interruption of service to critical points such as natural gas compressor stations during load shed events. [52] However, the RRC has not yet implemented any weatherization standards for natural gas suppliers, even though such regulations have been recommended by both the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation since the 1989 Texas Freeze. [52]

From Texas Senate Bill 3, passed in Texas after Winter Storm Uri, the following reforms are required by Texas law that would have in impact during extreme summer events as well: [53]

- Create a communication system for extreme weather events
    - Coordinate information with local news stations
    - Provide information for citizens to best prepare for the weather that is coming and its impacts on them
- Require power plants and natural gas facilities to register their sites as critical with the utility so that electricity is not cut off from them in the case of load shedding

[i] Bulk-Power System means facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. [61]

The Federal Energy Regulatory Commission also provided robust recommendations to ERCOT, while these recommendations are not required to be implemented, they provided helpful guidance to address reliability problems on the ERCOT Grid: [54]

- Recommendation 1 G: better define roles between generator owners, operators, and balancing authorities in determining the amount of energy that can be relied on during extreme weather events
- Recommendation 1 H: prohibit the use of critical natural gas infrastructure to be used in demand response
- Recommendation 1 J: separate circuits used for manual load shed, underfrequency load shed, and serving critical load

2 ERCOT SUMMER SCENARIOS

ERCOT releases several resource adequacy assessments throughout the year, with the primary assessments being the SARA and the CDR reports. SARA releases are seasonal, with the preliminary 2022 Summer SARA released in May. [3] The Summer 2022 SARA includes a summary of the expected total capacity from various resource types that are expected to contribute to summer peak demand as well as detailed descriptions of baseline, moderate, and extreme risk scenarios. These various risk scenarios include adjustments for peak load based on historic load and weather data, derates for low variable renewable energy (VRE) output and forced outage adjustments. In 2022, the SARA forecasts a peak load of 77,884 MW with adjustments of 1,922 MW and 4,250 MW for high and extreme peak loads, respectively. The baseline prediction is based on average weather conditions from 2006 through 2020 while the high and extreme risk scenarios are based on the 90th percentile and most extreme weather conditions from the same period, respectively. [3]

Based on the forecasts presented in the SARA, six scenarios were developed using ABB's PROMOD IV to assess the LOLE risk to ERCOT for the 2022 summer season. As shown in Exhibit 2-1, the scenarios account for various levels of load adjustments, forced outages, and VRE output. Generation in the model was updated using the generation available in the May 2022 SARA.[j] The base case uses the SARA peak load estimate and the expected thermal forced outages. The high forced outage scenario adds the high thermal forced outages in the SARA to peak load and typical forced outages. 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 and peak load under normal weather conditions. The high load scenario assumes an extreme weather event, similar to the 2011 heat wave when ERCOT's load exceeded its all-time record on 15 non-consecutive days. [55] High weather induced peak load is added to the base load, with typical, and high forced outages. The low VRE scenarios substituted ERCOT's actual 2021 hourly wind and solar outputs, respectively, for PROMOD's default profile. 2021 wind and solar profiles were selected by comparing hourly VRE output from 2018 through 2021 to the installed renewable capacity at that time and estimating the capacity factor at that hour. Averages were computed for each year based on the months of June through September and the lowest summer averages were selected for the low VRE scenarios. The final scenario is the extreme peak load and forced outages scenario, which uses the low 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.

[j] PROMOD model data is created using the 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.

Exhibit 2-1. PROMOD peak load scenarios

Scenario Name	Description	Peak Demand (MW)	Normal Forced Outages (MW)	High Forced Outages (MW)	High Peak Load (MW)	Extreme Peak Load (MW)	Extreme Forced Outages (MW)	Historic Wind (MW)	Historic Solar (MW)	Net Effective Peak Load (MW)
1	Base Case	77,884	4,105							81,989
2	Base case + High Forced Outages	77,884	4,105	3,985						85,974
3	Base case + High Forced Outages + High Peak Load	77,884	4,105	3,985	1,922					87,896
4	Base case + High Forced Outages + High Peak Load + Historic Low Wind	77,884	4,105	3,985	1,922			x		87,896
5	Base case + High Forced Outages + High Peak Load + Historic Low Wind + Historic Low Solar	77,884	4,105	3,985	1,922			x	x	87,896
6	Base case + Extreme Forced Outages + Extreme Peak Load + Historic Low Wind + Historic Low Solar	77,884	4,105			4,250	9,595	x	x	95,834

Because of the importance of natural gas prices in ERCOT's economic generation dispatch, PROMOD's forward Henry Hub natural gas prices were updated with the Energy Information Administration's most recent short-term energy outlook for natural gas to increase the accuracy of the six scenarios. [56] ERCOT currently assumes that battery energy storage systems provide ancillary services rather than sustained capacity available to meet peak loads. Therefore, all battery energy storage system resources were removed from the PROMOD analysis. [3] [k]To reflect the recent changes to the system-wide offer cap, the cost of emergency energy and the bid adders for interruptible loads were updated to $5,000/MWh and $4,999/MWh, respectively.

Based on the total summer capacity shown in Exhibit 2-1, ERCOT is expected to have sufficient reserves to meet loads in the five least extreme PROMOD scenarios outlined in Exhibit 2-2. The extreme peak load scenario exceeds the available capacity by 4,800 MW. This estimation does not take into account variation in VRE generation or planned outages on the system.

Exhibit 2-2. Available generating capacity

Category	Capacity (MW)
Thermal*	**71,089**
Hydro (Derated)	475
Wind (Derated)	9,366
Solar (Derated)	9,254
DC Ties (Derated)	**850**
Total Capacity	**91,034**

*Includes switchable units

The total number of reserve shortfalls in each scenario is detailed in

[k] If the scenarios presented here were to include energy storage in spite of the assumption that ERCOT makes in its SARA, this would only increase available capacity by a maximum of 2,318 MW, assuming storage is at full charge at peak and not operationally constrained by thermal operating limits. While the inclusion may reduce the number of violation days, it would not completely eliminate them, nor would it change the outcome in scenarios 2 through 6 where reserves are projected to fall below zero. Additional scenario sensitivities would need to be executed to explore the impacts of potential peak shifting due to storage charging.

Exhibit 2-3. For all scenarios, excluding the base case, there were some hours where the modeled load exceeded the calculated reserve capacity. Comparing these results to the prior NETL report, *2021 Summer Resource Adequacy in the ERCOT Region,* there are more modeled EEA and reference margin violations events in the 2022 model. This is due in part to the significant growth of VRE assets as well as higher modeled loads.

Exhibit 2-3. Number of days with reserve shortfall under six modeled scenarios

Scenario	Daily Violations					Common Period of Concern During Scenarios
	<13.75% Reserve	EEA 1	EEA 2	EEA 3	<0% Reserve	
1	9	0	0	0	0	–
2	38	11	10	10	8	PM Ramp
3	47	18	16	14	11	PM Ramp
4	46	10	9	8	7	AM Ramp
5	44	10	8	7	6	AM Ramp
6	66	20	19	17	16	PM Ramp

Exhibit 2-4 through Exhibit 2-9 show the hourly reserve capacity of each day compared against the minimum target reserve margin of 13.75 percent.[l] [57] The reserve capacity is calculated as the available capacity at each hour, minus the total load at that hour. The base case, shown in Exhibit 2-4, shows violations only of the 13.75 percent minimum reserve margin, which indicates that if conditions are relatively mild in terms or weather, load, and forced outages, the ERCOT system can avoid emergency load shed measures. The high forced outages and high peak load scenario, shown in Exhibit 2-5 and Exhibit 2-6, respectively, show significantly more reserve shortfalls compared to the base case. This shows that the resource adequacy in ERCOT remains tight and that some emergency measures such as load shedding may be needed to ensure system reliability this summer. The Low VRE generation scenarios, shown in Exhibit 2-7 and Exhibit 2-8, show fewer reserve shortfalls compared to the high forced outages and high peak load scenarios. This is a result of the changes made to the hourly VRE generation profiles, which changes the modeled times where the load is greater than the reserves. This points to the importance and uncertainty in VRE generation. The extreme forced outages and peak load scenario, shown in Exhibit 2-9, had the largest number of reserve shortfalls and the largest shortfall magnitude of 15,240 MW. This indicates the potential for an extreme event in Summer 2022 to require significant load shedding.

[l] The 13.75% reference margin shown in Exhibit 2-4 through Exhibit 2-9 is calculated on the estimated load for each scenario. For the base case and high forced outage scenario, the reference margin is calculated as 13.75% of 77,884 MW. For the high load and low VRE scenarios, the reference margin is calculated as 13.75% of 79,806 MW. For the extreme peak load and forced outages scenarios, the reference margin is calculated as 13.75% of 82,134 MW.

Exhibit 2-4. Scenario 1, base case (peak load: 81,989 MW)

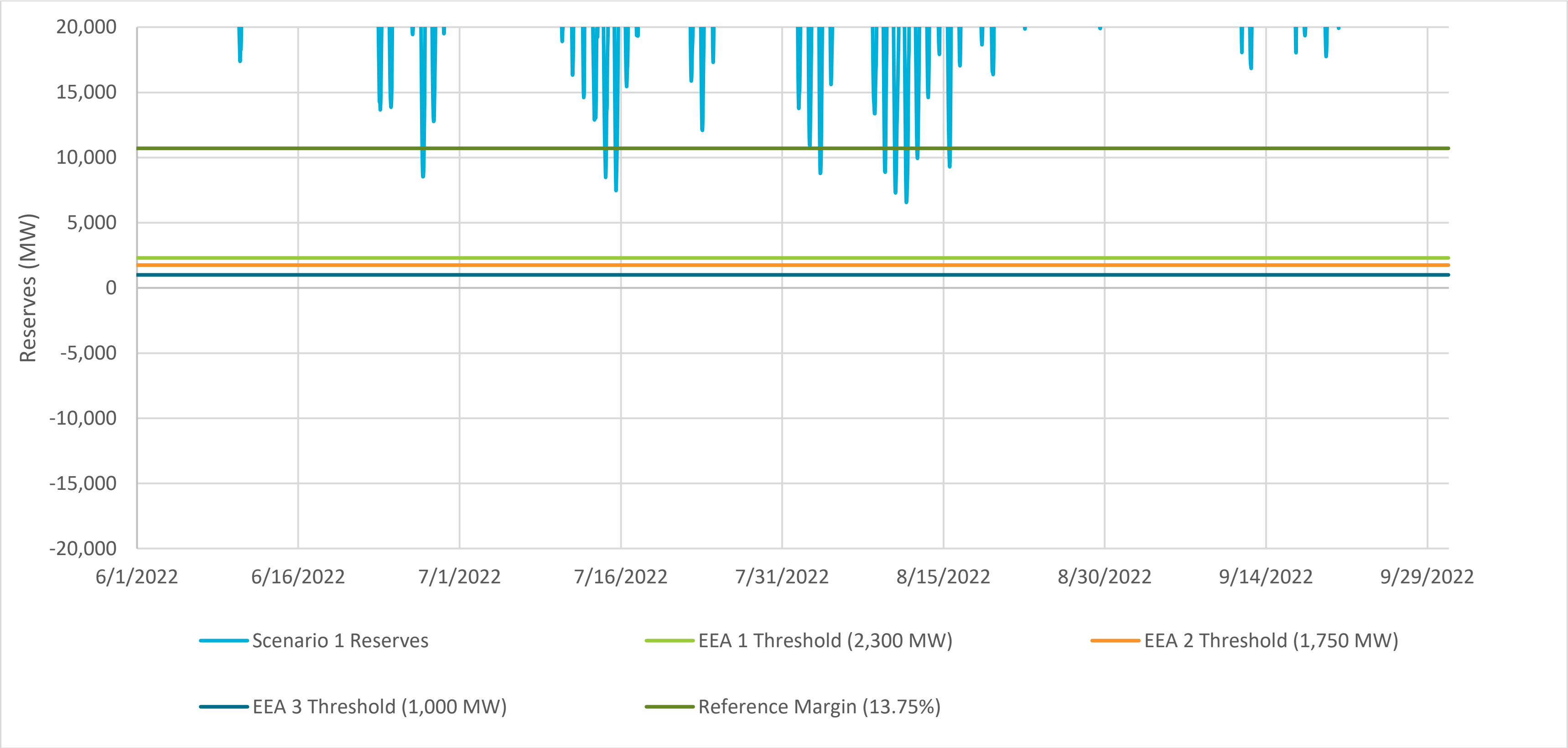


Exhibit 2-5. Scenario 2, high forced outages (peak load: 85,974 MW)

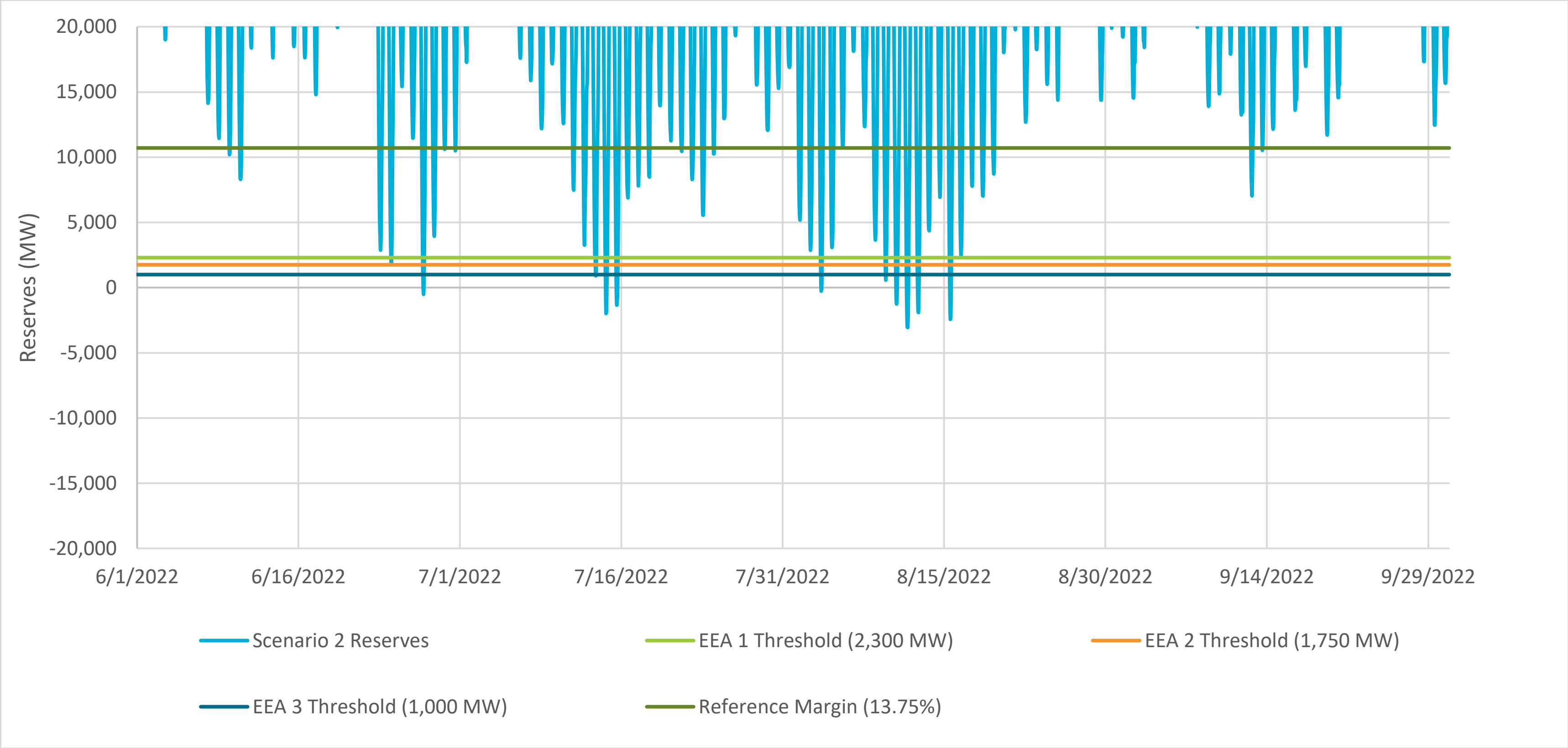


Exhibit 2-6. Scenario 3, high peak load (peak load: 87,896 MW)

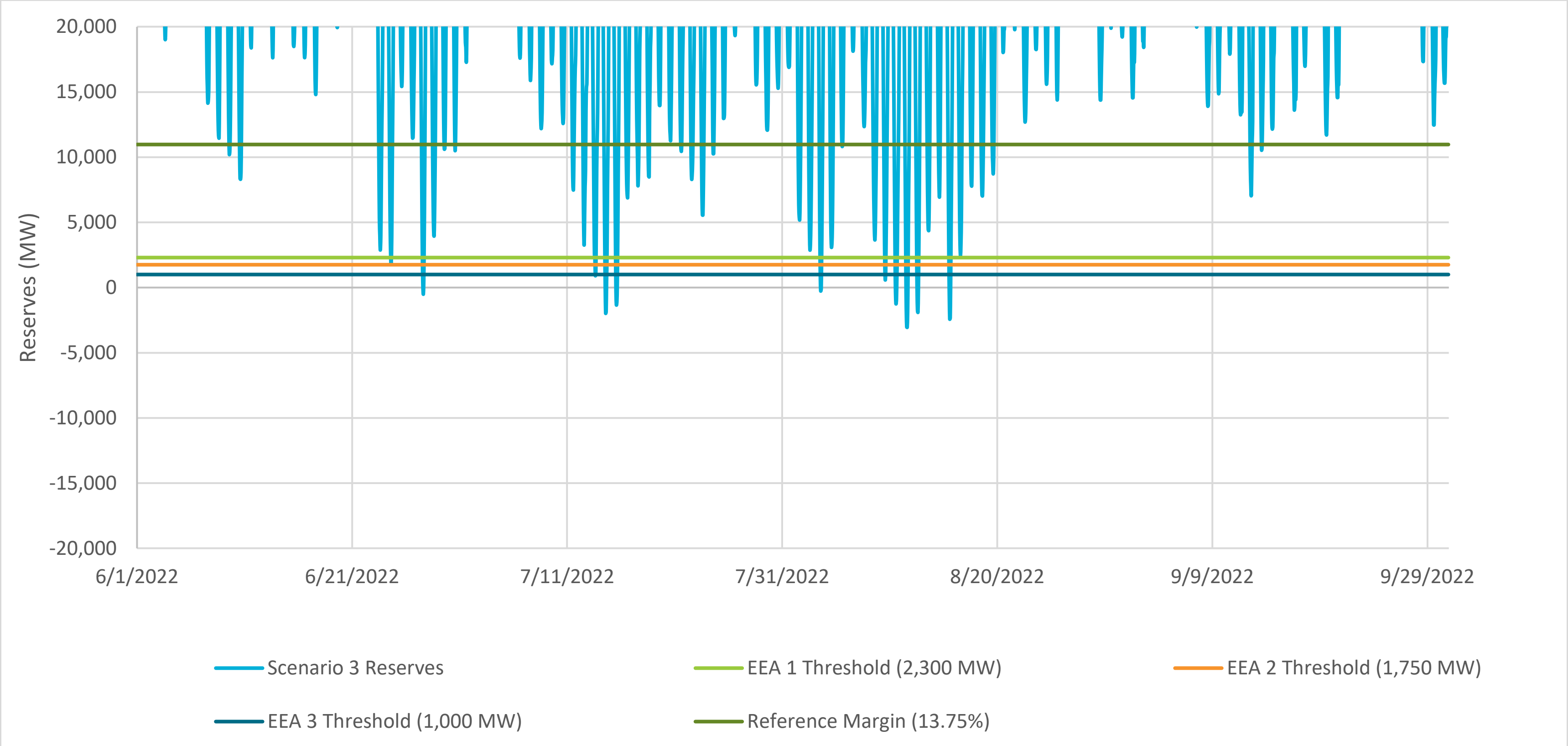


Exhibit 2-7. Scenario 4, low wind (peak load: 87,896 MW)

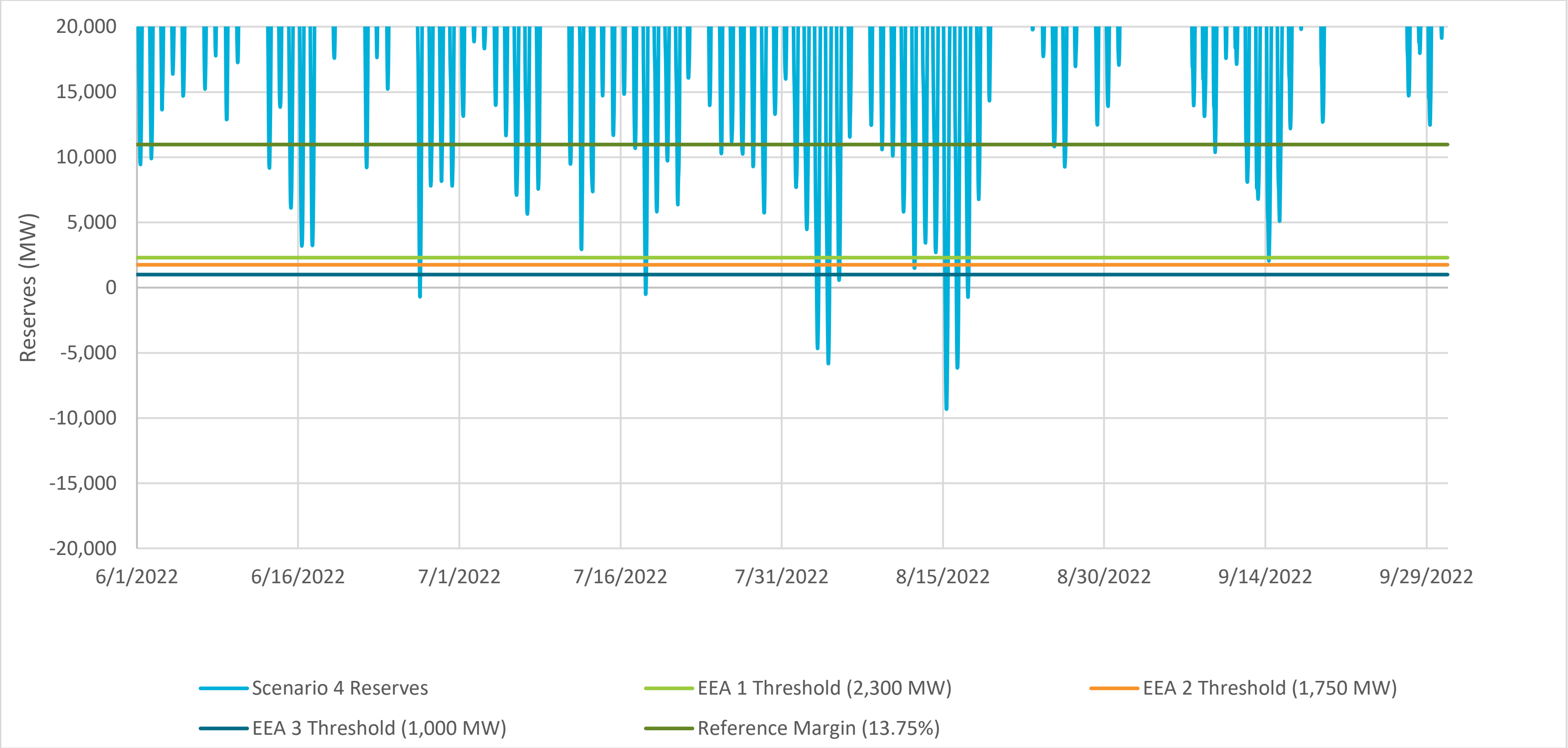


Exhibit 2-8. Scenario 5, low solar and wind (peak load: 87,896 MW)

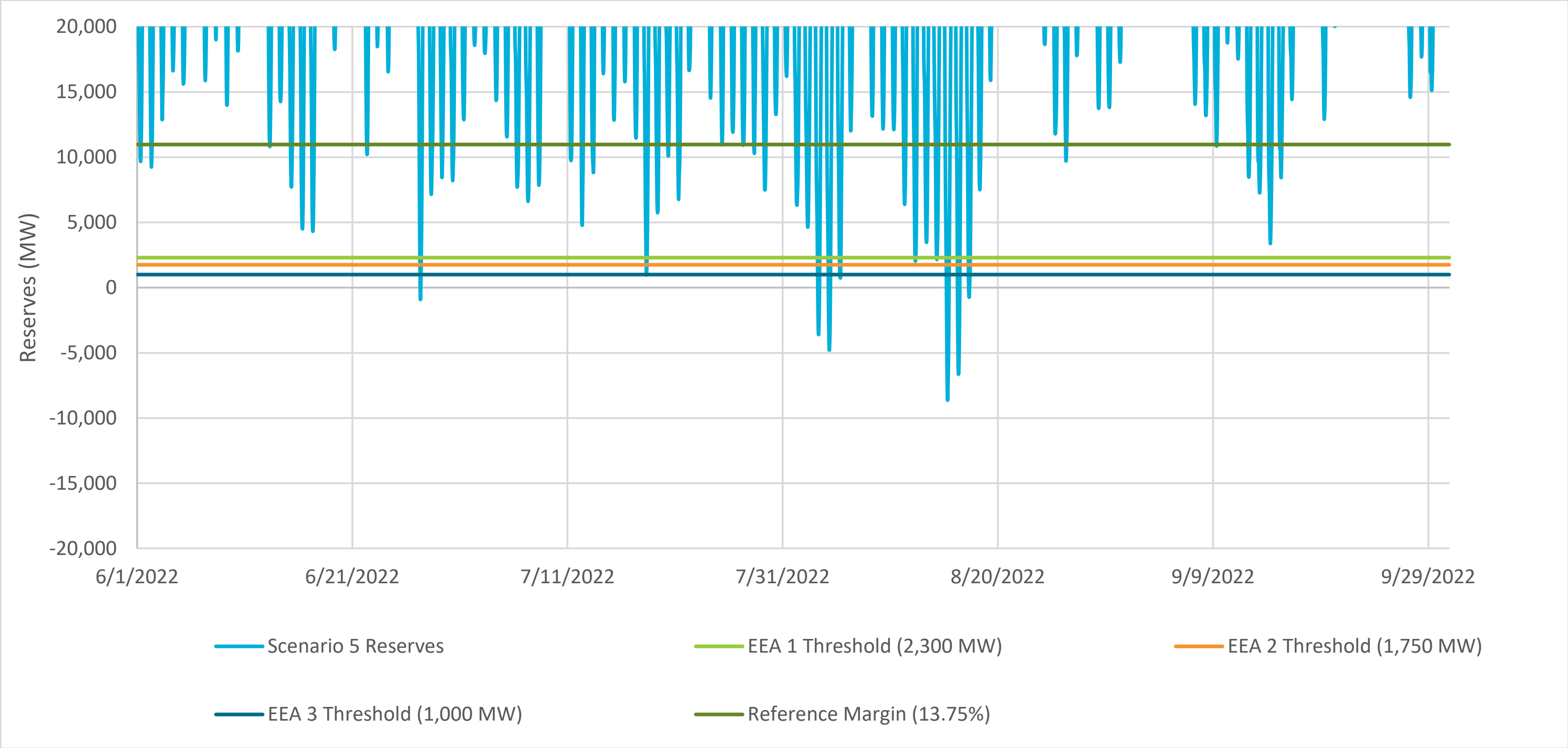
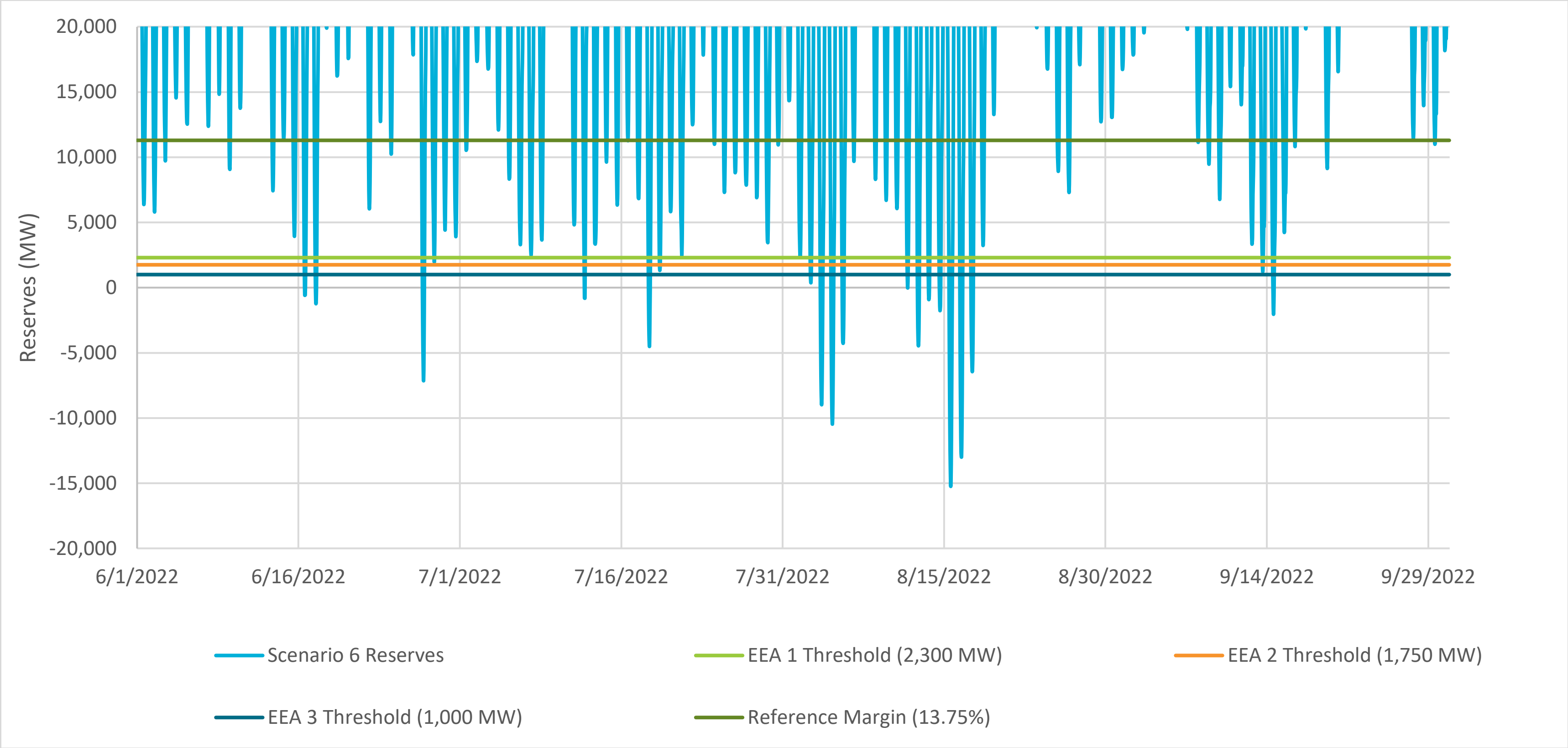


Exhibit 2-9. Scenario 6, extreme peak load and outages (peak load: 99,819 MW)



3 SUMMARY

Despite the numerous changes to the energy market enacted by PUCT, ERCOT, RRC, and Texas State Legislature, the Texas grid still faces resource adequacy challenges. While annualized electricity prices and emissions have been trending down over the last few years, surging natural gas prices, increasingly extreme weather events, earlier seasonal high demand and transmission congestion all point to a potential for higher electricity price spikes and increased summer seasonal prices in 2022. Early indicators of these problems include the high electricity prices seen near Houston in May 2022. [24]

Adoption of changes following the 2021 Winter Storm Uri disaster has also been somewhat slow. RRC has so far not implemented weatherization standards for natural gas suppliers, although there have been some efforts to improve natural gas and power system interdependencies. [52] In addition, ERCOT has stated that it will be a matter of years before updated ERCOT Contingency Reserve Service, Emergency Management System, firm fuel supply service, and other ancillary service enhancements are made due to technical and organizational constraints, although several market changes have already been implemented, such as updated to the ORDC. [47]

The PROMOD scenarios suggest a low probability of ERCOT making it through the 2022 summer season without a LOLE, even if weather and generator forced outage rates remains normal, given the instances of negative reserves in all six scenarios. If demand and forced outage rates reach potential peak levels, ERCOT may face an event on the scale of 2011.

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