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Short-Term Energy Outlook Supplement: Sources of Price Volatility in the ERCOT Market

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1. Introduction

The primary responsibility of U.S. power system operators is to balance the supply of electricity and power demand. In addition to managing the power grid on a real-time basis, they must also ensure an adequate amount of electricity supply will be available to fulfill uncertain levels of future demand. In some jurisdictions, utility regulators create requirements for levels of generating capacity to be maintained to meet expected electric demand. In other areas, system operators have set up forward auction markets specifically to coordinate commitments to meet expected future generating capacity needs.[1]

Instead of specific requirements or a formal capacity market, Texas's grid operator, the Electric Reliability Council of Texas (ERCOT), designed its day-to-day wholesale power market to provide incentives for the development of future generating capacity.[2] Specifically, ERCOT's power market has mechanisms that allow the energy component of wholesale prices to substantially increase during periods when resource availability is especially low. The potential for significant electricity price volatility is an inherent feature of ERCOT's energy-only wholesale market design that is meant to encourage investment in new capacity. The wholesale electricity price in ERCOT includes a unique electricity price adder to reflect the level of scarcity in the system. When reserve resources are plentiful no price adder is applied, but when reserve resources are scarce the price adder increases up to ERCOT’s price cap, which is currently set at $5,000 per megawatthour (MWh).[3] The growth in ERCOT’s peak electricity load combined with its increasing use of intermittent renewable generation sources has supported recent price volatility.

At the start of each season, ERCOT releases an analysis called the Seasonal Assessment of Resource Adequacy (SARA) that reviews whether the planned level of power supply will adequately fulfill the expected highest level of electricity demand.[4] Because of the inherent uncertainty in forecasting the future, as a part of this process, ERCOT also analyzes the impact of different assumptions regarding supply and demand. The SARA report is focused on assessing grid resiliency under different conditions, and it does not evaluate those conditions effects on wholesale power prices. In this supplement to the *Short-Term Energy Outlook* (STEO), we used a production cost model to assess four scenarios that are similar to those in ERCOT's report, with a focus on analyzing how the assumptions in these scenarios may affect wholesale power prices and market conditions in ERCOT:

[1] U.S. Energy Information Administration, “Forward capacity markets help ensure future electricity supplies,” *Electricity Monthly Update*, March 2021. https://www.eia.gov/electricity/monthly/update/archive/march2021/

[2] Hogan, William W. "Electricity Market Design." Presentation at ACCC/AER Regulatory Conference, July 30, 2021. https://scholar.harvard.edu/files/whogan/files/hogan_accc_073021.pdf

[3] The Public Utility Commission of Texas, “Chapter 25. Substantive Rules Applicable to Electric Service Providers,” May 11, 2022. https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.509/25.509.pdf

[4] Electric Reliability Council of Texas, Seasonal Assessment of Resource Adequacy reports, https://www.ercot.com/gridinfo/resource#details-d4b75b8d-e29e-a0c8-5574-c295a3266b36

- Normal levels of load and wind generation
- High levels of peak electricity load
- Low levels of wind generation
- Simultaneous occurrence of high peak load and low wind generation

Our analysis shows that electricity prices in ERCOT reflect the variable cost to generate electricity in the early morning hours and at the end of the day. However, when electricity demand starts increasing around noon, electricity prices can increase well above marginal generation costs. In our Base case, which assumes a normal summer peak day in Texas, the highest simulated hourly wholesale electricity price is $90/MWh, but in our High Peak case wholesale prices jump 17% to a high of $105/MWh. In our Low Wind case, with demand similar to Base case levels, the maximum price increases to $709/MWh. Our final scenario combines assumptions from the High Peak case and the Low Wind case to create the Extreme case, where the electricity price exceeds $2,900/MWh. The wide range of simulated wholesale prices across the scenarios reflects the design of the ERCOT wholesale market (Table 1).

Table 1. Comparison of case assumptions and simulated ERCOT wholesale prices

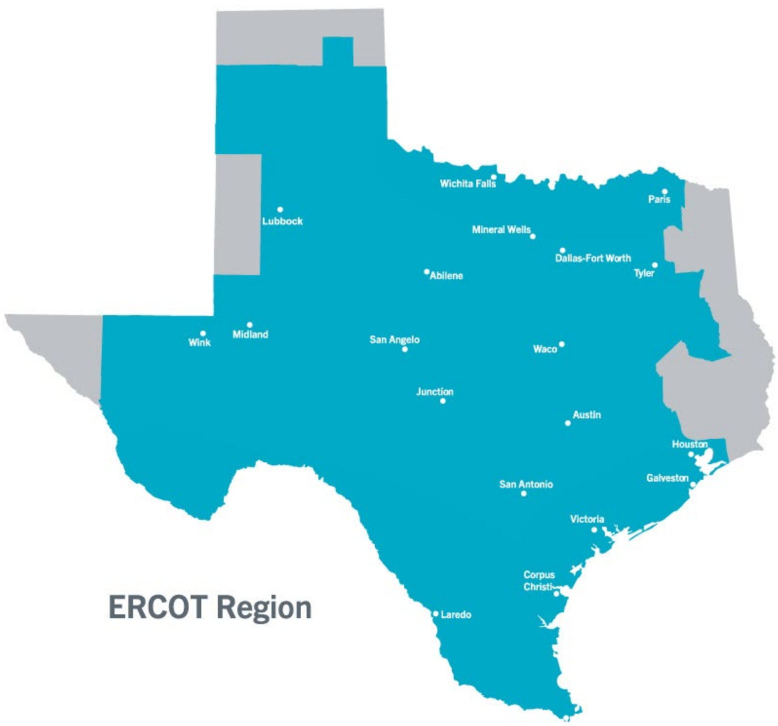
	Base	High Peak	Low Wind	Extreme
Peak load (megawatts)	77,498	80,152	77,498	80,152
Wind availability (megawatts)	10,144	10,144	3,064	3,064
Maximum simulated wholesale price (dollars per megawatthour)	$90	$105	$709	$2,905
Energy component	$90	$105	$ 99	$ 601
Scarcity adder	—	—	$610	$2,304

Data source: U.S. Energy Information Administration, Short Term Integrated Forecasting System simulation of the Electric Reliability Council of Texas (ERCOT) power market

2. Issues Overview

The Electric Reliability Council of Texas (ERCOT) is a non-profit organization that serves as the independent system operator (ISO) for most of Texas (Figure 1). As the ISO, ERCOT manages the flow of electricity in Texas, serving about 90% of Texas's electricity load. ERCOT also runs the competitive wholesale bulk-power market and provides administrative services for retail customers in competitive choice areas. ERCOT's members include consumers, transmission owners, distribution and full-service utilities, generators, power marketers, and retail electricity providers. ERCOT is governed by a board of directors and is overseen by the Public Utility Commission of Texas and the Texas legislature. The ERCOT market, unlike other electricity markets in the United States, is not regulated by the Federal Energy Regulatory Commission (FERC). ERCOT, however, does collaborate on bulk power system reliability and security issues with the North American Reliability Corporation (NERC), which is subject to oversight by FERC.[5]

Figure 1. Areas of Texas served by Electric Reliability Council of Texas (ERCOT)



Source: Electric Reliability Council of Texas (ERCOT), Maps

[5] The Texas Reliability Entity, Inc. (TRE) serves as NERC's representative for the ERCOT interconnection

The structure of the ERCOT market and wholesale price determination

ERCOT operates an hourly day-ahead market and a real-time market for both energy and ancillary services to balance electricity supply and demand. The day ahead market matches willing buyers and sellers of electricity, subject to transmission grid limits and other constraints. Energy dispatch is co-optimized with ancillary services and transmission flows to provide least-cost scheduling for each hour of the next day. The real-time market re-optimizes the supply schedule at 5-minute intervals to meet actual demand needs in real time.

The ERCOT system energy component of the wholesale price reflects the cost of the most expensive (marginal) generator that is needed to fulfill the grid's electricity demand in any given period. In addition to this cost of providing energy for the system, ERCOT calculates locational marginal prices (LMPs)[6] for thousands of specific locations (referred to as buses or nodes). These locational prices include system energy cost plus the cost of delivering the electricity into or out of a specific location.

ERCOT added another component to wholesale prices in 2015, a scarcity adder.[7] This scarcity adder represents the value of additional resources to grid reliability. In general, the more resources a grid operator has in reserve to respond to unexpected changes in supply or demand, the greater the grid's reliability. ERCOT uses a pricing mechanism known as the Operating Reserve Demand Curve (ORDC) to determine the scarcity adder, which represents the value of these real-time, reserve resources. When these reserve resources fall below a pre-determined level, the scarcity adder is applied to the system energy component of the wholesale price. The use of the scarcity adder, which varies with changes in electricity supply and demand, is designed to create the potential for additional variation in ERCOT electricity prices (which is generally characterized by market participants as price *volatility*).

In ERCOT, there is an administratively-determined relationship between real-time reserves and the real-time scarcity adder (Figure 2). As reserves decrease, their value increases in proportion with the probability of needing to curtail energy delivery. When reserves drop below a specific level, which is currently set at 3,000 MW ("minimum contingency level") the ERCOT price ceiling is reached.

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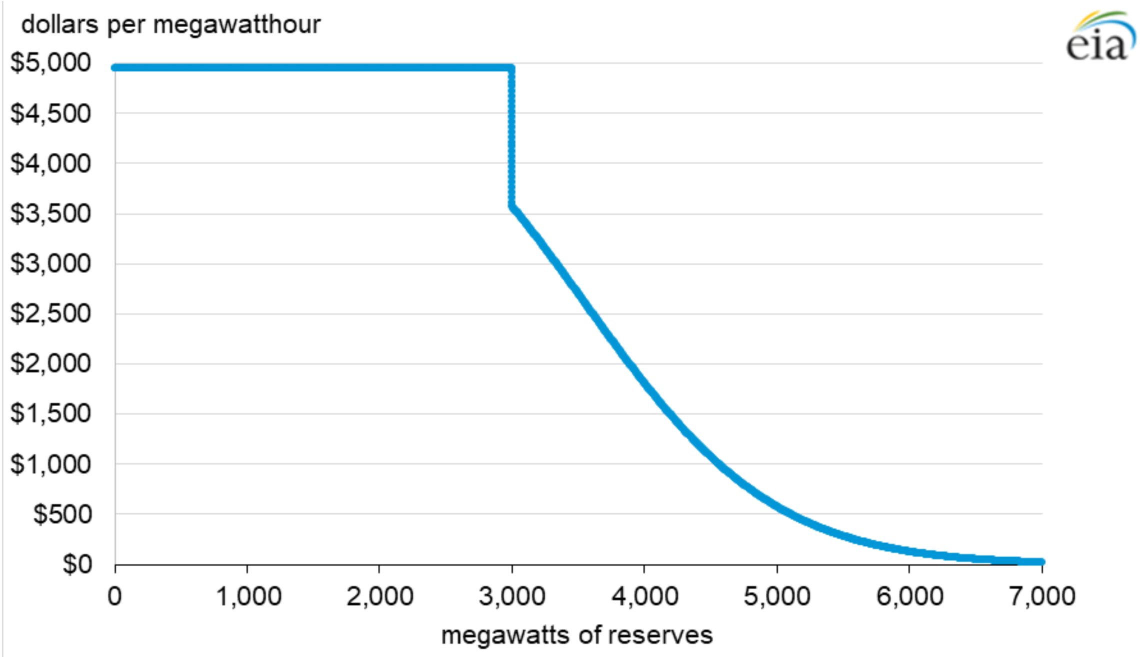
[6] See EIA Glossary definition of *location marginal price*: https://www.eia.gov/tools/glossary/index.php?id=L

[7] Potomac Economics, "*2014 State of the Market Report for the ERCOT Wholesale Electricity Markets*", July 2015, p. 101. https://www.puc.texas.gov/industry/electric/reports/ERCOT_annual_reports/2014annualreport.pdf

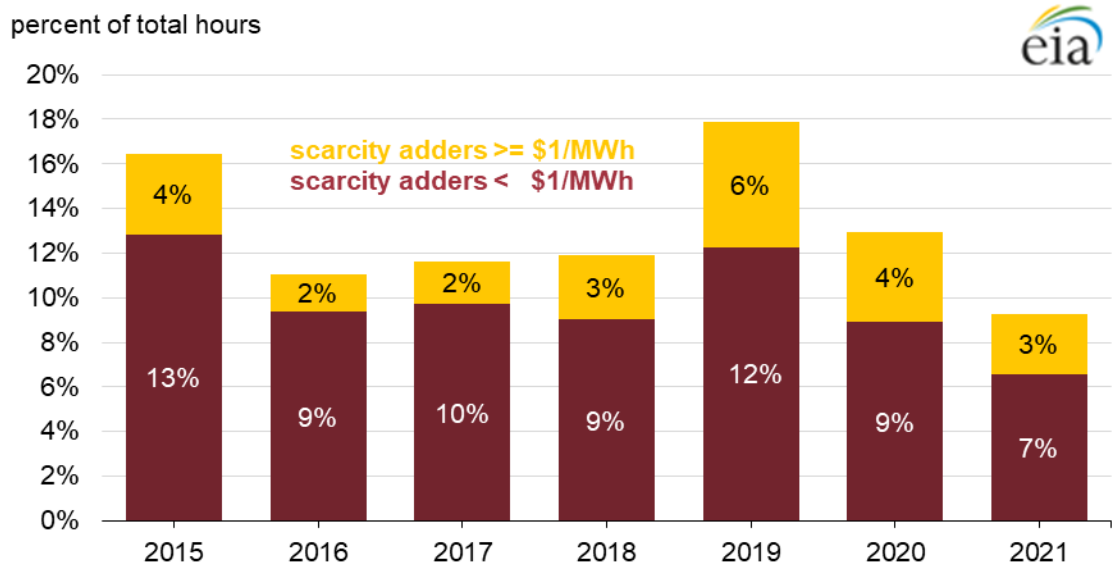
Figure 2. ERCOT Operating Reserves Demand Curve (ORDC)



Data source: Electric Reliability Council of Texas (ERCOT), Operating Reserve Demand Curve - WBT

ERCOT's use of scarcity adders was most common in 2019 (Figure 3), which coincided with ERCOT's lowest summer planning reserve margin. In 2019, 18% of the hours included scarcity adders and 6% of the hours had adders greater than $1/MWh. Overall, it is uncommon for adders to exceed $1/MWh. During 2021, the scarcity adder was greater than $0/MWh during 10% of all hours. The scarcity adder ranged from $0.01/MWh to $7,053/MWh in 2021.

Figure 3. Share of hours that scarcity adders were applied to ERCOT electricity prices, 2014–2021



Data source: Electric Reliability Council of Texas (ERCOT) Market Information list data, Historical Real-Time ORDC and Reliability Deployment Prices for 15-minute Settlement Interval

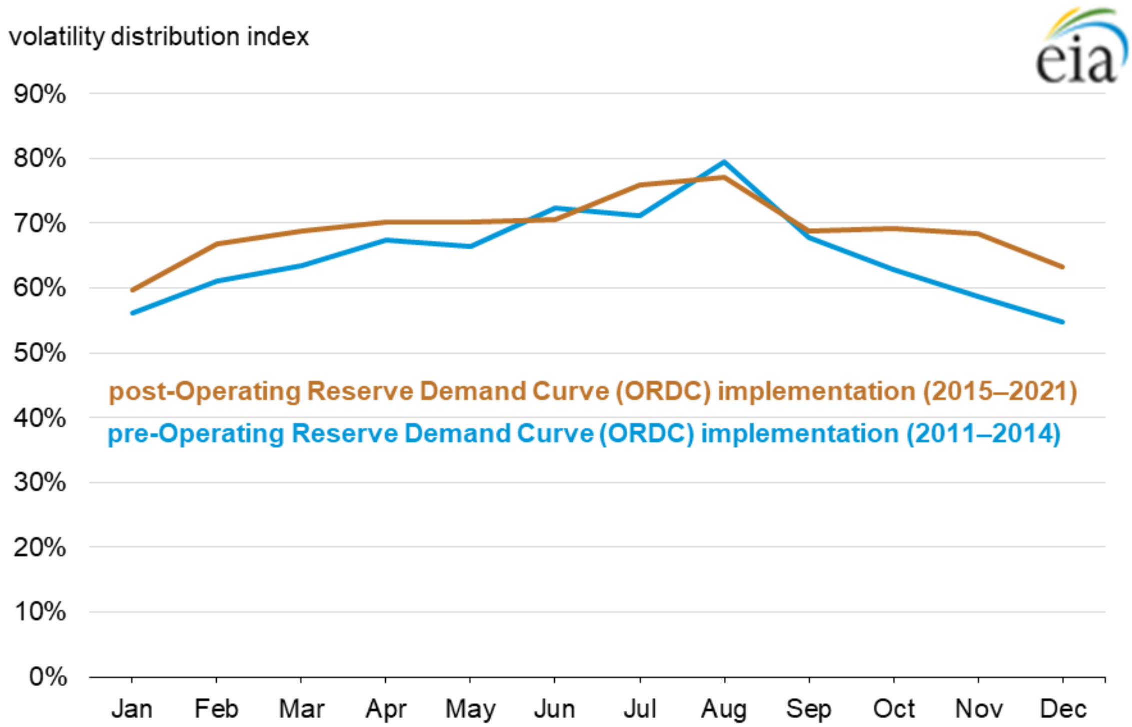
In February 2021, extremely cold temperatures during Winter Storm Uri caused a large amount of much needed generation equipment to freeze up, resulting in days-long blackouts across much of Texas. The scarcity adder contributed to the high ERCOT energy prices, which stayed at the price cap of $9,000/MWh for three days, creating uncertainty about the financial stability of retail suppliers purchasing energy in the real-time market and their customers who had variable electricity rates.[8]

Following Winter Storm Uri, ERCOT made several changes to the ORDC pricing mechanism. The minimum contingency level was increased from 2,000 megawatts (MW) to 3,000 MW, lowering the amount of reserves that would trigger the scarcity adder. In addition, ERCOT reduced the electricity price cap from $9,000 to $5,000/MWh, which lowers the maximum value of real-time reserves.[9]

Prior to the implementation of the ORDC, when low energy prices were insufficient to spur investment in more resources, ERCOT raised the price cap. Higher price caps, however, did not yield the intended outcome of more resources to meet reliability objectives. Because the ORDC price adder varies with reserves and is a component of the energy price, the energy price now directly reflects the value to reliability of more resources. This scarcity adder contributes to the ERCOT intraday wholesale price volatility. A comparison of intraday price volatility before and after the ORDC pricing mechanism was implemented indicates that in most months, volatility has been greater than in those years before the ORDC was implemented. The summer months of June and August have been notable exceptions, emphasizing the variety of factors at play in pricing during that season. August has been the most volatile month historically (Figure 4).

[8] https://www.ercot.com/files/docs/2021/03/03/Texas_Legislature_Hearings_2-25-2021.pdf, p.22
[9] Public Utility Commission of Texas, "*Review of the ERCOT scarcity pricing mechanism*", https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.505/52631adt.pdf

Figure 4. Monthly average intraday price volatility in ERCOT electricity prices, 2011–2021



Data source: Electric Reliability Council of Texas (ERCOT), *Market Information*
Note: The intraday price volatility index is defined as the ratio of the difference between average maximum daily price per month and the minimum price per month divided by the minimum price per month.

Although the ORDC pricing mechanism is only applied in the real-time market, the presence of scarcity pricing in real-time trading can influence the day-ahead market clearing prices. Our analysis captures this market-interaction effect by including the value of forecast real-time reserves on day-ahead prices in our cases.

Key determinants of price volatility in ERCOT

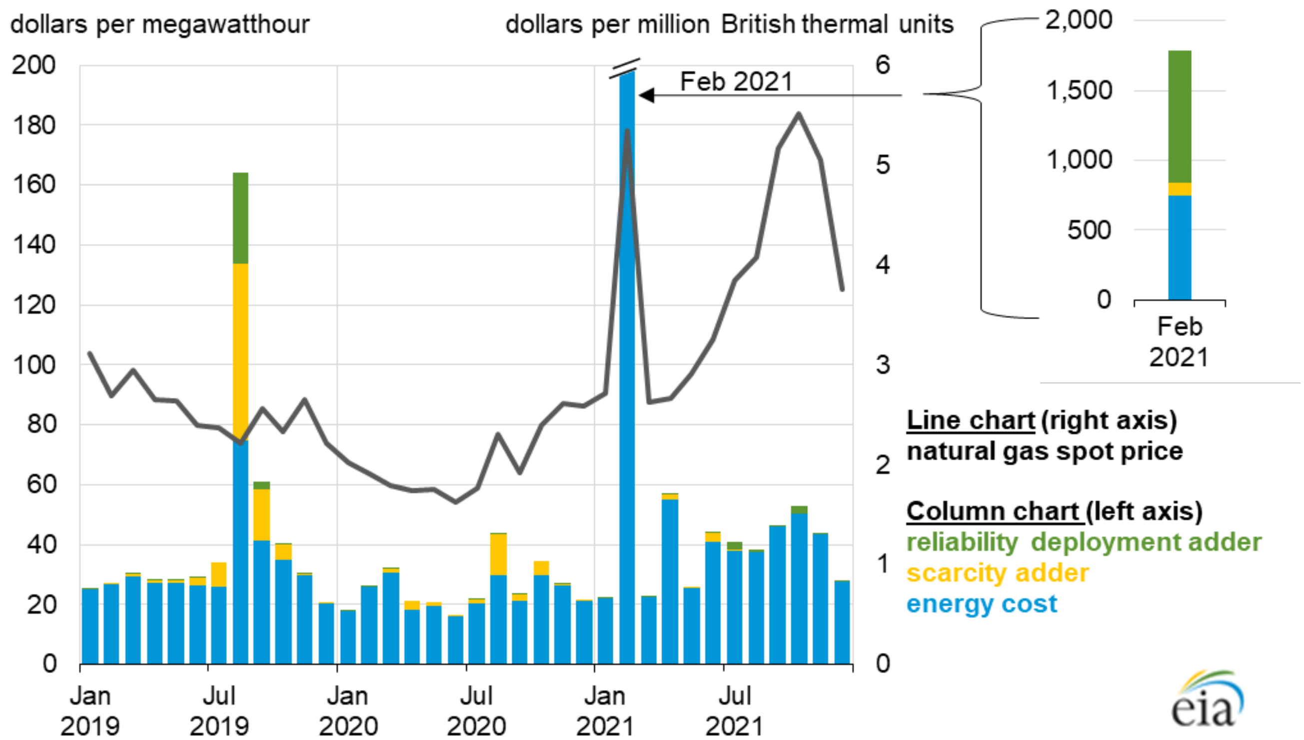
The wholesale real-time system energy price in ERCOT is designed to reflect the cost of meeting load in the market and provide incentive for future investment in new generating capacity. In addition to the costs of generating electricity, it also includes the scarcity adder and another reliability adder to compensate units that are required to generate for reliability purposes no matter their cost. The scarcity adder and the reliability deployment adder are intended to cover the costs of maintaining real-time grid reliability.

The contribution of each cost component to the wholesale price has varied on a monthly basis over the past three years (Figure 5). Although a variety of factors influence prices in the ERCOT area, our analysis suggests the three most significant are:

- Fuel cost for electric power (principally natural gas)
- Growth in peak load
- Availability of intermittent generation from renewable sources

The cost of generating energy has been the largest component of the price of electricity, and natural gas prices and the cost of generating energy have generally moved in tandem. During normal conditions, ERCOT's wholesale electricity prices are highly correlated with the price of natural gas, which is the fuel most often used by the most expensive (marginal) generator that sets the prices during most hours.

Figure 5. ERCOT electricity prices and Henry Hub natural gas prices, 2019–2021

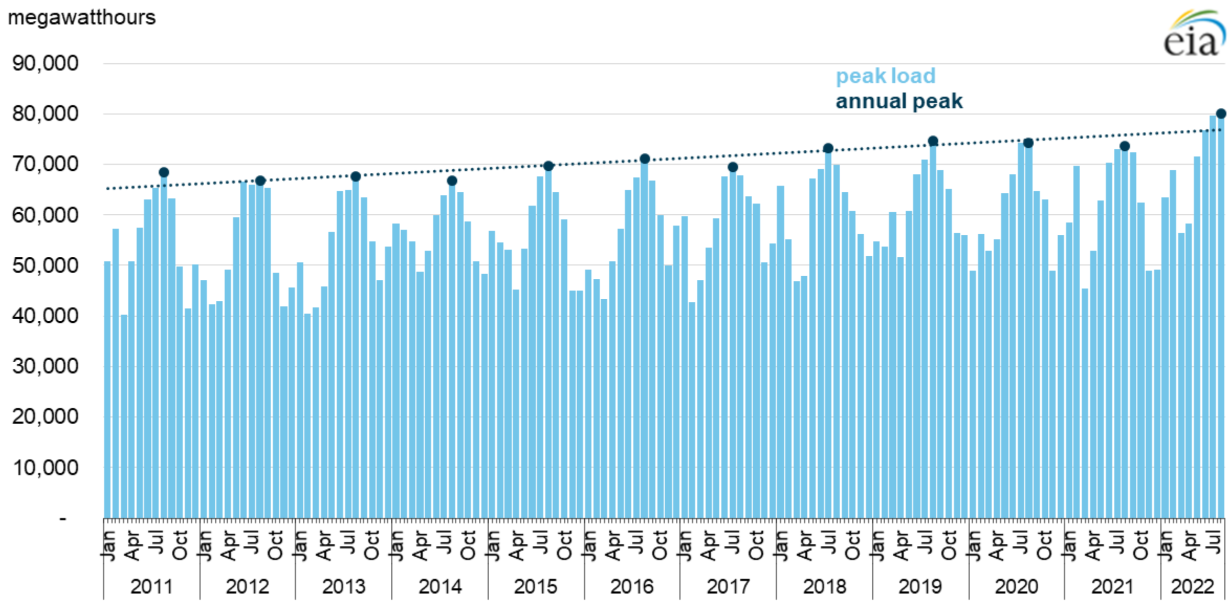


Data source: Potomac Economics, *2021 State of the Market Report* (ERCOT electricity price components); U.S. Energy Information Administration (Henry Hub spot natural gas price)
Note: ERCOT is the Electric Reliability Council of Texas.

Electricity demand is also an important determinant of prices. ERCOT dispatches the least-cost generators first and brings progressively more expensive generators online to fulfill increasing demand. Electricity load in ERCOT has been growing steadily over the past decade, reflecting Texas's growing population and expanding economy. The annual peak load grew at an average rate of 1.7% between 2010 and 2022 (Figure 6). In the summer of 2022, ERCOT exceeded the previous peak-load record of 74,666 MW on numerous days, and it had to ask electricity customers to follow voluntary conservation measures.[10] The total system load in ERCOT reached a new all-time record of 80,038 MW on July 20, 2022.

[10] ERCOT news release, "ERCOT Issues Conservation Appeal to Texans and Texas Businesses," July 10, 2022. https://www.ercot.com/news/release?id=90030206-5cf5-db8e-13d1-f8fe2bd0128f

Figure 6. ERCOT monthly and annual peak loads (Jan 2011–Jul 2022)

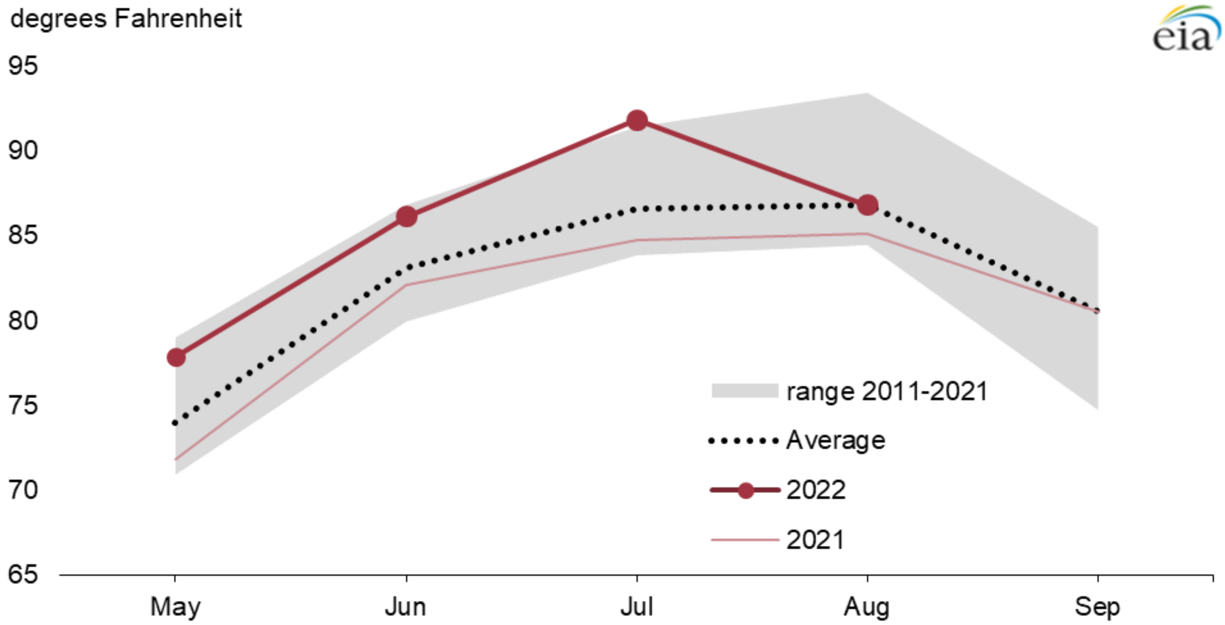


Data source: U.S. Energy Information Admisnitration, *Short-Term Energy Outlook*

Within these longer-term trends, variability in electricity load has been strongly correlated with relative temperatures. Historically, in ERCOT, electricity load peaks in the summer months. Summer days with extremely hot temperatures can lead to peak hourly demand approaching available generation capacity, leading to low reserves.[11] The highest temperatures on record in in the Dallas-Fort Worth-Arlington area of Texas, which accounts for about 25% of the state's population,[12] were reached in August 2011, and the July 2022 temperature exceeded the 10 year average value for July (Figure 7). At times, winter temperatures that are colder-than-normal have also led to high peak load.

[11] U.S. Energy Information Administration, *Today in Energy* article, "NERC report highlights potential summer electricity issues for Texas and California, " June 18, 2019. https://www.eia.gov/todayinenergy/detail.php?id=39892
[12] Texas Comptroller of Public Accounts, "*The Metroplex Region 2020 Regional Report*" https://comptroller.texas.gov/economy/economic-data/regions/2020/metroplex.php

Figure 7. Monthly average temperature in Dallas-Fort Worth area, (2011–2022, May–Sep)



Data source: National Oceanic and Atmospheric Administration, National Weather Service

For most of its history, ERCOT has generated electricity primarily with fossil fuel-fired power plants, supplemented by a smaller amount of nuclear generating capacity. Substantial growth in wind generating capacity over the past decade was a result of the combination of improved wind turbine generator technology and greater transmission access to areas of the state with substantial wind resources (largely in West Texas). Conversely, almost 6,000 megawatts of coal-fired generating capacity retired since 2011.[13] [14]Most recently, the pace of additions of utility-scale solar photovoltaic projects has accelerated, including the installation of hybrid projects combining solar and battery storage at the same interconnection point.

Although most generation in ERCOT is still fueled by natural gas, renewable generation from wind and solar has been making up a greater proportion of generation in recent years. The increasing use of wind power in the ERCOT market has been accompanied by larger swings in natural gas generation (Figure 8).

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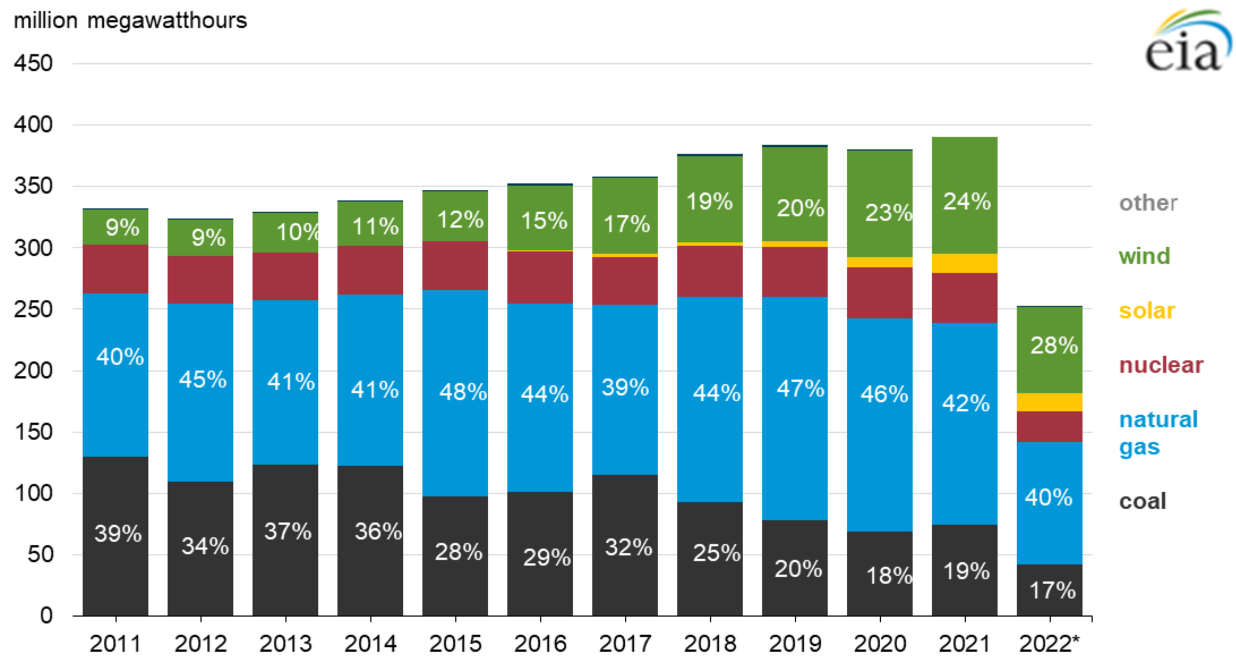
[13] ERCOT_2011_Capacity_Demand and Reserves Report, May 2011, p. 45 (19,034 MW of coal) https://www.ercot.com/files/docs/2017/11/03/ERCOT_2011__Capacity__Demand_and_Reserves_Report.pdf

[14] ERCOT Fact Sheet, July 2022 https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf (≅11,040 MW of coal)

Figure 8. Historical annual ERCOT generation by energy source, 2011–2022



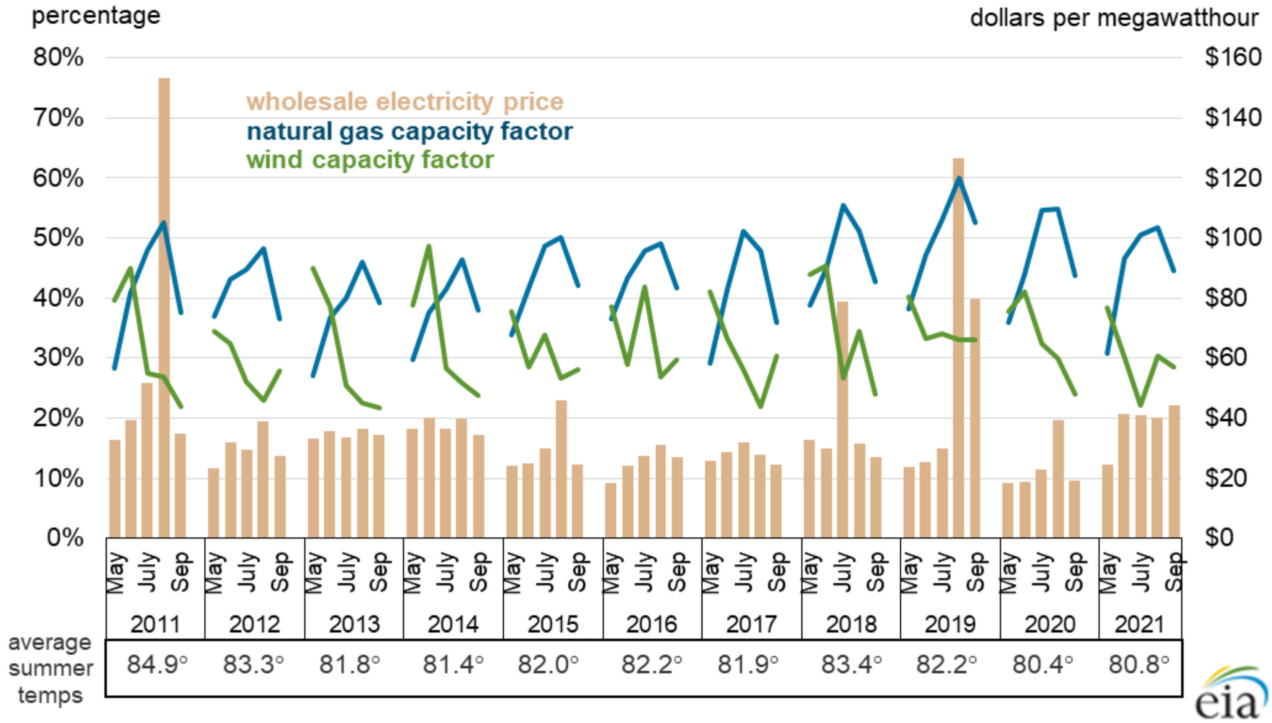
Data source: Electric Reliability Council of Texas (ERCOT) Grid Information, *Fuel Mix*
Note: Data for 2022 are from January to July.

This inherent variability in wind generation has led to increased variability in natural gas generation in ERCOT. As wind generation decreases, a wind generator's capacity factor, which is represented by the amount of generation during a specific time interval divided by the product of the installed capacity of the unit multiplied by the time interval, also decreases. Capacity factor comparisons across diffent types of units are useful for comparing how much of the installed capacity is relied upon for generation. When wind capacity factors decrease, there is less wind generation, and natural gas generation increases to make up the difference. Since natural gas plants have a higher fuel cost than wind generators, electricity prices increase (Figure 9). As temperaturatures rise in the summer months, electricity generation coming from wind resources starts to decline, as is typical in Texas at that time of year. Wholesale electricity prices are typically highest in the months of July and August when demand for cooling increases and lower cost wind resources are not generating as much, which leads to more generation from natural gas to meet the load.

Although the cost of natural gas is an important component of wholesale electricity prices, this analysis focuses on the effect of changes in peak electricity demand and fluctuations in wind availability (and the resulting potential for higher scarcity pricing), which can lead to temporary spikes in ERCOT prices.[15]

[15] The impact of natural gas price variability on wholesale electricity price will be considered in future analysis.

Figure 9. ERCOT prices and capacity factors for selected fuels, 2011–2021 (May–Sept)



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook; Electric Reliability Council of Texas (ERCOT), Hourly Aggregated Wind and Solar Output; and National Oceanic and Atmospheric Administration

3. Methodology

The UPLAN production cost model component of the Short-Term Integrated Forecasting System, which we use for developing the STEO electricity supply forecasts,[16] is a network model that simulates energy and ancillary service procurement and congestion management for the three main interconnections in North America. UPLAN includes a module of the ERCOT interconnection market that represents ERCOT's unique market rules, as well as the ERCOT market changes instituted after winter storm Uri in February 2021.[17]

The STEO forecasts are developed using a zonal version of the UPLAN models. To capture in detail the factors contributing to price volatility in the ERCOT market, for this analysis we simulated the nodal version of UPLAN, which simulates the operation of generators and the transmission network covering more than 9,500 nodes. By contrast, the zonal version of UPLAN is a simplified model that represents electricty generation and flows between four aggregated zones in ERCOT Our Base case assumptions are from the STEO forecast published in July 2022. For comparison, we also developed three stress case scenarios that explored the effects under the following conditions: very high peak load growth, very low wind generation, and a combination of these market stresses. We focus on simulating the hourly price patterns for the first week of August 2022, which based on a review of historic patterns, is the time period most likely to see a coincidence of low wind availability and peak load levels.

Modeling peak load

The key sources of uncertainty when forecasting short-term electricity demand are weather and economic conditions. For this STEO supplement, we developed econometric equations for modeling peak-hour electricity load. In these new equations, we model the ratio of peak load to average monthly load as a function of key independent variables, including heating degree days (HDD) for November through April and cooling degree days (CDD) for May through October.

In May 2022, ERCOT planners released their summer Seasonal Assessment of Resource Adequacy (SARA), in which they present their expectations for the potential risks to the reliability of the region's electricity system. The SARA reports the system's planning reserve margin given available generating supply and expectations of power demand under normal system conditions. In addition, the SARA outlines how these expectations could change under moderate and extreme assumptions, including higher-than-anticipated electricity load, lower availability of renewable resources, and high levels of unplanned outages.

For their SARA reliability assessments, ERCOT planners use results from simulations of their electricity demand model. The expected level of peak load is developed using weather data from the last 15 years and various resource availability assumptions as model inputs. While the SARA includes

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[16] For detail on use of UPLAN in the STEO electric sector forecast, see "Short-Term Energy Outlook Model Documentation: Electricity Supply Module," November 2021. https://www.eia.gov/analysis/handbook/pdf/STEO_Electricity_Supply.pdf

[17] Following winter storm URI, the Public Utility Commission of Texas increased the minimum contingency level and lowered the energy price cap, http://interchange.puc.texas.gov/Documents/52373_268_1172004.PDF

seven unique risk scenarios, three of them cover the range of ERCOT's assumptions about moderate and extreme peak load and wind availability.[18] In this STEO supplement, our scenarios include peak load and wind availability assumptions that are similar to those in ERCOT's summer 2022 SARA report (Table 2).

Table 2. Comparison of peak load and wind assumptions

	EIA STEO Supplement (Sep 2022)				ERCOT SARA Summer 2022*		
	Base	High Peak	Low Wind	Extreme	Base Risk	Moderate Risk	Extreme Risk
Peak load (megawatts)	77,498	80,152	77,498	80,152	77,317	77,317	81,567
difference from Base	—	+2,654	—	+2,654	—	-	+4,250
Wind availability (megawatts)	10,144	10,144	3,064	3,064	9,367	2,878	263
difference from Base	—	—	−7,080	−7,080	—	−6,489	−9,104

Data source: U.S. Energy Information Administration and Electric Reliability Council of Texas (ERCOT), *Seasonal Assessment of Resource Adequacy*, May 2022

Note: In the table Base Risk corresponds to ERCOT's "Forecasted Peak Load/Typical Unplanned Outages/Typical Renewable Output" scenario in the SARA report; Moderate Risk corresponds to "Forecasted Peak Load/Typical Unplanned Outages/Low Renewable Output"; and Extreme Risk corresponds to "High Peak Load/Extreme Unplanned Outages/Extreme Low Renewable Output".

The peak load of our Base and Low Wind cases is 77,498 MW, while the peak load in the SARA Base Risk scenario is 77,317 MW. The SARA peak load projection is based on average historical temperatures between 2006 and 2020. The peak load for our Base and Low Wind cases is based on our July STEO forecast input assumptions. The SARA also includes a scenario for an extreme peak load of 81,567 MW, which assumes that the highest recorded temperatures from 2011 will occur again in Texas. For this STEO supplement we assume a high peak load level that is also based on 2011 weather, specifically the monthly cooling degree day values from that year. Our High Peak and Extreme cases have a peak load of 80,152 MW, which is 3.4% more than our Base case estimate. In contrast, ERCOT's Extreme Risk scenario estimate is 81,567 MW, which is 5.5% higher than its Base Risk scenario.

In our Low wind and Extreme cases, we assume wind availability will be reduced by 70% from the levels in the Base and High Peak cases. This reduction in wind availability is similar to ERCOT's Moderate risk scenario. In contrast, ERCOT's Extreme risk scenario assumes a 97% reduction in wind availability compared to its Base risk scenario.

In our Base case, we assume 93,020 MW of total generating resources are available during the peak load hour of August (Figure 10). This assumption about available resources includes a reduction of 2,508 MW of unplanned outages during that hour. Comparing this level of resource availability to our Base case peak load assumption of 77,498 MW indicates a reserve margin of 20% (defined as the difference between resources and peak load, divided by peak load).[19]

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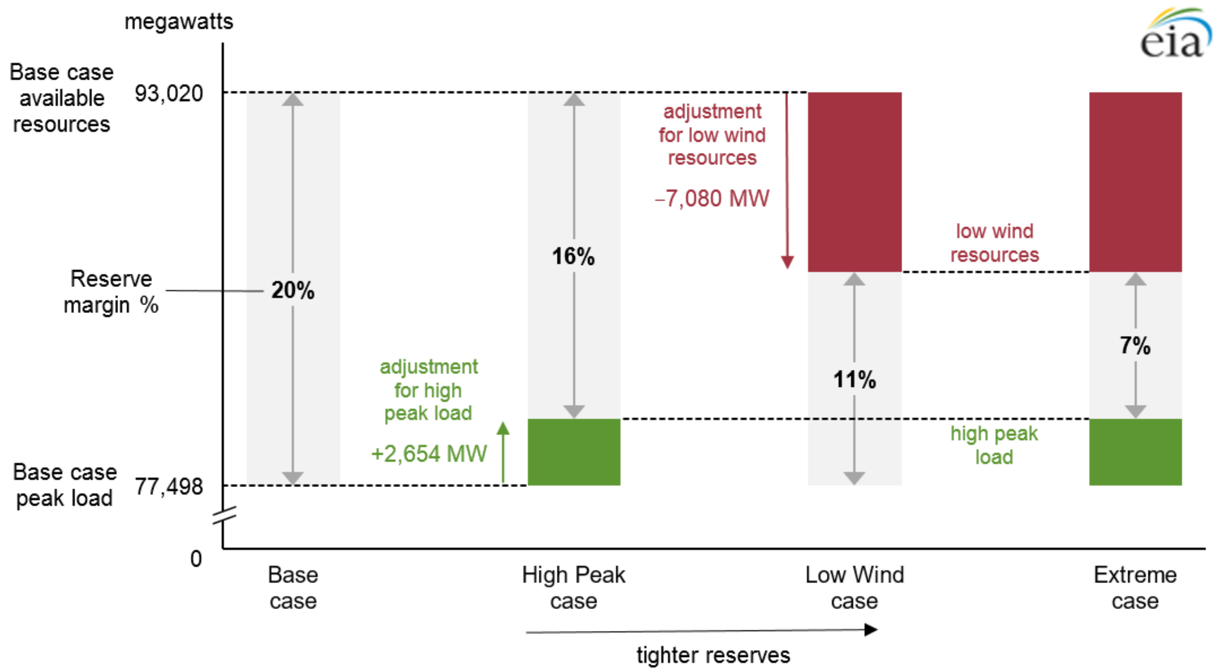
[18] ERCOT's summer 2022 SARA also examines the the potential effect of higher-than-expected unplanned outages.

[19] North American Electric Reliability Corporation, 2022 Summer Reliability Assessment, May 2022, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf, p. 36

In our Low Wind case, the assumed reduction of 7,080 MW of wind resources pushes the reserve margin down to 11%. Conversely, our assumption of high peak load that is 2,654 MW higher than in the Base case leads to a reserve margin of 16%. Combining these two effects of reduced resources and higher demand in the Extreme case results in a reserve margin of 7%.

Figure 10. Change in simulated ERCOT reserve margins under different case assumptions



Data source: U.S. Energy Information Administration, Short-Term Integrated Forecasting System simulation of the Electric Reliability Council of Texas (ERCOT) power market

4. Findings

EIA prepared several different cases that simulated ERCOT power plant operations and projected energy prices given different peak load and wind availability assumptions (Table 3).

Table 3. Comparison of case assumptions and simulated wholesale ERCOT prices

	Base	High Peak	Low Wind	Extreme
Peak load (megawatts)	77,498	80,152	77,498	80,152
Wind availability (megawatts)	10,144	10,144	3,064	3,064
Maximum wholesale price (dollars per megawatthour)	$90	$105	$709	$2,905
Energy component	$90	$105	$ 99	$ 601
Scarcity adder	—	—	$610	$2,304

Data source: U.S. Energy Information Administration, Short Term Integrated Forecasting System simulation of the Electric Reliability Council of Texas (ERCOT) power market

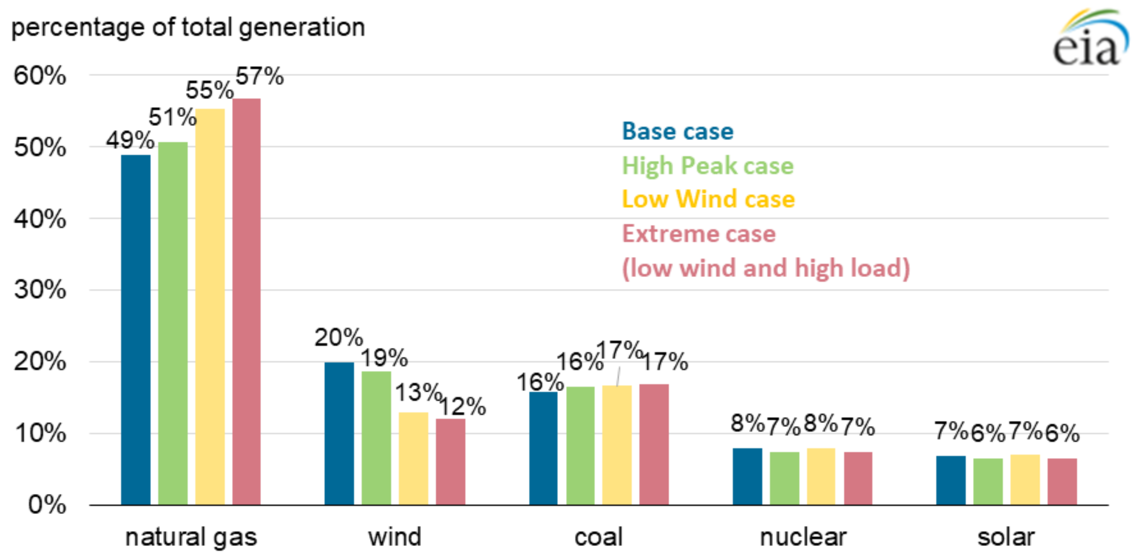
A case-by-case review of the simulation findings produced the following observations:

- The range of cases conducted demonstrate the significant effect of ERCOT's scarcity pricing program on projected electricity prices in the region
- Our analysis indicates that during most summer days, scarcity pricing does not occur, even with high electricity demand
- Instead, scarcity pricing is more likely to occur when wind resources fall short of typical levels, causing available reserves to fall
- The combination of high peak demand and low wind conditions can result in even higher scarcity adders
- Our analysis shows that low wind and high demand affect prices in locations throughout Texas differently

Although we present the findings from our analysis for the day of highest assumed load, we simulated the ERCOT market in our model for the entire first week of August to better account for the differences in generator start times. Some generators take only minutes to start, while others can take days.

The results from all of our cases show the same patterns in fuel use (Figure 11). Generation from coal, nuclear and solar are largely unchanged when electricity load increases or when wind generation falls. In addition, an increase in electricity demand or a decrease in wind generation yields more generation from natural gas. In our High Peak case, generation from natural gas-fired power plants increases by 2% over the Base case, rising from 49% to 51% on the peak-load day. In the Low Wind case, natural gas generation increases by 6% over the Base case. In the Extreme case, in which electricity demand is high and wind generation is low, natural gas accounts for 57% of peak-day generation. While batteries also contribute to meeting demand in all of the cases, their contribution is minimal.

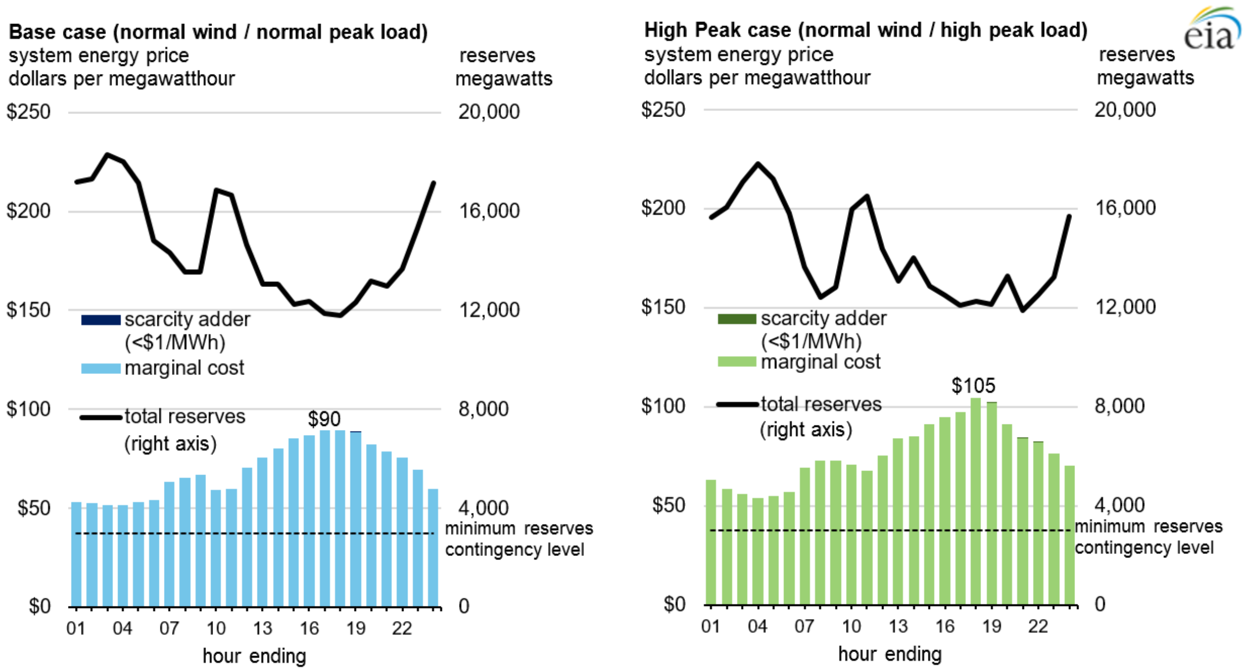
Figure 11. Simulated ERCOT peak-day generation shares



Data source: U.S. Energy Information Administration, Short Term Integrated Forecasting System simulation of the Electric Reliability Council of Texas (ERCOT) power market

The increased use of natural gas generation to meet higher loads or to replace low levels of wind generation results in higher electricity prices, specifically by raising the system energy cost component of the wholesale electricity price (Figure 12). In the Base case, the highest hourly ERCOT system energy price for the peak day is $90/MWh. With the higher electricity demand in the High Peak case, less efficient natural gas power plants increase generation to meet the high levels of electricity demand, pushing up the system energy price during the peak hour by 17% over the Base case to $105/MWh. In the Base case and High Peak case, reserve resources fall to about 12,000 MW during the peak hour. With these reserve levels, the scarcity adder to ERCOT's system energy price is less than $1/MWh.

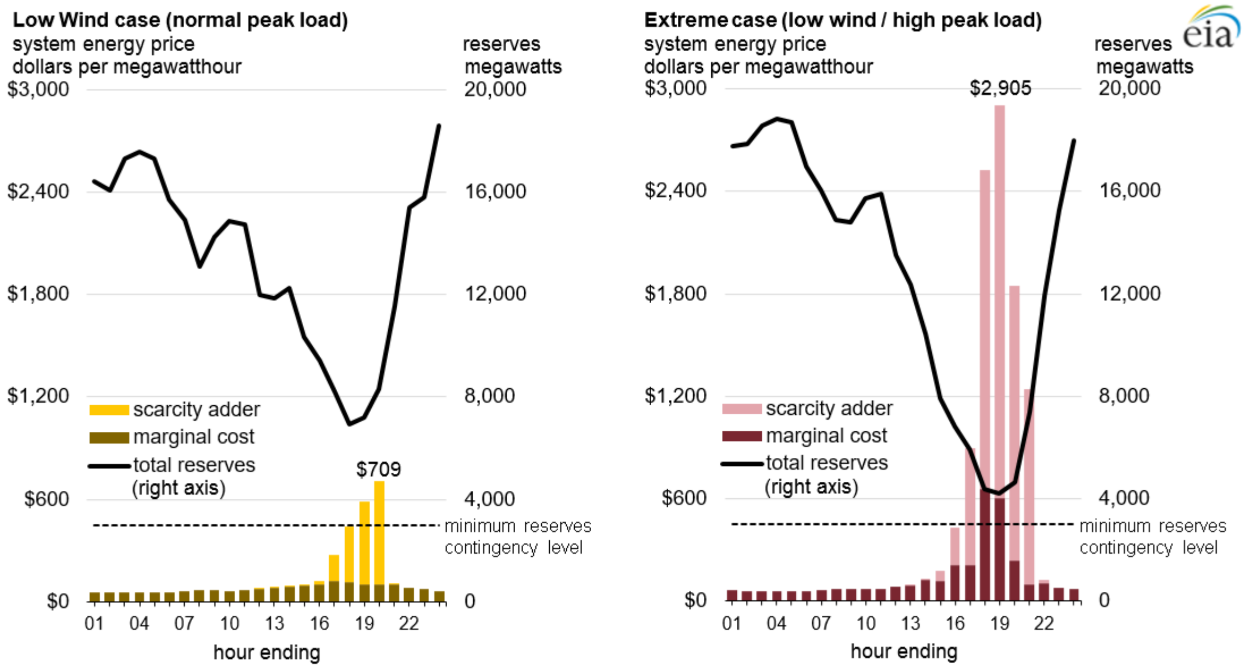
Figure 12. Simulated ERCOT electricity price & reserve capacity (Base and High Peak cases)



Data source: U.S. Energy Information Administration, Short-Term Integrated Forecasting System simulation of the Electric Reliability Council of Texas (ERCOT) power market
Notes: Simulated results are shown for day with highest peak load.

In the Low wind case, less efficient, natural gas plants also increase generation to compensate for the reduction in wind, however, with the reduced availability of wind resources, online reserves fall below 8,000 MW, triggering the scarcity pricing and energy prices climb to more than $700/MWh (Figure 13). In our Extreme case, the combination of low wind and high peak conditions further increases the use of less efficient natural gas power plants to meet high electricity demand. In addition, reserve levels fall to about 4,000 MW, and the electricity price adder reaches $2,300/MWh, accounting for 79% of the total wholesale electricity price, $2,905/MWh.

Figure 13. Simulated ERCOT electricity price & reserve capacity (Low Wind and Extreme cases)

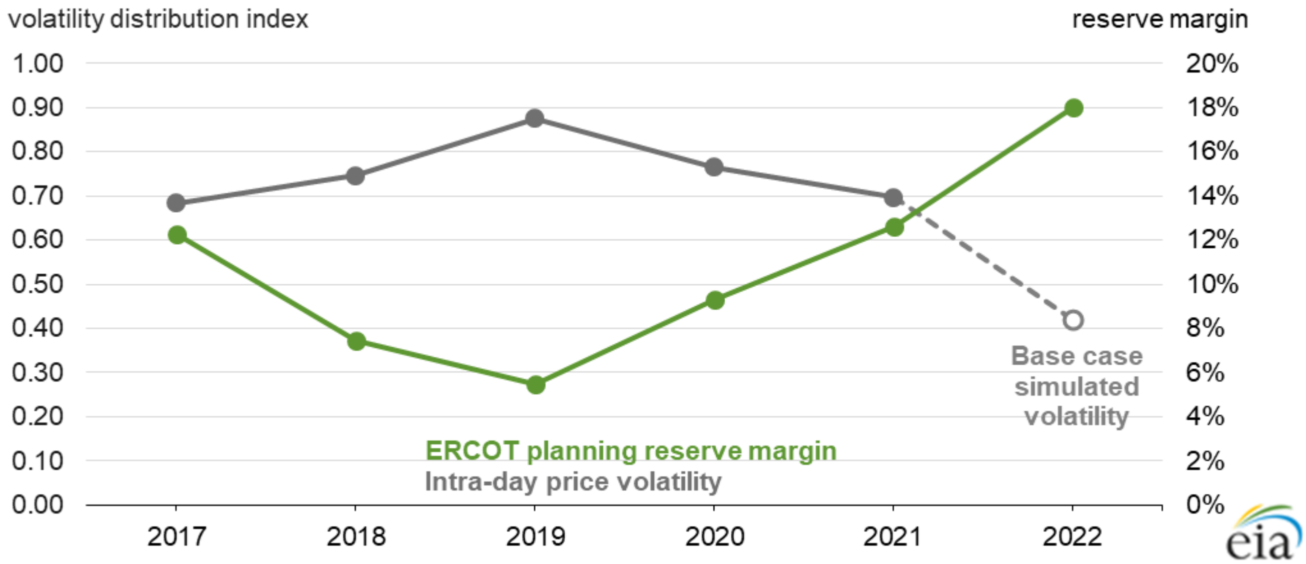


Data source: U.S. Energy Information Administration, Short-Term Integrated Forecasting System simulation of the Electric Reliability Council of Texas (ERCOT) power market
Notes: Simulated results are shown for day with highest peak load.

Our four cases indicate that under a range of plausible summer conditions for the ERCOT market, operating reserves can vary significantly over the course of the day. In the cases with low wind availability such variability in reserves can trigger the application of scarcity pricing, which can result in large increases (up to an ERCOT specified limit) in projected market prices as reserves shrink. In addition, with higher demand or low wind availability, generation costs increase as quick-starting, but less efficient natural gas power plants start up to meet the system load. So, over the course of any summer day, ERCOT prices can be expected to rise and fall significantly, leading to higher intraday volatility, depending on underlying market conditions and available reserves.

The average intraday summer price volatility in the ERCOT day-ahead market since 2017 has generally had an inverse relationship with the reserve margin that ERCOT projects in their SARA planning report at the beginning of each summer (Figure 14). That is, as expected summer reserve margins fall, intraday volatility has generally risen, and vice versa. The relatively low simulated intraday price volatility from our Base case coincides with the relatively high planning reserve margin that ERCOT published in its summer 2022 SARA report. The projected levels of intraday volatility are linked with the operating reserve margin, and any significant differences are directly attributable to the scarcity adder.

Figure 14. Intraday ERCOT price volatility vs. SARA projected reserve margin, 2017–2022



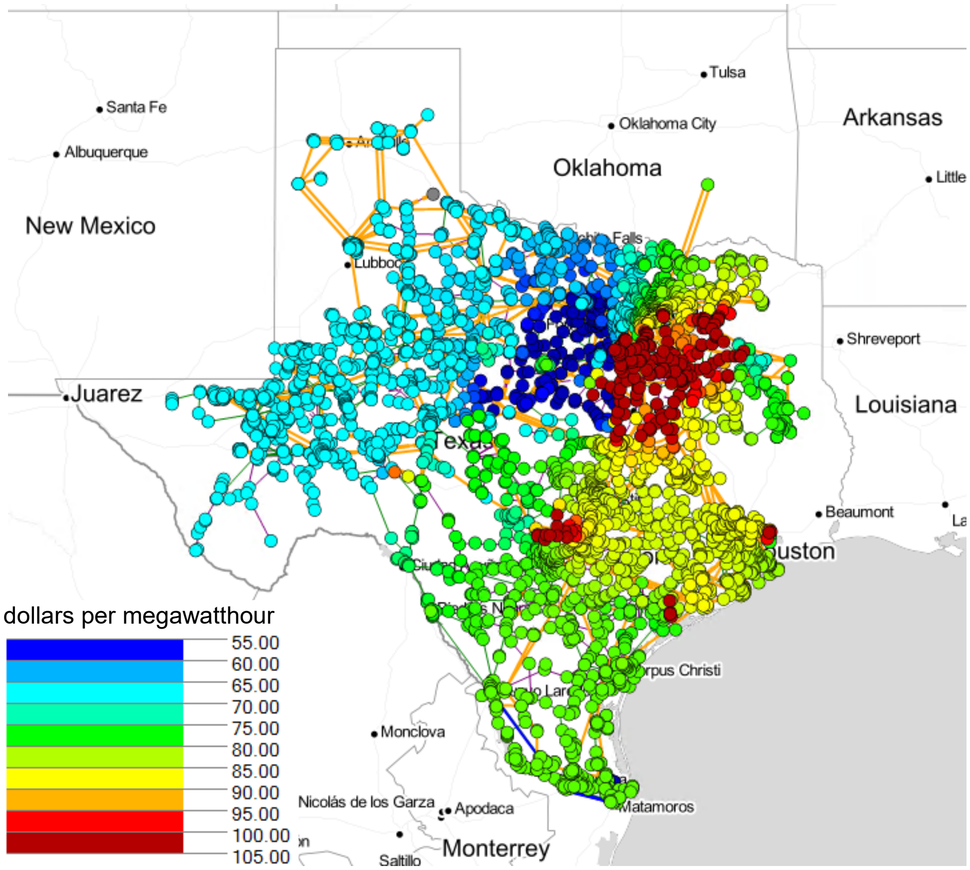
Data source: U.S. Energy Information Administration, Short-Term Integrated Forecasting System simulation of the Electric Reliability Council of Texas (ERCOT) power market
Note: The intraday price volatility index is defined as the difference between average maximum daily price per month and the minimum price per month divided by the minimum price per month.

Although the ERCOT market clears prices on a region-wide basis, the specific price paid for electricity at each location, or node, on the grid can differ depending on the loading levels on the transmission lines that connect the nodes. Under typical summer day conditions, locational prices are not significantly different than the system-wide energy price. When a transmission line reaches its maximum flow, however, the locational marginal prices (LMPs) at each node on the system can be different, and the difference is considered a congestion price. The congestion price is the difference between the simulated nodal LMPs at each node and the simulated ERCOT system energy price.

When transmission congestion occurs, the highest LMPs within ERCOT often occur at nodes in the North load zone where electricity demand is highest, especially around the Dallas-Fort Worth area. Relative LMPs are generally lower in the West load zone where there is less demand and substantial wind generating capacity. For all four of our cases, there is some level of congestion during the hour with the highest simulated system energy price, so the nodal LMPs will vary from the system energy price.

As discussed above, the ERCOT system energy price in our Base case reaches a peak of $90/MWh. The simulated load-weighted LMP in the North zone of ERCOT during that hour averages $102/MWh (Figure 15). This zone also has the largest variation of nodal prices with just as many nodes having LMPs less than $60/MWh as nodes with LMPs in excess of $100. However, most of the load in the North zone is located at the higher-priced nodes. In the West zone, the load-weighted average price is $68/MWh with more than 90% of nodes in the zone having LMPs between $60/MWh and $70/MWh.

Figure 15. Base case: Simulated peak-hour ERCOT locational marginal prices (LMP) at nodes

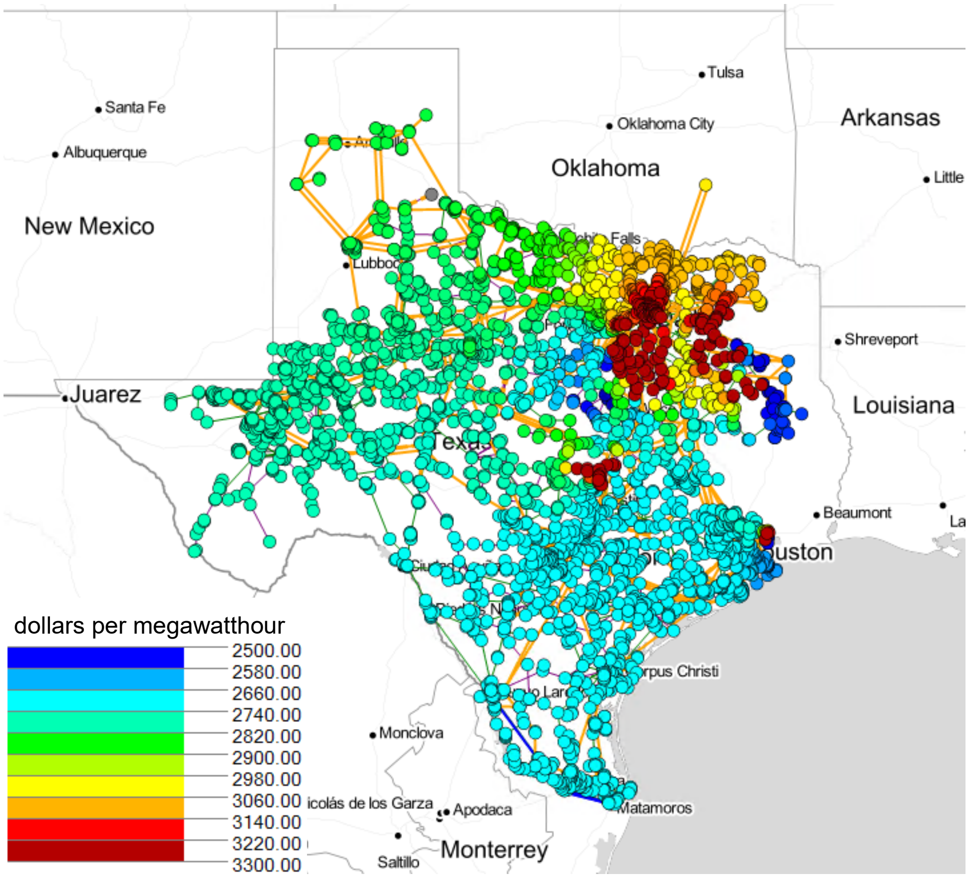


Data source: U.S. Energy Information Administration Short Term Integrated Forecasting System and LCG Consulting
Note: Prices in map are for the hour with the highest system energy price. ERCOT is the Electric Reliability Council of Texas.

The Extreme case has the highest simulated system energy price ($2,905/MWh), but also has a slightly different pattern of congestion and nodal LMPs than in the Base case (Figure 16). Congestion in the Extreme case is relatively lower than in the Base case, likely due to the lack of wind availability and the need for generating resources to supply high levels of local power demand instead of transmitting the power to more distant load centers.

Simulated prices in the Extreme case are still highest in the North load zone, with a zonal average of $3,134 and half of the node in the zone having an LMP in excess of $3,000/MWh. In contrast to the Base case, the lowest regional prices for our Extreme case occur in the Houston load zone with an average price of $2,742/MWh and nearly all nodes with an LMP less than $2,800. The average zonal price in the West zone is $2,833/MWh.

Figure 16. Extreme case: Simulated peak-hour ERCOT location marginal prices (LMP) at nodes



Data source: U.S. Energy Information Administration Short Term Integrated Forecasting System and LCG Consulting
Note: Prices in map are for the hour with the highest system energy price. ERCOT is the Electric Reliability Council of Texas.