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2021 State of the Market Report for the ERCOT Electricity Markets

POTOMAC ECONOMICS

Independent Market Monitor
for ERCOT

May 2022

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4CP	4-Coincident Peak	NOIE	Non Opt-In Entity
CAISO	California Independent System Operator	NPRR	Nodal Protocol Revision Request
CDR	Capacity, Demand, and Reserves Report	NSO	Notification of Suspension of Operations
CFE	Comisión Federal de Electricidad	NYISO	New York Independent System Operator
CONE	Cost of New Entry	OBD	Other Binding Document
CRR	Congestion Revenue Rights	ORDC	Operating Reserve Demand Curve
DAM	Day-Ahead Market	PCRR	Pre-Assigned Congestion Revenue Rights
DC Tie	Direct-Current Tie	PRC	Physical Responsive Capability
EEA	Energy Emergency Alert	PTP	Point-to-Point
ERCOT	Electric Reliability Council of Texas	PTPLO	Point-to-Point Obligation with links to an Option
ERS	Emergency Response Service	PUC	Public Utility Commission
FIP	Fuel Index Price	PURA	Public Utility Regulatory Act
GTC	Generic Transmission Constraint	QSE	Qualified Scheduling Entity
GW	Gigawatt	RDI	Residual Demand Index
HCAP	High System-Wide Offer Cap	RENA	Real-Time Revenue Neutrality Allocation
HE	Hour-ending	RDPA	Real-Time Reliability Deployment Price Adder
Hz	Hertz	RTCA	Real-Time Contingency Analysis
ISO-NE	ISO New England	RTOLCAP	Real-Time On-Line reserve capacity of all On-Line Resources
LDF	Load Distribution Factor	RUC	Reliability Unit Commitment
LDL	Low Dispatch Limit	SASM	Supplemental Ancillary Service Market
LMP	Locational Marginal Price	SCED	Security-Constrained Economic Dispatch
LOLP	Loss of Load Probability	SCR	System Change Request
LSL	Low Sustained Limit	SPP	Southwest Power Pool
MISO	Midcontinent Independent System Operator	SWOC	System-Wide Offer Cap
MMBtu	One million British Thermal Units	VMP	Voluntary Mitigation Plans
MW	Megawatt	VOLL	Value of Lost Load
MWh	Megawatt Hour		
NCGRD	Notification of Change of Generation Resource Designation		

EXECUTIVE SUMMARY

Potomac Economics provides this State of the Market Report for 2021 to the Public Utility Commission of Texas in our role as its Independent Market Monitor (IMM). This report presents our assessment of the outcomes of the wholesale electricity market in the Electric Reliability Council of Texas (ERCOT). Additionally, we recommend changes to improve the competitive performance and operation of the ERCOT markets.

ERCOT manages the production and flow of electric power to more than 26 million Texas customers – about 90% of the state's total electric demand. Every five minutes, the ERCOT markets coordinate the electricity production from more than 710 generating resources to satisfy customer demand and manage the resulting flows of power across more than 46,500 miles of transmission lines in the region. Additionally, the prices produced by the markets facilitate the long-term investment and retirements of resources in the ERCOT region. Hence, the markets' performance that we evaluate in this report is critical for maintaining reliability in Texas.

2021 was an extraordinary year for the ERCOT markets as it dealt with the effects and aftermath of Winter Storm Uri. This report includes a detailed discussion of the Winter Storm Uri event, including the lessons it provided. To isolate these effects and show the trends in other hours, we show two versions of a number of figures in this report, one for the entire year and a second one with the effects of the storm removed. In addition, we have added a new section to this report that discusses the changing grid and future needs of the market. These findings are summarized at the end of this executive summary. Key results in 2021 include the following:

Winter Storm Uri

- The defining event in ERCOT in 2021 occurred on February 13 through 19 when Winter Storm Uri hit the ERCOT region, causing widespread outages of generation, natural gas supply, and transportation equipment. These outages caused a severe supply/demand imbalance and required ERCOT to order curtailment of load to maintain the operation of the bulk electric system and prevent widespread collapse.

- Energy prices in the day-ahead market and real-time market remained at or near the offer cap for most of this time. The extended shortage pricing created extreme financial outcomes for some market participants. This was particularly true for those exposed to day-ahead or real-time prices due to insufficient coverage through financial contracts or generators unable to operate during the storm to hedge this exposure.

- The total value of electricity during this event was $59 billion.[1] Since many utilities supply some or all of their needs from owned or purchased generation, the net purchases of energy and ancillary services from ERCOT during the event was much less than that total value.

Competition and Market Power

- There is little evidence that suppliers abused market power in the wholesale market to raise system-wide prices through traditional withholding strategies.
  - However, a non-traditional withholding strategy emerged in the latter half of the year given ERCOT's increased commitment of resources through Reliability Unit Commitment (RUC) and the high RUC offer floor associated with that commitment established in the protocols.
  - This incentive issue has been subsequently addressed via a rule change proposed by the IMM and passed by the ERCOT stakeholders, the ERCOT Board of Directors, and the Public Utility Commission of Texas.[2]
- In some local areas, transmission system limitations on the amount of power that can flow into the area can increase opportunities to abuse market power. However, mitigated offer price caps in these situations effectively addressed these opportunities in 2021.

Demand for and Supply of Electricity

- The highest electricity demand in 2021 was 72,339 megawatts (MW), occurring on September 1 between 4 and 5 p.m. This was about 2,500 MW lower than the all-time peak demand set on August 12, 2019. Backcast analysis of Winter Storm Uri indicated that demand could have reached as high as 76,819 MW during the storm, had the ERCOT system been able to serve the entire demand.[3]
- Although total consumption was higher than 2020, the daily peaks were generally lower, partly because of the effects of the COVID-19 pandemic in the early part of the year.
- The supply of generation in the ERCOT region continues to evolve. Over 7,000 MW of new wind and solar resources, 820 MW of energy storage resources (ESRs), and approximately 700 MW of natural gas supply came online in 2021.
- Approximately 172 MW of wind and natural gas resources retired in 2021.

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1 We previously quantified the impact as $56 billion for February 14-19. In this report we also include February 13, which brings the total to $59 billion.

2 NPRR1092: *Reduce RUC Offer Floor and Limit RUC Opt-Out Provision.*

3 https://www.ercot.com/files/docs/2021/03/03/Texas_Legislature_Hearings_2-25-2021.pdf

Market Outcomes and Performance

- Average energy prices increased by more than six times to $167.88 per megawatt-hour (MWh). This change was primarily due to the extreme supply shortages and resulting prices during Winter Storm Uri, and to a lesser extent due to higher average natural gas prices during the balance of the year.
- Transmission congestion in the real-time market was up 46% in 2021, totaling $2.1 billion. More than $560 million of this was generated during Winter Storm Uri.
  - Electric transmission networks become congested when power flows reach the limit on a transmission line. To resolve the congestion, costs are incurred to alter generation in different locations.
- ERCOT is increasingly limiting the flows across certain network paths to maintain the stability of the system, which increases transmission congestion costs. These stability issues have partly been caused by the increase in inverter-based resources. The congestion rent associated with these stability constraints increased from $190 million in 2020 to $400 million in 2021, roughly 20 percent of all real-time congestion costs.
- ERCOT changed its operational posture in July 2021 by increasing reserves, which substantially affected market outcomes in the second half of the year. This change included:
  - Increased non-spinning reserve requirements;
  - More routine use of RUC, including issuing instructions earlier in the day and committing more longer-lead time resources; and
  - Adjusting the selection of forecasts to more frequently rely on the highest load forecast and the lowest wind and solar forecasts.

Planned Changes to Improve Market Performance

- The most important market change underway is ERCOT's improvement of its real-time market to optimize the scheduling of its resources each five minutes for providing energy and operating reserves, also known as "real-time co-optimization" or RTC.
  - This was planned to go live in 2025. Due to significant issues identified following Winter Storm Uri, ERCOT has postponed the RTC project.
  - RTC should be prioritized given its promise to improve pricing during supply shortages and better utilize the existing generation fleet.
- ERCOT continues to plan for the integration of emerging technologies, such as ESRs and distributed generation resources (DGRs).

Below are more detailed summaries of each of the key findings of this report.

Winter Storm Uri

In February 2021, the ERCOT grid experienced unprecedented disruptions in electricity and natural gas service during Winter Storm Uri, resulting in widespread prolonged outages throughout the ERCOT region. The storm produced unusually low temperatures across the state, which were sustained over many days. Taken together, these conditions were much more severe than typical peak winter conditions.

The Dallas-Ft. Worth (DFW) area experienced 140 consecutive hours at or below freezing, with a minimum temperature of -2° F. This is 15° F colder than in the winter event in 2011 and was sustained for 39 more hours.[4] In the Austin area, these extremes were even more pronounced, with nearly 100 more hours at or below freezing temperatures compared to 2011.

Beginning on February 12, 2021, a Declaration of a State of Disaster for all counties in Texas was issued pursuant to Texas Government Code § 418.014 in response to the extreme winter weather event. These extraordinary conditions simultaneously: a) increased electric demand significantly above forecasted peak winter demand and b) reduced the available generation because of forced outages and fuel shortages. The simultaneous sharp increase in the demand and large reduction in supply produced a large supply-demand imbalance that resulted in sustained demand outages. These conditions emerged in the early morning hours of February 15, 2021 when ERCOT declared its highest state of emergency, Energy Emergency Alert Level 3 (EEA3), as the exceptional electric demand exceeded the available supply. To stabilize the rapidly deteriorating grid conditions, ERCOT ordered transmission companies to reduce demand on the system by implementing outages for customers (also termed "load shed"). These outages are designed to rotate to reduce the impact to customers, but transmission companies were unable to rotate in many cases because of the depth of the load shed. ERCOT remained in EEA3 through mid-morning February 19, 2021.

At the height of the storm, more than 52 gigawatts (GW) of generation resources in the ERCOT region were unavailable. The majority of those outages were caused by equipment failure, fuel shortages, or other weather-related issues related to the storm. ERCOT also experienced a number of transmission issues during Winter Storm Uri that impacted grid operations. Unfortunately, the load shedding caused some natural gas facilities to lose power (facilities that were facing their own weather-related issues), reducing their ability to deliver gas to natural gas-fired generators, and exacerbating the supply shortage.

We did not find any evidence of ERCOT market participants exercising market power during the event. However, as we reported in last year's State of the Market[5], the energy and ancillary

4 https://comptroller.texas.gov/economy/fiscal-notes/2021/oct/winter-storm-impact.php

5 https://www.potomaceconomics.com/wp-content/uploads/2021/06/2020-ERCOT-State-of-the-Market-Report.pdf

services markets both produced outcomes that were inefficient. These issues were resolved on a going-forward basis after the storm.

Real-time Energy Pricing Outcomes

Real-time prices during shortage conditions is critical important, particularly in ERCOT's energy-only market, because it provides the economic signals necessary for generators to be available. When supply shortages prevent ERCOT from serving the load, prices should reflect the "value of lost load" (VOLL) of $9,000 per MWh, which is also the system-wide offer cap. However, despite firm load shed at the outset of Winter Storm Uri, energy prices cleared at less than $9,000 per MWh and dipped as low as approximately $1,200 per MWh on February 16, 2021. These prices were caused by prevailing pricing rules that did not account for the firm load shed, although they account for other out-of-market actions by operators.[6] In response, the Commission directed ERCOT to account to modify the pricing rules to address this issue, which corrected the pricing after February 16.[7]

It is equally important that prices not reflect VOLL when the system is not in shortage. Transmission operators received the recall of the last of the firm load shed instructions just before midnight on February 17, but prices were held at the VOLL of $9,000 per MWh through mid-morning on February 19. This increased the valuation of energy during the event substantially, but increased settlement costs to loads by much less because of load-serving entities' owned generation and supply purchases.

Finally, the system includes a form of "circuit breaker" for extended periods of high prices called the peaker net margin (PNM) threshold, which was exceeded during February 16, 2021, for the first time in ERCOT's history. The PNM is the estimated revenues a new peaking resources would earn above its marginal operating costs. When these estimated revenues exceed the established threshold of three times the annual cost building a new peaking unit (a.k.a., the "Cost of New Entry" or CONE), the system-wide offer cap is reduced from the initial high system-wide offer cap (HCAP or $9,000 per MWh) to the low system-wide offer (LCAP) for the remainder of the calendar year. In February 2021, the LCAP was defined as the greater of either $2,000 per MWh or 50 times the natural gas price (also known as the fuel index price or FIP).

Natural gas index prices reached values over $400 per MMBtu during the load shed event, compared to around $3 per MMBtu on average during previous years. As a result, the LCAP (50 times FIP, or up to $20,000) exceeded the HCAP of $9,000. Therefore, the Commission

6 These out-of-market-actions include ERCOT issuing RUC instructions or deploying ERS.

7 See *Calendar Year 2021 - Open Meeting Agenda Items without an Associated Control*, Project No. 51617, Second Order Directing ERCOT to take Action and Granting Exception to Commission Rules at 1-2 (Feb. 16, 2021).

suspended use of the LCAP[8] to avoid an outcome contrary to the purpose of the rule – to protect consumers from sustained high prices. Suspension of LCAP occurred on March 3, 2021.[9]

The Commission addressed real-time energy pricing issues following Winter Storm Uri. In PUC Project No. 51871, *Review of the ERCOT Scarcity Pricing Mechanism,* the Commission deleted the provision that tied the LCAP to natural gas prices. The revised rule makes resources whole to their actual marginal costs when the LCAP is in effect. In PUC Project No. 52631, *Review of 25.505*, the Commission lowered the HCAP to $5,000 per MWh effective January 1, 2022.

Ancillary Services Pricing Outcomes

During the February 2021 Winter Storm Uri, ancillary service market clearing prices for capacity (MCPCs) reached record highs, well above the system-wide offer cap in effect at the time due to the design of the day-ahead market (DAM) clearing algorithm, which considered resources' opportunity cost of providing other services. Those opportunity costs were higher than had previously been encountered. Additionally, the ancillary service penalty factors for not awarding ancillary services, the assumed cost of being short of ancillary services, were set at levels arbitrarily higher than the system-wide offer cap. This was significant because ancillary service offers were frequently insufficient during Winter Storm Uri. Therefore, the DAM algorithm set MCPCs in excess of $25,000 per MW, far above the VOLL and HCAP of $9,000 per MWh. Because ancillary services are procured to *reduce* the probability of shedding load, it is not economically reasonable to value them in excess of VOLL. This issue overvalued ancillary services by close to $2 billion and affected participants' net settlements by roughly $900 million after accounting for utilities' owned and purchased generation.

ERCOT and the IMM subsequently cosponsored NPRR1080, *Limiting Ancillary Service Price to System-Wide Offer Cap* and the accompanying Other Binding Document Revision Request (OBDRR030): *Related to NPRR1080, Limiting Ancillary Service Price to System-Wide Offer Cap*, both approved in June 2021, to limit ancillary service MCPCs to the system-wide offer cap. This limitation was implemented by reducing the penalty factors to values equal to or immediately below the system-wide offer cap. This will prevent MCPCs from exceeding the system-wide offer cap, consistent with sound economic principles.

In addition to extraordinarily high ancillary services prices, there were a number of instances during Winter Storm Uri when ancillary services were not provided by individual resources in real time because of forced outages or deratings. During normal conditions, an ERCOT operator typically notes the short amount so that the day-ahead ancillary service payment will be recouped

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8 *See Calendar Year 2021 - Open Meeting Agenda Items without an Associated Control, Project No. 51617, Second Order Directing ERCOT to take Action and Granting Exception to Commission Rules at 2 (Feb. 16, 2021).*

9 *Issues Related to the State of Disaster for the February 202 1 Winter Weather Event*, Project No. 51812, Order Reinstating Low System-Wide Offer Cap at 1-2 (Mar. 3, 2021).

the entity in settlement. However, the ERCOT operators did not complete this task during the winter event. Therefore the "failure to provide" settlements were not invoked in real time and short entities were able to keep their day-ahead payments.[10]

In response to a recommendation by the IMM,[11] the Commission directed ERCOT to resettle each entity that failed on its ancillary service supply responsibility in accordance with ERCOT Nodal Protocol section 6.4.9.1.3 for any hour of ERCOT's operating days February 14, 2021, through February 19, 2021.[12] Invoking the "failure to provide" settlement for these ancillary services ensured that market participants were not paid for services that they did not provide during Winter Storm Uri.

Moving Forward from Winter Storm Uri

The sustained shortage pricing led to billions of dollars in excess costs and numerous defaults that ERCOT and that the State of Texas will continue to grapple with for years to come. ERCOT short payments (money owed by entities that was not paid to ERCOT) during Winter Storm Uri exceeded $3 billion. Several retail electric providers were forced to exit the market and one large electric cooperative is seeking bankruptcy protection. The financial stress on the ERCOT market led to significant intervention by the Texas Legislature and the Commission discussed below, which together authorized and implemented broad securitization and financing measures to stabilize the wholesale market.[13]

Competition and Market Power

We evaluate market power from two perspectives: structural (does market power exist?) and behavioral (have attempts been made to exercise it?). Based on our analysis, we find that structural market power continues to exist in ERCOT, but there is no evidence that suppliers abused market power in 2021 based on traditional withholding strategies. However, we identified a specific withholding strategy related to ERCOT's new operational posture and filed a protocol change to address it.

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10 Removing the operator intervention step and automating the "failure to provide" settlement was contemplated in NPRR947, *Clarification to Ancillary Service Supply Responsibility Definition and Improvements to Determining and Charging for Ancillary Service Failed Quantities*; however, the NPRR was withdrawn in August 2020 because of the system cost, some complexities related to ancillary service trades, and the impending implementation of RTC.

11 *Issues Related to the State of Disaster for the February 202 1 Winter Weather Event*, Project No. 51812, Potomac Economics' Letter to Commissioners at 1 (Mar. 1, 2021).

12 *Id.*, Second Order Addressing Ancillary Services at 2 (Mar. 12, 2021).

13 See SB 2, SB 3, SB 2154, SB 1580, HB 4492, *Application of the Electric Reliability Council of Texas, Inc. for a Debt Obligation Order under PURA Chapter 39, Subchapter M, and Request for a Good Cause Exception,* Docket No. 52321 (Oct. 13, 2021), and *Application of the Electric Reliability Council of Texas, Inc. for a Debt Obligation Order to Finance Uplift Balances under PURA Chapter 39, Subchapter N, and for a Good Cause Exception,* Docket No. 52322 (Oct. 13, 2021).

Structural Market Power

In electricity markets, a more effective indicator of potential market power than traditional market concentration metrics is to analyze when a supplier is "pivotal." A supplier is pivotal when its resources are needed to fully satisfy customer demand or reduce flows over a transmission line to manage congestion. The results below indicate that market power continues to exist in ERCOT and requires mitigation measures to address it. Over the entire ERCOT region:

- Pivotal suppliers existed 18% of all hours in 2021, compared to 22% in 2020.
- Under high-load conditions, a supplier was pivotal in more than 70% of the hours, since competing supply is more likely to already have been fully utilized.

Market power can also be a much greater concern in local areas when power flows over the network cause transmission congestion that isolate these areas. Market rules cap prices that suppliers can offer in these cases, mitigating suppliers' ability to abuse market power.

Behavioral Evaluation

In addition to the structural analysis of market power, we evaluate behavior to assess whether suppliers engaged in behavior to withhold supply in order to increase prices. Economic withholding occurs when a supplier raises its offer prices to levels well above the expected marginal cost to produce electricity. This has the effect of withholding energy from the market that otherwise would have been economic to produce. Physical withholding occurs when a supplier makes a resource unavailable. Either of these strategies will result in the suppliers' other resources receiving a higher price because of the artificially decreased supply.

We examine the output gap metric to identify potential economic withholding. The output gap is the quantity of energy that is not produced by online resources even though the output would earn the supplier profits. Our analysis shows that in 2021, the output gap quantities remained very small, and only 22% of the hours in 2021 exhibited an output gap of any magnitude.

Regarding potential physical withholding, we find that both large and small market participants made more capacity available on average during periods of high demand in 2021 by minimizing planned outages and maximizing the generation offered from each resource. These results allow us to conclude that the ERCOT market performed competitively in 2021.

However, during the second half of 2021, we noted that self-commitment of a particular large supplier lagged previous trends, and we concluded that this was likely due to ERCOT's increased use of RUC and the high offer floor resulting from those actions. A market rule revision was proposed and passed by the ERCOT stakeholders to address this issue.[14]

Demand for and Supply of Electricity

Changes in the demand for and supply of electricity account for many of the trends in market outcomes. Therefore, we evaluate these changes to assess the market's performance.

Demand in 2021

Total demand for electricity in 2021 increased by roughly 3% from 2020 – an increase of approximately 1,300 MW per hour on average as the effects of the pandemic dissipated and the Texas economy continued to grow. The Houston area saw a 3.5% increase and the West Texas region showed an increase of 7.2% on average. The increase in the West zone is notable because it follows a 3% increase in 2020. In recent years, oil and natural gas production activity has been the driver for growing demand in the West zone, which slowed somewhat in 2020 because of the effects of the pandemic and low oil prices.

Weather impacts on demand were mixed across all zones. We measure the impact weather has on electricity use by quantifying heating and cooling degree days – the amount by which the average daily temperatures are above or below 65° F. Residential and commercial electricity use increases quickly as the number of cooling degree days grows because of the demand for air conditioning. In June, July and August, cooling degree days decreased 3%, 7% and 11% from 2020 in Houston, Dallas and Austin, respectively.

Peak hourly demand occurred on August 24, 2021, at 73,687 MW, lower than the record demand of 74,820 MW set in 2019.[15] The level of peak demand is important because it can affect the probability and frequency of supply shortage conditions. However, in recent years, peak *net* load (demand minus renewable resource output) has been a more important determinant of supply shortages. Supply shortage events are important in ERCOT because the very high prices during these events play a key role in supporting investment and maintaining the generation in ERCOT.

Supply in 2021

Approximately 8,800 MW of new generation resources came online in 2021, the bulk of which were intermittent renewable resources. The remaining capacity was:

[14] NPRR1092, *Reduce RUC Offer Floor and Limit RUC Opt-Out Provision*, was filed by the IMM and approved by the Board on April 27, 2022. As of May 13, 2022, the RUC offer floor was reduced to $250 per MWh but the RUC opt-out provision will become more limited in its applicability once ERCOT completes system implementation.

[15] https://www.ercot.com/files/docs/2021/11/09/DemandandEnergy2021.xlsx

- 660 MW from combustion turbines;
- 70 MW from combined cycle; and
- 820 MW of ESRs.

ERCOT had roughly 1,800 MW of new installed wind capacity and 2,500 MW of new installed solar capacity going into summer 2021 compared to summer 2020, with an effective peak serving capacity totaling 2,400 MW. Sixteen gas-fired projects, 36 wind projects and 26 solar projects came online in 2021. The 24 storage projects that came online in 2021 increased ERCOT's storage capacity by a factor of five to around 1 GW. There were 172 MW of retirements in 2021 – 150 MW wind and 22 MW gas.

These resource changes along with changes in fuel prices led to the following changes in electricity production in 2021:

- The percentage of total generation supplied by wind resources continued to increase to more than 24% of all annual generation.
- The share of generation from coal was slightly higher than in 2021, likely because rising gas prices made coal more economic than it was in 2020.
- Natural gas generation decreased in 2021 from 46% in 2020 to less than 42% in 2021 as natural gas prices rose sharply.
- The amount of utility-scale solar capacity added in 2021 (3,600 MW by the end of the year) was the largest amount of solar added to the ERCOT system in any year so far, bringing total installed capacity to nearly 9,600 MW.

One of the primary functions of the wholesale electricity market is to provide economic signals that will facilitate the investment needed to maintain an adequate set of resources to satisfy the system's needs. Although prices in 2021 did produce revenues sufficient to support profitable investment in new conventional resources, this was primarily due to Winter Storm Uri. These revenues are not likely to be expected in future years.

As described in more detail in the Future Needs of the ERCOT Market section, ERCOT adopted a more conservative posture with regard to operating the grid in July 2021. ERCOT began requiring additional operational reserves and bringing additional generation online outside of the market.[16] With this more conservative posture in ERCOT's operations and the significant market design changes being contemplated and implemented, we expect significant changes in the economic signals provided by the ERCOT markets. Therefore, it will be crucial to closely observe and evaluate the market outcomes in 2022 and beyond since these changes have implications for adequacy of ERCOT's resources in the long-term.

[16] https://www.ercot.com/news/release?id=5fef298c-fbd7-34d3-39ee-d3fc63e568c2

ERCOT heads into the summer months of 2022 with a calculated reserve margin of 23.9%, notably higher than the 15.5% reserve margin for 2021, 12.6% for 2020 and the 8.6% reserve margin from 2019. Most of the increase is due to new solar and wind resources, which is a trend expected to continue in the coming years.

Review of Market Outcomes and Performance

ERCOT operates electricity markets in real-time for energy (electricity output) and in the day-ahead timeframe for both energy and ancillary services (mainly operating reserves that can produce energy in a short period of time). We discuss the prices and outcomes in each of these markets below.

Real-Time Energy Prices

Real-time energy prices are critical in ERCOT even though only a small share of the power is actually transacted in the real-time market (i.e., far more is transacted in the DAM or bilaterally). This is because real-time prices are the principal driver of prices in the DAM and forward markets.

There are two primary drivers for market prices: the price of natural gas and the number of hours of supply shortages during the year. We expect electricity prices to be correlated with natural gas prices in a well-functioning market because fuel costs represent the majority of most suppliers' marginal production costs and natural gas units are generally on the margin in ERCOT.

In 2021, the average natural gas price was higher than any recent year. Combined with the extreme winter event, rising natural gas prices caused real-time energy prices to average just under $170 per MWh. Removing the period of Winter Storm Uri reveals an average real-time energy price of about $41 per MWh, which is consistent with the natural gas prices that prevailed in 2021. The following table shows the trend in prices throughout ERCOT in recent years.

Average Annual Real-Time Energy Market Prices by Zone

($/MWh)	2014	2015	2016	2017	2018	2019	2020	2021	2021 w/o Uri
ERCOT	**$40.64**	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**	**$167.88**	**$40.73**
Houston	$39.60	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54	$129.24	$42.78
North	$40.05	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97	$206.39	$41.57
South	$41.52	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63	$187.47	$39.98
West	$43.58	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58	$105.27	$35.51
($/MMBtu)									
Natural Gas	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99	$7.30	$3.62

This table shows that prices vary across the ERCOT market because of transmission congestion that arises as power is delivered across the network to consumers in different locations. The pattern of zonal pricing in 2021 differed from the last few of years, with the Houston and West zones experienced the lowest load-weighted prices because of lower load levels during Winter Storm Uri. When the effect of Winter Storm Uri is removed, the West zone has the lowest prices because of: 1) the completion of certain transmission projects in the West zone that had caused high prices in previous years; and 2) the large amount of local wind and solar generation that frequently causes export constraints to bind out of the zone.

As an energy-only market, ERCOT relies heavily on high real-time prices during shortage conditions to provide key economic signals for the development of new resources and retention of existing resources. Supply shortages are priced based on the value of operating reserves that ERCOT can no longer hold because of the limited supply. This value is embodied in the Operating Reserve Demand Curve (ORDC). When the system is in shortage, the relevant ORDC value will set operating reserve prices and be included in the energy price. The frequency and impacts of shortage pricing can vary substantially from year-to-year. For example, the extreme weather event in February 2021 led to prices greater than $1,000 per MWh in 166 hours in 2021 compared to only 7 hours in 2020. Additionally, in 2021 prices at or near the system-wide offer cap of $9,000 in intervals totaling roughly 98 hours.[17]

In reviewing the shortage pricing in ERCOT, it is important to note changes directed by the Commission in recent years. In 2019 and 2020, the Commission adjusted the ORDC curve to accelerate the shortage pricing toward the VOLL (normally $9,000 per MWh) at higher reserves levels. These 2019 and 2020 changes increased costs to load but also provided incentives to maintain higher operating and planning reserves. These changes were in place throughout 2021, including during Winter Storm Uri.

In the aftermath of Winter Storm Uri, the Commission made additional changes to the ORDC. Effective January 1, 2022, the Minimum Contingency Level (MCL) was increased to 3,000 MW and the HCAP and VOLL were reduced from $9,000 per MWh to $5,000 per MWh.[18] These changes will cause prices to rise more quickly at small shortage levels, but plateau at a lower

[17] See *Review of the ERCOT Scarcity Pricing Mechanism,* Project No. 51871, (Jun. 24, 2021), when the Commission directed the elimination of the provision that tied the value of the LCAP to the natural gas price index and replaced it with a provision that ensures resource entities are able to recover their actual marginal costs when the LCAP is in effect; and *Review of 25.505,* Project No. 52631, (Dec. 2, 2021), which set the high system-wide offer cap at $5,000 per MWh effective January 1, 2022.

[18] After a series of public work sessions and review of volumes of comments filed by market participant, the Commission directed ERCOT to address short- and long-term electric grid reliability concerns by enacting major reforms (see *Review of Wholesale Electric Market Design,* Project No. 52373 (pending)), at the December 16, 2021, open meeting. Specifically, the Commission approved the blueprint for the design of the wholesale electric market filed in the Project on December 6, 2021, including the ORDC changes.

maximum price in deeper reserve shortages.[19] The effect of those changes will be examined in next year's report.

Day-Ahead and Ancillary Services Markets

The DAM facilitates financial transactions to purchase or sell energy for delivery the next day. These transactions do not result in physical obligations, rather, they allow participants to manage the risks related to real-time prices and market outcomes. Day-ahead prices averaged $157 per MWh in 2021. This price closely aligns with prices from the real-time market, but does not reflect the risk premium exhibited in other years with tight conditions, such as 2019.

Ancillary services include operating reserves that are purchased on behalf of consumers to provide resources that can produce electricity quickly (or voluntarily reduce consumption) when needed. Awards for these products obligate the suppliers to physical supply them in real time. These operating reserves help ensure that ERCOT can continue to satisfy consumers' demand when unexpected things happen, such as the loss of a large generator or transmission line. Prices for ancillary services typically mirror the rise and fall of real-time energy prices because ancillary services prices include the profits a supplier forgoes by selling ancillary services rather than energy. Ancillary services costs rose sharply from $1 per MWh of load in 2020 to nearly $30 per MWh to 2021. This increase was due to the high ancillary services costs during Winter Storm Uri and the increase in procurement quantities in the latter half of 2021.

Transmission Congestion

Congestion arises when more power is flowing over a transmission line than it is designed to carry. Power flows over the network are almost entirely the result of where power is produced and consumed. When a transmission line is becoming overloaded, ERCOT will incur costs to shift generation to higher-cost generators in other locations to reduce the power flows over the transmission line. Hence, congestion prevents load from being served with the lowest-cost generators.

When transmission congestion occurs, the differences in costs of delivering electricity to different locations will be reflected in the energy prices at each location or "node" on the network. These differences in nodal prices provide efficient economic signals for generators and consumers to produce and consume electricity at different locations.

The congestion costs collected by ERCOT are based on these differences in locational prices; these costs equal the difference between the payments by loads at their locations and the

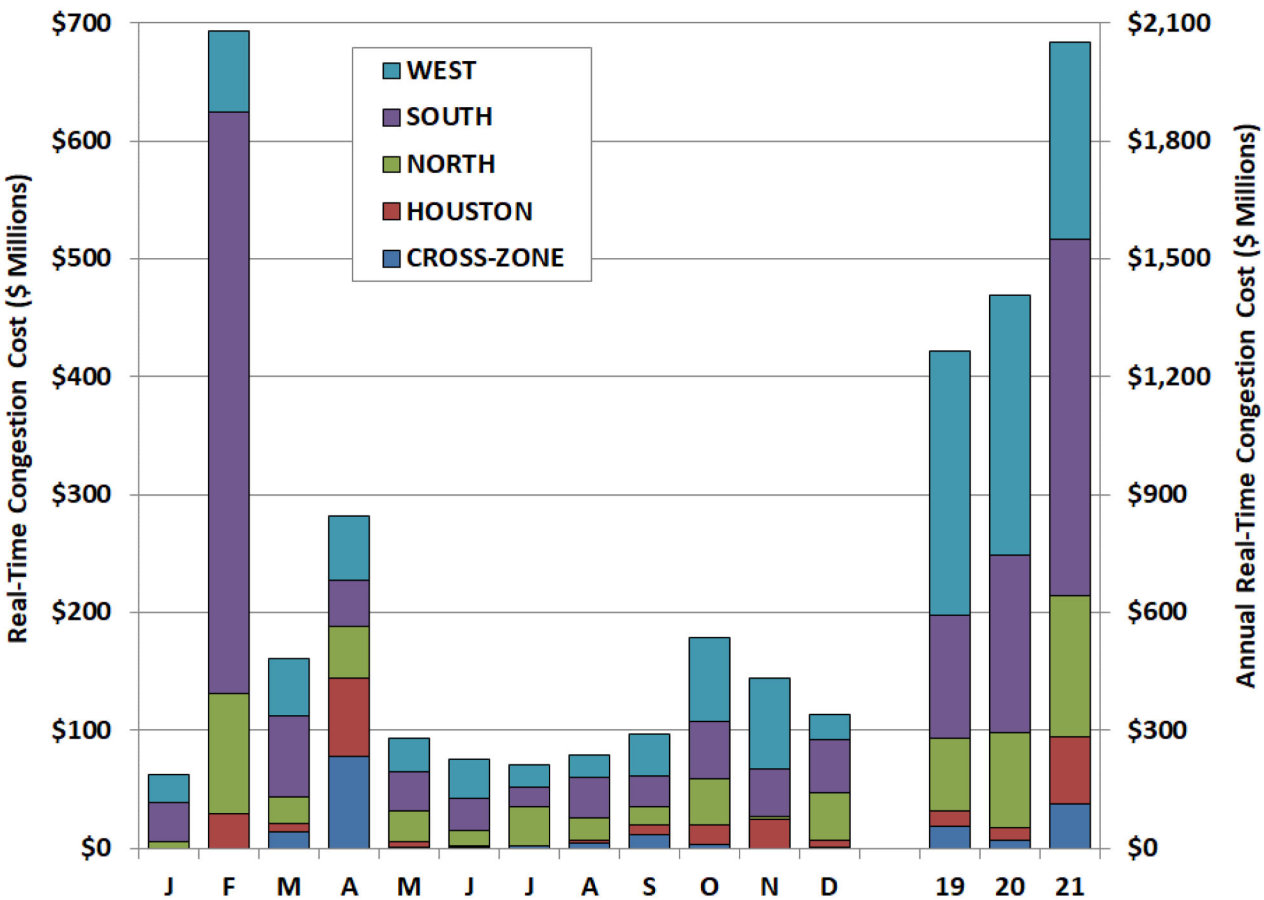
[19] Subsequently, the Commission de-coupled VOLL from the system-wide offer cap in Project No. 53191, although the VOLL remains at $5,000 per MWh for the time being.

payments to generators at their locations. These costs accrue to those that hold the rights to the transmission system known as Congestion Revenue Rights (CRRs), which are discussed below.

Real-Time Congestion Costs. To show the trends and fluctuations in congestion costs, the figure below shows real-time congestion costs by month and region for 2021 and a comparison with the annual costs in 2019 and 2020. The congestion costs in ERCOT's real-time market in 2021 were $2.1 billion, up 46% from 2020. This increase is largely attributable to high levels of congestion during Winter Storm Uri which accounted for almost one third of all of the congestion costs in 2021. Higher natural gas prices and generic transmission constraints (GTCs) also contributed to the increase. Congestion costs are correlated with natural gas prices because higher gas prices tend to increase the costs of the generators that are moved to manage transmission congestion and serve customers in congested areas.

The figure below shows that the South zone experienced the highest congestion costs in 2021, which is a departure from prior years. This is primarily attributable to congestion experienced in February during to Winter Storm Uri when roughly 70% of the congestion occurred in the South zone. The West zone exhibited the second highest congestion as result of high renewable output that is limited by GTCs.

Real-Time Transmission Congestion Costs in 2021



Day-Ahead Congestion Costs. Participants' expectation of this real-time congestion is also reflected in ERCOT's DAM prices and outcomes. The transmission congestion priced in the DAM totaled $1.4 billion. Although this is 5% higher than 2020, it is significantly lower than the real-time congestion costs. This indicates that some of the congestion was not well predicted by the DAM, which was particular true of the volatile congestion that occurred during Winter Storm Uri.

Congestion Revenue Rights. Participants can hedge congestion costs in the DAM by purchasing Congestion Revenue Rights (CRRs). CRRs are economic property rights that entitle the holder to the day-ahead congestion revenues between two locations on the network. They are auctioned by ERCOT in monthly and time-of-use blocks as much as three years in advance. The revenues collected through the CRR auction are given to load-serving entities to reduce the costs of paying for the transmission system. CRR auction revenues have risen steadily as transmission congestion has grown, totaling $832 million in 2021.

CRR auction revenues were less than the total congestion costs in 2021 mainly because the auction prices were less the CRRs were ultimately worth. This indicates that not all of the congestion was foreseen by the market. Much of this unexpected congestion occurred during the highly unusual conditions in February 2021. Other factors that contribute to the lower CRR auction revenues include the fact that 10% of the network capability is not sold in the auctions.

Generic Transmission Constraints. Finally, ERCOT operators increasingly need to use GTCs to limit the flow of electricity over certain portions of the transmission network. This has been necessary to address concerns regarding the stability of the transmission system in those areas. These concerns have arisen in large part due to the increased output from inverter-based generation resources such as wind, solar, and batteries that do not provide the same voltage support to the system as conventional resources. Ultimately, these GTCs increase transmission congestion and increase the total costs of serving customers in ERCOT by preventing low-cost power to be exported from these resources.

Market Improvements Underway

Real-Time Co-Optimization. The most important improvement to the ERCOT markets over the long term will be the implementation of changes to the real-time market to allow it to jointly optimize the scheduling of resources to provide energy and ancillary services in each dispatch interval (also termed real-time co-optimization or "RTC"). This Commission-approved project was delayed in 2021 and is now on hold until at least mid-2023 due to resource constraints caused by the market reform efforts described below.[20] Implementation of RTC will significantly improve the real-time coordination of ERCOT's generation and load resources,

[20] ERCOT RTC Update to TAC, January 31, 2022.

reduce overall production costs, and improve shortage pricing. These improvements will be key to helping efficiently transition to a future with a different resource mix as additional wind, solar, and storage resources enter the ERCOT market. We encourage continued focus on this important market improvement.

Market Reforms After Winter Storm Uri. The results of Winter Storm Uri raised significant concerns among policymakers in Texas and initiated a process to consider reforms to address the concerns. After a series of public work sessions and volumes of comments filed by market participants, the Commission directed major reforms to the ERCOT wholesale electricity market in PUC Project No. 52373, *Review of Wholesale Electric Market Design* at the December 16, 2021, open meeting.[21] Specifically, the Commission approved the blueprint for revisions to the design of the wholesale electric market filed in the Project on December 6, 2021.

The blueprint compiles directives and concepts designed to reform the ERCOT wholesale electricity market presented in two phases. Phase I of the blueprint is described as providing enhancements to current wholesale market mechanisms to enhance ancillary services and improve price signals and operational reliability. Phase II of the blueprint incorporates longer-term market design and structure reforms.

Recommendations

We have identified opportunities for improvement in the current ERCOT market and make a total of nine recommendations below. Four are new items to address inefficiencies or improve incentives affecting market performance and the remaining recommendations were initially raised in prior years. It is not unexpected that recommendations carry over from prior years since many of them require software changes that can take years to implement or require updates to the Commission's Substantive Rules. We are also retiring two recommendations from last year. Readers can find those and the status of each recommendation in the Appendix.

We continue to advocate implementation of RTC as a top priority, because it improves both reliability and efficiency. It will result in lower overall costs of satisfying the system's energy and ancillary service needs, will more effectively manage congestion, result in fewer RUCs and out-of-market actions, and reduce shortages in operating reserves.

The table below shows the recommendations organized by category. They are numbered to indicate the year in which they were introduced and the recommendation number in that year.

21 See *Review of Wholesale Electric Market Design; Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT,* Project No. 52373, *(pending).*

SOM Number	Brief Description
New Recommendations to Improve Market Performance	
2021-1	Eliminate the "small fish" rule
2021-2	Implement an uncertainty product
2021-3	Reevaluate net metering at certain sites
Additional Recommended Market Improvements from Prior Years	
2020-3	Implement smaller load zones that recognize key transmission constraints
2020-4	Implement a Point-to-Point Obligation bid fee
2019-1	Exclude fixed costs from the mitigated offer caps
2019-2	Price ancillary services based on the shadow price of procuring each service
2015-1	Modify the allocation of transmission costs by transitioning away from the 4 Coincident Peak (CP) method.

New Recommendations to Improve Market Performance

2021-1 – Eliminate the "small fish" rule

Under the so-called "small fish" rule, generators with less than 5% of the capacity installed in ERCOT are deemed not to have "ERCOT-wide market power."[22] The history behind this rule shows that it originated in a market design where high offers (offers significantly above the marginal cost of production) were required to produce high prices in shortage conditions. Since the introduction of the nodal market, with the Power Balance Penalty Curve and the Operating Reserve Demand Curve, economic withholding by small participants is not required for efficient shortage pricing. In fact, it has led to inefficient pricing in some cases.

As an example from 2021, a particular thermal generation resource frequently submitted classic "hockey-stick" offers into real-time, where a small portion of the top of the offer was economically withheld at high prices that are not reflective of that resource's short-run marginal costs. Protected from market power abuse concerns by the small-fish market power rule, this resource nonetheless was occasionally pivotal and set the real-time price higher than $250 per MWh in 333 SCED intervals (approximately 28 hours) in 2021. Withholding should not be allowed by pivotal suppliers. Small entities can be pivotal when conditions are tight market-wide or when the entity is located in a constrained area where supply is tight. This is particularly

22 *See* 16 TAC § 25.504(c).

important during ramp-constrained intervals in absence of RTC. In these intervals, the market's ability to access competing resources can be extremely limited. Therefore, the IMM recommends removing this market power presumption.

2021-2 – Implement an uncertainty product

ERCOT regularly commits resources outside of the market through the RUC process to ensure sufficient generation will be available to satisfy ERCOT's stated reliability margin of 6,500 MW of reserves plus an additional 1,000 MW of non-spinning reserve in uncertain hours. In addition, ERCOT has sought and obtained a change to the non-spinning reserve requirements to essentially make it a four-hour product (primarily impacting ESRs).[23] If these requirements were reflected in a targeted market product, prices would more efficiently reflect these requirements. Additionally, the market would schedule resources to satisfy these requirements, reducing the need for out-of-market actions by ERCOT's operators and the associated uplift costs that must be borne by Texas consumers.

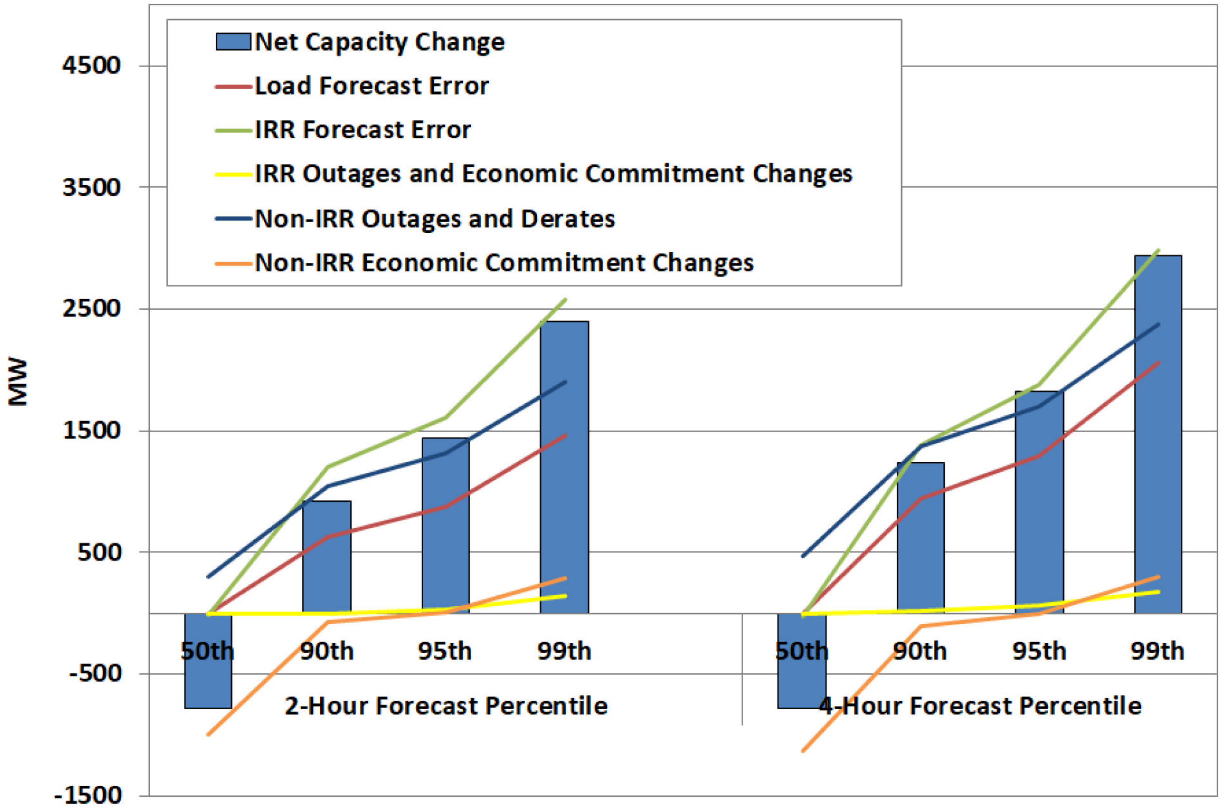
As the levels of renewable generation increase and ERCOT's conservative operations continue, these operational needs and out-of-market costs are likely to rise substantially. Hence, we recommend that ERCOT develop a DAM capacity product to account for increasing uncertainty associated with intermittent generation output, load, and other factors. This would be a two- to four-hour ancillary service that could be deployed when uncertainty results in tight real-time conditions. Such a product should be co-optimized with the current energy and ancillary services products and could be deployed to bring online longer lead-time units when ERCOT detects operating conditions are departing from expected conditions.

The figure below shows the net capacity changes (load minus supply) that ERCOT faces on average and in the worst hours, both in the two-hour ahead and four-hour ahead timeframe. This is intended to be illustrative and we have removed the highly unusual period during Winter Storm Uri. This figure shows that the worst hours, the net capacity change from two to four hours ahead to the operating timeframe can be substantial.

The markets should recognize and address this uncertainty, which can be accomplished by implementing a well-defined product that ERCOT can deploy to meet these needs. This product would: 1) be less costly than holding excessive amounts of 30-minute reserves; 2) allow co-optimized product prices to more fully reflect the value of managing uncertainty; and 3) reduce out-of-market actions and the costs associated with those actions. In the longer term, once an uncertainty product is implemented, ERCOT can return non-spinning reserve and ECRS to their previous duration requirements.

23 See NPRR1096, *Require Sustained Two-Hour Capability for ECRS and Four-Hour Capability for Non-Spin*.

Net Real-Time Capacity Changes



2021-3 – Reevaluate net metering at certain sites

The IMM agrees with the decision to implement nodal pricing for Controllable Load Resources (CLRs). However, we note that there has been a proliferation of proposed net metering schemes since adoption of NPRR945, *Net Metering Requirements*, that distorts the incentives provided by this directive. Loads that can be turned on and off quickly, such as data centers and cryptomines, should be incented to be dispatchable in real time through CLR participation rather reducing their consumption to avoid transmission cost allocation and other load charges. Net metering schemes should, at a minimum, only be allowed with affiliated entities. This would help support price formation and provide better congestion management.

Therefore, the IMM recommends requiring CLRs to have their own meters, rather than allowing net metering schemes amongst unaffiliated entities with meters at the point of interconnection.

Additional Recommended Market Improvements from Prior Years

2020-3 – Implement smaller load zones that recognize key transmission constraints

The four competitive load zones contain a large amount of load, particularly the North and South zones, relative to when they were defined in 2003. This zonal configuration has not changed even through many years of load growth and changing congestion patterns. The highly aggregated load zones distort the incentives of both price-responsive demand and active demand response to manage congestion. This is particularly noticeable in the South load zone where there is significant congestion inside the zone, not just between it and other zones. Incenting demand to respond to the load zone price often makes the local congestion worse.

As active demand response grows in the future (i.e., loads that can be controlled by the real-time market), transitioning to nodal pricing for those active loads will become increasingly beneficial for ERCOT and the market participants.[24] Beyond the active demand response, longer-term demand decisions may be influenced by the zonal prices. Such decisions may either relieve or aggravate congestion patterns, but are unfortunately not informed by the nodal prices.

Therefore, the IMM recommends that the load zone boundaries be re-evaluated and re-determined in future years (after the required four-year waiting period), based on prevailing congestion patterns. In particular, the new zones should minimize intra-zonal congestion.

2020-4 – Implement a Point-to-Point Obligation bid fee

Over the last few years, there have been numerous delays in running and posting the results of the DAM. These delays are disruptive to the market and create unnecessary risk for market participants. ERCOT analysis of the cause points to a significant increase in bids for point-to-point (PTP) obligations, a financial transaction cleared in the DAM used to manage congestion cost risk.[25] This is not a surprise because substantial increases in PTP transactions significantly increase the complexity of the optimization and the time required for the market software to find a solution.

Charging no fee for PTP bids, as ERCOT currently does, allows participants to submit numerous bids that are unlikely to clear and provide very little value to the market. Applying a small bid fee to the PTP bids is consistent with cost causation principles and would incentivize participants to submit fewer bids that are more valuable and more likely clear. Because even a small fee would likely reduce or eliminate the bids that are very unlikely to clear, this should substantially eliminate the delays in the DAM process. Hence, the IMM recommends that a small bid fee be applied to DAM PTP Obligation bids to more efficiently allocate DAM software resources.

24 Nodal pricing for controllable load resources is a part of the Commission's 2021 market design blueprint.
25 ERCOT's regression analysis can be found at http://www.ercot.com/calendar/2021/1/25/221086-WMWG.

2019-1 – Exclude fixed costs from the mitigated offer caps

In competitive markets, suppliers offer their resources at prices equal to their marginal costs (i.e., the incremental costs incurred to produce additional output). Offering at prices higher than this level can only reduce a supplier's profits in a competitive market because the supplier will be displaced by lower-cost resources. However, this is not true when a supplier has market power and an increase in its offer price will raise the market prices and its profits.

To effectively mitigate market power, replacement real-time energy offers used by ERCOT (such as mitigated offers) should only include short-run marginal costs. Currently, the mitigated offer cap includes a multiplier that increases the offer price as the unit runs more. The operations and maintenance portion of verifiable costs already accounts for costs that increase as a unit runs more so the multiplier is not reasonable. The exceptional fuel costs calculation during mitigation also contains a multiplier that does not correspond to a resource's marginal costs when these multipliers are included. Allowing generators with market power to raise prices is an economically inefficient means to achieve fixed cost recovery, so the IMM recommends that these two multipliers be removed to ensure that mitigated offer caps are set at competitive levels. This will help ensure that the market outcomes in ERCOT are competitive, while allowing these resources to recover fixed costs in the same manner as all other resources.

2019-2 – Price ancillary services based on the shadow price of procuring each service.

Clearing prices should reflect the constraints that are used by ERCOT to purchase ancillary services. However, this is not currently the case with certain ancillary services. ERCOT's procurement requirements for Responsive Reserve Service effectively limit the amount of under-frequency relay response that can be purchased from non-controllable load resources. Because these limits are not factored into the clearing prices, there is usually a surplus of relay response offered into the market. However, the surplus does not drive clearing prices down as one would expect in a well-functioning market. Each year the surplus grows, which is an indicator of the inefficient pricing in this market.

In addition, ERCOT will begin allowing non-controllable loads to participate in non-spinning reserve in 2022 but will limit their total participation. A new ancillary service, ERCOT Contingency Reserve Service (ECRS), will be implemented before 2025 and will also contain a constraint on certain resources. However, each of these services will have a single clearing price for both the limited and unlimited providers. Failure to include these constraints in the pricing of those products will require that inefficient market rules and restrictions be imposed. Such measures are not necessary when market participants' incentives are determined by efficient pricing. Therefore, the IMM recommends that the clearing price of ancillary services, both current and future, be based on all the constraints used to procure the services.

2015-1 – Modify the allocation of transmission costs by transitioning away from the Four Coincident Peak (4CP) method.

The current method of allocating transmission costs, the 4CP method, does not apply transmission costs equitably to all loads. Additionally, it does not forestall the need to invest in new transmission as intended when this method was implemented. Currently, transmission costs are allocated based on an entity's maximum 15-minute demand in each month of June through September.[26] This method was approved in 1996 and was intended to allocate transmission costs to the drivers of transmission build.

However, customer demand during the peak summer hours is no longer the main driver of transmission build in ERCOT today. Decisions to build transmission are based on transmission congestion patterns throughout the year and an analysis of whether generation can be delivered to serve customers reliably. Additionally, the method of allocating these costs provides a cost-avoidance signal to non-opt-in entities and transmission-level customers, both of which can artificially reduce their total customer demand in anticipation of a peak demand day to avoid transmission charges. Hence, the IMM continues to recommend that transmission cost allocation be changed to better reflect the true drivers for new transmission.

[26] 16 Tex. Admin. Code §25.192. Transmission Service Rates; http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.192/25.192.pdf

I. Future Needs of the ERCOT Market

The ERCOT market is currently experiencing major changes and evolving needs, which are driven by two primary factors. First, the generation mix is changing rapidly as the entry of wind, solar, energy storage, and distributed generation fleet accelerates. These new generation technologies have significantly different operational characteristics than conventional generation. Changes to the market are necessary to integrate them reliably and efficiently into the system.

Second, ERCOT has adopted a very conservative operating posture since July 2021. The conservative operating posture requires more operational reserves to be online in real-time. In addition to being very costly, this posture can at times suppress real-time prices and exacerbate the "missing money" problem[27] that can sometimes be faced by generators in an energy-only market.

This section discusses the evolving needs of the future ERCOT market stemming from these two factors. The current ERCOT market design requires the following changes, at a minimum, in order to accommodate the changes described above:

- Implement RTC as soon as possible;
- Model state of charge (SOC) for ESRs;
- Introduce an uncertainty ancillary service product to increase the flexibility of the system instead of trying to adapt current ancillary service products to requirements they are not well suited for (see SOM recommendation 2021-2 above);
- Address cost allocation issues, particularly transmission cost allocation (see SOM recommendation 2015-1 above); and
- Develop a market construct to address the missing money that cannot be provided by an energy-only market in which shortage conditions are not permissible.

A. ERCOT's Future Supply Portfolio

The ERCOT market's supply portfolio has changed considerably over the last twenty years and the current interconnection queue suggests that it will continue to change. Over the past two decades, a significant fraction ERCOT's natural gas steam and coal generation retired, a large amount of combined cycle capacity was built, and the penetration of wind resources steadily increased. More recently, solar, battery energy storage, and distributed generation have been interconnecting at a rapid pace. We discuss the challenges related to these new classes of resources in the subsections below.

[27] This refers to the idea that prices for energy in electricity markets may not fully reflect the value of investment in the resources needed to meet consumers' demand for reliable electric service.

Renewable Resources

Over the last five years: 15 GW of wind, 10 GW of solar, 1.5 GW of energy storage, and 1.5 GW of gas-fired capacity was installed,[28] while 5.6 GW of coal and 0.9 GW of gas steam capacity retired.[29] Looking forward, ERCOT's current interconnection queue is comprised of more than 1,000 active projects totaling over 200 GW,[30] and most of this capacity is wind, solar, and storage. Not all of these projects will be built, but of the 31 GW of projects with a completed interconnection study and interconnection agreement, 18 GW are solar, 8 GW are wind, 4 GW are energy storage, and only 1.5 GW are natural gas-fired resources. The increase in intermittent wind and solar generation will raise new operational demands that are discussed below.

Increasing Ramp Demands. One of the new demands is a much steeper and more uncertain net load ramp. Net load is defined as the system load minus the output of intermittent renewable resources that must be served by dispatchable resources. The prediction of the future shape of this curve once a large quantity of solar has entered has been referred to as the "duck curve" or, in Texas, the "dead armadillo curve." This curve indicates that conventional resources will have to ramp rapidly each evening as the sun goes down and the solar resources' output falls sharply. Similarly, shifting weather patterns can cause wind output to fall rapidly and the timing of these decreases can be difficult to predict.

This will require ERCOT's operators to utilize flexible dispatchable resources to accommodate these sharp and uncertain ramp demands. In addition to existing and new flexible natural gas resources, ERCOT will likely need to rely more heavily on:

- Demand-side resources can respond to higher prices during the ramp by reducing their consumption if the value of the energy exceeds their value of consuming it; and
- Energy storage has the capability to produce energy very quickly when deployed, as well as storing energy when intermittent output is high.

The evolution of the market design will also improve ERCOT's ability to meet these new operational challenges. For example, a multi-interval real-time market (MIRTM) will be increasingly valuable. It allows the market software to anticipate and address ramping needs in future intervals by pre-positioning the system for those needs. ERCOT and stakeholders evaluated a MIRTM in 2016, finding that the benefits of a MIRTM were insufficient to justify its implementation costs at the time of the study, but noting that "[c]hanges in the future resource mix, the balance of supply and demand or system conditions could demonstrate more significant

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28 https://www.ercot.com/files/docs/2022/03/07/Capacity_Changes_by_Fuel_Type_Charts_February_2022.xlsx

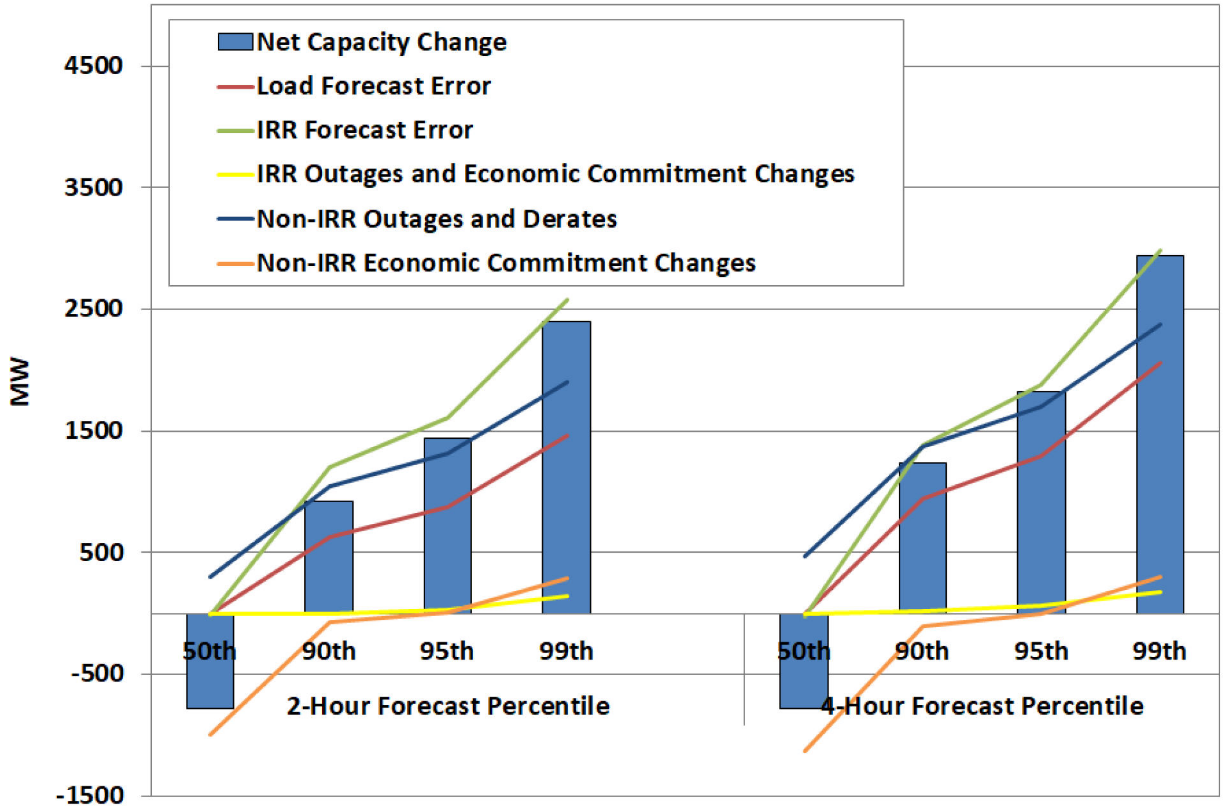
29 https://www.ercot.com/files/docs/2021/12/29/CapacityDemandandReservesReport_December2021.xlsx

30 ERCOT Generation Interconnection Study Report, February 2022. https://www.ercot.com/misdownload/servlets/mirDownload?mimic_duns=000000000&doclookupId=825830714

value to MIRTM."[31] As the penetration of intermittent resources increases, the operational benefits of a MIRTM will increase because it will improve the utilization of the dispatchable fleet to manage the net load ramps.

Increasing Supply Uncertainty. As noted above, the growth in intermittent resources and distributed generation will increase supply uncertainty. As shown in Figure 1 below, thermal generation trips, load forecast errors, and wind and solar forecast errors all contribute to the net uncertainty faced by the market operator. The growth in wind and solar, coupled with increasing amounts of distributed generation that is not dispatched by ERCOT, will significantly increase the uncertainty that ERCOT faces. This uncertainty significantly affects both ERCOT's planning and operations.

Figure 1: Net Real-Time Capacity Changes



In real-time operations, RTOs manage this uncertainty by committing additional resources outside of the market to have sufficient dispatch flexibility to manage this uncertainty. To allow the markets manage and price this uncertainty, we recommend that ERCOT create a two- to four-hour uncertainty product. This product was previously discussed in SOM recommendation 2021-2 as well as in PUC Project No. 52373, *Review of Wholesale Electric Market Design*.[32]

31 https://interchange.puc.texas.gov/Documents/41837_9_935430.PDF

32 *Review of Wholesale Electric Market Design*, Project No. 52373, IMM Proposals at 6-7 (Oct. 15, 2021)

Although the figure is illustrative and not intended indicate the size of the service, it shows that ERCOT faces substantial uncertainty from multiple sources in the two to four-hour ahead timeframe. The recommended product would procure and price resources that ERCOT can utilize when the uncertainty results in tight supply-demand conditions or high ramp demands.

Increasing Generic Transmission Constraints. Another challenge brought about by the increase in inverter-based generation (including wind, solar, and energy storage) is the increased prevalence of GTCs. The flows over most transmission facilities are limited by thermal limitations because increased flows increase the temperature of the facilities. GTCs are not typical thermals constraints and are used to limit overall flows over a path to maintain the stability of the system. They are harder to manage than thermal constraints and are sometimes not well known prior to committing a resource.

GTCs have increased significantly over the last few years with the expansion of inverter-based generation, with congestion on these constraints growing from $190 million in real-time congestion in 2020 to $400 million in 2021. NPRR1070, *Planning Criteria for GTC Exit Solutions*, is currently pending, and the Commission rulemaking to implement SB1281 has recently been opened to improve economic transmission planning criteria.[33] These two items should help develop solutions to the proliferation of GTCs.

System Inertia. A final challenge associated with the proliferation of inverter-based generation is that of maintaining sufficient system inertia. System inertia needed to maintain frequency within acceptable bounds when large generators, loads, or large DC ties trip offline. Inertia is provided by online generators that are synchronously connected to the grid, which is not generally true of inverter-based resources. Alternatively, with very fast control systems, "synthetic" inertia is possible from inverter-based resources or even loads. ERCOT has studied inertia previously and has procedures in place to ensure sufficient inertia is maintained.[34] However, inertia should fall as a larger share of the load is served by wind, solar, and ESRs. It may be beneficial in the future to supplement the markets to compensate resources for providing inertia as ERCOT has previously discussed.[35]

Energy Storage

It is important for ERCOT to improve upon its current modeling of ESRs to enable these resources to offer their full value to grid reliability and the market. In the current "dual model" or "combo model", the load and generation sides of an ESR are modeled as separate, independent devices. The dual model fits within ERCOT's existing software capabilities, but

[33] Review of Chapter 25.101, Project No. 53403 (Mar. 19, 2022).

[34] https://www.ercot.com/calendar/event?id=1520373953460

[35] http://www.ercot.com/content/wcm/key_documents_lists/55752/Proposal_for_Synchronous_Inertial_Response_Service_Market_March112015.docx

has significant modeling limitations, including the inability to model the state of charge (SOC) of the ESR. ERCOT has made substantial progress towards modeling ESRs as a single device with the approval of NPRRs: 989 - *BESTF-1 Energy Storage Resource Technical Requirements*, 1002 - *BESTF-5 Energy Storage Resource Single Model Registration and Charging Restrictions in Emergency Conditions*, and 1026 - *BESTF-7 Self-Limiting Facilities*. Unfortunately, implementation of these changes is currently on hold due to constraints on implementation resources. However, even with these improvements, additional enhancements are needed to fully model ESRs' unique characteristics, including most importantly implementing modeling of the SOC of ESRs.

Modeling the SOC in the DAM and RUC processes or real-time market will become critical as ESRs become a substantial fraction of the fleet. Modeling the SOC of ESRs, in conjunction with RTC, is necessary to allow ESRs to provide their full value to grid reliability, flexibility, and economics.

Distributed Resources

ERCOT is also currently addressing issues related to distributed resources. There are currently over 1,300 MW of unregistered DGRs in ERCOT, and an unknown number of potential but unregistered controllable load resources.[36] These amounts are increasing yearly. ERCOT is actively grappling with visibility and uncertainty around these resources. They are generally located on the distribution system, and therefore present challenges associated with modeling their location, behavior, and market participation. The challenges presented by distributed resources include:

- Operational visibility: The location and output of distributed resources may not be certain in the real-time market, leading to potential challenges managing network congestion and balancing the system.
- Operational control: Most DGRs are not dispatchable by ERCOT on a five-minute basis.
- Economic incentives: To the extent that distributed resources are affected by retail programs or rates, wholesale market rules and settlements may result in inefficient incentives to operate the resources or inefficient co-location schemes. This is particularly true regarding costs distributed on a load-ratio share basis, such as ancillary service and transmission cost allocations.

We encourage ERCOT to develop market rules and operating procedures that address these challenges. The most immediate concern in this are relates to behind the meter demand response resources. Loads that can be turned on and off quickly, such as data centers and crypto-currency mines, are increasingly locating in Texas. These types of loads should be incentivized to register

[36] Unregistered DG Installed Capacity Quarterly Report at https://www.ercot.com/services/rq/re/dgresource.

with ERCOT and be dispatchable in real-time rather than simply providing passive demand response in order to avoid transmission cost allocation and other load charges. As discussed above in SOM recommendation 2015-1, the transmission cost allocation method currently used provides incentives for these large loads to behave in ways that do not necessarily forestall the construction of new transmission equipment and that do not apply costs equitably. In SOM recommendation 2021-3 above, we recommend requiring controllable load resources to have their own meters, rather than allowing net metering schemes amongst unaffiliated entities with meters at the point of interconnection.

B. ERCOT's New Operational Posture

After the events of Winter Storm Uri, the Texas Legislature, the Commission, and stakeholders have been engaged in a process of evaluating changes to the ERCOT market design. High load and high levels of thermal generation outages for the period of June 13-15, 2021, caused ERCOT to issue a public conservation appeal on June 14.[37] Previous conservation appeals were considered routine; however, this conservation appeal raised public concern regarding the state of ERCOT grid. This led ERCOT to decide to adopt a more conservative operating posture by requiring additional operating reserves to be available in real-time.[38] Since July 2021, ERCOT has:

- Increased non-spinning reserve requirements such that that the total of upward-moving ancillary services, excluding those provided by loads on high-set under-frequency relays, equals 6,500 MW on a typical day and a 7,500 MW on days ERCOT deems to have high load uncertainty, such as those with rapidly changing weather events;
- Used RUC more routinely to ensure that there is 6,500 MW (or 7,500 MW) of dispatchable reserves in real-time. ERCOT previously targeted lower reserve levels in the range of 3,600-5,700 MW;
- Issued RUC instructions earlier in the operating day, committing more longer-lead time resources as well as relying less on market participant response; and
- Adjusted selection of forecast to more frequently rely on the highest load forecast and the lowest wind and solar forecasts.

The results of the changes, in combination with the 2022 ORDC adjustment,[39] are that the pricing outcomes have grown disconnected from the actual operational conditions. This is discussed in more detail in the RUC section of this report. This is problematic because the

37 https://www.ercot.com/news/release?id=9740321a-f509-31ab-8d0a-2a8421292239

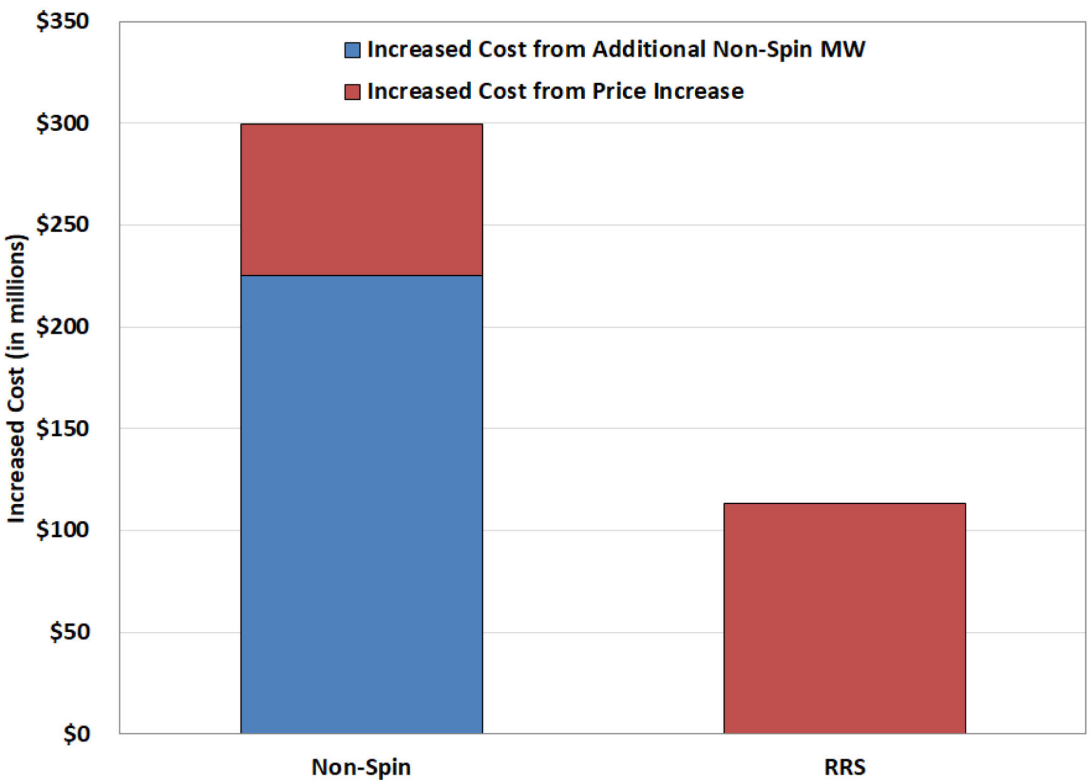
38 https://www.ercot.com/files/docs/2021/06/30/ERCOT_Addtional_Operational_Reserves_06302021.pptx

39 Effective January 1, 2022, the Minimum Contingency Level (MCL) was set at 3,000 MW and the high system-wide offer cap (HCAP) and value of lost load (VOLL) were set to $5,000 per MWh.

energy-only market design relies on efficient pricing that reflects the reliability needs of the system. In addition, this can increase risk for market participant if ERCOT over-commits the system and renders generation owner's decisions uneconomic.

Procuring additional non-spinning reserve also increases the costs paid by load. Although this additional procurement may increase reliability in some hours, the potential reliability benefits are difficult to justify based on the costs, particularly since the additional procurement is applied to all hours regardless of reliability need. As illustrated in Figure 2 below, we estimate that the combined cost increase of the higher procurement is in the range of $300-400 million for the period of July 12 to December 31, 2021.[40] This is based on our analysis of the effect of the increased procurement on non-spinning reserve prices and quantities, as well as the secondary effects on other ancillary service prices.

Figure 2: Non-Spin Cost Impact in 2021



While we continue to believe that an energy-only market can be successful and adapt to changing system needs, it is not compatible with ERCOT's current conservative operational posture. The distortion in the market's economic signals will diminish generators' expected revenues, which ultimately will threaten ERCOT's resource adequacy.

40 Due to the infeasibility of rerunning the DAM cases to determine price adjustments, our analysis estimates this cost based on historical pricing and modeling the range of impacts of the changes.

To address these concerns, we recommend the following:

- Develop the uncertainty produced described earlier in the section that will allow the markets to reflect ERCOT's operating posture.
- Consider adopting a form of capacity procurement that augments the economic signals provided by the energy-only market and ensures the adequacy of ERCOT's resources over the long term.

ERCOT should avoid a piecemeal approach that provides targeted payments to narrowly defined categories of resources when implementing any form of capacity procurement. A key component to any capacity proposal is defining a reliability standard. These discussions are currently underway at the Commission as part of its Phase II market design and structure reforms approach.

II. Review of Real-Time Market Outcomes

The performance of the real-time market in ERCOT is essential because that market:

- Coordinates the dispatch of generating resources to serve ERCOT loads and manage flows over the transmission network; and
- Establishes real-time prices that efficiently reflect the marginal value of energy and ancillary services throughout ERCOT.

The first function of the real-time market ensures reliability in ERCOT with the simultaneous objective of minimizing the system's production costs. The second function is equally important because real-time prices provide key short-term incentives to commit resources and follow ERCOT's dispatch instructions, as well as long-term incentives that govern participants' investment and retirement decisions.

Real-time prices have implications far beyond the settlements in the real-time market. Only a small share of the power produced in ERCOT is transacted in the real-time market. However, real-time energy prices set the expectations for prices in the DAM and bilateral forward markets and are, therefore, the principal driver of prices in these markets where most transactions occur. Because of the interaction between real-time and all forward prices, the importance of real-time prices to overall market performance is much greater than might be inferred from the proportion of energy actually paying real-time prices. This section evaluates and summarizes electricity prices in the real-time market during 2021.

A. Real-Time Market Prices

The first analysis of the real-time market evaluates the total cost of supplying energy to serve load in the ERCOT wholesale market. In addition to the costs of energy, loads incur costs associated with ancillary services and a variety of non-market-based expenses referred to as "uplift." Figure 3 shows the average "all-in" price of electricity for ERCOT that includes all these costs and is a measure of the total cost of serving load in ERCOT on a per MWh basis. The all-in price metric includes the load-weighted average of the real-time market prices from all zones, as well as ancillary services costs and uplift costs divided by real-time load to show costs on a per MWh of load basis.[41]

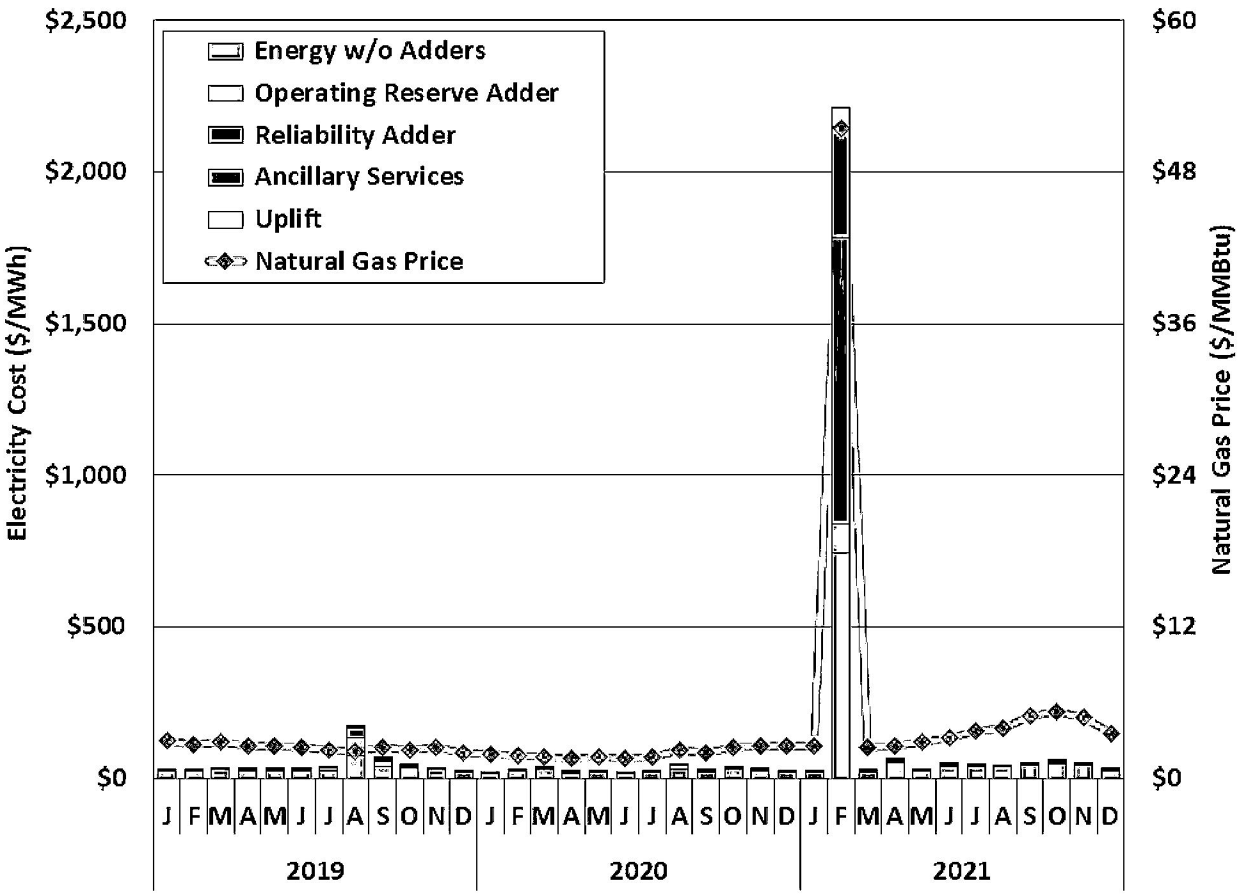
ERCOT real-time prices currently include the effects of two energy price adders that are designed to improve real-time energy pricing when conditions warrant or when ERCOT takes

41 For this analysis "uplift" includes: Reliability Deployment Adder Imbalance Settlement, Operating Reserve Demand Curve (ORDC) Adder Imbalance Settlement, Revenue Neutrality Total, Emergency Energy Charges, Base Point Deviation Payments, Emergency Response Service (ERS) Settlement, Black Start Service Settlement, and the ERCOT System Administrative Fee.

out-of-market actions for reliability. Although published energy prices include the effects of both adders, here we show the ORDC adder (operating reserve adder) and the Reliability Deployment Price Adder (reliability adder) separately from the base energy price. The operating reserve adder was implemented in mid-2014 to account for the value of reserves based on the probability of reserves falling below the MCL and VOLL. Taken together, an estimate of the economic value of increasingly low reserves in each interval in real-time can be included in prices. The reliability adder was implemented in June 2015 as a mechanism to ensure that certain reliability deployments do not distort the energy prices.[42]

In Figure 3 and Figure 4 below, the effects of Winter Storm Uri on the average all-in price for electricity in ERCOT are examined by showing the 2021 prices with the storm and without the storm.

Figure 3: Average All-in Cost for Electricity in ERCOT (with Uri)



42 The reliability adder is calculated by separately running the dispatch software with modifications to the inputs to reflect any RUCs, deployed load capacity, or certain other reliability actions. When the recalculated system lambda (average load price) is higher than the initial system lambda, the difference is the adder.

Because of the overwhelming effects of Winter Storm Uri on energy prices, the largest component of the all-in price in 2021 was the reliability adder, unlike previous years when the energy cost was the largest component. The correlation between the gas price and the energy price in the figure above indicates that natural gas prices were a primary driver of energy prices in most months, including in February during the storm. This correlation is expected in a well-functioning, competitive market because fuel costs represent the majority of most suppliers' marginal production costs. Because suppliers in a competitive market have an incentive to offer supply at marginal costs and natural gas is the most widely used fuel in ERCOT, changes in natural gas prices typically should translate to comparable changes in offer prices. This can be seen more clearly in Figure 4 below, showing the correlation between the all-in energy price and the natural gas price throughout the year with the severe effects of Winter Storm Uri removed from the analysis.

Average real-time prices rose to $167.88 per MWh in 2021, more than 6 times higher than in 2020, due almost entirely to the effects of Winter Storm Uri. The last time ERCOT experienced shortage pricing, in August and September of 2019, its magnitude and duration were much lower than experienced during Winter Storm Uri.

The extreme increase in shortage pricing was acutely reflected in the higher contributions from ERCOT's energy price adders: $8.32 per MWh from the operating reserve adder and almost $80.00 per MWh from the reliability adder. Both values are much higher than the 2020 values: $2.35 per MWh for the operating reserve adder and $0.01 per MWh for the reliability adder. The adders in 2021 are discussed in greater detail in Subsection F below.

Despite firm load shed across the system during the storm, energy prices were clearing at less than $9,000 per MWh, which was the system-wide offer cap at the time, pursuant to 16 TAC § 25.505(g)(6)(B). Energy prices dipped as low as approximately $1,200 per MWh on February 16, 2021. In response, the Commission directed ERCOT to account for firm load shed in EEA3, from the time of the Commission's order, in ERCOT's scarcity pricing signals.[43]

Due to the exceptionally high natural gas prices, the Commission suspended use of the low system-wide offer cap (LCAP) during Winter Storm Uri.[44] Because LCAP was calculated as "50 times the natural gas price index value," it would likely have exceeded the high system-wide offer cap (HCAP) of $9,000 per MWh and $9,000 per MW per hour under 16 TAC § 25.505(g)(6), an outcome contrary to the purpose of the rule, which was to protect consumers from substantially high prices in years with substantial generator revenues. Suspension of LCAP

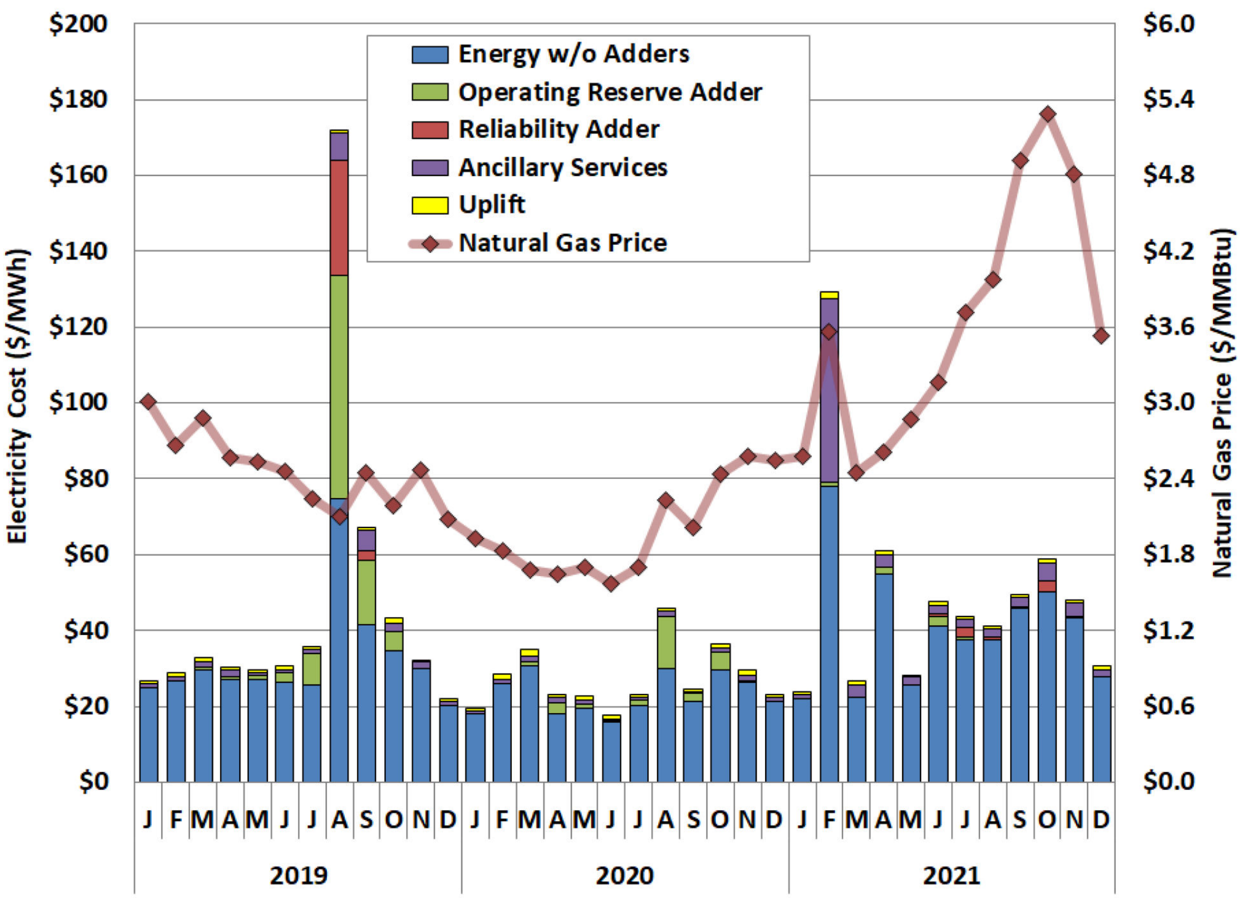
43 See *Calendar Year 2021 - Open Meeting Agenda Items without an Associated Control,* Project No. 51617, Second Order Directing ERCOT to Take Action and Granting Exception to Commission Rules at 1 -2 (Feb. 16, 2021).

44 *Id.* at 2.

was terminated on March 3, 2021, once the natural gas price index had stabilized and the LCAP was no longer expected to exceed the HCAP, and the Commission directed ERCOT to resume application of the LCAP when administering the scarcity pricing mechanism as provided by Commission rule.[45]

When the effects of Winter Storm Uri are removed from the analysis, as shown below in Figure 4, average real-time prices rose by 58% (to $40.73 per MWh) in 2021 compared to 2020, driven by higher natural gas prices throughout the year. The energy price adders in 2021 without the effects of Winter Storm Uri increased slightly from 2020 values – $0.55 per MWh for the operating reserve adder and $0.70 per MWh for the reliability adder in 2021.

Figure 4: Average All-in Cost for Electricity in ERCOT (without Uri)

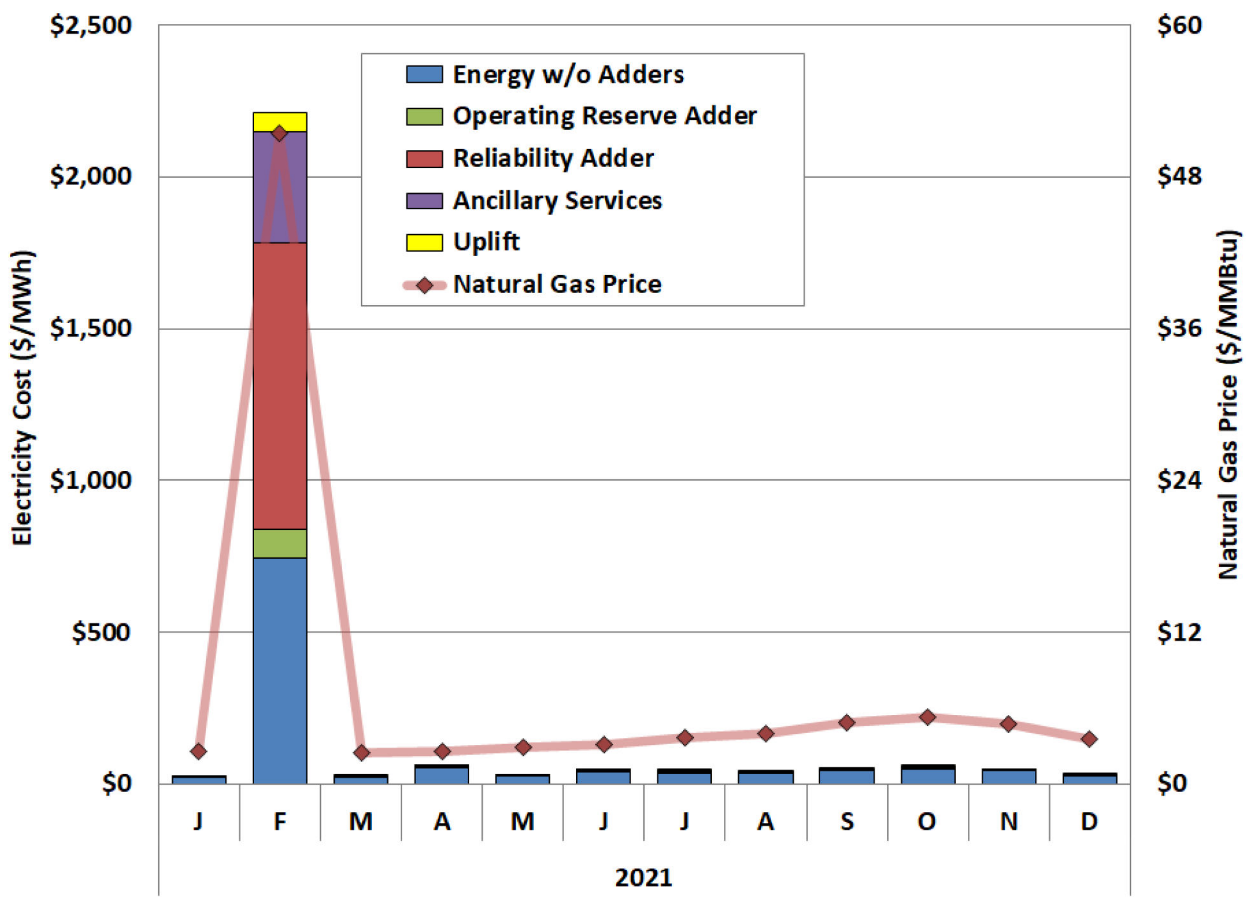


Other cost categories of the all-in electricity price were similarly altered by Winter Storm Uri, as shown in Figure 5 below. Ancillary services costs were $29.59 per MWh of load in 2021, up from $1.00 per MWh in 2020, discussed in more detail in in Section IV: Day-Ahead Market

45 *Issues Related to the State of Disaster for the February 202 1 Winter Weather Event,* Project No. 51812, Order Reinstating Low System-Wide Offer Cap at 1-2 (Mar. 3,2021).

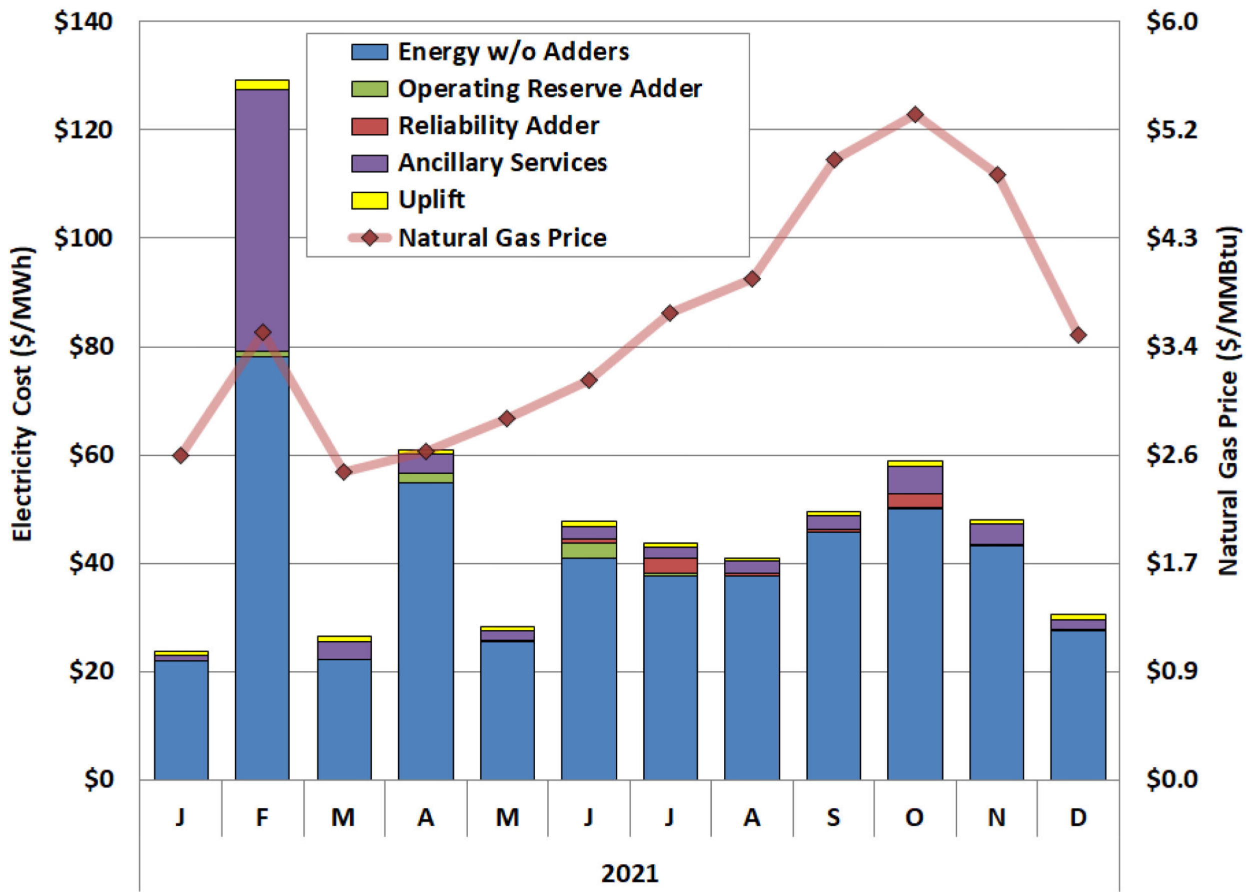
Performance. Uplift costs accounted for $5.34 per MWh of the all-in electricity price in 2021, up from $0.94 per MWh in 2020. The total amount of uplifted costs in 2021 was approximately $2.1 billion, vastly higher than the $359 million in 2020. The largest driver of this massive uplift value is the ancillary service imbalance settlement. There are many other costs included as uplift, but the largest components are the ERCOT system administrative fee ($218 million or $0.55 per MWh), Emergency Response Service (ERS) program costs ($35 million or $0.09 per MWh) and the real-time revenue neutrality allocation (RENA), which totaled less than $1 million or less than $0.01 per MWh in 2021. The dramatic decrease in RENA, down from $75 million in 2021, is attributable to high negative RENA during Winter Storm Uri.

Figure 5: All-in Electricity Costs in 2021 (with Uri)



As show in Figure 6 below, ancillary services costs without the period of Winter Storm Uri would have been $6.00 per MWh in 2021, up from $1.00 per MWh in 2020. This was still a large increase and was driven by high ancillary services prices that persisted for several days after Winter Storm Uri, and to a lesser extent the additional ancillary services quantities that ERCOT purchased during the second half of the year. Uplift costs would have accounted for $0.91 per MWh of the all-in electricity price in 2021, about the same as in 2020 ($0.94). The total amount of uplifted costs in 2021 would have been approximately $356 million, in line with the $338 million in 2019 and $359 million in 2020.

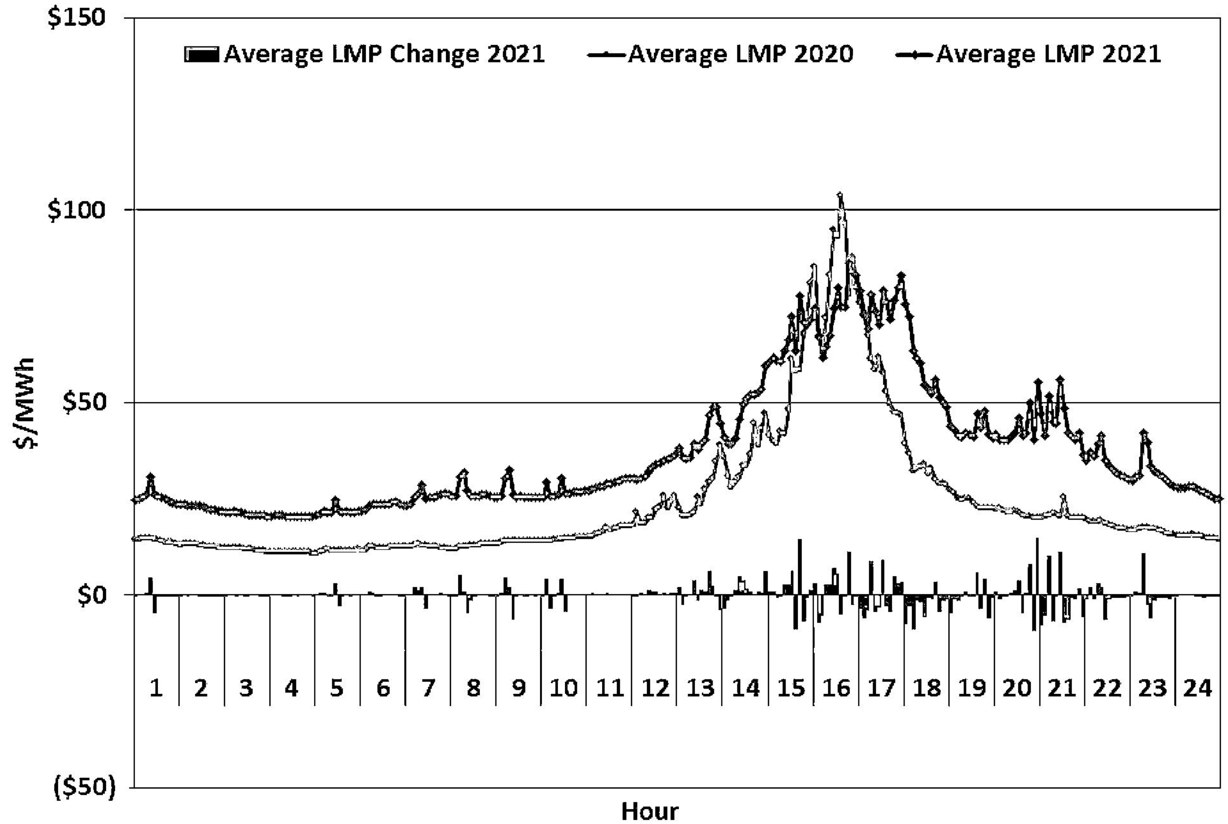
Figure 6: All in Prices 2021 (without Uri)



Real-time energy prices vary substantially by time of day. Figure 7 shows the 2021 load-weighted average real-time prices in ERCOT in each 5-minute interval during the summer months from May through September, when prices are typically the highest. It also shows in red the average change in the 5-minute prices in each interval. Average changes are mostly random and generally driven by changes in load or supply. Note that prices in the peak load hours were actually lower in 2021 than in 2020, and higher in all other hours. This was likely attributable to demand alterations in the earlier part of the year caused by the Covid-19 pandemic as well as a cooler summer weather and higher solar output during peak.

For additional analysis of load-weighted average real-time prices in ERCOT for the categories of Peak and Off-Peak for each month in 2021, see Figure A1 in the Appendix.

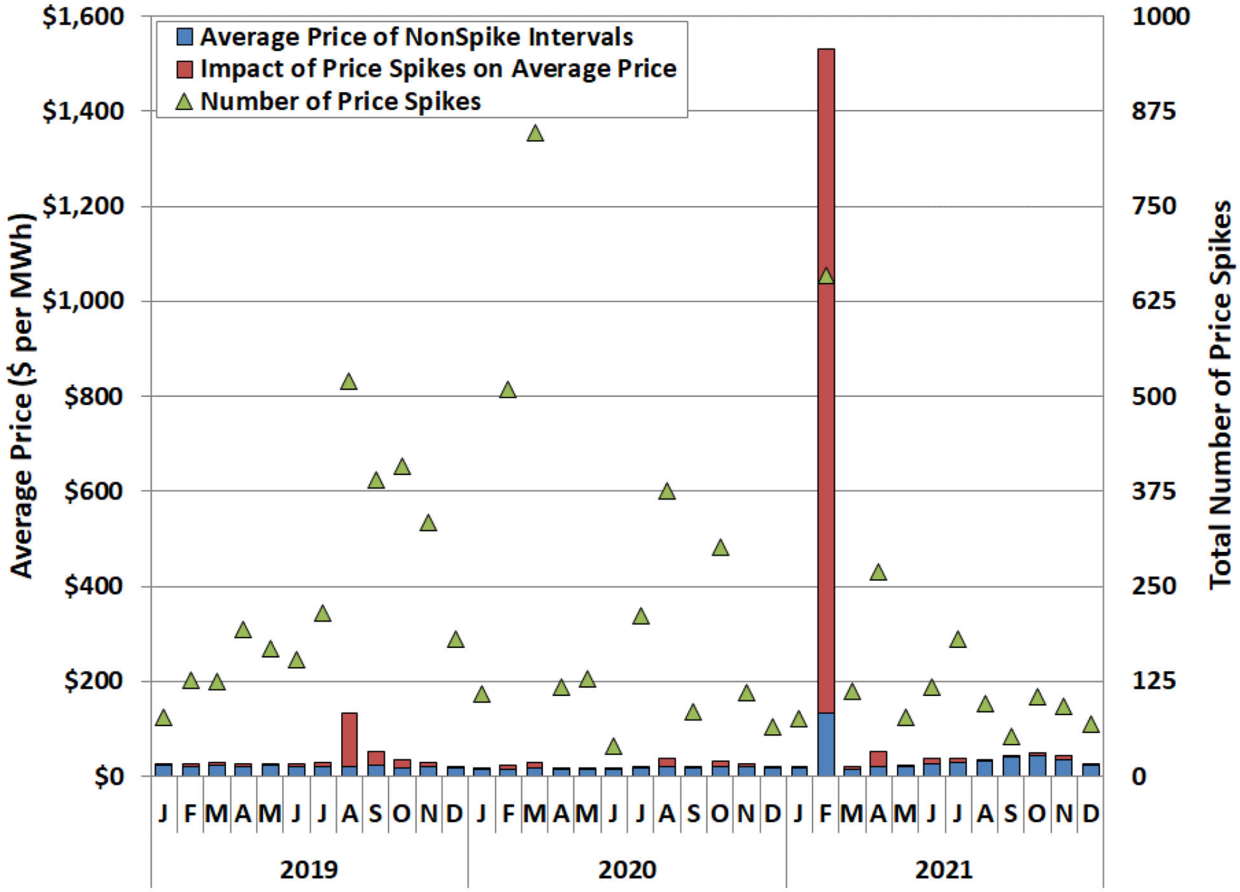
Figure 7: Prices by Time of Day
May-September 2021



To better observe the effect of the highest-priced hours on the average real-time energy price, Figure 8 shows the frequency of price spikes in the 2021 real-time energy market. For this analysis, price spikes are defined as 15-minute intervals when the load-weighted average energy price is greater than 18 MMBtu per MWh multiplied by the prevailing natural gas price (i.e., a heat rate of 18). Prices at this level typically exceed the marginal costs of virtually all on-line generators. As with many market outcomes in 2021, this analysis is once again dominated by the events of February 2021 and Winter Storm Uri.

Price spikes were less frequent in 2021 compared to 2020 in part due to higher gas prices and in part due to ERCOT's conservative operational posture but were far more consequential on prices because of the larger magnitude of prices during Winter Storm Uri as well as much higher average gas prices (above $7.00/MMBtu) throughout the year. With average gas prices so high throughout the year, energy prices have a much stronger correlation with heat rate as the other components of operations and maintenance costs become less impactful. This is typical in energy markets. The overall impact of price spikes in 2021 was $123.45 per MWh, or 74% of the total average price.

Figure 8: Average Real-Time Energy Price Spikes



B. Zonal Average Energy Prices in 2021

Energy prices vary across the ERCOT market because of congestion costs that are incurred as power is delivered over the network. Table 1 provides the annual load-weighted average price for each zone as well as the annual average natural gas price for the past seven years, plus an additional column containing 2021 without Winter Storm Uri (February 13-19, 2021).

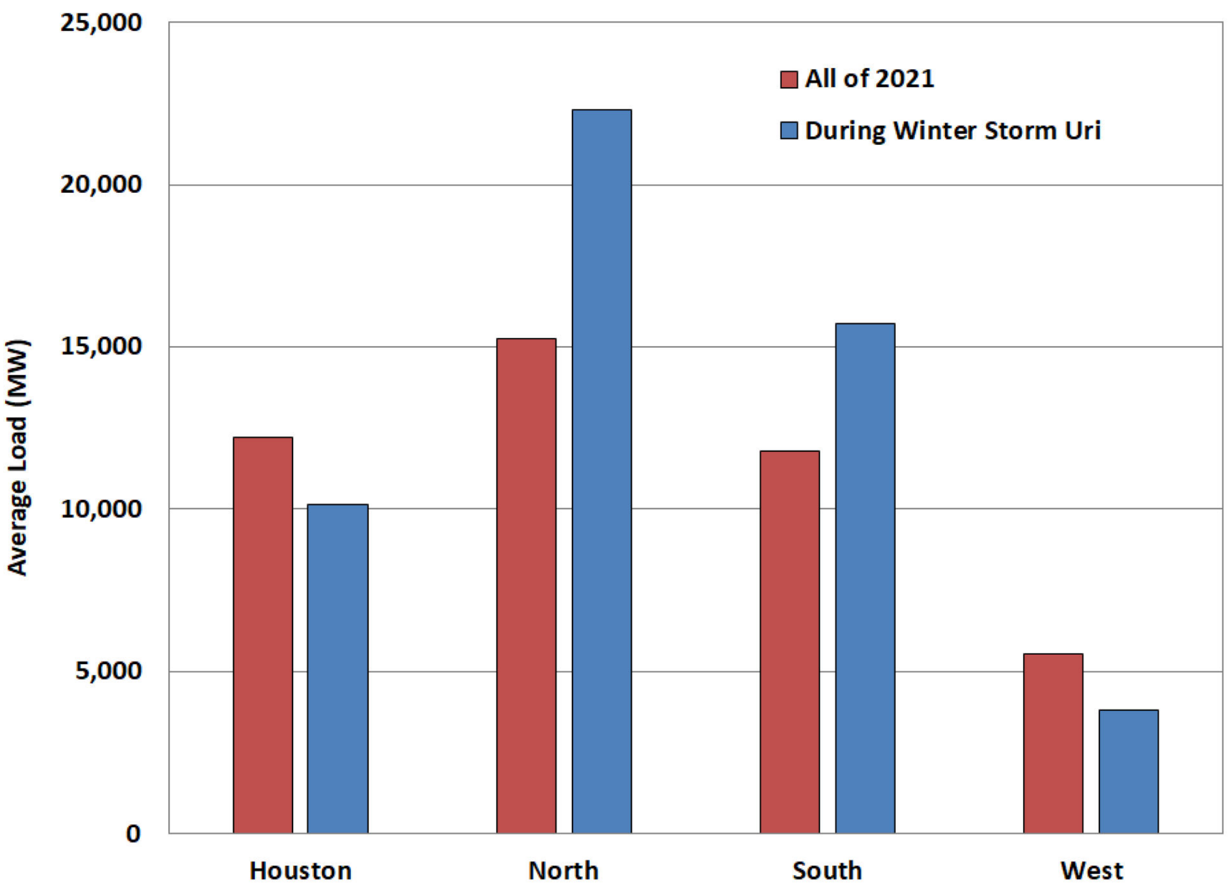
Table 1: Average Annual Real-Time Energy Market Prices by Zone

($/MWh)	2014	2015	2016	2017	2018	2019	2020	2021	2021 w/o Uri
ERCOT	**$40.64**	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**	**$167.88**	**$40.73**
Houston	$39.60	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54	$129.24	$42.78
North	$40.05	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97	$206.39	$41.57
South	$41.52	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63	$187.47	$39.98
West	$43.58	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58	$105.27	$35.51
($/MMBtu)									
Natural Gas	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99	$7.30	$3.62

Like Figure 3, Table 1 shows the historically close correlation between the average real-time energy price in ERCOT and the average natural gas price, including 2021. This relationship is consistent with competitive expectations in ERCOT where natural gas generators predominate and set prices in most hours. The average natural gas price was higher in 2021 than it has been in many years, and average real-time energy prices reflect that. For additional analysis on ERCOT average real-time energy prices as compared to the average natural gas prices, see Figure A2 in the Appendix.

Table 1 also shows that the relative prices of the four zones was different in 2021 compared to previous year, again due to Winter Storm Uri. The table contains load-weighted averages, and as shown in Figure 9, the North zone and South zone had higher load values than their yearly averages during Winter Storm Uri while the Houston and West zones had the opposite, so the extreme high prices during Winters Storm Uri influenced the annual averages of the North and South zones more than the Houston and West zones. With the effects of Uri removed, the Houston zone had the highest average price, due to multiple localized real-time transmission constraints in the area. For additional analysis on monthly load-weighted average prices in the four geographic ERCOT zones during 2021, see Figure A3 in the Appendix.

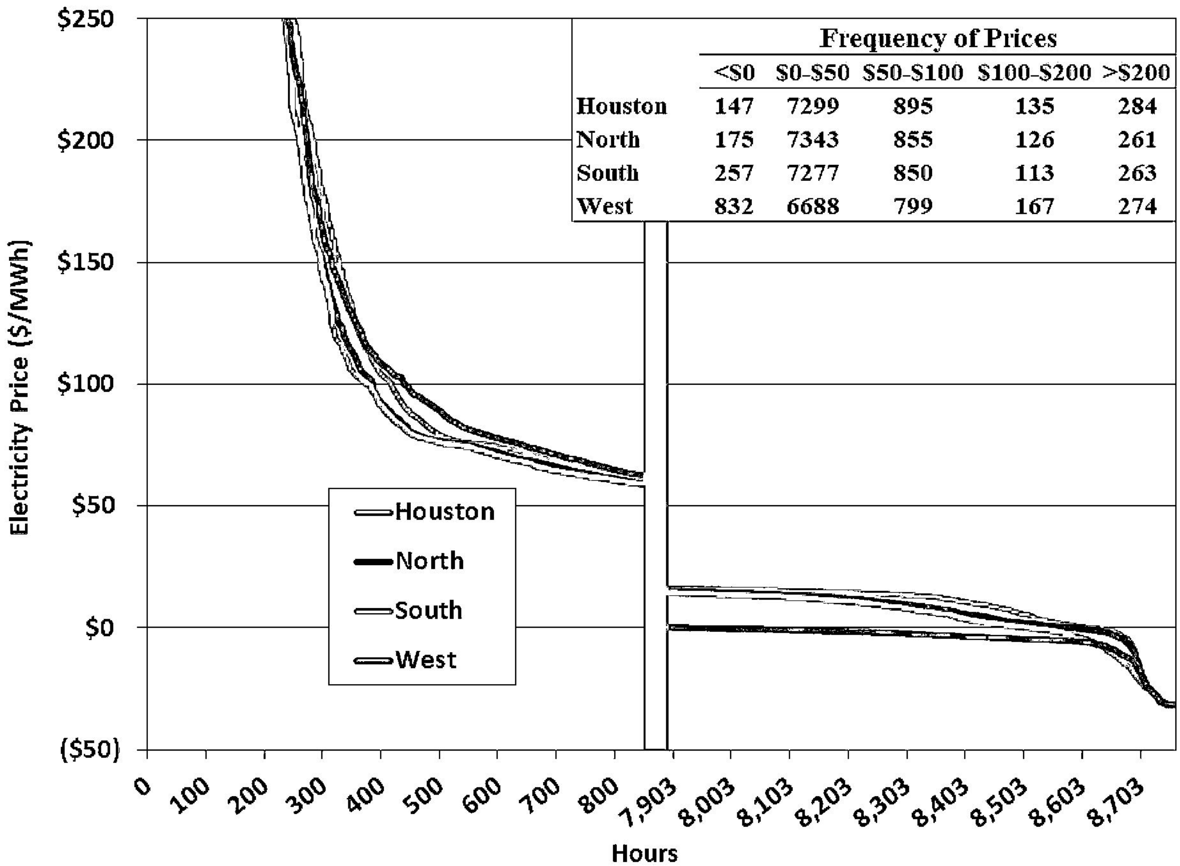
Figure 9: Average Load by Load Zone



More details about transmission constraints that influenced zonal energy prices are provided in Section V. That section also discusses Congestion Revenue Right (CRR) auction revenue distributions, which affect the ultimate costs of serving customers in each zone. For additional analysis of the effect of CRR auction revenues on the total cost to serve load borne by a QSE, see Figure A5 in the Appendix.

To examine the variation more closely in zonal real-time energy prices, Figure 10 shows the top 10% and bottom 10% of the duration curves of hourly average prices in 2021 for the four zones. Compared to the other zones, both low and high prices in the West zone were noticeably different in 2021, continuing a pattern seen in 2020. The lowest prices in the West zone were much lower than the lowest prices in the other zones and the highest prices in the West zone were also generally higher than high prices in the other zones. The differences on both ends of the curves can be explained by the effects of transmission congestion. Constraints limiting the export of low-priced wind and solar generation to the rest of the state explain low prices, whereas localized constraints limiting the flow of electricity to the increasing oil and gas loads in the West explain the higher prices, typically in times where wind and solar energy resource output is low.

Figure 10: Zonal Price Duration Curves



	Frequency of Prices				
	<$0	$0-$50	$50-$100	$100-$200	>$200
Houston	147	7299	895	135	284
North	175	7343	855	126	261
South	257	7277	850	113	263
West	832	6688	799	167	274

For additional analysis of price duration curves, see Figure A6 and Figure A8 in the Appendix.

C. Evaluation of the Revenue Neutrality Allocation Uplift

As shown in the all-in price analysis above, uplift costs increased substantially in 2021. However, this was not due to higher Revenue Neutrality Allocation Uplift (RENA, further described below), which decreased in 2021 to less than $1 million (less than $0.01 per MWh), down from $75 million ($0.20 per MWh) in 2020 (RENA would be about $57 million in 2021 but for the effects of February, representing what would otherwise be a drop of 24% from 2020). We evaluate the drivers of RENA in this subsection.

In general, RENA uplift occurs when there are certain differences in power flow modeling between the day-ahead and real-time markets. These factors include:

- Transmission network modeling inconsistencies between the day-ahead and real-time market (Model Differences);
- Differences between the load distribution factors used in day-ahead and the actual real-time load distribution (LDF Contribution);
- Day-ahead Point-to-Point (PTP) obligations linked to options[46] settlements (CRR Uplift);
- Extra congestion rent that accrued when real-time transmission constraints were violated (Overflow Credit); and
- Other factors, including the price floor in the real-time market at -$251 per MWh (Other).

Figure 11 provides an analysis of RENA uplift in 2021, separately showing the components of RENA on a monthly basis, with the effects of Winter Storm Uri included. Net negative uplift represents an overall payment to load.

Almost all the RENA uplift occurred in market hours when there was transmission congestion. The largest positive contributor to RENA uplift in 2021 was the LDF Contribution, contributing $120 million. The next largest positive contributor was CRR Uplift, related to NOIE PTP Options. Uplift from the contributions of transmission model differences between day-ahead and real-time, described as Model Differences, was mostly negative in 2021, with the most notable contribution in February during Winter Storm Uri. The negative and positive uplift almost completely offset each other over the course of the year, leaving less than $1 million in net overall RENA.

[46] A Point-to-Point obligation linked to an option (PTPLO) is a type of CRR that entitles a Non-Opt-In Entity's (NOIE's) PTP Obligation in the DAM to reflect the NOIE's PTP Option that it acquired in the CRR auction or allocation. Qualified PTPLOs are modeled as obligations but settled as if they were options.

Figure 11: ERCOT RENA Analysis (with Uri)

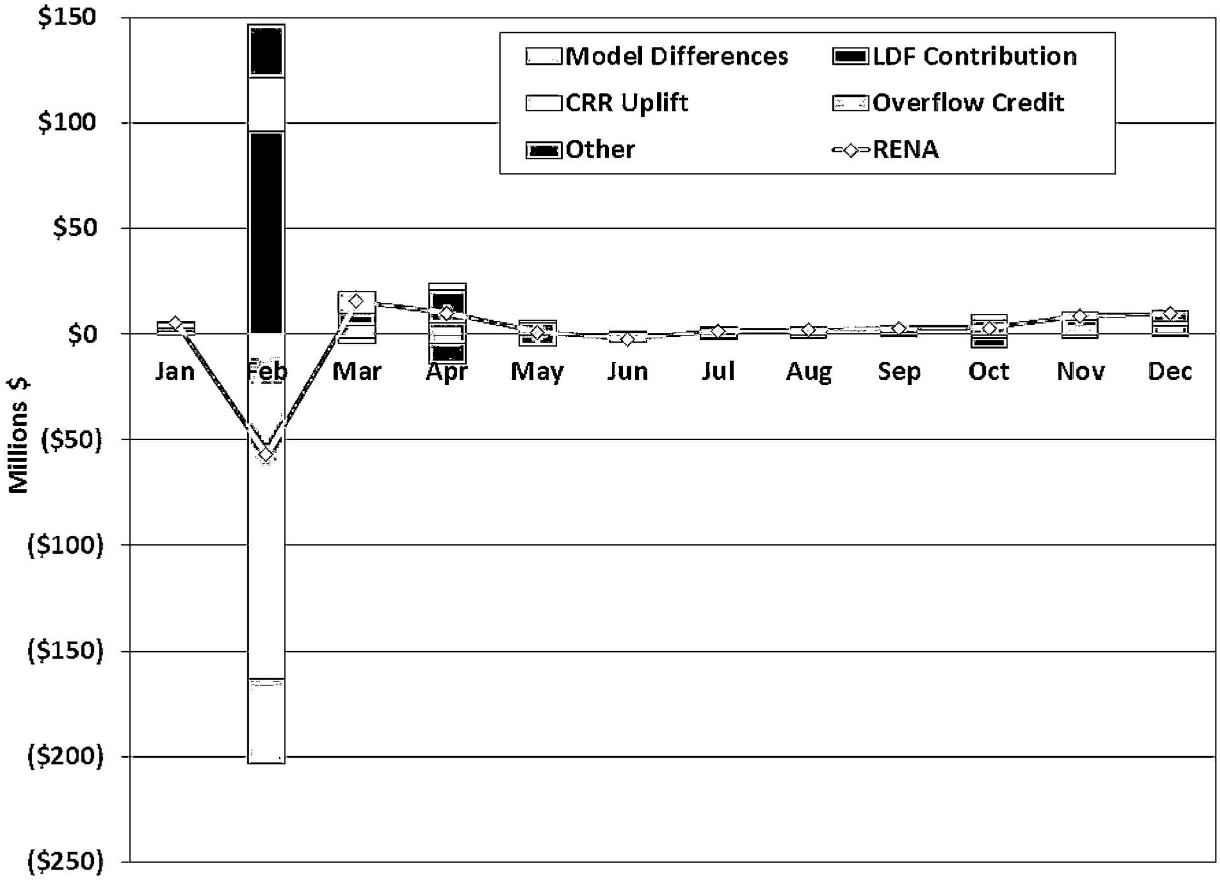
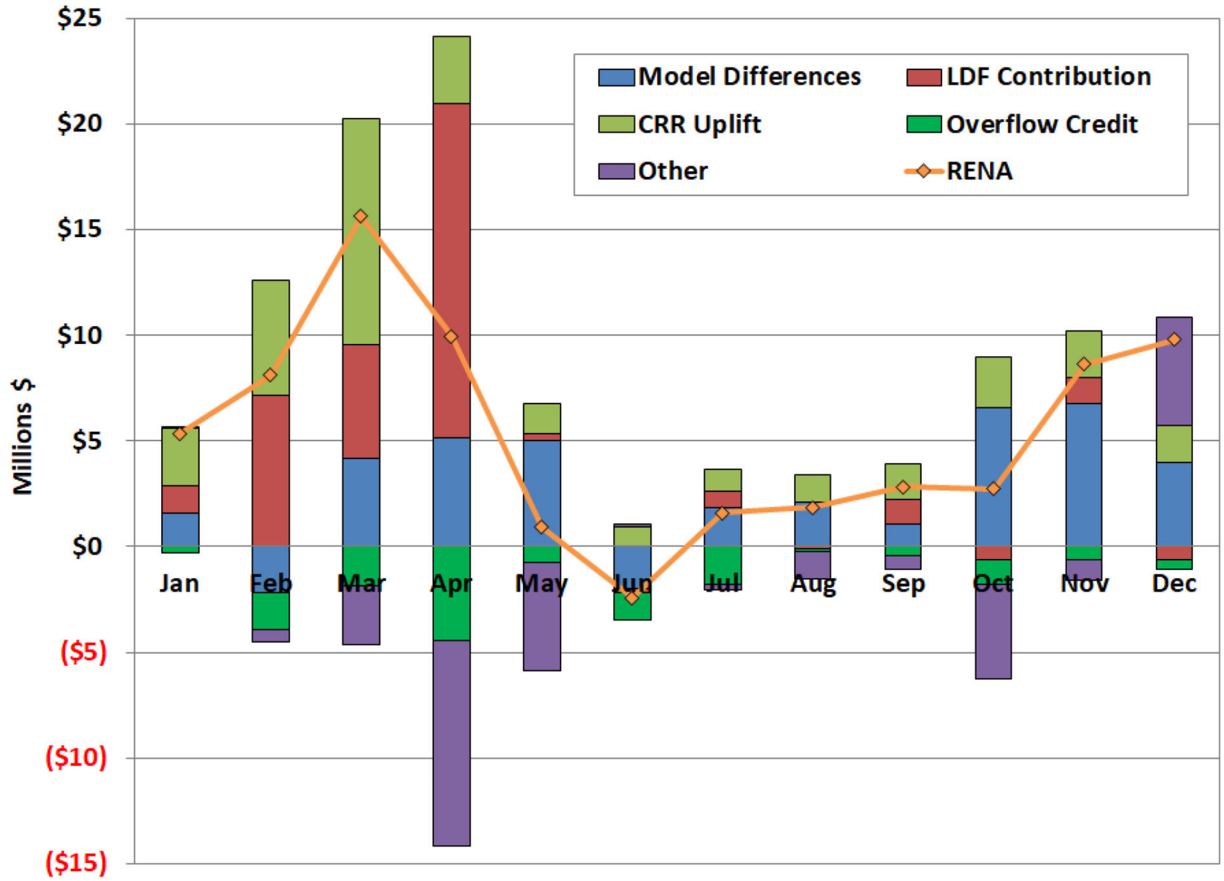


Figure 12 below provides an analysis of RENA uplift in 2021, separately showing the components of RENA on a monthly basis, without the effects of Winter Storm Uri included. Under this analysis, the largest contributors to RENA uplift in 2021 were due to oversold amounts in the DAM, contributing $66 million, and model differences, contributing $34 million. These uplift costs were partially offset by $15 million in negative uplift related to overflow credits when the shadow price reached the shadow price cap for a transmission constraint, and other negative uplift of $21 million.

Figure 12 also shows that RENA uplift from the settlement of DAM PTP obligations linked to options, described as CRR Uplift, was relatively high in March, and the uplift from transmission modelling differences was high in October and November.

Figure 12: ERCOT RENA Analysis (without Uri)



The task of maintaining accurate and consistent load distribution factors across all markets is a difficult one, made more so in areas with large amounts of localized load growth. These are exactly the types of areas that draw higher levels of market interest. To the extent ERCOT is unable to predict accurate load distribution factors across all markets, RENA impacts will persist. NPRR1004, *Load Distribution Factor Process Update*, (approved on August 11, 2020) is still pending an implementation date and should help reduce this uplift.

D. Real-Time Prices Adjusted for Fuel Price Changes

Although real-time electricity prices are driven largely by changes in natural gas prices, they are also influenced by other factors. To summarize the changes in energy price that were related to these other factors, an "implied marginal heat rate" is calculated by dividing the real-time energy price by the natural gas price. Figure 13 and Figure 14 show the implied marginal heat rates monthly in each of the ERCOT zones with and without the effects of Winter Storm Uri. This figure is the fuel price-adjusted versions of Figure A3 and A4 in the Appendix.

Figure 13: Monthly Average Implied Heat Rates (with Uri)

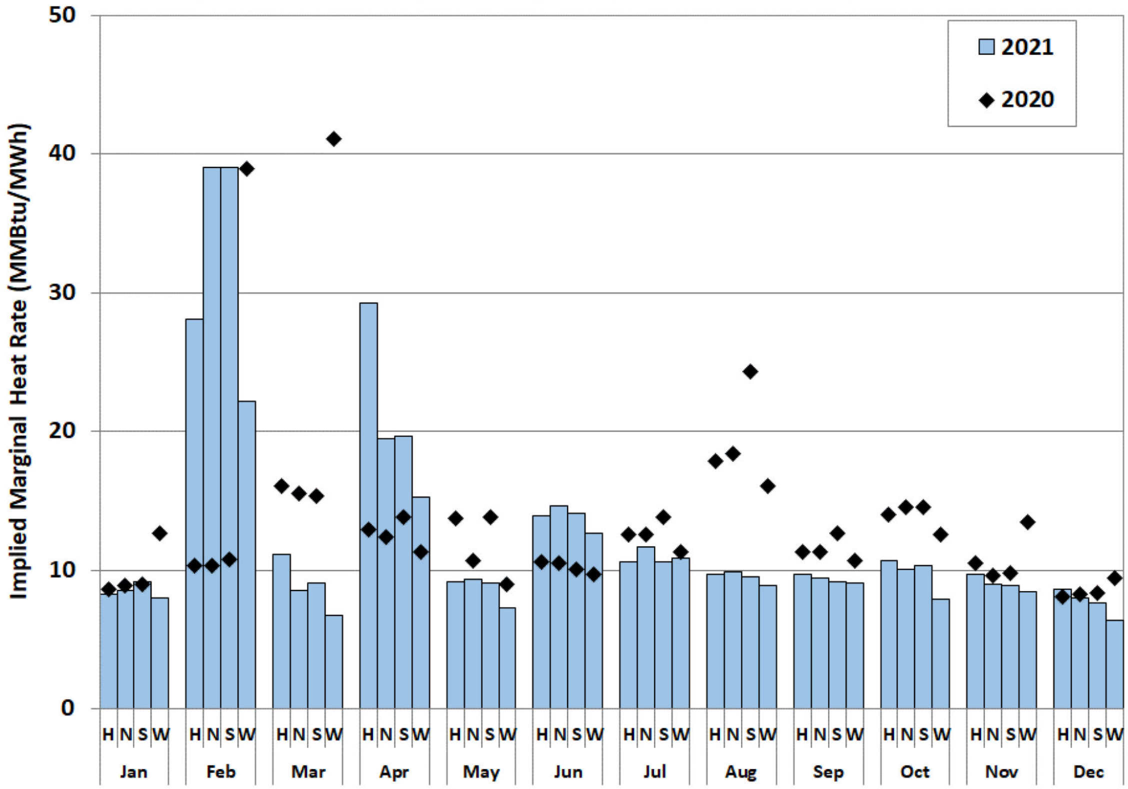
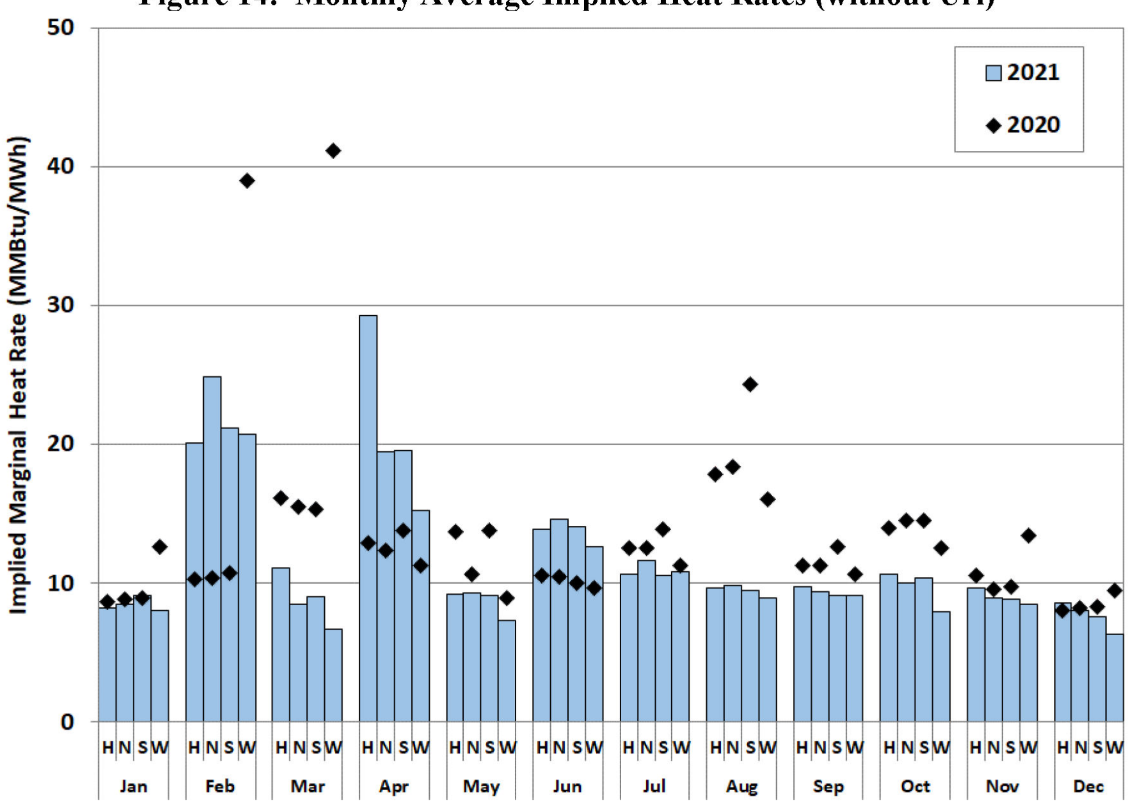


Figure 14: Monthly Average Implied Heat Rates (without Uri)

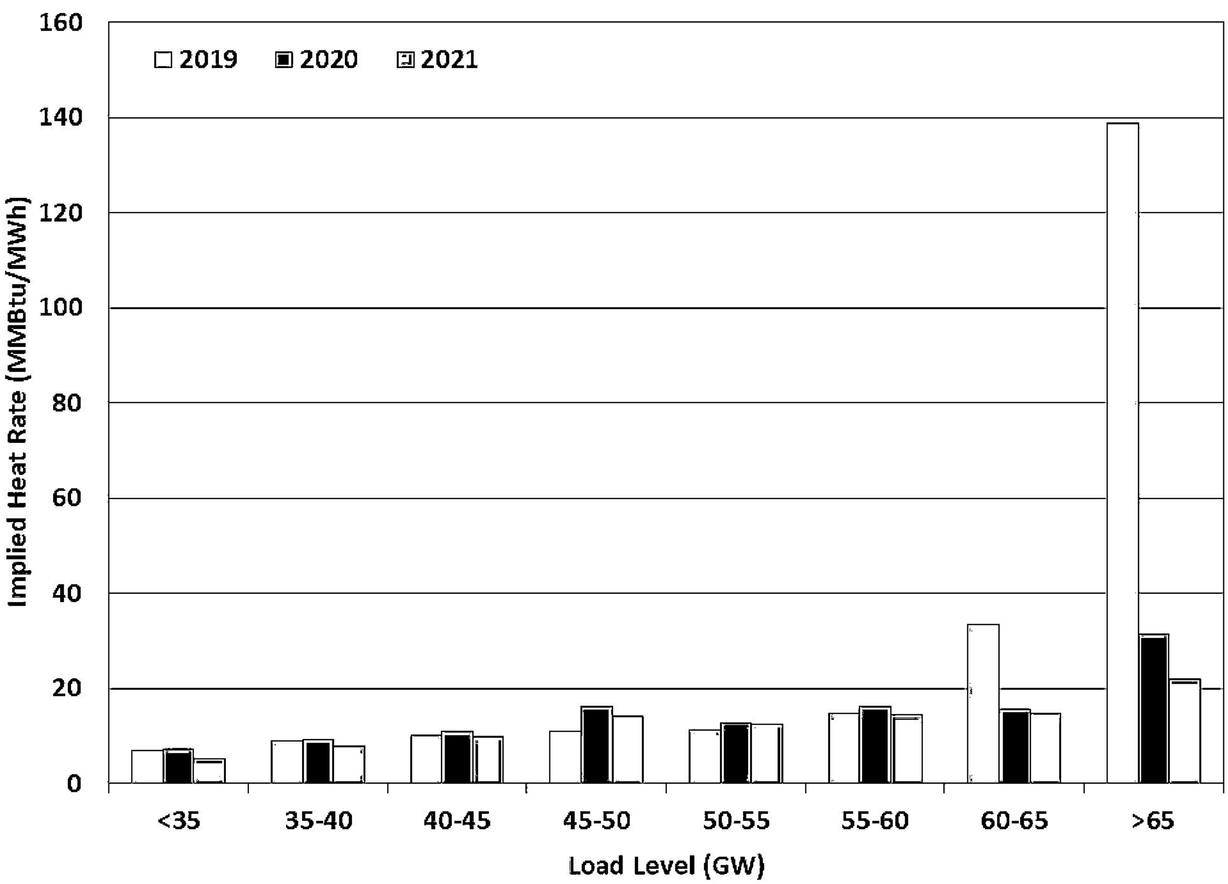


The implied heat rate varied substantially among zones in 2021, particularly in February as extreme cold weather led to high load levels and prices. Transmission congestion and differences in load levels drove zonal differences, particularly for the Houston and West zones in February and April 2021. Overall, average implied heat rates were as expected for a year with periods of extreme operating reserve shortages in February and minimal reserve shortages during the summer.

The implied heat rate is mostly lower than 2020 when the effects of the extreme cold weather of February are removed from the analysis, especially during the second half of the year. This can be attributable to more coal output due to the high natural gas prices, as well as the effect of more conservative operations in the latter half of the year.

Figure 15 shows how the implied heat rate varies by load level over the past three years. As expected in a well-performing market, 2021 exhibited a positive relationship between implied heat rate and load level, though the magnitude of the change is somewhat lower than the previous few years. Resources with higher marginal costs were dispatched as load approached peak. For additional analysis of real-time energy prices adjusted for fuel price changes, see Figure A9, Figure A10, and Table A2 in the Appendix.

Figure 15: Implied Heat Rate and Load Relationship



E. Aggregated Offer Curves

The next analysis compares the quantity and price of generation offered in 2021 to that offered in 2020. By averaging the amount of capacity offered at selected price levels, an aggregated offer stack can be assembled. Figure 16 provides the average aggregated generator offer stacks for the entire year, as well as the peak load hour of the year.

This figure shows that in both periods, as in previous years, the largest amount of capacity is not dispatchable because it is below generators' Low Sustainable Limit (LSL) and is a price-taking portion of the offer stack. The second largest share of capacity is priced at levels between zero and a value equal to 10 times the daily natural gas price (known as the Fuel Index Price, or FIP): $(10*FIP). This price range represents the incremental fuel price for the vast majority of the ERCOT generation fleet.

Figure 16: Aggregated Generation Offer Stack - Annual and Peak

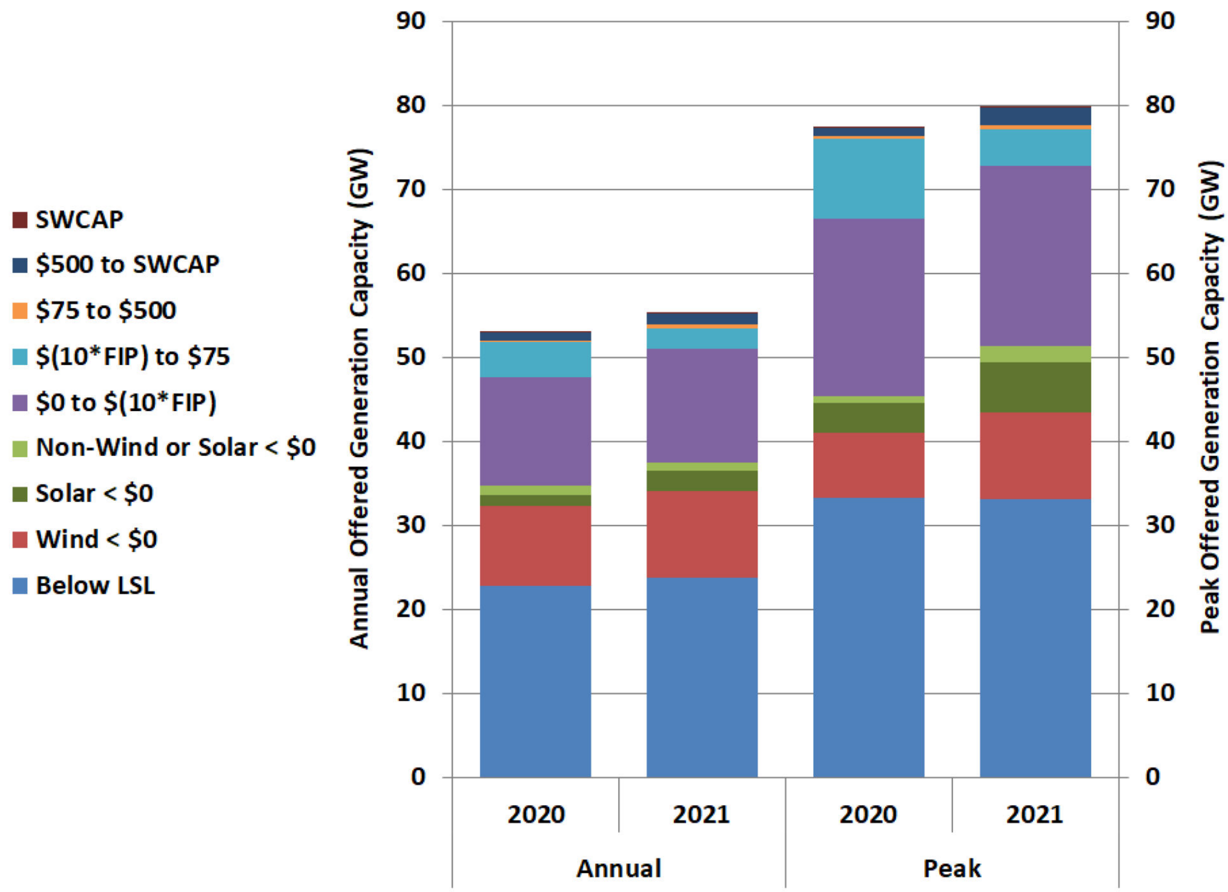


Figure 16 shows that in 2021, on average:

- The amount of capacity offered below LSL increased by about 1,000 MW
- The amount of capacity offered at prices less than zero attributable to wind and solar increased by approximately 1,900 MW.

- Non-wind and non-solar capacity offered at less than zero decreased by about 140 MW;
- Approximately 600 MW more capacity was offered between $0 and $(10*FIP);
- The amount of capacity offered at prices between $(10*FIP) and $75 per MWh decreased by 1,800 MW from 2020 to 2021; and
- The amount of capacity offered between $75 per MWh and the SWCAP increased by about 799 MW
- The total amount of generation capacity offered into ERCOT's real-time market increased by over 2,200 MW in 2021.

Figure 16 also shows that the changes in the aggregated offer stacks between the peak load hours of 2020 and 2021 were relatively consistent with those in the annual aggregated offer stacks for those years. In comparison to the 2020 peak load hour, in the 2021 peak load hour:

- The amount of capacity below LSL decreased by about 80 MW.
- The amount of capacity offered below $0 per MWh by wind and solar generators increased by about 5,000 MW.
- The amount of capacity offered below $0 per MWh by non-wind and non-solar generators increased by about 1,100 MW.
- Approximately 150 MW more capacity was offered between $0 and $(10*FIP).
- Approximately 4,900 MW less capacity was offered between $(10*FIP) and $75 per MWh.
- Approximately 1,200 MW more capacity was offered between $75 per MWh and SWCAP.
- The aggregate offer stack increased by approximately 2,500 MW from the previous year.

F. ORDC Impacts and Prices During Shortage Conditions

The Operating Reserve Demand Curve (ORDC) represents the reliability costs or risks of having a shortage of operating reserves. When resources are not sufficient to maintain the full operating reserve requirements of the system, the probability of "losing load" increases as operating reserve levels fall. This VOLL leads to efficient shortage pricing as it is reflected in both operating reserves and energy prices during shortages.

The Public Utility Commission directed ERCOT to move forward with implementing ORDC on September 12, 2013, including setting VOLL at $9,000 per MWh. Selected at the time as an easier-to-implement alternative to real-time co-optimization of energy and ancillary services, the ORDC places an economic value on the reserves being provided in real-time, with separate pricing for online and offline reserves. In 2019, the Commission approved a phased process to change the ORDC and directed ERCOT to use a single blended ORDC curve and implement a

0.25 standard deviation shift in the LOLP calculation implemented on March 1, 2019. The second step, consisting only of an additional 0.25 standard deviation shift in the LOLP calculation, was implemented on March 1, 2020.[47]

Effectively, these shifts accelerated the increase in prices toward VOLL at higher reserve levels. The changes made in 2019 and 2020 increased costs to load but also provided incentives for maintaining higher operating and planning reserves. These changes were in place throughout 2021, including during Winter Storm Uri in February 2021.

In the aftermath of Winter Storm Uri, the Commission further refined the ORDC. Effective January 1, 2022, the Minimum Contingency Level (MCL) was set at 3,000 MW and the HCAP and VOLL were reduced from $9,000 per MWh to $5,000 per MWh.[48]

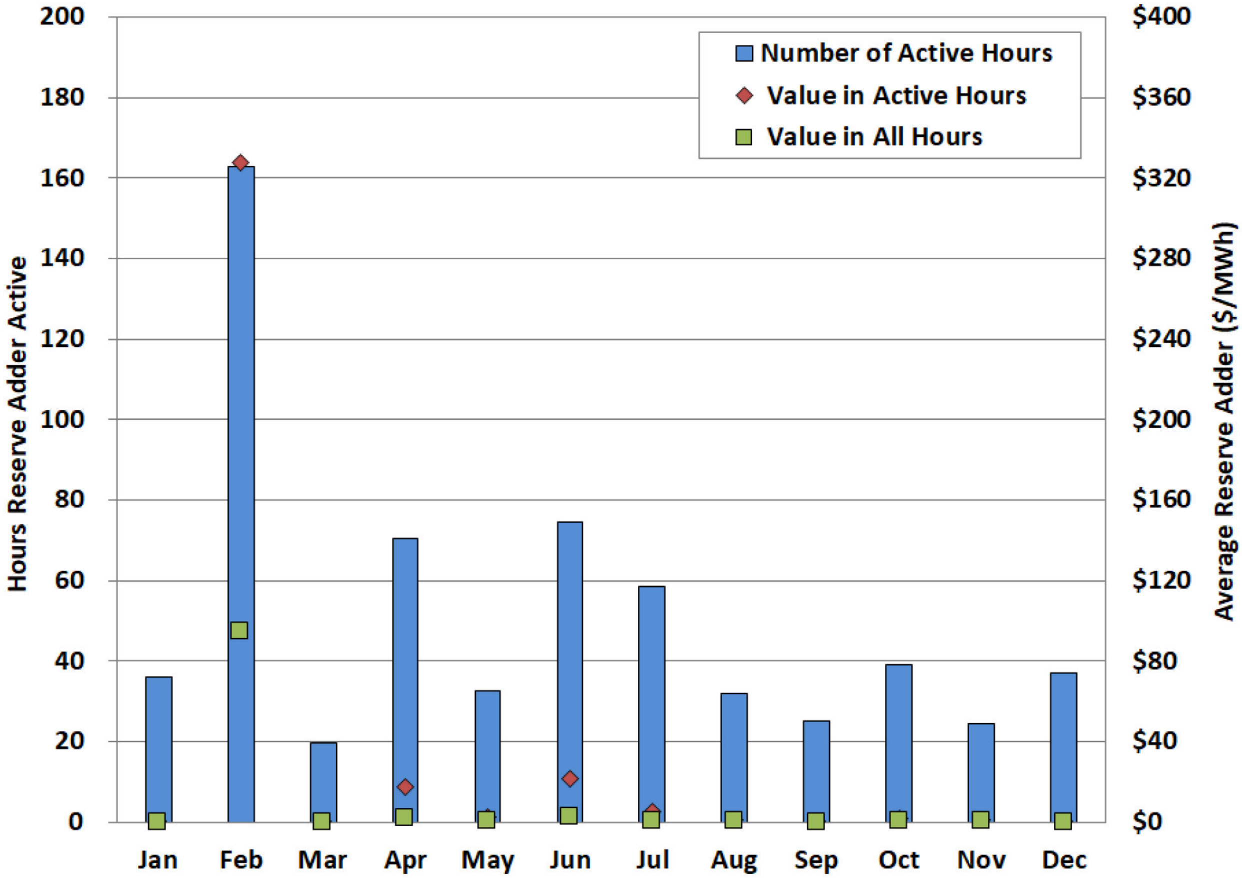
The following two analyses illustrate the contributions of the operating reserve adder and the reliability adder to real-time prices. Figure 17 shows the number of hours in which the operating reserve adder affected prices in each month of 2021, and the average price effect in these hours and all hours. This figure shows that in 2021, the operating reserve adder had the largest price impacts in February because of Winter Storm Uri and the extreme shortage conditions that occurred. The contribution from the operating reserve adder in 2021 was much higher than in 2020 because of the significant increase in shortage conditions.

The figure shows that April and June also had average operating reserve adders over $1, and there were minimal average adders in the remaining months of the year. Overall, the operating reserve adder contributed $8.32 per MWh, or approximately 5% of the annual average real-time energy price of $167.88 per MWh in 2021. The effects of the operating reserve adder are expected to vary substantially from year to year. It will have the largest effects when low supply conditions and high load conditions occur together and result in sustained shortages, like the market experienced in 2019 and 2021.

47 The ORDC changes were approved by the ERCOT Board of Directors at its February 12, 2019, meeting and implemented via OBDRR011, *ORDC OBD Revisions for PUC Project No. 48551*.

48 After a series of rigorous public work sessions and review of volumes of comments filed by market participant, the Commission directed ERCOT to address short- and long-term electric grid reliability concerns by enacting major reforms (see *Review of Wholesale Electric Market Design*, Project No. 52373 (pending)), at the December 16, 2021, open meeting. Specifically, the Commission approved the blueprint for the design of the wholesale electric market filed in the Project on December 6, 2021, including the ORDC changes.

Figure 17: Average Operating Reserve Adder (with Uri)

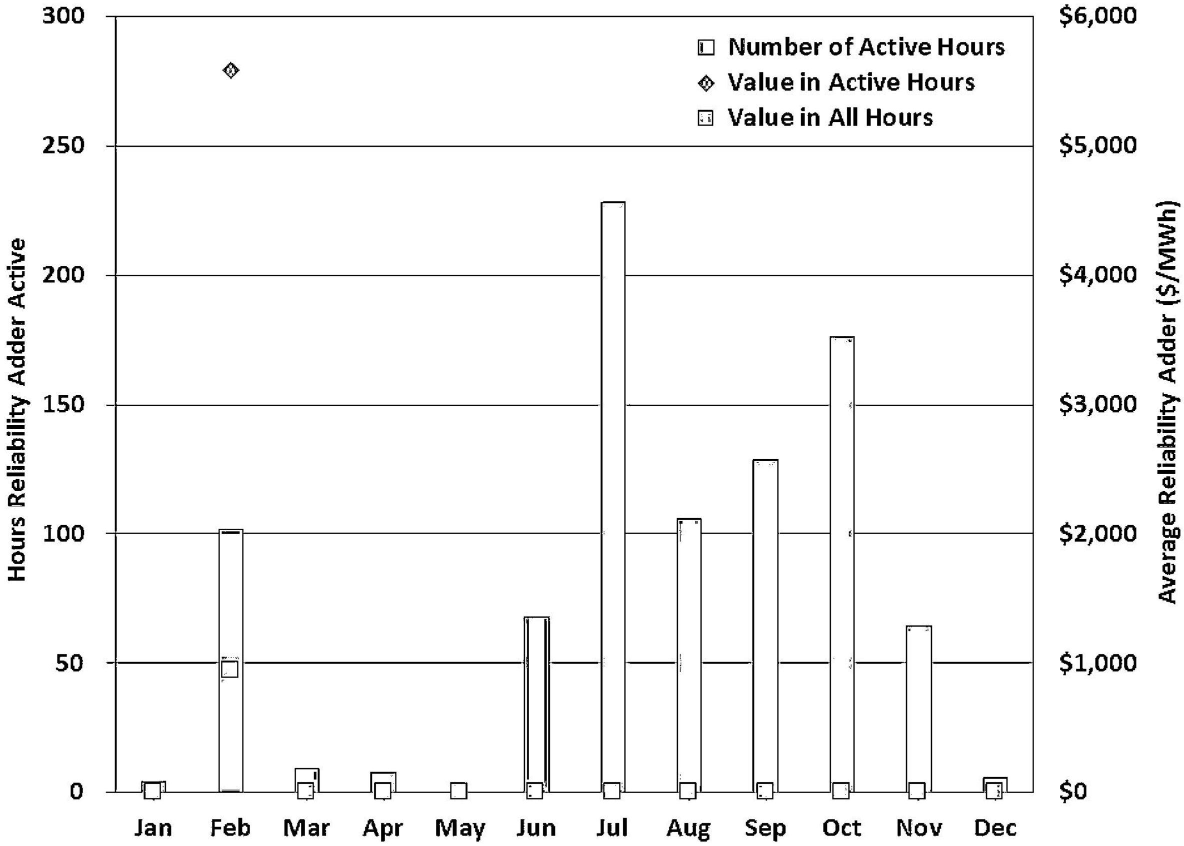


The second adder is the reliability adder. The reliability adder is intended to mitigate the price-suppressing effects of reliability actions taken by ERCOT, including RUCs and deployed load capacity. Absent this adder, prices will generally fall when these actions are taken because they increase supply or reduce demand outside of the market.

Figure 18 below shows the impacts of the reliability adder in 2021. When averaged across only the hours when the reliability adder was non-zero, the largest price impacts of the reliability adder occurred during February. The reliability adder was non-zero for 10.2% of the hours in 2021.

The highest contribution to the real-time energy price besides February were in June, July and October because of the evolution of ERCOT's more conservative operations after Winter Storm Uri and their increased reliance on RUCs, discussed in Section VI. The contribution from the reliability adder to the annual average load-weighted real-time energy price was almost $80 per MWh, primarily due to the extremely high reliability adders during Winter Storm Uri. Excluding Winter Storm Uri, the reliability adder in February would have been close to zero.

Figure 18: Average Reliability Adder (with Uri)



As an energy-only market, the ERCOT market relies heavily on pricing to provide key economic signals to guide decisions by market participants. However, the frequency and impacts of scarcity can vary substantially from year-to-year, as shown in the figure below.

To summarize the shortage pricing that has occurred since 2011, Figure 19 below shows the aggregate amount of time when the real-time system-wide energy price exceeded $1,000 per MWh, by month for 2019 through 2021, as well as annual summaries for 2011 through 2021. Figure 20 shows the same analysis excluding Winter Storm Uri.

Figure 19 shows that the duration of high prices in 2021 was far greater than anything the ERCOT market had previously experienced. Prices greater than $1,000 per MWh occurred in about 166 hours in 2021, when they occurred in only 7 hours in 2020. Prices were between $7,000 and $8,999 for nearly 34 hours, and the high system-wide offer cap of $9,000 was reached for intervals totaling more than 64 hours.[49]

Figure 20 shows that prices greater than $1,000 per MWh occurred in just under 20 hours, and never exceeded $5,000 per MWh in any other interval throughout the year.

[49] See *Review of 25.505*, Project No. 52631, (Dec. 2, 2021), in which the Commission reduced the high system-wide offer cap to $5,000 per MWh effective January 1, 2022.

Figure 19: Duration of High Prices (with Uri)

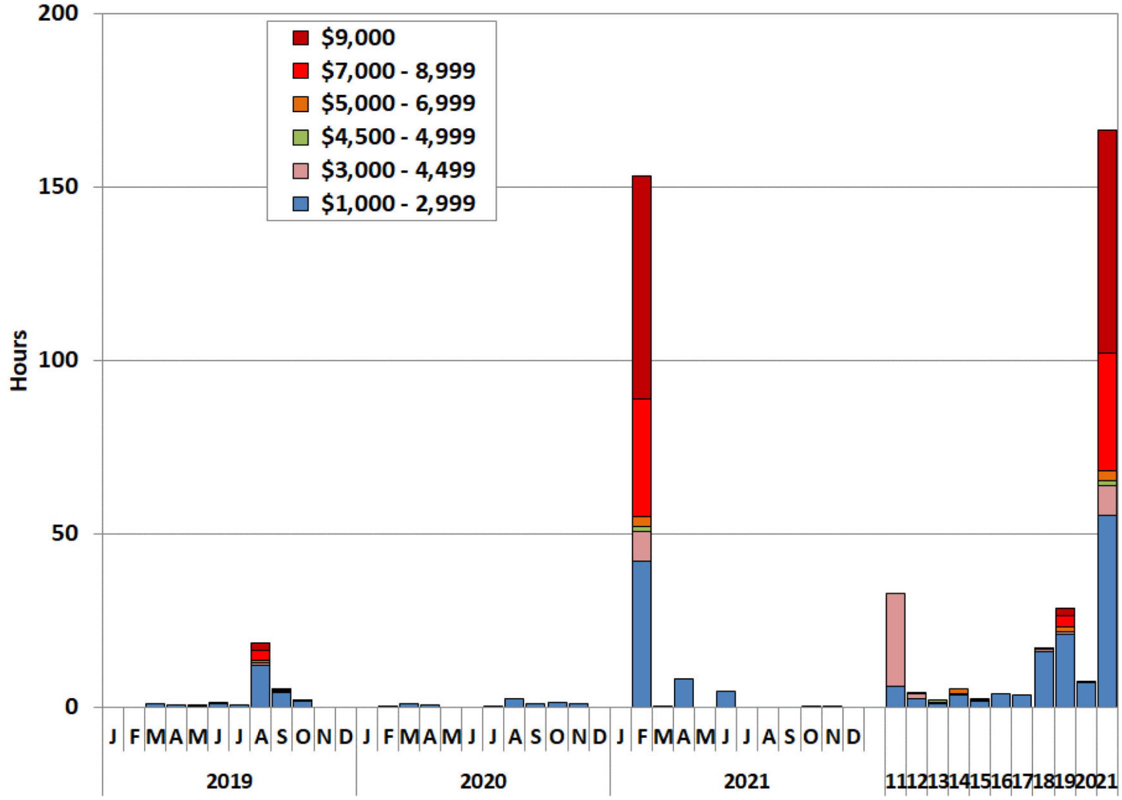
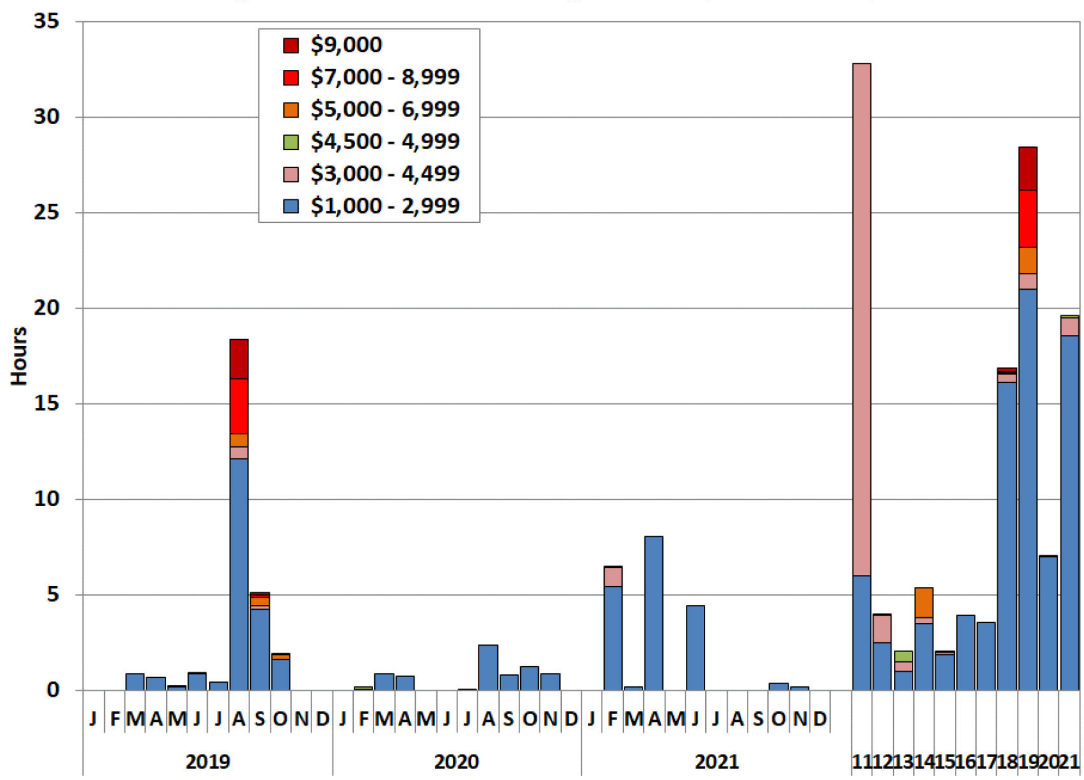


Figure 20: Duration of High Prices (without Uri)



G. Real-Time Price Volatility

To conclude our review of real-time market outcomes, we examine price volatility in this subsection. Volatility in real-time wholesale electricity markets is expected because system load can change rapidly and the ability of supply to adjust can be restricted by physical limitations of the resources and the transmission network. To present a view of price volatility, Table 2 below shows the average 15-minute absolute change in the 15-minute settlement point prices expressed as a percentage of annual average price for the four geographic zones for years 2013-2021. Larger values represent higher deviation from the mean.

Table 2: Zonal Price Variation as a Percentage of Annual Average Prices

Load Zone	2013	2014	2015	2016	2017	2018	2019	2020	2021	2021 w/o Uri
Houston	14.8%	14.7%	13.4%	20.8%	24.9%	21.5%	22.7%	21.2%	8.1%	21.9%
South	15.4%	15.2%	14.6%	19.9%	26.2%	23.5%	23.5%	21.7%	7.7%	21.1%
North	13.7%	14.1%	11.9%	15.5%	14.8%	20.7%	22.6%	19.8%	7.4%	20.5%
West	17.2%	15.4%	12.9%	16.8%	17.5%	21.8%	24.7%	26.5%	7.7%	23.1%

These results show overall volatility dropped markedly in all zones in 2021 when including the period of Winter Storm Uri. This overall decrease is explained by high system-wide pricing during February 2021 which significantly increased the average prices. For comparison, price volatility in 2021 would have been comparable with 2020 without the effects of Winter Storm Uri.

Congestion explains most of the inter-zonal differences in price volatility. Volatility was again highest in the West zone in 2021 because of higher congestion, though not quite as much volatility as seen in 2020. A similar set of factors in 2017 and 2018 caused the South zone to exhibit the highest price volatility in those years.

For additional analysis of real-time price volatility, see Figure A11 and Figure A12 in the Appendix.

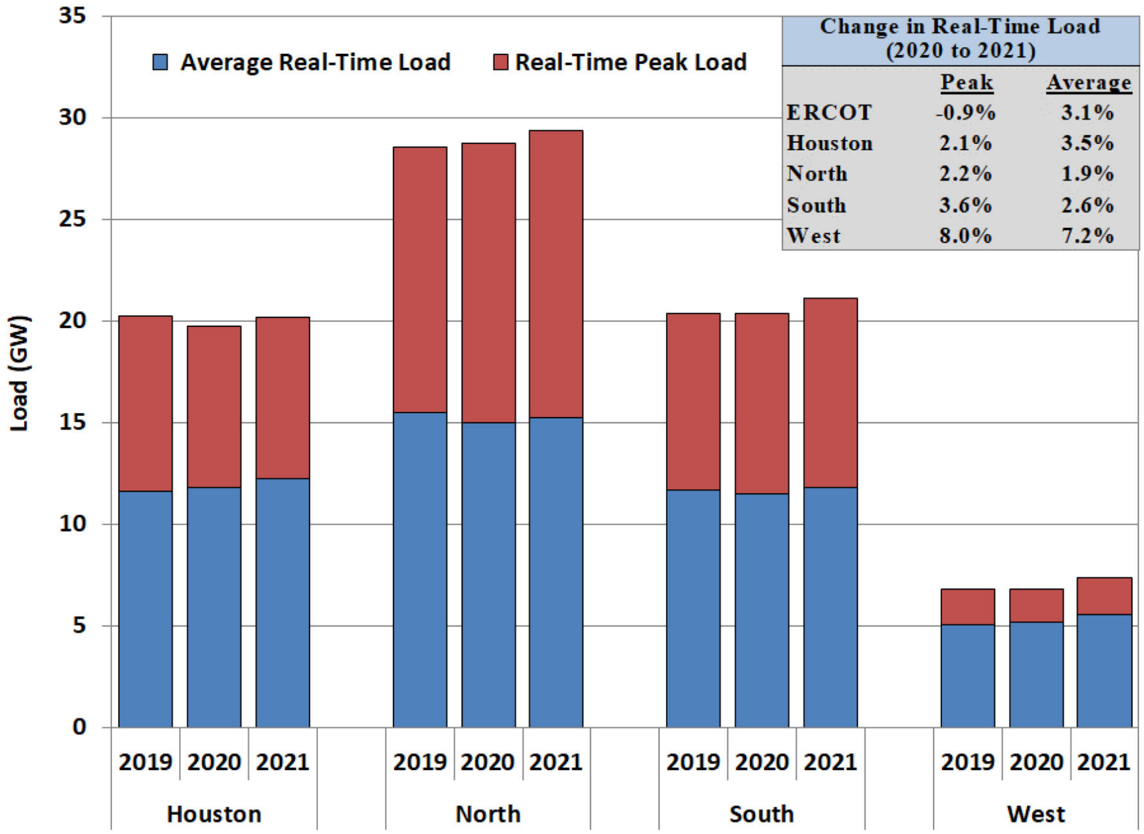
III. Demand and Supply in ERCOT

Many of the trends in market outcomes described in Section I are attributable to changes in the supply portfolio or load patterns in 2021. In this section, therefore, we review and analyze these load patterns and the generating capacity available to satisfy the load and operating reserve requirements. We include a specific analysis of the large quantity of installed wind and solar generation, along with discussion of the daily generation commitment characteristics. This section concludes with a review of the contributions from demand response resources.

A. ERCOT Load in 2021

We track the changes in average load levels from year to year to better understand the load trends, which captures changes in load over a large portion of the hours during the year. However, changes in the load during the highest-demand hours is important because it affects the probability and frequency of shortage conditions.[50] Figure 21 shows peak load and average load by geographic zone from 2019 through 2021.[51]

Figure 21: Annual Load Statistics by Zone



Change in Real-Time Load (2020 to 2021)		
	Peak	Average
ERCOT	-0.9%	3.1%
Houston	2.1%	3.5%
North	2.2%	1.9%
South	3.6%	2.6%
West	8.0%	7.2%

50 In recent years, peak net load (load minus intermittent renewable output) is a more direct cause of shortages.

51 Non-Opt In Entity (NOIE) load zones have been included with the proximate geographic zone.

Figure 21 shows that the total ERCOT load in 2021 increased over 3% from 2020, which is an increase of more than 1,300 MW on average. The Houston and West zones showed an increase in average real-time load in 2021 ranging from 3.5% in Houston to 7.2% in the West. The increase in the West zone continues a pattern of significant increases seen year over year. Continuing robust oil and natural gas production activity in the West zone has been the driver for high load growth.

Peak demand occurred on August 24, 2021, reaching 73,687 MW between 4 and 5 p.m., lower than the all-time peak demand record of 74,820 MW set on August 12, 2019. Fluctuations in peak and average load are usually driven by summer conditions. Cooling degree days is a measure of weather that is highly correlated with the demand for electricity for air conditioning. In June through August, there was a decrease in Houston, Dallas, and Austin (-3%, -7%, and -11%, respectively) compared to 2020. Cooling degree days is a metric that is highly correlated with summer loads.

A more detailed analysis of the load, via hourly load duration curves, is available in the Appendix in Figure A13 and Figure A14.

B. Generation Capacity in ERCOT

In this section we evaluate the generation portfolio in ERCOT in 2021. The distribution of capacity in the North and South zones is similar to the distribution of demand, and Houston generally imports more power than it generates and the West zone exports more power than it consumes. The Houston zone has increasingly relied on imports from the rest of the state as local resources have been mothballed and the reliance on intermittent resources has increased.

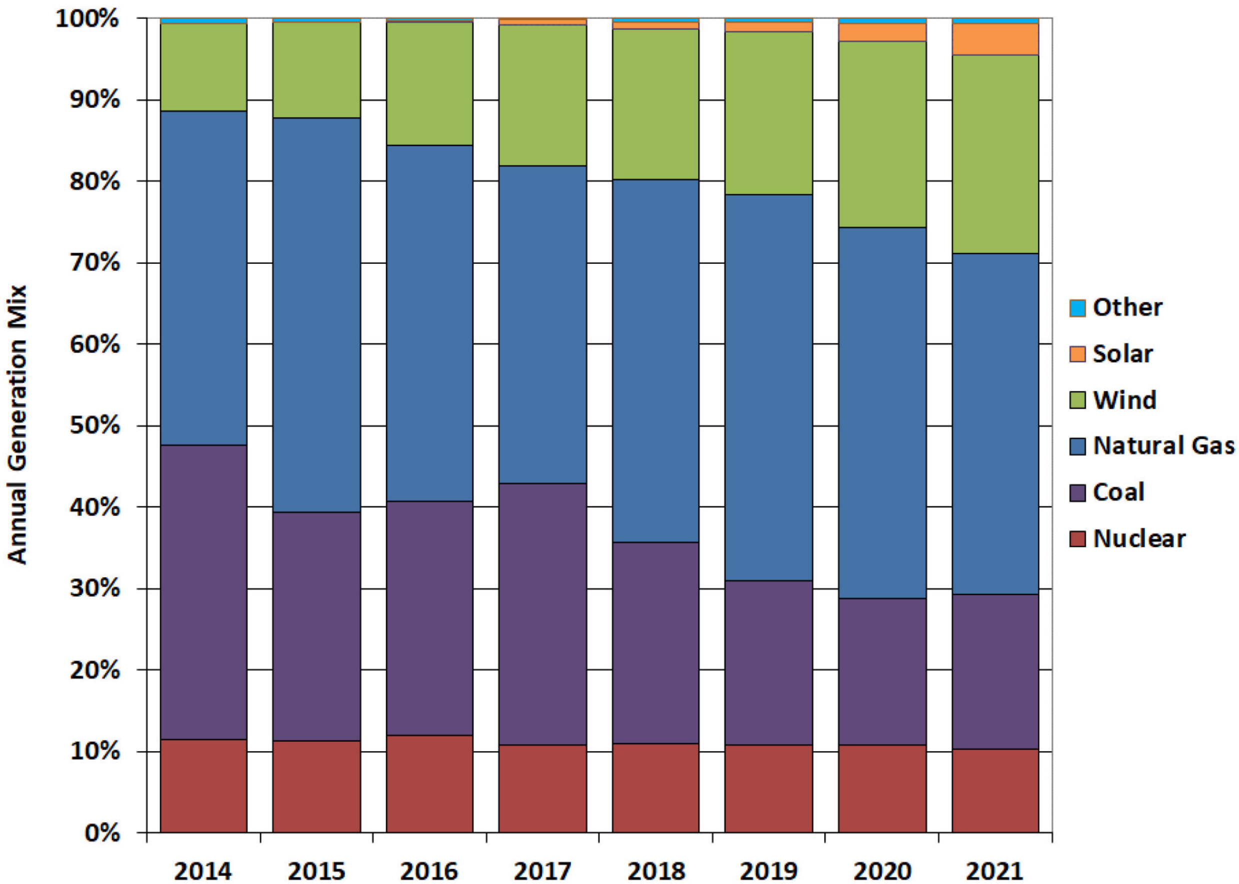
Approximately 8.8 GW of new generation resources came online in 2021. The bulk of this capacity was intermittent renewable resources and the remaining capacity was 660 MW of combustion turbines, 70 MW of combined cycle, and 820 MW of ESRs. ERCOT had roughly 1,800 MW of new installed wind capacity and 2,500 of new installed solar capacity going into summer 2021 compared to summer 2020, with an effective peak serving capacity totaling 2.4 GW.[52] Sixteen gas-fired projects, 36 wind projects, and 26 solar projects came online in 2021. The 24 energy storage projects that came online in 2021 increased ERCOT's storage capacity by about five times to around 1 GW. There were 172 MW of retirements in 2021, including 150 MW wind and 22 MW gas. These changes are detailed in Section V of the Appendix, along with a review of the vintage of the ERCOT fleet.

Figure 22 shows the annual composition of the generating output in ERCOT from 2014 to 2021. This figure shows the transition of ERCOT's generation fleet away from coal-fired resources to

52 The percentages of installed capacity to serve peak demand assume availability of 29% for panhandle wind, 61% for coastal wind, 19% for other wind, and 80% for solar.

natural gas and renewable resources. Some of this transition has been driven by the vintage of the generating units in ERCOT. For example, 70% of the total coal capacity in ERCOT was at least thirty years old in 2021. Combined cycle gas capacity was the predominant technology choice for new investment throughout the 1990s and early 2000s. However, between 2006 and 2019, wind has been the primary technology for new investment, and in 2020 and 2021 wind and solar both saw large increase in capacity. The amount of utility-scale solar capacity added in 2021 (3,600 MW) was the largest amount of solar added to the ERCOT system in any given year, bringing total installed capacity to nearly 9,600 MW

Figure 22: Annual Generation Mix in ERCOT



This figure shows:

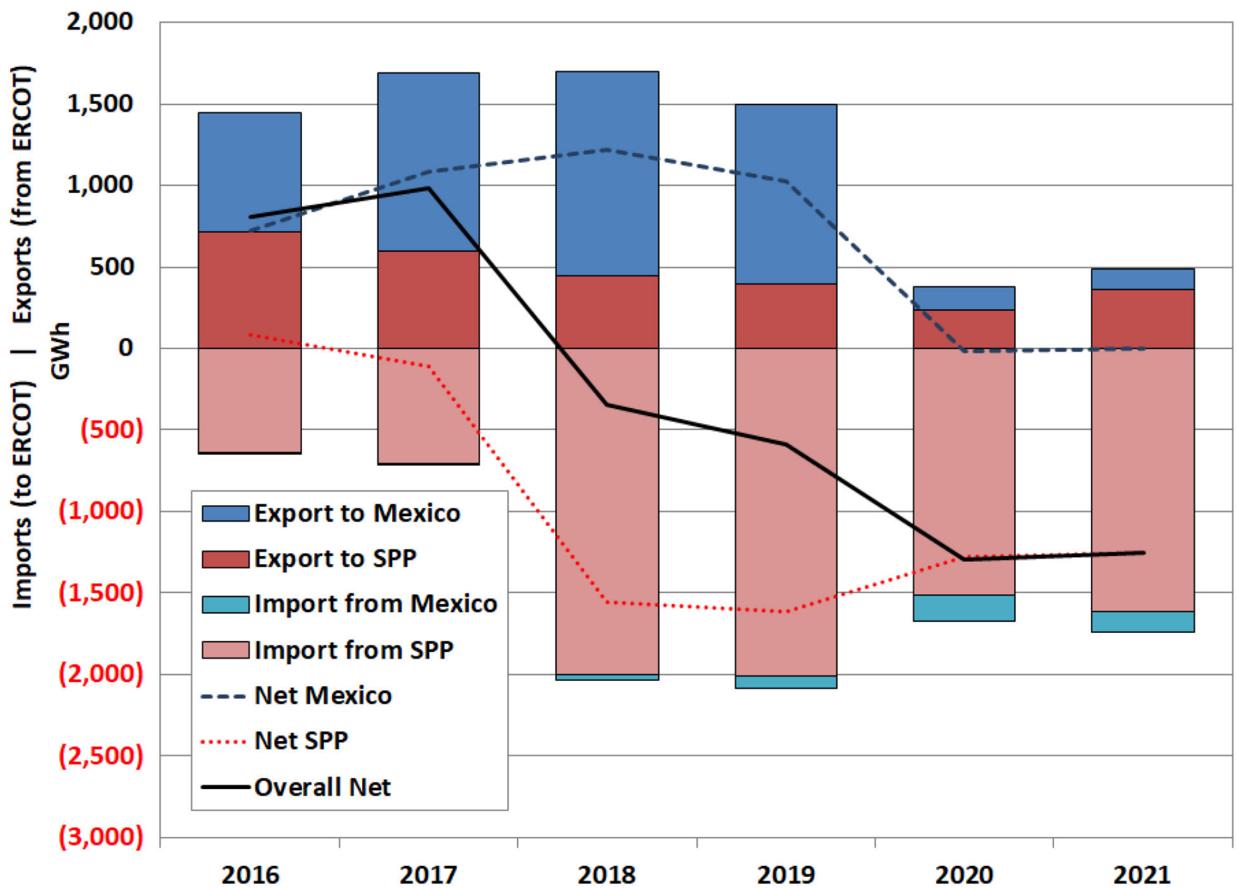
- The generation share from wind has increased every year, reaching over 24% of the annual generation in 2021.
- Solar increased from 2.3% of annual generation in 2020 to 4% of annual generation in 2021.
- The share of generation from coal was similar to 2021.
- Natural gas generation decreased again in 2021, from 46% in 2020 to less than 42% in 2021.

We expect these trends to continue because of the continued growth of wind, solar, and storage resources. Figure A15 in the Appendix shows the vintage of ERCOT installed capacity. The installed generating capacity by type in each zone is shown in Figure A16 in the Appendix.

C. Imports to ERCOT

The ERCOT region is connected to other regions in North America via multiple asynchronous ties. Two ties totaling 820 MW connect ERCOT with the Southwest Power Pool (SPP) and two ties totaling 400 MW connect ERCOT with Comisión Federal de Electricidad (CFE) in Mexico. Transactions across the direct current (DC) ties can be in either direction, into or out of ERCOT. These transactions can have the effect of increasing demand (exports) or increasing supply (imports). Figure 23 shows the total energy transacted across the ties for the past several years.

Figure 23: Annual Energy Transacted Across DC Ties



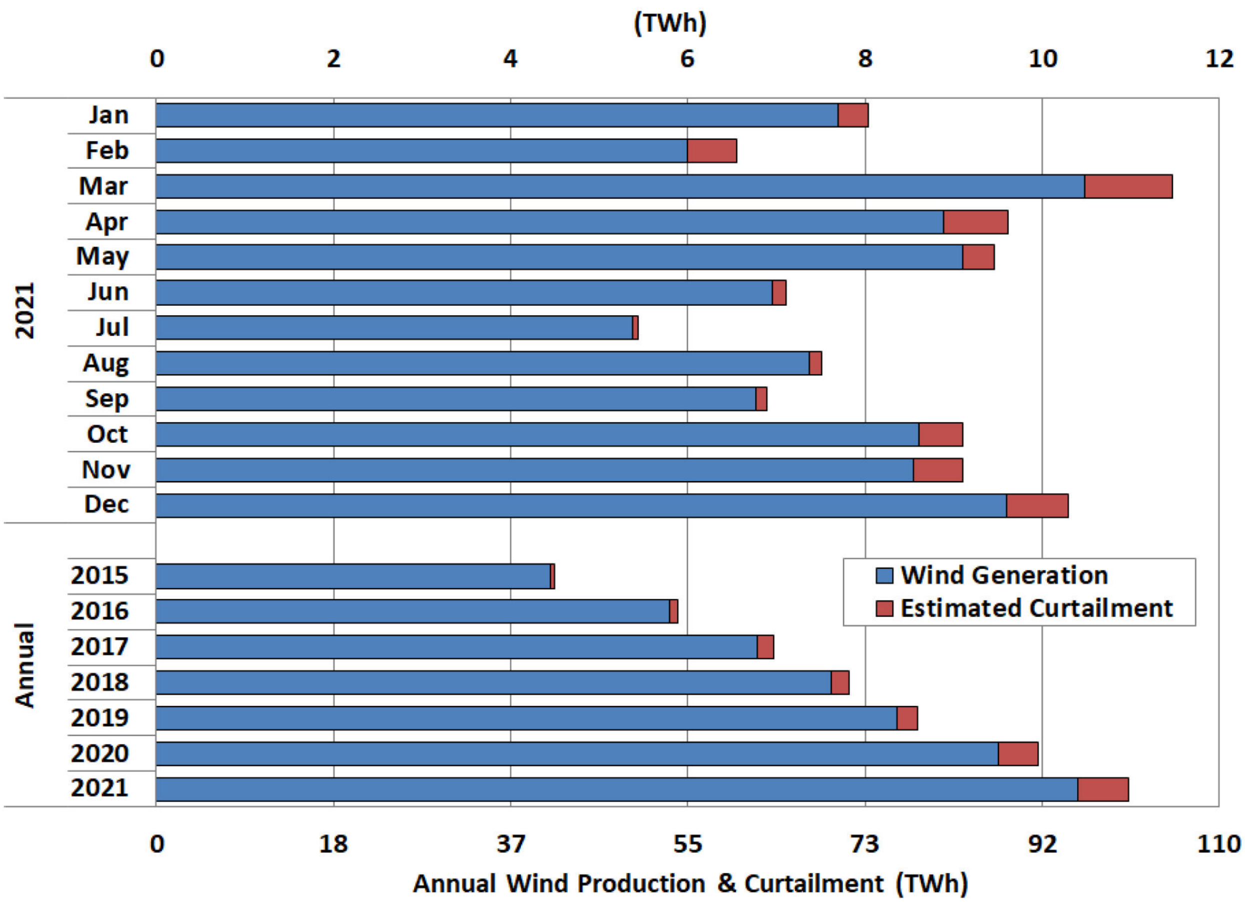
The figure shows that ERCOT remained a net importer in 2021. This trend began in 2018 due to tightening supply in ERCOT and the resulting higher prices in 2018 and 2019. The amount of tie activity in 2021 was comparable to the activity in 2020.

D. Wind and Solar Output in ERCOT

Investment in wind resources has continued to increase over the past few years in ERCOT. The amount of wind capacity installed in ERCOT was more than 34 GW at the end of 2021. Although much of the wind generation is in the West zone, more than 8 GW of wind generation is located in the South zone and 2 GW are in the North zone.

The value of wind in satisfying ERCOT's peak summer demand is limited by its negative correlation with load.[53] The highest wind production occurs during non-summer months, and predominately during off-peak hours. Peak prices ($9,000 per MWh) in August 2019 coincided peak *net* load – when wind output was low and therefore the demand was higher on other generation units. Wind output during high load periods will continue to be a pivotal determinant of shortages.

Figure 24: Wind Production and Curtailment



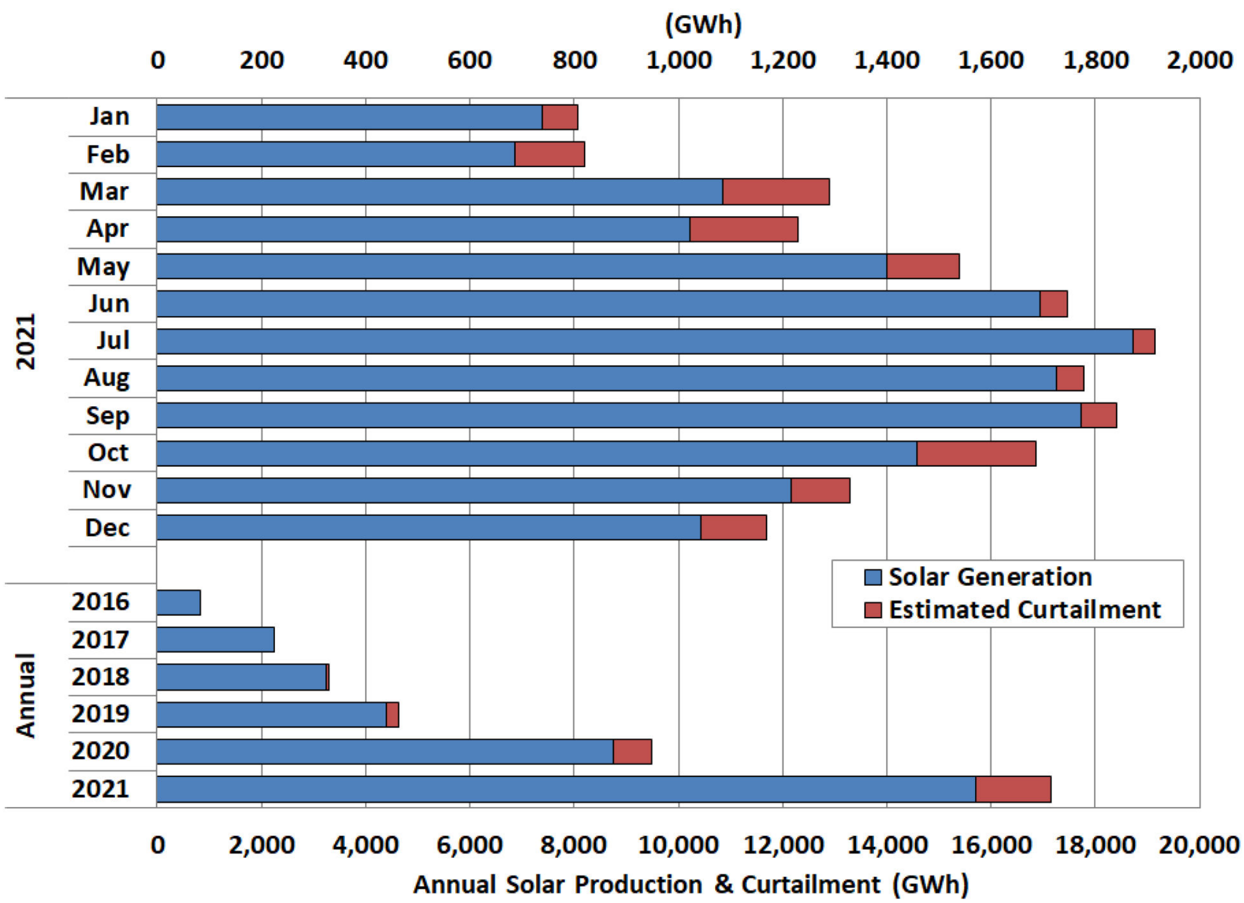
ERCOT continued to set new records for peak wind output. A new wind output record was set on October 21, 2021 (23,657 MW). The amount of power produced by wind resources (24%) continued to outpace coal (19%) in 2021.

53 Wind units in some areas do not exhibit this negative correlation, including the Gulf Coast.

Figure 24 reveals that the total production from wind resources continued to increase in 2021, while the quantity of curtailments implemented to manage congestion caused by the wind resources also increased from the prior year. These curtailments reduced wind output by less than 6%, compared to a peak of 17% in 2009.

Solar resources, although still a smaller component of overall generation than wind today, are positively correlated with load and produce at much higher capacity factors than wind during summer peak hours. The capacity factors during these hours was approximately 69% for facilities located in the west and 54% for those located in other areas of Texas. Hence, these resources provide a larger resource adequacy benefit than wind resources. Figure 25 shows that total solar production in 2021 was 15,700 GW, and an additional 8% was curtailed to manage congestion caused by solar resources.

Figure 25: Solar Production and Curtailment



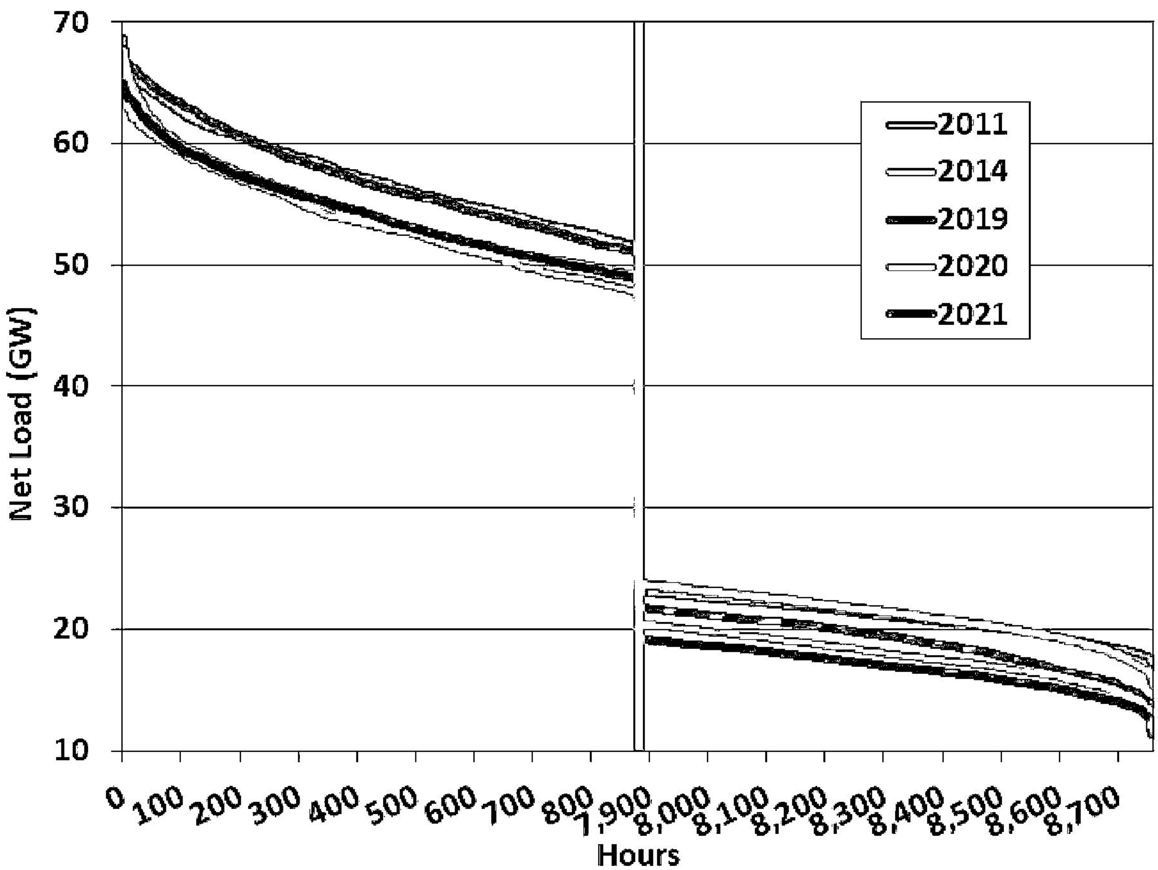
Increasing wind and solar output has important implications for other types of resources, by changing the shape of the remaining load available for them to serve. This also has important implications for resource adequacy in the ERCOT. For additional analysis of wind and solar output in ERCOT, see Figure A17, Figure A18, Figure A19, and Figure A20 in the Appendix.

Figure 26 shows net load in the highest and lowest hours in 2021. Figure 26 shows:

- In the hours with the highest net load (the left panel), the difference between the peak and the 95th percentile of net load was roughly 11 GW in 2021. This means that 11 GW of non-wind and non-solar capacity was needed to serve load in less than 440 hours of the year in 2021.
- In the hours with the lowest net load (the right panel), the minimum net load has dropped from roughly 20 GW in 2007 to about 11.3 GW in 2021, despite the sizable growth in annual average load. This trend has put economic pressure on baseload generation such as nuclear and coal.

For an historical perspective on net load duration curves in ERCOT, see Figure A21 in the Appendix.

Figure 26: Top and Bottom Deciles (Hours) of Net Load



E. Demand Response Capability

Demand response is a term that broadly refers to actions that can be taken by end users of electricity to reduce load in response to instructions from ERCOT or in response to other incentives. The ERCOT market allows participants with demand-response capability to provide energy and reserves in a manner similar to generating resources.

The primary ways that loads participate in the ERCOT-administered markets are through:

- The responsive reserves market;
- ERCOT-dispatched reliability programs, including ERS that responds prior to the reduction of firm load; or
- Statutorily-mandated demand response programs administered by the transmission and distribution utilities in their energy efficiency programs.

Additionally, loads may self-dispatch by adjusting consumption in response to energy prices or by reducing consumption during specific hours to lower transmission charges.

1. Reserve Markets

ERCOT allows qualified load resources to offer responsive reserves into the day-ahead ancillary services markets. Load relay response can be a highly effective mechanism for maintaining system frequency at 60Hz. Non-controllable load resources (NCLRs) providing responsive reserves have relay equipment that enables the load to be automatically tripped when the system frequency falls below 59.7 Hz (when demand exceeds supply), or they can be manually deployed in EEA Level 2. These events typically occur a very small number of times each year.

As of December 2021, approximately 7,624 MW of qualified NCLRs could provide responsive reserve service, which is an increase of approximately 700 MW during 2021.[54] However, the total amount of responsive reserves procured by ERCOT from load resources was a limited to a maximum of 880 to 1,780 MW per hour.

In 2021, there were two deployments of responsive reserve. The first was a system-wide deployment as a result of Emergency Conditions associated with Winter Storm Uri. The NCLR fleet was deployed at 01:09 on February 15, 2021, and remained deployed until a system recall at 09:05 on February 19, 2021. The initial response showed approximately a 70% response rate, which was short of the 95% requirement. The response rate improved throughout the early hours of the event and by 04:30 was at or above 95% for the remainder of the storm. It should also be noted that even though the deployment event occurred in February there were extended impacts affecting the capacity offered from the NCLRs up to approximately March 10, 2021.[55] There was a second deployment of responsive reserve on November 10, 2021, when two load resources were dispatched due to a Transmission Emergency Condition. Approximately 70 MW of load resource capacity was deployed starting at 11:03. The deployed load resources responded within the 10-minute ramp period and were recalled at 11:38.[56]

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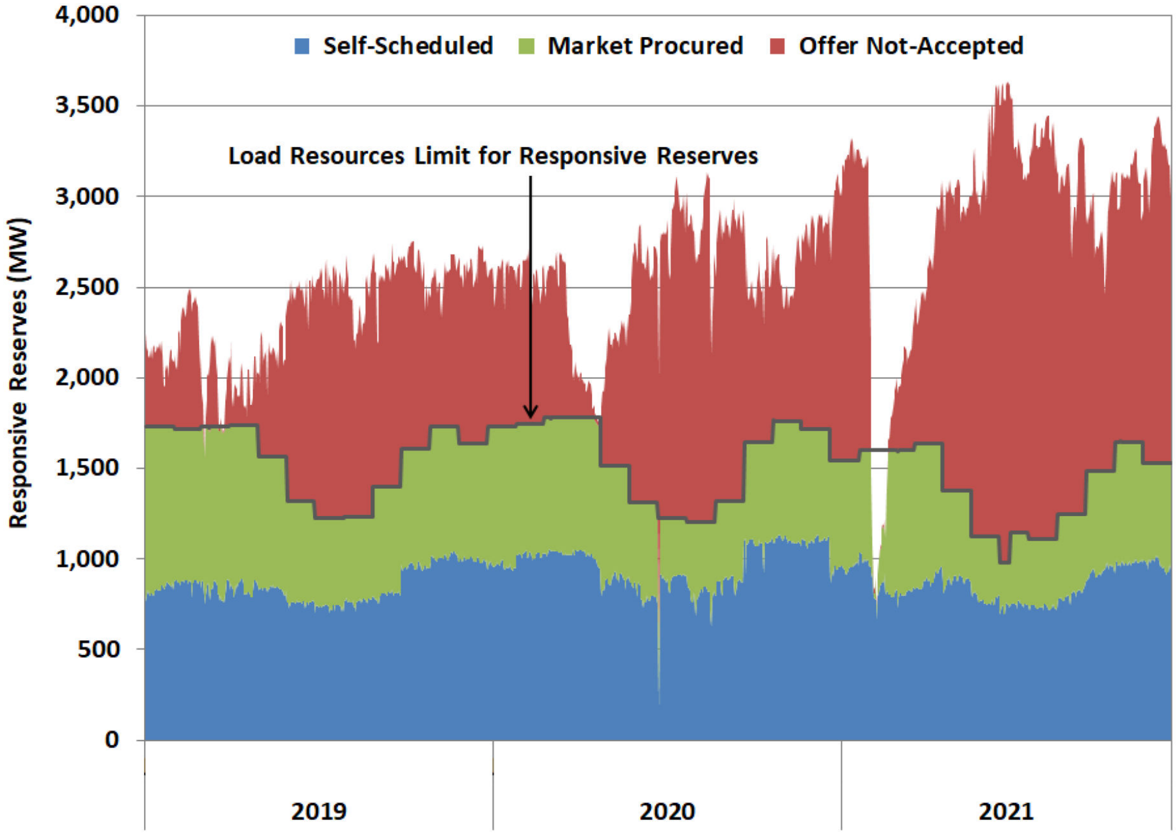
54 *See* ERCOT 2021 Annual Report of Demand Response in the ERCOT Region (Dec. 2021), available at http://www.ercot.com/services/programs/load.

55 *Id.*

56 *See* ERCOT 2021 Annual Report of Demand Response in the ERCOT Region (Dec. 2021), available at http://www.ercot.com/services/programs/load.

Figure 27 below shows the daily average amount of responsive reserves provided from load resources operating on relays for the past three years.[57]

Figure 27: Responsive Reserves from Loads with High-Set Under Frequency Relays



There were more offers for loads providing responsive reserve than the limit for much of 2021, especially in the summer. The total MWh of surplus offers grew by over 70% from the previous year. Modifying the pricing structure, as discussed in recommendation No. 2019-2 above, would remove the inappropriate incentives that are leading to this oversupply.

2. Reliability Programs

There are two main reliability programs in which demand can participate: i) Emergency Response Service (ERS), administered by ERCOT, and ii) load management programs offered by the transmission and distribution utilities (TDUs). The ERS program is defined by a Commission rule enacted in March 2012, which set a program budget of $50 million.[58] The capacity-weighted average price for ERS over the contract periods from February 2021 through

57 Until June 1, 2018, non-controllable load resources could provide a maximum of 50% of responsive reserves. NPRR815, *Revise the Limitation of Load Resources Providing Responsive Reserve (RRS) Service* increased this cap to 60%, while also requiring that at least 1,150 MW of responsive reserves be provided from generation resources. Beginning with calendar year 2021, NERC standards required an increase in this floor to 1,420 MW. Necessarily, this decreased the amount of capacity that can come from load resources.

58 16 TAC § 25.507.

November 2021 ranged from $4.35 to $6.83 per MWh. This price was lower than the average price paid for both responsive reserves and non-spinning reserves in 2021.

During Winter Storm Uri in February 2021, the majority of the ERS fleet was deployed and exhausted within 12 hours of deployment. The overall ERS fleet generally met or exceeded the aggregate obligation for the duration of the event, although ERS Loads generally over-performed while ERS Generators generally under-performed.59

There were slightly more than 204 MW of load participating in load management programs administered by the TDUs in 2021, which grew to 325 MW in the months of August and September.[60] Energy efficiency and peak load reduction programs are required by statute and Commission rule and most commonly take the form of load management, where participants allow electricity to selected appliances (typically air conditioners) to be curtailed.[61] These programs administered by TDUs may be deployed by ERCOT during a Level 2 Energy Emergency Alert (EEA).

3. Self-dispatch

In addition to these programs, loads in ERCOT can observe system conditions and reduce consumption voluntarily. This response comes in two main forms:

- By participating in programs administered by competitive retailers or third parties to provide shared benefits of load reduction with end-use customers.
- Through voluntary actions taken to avoid the allocation of transmission costs.

Of these two methods, the most significant impacts are related to actions taken to avoid incurring transmission costs that are charged to certain classes of customers based on their usage at system peak. Transmission costs are allocated based on load contribution to the highest 15-minute loads during each of the four months from June through September. This allocation mechanism is routinely referred to as Four Coincident Peak, or 4CP. By reducing demand during peak periods, load entities seek to reduce their share of transmission charges, which are substantial. Transmission costs have more than doubled since 2012, increasing an already significant incentive to reduce load during probable peak intervals in the summer. ERCOT estimates that as much as 4,000 MW of load was actively pursuing reduction during the 4CP intervals in 2021, higher than the 2020 estimate.[62]

59 ERCOT 2021 Annual Report of Demand Response in the ERCOT Region (Dec. 2021) at 10, available at http://www.ercot.com/services/programs/load.

60 *Id.*

61 *2016 Energy Efficiency Plans and Reports Pursuant to 16 TAC §25.181(n)*, Project 45675; SB 7. Section 39.905(a)(2) (http://www.capitol.state.tx.us/tlodocs/76R/billtext/html/SB00007F.htm).

62 *See* ERCOT, 2021 Annual Report of Demand Response in the ERCOT Region (Dec. 2021) at 18, available at http://www.ercot.com/services/programs/load.

Voluntary load reductions to avoid transmission charges are likely distorting prices during peak demand periods because the response is targeting peak demand reductions, rather than responding to wholesale prices. This was readily apparent in 2018 when significant reductions were observed on peak load days in June, July, and August when wholesale prices were less than $40 per MWh. The trend continued in 2019 with reductions in June when prices were only $65 at peak, and even starker in 2020 when prices were less than $35 for each of the four months. In 2021, there were reductions on July, August, and September when prices were less than $80. To address these distortions, we continue to recommend that modifications to ERCOT's transmission cost allocation methodology be explored (see recommendation No. 2015-1 above).

4. Demand Response and Market Pricing

When SCED clears the supply offers to meet the demand, it issues instructions (base points) for resources to follow and it publishes real-time prices. Two elements in the ERCOT market are intended to address the pricing effects of demand response in the real-time energy market. First, the initial phase of "Loads in SCED" was implemented in 2014, allowing controllable loads that can respond to those 5-minute dispatch instructions, or base points, to specify the price at which they no longer wish to consume.

For the first time, there were loads qualified to participate in real-time dispatch. In 2021, three new controllable load resources (CLRs) were registered and added to the ERCOT Network Model. These CLRs consist of data centers that have hundreds of servers that can be turned on and off on demand. The data centers use fast acting control systems to respond to frequency similar to the governors on a conventional thermal plant, which gives them the ability to follow base points from SCED. These CLRs have over 100 MW of online capacity and can participate in responsive reserve service, regulation service, and non-spinning reserve service. This represents the first substantial amount of conventional load to participate in the ancillary services market as a CLR. As this segment grows, implementing nodal pricing for CLRs will become more important and impactful.

Second, the reliability deployment price adder, discussed in more detail in Section I, includes a separate pricing run of the dispatch software to account for reliability actions. The pricing run did not account for firm load shed instructed by ERCOT, which led to prices below the VOLL during the first hours of Winter Storm Uri. The Commission directed ERCOT to account for the firm load shed instructed by ERCOT late on February 15, 2021, and following implementation of that change the pricing run did account for firm load shed. After the storm, NPRR1081, *Revisions to Real-Time Reliability Deployment Price Adder to Consider Firm Load Shed*, was approved on June 28, 2021, and it modified the calculation of the reliability deployment price adder so that the combination of System Lambda, the Real-Time On-Line Reserve Price Adder, and the Real-Time On-Line Reliability Deployment Price Adder will be equal to VOLL when ERCOT is directing firm load shed during EEA3.

IV. DAY-AHEAD MARKET PERFORMANCE

ERCOT's day-ahead market allows participants to make financially-binding forward purchases and sales of power for delivery in real-time. Bids and offers can take the form of either a:

- *Three-part supply offer*. Allows a seller to reflect the unique financial and operational characteristics of a specific generation resource, such as startup costs; or an
- *Energy-only bid or offer*. Location-specific offer to sell or bid to buy energy that are not associated with a generation resource or load.

In addition to the purchase and sale of power, the DAM also includes ancillary services and Point-to-Point (PTP) obligations. PTP obligations allow parties to hedge the incremental cost of congestion between day-ahead and real-time markets.

Except for ancillary services, the DAM is a financial-only market. Although all bids and offers are cleared respecting the limitations of the transmission network, there are no operational obligations resulting from the DAM. In addition to allowing participants to manage exposure to real-time prices or congestion, or arbitrage real-time prices, the DAM also helps inform participants' generator commitment decisions. Hence, effective performance of DAM is essential.

In this section, we examine day-ahead energy prices in 2021 and their convergence with real-time prices. We also review the activity in the DAM, including a discussion of PTP obligations. This section concludes with a review of the day-ahead ancillary service markets.
Overall, 2021 day-ahead prices were higher than 2020 for both energy and ancillary services, as expected given the increased operating shortages. Liquidity in the DAM was similar to previous years, which included active trading of congestion products in the DAM.

Table 3 below compares the average annual price for each ancillary service over the last three years, showing that the prices were orders of magnitude higher for each product in 2021 because of Winter Storm Uri. The increase in ancillary services prices caused the average ancillary service cost per MWh of load to increase from $1.00 per MWh in 2020 to $29.59 per MWh in 2021. We also include the prices without the effect of Winter Storm Uri, and the result shows an increase in prices due to increased procurement of ancillary services.

Table 3: Average Annual Ancillary Service Prices by Service

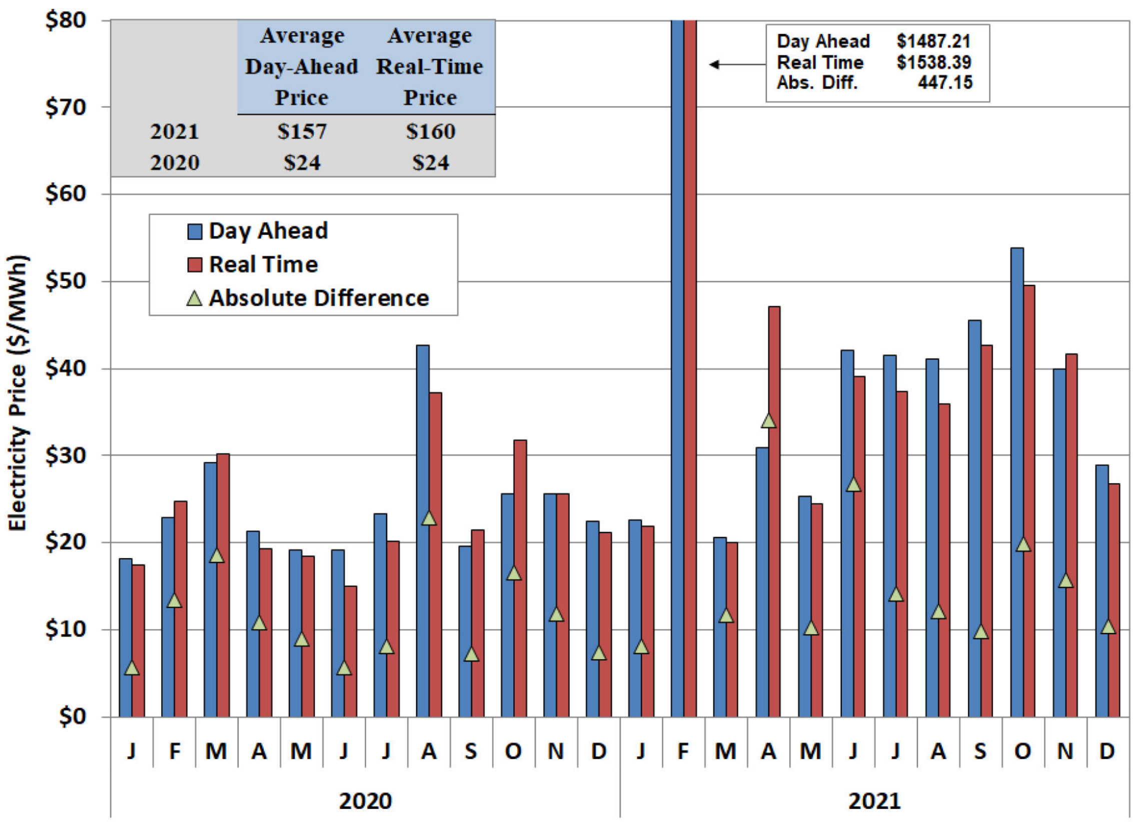
	2019 ($/MWh)	2020 ($/MWh)	2021 ($/MWh)	2021 without Uri ($/MWh)
Responsive Reserve	$26.61	$11.40	$331.46	$60.57
Non-spin Reserve	$13.44	$4.45	$83.75	$21.03
Regulation Up	$23.14	$11.32	$289.84	$54.33
Regulation Down	$9.06	$8.45	$120.70	$20.08

A. Day-Ahead Market Prices

Forward markets provide hedging opportunities for market participants. A primary indicator of the performance of any forward market is the extent to which forward prices converge with real-time prices over time. This price convergence will occur when: (1) there are low barriers to purchases and sales in either market; and (2) sufficient information is available to allow market participants to develop accurate expectations of future real-time prices. These two factors allow participants to arbitrage predictable differences between forward prices and real-time spot prices and bring about price convergence. Price convergence between the day-ahead and real-time markets is important because it leads to improved (more efficient) commitment of resources needed to satisfy the system's real-time needs. In this subsection, we evaluate the price convergence between the day-ahead and real-time markets.

This average price difference between forward prices and real-time spot prices reveals whether persistent and predictable differences exist between day-ahead and real-time prices that participants should arbitrage over the long term. Figure 28 shows the average day-ahead and real-time prices by month for the past two years. It also shows the average of the absolute value of the difference between the day-ahead and real-time price, calculated on a daily basis. This measure captures the volatility of the daily price differences, which may be large even if the prices converge on average.

Figure 28: Convergence Between Day-Ahead and Real-Time Energy Prices (with Uri)

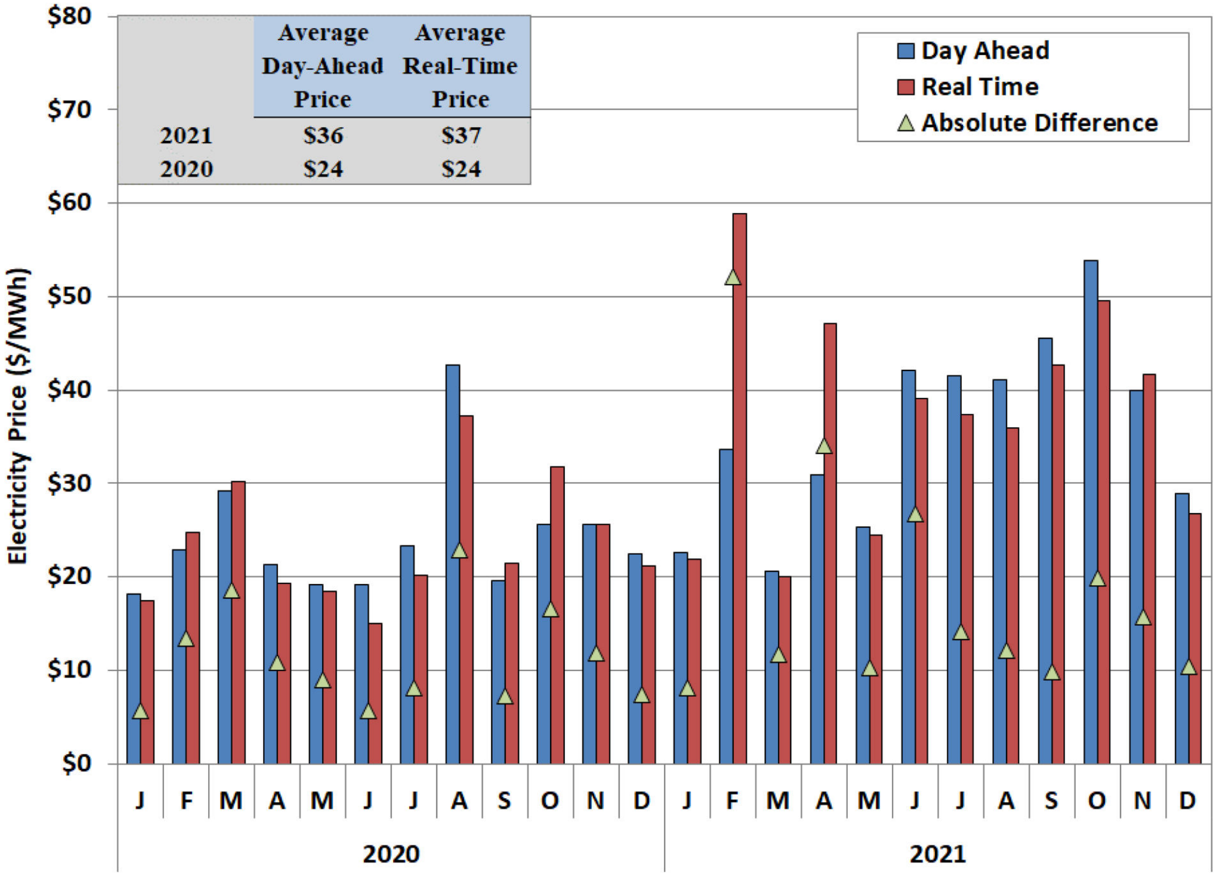


Day-ahead prices averaged $157 per MWh in 2021, while real-time prices averaged $160 per MWh.[63] This divergence was a change from the stability in 2020, which occurred throughout the year but especially in February because of the effects of Winter Storm Uri. The relative instability of real-time prices and persistence of tight conditions increased the risk premium associated with day-ahead hedges.

Price divergence was pronounced in February, April, the summer months and October in 2021, when conditions were tighter, real-time prices were higher, and ERCOT began a more conservative approach to operations, creating less price convergence on average for the year than recent years.

The average absolute difference between day-ahead and real-time prices was $52.70 per MWh in 2021, a sharp increase from $11.60 in 2020, $27.63 MWh in 2019 and $16.21 in 2018, respectively. The largest absolute difference primarily occurred in February, an astonishing $447.15, as expectations were rendered virtually meaningless as shortage conditions resulted in rolling blackouts.

Figure 29: Convergence Between Day-Ahead and Real-Time Energy Prices (without Uri)



[63] These values are simple averages, rather than load-weighted averages as presented in Figures 1 and 2.

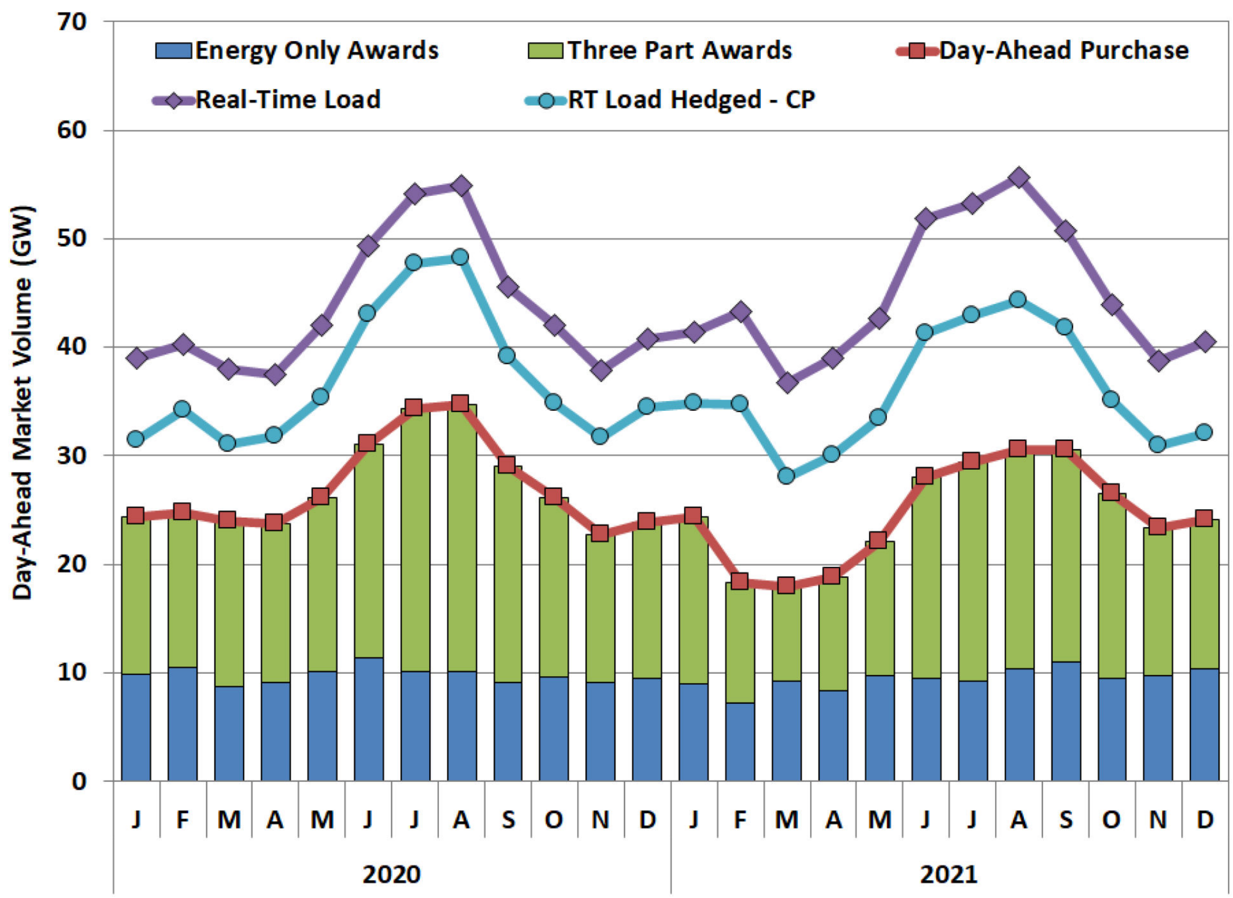
Even without the extreme effects of Winter Storm Uri included, there was significant divergence between day-ahead and real-time prices as demonstrated above in Figure 29. For additional price convergence results in 2020, see Figure A11, Figure A12, and Figure A22 in the Appendix.

B. Day-Ahead Market Volumes

Figure 30 summarizes the volume of DAM activity by month, which includes both purchases and sales of energy, for the last two years. The additional load shown as hedged in this figure (the difference between the red day-ahead purchases and the blue real-time load hedged) is load served by PTP obligations scheduled to a load zone from other locations.

Figure 30 shows that the volume of day-ahead energy purchases provided through a combination of generator-specific offers (also known as three-part offers) and virtual energy offers was 55% of real-time load in 2021, a decrease from 64% in 2020. Although it may appear that many loads are still subjecting themselves to greater risk by not locking in a day-ahead price and instead exposed to real-time volatility, other transactions or arrangements outside the organized market are used to hedge real-time prices. In these cases, often PTP obligations are scheduled to hedge real-time congestion costs to complement those transactions.

Figure 30: Volume of Day-Ahead Market Activity by Month



PTP obligations are financial transactions purchased in the DAM. Although PTP obligations do not themselves involve the direct supply of energy, a PTP obligation allows a participant to, in effect, buy the network flow from one location to another.[64] When coupled with a self-committed generating resource, the PTP obligation allows a participant to serve its load while avoiding the associated real-time exposure because the only remaining settlement would correspond to the congestion costs between the locations. PTP obligations are also scheduled by financial participants seeking to arbitrage locational congestion differences between the day-ahead and real-time markets.

PTP volumes have been growing quickly in recent years, with important implications for the DAM performance and ability to publish within the protocol timeline. They have increased four-fold over the last decade. According to ERCOT, the highest correlation to DAM performance issues in unawarded PTP obligations bids, i.e., the volume of bids submitted that are unlikely to be awarded is driving the problem.

Because the large and increasing quantities of PTP transactions are the principal cause of the delays, and the delays are costly to the market at large, cost causation principles dictate that PTP volumes bear some of the costs they are causing to provide incentives to resolve the issue. DAM software capability can be thought of as a scarce resource that must be allocated efficiently. Charging no fee for PTP bids allow participants to submit numerous bids that are unlikely to clear and provide very little value to the market. Additionally, they bear no share of ERCOT's administrative expenses even though they are consuming a large portion of the software and supporting resources. Applying a small bid fee to the PTP bids is consistent with cost causation principles and would incent participants to submit smaller quantities of bids that are more valuable and more likely clear. Because even a small fee would likely reduce or eliminate the bids that are very unlikely to clear, this should substantially eliminate the delays in the DAM process. In recommendation No. 2020-4 above, the IMM recommends a PTP bid fee as an economically rational way to manage this volume.

Figure 30 also shows the portion of the real-time load that is hedged either through day-ahead energy purchases or PTP obligations scheduled by Qualified Scheduling Entities (QSEs).[65] Although QSEs are the party financially responsible to ERCOT, their financial obligations are aggregated and held by a counterparty. When measured at this level, the percentage of real-time load hedged dropped slightly to 80% in 2021, slightly down from 85% seen in 2020.

The volume of three-part offers comprised less than half of DAM clearing. To determine whether this was due to small volumes of three-part offers being submitted versus three-part

64 PTP obligations are equivalent to scheduling virtual supply at one location and virtual load at another.

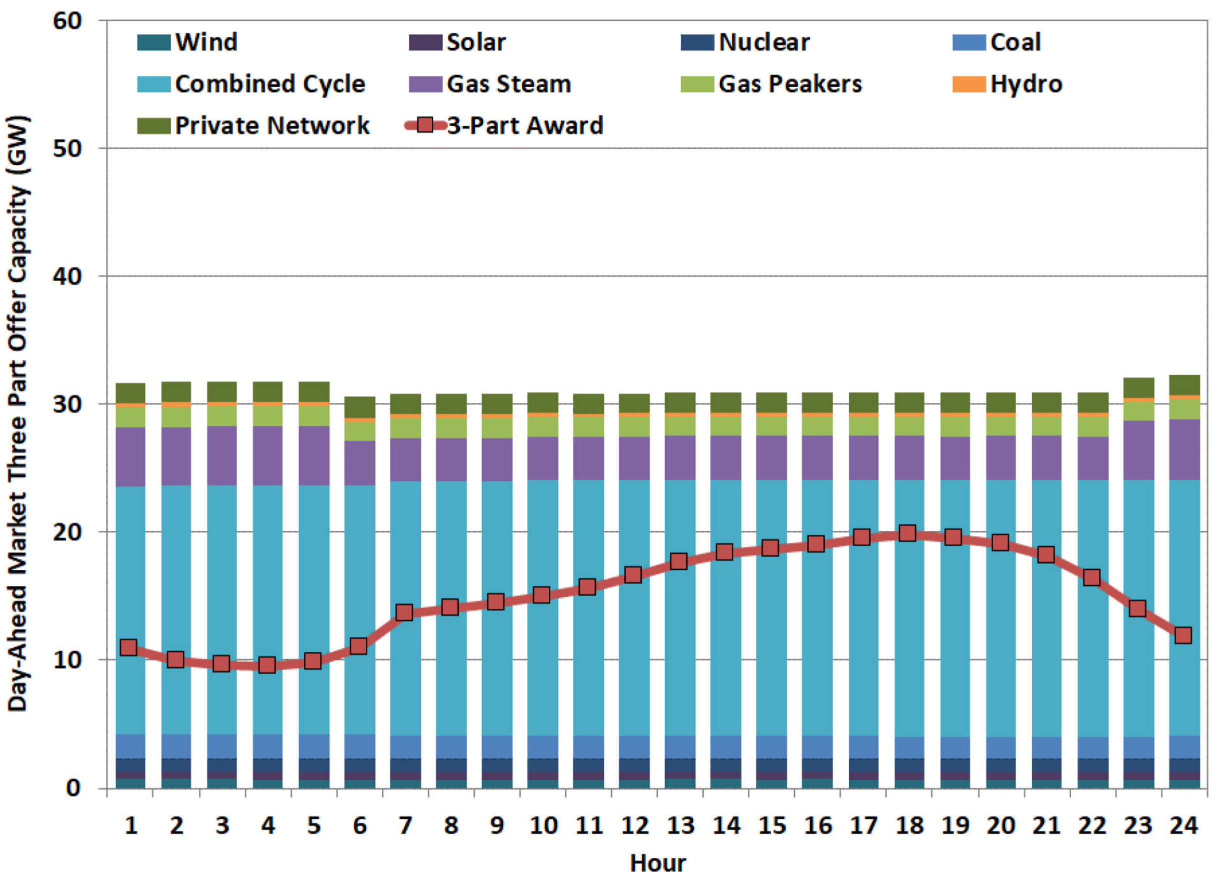
65 To estimate the volume of hedging activity, energy purchases are added to the volume of PTPs scheduled by QSEs with load that source or sink in load zones, then aggregated to the counterparty (CP) level.

offers being cleared, Figure 31 shows the total capacity from three-part offers submitted in the DAM for 2021.

The submitted capacity has been averaged for each month and is shown to be significantly more than the amount of capacity cleared. This is not unusual, given that load in most periods does not require all available generation to be scheduled. The portion of the generation cleared in the peak hours increases as one would expect.

With the largest share of installed capacity, it follows that combined cycle units are the predominant type of generation submitting offers in the DAM. More importantly, because combined cycle units are typically marginal units, offering that capacity into the DAM allows a market participant to determine whether its unit is economic. Conversely, few wind units offer in day-ahead because of uncertainty on whether wind will be available in real-time to cover any award. Further analysis on DAM activity volume can be found in Figure A24 in the Appendix.

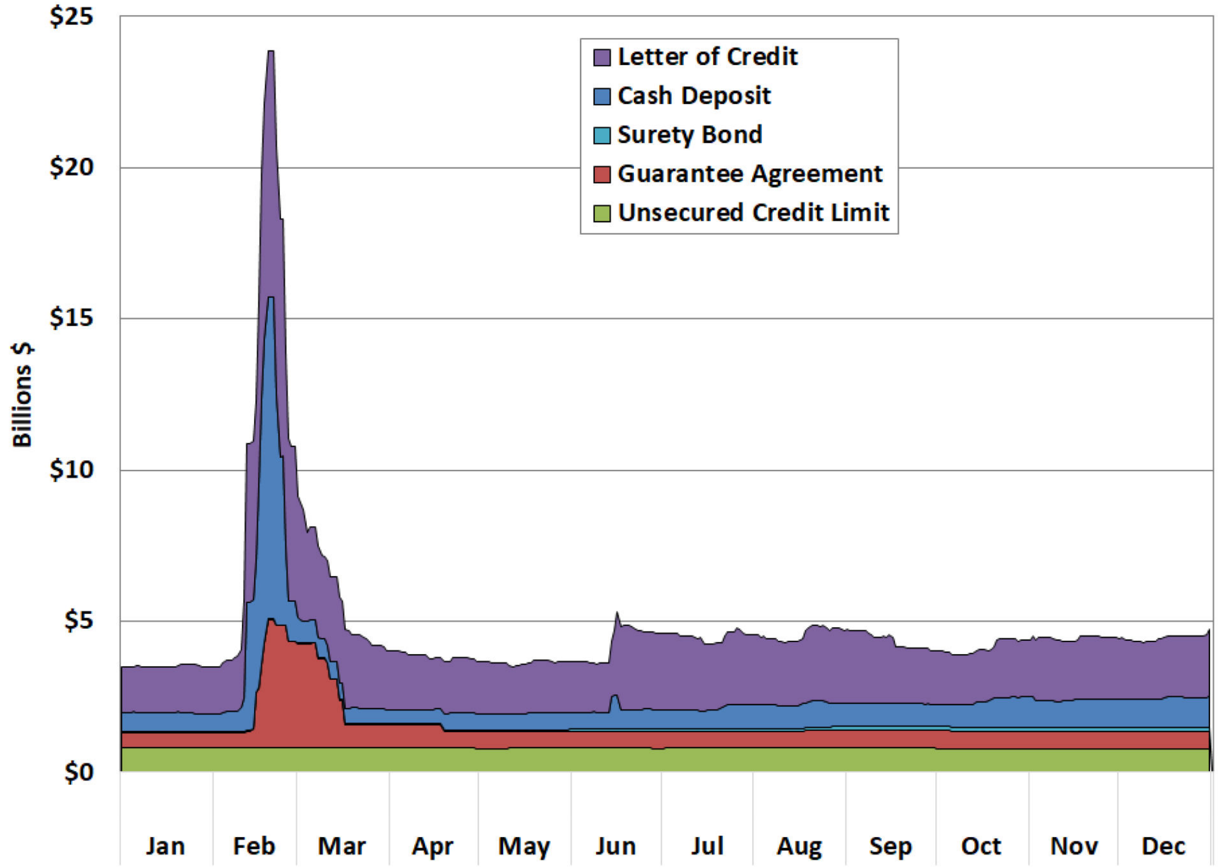
Figure 31: Day-Ahead Market Three-Part Offer Capacity



To participate in ERCOT's DAM, a market participant must have sufficient collateral with ERCOT. The total collateral requirements for 2021, significantly higher than anything seen before due to Winter Storm Uri, are shown below in Figure 32. ERCOT short payments (amounts owed but not paid) during the storm exceeded $3 billion, with several retail electric providers exiting the market and one electric cooperative seeking bankruptcy protection.

Credit requirements are a constraint on submitting bids in the DAM. When the available credit of a QSE is limited, its participation in DAM will necessarily be limited as well. Credit likely represented a barrier to participating in the DAM in February 2021 and into March due to the high requirements.

Figure 32: Daily Collateral Held by ERCOT

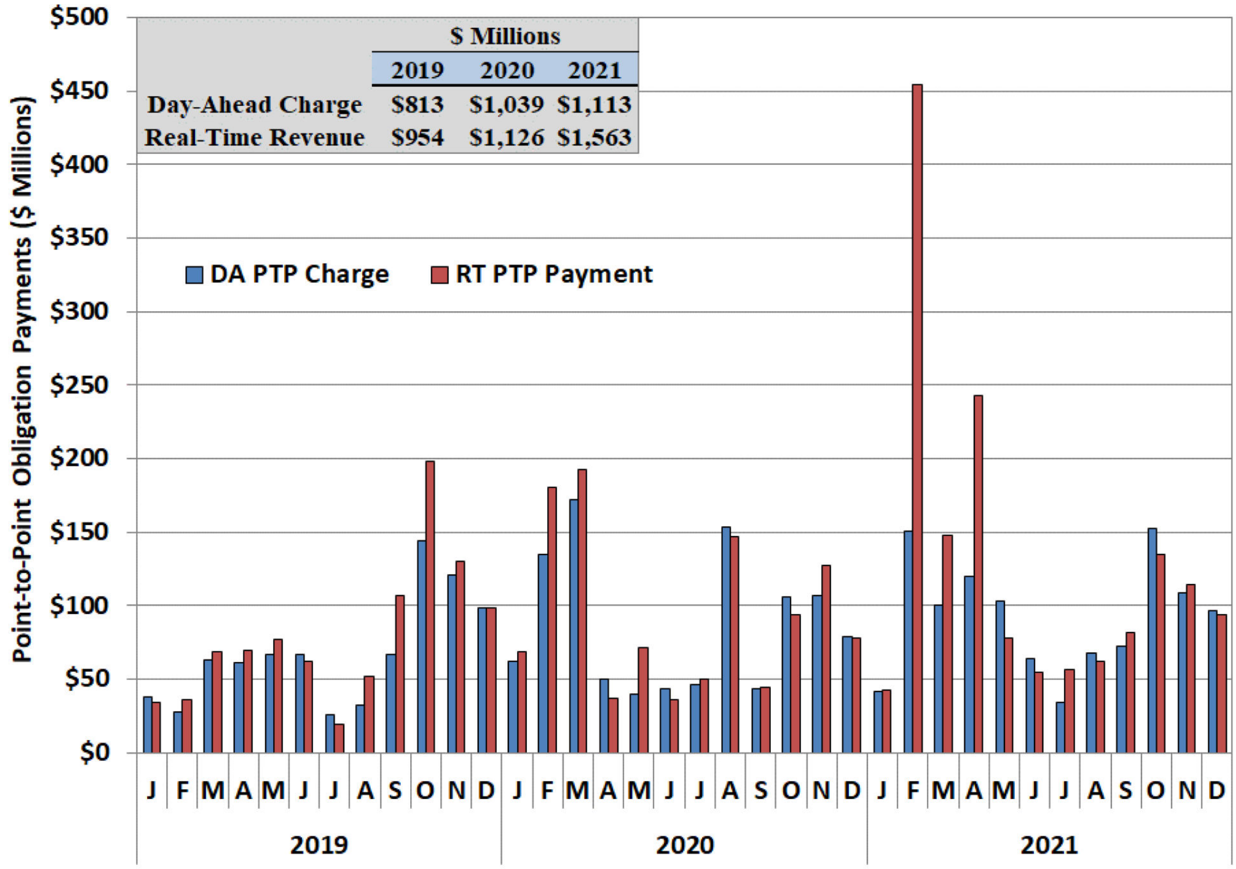


C. Point-to-Point Obligations

Purchases of PTP obligations comprise a significant portion of DAM activity. They are both similar to and can be used to complement Congestion Revenue Rights (CRRs). CRRs, as more fully described in Section V, are acquired via monthly and annual auctions and allocations. CRRs accrue value to their owner based on locational price differences as determined by the DAM.

Participants buy PTP obligations by bidding to pay the difference in prices between two locations in the DAM. The holder of the PTP obligation then receives the difference in prices between the same two locations in the real-time market. Hence, a participant that owns a CRR can use its CRR proceeds from the DAM to buy a PTP obligation between the same two points to transfer its hedge to real-time. Because PTP obligations represent such a substantial portion of the transactions in the DAM, additional details about the volume and profitability of these PTP obligations are provided in this subsection. The first analysis of this subsection, shown in Figure 33, compares the total day-ahead payments made to acquire these products, with the total amount of revenue received by the owners of PTP obligations in the real-time market.

Figure 33: Point-to-Point Obligation Charges and Revenues



As prices and total congestion costs have increased substantially in recent years, so have the costs and revenues associated with PTP obligations. This trend was reinforced again in 2021. The average volume of PTP obligations has been stable for the past three years from a quantity standpoint, although the numbers of individual transaction submissions have risen.

Figure 33 shows that the aggregated total revenue received by PTP obligation owners in 2021 was greater than the amount charged to the owners to acquire them, as in prior years. This indicates that, in aggregate, buyers of PTP obligations profited from the transactions, and occurs when real-time congestion costs are greater than DAM congestion costs. Profits were spread throughout 2021 (January, February, March, April, July, September and November), accruing when congestion priced in the DAM was lower than the congestion in real time. The profits were highest in February when payments were more than $454 million.

To provide additional insight on the profits that have accrued to PTP obligations, Figure 34 shows the profitability of PTP obligation holdings for all physical parties and financial parties (those with no real-time load or generation), as well as the profitability of "PTP obligations with links to options" in 2021. These are instruments available only to Non-Opt-In Entities and allow them to receive congestion revenue but not have congestion charges. As such, we show them below as "PTP Options," because they are settled as options, not obligations.

Figure 34: Average Profitability of Point-to-Point Obligations

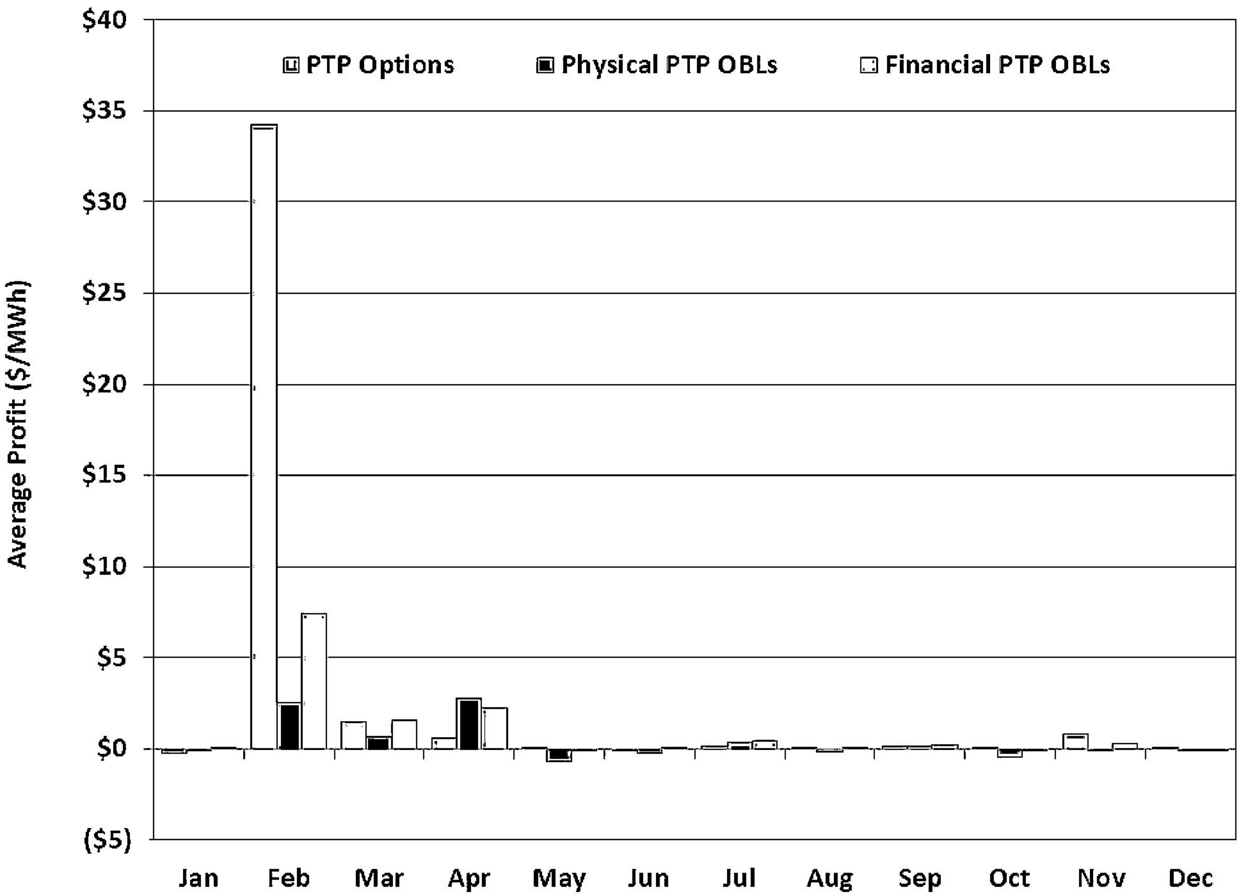


Figure 34 shows that in aggregate, PTP obligation transactions in 2021 were profitable for the year, yielding an average profit of $0.66 per MWh, higher than the average profit of $0.13 per MWh in 2020. PTP obligations were profitable during 2021 for all types of parties, with average profits of $0.33 per MWh for physical parties, $0.93 per MWh for financial parties, and $2.66 per MWh for PTP obligations settled as options. For analysis of the total volume of PTP obligation purchases in 2021, see Figure A25 in the Appendix.

D. Ancillary Services Market

The primary ancillary services are regulation up, regulation down, responsive reserves, and non-spinning reserves. Market participants may self-schedule ancillary services or have ERCOT purchase them on their behalf.

In general, the purpose of responsive and non-spinning reserves is to protect the system against unforeseen contingencies (*e.g.*, unplanned generator outages, load or wind forecast errors), rather than for meeting normal load fluctuations. ERCOT procures responsive reserves to ensure that the system frequency can quickly be restored to appropriate levels after a sudden, unplanned outage of generation capacity. Non-spinning reserves are provided from either online resources or from offline resources that can start quickly to respond to contingencies and to restore responsive reserve capacity.

Regulation reserves are capacity that responds every four seconds, either increasing or decreasing as necessary to keep output and load in balance from moment to moment. The quantity of regulation needed is affected by the accuracy of the supply and demand reflected in the 5-minute dispatch. In late 2021, NPRR1113, *Clarification of Regulation-Up Schedule for Controllable Load Resources in Ancillary Service Imbalance* was sponsored by ERCOT, which would adjust the definitions in Section 6.7.5 of the ERCOT Protocols to prohibit double-counting of the Regulation-Up (Reg-Up) Ancillary Service Schedule when calculating capacity in the Ancillary Service Imbalance Settlement for Controllable Load Resources available to Security-Constrained Economic Dispatch (SCED).

1. Ancillary Services Requirements

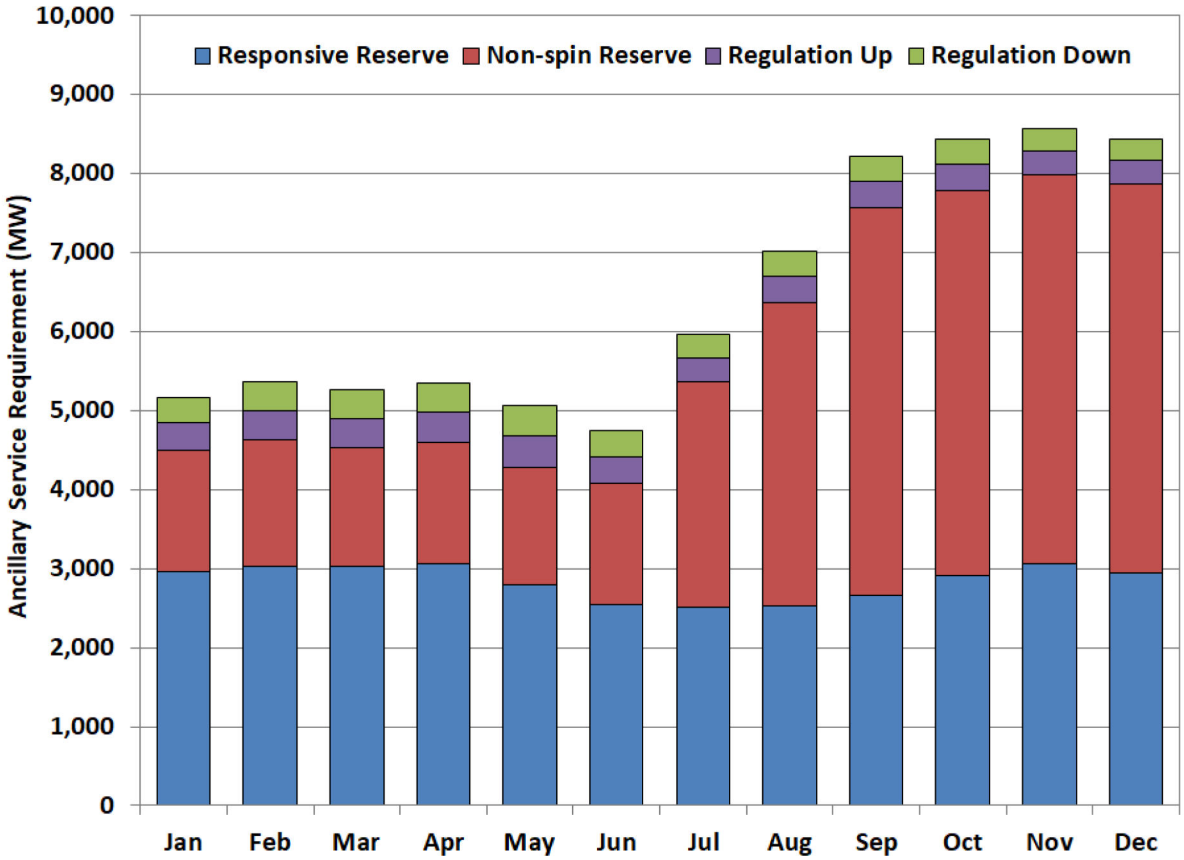
Since June 2015, ERCOT has calculated responsive reserves requirements based on a variable hourly need. This requirement is posted in advance for the year. Historically, ERCOT procured non-spinning reserves such that the combination of non-spinning reserves and regulation up will cover 95% of the calculated net load forecast error. ERCOT will always procure a minimum quantity of non-spinning reserves greater than or equal to the largest generation unit during on-peak hours. ERCOT did place a limit of 450 MW on resources providing Fast Frequency Response (FFR) when phase 1 of NPRR863, *Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve*, was implemented.

In late 2020, for calendar year 2021, ERCOT changed the minimum RRS from generators to 1,420 MW, and changed each of the methodologies used for computing non-spinning reserve and regulation reserves to account for growth in installed solar capacity.[66] In July 2021, ERCOT changed the procurement such that procures 2,800 MW of responsive reserve service over peak

[66] https://www.ercot.com/files/docs/2020/12/01/8_2021_ERCOT_Methodologies_for_Determining_Minimum_Ancillary_Service_Requirements.pdf

hours and additional non-spinning such that the total amount of upward ancillary services equals 6,500 MW (increasing to 7,500 MW when forecast variability is high).[67] However, ERCOT chose not to include load resources providing responsive reserve in this calculation, discounting the reliability service they provide, with the reason given that they were excluded since they can only be deployed in EEA. Figure 35 below displays the average quantities of ancillary services procured for each month in 2021, and Figure A26 in the Appendix shows ERCOT's yearly average ancillary service capacity by hour in 2021.

Figure 35: Average Ancillary Service Capacity by Month



This new conservative posture for operations in the aftermath of Winter Storm Uri is clear from the above figure. The cost of this additional AS procurement was discussed in the Future Needs section of this document.

ERCOT also adjusted its non-spinning reserve deployment methodology in 2021:

- Starting July 12, ERCOT added a condition for deploying non-spinning reserve when PRC is less than 3,200 MW and is not expected to recover within 30 minutes. This allows operators to deploy non-spinning reserve in advance of potential Emergency Conditions.

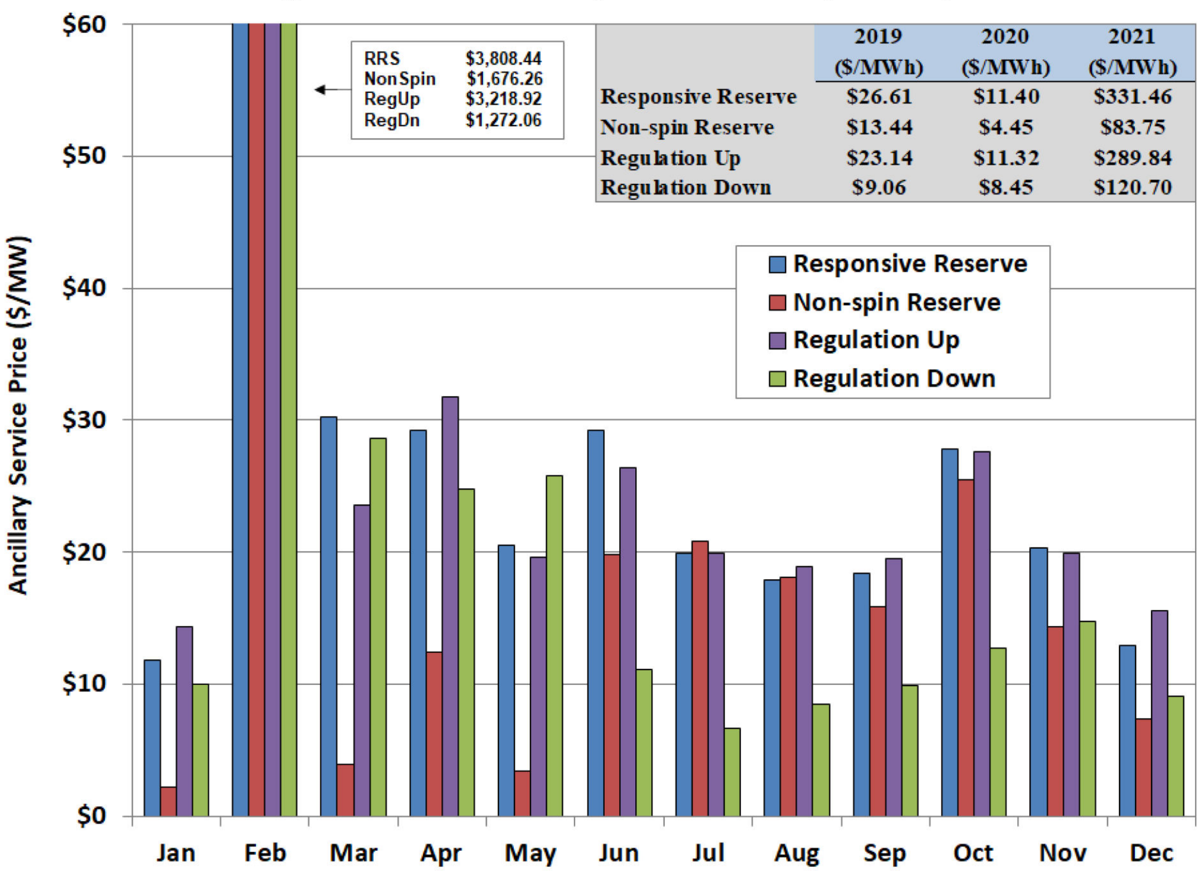
67 https://www.ercot.com/files/docs/2021/06/30/ERCOT_Addtional_Operational_Reserves_06302021.pptx

- Starting August 2, ERCOT changed the calculation for deploying non-spinning reserve currently based on High Ancillary Service Limit (HASL) less generation less the forecasted 30-minute load ramp such that it includes intermittent renewable resource (IRR) curtailment and 30-minute net load ramp instead of 30-minute load ramp.

2. Ancillary Services Prices

Figure 36 below presents the monthly average clearing prices of capacity for the four ancillary services in 2021, while the inset table shows the average annual prices over the last three years. The prices for ancillary service were by far highest in February because of Winter Storm Uri. This outcome is consistent with the higher clearing prices for energy in the DAM for August because ancillary services and energy are co-optimized in the DAM. This means that market participants need not include expectations of forgone energy sales in their ancillary service capacity offers. Because ancillary service clearing prices explicitly account for the opportunity costs of selling energy in the DAM, ancillary service prices should generally be correlated with day-ahead energy prices.

Figure 36: 2020 Ancillary Service Prices (with Uri)



	2019 ($/MWh)	2020 ($/MWh)	2021 ($/MWh)
Responsive Reserve	$26.61	$11.40	$331.46
Non-spin Reserve	$13.44	$4.45	$83.75
Regulation Up	$23.14	$11.32	$289.84
Regulation Down	$9.06	$8.45	$120.70

The extraordinary increase in ancillary services prices caused the average ancillary service cost per MWh of load to increase from $1.00 per MWh in 2020 to $29.59 per MWh in 2021. This is due to both the effects of Winter Storm Uri and the increased costs associated with the additional reserve procurement beginning July 2021. Figure A27 in the Appendix shows the monthly total ancillary service costs per MWh of ERCOT load.

3. Provision of Ancillary Services by QSEs

Day-ahead ancillary services are procured by resource, but the responsibility to provide them is aggregated up to the QSE. Table 4 shows the share of the 2021 ancillary services that were procured from the top ten QSE providers of ancillary services, in terms of volumes, compared to last year. This allows us to determine how concentrated the supply is for each product. The table also shows the total number of QSEs that represent resources that can supply each ancillary services product.

Table 4: Share of Reserves Provided by the Top QSEs in 2020-2021

	2020				2021			
	Responsive	Non-Spin	Reg Up	Reg Down	Responsive	Non-Spin	Reg Up	Reg Down
# of Suppliers	46	32	30	30	58	36	38	40
QLUMN	3%	27%	13%	40%	4%	20%	16%	37%
QNRGTX	11%	4%	6%	5%	13%	13%	9%	7%
QLCRA	12%	7%	3%	4%	12%	4%	3%	7%
QCALP	1%	3%	4%	10%	2%	7%	7%	8%
QCPSE	2%	5%	3%	2%	4%	5%	6%	5%
QEDF26	2%	0%	18%	4%	2%	0%	11%	5%
QAEN	3%	7%	4%	7%	2%	5%	3%	6%
QBRAZO(P)	3%	6%	10%	2%	3%	3%	8%	0%
QBROAD					2%	0%	5%	5%
QFPL12	0%	0%	9%	4%	0%	0%	8%	4%

During 2021, 58 different QSEs self-arranged or were awarded responsive reserves as part of the DAM. The number of providers had been roughly the same before 2021, with 12 additional providers in 2021 from the previous year.[68] Regarding the concentration of the supply for each product, Table 4 shows that in 2021:

- The supply of responsive reserves has not been highly concentrated, just as in 2020, with the largest QSE providing only 13% of ERCOT's responsive reserves (QNRGTX in 2021 as opposed to QLCRA in 2020).
- The provision of non-spinning reserves is still more concentrated than responsive reserves, but less so than in 2020. A single QSE (Luminant, shown above as "QLUMN") bore almost 27% of the requirements in 2020 but only 20% in 2021. Luminant's share has continued to fall from a high of 56% in 2017.
- Regulation up is provided by many different QSEs and the supply is not concentrated.

68 A breakdown of ancillary service providers by QSE, by type of service provided, can be found in Figure A29, Figure A30, Figure A31, and Figure A32 in the Appendix.

- Regulation down in 2021 exhibited similar concentration to regulation down (and non-spinning reserves) in 2020. Luminant remained the dominant supplier, selling 37% of all regulation down in 2020, with no other provider exceeding 10%.

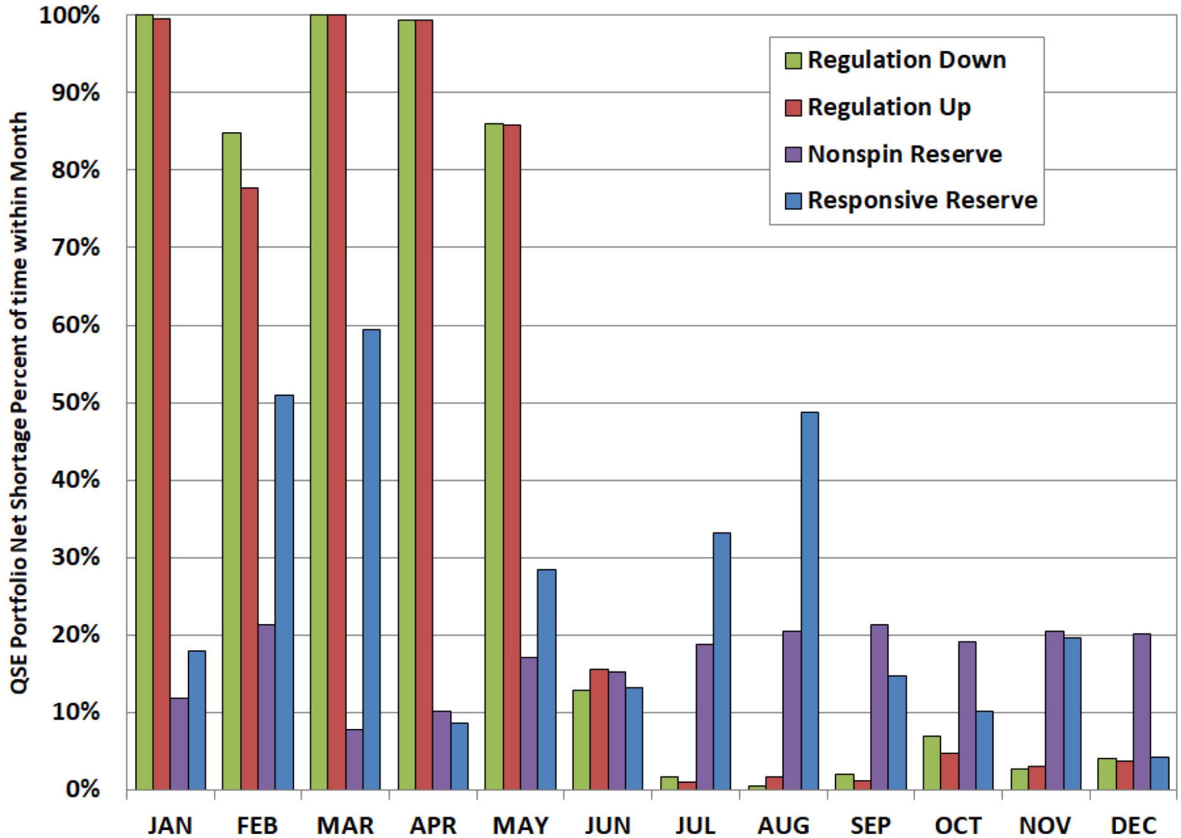
The ongoing concentration in the supply of non-spinning reserves and regulation down highlights the importance of modifying the ERCOT ancillary service market design and implementing RTC. Jointly optimizing all products in each interval will allow the market to substitute its procurements among units on an interval-by-interval basis to minimize costs and set efficient prices. Doing so will reduce the competitive disadvantage faced by smaller entities and should reduce concentration in these markets. Additionally, the use of ancillary service demand curves in the day-ahead co-optimization rather than absolute requirements will improve the efficiency of the day-ahead purchases by allowing those curves to set prices when there is a relative shortage of offers.

In addition to the procurement of ancillary services discussed above, our final evaluation relates to QSEs' delivery of the ancillary services sold in the DAM. Between the time an ancillary service is procured and the time that it is needed, a QSE with multiple units may review and adjust the resources that will provide its ancillary services, presumably to reduce the costs of providing the ancillary service. However, when all ancillary services are continually optimized in response to changing market conditions, the efficiencies will be much greater than can be achieved by QSEs acting individually. These efficiencies will be achieved through RTC.

Further, QSEs without large resource portfolios face higher risk than larger QSEs when selling ancillary services because of the replacement risk faced in having to rely on a supplemental ancillary services market (SASM). Whereas a QSE with a large portfolio can often replace ancillary services within its fleet without the need for a SASM, if there is a forced outage in a small portfolio, the replacement risk is substantial because the clearing prices for ancillary services procured in SASM are often much higher than the clearing prices from the DAM. RTC will address this issue by providing a liquid replacement for ancillary services awarded in the DAM. Because RTC is on the horizon for future implementation and will obviate the need for SASMs, we will not discuss SASM deficiencies and issues further, but we have discussed these issues in previous reports. See Section IV of the Appendix for more information on SASM activity in ERCOT in 2021.

Finally, QSEs do not always provide the ancillary services that they are obligated to provide via a combination of day-ahead awards, self-arrangement, or trades. Figure 37 below shows the percentage of each month during which there was at least one QSE that did not satisfy its full ancillary services obligation. A shortage is defined as greater than 0.1 MW of obligation not being provided for at least 15 minutes out of an hour.

Figure 37: QSE-Portfolio Net Ancillary Service Shortages



Deficiencies of QSEs in meeting their ancillary service responsibilities were pervasive in 2021, not just during February because of forced outages or derations. For market participants that are not able to meet their ancillary service responsibility, the ERCOT operator typically marks the short amount in the software, causing the ancillary service responsibility to be effectively removed and the day-ahead ancillary service payment to be clawed back in settlement.

ERCOT operators did not complete this task during the winter event, and therefore the "failure to provide" settlements were not invoked in real time. Removing the operator intervention step and automating the "failure to provide" settlement was contemplated in NPRR947, *Clarification to Ancillary Service Supply Responsibility Definition and Improvements to Determining and Charging for Ancillary Service Failed Quantities*; however, the NPRR was withdrawn in August 2020 because of the system cost, some complexities related to ancillary service trades, and the then-anticipated implementation of RTC. This item may need to be reconsidered given the delay in RTC and the significant shortages observed above.

Relying on a recommendation of the IMM,[69] the Commission directed ERCOT to settle each qualified scheduling entity that failed on its ancillary service supply responsibility in accordance

69 *Issues Related to the State of Disaster for the February 2021 Winter Weather Event*, Project No. 51812, Potomac Economics' Letter to Commissioners at 1 (Mar. 1, 2021).

with ERCOT Nodal Protocol section 6.4.9.1.3, entitled Replacement of Ancillary Service Due to Failure to Provide, for a particular ancillary service for any hour of ERCOT's operating days February 14, 2021 through February 19, 2021.[70] Invoking the "failure to provide" settlement for all ancillary services that market participants failed to provide during Winter Storm Uri produced market outcomes and settlements consistent with underlying market principles. Market participants should not be paid for services that they do not provide. Whether ERCOT marked the short amount in real-time or not should not affect the settlement of these ancillary services.

70 *Issues Related to the State of Disaster for the February 2021 Winter Weather Event*, Project No. 51812, Second Order Addressing Ancillary Services at 2 (Mar. 12, 2021).

V. Transmission Congestion and Congestion Revenue Rights

An essential function of any electricity market is to efficiently manage power flows on the transmission networks. Congestion management occurs as the markets coordinate the dispatch of generation to ensure that the resulting power flows do not exceed the operating limits of the transmission facilities. This coordination occurs through the real-time market dispatch software, which optimizes based on each generator's energy offer curve and how much of its output will flow across the overloaded transmission element. The result of this market dispatch is a set of locational prices that vary across the network and resulting congestion costs that are collected from participants. Congestion exists most of the time; at least one constraint was binding (with the flow at the constraint's limit) in real time during 70% of 2021.

The locational difference in prices caused by congestion can result in costs or risks for parties in long term power contracts who are liable for the price differences between the location of the generator and the location of the load. CRRs are economic property rights that are funded by the congestion collected through the DAM. CRR markets enable parties to purchase the rights to locational price differences in monthly blocks as much as three years in advance. Hence, CRRs provide a hedge for day-ahead congestion, and if desired can easily be converted into a real-time congestion hedge.

This section of the Report evaluates congestion costs and revenues in 2021. We first discuss the congestion costs in the day-ahead and real-time markets, which totaled $1.4 billion and $2.1 billion respectively, in 2021. We then discuss the CRR markets and funding in 2021.

A. Day-Ahead and Real-Time Congestion

As the DAM clears financially-binding supply, demand and PTP obligation transactions, it does so while also respecting the transmission system limitations. This can result in widely varying locational prices and associated congestion. This congestion can be affected by planned transmission outages, load, and renewable forecasts, which also inform market participants' decisions on how to hedge portfolios before real-time. In real-time, congestion costs represent the cost of managing the network flows resulting from physical dispatch of generators. Figure 38 and Figure 39 summarize the monthly and annual congestion costs in the day-ahead and real-time markets. The values are aggregated by geographic zone.

Figure 38 shows that the total day-ahead congestion costs in 2021 were roughly 5% higher than costs in 2020; similarly, real-time congestion costs increased 46%. Most of the differences in congestion costs between day-ahead and real-time were in the South zone, which constituted approximately 45% of all the congestion in ERCOT. The increase in congestion costs were driven by congestion during the extreme events of Winter Storm Uri.

Figure 38: Day-Ahead Congestion Costs by Zone

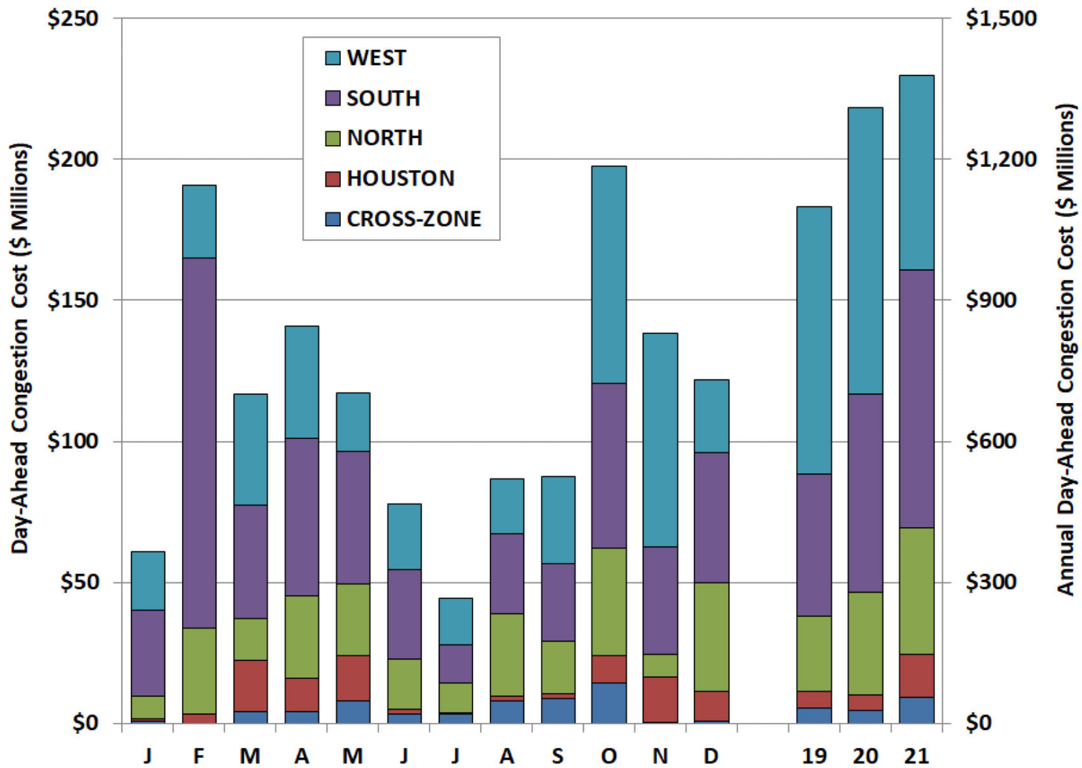
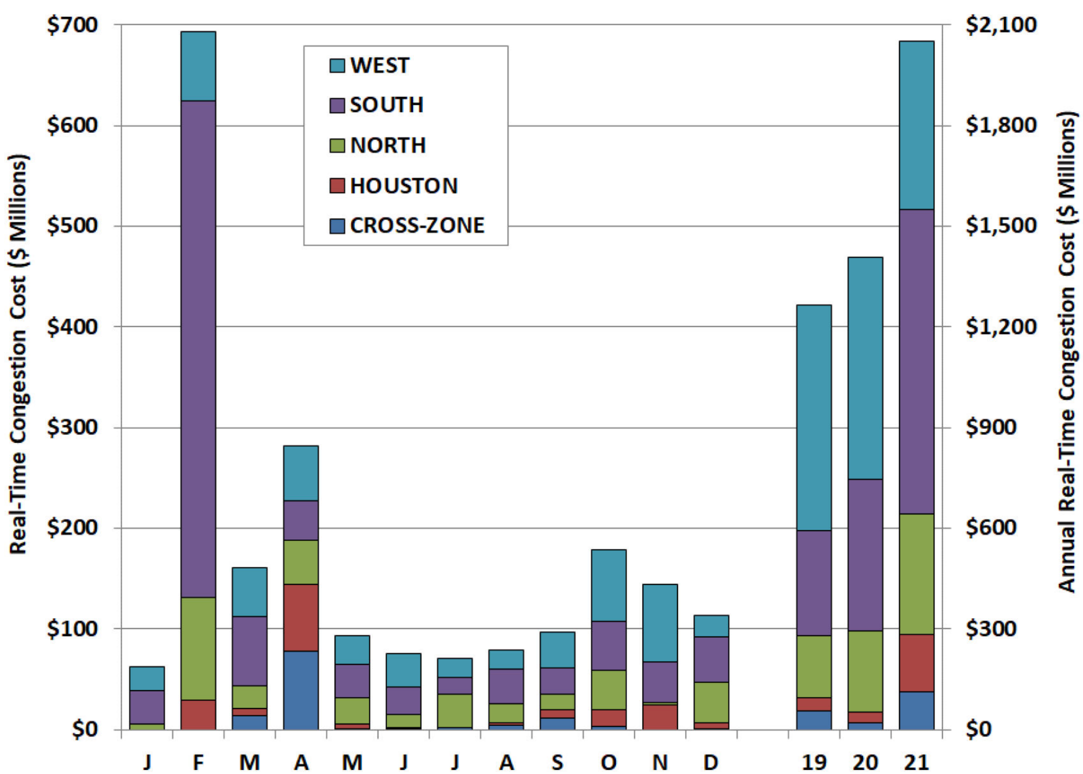


Figure 39: Real-Time Congestion Costs by Zone



The 2021 monthly congestion profile shows that congestion was highest in the winter and fall, which is an expected pattern, but especially in February during Winter Storm Uri. In typical years, most transmission and generation outages for maintenance and upgrades occur in shoulder months. The increased congestion in March and April was likely due to an increase in significant transmission and generation maintenance outages and repairs because of the operational issues encountered in February. Also, the limitation on allowing any outages occurring over the summer months has become highly significant with regard to outage scheduling.

The largest zonal contributor to congestion costs in 2021 was the South zone during Winter Storm Uri. The West zone, which had similar aggregate congestion costs between 2021 and 2020, had congestion driven by high intermittent renewable output. Specific top constraints in terms of dollars contributing to the real-time congestion costs are described in the next subsection.

B. Real-Time Congestion

While the expected costs of congestion are reflected in the DAM, physical congestion occurs only in the real-time market. ERCOT operators manage power flows across the network as physical constraints become binding in real time. Therefore, any review of congestion must focus on the real-time constraints and resulting congestion, which we evaluate and discuss in the section.

1. Types and Frequency of Constraints in 2021

Constraints arise in the real-time market through:

- Real-Time Contingency Analysis (RTCA) that runs on an ongoing basis; and
- GTCs that are determined by off-line studies, with limits determined prior to the operating day.[71]

RTCA is the process that evaluates the resulting flows on the transmission system under many different contingency scenarios. A base-case constraint exists if the flow on a transmission element exceeds its normal rating. A thermal contingency constraint exists if the outage of a transmission element (i.e., a contingency) would result in a flow higher than the rating of an in-service element.[72] Active transmission constraints are those that are passed by the operator to the

71 A GTC is a transmission constraint made up of one or more grouped Transmission Elements that is used to constrain flow between geographic areas of ERCOT for the purpose of managing stability, voltage, and other constraints that cannot otherwise be modeled directly in ERCOT's power flow and contingency analysis applications and are based on offline studies (i.e. RTCA will not provide indication of encroaching concerns.)

72 Typically, a contingency constraint is described as a contingency name plus the name of the resulting overloaded element. This section will refer to a constraint based solely on the overloaded element to identify the bottleneck in the electric grid.

dispatch software and that evaluated them, whereas some constraints are identified but not activated by the operator for various reasons. The active constraints are "binding" when positive dispatch costs are incurred to maintain transmission flows below the constraint limit and "not binding" when they do not require a redispatch of generation and thus have no effect on prices.

Our review of the active and binding constraints during 2021, Figure 40, shows the following:

- The ERCOT system had at least one binding constraint 70% of the time in 2021, a decrease from 75% in 2020.
- Consistent with previous years, the average number of active constraints generally increased with increasing load level
- On average, slightly more than ten constraints were identified for the higher load levels, up from approximately seven in 2020.

Figure 40: Frequency of Binding and Active Constraints by System Load Level

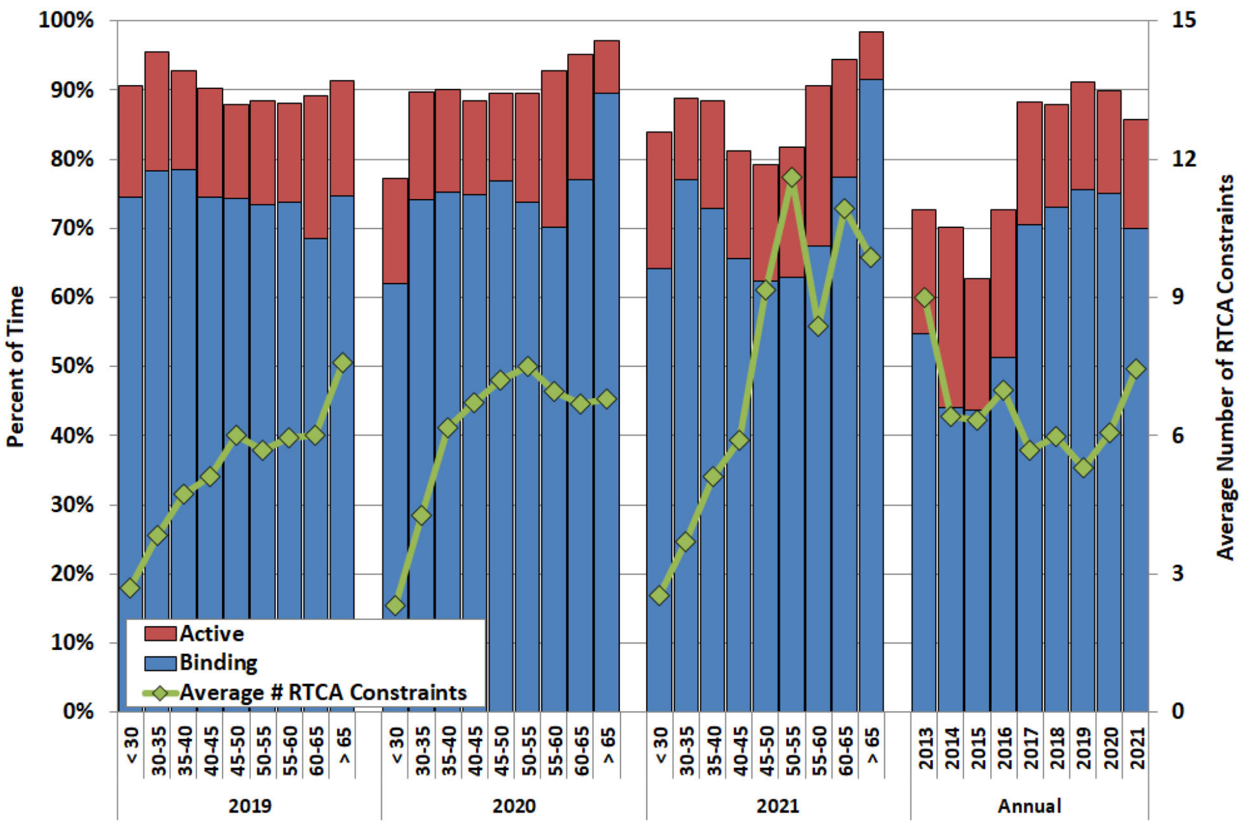


Table 5 below shows the GTCs and the number of binding intervals during 2020 and 2021. The number of GTC binding intervals in 2021 almost doubled compared to 2020 and represented 20 percent of real-time congestion rent. GTCs are used to ensure that the generation dispatch does not violate a transient or voltage stability condition. Certain GTC limits are determined in real-time using the Voltage Stability Assessment Tool (VSAT) or the Transient Stability Assessment

Tool (TSAT). These tools are used continuously to evaluate the North to Houston and the Rio Grande Valley Import limits, which provides a more accurate real-time limit than could be achieved through offline studies.

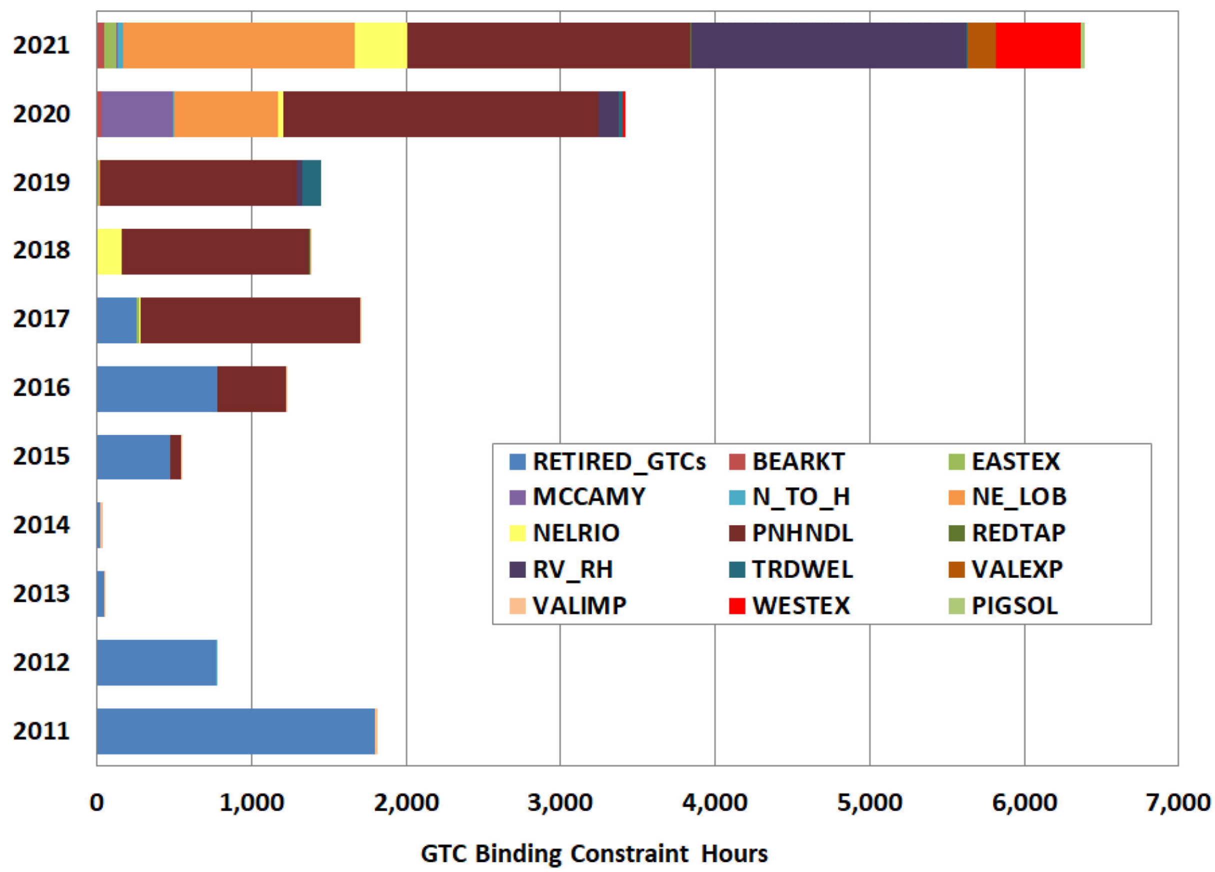
ERCOT has been working on getting better data for the full range of inverter technology, which over time will allow all GTC limits to be calculated in real-time rather than using more-conservative offline studies. This should result in less generation curtailment. Apart from the North to Houston, Rio Grande Valley Import, and East Texas constraints, all GTCs resulted from issues identified during the generation interconnection process. As more renewable generation and ESRs come online in the ERCOT region, the benefits of these dynamic VSAT and TSAT models will grow.

Table 5: Generic Transmission Constraints

Generic Transmission Constraint	Effective Date	# of Binding Intervals in 2020	# of Binding Intervals in 2021
North to Houston	December 1, 2010	37	377
Rio Grande Valley Import	December 1, 2010	-	-
Panhandle	July 31, 2015	24,762	22,416
Red Tap	August 29, 2016	-	64
North Edinburg - Lobo	August 24, 2017	8,230	18,451
Nelson Sharpe - Rio Hondo	October 30, 2017	524	4,271
East Texas	November 2, 2017	34	967
Treadwell	May 18, 2018	239	103
McCamey	March 26, 2018	5,660	152
Raymondville - Rio Hondo	May 2, 2019	1,703	21,884
Bearkat	November 20, 2019	354	547
Westex	October 1, 2020	235	6,720
Zapata - Starr	Novemeber 5, 2020	-	-
Valley Export	Novemeber 5, 2020	65	2,351
Pigcreek Solstice	November 16, 2020	-	265

The frequency in which GTCs are binding is also shown in Figure 41, depicting the aggregate total of GTC binding constraint hours from 2011 to 2021. GTCs were binding much more frequently in 2021 than in previous years.

Figure 41: GTC Binding Constraint Hours[73]



The next subsection describes where and some reasons why these constraints occurred.

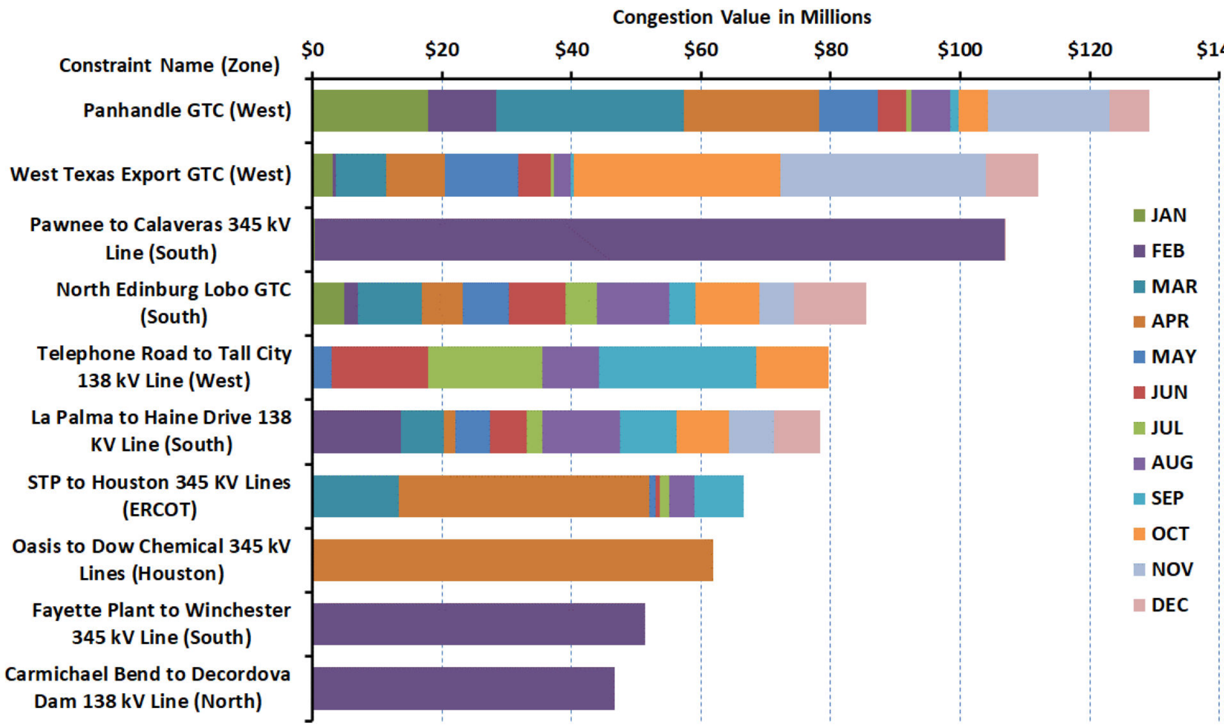
2. Real-time Constraints and Congested Areas

Our review of congested areas starts with describing the areas with the highest financial impact from real-time congestion. For this discussion, a congested area is identified by consolidating multiple real-time transmission constraints if the constraints are determined to be similar because of geographic proximity and constraint direction. We calculate the real-time congestion value by multiplying the shadow price of each constraint by the flow over the constraint. This gives the total dollar amount of the associate re-dispatch, where the shadow price represents the per-MW redispatch cost, defined as the marginal cost of the constraint (i.e., the dollar amount that would be avoided if the transmission element limit were 1 MW larger). Multiplying the shadow price by the flow over the transmission element itself gives that total cost of the constraint. The flow over the transmission element will be equal to the transmission element limit when the constraint is binding but may be over the limit if the constraint is violated.

[73] Retired GTCs are Ajo to Zorillo, Bakersfield, Laredo, Liston, Molina, North to West, SOP110, West to North, and Zorillo to Ajo.

There were 526 unique constraints that were either binding or violated at some point during 2021, with a median financial impact of approximately $310,000. In 2020, there were 450 unique constraints with a median financial impact of $222,000. Figure 42 displays the ten most costly real-time constraints with their respective zone measured by congestion value.

Figure 42: Most Costly Real-Time Congested Areas



The constraint with the highest congestion value in 2021 ($129 million) was the Panhandle GTC constraint, which was mostly caused by the interaction of high intermittent resources and planned transmission outages, including ETT maintenance outages, in the area. ETT maintenance is on track to complete work in 2022. Compared the Panhandle constraint's congestion cost of $139 million in 2020, the congestion cost in 2021 was about 10% lower in 2021.

The constraints on the Pawnee to Calaveras 345 kV Line, Fayette Plant to Winchester 345 kV Line and Carmichael Bend to Decordova Dam 138 kV Line solely occurred in February in conjunction to Winter Storm Uri. The STP to Houston 345 KV Lines and Oasis to Dow Chemical 345 kV Lines were due to planned and forced outages in the area. The other constraints were due to output from inverter-based resources; Panhandle GTC, West Texas Export GTC, North Edinburg Lobo GTC, Telephone to Tall City 138 kV Line, and La Palma to

Haine Drive 138 kV Line. ERCOT highlighted these areas in the 2021 Long-Term System Assessment (LTSA) report within the ERCOT Constraints and Needs Report. [74]

Day-ahead congestion costs were highest on the top three paths discussed above, with day-ahead congestion costs totaling roughly $1,380 million, somewhat less than the $2,050 million that accrued in the real-time market. This difference generally reflects the divergence between expectations in the DAM and actual real-time outcomes. This was more significant in 2021 due to transmission and generation outages from Winter Storm Uri. In the other months, less wind generation scheduled in the DAM is generally the factor. Figure A38 in the Appendix presents additional detail on real-time congested areas with their respective zones in 2021.

3. Irresolvable Constraints

The shadow price of a constraint represents the marginal cost of managing a constraint (i.e., the cost of achieving the last MW of needed relief through the real-time dispatch). However, because some constraints are more costly to manage than the reliability cost of allowing them to be violated, ERCOT caps the shadow price. Without the cap, the dispatch costs and shadow price could rise to unreasonable prices. When the dispatch model cannot find a solution to manage the constraint at a marginal cost less than the shadow price cap, the constraint will be "violated" in that interval, and the shadow price will be at the cap.[75] The shadow price caps during 2021 were:

- $9,251 per MW for base-case (non-contingency) constraints or voltage violations,[76]
- $4,500 per MW for 345 kV constraints,
- $3,500 per MW for 138 kV constraints, and
- $2,800 per MW for 69 kV thermal violations.

GTCs are considered base-case stability constraints (for voltage or transient conditions) with a shadow price cap of $9,251 per MW. Figure 43 shows the distribution of the percentage overload of violated constraints between 2020 and 2021. A more detailed review of violated constraints can be found in Figure A37 in the Appendix. Violated constraints continued to occur in a small fraction of all constraint intervals – 10% in 2021, up from 8% in 2020.

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74 *See* Report on Existing and Potential Electric System Constraints and Needs, December 2021; https://www.ercot.com/files/docs/2021/12/23/2021_Report_Existing_Potential_Electric_System_Constraints_Needs.pdf

75 Shadow price caps are intended to reflect the reduced reliability that occurs when a constraint is irresolvable. See Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints.

76 OBDRR037, *Power Balance Penalty and Shadow Price Cap Updates to Align with PUCT Approved High System-Wide Offer Cap*, reduced the shadow price cap for base-case constraints $5,251 per MW effective April 1, 2022.

Figure 43: Overload Distribution of Violated Constraints

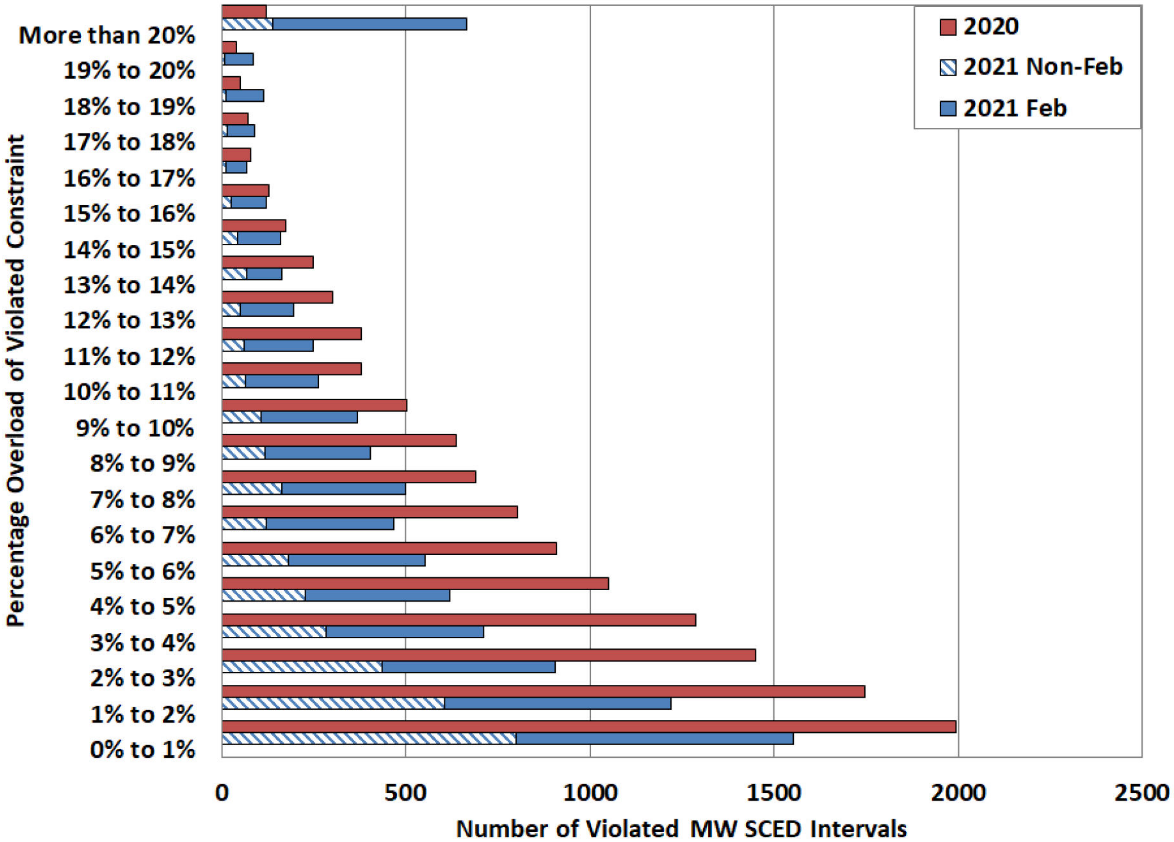


Figure 43 shows that there were less SCED intervals at the various violated constraint percentages in 2021 than in 2020, except for those above 17% of the constraint value. The month of February incurred the highest percentage in those categories in 2021. Finally, 16% of the violated constraints in 2021 were only slightly in violation (less than 1% over the rating), yet they are priced at the shadow price cap like the more severe violations. Almost 30% of the constraints are in violation by only small amount (between 0-2% of the transmission element rating) and these violations should be targeted for reduced shadow price caps. Implementing a well-designed transmission demand curve would recognize that the reliability risk of a post-contingency overload increases as the overload amount increases. Small violations should have lower shadow prices than large violations. The IMM filed a revision request to implement transmission constraint demand curves, which was ultimately withdrawn for lack of support.[77]

[77] Filed on January 21, 2020, by the IMM, OBDRR026, *Change Shadow Price Caps to Curves and Remove Shift Factor Threshold*, proposed to make certain congestion management changes for contingency constraints. This OBDRR would have 1) changed the default Shadow Price caps to curves (the change lowers the value for small violations and raises the value for large violations); and 2) removed the Shift Factor threshold as a factor for determining eligibility for Security-Constrained Economic Dispatch (SCED) consideration. Currently, a constraint is only eligible for resolution by SCED if at least one Resource exists that has a Shift Factor of greater than 2% or less than negative 2%. This OBDRR also proposed minor cleanup items and simplifications to Section 3, Elements for Methodology for Setting the Network Transmission System-Wide Shadow Price Caps. The revision request was withdrawn on January 6, 2022.

Violations may be resolved in subsequent intervals as generators ramp to provide relief. Nonetheless, a constraint-specific peaker net margin mechanism is applied such that once local price increases reach a predefined threshold, the constraint is deemed irresolvable and the constraint's shadow price cap is recalculated based upon the mitigated offer cap of existing resources and their ability to resolve the constraint.[78] Table A4 in the Appendix shows that 16 elements were deemed irresolvable in 2021 and had a shadow price cap imposed according to this methodology.

C. CRR Market Outcomes and Revenue Sufficiency

As discussed above, CRRs are valuable economic property rights entitling the holder to the day-ahead congestion payments or charges between two locations. CRRs are modeled as a power flow injection at the "source" and a withdrawal at the "sink." In this subsection, we discuss the results of the CRR auctions, the allocation of the revenues from the CRR auctions, and the funding of CRRs from the DAM congestion.

4. CRR Auction Revenues

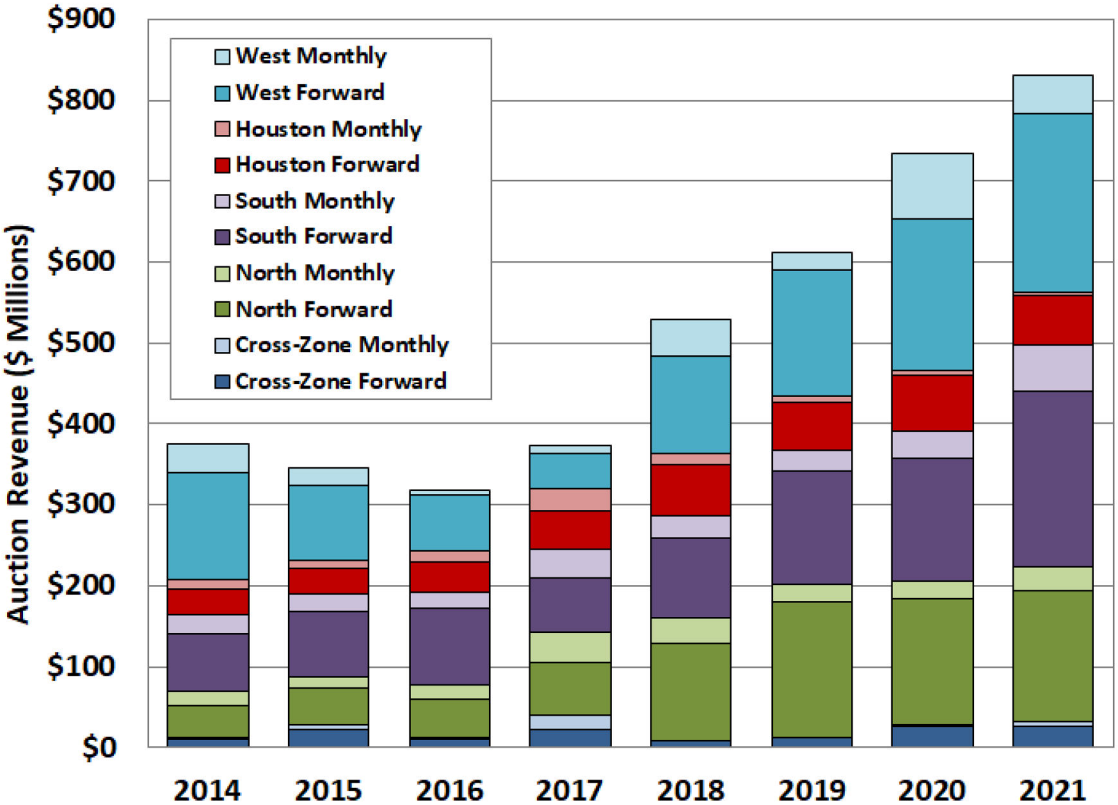
CRRs may be acquired in semi-annual and monthly auctions while Pre-Assigned Congestion Revenue Rights (PCRRs) are allocated to certain participants (Non Opt-In Entities or NOIEs) based on generation units owned or contracted for prior to the start of retail competition in Texas. Parties receiving PCRRs pay only a fraction of the auction value of a CRR between the same locations. To summarize the CRR market results, Figure 44 shows the revenues, calculated by multiplying the shadow price by the flow on binding constraints in the CRR auctions.

Our calculation of the zonal CRR revenue is based on the binding constraint location, which is different from the method used to allocate CRR revenues to loads. The costs are separately shown by whether they were incurred in a monthly auction (labeled "monthly") or one of the six-month long-term auctions (labeled "forward"). The "Cross-Zone" category contains costs associated with constraints having sources and sinks in different zones (for example North to Houston).

Figure 44 shows that aggregate CRR revenues have risen steadily since 2016. We note that all forward auction revenues for each of the zones increased between 2020 and 2021 except the Houston zone, whereas the monthly auction revenues increased except in the Houston and West zones. In general, monthly auctions will produce prices that reflect the most accurate expectations of actual congestion because they are closest to the operating horizon.

78 *See* Section 3.6.1 of the document, Setting the Shadow Price Caps and Power Balance Penalties in Security Constrained Economic Dispatch, which can be found in the Other Binding Document (OBD), Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints.

Figure 44: CRR Auction Revenues by Zone

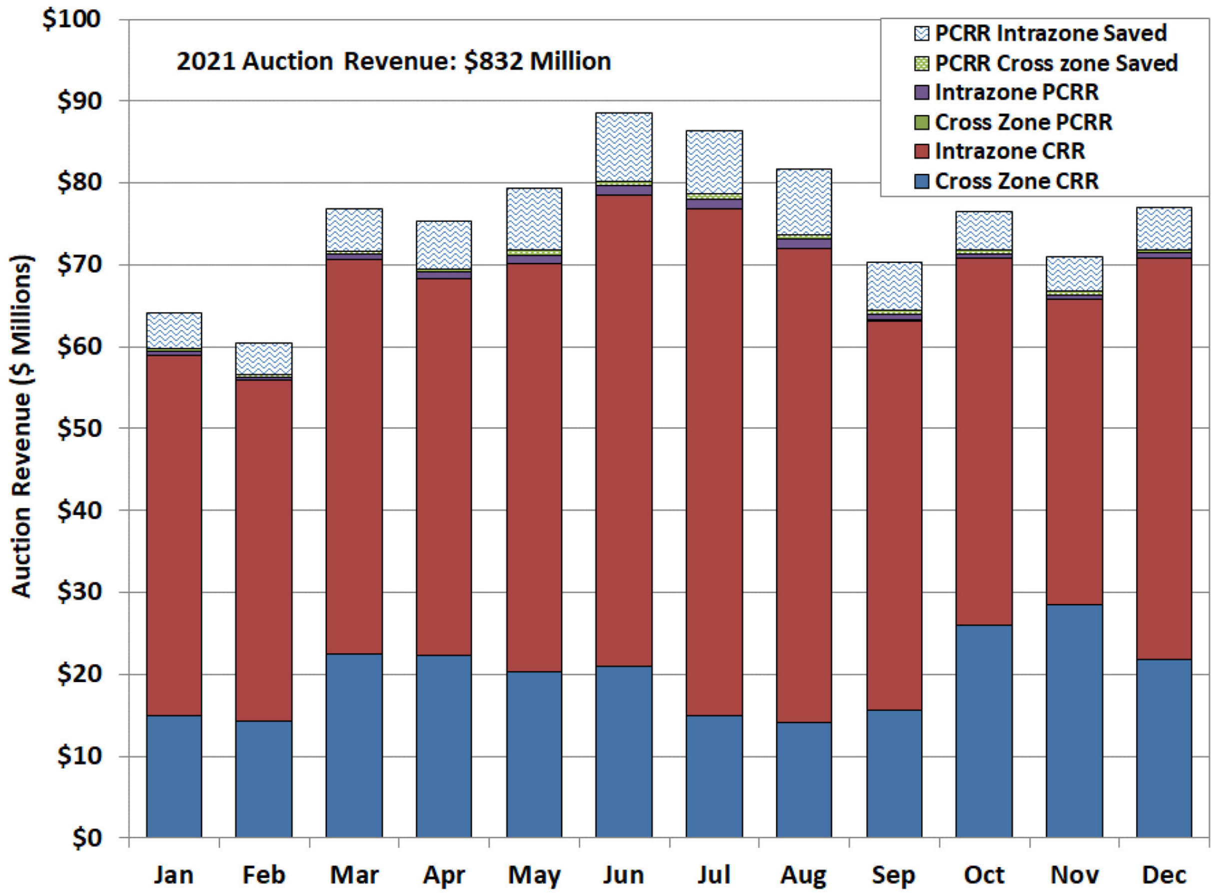


ERCOT has implemented third year CRR auctions, which caused more of the transmission capacity to be sold in advance of the monthly auctions. Opportunities to purchase CRRs earlier improve forward hedging and add liquidity. However, earlier purchases can also increase differences between CRR auction revenue and day-ahead payouts because more of the CRRs are sold when there is higher uncertainty regarding the status of transmission elements, generator availability, and load levels.

ERCOT distributes CRR auction revenues to loads in one of two ways. First, revenues from cross-zone CRRs are allocated to loads ERCOT-wide. Second, revenues from CRRs that have the source and sink in the same geographic zone are allocated to loads within that zone. Figure 45 summarizes the revenues collected by ERCOT in each month for all CRRs, including both auctioned and allocated. We also show the amount of the discount provided to the PCRR recipients: the PCRR discount ("PCRR Intrazone Avoided" and "PCRR Cross Zone Avoided") is the difference between the auction value and the value charged to the purchaser.

The total amount of CRR auction revenue increased to $831 million in 2021, up from $725 million in 2020 and $612 million in 2019, while the total PCRR discount increased from $61 million in 2020 to $76 million in 2021. These increases reflect a yearly trend of an increased expectation of congestion in 2021.

Figure 45: 2021 CRR Auction Revenue

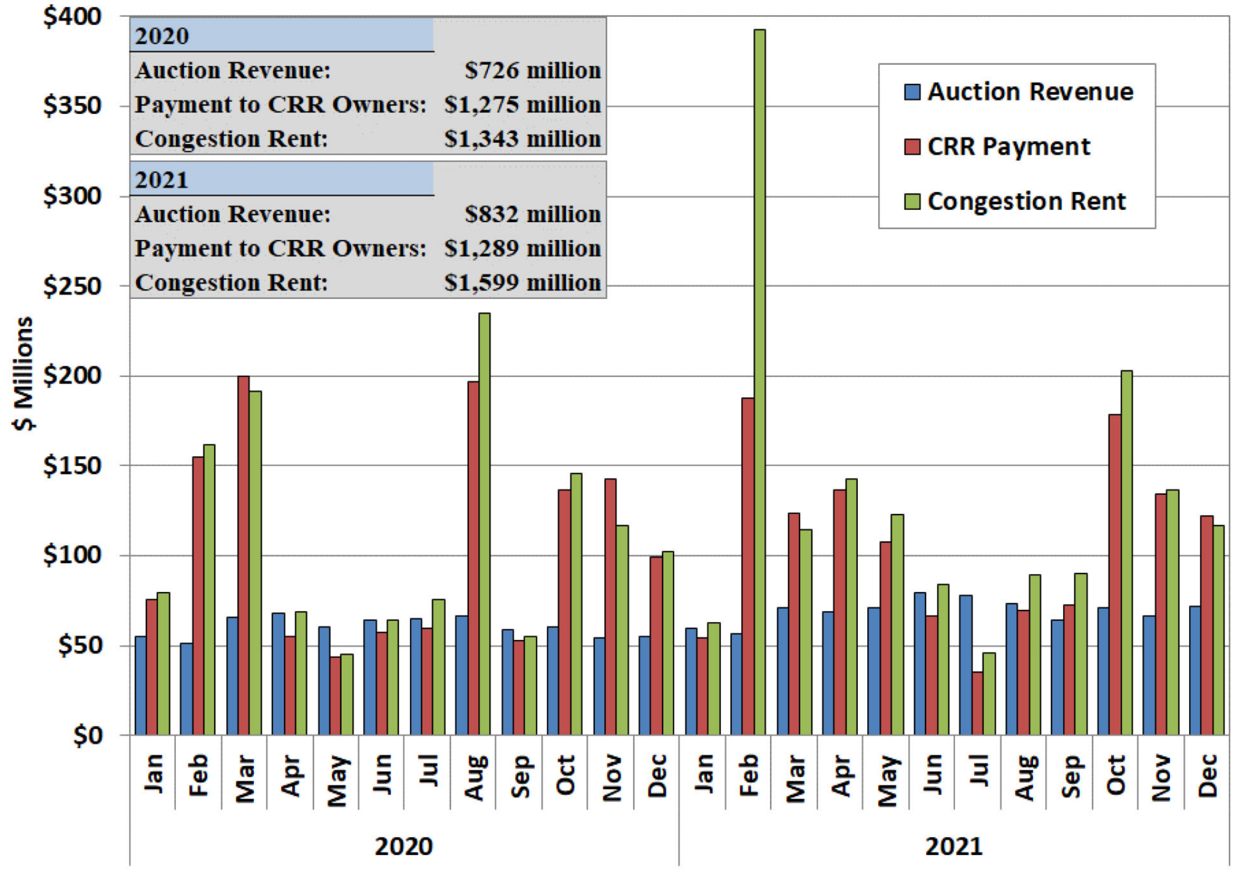


5. CRR Profitability

CRRs are purchased well in advance of the operating horizon when actual congestion revenues are uncertain. Therefore, they may be purchased at prices below their ultimate value (based on CRR payments) and referred to as "profitable," or may be purchased at prices higher than their ultimate value and be "unprofitable." Historically, CRRs have tended in aggregate to be profitable. Although results for individual participants and specific CRRs varied, this trend continued in 2021 with participants again paying much less for CRRs they procured than their ultimate value. To evaluate these results, Figure 46 shows the monthly CRR auction revenue, the day-ahead congestion rent collected to fund the CRRs, and the payout to the CRR owners.

Figure 46 shows that for the entire year, participants spent $832 million to procure CRRs and in aggregate received $1,289 million, as shown below. In general, this difference occurred because of the increase in congestion that occurred in 2021 was not foreseen by the market in the forward auction periods, in conjunction with the time value of money and with CRR obligation risk. The period of congestion that accounted for most of this difference was February, because of Winter Storm Uri, and October because it was a shoulder month with a lot of outages.

Figure 46: CRR Auction Revenue, Payments and Congestion Rent



Prices paid for CRRs represent the market expectations as of the time of the auction. Because many CRRs are purchased months (if not years) in advance, the factors that drove up the congestion costs in 2021 were likely not apparent when the bulk of the CRRs were purchased. Conversely, the CRR auction revenue in some months was higher than the CRR payouts when congestion was milder than expected. This occurred in June through August in 2021.

Finally, the payout can be less than the congestion rent collected in the DAM when the quantity of CRRs sold is less than the day-ahead network flows. This occurred in 2020, when the payout in aggregate was approximately $110 million less than the day-ahead congestion rent. One reason this occurs in ERCOT is that the CRR network model uses line ratings that are 90% of a conservative estimate of the lowest line ratings for the month. Therefore, CRRs tend to be a little undersold. Excess congestion rent will be discussed in the next subsection. It is instructive to review these three values over a longer timeframe, so Figure 47 provides the annual CRR auction revenues, payments to CRR owners and day-ahead congestion rent.