Filing Receipt

Filing Date - 2023-05-30 12:42:00 PM

Control Number - 34677

Item Number - 20

2022 State of the Market Report for the ERCOT Electricity Markets

POTOMAC ECONOMICS

Independent Market Monitor
for ERCOT

May 2023

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Guide to Acronyms

4CP	4-Coincident Peak	NOIE	Non Opt-In Entity
CDR	Capacity, Demand, and Reserves Report	NPRR	Nodal Protocol Revision Request
CFE	Comisión Federal de Electricidad	NSO	Notification of Suspension of Operations
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	PUCT	Public Utility Commission
FFSS	Firm Fuel Supply Service	PURA	Public Utility Regulatory Act
FIP	Fuel Index Price	QSE	Qualified Scheduling Entity
GTC	Generic Transmission Constraint	RDI	Residual Demand Index
GW	Gigawatt	RENA	Real-Time Revenue Neutrality Allocation
HCAP	High System-Wide Offer Cap	RDPA	Real-Time Reliability Deployment Price Adder
HE	Hour-ending	RTCA	Real-Time Contingency Analysis
Hz	Hertz	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 2022 to the Public Utility Commission of Texas (PUCT) in our role as the 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 electricity to more than 26 million Texas customers – about 90% of the state's total electric demand. Every five minutes, the ERCOT market coordinates the electricity output from more than 1,100 generating resources to satisfy customer demand and manage the resulting flows of power across more than 52,700 miles of transmission lines in the region. Additionally, the prices produced by the market are designed to facilitate the long-term investment and retirements of resources in the ERCOT region. Hence, the market's performance that we evaluate in this report is critical for maintaining reliability in Texas.

In addition to the continuing effects of 2021 Winter Storm Uri across all ERCOT markets, 2022 presented its own unique set of challenges. These challenges included load growth that led to a record-breaking summer, as well as continuing conservative operations by ERCOT. This report details the changes to the ERCOT markets implemented in 2022 in the aftermath of Winter Storm Uri (Operating Reserve Demand Curve adjustment, firm fuel supply service, etc.) and the outcomes produced by those changes. In addition, we discuss the features of the changing grid and future needs of the market. These findings are summarized at the end of this executive summary. Key results in 2022 include the following:

Competition and Market Power

- The ERCOT markets performed competitively in 2022 and we found little evidence that suppliers exercised market power in the ERCOT market, with the following exception.
  - The non-spinning reserve market became less competitive, as higher procurements caused large suppliers to frequently be pivotal. We estimate that this raised the costs of non-spinning reserves from a range of $385 to $480 million from August 2021 through December 2022.
    - The PUCT took actions to address this issue by modifying the Voluntary Mitigation Plans (VMPs) of large suppliers to recognize that mitigation is needed now in the non-spinning reserve market.
- 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 2022.
- We remain concerned about insufficient incentives for suppliers to self-commit generation resources in light of ERCOT's increased commitments through the Reliability

Unit Commitment (RUC) process. Recommendation 2022-2 below is intended to address this concern.

Demand for and Supply of Electricity

- Electricity demand peaked in 2022 at 80,038 megawatts (MW) on July 20, a new record and 8.8% higher than the peak in 2021. In fact, ERCOT broke peak demand records 11 times during the summer of 2022. The summer months of June through August 2022 were the second hottest on record for the state of Texas after only 2011.
- Average load in ERCOT grew 9.5% from 2021. The average load grew more than the peak load in all zones, especially in the South zone.
- The generation portfolio continues to evolve as over 7,000 MW of new wind and solar resources and 1,700 MW of energy storage resources (ESRs) entered the market. The installed capacity of wind increased to 37 GW, solar capacity to 13.7 GW, and ESRs to 2.7 GW by the end of 2022.
- Approximately 700 MW of new natural gas resources came online in 2022 while one 420 MW natural gas resource retired, resulting in a net addition of 280 MW.

Market Outcomes and Performance

- Average real-time prices fell to roughly $75 per MWh in 2022, a reduction of more than 50% from 2021 ($167.88 per MWh due almost entirely to the effects of Winter Storm Uri), but nearly triple the average prices in 2020 ($25.73 per MWh). This reflects a real-time energy value for 2022 of $32.2 billion.
  - The rise in real-time energy prices over the past two years was partly due to higher natural gas prices (close to $6/MMBtu), as well as sustained hotter than normal summer conditions in 2022.
- Transmission congestion in the real-time market – incurred to dispatch generators to reduce flows over constrained lines – was up 37% from 2021 to total $2.8 billion in 2022. More than $700 million was incurred during May related to Houston congestion.
  - ERCOT is increasingly limiting flows across certain network paths to maintain the stability of the system, which increases transmission congestion costs. These stability issues have partly resulted from the increase in inverter-based resources.
  - The congestion associated with stability constraints increased from $400 million in 2021 to $640 million in 2022 – representing roughly 20% of all real-time congestion.
- ERCOT's conservative operational posture continued throughout 2022, including:
  - More routine use of RUC, including issuing instructions earlier in the day and committing more longer-lead time resources;
  - Increased non-spinning reserve procurement; 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

- A critical market change underway is ERCOT's improvement of its real-time market to optimize the scheduling of its resources between energy and operating reserves every five minutes, also known as "real-time co-optimization" or RTC.
  - This change was planned to go live in 2025. Due to resource constraints following Winter Storm Uri in 2021, ERCOT postponed the RTC project. Recently, it is evaluating restarting the effort, with a new potential go-live date in late 2026.
  - 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).

Moving Forward from Winter Storm Uri

The sustained shortage pricing during Winter Storm Uri led to billions of dollars in excess costs and numerous defaults that ERCOT and that the State of Texas continued to contend with throughout 2022. ERCOT short payments (money owed but not paid by market participants) during Winter Storm Uri exceeded $3 billion. Several retail electric providers were forced to exit the market and one large electric cooperative sought bankruptcy protection. The financial stress on the ERCOT market led the Texas Legislature and the Commission to intervene by implementing broad securitization and financing measures to stabilize the market.[1] In addition, the bankruptcy was resolved with impacts discussed in this Report. Finally, the Commission worked throughout 2022 to develop market reforms designed to promote the development of dispatchable generation and improve reliability. We discuss these reforms later in this report.

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 2022, but there is little evidence that suppliers abused market power in the real-time energy market. However, the non-spinning reserve market produced non-competitive outcomes, an issue emerging as a result of the sharp increase in the procurement of these reserves. We also remain concerned about the incentives to self-commit generation resources in light of ERCOT's increased commitment of resources through RUC.

Structural Market Power

For 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

1 See SB 2, SB 3, SB 2154, SB 1580, HB 4492.

when its resources are needed to 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:

- At least one pivotal supplier existed in 16% of all hours in 2022, compared to 18% in 2021.
- Under high-load conditions, a supplier was pivotal in more than 50% of the hours, since the 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 isolates these areas. Market rules cap prices that suppliers can offer in these cases, mitigating suppliers' ability to abuse market power.

Behavioral Evaluation

We also 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. Physical withholding occurs when a supplier makes a resource unavailable. Either of these strategies will reduce output from the withheld resource and thereby increase the prices paid to the supplier's other resources.

We identify potential economic withholding by estimating the output gap metric – the quantity of clearly economic energy that is not produced by online resources. The output gap quantities remained very small in 2022 and only 2% of hours 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 2022 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 2022.

However, during the second half of 2021 and also for 2022, 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 incentives resulting from those actions. A market rule revision was proposed and passed by the ERCOT stakeholders to address this issue.[2] We propose an additional change, reflected below in our recommendation section (2022-2).

2 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 be removed once ERCOT completes system implementation.

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 2022

Total demand for electricity in 2022 increased by roughly 10% from 2021 – an increase of approximately 4,250 MW per hour on average as the Texas economy continued to grow. The South load zone saw a 11.9% increase and the West Texas region showed an increase of 18.9% on average. The increase in the West zone is notable because it follows a 7.2% increase in 2021. In recent years, oil and natural gas production activity has been the driver for growing demand in the West zone, particularly as natural gas prices have increased.

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 the summer of 2022, cooling degree days increased substantially from 2021 – 12%, 24% and 26% in Houston, Dallas and Austin, respectively.

Peak hourly demand of 80,038 MW occurred on July 20, 2022, setting a new record for the 11th time in the summer of 2022, up from the record demand prior to 2022 of 74,820 MW in 2019. A new winter record was also set in 2022 at a level near this 2019 summer peak record. Peak demand levels are important because they affect the probability and frequency of shortages. Winter peak demands are also raising reliability concerns more than in the past. However, peak *net* load (demand minus renewable resource output) has become a more important determinant of supply shortages. The largest pricing event during summer occurred on July 13 when demand was below the annual peak that occurred on July 20. High shortage prices play a key role in supporting investment and maintaining existing generation in ERCOT's energy-only market.

Supply in 2022

Approximately 9,700 MW of new generation resources came online in 2022, the bulk of which were intermittent renewable resources. ERCOT added roughly 3,100 MW of new installed wind capacity and 4,200 MW of new installed solar capacity going into summer 2022 compared to summer 2021, with an effective peak output capacity totaling 4 GW.

The remaining new capacity included 700 MW of combustion turbines and 1,700 MW of storage resources. Storage resources now total roughly 2.7 GW. There was one retirement of a 420 MW natural gas-fired resource in 2022. These resource changes, along with changes in fuel prices, led to the following changes in electricity production in 2022:

- The percentage of total generation supplied by wind resources increased slightly to almost 25% of all generation in 2022.
- The share of generation from coal fell from 19% in 2021 to 16.6% in 2022 as fuel supply and other supply-chain issues affected coal production.
- Natural gas generation was virtually unchanged, rising slightly from 41.9% in 2021 to 42.5% in 2022 even though natural gas prices were higher.
- Solar increased from 4.0% of annual generation in 2021 to 4.6% in 2022. Total installed capacity of solar generation is now 14,813 MW as of February 2023.
- While the energy production from ESRs remains relatively small, they are more likely than before to be the marginal resource during shortage conditions.

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. Prices in 2022 produced market revenues sufficient to support profitable investment in new conventional resources based on our net revenue analysis, as they have in three of the last four years. We discuss this further later in the Report, comparing estimated net revenues to cost of new entry of a combustion turbine. For 2022, the high market revenues were primarily due to high natural gas prices, hot summer conditions, and the change in the Operating Reserve Demand Curve (ORDC).

As described in the Future Needs of the ERCOT Market section, ERCOT adopted a more conservative operating posture and procedures starting in July 2021. ERCOT began requiring additional operational reserves and committing more generation outside of the market.[3] We are concerned that continued out-of-market intervention by ERCOT will reduce the efficiency of the market and distort the long-term market signals governing the entry and exit of resources.

ERCOT heads into the summer months of 2023 with a calculated reserve margin of 22.2% based on ERCOT's Capacity, Demand Reserves report, comparable to 2022 and higher than 2021. Most of the new additions contributing to the reserve margin are new solar 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 start up and produce energy in a short period of time). We discuss the prices and outcomes in each of these markets below.

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

Real-Time Energy Prices

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

There are two primary drivers of market prices: natural gas prices 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. This correlation continued to be evident in 2022 as the average natural gas price rose to levels higher than any recent year other than 2021. Combined with sustained hotter weather during the summer and changes to the shortage pricing provisions discussed below, this caused real-time energy prices to average just under $75 per MWh. The following table shows the trend in prices throughout ERCOT in recent years.

Average Annual Real-Time Energy Market Prices by Zone

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Energy Prices ($/MWh)									
ERCOT	**$40.64**	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**	**$167.88**	**$74.92**
Houston	$39.60	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54	$129.24	$81.07
North	$40.05	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97	$206.39	$75.52
South	$41.52	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63	$187.47	$72.96
West	$43.58	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58	$105.27	$65.53
Natural Gas Prices ($/MMBtu)									
ERCOT	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99	$7.30	$5.84

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 2022 differed from that of the last few of years, with the Houston and North zones experiencing the highest load-weighted prices. The West zone has the lowest prices because of the large amount of local wind and solar generation that frequently causes export constraints for delivery to other zones.

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 ORDC. When the system is in shortage, the relevant ORDC value will set operating reserve prices and be added to the energy price. The frequency and impacts of shortage pricing can vary substantially from year-to-year.

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 Value of Lost Load (VOLL) (then $9,000 per MWh) at higher reserves levels. These 2019 and 2020 changes increased average prices but also provided incentives to maintain higher operating and planning reserves.

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.[4] These changes will cause prices to rise more quickly as reserve levels fall and move toward shortage conditions, but plateau at a lower maximum price in deeper reserve shortages.[5] These changes more than doubled the effect of the ORDC on prices, totaling an additional $1.7 billion in 2022.

ORDC Revenue by Fuel Type

	Thermal	Wind & Solar	Batteries	Hydro	Biomass
ORDC Revenue ($ millions)	$2,524.0	$423.1	$18.3	$4.3	$11.7
% of ORDC Revenue	*85%*	*14%*	*0.6%*	*0.1%*	*0.6%*
ORDC Revenue per MWh	$8.49	$3.22	$40.19	$14.65	$27.16
Total Generation (GWh)	297,142	131,252	455	294	431
% of Generation (%)	*69%*	*31%*	*0.1%*	*0.1%*	*0.1%*

This table shows that thermal resources and batteries receives a higher proportion of ORDC revenues relative to their share of generation, while renewable resources received a much lower share of the revenue relative to their generation. This is appropriate because tight conditions tend to occur when renewables are producing at low levels and dispatchable thermal resources are producing at relatively high levels.

Overall, the operating reserve adder contributed $6.41 per MWh to the annual average real-time price (for an annual total of approximately $3 billion). In the past, the adder has had the largest effects when low supply conditions and high load conditions occur together and result in sustained shortages, as occurred in 2019 and 2021. However, with the adjustment to the MCL in the ORDC, the adder is much more likely to produce substantial adders even when conditions are not particularly tight.

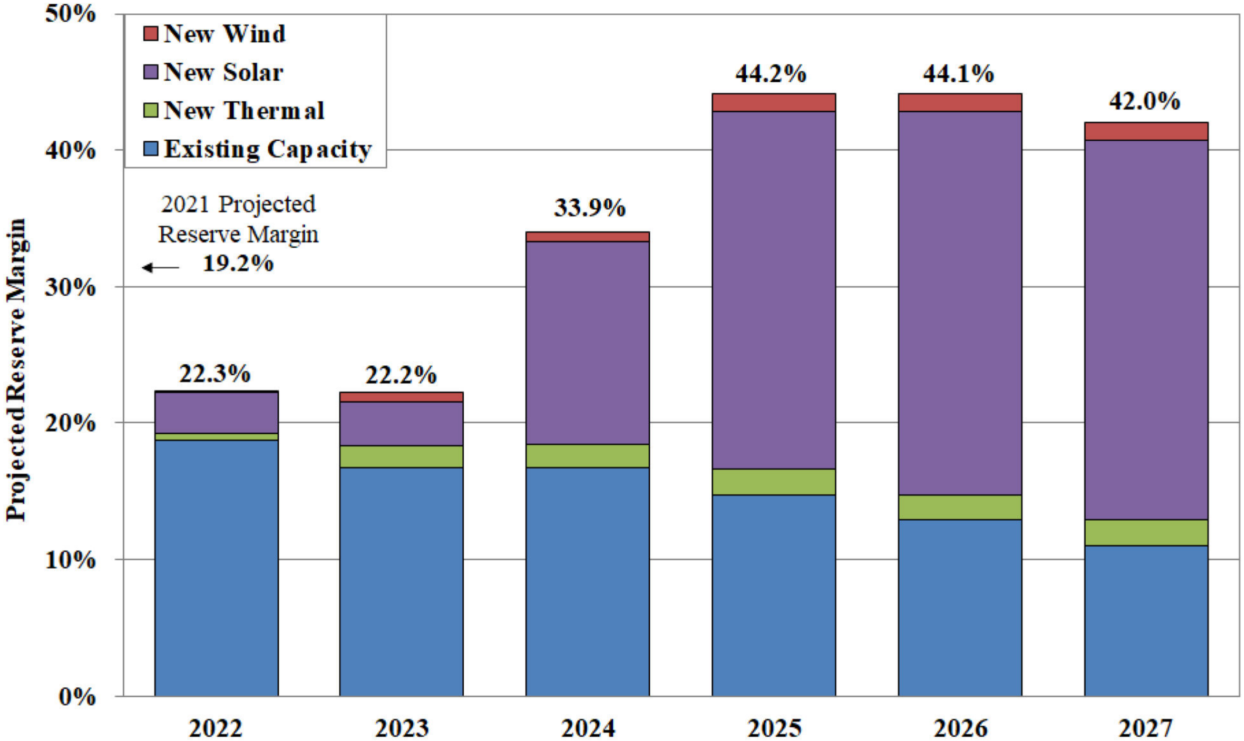
4 After a series of public work sessions and review of volumes of comments filed by market participant, the Commission directed ERCOT to address short- and long-term electric grid reliability concerns by enacting major reforms (see *Review of Wholesale Electric Market Design,* Project No. 52373 (pending)), 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.

5 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.

Revenues and Reserve Margins

The revenues observed in 2022 exceed typical expectations with the planning reserve margin that currently exists in ERCOT – the current 22.3% margin is well above a typical one-in-ten planning requirement. This planning reserve margin is expected to increase in the coming years. The following figure shows the expected planning reserve margin over the next six years, and we note that it excludes the contribution from ESRs.

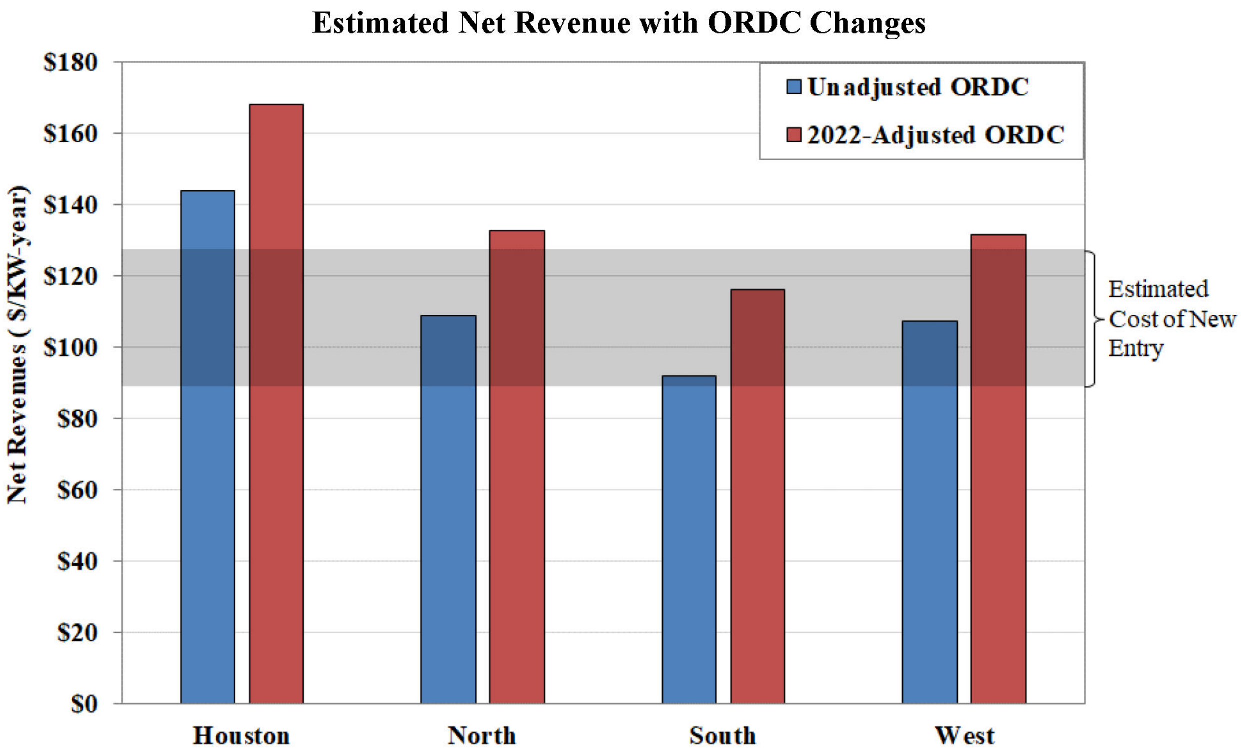
CDR Projected Reserve Margins



Source: ERCOT Capacity, Demand and Reserves Report, May 2023

This figure shows that planning reserve margins are projected to exceed 40%. Much of this increase is driven by the sharp rise in solar capability beginning in 2024. The figure also shows a consistent reduction in existing supply from 2022 to 2027 as resources retire. We believe both of these effects are overstated in the CDR calculations. The contribution of solar to reliability is lower than shown in the CDR because of the correlated nature of its output which impacts the deliverability of the output. We also believe the projected retirements are overstated because of the market changes being implemented that should provide sufficient revenue to retain some or all of these resources. Taking these two offsetting items into account, we expect the planning reserve margin will likely be sustained near or above 30% in 2024 and beyond, but not as high as over 40%.

The second chart below shows the existing profitability of combustion turbines with and without the Commission's January 1, 2022, ORDC changes. In a typical market, one would expect that net revenues would fall as the planning reserve margin rises. However, net revenues in 2022 rose substantially as a result of the changes ERCOT implemented to the ORDC. These increases throughout ERCOT show how impactful the Commission's revisions to the ORDC have been. With these changes, the net revenues in most zones would cover the costs of investing in new dispatchable resources, despite the prevailing capacity surplus.



Because net revenues now exceed the CONE range for new peaking resources (despite the prevailing capacity surplus), the IMM believes that the planned "bridging solutions"[6] are not necessary to provide efficient incentives to support investment in and retention of dispatchable resources.

Day-Ahead and Ancillary Services Markets

The day-ahead market 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 $66 per MWh in 2022. This price closely aligns with prices from the real-time market, while still reflecting a modest risk premium.

6 As discussed later, ERCOT is planning to add a floor to ORDC revenues at certain online reserve levels.

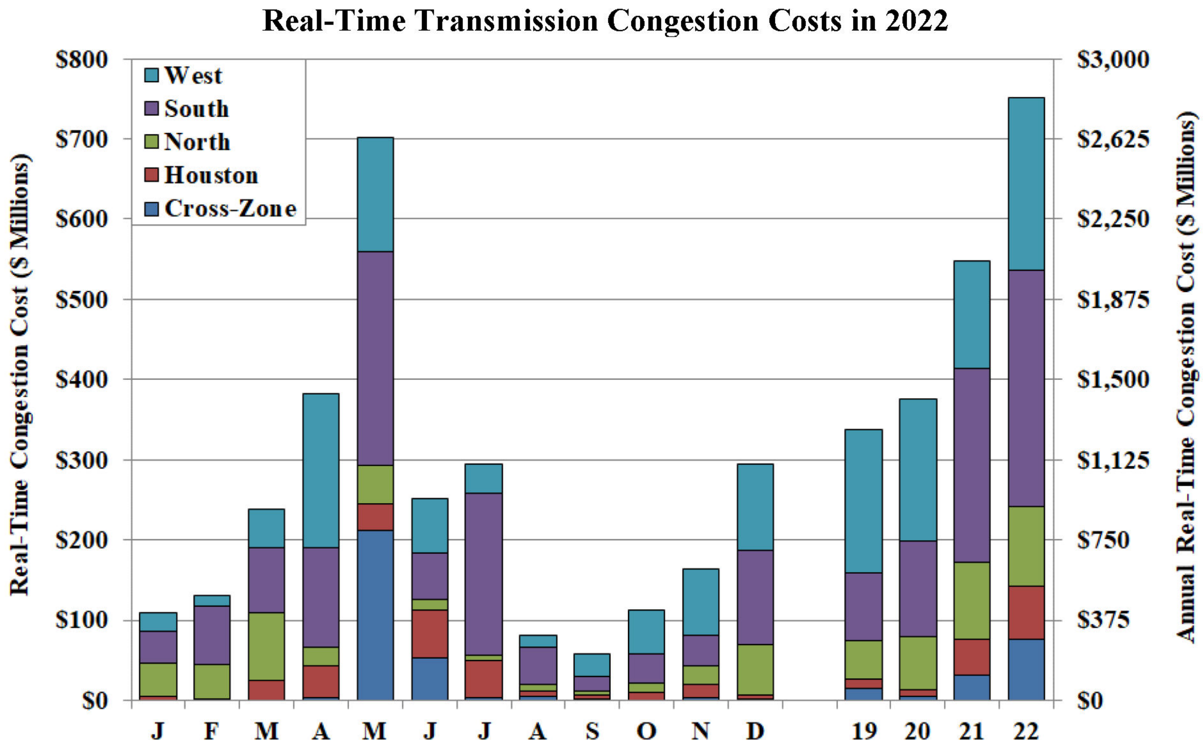
Ancillary services include operating reserves that are purchased on behalf of consumers to provide resources that can produce electricity quickly (or voluntarily reduce consumption) when needed. Awards for these products obligate the suppliers to physically supply them in real time. These operating reserves 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 are typically correlated with real-time energy prices because ancillary services prices include the profits an ancillary services supplier forgoes by not selling energy. Ancillary services costs rose from $1 to $3 per MWh of load from 2020 to 2022, largely because of the increase in procurement quantities that began in 2021. The annual market value of these services ranged from $28 million for regulation down to $743 million for non-spinning reserves.

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 close to being overloaded, the market will incur costs to shift generation to higher-cost generators in other locations to reduce the power flows over the line. Hence, congestion prevents load from being served by 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 the location of their consumption and the payments to generators at their location. These costs accrue to those that hold the financial 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 2022 and the trend in annual costs from 2019 through 2022.



The congestion costs in ERCOT's real-time market in 2022 were $2.8 billion, up 37% from 2021. High natural gas prices, outages of generators in load pockets, and frequently binding generic transmission constraints (GTCs) 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 dispatched to manage transmission congestion and serve customers in congested areas. The figure below shows:

- The South zone experienced the highest congestion costs in 2022, similar to 2021. This is a departure from prior years and is primarily attributable to load growth and GTCs in the Rio Grande valley,[7] as well as increased congestion from Port Lavaca into Houston;
- The West zone exhibited the second highest congestion as a result of high renewable output that is limited by GTCs. Given the expected increase in renewable development, we expect this congestion to increase in coming years.
- Cross-zone congestion increased substantially in 2022, primarily in May and early June because of outages into Houston affecting flows from both North and South into Houston. These outages also contributed to higher congestion in Houston.

Day-Ahead Congestion Costs. Participants' expectation of this real-time congestion is also reflected in ERCOT's day-ahead prices and outcomes. The transmission congestion priced in the day-ahead market totaled $2.3 billion. Although this is 60% higher than 2021, it is quite a bit lower than the real-time congestion costs. This indicates that some of the congestion was not

7 The Lower Rio Grande Valley System Enhancement project will likely resolve much of this congestion.

well predicted in the day-ahead market, which was particularly true of the high congestion that occurred during May.

Congestion Revenue Rights. Participants can hedge congestion costs in the day-ahead market by purchasing 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 $1.1 billion in 2022.

CRR auction revenues were less than the total congestion costs in 2022 mainly because the auction prices were less than what the CRRs were ultimately worth. This indicates that the congestion was not fully foreseen by the market, especially during the summer months. Additionally, the market design decision to require that 10% of the network capability not be sold in the CRR auctions contributes to the lower CRR revenues.

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 the total costs of serving customers in ERCOT by preventing the export of power from low-cost resources to load centers.

Market Improvements Underway

Real-Time Co-Optimization. In our opinion, the most important improvement to the ERCOT market 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 scheduled to come off of hold status in mid-2023.[8] Implementation of RTC will significantly improve the real-time coordination of ERCOT's generation and load resources, 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.

[8] ERCOT RTC Update to TAC, February 20, 2023.

Other Market Reforms. 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 PUCT Project No. 52373, *Review of Wholesale Electric Market Design* at the December 16, 2021, open meeting.[9] 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 compiled directives and concepts designed to reform the ERCOT wholesale electricity market in two phases. Phase I of the blueprint provided enhancements to ancillary services and changes aimed at improving price signals and operational reliability. The most significant change was the adjustments to the ORDC discussed above that increased revenues to generators in 2022 by $1.7 billion. These enhancements also included reforms to Emergency Response Service (ERS), approval and implementation of a new Firm Fuel Supply Service (FFSS), and accelerated implementation of a new ancillary service product called ERCOT Contingency Reserve Service (ECRS). The blueprint also featured weatherization preparation standards for generation resources and detailed mapping of critical natural gas facilities.

Phase II of the blueprint incorporates longer-term market design and structure reforms. On January 19, 2023, the PUCT adopted the Performance Credit Mechanism (PCM) as its recommended market design concept. Based on the outline provided, the PCM establishes a requirement for LSEs to purchase “performance credits” (PCs) – earned by generators based on their availability to the system during the top hours of highest risk – at a centrally determined clearing price. The PC requirement is a fixed quantity that is determined in advance of the compliance period, while the settlement process occurs retroactively based on the quantity of PCs that were actually produced.[10] Many of the design details must be developed by the PUCT and we plan to assist the PUCT in developing them as needed. The PUCT also directed ERCOT to evaluate “bridging options” until the PCM can be fully implemented.[11]

The 88th Legislature introduced a host of market design bills in March 2023 aimed at addressing operational flexibility and resource adequacy in ERCOT. The IMM looks forward to continuing to work with the Commission and market participants to identify and enact enhancements to ERCOT’s wholesale market to meet the State’s reliability objectives based on any new legislation.

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

10 *Review of Market Reform Assessment Produced by Energy and Environmental Economics, Inc. (E3)*, Project No. 54335, E3 Report, staff memo and updated questions (Nov. 10, 2022).

11 *Id.*, Order and Modified Memorandum (Jan. 19, 2023).

Recommendations

We have identified opportunities for improvement in the current ERCOT market and make thirteen recommendations in this report. Five 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 continue to advocate for implementation of RTC as a top priority because it improves both reliability and efficiency. It will 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.

SOM Number	Brief Description
New Recommendations to Improve Market Performance	
2022-1	Implement a multi-interval real-time market
2022-2	Institute 100% reliability unit commitment claw-back
2022-3	Allow transmission reconfigurations for economic benefits
2022-4	Change the linear ramp period for ERS summer deployments to 3 hours
2022-5	Change historical lookback period for ORDC mu and sigma calculations
Additional Recommended Market Improvements from Prior Years	
2021-1	Eliminate the "small fish" rule
2021-2	Implement an uncertainty product
2021-3	Reevaluate net metering at certain sites
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

2022-1 – Implement a multi-interval real-time market

The real-time market relies primarily on two classes of resources: online resources and offline resources that can start quickly. The real-time market efficiently dispatches online resources and sets nodal prices that reflect the marginal value of energy at every location, but ERCOT lacks software and processes to facilitate efficient commitment and decommitment of peaking resources that can start quickly (i.e., within 30 minutes). This is a concern because suboptimal dispatch of these resources raises the overall costs of satisfying the system's needs, can distort the real-time energy prices, and affects reliability. For these reasons, other markets have implemented this type of look-ahead process to optimize short-term commitments of peaking resources.

Further, as ERCOT attracts more intermittent wind and solar resources, the value of having access to and optimally using fast-starting dispatchable resources will grow. Additionally, the rising amounts of fluctuations in intermittent output will increase the demands on other resources to ramp up and down. A multi-interval dispatch model can meet these increasing ramp requirements by recognizing the needs of the system further into the future and beginning to move dispatchable resources to optimally satisfy them. In contrast, the current market optimizes each dispatch interval independently.

This is a recommendation that we made in years past. In 2017, ERCOT evaluated the potential benefits of a multi-interval real-time market and decided not to move forward because the costs were greater than the projected benefits.[12] This finding was influenced by the level of surplus capacity on the system and the much lower level of renewable resources. Much has changed since that time – we believe benefits will be much higher in the future and this capability will become essential for managing the growing renewable fleet. Hence, we recommend that it be reevaluated and prioritized for future implementation.

2022-2 – Institute 100% claw-back of excess market revenues for RUC units

The incentives regarding self-commitment of resources have changed dramatically with the increased frequency of RUC instructions that occur now under ERCOT's more conservative operations. Hence, previous market design decisions regarding RUC merit a fresh look; notably, we recommend rethinking RUC claw-back percentages. Currently, there are tiered claw-back percentages based on offers or awards in the day-ahead market. This design has been in place since the introduction of the nodal market and was a result of a desire to incent participation in the day-ahead market by generators. Such incentives are not needed because the day-ahead market provides revenue certainty and generally a risk premium to generators. In addition, there has proven to be robust participation and liquidity in the day-ahead market by all types of market participants.

However, receiving full operational cost recovery via RUC make-whole while also getting the opportunity to keep half or all of any revenues above cost can undermine the incentive to self-commit generators even when they would likely be economic.[13] For example, our analysis indicates that as much as 25% of the RUC-committed hours of combined-cycle and 30% of the RUC-committed hours of simple-cycle generators would have been economic.

Committing economic resources through the RUC process leads to artificial increases in ORDC revenues for the rest of a portfolio because of the RUC adjustment to online reserves, as well as additional revenues from the deployment price adder. We estimated the changes in these price adders that would have occurred if the RUC units economic to run had instead been self-

[12] See *PUCT Review of Real-Time Co-Optimization in the ERCOT Region,* Project No. 41837, ERCOT Report on the Multi-Interval Real-Time Market Feasibility Study (Apr. 6, 2017).

[13] It is notable that there is no requirement that the day-ahead market energy offer that triggers the reduced claw-back percentage be feasible, i.e., able to be awarded by the day-ahead market engine based on resource temporal constraints.

committed. We found that the total energy revenue from the deployment price adder and the online ORDC adder would have fallen by $41 million and $839 million, respectfully. The latter reduction is 30% of all ORDC revenue. Hence, we recommend implementing a 100% claw-back for economic RUC units, which would discipline self-commitment decisions by generators that are likely to be economic and lower costs for ERCOT's consumers.

2022-3 – Allow transmission reconfigurations for economic benefits

Currently, ERCOT's approval processes only allow constraint management plans[14] for reliability reasons. However, there are times in which a transmission reconfiguration can relieve congestion without negatively affecting reliability.[15] Such plans should be developed and utilized. Both MISO and SPP are moving forward with this effort, though MISO is farther along.[16]

We recommend that ERCOT accept a limited number of proposals and independently identify options to reconfigure transmission elements in the network operations model when they are physically feasible and economically beneficial. A process can be established to identify which limited number of reconfiguration options have the biggest benefits.

2022-4 – Change the linear ramp period for ERS summer deployments to 3 hours

In all summer ERS deployments to date, including the deployment in 2022, resources returned to pre-instruction levels in approximately three hours.[17] However, the current time value parameter for returning to the pre-instruction level in the reliability deployment price adder calculation (an output of the SCED pricing run) is 4.5 hours. This difference artificially inflates the reliability deployment price adder. We recommend that there instead be a separate summer value of 3 hours. A non-summer value of 4.5 hours can remain until such time as we have more ERS deployment data for non-summer months.

2022-5 – Change the lookback period for ORDC mean and standard deviation calculations

The current ORDC statistical values of the mean and standard deviation used as inputs to the ORDC shape are based on historical data going back to the introduction of the nodal market. The

14 A constraint management plan is a set of pre-defined manual transmission system actions, or automatic transmission system actions that do not constitute a Remedial Action Scheme, which are executed in response to system conditions to prevent or to resolve one or more thermal or non-thermal transmission security violations or to optimize the transmission system.

15 These are not post-contingency actions and so should have a negligible impact on the control room.

16 See, e.g., https://cdn.misoenergy.org/20230228%20RSC%20Item%2006%20Reconfiguration%20for%20Congestion%20Cost%20Update628023.pdf

17 https://www.ercot.com/files/docs/2022/09/13/DSWG%20-%20ERS%20event%20deployment%207-13-2022.pptx

ORDC uses these historical values because the values are meant to be self-correcting as hour-ahead errors rise and fall over time. Because the resource mix has changed substantially in the last 12 years, the self-correcting nature of the ORDC is not able to capture the more recent data appropriately. Therefore, we recommend a rolling 5-year lookback period for the mean (mu) and standard deviation (sigma) parameters. Our analysis shows that this may reduce mu but raise sigma. The effect of this in 2022 would have been a savings of over $160 million. The importance of reducing the historical lookback period will increase over time and this change over the longer term is likely to raise revenues for suppliers in ERCOT.

Additional Recommended Market Improvements from Prior Years

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."[18] This rule was originally implemented before ERCOT had effective shortage pricing under the ORDC and was intended to allow high offers (offers significantly above the marginal cost of production) to produce high prices in shortage conditions. This was rendered unnecessary by the introduction of the nodal market with the ORDC and economic withholding by small participants has led to inefficient pricing in some cases. Withholding should not be allowed by any pivotal supplier, and small entities can be pivotal when conditions are tight market-wide or when the system is ramp constrained. Therefore, the IMM recommends elimination of the small fish rule.

2021-2 – Implement an uncertainty product

ERCOT regularly commits resources through the RUC process (out-of-market commitments) to ensure sufficient generation will be available to satisfy ERCOT's stated reliability margin of 6,500 MW of operating reserves plus an additional 1,000 MW of non-spinning reserves in uncertain hours. In addition, ERCOT has changed the non-spinning reserve requirements to essentially make it a four-hour product (primarily impacting ESRs).[19] These requirements have been increased partly to address the increasing operating uncertainties. As the levels of renewable generation increase and ERCOT's conservative operations continue, these operational uncertainties and out-of-market costs are likely to rise substantially.

Hence, we recommend that ERCOT develop a day-ahead 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

18 *See* 16 TAC § 25.504(c).

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

energy and ancillary services products and could be deployed to bring longer lead-time units online when ERCOT detects operating conditions are departing from expectation.

This product would: 1) provide operating reserves that can be used to resolve reliability concerns arising from uncertain system conditions; 2) be less costly than holding excessive amounts of 30-minute reserves; 3) allow co-optimized market prices to more fully reflect the value of managing uncertainty; and 4) reduce out-of-market actions and the substantial costs associated with them. In the longer term after an uncertainty product is implemented, ERCOT can re-evaluate non-spinning reserve and ECRS procurement requirements, and also likely return those services to their previous duration requirements.

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*, which 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 than 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 ERCOT require CLRs to have their own meters, rather than allowing net metering amongst unaffiliated entities with meters at the interconnection point.

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, transitioning to nodal pricing for those active loads will become increasingly beneficial for ERCOT and the market participants.[20] 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.

[20] Nodal pricing for controllable load resources is a part of the Commission's 2021 market design blueprint but has not yet been implemented.

Therefore, the IMM recommends that the load zones be re-evaluated and defined in future years (after the required four-year waiting period), based on prevailing congestion patterns. In particular, the new zones should be defined to 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 day-ahead market. 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 day-ahead market used to manage real-time market congestion cost risk.[21] This is not a surprise because large increases in PTP transactions greatly increases the complexity of the optimization and the time required for the market software to solve.

Charging no fee for PTP bids, as ERCOT currently does, allows participants to submit numerous bids that are unlikely to clear and provides 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 day-ahead market process. Hence, the IMM recommends that a small bid fee be applied to day-ahead market PTP Obligation bids to more efficiently allocate day-ahead market software resources.

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 less.[22] The operations and maintenance portion of verifiable costs already accounts for costs that increase as a unit runs less so the multiplier is not reasonable. Allowing generators with market power to raise prices is an economically inefficient means to achieve fixed cost recovery, so the IMM recommends that these multipliers be removed to ensure that mitigated offer caps are set at

21 ERCOT's regression analysis can be found at http://www.ercot.com/calendar/2021/1/25/221086-WMWG.

22 Protocol section 4.4.9.4.1(1)(d).

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.[23]

In addition, a new ancillary service – ERCOT Contingency Reserve Service (ECRS) – will be implemented in 2023 and will contain an optimization constraint (quantity limit) 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 inefficient market rules and restrictions be imposed. Such measures are not necessary when efficient prices determine market participants' incentives. Therefore, the IMM recommends that the clearing price of all ancillary services 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.[24] This method was approved in 1996 and was intended to allocate transmission costs to the drivers of new transmission.

However, customer demand during the peak summer hours is no longer the main driver of new transmission 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-

23 We include a chart showing the surplus later in this Report.

24 16 Tex. Admin. Code §25.192. Transmission Service Rates; http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.192/25.192.pdf

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. Demand response driven by the incentive to avoid transmission costs is likely inconsistent with real-time price signals and can significantly distort market outcomes.

Hence, the IMM continues to recommend that transmission cost allocation be changed to better reflect the true drivers for new transmission. A tiered approach that incorporates daily peak demand, a 12CP method, and a 4CP method could be a big improvement. Such an approach could combine the existing peak methods with some allocation of costs that are unavoidable. This may be a compromise that would substantially address the incentive concerns described above.

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 interfere with efficient market signals in real time. It has also led to inefficiencies in ancillary service pricing due to the increased procurement. The online reserve level target of 6,500 MWs for real-time (or 7,500 MWs during certain conditions) was established in June 2021 and should be re-evaluated now considering increased planning reserve margins and the addition of new solar and storage resources on the grid. This has become increasingly important since ERCOT's "bridging solution" for the time period before implementation of Phase II market reform is targeted to increase energy revenues at this reserve level.[25]

This section discusses the evolving needs of the future ERCOT market stemming from these two factors. The IMM recommends the following changes, at a minimum, to address the needs described above:

- Implement RTC as soon as possible;
- Complete single model implementation of Energy Storage Resources (ESRs) and incorporate state of charge (SOC) in market clearing;
- 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
- Minimize out-of-market intervention to allow the energy-only market to perform appropriately to produce the price signals that facilitate long-term investment in generation and demand response in an economically justifiable way.

[25] On April 18, 2023, the ERCOT Board adopted ERCOT's recommendation for a $10 ORDC floor at 7,000 MW of online reserves and a $20 ORDC floor at 6,500 MW of online reserves. If adopted by the Commission, the floors are likely to be implemented later this year.

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 of 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 and wind has been slowing. We discuss the need for nimble adjustments related to these new classes of resources in the subsections below.

Renewable Resources

Over the last five years: 16 GW of wind, 14 GW of solar, 2.7 GW of energy storage, and 2.3 GW of gas-fired capacity were installed.[26] while 5.4 GW of coal and 1 GW of gas steam capacity were retired.[27] Looking forward, ERCOT's interconnection queue is comprised of more than 1,200 active projects totaling over 245 GW,[28] and most of this capacity is wind, solar, and storage resources. Not all of these projects will be built. However, of the 40 GW of projects with a completed interconnection study and agreement, 23 GW are solar, 8 GW are wind, 7 GW are energy storage, and 2 GW are natural gas-fired resources.

The increase in intermittent wind and solar generation raises different operational demands that are discussed below. It should be noted that solar output is highly correlated with ERCOT's peak demand and therefore contributes significantly to resource adequacy during the summer peak. In addition, many battery projects are co-locating with solar, which mitigates some of the operational demands we will discuss in this section.

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, including ESRs. Once a large quantity of solar has entered the ERCOT market, these dispatchable 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 at times be difficult to predict. This will require ERCOT's operators to utilize flexible dispatchable resources to accommodate these 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 that 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

[26] https://www.ercot.com/files/docs/2023/03/06/Capacity_Changes_by_Fuel_Type_Charts_February_2023.xlsx

[27] https://www.ercot.com/files/docs/2022/11/29/CapacityDemandandReservesReport_Nov2022.xlsx

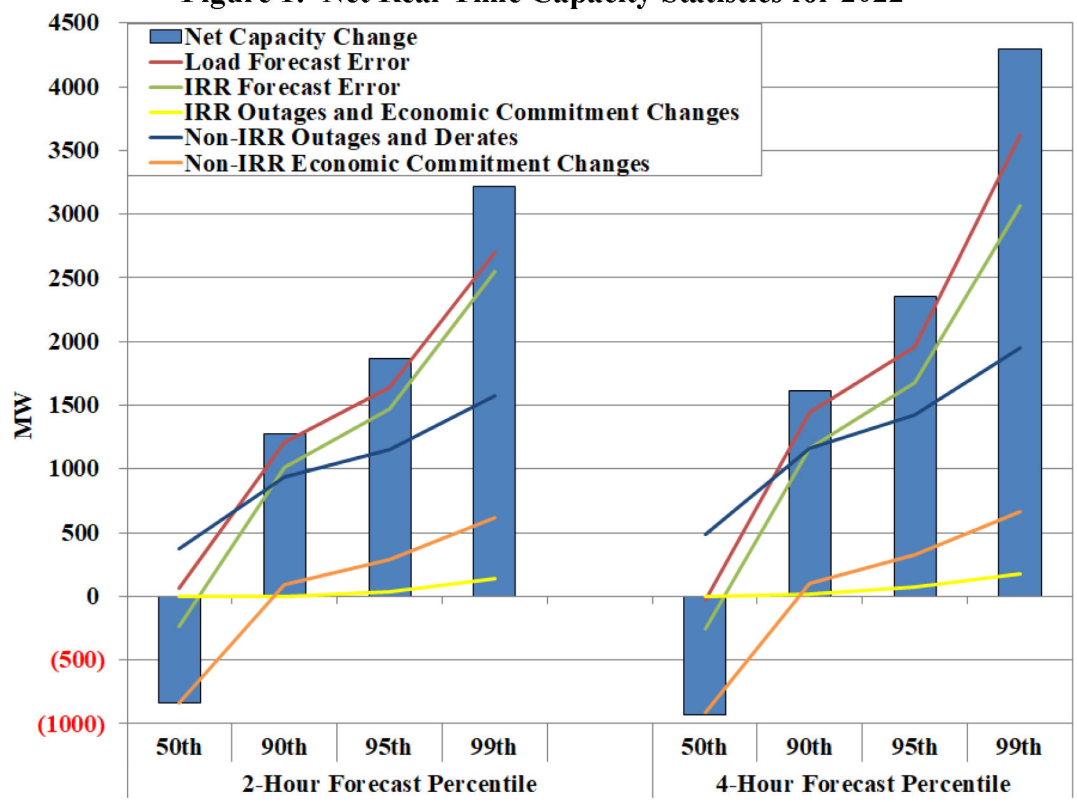
[28] ERCOT Generation Interconnection Study Report, December 2023. https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=887101481

- Energy storage, while duration limited, has the capability to produce energy very quickly when deployed, and store energy when intermittent output is high and demand is low.

Changes to the market design can 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, and at the time of the study, they found that the benefits of a MIRTM were insufficient to justify its implementation costs. However, they noted that "[c]hanges in the future resource mix, the balance of supply and demand or system conditions could demonstrate more significant value to MIRTM."[29] As the penetration of intermittent resources increases, the operational benefits of a MIRTM have increased because it will improve the utilization of the dispatchable fleet to manage the net load ramps. Therefore, we recommend that MIRTM be implemented, as discussed in recommendation 2022-1.

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.

Figure 1: Net Real-Time Capacity Statistics for 2022



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

The growth in wind and solar, coupled with rising amounts of distributed generation that is not dispatched by ERCOT, will significantly increase the uncertainty that ERCOT faces. In fact, it has increased over the past year.

Ideally, this uncertainty should be addressed through the market. However, many ISOs/RTOs manage this uncertainty in real-time operations by committing additional resources outside of the market in order to have sufficient dispatch flexibility to manage this uncertainty. To allow the markets to better 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 PUCT Project No. 52373, *Review of Wholesale Electric Market Design.*[30]

Although Figure 1 is illustrative and not intended to 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 use when the uncertainty results in tight supply-demand conditions or high ramp demands that cannot be met by existing online resources. This product would be an effective replacement for the extra procurement of non-spinning reserves. ERCOT is currently using non-spinning reserves to solve for uncertainty in a time horizon far ahead of the operating period, which is ill-suited for the 30-minute response time requirement of this product.

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. Typically, the flows over most transmission facilities are constrained by thermal limitations because increased flows raise the temperature of the facilities. GTCs are not thermal constraints, but are used to limit overall flows over a given path to maintain the stability of the system. They are harder to manage than thermal constraints and their limits are sometimes not well known prior to committing a resource, resulting in divergence between market outcomes and reliability needs.

GTCs have increased significantly over the last few years with the expansion of inverter-based generation. Real-time congestion rent on these constraints has grown from $400 million in real-time congestion in 2021 to $640 million in 2022. NPRR1070, Planning Criteria for GTC Exit Solutions, is currently pending in ERCOT's stakeholder process, and the Commission rulemaking to implement SB1281 has recently been completed to improve economic transmission planning criteria.[31] These two items should help develop solutions to the proliferation of GTCs.

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

31 *Review of Chapter 25.101*, Project No. 53403, Order Adopting Amendments to 16 TAC 25.101 as Approved at the November 30, 2022, Open Meeting (Dec. 7, 2022).

System Inertia. Proliferation of inverter-based generation has also raised concerns on maintaining sufficient system inertia. System inertia is 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.[32] However, as an increasing share of the load is served by wind, solar, and ESRs, system inertia will continue to fall. This may lead to a need to supplement the markets to compensate resources for providing inertia as ERCOT has previously discussed.[33]

Voltage support. A final challenge associated with the rapid increase in inverter-based generators is voltage support. Of particular note is the June 4, 2022, Odessa disturbance event that resulted in a loss of 1.7GW of intermittent renewable resources (IRRs) and a system frequency decline to 59.706 Hz.[34] Since that event, there have been multiple stakeholder discussions on tightening interconnection requirements and instituting more stringent voltage ride-through rules in order to prevent repeat large-scale resource trips in the future. Similar discussions and standards development have also been undertaken by NERC based on the Odessa event.[35] Additionally, ERCOT has noted instances where IRRs have oscillated with unstable reactive power control at low output and has approved a rule change on IRR reactive capability.[36] As voltage issues become more prevalent, it may be more economically efficient to implement a voltage support service (also stated in the Commission's Phase 1 Market Design blueprint[37]) that would incentivize improved reactive capability from inverter-based resources and proactively resolve reliability concerns arising from voltage stability issues.

Energy Storage

It is important for ERCOT to improve upon its 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 has significant modeling limitations, including the inability to incorporate the SOC of the ESRs in market clearing and

32 https://www.ercot.com/calendar/event?id=1520373953460

33 http://www.ercot.com/content/wcm/key_documents_lists/55752/Proposal_for_Synchronous_Inertial_Response_Service_Market_March112015.docx

34 https://www.ercot.com/files/docs/2022/11/10/Odessa%20Disturbance%202_JuneMeeting.pdf

35 https://www.nerc.com/comm/RSTC/IRPS/2022_Odessa_Disturbance_Webinar.pdf

36 https://www.ercot.com/mktrules/issues/NPRR1138

37 https://interchange.puc.texas.gov/Documents/52373_268_1172004.PDF

challenges with measuring basepoint deviation. ERCOT has made substantial progress towards modeling ESRs as a single device with the approval of the following protocol revisions:

- NPRR989 - BESTF-1 Energy Storage Resource Technical Requirements
- NPRR1002 - BESTF-5 Energy Storage Resource Single Model Registration and Charging Restrictions in Emergency Conditions
- NPRR1026 - BESTF-7 Self-Limiting Facilities

Implementation of these changes is currently on hold due to limited implementation resources, although ERCOT has been considering how and when to restart these efforts. However, even with these improvements, additional enhancements are needed to fully model ESRs' unique characteristics and to better reflect their performance attributes in market outcomes.

Modeling the SOC in the Day-Ahead Market, Reliability Unit Commitment, and the real-time market will become critical as ESRs become a more substantial portion of the fleet. In addition to the benefit of more accurate clearing prices, this will ensure that efficient commitment of other types of generation are made. Modeling the SOC of ESRs, in conjunction with RTC, is necessary to allow ESRs to provide their full value to grid reliability, operational flexibility, and market efficiency.

Distributed Resources

ERCOT is also currently addressing issues related to distributed resources. There are currently almost 2,000 MW of unregistered Distributed Generation Resources (DGRs) in ERCOT, and an unknown number of potential but unregistered controllable load resources.[38] The amounts of these resource in ERCOT are continuing to increase. 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 and could therefore be inaccurately represented in the real-time market, leading to potential challenges in 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.

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

Conclusion

We encourage ERCOT to develop market rules and operating procedures that address these challenges. The most immediate concerns are loads that can start and stop quickly, such as data centers and crypto-currency mines, which are increasingly interconnecting behind-the-meter.[39] These types of loads should be incentivized to register with ERCOT as they have the capability to actively participate in energy and ancillary services markets, 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 and that do not apply costs equitably. In SOM recommendation 2021-3, we recommend requiring controllable load resources (CLRs) to have their own meters, rather than allowing net metering amongst unaffiliated entities. We also recommend that ERCOT move quickly to implement nodal pricing for CLRs (ERCOT is currently working on developing the related protocol change request).

B. ERCOT's Operational Posture

In 2021, ERCOT adopted a more conservative operating posture by requiring additional operating reserves to be available in real-time.[40] Since July 2021, ERCOT has:

- Increased non-spinning reserve requirements so that the total upward ancillary services, excluding those provided by loads on high-set under-frequency relays, equals 6,500 MW on a typical day and 7,500 MW on days ERCOT deems to have high load uncertainty;
- 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 long-lead time resources as well as relying less on market participant response; and
- Adjusted the 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, are that the pricing outcomes have grown disconnected from the actual operational conditions.[41] This is discussed

[39] Of the 2,370 MW of large loads that have received approval to energy, ERCOT has observed a noncoincident peak consumption of 1,739 MW.

[40] https://www.ercot.com/files/docs/2021/06/30/ERCOT_Addtional_Operational_Reserves_06302021.pptx

[41] 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.

in more detail in the RUC section of this report. This is problematic because the energy-only market design relies on efficient pricing that reflects the reliability needs of the system.

Procuring additional non-spinning reserve also increases the costs paid by load. Although this additional procurement may increase reliability in some hours, the additional costs are difficult to justify based on the potential reliability benefits. We encourage ERCOT to re-evaluate the reserve level target, especially since the market and resource mix has evolved since the reserve level target was set back in June 2021. A reserve level target based on rigorous analysis would likely be substantially lower on most days and in most hours. More accurate reserve requirements would produce more efficient economic signals that govern short-term decisions to self-commit resources and long-term decisions to build and retire resources.

While we continue to believe that an energy-only market can continue to be successful and adapt to changing system needs, ERCOT's continued conservative operational posture interferes with the efficient signals it can produce. The distortion in the market's economic signals will affect generators' investment and retirement decisions, which may threaten ERCOT's resource adequacy over the longer term.

In addition, as we discuss later in this report, the ORDC changes regularly increase revenues when the system is not close to shortage, resulting in inflated net revenues for all types of resources. One established measure of net revenues, the Peaker Net Margin, has exceeded Cost of New Entry (CONE) in three of the last four years. This may not be entirely reasonable in a system that is currently meeting a 1-in-30 loss of load expectation reliability standard.[42] These signals will both attract additional investment, as well as forestalling retirement of existing resources.

42 *Review of Market Reform Assessment Produced by Energy and Environmental Economics, Inc. (E3)*, Project No. 54335, E3 Report, staff memo and updated questions at 126 ("The results showed that the current system achieves a loss of load expectation (LOLE) of 0.03 days/year, exceeding the common industry benchmark of 0.1 days/year or "one day in ten years.") (Nov. 10, 2022); https://interchange.puc.texas.gov/Documents/54335_2_1251720.PDF.

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 while minimizing the system's production costs. The second function, to establish efficient prices, is equally important because real-time prices provide key short-term incentives to commit resources and follow ERCOT's dispatch instructions. They also provide long-term incentives that govern participants' investment and retirement decisions.

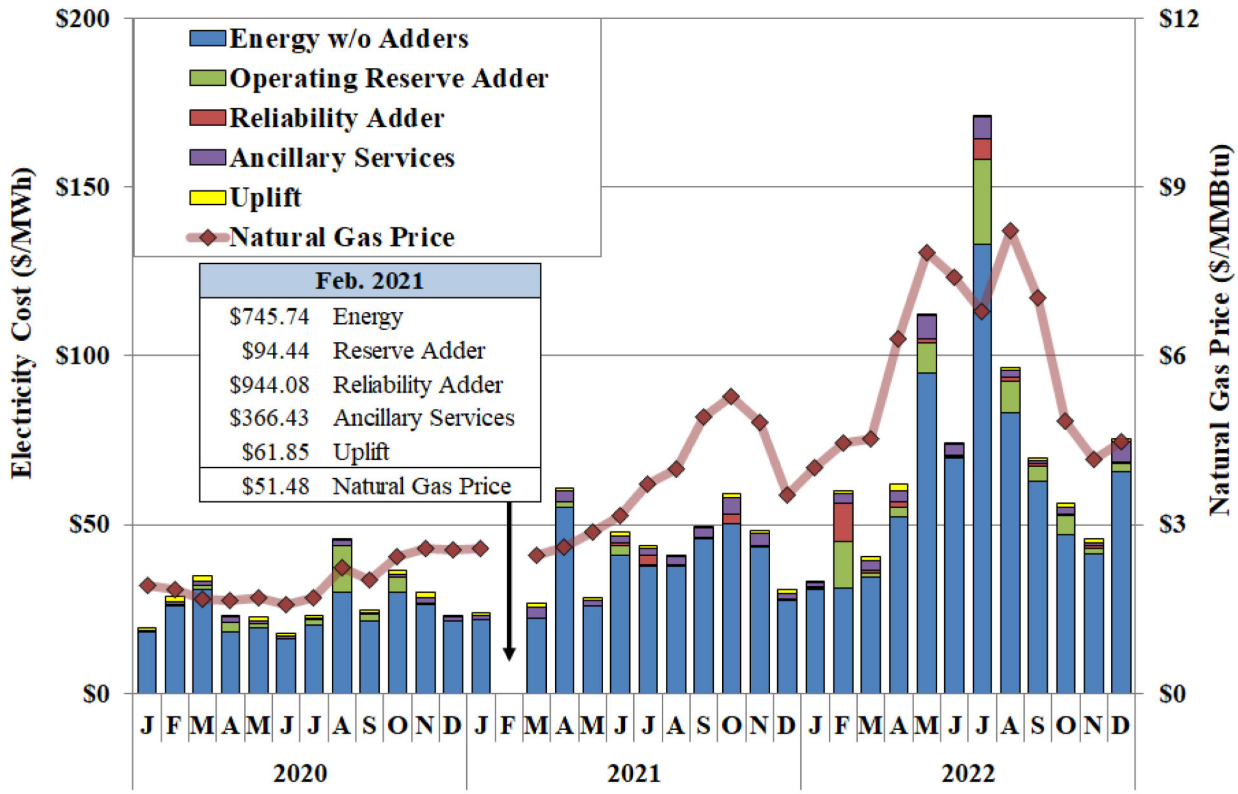
Real-time prices have implications far beyond the settlements in the real-time market. Only a small share of the power produced in ERCOT is transacted in the real-time market. However, real-time energy prices set the expectations for prices in the day-ahead market and bilateral forward markets and are, therefore, the principal driver of prices in these markets where most transactions occur. Because of the interaction between real-time and 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 settled at real-time prices. This section evaluates and summarizes electricity prices in the real-time market during 2022.

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 2 shows the average "all-in" wholesale 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.[43] Figure 2 shows the average all-in prices for electricity in ERCOT the last three years.

[43] 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.

Figure 2: Average All-in Cost for Electricity in ERCOT



ERCOT real-time prices currently include the effects of two energy price adders that are designed to improve real-time energy pricing when operating reserves diminish or when ERCOT takes out-of-market actions for reliability. Although published energy prices include the effects of both adders, we show the ORDC adder (operating reserve adder) and the Reliability Deployment Price Adder (reliability adder) separately from the base energy price in the figure. The operating reserve adder was implemented in mid-2014 to account for the value of reserves based on the Value of Lost Load and the probability of reserves falling below the Minimum Contingency Level. The reliability adder was implemented in June 2015 as a mechanism to ensure that certain out-of-market actions do not distort the energy prices.[44]

Figure 2 shows that average real-time prices fell to $74.92 per MWh in 2022, with an annual total market value of $32.2 billion. This average price is 50% lower than in 2021, largely because of the effects of Winter Storm Uri in 2021. Average real-time prices in 2022 were nearly triple the prices in 2020 ($25.73 per MWh) because of the increase in natural gas prices and the ORDC adjustments made in the beginning of 2022. The correlation between the gas price and the energy price is expected in a well-functioning, competitive market because fuel

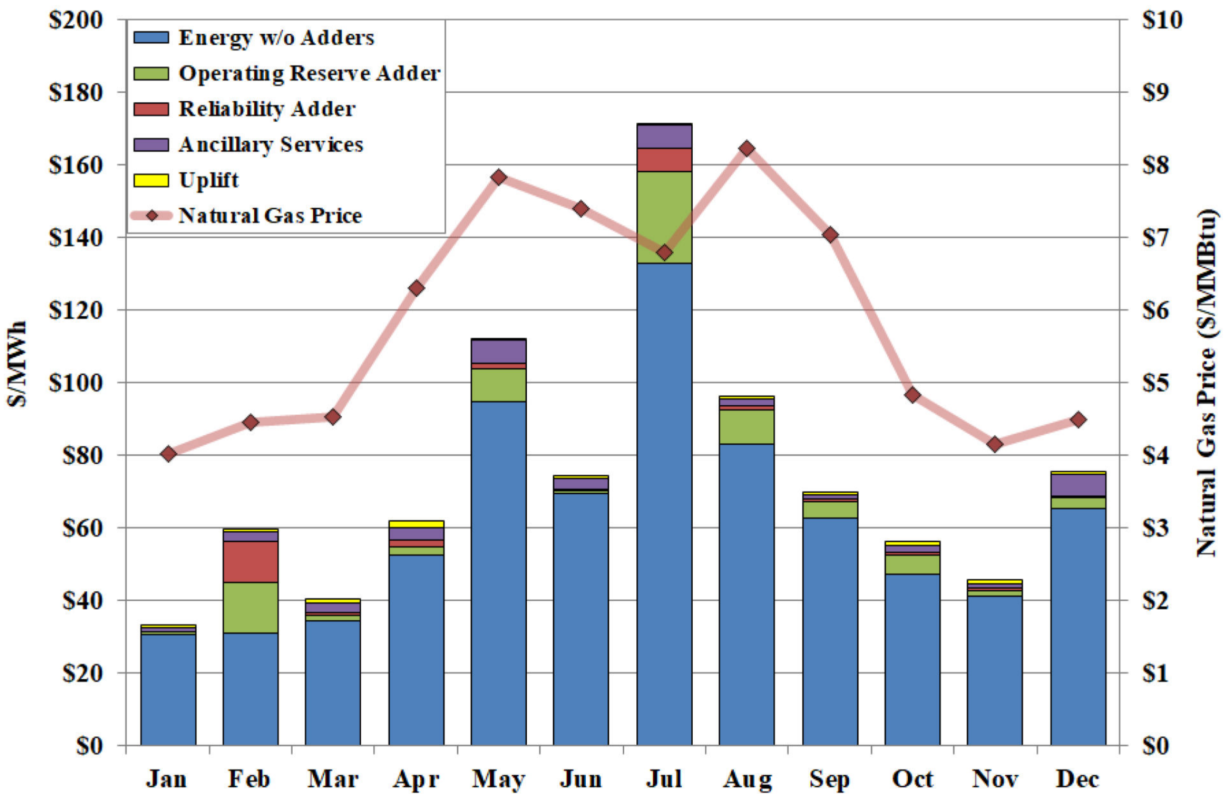
44 The reliability adder is calculated by separately running the dispatch software with modifications to the inputs to reflect any RUCs, deployed load capacity, or certain other reliability actions. When the recalculated system lambda (average load price) is higher than the initial system lambda, the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

costs represent the majority of most suppliers' marginal production costs. Suppliers in a competitive market have the incentive to offer resources at their marginal costs and natural gas is the most widely used fuel in ERCOT.

Individual cost categories of the all-in electricity price for 2022 are shown in Figure 3 below. Ancillary services costs were $3.29 per MWh of load in 2022, a nearly 90% reduction from 2021 ($29.59 per MWh of load) but more than triple the prices in 2020 ($1.00 per MWh). This is discussed in more detail in Section IV: Day-Ahead Market Performance. Uplift costs accounted for $0.77 per MWh of the all-in electricity price in 2022, down from $5.34 per MWh in 2021 (and the effects of Winter Storm Uri) and $0.94 per MWh in 2020.

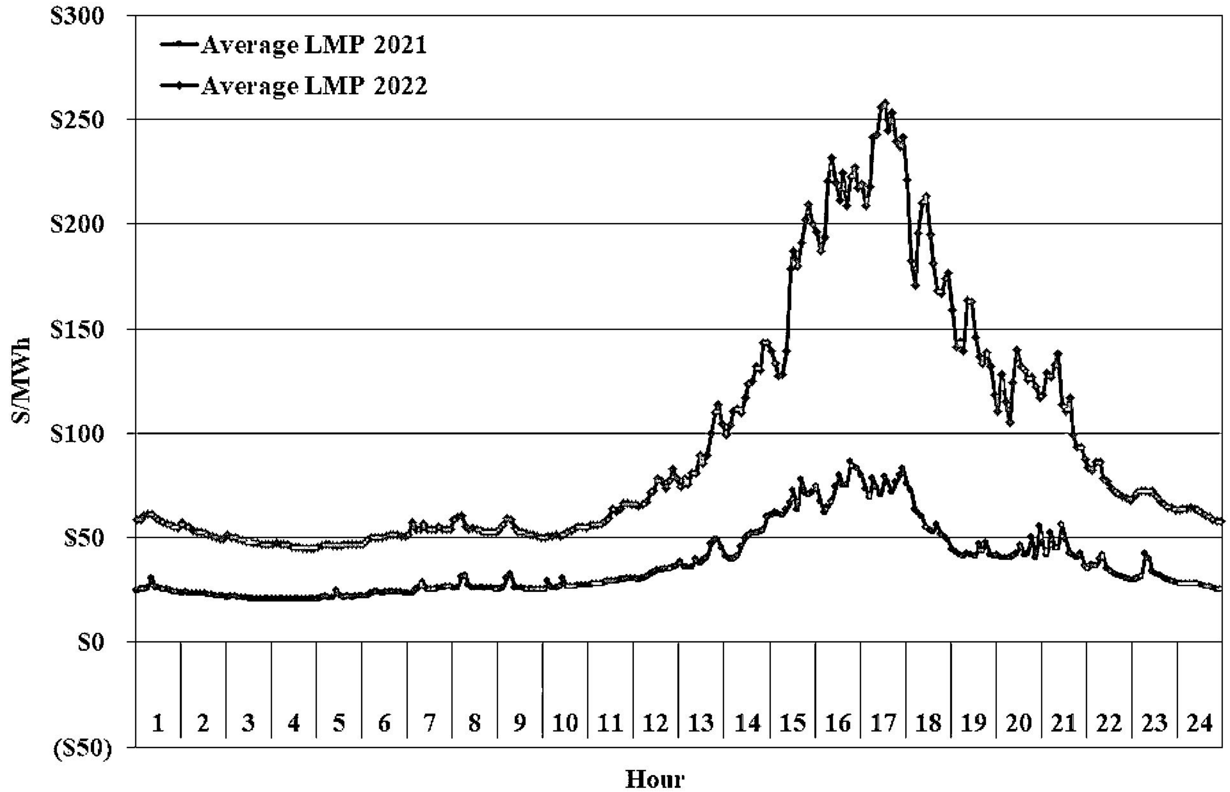
The total uplift costs in 2022 were approximately $368 million, much lower than the $2.1 billion in 2021, which was driven by ancillary service imbalance settlement associated with Winter Storm Uri. There are many other costs included as uplift, but the largest components are the ERCOT System Administrative Fee ($293 million or $0.55 per MWh), Emergency Response Service (ERS) program costs ($36 million or $0.08 per MWh) and the Real-Time Revenue Neutrality Allocation (RENA), which totaled $43 million or $0.10 per MWh in 2022. The dramatic increase in RENA, up from less than $1 million in 2021, is attributable to high negative RENA during Winter Storm Uri. RENA in 2022 was less than the $75 million level in 2020.

Figure 3: All-in Electricity Costs in 2022



Real-time energy prices vary substantially by time of day. Figure 4 shows the 2022 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. Average LMPs for summer 2022 were more than 150% higher than summer 2021. This was primarily due to a combination of hotter weather and associated demand, changes to the ORDC curve implemented in January 2022, and economic growth.

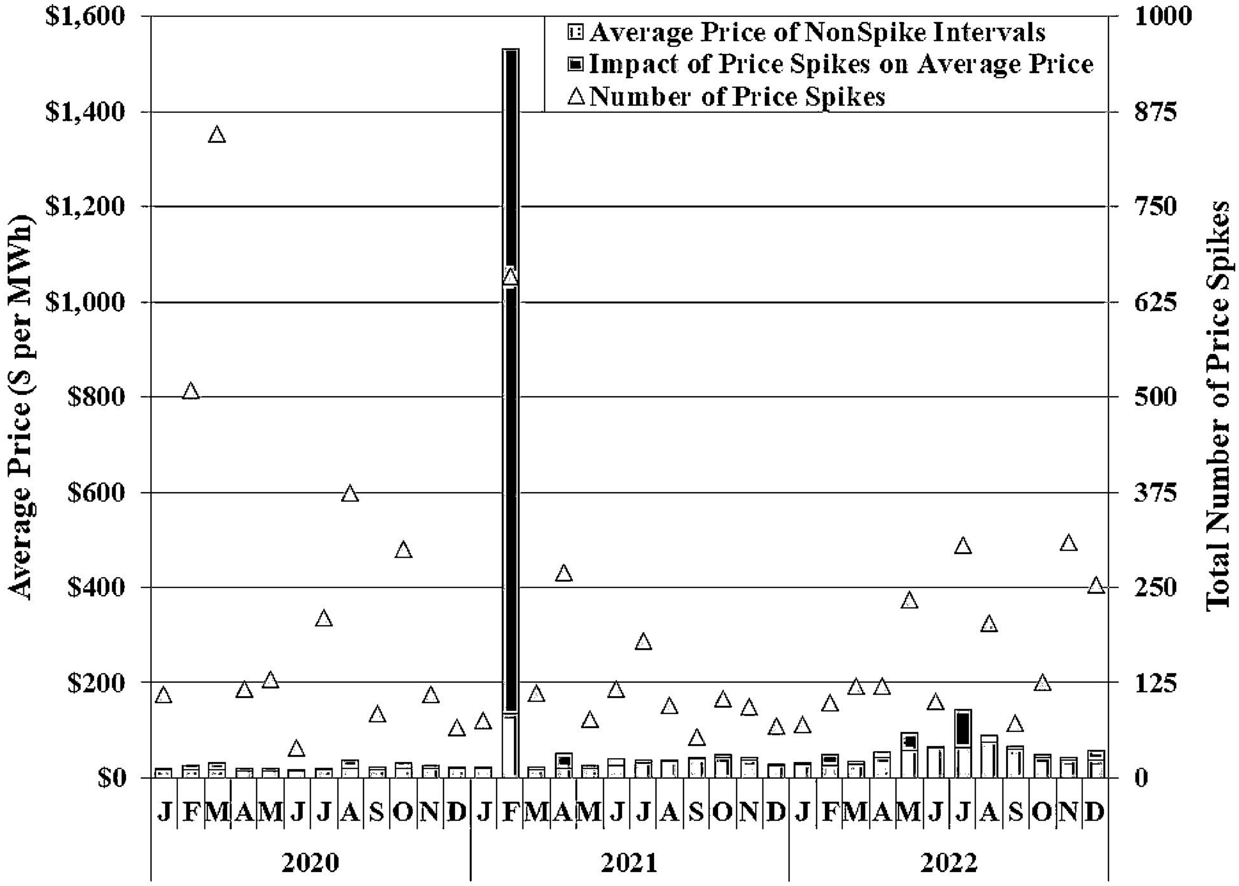
Figure 4: Prices by Time of Day
May-September 2022



To better observe the effect of the highest-priced hours on the average real-time energy price, Figure 5 shows the frequency of real-time energy price spikes in the 2022. 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., an implied heat rate of 18). Prices at this level typically exceed the marginal costs of virtually all on-line generators and are likely times when generators are recovering some fixed costs.

Price spikes were slightly more frequent in 2022 compared to 2021 in part due to continued higher gas prices (close to $6/MMBtu) throughout the year but were far less consequential on prices because there was no pricing event on par with Winter Storm Uri. Compared with 2020, a mild weather year, price spikes were less frequent in number in 2022 due to the impact of ERCOT's conservative operational posture. With average gas prices 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 2022 was $17.90 per MWh, or 24% of the total average price.

Figure 5: Average Real-Time Energy Price Spikes



B. Zonal Average Energy Prices in 2022

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 eight years.

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

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Energy Prices ($/MWh)									
ERCOT	**$40.64**	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**	**$167.88**	**$74.92**
Houston	$39.60	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54	$129.24	$81.07
North	$40.05	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97	$206.39	$75.52
South	$41.52	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63	$187.47	$72.96
West	$43.58	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58	$105.27	$65.53
Natural Gas Prices ($/MMBtu)									
ERCOT	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99	$7.30	$5.84

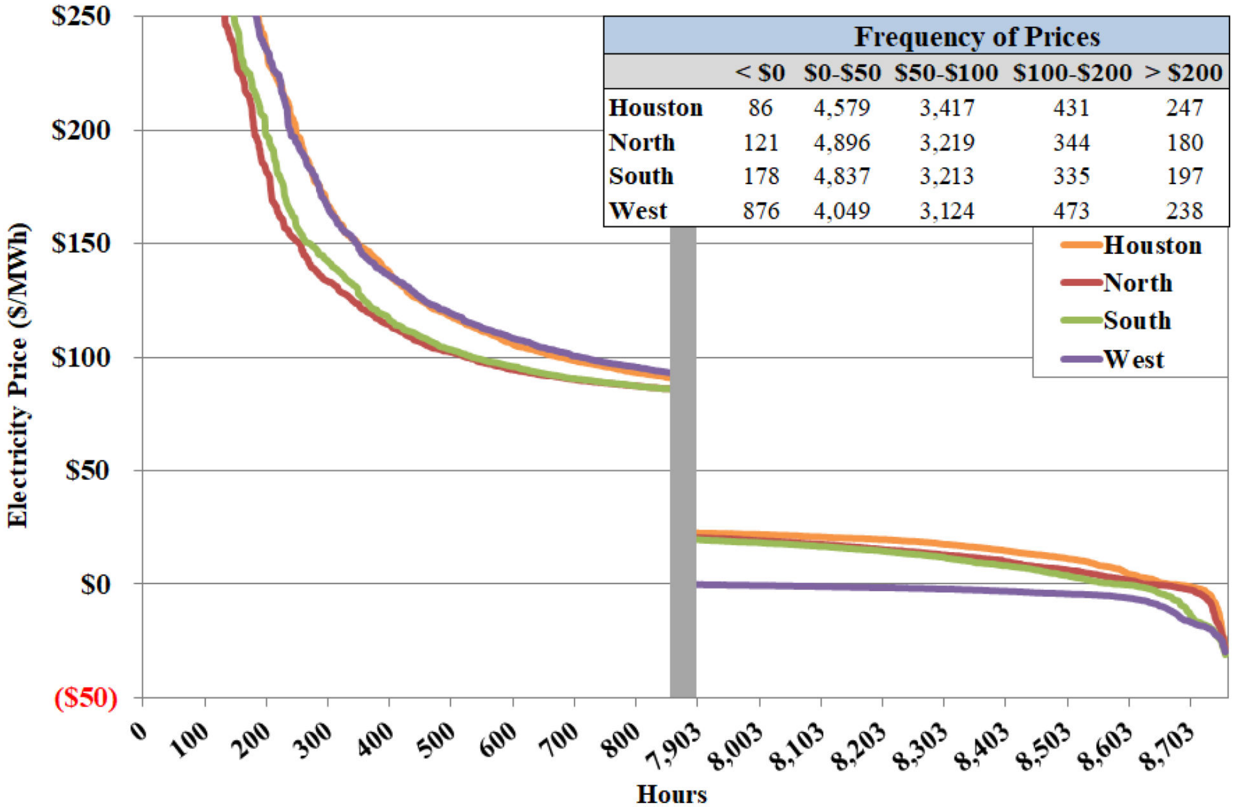
Like Figure 2, Table 1 shows the historically close correlation between the average real-time energy price in ERCOT and the average natural gas price. This relationship is consistent with competitive expectations in ERCOT where natural gas generators dominate and set prices in most hours. The average natural gas price was higher in 2022 than it has been in any year except 2021 because of Uri, which is reflected in the real-time energy prices. Additional analysis of the average real-time energy and natural gas prices is shown in Figure A1 in the Appendix.

Table 1 also shows that the relative average prices of the four zones were different in 2022 compared to previous year because of congestion into Houston, out of the West, and in the Rio Grande Valley. For additional analysis on monthly load-weighted average prices in the four ERCOT zones during 2022, see Figure A2 in the Appendix.

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.

To examine the variation in zonal real-time energy prices more closely, Figure 6 shows the top 10% and bottom 10% of the duration curves of hourly average prices in 2022 for the four zones.

Figure 6: Zonal Price Duration Curves



Compared to the other zones, low prices in the West zone were noticeably different in 2022, continuing a pattern seen in 2020. The lowest prices in the West zone were much lower than the lowest prices in the other zones. High prices in the West and Houston zones were much higher than the other zones in 2022.

The differences on both ends of the curves can be explained by the effects of transmission congestion. Constraints that limit the export of low-priced wind and solar generation to the rest of the state explain low prices. However, localized constraints limiting the flow of electricity to the increasing loads in the West, typically oil and gas loads, explain the higher prices that typically occur at times where wind and solar energy output is low. In contrast, high prices in the Houston zone were due to outages in the area affecting imports from the South and North.

C. Evaluation of the Revenue Neutrality Allocation Uplift

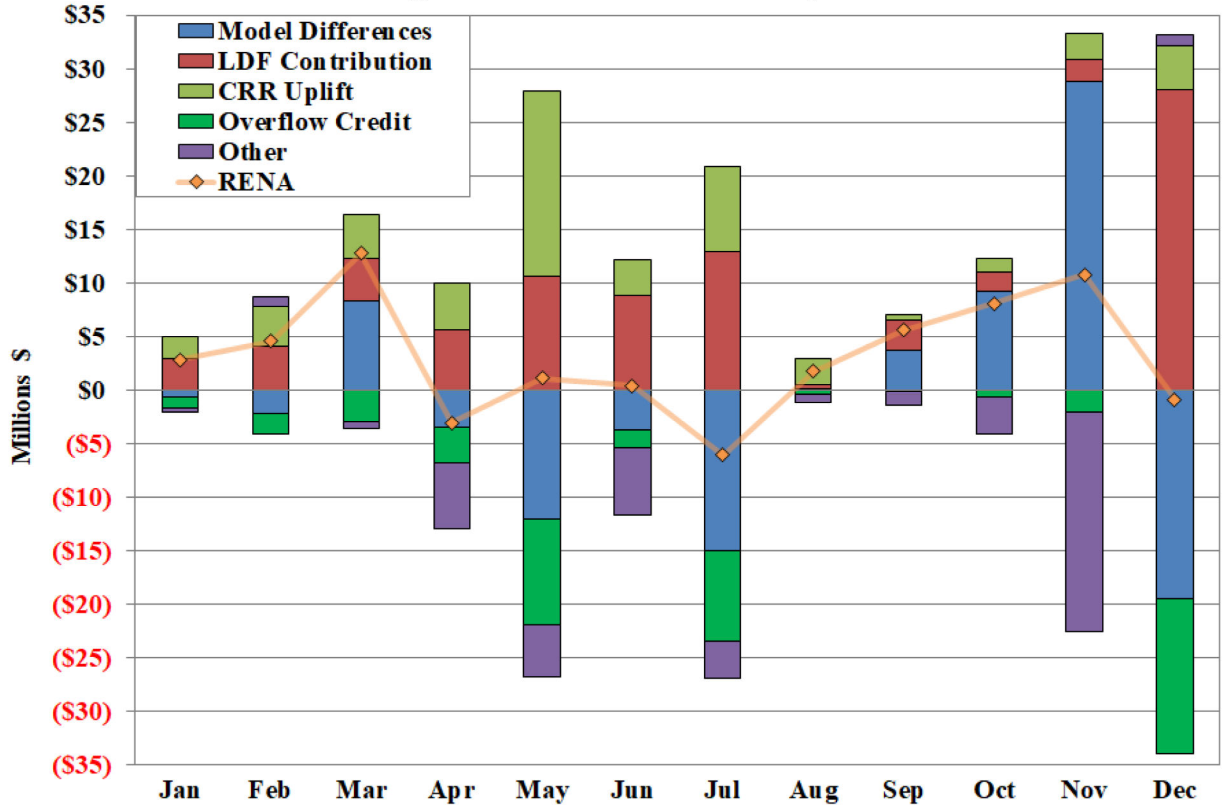
As shown in the all-in price analysis above, uplift costs decreased substantially in 2022, mainly because of the effects of Winter Storm Uri in 2021. However, there was higher Revenue Neutrality Allocation Uplift (RENA), which increased in 2022 to $38 million, up from less than $1 million (less than $0.01 per MWh) in 2021. RENA exists to ensure that ERCOT remains revenue neutral, with payments equaling charges. In general, RENA uplift occurs when there are differences in power flow modeling between the day-ahead and real-time markets, including:

- 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[45] 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 7 below provides an analysis of RENA uplift in 2022, separately showing the components of RENA on a monthly basis. Net negative uplift represents an overall payment to load. Almost all the RENA uplift occurred in market hours when there was transmission congestion. Based on this analysis, the largest positive contributor to RENA uplift in 2022 was the LDF Contribution, contributing $84 million, CRR Uplift, related to NOIE PTP Options, contributing $54 million. Uplift from the contributions of transmission model differences between day-ahead and real-time, described as Model Differences, was mostly negative in 2022. Despite negative uplift in some categories, overall net RENA in 2022 was $38 million.

45 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 day-ahead market 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 7: ERCOT RENA Analysis



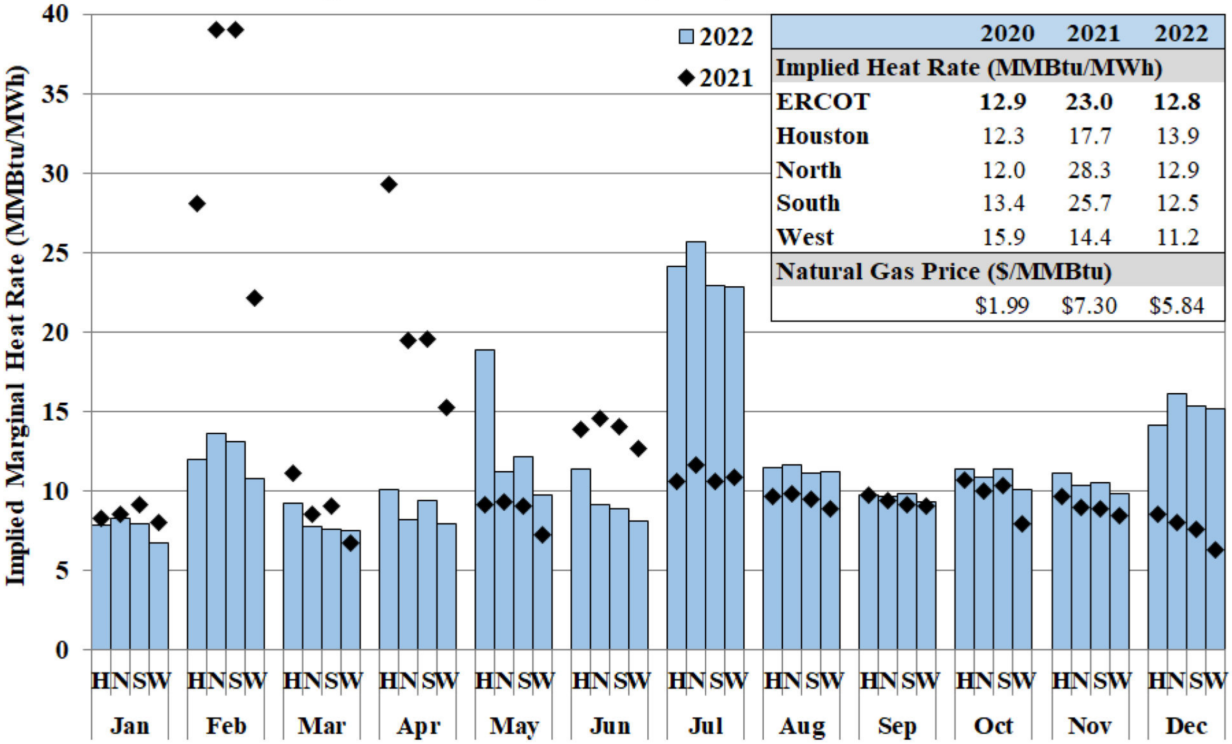
The task of maintaining accurate and consistent load distribution factors across all markets is a difficult one, made more so in areas with large amounts of localized load growth. These are exactly the types of areas that draw higher levels of market interest. To the extent ERCOT is unable to predict 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 8 shows the implied marginal heat rates monthly in each of the ERCOT zones. This figure is the fuel price-adjusted version of Figure A2 in the Appendix.

Figure 9 shows how the implied heat rate varies by load level over the past three years. For additional analysis of real-time energy prices adjusted for fuel price changes, see Figure A5, and Table A3 in the Appendix.

Figure 8: Monthly Average Implied Heat Rates



	2020	2021	2022
Implied Heat Rate (MMBtu/MWh)			
ERCOT	**12.9**	**23.0**	**12.8**
Houston	12.3	17.7	13.9
North	12.0	28.3	12.9
South	13.4	25.7	12.5
West	15.9	14.4	11.2
Natural Gas Price ($/MMBtu)			
	$1.99	$7.30	$5.84

Figure 9: Implied Heat Rate and Load Relationship

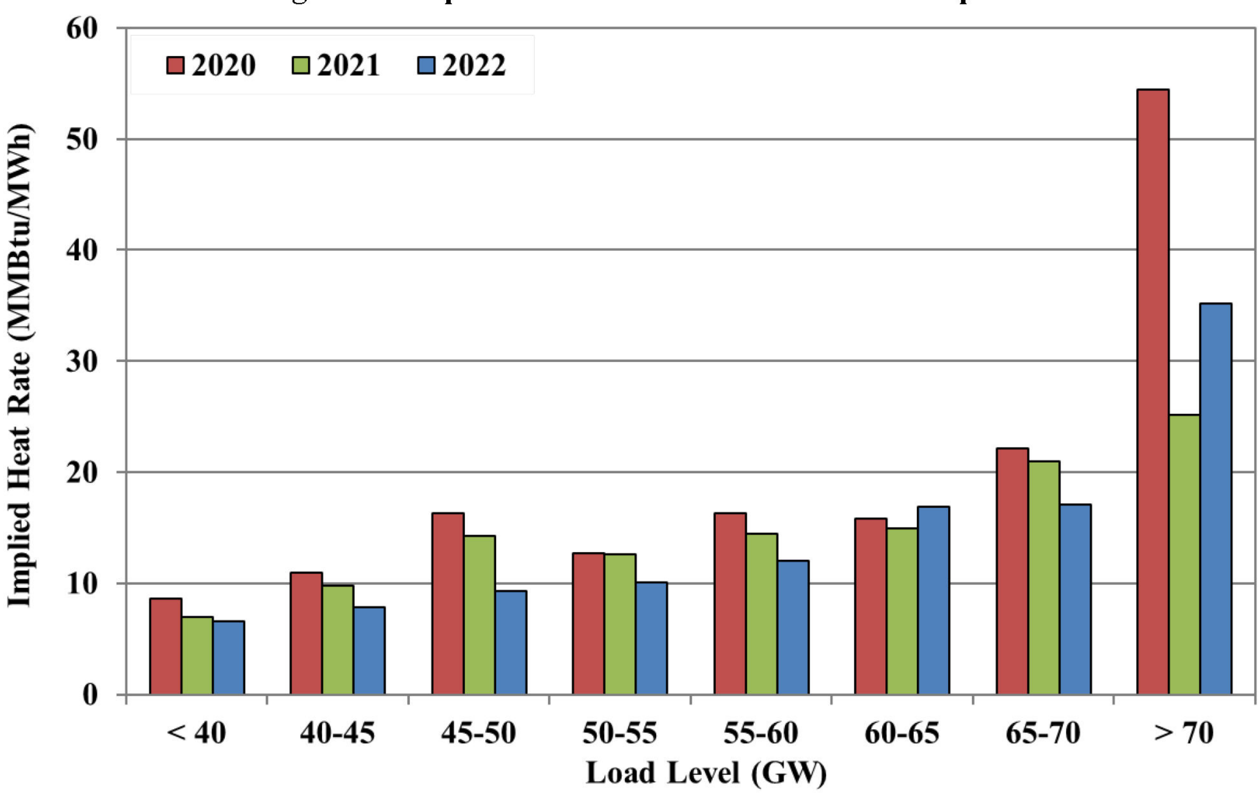


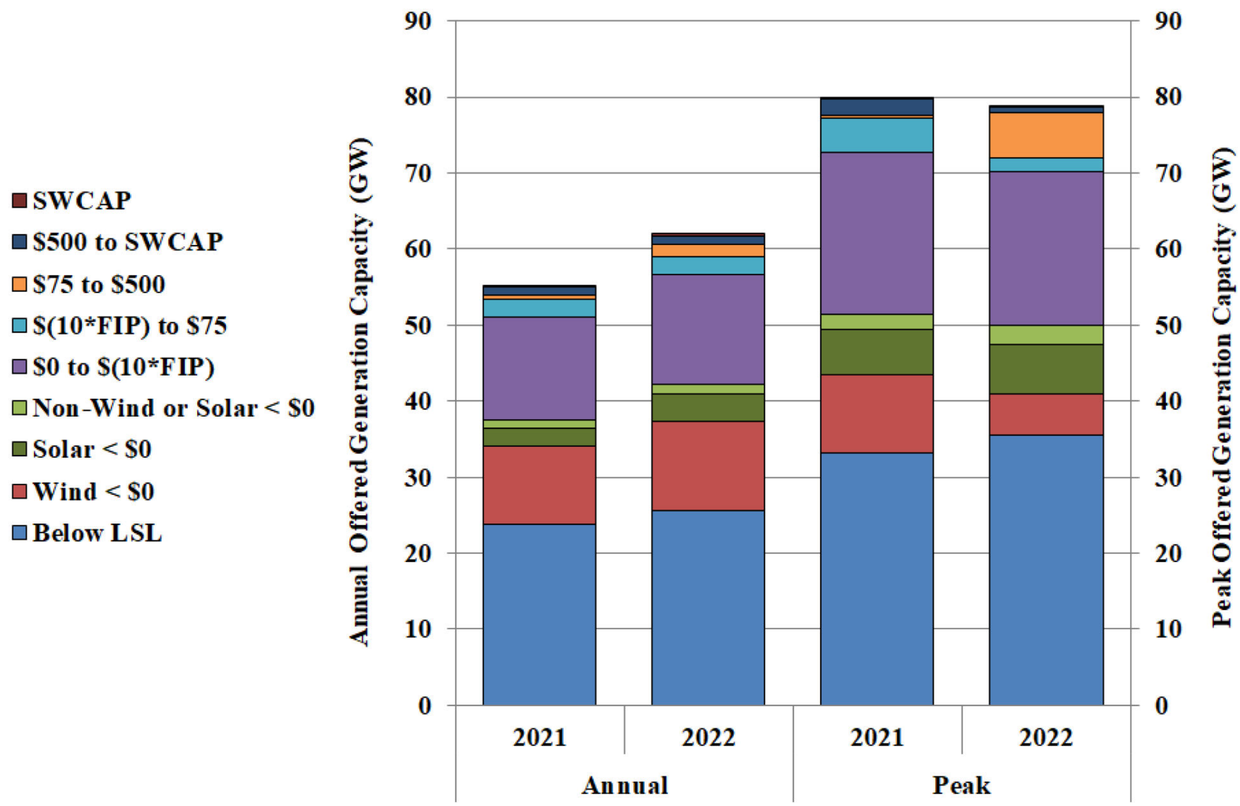
Figure 8 shows that the implied heat rate varied substantially among zones in 2022, particularly in May. Transmission congestion and differences in load levels drove zonal differences, particularly for the Houston zone in May. Overall, implied heat rates reflected the strong shortage pricing in 2022, an extended period of summer heat, and a pricing event in December.

Figure 9 shows a positive relationship between implied heat rate and load level as expected in a well-performing market for two reasons. First, resources with higher marginal costs were dispatched as the load approached peak. Second, the tight market conditions that cause the ORDC to produce price adders increase in frequency as load rises.

E. Aggregated Offer Curves

The next analysis compares the quantity and price of generation offered in 2022 and 2021. By averaging the amount of capacity offered at selected price levels, an aggregated offer stack can be assembled. Figure 10 provides the average aggregated generator offer stacks for the entire year, as well as the peak load hour of the year.

Figure 10: Aggregated Generation Offer Stack – Annual and Peak



This figure shows that in both periods, as in previous years, the largest amount of capacity was not dispatchable because it is below generators' Low Sustainable Limit (LSL) and is a price-taking (i.e., it will produce at any price). This quantity was 42% of the available capacity in 2022. This amount increases under peak conditions as more generators are online.

Roughly one quarter of the capacity in 2022 was offered below zero from wind, solar, and other resources. These resources have the incentive to produce when prices are negative because many of them receive production tax credits. Another quarter of the capacity was 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. Less than 10% of the capacity was offered above this level in both years.

Figure 10 shows that the amount of real-time capacity offered in 2022 increased by over 6,800 MW on average. The growth in renewable energy output accounts for 38% of this increase. Roughly 45% of this increase is from capacity offered below LSL or capacity offered above $75 per MWh up to the System-Wide Offer Cap (SWCAP). The increase in these two areas is largely driven by the ORDC changes that provided stronger incentives for resources to be online, ERCOT's high usage of the RUC process, and the higher non-spinning reserve requirements.

Similar increases were observed in peak hours, although the aggregate amount of offered capacity fell by 900 MW because of much lower renewable output in the peak hours in 2022.

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 Value of Lost Load (VOLL) leads to efficient shortage pricing as it is reflected in both operating reserves and energy prices during shortages.

Implementation and Adjustments to the ORDC

The Public Utility Commission directed ERCOT to implement ORDC in 2013, including setting VOLL at $9,000 per MWh. 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. It also implemented two standard deviation shifts of 0.25 in the Loss of Load Probability (LOLP) calculation in March of 2019 and 2020, respectively.[46] These shifts accelerate the increase in prices toward VOLL as reserve levels fall and provided incentives for maintaining higher operating and planning reserves.

[46] 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 PUCT Project No. 48551*.

In the aftermath of Winter Storm Uri, the Commission further modified the ORDC. On 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.[47] The significance of the MCL is that this is the level of reserves at which the price will be VOLL. Logically, this should occur at the level that would cause ERCOT to shed load. Currently, ERCOT will enter an energy emergency level 3 and shed load at a reserve level of 1430 MW. Pricing shortages at $5000 at an MCL of 3000 MW means that the effective VOLL is actually much higher than $5000 under the adjusted ORDC.

We developed a revenue equivalent ORDC that rises to VOLL at 1430 MW in order to estimate the true VOLL underlying the current ORDC and found that it is roughly $47K per MWh. This is a significant increase from the pre-2022 ORDC that reflected an implied VOLL of less than half of this value. However, based on studies that have attempted to quantify the VOLL for different classes of customers, we believe an average VOLL of $20K and $30K is reasonable and the VOLL of some commercial and industrial load is well above $30K.

Ultimately, we conclude that the Commission's action to adjust the ORDC in 2022 was significant and consistent with its objectives to greatly strengthen incentives for generation to be available, and for suppliers to build and maintain larger quantities of dispatchable resources.

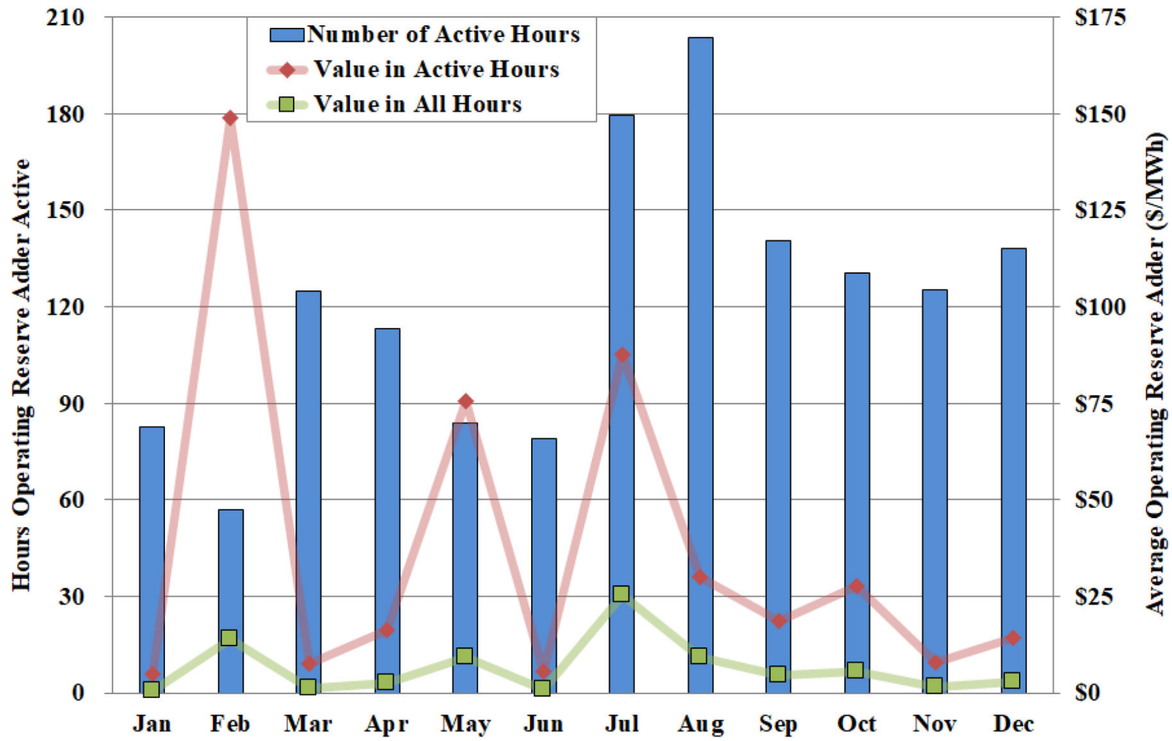
Revenue Effects of the ORDC

The following two analyses illustrate the contributions of the operating reserve adder and the reliability adder to real-time prices. Figure 11 shows the number of hours in which the operating reserve adder affected prices in each month of 2022, and the average price effect in these hours and all hours.

Figure 11 shows that in 2022, the operating reserve adder had the largest price impacts in February and July ($14.07 and $25.19 respectively) mainly due to the shortage conditions that occurred. The average adders in the remaining months of 2022 were also substantial and well above levels seen in recent years largely because of the change in the ORDC. As a result, the effects of the operating reserve adder were much higher for most months in 2022 than in 2021. Overall, the operating reserve adder contributed $6.41 per MWh, or approximately 9% of the annual average real-time energy price of $74.92 per MWh in 2022. This represents an annual contribution to energy market value of approximately $3 billion.

47 See *Review of Wholesale Electric Market Design*, Project No. 52373, at the December 16, 2021, open meeting. Specifically, the Commission approved the blueprint for the redesign of the wholesale electric market filed in the Project on December 6, 2021, including the ORDC changes.

Figure 11: Average Operating Reserve Adder in 2022



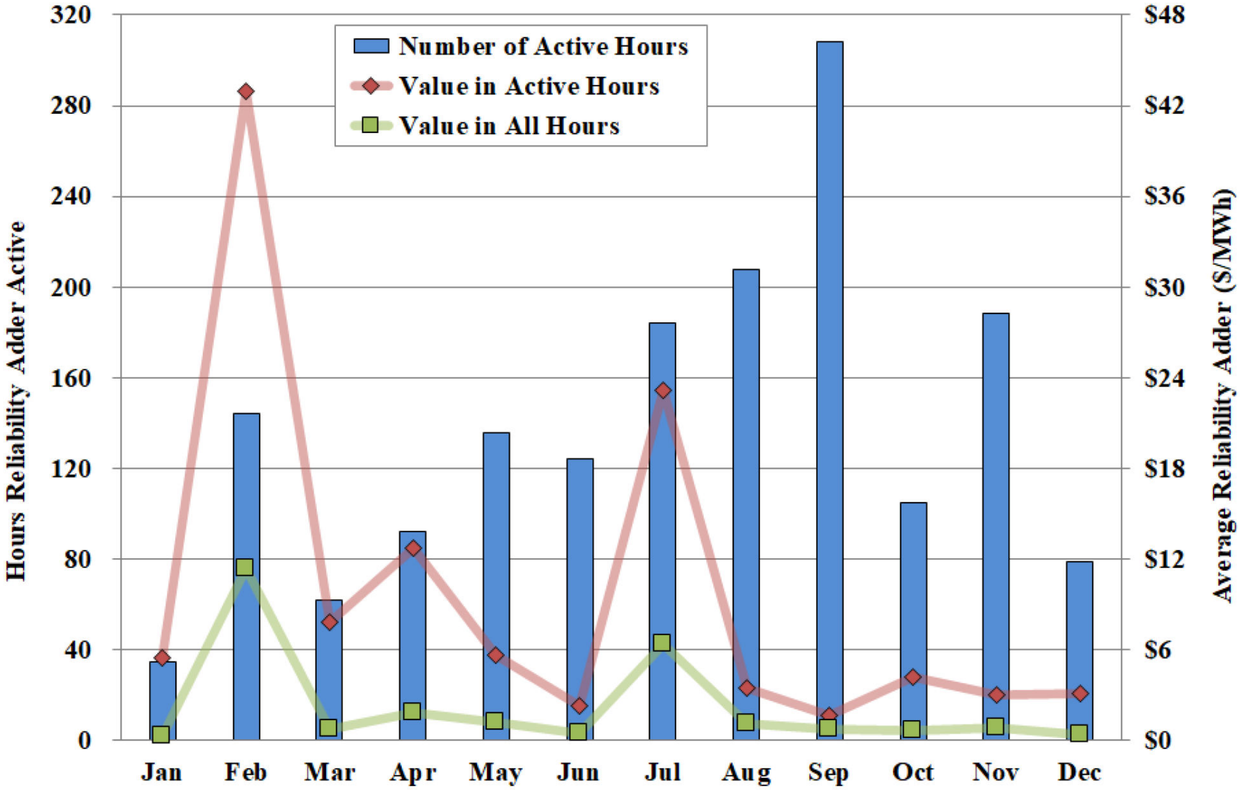
The effects of the operating reserve adder are expected to vary substantially from year to year. In the past, it has had the largest effects when low supply conditions and high load conditions occur together and result in sustained shortages as the market experienced in 2019 and 2021. However, with the adjustment to the minimum contingency level in the ORDC, the adder is much more likely to be active and produce significant adders under less tight, non-shortage conditions. This is evident in Figure 11, which shows that the average operating reserve adder value across all hours is above $1 per MWh in all but two months.

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 12 below shows the impacts of the reliability adder in 2022.

When averaged across only the hours when the reliability adder was non-zero, the largest price impacts of the reliability adder occurred during February due to many RUC commitments during winter. The reliability adder was non-zero for 19% of the hours in 2022.

The highest contribution to the real-time energy price besides February were in April and July because of the evolution of ERCOT's more conservative operations and the increased reliance on RUCs, discussed further in Section VI. In addition, ERS was deployed in July and that contributes to the reliability adder.

Figure 12: Average Reliability Adder in 2022



The contribution from the reliability adder to the annual average load-weighted real-time energy price was about $2.00 per MWh. This represents an annual contribution of $936 million to the total energy value. When averaged across only the hours when the reliability adder was non-zero (19% of all hours in 2022), the largest price impacts of the reliability adder occurred during February due to the large quantity of RUC commitments during winter. The highest contribution to the real-time energy price besides February were in April and July because of the evolution of ERCOT's more conservative operations and the increased reliance on RUCs, discussed further in Section VI. In addition, ERS was deployed in July and that contributes to the reliability adder.

As an energy-only market, ERCOT relies heavily on energy and ancillary services pricing to provide key economic signals to guide decisions by market participants. However, the frequency and impacts of shortage can vary substantially from year-to-year, as shown in the figure below. To summarize the shortage pricing that has occurred since 2012, Figure 13 below shows the aggregate amount of time when the real-time system-wide energy price exceeded $1,000 per MWh, by month for 2020 through 2022, as well as annual summaries for 2012 through 2022.

Figure 13: Duration of High Prices

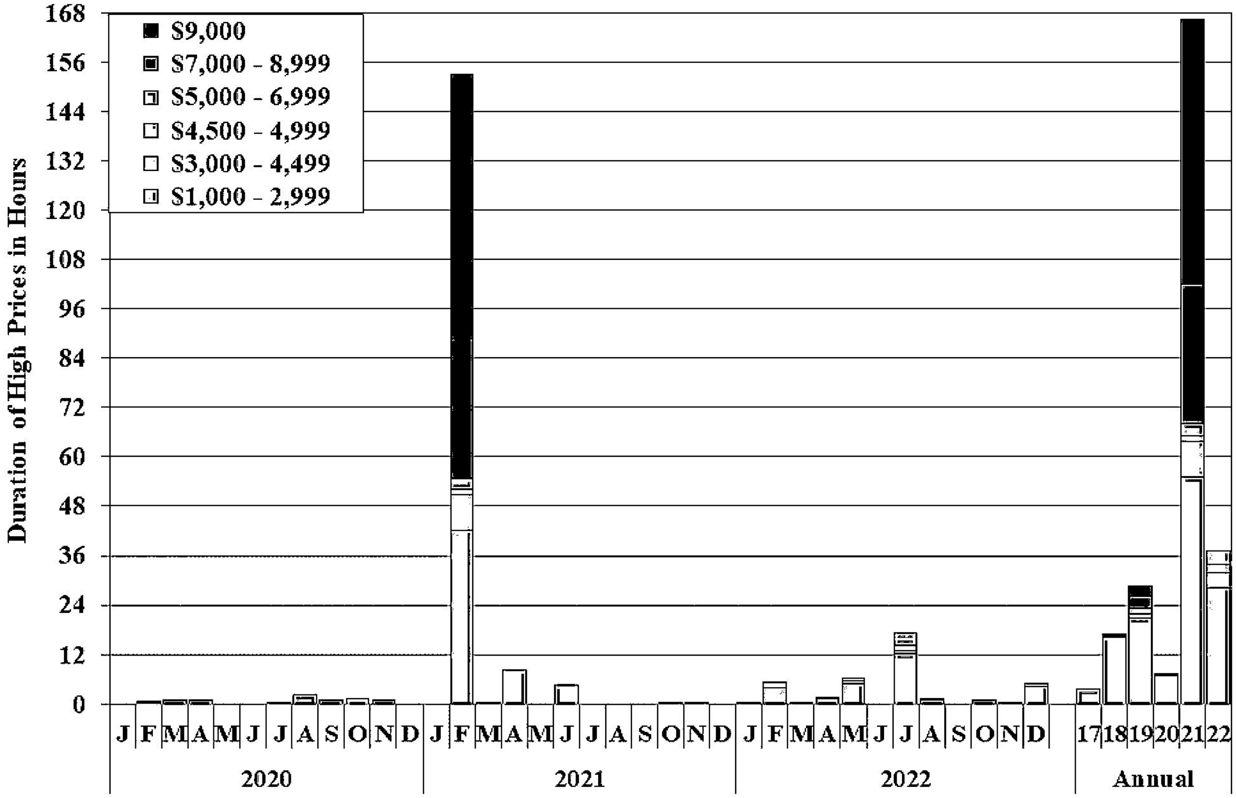


Figure 13 shows that the frequency of high prices in 2022 was the second highest in the history of the ERCOT market, second only to 2021 because of the extreme pricing event experienced during Winter Storm Uri. The increased frequency high prices in 2022 is in large part due to the substantial adjustments made to the ORDC in January 2022 that are described earlier in the Section.

Prices were greater than $1,000 for more than 37 hours in 2022, exceeding all of the previous ten years except for 2021 due to Winter Storm Uri. Prices above $1,000 were primarily concentrated during the months of February, May, July, and December. Prices reached the system-wide offer cap of $5,000 for more than three hours during 2022, primarily on July 13.

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 settlement point prices expressed as a percentage of annual average price for the four geographic zones for years 2014-2022. Larger values represent higher deviation from the mean.

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

Load Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022
Houston	14.7%	13.4%	20.8%	24.9%	21.5%	22.7%	21.2%	8.1%	19.7%
South	15.2%	14.6%	19.9%	26.2%	23.5%	23.5%	21.7%	7.7%	16.9%
North	14.1%	11.9%	15.5%	14.8%	20.7%	22.6%	19.8%	7.4%	16.2%
West	15.4%	12.9%	16.8%	17.5%	21.8%	24.7%	26.5%	7.7%	19.3%

These results show overall volatility increased year-over-year in all zones in 2022, due primarily to the impact of Winter Storm Uri on average prices in 2021. Compared to the three years before 2021, volatility in 2022 was actually lower across all load zones. Congestion explains most of the inter-zonal differences in price volatility. Volatility was highest in the Houston and West zones in 2022 because of higher congestion, though not quite as much volatility as seen in years before 2021. When the operating reserve adder is frequently active, it diminishes the inter-zonal volatility.

For additional analysis of real-time price volatility, see Figure A6 and Figure A7 in the Appendix.

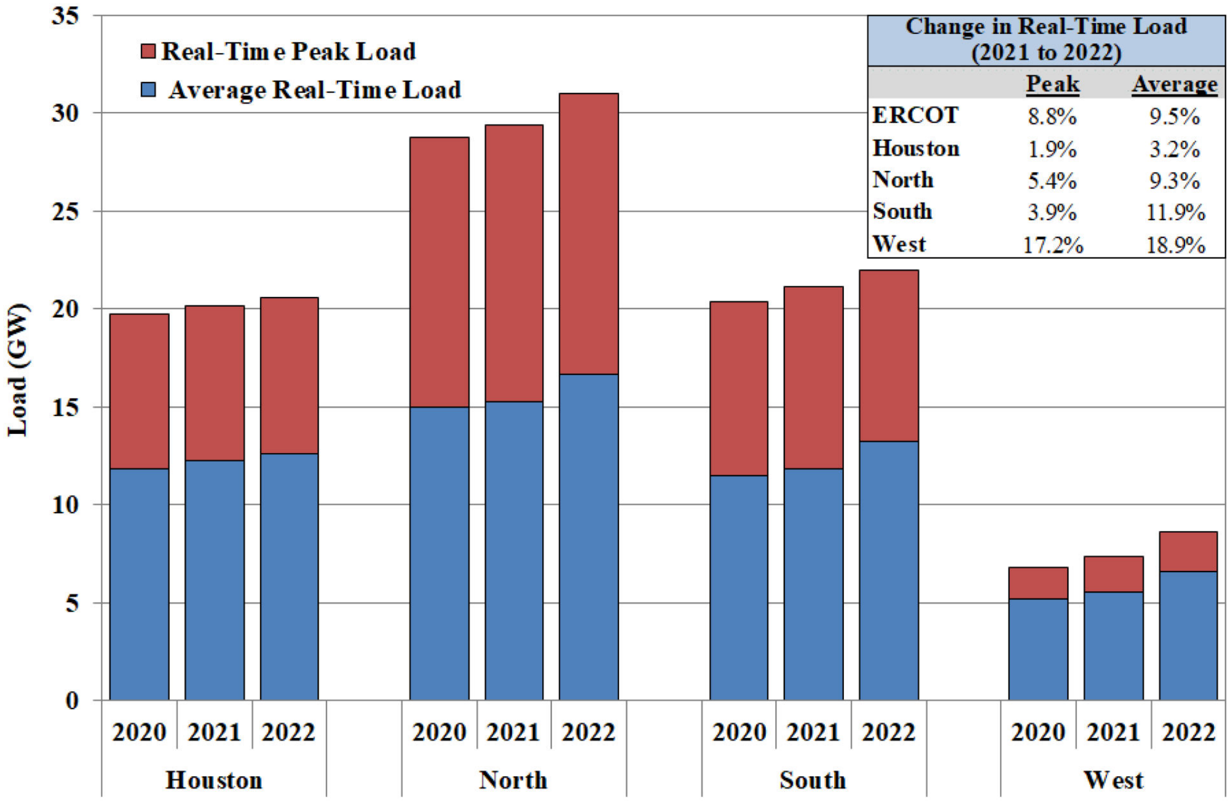
III. Demand and Supply in ERCOT

Many of the trends in market outcomes described in Section I are attributable to changes in the supply portfolio or load patterns in 2022. Therefore, we review and analyze these load patterns and the generating capacity available to satisfy the load and operating reserve requirements in this section. 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 2022

We track the changes in average load levels from year to year to better understand the load trends, which capture changes in load over a large portion of the hours during the year. However, changes in the load during the highest-demand hours are important because they affect the probability and frequency of shortage conditions.[48] Figure 14 shows peak load and average load by geographic zone from 2020 through 2022.[49]

Figure 14: Annual Load Statistics by Zone



Change in Real-Time Load (2021 to 2022)		
	Peak	Average
ERCOT	8.8%	9.5%
Houston	1.9%	3.2%
North	5.4%	9.3%
South	3.9%	11.9%
West	17.2%	18.9%

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

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

Figure 14 shows that the total ERCOT load in 2022 increased almost 10% from 2021, which is an increase of more than 4,250 MW on average. The South and West zones showed the largest increases in average real-time load in 2022 ranging from 11.9% in the South to 18.9% in the West. The increase in the North and South zones is due to population migration and high economic activity. 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.

ERCOT broke the all-time peak demand record 11 times during the summer of 2022, with the record all-time peak demand occurring on July 20, 2022, reaching 80,000 MW. The summer months of June through August 2022 were the second hottest on record for the state of Texas, with only 2011 being hotter. The average temperature for the June through August 2022 period was 84.8° F. Fluctuations in peak and average load are usually driven by summer conditions. Cooling degree days are a measure of weather that is highly correlated with the demand for electricity for air conditioning, and it is a metric that is highly correlated with summer loads. Cooling degree days were up for all large cities, by as much as 26% (for Austin).

Generation Capacity in ERCOT

In this section we evaluate the generation portfolio in ERCOT in 2022. The distribution of capacity in the North and South zones is similar to the distribution of demand. The West zone exports more power than it consumes. The Houston zone has increasingly relied on imports from the rest of the state as load has increased in the area and some resources in Houston have been mothballed.

Approximately 9.7 GW of new generation resources came online in 2022. The bulk of the new capacity was renewable resources, and the remaining included 16 new combustion turbines totaling 700 MW and 1.7 GW of energy storage resources (ESRs). The 36 new ESRs increased ERCOT's storage capacity to 2.7 GW. Roughly 3.1 GW and 4.2 GW of new installed wind and solar capacity with an effective peak serving capability of 4 GW entered the market between the summers of 2021 and 2022.[50] One 420 MW resource retired in 2022. These changes are detailed in Section V of the Appendix, along with a review of the vintage of the ERCOT fleet.

Figure 15 shows the annual composition of the generating output in ERCOT from 2014 to 2022. This figure shows the transition of ERCOT's generation fleet away from coal-fired resources to natural gas and renewable resources. Some of the reduction in the share of energy produced by coal was due to fuel supply and other supply chain challenges coal resources have faced over the past two years. However, most of the other changes have been driven by resource additions and retirements. Combined cycle gas capacity was the predominant technology choice for new

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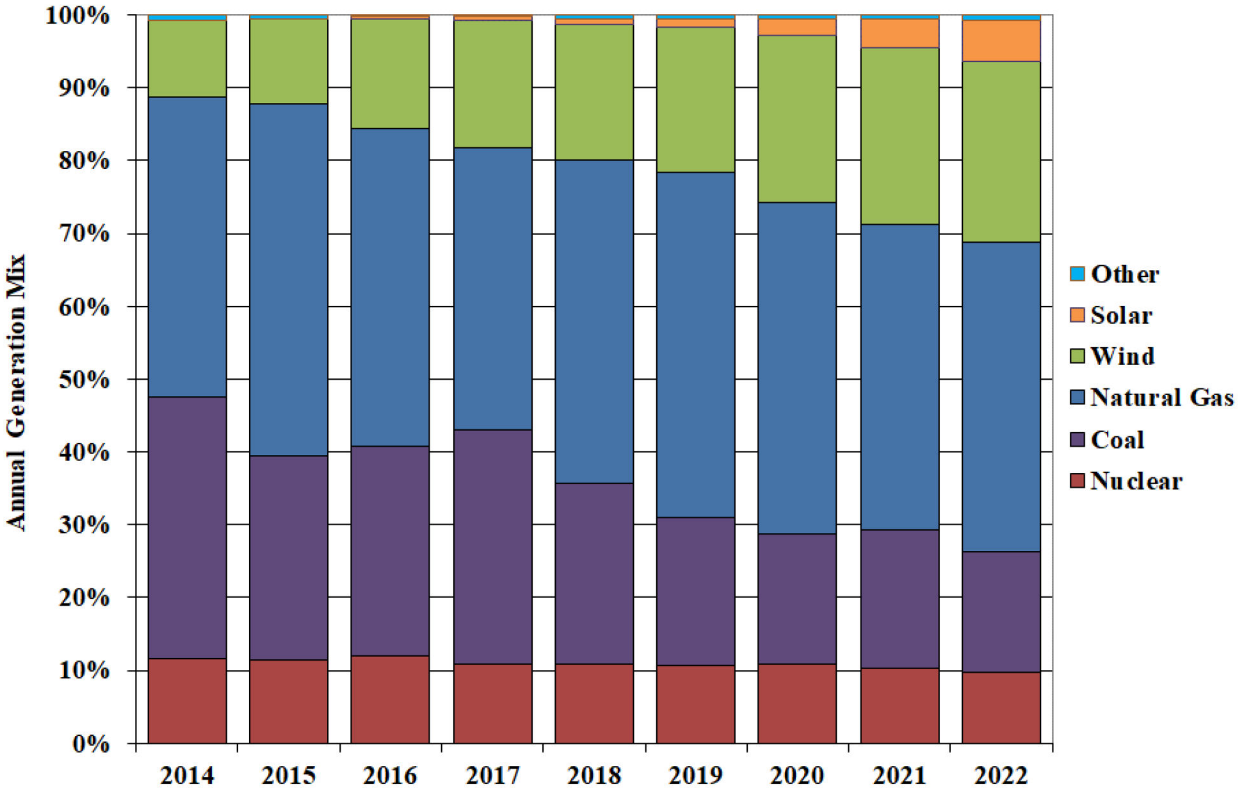
[50] The percentages of installed capacity to serve peak demand assume availability of 30% for panhandle wind, 60% for coastal wind, 20% for other wind, and 80% for solar.

investment throughout the 1990s and early 2000s. However, between 2006 and 2019, wind has been the primary technology for new investment, and since 2020, wind and solar both saw large increase in capacity. The amount of utility-scale solar capacity added in 2022 (4.2 GW) was the largest amount of solar added to the ERCOT system in any year, bringing total installed capacity to nearly 13.700 GW.

Figure 15: Annual Generation Mix in ERCOT



This figure shows:

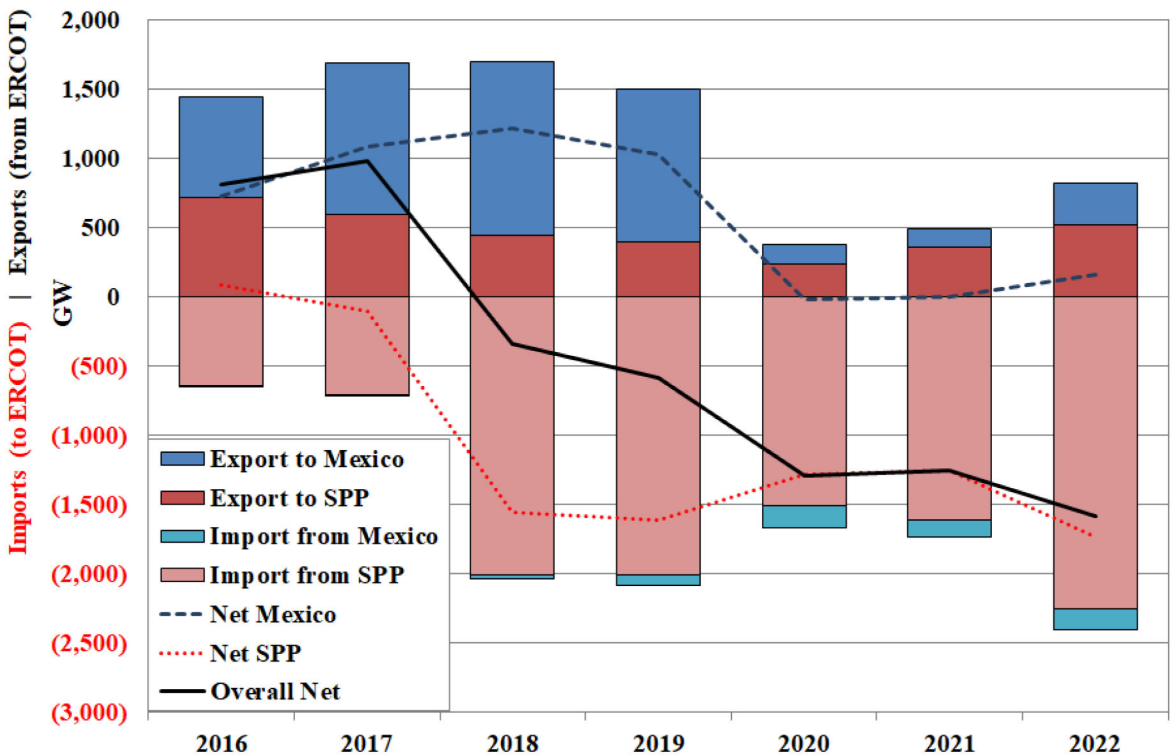
- The generation share from wind has increased every year and rose from just over 24% in 2021 to almost 25% of the annual generation in 2022.
- Solar increased from 4.0% of annual generation in 2021 to 5.6% in 2022.
- The share of generation from coal dropped from 19.0% in 2021 to 16.6% in 2022 even though it was much more economic due to much higher gas prices. This reduction was caused by fuel supply and other supply chain issues affecting many coal resources.
- Natural gas generation increased slightly in 2022, from 41.9% in 2021 to 42.5% in 2022.

We expect these trends to continue because of the continued growth of wind, solar, and storage resources. Figure A9 in the Appendix shows the vintage of ERCOT installed capacity. The installed generating capacity by type in each zone is shown in Figure A10 in the Appendix.

B. Imports to ERCOT

The ERCOT region is connected to other regions in North America via multiple direct current (DC) 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 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 16 shows the total energy transacted across the ties for the past several years.

Figure 16: Annual Energy Transacted Across DC Ties



The figure shows that ERCOT remained a net importer in 2022, and by an even wider margin than in 2021. This trend began in 2018 because of tightening supply in ERCOT and the resulting higher prices in 2018 and 2019. The amount of tie activity in general in 2022 was higher than the activity in 2021 because of the higher prices resulting from high summer demand, as well as the ORDC shift implemented on January 1, 2022.

C. Wind and Solar Output in ERCOT

Investment in wind resources has continued to increase in ERCOT. The amount of wind capacity installed in ERCOT was more than 37 GW at the end of 2022. 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 2.7 GW in the North zone.

The value of wind in satisfying ERCOT's peak summer demand is limited by its negative correlation with load.[51] The highest wind production occurs during non-summer months, and predominately during off-peak hours. Wind output during high load periods will continue to be a pivotal determinant of shortages, though this will be mitigated as more solar and batteries enter.

Figure 17: Wind Production and Curtailment

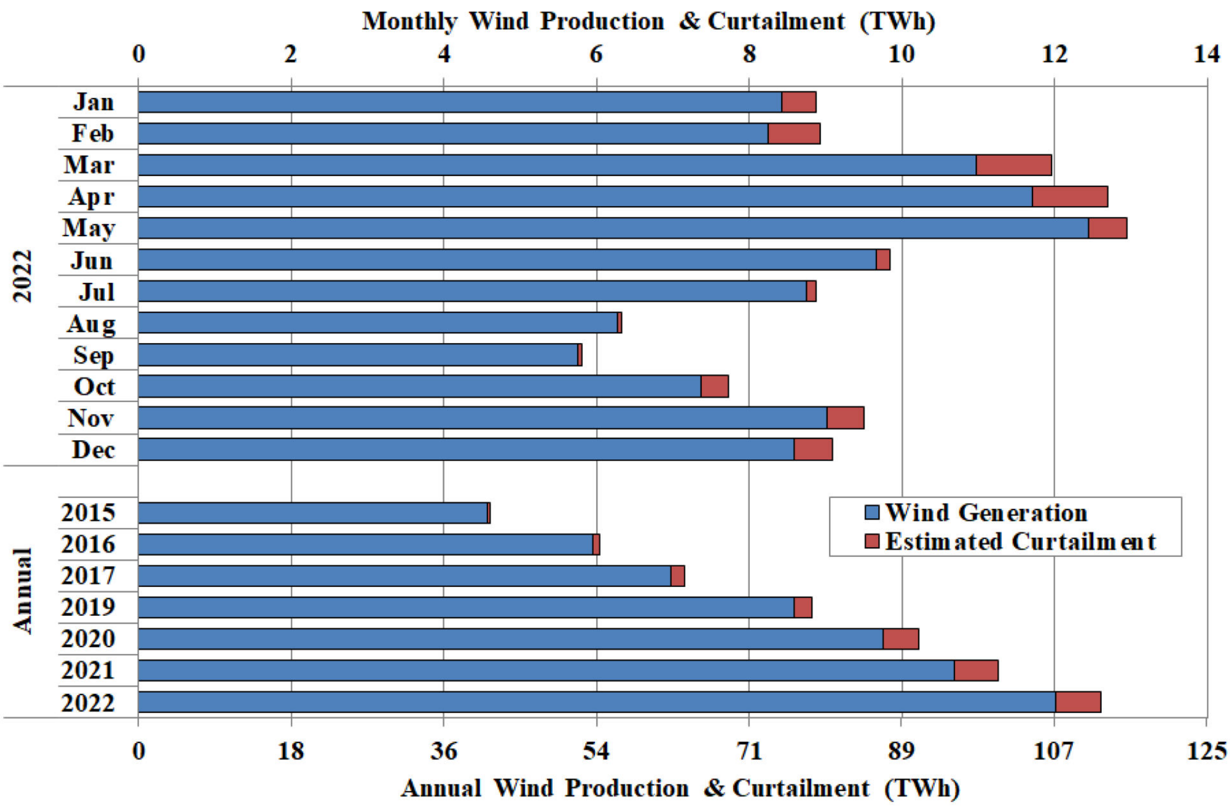


Figure 17 reveals that the total production from wind resources continued to increase in 2021 and a new wind output record was set on May 29, 2022 (27,044 MW). The quantity of curtailments implemented to manage congestion caused by the wind output also increased from the prior year. These curtailments reduced wind output by less than 5%, compared to a peak of 20% in 2009.

Solar resources, although still a smaller component of overall generation than wind today, are positively correlated with summer load and thus produce at much higher capacity factors than wind during summer peak hours. The capacity factors during these hours were 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 18 shows that total solar production in 2022 was 24,200 GWh and an additional 9% was curtailed to manage congestion caused by solar resources. For additional analysis of wind and solar output in ERCOT, see Figure A11 and Figure A12 in the Appendix.

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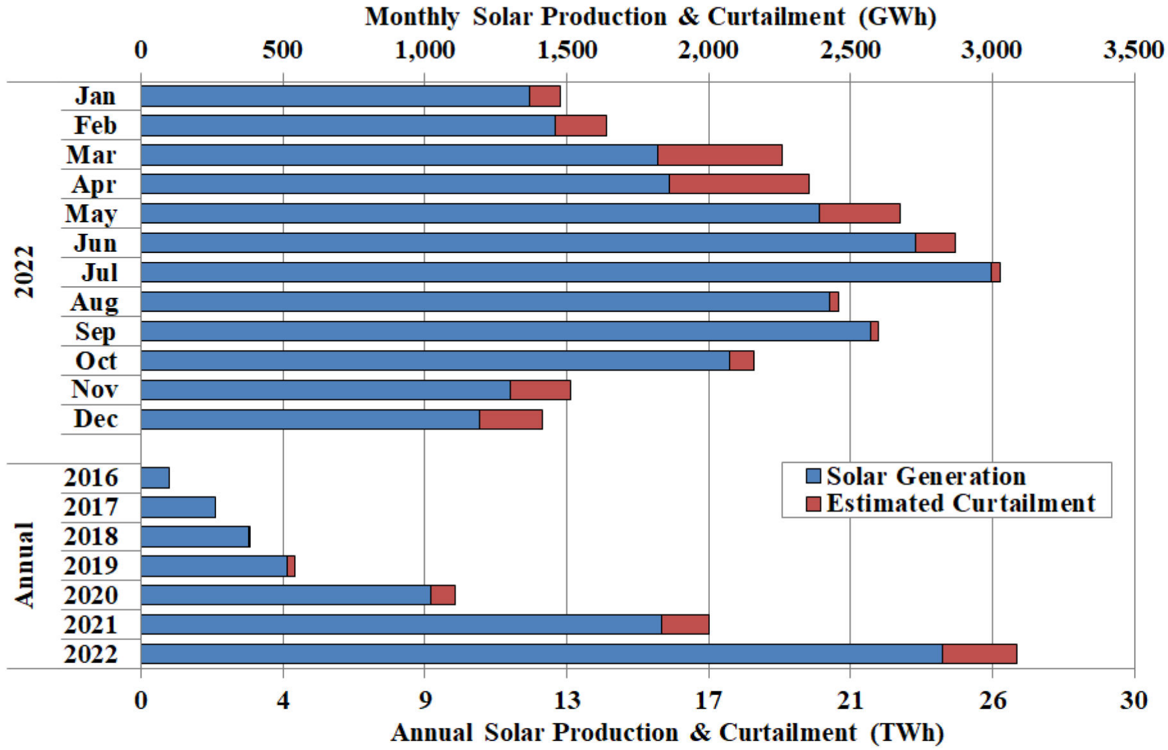
51 Wind units in some areas do not exhibit this negative correlation, including the Gulf Coast.

Figure 18: Solar Production and Curtailment



Rising wind and solar output has important implications for other types of resources by changing the shape of the remaining load they must serve. This also has important implications for resource adequacy in ERCOT. Figure 19 shows net load in the highest and lowest hours in 2022.

Figure 19: Top and Bottom Deciles (Hours) of Net Load

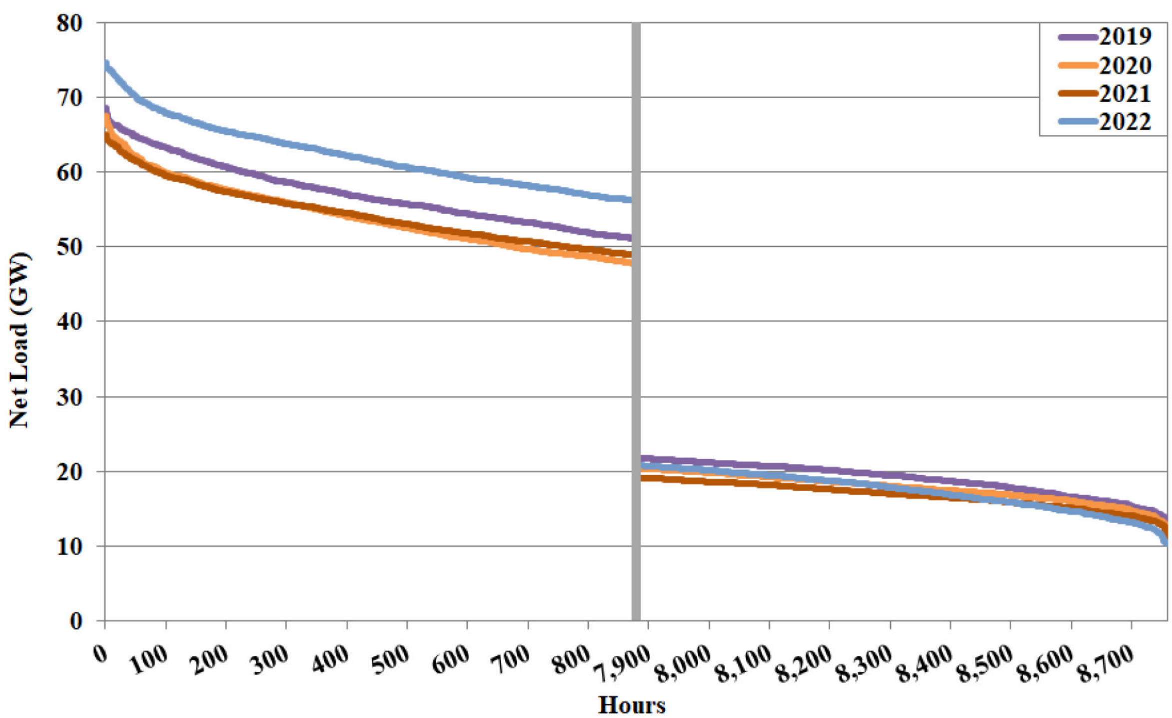


Figure 19 shows the peak net load was 74.5 GW and the 95th percentile was 61.5 GW in 2022. These net load values across the highest 440 net load hours reflect a 14% increase from 2021. This continues a trend of increasing load that must be served by non-renewable resources.

The minimum net load dropped from roughly 15 GW in 2016 to about 10.4 GW in 2022. This reflects the sizable increase in wind and solar output in off-peak hours in recent years. Although less load must be served by baseload resources in these hours (such as nuclear and coal), we believe the increases in real-time prices and net revenues discussed earlier in the report provide sufficient economic signals to retain these resources.

D. Demand Response Capability

Demand response is a term that refers to actions that can be taken by end users of electricity to reduce load in response to instructions from ERCOT for the sake of maintaining reliability or in response to economic 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 participation in: (i) reserve markets, (ii) ERCOT-dispatched reliability programs, and (iii) demand response programs administered by the transmission and distribution utilities. Additionally, loads may self-dispatch by reducing consumption in response to energy prices or during specific hours to lower transmission charges. We discuss each of the means to participate in the ERCOT markets in this subsection.

1. Reserve Markets

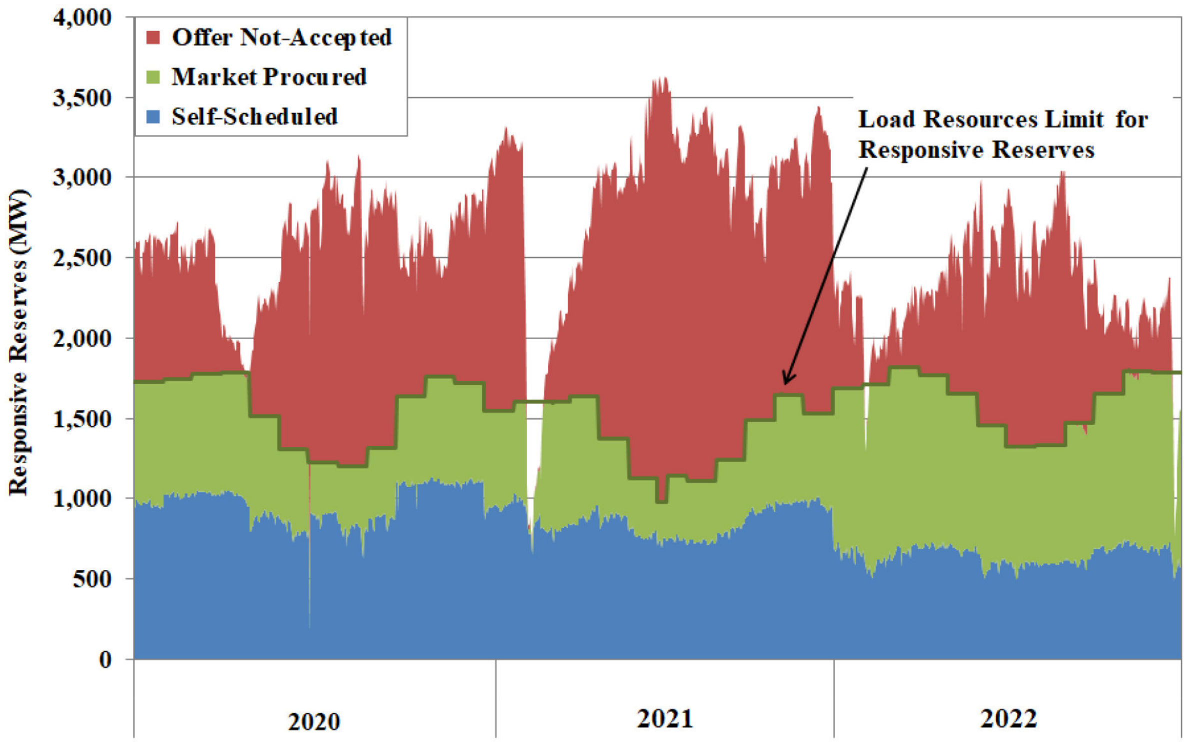
ERCOT allows qualified load resources to offer into the day-ahead ancillary services markets. Under-frequency relay response can be a highly effective mechanism for maintaining system frequency at 60Hz. Non-controllable load resources (NCLRs) providing responsive reserves have relay equipment that enables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

As of November 2022, 8,298 MW of responsive reserve service can be provided by qualified NCLRs, an increase of 674 MW during 2022.[52] However, the quantity of responsive reserves procured by ERCOT from load resources was limited to a maximum of 2,144 MW per hour. In 2022, there was one deployment of responsive reserve service (RRS) from NCLRs. This was a result of an under-frequency event that occurred on June 4 when 1,116 MW of NCLR capacity deployed automatically. Those resources were recalled approximately 14 minutes later.

[52] *See* ERCOT 2022 Annual Report of Demand Response in the ERCOT Region (Dec. 2022), available at http://www.ercot.com/services/programs/load.

Figure 20 below shows the daily average amount of responsive reserves provided from load resources operating on under-frequency relays for the past three years.[53]

Figure 20: Responsive Reserves from Loads with High-Set Under Frequency Relays



While the surplus did not grow in 2022 from 2021, there continues to be a large surplus of load resource offers into responsive reserve service beyond the limit placed on load resource participation. This surplus is partly the result of the fact that the price does not fall to efficiently reflect the procurement limitation. Recommendation 2019-2 discussed in this report would address this issue.

A small amount of non-spinning reserve service (57.8 MW) is now available from load resources. Non-spin prices were strong in 2022 and we would have expected that more load resources would be interested in providing the service given those market outcomes and oversupply in the responsive reserve market from NCLRs. It is possible that the frequent deployment of offline non-spin in real-time contributes to the low amount of load resources offering to provide the service.

53 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.

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 run 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.[54] In August 2022, the Commission increased the budget to $75 million. The capacity-weighted average price for ERS over the contract periods from December 2021 through November 2022 ranged from $3.14 to $9.64 per MWh. This price was lower than the average price paid for both responsive reserves and non-spinning reserves in 2021.

In October 2021, the Commission directed ERCOT to change the deployment of ERS and this was enacted in protocols via NPRR1106. Now the deployment of ERS may occur prior to the declaration of an EEA when Physical Responsive Capability (PRC) falls below 3,000 MW and is not expected to rise above that threshold within 30 minutes. This scenario occurred on July 13, 2022, and ERCOT deployed as much as 1,011 MWs of ERS for approximately 3.25 hours. The fleet generally underperformed during the first hour of the event and overperformed during the subsequent hours. Unlike previous ERS deployments, close to half of the portfolios failed to perform successfully across the entirety of the event. As a result, ERCOT is considering bringing back mandatory suspensions due to non-performance.[55]

There were roughly 300 MW of load participating in load management programs administered by the TDUs in 2022 during the summer.[56] 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.[57] These programs administered by TDUs may be deployed by ERCOT during a Level 2 Energy Emergency Alert (EEA), and can be self-deployed by the TDUs at any time.

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.

[54] 16 TAC § 25.507.

[55] https://www.ercot.com/files/docs/2023/02/13/ERS-Staff.pptx

[56] *Id.*

[57] *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).

- 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 as much as 3,200 MW of load reduction during the 4CP intervals in 2022, higher than the 2021 estimate.[58]

Voluntary load reductions to avoid transmission charges are likely distorting prices during peak demand periods because it is not an efficient response to wholesale prices. To address these distortions, we continue to recommend that modifications to ERCOT's transmission cost allocation methodology be explored (see Recommendation 2015-1).

4. Demand Response and Market Pricing

When Security-Constrained Economic Dispatch (SCED) clears the supply offers to meet the demand, it issues dispatch instructions for resources and associated 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 to specify the price at which they no longer wish to consume. Therefore, the prices will reflect these bid prices. Second, for loads that are not participating in SCED (such as ERS and NCLRs), SCED has a pricing run feature that will adjust for the impact of deploying those resources. The pricing run may result in a reliability deployment price adder adjustment to the published prices.

In 2021, loads were first qualified to participate in real-time dispatch. In 2022, sixteen new controllable load resources (CLRs) were registered and added to the ERCOT Network Model, and eight of them have qualified for SCED and RRS. 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 600 MW of online capacity and can participate in responsive reserve service, regulation

58 *See* ERCOT, 2022 Annual Report of Demand Response in the ERCOT Region (Dec. 2022) at 18, available at http://www.ercot.com/services/programs/load.

service, and non-spinning reserve service. As this segment grows, completing the implementation of nodal pricing for CLRs will become more important and impactful.

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

In this section, we examine day-ahead energy prices in 2022 and their convergence with real-time prices. We also review the activity in the day-ahead market, including a discussion of PTP obligations. This section concludes with a review of the day-ahead ancillary service markets.

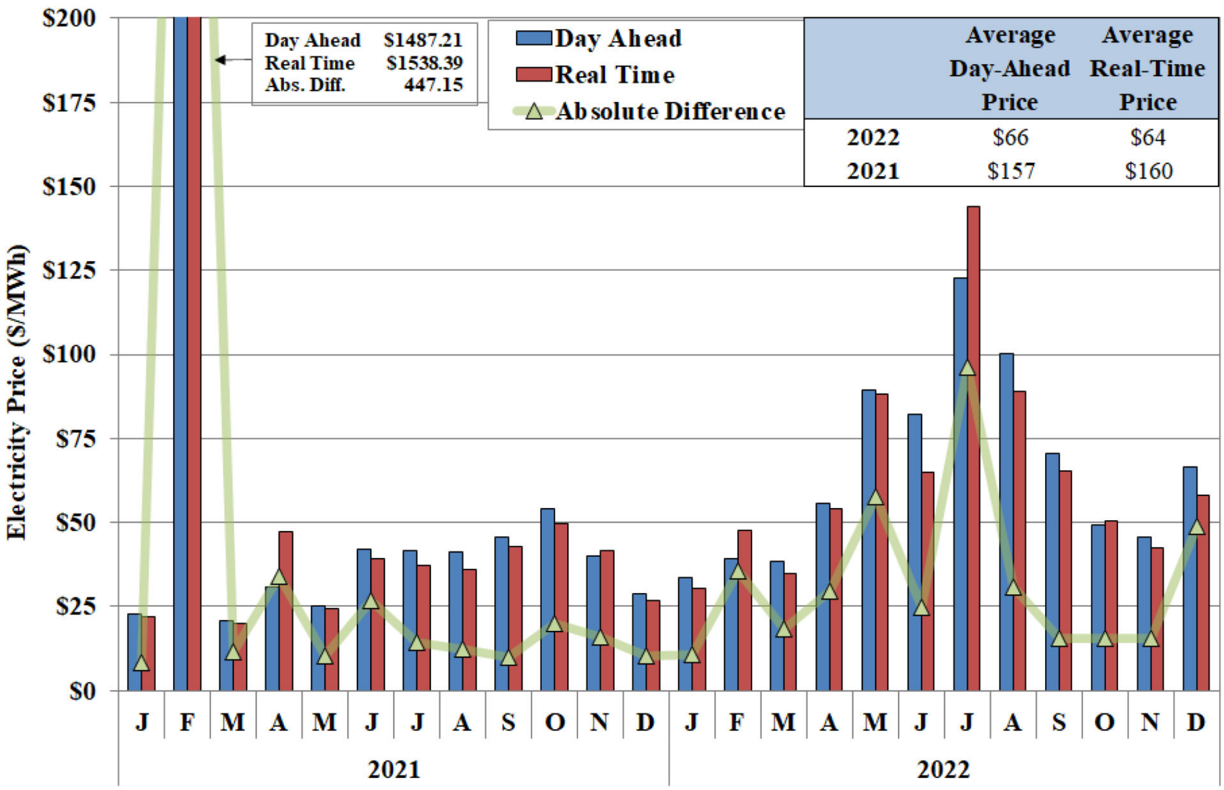
A. Day-Ahead Energy Market Performance

Overall, 2022 day-ahead prices were lower than 2021 for both energy and ancillary services, as expected given the effects of Winter Storm Uri in 2021 on average prices. Liquidity in the day-ahead market was similar to previous years, which included active trading of congestion products in the day-ahead market.

The day-ahead market provides 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 the real-time prices. This allows participants to arbitrage predictable differences between day-ahead prices and real-time prices and bring about price convergence. Price convergence between the day-ahead and real-time markets is important because it leads to more efficient commitment of resources to be used in real-time.

This average price difference between day-ahead prices and real-time spot prices reveals whether persistent and predictable differences exist that participants should arbitrage over the long term. Figure 21 shows the monthly 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 daily average day-ahead and real-time price. This measure captures the volatility of the daily price differences, which may be large even if the prices converge on average.

Figure 21: Convergence Between Day-Ahead and Real-Time Energy Prices



	Average Day-Ahead Price	Average Real-Time Price
2022	$66	$64
2021	$157	$160

Price convergence was good overall as day-ahead prices and real-time prices averaged $66 and $64 per MWh in 2022, respectively.[59] While day-ahead prices were generally higher, real-time prices were significantly higher in July 2022 because of real-time price volatility caused by hot weather. The small overall divergence is expected because the day-ahead market allows participants to hedge the risk associated with real-time price volatility.

The average absolute difference between day-ahead and real-time prices was $33.30 per MWh in 2022, much lower than the $85 per MWh in 2021 caused by Uri. The largest absolute difference ever occurred in February 2021, an astonishing $447.15, as shortage conditions led to prices that were difficult to forecast. However, the average absolute difference in 2022 was higher than previous non-Uri years ($27.63 MWh in 2019 and $16.21 in 2018). For additional price convergence results in 2022, see Figure A6, Figure A7, and Figure A13 in the Appendix.

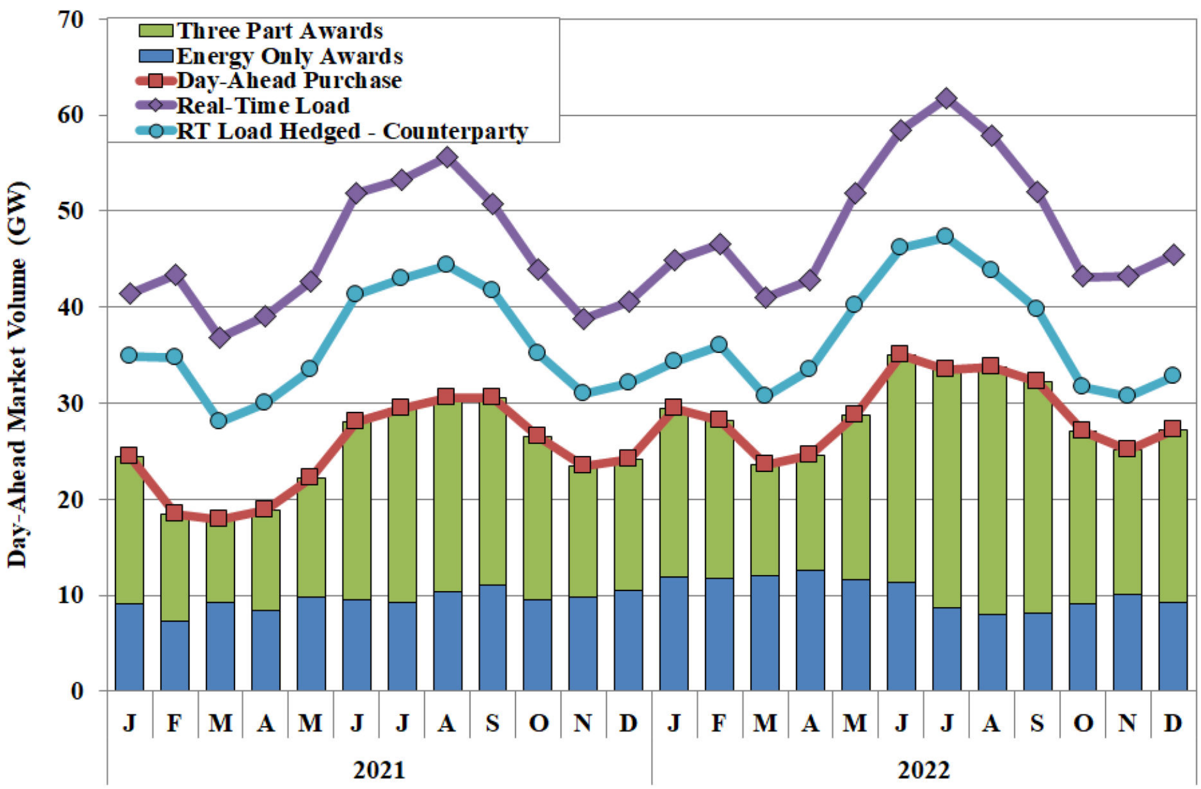
59 These values are simple averages, rather than load-weighted averages as presented in Figures 1 and 2.

B. Day-Ahead Market Activity

Figure 22 summarizes the day-ahead market 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 22 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 59% of real-time load in 2022, an increase from 55% of real-time load in 2021. Although it may appear that many loads are still subjecting themselves to greater risk by not locking in a day-ahead price and 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 associated with those transactions.

Figure 22: Volume of Day-Ahead Market Activity by Month



PTP obligations are financial transactions purchased in the day-ahead market. 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.[60] When coupled with a self-committed generating resource, the PTP obligation allows a participant to serve its

[60] PTP obligations are equivalent to scheduling virtual supply at one location and virtual load at another.

load while avoiding the associated real-time exposure. 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 and have caused day-ahead market performance issues related to ERCOT's ability to publish within the protocol timeline. The bids for PTP obligations have increased four-fold over the last decade. According to ERCOT, the highest correlation to day-ahead market performance issues is unawarded PTP obligations bids, i.e., the volume of bids submitted is affecting performance. Further, many of the bids being submitted are highly unlikely to be awarded because the bid price is not a reasonable expectation of the real-time congestion.

When the day-ahead market results are delayed, additional costs are borne by the entire ERCOT market. Cost causation principles dictate that entities that cause costs should bear some of the costs they are causing. Hence, participants submitting PTP obligation bids should have incentives that are aligned with performance costs they cause. Charging no fee for PTP bids allows 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.

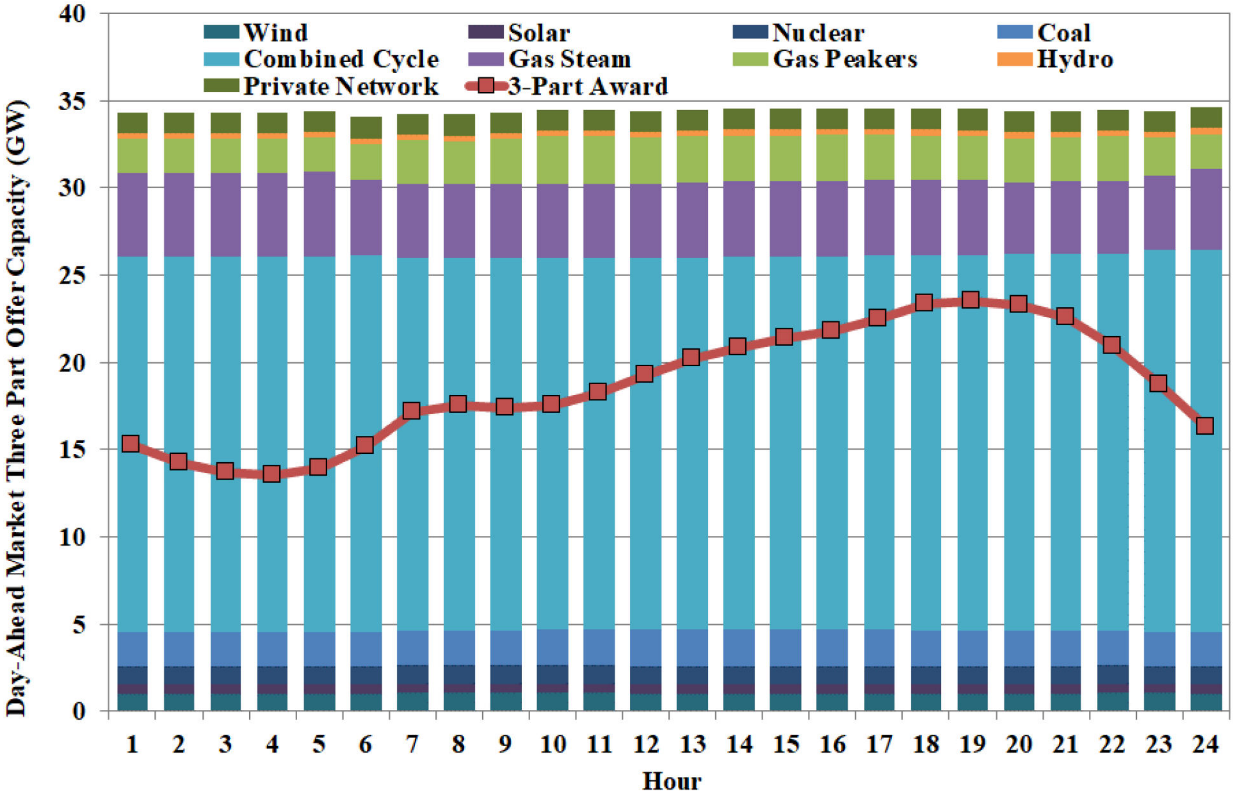
Applying a small bid fee to the PTP bids is consistent with cost causation principles and would incent participants to submit smaller quantities of bids that are more valuable and more likely to clear. Even a small fee would likely reduce or eliminate bids that are very unlikely to clear, and this should substantially eliminate the delays in the day-ahead market process. In recommendation No. 2020-4 above, the IMM recommends a PTP bid fee as an economically rational way to manage the volume of bids submitted.

Figure 22 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).[61] 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 76% in 2022, down from 80% in 2021.

In 2022, the volume of three-part offers comprised less than half of day-ahead market transactions that cleared, a fact consistent with the ERCOT market design. To determine whether this was due to small volumes of three-part offers being submitted versus those clearing, **Error! Reference source not found.** shows the total capacity from three-part offers in the day-ahead market for 2022. The submitted capacity has been averaged by hour and is significantly more than the amount of capacity cleared, i.e., three-part offers awarded.

61 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.

Figure 23: Day-Ahead Market Three-Part Offer Capacity

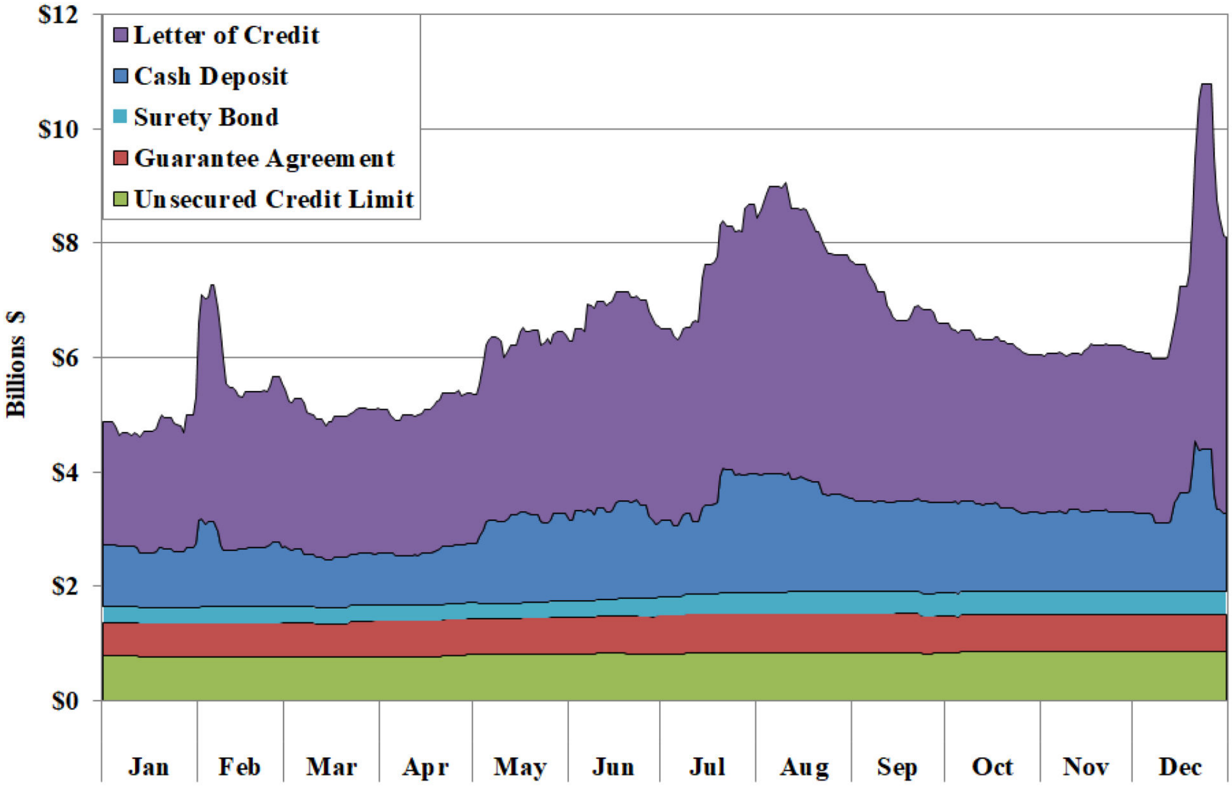


With the largest share of installed capacity, it follows that combined cycle units submit the largest quantity of offers in the day-ahead market. More importantly, because combined cycle units are typically marginal units, offering that capacity into the day-ahead market allows a market participant to determine whether its unit is economic given the market conditions. Conversely, few wind units are offered in the day-ahead market because of uncertainty on whether wind will be available in real-time to cover any award. Further analysis on day-ahead market activity volume can be found in **Error! Reference source not found.** in the Appendix.

To participate in ERCOT's day-ahead market, a market participant must have sufficient collateral with ERCOT. Credit requirements are a constraint on submitting bids in the day-ahead market. When the available credit of a QSE is limited, its participation in the day-ahead market will necessarily be limited as well. The total collateral requirements for 2022 are shown below in Figure 24.

Though daily collateral totals in 2022 never exceeded the maximums seen in 2021 due to Winter Storm Uri, the average daily collateral total in 2022 was nearly 27% higher than 2020. This increase is largely due to the increased prices and volatility that occurred in the summer and late in the year during Winter Storm Elliot.

Figure 24: Daily Collateral Held by ERCOT

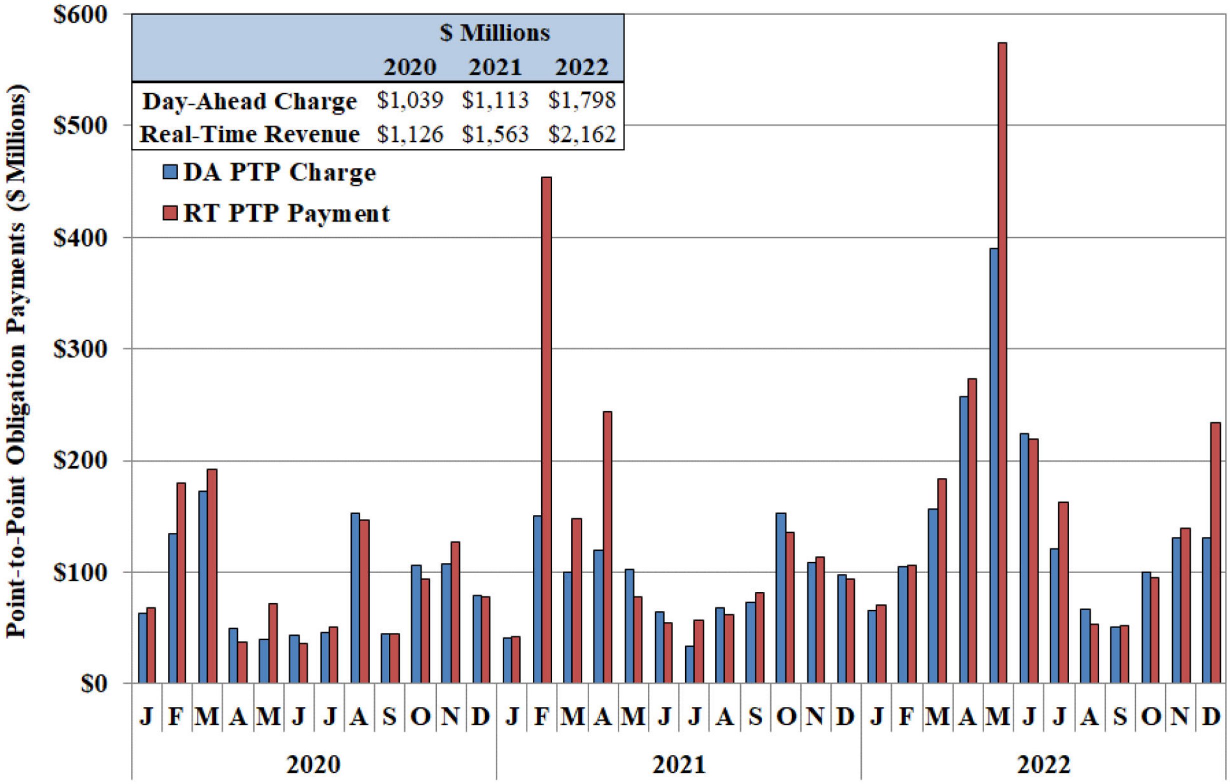


C. Point-to-Point Obligations

Purchases of PTP obligations comprise a significant portion of day-ahead market activity. Participants buy PTP obligations by bidding to pay the difference in prices between two locations in the day-ahead market. They are both similar to and can be used to complement Congestion Revenue Rights (CRRs). PTP obligations are acquired in the day-ahead market and accrue value in the real time based on the difference in prices between two locations caused by congestion costs. CRRs are acquired via monthly and annual auctions and allocations and accrue value to their owner based on locational price differences in the day-ahead market. A participant that owns a CRR can use its CRR proceeds from the day-ahead market to buy a PTP obligation between the same two points to transfer its hedge to real-time. CRRs are more fully described in Section V.

Because PTP obligations represent such a substantial portion of the transactions in the day-ahead market, this subsection summarizes the quantities and profitability of the PTP obligations. The first analysis of this subsection, shown in Figure 25, 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 for the last three years. When the payments are lower than the real-time revenues, the PTP obligations are profitable for the participant.

Figure 25: Point-to-Point Obligation Charges and Revenues

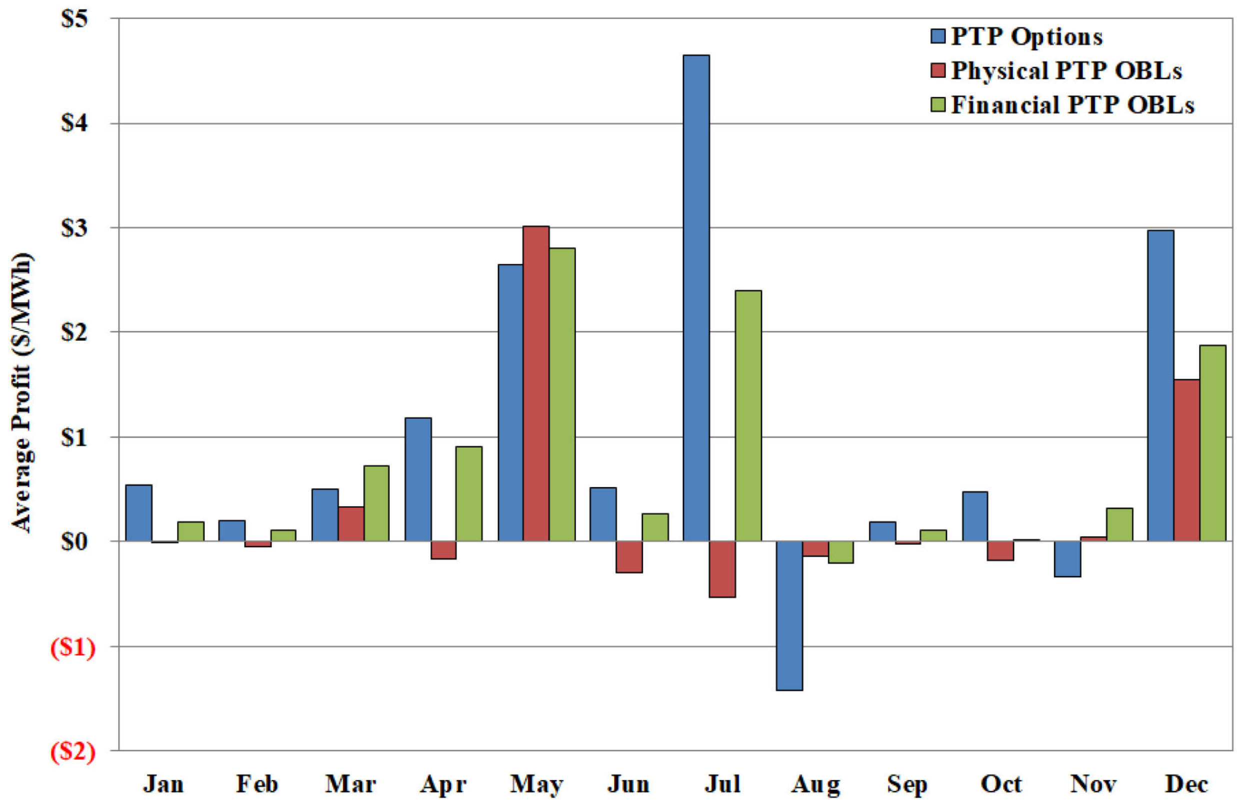


As prices and total congestion costs have increased substantially in recent years, so have the costs and revenues associated with PTP obligations. The average volume of PTP obligations has been stable for the past three years, although the quantity of transaction submissions has risen. Real-time revenue increased in 2022, though the difference between charges and payments (i.e., profits) was not as pronounced as it was in 2021 (~40% for 2021, ~20% for 2022). This is likely due to the outlier nature of 2021's markets.

Figure 25 shows that the aggregated total revenue received by PTP obligation owners in 2022 was greater than the amount charged to the owners to acquire them, as in prior years. This indicates that buyers of PTP obligations profited from the transactions in aggregate. Profits were spread throughout 2022 (particularly March, May, July, and December), accruing when congestion priced in the day-ahead market was lower than the congestion in real time. The profits were highest in May when congestion costs were the highest in 2022.

To provide additional insight on the profits that have accrued to PTP obligations, **Error! Reference source not found.** 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 2022 ("PTP options"). PTP options are available only to Non-Opt-In Entities and allow them to receive congestion revenue, but not be subject to congestion charges.

Figure 26: Average Profitability of Point-to-Point Obligations



Error! Reference source not found. shows that in aggregate, PTP obligation transactions in 2022 were profitable for the year, yielding an average profit of $0.58 per MWh. PTP obligations were profitable for all types of parties largely because of the profits that accrued during high-congestion periods in May and December. Profits averaged $0.29 per MWh for physical parties, $0.80 per MWh for financial parties, and $1.06 per MWh for PTP obligations settled as options. For analysis of the total volume of PTP obligation purchases in 2021, see Figure A14 in the Appendix.

D. Ancillary Services Market

The primary ancillary services are regulation up, regulation down, responsive reserves, and non-spinning reserves. ERCOT predetermines the amount of ancillary services to be procured and assigns a responsibility to all market participants that serve load. 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), 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.

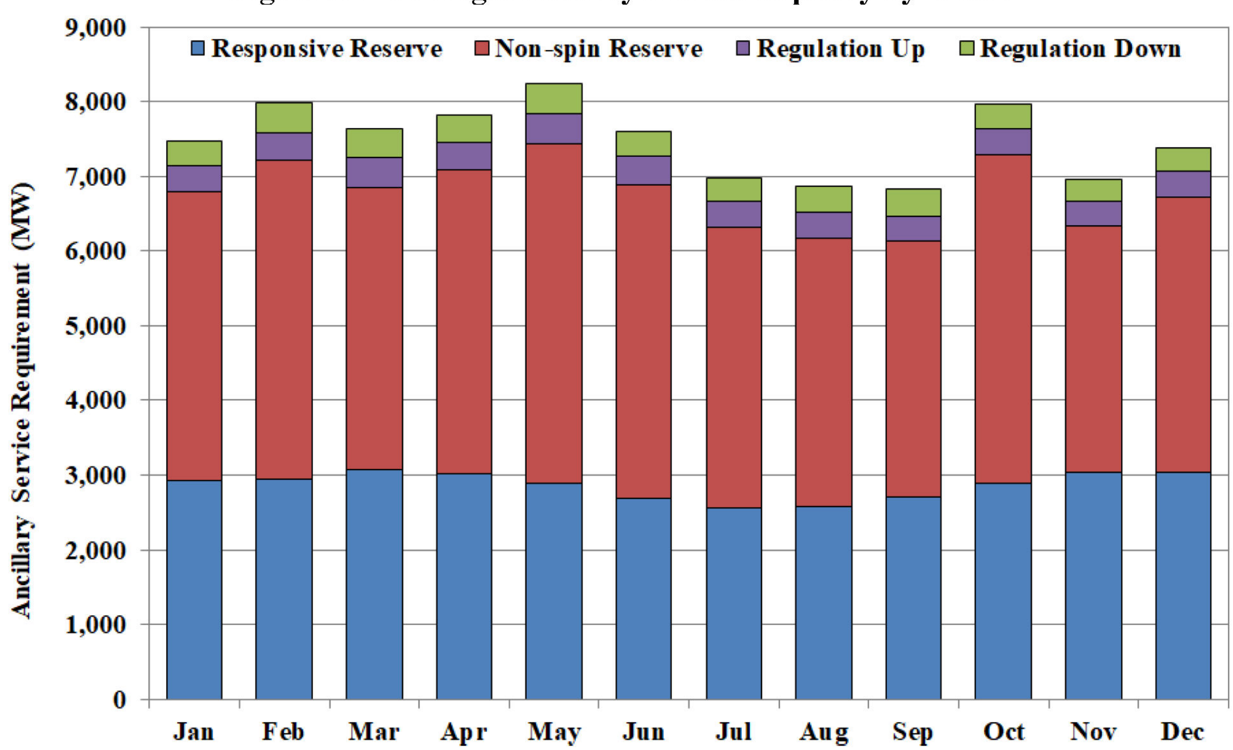
Non-spinning reserves are provided from either online resources or from offline resources that can start quickly to respond to contingencies and to restore responsive reserve capacity.

Regulation reserves are capacity that responds every four seconds, either increasing or decreasing as necessary to keep generation and load in balance from moment to moment. The quantity of regulation needed is contingent on the accuracy of the 5-minute dispatch instructions for supply to balance anticipated demand.

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 placed 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. Figure 27 below displays the average quantities of ancillary services procured for each month in 2022.

Figure 27: Average Ancillary Service Capacity by Month



This figure shows the substantial quantities of responsive reserves and non-spinning reserves procured by ERCOT throughout 2022, which was affected by the following changes:

- In late 2020, ERCOT changed the minimum amount of responsive reserve service procured from generators to 1,420 MW and changed each of the methodologies used for computing the amount of non-spinning reserve and regulation reserves to be procured to account for growth in installed solar capacity.[62]
- In July 2021, in accordance with their new operational posture, ERCOT changed the ancillary service procurement amounts such that the total amount of upward ancillary services equals 6,500 MW every day for every hour (increasing to 7,500 MW when forecast variability is high).[63]
- ERCOT increased its procurement of responsive reserve service to 2,800 MW in peak hours and procures additional non-spinning reserves as necessary to ensure it has at least 6,500 MW of total upward ancillary services for every hour of every day.
  - ERCOT chose not to include load resources providing responsive reserve in meeting the required 6,500 MW of reserves because they can only be deployed once ERCOT has issued an Energy Emergency Alert (EEA).

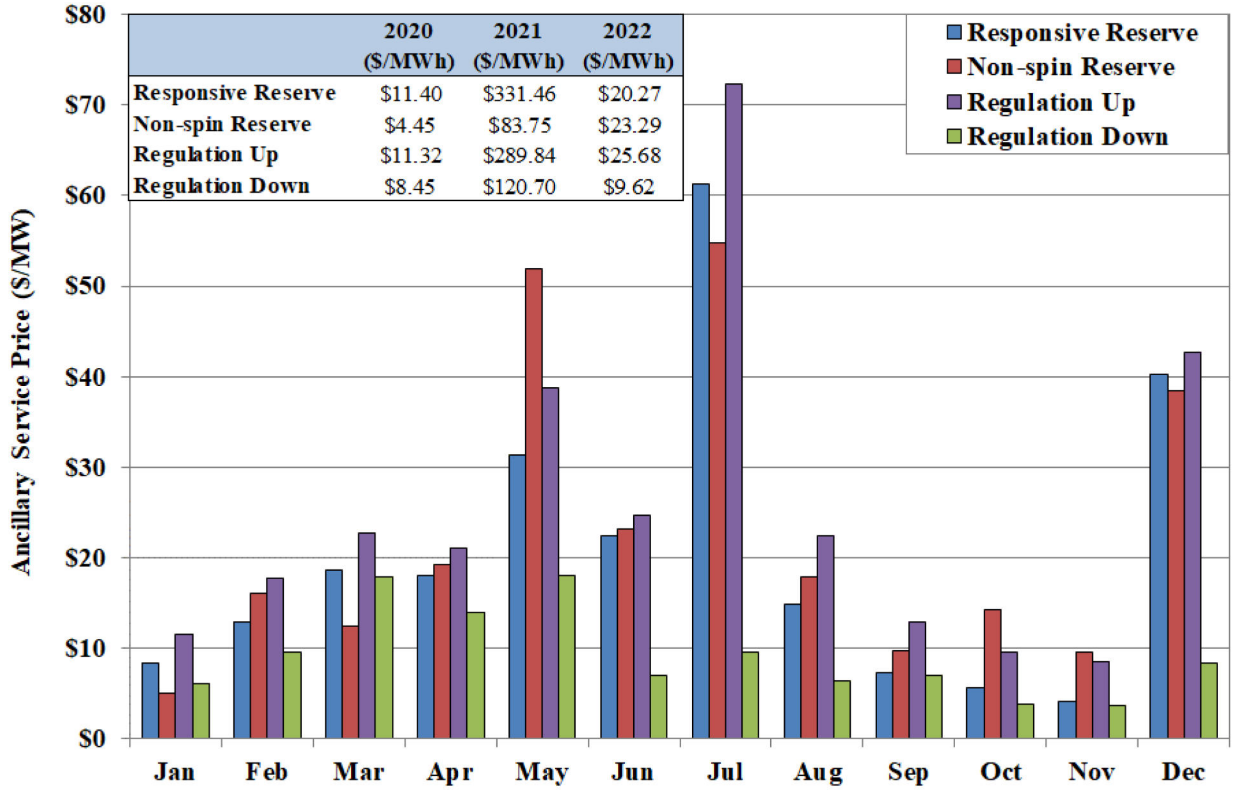
2. Ancillary Services Prices

Figure 28 below presents the monthly average clearing prices of capacity for the four ancillary services in 2022, while the inset table shows the average annual prices over the last three years.

62 https://www.ercot.com/files/docs/2020/12/01/8_2021_ERCOT_Methodologies_for_Determining_Minimum_Ancillary_Service_Requirements.pdf

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

Figure 28: 2022 Ancillary Service Prices



The prices for ancillary services were highest in May, July and December in 2022. This is consistent with the higher clearing prices for energy in the day-ahead market for those months (primarily due to weather conditions) because ancillary services and energy are co-optimized in the day-ahead market. The co-optimization means that market participants do not need to include additional costs related to expectations of forgone energy sales in their ancillary service capacity offers. Ancillary service prices should generally be correlated with day-ahead energy prices because ancillary service clearing prices explicitly account for the opportunity costs of selling energy in the day-ahead market.

The average ancillary service cost per MWh remained elevated in 2022 when compared to 2020 ($1.00 per MWh of load in 2020 vs. 3.29 in 2022). Average ancillary services costs in 2021 were unusually high because of Winter Storm Uri so we compare costs in 2022 to those in 2020. In 2022, responsive reserve prices almost doubled from 2020, but non-spinning reserve prices almost quintupled. Figure A15 in the Appendix shows the monthly total ancillary service costs per MWh of ERCOT load and Table A1 shows the annual market value of these services.

The sharp increase in responsive reserve and non-spinning reserve prices was due to ERCOT's conservative operating posture that resulted in procuring much higher quantities of these reserves beginning in July 2021. This increase in procurements associated with ERCOT's conservative operational posture substantially reduced the excess supply and caused large suppliers of the service to frequently be pivotal for satisfying the non-spinning reserve requirements. The reduction in excess supply caused large suppliers to be pivotal much more often. Pivotal suppliers often have market power and can raise prices by raising their offer prices. We find that such price increases occurred in 2022 as the market became substantially less competitive.

We estimate that this raised non-spin costs by $385 to $480 million between August 2021 through the end of 2022. We raised these market power concerns with the Commission and they took action to address them by modifying the three active Voluntary Mitigation Plans (VMPs) on March 23, 2023.[64] This is important because the conduct of the large suppliers in the non-spinning reserve market were exempt from mitigation under the VMPs previously.

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 3 shows the share of the 2022 ancillary services that were provided in real-time 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 3: Share of Reserves Provided by the Top QSEs in 2021-2022

	2021				2022			
	Responsive	Non-Spin	Reg Up	Reg Down	Responsive	Non-Spin	Reg Up	Reg Down
# of Suppliers	**58**	**36**	**38**	**40**	**52**	**36**	**37**	**38**
QLUMN	4%	20%	16%	37%	3%	19%	9%	35%
QBROAD	2%	0%	5%	5%	4%	0%	23%	17%
QNRGTX	13%	13%	9%	7%	9%	8%	5%	3%
QTEN25	0%	0%	0%	0%	1%	0%	11%	10%
QLCRA	12%	4%	3%	7%	9%	4%	3%	4%
QTEN23	0%	6%	0%	0%	0%	18%	0%	0%
QSUE23	1%	0%	2%	5%	2%	0%	9%	6%
QCPSE	4%	5%	6%	5%	3%	4%	4%	5%
QEDE20	10%	0%	0%	0%	14%	0%	0%	0%
QAEN	2%	5%	3%	6%	2%	4%	3%	4%
Total	***49%***	***52%***	***44%***	***73%***	***47%***	***57%***	***68%***	***84%***

During 2022, 52 different QSEs provided responsive reserves, which is the product with the highest number of participating QSEs. The number of suppliers in 2022 fluctuated only slightly

64 See *Request for Approval of an Amended Voluntary Mitigation Plan for Luminant Energy Company LLC Pursuant to PURA § 15.023(f) and 16 TAC § 25.504(e)*, Docket No. 54739 (Mar. 23, 2023); *Request for Ratification of Commission Staff's Termination in Part of the Amended Voluntary Mitigation Plan for NRG Companies*, Docket 54740, Order (Mar. 23, 2023); and *Request for Approval of an Amended Voluntary Mitigation Plan for Calpine Corporation Pursuant to PURA § 15.023(f) and 16 TAC § 25.504(e)*, Docket 54741, Order (Mar. 23, 2023).

from the previous year.[65] Regarding the concentration of the supply for each product, Table 3 shows that in 2022:

- The supply of responsive reserves has not been highly concentrated, just as in 2021, with the largest QSE providing only 14% of ERCOT's responsive reserves (QEDE20 in 2022 as opposed to QNRGTX in 2021).
- The provision of non-spinning reserves remained more concentrated than responsive reserves, in equal measure to 2021. Luminant ("QLUMN") bore almost 19% of the requirements in 2022, roughly the same as 20% in 2021. Luminant's share has fallen from a high of 56% in 2017. QTEN23 tripled its share from 6% in 2021 to 18% in 2022.
- Regulation up in 2021 was provided by many different QSEs, but in 2022 QBROAD provided almost a quarter of the regulation up services, demonstrating the rapid changes associated with the increased penetration of storage resources in ERCOT.
- Regulation down in 2022 exhibited similar concentration to regulation down in 2021, although QBROAD increased its share from 5% in 2021 to 17% in 2022. Luminant remained the dominant supplier, selling 35% of all regulation down in 2022. The top 5 suppliers represent 73% of the regulation down supply.

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 real-time co-optimization (RTC). Jointly optimizing all ancillary services and energy in each interval will allow the market to shift its procurements between resources to minimize costs and set efficient prices. Currently, only QSEs with multiple qualified resources may review and adjust the resources it commits to meet its ancillary services responsibility prior to real-time, but this is much less efficient than full optimization. Additionally, the use of ancillary service demand curves in the day-ahead co-optimization will improve the efficiency of the day-ahead purchases by allowing those curves to set prices when there is a shortage of offers.

Co-optimization will allow QSEs who have fewer qualified resources to better compete in the ancillary services markets. Such QSEs face higher risk than QSEs that represent a high number of qualified resources (i.e., a large portfolio) when selling ancillary services because of the replacement risk faced in having to rely on a SASM. ERCOT runs a SASM when additional ancillary services need to be procured and typically result in higher prices than the day-ahead market. 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 day-ahead clearing prices. RTC will address this issue by providing a liquid market for replacement for ancillary services awarded in the day-ahead market. Because RTC is

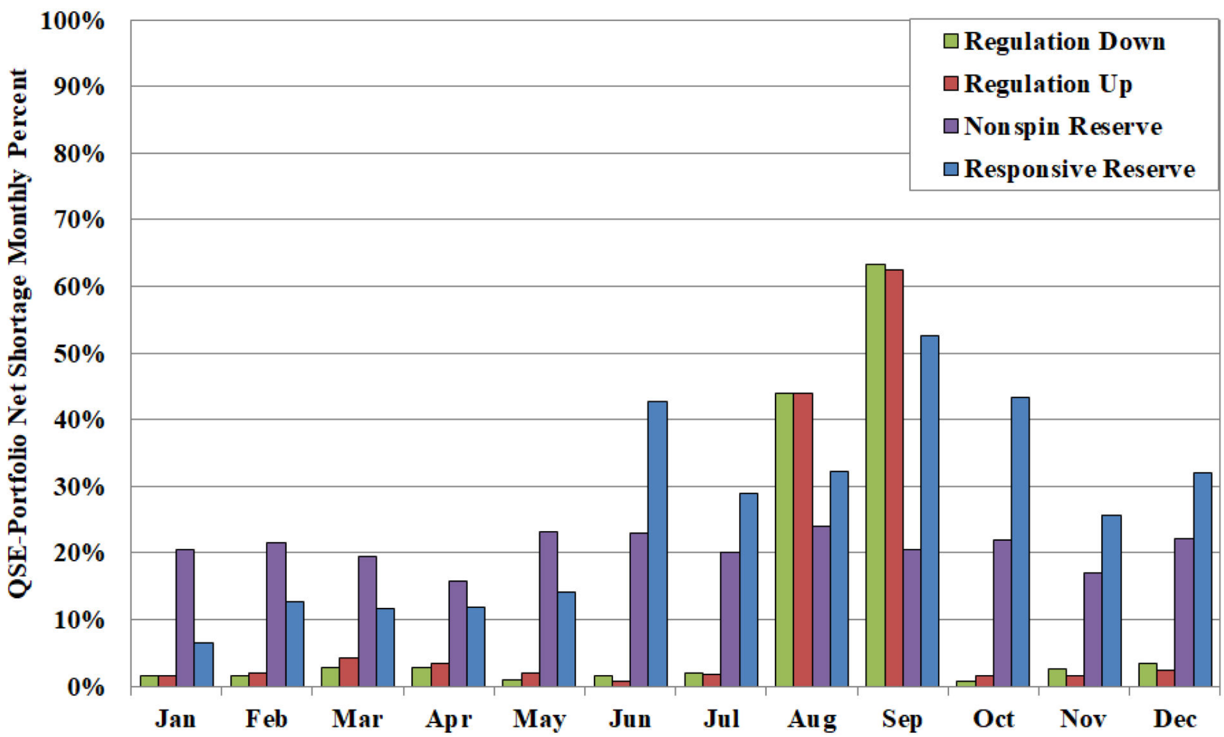
[65] A breakdown of ancillary service providers by QSE, by type of service provided, can be found in Figure A16, Figure A17, Figure A18, and Figure A19 in the Appendix.

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 0 of the Appendix for more information on SASM activity in ERCOT in 2022.

Finally, QSEs do not always provide the ancillary services that they are responsible for providing via a combination of day-ahead awards, self-arrangement, or trades. Figure 29 below shows the percentage of each month during which there was at least one QSE that did not satisfy its full ancillary services responsibility. A shortage is defined as greater than 0.1 MW of obligation not being provided for at least 15 minutes out of an hour. It does not necessarily mean that the QSE was charged for the shortage.

Figure 32 shows that deficiencies of QSEs in meeting their ancillary service responsibilities were pervasive again in 2022, especially in August and September. For market participants that do not meet their ancillary service responsibility, ERCOT can claw back the payment the QSE received in the day-ahead market for the amount it was paid to provide the service in real-time but did not. This claw-back process does not occur automatically but must be completed manually. NPRR1149, *Implementation of Systematic Ancillary Service Failed Quantity Charges* was approved in March 2023 and updates the protocols to make this process automated.

Figure 29: QSE-Portfolio Net Ancillary Service Shortages in 2022



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 75% of 2022.

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 day-ahead market. 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 2022. We first discuss the congestion costs in the day-ahead and real-time markets, which total $2.3 billion and $2.8 billion respectively, in 2022. We then discuss the CRR markets and funding in 2022.

A. Day-Ahead and Real-Time Congestion

As the day-ahead market 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 30 and Figure 31 summarize the monthly and annual congestion costs in the day-ahead and real-time markets. The values are aggregated by geographic zone.

Figure 30 shows that the total day-ahead congestion costs in 2022 were roughly 69% higher than costs in 2021, while real-time congestion costs increased 37% over the same time. The largest percentage difference in congestion costs between day-ahead and real-time were in cross-zone seeing an increase in 53%, followed by South with 23% and the West zone at 21%.

Figure 30: Day-Ahead Congestion Costs by Zone

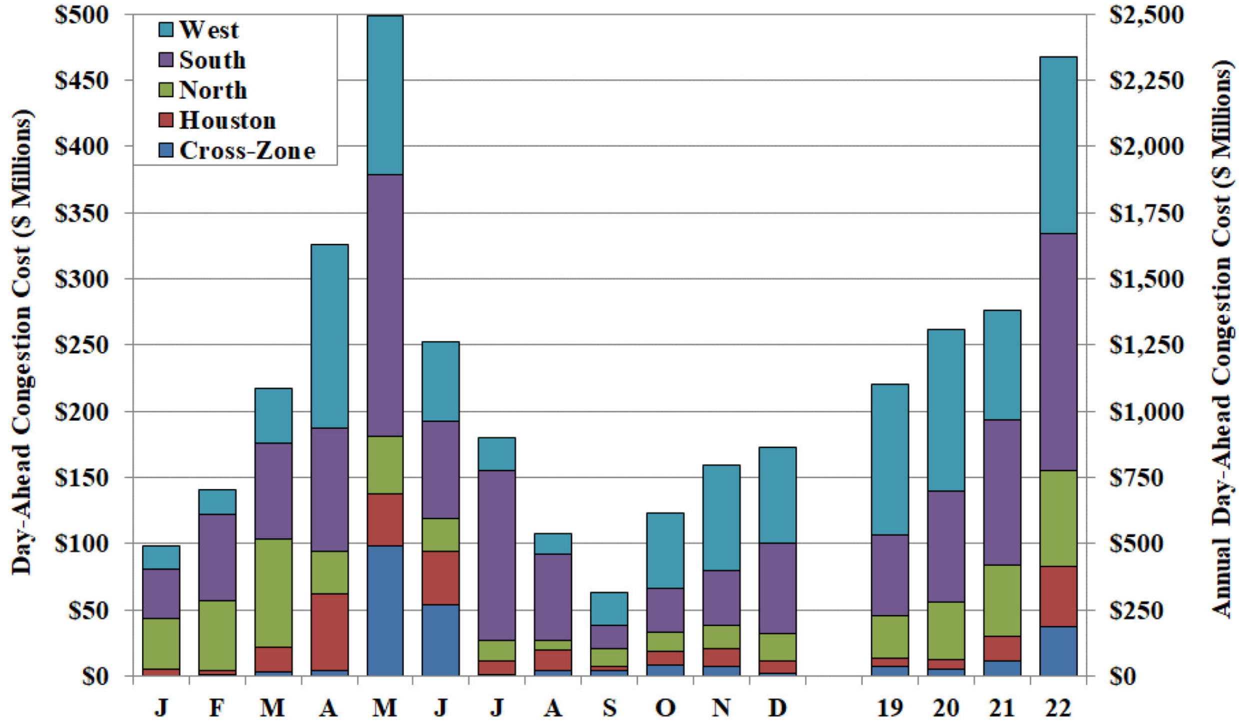
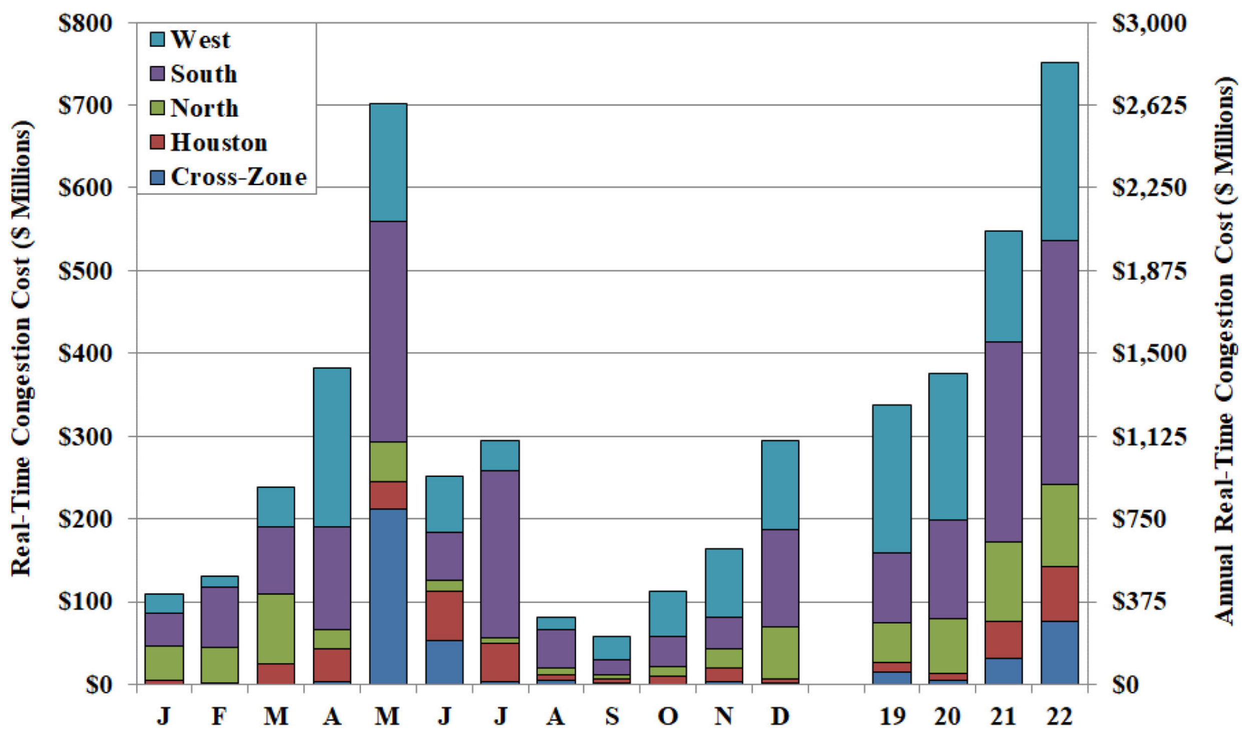


Figure 31: Real-Time Congestion Costs by Zone



The 2022 monthly congestion profile shows that congestion was highest in the late spring, especially in April and May. This is a somewhat atypical pattern and caused by an increase in significant transmission and generation maintenance outages and repairs in preparation for the hot summer months to follow. April experienced higher congestion from the West Texas Export GTC due to outages in the West, whereas May exhibited higher congestion because of outages into Houston affecting flows from both North and South into Houston. The limitation on allowing any outages in the summer months has significantly affected outage scheduling.

The largest zonal contributor to congestion costs in 2022 was the South zone, primarily caused by higher congestion activity in the Rio Grande Valley and flows from Port Lavaca into Houston. Cross-zonal congestion spiked in May due to outages along the North to Houston corridor to accommodate new transmission structures. The West zone, which had similar aggregate congestion costs between 2021 and 2020, had congestion driven by high intermittent renewable output coupled with oil and gas loads. 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 day-ahead market, 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, we evaluate and discuss real-time constraints and associated congestion in the section.

1. Types and Frequency of Constraints in 2022

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.[66]

The RTCA evaluates the resulting network flows under many 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.[67] Active transmission constraints are those that are modeled in the dispatch software. 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 have no effect on prices.

66 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).

67 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.

Our review of the active and binding constraints during 2022, Figure 32, shows the following:

- The ERCOT system had at least one binding constraint 75% of the time in 2022, an increase from 70% in 2021 and on par with 75% from 2020.
- Consistent with previous years, the average number of active constraints generally decreased with increasing load level.
- On average, nine constraints were identified for the higher load levels, down from approximately twelve in 2021.

Figure 32: Frequency of Binding and Active Constraints by System Load Level

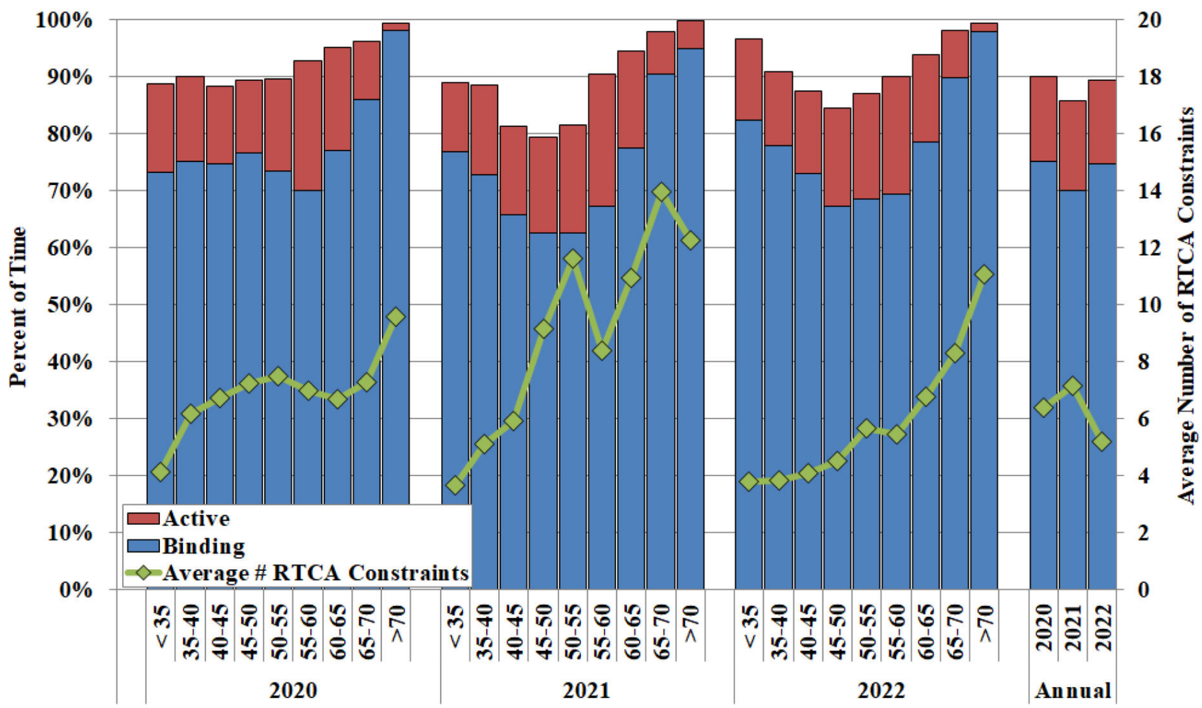


Table 4 shows the individual GTCs and the number of binding intervals during 2021 and 2022. The number of GTC binding intervals in 2022 was nearly identical to the number in 2021 and the associated congestion represented 23% of real-time congestion rent. GTCs are used to ensure that the generation dispatch 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.

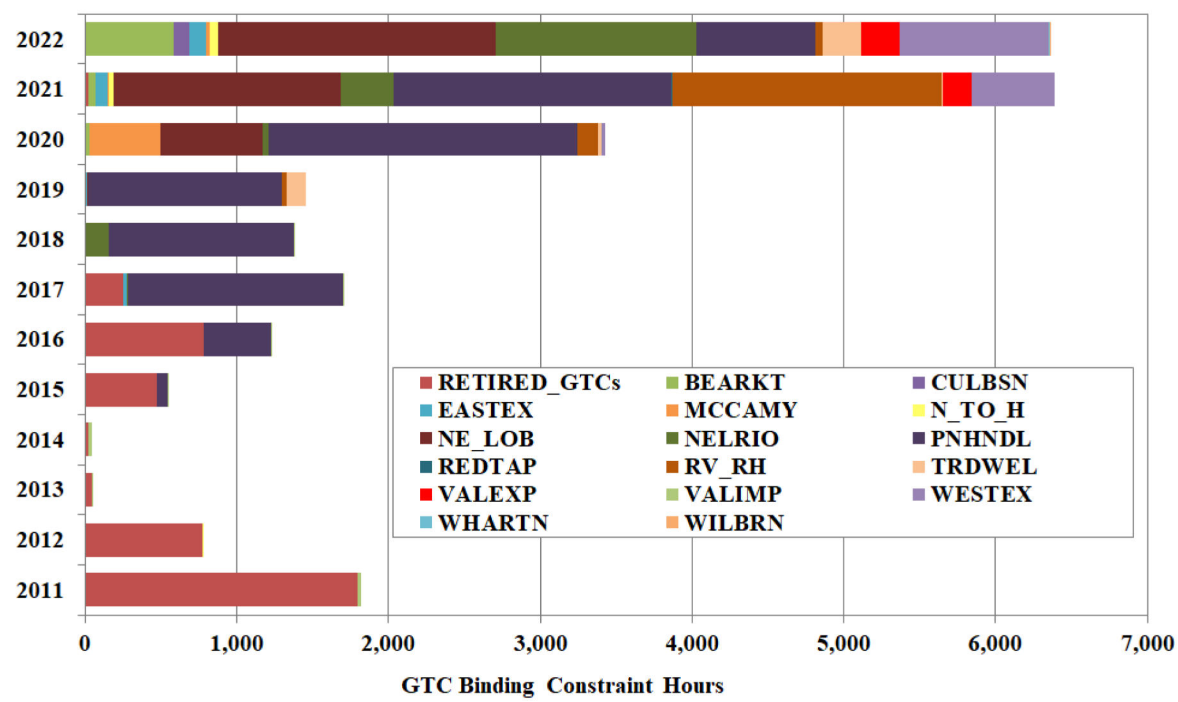
ERCOT has been working on getting better data for the full range of inverter technologies, which will allow all GTC limits to be calculated in real-time rather than using more conservative offline studies. This should result in less congestion and generation curtailment. Apart from the North to Houston,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

Table 4: Generic Transmission Constraints

Generic Transmission Constraint	Effective Date	# of Binding Intervals in 2021	# of Binding Intervals in 2022
North to Houston	December 1, 2010	377	657
Rio Grande Valley Import	December 1, 2010	-	-
Panhandle	July 31, 2015	22,416	9,530
Red Tap	August 29, 2016	64	-
North Edinburg - Lobo	August 24, 2017	18,451	22,371
Nelson Sharpe - Rio Hondo	October 30, 2017	4,271	16,166
East Texas	November 2, 2017	967	1,395
Treadwell	May 18, 2018	103	3,021
McCamey	March 26, 2018	152	322
Raymondville - Rio Hondo	May 2, 2019	21,884	631
Bearkat	November 20, 2019	547	7,059
West Texas Export	October 1, 2020	6,720	11,848
Zapata - Starr	Novemeber 5, 2020	-	-
Valley Export	Novemeber 5, 2020	2,351	3,157
Culberson	March 4, 2021	-	1,254
Williamson-Burnet	May 6, 2021	-	21
Wharton County	May 5, 2022	NA	93
Hamilton	August 3, 2022	NA	-

Figure 33 shows the aggregate number of hours in which GTCs were binding from 2011 to 2022. It shows the increase in binding hours in 2021, which continued in 2022.

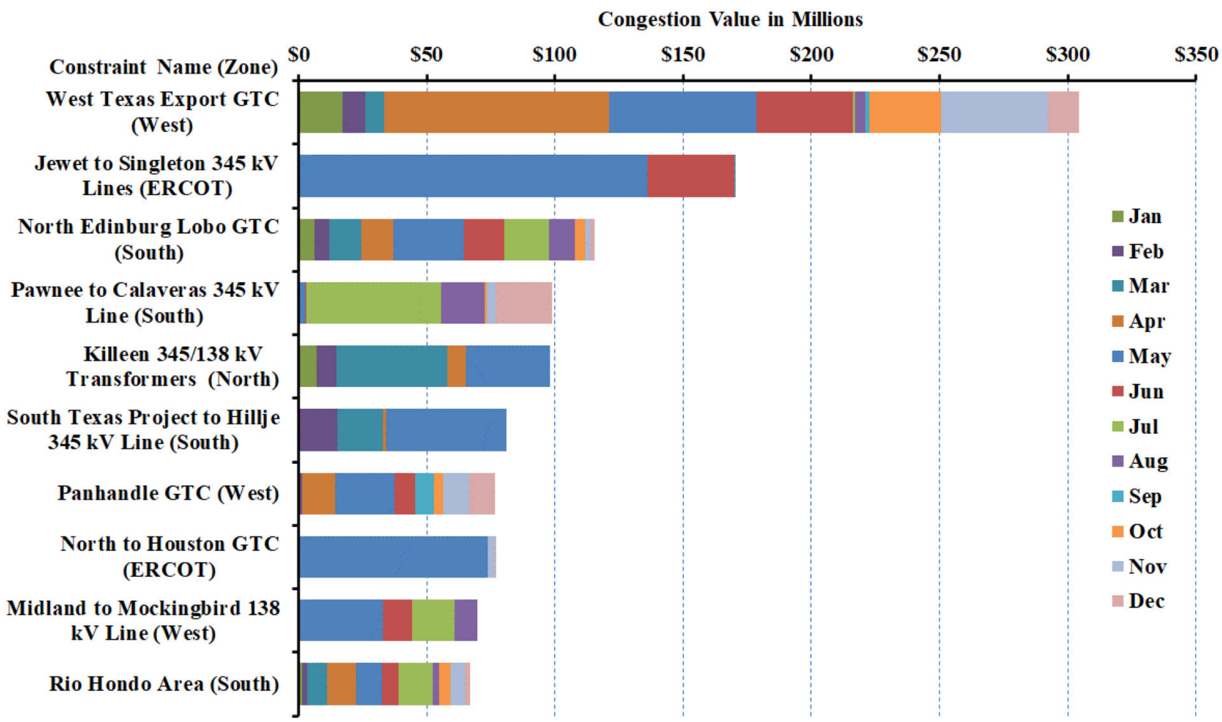
Figure 33: GTC Binding Constraint Hours



2. Real-time Constraints and Congested Areas

Our review of real-time congestion is based on its economic value, calculated by multiplying the shadow price of each constraint by the flow over the constraint. The shadow price is the marginal cost of the redispatch necessary to manage the constraint and, therefore, the benefit of relieving the constraints. 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. Figure 34 displays the ten most costly real-time constraints with their respective zone measured by congestion value.

Figure 34: Most Costly Real-Time Congested Areas



There were 536 unique constraints that were either binding or violated at some point during 2022, with a median financial impact of approximately $469,000. In 2021, there were 526 unique constraints with a median financial impact of $310,000. The constraint with the highest congestion value in 2022 ($304 million) was the West Texas Export GTC constraint, which was mostly caused by transmission maintenance outages in the West and high renewable output. The constraint with the highest value in 2021, the Panhandle GTC ($129 million), fell to seventh in 2022, because of the resolution of CREZ maintenance outages completed in 2022.

The constraints on the Jewet to Singleton 345 kV Lines, South Texas Project to Hillje 345 kV Line, and North to Houston GTC primarily occurred in May to accommodate new transmission structures along the North to Houston corridor. The Pawnee to Calaveras 345 kV Lines, Killeen 345/138 kV Transformers, Midland to Mockingbird 138 kV Line 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, and Rio Hondo Area. ERCOT highlighted these areas in the 2022 Long-Term System Assessment (LTSA) report within the ERCOT Constraints and Needs Report. [68]

Day-ahead congestion costs were highest on the top three paths discussed above. Day-ahead congestion costs totaled roughly $2.3 billion, less than the $2.8 billion that accrued in the real-time market. This difference generally reflects the divergence between expectations in the day-ahead market and actual real-time outcomes. In most months, less wind generation scheduled in the day-ahead market is a key factor. Figure A25 in the Appendix presents additional detail on real-time congested areas with their respective zones in 2022.

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.[69] The shadow price caps during 2022 were:

- $5,251 per MW for base-case (non-contingency) constraints or voltage violations,[70]
- $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 $5,251 per MW. Figure 35 shows the distribution of the percentage overload of violated constraints between 2021 and 2022. A more detailed review of violated constraints can be found in Figure A24 in the Appendix. Violated constraints continued to occur in a small fraction of all constraint intervals – 3% in 2022, down from 4% in 2021.

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68 *See* Report on Existing and Potential Electric System Constraints and Needs, December 2022; https://www.ercot.com/files/docs/2022/12/22/2022_Report_on_Existing_and_Potential_Electric_System_Constraints_and_Needs.pdf

69 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*.

70 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 from $9,251 per MW to $5,251 per MW effective April 1, 2022.

Figure 35: Overload Distribution of Violated Constraints

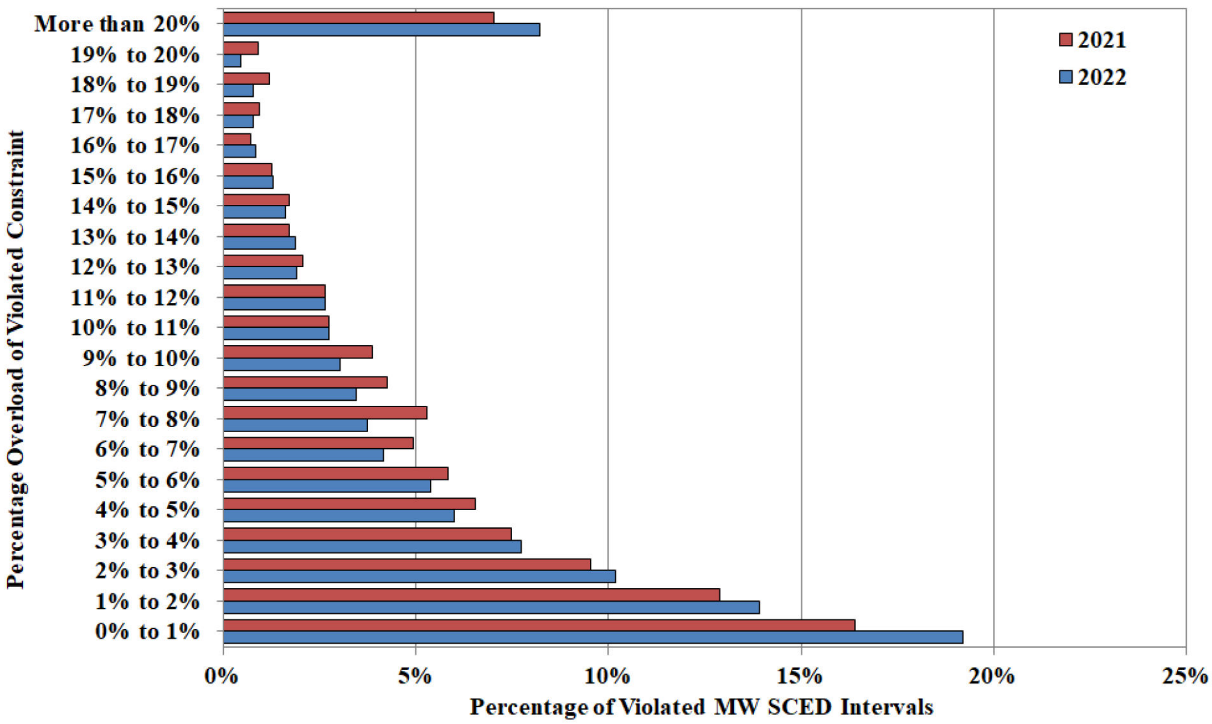


Figure 35 shows that number of SCED intervals at the various violated constraint percentages is roughly the same in 2021 and 2022. Over 30% of the constraints in 2022 were in violation by only small amount (between 0-2% of the transmission element rating), yet they are priced at the same shadow price cap as the more severe violations. 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 in 2022 for lack of support.[71]

Violations may be resolved in ensuing intervals as resources ramp up to provide relief. A constraint-specific peaker net margin mechanism is nonetheless applied such that once local

71 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.

price increases reach a predefined threshold, the constraint is deemed irresolvable and the constraint's shadow price cap is recalculated based on the mitigated offer cap of existing resources and their ability to resolve the constraint.[72] Table A4 in the Appendix shows that 10 elements were categorized as irresolvable in 2022 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 day-ahead market congestion.

1. 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. Parties receiving PCRRs pay only a fraction of the auction value of a CRR between the same locations.

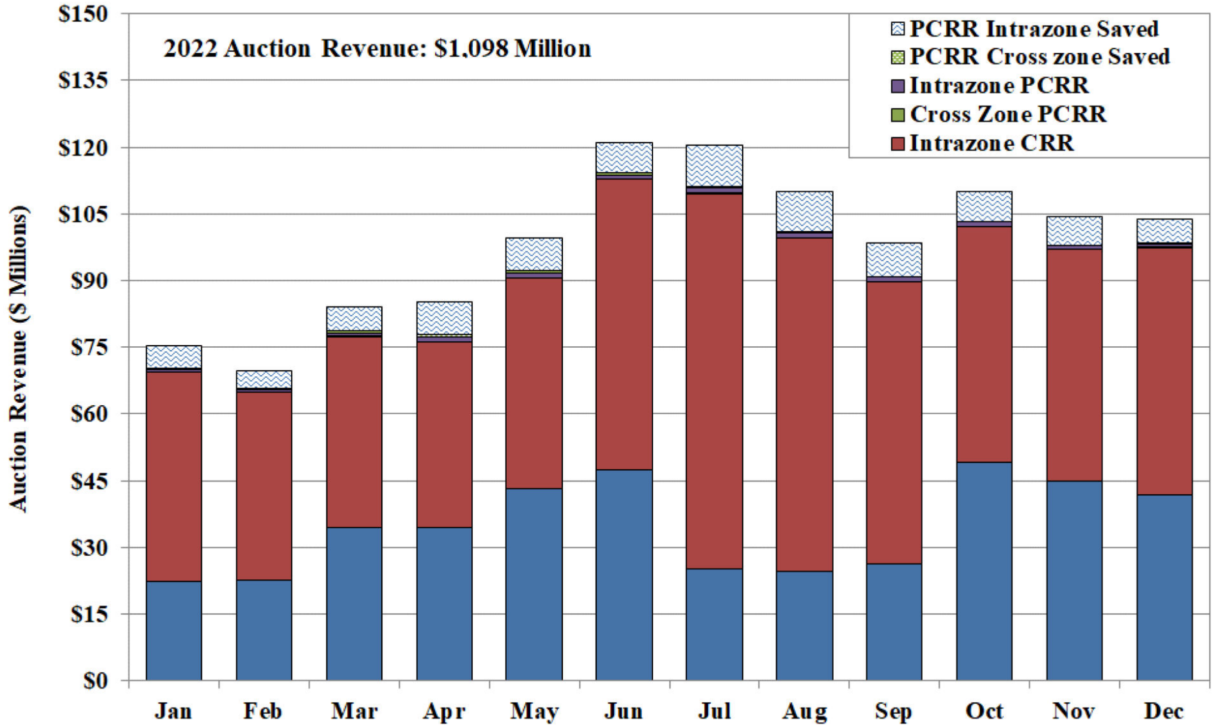
ERCOT has implemented third year CRR auctions, which caused more transmission capacity to be sold in advance of the monthly auctions. Opportunities to purchase CRRs earlier improve forward hedging and add liquidity. However, earlier purchases can also increase differences between CRR auction revenue and day-ahead payouts because earlier sales occur with more 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 36 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 $1,098 million in 2022, a 32% increase from the $831 million in 2021 (and up significantly from $725 million in 2020 and $612 million in 2019). The total PCRR discount increased from $76 million in 2021 to $84 million in 2022. These increases reflect a yearly trend of an increased expectation of congestion in 2022.

72 *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 36: 2022 CRR Auction Revenue

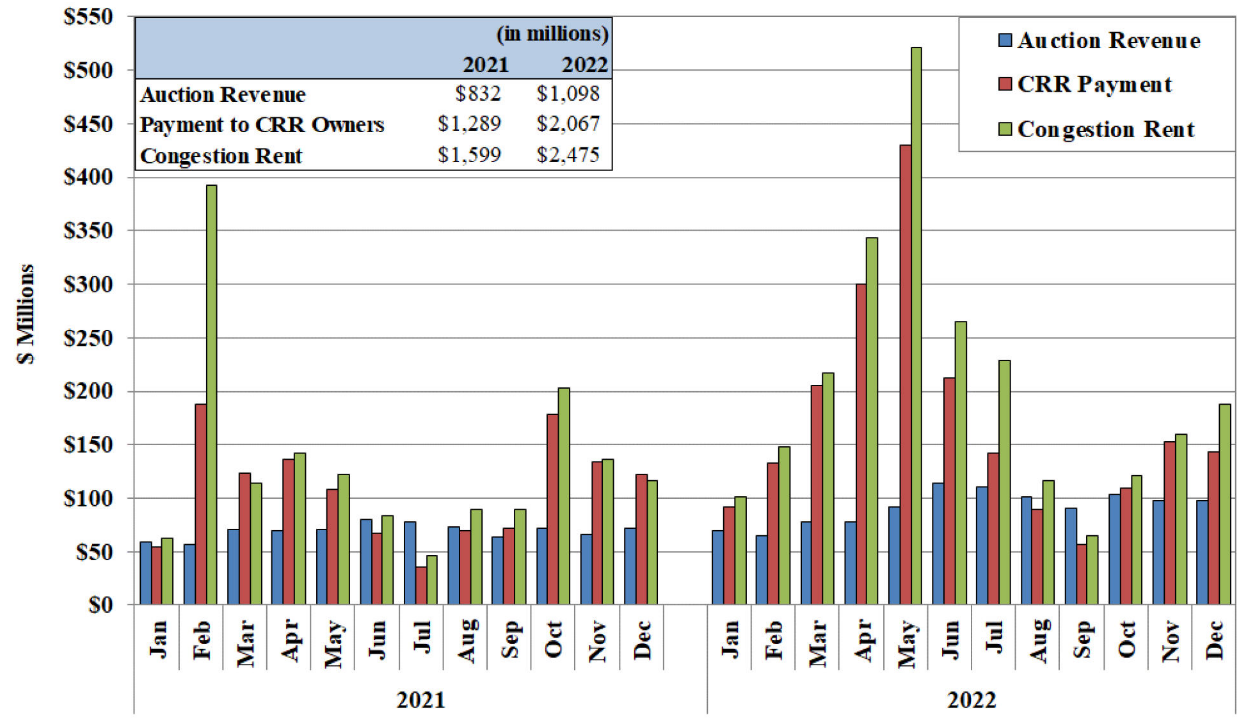


2. CRR Profitability

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 2022 with participants again paying much less for CRRs they procured than their ultimate value. To evaluate these results, Figure 37 shows the 2022 monthly CRR auction revenue, the day-ahead congestion rent collected to fund the CRRs, and the payout to the CRR owners.

Figure 37 shows that for the entire year, participants spent $1,098 million to procure CRRs and in aggregate received $2,067 million. There is a continuing annual trend of increased congestion that is not foreseen by the market in the forward auction periods, in conjunction with the time value of money and with CRR obligation risk. In 2022, the period from March through June was associated with the highest payment levels and the greatest differences between auction revenues and payments. The period of congestion that accounted for most of this difference was May, which was due to constraints in the Houston area that were not able to be well-modeled in the CRR auction. The year over year change in payments from 2021 to 2022 increased by more than 60%, a significant contrast to the period from 2020 to 2021 that saw consistent year over year payments.

Figure 37: 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 2022 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 August and September in 2022.

Finally, the payout can be less than the congestion rent collected in the day-ahead market when the quantity of CRRs sold is less than the day-ahead network flows. This occurred in 2022, when the payout in aggregate was approximately $400 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 undersold on average. Excess congestion rent will be discussed in the next subsection. It is instructive to review these three values over a longer timeframe, so Figure 38 provides the annual CRR auction revenues, payments to CRR owners and day-ahead congestion rent.

Figure 41 shows that 2022 marked a continuation of the five-year trend of CRR payments becoming increasingly profitable relative to the initial CRR auction revenues. The big jumps in congestion year-to-year were not well foreseen or modeled in the CRR auction due to the continued expansion of renewables, changes to GTCs, and high load growth. Note that this “profit” does not account for the time value of money, which is notable because a CRR is paid for at the time of the auction and those auctions can be as much as three years in advance.

Figure 38: CRR History

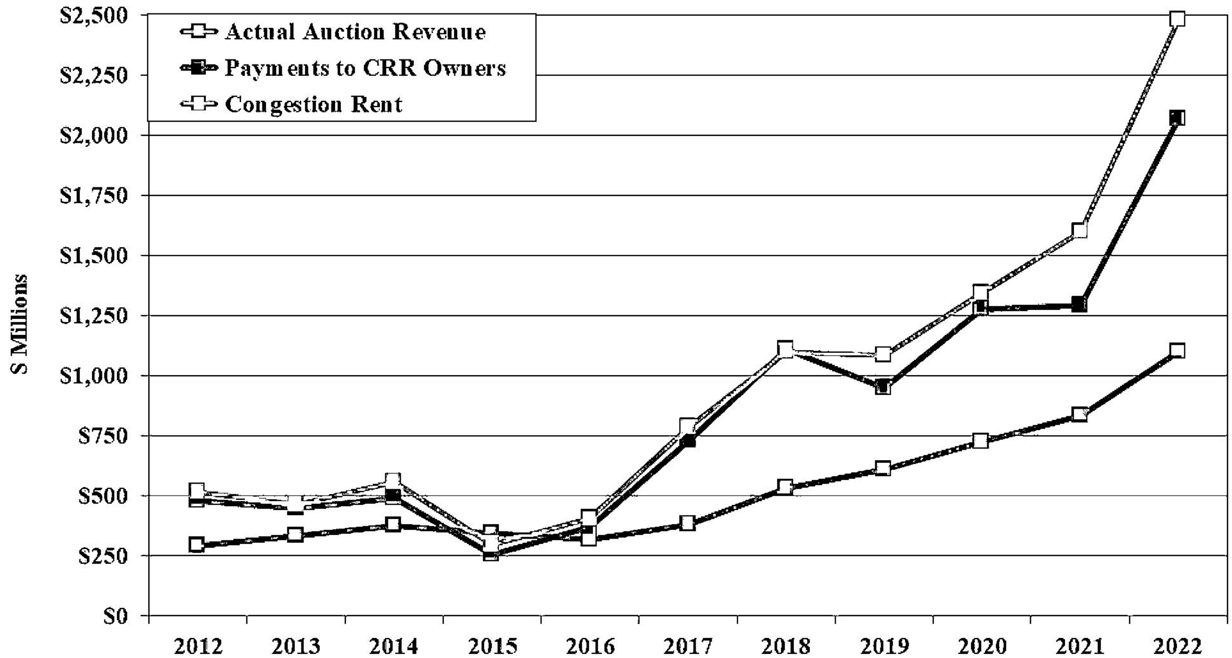


Figure 38 shows that actual congestion continues to rise more quickly than CRR auction revenues, although these revenues have been increasing in recent years. This is not unexpected because the markets must forecast the actual revenues and, even after the congestion has begun to materialize, must determine whether it will be sustained.

3. CRR Funding Levels

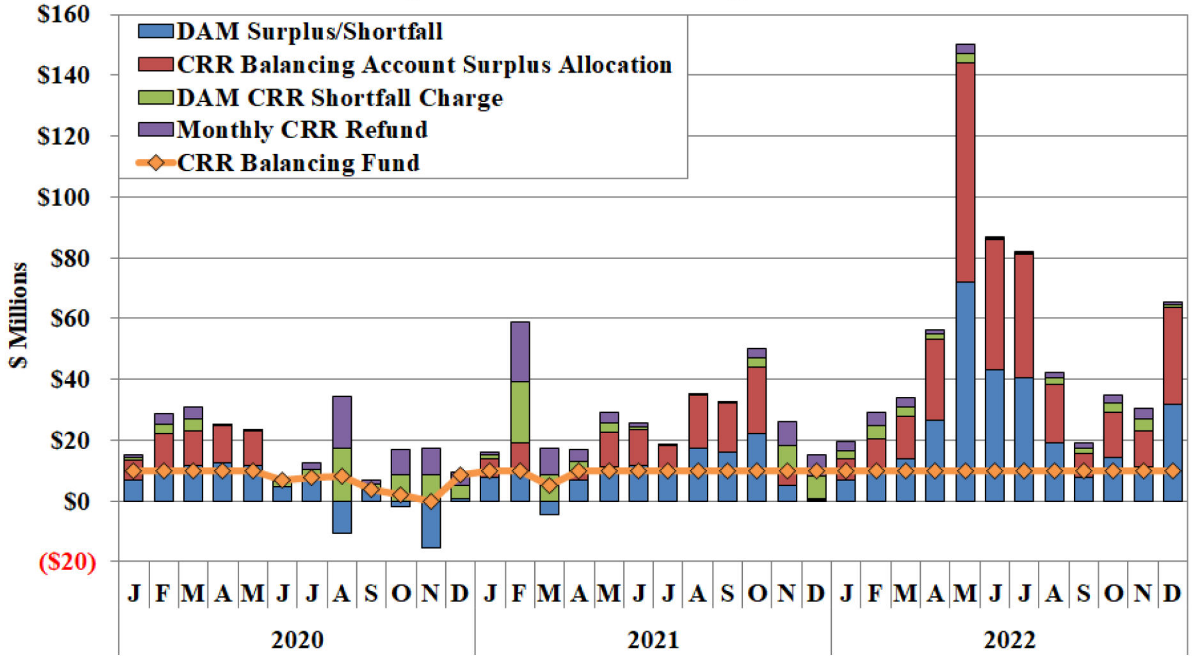
The target value of a CRR is the quantity of the CRR multiplied by the price difference between sink and source. It is desirable for the payout to fully equal the target value because it makes the CRR more valuable to the holder and ultimately will increase the CRR auction revenues. While the target value is paid to CRR account holders most of the time, ERCOT will pay less than the target value when the day-ahead congestion rent is insufficient (i.e., CRRs are not "fully funded"). This occurs when the CRRs' network flows exceed the capability of the day-ahead network. This is generally the result of unforeseen outages or other factors not able to be modeled in the CRR auction but that are modeled in the day-ahead market, reducing the network's transfer capability.

If this occurs on specific line or transformer (i.e., the flows on the line or transformer are "oversold"), CRRs that sink at resource nodes (generator locations) that affect the flows on the oversold transmission element have the potential to be "derated" based on the day-ahead capability of the element. Here, derated means that the CRR owner is not paid the full target value. After this deration process, if there are residual shortfalls then all holders of positively valued CRRs will receive a prorated shortfall charge. This shortfall charge has the effect of lowering the net amount paid to CRR account holders in the day-ahead settlement.

Sometimes there is excess day-ahead congestion rent that has not been paid out to CRR account holders at the end of the month (undersold hours). In that case, the excess congestion rent is tracked in a monthly settlement process referred to as the balancing account. Excess congestion rent residing in this balancing account is used to make the CRR account holders that received shortfall charges whole, i.e., they are refunded their shortfall charges. If there is not enough excess congestion rent from the current month to refund all shortfall charges, the rolling CRR balancing fund from prior months can be used to fully pay CRR account holders that received shortfall charges. Figure 39 shows the CRR balancing fund since the beginning of 2020. The CRR balancing fund has a $10 million cap, beyond which the remaining is dispersed to load.

The fact that ERCOT's processes are designed to only sell 90% of the forecasted transmission capability makes funding shortfalls less likely. Figure 39 shows that the total day-ahead surplus was nearly $300 million, an increase of approximately 169% year-over-year ($111 million surplus in 2021 and $42 million surplus in 2020). The total monthly CRR balancing account allocation to load fell by more than 50% year-over-year to approximately $27 million.

Figure 39: CRR Balancing Fund



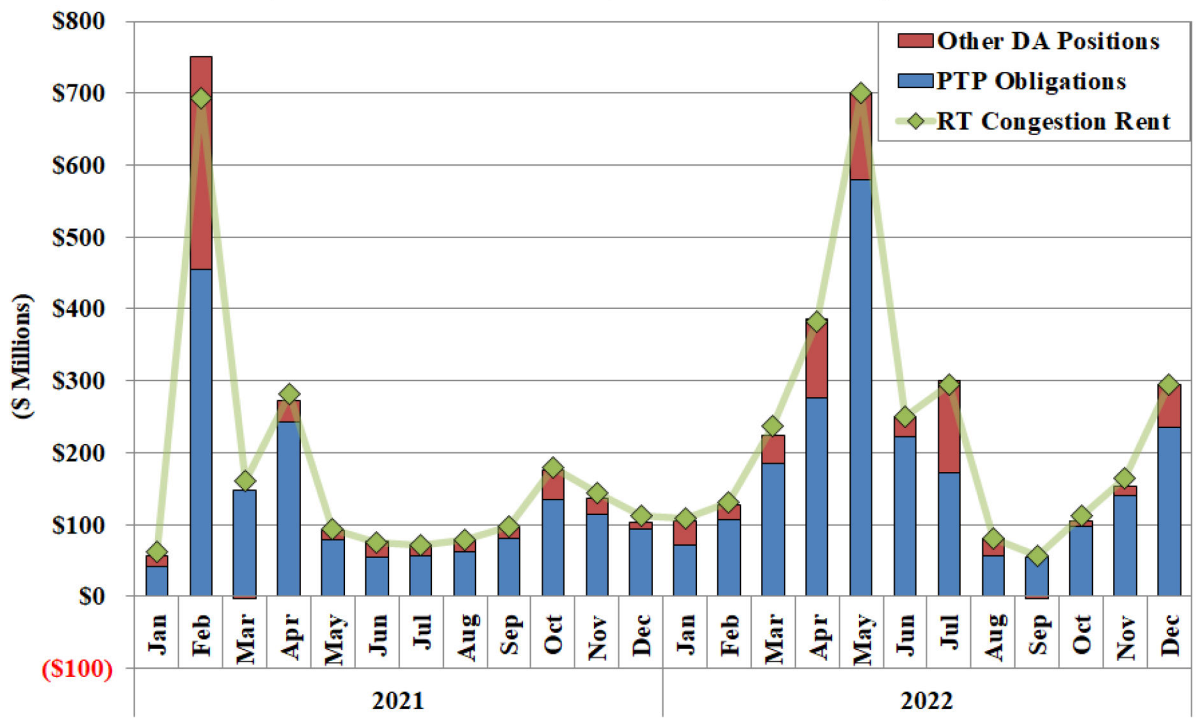
Importantly, even though the day-ahead market produced more than enough revenues to fully fund the CRRs, many CRRs were derated in 2022 and not paid the full target value due to the mandatory deration process. In total, CRR deratings resulted in a $15 million reduction in payments to CRR holders. These deratings reduced ERCOT's overall funding percentage to 99%, about the same as the previous year. ERCOT's deratings and shortfalls are shown on a monthly basis in Figure A27 in the Appendix. Derating CRRs, especially when the market is producing sufficient revenue to fully fund them, introduces unnecessary risk to those buying CRRs, which ultimately results in lower CRR auction revenues.

4. Real-Time Congestion Shortfalls

Just as reductions in network capability from the CRR auctions to the day-ahead market can result in CRR shortfalls, reductions in the network capability between the day-ahead market and the real-time market can result in real-time congestion shortfalls. In addition to outages or limit changes, a binding real-time constraint that is not modeled in the day-ahead market can result in real-time congestion shortfalls. In summary, if ERCOT schedules more network flows in the day-ahead market than it can support in real time, then costs must be incurred in real time to provide revenue neutrality. These real-time congestion shortfall costs are paid for by charges to load as part of the uplift charge known as Real-Time Revenue Neutrality Allocation or "RENA".

The day-ahead schedule flows are comprised of PTP obligations and other day-ahead positions that generate flows over the network. Figure 40 shows the combined payments to all these day-ahead positions compared to the total real-time congestion rent.

Figure 40: Real-Time Congestion Rent and Payments



In 2022, real-time congestion rent was $2,815 million, while payments for PTP obligations (including those with links to CRR options) were $2,193 million and payments for other day-ahead positions were $584 million. This resulted in a surplus of approximately $38 million for the year. By comparison, payments for PTP obligations and options were $1,563 million in 2022 and payments for other day-ahead positions were $489 million. Higher congestion cost can also drive higher shortfall amounts. In general, ERCOT has improved in coordinating the network capability in its day-ahead and real-time market. Continuous improvement in this area should be the goal of all ISOs.

VI. RELIABILITY COMMITMENTS

One important characteristic of any electricity market is the extent to which it results in the efficient commitment of generating resources. Under-commitment can cause shortages in the real-time market and inefficiently high energy prices, while over-commitment can result in excessive production costs, uplift charges, and inefficiently low energy prices.

The ERCOT market does not include a mandatory centralized unit commitment process. The decision to start-up or shut-down a resource is made by the market participant. ERCOT's day-ahead market informs these decisions, but schedules are only financially binding – there is no requirement to actually start a resource, although it must buy back the energy at real-time prices if it does not. This decentralized commitment depends on price signals to ensure an efficient combination of units are online and available for dispatch. In its role as reliability coordinator, ERCOT has the responsibility to commit units outside the market to ensure the reliable operation of the grid through its RUC process. In this way, ERCOT bridges any gaps between the economic decisions of its suppliers and the reliability needs of the system.

RUC-committed resources are eligible for make-whole payments, but forfeit some or all market profit through a claw-back provision. Generators complying with a RUC instruction are guaranteed to recover their costs, but any market revenue received in excess of their costs are either partially or fully clawed back. However, suppliers can opt to forfeit the make-whole payments and waive the claw-back charges, effectively self-committing the resource and accepting the market risks.

From a market pricing perspective, ERCOT applies an offer floor of $250 per MWh to the resource's offer and calculates a Real-Time On-Line Reliability Deployment Adder (reliability adder) that was described in Section I. In the past four years, ERCOT made improvements to the RUC process relating to fast-starting generators (those that can come online within two intervals) and switchable generators that are dually connected to other control areas. These improvements had caused the number of RUCs to drop dramatically, a trend that ended suddenly in June 2021 when ERCOT adopted its much more conservative operational posture. For a complete list of the historical changes in the RUC processes and rules, see Section VI in the Appendix.

In this section, we describe the outcomes of RUC activity in 2022, including the sustained increase in RUC activity due to ERCOT's more conservative operating posture. In 2021, RUC activity picked up significantly after June 2021 when ERCOT adopted much more conservative operating procedures. Part of that approach included bringing more generation online and doing so earlier in the day. That trend continued throughout 2022. We evaluate how that affected the relationship of the Physical Responsive Capability (PRC) to ORDC reserves (RTOLCAP). We also describe the COP data submitted by QSEs and used by ERCOT to determine the need for a RUC, whether for capacity or local congestion.

A. RUC Outcomes and Effects

ERCOT continually assesses the adequacy of market participants' resource commitment decisions using the RUC process, which executes both on a day-ahead and hourly basis. Additional resources may be needed for two primary reasons:

- To satisfy the forecasted system-wide demand (87% of RUC commitments in 2022); or
- To manage a transmission constraint (13% of RUC commitments in 2022).

In this subsection, we summarize the trends in RUC commitments by ERCOT and discuss its effects on participants and overall costs.

1. Summary of RUC Activity

In 2020, all RUC commitments were issued to manage transmission congestion. However, that changed in 2021 as RUC activity increased with most of them being made for capacity. 4,052 unit-hours of RUC instructions were issued in 2021, compared to the 224 unit-hours in 2020, the highest number since the start of the nodal market. In 2022, that number more than doubled, up to 8245 unit-hours of RUC-instructions, far beyond any other year of the nodal market.

Figure 41 shows RUC activity by month for the past three years, indicating the volume of generators receiving a RUC instruction that had offers in the day-ahead market or chose to opt-out of the RUC instruction. It shows the tremendous and steady increase in RUC since the latter half of 2021, peaking in September 2022 under ERCOT's new conservative operational posture.

Figure 41: Day-Ahead Market Activity of Generators Receiving a RUC

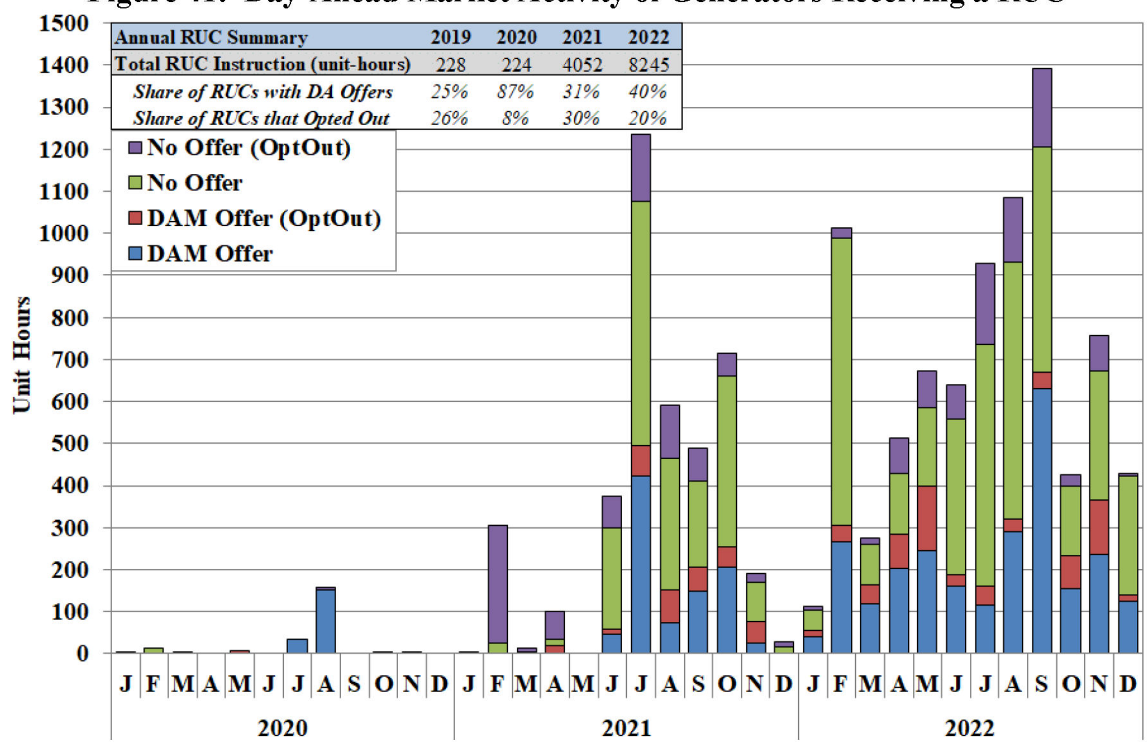


Table 5 below lists the generation resources that received the most RUC instructions in 2022 and includes the total hours each unit was settled as a RUC and the number of hours in which the unit opted out of RUC settlement. Almost 90% of the RUC-Resource hour instructions for 2022 were for capacity, and the other 10% was for congestion. The RUC instructions were geographically distributed as follows: 16% in the South zone, 16% in the West zone, 8% in the Houston zone, and the remaining 59% in the North zone, similar to the distribution in 2021.

Table 5: Most Frequent Reliability Unit Commitments

Resource	Location	Unit-RUC Hours	Unit-OPTOUT Hours	Average LSL during Dispatchable Hours	Average Dispatch during Dispatchable Hours	Average HSL during Dispatchable Hours
Stryker Creek Unit 2	DFW	628	65	75	95	491
Graham Unit 1	DFW	605	1	51	57	234
Graham Unit 2	DFW	580	1	43	56	393
Trinidad Unit 6	DFW	490	18	50	60	236
Lake Hubbard Unit 1	DFW	362	87	85	99	355
Lake Hubbard Unit 2A	DFW	299	358	90	246	493
Braunig VHB2	San Antonio	263	81	60	71	190
R W Miller STG 2	DFW	242	24	38	37	116
Handley Unit 3	DFW	212	10	102	108	374
Stryker Creek Unit 1A	East Texas	207	93	38	46	166
R W Miller STG 3	DFW	204	90	40	41	190
Powerlane Plant STG1	DFW	156	-	10	9	18
Handley Unit 5	DFW	139	9	120	124	377
Handley Unit 4	DFW	131	16	120	122	435

Figure 45 compares the average real-time dispatched output of the reliability-committed units, including those that opted out, with the average operational limits of the units. It shows that:

- The monthly average SCED dispatch of units receiving RUC instructions has rarely been close to the average high limit, with 2022 being no exception.
- The average quantity dispatched is very close to the respective average low sustainable limit (LSL) for all months in 2022 with RUC instructions, primarily because of the $250 per MWh offer floor.

Some RUC resources are dispatched above their LSLs because they are mitigated when resolving non-competitive constraints. That mitigation eliminates the $250 per MWh offer floor for those resources in those RUC intervals and dispatches them on their mitigated offer curve. Section VI in the Appendix provides more detail on the RUC activity, showing total activity by month, statistics on day-ahead offers and decisions to opt-out of the RUC instruction, as well as the RUC instructions issued to individual generating resources.