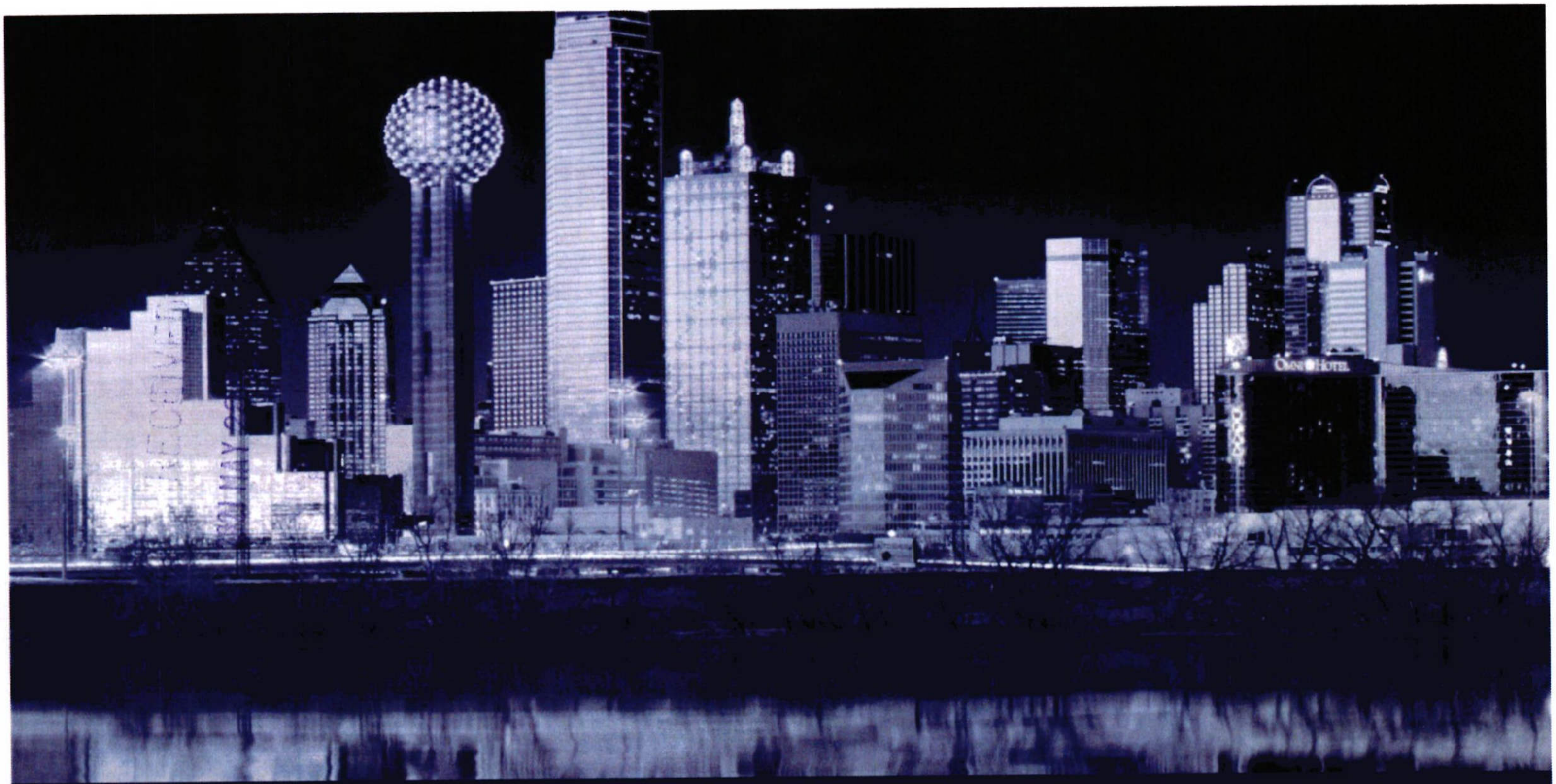

2020 State of the Market Report for the ERCOT Electricity Markets

POTOMAC
ECONOMICS

Independent Market Monitor
for ERCOT

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

EXECUTIVE SUMMARY

Potomac Economics provides this State of the Market Report for 2020 to the Public Utility Commission of Texas in our role as its Independent Market Monitor (IMM). The report assesses the outcomes of the wholesale electricity market in the Electric Reliability Council of Texas (ERCOT) region. Additionally, the report recommends improvements for the competitiveness and efficiency of the wholesale market and to ERCOT's operating procedures.

ERCOT manages the flow of electric power to more than 26 million Texas customers, or about 90% of the state's total electric demand. Every five minutes, ERCOT coordinates the electricity production from more than 710 generating resources those that will make electricity to satisfy customer demand and manage the resulting flows of power across the more than 46,500 miles of transmission lines in the region.

Overall, the ERCOT wholesale market performed competitively in 2020. Key results from 2020 include the following:

Market Power

- There is little evidence that suppliers abused market power in the wholesale market to raise system-wide prices.
- In some smaller areas of the region, transmission system limitations on the amount of power that can flow into the area can increase opportunities to abuse market power. However, offer price caps in these areas effectively addressed these opportunities in 2020.

Demand for and Supply of Electricity

- The highest electricity demand in 2020 was 74,328 megawatts, occurring on August 13th between 4 p.m. and 5 p.m. This was about 500 MW lowers than the all-time peak demand on August 12, 2019.
- Although the summer was generally warmer in 2020, which predictably increases electricity consumption, average consumption was slightly lower than in 2019 partly because of the effects of the COVID-19 pandemic.
- The supply of generation in the ERCOT region continues to evolve. More than 7,000 MW of new wind and solar resources and about 400 MW of natural gas supply started commercial operations in 2020.
- Approximately 1,000 MW of fossil-fuel resources were retired in 2020.

Market Outcomes and Performance

- Average energy prices decreased by 45% to $25.73 per megawatt-hour (MWh). This change was due primarily to a nearly 20% drop in natural gas prices and fewer instances of supply shortages, which result in very high market prices.
- Electric transmission networks can become congested when power flows reach the limit on a transmission line. The market resolves and prices such congestion results by incurring costs to alter generation in different locations.
  - Transmission congestions in the real-time market was up 11% in 2020, totaling $1.4 billion.
  - The expectation of this congestion is also reflected in ERCOT's day-ahead market prices and outcomes.
- In addition, ERCOT operators are increasingly reducing the amount of power that can flow across parts of the network to protect the stability of the system, which results in additional transmission congestion costs. These stability issues have partly been caused by the increase in renewable resources.

Changes to Improve Market Performance

- ERCOT continues its work to implement allowing its real-time market to optimize the scheduling of resources to provide energy or operating reserves every five minutes. Real-time co-optimization is planned to go live in 2025 and promises to significantly lower costs and improve pricing during supply shortages.
- ERCOT implemented two changes to accelerate the increase in prices as supply shortages emerge. These changes increased generator revenues by $400 million in 2020, and will have larger effects in years with more frequent supply shortages.
- ERCOT continues to plan for the integration of future technologies, such as Energy Storage Resources (ESRs) and Distribution Generation Resources (DGRs). Both technologies are beginning to enter, with ESRs entering more rapidly as their costs decline.

Winter Storm Uri

- While this report focuses on market outcomes from 2020, we find it important to raise a few initial issues related to Winter Storm Uri now so that the Public Utility Commission and market participants may consider corrective actions soon. A full analysis of the impacts of the February 2021 winter storm will be included in a future report.
- We offer two recommendations to address market design flaws that resulted in costly and inefficient pricing during the sustained winter event.

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

Market Power

We evaluate market power from two perspectives: structural (does market power exist?) and behavioral (have attempts been made to exercise it?). Based on our analysis, we find that structural market power continues to exist in ERCOT, but little evidence that suppliers abused market power in 2020.

Structural Market Power

In electricity markets, a more effective indicator of potential market power than traditional market concentration metrics is to analyze when a supplier is "pivotal." A supplier is pivotal when its resources are needed to fully satisfy customer demand or reduce flows over a transmission line to manage congestion. Over the entire ERCOT region:

- Pivotal suppliers existed 22% of all hours in 2020, compared to 24% in 2019.
- Under high-load conditions, a supplier was pivotal in more than 80% of the hours since competing supply is more likely to already be fully utilized.
- These results indicate that market power continues to exist in ERCOT and requires mitigation measures to address it.

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

Behavioral Evaluation

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

We examine the output gap metric to identify potential economic withholding. The output gap is the quantity of energy that is not produced by online resources even though the output would earn the supplier profits. Our analysis shows that in 2020, the output gap quantities were very small, and only 22% of the hours in 2020 exhibited an output gap of any magnitude.

Regarding potential physical withholding, we find that both large and small market participants made more capacity available to the market during periods of high demand in 2020 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 2020.

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 review and analyze these changes to assess these outcomes and the market's overall performance.

Demand in 2020

Although the summer was generally warmer in 2020, total demand for electricity in 2020 decreased by roughly 1% from 2019 – a decrease of approximately 360 MW per hour on average. This decrease partly reflect the effects of the COVID-19 pandemic.

Despite this overall reduction, the Houston area saw a 1.7% increase and the West Texas region showed an increase of 2.8%. The increase in the West zone is notable because it follows a 13% increase experienced in 2019. Continued oil and natural gas production activity in the West zone has been the driver for growing demand. However, the pandemic and low oil and gas prices slowed this growth trend in 2020.

Weather impacts on demand were mixed across all zones. We measure the impact weather has on electricity use by quantifying the amount by which the average daily temperatures are above or below 65° F. For example, cooling degree days are the number of days and degrees by which temperatures exceed 65° F. Residential and commercial electricity use increases quickly as the number of cooling degree days grows because of the demand for air conditioning. In June, July and August, cooling degree days increased 6% and 2% from 2019 in Dallas and Austin, respectively. In contrast, Houston experienced a 2% decrease from 2019.

Peak demand occurred on August 13, 2020, reaching 74,328 MW, slightly lower than the record demand. The level of peak demand is important because it affects the probability and frequency of supply shortage conditions. However, in recent years, peak *net* load (demand minus renewable resource output) has been a more important determinant of supply shortages. Supply shortage events are important in ERCOT because the very high prices during these events play a key role in supporting investment and maintaining the generation based in ERCOT.

Supply in 2020

Approximately 7,700 MW of new generation came online in 2020, including 7,250 MW of wind and solar resources. The amount of utility-scale solar capacity added in 2020 was the largest amount added to the ERCOT system in any one year, bringing total installed capacity to over 5,600 MW. In addition, 70 MW of battery energy storage resources began commercial operations in 2020. In addition, three resources retired permanently, representing a decrease of 1,030 MW.

These resource changes along with changes in fuel prices led to the following changes in electricity production in 2020:

- The percentage of total generation supplied by wind resources continued to increase, totaling almost 23% of all annual generation.
- The share of fossil-fuel generation declined in 2020: coal-fired generation dropped to roughly 18% and natural gas generation was flat at 46% of total generation in 2020.

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 2020 did not produce revenues sufficient to support profitable investment in new conventional resources, primarily because shortage pricing was infrequent and modest. Given the current reserve margins, this is expected and raises no substantial concerns.

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

Review of Market Outcomes and Performance

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

Real-Time Energy Prices

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

There are two primary drivers for market prices: the price of natural gas and the number of hours of supply shortages during the year. We expect electricity prices to track the rise and fall of natural gas prices in a well-functioning market because fuel costs represent the majority of most suppliers' production costs.

In 2020, the average natural gas price was lower than it has been in many years. Combined with the absence of significant supply shortage events, falling natural gas prices caused real-time energy prices to decrease to just under $26 per MWh. The following table shows the trend in prices throughout ERCOT in recent years.

Average Annual Real-Time Energy Market Prices by Zone

($/MWh)	2014	2015	2016	2017	2018	2019	2020
ERCOT	**$40.64**	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**
Houston	$39.60	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54
North	$40.05	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97
South	$41.52	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63
West	$43.58	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58
($/MMBtu)							
Natural Gas	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99

In addition to the falling prices in recent years, this table shows that prices vary across the ERCOT market because of transmission congestion that arises as power is delivered to consumers. The pattern of zonal in 2020 was fairly consistent with recent years, with the West zone experiencing the highest prices because of localized transmission congestion that raises prices in the area. The growth in renewable generation in the West can also cause congestion exporting the power from the area that lowers prices sharply in some hours.

As an energy-only market, ERCOT relies heavily on high real-time prices that occur during shortage conditions to provide key economic signals that govern the development of new resources and retention of existing resources.

The frequency and impacts of shortage pricing can vary substantially from year-to-year:

- Moderate weather and improved planning reserve margin in the summer of 2020 led to prices that exceeded $1,000 per MWh in just 7 hours in 2020 and prices did not exceed $5,000 in any hour.
- In comparison, prices were higher than $1,000 per MWh in more than 28 hours in 2019 and above $7,000 for more than 5 hours, including roughly 2 hours at the system-wide offer cap of $9,000 per MWh during the peak week of August 12, 2019.

In reviewing the shortage pricing in ERCOT, it is important to note the changes made by ERCOT over the past two years. Supply shortages are priced based on the value of operating reserves that ERCOT can no longer hold because of the limited supply. This value is embodied in the Operating Reserve Demand Curve (ORDC). When the system is in shortage, the relevant ORDC value will set operating reserve prices and be included in the energy price.

On March 1, 2020, ERCOT implemented the second of two rightward shifts to the ORDC.[1]

- The shifts accelerate the rise in prices to the Value of Lost Load (VOLL) of $9,000 per MWh as reserve shortages emerge and were made to ensure that shortage pricing effectively facilitates long-term investment and retirement decisions.
- These shifts increased the total effects of shortage pricing on average prices by $1 per MWh in 2020. This relatively small effect is attributable to the modest shortage conditions experienced in 2020.

Day-Ahead and Ancillary Services Markets

The day-ahead market allows participants to make financial commitments for purchases or sale of energy to be delivered the next day. There are no physical obligations that result from participation in the day-ahead market; rather, it serves as a method for participants to manage the risks related to exposure to real-time prices during the operating day. Day-ahead prices averaged $24 per MWh in 2020. This price closely aligns with prices from the real-time market and represents a change from the day-ahead premium in 2019. The relative stability of real-time prices and reduction of tight conditions reduced the risk premium reflected in day-ahead prices.

Ancillary services are products purchased in the ERCOT market on behalf of consumers to provide resources that can produce electricity quickly (or voluntarily reduce consumption). These operating reserves help ensure that ERCOT can continue to satisfy consumers' demand when unexpected things happen, such as the loss of a large generator or transmission line. Prices for ancillary services typically mirror the rise and fall of prices in the real-time energy market because the cost of selling ancillary services includes the profits a supplier would give up by not producing electricity. The average prices for most ancillary services fell by more than 50% in 2020 from 2019. This caused the total costs of ancillary services per MWh of electricity consumption to fall from $2.33 per MWh in 2019 to $1.00 per MWh in 2020, down. This decrease was largely because of the absence of extreme shortage pricing in 2020.

Transmission Congestion

Similar to an interstate highway system, congestion can arise when more power is flowing over a transmission line than it is designed to carry. Unlike a traffic jam, however, where cars can exit the highway and travel on side streets, power flows over the network are almost entirely the result of where power is produced and where it is consumed. Therefore, when a transmission line is becoming overloaded, ERCOT will incur costs to shift generation to other higher-cost generators in different locations to reduce the transmission congestion.

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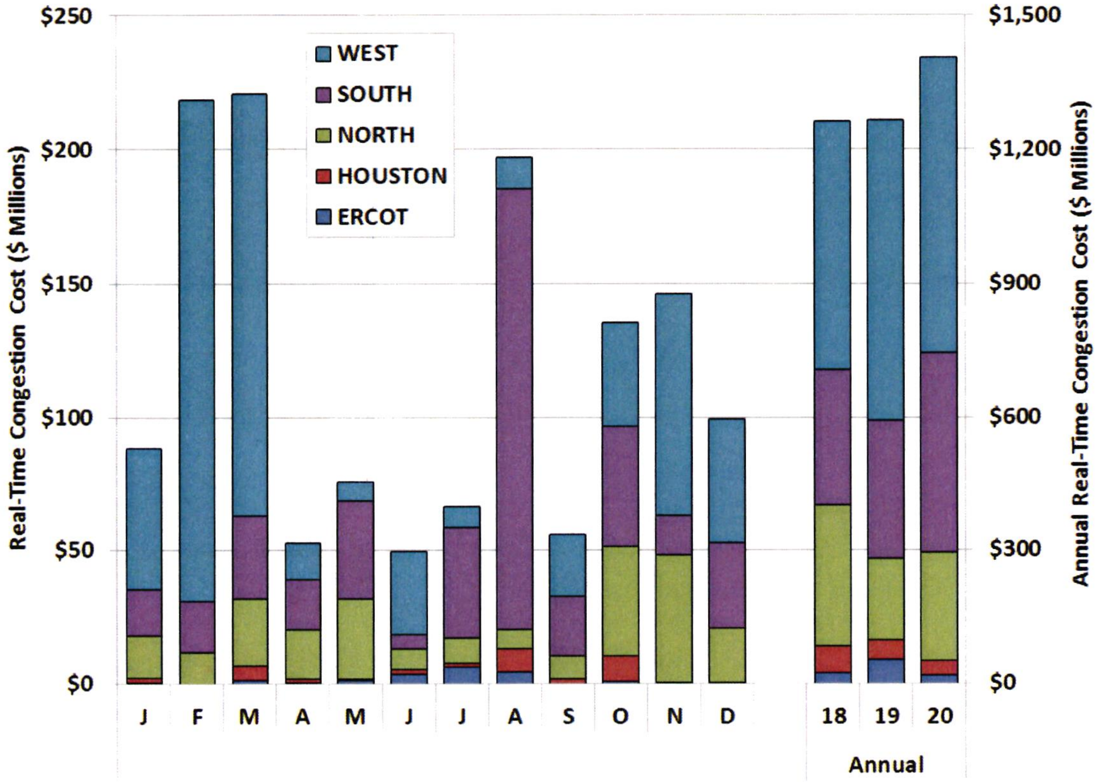
1 These changes were made to the Other Binding Document: "Methodology for Implementing Operating Reserve Demand Curve (ORDC) to Calculate Real-Time Reserve Price Adder" (OBDRR011). The changes were directed by the Commission and approved by the ERCOT Board of Directors on February 12, 2019.

When transmission congestion occurs, the differences in costs of delivering electricity to some locations rather than others 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 in ERCOT's real-time market in 2020 $1.4 billion, up 11% from 2019. This increase is notable given the 20% decrease in natural gas prices. Lower gas prices tend to reduce the costs of the generators that are moved to manage transmission congestion and to serve customers in congested areas. To show the trends and fluctuations in congestion costs, the figure below shows real-time congestion costs by month and region for 2020 and a comparison with the annual costs in 2018 and 2019.

Real-Time Transmission Congestion Costs in 2020



The largest contributor to congestion costs in 2020, as was the case in 2019, was the congestion in the West zone. Congestion continued to be a result of the high demand caused by oil and gas development in the Permian Basin, alongside transmission outages in the area required for maintenance, new construction, and upgrades. The South zone experienced weather-related outages due to Hurricane Hanna in July 2020, which led to the high congestion costs in August.

Participants' expectation of this congestion is also reflected in ERCOT's day-ahead market prices and outcomes. Hence, the transmission congestion priced in the day-ahead market totaled

$1.3 billion, up 19% from 2019. This congestion can be hedged by participants by purchasing Congestion Revenue Rights (CRRs).

CRRs are economic property rights that entitle the holder to the day-ahead congestion revenues between two locations on the network. They are auctioned by ERCOT in monthly blocks as much as three years in advance. The revenues collected through the CRR auction help pay for the transmission system. CRR auction revenues have risen steadily as transmission congestion has grown, totaling $726 million in 2020. This value is less than the total congestion costs in 2020 in part because participants paid less to buy the CRRs than they were ultimately worth. This indicates that not all of the congestion in 2020 was not foreseen by the market.

Finally, ERCOT operators are increasingly using generic transmission constraints 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 renewable energy resources that do not provide the same voltage support to the system as conventional resources. Ultimately, these generic transmission constraints increase transmission congestion and increase the total costs of serving customers in ERCOT.

Market Improvements Underway

ERCOT made progress in 2020 on the Commission-approved implementation of co-optimization of energy and ancillary services in the real-time market, which is now planned to go live in 2025. Implementation will significantly improve the real-time coordination of ERCOT's resources, lower overall production costs, and improve shortage pricing. These improvements will be key for helping efficiently transition to a future with a different resource mix as additional wind and solar resources enter the ERCOT market. Unfortunately, the go-live date has been delayed due to staffing resources at ERCOT, Inc., but we encourage continued focus on this important market improvement.

Additionally, ERCOT continues to work with stakeholders to plan for the market integration of future technologies, such as Energy Storage Resources (ESRs) and Distribution Generation Resources (DGRs). Declining costs is accelerating its growth from the more than 300 MW existing today. Several hundred MWs of ESRs are planned to enter soon. DGRs that connect at the distribution level (< 60 kV) are also beginning to enter the ERCOT system and will require significant changes in the market rules.

Winter Storm Uri

We have not conducted our full analysis on the outcomes of market events during the week starting February 14, 2021. Data is still being collected through requests for information sent to both individual market participants and ERCOT operations. We anticipate a complete report will be available in 2022. However, we offer this short initial discussion to provide context for the two storm-related recommendations detailed in the next section.

Winter storm Uri produced unusually low temperatures, which were sustained over many days. The Dallas-Ft. Worth area, for example, experienced 140 consecutive hours at or below freezing, with a minimum temperature of -2° F. Compared with the winter event in 2011, this represents 39 more hours and minimum temperatures that were 15° F colder. In the Austin area, these extremes were even more pronounced. Austin had nearly 100 more hours at or below freezing temperatures.

At the height of the storm event, more than 52 gigawatts of generation resources in the ERCOT region were unavailable. Eighty-five percent of those outages were in some way related to winter storm Uri, whether due to equipment failure, fuel supply shortages, or other weather-related issues. In some instances, the same units tripped offline, were restored to service, and then tripped offline again. At the same time, the cold temperatures resulted in electricity demand as high as the hottest day in the summer. Ultimately, this led to widespread and extended power outages in ERCOT. Unfortunately, some of these outages caused natural gas facilities to lose power, leading to less available natural gas and higher outages of gas-fired generators.

It is too early for us to conclude whether any market participants exercised market power during the event. However, we can report that the market did not perform efficiently. Both the ancillary services market and the real-time energy market produced outcomes that were inconsistent with sound economic principles. Those inefficiencies resulted in:

- Prices for ancillary services that substantially exceeded the true value of the ancillary services during the shortages; and
- Real-time energy prices that continued to reflect the costs of the energy shortage artificially for 32 hours after the shortage was over.

These issues have led to billions of dollars in excess costs and numerous defaults that ERCOT and the state of Texas will be grappling with for some time to come. We detail these inefficiencies and recommendations to address them below.

Recommendations

Although ERCOT markets performed well in 2020, we have identified certain opportunities for improvement. We make a total of seven recommendations below. While a full review and analysis of the February 2021 arctic event will be contained within the eventual 2021 State of the Market report, two of our recommendations address pricing flaws revealed by that event that merit urgent attention. The remaining recommendations contain two made in previous years and three new items to address inefficiencies or improve incentives affecting market performance. We are also retiring six recommendations from prior years. Readers can find those and a discussion of the status of each in the appendix.

Recommendations to Address Pricing Flaws Revealed in 2021

2020-1 – Include firm load shed in the calculation of the reliability adder

Real-time energy prices should reflect that shedding firm load is an out-of-market action with a cost equal to the Value of Lost Load (VOLL), a number usually equal to the system-wide high offer cap of $9,000 per megawatt-hour. This is clear because one additional MW of energy under these conditions would allow ERCOT to serve an additional MW of load, so the value of this energy must equal VOLL. Efficient pricing during these extreme shortages is essential in an energy-only market because it provides necessary economic signals to increase the electric generation needed to restore the load in the short term and service it reliably over the long term.

During the February 2021 winter event, firm load shed was initially excluded from the reliability adder, causing settlement prices to be well below $9,000 per MWh. The PUCT issued an emergency order on February 16 to address this issue.[2] However, later in the event, ERCOT decided to include other load that had not been restored in the calculation of the reliability adder, even though it was not subject to a load shedding instruction from ERCOT. This caused prices to clear at $9,000 per MWh for 32 hours after the load shedding ceased, resulting in substantial inefficient costs to be incurred.

We recommend that the protocols be modified to designate that firm load shedding directed by ERCOT be included in the calculation of the reliability deployment price adder, and specify that load reductions that are not directed by ERCOT *not* be included in this calculation.

2020-2 – Cap ancillary services prices in the day-ahead market

ERCOT operates its day-ahead market in manner that may incur extremely high costs attempting to procure all available ancillary services up to its ancillary services requirement. During the 2021 arctic event, this resulted in day-ahead market prices for ancillary services as high as over $25,000 per MW.[3] Ancillary service prices more than VOLL violate fundamental economic principles and generate inefficient market outcomes. Since reserves are procured to reduce the probability of losing load, the value of reserves should not exceed the cost of actually losing load – VOLL. This economic inconsistency will be resolved with the implementation of real-time co-optimization in 2025.

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2 PUC Project No. 51617, Calendar Year 2021 – Open Meeting Agenda Items without an Associated Control; Item No. 4, *Second Order Directing ERCOT to take Action and Granting Exception to Commission Rules* at 1-2 (Feb. 16, 2021); PUC Project No. 51812, Issues Related to the State of Disaster for the February 2021 Winter Weather Event, Item No. 31, *Order Directing ERCOT to take Action and Granting Exception to Commission Rules* (Mar. 1, 2021).

3 PUC Project No. 51812, Issues Related to the State of Disaster for the February 2021 Winter Weather Event, Item No. 149, Potomac Economics' *Follow Up Letter*, (Mar. 11, 2021).

In the meantime, we recommend that ERCOT address this issue by: a) utilizing a penalty price for ancillary services that is equal to or less than VOLL, and b) capping the ancillary service MCPCs at VOLL. This will prevent future irrational ancillary services pricing until 2025.

Recommendations to Improve Market Performance

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

In competitive markets, suppliers offer their resources at prices equal 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. 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, therefore, replacement real-time energy offers used by ERCOT (such as mitigated offers) should only include short-run marginal costs. Currently, the mitigated offer cap includes a multiplier that increases the offer price as the unit runs more. The operations and maintenance portion of verifiable costs already accounts for costs that increase as a unit runs more so the multiplier is not reasonable. The exceptional fuel costs calculation during mitigation also contains a multiplier that does not correspond to a resource's marginal costs when these multipliers are included. Given that allowing generators with market power to raise prices is a poor means to achieve fixed cost recovery, the IMM recommends that these two multipliers be removed to ensure that only marginal costs are included in the mitigated offer caps. 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.

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. This zonal configuration has not changed even through many years of load growth and changing congestion patterns. Consequently, the highly aggregated load zones and inability to price demand more granularly negatively impacts congestion management by distorting the incentives of both price-responsive demand and active demand response. This is particularly noticeable in the South load zone where there is significant congestion inside the zone, not just between it and other zones. Incenting demand to respond to the load zone price often makes the local congestion worse.

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

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

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

Recently, 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 obligations, a financial transaction cleared in the day-ahead market used to manage congestion cost risk.[4] This is not a surprise because substantial increases in PTP transactions significantly increase the complexity of the optimization and the time required to find a solution.

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

Additional Recommended Market Improvements from Prior Year(s)

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

The current method of allocating transmission costs provides incentives for load to behave in ways that do not necessarily forestall the construction of new transmission equipment and that do not apply transmission costs equitably to all loads.

Currently, transmission costs are allocated based on an entity's maximum 15-minute demand in June through September. This method was approved in 1996 and intended to allocate transmission costs to the drivers of transmission build. Today, however, customer demand during the peak summer hours is no longer the main driver of transmission build in ERCOT.

Rather, decisions to build transmission are based on transmission congestion patterns throughout the year and an analysis of whether generation can be delivered to serve customer reliably. Additionally, the method of billing these costs provides a price signal to non-opt-in entities and

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

transmission-level customers, both of which can artificially reduce their total customer demand in anticipation of a peak demand day to avoid transmission charges.

The IMM continues to recommend that transmission cost allocation be changed such that the resulting incentive better reflects the true drivers for new transmission.

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 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, an indicator of the inefficient pricing in this market.

In addition, a new ancillary service, ERCOT Contingency Reserve Service, will be implemented before 2025 and will contain a constraint on certain resources. However, a single price is envisioned for that service as well. Failure to include this constraint in the pricing of that product will require that inefficient market rules and restrictions be imposed. Such measures are not necessary when market participants' incentives are determined by efficient pricing.

Therefore, the IMM recommends that the clearing price of ancillary services, both current and future, be based on all the constraints used to procure the services.

I. Review of Real-Time Market Outcomes

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

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

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

Real-time prices have implications far beyond the settlements in the real-time market. Only a small share of the power produced in ERCOT is transacted in the real-time market. However, real-time energy prices set the expectations for prices in the 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 all forward prices, the importance of real-time prices to overall market performance is much greater than might be inferred from the proportion of energy actually paying real-time prices. This section evaluates and summarizes electricity prices in the real-time market during 2020.

A. Real-Time Market Prices

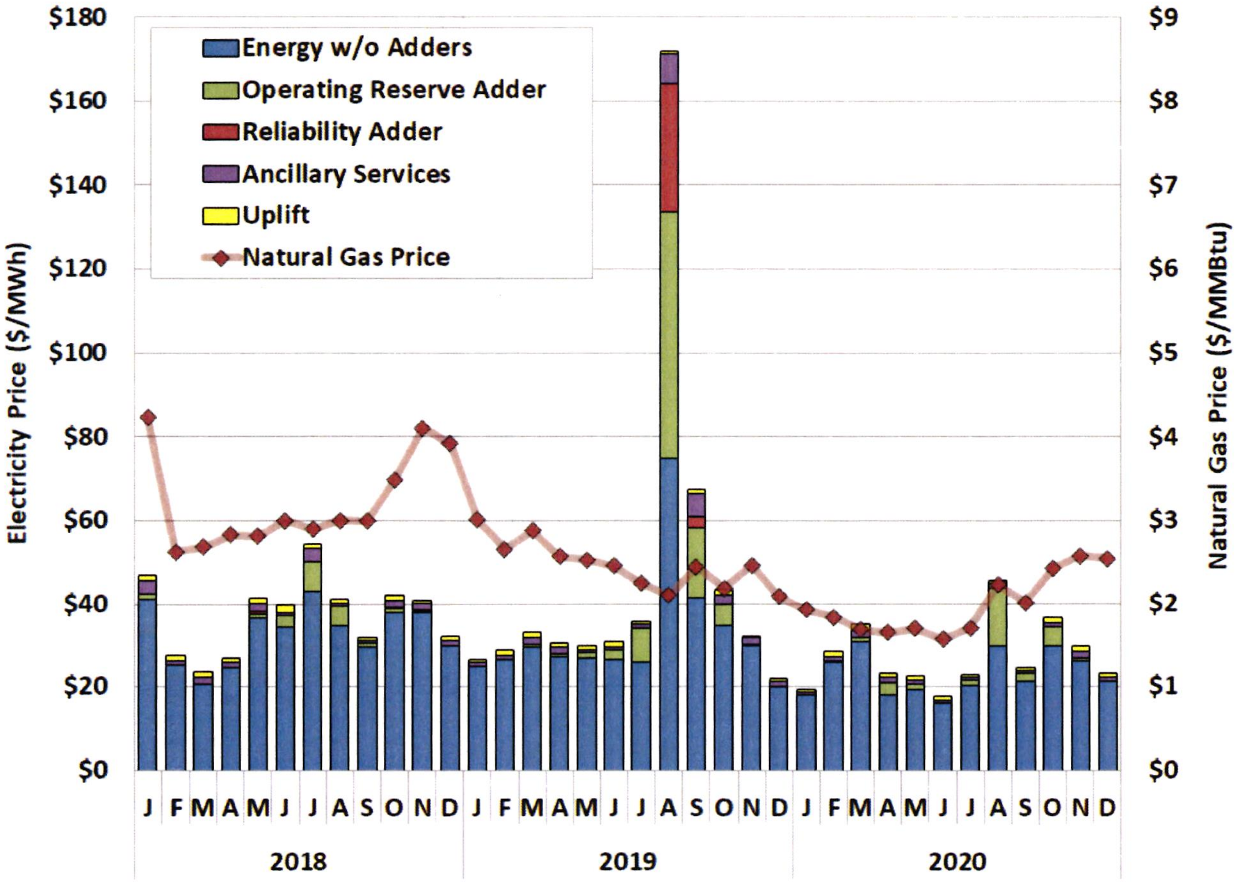
The first analysis of the real-time market evaluates the total cost of supplying energy to serve load in the ERCOT wholesale market. In addition to the costs of energy, loads incur costs associated with ancillary services and a variety of non-market-based expenses referred to as "uplift." Figure 1 shows the average "all-in" price of electricity for ERCOT that includes all these costs and is a measure of the total cost of serving load in ERCOT on a per MWh basis. The all-in price metric includes the load-weighted average of the real-time market prices from all zones, as well as ancillary services costs and uplift costs divided by real-time load to show costs on a per MWh basis.[5]

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

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

out-of-market actions for reliability. Although published energy prices include the effects of both adders, we show the ORDC adder (operating reserve adder) and the Reliability Deployment Price Adder (reliability adder) separately here from the base energy price. The operating reserve adder was implemented in mid-2014 to account for the value of reserves based on the probability of reserves falling below the minimum contingency level and the value of lost load. Taken together, an estimate of the economic value of increasingly low reserves in each interval in real-time can be included in prices. The reliability adder was implemented in June 2015 as a mechanism to ensure that certain reliability deployments do not distort the energy prices.[6]

Figure 1: Average All-in Price for Electricity in ERCOT



The largest component of the all-in price is the energy cost. The figure above indicates that natural gas prices continued to be a primary driver of energy prices in most months. This correlation is expected in a well-functioning, competitive market because fuel costs represent the majority of most suppliers' marginal production costs. Because suppliers in a competitive market have an incentive to offer supply at marginal costs and natural gas is the most widely-

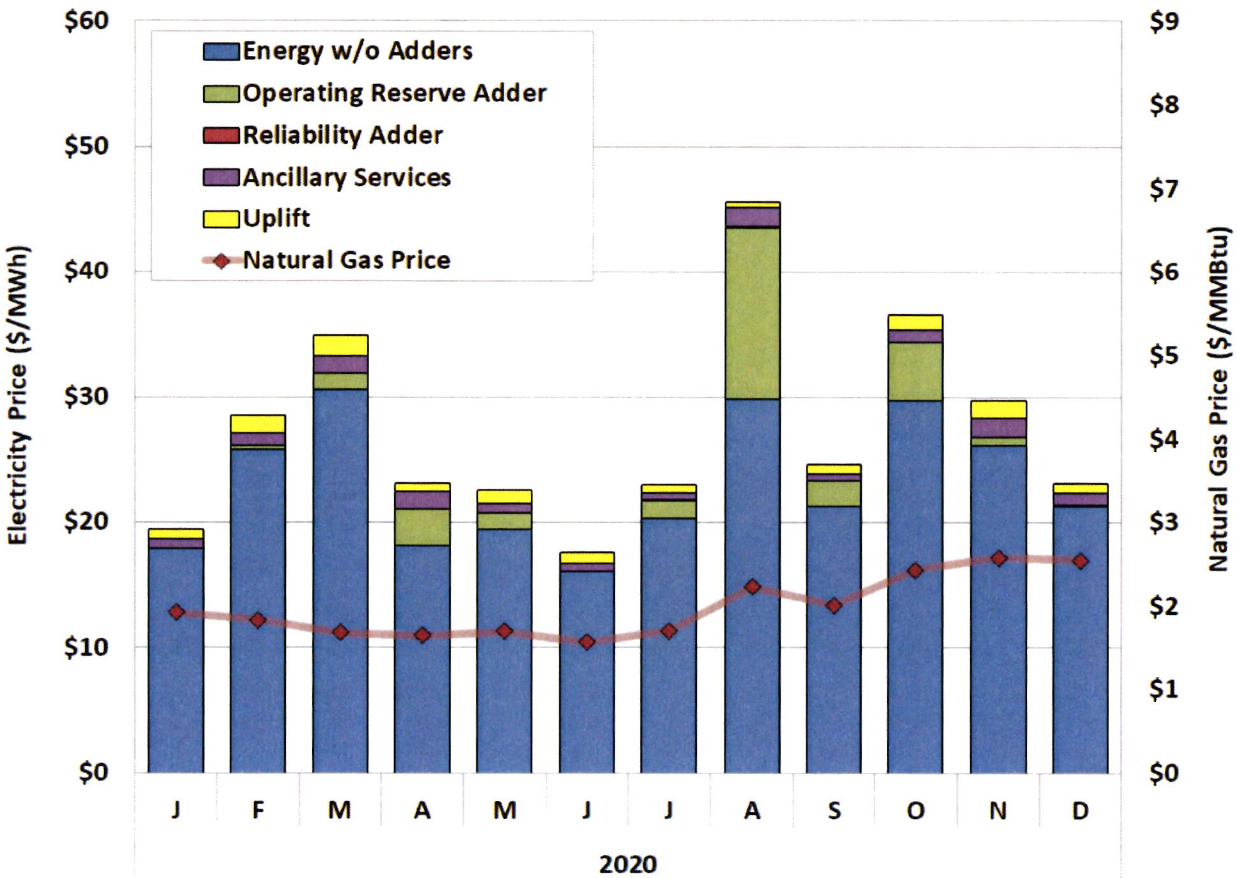
6 The reliability adder is calculated by separately running the dispatch software with any reliability unit commitments (RUC) or deployed load capacity removed and recalculating prices. When the recalculated system lambda (average load price) is higher than the initial system lambda, the increment is the adder.

used fuel in ERCOT, changes in natural gas prices typically should translate to comparable changes in offer prices.

Average real-time prices dropped by 45% (to $25.73 per MWh) in 2020 compared to 2019, due in large part to the absence of both tighter conditions and shortages of dispatchable capacity. In times where there are shortages of dispatchable capacity, such as in August and September of 2019, shortage pricing mechanisms will drive the price significantly higher. This decrease in average real-time prices occurred in conjunction with historically low average natural gas prices in 2020, under $2.00 for the year.

The decrease in shortage pricing was acutely reflected in the lower contributions from ERCOT's energy price adders: $2.64 per MWh from the operating reserve adder and $0.01 per MWh from the reliability adder. Both values are significantly lower than the comparable values in 2019: $9.76 per MWh for the operating reserve adder and $3.55 per MWh for the reliability adder. The adders in 2020 are discussed in greater detail in Subsection F: ORDC Impacts and Prices During Shortage Conditions.

Figure 2: All in Prices 2020

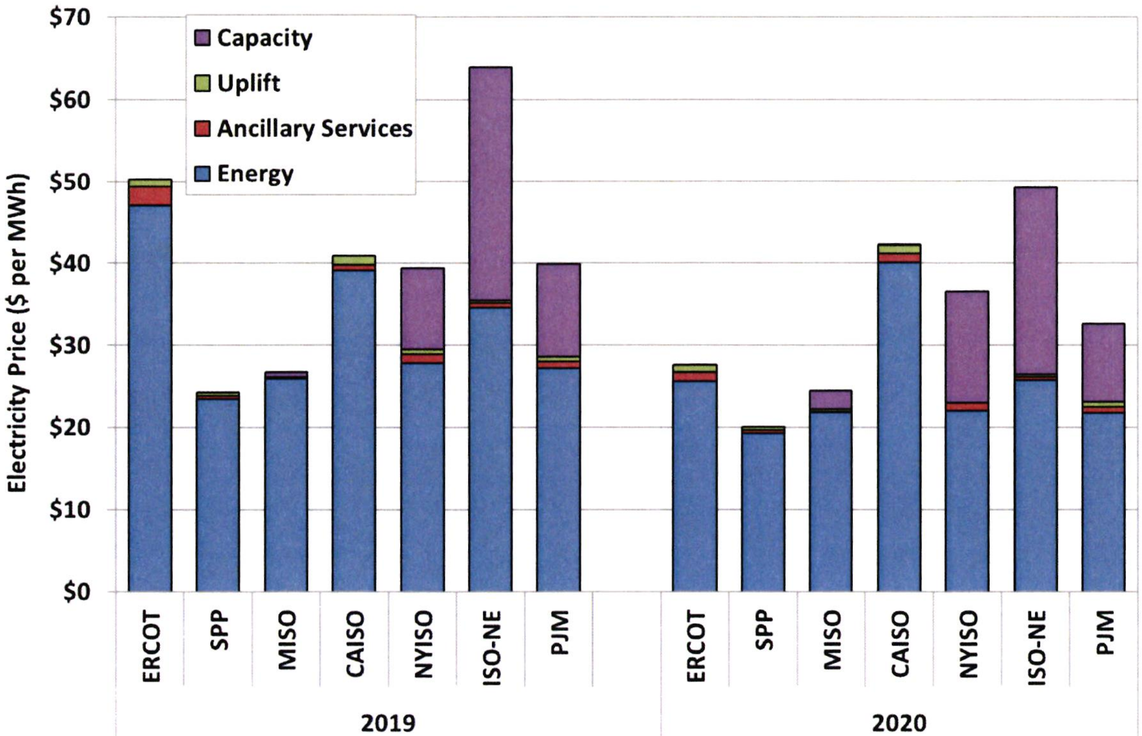


Other cost categories continue to be a relatively small portion of the all-in electricity price. Ancillary services costs were $1.00 per MWh in 2020, down from $2.33 per MWh in 2019 for reasons described in Section III: Day-Ahead Market Performance. Uplift costs accounted for $0.97 per MWh of the all-in electricity price in 2020, up from $0.88 per MWh in 2019. The total amount of uplifted costs in 2020 was approximately $359 million, up from $338 million in 2019. There are many costs included as uplift, but the largest components are the ERCOT system administrative fee ($212 million or $0.56 per MWh), Emergency Response Service (ERS) program costs ($46 million or $0.12 per MWh) and the real-time revenue neutrality allocation (RENA), which totaled $75 million or $0.20 per MWh in 2020.

To provide additional perspective on the outcomes in the ERCOT market, Figure 3 below compares the all-in price in ERCOT with other organized electricity markets in the United States: Southwest Power Pool (SPP), Midcontinent ISO (MISO), California ISO (CAISO), New York ISO (NYISO), ISO New England (ISO-NE), and the PJM Interconnection. The figure separately shows the components of the all-in price, including energy, capacity market costs (if applicable), uplift, ancillary services (reserves and regulation), and energy.

Figure 3 also shows that all-in prices were generally lower across U.S. markets in 2020, with CAISO as the exception.

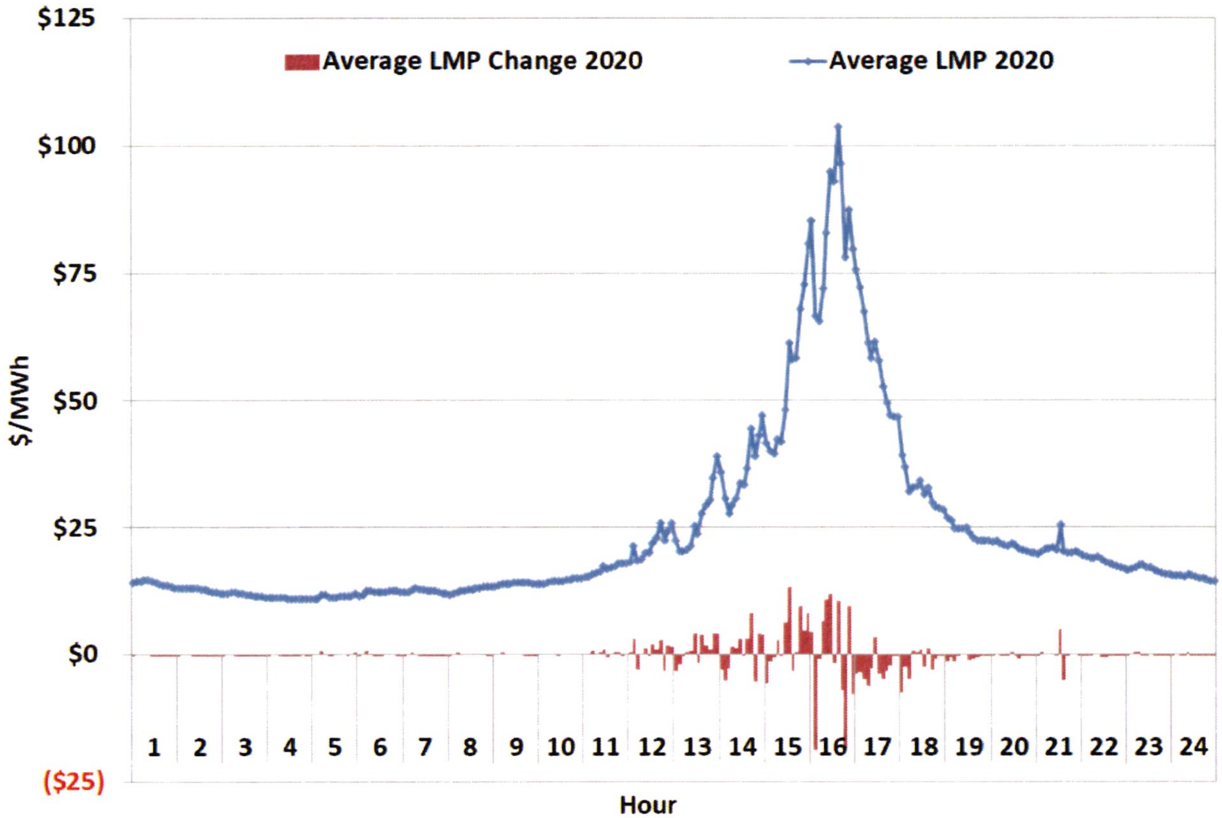
Figure 3: Comparison of All-in Prices Across Markets



Real-time energy prices vary substantially by time of day. Figure 4 shows the 2020 load-weighted average real-time prices in ERCOT in each 5-minute interval during the summer months from May through September, when prices were the highest. It also shows in red the average change in the 5-minute prices in each interval.

The figure shows that the downward changes in five-minute prices were highest at the top of peak hour 16. This is largely caused by changes in generator commitments at the top of the hour. When additional resources come online, supply expands, and prices sometimes fall sharply. Average changes in other intervals are far more random and generally driven by changes in load or supply. Note that prices in the peak load hours were much lower in 2020 than in 2019. This was primarily attributable to the relative absence of shortage conditions in 2020 that prevailed during the peak hours in August 2019.

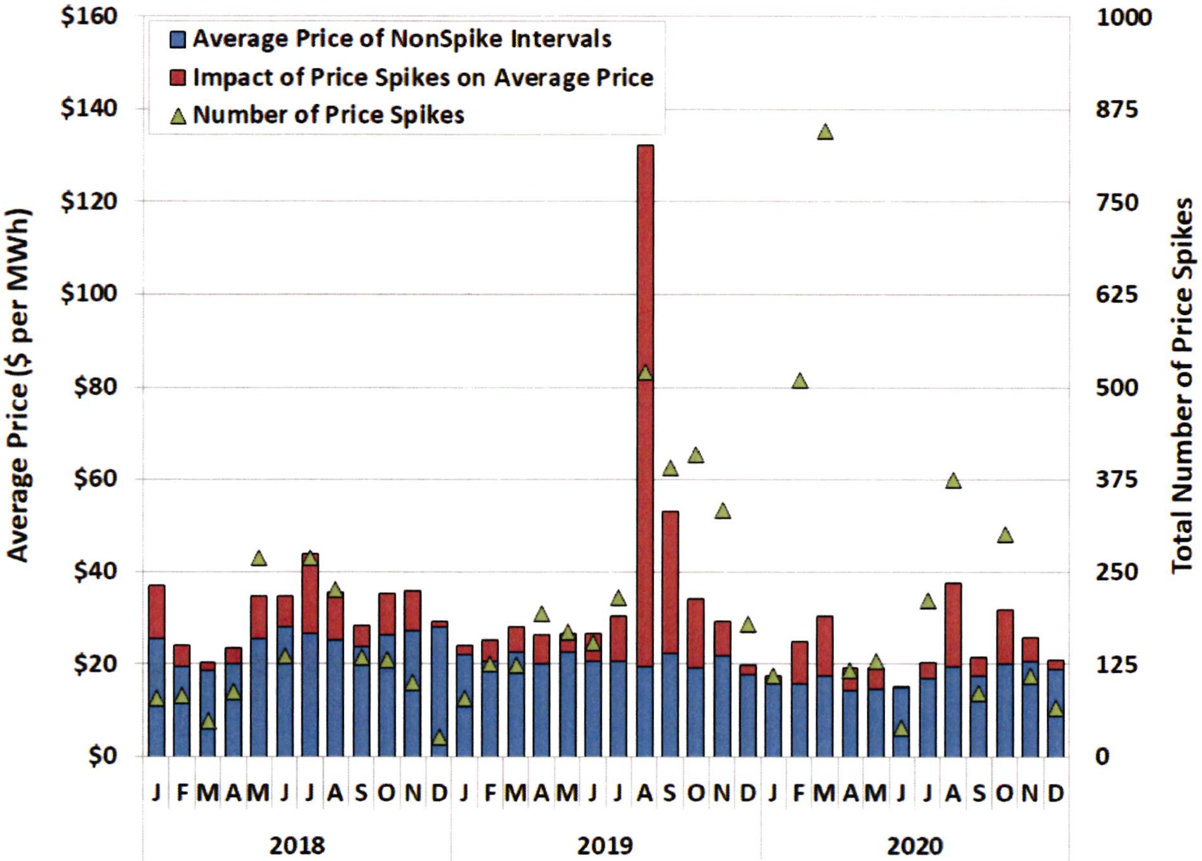
Figure 4: Prices by Time of Day
May-September 2020



For additional analysis of load-weighted average real-time prices in ERCOT for the categories of Peak and Off-Peak for each month in 2020, see Figure A1 in the Appendix.

To better observe the effect of the highest-priced hours on the average real-time energy price, Figure 5 shows the frequency of price spikes in the 2020 real-time energy market. For this analysis, price spikes are defined as intervals when the load-weighted average energy price is greater than 18 MMBtu per MWh multiplied by the prevailing natural gas price (i.e., a heat rate of 18). Prices at this level typically exceed the marginal costs of virtually all on-line generators.

Figure 5: Average Real-Time Energy Price Spikes



Price spikes were more frequent in 2020 compared to 2019 but less consequential on prices because of smaller contributions from the changed operating reserve adder during scant periods of reduced reserve availability as well as ultra-low gas prices (below $2.00/MMBtu). With average gas prices so low throughout the year, energy prices have less correlation with heat rate as the other components of operations and maintenance costs become more relevant. This is an outlier in how energy prices are typically viewed. The overall impact of price spikes in 2020 was $6.57 per MWh, or 26% of the total average price.

B. Zonal Average Energy Prices in 2020

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 for the past seven years and includes the annual average natural gas price. Like Figure 1, Table 1 shows the historically close correlation between the average real-time energy price in ERCOT and the average natural gas price, including 2020. This relationship is consistent with competitive expectations in ERCOT where natural gas generators predominate and set prices in most hours. However, we note that in 2019, this trend diverged as substantial shortage pricing led to higher energy prices as expected in periods with low reserve margins or extreme weather. The average natural gas price was lower in 2020 than it has been since 2014, and average real-time energy prices dropped back down from historic highs in 2019 to more typical levels in 2020. For additional analysis on ERCOT average real-time energy prices as compared to the average natural gas prices, see Figure A2 in the Appendix.

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

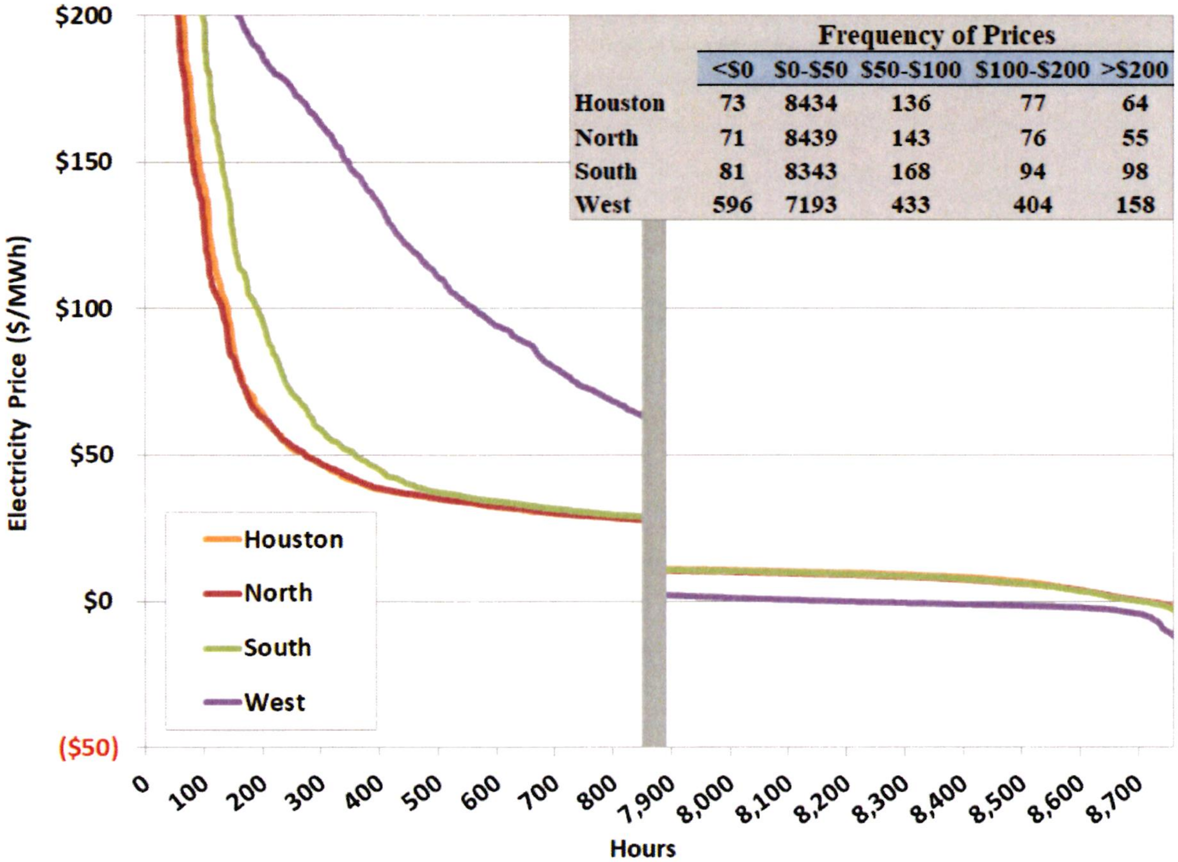
($/MWh)	2014	2015	2016	2017	2018	2019	2020
ERCOT	**$40.64**	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**
Houston	$39.60	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54
North	$40.05	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97
South	$41.52	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63
West	$43.58	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58
($/MMBtu)							
Natural Gas	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99

Table 1 also shows that the pattern of zonal prices in 2020 was fairly consistent with the pattern seen in recent years. The West zone again had the highest prices, primarily because of multiple localized real-time transmission constraints. Prices in this zone have varied substantially as the growth in wind generation created export congestion from the West zone prior to 2012 and from 2015 to 2017, resulting in the lowest zonal average prices in ERCOT in these years. In other years, including 2020, localized constraints resulted in the highest zonal prices in ERCOT. For additional analysis on monthly load-weighted average prices in the four geographic ERCOT zones during 2020, see Figure A3 in the Appendix.

The South zone was again the second highest-priced zone in 2020 because of congestion caused by the forced outages from Hurricane Hanna in the Rio Grande Valley. More details about the transmission constraints influencing zonal energy prices are provided in Section IV: Transmission Congestion and Congestion Revenue Rights. That section also discusses Congestion Revenue Right (CRR) auction revenue distributions, which affect the ultimate costs of serving customers in each zone. For additional analysis of the effect of CRR auction revenues on the total cost to serve load borne by a QSE, see Figure A4 in the Appendix.

To more closely examine the variation in zonal real-time energy prices, Figure 6 shows the top 10% and bottom 10% of the duration curves of hourly average prices in 2020 for the four zones. Compared to the other zones, both low and high prices in the West zone were noticeably different in 2020. The lowest prices in the West zone were much lower than the lowest prices in the other zones and the highest prices in the West zone were also noticeably higher than high prices in the other zones. The differences on both ends of the curves can be explained by the effects of transmission congestion. Constraints limiting the export of low-priced wind and solar generation to the rest of the state explain low prices, whereas localized constraints limiting the flow of electricity to the burgeoning oil and gas loads in the West explain the higher prices, typically in times where wind and solar energy resource output is low.

Figure 6: Zonal Price Duration Curves



For additional analysis of price duration curves, see Figure A5 and Figure A6 in the Appendix.

C. Evaluation of the Revenue Neutrality Allocation Uplift

As shown in the all-in price analysis above, uplift costs increased substantially. Much of this increase was due to higher RENA, which increased 52% to $49 million ($0.13 per MWh) in 2020 to $75 million ($0.20 per MWh). We evaluate the drivers of RENA in this subsection.

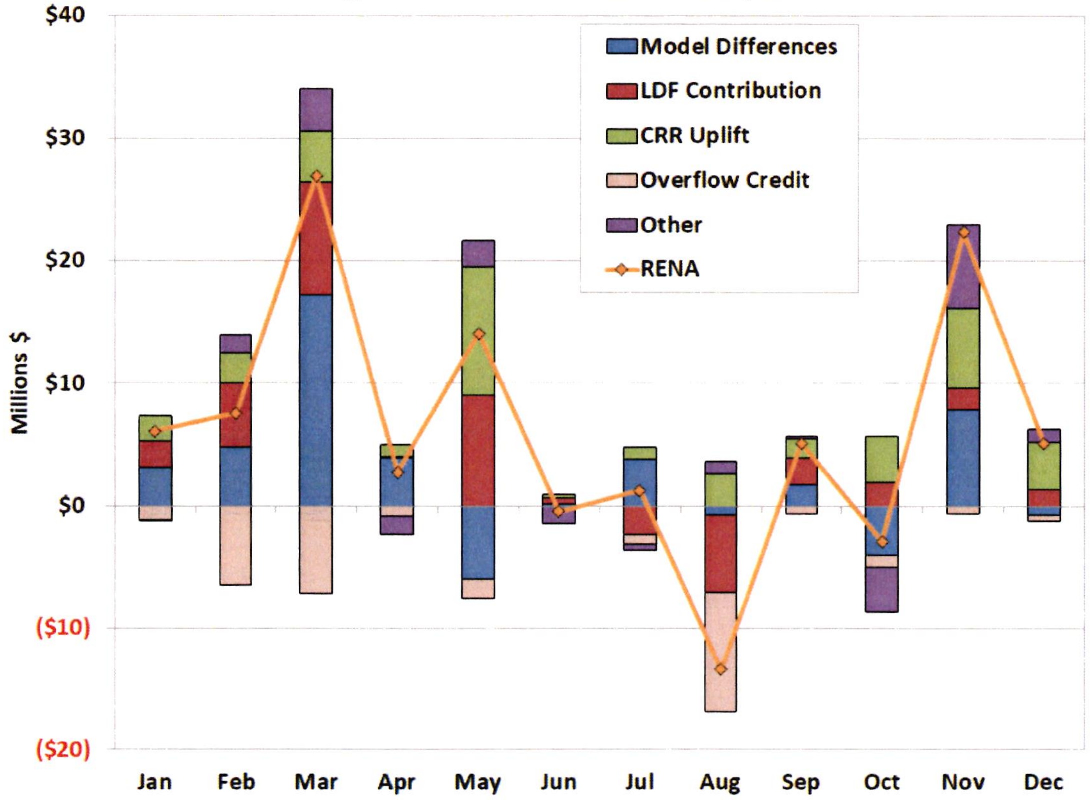
In general, RENA uplift occurs when there are certain differences in power flow modeling between the day-ahead and real-time markets. These factors include:

- Transmission network modeling inconsistencies between the day-ahead and real-time market (Model Differences);
- Differences between the load distribution factors used in day-ahead and the actual real-time load distribution (LDF Contribution);

- Day-ahead Point-to-Point (PTP) obligations linked to options[7] 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 provides an analysis of RENA uplift in 2020, separately showing the components of RENA on a monthly basis. Net negative uplift represents an overall payment to load.

Figure 7: ERCOT RENA Analysis



Detailed studies show that almost all the RENA uplift occurred in market hours when there was transmission congestion. The largest contributors to RENA uplift in 2020 were NOIE PTP obligations settled as options and model differences, contributing $40 million and $31 million, respectively. These uplift costs were offset by $31 million in negative uplift related to overflow credits when the shadow price reached the shadow price cap for a transmission constraint.

Figure 7 above also shows that RENA uplift from the settlement of day-ahead PTP obligations linked to options, described as CRR Uplift, was relatively high in March and November, as was

7 A Point-to-Point obligation linked to an option (PTPLO) is a type of CRR that entitles a Non-Opt-In Entity's (NOIE's) PTP Obligation in the DAM to reflect the NOIE's PTP Option that it acquired in the CRR auction or allocation. Qualified PTP Obligations with Links to an Option shall be settled as if they were a PTP Option.

the uplift from transmission modelling differences. Uplift from the contributions of load distribution factor differences between day-ahead and real-time, described as LDF Contribution, was mostly positive in 2020, with the most notable contributions in March and May.

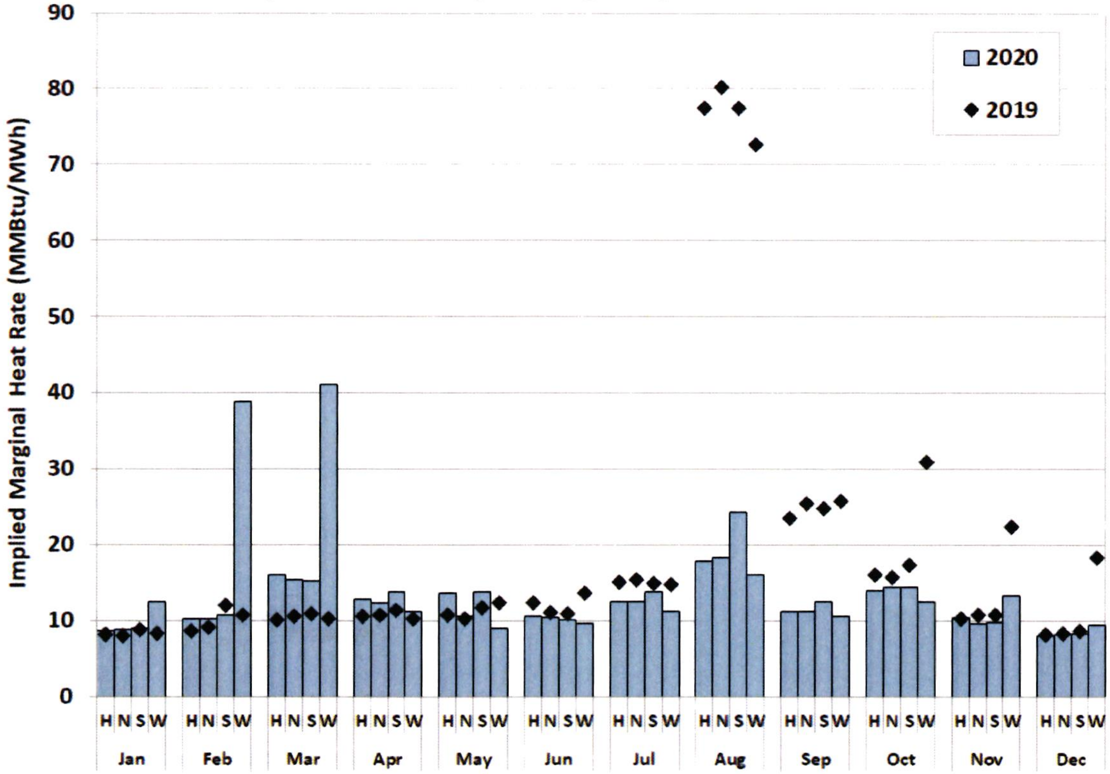
The task of maintaining accurate and consistent load distribution factors across all markets is a difficult one, made more so in areas with large amounts of localized load growth. These are exactly the types of areas that draw higher levels of market interest. To the extent ERCOT is unable to predict accurate load distribution factors across all markets, RENA impacts will persist. In 2020, a new process was created for determining the load distribution factors used in the Congestion Revenue Rights (CRR) Auctions and day-ahead market clearing using load forecasting models and existing validation and error correction to determine daily load distribution factors, which represents a significant improvement over the previous process.[8]

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 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 A3 in the Appendix.

8 NPRR1004, *Load Distribution Factor Process Update* (approved on August 11, 2020).

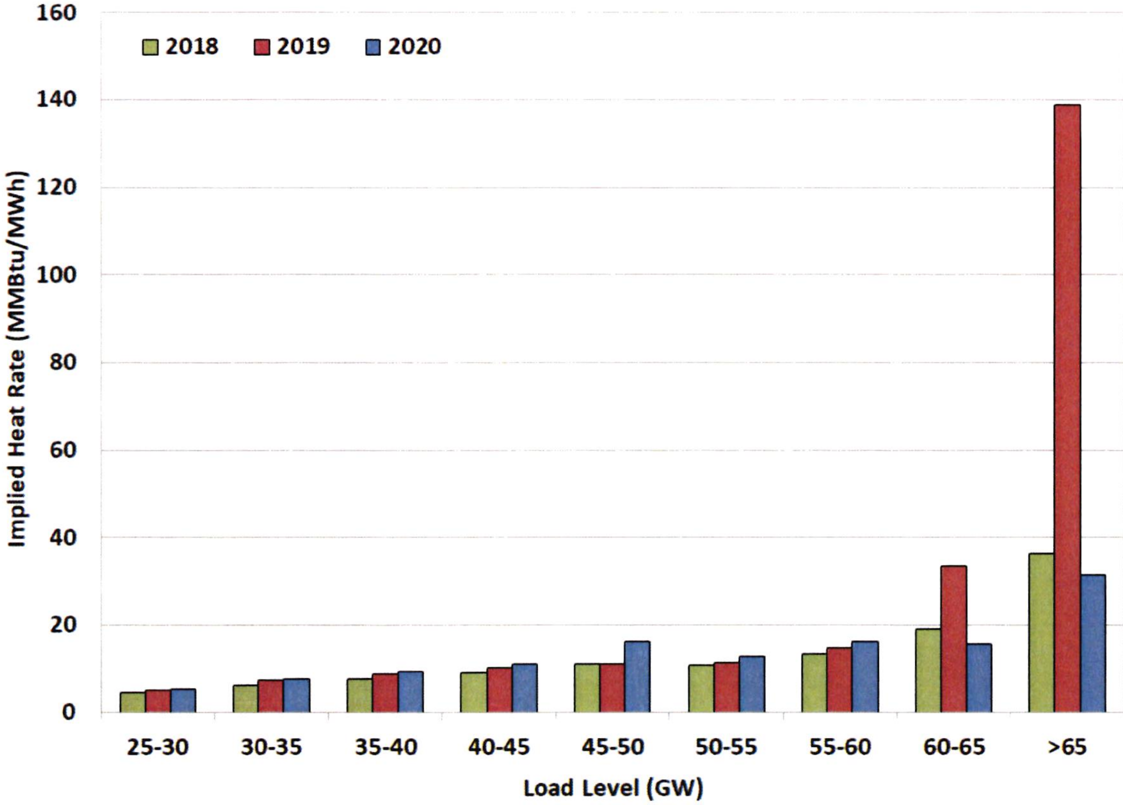
Figure 8: Monthly Average Implied Heat Rates



The implied heat rate varied substantially among zones. The most significant increase occurred in August as hot weather led to high load levels and prices. Transmission congestion drove zonal differences, particularly for the West zone in February and March 2020. Overall, average implied heat rates were as expected for a year without frequent operating reserve shortages.

Figure 9 shows how the implied heat rate varies by load level over the past three years. As expected in a well-performing market, 2020 exhibited a positive relationship between implied heat rate and load level. Resources with higher marginal costs were dispatched as load approached peak. For additional analysis of real-time energy prices adjusted for fuel price changes, see Figure A7, Figure A8, and Table A2 in the Appendix.

Figure 9: Implied Heat Rate and Load Relationship

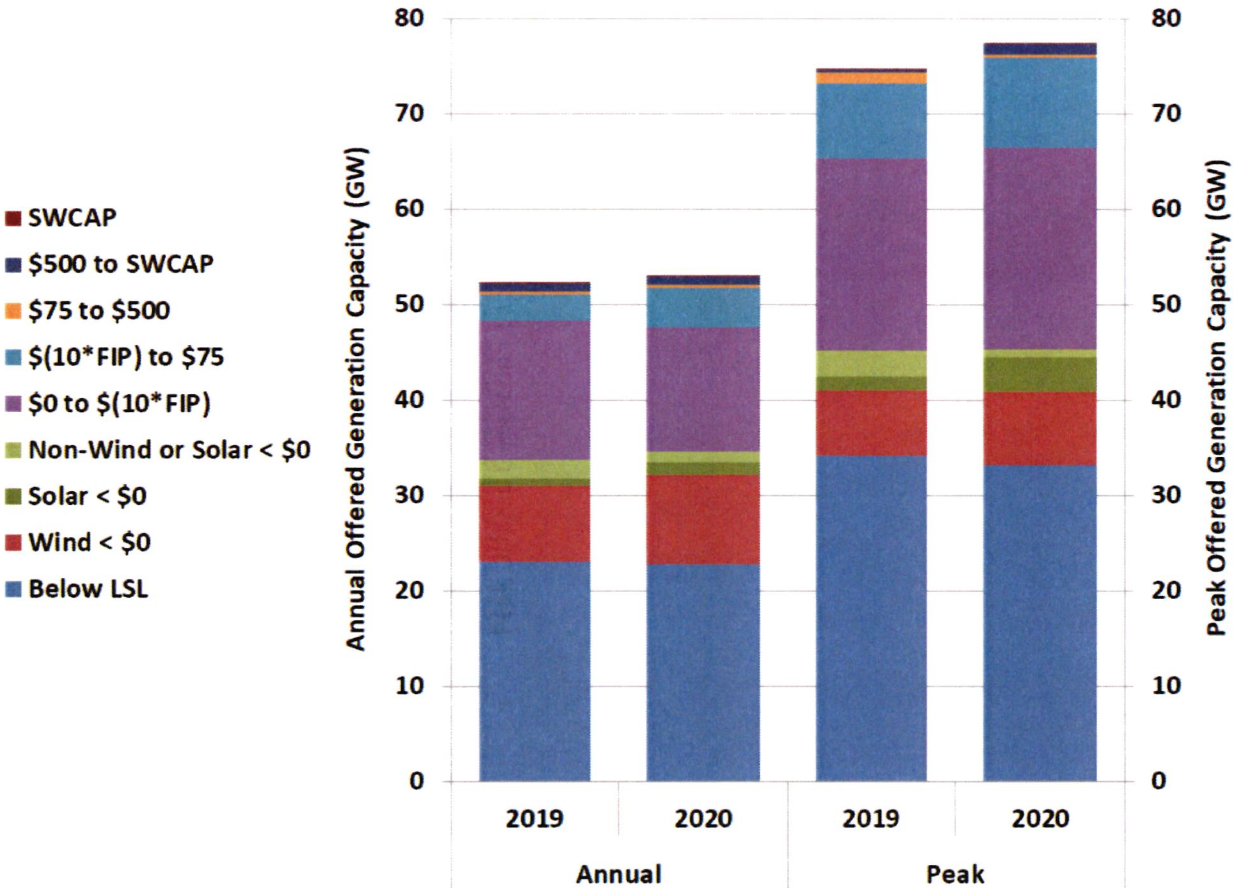


E. Aggregated Offer Curves

The next analysis compares the quantity and price of generation offered in 2020 to that offered in 2019. 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 offers in the summer.

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

Figure 10: Aggregated Generation Offer Stack - Annual and Peak



The average annual offer patterns shown in Figure 10 reveal that in 2020:

- The amount of capacity offered at prices less than zero attributable to wind and solar increased by more than 1,000 MW, while non-wind and solar capacity offered at less than zero decreased by more than 500 MW;
- Approximately 1,600 MW less capacity was offered between $0 and $(10*FIP). This was likely related to the low natural gas price and the higher contribution of other components of short-run marginal costs in the offers;
- The amount of capacity offered at prices between $(10*FIP) and $75 per MWh increased by 1,400 MW from 2019 to 2020; and
- The aggregate amount of generation capacity offered into ERCOT's real-time market increased by nearly 650 MW in 2020.

Figure 10 also shows that the changes in the aggregated offer stacks between the summers of 2019 and 2020 were somewhat different than those in the annual aggregated offer stacks for those years. The changes that occurred in 2020 during the summer included:

- The aggregate offer stack increased by approximately 2,750 MW from the previous year.

- The amount of capacity offered at negative prices increased overall, with 880 MW of additional negative-priced offers from wind generators and 2110 MWs from solar, but 1870 MW less from thermal generators.
- There was an increase of approximately 1,000 MW capacity offered at prices between $0 and $(10*FIP), and of 1,500 MW of capacity offered at $(10*FIP) and $75 per MWh.

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 leads to efficient shortage pricing as it is reflected in both operating reserves and energy prices during shortages.

The ORDC reflects the loss of load probability (LOLP) at varying levels of operating reserves multiplied by the deemed value of lost load (VOLL).[9] Selected at the time as an easier-to-implement alternative to real-time co-optimization of energy and ancillary services, the ORDC places an economic value on the reserves being provided, with separate pricing for online and offline reserves. On January 17, 2019, the Commission approved a phased process to change the ORDC and directed ERCOT to use a single blended ORDC curve and implement a 0.25 standard deviation shift in the LOLP calculation implemented on March 1, 2019. The second step, consisting only of an additional 0.25 standard deviation shift in the LOLP calculation, was implemented on March 1, 2020.[10]

Effectively, these shifts accelerate the increase in prices toward the Value of Lost Load ($9,000 per MWh) and cause the market to set prices at VOLL when load shedding remains a small risk. Inflating the shortage pricing above the expected VOLL increases costs as described above, but will also provide incentives for ERCOT to maintain a higher planning reserve. Though these shifts remain significant, their effects were more muted in 2020 because of the COVID-19 pandemic and absence of shortage events throughout the summer months.

The effects of these changes are shown in Figure 11. This figure depicts single blended ORDC curves and magnitude of the first and second 0.25 standard deviation shifts in the LOLP calculation.

9 At the open meeting on September 12, 2013, the Commission directed ERCOT to move forward with implementing ORDC, including setting the Value of Lost Load at $9,000.

10 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 48551.

Figure 11: Blended Operating Reserve Demand Curves

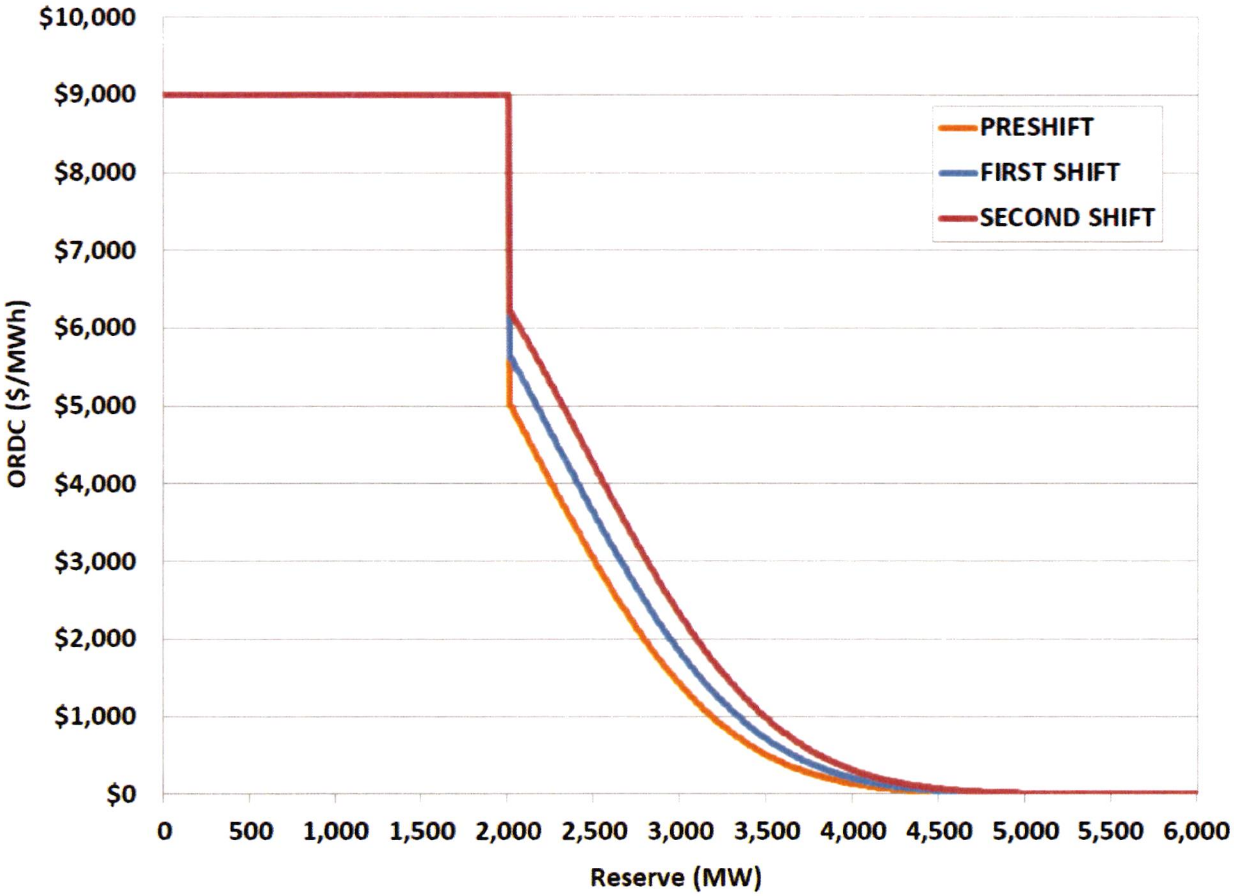
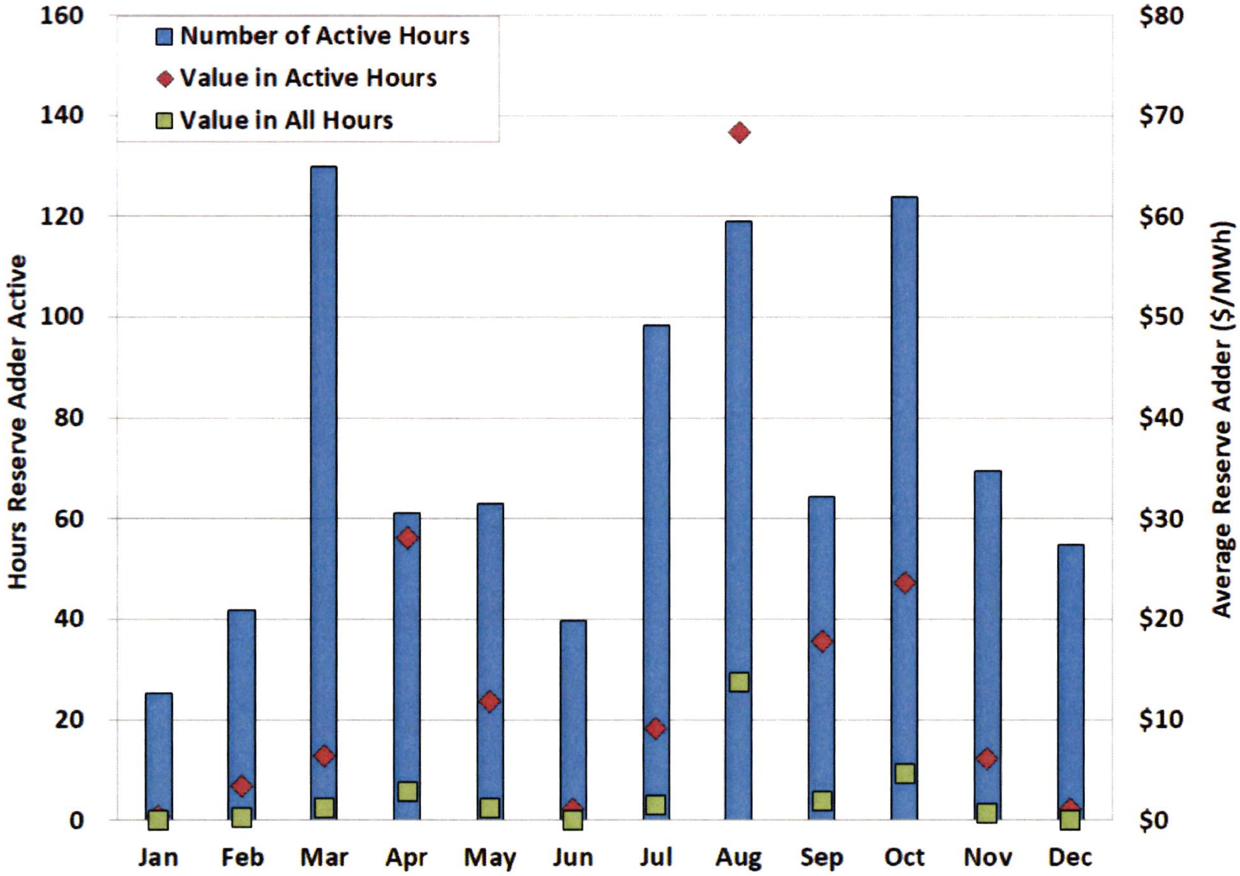


Figure 11 shows how each incremental shift increased the level of ORDC contributions to price as reserve capacity drops. For example, the price at 3,000 MW reserve level rises from roughly $1,400 per MWh on the pre-shift curve to approximately $1,800 per MWh on the first shift curve, and approximately $2,300 per MWh on the second shift curve. Regardless of the shifts, once available operating reserve levels decrease to 2,000 MW, prices will always rise to $9,000 per MWh.

The following two analyses illustrate the contributions of the operating reserve adder and the reliability adder to real-time prices. The first adder, the operating reserve adder, is a shortage value intended to reflect the expected value of lost load given online and offline reserve levels.

Figure 12 shows the number of hours in which the adder affected prices in 2020, and the average price effect in these hours and all hours. This figure shows that in 2020, the operating reserve adder had the largest price impacts in August because of the relatively small but still significant shortage conditions that occurred. The contribution from the operating reserve adder in 2020 was much lower than in 2019 because of the decrease in shortage conditions, despite the modifications to the ORDC described above.

Figure 12: Average Operating Reserve Adder



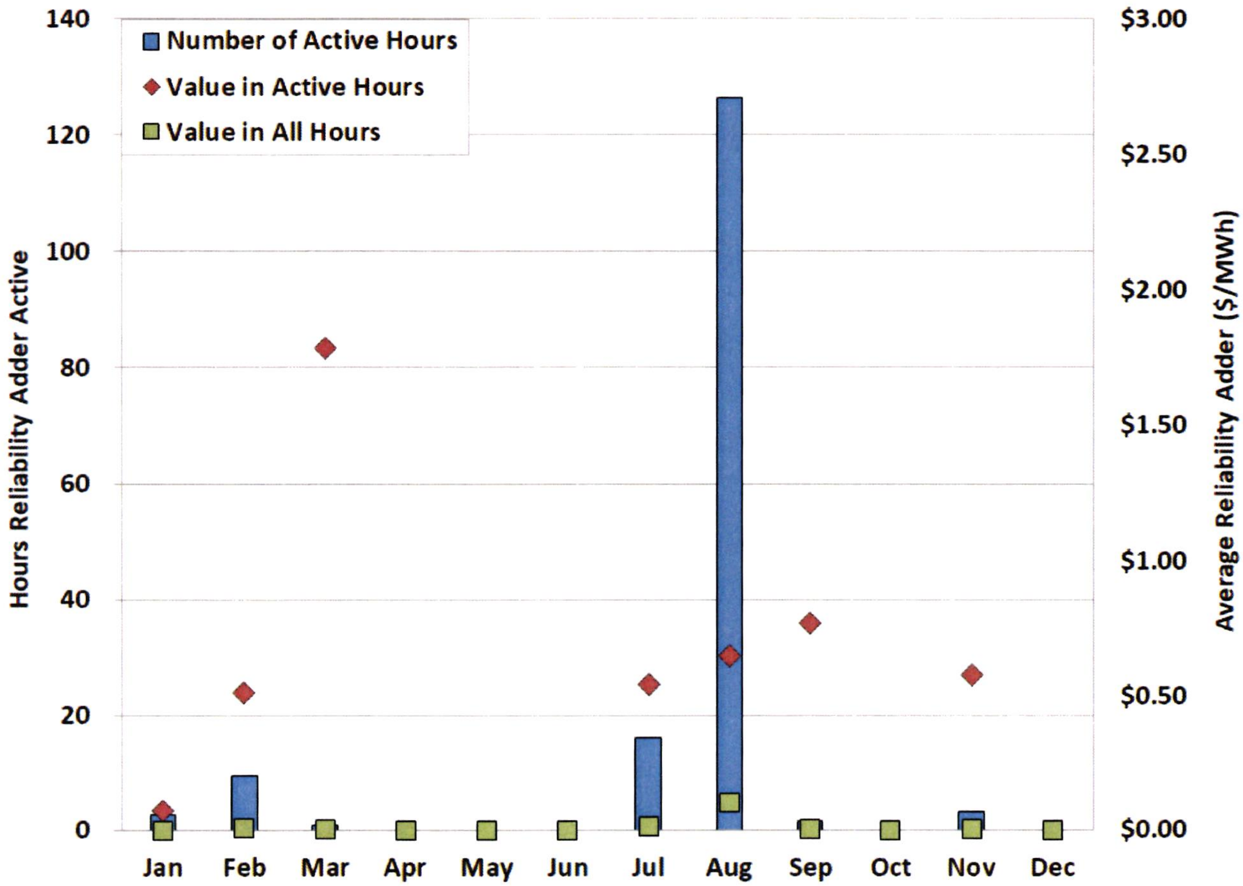
Overall, the operating reserve adder contributed $2.64 per MWh, or approximately 10% of the annual average real-time energy price of $25.73 per MWh in 2020. The effects of the operating reserve adder are expected to vary substantially from year to year. It will have the largest effects when low supply conditions and high load conditions occur together and result in sustained shortages, more like the market experienced in 2019 than those experienced in 2020.

The reliability adder is intended to allow prices to reflect the costs 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 13 below shows the impacts of the reliability adder in 2020. When averaged across only the hours when the reliability adder was non-zero, the largest price impacts of the reliability adder occurred during March. A fast-starting unit was brought online via RUC instruction for congestion, and the adders for that hour indicate the RUC offer floor impacted the energy price. The reliability adder was non-zero for 1.83% of the hours in 2020, most of which occurred in August. The highest contribution to the real-time energy price were in February, March, July, August, September, and November. The reliability adder in these months was a product of the

RUC instructions issued by ERCOT, discussed in Section V: Reliability Commitments. The contribution from the reliability adder to the annual average load-weighted real-time energy price was $0.01 per MWh.

Figure 13: Average Reliability Adder

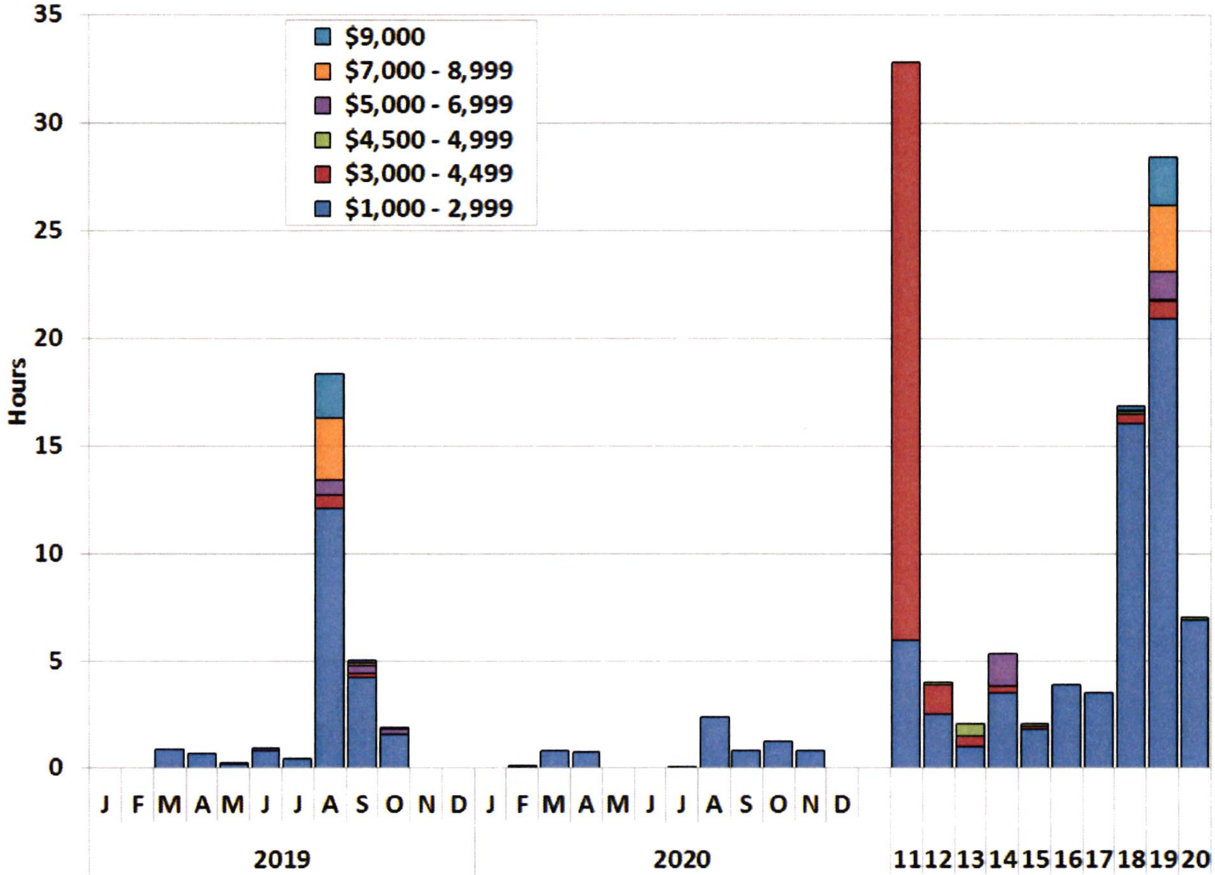


A weakness in the implementation of the reliability deployment adder was identified in 2019 and addressed in 2020. The primary flaw identified the restoration presumption adopted through Nodal Protocol Revision Request (NPRR) 626, *Reliability Deployment Price Adder ("formerly ORDC Price Reversal Mitigation Enhancements")*, caused prolonged high Real-Time On-Line Reliability Deployment Price Adder values for many hours after Energy Emergency Alert (EEA) conditions subsided during the summer of 2019. In June 2020, NPRR1006, *Update Real-Time On-Line Reliability Deployment Price Adder Inputs to Match Actual Data* was approved, returning the ERS resources in a linear curve over a four and a half-hour period following recall, rather than ten hours, to account for the data seen from summer 2019 as well as winter 2014 with the recognition that three days' data does not provide definitive information for further reduction. The NPRR also changed the process for updating this parameter in the future so that it can be updated by the ERCOT Technical Advisory Committee each year as appropriate, without the need to file a new NPRR.

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

To summarize the shortage pricing that has occurred since 2011, Figure 14 below shows the aggregate amount of time when the real-time system-wide energy price exceeded $1,000 per MWh, by month for 2019 through 2020, as well as annual summaries for 2011 through 2020.

Figure 14: Duration of High Prices



This figure shows that the frequency of high prices in 2020 remained relatively strong from a historic perspective, but considerably lower than the frequency and magnitude found in 2019. Prices greater than $1,000 per MWh occurred in about 7 hours in 2020 and were between $4,500 and $4,999 for just shy of 1 hour. Prices greater than $1,000 per MWh occurred in more than 28 hours in 2019 and were between $7,000 and $8,999 for more than 3 hours. In 2019, the system-wide offer cap was reached for intervals totaling more than two full hours during the peak week of August 12. Prices never approached those levels in 2020.

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 variation in 15-minute settlement point prices, expressed as a percentage of annual average price, for the four geographic zones for years 2014-2020. 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
Houston	14.7%	13.4%	20.8%	24.9%	21.5%	22.7%	21.2%
South	15.2%	14.6%	19.9%	26.2%	23.5%	23.5%	21.7%
North	14.1%	11.9%	15.5%	14.8%	20.7%	22.6%	19.8%
West	15.4%	12.9%	16.8%	17.5%	21.8%	24.7%	26.5%

These results show overall volatility dropped in all zones except the West zone in 2020. This overall decrease is consistent with the rising operating reserve margins that led to less frequent instances of tight supply conditions in 2020.

Congestion explains most of the inter-zonal differences in price volatility. Volatility was again highest in the West zone in 2020 because of increased congestion, frequently related to planned outages. A similar set of factors in 2017 and 2018 caused the South zone to exhibit the highest price volatility in those years.

For additional analysis of real-time price volatility, see Figure A9 and Figure A10 in the Appendix.

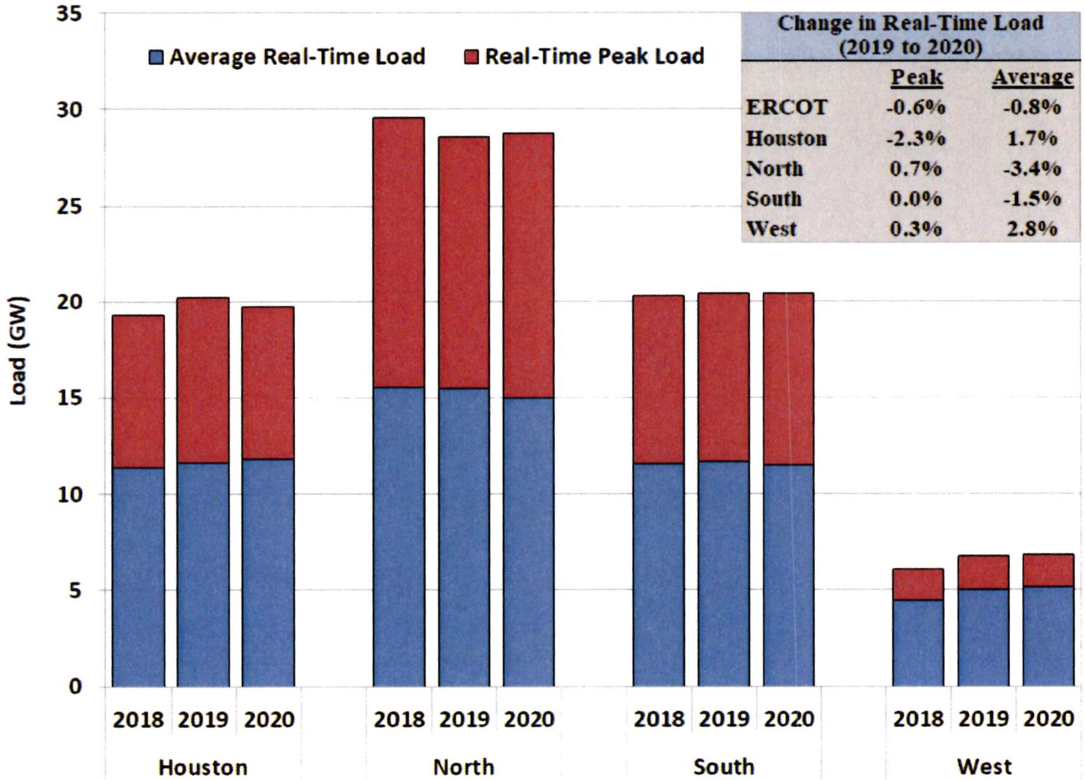
II. DEMAND AND SUPPLY IN ERCOT

Many of the trends in market outcomes described in Section I are attributable to changes in the supply portfolio or load patterns in 2020. In this section, therefore, we review and analyze these load patterns and the generating capacity available to satisfy the load and operating reserve requirements. We include a specific analysis of the large quantity of installed wind and solar generation, along with discussion of the daily generation commitment characteristics. This section concludes with a review of the contributions from demand response resources.

A. ERCOT Load in 2020

We track the changes in average load levels from year to year to better understand the load trends, which captures changes in load over a large portion of the hours during the year. However, changes in the load during the highest-demand hours is important because it affects the probability and frequency of shortage conditions.[11] Figure 15 shows peak load and average load by geographic zone from 2018 through 2020.[12]

Figure 15: Annual Load Statistics by Zone



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

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

Figure 15 shows that the total ERCOT load in 2020 decreased by roughly 1% from 2019, a decrease of approximately 360 MW per hour on average. The Houston and West zones showed an increase in average real-time load in 2020 ranging from 1.7% in Houston to 2.8% in the West. The increase in the West zone is particularly notable in that it comes on top of a 13% increase in 2019. Continuing robust oil and natural gas production activity in the West zone has been the driver for high load growth, though the pandemic and associated low oil and gas prices slowed this down in 2020. Weather impacts on load in 2020 were mixed across the zones.

Peak demand occurred on August 13, 2020, reaching 74,328 MW between 4 and 5 p.m., lower than the all-time peak demand record of 74,820 MW set on August 12, 2019. Fluctuations in peak and average load are driven by summer conditions. Cooling degree days is a measure of weather that is highly correlated with the demand for electricity for air conditioning. In June through August, there was a 6% increase from 2019 in cooling degree days in Dallas. Cooling degree days is a metric that is highly correlated with summer loads. In the same timeframe, Austin had a 2% increase and Houston had a decrease of 2% in cooling degree days from 2019.

Peak demand impacts were the largest in April 2020 due to "stay-at-home" recommendations in response to COVID-19, which declined beginning in late June. By the end of the summer, there were no discernable impacts due to COVID-19. A more detailed analysis of the load, via hourly load duration curves, is available in the Appendix in Figure A11 and Figure A12.

B. Generation Capacity in ERCOT

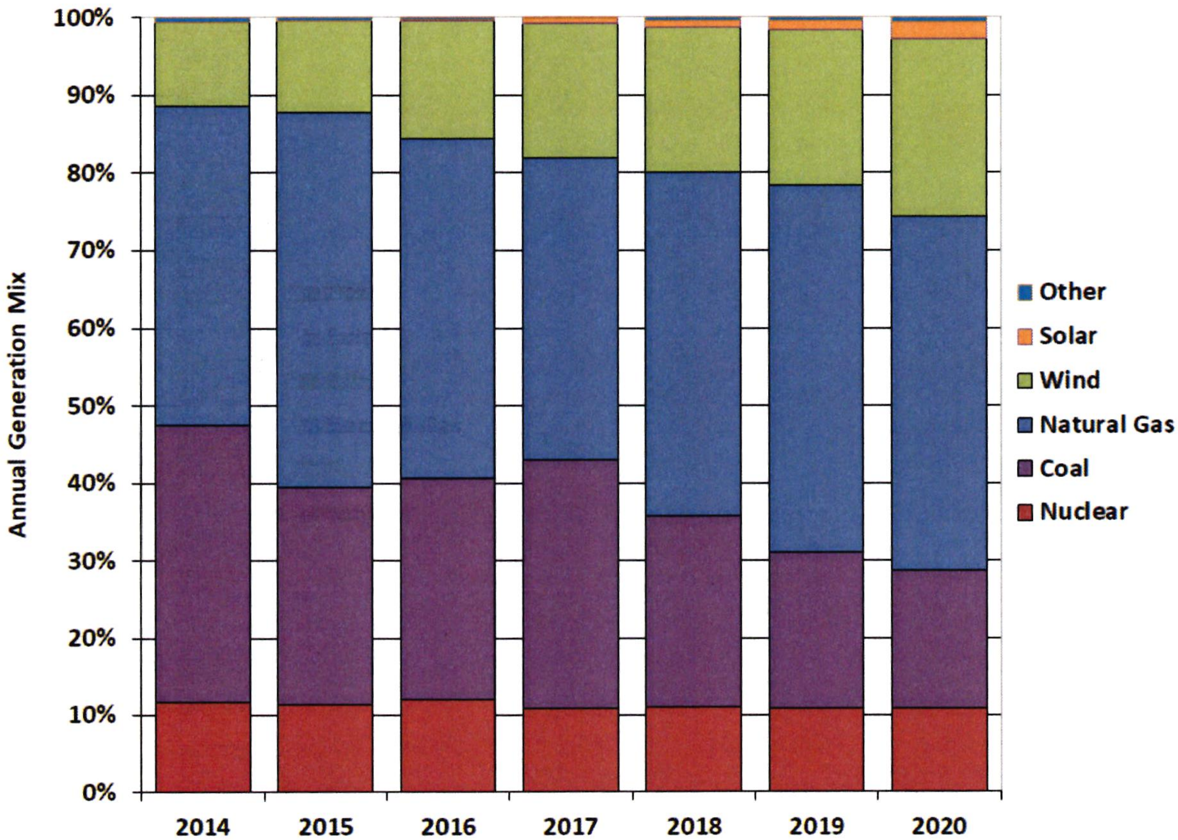
In this section we evaluate the generation portfolio in ERCOT in 2020. The distribution of capacity among the four ERCOT geographic zones is similar to the distribution of demand for the North and South zone. Houston is generally importing while the West is generally exporting. The Houston zone has increasingly relied on imports from the rest of the state as resources have been mothballed and the reliance on intermittent resources has increased.[13]

Approximately 7.7 GW of new generation resources came online in 2020, the bulk of which were intermittent renewable resources and the remaining capacity was 390 MW from combustion turbines and 70 MW of power storage. ERCOT had roughly 4,000 MWs of new installed wind capacity and 2,100 of new installed solar capacity going into summer 2020 compared to summer 2019, with an effective peak serving capacity totaling 3.5 GW. Two gas-fired projects, 20 wind projects and 16 solar projects came online in 2020. The nine storage projects that came online in 2020 doubled ERCOT's storage capacity to around 200 MW. There were 1,030 MW of retirements in 2020, 650 MW coal and 380 MW gas. These changes are detailed in Section IV of the Appendix, along with a review of the vintage of the ERCOT fleet.

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

Figure 16 shows the annual composition of the generating output in ERCOT from 2014 to 2020. This figure shows the transition of ERCOT's portfolio away from coal-fired resources to natural gas and renewable resources. Some of this transition has been driven by the vintage of the generating fleet in ERCOT. For example, 70% of the total coal capacity in ERCOT was at least thirty years old in 2020. Combined cycle gas capacity was the predominant technology choice for new investment throughout the 1990s and early 2000s. However, since 2006, wind has been the primary technology for new investment. The contribution from solar is steadily growing.

Figure 16: Annual Generation Mix in ERCOT



This figure shows:

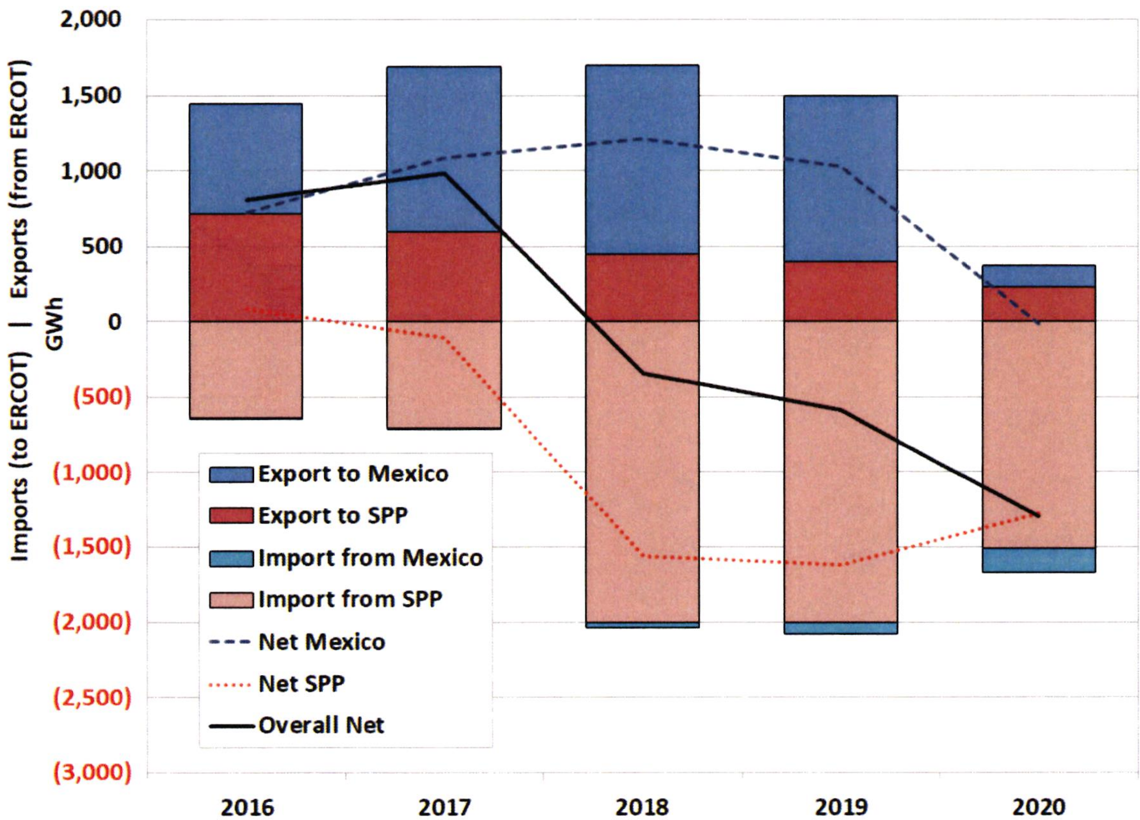
- The generation share from wind has increased every year, reaching almost 23% of the annual generation in 2020.
- The amount of utility-scale solar capacity added in 2020 (2,983 MW) was the largest amount of solar added to the ERCOT system in any given year, bringing total installed capacity to nearly 5,500 MW.
- The share of generation from coal continues to fall, down to approximately 18% in 2020.
- Natural gas generation decreased slightly, from 47% in 2019 to less than 46% in 2020.

We expect these trends to continue because of the continued growth of wind, solar, and storage resources. Figure A13 in the Appendix shows the vintage of ERCOT installed capacity. The installed generating capacity by type in each zone is shown in Figure A14 in the Appendix.

C. Imports to ERCOT

The ERCOT region is connected to other regions in North America via multiple asynchronous ties. Two ties totaling 820 MW connect ERCOT with the Southwest Power Pool (SPP) and three ties totaling 430 MW connect ERCOT with Comisión Federal de Electricidad (CFE) in Mexico. Transactions across the direct current (DC) ties can be in either direction, into or out of ERCOT. These transactions can have the effect of increasing demand (exports) or increasing supply (imports). Figure 17 shows the total energy transacted across the ties for the past several years.

Figure 17: Annual Energy Transacted Across DC Ties



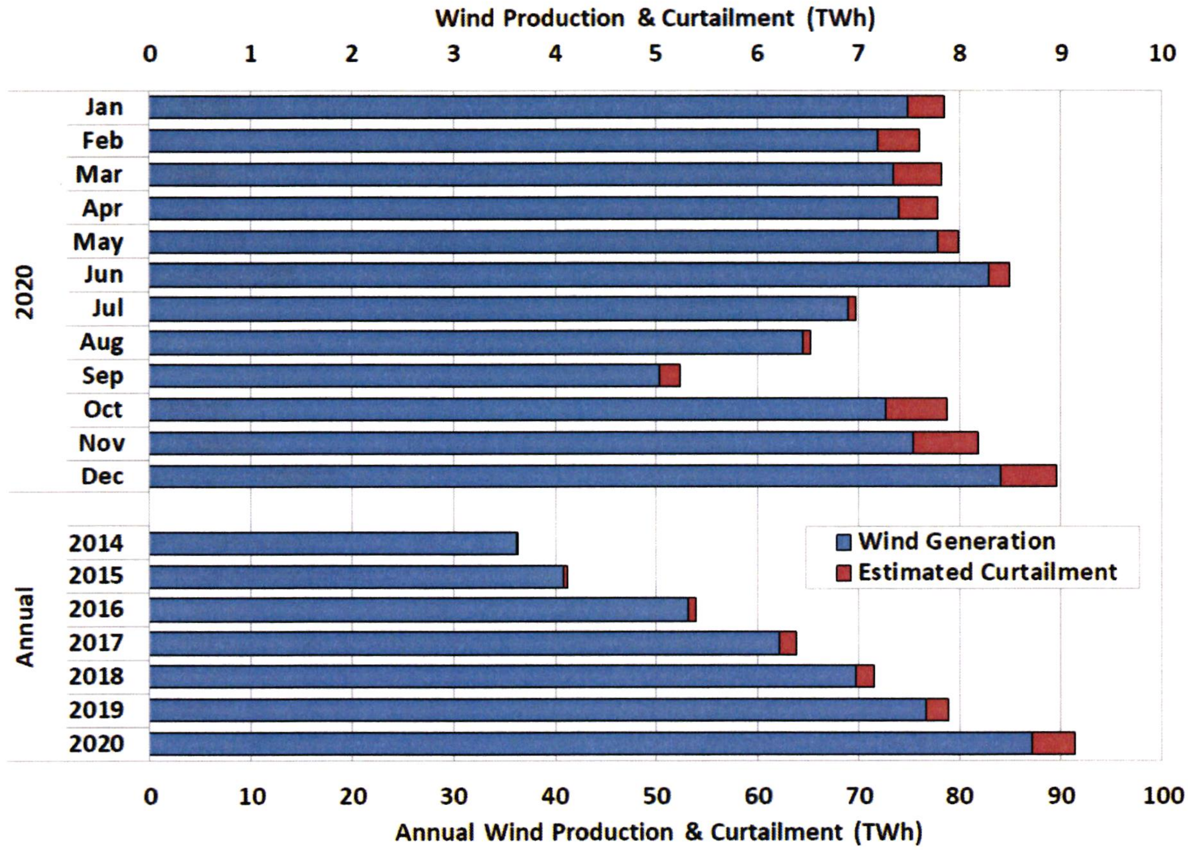
The figure shows that ERCOT remained a net importer in 2020. This trend began in 2018 due to tightening supply in ERCOT and the resulting higher prices in 2018 and 2019. But while that trend continued in 2020, total activity over the ties decreased, as both imports and exports on average were significantly lower in 2020. The only increase in 2020 were imports from Mexico, while exports to Mexico decline quite a bit. The decrease in tie activity is likely attributable to lower prices across the larger region in 2020.

D. Wind and Solar Output in ERCOT

Investment in wind resources has continued to increase over the past few years in ERCOT. The amount of wind capacity installed in ERCOT was more than 31 GW at the end of 2020. Although most wind generation is in the West zone, more than 7.8 GW of wind generation is located in the South zone and 2 GW are in the North zone.

The value of wind in satisfying ERCOT's peak summer demand is limited by its negative correlation with load.[14] The highest wind production occurs during non-summer months, and predominately during off-peak hours. Peak prices ($9,000 per MWh) in August 2019 coincided peak *net* load – when wind output was low and increased the demand on other generation units. Wind output during high load periods will continue to be a pivotal determinant of shortages.

Figure 18: Wind Production and Curtailment



ERCOT continued to set new records for peak wind output. A new wind output record was set on December 22, 2020 (21,972 MW). The amount of power produced by wind resources (23%) outpaced coal (18%) in 2020.

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

Figure 18 reveals that the total production from wind resources continued to increase in 2020, while the quantity of curtailments implemented to manage congestion caused by the wind resources also increased. These curtailments reduced wind output by less than 5%, compared to a peak of 17% in 2009.

Increasing wind output has important implications for non-wind resources, reducing the energy available for them to serve while not offering substantial contributions to serving the system's peak load requirements. This also has important implications for resource adequacy in the ERCOT. For additional analysis of wind output in ERCOT, see Figure A15, Figure A16, and Figure A17 in the Appendix.

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

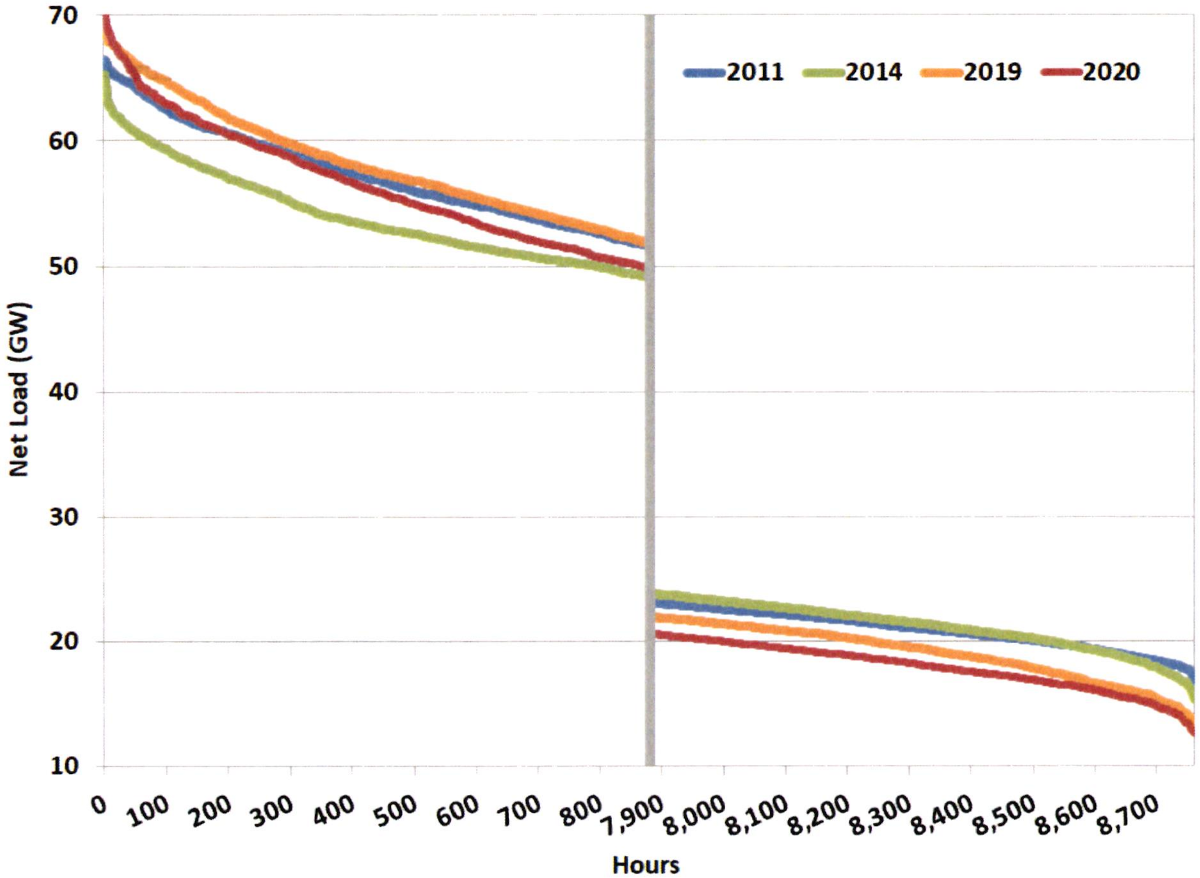


Figure 19 shows net load in the highest and lowest hours in 2020. Even with the increased development activity in the coastal area of the South zone, 67% of the wind resources in ERCOT are in West Texas (including the Panhandle). The wind profiles in this area result in only modest reductions of the net load relative to the actual load during the highest demand hours, but much larger reductions in the net load in the other hours. Hence, wind output displaces the load served by baseload units that often must produce at their minimum output level, particularly at night. This decreases the need for baseload resources and increasing the need for peaking resources.

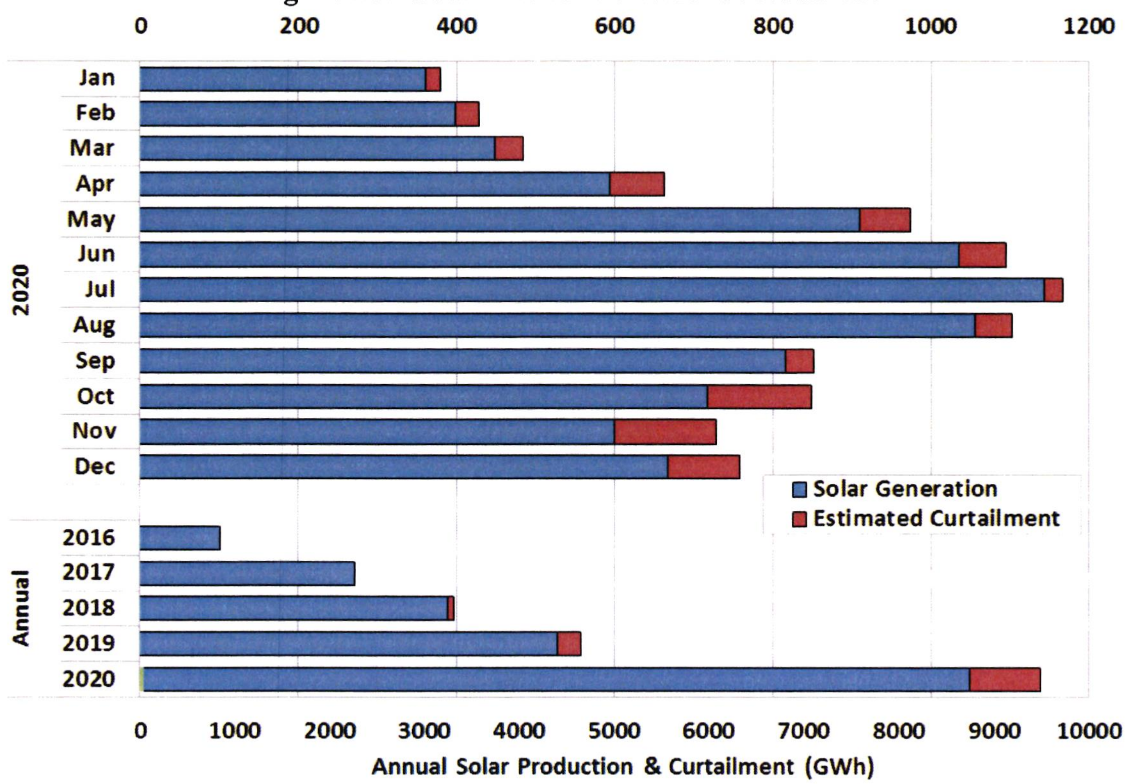
Figure 19 shows:

- In the hours with the highest net load (the left panel), the difference between the peak and the 95th percentile of net load was approaching 15 GW in 2020. This means that 15 GW of non-wind capacity is needed to serve load in less than 440 hours of the year in 2020.
- In the hours with the lowest net load (the right panel), the minimum net load has dropped from roughly 20 GW in 2007 to below 12.7 GW in 2020, despite the sizable growth in annual load. This trend has put economic pressure on nuclear and coal generation.

Peak net load is projected to continue to increase and create a growing need for non-wind capacity to satisfy ERCOT's reliability requirements. However, the non-wind fleet can expect to operate for fewer hours as wind penetration increases. This outlook further reinforces the importance of efficient energy pricing during peak demand conditions and other times of system stress, particularly in the context of the ERCOT energy-only market design. For an historical perspective on net load duration curves in ERCOT, see Figure A18 in the Appendix.

We note that solar resources, although a relatively small component of overall generation today, are positively correlated with load and produce at much higher capacity factors during summer peak hours. The capacity factors during these hours was almost 81% for facilities located in the west and 70% for those in central Texas. Hence, these resources provide a larger resource adequacy benefit than wind resources. Figure 20 shows that total solar production in 2020 was 8,700 GW, which was curtailed by 8% to manage congestion caused by solar resources.

Figure 20: Solar Production and Curtailment



E. Demand Response Capability

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

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

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

1. Reserve Markets

ERCOT allows qualified load resources to offer responsive reserves into the day-ahead ancillary services markets. Load relay response can be a highly effective mechanism for maintaining system frequency at 60Hz. Load resources providing responsive reserves have relay equipment that enables the load to be automatically tripped when the system frequency falls below 59.7 Hz (when demand exceeds supply). These events typically occur only a few times each year.

As of December 2020, approximately 6,926 MW of qualified load resources could provide responsive reserve service, an increase of approximately 1,420 MW during 2020.[15] However, the total amount of responsive reserves procured by ERCOT was a maximum of 1,856 MW per hour. During 2020, there were no deployments of load resources providing responsive reserve service. Figure 21 below shows the average amount of responsive reserves provided from load resources on a daily basis for the past three years.

Until June 1, 2018, 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.[16]

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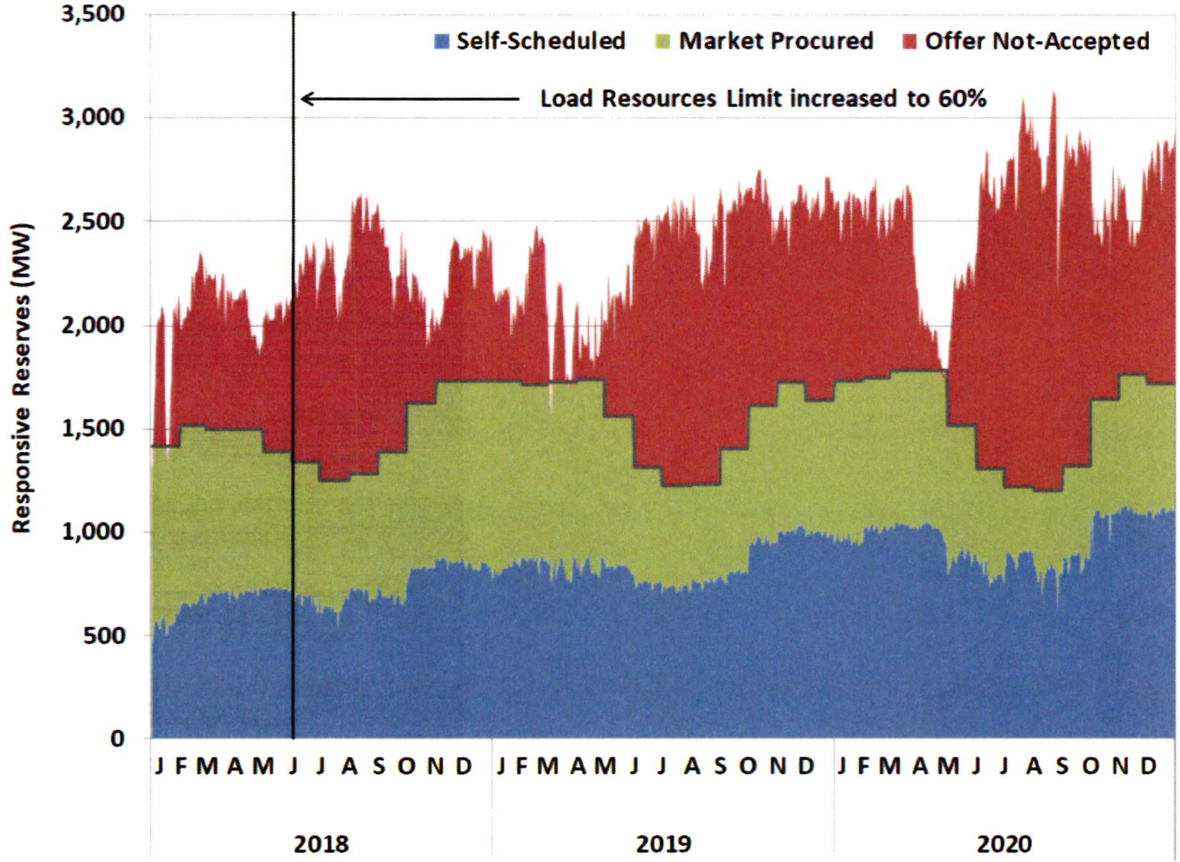
15 *See* ERCOT 2020 Annual Report of Demand Response in the ERCOT Region (Dec. 2020), available at http://www.ercot.com/services/programs/load.

16 *See* NPRR815: *Revise the Limitation of Load Resources Providing Responsive Reserve (RRS)* Service (http://www.ercot.com/mktrules/issues/NPRR815).

Figure 21: Daily Average of Responsive Reserves Provided by Load Resources



Beginning with calendar year 2021, NERC standards will require an increase in this floor to 1,420 MW. Necessarily, this will decrease in the amount of capacity that can come from load resources. There were more offers for load providing responsive reserve than the limit for almost all of 2020, and the total amount of surplus offer MWs grew by nearly 20% from the previous year. Modifying the pricing structure, as discussed in recommendation No. 2019-2 above, would remove the inappropriate incentives that are leading to this oversupply.

2. Reliability Programs

There are two main reliability programs in which demand can participate: i) ERS, administered by ERCOT, and ii) load management programs offered by the transmission and distribution utilities (TDUs). The ERS program is defined by a Commission rule enacted in March 2012, which set a program budget of $50 million.[17] The time- and capacity-weighted average price for ERS over the contract periods from February 2020 through January 2021 was $6.06 per MWh, down from $6.59 per MWh the previous program year. This price was lower than the average price paid responsive reserves ($11.40 on average) in 2020 but higher than non-spinning reserves ($4.45 on average).

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[17] *See* 16 TAC § 25.507.

There were slightly more than 285 MW of load participating in load management programs administered by the TDUs in 2020, which grew to 308 MWs in the months of August and September.[18] 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.[19] These programs administered by TDUs may be deployed by ERCOT during a Level 2 Energy Emergency Alert (EEA).

3. Self-dispatch

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

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

Of these two methods, the most significant impacts are related to actions taken to avoid incurring transmission costs that are charged to certain classes of customers based on their usage at system peak. For decades, transmission costs have been 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 doubled since 2012, increasing an already significant incentive to reduce load during probable peak intervals in the summer. ERCOT estimates that as much as 2,800 MW of load were actively pursuing reduction during the 4CP intervals in 2020, higher than the 2019 estimate.[20]

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

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18 *See* ERCOT 2020 Annual Report of Demand Response in the ERCOT Region (Dec. 2020) at 10, available at http://www.ercot.com/services/programs/load.

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

20 See ERCOT, 2020 Annual Report of Demand Response in the ERCOT Region (Dec. 2020) at 18, available at http://www.ercot.com/services/programs/load.

4. Demand Response and Market Pricing

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

For the first time, there were loads qualified to participate in real-time dispatch. In 2020, three new Controllable Load Resources (CLRs) were registered and added to the ERCOT Network Model. These CLRs consist of data centers that have hundreds of servers that can be turned on and off on demand. The data centers use fast acting control systems to respond to frequency similar to the governors on a conventional thermal plant, which gives them the ability to follow base points from SCED. These CLRs have over 100 MW of online capacity and can participate in responsive reserve service, regulation service, and non-spinning reserve service. This represents the first substantial amount of conventional Load to participate in the Ancillary Services market as a CLR. As this segment grows, considering nodal pricing for CLRs will become more important and impactful.

Second, the reliability deployment price adder (RDPA), discussed in more detail in Section I, includes a separate pricing run of the dispatch software to account for reliability actions. A flaw in this was revealed in 2021 in that it does not directly account for firm load shed instruction by ERCOT, and thus the adder is undervalued during EEA. We recommend that this be changed, as noted in recommendation No. 2020-1 above.

III. Day-Ahead Market Performance

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

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

In addition to the purchase and sale of power, the 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. Although all bids and offers are cleared respecting the limitations of the transmission network, there are no operational obligations resulting from the day-ahead market. 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 the day-ahead market is essential.

In this section, we examine day-ahead energy prices in 2020 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. Overall, 2020 day-ahead prices were lower than 2019 for both energy and ancillary services, as expected given the higher reserve margin. Liquidity in the day-ahead market was similar to previous years, which included active trading of congestion products in the day-ahead market.

Table 3 below compares the average annual price for each ancillary service over the last three years, showing that the prices were lower for each product in 2020. The decrease in ancillary services prices caused the average ancillary service cost per MWh of load to decrease to $1.00 per MWh in 2020 from $2.33 per MWh in 2019.

Table 3: Average Annual Ancillary Service Prices by Service

	2018 ($/MWh)	2019 ($/MWh)	2020 ($/MWh)
Responsive Reserve	**$17.64**	**$26.61**	**$11.40**
Non-spin Reserve	**$9.20**	**$13.44**	**$4.45**
Regulation Up	**$14.03**	**$23.14**	**$11.32**
Regulation Down	**$5.19**	**$9.06**	**$8.45**