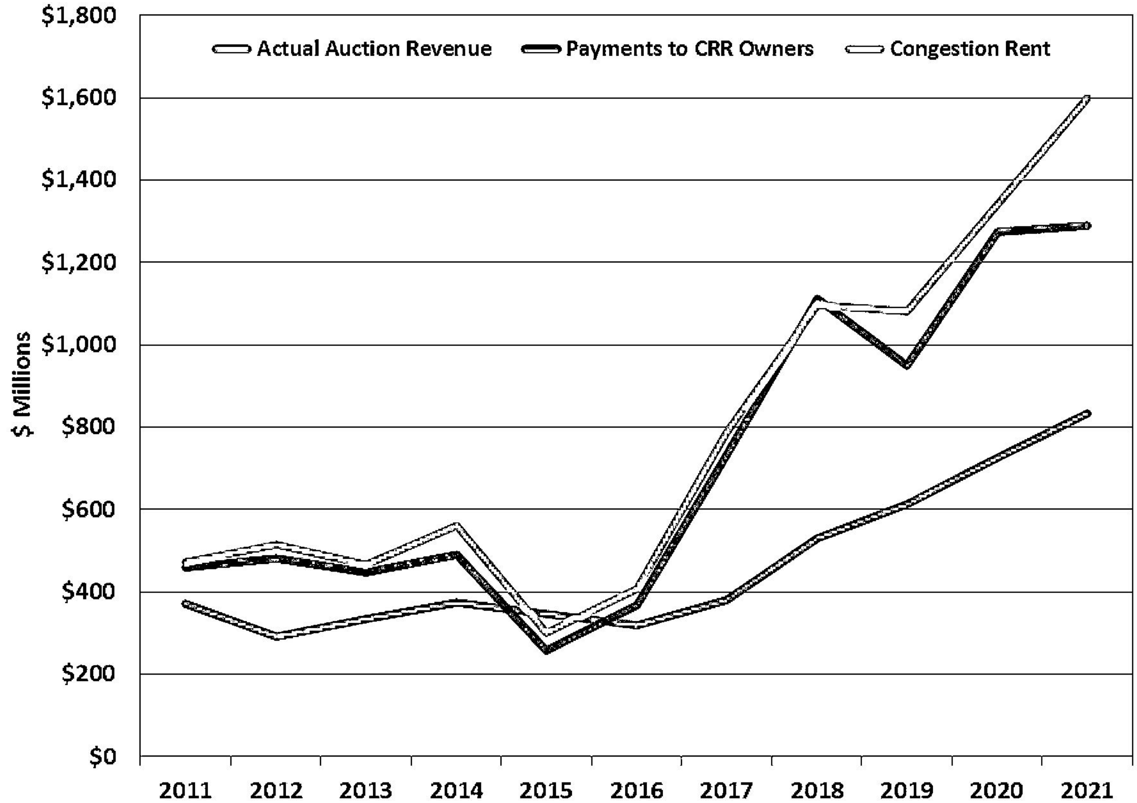
Figure 47: CRR History



In 2021, like the four years prior, CRRs were profitable in aggregate because of unanticipated factors that led to much higher congestion. Note that this "profit" does not account for the time value of money, which is notable because a CRR is paid for at the time of the auction and that auctions can be as much as three years in advance.

Figure 47 above shows that actual congestion continues to rise more quickly than CRR auction revenues, although these revenues have been increasing in recent years. This is not unexpected because the markets must forecast the actual revenues and, even after the congestion has begun to materialize, must determine whether it will be sustained. Figure A39 in the Appendix shows the price spreads between each hub and its corresponding load zone separately at: the average of the six semi-annual CRR auctions, at the monthly CRR auction, day-ahead, and real-time.

6. CRR Funding Levels

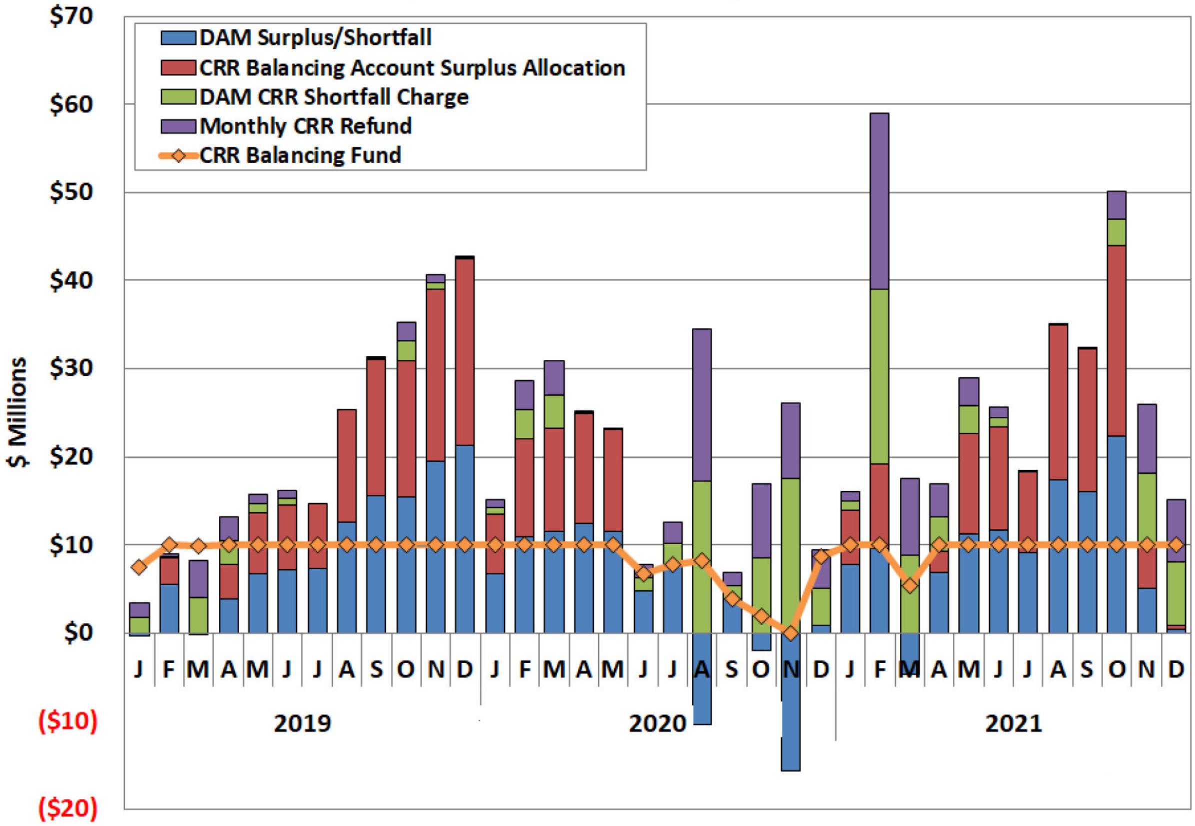
The target value of a CRR is the quantity of the CRR multiplied by the price difference between sink and source. It is desirable for the payout to fully equal the target value because it makes the CRR more valuable to the holder and ultimately will increase the CRR auction revenues. While the target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

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

Sometimes there is excess day-ahead congestion rent that has not been paid out to CRR account holders at the end of the month (undersold hours). In that case, the excess congestion rent is tracked in a monthly settlement process referred to as the balancing account. Excess congestion rent residing in this balancing account is used to make the CRR account holders that received shortfall charges whole, i.e., they are refunded their shortfall charges. If there is not enough excess congestion rent from the current month to refund all shortfall charges, the rolling CRR balancing fund from prior months can be used to fully pay CRR account holders that received shortfall charges. Figure 48 shows the CRR balancing fund since the beginning of 2019. The CRR balancing fund has a $10 million cap, beyond which the remaining is dispersed to load.

The fact that ERCOT's processes are designed to only sell 90% of the forecasted transmission capability makes funding shortfalls less likely. Figure 48 shows that in 2021, despite this design, CRR holders experienced shortfalls in March due to the unmodeled outages in the auction. The total day-ahead surplus was nearly about $111 million, much higher than the $42 million surplus in 2020, but similar to the surplus of $115 million in 2019. From the perspective of the load, the monthly CRR balancing account allocation to load totaled amount of $56 million at the end of the year.

Figure 48: CRR Balancing Fund



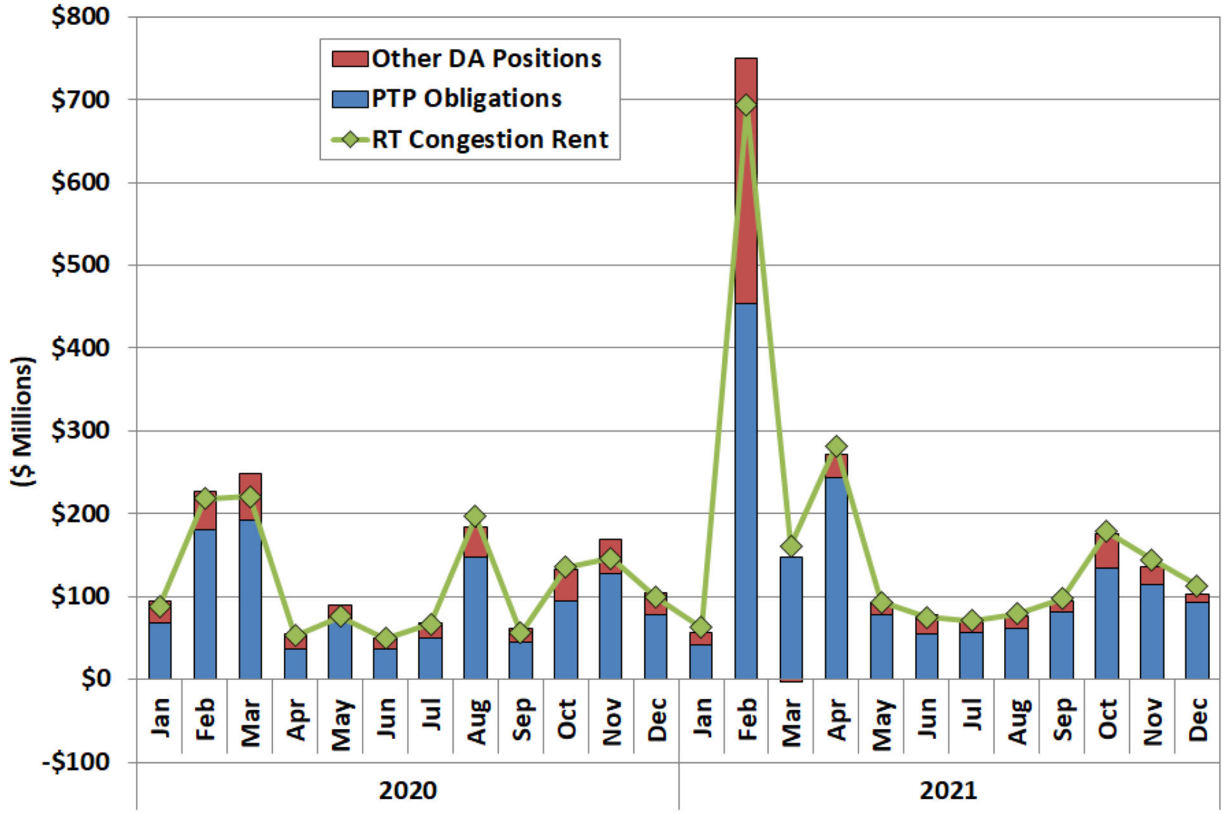
Importantly, even though the DAM produced more than enough revenues to fully fund the CRRs, many CRRs were derated in 2021 and not paid the full target value due to the mandatory deration process. In total, CRR deratings resulted in a $32 million reduction in payments to CRR holders. These deratings reduced ERCOT's overall funding percentage to 98%, about the same as the previous year. ERCOT's deratings and shortfalls are shown on a monthly basis in Figure A40 in the Appendix. Derating CRRs, especially when the market is producing sufficient revenue to fully fund them, introduces unnecessary risk to those buying CRRs, which ultimately results in lower CRR auction revenues.

7. Real-Time Congestion Shortfalls

Just as reductions in network capability from the CRR auctions to the DAM can result in CRR shortfalls, reductions in the network capability between the DAM and the real-time market can result in real-time congestion shortfalls. In addition to outages or limit changes, a binding real-time constraint that is not modeled in the DAM can result in real-time congestion shortfalls. In summary, if ERCOT schedules more flows in the DAM over the network than it can support in real time, there may be more financial rights sold than congestion rent generated in real time. These real-time congestion shortfall costs are paid for by charges to load as part of the uplift charge known as Real-Time Revenue Neutrality Allocation or "RENA".

The day-ahead schedule flows are comprised of PTP obligations and other day-ahead positions that generate flows over the network. Figure 49 shows the combined payments to all these day-ahead positions compared to the total real-time congestion rent.

Figure 49: Real-Time Congestion Rent and Payments



In 2021, real-time congestion rent was $2,052 million, while payments for PTP obligations (including those with links to CRR options) were $1,563 million and payments for other day-ahead positions were $489 million. This resulted in a shortfall of approximately $80 million for the year. By comparison, payments for PTP obligations and options were $1,125 million in 2020 and payments for other day-ahead positions were $356 million, resulting in a shortfall of approximately $75 million for the year. Higher congestion cost can tend to also drive higher shortfall amounts; in general, ERCOT has improved in coordinating the network capability in its day-ahead and real-time market. Continuous improvement in this area should be the goal of all ISOs.

VI. RELIABILITY COMMITMENTS

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

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

When ERCOT makes these RUCs, the units become eligible for a make-whole payment, but also forfeit some or all market profit through a "clawback" provision. Generators complying with a RUC instruction are guaranteed to recover their costs, but any market revenue received in excess of their costs are either partially or fully taken away. However, suppliers can opt to forfeit the make-whole payments and waive the clawback charges, effectively self-committing the resource and accepting the market risks.

From a market pricing perspective, ERCOT applies an offer floor of $1,500 per MWh the resource and calculates a Real-Time On-Line Reliability Deployment Adder (reliability adder) that was described in Section I. In the past three years, ERCOT made several improvements to the RUC process relating to fast-starting generators and switchable generators that are dually connected to other control areas. These improvements had caused the number of RUCs to drop dramatically, a trend that is ended suddenly in June 2021 when ERCOT adopted its conservative operational posture. For a complete list of the historical changes in the RUC processes and rules, see Section VI in the Appendix.

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

A. RUC Outcomes

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

- To satisfy the forecasted system-wide demand (80% of RUC commitments in 2021); or
- To make a specific generator available resolve a transmission constraint (20% of RUC commitments in 2021).

In 2020, all RUC commitment reasons were all issued to manage transmission congestion. However, that changed in 2021 with an overall increase to the number of RUC instructions, most of them for capacity. The 4,052 unit-hours of RUC instructions were issued in 2021, compared to the 224 unit-hours in 2020, and were the highest number since the start of the nodal market.

Figure 50 shows RUC activity by month for the past three years, indicating the volume of generators receiving a RUC instruction that had offers in the DAM or chose to opt-out of the RUC instruction. It shows the shows the tremendous increase in RUC in the latter half of the year, peaking in July under ERCOT's new conservative operational posture.

Figure 50: Day-Ahead Market Activity of Generators Receiving a RUC

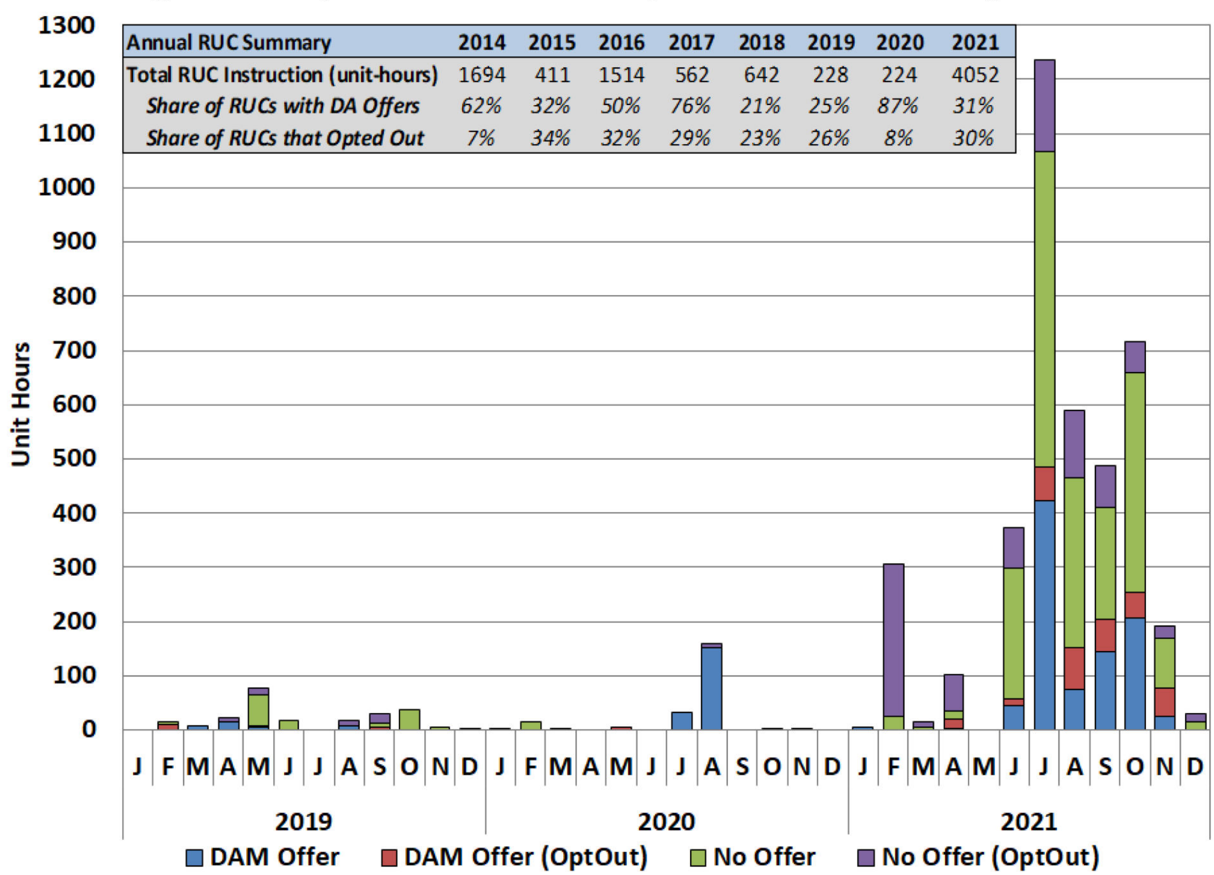


Table 6 below lists the generation resources that received the most RUC instructions in 2021 and includes the total hours each unit was settled as a RUC and the number of hours in which the unit opted out of RUC settlement. The unit highlighted in gray received similar RUC instructions in 2020. About 80% of the RUC-Resource hour instructions for 2021 were for capacity, and the other 20% was for congestion. The RUC instructions were geographically distributed as follows: 19% in the South zone, 10% in the West zone, 7% in the Houston zone, and the remaining 64% in the North zone.

Table 6: Most Frequent Reliability Unit Commitments

Resource	Location	Unit-RUC Hours	Unit OPTOUT Hours	Average LSL during Dispatchable Hours	Average LDL during Dispatchable Hours	Average Dispatch during Dispatchable Hours	Average HSL during Dispatchable Hours
R W Miller STG 2	DFW	279	59	39	41	43	105
Stryker Creek Unit 1A	East Texas	227	65	35	50	53	169
Lake Hubbard Unit 1	DFW	153	97	59	127	137	386
Graham Unit 1	DFW	171	71	46	84	102	236
Trinidad Unit 6	DFW	188	50	51	69	79	237
Lake Hubbard Unit 2A	DFW	163	32	48	116	122	518
Braunig VHB2	San Antonio	176	18	91	91	91	230
Stryker Creek Unit 2	DFW	128	49	35	115	124	472
Graham Unit 2	DFW	110	17	36	62	66	391
Handley Unit 3	DFW	123	-	100	102	103	375
R W Miller STG 3	DFW	100	16	43	50	53	199
Mountain Creek Unit 8	DFW	50	47	160	201	210	562
Spencer Unit 4	DFW	56	40	15	16	17	43
Braunig VHB1	San Antonio	55	39	61	81	94	217
Ray Olinger CTG 3	DFW	93	1	25	25	25	134

Our next analysis compares the average real-time dispatched output of the reliability-committed units, including those that opted out, with the average operational limits of the units. It shows that the monthly average SCED dispatch of units receiving RUC instructions has rarely been close to the average high capacity limit.

- The average quantity dispatched exceeded the respective average low-sustainable limit (LSL) for all months in 2021 with RUC instructions.
- No RUC activity occurred in May.
- In February through December, excluding May 2021, the average dispatch level was more than the average low limit because of scarcity in February and mitigation of the resource in the other months.
- Also, in the same months previously mentioned, the average dispatch level was higher due to some RUC resources choosing to opt out and thus not being subject to the $1,500 per MWh offer floor.

Figure 51: Average Reliability Unit Commitment Capacity and Dispatch Level

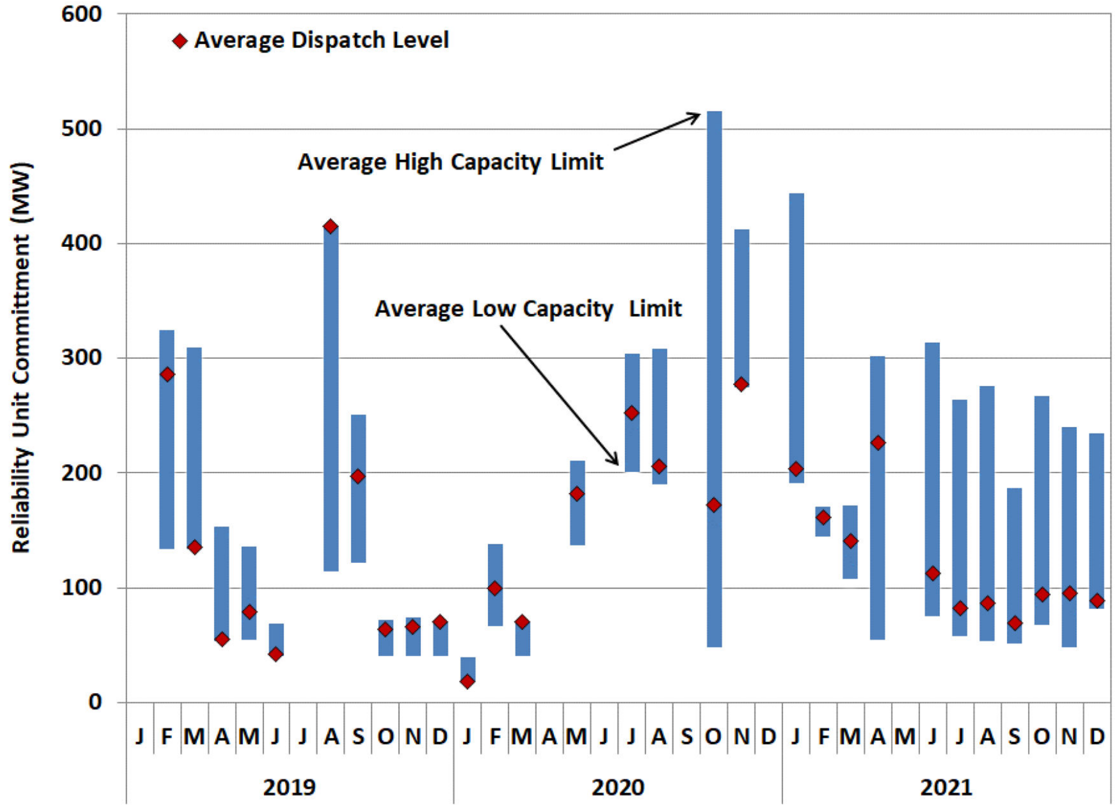


Table 7 displays the total annual amounts of make-whole payments and clawback charges attributable to RUCs since 2011. There are two sources of funding for RUC make-whole payments. The first is from QSEs that do not provide enough capacity to meet their short real-time position, rendering them "capacity short." The remaining make-whole amount is uplifted to all QSEs on a load-ratio share basis. RUC make-whole payments in 2021 were collected almost exclusively from QSEs that were capacity short.

Table 7: RUC Settlement Quantities

	Claw-Back from Generator in millions	Make-Whole to Generator in millions
2011	$8.54	$27.80
2012	$0.34	$0.44
2013	$1.15	$2.88
2014	$2.81	$3.83
2015	$0.34	$0.48
2016	$1.41	$1.24
2017	$1.20	$0.54
2018	$3.07	$0.61
2019	$0.90	$0.05
2020	$0.48	$0.40
2021	$3.11	$5.25

Table 7 shows that the make-whole payments rose significantly to roughly $5.3 million in 2021, higher than any year since the early part of the nodal market in 2011. This increase from preceding years was due to ERCOT's desire to have at least 6,500 MW in reserve above the load forecast, which began in July 2021. The clawback amount was lower than the make-whole payment in 2021. In theory, the clawback amount should be low because units that are economic (and therefore subject to the clawback provision) would generally benefit by opting out of the RUC instruction, if such profitability is foreseeable. However, that will diverge if ERCOT is relying on more conservative forecasts than the market participants are using in their commitment decisions. In 2021, approximately 30% of RUC units opted out.

RUC Generators with Day-Ahead Offers. Generators that participate in the DAM forfeit only 50% of markets revenues above cost through the clawback, rather than 100%. In 2021, 31% of the total RUC unit-hours had day-ahead offers within the RUC-hour, a sharp decrease from 2020 when 87% of the total RUC unit-hours had day-ahead offers, likely attributable to the pivot in conservative operations in the latter half of 2021.

Section VI in the Appendix provides more detail on the RUC activity, showing total activity by month, statistics on day-ahead offers and decisions to opt-out of the RUC instruction, as well as the RUC instructions issued to individual generating resources. Section V also summarizes the dispatch levels of the RUC resources, which is generally at their low dispatch limit (LDL) given the $1,500 per MWh offer floor. However, RUC resources were dispatched above their LDLs in 2021 because of the mitigation of some of the resources committed to resolve non-competitive constraints. That mitigation eliminates the $1,500 per MWh offer floor for those resources in those RUC intervals and dispatches them on their mitigated offer curve.

B. Operational Reserves Compared to Market Reserves

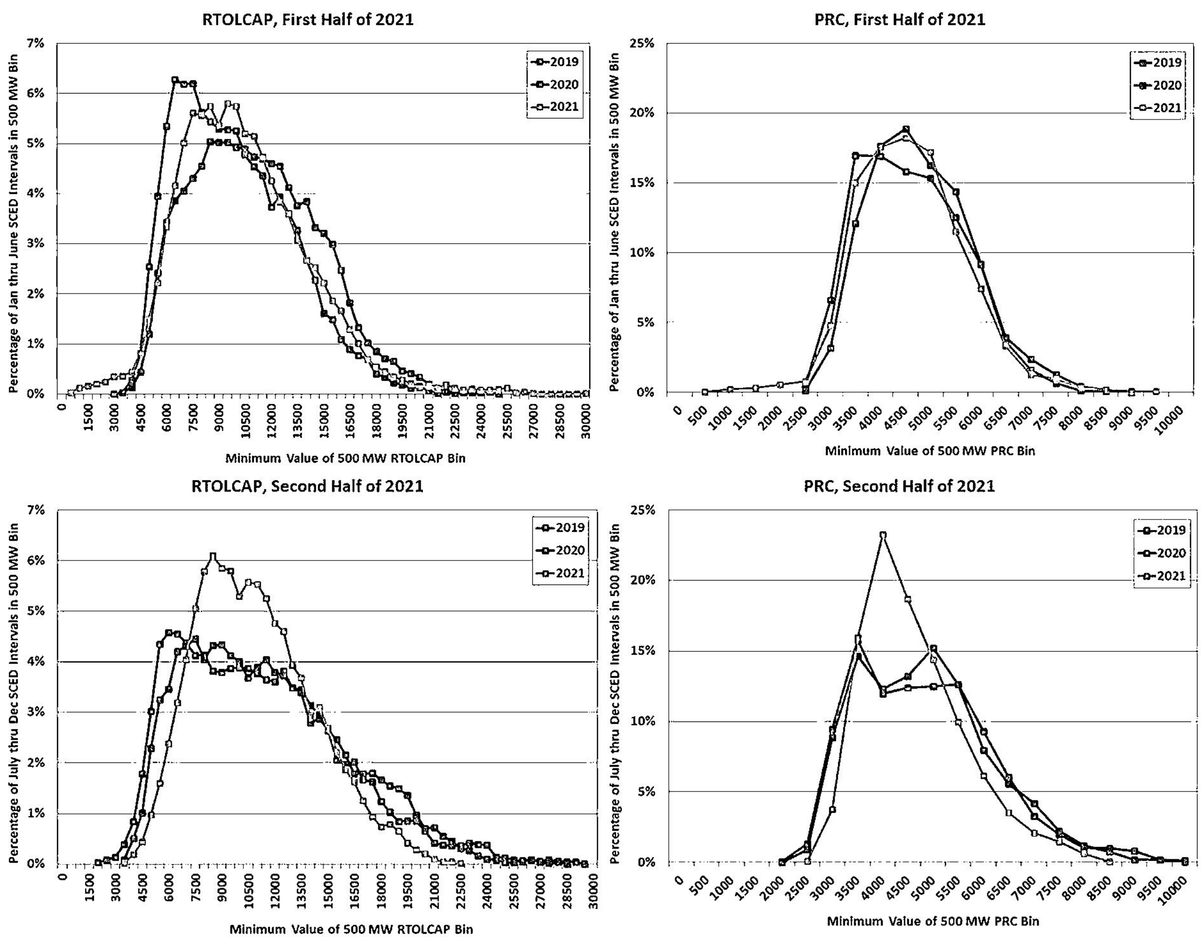
The IMM performed an analysis comparing the operational reserves to the market reserves (Physical Responsive Capability[79] or PRC vs Real-Time On-Line Reserve Capacity[80] or RTOLCAP) for 2019 through 2021. The two reserve calculations can diverge because different types of capacity are counted in the two metrics. Additionally, when units with RUC instructions are online, the capacity provided by those units is excluded from the ORDC capacity calculation. The additional non-spinning reserve procurement and increased RUC activity have contributed to both higher PRC and a more marked divergence in the two measures of reserve in the second half of 2021. It is important for the real-time market prices to reflect the underlying reliability conditions such as loss of load probability.

79 A representation of the total amount of frequency responsive online reserve capacity.

80 Real-Time On-Line reserve capacity of all On-Line Resources that remains after SCED dispatch instructions.

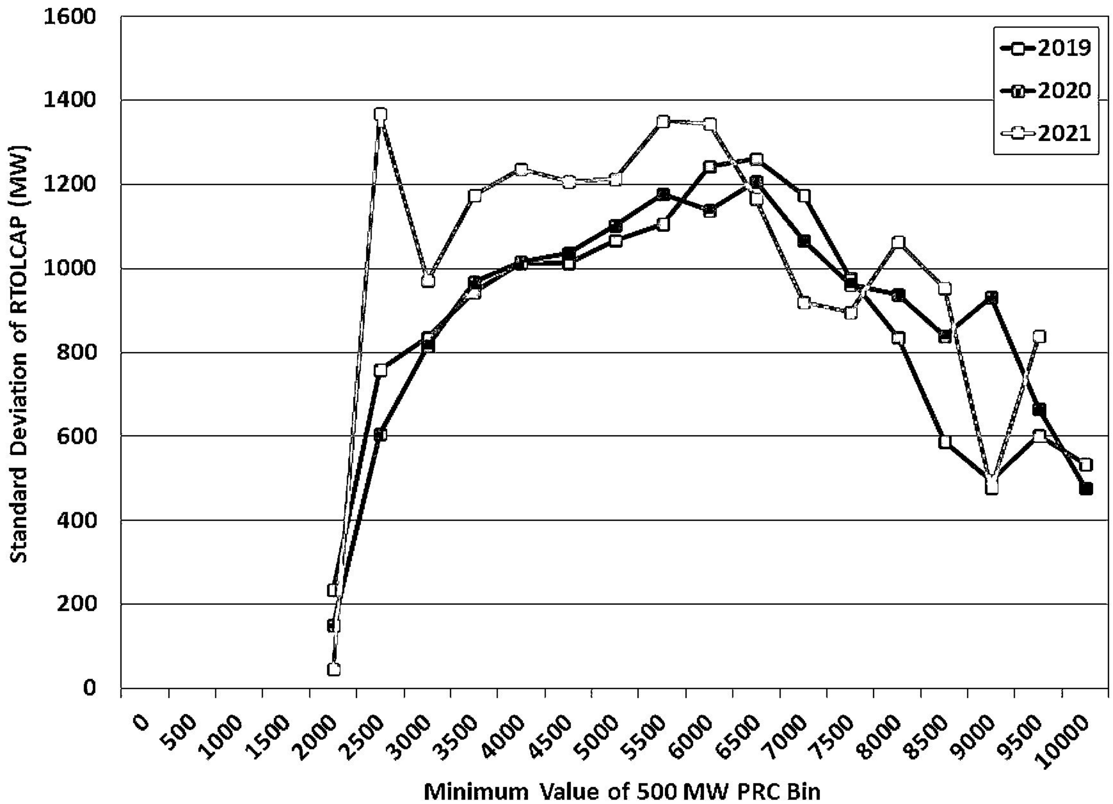
First, we evaluate histograms of the distributions of PRC (a measure of frequency responsive online reserves) and RTOLCAP (a measure of total online reserves) for the first and second halves of the years 2019 through 2021. The top part of Figure 52 shows histograms for the first half of the year and the bottom part shows histograms for the second half of the year. Each year line represents somewhat different shape, driven by the unique grid and market conditions of that year. However, the second half of 2021 shows a more marked departure from the other two recent years. This time period coincides with ERCOT's new conservative operational posture, which includes significantly higher frequency and magnitude of RUC commitments. In comparison to the other years, the second half of 2021 has markedly fewer intervals in the range of PRC below 3,500 MW and RTOLCAP below 6,000 MW, more intervals in the range of PRC between 3,500 MW and 5,000 MW and RTOLCAP between 7,500 and 12,500 MW.

Figure 52: RTOLCAP and PRC Histograms



Second, Figure 52 shows the standard deviation of the RTOLCAP values for each 500 MW bin of PRC, for 2019 through 2021. Note that this figure excludes both the week of Winter Storm Uri as well as the week after, since they are outliers on both ends of the spectrum. Due to the pendulum effect of that event, in the week after the storm many generators stayed online for several days despite negative prices. The increase in the standard deviation is attributable to increased variability in the relationship between PRC and RTOLCAP in the months following ERCOT's change in operational posture. During this time there are periods where there are large amounts of capacity that was under RUC instruction and therefore contributing to PRC but not to RTOLCAP. RUC activity can cause operational reserves and market reserves to diverge from their historical relationship and therefore prices to diverge from the historical relationship with grid reliability conditions.

Figure 53: Standard deviation of RTOLCAP at different levels of PRC[81]



C. QSE Operation Planning

The Current Operating Plan (COP) is the mechanism used by QSEs to communicate the expected status of their resources to ERCOT. After aggregating COP information about the amount of capacity that QSEs expect to be online every hour, ERCOT then evaluates any potential locational or system-wide capacity deficiency. If such a deficiency is identified and there is insufficient time remaining in the adjustment period to allow for self-commitment, ERCOT will issue a RUC instruction to ameliorate the shortfall.

81 Data for all 3 years except February 13-26, 2021.

The accuracy of COP information greatly influences ERCOT's ability to effectively perform supplemental commitment using the RUC process. COPs are updated on an ongoing basis by QSEs, providing multiple views of their expectations for a particular operating hour. Presumably, QSE expectations about which units will be online in a particular hour are most accurate for the COP submitted just before the operating hour. Figure 54 evaluates the accuracy of the COPs by showing the average difference between the actual online unit capacity and the capacity represented in the COPs in the peak hours (hour ending 12-20) in July and August, as submitted each of the 24 hours leading up to the close of the adjustment period. We show these differences for each of the past three years.

Figure 54: Capacity Commitment Timing – July and August Hour Ending 12 through 20

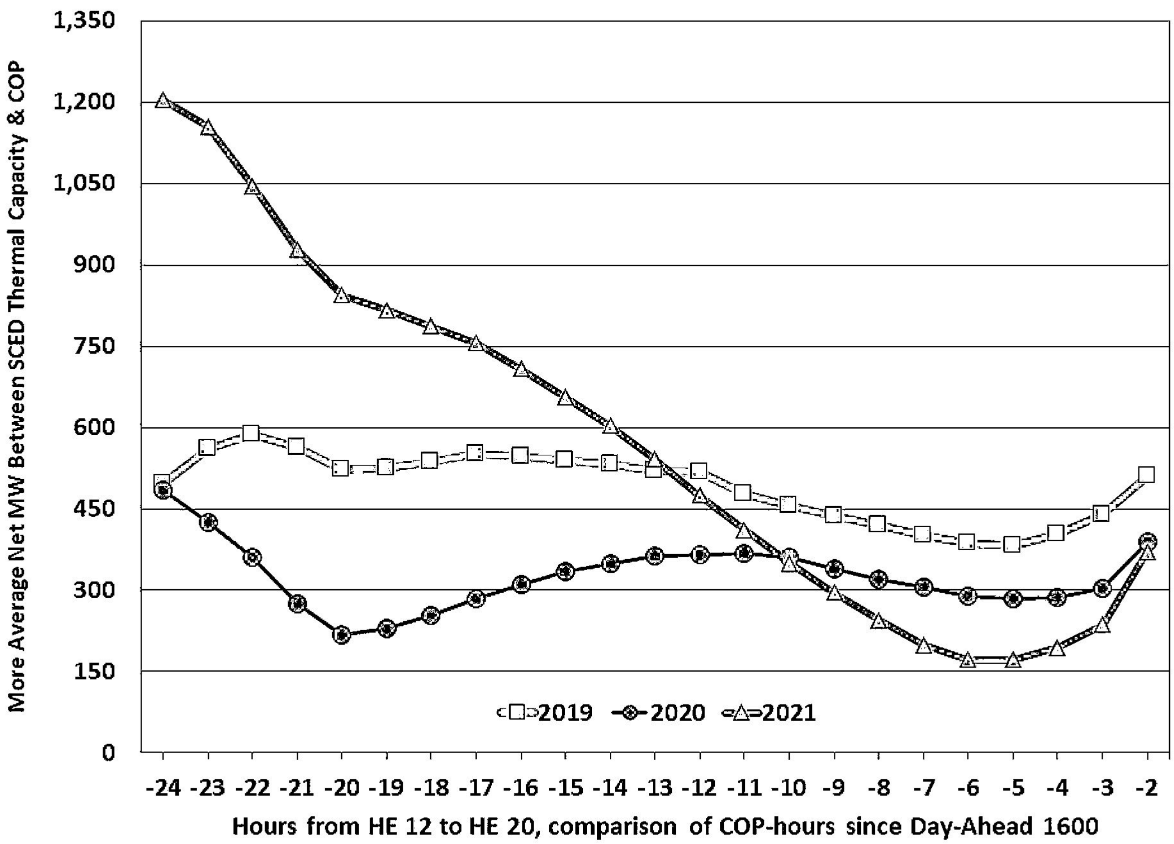


Figure 54 shows that the amount of online capacity in real-time exceeded the thermal capacity represented in COPs at the end of the adjustment period, signifying that generators either did not reflect their commitment decisions in their COPs or changed their commitment decisions within the operating period. Commitment of resources for hours ending 10 to 24 show that 2021 had much later commitments on average than in 2020. The difference in the last COP on average was very similar, however, in 2021 as it was in 2020.

Additional analysis on COP behavior is presented in the Section VI of the Appendix, which includes the analysis of hour ending 17 discussed above.

VII. Resource Adequacy

One of the primary functions of the organized wholesale electricity market is to provide economic signals that will facilitate investment needed to maintain a set of resources adequate to satisfy the system's needs. Without revenue contributions from an installed capacity market, energy and reserve prices provide the only funding for compensation to generators. To ensure that revenues will be sufficient to maintain resource adequacy in an energy-only market, prices should rise during shortage conditions to reflect the diminished reliability and increased possibility of involuntary curtailment of service to customers. The sufficiency of revenues is a long-term expectation and will not necessarily be met in any one year: actual revenues may vary greatly from year to year.

The ERCOT market has seen many years of excess generation capacity, with revenues less than estimated costs of investing in new generation (known as the "cost of new entry" or CONE). If long-term expectations of revenues sufficient to support resource adequacy are to be met, revenues that far exceed the CONE must occur in some years as well. This principle of cyclical revenue sufficiency to maintain resource adequacy is applied in the evaluation in this section.

This section begins with our evaluation of these economic signals in 2021 by estimating the "net revenue" that resources received from the ERCOT real-time and ancillary services markets and providing comparisons to other markets. Next, we review the effectiveness of the Scarcity Pricing Mechanism.[82] We present the current estimate of planning reserve margins for ERCOT, followed by a description of the factors necessary to ensure resource adequacy in an energy-only market design, subject to the previous discussion in the Future Needs section. Finally, we conclude with a discussion of the Reliability Must Run and Must Run Alternative (MRA) processes in ERCOT in 2021.

A. Net Revenue Analysis

We calculate net revenue by determining the total revenue that could have been earned by a generating unit less its variable production costs. Put another way, it is the revenue in excess of short-run operating costs that is available to recover a unit's fixed and capital costs, including a return on the investment. In ERCOT's energy-only market, the net revenues from the ancillary services and real-time energy markets alone provide the economic signals that inform suppliers' decisions to invest in new generation or, conversely, to retire existing generation. To the extent that revenues are available through the DAM or other forward bilateral contract markets, these revenues are ultimately derived from the expected ancillary service and real-time energy prices. Although most suppliers are likely to receive the bulk of their revenues through bilateral

[82] *See* 16 TAC §25.505(g). This report generally employs the more accurate "shortage pricing" terminology in place of "scarcity pricing", except in cases where Scarcity is part of a name.

contracts, the spot prices produced in the real-time energy market should drive bilateral energy prices over time and thus are appropriate to use for this evaluation. It is important to note that this net revenue calculation is a look back at the estimated contribution based on actual market outcomes. Suppliers will typically base investment decisions on expectations of future electricity prices. Although expectations of future prices are informed by history, they also factor in the likelihood of shortage pricing conditions that may or may not actually occur.

In this analysis, we compute the energy net revenues based on the generation-weighted settlement point prices from the real-time energy market.[83] The analysis may over-estimate the net revenues because it does not include: 1) start-up and minimum energy costs; or 2) ramping restrictions that can prevent generators from profiting during brief price spikes. Despite these limitations, the analysis provides a useful summary of signals for investment in ERCOT.

The next figures provide an historical perspective of the net revenues available to support investment in a new natural gas combustion turbine (Figure 55 includes Winter Storm Uri and Figure 56 excludes Winter Storm Uri) and combined cycle generation (Figure 57 includes Winter Storm Uri and Figure 58 excludes Winter Storm Uri), which we selected to represent the marginal new supply that may enter when new resources are needed. We calculate net revenues for these units by assuming they will produce energy in any hour in which it is profitable to do so. We further assume that when they are not producing energy, that both types of units will be available to sell responsive or non-spinning reserves in other hours, and that combined cycle units can provide regulation.[84] The figures also show the estimated CONE for each technology for comparison purposes.

These figures show that in 2021, the estimated CONE values for both types of resources increased, with the CONE values for natural gas combustion turbines ranging from $70 to $117 per kW-year. Due to the extreme prices during Winter Storm Uri, the ERCOT market did provide net revenues above the CONE level needed to support new investment in 2021:

- Net revenues for combustion turbines rose to almost $700 per kW-year across all zones (net revenues would have ranged from $60 per kW-year to $78 per kW-year but for Winter Storm Uri); while
- Net revenues for combined-cycle units rose to almost $800 per kW-year across all zones (net revenues would have ranged from $81 per kW-year to $105 per kW-year but for Winter Storm Uri).

In an energy-only market, shortages play a key role in delivering the net revenues an investor needs to recover its investment. Such shortages will tend to be clustered in years with unusually high load or poor generator availability – both of which occurred during Winter Storm Uri.

83 This can mask the effects of unusually high or low prices at a specific generator location.

84 For purposes of this analysis, we used the following assumptions: heat rates of 7 MMBtu per MWh for a combined cycle unit, 10.5 MMBtu per MWh for a gas turbine, and $4 per MWh in variable operating and maintenance costs. A total outage rate (planned and forced) of 10% was assumed for each technology.

Figure 55: Combustion Turbine Net Revenues (with Uri)

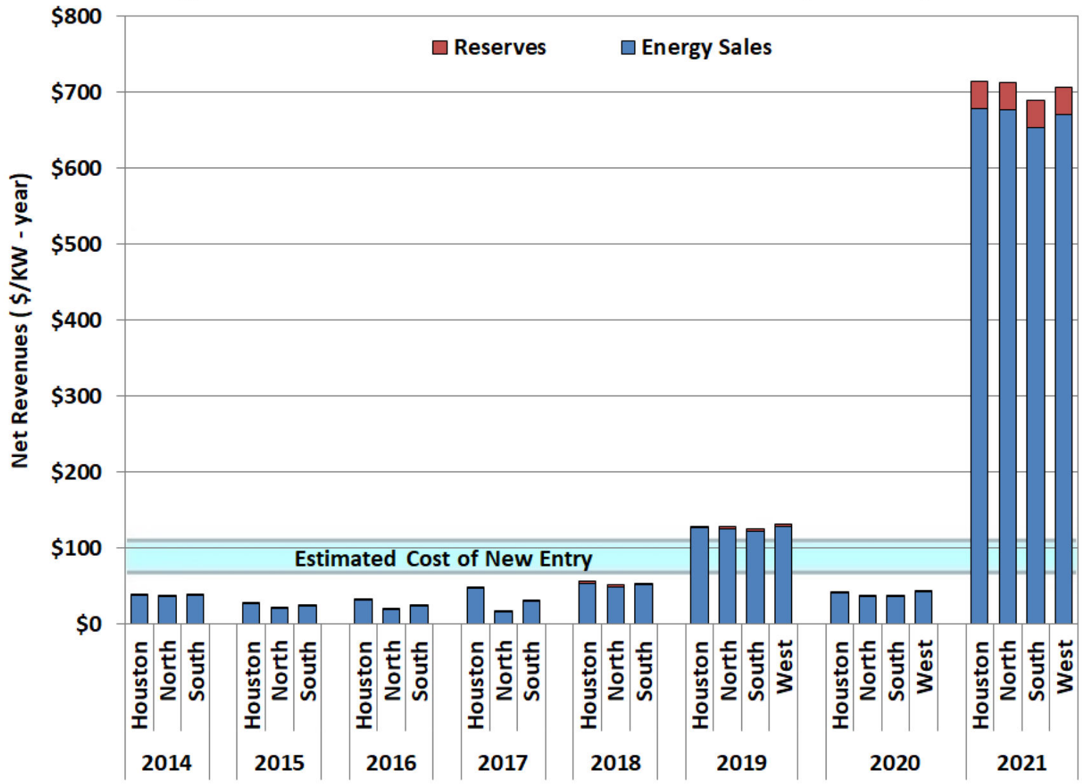


Figure 56: Combustion Turbine Net Revenues (without Uri)

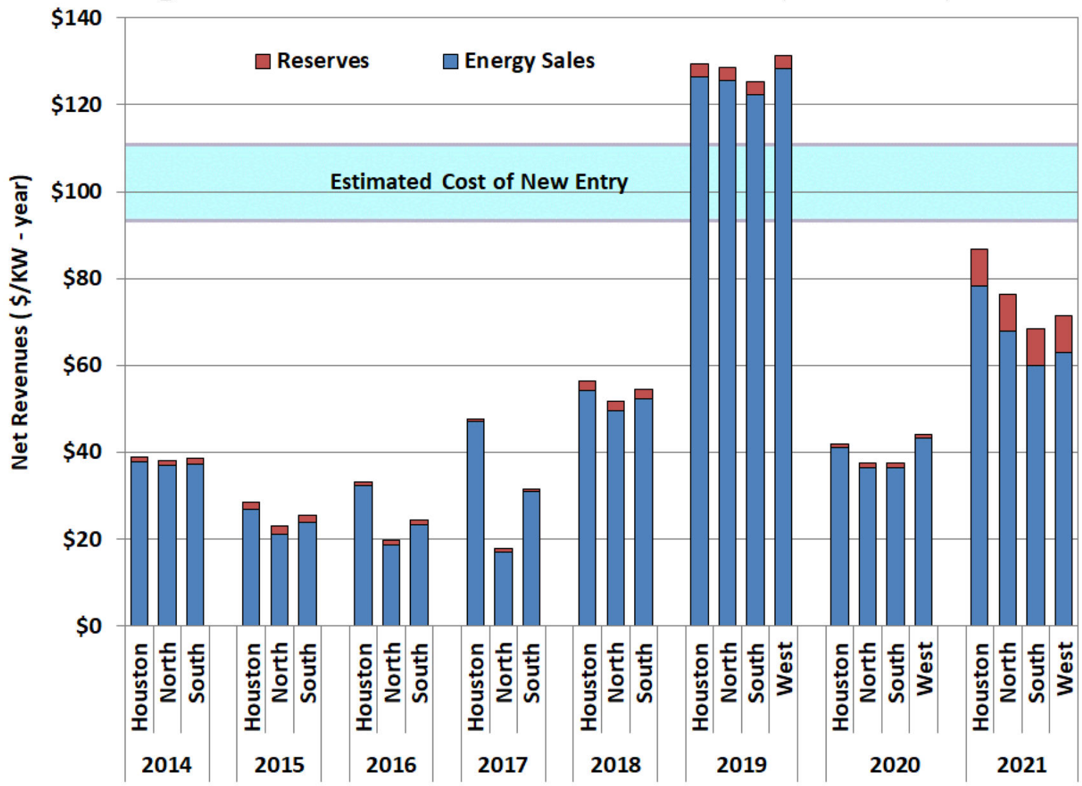


Figure 57: Combined Cycle Net Revenues (with Uri)

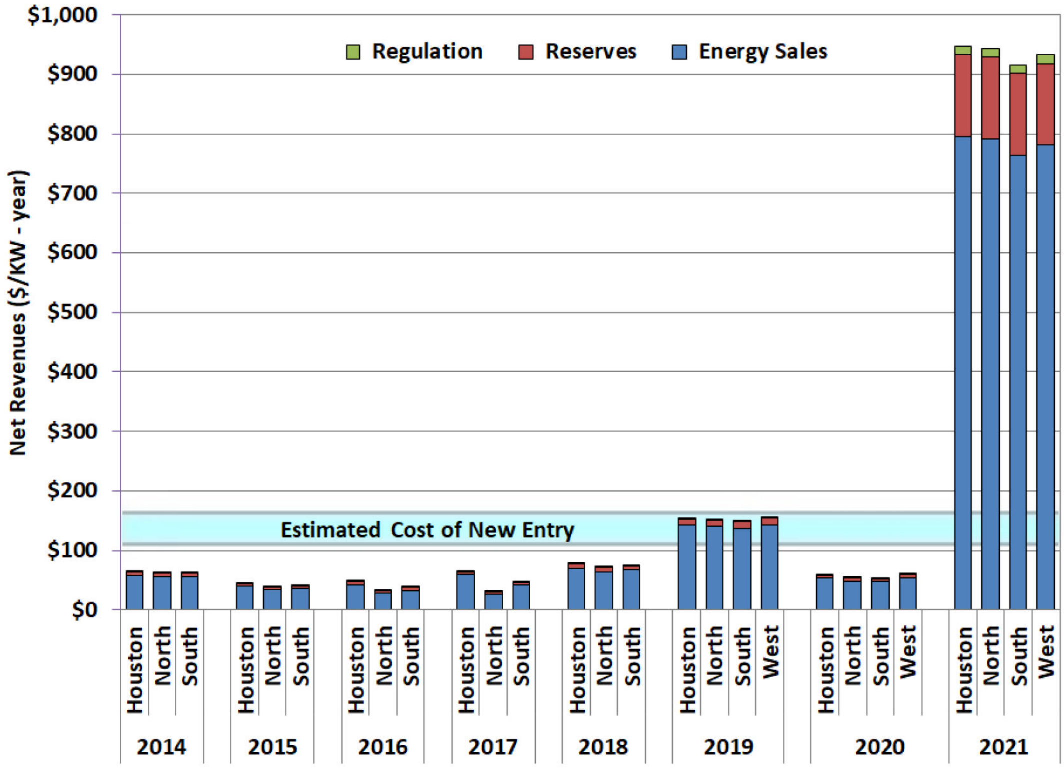
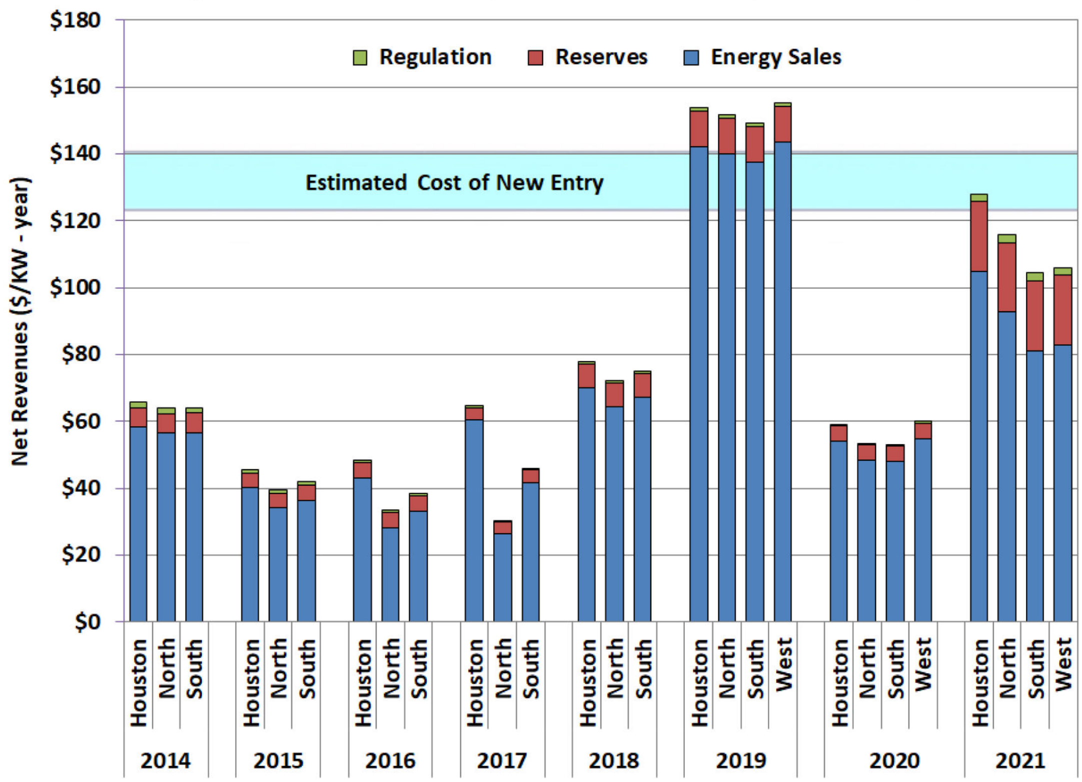


Figure 58: Combined Cycle Net Revenues (without Uri)



The figures above also show that average net revenues were highest in the Houston zone in 2021 as congestion led to higher prices in that zone. In 2021, we saw the continuing trend of the separation in natural gas prices between the Waha and Katy locations lessen versus the last couple of years.

Because of lower fuel cost at Waha, generators served by the Waha location would tend to have higher net revenues than those procuring gas at Katy. In Section VII of the Appendix, we show the fuel price trends at these locations and the differences in net revenues that they would produce for the two new resources. This analysis shows that the new resources would produce net revenue ranging from $770 to $850 per KW-year at the Waha location, compared to net revenues of $700 to $800 per KW-year at Katy, based on 2021 revenues.

B. Net Revenues of Existing Units

Given the continuing effects of low natural gas prices, we evaluate the economic viability of existing coal and nuclear units that have experienced falling net revenues. Non-shortage prices, which have been substantially affected by the prevailing natural gas prices, are the primary determinant of the net revenues received by these baseload units. Low natural gas prices tend to lead to lower system-wide average prices, but it is the prices at these units' specific locations that matter; the prices at these locations have tended to be lower than the ERCOT-wide average prices. As previously described, the load-weighted ERCOT-wide average energy price in 2020 was $167.88 per MWh. Table 8 shows the output-weighted average price by generation type based on the generators' specific locational prices in 2021.

Table 8: Settlement Point Price by Fuel Type

Generation Type	Output-Weighted Price		
	2019	2020	2021
Coal	$43.92	$24.84	$148.06
Combined Cycle	$47.06	$24.60	$207.84
Gas Peakers	$126.16	$60.26	$1,023.09
Gas Steam	$135.16	$41.90	$405.10
Hydro	$42.90	$23.88	$305.15
Nuclear	$35.38	$20.31	$137.71
Power Storage	$154.80	$80.50	$109.29
Private Network	$46.16	$24.08	$176.76
Renewable	$141.09	$35.23	$43.54
Solar	$61.45	$25.49	$75.97
Wind	$20.54	$11.45	$60.53

Table 8 shows that the prices and associated net revenues were high at all resources' locations in 2021 than the previous two years. This is again explained by the effects of Winter Storm Uri.

Nuclear Profitability. According to data published by the Nuclear Energy Institute, the average total generating cost for nuclear energy was $29.37 per MWh in 2020. The 2020 total generating costs were not only 4.6% lower than in 2019 but also were 35% below 2012 costs.[85] Assuming that operating costs in ERCOT are similar to the U.S. average, and that nuclear operating costs have either continued to be stable or declining, ERCOT's 5 GW of nuclear capacity should have costs less than $30 per MWh. The table above shows an average price for the nuclear units of approximately $138 per MWh making it likely that the nuclear units in ERCOT that were able to stay online during Winter Storm Uri were profitable in 2021. The prices prices during Winter Storm Uri and subsequent profitability are not expected to continue at that level in the coming years due to the rarity of that event.

Coal Profitability. The generation-weighted price of all coal and lignite units in ERCOT during 2021 was $148.06 per MWh, an increase from $20.98 per MWh in 2020, although that level of increase is deceiving based on the extraordinary events of February 2021. Although specific unit costs may vary, index prices for Powder River Basin coal delivered to ERCOT were approximately $2.78 per MMBtu in 2021, slightly higher than 2020. At these average fuel prices, coal units in ERCOT that were able to stay online during Winter Storm Uri are likely receiving more than enough revenue to cover operating costs.

Natural Gas-Fired Resource Profitability. In 2021, the revenues rose significantly because of Winter Storm Uri in February. The shortage pricing for energy and ancillary services produced a spike in net revenues for natural gas resources, although many gas-fired generators failed to stay online during the storm. This caused them to miss the opportunity for these net revenues and, in some cases, to have to buy back energy back at the extreme prices that they sold day ahead.

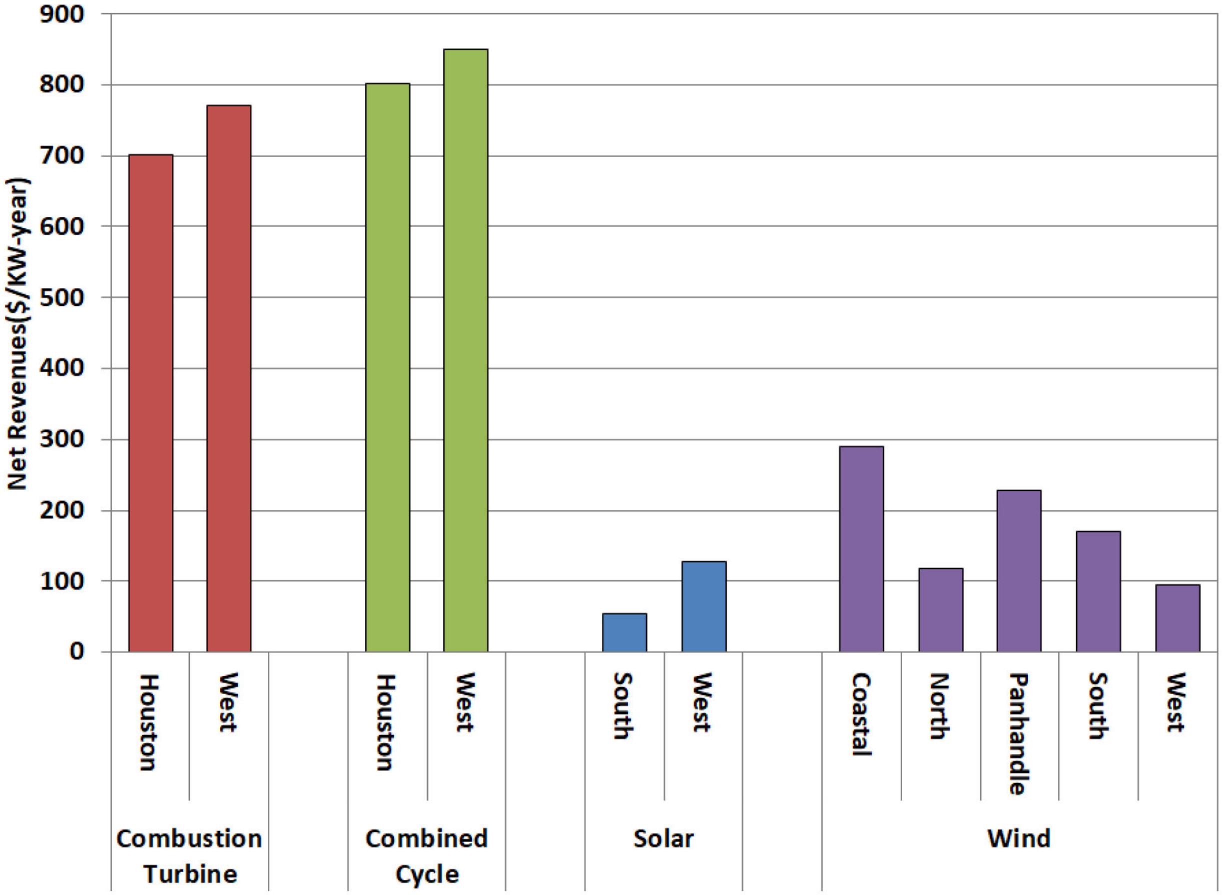
Net Revenues by Technology and Location. Figure 59 shows the net revenues at different locations for a variety of technologies. Because natural gas prices can vary widely, the revenues for natural gas units are shown for the Houston zone (reflecting Katy hub prices) and the West zone (for Waha). Historically, the high natural gas production in the Permian Basin and limited export capability has resulted in low gas prices at the Waha location and much higher net revenues for gas resources in this area. New transportation projects are currently underway and thus that basis difference in natural gas prices has decreased.

Figure 59 also shows the net revenues for wind and solar generation at multiple locations. The profitability of those resources is chiefly determined by the available natural resource and the prevailing price to be received. Net revenues for wind and solar were lower than gas technologies in 2021 in all areas. This is partly because intermittent technologies cannot maximize their output and associated revenues during shortage conditions. This is particularly

85 https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context

true for wind resources that tend to produce less output during hot summer conditions. In 2021, these differences were more pronounced because of Winter Storm Uri.

Figure 59: Net Revenues by Generation Resource Type



Interpreting Single-Year Net Revenues. These results indicate that on a stand-alone basis during 2021, the ERCOT markets did provide sufficient revenues to support profitable investment in combustion turbine and combined cycle technologies. Net revenues were the highest they have ever been as result of the extreme shortage pricing in 2021. Investors' response to these prices will depend on their future revenue expectations over a number of years. The prevailing capacity surplus and the changes in how policymakers and ERCOT will be managing the system going forward are likely to limit these expectations. However, it is also important to recognize that investors may invest instead in new technologies, such as battery energy storage or load-flexible renewables, which have different value propositions than traditional generation.

For all these reasons, it is important to be cautious in interpreting single-year net revenues and projecting their long-term effects, especially in a year where revenues were higher than they likely to ever be again. Please see Section VII of the Appendix for additional detail and discussion of the net revenue results presented in this subsection.

C. Planning Reserve Margin

Ultimately, the importance of the market signals discussed above is that they facilitate the long-term investment and retirement decisions by market participants that will maintain an adequate resource base. This subsection discusses the trends in the planning reserve margin, which is one measure of the adequacy of the resource base.

There are many ways that the market can respond to high prices, all of which result in rising planning reserve margins:

- Building new generation facilities;
- Increasing investment in existing resources, including more maintenance to improve availability, as well as capital investment to increase the capability of the resource; or
- Loads investing in systems and procedures to enable non-consumption during shortage pricing events (demand response).

In 2020, there were no significant expected or actual shortages, partly because the effects of the COVID-19 reduced load and the summer weather was mild. In 2021, those same expectations were subverted by Winter Storm Uri. The extreme conditions in February 2021 could not have been expected by participants. Resources were not properly winterized, coordination with the natural gas industry was insufficient, and exposure to real-time prices at the cap for more than four days was a catastrophic reality for many market participants. The year was an outlier in ERCOT market history and it will take time to fully understand how the market will evolve.

Similar to the analysis of net revenues year over year above, it is important to be cautious in interpreting single-year lack of shortage pricing and projecting the long-term based on planning reserves, as shortages can occur in peak net load intervals that may be different than those studied in the planning horizon. Planning reserves take a more holistic and long-term view of market conditions and may not indicate the frequency of shortage conditions in any given year.

In the December 2020 Capacity, Demand, and Reserves (CDR) report, the 2021 summer reserve margin was forecasted to be 15.5%, based on resource updates provided to ERCOT from generation developers and an updated peak demand forecast. This was down 1.8% from what was reported in the May 2020 CDR due to solar and wind project delays and cancellations.

In 2021, ERCOT saw a significant increase in utility-scale solar resources. Based on ERCOT's interconnection queue, this trend is expected to continue over the next several years and increase the forecasted planning reserve margin for 2022 through 2025 up to 40 to 42%.[86] Figure 60 shows ERCOT's current projection of planning reserve margins over the next five years, including the new generators that account the changes in the reserve margin.

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86 *See* Report on the Capacity, Demand and Reserves in the ERCOT Region, 2022-2031 (December 29, 2021), https://www.ercot.com/files/docs/2021/12/29/CapacityDemandandReservesReport_December2021.pdf.

Figure 60: Projected Planning Reserve Margins

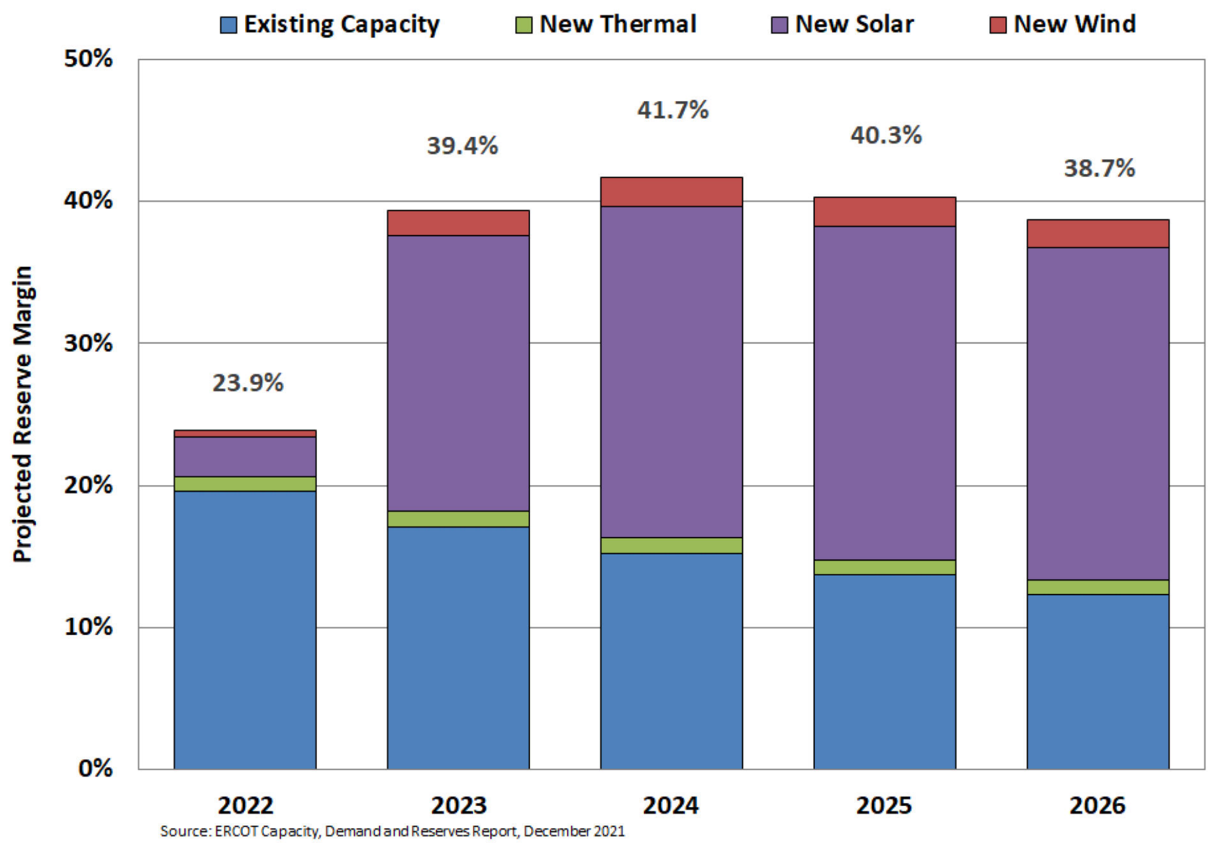


Figure 60 indicates that Texas heads into the summer months of 2022 with an improved planning reserve margin of 23.9%, much higher than the 15.5% reserve margin for 2021. We note that the current methodology of performing the CDR does not consider ESRs. Including the growing quantity of storage resources would increase the reserve margin. In addition, the CDR relies solely on hour ending 5 p.m. (the peak hour). The peak net load hour is likely a more accurate predictor of shortage conditions, particularly as solar generation continues to be added to the ERCOT system.

D. Effectiveness of the Shortage Pricing Mechanism

One of the primary goals of an efficient electricity market is to ensure that, over the long term, there is an adequate supply of resources to meet customer demand plus any required installed or planning reserves. Generators earn revenues from three sources: energy prices during non-shortage, energy prices during shortage and capacity payments. Without a capacity market in ERCOT, suppliers' revenues are derived solely from energy prices under shortage and non-shortage conditions. Revenues during non-shortage conditions tend to be more stable as planning margins fluctuate, but shortage revenues are the primary means to provide investment incentives when planning margins fall (or incentives to keep existing units in operation). Therefore, the performance of shortage pricing in the ERCOT market is essential.

1. Background on Shortage Pricing in ERCOT

Shortage pricing refers to the price escalation that occurs when supply is not sufficient to satisfy all the system's energy and operating reserve requirements. In these cases, prices should reflect the reliability risks borne by the system as the shortage deepens. Ideally, the value of the shortage should be priced based on the loss of load probability at varying levels of operating reserves multiplied by VOLL.

Shortage pricing in ERCOT occurs through the ORDC that was implemented in 2014, which automatically increases the prices as reserves levels drop. The ORDC is described in more detail in Section I. Over the time it has been in effect, ORDC has had an increasingly material impact on real-time prices, especially in 2019 when reduced installed reserves led to higher expectations of shortage pricing. The ORDC adder reflects VOLL, which was set to $9,000 per MWh in June 2014. The real-time prices are increased by the Real-Time Reserve Price, which is determined based on the value of the remaining reserves in the system as specified by the predefined ORDC.

The Scarcity Pricing Mechanism includes a provision termed the Peaker Net Margin (PNM) threshold that is designed to provide a pricing "fail-safe" measure. If the PNM threshold is exceeded, the system-wide offer cap is reduced. PNM also serves as a simplified measure of the annual net revenue of a hypothetical peaking unit.[87] Section I contains several summaries and discussions of the shortage pricing that occurred in 2021. The next section compares pricing in prior years to 2021, the first year that the PNM threshold was ever reached.

2. Peaker Net Margin in 2021

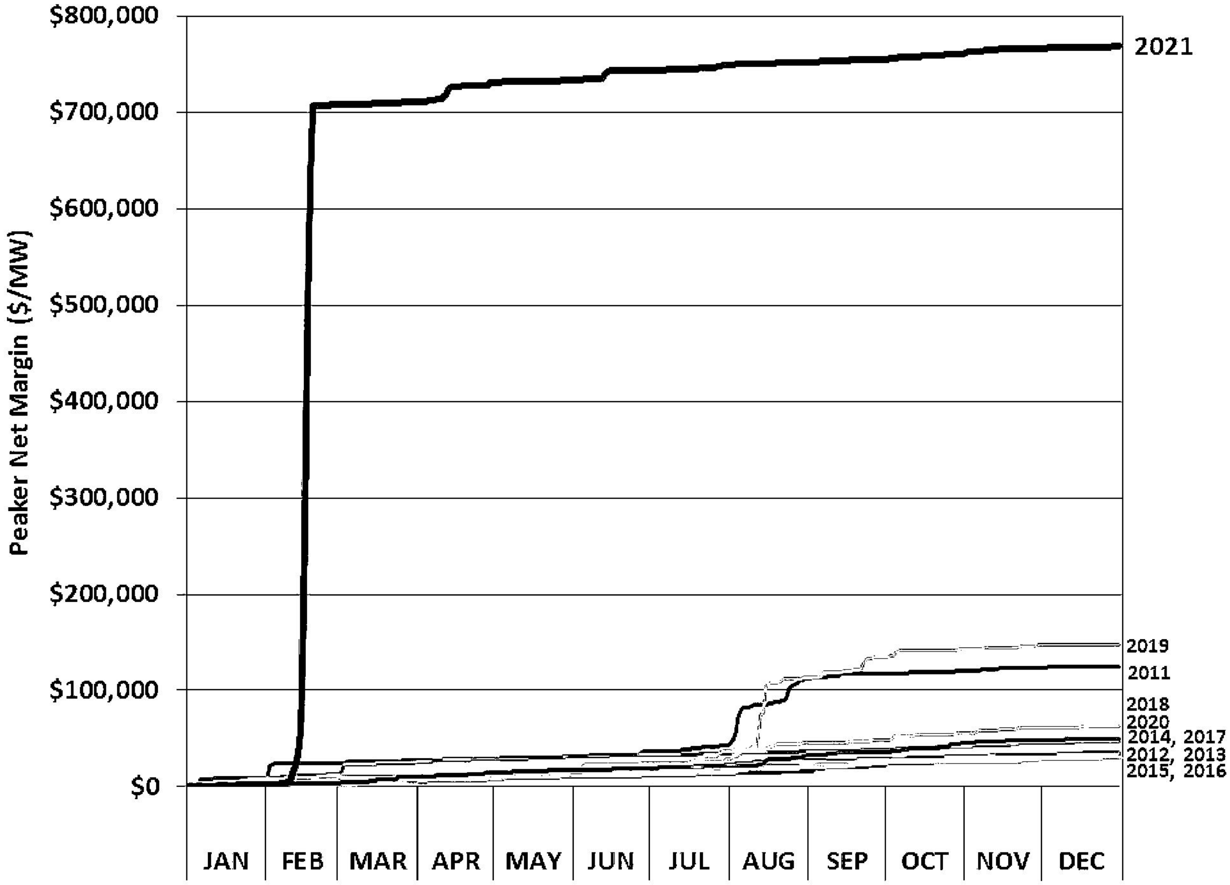
Figure 61 shows the cumulative PNM results for each year since the creation of the Scarcity Pricing Mechanism. When administering the scarcity-pricing mechanism in ERCOT under 16 TAC § 25.505, the system-wide offer cap is set equal to the high system-wide offer cap (HCAP) at the beginning of each calendar year and maintained at this level until the PNM during a calendar year exceeds a threshold of three times the annual cost of new entry of new generation plants ($315,000). This figure shows that the $315,000 PNM threshold was exceeded for the first time in ERCOT's history during the ERCOT operating day of February 16, 2021.

Once the peaker net margin threshold is achieved, the system-wide offer cap is set at the low system-wide offer (LCAP) for the remainder of the calendar year. The LCAP is set at the greater of either $2,000 per MWh and $2,000 per MW per hour or 50 times the natural gas price index value determined by ERCOT. However, the exceptionally high natural gas prices $400/MMBtu during Winter Storm Uri (up to $400/MMBtu or more than 100 times normal levels) caused the LCAP rise to more than double the HCAP. Therefore, the Commission suspended use of the

[87] The proxy combustion turbine in the Peaker Net Margin calculation assumes a heat rate of 10 MMBtu per MWh and includes no other variable operating costs or startup costs.

LCAP on March 3 to avoid outcomes contrary to the purpose of the rule, which was to protect consumers from sustained high prices in years with exceptional generator revenues.[88] Once the natural gas prices had stabilized and the LCAP was no longer expected to exceed the HCAP, and the Commission reinstituted the application of the LCAP.[89]

Figure 61: Peaker Net Margin



The Commission made an additional change to the LCAP in PUC Project No. 51871, *Review of the ERCOT Scarcity Pricing Mechanism,* when it eliminated the provision that tied the value of the LCAP to natural gas prices. The revised rule instead makes resources whole to their actual marginal costs when the LCAP is in effect.

3. Changes to the ORDC

The Commission directed notable changes to the ORDC in 2021. In previous years, the Commission considered proposals modifying various defining aspects of the ORDC, including

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88 *See Calendar Year 2021 - Open Meeting Agenda Items*, Project No. 51617, Second Order Directing ERCOT to take Action and Granting Exception to Commission Rules at 2 (Feb. 16, 2021).

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

shifting the LOLP portion of the curve.[90] The LOLP portion of the curves used to determine the ORDC price adder has typically been constructed using normal probability distributions defined by two factors: a) the average of historical differences between expected and actual operating reserves ("mu"), and b) the standard deviation in those values ("sigma").[91] On January 17, 2019, the Commission approved a two-part process to modify the ORDC in two steps:

1. Transitioning to a single blended ORDC curve and implementing a 0.25 standard deviation shift in the LOLP calculation in the spring of 2019, and
2. Implementing a second 0.25 standard deviation shift in the spring of 2020. The second step of the ORDC change was implemented on March 1, 2020.

Following Winter Storm Uri, the Commission worked with participants to develop a blueprint for reforms to the design of the wholesale electric market.[92] The blueprint compiles directives and reforms to be implemented in two phases. Phase I of the blueprint focuses on enhancements to current wholesale markets to improve price signals and operational reliability. Part of Phase I of the blueprint included significant changes to the ORDC.

Aimed at rewarding reliable generation assets that are available as shortage conditions emerge, the modified ORDC is designed to cause prices to rise more quickly as conditions start to become tight. This provides incentives to bring generation units online and prompt consumer demand response earlier to help enhance regular market operations and avoid conservation appeals. Changes to the ORDC were made effective January 1, 2022, to set the MCL at 3,000 MW and set the high system-wide offer cap and VOLL to $5,000 per MWh.

After that initial implementation, the Commission committed to considering decoupling of the system-wide offer cap and VOLL. This includes establishing a new VOLL based on quantitative analysis of new revenue to the market that would be directed to reliable generation assets during shortage events. The Commission also required a report from ERCOT to the Commission by November 1 of every even-numbered year analyzing the efficacy, utilization, related costs and contribution of the ORDC to grid reliability in ERCOT.

E. Reliability Must Run and Must Run Alternatives

Reliability-Must-Run procedures are essential for determining and addressing the need for generation units to support grid reliability.[93] A Reliability Must Run (RMR) Unit is a resource

90 *Review of Summer 2018 ERCOT Market Performance*, Project No. 48551.

91 Mu and sigma are separately calculated for each of the twenty-four curves currently used (six time of day blocks and four seasons).

92 *Review of Wholesale Electric Market Design*, Project No. 52373, Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT (Jan. 13, 2022).

93 http://www.ercot.com/content/wcm/lists/89476/OnePager_RMR_May2016_FINAL.pdf

operated under the terms of an agreement with ERCOT that would not otherwise be operated except that it is necessary to provide voltage support, stability or management of localized transmission constraints under credible single contingency criteria where market solutions do not exist. If ERCOT determines a resource is needed to maintain electric stability, it can enter into an RMR agreement to pay the plant an "out-of-market" payment to continue operating. ERCOT also has a process to consider other resources, known as Must-Run Alternatives (MRA). In lieu of paying an uneconomic to stay open to ensure grid reliability, ERCOT may issue a Request for Proposals for alternative solutions that can address the specific reliability concern.

A Notice of Suspension of Operations (NSO) is required of any generator suspension that lasts greater than 180 days. A number of NSOs were submitted in 2021.[94] ERCOT determined that none of the units were necessary to support ERCOT transmission system reliability, therefore no Reliability Must-Run (RMR) contracts were awarded in 2021.[95]

94 South Houston Green Power LLC (RE) – AMOCOOIL_AMOCO_S2; Petra Nova Power I LLC (RE) – PNPI_GT2; Snyder Wind Farm LLC – ENAS_ENA1; City of Austin dba Austin Energy (RE) – DECKER_DPG2; Sherbino I Wind Farm LLC – KEO_KEO_SM1; City of Garland – OLINGR_OLING_1; Wharton County Generation LLC – TGF_TGFGT_1.

95 The last RMR contract was executed in 2016, for Greens Bayou 5, a 371 MW natural gas steam unit built in 1973 and located in Houston. That RMR contract was ultimately cancelled effective May 29, 2017.

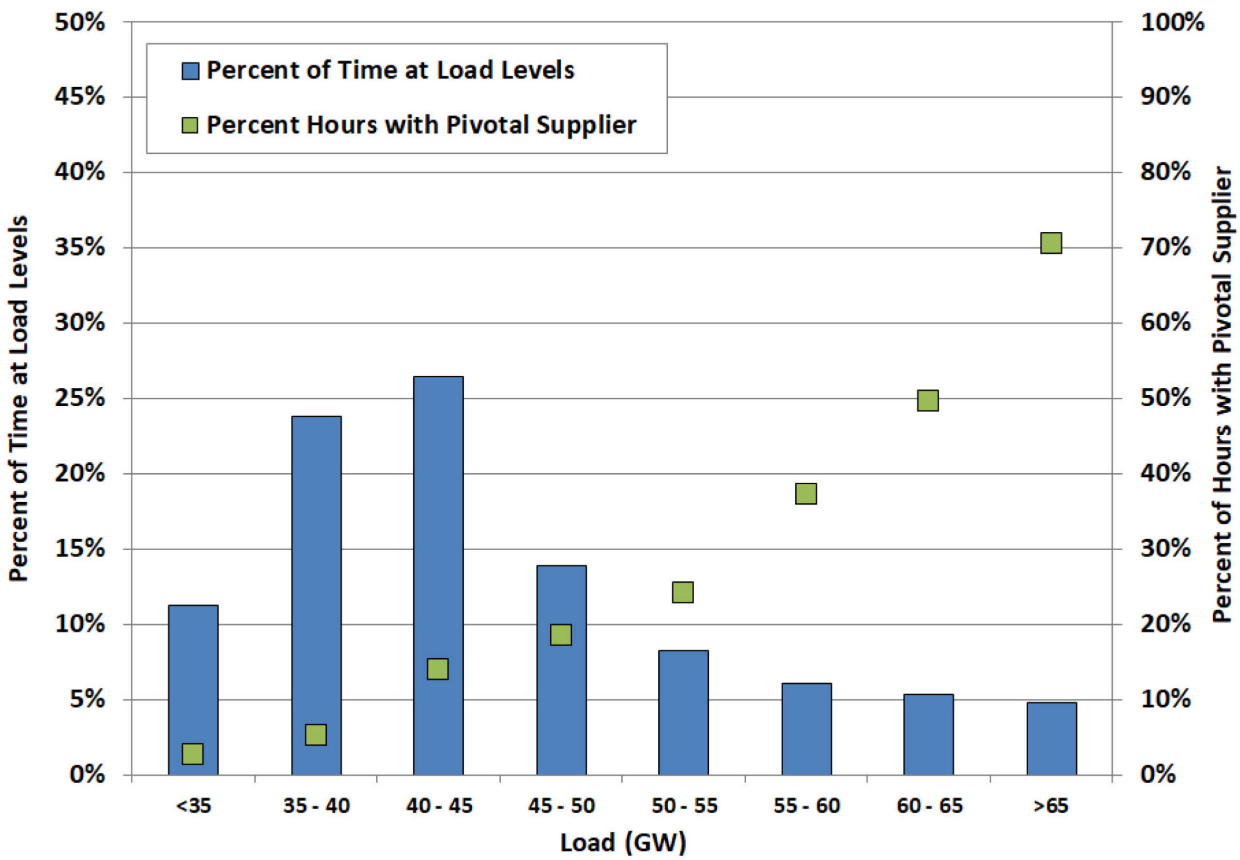
VIII. Analysis of Competitive Performance

In this section, we evaluate market power from two perspectives: structural (does market power exist) and behavioral (have attempts been made to exercise it). This section begins by evaluating a structural indicator of potential market power, then evaluates market participant conduct by reviewing measures of potential physical and economic withholding. Finally, this section includes a summary of the Voluntary Mitigation Plans in effect during 2021. Based on these analyses, we find that the ERCOT wholesale market performed competitively in 2021.

A. Structural Market Power Indicators

Traditional market concentration measures are not reliable market power indicators in electricity markets. They do not include the impacts of load obligations that affect suppliers' incentives to raise prices. They also do not account for excess supply, which affects the competitiveness of the market. A more reliable indicator of market power is whether a supplier is "pivotal", i.e., when its resources are necessary to satisfy load or manage a constraint. Figure 62 summarizes the results of the pivotal supplier analysis by showing the portion of time at each load level there was a pivotal supplier. The figure also displays the portion of time each load level occurred.

Figure 62: Pivotal Supplier Frequency by Load Level



At loads greater than 65 GW, there was a pivotal supplier approximately 71% of the time in 2021. This high percentage is expected because at high load levels the largest suppliers' resources are more likely to needed as other suppliers' resources are more fully utilized serving the load. Pivotal suppliers existed 18% of all hours in 2021, which was slightly lower than 2019 and 2020. Even with this reduction, market power continues to be a potential concern in ERCOT, requiring effective mitigation measures to address it. More detailed analysis of the pivotal supplier issue is presented in Figure A46 in the Appendix.

We cannot make inferences regarding market power solely from pivotal supplier data because it does not consider the contractual position of the supplier. Bilateral and other financial contract obligations can affect whether a supplier has the incentive to raise prices. For example, a small supplier selling energy only in the real-time energy market may have a much greater incentive to exercise market power than a large supplier with substantial long-term sales contracts. We recommend that the "small fish" rule be removed to address this concern (see SOM Recommendation 2021-1).

It should be noted that the analysis above evaluates the structure of the entire ERCOT market. In general, local market power in narrower areas that can become isolated by transmission constraints raise more substantial competitive concerns. As more fully discussed in Section VI, this local market power is addressed through: (a) structural tests that determine "non-competitive" constraints that can create local market power; and (b) the "mitigation" or application of limits on offer prices in these areas.

B. Evaluation of Supplier Conduct

This subsection provides the results of our evaluation of actual conduct to assess whether market participants have attempted to exercise market power through physical or economic withholding. First, we examine unit deratings and forced outages to detect physical withholding, and then the "output gap" used to detect economic withholding.

In a single-price auction like the real-time energy market, suppliers may attempt to exercise market power by withholding resources. The purpose of withholding is to cause more expensive resources to set higher prices, allowing the supplier to profit on its other sales in the market. Because forward prices are highly correlated with spot prices, price increases in the real-time energy market can also increase a supplier's profits in the bilateral energy market. This strategy is profitable if the incremental profit exceeds the foregone profits from its withheld capacity.

1. Generation Outages and Deratings

At any given time, some portion of the generation is unavailable because of outages and deratings. Due to limitations in outage data, we infer the outage type by cross-referencing unit status information provided to ERCOT with outage submissions, assuming that all scheduled outages are planned outages. Derated capacity is the difference between the summer maximum capacity of a resource as registered with ERCOT and its actual capability. It is common for generating capacity to be partially derated because the resource cannot achieve its installed capacity level due to technical or environmental factors (e.g., equipment failures or ambient temperatures). Wind generators rarely produce at the installed capacity rating because of variations in wind speed. Due to the high numbers, we show wind separately in our evaluation of deratings. As discussed in Section VI above, summer availability has been increasing since 2017 in ERCOT because of the incentives provided by the recent increase in shortage pricing.

Figure 63 shows a breakdown of total installed capacity for ERCOT on a daily basis during 2021. This analysis includes all in-service and switchable capacity. From the total installed capacity, we subtract the following: (a) capacity from private networks not available for export to the ERCOT grid; (b) wind capacity not available because of the lack of wind input; (c) short-term deratings; (d) short-term planned outages; (e) short-term forced outages; and (e) long-term outages and deratings greater than 30 days. What remains is the available capacity.

Figure 63: Reductions in Installed Capacity

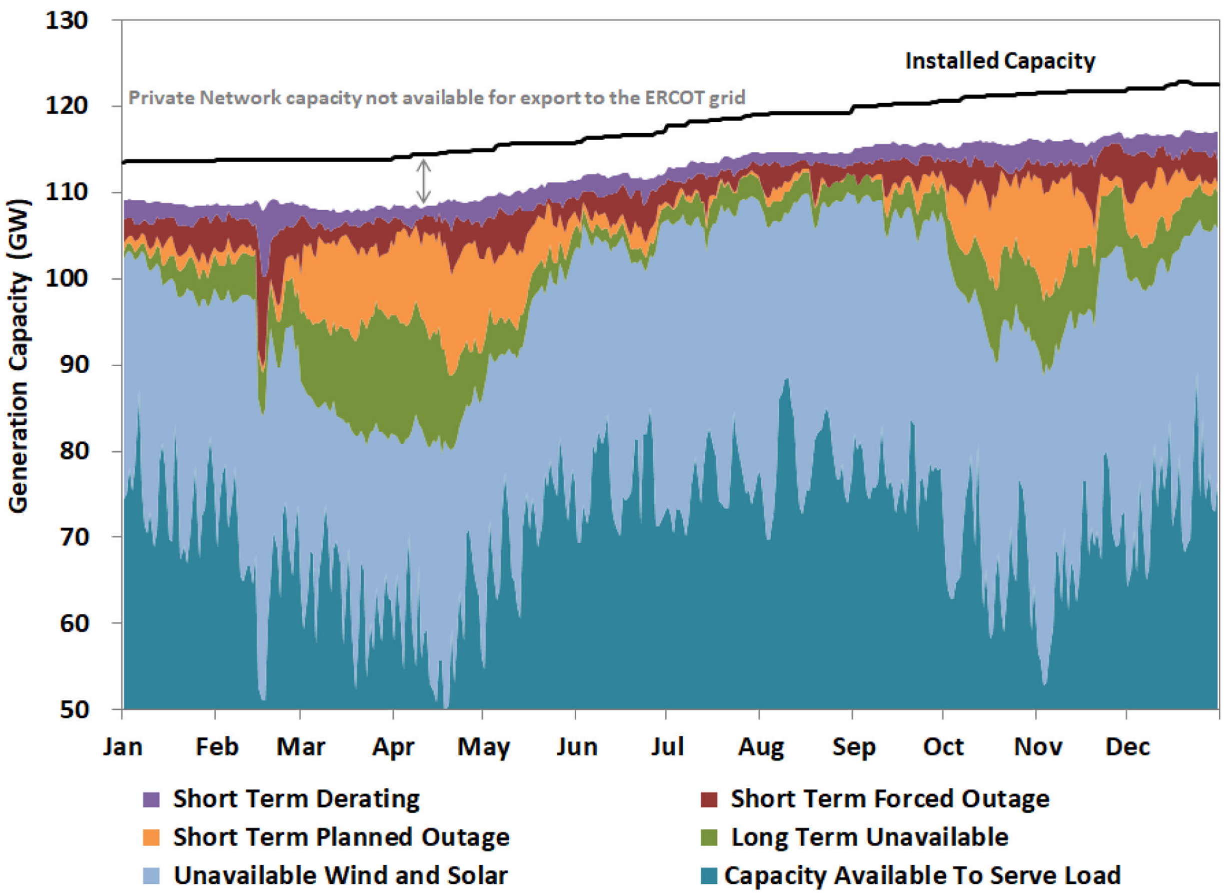


Figure 63 shows that short-term outages and deratings of non-wind generators fluctuated between 1.4 to 21.4 GW, while wind unavailability varied between 7.5 and 30 GW. Short-term planned outages were largest in the shoulder months of April and November, while smallest during the summer months, consistent with our expectations. Short-term forced outages and deratings spiked in February during Winter Storm Uri which led to more long-term outages in the following months to perform repairs. The quantity of long-term (greater than 30 days) unavailable capacity peaked in March at more than 14 GW, with almost all capacity returned to service in anticipation of any warm temperatures and shortage conditions in the summer of 2021.

In the next analysis, we focus specifically on short-term planned outages and forced outages and deratings of non-wind units because these classes of outages and deratings are the most likely to be used to physically withhold units in attempts to raise prices. The following Figure 64 provides a comparison of the monthly outage and derating values for 2020 and 2021.

Figure 64: Short-Term Deratings and Outages

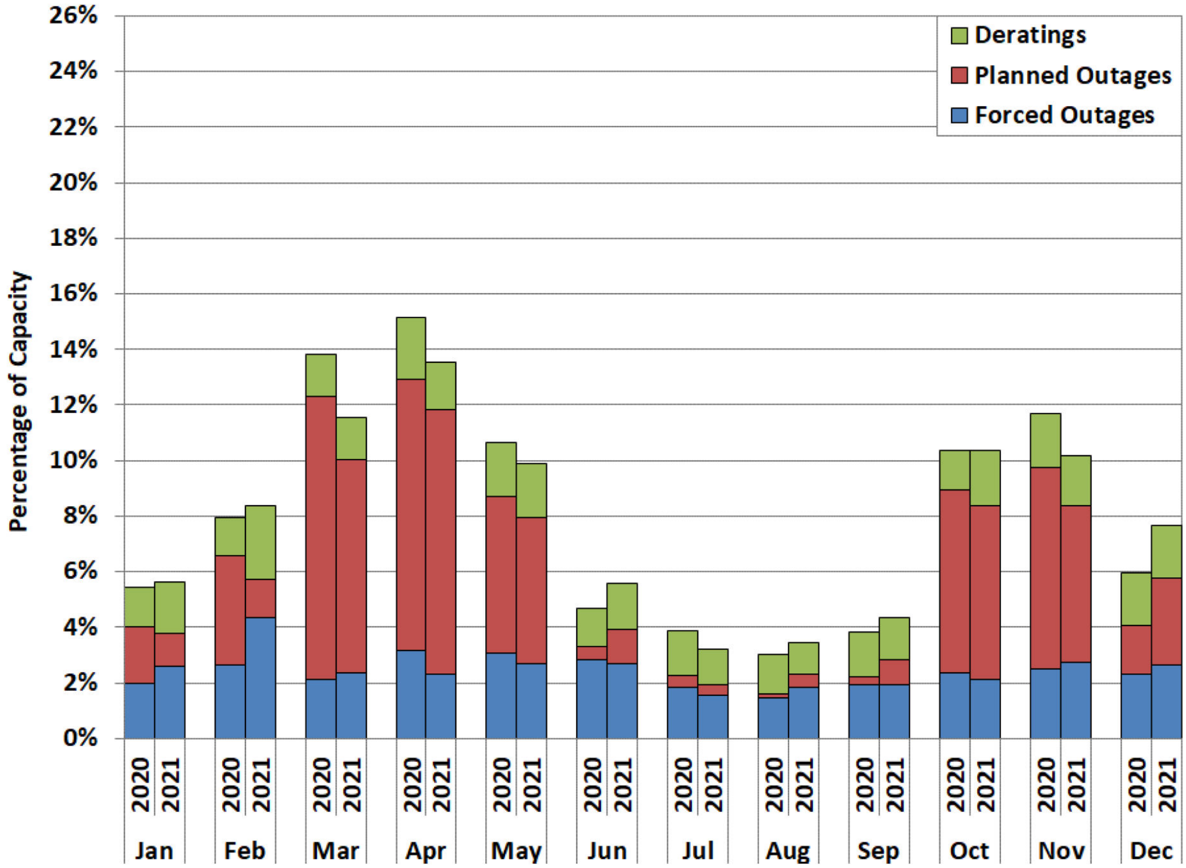


Figure 64 shows a general consistency of forced outages from last year, with the exception of the forced outages that occurred during Winter Storm Uri in February. Planned outages were low in February 2021, indicating that there was deferral of some outages in anticipation of the winter event. However, those actions likely were at the cost of higher outage rates in October and November in both years. Finally, the significant increase in planned outages scheduled during spring and fall in both years is an indicator of preparation for summers in which the ability to capture shortage pricing is the highest.

The consistently modest amount of deratings across most months of 2021 indicates that generators were intent on maximizing generator availability. The low forced outage rates during July and August 2021 and the low level of derations overall are likely a result of increased planned maintenance activities. Overall, these results show that suppliers behaved competitively, maximizing availability in the highest load hours. Figure A47 in the Appendix shows the average magnitude of the short-term outages and deratings lasting less than 30 days for the year and for each month during 2021. Figure A48 in the Appendix also includes long-term outages, which rose sharply in March and April as generators made repairs and upgrades after Winter Storm Uri.

2. Evaluation of Potential Physical Withholding

Physical withholding occurs when a participant makes unavailable for dispatch resources that are otherwise physically capable of providing energy and are economic at prevailing market prices. A plant operator can withhold either by derating a unit or declaring the unit as forced out of service. Because generator deratings and forced outages are unavoidable, the goal of the analysis in this subsection is to differentiate justifiable deratings and outages from physical withholding. We conduct a test for physical withholding by examining deratings and outage data to ascertain whether the data are correlated with conditions under which physical withholding would likely be most profitable.

The pivotal supplier results shown in Figure 62 indicate that the potential for market power abuse rises at higher load levels as the frequency of intervals in which suppliers are pivotal increases. Hence, if physical withholding is occurring, one would expect to see increased deratings and outages at the highest load levels. Conversely, because competitive prices increase as load increases, deratings and outages in a market performing competitively will tend to decrease as load approaches peak levels. Suppliers that lack market power will take actions to maximize the availability of their resources because their output is generally most profitable in peak periods.

Figure 65 shows the average short-term deratings and forced outages as a percentage of total installed capacity for large and small suppliers during summer months, as well as the relationship to different real-time load levels. Portfolio size is important in determining whether individual suppliers have incentives to withhold available resources. Hence, we look at the patterns of outages and deratings of large suppliers and compare them to the small suppliers' patterns.

Long-term deratings are unlikely to constitute physical withholding given the cost of such withholding and are therefore excluded from this analysis. Wind and private network resources are also excluded from this analysis because of the high variation in the availability of these classes of resources. The large supplier category includes the five largest suppliers in ERCOT. The small supplier category includes the remaining suppliers.

Figure 65: Outages and Deratings by Load Level and Participant Size, June-August

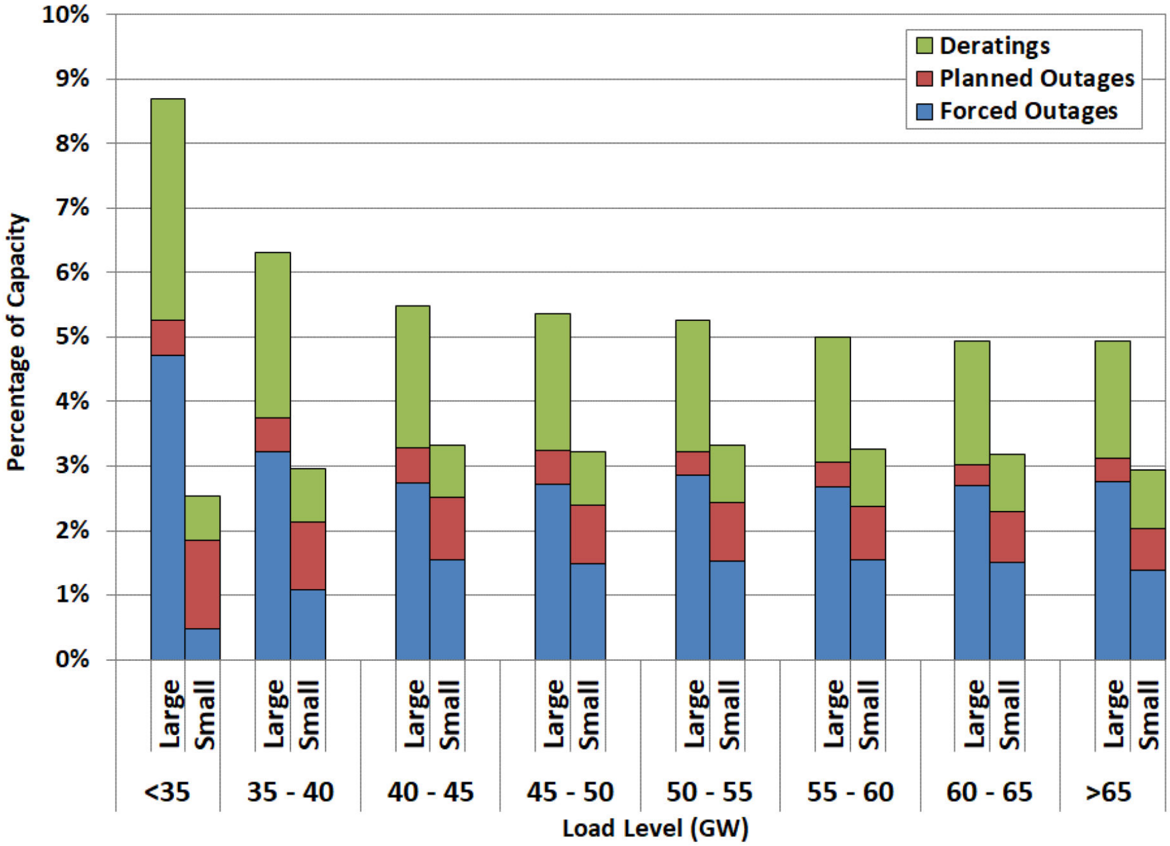
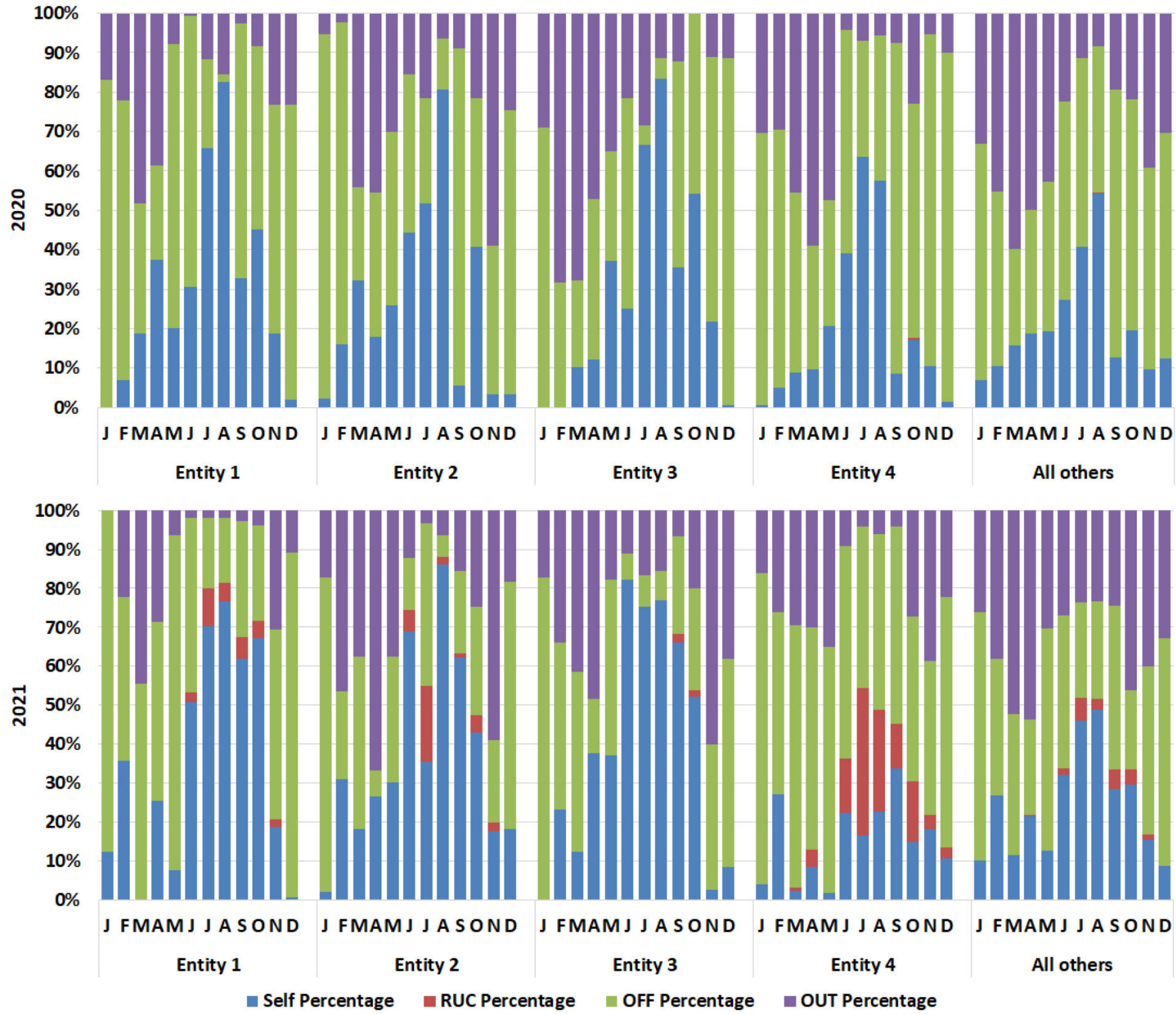


Figure 65 confirms the pattern we have seen since 2018 that as demand for electricity increases, all market participants tend to make more capacity available to the market by scheduling planned outages during low load periods. Because small participants have less incentive to physically withhold capacity, the outage rates for small suppliers serves as a good benchmark for competitive behavior expected from the larger suppliers. Outage rates for large suppliers at all load levels exceeded those for small suppliers, but remain at levels that are small enough to raise no competitiveness concerns. Small suppliers have the most incentive to ensure generator availability because each unit in their fleet makes up a larger percentage of the total, which means that any outage has the potential for larger financial impacts.

We did identify a withholding strategy that arose out of the frequent use of the RUC tool in the latter half of 2021. Given the predictability of the RUC instructions, the ability to opt out of RUC settlement during the operating hour if conditions changed, and the high RUC offer floor which economically withheld MWs under a RUC instruction, a disincentive to self-commit existed for large suppliers. One large supplier did in fact adjust its self-commitment behavior and was far more likely to run under RUC commitment than was seen in prior years. Figure 66 below depicts the difference in behavior of entities between 2020 and 2021 for resource-daily decisions for gas steam resources. Entity 4 exhibited a marked reduction in self-commitment for these resources, a pattern that did not exist for other entities.

Figure 66: Monthly Commitment Percentages of Gas-Steam Units



To address this incentive issue with the frequent use of RUCs and the high RUC offer floor, we filed NPRR1092, *Reduce RUC Offer Floor and Limit RUC Opt-Out Provision.* This rule change reduced the RUC offer floor to $250 per MWh and made the RUC opt-out provision limited in its applicability. The rule change was approved by the Board on April 27, 2022, and partially implemented on May 13, 2022.

3. Evaluation of Potential Economic Withholding

In this subsection we evaluate potential economic withholding by calculating an "output gap." The output gap is the quantity of energy that is not being produced by online resources even though the output is economic to produce by a substantial margin given the real-time energy price. A participant can economically withhold resources, as measured by the output gap, by raising its energy offers so as not to be dispatched.

A resource is evaluated for inclusion in the output gap when it is committed and producing at less than full output. Energy not produced from a committed resource is included in the output gap if the real-time energy price exceeds that unit's mitigated offer cap by at least $30 per MWh. The mitigated offer cap serves as a proxy for the marginal production cost of energy from that resource.

Figure 67: Incremental Output Gap by Load Level and Participant Size – Step 2

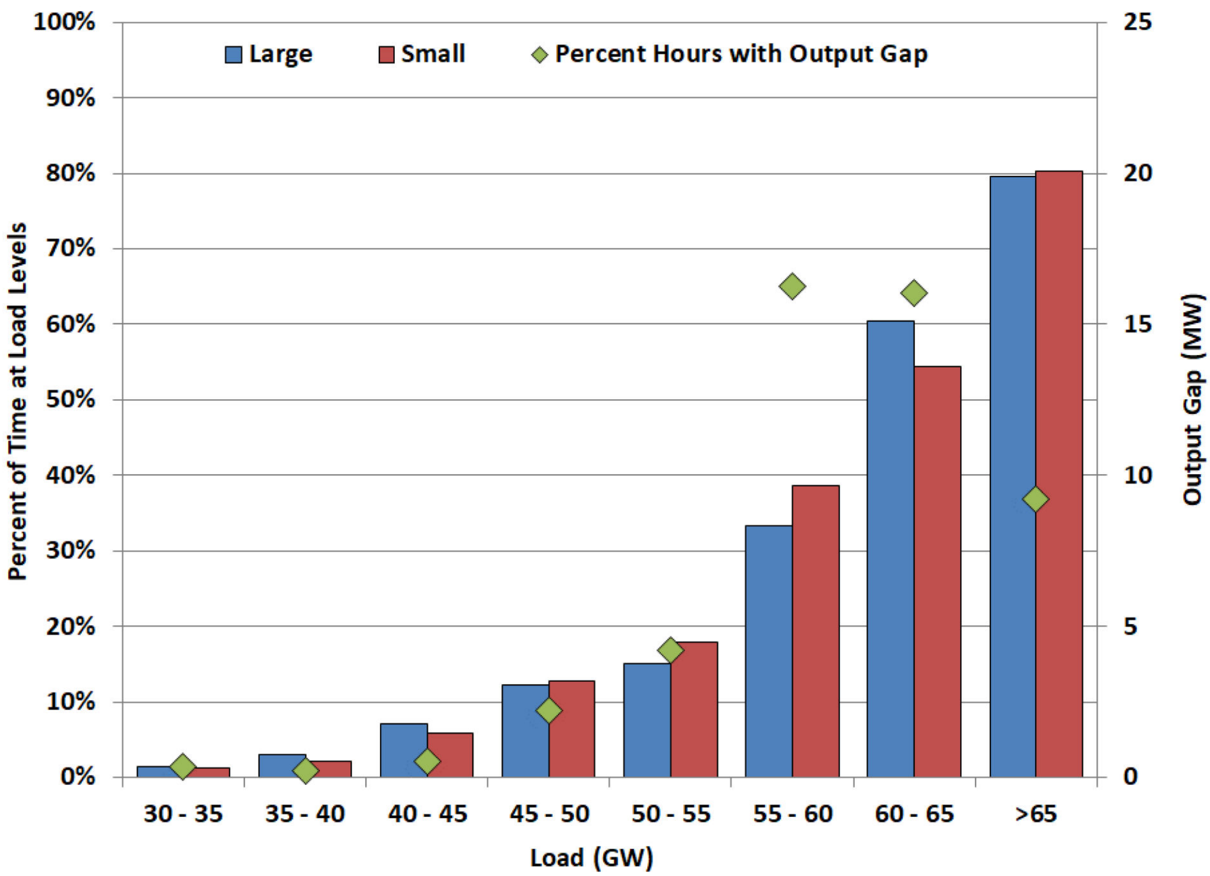


Figure 67 shows the average output gap levels, measured by the difference between a unit's operating level and the output level had the unit been offered to the market based on a proxy for a competitive offer, i.e., the mitigated offers, but with a few changes. We use generic costs instead of verifiable for quick-start units since verifiable costs may contain startup costs inappropriate for comparison here. In addition, fuel adders are removed since they represent fixed costs.

Finally, we do not count quick-start units if they have zero output. Relatively small quantities of capacity are considered part of this output gap, although 22% of the hours in 2021 exhibited an output gap. Taken together, these results show that potential economic withholding levels were low in 2021 and considering all of our evaluation of the market outcomes presented in this Report, allow us to conclude that the ERCOT market performed competitively in 2021.

C. Voluntary Mitigation Plans

Voluntary Mitigation Plans (VMPs) can be filed and if subsequently approved by the Commission, adherence to such plans constitute an absolute defense against an allegation of market power abuse with respect to behaviors addressed by the plan. In 2021, Calpine, NRG and Luminant had active and approved VMPs filed with the Commission.[96] Further details of all three VMPs can be found in Section VII of the Appendix. Generator owners are motivated to enter into VMPs, and the increased regulatory certainty afforded to a generation owner regarding its energy offers in the ERCOT real-time market must be balanced by appropriate protections against a potential abuse of market power in violation of PURA §39.157(a) and 16 TAC §25.503(g)(7).

VMPs should promote competitive outcomes and prevent abuse of market power through economic withholding in the ERCOT real-time energy market. The same restrictions are not required in forward energy markets (e.g., the ERCOT DAM) because the prices in forward energy markets are derived from expectations for real-time energy prices. Forward energy markets are voluntary, and the market rules do not inhibit arbitrage between the forward energy markets and the real-time energy market. Therefore, competitive outcomes in the real-time energy market serve to discipline the potential abuse of market power in the forward energy markets.

Key elements in the three existing VMPs are the termination provisions. The approved VMPs may be terminated by the Executive Director of the Commission with three business days' notice, subject to ratification by the Commission.[97] PURA defines market power abuses as "practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition."[98] The *exercise* of market power may not rise to the level of an *abuse* of market power if the actions in question do not unreasonably impair competition. Impairment of competition would typically involve profitably raising prices materially above the competitive level for a significant period of time. Thus, although the offer thresholds provided in the VMPs are designed to promote competitive market outcomes, the short termination provision provides additional assurance that any unintended consequences associated with the potential exercise of market power can be addressed in a timely manner.

96 *See Petition of Calpine Corporation for Approval of Voluntary Mitigation Plan*, Docket No. 40545, Order (Mar. 28, 2013); *Request for Approval of a Voluntary Mitigation Plan for NRG Companies Pursuant to PURA § 15.023(f) and P.U.C. Subst. R. 25.504(e),* Docket No. 40488, Order (Jul. 13, 2012); *Request for Approval of an Amended Voluntary Mitigation Plan for NRG Companies,* Docket No. 42611, Order (Jul. 11, 2014); and *Commission Staff Request for Approval of a Voluntary Mitigation Plan for Luminant Energy Company, LLC under PURA §15.023(f) and 16 TAC §25.504(e),* Docket No. 49858, (Dec. 13, 2019).

97 Further, Luminant's VMP will terminate on the earlier of ERCOT's go-live date for RTC or seven years after approval.

98 PURA § 39.157(a).

D. Market Power Mitigation

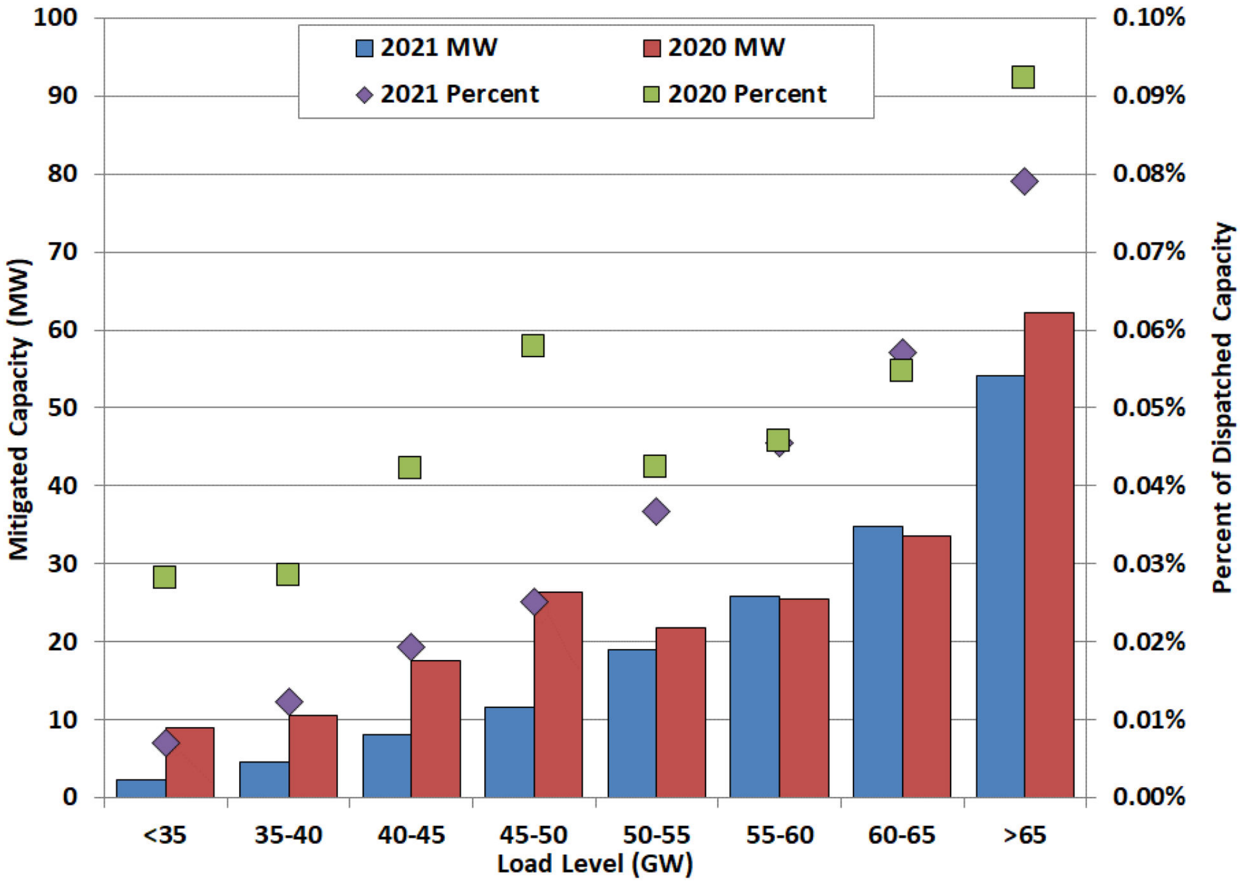
In situations where competition is not robust and suppliers have market power, it is necessary for an independent system operator to mitigate offers to a level that approximates competitive offers. ERCOT's real-time market includes a mechanism to mitigate offers for resources that are required to resolve a transmission constraint. Mitigation applies whether the unit is self-committed or receives a RUC instruction. RUC instructions were typically given to resolve transmission constraints in previous years, though in 2021 RUC for system-wide capacity was common. When units that receive RUC instructions are required to resolve a non-competitive transmission constraint, they often end up mitigated in real-time.

ERCOT's dispatch software includes an automatic, two-step mitigation process. In the first step, the dispatch software calculates output levels (base points) and associated locational marginal prices using the participants' offer curves and considers only the transmission constraints that have been deemed competitive. These "reference prices" at each generator location are compared with that generator's mitigated offer cap, and the higher of the two is used to formulate the offer curve used for that generator in the second step in the dispatch process. The resulting mitigated offer curve is used by the dispatch software to determine the final dispatch levels and locational marginal prices, taking all transmission constraints into consideration.

This approach is intended to limit the ability of a generator to exercise market power, i.e., to limit its ability use its offer to raise prices in the event of a transmission constraint that requires its output to resolve. In this subsection, we analyze the quantity of mitigated capacity in 2021. The automatic price mitigation aspect of the two-step dispatch process only has the potential to have an effect when a non-competitive transmission constraint is active and binding in SCED.

Figure 68 shows the percentage of capacity, on average, that is actually mitigated during each dispatch interval. The results are provided by load level. The amount of mitigation in 2021 was generally lower than in 2020. This was due to fewer non-competitive constraints binding in 2021 than in 2020. In particular, when resources are necessary to resolve a local constraint, it is more likely to be deemed non-competitive and result in mitigation. Only the amount of capacity that could be dispatched within one interval is counted as mitigated for the purpose of this analysis. More analysis of mitigation is presented and discussed in Section VI in the Appendix.

Figure 68: Mitigated Capacity by Load Level



CONCLUSION

As the IMM for the Commission, Potomac Economics is providing this Report to review and evaluate the outcomes of the ERCOT wholesale electricity market in 2021. The year saw unprecedented shortages and outages because of severe cold weather in February, culminating in record levels of shortage pricing. The ripple effects of the Winter Storm Uri reverberated in all corners of the market and system throughout the remainder of the year. The results of that extreme event prompted much more conservative operations of the system by ERCOT, as well as the development of a number of market reforms. We will monitor and evaluate these changes in future reports.

Overall, our evaluation of a number of factors suggests that the market performed competitively in 2021. We identified one incentive concern related to the increase in RUC activity. Our proposed resolution of this concern was implemented in 2022. In the longer term, we continue to look to the implementation of RTC as the most significant change to improve the reliability and competitive performance of the ERCOT markets. We also recommend a number of other improvements to the design and operations of the ERCOT market that will be key in the future as the system transitions to much heavier reliance on intermittent renewable resources.

APPENDIX

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INTRODUCTION

This Appendix provides supplemental analysis of certain topics raised in the main body of the Report. We present the methods and motivation for each of the analyses. However, our conclusions from these analyses and how they relate to performance of the markets are discussed in the main body of the Report. In addition, the body of the Report includes a discussion of our recommendations to improve the design and competitiveness of the market. Below are the two retired previous IMM recommendations this year, indicating the status of each.

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

Status: Resolved via NPRR1081, *Revisions to Real-Time Reliability Deployment Price Adder to Consider Firm Load Shed.*

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

Status: Resolved via NPRR1080, *Limiting Ancillary Service Price to System-Wide Offer Cap.*

I. APPENDIX: KEY CHANGES AND IMPROVEMENTS IN 2021

Key changes or improvements implemented or proposed by the Texas Legislature, the PUC and ERCOT in 2021 are outlined below. In the aftermath of Winter Storm Uri, the Texas Legislature, during 87th session, approved several measures to address market outcomes and reliability concerns. Other key changes include PUC dockets and ERCOT protocol changes as a result of these reforms or other initiatives.

Legislative ERCOT & PUC Reforms

In May 2021, the Texas Legislature approved Senate Bill 2 overhauling the ERCOT Board of Directors, making it fully independent.[99] Senate Bill 2 increased legislative oversight of ERCOT and reformed and restructured its Board of Directors in several ways, including requiring members to live in Texas. The bill requires that the Chairman of the Board and its five unaffiliated members be appointed by the Governor and confirmed by the Senate. The independent members are now selected by a search firm based on executive level experience in a range of fields, including finance, business, engineering, risk management, law, and electric market design. None of them may own a financial interest in the companies operating in the ERCOT market. Once selected, those members must be confirmed by the newly created Board Selection Committee consisting of three appointees: one each from the Governor, the Lt. Governor and the Speaker of the House. This committee will also select the Chair and Vice-

[99] https://capitol.texas.gov/billlookup/text.aspx?LegSess=87R&Bill=SB2

Chair. Senate Bill 2 additionally requires all major protocol changes at ERCOT to be reviewed by the PUC before adoption, giving the PUC veto authority over those changes.

The Legislature also passed Senate Bill 3, the omnibus reform bill related to Winter Storm Uri.[100] This bill included a number of changes including the creation of a power outage alert system, formalizing the Texas Energy Reliability Council (TERC), creating the Texas Electric Supply Chain Mapping Committee, requiring weatherization and providing for increased administrative penalties as well as the inspection of facilities by ERCOT. The bill called for a study on ancillary services, established an emergency pricing program, and made changes to help improve the load shedding process. Senate Bill 3 limited weatherization requirements to "critical" facilities and excluded an amendment to provide grants for backup power at health care facilities.

Finally, the Legislature overhauled the Public Utility Commission of Texas by moving the number of Commissioners from three to five and made changes to Commissioner qualifications with the passing of Senate Bill 2154.[101] The bill required that all five Commissioners be Texas residents, and that only two are well informed and qualified in the field of utility regulation.

Securitization and Financing

The Legislature authorized different forms of financing to "serve[] the public purpose of allowing the commission to stabilize the wholesale electricity market in the ERCOT power region." PURA § 39.651(c). To address the unpaid balances of electric cooperatives and retail energy providers to the wholesale power market totaling over $3 billion, the Legislature passed House Bill 4492 and Senate Bill 1580, which authorize the use of securitization and financing from the state's "rainy day" fund balance, the Economic Stabilization Fund (ESF), to be repaid by ERCOT market participants through default charges established by the PUC.

Senate Bill 1580 establishes a securitization mechanism specifically for electric co-ops to finance the costs incurred during Winter Storm Uri.[102] The broader House Bill 4492 provides a financing program available to retail electric providers for ancillary service charges and reliability deployment price adders above the $9,000 system-wide off cap.[103] The bill allows electric companies and retail electric providers to finance up to $2.1 billion for electricity that companies paid for but never received during the storm, as well as additional charges from the high wholesale power prices while specifically disallowing securitizing amounts that were part of the prevailing settlement point price. Another $800 million would be loaned to pay off debts

100 https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=87R&Bill=SB3

101 https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=87R&Bill=SB2154

102 https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=87R&Bill=SB1580

103 https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=87R&Bill=HB4492

to ERCOT, which functions as the transaction house for the electricity market. The ESF's 2020 ending balance was approximately $10 billion.

PUC Dockets & Projects

Addressing specific issues arising from Winter Storm Uri as well as the clear directives from the Texas Legislature, a number of projects and dockets were opened to implement reform to the wholesale market.

Scarcity Pricing Mechanism

Project No. 51871, *Review of the ERCOT Scarcity Pricing Mechanism* eliminated the provision that tied the value of the LCAP to the natural gas price index and replaced it with a provision that ensures resource entities are able to recover their actual marginal costs when the LCAP is in effect. In PUC Project No. 52631, *Review of 25.505*, the HCAP was set at $5,000 per MWh effective Jan. 1, 2022.

PUC Implementation of Securitization and Financing

In Subchapter M of PURA Chapter 39, the Legislature approved a process by which ERCOT could seek approval of a Debt Obligation Order authorizing financing of the Default Balance, which is defined by PURA to include: (1) amounts owed to ERCOT by competitive wholesale market participants from the Period of Emergency that otherwise would be or have been uplifted to other wholesale market participants; (2) financial revenue auction receipts used by ERCOT to temporarily reduce amounts short-paid to wholesale market participants related to the Period of Emergency; and (3) reasonable costs incurred by a state agency or ERCOT to implement a debt obligation order, including the cost of retiring or refunding existing debt. PURA § 39.602(1).[104]

In Subchapter N of PURA Chapter 39, the Legislature authorized ERCOT to seek approval of a Debt Obligation Order to finance the Uplift Balance, including Reliability Deployment Price Adder ("RDPA") charges and Ancillary Service costs above the Commission' s system-wide offer cap as that term is defined in PURA § 39.652.[105] Accordingly, ERCOT filed applications for Debt Obligation Orders pursuant to Subchapter M and N of Chapter 39 of the Public Utility Regulatory Act (PURA), to finance the Winter Storm Uri Default and Uplift Balances in July 2021. The Debt Obligation Orders were issued on October 13, 2021.

In the Subchapter M Order, the Commission directed the following:

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104 *Application of Electric Reliability Councill of Texas, Inc. for a Debt Obligation Order to Finance Default Balances Under PURA Chapter 39, Subchapter M and Request for Good Cause Exception,* Docket No. 52321 (Oct. 13, 2021).

105 *Application of the Electric Reliability Councill of Texas, Inc. for a Debt Obligation Order to Finance Uplift Balances Under PURA Chapter 39, Subchapter N, and for a Good-Cause Exception,* Docket No. 52322, (Oct. 13, 2021).

- the default balance in an aggregate amount of up to $800 million;
- the assessment of default charges to all wholesale market participants, except those expressly exempted by PURA, in an amount sufficient to ensure the recovery of amounts expected to be necessary to timely provide all payments of debt service and other required amounts and charges in connection with the issuance of debt obligations (referred to in this Order as subchapter M bonds);
- the issuance of subchapter M bonds in one or more series in an aggregate amount of up to $800 million for the payment of the default balance;
- the financing or securitization of default charges and the creation of default property.

A compliance docket was opened in accordance with ordering paragraph 45C of the Debt Obligation Order for all filings required by the Debt Obligation Order.[106] Approved on December 16, 2021, NPRR1103, *Securitization – PURA Subchapter M Default Charges*, established processes for the assessment and collection of Default Charges and Default Charge Escrow Deposits to QSEs and CRRAHs pursuant to the Debt Obligation Order (DOO) issued in PUC Docket No. 52321, *Application of Electric Reliability Council of Texas, Inc. for a Debt Obligation Order Pursuant to Chapter 39, Subchapter M, of PURA*.

In the Subchapter N docket, an agreement was filed resolving many issues after a hearing on the merits of the application was held. All parties that filed testimony signed the agreement and no party opposes the agreement. The parties agreed on issues related to opting out, allocating the uplift balance, and distributing the proceeds of the financing. A parallel project was opened to accommodate the requirements of PUC Docket No. 52322.[107] The Debt Obligation Order approved, ensured, and established the following:

- the mechanisms that allow the uplift balance to be determined, the amount of the financing proceeds to be distributed, and the documentation and calculations required to determine these amounts;
- the mechanisms to calculate and assess uplift charges to repay the uplift balance and other amounts necessary to implement this Order and the financing mechanism established by this Order;
- that uplift charges are non-bypassable and establishes mechanisms to ensure that uplift charges are reviewed and adjusted on a quarterly basis to ensure sufficient amounts of revenue are available to make timely payments of debt service and other required amounts related to the debt obligation;

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106 *Compliance Filing for Docket No. 52321 (Application of the Electric Reliability Council of Texas, Inc. for a Debt Obligation Order under PURA Chapter 39, Subchapter M, of the Public Utility Regulatory Act),* Docket No. 52709, (Oct. 13, 2021).

107 *Proceeding for Eligible Entities to File and Opt-Out Pursuant to § 39.653(d) and for Load-Serving Entities to File Documentation of Exposure to Costs Pursuant to the Debt Obligation Order in Docket No. 52322*, Project No. 52364, (Dec. 3, 2021).

- ERCOT's proposal to issue bonds through a special purpose entity to finance the uplift balance providing security of uplift property and the use of credit enhancements to minimize uplift charges;
- the securitization of uplift charges and the creation of uplift property;
- certain criteria in this Order that must be met for the approvals and authorizations granted in this Order to become effective, requiring specified documents and other information be filed with the Commission so that it can ensure compliance with this Order.

Posted on December 29, 2021, and approved on March 31, 2022, NPRR1114, *Securitization – PURA Subchapter N Uplift Charges,* established processes to assess and collect Uplift Charges to QSEs representing LSEs pursuant to the DOO issued in PUC Docket No. 52322.

Review of Wholesale Electric Market Design (Phases I and II Blueprint)

After a series of rigorous public work sessions and review of volumes of comments filed by market participants, the Commission directed ERCOT to enact major reforms in PUC Project No. 52373, *Review of Wholesale Electric Market Design* at the December 16, 2021, open meeting.[108] Specifically, the Commission approved the blueprint for the design of the wholesale electric market filed in the Project on December 6, 2021. The blueprint compiles directives and concepts designed to reform the ERCOT wholesale electricity market presented in two phases. Phase I of the blueprint provides enhancements to current wholesale market mechanisms to enhance ancillary services and improve price signals and operational reliability. Phase II of the blueprint incorporates long-term market design reforms to promote the supply of dispatchable generation and develop a backstop reliability service.

The Commission approved the following directives as part of **Phase I** of the blueprint as the end of 2021 (not an exhaustive list):

Operating Reserve Demand Curve (ORDC)

- Changes to the ORDC should be made effective January 1, 2022, to set the MCL at 3,000 MW and set the HCAP and VOLL to $5,000 per MWh.

Demand Response

- Pursue market modifications and technical measures to improve transparency of price signals for load resources, such as changing demand response pricing from zonal to LMPs;
- Set higher performance standards for energy efficiency programs;
- Direct ERCOT to evaluate actions that have already been taken to accommodate customer aggregation participation - i,e., virtual power plants (VPPs)-in the

[108] *Review of Wholesale Electric Market Design,* PUC Project No. 52373, Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT (Jan. 13, 2022).

ERCOT market, determine how much customer aggregations currently participate in the ERCOT market, and identify current barriers for VPP participation in the ERCOT real-time and ancillary services markets.

Emergency Response Service (ERS) Reform

- Codify good cause exception ordered by the Commission in the Fall of 2021 directing ERCOT to deploy ERS at MCL.
- Determine whether the ERS procurement methodology should be changed to provide for the procurement of a specific MW quantity or some other measure than a fixed dollar amount;
- Determine whether the ERS program should include seasonal apportionment.

Firm Fuel Product[109]

- Determine whether this stand-alone, discrete service can be incorporated into a load-side reliability mechanism in the future.
- Determine whether this product should be procured by ERCOT through a competitive auction, competitive request for proposal (RFP) process (similar to ERCOT's current Black Start program), or some other competitive procurement method.

Voltage Support Compensation

- Analyze and develop a product to compensate resources for voltage support.

ECRS (New Ramping Ancillary Service Product)

- ERCOT will accelerate the implementation of this new reliability product.
- Determine options for sizing the product.
- Allocate cost of ECRS consistent with cost-causation principles, in a nondiscriminatory manner pursuant to SB 3.

Additionally, the Commission committed to opening rulemaking proceedings and other projects to request technical feedback and provide rate recovery of reasonable and necessary distribution voltage reduction costs and review DG interconnection procedures.

As part of **Phase II** of the market design blueprint, the Commission agreed to investigate and develop the following concepts:

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109 NPRR1120, *Create Firm Fuel Supply Service*, approved on March 31, 2022, creates a new reliability service, Firm Fuel Supply Service (FFSS). This new reliability service will be procured via request for proposal (RFP) and the NPRR focused on components that require accommodation in the Settlement and Billing system. Additional requirements will be reflected in the RFP that will be forthcoming; see also *Wholesale Electric Market Design Implementation*, Project No. 53298 (pending).

1. Load-side reliability mechanism
2. Backstop Reliability Service

The Commission committed to exploring a load-side reliability mechanism (either a Load-Serving Entity (LSE) Obligation, Dispatchable Energy Credits (DECs), or a combination of the two) with the stated purpose of ensuring the supply of dispatchable generation is sufficient to meet system demand in ERCOT. The Commission also committed to exploring a Backstop Reliability Service, either alone or in conjunction with a load-side reliability mechanism. The backstop reliability service will be used to procure accredited new and existing dispatchable resources to serve as an insurance policy to help prevent emergency conditions in ERCOT.

The IMM looks forward to working with the Commission and market participants to explore these options and identify meaningful enhancements to ERCOT's wholesale market.

ERCOT Protocols Revisions

ERCOT approved or at least began deliberating a number of Nodal Protocol Revision Requests (NPRRs) to reflect and implement the changes authorized by the Texas Legislature and PUC, as well as a suite of general market improvements, outlined below.

- NPRR1075, *Update Telemetered HSL and/or MPC for ESRs in Real-Time to Meet Ancillary Service Resource Responsibility.*
  - Status: Approved on June 8, 2021; effective on June 9, 2021.
  - Description: This NPRR allows ESRs to update their High Sustained Limit (HSL) and/or Maximum Power Consumption (MPC) in Real-Time for the purposes of maintaining sufficient energy to meet an Ancillary Service Resource Responsibility. The ability for ESRs to update their Real-Time HSL and/or MPC would expire at the earlier of system implementation of RTC or implementation of a Mitigated Offer Cap for ESRs other than the System-Wide Offer Cap.

- NPRR1080, *Limiting Ancillary Service Price to System-Wide Offer Cap*; OBDRR030, *Related to NPRR1080, Limiting Ancillary Service Price to System-Wide Offer Cap.*
  - Status: Approved on June 28, 2021; effective on July 1, 2021.
  - Description: ERCOT and the IMM cosponsored an NPRR and accompanying OBDRR to limit ancillary service MCPCs to the system-wide offer cap. This limitation was achieved by reducing the ASPFs to values equal to or immediately below the system-wide offer cap, which prevents ancillary service shadow prices, and in turn, MCPCs, from exceeding the system-wide offer cap, consistent with economic market design principles. Because ancillary services are procured to reduce the probability of losing load, such principles dictate that the value of reserves should not exceed VOLL, which is equal to the system-wide offer cap. However, reducing ASPFs to the system-wide offer cap increases the likelihood

of ancillary service insufficiency during tight conditions because the DAM algorithm will have the option of forgoing an ancillary service offer at a lower cost.

- NPRR1081, *Revisions to Real-Time Reliability Deployment Price Adder to Consider Firm Load Shed.*
  - Status: Approved on June 28, 2021,
  - Description: This NPRR modifies the calculation of the Real-Time On-Line Reliability Deployment Price Adder so that the combination of System Lambda, the Real-Time On-Line Reserve Price Adder, and the Real-Time On-Line Reliability Deployment Price Adder will be equal to the VOLL when ERCOT is directing firm Load shed during EEA3.

- NPRR1086, *Recovery, Charges, and Settlement for Operating Losses During an LCAP Effective Period.*
  - Status: Approved on August 19, 2021; effective on August 20, 2021
  - Description: This NPRR aligns the Protocols with the order amending 16 TAC § 25.505 in PUC Project No. 51871 (51871 Order), which modifies the value of the Low System-Wide Offer Cap (LCAP) by eliminating a provision that ties the value of LCAP to the natural gas price index, and adding a provision that ensures that a Resource Entity (through its Qualified Scheduling Entity (QSE)) can recover its actual marginal costs when a scarcity pricing situation occurs while the LCAP is in effect (LCAP Effective Period). An LCAP Effective Period occurs when the Peaker Net Margin (PNM) during a calendar year exceeds a threshold of three times the cost of new entry for new generation plants. During an LCAP Effective Period, the System-Wide Offer Cap (SWCAP) will be set to the LCAP for the remainder of the calendar year.

- NPRR1092, *Reduce RUC Offer Floor and Limit RUC Opt-Out Provision.*
  - Status: Approved by the Board on April 28, 2022; effective date of May 13, 2022, for Section 6.5.7.3, Security Constrained Economic Dispatch, and upon system implementation for the remainder.
  - Description: Posted on August 11, 2021, by the IMM, this NPRR as filed would have reduced the value of the offer floor on Resources that have the status of ONRUC to $75/MWh and removed the ONOPTOUT status. This NPRR was still pending at the end of 2021, but a modified version was approved in 2022. That version sets a $250/MWh RUC offer floor and allows ONOPTOUT status in more limited circumstances.

- NPRR1093, *Load Resource Participation in Non-Spinning Reserve.*

  - Status: Approved on October 28, 2021, effective upon system implementation.
  - Description: This NPRR changes the Protocols to allow Load Resources that are not Controllable Load Resources to provide Non-Spin. The NPRR largely reinstates Protocol requirements that were in place during the first five years of the Nodal Market implementation that were subsequently changed to enable Controllable Load Resource participation in Security-Constrained Economic Dispatch (SCED) and Non-Spin. Additionally, it also incorporates market design changes that have been made for the Operating Reserve Demand Curve (ORDC) and Reliability Deployment Price Adder process when deploying Ancillary Services from Load Resources that are not Controllable Load Resources.

- NPRR1096, *Require Sustained Six Hour Capability for ECRS and Non-Spin.*
  - Status: Posted on September 28, 2021, by ERCOT and still pending at the end of 2021, but approved by the Board on April 28, 2021.
  - Description: This NPRR would require Resources that provide ECRS and/or Non-Spinning Reserve (Non-Spin) to limit their responsibility to a quantity of capacity that is capable of being sustained for six consecutive hours. Additionally, this NPRR would also require ERCOT to conduct unannounced tests on ESRs that are providing ECRS and/or Non-Spin in Real-Time.

- NPRR1103, *Securitization – PURA Subchapter M Default Charges.*
  - Status: Approved on December 16, 2021, with Phase 1 effective December 17, 2021.
  - Description: This NPRR established processes for the assessment and collection of Default Charges and Default Charge Escrow Deposits to QSEs and CRRAHs pursuant to the Debt Obligation Order (DOO) issued in PUC Docket No. 52321, *Application of Electric Reliability Council of Texas, Inc. for a Debt Obligation Order Pursuant to Chapter 39, Subchapter M, of PURA*.

- NPRR1114, *Securitization – PURA Subchapter N Uplift Charges.*
  - Status: Posted on December 29, 2021, and still pending at the end of 2021, but approved on March 31, 2022.
  - Description: This NPRR would establish processes to assess and collect Uplift Charges to QSEs representing LSEs pursuant to the DOO issued in PUC Docket No. 52322.

II. Appendix: Review of Real-Time Market Outcomes

In this section of the Appendix, we provide supplemental analyses of 2021 prices and outcomes in ERCOT's real-time energy market. Table A1 is the annual aggregate costs of various ERCOT charges or payments in 2021, including AS charges by type. This does not reflect the total cost of each AS because it is the net charges after self-arrangement.

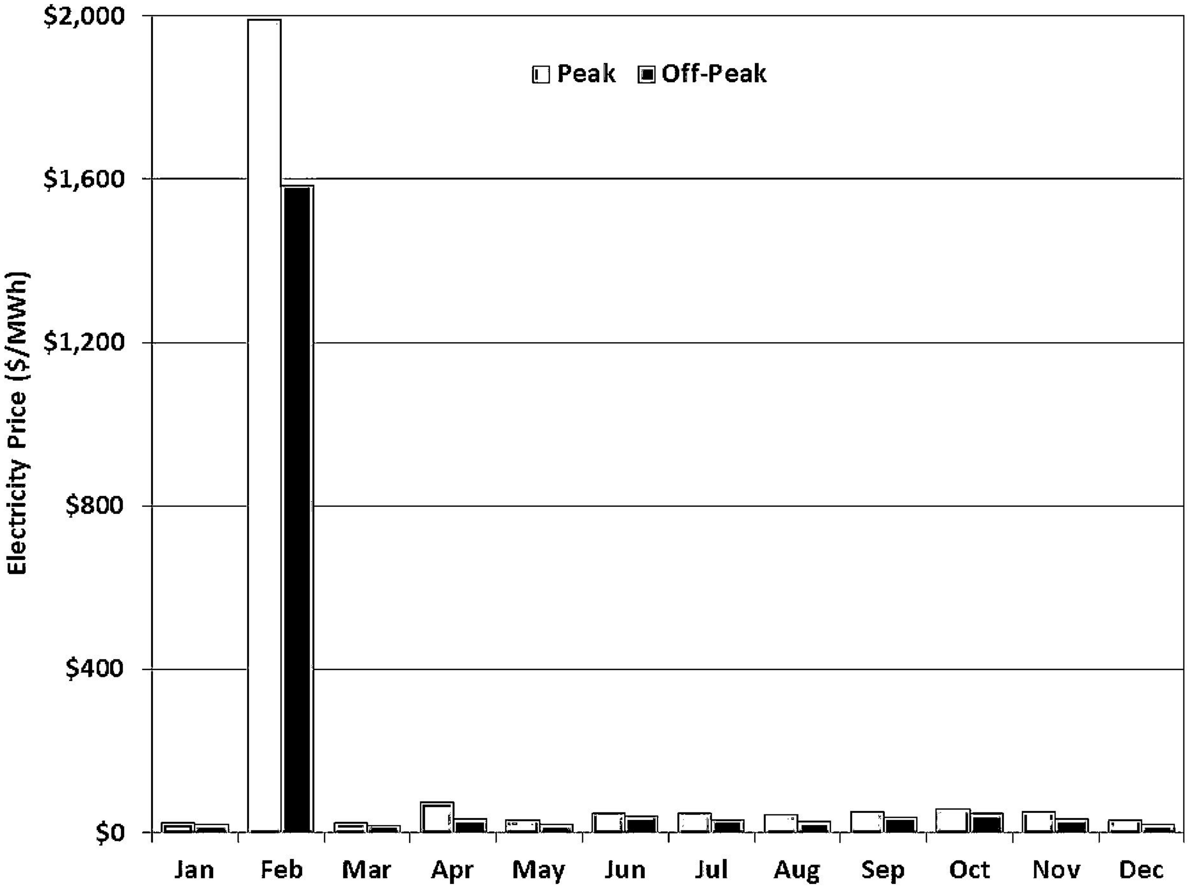
Table A1: ERCOT 2021 Year at a Glance (Annual)

Cost Type	Annual Total ($M)
Energy	$65,946
Regulation Up	$869
Regulation Down	$348
Responsive Reserve	$8,232
Non-Spin	$2,176
CRR Auction Distribution	$831
Balancing Account Surplus	$111
CRR DAM Payment	$1,289
PTP DAM Charge	$1,113
PTP RT Payment	$1,563
Emergency Response Service	$59
Revenue Neutrality	$1
ERCOT Fee	$218
Other Load Allocation	$1,831

A. Real-Time Market Prices

Real-time energy prices vary substantially by time of day. Figure A1 shows the load-weighted average real-time prices in ERCOT for the categories of Peak and Off-Peak for each month in 2021. The Peak block includes hour ending (HE) 7 to HE 22 on weekdays; the Off-Peak block includes all other hours. These pricing blocks align with the categories traded in forward markets.

Figure A1: Peak and Off-Peak Pricing



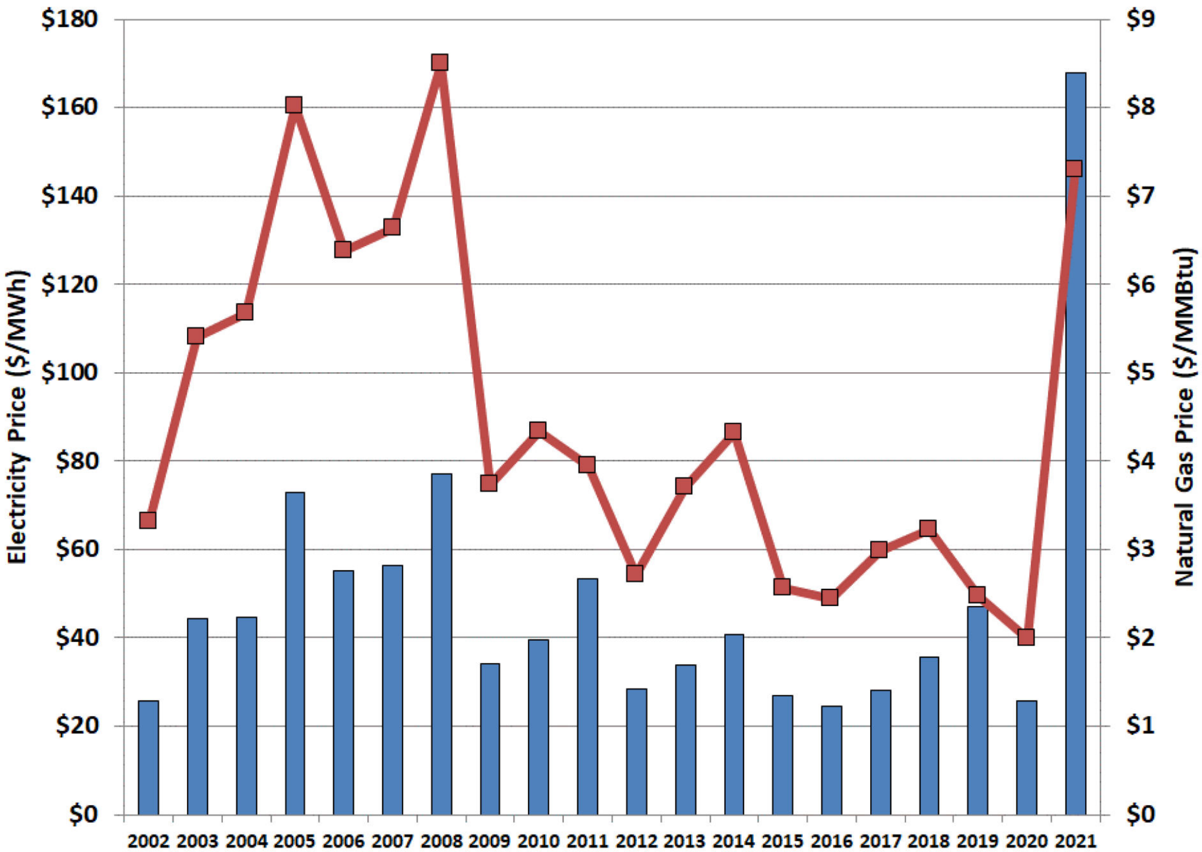
As expected, Peak hours were higher priced than Off-Peak hours for every month in 2021, with prices in February (both Peak and Off-Peak) far exceeding all other months due to Winter Storm Uri. In February, the difference between Peak and Off-Peak was $408.21. For all other months, the difference ranged from a minimum of $2.71 per MWh in January to a maximum of $39.34 per MWh in April due to low renewable output in April.

The extreme price differential in February even surpassed the differential seen in August 2019, the most recent example of significant shortage pricing prior to 2021, when the difference was $275.00 per MWh due primarily to shortage conditions and the resulting high prices (multiple intervals at the HCAP of $9,000 per MWh) seen during peak hours in the week of August 12, 2019. The average difference between monthly Peak and Off-Peak pricing in 2021 was $46.45 per MWh with February included, but only a more modest $13.56 with February excluded.

B. Zonal Average Energy Prices in 2021

Figure A2 below provides additional historic perspective on the ERCOT average real-time energy prices as compared to the average natural gas prices in each year from 2002 through 2021.

Figure A2: ERCOT Historic Real-Time Energy and Natural Gas Prices



Like Figure 3 in the body of the report, Figure A2 shows the historically close correlation between the average real-time energy price in ERCOT and the average natural gas price. Such relationship is consistent with expectations in ERCOT where natural gas generators predominate and tend to set the marginal price; this is an indication that the price of electricity is reflective of the cost of production.

Figure A3 shows the monthly load-weighted average prices in the four geographic ERCOT zones during 2020 and 2021, both with and without the effects of Winter Storm Uri. These prices are calculated by weighting the real-time energy price for each interval and each zone by the total load in that interval. Load-weighted average prices are most representative of what loads are likely to pay, assuming that real-time energy prices are, on average, generally consistent with bilateral or other forward contract prices. Aside from the month of February, these prices in 2021 were not particularly volatile month-to-month.

Figure A3: Average Real-Time Energy Market Prices by Zone (with Uri)

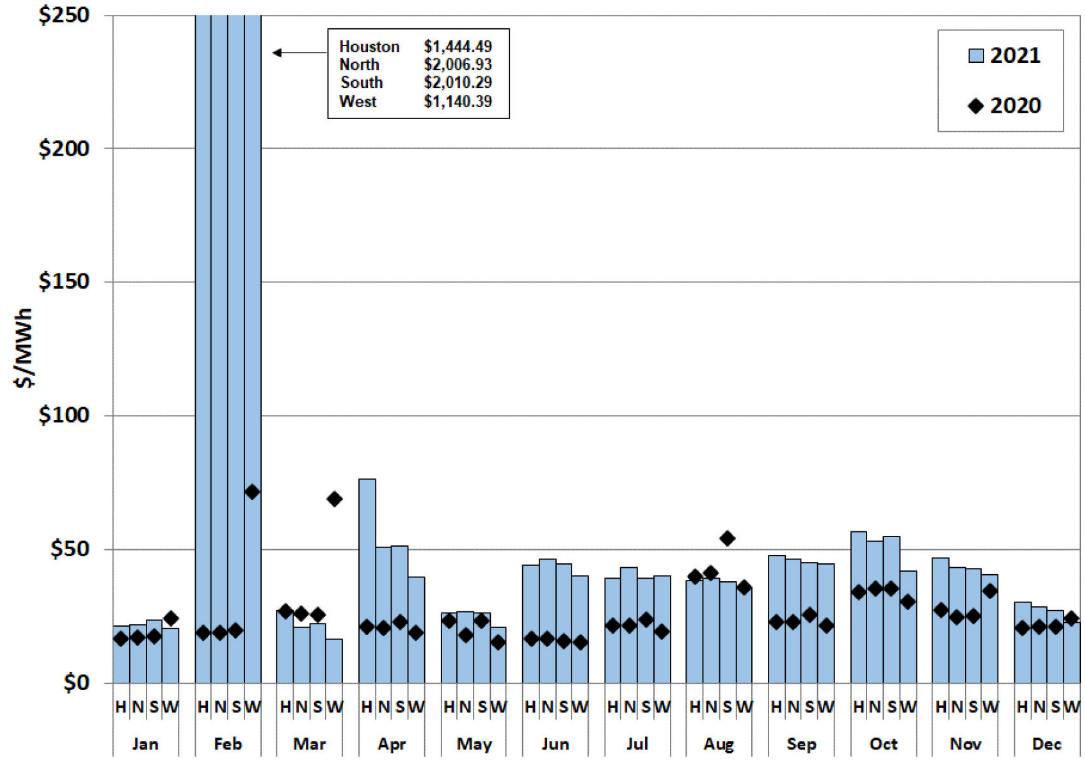
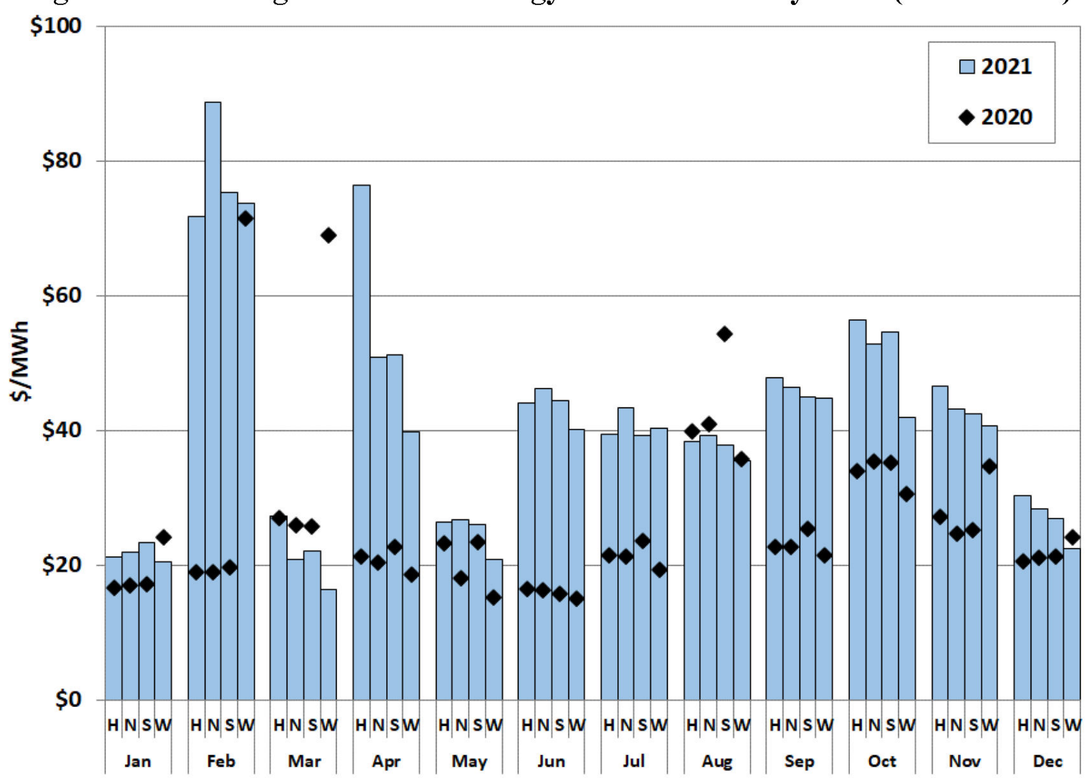


Figure A4: Average Real-Time Energy Market Prices by Zone (without Uri)



Another factor influencing zonal price differences is CRR auction revenue distributions. These are allocated to Qualified Scheduling Entities (QSEs) representing load, based on both zonal and ERCOT-wide monthly load-ratio shares. The CRR auction revenues have the effect of reducing the total cost to serve load borne by a QSE.

Figure A5 shows the effect that this reduction has on a monthly basis, by zone, in 2021. However, it is difficult to view the credit due to the skewing effects of Winter Storm Uri. Therefore, we remove the effect of Winter Storm Uri so that the other details can be visualized and present the same chart as Figure A6.

Figure A5: Effective Real-Time Energy Market Prices (with Uri)

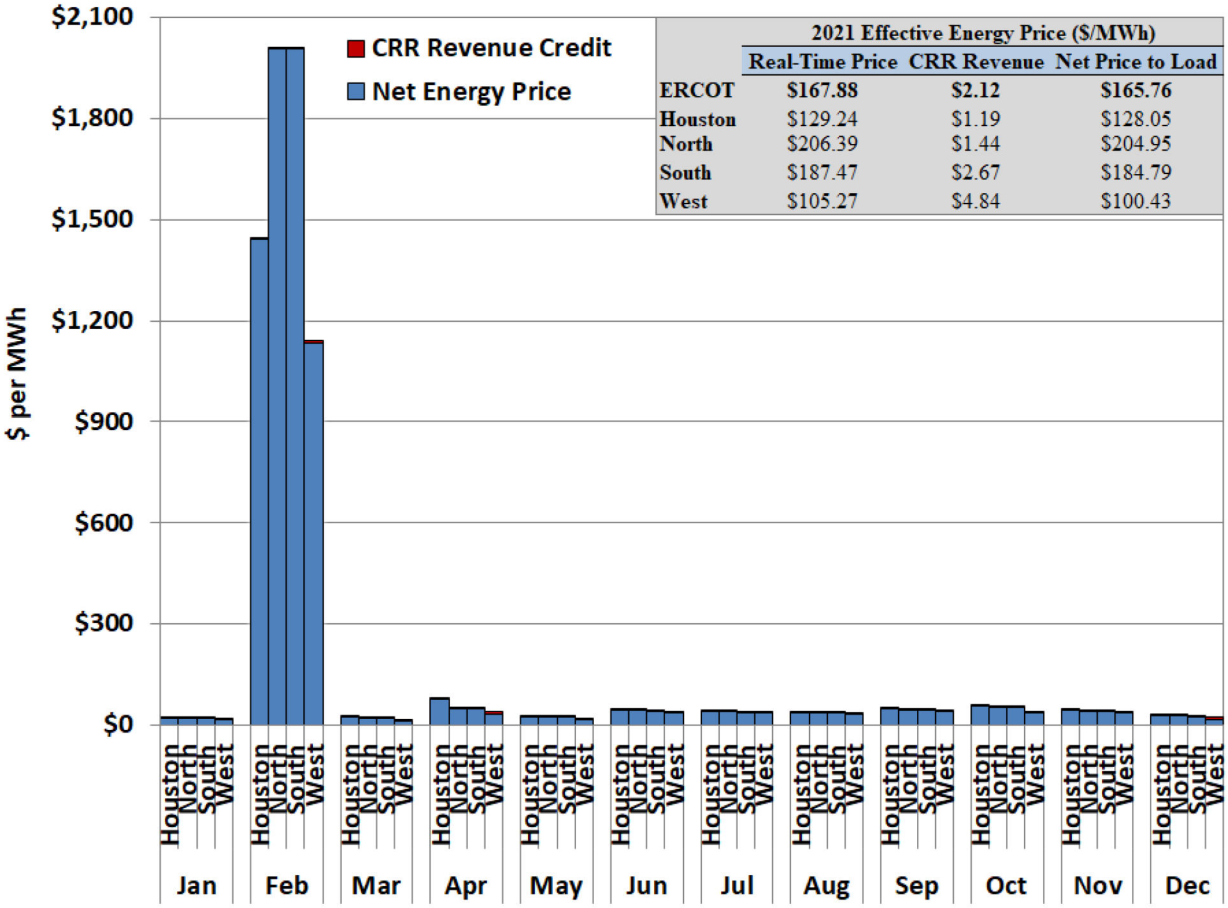
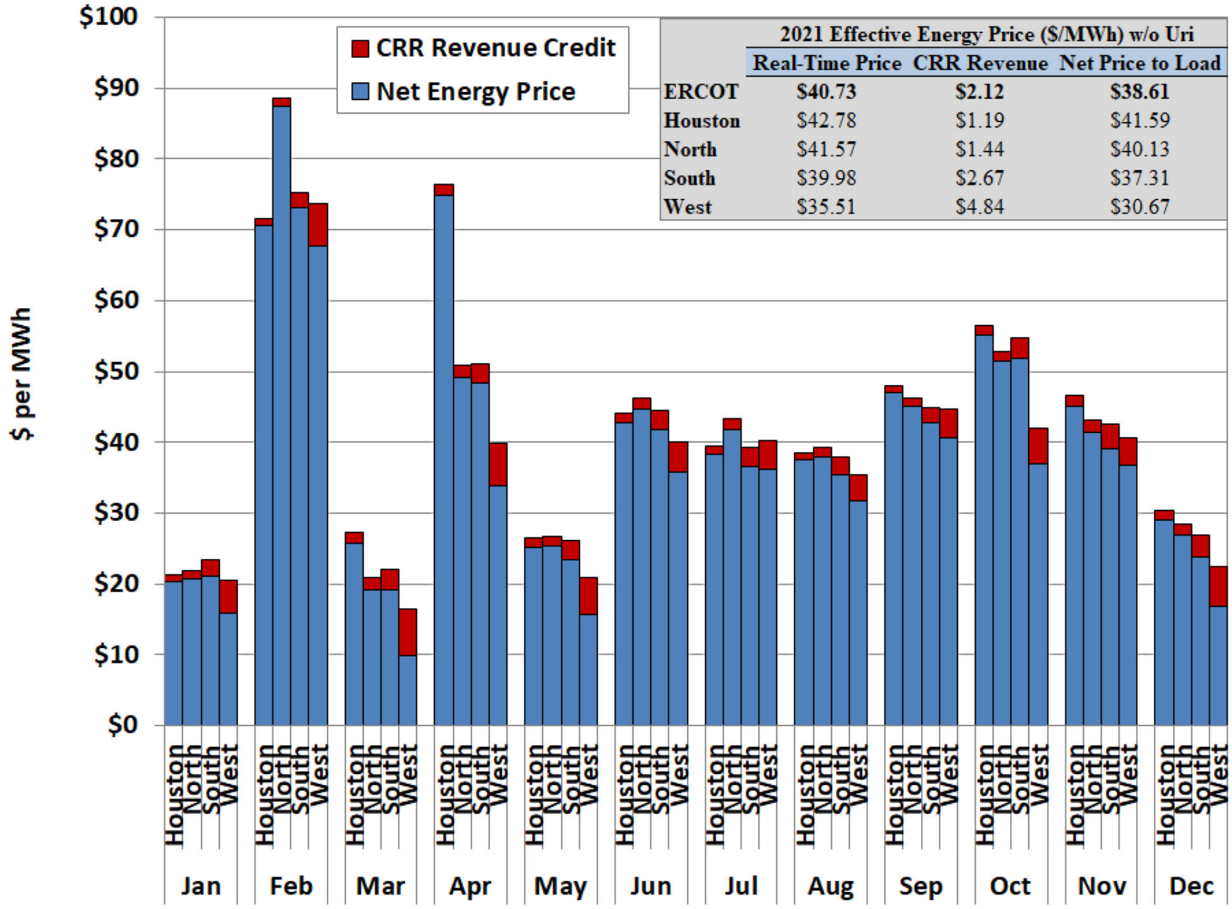


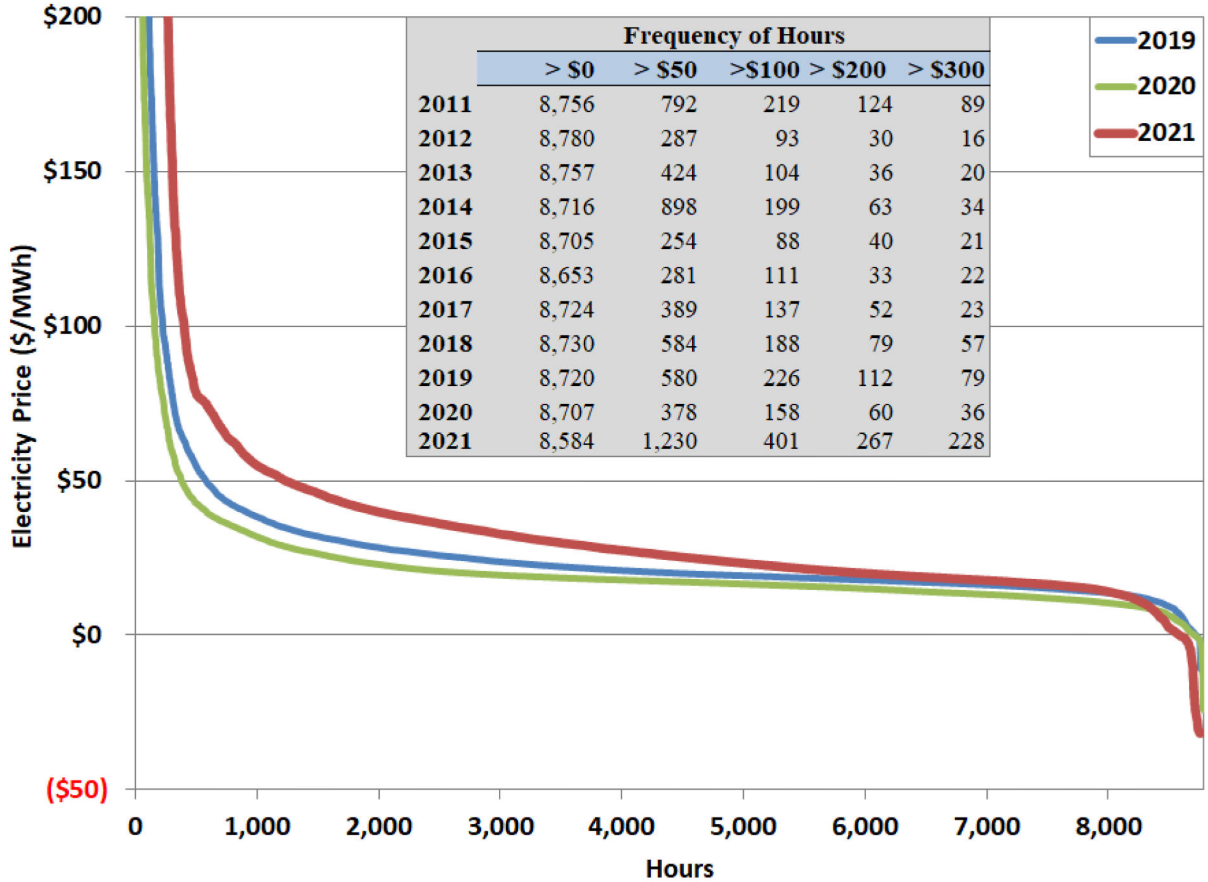
Figure A6: Effective Real-Time Energy Market Prices (without Uri)



A price duration curve indicates the number of hours (shown on the horizontal axis) that the price is at or above a certain level (shown on the vertical axis). Figure A5 shows price duration curves for the ERCOT energy market for 2019 through 2021, with 2019 showing the most shortage pricing hours since the nodal market implementation before the extreme impacts of Winter Storm Uri in 2021. The prices in this figure are the hourly ERCOT average prices derived by load weighting the zonal settlement point prices.

Negative ERCOT-wide prices may occur when wind is the marginal generation. More installed wind generation and additional transmission infrastructure led to increased occurrences of negative prices over the past few years. In 2021, there were 176 hours with ERCOT-wide prices at or below zero, an increase from the 77 hours in 2020. Figure A7 represents a price duration curve to show this effect.

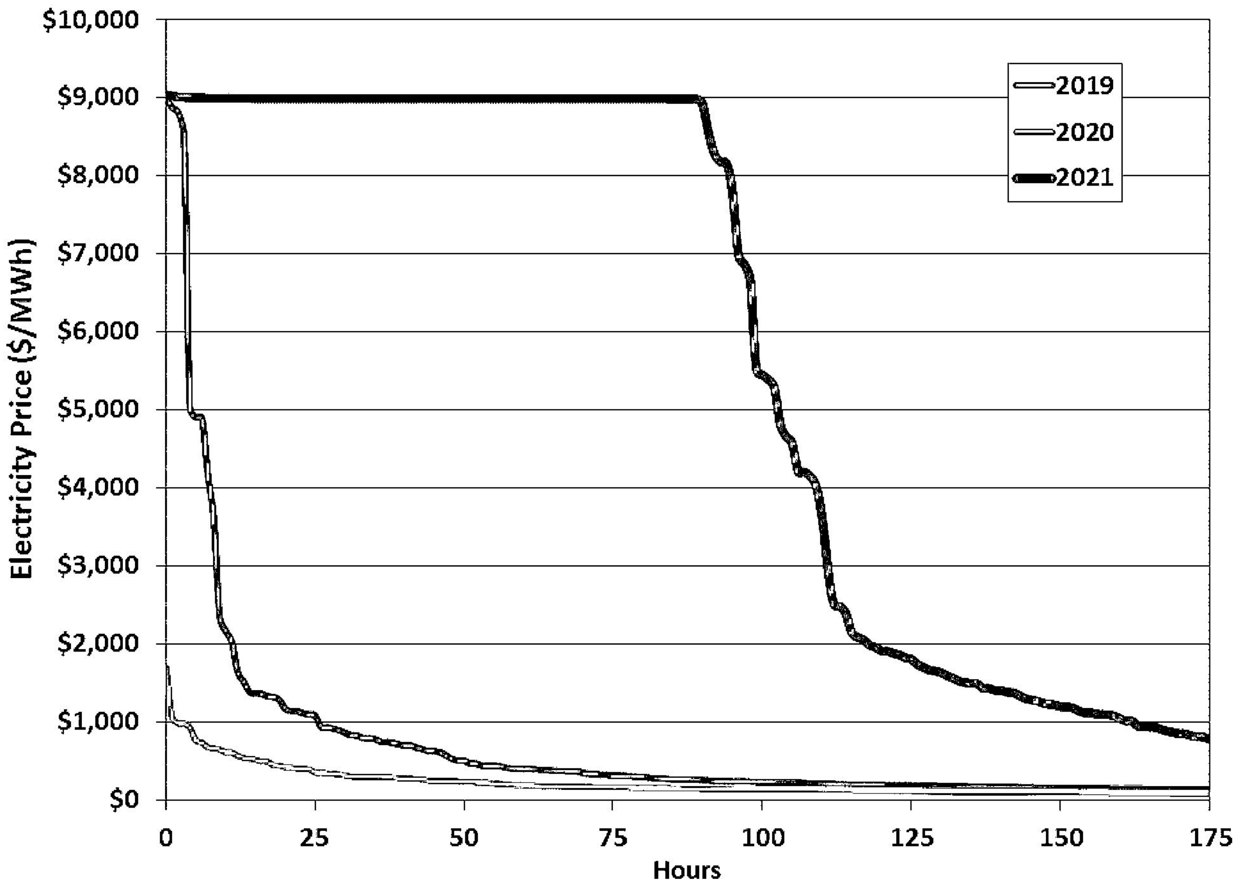
Figure A7: ERCOT Price Duration Curve



Frequency of Hours	> $0	> $50	>$100	> $200	> $300
2011	8,756	792	219	124	89
2012	8,780	287	93	30	16
2013	8,757	424	104	36	20
2014	8,716	898	199	63	34
2015	8,705	254	88	40	21
2016	8,653	281	111	33	22
2017	8,724	389	137	52	23
2018	8,730	584	188	79	57
2019	8,720	580	226	112	79
2020	8,707	378	158	60	36
2021	8,584	1,230	401	267	228

Figure A8 compares prices for the highest-priced 2% of hours in 2019 through 2021. Energy prices for the highest 100 hours of 2021 were significantly higher than those in 2019 and 2020, with Winter Storm Uri driving 2021 to be the peak year since the nodal market implementation by a significant margin. The higher prices in 2019 and again in 2021 illustrate the effects of the changes to the shortage pricing mechanism over recent years, most importantly the increase of the System Wide Offer Cap to $9,000 per MWh, the implementation of the Operating Reserve Demand Curve and subsequent changes to its parameters, and the implementation of the Reliability Deployment Adder.

Figure A8: ERCOT Price Duration Curve – Top 2% of Hours



C. 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 A9 and Figure A10 show the load-weighted, hourly average real-time energy price adjusted to remove the effect of natural gas price fluctuations. The first chart displays the number of hours (shown on the horizontal axis) that the implied heat rate is at or above a certain level (shown on the vertical axis).

Figure A9: Implied Heat Rate Duration Curve – All Hours

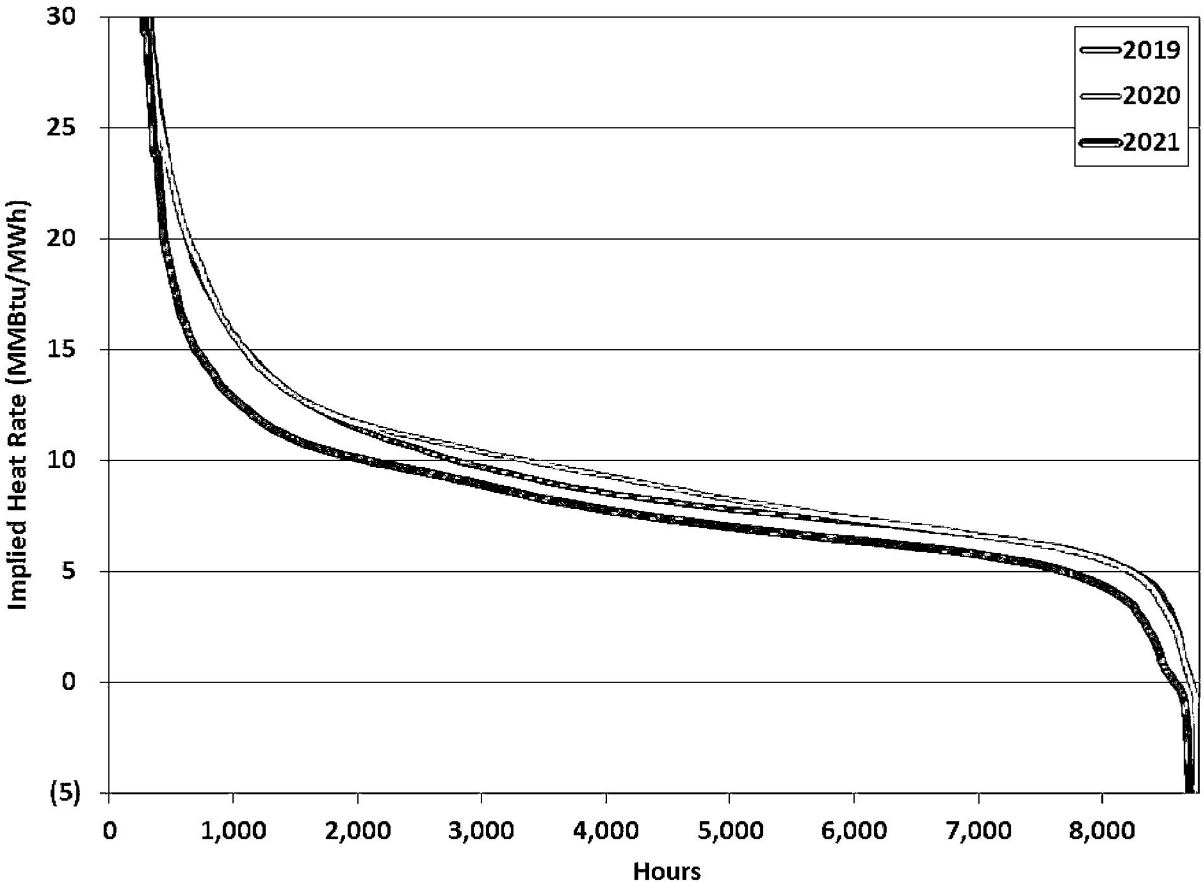


Figure A10 shows the implied marginal heat rates for the top 2% of hours from 2019 to 2021. The implied heat rate duration curve for the top 2% of hours in 2020 and 2021 were much lower than 2019 despite significant contributions from shortage pricing in 2021, due to the high natural gas prices during 2021 especially during Winter Storm Uri, and due to mild conditions and an absence of significant shortage pricing in 2020

Figure A10: Implied Heat Rate Duration Curve – Top 2% of Hours

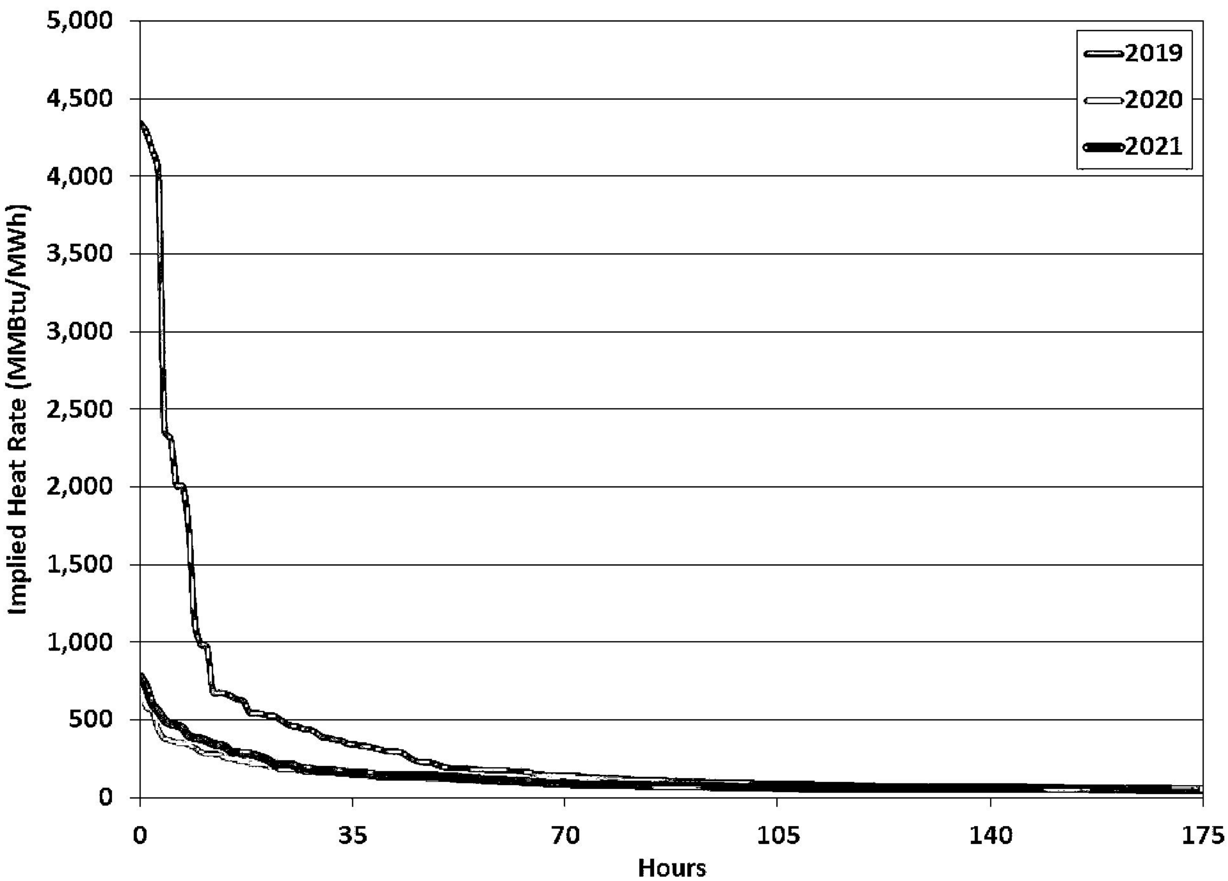


Table A2 displays the annual average implied heat rates by zone for 2014 through 2021. Adjusting for natural gas price influence, Figure A10 above shows that the annual, system-wide average implied heat rate was relatively consistent from 2020 to 2021. Zonal variations in the implied heat rate were greater in 2021 because of the differences in load levels during Winter Storm Uri.

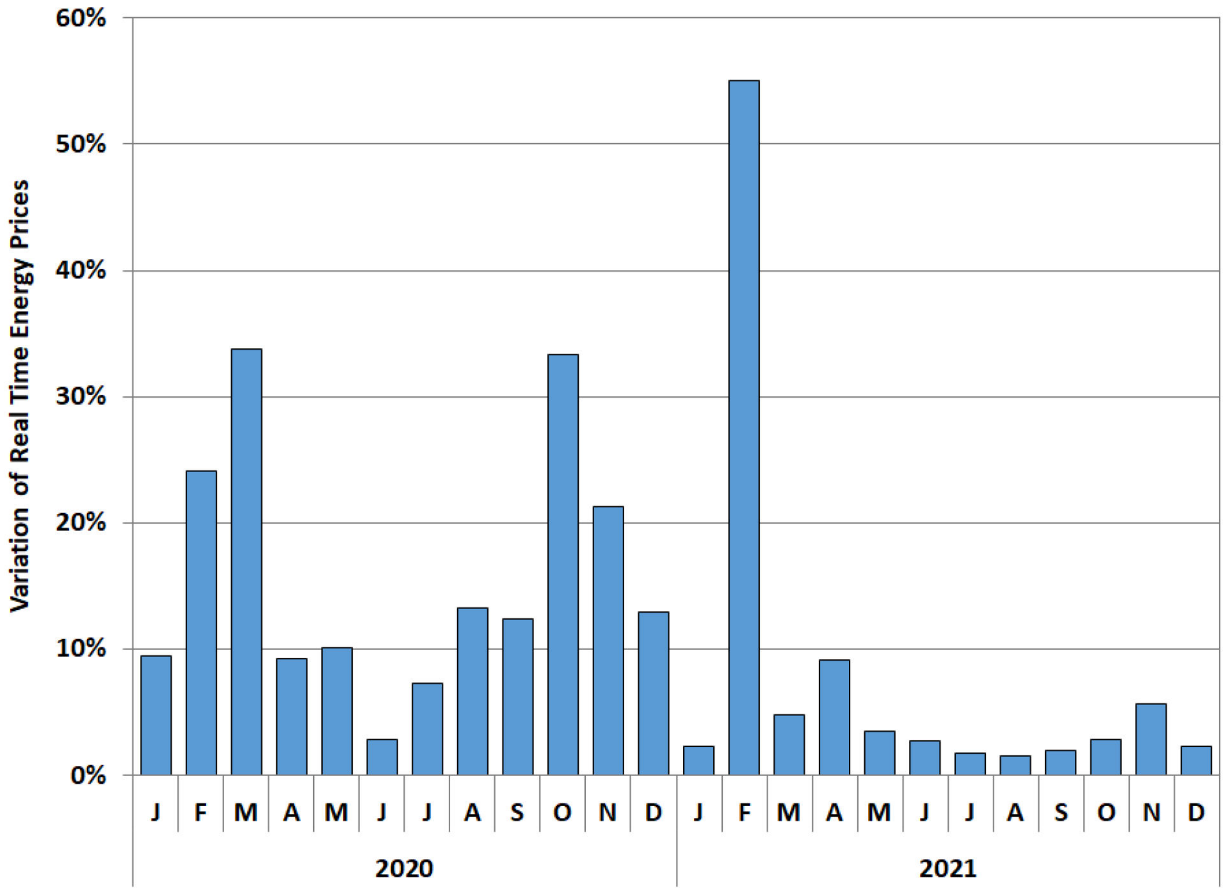
Table A2: Average Implied Heat Rates by Zone

(MMBtu/MWh)	2014	2015	2016	2017	2018	2019	2020	2021
ERCOT	**9.4**	**10.4**	**10.1**	**9.5**	**11.1**	**19.0**	**12.9**	**23.0**
Houston	9.2	10.5	10.8	10.7	10.7	18.4	12.3	17.7
North	9.3	10.2	9.7	8.6	10.9	18.9	12.0	28.3
South	9.6	10.6	10.1	9.9	11.2	19.2	13.4	25.7
West	10.1	10.4	9.0	8.2	12.3	20.5	15.9	14.4
($/MMBtu)								
Natural Gas	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99	$7.30

D. Real-Time Price Volatility

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. Expanding the view of price volatility, Figure A11 below shows monthly average changes in five-minute real-time prices by month for 2020 and 2021.

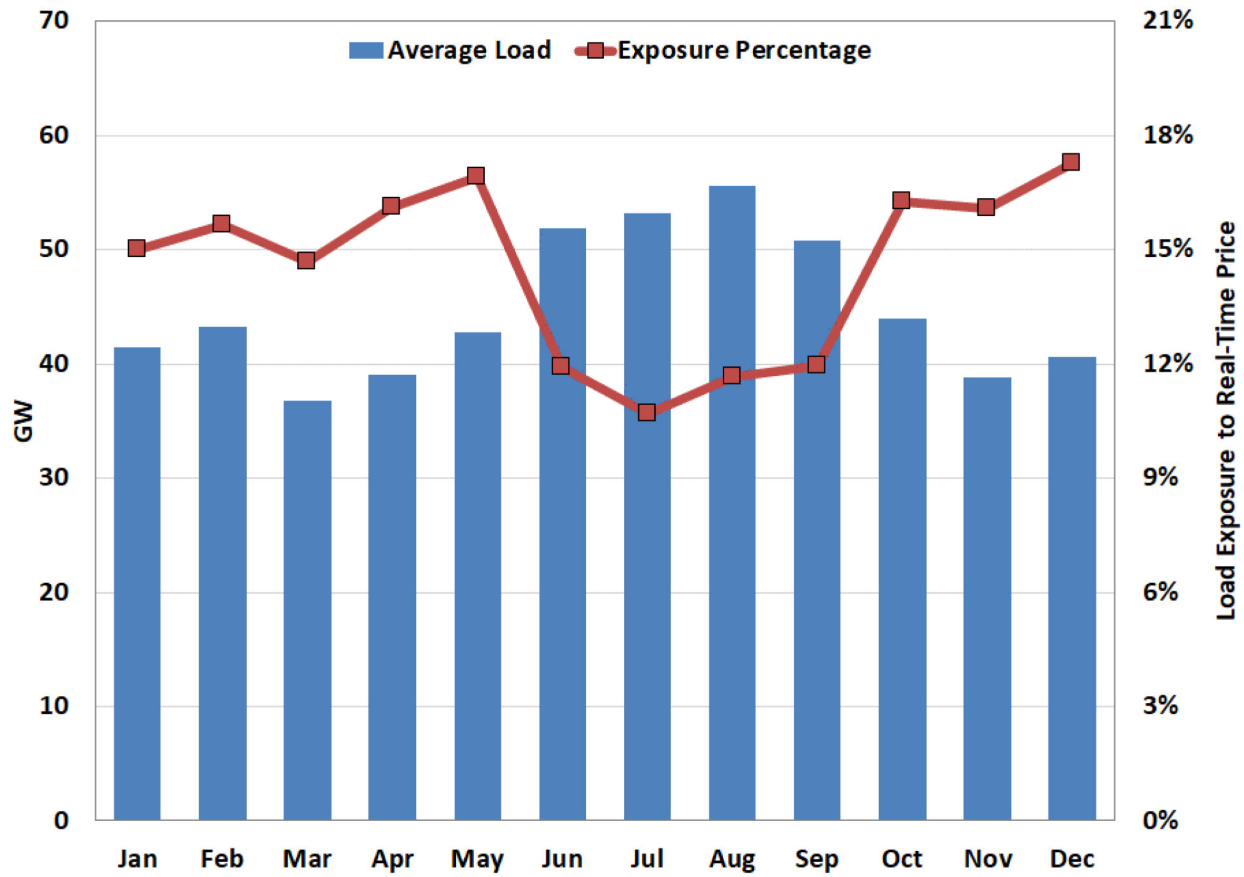
Figure A11: Monthly Price Variation



As expected, the high price variability that occurred during February 2021 when occurrences of shortage pricing was unlike anything seen in 2020, or any other year. However, April and November 2021 saw higher than normal price variability because of outages reducing available transmission capacity as well as variability in renewable output.

Finally, Figure A12 below shows the percentage of load exposed to real-time energy prices.

Figure A12: Monthly Load Exposure



This determination of exposure is based solely on ERCOT-administered markets and does not include any bilateral or over-the-counter (OTC) index purchases. The smallest portions of load potentially exposed to real-time prices in 2021 was lowest in the summer months with the lowest exposure occurring in July. Unhedged loads would be vulnerable to any shortage conditions that may occur during the year, and it is therefore expected that hedging activity would increase during months with the highest likelihood of extreme weather and shortage conditions (typically, though obviously not exclusively, summer in Texas).

The highest portions of load potentially exposed to real-time prices in 2021 occurred during April and May, and at the end of the year in October, November, and December. Likely this is due to higher real-time price expectations over the summer months plus January and February for potential cold weather. Although the overwhelming majority of load is not exposed to real-time prices, these prices do form the foundation for all pricing expectations, which inform both supplier and consumer contracting decisions.

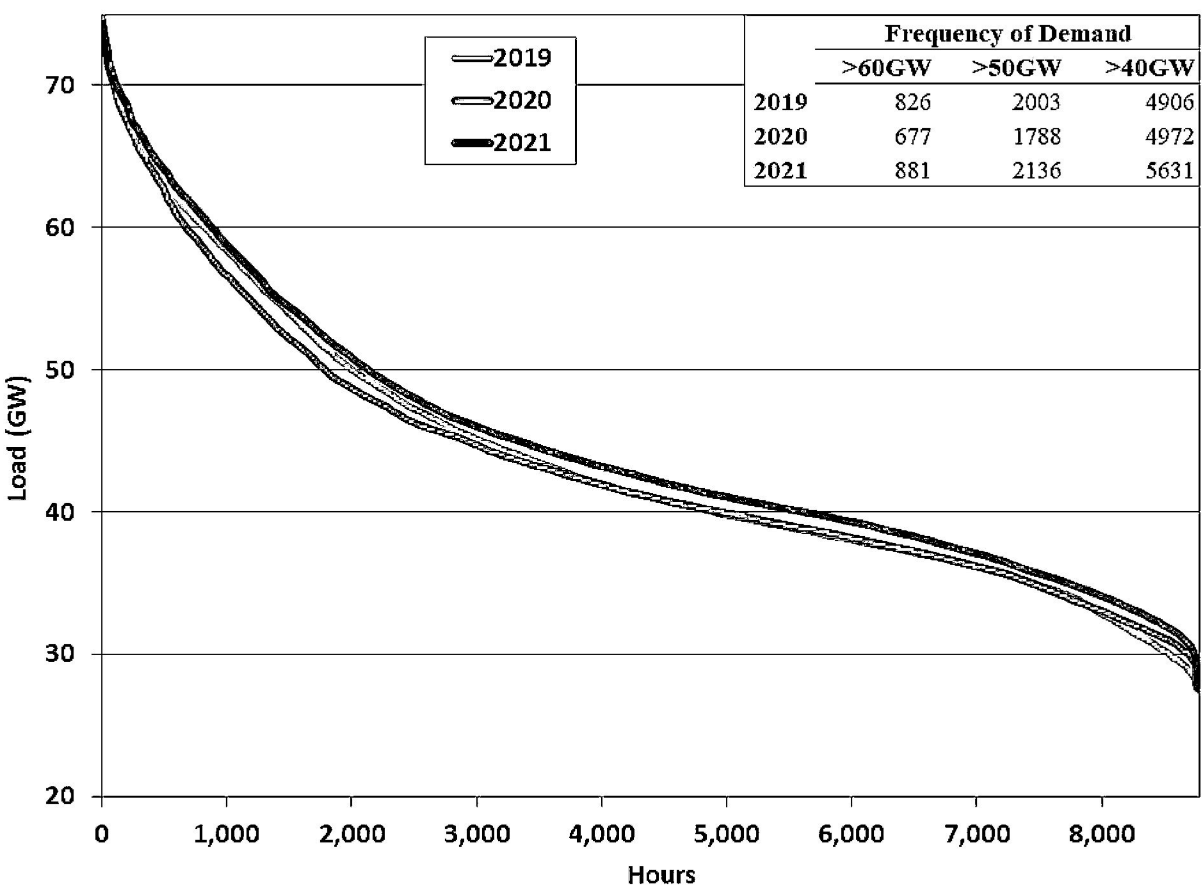
III. APPENDIX: DEMAND AND SUPPLY IN ERCOT

In this section, we provide supplemental analyses of load patterns during 2021 and the existing generating capacity available to satisfy the load and operating reserve requirements.

A. ERCOT Load in 2020

To provide a more detailed analysis of load at the hourly level, Figure A13 compares load duration curves for each year from 2019 through 2021. A load duration curve illustrates the number of hours (shown on the horizontal axis) that load exceeds a particular level (shown on the vertical axis). ERCOT has a fairly smooth load duration curve, typical of most electricity markets, with low to moderate electricity demand in most hours, and peak demand usually occurring during the late afternoon and early evening hours of days with exceptionally high temperatures. The load duration curve in 2021 was similar to both 2019 and 20120, though slightly higher as load growth continues in ERCOT.

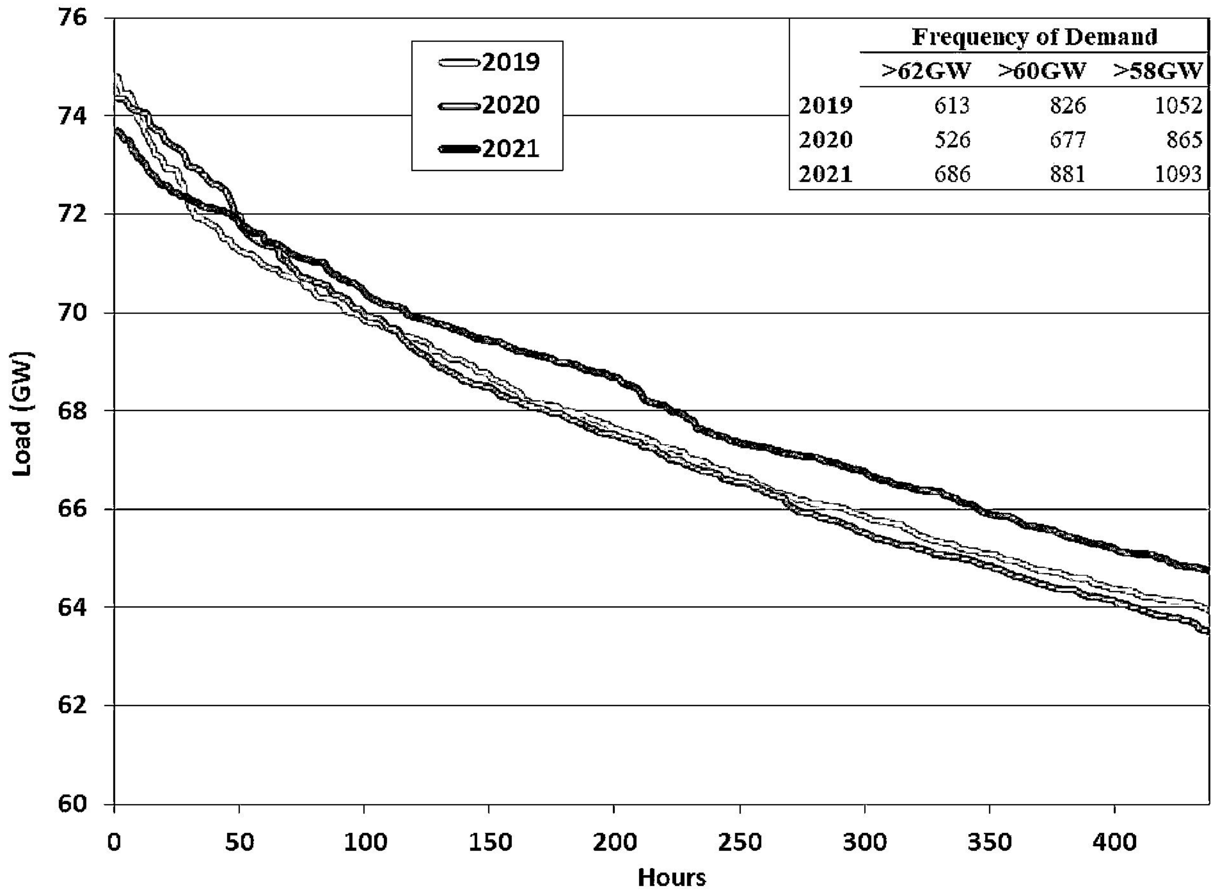
Figure A13: Load Duration Curve – All Hours



	Frequency of Demand		
	>60GW	>50GW	>40GW
2019	826	2003	4906
2020	677	1788	4972
2021	881	2136	5631

To better illustrate the differences in the highest-demand periods between years, Figure A14 below shows the load duration curve for the 5% of hours with the highest loads for the last three years. This figure also shows that the peak load in each year was significantly greater than the load at the 95th percentile of hourly load. Since 2011, the peak load has averaged 13% to 19% greater than the load at the 95th percentile. These load characteristics imply that a substantial amount of capacity – at times more than 10 GW – is needed to supply energy in less than 5% of the hours.

Figure A14: Load Duration Curve – Top 5% of Hours with Highest Load



B. Generation Capacity in ERCOT

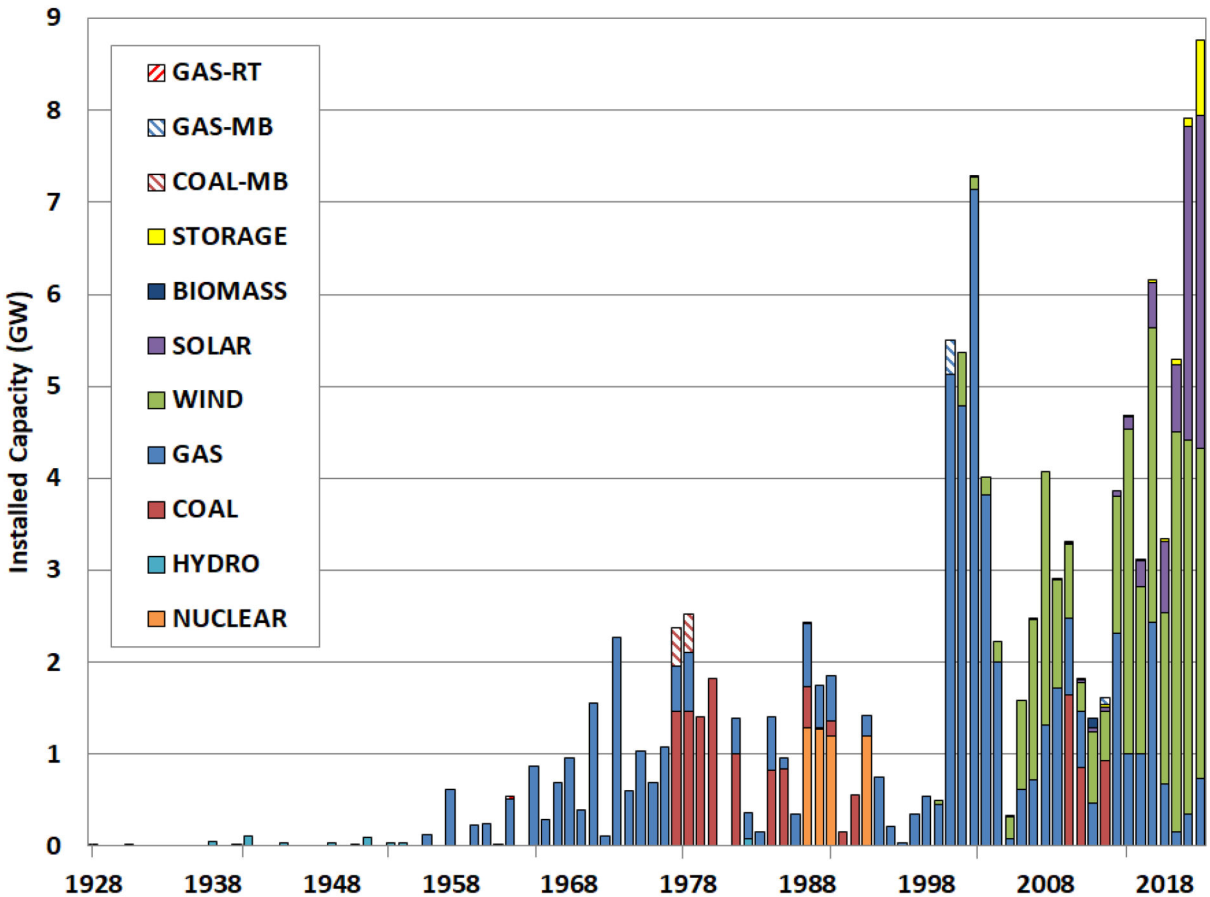
The generation mix in ERCOT is presented in this subsection. Figure A15 shows the vintage of generation resources in ERCOT shown as operational in the December 2021 Capacity, Demand, and Reserves (CDR) report[110] and it also includes resources that came online but were not yet commercial. The evaluation excludes Private Use Network capacity contributions to the CDR.

[110] ERCOT Capacity, Demand, and Reserves Report (Dec. 29, 2021), available at https://www.ercot.com/files/docs/2021/12/29/CapacityDemandandReservesReport_December2021.pdf.

The "GAS-RT" label applies to gas-fired units that were retired in 2021, and the "GAS-MB" and "COAL-MB" label applies to gas- or coal-fired units that were mothballed in 2021.

The figure shows several distinct periods of time where different technologies were added. The period prior to 1954 is entirely hydro generation additions. Between 1955 and 1977, the majority of additions were gas-fired boiler units. Additions during the period of 1978 to 1985 were primarily nuclear capacity. Between 1986 and 2006 the additions were primarily gas-fired combined cycle generators. Between 2006 and 2019 the additions were primarily wind, and beginning in 2020 a substantial amount of solar and some storage were added. In 2020, almost 39% of new capacity was solar, and in 2021, that number was over 40%.

Figure A15: Vintage of ERCOT Installed Capacity

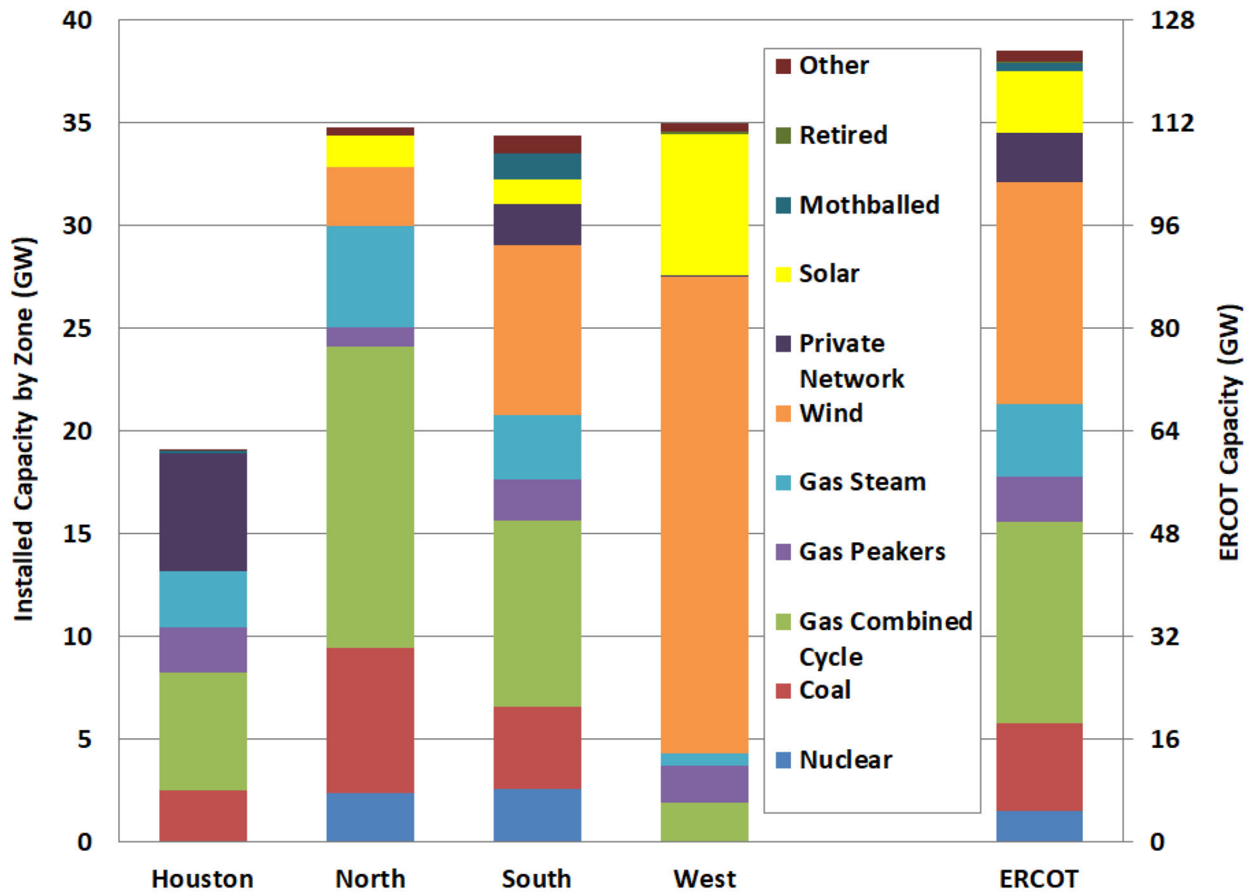


When excluding mothballed resources and including only the fraction of wind capacity deemed available to reliably meet peak demand, the distribution of capacity among the North, South, and West zones was nearly the same.[111] Based on that metric, the North zone accounted for

111 The percentages of installed capacity to serve peak demand assume availability of 30% for panhandle wind, 57% for coastal wind, 20% for other wind, and 81% for solar.

approximately 34% of capacity, the South zone 29%, the Houston zone 20%, and the West zone 17% in 2021. The installed generating capacity by type in each zone is shown in Figure A16.

Figure A16: Installed Capacity by Technology for Each Zone



Approximately 8.8 GW of new generation resources came online in 2021; the 3.6 GW of wind resources has a deemed effective peak serving capacity of about 0.8 GW and the 3.6 GW of solar resources has a deemed effective peak serving capacity of 3 GW. The remaining new capacity is from 660 MW of combustion turbines and 820 MW of ESRs. Half of the new resources were located in the West, 23% in the North, and 15% in the South. In addition, two resources retired permanently, representing a total capacity of 172 MW.

C. Wind and Solar Output in ERCOT

The average profile of wind production is negatively correlated with the load profile, with the highest wind production occurring during non-summer months, and predominately during off-peak hours. Figure A17 shows average wind production for each month in 2020 and 2021, with the average production in each month divided into four-hour blocks. The lowest wind output generally occurs during summer afternoons, and the average wind output during summer peak period remained steady from 2020 to 2021 at about 7 GW, due to a strong presence of wind capacity in ERCOT along with increased geographic diversity of those resources. This may be a small fraction of the total installed capacity, but it indicates that wind generation is a significant contributor to generation supply.

Figure A17: Average Wind Production

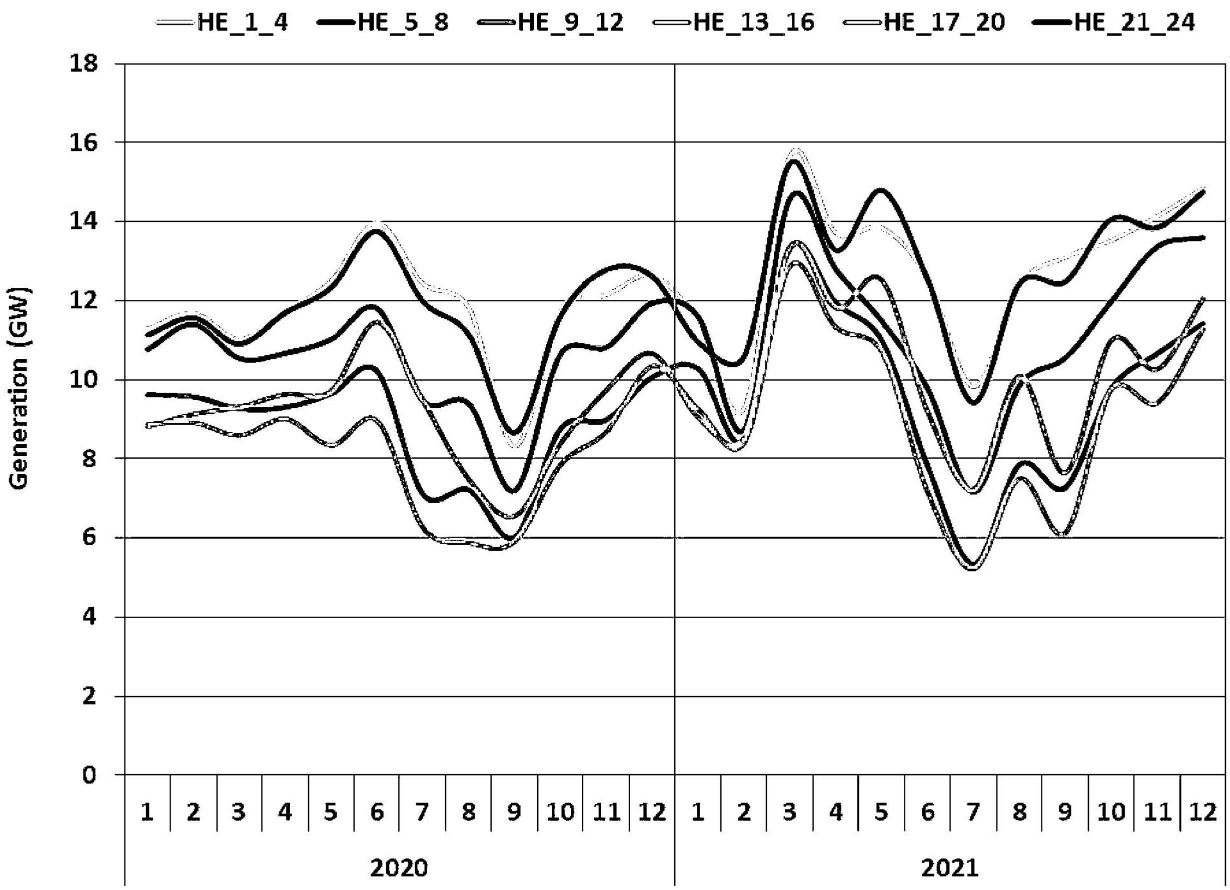
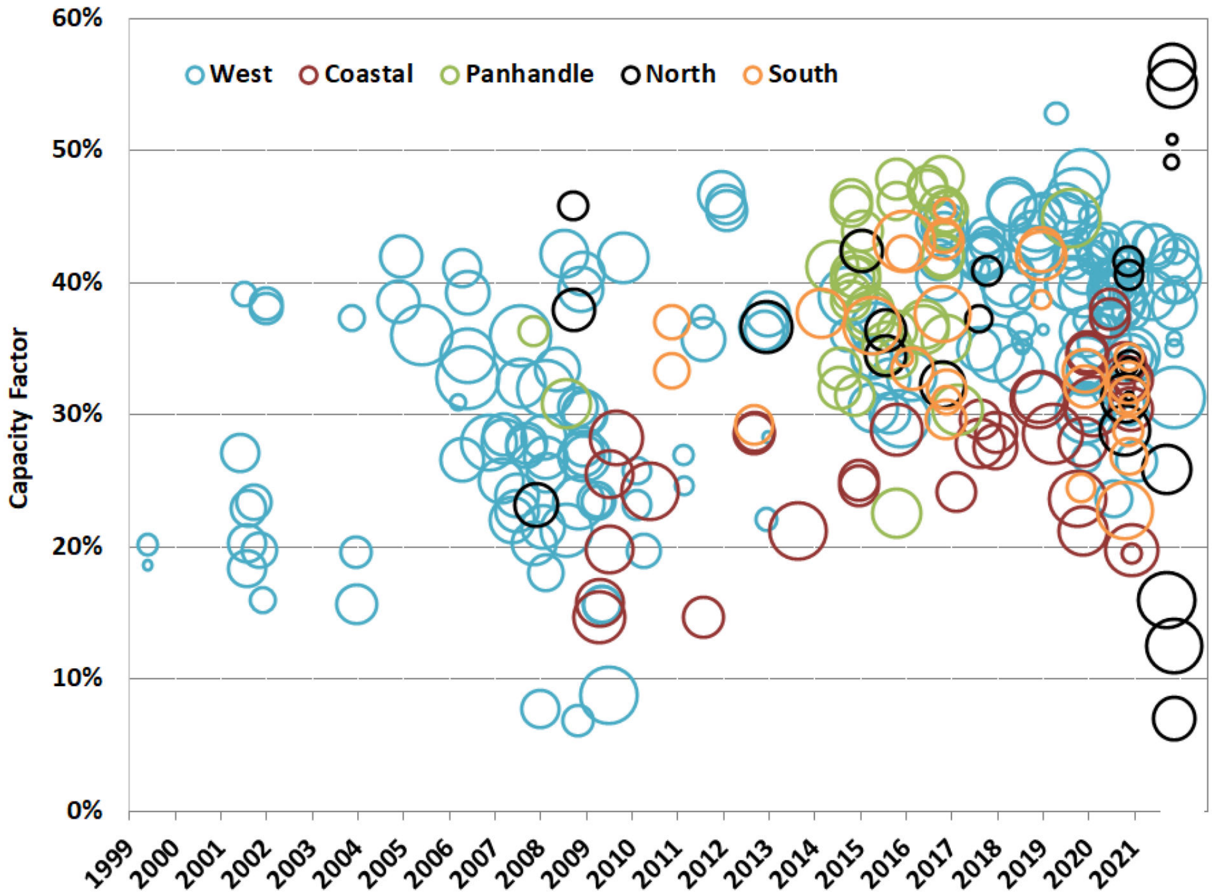


Figure A18 shows the capacity factor (the ratio of actual energy produced by a resource to the hypothetical maximum possible at is full rating) and relative size for wind generators by year installed. The chart also distinguishes wind generation units by location because of the different wind profiles for each location. Resources in the north showed both the highest and lowest capacity factors due to the relationship between individual locations and the West Texas Export GTC.

Figure A18: Wind Generator Capacity Factor by Year Installed



As more wind generation capacity is installed in ERCOT, more energy from that capacity will be produced. However, the amount of energy produced will vary depending on actual wind speeds, which can vary from year to year. The next figure shows the annual average wind speed in ERCOT, as weighted by the locations of the installed wind generation. Figure A19 provides a means to compare the weighted wind speeds on an annual basis and indicates that the weighted average wind speed increased in 2020 and again in 2021 compared to previous years.

Figure A19: Historic Average Wind Speed

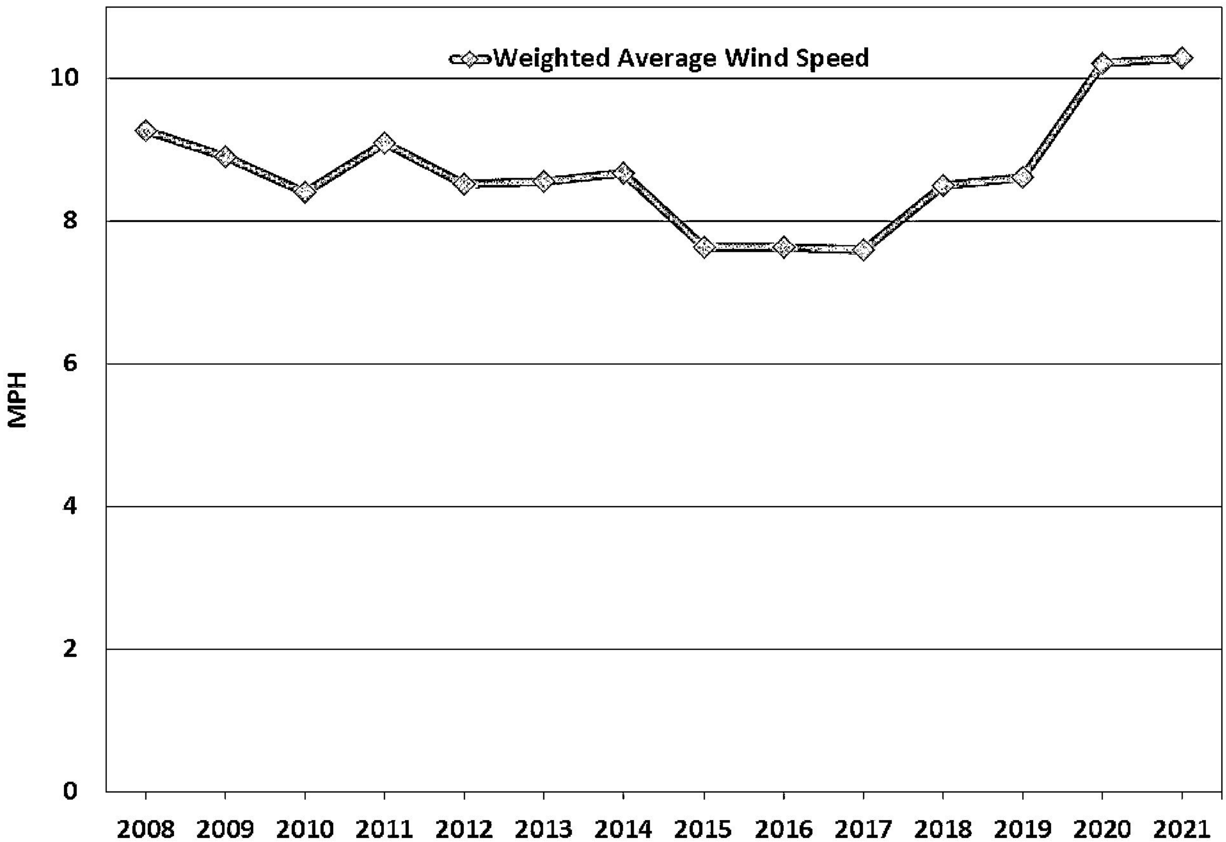


Figure A20 below shows average solar production for each month in 2020 and 2021, with the average production in each month divided into four-hour blocks. The average solar output nearly doubled from 2020 to 2021 due to a significant increase in solar capacity of 2,500 MW along with increased geographic diversity of those resources.

Figure A20: Average Solar Production

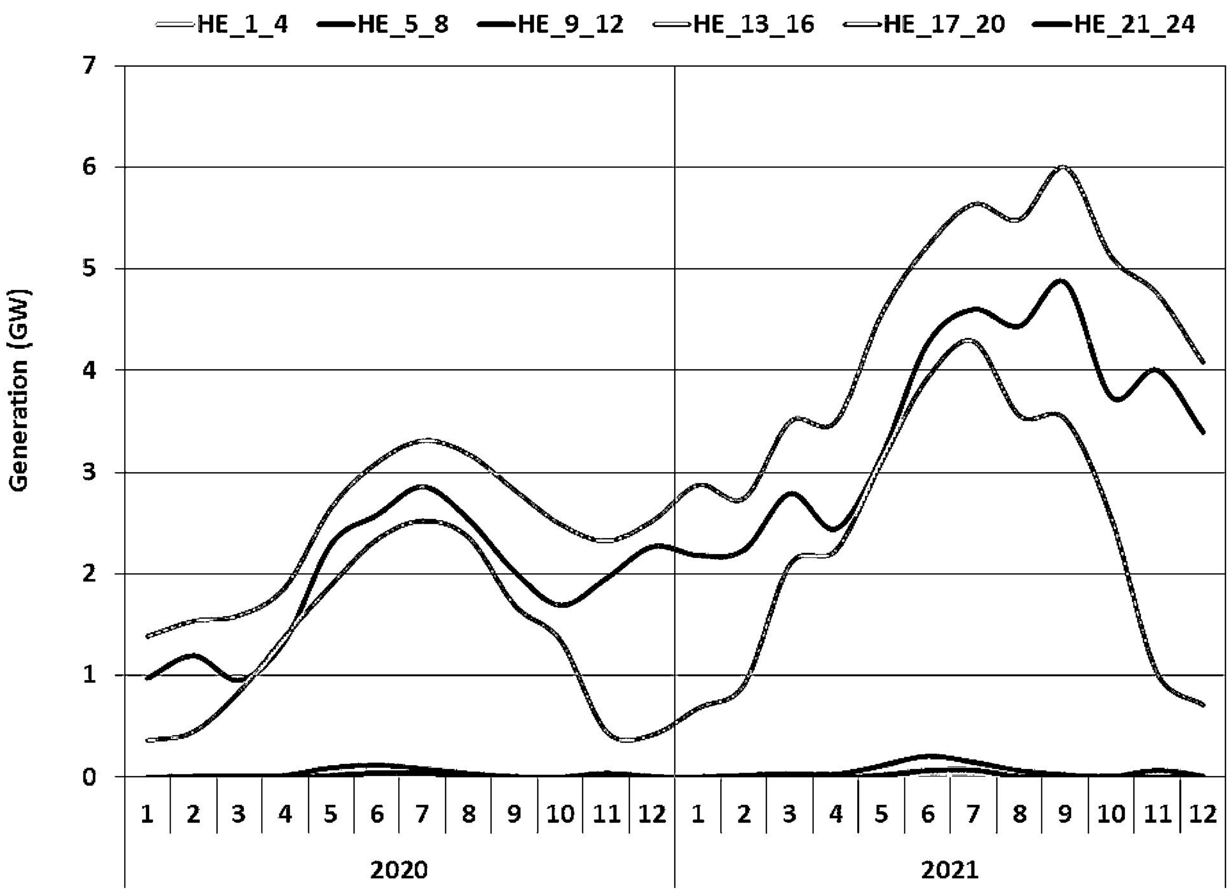
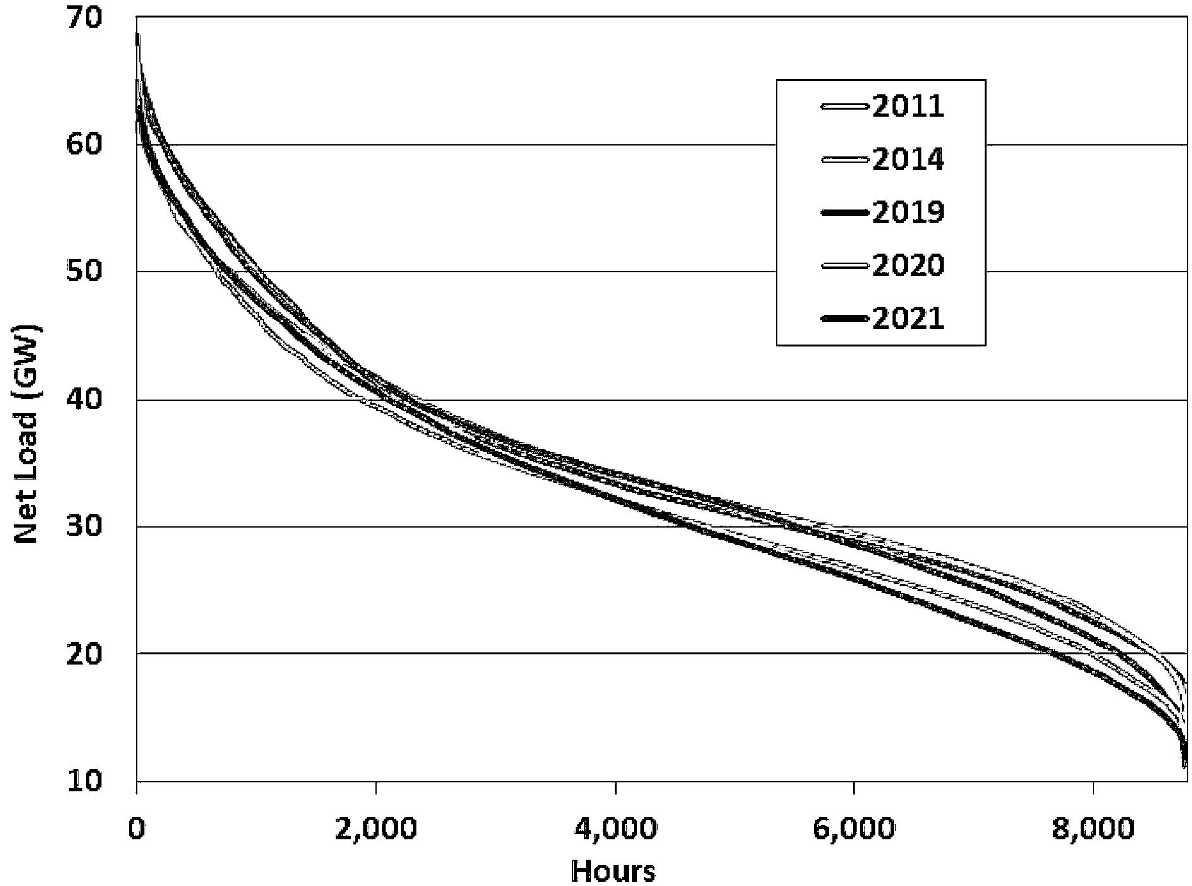


Figure A21 shows the net load duration curves for the years 2011, 2014, 2020 and 2021. Years 2011 and 2014 are included for historical context as they were years with stressed operating conditions. Volatility in the net load amounts continues to increase. Increasing wind output has important implications for non-wind resources and for resource adequacy in the ERCOT region as growth in peak demand requires additional resources to be added, but the energy available to be served by non-wind resources overall is reduced.

Figure A21: Net Load Duration Curves



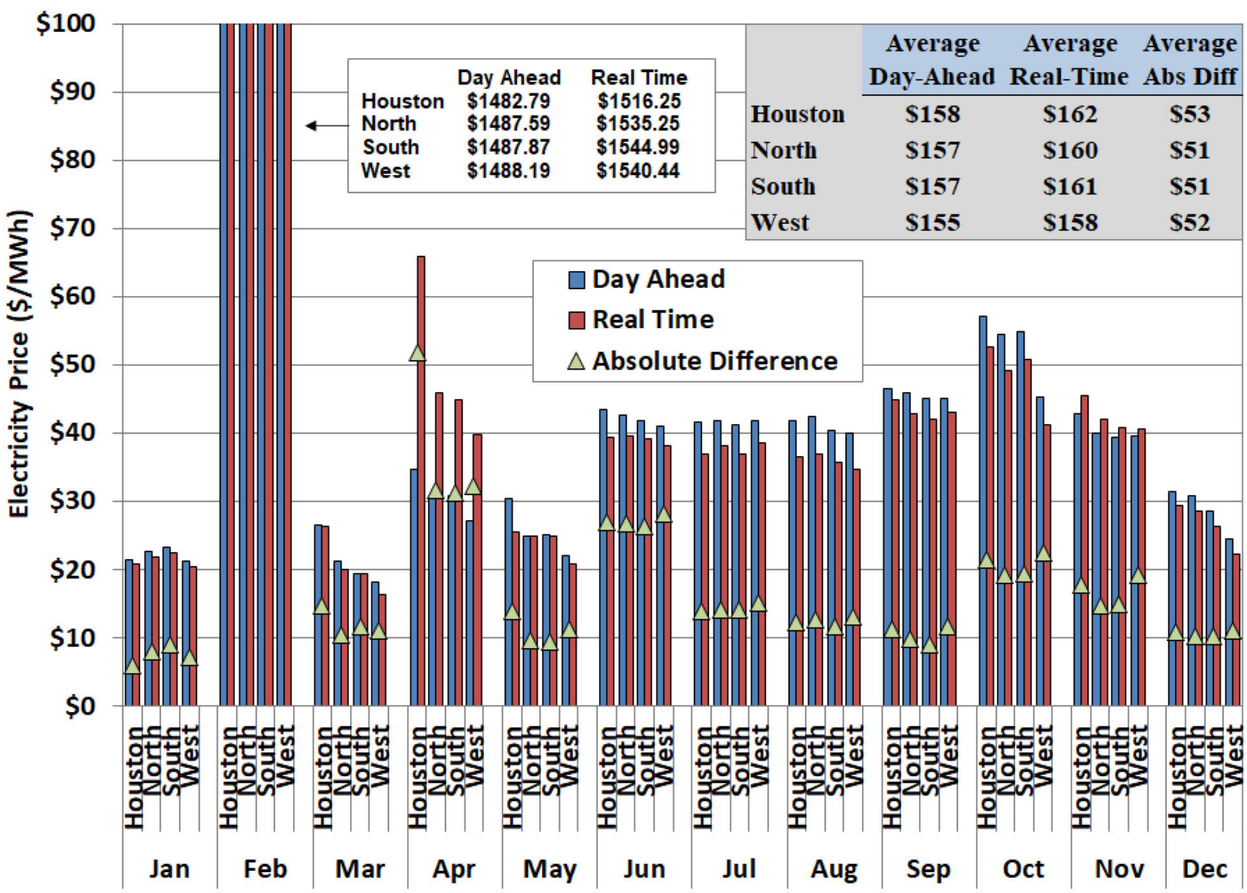
IV. APPENDIX: DAY-AHEAD MARKET PERFORMANCE

In this section, we provide supplemental analyses of 2020 prices and outcomes in ERCOT's day-ahead energy market.

A. Day-Ahead Market Prices

In Figure A22 and Figure A23 below, monthly day-ahead and real-time prices for 2021 are shown for each of the geographic zones, including and excluding the impacts of Winter Storm Uri respectively. Overall volatility was relatively high in 2021 across all zones, as shown in Figure A19. February 2021 witnessed the most pronounced price differences, with an average difference between day-ahead and real-time prices of $445 per MWh due to the extraordinary weather and outage event. Although the average day-ahead and real-time prices were similar in all zones, the average absolute difference in the Houston zone was the largest. This trend is explained by wide swings in Houston zone prices, the result of transmission congestion in the area related to high load in real-time.

Figure A22: Day-Ahead and Real-Time Prices by Zone (with Uri)

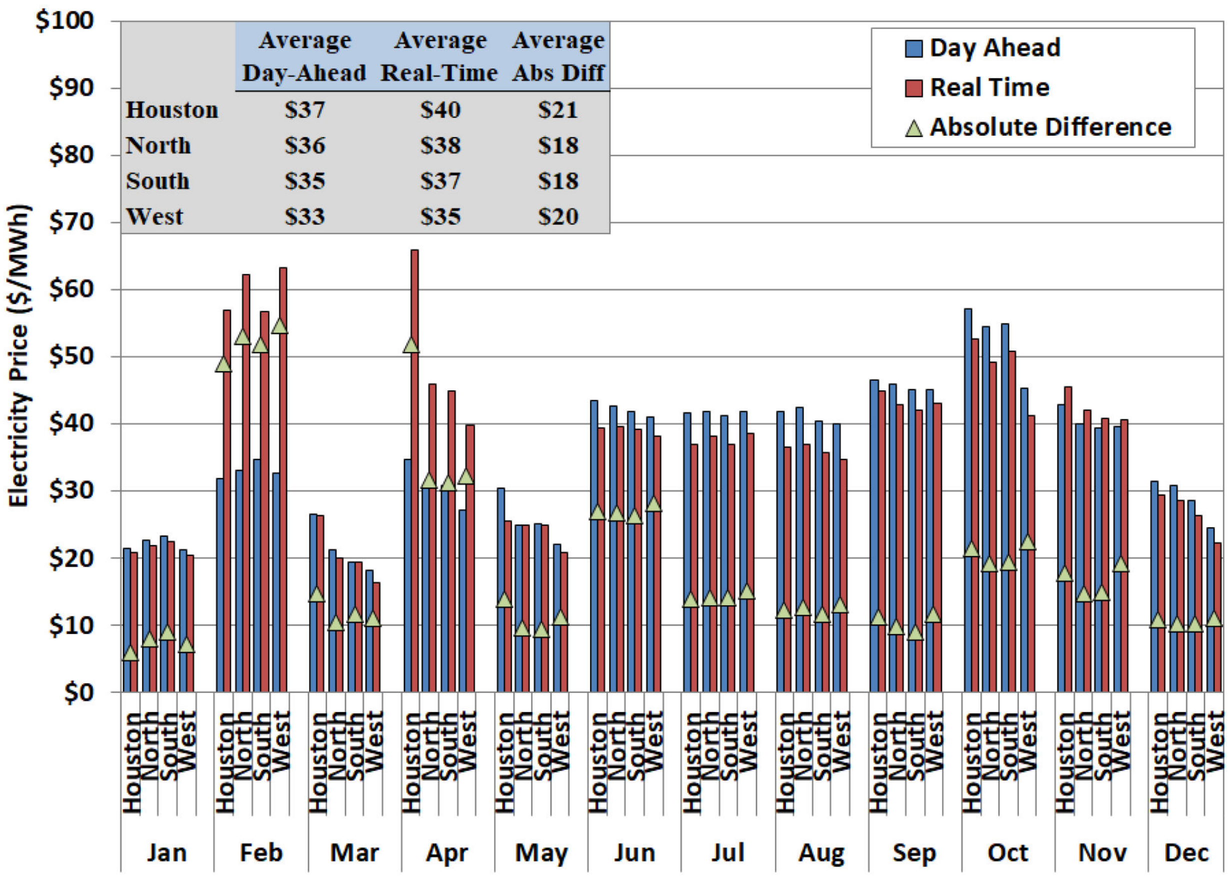


	Day Ahead	Real Time
Houston	$1482.79	$1516.25
North	$1487.59	$1535.25
South	$1487.87	$1544.99
West	$1488.19	$1540.44

	Average Day-Ahead	Average Real-Time	Average Abs Diff
Houston	$158	$162	$53
North	$157	$160	$51
South	$157	$161	$51
West	$155	$158	$52

Without the impacts of Winter Storm Uri, as shown below in Figure A22, February still had the most pronounced price differences due to cold weather before Winter Storm Uri, but the difference in April 2021 was also exceptionally high, with an average difference between day-ahead and real-time prices of $36.77 per MWh due to two days with scarcity conditions in real-time that were not predicted by day-ahead pricing.

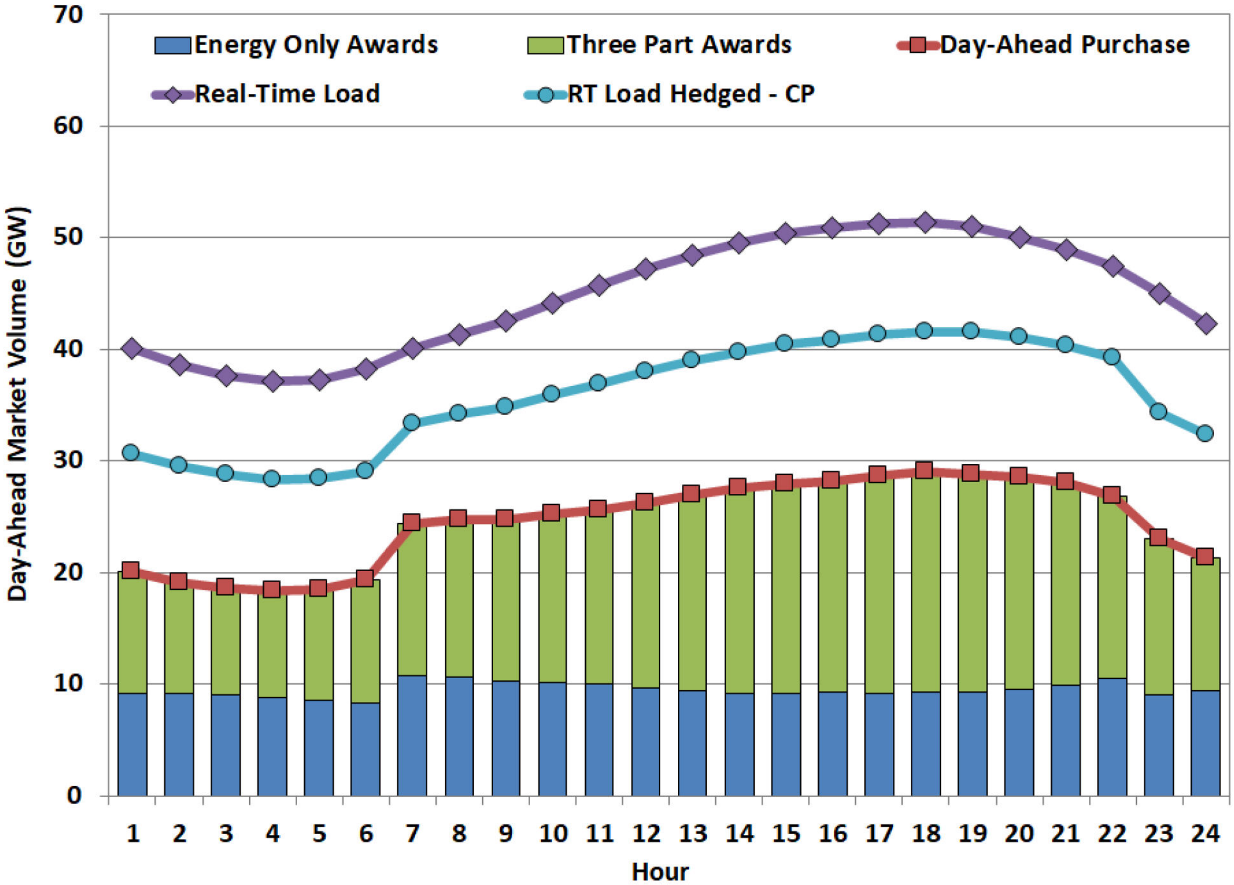
Figure A23: Day-Ahead and Real-Time Prices by Zone (without Uri)



B. Day-Ahead Market Volumes

Figure A24 below presents the same DAM activity data in 2021 summarized by hour of the day. In this figure, the volume of DAM transactions is disproportionate with load levels between hour ending 7 and 22. Because these times align with common bilateral and financial market transaction terms, the results in this figure are consistent with market participants using the DAM to trade around those positions.

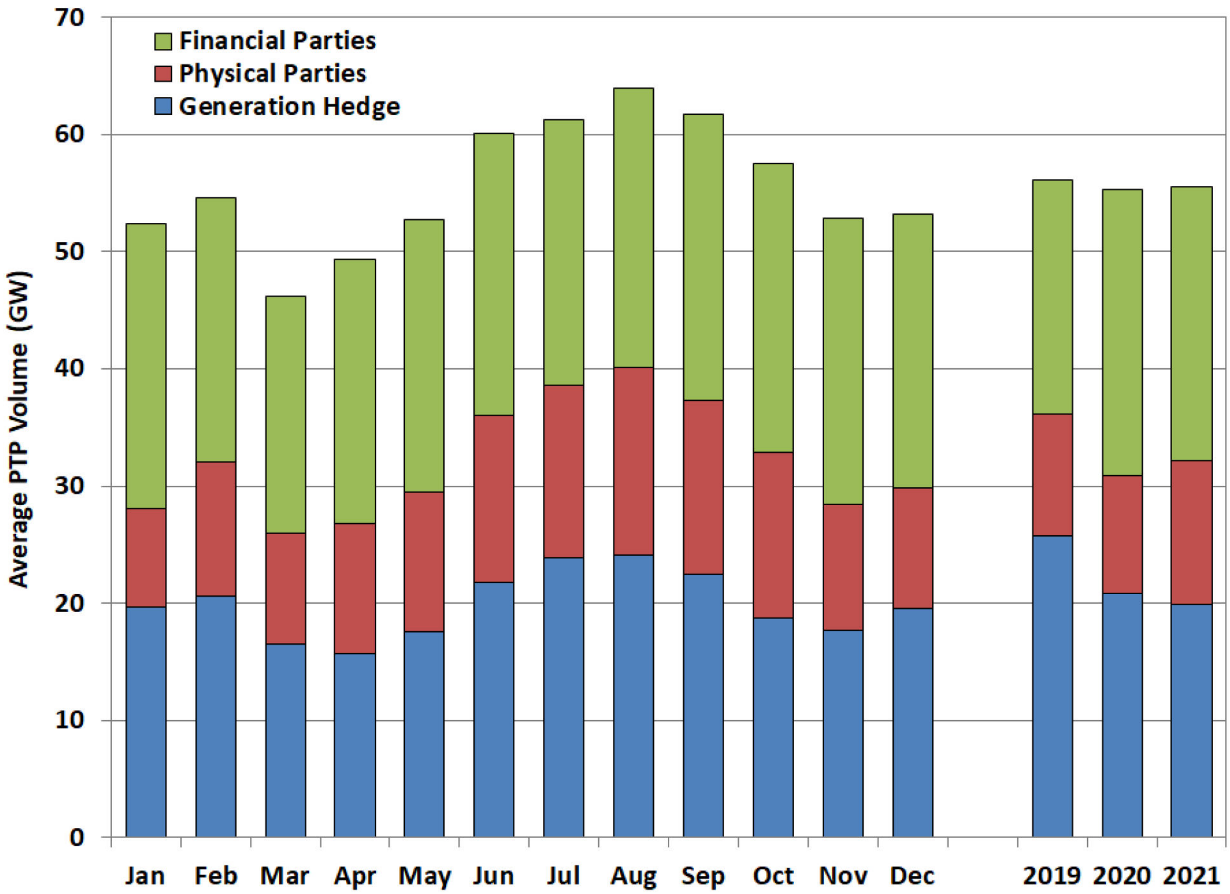
Figure A24: Volume of Day-Ahead Market Activity by Hour



C. Point-to-Point Obligations

Figure A25 below presents the total volume of PTP obligation purchases in 2021 divided into three categories. There can be multiple PTP obligations sourcing and sinking at the same settlement point, however the volumes in this figure do not net out those injections and withdrawals. Average purchase volumes are presented on both a monthly and annual basis. The total volume of PTP obligation cleared purchases has been fairly stable in recent years, with 2021 falling in between 2019 and 2020.

Figure A25: Point-to-Point Obligation Volume



For all PTP obligations that source at a generator location, the capacity up to the actual generator output is considered to be hedging the real-time congestion associated with generating at that location. The figure above shows that in 2021, like in 2020, financial parties comprised the plurality of the volume of PTP obligations purchased (41%), although generation hedging comprised a similar volume of PTP obligations purchased for the year (37%). Other than generation hedging, the volumes of PTP obligations are not directly linked to a physical position. They are assumed to be purchased primarily to arbitrage anticipated price differences between two locations or to hedge trading activities occurring outside of the ERCOT market. This arbitrage activity is further separated by type of market participant.

Physical parties are those that have actual real-time load or generation, whereas financial parties have neither. Financial parties purchased 41% of the total volume of PTP obligations in 2021, consistent with the 42% in 2020 and 36% in 2019. Financial parties increasing volumes can have liquidity benefits but also strains the software, particularly those bids that are unlikely to be awarded. As discussed in our recommendation No. 2020-4, a bid fee would better allocate the scarce labor and hardware resources in the DAM, especially since these parties do not contribute otherwise to the administration of ERCOT.

D. Ancillary Services Market

Figure A26 presents an alternate view of ancillary service requirements, displaying them by hour, averaged over the year. In this view the larger variation in quantities between some adjacent hours seen in 2020 was not apparent in 2021 due to the adjusted methodology in July 2021 that procured a stable amount on non-spinning reserve throughout the day.

Figure A26: Average Ancillary Service Capacity by Hour for all of 2021

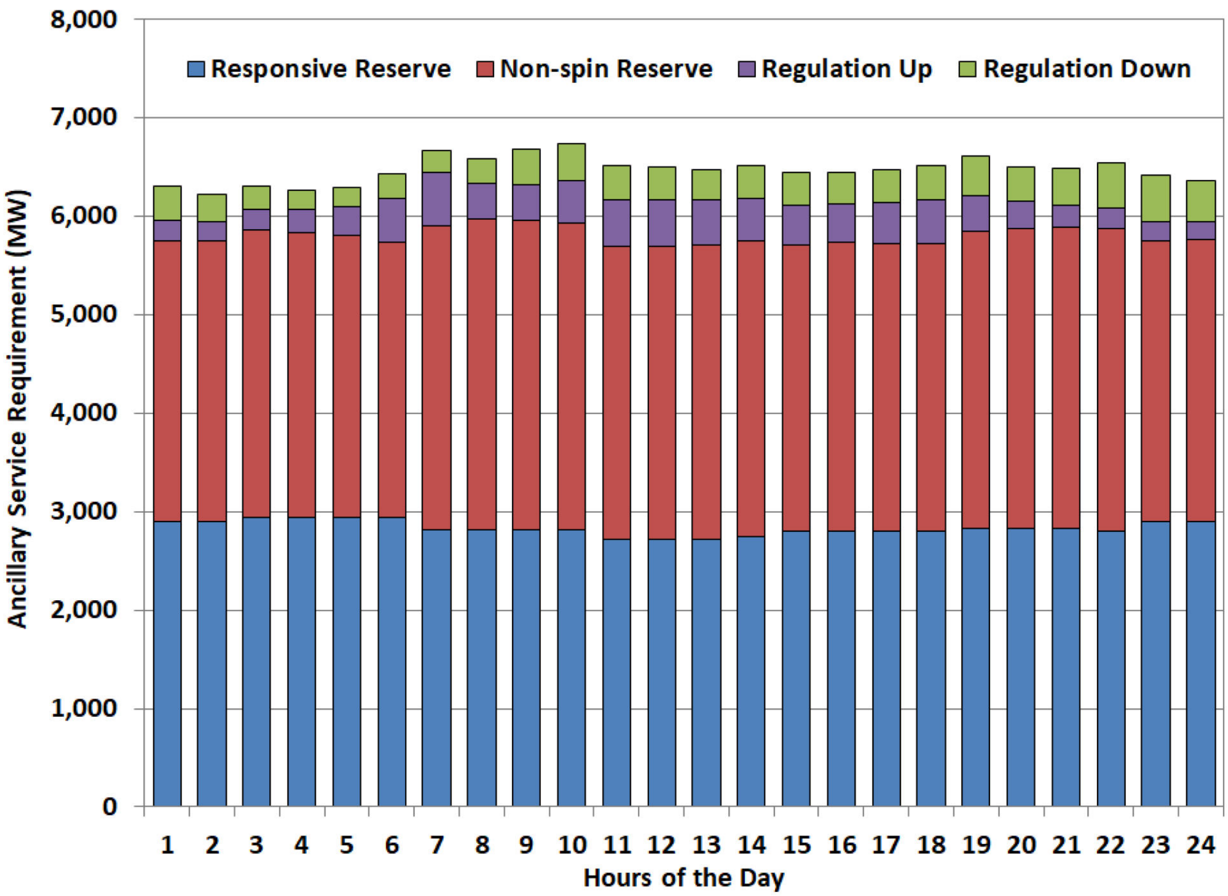


Figure A27 below shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2019 through 2021. Figure A28 includes the same analysis but removes the impacts of Winter Storm Uri.

Figure A27: Ancillary Service Costs per MWh of Load (with Uri)

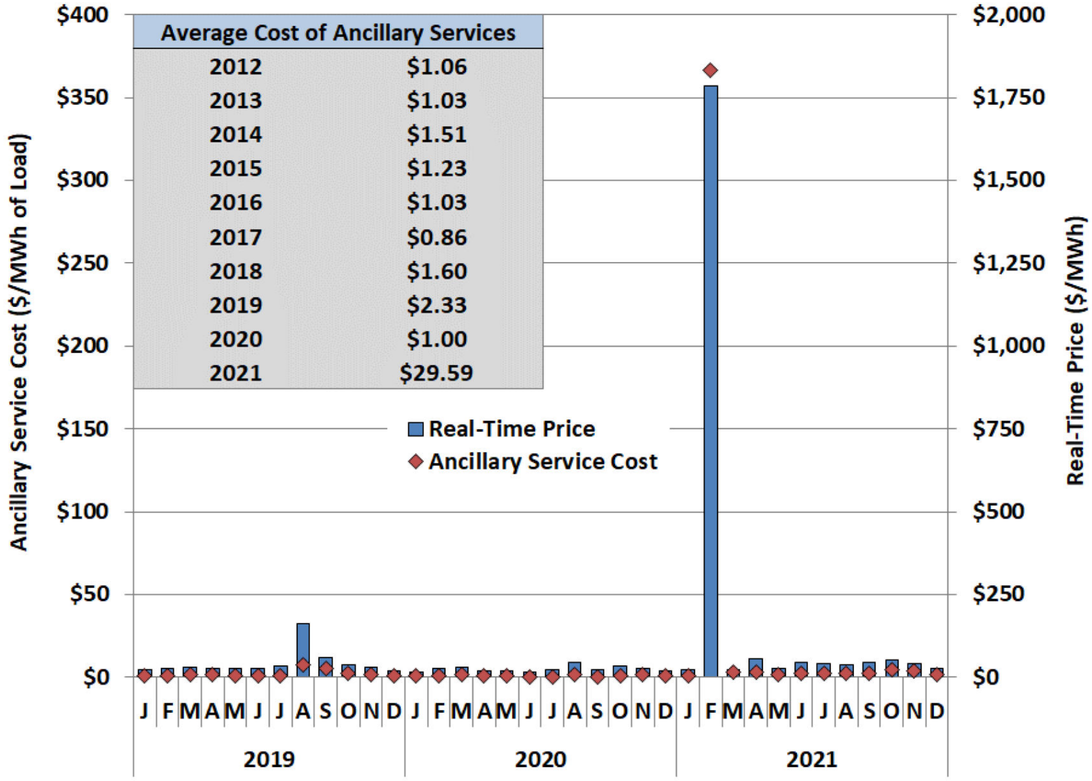
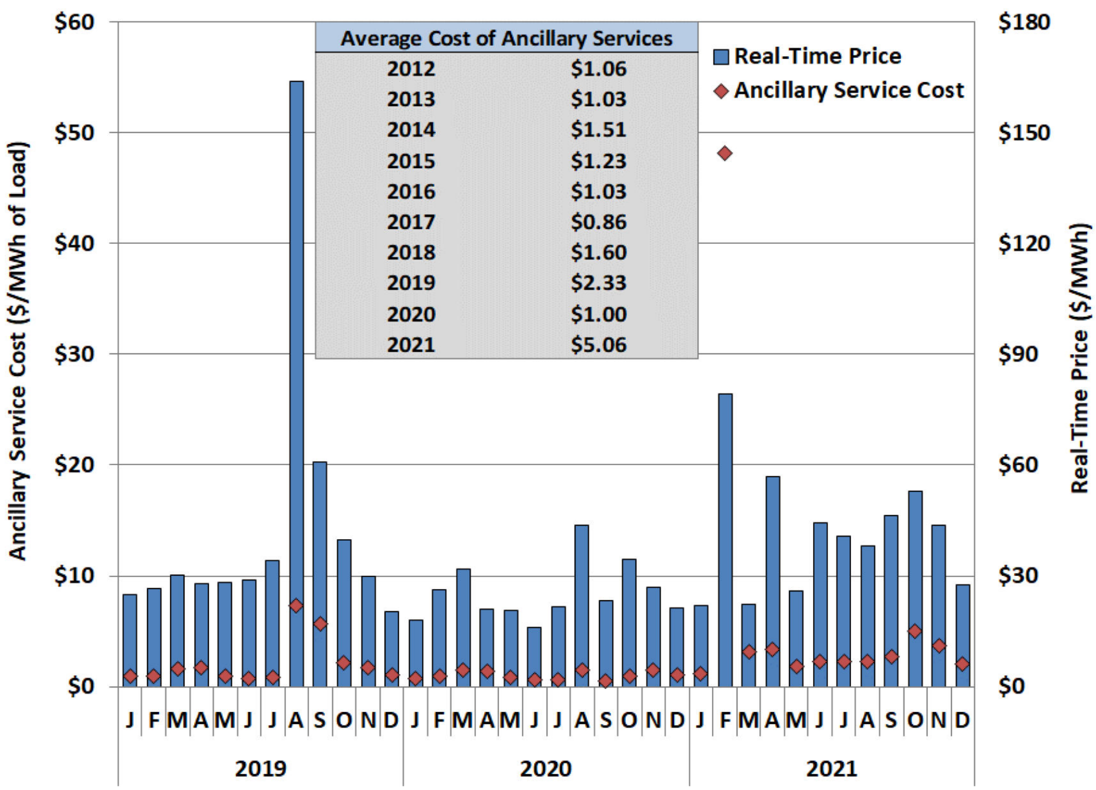


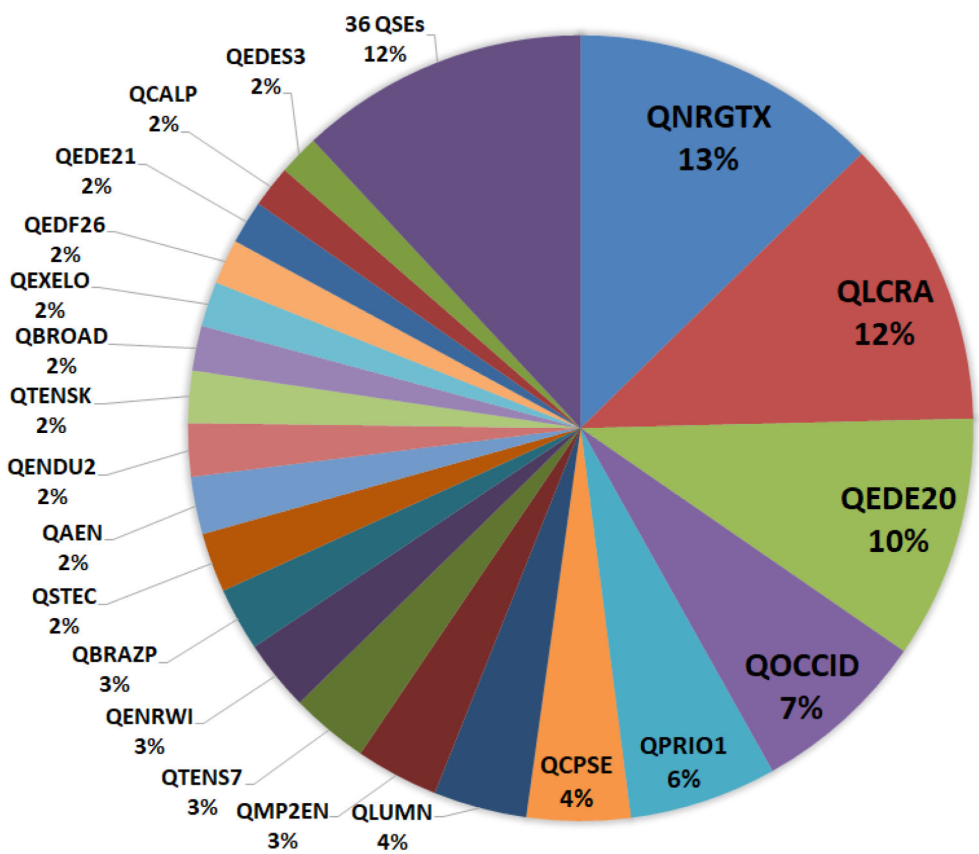
Figure A28: Ancillary Service Costs per MWh of Load (without Uri)



The average ancillary service cost per MWh of load increased from $1.00 per MWh in 2020 to $29.59 per MWh in 2021, mostly due to the effects of Winter Storm Uri. When the time period of the storm is removed from the analysis, the average ancillary service cost per MWh of load was $5.06 in 2021, still over double the next highest year (2019). Part of this increase is due to the week after Winter Storm Uri when ancillary service prices remained high, part is due to higher natural gas prices throughout the year, and part is due to the higher AS procurement volumes.

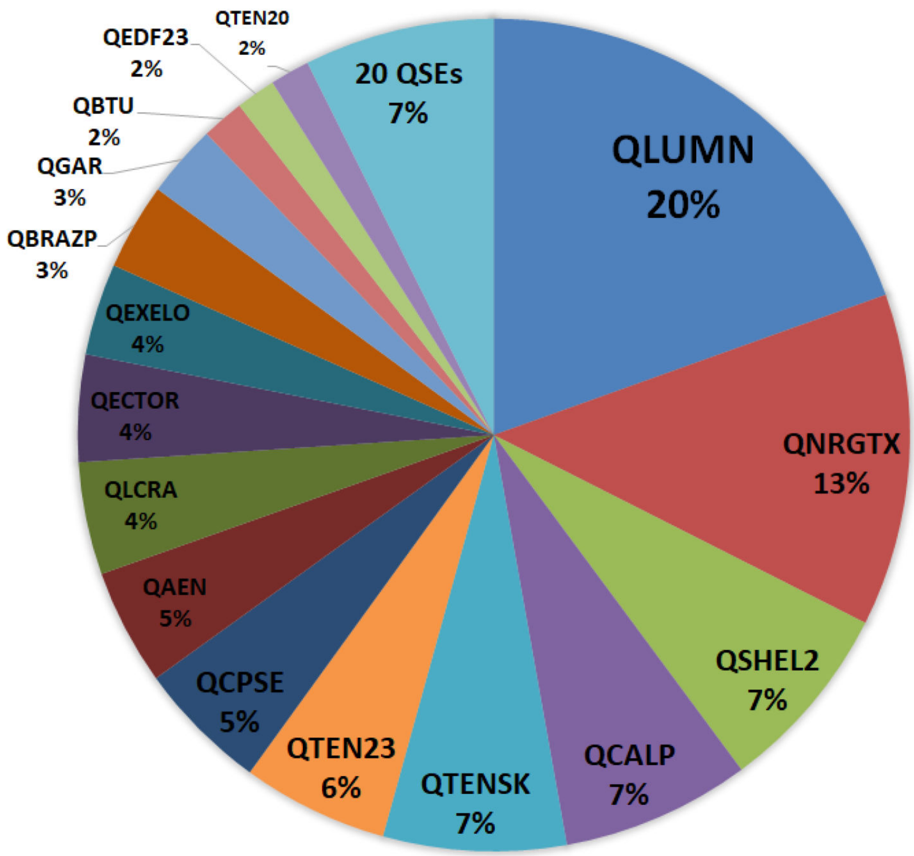
Figure A29 below shows the share of the 2021 annual responsive reserve responsibility including both load and generation, displayed by QSE. During 2020, 58 different QSEs self-arranged or were awarded responsive reserves as part of the DAM. The number of providers had been roughly the same for the past five years (46 in 2020, 43 in 2019 and 2018, 45 in 2017, 42 in 2016, and 46 in 2015). 2021 represents a significant increase due to the increasing ancillary service requirements in the second half of 2021. NRG (QNRGTX) and LCRA (QLCRA) were again the largest providers of responsive reserves in 2021, and generally there were no significant changes from 2020 in the largest providers or in the share of responsive reserve provided.

Figure A29: Responsive Reserve Providers



In contrast, Figure A30 below shows that the provision of non-spinning reserves is much more concentrated, with a single QSE (Luminant, QLUMN) still bearing are large share of the total responsibility, but a smaller share than in years past. Luminant's 20% share of non-spin responsibility in 2021 was a decrease from the 27% share it held in 2020, down from 37% in 2019, 41% in 2018, and 56% in 2017. As Luminant's non-spin responsibility decreased again in 2021, many other suppliers such as NRG (QNRGTX) and Calpine (QCALP) noticeably increased their shares as well.

Figure A30: Non-Spinning Reserve Providers



The ongoing concentration in the supply of non-spinning reserve highlights the importance of modifying the ERCOT ancillary service market design and implementing RTC. Jointly optimizing all products in each interval will allow the market to substitute its procurements among units on an interval-by-interval basis to minimize costs and set efficient prices. Additionally, it will allow higher quality reserves (e.g., responsive reserves) to be economically substituted for lower quality reserves (e.g., non-spinning reserves), potentially distributing the provision of ancillary services among even more entities.

Figure A31: Regulation Up Reserve Providers

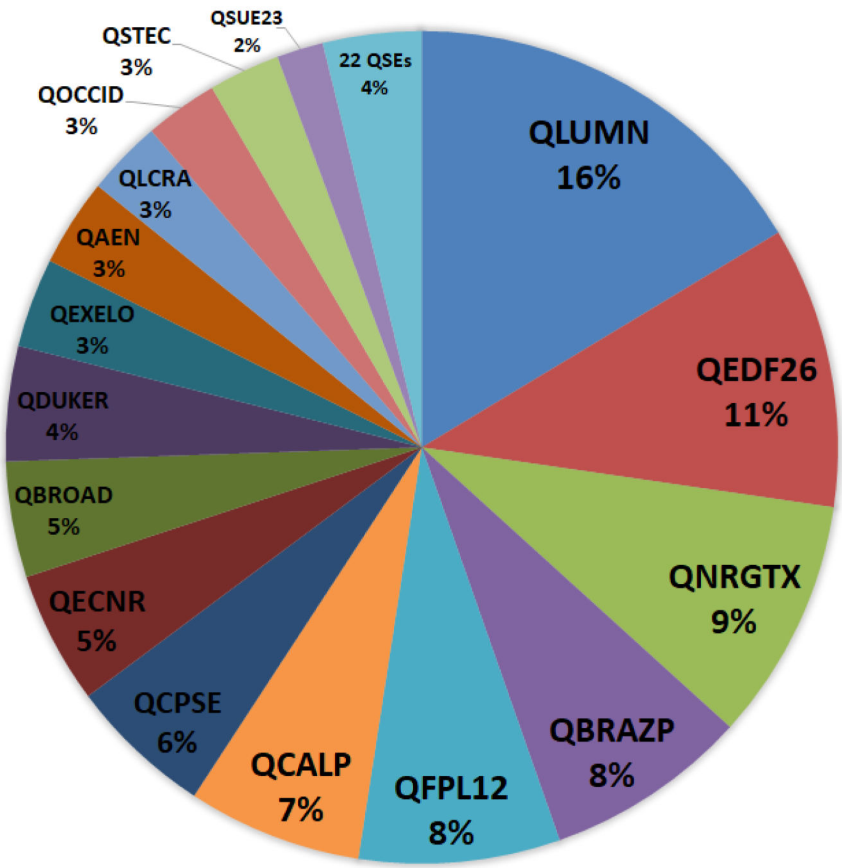
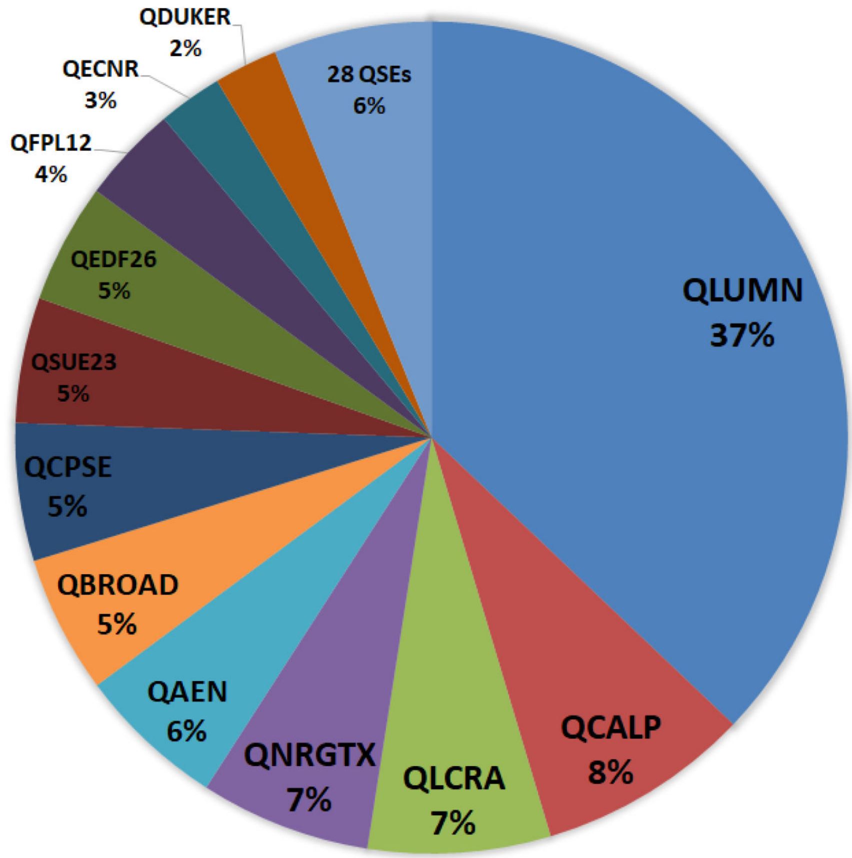


Figure A31 above shows the distribution for regulation up reserve service providers and Figure A32 shows the distribution for regulation down reserve providers in 2021. Figure A31 shows that regulation up was spread more evenly, with Luminant (QLUMN) once again providing the most regulation up reserve service in 2021. Figure A32 shows that that regulation down had similar concentration to non-spinning reserves in 2021. Luminant once more had a dominant position in the provision of regulation down. Its 37% share of the regulation down responsibility in 2021 was on par with the 40% it provided in 2020, and the 43% in 2019.

Figure A32: Regulation Down Reserve Providers



Ancillary service capacity is procured as part of the DAM clearing. Between the time an ancillary service is procured and the time that it is needed, changes often occur that prompt a QSE to move all or part of its ancillary service responsibility from one unit to another. These changes may be due to a unit outage or to other changes in market conditions affecting unit commitment and dispatch. In short, QSEs with multiple units are continually reviewing and moving ancillary service requirements, presumably to improve the efficiency of ancillary service provision, at least from the QSE's perspective. Moving ancillary service responsibility is assumed to be in the QSE's self-interest. When all ancillary services are continually reviewed and adjusted in response to changing market conditions when RTC is implemented, the efficiencies will flow to all market participants and be greater than what can be achieved by QSEs acting individually.

1. Supplemental Ancillary Services Market (SASM)

The ERCOT market appropriately reflects the tradeoff between providing capacity for ancillary services versus providing energy in its co-optimized DAM. Those same tradeoffs exist in real-time. Until comprehensive, market-wide co-optimization is implemented, the ERCOT market will continue to be subject to the choices of individual QSEs. These choices are likely to be in the QSE's best interest, and therefore are not likely to lead to the most economic provision of energy and ancillary services for the market as a whole. Further, QSEs without large resource portfolios still face larger risks than QSEs with small portfolios because of the replacement risk faced in having to rely on a supplemental ancillary services market (SASM). This replacement risk is substantial. Clearing prices for ancillary services procured in SASM are often three to four times greater than clearing prices from the DAM.

A SASM may also be opened if ERCOT changes its ancillary service plan, although this did not occur during 2021. A SASM was executed 37 times in 2021, with SASM awards providing 340 service-hours. SASMs were more frequent but for fewer total hours in 2021; in 2020, a SASM was executed 25 times, and 490 service-hours were awarded. In addition to more frequent shortages, it appears that ERCOT operators were more sensitive to AS shortages in 2021 than in previous years and took the step to procure replacement MWs more often. Figure A33 below provides the aggregate quantity of each service-hour that was procured via SASM over the last three years.

Figure A33: Ancillary Service Quantities Procured in SASM

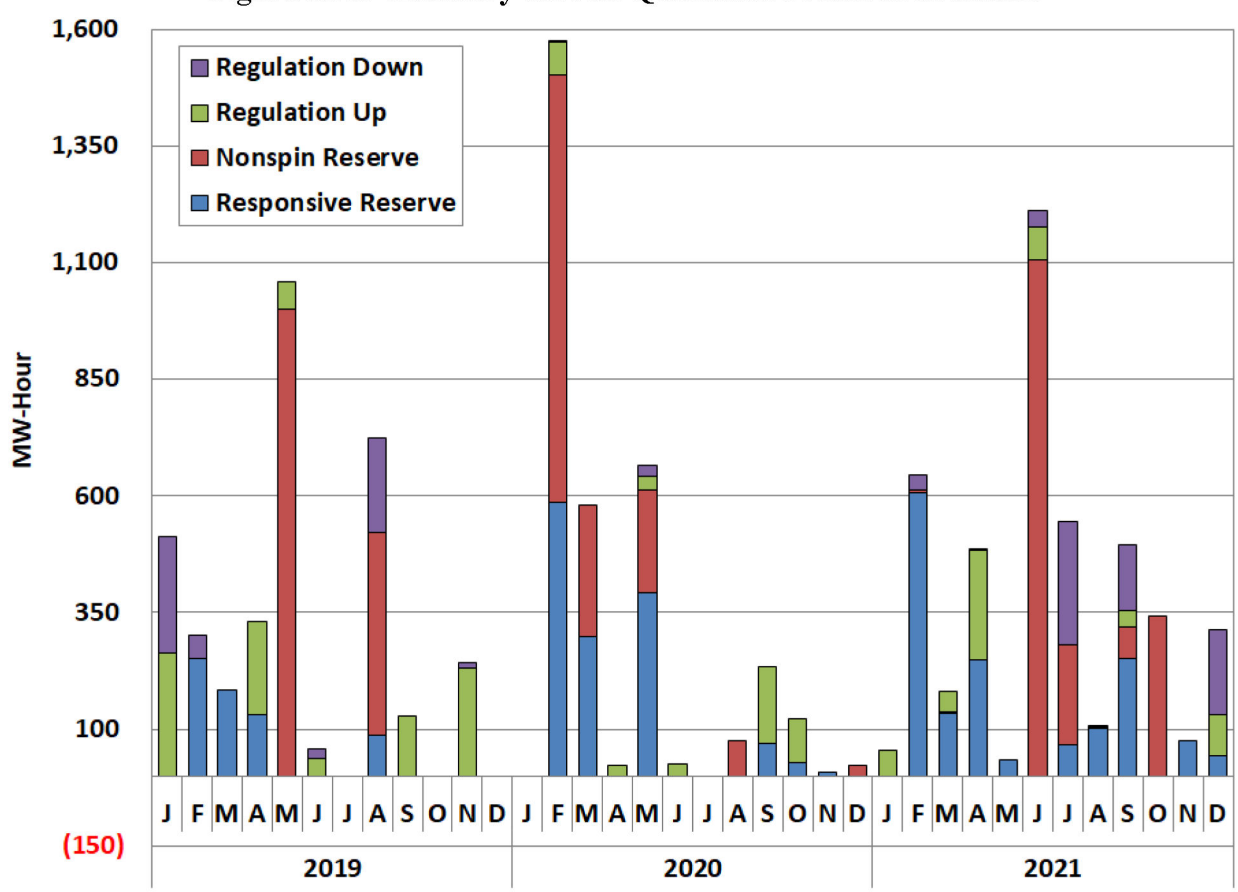
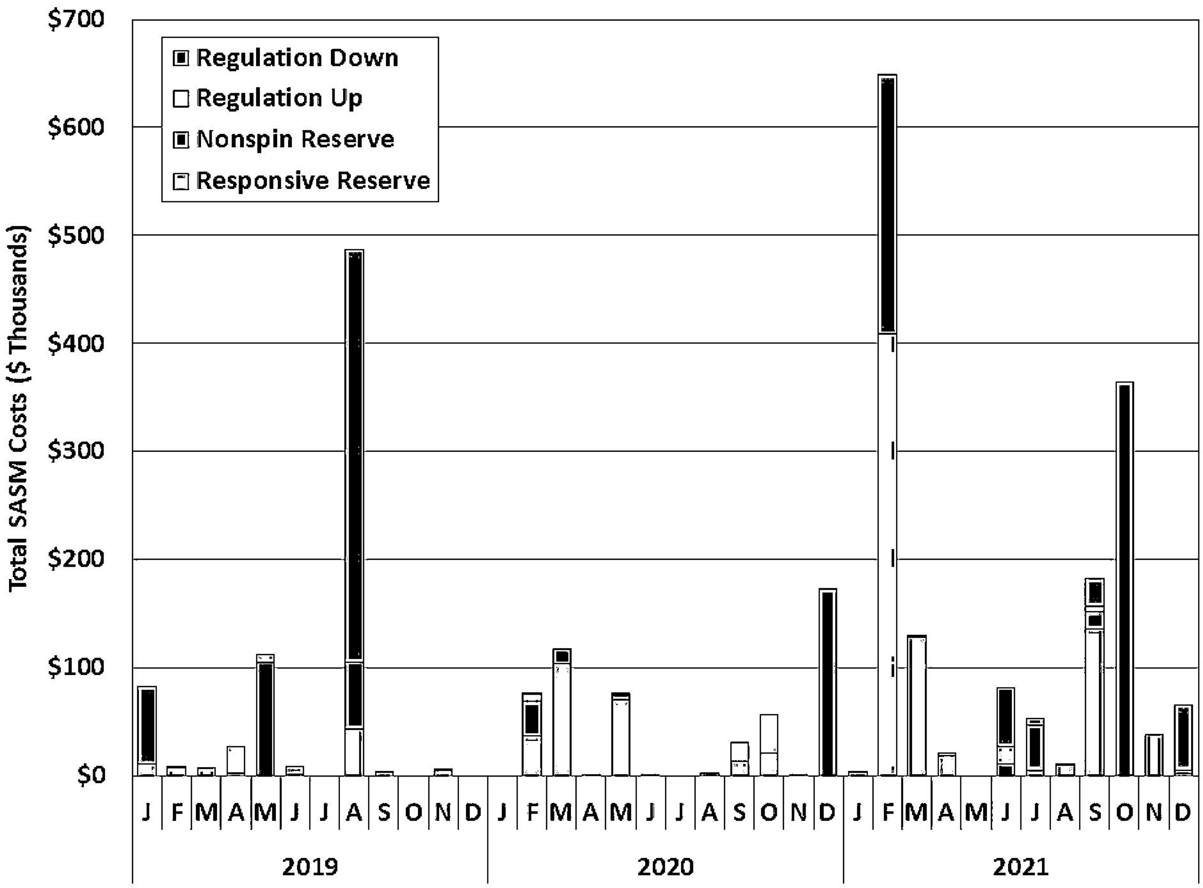


Figure A33 shows that the volume of service-hours procured via SASM over the year (4,486 MW of service-hours in 2021) is very small when compared to the total ancillary service requirement of nearly 42 million MW of service-hours.

Figure A34 shows the average cost of the replacement ancillary services procured by SASM over the last three years. The total SASM costs seen in February 2021 exceeded the previous high of August of 2019, which were the highest SASM costs up to that point in time. If a resource has reserve responsibilities under tight shortage conditions, the QSE would factor in the risk of covering responsibilities for those who could not provide ancillary services when they themselves might need to provide energy, so they have high reserve costs to cover their energy requirements if they end up providing reserves. However, because of the extreme shortage conditions in February, and tighter than expected conditions throughout the year, especially in October, resources were more likely to be diverted to provide energy rather than reserves, thus raising the cost of ancillary services in 2021.

Figure A34: Average Costs of Procured SASM Ancillary Services

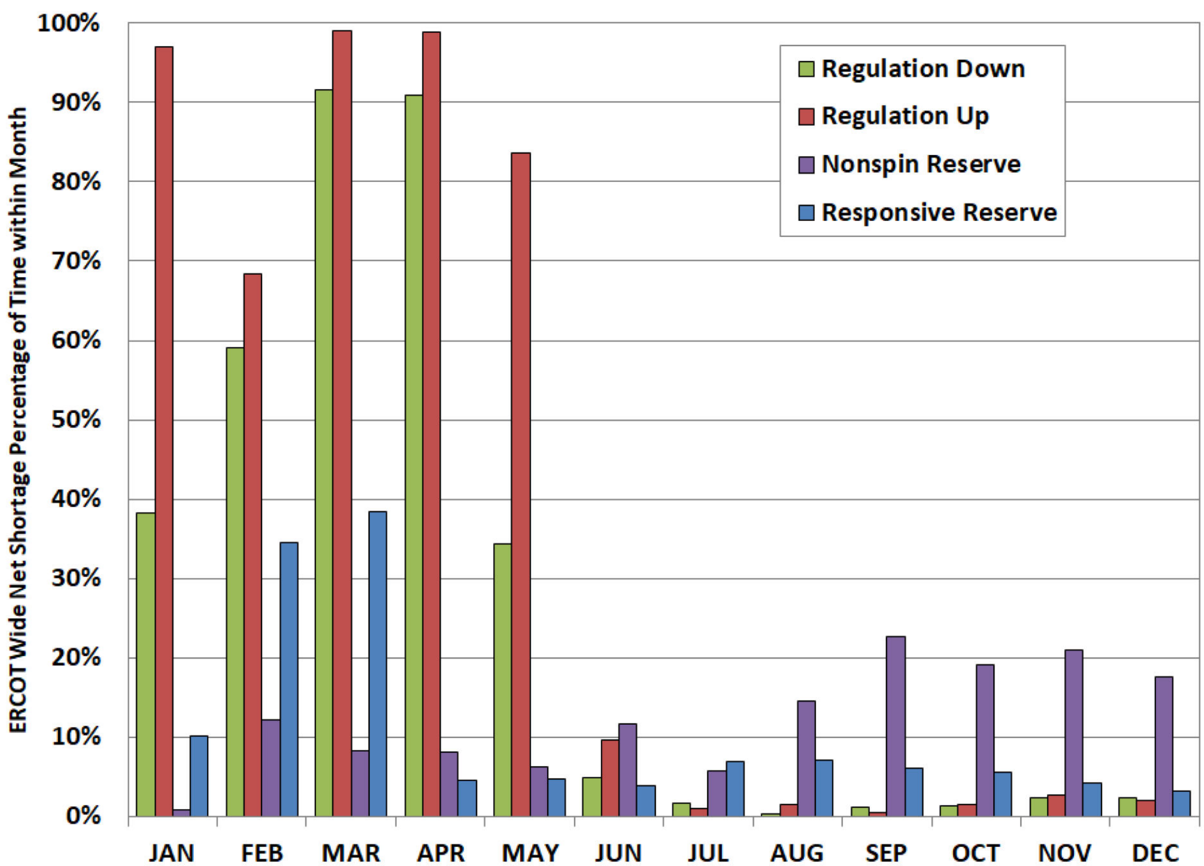


Real-time co-optimization of energy and ancillary services will not require resources to estimate opportunity costs between providing energy or reserves, will eliminate the need for the SASM mechanism, and allow ancillary services to be continually shifted to the most efficient provider.

The greatest benefit will be to effectively handle situations where entities that had day-ahead ancillary service awards were unable to fulfill that commitment, e.g., because of a generator forced outage. Thus, implementation of RTC will provide benefits across the market in future years.

In addition to its other weaknesses, a SASM is only useful for replacing ancillary services as part of a forward-looking view of the grid conditions. However, there are instances where the system is short ancillary services in real-time as per the resource details telemetered to ERCOT. Figure A35 depicts the percentage of hours in each month of 2021 where there was an ERCOT-wide shortage in the respective ancillary service. For this analysis, a shortage is defined as greater than 0.1 MW of obligation not being provided for at least 15 minutes out of an hour.

Figure A35: ERCOT-Wide Net Ancillary Service Shortages



This analysis shows that ERCOT-wide shortages for all ancillary services were extraordinarily high in 2021, with shortages of regulation up and down particularly pronounced from January through May. Again, this analysis is based on the telemetered status provided by the parties with the responsibility.

Table A3 is the monthly aggregate costs of various ERCOT market settlement totals in 2021, including AS costs by type.

Table A3: Market at a Glance Monthly

	Monthly Totals (Millions)											
	Jan	**Feb**	**May**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**
Energy	$677	$51,915	$610	$1,593	$819	$1,661	$1,616	$1,582	$1,688	$1,730	$1,219	$835
Regulation Up	$4	$809	$7	$9	$6	$7	$5	$5	$5	$7	$4	$3
Regulation Down	$2	$307	$8	$6	$7	$3	$1	$2	$2	$3	$3	$2
Responsive Reserve	$26	$7,738	$68	$64	$43	$54	$37	$34	$35	$60	$45	$28
Non-Spin	$2	$1,807	$4	$14	$4	$22	$44	$52	$56	$93	$51	$27
CRR Auction Distribution	$59	$56	$71	$69	$71	$80	$78	$73	$64	$71	$66	$72
Balancing Account Surplus	$6	$10	$0	$2	$11	$12	$9	$17	$16	$22	$5	$0
CRR DAM Payment	$54	$187	$124	$137	$108	$67	$35	$69	$72	$178	$134	$122
PTP DAM Charge	$41	$151	$100	$120	$103	$64	$34	$68	$73	$153	$109	$97
PTP RT Payment	$42	$455	$148	$243	$78	$55	$57	$62	$81	$135	$114	$94
Emergency Response Service	$0	$19	$0	$0	$0	$16	$0	$0	$0	$14	$0	$9
Revenue Neutrality	$5	($57)	$16	$10	$1	($2)	$2	$2	$3	$3	$9	$10
ERCOT Fee	$17	$16	$15	$16	$18	$21	$22	$23	$20	$18	$16	$17
Other Load Allocation	$1	$1,821	$1	($1)	$1	$2	$4	$1	$1	($0)	$1	$1

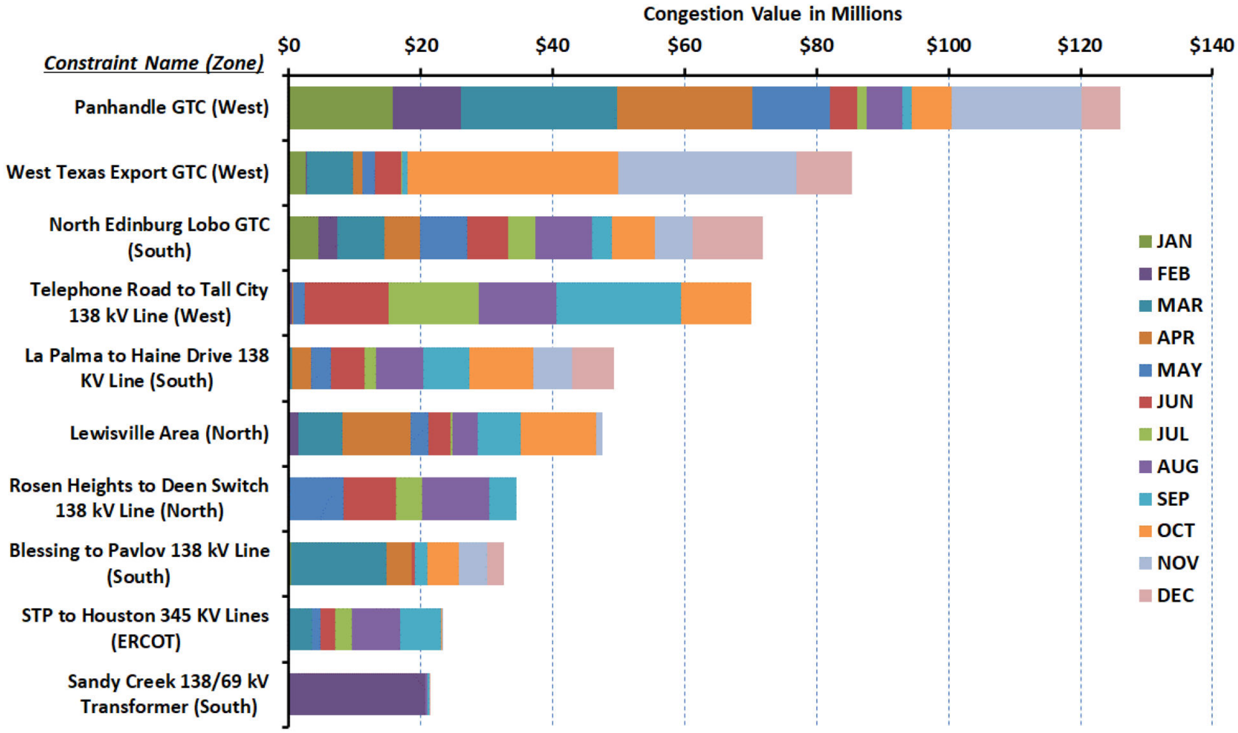
V. Appendix: Transmission Congestion and Congestion Revenue Rights

In this section, we provide supplemental analyses of transmission congestion in 2020, review the costs and frequency of transmission congestion in both the day-ahead and real-time markets, as well as review the activity in the CRR market.

A. Day-Ahead and Real-Time Congestion

In this subsection, we provide a review of the transmission constraints from the DAM in 2021. Figure A36 presents the ten most congested areas from the DAM, ranked by their value. Eight of the constraints listed here were described in Figure 42: Most Costly Real-Time Congested Areas. To the extent the model of the transmission system used for the DAM matches the real-time transmission system, and assuming market participants transact in the DAM similar to how energy flows in real-time, the same transmission constraints are expected to appear in both markets.

Figure A36: Most Costly Day-Ahead Congested Areas



Since the start of the nodal market, it had been common for the day-ahead constraint list to contain many constraints that were unlikely to occur in real-time. However, for the fourth year in a row, the majority of the costliest day-ahead constraints in 2021 were also costly real-time constraints. Aside from the Lewisville Area, Rosen Heights to Deen Switch, Blessing to Pavlov and Sandy Creek, the rest of the constraints that exist in both the top ten real-time market and the top ten DAM incurred less congestion value in the DAM than the real-time market. This is a result of less wind generation participating in the DAM, likely because of the uncertainty associated with predicting its output. The Sandy Creek constraint was a result of transmission conditions from Winter Storm Uri.

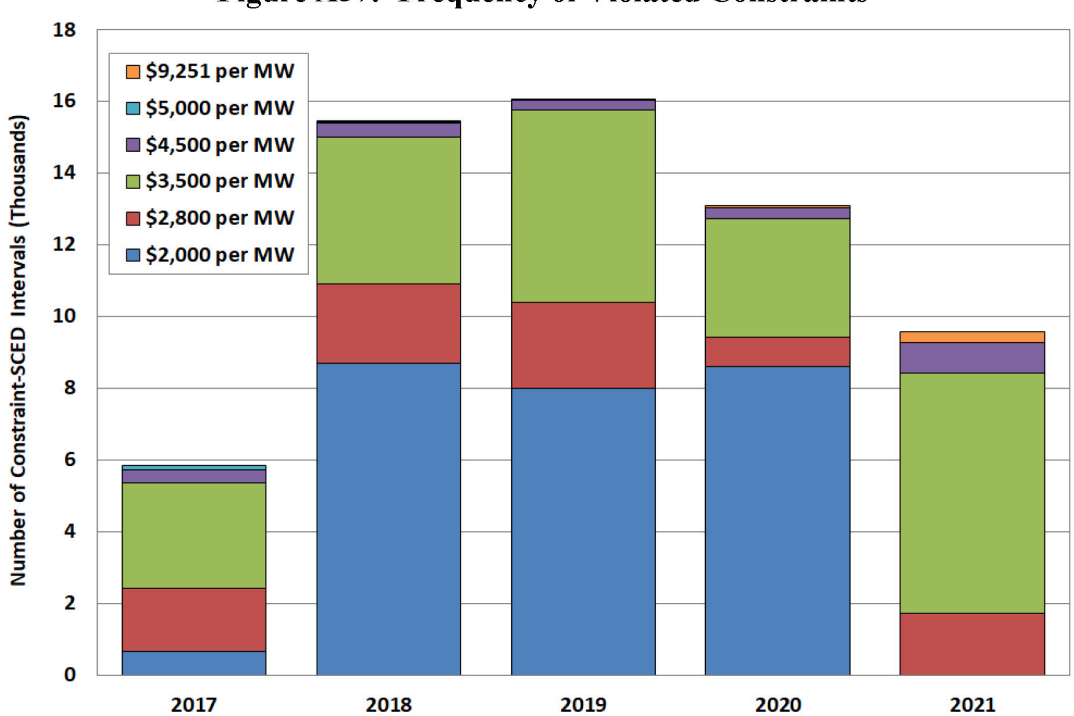
B. Real-Time Congestion

All actual physical congestion occurs in real-time and the real-time market and ERCOT operators manage power flows across the network. The expected costs of this congestion are reflected in the DAM, but the ultimate source of the congestion is the physical constraints binding in real time.

1. Types and Frequency of Constraints in 2021

Figure A37 below depicts constraints were violated (i.e., at maximum shadow prices) less frequently in 2021 than they were in 2020, continuing the trend form 2019. In 2019, the majority of the violated constraints occurring at the $2,000 per MW value were related to the Dollarhide to No Trees 138 kV line irresolvable element but dropped to 30% in 2020 due to the upgrades addressing the irresolvable element completed in spring 2020. In 2021, the majority of the violated constraints occurred at the $3,500 per MW value, the 138kv level, because of congestion due to Winter Storm Uri in the south zone. Violated constraints continued to occur in a small share of all the constraint-intervals, 4% in 2021, down from 5% in 2020 and 7% in 2019.

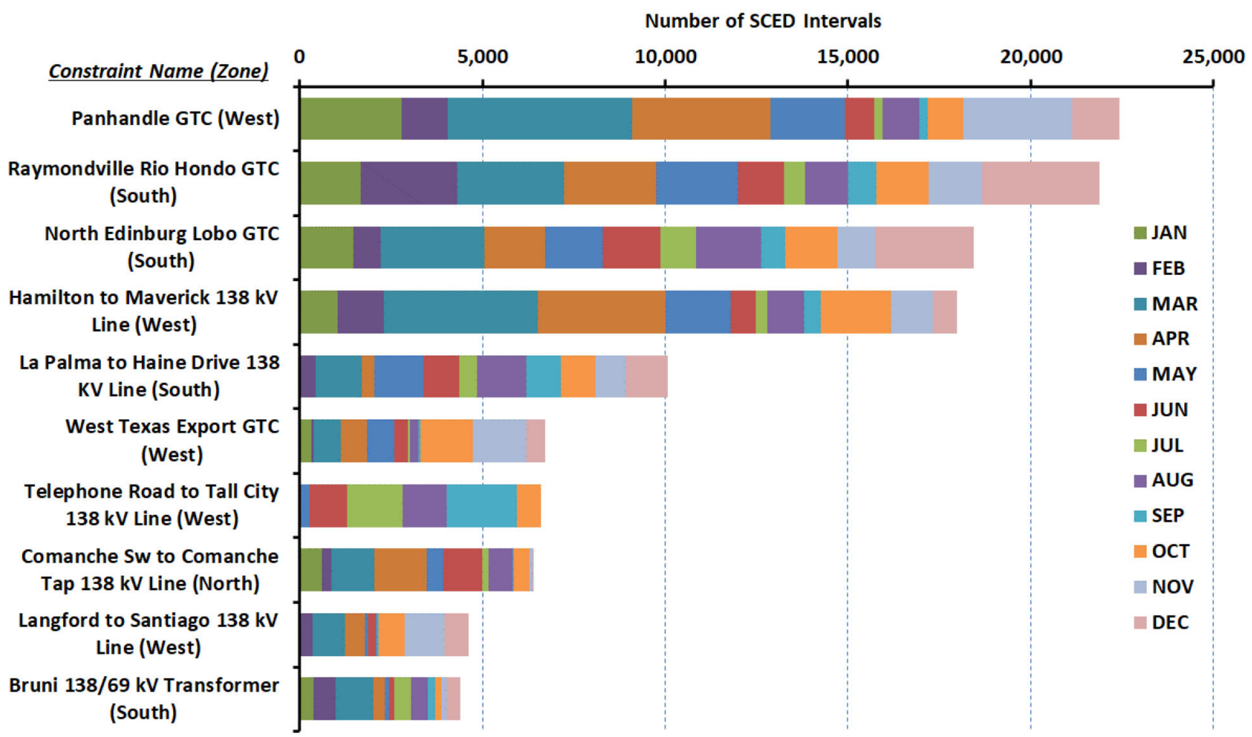
Figure A37: Frequency of Violated Constraints



2. Real-time Constraints and Congested Areas

Three GTCs (Panhandle, West Texas Export, and North Edinburg Lobo GTC) were in the top ten congested valued areas in 2021, up from 2 in 2020. GTC constraints doubled in congestion value to approximately $410 million from $190 million in 2020. While there were planned transmission upgrades to previously congested areas, such as Pig Creek and Lewisville, congestion continues due to inverter-based resource output. ERCOT continues to create workshops and taskforces to study and analyze models and future needs. While within the top ten constraints in terms of congestion cost, four of the top ten accrued congestion costs during and after Winter Storm Uri. However, all constraints listed in Figure A38 were frequently constrained in 2021 due to variable renewable output. The top ten most congested valued real-time constraints totaled to $820 million, whereas the top ten most frequently constrained constraints totaled $566 million.

Figure A38: Most Frequent Real-Time Constraints



3. Irresolvable Constraints

As shown in Table A4, 14 element combinations were deemed irresolvable in 2021 and had a shadow price cap imposed according to the irresolvable constraint methodology. Shadow price caps are based on a reviewed methodology,[112] and are intended to reflect the level of reduced reliability that occurs when a constraint is irresolvable. The shadow price caps are $9,251 per MW for base-case (non-contingency) or voltage violations, $4,500 per MW for 345 kV constraints, $3,500 per MW for 138 kV, and $2,800 per MW for 69 kV thermal violations. GTCs are considered stability constraints either for voltage or transient conditions with a shadow price cap of $9,251 per MW.

Table A4: Irresolvable Elements

Contingency Code	Irresolvable Element	Equivalent Element Max Shadow Price ($ per MWh)	2021 Adjusted Max Shadow Price ($ per MWh)	Irresolvable Effective Date	Termination Date	Load Zone	# of Binding Intervals in 2021
Base Case	Valley Import GTC	9,251	2,000	1/1/12	-	South	-
SSOLFTS8	Fort Stoctkon to Barilla 69 kV Line	2,800	2,000	5/13/19	1/30/21	West	-
XFRI89	Sonora 138/69 kV Transformer	2,800	2,000	5/24/19	1/30/21	West	-
SECNMO28	Andrews County South to Amoco Three Bar Tap 138 kV Line	2,800	2,000	9/23/19	1/30/21	West	-
SECNMO28	Dollarhide to No Trees Switch 138 kV Line	3,500	2,000	10/15/19	1/30/21	West	-
DWINDUN8	Dollarhide to No Trees Switch 138 kV Line	3,500	2,000	10/23/19	1/30/21	West	-
DYKNWIN8	Dollarhide to No Trees Switch 138 kV Line	3,500	2,000	11/29/19	1/30/21	West	-
SHACPB38	Rio Pecos to Woodward 2 138 kV Line	3,500	2,000	1/1/20	1/30/21	West	-
DWINDUN8	Andrews County South to Amoco Three Bar Tap 138 kV Line	3,500	2,000	3/24/20	1/30/21	West	-
DNEDWED8	Hidalgo Energy Center to Azteca Sub 138 kV Line	3,500	2,000	8/5/20	-	South	-
SMV_ALT8	Weslaco Switch to North Alamo 138 kV Line	3,500	2,000	8/7/20	-	West	-
SPHAWES8	Key Switch to North McAllen 138 kV Line	3,500	2,000	8/10/20	-	West	-
SHACPB38	Lynx to Tombstone 138 kV Line	3,500	2,000	11/30/20	-	West	-
SBEVASH8	Hamilton to Maverick 138 kV Line	3,500	2,000	2/18/21	-	West	435
SCRDJON5	Decordova Dam to Carmichael Bend Switch 138 kV Line	3,500	2,000	2/20/21	-	West	425

112 Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints (ERCOT Board Approved December 8, 2020, effective December 10, 2020), available at http://www.ercot.com/content/wcm/key_documents_lists/89286/Methodology_for_Setting_Maximum_Shadow_Prices_for_Network_and_Power_Balance_Constraints.zip.

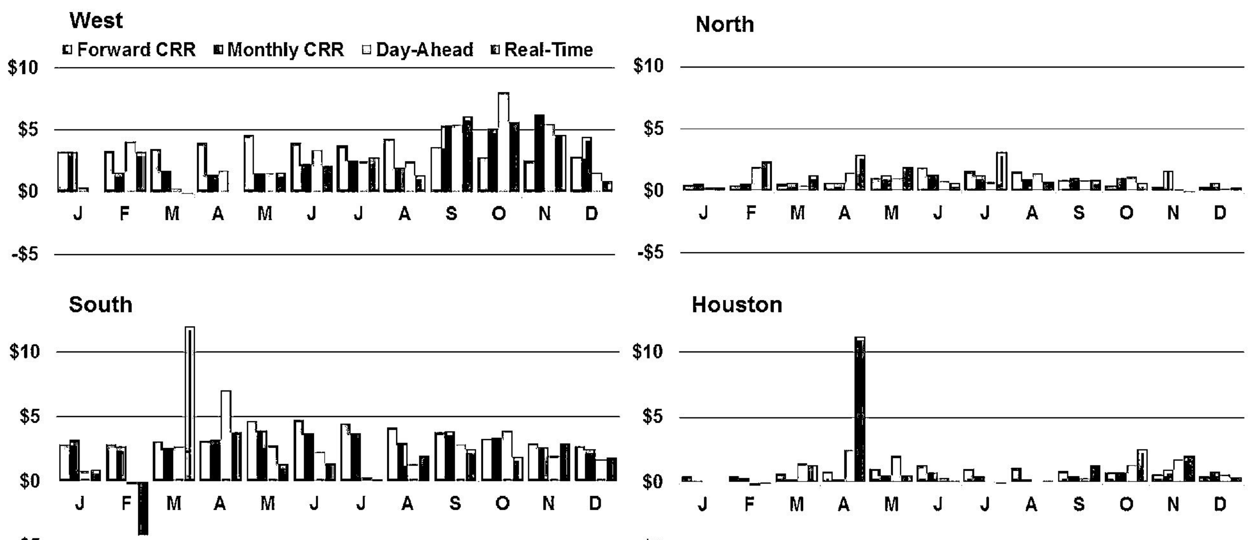
Eight constraints identified with a termination date of 1/30/21, were deemed resolvable during ERCOT's annual review and were removed from the list. All irresolvable constraints are located in the West zone with the exception of the Valley Import GTC and Hidalgo Energy Center to Azteca 138 kV line, which is located in the South zone.

C. CRR Market Outcomes and Revenue Sufficiency

1. CRR Profitability

Figure A39 below shows the price spreads between all hub and load zones in 2021 as valued at four separate points in time – at the average of the four semi-annual CRR auctions, monthly CRR auction, day-ahead, and real-time.

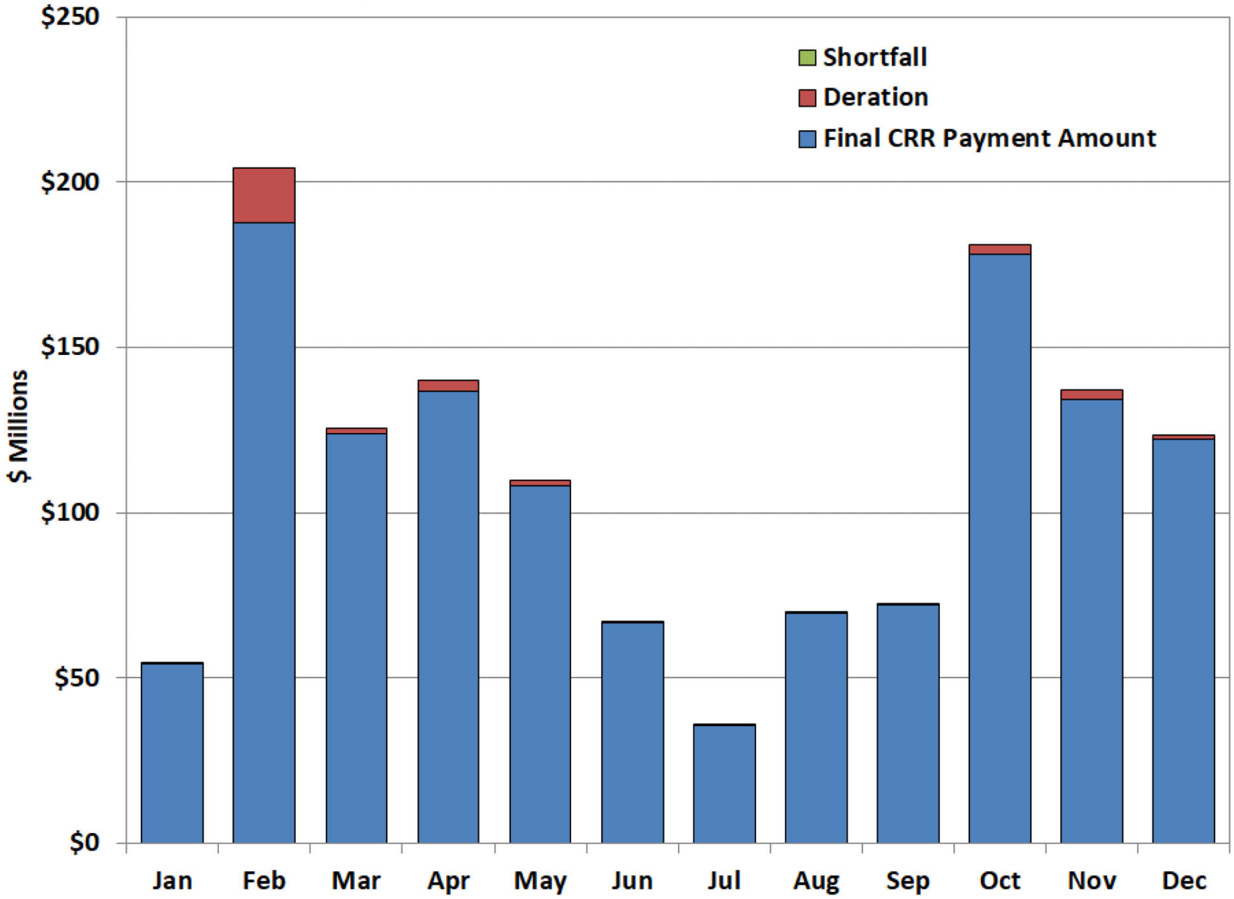
Figure A39: Hub to Load Zone Price Spreads



2. CRR Funding Levels

Figure A40 shows the amount of target payment, deration amount, and final shortfall for 2021. In 2021, the total target payment to CRRs was approximately $1.3 billion, similar to 2020; there were approximately $32 million of derations but no shortfall charges resulting in a final payment to CRR account holders of $1.23 billion. This final payment amount corresponds to a CRR funding percentage of 98%, the same as the funding percentage in 2020.

Figure A40: CRR Shortfall and Derations



VI. Appendix: Reliability Unit Commitments

In this section, we provide supplemental analyses of RUC activity in 2021 as well as the Current Operating Plan data submitted by Qualified Scheduling Entities (QSEs) and used by ERCOT to determine the need for a RUC.

A. History of RUC-Related Protocol Changes

The RUC process has undergone several modifications since the nodal market began in 2010. Changes have been implemented in an effort to improve the commitment process and market outcomes associated with RUC. In March 2012, an offer floor was put in place for energy above the Low-Sustained Limit (LSL) for units committed through RUC, and it is currently set at $1,500 per MWh. Resources committed through the RUC process are eligible for a make-whole payment but also forfeit any profit through a clawback provision. Beginning on January 7, 2014, resources committed through the RUC process could forfeit the make-whole payments and waive the clawback charges, effectively self-committing and accepting the market risks associated with that decision. This buyback or "opt-out" mechanism for RUC initially required a resource to update its Current Operating Plan (COP) before the close of the adjustment period for the first hour of a RUC.

On June 25, 2015, ERCOT automated the RUC offer floor of $1,500 per MWh and implemented the Real-Time On-Line Reliability Deployment Adder (reliability adder). ERCOT systems now automatically set the energy offer floor at $1,500 per MWh when a resource properly telemeters a status indicating it has received a RUC instruction. The reliability adder, as discussed more in Section II: Review of Real-Time Market Outcomes, captures the impact of reliability deployments such as RUC on energy prices.

The RUC process was modified again in 2017. On June 1, 2017, ERCOT began using a telemetered snapshot at the start of each RUC instruction block as the trigger to calculate the reliability adder. This was an improvement over the previous calculation trigger, which required the QSE to telemeter the correct resource status. Another impact of the change is that resources could opt-out of RUC settlement after the close of the adjustment period, because the opt-out decision is no longer communicated via the COP.

In 2018, the RUC engine was modified to consider fast-start generators (those with a start time of one hour or less) as self-committed for future hours, allowing ERCOT to defer supplementary commitment decisions, and allowing market participants full opportunity to make their own unit commitment decisions. RUC-related improvements in 2019 included approval and implementation of NPRR901, *Switchable Generation Resource Status Code*, which created a new resource status code of Switchable Generation Resources (SWGRs) operating in a non-ERCOT Control Area to provide additional transparency for operations and reporting. New logic was implemented that now prevents the triggering of the Real-Time Reliability Deployment Price Adder and the application of a RUC offer floor when a RUC Resource was awarded a resource-specific offer in the DAM. A new settlement structure for SWGRs that receive a RUC instruction was approved and implemented in 2019 to address concerns of inadequate compensation for SWGRs that were instructed to switch from a non-ERCOT control area to the ERCOT Control Area.

RUC-related improvements in 2020 included updates to ERCOT systems to effectively manage cases where ERCOT issues a RUC instruction to a combined cycle resource that is already QSE-committed for an hour, with the instruction being that the resource operate in a configuration with greater capacity for that same hour. Further, the maximum amount that may now be recovered for fuel oil disputes is the difference between the RUC Guarantee based on the actual price paid and the adjusted Fuel Oil Price (FOP). And finally, ERCOT systems now automatically create a proxy Energy Offer Curve with a price floor of $4,500 per MWh for each RUC-committed SWGR as opposed to requiring QSEs to submit Energy Offer Curves reflecting the $4,500 per MWh floor.[113]

In 2021, RUC activity picked up significantly after Winter Storm Uri in February. ERCOT committed to taking a more conservative approach to operating the grid. According to ERCOT, their grid management is at its most aggressive since the market was created two decades ago. ERCOT is increasing operational reserves to ensure adequate generation is available to Texas homes and businesses and is bringing more generation online sooner if it is needed to balance supply and demand. ERCOT is also purchasing more reserve power, especially on days when the weather forecast is uncertain.[114] The effects of this new conservative approach and the resulting increase in RUC activity are outlined below.

B. QSE Operation Planning

The following set of analyses quantify the difference between the aggregated capacity commitments as described by all the COP submissions, and the actual capacity commitments as a percentage of the actual capacity observed in real-time. These analyses are limited to the peak hours of 12 through 20 for the summer months of July and August. Multiple COP submissions

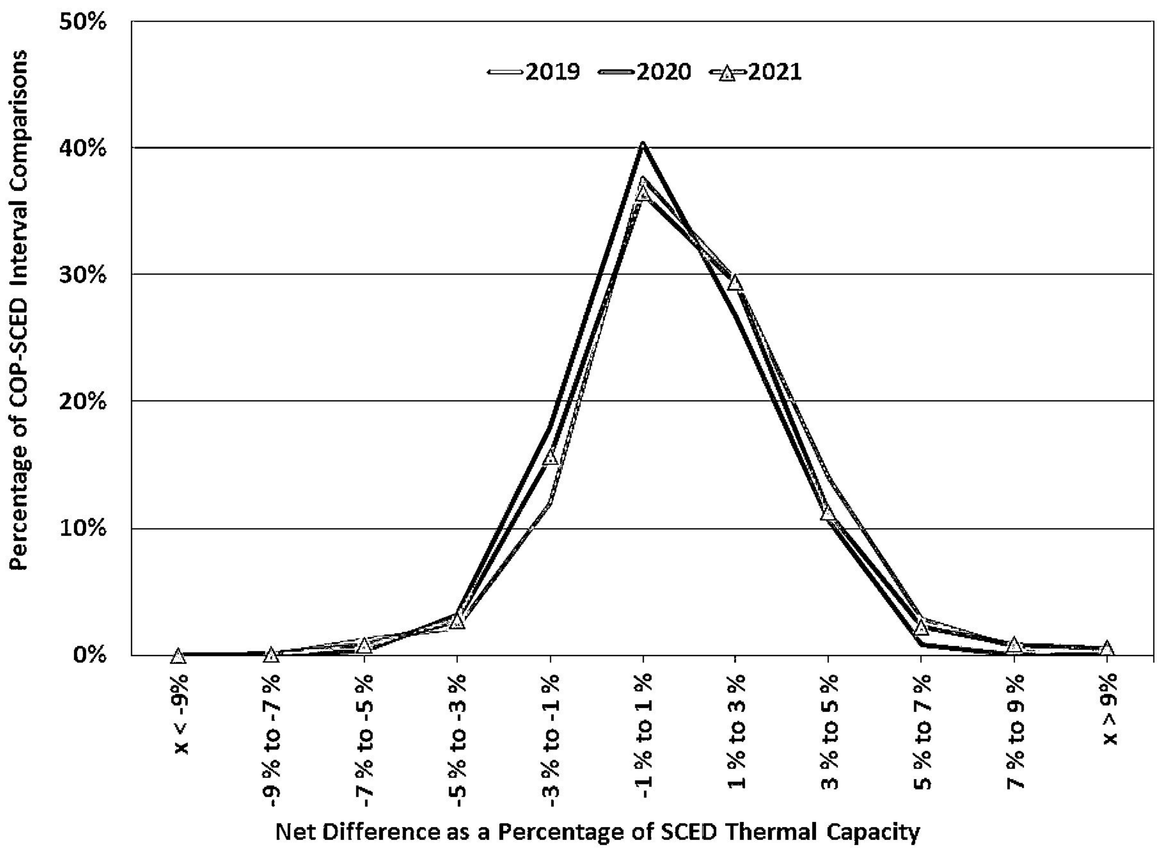
[113] *See* NPRR856, *Treatment of OFFQS Status in Day-Ahead Make Whole and RUC Settlements* (implemented May 2020); NPRR884, *Adjustments to Pricing and Settlement for Reliability Unit Commitments (RUCs) of On-Line Combined Cycle Generation Resources* (implemented May 2020); NPRR970, *Reliability Unit Commitment (RUC) Fuel Dispute Process Clarification* (implemented March 2020); NPRR977, *Create MIS Posting for RUC Cancellations* (implemented May 2020); NPRR1019, *Pricing and Settlement Changes for Switchable Generation Resources (SWGRs) Instructed to Switch to ERCOT* (partially implemented June 2020; automation of offers will be delivered separately as part of a future project); NPRR1028, *RUC Process Alignment with Resource Limitations Not Modeled in the RUC Software* (approved December 2020); and NPRR1032, *Consideration of Physical Limits of DC Ties in RUC Optimization and Settlements* (approved December 2020).

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

as of day-ahead 1600 provide data for each of the hours being evaluated, and there can be large variations in unit commitment expectations reflected in those multiple COPs, even for the same operating hour. Because unit commitment decisions for renewable resources are influenced by the solar and wind forecasts, which are discussed in Section III: Appendix: Demand and Supply in ERCOT, the differences will not be highlighted here.

Figure A41 summarizes the frequency of percentage error between SCED thermal capacity and its respective COP. The comparisons include relevant COPs since day-ahead 1600 - 24 hours prior to HE 12 through HE 20, to the COP at the end of the adjustment period. The analysis focuses on the net difference as a percentage of the SCED thermal capacity due to load fluctuations between years. The last three years have shown a tendency towards an error greater than 1%. In 2019, 15.3% of the COP-SCED interval comparisons were below -1% error, 37.6% occurring within 1%, 47.1% had a percentage error greater than 1%, and 17.5% were greater than 3%. In 2020, 21.4% of the COP-SCED interval comparisons were below -1% error, 40.4% occurring within 1%, 38.2% had a percentage error greater than 1%, and 11.5% were greater than 3%. In 2021, 19.9% of the COP-SCED interval comparisons were below -1% error, 35.6% occurring within 1%, 44.5% had a percentage error greater than 1%, and 16.0% were greater than 3%.

Figure A41: Real-Time to COP Comparisons for Thermal Capacity

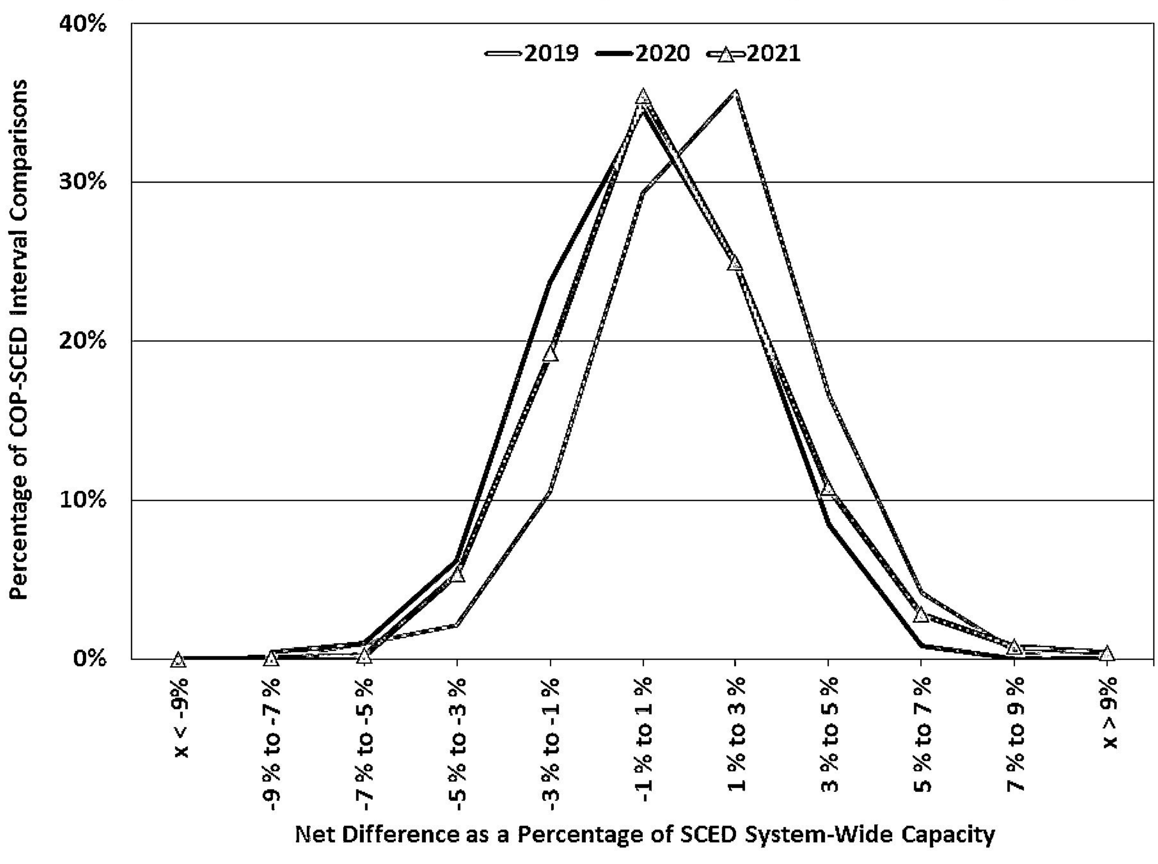


When analyzing the average net between SCED thermal capacity and the respective COP reported from 24 hours to the last valid COP, there appears to be a tendency to under-report COP capacity 24 hours ahead, commit some capacity, and then under-report the COP at the end of the adjustment period a small percentage of the time. The curve from 2021 is similar to the curves from the previous two years, with 2021 exhibiting a slightly smaller contrast.

In 2019, there was a bias towards under-representing the amount of capacity that would materialize in real-time. In 2020 and 2021, the shape of the curve indicates a more evenly distributed representation of capacity in real-time versus the COP capacities.

Figure A42 summarizes the same analysis as above, but for system-wide capacity. 2021 shows a similar about of capacity occurring in real-time at the system-wide level, including intermittent renewable resources, as occurred in 2020. A possible explanation for this is better forecast for the renewables leading up to the operating hour.

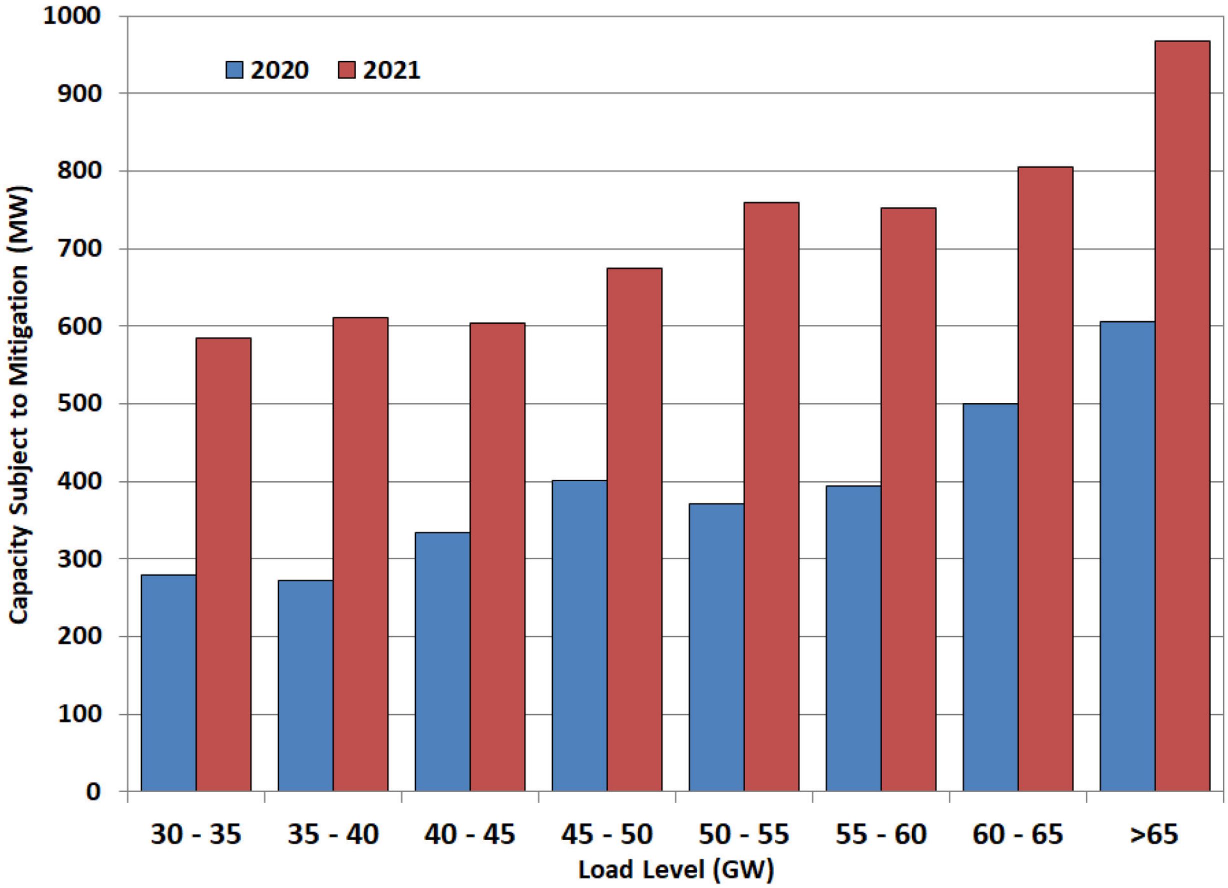
Figure A42: Real-Time to COP Comparisons for System-Wide Capacity



C. Mitigation

The next analysis computes the total capacity of RUC and self-committed resources subject to mitigation, by comparing a generator's mitigated and unmitigated (as submitted) offer curves and determining the point at which they diverge. The difference between the total unit capacity and the capacity at the point the curves diverge is calculated for all units and aggregated by load level. The results are shown in Figure A43.

Figure A43: Average Capacity Subject to Mitigation



The average amount of capacity subject to mitigation in 2021 was higher than 2020 in all load levels. It is important to note that this measure includes all capacity above the point at which a unit's offers become mitigated, without regard for whether that capacity was actually required to serve load.

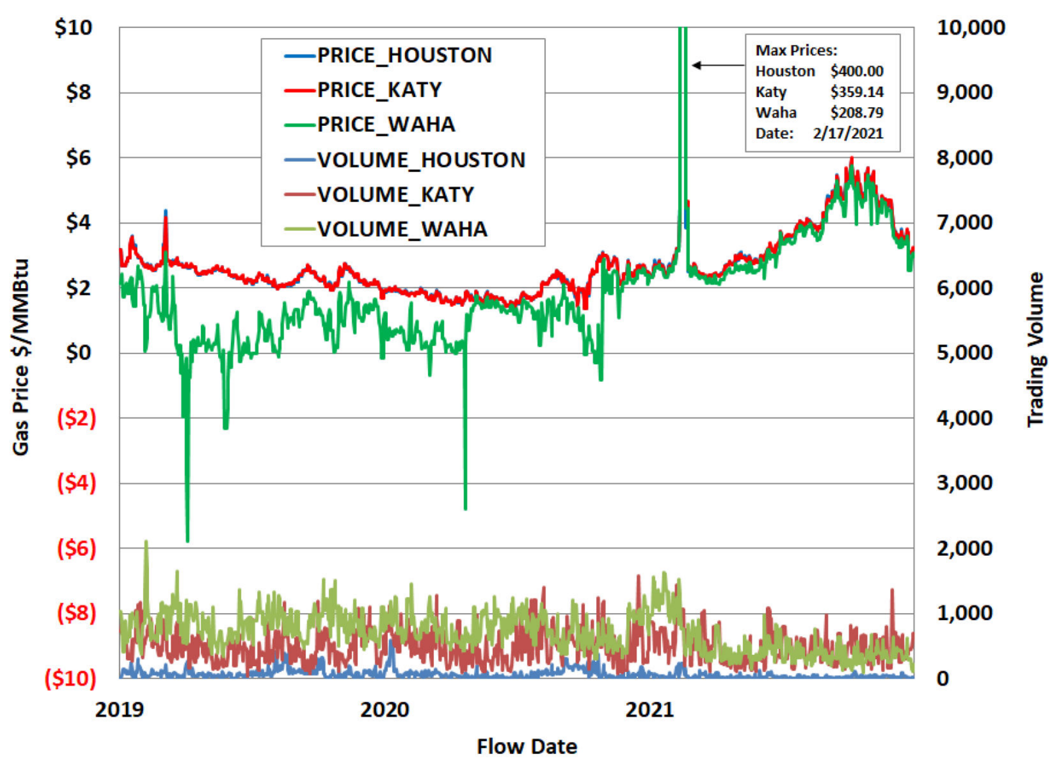
VII. APPENDIX: RESOURCE ADEQUACY

In this section, we provide a supplemental analysis of the economic signals that will facilitate the investment needed to maintain a set of resources that are adequate to satisfy the system's needs by estimating the "net revenue" resources received from ERCOT real-time and ancillary services markets and providing comparisons to other markets.

A. Locational Variations in Net Revenues in the West Zone

Fuel prices are a substantial determinant of net revenues because they are the primary offset from market revenues when calculating net revenues. In 2020, we saw a continuing trend evident of the growing separation in natural gas prices between the Waha and Katy locations in the West.[115] Drilling activity in the Permian Basin of far west Texas has produced a glut of natural gas and consequently, much lower prices at the Waha location. In 2021, the rise in natural gas prices in February, across all indices, was unprecedented during the freezing conditions of Winter Storm Uri. As seen in Figure A44 below, Waha prices dipped below $0 multiple times throughout 2021, and were more volatile than Katy.

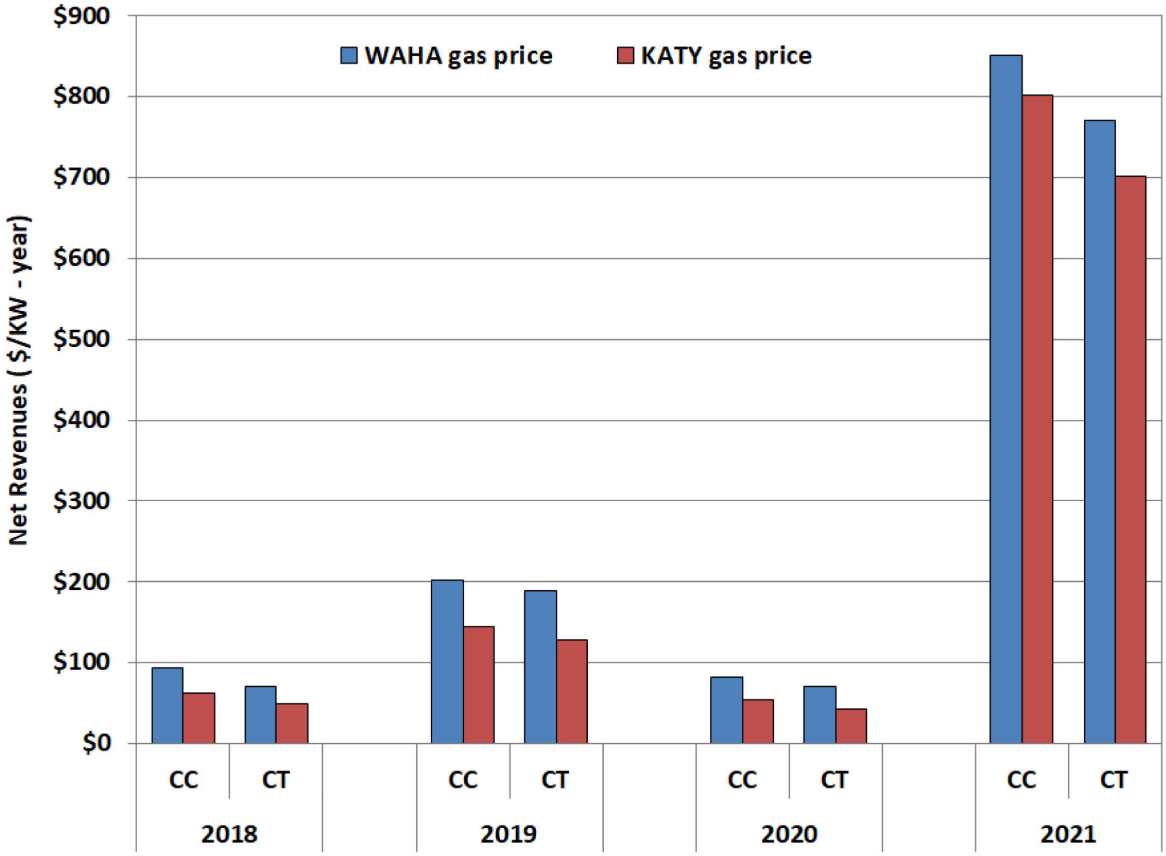
Figure A44: Gas Price and Volume by Index



115 Effective December 12, 2019, the Katy Hub replaced Houston Ship Channel as the reference for the Fuel Index Price (FIP) for natural gas in ERCOT's systems. See NPRR952, *Use of Katy Hub for the Fuel Index Price*. ERCOT has the flexibility to select an appropriate natural gas price index for the purposes of calculating the Peaker Net Margin (PNM) threshold and the Low System-Wide Offer CAP (LCAP).

Historically, resources in the West zone have had lower net revenues that resources in the other zones, but that was not the case in 2019 through 2021. Additionally, the divergence between Waha and Katy gas prices contributed to greater net revenues for West Texas gas-fired generators. Figure A45 provides a comparison of net revenue for both types of natural gas units assuming Katy and Waha gas prices. Net revenues based on Waha gas prices are higher than in the other three zones.

Figure A45: West Zone Net Revenues



B. Reliability Must Run and Must Run Alternative

Reliability-Must-Run procedures are essential for determining and addressing the need for generation units to support grid reliability. Although no new Reliability Must-Run (RMR) contracts were awarded in 2020, a number of Notice of Suspension of Operations (NSO) were submitted in 2020.[116] ERCOT determined that none of the resources listed below were necessary to support ERCOT transmission system reliability.

116 South Houston Green Power LLC (RE) – AMOCOOIL_AMOCO_S2; Petra Nova Power I LLC (RE) – PNPI_GT2; Snyder Wind Farm LLC – ENAS_ENA1; City of Austin dba Austin Energy (RE) – DECKER_DPG2; Sherbino I Wind Farm LLC – KEO_KEO_SM1; City of Garland – OLINGR_OLING_1; Wharton County Generation LLC – TGF_TGFGT_1.

On January 22, 2021, ERCOT received an NSO for Sherbino I Wind Farm LLC's KEO_KEO_SM1 resource. The NSO indicated that the resource had ceased operations due to a forced outage and would be decommissioned and retired permanently as of February 1, 2021. The NSO further indicated that the resource had a summer Seasonal Net Max Sustainable Rating of 120 MW (Operating). Pursuant to ERCOT Protocol Section 3.14.1.1(3), the Generation Resource was not evaluated for RMR status, and the NSO was not posted on the Market Information System (MIS).

On January 27, 2021, ERCOT received an NSO for South Houston Green Power LLC (RE)'s AMOCOOIL_AMOCO_S2 resource. The NSO indicated that operation of the resource would be suspended due to forced outage with a planned to bring the resource back to service on December 31, 2022. The NSO further indicated that the resource has a summer Seasonal Net Max Sustainable Rating of 125 MW, and a summer Seasonal Net Minimum Sustainable Rating of 25 MW.

On January 27, 2021, ERCOT received an NSO for Petra Nova Power I LLC (RE)'s PNPI_GT2 resource. The NSO indicated that the resource would be mothballed indefinitely as of June 26, 2021. The NSO further indicated that the resource had a summer Seasonal Net Max Sustainable Rating of 71 MW and a summer Seasonal Net Minimum Sustainable Rating of 65 MW.

On May 26, 2021, ERCOT received an NSO for Snyder Wind Farm LLC's ENAS_ENA1 resource. The NSO indicated that operation of the resource had ceased due to a forced outage and would be decommissioned and retired permanently as of June 1, 2021. The NSO further indicated that the resource had a summer Seasonal Net Max Sustainable Rating of 63 MW. Pursuant to ERCOT Protocol Section 3.14.1.1(3), the resource was not evaluated for RMR status, and the NSO was not posted on the Market Information System (MIS).

On November 1, 2021, ERCOT received an NSO for City of Austin dba Austin Energy (RE)'s DECKER_DPG2 resource. The NSO indicated that the resource would be decommissioned and retired permanently as of March 31, 2022. The NSO further indicated that the resource had a summer Seasonal Net Max Sustainable Rating of 420 MW, and a summer Seasonal Net Minimum Sustainable Rating of 50 MW.

On November 4, 2021, ERCOT received an NSO for City of Garland's OLINGR_OLING_1 resource indicating that operation of the resource would be suspended indefinitely as of April 5, 2022. The NSO further indicated that the resource had a summer Seasonal Net Max Sustainable Rating of 78 MW, and a summer Seasonal Net Minimum Sustainable Rating of 15 MW.

On December 17, 2021, ERCOT received a Notification of Change of Generation Resource Designation (NCGRD) for Wharton County Generation LLC's TGF_TGFGT_1 resource. The NCGRD indicated that the resource, which was then decommissioned and retired, would change its resource designation to operational as of February 4, 2022.

VIII. APPENDIX: ANALYSIS OF COMPETITIVE PERFORMANCE

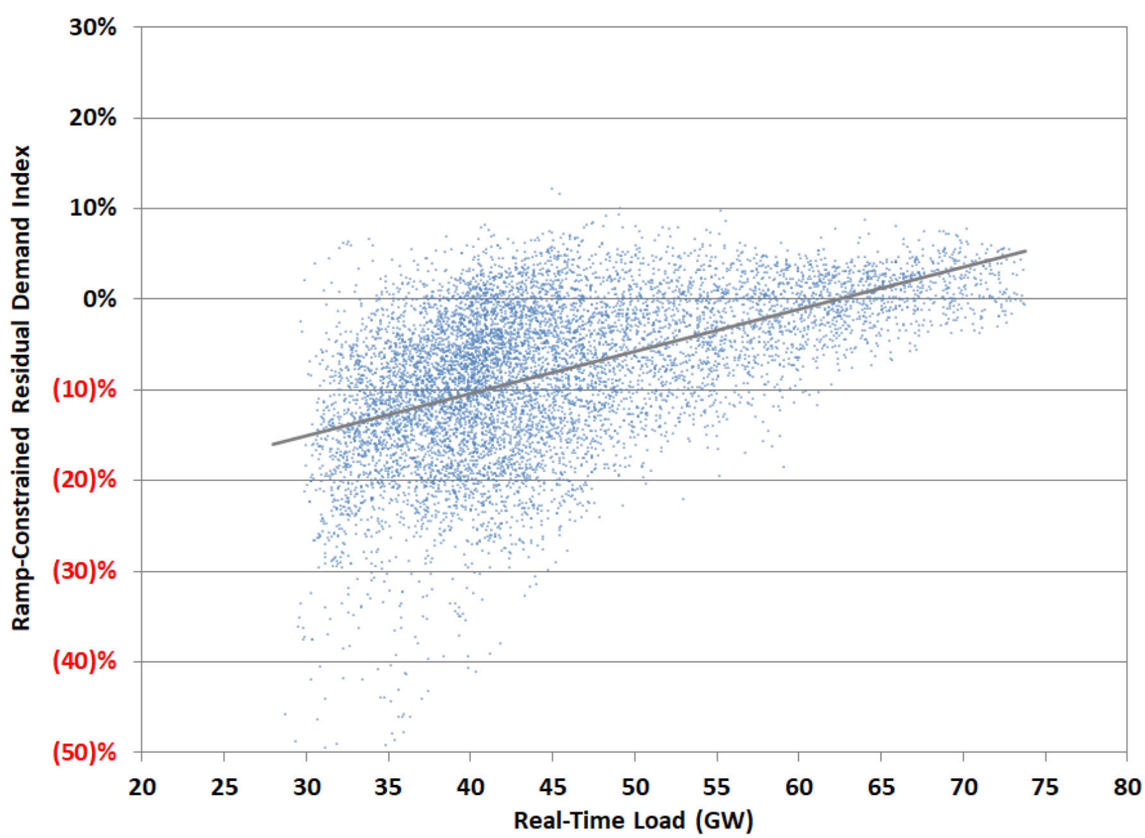
In this section, we provide supplemental analyses to evaluate market power from two perspectives: structural (does market power exist?) and behavioral (have attempts been made to exercise it?). Market structure is examined by using a pivotal supplier analysis that indicates the frequency with which a supplier was pivotal at higher load levels. Market participant conduct is evaluated by reviewing measures of physical and economic withholding. These withholding patterns are examined relative to the level of demand and the size of each supplier's portfolio.

A. Structural Market Power Indicators

When the Residual Demand Index (RDI) is greater than zero, the largest supplier is pivotal (i.e., its resources are needed to satisfy the market demand). When the RDI is less than zero, no single supplier's resources are needed to serve the load if the resources of its competitors are available.

Figure A46 shows the ramp-constrained RDI, calculated at the QSE level, relative to load for all hours in 2021. The occurrences of a pivotal supplier are not limited to just the high load summer period. This analysis indicated the existence of a pivotal supplier for some fraction of time at load levels as low as 30 GW. The trend line indicates a strong positive relationship between load and the RDI.

Figure A46: Residual Demand Index



1. Voluntary Mitigation Plans

In 2021, three market participants had active VMPs that remain unchanged throughout the year. Calpine's VMP was approved in March of 2013.[117] Because its generation fleet consists entirely of natural gas fueled combined cycle units, the details of the Calpine plan are somewhat different than the others. Calpine may offer up to 10% of the dispatchable capacity of its portfolio at prices up to $500 per MWh. Additionally, Calpine may offer up to 5% of the dispatchable capacity of its portfolio at prices no higher than the system-wide offer cap. When approved, the amount of capacity covered by these provisions was approximately 500 MW. With additions to Calpine's generation fleet made since the VMP was approved, its current amount of offer flexibility has increased to approximately 700 MW. Calpine's VMP remains in effect from the date it was approved by the Commission until terminated by the Executive Director of the Commission or Calpine.

NRG's plan, initially approved in June 2012 and modified in May 2014,[118] allows the company to offer some of its capacity at prices up to the system-wide offer cap. Specifically, up to 12% of the difference between the high sustained limit and the low sustained limit – the dispatchable capacity – each natural gas unit (5% for each coal or lignite unit) may be offered no higher than the greater of $500 per MWh or 50 times the natural gas price. Additionally, up to 3% of the dispatchable capacity for each natural gas unit may be offered no higher than the system-wide offer cap. The amount of capacity covered by these provisions is approximately 500 MW. NRG's VMP remains in effect from the date it was approved by the Commission until terminated by the Executive Director of the Commission or by NRG.

Luminant received approval from the Commission for a new VMP in December 2019.[119] The Commission terminated Luminant's previous VMP on April 9, 2018, as a result of its merger with Dynegy, Inc.[120] The new VMP provides for small amounts of capacity from non-quick start, non-combined cycle natural gas-fired units to be offered up to 12% of the dispatchable

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117 *Petition of Calpine Corporation for Approval of Voluntary Mitigation Plan*, Docket No. 40545, Order (Mar. 28, 2013).

118 *Request for Approval of a Voluntary Mitigation Plan for NRG Companies Pursuant to PURA § 15.023(f) and P.U.C. Subst. R. 25.504(e)*, Docket No. 40488, Order (Jul. 13, 2012); *Request for Approval of an Amended Voluntary Mitigation Plan for NRG Companies*, Docket No. 42611, Order (Jul. 11, 2014).

119 *Commission Staff Request for Approval of a Voluntary Mitigation Plan for Luminant Energy Company, LLC under PURA §15.023(f) and 16 TAC §25.504(e)*, Docket No. 49858, (Dec. 13, 2019).

120 *See Application of Luminant Power Generation LLC, Big Brown Power Company LLC, Comanche Peak Power Company LLC, La Frontera Holdings LLC, Oak Grove Management Company LLC, and Sandow Power Company Under Section § 39.158 of the Public Utility Regulatory Act*, Docket No. 47801 (Nov. 22, 2017); on April 9, 2018, Luminant filed a letter with the Commission terminating its VMP upon closing of the proposed transaction approved by the Commission in Finding of Fact No. 36 of the Order in Docket No. 47801, see also *Request for Approval of a Voluntary Mitigation Plan for Luminant Companies Pursuant to PURA § 15.023(f) and P.U.C. Subst. R. 25.504(e)*, Docket No. 44635, Order Approving VMP Settlement (May 22, 2015).

capacity for each unit at prices up to $500 per MWh, and up to 3% of the dispatchable capacity may be offered at prices up to and including the high system-wide offer cap (HCAP). When approved in late 2019, the amount of capacity covered by these provisions was less than 900 MW. In addition, the plan defines allowable limits for energy offers from Luminant's quick start combustion turbines.

B. Evaluation of Supplier Conduct

1. Generation Outages and Deratings

Figure A47 shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2021.

Figure A47: Short-Term Outages and Deratings

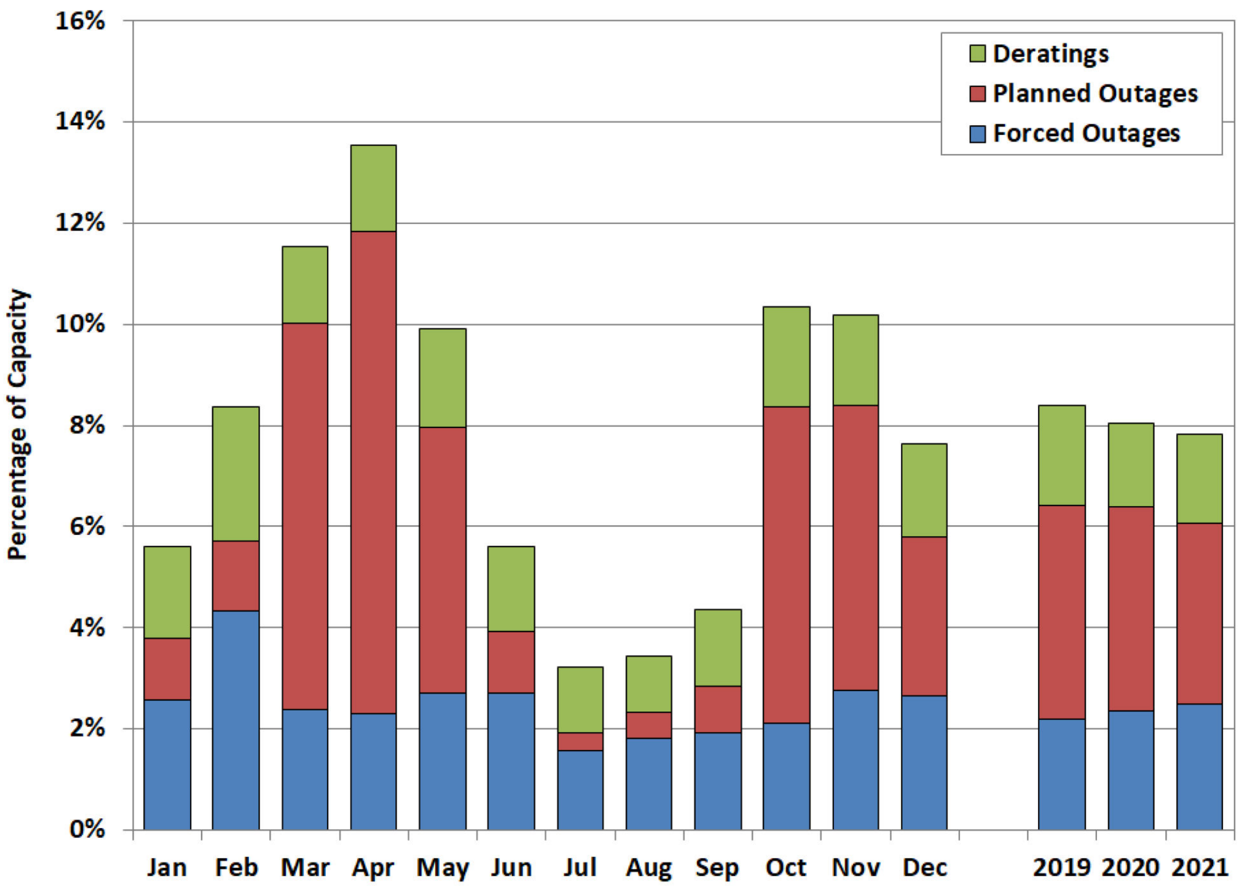

Figure A47 shows that short-term outages and deratings in 2021 followed a pattern similar to what occurred in 2019 and 2020, as the expectations for summer shortage in both years prompted short-term outage and derating spikes in shoulder months. The total short-term deratings and outages in 2021 were approximately 13.5% of installed capacity in April (down 15.2% in 2020) and dropped to less than 4% during July and August (the same as in 2019 and 2020).

Most of this fluctuation was due to planned outages. Winter Storm Uri did not significantly impact short-term outages and deratings in 2021. The amount of capacity unavailable during 2020 averaged 7.8% of installed capacity, a modest decrease from the 8.0% in 2020 and 8.3% experienced in 2019. The numbers of planned outages dropped slightly in 2021, 3.6% on average, down from 4.0% in 2020 and 4.2% in 2019. This slight downward trend can be explained by the heightened expectations for shortages during the summer and generators taking outage time to ensure higher availability. The low levels of deratings the last three years may be similarly explained by generators operating in modes that would allow them to maximize generation.

While we only focus on short-term outages for the purposes of this evaluation, it is of some interest to also look at long-term outage rates to see the impact of Winter Storm Uri on maintenance activities. We performed this analysis, and the results are shown in the Figure A48 below. When both lengths of outages are included, there were consistently higher rates of planned and forced outages in April through December 2021 than there were in those same months in 2020, although the magnitude is fairly small.

Figure A48: Short- and Long-Term Deratings and Outages