Table 6: Effect of ORDC Shift on Price

	Average RT price $ per MWh	ORDC contribution $ per MWh	ORDC Price increase $ per MWh	Percent increase %	Total RT Market Cost $ in Millions	RT Market Cost Increase $ in Millions
March	30	<1	<0.1	<1	838	0
April	28	<1	1	2	751	14
May	28	1	1	3	907	25
June	29	2	2	6	1,010	58
July	34	8	6	17	1,329	221
August	162	52	25-31	15-19	6,772	1,035-1,274
September	60	17	12	19	2,237	429
October	39	5	3	0	1,198	106
November	29	0	0	0	812	4
December	20	0	0	0	581	0
Total	50	11	6-7	12-13	16,433	1,890-2,130

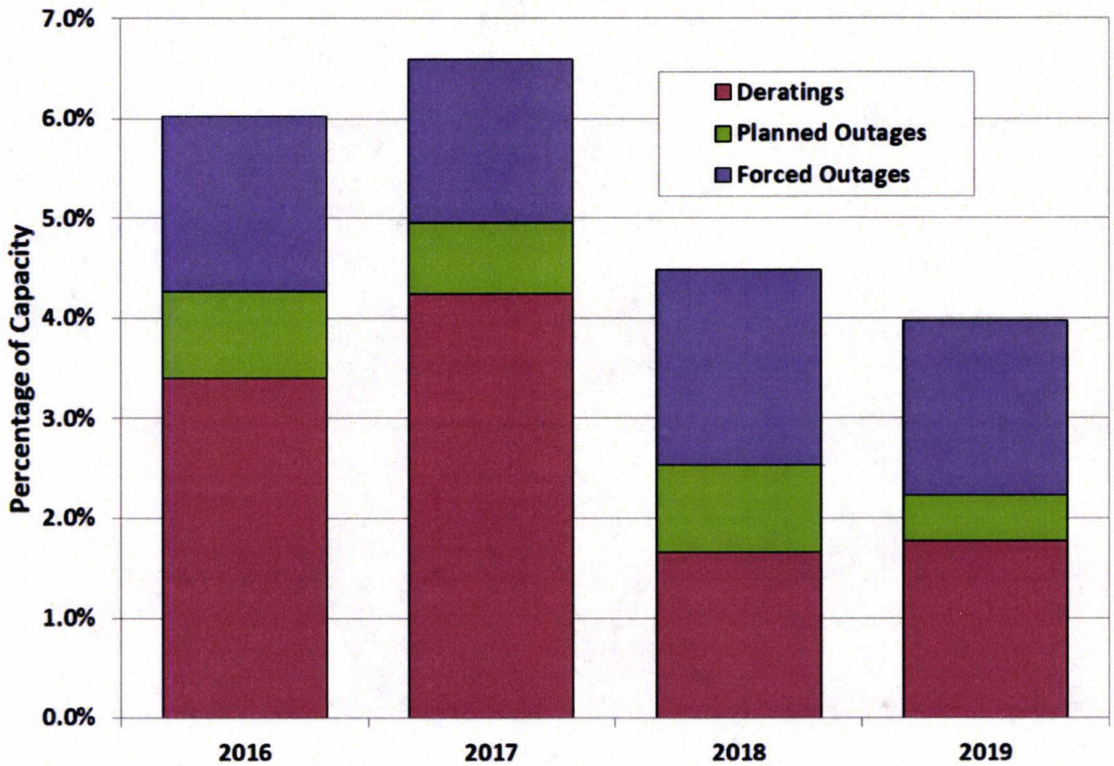
Table 6 above shows that the ORDC change increased the effects of shortage pricing by an estimated 12 to 13% -- increasing the total impact of the ORDC on average prices from $6 to $7 per MWh. This led to increased market costs and revenues to generators of roughly $2 billion in 2019. Although further changes are being implemented for 2020, shortage pricing will not likely exceed 2019 levels if planning reserve margins rise as projected.

4. Short-Term Effects of Shortage Pricing in 2019

In addition to the long-term incentives that shortage pricing creates to facilitate investment and retirement decisions, it also creates important short-term incentives. For example, it creates a very strong incentive for generators to be available at the times when they are expected to be needed most. Figure 44 shows the level of outages and deratings that have occurred during summer peak conditions over the past four years.

This figure shows that as the planning reserve margin has declined and expectations of shortages have increase, outages have decreased substantially. Most of these reductions were in planned outages and deratings, the class for which the suppliers have the most control. These results demonstrate that the suppliers in ERCOT respond to price signals and associated incentives.

Figure 44: Summer Month Outage Percentages



E. Reliability Must Run and Must Run Alternative

A Notice of Suspension of Operations (NSO) is required of any generator suspension that lasts greater than 180 days. ERCOT received a number of NSOs in 2019, and determined that none of the units were necessary to support ERCOT transmission system reliability, therefore no new Reliability Must-Run (RMR) contracts were awarded in 2019.[49] However, review of the RMR and Must-Run Alternative (MRA) evaluation processes remained active throughout the 2019, culminating in the approval of several changes to ERCOT protocols discussed below. In addition, multiple other Nodal Protocols Revision Requests (NPRRs) regarding this topic remained pending at the end of 2019.

Two NPRRs were approved on June 11, 2019 (NPRR885 and NPRR896) that in tandem provide an appropriate Protocol framework for MRA evaluation, contracting, processes and settlement. NPRR885 proposed new Protocol language to address numerous issues related to the solicitation and operation of MRA service.[50] Taken in conjunction with NPRR885, NPRR896 outlines the process ERCOT will use to evaluate the cost-effectiveness of procuring RMR or MRA service.[51]

[49] 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.

[50] NPRR885, *Must-Run Alternative (MRA) Details and Revisions Resulting from PUCT Project No. 46369, Rulemaking Relating to Reliability Must-Run Service*

[51] NPRR896, *RMR and MRA Alternative Evaluation Process.*

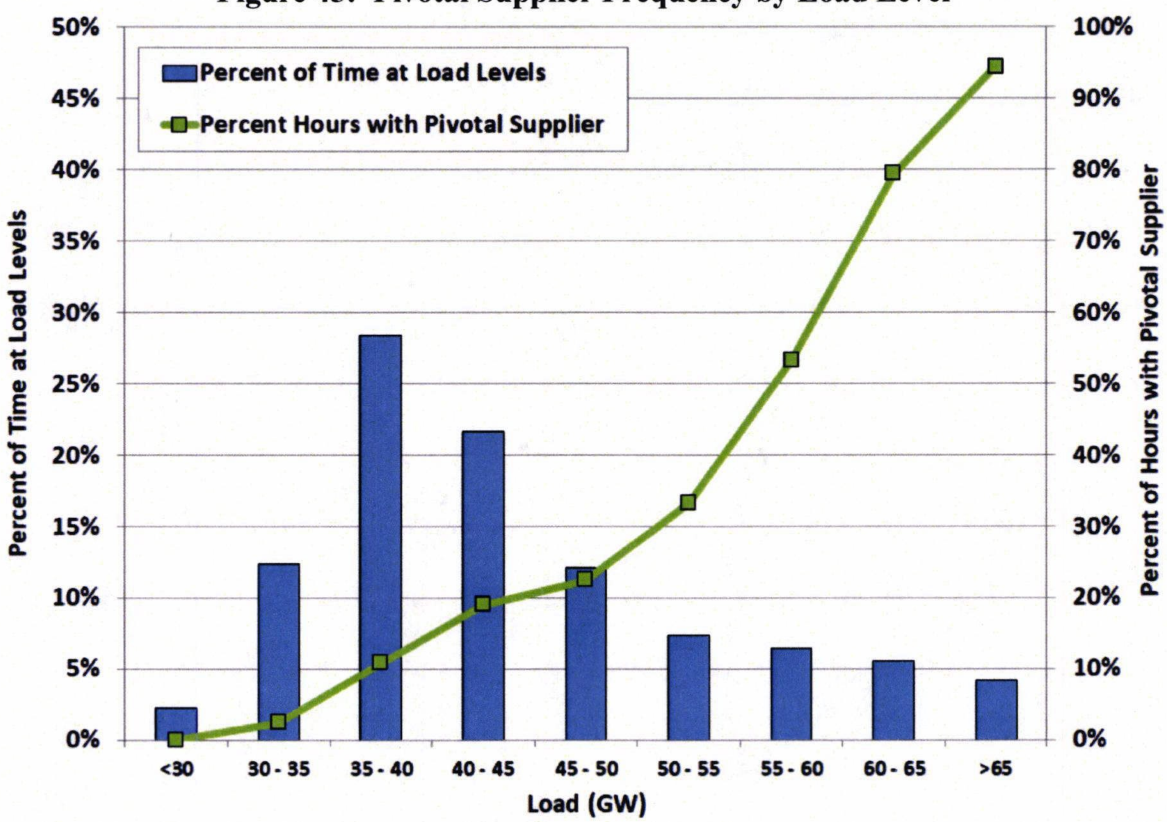
VII. Analysis of Competitive Performance

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 also includes a summary of the Voluntary Mitigation Plans in effect during 2019. Based on these analyses, we find that the ERCOT wholesale market performed competitively in 2019.

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 45 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 45: Pivotal Supplier Frequency by Load Level



[redacted]

At loads greater than 65 GW, there was a pivotal supplier approximately 94% of the time. This is expected because at high load levels the largest suppliers are more likely to be pivotal as other suppliers' resources are more fully utilized serving the load. Pivotal suppliers existed 24% of all hours in 2019, which was less frequent than in 2018 when pivotal suppliers existed in 30% of all hours. 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 analysis is presented in Figure A47 in the Appendix.

We cannot make inferences regarding market power solely from pivotal supplier data. 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. The pivotal supplier results shown in the previous figure does not consider the contractual position of the supplier, which can increase a supplier's incentive to exercise market power compared to the load-adjusted capacity assumption made in this analysis.

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 V, this local market power is addressed through: (a) structural tests that determine "non-competitive" constraints that can create local market power; and (b) the application of limits on offer prices in these areas.

B. Evaluation of Supplier Conduct

This subsection provides the results of our evaluation of actual participant 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. We then examine potential physical and 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 will generally be 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 only if the withholding firm's incremental profit as a result of higher price is greater than the lost profit from the foregone sales of its withheld capacity.

[redacted]

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 very 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 V above, summer availability has been increasing since 2017 in ERCOT because of the incentives provided by the recent increase in shortage pricing.

Figure 46 shows a breakdown of total installed capacity for ERCOT on a daily basis during 2019. 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 46: Reductions in Installed Capacity

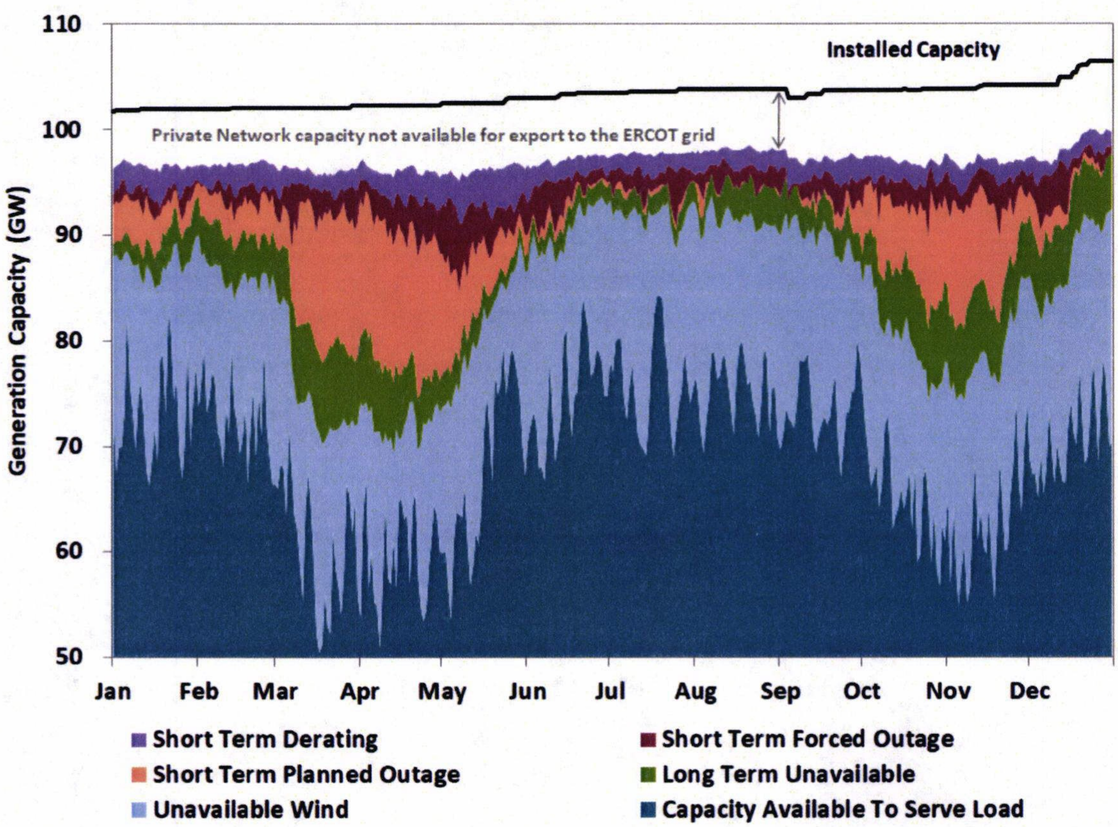


Figure 46 shows that short-term outages and deratings of non-wind generators fluctuated between two and 21 GW, while wind unavailability varied between four and 23 GW. Short-term planned outages were largest in the shoulder months of April and November, while smallest during the summer months, consistent with our expectations. Short-term forced outages and deratings had no discernable seasonal pattern, occurring throughout the year, also consistent with our expectations. The quantity of long-term (greater than 30 days) unavailable capacity, peaked in March at more than 8 GW, with almost all capacity returned to service in anticipation of tighter conditions during the summer of 2019.

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 47 provides a comparison of the monthly outage and derating values for 2018 and 2019.

Figure 47: Derating, Planned Outages and Forced Outages

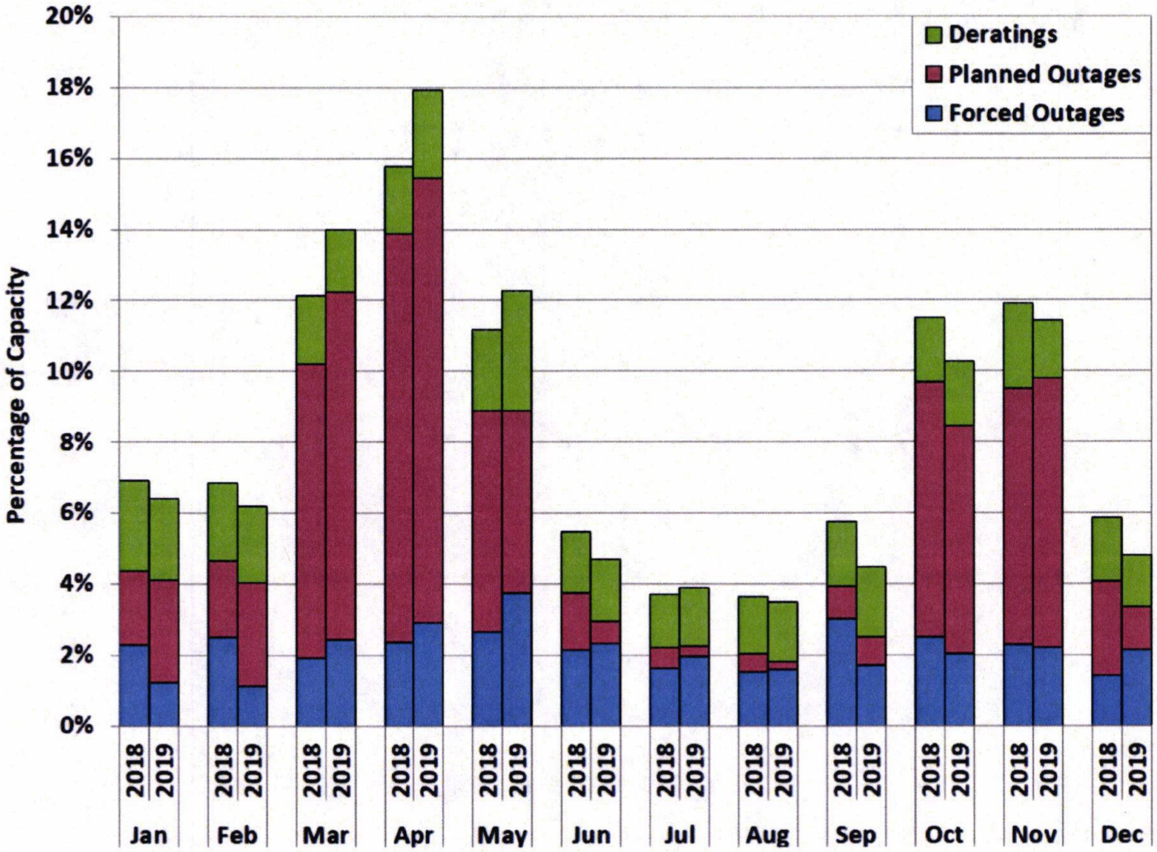


Figure 47 shows a general consistency of forced outages from last year, implying that expectations for 2019 were similar to those in 2018, and that generator operators were again able to defer the impacts of unexpected equipment limitations through September. However, those actions likely were at the cost of higher outage rates in October and November both years. The significant increase in planned outages scheduled during spring and fall in both years is an indicator of intense preparation for what was expected by many to be a summer with very tight operating conditions. The consistently small number of deratings across all months of 2019 indicates that generators were intent on maximizing generator availability. The low outage rates during August and the low level of derations overall may have been partly a result of increased planned maintenance activities. Overall, these results show that suppliers behaved competitively, maximizing availability in the highest load hours.

Figure A48 in the Appendix shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2019.

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 45 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 48 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 48: Outages and Deratings by Load Level and Participant Size, June-August

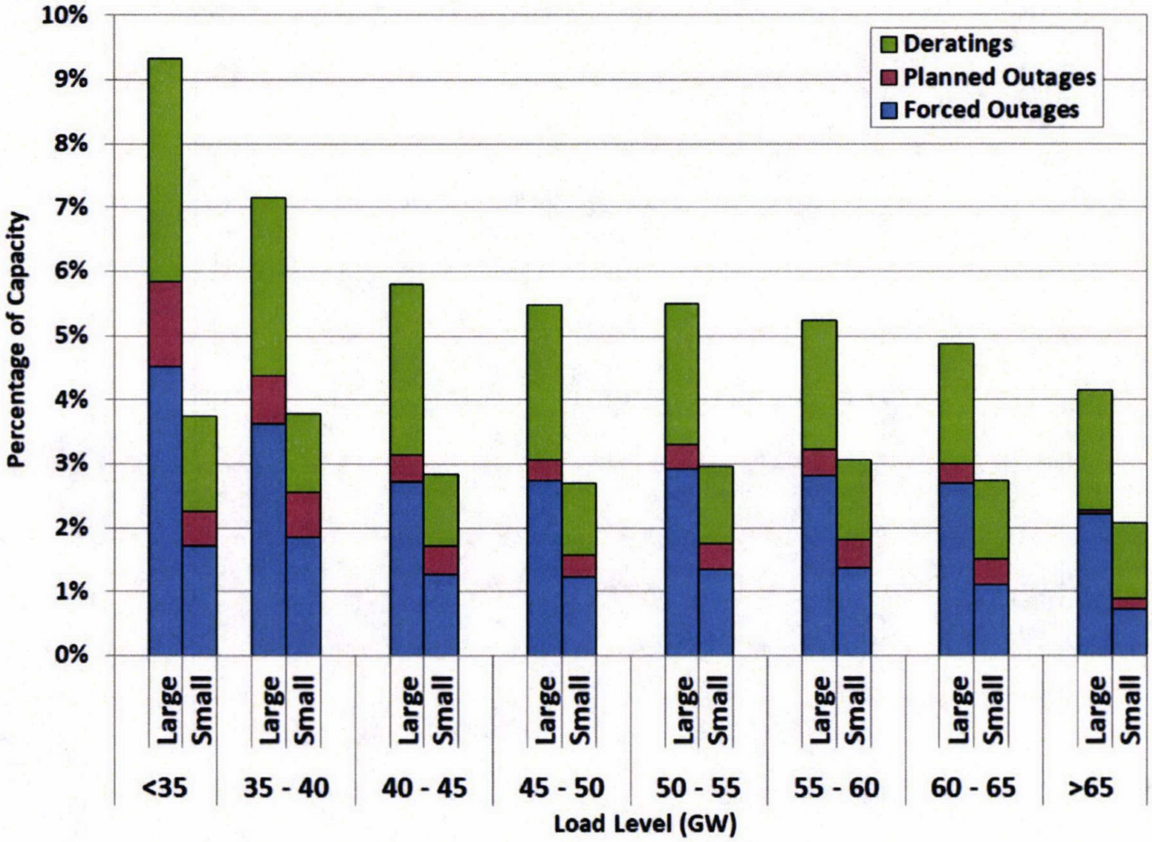


Figure 48 confirms the pattern we saw in 2018 that as demand for electricity increases, all market participants tend to make more capacity available to the market by scheduling planned outages during low load periods. Because small participants have less incentive to physically withhold capacity, the 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. Outages rates for small suppliers were historically low in 2019. 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.

3. Evaluation of Potential Economic Withholding

To complement the prior analysis of physical 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 $50 per MWh. The mitigated offer cap serves as a proxy for the marginal production cost of energy from that resource.

Figure 49: Incremental Output Gap by Load Level and Participant Size – Step 2

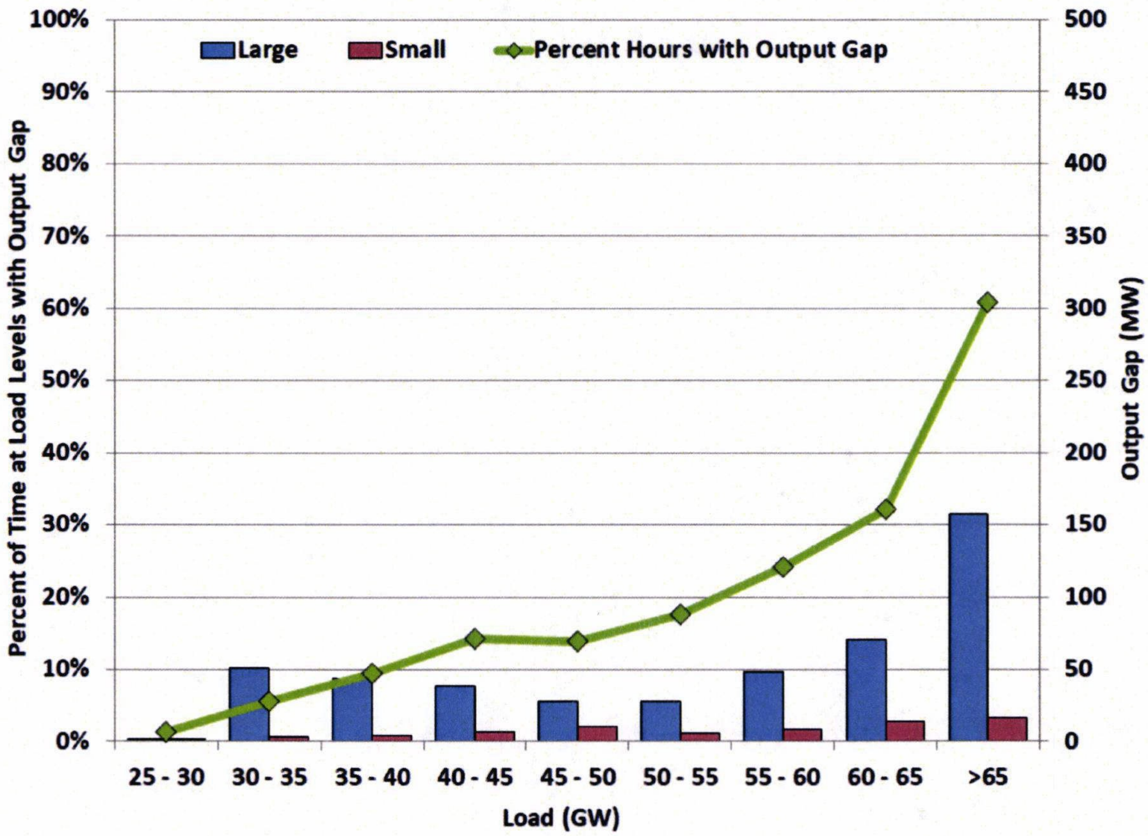


Figure 49 shows the average output gap levels, measured by the difference between a unit's operating level and the output level had the unit been competitively offered to the market. Relatively small quantities of capacity are considered part of this output gap, although 22% of the hours in 2019 exhibited an output gap. If the three entities that are under a VMP are removed from the analysis, the capacity and number of hours exhibiting output gaps are de minimis. Taken together, these results show that potential economic withholding levels were low in 2019, 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 2019.

Notwithstanding the findings above, the existence of some of these output gaps is the result of shortcomings in the mitigated offer caps. Specifically, the verifiable cost process that feeds most mitigated offer caps should allow for the pricing of:

- Opportunity costs that result from operating limitations that cause it to forego future output when it runs in the current hour;
- The costs of major maintenance; and
- Operating risks.

We recommend that ERCOT pursue these improvements to ensure that mitigation is reasonable and effective. See recommendation No. 7 above.

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. VMPs existed for three market participants at various times in 2019. By the end of 2019, Calpine, NRG and Luminant had active and approved VMPs. 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 day-ahead market) 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.

There were no changes to Calpine or NRG's VMPs in 2019, and details can be found in Section VII of the Appendix. Luminant received approval from the Commission for a new VMP in December 2019.[52] The Commission terminated Luminant's previous VMP on April 9, 2018, as a result of its merger with Dynegy, Inc.[53] The new VMP provides for small amounts of

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52 PUCT Docket No. 49858, 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)* (Dec. 13, 2019).

53 *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 PUCT Docket No. 44635, *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)*, Order Approving VMP Settlement (May 22, 2015).

capacity from non-quick start, non-combined cycle natural gas-fired units to be offered up to 12% of the dispatchable 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. These limits are defined by a simplified formula, which is expected to produce prices lower than what has historically been deemed allowable.

The final 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.[54] 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."[55] 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.

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 are typically given to resolve transmission constraints. Thus, units that receive RUC instructions are typically required to resolve a non-competitive transmission constraint, and therefore end up mitigated in real-time. As discussed previously in Section V, units that received a RUC instruction were frequently dispatched above their low sustained limits in 2018. This higher dispatch was most often the result of the RUC units being dispatched based on their mitigated offer to resolve non-competitive constraints, and mitigated offers are lower than the RUC offer floor of $1,500 per MWh.

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

54 Further, Luminant's VMP will terminate on the earlier of ERCOT's go-live date for real-time co-optimization or seven years after approval.

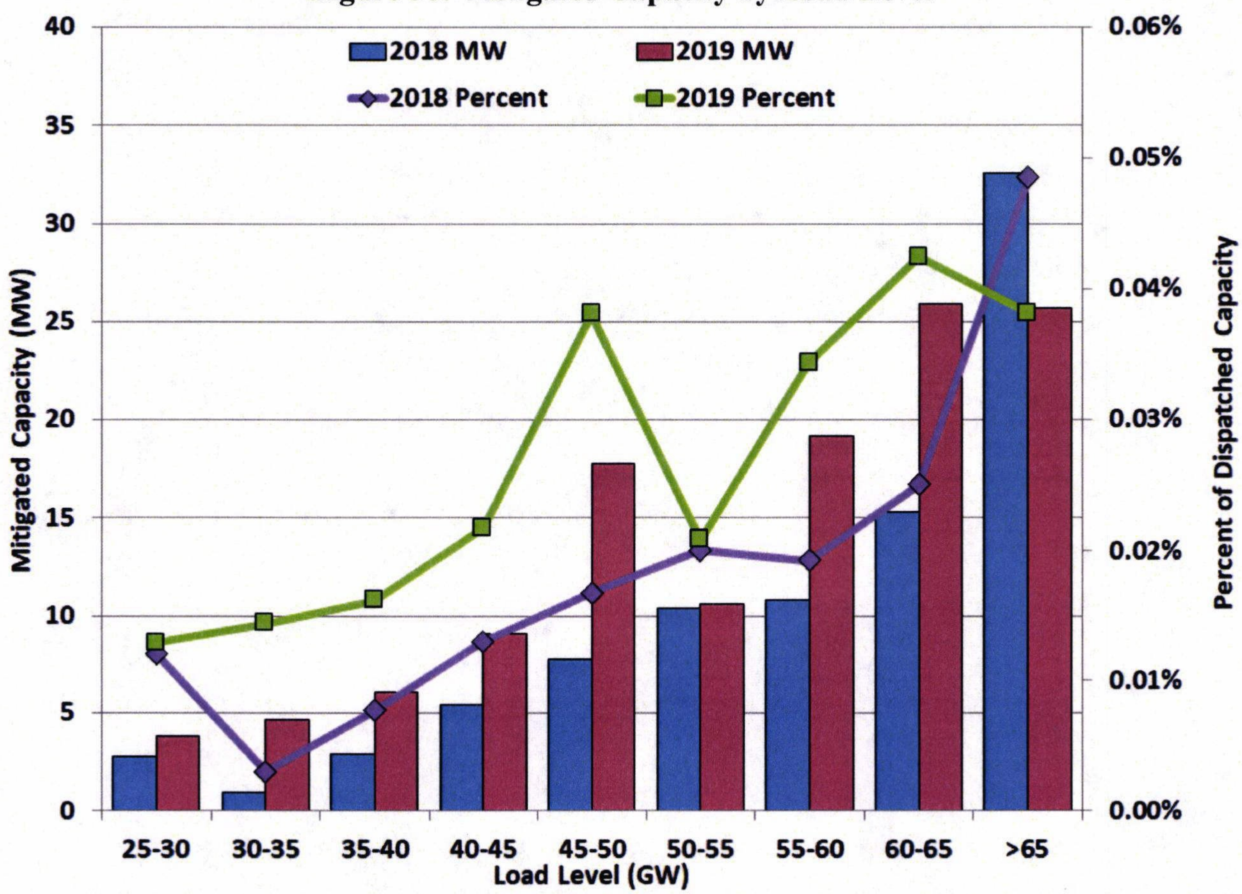
55 PURA § 39.157(a).

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 2019. Although executing at all times, 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.

The analysis shown in Figure 50 computes the percentage of capacity, on average, that is actually mitigated during each dispatch interval. The results are provided by load level.

Figure 50: Mitigated Capacity by Load Level



The amount of mitigation in 2019 was generally higher than in 2018. This is somewhat expected given the RUC instructions given to the combustion turbines in the Permian Basin, even with similar congestion costs between 2018 and 2019. If RUC instructions are necessary to resolve a local constraint, that constraint is more likely to be deemed noncompetitive, resulting in mitigation. Another factor for most of 2019 may be the separation in natural gas prices between the ERCOT Fuel Index Price and Waha fuel price indices.[56] To the extent some generator offers (and costs) were based on very low Waha gas prices, there would be no need to mitigate them based on Fuel Index Price prices. 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 V in the Appendix.

[56] 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*. his change is consistent with recent amendments to P.U.C. SUBST. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region, adopted by the Public Utility Commission of Texas (PUCT) in Project No. 48721, which give ERCOT 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).

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 2019. The year contained record peak demand and low reserve margins, culminating in significant shortage pricing. Our evaluation of a number of factors suggests that the market performed competitively in 2019. We recommend several corrections and improvements to continue the evolution of the market design.

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.

Key changes or improvements implemented in 2019 included:

- On February 8, 2019, ERCOT implemented SCR 794, Updated SCED Limit Calculation, which adjusted the methodology for converting Megavolt Ampere (MVA) limits for transmission elements into Megawatt (MW) limits that can be used by SCED. This improved the calculation in cases when the MW flow approached zero, when the previous methodology for MVA limit conversion was not as accurate.
- On March 1, 2019, the ORDC was changed to shift the Loss of Load Probability (LOLP) curve to the right in the positive direction by 0.25 standard deviations and to replace the seasonal and time-of-day blocks with a blended curve.
- On April 5, 2019, ERCOT implemented NPRR833, Modify PTP Obligation Bid Clearing Change, which modified pricing outcomes to be consistent with bid prices in cases where a contingency disconnects a source or sink Settlement Point.
- On April 5, 2019, ERCOT also implemented NPRR847, Exceptional Fuel Cost Included in the Mitigated Offer Cap, to allow Qualified Scheduling Entities (QSEs) to incorporate intraday weighted average fuel prices in mitigated offers to accommodate high fuel price events.
- Regarding improvements to the RMR process, on April 5, 2019, ERCOT implemented NPRR845, making a number of changes to the RMR agreement and settlement.
- On April 10, 2019, ERCOT lowered the mitigated offer floor for natural gas resources to \$0/MWh, due to the very low-to-negative fuel costs in West Texas (NPRR916, Mitigated Offer Floor Revisions). On May 31, 2019, ERCOT lowered it further to (-\$20)/MWh.
- On May 31, 2019, ERCOT implemented NPRR901, Switchable Generation Resource Status Code, which created a separate status code of Switchable Generation Resources (SWGRs) operating in a non-ERCOT Control Area. In addition, a new settlement mechanism was added to address RUC instructions to these SWGRs (NPRR912).
- On May 31, 2019, ERCOT also implemented new logic to prevent the triggering of the Real-Time Reliability Deployment Price Adder and the application of a RUC offer floor when a RUC Resource has previously been awarded a Three-Part Supply offer (NPRR910).

- On July 1, 2019, NPRR821, Elimination of the Congestion Revenue Right (CRR) Deration Process for Resource Node to Hub or Load Zone CRRs, was made effective, leaving only CRRs that sink at Resource Nodes to remain subject to deration when paths are oversold.
- On August 9, 2019, ERCOT implemented restrictions on financial transactions in the Day-Ahead Market at certain Private Use Network settlement points, eliminating a source of RENA uplift (SCR796).
- On December 12, 2019, ERCOT switched the Fuel Index Price to use Katy Hub rather than Houston Ship Channel as the delivery point, due to its superior liquidity (NPRR952).
- On December 16, 2019, NPRR920, Change to Ramp Rate Calculation in Resource Limit Calculator, was implemented to dynamically adjust the amount of ramp rate reserved for Regulation Service in real-time to optimize ramp sharing between Regulation and SCED.

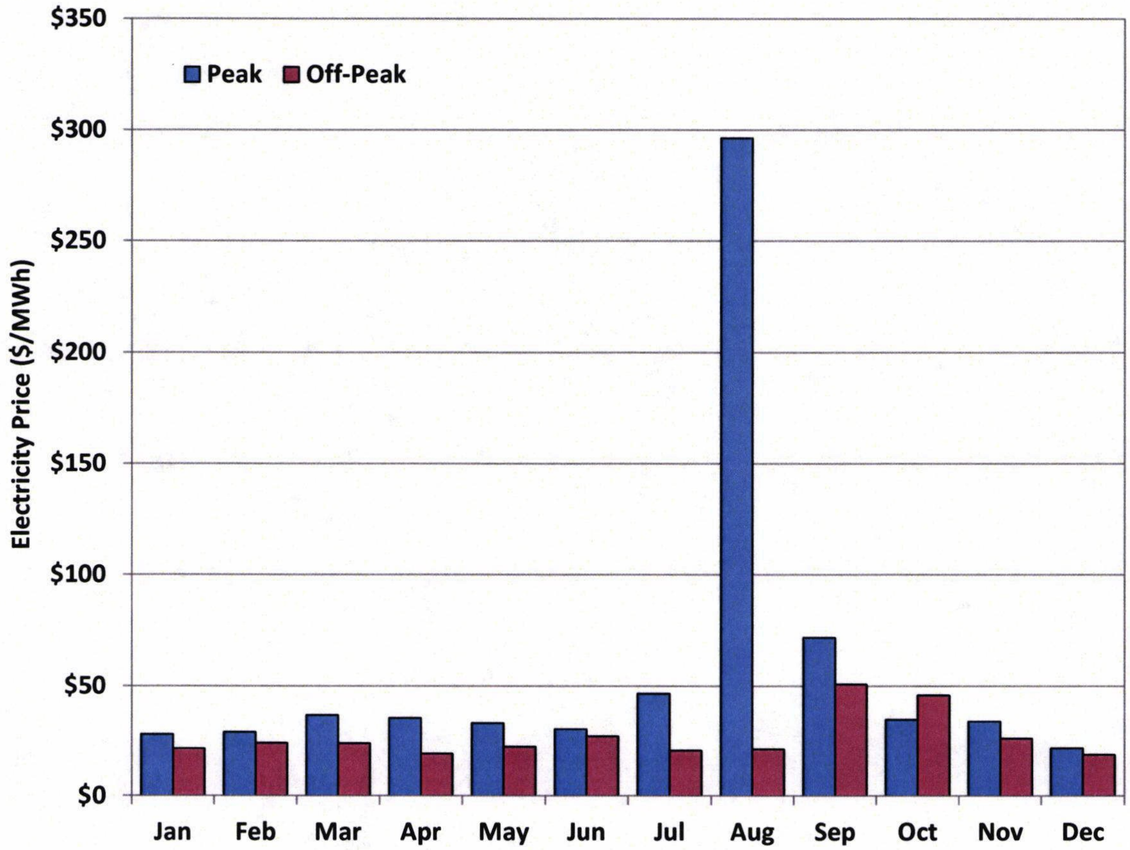
I. APPENDIX: REVIEW OF REAL-TIME MARKET OUTCOMES

In this section of the Appendix, we provide supplemental analyses of the prices and outcomes in ERCOT's real-time energy market.

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 2019. 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



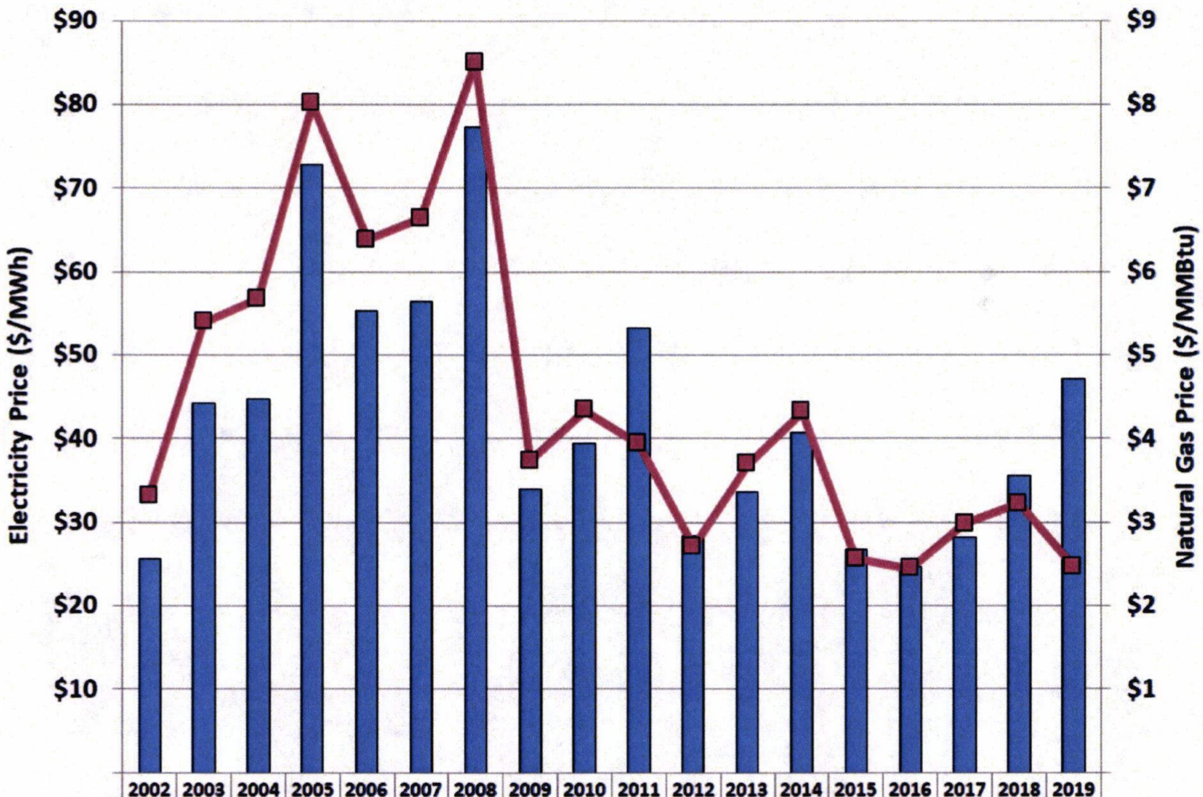
As expected, Peak hours were higher priced than Off-Peak hours for every month in 2019, with the exception of October, when Off-Peak hour prices were $10.96 per MWh higher than peak hour prices, due to transmission emergency conditions in the far side of the West zone during planned outages in the evening. For all other months, the difference ranged from a minimum of $3.14 per MWh in December to a maximum of $275.00 per MWh in August. The difference in

August was due primarily to shortage conditions and the resulting high prices (multiple intervals at the high system-wide offer cap (HCAP) of $9,000 per MWh) seen during peak hours in the week of August 12th. Excluding the effects of those intervals reduces the difference to $26.55. The average difference between monthly Peak and Off-Peak pricing was $13.63 per MWh.

B. Zonal Average Energy Prices in 2019

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 2019.

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

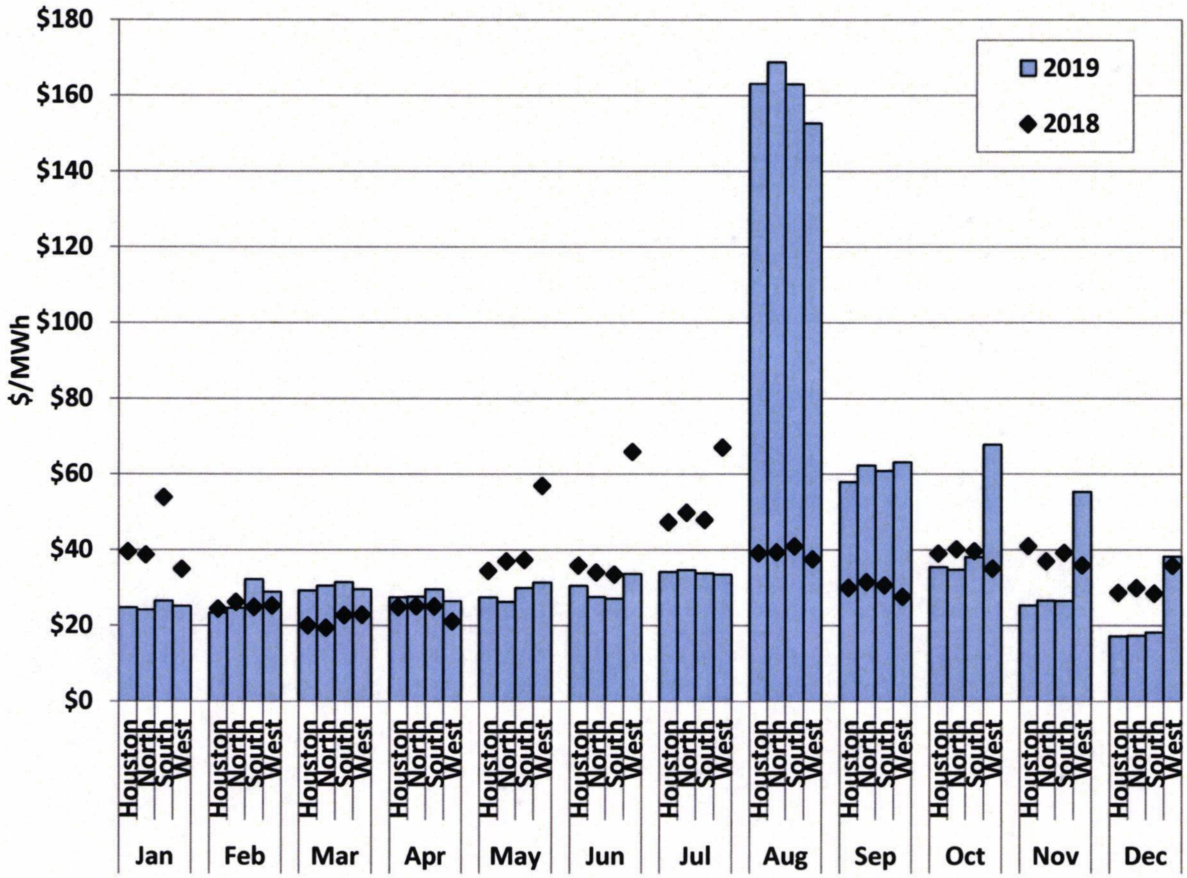


	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ERCOT	25.64	44.26	44.64	72.79	55.22	56.35	77.19	34.03	39.40	53.23	28.33	33.71	40.64	26.77	24.62	28.25	35.63	47.06
Gas	3.32	5.40	5.68	8.01	6.38	6.64	8.50	3.74	4.34	3.94	2.71	3.70	4.32	2.57	2.45	2.98	3.22	2.47

Like Figure 1 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. However, in 2011 and 2019 the trends diverge; in both those years there was significant shortage pricing; that is, the cost of electricity reflected both the cost of production and shortage conditions. This outcome is expected in years with low reserve margins or extreme weather.

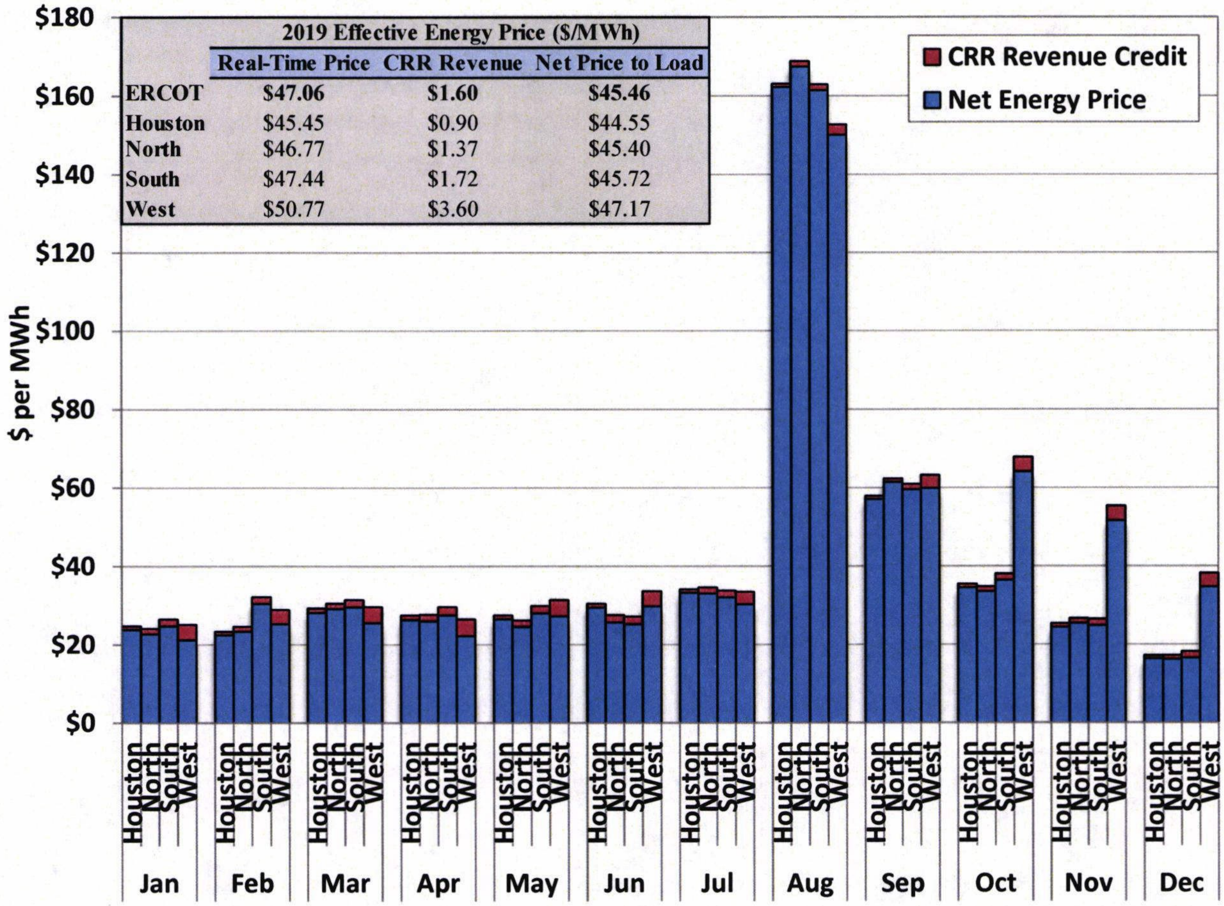
Figure A3 shows the monthly load-weighted average prices in the four geographic ERCOT zones during 2018 and 2019. These prices are calculated by weighting the real-time energy price for each interval and each zone by the total load in that interval. Load-weighted average prices are most representative 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.

Figure A3: Average Real-Time Energy Market Prices by Zone



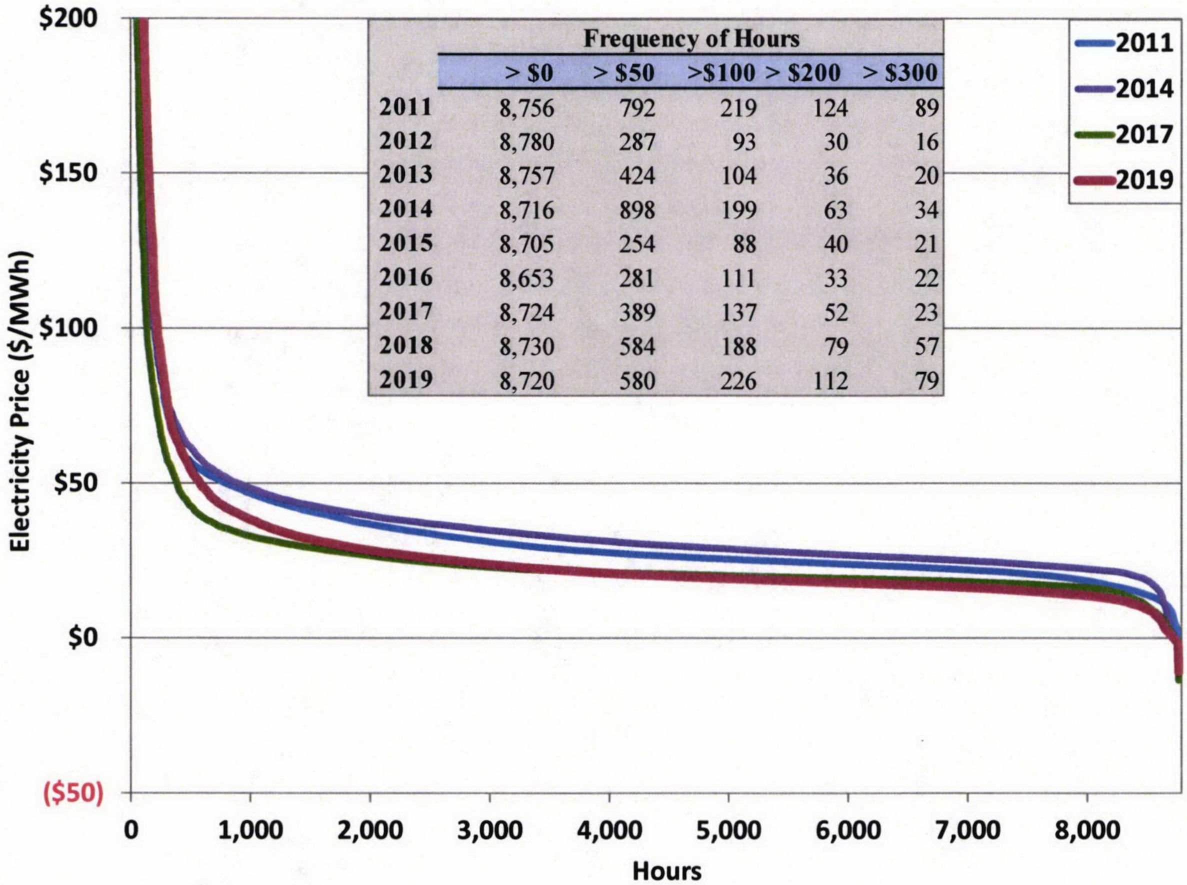
Another factor influencing zonal price differences is CRR auction revenue distributions. These are allocated to Qualified Scheduling Entities (QSEs) representing load, based on both zonal and ERCOT-wide monthly load-ratio shares. The CRR auction revenues have the effect of reducing the total cost to serve load borne by a QSE. Figure A4 shows the effect that this reduction has on a monthly basis, by zone.

Figure A4: Effective Real-Time Energy Market Prices



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 A shows price duration curves for the ERCOT energy market for 2017 and 2019, and includes 2011 and 2014 for historical context, because those years show the second and third most shortage pricing hours (2019 is the first) since the nodal market implementation. The prices in this figure are the hourly ERCOT average prices derived by load weighting the zonal settlement point prices.

Figure A5: ERCOT Price Duration Curve

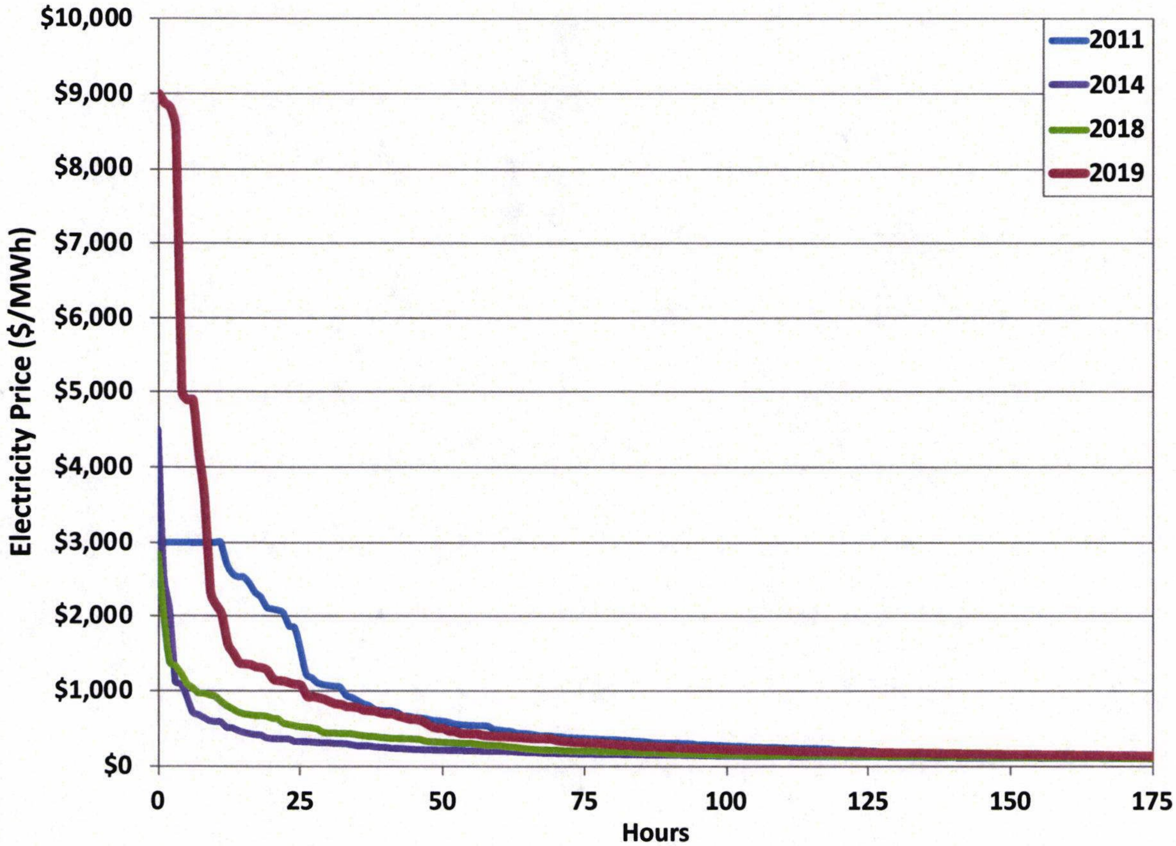


	> $0	> $50	>$100	> $200	> $300
2011	8,756	792	219	124	89
2012	8,780	287	93	30	16
2013	8,757	424	104	36	20
2014	8,716	898	199	63	34
2015	8,705	254	88	40	21
2016	8,653	281	111	33	22
2017	8,724	389	137	52	23
2018	8,730	584	188	79	57
2019	8,720	580	226	112	79

Negative ERCOT-wide prices may occur when wind is the marginal generation. More installed wind generation and additional transmission infrastructure has led to increased occurrences of negative prices over the past few years, reaching a high of 131 hours in 2016. That trend reversed in 2017, when there were 36 hours with ERCOT-wide prices at or below zero. In 2019, there were 40 hours with ERCOT-wide prices at or below zero, an increase from the 30 hours in 2018.

Figure A6 compares prices for the highest-priced 2% of hours in 2018 with 2019. Years 2014 and 2011 are also included for historical context. Energy prices for the highest 100 hours of 2019 were significantly higher than even those in 2011, the previous peak year. The higher prices in 2019 illustrate the effects of the changes to the shortage pricing mechanism over the past decade, most importantly the increase of the System Wide Offer Cap (SWOC) to $9000/MWh, the implementation of the Operating Reserve Demand Curve and subsequent changes to its parameters, and the implementation of the Reliability Deployment Adder.

Figure A6: 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 A7 and Figure A8 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 A7: Implied Heat Rate Duration Curve – All Hours

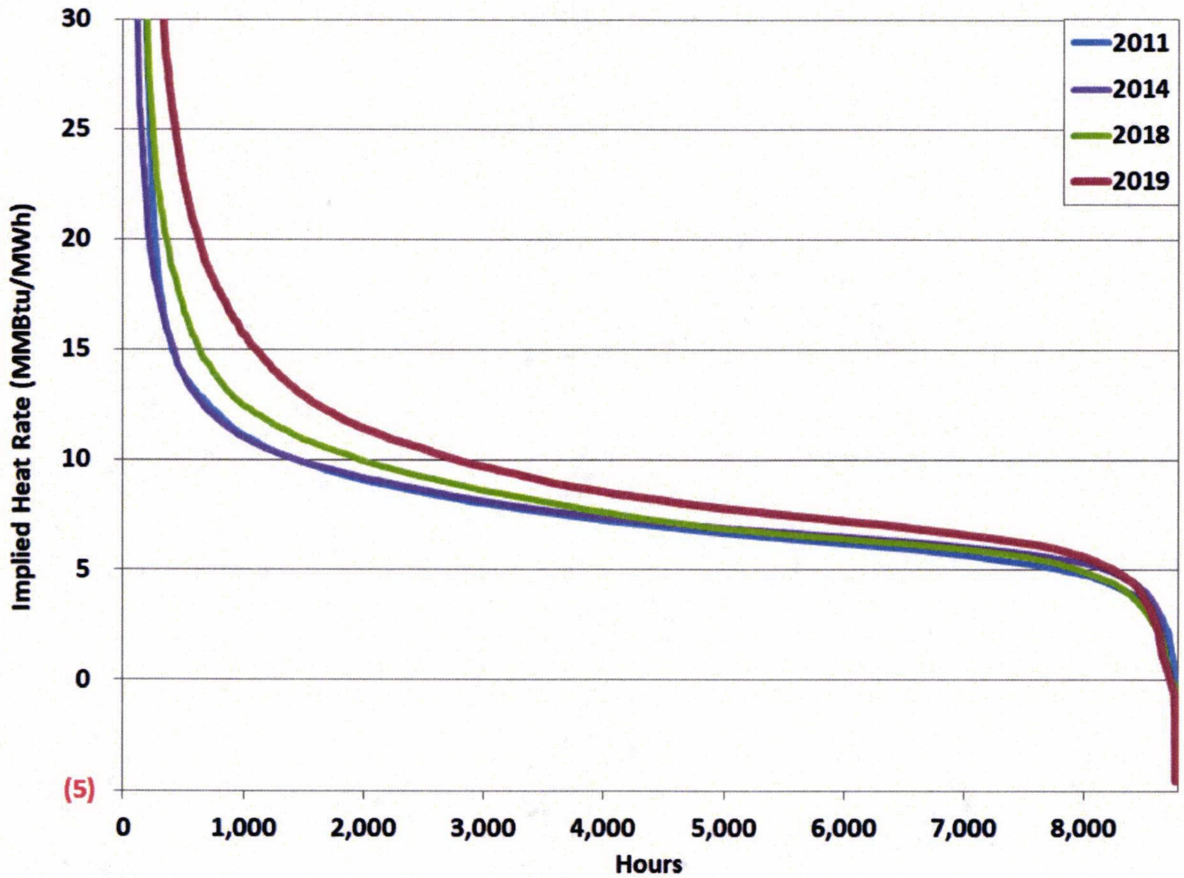


Figure A8 shows the implied marginal heat rates for the top 2% of hours in 2018 and 2019, with years 2014 and 2011 included for historical context. The implied heat rate duration curve for the top 2% of hours in 2019 was higher than 2018 because of the significant increased contribution of shortage pricing. Because of the increased contribution from shortage pricing in 2019, the implied heat rates in 2019 rose above even the levels seen in 2011, a year with extreme and record-breaking heat and drought.

Figure A8: Implied Heat Rate Duration Curve – Top 2% of Hours

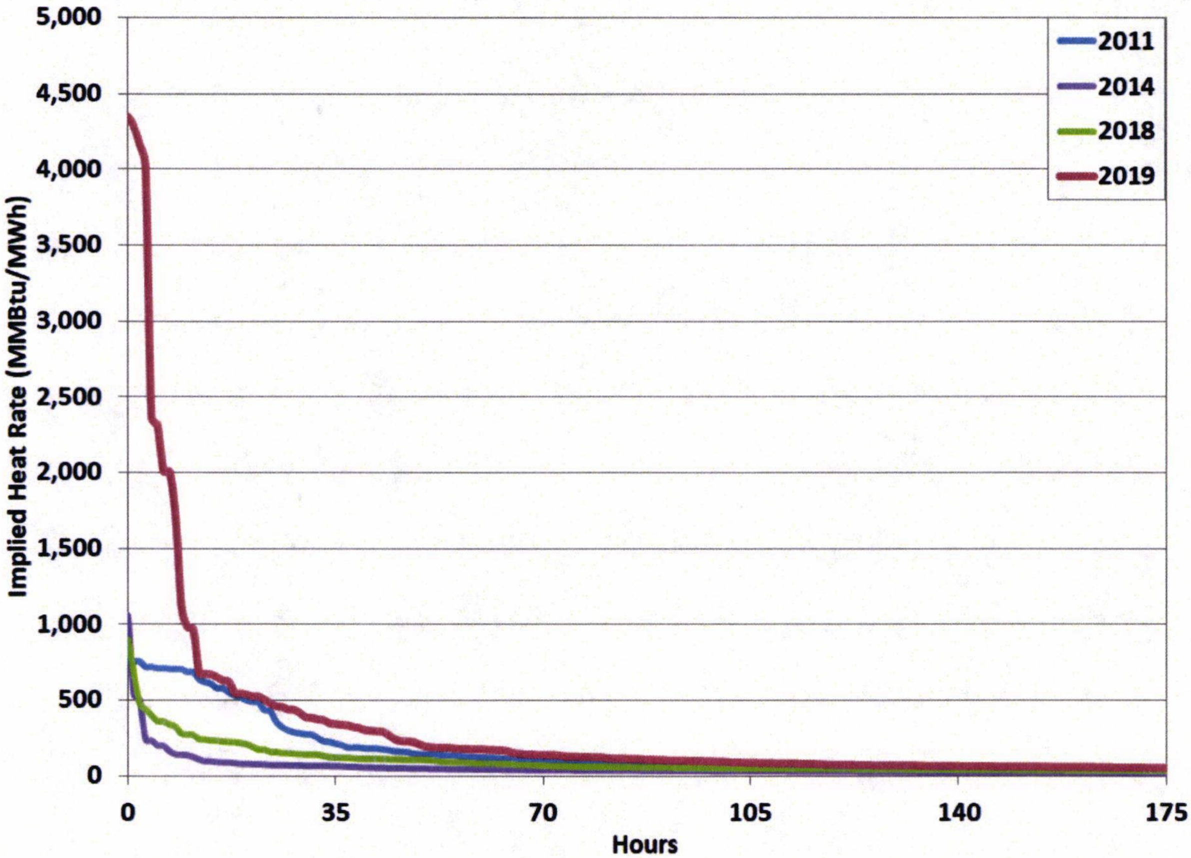


Table A1 displays the annual average implied heat rates by zone for 2011 through 2019. Adjusting for natural gas price influence, Figure A8 shows that the annual, system-wide average implied heat rate increased significantly in 2019 compared to 2018. Further, zonal implied heat rates in 2019 were the highest experienced in the nodal market, higher even than 2011.[57] Zonal variations in the implied heat rate were greater in 2017 because of the increased influence of transmission congestion. The zonal variations in 2018 and 2019 were not as pronounced.

57 The implied heat rate for the West zone was highest in 2012 due to extreme transmission congestion.

Table A1: Average Implied Heat Rates by Zone

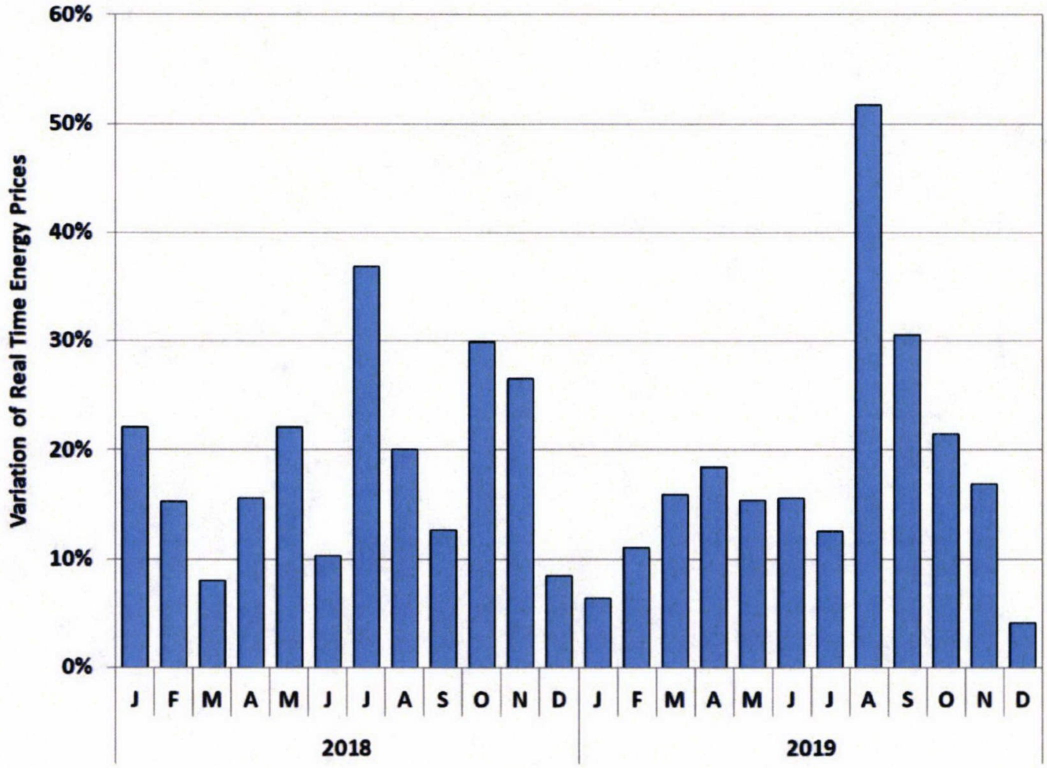
(MMBtu/MWh)	2011	2012	2013	2014	2015	2016	2017	2018	2019
ERCOT	**13.5**	**10.5**	**9.1**	**9.4**	**10.4**	**10.1**	**9.5**	**11.1**	**19.0**
Houston	13.3	10.0	9.1	9.2	10.5	10.8	10.7	10.7	18.4
North	13.7	10.2	8.9	9.3	10.2	9.7	8.6	10.9	18.9
South	13.8	10.2	9.2	9.6	10.6	10.1	9.9	11.2	19.2
West	11.9	14.1	10.3	10.1	10.4	9.0	8.2	12.3	20.5
($/MMBtu)									
Natural Gas	$3.94	$2.71	$3.70	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47

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.

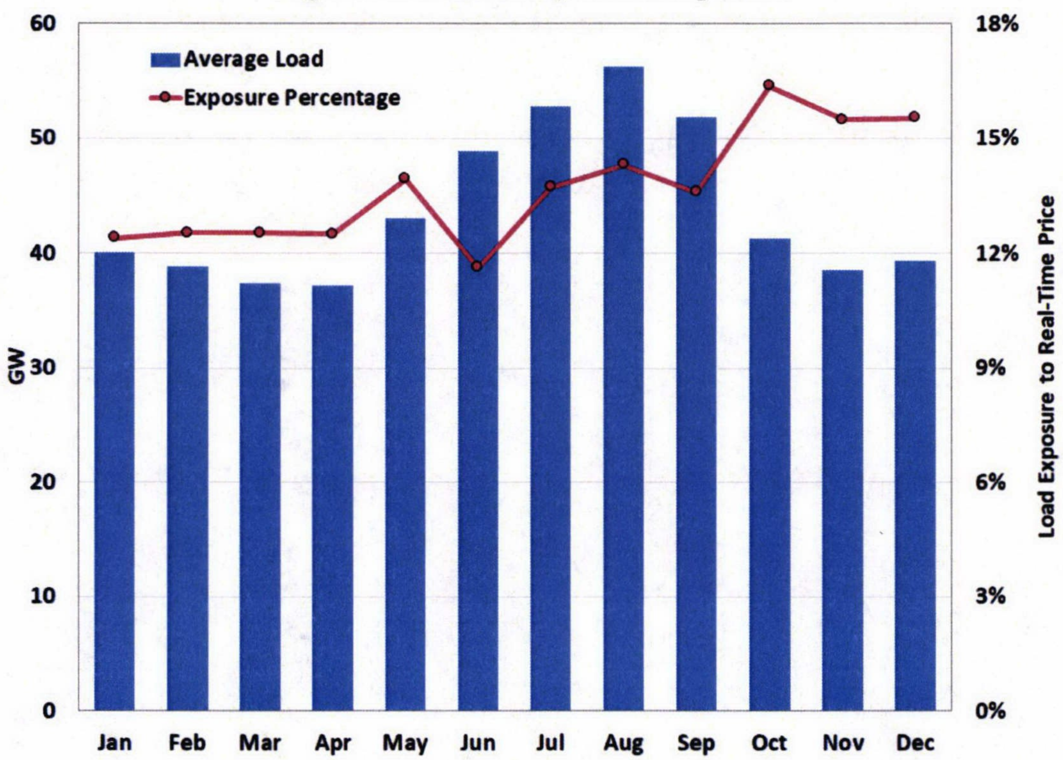
Expressed as a percentage of average price, the average absolute value of changes in five-minute real-time energy prices during the months of May through August was 6.4% in both 2018 and 2019. Expanding the view of price volatility, Figure A9 below shows monthly average changes in five-minute real-time prices by month for 2018 and 2019. As expected, the highest price variability occurred during August when occurrences of shortage pricing were most frequent in 2019.

Figure A9: Monthly Price Variation



Finally, Figure A10 below shows the percentage of load exposed to real-time energy prices.

Figure A10: 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. While the smallest portion of load potentially exposed to real-time prices was lowest in June, that portion rose again during the high-load summer months of July, August, and September, when even hedged loads were more vulnerable to the shortage conditions and high prices (multiple intervals at the high system-wide offer cap (HCAP) of $9,000 per MWh) seen during those months. 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.

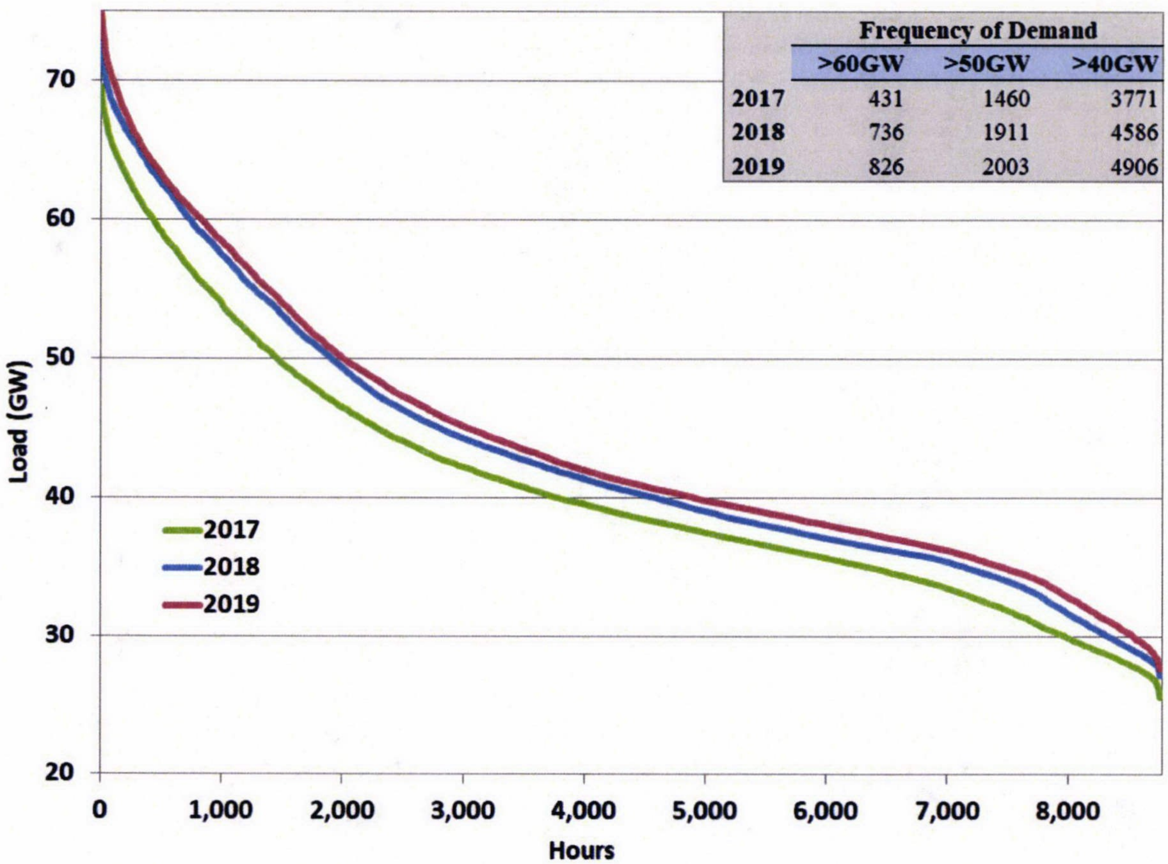
II. Appendix: Demand and Supply in ERCOT

In this section, we provide supplemental analyses of load patterns during 2019 and the existing generating capacity available to satisfy the load and operating reserve requirements.

A. ERCOT Load in 2019

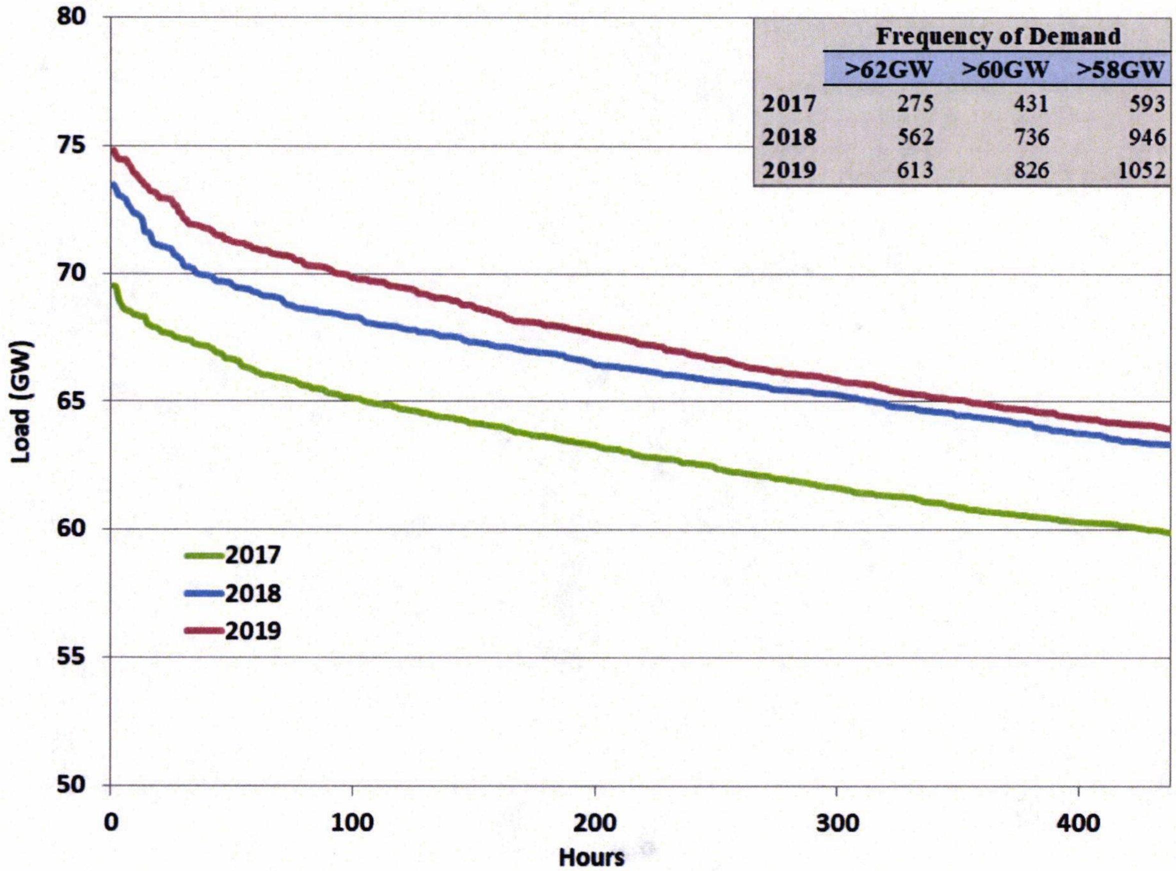
To provide a more detailed analysis of load at the hourly level, Figure A11 compares load duration curves for each year from 2017 through 2019. A load duration curve illustrates the number of hours (shown on the horizontal axis) that load exceeds a particular level (shown on the vertical axis). ERCOT 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 2019 was similar to 2018 and 2017, though slightly higher as load continues to increase in ERCOT.

Figure A11: Load Duration Curve – All Hours



To better illustrate the differences in the highest-demand periods between years, Figure A12 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 16% to 19% greater than the load at the 95th percentile. These load characteristics imply that a substantial amount of capacity – more than 10 GW – is needed to supply energy in less than 5% of the hours.

Figure A12: Load Duration Curve – Top 5% of Hours with Highest Load



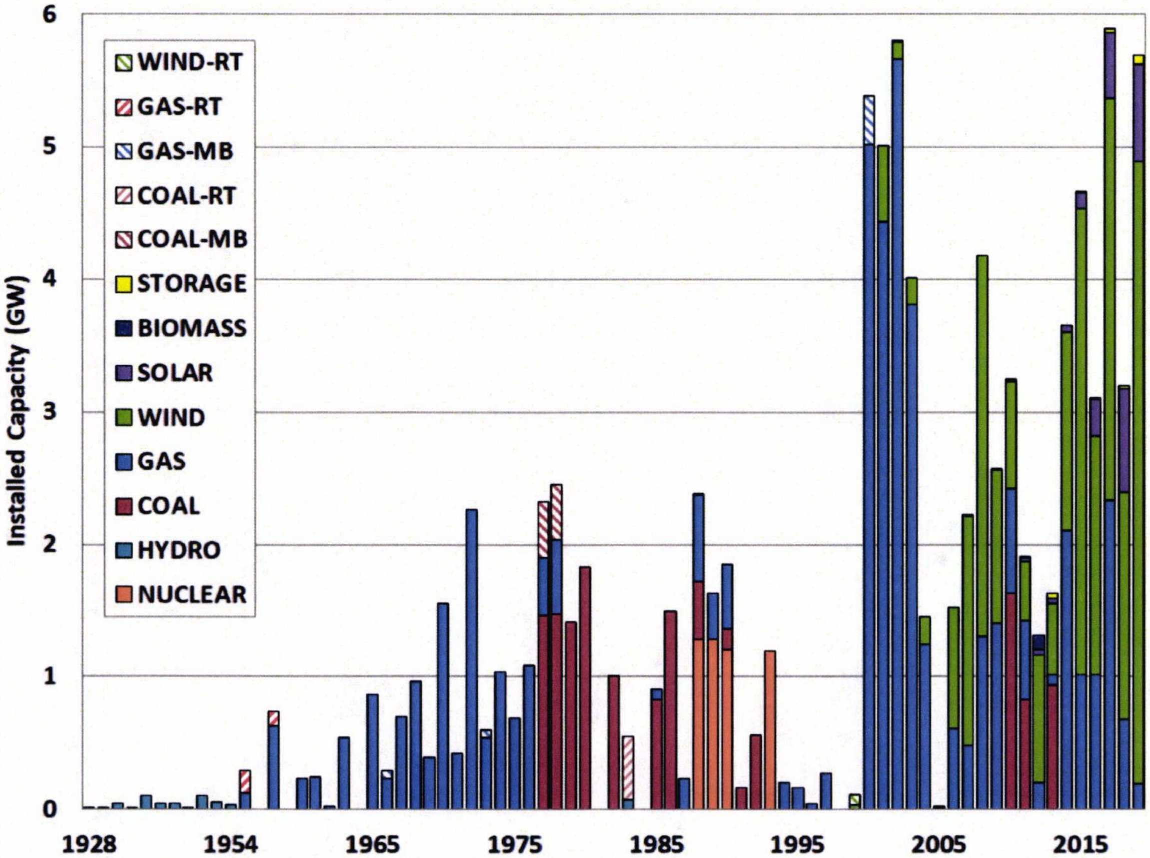
B. Generation Capacity in ERCOT

The generation mix in ERCOT is evaluated in this subsection.

Figure A13 shows the vintage of generation resources in ERCOT shown as operational in the December 2019 Capacity, Demand, and Reserves (CDR) report[58] and also includes resources that came online but were not yet commercial. The evaluation excludes Private Use Network capacity contributions to the CDR. Seventy percent of the total coal capacity in ERCOT was at least thirty years old in 2019. Combined cycle gas capacity had been the predominant addition for years; however, wind has been the primary technology for new capacity since 2006.

58 ERCOT Capacity, Demand, and Reserves Report (Dec. 5, 2019), available at http://www.ercot.com/content/wcm/lists/167023/CapacityDemandandReserveReport-Dec2019.xlsx.

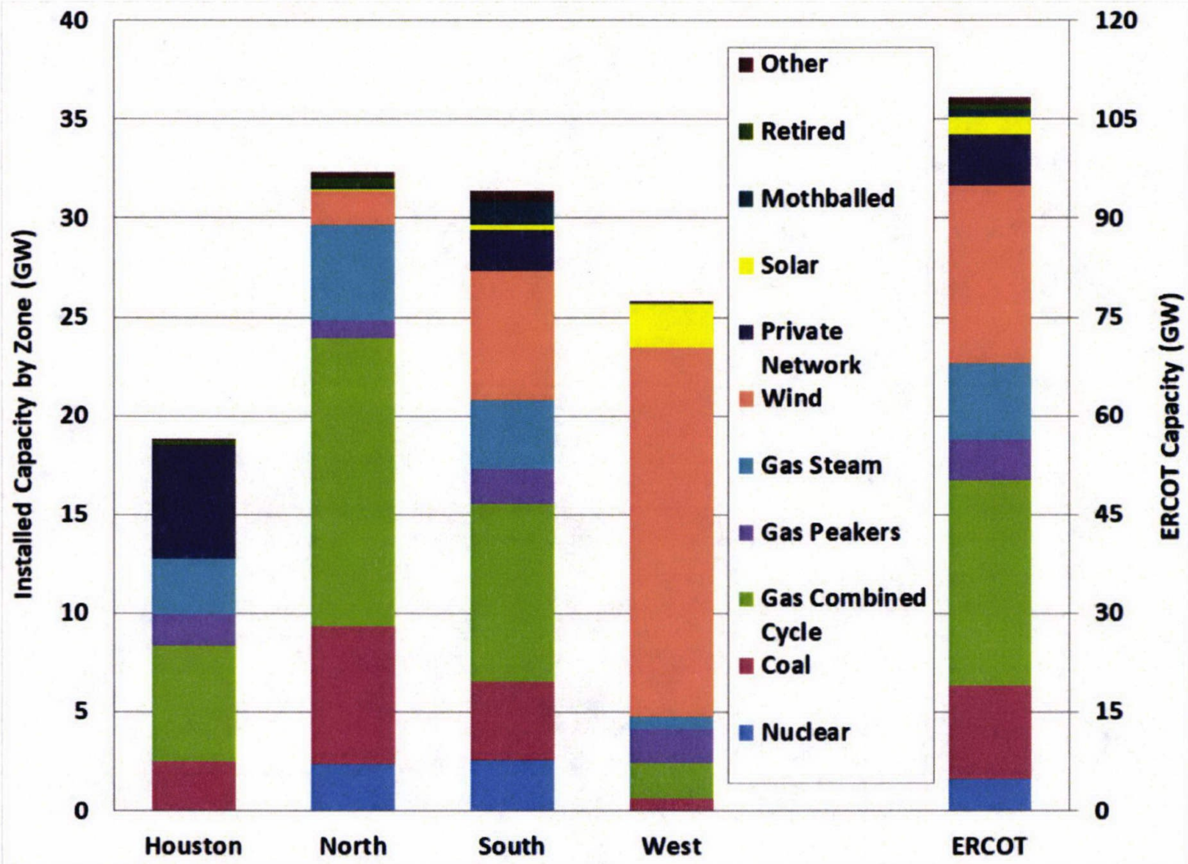
Figure A13: Vintage of ERCOT Installed Capacity



When excluding mothballed resources and including only the fraction of wind capacity available to reliably meet peak demand, the distribution of capacity among the four ERCOT geographic zones in 2019 is similar to the distribution of demand in those same zones, with the exception of the Houston zone.[59] Based on that metric, the North zone accounted for approximately 35% of capacity, the South zone 31%, the Houston zone 22%, and the West zone 12% in 2019. The installed generating capacity by type in each zone is shown in Figure A14.

59 The percentages of installed capacity to serve peak demand assume availability of 29% for panhandle wind, 63% for coastal wind, 16% for other wind, and 76% for solar.

Figure A14: Installed Capacity by Technology for Each Zone



Approximately 4.9 GW of new generation resources came online in 2019, the bulk of which were wind resources with total capacity of 4.7 GW.

On May 23, 2019, ERCOT received a Notification of Suspension of Operations (NSO) for West Texas Wind Energy Partners, LP's Southwest Mesa (SW_MESA_SW_MESA) Generation Resource. The NSO indicated that the Resource Entity would decommission and retire the resource permanently on November 15, 2019. The NSO further indicated that Southwest Mesa (SW_MESA_SW_MESA) has a summer Seasonal Net Max Sustainable Rating of 80 MW, and a summer Seasonal Net Minimum Sustainable Rating of 0 MW.

On June 28, 2019, ERCOT received a Notification of Change of Generation Resource Designation (NCGRD) for the City of Garland's Gibbons Creek Generating Station (GIBCRK_GIB_CRG1) indicating the resource would be decommissioned and retired permanently as of October 23, 2019. Gibbons Creek is a 470 MW coal unit located in Grimes County (20 miles southeast of College Station) and owned by the Texas Municipal Power Agency (TMPA), which is an organization jointly owned by four municipalities: the cities of Garland, Denton, Bryan and Greenville.

C. Wind 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 A15 shows average wind production for each month in 2018 and 2019, with the average production in each month divided into four-hour blocks. Though the lowest wind output generally occurs during summer afternoons, the average wind output during summer peak period increased to 5.5 GW, due to increases in the amount 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 wind generation is a significant contributor to generation supply, even at its lowest outputs.

Figure A15: Average Wind Production

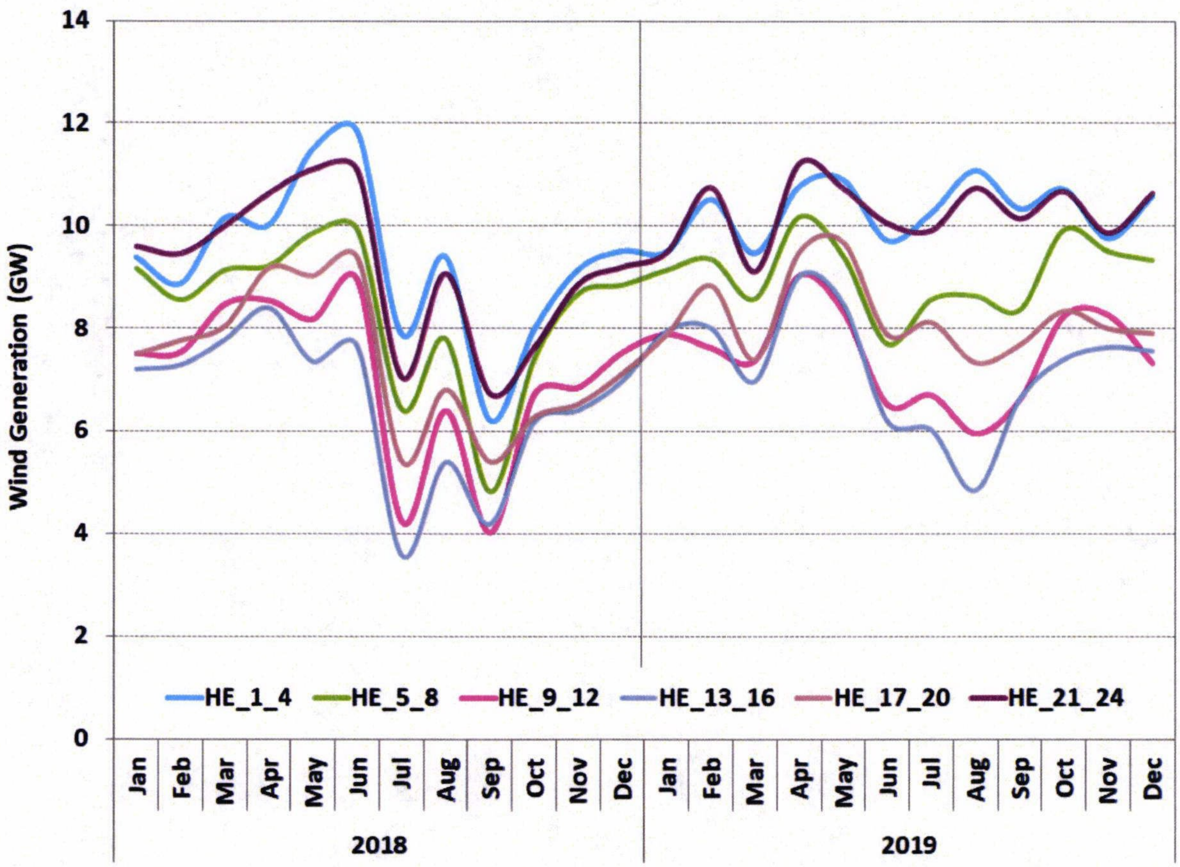
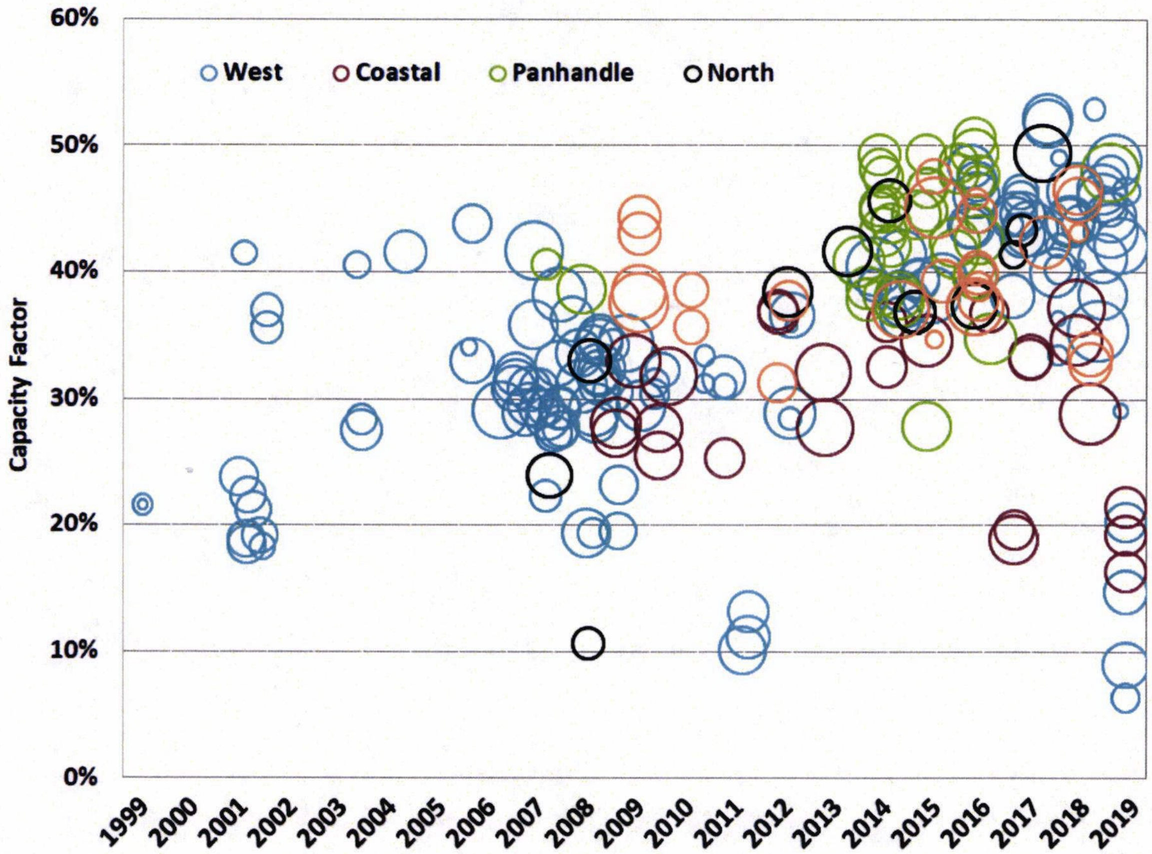


Figure A16 shows the capacity factor (the ratio of actual energy produced by an energy generating unit or system in a given period, to the hypothetical maximum possible, i.e. energy produced from continuous operation at full rated power) and relative size for wind generators by year installed. The chart also distinguishes wind generation units by location because of the different wind profiles for each. Transmission maintenance for some 345 kV transmission lines had the effect of limiting output from some of the resources in the Panhandle, reducing their capacity factors.

Figure A16: 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 average wind speed in ERCOT, as weighted by the locations of current installed wind generation. Figure A17 provides a means to compare wind speeds on an annual basis and indicates that the average wind speed in 2019 increased slightly from 2018 and was higher than the average over the past 10 years.

Figure A17: Historic Average Wind Speed

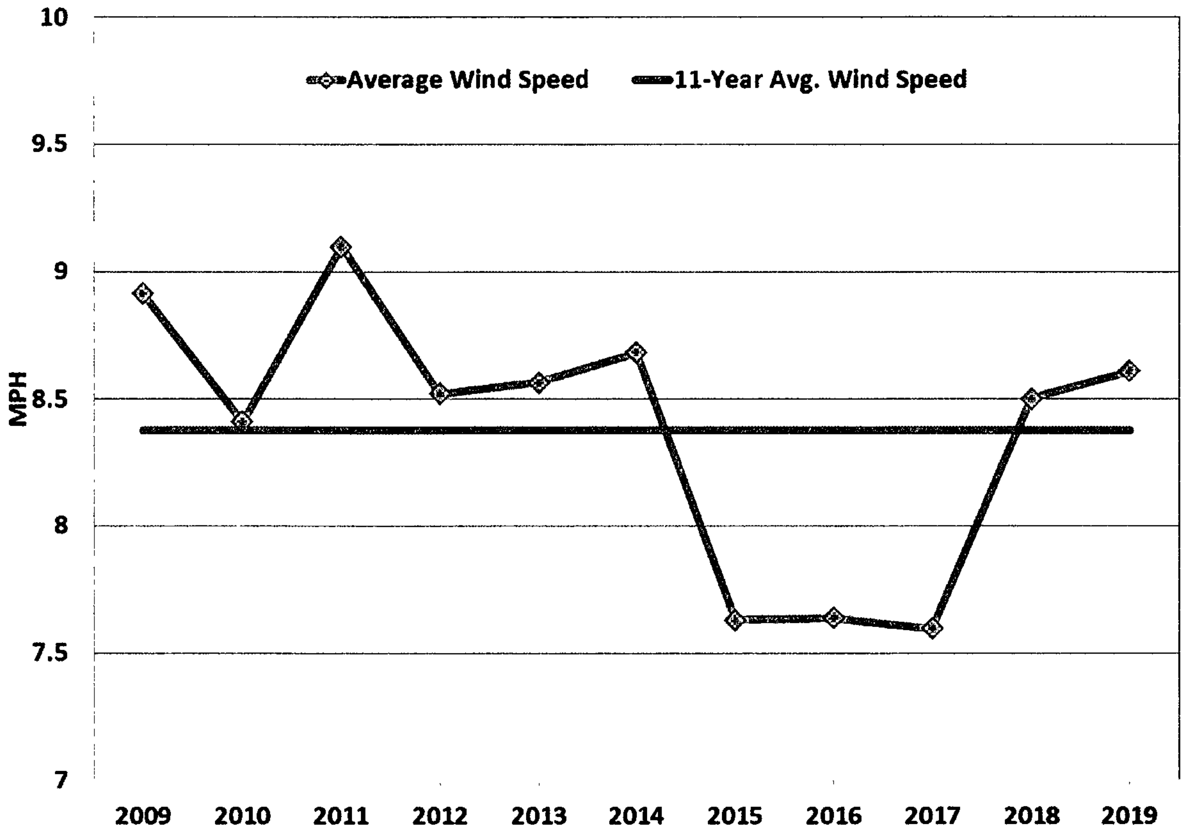
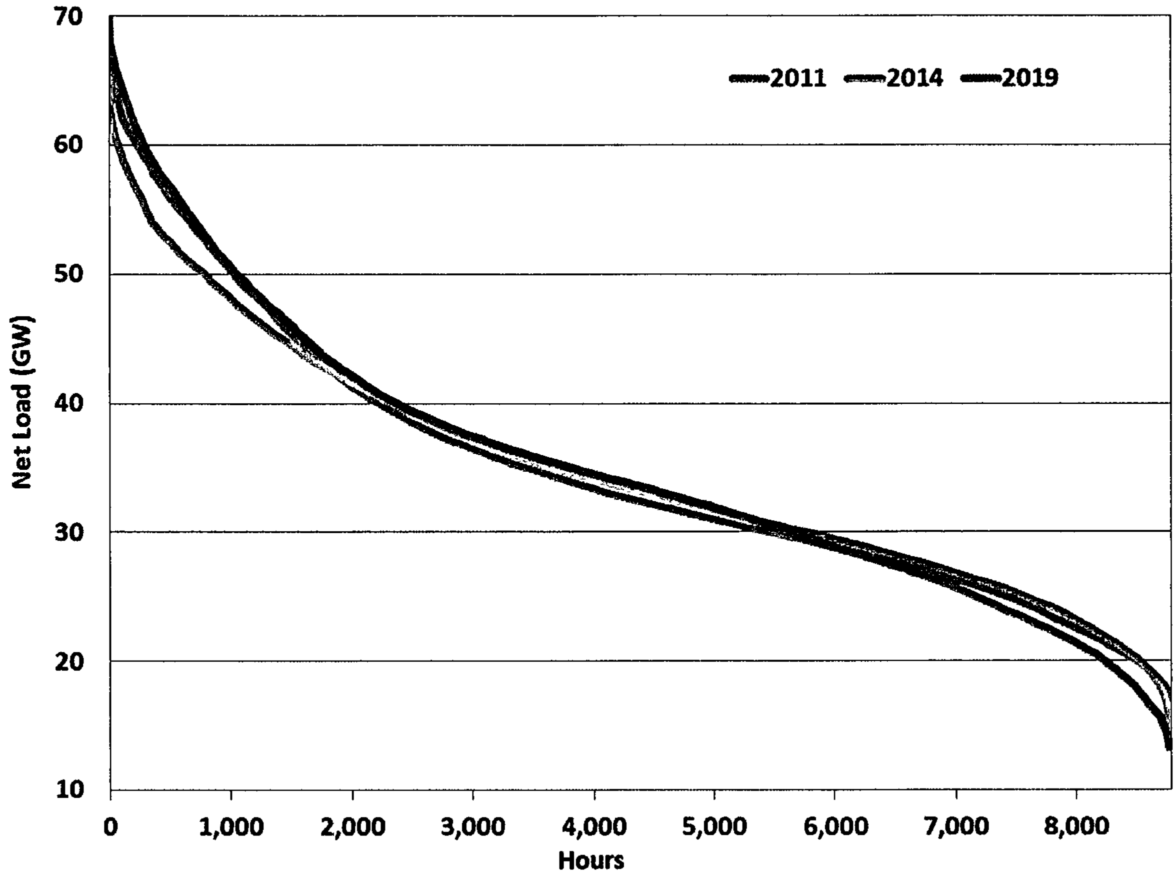


Figure A18 shows the net load duration curves for the years 2011, 2014, and 2019. Increasing wind output has important implications for non-wind resources and for resource adequacy in the ERCOT region as growth in peak demand requires additional resources to be added, but the energy available to be served overall is reduced.

Figure A18: Net Load Duration Curves



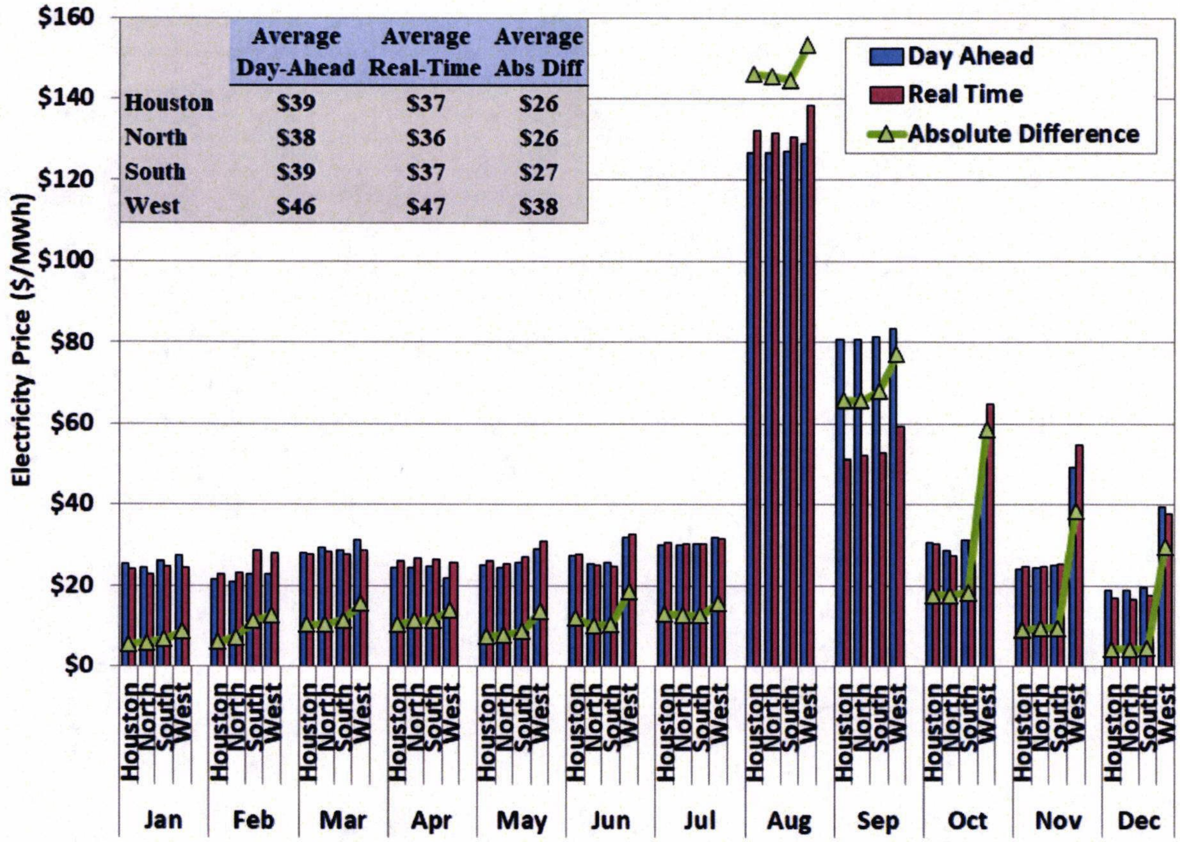
III. APPENDIX: DAY-AHEAD MARKET PERFORMANCE

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

A. Day-Ahead Market Prices

In Figure A19 below, monthly day-ahead and real-time prices are shown for each of the geographic zones. Overall volatility was relatively low in 2019 across all zones. September 2019 witnessed the most pronounced price differences, with an average difference between day-ahead and real-time prices of $27.84 per MWh. Finally, although the average day-ahead and real-time prices were the most similar in the West zone, the average absolute difference in the West zone was the largest. This trend is explained by wide swings in West zone prices, the result of different kinds of transmission congestion constraints in the area related to outages and high load.

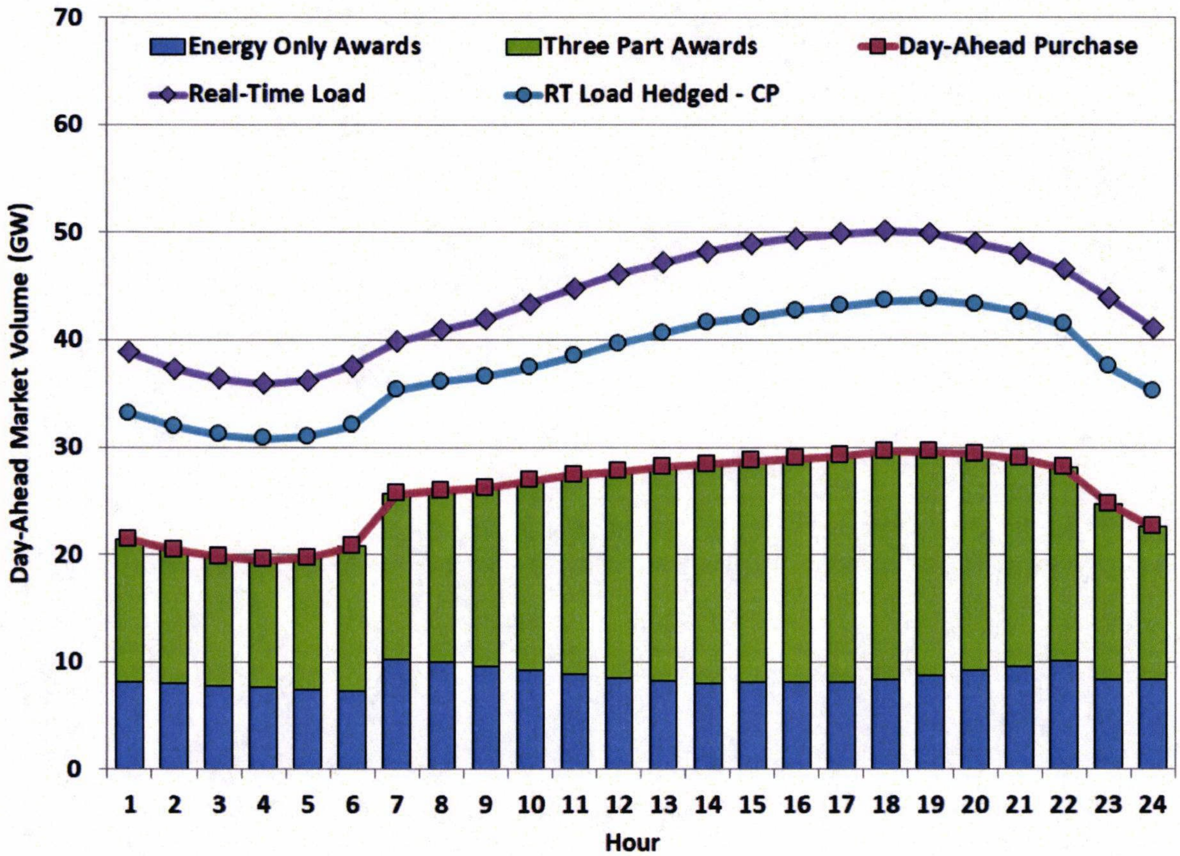
Figure A19: Day-Ahead and Real-Time Prices by Zone



B. Day-Ahead Market Volumes

Figure A20 below presents the same day-ahead market activity data summarized by hour of the day. In this figure, the volume of day-ahead market transactions is disproportionate with load levels between HE 7 and HE 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 day-ahead market to trade around those positions.

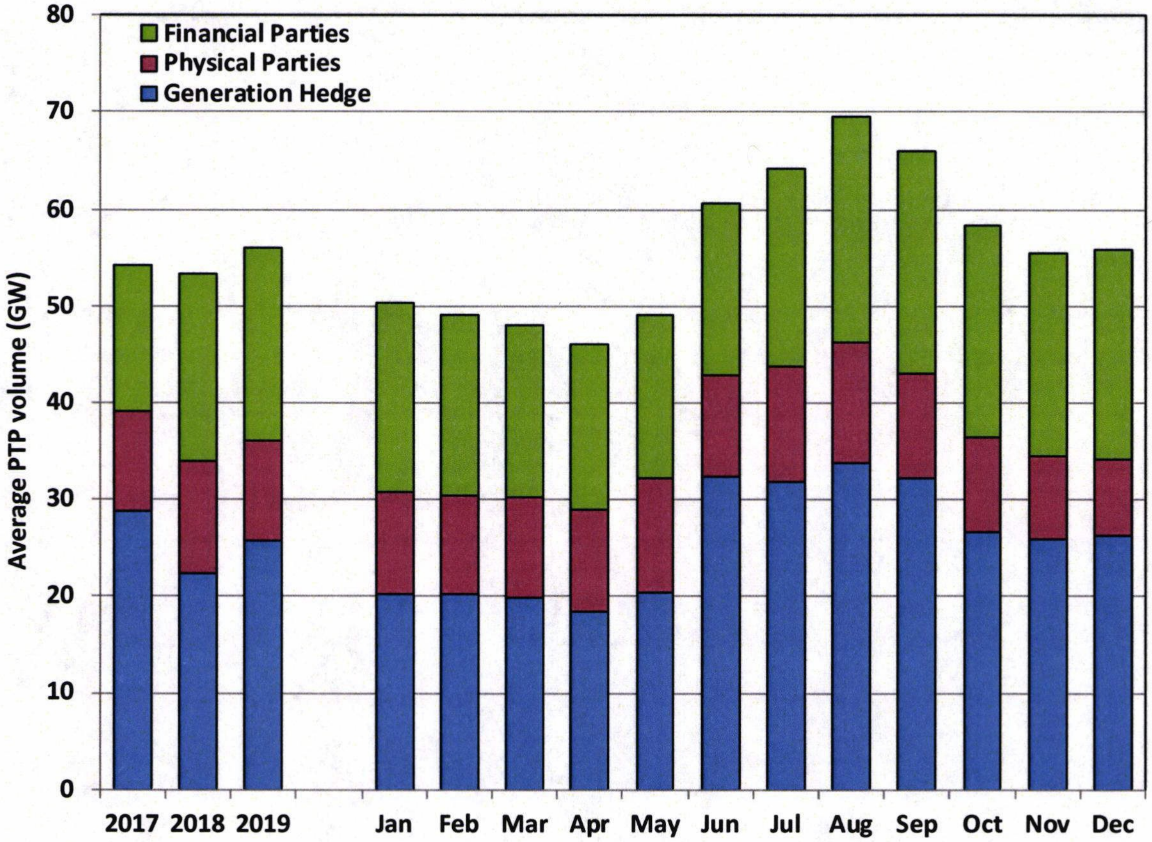
Figure A20: Volume of Day-Ahead Market Activity by Hour



C. Point-to-Point Obligations

Figure A21 below presents the total volume of PTP obligation purchases in 2019 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 purchases has been fairly stable for the past three years.

Figure A21: 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 generation hedging comprised most of the volume of PTP obligations purchased. The remaining 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 organized 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 again purchased 36% of the total volume of PTP obligations in 2019, the same as in 2018, and an increase from 28% in 2017.

D. Ancillary Services Market

Figure A22 below displays the hourly average quantities of ancillary services procured for each month in 2019.

Figure A22: Hourly Average Ancillary Service Capacity by Month

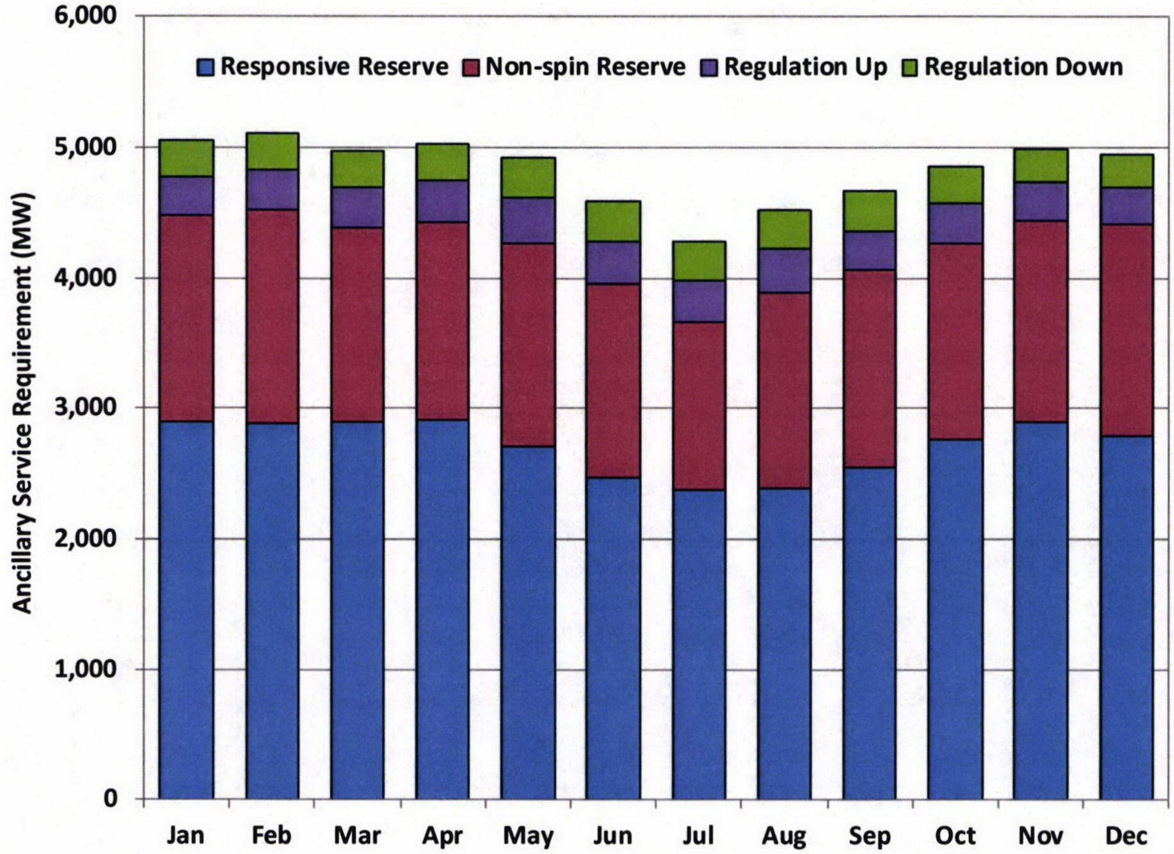


Figure A23 presents an alternate view of ancillary service requirements, displaying them by hour, averaged over the year. In this view the large variation in quantities between some adjacent hours was readily apparent. For example, capacity requirements increased almost 400 MW in HE 7, decreased 237 MW in HE 8 and gradually increased for the next two hours. Hour 23 provided another example of an increase in requirements in the hour prior to a decrease. This pattern was a result of the methodology that sets responsive and non-spinning reserve quantities in four-hour blocks, while regulation reserve quantities are set hourly.

Figure A23: Yearly Average Ancillary Service Capacity by Hour

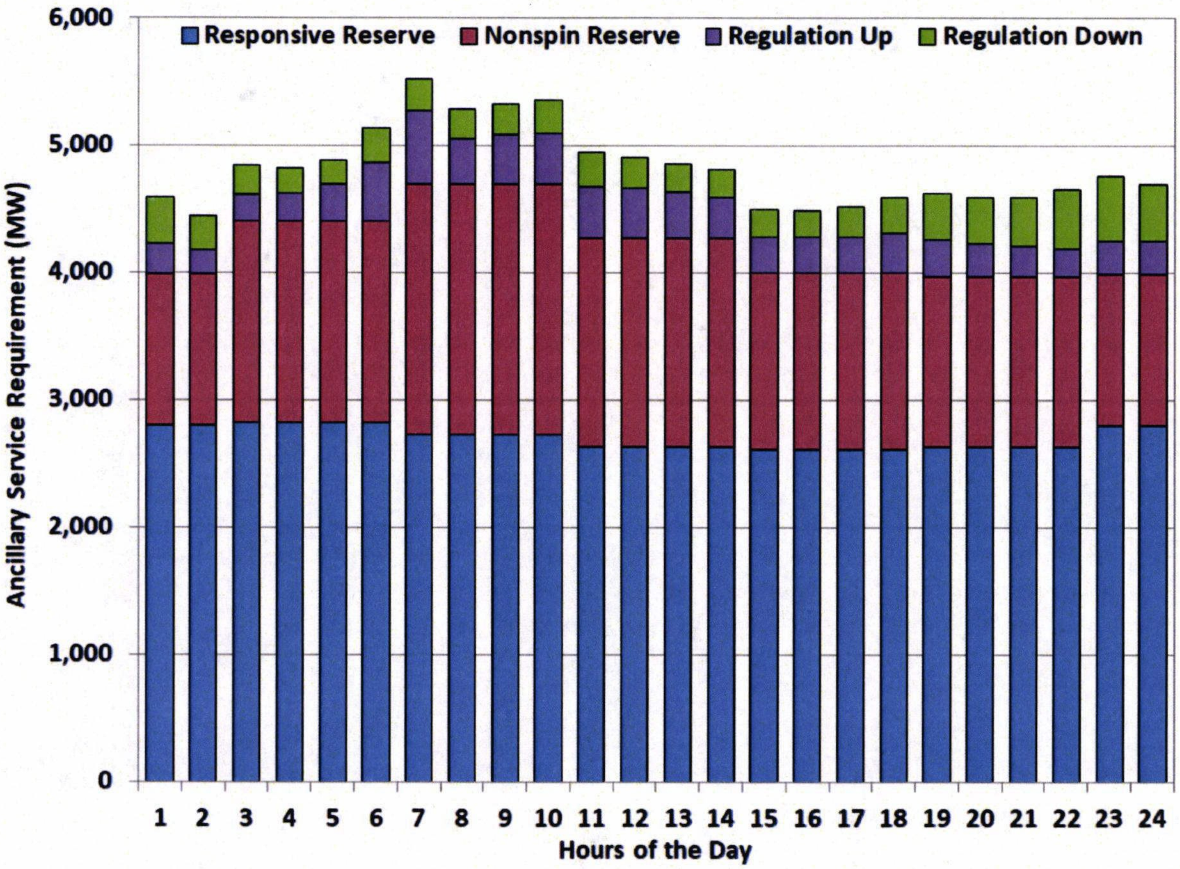
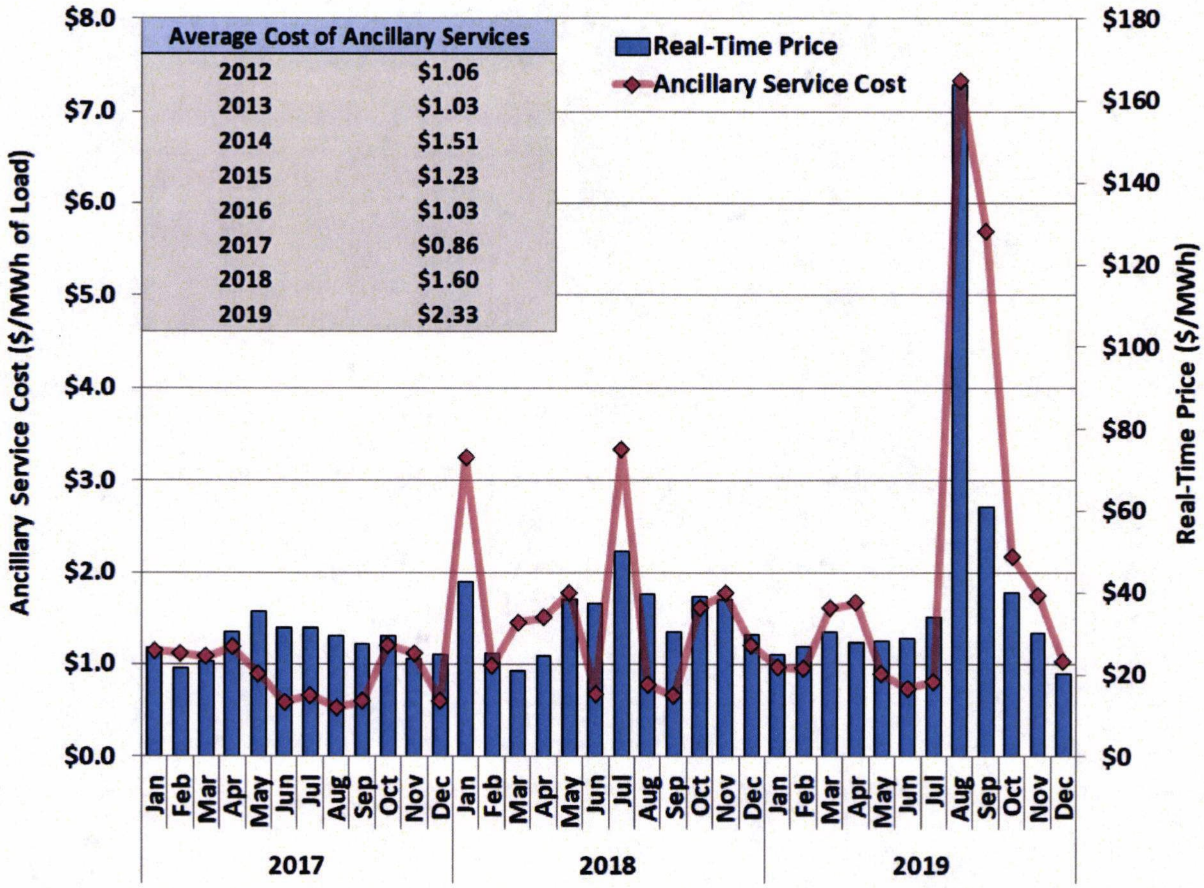


Figure A24 shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2017 through 2019.

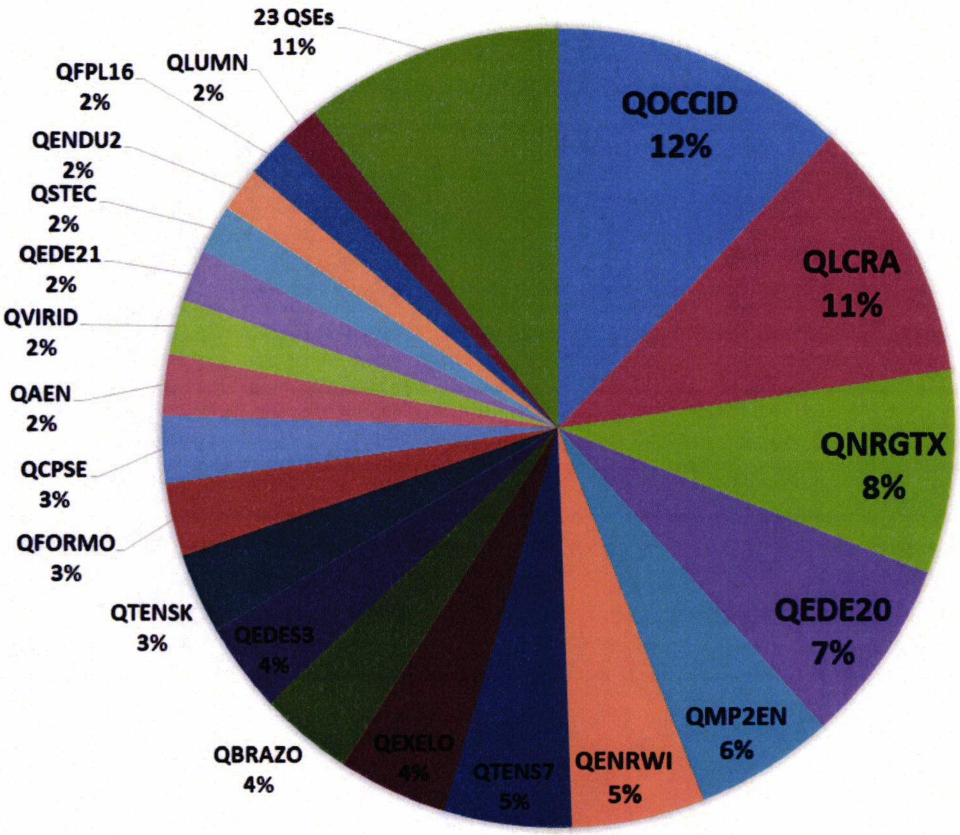
Figure A24: Ancillary Service Costs per MWh of Load



The average ancillary service cost per MWh of load increased to $2.33 per MWh in 2019 from $1.60 per MWh in 2018 and the all-time low of $0.86 per MWh in 2017. Total ancillary service costs were approximately 5% of the load-weighted average energy price in 2019, compared to 4.5% in 2018 and 3.0 % in 2017, continuing the upward trend started a year ago.

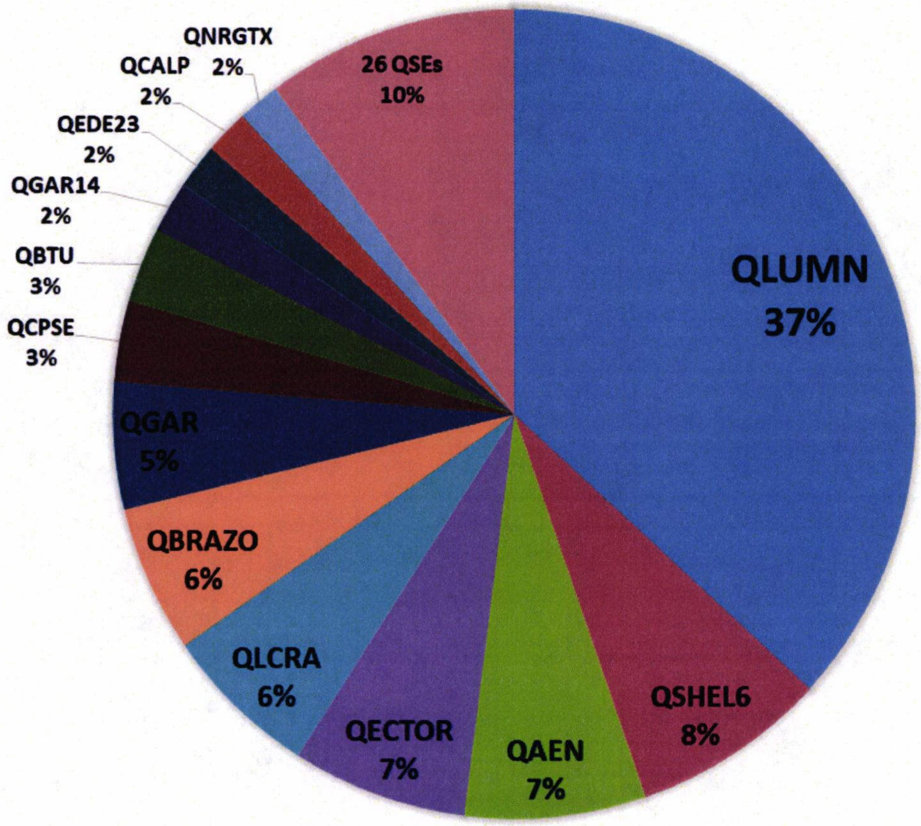
Figure A25 below shows the share of the 2019 annual responsive reserve responsibility including both load and generation, displayed by QSE. During 2019, 43 different QSEs self-arranged or were awarded responsive reserves as part of the day-ahead market. The number of providers has been roughly the same for the past five years (43 in 2018, 45 in 2017, 42 in 2016, and 46 in 2015). There were no significant changes from 2018 in the largest providers or in the share of responsive reserve provided.

Figure A25: Responsive Reserve Providers



In contrast, Figure A26 below shows that the provision of non-spinning reserves is much more concentrated, with a single QSE (Luminant) still bearing almost 40% the total responsibility. Luminant's 37% share of non-spin responsibility however was a decrease from the 41% share it held in 2018 and 56% in 2017. The change in composition of Luminant's generation fleet, due to merger and retirements, likely explains the continued reduction. As Luminant's non-spin responsibility decreased again in 2019, many other suppliers such as Austin Energy (QAEN) and Ector County Energy Center (QECTOR) increased their share slightly.

Figure A26: 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 real-time co-optimization of energy and ancillary services. 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), perhaps distributing the responsibility to provide among more entities.

Figure A27: Regulation Up Reserve Providers

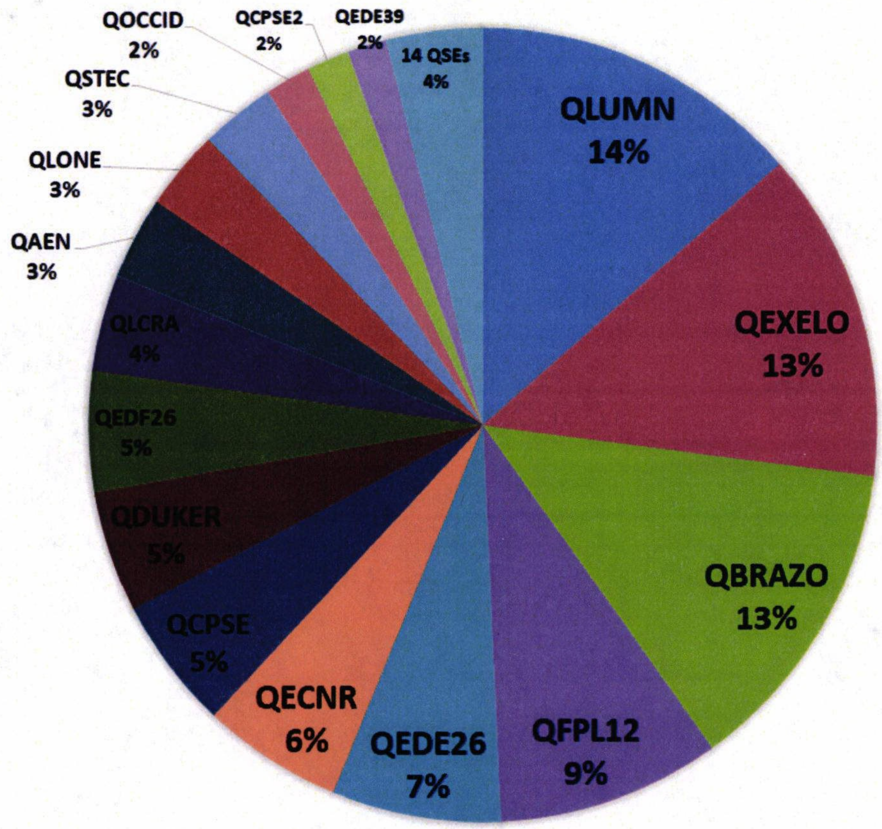
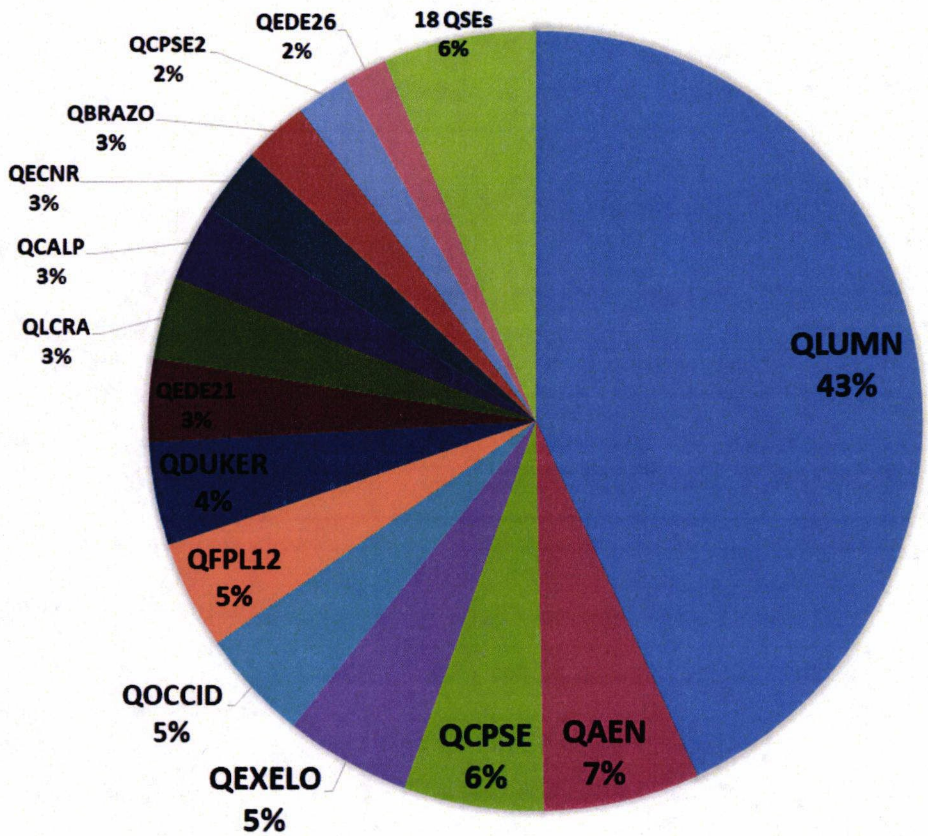


Figure A27 above shows the distribution for regulation up reserve service providers and Figure A28 shows the distribution for regulation down reserve providers in 2019. Figure A27 shows that regulation up was spread fairly evenly, similar to responsive reserve providers, while Figure A28 shows that that regulation down had similar concentration to non-spinning reserves in 2019. Again, Luminant had a dominant position in the provision of regulation down. Its 43% share of the regulation down responsibility in 2018 was higher than in preceding years (41% in 2018, 25% in 2017 and 10% in 2016).

Figure A28: Regulation Down Reserve Providers



Ancillary service capacity is procured as part of the day-ahead market 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, 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 day-ahead market. 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 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 are still effectively precluded from participating in ancillary service markets 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 typically three to 40 times greater than annual average clearing prices from the day-ahead market.

A SASM may also be opened if ERCOT changes its ancillary service plan, although this did not occur during 2019. A SASM was executed 22 times in 2019, with SASM awards providing 168 service-hours. SASMs were almost equally frequent in 2019 and 2018, where 2018 awarded 245 service-hours.

Figure A29 below provides the aggregate quantity of each service-hour that was procured via SASM over the last three years. The volume of service-hours procured via SASM over the year (more 3,500 MWs of service-hours in 2019) is still infinitesimal when compared to the total ancillary service requirement of nearly 43 million MWs of service-hours.

Figure A29: Ancillary Service Quantities Procured in SASM

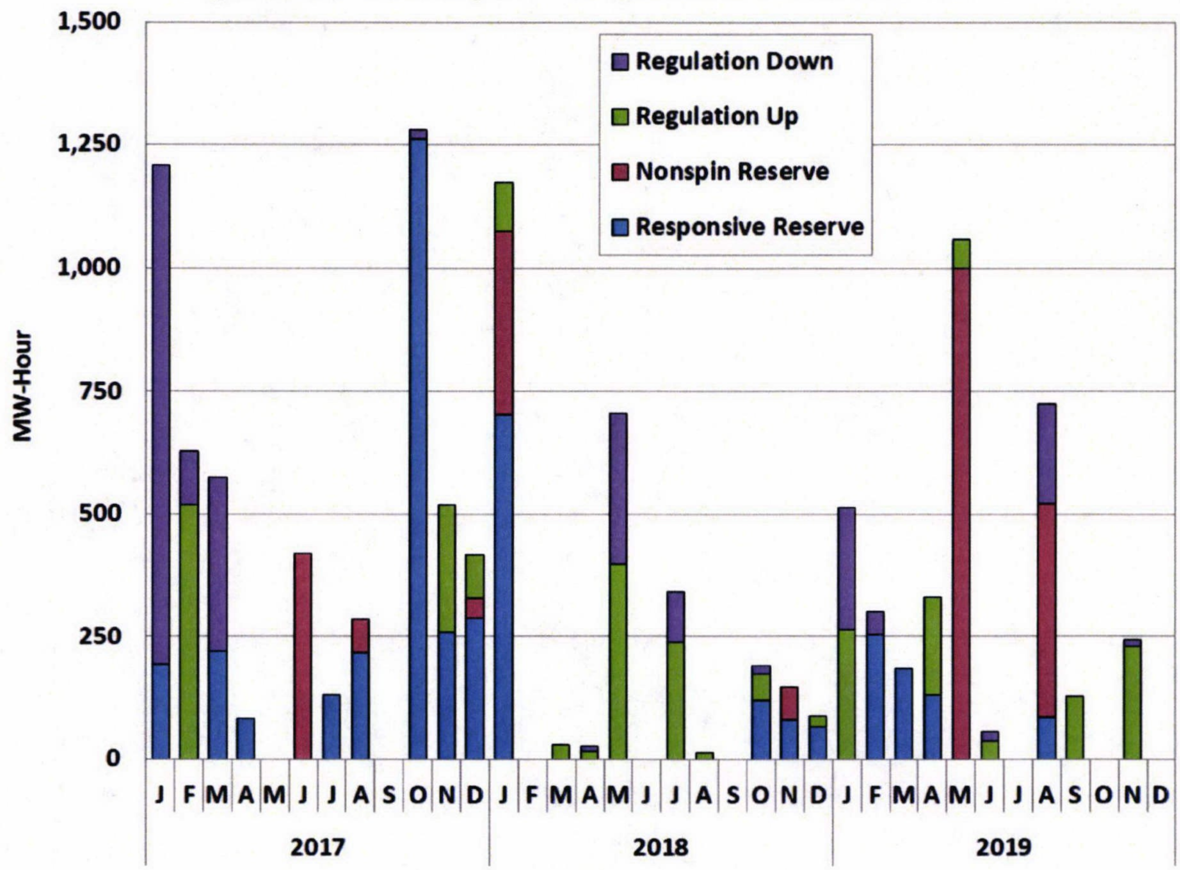
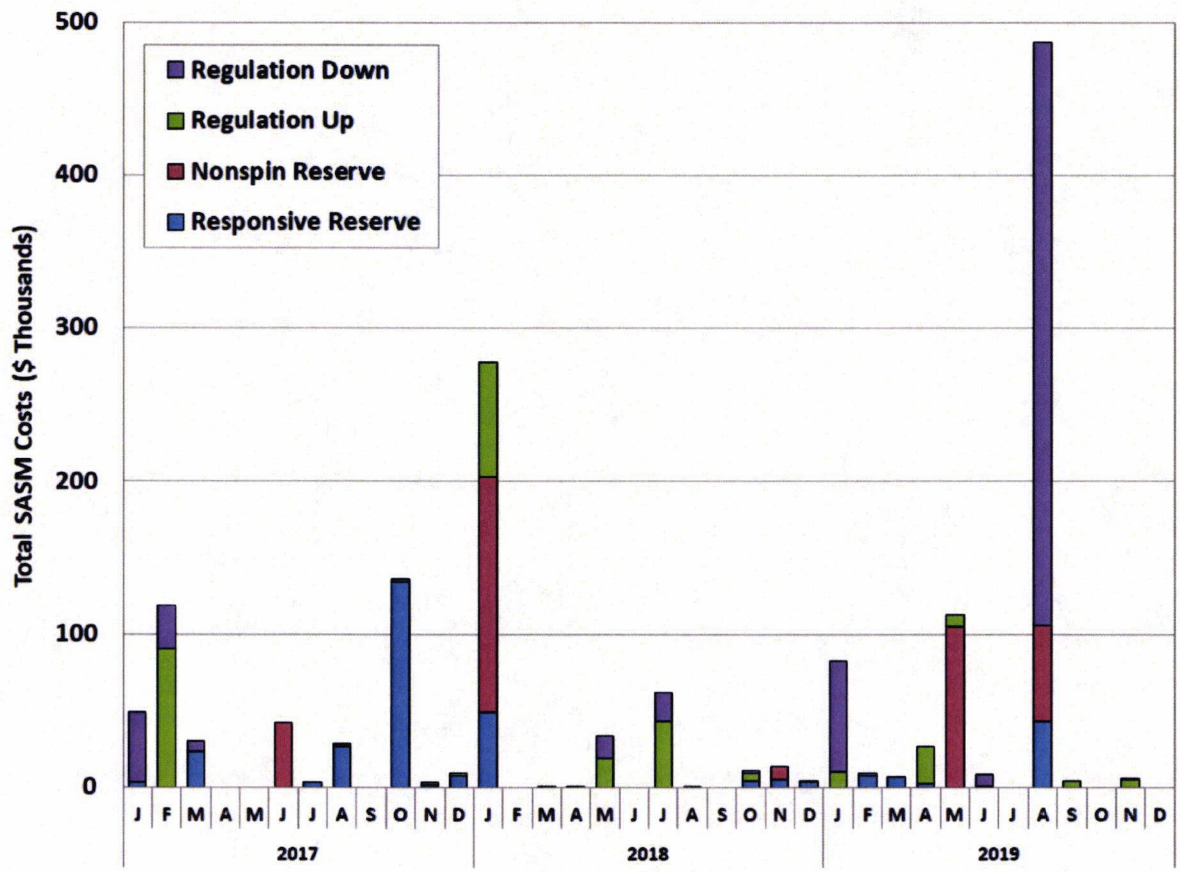


Figure A30 shows the average cost of the replacement ancillary services procured by SASM in 2019. Total SASM costs in August of 2019 were by far the highest SASM costs seen since the beginning of 2017. August 2019 saw high temperatures and very high energy prices, particularly during the week of August 12. Under such conditions, resources might be diverted to provide energy rather than reserves, thus raising the cost of ancillary services. If a resource had reserve responsibilities under those tight 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.

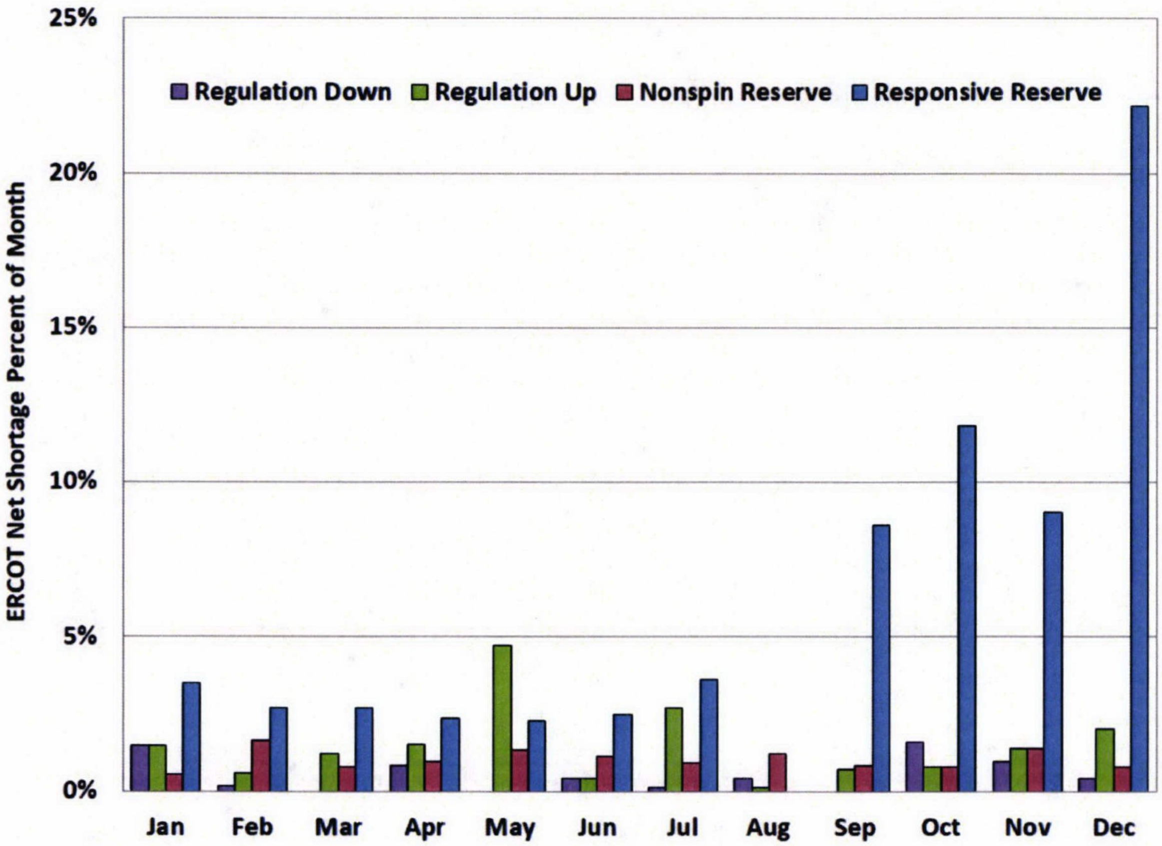
Figure A30: Average Costs of Procured SASM Ancillary Services



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 real-time co-optimization 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 A31 depicts the percentage of hours in each month of 2019 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 A31: ERCOT-Wide Net Ancillary Service Shortages



This analysis shows that ERCOT-wide shortages for all ancillary services were considerably lower in 2019 compared to 2018, generally below 5% in all months for all services, although responsive reserve experienced slightly higher shortages during the fall months, occurring in more than 10% of hours in October and December. Again, this analysis is based on the telemetered status provided by the parties with the responsibility.

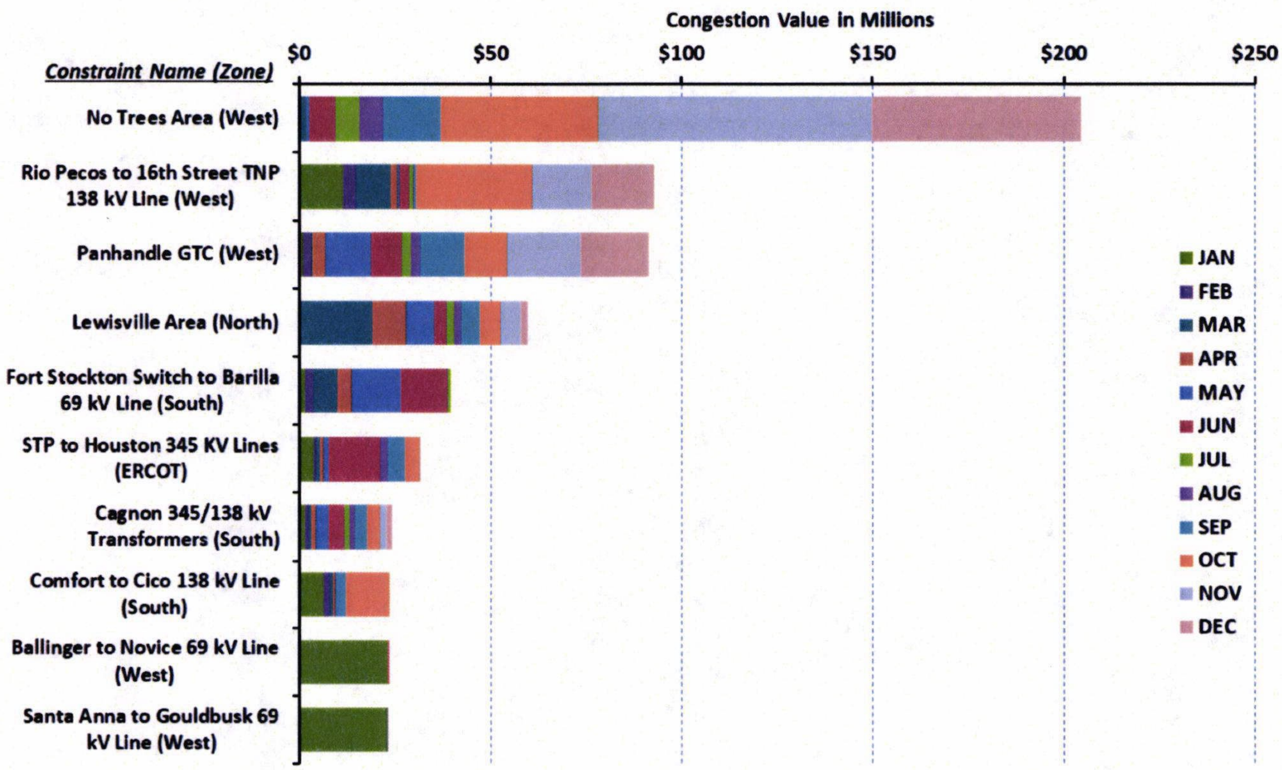
IV. Appendix: Transmission Congestion and Congestion Revenue Rights

In this section, we provide supplemental analyses of transmission congestion in 2019, 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 day-ahead market in 2019. Figure A32 presents the ten most congested areas from the day-ahead market, ranked by their value. Seven of the constraints listed here were described in Figure 30: Most Costly Real-Time Congested Areas. To the extent the model of the transmission system used for the day-ahead market matches the real-time transmission system, and assuming market participants transact in the day-ahead market similar to how energy flows in real-time, the same transmission constraints are expected to appear in both markets.

Figure A32: 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 third year in a row, the majority of the costliest day-ahead constraints in 2019 were also costly real-time constraints. Aside from the Lewisville area and Fort Stockton Switch to Barilla, the rest of the constraints that exist in both the top 10 real-time and the top 10 day-ahead incurred less congestion value in the day-ahead market than the real-time market. This is a result of less wind generation participating in the day-ahead market, likely because of the uncertainty associated with predicting its output.

The three other constraints are prime examples that would not have incurred similar real-time congestion costs seen from the day-ahead: Cagnon 345/138 kV transformers, Ballinger to Novice, and Santa Anna to Gouldbusk 69 kV lines. The Cagnon constraint is a combination of the high and low side of the transformer. The other two are a representation of a series of two lines: Ballinger to Humble to Novice and Santa Anna to Coleman Junction to Gouldbusk. Only one of the pairs of contingency and overloaded element would be active in real-time at a time for each group due to constraint filtering procedures in place.

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 day-ahead market, but the ultimate source of the congestion is the physical constraints binding in real time.

1. Types and Frequency of Constraints in 2019

Our review of the active and binding constraints in 2019 is shown in Figure A33 and Figure A34.

Figure A33: Frequency of Binding and Active Constraints

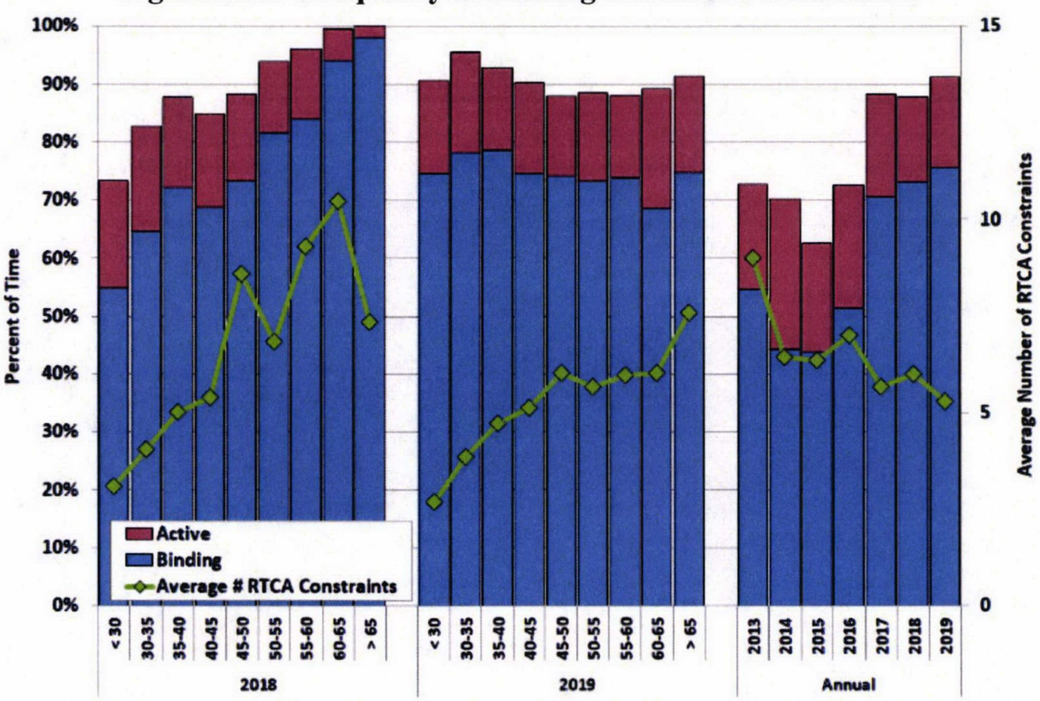
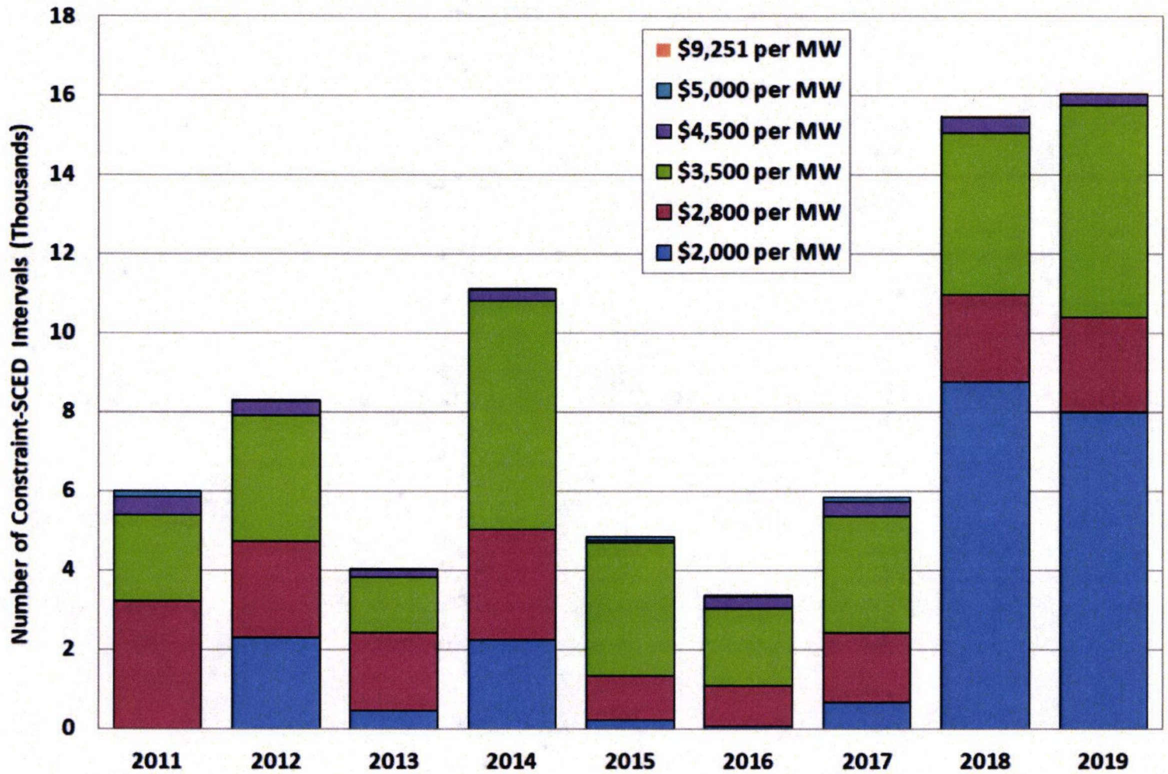


Figure A34 below depicts constraints were violated (i.e., at maximum shadow prices) slightly more frequently in 2019 than they were in 2018. The majority of the violated constraints occurring at the $2,000 per MW value were related to the Dollarhide to No Trees 138 kV line irresolvable element. Violated constraints continued to occur in only a small fraction of all of the constraint-intervals, 8% in 2018, up from 3% in 2017.

Figure A34: Frequency of Violated Constraints



A GTC was binding in 16% of the time in 2019 compared to 15% in 2018. GTCs are used to ensure that the generation dispatch does not violate a transient or voltage stability condition. Table A2 below shows the GTCs that were binding in real-time.

Table A2: Generic Transmission Constraints

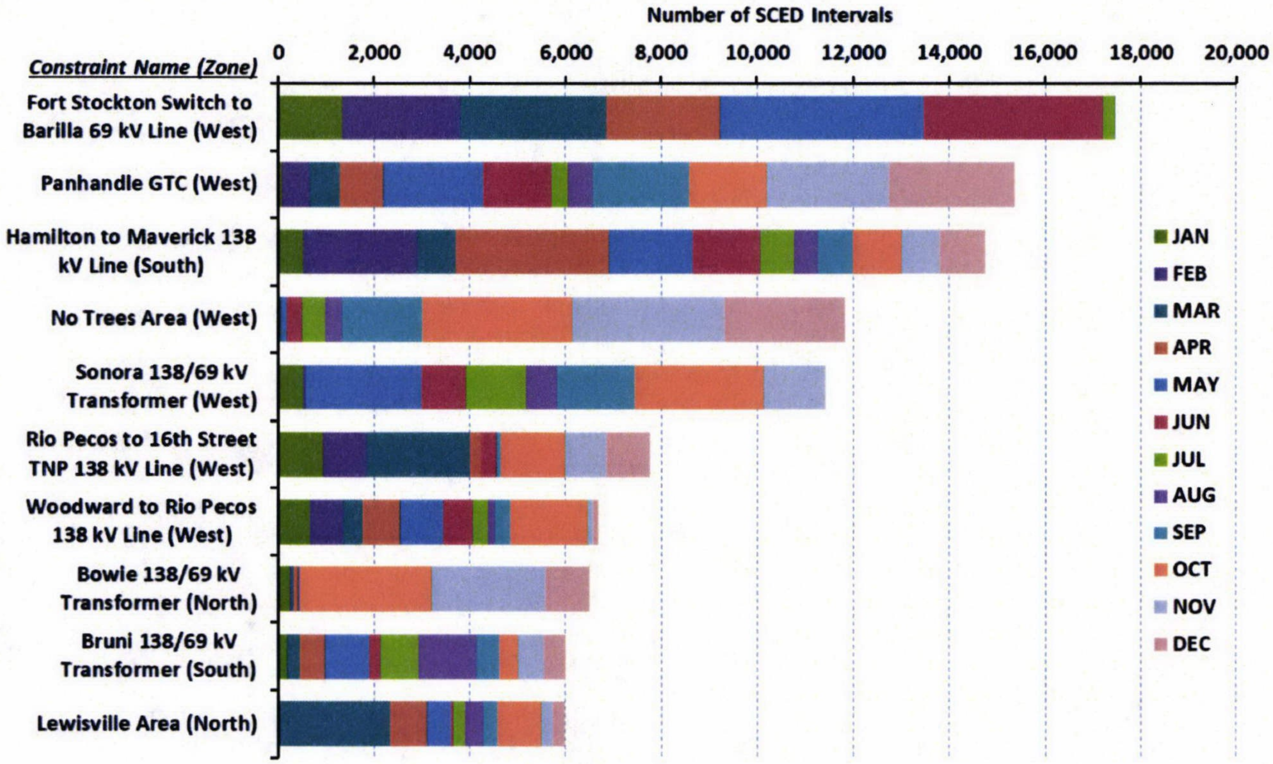
Generic Transmission Constraint	Effective Date	# of Binding Intervals in 2019
Panhandle	July 31, 2015	15,352
Treadwell	May 18, 2018	1,539
Raymondville - Rio Hondo	May 2, 2019	385
East Texas	November 2, 2017	155
North Edinburg - Lobo	August 24, 2017	59
Bearkat	November 20, 2019	14
McCamey	March 26, 2018	3
North to Houston	December 1, 2010	-
Rio Grande Valley Import	December 1, 2010	-
Red Tap	August 29, 2016	-
Nelson Sharpe - Rio Hondo	October 30, 2017	-

2. Real-time Constraints and Congested Areas

The Panhandle export contributes to the congestion in the Lewisville area and Eagle Mountain to Morris Dido 138 kV line, which is near Dallas-Fort Worth. The components of the Lewisville area include the Lakepoint to Carrollton Northwest, the West TNP to TI TNP, and the Lewisville to Jones Street TNP 138 kV lines. The congestion values for these constraints reduced by 50% since 2018 at $51 million. Eagle Mountain to Morris Dido 138 kV line is one-line segment of the Eagle Mountain congested area in 2018, which was the fourth most costly, a 50% reduction in value at $28 million. The activation of constraints in the Panhandle GTC, Lewisville area, and the Eagle Mountain to Morris Dido 138 kV line all had the effect of dispatching wind output down and increasing the generation in the North. While there are transmission upgrades in the Lewisville and Eagle Mountain area, the congestion appears to be shifting from one local area to the next when upgrades are completed.

All constraints listed in Figure A35 were frequently constrained due to variable renewable output. Five of the ten most frequently occurring constraints in 2019 were also among the ten most costly constraints, consisting of Fort Stockton to Barilla 69 kV line, Panhandle GTC, No Trees Area, Rio Pecos to 16th Street 138 kV line, and Lewisville Area. The other half of the most frequent constraints aggregated more than $50 million in congestion value.

Figure A35: Most Frequent Real-Time Constraints



3. Irresolvable Constraints

Shadow price caps are based on a reviewed methodology,[60] 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.

As shown in Table A3, 12 elements were deemed irresolvable in 2019 and had a shadow price cap imposed according to the irresolvable constraint methodology. Two constraints, the Emma to Holt Switch 69 kV line and Yucca Drive Switch to Gas Pad 138 kV line, 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, which is located in the South zone. The Fort Stockton Switch to Barilla 69 kV line constraint, located in far west Texas, was deemed irresolvable in January 2018. The area was also impacted by solar

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[60] Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints (ERCOT Board Approved June 11, 2019, effective June 12, 2019), 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.

installations and Permian Basin load development. While the constraint was deemed irresolvable, the shadow price cap was not lowered for 2018, so its status as irresolvable had no impact. However, in 2019, the constraint reached the threshold in which the maximum shadow price was reduced to 2,000 per MWh in May. This constraint was also the most frequently activated in SCED for 2019. There is a future project planned to upgrade the 69-kV line to 138 kV identified in ERCOT's *2018 Constraints and Needs Report.*[61]

Table A3: Irresolvable Elements

Contingency Code	Irresolvable Element	Equivalent Element Max Shadow Price	2019 Adjusted Max Shadow Price	Irresolvable Effective Date	Termination Date	Load Zone	# of Binding Intervals in 2019
Base Case	Valley Import	$9,251	$2,000	1/1/12	-	South	-
SMDFHLT8/ SBAKHL48	Emma to Holt Switch 69 kV Line	$2,800	$2,000	10/27/14	1/30/19	West	-
SSOLFTS8	Barilla to Fort Stockton Switch 69 kV Line	$2,800	$2,800	1/1/18	5/12/19	West	2,950
		$2,800	$2,000	5/13/19	-	West	6,302
DCASTXR8	Moore to Hondo Creek Switching Station 138 kV Line	$3,500	$2,549	1/2/18	-	West	-
SWINYUC8	Wickett TNP to Winkler County 6 TNP 69 kV Line	$2,800	$2,000	4/9/18	-	West	-
SWCSBOO8	Yucca Drive Switch – Gas Pad 138 kV line	$3,500	$2,000	5/4/18	1/30/19	West	-
SJUNYEL9	Yellow Jacket to Hext LCRA 69 kV line	$2,800	$2,000	5/18/18	-	West	-
XFRI89	Sonora 138/69 kV Transformer	$2,800	$2,000	5/24/19	-	West	2,970
SECNMO28	Andrews County South to Amoco Three Bar Tap 138 kV Line	$2,800	$2,000	9/23/19	-	West	996
SECNMO28	Dollarhide to No Trees Switch 138 kV Line	$2,800	$2,000	10/15/19	-	West	5,317
DWINDUN8	Dollarhide to No Trees Switch 138 kV Line	$2,800	$2,000	10/23/19	-	West	2,107
DYKNWIN8	Dollarhide to No Trees Switch 138 kV Line	$2,800	$2,000	11/29/19	-	West	391

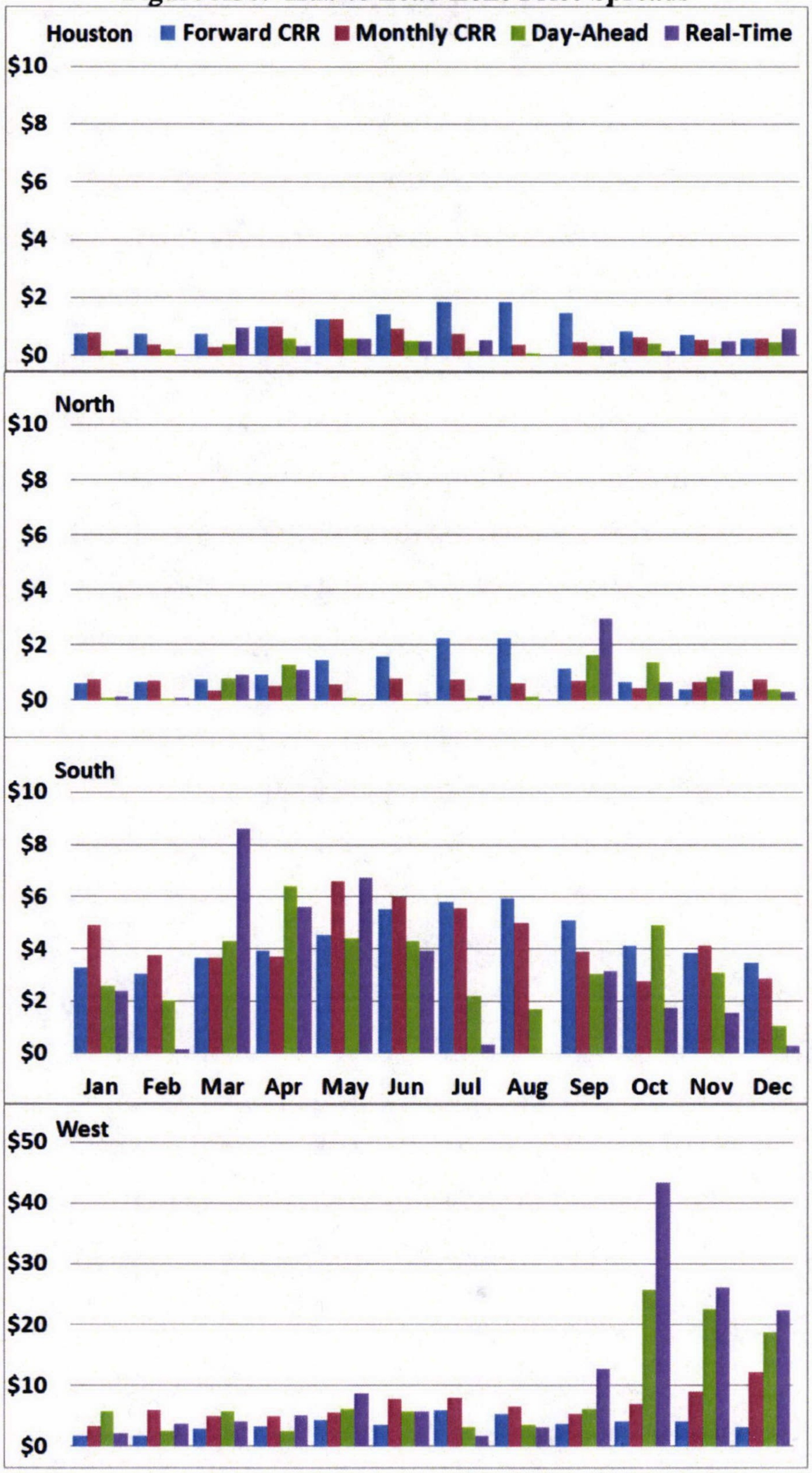
C. CRR Market Outcomes and Revenue Sufficiency

1. CRR Profitability

Figure A36 below shows the price spreads between all hub and load zones 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.

61 The percentages of installed capacity to serve peak demand assume availability of 29% for panhandle wind, 63% for coastal wind, 16% for other wind, and 76% for solar.

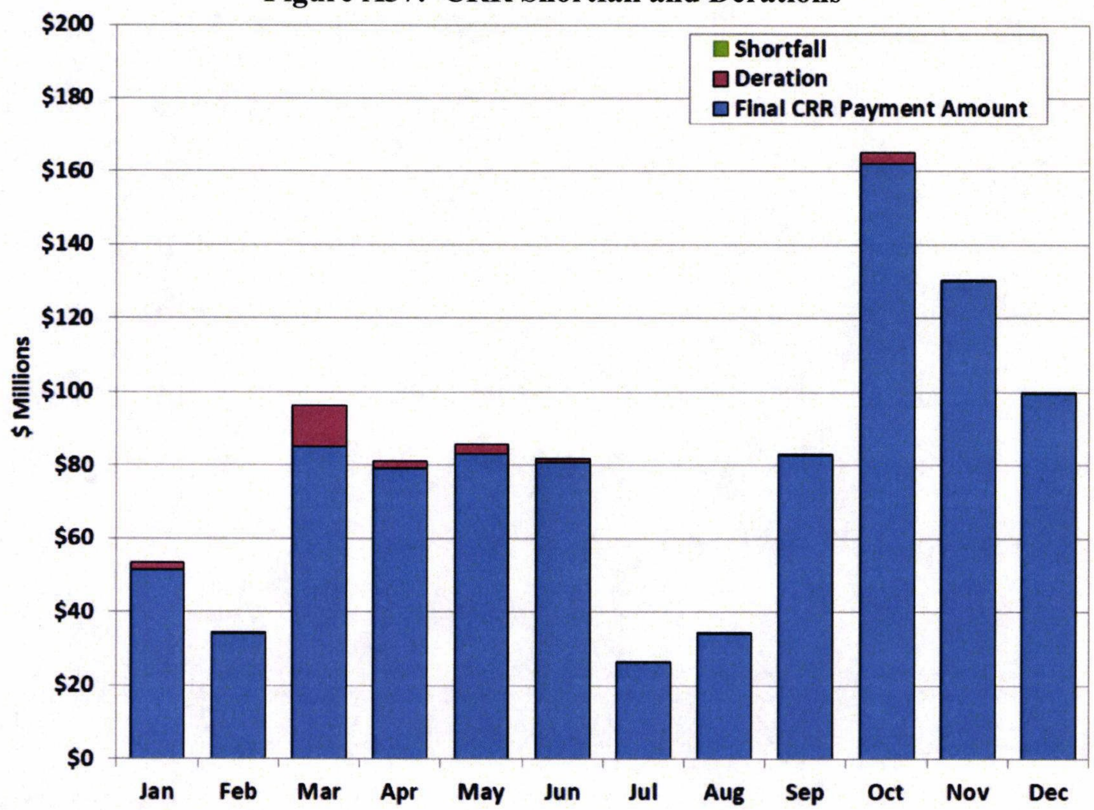
Figure A36: Hub to Load Zone Price Spreads



2. CRR Funding Levels

Figure A37 shows the amount of target payment, deration amount, and final shortfall for 2019. In 2019, the total target payment to CRRs was $972 million; however, there were $23 million of derations and no non-refunded shortfall charges resulting in a final payment to CRR account holders of $949 million. This final payment amount corresponds to a CRR funding percentage of 97.6%, slightly higher than the funding percentage of 95% in 2018.

Figure A37: CRR Shortfall and Derations



V. APPENDIX: RELIABILITY UNIT COMMITMENTS

In this section, we provide supplemental analyses of RUC activity in 2019 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 "claw-back" provision. Beginning on January 7, 2014, resources committed through the RUC process could forfeit the make-whole payments and waive the claw-back 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 I: 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 day-ahead market. And finally, 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.

B. 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 hour-ahead basis. Additional resources may be needed for two primary reasons – to satisfy the total forecasted demand, or to make a specific generator available resolve a transmission constraint. The transmission constraint may be either a thermal limit or voltage concern.

Figure A38 below shows RUC activity by month for 2017 through 2019, indicating the volume of generators receiving a RUC instruction that had offers in the day-ahead market or chose to opt-out of the RUC instruction. The monthly data shows no consistent pattern of RUC activity over the past three years. For comparison, annual summaries are also provided in the table going back to 2014, the year with the highest amount of RUC activity.

Figure A38: Day-Ahead Market Activity of Generators Receiving a RUC

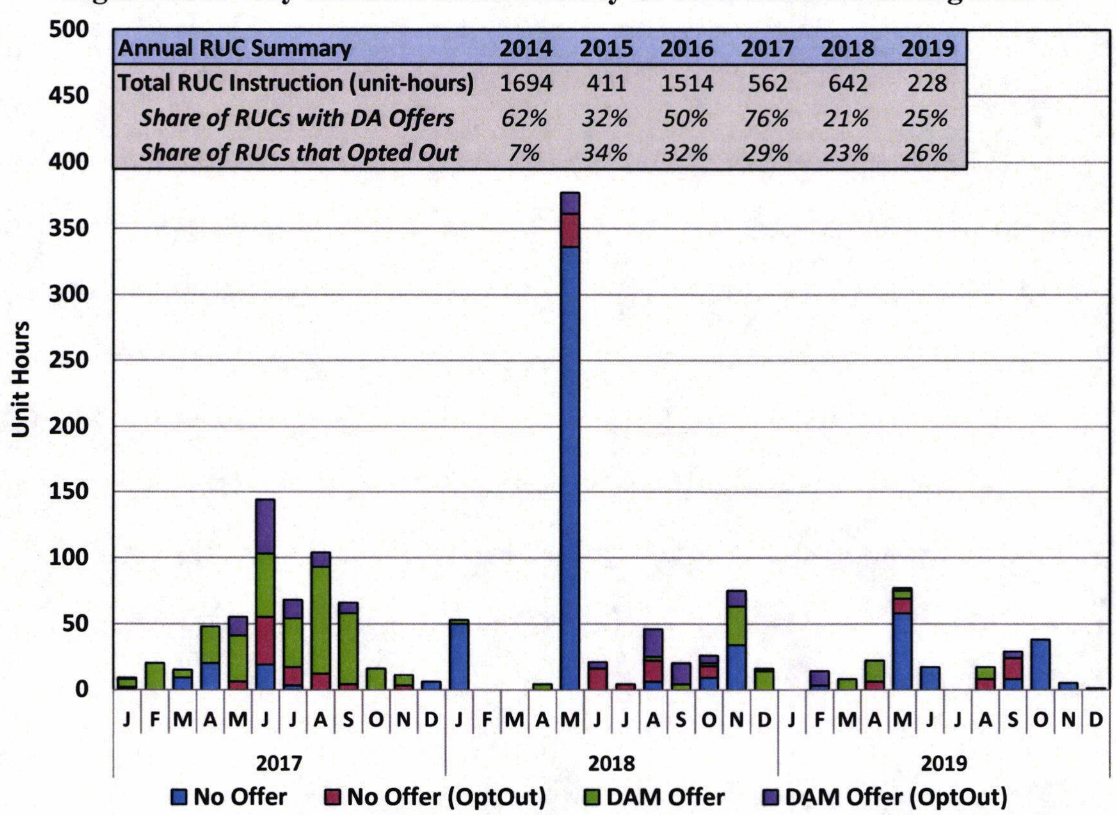


Table A4 below lists the generation resources that received the most RUC instruction in 2019 and includes the total hours each unit was settled as a RUC and the number of hours in which the unit opted out of RUC settlement. The units highlighted in gray are the ones that similarly received RUC instructions in 2018. ERCOT issued frequent RUC instructions to the Permian Basin units due to localized transmission congestion related to high area loads, intermittent generation, and line outages.

Table A4: 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
Permian CT 1	Far West	53	0	41	41	48	70
Permian CT 2	Far West	46	0	41	41	55	70
Nueces Bay CC1	Corpus	8	11	134	216	222	318
Mountain Creek Unit 7	DFW	16	0	15	15	15	118
Permian CT 4	Far West	14	0	41	41	45	66
Tenaska CC1	North	3	9	116	123	191	200
Lake Hubbard Unit 2A	DFW	0	12	110	288	324	518
Stryker Unit 2	DFW	3	4	35	317	409	468
Jack County CC1	DFW	6	0	165	172	180	264
Permian CT 5	Far West	6	0	41	44	70	75
Braunig VHB1	San Antonio	0	6	62	106	134	217
Duke CC1	Valley	0	6	157	155	162	248
Silas Ray 10	Valley	0	3	20	20	36	38
Frontier CC1	Bryan	3	0	365	500	504	629
Laredo Unit G5	Laredo	0	2	35	35	90	90

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) seven months in 2019.
- No RUC activity occurred in January or July.
- In May, October, November, and December 2019, the average dispatch level was more than the average low limit because of mitigation of the resource.
- Also, in both May and September, the average dispatch level was higher due to RUC resources choosing to opt out and thus not being subject to the $1,500 per MWh offer floor.

- Real-time system-wide scarcity in August and September caused RUC resources that did not opt out to have an average dispatch above average LSL.

Figure A39: Reliability Unit Commitment Capacity

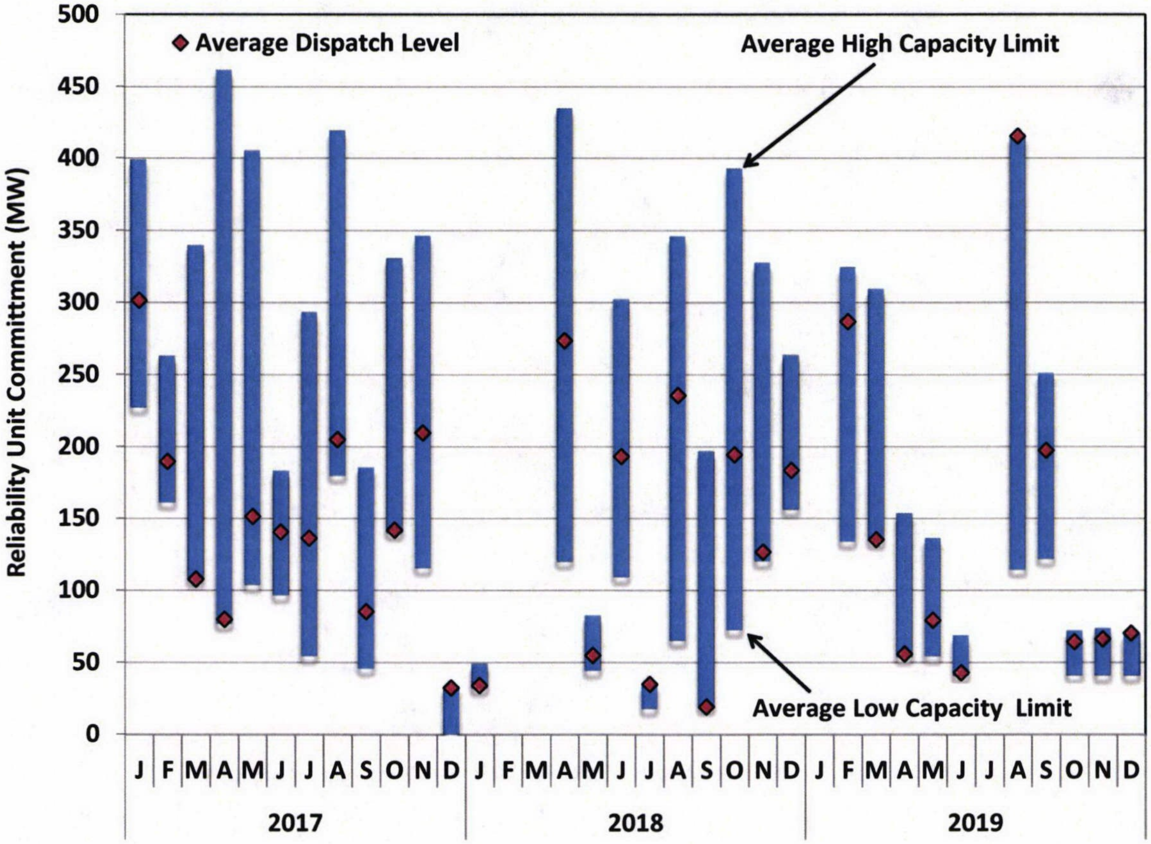


Figure A39 shows in 40% of intervals with RUC resources, one or more resources were dispatched above their low dispatch limit (LDL), whereas in prior years, resources receiving a RUC were infrequently dispatched above LDL, an increase from 27% of the intervals in 2018. This higher dispatch level indicates that most units receive RUC instructions to resolve local constraints, and that these local constraints are non-competitive. As a result, units are dispatched based on their mitigated offers. It is rare for a generator receiving a RUC instruction to be dispatched above LDL with its offer at or above the $1,500 per MWh offer floor. In 2019, this occurred in only 1% of the intervals with a RUC-settled resource.

C. QSE Operation Planning

The two figures below are related to the discussion in the Report surrounding the accuracy of COP submissions and how the accuracy changes as time approaches the operating hour. An example of large changes or trends of changes are relayed in the graphs, one regarding a large supplier and the other a NOIE.

Figure A40: Large Supplier Capacity Commitment Timing – July and August Hour Ending 17

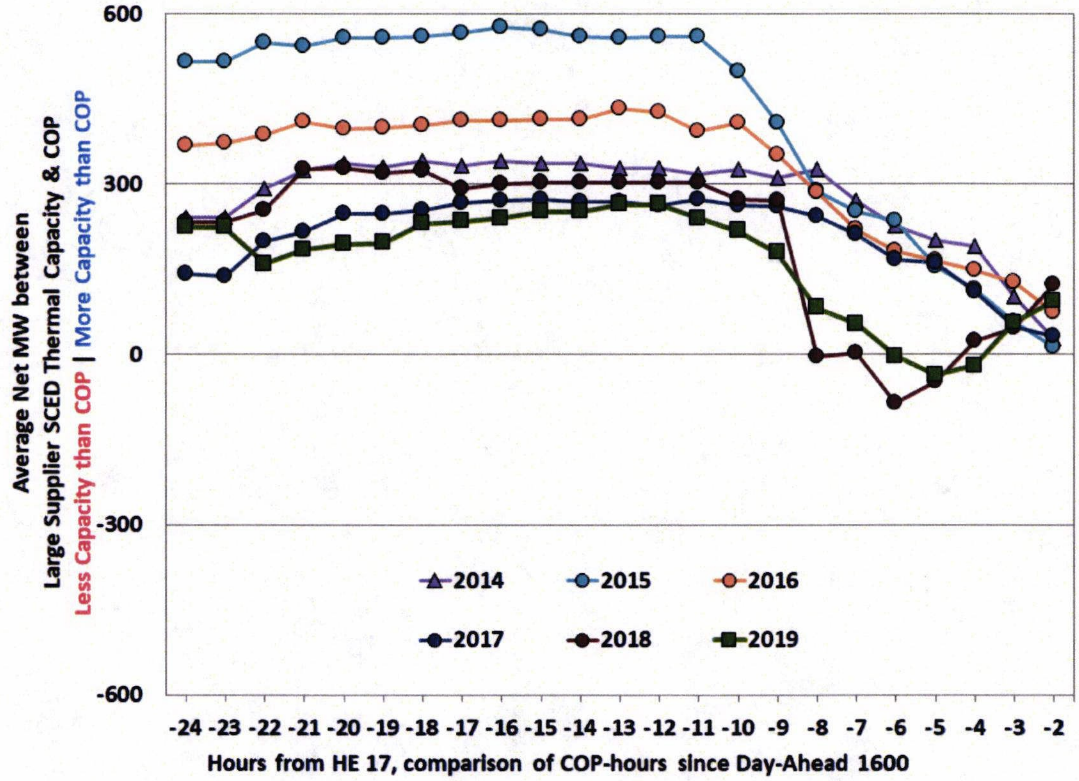
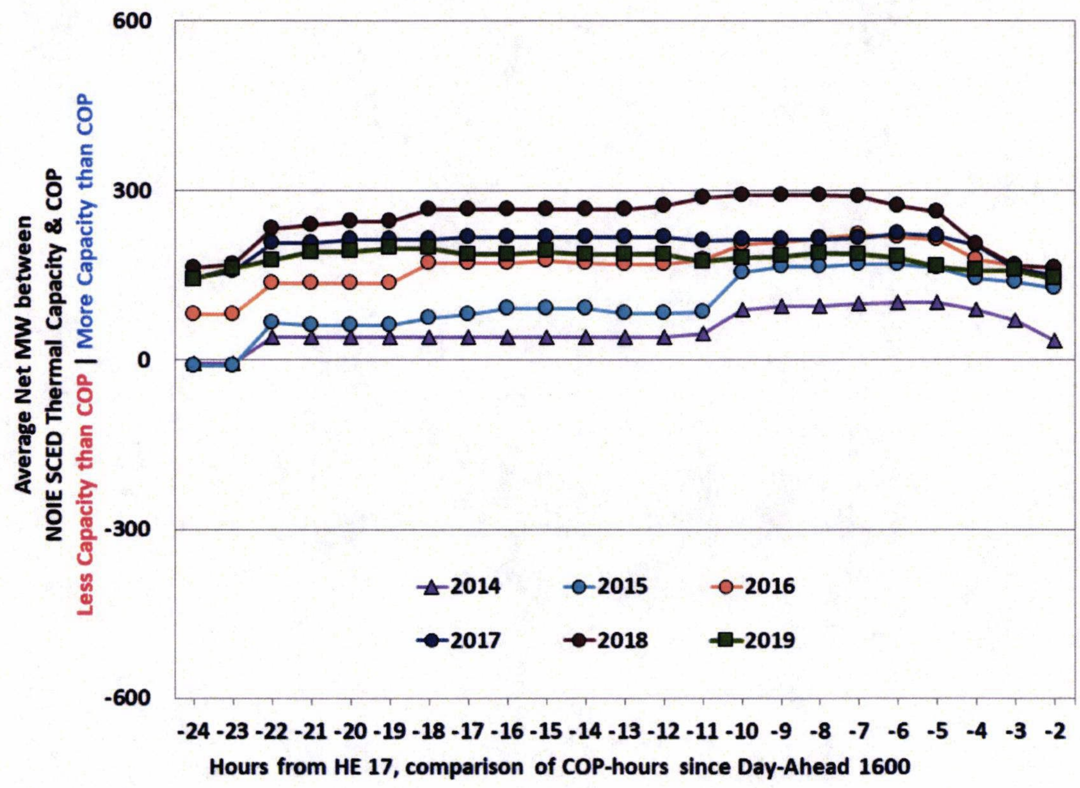


Figure A41: NOIE Capacity Commitment Timing – July and August Hour Ending 17

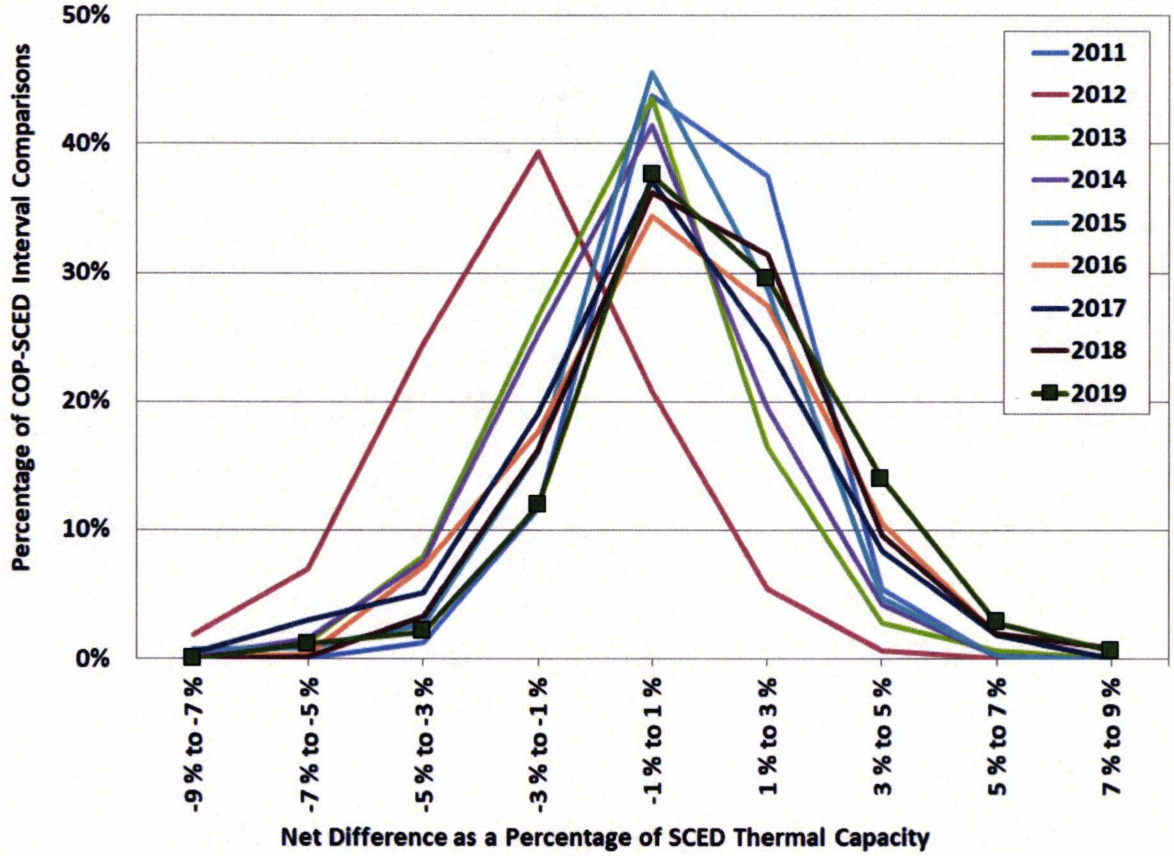


The next set of analyses quantify the difference between the aggregated capacity commitments as described by all the COP submissions, and the actual capacity commitments as a percentage of the actual capacity observed in real-time. These analyses are limited to the peak hours of 12 through 20 for the summer months of July and August. Multiple COP submissions 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 II: Appendix: Demand and Supply in ERCOT, the differences will not be highlighted here.

Figure A42 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. A trend of having less thermal SCED capacity materialize than expected via the COP below -1% percentage error continued through 2014, but the frequency peaks are within the 1% percentage error. In 2015, 45.6% of the COP-SCED interval comparisons were within 1% of the SCED thermal capacity, the highest since 2011, and shifted to seeing more thermal SCED capacity materialize than what was shown in the COP. The last five 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 21.2% were greater than 3%.

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 curves from 2018 and 2019 are similar, with 2019 exhibiting a slightly bigger contrast.

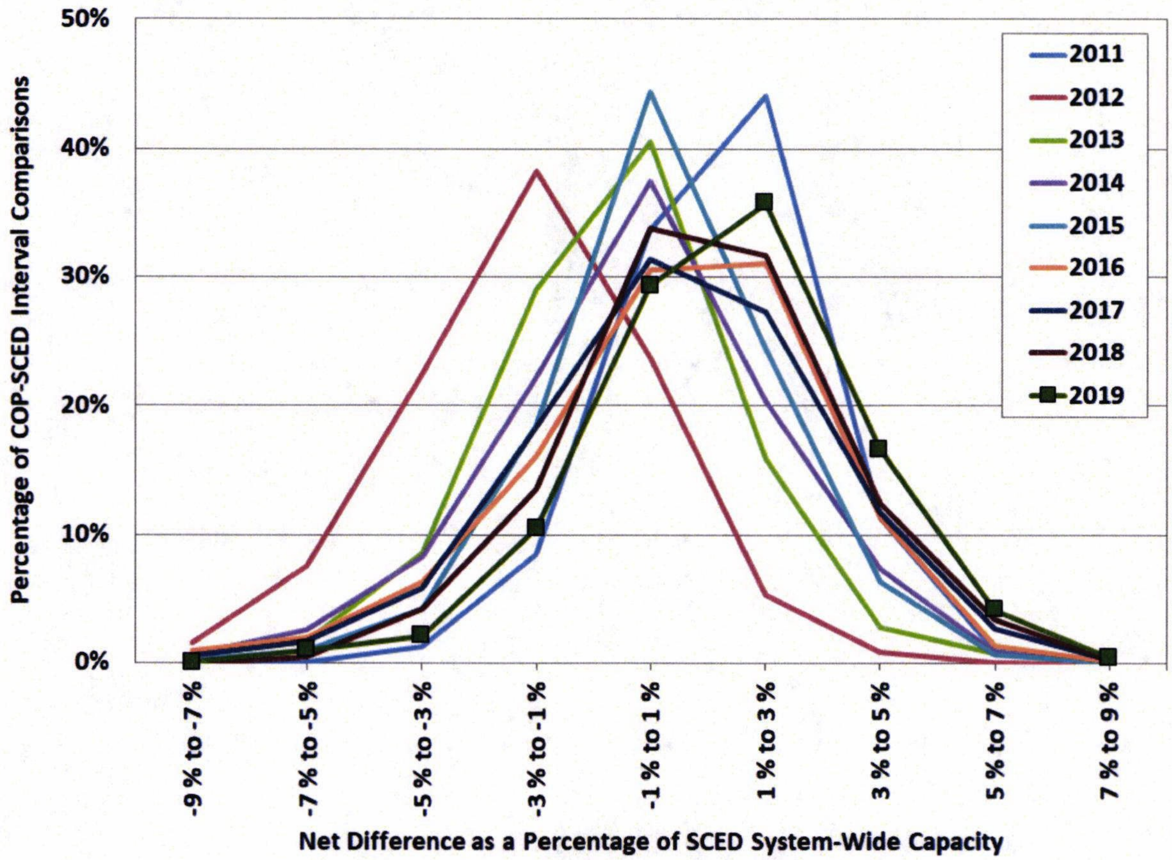
Figure A42: Real-Time to COP Comparisons for Thermal Capacity



One explanation for this trend is the accuracy of the load forecast improving and the changes in market behavior resulting in representing less capacity from the day ahead 1600 COP to the end of the adjustment period. Another explanation for COP under-reporting includes resources that were currently on startup or shutdown before and after their operating periods, additional capacity available from power augmentation not being shown in the COP value, offline non-spin resources deploying, resources coming online responding to market activity, or combined cycle resources increasing their configuration size.

Figure A43 summarizes the same analysis as above, but for system-wide capacity. The most interesting difference between Figure A42 and Figure A43 is the shift in the peak for years 2011 and 2019, where more than 30% of the COP-SCED intervals analyzed were in the 1% to 3% error category. In 2011, the shift was the result of the combination of the wind contribution and the increase in thermal capacity coming online to meet the higher expected load in July and August. In 2019, the shift is more largely attributed to the increase in renewables, both wind and solar, in HE 12 through HE 20. In 2011, the difference was due to installed capacity of about 9 GW of wind to about 30 GW in 2019 for wind and solar.

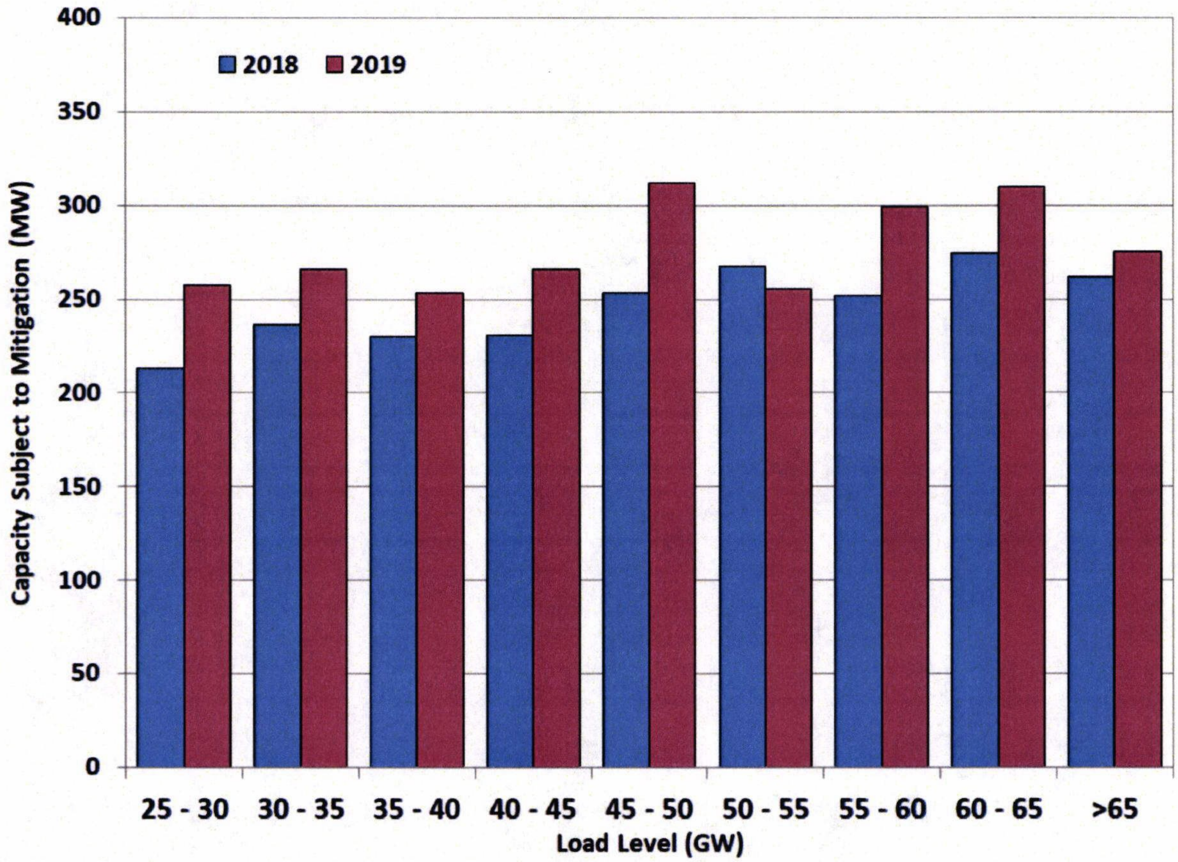
Figure A43: Real-Time to COP Comparisons for System-Wide Capacity



D. Mitigation

The next analysis computes the total capacity 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 A44.

Figure A44: Capacity Subject to Mitigation



As in the prior analysis, the amount of capacity subject to mitigation in 2019 was higher than 2018 in all but the 50 to 55 GW load level. As described previously, the reduction may be explained by the overall higher costs in 2019 and the separation in natural gas prices between Fuel Index Price and Waha. 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.

E. Reliability Must Run and Must Run Alternative

On May 23, 2019, ERCOT received a Notification of Suspension of Operations (NSO) for West Texas Wind Energy Partners, LP's Southwest Mesa (SW_MESA_SW_MESA) Generation Resource. The NSO indicated that the Resource Entity would decommission and retire the generation resource permanently on November 15, 2019. The NSO further indicated that Southwest Mesa (SW_MESA_SW_MESA) has a summer Seasonal Net Max Sustainable Rating of 80 MW, and a summer Seasonal Net Minimum Sustainable Rating of 0 MW.

On June 28, 2019, ERCOT received a Notification of Change of Generation Resource Designation (NCGRD) for the City of Garland's Gibbons Creek Generating Station

(GIBCRK_GIB_CRG1). The NCGRD stated that this resource, which was under a mothballed status, would change to a status of decommissioned and retired permanently as of October 23, 2019. Gibbons Creek is a 470 MW coal unit located in Grimes County (20 miles southeast of College Station) and owned by the Texas Municipal Power Agency (TMPA), which is an organization jointly owned by four municipalities – the cities of Garland, Denton, Bryan and Greenville.

Finally, on July 29, 2019, ERCOT received an NSO for Gregory Power Partners, LLC's LGE Generation Resources.[62] The NSO indicated that these Resources would suspend operations on a year-round basis (i.e., mothball) beginning October 17, 2019, with a Seasonal Operation Period of June 1 through September 30. The NSO further indicated that these Resources have a summer Seasonal Net Max Sustainable Rating of 365 MW, and a summer Seasonal Net Minimum Sustainable Rating of 195 MW.

[62] LGE_LGE_GT1, LGE_LGE_GT2 and LGE_LGE_STG.

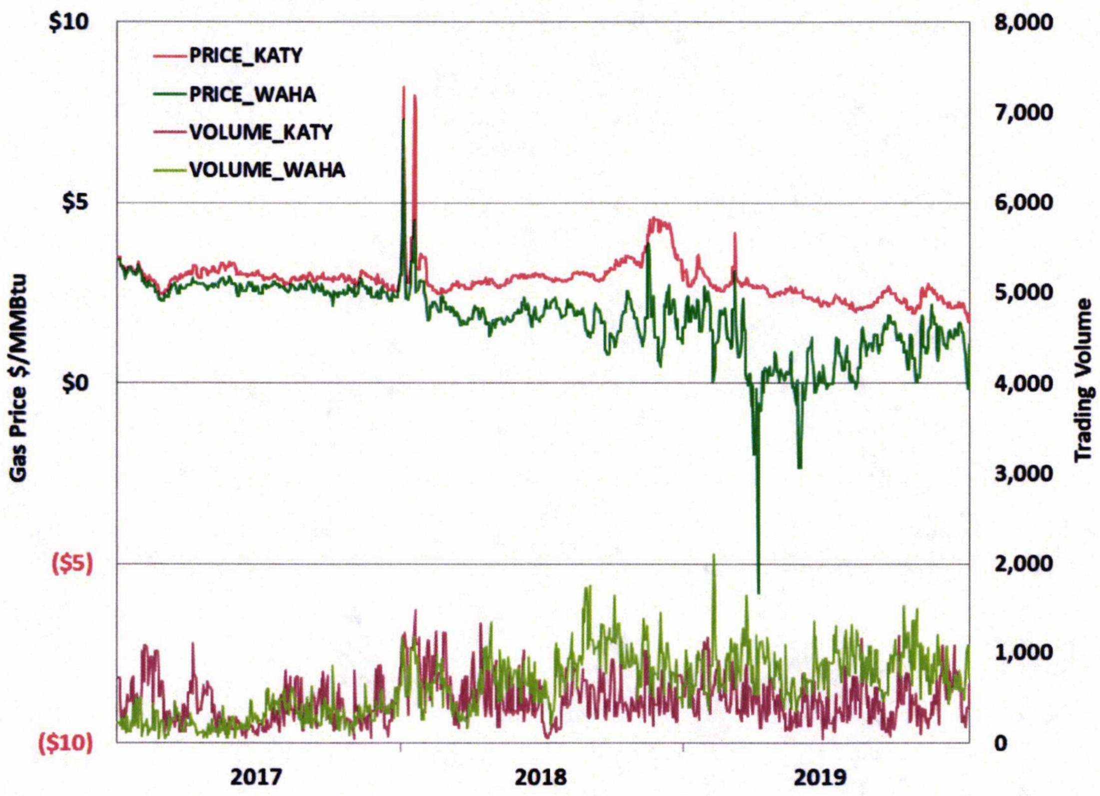
VI. APPENDIX: RESOURCE ADEQUACY

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 2019, we saw a continuing trend evident of the growing separation in natural gas prices between the Waha and Katy locations in the West.[63] Increased 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. As seen in Figure A45 below, Waha prices dipped below $0 multiple times throughout 2019, and were more volatile than Katy.

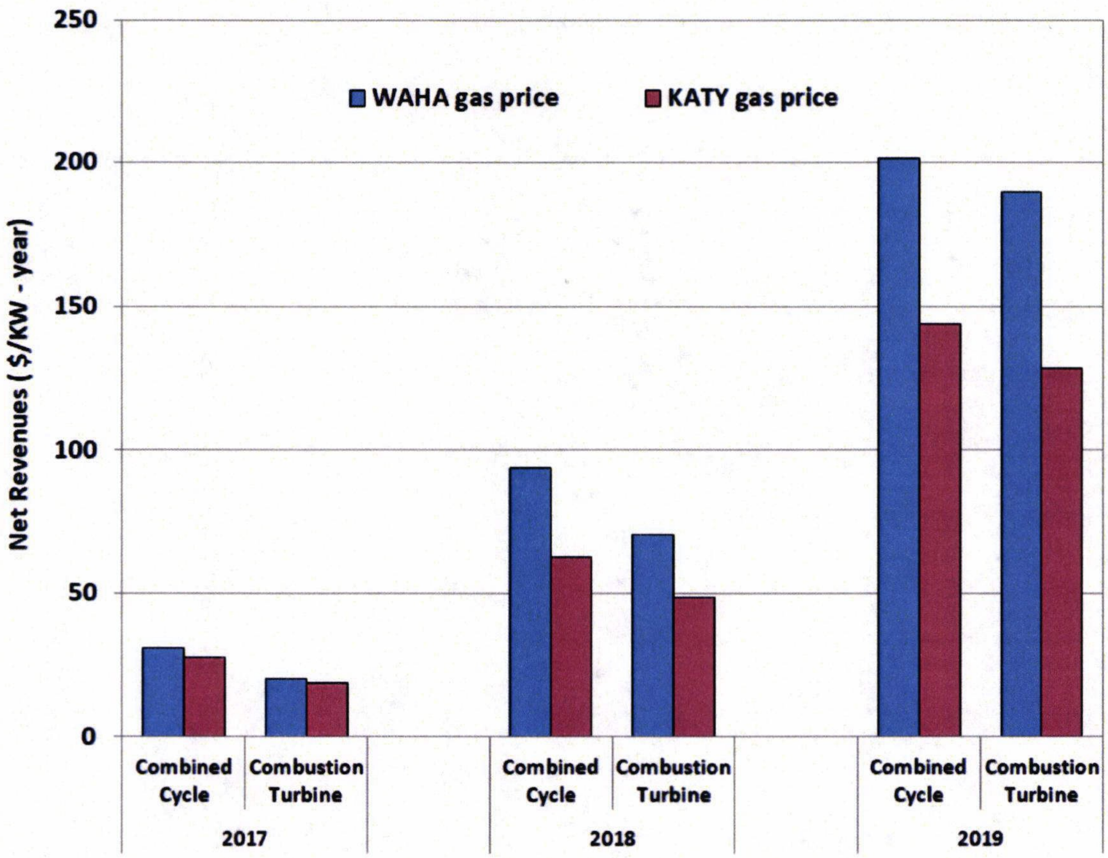
Figure A45: Gas Price and Volume by Index



63 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. Additionally, the divergence between Waha and Katy gas prices contributed to even greater net revenues for West Texas gas-fired generators. Figure A46 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 significantly higher than in the other three zones.

Figure A46: West Zone Net Revenues



VII. Appendix: Analysis of Competitive Performance

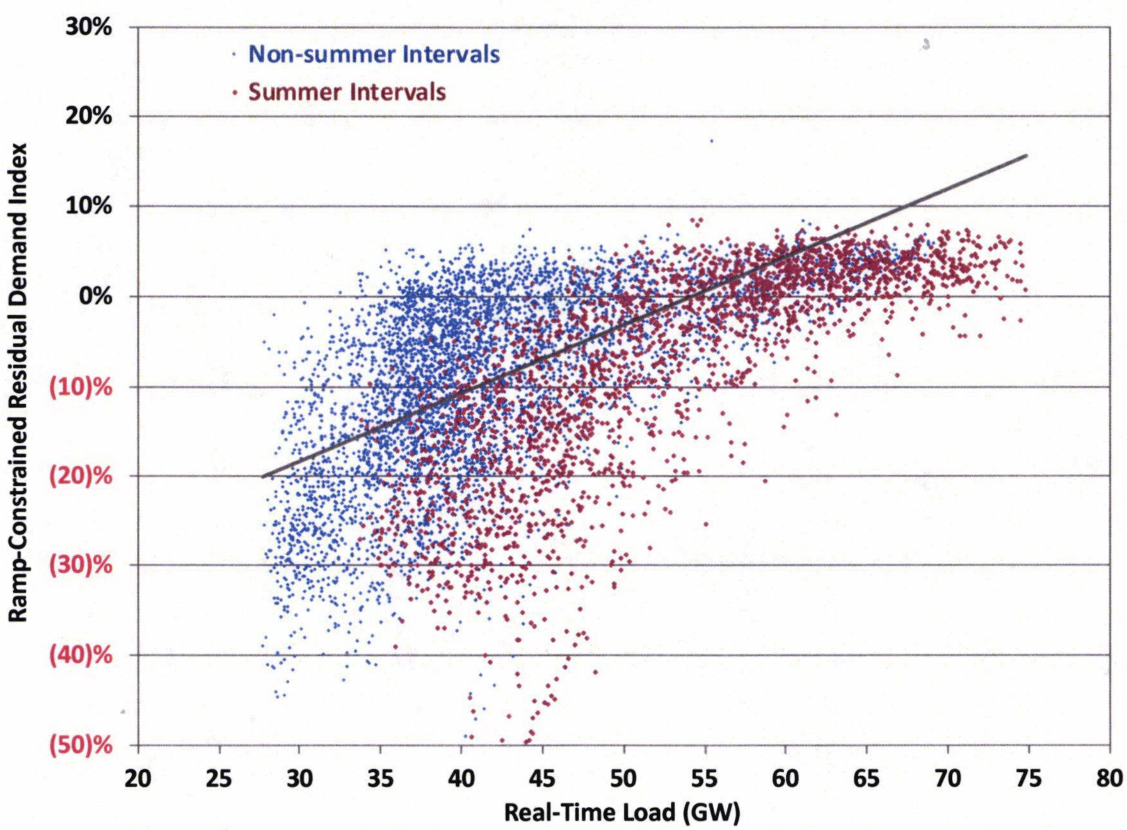
In this section, we provide supplemental analyses to evaluate market power from two perspectives: structural (does market power exist?) and behavioral (have attempts been made to exercise it?). Market structure is examined by using a pivotal supplier analysis that indicates the frequency with which a 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 need to serve the load if the resources of its competitors are available.

Figure A47 shows the ramp-constrained RDI, calculated at the QSE level, relative to load for all hours in 2019. 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 35 GW. The trend line indicates a strong positive relationship between load and the RDI.

Figure A47: Residual Demand Index



1. Voluntary Mitigation Plans

Calpine's VMP was approved in March of 2013.[64] 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,[65] 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.

B. Evaluation of Supplier Conduct

1. Generation Outages and Deratings

Figure A48 shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2019.

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

65 PUCT Docket No. 40488, *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)*, Order (Jul. 13, 2012); PUCT Docket No. 42611, *Request for Approval of an Amended Voluntary Mitigation Plan for NRG Companies*, Order (Jul. 11, 2014).

Figure A48: Short-Term Outages and Deratings

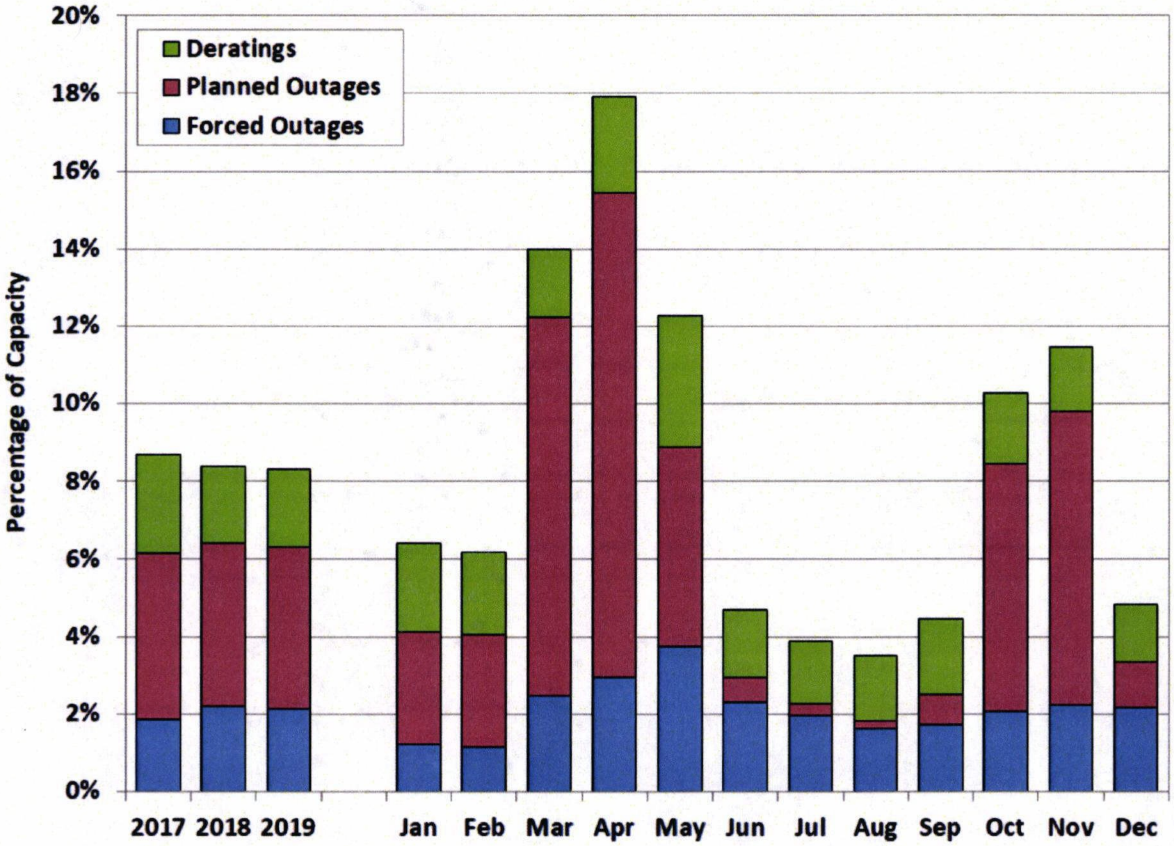


Figure A48 shows that short-term outages and deratings in 2019 followed a pattern similar to what occurred in 2018, as the expectations for summer shortage in both years prompted short-term outage and derating spikes in shoulder months. The total short-term deratings and outages in 2019 were almost 18% of installed capacity in April (up from 14% in 2018) and dropped to less than 4% during July and August (the same as in 2018).

Most of this fluctuation was due to planned outages. The amount of capacity unavailable during 2019 averaged 8.3% of installed capacity, a modest decrease from the 8.4% experienced in 2018, and 8.7% experienced in 2017. The numbers of planned outages remained steady in 2019, 4.2% on average for both 2018 and 2019. This 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 two years may be similarly explained by generators operating in modes that would allow them to maximize generation.