2013 STATE OF THE MARKET REPORT FOR THE ERCOT WHOLESALE ELECTRICITY MARKETS

POTOMAC ECONOMICS, LTD.

Independent Market Monitor for the
ERCOT Wholesale Market

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EXECUTIVE SUMMARY

A. Introduction

This report reviews and evaluates the outcomes of the ERCOT wholesale electricity markets in 2013, and is submitted to the Public Utility Commission of Texas ("PUCT") and the Electric Reliability Council of Texas ("ERCOT") pursuant to the requirement in Section 39.1515(h) of the Public Utility Regulatory Act. It includes assessments of the incentives provided by the current market rules and procedures, and analyses of the conduct of market participants. This report also assesses the effectiveness of the Scarcity Pricing Mechanism ("SPM") pursuant to the provisions of PUCT Substantive Rule 25.505(g).

Key findings and statistics from 2013 include the following:

- The ERCOT wholesale market performed competitively in 2013.

- The ERCOT-wide load-weighted average real-time energy price was $33.71 per MWh in 2013, a 19 percent increase from $28.33 per MWh in 2012. The increase was primarily driven by higher natural gas prices in 2013.

  - The average price for natural gas was 37 percent higher in 2013 than in 2012, increasing from $2.71 per MMBtu in 2012 to $3.70 per MMBtu in 2013.

  - Loads in 2013 were slightly higher than 2012, but the frequency of shortage conditions decreased. Total ERCOT load in 2013 was 2.1 percent higher than 2012, while the peak load increased by 1.0 percent.

  - Prices at the system-wide offer cap were experienced in dispatch intervals which totaled less than 15 minutes in 2013.

- The total congestion revenue generated by the ERCOT real-time market in 2013 was $466 million, a decrease of 3 percent from 2012. Given the increase in natural gas prices, a decrease in congestion revenue is a testament to the benefits accrued from investment in transmission facilities.

- The Odessa area continued to be the most highly congested area in 2013. This and other constraints in west Texas had significant financial impacts, causing the West zone average price to be higher than the ERCOT average for the second year in a row.

- Even with the increased system-wide offer cap implemented in 2013, net revenues provided by the market were once again not sufficient to support new generation entry despite the fact planning reserve margins have fallen to levels that are close to the minimum planning reserve targets.

B. Review of Real-Time Market Outcomes

As is typical in other wholesale electricity markets, only a small share of the power produced in ERCOT is transacted in the spot market. However, prices in the real-time energy market are very important because they set the expectations for prices in the day-ahead and other forward markets where most transactions take place. Unless there are barriers preventing arbitrage of the prices between the spot and forward markets, the prices in the forward market should be directly related to the prices in the spot market.

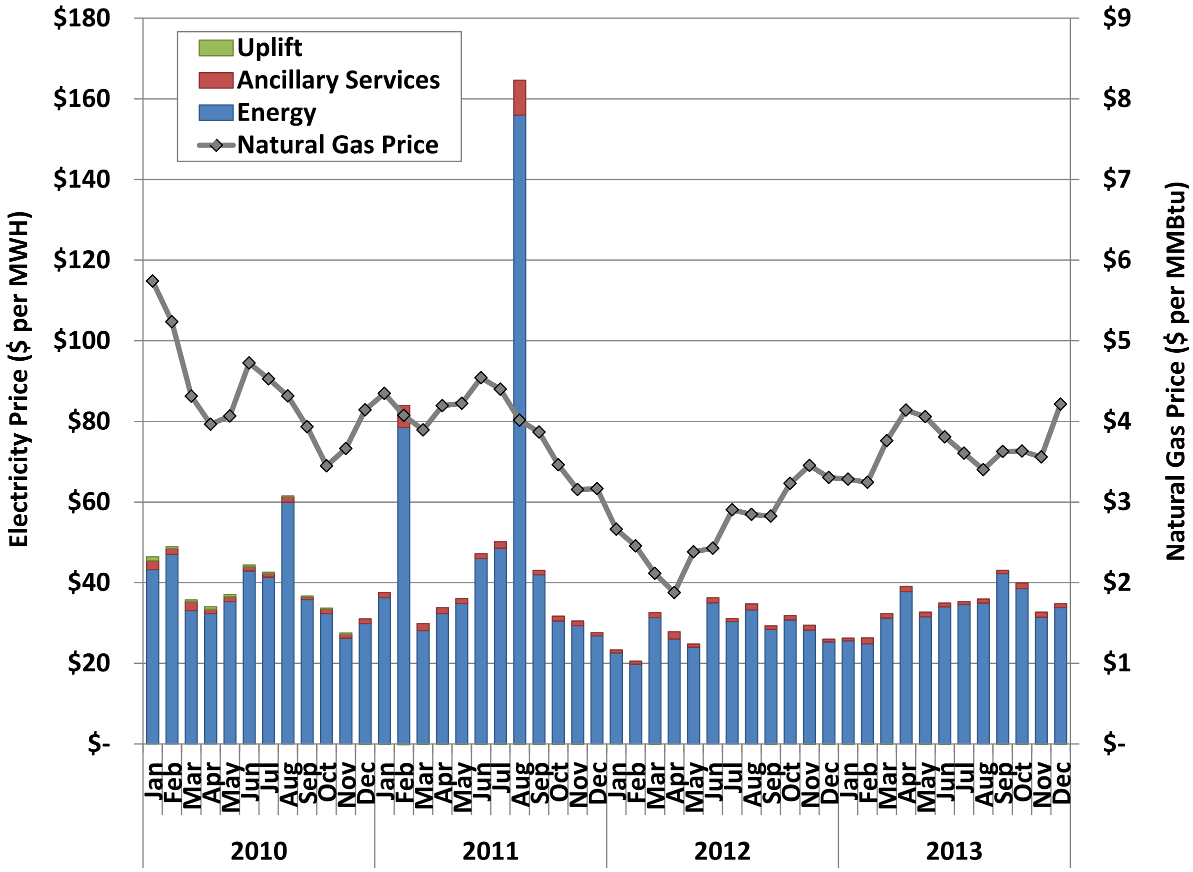
The average real-time energy prices by zone in 2010 through 2013 are shown below:

Average Real-Time Electricity Price
($ per MWh)

	2010	2011	2012	2013
ERCOT	**$39.40**	**$53.23**	**$28.33**	**$33.71**
Houston	$39.98	$52.40	$27.04	$33.63
North	$40.72	$54.24	$27.57	$32.74
South	$40.56	$54.32	$27.86	$33.88
West	$33.76	$46.87	$38.24	$37.99
Natural Gas ($/MMBtu)	$4.34	$3.94	$2.71	$3.70

The next figure summarizes changes in energy prices and other market costs by showing the all-in price of electricity, which is a measure of the total cost of serving load in ERCOT. The all-in price of electricity is equal to the load-weighted average real-time energy price, plus ancillary services, and real-time uplift costs per MWh of real-time load. The largest component of the all-in cost of wholesale electricity is the energy cost, which is reflected in the real-time locational marginal prices. ERCOT average real-time market prices were 19 percent higher in 2013 than in 2012. The ERCOT-wide load-weighted average price was $33.71 per MWh in 2013 compared to $28.33 per MWh in 2012.

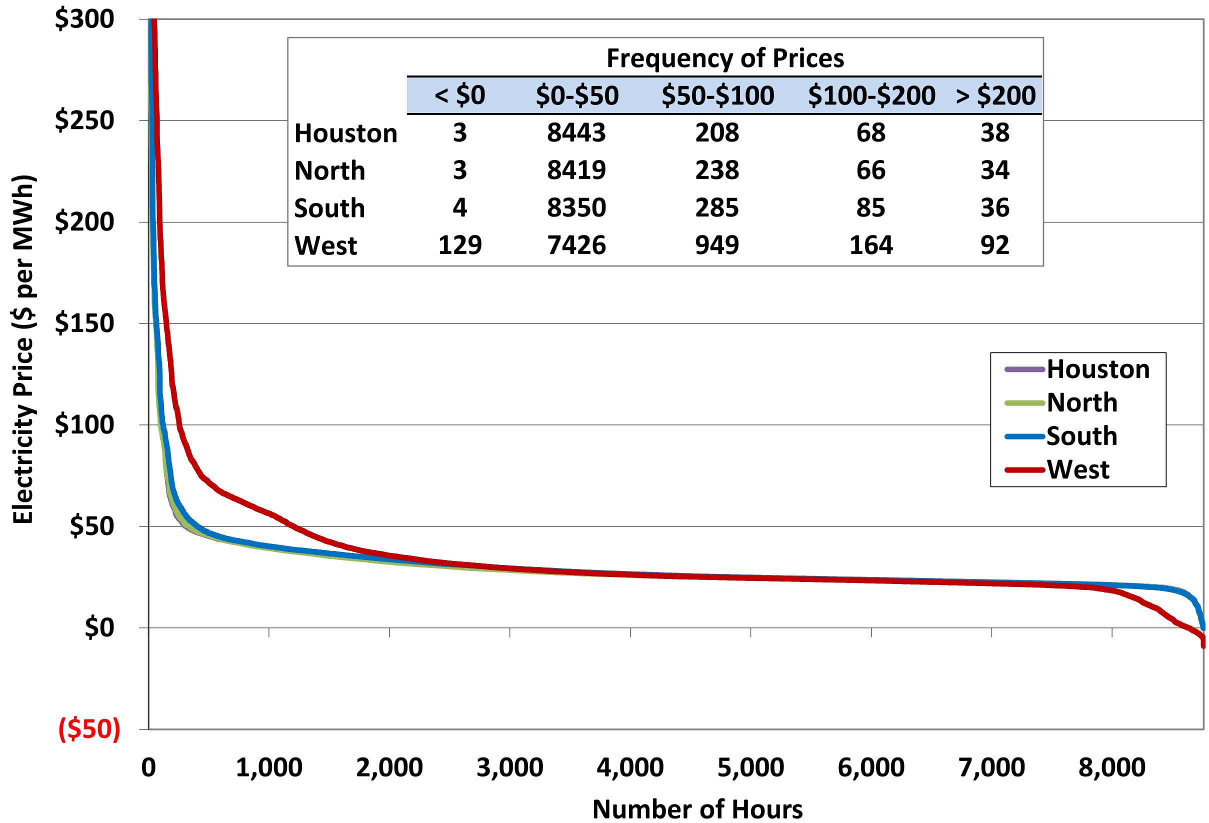
Average All-in Price for Electricity in ERCOT



The increase in real-time energy prices was correlated with higher fuel prices in 2013. The average natural gas price in 2013 was $3.70 per MMBtu, a 37 percent increase compared to $2.71 per MMBtu in 2012. Ancillary service prices represent a relatively small portion of the all-in price of electricity and decreased slightly from 2012 to 2013.

To depict how real-time energy prices vary by hour in each zone, the next figure shows the hourly average price duration curve in 2013 for four ERCOT load zones. The Houston, North and South load zones had similar prices over the majority of hours. The price duration curve for the West zone is noticeably different than the other zones, with more hours with prices greater than $50 per MWh and 129 hours when the average hourly price was less than zero.

Zonal Price Duration Curves

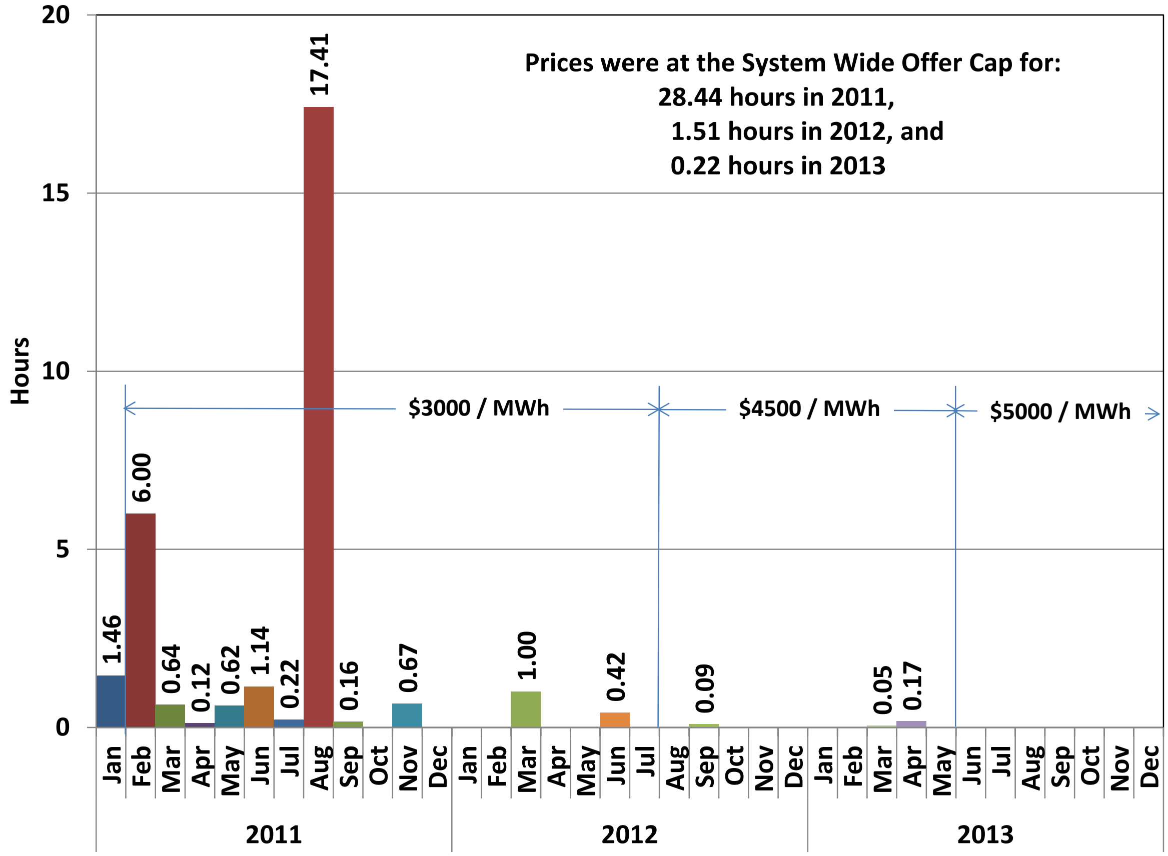


As observed over the past few years, West zone prices are lower than the rest of ERCOT when high wind output in the west results in congested transmission interfaces from the West zone to the other zones in ERCOT. Recently, prices higher than the rest of ERCOT have occurred in the West zone due to local transmission constraints that typically occur under low wind and high load, or outage conditions. Specifics about these transmission constraints are provided in Section III, Transmission and Congestion.

As discussed in Section IV, Load and Generation, overall demand for electricity was slightly higher in 2013 than in 2012. However, there were fewer occasions when the available supply of generation resources was insufficient to satisfy the system's demands and, thus, less frequent instances of shortage pricing.

The figure below shows the aggregated amount of time where the real-time energy price was at the system-wide offer cap, displayed by month. Prices during 2013 were at the system-wide offer cap for only 0.22 hours (less than 15 minutes), a reduction from 1.51 hours in 2012 and a significant reduction from the 28.44 hours in 2011. Approved during 2012, PUCT SUBST. R.25.508 increased the system-wide offer cap to $4,500 per MWh effective August 1, 2012. Revisions to PUCT SUBST. R.25.505 raised the system-wide offer cap to $5,000 per MWh effective June 1, 2013. As shown in the figure below, there was only a brief period when energy prices rose to the cap after these changes were implemented.

Duration of Prices at the System-Wide Offer Cap



These results are not surprising because shortage pricing is highly variable year-to-year. When temperatures lead to weather dependent loads that are significantly higher than normal or supply is less available than normal, the frequency of shortages tend to increase exponentially. Hence, one should expect that shortages will be very infrequent in normal or mild years, such as in 2012 and 2013. Although the shortages in 2011 seemed relatively severe, adequate long-term incentives will only exist in ERCOT if the total value of shortages exceeds the value exhibited in 2011 every few years.

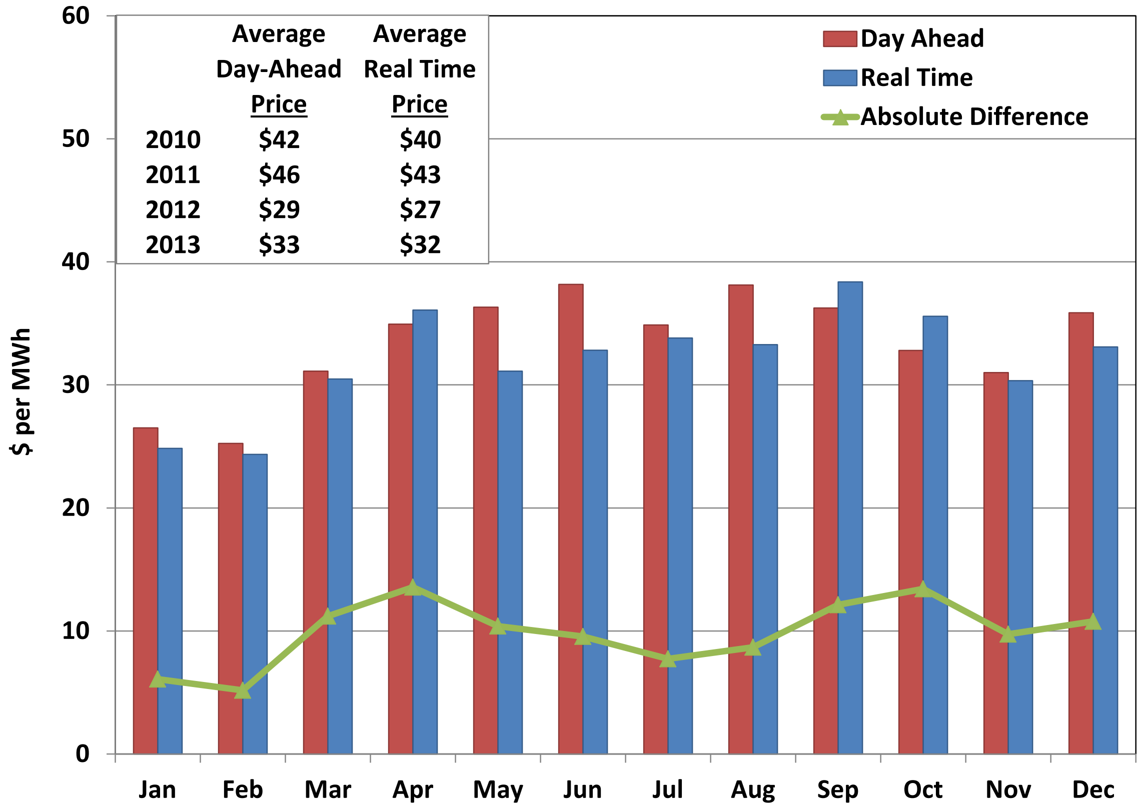
C. Review of Day-Ahead Market Outcomes

ERCOT's centralized day-ahead market allows participants to make financially binding forward purchases and sales of power for delivery in real-time. Although all bids and offers are evaluated in the context of their ability to reliably flow on the transmission network, there are no operational obligations resulting from the day-ahead market clearing. These transactions are made for a variety of reasons, including satisfying the participant's own supply, managing risk by hedging the participant's exposure to the real-time market, or arbitraging with the real-time markets. For example, load serving entities can insure against volatility in the real-time market by purchasing in the day-ahead market. Finally, the day-ahead market plays a critical role in coordinating generator commitments. For all of these reasons, the performance of the day-ahead market is essential.

Day-ahead market performance is primarily evaluated by the degree to which its outcomes converge with those of the real-time market because the real-time market reflects actual physical supply and demand for electricity. In a well-functioning market, participants should eliminate sustained price differences on a risk-adjusted basis by making day-ahead purchases or sales to arbitrage them over the long-term.

The figure below shows the price convergence between the day-ahead and real-time market, summarized by month. The simple average of day-ahead prices in 2013 was $33 per MWh, compared to the simple average of $32 per MWh for real-time prices. The average absolute difference between day-ahead and real-time prices was $9.86 per MWh in 2013; slightly lower than in 2012 when average of the absolute difference was $9.96 per MWh.

Convergence between Forward and Real-Time Energy Prices

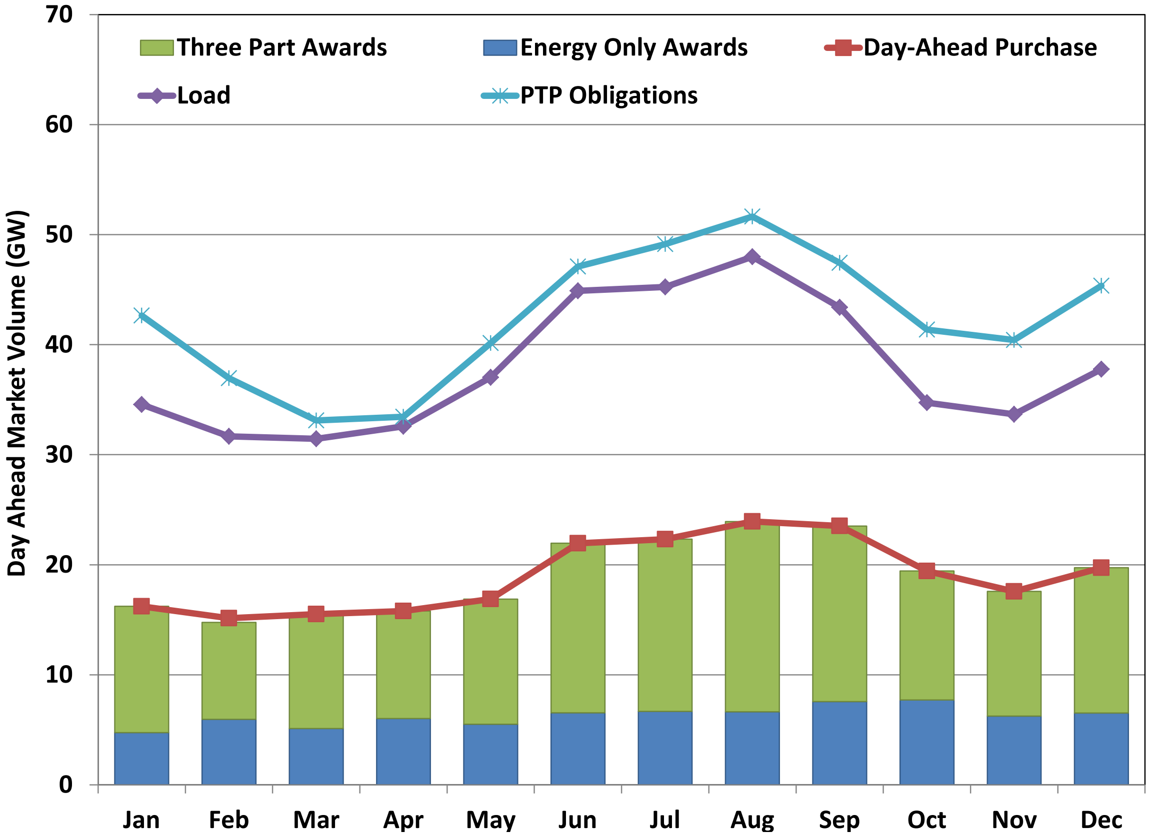


This day-ahead premium is consistent with expectations due to the much higher volatility of real-time prices. Risk is lower for loads purchasing in the day-ahead and higher for generators selling day-ahead. The higher risk for generators is associated with the potential of incurring a forced outage and as a result, having to buy back energy at real-time prices. This explains why the highest premiums tend to occur during the months with the highest demand and highest prices.

Overall, the day-ahead premiums were very similar to the differences observed in 2012, but remain higher than observed in other organized electricity markets. Real-time energy prices in ERCOT are allowed to rise to levels that are much higher than what is allowed in other organized electricity markets, which increases risk and helps to explain the higher day-ahead premiums regularly observed in ERCOT. Although most months experienced a day-ahead premium (*e.g.*, $5 per MWh in May, June and August), it should not be expected over time that every month will always produce a day-ahead premium as the real-time risks that lead to the premiums will materialize unexpectedly on occasion, resulting in real-time prices that exceed day-ahead prices (*e.g.*, in April, September and October).

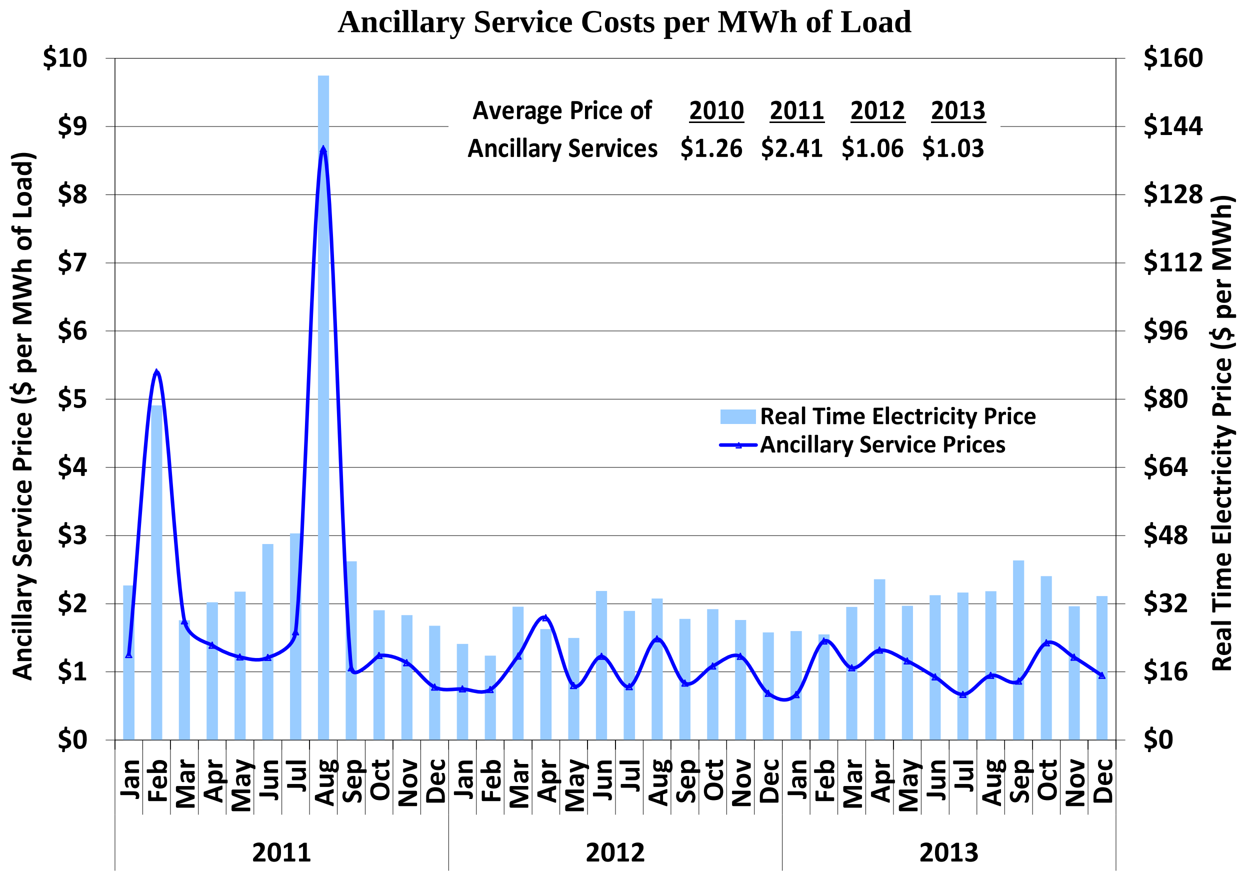
Summarized in the figure below is the volume of day-ahead market activity by month. It shows that day-ahead purchases are approximately 50 percent of real-time load, which is an increase from 2012 when they averaged 45 percent.

Volume of Day-Ahead Market Activity by Month



This figure also shows the volume of Point to Point Obligations, which are financial instruments purchased in the day-ahead market. Although these instruments do not themselves involve the direct supply of energy, they do provide the ability to avoid the congestion costs associated with transferring the delivery of energy from one location to another. To show the volume of these transactions, we aggregate all of these "transfers", netting location specific injections against withdrawals. To provide a sense of the magnitude of the PTP transactions, the figure shows that by adding the aggregated transfer capacity associated with purchases of PTP Obligations, total volumes transacted in the day-ahead market on average are greater than real-time load in each month.

Ancillary Service capacity is procured through the day-ahead market. The figure below shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2011 through 2013. Total ancillary service costs are generally correlated with real-time energy price movements, which in turn are highly correlated with natural gas price movements. The average ancillary service cost per MWh of load decreased to $1.03 per MWh in 2013 compared to $1.06 per MWh in 2012, a decrease of 3 percent. Total ancillary service costs decreased from 3.7 percent of the load-weighted average energy price in 2012 to 3.0 percent in 2013.



D. Transmission and Congestion

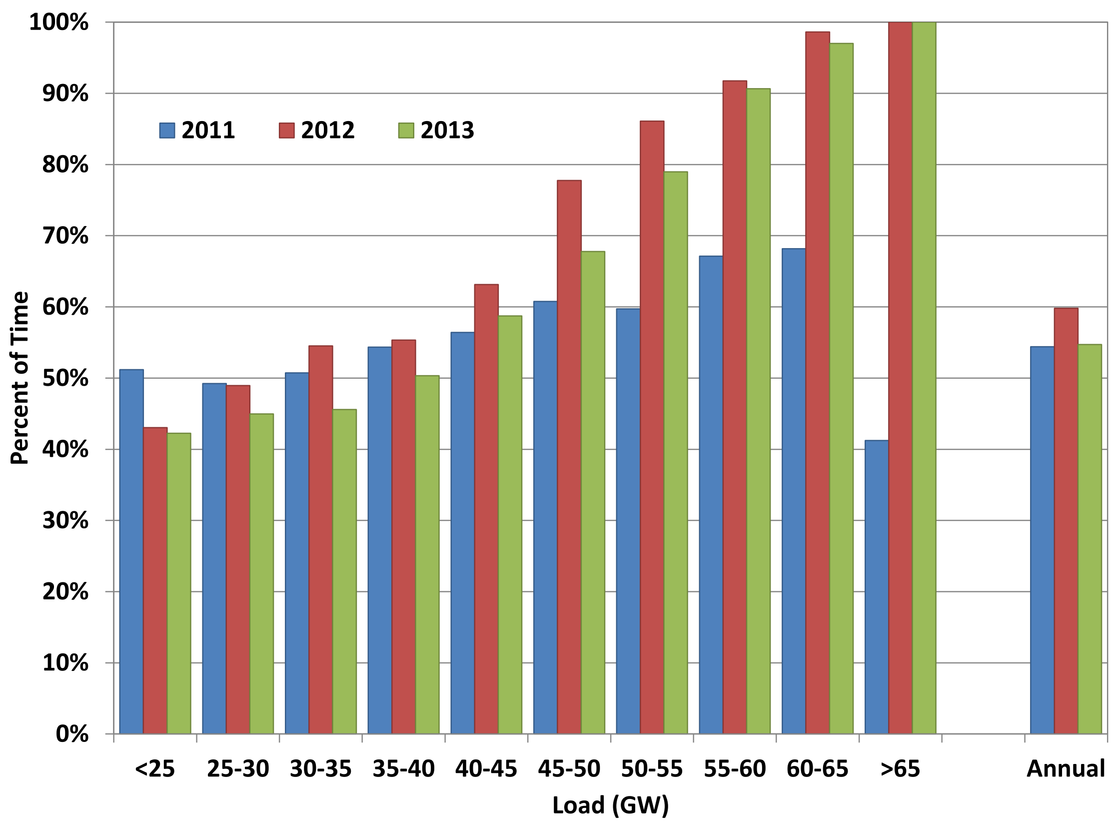
The total congestion revenue generated by the ERCOT real-time market in 2013 was $466 million, a decrease of 3 percent from 2012. This decrease is mostly attributed to transmission improvements in west Texas, specifically in the Odessa area and the completion of CREZ transmission projects. The largest contributors to the overall costs of congestion in 2013 were several localized transmission constraints in far west and south Texas.

Real-time transmission congestion during 2013 continued the trend seen since 2012 of localized higher load due to increased oil and natural gas production activity as the cause of most significant constraints. There was an increase in congestion within the South zone related to higher loads associated with increased activity in the Eagle Ford shale during 2013 and transmission equipment outages within the South zone.

Given increases in local loads and the increase in fuel prices, it is noteworthy that transmission congestion decreased in 2013. This reduction was due in large part to transmission improvements that decreased the congestion levels in the West zone. Annual prices for loads located in the West zone were $11 per MWh higher than ERCOT average in 2012. In 2013, West zone prices were $5 per MWh higher. By the end of 2013, the completion of the CREZ transmission lines virtually eliminated longstanding limitations affecting wind exports from the West zone.

The next figure shows the amount of time transmission constraints were active at various load levels in 2013, 2012 and 2011.

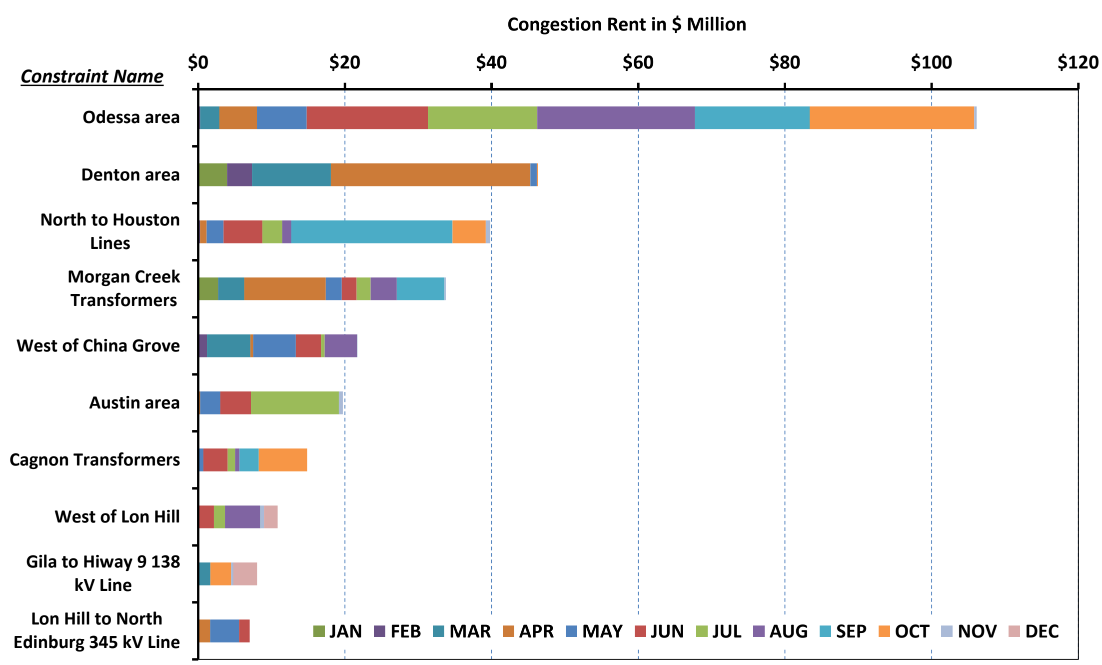
Frequency of Active Constraints



This figure shows that constraints were active slightly less frequently in 2013 than in 2012, but still more frequently than 2011. We previously observed that during 2011, ERCOT operators did not always activate (or sometimes de-activated) transmission constraints during periods of higher system loads. This was due to a concern that by having a constraint active during periods of high demand the total capacity available to serve load may be limited. However, ERCOT's dispatch software contains parameters that allow it to automatically make the correct decision about when to violate transmission constraints when necessary to serve total system load. Therefore, ERCOT modified this practice in 2012 to retain active transmission constraints even during periods of high demand. Further, NERC standards support the continued management of transmission constraints under higher loads and potential scarcity conditions.

The figure below displays the ten areas that generated the most real-time congestion and indicates that the Odessa area was again the most congested location in 2013. The primary constraint in the area is the Odessa to Odessa North 138 kV line, representing 54 percent of the total cost for the area. Congestion in this area became more pronounced in 2012 and is mainly attributed to load growth in far west Texas driven by increased oil and natural gas activity.

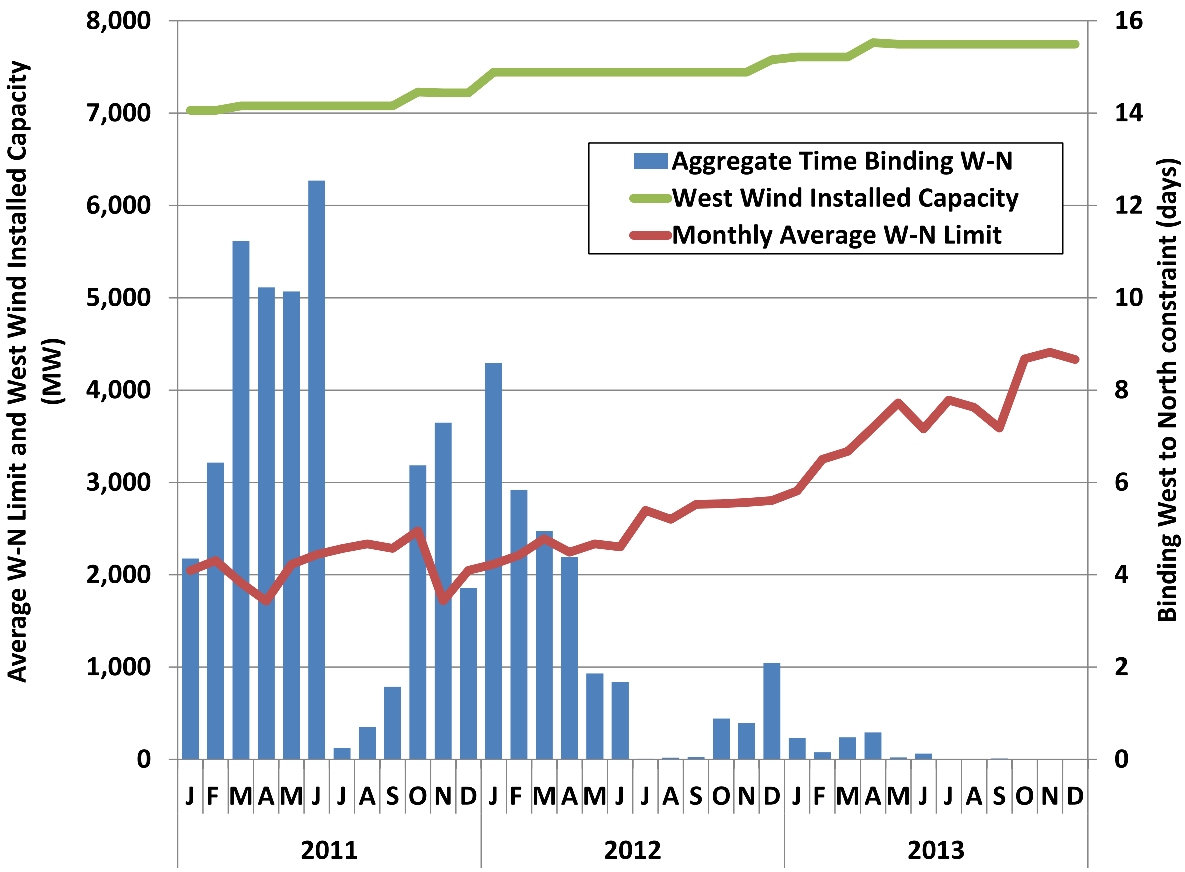
Top Ten Real-Time Constraints



The most significant constraint in 2012, the Odessa North 138/69 kV transformer, was no longer binding in 2013 because the transformer was upgraded in late 2012. Even with the elimination of the most significant constraint in 2012, the Odessa area continues to have the most real-time congestion in ERCOT, with more than twice the financial impact of the second most congested area.

The figure below shows the number of 24-hour periods that the West to North interface transmission constraint was binding each month from 2011 through 2013. Even with continued increases in wind resources in the West zone, binding constraints affecting exports from the West zone fell sharply as the completion of CREZ lines resulted in higher limits on the West to North constraint.

Utilization of the West to North Interface Constraint

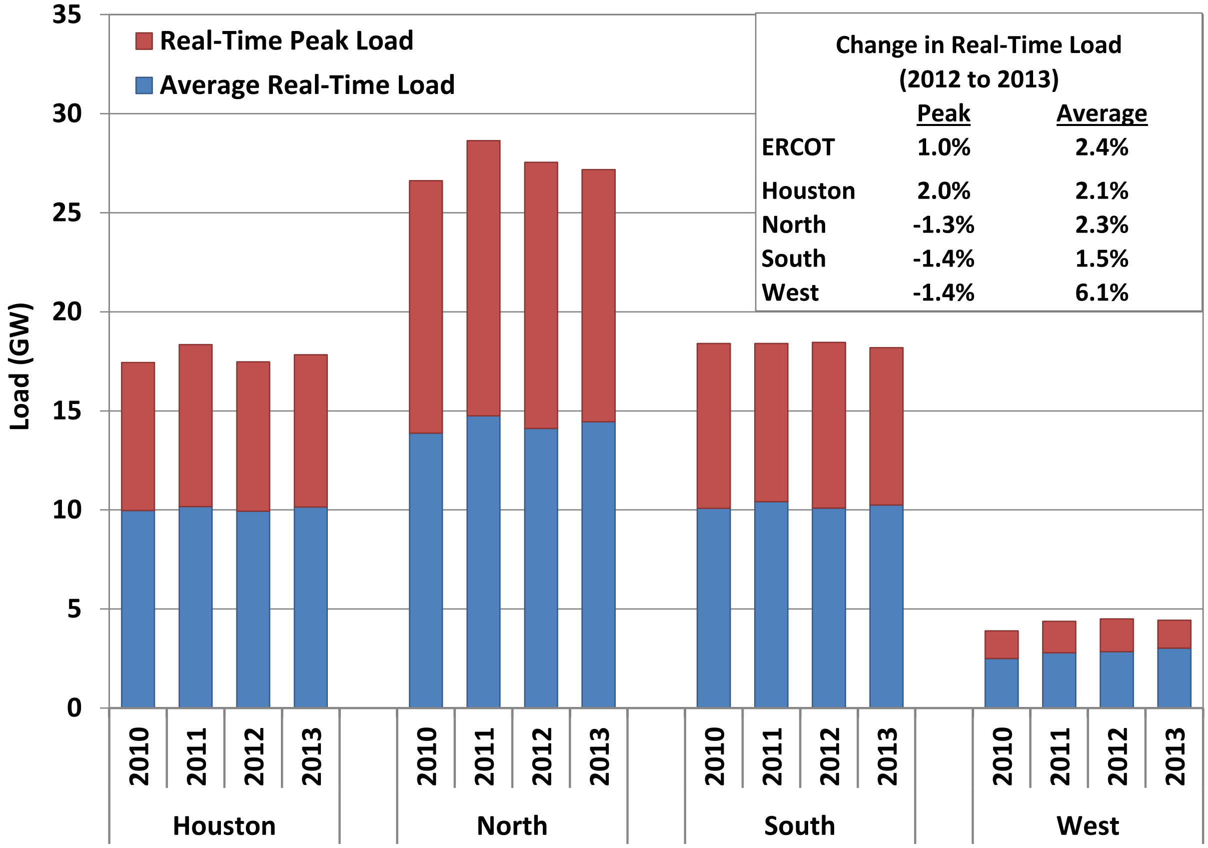


Prior to 2013, the West to North transmission constraint was perennially a top 10 real-time constraint. However, with the completion of the CREZ transmission lines at the end of 2013, the West to North constraint is no longer a significant factor.

E. Load and Generation

The figure below shows peak load and average load in each of the ERCOT zones from 2010 to 2013. In each zone, as in most electrical systems, peak demand significantly exceeds average demand. The North zone is the largest zone (with about 38 percent of the total ERCOT load); the South and Houston zones are comparable (27 percent) while the West zone is the smallest (8 percent of the total ERCOT load). The figure also shows the annual non-coincident peak load for each zone. This is the highest load that occurred in a particular zone for one hour during the year; however, the peak can occur in different hours for different zones. As a result, the sum of the non-coincident peaks for the zones is greater than the annual ERCOT peak load.

Annual Load Statistics by Zone



Total ERCOT load increased from 325 TWh in 2012 to 332 TWh in 2013, an increase of 2.1 percent or an average of 870 MW every hour. Similarly, the ERCOT coincident peak hourly demand increased from 66,559 MW to 67,245 MW in 2013, an increase of 686 MW, or 1.0 percent.

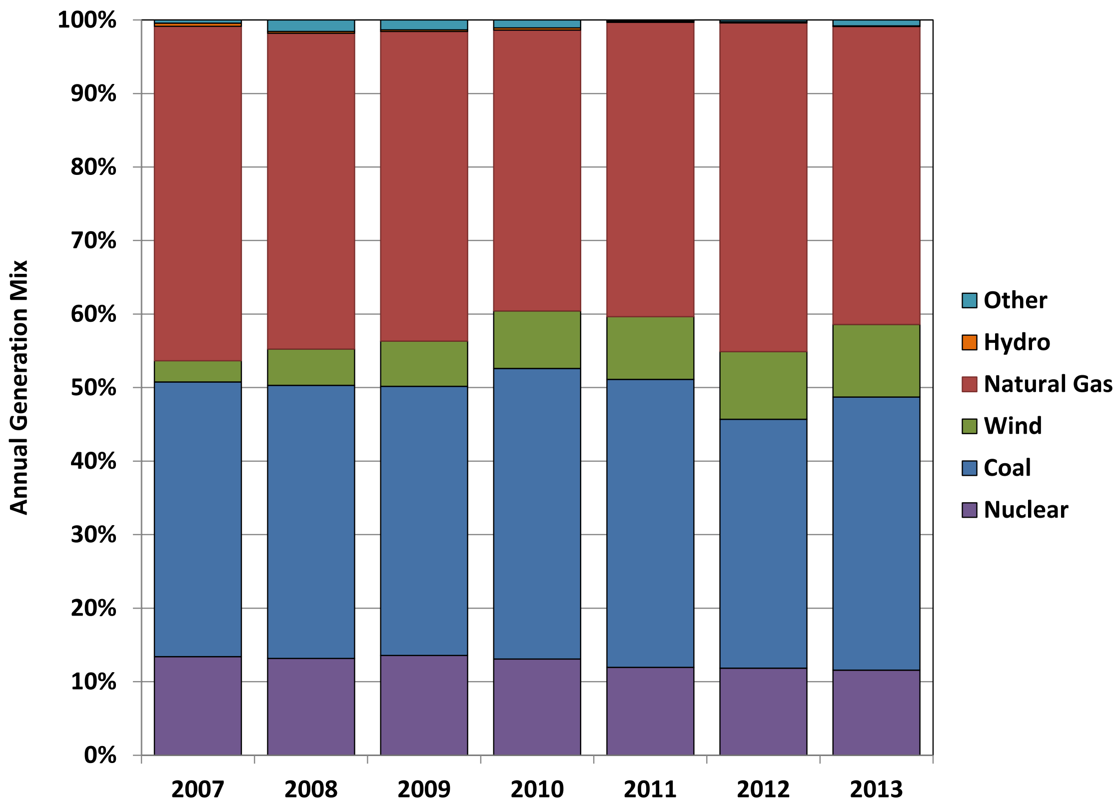
The changes in load at the zonal level are not the same. Peak load in the Houston zone increased, while it decreased in the other zones. The average growth rate of load in the West zone once again was much higher than in the other zones.

Approximately 1.6 GW of new generation resources came online in 2013, the bulk of which was a single large (970 MW) coal unit. The other additions were wind, gas and solar units. When unit retirements are included, the net capacity addition in 2013 was 1 GW. After the capacity changes in 2013 the mix between natural gas and coal generation remains stable. Natural gas generation accounts for approximately 48 percent of total ERCOT installed capacity and coal for approximately 21 percent.

Over the seven years from 2007 to 2013, wind and coal generation capacity increased the most. The sizable additions in these two categories have been more than offset by retirements of natural gas-fired steam units, resulting in less installed capacity in 2013 than there was in 2007.

The figure below shows the percentage of annual generation from each fuel type for the years 2007 through 2013.

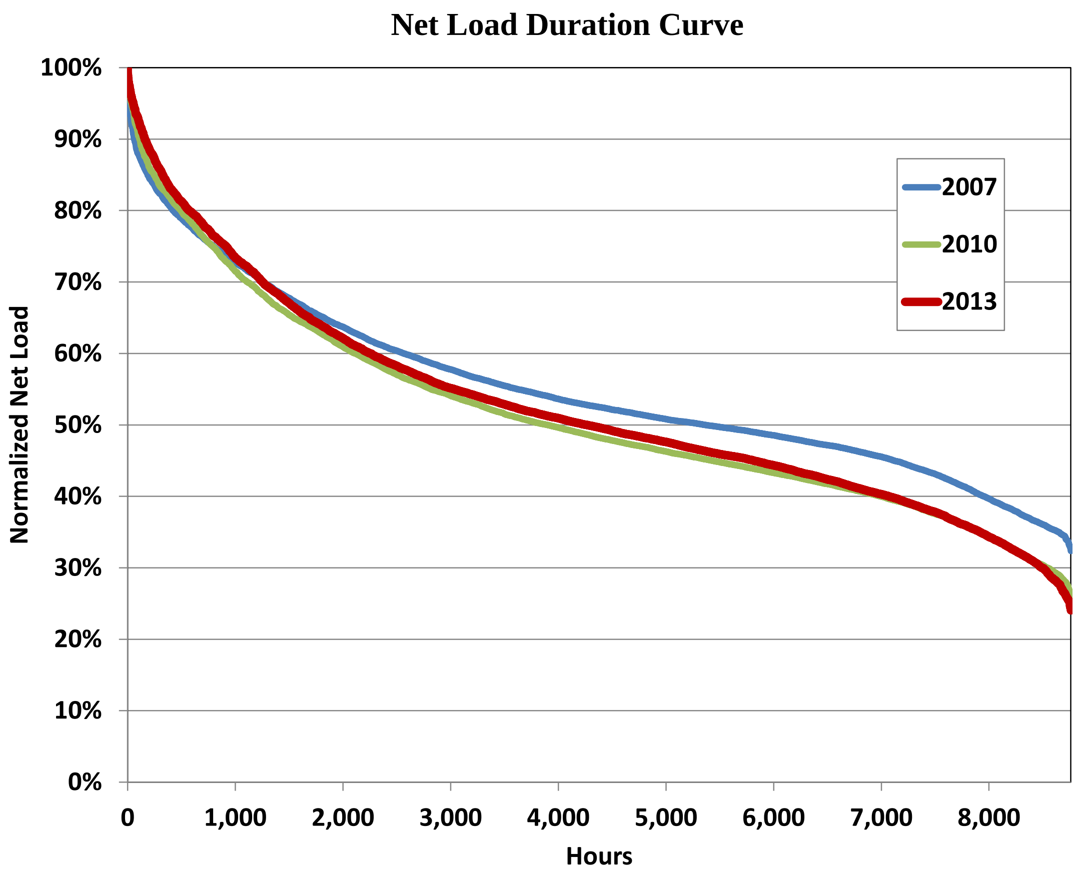
Annual Generation Mix



The generation share from wind has increased every year, reaching 10 percent of the annual generation requirement in 2013, up from 3 percent in 2007. During the same period the percentage of generation provided by natural gas has ranged from a high of 45 percent in 2007 to a low of 38 percent in 2010. In 2013 the percentage of generation from natural gas decreased slightly from 2012 to 41 percent. Correspondingly, the percentage of generation produced by coal units ranged from a high of 40 percent in 2010 to a low of 34 percent in 2012. The percentage of generation from coal increased to 37 percent in 2013. The rebound in the share of generation produced by coal in 2013 was due to the increase in natural gas prices from the historical low levels experienced in 2012.

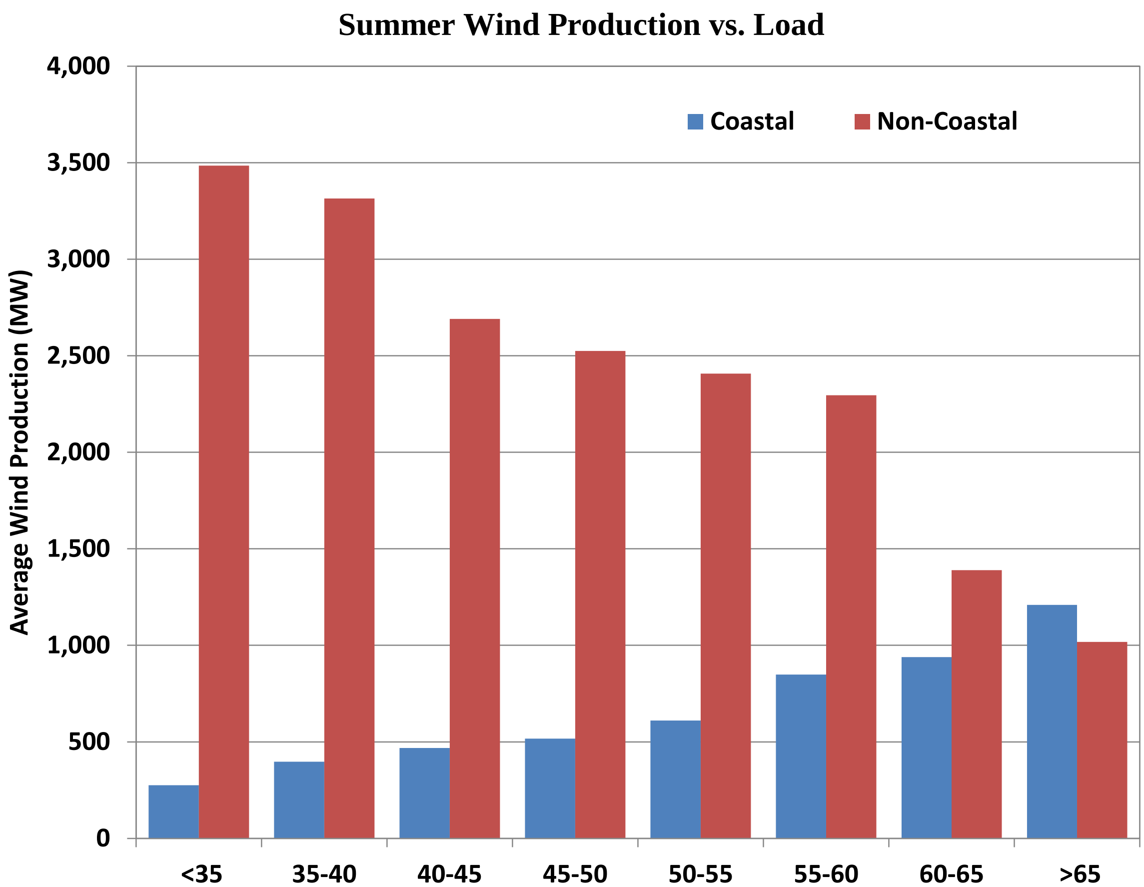
While coal/lignite and nuclear plants produce a large share of the energy in ERCOT because they operate primarily as base load units, natural gas resources are most frequently on the margin setting the real-time energy prices. This accounts for the high correlation between real-time energy prices and the price of natural gas fuel. There is approximately 23.5 GW of coal and nuclear generation in ERCOT. Generally, when ERCOT load is above this level, natural gas resources will be on the margin and set the real-time energy spot price.

Increasing levels of wind resource in ERCOT also has important implications for the net load duration curve faced by the non-wind fleet of resources. For the following analysis, we define net load as the system load minus wind production. The figure below shows the net load duration curves for selected years since 2007, normalized as a percent of peak load. This figure shows the continued erosion of residual load for non-wind units to serve during most hours of the year. These results show that these impacts were much less during the highest load periods because wind tends to produce much less during peak load conditions.



Thus, although the peak net load and reserve margin requirements are projected to continue to increase, the non-wind fleet is expected to operate for fewer hours as wind penetration increases. This outlook further reinforces the importance of efficient energy pricing during peak demand conditions and other times of system stress, particularly within the context of the ERCOT energy-only market design.

The next figure compares the output during the summer months of June through August from wind units located in the coastal area of the South zone with those located elsewhere in ERCOT.



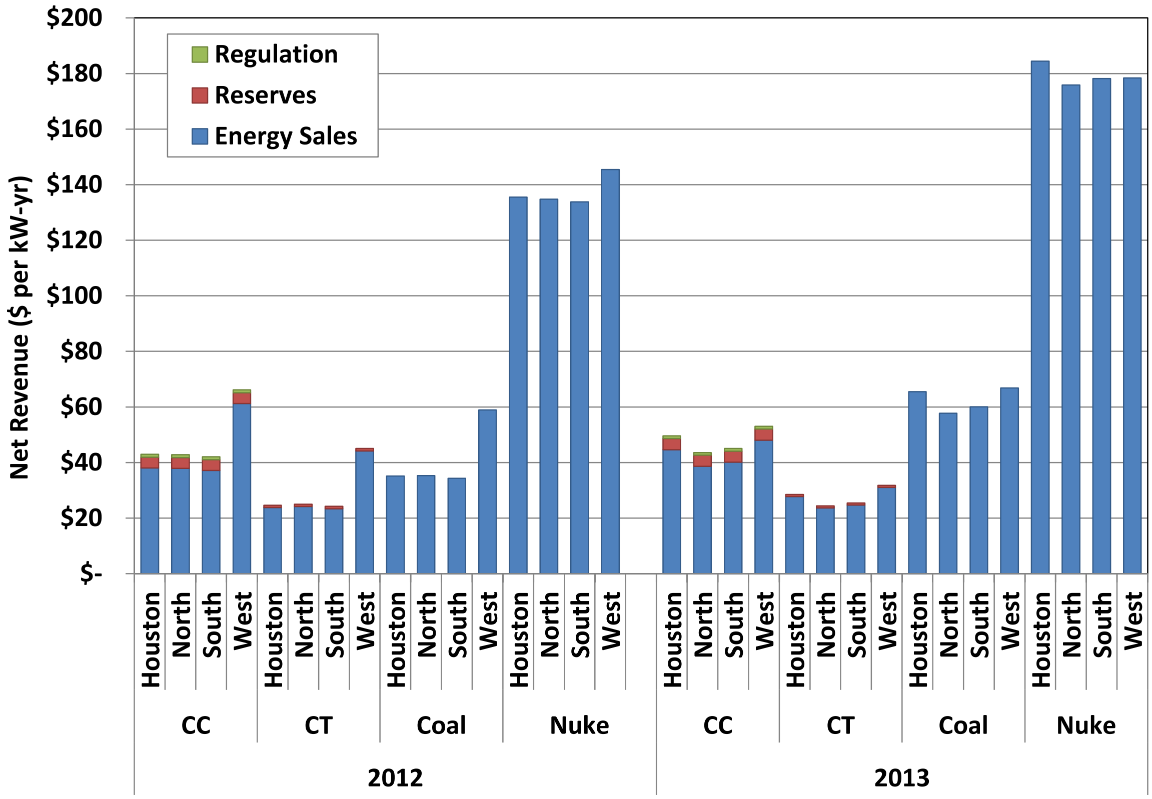
It shows a strong negative relationship between non-coastal wind output and increasing load levels. This pattern limits the value of wind resources in satisfying ERCOT's resource adequacy needs described in the next subsection. It also shows that the output from wind generators located in the coastal area of the South zone is much more highly correlated with peak electricity demand than is non-coastal wind.

F. Resource Adequacy

1. Long-Term Incentives: Net Revenue

One of the primary functions of the wholesale electricity market is to provide economic signals that will encourage the investment needed to maintain a set of resources that are adequate to satisfy the system's demands and reliability needs. These economic signals are evaluated by estimating the "net revenue" new resources would receive from the markets. Net revenue is the revenue in excess of short-run operating costs that is available to recover a unit's fixed and capital costs, including a return on the investment. Net revenues from the energy and ancillary services markets together provide the economic signals that inform suppliers' decisions to invest in new generation or retire existing generation. In long-run equilibrium, markets should provide sufficient net revenue to allow an investor to receive a return of, and on an investment in a new generating unit.

Estimated Net Revenue



The figure above shows the results of the net revenue analysis for four types of hypothetical new units in 2012 and 2013. These are: (a) natural gas-fired combined-cycle, (b) natural gas-fired combustion turbine, (c) coal-fired generator, and (d) a nuclear unit. For the natural gas units, net revenue is calculated by assuming the unit will produce energy in any hour for which it is profitable and by assuming it will be available to sell reserves and regulation in other hours that it is available. For coal and nuclear technologies, net revenue is calculated by assuming that the unit will produce at full output.

The figure above shows that the 2013 net revenue for new natural gas-fired units was similar to 2012 levels, with the notable exception of in the West zone. The decrease in net revenues in the West zone was due to reduced transmission congestion resulting in lower prices in the West zone. Net revenues for coal and nuclear technologies were higher in 2013 than in 2012 because of higher natural gas prices, but still not close to being sufficient to support new entry for either of these technologies.

- For a new coal-fired unit, the estimated net revenue requirement is approximately $275 to $350 per kW-year. The estimated net revenue in 2013 for a new coal unit ranged from $58 to $67 per kW-year.
- For a new nuclear unit, the estimated net revenue requirement is approximately $415 to $540 per kW-year. The estimated net revenue in 2013 for a new nuclear unit was approximately $180 per kW-year.
- For a new natural gas-fired combustion turbine, the estimated net revenue requirement is approximately $80 to $105 per kW-year. The estimated net revenue in 2013 for a new gas turbine was approximately $26 per kW-year.
- For a new combined cycle unit, the estimated net revenue requirement is approximately $105 to $135 per kW-year. The estimated net revenue in 2013 for a new combined cycle unit was approximately $45 per kW-year.

These results indicate that during 2013 the ERCOT markets would not have provided sufficient revenues to support profitable investment in any of the types of generation technology evaluated. The net revenues in 2013 were very similar to those in 2012, and both years were much lower than in 2011. This is not surprising because shortages were very infrequent over the past two years. Shortage pricing plays a pivotal role in providing investment incentives in an energy-only market like ERCOT's. In order to provide adequate incentives, some years must exhibit an extraordinary number of shortages and net revenues that are multiples of annual net revenues needed to support investment.

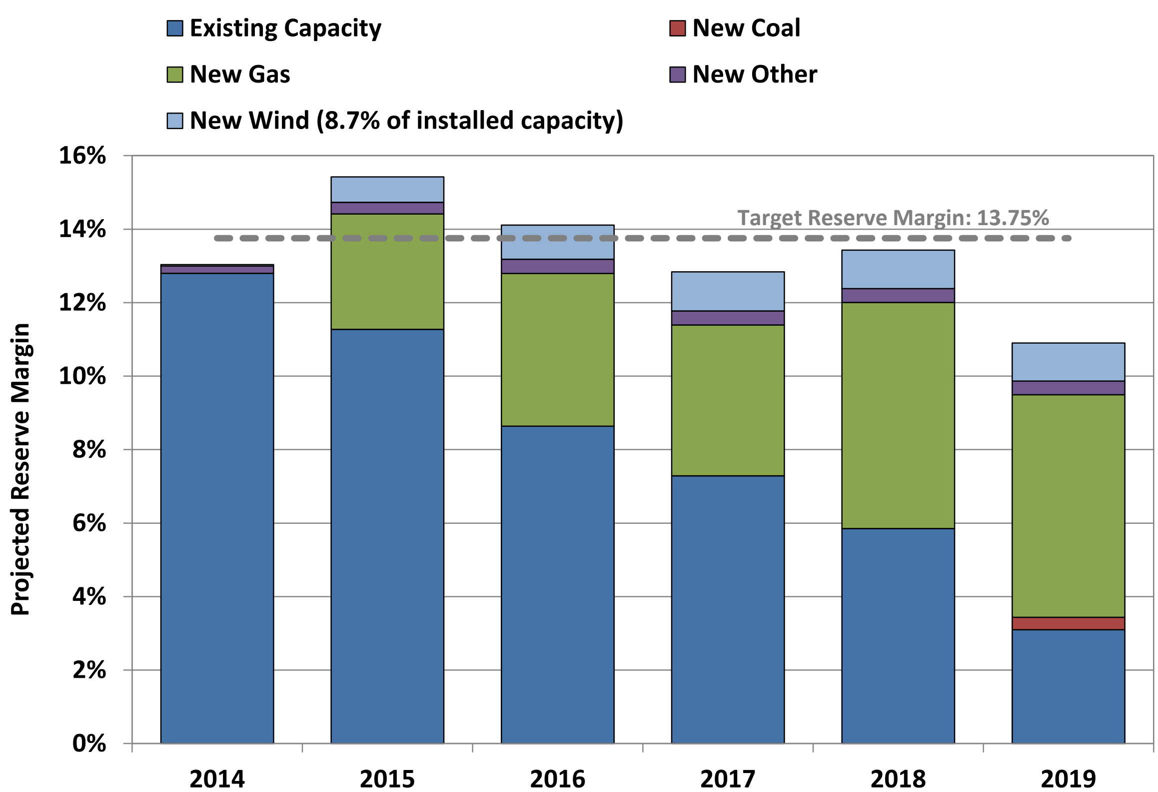
While 2011 exhibited much more frequent shortages than in the years prior or since, it is important to recognize that 2011 was highly anomalous with some of the hottest summer temperatures on record. Notwithstanding these conditions, net revenues may have been narrowly sufficient to cover the annual costs of a new combined cycle or new combustion turbine. This indicates that higher shortage prices are likely necessary to provide adequate long-term economic signals to invest in and maintain generating resources in ERCOT. As more fully described in

Section V, Resource Adequacy, the PUC has taken actions over the past year to increase energy and ancillary prices during shortage and near-shortage conditions.

2. Planning Reserve Margin

The prior subsection discusses and evaluates the economic signals produced by the ERCOT markets to facilitate efficient decisions by suppliers to maintain an adequate base of resources. This subsection summarizes and discusses the current level of capacity in ERCOT, as well as the long-term need for capacity in ERCOT. The figure below shows ERCOT's projection of reserve margins developed prior to the summer of 2014.

Projected Reserve Margins



Source: ERCOT Capacity Demand Reserve Report issued February 2014

It indicates that the region would have a 13.0 percent reserve margin heading into the summer of 2014. After completion of announced generation additions, the reserve margin is expected to reach 15.4 percent in 2015. This increase in expected reserve margin is partially a result of ERCOT's revised load forecasting methodology, which has reduced historical forecasts of load growth. The total quantity of expected future generation additions has also decreased. The bulk of the new capacity being added is natural gas-fired generation, approximately a quarter of which is expansions at existing facilities.

Even with the forecasted additions, ERCOT is projected to sustain lower reserve margins than all other RTOs, and less than its target reserve margin after 2016. This is not necessarily a problem since the 13.75 percent level is just a target. However, it is nonetheless important to ensure that the ERCOT market is designed to provide adequate economic signals to remain near this target, which is discussed below.

3. Ensuring Resource Adequacy

One of the primary goals of an efficient and effective electricity market is to ensure that over the long term there is an adequate supply of resources to meet customer demand plus any required installed or planning reserves. To incent generation additions the market design must provide revenues such that the marginal resource receives revenues sufficient to make that resource economic. Generators earn revenues from three sources: energy prices during non-scarcity, energy prices during scarcity and capacity payments. Generator revenue in ERCOT is overwhelmingly derived from energy prices under both scarcity and non-scarcity conditions.

Expectations for energy pricing under non-scarcity conditions are the same regardless of whether payments for capacity exist, or not. In ERCOT, with no capacity payments available, the amount a generator may receive from energy pricing under scarcity conditions must be large enough to provide the necessary incentives for new capacity additions and to maintain existing resources. This will occur when energy prices are allowed to rise substantially at times when the available supply is insufficient to simultaneously meet both energy and minimum operating reserve requirements.

Ideally, energy and reserve prices during shortages should reflect the diminished system reliability under these conditions, which is equal to the increased probability of “losing” load times the value of the lost load. Allowing energy prices to rise during shortages mirrors the outcome expected if loads were able to actively specify the quantity of electricity they wanted and the price they would be willing to pay. The energy-only market design relies exclusively on these relatively infrequent occurrences of high prices to provide the appropriate price signal for demand response and new investment when required. In this way, energy-only markets can provide price signals that will sustain a portfolio of resources to be used in real time to satisfy the needs of the system. However, this portfolio may produce a planning reserve margin that is less than the planning reserve target.

Faced with reduced levels of generation development activity coupled with higher than expected loads resulting in diminishing planning reserve margins, the PUCT has devoted considerable effort recently deliberating issues related to resource adequacy. These deliberations have resulted in changes to the rules governing the system-wide offer cap and the Peaker Net Margin mechanism. The PUCT continues to support the energy-only nature of the ERCOT market and has directed market modifications to introduce an additional pricing mechanism based on the quantity of available operating reserves.

As directed by the PUCT, a more analytically rigorous approach will be introduced to complement the Power Balance Penalty Curve. The Operating Reserve Demand Curve ("ORDC") is an operating reserve pricing mechanism that reflects the loss of load probability at varying levels of operating reserves multiplied by the value of lost load ("VOLL"). Selected as an easier to implement alternative to real-time co-optimization of energy and ancillary services, the ORDC will create a new payment mechanism for online and offline reserves. As the quantity of reserves decreases, payments will increase. As conceptualized, once available reserve capacity drops to 2000MW, payment for reserve capacity will rise to VOLL, or $9000 per MWh.

These changes will likely increase the net revenues a new investor would expect during shortage conditions. Whether they will be sufficient to maintain capacity margins near the target reserve margin is unknown, which will require continued monitoring and evaluation. Additionally, we continue to recommend that ERCOT implement a system to co-optimize energy and ancillary services because this would improve the efficiency of ERCOT's dispatch, more fully utilize its resources, and allow for improvements in its shortage pricing.

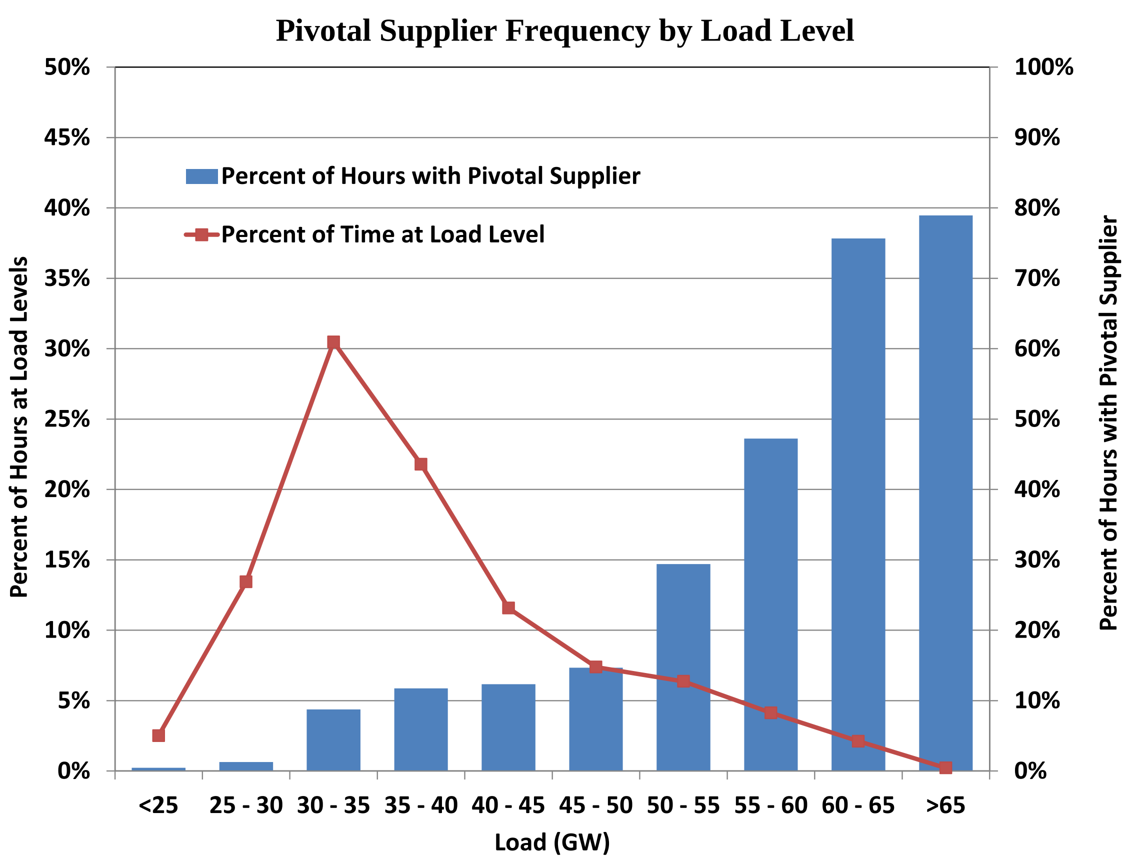
G. Analysis of Competitive Performance

The report evaluates market power from two perspectives, structural (does market power exist) and behavioral (have attempts been made to exercise it).

1. Structural Market Power

The Residual Demand Index ("RDI") is used as the primary indicator of potential structural market power. The RDI measures the percentage of load that cannot be served without the resources of the largest supplier, assuming that the market could call upon all committed and quick-start capacity owned by other suppliers. When the RDI is greater than zero the largest supplier is pivotal; that is, its resources are needed to satisfy the market demand. When the RDI is less than zero, no single supplier's resources are required to serve the load as long as the resources of its competitors are available.

The RDI is a useful structural indicator of potential market power, although it is important to recognize its limitations. As a structural indicator, it does not illuminate actual supplier behavior to indicate whether a supplier may have exercised market power. The RDI also does not indicate whether it would have been profitable for a pivotal supplier to exercise market power. However, it does identify conditions under which a supplier would have the ability to raise prices significantly by withholding resources.



The figure above summarizes the results of the RDI analysis by displaying the percentage of time at each load level there was a pivotal supplier. At loads greater than 65 GW there was a pivotal supplier 79 percent of the time. The figure also displays the percentage of time each load level occurs. Combining these values we find that there was a pivotal supplier in approximately 14 percent of all hours of 2013, which indicates that market power is a potential concern in ERCOT and underscores the need for the current mitigation measures that address it.

Additionally, we note 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. This local market power is addressed through a) structural tests that determine "non-competitive" constraints that can create local market power, b) the application of limits on offer prices in these areas.

2. Evaluation of Conduct

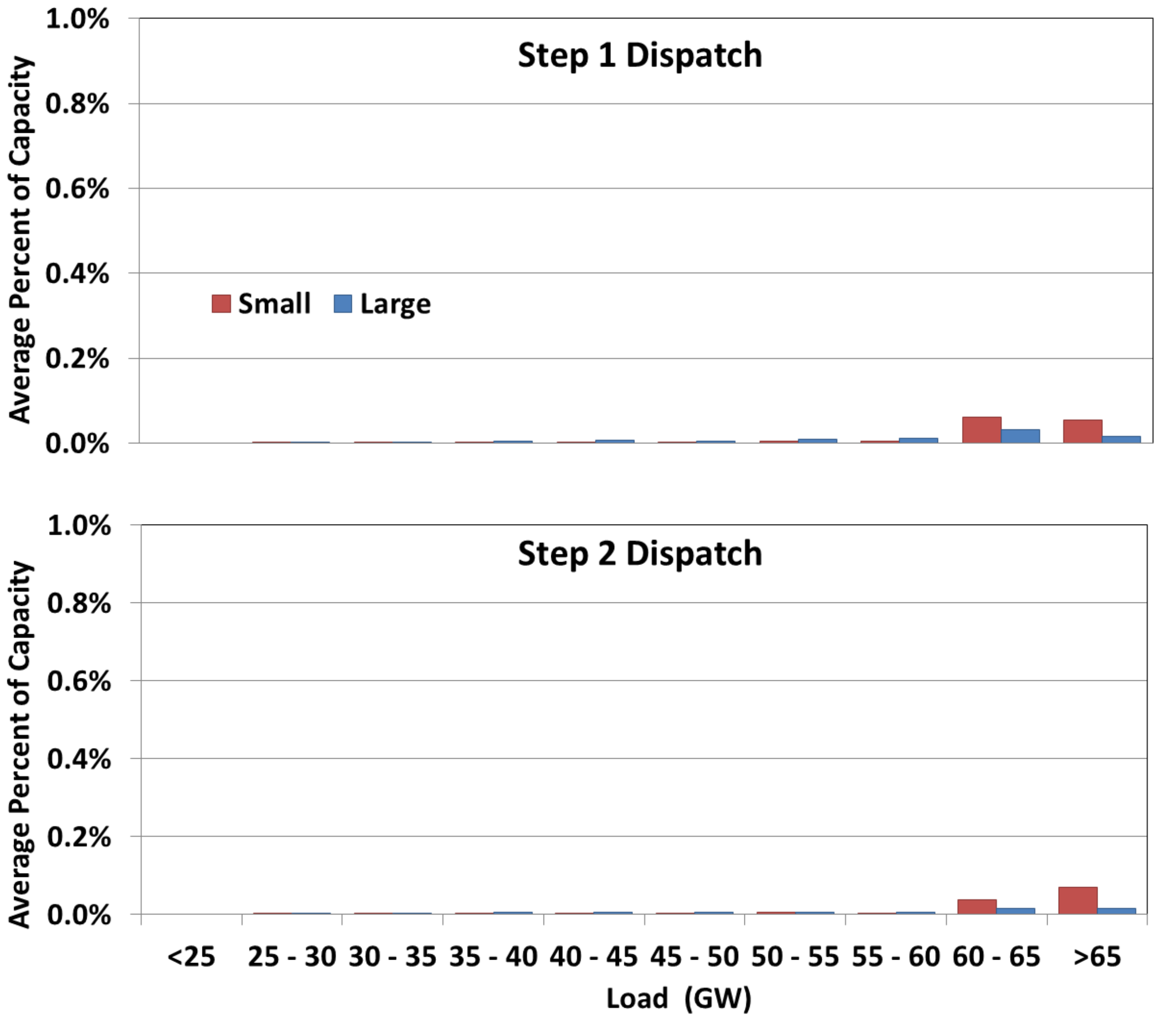
This report assesses potential physical withholding and economic withholding using a variety of metrics. In this subsection, we describe our evaluation of potential economic withholding, which is conducted by calculating an "output gap". The output gap is defined as the quantity of energy that is not being produced by in-service capacity even though the in-service capacity is economic 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.

Resources are considered for inclusion in the output gap when they are committed and producing at less than full output. Energy not produced from committed resources is included in the output gap if the real-time energy price exceeds by at least $50 per MWh that unit's mitigated offer cap, which serves as an estimate of the marginal production cost of energy from that resource.

The output gap is measured at both steps in ERCOT's two-step dispatch because if a market participant has sufficient market power, it might raise its offer in such a way to increase the reference price in the first step of ERCOT's dispatch process. Although in the second step, the offer appears to be mitigated, the market participant has still influenced the market price. This output gap is measured by the difference between the capacity level on a generator's original offer curve at the first step reference price and the capacity level on the generator's cost curve at the first step reference price. However, this output gap is only indicative because no output instructions are sent based on the first step. It is only used to screen out whether a market participant is withholding in a manner that may influence the reference price.

The ultimate output gap is measured by the difference between a unit's operating level and the output level had the unit been competitively offered to the market. In the second step of the dispatch, the after-mitigation offer curve is used to determine dispatch instructions and locational prices. Even though the offer curve is mitigated there is still the potential for the mitigated offer curve to be increased as a result of a high first step reference price due to a market participant exerting market power. The following figure shows the output gap after each step.

Incremental Output Gap by Load Level and Participant Size



The results of the analysis shown in the figure above indicate small quantities of capacity at the highest loads that were potentially economically withheld by small suppliers. Almost all of these quantities reflect the conduct of GDF SUEZ. GDF SUEZ is deemed not to have ERCOT-wide market power under P.U.C Subst. R. 25.504 (c) because they control less than 5 percent of the capacity in ERCOT and, therefore, are able to offer its resources at any price up to the system-wide offer cap. In evaluating this conduct, we estimated that the aggregate effect of its conduct was less than $1 per MWh and, therefore, does not raise substantial competitive concerns.

In addition to this analysis of potential economic withholding, we also evaluate outages, deratings, and economic units that were not committed to identify other means suppliers may have used to withhold resources. We found very little evidence of potential physical withholding. Based on our analyses above and the results of our ongoing monitoring, we find the overall performance of the ERCOT market to be competitive in 2013.

H. Recommendations

Overall, we find that the ERCOT market performed well in 2013. Nonetheless, we have identified and recommended a number of potential improvements over the past few years. We describe these recommendations in this section.

In the 2012 ERCOT State of the Market report we recommended changes to the automated mitigation procedures that are part of the real-time dispatch to eliminate the occurrences of over-mitigation we have observed. As more fully described in Section I.F, Mitigation, we supported the changes described in NPRR520, which introduced a test to determine whether a unit is either contributing to, or helping to resolve a transmission constraint. Only the units providing relief are mitigated because only these suppliers may have local market power. These changes were implemented on June 21, 2013 and substantially reduced inappropriate mitigation of resources that are not in a position to exercise local market power.

1. In the 2012 ERCOT State of the Market report we also recommended a change to the real-time market software to allow it to "look ahead" a sufficient amount of time to better commit load and generation resources that can be online within 30 minutes. ERCOT started producing non-binding generation dispatch and price projections on June 28, 2012. It is unclear what, if any effect this indicative information has had on the operational actions of ERCOT or its market participants. We continue to believe there is opportunity to improve the commitment and dispatch of both load and generation resources that require longer than 5 minutes, but are responsive within 30 minutes. Therefore, we recommend that ERCOT evaluate improvements to this process that would allow it to facilitate better real-time generator commitments.

2. Last year's recommendation to improve reserve shortage pricing has been superseded by the Commission's direction to implement an Operating Reserve Demand Curve (ORDC). The ORDC provides a more analytically rigorous mechanism for settling real-time energy prices that reflect the expected value of lost load. However, additional benefits can be achieved by implementing real-time co-optimization of energy and ancillary services. In addition to improving the shortage pricing in ERCOT, co-optimization

would improve the efficiency of ERCOT's dispatch in all intervals. Therefore, we continue to recommend ERCOT implement co-optimization.

3. We continue to recommend modifying the Protocols related to proxy offer curve provisions such that all unoffered capacity is not automatically priced at the system-wide offer cap. Currently, if available capacity does not have an associated energy offer, ERCOT's dispatch software "fills in" with an offer that is priced at the system-wide offer cap. During 2013, the average amount of capacity priced in this manner exceeded 180 MW.

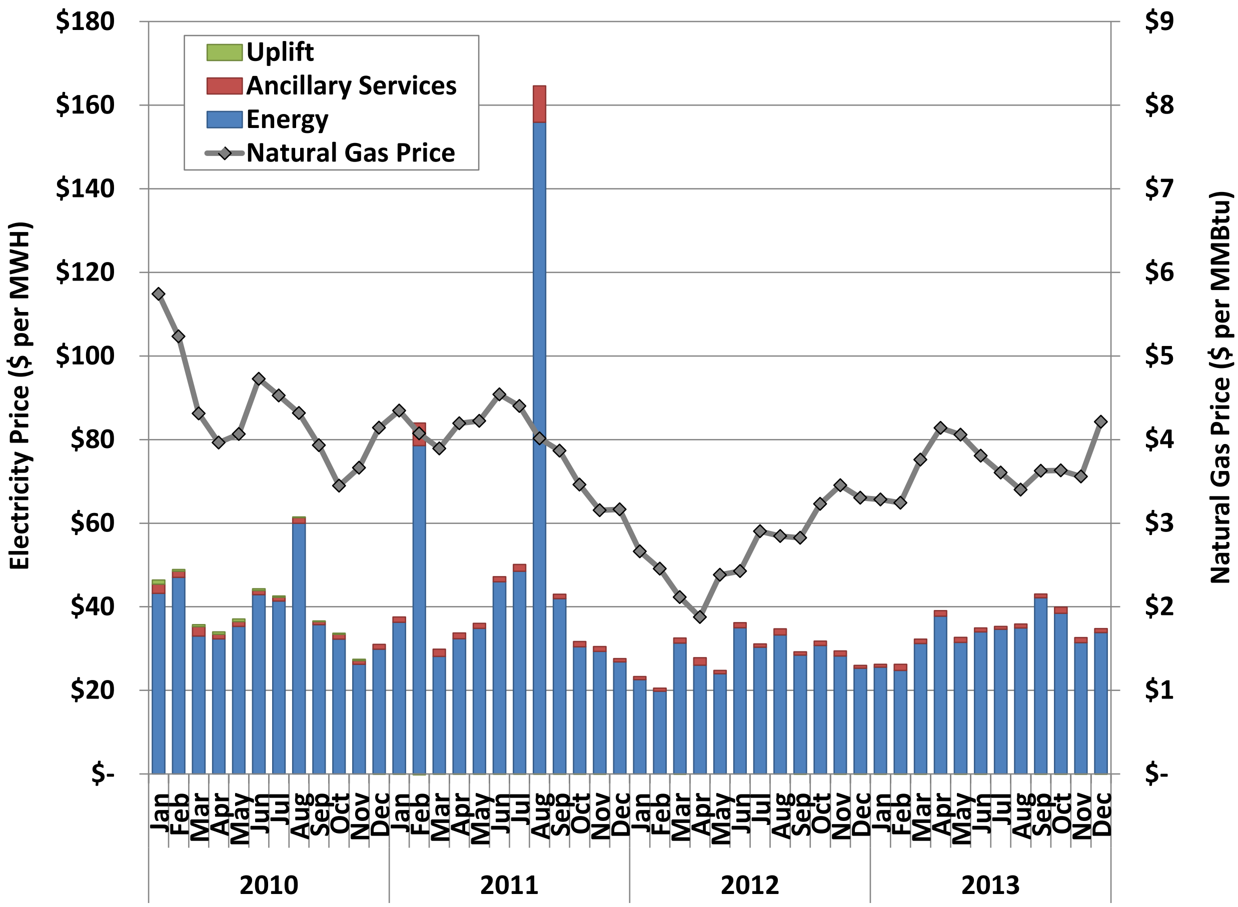
4. We continue to recommend that changes be implemented to ensure ERCOT deployments of load resources, Emergency Response Service (ERS), or the involuntary curtailment of firm load are reflected in the real-time dispatch energy and reserve prices. Building on the Phase 1 efforts of Loads in SCED, this recommendation could be addressed in various ways. It may be possible to integrate load bids and emergency resources in the real-time dispatch software and allow them to set prices when they are effectively marginal. Alternatively, it may be adequate to address this concern through administrative shortage pricing rules.

I. Review of Real-Time Market Outcomes

A. Real-Time Market Prices

Our first analysis evaluates the total cost of supplying energy to serve load in the ERCOT wholesale market. In addition to the costs of energy, loads incur costs associated with ancillary services and a variety of non-market based expenses referred to as "uplift". We have calculated an average "all-in" price of electricity for ERCOT that is intended to reflect wholesale energy costs as well as these additional costs.

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



Energy, ancillary services and uplift costs are the three components in the all-in price of electricity. The ERCOT wide price is the load weighted average of the real-time market prices from all load zones. Prior to ERCOT's conversion to the nodal market in December 2010, energy costs were determined from the zonal balancing energy market. Ancillary services costs are estimated based on total system demand and prices in the ERCOT markets for regulation, responsive reserves, and non-spinning reserves. Uplift costs are assigned market-wide on a load-ratio share basis to pay for charges associated with additional reliability unit commitment and any reliability must run contracts.[1]

Figure 1 shows the monthly average all-in price for all of ERCOT from 2010 to 2013 and the associated natural gas price. This figure indicates that natural gas prices were a primary driver of the trends in electricity prices from 2010 to 2013. Again, this is not surprising given that natural gas is a widely-used fuel for the production of electricity in ERCOT, especially among generating units that most frequently set locational marginal prices in the nodal market.

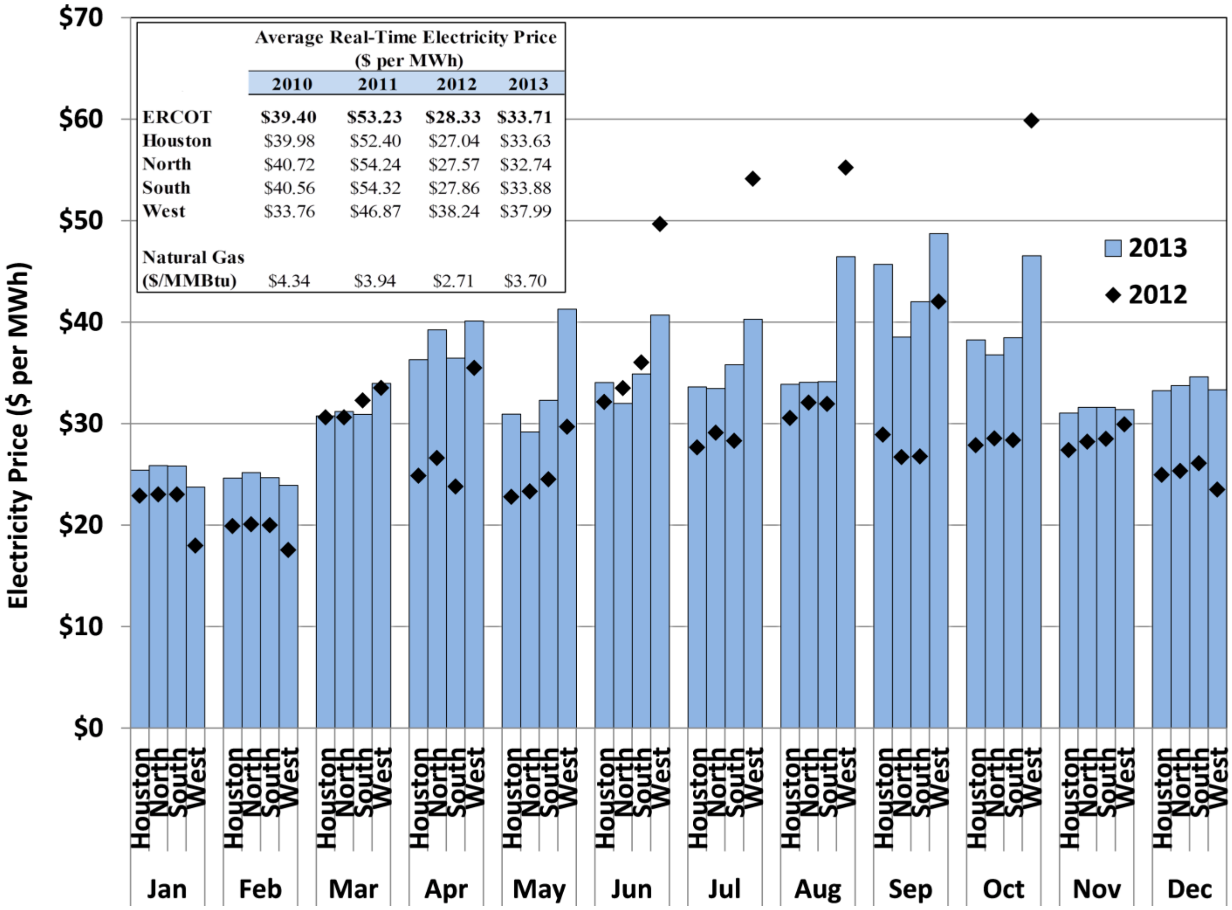
The largest component of the all-in cost of wholesale electricity is the energy cost, which is reflected by the locational marginal prices. As is typical in other wholesale electricity markets, only a small share of the power produced in ERCOT is transacted in the spot market. However, prices in the real-time energy market are very important because they set the expectations for prices in the forward markets (including bilateral markets) where most transactions take place. Unless there are barriers preventing arbitrage of the prices between the spot and forward markets, the prices in the forward market should be directly related to the prices in the spot market (*i.e.*, the spot prices and forward prices should converge over the long-run). Hence, artificially low prices in the real-time energy market will translate to artificially-low forward prices. Likewise, price spikes in the real-time energy market will increase prices in the forward markets. This section evaluates and summarizes electricity prices in the real-time market during 2013.

ERCOT average real-time market prices were 19 percent higher in 2013 than in 2012. The ERCOT-wide load-weighted average price was $33.71 per MW in 2013 compared to $28.33 per MWh in 2012. The increase in real-time energy prices was correlated with much higher fuel prices in 2013. The steady increase in natural gas prices from May 2012 to 2013 resulted in the 2013 average natural gas price of $3.70 per MMBtu, a 37 percent increase compared to $2.71 per MMBtu in 2012.

1 Prior to December 2010 uplift costs included charges for out-of-merit energy and capacity, replacement reserve services and any reliability must run contracts.

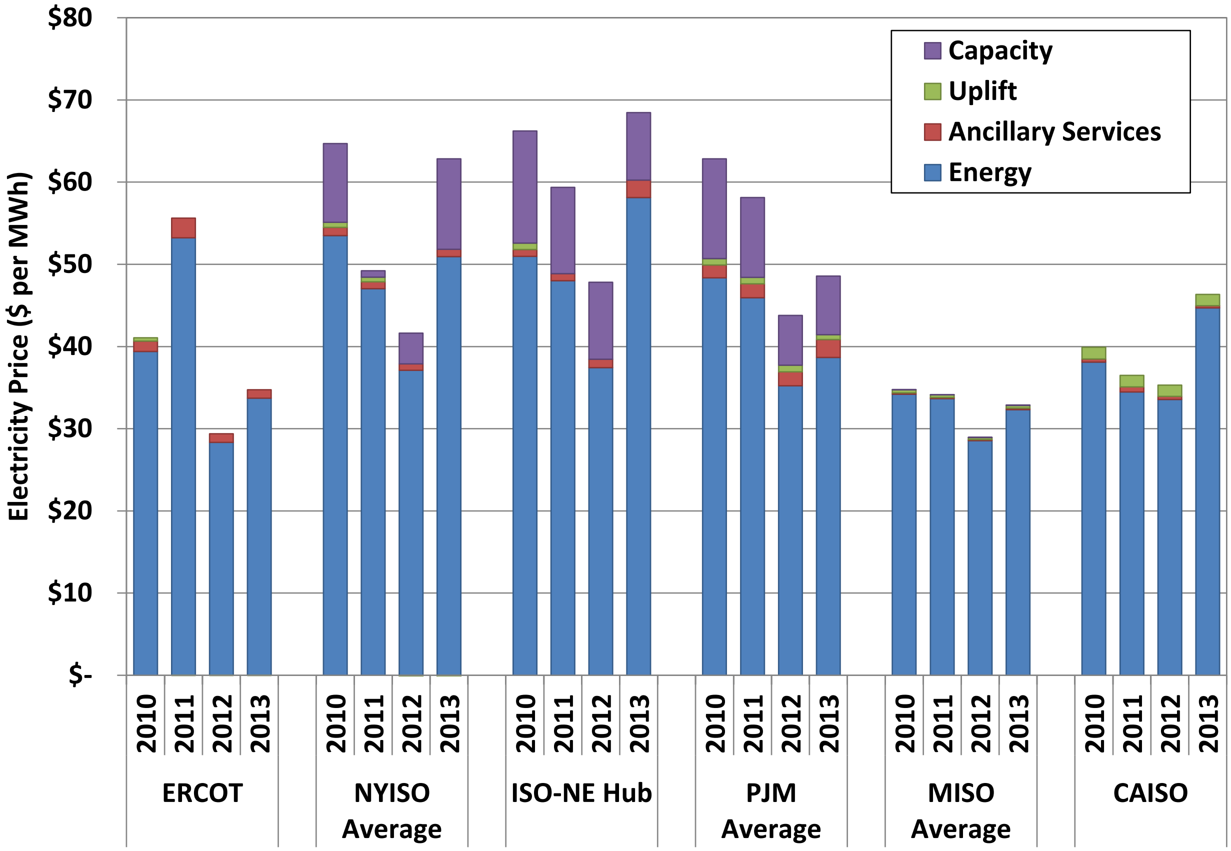
To summarize the price levels during the past four years, Figure 2 shows the monthly load-weighted average prices in the four geographic ERCOT load zones. These prices are calculated by weighting the energy price for each interval and each zone by the total zonal load in that interval. Since December 2010 these prices were determined by the nodal real-time energy market. Prior prices were derived from the zonal balancing energy market. Load-weighted average prices are the most representative of what loads are likely to pay, assuming that real-time energy prices are, on average, generally consistent with bilateral contract prices.

Figure 2: Average Real-Time Energy Market Prices



To provide additional perspective on the outcomes in the ERCOT market, our next analysis compares the all-in price metrics for ERCOT and other electricity markets. The following figure compares the all-in prices in ERCOT with other organized electricity markets in the United States: New York ISO, ISO New England, PJM, Midcontinent ISO, and California ISO.

Figure 3: Comparison of All-in Prices across Markets

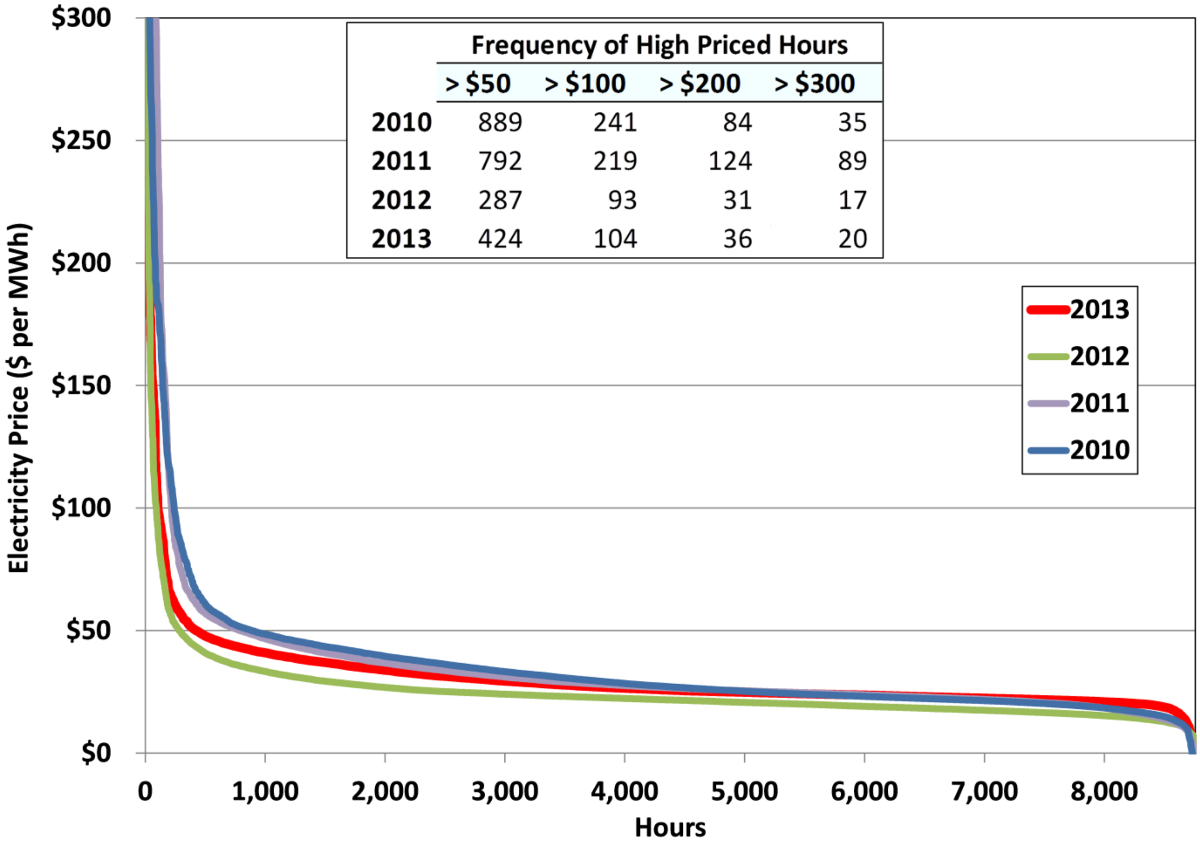


For each region, the figure reports the average cost (per MWh of load) for energy, ancillary services (reserves and regulation), capacity markets (if applicable), and uplift for economically out-of-merit resources. Figure 3 shows that ERCOT all-in prices in 2013 were slightly higher than in the Midcontinent ISO and significantly lower than all other regions. Prices in all markets increased from 2012 to 2013.

Figure 4 presents price duration curves for ERCOT energy markets in each year from 2010 to 2013. 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). The prices in this figure are the hourly load-weighted zonal balancing energy price for the zonal market and hourly load-weighted nodal settlement point price for the nodal market.[2]

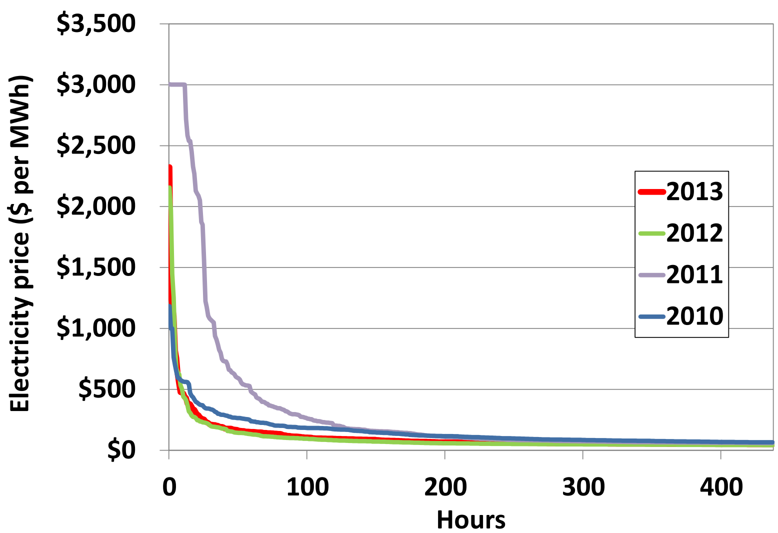
[2] ERCOT switched to a nodal market on December 1, 2010. The December nodal prices are included in the 2010 price duration curve.

Figure 4: ERCOT Price Duration Curve



Due to the lowest natural gas prices seen in ten years, the 2012 price duration curve is below the duration curve of other years in most hours.

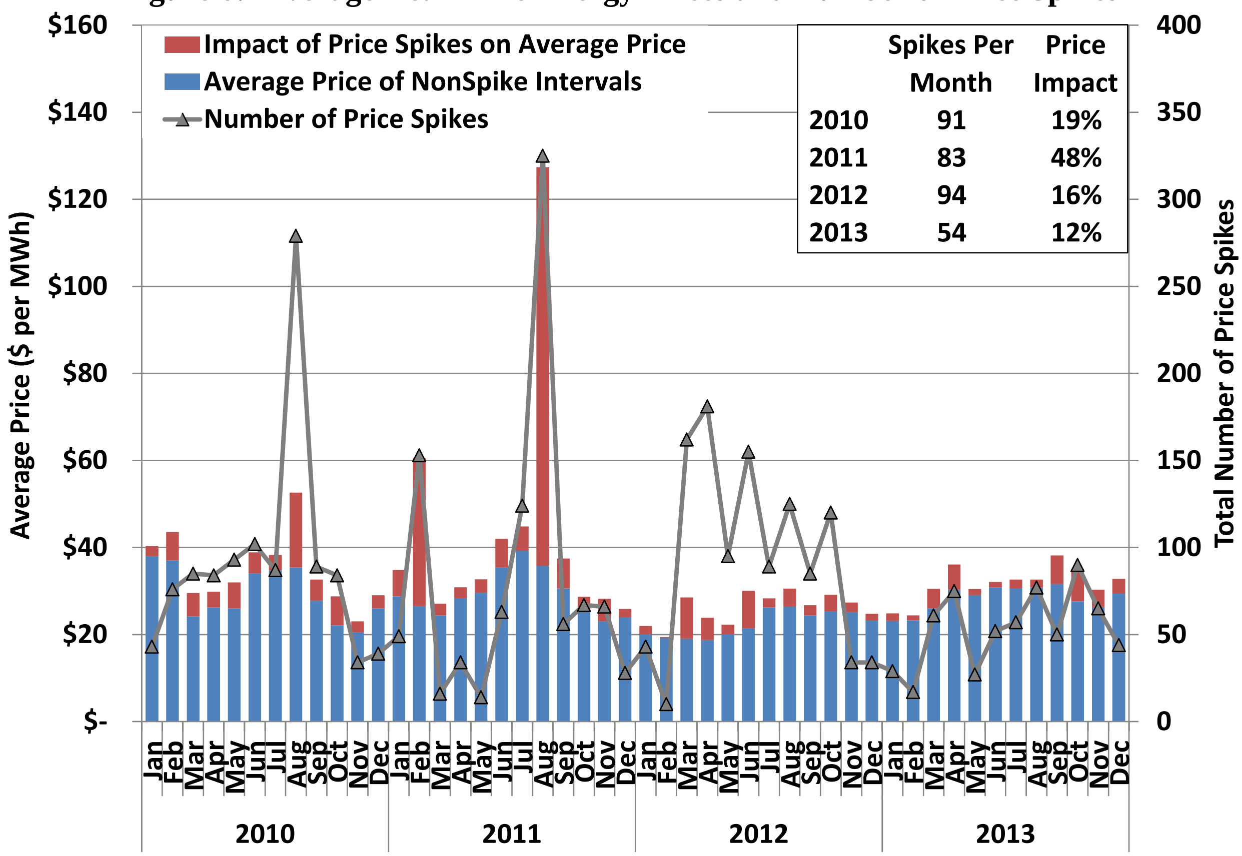
Figure 5: ERCOT Price Duration Curve – Top 5% of Hours



To see where the prices during 2013 were much different than in the previous three years, we present a comparison of prices for the highest 5 percent of hours. In 2011, energy prices for the top 100 hours were significantly higher due to higher loads leading to more shortage conditions coupled with a more effective shortage pricing mechanism implemented as part of the nodal market design. In 2012 and 2013, the energy duration curves for the top 5 percent of hours are very similar and reflect fewer occassions of shortage conditions resulting from lower loads.

To better observe the effect of the highest-priced hours, the following analysis focuses on the frequency of price spikes in the real-time energy market. Data prior to December 2010 is from the zonal balancing energy market. Figure 6 shows the average price and the number of price spikes in each month. For this analysis, price spikes are defined as intervals where the load-weighted average energy price in ERCOT is greater than 18 MMBtu per MWh times the prevailing natural gas price. Prices at this level have historically exceeded the marginal costs of virtually all of the on-line generators in ERCOT.

Figure 6: Average Real-Time Energy Prices and Number of Price Spikes

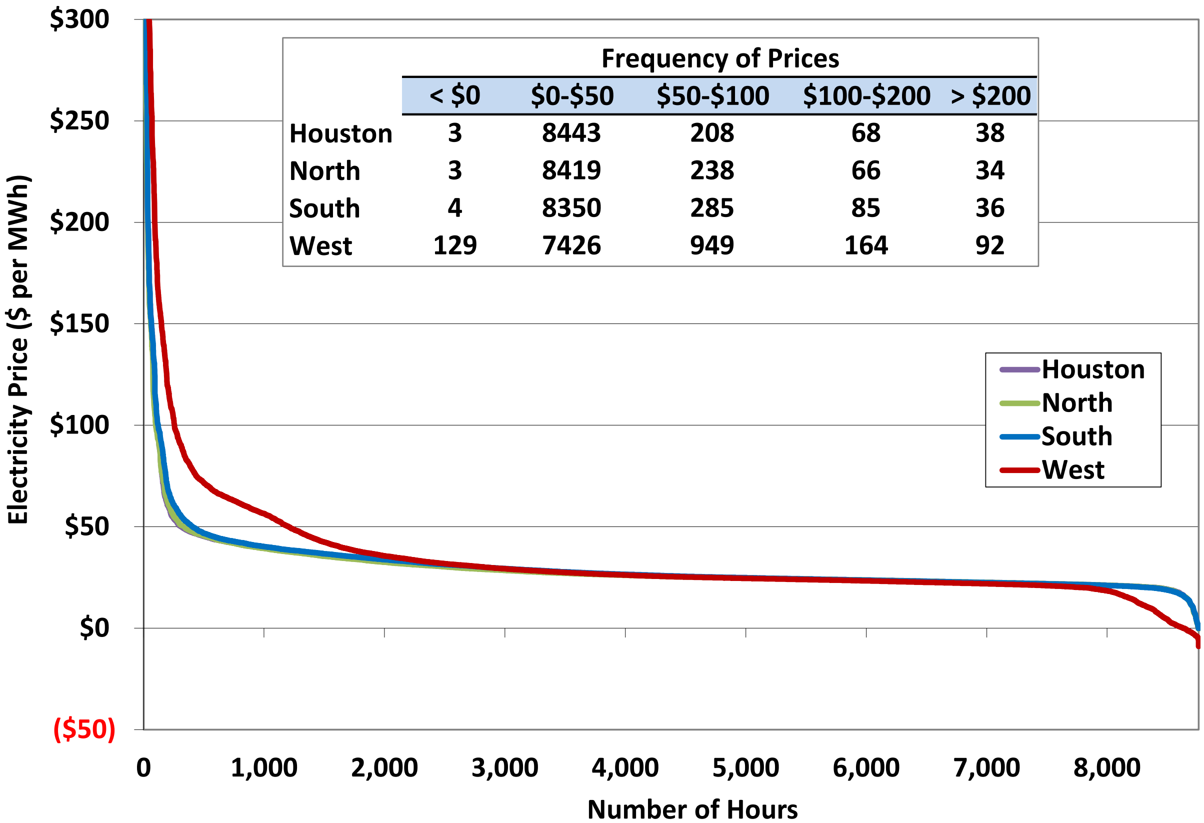


The number of price spike intervals during 2013 was 54 per month, a large decrease from the number of price spike intervals during 2012, which totaled 94 per month. However, as described in the 2012 SOM, the high number of price spikes in 2012 was related to the very low price of natural gas and the resulting 'overlap' of offers from natural gas and coal.

To measure the impact of these price spikes on average price levels, the figure also shows average prices with and without the price spike intervals. The top portions of the stacked bars show the impact of price spikes on monthly average price levels. Prior to 2012, the impact grew with the frequency of the price spikes, averaging \$5.53 and \$14.09 per MWh during 2010 and 2011, respectively. Although the frequency of price spikes increased in 2012, the magnitude of their price impact decreased. The magnitude decreased again in 2013, with an average \$3.43 per MWh impact on the average energy price in 2013.

To depict how real-time energy prices vary by hour in each zone, Figure 7 below shows the hourly average price duration curve in 2013 for four ERCOT load zones.

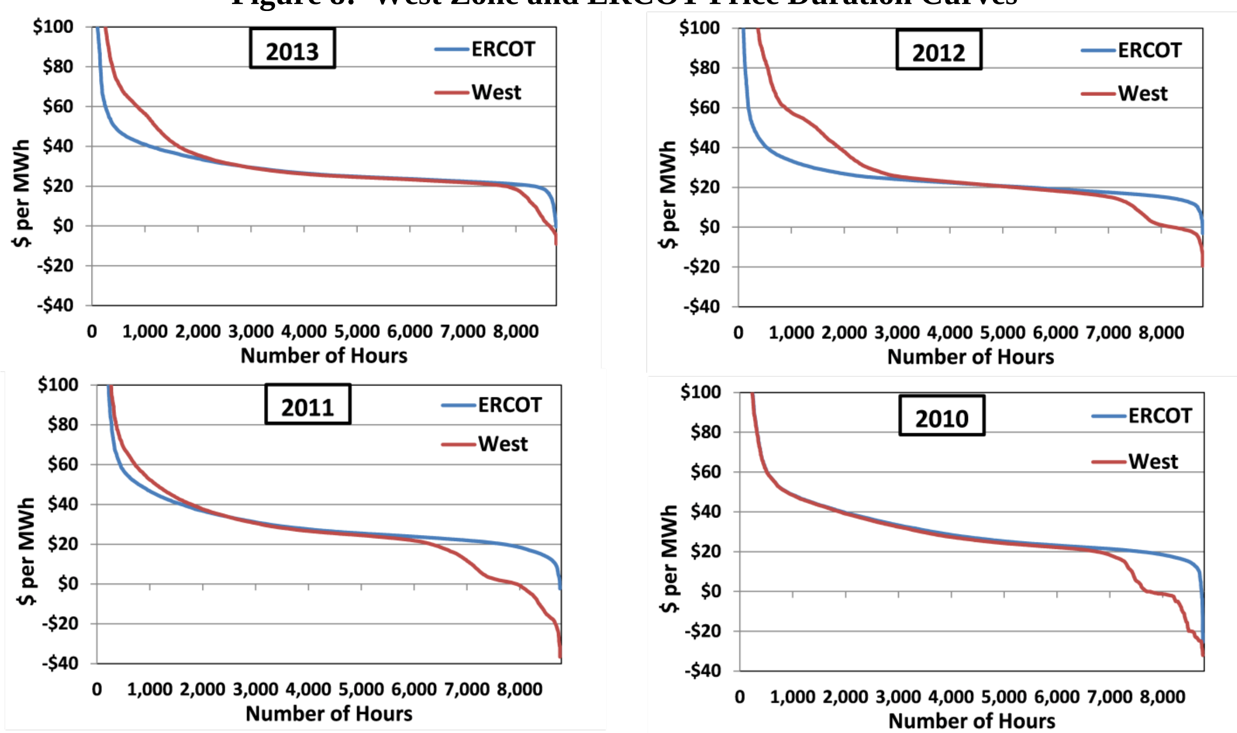
Figure 7: Zonal Price Duration Curves



The Houston, North and South load zones had similar prices over the majority of hours. The price duration curve for the West zone is noticeably different than the other zones, with more hours with prices greater than $50 per MWh and 129 hours when the average hourly price was less than zero. As observed over the past few years, West zone prices are lower than the rest of ERCOT when high wind output in the West results in congested transmission interfaces from the West zone to the other zones in ERCOT. Recently, prices higher than the rest of ERCOT have occurred in the West zone due to local transmission constraints that typically occur under low wind and high load, or outage conditions.

Figure 8 below shows the relationship between West zone and ERCOT average prices for the 2010 through 2013.

Figure 8: West Zone and ERCOT Price Duration Curves



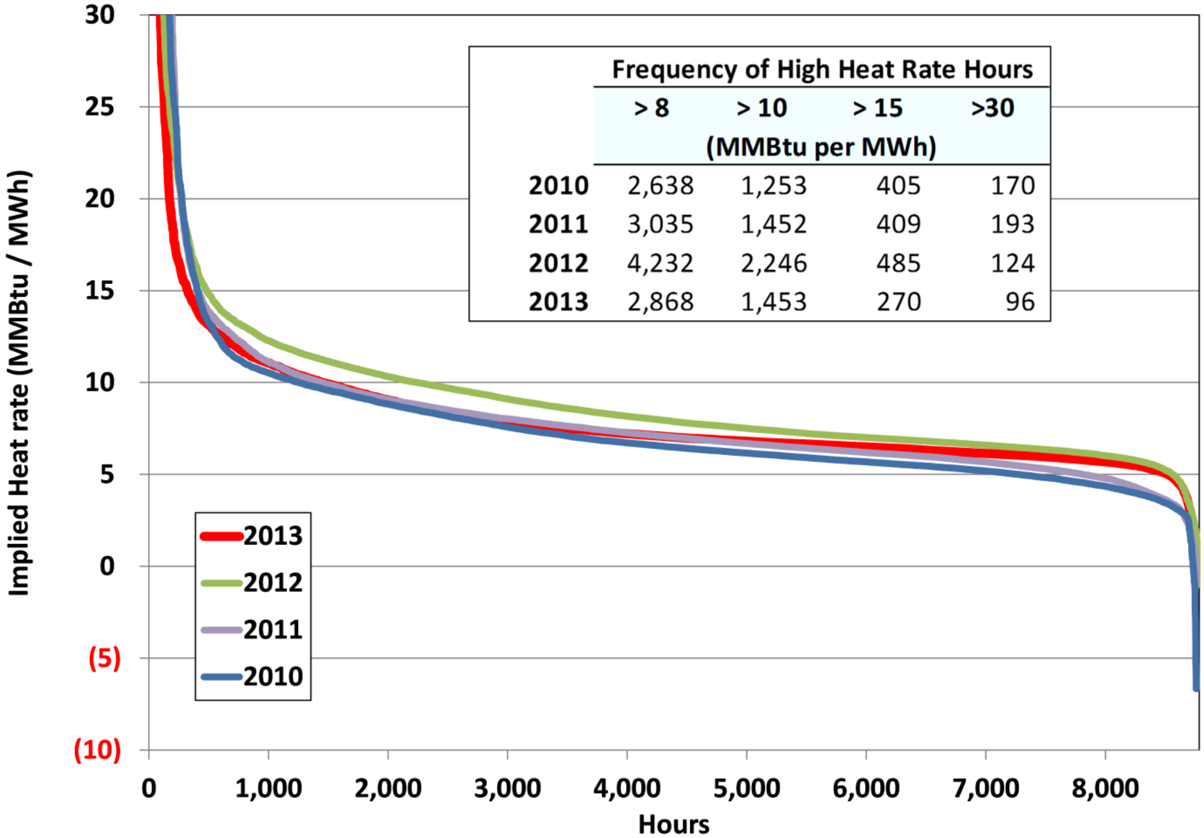
On the low price end, we observe a reduction in the number of hours when West zone prices were below the ERCOT average. We also note that minimum West zone prices have increased; that is, become "less negative". West zone prices were noticeably higher than the ERCOT average for a significant number of hours in 2013, although not to the same magnitude as they were in 2012. But like 2012, the combination of more hours with higher prices, and fewer hours with less negative prices resulted in the average real-time energy price in the West zone being greater than the ERCOT average.

More details about the transmission constraints influencing energy prices in the West zone are provided in Section III, Transmission and Congestion.

B. Real-Time Prices Adjusted for Fuel Price Changes

Although real-time electricity prices are driven to a large extent by changes in fuel prices, natural gas prices in particular, they are also influenced by other factors.

Figure 9: Implied Marginal Heat Rate Duration Curve – All hours



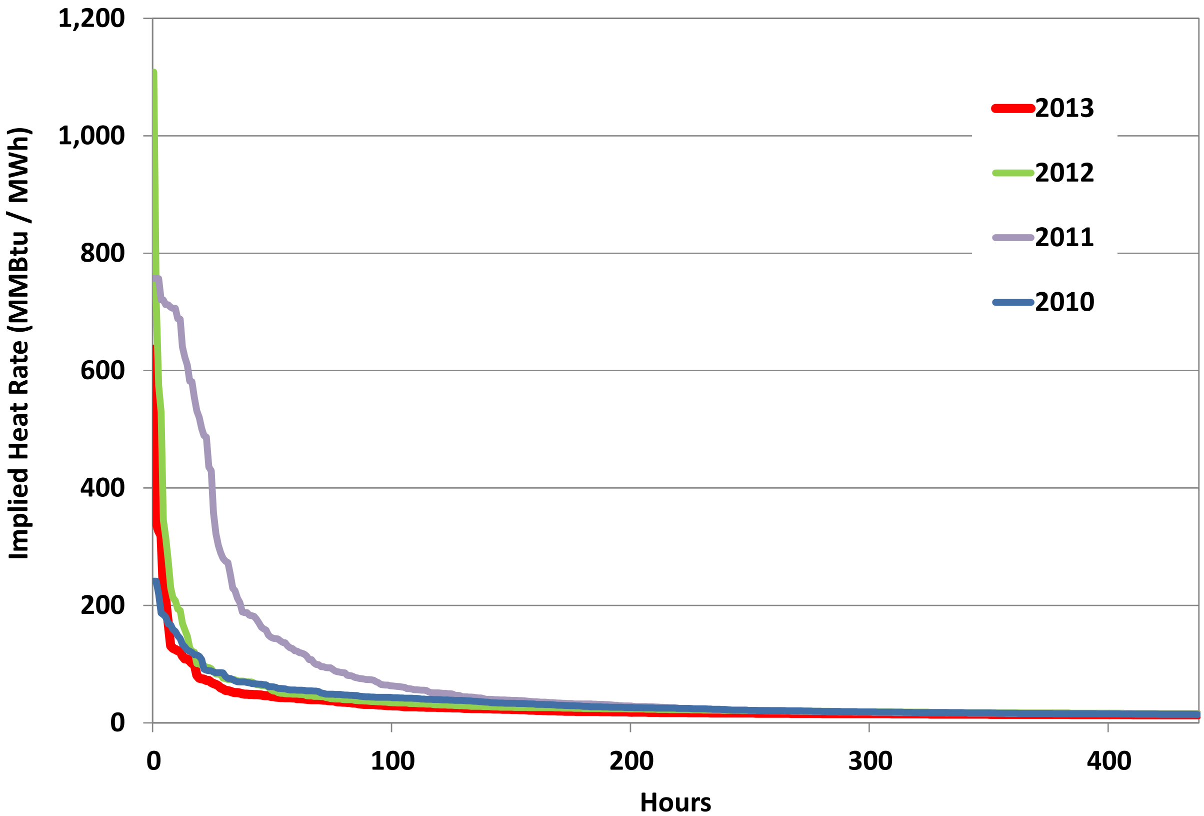
To clearly identify changes in electricity prices that are not driven by changes in natural gas prices, Figure 9 and Figure 10 show the load weighted, hourly average real-time energy price adjusted to remove the effect of natural gas price fluctuations. The first chart shows a duration curve where the real-time energy price is replaced by the marginal heat rate that would be implied if natural gas was always on the margin.[3] Implied heat rates in 2012 were noticeably

[3] The *Implied Marginal Heat Rate* equals either the *Balancing Energy Price* (zonal) or the *Real-Time Energy Price* (nodal) divided by the *Natural Gas Price*. This methodology implicitly assumes that electricity prices move in direct proportion to changes in natural gas prices.

higher for the majority of hours, as compared to the other three years. This can be explained by the very low natural gas prices experienced in 2012, and resulting pricing outcomes which were influenced by coal, not natural gas being the marginal fuel.[4]

Figure 10 shows the implied marginal heat rates for the top 5 percent of hours in 2010 through 2013 and highlights that the implied heat rate in 2013 at the top 5 percent of hours is consistent with other years, except for 2011, where the heat rates were higher at top hours.

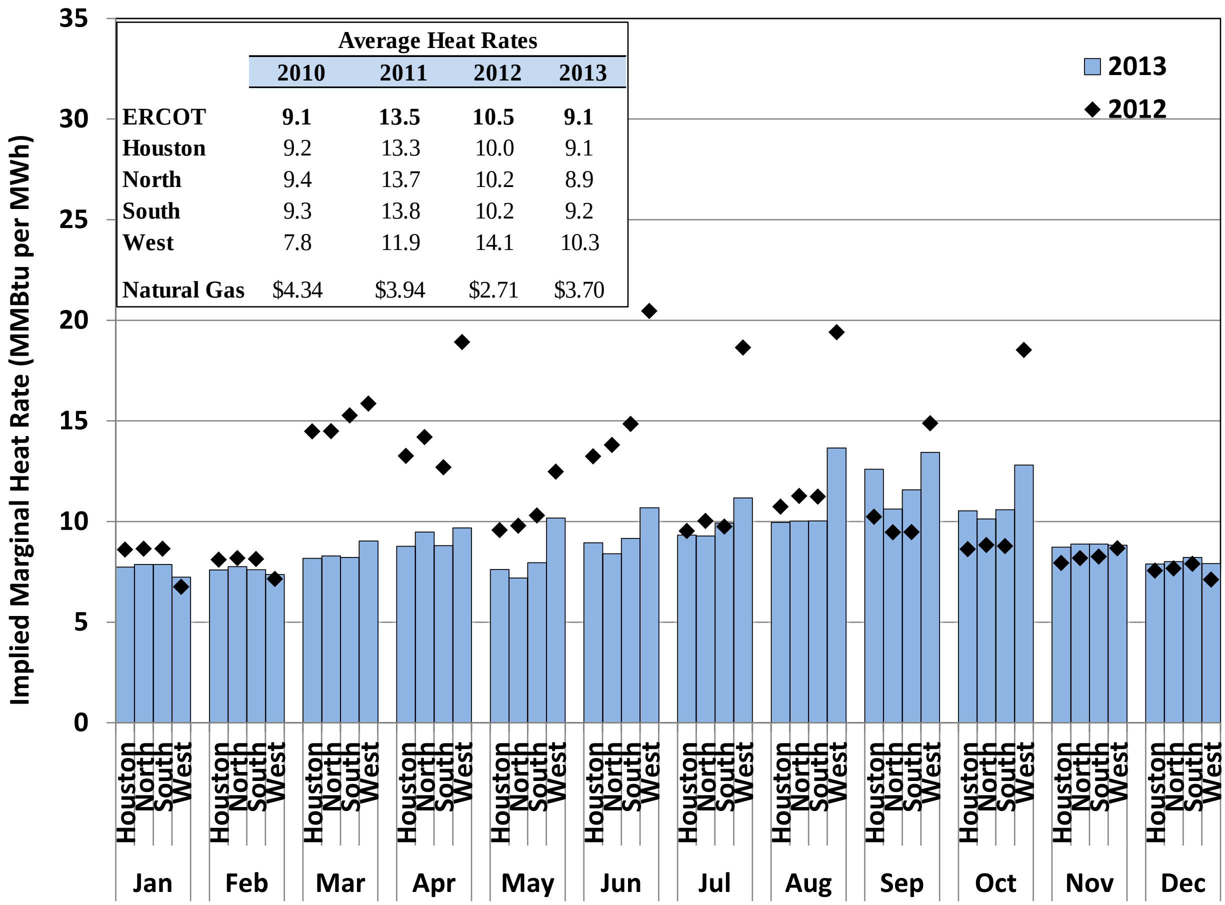
Figure 10: Implied Marginal Heat Rate Duration Curve – Top Five Percent of Hours



To further illustrate these differences, the next figure shows the implied marginal heat rates on a monthly basis in each of the ERCOT zones in 2012 and 2013, with annual average heat rate data for 2010 through 2013. This figure is the fuel price-adjusted version of Figure 2 in the prior subsection. Adjusting for natural gas price influence, Figure 11 shows that the annual, system-wide average implied heat rate decreased in 2013 compared to 2012.

4 See 2012 ERCOT SOM report at pages 12-13.

Figure 11: Monthly Average Implied Heat Rates

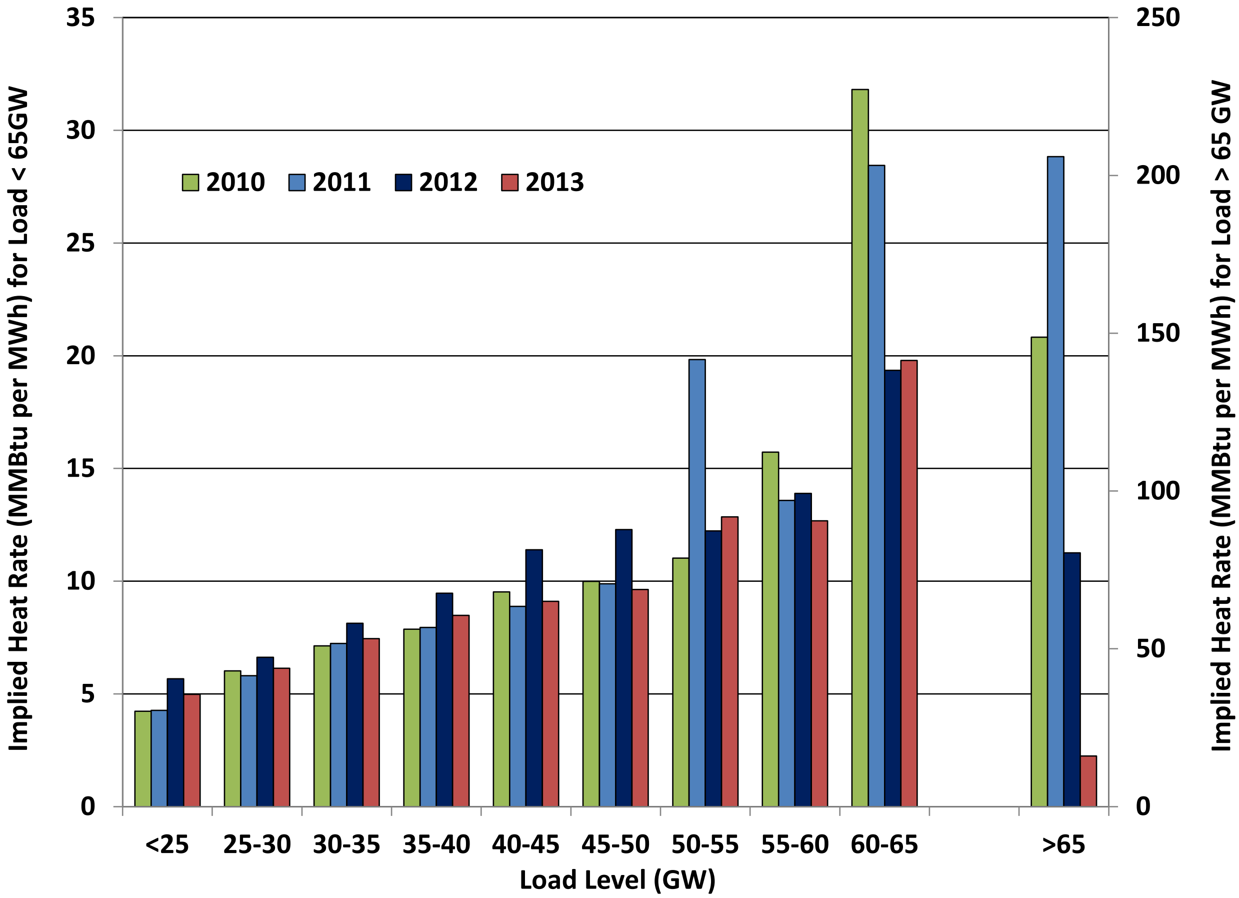


The monthly average implied heat rates in 2013 are generally lower than those in 2012 up until September, when 2013 monthly heat rates started to exceed those in 2012. This trend is generally consistent with rising gas prices and higher loads in late 2013 compared to the same months of 2012. The largest differences in the average annual implied heat rates observed at the zonal level are for the West zone. The differences can be attributed to congestion related to wind generation exports resulting in lower implied heat rates in 2010 and 2011, and congestion related to serving higher loads related to oil and gas production resulting in higher implied heat rates in 2012 and 2013.

We conclude our examination of implied heat rates from the real-time energy market by evaluating them at various load levels. Figure 12 below, provides the average heat rate at various system load levels from 2010 through 2013.[5]

[5] To appropriately compare twelve months of data under each market design, data labeled as 2010 in Figure 12

Figure 12: Heat Rate and Load Relationship



In a well performing market, a clear positive relationship between these two variables is expected since resources with higher marginal costs must be dispatched to serve higher loads. Although we do see a generally positive relationship, there is a noticeable disparity for loads between 50 and 55 GW. During the extreme cold weather event in early February 2011, loads were at this level while prices reached $3,000 per MWh for a sustained period of time. The higher heat rates observed at lower loads in 2012 are likely due to the interplay between coal and natural gas prices because of the low natural gas prices experienced in 2012.

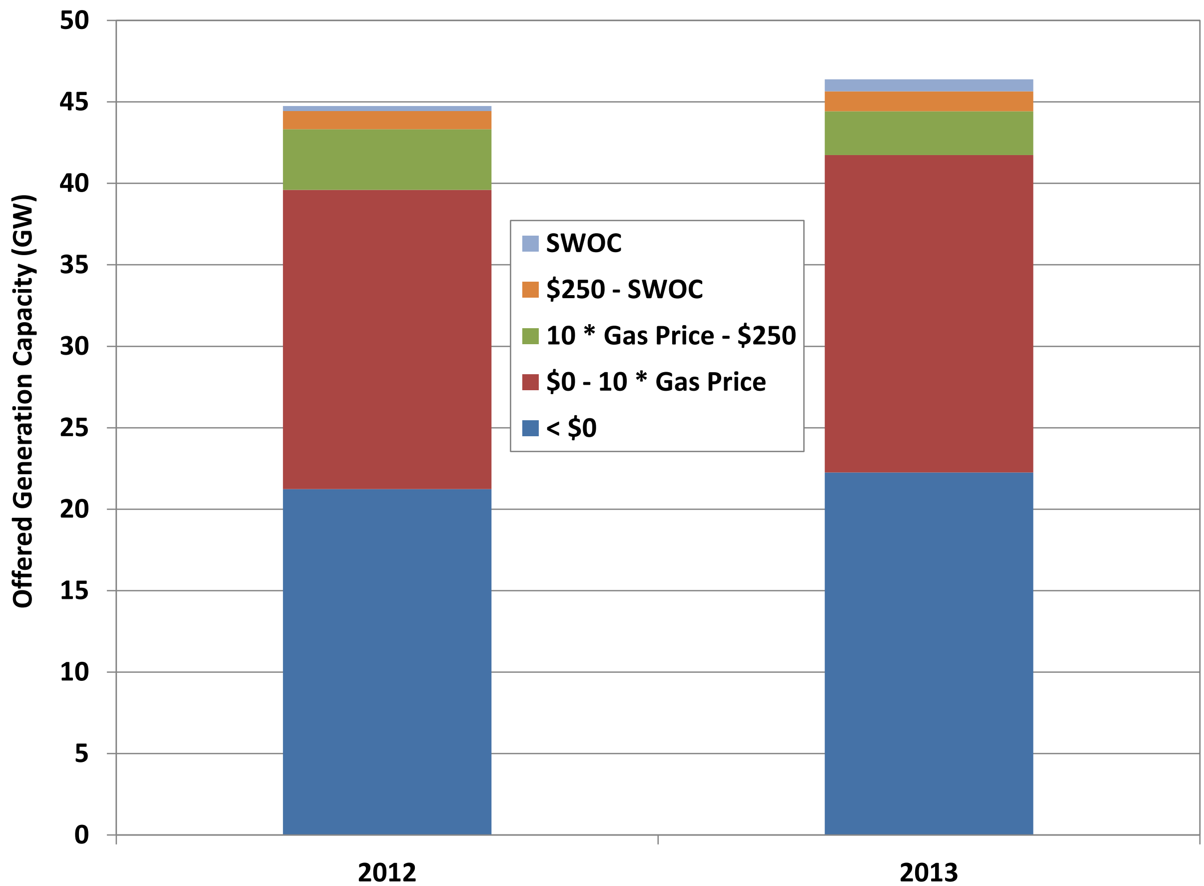
A noticeable difference in 2013 relative to the other years is the lower implied marginal heat rate at highest loads. At loads greater than 65GW, the implied heat rate was approximately 16 MMBtu per MWh in 2013 compared to 80 MMBtu per MWh in 2012.

are from December 1, 2009 through November 30, 2010.

C. Aggregated Offer Curves

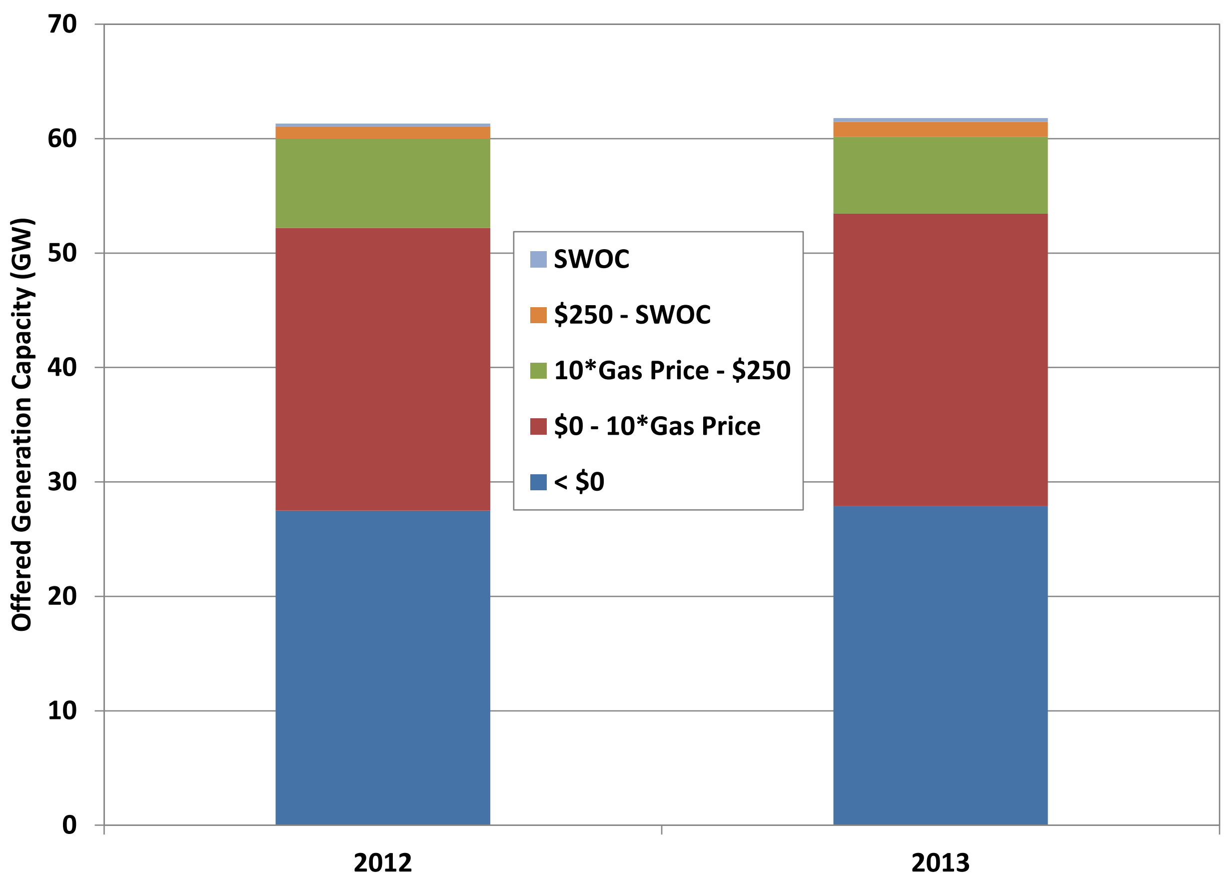
The next analysis provides the quantity and price of generation offered in 2013 compared to 2012. By averaging the amount of capacity offered at selected price levels we can assemble an aggregated offer stack. Figure 13 provides the aggregated generator offer stacks for the entire year. Comparing 2013 to 2012, we observe more capacity offered at lower prices. Specifically, there was more than 1000 MW of additional capacity offered both at prices less than zero, and at prices between zero and ten multiplied times the daily natural gas price. There was approximately 1,000 MW less capacity offered at prices between 10 multiplied times the daily natural gas price and $250 per MWh. With smaller changes to the quantities of generation offered at prices above $250 per MWh, the resulting average aggregated generation offer stack was roughly 1,600 MW greater in 2013 than in 2012.

Figure 13: Aggregated Generation Offer Stack - Annual



The next analysis provides a similar comparison for only the summer season. As shown in Figure 14, the changes in the aggregated offer stacks between the summer of 2013 and 2012 were similar to those just described. Comparing 2013 to 2012, there was 1,270 MW additional capacity offered at prices less than 10 multiplied times the daily natural gas price; 389 MW additional at prices less than zero, and 881 MW additional at prices greater than zero. There was approximately 1,100 MW less capacity offered at prices between 10 multiplied times the daily natural gas price and $250 per MWh. With smaller changes to the quantities of generation offered at prices above $250 per MWh, the resulting average aggregated generation offer stack for the summer season was 480 MW greater in 2013 than in 2012.

Figure 14: Aggregated Generation Offer Stack - Summer

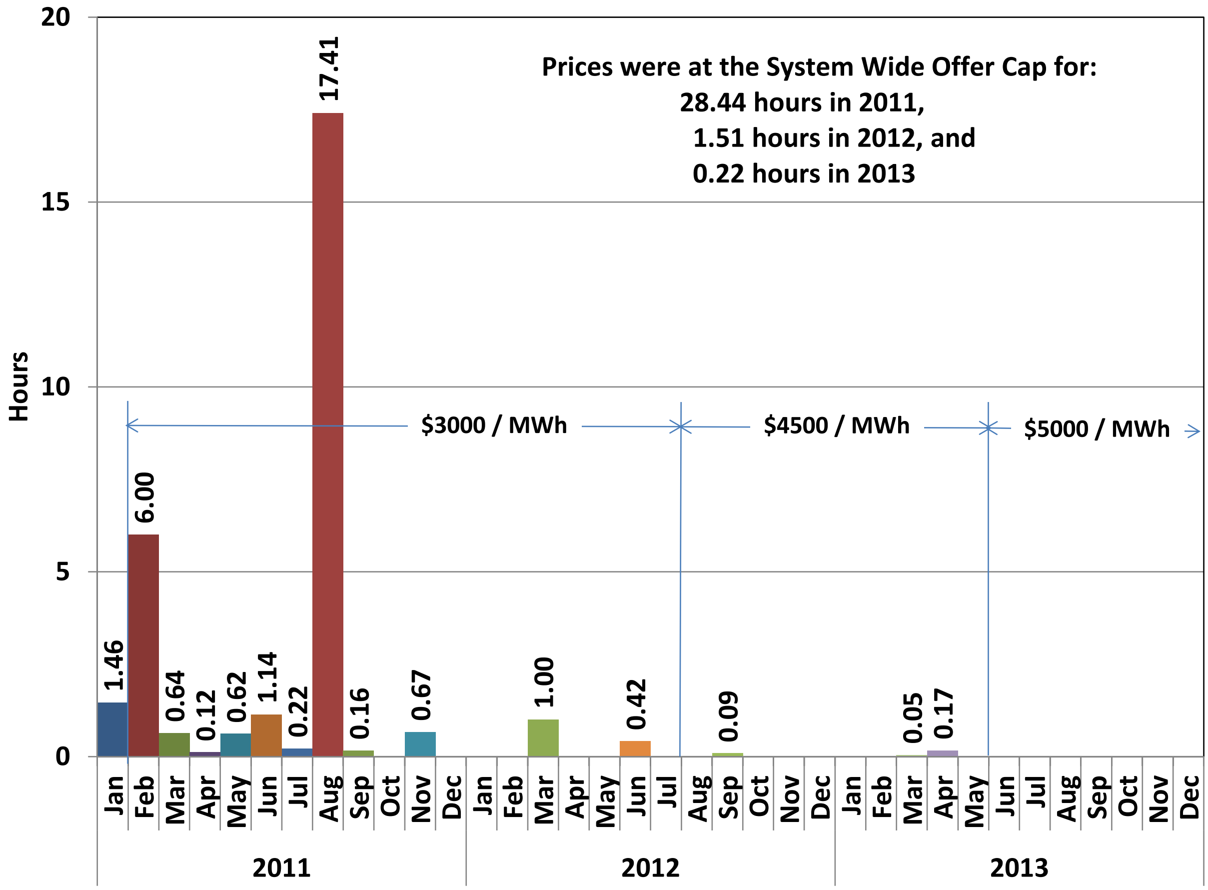


D. Prices at the System-Wide Offer Cap

After the extremes of 2011, weather conditions in Texas returned to closer to normal in 2012 and 2013. As more fully discussed in Section IV, Load and Generation, overall demand for electricity was higher in 2013 than in 2012 but lower than in 2011, resulting in few occasions when the available supply generation capacity was unable to meet customer demands. This resulted in a decreased likelihood that the available generation capacity was not sufficient to meet customer demands for electricity and maintain the required reliability reserves. As more fully described later in Section V, Resource Adequacy, independent of the energy offers by generators, energy prices rise toward the system-wide offer cap as available operating reserves approach minimum required levels to reflect the degradation in system reliability.

Figure 15 below shows the aggregated amount of time where the real-time energy price was at the system-wide offer cap, displayed by month.

Figure 15: Duration of Prices at the System-Wide Offer Cap

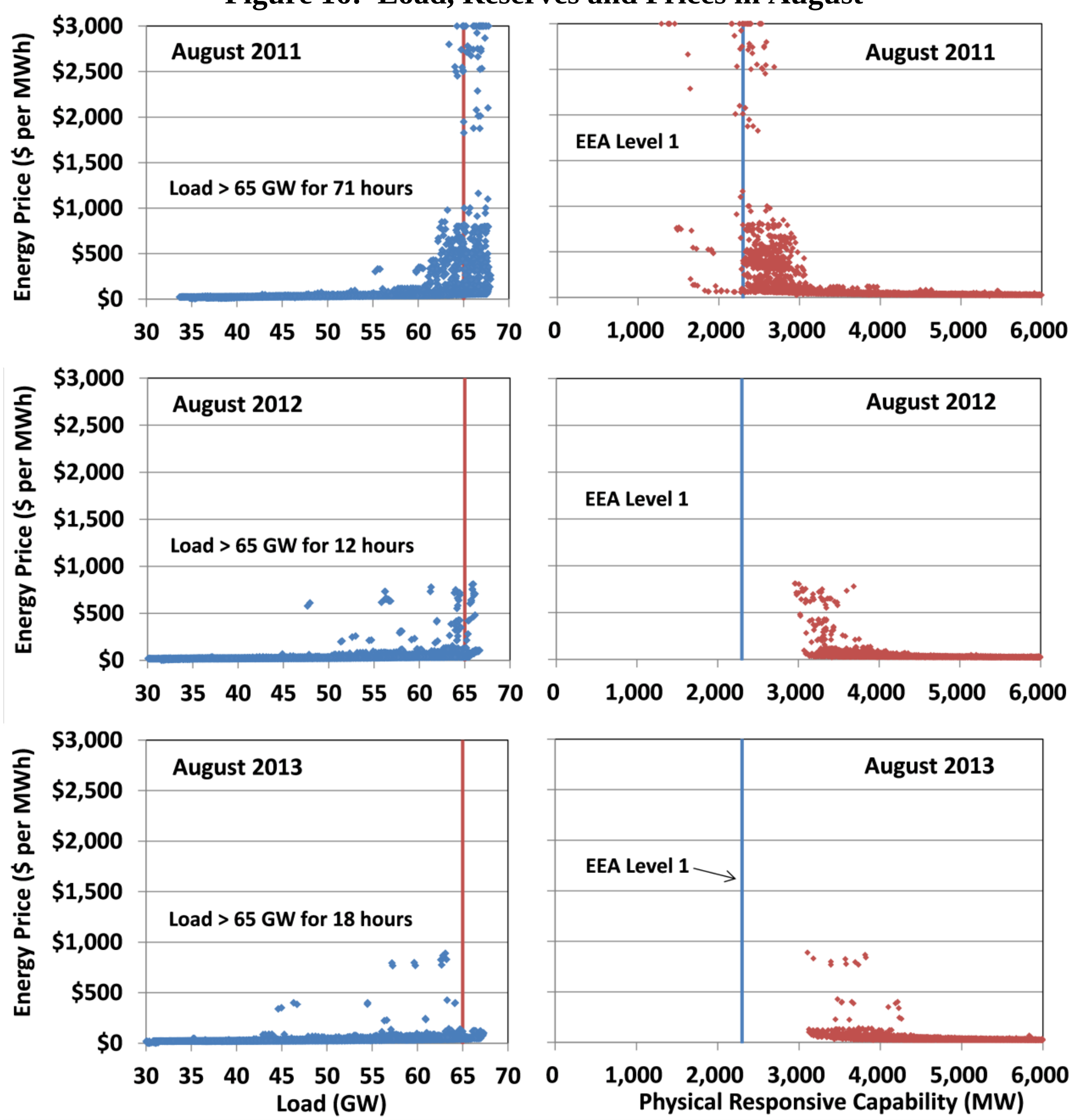


Prices during 2013 were at the system-wide offer cap for only 0.22 hours, a reduction from 1.51 hours in 2012 and a significant reduction from the 28.4 hours experienced in 2011. Approved during 2012, PUCT SUBST. R.25.508 increased the system-wide offer cap to $4,500 per MWh effective August 1, 2012. Revisions to PUCT SUBST. R.25.505 raised the system-wide offer cap to $5,000 per MWh effective June 1, 2013. As shown in Figure 15 above, there was only a brief period when energy prices rose to the cap after this change was implemented.

Further, there were no instances in 2013 of energy prices rising to the cap after the system-wide offer cap was increased to $5000 per MWh on June 1.

The next figure provides a detailed comparison of August's load, required reserve levels, and prices for 2011, 2012 and 2013. As expected, the weather in ERCOT was extremely hot and dry during August, but there were very few dispatch intervals when real-time energy prices reached the system-wide offer cap in 2012 and 2013 compared to the relatively high frequency it occurred in 2011. Although the weather may have been similar, there were significant differences in load and available operating reserve levels, resulting in much higher prices in August 2011.

Figure 16: Load, Reserves and Prices in August



Shown on the left side of Figure 16 is the relationship between real-time energy price and load level for each dispatch interval for the months of August 2011, 2012, and 2013. ERCOT loads were greater than 65 GW for 71 hours in 2011, whereas loads reached that level for 12 hours during August 2012 and 18 hours in August 2013. As previously discussed, a strong positive correlation between higher load and higher prices is expected in a well-functioning energy market. We observe such a relationship between higher prices and higher loads for all three months. However, that relationship appears to be weaker in the past two years with higher prices occurring at lower loads.

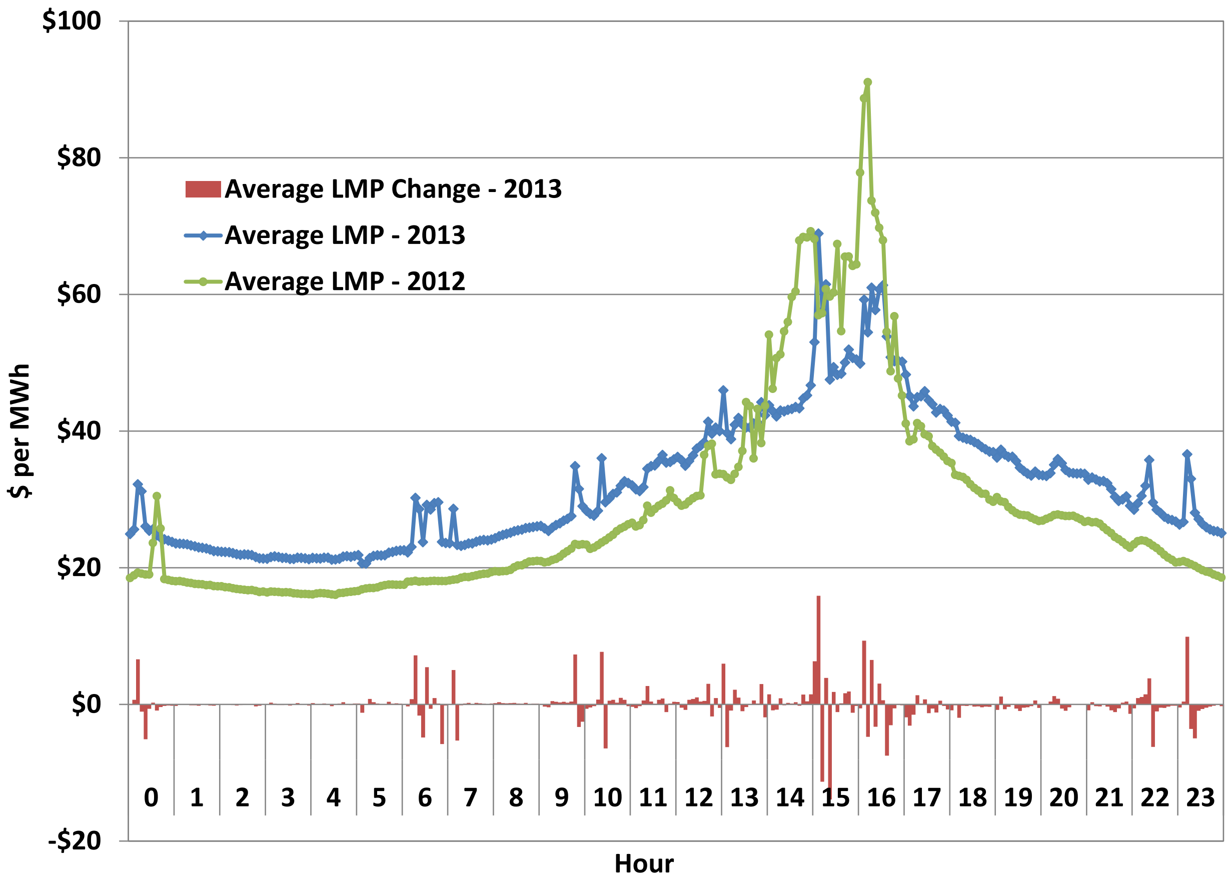
Although load levels are strong predictors of energy prices, an even more important predictor is the level of operating reserves. Simply put, operating reserves are the difference between the total capacity of operating resources and the current load level. As load level increases against a fixed quantity of operating capacity, the amount of operating reserves diminishes. The minimum required operating reserves prior to the declaration of Energy Emergency Alert ("EEA") Level 1 by ERCOT is 2,300 MW. As the available operating reserves approach the minimum required amount, energy prices should rise toward the system-wide offer cap to reflect the degradation in system reliability.

On the right side of Figure 16 are data showing the relationship between real-time energy prices and the quantity of available operating reserves for each dispatch interval during August of 2011, 2012, and 2013. This figure shows a strong correlation between diminishing operating reserves and rising prices. With the lower loads in August 2012 and 2013, available operating reserves were well above minimum levels for the entire month, and there were no occurrences where the energy price reached the system-wide offer cap. In contrast, there were numerous dispatch intervals in August 2011 when the minimum operating reserve level was approached or breached, with 17.4 hours where prices reached the system-wide offer cap. It should be noted that during August 2011 there were a number of dispatch intervals where operating reserves were below minimum requirements with prices well below the level that would be reflective of the reduced state of reliability. In Section IV, Load and Generation at page 98, we provide an example explaining why this can occur and offer a recommendation for improvement.

E. 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. Figure 17 below presents a view of the price volatility experienced in ERCOT's real-time energy market during the summer months of May through August. Average five-minute real-time energy prices are presented along with the magnitude of change in price for each five-minute interval. Average real-time energy prices from the same period in 2012 are also presented. Comparing average real-time energy prices for 2013 with those from 2012, the effects of higher natural gas prices on average prices during non-peak hours and the effects of fewer shortage intervals during peak hours are observed.

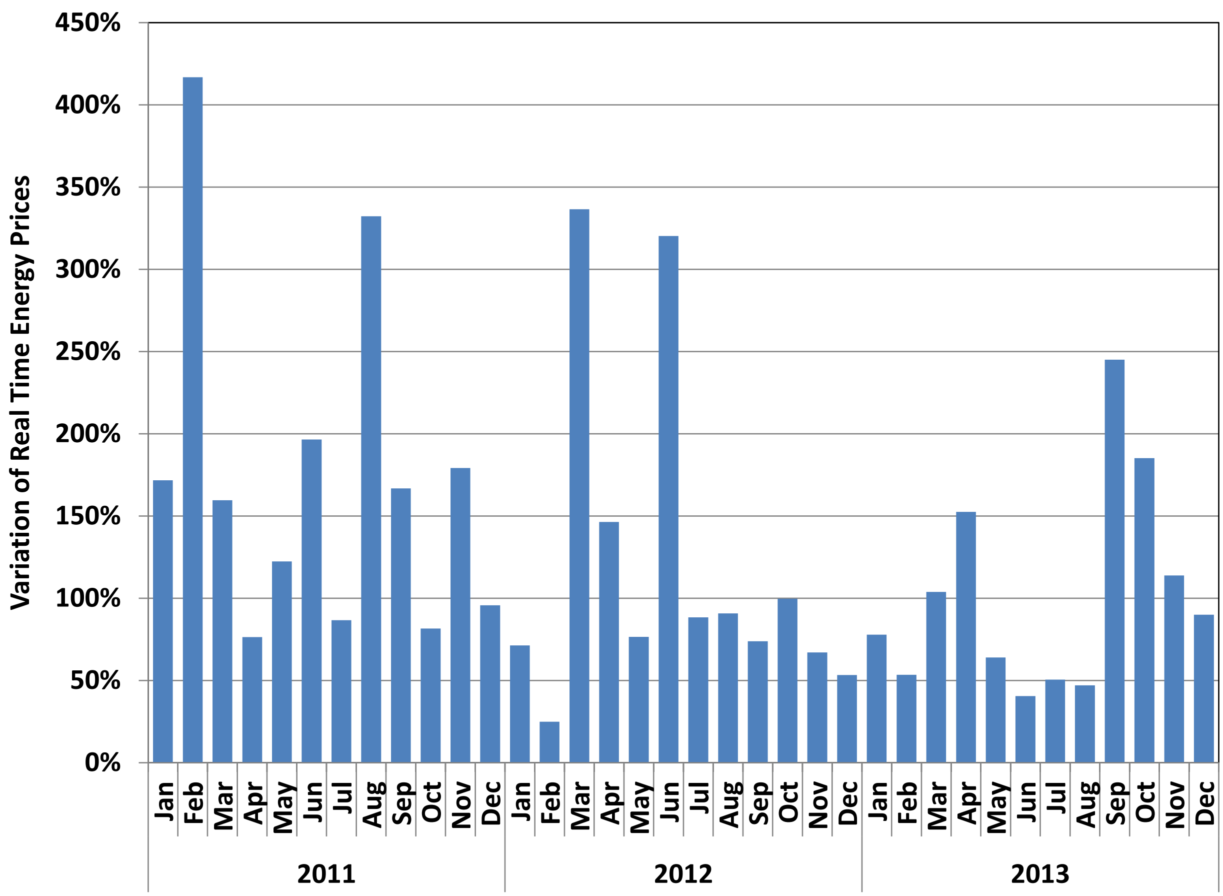
Figure 17: Real-Time Energy Price Volatility (May – August)



Outside of the hours from 15 to 18 (2:00 pm to 6:00 pm), short-term increases in average real-time energy prices are typically due to high prices resulting from generator ramp rate limitations occurring at times when significant amounts of generation is changing its online status. With higher natural gas prices in 2013, the price effects of these ramp limited periods were more noticeable in 2013. The average of the absolute value of changes in five-minute real-time energy prices, expressed as a percentage of average price was 3.4 percent in 2013, compared to 3.6 percent in 2012 and approximately 6.2 percent for the same period in 2011.

Expanding our view of price volatility, Figure 18 below presents the monthly variation in real-time prices. We observe that generally the months with highest price variability are those when real time prices rose to the system wide offer cap. Notable exceptions to this trend are observed in September and October of 2013.

Figure 18: Monthly Price Variation



The volatility of 15 minute settlement point prices for the four geographic load zones in 2013 was similar to that seen in 2012, as shown below in Table 1.

Table 1: 15 Minute Price Changes as a Percentage of Annual Average Price

Load Zone	*2011*	*2012*	*2013*
Houston	21.4%	13.0%	14.8%
South	19.9	13.1	15.4
North	22.5	13.9	13.7
West	26.2	19.4	17.2

The table shows that the price volatility fell substantially from 2011 to 2012 and 2013. This was primarily due to the reduced duration of shortage pricing in 2012 and 2013. In contrast, 2011 exhibited the hottest summer temperatures in more than 100 years, leading to frequent shortages and associated higher price volatility. The table also shows that price volatility in the West zone has continued to be higher than in the other zones, which is expected given the very high penetration of variable output wind generation located in that area.

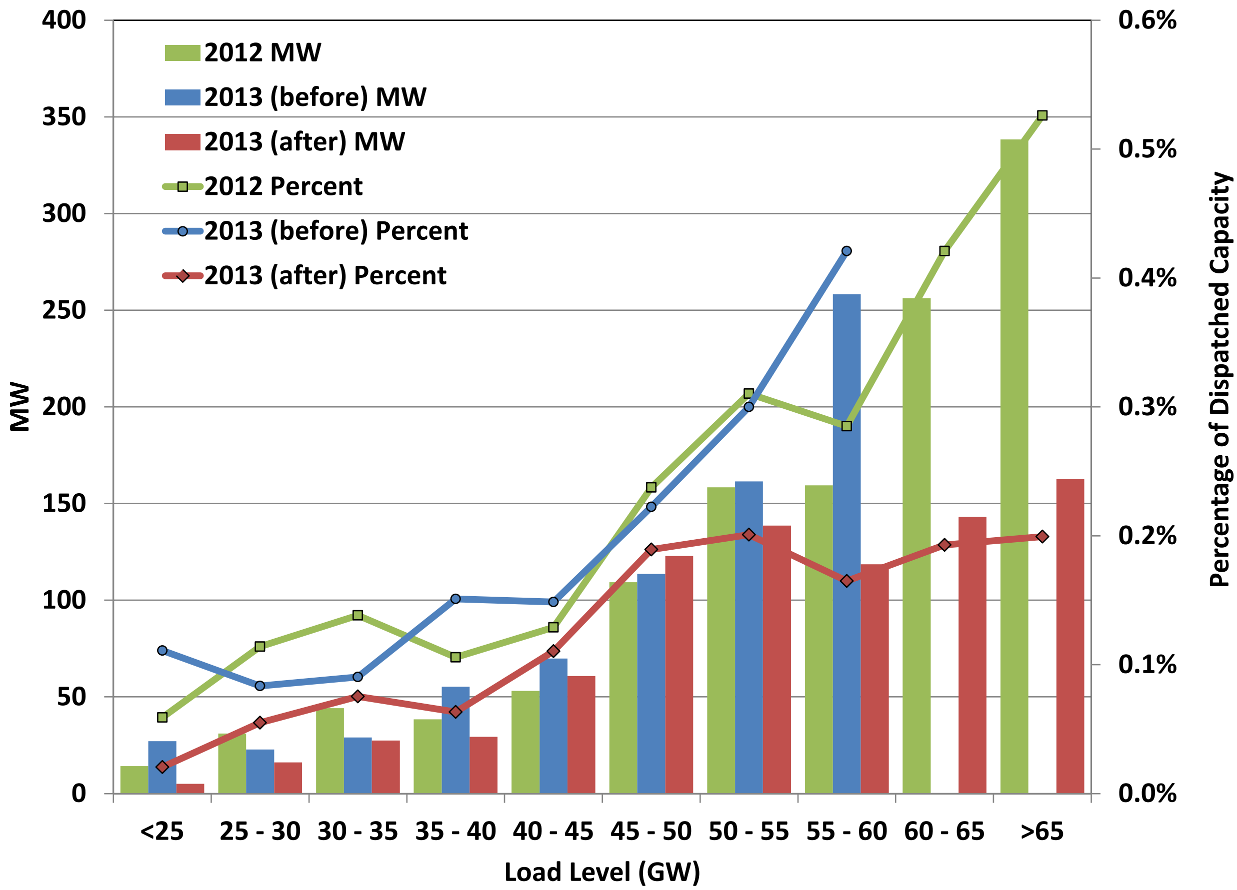
F. Mitigation

ERCOT's dispatch software includes an automatic, two step price mitigation process. In the first step, the dispatch software calculates output levels (Base Points) and associated locational marginal prices using the participants' offer curves and only considering 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 to be 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 output levels for each generator, taking all transmission constraints into consideration. This approach is intended to limit the ability of a specific generator to raise prices in the event of a transmission constraint that requires their output to resolve. In this subsection we describe a change to the mitigation process that was implemented during 2013 and analyze the quantity of capacity affected by this mitigation process.

Although executing all the time, the automatic price mitigation aspect of the two step dispatch process only has an effect when a non-competitive transmission constraint is active. The mitigation process should limit the ability of a generator to affect price when their output is required to manage congestion. The process as initially implemented did not identify situations with sufficient competition between generators on the other (harmful) side of the constraint and would mitigate their offers as well. This unnecessary mitigation was addressed on June 12, 2013 with the implementation of changes described in NPRR520. With the introduction of an impact test to determine whether units are relieving or contributing to a transmission constraint, only the relieving units are now subject to mitigation. As shown below this had a noticeable effect on the amount of capacity subject to mitigation.

Our first analysis computes how much capacity, on average, is actually mitigated during each dispatch interval. The results, shown in Figure 19, are provided by load level.

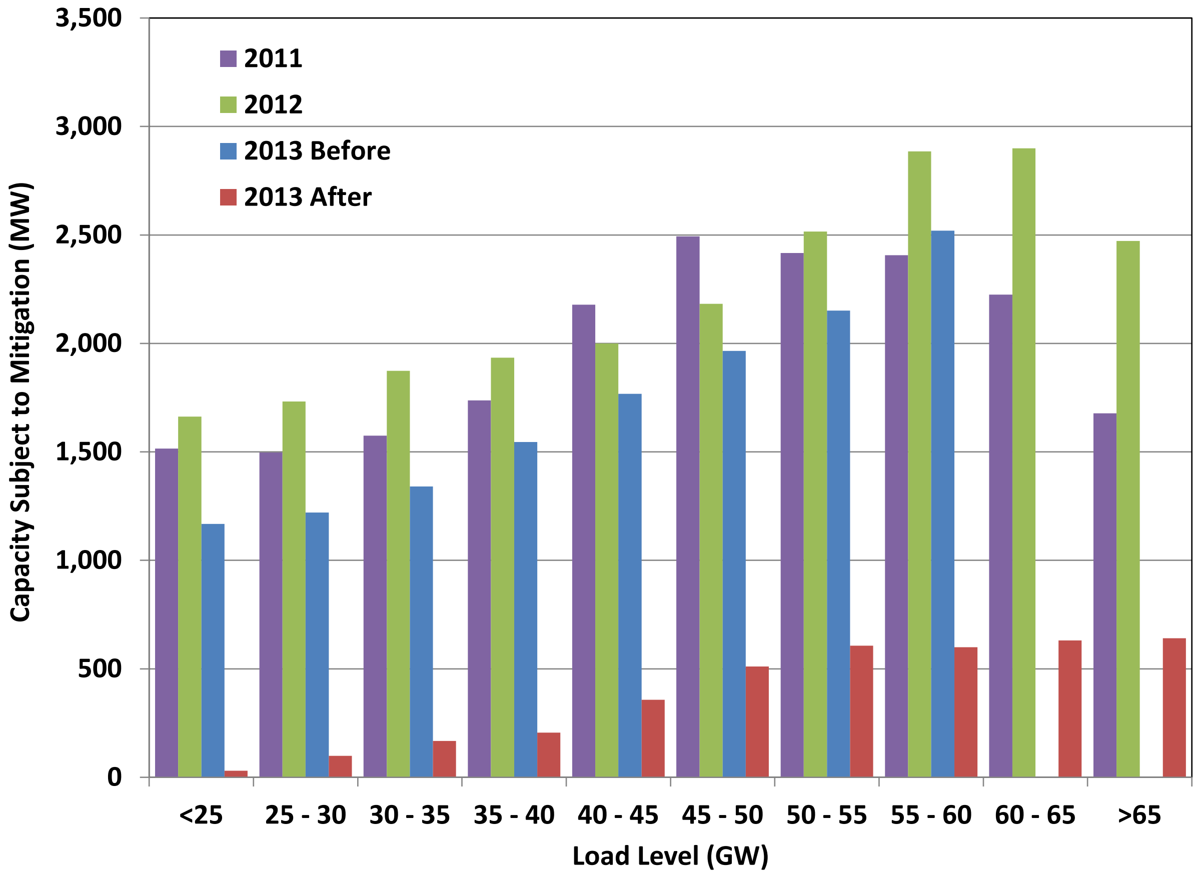
Figure 19: Mitigated Capacity by Load Level



The level of mitigation in 2013 before the rule change was very similar to that experienced in 2012. After the rule change there was a noticeable reduction in the percentage of dispatchable capacity being mitigated across all load levels. Further, during high load periods the amount of capacity being mitigated was reduced approximately in half.

In the previous figure only the amount of capacity that could be dispatched within one interval was counted as mitigated. In our next analysis we compute the total capacity subject to mitigation. These values are determined by comparing a generator's mitigated and unmitigated (as submitted) offer curves and determining the point at which they diverge. We then take the difference between the total unit capacity and the capacity at the point the curves diverge. This calculation is performed for all units and aggregated by load level, as shown in Figure 20.

Figure 20: Capacity Subject to Mitigation



The effects of the rule change are very noticeable in Figure 20. Compared to 2012 where the amount of capacity subject to mitigation exceeded 1500 MW for all load levels, the amount of capacity subject to mitigation after the rule change in 2013 never reached 700 MW. Put another way, up to 7 percent of capacity required to serve load in 2012 was subject to mitigation. After the rule change this percentage decreased to 1 percent. An important note about this capacity measure is that it 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.

II. Review of Day-Ahead Market Outcomes

ERCOT's centralized day-ahead market allows participants to make financially binding forward purchases and sales of power for delivery in real-time. Offers to sell can take the form of either a three-part supply offer, which allows sellers to reflect the unique financial and operational characteristics of a specific generation resource, or an energy only offer, which is location specific but is not associated with a generation resource. Bids to buy are also location specific. Ancillary services are also procured as part of the day-ahead market clearing. The third type of transaction included in the day-ahead market is bids to buy Point to Point ("PTP") Obligations, which allow parties to hedge the incremental cost of congestion between day-ahead and real-time operations.

With the exception of the acquisition of ancillary service capacity, the day-ahead market is a financial market. Although all bids and offers are evaluated in the context of their ability to reliably flow on the transmission network, there are no operational obligations resulting from the day-ahead market clearing. These transactions are made for a variety of reasons, including satisfying the participant's own supply, managing risk by hedging the participant's exposure to the real-time market, or arbitraging with the real-time markets. For example, load serving entities can insure against volatility in the real-time market by purchasing in the day-ahead market. Finally, the day-ahead market plays a critical role in coordinating generator commitments. For all of these reasons, the performance of the day-ahead market is essential.

In this section we review energy pricing outcomes from the day-ahead market and compare their convergence with real-time energy prices. We will also review the volume of activity in the day-ahead market, including a discussion of PTP Obligations. We conclude this section with a review of the ancillary service markets.

A. Day-Ahead Market Prices

One indicator of market performance is the extent to which forward and real-time spot prices converge over time. Forward prices will converge with real-time prices when two main conditions are in place: a) there are low barriers to shifting purchases and sales between the forward and real-time markets; and b) sufficient information is available to market participants to allow them to develop accurate expectations of future real-time prices. When these conditions are met, market participants can be expected to arbitrage predictable differences between forward prices and real-time spot prices by increasing net purchases in the lower-priced market and increasing net sales in the higher-priced market. These actions will tend to improve the convergence of forward and real-time prices.

In this subsection, we evaluate the price convergence between the day-ahead and real-time markets. This analysis reveals whether persistent and predictable differences exist between day-ahead and real-time prices, which participants should arbitrage over the long-term. To measure the short-term deviations between real-time and day-ahead prices, we also calculate the average of the absolute value of the difference between the day-ahead and real-time price on a daily basis.

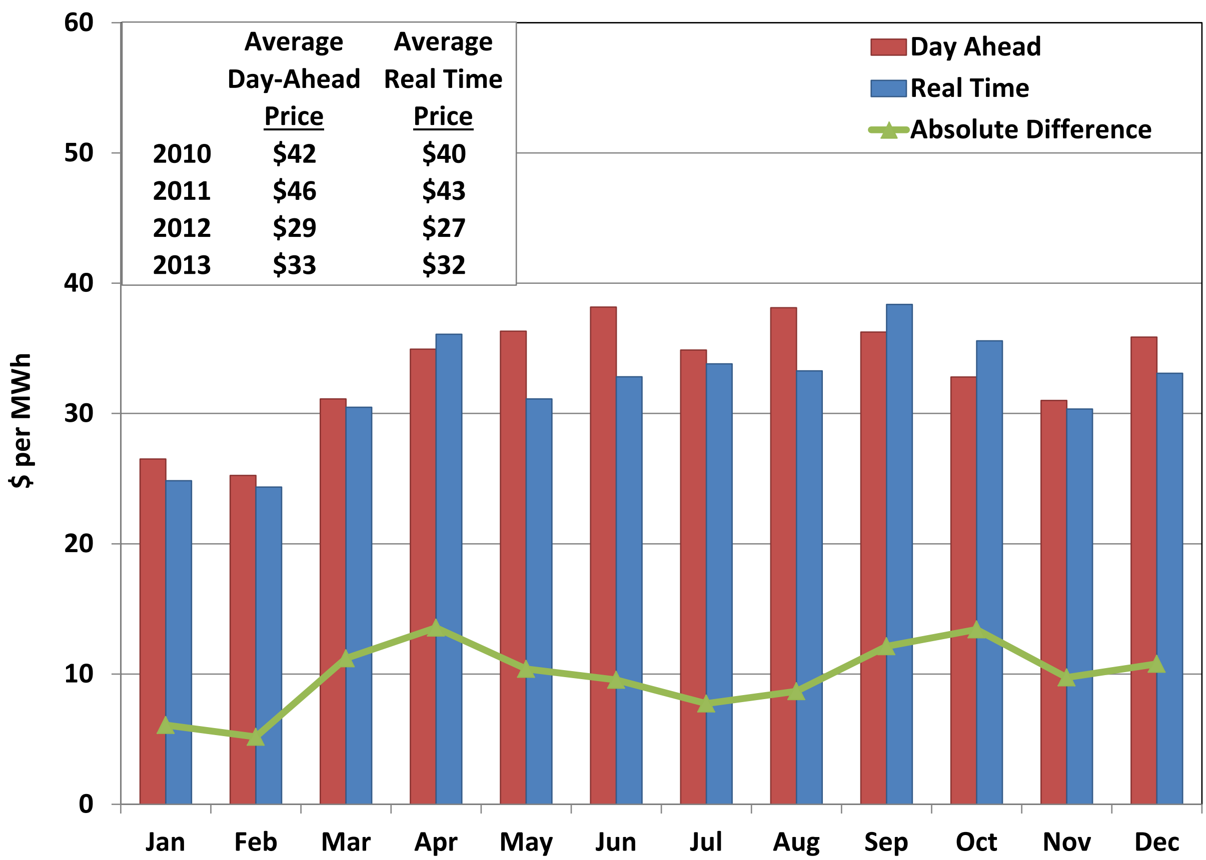
This measure captures the volatility of the daily price differences, which may be large even if the day-ahead and real-time energy prices are the same on average. For instance, if day-ahead prices are $70 per MWh on two consecutive days while real-time prices are $40 per MWh and $100 per MWh on the two days, the absolute price difference between the day-ahead market and the real-time market would be $30 per MWh on both days, while the difference in average prices would be $0 per MWh.

Figure 21 shows the price convergence between the day-ahead and real-time market, summarized by month. Day-ahead prices averaged $33 per MWh in 2013 compared to an average of $32 per MWh for real-time prices.[6] The average absolute difference between day-ahead and real-time prices was $9.86 per MWh in 2013; slightly lower than in 2012 when average of the absolute difference was $9.96 per MWh. This day-ahead premium is consistent with expectations due to the much higher volatility of real-time prices. Risk is lower for loads purchasing in the day-ahead and higher for generators selling day-ahead. The higher risk for generators is associated with the potential of incurring a forced outage and as a result, having to buy back energy at real-time prices. This explains why the highest premiums tend to occur during the months with the highest demand and highest prices.

[6] These values are simple averages, rather than load-weighted averages presented in Figure 1and Figure 2.

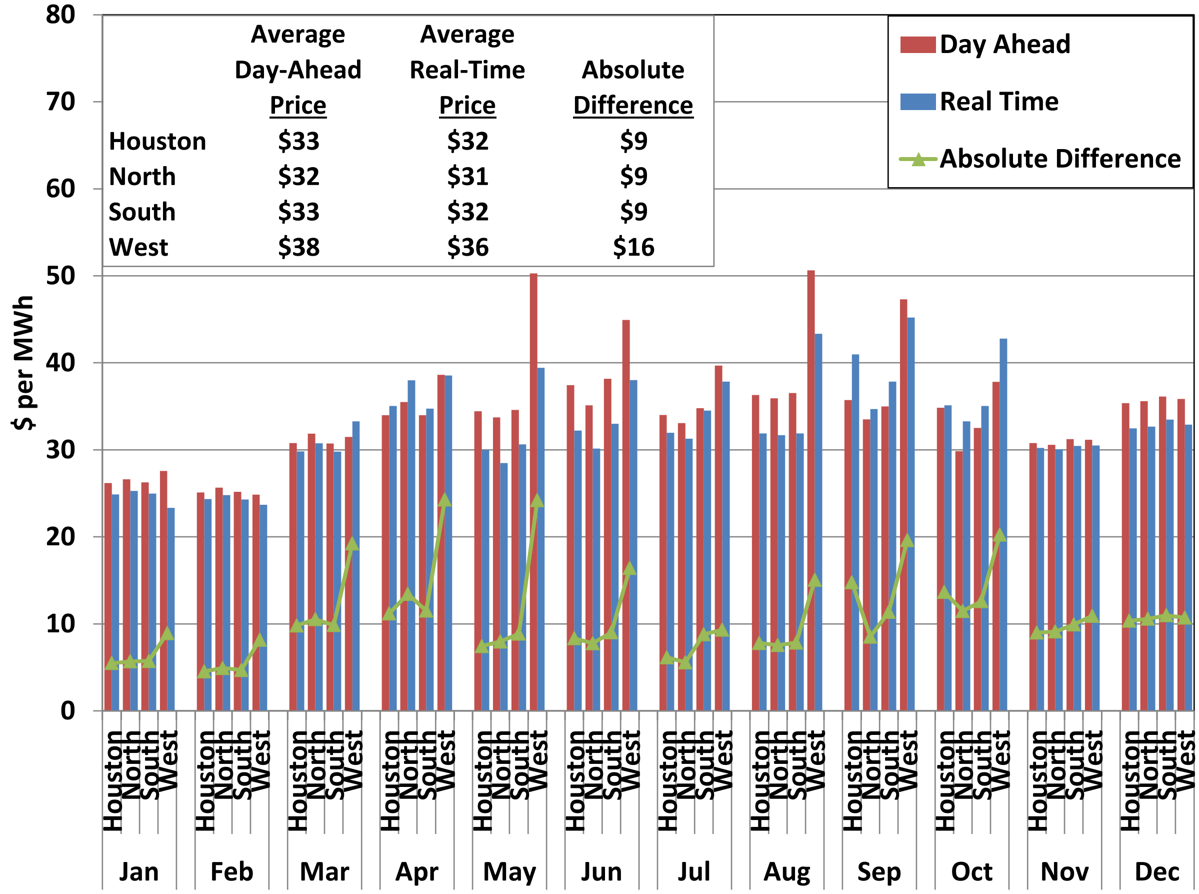
Overall, the day-ahead premiums were very similar to the differences observed in 2012, but remain higher than observed in other organized electricity markets. Real-time energy prices in ERCOT are allowed to rise to levels that are much higher than what is allowed in other organized electricity markets, which increases risk and helps to explain the higher day-ahead premiums regularly observed in ERCOT. Although most months experienced a day-ahead premium (*e.g.*, $5 per MWh in May, June and August), it should not be expected over time that every month will always produce a day-ahead premium as the real-time risks that lead to the premiums will materialize unexpectedly on occasion, resulting in real-time prices that exceed day-ahead prices (*e.g.*, in April, September and October).

Figure 21: Convergence between Forward and Real-Time Energy Prices



In Figure 22 below, monthly day-ahead and real-time prices are shown for each of the geographic load zones. Of note is the difference in the West zone data compared to the other regions. The higher volatility in West zone pricing is likely associated with the uncertainty of forecasting wind generation output and the resulting price differences between day-ahead and real-time.

Figure 22: Day-Ahead and Real-Time Prices by Zone



B. Day-Ahead Market Volumes

Our next analysis summarizes the volume of day-ahead market activity by month. In Figure 23 below, we find that the volume of day-ahead purchases provided through a combination of generator specific and virtual energy offers was approximately 50 percent of real-time load in 2013. This is an increase from 2012, when they totaled 45 percent. This increase was primarily due to a 42 percent increase in the volume of virtual energy offers. The volume of generator specific purchases increased approximately 2 percent in 2013 compared to 2012.

As discussed in more detail in the next subsection, Point to Point Obligations are financial instruments purchased in the day-ahead market. Although these instruments do not themselves involve the direct supply of energy, they do provide the ability to avoid the congestion costs associated with transferring the delivery of energy from one location to another. To provide a volume comparison we aggregate all of these "transfers", netting location specific injections against withdrawals. The volume of PTP Obligations in 2013 was almost 6 percent lower than in 2012.

By adding the aggregated transfer capacity associated with purchases of PTP Obligations, we find that total volumes transacted in the day-ahead market are greater than real-time load by an average of 12 percent. However, the volume in excess of real-time load decreased in 2013 compared to 2012, when on average the monthly volume of PTP Obligations was 22 percent greater than real-time load.

Figure 23: Volume of Day-Ahead Market Activity by Month

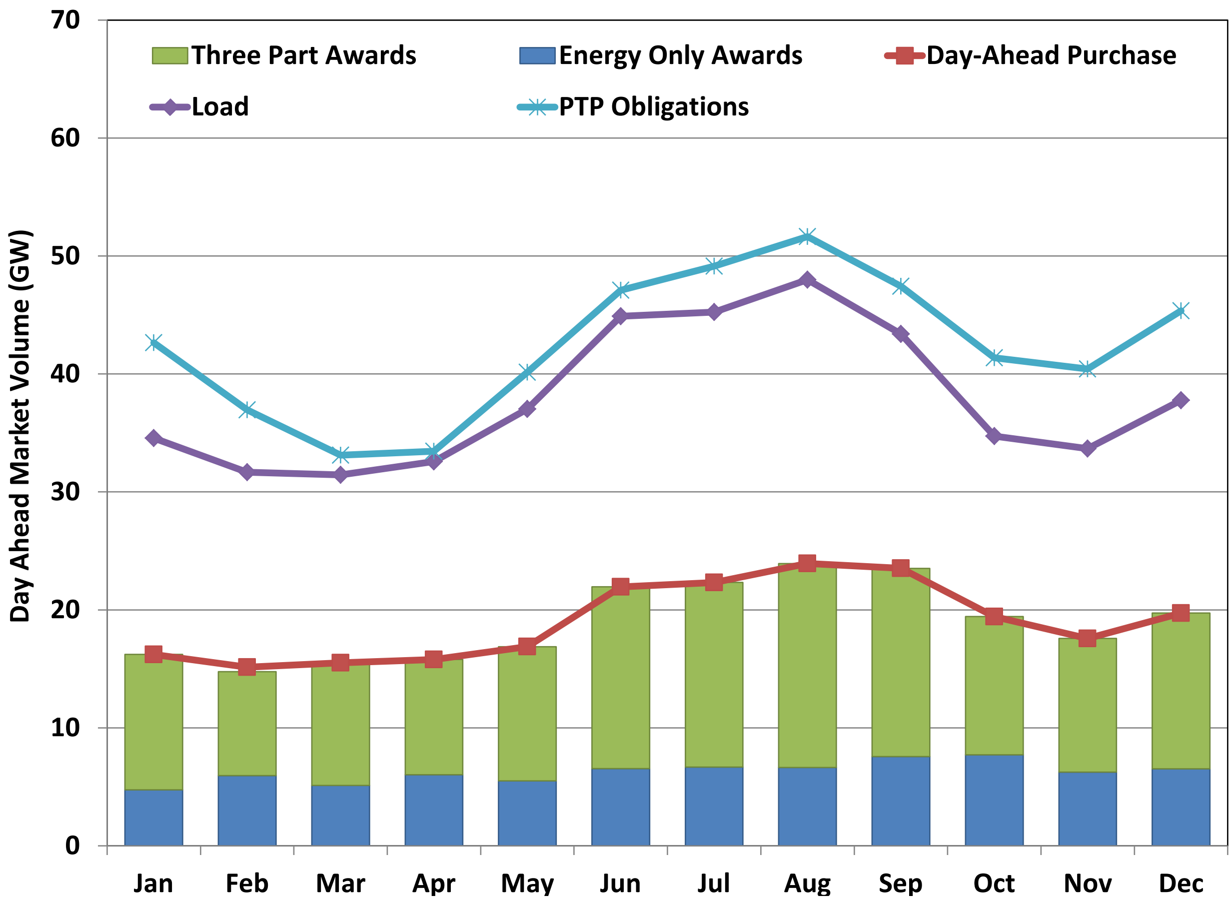
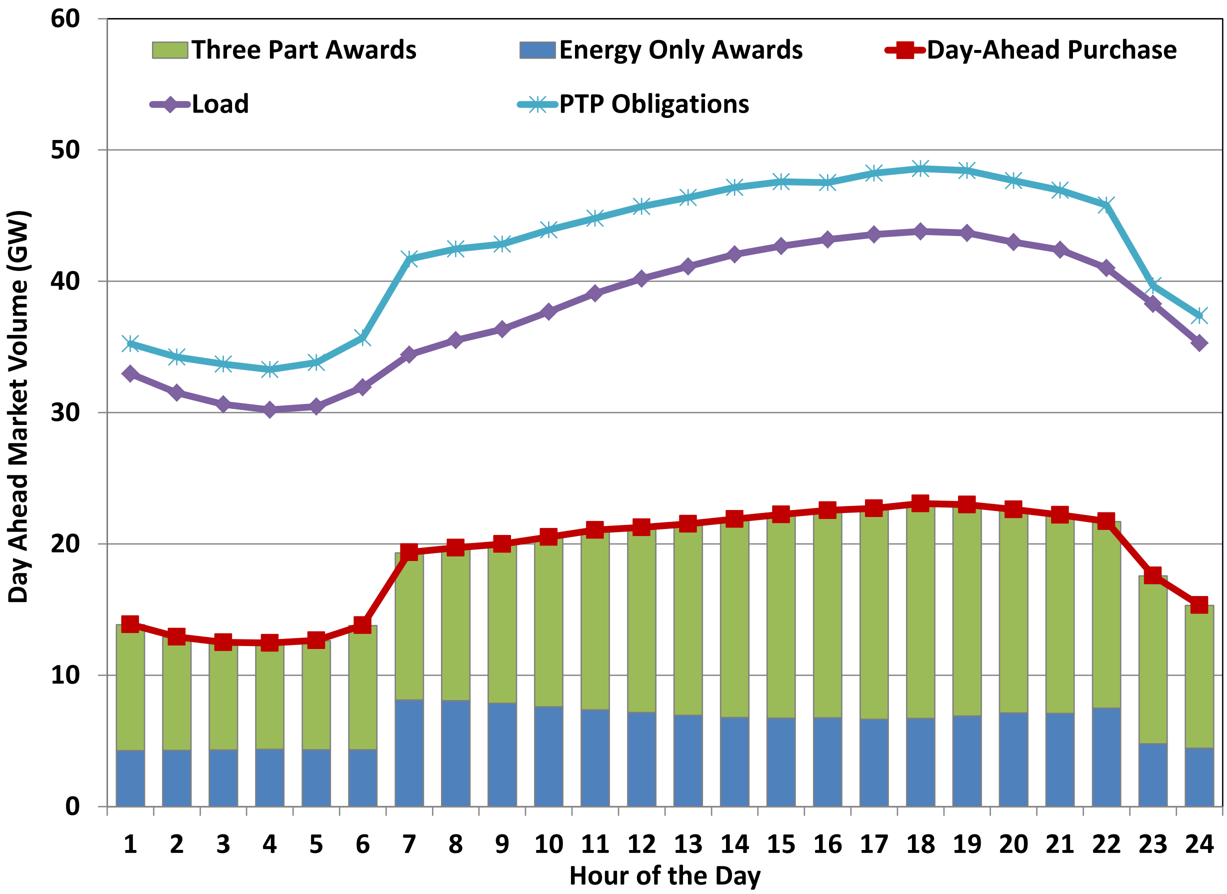


Figure 24 below, presents the same day-ahead market activity data summarized by hour of the day. In this figure the volume of day-ahead market transactions is disproportionate with load levels between the hours of 6 and 22. Since these times align with common bilateral transaction terms, it appears that market participants are using the day-ahead market to trade around those positions.

Figure 24: Volume of Day-Ahead Market Activity by Hour



C. Point to Point Obligations

Purchases of Point to Point ("PTP") Obligations comprise a significant portion of day-ahead market activity. These instruments are similar to, and can be used to complement Congestion Revenue Rights (CRRs). CRRs, as more fully described in Section III, are acquired via monthly and annual auctions and allocations. CRRs accrue value to their owner based on locational price differences as determined by the day-ahead market. PTP Obligations are instruments that are purchased as part of the day-ahead market and accrue value to their owner based on real-time locational price differences. By acquiring a PTP Obligation using the proceeds due to them from their CRR holding, a market participant may be described as rolling their hedge to real-time.

In this subsection we provide additional details about the volume and profitability of these PTP Obligations.

Figure 25: Point to Point Obligation Volume

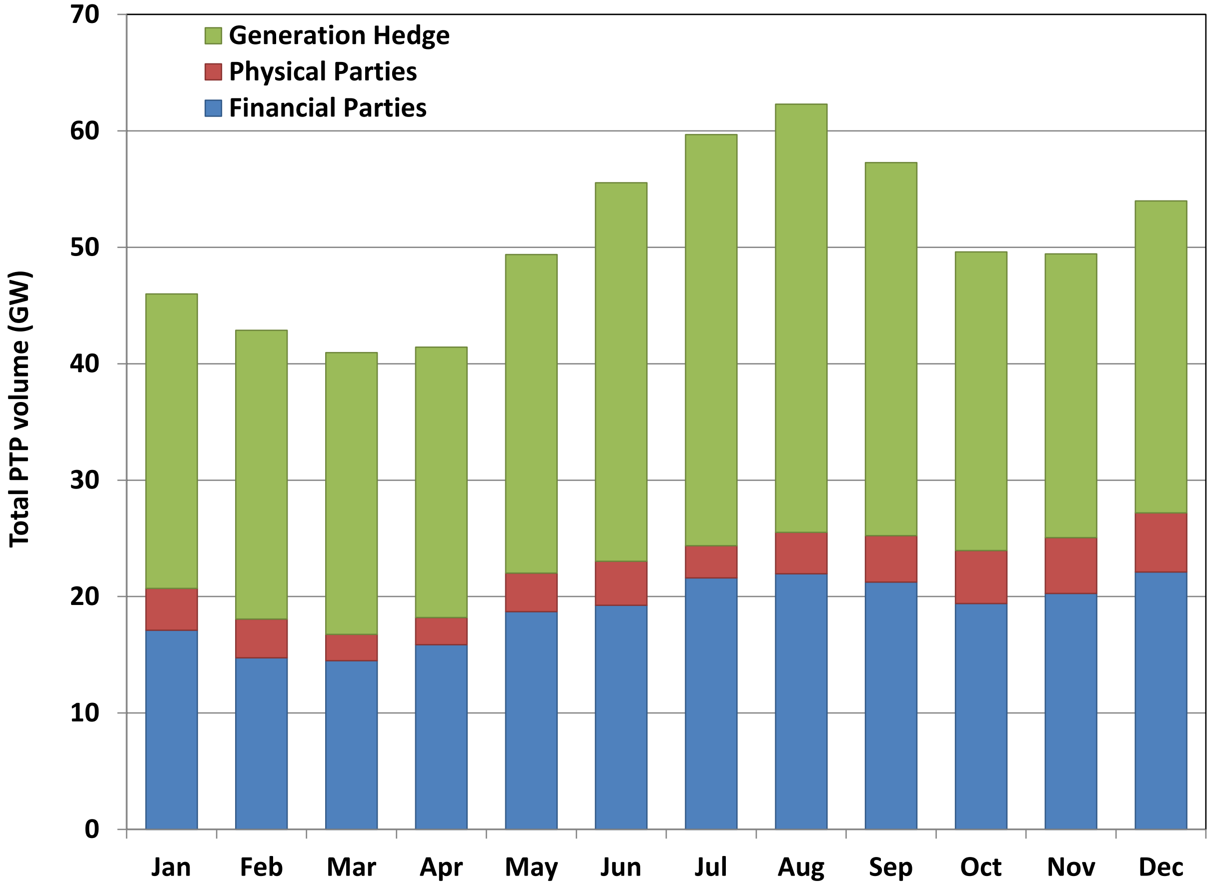
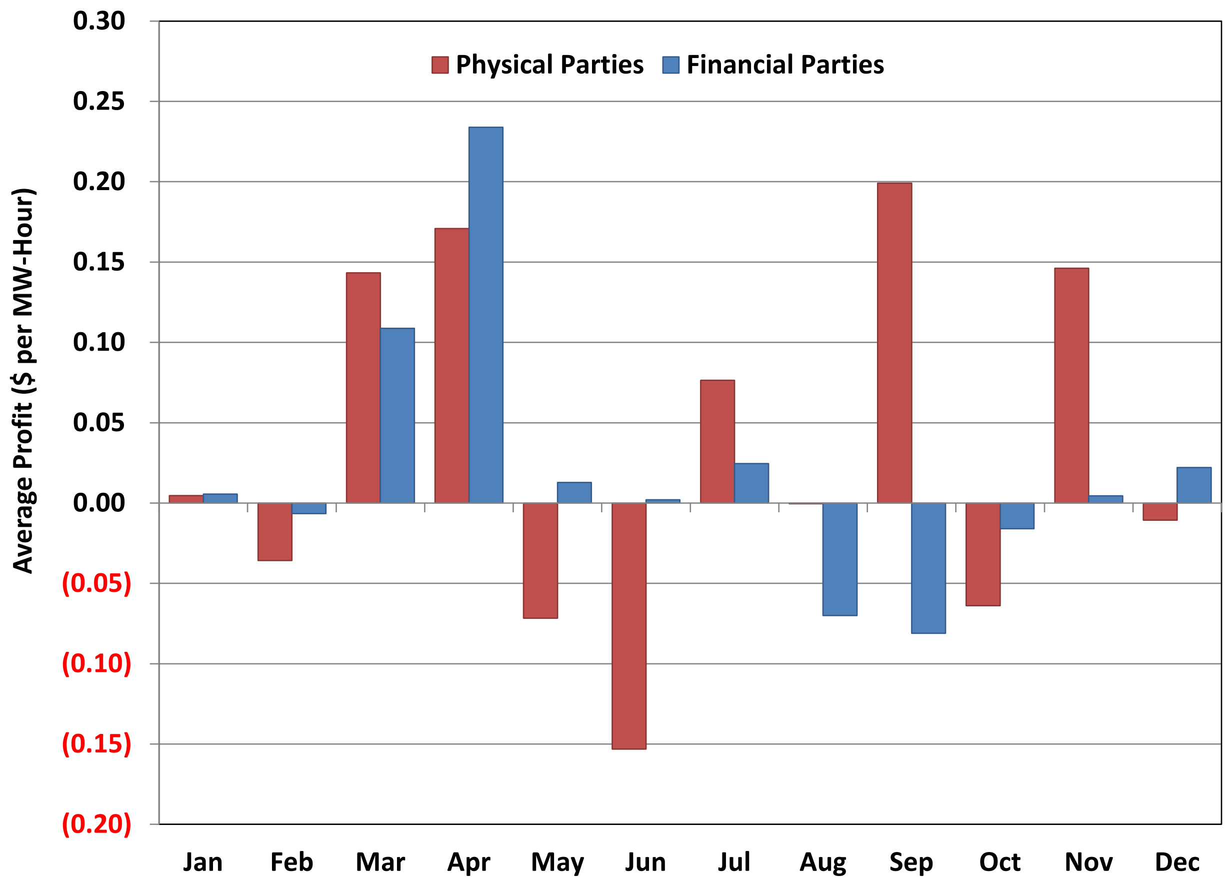


Figure 25 presents the total volume of PTP Obligation purchases divided into three categories. Compared to the previous two figures which showed net flows associated with PTP Obligations, in this figure we examine the total volume. For all PTP Obligations that source at a generator location, we attribute capacity up to the actual generator output as a generator hedge. From the figure above we see that this comprised most of the volume of PTP Obligations purchased. The remaining volumes of PTP Obligations are not directly linked to a physical position and are assumed to be purchased primarily to profit from anticipated price differences between two locations. We further separate this arbitrage activity by type of market participant. Physical parties are those that have actual real-time load or generation, whereas financial parties have neither.

To the extent the price difference between the source and sink of a PTP Obligation is greater in real-time than it was for the day-ahead price, the owner will have made a profit. Conversely, if the price difference does not materialize in real-time, the PTP Obligation may be considered unprofitable. We compare the profitability of PTP Obligation holdings by the two types of participants in Figure 26.

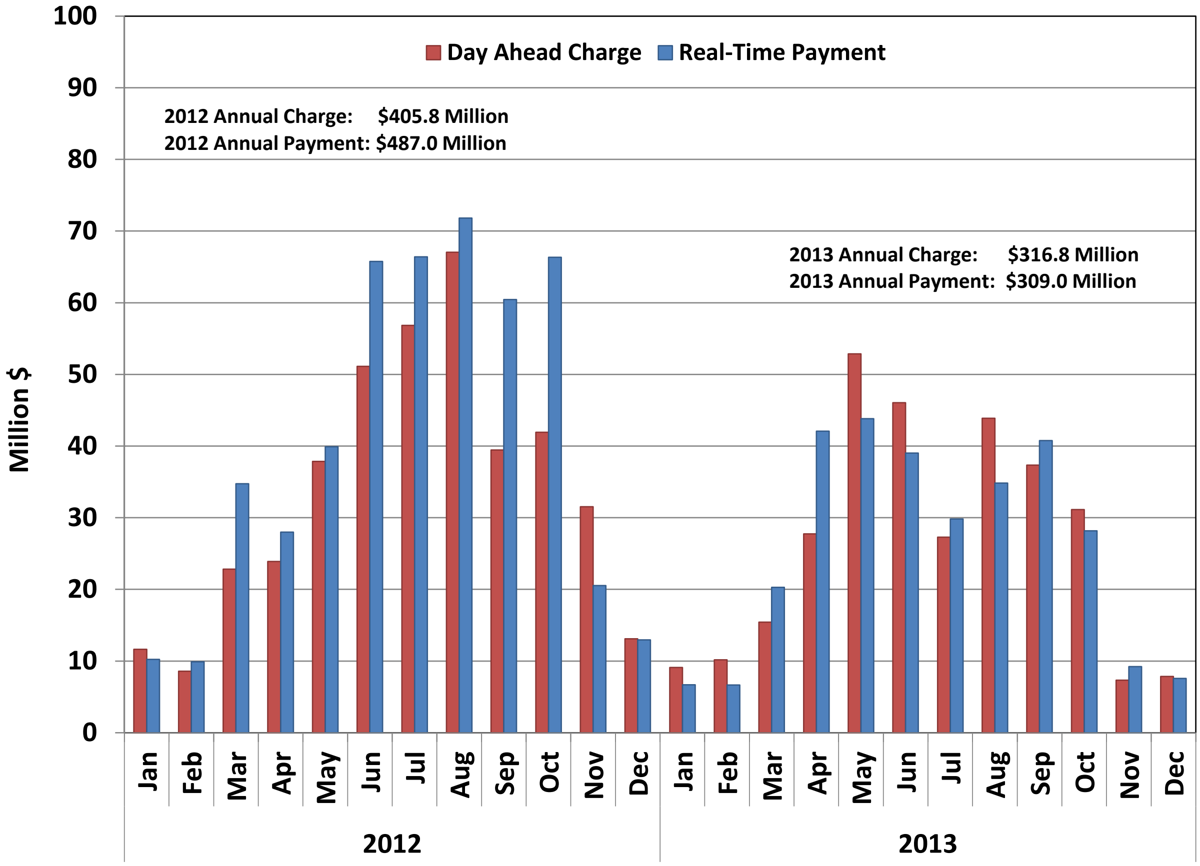
Figure 26: Average Profitability of Point to Point Obligations



In previous years this analysis has shown that there were two or three months where physical participants PTP Obligation holdings were unprofitable, and that the holdings of financial participants, in aggregate were profitable in all months. We may infer from the data shown in Figure 26 that PTP Obligation holdings, in aggregate, were much less profitable in 2013. These outcomes are more problematic for financial participants. With no real-time load or generation and therefore no other exposure to real-time prices, if a financial participant is not making a profit on their PTP Obligations there is no reason for them to buy any. It is their profit seeking action of buying PTP Obligations between points where congestion is expected that helps make the day-ahead market converge with real-time market outcomes. On the other hand, physical participants do have exposure to real-time prices. It is reasonable to expect that this type of participant is most interested in limiting that exposure by using PTP Obligations as a hedge.

To conclude our analysis of PTP Obligations, in Figure 27 we compare the total amount paid for these instruments day-ahead, with the total amount received by their holders in real-time.

Figure 27: Point to Point Obligation Charges and Payments

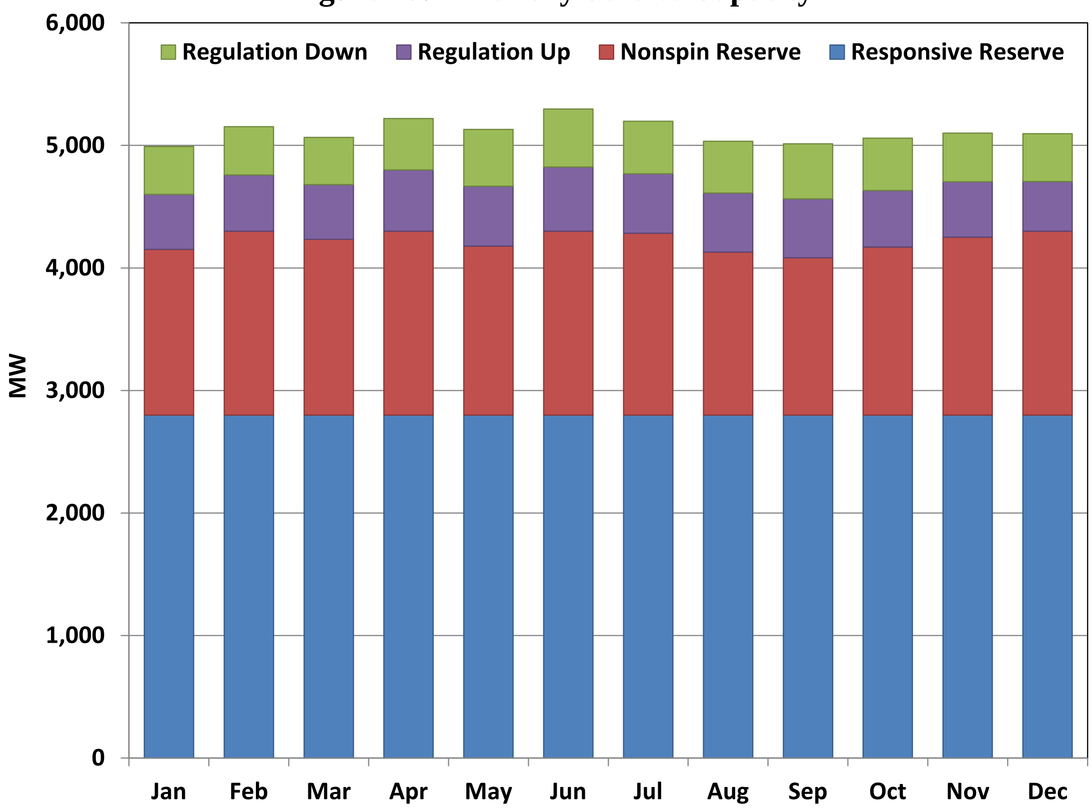


In prior years the aggregated total payments received by PTP Obligation owners was greater than the amount charged to the owners to acquire them. This occurs when real-time congestion is greater than what occurred in the day-ahead. This was not the case in 2013. Across the year, and in seven of twelve months, the acquisition charges were greater than the payments received, implying that expectations of congestion as evidenced by day-ahead purchases were greater than the actual congestion that occurred in real-time. The payments made to PTP Obligation owners come from real-time congestion rent. We assess the sufficiency of real-time congestion rent to cover both PTP Obligations and payments to owners of CRRs who elect to receive payment based on real-time prices in Section III, Transmission and Congestion at page 56.

D. Ancillary Services Market

The primary ancillary services are up regulation, down regulation, responsive reserves, and non-spinning reserves. Market participants may self-schedule ancillary services or purchase their required ancillary services through the ERCOT markets. This subsection reviews the results of the ancillary services markets in 2013. We start with a display of the quantities of each ancillary service procured each month shown in Figure 28.

Figure 28: Ancillary Service Capacity

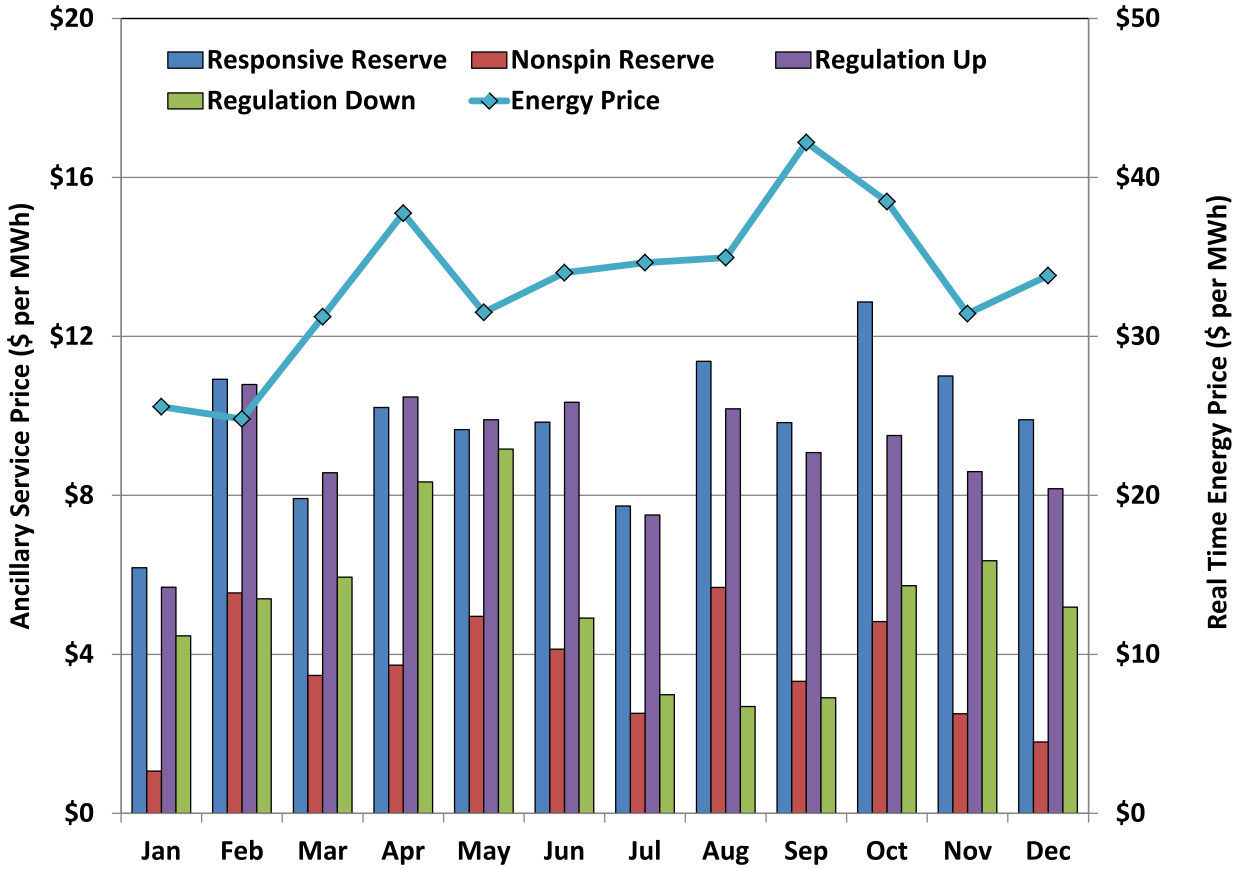


In general, the purpose of responsive and non-spinning reserves is to protect the system against unforeseen contingencies (*e.g.*, unplanned generator outages, load forecast error, wind forecast error), rather than for meeting normal load fluctuations. ERCOT procures responsive reserves to ensure that the system frequency can quickly be restored to appropriate levels after a sudden, unplanned outage of generation capacity. Non-spinning reserves are provided from slower responding generation capacity, and can be deployed alone, or to restore responsive reserve capacity. Regulation reserves are capacity that responds every four seconds, either increasing or decreasing as necessary to fill the gap between energy deployments and actual system load.

The amount of responsive reserve was increased by 500 MW beginning in April 2012. This 500 MW increase was balanced with the same amount of decrease in the amount of non-spinning reserves procured. Although the minimum level of required responsive reserve remains at 2,300 MW, having the additional 500 MW of responsive reserve provides a higher quality – that is, faster responding capacity available to react to sudden changes in system conditions.

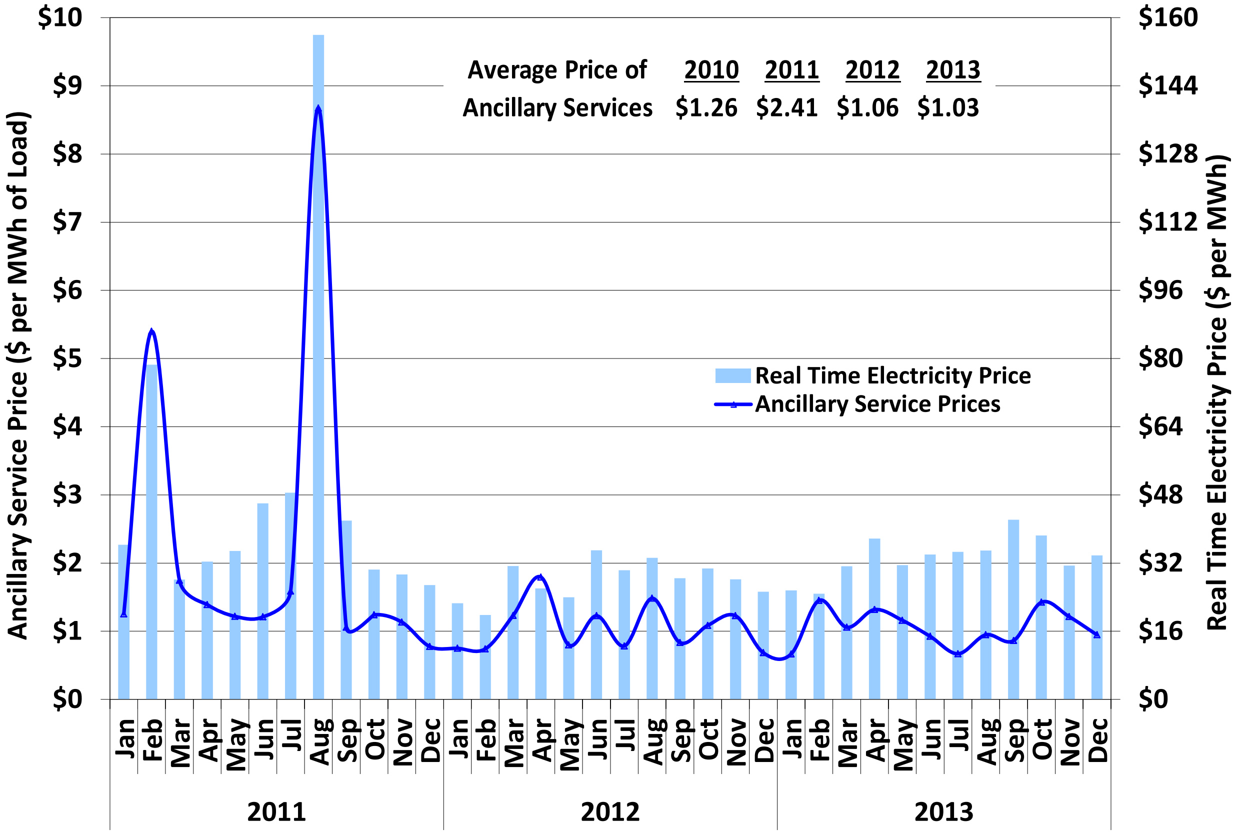
Under the nodal market, ancillary service offers are co-optimized as part of the day-ahead market clearing. This means that market participants no longer have to include their expectations of forgone energy sales in their ancillary services capacity offers. As a result of ancillary services clearing prices explicitly accounting for the value of energy, there is a much higher correlation between ancillary services prices and real-time energy prices.

Figure 29: Ancillary Service Prices



With average energy prices varying between $20 and $45 per MWh, we observe the prices of ancillary services remaining fairly stable throughout the year. In contrast to the previous data that showed the individual ancillary service capacity prices, Figure 30 shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2011 through 2013. This figure shows that total ancillary service costs are generally correlated with real-time energy price movements, which are highly correlated with natural gas price movements as previously discussed. This occurs for two primary reasons. First, higher energy prices increase the opportunity costs of providing reserves and, therefore, can contribute to higher ancillary service prices. Second, shortages cause both ancillary service prices and energy prices to rise sharply so increases or decreases in the frequency of shortages will contribute to this observed correlation.

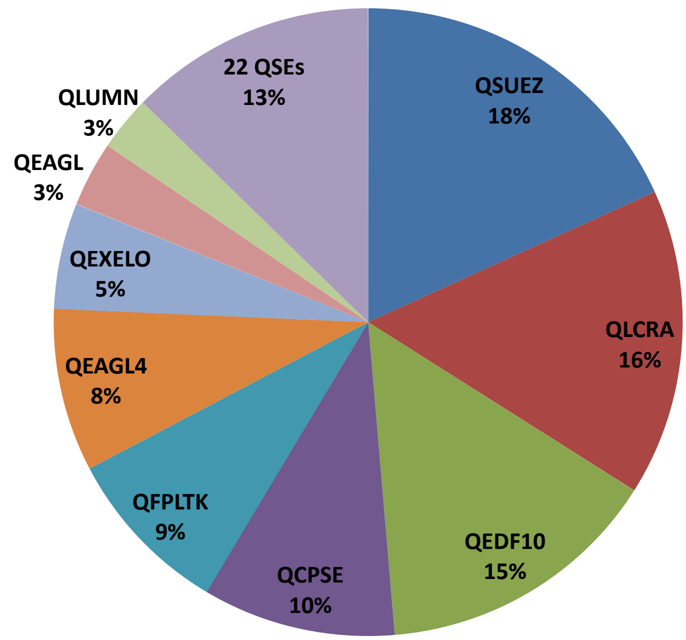
Figure 30: Ancillary Service Costs per MWh of Load



The average ancillary service cost per MWh of load decreased to $1.03 per MWh in 2013 compared to $1.06 per MWh in 2012, a decrease of 3 percent. Total ancillary service costs decreased from 3.7 percent of the load-weighted average energy price in 2012 to 3.0 percent in 2013.

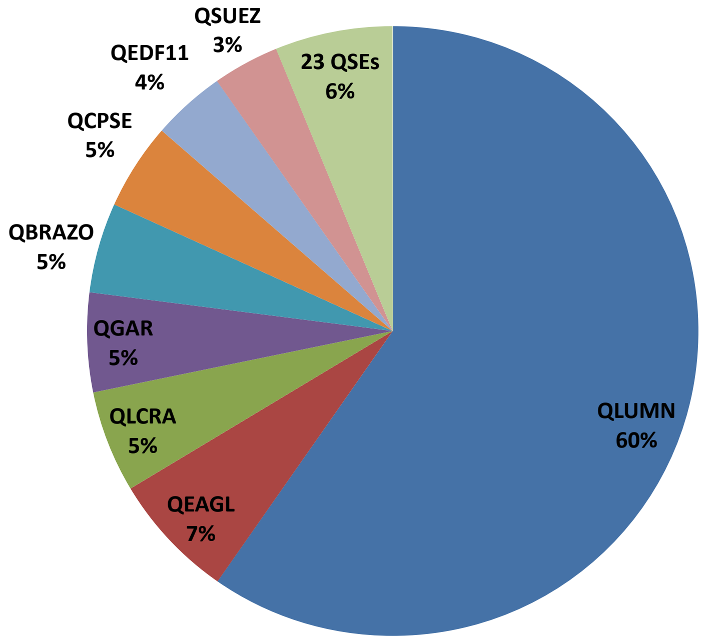
Responsive reserve service is the largest quantity and typically the highest priced ancillary service product. Figure 31 below shows the share of the 2013 annual responsive reserve requirements provided by each QSE. We observe that 31 different QSEs provided responsive reserve at some point during 2013, with multiple QSEs providing sizable shares.

Figure 31: Responsive Reserve Providers



In contrast, Figure 32 below shows that the provision of non-spinning reserves is highly concentrated, with a single QSE providing 60 percent of the total amount of non-spinning reserves procured last year. We are not raising concerns with the competitiveness of the provision of this service during 2013. However, the fact that one party is consistently providing the preponderance of this service should be considered in the ongoing efforts to redefine the definition and required quantities of ERCOT ancillary services. Further, it highlights the importance of modifying the ERCOT ancillary service market design to co-optimize energy and ancillary services. Jointly optimizing all products in each interval allows the market to substitute its procurements between units on an interval-by-interval basis to minimize costs and set efficient prices. Additionally, it would allow higher quality reserves (e.g., responsive reserves) to be substituted for lower quality reserves (e.g., non-spin reserves), reducing the reliance upon a single entity to provide this type of lower quality reserves.

Figure 32: Non-Spin Reserve Providers

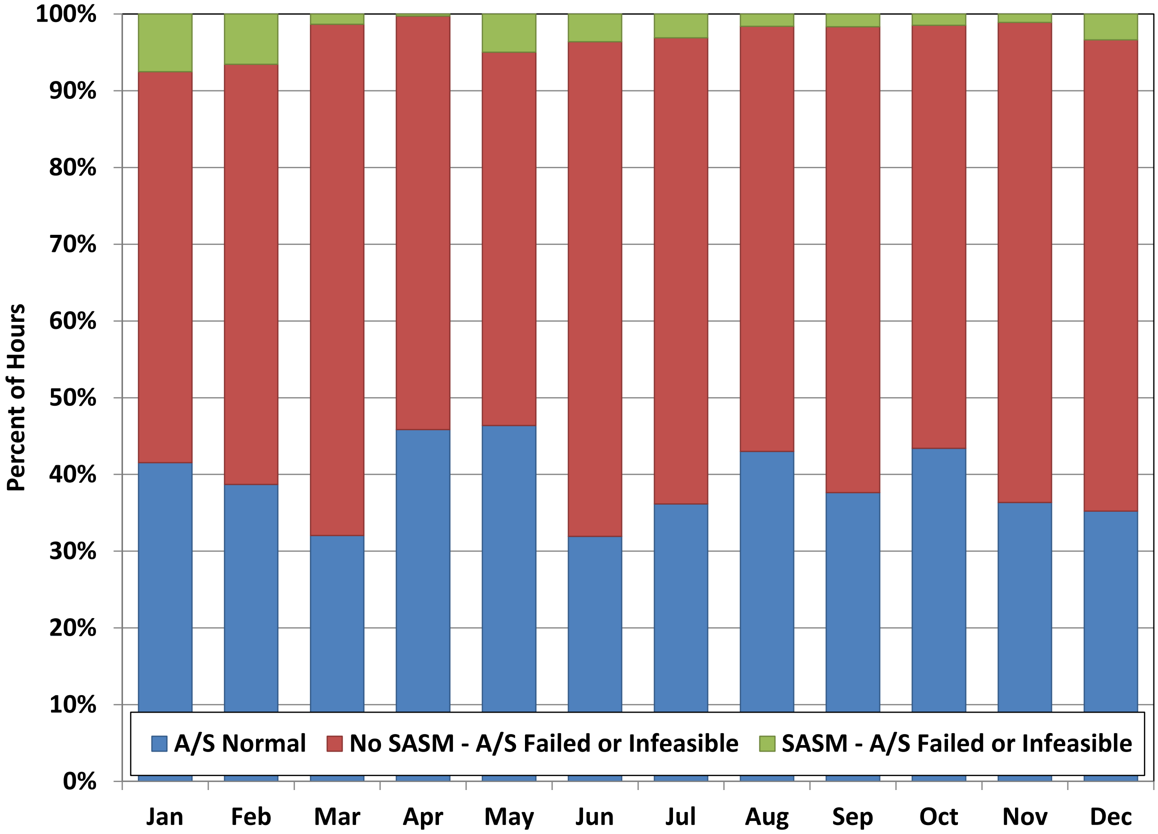


Ancillary Service capacity is procured as part of the day-ahead market clearing. Between the time it is procured and the time that it is required to be provided events can occur which make this capacity unavailable to the system. Transmission constraints can arise which make the capacity undeliverable. Outages or limitations at a generating unit can lead to failures to provide. When either of these situations occurs, ERCOT may open a supplemental ancillary services market ("SASM") to procure replacement capacity.[7]

Figure 33 below, presents a summary of the frequency with which ancillary service capacity was not able to be provided and the number of times that a SASM was opened in each month. The percent of time that capacity procured in the day-ahead actually provided the service in the hour it was procured for decreased to 39 percent in 2013, compared to 52 percent in 2012 and 43 percent in 2011. Even though in more than 60 percent of the hours there were deficiencies in ancillary service deliveries, SASMs were opened to procure replacement capacity in only 3 percent of the total hours, down from 7 percent of the hours in 2012 and 9 percent in 2011.

[7] ERCOT may also open a SASM if they change their ancillary service plan. This did not occur during 2013.

Figure 33: Frequency of SASM Clearing



The primary reason that SASMs were infrequent was the dearth of ancillary service offers typically available throughout the operating day, limiting the opportunity to replace ancillary service deficiencies via a market mechanism. Without sufficient ancillary service offers available, ERCOT more frequently brings additional capacity online using reliability unit commitment procedures (RUC). Because co-optimization allows the real-time market far more flexibility to procure energy and ancillary services from online resources, it would likely substantially reduce ERCOT's need to use the RUC procedures to acquire ancillary services.

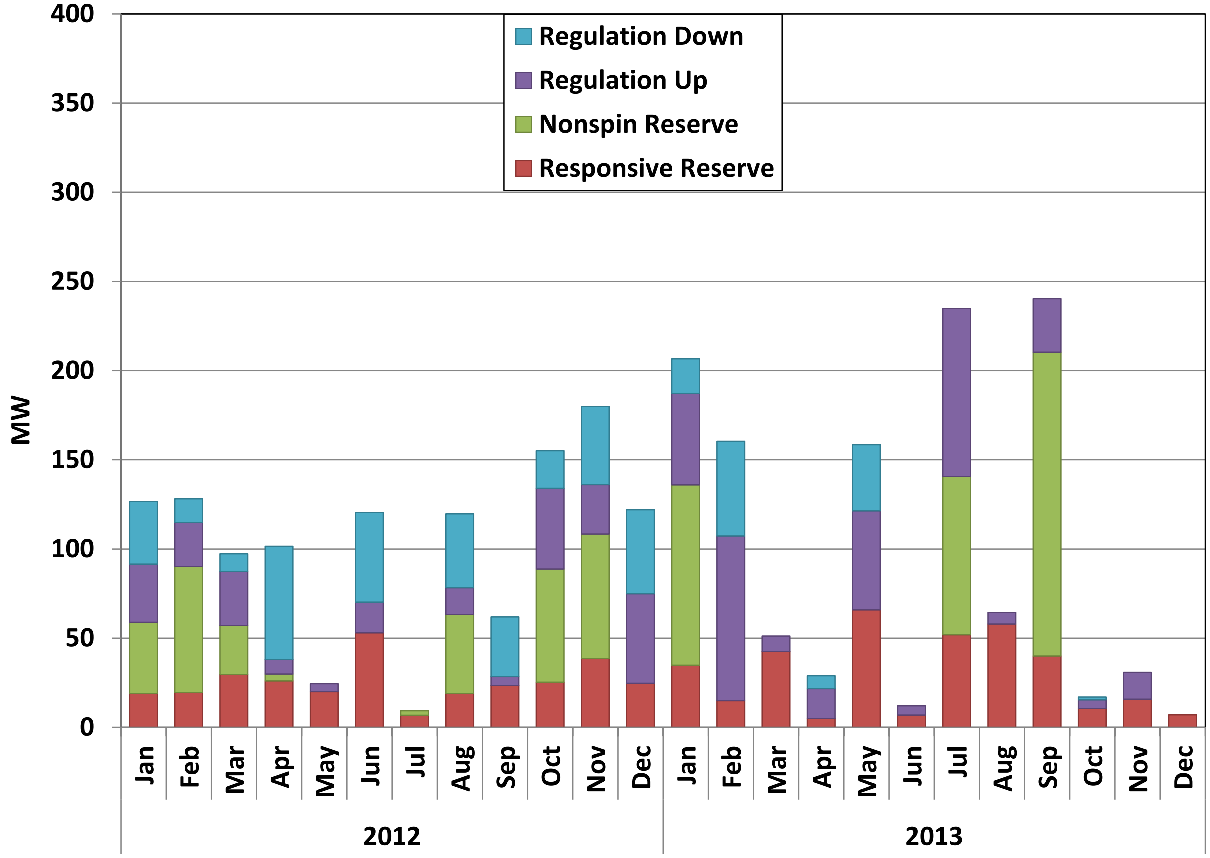
In Table 2 below, we provide an annual summary of the frequency and quantity of ancillary service deficiency, which is defined as either failure-to-provide or as undeliverable.

Table 2: Ancillary Service Deficiency

Service	*Hours Deficient*	*Mean Deficiency (MW)*	*Median Deficiency (MW)*
2013			
Responsive Reserve	3138	43	20
Non-Spin Reserve	610	50	38
Up Regulation	689	38	20
Down Regulation	575	39	15
2012			
Responsive Reserve	3756	34	15
Non-Spin Reserve	664	36	8
Up Regulation	750	41	25
Down Regulation	522	48	39
2011			
Responsive Reserve	4053	39	20
Non-Spin Reserve	1254	90	39
Up Regulation	1222	27	20
Down Regulation	1235	22	11

The number of hours with deficiency for most services decreased in 2013 when compared to 2012. The exception was down regulation, which had about a 10 percent increase in the number of hours of deficiency in 2013. Again during 2013, responsive reserve service was deficient most frequently. Well over 90 percent of the deficiency occurrences were caused by failure to provide by the resource rather than undeliverability related to a transmission constraint. The change in the average magnitude of deficiency was mixed, with responsive reserve and non-spin increasing and the regulation services decreasing slightly.

Figure 34: Ancillary Service Quantities Procured in SASM



Our final analysis in this section, shown in Figure 34, summarizes the average quantity of each service that was procured via SASM. As previously discussed, SASM was rarely used to replace deficiencies in ancillary services in 2013. When a SASM was used in 2013, the quantity of ancillary services procured was similar to that seen in 2012. Non-spinning reserves were procured less frequently, but in larger quantity. Regulation down was also procured less frequently and in smaller quantity.

III. Transmission and Congestion

One of the most important functions of any electricity market is to manage the flows of power over the transmission network by limiting additional power flows over transmission facilities when they reach their operating limits. The action taken to ensure operating limits are not violated is called congestion management. The effect of congestion management is to change generator(s) output level so as to reduce the amount of electricity flowing on the transmission line nearing its operating limit. Because the transmission system is operated such that it can withstand the unexpected outage of any element at any time, congestion management actions most often occur when a transmission element is expected to be overloaded if a particular unexpected outage (contingency) were to occur. Congestion leads to higher costs due to lower cost generation being reduced and higher priced generation increased. Different prices at different nodes are the result. The decision about which generator(s) will vary their output is based on the generator's energy offer curve and its relative shift factors to the contingency and constraint pair. This leads to a dispatch of the most efficient resources available to reliably serve demand.

This section of the report summarizes congestion activity in 2013, provides a review of the costs and frequency of transmission congestion in both the day-ahead and real-time markets, and concludes with a review of the activity in the congestion rights market.

A. Summary of Congestion

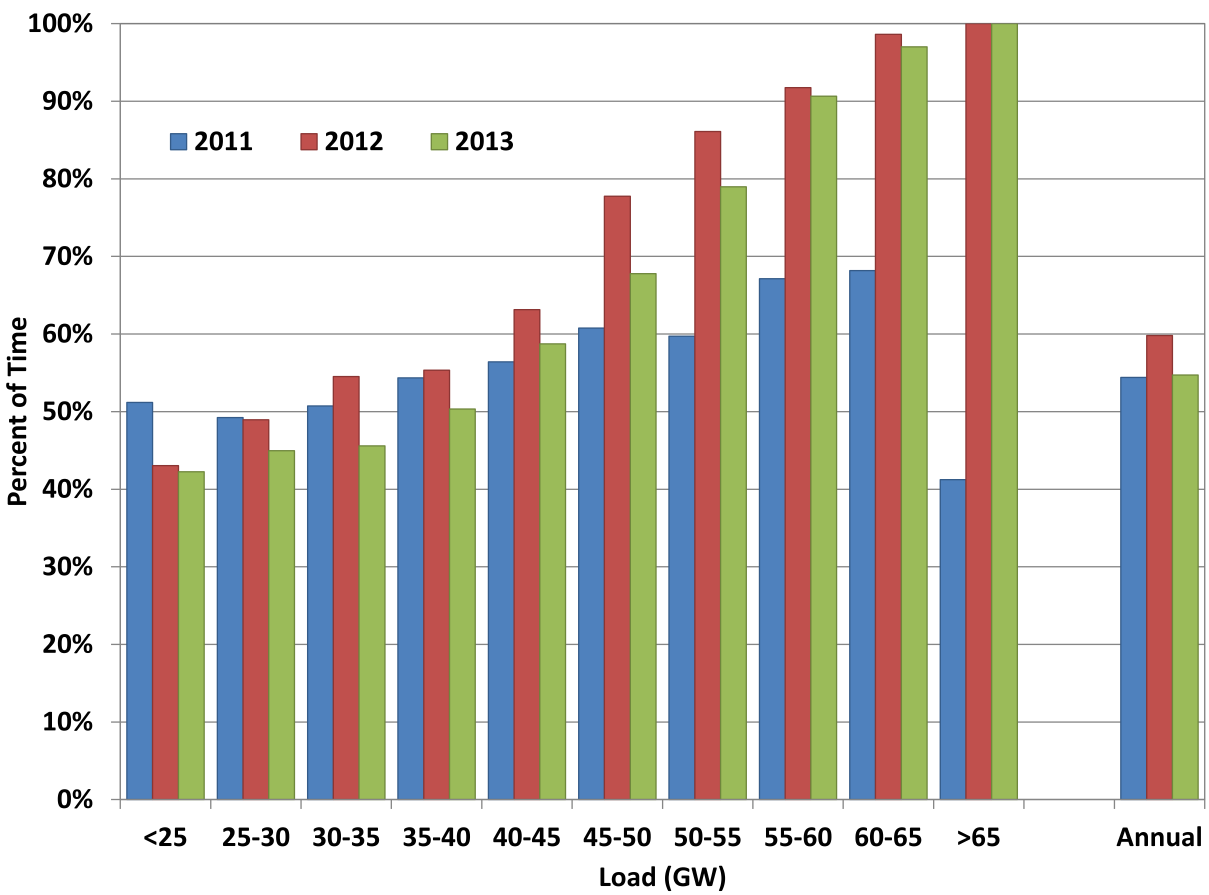
The total congestion revenue generated by the ERCOT real-time market in 2013 was $466 million, a decrease of 3 percent from 2012. This decrease is mostly attributed to transmission improvements in west Texas, specifically in the Odessa area as well as the completion of CREZ transmission projects. The largest contributors to the overall costs of congestion in 2013 were several localized transmission constraints in far west and south Texas.

Real-time transmission congestion during 2013 continued the trend seen since 2012 of localized higher load due to increased oil and natural gas production activity as the cause of most significant constraints. There was an increase in congestion within the South zone related to higher loads due to increased activity in the Eagle Ford shale during 2013 and outages within the South zone.

Given increases in local loads and the increase in fuel prices, it is noteworthy that transmission congestion decreased in 2013. This reduction was due in large part to transmission improvements that decreased the congestion levels in the West zone. Annual prices for loads located in the West zone were $11 per MWh higher than ERCOT average in 2012. In 2013, West zone prices were $5 per MWh higher. Further, due to the completion of the CREZ transmission lines longstanding limitations in the ability to export wind generation from the West zone were virtually eliminated by the end of 2013.

Figure 35 provides a comparison of the amount of time transmission constraints were active at various load levels in 2011 through 2013. Active transmission constraints are those for which generators are being dispatched to a less efficient output level in order to maintain transmission flows at reliable levels.

Figure 35: Frequency of Active Constraints



We observe that in 2013 the likelihood of having an active transmission constraint was slightly lower than in 2012, but still greater than 2011. We previously observed that during 2011, ERCOT operators did not always activate (or sometimes de-activated) transmission constraints during periods of higher system loads. This was due to a concern that by having a constraint active during periods of high demand the total capacity available to serve load may be limited. However, ERCOT's dispatch software contains parameters that allow it to automatically make the correct decision about when to violate transmission constraints when necessary to serve total system load. Therefore, ERCOT modified their practice in 2012 to retain active transmission constraints even during periods of high demand. Further, NERC standards support the continued management of transmission constraints under higher loads and potential scarcity conditions.

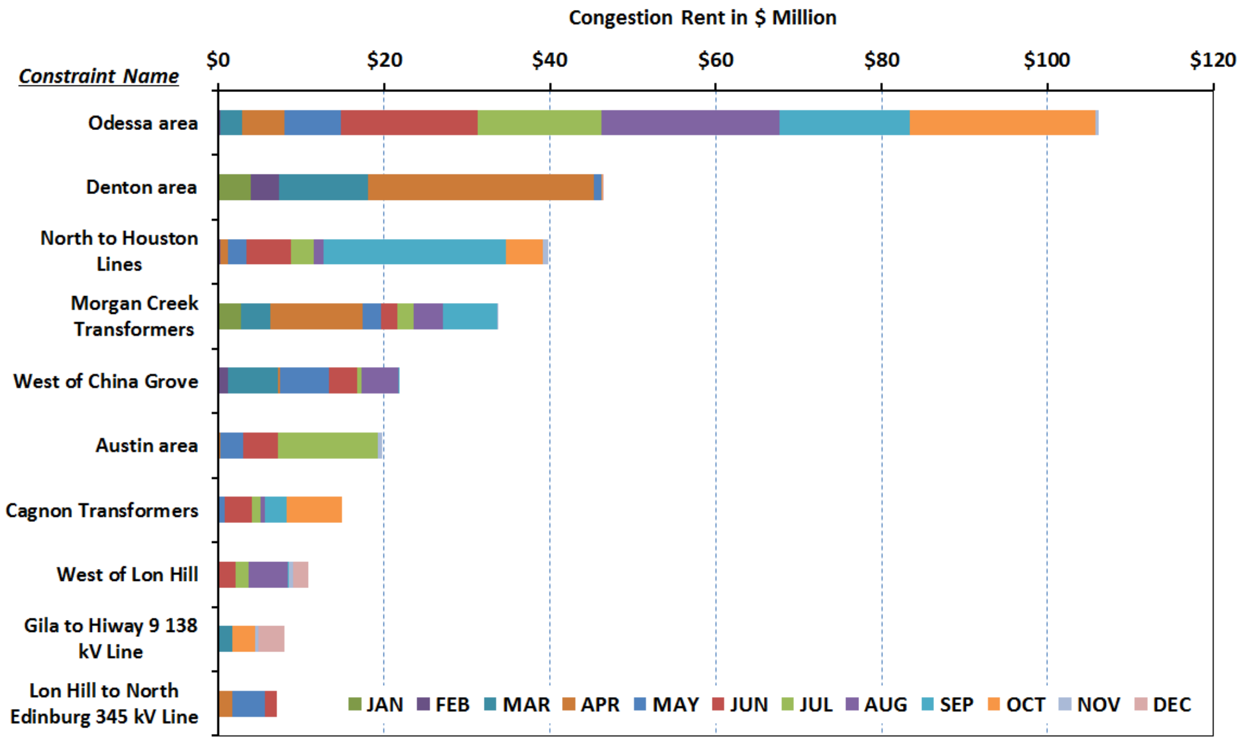
B. Real-Time Constraints

We begin our review by examining the congested areas with the highest financial impact as measured by congestion rent. For this discussion we define a congested area by consolidating multiple real-time transmission constraints that we define as similar due to their geographical proximity and constraint direction. There were 388 unique constraints active at some point during 2013, a slight increase from the 360 constraints that were active in 2012. The median financial impact, as measured by congestion rent, was approximately $130,000 during 2013. This is a significant decrease from 2012, when the median impact was approximately $200,000.

Figure 36 below displays the ten most highly valued real-time congested areas as measured by congestion rent and indicates that the Odessa area was again the most congested location in 2013. The primary constraint in the area is attributed to the Odessa to Odessa North 138 kV line at $57 million, representing 54 percent of the total cost for the area. Following are the specific constraints comprising the Odessa area:

- Odessa to Odessa North 138 kV line
- Odessa EHV to Big Three Odessa 138 kV line
- Moss Switch to Amoco North Cowden 138 kV line
- Odessa North to Odessa Basin Switch 69 kV line
- Odessa North to North Cowden 69 kV line

Figure 36: Top Ten Real-Time Congested Areas



The most significant constraint in 2012, the Odessa North 138/69 kV transformer, was no longer binding in 2013 because the transformer was replaced with one of a larger capacity in late 2012. Even with the elimination of the most significant constraint in 2012, the Odessa area continues to have the most real-time congestion in ERCOT, with more than twice the financial impact of the second congested area on the list.

The second congested area on the list is the Denton area, which contains the following constraints:

- Jim Christal – North Denton 138 kV line
- Fort Worth to Teasley 138 kV line
- Teasley – Pockrusc 138 kV line

The majority of the congestion in this area was due to outages in the area to accommodate transmission ugprades to support load growth in the Denton area.

A number of lines in the North to Houston corridor comprised the third most congested area in 2013:

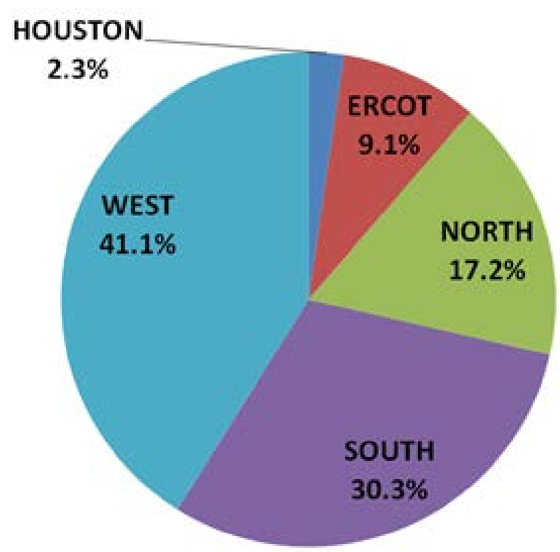
- Singleton to Zenith 345 kV line
- Singleton to Tomball 345 kV line
- Twin Oak – Jack Creek 345 kV line
- Jewett to Singleton 345 kV line
- Roans Prairie to Kuykendahl 345 kV line

Projects to decrease the impact of North to Houston congestion were being reviewed through the ERCOT Regional Planning process starting in July 2013.

Congestion related to the Morgan Creek transformer and in the area west of China Grove further highlights the impact load growth in the far west area of ERCOT. The Austin area and Cagnon transformer constraints were primarily due to nearby outages. The last three congested areas are smaller south zone constraints which contributed to making South zone congestion more prominent in 2013. Two of these three constraints are near Corpus Christi and the Eagle Ford shale, which has seen much higher loads due to oil and natural gas development. The third constraint, Lon Hill to North Edinburg 345 kV line, is related to longtime Valley Import limitations.

Figure 37 displays the percentage of real-time congestion costs attributed to each geographic zone. Those costs associated with constraints that cross zonal boundaries, i.e. North to Houston, are shown in the ERCOT category. The amount of real-time congestion associated with facilities located in the West zone was more than 40 percent of the total congestion costs in 2013. This is a decrease from 2012 when more than 55 percent of real-time congestion costs were from the West zone. As the percentage of congestion attributed to the West zone decreased, the share of congestion attributed to the south zone increased from less than 20 percent in 2012 to 30 percent in 2013.

Figure 37: Real-Time Congestion Costs



Irresolvable Constraints

When a constraint becomes irresolvable, ERCOT's dispatch software can find no combination of generators to dispatch in a manner such that the flows on the transmission line(s) of concern are below where needed to operate reliably. In these situations, offers from generators are not setting locational prices. Prices are set based on predefined rules, which since there are no supply options for clearing, should reflect the value of reduced reliability for demand. To address the situation more generally, a regional peaker net margin mechanism was introduced such that once local price increases accumulate to a predefined threshold due to an irresolvable constraint; the shadow price of that constraint would drop.

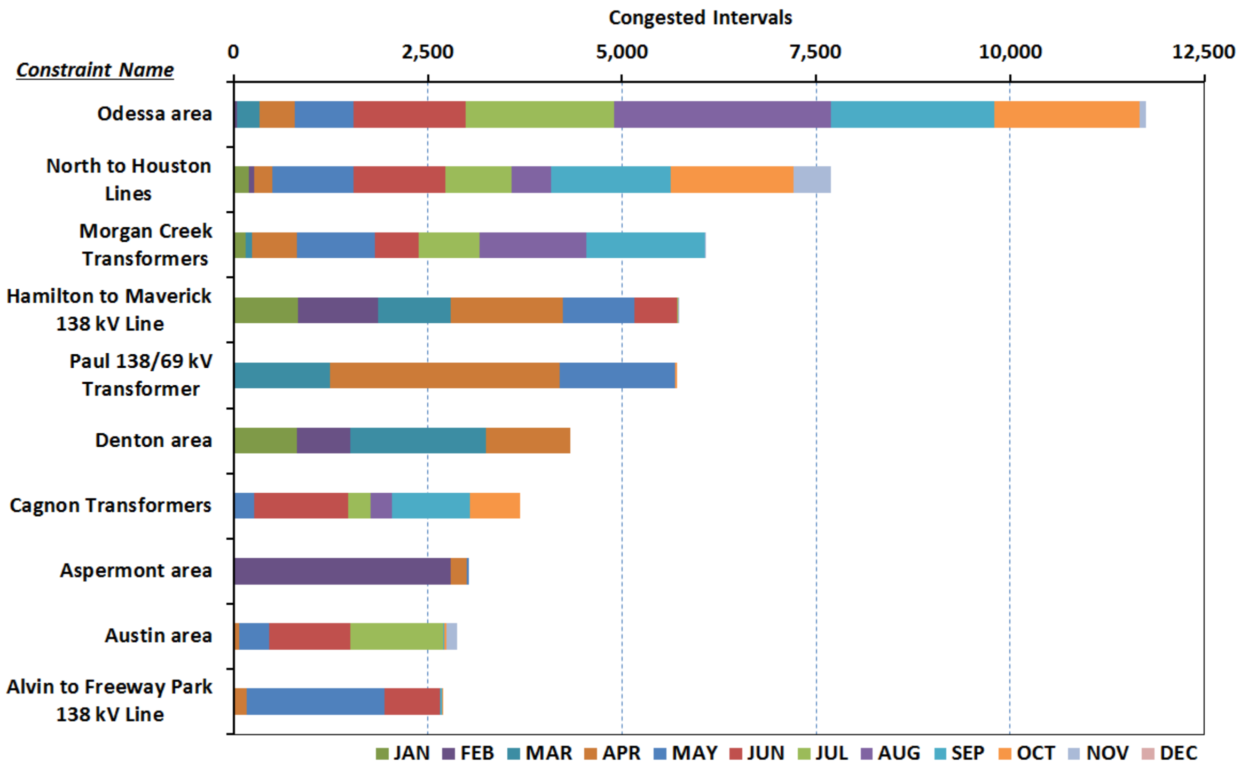
As shown below in Table 3, ten constraints, each comprised of a contingency and overloaded element, were deemed irresolvable in 2013 and as such, had a maximum shadow price cap imposed according to the Irresolvable Constraint Methodology. Three constraints are within the top ten real-time congested areas. Odessa North 138/69 kV transformer, China Grove to Bluff Creek 138 kV line, and Morgan Creek #1 345/138 kV Autotransformer were designated as irresolvable in 2013. The Wink TNP to Wink Sub 69 kV line qualified as irresolvable for the first time in May 2013. Four constraints from 2012 were deemed resolvable during the ERCOT analysis annual review and were removed from the list.

Table 3: Irresolvable Constraints

Loss of:	Overloads:	Maximum Shadow Price	Effective Date
Base case	Valley Import	$2,000.00	Jan 1, 2012
Graham to Long Creek 345 kV line	Bomarton to Seymour 69 kV line	$2,000.00	Jan 1, 2012
Denton to Argyle / West Denton 138 kV lines	Jim Crystal to West Denton 69 kV line	$2,000.00	Jan 1, 2012
Odessa North to Holt 69 kV line	Odessa Basin to Odessa North 69 kV line	$2,800.00	Jan 1, 2012
Odessa to Morgan Creek / Quail 345 kV lines	China Grove to Bluff Creek 138 kV line	$2,000.00	May 3, 2012
Holt to Moss 138 kV line	Odessa North 138/69 kV transformer	$2000.00	Aug 6, 2012
Sun Switch to Morgan Creek 138 kV line	China Grove to Bluff Creek 138 kV line	$2,000.00	Oct 11, 2012
Morgan Creek #4 345 kV/138 kV Autotransformer	Morgan Creek #1 345 kV/138 kV Autotransformer	$2,000.00	Nov 2, 2012
Odessa Basin to Odessa North 69 kV line	Holt to Ector Shell Tap 69 kV line	$2,320.68	Jan 1, 2013
Wink TNP 138 kV/69 kV Autotransformer	Wink TNP – Wink Sub 69 kV line	$2,000.00	May 20, 2013

Figure 38 presents a slightly different set of real-time congested areas. These are the most frequently occurring.

Figure 38: Most Frequent Real-Time Congested Areas

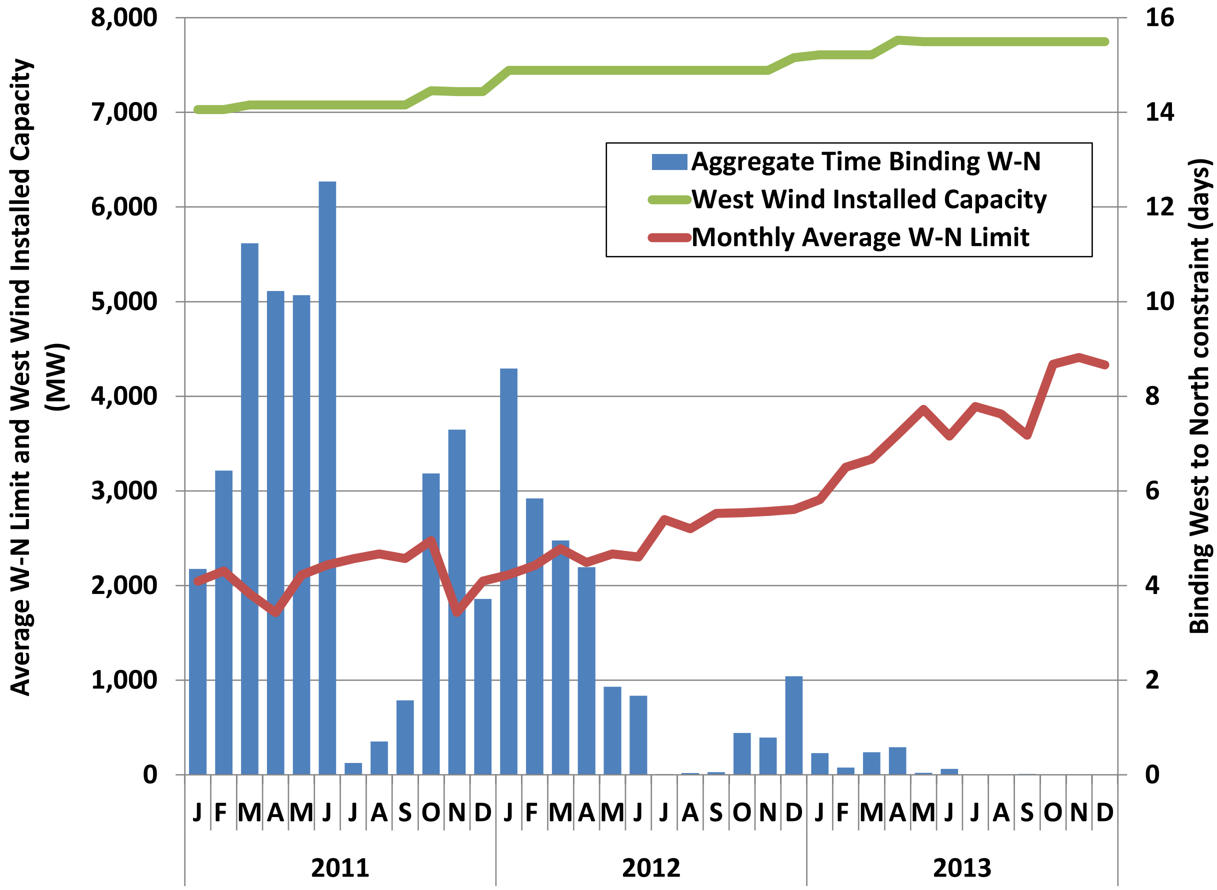


The Hamilton to Maverick 138 kV line, Paul 138/69 kV transformer, Aspermont area, and Alvin to Freeway Park 138 kV line are congested areas that did not have significant congestion costs. Hamilton to Maverick 138 kV line is a constraint in areas with limited transmission and also flows to an area in proximity to the Eagle Ford shale. The Paul 138/69 kV transformer, Aspermont area, and Alvin to Freeway Park 138 kV line are constraints that occurred due to outages in close proximity.

To maximize the economic use of scarce transmission capacity, the ideal outcome would be for the actual transmission line flows to reach, but to not exceed the physical limits required to maintain reliable operations. Prior to 2013, the West to North transmission constraint was perennially a top 10 real-time constraint. However, with the completion of the CREZ transmission lines at the end of 2013, the West to North constraint is no longer a significant factor. Figure 39 below presents a summary of the number of 24-hour periods that the West to

North interface transmission constraint was binding each month from 2011 through 2013. Even with continued increases in wind resources in the West zone, binding constraints affecting exports from the West zone fell sharply as the completion of CREZ lines resulted in higher limits on the West to North constraint.

Figure 39: Utilization of the West to North Interface Constraint



C. Day-Ahead Constraints

In this subsection we review transmission constraints from the day-ahead market. 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 DAM similarly to how they transact in real-time, we would expect to see the same transmission constraints appear in the day-ahead market as actually occurred during real-time.

Figure 40: Top Ten Day-Ahead Congested Areas

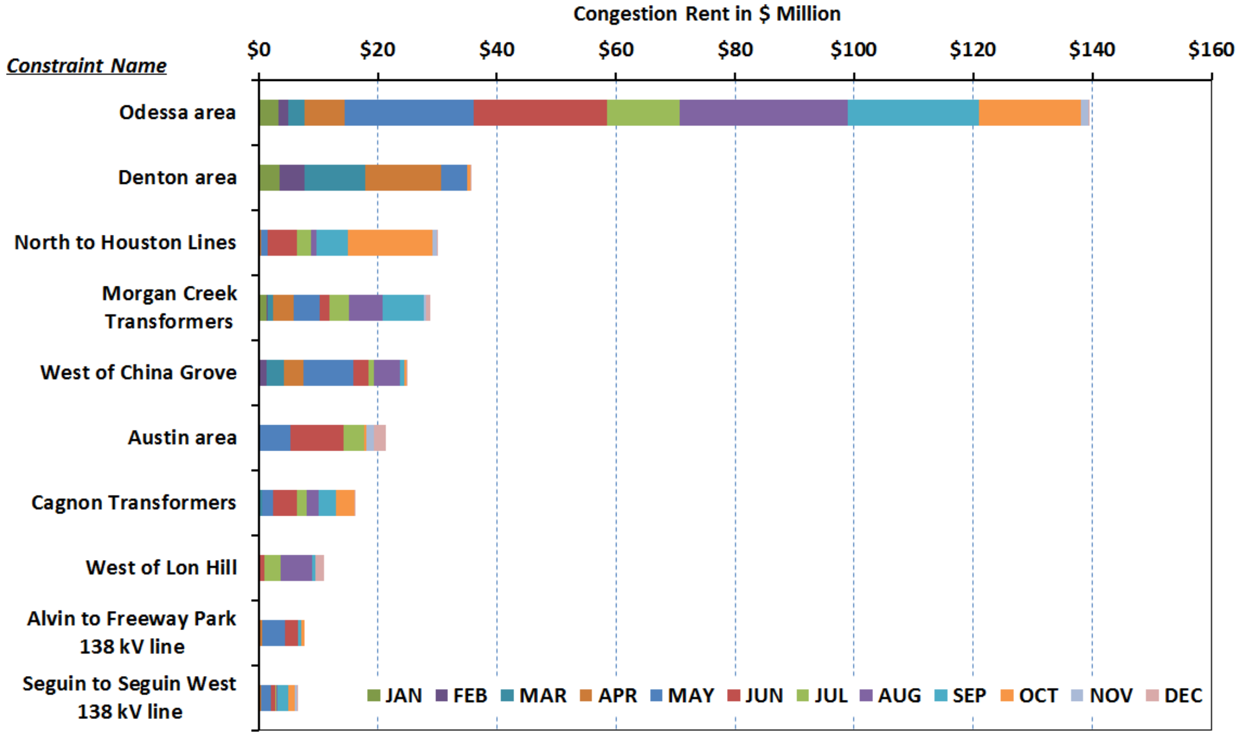
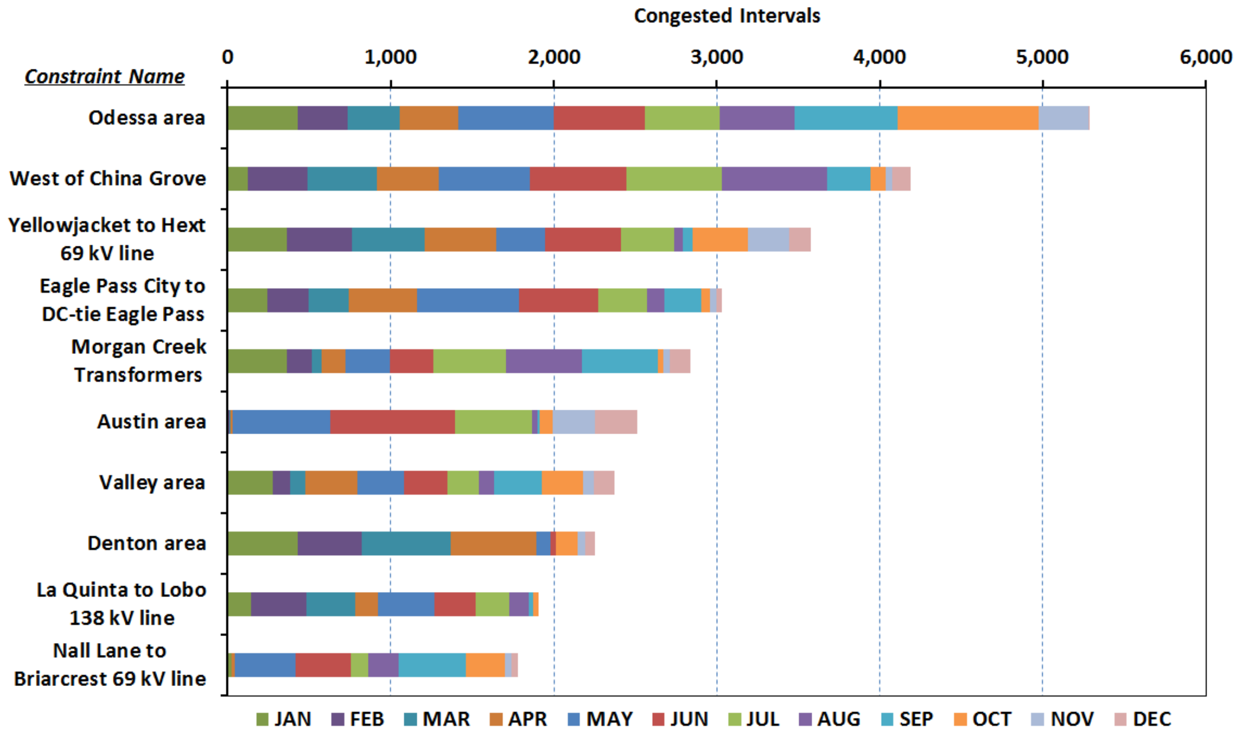


Figure 40 presents the top ten congested areas from the day-ahead market, ranked by their financial impact as measured by congestion rent. As was the case with the real-time constraints, day-ahead constraints in the Odessa area had the most significant financial impact. Only the Seguin to Seguin West 138 kV line constraint, which is related to serving load in the San Antonio area, was not included in the real-time list of constraints.

In our final analysis of this subsection we review the most frequently occurring day-ahead constraints shown in Figure 41.

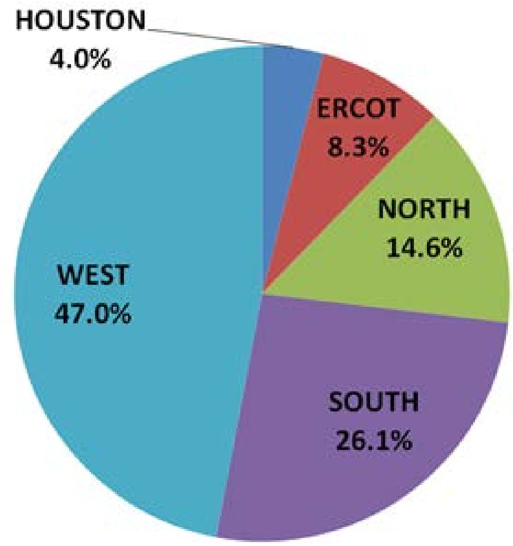
Figure 41: Most Frequent Day-Ahead Congested Areas



Two of the constraints appearing on the list would not occur in real-time. The Eagle Pass City to Eagle Pass DC Tie constraint appears frequently as a day-ahead constraint, but in real-time operations all transactions with Mexico using this DC Tie are scheduled using a separate process. The process would strictly limit the volume of transactions and not allow a constraint to occur. The Yellowjacket to Hext constraint is affected by a nearby phase shifter that depending on the tap setting of the element will have different impedances through the phase shifter. In the day-ahead market, the phase shifters are set at one value throughout the day, typically a mid-setting of the full range. The constraint seen in the day-ahead would likely not bind in real-time due to the fact that the tap settings can be changed to alter the flow over the elements.

With the exception of the La Quinta to Lobo 138 kV line, the remaining constraints listed in Figure 41 are related to limitations in the ability to transfer electricity to various load serving areas. The La Quinta to Lobo 138 kV line is located in a sparse transmission area of South Texas and related to the increased activity in the Eagle Ford Shale.

Figure 42: Day-Ahead Congestion Costs



To further emphasize the effects of West and South zone congestion in 2013, Figure 42 highlights that, like real-time, day-ahead West and South zone congestion accounted for more than half the congestion in 2013. The amount of real-time congestion associated with facilities located in the West zone was more than 40 percent of the total congestion costs in 2013. This is a decrease from 2012 when more than 53 percent of real-time congestion costs were from the West zone.

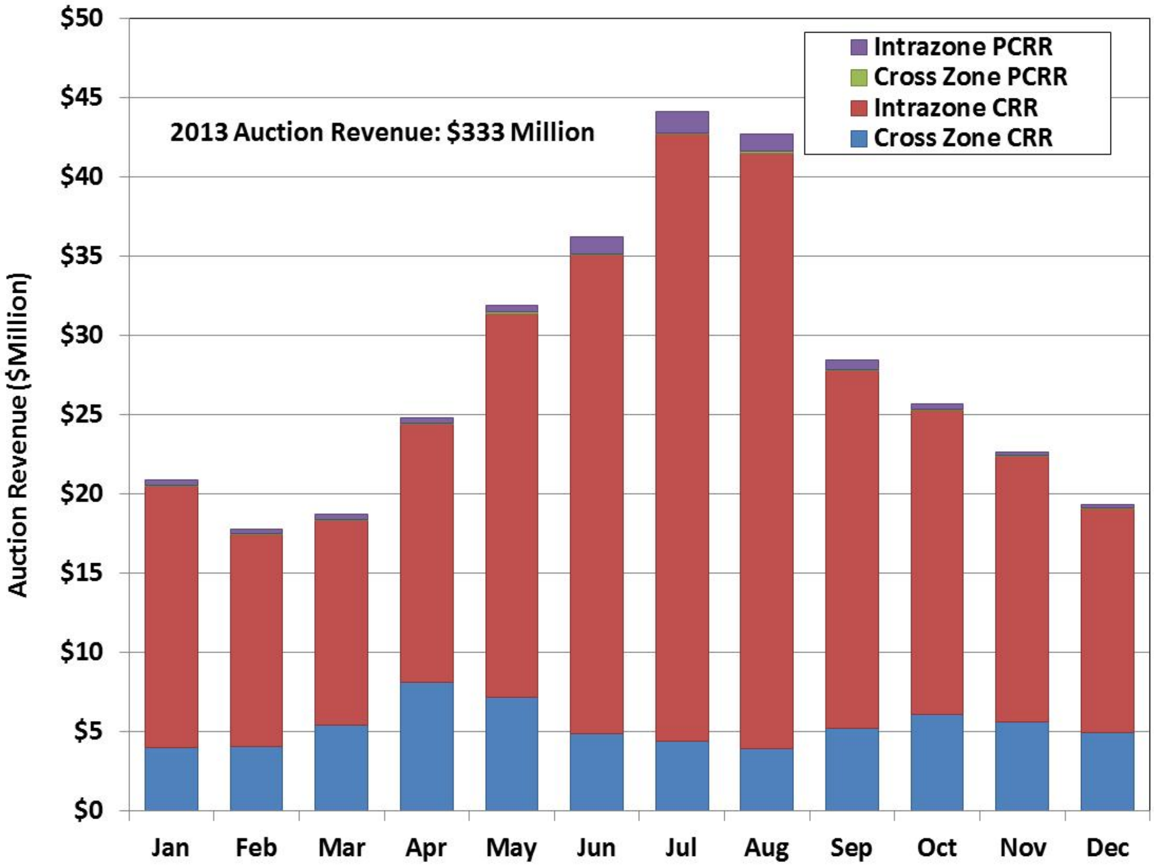
D. Congestion Rights Market

Congestion can be significant from an economic perspective, compelling the dispatch of higher-cost resources because power produced by lower-cost resources cannot be delivered due to transmission constraint(s). Under the nodal market design, one means by which ERCOT market participants can hedge these price differences is by acquiring Congestion Revenue Rights ("CRRs") between any two settlement points.

CRRs are acquired by annual and monthly auctions while Pre-assigned Congestion Revenue Rights ("PCRRs") are allocated to certain participants based on their historical patterns of transmission usage. Parties receiving PCRRs pay only a fraction of the auction value of a CRR between the same source and sink. Both CRRs and PCRRs entitle the holder to payments corresponding to the difference in locational prices of the source and sink.

Figure 43 summarizes the revenues collected by ERCOT in each month for all CRRs, both auctioned and allocated. These revenues are distributed to loads in one of two ways. Revenues from cross zone CRRs are allocated to loads ERCOT wide. Revenues from CRRs that have their source and sink in the same geographic zone are allocated to loads within that zone. This method of revenue allocation provides a disproportionate share of CRR auction revenues to loads located in the West zone. In 2013, CRRs with both their source and sink in the West zone accounted for 45 percent of CRR Auction revenues. This revenue was allocated to West zone loads, which accounted for only 8 percent of the ERCOT total. In comparison, in 2012, 27 percent of CRR Auction revenues were allocated to the West zone load, which accounted for 7 percent of the ERCOT total. Allocating CRR Auction revenues in this manner helps reduce the impact of the higher congestion on West zone prices.

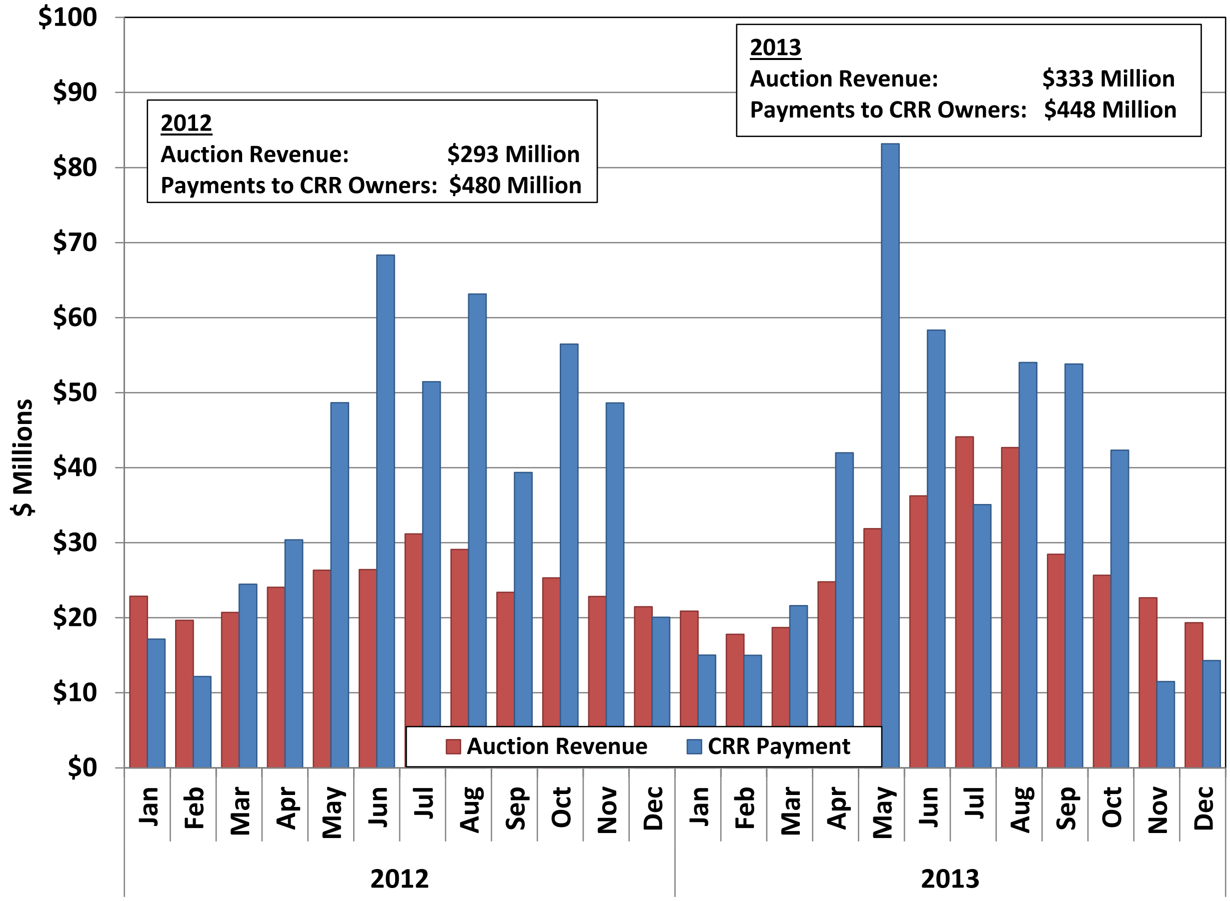
Figure 43: CRR Auction Revenue



As we showed in Section I.A, Real-Time Market Prices, the annual average price for the West zone was $37.99 per MWh, nearly $4 per MWh higher than the ERCOT-wide average. The value of CRR Auction revenues distributed only to the West zone equated to more than $5.50 per MWh higher than the amounts distributed to other zones. This was sufficient to offset the higher real-time prices incurred in the West load zone during 2013. In 2012 the annual average price for the West zone was $38.24 per MWh, which was about $10 per MWh higher than the ERCOT-wide average, and the incremental CRR Auction revenues were almost $3 per MWh.

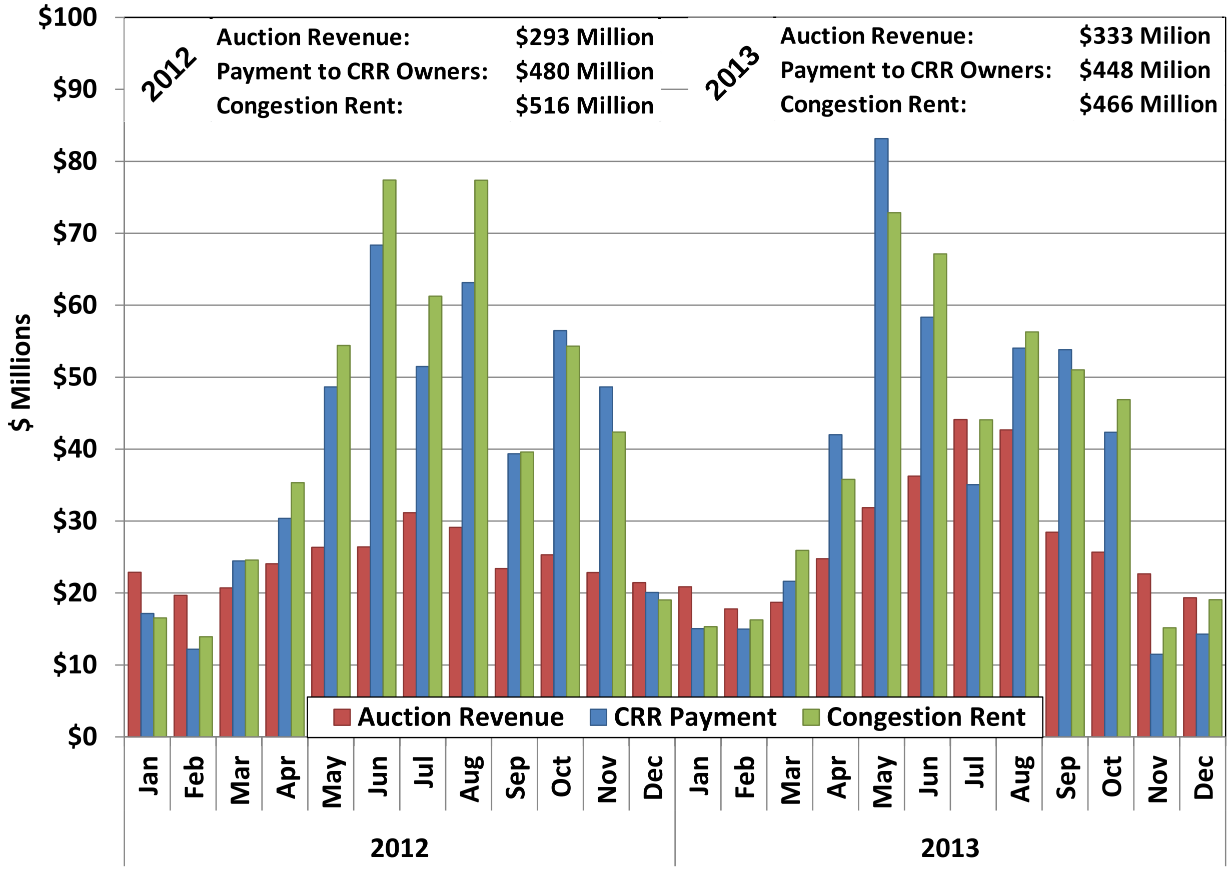
Next, in Figure 44 we examine the value CRR owners (in aggregate) received compared to the price they paid to acquire the CRRs. Although results for individual participants and specific source/sink combinations varied, we find that in most months participants did not over pay in the auction. Across the entire year of 2013, participants spent $333 million to procure CRRs and received $448 million.

Figure 44: CRR Auction Revenue and Payment Received



In our next look at aggregated CRR positions, we add congestion rent to the picture. Simply put, congestion rent is the difference between the total costs that loads pay and the total revenue that generators receive. Congestion rent creates the source of funds used to make payments to CRR owners. Figure 45 presents all three values for each month of 2012 and 2013. Congestion rent for the year 2013 totaled $466 million and payments to CRR owners were $448 million.

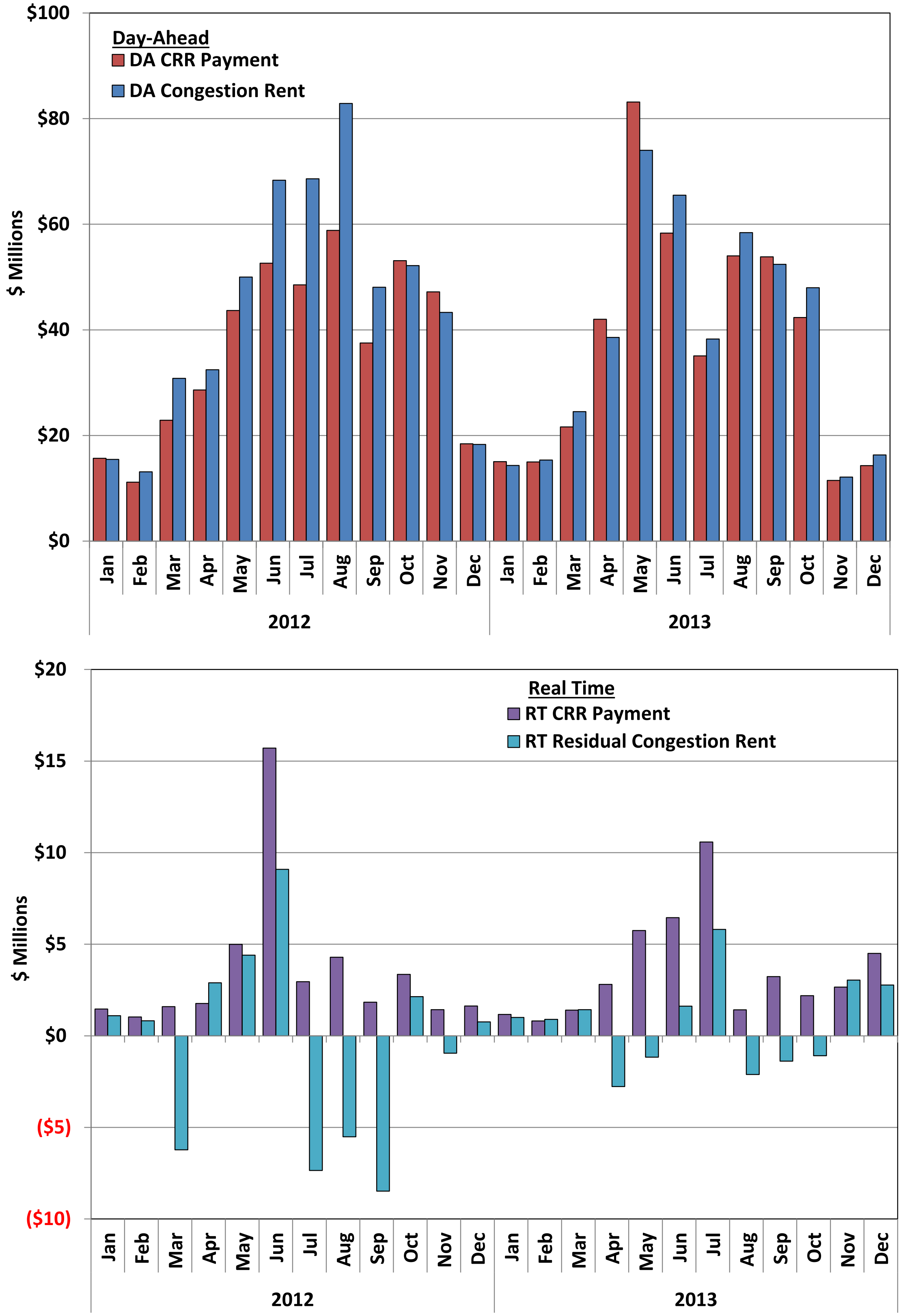
Figure 45: CRR Auction Revenue, Payments and Congestion Rent



We further analyze the relationship between congestion rent and payments to CRR owners by separating the impacts of CRRs that are settled based on day-ahead prices from the subset of CRRs that are paid based on real-time prices.

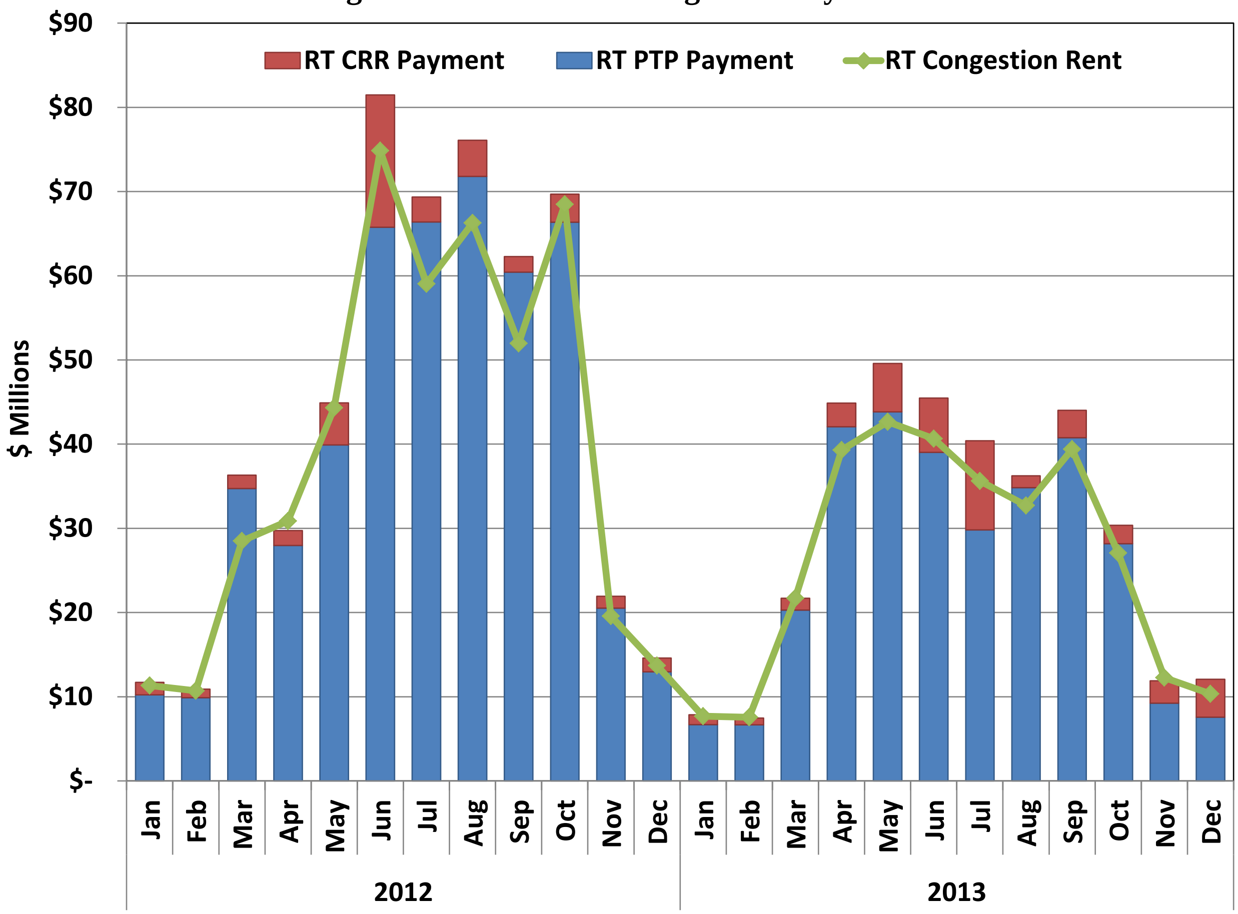
The top portion of Figure 46, shown below, displays the comparison of day-ahead congestion rent to payments received by CRR owners. Congestion rent was larger than payments in most months of 2013 and for the year congestion rent was $458 million compared to $446 million that was paid to CRR owners.

Figure 46: Day-Ahead and Real-Time Congestion Payments and Rent



The bottom portion of Figure 46 presents a different view. For this analysis we have assumed that all PTP Obligations have been fully funded from real-time congestion rent and any residual real-time congestion rent is available to fund payments to the subset of CRR owners that elected to have their CRRs be settled based on real-time prices. In 2013 there was more real-time congestion rent than the payments to holders of PTP Obligations, resulting in a $8 million surplus. However, there were real-time CRR payments of $43 Million. Hence, real-time congestion rent was insufficient to fund all PTP Obligations and CRRs being settled in real-time in the amount of $35 million. The next figure shows this explicitly.

Figure 47: Real-Time Congestion Payments



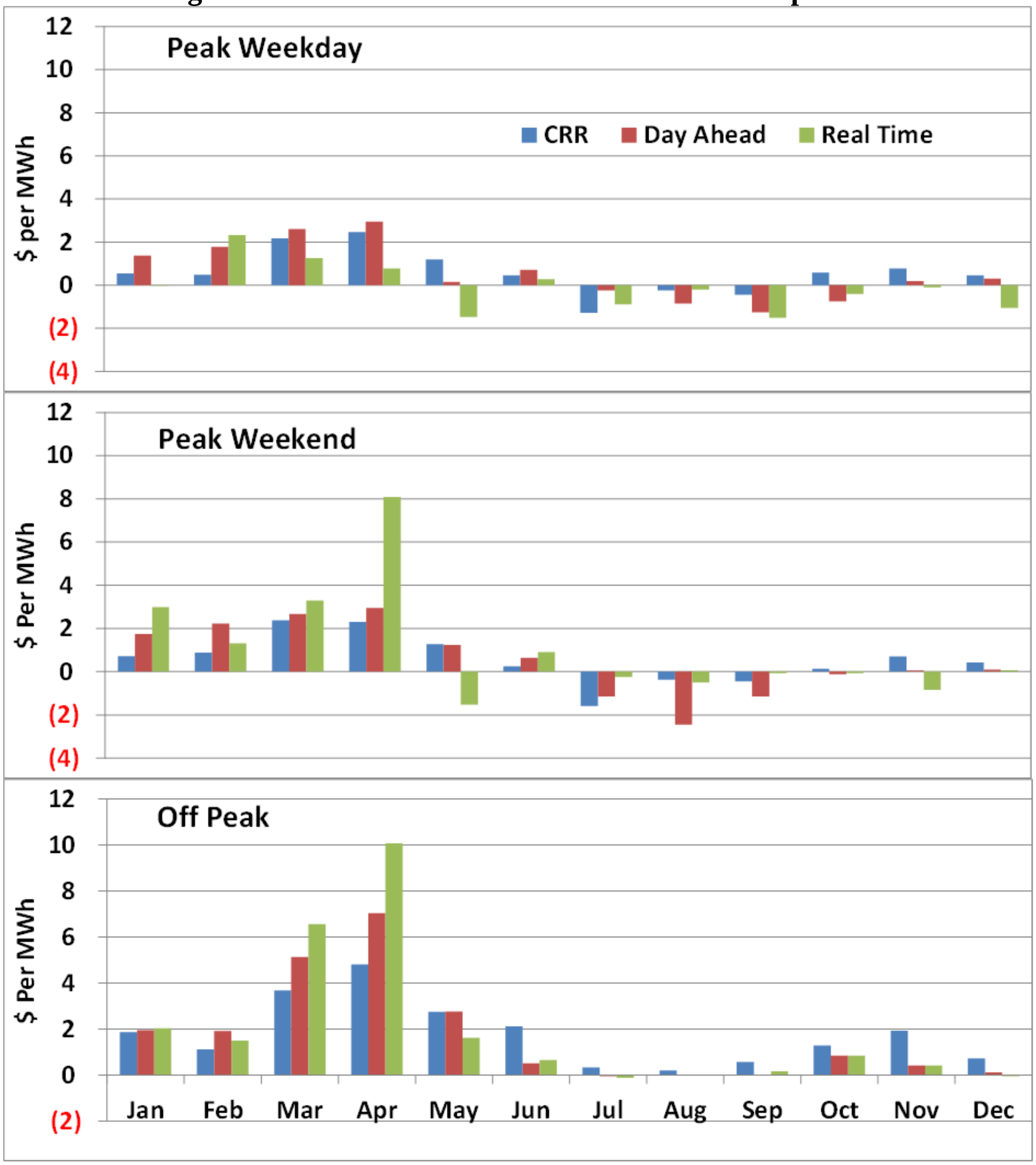
In Figure 47 the combined payments to PTP Obligation owners and CRR owners that have elected to receive real-time payments are compared to the total real-time congestion rent. For the year of 2013, real-time congestion rent was $317 million, payments for PTP Obligations were $309 million and payments for real-time CRRs were $43 million, resulting in a shortfall of approximately $35 million for the year. For the year of 2012, real-time congestion rent was

$480 million, payments for PTP Obligations were $487 million and payments for real-time CRRs were $42 million, resulting in a shortfall of approximately $49 million for the year. This type of shortfall typically results from discrepancies between transmission topology assumptions used when clearing the day-ahead market and the actual transmission topology that exists during real-time. Specifically, if the day-ahead topology assumptions allow too many real-time congestion instruments (PTP Obligations and CRRs settled at real-time prices) with impacts on a certain path, and that path constrains at a lower limit in real-time, there will be insufficient rent generated to pay all of the congestion instruments.

From Figure 47 we can see that April through October were the months with the most noticeable deficiencies. A detailed examination of the daily congestion pattern revealed no systemic concerns with the level of insufficiency. Deficiencies were generally small and attributed to many different constraints located in many different areas of ERCOT.

For our last look at congestion we examine the impacts of the West to North constraint in more detail. Figure 48 presents the price spreads between the West Hub and North load zone as valued at three separate points in time – at the monthly CRR auction, day-ahead and in real-time.

Figure 48: West Hub to North Load Zone Price Spreads



Since CRRs are sold for one of three defined time periods, weekday on peak, weekend on peak, and off peak, Figure 48 includes a separate comparison for each.

As expected, most real-time congestion, as evidenced by the largest price spread, occurred in the off peak period, for the months of March and April. The day-ahead price spreads were very similar for this period, while the prices paid for CRRs in March and April were more than the value received. Conversely, during the summer months of July and August, there was very little West to North congestion.

IV. LOAD AND GENERATION

This section reviews and analyzes the load patterns during 2013 and the existing generating capacity available to satisfy the load and operating reserve requirements. We provide specific analysis of the large quantity of installed wind generation and conclude this section with a discussion of the daily generation commitment characteristics.

A. ERCOT Loads in 2013

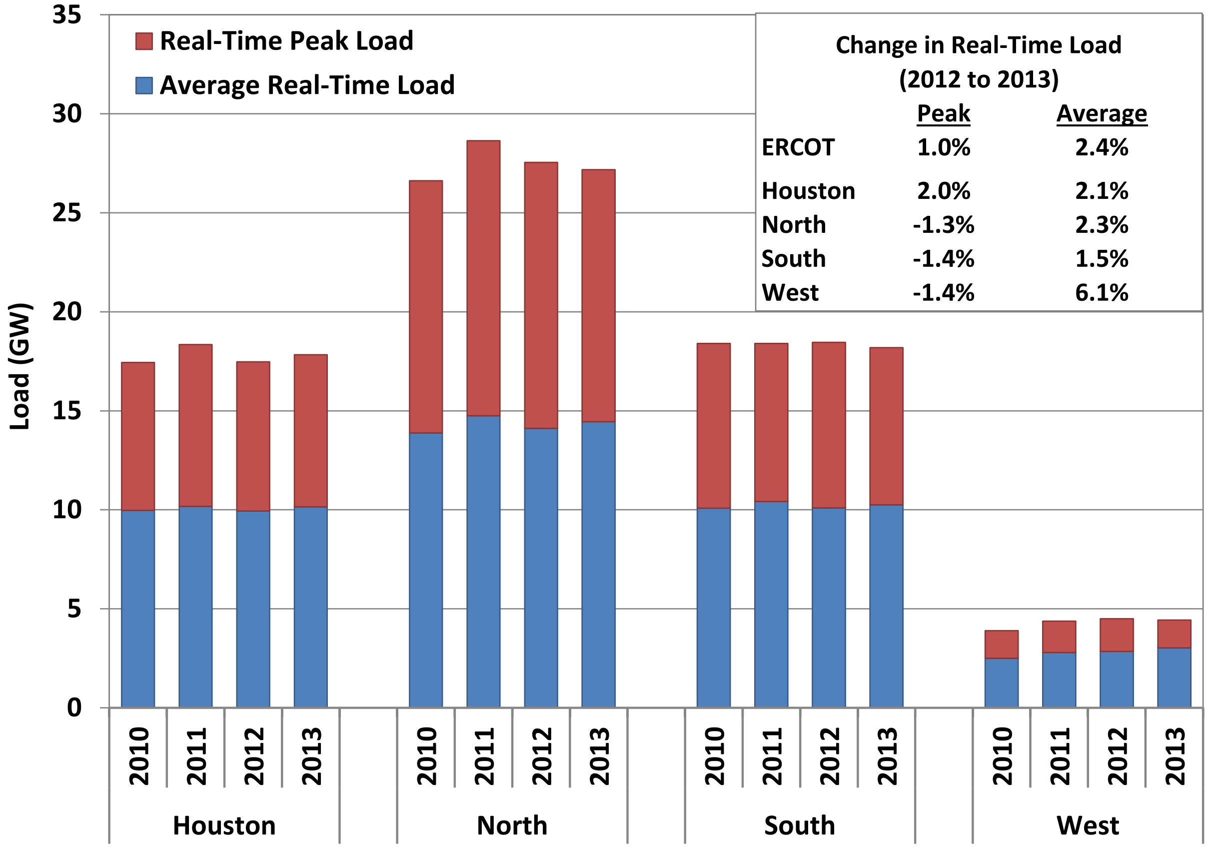
The changes in overall load levels from year to year can be shown by tracking the changes in average load levels. This metric will tend to capture changes in load over a large portion of the hours during the year. It is also important to separately evaluate the changes in the load during the highest-demand hours of the year. Significant changes in peak demand levels play a major role in assessing the need for new resources. They also affect the probability and frequency of shortage conditions (i.e., conditions where firm load is served but minimum operating reserves are not maintained). The expectation of resource adequacy is based on the value of electric service to customers and the harm and inconvenience to customers that can result from interruptions to that service. Hence, both of these dimensions of load during 2013 are examined in this subsection and summarized in Figure 49.

This figure shows peak load and average load in each of the ERCOT zones from 2010 to 2013.[8] In each zone, as in most electrical systems, peak demand significantly exceeds average demand. The North zone is the largest zone (with about 38 percent of the total ERCOT load); the South and Houston zones are comparable (27 percent) while the West zone is the smallest (8 percent of the total ERCOT load).

Figure 49 also shows the annual non-coincident peak load for each zone. This is the highest load that occurred in a particular zone for one hour during the year; however, the peak can occur in different hours for different zones. As a result, the sum of the non-coincident peaks for the zones is greater than the annual ERCOT peak load.

[8] For purposes of this analysis NOIE Load Zones have been included with the proximate geographic Load Zone.

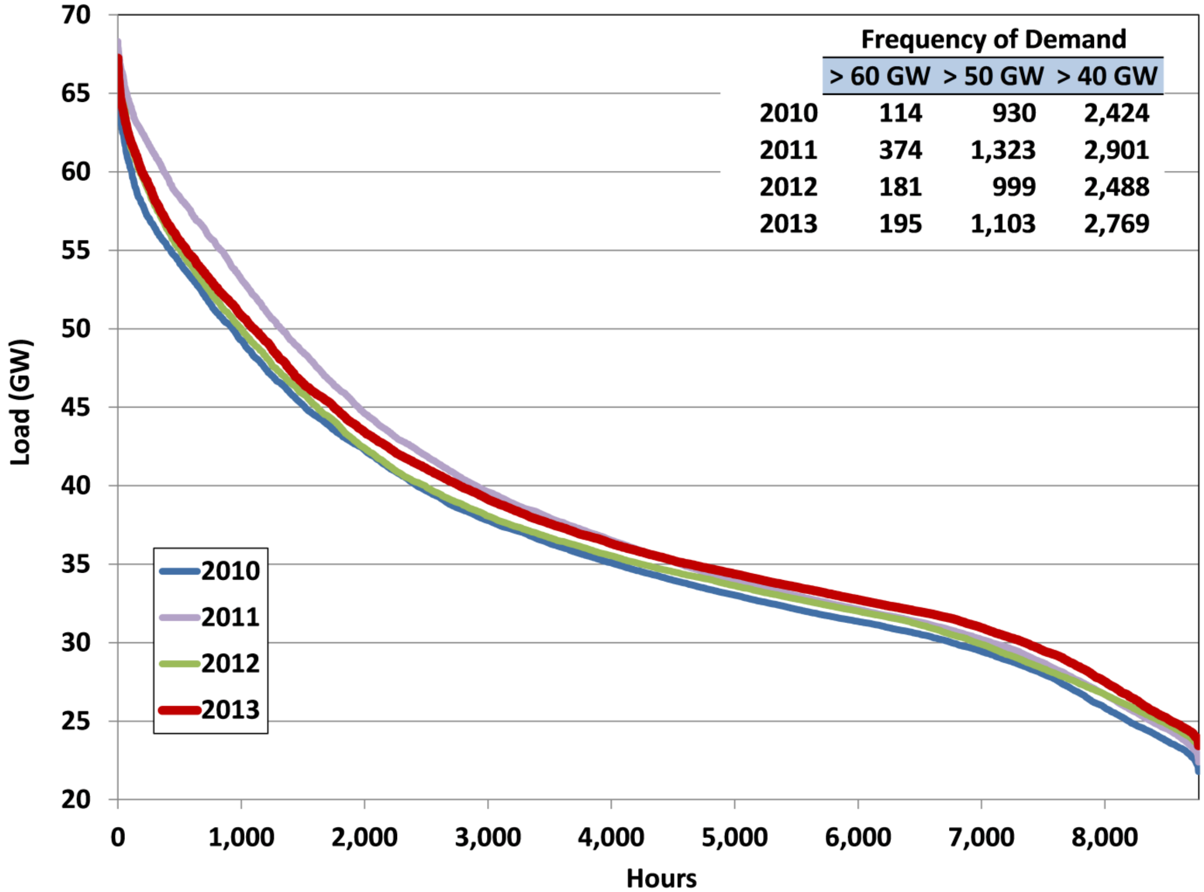
Figure 49: Annual Load Statistics by Zone



Total ERCOT load increased from 325 TWh in 2012 to 332 TWh in 2013, an increase of 2.1 percent or an average of 870 MW every hour. Similarly, the ERCOT coincident peak hourly demand increased from 66,559 MW to 67,245 MW in 2013, an increase of 686 MW, or 1.0 percent. The changes in load at the zonal level are not the same. Peak load in the Houston zone increased, while it decreased in the other zones. The average growth rate of load in the West zone once again was much higher, on a percentage basis, than the other zones.

To provide a more detailed analysis of load at the hourly level, Figure 50 compares load duration curves for each year from 2010 to 2013. A load duration curve shows 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.

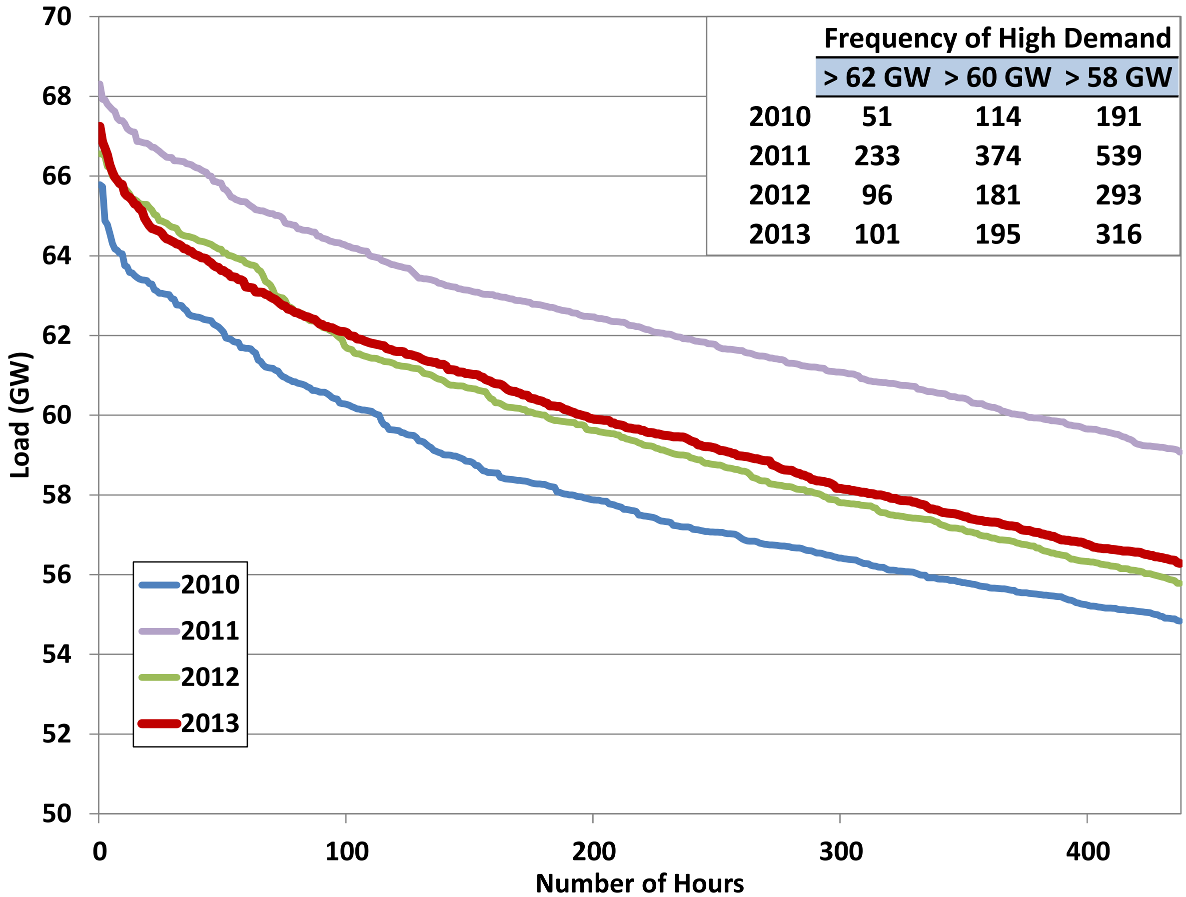
Figure 50: Load Duration Curve – All hours



As shown in Figure 50, the load duration curve for 2013 is slightly higher than in 2012 for most of the hours in the year. This is consistent with the aforementioned 2.1 percent load increase from 2012 to 2013.

To better illustrate the differences in the highest-demand periods between years, Figure 51 shows the load duration curve for the 5 percent of hours with the highest loads. This figure also shows that the peak load in each year is significantly greater than the load at the 95th percentile of hourly load. From 2010 to 2013, the peak load value averaged nearly 19 percent 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 percent of the hours.

Figure 51: Load Duration Curve – Top five percent of hours

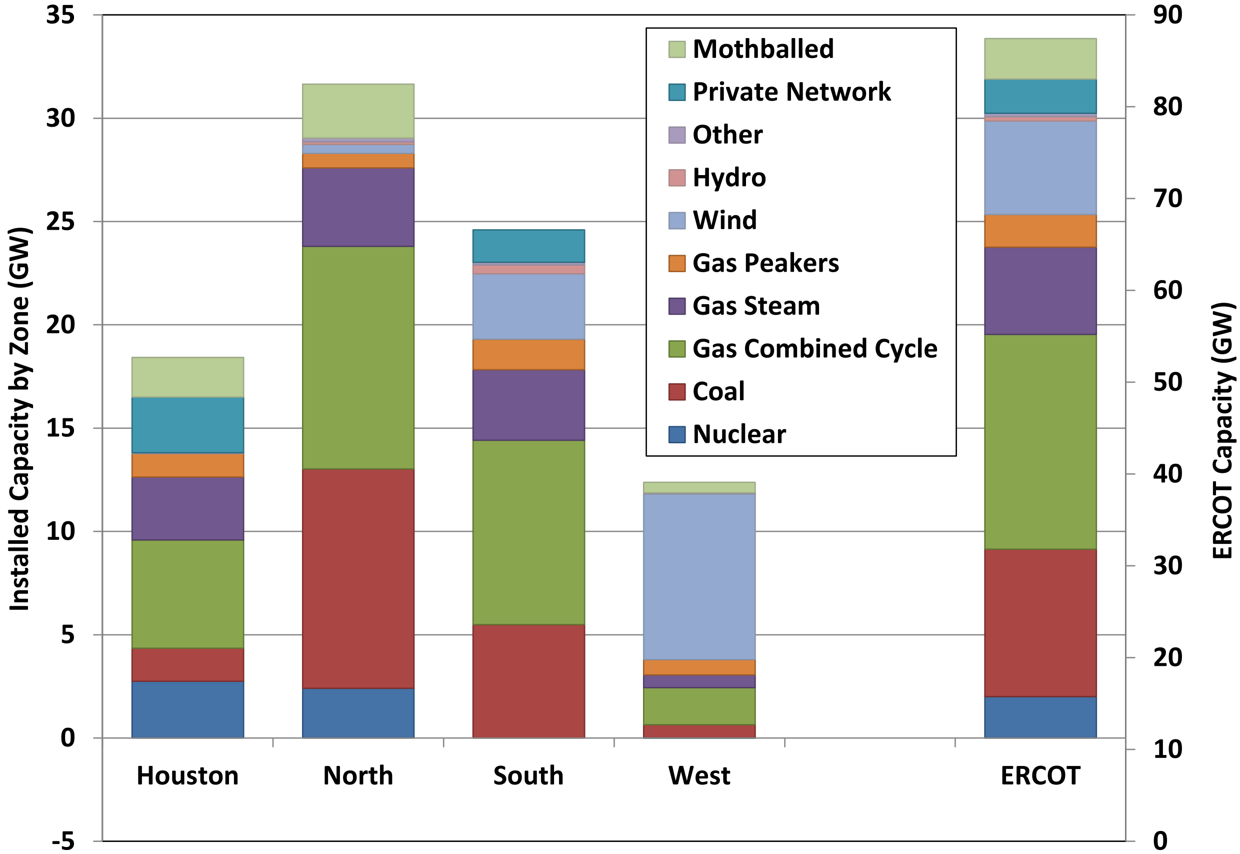


B. Generation Capacity in ERCOT

In this subsection we evaluate the generation mix in ERCOT. The distribution of capacity among the ERCOT zones is similar to the distribution of demand with the exception of the large amount of wind capacity in the West zone. The North zone accounts for approximately 36 percent of capacity, the South zone 28 percent, the Houston zone 21 percent, and the West zone 14 percent. The Houston zone typically imports power, while the West zone typically exports power. Excluding mothballed resources and including only 8.7 percent of wind capacity as capacity available to reliably meet peak demand, the North zone accounts for approximately 40 percent of capacity, the South zone 30 percent, the Houston zone 23 percent, and the West zone 6 percent. Figure 52 shows the installed generating capacity by type in each of the ERCOT zones.[9]

9 For purposes of this analysis, generation located in a NOIE Load Zone has been included with the proximate geographic Load Zone

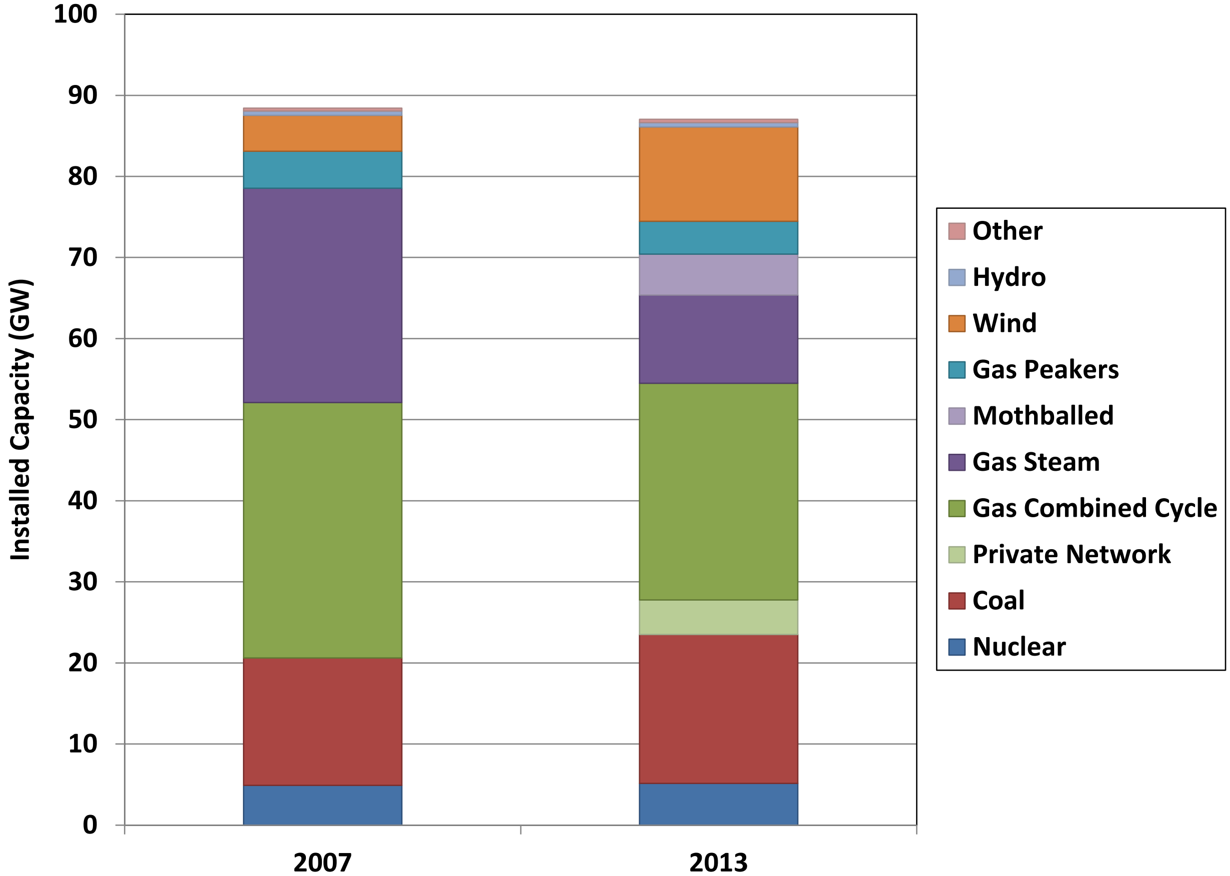
Figure 52: Installed Capacity by Technology for each Zone



Approximately 1.6 GW of new generation resources came online in 2013, the bulk of which was a large (970 MW) coal unit. The other additions were wind, gas and solar units. When unit retirements are included, the net capacity addition in 2013 was 1 GW. After the capacity changes in 2013 the mix between natural gas and coal generation remains stable. Natural gas generation accounts for approximately 48 percent of total ERCOT installed capacity and coal for approximately 21 percent.

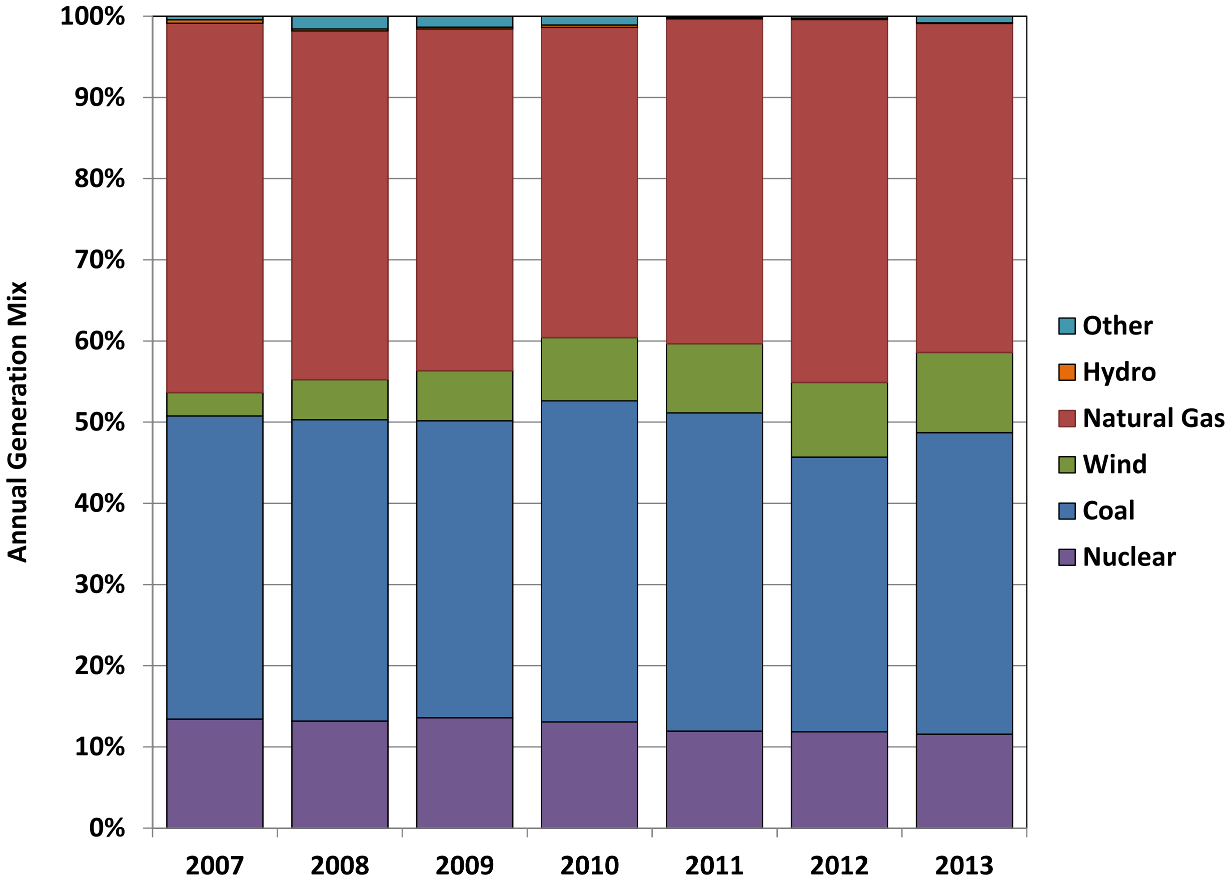
By comparing the current mix of installed generation capacity to that in 2007, as shown in Figure 53, we can see the effects of longer term trends. Over these seven years, wind and coal generation are the two categories with the most increased capacity. The sizable additions in these two categories have been more than offset by retirements of natural gas-fired steam units, resulting in less installed capacity in 2013 than there was in 2007.

Figure 53: Installed Capacity by Type: 2007 to 2013



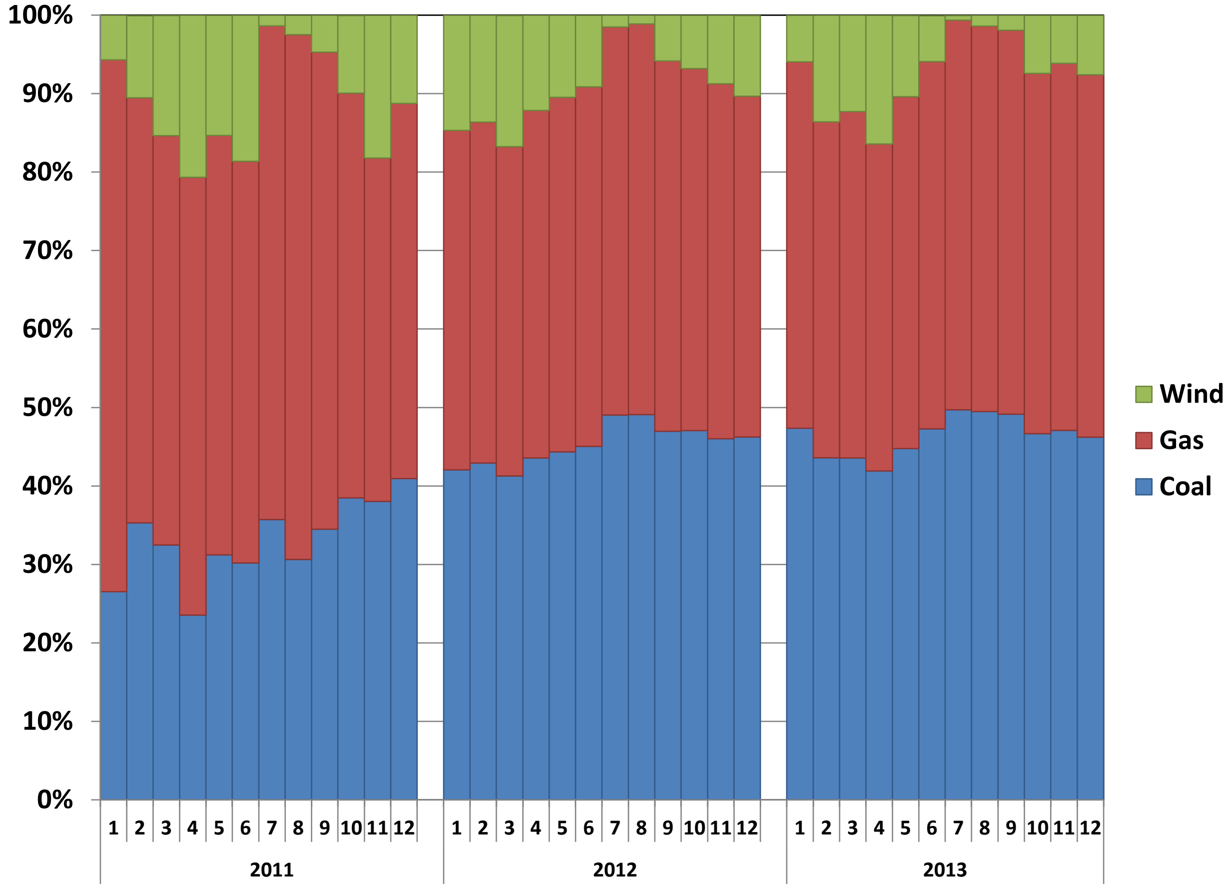
The shifting contribution of coal and wind generation is evident in Figure 54, which shows the percentage of annual generation from each fuel type for the years 2007 through 2013. The generation share from wind has increased every year, reaching 10 percent of the annual generation requirement in 2013, up from 3 percent in 2007. During the same period the percentage of generation provided by natural gas has ranged from a high of 45 percent in 2007 to a low of 38 percent in 2010. In 2013 the percentage of generation from natural gas decreased slightly from 2012 to 41 percent. Correspondingly, the percentage of generation produced by coal units ranged from a high of 40 percent in 2010 to a low of 34 percent in 2012. The percentage of generation from coal increased to 37 percent in 2013. The rebound in the share of generation produced by coal in 2013 was due to the increase in natural gas prices from the historical low levels experienced in 2012.

Figure 54: Annual Generation Mix



While coal/lignite and nuclear plants operate primarily as base load units in ERCOT, it is the reliance on natural gas resources that drives the high correlation between real-time energy prices and the price of natural gas fuel. There is approximately 23.5 GW of coal and nuclear generation in ERCOT. Generally, when ERCOT load is above this level, natural gas resources will be on the margin and set the real-time energy spot price. However, due to the low price of natural gas in 2012, we observed that the share of generation produced from coal-fired and nuclear units decreased to less than half of the energy in ERCOT, with the reduction coming from decreased coal generation. This reduction in the share of coal generation resulted in an increase in the occurrences when coal units were setting the price. This happens because the decrease in natural gas price results in those units becoming infra-marginal; that is, less costly than the last unit needed to satisfy total demand. As natural gas units are marginal less frequently, coal units increasingly become marginal. We can see the results of this tradeoff in Figure 55 which shows that the frequency with which coal was the marginal fuel was greater than 40 percent in all months during 2012, a noticeable increase from 2011. With more coal generation capacity and lower system loads in the first part of the year, this trend continued through 2013.

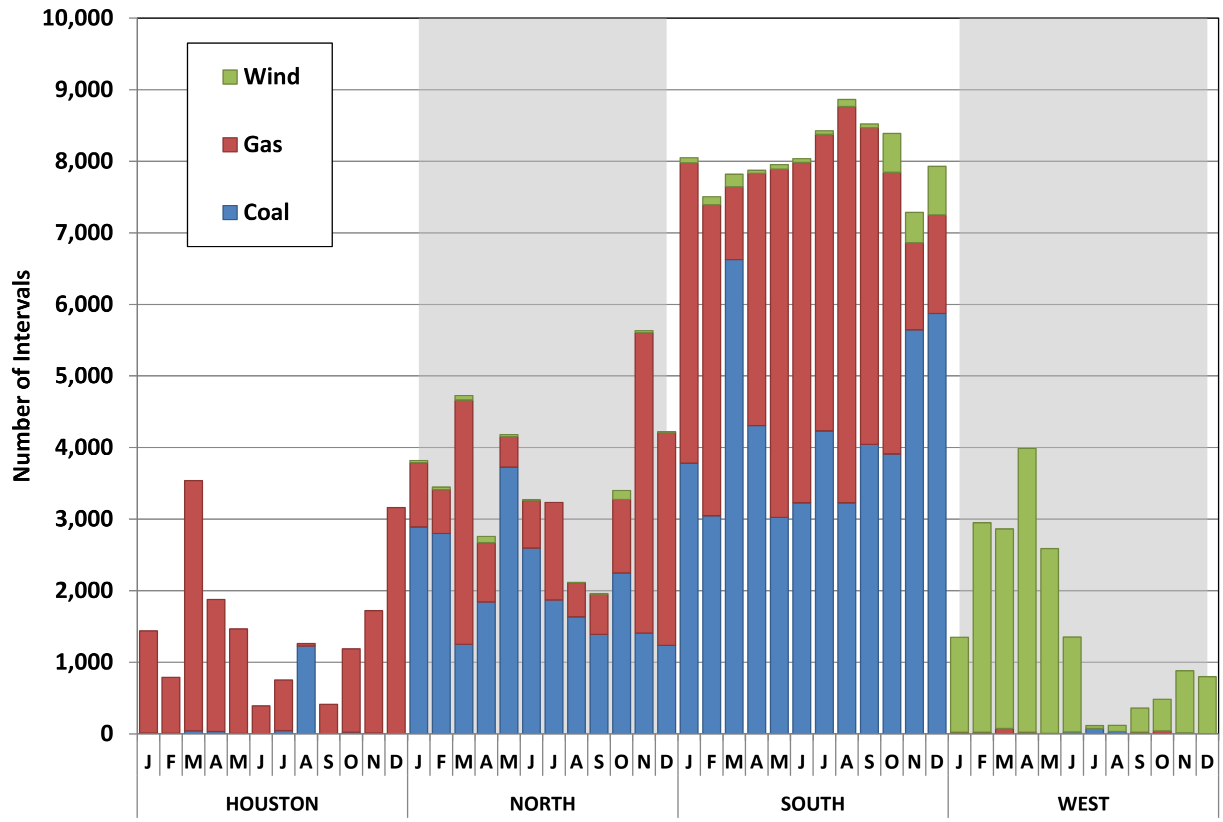
Figure 55: Marginal Unit Frequency by Fuel Type



The methodology used in this analysis reflects the details of the unit specific dispatch that are available under the nodal market design. For every five-minute interval we determine which units are marginal, that is they are being dispatched and their offer price is contributing to the locational marginal price. When there is congestion, units with different prices can be marginal at the same time. With all the marginal units identified, we aggregate by their fuel type to compute monthly percentages. This aggregation ignores all locational price differences and does not provide much insight into the pricing outcomes.

In the next figure we show the marginal units by location. Using the same methodology previously described we count the occurrences of each fuel type being marginal and aggregate the number of occurrences by zone. From this we can see that the contribution of wind to clearing prices is primarily in the West zone and occurs much less frequently than either coal or gas.

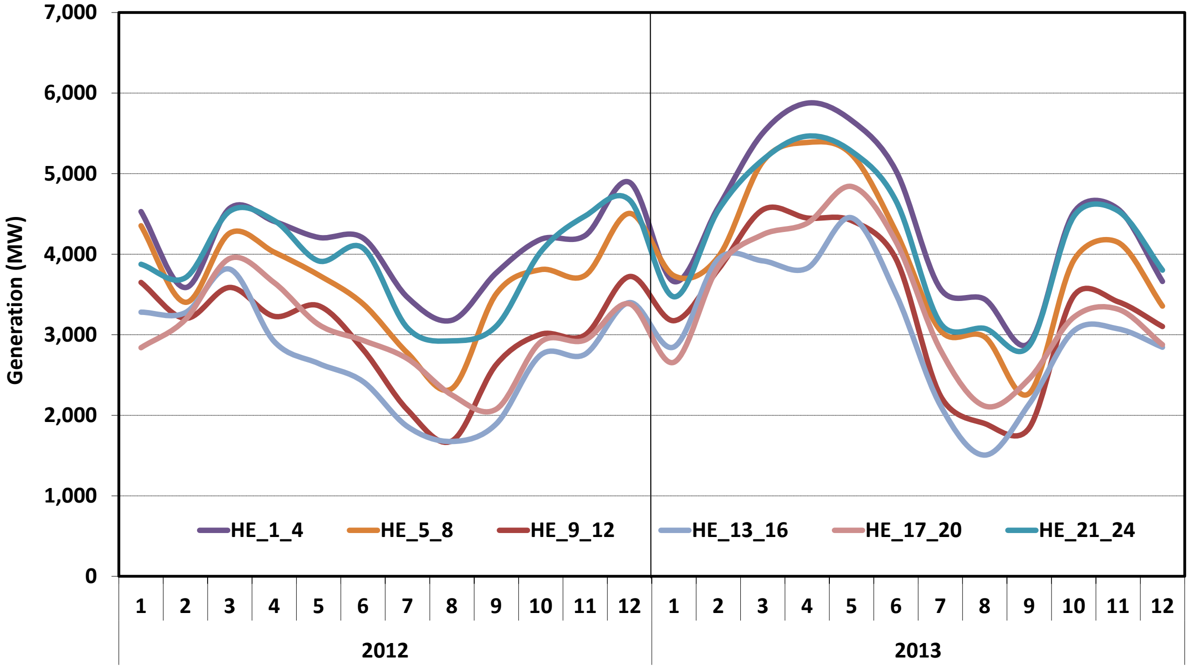
Figure 56: Marginal Units by Zone



1. Wind Generation

The amount of wind generation installed in ERCOT exceeded 11 GW by the end of 2013. Although the large majority of wind generation is located in the West zone, more than 2 GW of wind generation has been located in the South zone. Additionally, a private transmission line went into service in late 2010 allowing nearly another 1 GW of West zone wind to be delivered directly to the South zone. This subsection will more fully describe the characteristics of wind generation in ERCOT.

Figure 57: Average Wind Production



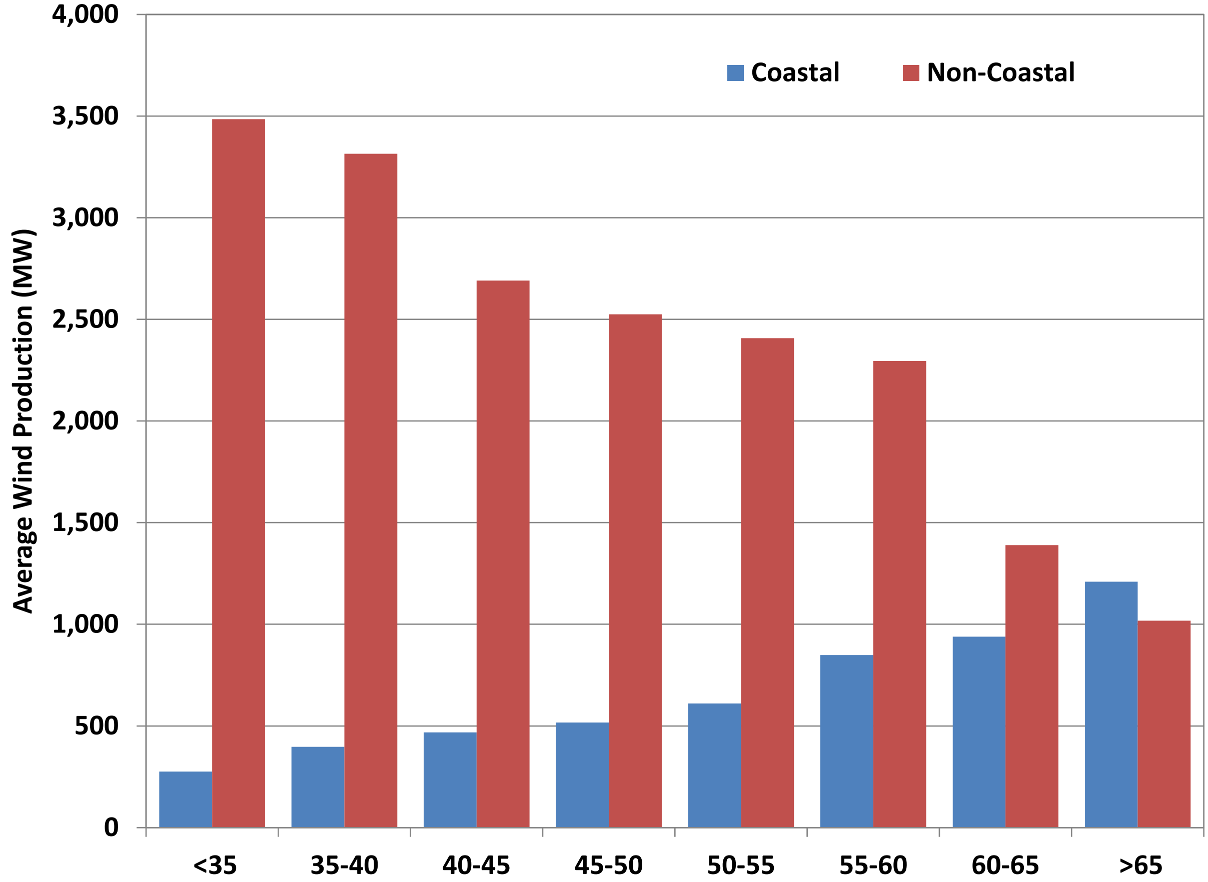
The average profile of wind production is negatively correlated with the load profile, with the highest wind production occurring during non-summer months, and predominately during off-peak hours. Figure 57 shows average wind production for each month in 2012 and 2013, with the average production in each month shown separately in four hour blocks.[10]

The amount of average wind generation in the spring of 2013 is markedly higher across all hours when compared to 2012. This increase is likely due to the completion of the CREZ transmission lines resulting in reduced curtailments.

Examining wind generation in total masks the different wind profiles that exist for locations across ERCOT. Wind developers have more recently been attracted to site facilities along the Gulf coast of Texas due to the higher correlation of winds with electricity demands. Next we compare the differences in output for wind units located in the coastal area of the South zone and those located elsewhere in ERCOT.

10 Figure 57 shows actual wind production, which was affected by curtailments at the higher production levels. Thus, the higher levels of actual wind production in Figure 57 are lower than the production levels that would have materialized absent transmission constraints.

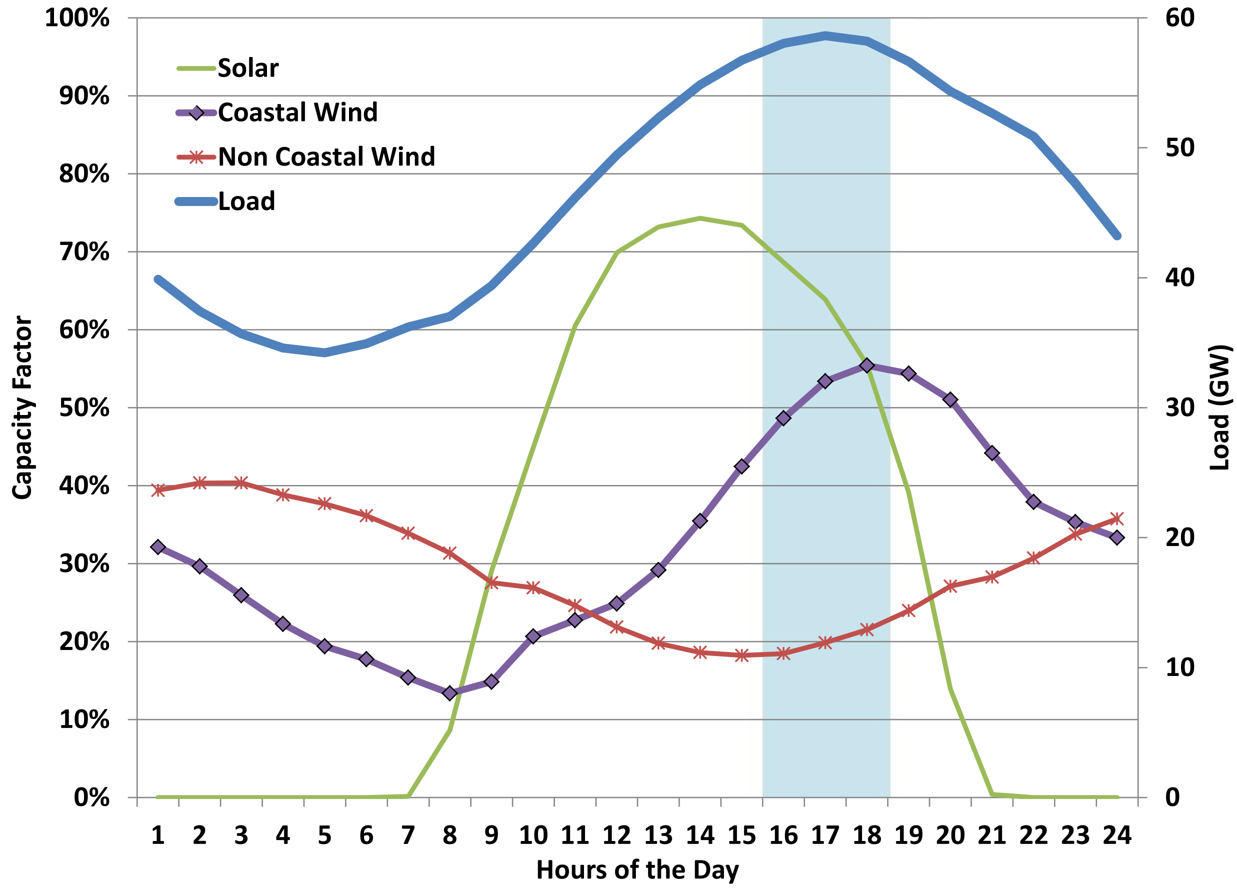
Figure 58: Summer Wind Production vs. Load



In Figure 58 data is presented for the summer months of June through August, comparing the average output for wind generators located in coastal and non-coastal areas in ERCOT across various load levels. It shows a strong negative relationship between non-coastal wind output and increasing load levels. It further shows that the output from wind generators located in the coastal area of the South zone is much more highly correlated with peak electricity demand.

The growing numbers of solar generation facilities in ERCOT also have an expected generation profile highly correlated with peak summer loads. Figure 59 below compares average summertime (June through August) hourly loads with observed output from solar and wind resources. Generation output is expressed as a ratio of actual output divided by installed capacity. The solar output shown is from relatively small central station photovoltaic facilities totaling approximately 50 MW. However, its production as a percentage of installed capacity is the highest, exceeding 70 percent in the early afternoon, and producing more than 50 percent of its installed capacity during peak.

Figure 59: Summer Renewable Production



The contrast between coastal wind and non-coastal wind is also clearly displayed in Figure 59. Coastal wind produced greater than 50 percent of its installed capacity during summer peak hours while output from non-coastal wind was approximately 20 percent.

Figure 60: Wind Production and Curtailment

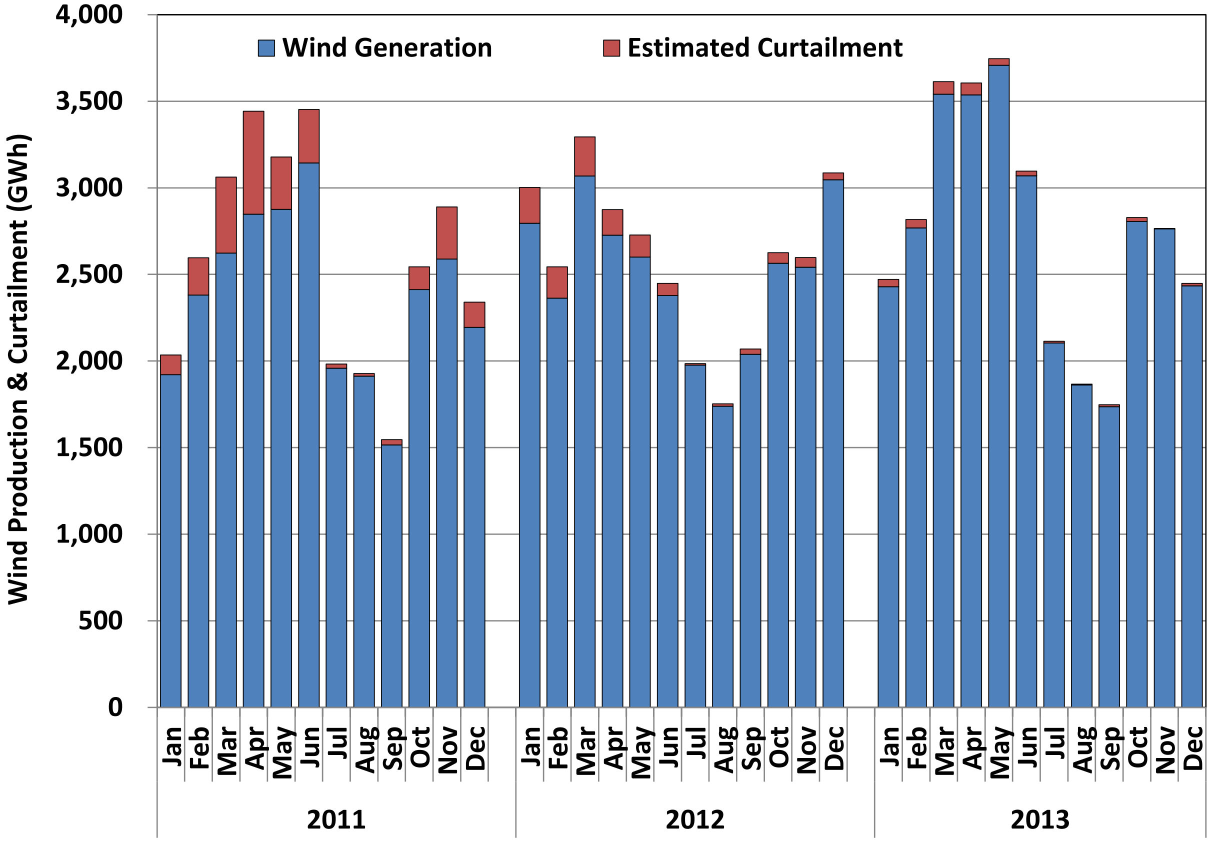
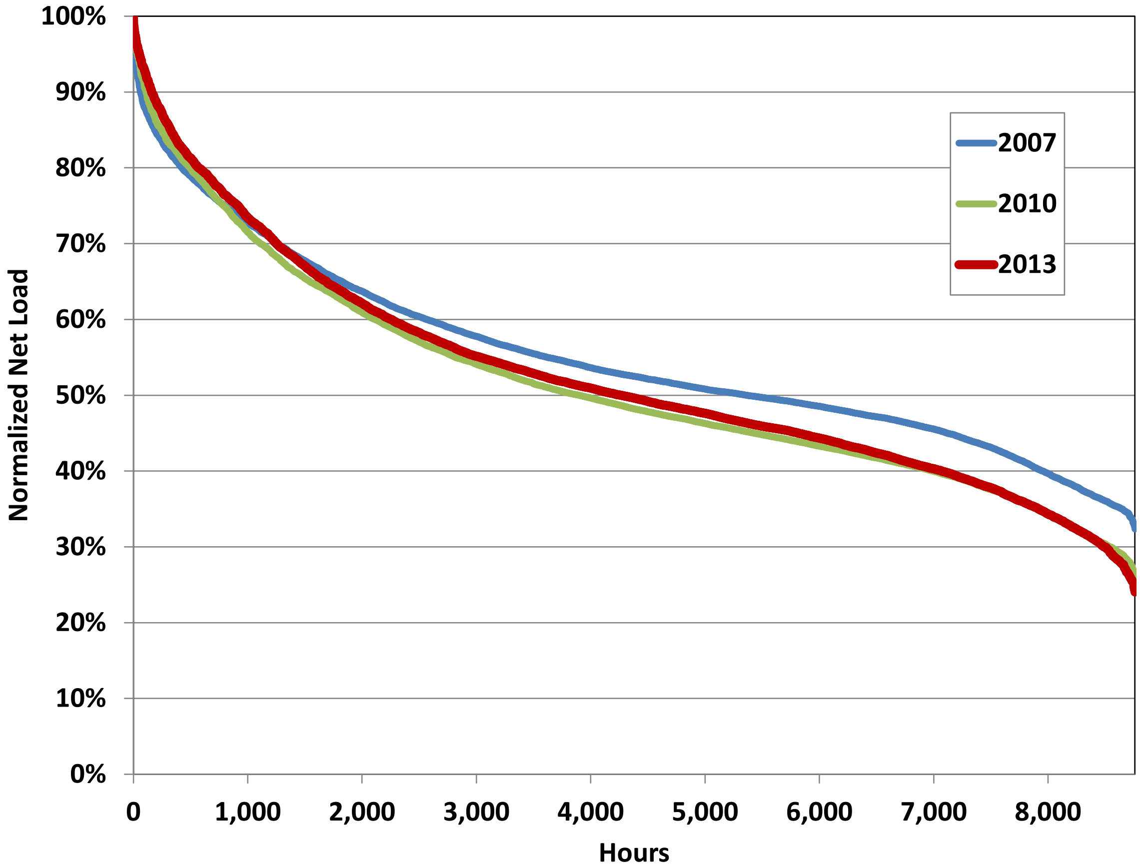


Figure 60 shows the wind production and estimated curtailment quantities for each month of 2011, 2012 and 2013. This figure reveals that the total production from wind resources increased significantly in 2013. More importantly, the quantity of curtailments continues to shrink. The volume of wind actually produced was almost 99 percent of the total available wind in 2013, up from approximately 96 percent in 2012 and 92 percent in 2011.

Increasing levels of wind resources in ERCOT also has important implications for the net load duration curve faced by the non-wind fleet of resources. Net load is defined as the system load minus wind production. Figure 61 shows the net load duration curves for selected years since 2007, normalized as a percentage of peak load.

Figure 61: Net Load Duration Curves

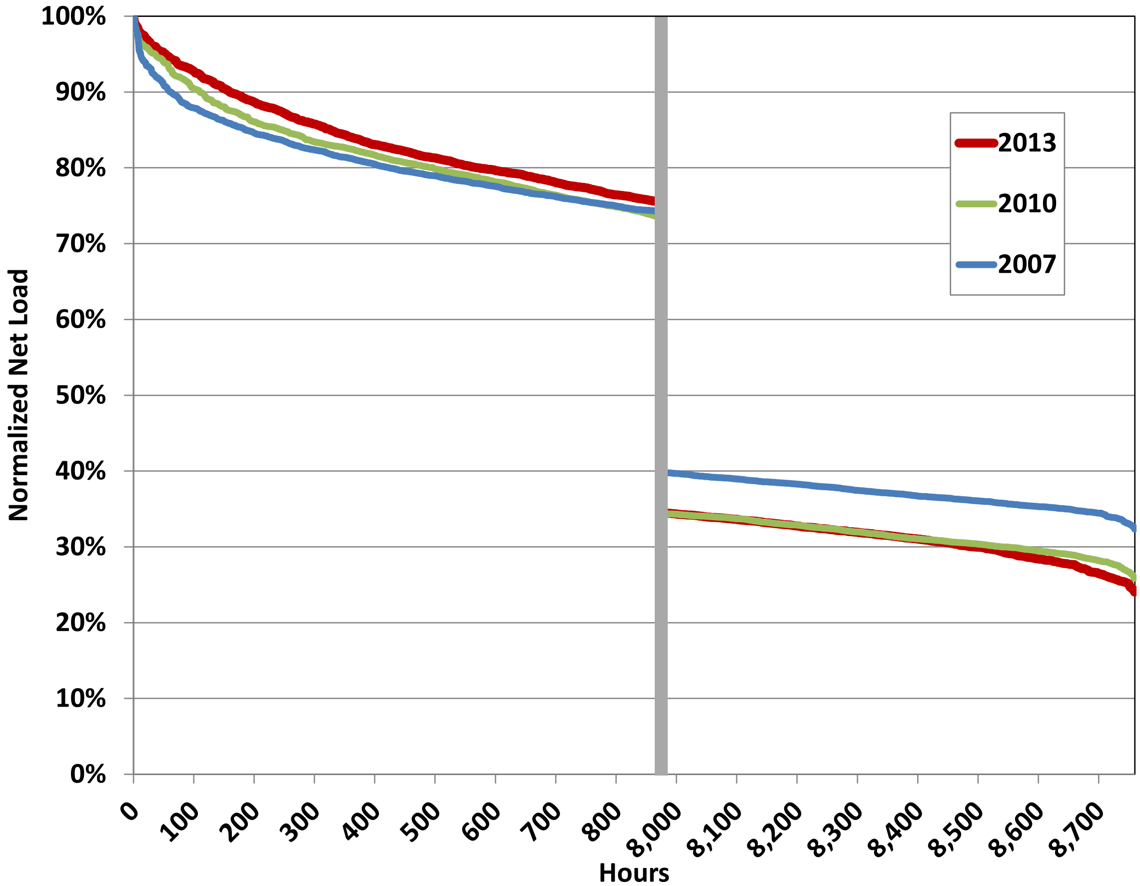


This figure shows the continued erosion of remaining energy available for non-wind units to serve during most hours of the year, with much less impact during the highest loads.

Even with the increased development activity in the coastal area of the South zone, nearly 80 percent of the wind resources in the ERCOT region are located in west Texas. The wind profiles in this area are such that most of the wind production occurs during off-peak hours or other times of relatively low system demand. This profile results in only modest reductions of the net load relative to the actual load during the hours of highest demand, but much more significant reductions in the net load relative to the actual load in the other hours of the year.

Focusing on the left side of the net load duration curve shown in Figure 62, the difference between peak net load and the 95th percentile of net load has been between 9.5 and 12.5 GW for the previous seven years.

Figure 62: Top and Bottom Ten Percent of Net Load



On the right side of the net load duration curve, the minimum net load has dropped from approximately 20 GW in 2007 to below 16 GW last year, even with sizable growth in total annual load. This continues to put operational pressure on the 23.5 GW of nuclear and coal-fired generation currently installed in ERCOT.

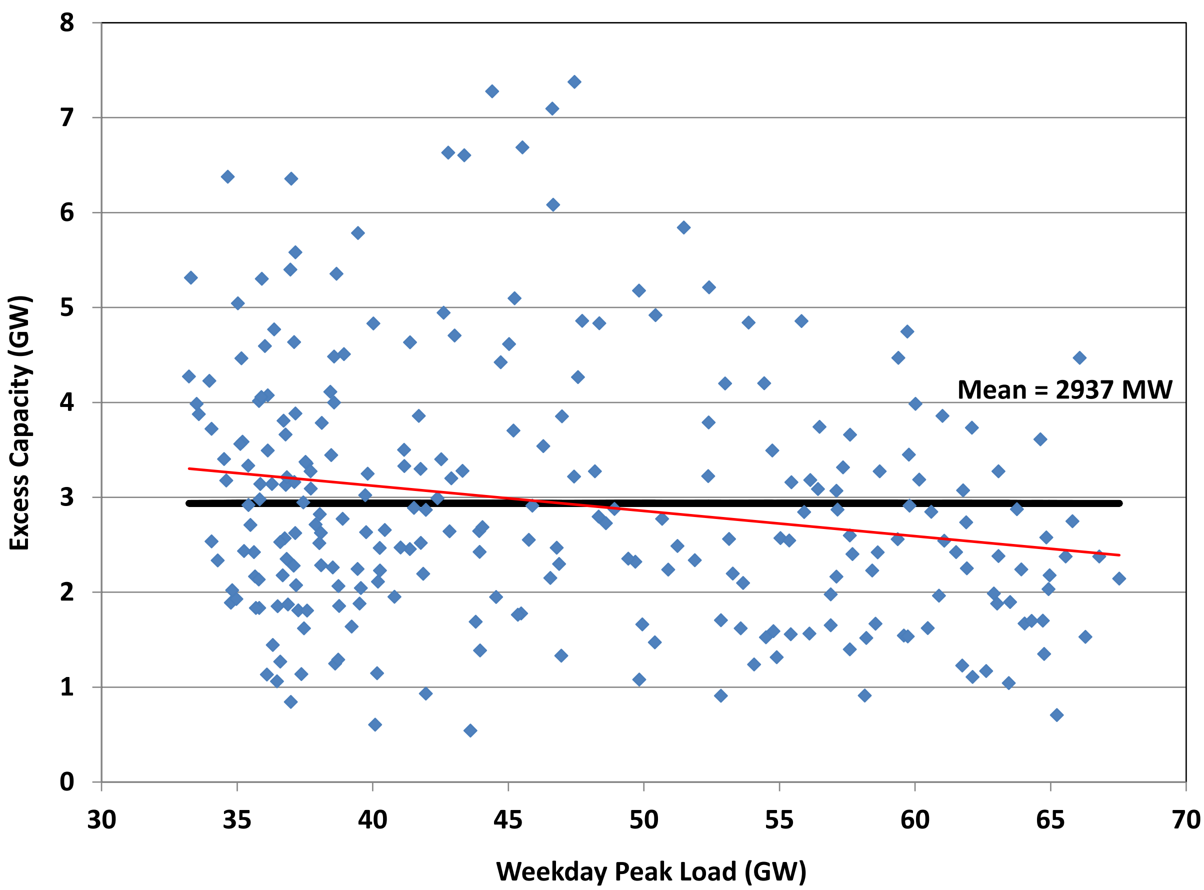
Thus, although the peak net load and reserve margin requirements are projected to continue to increase and create an increasing need for non-wind capacity to meet net load and reliability requirements, the non-wind fleet is expected to operate for fewer hours as wind penetration continues to increase. This outlook further reinforces the importance of efficient energy pricing during peak demand conditions and other times of system stress, particularly within the context of the ERCOT energy-only market design.

2. Daily Generator Commitments

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

This subsection evaluates the commitment patterns in ERCOT by examining the levels of excess capacity. Excess capacity is defined as the total capacity of online plus quick-start generators minus the demand for energy, responsive reserve, up regulation and non-spinning reserve provided from online capacity or quick-start units. To evaluate the commitment of resources in ERCOT, Figure 63 plots the excess capacity compared to peak load during 2013.

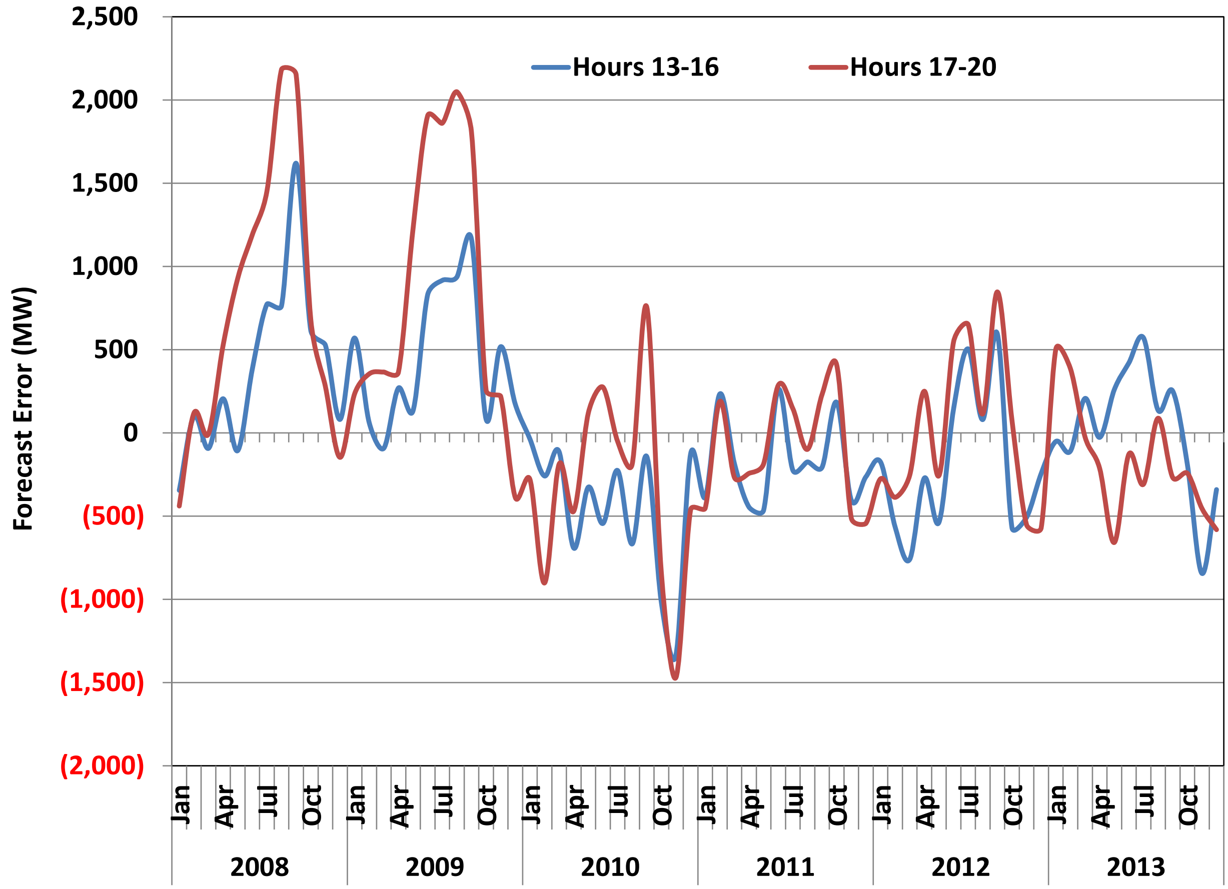
Figure 63: Excess On-Line and Quick Start Capacity



The figure shows the excess capacity in only the peak hour of each weekday because the largest generation commitment usually occurs at the peak hour. Hence, one would expect larger quantities of excess capacity in other hours. The excess on-line capacity during daily peak hours on weekdays, as shown in Figure 63, averaged 2,937 MW in 2013 which was approximately 7.7 percent of the average load in ERCOT. These values have remained consistent for the past three years. In 2012 the average excess on-line capacity was 2,880 MW, or 7.8 percent of average load and in 2011 the average was 2,901 MW, or 7.6 percent.

Even with improved unit commitment coming from having a day-ahead market, if ERCOT's day-ahead load forecast continued to show significant bias toward over-forecasting peak load hours,[11] we would expect to see over commitment of generation using non-market means.

Figure 64: Load Forecast Error



From Figure 64 we can see the noticeable reduction in ERCOT's load forecast bias since 2009. This was due to a procedure change implemented four years ago under which ERCOT identifies

[11] See 2010 ERCOT SOM report at pages 49-51 and 2009 ERCOT SOM report at pages 68-70.

and subtracts out the bias from their load forecast and procures additional non-spin capacity in an equal amount. After being in place for four years this procedure has effectively reduced the amount of load forecast bias previously seen, and the corresponding adder to the amount of non-spin procure was minimal. As part of the "Methodologies for Determining Ancillary Service Requirements" document approved in December 2013, ERCOT will stop explicitly calculating the amount of load forecast bias as part of their calculation of the quantity of Non-Spin to procure.

Once ERCOT assesses the unit commitments resulting from the day-ahead market, additional capacity commitments are made, if needed, using a reliability unit commitment process that executes both on a day-ahead and hour-ahead basis. These additional unit commitments may be made for one of two reasons. Either additional capacity is required to ensure forecasted total demand will be met, or a specific generator is required to resolve transmission congestion.

Figure 65: Frequency of Reliability Unit Commitments

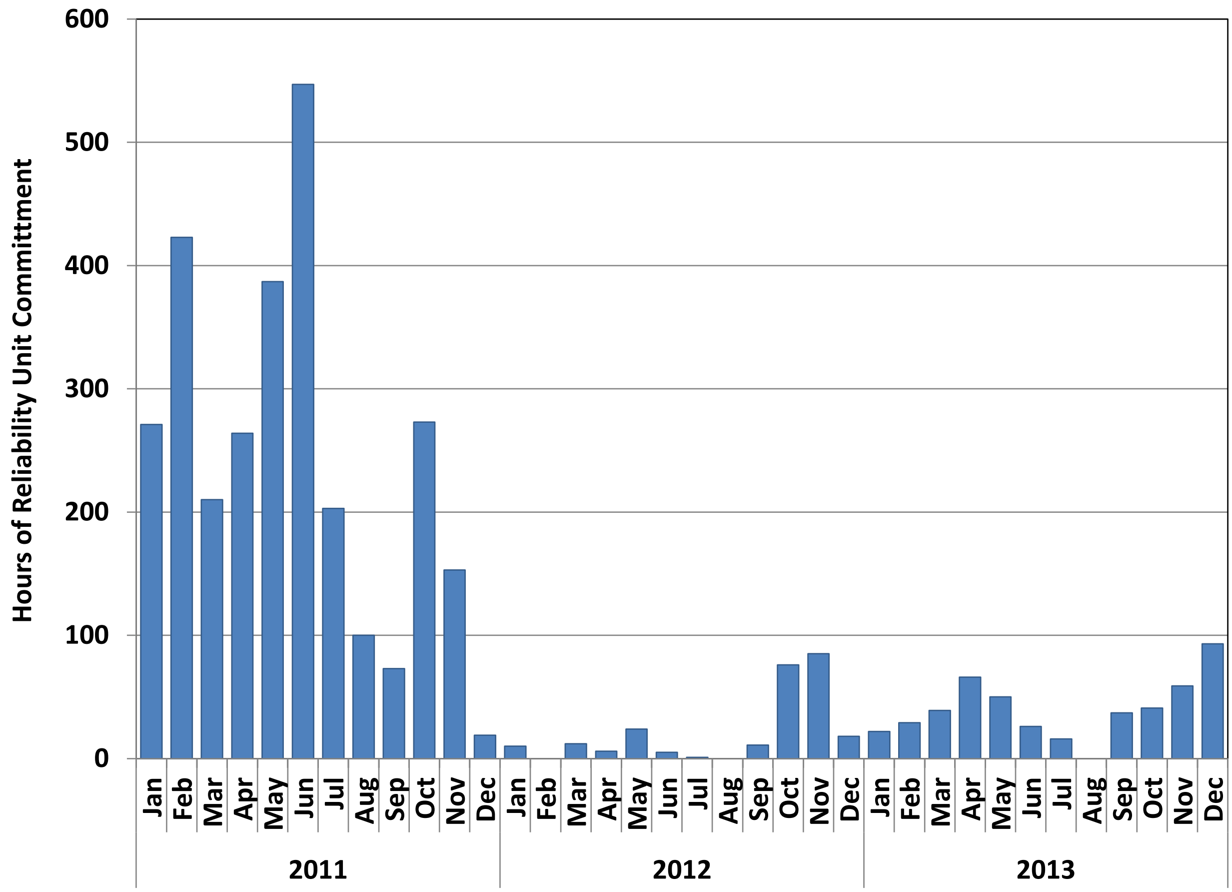


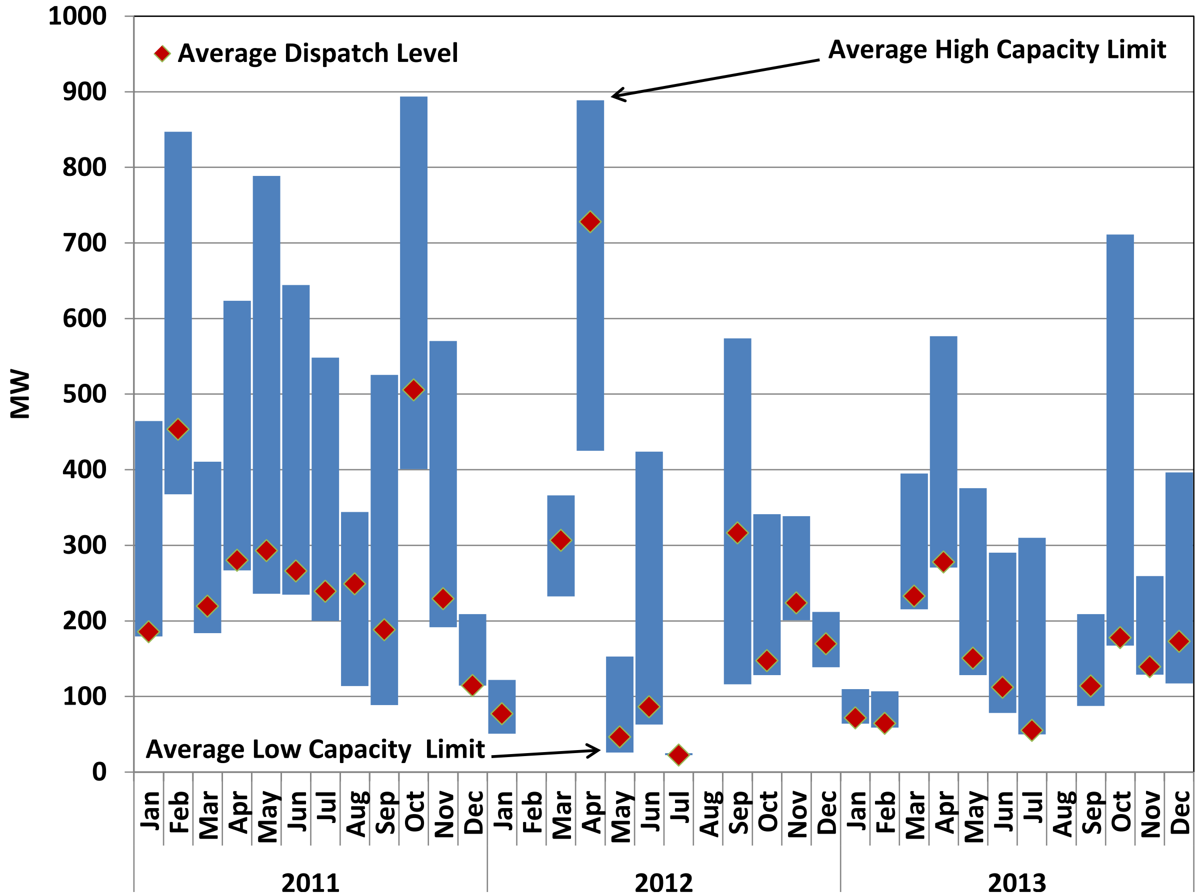
Figure 65 summarizes, by month, the number of hours with units committed via the reliability unit commitment process. We observe a significant reduction in the reliance upon the reliability unit commitment process in 2012 and 2013 as compared to 2011. Approximately one third of the hours during 2011 had at least one unit committed by ERCOT through the reliability unit commitment process. During 2013 the number of hours with at least one unit receiving a reliability unit commitment instruction was 5 percent, a slight increase from 2012 when the value was 3 percent.

The reduction can in part be attributed to the less extreme weather and resulting lower load levels experienced during 2012 and 2013. There also was an operational change midway through 2011 which also contributed to the reduced frequency of reliability unit commitments. During the initial months of operating the nodal market it was common for ERCOT to commit units that were providing non-spin reserves if they were needed to resolve congestion. This practice was greatly reduced starting in July 2011.

The majority of reliability unit commitment instructions are to resolve localized transmission constraints. Less than 15 percent of the unit hours of RUC instructions in 2013 were for system-wide capacity requirements.

The next analysis compares the average dispatched output of the reliability committed units with their operational limits. Figure 66 below shows that the quantity of reliability unit commitment generation in 2013 was similar to the 2012 quantities and both years were lower than 2011 quantities.

Figure 66: Reliability Unit Commitment Capacity



The largest amount of reliability unit commitment capacity typically occurs during off-peak months. Factors contributing to the high average capacity in October 2013 included an unseasonably warm day leading to system-wide capacity deficiency and localized generation requirements because of North to Houston and Valley import transmission constraints. April 2013 capacity needs were primarily in the DFW area for voltage support. The large amounts of reliability unit committed capacity in April 2012 were related to brief generator outages resulting in reactive power deficiencies in the Dallas-Fort Worth area. This was similar to the situation that existed during October 2011. The larger quantity of committed capacity in February 2011 was a result of ERCOT operator action taken to attempt to ensure overall capacity adequacy during both the extreme cold weather event that occurred early in the month, and a subsequent bout of cold weather that occurred one week later.

V. RESOURCE ADEQUACY

One of the primary functions of the wholesale electricity market is to provide economic signals that will facilitate the investment needed to maintain a set of resources that are adequate to satisfy the system's demands and reliability needs. We begin this section with an evaluation of these economic signals by estimating the "net revenue" new resources would receive from the markets. Next, we review of the effectiveness of the Public Utility Commission's Scarcity Pricing Mechanism and ERCOT's planning reserve margin. We then describe the factors to necessary to ensure resource adequacy in an energy-only market design. We conclude this section with a review of the contributions from demand response toward meeting resource adequacy objectives in ERCOT.

A. Net Revenue Analysis

Net revenue is the total revenue that can be earned by a new generating unit less its variable production costs. Put another way, it is the revenue in excess of short-run operating costs that is available to recover a unit's fixed and capital costs, including a return on the investment. Net revenues from the energy and ancillary services markets together provide the economic signals that inform suppliers' decisions to invest in new generation or retire existing generation. In long-run equilibrium, markets should provide sufficient net revenue to allow an investor to receive a return of, and on an investment in a new generating unit when that unit is needed. In the short-run, if the net short-run revenues produced by the market are not sufficient to justify entry, then one or more of these conditions exist:

- New capacity is not needed because there is sufficient generation already available;
- Load levels, and thus energy prices, are temporarily low due to mild weather or economic conditions;
- Market rules or operational practices are causing revenues to be reduced inefficiently; or
- Market rules are not sufficiently linked in short-term operations to ensure long-term resource adequacy objectives are met.

Likewise, the opposite would be true if the markets provide excessive net revenues in the short-run. The persistence of excessive net revenues in the presence of a capacity surplus is an indication of competitive issues or market design flaws. In this subsection, we analyze the net revenues that would have been received by various types of generators in each zone.

Although most suppliers are likely to receive the bulk of their revenues through bilateral contracts, the spot prices produced in the real-time energy market should drive bilateral energy prices over time and are appropriate to use for this evaluation. For purposes of this analysis, heat rates of 7 MMBtu per MWh for a combined cycle unit, 10.5 MMBtu per MWh for a combustion turbine, and 9.5 MMBtu per MWh for a new coal unit were assumed. Variable operating and maintenance costs of $4 per MWh for the natural gas units and $5 per MWh for the coal unit and fuel and variable operating and maintenance costs of $8 per MWh for the nuclear unit were assumed. For purposes of this analysis, a total outage rate (planned and forced) of 10 percent was assumed for each technology.

The energy net revenues are computed based on the generation weighted settlement point prices from the real-time energy market. Weighting the energy values in this way masks what may be very high locational values for a specific generator location. Some generators may also receive uplift payments because of their specific reliability contributions, either as a reliability must run unit, or through reliability unit commitment actions. This source of revenue is not considered in this analysis. The analysis also includes simplifying assumptions that can lead to over-estimates of the profitability of operating in the wholesale market. The following factors are not explicitly accounted for in the net revenue analysis: (i) start-up costs, which can be significant; and (ii) minimum running times and ramping restrictions, which can prevent generators from profiting during brief price spikes. Despite these limitations, the net revenue analysis provides a useful summary of signals for investment in the wholesale market.

Figure 67 shows the results of the net revenue analysis for four types of hypothetical new units in 2012 and 2013. These are: (a) natural gas-fired combined-cycle, (b) natural gas-fired combustion turbine, (c) coal-fired generator, and (d) a nuclear unit. For the natural gas units, net revenue is calculated by assuming the unit will produce energy in any hour for which it is profitable and by assuming it will be available to sell reserves and regulation in other hours that it is available (*i.e.*, when it is not experiencing a planned or forced outage). For coal and nuclear technologies, net revenue is calculated by assuming that the unit will produce at full output.

Figure 67: Estimated Net Revenue by Zone and Unit Type

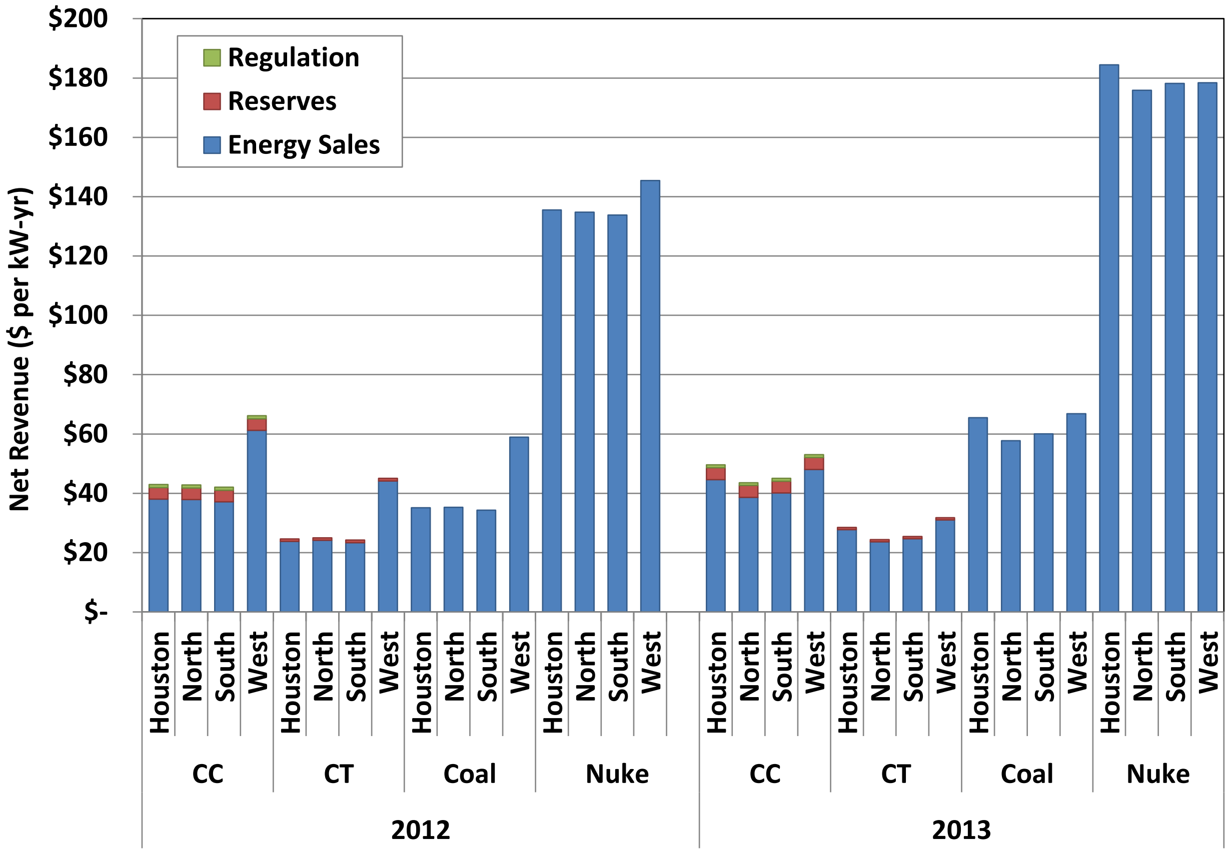


Figure 67 shows that the 2013 net revenue for the natural gas-fired technologies was similar to 2012 levels, with the notable exception of in the West zone. The decrease in net revenues in the West zone was due to reduced transmission congestion resulting in lower prices in the West zone. Net revenues for coal and nuclear technologies were higher in 2013 than in 2012 because of higher natural gas prices, but still not close to being sufficient to support new entry for either of these technologies.

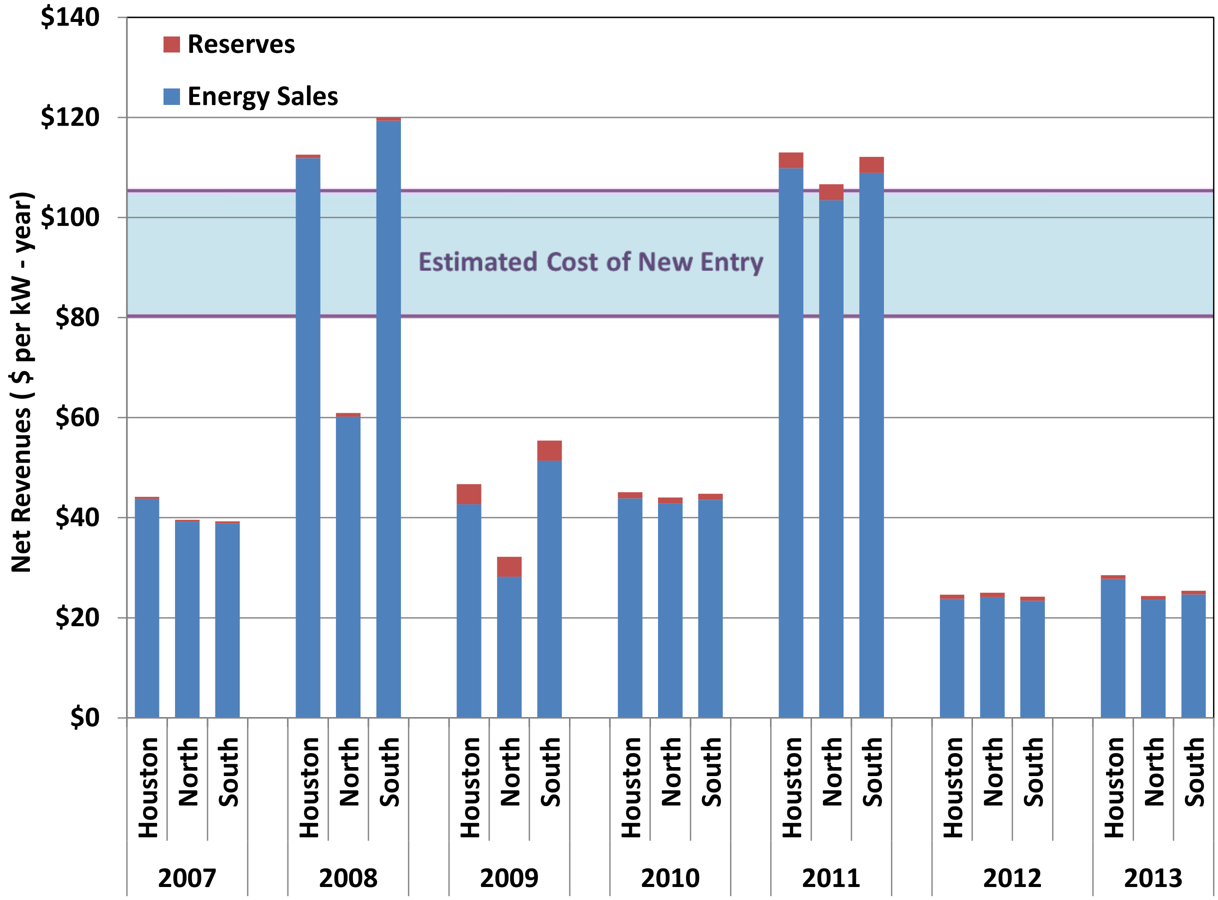
- For a new coal unit, the estimated net revenue requirement is approximately $275 to $350 per kW-year. The estimated net revenue in 2013 for a new coal unit ranged from $58 to $67 per kW-year.

- For a new nuclear unit, the estimated net revenue requirement is approximately $415 to $540 per kW-year. The estimated net revenue in 2013 for a new nuclear unit was approximately $180 per kW-year.

Prior to 2005, net revenues were well below the levels necessary to justify new investment in coal and nuclear generation. Higher natural gas prices through 2008 resulted in sustained energy prices high enough to support new entry for these technologies. The production costs of coal and nuclear units did not change significantly over this period, leading to a dramatic rise in net revenues. However, natural gas prices have been on the decline since 2008, resulting in reduced net revenues for coal and nuclear technologies. Even with the higher energy prices experienced in 2011, net revenues for these technologies were insufficient to support new entry. Very low natural gas prices and few occurrences of shortage pricing during 2012 resulted in the estimated net revenue for either a new coal or a nuclear unit in ERCOT was well below the levels required to support new entry. Although natural gas prices increased in 2013, the net revenue for coal and nuclear technologies continues to be insufficient to support new entry.

The next two figures provide an historical perspective of the net revenues available to support new gas turbine (Figure 68) and combined cycle generation (Figure 69).

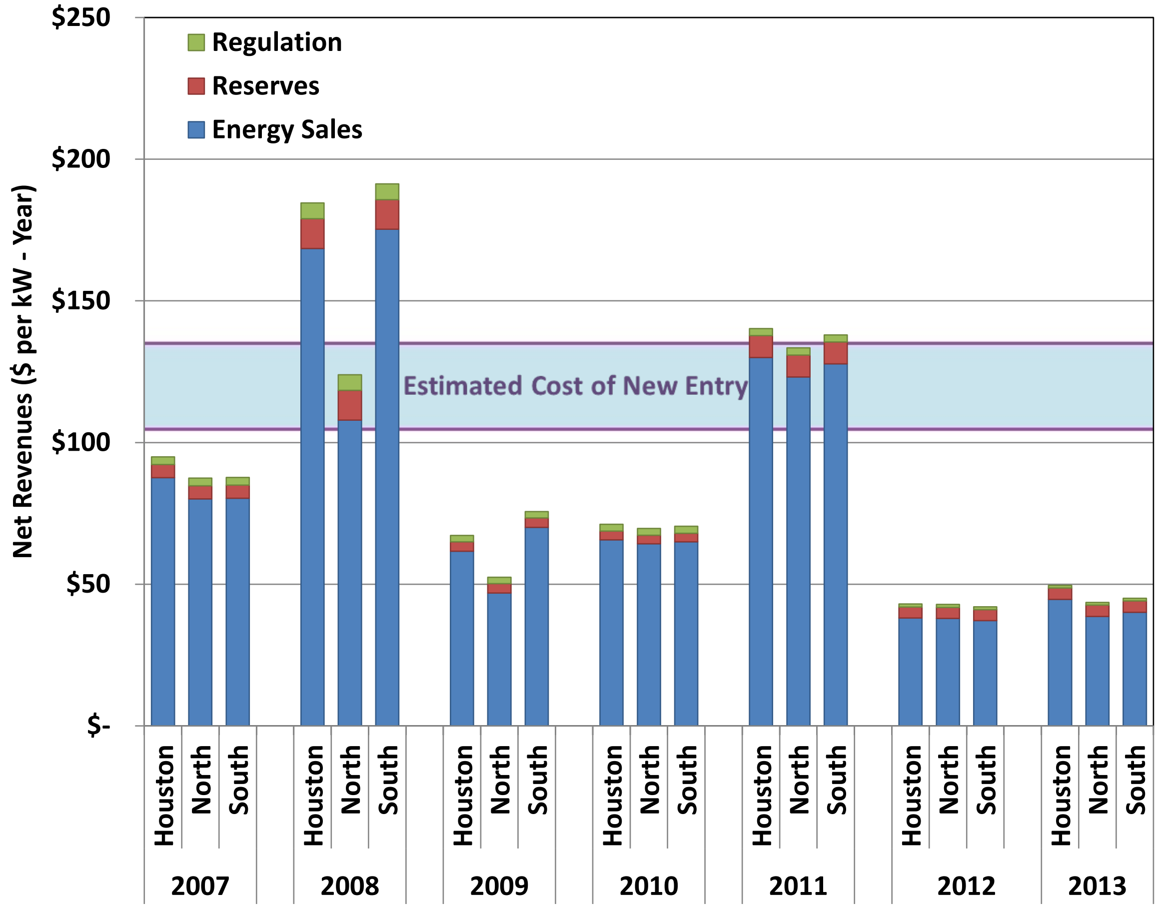
Figure 68: Gas Turbine Net Revenues



Based on our estimates of investment costs for new units, the net revenue required to satisfy the annual fixed costs (including capital carrying costs) of a new gas turbine unit ranges from $80 to $105 per kW-year. The estimated net revenue in 2013 for a new gas turbine was approximately $26 per kW-year, far below the levels required to support new gas turbine generation.

For a new combined cycle unit, the estimated net revenue requirement is approximately $105 to $135 per kW-year. The estimated net revenue in 2013 for a new combined cycle unit was approximately $45 per kW-year, also far below the levels to support new combined cycle generation in ERCOT.

Figure 69: Combined Cycle Net Revenues



Even though net revenues for the Houston and South zones in 2008 may have appeared to be sufficient to support new natural gas-fired generation, it was actually extremely inefficient transmission congestion management and inefficient pricing mechanisms associated with the deployment of non-spinning reserves which led to high prices and resulting higher than warranted net revenues. Discounting the effect that the 2008 results would have had on forward price signals, we find that 2011 has been the only year during our tenure monitoring the ERCOT market that net revenues have been sufficient to support either new gas turbine or combined cycle generation.

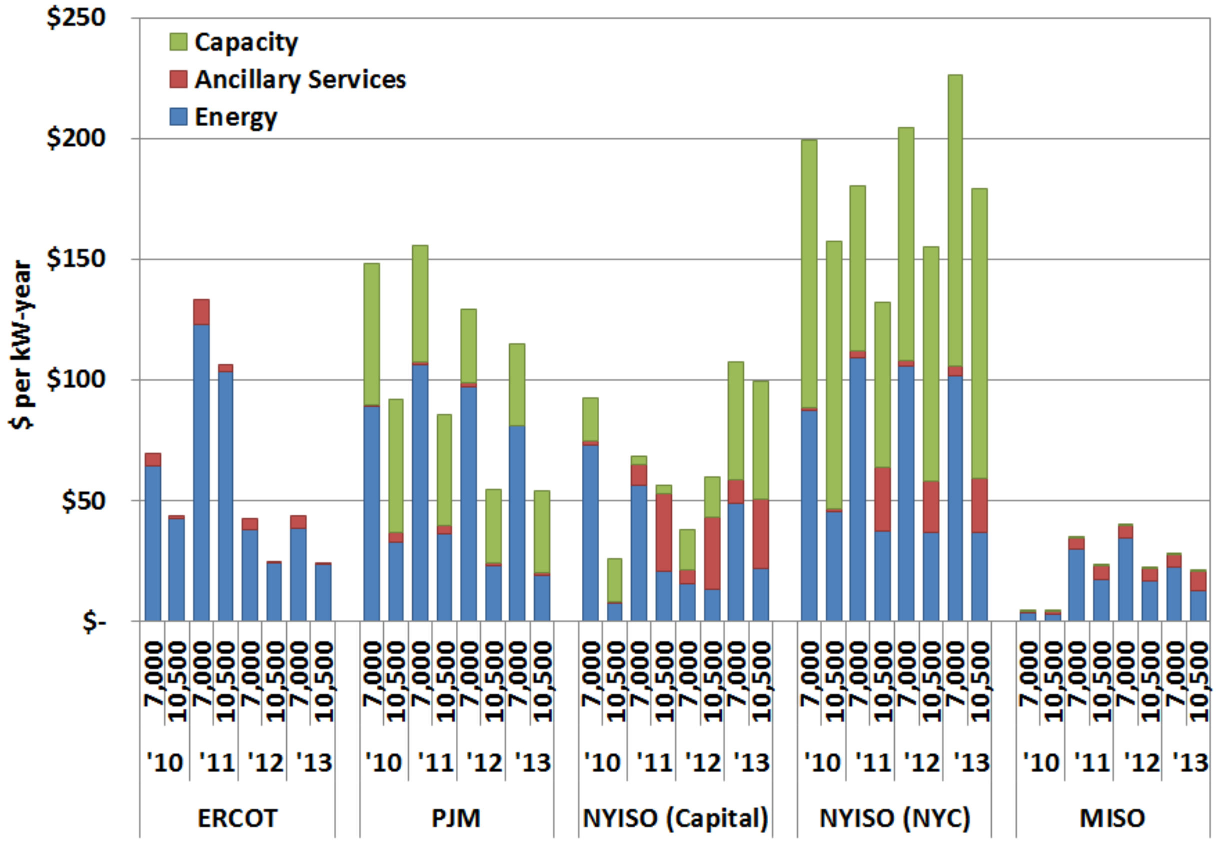
These results indicate that during 2013 the ERCOT markets would not have provided sufficient revenues to support profitable investment in any of the types of generation technology evaluated. The net revenues in 2013 were very similar to those in 2012, and both years were much lower than in 2011. This is not surprising because shortages were very infrequent over the past two years. Shortage pricing plays a pivotal role in providing investment incentives in an energy-only market like ERCOT's. In order to provide adequate incentives, some years must exhibit an extraordinary number of shortages and net revenues that are multiples of annual net revenues needed to support investment.

While 2011 exhibited much more frequent shortages than in the years prior or since, it is important to recognize that 2011 was highly anomalous with some of the hottest summer temperatures on record. Notwithstanding these conditions, net revenues may have been narrowly sufficient to cover the annual costs of a new combined cycle or new combustion turbine. This indicates that higher shortage prices are likely necessary to provide adequate long-term economic signals to invest in and maintain generating resources in ERCOT. The PUC has taken actions over the past year to increase energy and ancillary prices during shortage and near-shortage conditions.

To provide additional context for the net revenue results presented in this subsection, we also compared the net revenue in the ERCOT market for two types of natural gas-fired technologies with the net revenue that those technologies could expect in other wholesale markets with centrally cleared capacity markets. The technologies are differentiated by their assumed heat rate; 7,000 MMBtu per MWh for combined cycle and 10,500 MMBtu per MWh for simple-cycle combustion turbine.

Figure 70 compares estimates of net revenue for the ERCOT North zone, PJM, two locations within the New York ISO, and the Midcontinent ISO. Most of these locations are central locations with the exception of New York City, which is significantly affected by congestion.

Figure 70: Comparison of Net Revenue of Gas-Fired Generation between Markets



The figure includes estimates of net revenue from energy, reserves and regulation, and capacity. ERCOT does not have a capacity market, and thus, does not have any net revenue from capacity sales. For that reason, the net revenues in ERCOT and MISO, which also lacks a functional capacity market, are the lowest among these markets. This is notable because ERCOT's reserve margin is also the lowest among these markets, which should contribute to higher net revenues.

Figure 70 shows net revenues in ERCOT for both technologies did not change much in 2013 when compared to 2012. Net revenues for both technologies decreased in PJM and Midcontinent ISO, while they increased for both technologies at both locations in NY ISO. In the figure net revenues are calculated for central locations. However, there are load pockets within each market where net revenue and the cost of new investment may be higher. Thus, even if new investment is not generally profitable in a market, it may be economic in certain areas. Finally, resource investments are driven primarily by forward price expectations, so historical net revenue analyses do not provide a complete picture of the future pricing expectations that will spur new investment. In an energy only market, we would expect net revenues to be less than required to support new investment. However, in the small number years that are much worse than normal, the sharp increase in the frequency of shortage pricing should cause the net revenues in that year to be multiples of the annual level required to support investment. This pattern over the long run must create an expectation that net revenues, on average, will support the new investments.

B. Effectiveness of the Scarcity Pricing Mechanism

The Public Utility Commission of Texas ("PUCT") adopted rules in 2006 that define the parameters of an energy-only market. These rules include a Scarcity Pricing Mechanism ("SPM") that increased the system-wide offer cap in multiple steps until it reached $3,000 per MWh shortly after the implementation of the nodal market. PUCT SUBST. R. 25.505 provides that the IMM may conduct an annual review of the effectiveness of the SPM. This subsection provides an assessment of the effectiveness of the SPM in 2013 under ERCOT's energy-only market structure.

Approved during 2012, new PUCT SUBST. R. 25.508 increased the system-wide offer cap to $4,500 per MWh effective August 1, 2012. Revisions to PUCT SUBST. R. 25.505 were also adopted that specified the following increases to the system-wide offer cap:

- $5,000 per MWh beginning on June 1, 2013,
- $7,000 per MWh beginning on June 1, 2014, and
- $9,000 per MWh beginning on June 1, 2015.

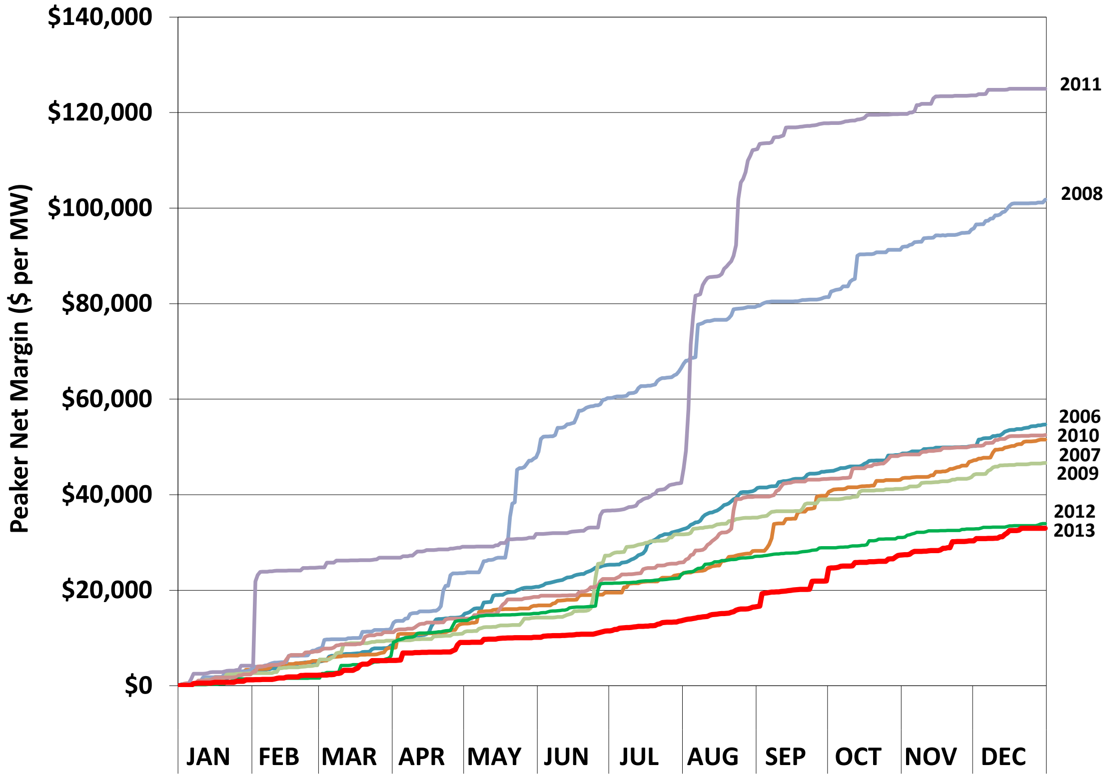
As shown in Figure 15 on page 15 there have been very brief periods when energy prices rose to the cap since the system-wide offer cap was increased to greater than $3,000 per MWh.

The SPM includes a provision termed the Peaker Net Margin ("PNM") that is designed to provide a fail-safe pricing measure, which if exceeded would result in reducing the system-wide offer cap. PNM also serves as a simplified measure of the annual net revenue of a hypothetical peaking unit.[12] This aspect of the rule was also amended in 2012. Under the current rule, if the PNM for a year reaches a cumulative total of $300,000 per MW, the system-wide offer cap is

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

then reduced to the higher of $2,000 per MWh or 50 times the daily natural gas price index.[13] Figure 71 shows the cumulative PNM results for each year from 2006 through 2013 and shows that PNM in 2013 was the lowest it has been since its implementation.

Figure 71: Peaker Net Margin



As previously described, the net revenue required to satisfy the annual fixed costs (including capital carrying costs) of a new gas turbine unit ranges from $80,000 to $105,000 per MW-year. Thus, as shown in Figure 71 and consistent with the previous findings in this section relating to net revenue, the PNM was again nowhere near sufficient to support new entry in 2013. Only in two of the seven years since the rule was implemented has the PNM been sufficient – 2008 and 2011. A significant portion of the net revenue increase in 2008 was associated with extremely inefficient transmission congestion management and inefficient pricing mechanisms associated with the deployment of non-spinning reserves.[14] With these issues addressed in the zonal

13 For 2014 and each subsequent year, ERCOT shall set the PNM threshold at three times the cost of new entry of new generation plants. The PNM threshold for 2014 and each subsequent year will be set to $315,000 per MW-yr based on the analysis prepared by Brattle dated June 1, 2012, unless there is a change identified in the cost of new entry of new generation plants.

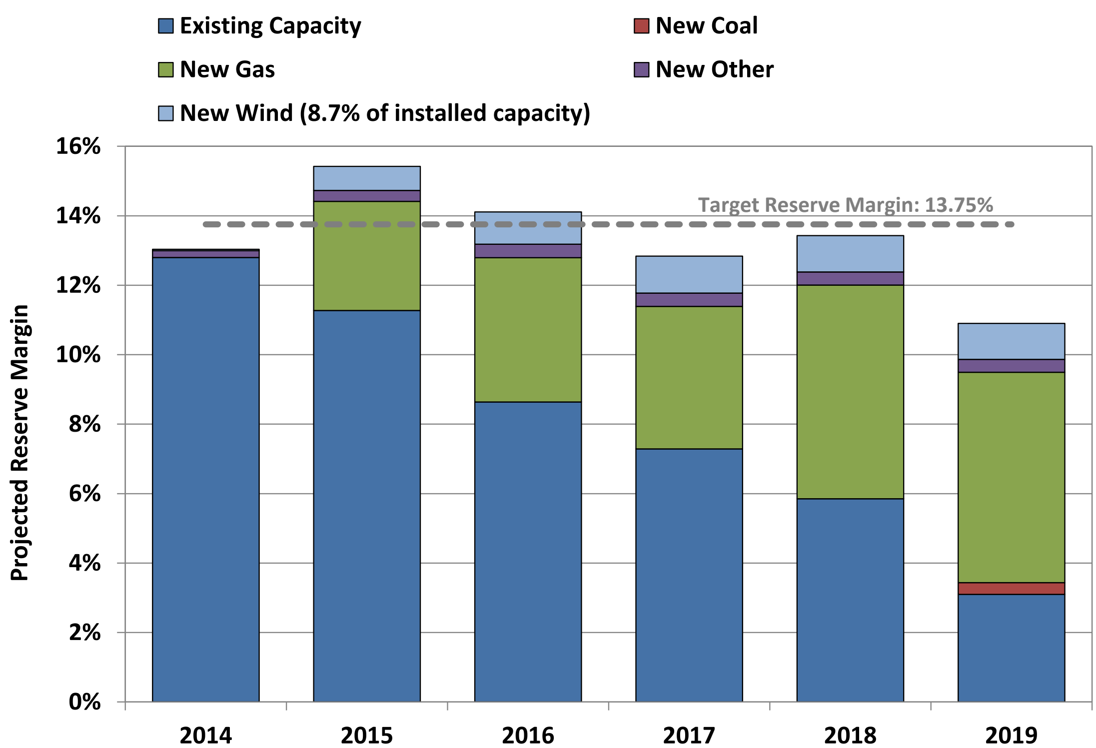
14 See 2008 ERCOT SOM Report at pages 81-87.

market, the PNM dropped substantially in 2009 and 2010. The extreme weather experienced in 2011 was highly anomalous. Hence, although the PNM may have been sufficient to cover the costs of a new combustion turbine in 2011, we would not expect this to be true on a continuous basis into the future.

C. Planning Reserve Margin

The prior subsection discusses and evaluates the economic signals produced by the ERCOT markets to facilitate efficient decisions by suppliers to maintain an adequate base of resources. This subsection summarizes and discusses the current level of capacity in ERCOT, as well as the long-term need for capacity in ERCOT. The figure below shows ERCOT's projection of reserve margins developed prior to the summer of 2014.

Figure 72: Projected Reserve Margins



Source: ERCOT Capacity Demand Reserve Report issued February 2014

Figure 72 above indicates that the region would have a 13.0 percent reserve margin heading into the summer of 2014. After completion of announced generation additions, the reserve margin is expected to reach 15.4 percent in 2015. This increase in expected reserve margin is partially a result of ERCOT's revised load forecasting methodology, which has reduced historical forecasts of load growth. The total quantity of expected future generation additions has also decreased. The bulk of the new capacity being added is natural gas-fired generation, approximately a quarter of which is expansions at existing facilities.

To compare the situation in ERCOT with other regions, Figure 73 provides the anticipated reserve margins for all the American NERC regions for the summer of 2014.[15]

Figure 73: Reserve Margins in Other Regions

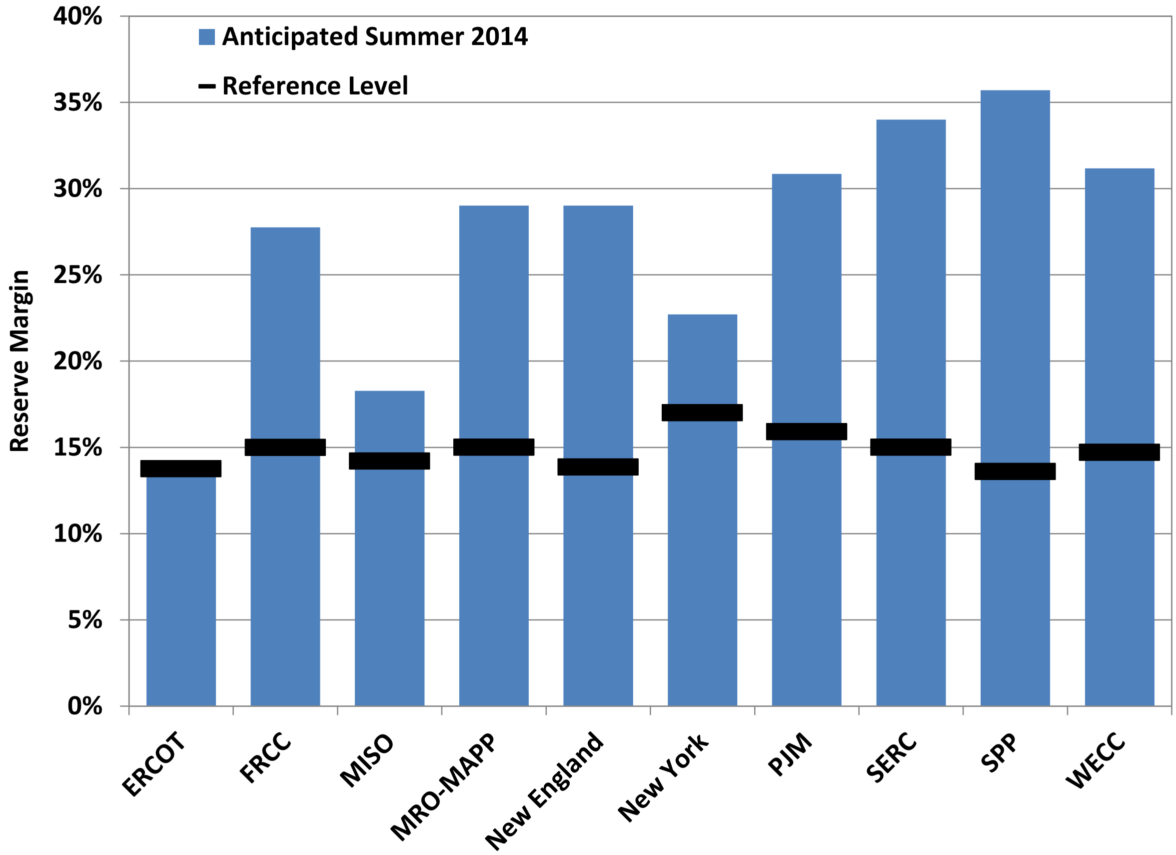


Figure 73 shows that required, or reference level reserve margins center around 15 percent across other regions. These regions run the gamut from traditional bundled, regulated utility service territories to fully competitive, centrally operated wholesale markets. There are large differences in the level of planning reserves expected for the summer of 2014. ERCOT is unique in that its

15 Data from NERC 2013 Long-Term Reliability Assessment (December 2013) available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf

anticipated reserve margin is right at its target level. Even with the forecasted additions, ERCOT is projected to sustain lower reserve margins than all other RTOs, and less than its target reserve margin after 2016. This is not necessarily a problem since the 13.75 percent level is just a target. However, it is nonetheless important to ensure that the ERCOT market is designed to provide adequate economic signals to remain near this target, which is discussed below.

D. Ensuring Resource Adequacy

One of the primary goals of an efficient and effective electricity market is to ensure that over the long term there is an adequate supply of resources to meet customer demand plus any required installed or planning reserves. In a region like ERCOT, where customer requirements for electricity are continually increasing, even with growing demand response efforts, maintaining adequate supply requires capacity additions. To incent these additions the market design must provide revenues such that the marginal resource receives revenues sufficient to make that resource economic. In this context, ‘economic’ includes both a return of, and on capital investment.

Generators earn revenues from three sources: energy prices during non-scarcity, energy prices during scarcity and capacity payments. The capacity payments generators receive in ERCOT are related to the provision of ancillary services. As we described in the discussion of net revenue in a previous subsection, ancillary service payments are a small contributor: $5 - $10 per kW-year. Setting them aside, generator revenue in ERCOT is overwhelmingly derived from energy prices under both scarcity and non-scarcity conditions.

Expectations for energy pricing under non-scarcity conditions are the same regardless of whether payments for capacity exist, or not. In ERCOT, with no capacity payments available, the amount a generator may receive from energy pricing under scarcity conditions must be large enough to provide the necessary incentives for new capacity additions. This will occur when energy prices are allowed to rise substantially at times when the available supply is insufficient to simultaneously meet both energy and minimum operating reserve requirements.

Ideally, energy and reserve prices during shortages should reflect the diminished system reliability under these conditions, which is equal to the increased probability of “losing” load times the value of the lost load. Allowing energy prices to rise during shortages mirrors the outcome expected if loads were able to actively specify the quantity of electricity they wanted and the price they would be willing to pay. The energy-only market design relies exclusively on these relatively infrequent occurrences of high prices to provide the appropriate price signal for demand response and new investment when required. In this way, energy-only markets can provide price signals that will sustain a portfolio of resources to be used in real time to satisfy the needs of the system. However, this portfolio may produce a planning reserve margin that is less than the planning reserve target.

As a general principle, competitive and efficient market prices should be consistent with the marginal cost of the marginal action taken to satisfy the market's demand. In the vast majority of hours, the marginal cost of the marginal action is associated with the dispatch of the last generator required to meet demand. It is appropriate and efficient in these hours for this generator to "set the price". However, this is not true under shortage conditions. When the system is in shortage, the demand for energy and minimum operating reserves cannot be satisfied with the available resources, which will cause the system operator to take one or more of the following actions:

- Sacrifice a portion of the operating reserves by dispatching them for energy;
- Voluntarily curtail load through demand response programs;
- Curtail exports or make emergency imports; or
- Involuntarily curtail load.

A market design that adheres to the pricing principles stated above will set prices that reflect each of these actions. When there is a shortage of supply in the market, the marginal action first taken by the system operator is generally to not satisfy operating reserves requirements (*i.e.*, dispatching reserves for energy). Diminished operating reserves results in diminished reliability, which has a real cost to electricity consumers. In this case, the value of the foregone reserves – which is much higher than the marginal cost of the most expensive online generator – should be reflected in energy prices to achieve efficient economic signals governing investment in generation, demand response and transmission.

Faced with reduced levels of generation development activity coupled with higher than expected loads resulting in diminishing planning reserve margins, the PUCT has devoted considerable effort recently deliberating issues related to resource adequacy. In addition to increasing the system-wide offer cap and adjusting the Peaker Net Margin threshold, as previously described, these deliberations have included the question of whether the planning reserve margin is a target or a minimum requirement. Further, if it is a minimum requirement, whether the energy-only market design can ensure the desired reliability level or whether an alternate market design mechanism may be required. To date, the PUCT continues to support the energy-only nature of the ERCOT market and has directed market modifications to introduce an additional pricing mechanism based on the quantity of available operating reserves.

Regardless of the means by which revenues are produced in a wholesale electricity market, it is fundamental that investment will only occur when the total net revenues expected by the investor are greater than its entry costs, which include profit on its investment. Additionally, these sources of revenue must be available to all resources, both new and existing, in order to facilitate efficient investment, maintenance, and retirement decisions by all suppliers.

In an energy only market, the primary source of such revenue is the net revenues received during periods of shortage. Expectations about both the magnitude of the energy price during shortage conditions and the frequency of shortage conditions are the primary means to attract new investment in an energy-only market. If the expected revenues are not high enough to facilitate enough investment to satisfy the planning reserve target, one option is to increase the shortage pricing levels to levels that substantially exceed the expected value of lost load. As the planning reserve levels grow, however, the frequency of shortages will tend to drop sharply, which can make it difficult to use this means to meet planning reserve requirements.

Most other competitive electricity markets do not rely solely on shortage pricing to generate sufficient revenue to support the capacity additions necessary to satisfy their planning reserve requirements. They employ capacity markets to competitively generate capacity payments over the year that are made to suppliers in return for meeting defined capacity obligations. Capacity prices and associated payments vary monthly or annually based on long-term planning reserve levels, independent of the real-time supply and demand conditions. These capacity markets are designed to ensure that a specified planning reserve margin is achieved.

With the implementation of the nodal market, more reliable and efficient shortage pricing has been achieved by establishing pricing rules that recognize when operating reserve shortages exist and allowing energy prices to rise automatically. Figure 16 on page 16 clearly shows this relationship between increasing prices as operating reserve levels decline. This approach is more reliable than what existed in the previous zonal market because it is not dependent upon the submission of high-priced offers by small market participants to be effective. It is also more efficient during the vast majority of time in which shortage conditions do not exist because it is not necessary for market participants to effectively withhold lower cost resources by offering relatively small quantities at prices dramatically higher than their marginal cost. At times when there is insufficient capacity available to meet both energy and minimum operating reserve requirements, all available capacity will be dispatched and the clearing price will rise in a predetermined manner to a maximum of the system-wide offer cap.

In conjunction with the offer floors for non-spinning reserves, the Power Balance Penalty Curve ("PBPC") and the offer floors for up regulation and responsive reserve provided from generation resources defines the relationship between the quantity of operating reserve deficiency and the resulting energy price. The PBPC was modified during 2013 in conjunction with the increase in the system-wide offer cap to $5,000 per MWh. This curve is shown below in Table 4.

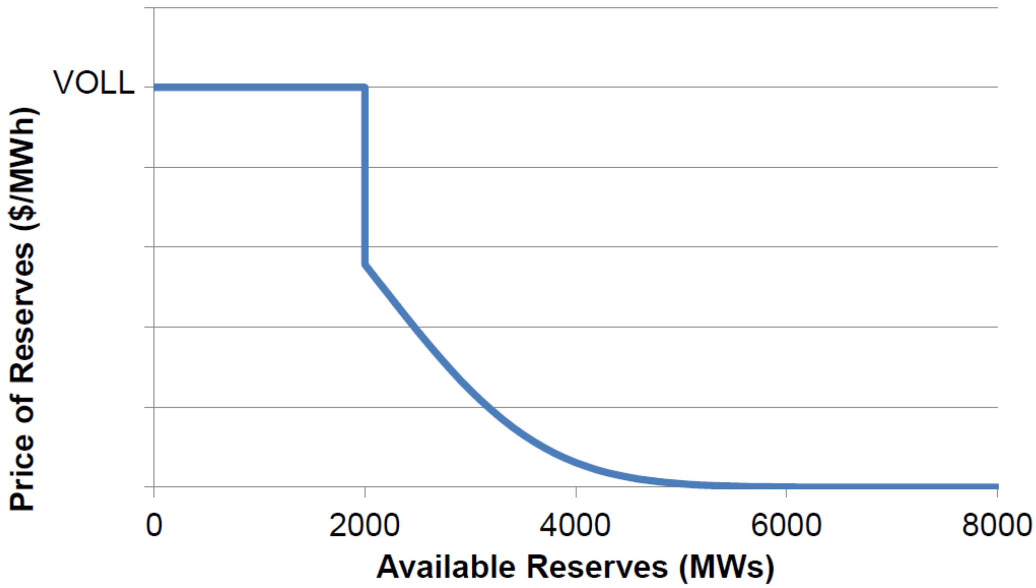
Under the current curve, if operating reserves are deficient by 5 MW or less, the energy price will be $250 per MWh. If the deficiency is greater than 150 MW but less than 200 MW, the energy price would be set at $4,000 per MWh. Once the 200 MW from the PBPC is exhausted, the only remaining energy available is from generator provided responsive reserves and up regulation reserves. Since energy provided by these services is required to be offered at the system-wide offer cap, real-time energy prices will be set at that level.

Table 4: Power Balance Penalty Curve

Maximum Operating Reserve Deficiency (MW)	Energy Price ($ per MWh) Current Curve
5	$250
10	$300
20	$400
30	$500
40	$1,000
50	$2,250
100	$3,000
150	$3,500
200	$4,000
>200	$5,001

The current relationship between operating reserve deficiency and energy prices defined by the PBPC and the operating reserve offer floors has no real analytic basis other than having its end anchored by the system-wide offer cap. As directed by the PUCT, a more analytically rigorous approach will be introduced to complement the PBPC. The Operating Reserve Demand Curve ("ORDC") is an operating reserve pricing mechanism that reflects the loss of load probability ("LOLP") at varying levels of operating reserves multiplied by the value of lost load ("VOLL"). Selected as an easier to implement alternative to real-time co-optimization of energy and ancillary services, the ORDC will create a new payment mechanism for online and offline reserves. As the quantity of reserves decreases, payments will increase. As conceptualized below in Figure 74, once available reserve capacity drops to 2000MW, payment for reserve capacity will rise to VOLL, or $9000 per MWh.

Figure 74: Operating Reserve Demand Curve



These changes will likely increase the net revenues a new investor would expect during shortage conditions. Whether they will be sufficient to maintain capacity margins near the target reserve margin is unknown, which will require continued monitoring and evaluation. If it does not, the reliability implications of allowing the planning reserve margin to fall will need to be assessed and other changes in the ERCOT markets to improve long-run economic signals may need to be considered.

With regard to the ORDC, we are also concerned that prices resulting from ORDC will rise to levels approaching the VOLL when the available reserves are at levels where the LOLP is less than 1.0 and involuntary load curtailment is not imminent, which may facilitate inefficient actions by participants when these conditions are probable. We will evaluate this concern going forward as the ORDC is fully implemented.

Finally, we continue to recommend that ERCOT implement a system to co-optimize energy and ancillary services because this would improve the efficiency of ERCOT's dispatch, more fully utilize its resources, and allow for improvements in its shortage pricing.

E. Demand Response Capability

Demand response is a term that broadly refers to actions that can be taken by end users of electricity to reduce load in response to instructions from ERCOT or in response to certain market or system conditions. The ERCOT market allows participants with demand-response capability to provide energy and reserves in a manner similar to a generating resource. The ERCOT Protocols allow for loads to actively participate in the ERCOT administered markets as Load Resources. Additionally, loads may participate passively in the market by simply adjusting consumption in response to observed prices. Unlike active participation in ERCOT administered markets, passive demand response is not directly tracked by ERCOT.

ERCOT allows qualified load resources to offer responsive reserves and non-spinning reserves into the day-ahead ancillary services markets. Those providing responsive reserves must have high set under-frequency relay equipment, which enables the load to be automatically tripped when the frequency falls below 59.7 Hz, which will typically occur only a few times in each year. Deployments of non-spinning reserves occur much more frequently. To date, load resources have shown a clear preference for providing responsive reserve service.

As of December 2013, approximately 2,950 MW of capability were qualified as Load Resources. Figure 75 shows the amount of responsive reserves provided from load resources on a daily basis in 2013. The high level of participation by demand response in the ancillary service markets sets ERCOT apart from other operating electricity markets. For reliability reasons the maximum amount of responsive reserves that can be provided by load resources was limited to 1,150 MW until April 2012. At that time, the limitation on load resources providing responsive reserve increased to 1,400 MW, corresponding with the increase in total responsive reserve requirements.

Figure 75: Daily Average of Responsive Reserves provided by Load Resources

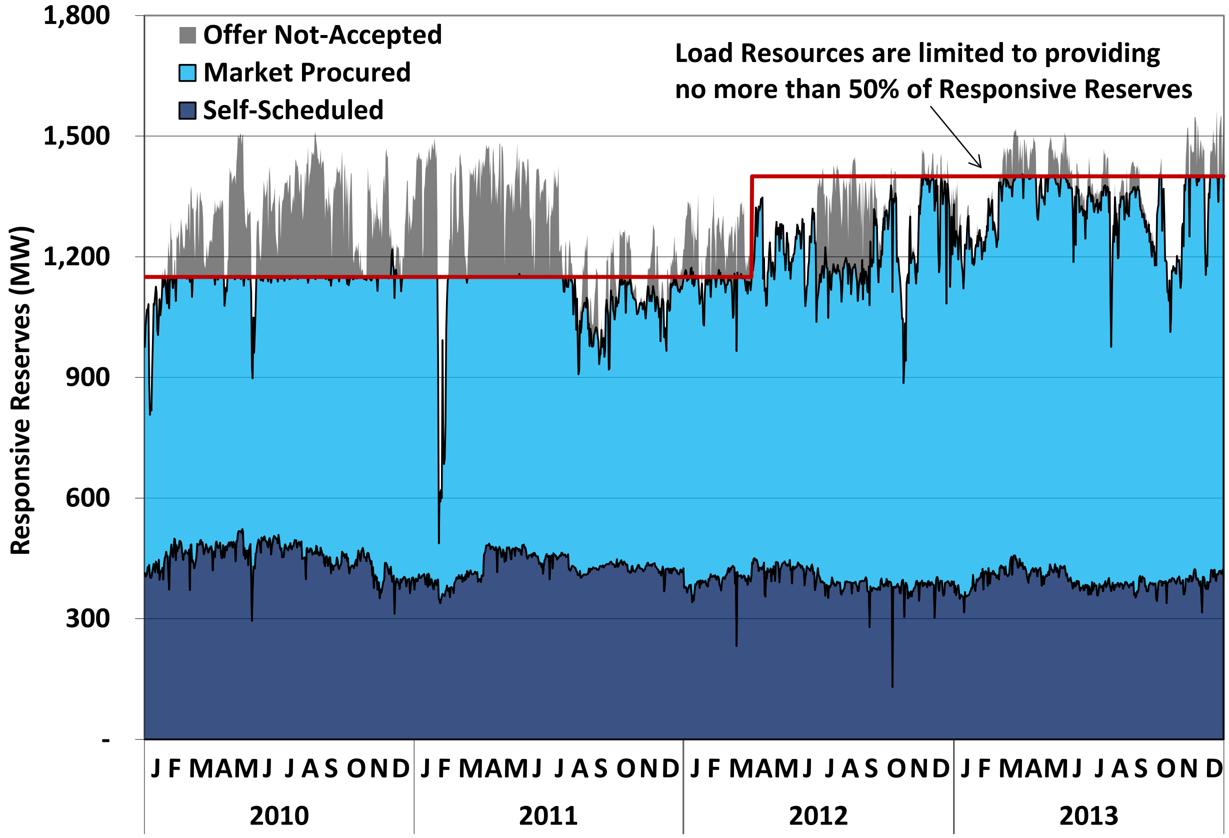


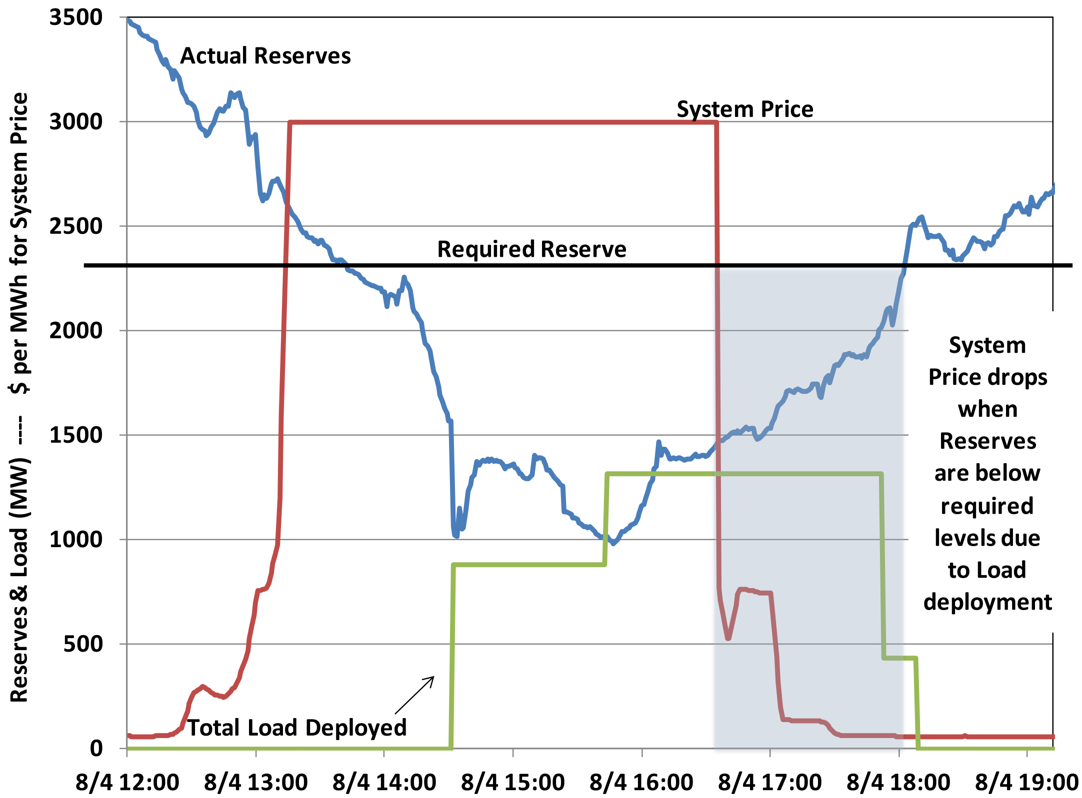
Figure 75 shows that it took a few months after implementing the increased requirement for the amount of offers by load resources to routinely reach this level. During 2011 there was a significant reduction in loads offering to provide responsive reserve during early February and again starting in mid-July. Both of these times corresponded with expected high real-time prices. Since load resources provide capacity by reducing their consumption, they have to actually be consuming energy to be eligible to provide the capacity service. During periods of expected high prices the price paid for the energy can exceed the value received from providing responsive reserves.

Pricing During Load Deployments

During times when there are shortages of supply offers available for dispatch and Responsive Reserves are deployed, that is, converted to energy as one of the last steps taken before shedding firm load, the value of the foregone reserves – which is much higher than the marginal cost of the most expensive online generator – should be reflected in energy prices to achieve efficient economic signals governing investment in generation, demand response and transmission.

Unfortunately, ERCOT's dispatch software does not recognize that load has been curtailed, and computes prices based on supplying only the remaining load. A good example of this situation occurred on August 4, 2011. Figure 76 displays available reserves and the system price for that afternoon and shows that even though reserves were below required levels, system price dropped to $60 per MWh. At this level prices are being set based on supply offers and do not reflect the value of the load that is being curtailed to reliably serve the remaining system demand.

Figure 76: Pricing During Load Deployments



In 2014 ERCOT will take the first step toward including the actions taken by load during the real-time energy market. The first phase of "Loads in SCED" will allow those controllable loads that can respond to 5 minute dispatch instructions to specify the price at which they no longer wish to consume. Although an important first step, there are very few loads that can respond to price in this manner.

We recommend that ERCOT implement system changes that will ensure that ***all*** demand response that is actively deployed by ERCOT be able to set the price at the value of load at times when such deployments are necessary to reliably serve the remaining system demand. This includes load resources and Emergency Response Service (ERS) providers being deployed for the services they contracted to provide or when firm load is involuntarily curtailed. It may be possible to integrate load bids and emergency resources in the real-time dispatch software and allow them to set prices when they are effectively marginal. Alternatively, it may be adequate to address this concern through administrative shortage pricing rules.

VI. 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). We examine market structure by using a pivotal supplier analysis that indicates the frequency with which a supplier was pivotal increased at higher levels of demand. This is consistent with observations in prior years. This section also includes a summary of the Voluntary Mitigation Plans in effect during 2013. To evaluate participant conduct we estimate measures of physical and economic withholding. We examine withholding patterns relative to the level of demand and the size of each supplier's portfolio. In this discussion we single out the conduct of one participant that was noticeable for being outside the bounds of competitive expectations. However, the behavior is allowed under current PUCT Rules and its impact on prices was minimal.

Based on these analyses, we find the overall performance of the ERCOT wholesale market to be competitive in 2013.

A. Structural Market Power Indicators

We analyze market structure by using the Residual Demand Index ("RDI"), a statistic that measures the percentage of load that could not be satisfied without the resources of the largest supplier. The RDI is used to measure the percentage of load that cannot be served without the resources of the largest supplier, assuming that the market could call upon all committed and quick-start capacity owned by other suppliers.[16] When the 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 required to serve the load as long as the resources of its competitors are available.

The RDI is a useful structural indicator of potential market power, although it is important to recognize its limitations. As a structural indicator, it does not illuminate actual supplier behavior to indicate whether a supplier may have exercised market power. The RDI also does not indicate

[16] For the purpose of this analysis, "quick-start" includes off-line simple cycle gas turbines that are flagged as on-line in the current operating plan with a planned generation level of 0 MW that ERCOT has identified as capable of starting-up and reaching full output after receiving a dispatch instruction from the real-time energy market.

whether it would have been profitable for a pivotal supplier to exercise market power. However, it does identify conditions under which a supplier would have the ability to raise prices significantly by withholding resources.

Figure 77 shows the RDI relative to load for all hours in 2013. The trend line indicates a strong positive relationship between load and the RDI. This analysis shown below is done at the QSE level because the largest suppliers that determine the RDI values own a large majority of the resources they are offering. It is possible that they also control other capacity through bilateral arrangements, although we do not know whether this is the case. To the extent that the resources scheduled by the largest QSEs are not controlled by or provide revenue to the QSE, the RDIs will tend to be slightly overstated.

Figure 77: Residual Demand Index

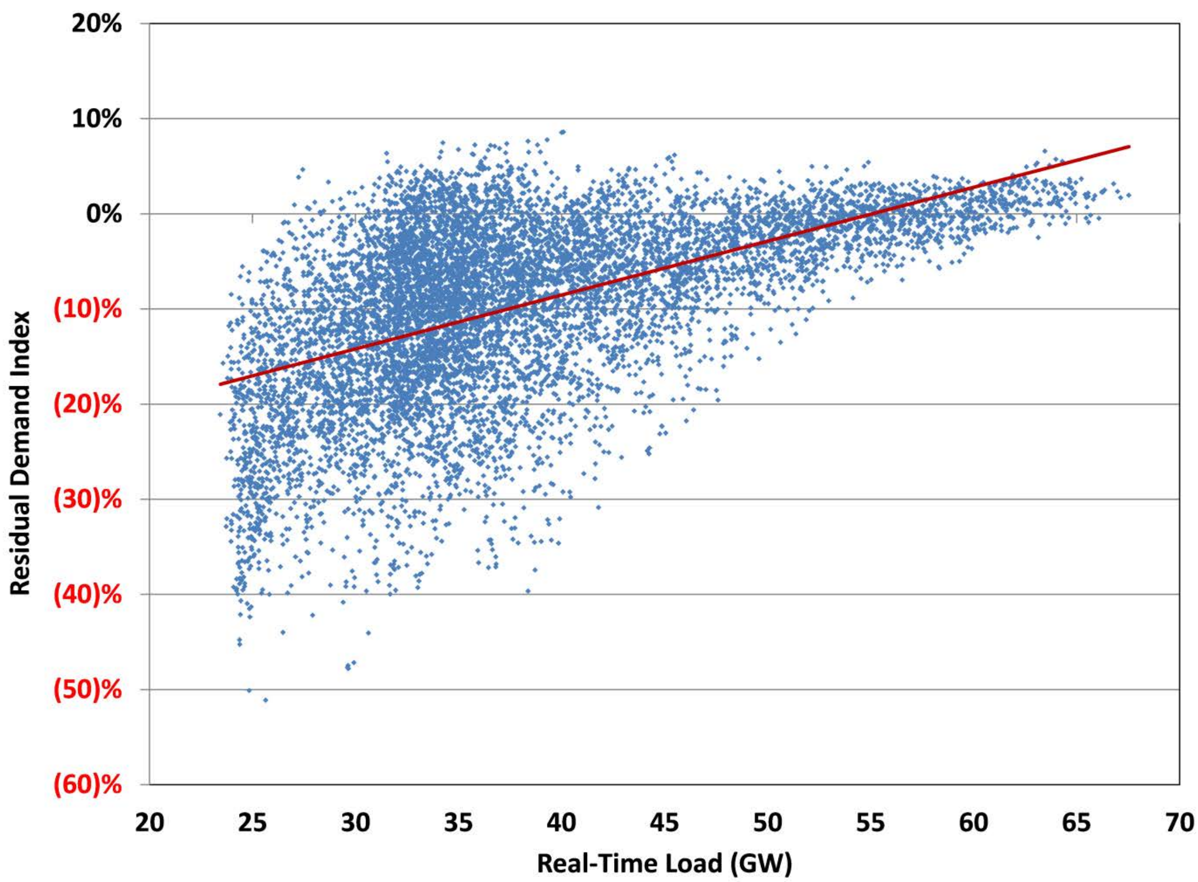
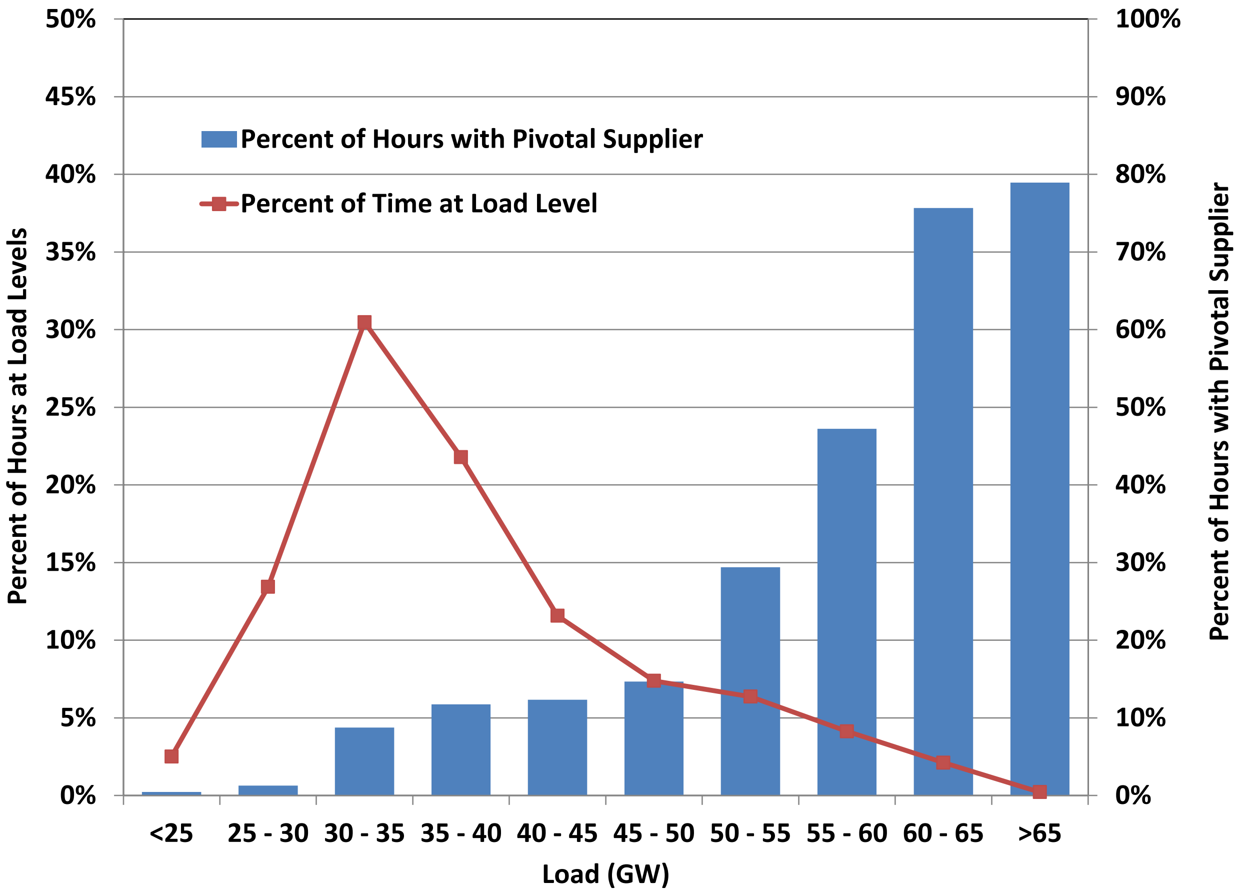


Figure 78 below summarizes the results of our RDI analysis by displaying the percentage of time at each load level there was a pivotal supplier. At loads greater than 65 GW there was a pivotal supplier 79 percent of the time. The figure also displays the percentage of time each load level occurs. Combining these values we find that there was a pivotal supplier in approximately 14 percent of all hours of 2013, which indicates that market power is a potential concern in ERCOT and underscores the need for the current mitigation measures that address it.

Figure 78: Pivotal Supplier Frequency by Load Level



It is important to recognize that inferences regarding market power cannot be made solely from this data. Bilateral contract obligations can affect a supplier's potential market power. For example, a smaller supplier selling energy in the real-time energy market and through short-term bilateral contracts may have a much greater incentive to exercise market power than a larger supplier with substantial long-term sales contracts. The RDI measure 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.

Voluntary Mitigation Plans

Voluntary Mitigation Plans (“VMP”) existed for three market participants – NRG, Calpine and GDF SUEZ – during 2013. Generation owners are motivated to enter into VMPs because adherence to a plan approved by the commission constitutes an absolute defense against an allegation of market power abuse through economic withholding with respect to behaviors addressed by the plan. This 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 PUCT SUBST. R. 25.503(g)(7).

It is our position that VMPs should promote competitive outcomes and prevent abuse of market power in the ERCOT real-time energy market through economic withholding. The same restrictions are not required in forward energy markets (e.g., the ERCOT day-ahead market) because the price in forward energy markets is derived from the real-time energy prices. Because the forward energy markets are voluntary and the market rules do not inhibit arbitrage between the forward energy markets and the real-time energy market, competitive outcomes in the real-time energy market serve to discipline the potential abuse of market power in the forward energy markets.

The plan approved for NRG in June 2012 allows the company to offer some of its capacity at prices up to the system-wide offer cap. Specifically, up to 12 percent of the difference between the high sustained limit and the low sustained limit for each natural gas-fired unit (5 percent for each coal/lignite unit) may be offered no higher than the higher of $500 per MWh or 50 times the natural gas price. Additionally, up to 3 percent of the difference between the high sustained limit and the low sustained limit for each natural gas-fired unit may be offered no higher than the system-wide offer cap. The amount of capacity covered by these provisions would be less than 500 MW.

Calpine’s VMP was approved in March of 2013. Because their generation fleet is entirely fueled by natural gas, the details of Calpine’s plan are somewhat different that NRG’s. Calpine may offer up to 10 percent of their portfolio's dispatchable capacity at prices up to $500 per MWh. Additionally, Calpine may offer up to 5 percent of their portfolio's dispatchable capacity at prices no higher than the system-wide offer cap. The amount of capacity covered by these provisions would also be less than 500 MW.

Allowing offers up to these high levels is intended to accommodate potential legitimate fluctuations in marginal cost that may exceed the base offer caps, such as operational risks, short-term fluctuations in fuel costs or availability, or other factors. However, both NRG's and Calpine's VMPs contains a requirement that these offers, if offered in any hour of an operating day, must be offered in the same price/quantity pair for all hours of the operating day. This provision, along with the quantity limitations, significantly reduces the potential that the VMPs will allow market power to be exercised.

The final key element in these two VMPs is the timing of termination. The approved VMPs for NRG and Calpine may each be terminated after three business days' notice. PURA §39.157(a) 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..." The exercise of market power may not rise to the level of an abuse of market power if it does not unreasonably impair competition, which would involve profitably raising prices significantly above the competitive level for a significant period of time. Thus, although the offer thresholds provided in the VMP are designed based on experience 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 rather than persisting and rising to the level of an abuse of market power.

The VMP for GDF SUEZ was approved in March 2013 and confirmed that the amount of capacity in their portfolio does not exceed 5 percent of installed capacity in ERCOT. Given that their generation portfolio does not exceed the threshold set in P.U.C Subst. R. 25.504 (c), GDF SUEZ is deemed not to have ERCOT-wide market power, and therefore has "an absolute defense against an allegation of an abuse of market power through economic withholding with respect to real-time energy offers up to and including the system-wide offer cap."[17]

Although 5 percent of total ERCOT capacity may seem like a small amount, the potential market impacts of a market participant whose size is just under the 5 percent threshold choosing to exercise flexibility and offering a significant portion of their fleet at very high prices could be large.

The figure below shows the amount of surplus capacity available in each hour of every day during 2011, 2012 and 2013. For this analysis, surplus capacity is defined as online generation plus any offline capacity that was available day ahead, plus DC Tie imports (minus exports), minus responsive reserves provided by generation and regulation up capacity, minus load. Over the past three years there were 13 hours with no surplus capacity, the large majority occurring in 2011. These correspond to times when ERCOT was unable to meet load and maintain all operating reserve obligations.

Currently, the 5 percent "small fish" threshold is roughly 4,000 MW, as indicated by the red line in Figure 79. There were 465 hours over the past three years with less than 4,000 MW of surplus capacity. During these times a large "small fish" would have been pivotal and able through their offers to increase the market clearing price, potentially as high as the system-wide offer cap.

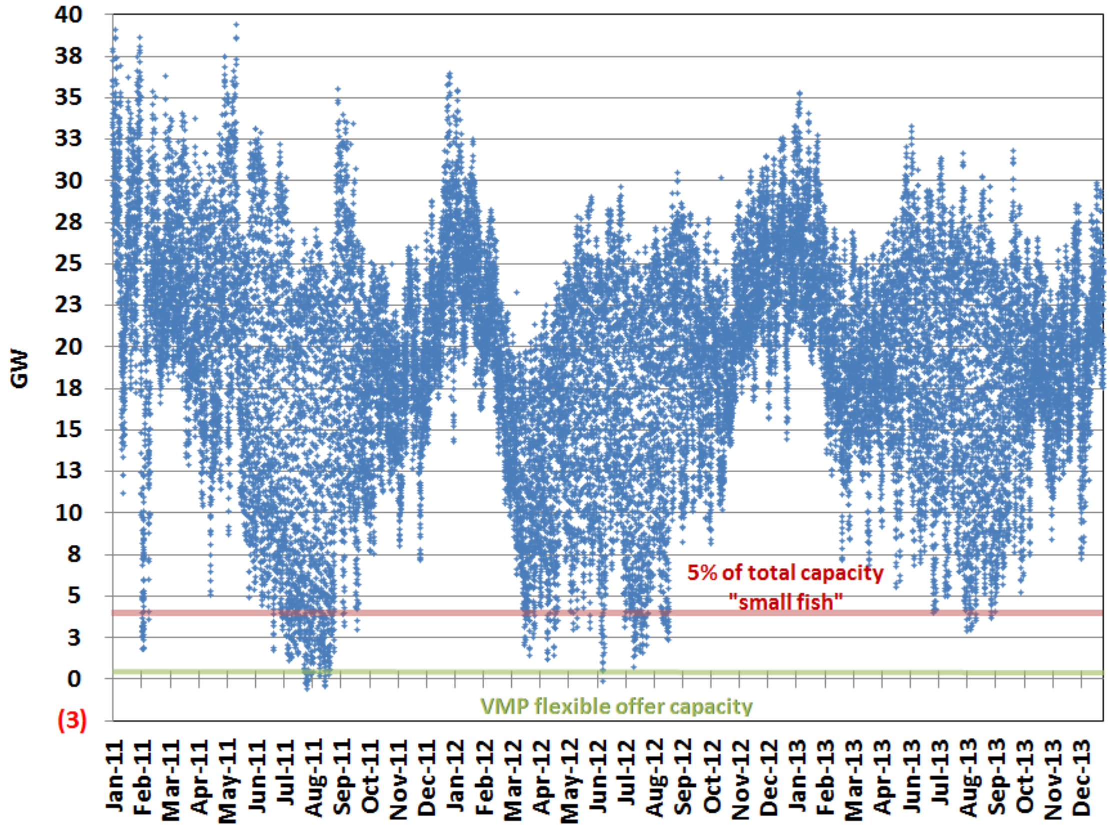
The effects of such actions became much more pronounced after June 21, 2013 when changes to real-time mitigation measures went into effect. These changes narrowed the scope of mitigation addressing the previously discussed issue where mitigation measures were being applied much more broadly than intended or necessary in the ERCOT real-time energy market.[18] Although "small fish" market participants have always been allowed to offer all of their capacity at prices up to the system-wide offer cap, the effect on market outcomes of a large "small fish" offering

[17] Order & Settlement Agreement and Voluntary Mitigation Plan Pursuant to PURA §15.023(f) and P.U.C. SUBST. R. 25.504(e), page 10, filed March 28, 2013, in Docket 41276

[18] Refer to Section I.F, Mitigation at page 20.

substantial quantities at high prices became more noticeable after the scope of mitigation was narrowed.

Figure 79: Surplus Capacity



The next subsection evaluates the competitive conduct of all suppliers in ERCOT, including the small fish.

B. Evaluation of Supplier Conduct

The previous subsection presented a structural analysis that supports inferences about potential market power. In this subsection we evaluate 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 we evaluate the “output gap” to detect economic withholding.

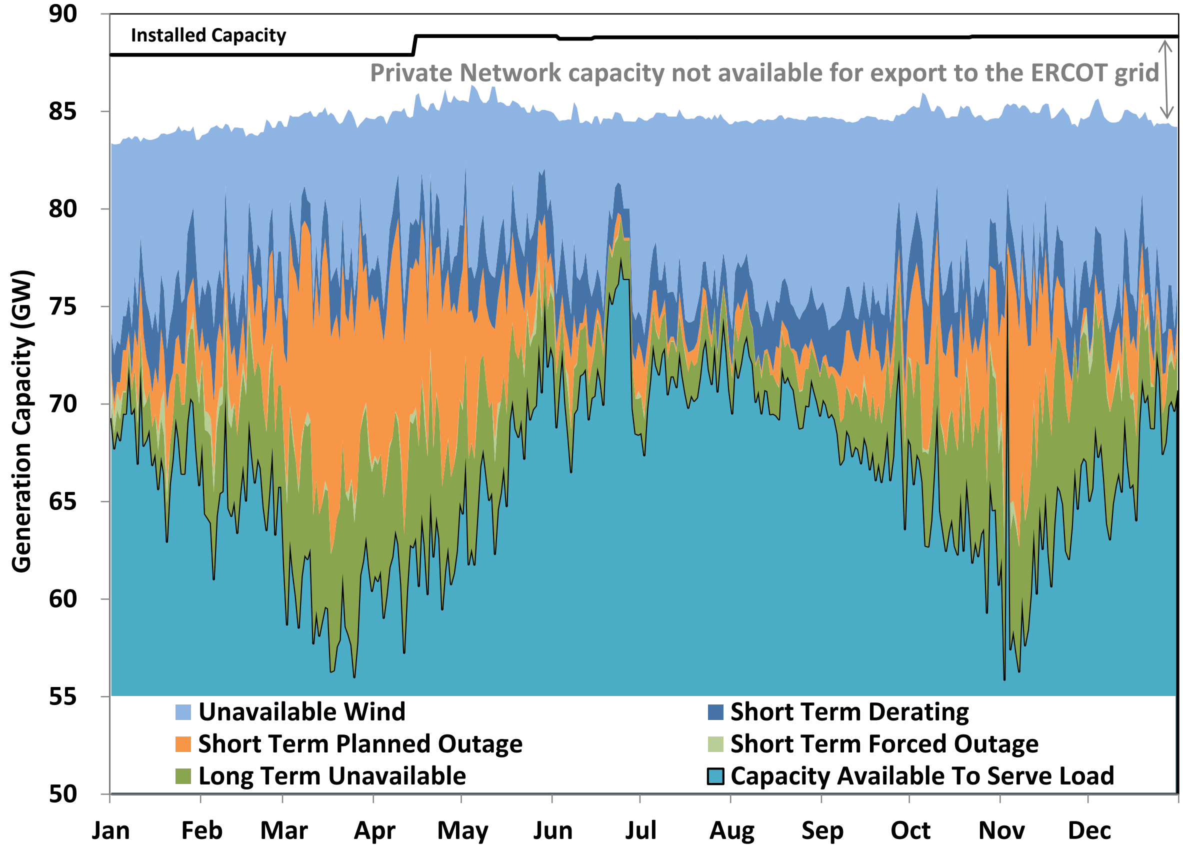
In a single-price auction like the real-time energy market, suppliers may attempt to exercise market power by withholding resources. The purpose of withholding is to cause more expensive resources to set higher market clearing prices, allowing the supplier to profit on its other sales in the real-time energy 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. The strategy is profitable only if the withholding firm's incremental profit due to higher price is greater than the lost profit from the foregone sales of its withheld capacity.

1. Generation Outages and Deratings

A substantial portion of the installed capability is frequently unavailable due to generator outages and deratings. Due to data limitations on outages, we must infer what type of outage is occurring. To do this, we start with the unit status information communicated to ERCOT on a continuous basis. For those units with a status of OUT, meaning they are unavailable, we then cross check to see if an outage had been scheduled. If there is a corresponding scheduled outage, we consider the unit on planned outage. If not, it is considered to be a forced outage. We further define derated capacity as the difference between the summertime maximum capability of a generating resource and its actual capability as communicated to ERCOT on a continuous basis. It is very common for generating capacity to be partially derated (e.g., by 5 to 10 percent) because the resource cannot achieve its installed capability level due to technical or environmental factors (e.g., component equipment failures or ambient temperature conditions). It is rare for wind generators to produce at their installed capacity rating due to variations in available wind input. Because such a large portion of derated capacity is related to wind generation we show it separately. In this subsection, we evaluate long-term and short-term deratings to inform our evaluation of ERCOT capacity levels.

Figure 80 shows a breakdown of total installed capability for ERCOT on a daily basis during 2013. This analysis includes all in-service and switchable capacity. From the total installed capacity we subtract: (a) capacity from private networks not available for export to the ERCOT grid, (b) wind capacity not available due to 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 capacity available to serve load.

Figure 80: Reductions in Installed Capability



Outages and deratings of non-wind generators fluctuated between 3 and 21 GW, as shown in Figure 80, while wind unavailability varied between 3 and 11 GW. Short term planned outages were largest in March, April, October and November and small during the summer, which are consistent with expectations. Short term forced outages also declined during the summer. Short term deratings peaked during October.

The quantity of long term (greater than 30 days) unavailable capacity, peaked in March at nearly 8.4 GW, reduced to 1.5 GW during the summer months and increased to almost 7.7 GW in November. This pattern reflects the choice by some owners to mothball certain generators on a seasonal basis, maintaining the units' operational status only during the high load summer season when more costly units have a higher likelihood of operating.

The next analysis focuses specifically on short-term planned and forced outages and deratings because these classes of outages and deratings are the most likely to be used to physically withhold units in an attempt to raise prices. Figure 81 shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2013.

Figure 81: Short-Term Outages and Deratings

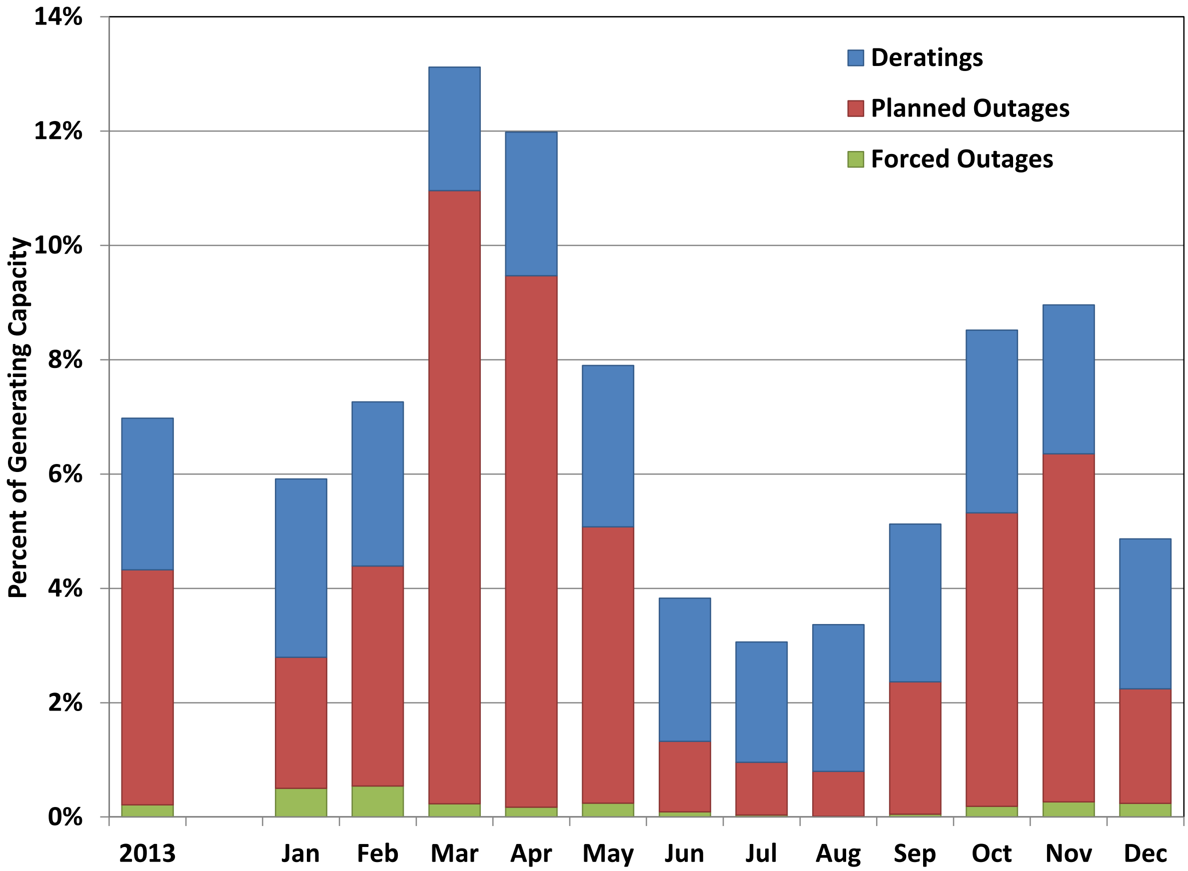


Figure 81 shows that total short-term deratings and outages were as large as 13.1 percent of installed capacity in October, and averaged a little above 3 percent during the summer. Most of this fluctuation was due to anticipated planned outages. The amount of capacity unavailable during 2013 averaged slightly more than 7 percent of installed capacity. This is an increase from 2012, when the amount was greater than 5 percent and 2011 when the value was greater than 6 percent. Similar metrics from the zonal market were consistently above 15 percent. The large disparity between values from the zonal and nodal markets is likely due to combined effects of improved incentives in the nodal market and the lack of unit specific data available from zonal market systems. Overall, the fact that outages and deratings are lowest during the summer when load is expected to be highest is consistent with expectations in a competitive market.

2. Evaluation of Potential Physical Withholding

Physical withholding occurs when a participant makes resources unavailable for dispatch that are otherwise physically capable of providing energy and that are economic at prevailing market prices. This can be done either by derating a unit or declaring it 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 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 RDI results shown in Figure 77 and Figure 78 indicate that the potential for market power abuse rises at higher load levels as the frequency of positive RDI values increases. Hence, if physical withholding is occurring, we 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 since their output is generally most profitable in peak periods.

Figure 82 shows the average relationship of short-term deratings and forced outages as a percentage of total installed capacity to real-time load level for large and small suppliers. Portfolio size is important in determining whether individual suppliers have incentives to withhold available resources. Hence, the patterns of outages and deratings of large suppliers can be usefully evaluated by comparing them to the small suppliers' patterns.

Long-term deratings are not included in this analysis because they are unlikely to constitute physical withholding given the cost of such withholding. 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 82: Outages and Deratings by Load Level and Participant Size
June to August, 2013

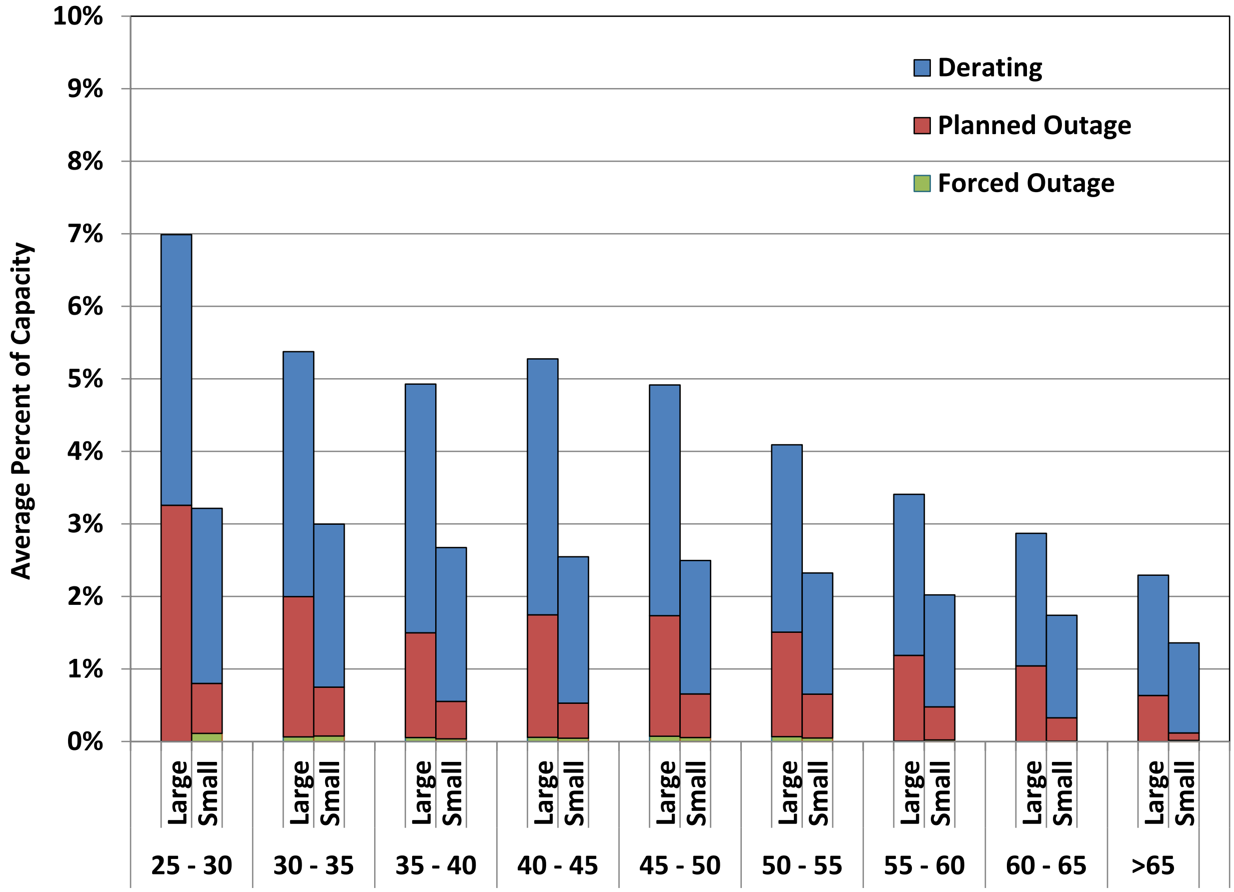


Figure 82 suggests that as demand for electricity increases, all market participants tend to make more capacity available to the market. For large suppliers, the combined short-term derating and forced outage rates decreased from 7 percent at low demand levels to approximately 2 percent at load levels above 65 GW. These are larger than for small suppliers at all load levels, which at first look may be seen as a competitive concern. However, large supplier outage rates are roughly the same as they were in 2012, whereas small supplier outage rates reduced nearly 50 percent. We attribute this greater reduction in small supplier outage rates to the heightened impact that competitive forces exert on small suppliers. Given the overall low magnitude of outage rates for all suppliers, these results raise no competitiveness concerns.

3. Evaluation of Potential Economic Withholding

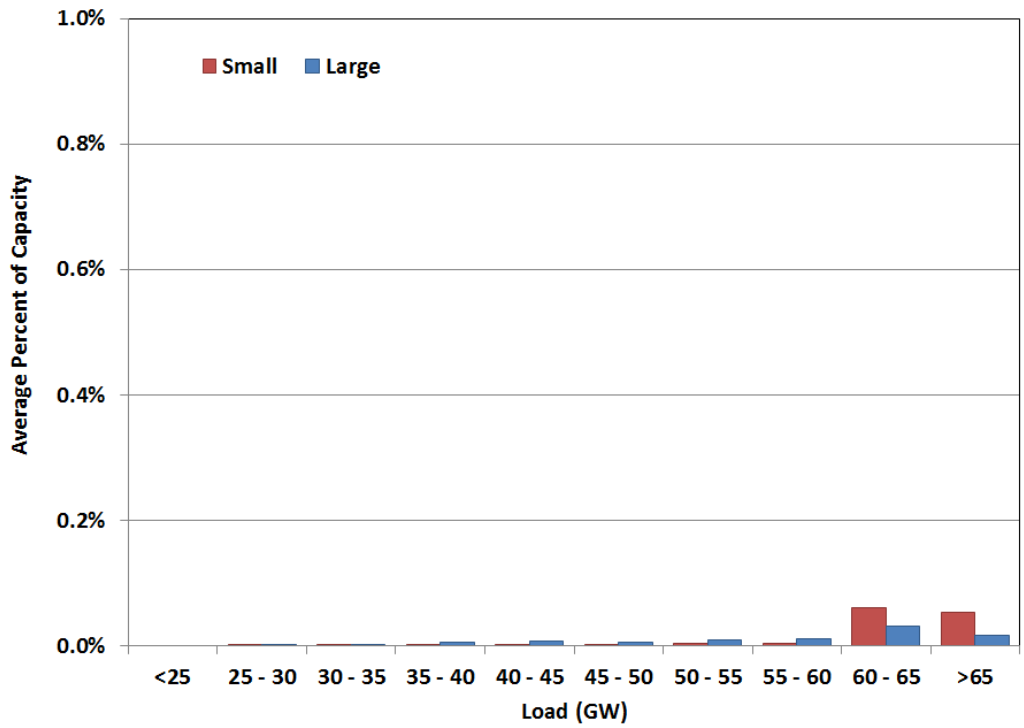
To complement the prior analysis of physical withholding, this subsection evaluates potential economic withholding by calculating an "output gap". The output gap is defined as the quantity of energy that is not being produced by in-service capacity even though the in-service capacity is economic by a 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.

Resources are considered for inclusion in the output gap when they are committed and producing at less than full output. Energy not produced from committed resources is included in the output gap if the real-time energy price exceeds by at least $50 per MWh that unit's mitigated offer cap, which serves as an estimate of the marginal production cost of energy from that resource.

Before presenting the results of the Output Gap analysis, a description of the two-step aspect of ERCOT's dispatch software is required. In the first step, the dispatch software calculates output levels (Base Points) and associated locational marginal prices using the participants' offer curves and only considering 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 to be 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 output levels for each generator, taking all transmission constraints into consideration.

If a market participant has sufficient market power, it might raise its offer in such a way to increase the reference price in the first step. Although in the second step the offer appears to be mitigated, the market participant has still influenced the market price. This output gap is measured by the difference between the capacity level on a generator's original offer curve at the first step reference price and the capacity level on the generator's cost curve at the first step reference price. However, this output gap is only indicative because no output instructions are sent based on the first step. It is only used to screen out whether a market participant is withholding in a manner that may influence the reference price.

Figure 83: Incremental Output Gap by Load Level and Participant Size – Step 1

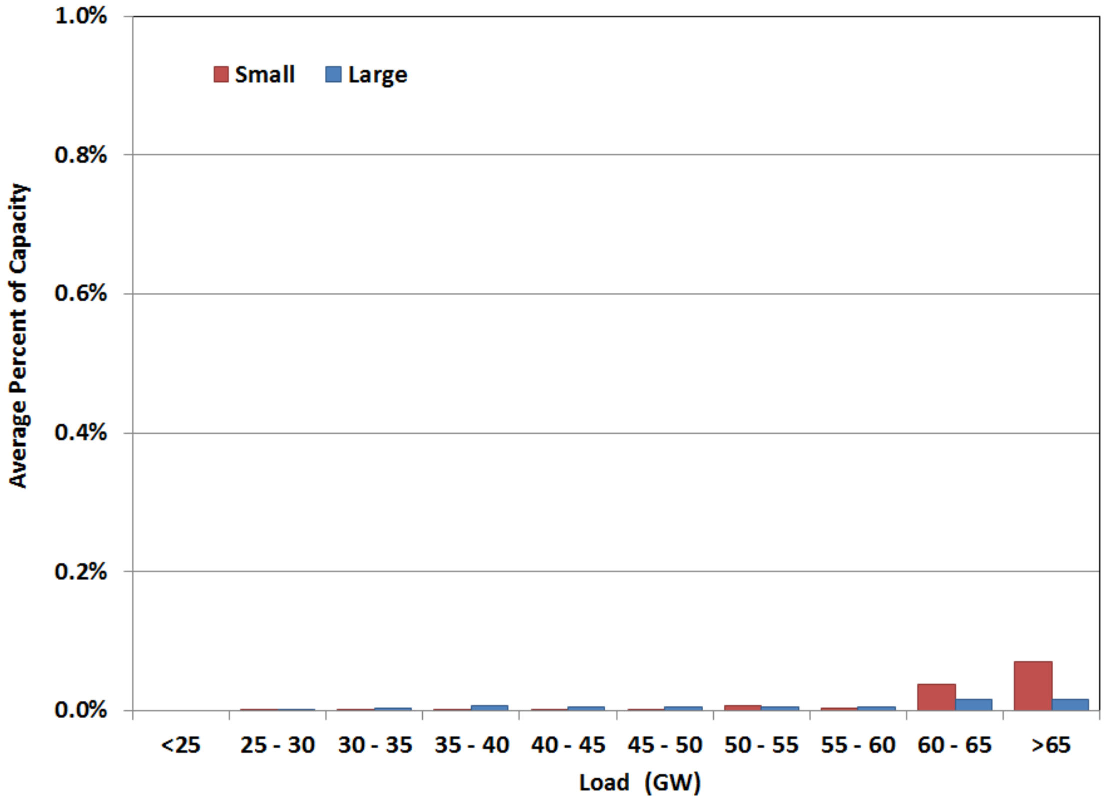


The results of the analysis shown in Figure 83 indicate small quantities of capacity at the highest loads that were potentially economically withheld by small suppliers.

Figure 84 shows the ultimate output gap, measured by the difference between a unit's operating level and the output level had the unit been competitively offered to the market. In the second step of the dispatch, the after-mitigation offer curve is used to determine dispatch instructions and locational prices. As previously illustrated, even though the offer curve is mitigated there is still the potential for the mitigated offer curve to be increased as a result of a high first step reference price being influenced by a market participant raising prices.

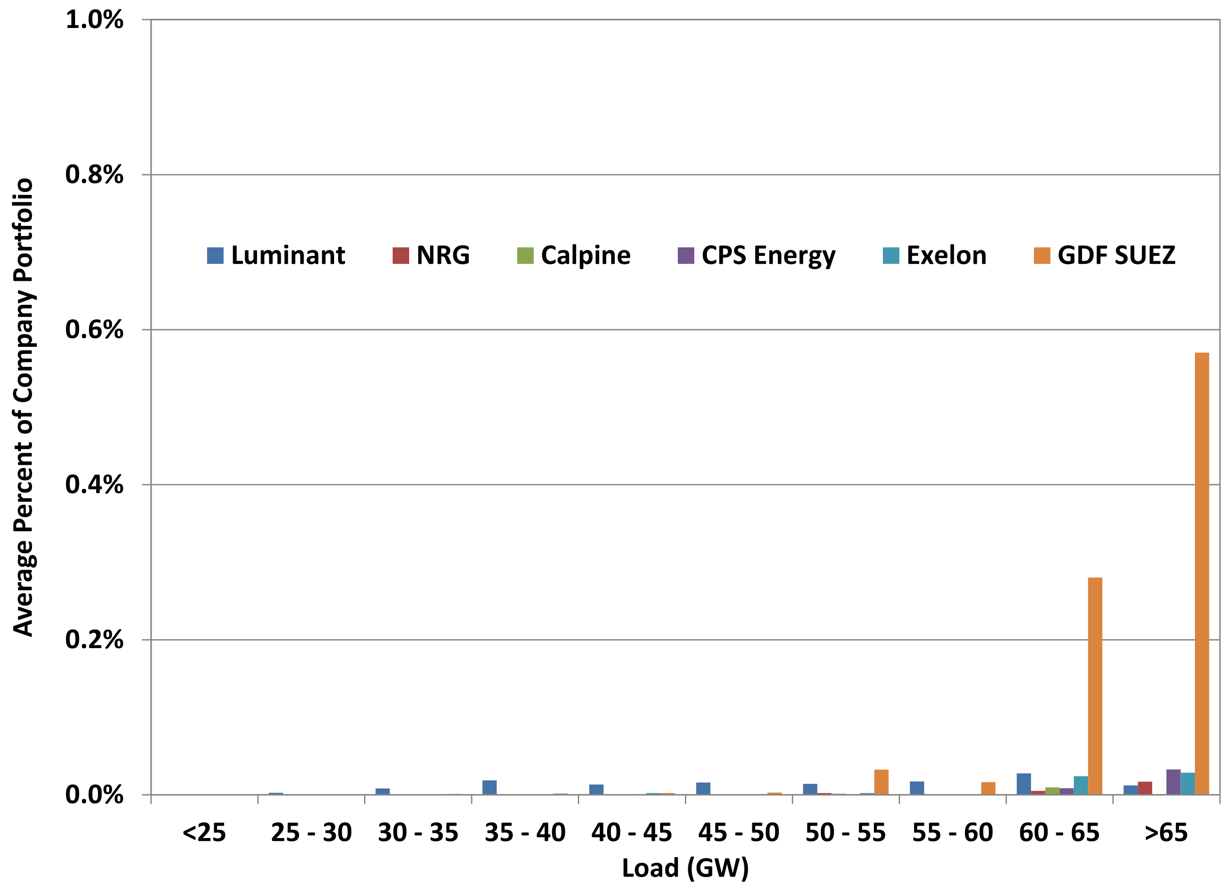
Similar to the previous analysis, Figure 84 shows small, but noticeable quantities of capacity at the highest loads that would be considered part of this output gap from small suppliers.

Figure 84: Incremental Output Gap by Load Level and Participant Size – Step 2



To evaluate these quantities in more detail, we provide a comparison of the output gap of several of the largest suppliers in ERCOT in Figure 85. This figure shows that the offering conduct of GDF SUEZ stands apart from the others. At the very highest load levels, up to 400 MW of GDF SUEZ's resources were not producing even though real-time energy prices were at least $50 per MWh greater than assumed short run marginal costs. We observed many instances during 2013 where GDF SUEZ changed their offer curves intraday, increasing the offer price for hundreds of MWs of their capacity during the highest load hours, then reducing the price of their offered generation after the peak load period. The effects on real time energy prices of GDF SUEZ's offer patterns were mixed and were only material after the changes to real-time mitigation went into effect on June 21, 2013. We estimate the overall impact that GDF SUEZ's offer patterns on the ERCOT average real-time energy prices was less than $1.00 per MWh.

Figure 85: Company Specific Output Gap



Given that their generation portfolio does not exceed the threshold set in P.U.C Subst. R. 25.504 (c), GDF SUEZ is deemed not to have ERCOT-wide market power.[19] Further, their offering behavior had a relatively modest price impact, which did not meaningfully affect the competitiveness of the ERCOT market.

19 On June 20, 2014 the Commission denied Raiden Commodities' petition for initiation of a rulemaking. The petition, filed in docket 42424, sought to eliminate P.U.C. SUBST. R. 25.504(c), relating to the exemption from the market power definition of entities controlling less than five percent of the generation capacity in the ERCOT Region.