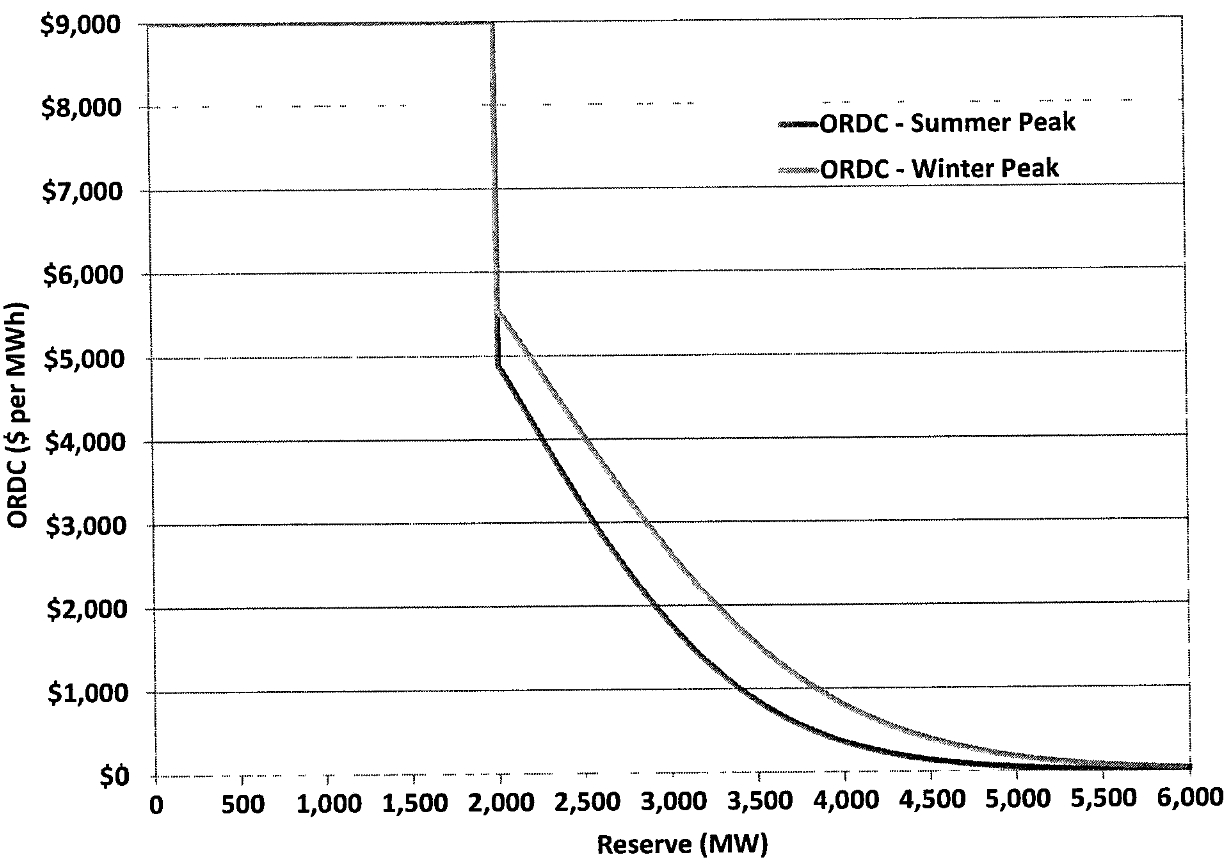
separate pricing for online and offline reserves. As the quantity of reserves decreases, payments for reserves will increase. As shown below in Figure 16, once available reserve capacity drops to 2,000 MW, payment for reserve capacity will rise to $9,000 per MWh.

Figure 16: Operating Reserve Demand Curves

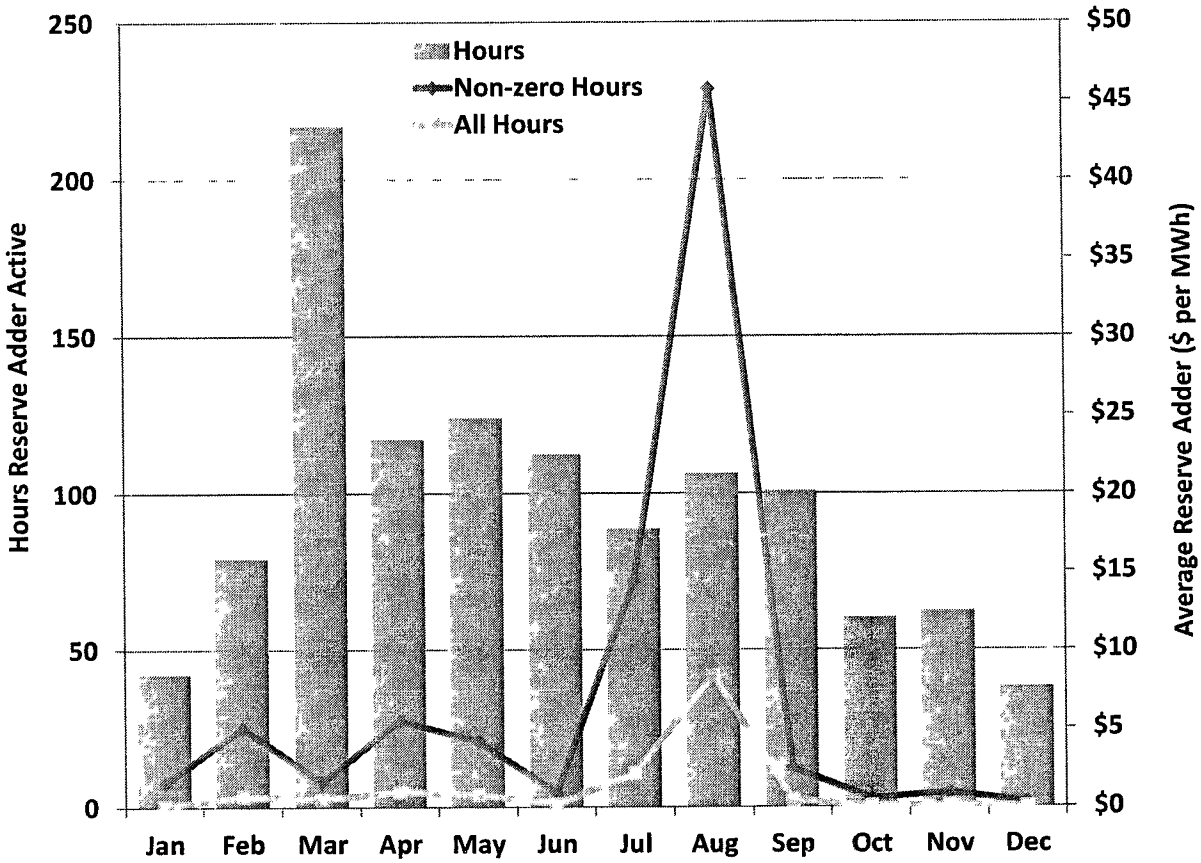


The following two analyses illustrate the contributions of the operating reserve adder and the newly-implemented reliability adder to shortage pricing. Since the operating reserve adder was implemented mid-year in 2014, 2015 provides the first full calendar year for reviewing the operating reserve adder performance.

Figure 17 shows the number of hours in which the adder affected prices, and the average price effect in these hours and all hours. This figure shows that the operating reserve adder had a relatively modest impact on prices in 2015, with the largest impact during the summer months. The operating reserve adder contributed $1.41 per MWh or 5 percent to the annual average real time price of $26.77 per MWh. While the largest number of hours with the operating reserve adder occurred in the spring months, the average price impacts in those months were minimal.

These results do not indicate that ORDC has been ineffective or that it should be modified. The effects of the operating reserve adder are expected to vary substantially from year to year, and to have the largest effects when poor supply conditions and unusually high load conditions occur together and result in sustained shortages.

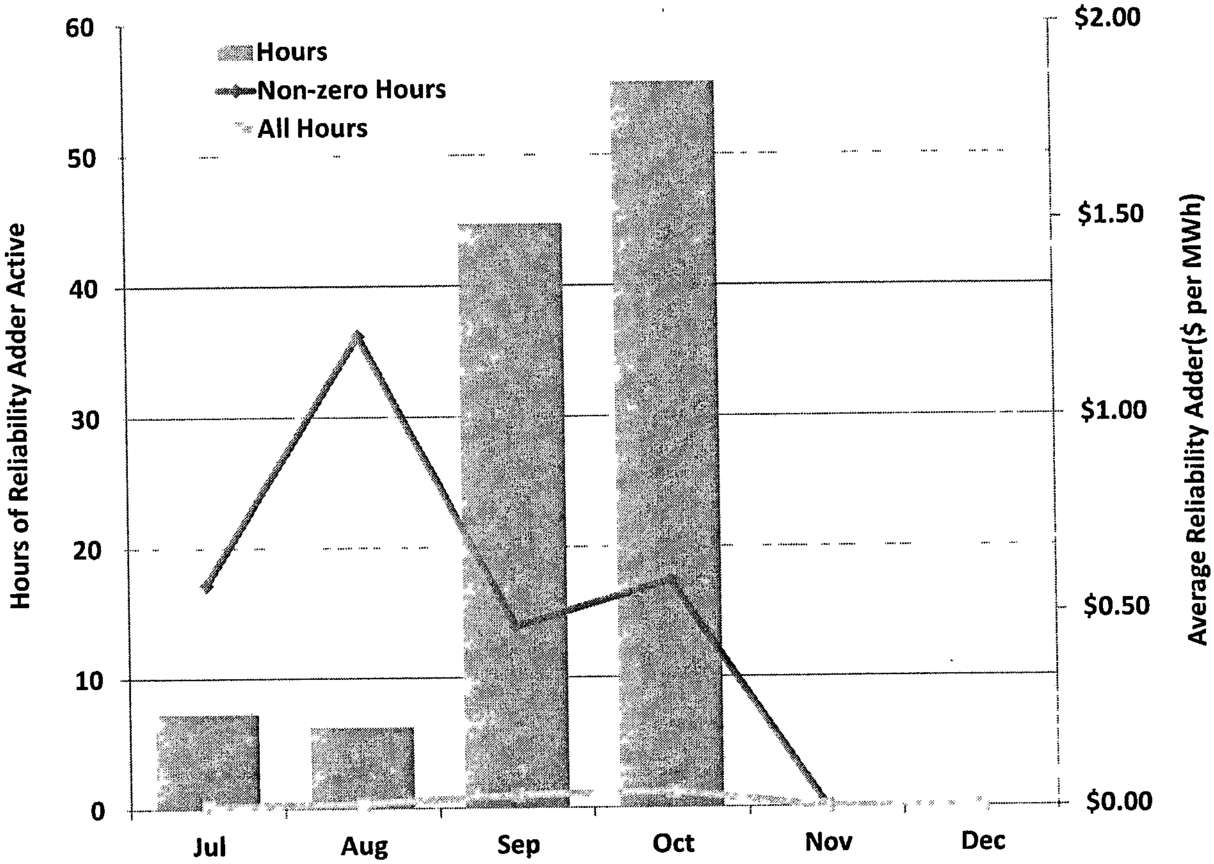
Figure 17: Average Operating Reserve Adder



In addition to the operating reserve adder, a reliability adder was implemented at the end of June 2015. The reliability adder is intended to allow prices to reflect the costs of reliability actions taken by ERCOT, including RUC commitments and deployed load capacity. Absent this adder, prices will generally fall when these actions are taken.

Figure 18 below shows the impacts of the reliability adder. When averaged across the active hours, the largest price impact of the reliability adder occurred in August. The contribution from the reliability adder to the annual average real-time energy price was $0.01 per MWh.

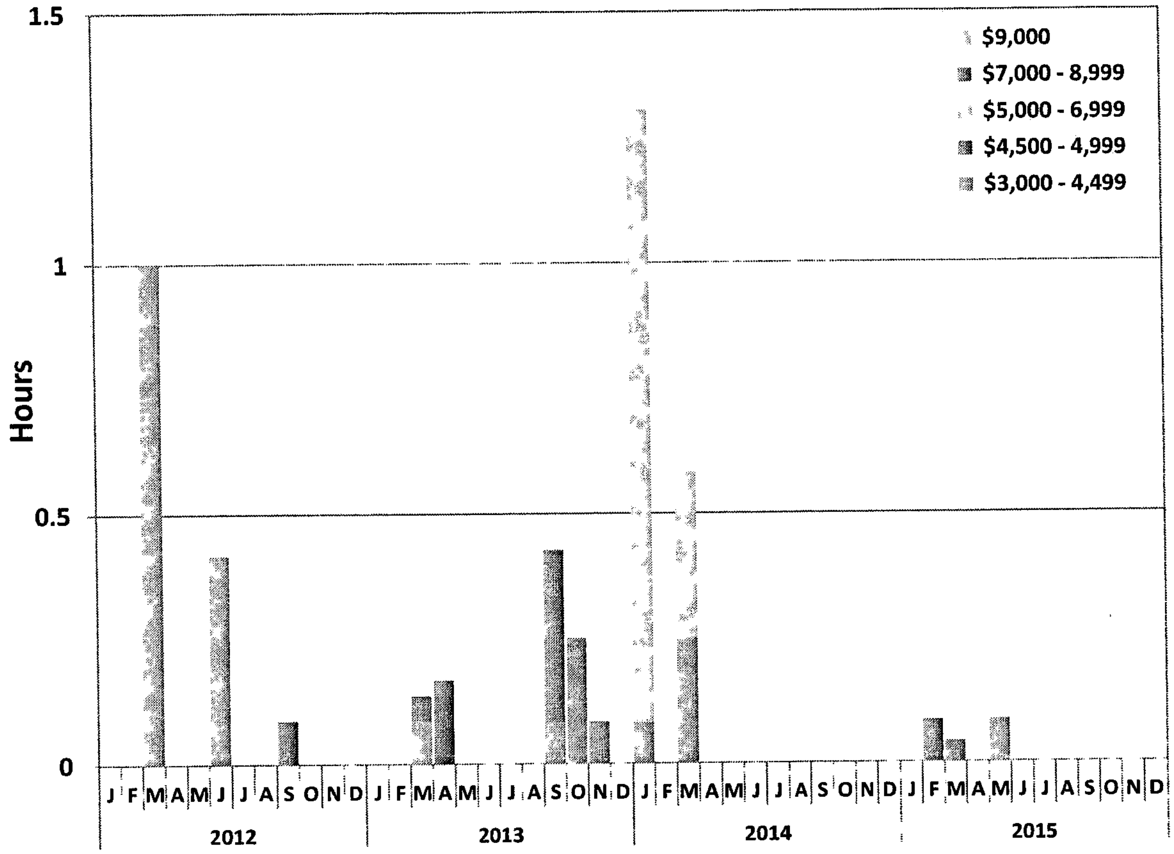
Figure 18: Average Reliability Adder



As an energy-only market, the ERCOT market relies heavily on high real-time prices that occur during shortage conditions. These prices provide key economic signals that provide incentives to build new resources and retain existing resources. However, the frequency and impacts of shortage pricing can vary substantially from year-to-year.

To summarize the shortage pricing that occurred from 2012 to 2015, Figure 19 below shows the aggregate amount of time when the real-time energy price was at the system-wide offer cap, by month. This figure shows that there were no instances in 2015 of energy prices rising to the system-wide offer cap, which was $7,000 per MWh through May 31 and $9,000 per MWh for the remainder of the year. Prices did exceed $3,000 per MWh for a total of 0.21 hours, or less than 15 minutes. Prices during 2014 exceeded $3,000 per MWh for a total of 1.89 hours and were at the system-wide offer cap for only 1.56 hours, an increase from 0.22 hours and 1.51 hours in 2013 and 2012, respectively.

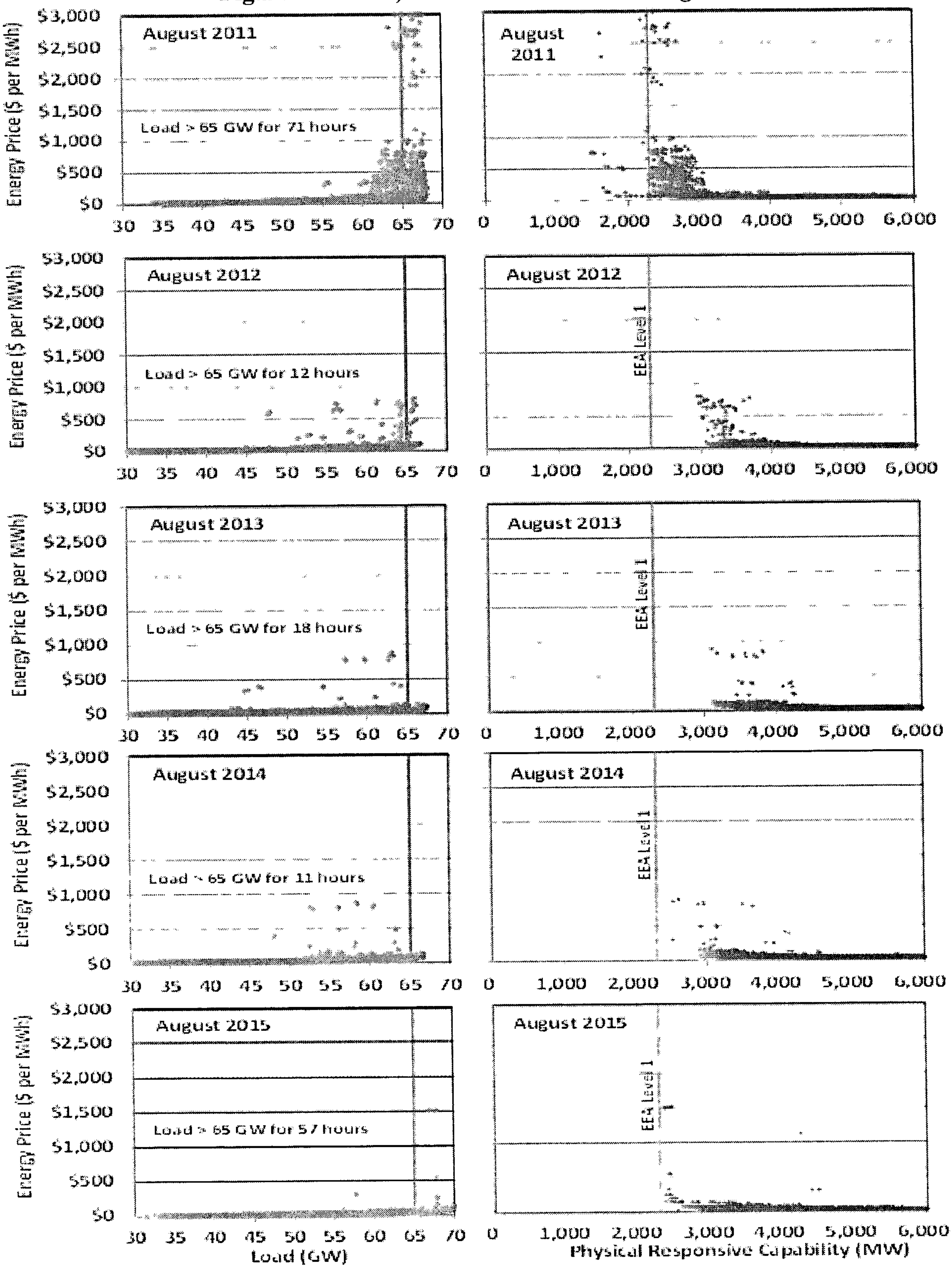
Figure 19: Prices at the System-Wide Offer Cap



The frequency of the market clearing at the cap in all of these years was much lower than the 28.44 hours experienced in 2011, which was caused by unusually hot and sustained summer temperatures. This is the type of year when one should expect much more frequent shortages. Shortages in years with normal weather should be infrequent. As capacity margins fall, the frequency of shartages is likely to increase but will still vary substantially year-to-year.

Figure 20 provides a detailed comparison for 2011 through 2015 of each August's load, required reserve levels, and prices for 2011 through 2015. There were very few dispatch intervals when real-time energy prices reached the system-wide offer cap in 2012, 2013, 2014, and 2015 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 20: Load, Reserves and Prices in August



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The left side of Figure 20 shows the relationship between real-time energy price and load level for each dispatch interval for the months of August in the years 2011 to 2015. ERCOT loads in August were greater than 65 GW for 71 hours in 2011, whereas loads reached that level for 12 hours, 18 hours, and 11 hours in 2012, 2013, and 2014, respectively.

Because temperatures were relatively hot in August of 2015, ERCOT load exceeded 65 GW for 57 hours. As previously discussed, a strong positive correlation between higher load and higher prices is expected in a well-functioning energy market, and this analysis shows such a relationship. However, this relationship appears to be weaker in years 2012 to 2014 with more instances of higher prices occurring at lower loads. These instances are generally due to high-priced, fast ramping generation being dispatched at times when changing system conditions exceed the capabilities of other available generation to respond.

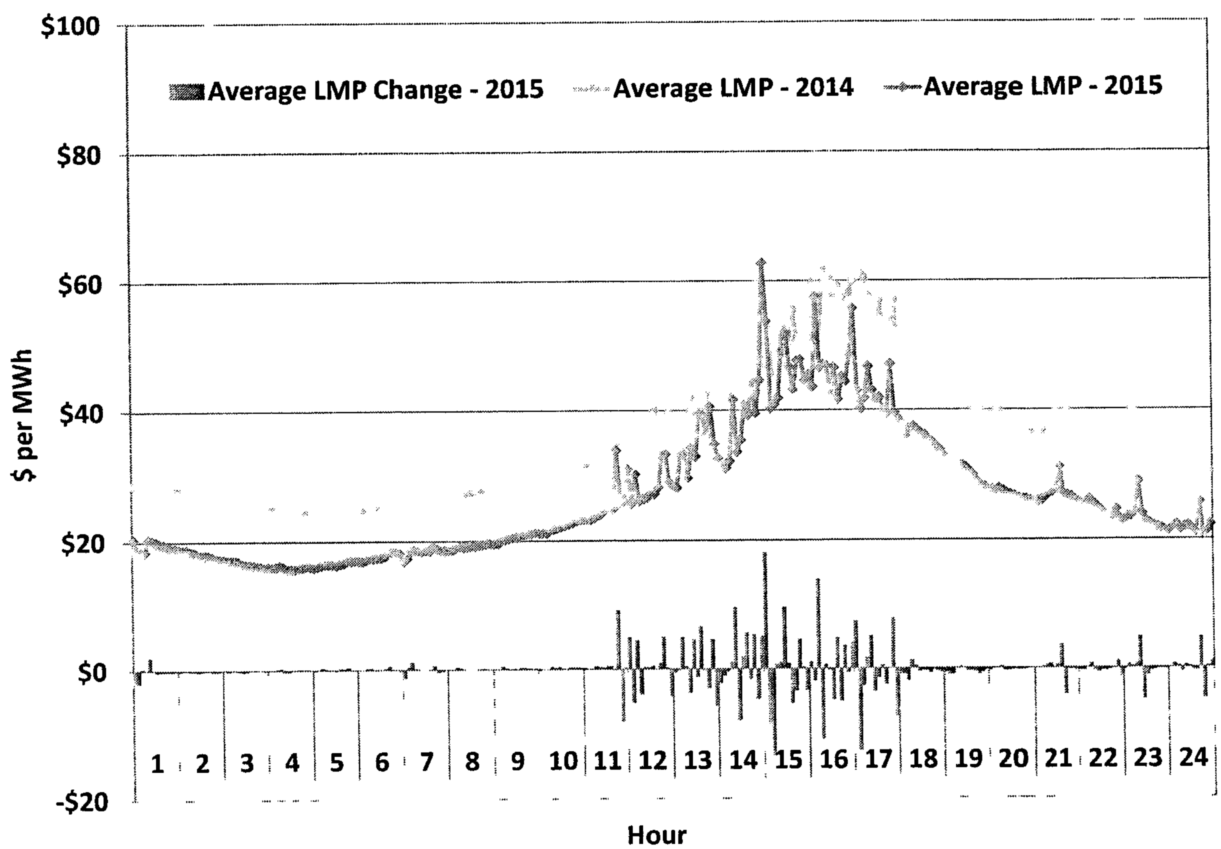
Although load levels are strong predictors of energy prices, an even more important predictor is the level of operating reserves. Simply put, operating reserves are the difference between the total capacity of operating resources and the current load level. As load level increases against a fixed quantity of operating capacity, the amount of operating reserves diminishes. The minimum required operating reserves prior to ERCOT declaring Energy Emergency Alert (EEA) Level 1 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 and the associated value of loss of load.

The right side of Figure 20 shows the relationship between real-time energy prices and the quantity of available operating reserves for each dispatch interval during August of 2011, 2012, 2013, 2014, and 2015. This figure shows a strong correlation between diminishing operating reserves and rising prices. Operating reserves did get very close to the minimum required level on one day in August 2015, but remained just above the level at which ERCOT would declare EEA Level 1. Concerns have been expressed that real-time prices were not higher in this situation. As discussed in Section V.B, in response to those concerns a review of the ORDC parameters is ongoing. Lower loads in August 2012, 2013, and 2014, resulted in available operating reserves remaining well above minimum levels for the entire month, and there were no occurrences when 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, and prices reached the system-wide offer cap in 17.4 hours.

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 21 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 2014 are also presented. Comparing average real-time energy prices for 2015 with those from 2014, the effects of lower natural gas prices on average prices may be observed. Although prices were lower in 2015, there was more price volatility (variability) in 2015.

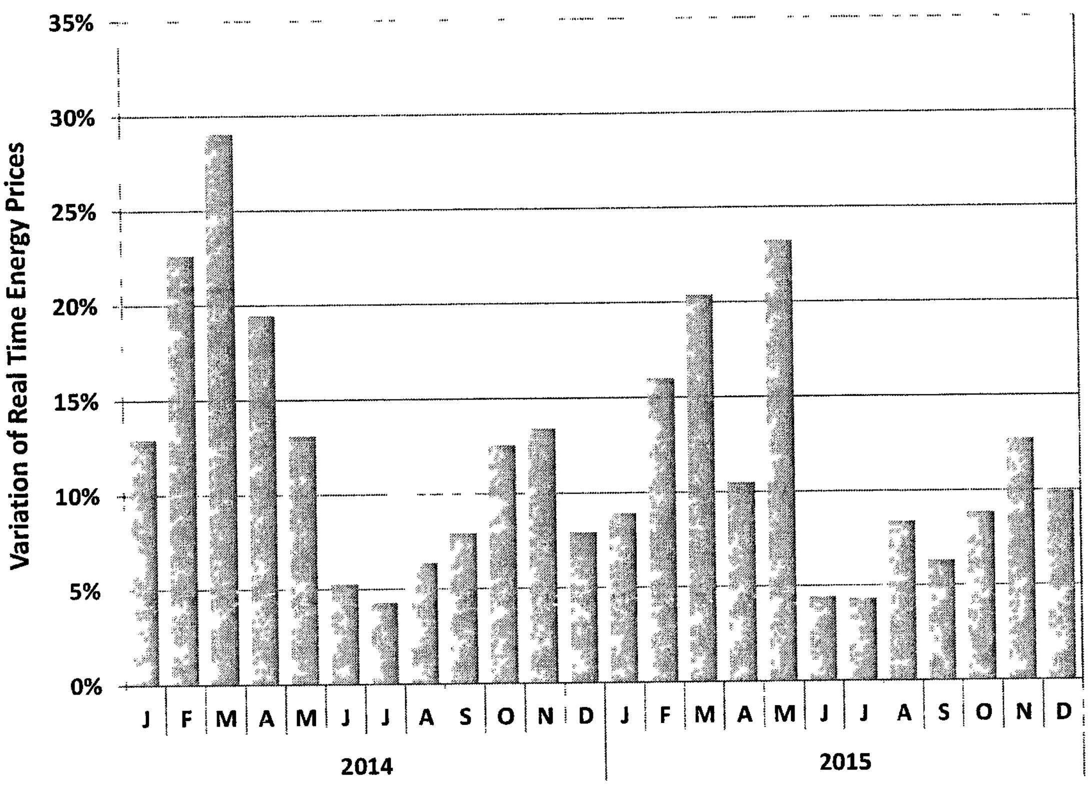
Figure 21: Real-Time Energy Price Volatility (May – August)



The average of the absolute value of changes in five-minute real-time energy prices, expressed as a percent of average price, was 4.9 percent in 2015, compared to a range of 3.0 percent to 3.6 percent in the prior three years. In 2011, the absolute value of five-minute price changes was 6.2 percent.

Expanding the view of price volatility, Figure 22 below shows monthly average changes in five-minute real-time prices. Without any prices at, or close to the system-wide offer cap, the highest price variability occurs during spring and fall months when wind generation variations and load and wind generation forecast errors are the highest.

Figure 22: Monthly Price Variation



To show how the price volatility has varied by location, Table 2 below, shows the volatility of 15-minute settlement point prices for the four geographic load zones in 2015.

Table 2: 15-Minute Price Changes as a Percentage of Annual Average Prices

Load Zone	2012	2013	2014	2015
Houston	13.0	14.8	14.7	13.4
South	13.1	15.4	15.2	14.6
North	13.9	13.7	14.1	11.9
West	19.4	17.2	15.4	12.9

These results show that price volatility is generally lower in 2015 than in the prior three years. The table also shows that price volatility in the West Load Zone has continued to decrease, likely as a result of transmission investment in the region. In fact, price volatility in the West zone in 2015 was lower than price volatility in the South Load Zone.

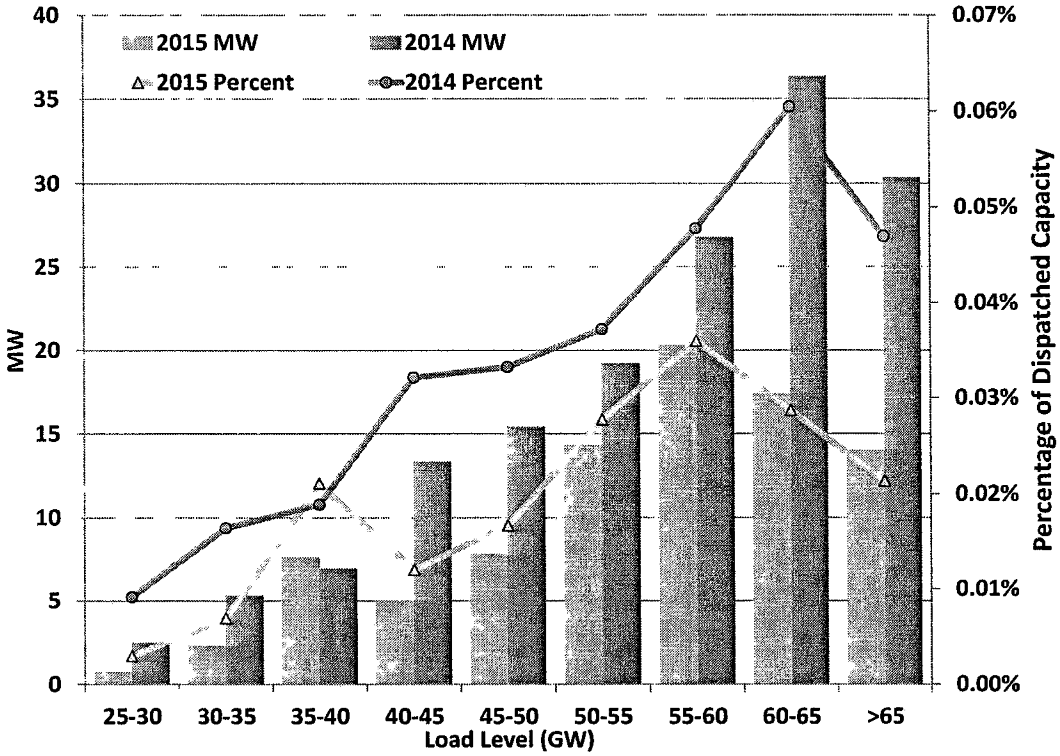
F. Mitigation

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 considers only the transmission constraints that have been deemed competitive. These "reference prices" at each generator location are compared with that generator's mitigated offer cap, and the higher of the two is used to formulate the offer curve 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 generator to raise prices in the event of a transmission constraint that requires its output to resolve. In this subsection the quantity of mitigated capacity in 2015 is analyzed. Although executing all the time, the automatic price mitigation aspect of the two-step dispatch process only has the potential to have an effect when a non-competitive transmission constraint is active. With the introduction in 2013 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. This change has significantly reduced the amount of capacity subject to mitigation.

The analysis shown in Figure 23 computes how much capacity, on average, is actually mitigated during each dispatch interval. The results are provided by load level.

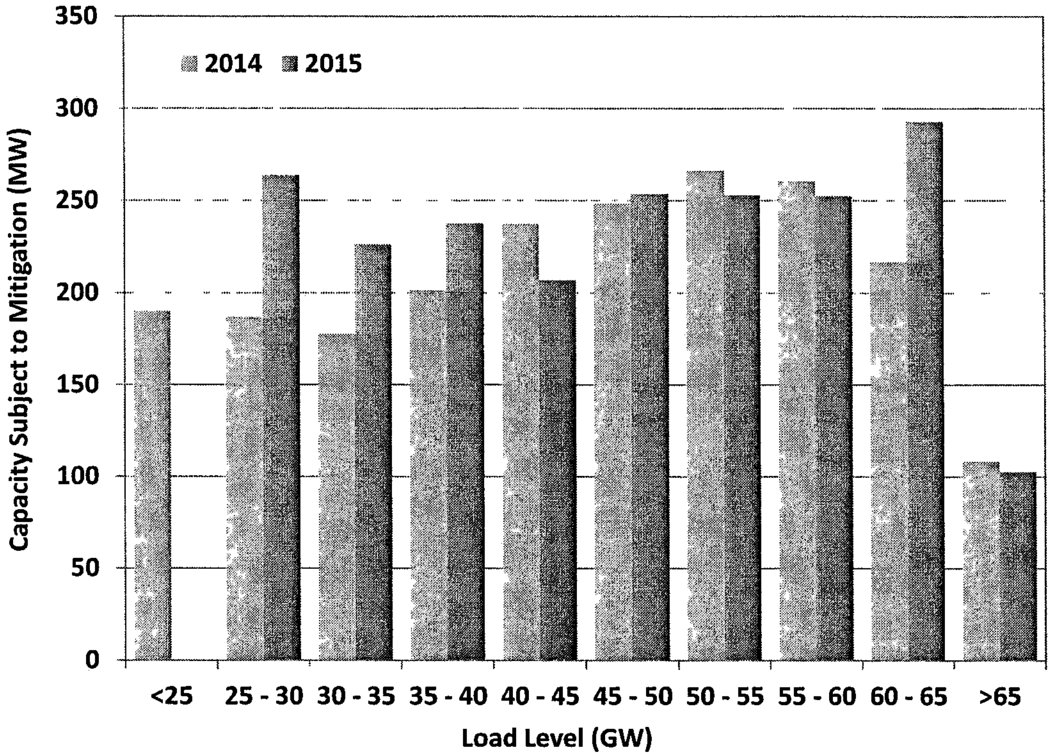
Figure 23: Mitigated Capacity by Load Level



The level of mitigation in 2015 was lower than in 2014. The average amount of mitigated capacity was less than 20 MW for all load levels in 2015, slightly lower than in 2014 when the greatest quantity of mitigated capacity being dispatched was just over 35 MW at high load levels. The similar frequency of congestion that occurred in 2015 and 2014, as described later in Section III, supports the similar mitigation levels experienced in the two years.

In the previous figure, only the amount of capacity that could be dispatched within one interval was counted as mitigated. The next analysis computes the total capacity subject to mitigation, by comparing a generator's mitigated and unmitigated (as submitted) offer curves and determining the point at which they diverge. The difference between the total unit capacity and the capacity at the point the curves diverge is calculated for all units and aggregated by load level. The results are shown in Figure 24.

Figure 24: Capacity Subject to Mitigation



As in the previous analysis, the amount of capacity subject to mitigation in 2015 was similar to the amounts in 2014. The largest amount of capacity subject to mitigation has not exceeded 300 MW for the past two years. This is in contrast to the situation prior to mid-2013 when the mitigation rules were modified to only apply to generators that can relieve non-competitive constraints.

By comparison, in 2012, prior to the change, up to 7 percent of capacity required to serve load was subject to mitigation. In 2015, this percentage was less than 1 percent. It is important to note that this measure includes all capacity above the point at which a unit's offers become mitigated, without regard for whether that capacity was actually required to serve load.

II. REVIEW OF DAY-AHEAD MARKET OUTCOMES

ERCOT's 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. In addition to power, the day-ahead market also includes ancillary services and Point-to-Point (PTP) Obligations. PTP Obligations allow parties to hedge the incremental cost of congestion between day-ahead and real-time 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 for the ability to reliably flow on the transmission network, there are no operational obligations resulting from the day-ahead market. These transactions are made for a variety of reasons, including satisfying the participant's own demand, managing risk by hedging the participant's exposure to real-time prices, or arbitraging with the real-time prices. 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 energy pricing outcomes from the day-ahead market are reviewed and convergence with real-time energy prices is examined. The volume of activity in the day-ahead market, including a discussion of PTP Obligations is also reviewed. This section concludes 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: (1) there are low barriers to shifting purchases and sales between the forward and real-time markets; and (2) 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. This improves the convergence of forward and real-time prices, which generally improves the commitment of resources needed to satisfy the system's real-time needs.

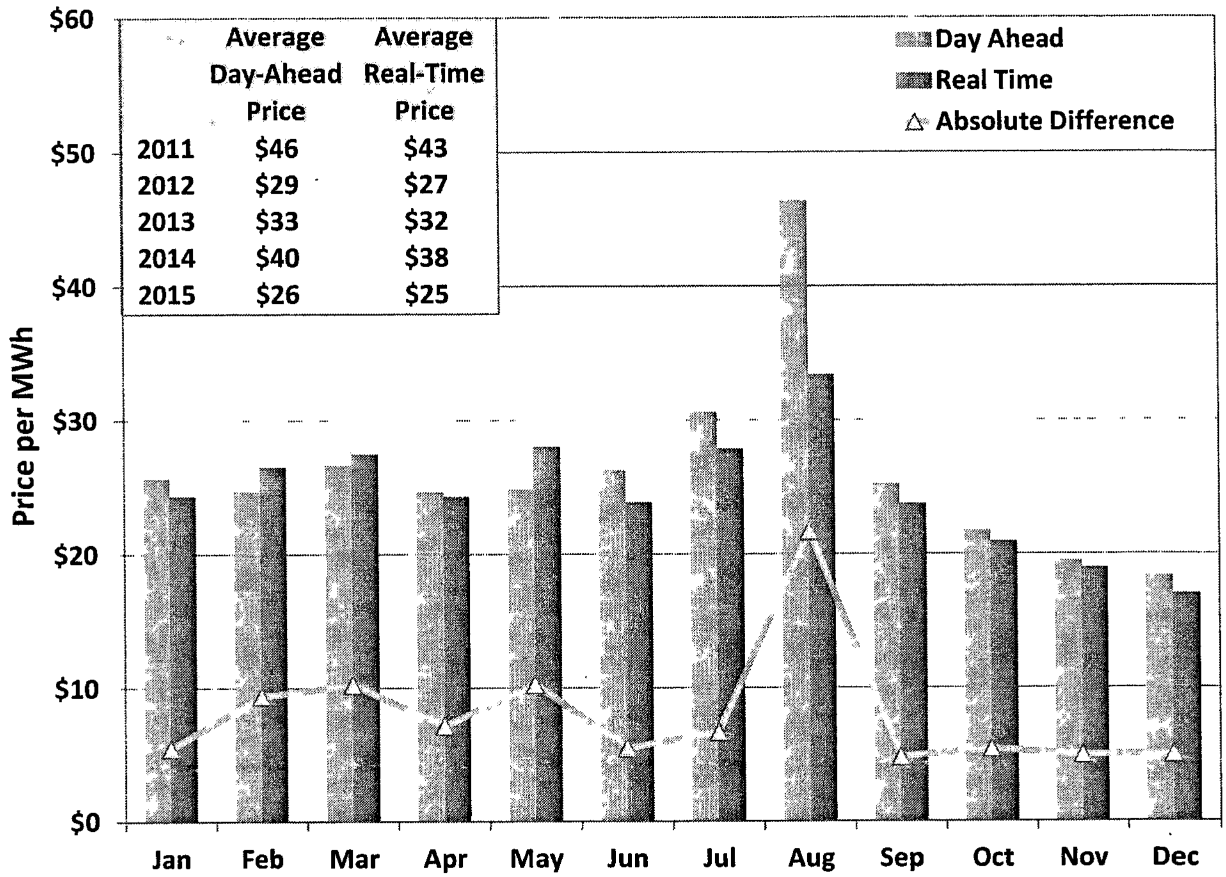
In this subsection, price convergence between the day-ahead and real-time markets is evaluated. This average price difference reveals whether persistent and predictable differences exist between day-ahead and real-time prices, which participants should arbitrage over the long term. To measure the short-term deviations between real-time and day-ahead prices, the average of the absolute value of the difference between the day-ahead and real-time price are calculated 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.[10]

Figure 25 summarizes the price convergence between the day-ahead and real-time market, by month. Day-ahead prices averaged $26 per MWh in 2015 compared to an average of $25 per MWh for real-time prices.[11] 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 market 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 relative demand and highest prices, as was seen in August 2015. The overall day-ahead premium decreased in 2015 compared to 2014, due to low natural gas prices resulting in overall lower electricity prices and few occurrences of shortage pricing in 2015. The average absolute difference between day-ahead and real-time prices fell by more than a third to $8.08 per MWh in 2015 which was attributable to lower real-time price volatility and low fuel prices in 2015.

10 For instance, if day-ahead prices are $30 per MWh on two consecutive days while real-time prices are $20 per MWh and $40 per MWh respectively, the absolute price difference between the day-ahead market and the real-time market would be $10 per MWh on both days, while the difference in average prices would be $0 per MWh.

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

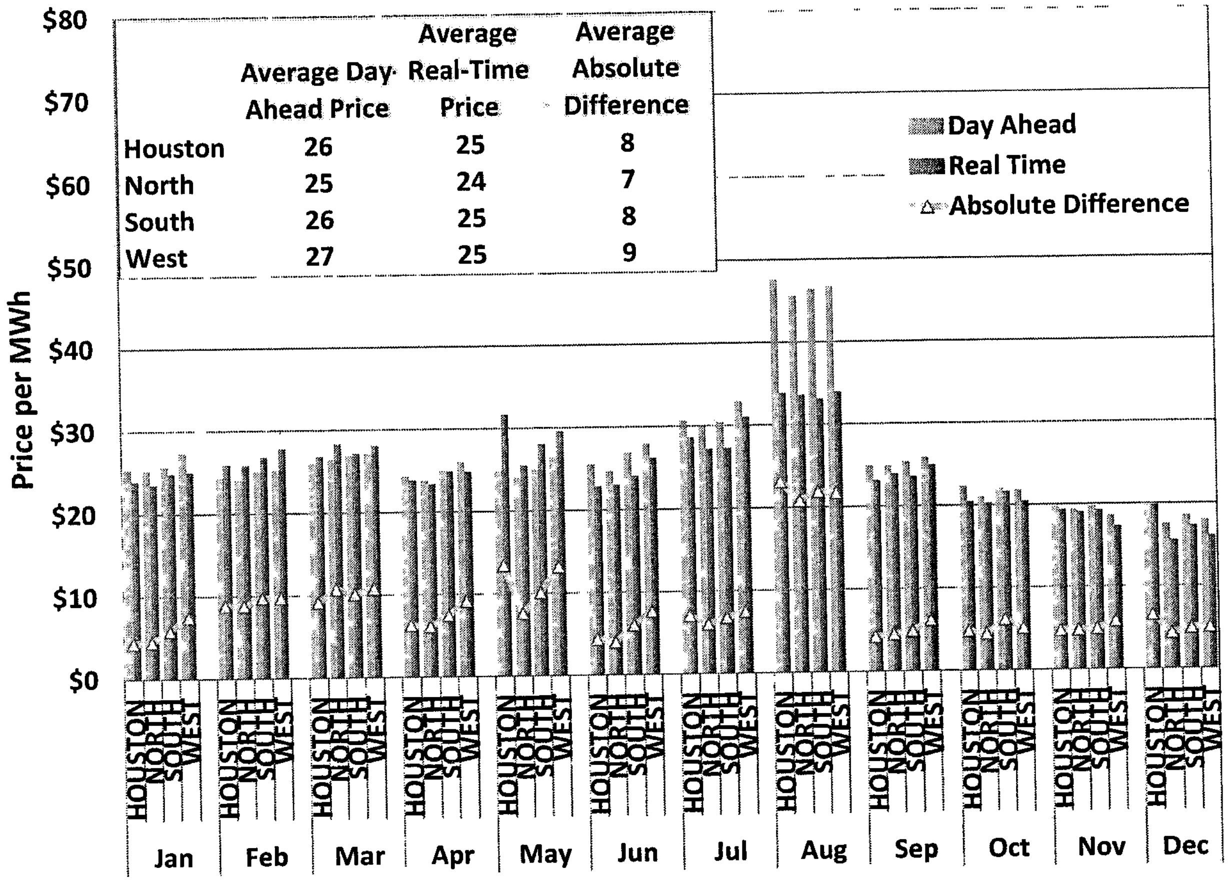
Figure 25: Convergence Between Day-Ahead and Real-Time Energy Prices



Day-ahead premiums in high-load months in ERCOT 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 the shortage pricing 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 in 2015, it should not be expected that every month will produce a day-ahead premium. 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 February, March and May).

In Figure 26 below, monthly day-ahead and real-time prices are shown for each of the geographic load zones. Of note is that the volatility in the West zone has decreased and more closely resembles the relative stability of the other load zones. The larger difference between day-ahead and real-time prices previously observed in the West zone was likely associated with the uncertainty of forecasting wind generation output and associated transmission congestion.

Figure 26: Day-Ahead and Real-Time Prices by Zone



B. Day-Ahead Market Volumes

The next analysis summarizes the volume of day-ahead market activity by month. Figure 27 below shows that the volume of day-ahead purchases provided through a combination of generator-specific and virtual energy offers was approximately 51 percent of real-time load in 2015, which was a slight increase compared to 2014 activity.

As discussed in more detail in the next subsection, PTP Obligations are financial transactions purchased in the day-ahead market. Although PTP Obligations do not themselves involve the direct supply of energy, allow a participant to buy the network flow from one location to another.[12] In doing so, the participant can avoid the associated real-time congestion costs between the locations. To provide a volume comparison, all of these "transfers" are aggregated

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

with other energy purchases and sales, netting location-specific injections against withdrawals to arrive at a net system flow. The net system flow in 2015 was almost 8 percent higher than in 2014.

Adding the aggregated transfer capacity associated with purchases of PTP Obligations to the other injections and withdrawals demonstrates that net system flow volume transacted in the day-ahead market exceeds real-time load by approximately 30 percent. The volume in excess of real-time load increased in 2015 compared to 2014, when the monthly net system flow averaged 23 percent more than real-time load.

Figure 27: Volume of Day-Ahead Market Activity by Month

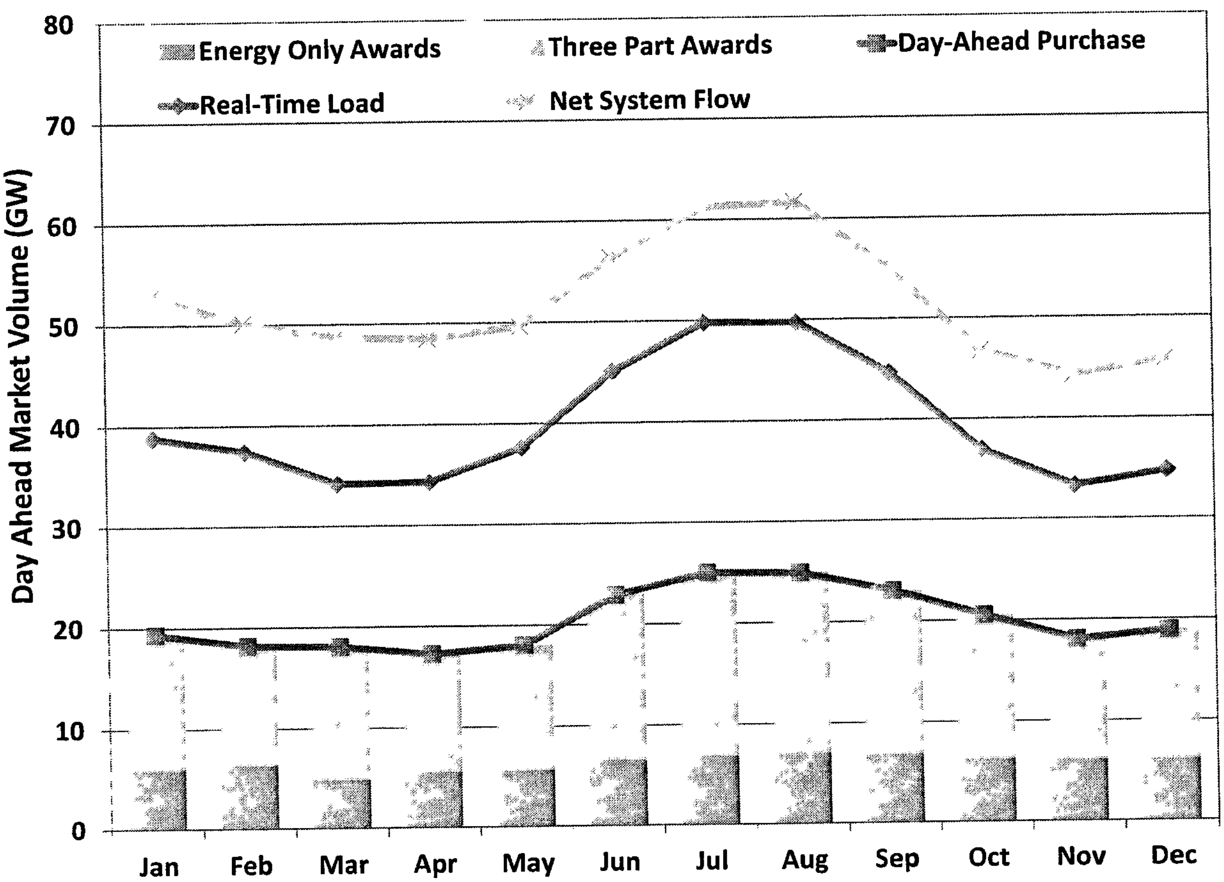
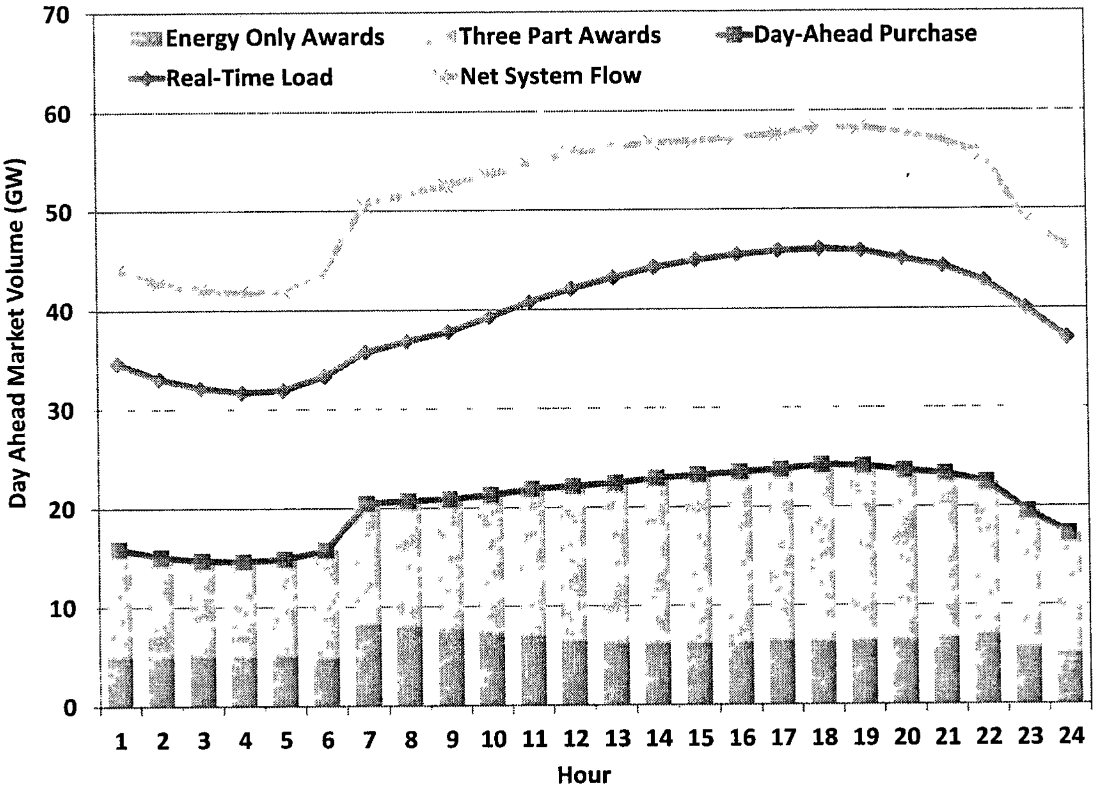


Figure 28 below, presents the same day-ahead market activity data summarized by hour of the day. In this figure the volume of day-ahead market transactions is disproportionate with load levels between the hours of 6 and 22. Since these times align with common bilateral transaction terms, the results in this figure are consistent with market participants using the day-ahead market to trade around those positions.

Figure 28: Volume of Day-Ahead Market Activity by Hour



C. Point-to-Point Obligations

Purchases of PTP Obligations comprise a significant portion of day-ahead market activity. They are similar to, and can be used to complement Congestion Revenue Rights (CRRs). CRRs, as more fully described in Section III.D, 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.

Participants buy PTP Obligations by paying the difference in prices between two locations in the day-ahead market. They receive the difference in prices between the same two locations in the real-time market. Hence, a participant that owns a CRR can use its CRR proceeds from the day-ahead market to buy the PTP Obligation in order to transfer its hedge to real-time. Because PTP Obligations represent such a substantial portion of the transactions in the day-ahead market, additional details about the volume and profitability of these PTP Obligations are provided in this subsection.

Figure 29: Point-to-Point Obligation Volume

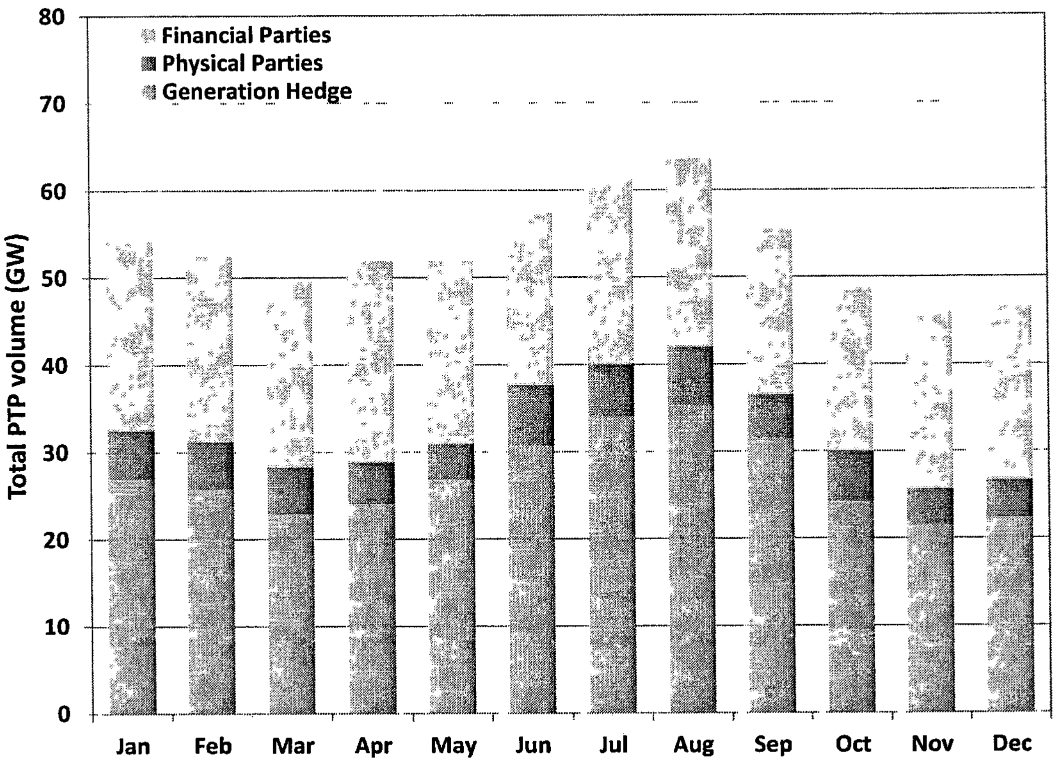


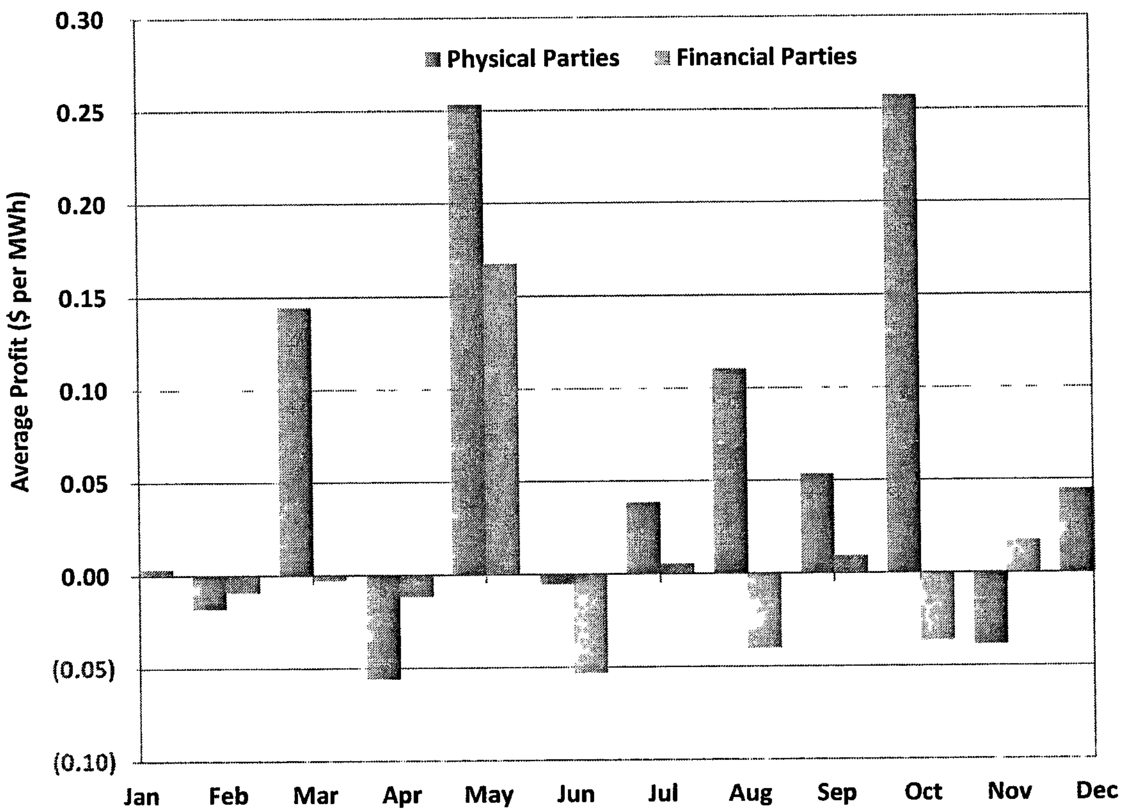
Figure 29 presents the total volume of PTP Obligation purchases divided into three categories. This figure presents total volume, compared to the previous two figures that showed net flows associated with PTP Obligations. The volumes in this figure do not net out the injections and withdrawals occurring at the same location, as is done to calculate the net flows.

For all PTP Obligations that source at a generator location, the capacity up to the actual generator output is considered to be hedging the real-time congestion associated with generating at that location. The figure above shows that 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 arbitrage anticipated price differences between two locations. This arbitrage activity is further separated by type of market participant. Physical parties are those that have actual real-time load or generation, whereas financial parties have neither.

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 profit. Conversely, if the price difference does not materialize in real-time, the PTP Obligation may be unprofitable.

The profitability of PTP Obligation holdings by the two types of participants are compared in Figure 30.

Figure 30: Average Profitability of Point-to-Point Obligations



This analysis shows that in aggregate PTP Obligation transactions were profitable overall in 2015 for both classes of participants. However, transactions of physical participants were more consistently profitable than those of financial participants. The profits and losses shown in this figure are relatively small and the profitability of the PTP Obligation transactions were slightly lower in 2015 than 2014 in aggregate. This is due in part to the fact that the day-ahead and real-time prices were relatively well arbitraged.

To conclude the analysis of PTP Obligations, Figure 31 compares the total day-ahead payments for these transactions with the total amount of revenue they received in the real-time market.

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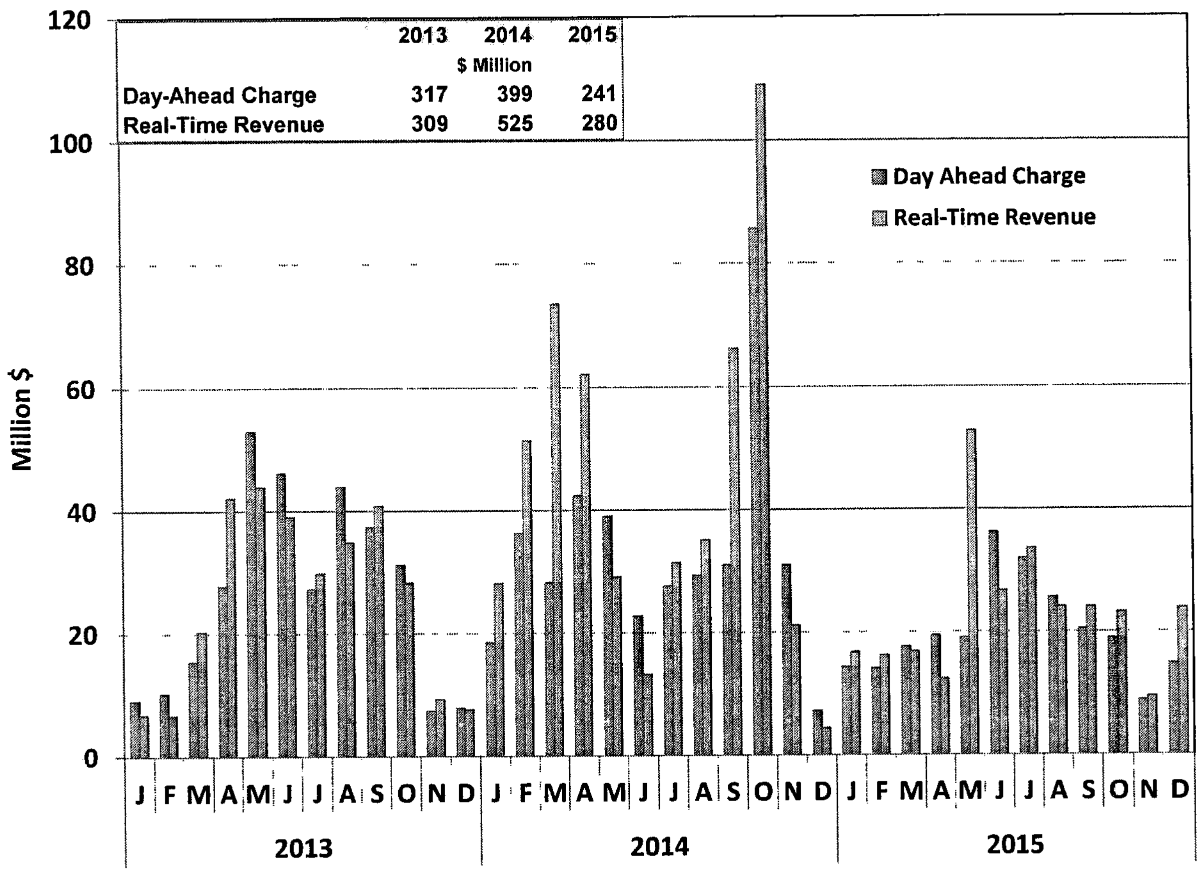
Figure 31: Point-to-Point Obligation Charges and Revenues



As in prior years, with the exception of 2013, the aggregated total revenues received by PTP Obligation owners was greater than the amount charged to the owners to acquire them. This indicates that, in aggregate, buyers of PTP Obligation profited from the transactions. This occurs when real-time congestion is greater than day-ahead market congestion. Across the year, and in eight of twelve months, the acquisition charges were less than the revenues received, implying that expectations of congestion as evidenced by day-ahead purchases were less than the actual congestion that occurred in real-time. The largest net revenues paid to PTP Obligation owners was $30 Million in May when unexpected North to Houston real-time congestion occurred.

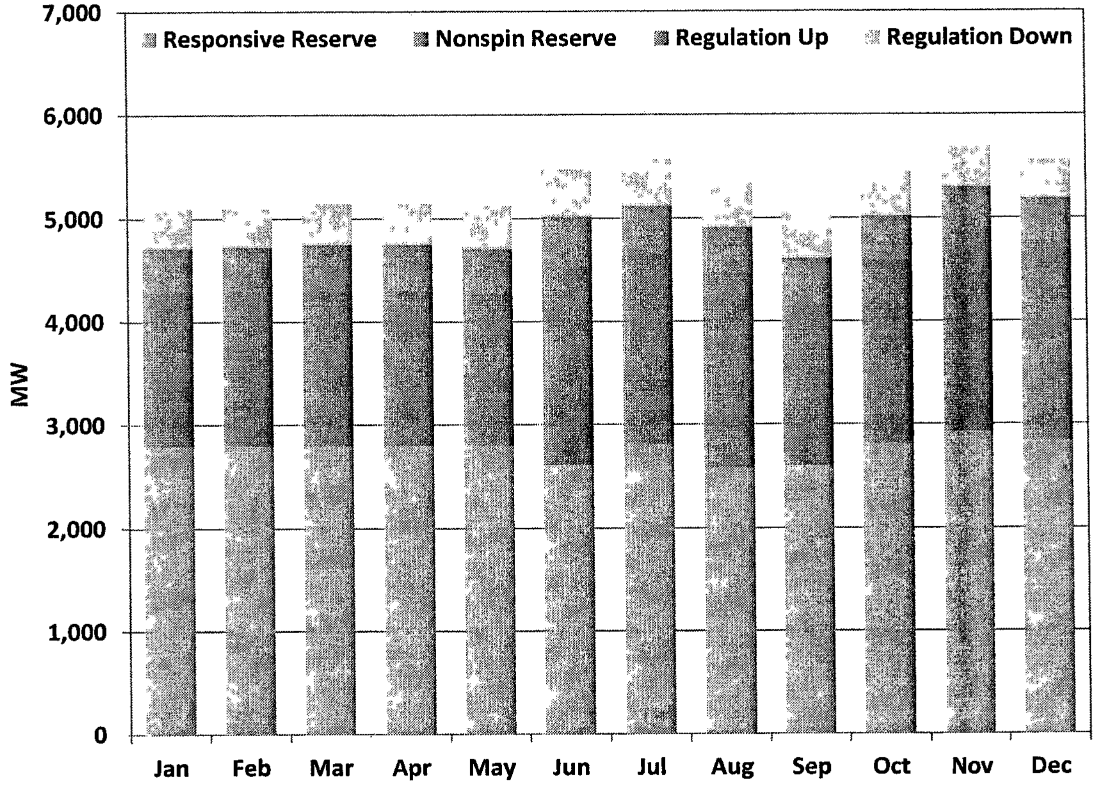
The payments made to PTP Obligation owners come from real-time congestion rent. The sufficiency of real-time congestion rent to cover both PTP Obligations and payments to owners of CRRs who elect to receive payment based on real-time prices are assessed in Section III.E.

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 them through the ERCOT markets. 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.

ERCOT's procurement methodology for responsive and non-spinning reserves was adjusted effective June 1, 2015. For responsive reserves, ERCOT now calculates the requirement based on a variable hourly need; this requirement is determined and posted in advance for the year. ERCOT procures non-spinning reserves such that the combination of non-spinning reserves and regulation up will cover 95 percent of the calculated Net Load forecast error. ERCOT will always procure a minimum quantity of non-spinning reserves greater than or equal to the largest generation unit. Figure 32 displays the hourly average quantities of ancillary services procured for each month in 2015.

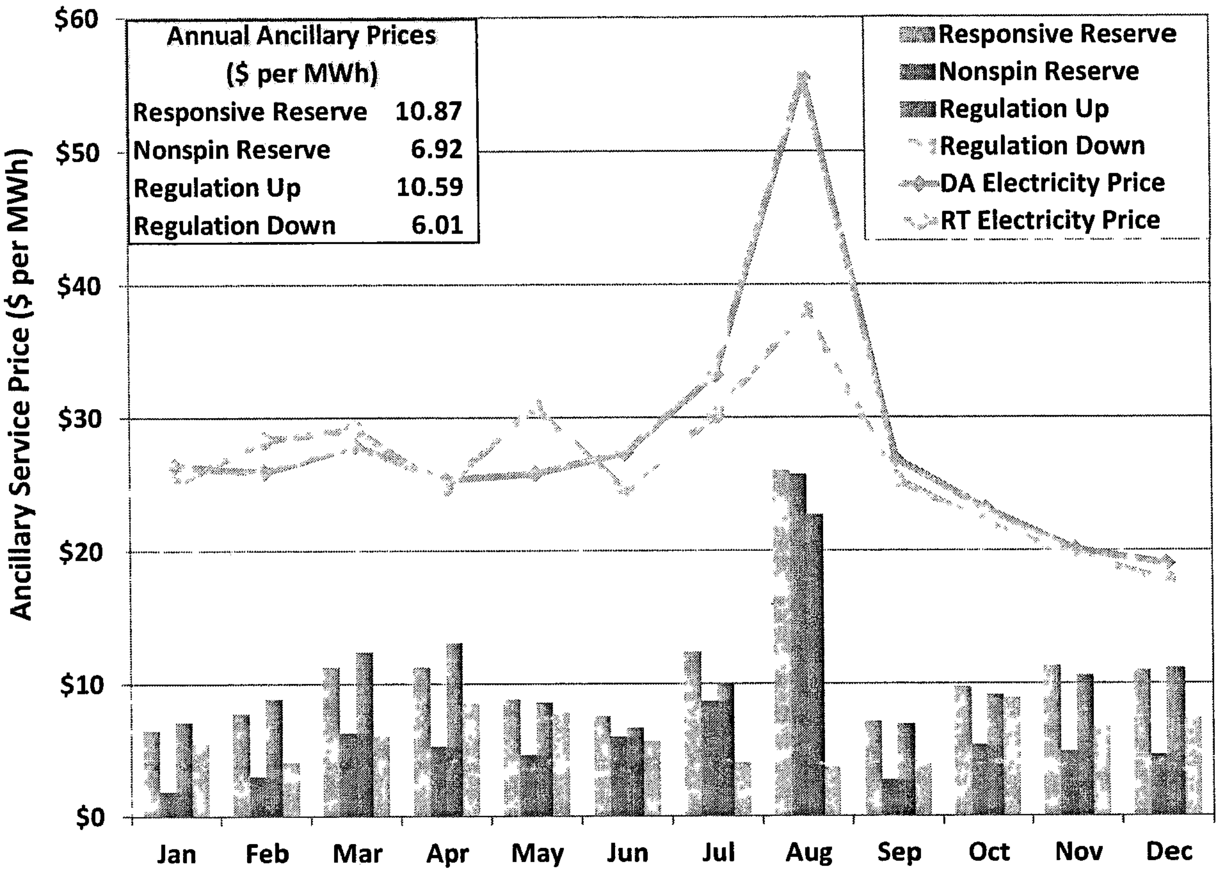
Figure 32: Hourly Average Ancillary Service Capacity



Under the nodal market, ancillary services and energy are co-optimized in the day-ahead market. This means that market participants do not have to include their expectations of forgone energy sales in their ancillary service capacity offers. Because ancillary service clearing prices explicitly account for the opportunity costs of selling energy in the day-ahead market, ancillary service prices are highly correlated with day-ahead energy prices and, by extension, with real-time energy prices.

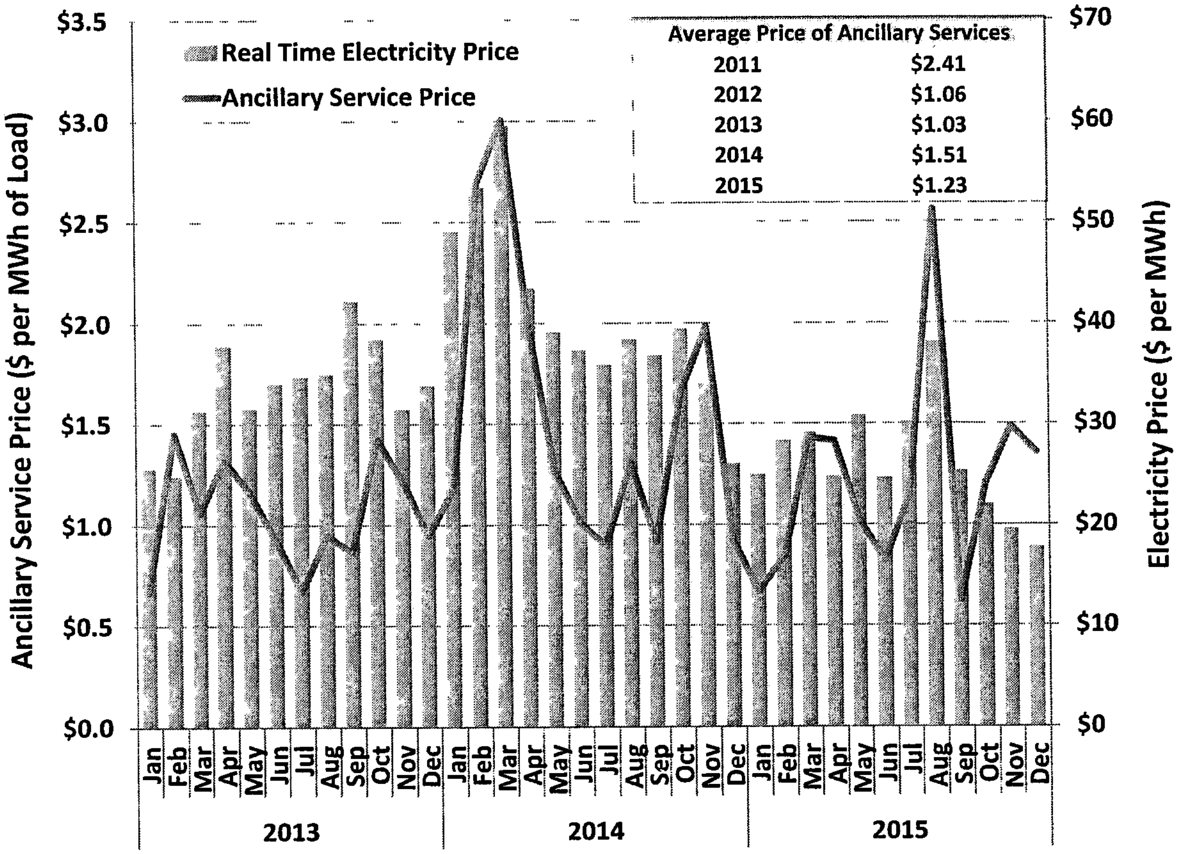
Figure 33 below presents the average clearing prices of capacity for the four ancillary services, along with day-ahead and real-time prices for energy. With average energy prices varying between \$18 and \$55 per MWh, the prices of ancillary services remained fairly stable throughout the year, with the exception of August. The price for ancillary services spiked in August, corresponding to the higher real-time electricity prices caused by ERCOT's shortage pricing and the associated increase in day-ahead price.

Figure 33: Ancillary Service Prices



In contrast to the previous figure that showed the individual ancillary service prices, Figure 34 shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2013 through 2015. This figure shows that total ancillary service costs are generally correlated with day-ahead and real-time energy price movements, which 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.

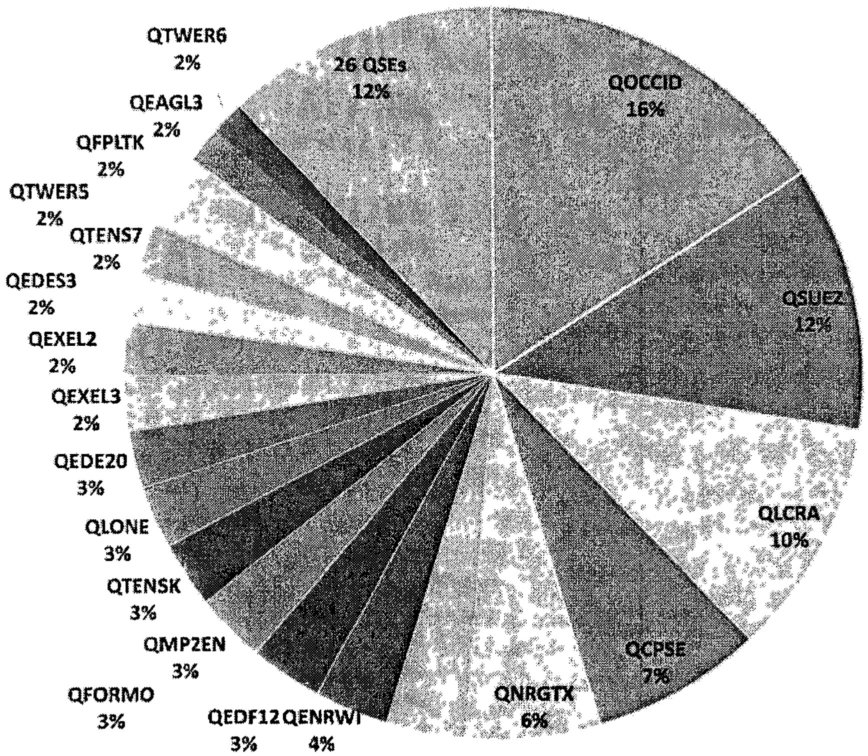
Figure 34: Ancillary Service Costs per MWh of Load



In absolute terms, the average ancillary service cost per MWh of load decreased to $1.23 per MWh in 2015 compared to $1.51 per MWh in 2014. Although the reduction in ancillary service prices and energy prices were both primarily caused by lower natural gas prices, the reduction in ancillary service prices was smaller than the decrease in ERCOT's energy prices. As a result, as a percent of the load-weighted average, total ancillary service costs increased from 3.7 percent of the load-weighted average energy price in 2014 to 4.6 percent in 2015 ($1.23 of $26.77).

Responsive reserve service is the largest quantity and typically the highest priced ancillary service product. Figure 35 below shows the share of the 2015 annual responsive reserve responsibility including both load and generation, displayed by Qualified Scheduling Entity (QSE). During 2015, 46 different QSEs self-arranged or were awarded responsive reserves as part of the day-ahead market; an increase from 38 different providers in 2014.

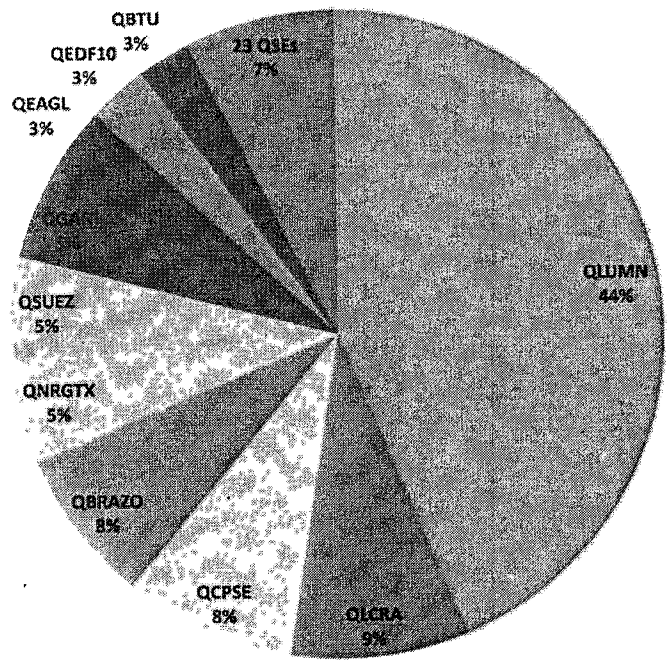
Figure 35: Responsive Reserve Providers



In contrast, Figure 36 below shows that the provision of non-spinning reserves is much more concentrated, with a single QSE having nearly half the responsibility to provide non-spinning reserves. Notably, this concentration decreased from 55 percent of the total in 2014 to 44 percent of the total in 2015. While this is an improvement, the fact that one party is consistently providing the preponderance of this service should be considered in the ongoing efforts to redefine ERCOT ancillary services.

It also highlights the importance of modifying the ERCOT ancillary service market design to include real-time co-optimization of energy and ancillary services. Jointly optimizing all products in each interval would allow 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-spinning reserves), reducing the reliance upon a single entity to provide this type of lower quality reserves.

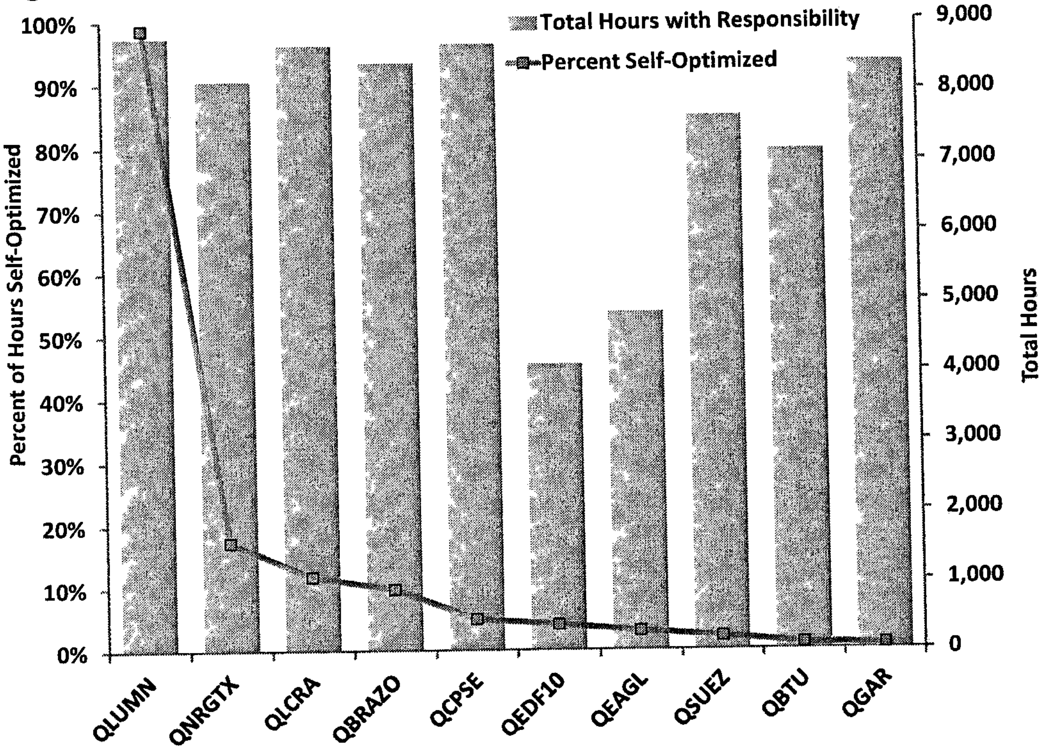
Figure 36: Non-Spinning Reserve Providers



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 needed, changes often occur that prompt a QSE to move all or part of its ancillary service responsibility from one unit to another. These changes may be due to a unit outage or to other changes in market conditions affecting unit commitment and dispatch. In short, QSEs with multiple units are continually reviewing and moving ancillary service requirements, presumably to improve the efficiency of ancillary service provision, at least from the QSE's perspective.

The charts below shows the percentage of time in which each QSE with a unit-specific ancillary service responsibility at 16:00 day-ahead, moved any portion of its ancillary service responsibility to a different unit in its portfolio for real-time operations. Figure 37 shows the total hours of non-spinning reserve responsibility by QSE along with the percent of hours when the non-spinning reserve responsibility was moved to a different unit within the QSE portfolio before real-time operations.

Figure 37: Internal Management of Non-Spinning Reserve Portfolio by QSE



The QSEs are listed in descending order based on the frequency of self-optimization. This figure, taken in conjunction with Figure 36, shows that the provider with the largest share of non-spinning reserve responsibility also most frequently moved the responsibility between its units. Furthermore, a comparison of NRG (QNRGTX) and the City of Garland (QGAR) reveals that QSEs with larger fleets may have more opportunity to self-optimize. As shown in Figure 36, both QSEs provided 5 percent of ERCOT's non-spinning reserve requirements in 2015. NRG, with its much larger generation fleet, self-optimized more than 17 percent of the time, while Garland self-optimized less than 1 percent of the time.

Figure 38 below provides a similar analysis for the percent of time when responsive reserve service was self-optimized by a QSE, that is, moving the day-ahead responsibility to a different unit before real-time.

Figure 38: Internal Management of Responsive Reserve Portfolio by QSE

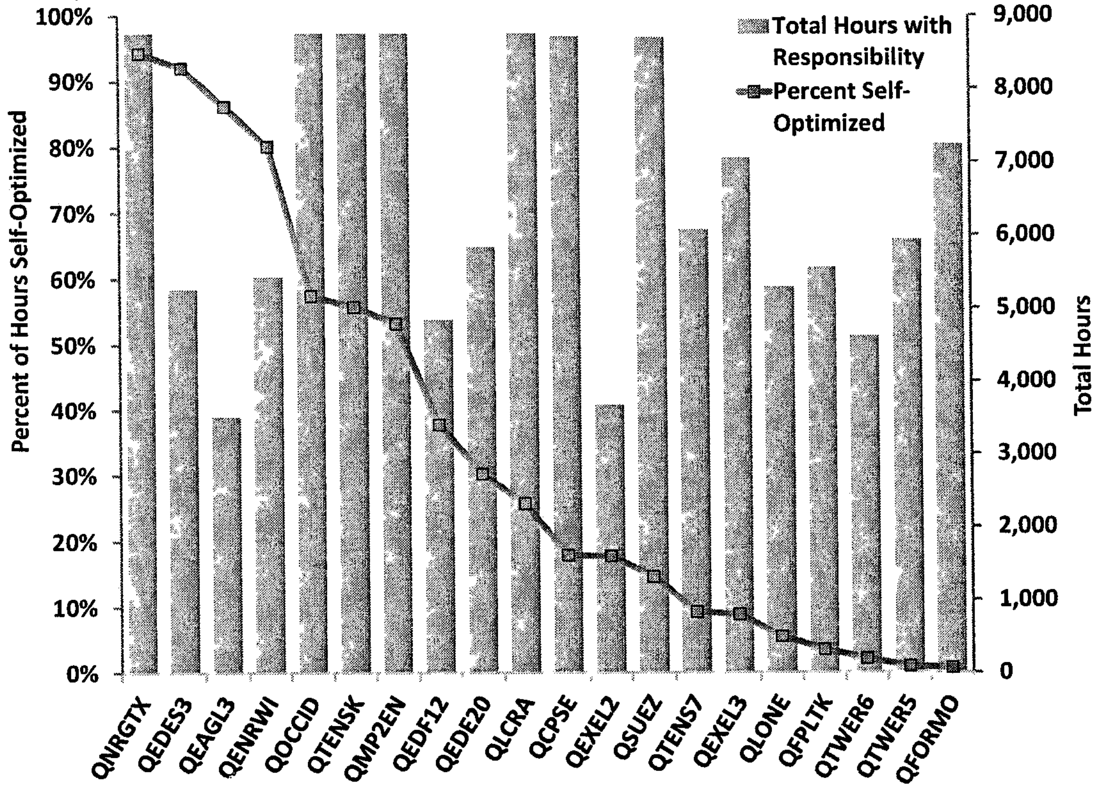


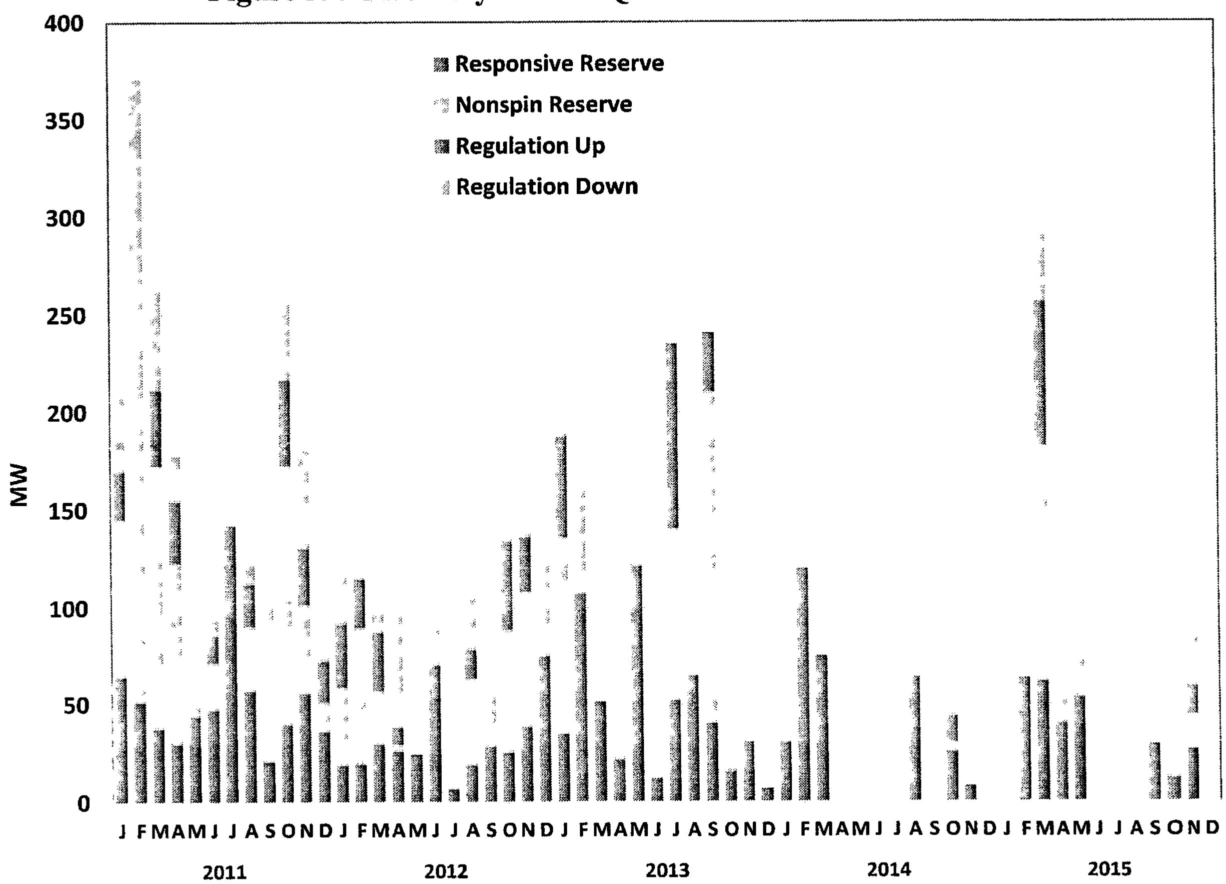
Figure 38 demonstrates that QSEs moved responsive reserve responsibilities between units more routinely than QSEs providing non-spinning reserve service. For responsive reserve service, seven QSEs moved the responsibility more than 50% of the time; whereas only one QSE moved non-spinning reserve responsibility more than 50% of the time.

If all ancillary services could be continually reviewed and adjusted in response to changing market conditions, the efficiencies would flow to all market participants and would be greater than what can be achieved by QSEs acting individually. This improved efficiency is why the IMM has been recommending, since the initial consideration of ERCOT's nodal market design, that ERCOT implement real-time co-optimization of energy and ancillary services.

Without comprehensive, market-wide co-optimization, the ERCOT market will continue to be subject to the choices of individual QSEs. These choices are likely to be in the QSE's best interest. They are not likely to lead to the most economic provision of energy and ancillary services for the market as a whole. Further, QSEs without large resource portfolios are effectively precluded from participating in ancillary service markets due to the replacement risk they face having to rely on a supplemental ancillary services market (SASM). This replacement risk is substantial. Clearing prices for ancillary services procured in SASM are thirty to fifty times greater than annual average clearing prices from the day-ahead market.

SASMs are used to procure replacement ancillary service capacity when transmission constraints arise which make the capacity undeliverable, or when outages or limitations at a generating unit lead to failure to provide. A SASM may also be opened if ERCOT changes its ancillary service plan; this did not occur during 2015. ERCOT executed a SASM for 67 hours, or less than one percent of the time in 2015. The frequency of SASMs continues to decline, from seven percent in 2012, three percent in 2013, to two percent in 2014. The final analysis in this section, shown in Figure 39, summarizes the average quantity of each service that was procured via SASM. As previously discussed, SASM was rarey used to replace deficiencies in ancillary services in 2015.

Figure 39: Ancillary Service Quantities Procured in SASM



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 must resort to using reliability unit commitment (RUC) procedures to bring additional capacity online.

The SASM procurement method, while offer based, is inefficient and problematic. Because ancillary services are not co-optimized with energy in the SASM, potential suppliers are required to estimate their opportunity cost rather than have the auction engine calculate it directly, which leads to resources that underestimate their opportunity costs being inefficiently preferred over resources that overestimate their opportunity costs. Further, the need to estimate the opportunity costs, which change constantly and significantly over time as the energy price changes, provides a strong disincentive to SASM participation, contributing to the observed lack of SASM offers. The paucity of SASM offers frequently leaves ERCOT with two choices: (1) use an out-of - market ancillary service procurement action with its inherent inefficiencies; or (2) operate with a deficiency of ancillary services with its inherent increased reliability risk.

Real-time co-optimization of energy and ancillary services does not require resources to estimate opportunity costs, would eliminate the need for the SASM mechanism, and allow ancillary services to be continually shifted to the most efficient provider. Because co-optimization allows the real-time market far more flexibility to procure energy and ancillary services from online resources, it would also reduce ERCOT's need to use RUC procedures to acquire ancillary services. Its biggest benefit would be to effectively handle situations where entities that had day-ahead ancillary service awards were unable to fulfill that commitment, e.g. due to a generator forced outage. Thus, implementation of real-time co-optimization would provide benefits across the market.

III. TRANSMISSION CONGESTION AND CRRS

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 the output level of one or more generators so as to reduce the amount of electricity flowing on the transmission line nearing its operating limit.[13] Congestion leads to higher costs because higher cost resources must sometimes produce more and lower cost resources must produce less in order to manage flows over the network. These trade-offs result in different prices at different nodes. The decision about which generator(s) will vary its output is based on the generator's energy offer curve and how much of its output will flow across the overloaded transmission element. This leads to a dispatch of the most efficient resources available to reliably serve demand.

This section of the report summarizes transmission congestion in 2015, 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

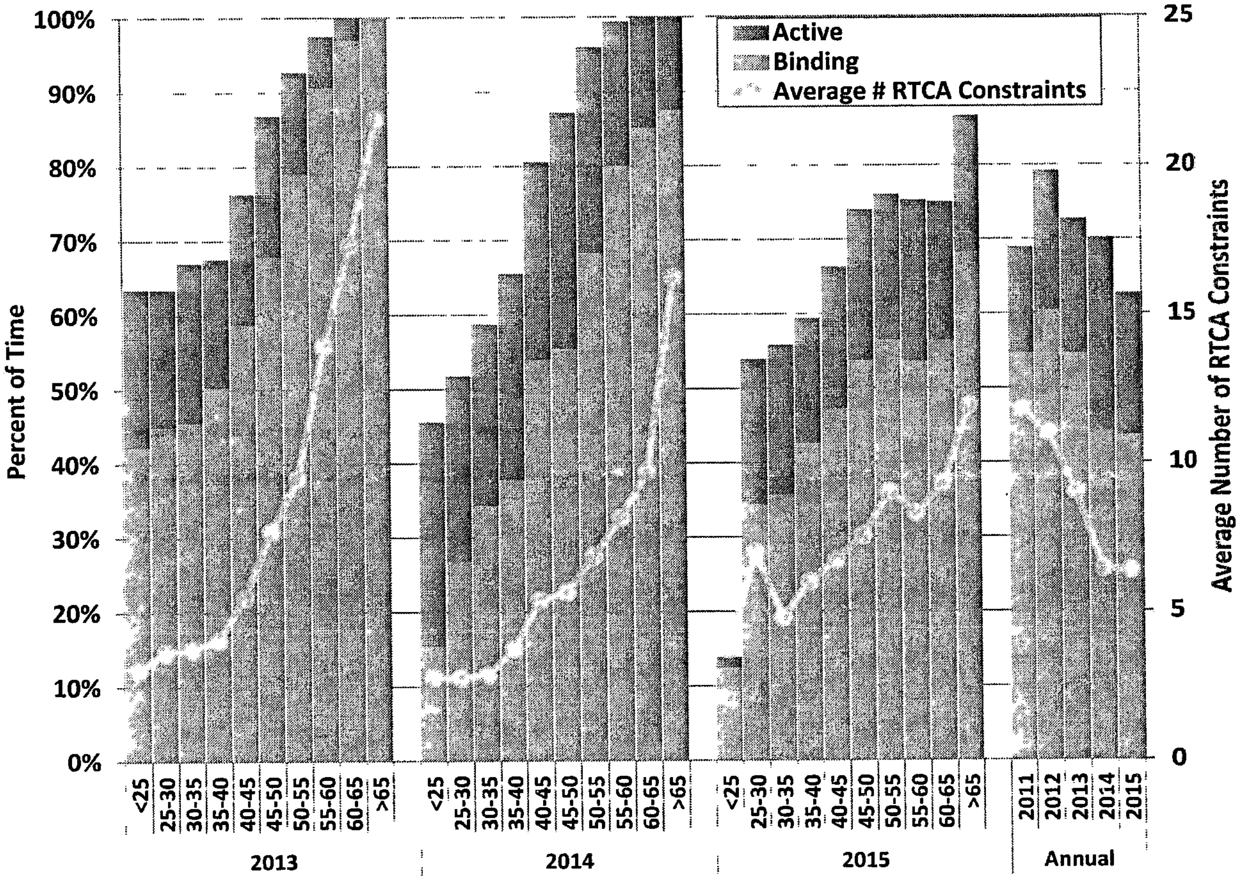
The total congestion costs generated by the ERCOT real-time market in 2015 was $352 million, a 50 percent reduction from 2014 values. Although the price impacts of congestion were greatly reduced, the frequency of congestion was similar to 2014. Congestion between the North and Houston zones increased, while congestion within all zones decreased in 2015.

Figure 40 provides a comparison of the amount of time transmission constraints were binding or active at various load levels in 2013 through 2015. This figure also indicates the average number of constraints in a Real-Time Contingency Analysis (RTCA) execution for each load level.

13 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.

Binding transmission constraints are those for which the dispatch levels of generating resources are actually altered in order to maintain transmission flows at reliable levels. The costs associated with this re-dispatch are the system's congestion costs and are included in nodal prices. Active transmission constraints are those which the dispatch software evaluated, but did not require a re-dispatch of generation.

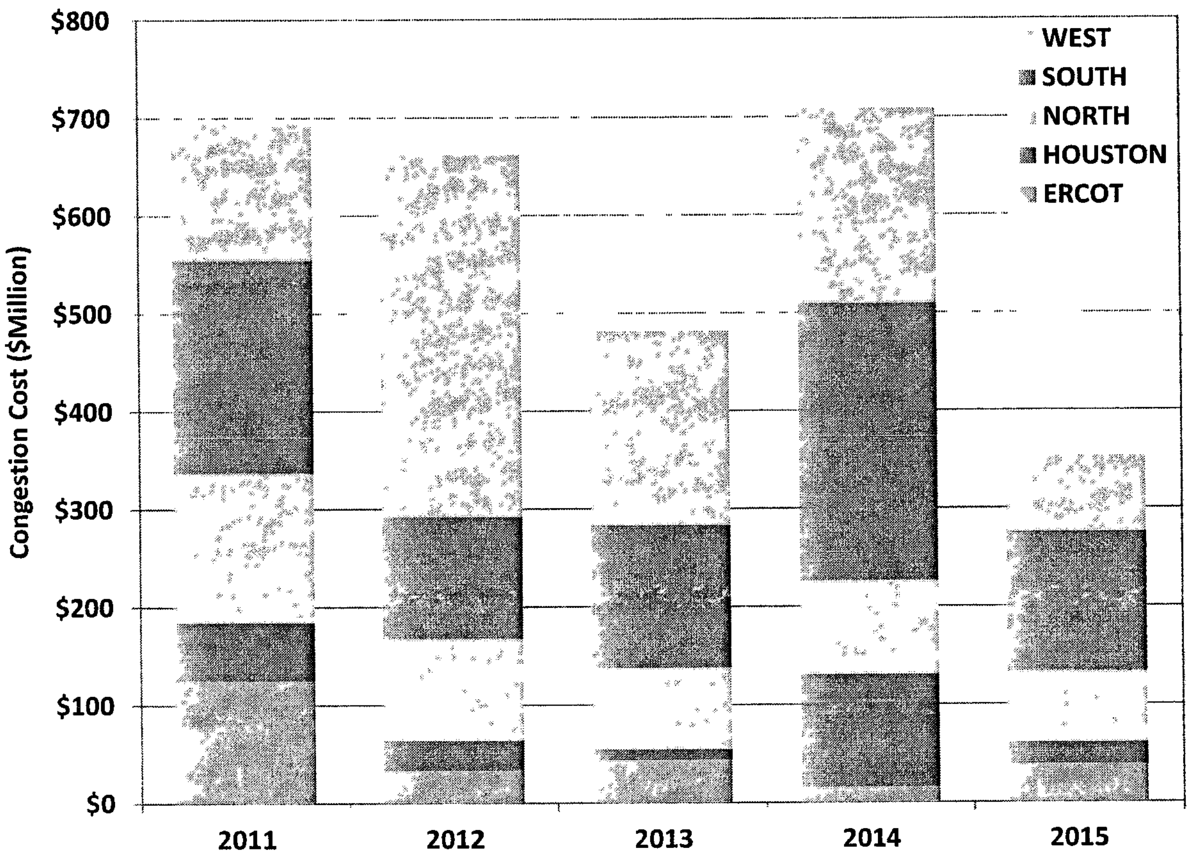
Figure 40: Frequency of Binding and Active Constraints



Constraints were activated much less frequently in 2015, only 63 percent of the time compared to 70 percent of the time in 2014. The reduction in frequency of binding transmission constraints is most notable at the very highest load levels. There was a binding transmission constraint 68 percent of the time when load exceeded 65 GW in 2015. This compares to 88 percent of the time at the same load levels in 2014 and 100 percent of the time in 2013. These reductions in frequency are likely attributed to transmission construction, most notably completion of Competitive Renewable Energy Zone (CREZ) lines reducing congestion in lower load (high wind) periods. Other transmission projects to improve the high load growth areas associated with increased oil and gas development in the Permian Basin and Eagle Ford Shale have likely contributed to reduced congestion frequency during high load periods.

Although the frequency of binding transmission constraints remained similar to 2014 at 44 percent, the congestion costs in 2015 were much lower. The much lower congestion costs were a direct result of the low natural gas prices in 2015 because natural gas resources are generally the resources re-dispatched to manage network flows. Figure 41 displays the amount of real-time congestion costs attributed to each geographic zone. Costs associated with constraints that cross zonal boundaries, i.e. North to Houston, are shown in the ERCOT category.

Figure 41: Real-Time Congestion Costs



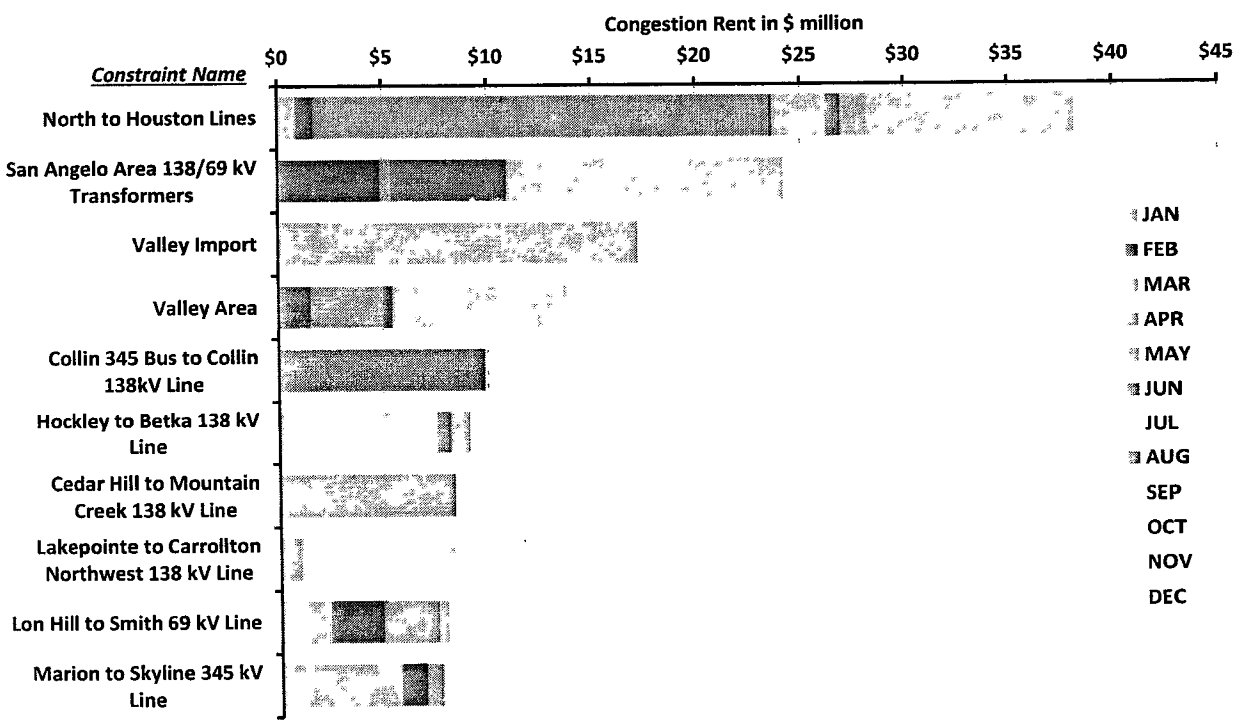
While cross zonal congestion was higher in 2015 versus 2014, all other intra-zonal congestion has decreased. Annual congestion costs in 2015 were the lowest since the start of the nodal market. This is largely due the significant reduction in natural gas prices and the cumulative benefits of large investments in transmission facilities.

B. Real-Time Constraints

The review of real-time congestion begins with describing the congested areas with the highest financial impact as measured by congestion rent. For this discussion a congested area is determined by consolidating multiple real-time transmission constraints that are defined as similar due to their geographic proximity and constraint direction. There were 350 unique constraints that were binding at some point during 2015, about the same number of constraints that were binding in 2014 and 2013. The median financial impact of the 2015 constraints was approximately $162,000. This was a 49 percent decrease from the median impact in 2014.

Figure 42 below displays the ten most highly valued real-time congested areas as measured by congestion rent. The North to Houston interface and lines, which includes the double circuit Singleton to Zenith 345 kV lines, double circuit Gibbons Creek to Singleton 345 kV lines and double circuit Jewett to Singleton 345 kV lines, were the most congested location in 2015 at $38 million. In contrast, the most congested area in 2014 was the Heights TNP 138/69 kV autotransformers at a cost of $74 million which was due to a few months of outage-related congestion.

Figure 42: Top Ten Real-Time Constraints



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The second-highest valued congested element was the San Angelo area 138/69 kV auto-transformer with impacts of $24 million. All of the impacts occurred from February through July, and were related to a planned transformer outage that serves the San Angelo area and for the installation of a new station. This constraint is the only West zone constraint remaining in the top ten constraints following significant transmission upgrades in the West.

In aggregate, congestion related to serving load in the lower Rio Grande Valley was almost as large as the most costly single constraint, totaling $31 million. However, the impacts of the Valley Import constraint and constraints within the Valley are shown separately. The Valley Import constraint is sensitive to the amount of generation available within the Valley. It was active at times when local generating units were on unplanned or forced outage. There has been a generation change in the Rio Grande Valley of note, due to its potential impact on the congestion in the area.

In April 2015, Frontera disconnected one of the gas turbines at its combined cycle plant from the ERCOT grid and connected it to the Comisión Federal de Electricidad (CFE) grid. This switchable capability was part of the unit's original design more than fifteen years ago, but it has rarely been exercised. With the announcement that the entire Frontera combined cycle unit will disconnect from ERCOT and connect to CFE in 2016, there is an increased likelihood of congestion in the Valley, especially during construction of the 345kV lines from Lobo to North Edinburg and North Edinburg to Loma Alta. These lines are scheduled for completion in June 2016. The two constraints located within the Valley are the La Palma to Villa Cavazos 138 kV line ($12 million) and Rio Hondo to East Rio Hondo 138 kV line ($2 million). These constraints were often in effect during the time that other transmission facilities in the area were taken out of service to accommodate the construction of transmission upgrades in the area.

The next four constraints were due to planned outages and/or high loads in the area. The Collin constraint is located north of Dallas with congestion occurring solely in August. Located northwest of Houston, the Hockley to Betka constraint was the 9th most costly constraint in 2014. In July 2015 the line was congested due to a planned outage nearby. Both Cedar Hill to Mountain Creek 138 kV and Lakepoint to Carrollton Northwest 138 kV are located near the Dallas area.

Congestion on the Lon Hill to Smith 69kV line west of Corpus Christi totaled $8 million, a $10 million reduction from the cost in 2014. Congestion on this line was due to the increased loads related to oil and natural gas development in the Eagle Ford Shale. It was not an active constraint after May due to completed transmission upgrades in the area.

The last element on the list, the Marion to Skyline 345 kV line, is located north and east of San Antonio and was affected by transmission outages in the area.

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 element(s) of concern are below where needed to operate reliably. In these situations, offers from generators do not set locational prices since there are no supply options for resolving the constraint. Prices are set based on predefined rules, intended to 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.

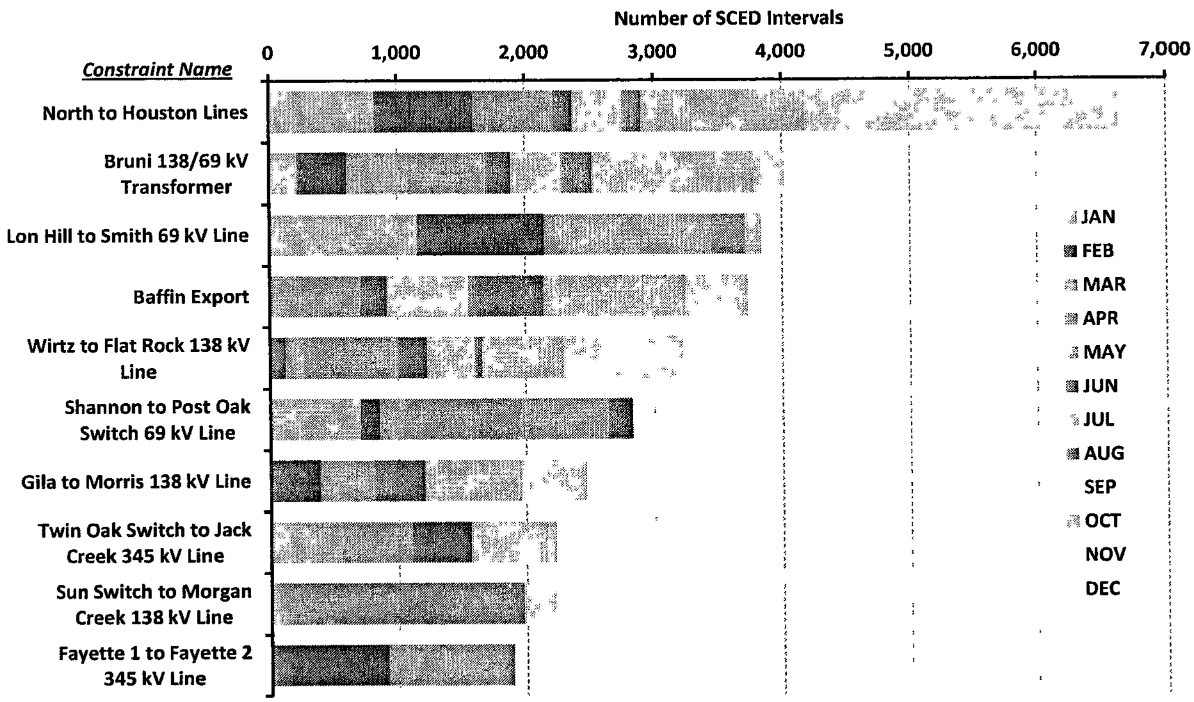
As shown below in Table 3, twelve elements were deemed irresolvable in 2015 and had a maximum shadow price cap imposed according to the Irresolvable Constraint Methodology. The two highlighted irresolvable elements were previously discussed as costly real-time constraints. Three elements were deemed resolvable during ERCOT's annual review and were removed from the list. In ERCOT's ongoing analysis, one more element was deemed resolvable in February. All three irresolvable constraints located in the South Load Zone are located in the Valley.

Table 3: Irresolvable Elements

Irresolvable Element:	Original Max Shadow Price	2015 Adjusted Max Shadow Price	Irresolvable Effective Date	Termination Date	Load Zone
Valley Import	$5,000	$2,000.00	1/1/12	-	South
Odessa Basin to Odessa North 69 kV line	$2,800	$2,800.00	1/1/12	1/30/15	West
China Grove to Bluff Creek 138 kV line	$3,500	$2,000.00	5/3/12	1/30/15	West
Morgan Creek #1 345/138 kV autotransformer	$4,500	$2,000.00	11/2/12	1/30/15	West
Midland East to Buffalo 138 kV line	$3,500	$2,377.57	7/24/14	2/11/15	West
Heights TNP #1 138/69 kV transformer	$3,500	$2,000.00	9/23/14	-	Houston
Abilene Northwest to Ely Rea Tap 69 kV line	$2,800	$2,780.38	9/26/14	-	West
Harlingen to Oleander 69 kV line	$2,800	$2,000.00	10/9/14	-	South
Rio Hondo to East Rio Hondo 138 kV line	$3,500	$2,000.00	10/10/14	-	South
Emma to Holt Switch 69 kV line	$2,800	$2,800.00	10/27/14	-	West
Heights TNP #2 138/69 kV transformer	$3,500	$2,000.00	10/28/14	-	Houston
San Angelo College Hills 138/69 kV autotransformer	$3,500	$2,000.00	7/22/15	-	West

Figure 43 presents a slightly different set of real-time congested areas. These are the most frequently occurring.

Figure 43: Most Frequent Real-Time Constraints



Of the ten most frequently occurring constraints, two have already been described as costly. They are the North to Houston Lines and Lon Hill to Smith 69kV line. The rest of the constraints, although frequently occurring, had very small financial impacts. This can result if the generation to be re-dispatched is similarly priced. The Bruni 138/69 kV transformer constraint frequently limits the output from two wind generators located east of Laredo. Similarly, the Baffin Export is also a limitation on multiple wind generators near Ajo. The Shannon to Post Oak Switch 69 kV line is located between Fort Worth and Wichita Falls. The Gila to Morris 138 kV line is located in the Corpus Christi area. Twin Oak Switch to Jack Creek 345 kV line is located between North and Houston and feeds into College Station. Sun Switch to

Morgan Creek 138 kV line is in the West and Fayette 1 to Fayette 2 345 kV line is located between Austin and Houston.

C. Day-Ahead Constraints

This subsection provides a review of the 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 day-ahead market similarly to how they transact in real-time, the same transmission constraints are expected to appear in both markets.

Figure 44: Top Ten Day-Ahead Congested Areas

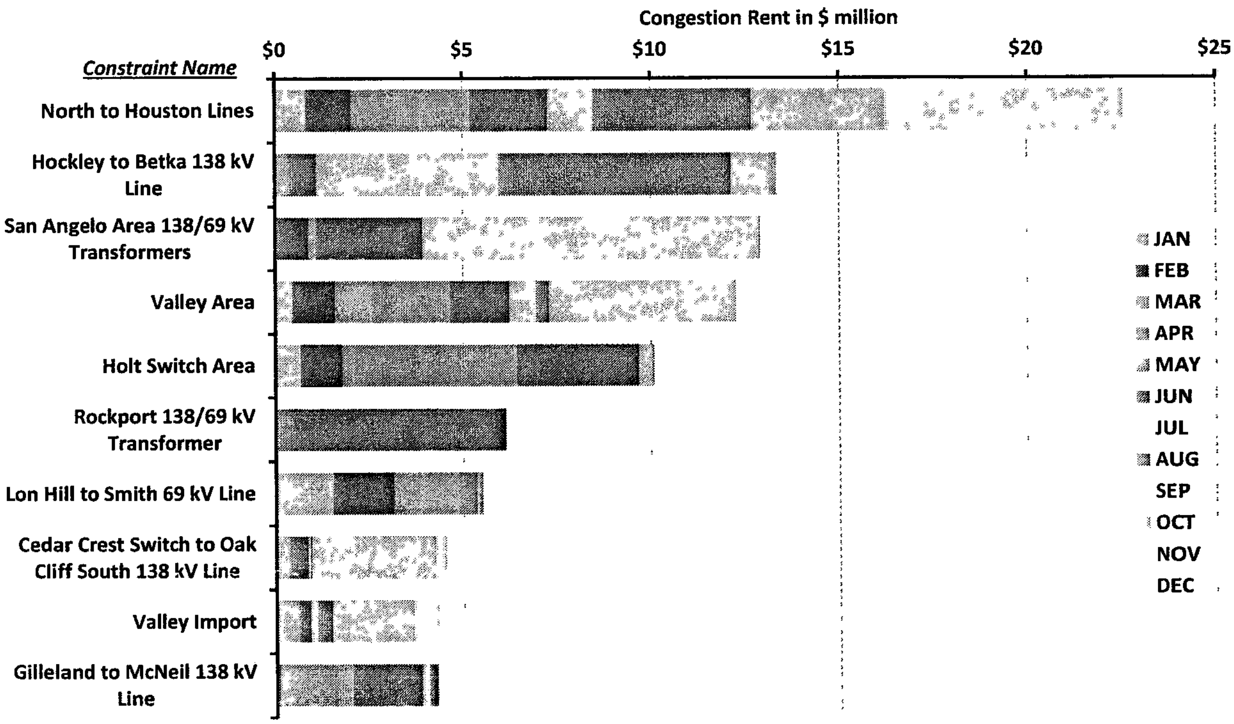
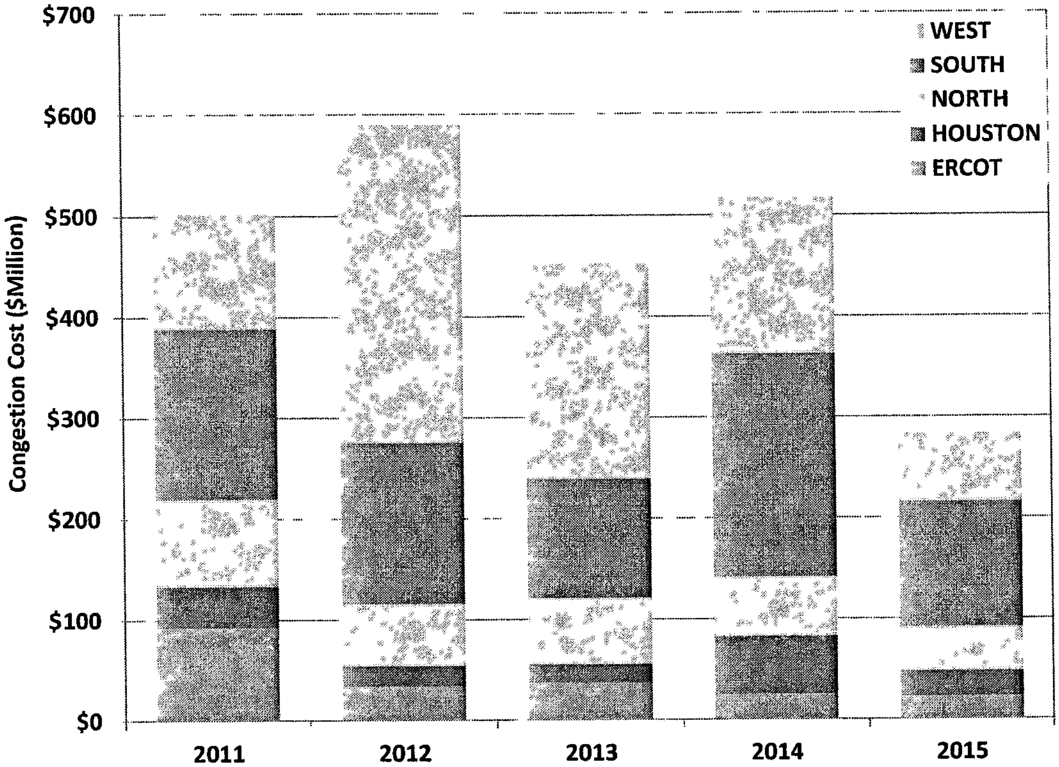


Figure 44 presents the top ten congested areas from the day-ahead market, ranked by the financial impact as measured by congestion rent. Five of the constraints listed here were previously described in the real-time subsection. Holt Switch to Amoco Midland Farms 138 kV ($6.4 million) line and the Holt Switch to Emma Tap 69 kV line ($3.7 million) comprise Holt Switch Area in the Far West. The Rockport 138/69 kV transformer is located in Corpus Christi and its congestion was likely related to expected impacts from a planned outage in the area. The last two constraints are Cedar Crest Switch to Oak Cliff South 138 kV line located in Dallas and Gilleland to McNeil 138 kV line is in Austin.

Figure 45: Day-Ahead Congestion Costs by Zone



As they were in real-time, day-ahead congestion in all zones was lower in 2015 than 2014. The total reduction in day-ahead congestion costs was 45 percent. The Houston zone experienced the greatest decrease between 2014 and 2015 with an 81 percent reduction in both day-ahead and real-time congestion costs. This is primarily because the Heights TNP transformers, located in Houston, were the subject of significant congestion in 2014.

D. Congestion Revenue 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 constraints. 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 semi-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 day-ahead locational prices of the source and sink.

Figure 46: CRR Costs by Zone

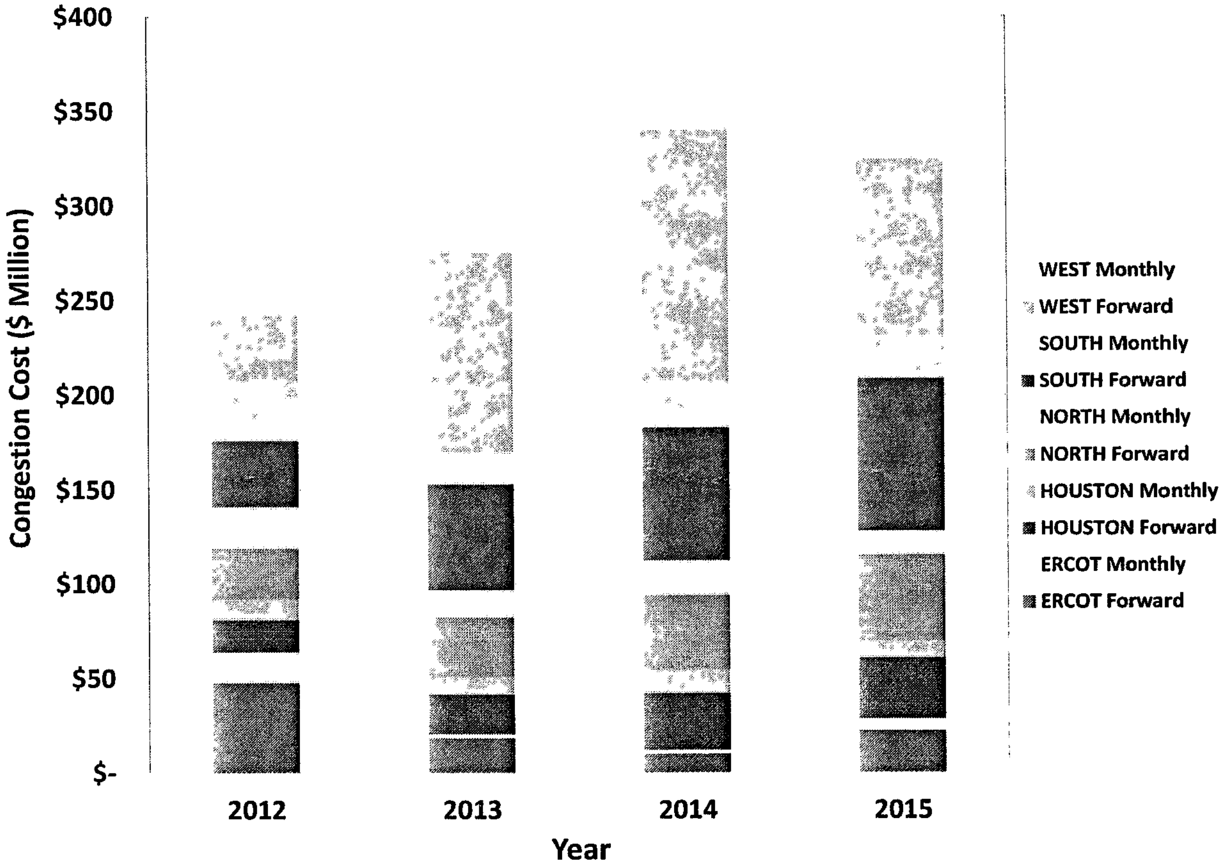
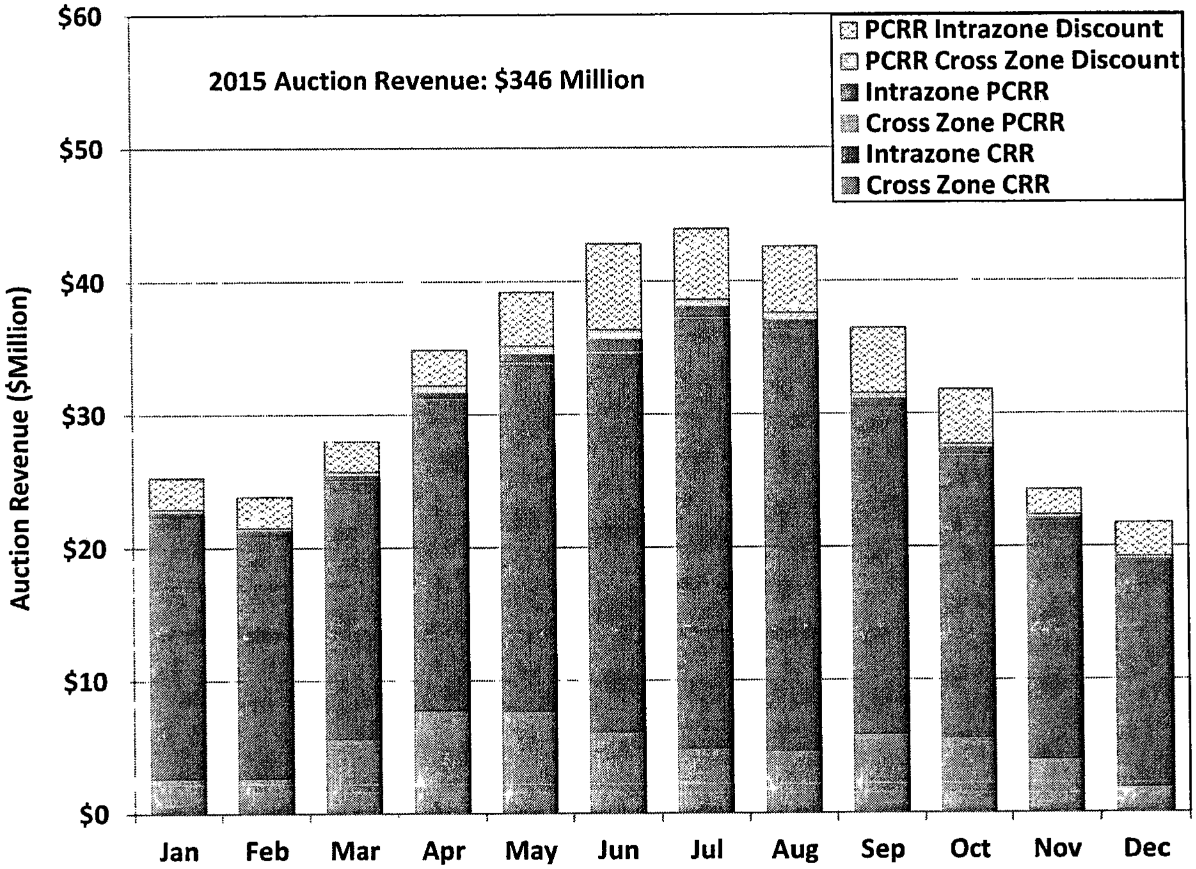


Figure 46 above details the congestion cost as calculated by shadow price and flow on binding constraints in the CRR auctions. The costs are broken down by zone and whether they were incurred in a monthly auction (Monthly) or a seasonal or annual auction (Forward). The CRR congestion shown in Figure 46 indicates different trends than the day-ahead and real-time congestion. Namely the forward congestion costs (with the exception of those in the West) increased rather than decreased. The monthly costs decreased (except for the inter-zonal "ERCOT" congestion) but did not decrease as much as the day-ahead and real-time congestion.

Figure 47 summarizes the revenues collected by ERCOT in each month for all CRRs, both auctioned and allocated.

Figure 47: CRR Auction Revenue

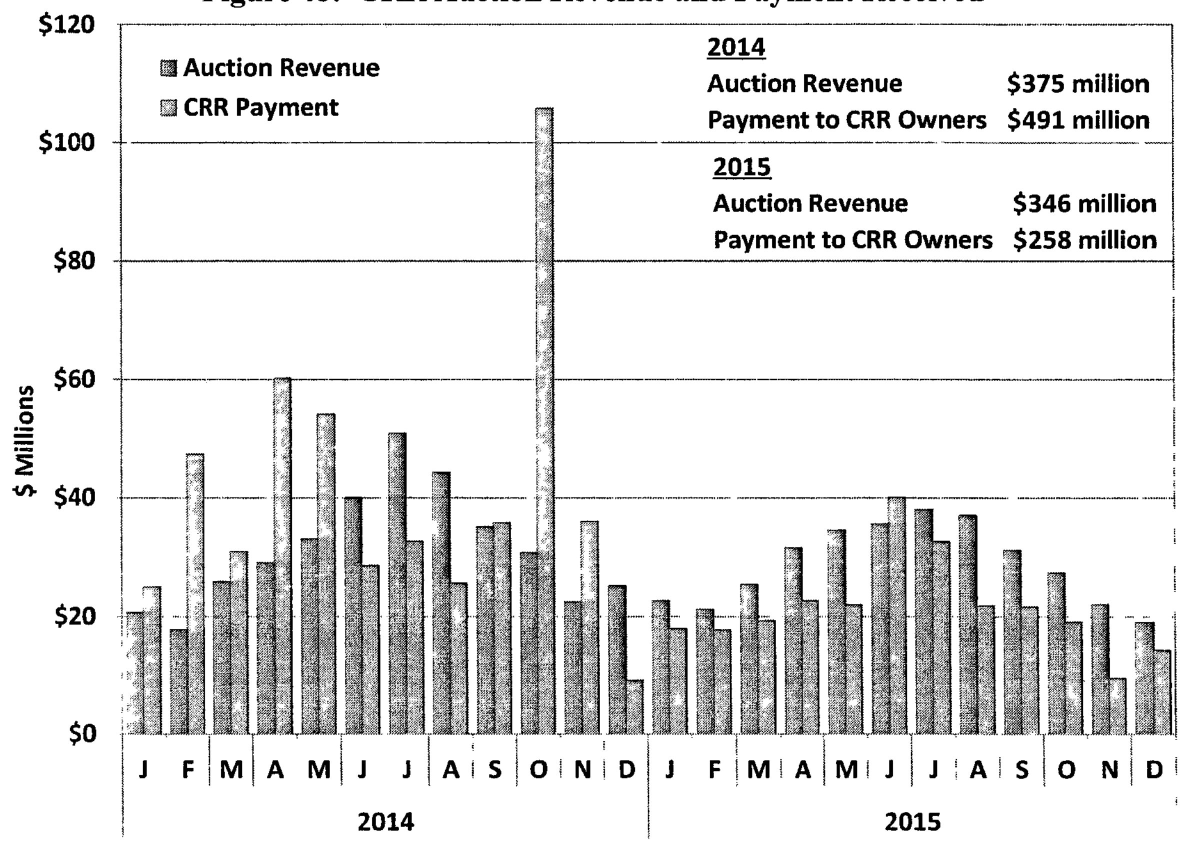


ERCOT distributes these revenues to loads in one of two ways. Revenues from cross-zone CRRs are allocated to loads ERCOT wide. Revenues from CRRs that have the source and sink in the same geographic zone are allocated to loads within that zone. This method of revenue allocation provides a disproportionate share of CRR Auction revenues to loads located in the West zone. In 2015, CRRs with both the source and sink in the West zone accounted for 32 percent of CRR Auction revenues. This revenue was allocated to West zone loads, which accounted for only 9 percent of the ERCOT total. By comparison, in 2014, 42 percent of CRR Auction revenues were allocated to the West zone load, which accounted for 9 percent of the ERCOT total. Allocating CRR Auction revenues in this manner helps reduce the impact of the higher congestion on West zone prices. As shown in Figure 3, the annual average real-time energy price for the West zone was $26.83 per MWh, 6 cents per MWh higher than the ERCOT-wide average. The value of CRR Auction revenues distributed only to the West zone equated to $2.79 per MWh higher than the ERCOT-wide average distribution of CRR Auction revenues. In 2015, like 2014, the effective load zone price for the West zone, $23.05 per MWh, was the lowest in ERCOT.

As previously mentioned in this section, purchasers of PCRRs are only charged a fraction of the PCRR auction value. The difference between the auction value and the value charged to the purchaser is shown in Figure 47 as the PCRR Discount. The total PCRR discount for 2015 was $49 million.

Next, Figure 48 compares the value received by CRR owners (in aggregate) to the price paid to acquire the CRRs.

Figure 48: CRR Auction Revenue and Payment Received

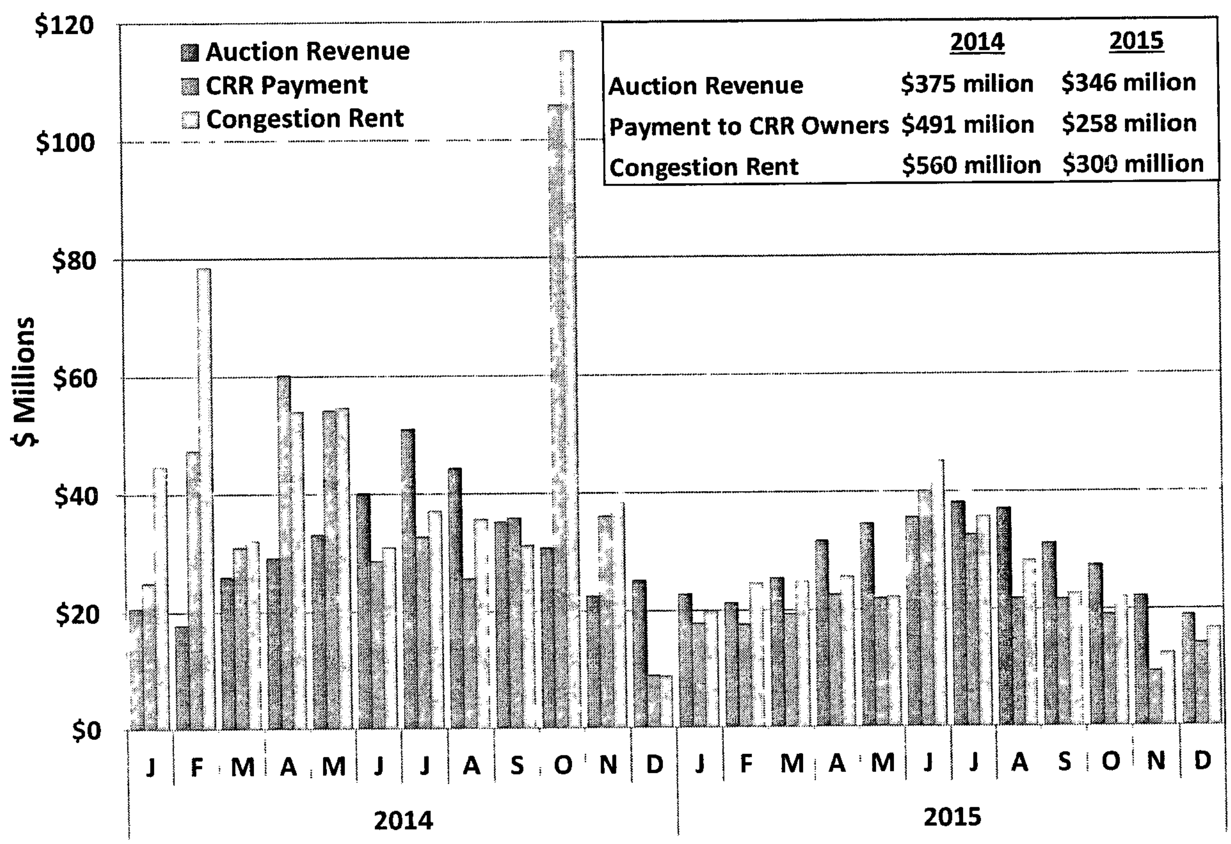


Although results for individual participants and specific source/sink combinations varied, the aggregated results for the year and in most months show that participants overpaid to acquire

CRRs in 2015. This is the first time since the implementation of the Nodal market that is the case. For the entire year of 2015 participants spent $346 million to procure CRRs and received $258 million.

The next analysis of aggregated CRR positions adds day-ahead congestion rent to the picture. Day-ahead congestion rent is the difference between the total costs that loads pay and the total revenue that generators receive in the day-ahead market. Day-ahead congestion rent creates the source of funds used to make payments to CRR owners. Figure 49 presents CRR Auction revenues, payment to CRR owners, and day-ahead congestion rent in 2014 and 2015, by month. Congestion rent for the year 2015 totaled $300 million and payment to CRR owners was $258 million.

Figure 49: CRR Auction Revenue, Payments and Congestion Rent



The target value of a CRR is the MW amount of the CRR multiplied by the LMP of the sink of the CRR less the LMP of the source of the CRR. While the target value is paid to CRR account holders most of the time, there are two circumstances where an amount less than the target value is paid. The first circumstance happens when the CRR is modeled on the day-ahead network and causes a flow on a transmission line that exceeds the line's limit. In this case, CRRs with a positive value that have a source and/or a sink located at a resource node settlement point are often derated, that is, paid a lower amount than the target value.

The second circumstance occurs when there is not enough day-ahead congestion rent to pay all the CRRs at target (or derated, if applicable) value. In this case, all holders of positively valued CRRs receive a prorated shortfall charge such that the congestion revenue plus the shortfall charge can pay all CRRs at target or derated value. This shortfall charge has the effect of lowering the net amount paid to CRR account holders; however, if at the end of the month there is excess day-ahead congestion rent that has not been paid out to CRR account holders, the excess congestion rent can be used to make whole the CRR account holders that received shortfall charges. If there is not enough excess congestion rent from the month, the rolling CRR balancing fund can be drawn upon to make whole CRR account holders that received shortfall charges.

2015 was the first full year with a rolling CRR balancing fund.[14] The CRR balancing fund grew from $20 thousand to its capped present value of $10 million and was only drawn upon once to cover a shortfall of $1.3M for the month of May.

[14] The CRR Balancing Fund was implemented with NPRR580.

Figure 50: CRR Shortfalls and Derations

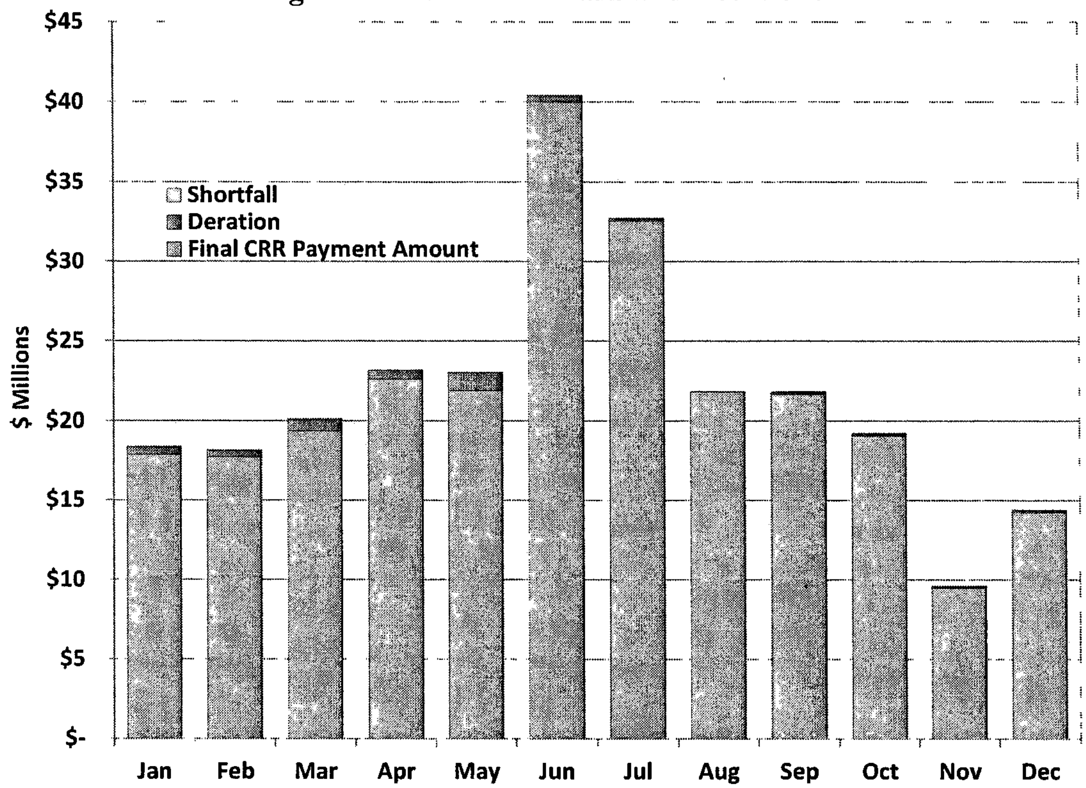


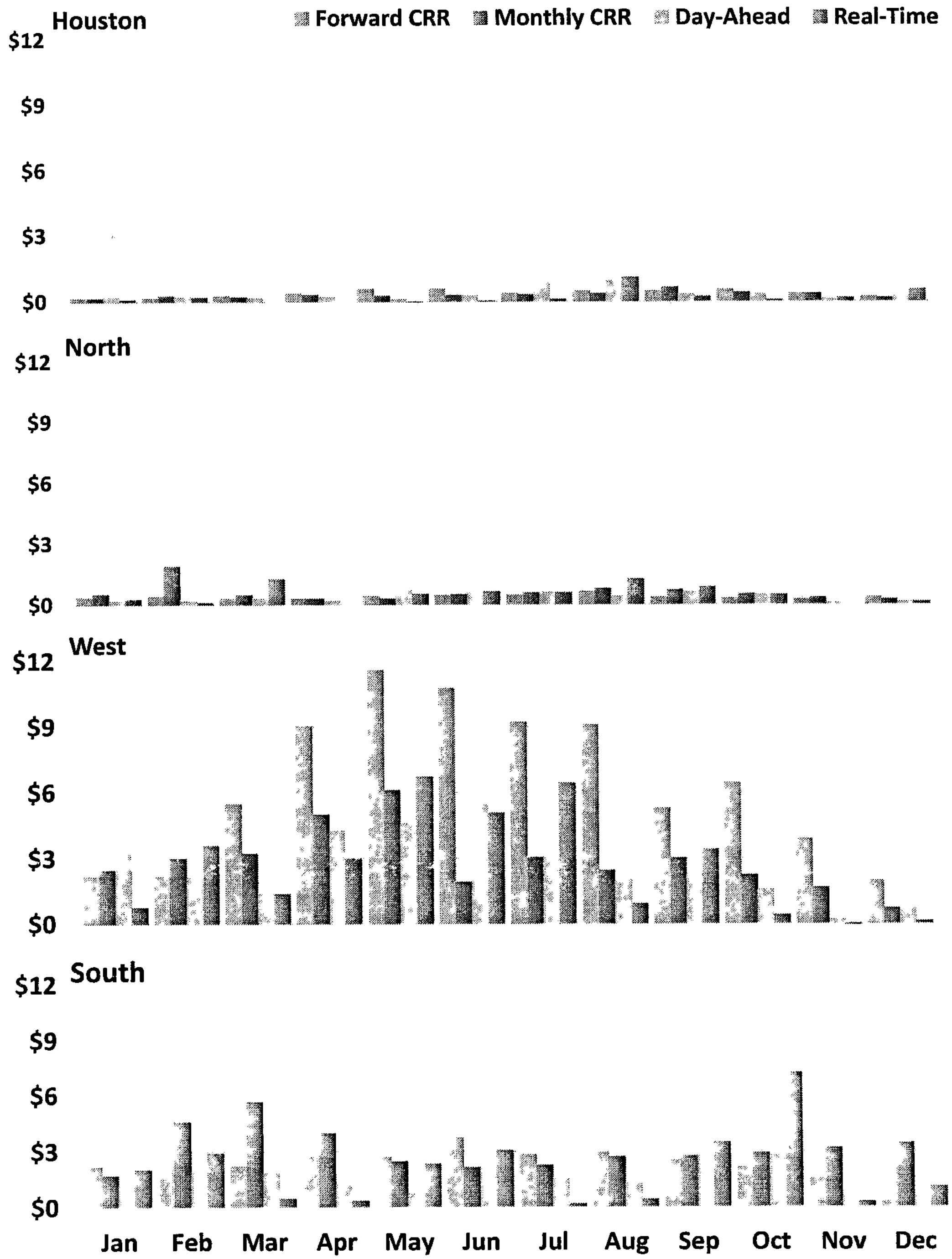
Figure 50 shows the amount of target payment, deration amount, and net shortfall charges (after make whole payments) for 2015. In 2015 the total target payment to CRRs was $262 million; however, there were $4.3 million of derations and no shortfall charges leaving a final payment to CRR account holders of $258 million. This corresponds to a CRR funding percentage of 98 percent.

The last look at congestion examines the price spreads for each pair of hub and load zone in more detail. These price spreads are interesting as many loads may have contracts that hedge them to the hub price and are thus exposed to the price differential between the hub and its corresponding load zone. Figure 51 presents the price spreads between all Hub and load zones as valued at four separate points in time – at the semi-annual CRR Auction, monthly CRR auction, day-ahead and in real-time.

Of note is that the same intra-zone congestion that drives the relatively high CRR auction revenue amounts for the West zone also drives high price spreads between the West hub and the

West load zone. Of the other zones only the South has an average price spread over a dollar per MWh.

Figure 51: Hub to Load Zone Price Spreads

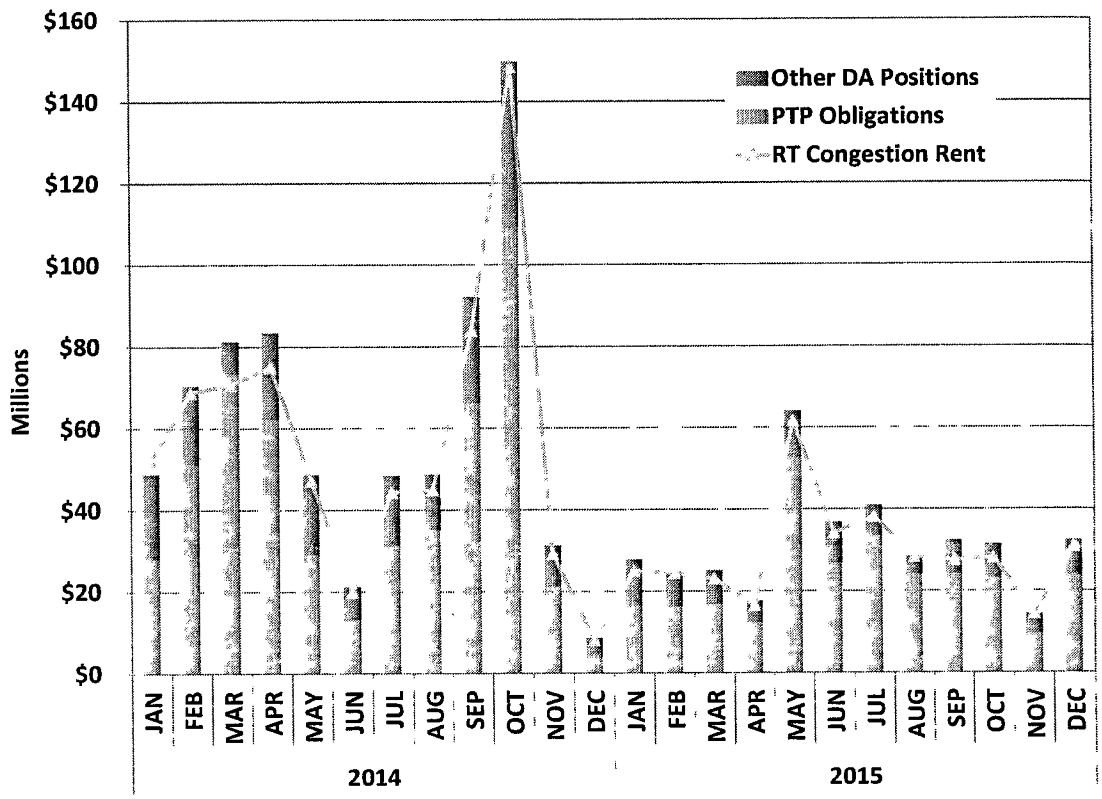


E. Revenue Sufficiency

In Figure 52 the combined payments to Point-to-Point (PTP) Obligation owners and effective payments to other day-ahead positions are compared to the total real-time congestion rent. For 2015, real-time congestion rent was $352.3 million, payments for PTP Obligations (including those with links to CRR Options) were $279.8 million and payments for other day-ahead positions were $95.3.3 million, resulting in a shortfall of approximately $23 million for the year.

By comparison, the real-time congestion rent was $692.5 million in 2014. Payments for PTP Obligations and real-time CRRs were $524.5 million and payments for other day-ahead positions were $207.5 million, resulting in a shortfall of approximately $39.5 million for the year.

Figure 52: Real-Time Congestion Rent and Payments



Most of the 2015 shortfall, $16.5 million, was the result of settling PTP Obligations with links to CRR Options as options. The remainder is the result of discrepancies between transmission topology assumptions used when clearing the day-ahead market and the actual transmission topology that occurs during real-time. The total shortfall is effectively paid by all loads, allocated on a load-ratio share.