Shown on the left side of Figure 17 is the relationship between real-time energy price and load level for each dispatch interval for the months of August 2011, 2012, 2013, and 2014. ERCOT loads were greater than 65 GW for 71 hours in 2011, whereas loads reached that level for 12 hours during August 2012, 18 hours in August 2013 and 11 hours in August 2014. As previously discussed, a strong positive correlation between higher load and higher prices is expected in a well-functioning energy market. Such a relationship between higher prices and higher load is observed in this analysis. However, that relationship appears to be weaker in the past three years with more instances of higher prices occurring at lower loads.

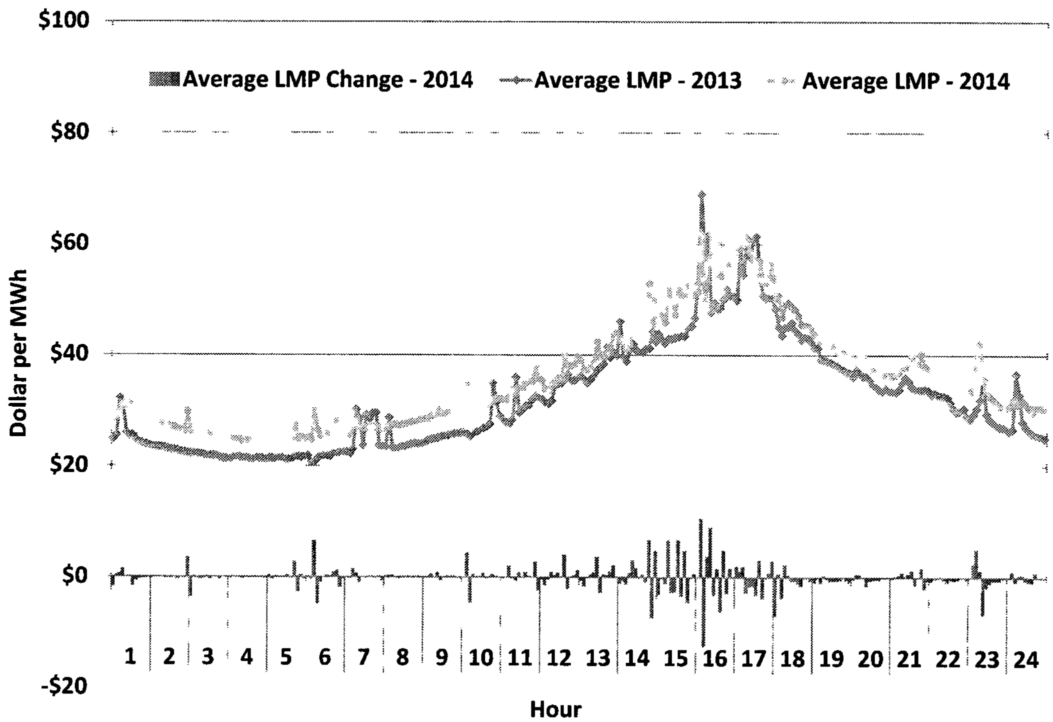
Although load levels are strong predictors of energy prices, an even more important predictor is the level of operating reserves. Simply put, operating reserves are the difference between the total capacity of operating resources and the current load level. As load level increases against a fixed quantity 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 and the associated value of loss of load.

On the right side of Figure 17 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, 2013, and 2014. This figure shows a strong correlation between diminishing operating reserves and rising prices. With the lower loads in August 2012, 2013, and 2014, available operating reserves were 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, 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 when 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.C., Demand Response Capability, at page 79, an example is provided explaining why this can occur and a recommendation for improvement is offered.

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 18 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 2013 are also presented. Comparing average real-time energy prices for 2014 with those from 2013, the effects of higher natural gas prices on average prices may be observed.

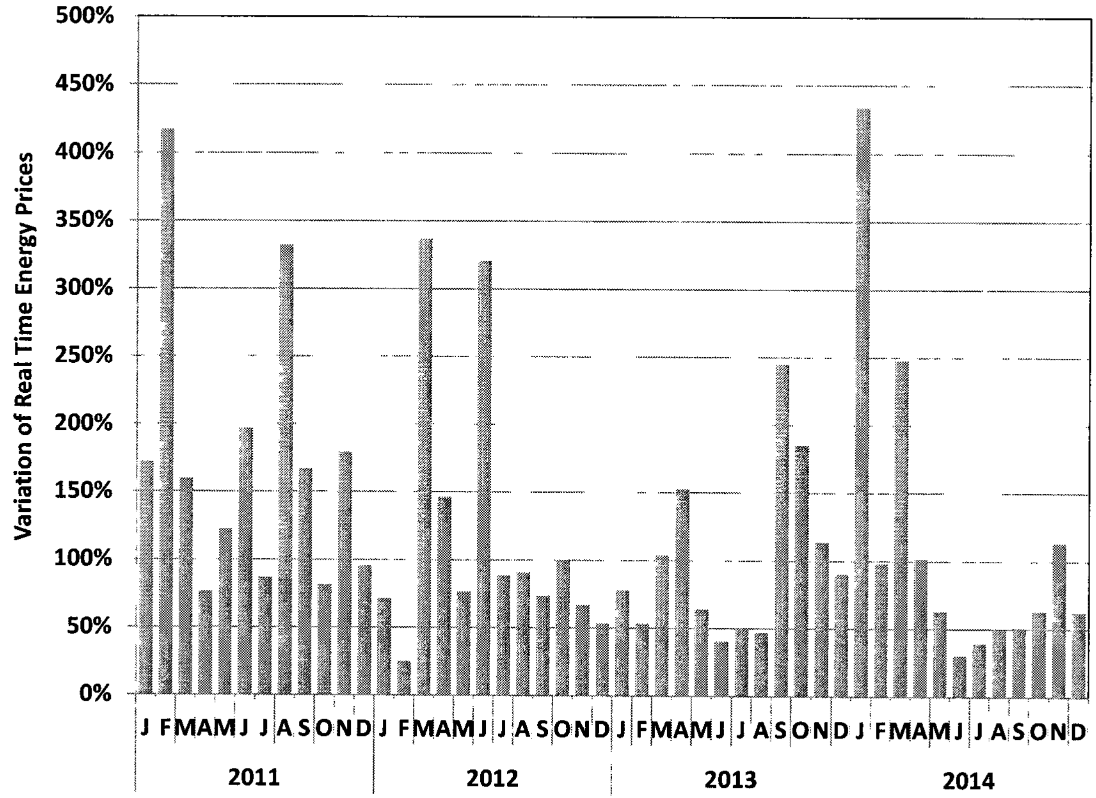
Figure 18: Real-Time Energy Price Volatility (May – August)



Outside of the hours from 15 to 18 , 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 are changing online status. The price effects of these ramp-limited periods were similar in 2013 and 2014. The average of the absolute value of changes in five-minute real-time energy prices, expressed as a percentage of average price, was 3.0 percent in 2014, compared to 3.4 percent in 2013, 3.6 percent in 2012 and approximately 6.2 percent for the same period in 2011. This steady decline may be attributed to a decrease in shadow price cap intervals from 2011-2012 and the decrease in West zone price volatility from 2012 to 2014.

Expanding the view of price volatility, Figure 19 below presents the monthly variation in real-time prices. The highest price variability occurs during months when real-time prices rose to the system wide offer cap.

Figure 19: Monthly Price Variation



The volatility of 15-minute settlement point prices for the four geographic load zones in 2014 was similar to that seen in 2013 and 2012, as shown below in Table 1.

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

Load Zone	*2012*	*2013*	*2014*
Houston	13.0%	14.8%	14.7%
South	13.1	15.4	15.2
North	13.9	13.7	14.1
West	19.4	17.2	15.4

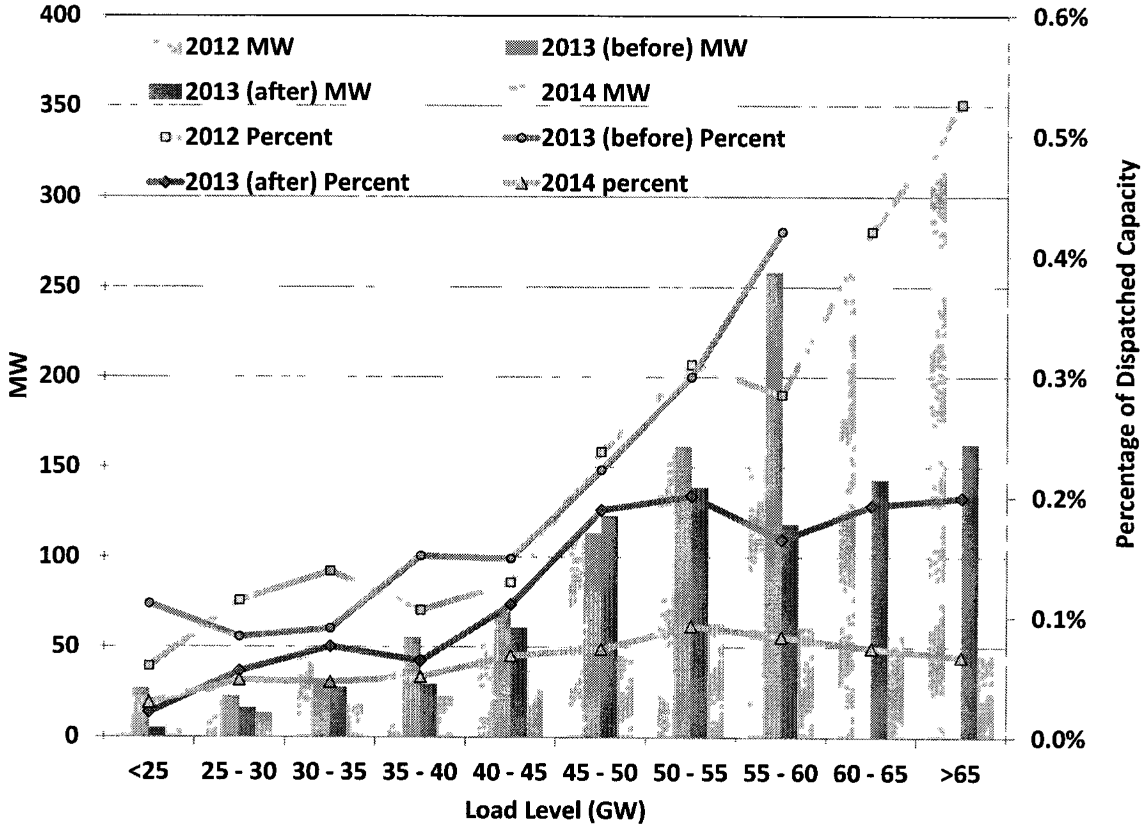
Price volatility in the Houston, North, and South zones was similar in 2014 to the levels experienced in 2013. The table also shows that price volatility in the West zone has decreased, likely as a result of transmission investment in the region. Price volatility in the West zone in 2014 was similar to the other zones.

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 its output to resolve. In this subsection the quantity of capacity being mitigated in 2014 during this mitigation process is analyzed. 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 its 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 those offers as well. This unnecessary mitigation was addressed on June 12, 2013 with the implementation of 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.

The analysis shown in Figure 20 computes how much capacity, on average, is actually mitigated during each dispatch interval. The results are provided by load level.

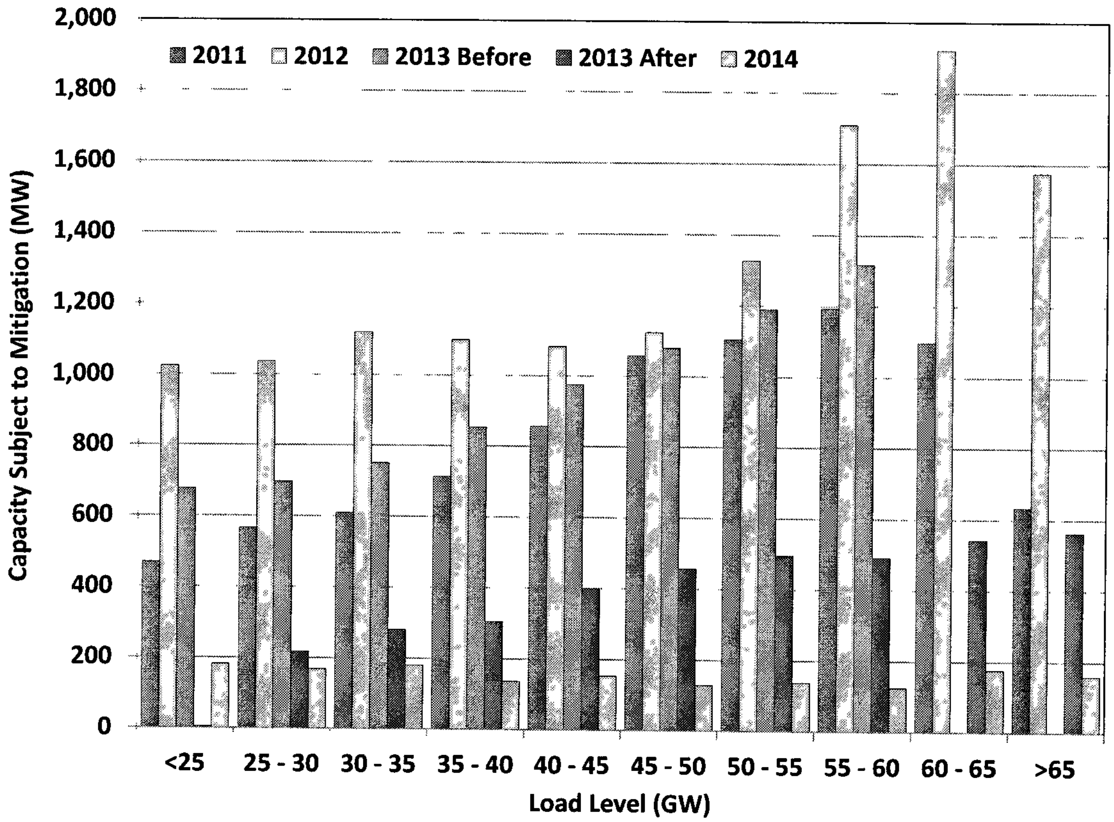
Figure 20: Mitigated Capacity by Load Level



The level of mitigation in 2014 was much lower than in 2012 and 2013, even after the mitigation rule changed in mid-2013. The amount of mitigated capacity averaged just over 60 MW at its highest during 2014. At similar load levels in 2013 (after the change) the mitigated amounts were well over 100 MW and exceeded 150 MW at the very highest load levels. One explanation for this reduction is that the higher gas prices in 2014 led to an increase in the mitigated offer cap and a corresponding reduction in the amount of offers over the mitigated offer cap. A second explanation is the decrease in the number of intervals during 2014 when congestion was present. As described later in Section III. Transmission and Congestion, congestion occurred in only 44 percent of intervals in 2014 compared to 55 percent in 2013.

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, as shown in Figure 21.

Figure 21: Capacity Subject to Mitigation

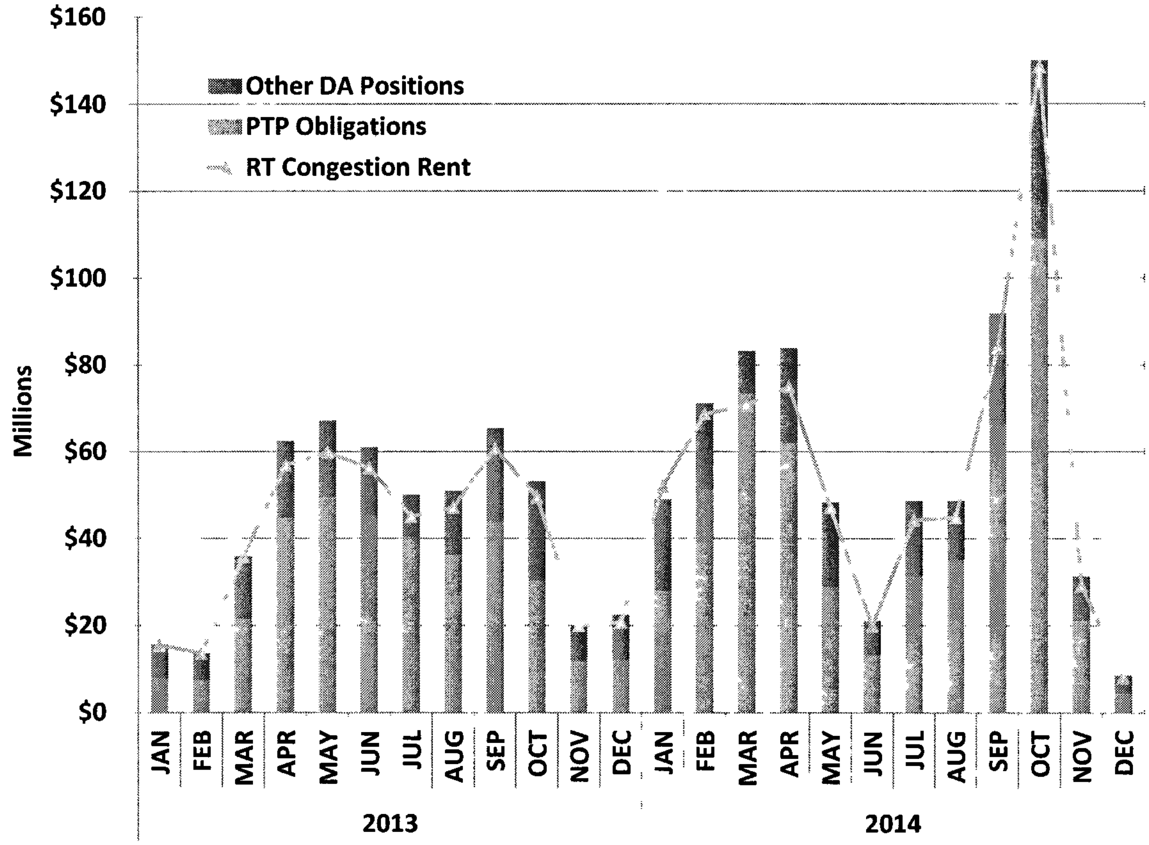


The effects of the rule change are very noticeable in Figure 21. Compared to 2012 when the amount of capacity subject to mitigation exceeded 1500 MW for all load levels, the amount of capacity subject to mitigation after the rule change in 2013 was always below 700 MW. In 2014, the largest amount being mitigated was lower than 350 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 less than 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.

G. Revenue Sufficiency

In Figure 22 the combined payments to PTP Obligation owners and effective payments to other day-ahead positions are compared to the total real-time congestion rent. For the year of 2014, real-time congestion rent was $692.5 million, payments for PTP Obligations (including those with links to CRR Options) were $524.5 million and effective payments for other day-ahead positions were $211.3 million, resulting in a shortfall of approximately $43 million for the year. This shortfall is effectively paid by all loads, allocated on a load ratio share.

Figure 22: Real-Time Congestion Rent and Payments



For the year of 2013, real-time congestion rent was $481 million, payments for PTP Obligations and real-time CRRs were $352 million and effective payments for other day-ahead positions were $167 million, resulting in a shortfall of approximately $37 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 and the balance will be uplifted to 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. In addition to power, the day-ahead market also includes ancillary services and 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 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 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 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, price convergence between the day-ahead and real-time markets is evaluated. 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, 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. 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.

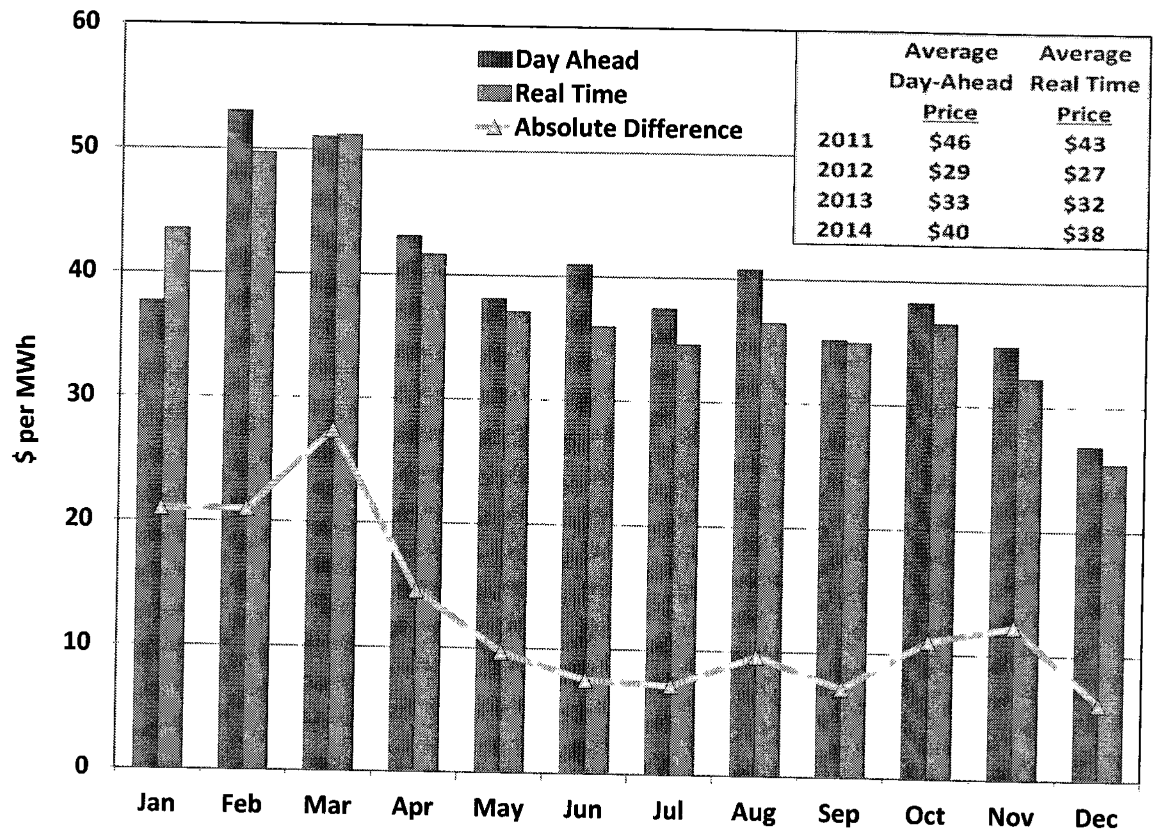
Figure 23 shows the price convergence between the day-ahead and real-time market, summarized by month. Day-ahead prices averaged $40 per MWh in 2014 compared to an average of $38 per MWh for real-time prices.[4] The average absolute difference between day-ahead and real-time prices was $12.87 per MWh in 2014; higher than in 2013 when the average of the absolute difference was $9.86 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 relative demand and highest prices.

The overall day-ahead premium increased in 2014 compared to 2013, as a result of the much higher premiums in January through March. Although peak loads during the winter are somewhat lower than those in the summer, loads during the first months of 2014 set record highs for that time of the year. Day-ahead premiums in ERCOT remain higher than observed in other

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

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 2014, 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 January and March).

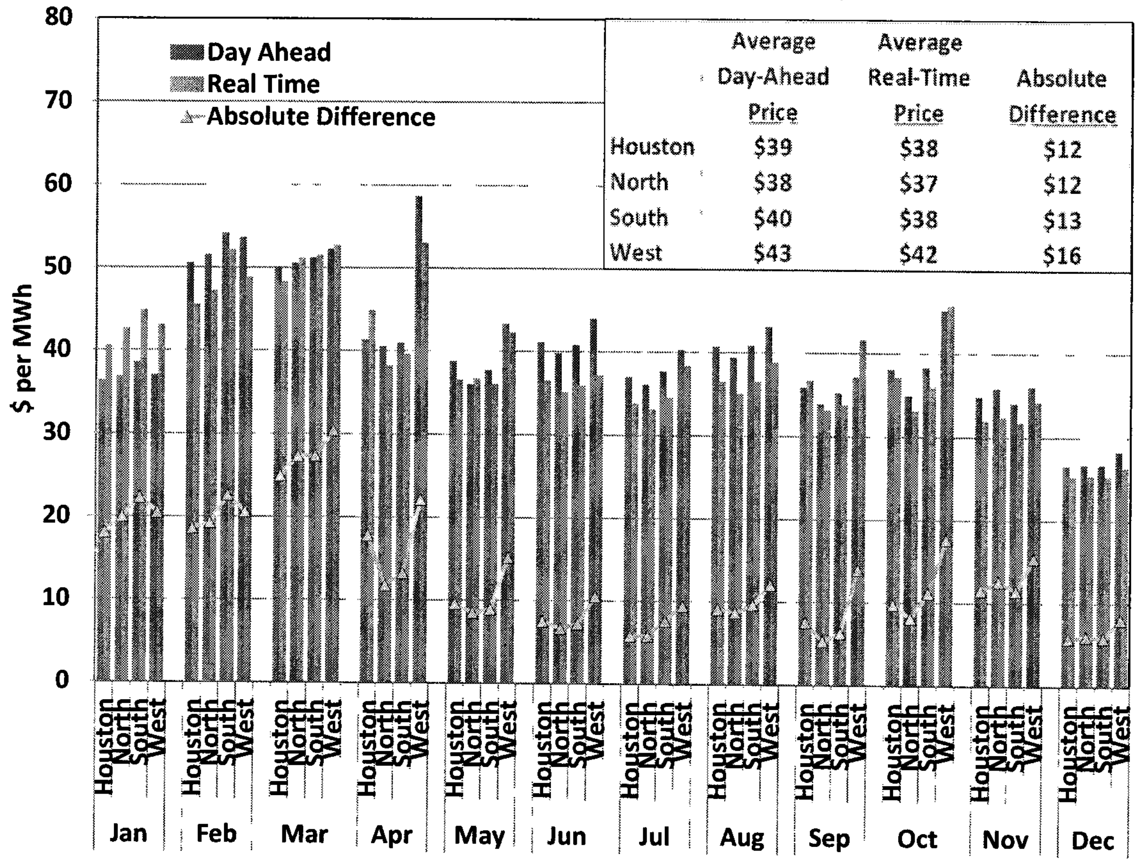
Figure 23: Convergence Between Forward and Real-Time Energy Prices



	Average Day-Ahead Price	Average Real Time Price
2011	$46	$43
2012	$29	$27
2013	$33	$32
2014	$40	$38

In Figure 24 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 24: 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 25 below shows 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 2014, which is similar to 2013 activity.

As discussed in more detail in the next subsection, PTP 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, all of these "transfers" are aggregated with other energy purchases and sales, netting location specific injections against withdrawals to arrive at a net system flow. The net system flow in 2014 was almost 5 percent higher than in 2013.

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 is greater than real-time load by an average of 14 percent. The volume in excess of real-time load increased in 2014 compared to 2013, when on average the monthly net system flow volume was 12 percent greater than real-time load.

Figure 25: Volume of Day-Ahead Market Activity by Month

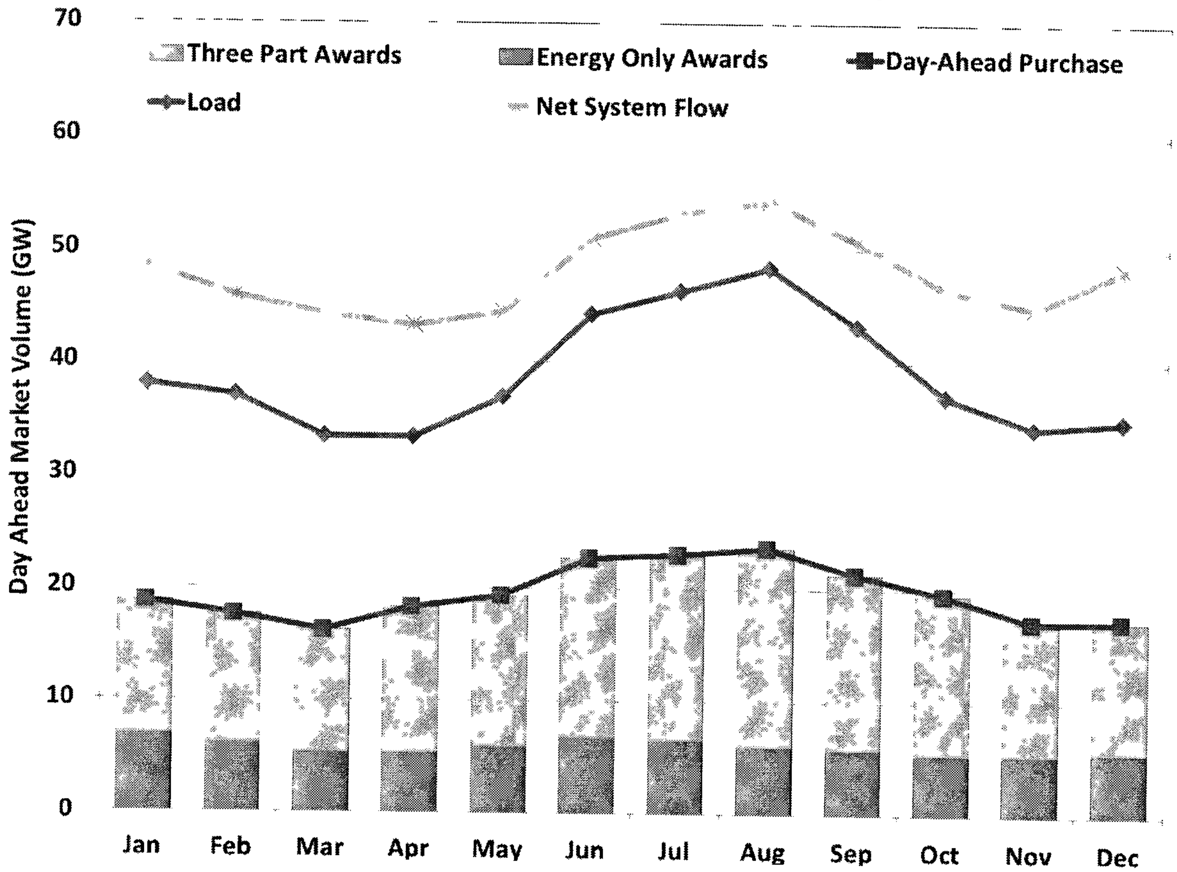
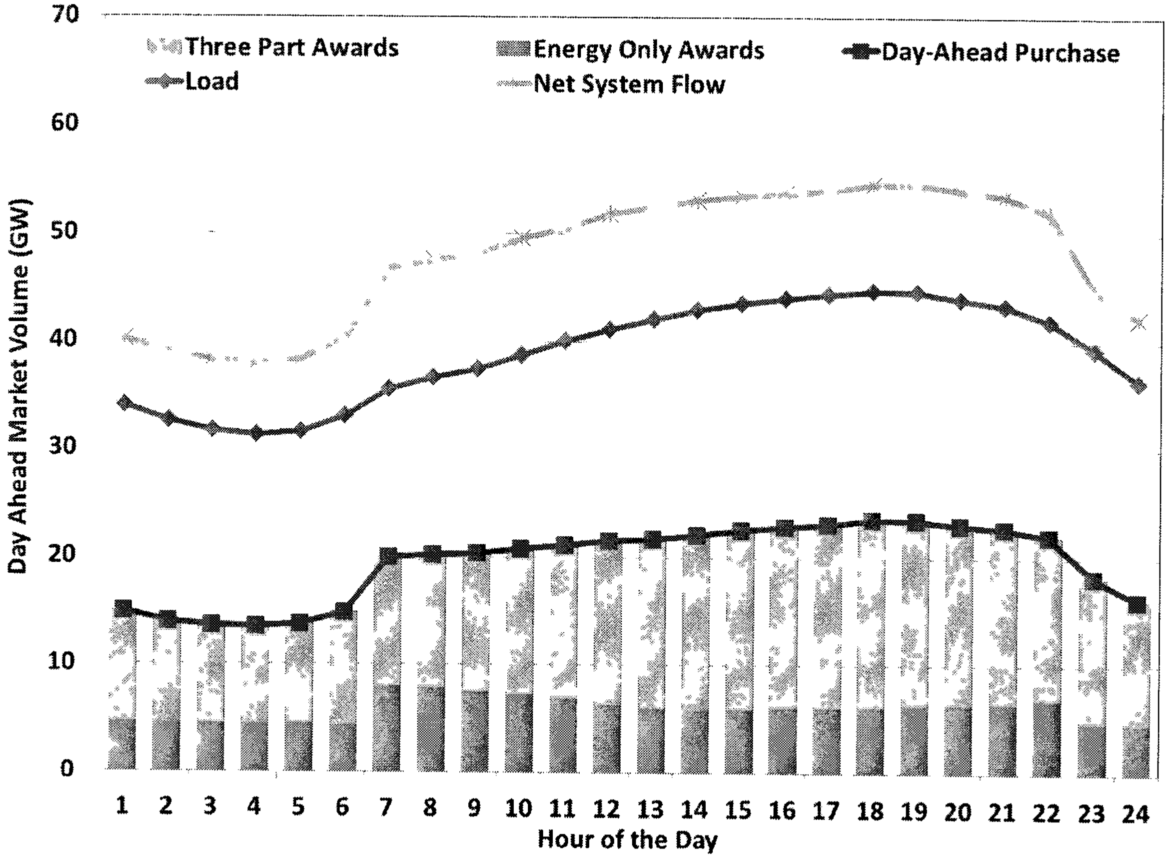


Figure 26 below, presents the same day-ahead market activity data summarized by hour of the day. In this figure the volume of day-ahead market transactions is disproportionate with load levels between the hours of 6 and 22. Since these times align with common bilateral transaction terms, it appears that market participants are using the day-ahead market to trade around those positions.

Figure 26: 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. These instruments are similar to, and can be used to complement Congestion Revenue Rights (CRRs). CRRs, as more fully described in Section III. Transmission and Congestion, 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 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 its hedge to real-time. Additional details about the volume and profitability of these PTP Obligations are provided in this subsection.

Figure 27: Point to Point Obligation Volume

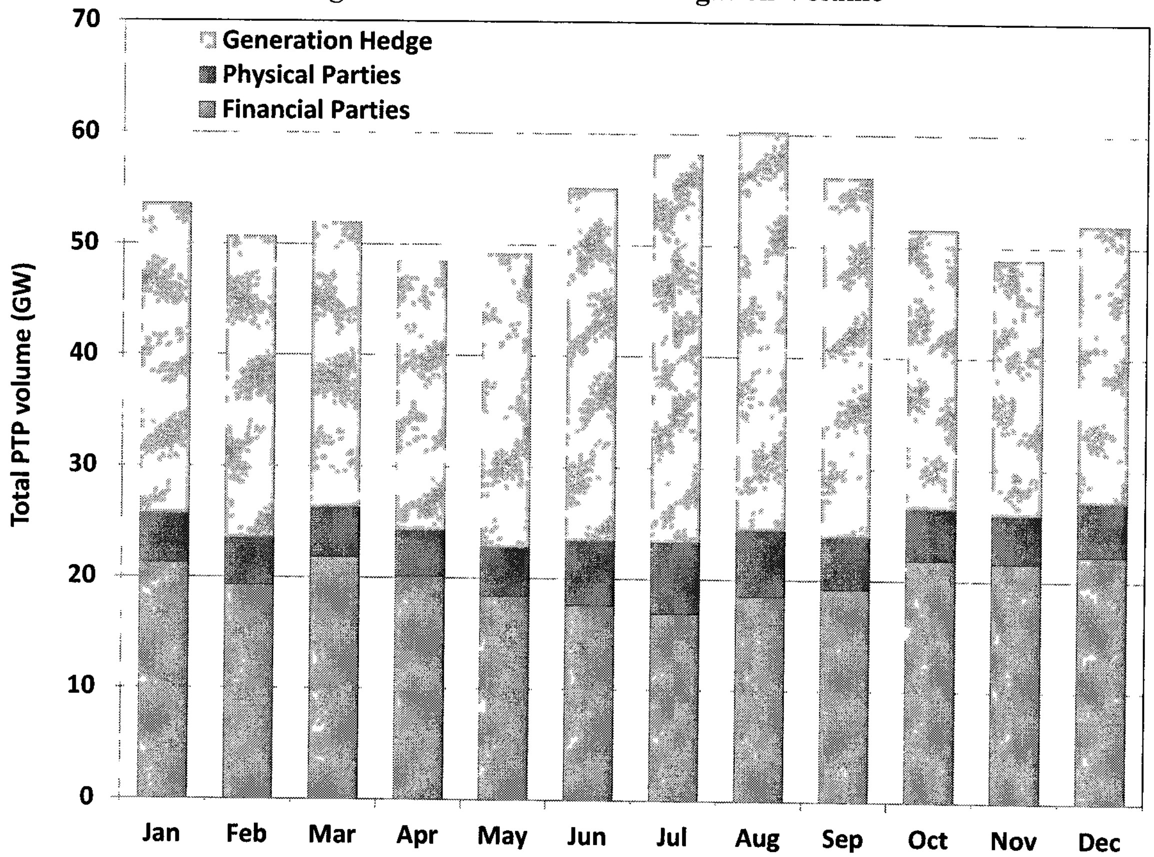
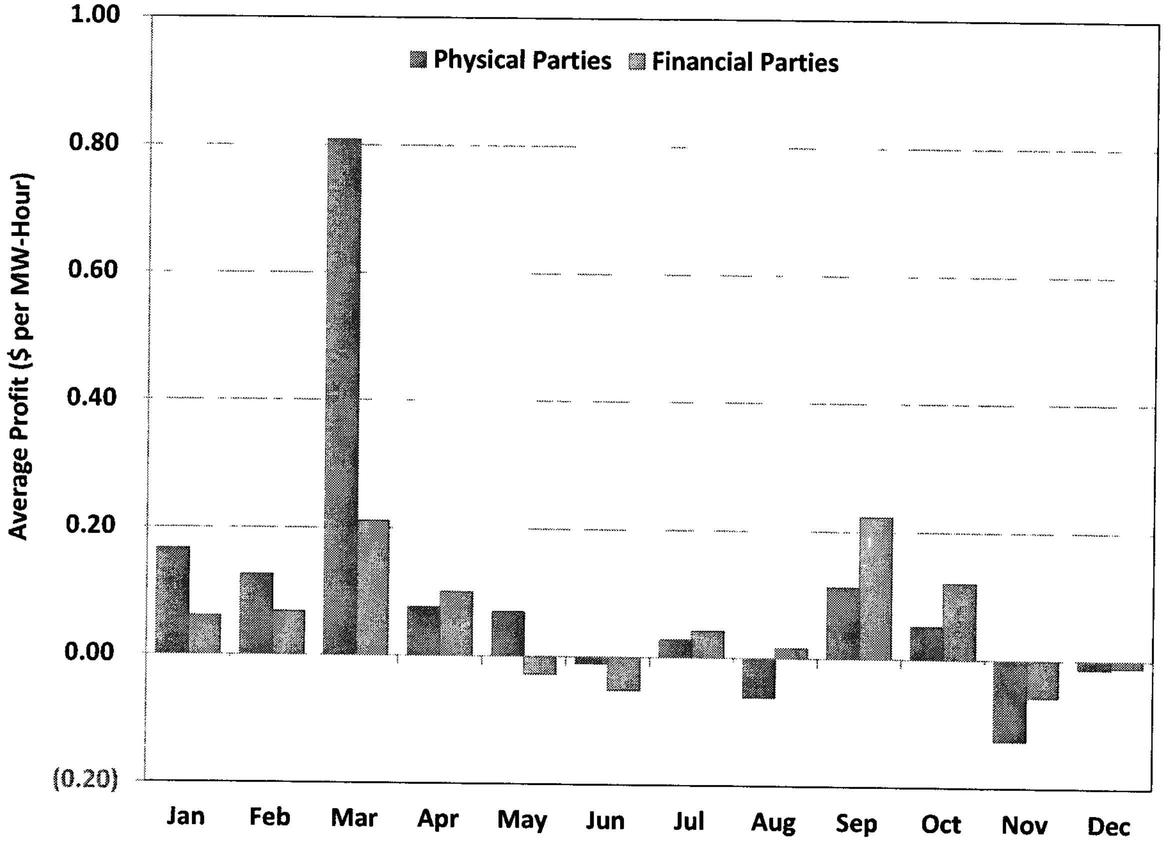


Figure 27 presents the total volume of PTP Obligation purchases divided into three categories. Compared to the previous two figures which showed net flows associated with PTP Obligations, in this figure the total volume is presented. For all PTP Obligations that source at a generator location, the capacity up to the actual generator output is considered a generator hedge. 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 profit from 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 have made a profit. Conversely, if the price difference does not materialize in real-time, the PTP Obligation may be considered unprofitable. The profitability of PTP Obligation holdings by the two types of participants are compared in Figure 28.

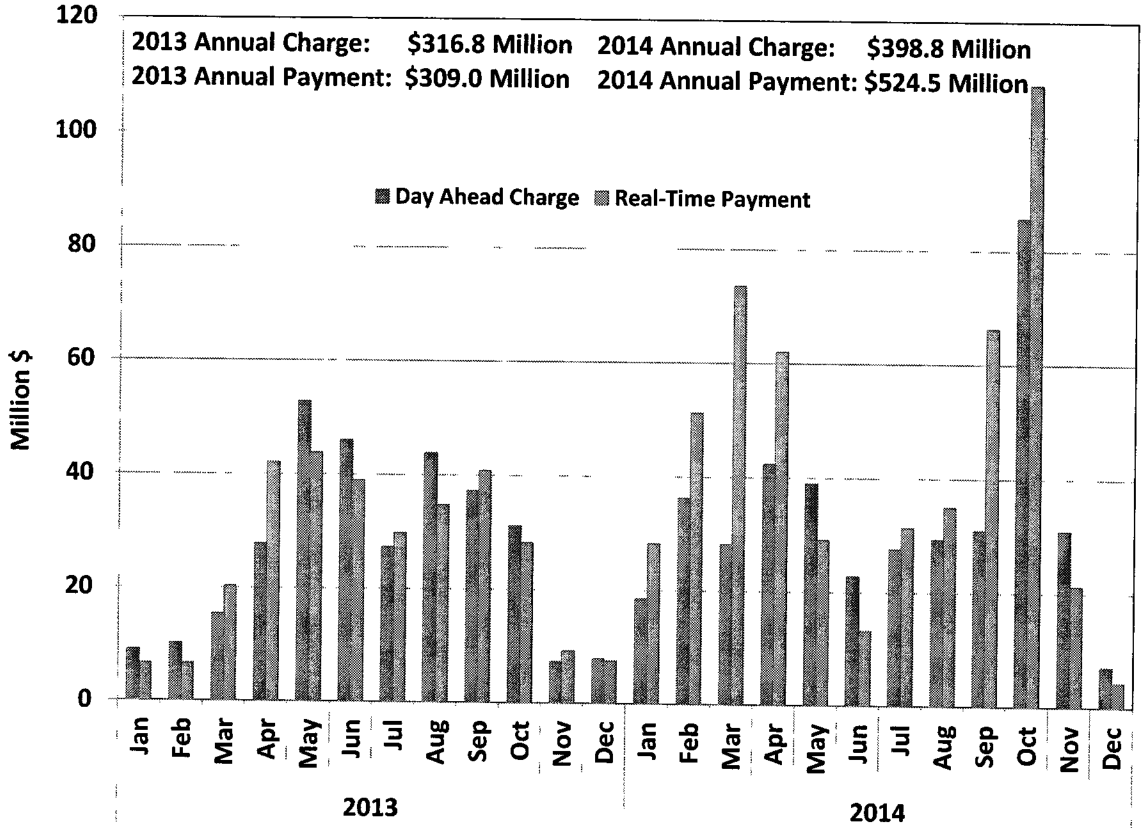
Figure 28: Average Profitability of Point to Point Obligations



This analysis shows that in aggregate the PTP Obligation holdings of both physical and financial participants were profitable. However, both financial and physical participants had four months where PTP Obligation holdings were unprofitable. It may be inferred from the data shown in Figure 28 and in Figure 29 that PTP Obligation holdings, in aggregate, were more profitable in 2014 than they were in 2013.

To conclude the analysis of PTP Obligations, Figure 29 compares the total amount paid for these instruments day-ahead, with the total amount received by holders in real-time.

Figure 29: Point to Point Obligation Charges and Payments

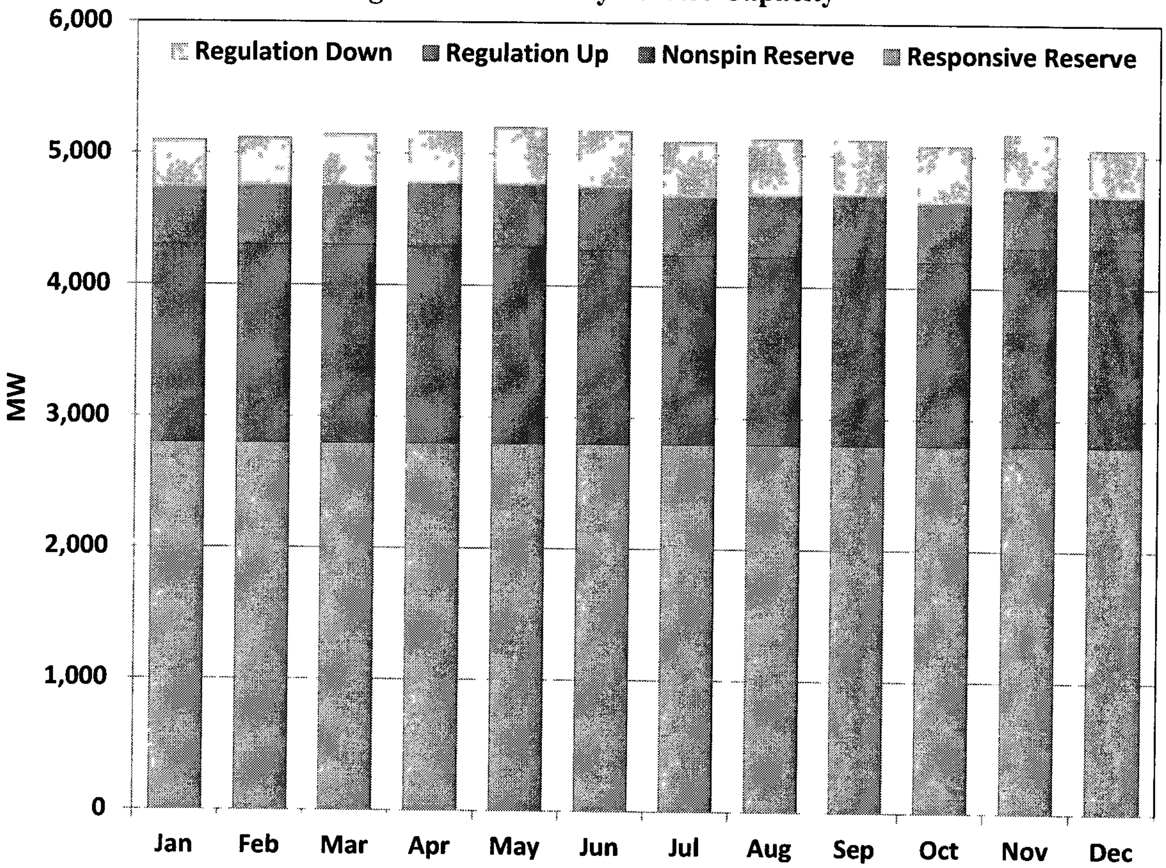


As in prior years, with the exception of 2013, the aggregated total payments received by PTP Obligation owners was greater than the amount charged to the owners to acquire them. This occurs when real-time congestion is greater than what occurred in the day-ahead. Across the year, and in eight of twelve months, the acquisition charges were less than the payments received, implying that expectations of congestion as evidenced by day-ahead purchases were less than the actual congestion that occurred in real-time. 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. Transmission and Congestion.

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 2014, starting with a display of the quantities of each ancillary service procured each month shown in Figure 30.

Figure 30: 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 do not 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 in the day-ahead market, ancillary services prices are highly correlated with day-ahead energy prices and, by extension, with real-time energy prices.

Figure 31: Ancillary Service Prices

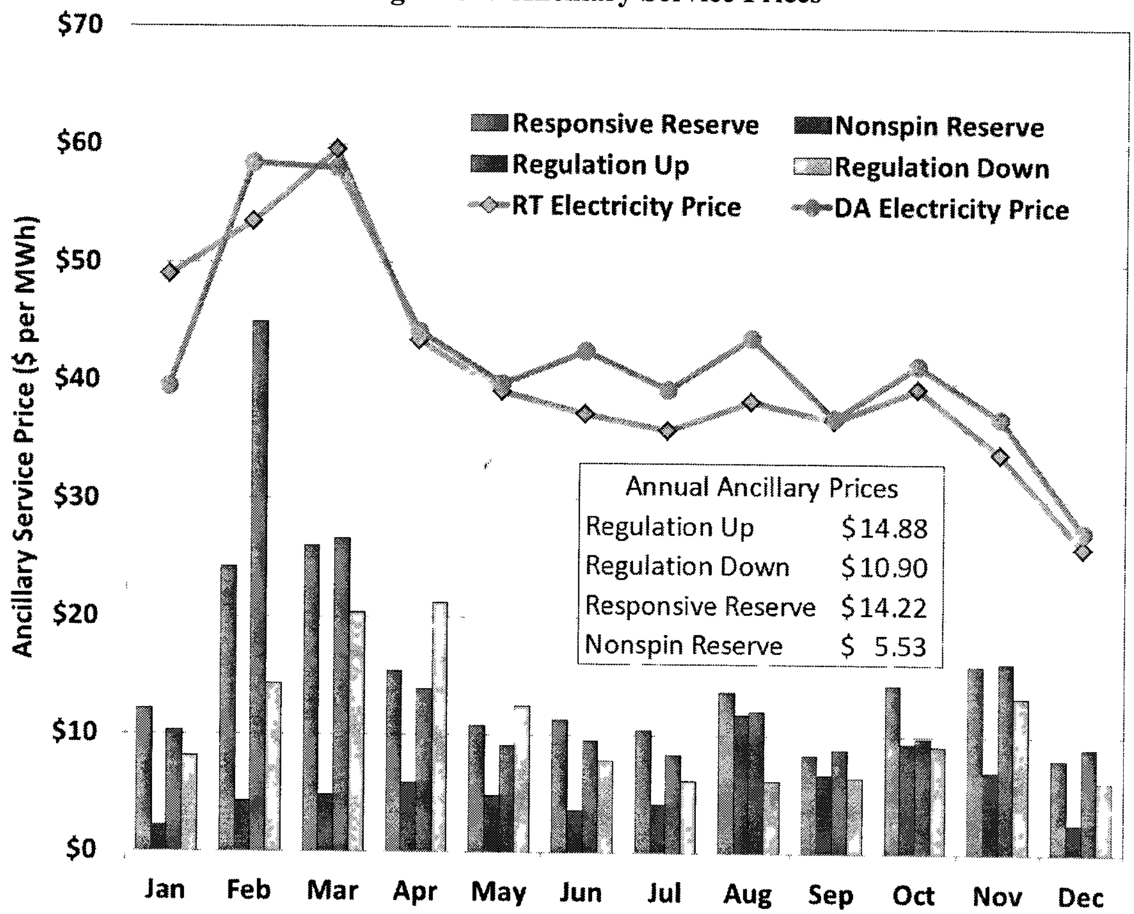
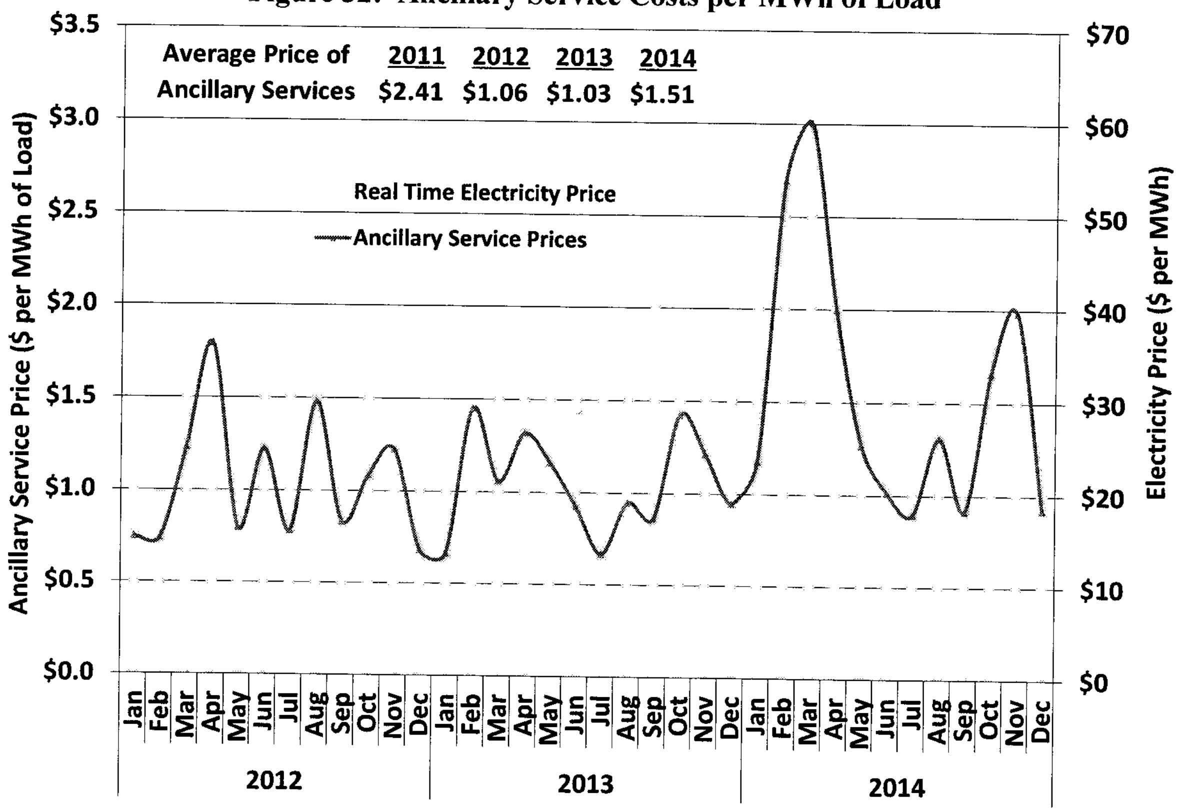


Figure 31 above presents the average clearing prices of capacity for the four ancillary services, along with day-ahead and real-time energy prices for energy. With average energy prices varying between $25 and $60 per MWh, the prices of ancillary services remained fairly stable throughout the year.

In contrast to the previous data that showed the individual ancillary service capacity prices, Figure 32 shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2012 through 2014. This figure shows that total ancillary service costs are generally correlated with day-ahead and real-time energy price movements, which, as previously discussed, are highly correlated with natural gas price movements. 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.

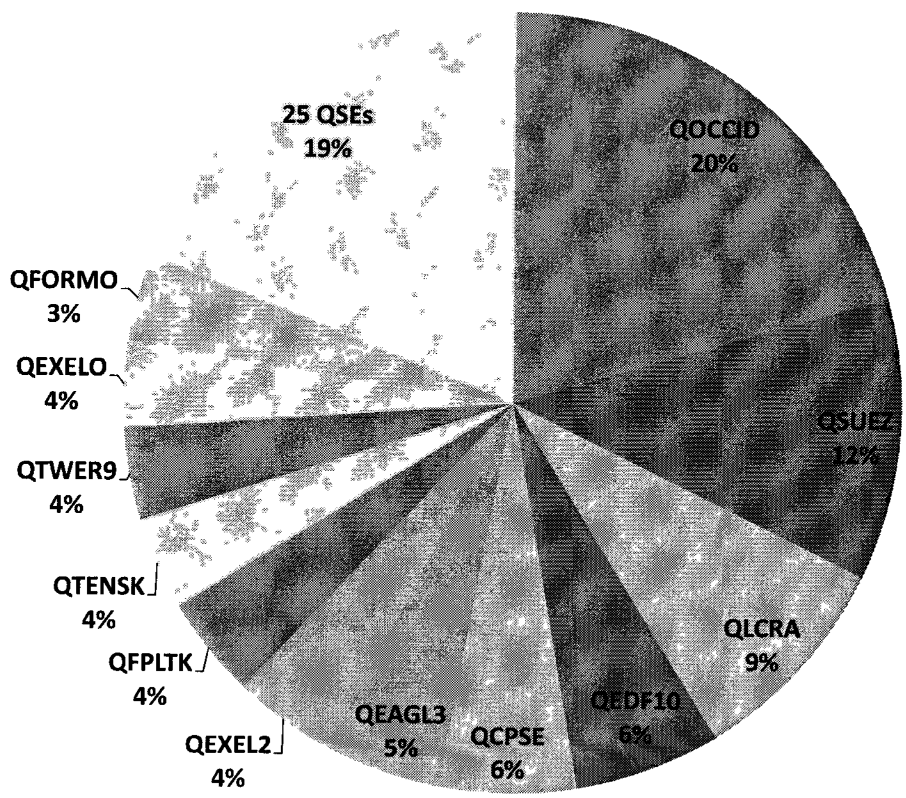
Figure 32: Ancillary Service Costs per MWh of Load



The average ancillary service cost per MWh of load increased to $1.51 per MWh in 2014 compared to $1.03 per MWh in 2013, an increase of 47 percent. Total ancillary service costs increased from 3.0 percent of the load-weighted average energy price in 2013 to 3.7 percent in 2014.

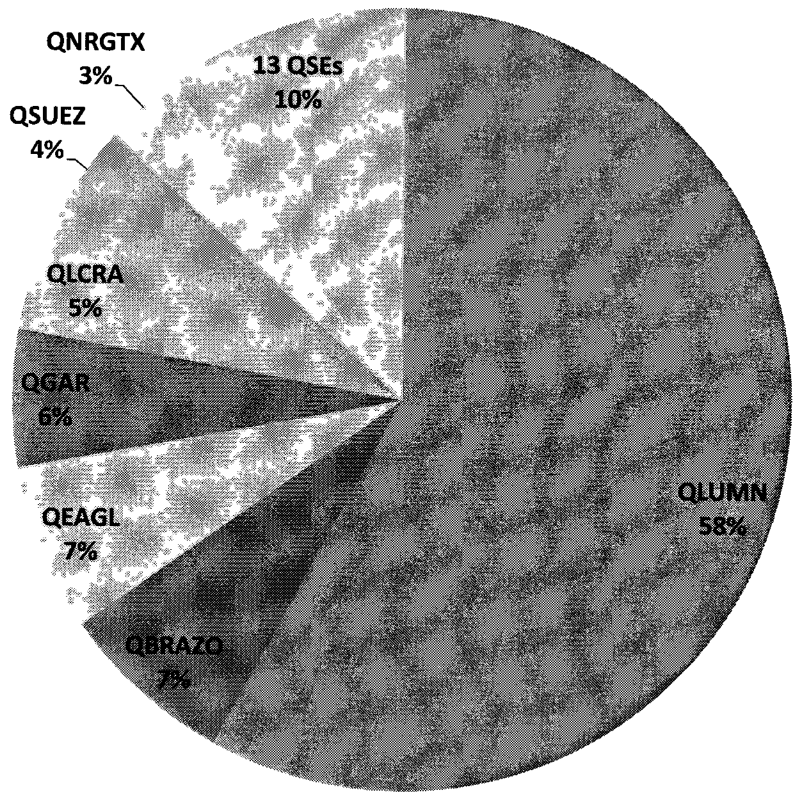
Responsive reserve service is the largest quantity and typically the highest priced ancillary service product. Figure 33 below shows the share of the 2014 annual responsive reserve requirements, including both load and generation provided by each QSE. During 2014, 37 different QSEs provided responsive reserves at some point, with multiple QSEs providing sizable shares.

Figure 33: Responsive Reserve Providers



In contrast, Figure 34 below shows that the provision of non-spinning reserves is highly concentrated, with a single QSE providing 58 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 2014; 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 include real-time co-optimization of 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.

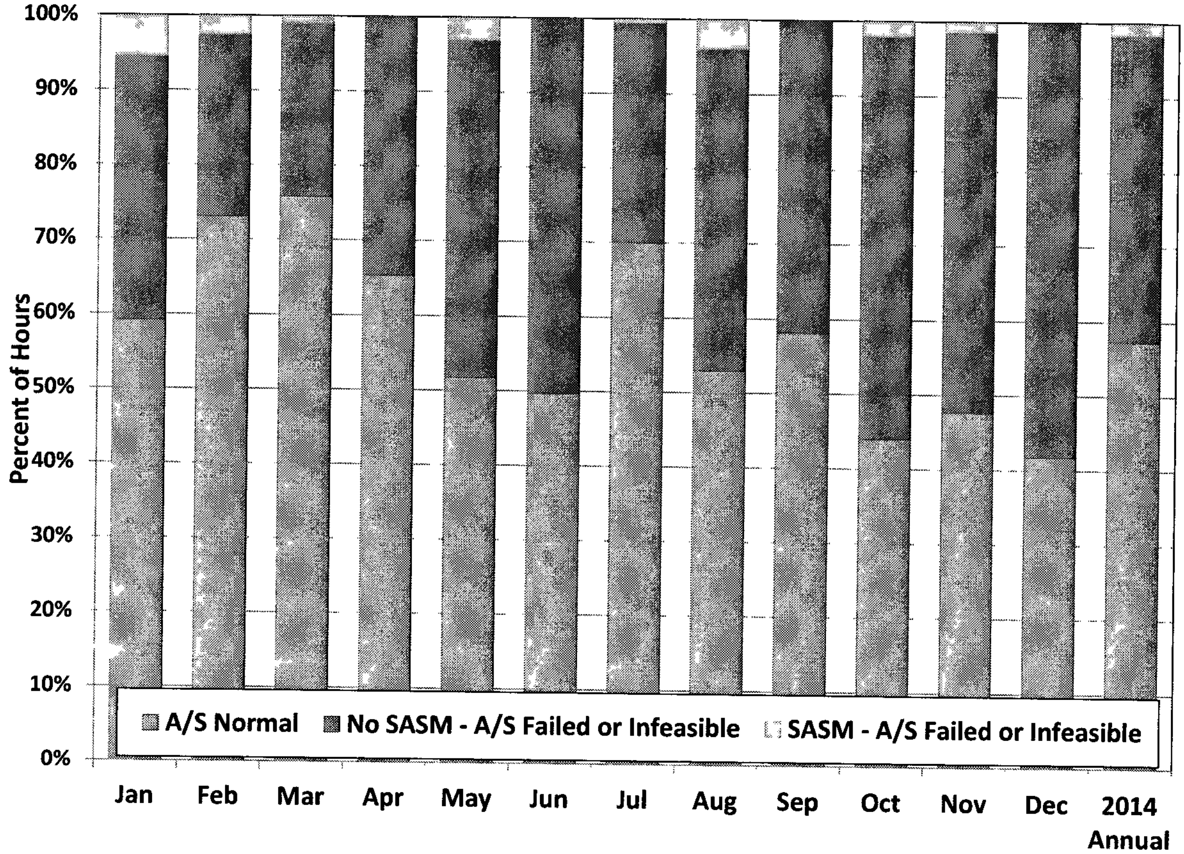
Figure 34: Non-Spin Reserve Providers



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 needed, 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.[5]

Figure 35 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 increased to 57 percent in 2014, compared to 39 percent in 2013 and 52 percent in 2012. Even though there were deficiencies in ancillary service deliveries for more than 40 percent of the hours, SASMs were opened to procure replacement capacity in only 2 percent of the total hours, down from 3 percent of the hours in 2013 and 7 percent in 2012.

Figure 35: 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

5 ERCOT may also open a SASM if they change their ancillary service plan. This did not occur during 2014.

service deficiencies via a market mechanism. Without sufficient ancillary service offers available, ERCOT more frequently brings additional capacity online using reliability unit commitment (RUC) procedures.

The frequency and quantity of ancillary service deficiency, which is defined as either failure-to-provide or as undeliverable, is summarized in Table 2 below.

Table 2: Ancillary Service Deficiency

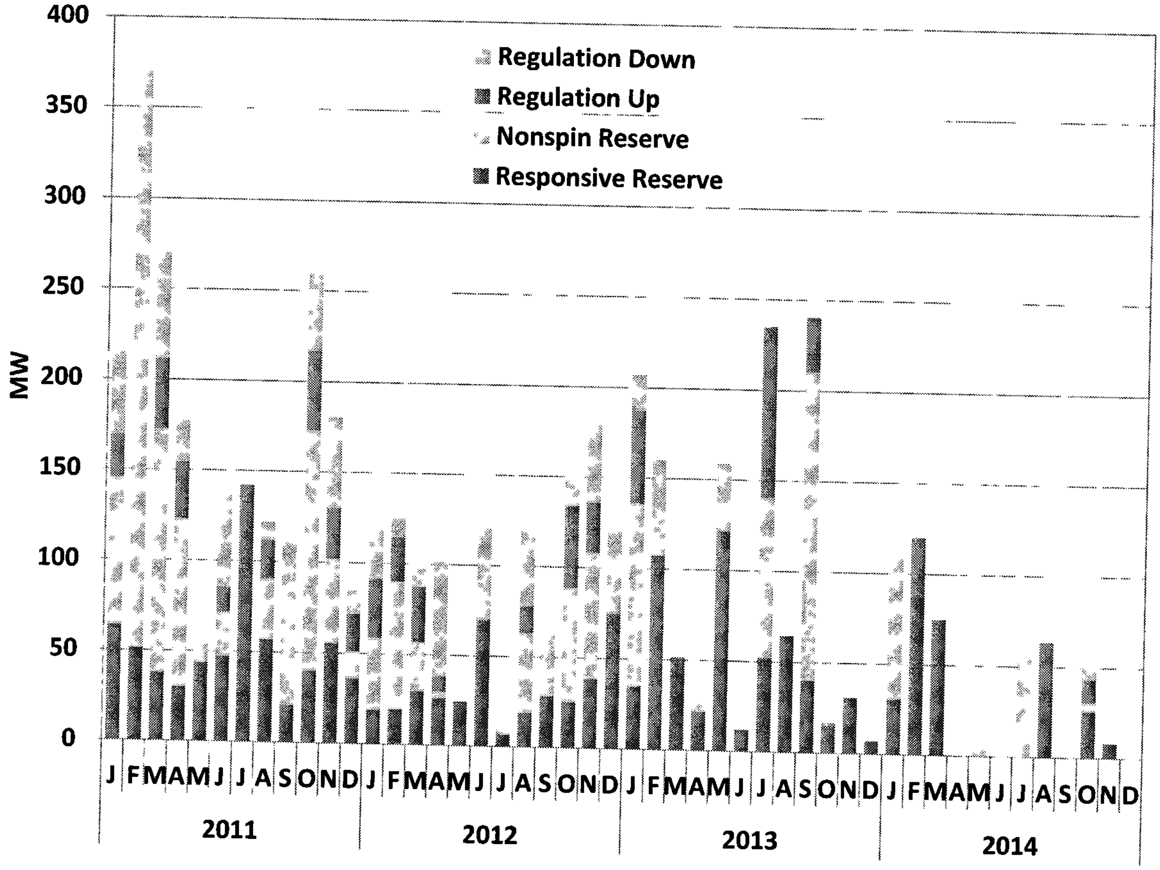
Service	*Hours Deficient*	*Mean Deficiency (MW)*	*Median Deficiency (MW)*
2014			
Responsive Reserve	**2929**	**46**	**20**
Non-Spin Reserve	**723**	**48**	**40**
Up Regulation	**686**	**40**	**20**
Down Regulation	**850**	**34**	**15**
2013			
Responsive Reserve	**3138**	**43**	**20**
Non-Spin Reserve	**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 deficiencies in responsive reserve and up regulation services decreased by 7 percent and 0.4 percent respectively in 2014 when compared to 2013. Down regulation and non-spin reserve had about 19 percent and 48 percent increases in the number of hours of deficiency in 2014. Again during 2014, responsive reserve service was deficient most frequently. As in 2013, 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 the regulation services increasing and the non-spin reserve decreasing slightly.

The SASM procurement method, while offer based, is inefficient and problematic. Because ancillary services are not co-optimized with energy in the SASM, potential participants 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 scarcity 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 their opportunity costs, and 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 likely substantially 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.

Figure 36: Ancillary Service Quantities Procured in SASM



The final analysis in this section, shown in Figure 36, 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 2014. When a SASM was used in 2014, the quantity of ancillary services procured was less than that seen in 2013. An exception to that trend was responsive reserves, which were procured less frequently, but in larger 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 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. 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.

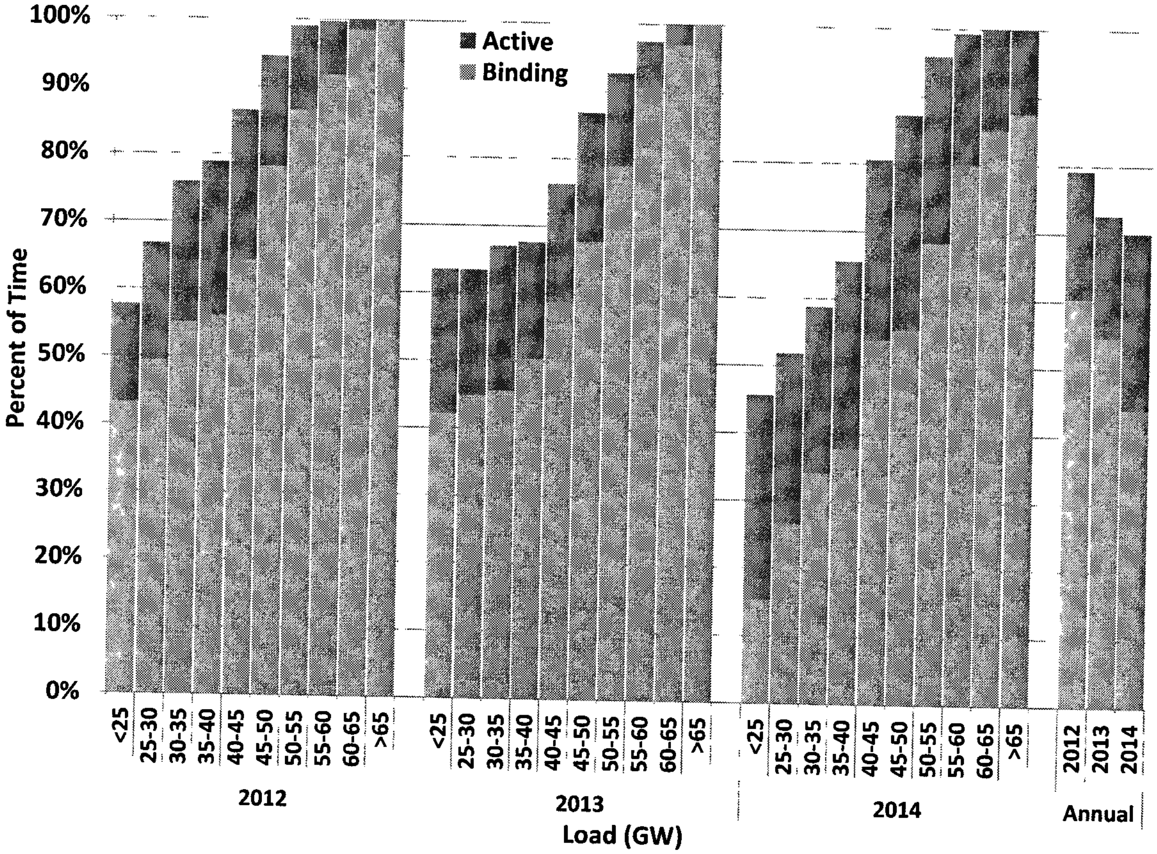
This section of the report summarizes congestion activity in 2014, provides a review of the costs and frequency of transmission congestion in both the day-ahead and real-time markets, and concludes with a review of the activity in the congestion rights market.

A. Summary of Congestion

The total congestion revenue generated by the ERCOT real-time market in 2014 was $708 million. As discussed further below, the amount of time where transmission constraints had an effect on prices actually decreased in 2014. Congestion in the West zone remained about the same as it was in 2013. Completion of the CREZ transmission projects has eliminated the longstanding limitations on the export of power from the West. However, limitations on the ability to transfer power to the West, particularly under high load and low wind conditions continue. Constraints associated with oil and gas activity in the Eagle Ford Shale area and limitations serving the lower Rio Grande valley had a larger impact in 2014.

Figure 37 provides a comparison of the amount of time transmission constraints were binding or active at various load levels in 2012 through 2014. Binding transmission constraints are those for which the dispatch levels of generating resources are being 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 priced in its LMPs. Active transmission constraints are those that did not require a re-dispatch of generation.

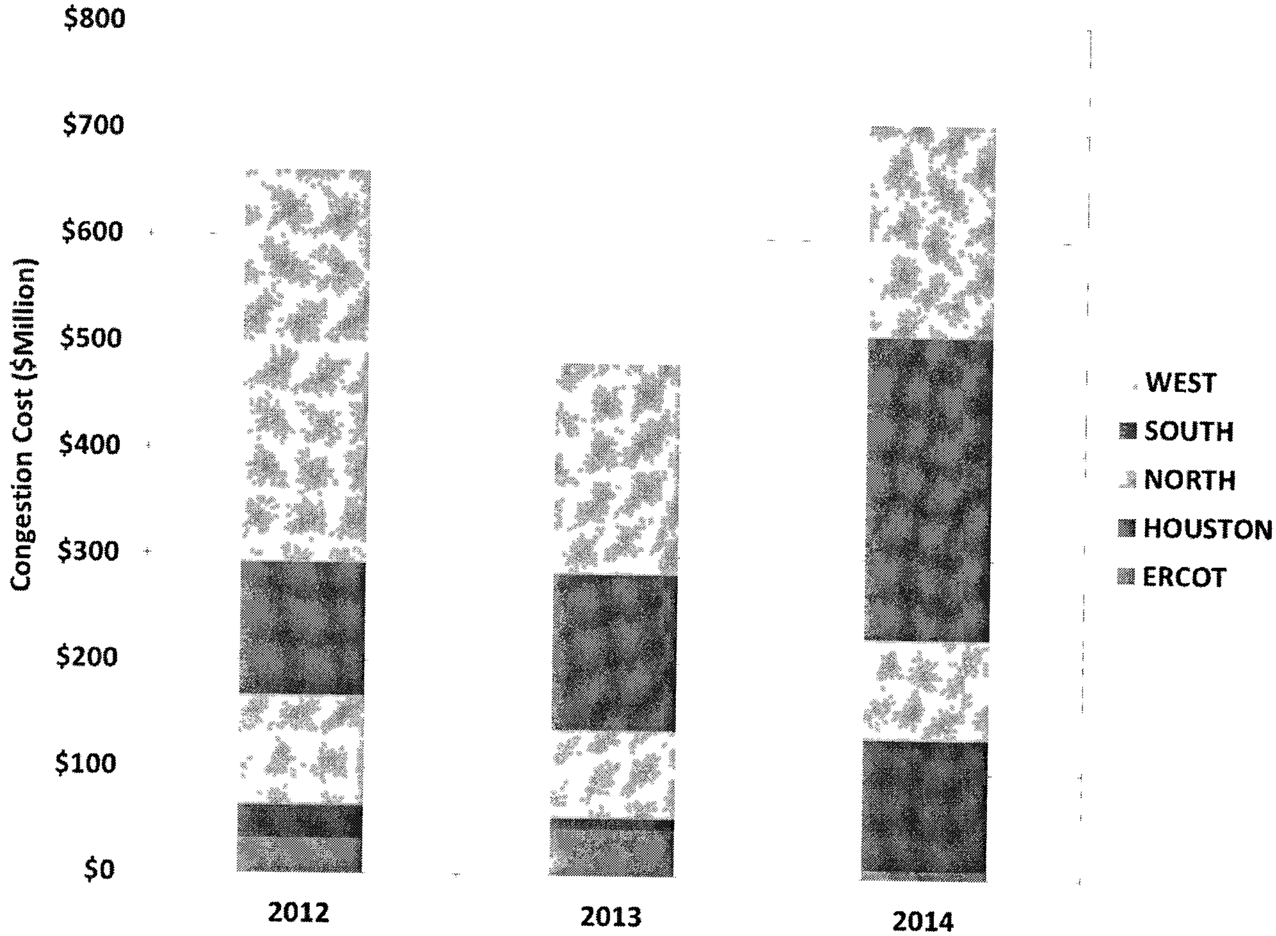
Figure 37: Frequency of Binding and Active Constraints



The frequency of binding transmission constraints decreased again in 2014. There was a binding constraint only 44 percent of time in 2014, down from 55 percent of the time in 2013 and 60 percent in 2012. The likelihood of binding constraints increases at higher load levels, which is consistent with the results for ERCOT shown in Figure 37. However, it is noteworthy that there were binding constraints less than 90 percent of the time during the very highest load levels in 2014, much lower than in prior years. Because the overall frequency of binding constraints decreased in 2014, the effect on LMPs also decreased in 2014.

Figure 38 displays the amount 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. Higher costs associated with constraints in the South and Houston zones are the key drivers leading to increased total congestion costs in 2014.

Figure 38: Real-Time Congestion Costs

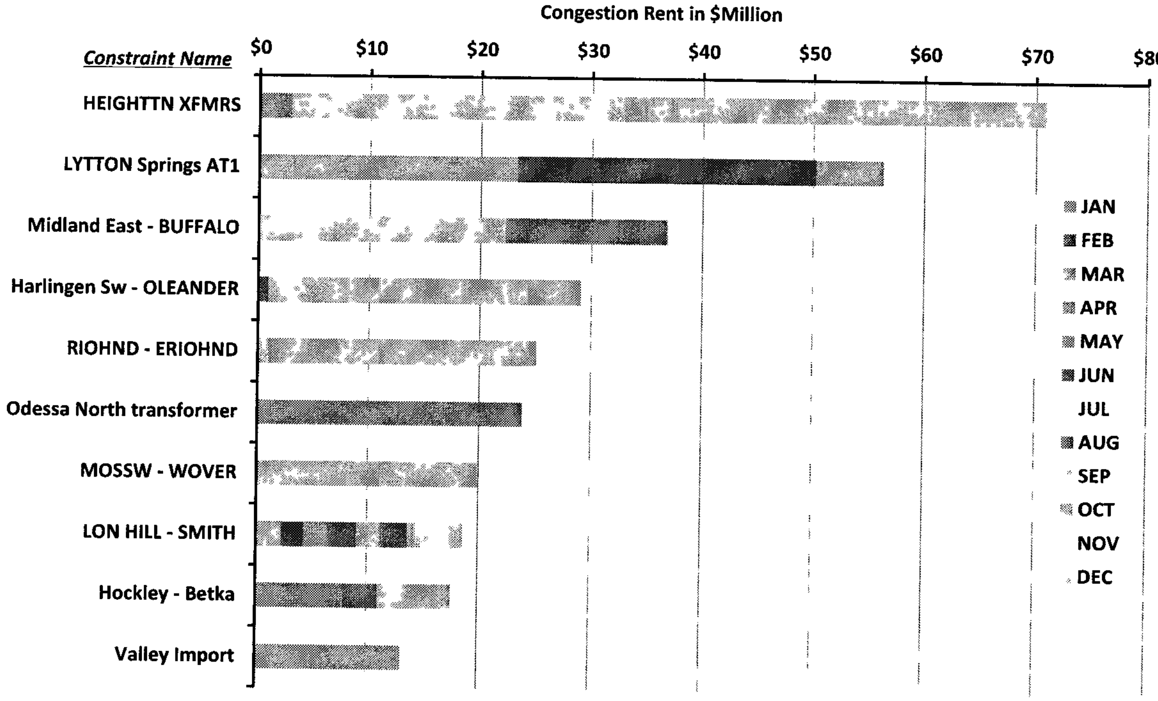


B. Real-Time Constraints

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 geographical proximity and constraint direction. There were 350 unique constraints that were binding at some point during 2014. The median financial impact of these constraints was approximately $316,000.

Figure 39 below displays the ten most highly valued real-time congested areas as measured by congestion rent. The Heights TNP 138/69 kV autotransformers were the most congested location in 2014 at $74 million. These transformers are located in the industrialized area southeast of Houston and were the limiting element due to outages of other transmission facilities in the area. As shown in Table 3 below, two constraints with the Heights autotransformer as the overloaded element were designated as irresolvable constraints during 2014.

Figure 39: Top Ten Real-Time Constraints



The second highest valued congested element was the Lytton Springs 345/138 kV #1 auto-transformer with impacts of $56 million. All of the impacts occurred during the early part of the year, January through March, and were related to a planned outage that occurred during times of higher than normal loads.

Congestion in the Midland area totaled $51 million. This congestion was most prevalent during the months of July and August. Although multiple constraints appear to be binding at different times during the year, the different names were a result of topology changes related to Sharyland load integrating into ERCOT. The Midland East to Buffalo 138 kV line ($37 million) was the largest contributor to congestion in the Midland area.

Taken in aggregate, congestion in the Valley area was almost as large as the most costly single constraint, totaling $73 million. Three of the top congested elements are related to limitations on the ability to import power to serve load in the Rio Grande Valley. They are Harlingen Switch to Oleander 138 kV line ($29 million) and Rio Hondo to East Rio Hondo 138 kV line ($25 million) and the Valley Import ($13 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. A large contribution to total cost occurred in October, when a combination of generation and transmission outages led to significant congestion. Ultimately, on October 8th the situation in the Valley required that firm load be curtailed.

The next two most costly constraints were the Odessa North 138/69 kV Autotransformer ($24 million) and the Moss Switch to Westover 138 kV line ($20 million). The Odessa area, which consists of the two aforementioned constraints among others, remains one of the most highly congested areas due to oil and gas development activity in the area. However, the $63 million impacts in 2014 were a significant reduction compared to what was experienced in 2013.

Congestion on the Lon Hill to Smith 69kV line west of Corpus Christi totaled $19 million and was one of three 69kV lines in the area that were congested due to the increased loads due to oil and natural gas development in the Eagle Ford shale. The total for all three lines was $33 million.

The last element on the list, the Hockley to Betka 138 kV line, is located north and west of Houston and is affected by North to Houston transfers.

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, seventeen constraints, each comprised of a contingency and overloaded element, were deemed irresolvable in 2014 and as such, had a maximum shadow price cap imposed according to the Irresolvable Constraint Methodology. Many of the irresolvable constraints were the previously discussed most costly constraints. Five constraints were deemed resolvable during the ERCOT analysis annual review and were removed from the list.

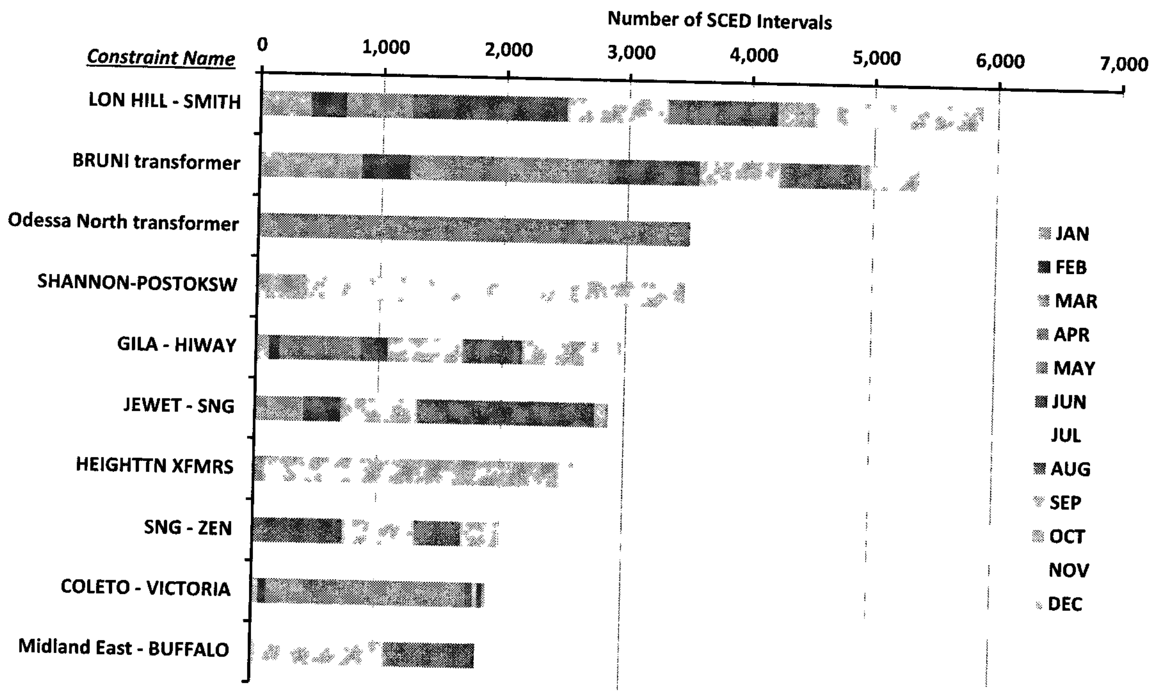
Table 3: Irresolvable Constraints

Loss of:	Overloads:	Original Max Shadow Price	Adjusted Max Shadow Price	Effective Date	Termination Date
Base case	Valley Import	$5,000	$2,000.00	1/1/12	-
Denton to Argyle / West Denton 138 kV lines	Jim Crystal to West Denton 69 kV line	$2,800	$2,000.00	1/1/12	1/29/14
Graham to Long Creek 345 kV line	Bomarton to Seymour 69 kV line	$2,800	$2,000.00	1/1/12	1/29/14
Odessa North to Holt 69 kV Line	Odessa Basin to Odessa North 69 kV line	$2,800	$2,800.00	1/1/12	-
Odessa to Morgan Creek/Quail Sw 345 kV lines	China Grove to Bluff Creek 138 kV line	$3,500	$2,000.00	5/3/12	-
Holt to Moss 138 kV line	Odessa North 138/69 kV transformer	$3,500	$2,000.00	8/6/12	1/29/14
Sun Switch to Morgan Creek 138 kV Line	China Grove to Bluff Creek 138 kV Line	$3,500	$2,000.00	10/11/12	-
Morgan Creek Autotransformer #4 345/148 kV	Morgan Creek Autotransformer #1 345/138 kV	$4,500	$2,000.00	11/2/12	-
Odessa Basin to Odessa North 69 kV line	Holt to Ector Shell Tap 69 kV line	$2,800	$2,320.68	1/1/13	1/29/14
Wink TNP 138 kV/69 kV Autotransformer	Wink TNP to Wink Sub 69 kV line	$2,800	$2,000.00	5/20/13	1/29/14
Skywest to Salt Flat Road 138 kV Line	Midland East to Buffalo 138 kV Line	$3,500	$2,377.57	7/24/14	-
Tejas to Greenbelt 138 kV Line	Heights TNP 138/69 kV Transformer	$3,500	$2,000.00	9/23/14	-
Estokta to McElmurray and Abilene South to Moore 138 kV Lines	Abilene Northwest to Ely Rea Tap 69 kV Line	$2,800	$2,131.06	9/26/14	-

Loss of:	Overloads:	Original Max Shadow Price	Adjusted Max Shadow Price	Effective Date	Termination Date
Las Palma to Rio Hondo 138 kV Line	Harlingen to Oleander 69 kV Line	$2,800	$2,000.00	10/9/14	-
Las Palma to Rio Hondo 138 kV Line	Rio Hondo to East Rio Hondo 138 kV Line	$3,500	$2,000.00	10/10/14	-
Bakke to Unocal Parker 138 kV Line	Emma to Holt Switch 69 kV Line	$2,800	$2,800.00	10/27/14	-
Caddo to Apache 138 kV Line	Heights TNP 138/69 kV Transformer	$3,500	$2,000.00	10/28/14	-

Figure 40 presents a slightly different set of real-time congested areas. These are the most frequently occurring.

Figure 40: Most Frequent Real-Time Constraints



Of the ten most frequently occurring constraints, four have already been described as the most costly. They are the Lon Hill to Smith 69kV line, the Odessa North 138/69 kV Autotransformer, the Heights TNP 138/69 kV autotransformers, and the Midland East to Buffalo 138 kV line. The Bruni 138/69 kV transformer constraint frequently limits the output from two wind generators located east of Laredo. The Shannon to Post Oak Switch 69 kV line is located between Fort Worth and Wichita Falls. The Gila to Highway 138 kV line is located in the

Corpus Christi area. The Jewett to Singleton and Singleton to Zenith 345kV lines provide part of the current Houston import capability.

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 the day-ahead market as actually occurred during real-time.

Figure 41: Top Ten Day-Ahead Congested Areas

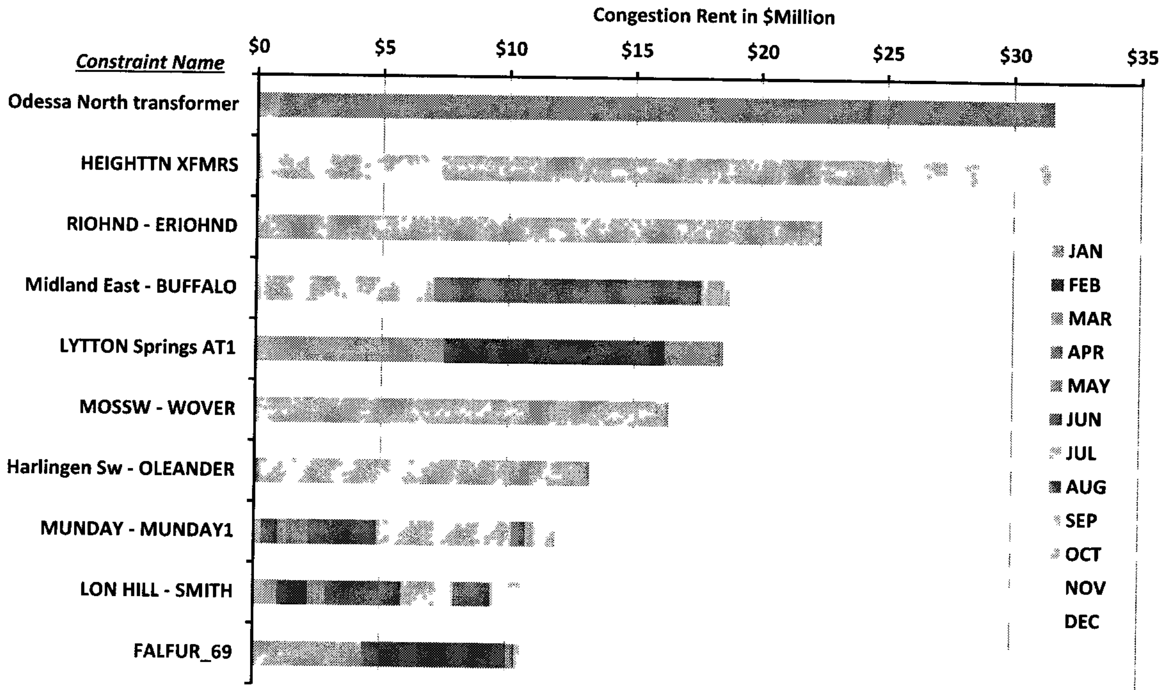
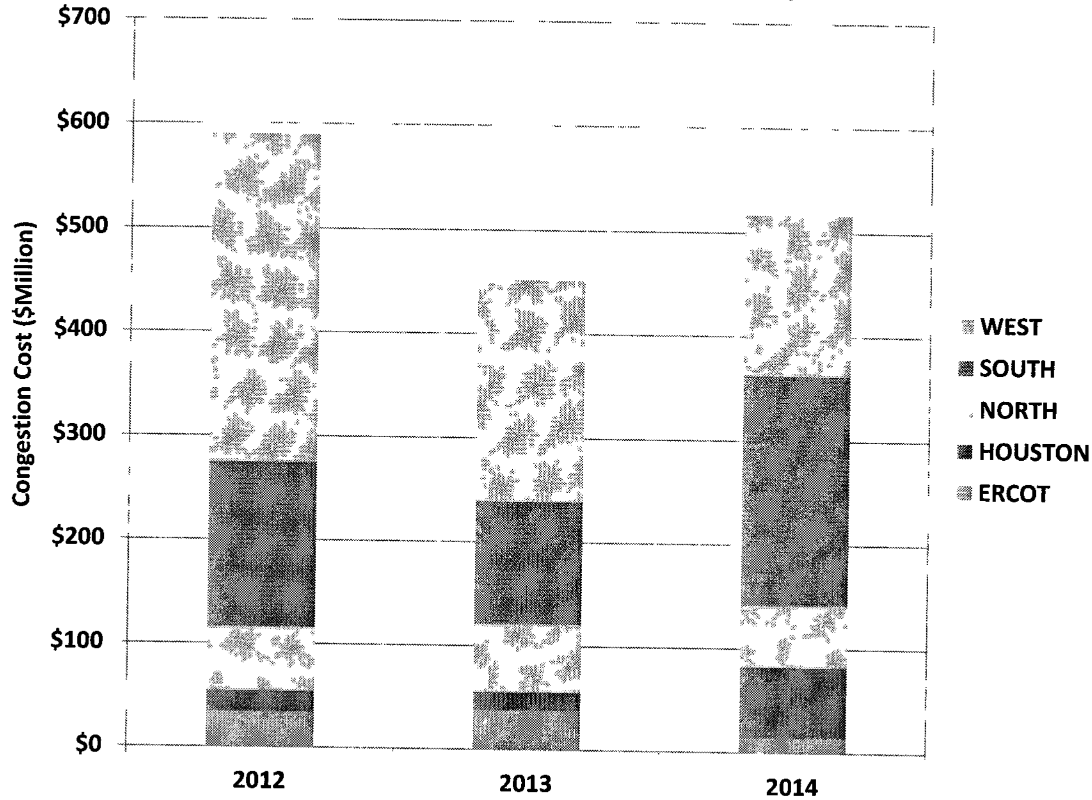


Figure 41 presents the top ten congested areas from the day-ahead market, ranked by the financial impact as measured by congestion rent. There is a close correlation between constraints with high day-ahead impacts and those previously described in the real-time subsection. The only two constraints that appear here that have not already been discussed are the Munday AEP to Bkem Munday 69 kV line located south and west of Wichita Falls, and the Falfurrias 138/69kV transformer located south of the Eagle Ford shale.

Figure 42: Day-Ahead Congestion Costs by Zone



As they were in real time, higher costs associated with constraints in the South and Houston zones were the key drivers leading to increased total congestion costs in the day-ahead market during 2014.

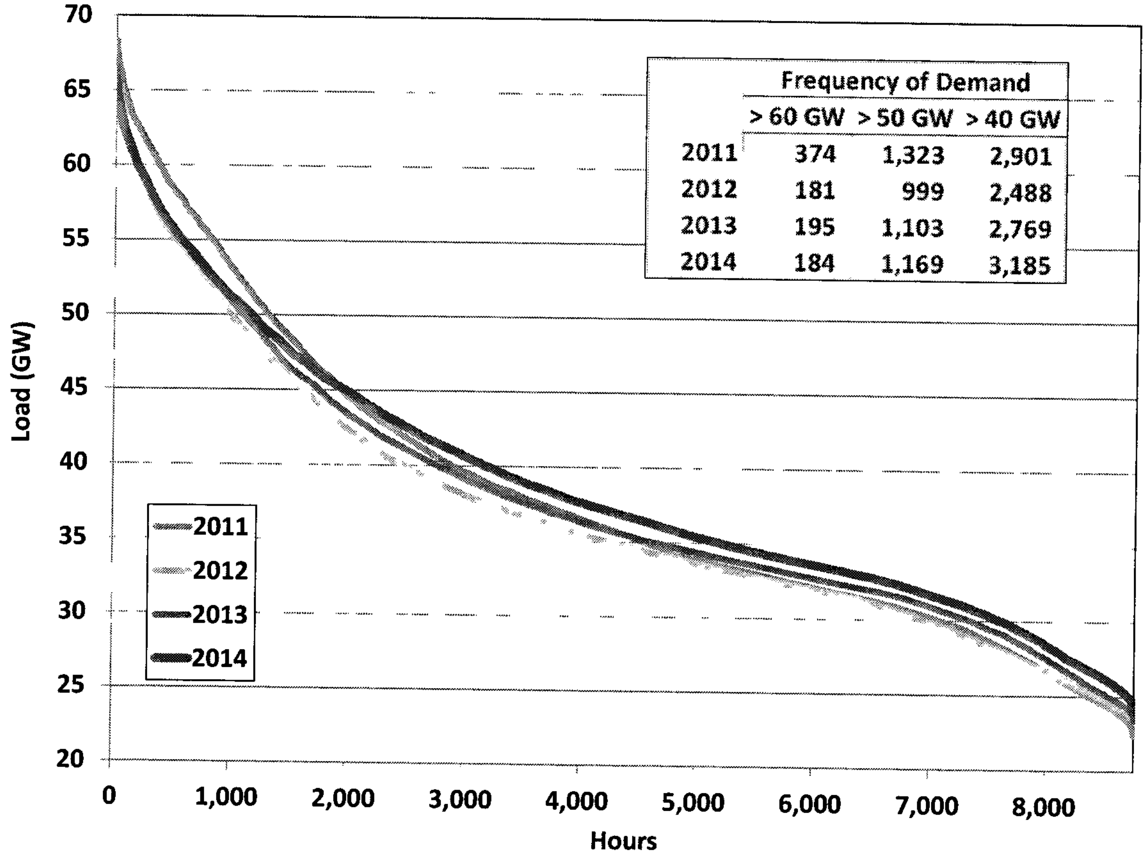
D. Congestion Revenue Rights Market

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

To provide a more detailed analysis of load at the hourly level, Figure 52 compares load duration curves for each year from 2011 to 2014. 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 52: Load Duration Curve – All Hours



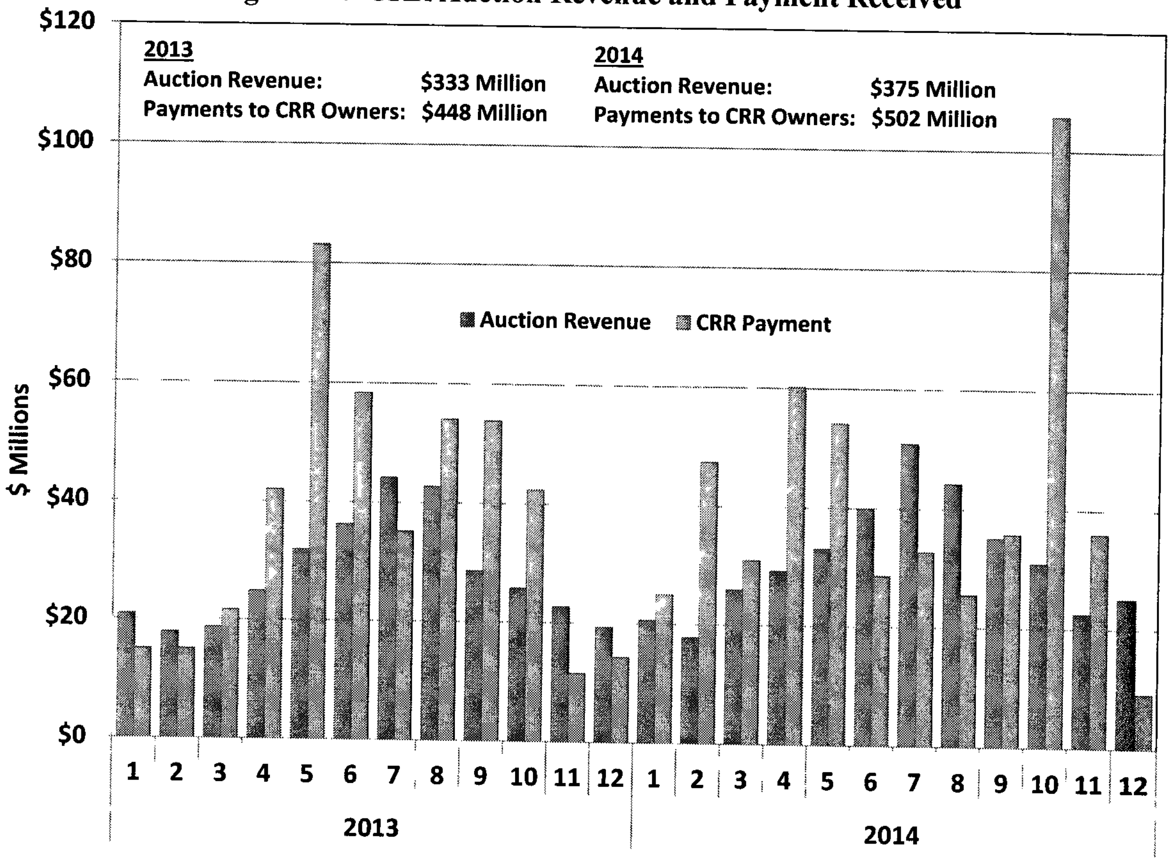
As shown in Figure 52, the load duration curve for 2014 is higher than in 2013 for all but the very highest load hours in the year. This is consistent with the aforementioned 2.5 percent load increase from 2013 to 2014. Still noticeable are the much higher loads experienced in 2011. Even with three years of energy growth the highest 2,000 hours of loads experienced in 2011 remain the highest.

To better illustrate the differences in the highest-demand periods between years, Figure 53 shows the load duration curve for the 5 percent of hours with the highest loads. This figure also shows

As shown in Figure 2, the annual average real-time energy price for the West zone was $43.58 per MWh, nearly $3 per MWh higher than the ERCOT-wide average. The value of CRR Auction revenues distributed only to the West zone equated to $4.40 per MWh higher than the ERCOT-wide average distribution of CRR Auction revenues. This was sufficient to offset the higher real-time prices incurred in the West load zone during 2014. In 2013 the annual average price for the West zone was $37.99 per MWh, which was about $4 per MWh higher than the ERCOT-wide average, and the incremental CRR Auction revenues were almost $5.50 per MWh.

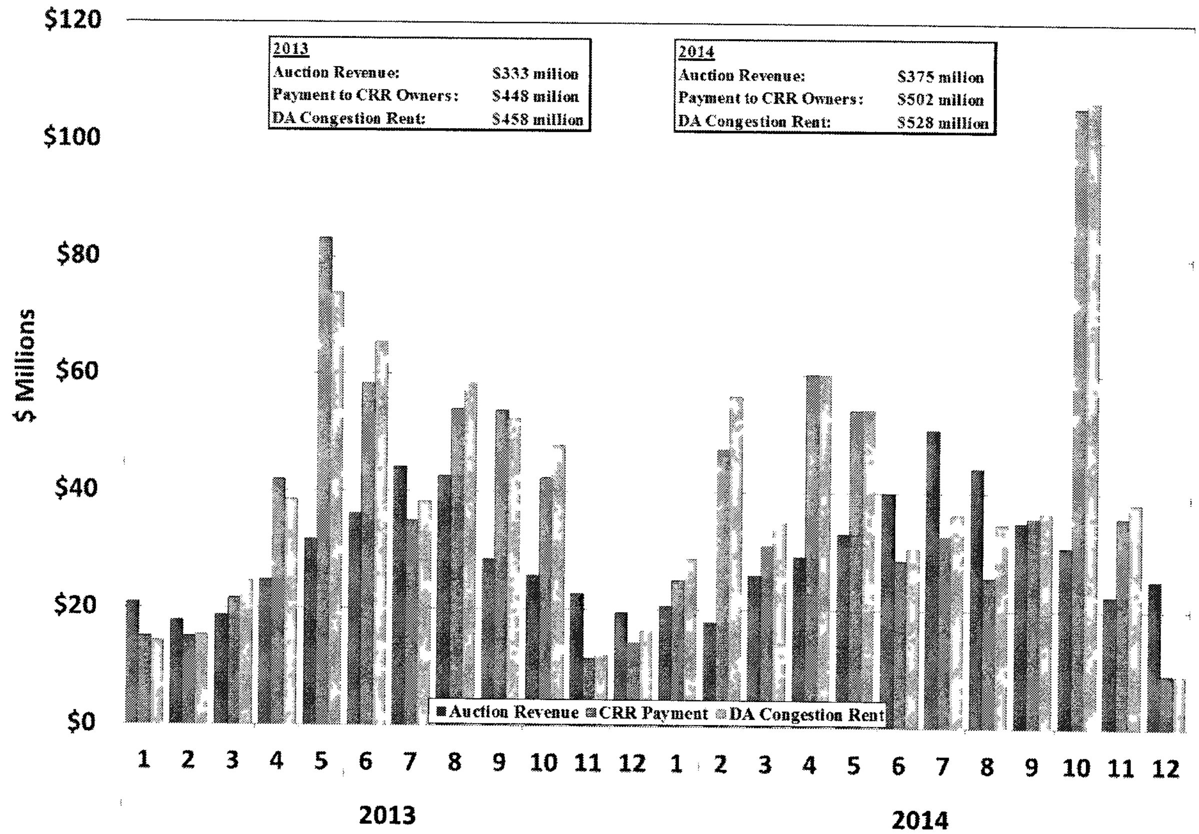
Next, Figure 44 compares the value received by CRR owners (in aggregate) to the price paid to acquire the CRRs. Although results for individual participants and specific source/sink combinations varied, the aggregated results in most months show that participants did not overpay in the auction. The exceptions were the summer months of June, July and August. Across the entire year of 2014, participants spent $375 million to procure CRRs and received $491 million.

Figure 44: CRR Auction Revenue and Payment Received



The next look at aggregated CRR positions adds day-ahead congestion rent to the picture. Simply put, 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. Revenue from congestion rent creates the source of funds used to make payments to CRR owners. Figure 45 presents CRR Auction revenues, payment to CRR owners, and day-ahead congestionrent in 2013 and 2014, by month. Congestion rent for the year 2014 totaled $528 million and payment to CRR owners was $491 million.

Figure 45: 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 CRRs, if modeled on the day-ahead network, would cause a higher flow on a transmission line than the line's rating, thereby creating a constraint. 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, that excess congestion rent can be used to make whole the CRR account holders that received shortfall charges.

Figure 46: CRR Shortfalls and Derations

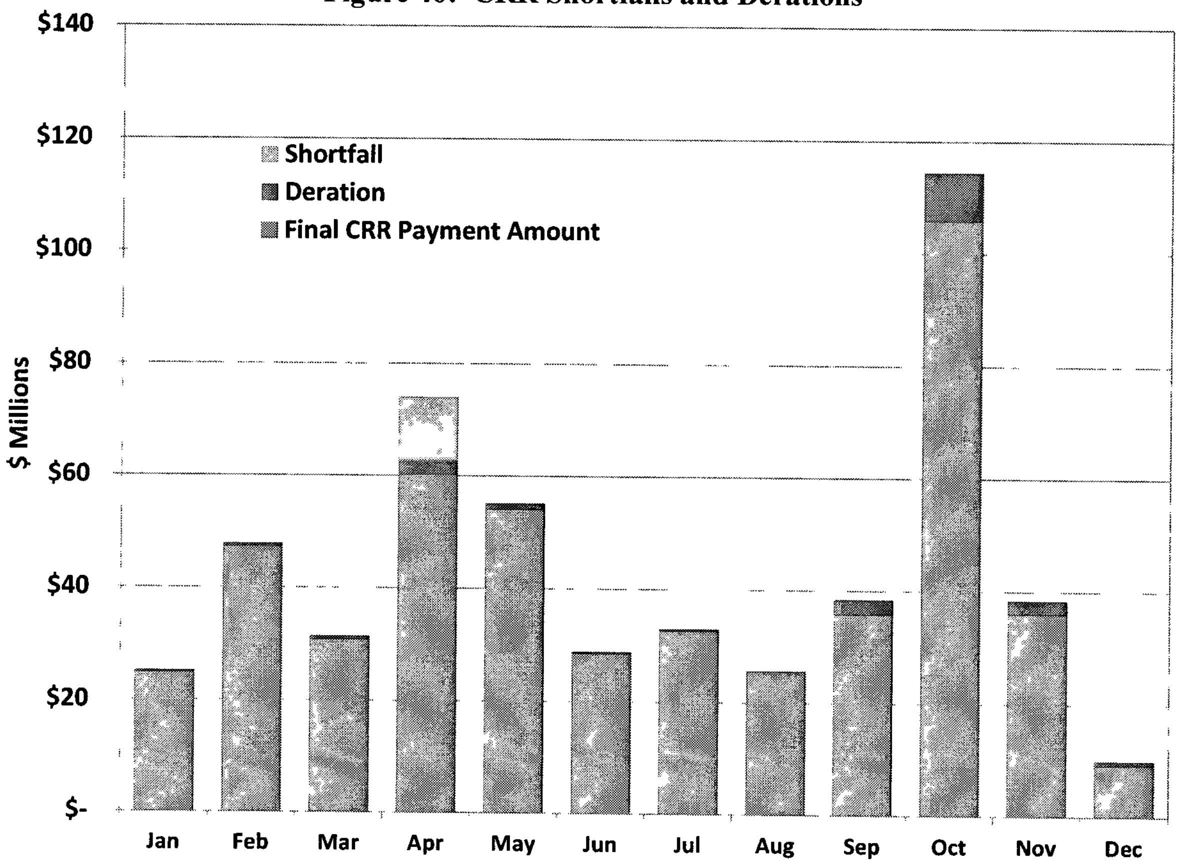


Figure 46 shows the amount of target payment, deration amount, and net shortfall charges (after make whole payments) for 2014. In 2014 the total target payment to CRRs was $521 million; however, there were $19 million of derations and $11 million of shortfall charges leaving a final payment to CRR account holders of $491 million. This corresponds to a CRR funding percentage of 94 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 47 presents the price spreads between the West Hub and West load zone as valued at four separate points in time – at the semi-annual CRR Auction, monthly CRR auction, day-ahead and in real-time. Since CRRs are sold for one of three defined time periods, weekday on peak, weekend on peak, and off peak, Figure 47 includes a separate comparison for each. Figure 48, Figure 49, and Figure 50 present the same information for the North, South and Houston load zones, respectively.

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 price spreads approaching those of the West.

Figure 47: West Hub to West Load Zone Price Spreads

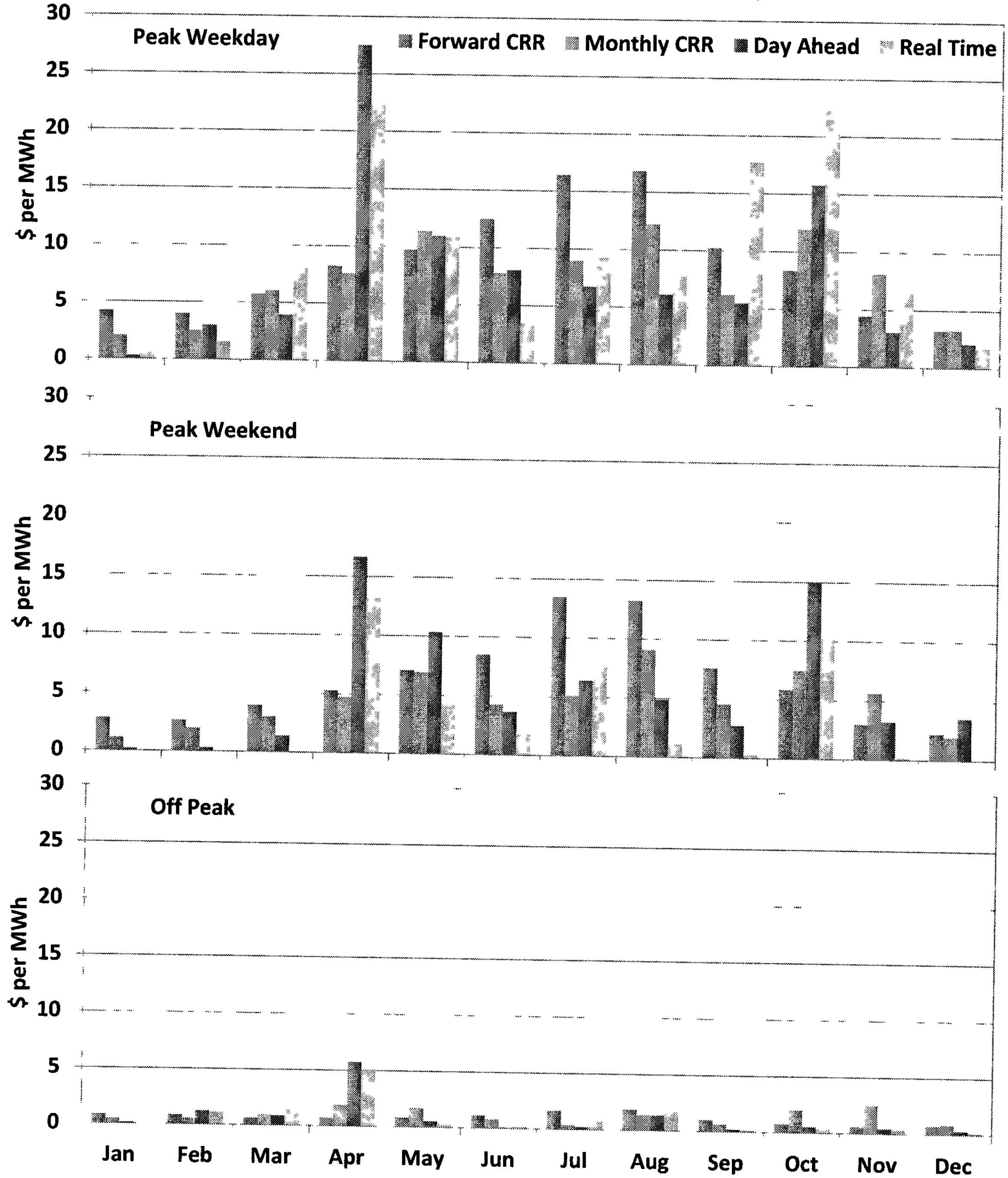


Figure 48: North Hub to North Load Zone Price Spreads

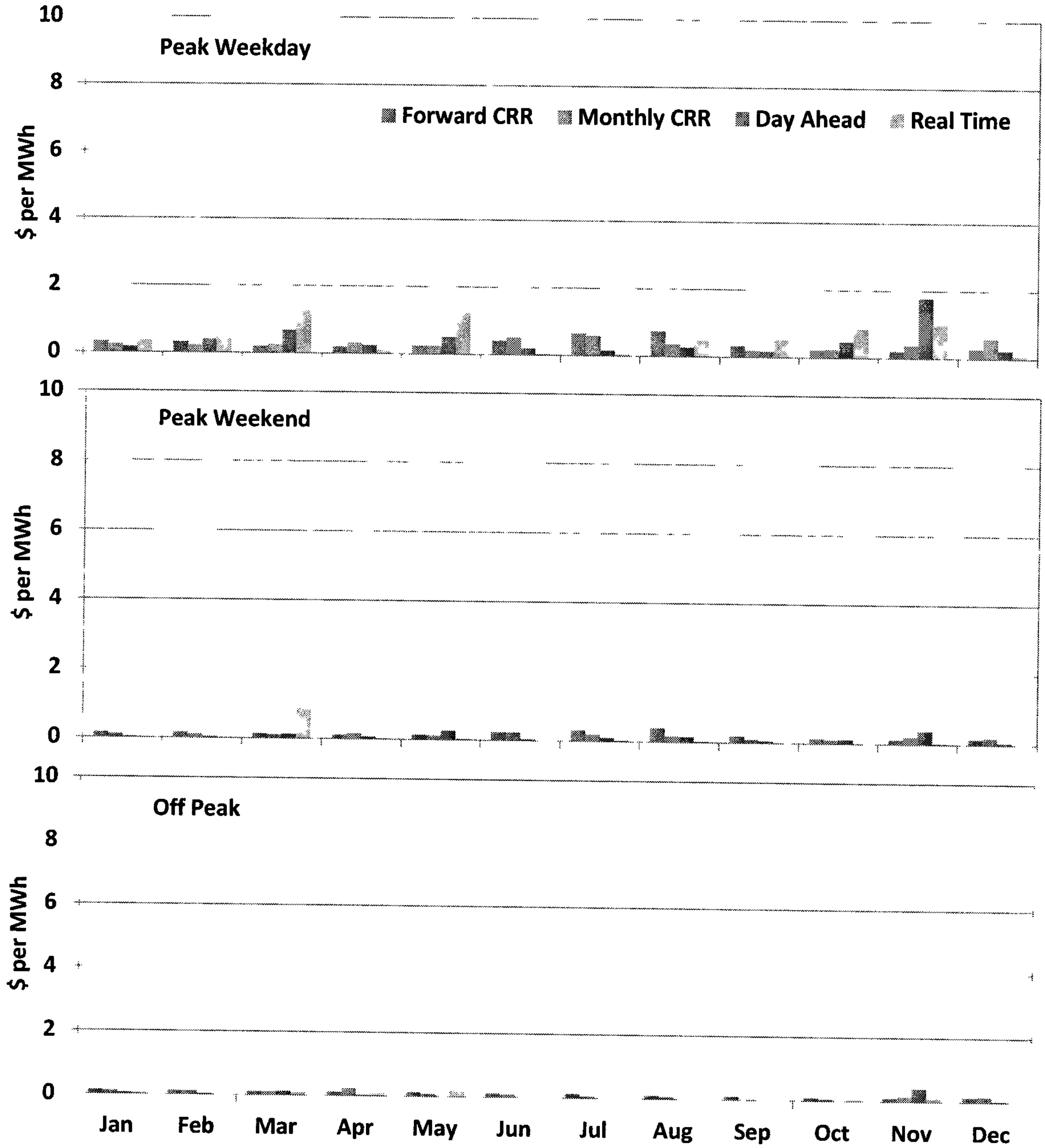


Figure 49: South Hub to South Load Zone Price Spreads

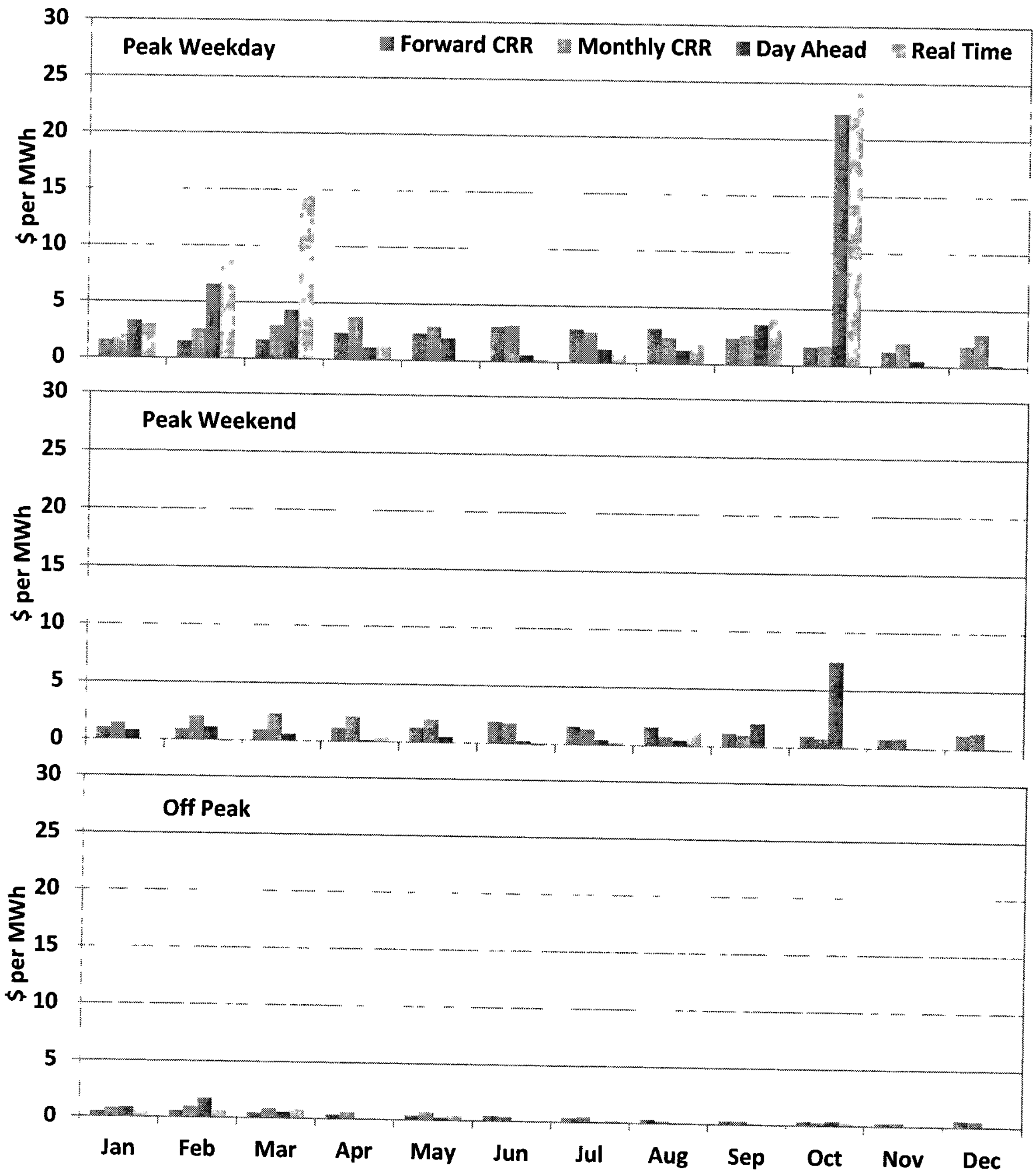
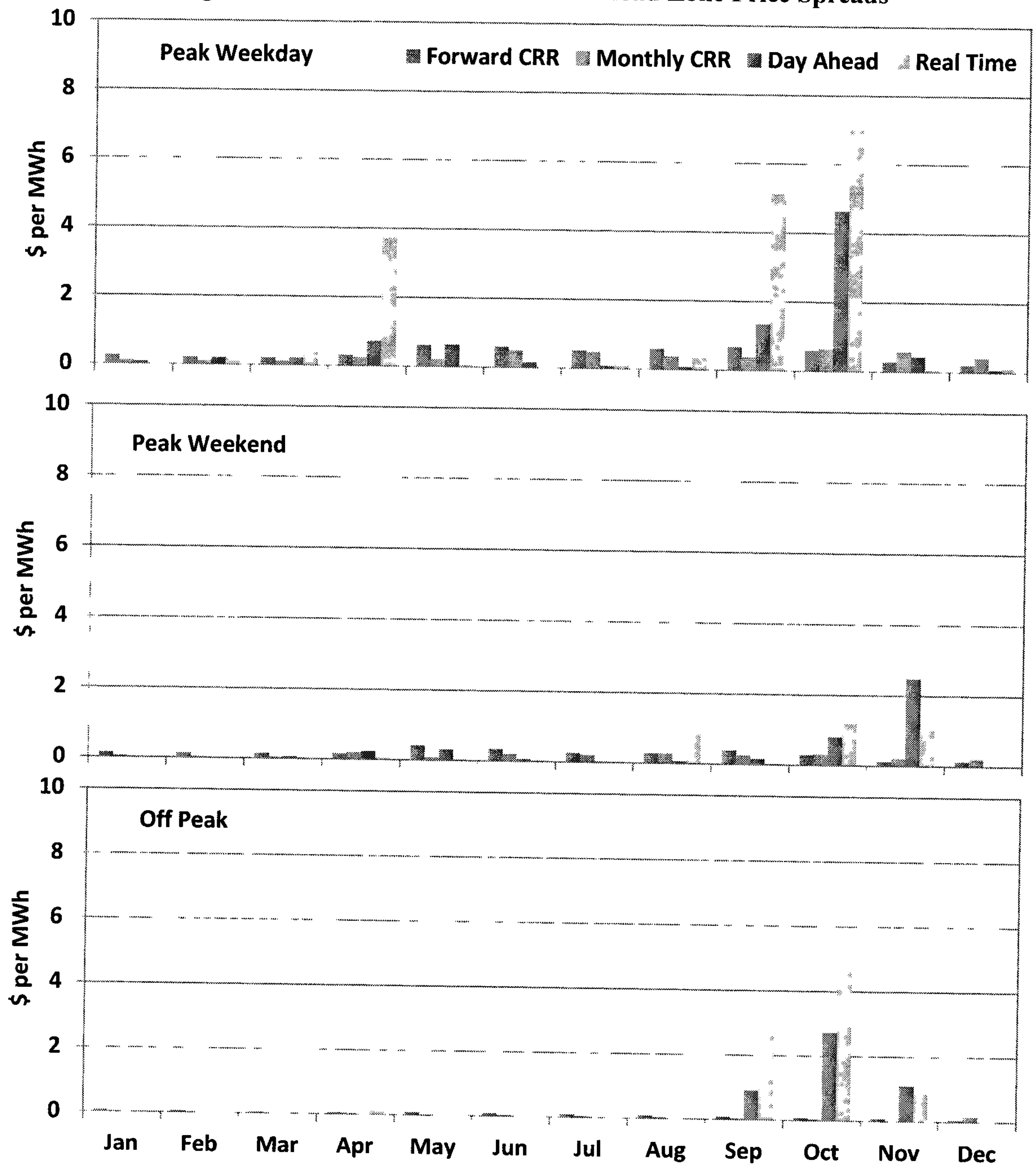


Figure 50: Houston Hub to Houston Load Zone Price Spreads



IV. DEMAND AND SUPPLY

This section reviews and analyzes the load patterns during 2014 and the existing generating capacity available to satisfy the load and operating reserve requirements. Specific analysis of the large quantity of installed wind generation is included, along with a discussion of the daily generation commitment characteristics. This section concludes with a discussion of demand response resources.

A. ERCOT Loads in 2014

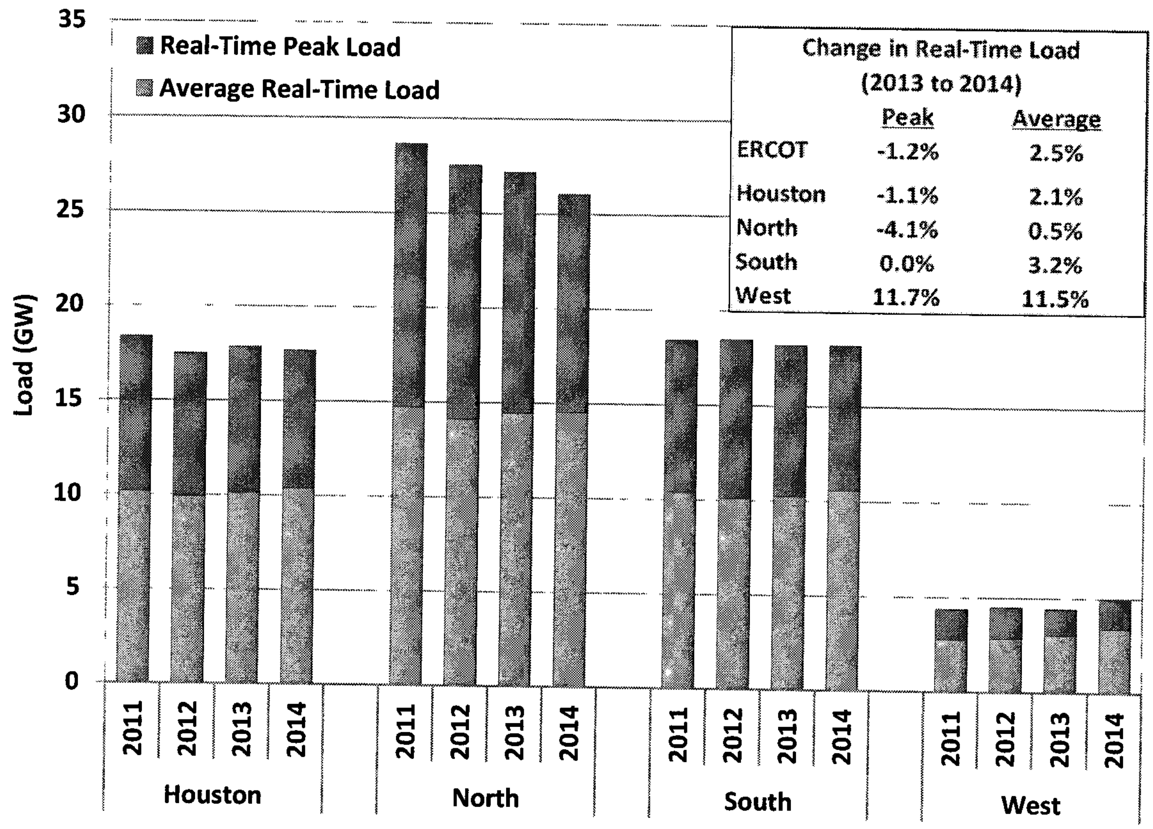
The changes in overall load levels from year to year can be shown by tracking the changes in average load levels. This metric will tend to capture changes in load over a large portion of the hours during the year. It is also important to separately evaluate the changes in the load during the highest-demand hours of the year. Significant changes in peak demand levels play a major role in assessing the need for new resources. The level of peak demand also affects 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 2014 are examined in this subsection and summarized in Figure 51.

This figure shows peak load and average load in each of the ERCOT zones from 2011 to 2014.[6] In each zone, as in most electrical systems, peak demand significantly exceeds average demand. The North zone is the largest zone (with about 37 percent of the total ERCOT load); the South and Houston zones are comparable (27 percent) while the West zone is the smallest (9 percent of the total ERCOT load).

Figure 51 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.

6 For purposes of this analysis, Non-Opt In Entity (NOIE) Load Zones have been included with the proximate geographic Load Zone.

Figure 51: Annual Load Statistics by Zone



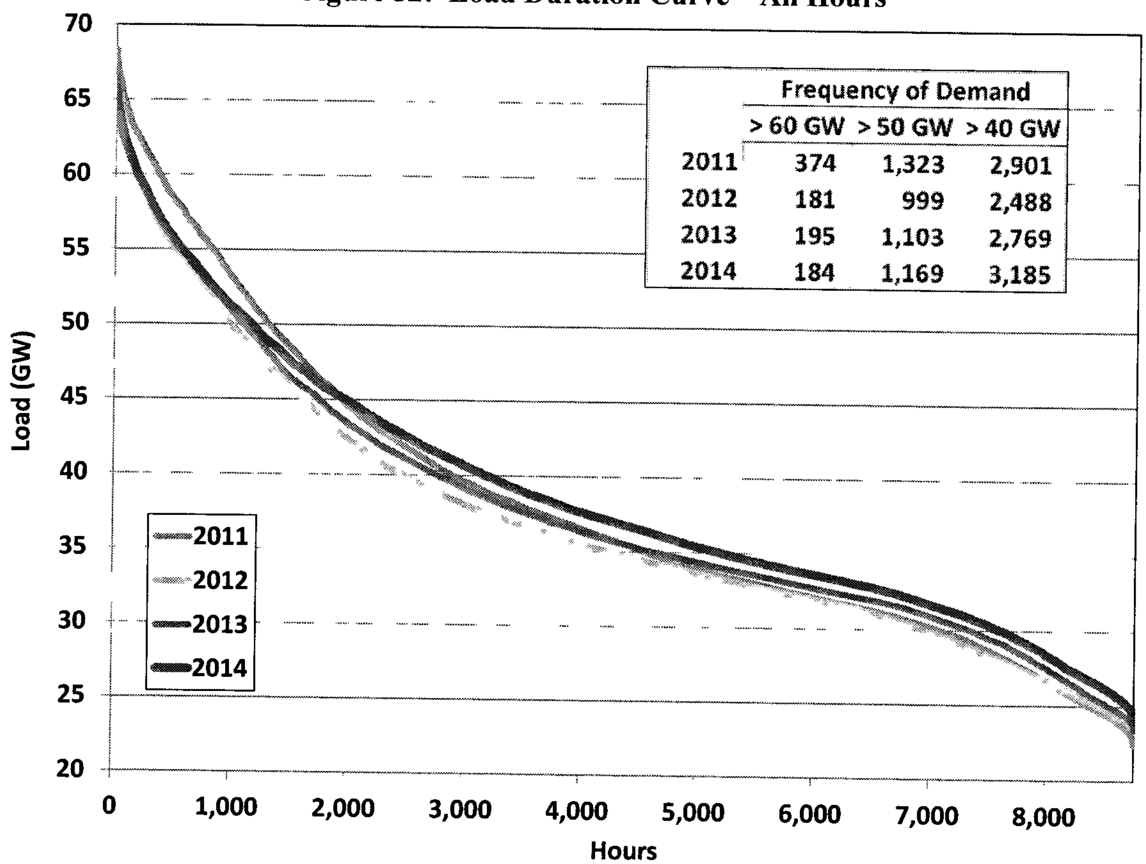
Total ERCOT load over the calendar year increased from 332 terawatt-hours (TWh) in 2013 to 340 TWh in 2014, an increase of 2.5 percent or an average of 960 MW every hour. Much of this increase occurred in the first quarter as extremely cold weather contributed to record levels of winter load.

Despite the increase in average load, the ERCOT coincident peak hourly demand decreased from 67,247 MW to 66,451 MW in 2014, a decrease of 795 MW, or 1.2 percent. The highest peak demand experienced in ERCOT remains 68,311 MW that occurred during August of 2011.

The changes in load at the zonal level are not the same as the ERCOT-wide changes. The growth rate of West zone average load was once again much higher, on a percentage basis, than the other zones. Similarly, peak load in the West zone increased nearly 500 MW in 2014. Peak load did not increase in any other zone.

To provide a more detailed analysis of load at the hourly level, Figure 52 compares load duration curves for each year from 2011 to 2014. 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.

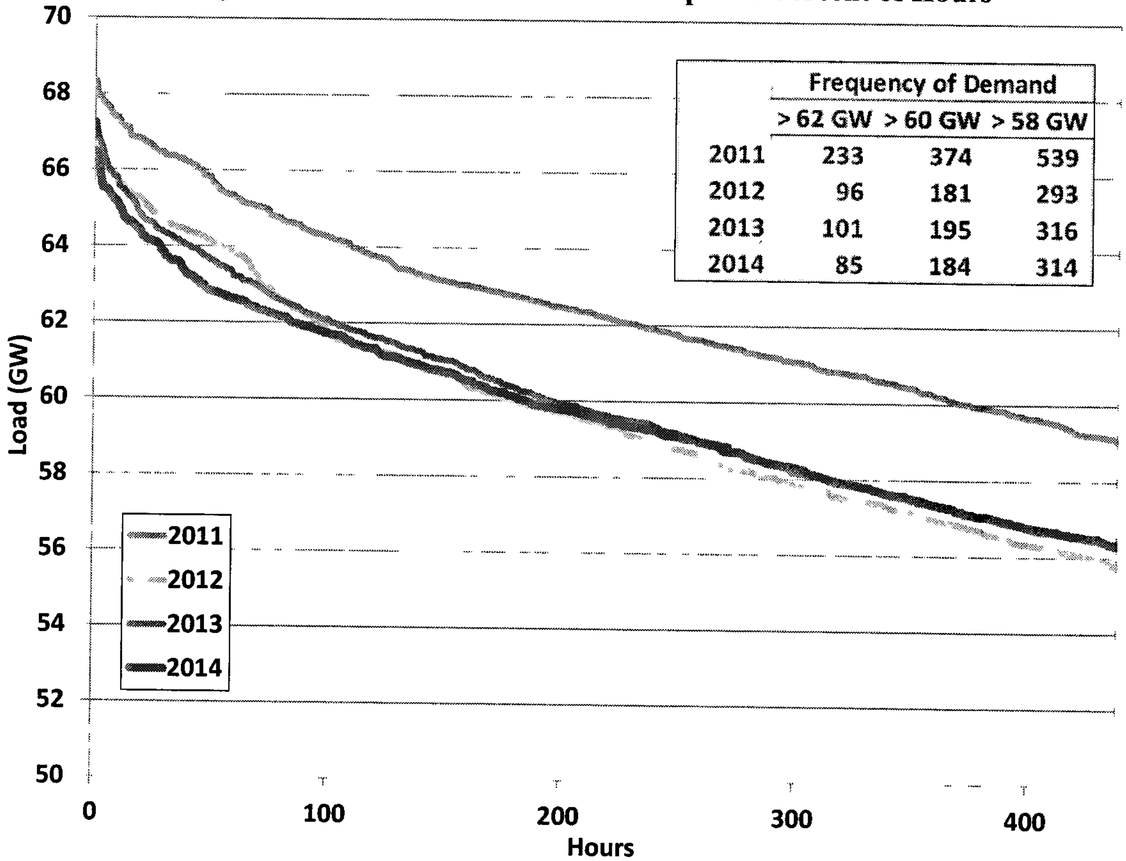
Figure 52: Load Duration Curve – All Hours



As shown in Figure 52, the load duration curve for 2014 is higher than in 2013 for all but the very highest load hours in the year. This is consistent with the aforementioned 2.5 percent load increase from 2013 to 2014. Still noticeable are the much higher loads experienced in 2011. Even with three years of energy growth the highest 2,000 hours of loads experienced in 2011 remain the highest.

To better illustrate the differences in the highest-demand periods between years, Figure 53 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 2011 to 2014, the peak load value averaged nearly 18 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 53: Load Duration Curve – Top Five Percent of Hours



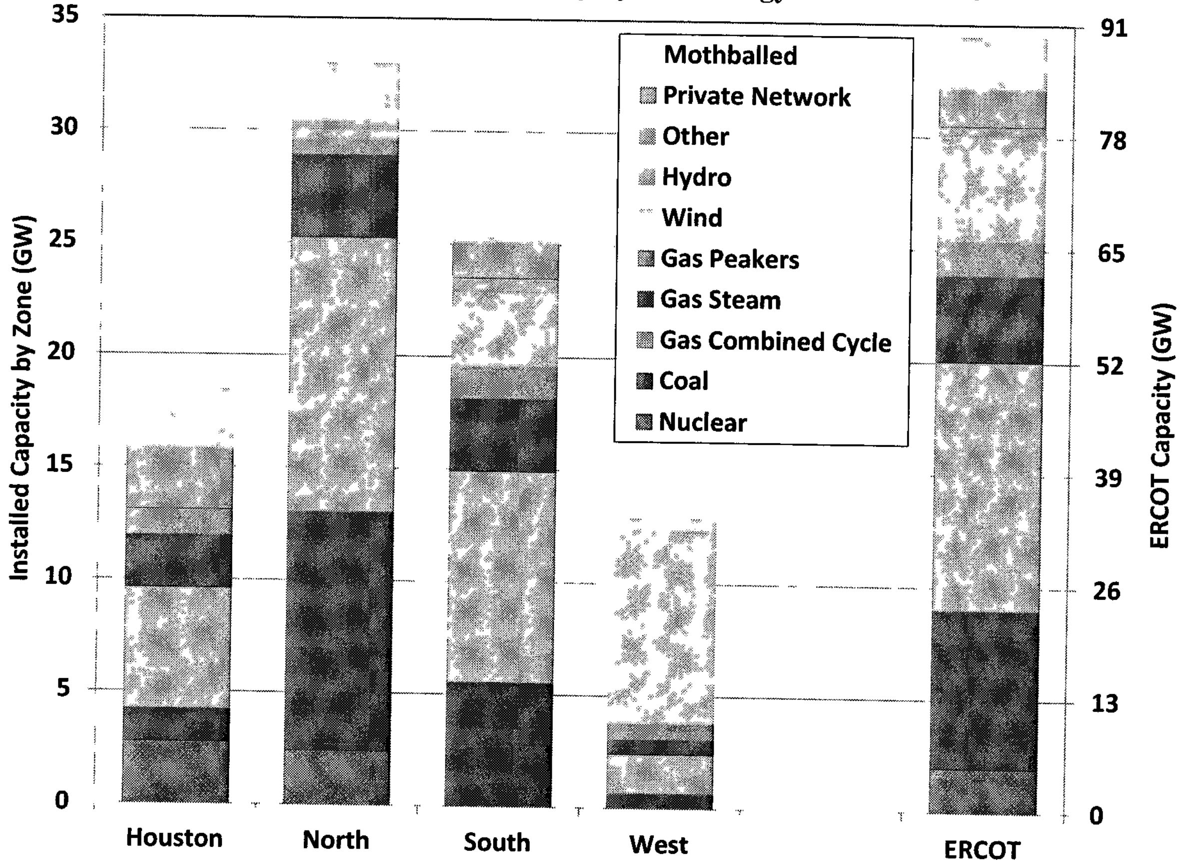
B. Generation Capacity in ERCOT

The generation mix in ERCOT is evaluated in this subsection. 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 37 percent of capacity, the South zone 28 percent, the Houston zone 21 percent, and the West zone 14 percent. Excluding mothballed resources and including only the fraction of wind capacity available to reliably meet peak demand,[7] the North zone accounts for approximately

[7] The percentages of installed capacity to serve peak demand assume wind availability of 12 percent for non-coastal wind and 56 percent for coastal wind.

40 percent of capacity, the South zone 32 percent, the Houston zone 21percent, and the West zone 7 percent. Figure 54 shows the installed generating capacity by type in each of the ERCOT zones.[8]

Figure 54: Installed Capacity by Technology for Each Zone



Approximately 2.8 GW of new generation resources came online in 2014. Gas-fueled units accounted for 2.1 GW of the total additions, primarily from two new combined cycle units. The remaining gas additions were a new combined cycle unit built on an existing site of a retired gas steam unit, and the addition of a gas turbine at an existing generator location. The remaining resource additions were wind (0.7 GW) and small solar units. When unit retirements are included, the net capacity addition in 2014 was 1.6 GW. Natural gas generation continues to account for approximately 48 percent of total ERCOT installed capacity while the share of coal generation dropped slightly from 21 percent in 2013 to 20 percent in 2014.

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