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2012 STATE OF THE MARKET REPORT FOR THE ERCOT WHOLESALE ELECTRICITY MARKETS

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Independent Market Monitor for the
ERCOT Wholesale Market

June 2013

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EXECUTIVE SUMMARY

A. Introduction

This report reviews and evaluates the outcomes of the ERCOT wholesale electricity markets in 2012, and is submitted to the Public Utility Commission of Texas ("PUCT") and the Electric Reliability Council of Texas ("ERCOT") pursuant to the requirement in Section 39.1515(h) of the Public Utility Regulatory Act. It includes assessments of the incentives provided by the current market rules and procedures, and analyses of the conduct of market participants. This report also assesses the effectiveness of the Scarcity Pricing Mechanism ("SPM") pursuant to the provisions of PUCT Substantive Rule 25.505(g).

Key findings and statistics from 2012 include the following:

- The ERCOT wholesale market performed competitively in 2012.
- The ERCOT-wide load-weighted average real-time energy price was $28.33 per MWh in 2012, a 47 percent decrease from $53.23 per MWh in 2011. The decrease was primarily driven by more moderate weather and much lower natural gas prices in 2012.
  - The average price for natural gas was 31 percent lower in 2012 than in 2011, decreasing from $3.94 per MMBtu in 2011 to $2.71 per MMBtu in 2012.
  - After the extremes of 2011, loads in 2012 were more moderate with reduced occurrences of shortage conditions. Total ERCOT load in 2012 was 2.7 percent lower than 2011. Peak load decreased by 2.6 percent. Prices at the system-wide offer cap were experienced in dispatch intervals which totaled 1.5 hours in 2012.
- The total congestion revenue generated by the ERCOT real-time market in 2012 was $480 million, a decrease of 9 percent from 2011. This decrease is not as large as might be expected given the much larger decreases in average natural gas prices and real-time energy prices.
  - The Odessa North transformer constraint was the most frequently occurring transmission constraint in 2012. This, and other related localized constraints in west

Texas had significant financial impacts, causing the West zone average price to be higher than the ERCOT average for the first time.

- Even with the increased system-wide offer cap implemented in 2012, net revenues provided by the market were at historic lows as energy prices fell substantially.
  - Net revenues were insufficient to support investment in new generation even though planning reserve margins have fallen to levels that are close to the minimum planning reserve targets.
  - These results underscore the importance of the resource adequacy issues currently under consideration by the Commission, which we discuss in this report.

B. Review of Real-Time Market Outcomes

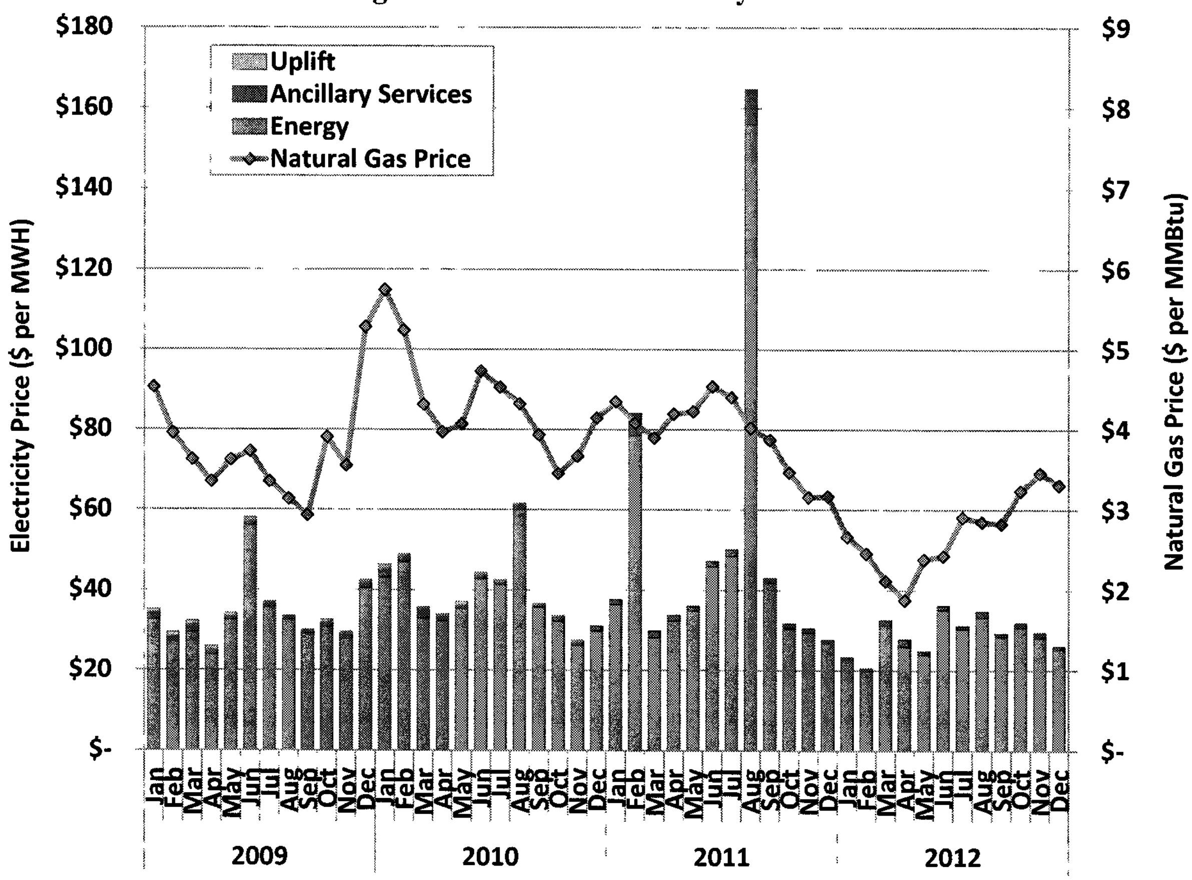
As is typical in other wholesale electricity markets, only a small share of the power produced in ERCOT is transacted in the spot market. However, prices in the real-time energy market are very important because they set the expectations for prices in the forward markets where most transactions take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

The average real-time energy prices by zone in 2009 through 2012 are shown below:

	Average Real-Time Electricity Price ($ per MWh)			
	2009	**2010**	**2011**	**2012**
ERCOT	**$34.03**	**$39.40**	**$53.23**	**$28.33**
Houston	$34.76	$39.98	$52.40	$27.04
North	$32.28	$40.72	$54.24	$27.57
South	$37.13	$40.56	$54.32	$27.86
West	$27.18	$33.76	$46.87	$38.24
Natural Gas ($/MMBtu)	$3.74	$4.34	$3.94	$2.71

The largest component of the all-in cost of wholesale electricity is the energy cost, which is reflected by the locational marginal prices determined in the real-time energy market. ERCOT average real-time market prices were 47 percent lower in 2012 than in 2011. The ERCOT-wide load-weighted average price was $28.33 per MWh in 2012 compared to $53.23 per MWh in 2011.

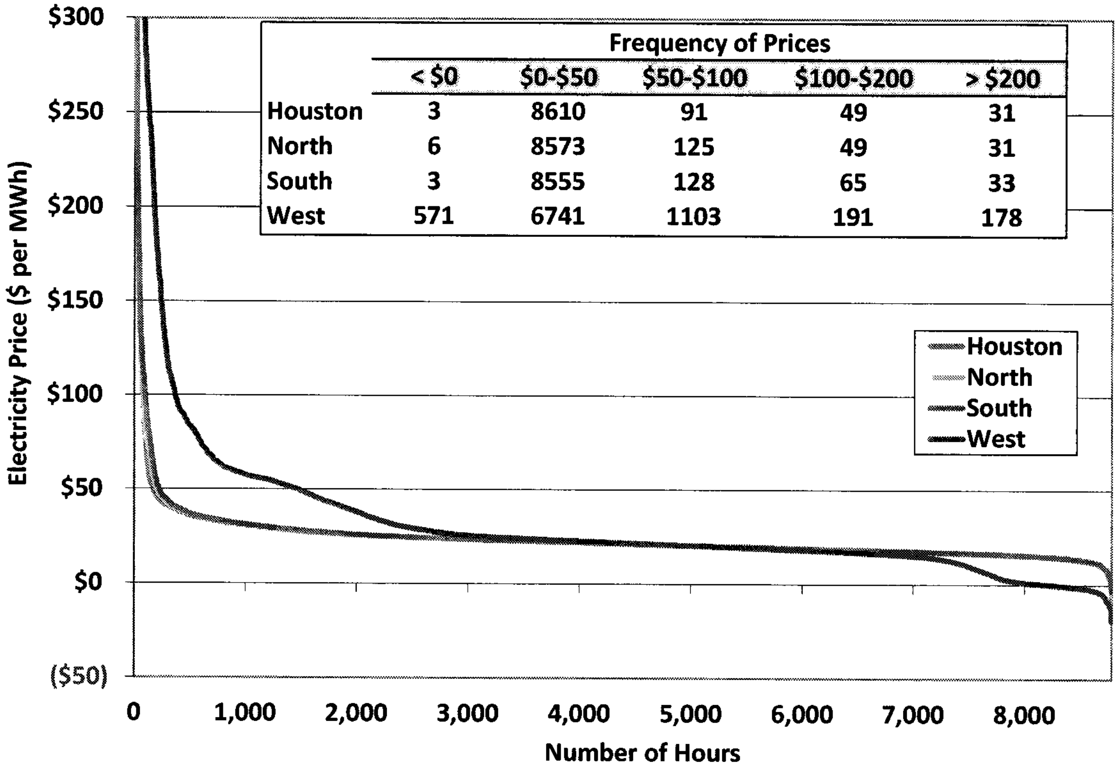
Average All-in Price for Electricity in ERCOT



The decrease in real-time energy prices was correlated with much lower fuel prices in 2012. The steady decline in natural gas prices from June 2011 to April 2012 resulted in the 2012 average natural gas price of $2.71 per MMBtu, a 31 percent decrease compared to $3.94 per MMBtu in 2011.

To depict how real-time energy prices vary by hour in each zone, the next figure shows the hourly average price duration curve in 2012 for four ERCOT load zones. The Houston, North and South load zones had similar prices over the majority of hours. The price duration curve for the West zone is noticeably different than the other zones, with more hours with prices greater than $50 per MWh and more than 500 hours (6 percent of the time) when the average hourly price was less than zero.

Zonal Price Duration Curves

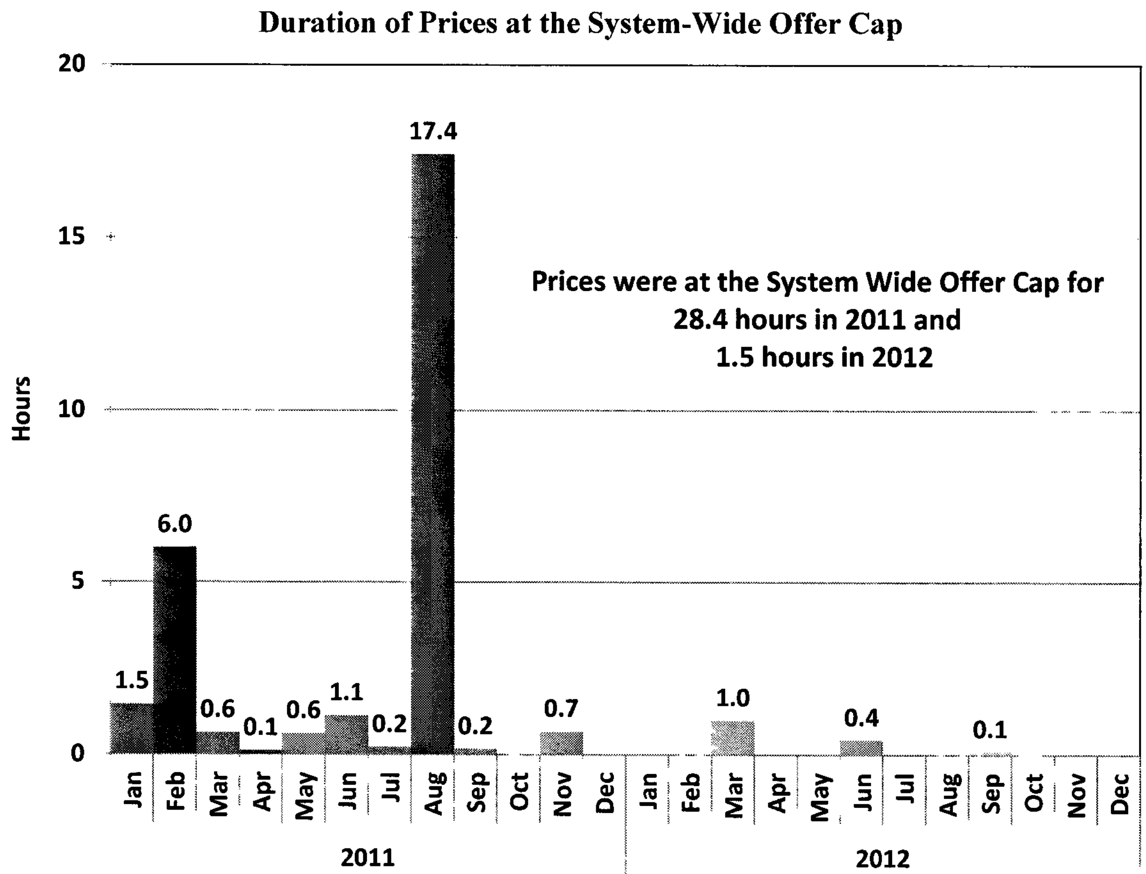


	Frequency of Prices				
	< $0	$0-$50	$50-$100	$100-$200	> $200
Houston	3	8610	91	49	31
North	6	8573	125	49	31
South	3	8555	128	65	33
West	571	6741	1103	191	178

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

After the extremes of 2011, weather conditions in Texas returned to closer to normal in 2012. As more fully discussed in Section IV, Load and Generation, overall demand for electricity was lower in 2012 than in 2011, resulting in much fewer occasions when the available supply generation capacity was unable to meet customer demands. This resulted in a decreased likelihood that the available generation capacity was not sufficient to meet customer demands for electricity and maintain the required reliability reserves.

As more fully described later in Section V, Resource Adequacy, the nodal market causes energy prices to rise toward the system-wide offer cap as available operating reserves approach minimum required levels to reflect the degradation in system reliability.



Presented in the figure above is the aggregated amount of time represented by all five-minute dispatch intervals where the real-time energy price was at the system-wide offer cap, displayed by month. Prices during 2012 were at the system-wide offer cap for only 1.5 hours, a significant reduction from the 28.4 hours experienced in 2011. Approved during 2012, PUCT SUBST. R.25.508 increased the system-wide offer cap to $4,500 per MWh effective August 1, 2012. As shown in the figure above, there was only a brief period when energy prices rose to the cap after this change was implemented.

Finally, after the multiple protocol revisions implemented in 2012, the non-spinning reserve deployment process remains sub-optimal from a reliability and efficiency perspective. As more fully described in Section I.H, Recommendations, we continue to recommend that ERCOT develop a mechanism that will rationally commit generation and load resources that can start or curtail within 30 minutes. This deficiency in ERCOT's nodal market design should be addressed by implementing a "look ahead" dispatch functionality for the real-time market to produce an energy and ancillary services commitment and dispatch results that are co-optimized and recognize anticipated changes in system demands. This additional functionality represents a major change to ERCOT systems; one we recommend together with improved pricing provisions that will allow offers from load resources to set prices if they are required to meet system demand.

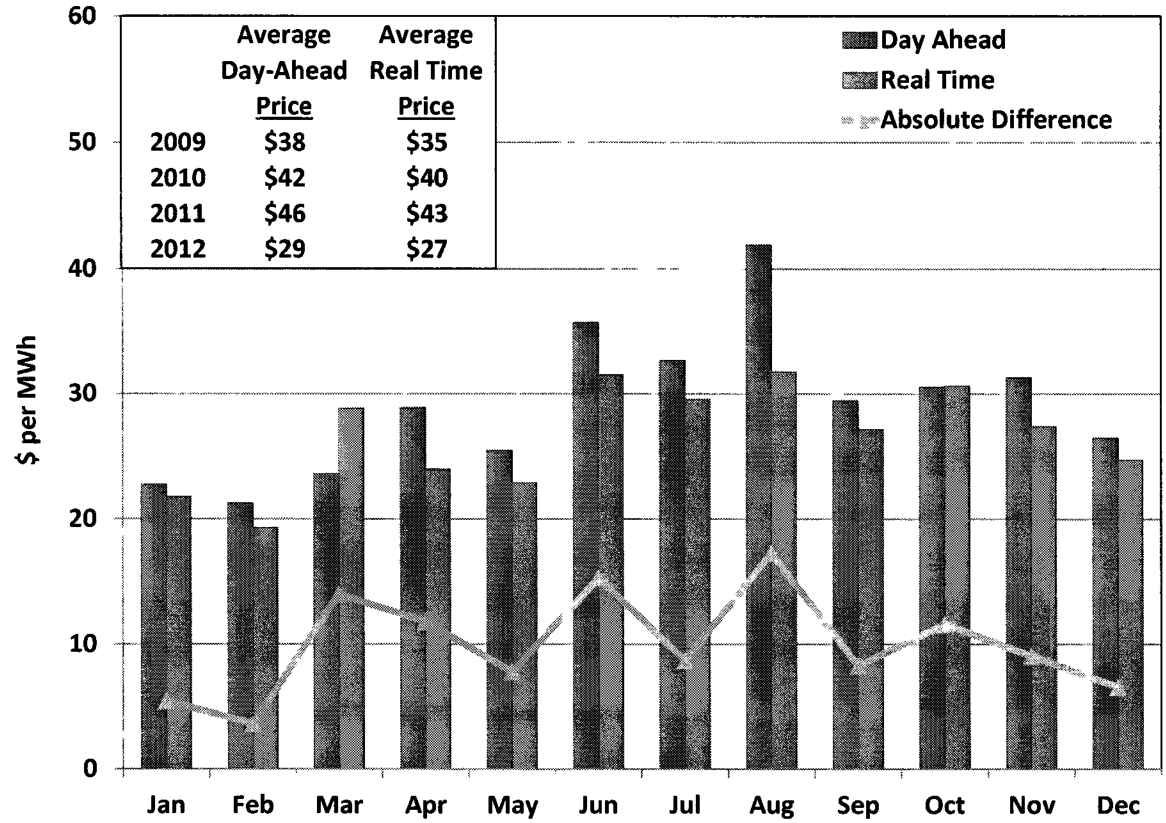
C. Review of Day-Ahead Market Outcomes

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

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

The figure below shows the price convergence between the day-ahead and real-time market, summarized by month. The simple average of day-ahead prices in 2012 was $29 per MWh, compared to the simple average of $27 per MWh for real-time prices. The average absolute difference between day-ahead and real-time prices was $9.96 per MWh in 2012; much lower than in 2011 when average of the absolute difference was $24.50 per MWh. This reduction was due to fewer occurrences of shortage intervals and associated high prices in 2012.

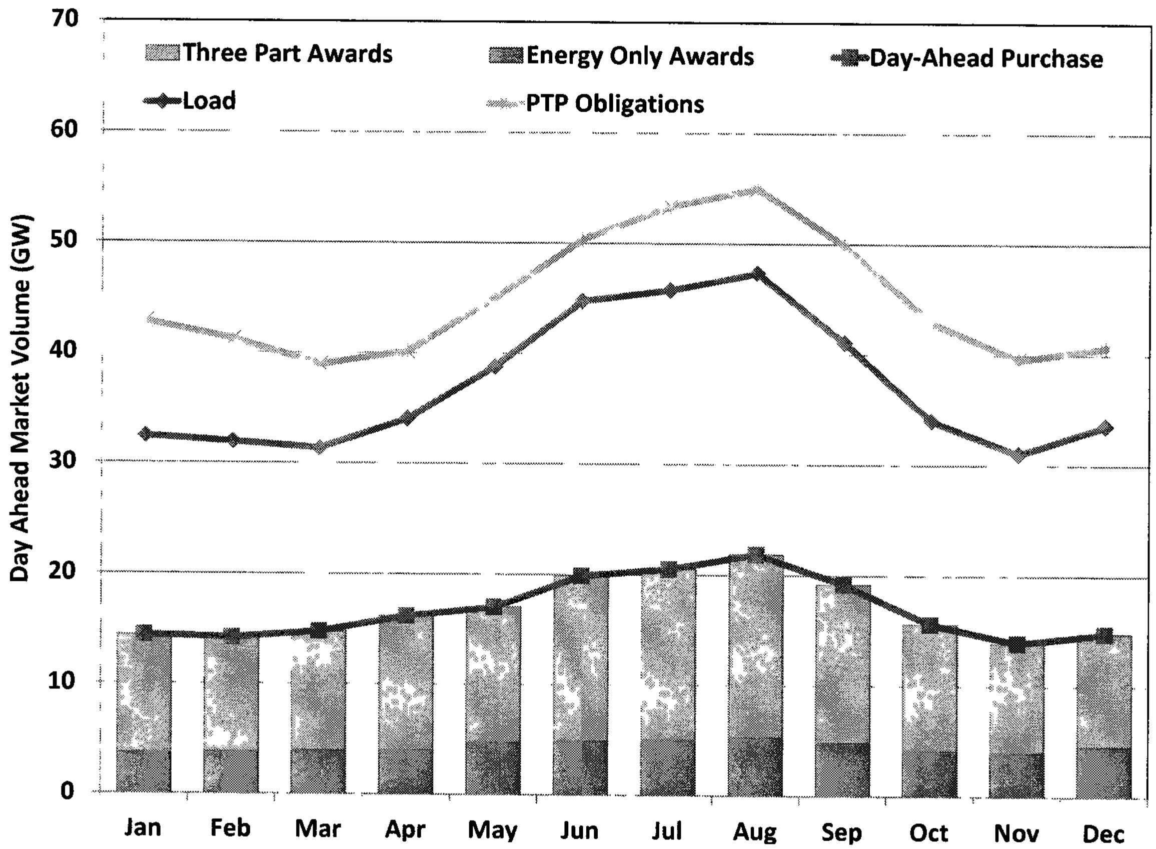
Convergence between Forward and Real-Time Energy Prices



This day-ahead premium is consistent with expectations due to the much higher volatility of real-time prices. Risk is lower for loads purchasing in the day-ahead and higher for generators selling day-ahead. The higher risk for generators is associated with the potential of incurring a forced outage and as a result, having to buy back energy at real-time prices. This explains why the highest premiums tend to occur during the months with the highest demand and highest prices. Overall, the day-ahead premiums were very similar to the differences observed in 2010 and 2011, but remain higher than observed in other organized electricity markets. Real-time energy prices in ERCOT are allowed to rise to levels that are much higher than what is allowed in other organized electricity markets, which increases risk and helps to explain the higher day-ahead premiums regularly observed in ERCOT. Although most months experienced a day-ahead premium (*e.g.*, $10 per MWh in August), it should not be expected over time that every month will always produce a day-ahead premium as the real-time risks that lead to the premiums will materialize unexpectedly on occasion, resulting in real-time prices that exceed day-ahead prices (*e.g.,* in March).

Summarized in the figure below is the volume of day-ahead market activity by month. It shows that day-ahead purchases are approximately 45 percent of real-time load.

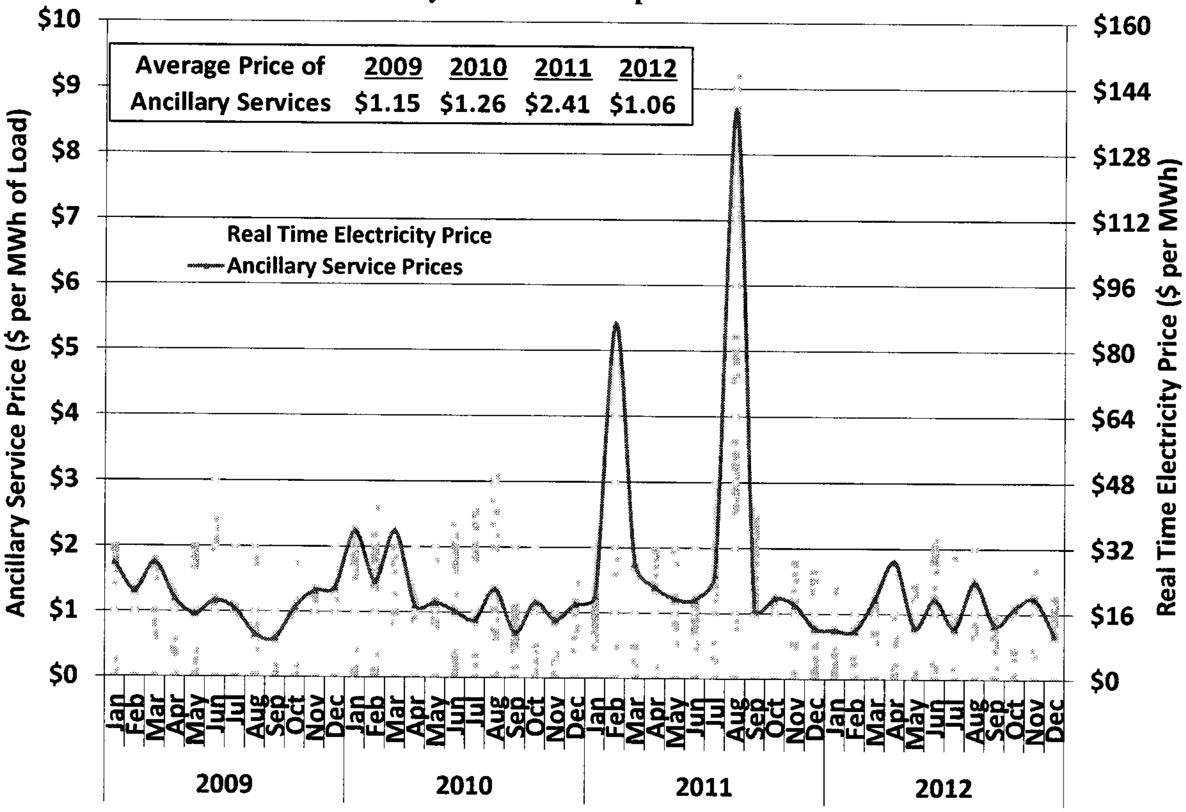
Volume of Day-Ahead Market Activity by Month



Point to Point Obligations are financial instruments purchased in the day-ahead market. Although they do not provide any energy supply themselves, they do provide the ability to avoid the congestion costs associated with transferring the delivery of energy from one location to another. To provide a volume comparison we aggregate all of these "transfers", netting location specific injections against withdrawals. By adding the aggregated transfer capacity associated with purchases of PTP Obligations, we find that on average total volumes transacted in the day-ahead market are greater than real-time load.

Ancillary Service capacity is procured as part of the day-ahead market clearing. The figure below shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2009 through 2012. Total ancillary service costs are generally correlated with real-time energy price movements, which in turn are highly correlated with natural gas price movements. The average ancillary service cost per MWh of load decreased to $1.06 per MWh in 2012 compared to $2.41 per MWh in 2011, a decrease of 56 percent. Total ancillary service costs decreased from 4.5 percent of the load-weighted average energy price in 2011 to 3.7 percent in 2012.

Ancillary Service Costs per MWh of Load



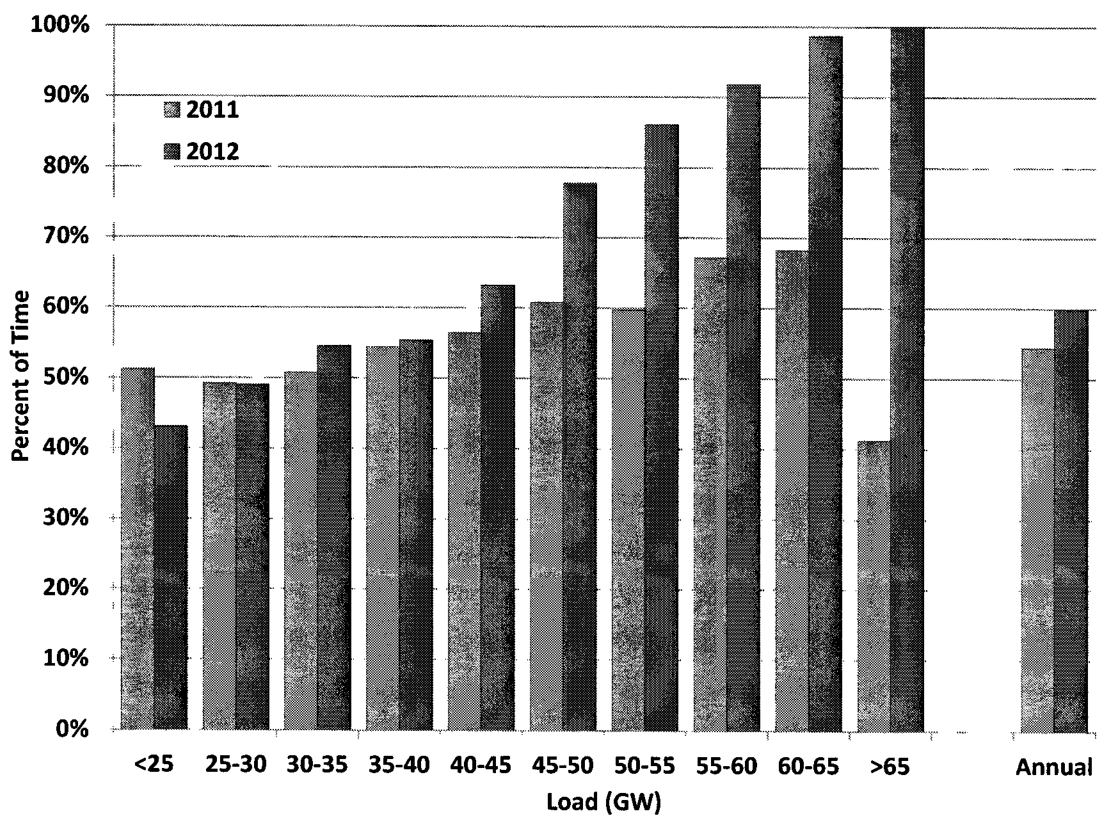
D. Transmission and Congestion

There was a marked change in the nature of real-time transmission congestion during 2012 when compared to previous years. For the past several years a significant portion of real-time transmission congestion could be described as limiting the export of wind generation ***from*** the West zone to the load centers across the rest of ERCOT. Transmission congestion in 2012 was more significantly the result of limitations on the ability to get generation ***to*** loads in the West zone. Some portion of the limitation can be attributed to transmission outages taken to enable the construction of new CREZ transmission lines. Another factor is that loads in far west Texas have increased more than the system-wide average.

The total congestion revenue generated by the ERCOT real-time market in 2012 was $480 million, a decrease of 9 percent from 2011. This decrease is not as large as might be expected given the much larger decreases in average natural gas prices real-time energy prices. Two factors influencing the overall costs of congestion in 2012 were the significant financial impact of several localized transmission constraints in far west Texas and the higher frequency of active transmission constraints.

Shown below is a comparison of the amount of time transmission constraints were active at various load levels in 2012 and 2011.

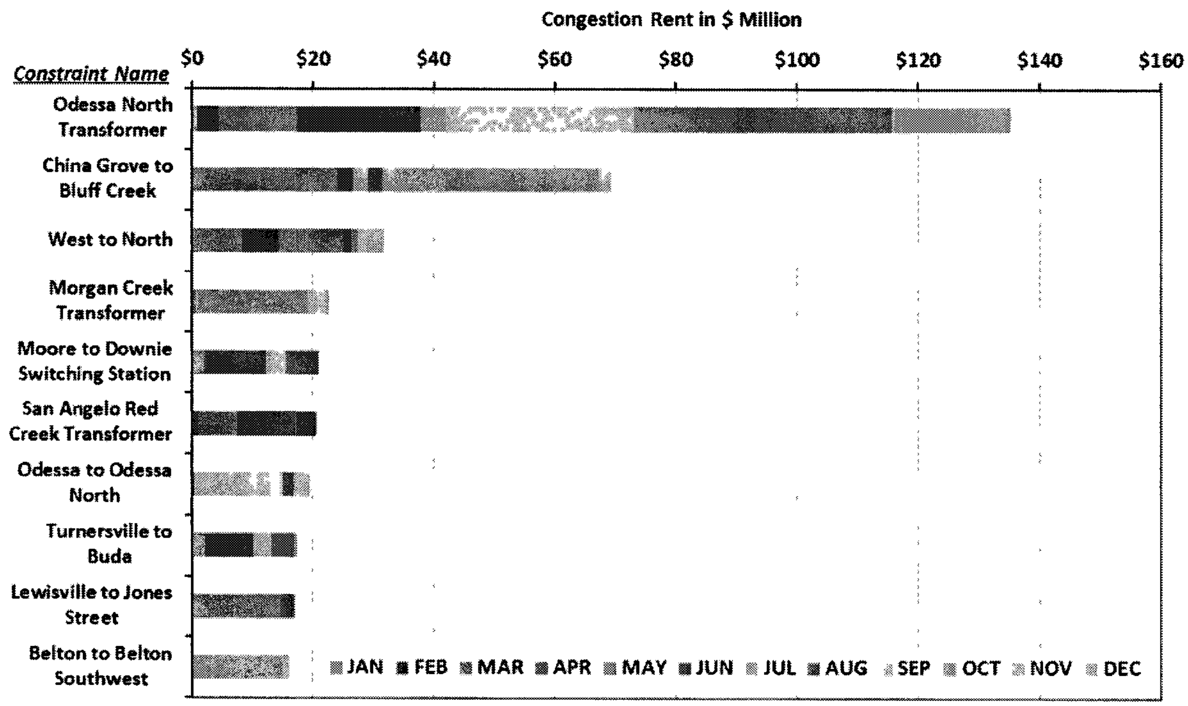
Frequency of Active Constraints



We observe that in 2012 the likelihood of having an active transmission constraint was higher than it was in 2011 and that for loads above 45 GW the frequency was much higher. During 2011, we observed that at higher system loads ERCOT operators did not always activate (or sometimes de-activated) transmission constraints. This was due to a concern that by having a constraint active during periods of high demand the total capacity available to serve load may be limited. However, ERCOT's dispatch software contains parameters that allow it to automatically make the correct decision about when to violate transmission constraints when necessary to serve total system load. Therefore, ERCOT modified their practice in 2012 to retain active transmission constraints even during periods of high demand.

The figure below displays the ten most costly real-time constraints and indicates that the Odessa North 138/69 kV transformer constraint was by far the most highly valued during 2012. This constraint became more pronounced from 2011 to 2012 and is mainly attributed to load growth in far west Texas driven by increased oil and natural gas activity.

Top Ten Real-Time Constraints

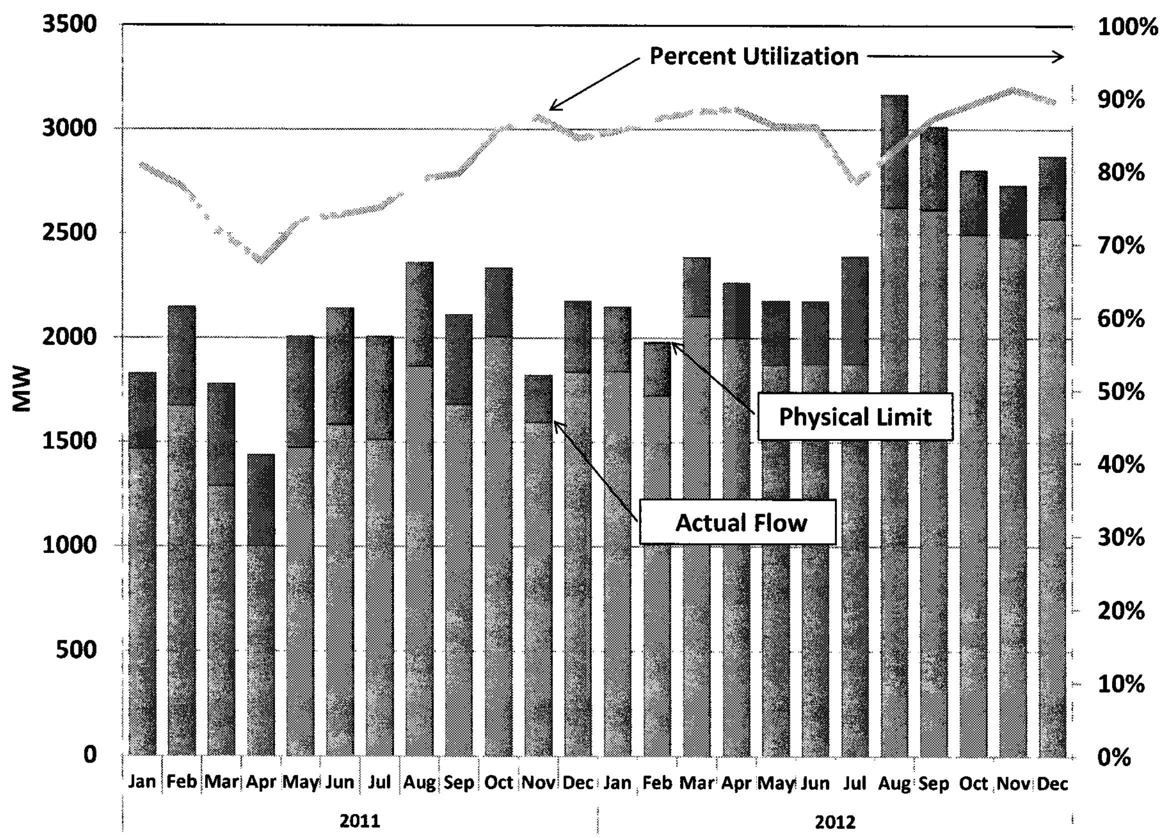


The Odessa North 138/69 kV transformer typically overloads during low wind conditions. The characteristics that load the Odessa North 138/69 kV transformer are the same conditions that also affect Odessa to Odessa North 138 kV line, which is shown as the seventh constraint on the list. Not only did this constraint have nearly twice the financial impact of the second constraint on the list, its impact was more than 40 percent greater than the top constraint from 2011. Its magnitude is even more significant given the overall lower costs of energy in 2012.

Not surprisingly, much public attention was focused on this constraint; much of it questioning its causes and the potential for short-term remedies. ERCOT and the local transmission provider were able to identify two transmission lines, which when opened greatly reduced congestion around the Odessa North station without causing other reliability concerns. After the lines were opened in mid-September, congestion around Odessa North was almost eliminated for the rest of the year.

The figure below presents a summary of the utilization of the West to North interface. The West to North constraint continued to be active at some point during every month of 2012 but with far less impact than in 2011.

Utilization of the West to North Interface Constraint



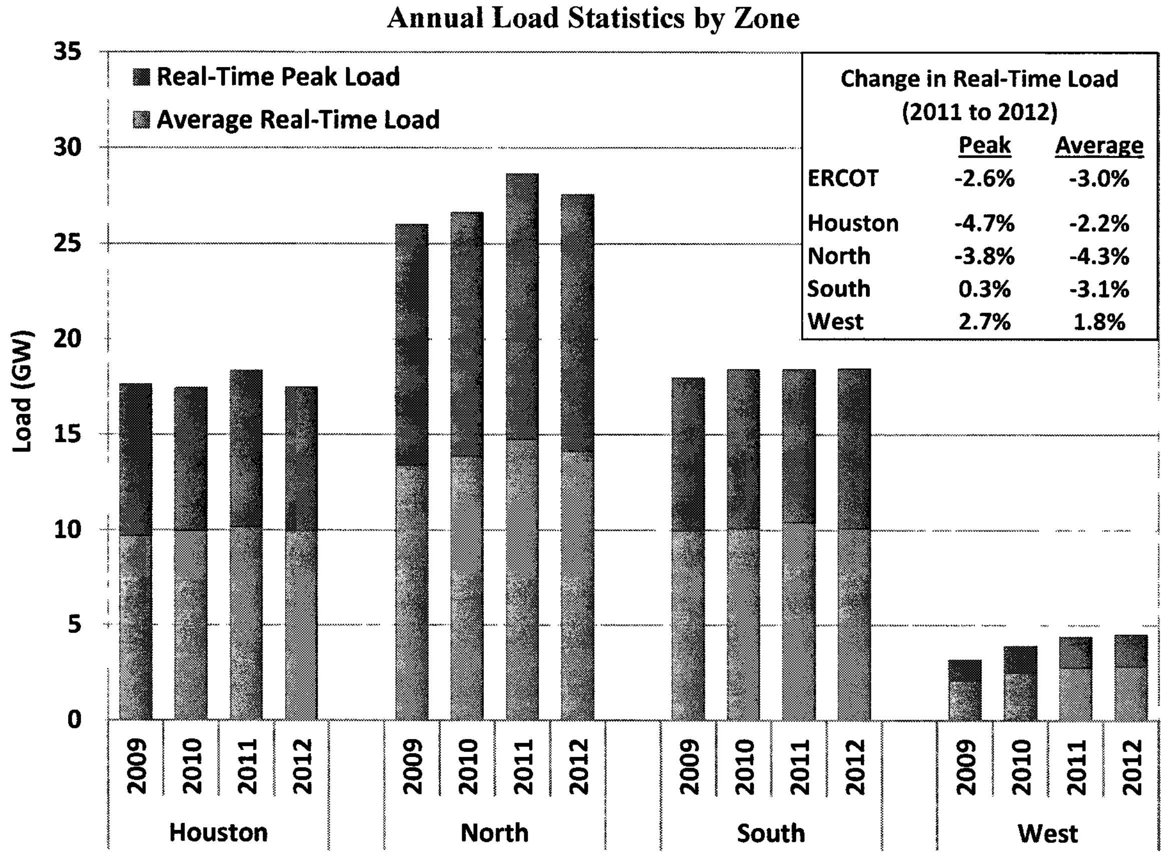
Through the years this constraint has been a major impediment to delivering all the wind generation located and produced in the western reaches of ERCOT to the load centers. This constraint had the highest financial impact of all real-time transmission constraints during 2011, but in 2012 its impact dropped to one third that level. The reduction was a result of the combined impact of higher loads in the west and increased transfer capability due to the first CREZ transmission lines being placed in service.

Through July 2012, the average physical limit was approximately 2,200 MW and the average actual flow during constrained intervals was approximately 1,900 MW. After July 2012, the physical limit increased to an average of 2,900 MW and the actual flow increased to approximately 2,500 MW. In March 2012, a new real-time analysis tool was implemented to better track the dynamic nature of the transient stability limit of the West to North interface. However, there was not a noticeable increase to the transfer limit corresponding to its implementation due to the effects of transmission outages occurring to accommodate maintenance activities and the installation of CREZ lines. Many of these outages were complete by July 2012 which accounts for the increase in the West to North limit.

The average annual utilization of the West to North constraint was 87 percent in 2012, which compares favorably to 78 percent utilization experienced in 2011. Over the long term, the physical limit will continue to increase as CREZ transmission projects are completed.

E. Load and Generation

The figure below shows peak load and average load in each of the ERCOT zones from 2009 to 2012. In each zone, as in most electrical systems, peak demand significantly exceeds average demand. The North zone is the largest zone (with about 38 percent of the total ERCOT load); the South and Houston zones are comparable (27 percent); while the West zone is the smallest (8 percent of the total ERCOT load). The figure also shows the annual non-coincident peak load for each zone. This is the highest load that occurred in a particular zone for one hour during the year; however, the peak can occur in different hours for different zones. As a result, the sum of the non-coincident peaks for the zones was greater than the annual ERCOT peak load.

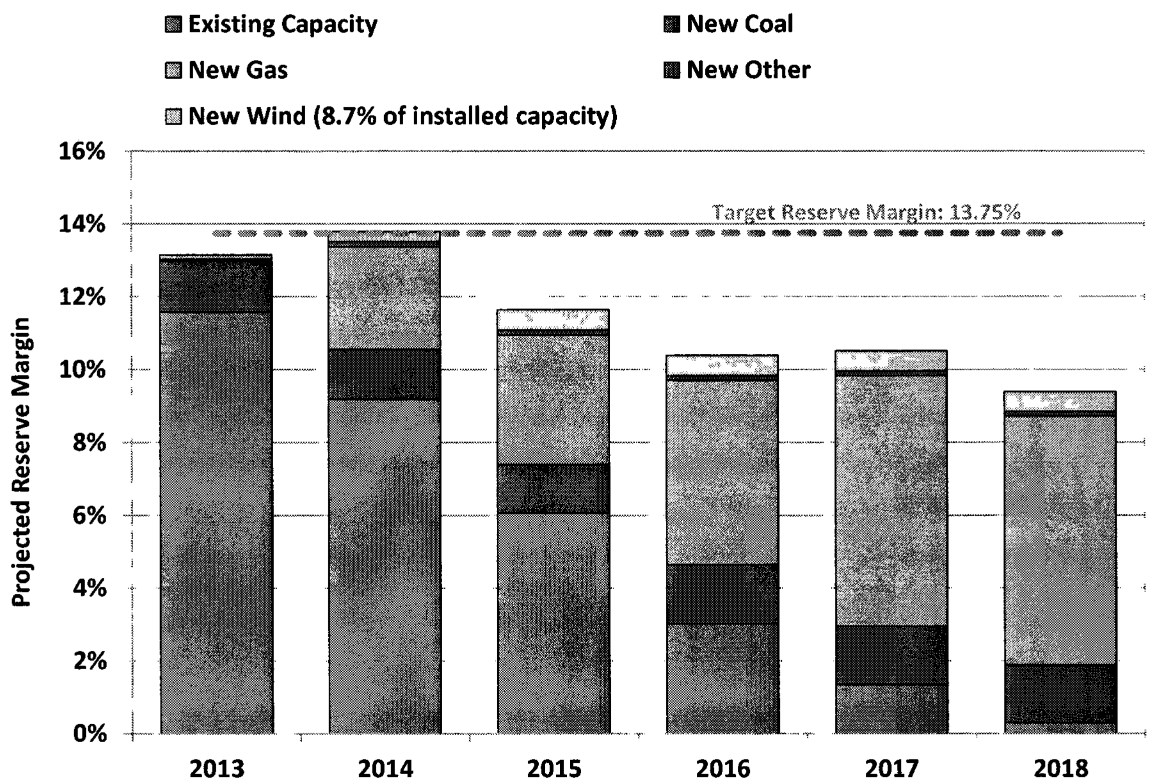


Total ERCOT load decreased from 334 TWh in 2011 to 325 TWh in 2012, a decrease of 2.7 percent or an average of 1,130 MW every hour. Similarly, the ERCOT coincident peak hourly demand decreased from 68,311 MW in 2011 to 66,559 MW, a decrease of 1,752 MW, or 2.6 percent. The results at the zonal level are not consistent. Average load decreased in three of the four zones, but grew by 1.8 percent in the West zone.

New generation resources in 2012 totaled approximately 1 GW; most of which were wind units and the remainder were solar and biomass. Comparing the current mix of installed generation capacity to that in 2007, we find that over these six years wind and coal generation are the two categories with the most increased capacity. The sizable additions in these two categories have been more than offset by retirements of natural gas-fired steam units, resulting in less installed capacity in 2012 than there was in 2007.

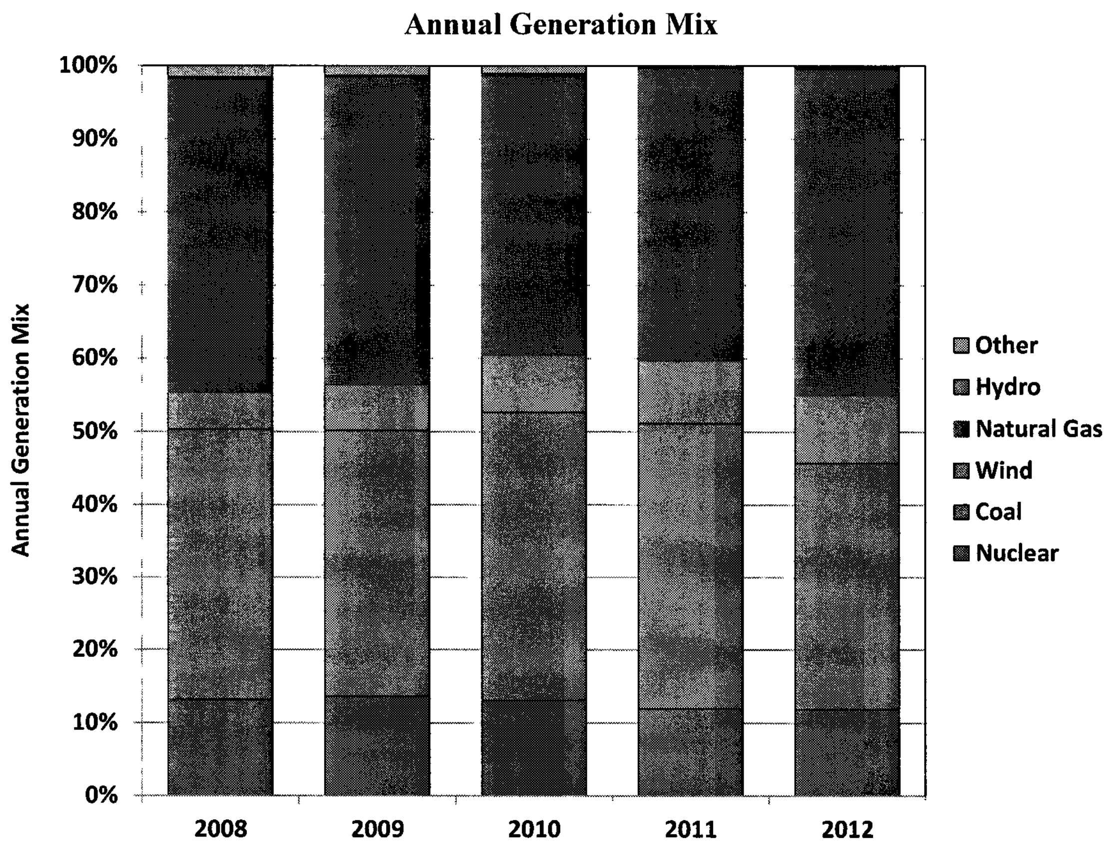
Shown below is ERCOT's most current projection of reserve margins. It indicates that the region will have a 13.2 percent reserve margin heading into the summer of 2013. With the addition of recently announced generation additions, in 2014 the reserve margin is expected to reach 13.8 percent -- just barely above the current target. The bulk of the new capacity being added is natural gas-fired generation, approximately a quarter of which are expansions at existing facilities.

Projected Reserve Margins



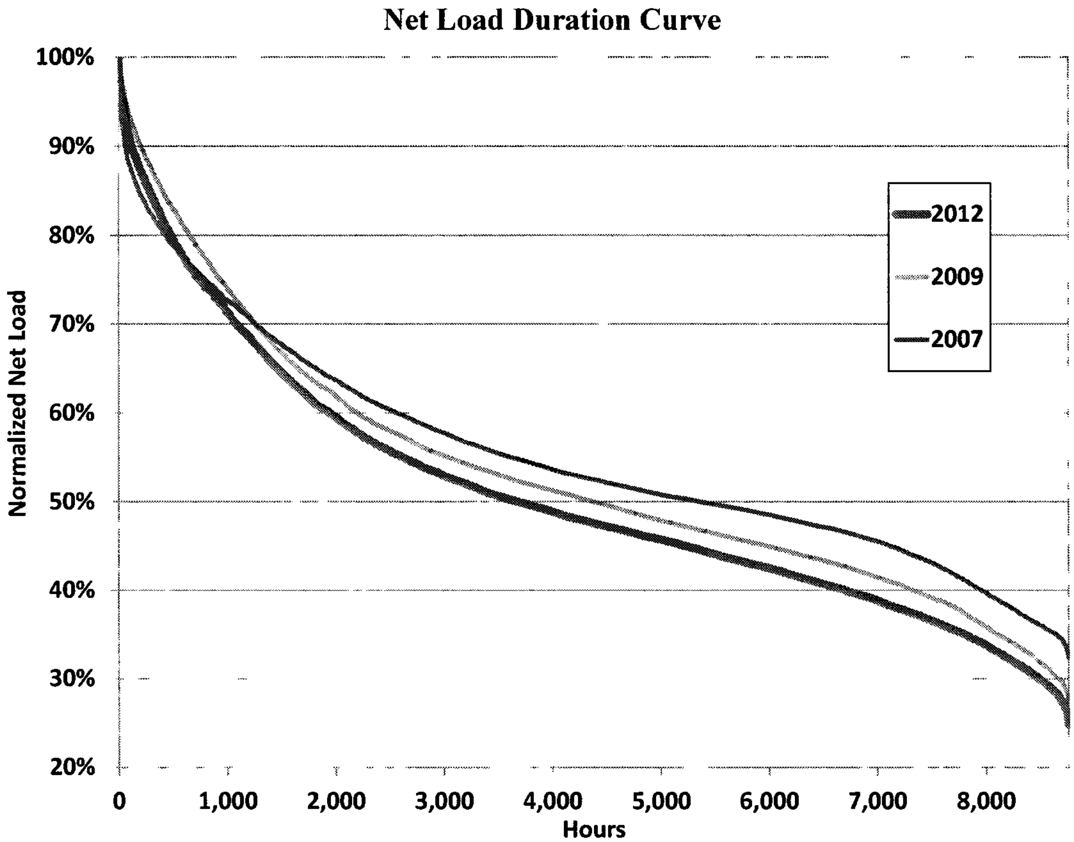
Source: ERCOT Capacity Demand Reserve Reports / 2013 data from Winter 2012, 2014 - 2018 from May 2013

The figure below shows the percent of annual generation from each fuel type for the years 2008 through 2012. The generation share from wind has increased every year, reaching 9 percent of the annual generation requirement in 2012, up from 5 percent in 2008. During the same period, the percentage of generation provided by natural gas decreased from 43 percent in 2008 to 38 percent in 2010, before increasing to 45 percent in 2012. Correspondingly, the percentage of generation produced by coal units increased from 37 percent to 40 percent in 2010 before decreasing to 34 percent in 2012. The increase in the share of generation produced by natural gas, and corresponding reduction in coal generation is due to historically low price of natural gas in 2012.



While coal/lignite and nuclear plants operate primarily as base load units in ERCOT, it is the reliance on natural gas resources that drives the high correlation between real-time energy prices and the price of natural gas fuel. There is approximately 23 GW of coal and nuclear generation in ERCOT. Generally, when ERCOT load is above this level, natural gas resources will be on the margin and set the real-time energy spot price. However, due to the low price of natural gas in 2012, we observe that the share of generation produced from coal-fired and nuclear units decreased to less than half of the energy in ERCOT, with the reduction coming from decreased coal generation.

Increasing levels of wind resource in ERCOT also has important implications for the net load duration curve faced by the non-wind fleet of resources. Net load is defined as the system load minus wind production. The figure below shows the net load duration curves for selected years since 2007, normalized as a percent of peak load. This figure shows the continued erosion of remaining energy available for non-wind units to serve during most hours of the year, with much less impact during the highest loads.

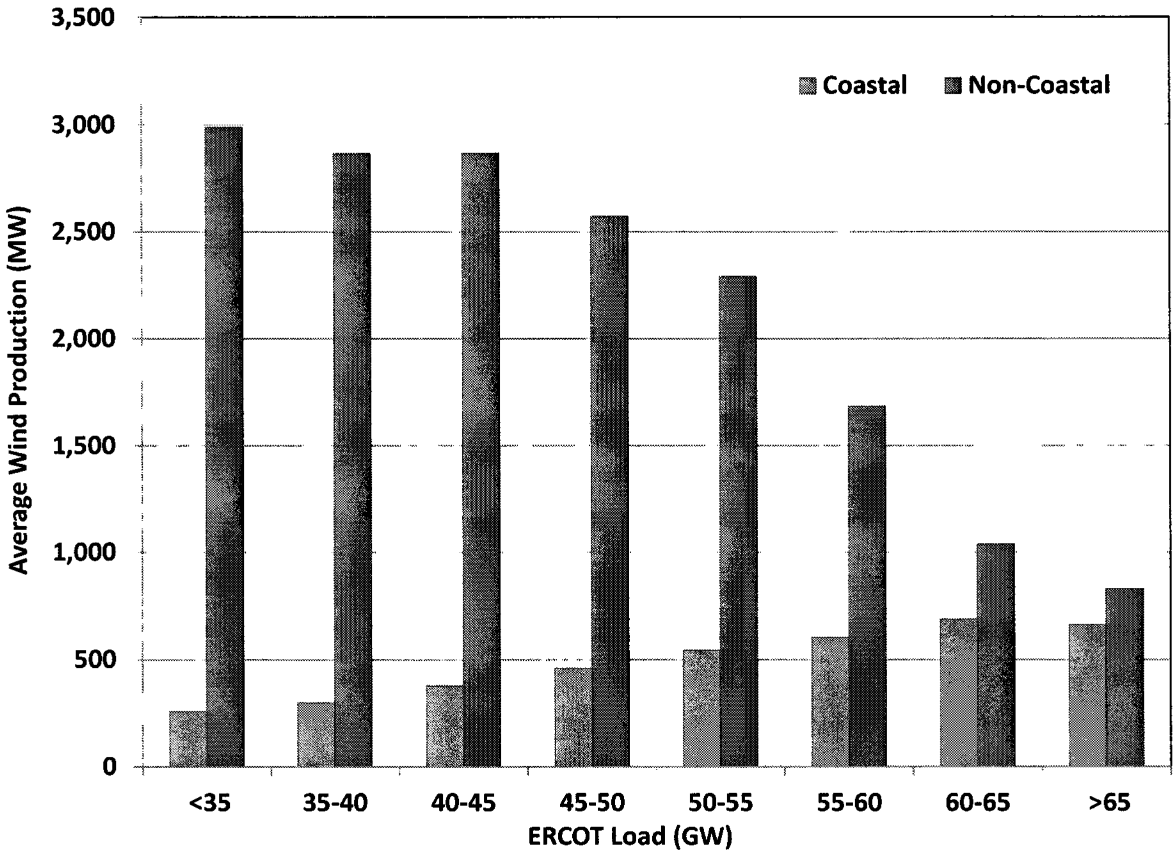


Thus, although the peak net load and reserve margin requirements are projected to continue to increase and create an increasing need for non-wind capacity to meet net load and reliability requirements, the non-wind fleet is expected to operate for fewer hours as wind penetration continues to increase.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

Even with the increased development activity in the coastal area of the South zone, more than 80 percent of the wind resources in the ERCOT region are located in west Texas. The wind profiles in this area are such that most of the wind production occurs during off-peak hours or other times of relatively low system demand. This profile results in only modest reductions of the net load relative to the actual load during the hours of highest demand, but much more significant reductions in the net load relative to the actual load in the other hours of the year. The trend shown from 2007 in the figure above may continue with the addition of new wind resources and the reduction in the curtailment of existing wind resources after completion of new transmission facilities.

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

Summer Wind Production vs. Load



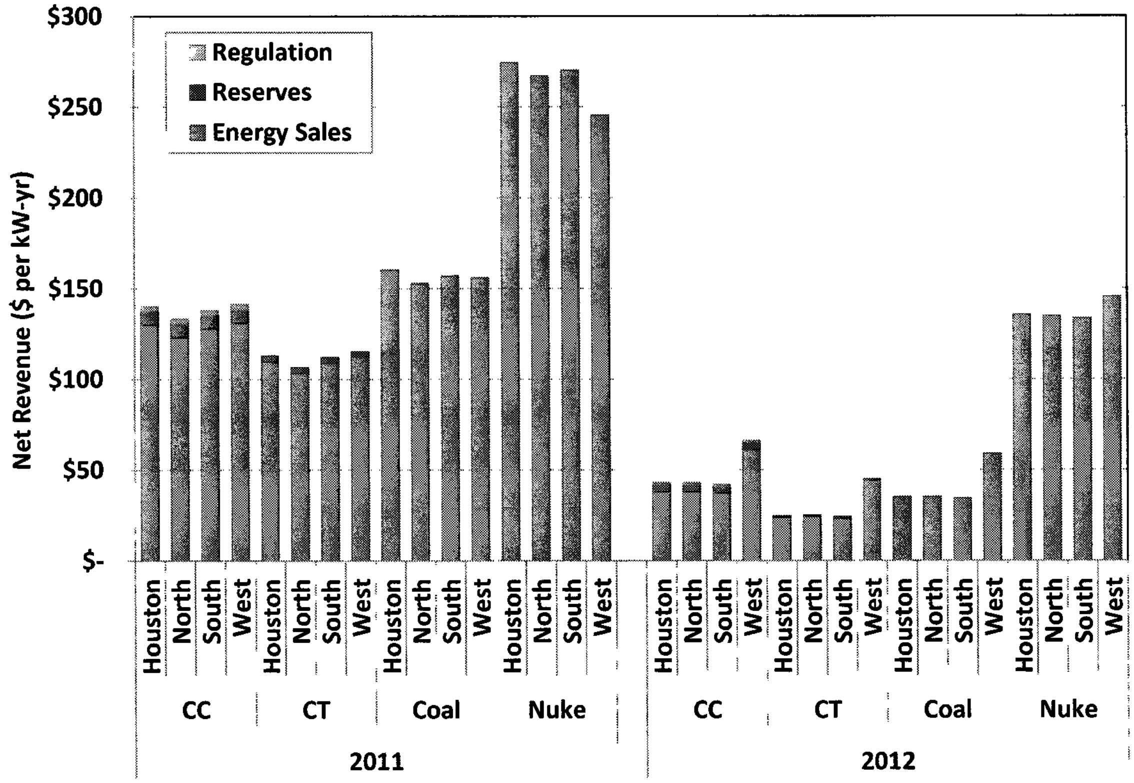
It shows a strong negative relationship between non-coastal wind output and increasing load levels. It further shows that the output from wind generators located in the coastal area of the South zone is much more highly correlated with peak electricity demand.

F. Resource Adequacy

Long-Term Economic Signals: Net Revenue

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

Estimated Net Revenue



The figure above shows the results of the net revenue analysis for four types of hypothetical new units in 2011 and 2012. These are: (a) natural gas-fired combined-cycle, (b) natural gas-fired combustion turbine, (c) coal-fired generator, and (d) a nuclear unit. For the natural gas-fired technologies, net revenue is calculated by assuming the unit will produce energy in any hour for which it is profitable and by assuming it will be available to sell reserves and regulation in other hours that it is available. For coal and nuclear technologies, net revenue is calculated by assuming that the unit will produce at full output.

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

The figure above shows that the net revenue for every generation technology type decreased substantially in 2012 compared to each zone in 2011.

- For a new coal-fired unit, the estimated net revenue requirement is approximately $210 to $270 per kW-year. The estimated net revenue in 2012 for a new coal unit was approximately $35 per kW-year.
- For a new nuclear unit, the estimated net revenue requirement is approximately $280 to $390 per kW-year. The estimated net revenue in 2012 for a new nuclear unit was approximately $134 per kW-year.
- For a new natural gas-fired combustion turbine, the estimated net revenue requirement is approximately $80 to $105 per kW-year. The estimated net revenue in 2012 for a new gas turbine was approximately $25 per kW-year.
- For a new combined cycle unit, the estimated net revenue requirement is approximately $105 to $135 per kW-year. The estimated net revenue in 2012 for a new combined cycle unit was approximately $42 per kW-year.

These results indicate that the ERCOT markets would not have provided sufficient revenues to support profitable investment in any of the types of generation technology evaluated. Higher energy prices in the West zone during 2012 resulted in higher net revenues in that zone, but they were still not high enough to support new entry there. The net revenues in 2012 were much lower than in 2011. However, it is important to recognize that 2011 was highly anomalous, with some of the hottest summer temperatures on record. Net revenues may have been sufficient to cover the costs of a new combined cycle or new combustion turbine in 2011, however, we would not expect this to be consistently true in years with comparable reserve margins absent the extreme weather conditions, as evidenced by the 2012 net revenue results.

Shortage Pricing, Capacity Markets, and Resource Adequacy

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

The nodal market implementation brought about more reliable and efficient shortage pricing. Modifications implemented during 2012, which introduced offer floors associated with the deployment of generator-provided responsive reserves and non-spinning reserves, further improved pricing outcomes. However, ERCOT's real-time energy pricing can be improved by ensuring the value of curtailed load is fully reflected in prices when load resources are deployed and further improving its shortage pricing as recommended in this report.

The PUCT has devoted considerable effort over the past two years deliberating issues related to resource adequacy. These deliberations have resulted in changes to the rules governing the system-wide offer cap and the peaker net margin ("PNM") mechanism. The system-wide offer cap was increased to $4,500 per MWh effective August 1, 2012 and is scheduled to increase every year up to $9,000 per MWh on June 1, 2015. This is intended to raise market revenues to help address resource adequacy concerns. However, inflating the system-wide offer cap may raise efficiency concerns if the resulting energy prices are set at or above levels consistent with the value of lost load during periods when the system is only slightly short of operating reserves and involuntary load curtailment is not imminent. This is a concern because setting prices substantially higher than the expected value of lost load can cause market participants to take inefficient actions, resulting in higher overall market costs. To address this concern, we recommend that ERCOT:

- Modify the slope of the existing power balance penalty curve and the offer floor for responsive reserve service to provide a more gradual slope up to the system-wide offer cap; and
- Modify the automatic pricing of unoffered capacity such that it is not all priced at the system-wide offer cap to avoid the inefficiencies associated with the automated economic withholding of such capacity.

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

In an energy only market, the primary source of such revenue is the net revenues received during periods of shortage. Expectations about both the magnitude of the energy price during shortage conditions and the frequency of shortage conditions are the primary means to attract new investment in an energy-only market. If the expected revenues are not high enough to facilitate enough investment to satisfy the planning reserve target, one option is to increase the shortage pricing levels to levels that substantially exceed the expected value of lost load. As the planning reserve levels grow, however, the frequency of shortages will tend to drop sharply, which can make it difficult to use this means to meet planning reserve targets.[1] Additionally, as discussed below, such approaches introduce costly operational inefficiencies into the ERCOT energy markets.

1 The difficulty of relying primarily on shortage pricing will depend on how high the planning reserve target is relative to the planning reserve levels any energy-only market priced at the expected value of lost load would provide. See the discussion of the Brattle Report below.

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

In 2012, ERCOT engaged The Brattle Group to assess its resource adequacy outlook by evaluating a number of market design scenarios.[2] Brattle also supplemented its report with a comparison of costs and reliability for the energy-only market and two capacity market scenarios with 10% and 14% reserve margin requirements.[3] The results of this analysis are summarized in the table below.

COMPARISON OF COSTS AND RELIABILITY

	Energy-Only Equilibrium	10% Reserve Margin Requirement	14% Reserve Margin Requirement
Reliability			
Reserve Margin	8%	10%	14%
Reserve Margin Certainty	Uncertain	More Certain	More Certain
Annual Avg. Loss of Load Hours	4.1	2.2	0.3
Customer Costs			
Energy Costs ($billions)	$18.3	$16.3	$14.0
Capacity Costs ($billions)	$0	$2.1	$4.7
Total Costs ($billions)	$18.3	$18.4	$18.7
Cost Increase over Energy-Only Equilibrium (%)	NA	0.7%	2.4%
Rate Increase over Energy-Only Equilibrium (%)	NA	0.4%	1.4%
Combustion Turbine Energy Margins and Capacity Revenues			
Energy Margins ($/kW-y)	$105	$75	$41
Capacity Revenues ($/kW-y)	$0	$30	$64
Total Margins ($/kW-y)	$105	$105	$105

Notes. 8% energy-only equilibrium reserve margin based on The Brattle Group's simulations with a $9,000 price cap and gradually sloping scarcity pricing function. Rate impacts assume generation costs comprise 60% of total retail rates.

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[2] *ERCOT Investment Incentives and Resource Adequacy,* The Brattle Group, PUCT Docket No. 37987 (June 1, 2012).

[3] *Customer Cost Comparison*, The Brattle Group, PUCT Docket No. 40000 (Sept. 4, 2012).

As indicated in the table above, Brattle estimates that even with $9,000 per MWh system-wide offer caps, economic equilibrium for the ERCOT energy-only market is achieved at an 8 percent planning reserve margin, although the actual reserve margin outcomes will be uncertain. Brattle further estimates that in the energy-only market at annual equilibrium, wholesale generation costs will be $18.3 billion. In contrast, Brattle's assessment of a capacity market with a more certain 14 percent reserve margin expectation, estimates generation costs at annual equilibrium to be $18.7 billion.

It is important to recognize that this increase in cost is not due to the introduction of the capacity market, it is due to the requirement to sustain a planning reserve margin greater than 8 percent. In fact, the Brattle analysis indicates that a capacity market would deliver the higher planning reserve margin at a relatively low incremental cost with much more certainty. Further, recent studies have indicated that to maintain the same small level of risk of having an involuntary curtailment of firm load, the planning reserve target should be increased from 13.75 percent to approximately 16 percent. Hence, the difficulty of satisfying ERCOT's planning needs with shortage pricing alone will grow if this recommendation is adopted.

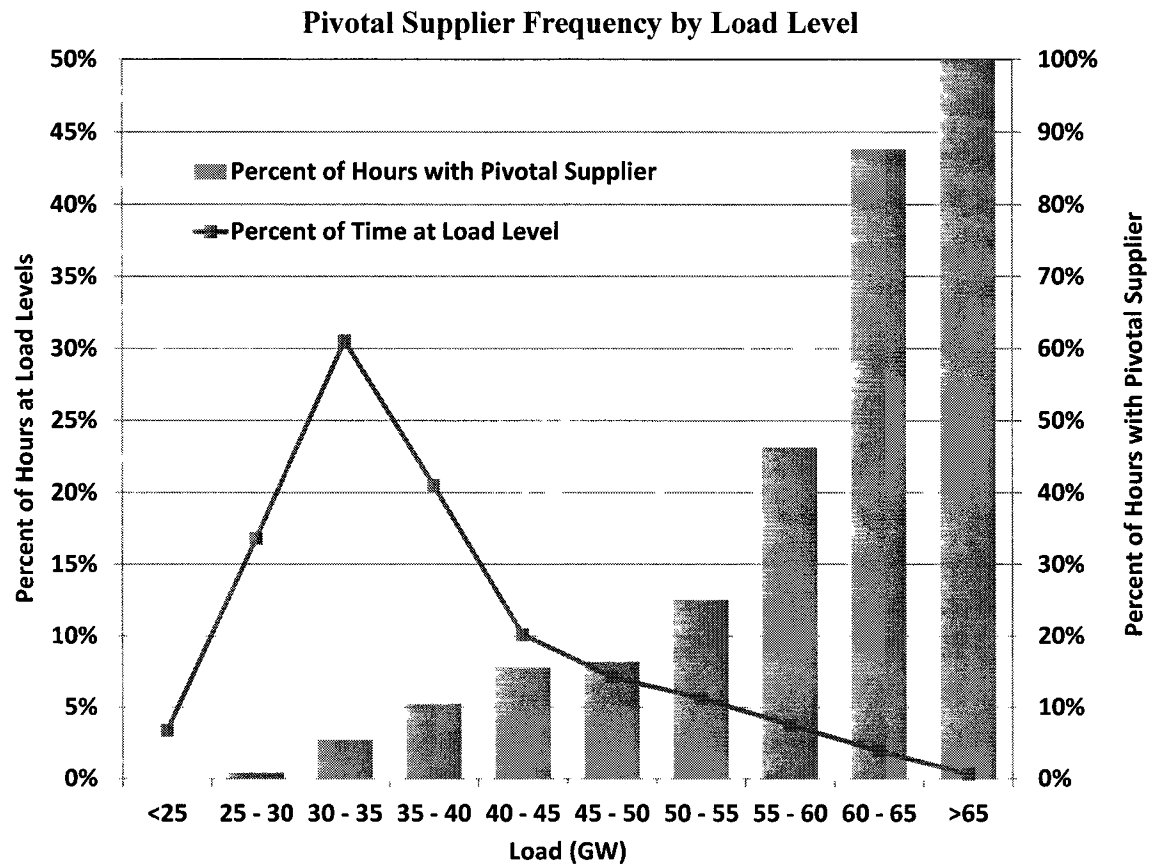
In response to these observations, proposals have been put forth that would introduce significant operational inefficiencies into the ERCOT energy markets, such as a requirement to substantially increase the quantity of operating reserves ERCOT procures and to, by rule, economically withhold these surplus reserves from the market. Such approaches would introduce significant inefficiencies into ERCOT day ahead and real time operations in an effort to manufacture more frequent shortage pricing and a higher planning reserve margin than would be achieved in a pure energy-only market framework. However, such approaches will not guarantee that the planning reserve targets will be satisfied and, because of the resulting operational inefficiencies, will be more costly for ERCOT's consumers. Hence, consistent with Brattle's findings, it is our view that if the planning reserve margin is viewed as a minimum requirement, implementation of a capacity market is the most efficient mechanism to achieve this objective. As observed by Brattle, a well-designed capacity market can efficiently meet a planning reserve requirement without impairing the efficiency of energy market operations. However, there are many determinations required in the design, implementation and maintenance of a capacity market construct.[4]

G. Analysis of Competitive Performance

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

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

[4] *ERCOT Investment Incentives and Resource Adequacy,* The Brattle Group, at 115-119, PUCT Docket No. 37987 (June 1, 2012).



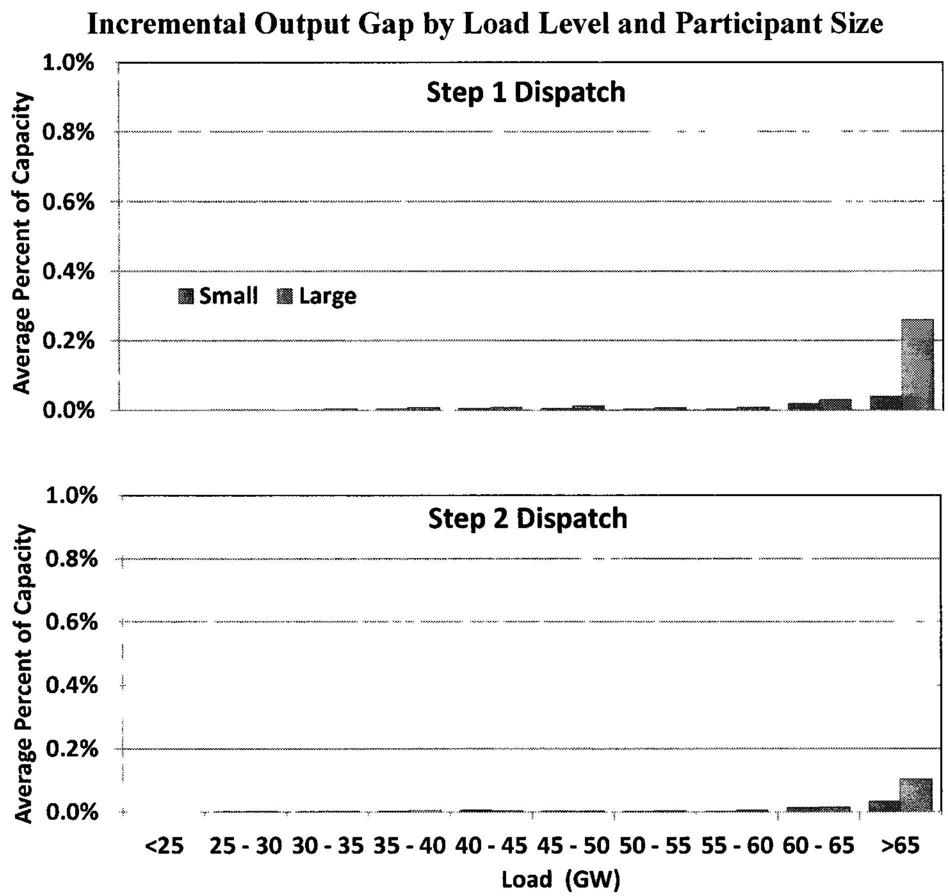
The figure above summarizes the results of the RDI analysis by displaying the percent of time at each load level there was a pivotal supplier. At loads greater than 65 GW there was a pivotal supplier 100 percent of the time. The figure also displays the percent of time each load level occurs. Combining these values we find that there was a pivotal supplier in approximately 12 percent of all hours of 2012. As a comparison, the same system-wide measure for the Midwest ISO showed less than 1 percent of all hours with a pivotal supplier.

The behavioral aspects of market power abuse are evaluated by calculating an "output gap." The output gap is defined as the quantity of energy that is not being produced by in-service capacity even though the in-service capacity is economic by a substantial margin given the real-time energy price. A participant can economically withhold resources, as measured by the output gap, by raising its energy offers so as not to be dispatched.

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

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

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



The figure above shows the magnitude of the output gap to be very small, even at the highest load levels, for both steps in the dispatch process, and for both small and large generators. These small quantities raise no competitive concerns. In addition to this metric, we also evaluate outages, deratings, and economic units that were not committed to identify other means suppliers may have used to withhold resources. Based on the analysis above and our other monitoring screens, we find that the ERCOT nodal wholesale market performed competitively in 2012.

H. Recommendations

Last year we recommended changes to the automated mitigation procedures that are part of the real-time dispatch to eliminate the occurrences of over-mitigation we have observed. As more fully described in Section I.E, Mitigation at page 20, we support the introduction of a test to determine whether a unit is either contributing to, or helping to resolve a transmission constraint and only subject the relieving units to mitigation. These changes were included in NPRR520 and should substantially reduce the occurrence of mitigating resources that are not in a position to exert market power related to the relief of transmission constraints. Various parameters will be approved related to the implementation of these changes, currently scheduled for summer 2013, and performance should be closely monitored to determine if any adjustments are required.

Last year we also recommended a change to the real-time market software to allow it to "look ahead" a sufficient amount of time to better commit load and generation resources that can be online within 30 minutes. More discussion of this topic can be found starting on page 84 in Section V.B, Effectiveness of the Scarcity Pricing Mechanism. We still believe this functionality would enhance the performance of the ERCOT market. However, this will need to be coordinated with the other fundamental market design changes still currently under consideration.

Whatever these future market design changes may entail, we recommend stakeholder consideration of the following three modifications, particularly as the system-wide offer cap rises above $5,000 per MWh.

1. Modify the slope of the existing power balance penalty curve and the offer floors for responsive reserve service to provide a more gradual slope up to the system-wide offer cap such that the cap is reached when operating reserves are down to the level that ERCOT would initiate involuntary curtailment of firm load.

    - If system-wide offer caps of $5,000, $7,000 or $9,000 are intended to reflect the value of lost load, then real-time energy prices should only get to those levels once firm load is being involuntarily curtailed.

- A more "well-behaved" reserve shortage pricing function could be achieved in the following ways:
  - Implement real-time co-optimization of energy and reserves with an operating reserve demand curve;
  - Introduce an operating reserve demand curve but not include real-time co-optimization.
  - Adjust the current operating reserve offer floors to better reflect the loss of load probability and the value of lost load at various levels of operating reserves.

2. Modify the Protocols related to proxy offer curve provisions such that all unoffered capacity is not automatically priced at the system-wide offer cap. Currently, if available capacity does not have an associated energy offer, ERCOT's dispatch software "fills in" with an offer priced at the system-wide offer cap. During 2012, the average amount of capacity priced in this manner exceeded 100 MW.

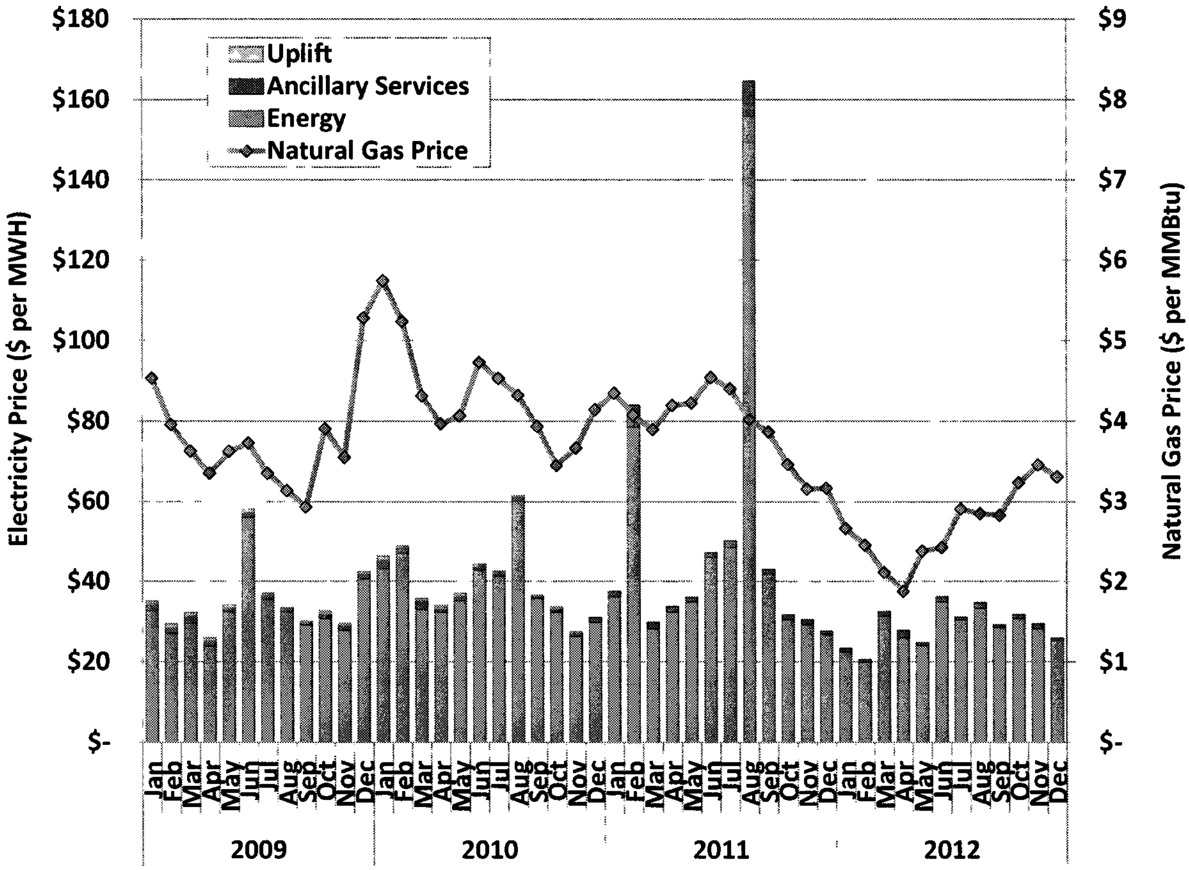
3. Implement changes that ensure ERCOT deployments of load resources, Emergency Response Service (ERS), or the involuntary curtailment of firm load are reflected in the real-time dispatch energy and reserve prices. This may be achieved through various means, either as a component of integrating load bids in the real-time dispatch software, or through simple administrative shortage pricing rules.

I. Review of Real-Time Market Outcomes

A. Real-Time Market Prices

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

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



Energy, ancillary services and uplift costs are the three components in the all-in price of electricity. The ERCOT wide price is the load weighted average of the real-time market prices from all load zones. Prior to ERCOT's conversion to the nodal market in December 2010, energy costs were determined from the zonal balancing energy market. Ancillary services costs are estimated based on total system demand and prices in the ERCOT markets for regulation, responsive reserves, and non-spinning reserves. Uplift costs are assigned market-wide on a loadratio share basis to pay for charges associated with additional reliability unit commitment and any reliability must run contracts.[5]

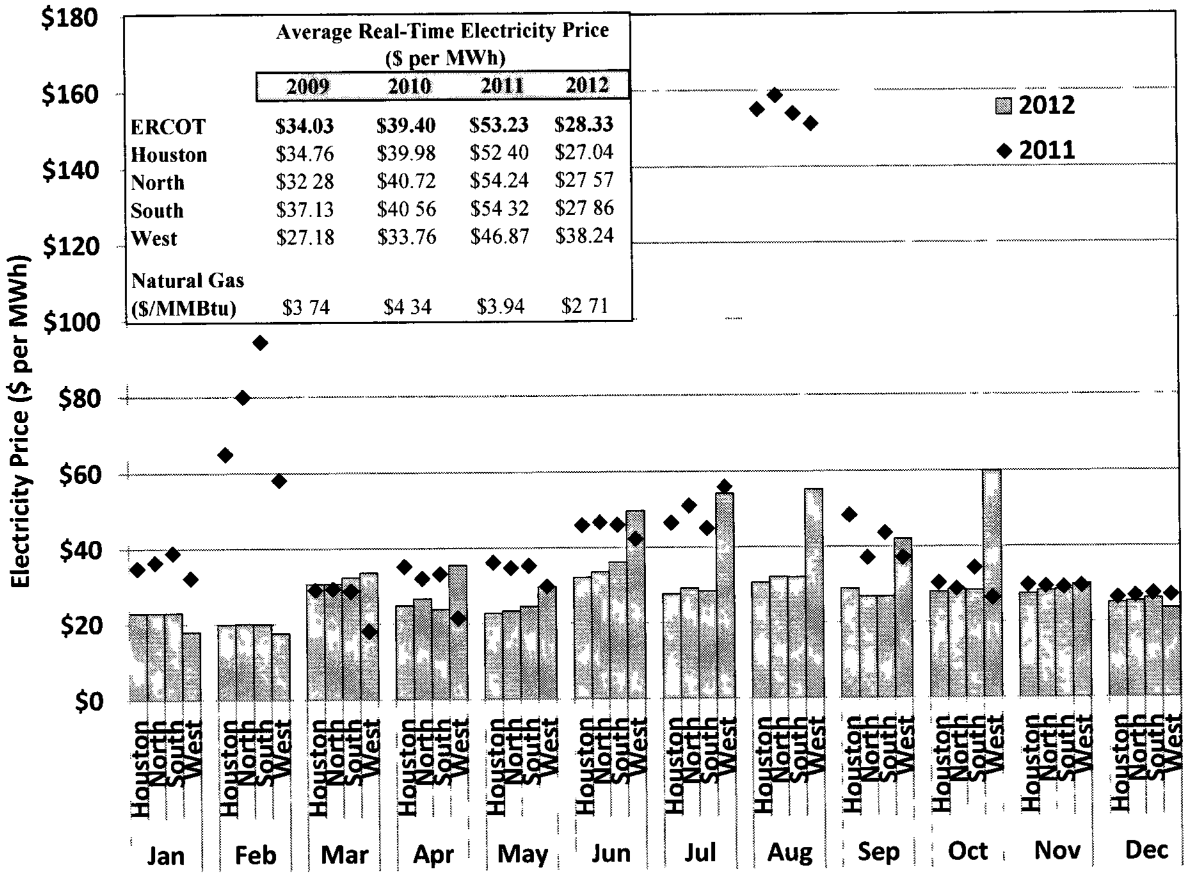
Figure 1 shows the monthly average all-in price for all of ERCOT from 2009 to 2012 and the associated natural gas price. This figure indicates that natural gas prices were a primary driver of the trends in electricity prices from 2009 to 2012. Again, this is not surprising given that natural gas is a widely-used fuel for the production of electricity in ERCOT, especially among generating units that most frequently set locational marginal prices in the nodal market.

The largest component of the all-in cost of wholesale electricity is the energy cost, which is reflected by the locational marginal prices. As is typical in other wholesale electricity markets, only a small share of the power produced in ERCOT is transacted in the spot market. However, prices in the real-time energy market are very important because they set the expectations for prices in the forward markets (including bilateral markets) where most transactions take place. Unless there are barriers preventing arbitrage of the prices between the spot and forward markets, the prices in the forward market should be directly related to the prices in the spot market (*i.e.*, the spot prices and forward prices should converge over the long-run). Hence, artificially low prices in the real-time energy market will translate to artificially-low forward prices. Likewise, price spikes in the real-time energy market will increase prices in the forward markets. This section evaluates and summarizes electricity prices in the real-time market during 2012.

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

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

Figure 2: Average Real-Time Energy Market Prices

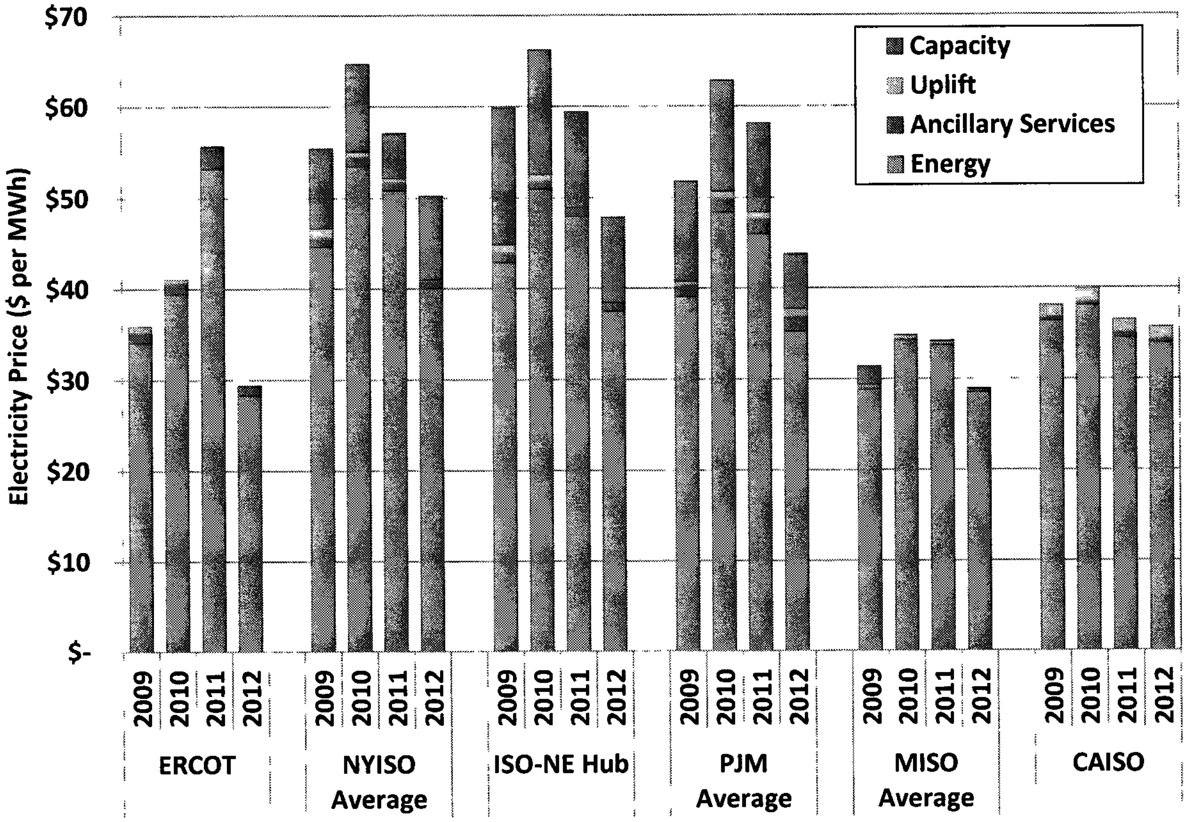


	2009	2010	2011	2012
ERCOT	**$34.03**	**$39.40**	**$53.23**	**$28.33**
Houston	$34.76	$39.98	$52 40	$27.04
North	$32 28	$40.72	$54.24	$27 57
South	$37.13	$40 56	$54 32	$27 86
West	$27.18	$33.76	$46.87	$38.24
Natural Gas ($/MMBtu)	$3 74	$4 34	$3.94	$2 71

ERCOT average real-time market prices were 47 percent lower in 2012 than in 2011. The ERCOT-wide load-weighted average price was $28.33 per MWh in 2012 compared to $53.23 per MWh in 2011. The decrease in real-time energy prices was correlated with much lower fuel prices in 2012. The steady decline in natural gas prices from June 2011 to April 2012 resulted in the 2012 average natural gas price of $2.71 per MMBtu, a 31 percent decrease compared to $3.94 per MMBtu in 2011.

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

Figure 3: Comparison of All-in Prices across Markets

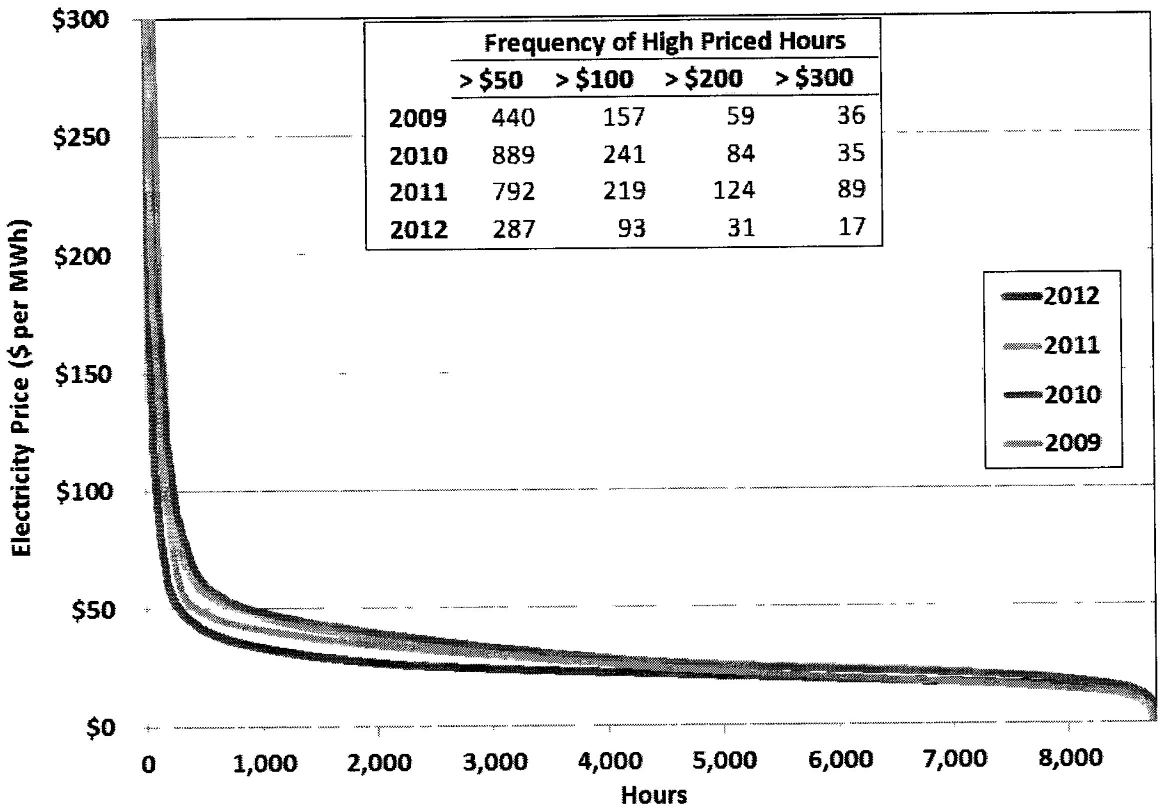


For each region, the figure reports the average cost (per MWh of load) for energy, ancillary services (reserves and regulation), capacity markets (if applicable), and uplift for economically out-of-merit resources. Figure 3 shows that ERCOT all-in prices in 2012 were roughly equivalent to the Midwest ISO and significantly lower than all other regions. Although prices in all markets declined from 2011 to 2012, no other region experienced anything close to the magnitude of reduction seen in ERCOT.

Figure 4 presents price duration curves for ERCOT energy markets in each year from 2009 to 2012. A price duration curve indicates the number of hours (shown on the horizontal axis) that the price is at or above a certain level (shown on the vertical axis). The prices in this figure are the hourly load-weighted zonal balancing energy price for the zonal market and hourly load-weighted nodal settlement point price for the nodal market.[6]

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

Figure 4: ERCOT Price Duration Curve

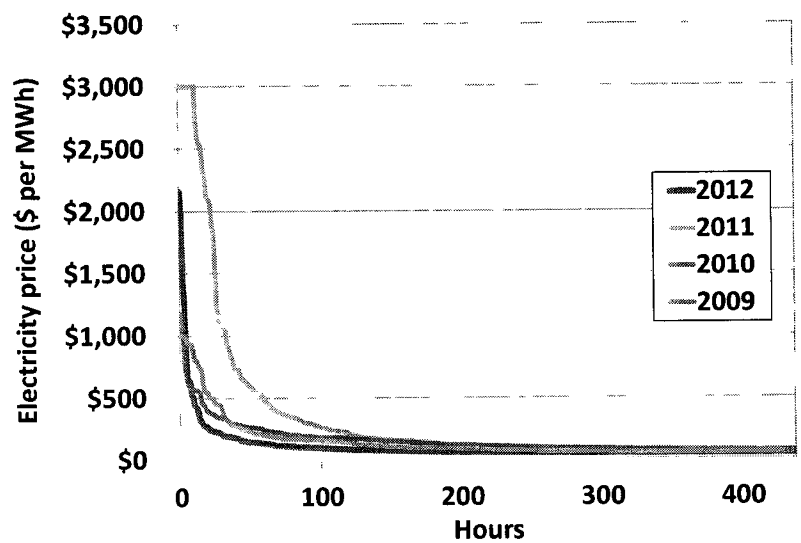


	Frequency of High Priced Hours			
	> $50	> $100	> $200	> $300
2009	440	157	59	36
2010	889	241	84	35
2011	792	219	124	89
2012	287	93	31	17

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

To see where the prices during 2012 were much different than in the previous three years, we present Figure 5, which compares prices for the highest five percent of hours. In 2011, energy prices for the top 100 hours were significantly higher due to higher loads leading to more shortage conditions coupled with a more effective shortage pricing mechanism

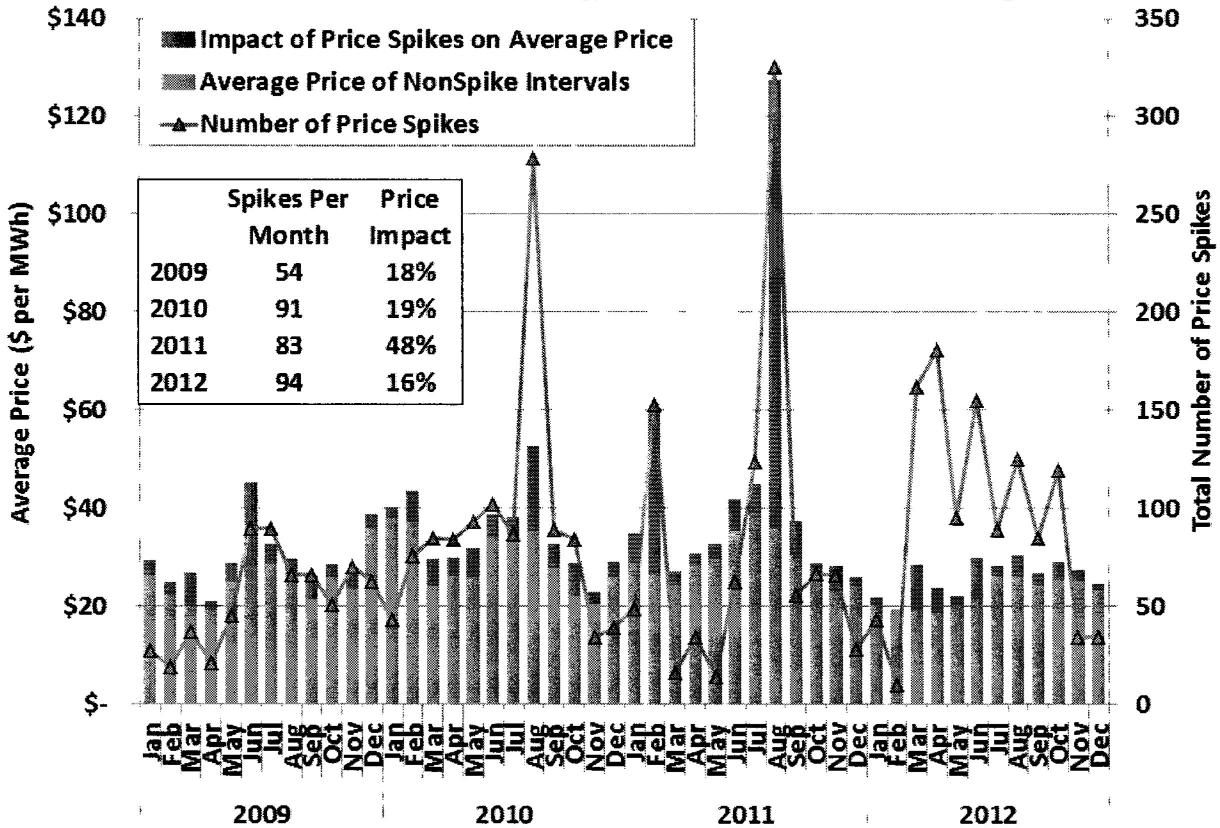
Figure 5: ERCOT Price Duration Curve Top 5% of Hours



implemented as part of the nodal market design. In 2012, the energy duration curve for the top five percent of hours is lower than the past three years for the majority of hours, reflecting lower loads and resulting fewer occassions of shortage conditions. However, during the brief periods of shortage that were experienced in 2012 prices rose to levels higher than those experienced in 2009 and 2010 when all prices in the zonal market were the result of actual submitted offers.

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

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

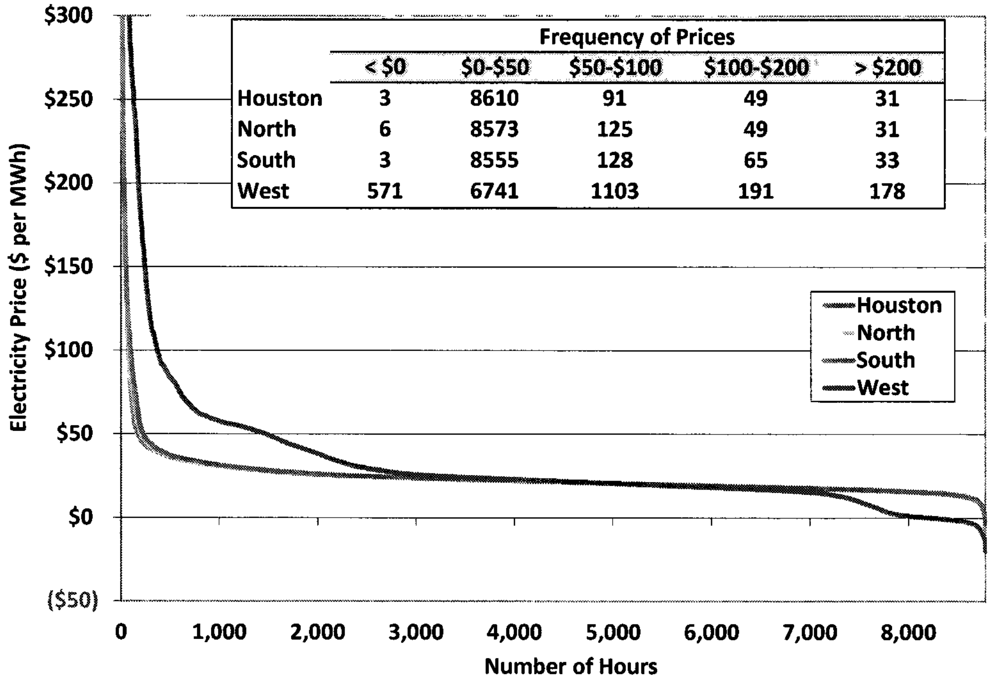


The number of price spike intervals during 2012 was 94 per month, an increase from the 83 per month in 2011. However, just looking at the average can be misleading. Due to extreme weather in February and August 2011, there were only two months with very high numbers of price spikes in 2011. In contrast, all months from March to October 2012 had at least 85 price spikes. As discussed later in this section, the high number of price spikes in 2012 is likely related to the very low price of natural gas and resulting 'overlap' of offers from natural gas and coal-fired units.

To measure the impact of these price spikes on average price levels, the figure also shows average prices with and without the price spike intervals. The top portions of the stacked bars show the impact of price spikes on monthly average price levels. Prior to 2012, the impact grew with the frequency of the price spikes, averaging $4.67, $5.53 and $14.09 per MWh during 2009, 2010 and 2011, respectively. Although the frequency of price spikes increased in 2012, the magnitude of their price impact decreased. The impact on average energy price in 2012 declined to $3.63 per MWh, or 16 percent of the annual average price. This is explained by much lower natural gas prices in 2012, resulting in a much lower threshold level for the definition of a "price spike".

To depict how real-time energy prices vary by hour in each zone, Figure 7 below shows the hourly average price duration curve in 2012 for four ERCOT load zones. The Houston, North and South load zones had similar prices over the majority of hours. The price duration curve for the West zone is noticeably different than the other zones, with more hours with prices greater than $50 per MWh and more than 500 hours (6 percent of the time) when the average hourly price was less than zero. As observed over the past few years, West zone prices are lower than the rest of ERCOT when high wind output in the West results in congested transmission interfaces from the West zone to the other zones in ERCOT. Recently, prices higher than the rest of ERCOT have occurred in the West zone due to local transmission constraints that typically occur under low wind and high load, or outage conditions.

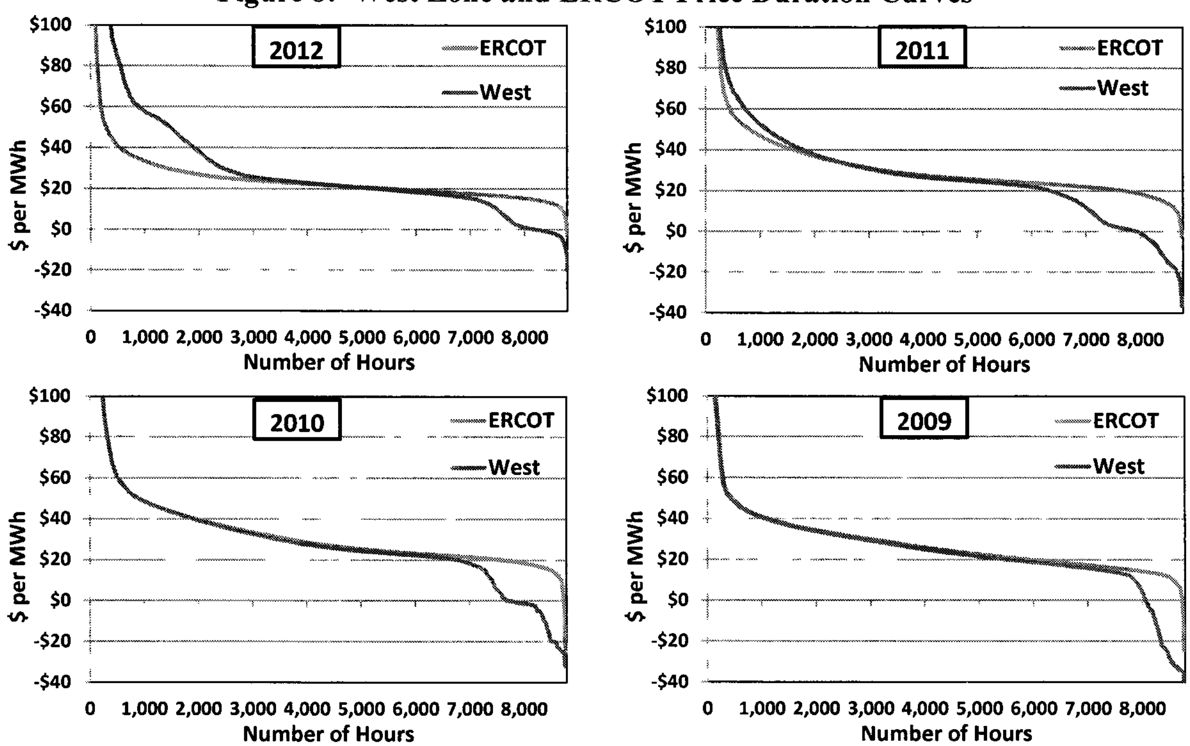
Figure 7: Zonal Price Duration Curves



	Frequency of Prices				
	< $0	$0-$50	$50-$100	$100-$200	> $200
Houston	3	8610	91	49	31
North	6	8573	125	49	31
South	3	8555	128	65	33
West	571	6741	1103	191	178

Figure 8 below shows the relationship between West zone and ERCOT average prices for the 2009 through 2012.

Figure 8: West Zone and ERCOT Price Duration Curves



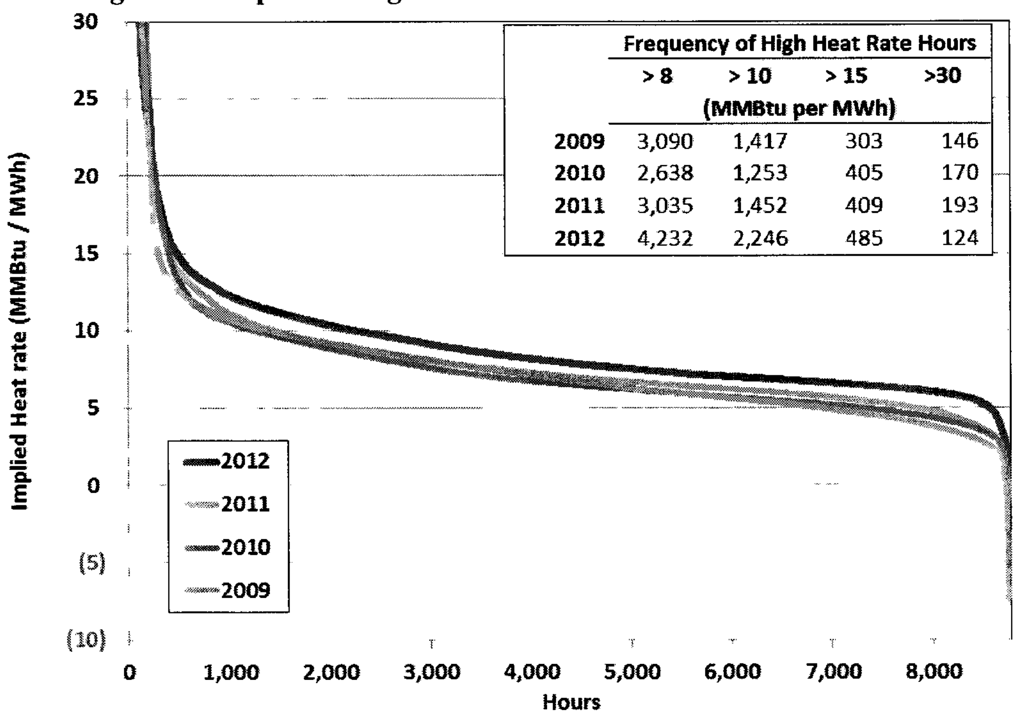
On the low price end, we observe a reduction in the number of hours when West zone prices were below the ERCOT average. We also note that minimum West zone prices have increased; that is, become "less negative". During 2012, for the first time, West zone prices were much higher than ERCOT average for a significant number of hours. The combination of more hours with higher prices, and fewer hours with less negative prices resulted in the average real-time energy price in the West zone being greater than the ERCOT average.

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

B. Real-Time Prices Adjusted for Fuel Price Changes

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

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



To clearly identify changes in electricity prices that are not driven by changes in natural gas prices, Figure 9 and Figure 10 show the load weighted, hourly average real-time energy price adjusted to remove the effect of natural gas price fluctuations. The first chart shows a duration curve where the real-time energy price is replaced by the marginal heat rate that would be implied if natural gas was always on the margin.[7]

The second chart shows the same duration curves for the five percent of hours in each year with the highest implied heat rate. Both figures show duration curves for the implied marginal heat rate for 2009 to 2012. In contrast to Figure 4 where the 2012 price duration curve lies below the curves of other years, Figure 9 shows that the implied marginal heat rates were higher in 2012 as compared to the three prior years. This can be explained by the much lower natural gas prices in 2012.

Figure 10: Implied Marginal Heat Rate Duration Curve – Top five percent of hours

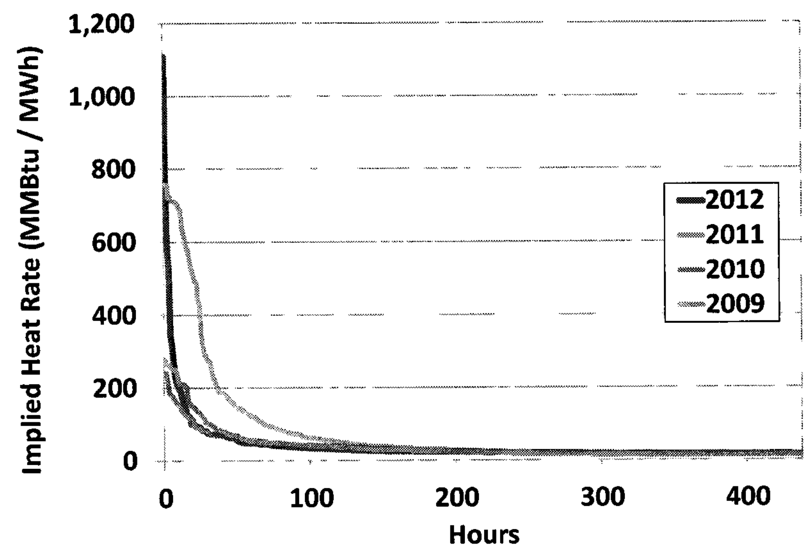
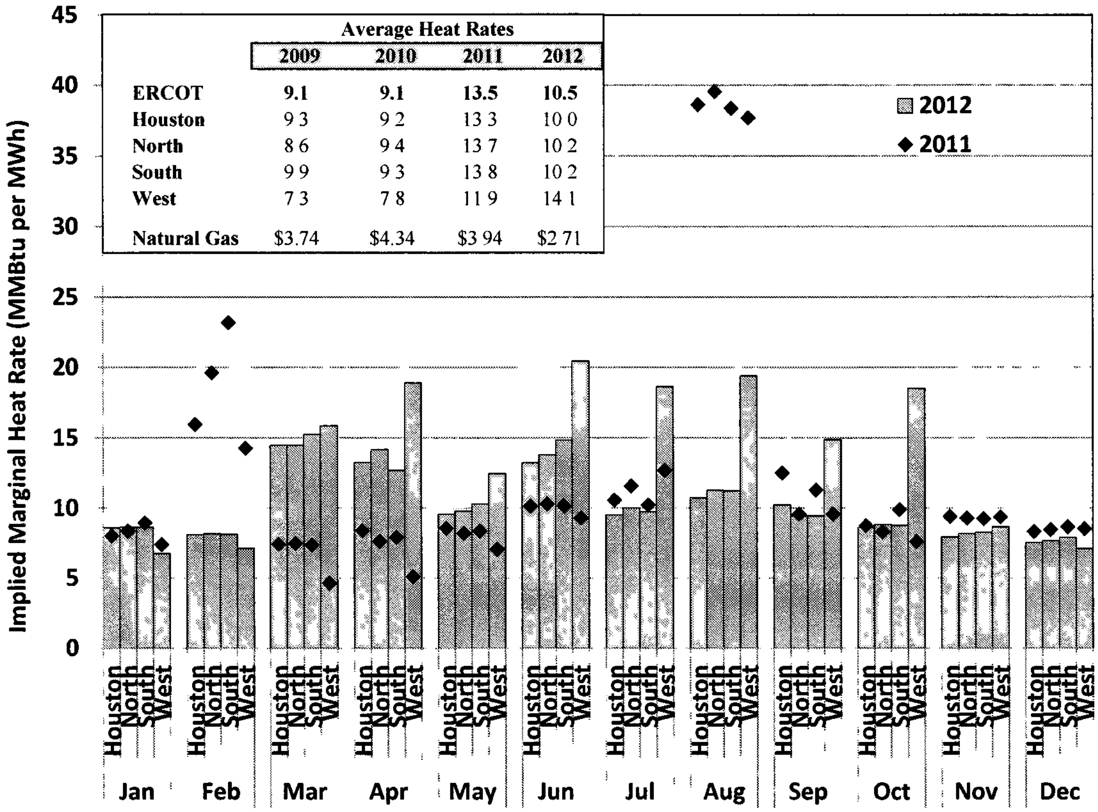


Figure 10 shows the implied marginal heat rates for the top five percent of hours in 2009 through 2012 and highlights that the implied heat rate in 2012 at the top 5 percent of hours is consistent with other years, except for 2011, where the heat rates were higher at top hours.

To further illustrate these differences, the next figure shows the implied marginal heat rates on a monthly basis in each of the ERCOT zones in 2011 and 2012, with annual average heat rate data for 2009 through 2012. This figure is the fuel price-adjusted version of Figure 2 in the prior sub-section. Adjusting for natural gas price influence, Figure 11 shows that the annual, system-wide average implied heat rate decreased in 2012 compared to 2011. However, it was still higher than 2009 and 2010.

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

Figure 11: Monthly Average Implied Heat Rates



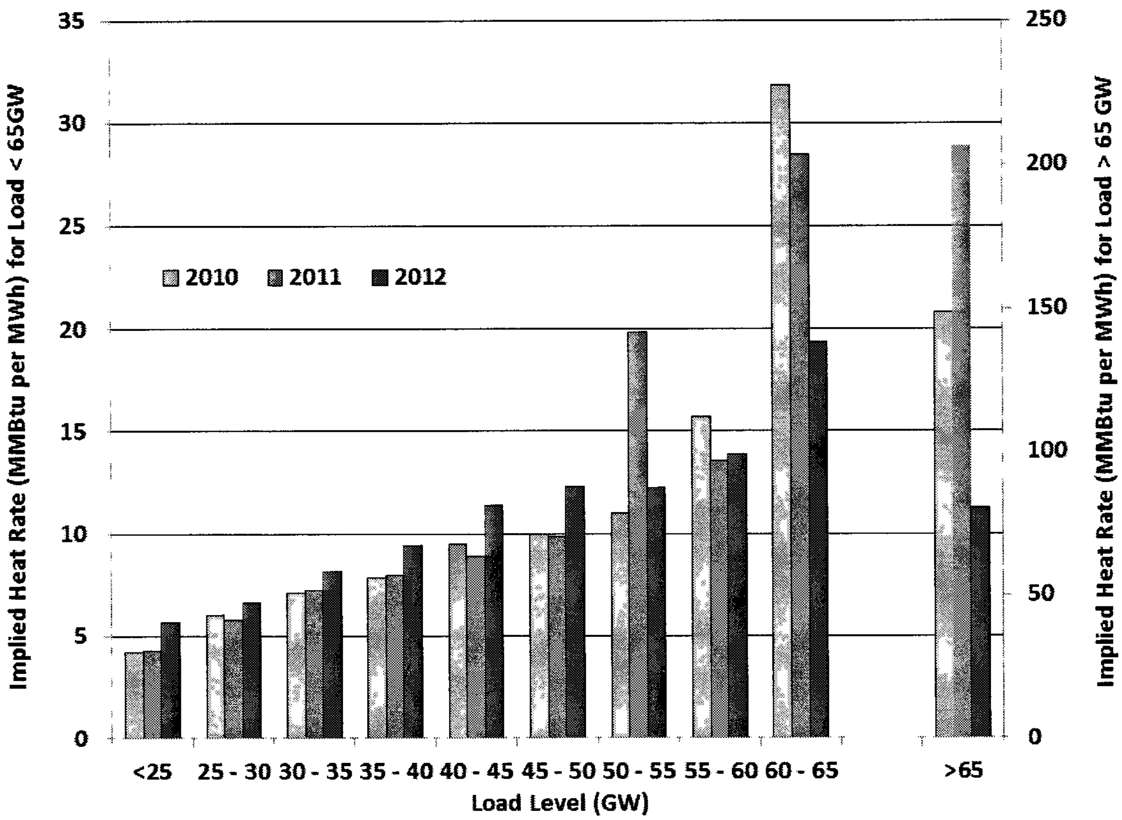
Average Heat Rates	2009	2010	2011	2012
ERCOT	**9.1**	**9.1**	**13.5**	**10.5**
Houston	9.3	9.2	13.3	10.0
North	8.6	9.4	13.7	10.2
South	9.9	9.3	13.8	10.2
West	7.3	7.8	11.9	14.1
Natural Gas	$3.74	$4.34	$3.94	$2.71

The monthly average implied heat rates in 2012 are generally consistent with 2011, with notable exceptions in February and August 2011. Higher heat rates in February can be explained by the extended period when real-time prices were $3,000 per MWh due to extreme cold weather and the resulting unplanned outages of numerous generators. Extended hot, dry weather resulted in record system peak demands in August, and another extended period of energy prices reflecting shortage conditions. The differences in the average annual implied heat rates observed at the zonal level can be attributed to the continued significant congestion related to wind generation exports from the West zone.

We conclude our examination of implied heat rates from the real-time energy market by evaluating them at various load levels. Figure 12 below, provides the average heat rate at various system load levels from 2010 through 2012.[8]

8 To appropriately compare twelve months of data under each market design, data labeled as 2010 in Figure 12 are from December 1, 2009 through November 30, 2010.

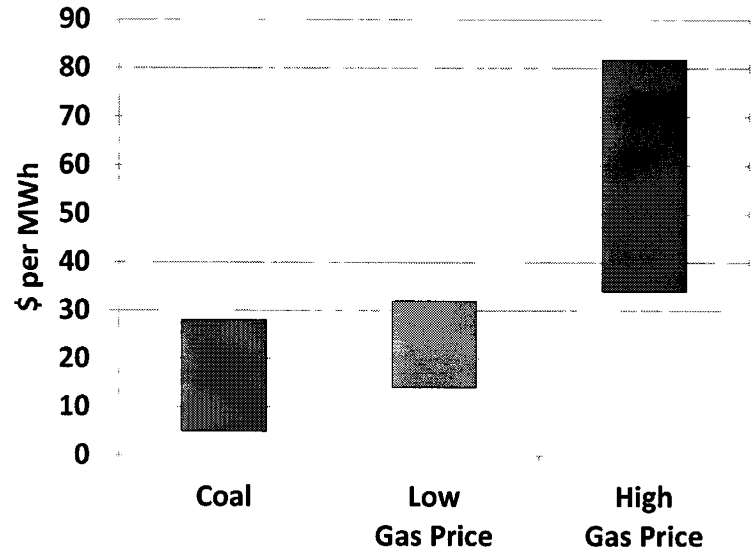
Figure 12: Heat Rate and Load Relationship



In a well performing market, a clear positive relationship between these two variables is expected since resources with higher marginal costs must be dispatched to serve higher loads. Although we do see a generally positive relationship, there is a noticeable disparity for loads between 50 and 55 GW. During the extreme cold weather event in early February 2011, loads were at this level while prices reached $3,000 per MWh for a sustained period of time. Focusing on 2012 data, we observe the desired positive relationship between load and implied heat rates.

The higher heat rates observed at lower loads in 2012 are likely due to the interplay between coal and natural gas prices because of the low natural gas prices experienced in 2012. This interaction warrants more explanation. The price of energy offered from coal units is generally very stable, due to the long term nature of contracts for both fuel and transportation. The large majority of energy offered from coal units is generally priced between $5 and $30 per MWh. The price of energy from natural gas-fired units in ERCOT is much more variable but closely tied to the price of natural gas fuel. In fact, the implied heat rate (the measure of conversion efficiency from MMBtu of fuel to MWh of electricity) of natural gas based offers has remained within a fixed range of 7.5 MMBtu per MWh to 18 MMBtu per MWh. Focusing on the past two years, natural gas prices peaked in June 2011 at $4.54 per MMBtu and declined steadily to a nadir of $1.88 per MMBtu in April 2012. At these low prices, energy offers from natural gas units competed directly with offers from coal units. Figure 13 compares the typical ranges of energy offers from coal units with those from natural gas units, under both high and low natural gas prices. As discussed later, one of the effects of this price overlap was reduced generation from coal units during 2012. At natural gas prices above $3 per MMBtu the amount of overlap between energy offers from coal and natural gas units decreases.

Figure 13: Typical Energy Offers



C. Real-Time Price Volatility

Volatility in real-time wholesale electricity markets is expected because system load can change rapidly and the ability for supply to adjust can be restricted by physical limitations of the resources and the transmission network. Figure 14 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 2011 are also presented. Comparing average real-time energy prices for 2012 with those from 2011, the effects of lower natural gas prices on average prices during non-peak hours and the effects of fewer shortage intervals during peak hours are observed. Outside of the hours from 15 to 18 (2:00 pm to 6:00 pm), short-term increases in average real-time energy prices are typically due to high prices resulting from generator ramp rate limitations occurring at times when significant amounts of generation is changing its online status. Factoring current market conditions into generators' daily operational decisions about the specific timing of startup and