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2009 State of the Market Report
for the
ERCOT Wholesale Electricity Markets

Potomac Economics, Ltd.

Independent Market Monitor for the
ERCOT Wholesale Market

July 2010

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EXECUTIVE SUMMARY

A. Introduction

This report reviews and evaluates the outcomes of the ERCOT wholesale electricity markets in 2009, 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 pursuant to the provisions of PUCT Substantive Rule 25.505(g). Key findings in the report include the following:

★ The average wholesale electricity price was $34.03 per MWh in 2009, which is 56 percent lower than the 2008 average price of $77.19 per MWh. This is the lowest annual average price experienced in the ERCOT wholesale market since 2002.

★ All-in wholesale electricity prices for the ERCOT market in 2009 were lower than in the organized wholesale electricity markets in California, New England, the New York ISO, and the PJM Interconnection.

★ Lower wholesale electricity prices provide benefits to consumers in the short-term. However, pricing outcomes in 2009 continued to inadequately reflect market conditions during times of operating reserve scarcity. During such shortage conditions when demand for energy and operating reserves cannot be met with available resources, prices should rise sharply to reflect the value of diminished reliability as reserves are used to meet energy needs. Although these shortage conditions occur in only a handful of hours each year, efficient shortage pricing is critical to the long-term success of the ERCOT energy-only market.

★ As a result of inadequate shortage pricing and the fact that the number of shortage intervals in 2009 were roughly one-half of that experienced in 2008, estimated net revenues in 2009 were substantially below the levels required to support market entry for natural gas combined-cycle and combustion turbine resources at all locations in the ERCOT region. Estimated net revenues for nuclear and coal resources were also insufficient to support new entry in 2009, although these results were more affected by the reduction in natural gas prices and associated reduction in wholesale energy prices than by pricing outcomes during shortage conditions.

★ Ancillary service costs generally track wholesale energy price movements, and therefore were significantly lower in 2009 than in recent years.

★ Load participation in the responsive reserve market declined in late 2008 and in 2009 relative to prior years, likely as a result of general economic conditions.

★ Interzonal price disparities were larger in 2008 and 2009 than in prior years, primarily as a result of increased wind capacity in the West Zone and inefficiencies that are inherent to the zonal market design.

★ The number of hours in which coal was the marginal (*i.e.*, price-setting) fuel in the ERCOT region was much higher in 2009 than in prior years. This increase can be attributed to (1) increased wind resource production; (2) a slight reduction in demand in 2009 due to the economic downturn; and (3) periods when natural gas prices were very low thereby making coal and natural gas combined-cycle resources competitive from an economic dispatch standpoint.

★ The ERCOT wholesale market performed competitively in 2009, with the competitive performance measures showing a trend of increasing competitiveness over the period 2005 through 2009.

In addition to these key findings, the report generally confirms prior findings that the current market rules and procedures are resulting in systemic inefficiencies. Our previous reports regarding ERCOT electricity markets have included a number of recommendations designed to improve the performance of the current ERCOT markets.[1] Some of these recommendations have

1 "ERCOT State of the Market Report 2003", Potomac Economics, August 2004 ("2003 SOM Report"); "2004 Assessment of the Operation of the ERCOT Wholesale Electricity Markets", Potomac Economics, November 2004; "ERCOT State of the Market Report 2004", Potomac Economics, July 2005 ("2004 SOM Report"); "ERCOT

been implemented. Given the approaching implementation of the nodal market design in December 2010, no additional recommendations for the current market design are offered at this time. In particular, implementation of the nodal market will provide the following improvements:

★ The nodal market design will fundamentally improve ERCOT's ability to efficiently manage transmission congestion, which is one of the most important functions in electricity markets.

★ The wholesale market should function more efficiently under the nodal market design by providing better incentives to market participants, facilitating more efficient commitment and dispatch of generation, and improving ERCOT's operational control of the system. The congestion on all transmission paths and facilities will be managed through market-based mechanisms in the nodal market. In contrast, under the current zonal market design, transmission congestion is most frequently resolved through non-transparent, non-market-based procedures.

★ Under the nodal market, unit-specific dispatch will allow ERCOT to more fully utilize generating resources than the current market, which frequently exhibits price spikes even when generating capacity is not fully utilized.

★ The nodal market will allow ERCOT to increase the economic and reliable utilization of scarce transmission resources well beyond that attainable in the zonal market.

★ The nodal market will significantly improve the ability to efficiently and reliably integrate the ever-growing quantities of intermittent resources, such as wind and solar generating facilities.

★ The nodal market will produce price signals that better indicate where new generation is most needed (and where it is not) for managing congestion and maintaining reliability.

State of the Market Report 2005", Potomac Economics, July 2006 ("2005 SOM Report"); "ERCOT State of the Market Report 2006", Potomac Economics, August 2007 ("2006 SOM Report"), "ERCOT State of the Market Report 2007", Potomac Economics, August 2008 ("2007 SOM Report"); and "ERCOT State of the Market Report 2008", Potomac Economics, August 2009 ("2008 SOM Report").

In the long-term, these enhancements to overall market efficiency should translate into substantial savings for consumers.

B. Review of Market Outcomes

1. Balancing Energy Prices

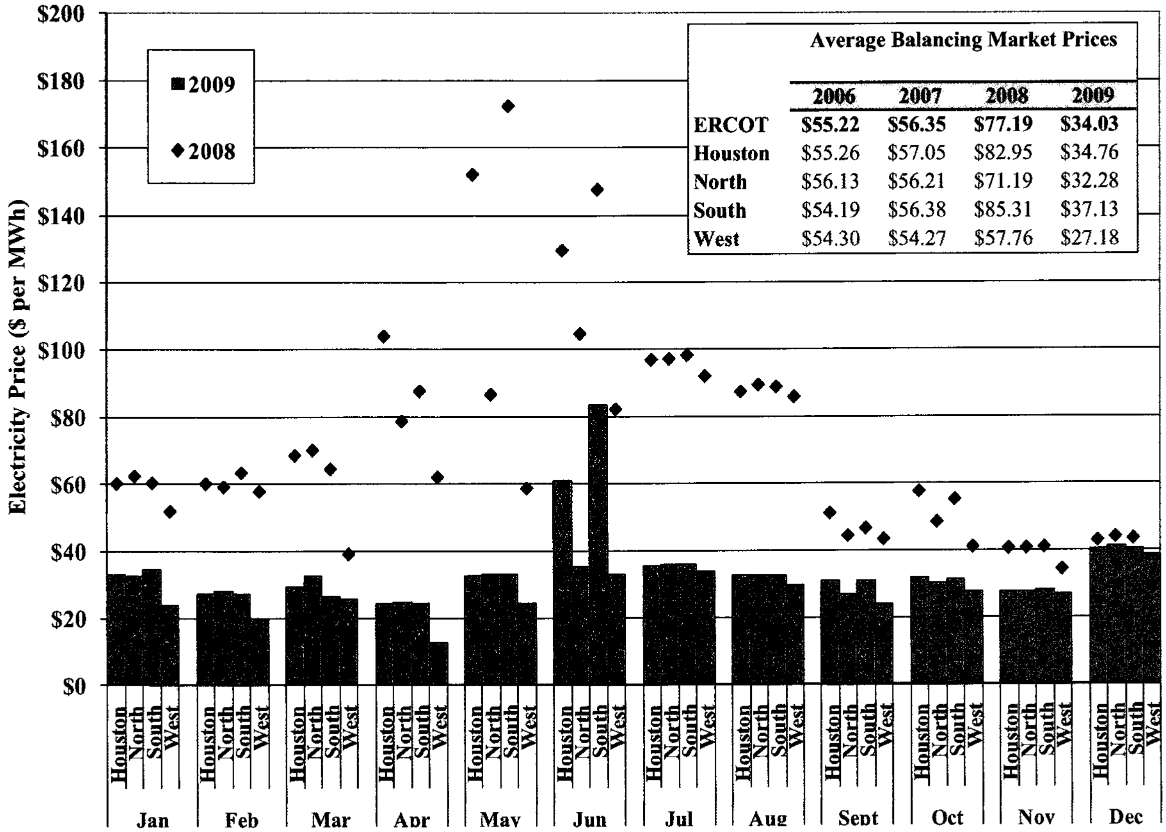
The balancing energy market allows participants to make real-time purchases and sales of energy to supplement their forward bilateral contracts. While on average only a relatively small portion of the electricity produced in ERCOT is cleared through the balancing energy market, its role is critical in the overall wholesale market. The balancing energy market governs real-time dispatch of generation by altering where energy is produced to: a) balance supply and demand; b) manage interzonal congestion, and c) displace higher-cost energy with lower-cost energy given the energy offers of the Qualify Scheduling Entities ("QSEs").

In addition, the balancing energy prices also provide a vital signal of the value of power for market participants entering into forward contracts. Although most power is purchased through forward contracts of varying duration, the spot prices emerging from the balancing energy market should directly affect forward contract prices.

As shown in the following figure, ERCOT average balancing energy market prices were 56 percent lower in 2009 than in 2008, with an ERCOT-wide load weighted average price of $34.03 per MWh in 2009 compared to $77.19 per MWh in 2008. April through August experienced the highest balancing energy market price reductions in 2009, averaging 66 percent lower than the prices in the same months in 2008. With the exception of the West Zone in December, the balancing energy prices in 2009 were lower in every month in all zones than in 2008.

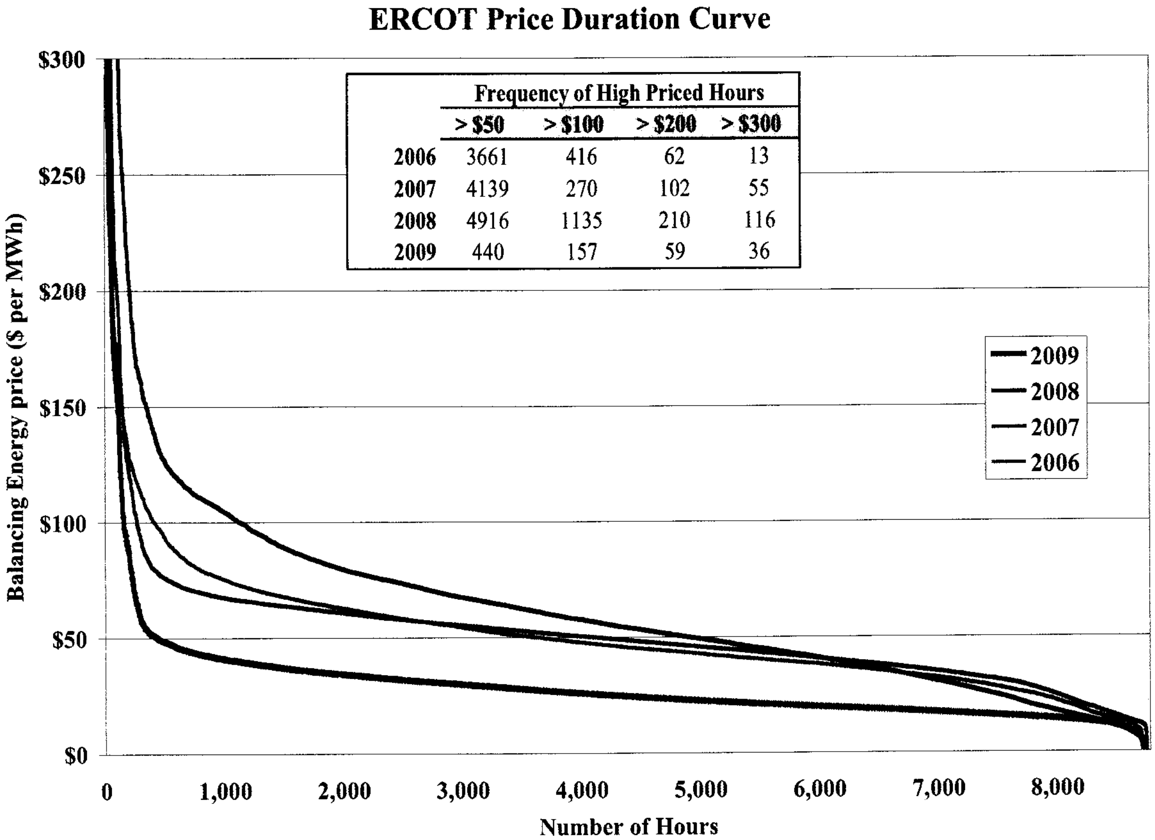
The average natural gas price fell 56 percent in 2009, averaging $3.74 per MMBtu in 2009 compared to $8.50 per MMBtu in 2008. Natural gas prices reached a maximum monthly average of $12.37 per MMBtu in July 2008, and reached a minimum monthly average of $2.93 per MMBtu in September 2009. Hence, the changes in energy prices from 2008 to 2009 were largely a result of natural gas price movements.

Average Balancing Energy Market Prices



	2006	2007	2008	2009
ERCOT	**$55.22**	**$56.35**	**$77.19**	**$34.03**
Houston	$55.26	$57.05	$82.95	$34.76
North	$56.13	$56.21	$71.19	$32.28
South	$54.19	$56.38	$85.31	$37.13
West	$54.30	$54.27	$57.76	$27.18

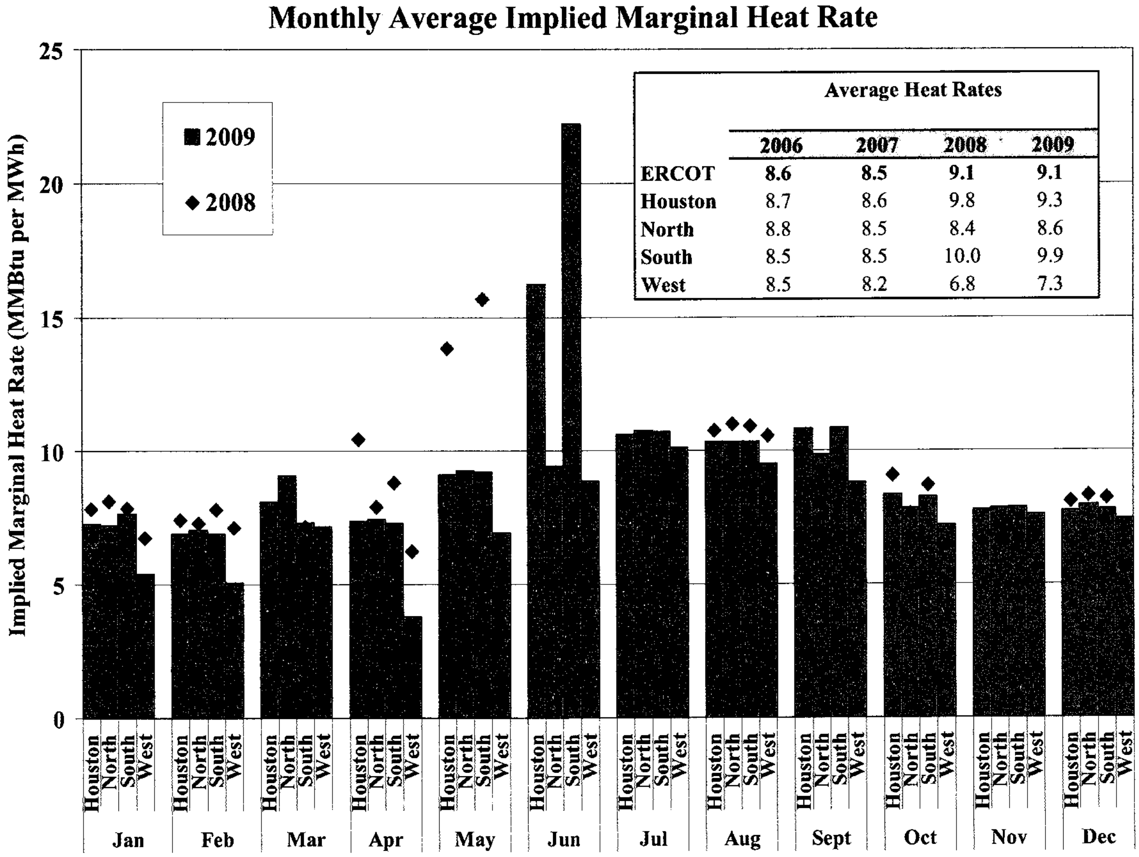
The following figure shows the price duration curves for the ERCOT balancing energy market each year from 2006 to 2009. A price duration curve indicates the number of hours (shown on the horizontal axis) that the price is at or above a certain level (shown on the vertical axis). The prices in this figure are hourly load-weighted average prices for the ERCOT balancing energy market.



	Frequency of High Priced Hours			
	> $50	> $100	> $200	> $300
2006	3661	416	62	13
2007	4139	270	102	55
2008	4916	1135	210	116
2009	440	157	59	36

Balancing energy prices exceeded $50 per MWh in 440 hours in 2009 compared to more than 4,900 hours in 2008. These year-to-year changes reflect lower natural gas prices in 2009 that directly affect electricity prices in a broad range of hours.

Although fuel price fluctuations are the dominant factor driving electricity prices in the ERCOT wholesale market, fuel prices alone do not explain all of the price outcomes. The following figure presents ERCOT balancing energy market prices adjusted for natural gas price fluctuations to better highlight variations in electricity prices not related to fuel costs.



Adjusted for gas price influence, the above figure shows that average implied heat rate for all hours of the year was comparable in 2009 to 2008.[2] The average implied heat rate was significantly higher in 2008 than in 2009 during the months of April and May due to significant zonal congestion on the North to South and North to Houston interfaces that materialized in these months in 2008. Similarly, the magnitude of zonal congestion on the North to South interface increased significantly in late June 2009, causing the implied heat rate in June to be significantly higher in 2009 than in 2008. The implied heat rate in July was higher in 2009 than in 2008, primarily because of a stretch of extremely high temperatures and load levels, including the setting of a new record peak demand of 63,400 MW on July 13, 2009. Finally, the implied heat rate in September was much lower in 2008 than in 2009 because of the landfall of Hurricane Ike in September 2008 that resulted in widespread and prolonged loss of load in the Houston area.

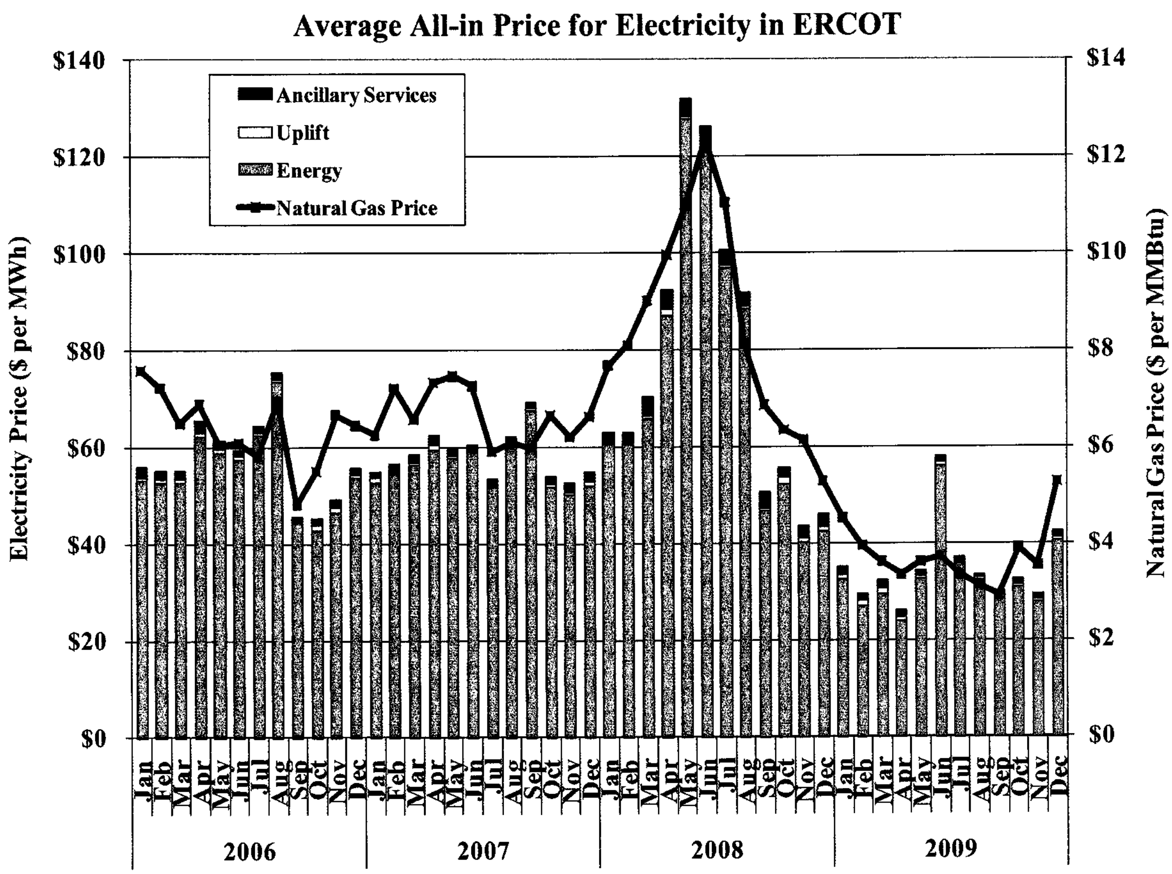
2 The *Implied Marginal Heat Rate* equals the *Balancing Energy Market Price* divided by the *Natural Gas Price.*

The report evaluates two other aspects of the balancing energy prices: 1) the correlation of the balancing energy prices with forward electricity prices in Texas, and 2) the primary determinants of balancing energy prices. Natural market forces should push forward market prices to levels consistent with expectations of spot market prices. Day-ahead prices averaged $38 per MWh in 2008 compared to an average of $35 per MWh for real-time prices. Although the day-ahead and real-time prices exhibited relatively good average convergence in 2009, the average absolute price difference increased during the months of June and July 2009.

The price volatility in June 2009 was due in large part to the significant and unpredictable transmission congestion experienced in that timeframe that caused average real-time prices to exceed day-ahead prices in June 2009. In contrast, average day-ahead prices were significantly higher than real-time prices in July 2009, which may be associated with transmission congestion expectations based on the experience in the prior month, as well as real-time pricing expectations associated with the extremely high temperatures and loads experienced during July 2009. The introduction of the nodal market, which will include an integrated day-ahead market, should also improve the convergence between day-ahead and real-time energy prices.

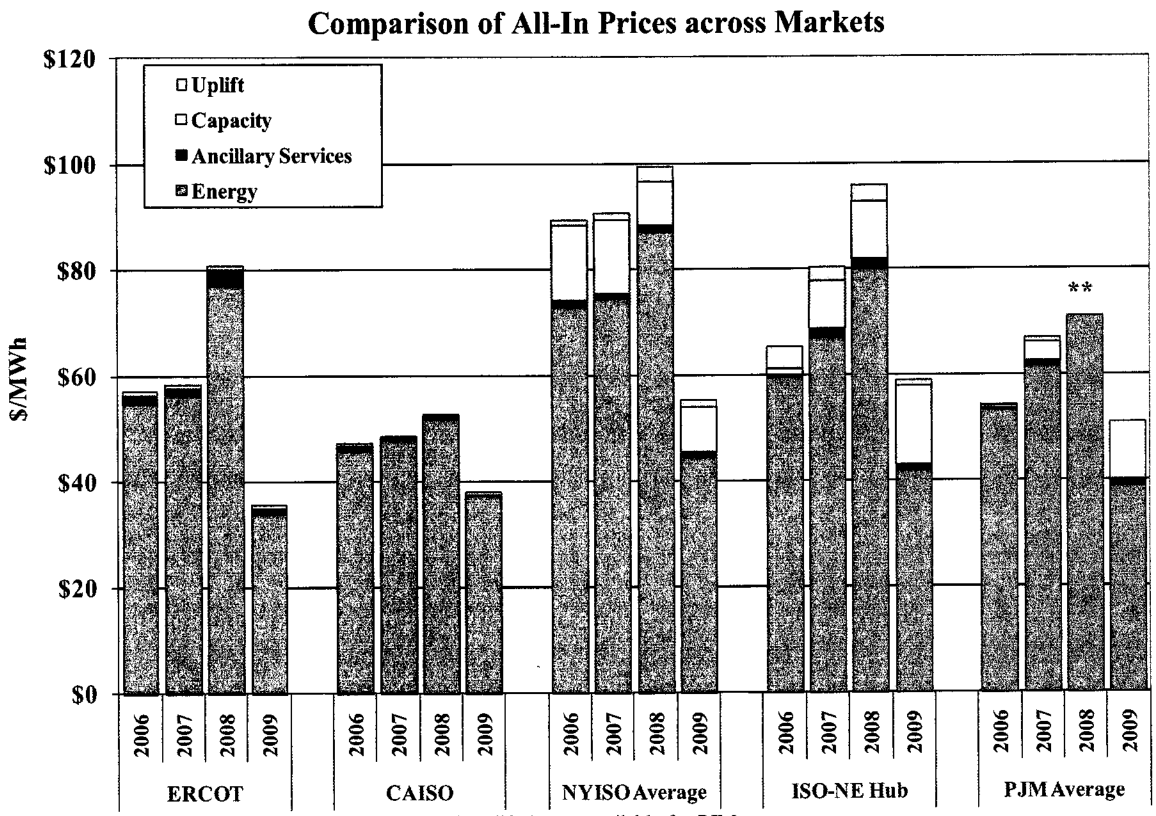
2. All-In Electricity Prices

In addition to the costs of energy, loads incur costs associated with operating reserves, regulation, and uplift. The uplift costs include payments for out-of-merit capacity ("OOMC"), Replacement Reserve ("RPRS"), out-of-merit energy ("OOME"), and reliability must run agreements ("RMR"), but exclude administrative charges such as the ERCOT fee. These costs, regardless of the location of the congestion, are borne proportionally by all loads within ERCOT.



The monthly average all-in energy prices for the past four years are shown in the figure above along with the monthly average price of natural gas. This figure indicates that natural gas prices were the primary driver of the trends in electricity prices from 2006 to 2009. Average natural gas prices decreased in 2009 by 56 percent from 2008 levels. The average all-in price for electricity was $80.97 in 2008 and $35.09 in 2009, a decrease of 56 percent.

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.: California ISO, New York ISO, ISO New England, and PJM. 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.



** 2008 Capacity, Ancillary Services and Uplift data unavailable for PJM

This figure shows that energy prices decreased in wholesale electricity markets across the U.S. in 2009, primarily due to decreases in fuel costs, and that the ERCOT market experienced the lowest all-in wholesale prices of any of these markets in 2009.

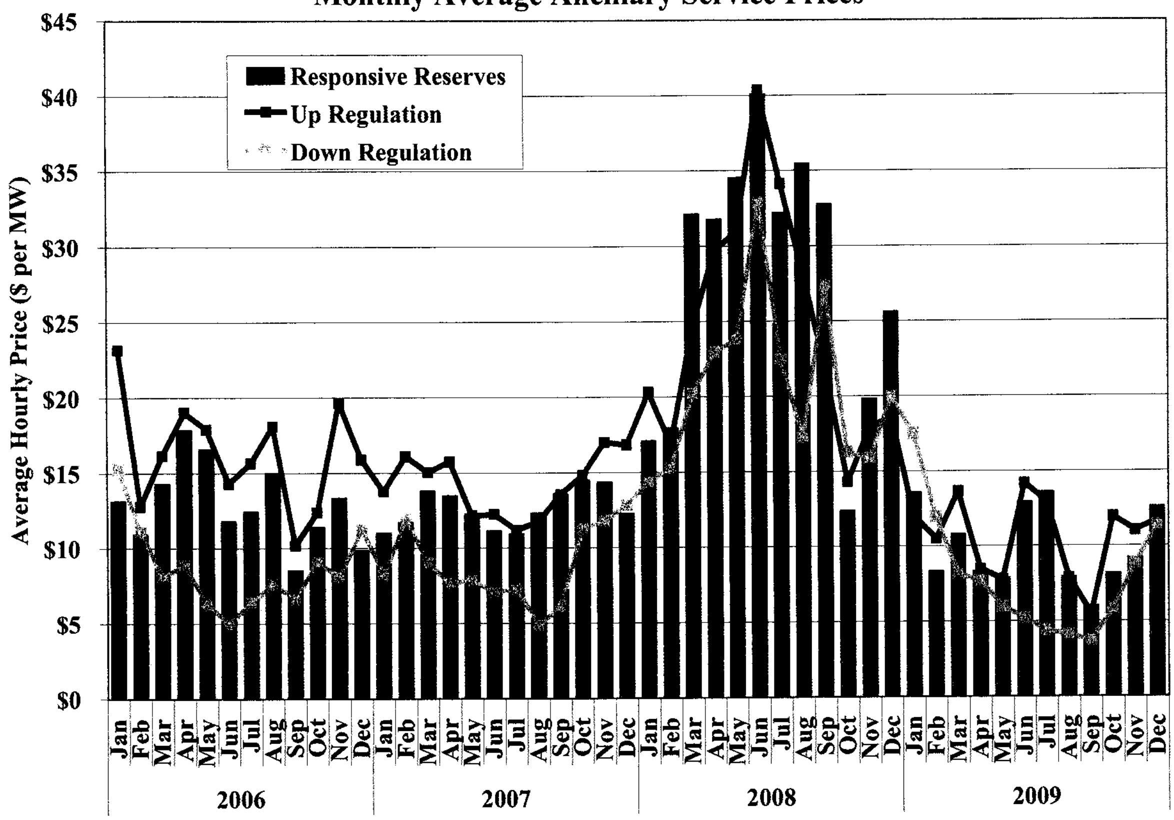
3. Ancillary Services Markets

The primary ancillary services are up regulation, down regulation, and responsive reserves. Historically, ERCOT has also procured non-spinning reserves as needed during periods of increased supply and demand uncertainty. However, beginning in November 2008, ERCOT began procuring non-spinning reserves across all hours based on its assessment of "net load" error, where "net load" is equal to demand minus wind production. QSEs may self-schedule ancillary services or purchase their required ancillary services through the ERCOT markets. This section reviews the results of the ancillary services markets in 2009.

Because ancillary services markets are conducted prior to the balancing energy market, participants must include their expected value of foregone sales in the balancing energy market in their offers for responsive reserves and regulation. Providers of both responsive reserves and up regulation can incur such opportunity costs if they reduce the output from economic units to make the capability available to provide these services. Likewise, providers of down regulation can incur opportunity costs in real-time if they receive instructions to reduce their output below the most profitable operating level. Further, because generators must be online to provide regulation and responsive reserves, there is an economic risk during low price periods of operating uneconomically at minimum output levels (or having to operate above minimum output levels if providing down regulation). The figure below shows the monthly average prices for regulation and responsive reserve services from 2006 to 2009.

This figure shows that ancillary service capacity prices generally returned to levels seen in 2006 and 2007 after reaching significantly higher levels in 2008. These price movements can be primarily attributed to the variations in energy prices that occurred over the same timeframe.

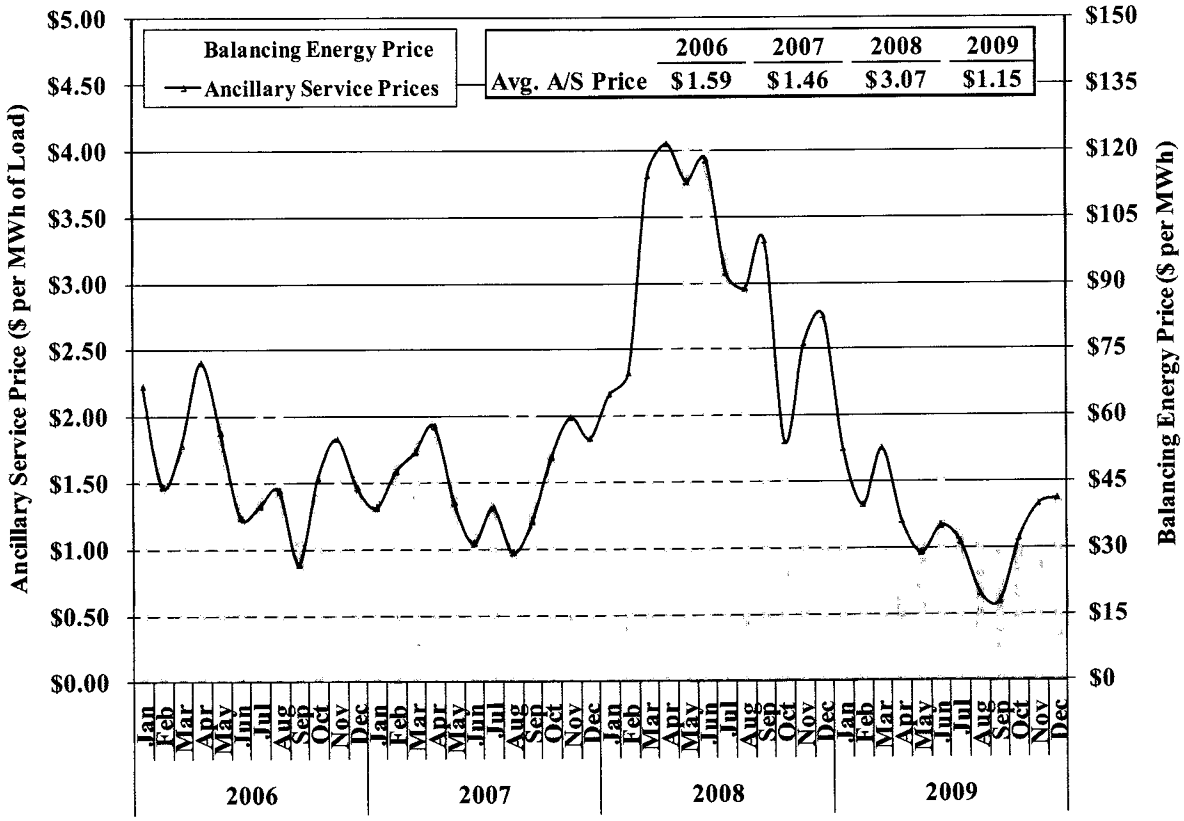
Monthly Average Ancillary Service Prices



The current Nodal Protocols specify that energy and ancillary services will be jointly optimized in a centralized day-ahead market. This is likely to improve the overall efficiency of the day-ahead unit commitment. Additionally, although not possible to implement at the inception in the nodal market, we also recommend the development of real-time markets that co-optimize energy and reserves to further enhance the efficient dispatch of resources and pricing in real-time.

While the previous figure shows the individual ancillary service capacity prices, the following figure shows the monthly total ancillary service costs per MWh of ERCOT load and the average balancing energy price for 2006 through 2009.

Ancillary Service Costs per MWh of Load



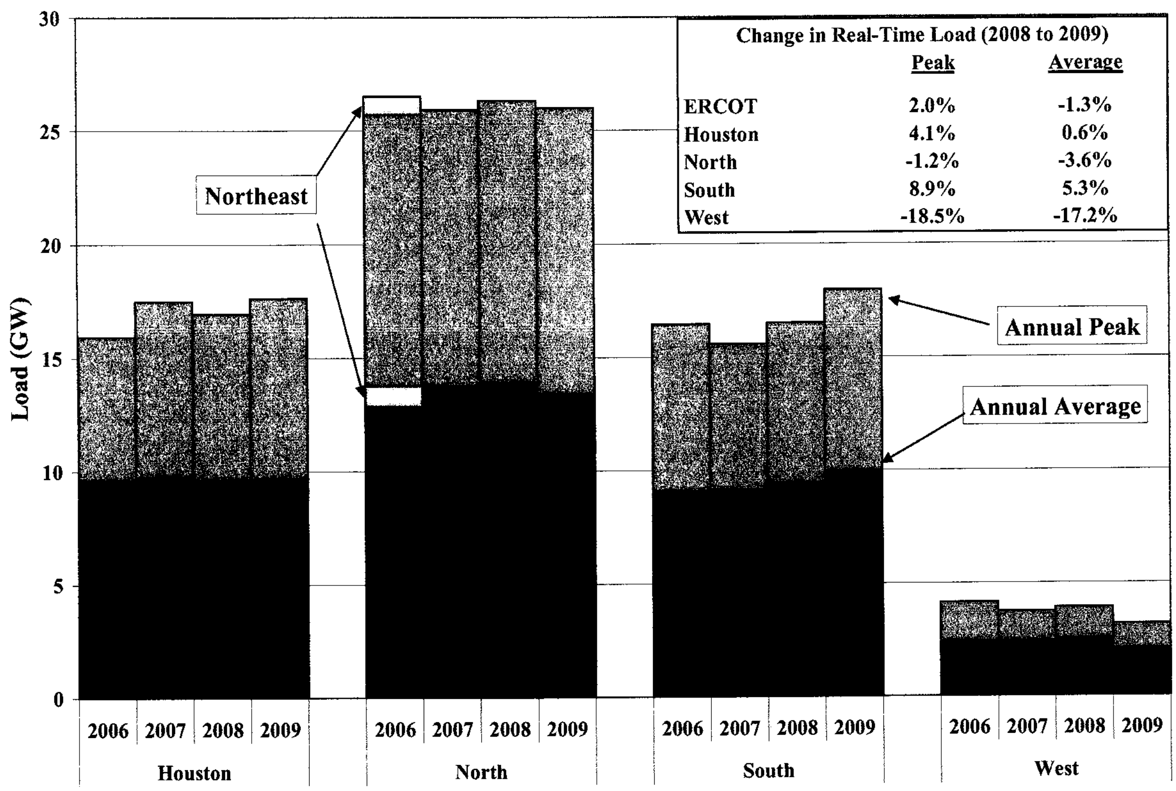
This figure shows that total ancillary service costs are generally correlated with balancing energy price movements which, as previously discussed, are highly correlated with natural gas price movements. The average ancillary service cost per MWh of load decreased to $1.15 per MWh in 2009 compared to $3.07 per MWh in 2008, a decrease of more than 63 percent. Ancillary service costs were equal to 4.0 and 3.5 percent of the load-weighted average energy price in 2008 and 2009, respectively.

C. Demand and Resource Adequacy

1. ERCOT Loads in 2009

This section examines changes in average and peak load levels in 2009 of these dimensions of load during 2009. The following figure shows peak load and average load in each of the ERCOT zones from 2006 to 2009. This figure indicates that in each zone, as in most electrical systems, peak demand significantly exceeds average demand. The North Zone is the largest zone (about 38 percent of the total ERCOT load);[3] the South and Houston Zones are comparable (with about 28 percent) while the West Zone is the smallest (with about 6 percent of the total ERCOT load).

Annual Load Statistics by Zone

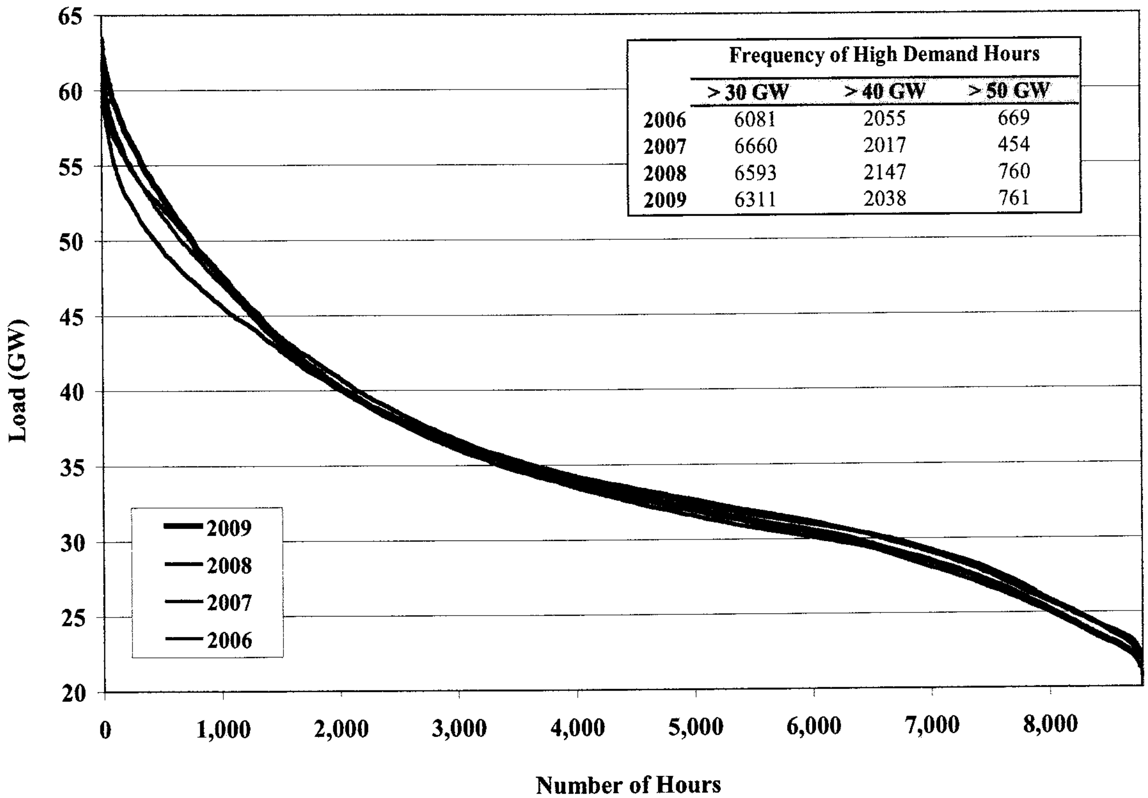


Some of the changes in zonal peak and average loads from 2008 to 2009 can be attributed to changes to the zonal definitions that resulted in some loads moving to a different zone in 2009. Overall, the ERCOT average load decreased from 312,401 GWh in 2008 to 308,278 GWh in 2009, a decrease of 1.3 percent. In contrast, the ERCOT coincident peak demand increased from 62,174 MW in 2008 to 63,400 MW in 2009, an increase of 2.0 percent.

3 The Northeast Zone was integrated into the North Zone in 2007.

To provide a more detailed analysis of load at the hourly level, the next figure compares load duration curves for each year from 2006 to 2009. 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, as most hours exhibit low to moderate electricity demand, with peak demand usually occurring during the afternoon and early evening hours of days with exceptionally high temperatures.

ERCOT Load Duration Curve – All Hours

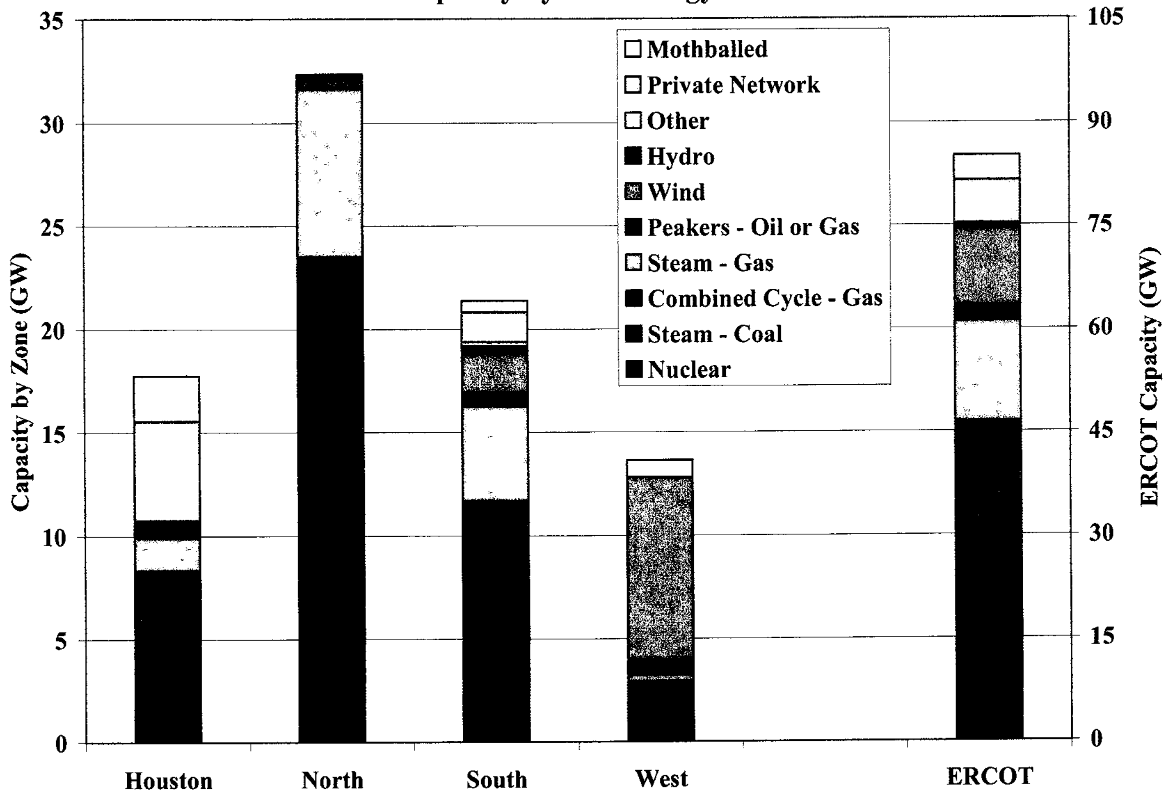


As shown in the figure above, the load duration curve for 2009 is slightly lower than in 2008 at load levels less than 45 GW, which accounts for approximately 85 percent of the hours in 2009 and is consistent with the load reduction of 1.3 percent from 2008 to 2009. However, the number of high demand hours (more than 50 GW) in 2008 and 2009 are at comparable levels (760 and 761 hours respectively). Load exceeded 58 GW in 160 hours in 2009, more than double the hours in 2008.

2. Generation Capacity in ERCOT

This section evaluates the generation mix in ERCOT. With the exception of the wind resources in the West Zone and the nuclear resources in the North and Houston Zones, the mix of generating capacity is relatively uniform in ERCOT. The following figure shows the installed generating capacity by type in each of the ERCOT zones.

Installed Capacity by Technology for each Zone

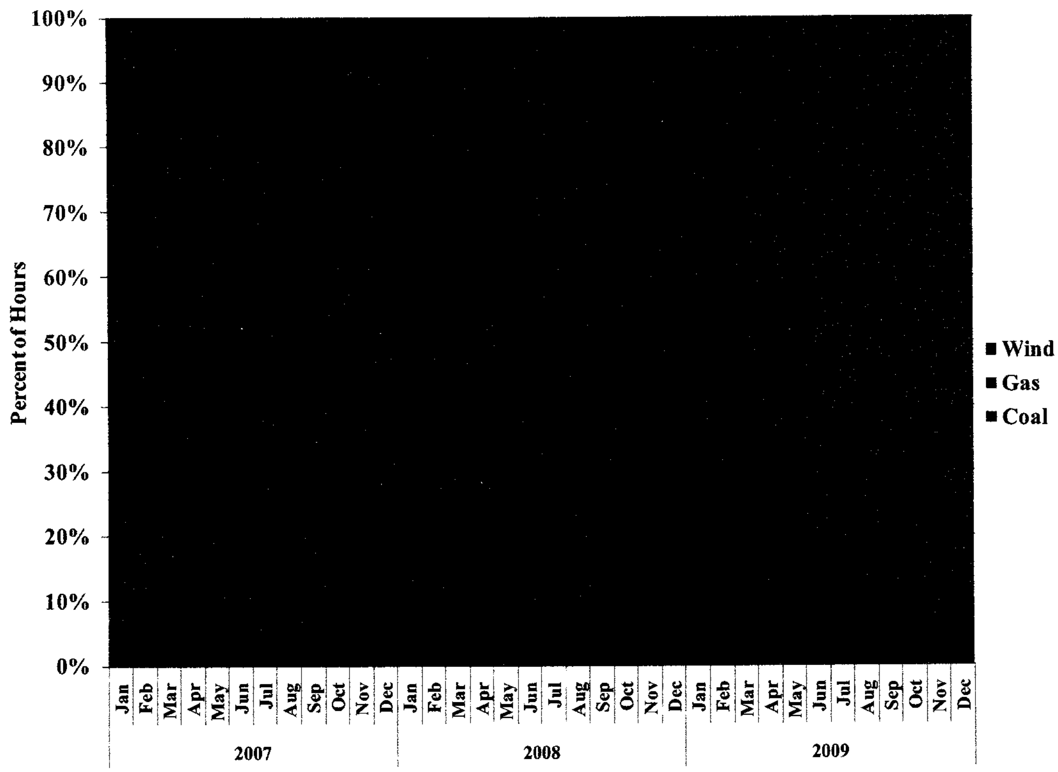


The distribution of capacity among the ERCOT zones is similar to the distribution of demand with the exception of the large amount of wind capacity in the West Zone.

While ERCOT has coal/lignite and nuclear plants that operate primarily as base load units, its reliance on natural gas resources makes it vulnerable to natural gas price spikes. There is approximately 22.6 GW of coal and nuclear generation in ERCOT. Because there are very few hours when ERCOT load drops as low as 20 GW, natural gas resources will be dispatched and set the balancing energy spot price in most hours. Hence, although coal-fired and nuclear units combined produce approximately half of the energy in ERCOT, they have historically played a much less significant role in setting spot electricity prices. However, with the significant increases in wind capacity that has a lower marginal production cost than coal and lignite, the frequency at which coal and lignite are the marginal units in ERCOT is expected to increase in the future, particularly during the off-peak hours in the spring and fall, and even more as additional transmission capacity is added that will accommodate increased levels of wind production in the West Zone.

The figure below shows the marginal fuel frequency for the Houston Zone, for each month from 2007 through 2009. The marginal fuel frequency is the percentage of hours that a generation fuel type is marginal and setting the price at a particular location.

Marginal Fuel Frequency (Houston Zone)



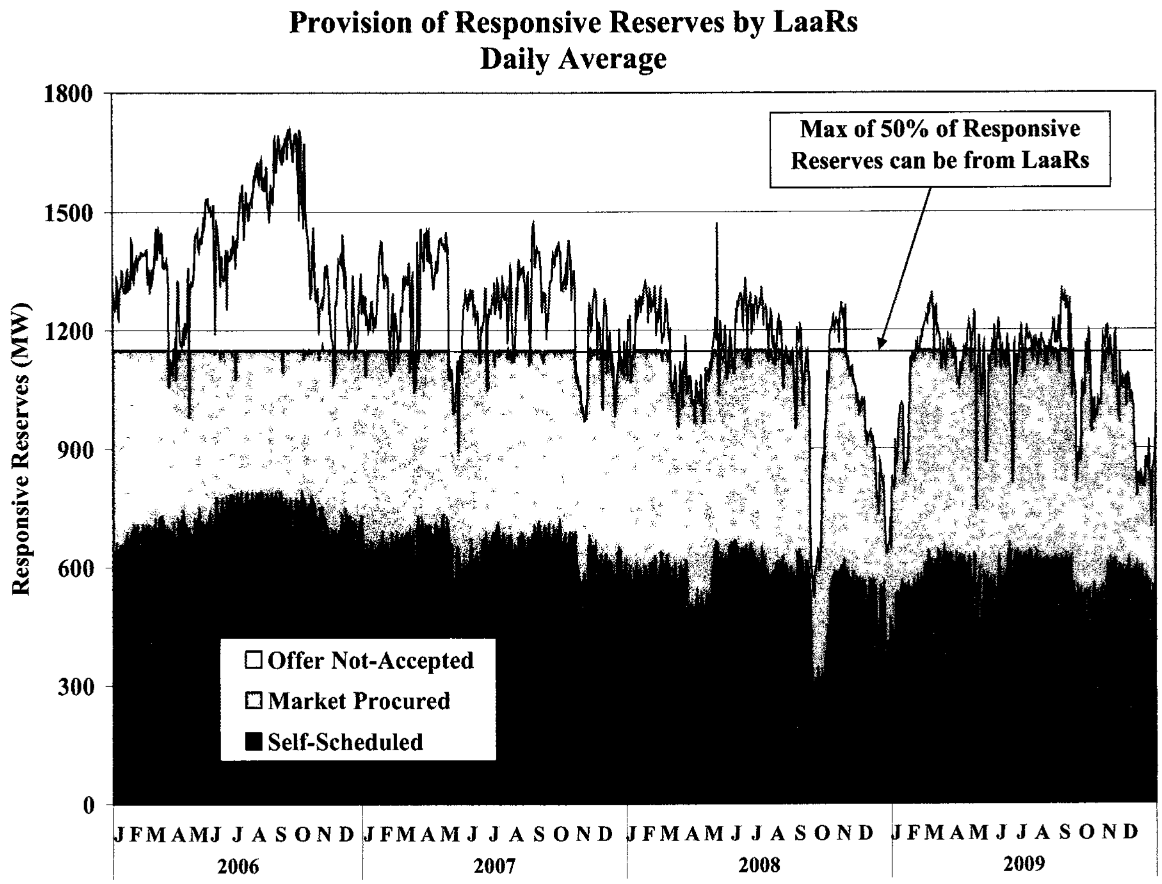
As shown in the figure above, the frequency at which coal was the price setting fuel for the Houston Zone experienced a significant and sustained increase beginning in September 2008. This increase can be attributed to (1) increased wind resource production; (2) a slight reduction in demand in 2009 due to the economic downturn; and (3) periods when natural gas prices were very low thereby making coal and combined-cycle natural gas resources competitive from an economic dispatch standpoint. As significant additional wind, coal and potentially nuclear resources are added to the ERCOT region and transmission constraints that serve to limit existing wind production are alleviated, it is likely that the marginal fuel frequency of coal will increase in coming years.

3. Load Participation in the ERCOT Markets

The ERCOT Protocols allow for loads to participate in the ERCOT-administered markets as either Load acting as Resources ("LaaRs") or Balancing Up Loads ("BULs"). LaaRs are loads that are qualified by ERCOT to offer responsive reserves, non-spinning reserves, or regulation into the day-ahead ancillary services markets and can also offer blocks of energy in the balancing energy market.

As of December 2009, over 2,200 MW of capability were qualified as LaaRs. In 2009, LaaRs were permitted to supply up to 1,150 MW of the responsive reserves requirement. Although the participants with LaaR resources are qualified to provide non-spinning reserves and up balancing energy in real-time, LaaR participation in the non-spinning reserve and balancing energy market was negligible in 2009.[4] This is not surprising because the value of curtailed load tends to be relatively high, and providing responsive reserves offers substantial revenue with very little probability of being deployed. In contrast, resources providing non-spinning reserves have a much higher probability of being curtailed. Hence, most LaaRs will have a strong preference to provide responsive reserves over non-spinning reserves or balancing energy. The following figure shows the daily average provision of responsive reserves by LaaRs in the ERCOT market from 2006 through 2009.

4 Although there was no active participation in the balancing energy market, loads can and do respond to market prices without actively submitting a bid to ERCOT. This is often referred to as passive load response.



The high level of participation by demand response participating in the ancillary service markets sets ERCOT apart from other operating electricity markets. The figure above shows that the amount of responsive reserves provided by LaaRs has held fairly constant at 1,150 MW since the beginning of 2006. Exceptions include a decrease in September of 2008 corresponding to the Texas landfall of Hurricane Ike and a more prolonged reduction from November 2008 through January 2009 that was likely a product of the economic downturn and its effect on industrial operations.

4. Net Revenue Analysis

Net revenue is defined as the total revenue that can be earned by a new generating unit less its variable production costs. It represents the revenue that is available to recover a unit's fixed and capital costs. Hence, this metric shows the economic signals provided by the market for investors to build new generation or for existing owners to retire generation. In long-run equilibrium, the markets should provide sufficient net revenue to allow an investor to break-even on an investment in a new generating unit, including a return of and on the investment.

In the short-run, if the net revenues produced by the market are not sufficient to justify entry, then one of three conditions likely exists:

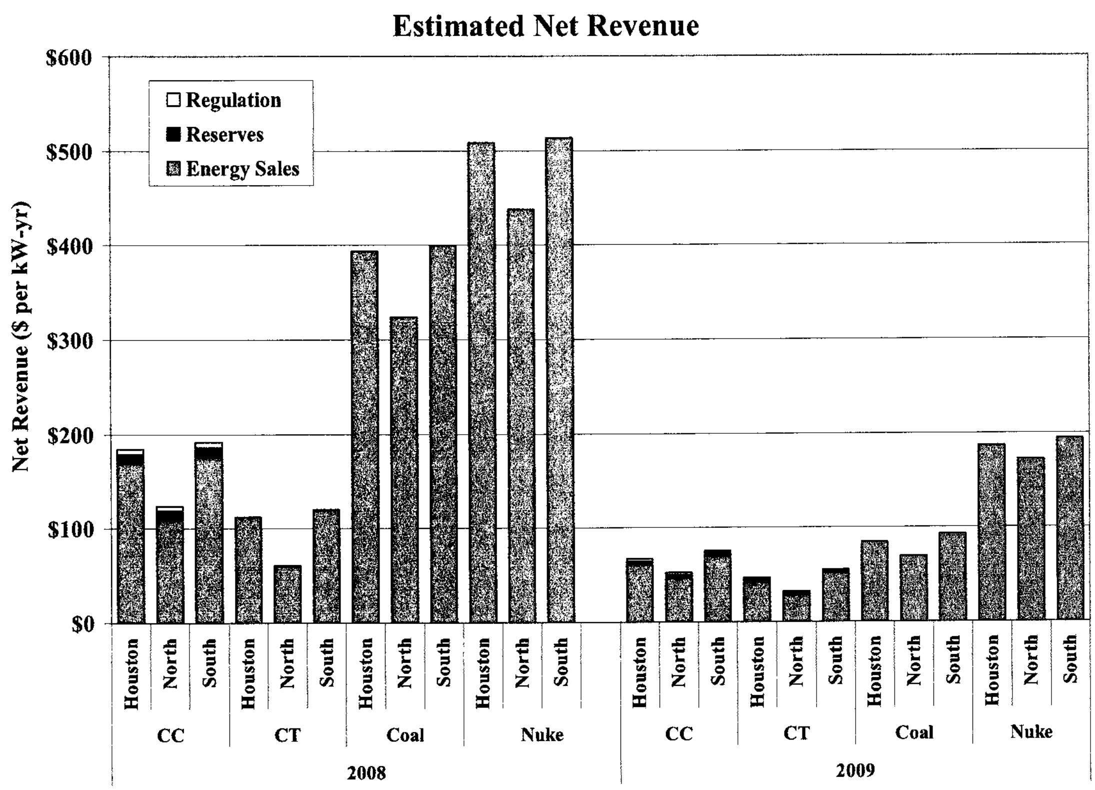
(i) New capacity is not currently needed because there is sufficient generation already available;

(ii) Load levels, and thus energy prices, are temporarily low due to mild weather or economic conditions; or

(iii) Market rules are causing revenues to be reduced inefficiently.

Likewise, the opposite would be true if the markets provide excessive net revenue in the short-run. Excessive net revenue that persists for an extended period in the presence of a capacity surplus is an indication of competitive issues or market design flaws.

The report estimates the net revenue that would have been received in 2008 and 2009 for four types of units: a natural gas combined-cycle generator, a simple-cycle gas turbine, a coal unit, and a nuclear unit.



The figure above shows that the net revenue decreased substantially in 2009 compared to each zone compared in 2008. Based on our estimates of investment costs for new units, the net revenue required to satisfy the annual fixed costs (including capital carrying costs) of a new gas turbine unit ranges from $70 to $95 per kW-year. The estimated net revenue in 2009 for a new gas turbine was approximately $55, $47 and $32 per kW-year in the South, Houston and North Zones, respectively. For a new combined cycle unit, the estimated net revenue requirement is approximately $105 to $135 per kW-year. The estimated net revenue in 2009 for a new combined cycle unit was approximately $76, $67 and $52 per kW-year in the South, Houston and North Zones, respectively. These values indicate that the estimated net revenue in 2009 was well below the levels required to support new entry for a new gas turbine or a combined cycle unit in the ERCOT region. Prior to 2005, net revenues were well below the levels necessary to justify new investment in coal and nuclear generation. However, high natural gas prices through 2008 allowed energy prices to remain at levels high enough to support new entry for these technologies. The production costs of coal and nuclear units did not change significantly over this period, leading to a dramatic rise in net revenues. With the significant decline in natural gas and energy prices in 2009, these results changed dramatically from recent years. For a new coal unit, the estimated net revenue requirement is approximately $190 to $245 per kW-year. The estimated net revenue in 2009 for a new coal unit was approximately $93, $84 and $70 per kW-year in the South, Houston and North Zones, respectively. For a new nuclear unit, the estimated net revenue requirement is approximately $280 to $390 per kW-year. The estimated net revenue in 2009 for a new nuclear unit was approximately $194, $187 and $172 per kW-year in the South, Houston and North Zones, respectively. These values indicate that the estimated net revenue for a new coal and nuclear unit in the South, Houston and North Zones was well below the levels required to support new entry in 2009.

5. Effectiveness of the Scarcity Pricing Mechanism

The PUCT adopted rules in 2006 that define the parameters of an energy-only market. These rules include a Scarcity Pricing Mechanism ("SPM") that relaxed the existing system-wide offer cap by gradually increasing it to $1,500 per MWh on March 1, 2007, $2,250 per MWh on March 1, 2008, and to $3,000 per MWh shortly after the implementation of the nodal market. Additionally, market participants controlling less than five percent of the capacity in ERCOT by definition do not possess market power under the PUCT rules. Hence, these participants can submit very high-priced offers that, per the PUCT rule, will not be deemed to be an exercise of market power. However, because of the competition faced by the smaller market participants, the quantity offered at such high prices – if any – is very small.

Unlike markets with a long-term capacity market where fixed capacity payments are made to resources across the entire year regardless of the relationship of supply and demand, the objective of the energy-only market design is to allow energy prices to rise significantly higher during legitimate shortage conditions (*i.e.*, when the available supply is insufficient to simultaneously meet both energy and operating reserve requirements) such that the appropriate price signal is provided for demand response and new investment when required. During non-shortage conditions (*i.e.*, most of the time), the expectation of competitive energy market outcomes is no different in energy-only than in capacity markets.

Consistent with the previous findings relating to net revenue, the PNM reached the level sufficient for new entry in only one of the last four years (2008). In 2008, the peaker net margin and net revenue values rose substantially, surpassing the level required to support new peaker entry. However, a significant portion of the net revenue increase in 2008 was associated with extremely inefficient transmission congestion management and inefficient pricing mechanisms associated with the deployment of non-spinning reserves.[5] Both of these issues were corrected in the zonal market and will be further improved with the implementation of the nodal market in late 2010. With these issues addressed, the peaker net margin dropped substantially in 2009, decreasing to $46,650 per MW-yr from $101,774 per MW-yr in 2008. Net revenues also dropped substantially for other technologies largely due to significant decreases in natural gas prices in 2009, but decreased natural gas price are not the driver for the reduction in net revenues for peaking resources. Beyond the correction of the market design inefficiencies that existed in 2008, there were three other factors that influenced the effectiveness of the SPM in 2009:

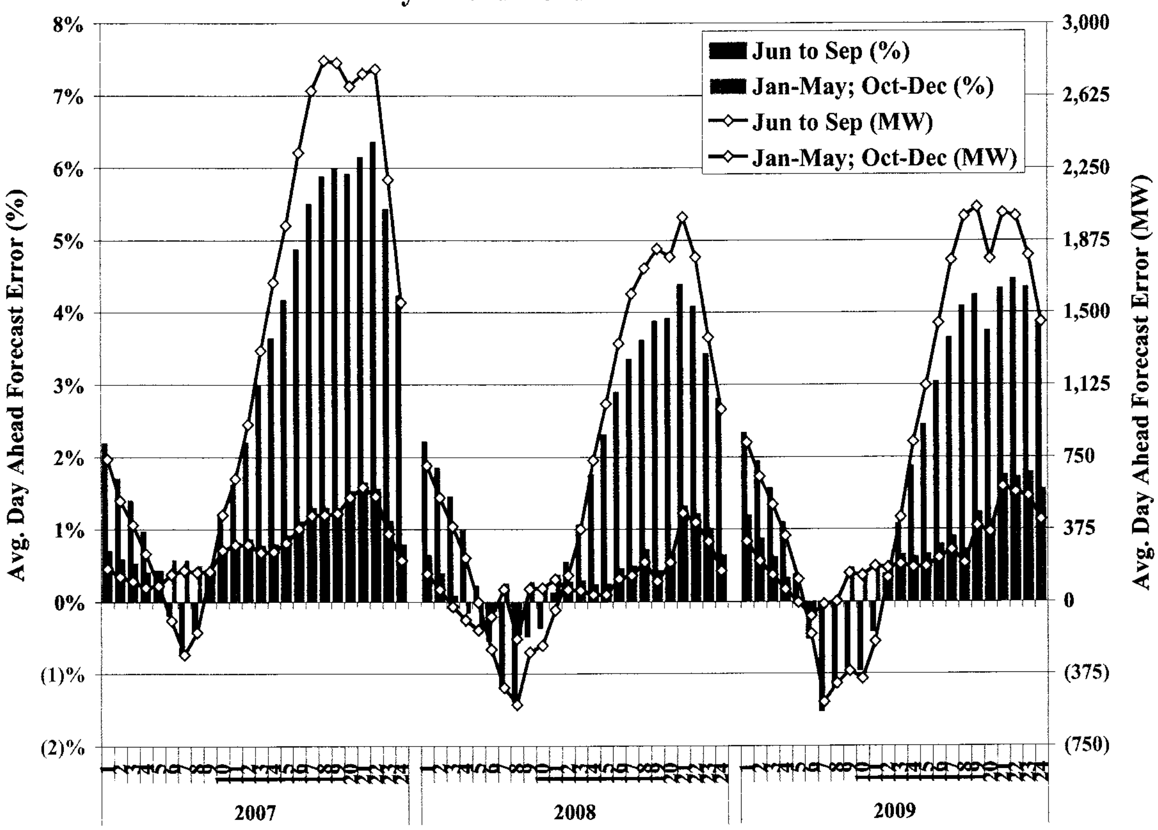
- A continued strong positive bias in ERCOT's day-ahead load forecast -- particularly during summer on-peak hours – that creates the tendency to regularly commit online resources in excess of the quantity required to meet expected demand and operating reserve requirements;
- The implementation of PRR 776, which allowed for quick start gas turbines providing non-spinning reserves to offer the capacity into the balancing energy market; and

5 *See* 2008 ERCOT SOM Report at 81-87.

- The dependence on market participants to submit offers at or near the offer cap to produce scarcity level prices during legitimate operating reserve shortage conditions

The following figure shows the ERCOT day-ahead load forecast error by hour in 2007 through 2009, with the summer and non-summer months presented separately. In this figure, positive values indicate that the day-ahead load forecast was greater than the actual load in real-time.

Day-Ahead Load Forecast Error



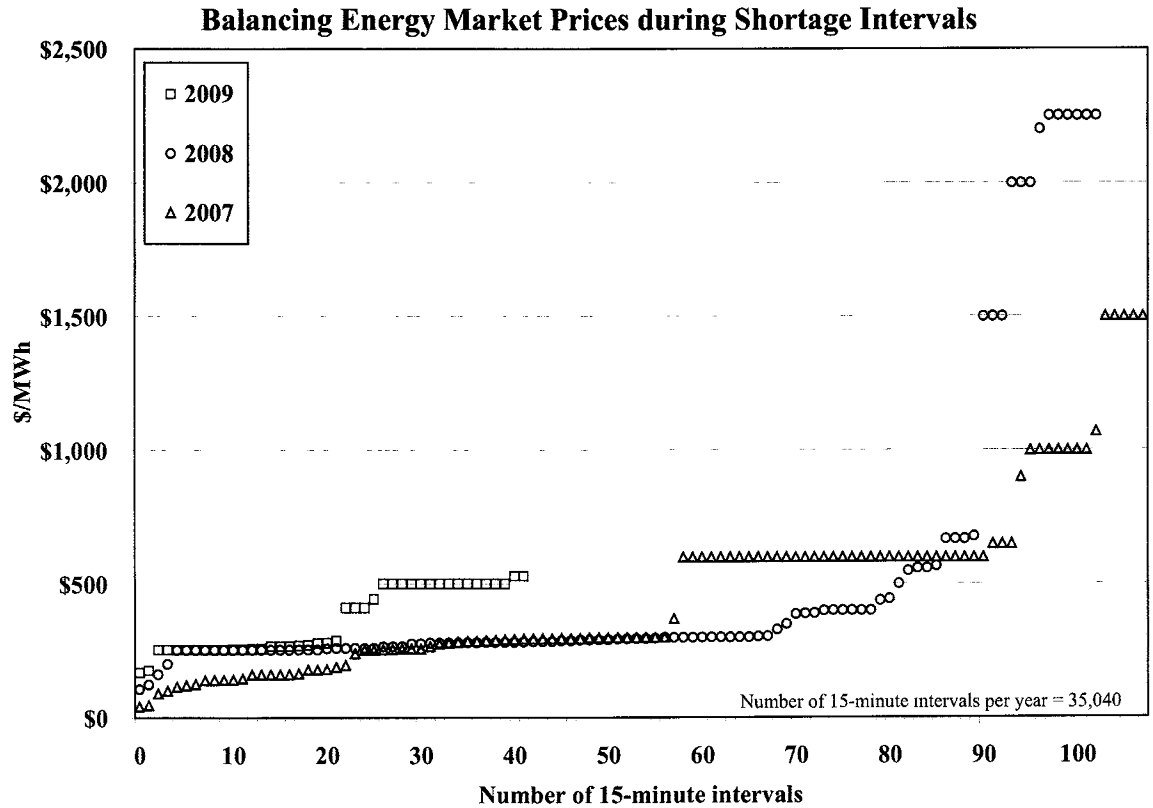
The existence of such a strong and persistent positive bias in the day-ahead load forecast will tend to lead to an inefficient over-commitment of resources and to the depression of real-time prices relative to a more optimal unit commitment. To the extent load uncertainty is driving the bias in the day-ahead load forecast, such uncertainty is more efficiently managed through the procurement of ancillary services such as non-spinning reserve, or through supplemental commitments of short-lead time resources at a time sufficiently prior to, but closer to real-time as uncertainty regarding real-time conditions diminishes.

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

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

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

Under the PUCT rules governing the energy-only market, the mechanism that allows for such pricing during shortage conditions relies upon the submission of high-priced offers by small market participants. The following figure shows the balancing market clearing prices during the 15-minute shortage intervals in 2007 through 2009.



The 42 shortage intervals in 2009 are significantly fewer than the 108 and 103 shortage intervals that occurred in 2007 and 2008, respectively. This reduction can be primarily attributed to the implementation of PRR 776, which allows more timely access to non-spinning reserves through the balancing energy market, thereby reducing the probability of transitional shortages of the core operating reserves. As shown in the figure above, prices during these 42 shortage intervals in 2009 ranged from $168 per MWh to $529 per MWh, with an average price of $364 per MWh and a median price of $283 per MWh.

Although each of the data points in the figure above represents system conditions in which the market was in shortage, the pricing outcomes are widely varied, with the majority of prices reflecting the marginal offer of the most expensive generation resource dispatched as opposed to the value of foregone operating reserves. These results indicate that relying exclusively upon the submission of high-priced offers by market participants was generally not a reliable means of producing efficient scarcity prices during shortage conditions in 2007 through 2009. In fact, although the current system-wide offer cap is $2,250 per MWh, there no hours in 2009 where an offer was submitted by a market participant that approached the offer cap. There were only 33 hours with an offer that exceeded $1,000 per MWh, and the average of the highest offers submitted by any market participant in all hours in 2009 was approximately $400 per MWh.

Despite the mixed and widely varied results of the SPM, private investment in generation capacity in ERCOT has continued, although such investment has been dominated by baseload (non-natural gas fueled) and wind generation. As indicated in the net revenue analyses, these investments are largely driven by significant increases in natural gas prices in the four years prior to 2009. In contrast, private investment in peaking resources in ERCOT has been relatively thin. In an energy-only market, net revenue expectations for peaking resources are much more sensitive the effectiveness of the shortage pricing mechanism than to factors such as the magnitude of natural gas prices, and efficient shortage pricing is a particularly critical element in the ERCOT energy-only market to ensure that the long-term resource adequacy requirements are achieved.

D. Transmission and Congestion

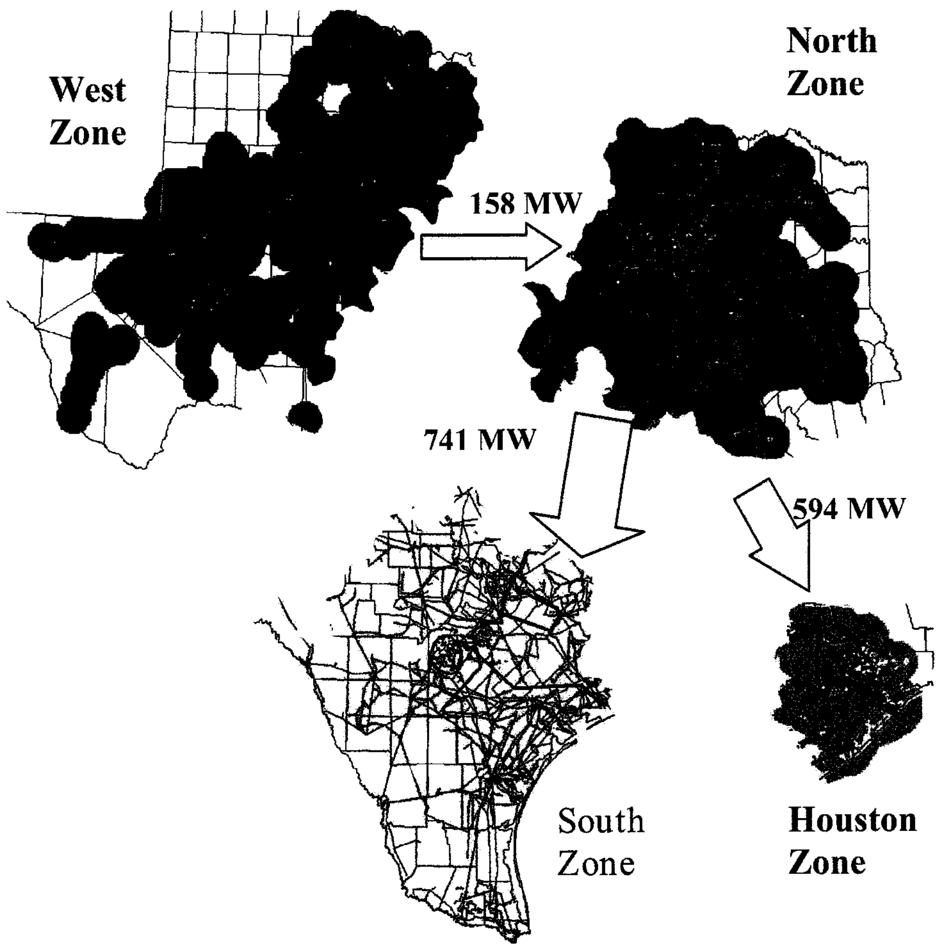
One of the most important functions of any electricity market is to manage the flows of power over the transmission network, limiting additional power flows over transmission facilities when they reach their operating limits. In ERCOT, constraints on the transmission network are managed in two ways. First, ERCOT is made up of zones with the constraints between the zones managed through the balancing energy market. The balancing energy market increases energy production in one zone and reduces it in another zone to manage the flows between the two zones when the interface constraint is binding (*i.e.*, when there is interzonal congestion). Second, constraints within each zone (*i.e.*, local congestion) are managed through the redispatch of individual generating resources. The report evaluates the ERCOT transmission system usage and analyzes the costs and frequency of transmission congestion.

1. Electricity Flows between Zones and Interzonal Congestion

The balancing energy market uses the Scheduling, Pricing, and Dispatch ("SPD") software that dispatches energy in each zone to serve load and manage congestion between zones. The SPD model embodies the market rules and requirements documented in the ERCOT protocols. To manage interzonal congestion, SPD uses a simplified network model with four zone-based locations and five transmission interfaces. The transmission interfaces are referred to as

Commercially Significant Constraints ("CSCs"). The following figure shows the average flows modeled in SPD during 2009 over each of these CSCs.

Average Modeled Flows on Commercially Significant Constraints



When interzonal congestion exists, higher-cost energy must be produced within the constrained zone because lower-cost energy cannot be delivered over the constrained interfaces. When this occurs, participants must compete to use the available transfer capability between zones. To allocate this capability in the most efficient manner possible, ERCOT establishes a clearing price for each zone and the price difference between zones is charged for any interzonal transactions.

The analysis of these CSC flows in this report indicates that:

- The simplifying assumptions made in the SPD model can result in modeled flows that are considerably different from actual flows.

- A considerable quantity of flows between zones occurs over transmission facilities that are not defined as part of a CSC. When these flows cause congestion, it is beneficial to create a new CSC to better manage congestion over that path.
- The differences between SPD-modeled flows and actual flows on CSCs create operational challenges for ERCOT that result in the inefficient use of scarce transmission resources.

Inter-zonal congestion was most frequent in 2009 on the West to North CSC, followed by the North to Houston and the North to South CSCs.

The North to Houston CSC was binding in 625 15-minute intervals with an annual average shadow price of $2.01 per MW.[6] These values represent a significant reduction in both the frequency and magnitude of congestion compared to 2008 when the North to Houston CSC was binding in 1,447 intervals with an annual average shadow price of $20.

The North to South CSC was binding in 387 15-minute intervals with an annual average shadow price of $8.39 per MW. Like the North to Houston CSC, these values represent a significant reduction in both the frequency and magnitude of congestion compared to 2008 when the North to South CSC was binding in 2,531 intervals with an annual average shadow price of $22.

The decreased congestion on the North to Houston and North to South CSCs in 2009 is primarily attributable to the implementation of PRR 764 in June 2008 that revised the definition of valid zonal transmission constraints and improved the efficiency of transmission congestion management within the context of the zonal market model.[7]

A significant percentage of the congestion on the North to South CSC occurred during June 2009. During this timeframe, the ERCOT market experienced very high temperatures and associated increases in load levels, as well as a number of outages at baseload generating facilities, particularly in the South Zone. This combination of events led to an increase in the frequency of congestion on the North to South CSC as well as local congestion related to import limitations into the San Antonio area from the north. In the zonal model, the most effective

6 The shadow price of a transmission constraint represents the marginal value of the use a transmission element. The shadow price of a transmission element will be zero unless the transmission element is bieing used to its full capacity, in which case it will have a positive shadow price.

7 *See* 2008 ERCOT SOM Report at 81-87.

resolution to North to South congestion is to increase generation in the South Zone. However, effective zonal congestion management on the North to South CSC was affected by the local congestion in the San Antonio area, which is most effectively resolved by increasing generation in and South of San Antonio, and decreasing generation north of San Antonio. Because most of the generation resources located north of San Antonio required to decrease output to manage the local congestion in the San Antonio area are also in the South Zone that was broadly required to increase output to manage the zonal North to South congestion, competing reliability objectives were present that complicated the simultaneous resolution of both the North to South zonal congestion and the intrazonal San Antonio import-related congestion. Faced with these competing reliability objectives and the inability to resolve both reliability issues within the context of the zonal model and its bifurcated process of zonal and local transmission congestion management, ERCOT implemented a temporary transmission switching solution in late June that effectively increased the transfer capability on the North to South CSC, thereby resolving these competing reliability objectives under the atypical load and generator outage conditions experienced at that time.

The West to North CSC was binding in 3,121 15-minute intervals in 2009. This was more frequent than any other CSC in 2009 and, with the exception of the same CSC in 2008 that was binding for 5,320 intervals, more frequent than any other CSC since the inception of single control area operations in 2001. The primary reason for the high frequency of congestion on the West to North CSC in 2008 and 2009 is the significant increase in installed wind generation relative to the load in the West Zone and limited transmission export capability to the broader market.

Although the marginal production cost of wind generators is near zero, the operating economics are affected by federal production tax credits and state renewable energy credits, which lead to negative-priced offers from most wind generators. Thus, when transmission congestion occurs that requires wind generators to curtail their output, negative balancing energy market prices will result in the West Zone. The hourly average balancing energy market price in the West Zone was less than zero in over 700 hours during 2009.

Although the frequency of zonal transmission congestion on the West to North CSC was very high in 2009 compared to other zonal constraints, the frequency of congestion on this constraint was lower than in 2008. However, zonal congestion data do not provide a complete view of the congestion situation in the West Zone. While the quantity of zonal curtailments for wind resources in the West Zone decreased from 604,000 MWh in 2008 to 442,000 MWh in 2009, the quantity of local curtailments increased significantly, rising from 812,000 MWh in 2008 to over 3,400,000 MWh in 2009. Hence, while curtailments in the West Zone associated with zonal congestion decreased in 2009, total congestion-related curtailments in the West Zone increased significantly in 2009.

Given the current transmission infrastructure and the level of existing wind facilities in the West Zone, the quantity of wind production that can be reliably accommodated in the West Zone will continue to be significantly limited for several years until the planned transmission improvements identified through the Competitive Renewable Energy Zone ("CREZ") project can be completed.

2. Transmission Congestion Rights and Payments

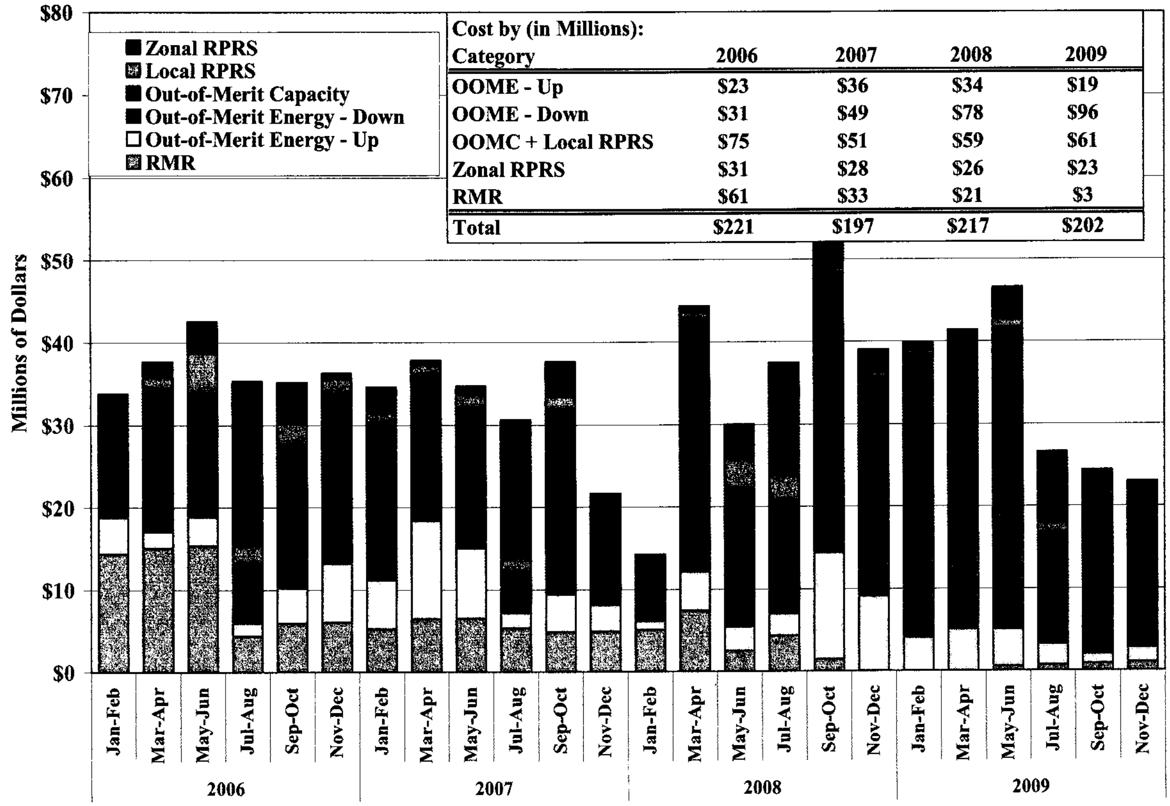
Participants in Texas can hedge against congestion in the balancing energy market by acquiring Transmission Congestion Rights ("TCRs") between zones, which entitle the holder to payments equal to the difference in zonal balancing energy prices. Because the modeled limits for the CSC interfaces vary substantially, the quantity of TCRs defined over a congested CSC frequently exceeds the modeled limits for the CSC. When this occurs, the congestion revenue collected by ERCOT will be insufficient to satisfy the financial obligation to the holders of the TCRs and the revenue shortfall is collected from loads through uplift charges. Payments to TCR holders have consistently exceeded the congestion rents that have been collected from the balancing market in 2006 through 2009. In 2009 congestion rents covered only 72 percent of the payments to TCR holders, with an annual net revenue shortfall of $53 million.

In a perfectly efficient system with no uncertainty, the average congestion cost in real-time should equal the auction price of the congestion rights. In the real world, however, we would expect reasonably close convergence with some fluctuations from year to year due to uncertainties. Market participants generally under-estimated the value of congestion by a wide margin in 2008, particularly during the first half of the year. These outcomes were likely influenced by the congestion management procedures that were applied during the first half of the year and modified by the implementation of PRR 764 in June 2008. In 2009, market participant over-estimated the value of congestion on the West to North and North to Houston CSCs, but once again underestimated the value of congestion on the North to South CSC. This was likely due to the unexpected nature of the contributors leading to congestion on this CSC.

3. Local Congestion and Local Capacity Requirements

ERCOT manages local (intrazonal) congestion by using out-of-merit dispatch ("OOME up" and "OOME down"), which causes units to depart from their scheduled output levels. When insufficient capacity is committed to meet local or system reliability requirements, ERCOT commits additional resources to provide the necessary capacity in either the day-ahead market or in the adjustment period (the adjustment period includes the hours after the close of the day-ahead market up to one hour prior to real-time). Capacity required for local reliability constraints is procured through either the Replacement Reserve Service market ("Local RPRS") or as out-of-merit capacity ("OOMC"). Capacity required for system reliability requirements (*i.e.,* the requirement that the total system-wide online capacity be greater than or equal to the sum of the ERCOT load forecast plus operating reserves in each hour) is procured through either the RPRS market ("Zonal RPRS") or as OOMC. ERCOT also enters into RMR agreements with certain generators needed for local reliability that may otherwise be mothballed or retired. When RMR units are called out-of-merit, they receive revenues specified in the agreements rather than standard OOME or OOMC payments. The following figure shows the out-of-merit energy and capacity costs, including RMR costs, from 2006 to 2009.

Expenses for Out-of-Merit Capacity and Energy



The results in the figure above show that overall uplift costs for RMR units, OOME units, OOMC/Local RPRS and Zonal RPRS[8] units were $202 million in 2009, which is a $15 million decrease over the $217 million in 2008. OOME Down and RMR costs accounted for the most significant portion of the change in 2009. OOME down increased from $78 million in 2008 to $96 million in 2009. These values represent significant increases in OOME Down costs from 2006 and 2007, and are primarily attributable to increases in OOME Down instructions for wind resources in the West Zone. RMR costs decreased from $21 million in 2008 to $3 million in 2009. This figure also shows that the highest Zonal RPRS costs occur in July and August when electricity demand in the ERCOT region is at its highest levels.

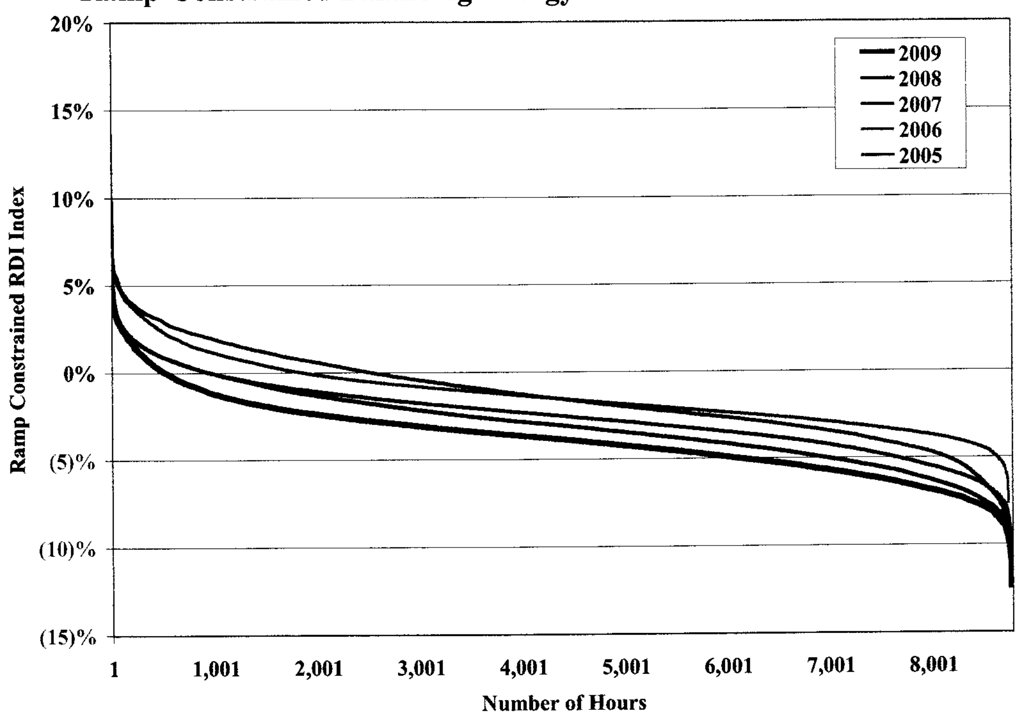
8 Zonal RPRS for system adequacy is deployed at the second stage of the RPRS run, which is affected by the deployment at the first stage of the RPRS run, or the local RPRS deployment. Because ERCOT Protocols allocate the costs of local and zonal RPRS in the same manner, we have included both as local congestion costs.

E. Analysis of Competitive Performance

The report evaluates two aspects of market power, structural indicators of market power and behavioral indicators that would signal attempts to exercise market power. The structural analysis in this report focuses on identifying circumstances when a supplier is "pivotal," *i.e.*, when its generation is essential to serve the ERCOT load and satisfy the ancillary services requirements.

The pivotal supplier analysis indicates that the frequency with which a supplier was pivotal in the balancing energy market decreased in 2009 compared to 2008. The following figure shows the ramp-constrained balancing energy market Residual Demand Index ("RDI") duration curves for 2005 through 2009. When the RDI is greater than zero, the largest supplier's balancing energy offers are necessary to prevent a shortage of offers in the balancing energy market.

Ramp-Constrained Balancing Energy Market RDI Duration Curve

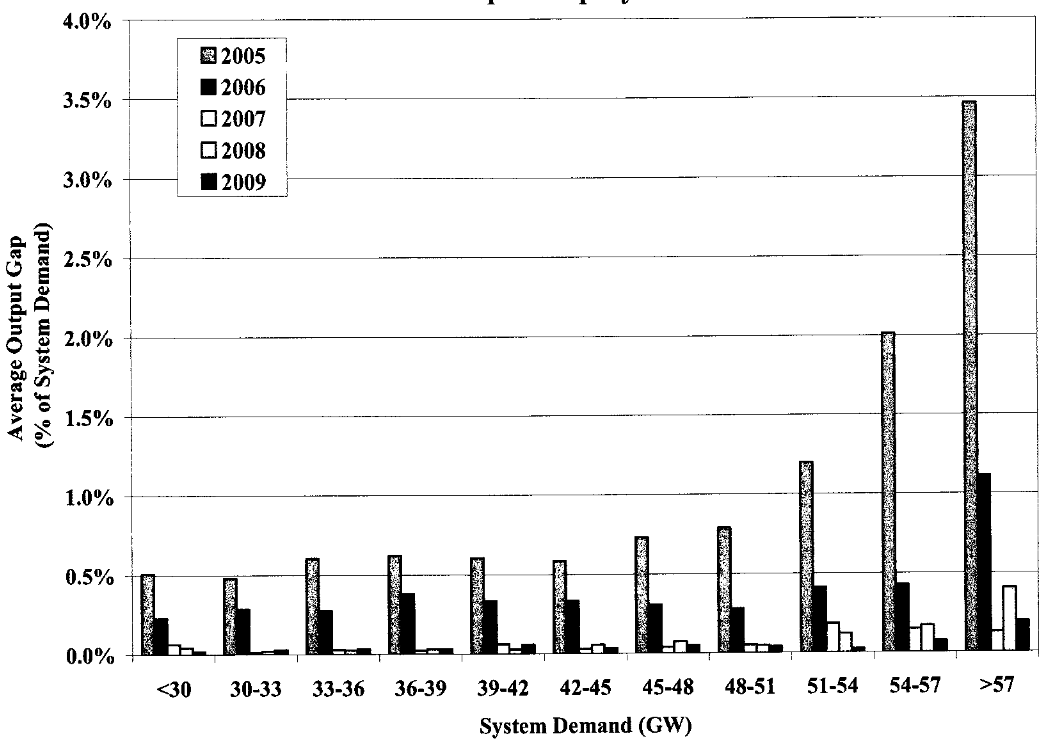


The frequency with which at least one supplier was pivotal (*i.e.*, an RDI greater than zero) has fallen consistently over the last five years from 29 and 21 percent of the hours in 2005 and 2006, respectively, to less than 11 percent of the hours in 2007 and 2008, to less than 6 percent of the hours in 2009. These results highlight the trend of continued improvement in the structural competitiveness of the balancing energy market over the last five years.

A behavioral indicator that evaluates potential economic withholding is measured 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 balancing energy price. A participant can economically withhold resources, as measured by the output gap, by raising its balancing energy offers so as not to be dispatched or by not offering unscheduled energy in the balancing energy market.

The figure below compares the real-time load to the average incremental output gap for all market participants as a percentage of the real-time system demand from 2005 through 2009.

Incremental Output Gap by Load Level



The figure above shows that the competitiveness of supplier offers improved considerably in 2006 compared to 2005, followed by even more substantial improvement in 2007 through 2009. In 2009, the overall magnitude of the incremental output gap remains very small and does not raise significant economic withholding concerns.

Overall, based upon the analyses in this section, we find that the ERCOT wholesale market performed competitively in 2009.

I. Review of Market Outcomes

A. Balancing Energy Market

1. Balancing Energy Prices During 2009

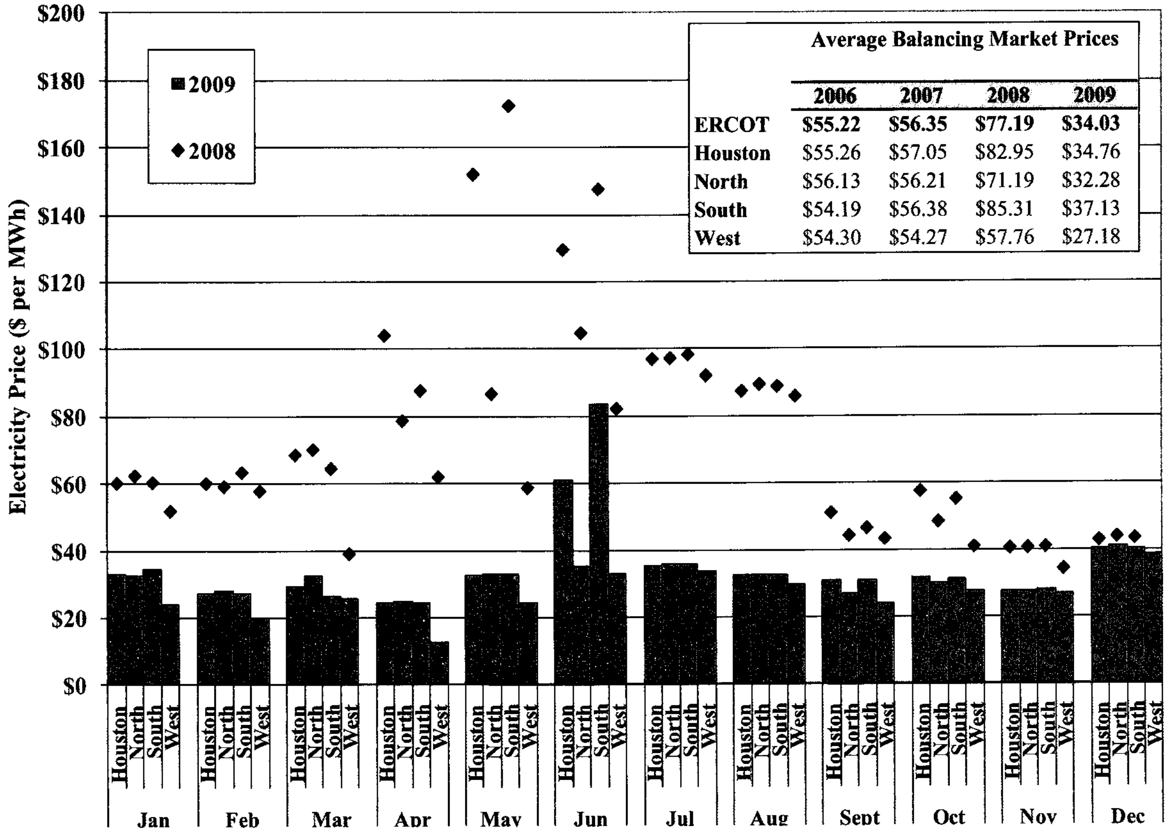
The balancing energy market is the spot market for electricity in ERCOT. As is typical in other wholesale markets, only a small share of the power produced in ERCOT is transacted in the spot market, although at times such transactions can exceed 10 percent of total demand. Although most power is purchased through bilateral forward contracts, outcomes in the balancing energy market are very important because of the expected pricing relationship between spot and forward markets (including bilateral markets).

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 balancing energy market will translate to artificially-low forward prices. Likewise, price spikes in the balancing energy market will increase prices in the forward markets. This section evaluates and summarizes balancing energy market prices during 2009.

To summarize the price levels during the past four years, Figure 1 shows the monthly load-weighted average balancing energy market prices in each of the ERCOT zones during 2008 and 2009, with annual summary data for 2006 and 2007.[9]

9 The load-weighted average prices are calculated by weighting the balancing energy price for each interval and each zone by the total zonal load in that interval. For this evaluation, balancing energy prices are load-weighted since this is the most representative of what loads are likely to pay (assuming that balancing energy prices are generally consistent with bilateral contract prices).

Figure 1: Average Balancing Energy Market Prices

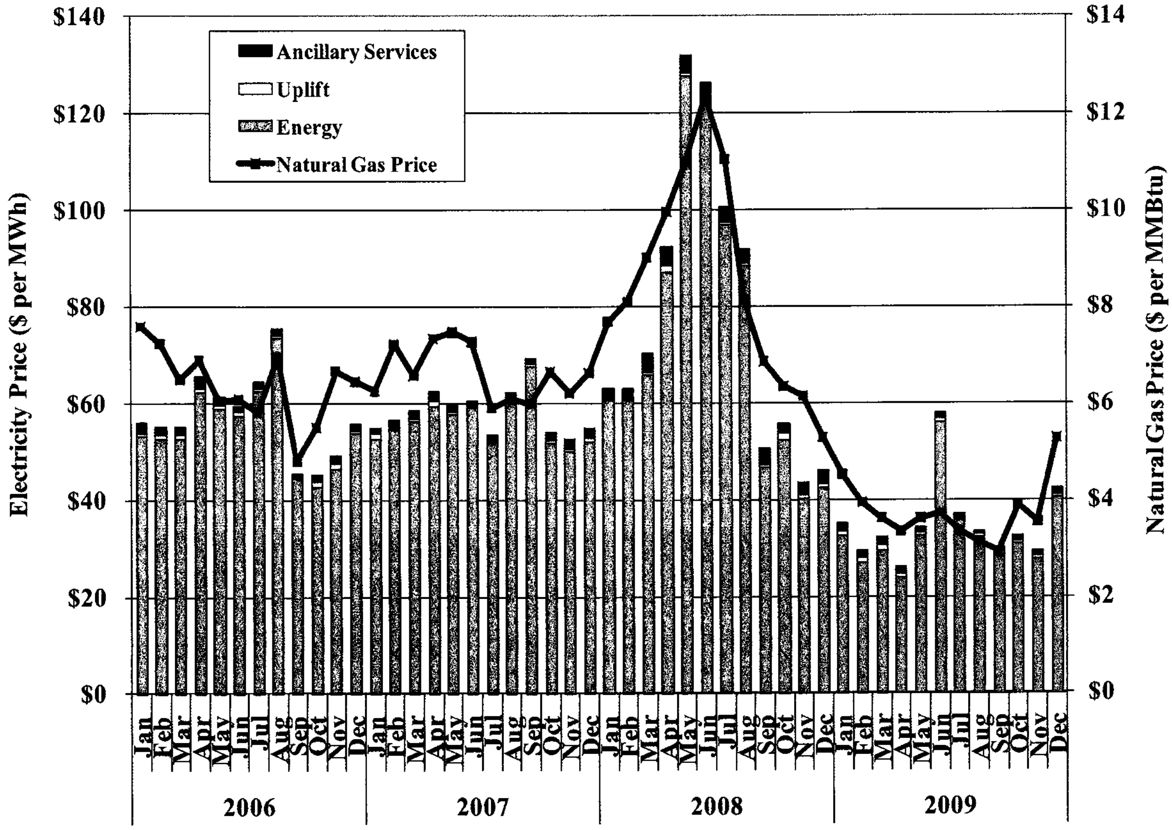


ERCOT average balancing energy market prices were 56 percent lower in 2009 than in 2008, with an ERCOT-wide load weighted average price of $34.03 per MWh in 2009 compared to $77.19 per MWh in 2008. April through August experienced the highest balancing energy market price reductions in 2009, averaging 66 percent lower than the prices in the same months in 2008. With the exception of the West Zone in December, the balancing energy prices were lower in every month in all zones in 2009 than in 2008.

The average natural gas price fell 56 percent in 2009, averaging $3.74 per MMBtu in 2009 compared to $8.50 per MMBtu in 2008. Natural gas prices reached a maximum monthly average of $12.37 per MMBtu in July 2008, and reached a minimum monthly average of $2.93 per MMBtu in September 2009. Hence, the changes in energy prices from 2008 to 2009 were largely a function of natural gas price movements.

The next analysis evaluates the total cost of serving load in the ERCOT wholesale market. In addition to the costs of energy, loads incur costs associated with ancillary services and "uplift".[10] 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 2 shows the monthly average all-in price for all of ERCOT from 2006 to 2009 and the associated natural gas price.

Figure 2: Average All-in Price for Electricity in ERCOT



The components of the all-in price of electricity include:

- Energy costs: Balancing energy market prices are used to estimate energy costs, under the assumption that the price of bilateral energy purchases converges with balancing energy market prices over the long-term, as discussed above.
- Ancillary services costs: These are estimated based on the demand and prices in the ERCOT markets for regulation, responsive reserves, and non-spinning reserves.

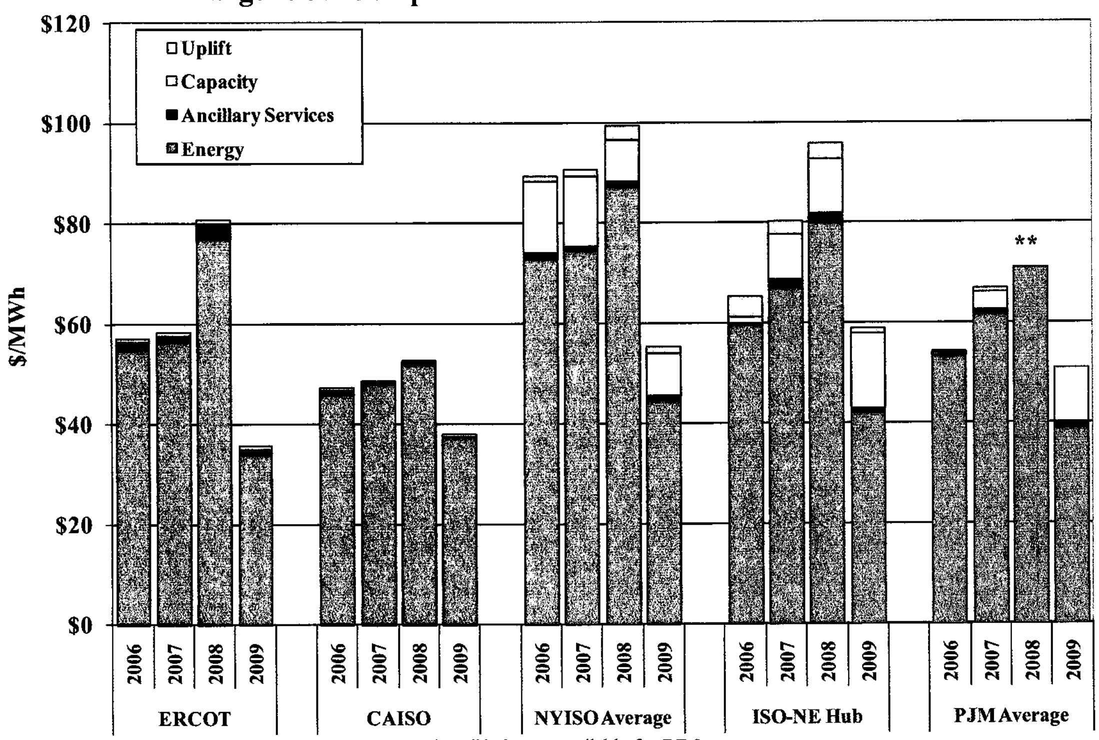
10 As discussed in more detail in Section III, uplift costs are costs that are allocated to load that pay for out-of-merit dispatch, out-of-merit commitment, and Reliability Must Run contracts.

- Uplift costs: Uplift costs are assigned market-wide on a load-ratio share basis to pay for out-of-merit energy dispatch, out-of-merit commitment, replacement reserve services and Reliability Must Run contracts.

Figure 2 indicates that natural gas prices were a primary driver of the trends in electricity prices from 2006 to 2009. 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 the balancing energy market prices.

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

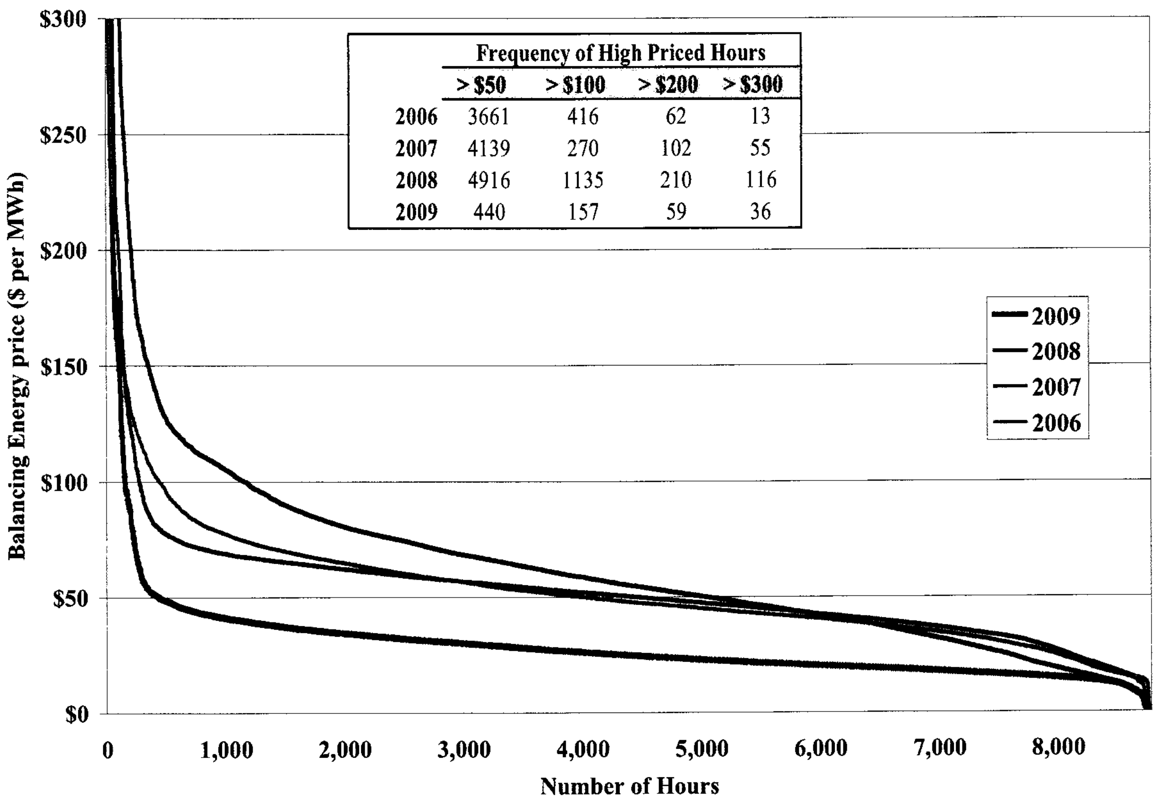


** 2008 Capacity, Ancillary Services and Uplift data unavailable for PJM

Figure 3 shows that energy prices increased in wholesale electricity markets across the U.S. in 2009, primarily due to decreases in fuel costs, and that the ERCOT market experienced the lowest all-in wholesale prices of any of these markets in 2009

Figure 4 presents price duration curves for the ERCOT balancing energy market in each year from 2006 to 2009. 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 hourly load-weighted average prices for the ERCOT balancing energy market.

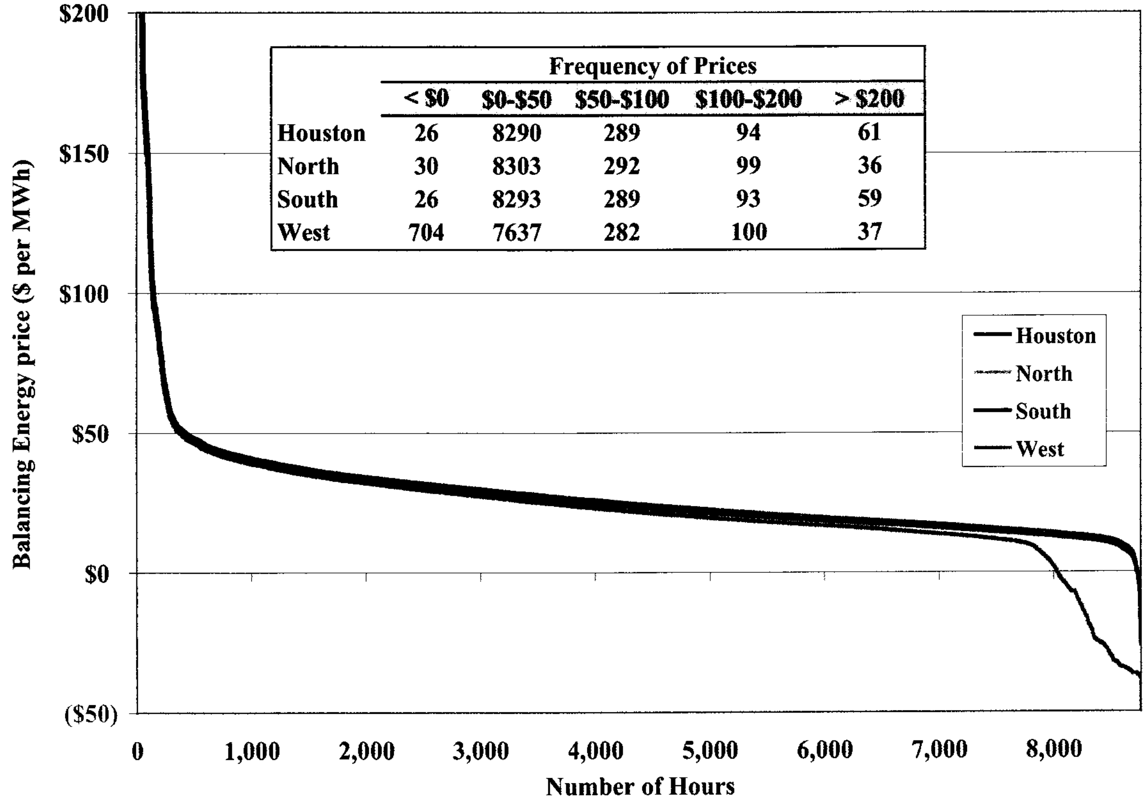
Figure 4: ERCOT Price Duration Curve



	Frequency of High Priced Hours			
	> $50	> $100	> $200	> $300
2006	3661	416	62	13
2007	4139	270	102	55
2008	4916	1135	210	116
2009	440	157	59	36

Balancing energy prices exceeded $50 per MWh in only 440 hours in 2009 compared to more than 4,900 hours in 2008. These year-to-year changes reflect lower natural gas prices in 2009 that affect electricity prices in a broad range of hours.

Figure 5: Zonal Price Duration Curves

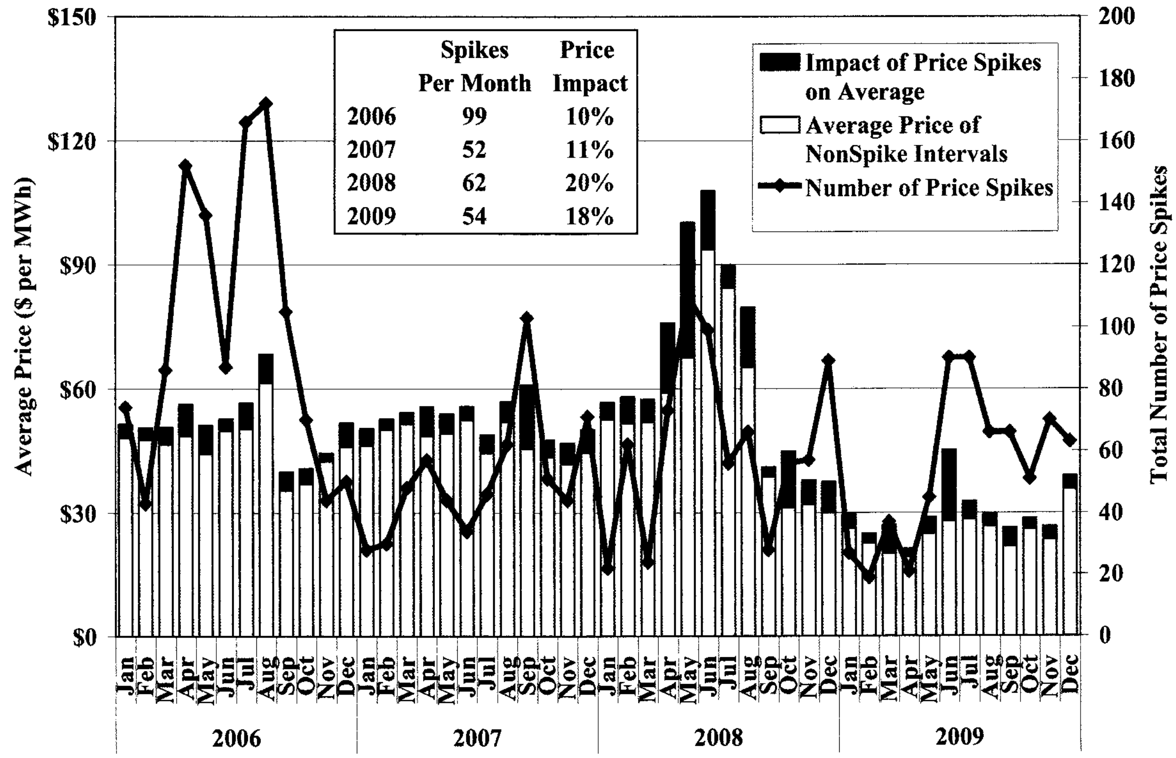


	Frequency of Prices				
	< $0	$0-$50	$50-$100	$100-$200	> $200
Houston	26	8290	289	94	61
North	30	8303	292	99	36
South	26	8293	289	93	59
West	704	7637	282	100	37

Figure 5 shows the hourly average price duration curve for each of the four ERCOT zones in 2009 and that the Houston, North and South Zones had similar prices over the majority of hours in 2009. The price duration curve for the West Zone is generally lower than all other zones, with over 700 hours when the average hourly price was less than zero. These zonal price differences are caused by zonal transmission congestion, as discussed in more detail in Section III.

Other market factors that affect balancing energy prices occur in a subset of intervals, such as the extreme demand conditions that occur during the summer or when there is significant transmission congestion. Figure 4 shows that there were differences in balancing energy market prices between 2006 and 2009 at the highest price levels. For example, 2008 experienced considerably more occasions when prices spiked to greater than $300 per MWh than previous years. To better observe the effect of the highest-priced hours, the following analysis focuses on the frequency of price spikes in the balancing energy market from 2006 to 2009. Figure 6 shows average prices and the number of price spikes in each month of 2006 to 2009. In this case, price spikes are defined as intervals where the load-weighted average Market Clearing Price of Energy ("MCPE") in ERCOT is greater than 18 MMbtu per MWh times the prevailing natural gas price (a level that should exceed the marginal costs of virtually all of the on-line generators in ERCOT).

Figure 6: Average Balancing Energy Prices and Number of Price Spikes



The number of price spike intervals was 62 per month during 2008. The number decreased in 2009 to 54 per month. The highest frequency of price spikes occurred in June and July during 2008, caused by significant transmission congestion that ERCOT was inefficiently attempting to resolve by using zonal congestion management techniques.[11] The high number of price spikes during June 2009 was also the result of zonal congestion management actions, although for reasons different than in 2008, as discussed in Section III. Other months with a higher frequency of price spikes in 2009 – particularly in the months after May 2009 – can be attributed to the more frequent deployment of off-line, quick start gas turbines in the balancing energy market as a result of the implementation of PRR 776 in May 2009, as discussed in Section II. Off-line, quick start gas turbines typically have a marginal cost that is greater than the 18 MMBtu per MWh threshold used in Figure 6.

11 *See* 2008 ERCOT SOM Report, at 81-87.

To measure the impact of these price spikes on average price levels, the figure also shows the 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. The impact grows with the frequency of the price spikes, averaging $4.68, $5.30, $10.71 and $4.67 per MWh during 2006, 2007, 2008 and 2009, respectively. Even though price spikes account for a small portion of the total intervals, they have a significant impact on overall price levels.

Although fuel price fluctuations are the dominant factor driving electricity prices in the ERCOT wholesale market, fuel prices alone do not explain all of the price outcomes. Several other factors provided a meaningful contribution to price outcomes in 2009. These factors include (1) changes in peak demand and average energy consumption levels, as discussed in Section II; (2) changes in the frequency and magnitude of transmission congestion, as discussed in Section III; (3) the increased penetration of wind resources, as discussed in Sections II and III; (4) the effectiveness of the scarcity pricing mechanism, as discussed in Section II; and (5) the competitive performance of the wholesale market, as discussed in Section IV. Analyses in the next subsection adjust for natural gas price fluctuations to better highlight variations in electricity prices not related to fuel costs.

2. Balancing Energy Prices Adjusted for Fuel Price Changes

The pricing patterns shown in the prior subsection are driven to a large extent by changes in fuel prices, natural gas prices in particular. However, prices are influenced by a number of other factors as well. To clearly identify changes in electricity prices that are not driven by changes in natural gas prices, Figure 7 and Figure 8 show balancing energy prices adjusted to remove the effect of natural gas price fluctuations. The first chart shows a duration curve where the balancing energy price is replaced by the marginal heat rate that would be implied if natural gas were always on the margin. The *Implied Marginal Heat Rate* equals the *Balancing Energy Price* divided by the *Natural Gas Price*.[12] 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 2006 to 2009.

12 This methodology implicitly assumes that electricity prices move in direct proportion to changes in natural gas prices.

In contrast to Figure 4, Figure 7 shows that the implied marginal heat rates were relatively consistent across the majority of hours from 2006 to 2009. The drop in energy prices from 2008 to 2009 is much less dramatic when the effect of fuel price changes is removed, which confirms that the increase in prices in most hours is primarily due to the rise in natural gas prices. However, the price differences that were apparent from Figure 4 in the highest-priced hours persist even after the adjustment for natural gas prices. For example, the number of hours when the implied heat rate was greater than 30 MMBtu per MWh was 73, 103, 145 and 146 in 2006, 2007, 2008 and 2009, respectively. This indicates that there are price differences that are due to factors other than changes in natural gas prices. The increase in the number of hours when the implied heat rate was greater than 30 MMBtu per MWh in 2008 compared to 2006 and 2007 is primarily attributable to chronic and severe congestion on the North to Houston and North to South constraints in April through June 2008. In contrast, although a portion of the 146 hours with an implied heat rate greater than 30 MMBtu per MWh in 2009 is associated with significant congestion on the North to South constraint in late June 2009, many of these hours in 2009 are associated with the implementation of PRR 776 that increased the frequency of the deployment of off-line, quick start gas turbines in the balancing energy market, as discussed in Section II. Figure 8 shows the implied marginal heat rates for the top five percent of hours in 2006 through 2009 and highlights the increase in the number of with an implied marginal heat rate greater than 30 MMBtu per MWh in 2008 and 2009 compared to 2006 and 2007.