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2007 STATE OF THE MARKET REPORT
FOR THE
ERCOT WHOLESALE ELECTRICITY MARKETS

POTOMAC ECONOMICS, LTD.

Independent Market Monitor for the
ERCOT Wholesale Market

August 2008

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EXECUTIVE SUMMARY

This report reviews and evaluates the outcomes of the ERCOT wholesale electricity markets in 2007. It includes assessments of the incentives provided by the current market rules and procedures, and analyses of the conduct of market participants. We find improvements in a number of areas over the results in prior years that can be attributed to changes in the market rules or operation of the markets. Our analysis also indicates that the market performed competitively in 2007. However, the report generally confirms prior findings that the current market rules and procedures are resulting in systematic inefficiencies. This report also assesses the effectiveness of the scarcity pricing mechanism pursuant to the provisions of Public Utility Commission of Texas ("PUCT") Substantive Rule 25.505(g).

Many of these findings can be found in five previous reports we have issued regarding the ERCOT electricity markets.[1] These reports included a number of recommendations designed to improve the performance of the current ERCOT markets. Many of these recommendations were considered by ERCOT working groups and some were embodied in protocol revision requests ("PRRs"). Most of the remaining recommendations will be addressed by the introduction of a nodal market design.

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, most transmission congestion is resolved through non-transparent, non-market-based procedures.

Under the nodal market, unit-specific dispatch will allow ERCOT to more fully utilize the generating resources than the current market, which frequently exhibits shortage prices when the generating capacity is not fully utilized. Finally, the nodal market will produce price signals that

[1] "ERCOT State of the Market Report 2003", Potomac Economics, August 2004 (hereafter "2003 SOM Report"); "2004 Assessment of the Operation of the ERCOT Wholesale Electricity Markets", Potomac Economics, November 2004 (hereafter "Assessment of Operations"); "ERCOT State of the Market Report 2004", Potomac Economics, July 2005 (hereafter "2004 SOM Report"); "ERCOT State of the Market Report 2005", Potomac Economics, July 2006 (hereafter "2005 SOM Report"); and "ERCOT State of the Market Report 2006", Potomac Economics, August 2007 (hereafter "2006 SOM Report").

provide incentives to build new generation where it is most needed for managing congestion and maintaining reliability. In the long-term, these enhancements to overall market efficiency should translate into substantial savings for consumers.

A. Review of Market Outcomes

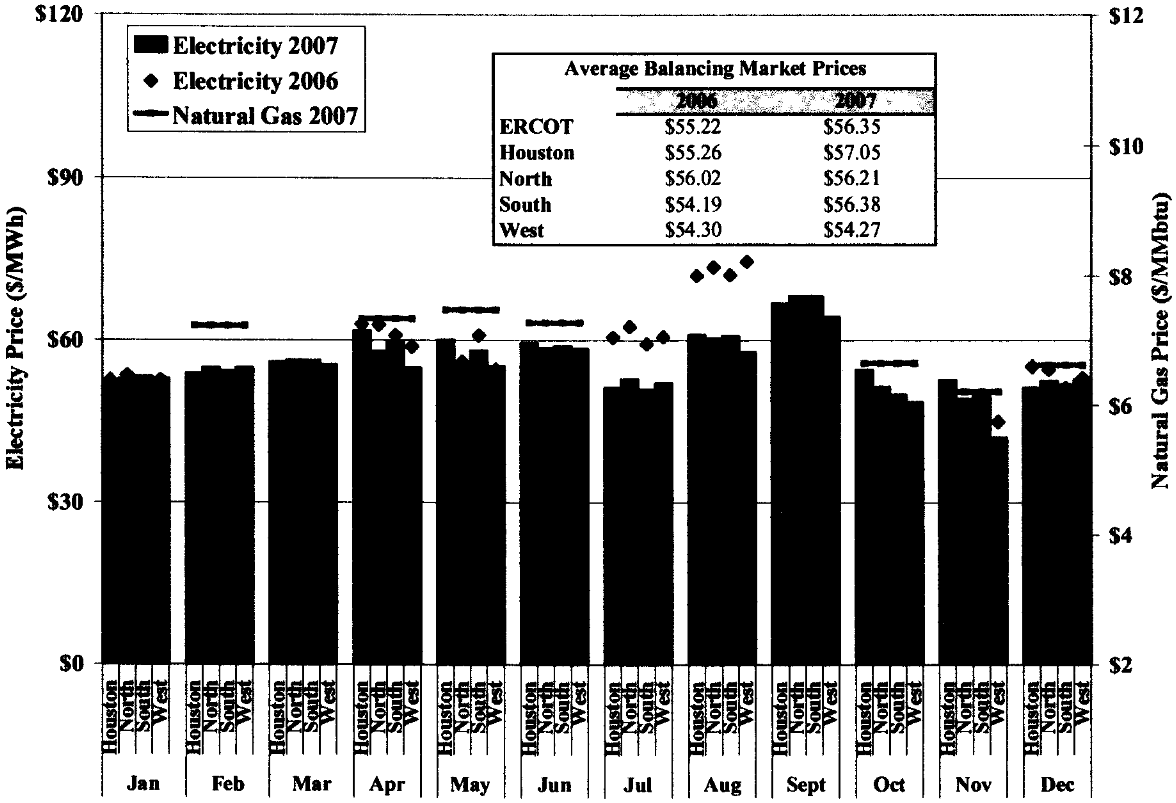
1. Balancing Energy Prices

The balancing energy market allows participants to make real-time purchases and sales of energy in addition to their forward schedules. While on average only a 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) manage interzonal congestion, and b) 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.

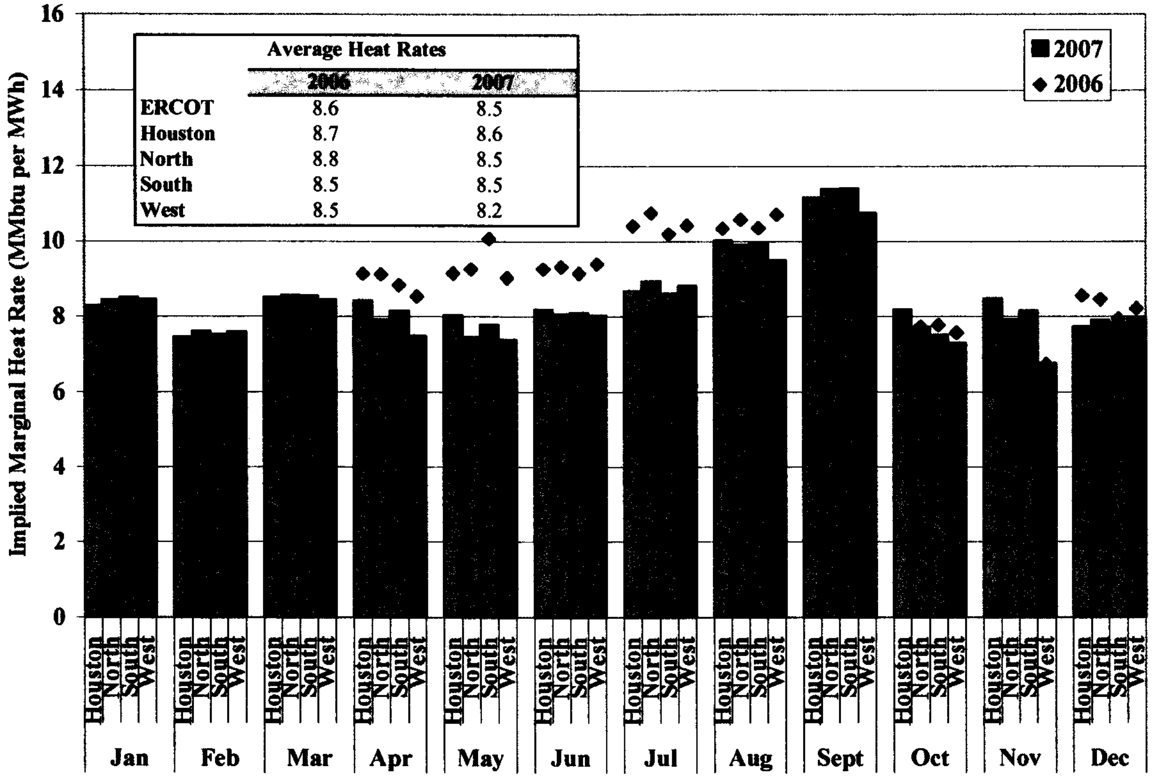
As shown in the following figure, balancing energy market prices were 2 percent higher in 2007 than in 2006, with September 2007 showing the largest increase from the same month in 2006. The average natural gas price in 2007 increased 4 percent over 2006 levels, with monthly changes ranging from a 25 percent increase in September ($4.81/MMBtu in September 2006 and $5.99/MMBtu in September 2007) to an 18 percent decrease in Janauary ($7.59/MMBtu in January 2006 and $6.26/MMBtu in January 2007). Natural gas is typically the marginal fuel in the ERCOT market. Hence, the movements in wholesale energy prices from 2006 to 2007 were largely a function of natural gas price levels.

Balancing Energy Market Prices
2006 & 2007



Although natural gas price fluctuations are the dominant factor driving electricity prices in the ERCOT wholesale market, fuel prices alone do not explain all of the price changes. At least three other factors contributed to price changes in 2007. First, as discussed in Section III of this report, ERCOT peak demand and installed capacity were relatively flat in 2007, and energy production increased only slightly in 2007 compared to 2006. In contrast to prior years with increasing demand and decreasing supply, the static supply and demand characteristics from 2006 to 2007 contributed to comparable wholesale pricing outcomes over the course of these two years. Second, the balancing energy offer cap was raised to $1,500 on March 1, 2007, whereas the offer cap was $1,000 in 2006. The increased offer caps are intended to produce higher prices during shortage conditions. However, as discussed in Section I, this mechanism was not always effective in achieving this intended outcome. Finally, the overall competitive performance of the market exhibited continued improvement in 2007, which will tend to lower prices and is examined in detail in Section V. 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.

Monthly Average Implied Marginal Heat Rate
2006 & 2007



Adjusted for gas price influence, the above figure shows that average implied heat rate for all hours of the year decreased by 1.2 percent from 8.6 in 2006 to 8.5 in 2007.[2] On average, the implied heat rate was lower in 2007 than in 2006 for the months of April through August. With the exception of December, the average implied heat rate for the remaining months was higher in 2007 than in 2006. The decreases in implied heat rates during the summer of 2007 relative to 2006 are explained in part due to significantly above average rainfall levels 2007. The higher implied heat rates in September 2007 were due to several days in which non-spinning reserves were deployed and balancing market clearing prices were corrected to significantly higer levels pursuant to the provisions of the ERCOT Protocols.[3]

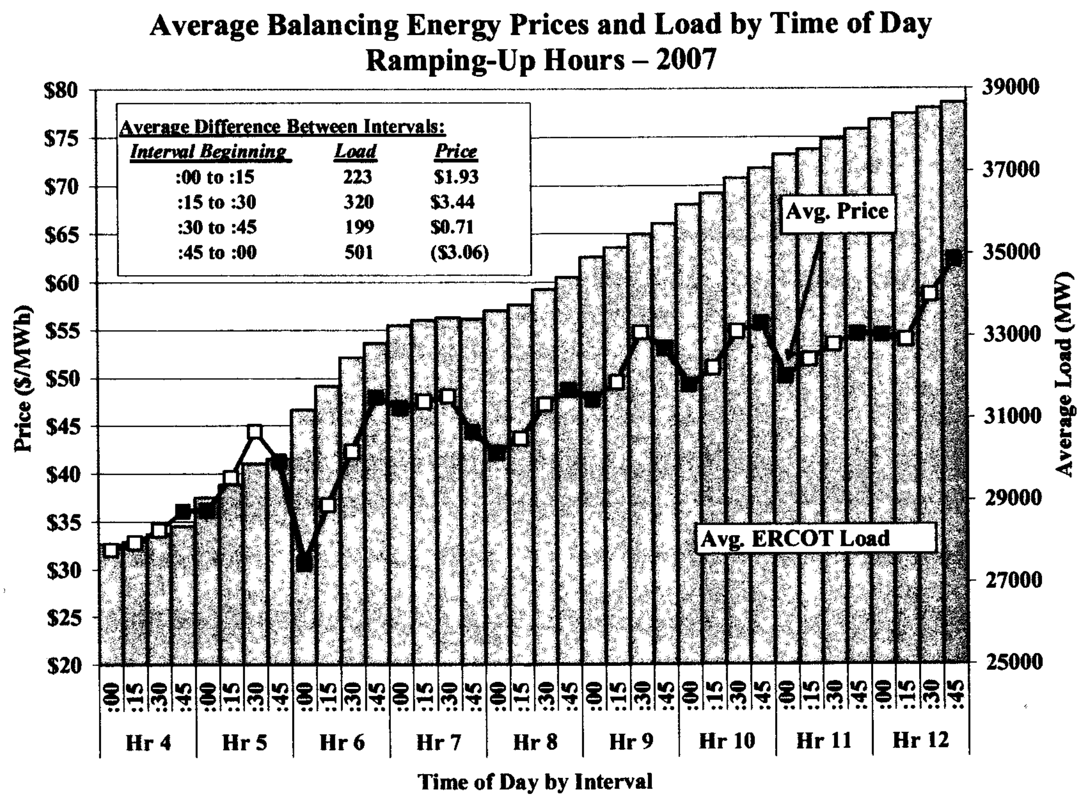
2 The *Implied Marginal Heat Rate* equals the *Balancing Energy Market Price* divided by the *Natural Gas Price.*

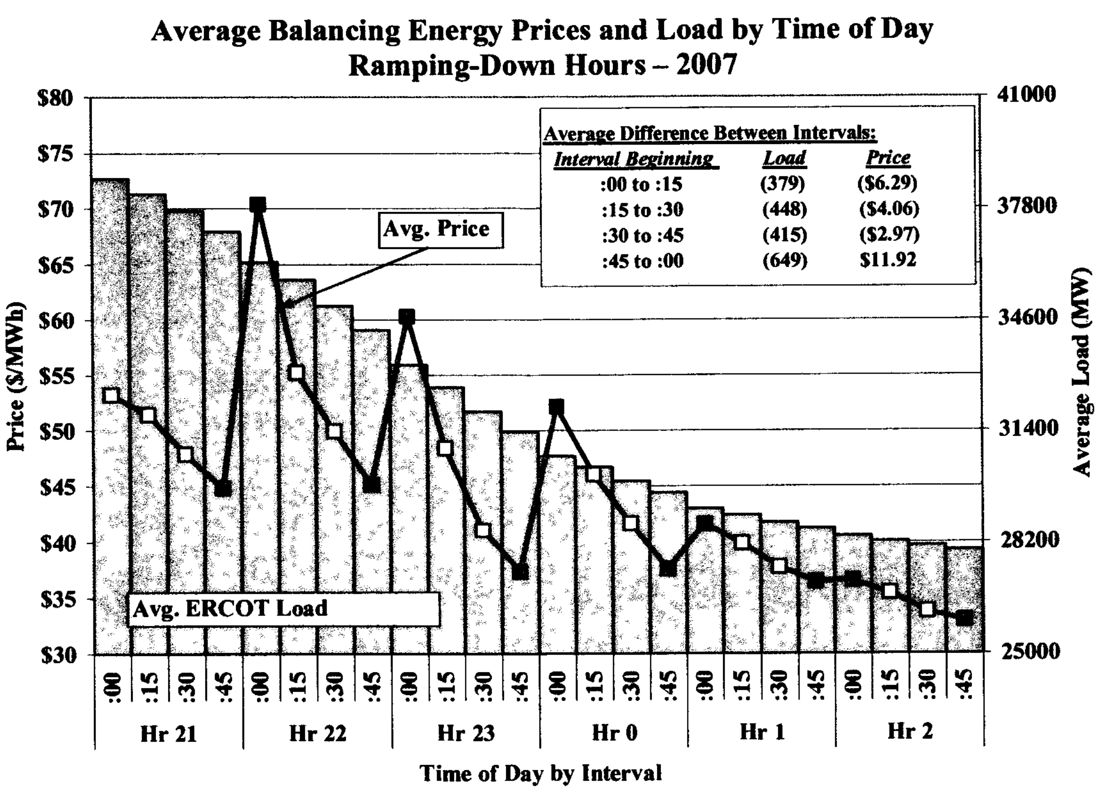
3 The price correction provisions were adopted in Protocol Revision Request No. 650. The appropriateness

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. Forward prices were relatively consistent with balancing energy prices on the vast majority of days in 2007, although the introduction of the nodal market that includes an integrated day-ahead market should improve the convergence between day-ahead and real-time energy prices.

As discussed in prior reports, we continue to observe in 2007 a clear relationship between the net balancing energy deployments and the balancing energy prices. This is not expected in a well-functioning market. This relationship is partly due to the hourly scheduling patterns of most of the market participants. The energy schedules change by large amounts at the top of each hour while load increases and decreases smoothly over time. This creates extraordinary demands on the balancing energy market and erratic balancing energy prices, particularly in the morning when loads are increasing rapidly and in the evening when loads are decreasing rapidly.

of these price correction provisions was addressed in the 2006 SOM Report (2006 SOM Report, at 41-42).


Average Balancing Energy Prices and Load by Time of Day
Ramping-Up Hours – 2007
Average Difference Between Intervals:
Interval Beginning Load Price
:00 to :15 223 $1.93
:15 to :30 320 $3.44
:30 to :45 199 $0.71
:45 to :00 501 ($3.06)
Avg. Price
Avg. ERCOT Load
Price ($/MWh)
Average Load (MW)
$80
$75
$70
$65
$60
$55
$50
$45
$40
$35
$30
$25
$20
39000
37000
35000
33000
31000
29000
27000
25000
:00
:15
:30
:45
Hr 4
Hr 5
Hr 6
Hr 7
Hr 8
Hr 9
Hr 10
Hr 11
Hr 12
Time of Day by Interval

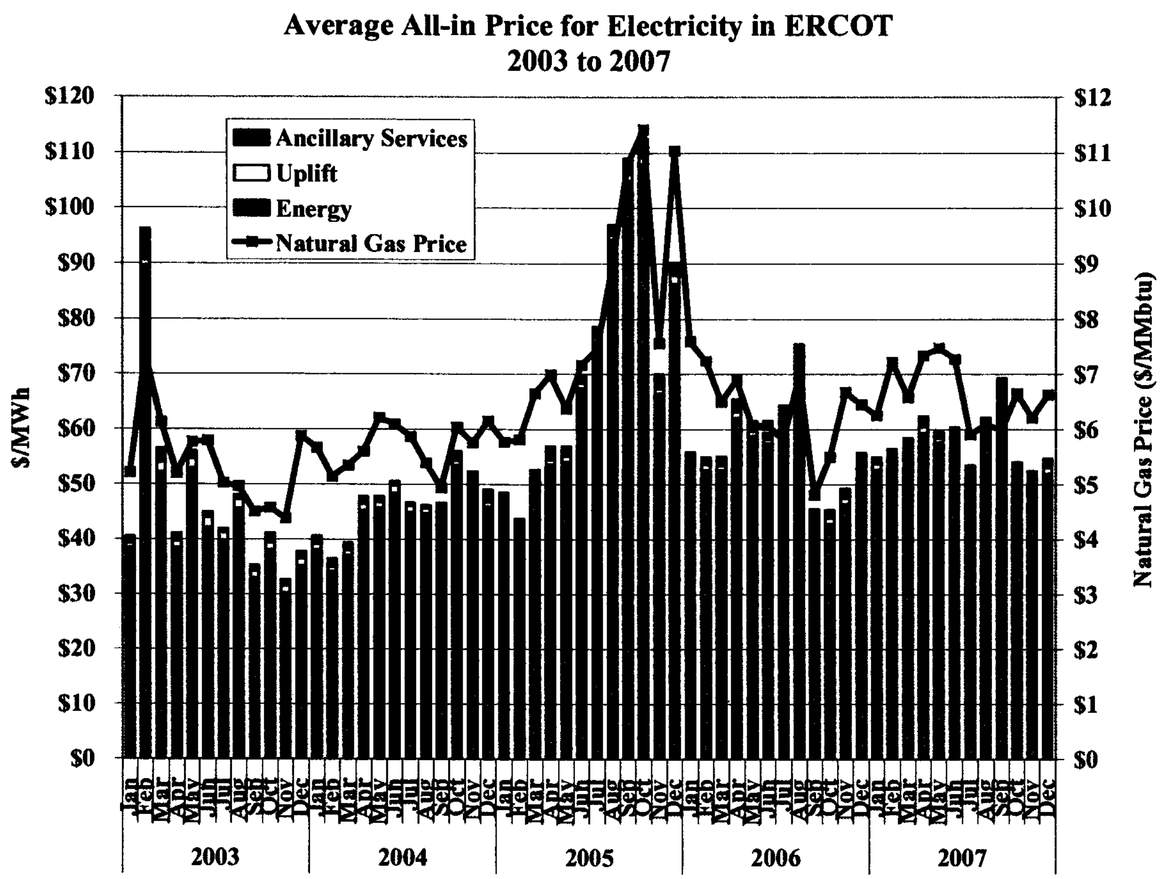

Average Balancing Energy Prices and Load by Time of Day
Ramping-Down Hours – 2007
Average Difference Between Intervals:
Interval Beginning Load Price
:00 to :15 (379) ($6.29)
:15 to :30 (448) ($4.06)
:30 to :45 (415) ($2.97)
:45 to :00 (649) $11.92
Avg. Price
Avg. ERCOT Load
Price ($/MWh)
Average Load (MW)
$80
$75
$70
$65
$60
$55
$50
$45
$40
$35
$30
41000
37800
34600
31400
28200
25000
:00
:15
:30
:45
Hr 21
Hr 22
Hr 23
Hr 0
Hr 1
Hr 2
Time of Day by Interval

The previous two figures summarize these erratic price patterns by showing the balancing energy prices and actual load in each 15-minute interval during the morning "ramping-up" hours and evening "ramping-down" hours. These pricing patterns raise significant efficiency concerns regarding the operation of the balancing energy market. Moreover, this pattern has been consistently observed for several years and is likely to continue until changes are made to the market rules.[4] In prior reports, we have made several recommendations to address the issue under the current zonal design, although most have not been implemented because of the effort to timely implement the nodal market. The nodal market will provide for a comprehensive solution to the operational issues described in this and prior reports.

2. All-In Electricity Prices

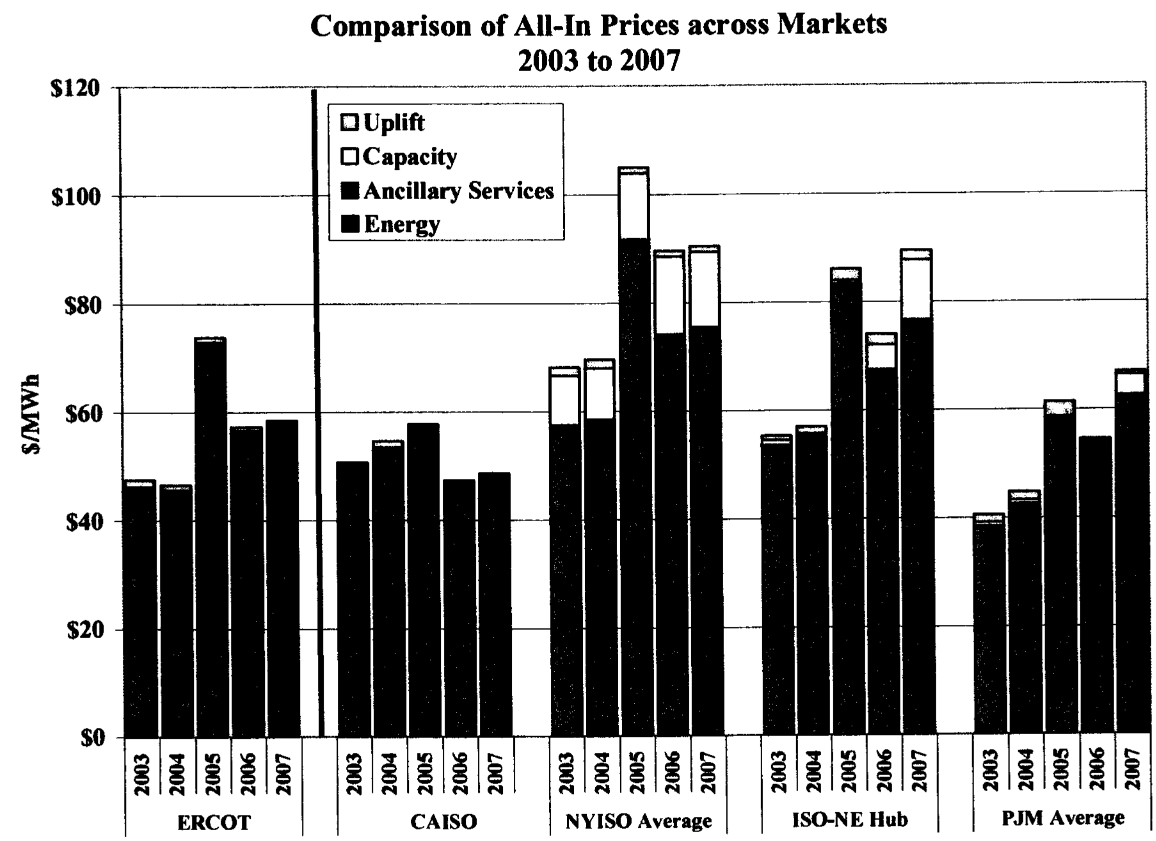
In addition to the costs of energy, loads incur costs associated with operating reserves, regulation, and uplift. The uplift costs include payments for out-of-merit capacity ("OOMC"), Replacement Reserve ("RPRS") out-of-merit energy ("OOME"), and reliability must run agreements ("RMR"), but excluding administrative charges such as the ERCOT fee. These costs, regardless of the location of the congestion, are borne equally by all loads within ERCOT. We calculated an average all-in price of electricity that includes balancing energy costs, ancillary services costs, and uplift costs. The monthly average all-in energy prices for the past four years are shown in the figure below along with a natural gas price trend.

4 See 2003 SOM Report, Assessment of Operations, 2004 SOM Report, 2005 SOM Report and 2006 SOM Report.



The figure indicates that natural gas prices were the primary driver of the trends in electricity prices from 2003 to 2007. Natural gas prices increased in 2005 by an average of more than 41 percent from 2004 levels while the all-in price for electricity increased by 63 percent. In 2006, the natural gas price dropped by an average of 20 percent from 2005 levels and the all-in price for electricity decreased by 23 percent. In 2007, the natural gas price increase by an average of 4 percent from 2006 levels and the all-in price for electricity increased by 0.5 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 four organized electricity markets in the U.S.: (a) California ISO, (b) New York ISO, (c) ISO New England, and (d) 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.



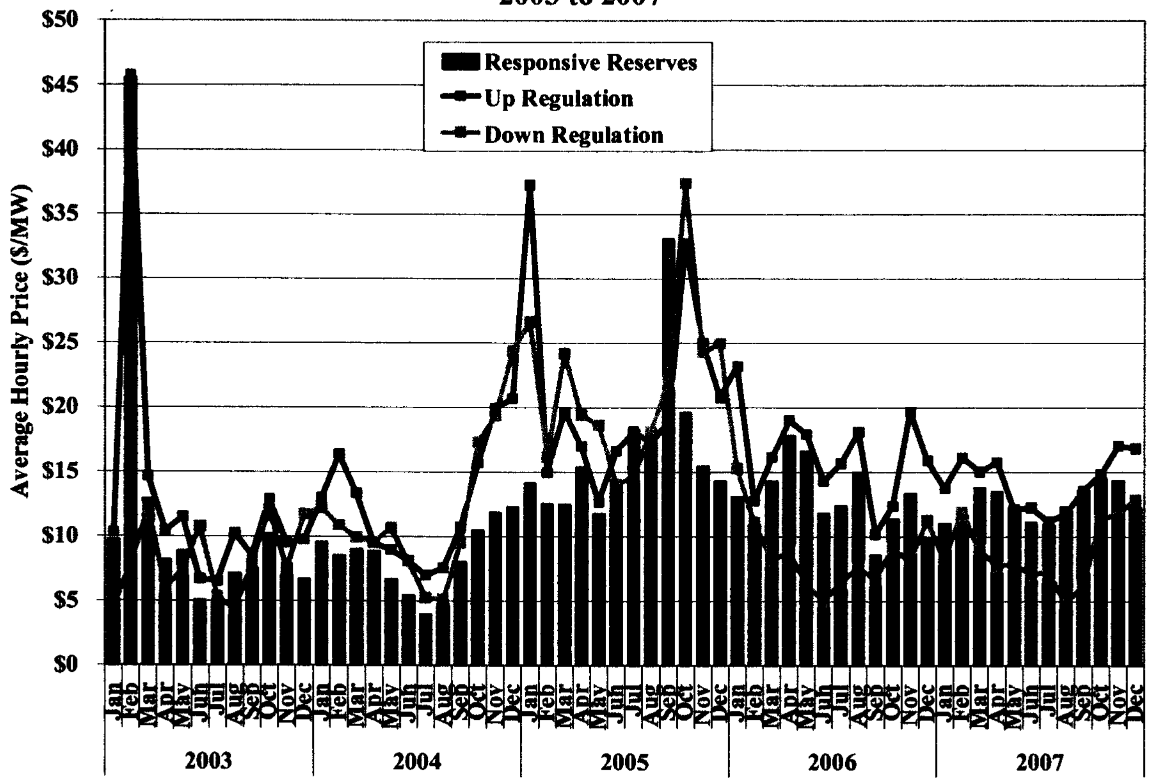
Wholesale electricity markets in the U.S. experienced substantial increases in energy prices from 2002 to 2003 and from 2004 to 2005 due to increased fuel costs. In 2006, energy prices in the U.S. dropped in every region due to decreased fuel costs. In 2007, the all-in prices increased in all the above five regions, with relatively small increases in ERCOT, California and New York, and more significant increases in New England and PJM.

3. Ancillary Services Markets

The primary ancillary services are up regulation, down regulation, and responsive reserves. ERCOT may also procure non-spinning reserves as needed. 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 2007.

Ancillary services prices were comparable in 2006 and 2007, with both years showing modest increases over the levels prevailing in 2003. This is consistent with long-term trends in natural gas and electricity prices, and significantly below the price levels experienced in 2005. Because ancillary services markets are conducted prior to the balancing energy market, participants must include their expected costs of foregone sales in the balancing energy market in their offers for responsive reserves and regulation. Providers of responsive reserves and regulation can incur opportunity costs when they reduce the output from economic units to make the capability available to provide these services. The following figure shows the monthly average prices for regulation and responsive reserve services from 2003 to 2006.

Monthly Average Ancillary Service Prices 2003 to 2007



Although ancillary services prices have generally risen over the last several years, the impact has been partly mitigated by reductions in the required quantities of regulation. In 2002, ERCOT required approximately 3,000 MW of combined up and down regulation. By 2007, the requirement was reduced to an average of 1,800 MW during ramping hours and 1,420 MW during non-ramping hours. This has *directly* reduced regulation costs by reducing the overall quantity scheduled, either through bilateral arrangements or through the day-ahead auction. This has also *indirectly* reduced regulation costs by reducing the clearing prices of regulation that would have prevailed under higher demand levels for regulation. The reduction in average regulation quantities in 2007 is at least partly explained by ERCOT's change in its regulation procurement practices that was implemented in mid-2007. This change allows for a different quantity of regulation to be procured in each hour of each day during a month based upon analysis of historical deployment data, rather than the procurement of fixed quantities over 4 to 5 blocks of hours in each day. The result of this change has been a relative decrease in regulation quantities procured in many hours of each day, with an increase in some hours when regulation demand is the highest. Overall change in the procurement methodology has contributed to a reduction in the average quantities of regulation procured in 2007.

In this report, we compare the amounts of capacity scheduled to provide operating reserves to the quantities of capacity that are actually available in real time. In general, we find that the capacity available to provide reserves in real time far exceeds the quantities scheduled to meet the operating reserves requirements. This highlights issues relating to the efficiency of the ERCOT markets, which are expected to improve with the implementation of the nodal market.

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 it is 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.

4. Net Revenue Analysis

The next analysis of the outcomes in the ERCOT markets in 2007 is the analysis of "net revenue". 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 2005 to 2007 for four types of units: a natural gas combined-cycle generator, a simple-cycle gas turbine, a coal-fired steam turbine with scrubbers, and a nuclear unit. Net revenue was insufficient to support new entry for gas-fired units in 2007, although the net revenue for gas-fired units in 2007 remained significantly higher than years prior to 2005. As in 2005 and 2006, net revenue for coal and nuclear units remained above the levels required to support new entry. The net revenue outcomes in the ERCOT markets in 2007 were primarily affected by the following factors:

- Although continuing to decline relative to prior years, planning reserve margins in 2007 were approximately 14.6 percent, which remains above the minimum requirement of 12.5 percent. Excess capacity lowers net revenue by reducing prices whereas relatively low reserve margins can cause net revenue levels to substantially exceed the annualized cost of a new unit.
- Natural gas prices were relatively flat in 2007 compared to 2006, but remained at levels significantly higher than the years prior to 2005. Thus, net revenue for coal and nuclear units continued to be at levels sufficient to support new entry.
- The effectiveness of the Scarcity Pricing Mechanism was challenged by several operational factors, which are discussed in more detail in Section I.D.
- The competitive performance of the ERCOT market continued to improve in 2007.

In a market with efficient pricing, spot price signals should indicate when and where new generation investment is needed and when existing generation should be retired. Under the nodal market design, it will be important to ensure that the market sends efficient signals for new investment and retirement. This is primarily accomplished in one of two ways:

- A capacity market; and/or
- Shortage pricing provisions to ensure that prices rise appropriately in the energy and ancillary services markets to reflect the true costs of shortages when resources are insufficient to satisfy both the energy and ancillary services requirements.

The PUCT adopted rules in 2006 that define the parameters of an energy-only market. These rules include a Scarcity Pricing Mechanism ("SPM") that provides for a gradual increase in the system-wide offer cap 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, the Modified Competitive Solution Method – a mechanism that, per PUCT rules, required *ex post* reductions to the clearing price when all available energy was exhausted – was eliminated by the new rules.

5. Effectiveness of the Scarcity Pricing Mechanism in 2007

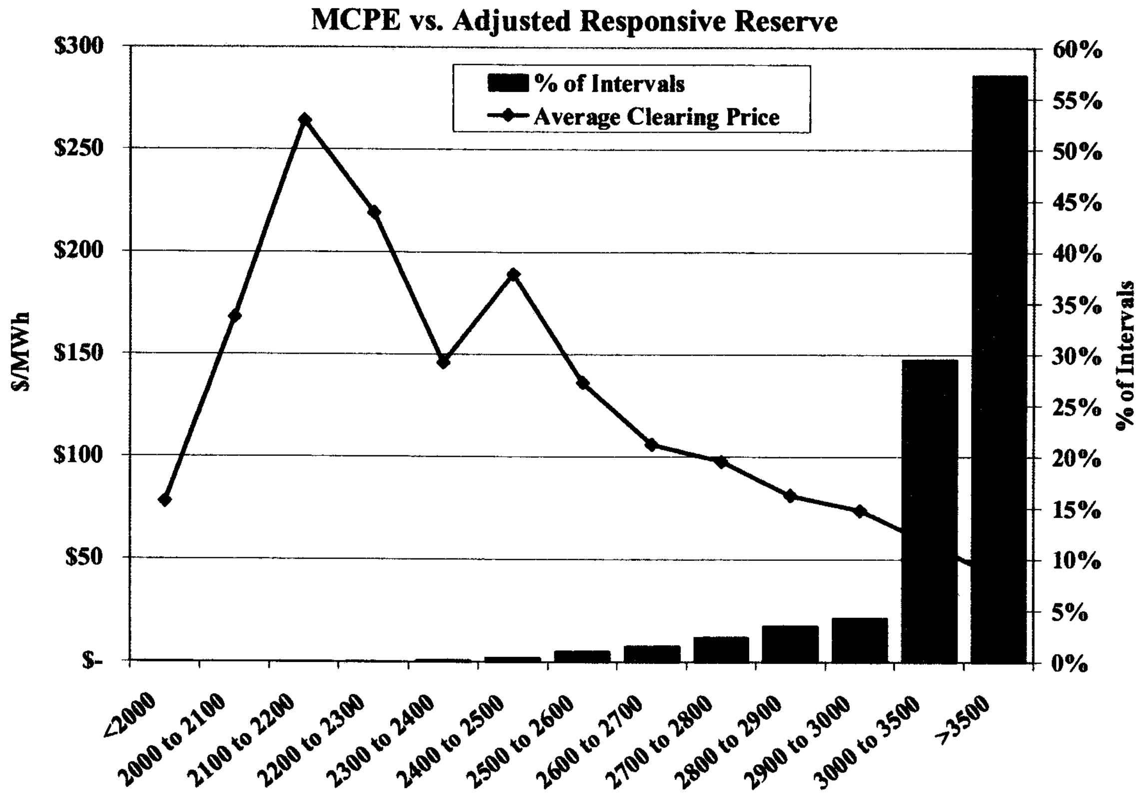
Unlike markets with a long-term capacity market where fixed capacity payments are made to resources across the entire year regardless of the relationship of supply and demand, the objective of the energy-only market design is to allow prices to rise significantly higher during legitimate shortage conditions (*i.e.*, when the supply of resources 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.

The Scarcity Pricing Mechanism ("SPM") includes a provision termed the Peaker Net Margin ("PNM") that is designed to measure the annual net revenue of a hypothetical peaking unit. Under the rule, if the PNM for a year reaches a cumulative total of $175,000 per MW, the system-wide offer cap is then reduced to the higher of $500 per MWh or 50 times the daily gas price index. Consistent with the results of the net revenue analysis, the PNM reached the level sufficient for new entry in only one of the last five years (2005).

There were several factors that challenged the effectiveness of the SPM in 2007, including:

- Frequent out-of-merit ("OOM") deployments by ERCOT during declared short-supply conditions;
- The dependence on market participants to submit offers at or near the offer cap to produce scarcity level prices during legitimate shortage conditions; and
- A strong positive bias in ERCOT's day-ahead load forecast that tended to regularly commit online resources in excess of the quantity required to meet expected demand and operating reserve requirements.

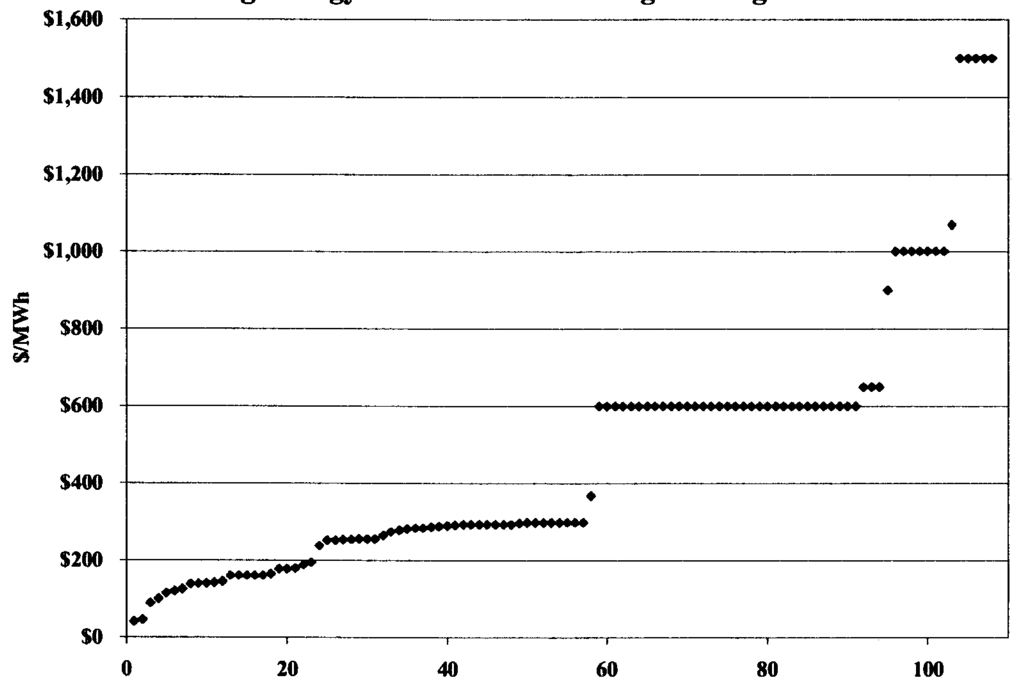
The following figure illustrates the relationship between the balancing energy price and the amount of adjusted responsive reserve ("ARR"), which is a measure of the market operating reserve margin or shortage condition. ERCOT begins taking short-supply actions when ARR decreases below 2,500 MW, and declares an alert when ARR decreases below 2,300 MW. As ARR decreases to toward these levels and below, a gradual and ultimately very sharp increase in price should result if the scarcity pricing mechanism is effective. However, as can be seen from the following figure, frequent OOM deployments had the effect of depressing the price under these shortage conditions.



As shown in the figure above, the average price rose in 2007 as ARR dropped from 3,500 to 2,500 MW. However, once ARR reached 2,500 MW, the average price dropped, which can be attributed to the initial OOM actions taken by ERCOT when ARR reaches 2,500. Prices resumed their increase for ARR levels between 2,100 and 2,400 MW, but dropped significantly at ARR levels less than 2,100 MW. Although only approximately 0.6 percent of the hours in the year (about 50 hours) experienced ARR less than 2,500 MW, it is critical to the success of the energy-only market design and the achievement of long-term resource adequacy objectives that prices be set efficiently during these relatively infrequent shortage and near-shortage conditions.

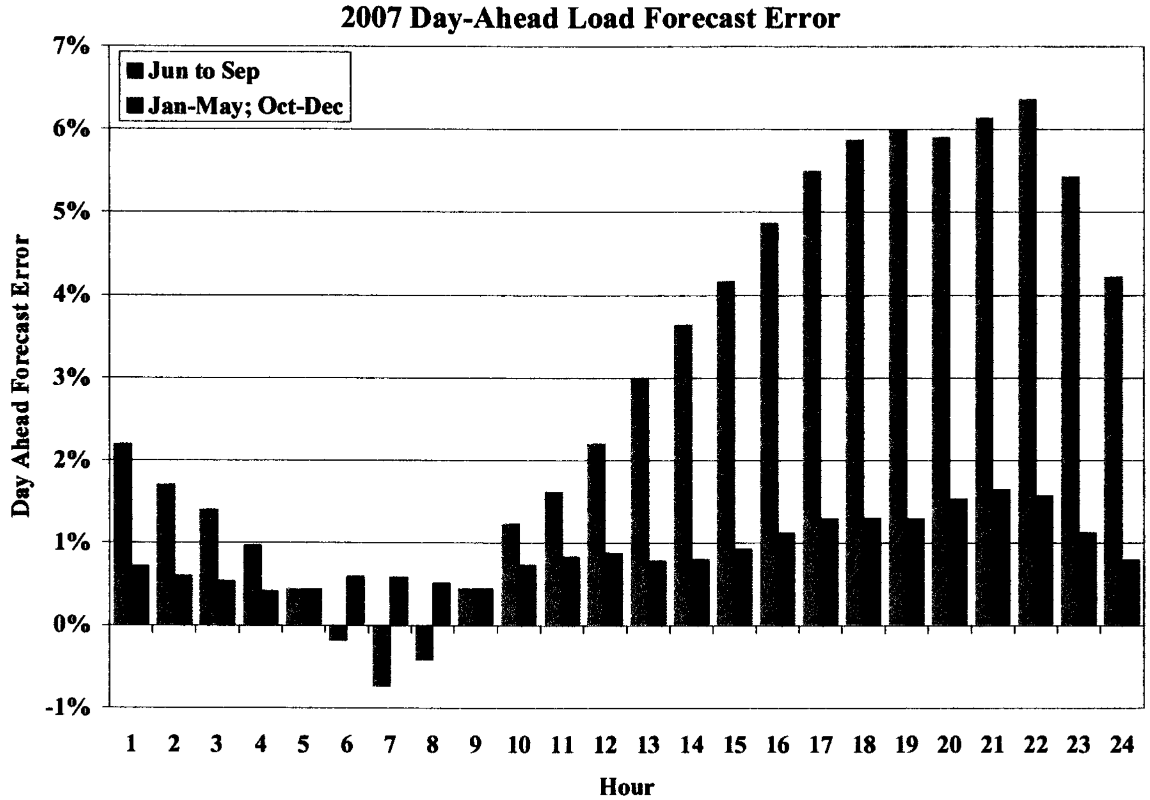
Under the PUCT rules governing the energy-only market, the mechanism that allows for such pricing during shortage conditions relies upon the submission of high-priced offers by smaller market participants. The following figure shows the balancing market clearing prices during the 108 15-minute intervals in 2007 when all available balancing energy was exhausted.

Balancing Energy Market Prices During Shortage Intervals



As shown in the above figure, the prices during these 108 shortage intervals in 2007 ranged from $40 per MWh to the offer cap of $1,500 per MWh. Also evident from the data in this figure are distinct offer thresholds at about $300 per MWh and at $600 per MWh. Hence, although each of these data points represents identical system conditions in which all available balancing energy was exhausted, the pricing outcomes are widely varied, indicating that relying upon the submission of high priced offers by some market participants to produce scarcity prices during shortage conditions was rather unreliable during 2007.

Along with the factors above, the existence of a strong and persistent positive bias in the day-ahead load forecast in 2007 has the effect of producing an inefficient over-commitment of resources and depressing real-time prices relative to a more optimal unit commitment. The following figure shows the ERCOT day-ahead load forecast error by hour in 2007, with the summer and non-summer months presented separately.



Because of the inefficiencies associated with a persistently high day-ahead load forecast, we recommend that ERCOT review the causes of the positive bias in its day-ahead load forecast, and explore potential changes to its reserve procurement policies and its day-ahead and supplemental unit commitment procedures.

B. Balancing Energy Offers and Schedules

QSEs play an important role in the current ERCOT markets. QSEs must submit balanced schedules so that the quantity of generation scheduled matches the quantity of load scheduled prior to real-time. However, there is no requirement for the scheduled load to match the forecast of real-time load. When actual real-time load exceeds the energy scheduled prior to real-time, the remaining load is served by energy purchased in the balancing energy market. Conversely, when scheduled energy exceeds actual real-time load, load serving entities sell their excess to the balancing energy market. QSEs submit balancing energy offers to increase or decrease their energy output from the scheduled energy level. The balancing-up offers correspond to the unscheduled output from the QSEs' online and quick-start resources.

In addition to the forward schedules and offers, QSEs submit resource plans that provide a non-binding indication of the generating resources that the QSE will have online and producing energy to satisfy its energy schedule and ancillary services obligations. The report evaluates the effects on the balancing energy market of the QSEs' schedules, offers, and resource plans.

1. Hourly Schedule Changes

One of the most significant issues affecting the ERCOT balancing energy market is the changes in energy schedules that occur from hour to hour, particularly in hours when loads are changing rapidly (*i.e.*, "ramping") in the morning and evening. The report shows that:

- In these ramping hours, the loads are generally moving approximately 300 to 500 MW each 15-minute interval.
- Although QSE's can modify their schedules each interval, most only change their schedules hourly, resulting in schedule changes averaging 1,000 to 4,000 MW in these hours (and sometimes significantly larger).
- The inconsistency between the changes in schedules and actual load in these hours places an enormous burden on the balancing energy market, resulting in the erratic pricing patterns shown above.

Several changes have been recommended in prior reports to address this issue, most of which will not be implemented because of the transition to the nodal market. The issues that these recommendations were designed to address should be resolved by the implementation of unit-specific dispatch under the nodal market design.

2. Portfolio Offers in the Balancing Energy Market

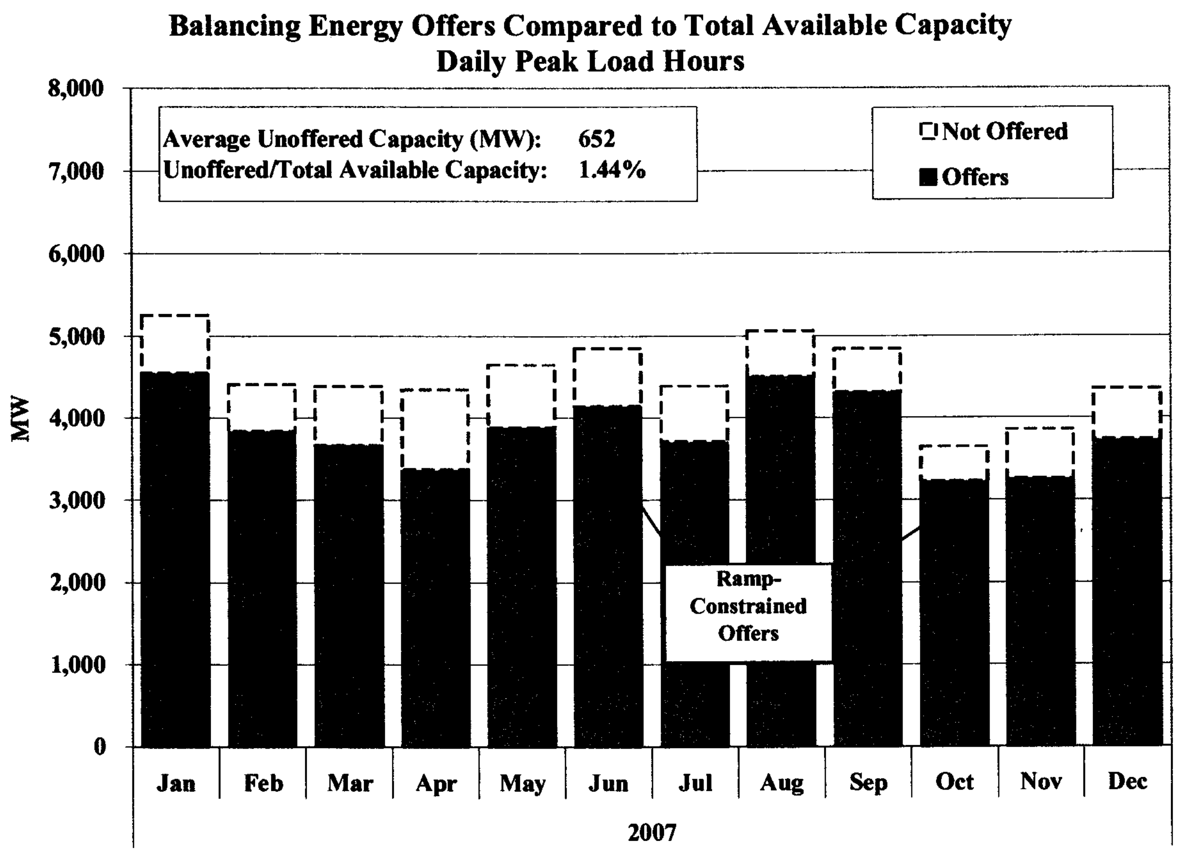
The report evaluates the portfolio offers submitted by QSEs in the balancing energy market, including both the quantity and ramp rate of the offers (the amount of the offer that can be deployed in any single 15-minute interval).

The volatility of the balancing energy prices in each interval is primarily related to the balancing energy deployments. However, this volatility can be exacerbated when the portfolio ramp rates are binding. Portfolio ramp rates are constraints QSEs submit with their balancing energy offers to limit the quantity of balancing up or balancing down energy that may be deployed in one interval. These ramp rates are important because they prevent a QSE from receiving deployment instructions that it cannot meet physically. Large changes in balancing energy deployments from interval to interval can cause the ramp rate constraints to bind, preventing the deployment of lower-cost offers and compelling the deployment of higher-cost offers from other QSEs. Ramp rate constraints can also be limiting when resources are instructed to ramp down quickly, although this is less common.

In many cases, the lack of ramp capable resources offered to the balancing energy market results in unnecessary price spikes (as well as large negative prices). There are three aspects of the current market design that inhibit QSEs from fully utilizing the ramp capability of their portfolio. These are: (1) portfolio ramp rates; (2) portfolio level rather than unit level dispatch; and (3) lack of coordination between energy schedules and ramping. These issues were discussed in detail in the 2005 SOM Report. The operational implications associated with these issues continued in 2007 and will likely continue until the current zonal market design is replaced. However, each of these issues will be significantly ameliorated or eliminated with the implementation of the nodal market.

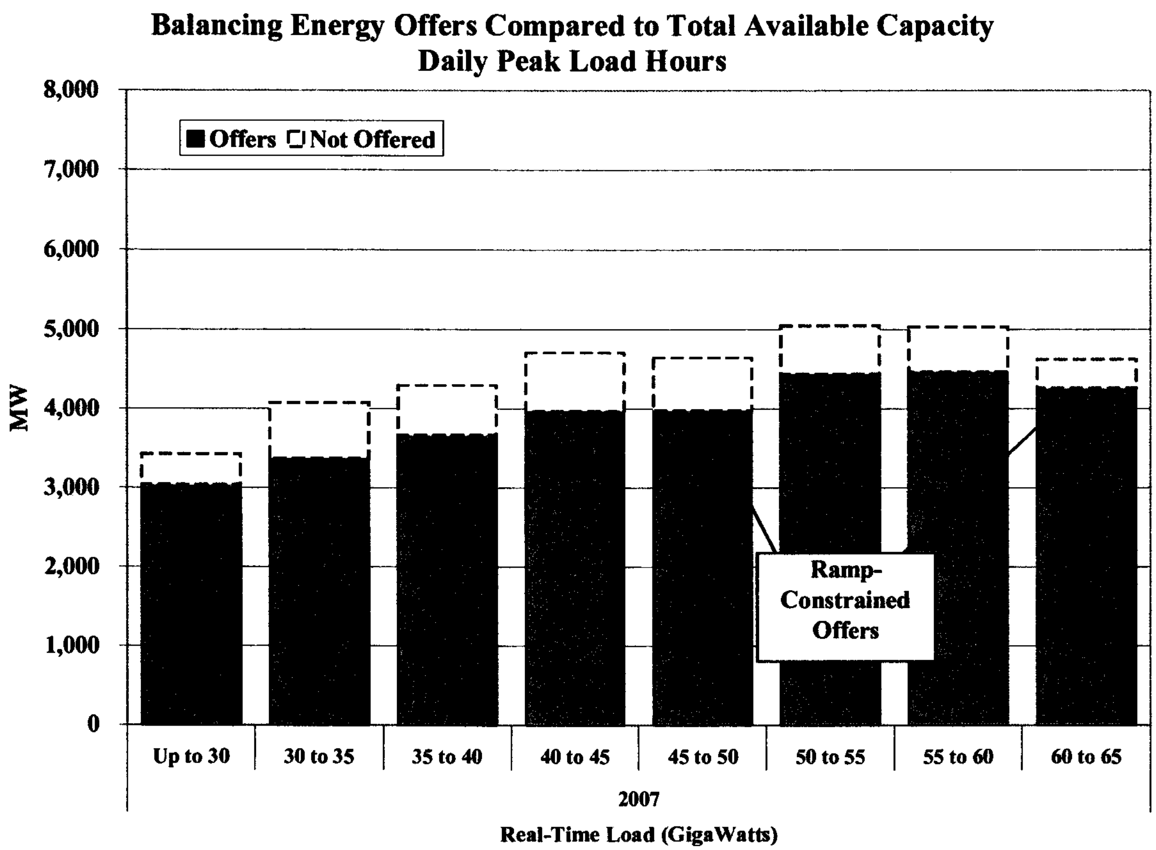
3. Balancing Energy Market Offer Patterns

We also evaluate balancing energy offer patterns by analyzing the rate at which capacity is offered. The figure below shows the average amount of capacity offered to supply balancing up service relative to all available capacity.



The figure above shows only slight variation in 2007 over time in quantities of energy available and offered to the balancing energy market. As discussed in more detail in the 2005 and 2006 ERCOT SOM Reports, there are various structural impediments associated with the zonal market model that serve to explain the residual quantity of un-offered capacity that persists from month-to-month.

Un-offered energy can raise competitive concerns to the extent that it reflects withholding by a dominant supplier that is attempting to exercise market power. To investigate whether this has occurred, the figure below shows the same data as the previous figure, but arranged by load level for daily peak hours in 2007. Because prices are most sensitive to withholding under the tight conditions that occur when load is relatively high, increases in the un-offered capacity at high load levels would raise competitive concerns.



This figure indicates that in 2007, the average amount of capacity available to the balancing market increased gradually up to 60 GW of load and then declined at higher levels. The decline in balancing energy available at higher load levels is associated with the fact that scheduled generation increases at higher load levels, thereby leaving less residual capacity available to be offered as balancing energy. As indicated in the figure, the quantity of un-offered capacity does not change significantly as load levels increase.

The pattern of un-offered capacity shown in the figure above does not raise significant competitive concerns. If the capacity were being strategically withheld from the market, we would expect it to occur under market conditions most susceptible to the exercise of market power. Thus, we would expect more un-offered capacity under higher load conditions. However, the figure shows that portions of the available capacity that are un-offered do not change significantly as load levels increase. Based on this analysis and other analyses in the report at the supplier level, we do not find that the un-offered capacity raises potential competitive concerns.

C. Demand and Resource Adequacy

1. Installed Capacity and Peak Demand

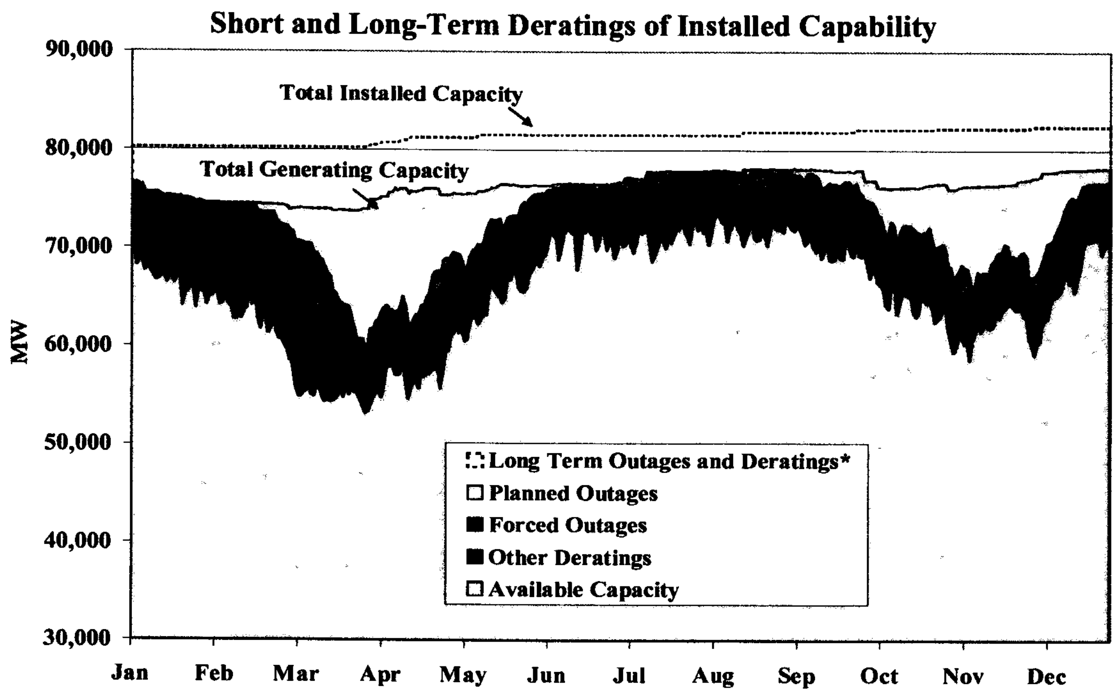
Since electricity cannot be stored, the electricity market must ensure that generation matches load on a continuous basis. Thus, one critical issue for a wholesale electricity market is whether sufficient supplies exist to satisfy demand under peak conditions. In 2007, the load served by ERCOT reached a peak of over 62 GW. The total load level increased about 0.7 percent in 2007 from 2006. Changes in the peak demand levels are very important because they are a key determinant of the probability and frequency of shortage conditions, although daily unit commitment practices, load uncertainty and unexpected resource outages are also contributing factors.

More broadly, peak demand levels and the capability of the transmission network are the primary factors that determine whether the existing generating resources are adequate to maintain reliability. The report provides an accounting of the current ERCOT generating capacity, which is dominated by natural gas-fired resources. These resources account for 70 percent of generation capacity in ERCOT as a whole, and 85 percent in the Houston Zone.

ERCOT has more than 80 GW of installed capacity. This includes import capability, resources that can be switched to the SPP, and Loads acting as Resources ("LaaRs"). However, significant amounts of this are not kept constantly in service. ERCOT estimates that about 5 GW was mothballed during 2007 and a large amount of capacity is used to satisfy cogeneration demands rather than to produce electricity. Furthermore, ambient temperature restrictions increase during the summer months when demand is highest, leading to substantial deratings. Although ERCOT had sufficient capacity to meet load and ancillary services needs during the 2007 peak, it is important to consider that electricity demand will continue to grow and that a significant number of generating units in Texas will soon reach or are already exceeding their expected lifetimes. Without significant capacity additions, these factors may cause the resource margins in ERCOT to diminish rapidly over the next three to five years. This reinforces the importance of ensuring that efficient economic signals are provided by the ERCOT market.

2. Generator Outages and Commitments

Despite adequate installed capacity, resource adequacy must be evaluated in light of the resources that are actually available on a daily basis to satisfy the energy and operating reserve requirements in ERCOT. A substantial portion of the installed capability is frequently unavailable due to generator deratings.



* Includes all outages and deratings lasting greater than 60 days and all mothballed units.

** Switchable capacity is included under installed capacity in this figure.

A derating is the difference between the installed capability of a generating resource and its maximum capability (or "rating") in a given hour. Generators can be fully derated (rating equals 0) due to a forced or planned outage. However, it is very common for a generator to be partially derated (*e.g.*, by 5 to 10 percent) because the resource cannot achieve its installed capability level due to technical or environmental factors (*e.g.*, ambient temperature conditions). The previous figure shows the daily available and derated capability of generation in ERCOT.

The figure shows that long-term outages and other deratings fluctuated between 7 and 22 GW. These outages and deratings reduce the effective resource margins in ERCOT from the levels reported above. Most of these deratings reflect:

- Cogeneration resources unavailable to serve market load because they are being used to serve self-serve load;
- Resources out-of-service for economic reasons (*e.g.*, mothballed units);
- Output ranges on available generating resources that are not capable of producing up to the full installed capability level (*e.g.*, wind resources); or
- Resources out-of-service for extended periods due to maintenance requirements.

With regard to short-term deratings and outages, the patterns of planned outages and forced outages were consistent with expectations:

- Forced outages occurred randomly over the year and the forced outage rates were relatively low (although all forced outages may not be reported to ERCOT).
- Planned outages were relatively large in the spring and fall and extremely small during the summer, as expected.

In addition to the generation outages and deratings, the report evaluates the results of the generator commitment process in ERCOT, which is decentralized and largely the responsibility of the QSEs. This evaluation includes analysis of the real-time excess capacity in ERCOT. We define excess capacity as the total online capacity plus quick-start units each day minus the daily peak demand for energy, responsive reserves provided by generation, and up regulation. Hence, it measures the total generation available for dispatch in excess of the electricity needs each day.

The report finds that the excess on-line capacity during daily peak hours on weekdays averaged 3,020 MW in 2007, which is approximately 8 percent of the average load in ERCOT. The overall trend in excess on-line capacity also indicates a movement toward more efficient unit commitment across the ERCOT market; however, the current market structure is still based primarily upon a decentralized unit commitment process whereby each participant makes independent generator commitment decisions that are not likely to be optimal. Further contributing to the suboptimal results of the current unit commitment process is that the decentralized unit commitment is reported to ERCOT through non-binding resource plans that form the basis for ERCOT's day-ahead planning decisions. However, these non-binding plans can be modified by market participants after ERCOT's day ahead planning process has concluded. Consequently, ERCOT frequently takes additional actions to ensure reliability that may be more costly and less efficient. Hence, the introduction of a day-ahead energy market with centralized Security Constrained Unit Commitment ("SCUC") that is financially binding under the nodal market design promises substantial efficiency improvements in the commitment of generating resources.

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.

During 2007, 2,050 MW of capability were qualified as LaaRs. The amount of responsive reserves provided by LaaRs has gradually increased from about 900 MW at the beginning of 2004 and stood at 1,985 MW at the end of 2005. In 2007, 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 2007.[5] 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 are 70 times more likely to be deployed. Hence, most LaaRs will have a strong preference for providing responsive reserves over non-spinning reserves or balancing energy.

The clearing price for responsive reserves provided by LaaRs is set by the marginal generator, although the quantity of LaaRs willing to supply responsive reserves at the clearing price typically exceeds the demand (*i.e.*, 1,150 MW). The design of this market encourages inefficient behavior by QSEs that want to sell responsive reserves from their demand resources and results in inefficient prices in the responsive reserve market.

To improve the efficiency of responsive reserves pricing and incentives for suppliers, we recommend that ERCOT set separate prices for the two types of responsive reserves. The best

5 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.

way to accomplish this would be by having two responsive reserves constraints in the ancillary services auction: (i) that the responsive reserves procurement (including bilateral schedules) be greater than or equal to 2,300 MW and (ii) that the responsive reserves procurement from LaaRs (including bilateral schedules) be less than or equal to 1,150 MW. The clearing price paid to generators would be equal to the shadow price of the first constraint only, while the clearing price paid to LaaRs would be equal to the shadow price of the first constraint minus the shadow price of the second constraint.

ERCOT stakeholders considered this change in 2006 and, due to resource constraints, decided not to implement it in the current market and instead drafted a protocol revision to implement it in the nodal market. However, this protocol revision failed to receive the necessary two-thirds vote at the ERCOT Technical Advisory Committee in 2007; thus, there is currently no plan to implement any of the changes described above for the RRS market. As previously discussed, the current mechanism for selecting providers and determining clearing prices for responsive reserves is inefficient and leads to excessive reliability costs for consumers. Therefore, we recommend that these changes be reconsidered for implementation in the nodal market design.

D. Transmission and Congestion

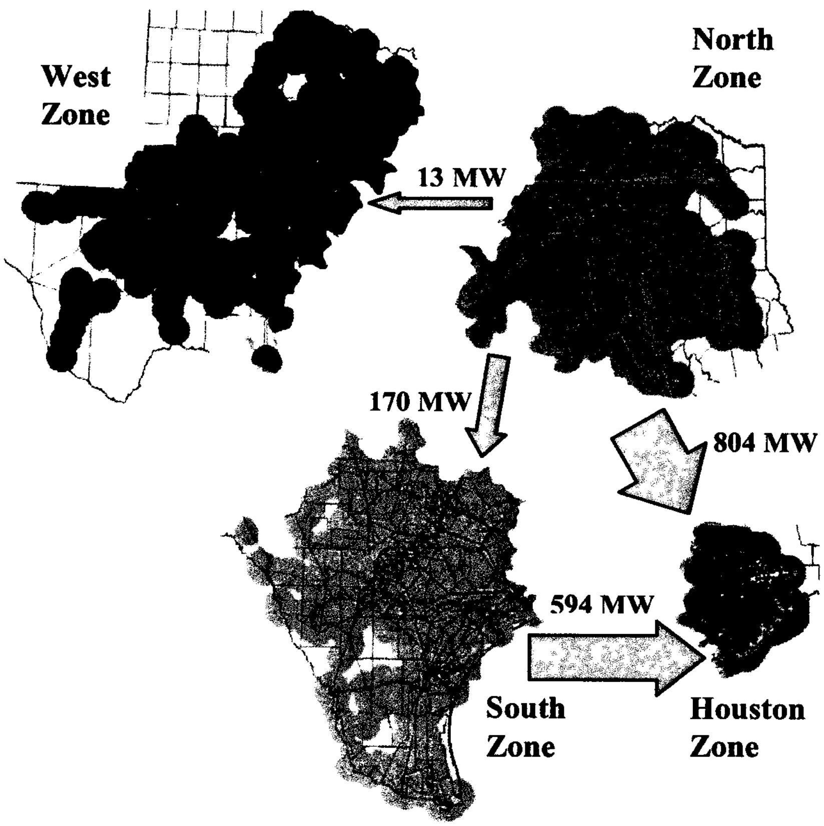
One of the most important functions of any electricity market is to manage the flows of power over the transmission network, limiting additional power flows over transmission facilities when they reach their operating limits. In ERCOT, constraints on the transmission network are managed in two ways. 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 which 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 2007 over each of these CSCs.

Average Modeled Flows on Commercially Significant Constraints
2007



Note: In the figure above, CSC flows are averaged taking the direction into account. So one arrow shows the average flow for the North-to-West CSC was 13 MW, which is equivalent to saying that the average for the West-to-North CSC was *negative* 13 MW.

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.

- Based on modeled flows, Houston is a significant importer while the North Zone and the South Zone export significant amounts of power.
- The physical flow vs. physical limit analysis reveals that the physical limits sometimes differ significantly from the actual flows.

When interzonal congestion arises, 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 levels of interzonal congestion increased considerably to $114 million in 2007, which reflects an increase of $45 million from 2006. This increase was the result of more frequent congestion on the North-to-Houston, North-to-West, and West-to-North CSCs, as well as increased shadow price caps.[6]

To account for the fact that the modeled flows can vary substantially from the actual physical flows (due to the simplifying assumptions in the model), ERCOT operators must adjust the modeled limits for the CSC interfaces to ensure that the physical flows do not exceed the physical limits. This process results in highly variable limits in the market model for the CSC interfaces.

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. The aggregate shortfall increased considerably to $61 million in 2007, up from $7 million in 2006. This increase was

6 A shadow price is the economic value of a constraint that is reflected in the zonal prices. The cap prevents the shadow price from rising above the cap.

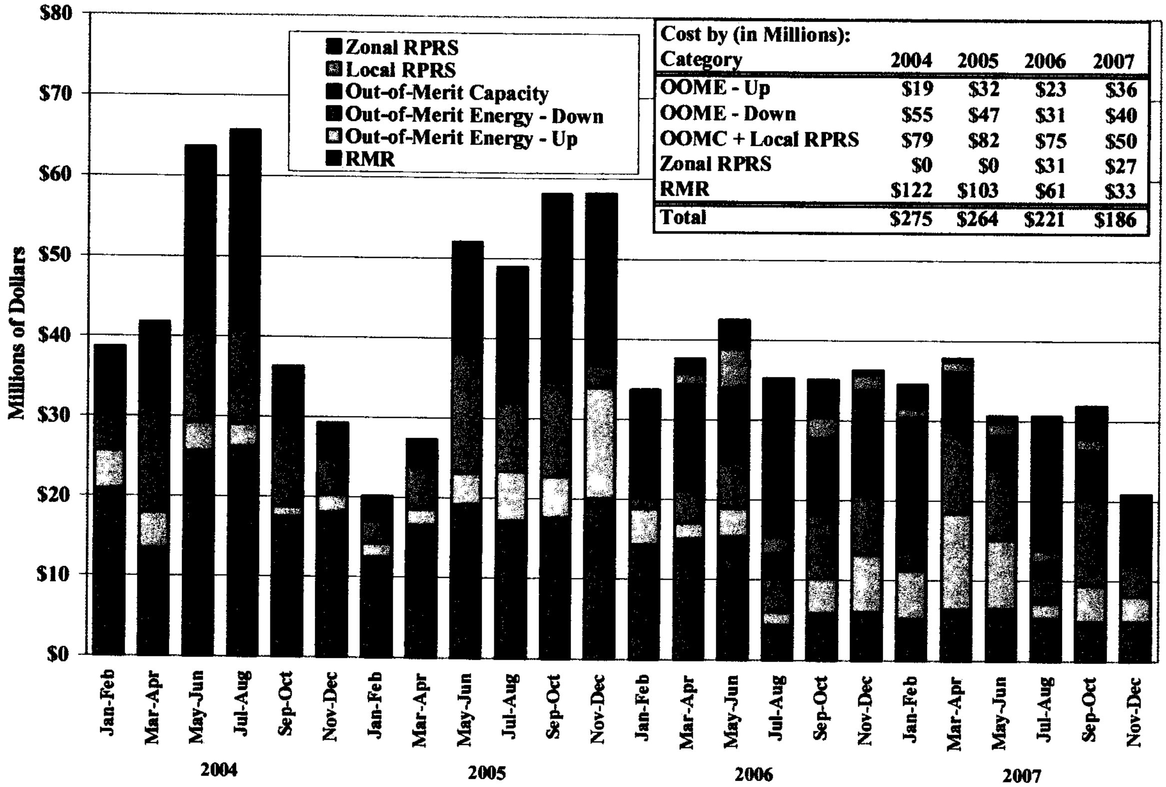
primarily due to increased interzonal congestion in 2007 and decreased accuracy in the quantity of TCRs sold in the monthly auction, especially for the West-to-North and North-to-West CSC.

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 only reasonably close convergence with some fluctuations from year to year due to uncertainties. In 2006, market participants over-estimated the value of congestion on the South to North, South to Houston, and North to Houston CSCs. In 2007, market participants still over-estimated the value of congestion on the South to North and South to Houston CSCs, but significantly under-estimated the value of congestion on the North to Houston, North to West and West to North CSCs. The auction values correlate closely with actual congestion values from prior years, indicating that market participants have difficulty in accurately estimating future congestion costs.

3. Local Congestion and Local Capacity Requirements

ERCOT manages local (intrazonal) congestion using out-of-merit dispatch ("OOME up" and "OOME down"), which causes units to depart from their scheduled output levels. When not enough capacity is committed to meet local reliability requirements, ERCOT sends OOMC instructions for offline units to start up to provide energy and reserves in the relevant local area. ERCOT also enters into RMR agreements with certain generators needed for local reliability that may otherwise be mothballed or retired. When these units are called out-of-merit order, 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 2004 to 2007.

Expenses for Out-of-Merit Capacity and Energy
2004-2007



Cost by (in Millions): Category	2004	2005	2006	2007
OOME - Up	$19	$32	$23	$36
OOME - Down	$55	$47	$31	$40
OOMC + Local RPRS	$79	$82	$75	$50
Zonal RPRS	$0	$0	$31	$27
RMR	$122	$103	$61	$33
Total	$275	$264	$221	$186

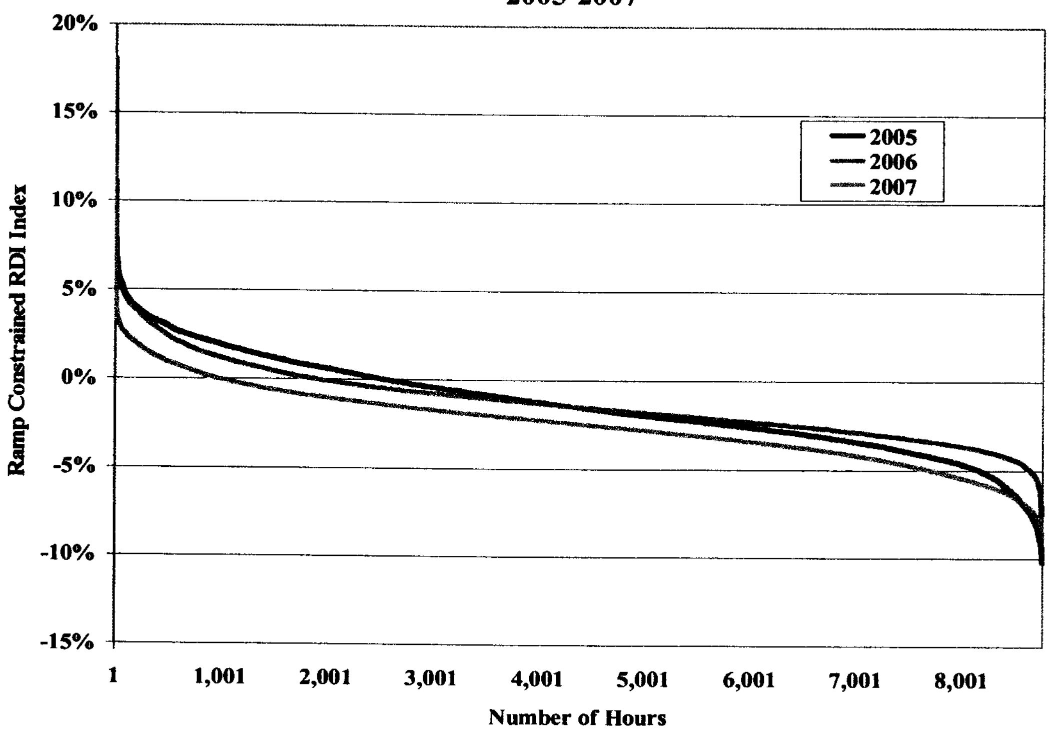
The results in the figure above show that overall uplift costs for RMR units, OOME units, and OOMC/Local RPRS units were relatively consistent between 2004 and 2005. The costs decreased by $74 million in 2006 from $264 million to $221 million, a reduction of 16 percent. In 2007, there was a further decrease from $221 million to $186 million, a reduction of 16 percent. There were substantial reductions to RMR cost due to the expiration of RMR agreements in 2007, which accounts for $28 million of the $35 million decrease from 2006 to 2007. Total OOME Up and OOME Down costs increased from $54 million in 2006 to $76 million in 2007. In constrast, out of merit commitment cost (OOMC and RPRS) decreased from $106 million in 2006 to $77 million in 2007.

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 needed 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 significantly in 2007 compared to 2006. The following figure shows the ramp-constrained balancing energy market Residual Demand Index ("RDI") duration curves for 2005 and 2007. 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 2005-2007

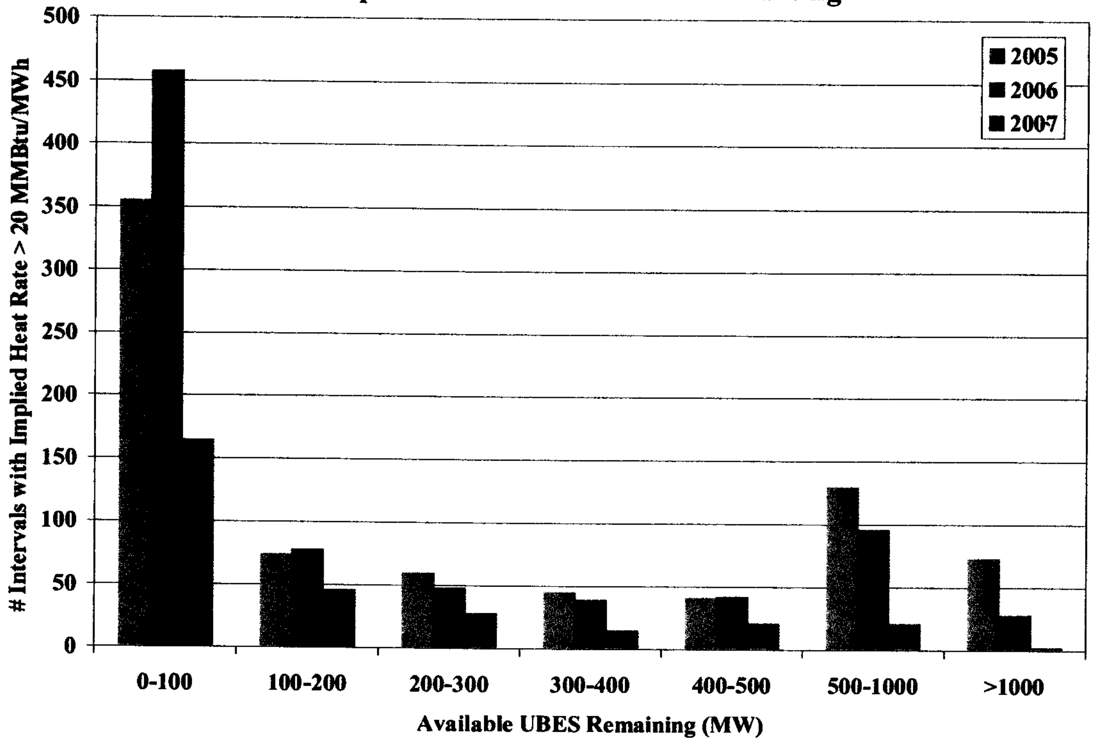


The frequency with which at least one supplier was pivotal (*i.e.*, an RDI greater than zero) has fallen consistently from 29 percent of hours in 2005 to 21 percent of the hours in 2006 and less than 11 percent of hours in 2007. These results indicate that the structural competitiveness of the balancing energy market improved in 2007.

A final measure used to evaluate the potential for economic withholding analyzes the number of balancing energy market price spikes compared to the available Up Balancing Energy Service

("UBES") remaining. If the market is operating competitively, price spikes should occur during shortage and near shortage conditions, and the number of price spikes should reduce significantly as the amount of available surplus energy increases.

Price Spikes vs. Available UBES Remaining



The results in the figure above indicate very competitive market outcomes in 2007, with over 92 percent of the price spikes occurring during intervals with less than 500 MW of available UBES remaining. These results show significant improvement over 2005 and 2006 when only 74 and 84 percent, respectively, of the price spikes occurred during intervals with less than 500 MW of available UBES remaining.

While structural market power indicators are very useful in identifying potential market power issues, they do not address the actual conduct of market participants. Accordingly, we analyzed measures of potential physical and economic withholding to further evaluate competitive performance of the ERCOT market. Potential withholding measures were examined relative to the level of demand and the size of each supplier's portfolio. The results of these analyses do not indicate significant concerns related to physical or economic withholding in 2007.

Overall, based upon the analyses in Section V, we find that the ERCOT wholesale market performed competitively in 2007.

F. Summary of Recommendations

As in prior reports, most of the operational issues identified in this report will be significantly improved with the implementation of the nodal market. As such, the following recommendations consist of issues that are either independent of the wholesale market model, or enhancements to the nodal market implementation:

- Real-time co-optimization of energy and reserves: As discussed in Section I.B., future implementation of real-time co-optimization of energy and reserves should be considered as a post-"go live" nodal market enhancement to further improve the efficient operation of the real-time market Real-time co-optimization.
- Operating Reserve Demand Curves: As discussed in Section I.D., relying upon the offers of small participants to ensure scarcity prices during legitimate shortage conditions produced unreliable results in 2007. More reliable and efficient shortage pricing could be achieved by establishing pricing rules that automatically produce scarcity level prices when defined shortage conditions exist on the system. Ideally, operating reserve demand curves would be implemented in conjunction with real-time co-optimization of energy and reserves, although the latter is not an absolute prerequisite.
- Efficient Responsive Reserve Pricing: As discussed in Section III.C., ERCOT manages over-supply of Loads Acting as Resources ("LaaRs") in the responsive reserve market by relying upon administrative rules rather than prices to ration the product. This is inefficient and leads to excessive reliability costs for consumers. To improve the efficiency of responsive reserve pricing and incentives for suppliers, ERCOT should impose two responsive reserves constraints in the ancillary services auction: (i) that the responsive reserves procurement (including bilateral schedules) be greater than or equal to 2,300 MW and (ii) that the responsive reserves procurement from LaaRs (including bilateral schedules) be less than or equal to 1,150 MW. The clearing price paid to generators would be equal to the shadow price of the first constraint only, while the clearing price paid to LaaRs would be equal to the shadow price of the first constraint

minus the shadow price of the second constraint (a single price would result if the LaaR constraint is not binding).

- Day-Ahead Load Forecast Error: As discussed in Section I.D., ERCOT's day-ahead load forecast exhibited a persistent positive bias in 2007 that was particularly high during the summer months, which 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. ERCOT should review the causes of the positive bias in its day-ahead load forecast,
- Assessment of Ancillary Service Products and Quantities: In conjuction with the day-ahead load forecast review, ERCOT should explore potential changes to its reserve procurement policies and its day-ahead and supplemental unit commitment procedures in an effort to enhance the efficiency of its unit commitment processes while still satisfying reliability requirements. Additionally, although not a significant issue for most of 2007, this review should include the effects of the considerable increase in the installed wind generation capacity in the ERCOT region recently. Substantial addition of more unpredictable and uncontrollable resources has significant implications related to efficient and reliable unit commitment and real-time operations.
- Re-evaluation of the Reserve Discount Factor: As discussed in Section I.D., ERCOT implemented a factor that discounts the stated capacity of online generating units for the purpose of calculating available responsive reserves in 2007. To compensate for the application of the discount factor, the quantity of responsive reserves procured was increased by amounts ranging from 200 to 500 MW in 2008. In parallel, Protocol Revision Request ("PRR") No. 750 was implemented in March 2008 related to unannounced unit testing. The objective of this increased testing is increased confidence in the stated capacity of generating resources and the elimination of the discount factor, thereby also eliminating the incremental quantities of responsive reserve procurement. The increased responsive reserve quantities are an interim measure. The more efficient and less costly solution for consumers is to re-establish confidence in the stated capacity values for generating resources. Therefore, ERCOT should obtain sufficient unit testing data to provide for a statistical re-evaluation of the reserve discount factor and the associated increased quantities of responsive reserve in 2008. If possible, ERCOT should

eliminate the discount factor or at least reducing it to two percent or lower (which would eliminate the procurement of additional responsive reserve quanties above 2,300 MW).

- Peaker Net Margin Calculation: As discussed in Section I.D., PUCT rules specify the price that is used to calculate the peaker net margin as the price at an ERCOT-wide hub.[7] Essentially, this is an average price for the ERCOT market. To better account for regional price disparities, we recommend that the price that is used in the peaker net margin calculation in the PUCT's rules be modified to be a set of regional prices, and that the cumulative peaker net margin be calculated as the highest cumulative regional value. Once the annual cumulative peaker net margin threshold set forth in the PUCT rules is reached for any of the defined regions, we recommend ERCOT transition from the high system offer cap to the low system offer cap for the duration of the scarcity pricing mechanism cycle.

7 The Peaker Net Margin ("PNM") is designed to measure the annual net revenue for a hypothetical peaking unit. Under PUCT rules, if the PNM reaches a cumulative total of $175,000 per MW in a calendar year, the system-wide offer cap is reduced to the higher of $500 per MWh or 50 times the daily gas price index.

I. REVIEW OF MARKET OUTCOMES

A. Balancing Energy Market

1. Balancing Energy Prices During 2007

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 such transactions can at times be well in excess of 10 percent of the 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 that prevent arbitrage of the prices in 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).[8] 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. The analyses in this section summarize and evaluate the prices that prevailed in the balancing energy market during 2007.

To summarize the price levels during the past two years, Figure 1 shows the load-weighted average balancing energy market prices in each of the ERCOT zones in 2006 and 2007.[9] Balancing energy market prices were 2 percent higher in 2007 than in 2006, with September 2007 showing the largest increase from the same month in 2006.

The average natural gas price in 2007 increased 4 percent from 2006, with the largest increase occurring in September at 25 percent. Natural gas is typically the marginal fuel in the ERCOT

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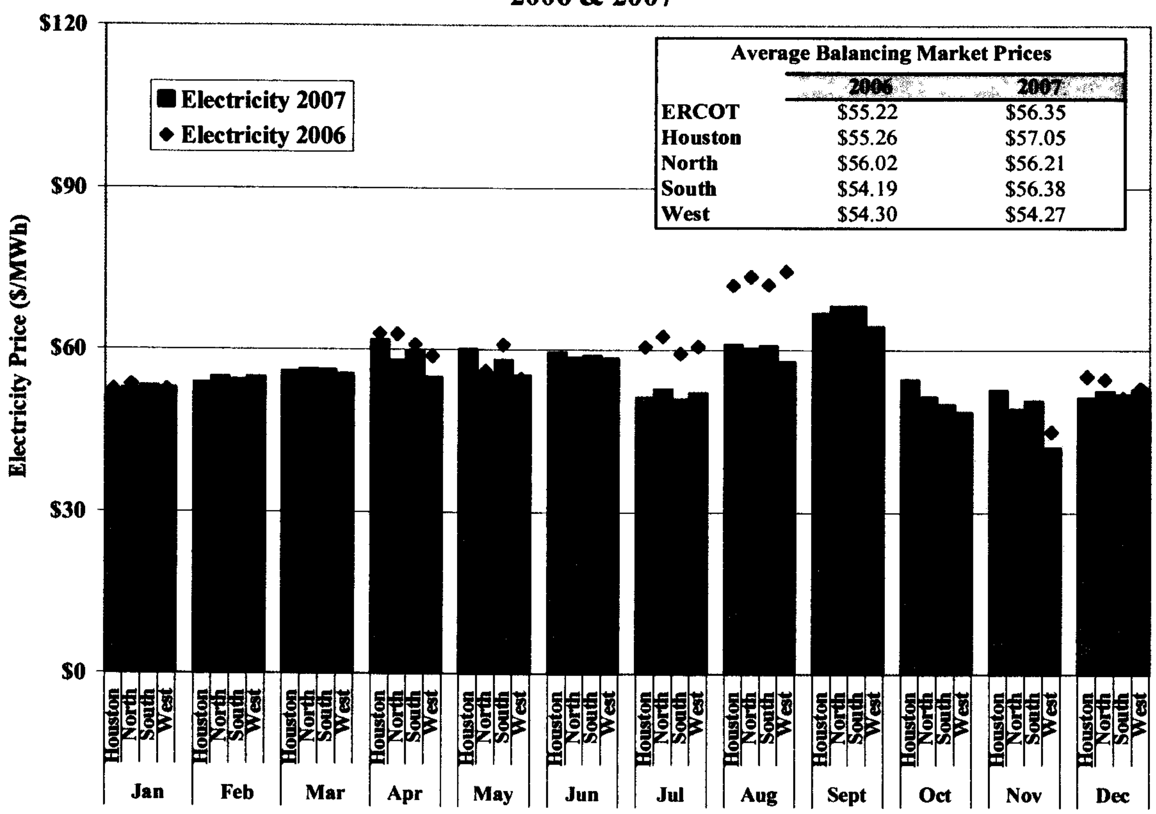
8 See Hull, John C. 1993. *Options, Futures, and other Derivative Securities*, second edition. Englewood New Jersey: Prentice Hall, p. 70-72.

9 The load-weighted average prices are calculated by weighting the balancing energy price in each interval and zone by the total zonal loads in that interval. This is not consistent with average prices reported elsewhere that are weighted by the balancing energy procured in the interval, which is a methodology we use to evaluate certain aspects of the balancing energy market. 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).

market. Hence, the changes in energy prices from 2006 to 2007 were largely a function of natural gas price movements.

Figure 1: Average Balancing Energy Market Prices 2006 & 2007



The next analysis evaluates the total cost of serving load in the ERCOT market. In addition to the costs of energy, loads incur costs associated with operating reserves, regulation, and "uplift".[10] We have calculated an average all-in price of electricity for ERCOT that is intended to reflect energy costs as well as these additional costs. Figure 2 shows the monthly average all-in price for all of ERCOT from 2003 to 2007.

10 As discussed in more detail in Section IV, 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.

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.
- Uplift costs: Uplift costs are assigned market-wide on a load-ratio share basis.

Figure 2: Average All-in Price for Electricity in ERCOT 2003 to 2007

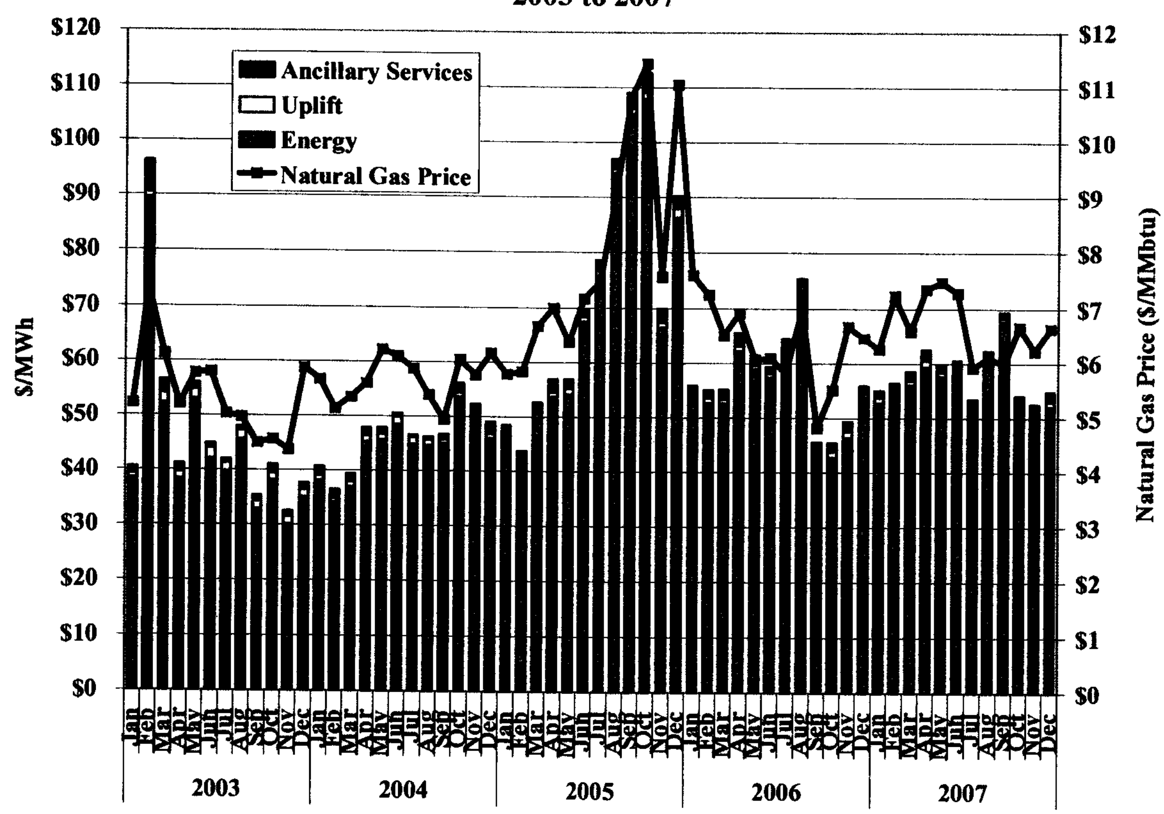


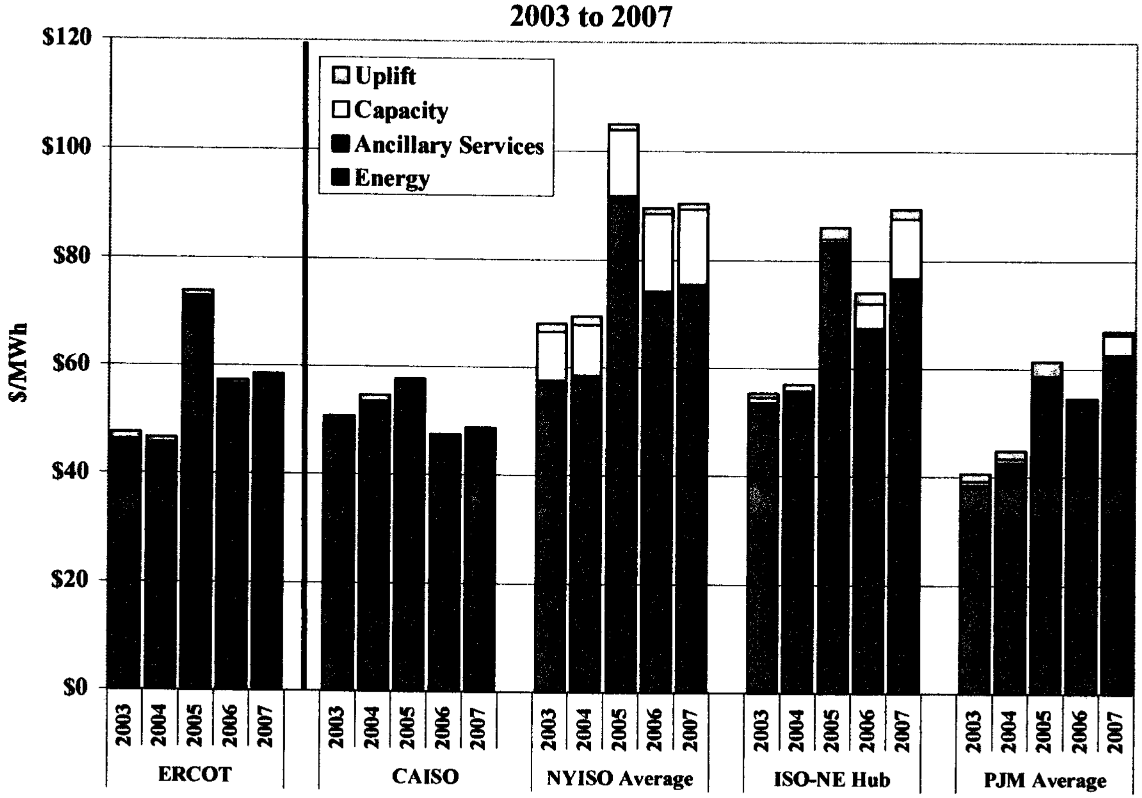
Figure 2 indicates that natural gas prices were a primary driver of the trends in electricity prices from 2003 to 2007. This is not surprising given that natural gas is the predominant fuel in ERCOT, especially among the generating units that most frequently set the balancing energy market prices. In 2007, the average natural gas price increased by 4 percent from 2006 levels and the all-in price for electricity increased by 0.5 percent.

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. At least three other factors contributed to price outcomes in 2007. First, as discussed in Section III of this report, ERCOT peak demand and installed capacity were relatively flat in 2007, and energy production increased only slightly in 2007 compared to 2006. In contrast to prior years with increasing demand and decreasing supply, the static supply and demand characteristics from 2006 to 2007 contributed to comparable wholesale pricing outcomes over the course of these two years. Second, the balancing energy offer cap was raised to $1,500 in 2007, whereas the offer cap was $1,000 in 2006. The increased offer caps are intended to produce higher prices during system shortage conditions. However, as discussed later in this section, this mechanism was not always effective in achieving this intended outcome. Finally, the overall competitive performance of the market exhibited continued improvement in 2007, which will tend to lower prices and is examined in detail in Section V. Analyses in the next sub-section adjust for natural gas price fluctuations to better highlight variations in electricity prices not related to fuel costs.

From 2006 to 2007, an 8 percent decrease in ancillary services costs result in a 0.2 percent decrease in the all-in price for electricity. Generally, the ancillary service prices coincided with price movements in the balancing energy market, which is to be expected since the energy and ancillary service requirements are satisfied by the same resources.

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 for ERCOT with four organized electricity markets in the U.S.: (a) California ISO, (b) New York ISO, (c) ISO New England, and (d) 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.

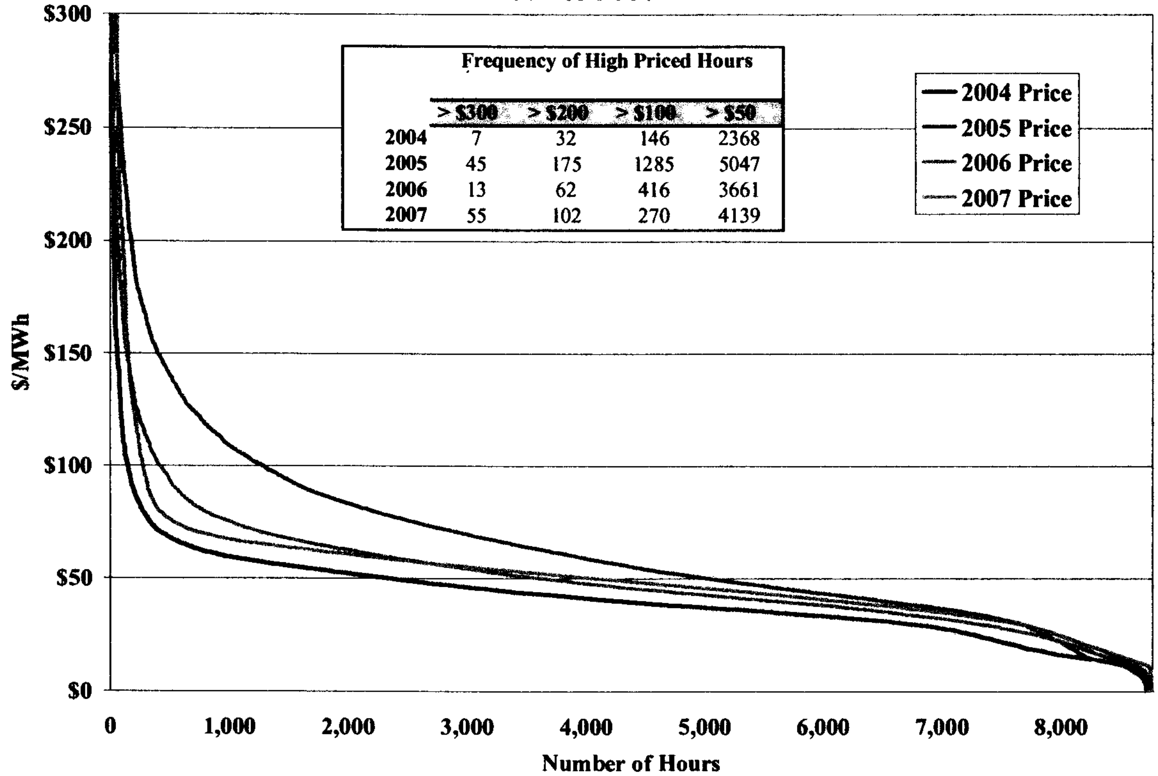
Figure 3: Comparison of All-in Prices Across Markets
2003 to 2007



Wholesale electricity markets in the U.S. experienced substantial increases in energy prices from 2004 to 2005 due to increased fuel costs. In 2006, energy prices in the U.S. dropped in every region due to decreased fuel costs. In 2007, the all-in prices increased in all the above five regions, with relatively small increases in ERCOT, California and New York, and more significant increases in New England and PJM.

Figure 4 presents price duration curves for the ERCOT balancing energy market in each year from 2004 to 2007. 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.

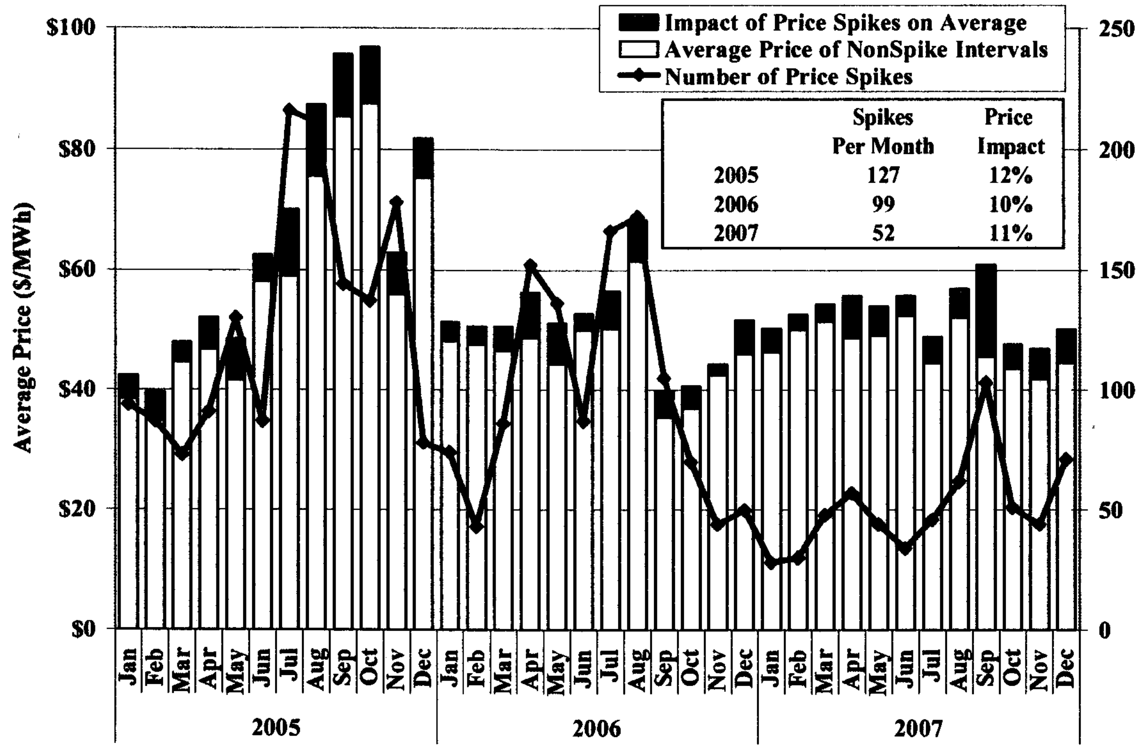
Figure 4: ERCOT Price Duration Curve
2004 to 2007



Balancing energy prices exceeded $50 in more than 4,000 hours in 2007 compared to more than 3,500 hours in 2006. These year-to-year changes reflect the effects of slightly higher fuel prices in 2007, which impact electricity prices in a broad range of hours.

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. Figure 4 shows that there were differences in balancing energy market prices between 2004 and 2007 at the highest price levels. For example, 2007 experienced considerably more price spikes greater than $300 per MWh than 2005 or 2006, even though average prices were comparable to 2006 and lower than in 2005. 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 2005 to 2007. Figure 4 shows average prices and the number of price spikes in each month of 2005 to 2007. 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 generators in ERCOT).

Figure 5: Average Balancing Energy Prices and Number of Price Spikes 2005 to 2007



The number of price spike intervals was 127 per month during 2005. The number decreased in 2006 to 99 per month, and further decreased to 52 per month in 2007. 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 approximately $6.98 per MWh during 2005. In 2006, the impact was $4.68 per MWh in average in 2006 and the impact averaged $5.30 per MWh in 2007. Even though price spikes account for a small portion of the total intervals, they have a significant impact on overall price levels.

Figure 6 through Figure 8 show the frequency of price spikes in the regulation and responsive reserve markets during 2005 through 2007. These figures show that price spikes in the markets for ancillary services have also dropped significantly over this time period.

Figure 6: Average Regulation Up Prices and Number of Price Spikes 2005 to 2007

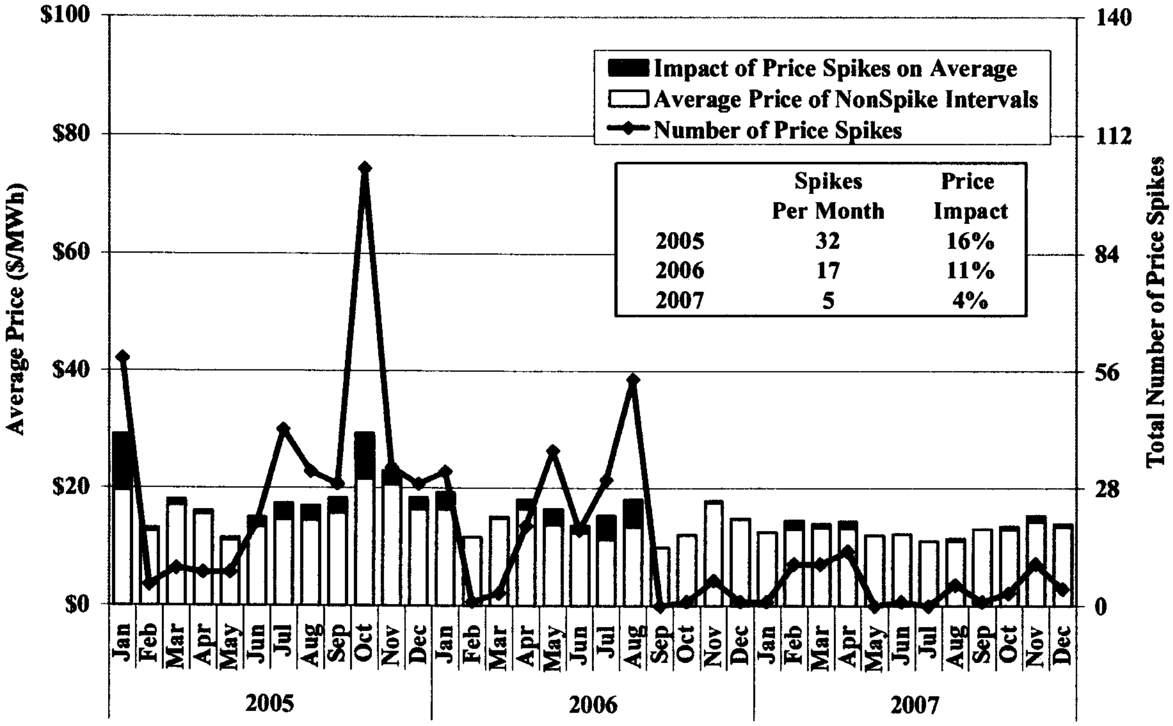


Figure 7: Average Regulation Down Prices and Number of Price Spikes 2005 to 2007

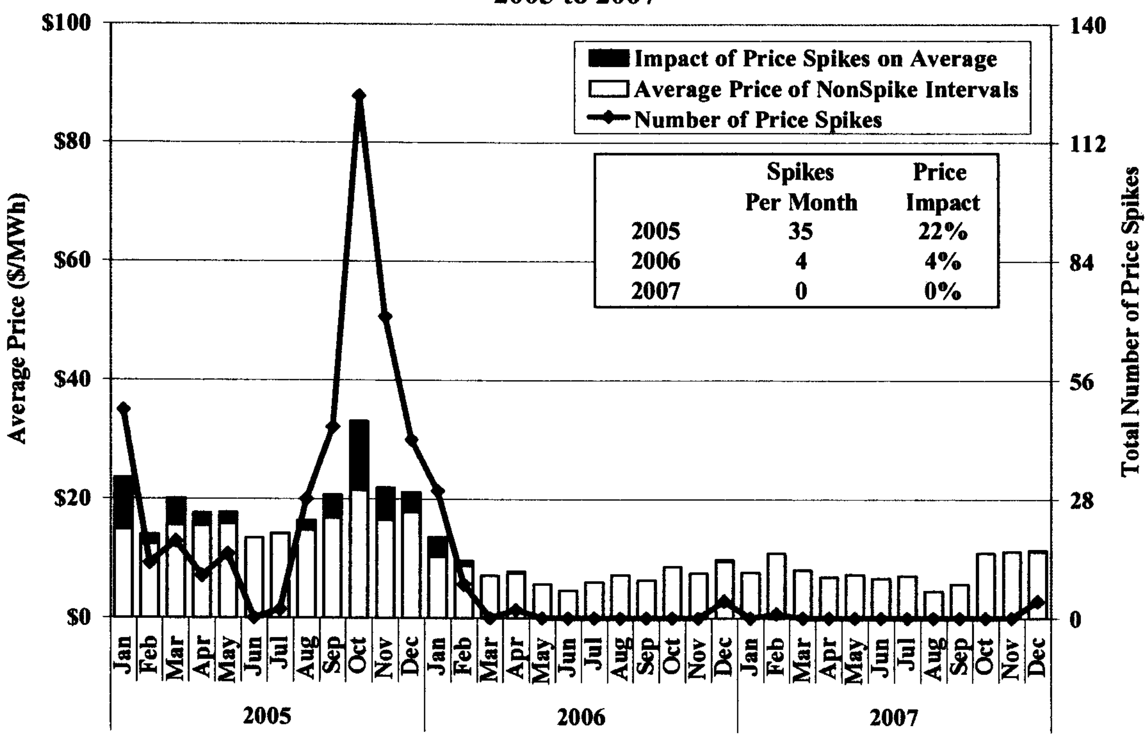
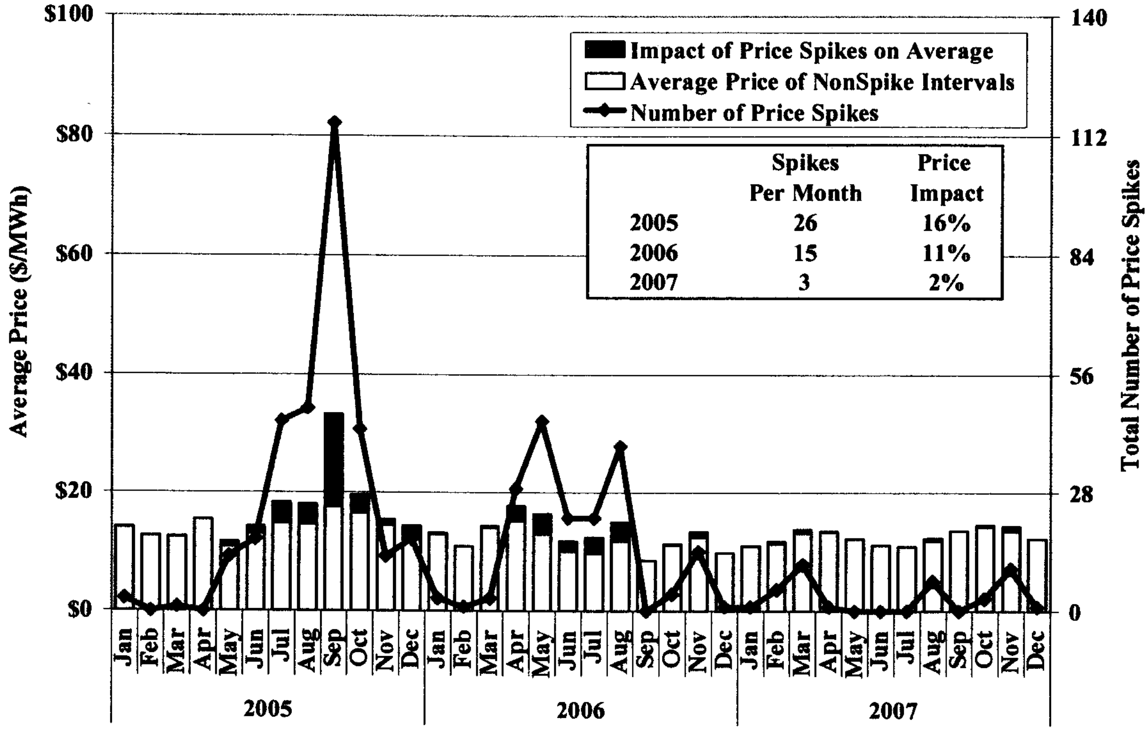


Figure 8: Average Responsive Reserve Prices and Number of Price Spikes 2005 to 2007



During 2005, there were 32 price spike hours per month for regulation up, 35 for regulation down, and 26 for responsive reserves.[11] In 2006, the number of price spike hours decreased, with 17 per month for regulation up, 4 per month for regulation down, and 15 per month for responsive reserves. In 2007, the number of price spike hours further decreased, with 5 per month for regulation up, 0 for regulation down, and 3 for responsive reserves. Because the same resources are used to supply ancillary services and energy, fluctuations in energy prices should lead to corresponding changes in ancillary services prices. The relationship between balancing energy prices and ancillary services prices is discussed in greater detail later in this section.

While the price spikes directly impact a small portion of the total consumption of energy and ancillary services, persistent price spikes will eventually flow through to consumers. Price spikes in the ancillary service markets have decreased over the last three years, as has the frequency of overall price spikes in the balancing energy market. However, the frequency of extreme price spikes (i.e., prices greater than $300 per MWh) was higher in 2007 than in 2005 or

[11] Price spikes are defined as hours where the price exceeds a threshold of $50 per MW for regulation up, regulation down, or responsive reserves.

2006. To the extent that price spikes reflect true scarcity of generation resources, they send efficient economic signals in the short-run for commitment and dispatch, and in the long-run for new investment. However, to the extent that price spikes occur when economic resources are not efficiently utilized, they raise costs to consumers and send inefficient economic signals. This issue is examined in more detail in Section V.

2. Balancing Energy Prices Adjusted for Fuel Price Changes

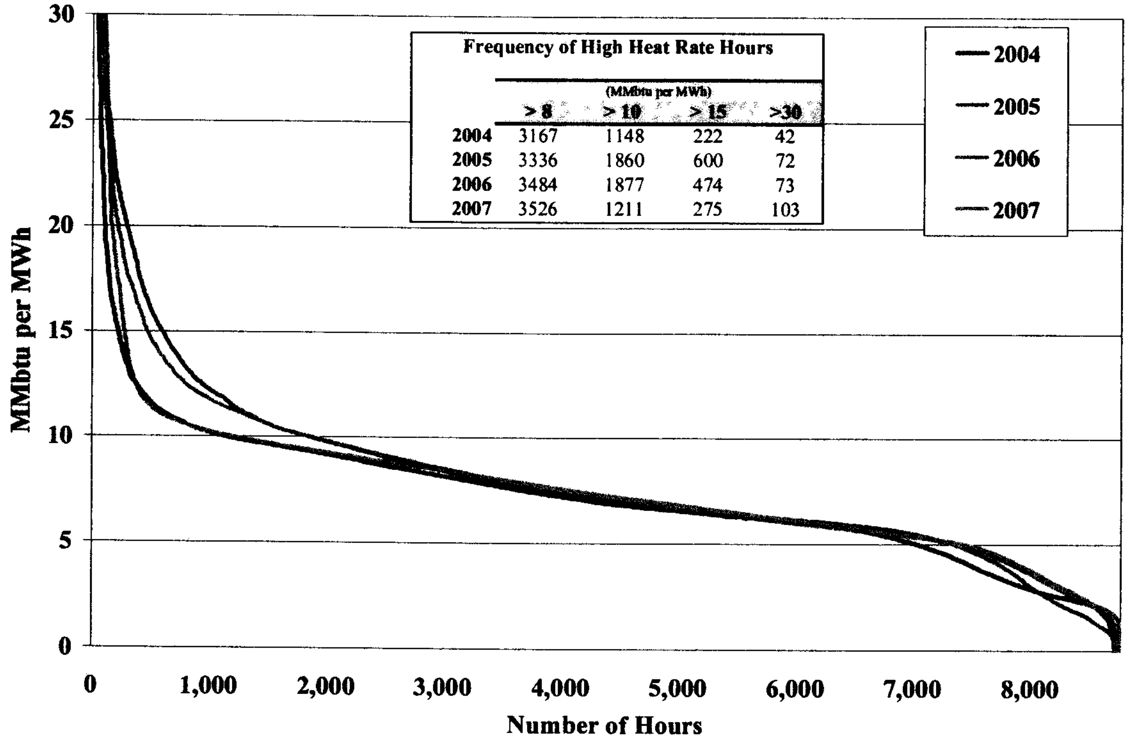
The pricing patterns shown in the prior sub-section are driven to a large extent by changes in fuel prices, natural gas prices in particular. However, prices are influenced by a number of other factors as well. To clearly identify changes in electricity prices that are not driven by changes in natural gas prices, Figure 9 and Figure 10 show balancing energy prices corrected for 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 top five percent of hours in each year. The figure shows duration curves for the implied marginal heat rate for 2003 to 2007.

In contrast to Figure 4, Figure 9 shows that the implied marginal heat rates were relatively consistent across the majority of hours from 2003 to 2007. For instance, the table in Figure 9 indicates that the number of hours when the implied heat rate exceeded 8 MMbtu per MWh was relatively consistent across the five years. The rise in energy prices from 2003 to 2007 is much less dramatic when we explicitly control for fuel price changes, 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 10 was 1,860 in 2005 and 1,877 in 2006, but declined to 1,211 in 2007. This indicates that there are price differences that are due to factors other than changes in natural gas prices.

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

Figure 10 shows the implied marginal heat rates for the top five percent of hours in 2004 through 2007. These data reveal that the frequency of price spikes with an implied marginal heat rate greater than 30 increased significantly in 2007 compared to prior years.

Figure 9: Implied Marginal Heat Rate Duration Curve
All Hours – 2004 to 2007



	> 8	> 10	> 15	>30
2004	3167	1148	222	42
2005	3336	1860	600	72
2006	3484	1877	474	73
2007	3526	1211	275	103