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2006 STATE OF THE MARKET REPORT FOR THE ERCOT WHOLESALE ELECTRICITY MARKETS

POTOMAC ECONOMICS, LTD.

ERCOT Independent Market Monitor

August 2007

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EXECUTIVE SUMMARY

This report reviews and evaluates the outcomes of the ERCOT wholesale electricity markets in 2006. 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. Additionally, balancing energy prices decreased by over 24 percent in 2006 due to lower fuel prices (particularly natural gas) and improved competitive performance of the market. However, the report generally confirms prior findings that the current market rules and procedures are resulting in systematic inefficiencies.

These findings can be found in four 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, which is currently being developed for implementation by 2009.

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 pricing will result in price signals that provide incentives to build new generation where it is most needed for managing congestion and

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"); and "ERCOT State of the Market Report 2005", Potomac Economics, July 2006 (hereafter "2005 SOM Report").

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

A. Review of Market Outcomes

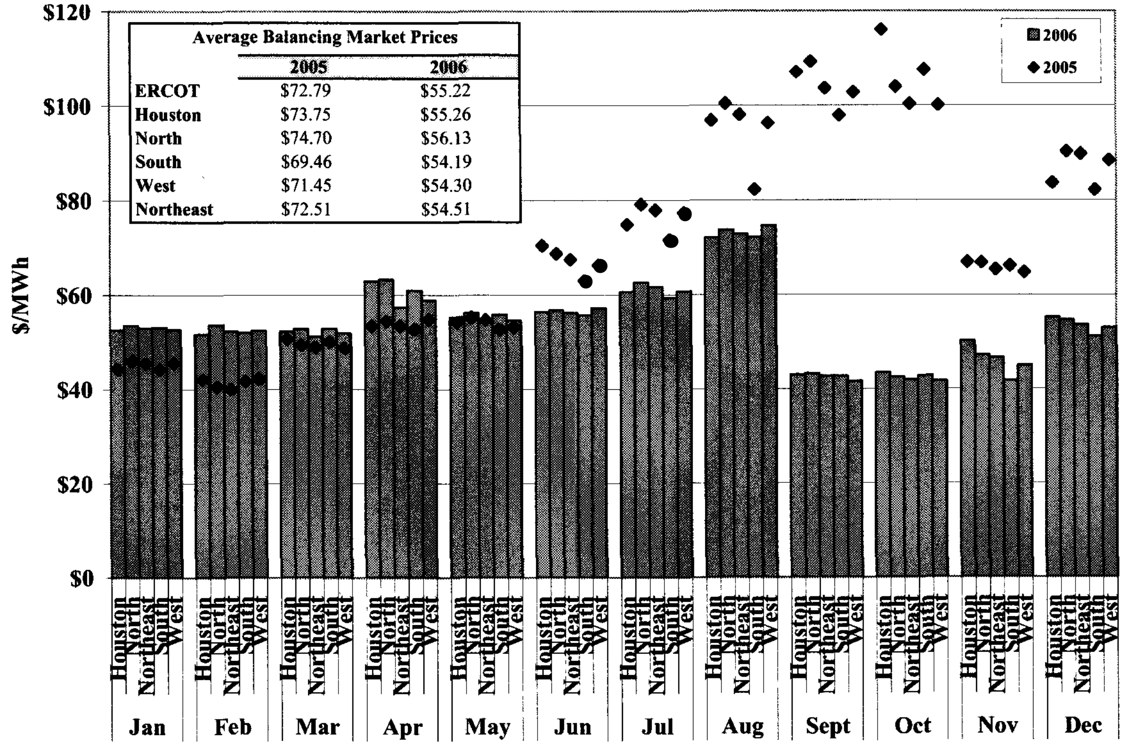
1. Balancing Energy Prices

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 in order 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.

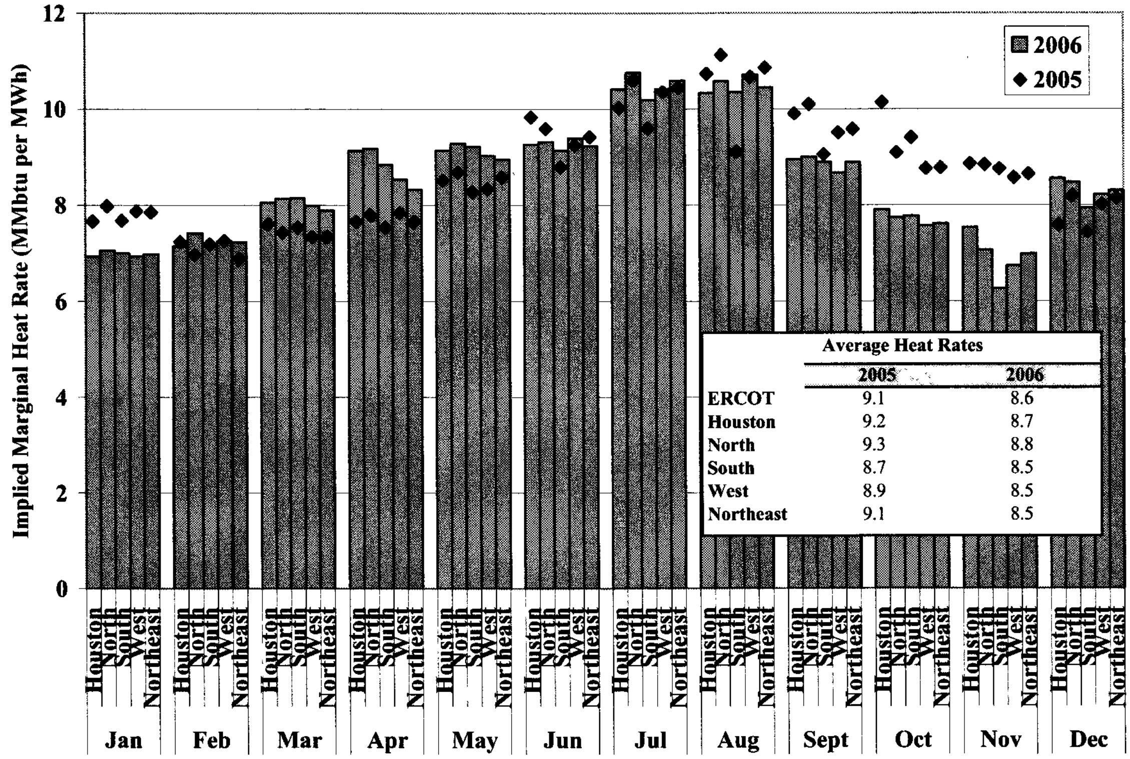
As shown in the following figure, balancing energy market prices were over 24 percent lower in 2006 than in 2005, with the latter half of the year showing the largest reductions from 2005. In 2005, natural gas prices began to rise significantly during the summer and remained at high levels through the end of the year. This increase was largely due to the effects of the hurricanes on the productive capability of the Gulf Coast region. However, natural gas prices settled to relatively lower levels in 2006, especially during the latter half of the year. Natural gas is typically the marginal fuel in the ERCOT market. Hence, the changes in energy prices from 2005 to 2006 were largely a function of natural gas price movements.

Balancing Energy Market Prices
2005 & 2006



Although fuel price fluctuations have been the dominant factor driving the decreases in electricity prices in 2006, fuel prices alone do not explain all of the price changes. At least three other factors contributed to price changes in 2006. First, ERCOT demand increased in 2006, while the supply remained relatively static. Second, ERCOT generally committed less excess capacity on a daily basis in 2006. Third, the overall competitive performance of the market improved in 2006 relative to 2005. The first two factors will tend to produce an upward pressure on prices in 2006 relative to 2005, and these factors are discussed in greater detail in Section III of this report. In contrast, the third factor will tend to lower prices and is examined in Section V. To account for changes in fuel prices, the following figure compares the implied marginal heat rate in 2005 and 2006. The implied marginal heat rate is calculated by dividing the balancing energy price by the natural gas price.

Monthly Average Implied Marginal Heat Rate
2005 & 2006



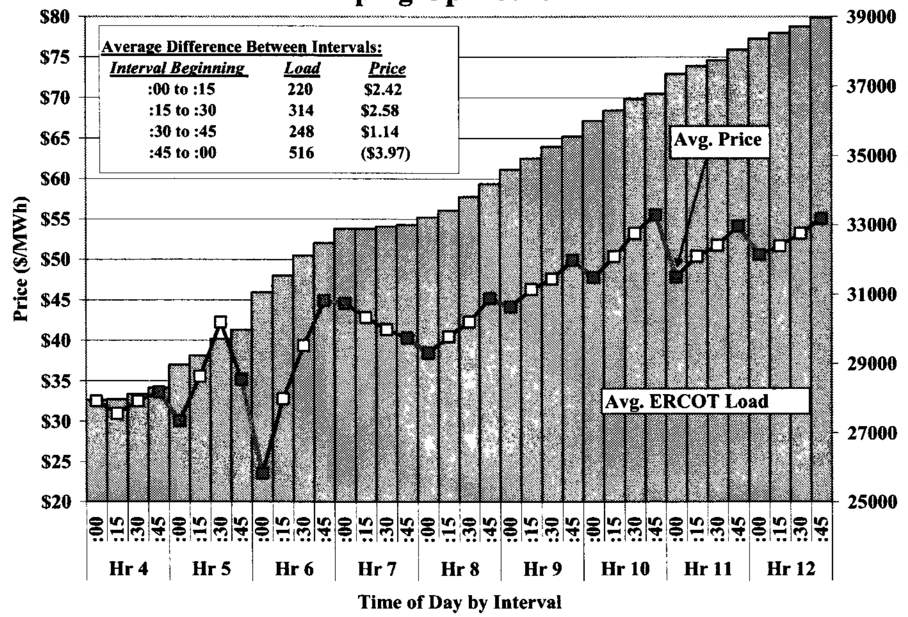
	2005	2006
ERCOT	9.1	8.6
Houston	9.2	8.7
North	9.3	8.8
South	8.7	8.5
West	8.9	8.5
Northeast	9.1	8.5

Adjusted for gas price influence, the above figure shows that average implied heat rate for all hours of the year decreased by 5.5 percent from 9.1 in 2005 to 8.6 in 2006. On average, the implied heat rate was lower in 2006 than in 2005 for the months of June through November. With the exception of January, the average implied heat rate for the remaining months was higher in 2006 than in 2005.

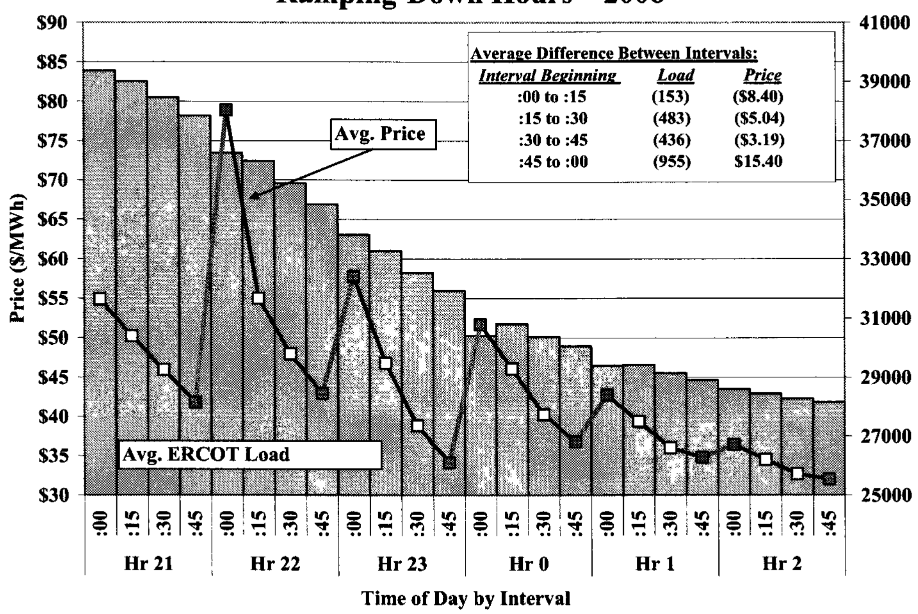
The report evaluates two other aspects of the balancing energy prices: 1) the correlation of the balancing energy prices with forward electricity prices in Texas, and 2) the primary determinants of balancing energy prices. Natural market forces should push forward market prices to levels consistent with expectations of spot market prices. Forward prices were relatively consistent with balancing energy prices on the vast majority of days in 2006.

As discussed in prior reports, we continue to observe in 2006 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.

Average Balancing Energy Prices and Load by Time of Day
Ramping-Up Hours – 2006



Average Balancing Energy Prices and Load by Time of Day
Ramping-Down Hours – 2006



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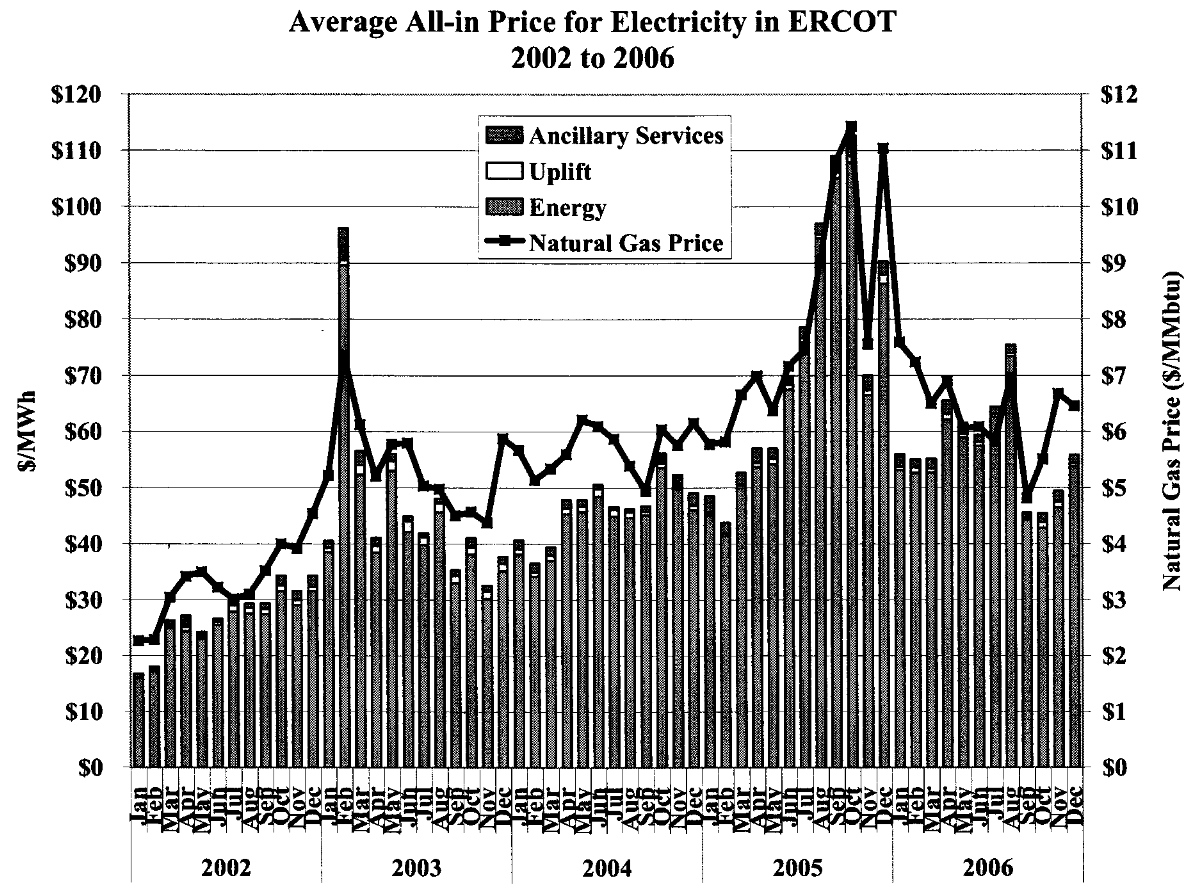
The previous two figures summarize these erratic price patterns by showing the balancing energy prices and actual load in each 15-minute interval during the morning "ramping-up" hours and evening "ramping-down" hours. These pricing patterns raise significant efficiency concerns regarding the operation 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.[2] In prior reports, we have made several recommendations to address the issue under the current zonal design. However, significant modifications to the zonal market design may not be practical at this time given the scheduled implementation of the nodal market by 2009. 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"). 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.

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



The figure indicates that natural gas prices were a primary driver of the trends in electricity prices from 2002 to 2006. Natural gas prices increased in 2003 by more than 65 percent from 2002 levels on average while the all-in price for electricity increased by 72 percent. Again, 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.

To provide some 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 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.

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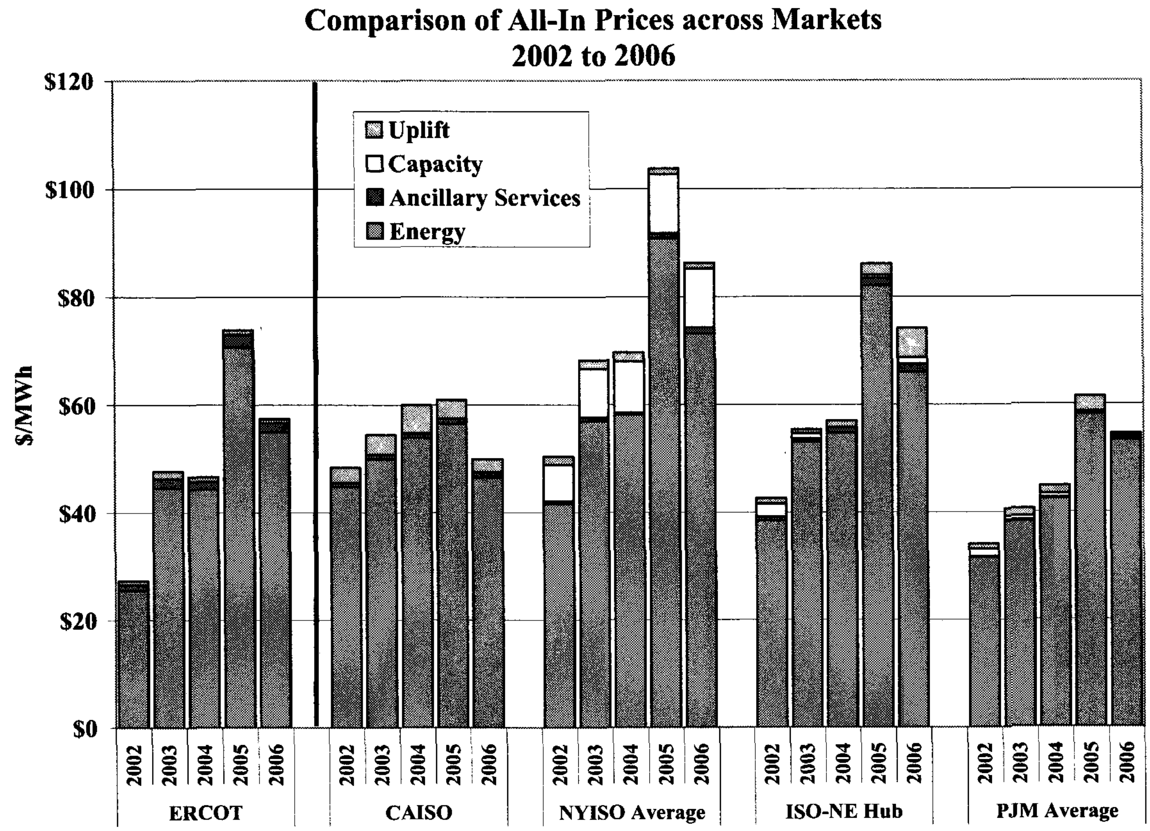

Wholesale electricity markets in the U.S. experienced substantial increases in energy prices from 2002 to 2003 and from 2004 to 2005 due to increased fuel costs. In 2006, energy prices in the U.S. dropped in every region due to decreased fuel costs. Although the markets vary substantially in the portion of their generating capacity that is fueled by natural gas, these units are on the margin and setting the wholesale spot prices in a large share of the hours in each of the markets. The largest decreases in electricity prices occurred in ERCOT, indicating natural gas resources are on the margin more frequently in this market than other markets. PJM had the smallest percentage decrease in electricity price in 2006 from 2005. Coal-fired generation is on the margin in a larger share of the hours in PJM, making prices in that market less sensitive to changes in natural gas prices.

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

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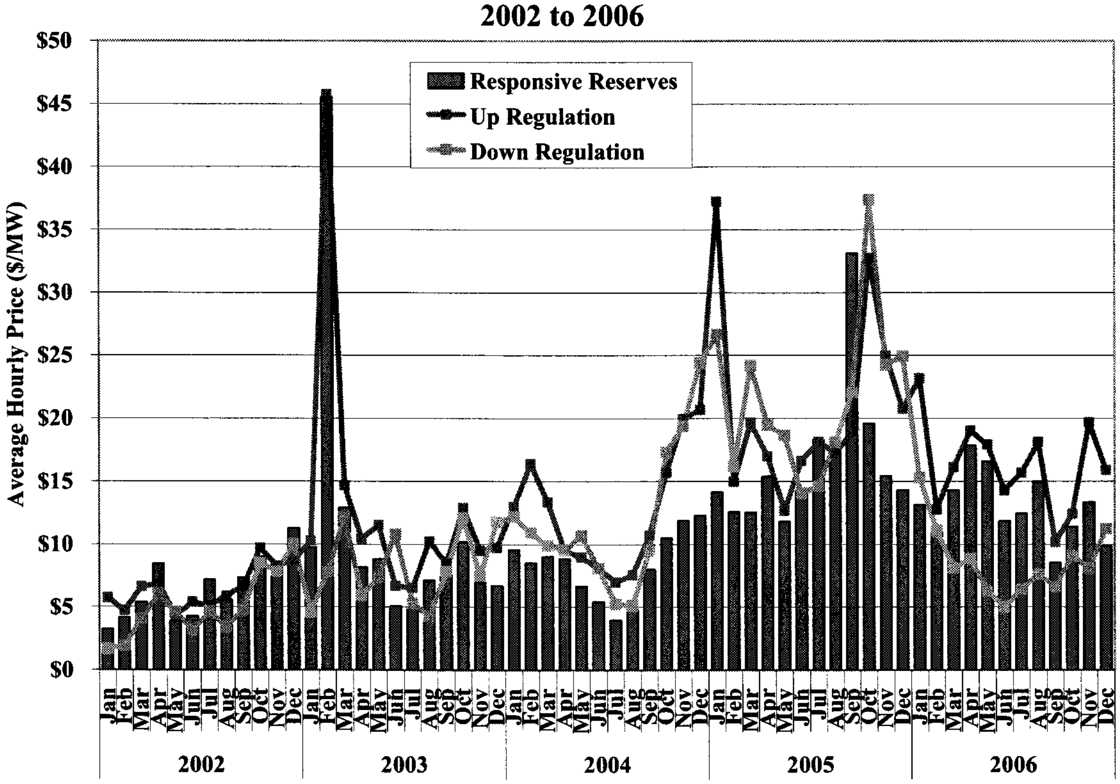
services or purchase their required ancillary services through the ERCOT markets. This section reviews the results of the ancillary services markets in 2006.

Ancillary services prices have risen considerably since 2002, peaked in 2005 and dropped in 2006, consistent with long-term trends in natural gas and electricity prices. 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 average prices for regulation and responsive reserve services from 2002 to 2006.

Monthly Average Ancillary Service Prices 2002 to 2006



Although ancillary services prices have generally risen over the last few 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 2006, the requirement was reduced to an average of 1,950 MW during ramping hours and 1,500 MW

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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.

Currently, ERCOT's regulation procurement methodologies group regulation procurement quantities into 4 to 6 blocks of hours and procure the same quantity in each block for each day in each month. In late 2006, we initiated discussions with ERCOT to investigate modifications to this methodology that would allow 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. The ERCOT Board approved the changed methodology in June 2007 to be implemented in August 2007. It is expected that this change will reduce the overall quantities of regulation procured over all hours, but may increase the regulation quantities procured in certain hours. This change should result in more efficient procurement of regulation up and down service while maintaining or even improving reliability.

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 by 2009.

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. However, although the functionality will not be implemented at the inception in the nodal market in 2009, we also recommend the development of real-time markets that co-optimize ancillary services and energy to further enhance the efficient dispatch of resources and pricing in real-time.

4. Net Revenue Analysis

A final analysis of the outcomes in the ERCOT markets in 2006 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

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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.

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 2004 to 2006 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. The net revenue increased significantly from 2002 to 2005, largely due to rising natural gas prices and more frequent price spikes in the balancing energy market.

In contrast to 2005, net revenue was insufficient to support new entry for gas-fired units in 2006, although the net revenue for gas-fired units in 2006 remained significantly higher than years prior to 2005. As in 2005, net revenue for coal and nuclear units remained above the levels required to support new entry. These outcomes were primarily affected by the following factors:

- Although continuing to decline relative to prior years, planning reserve margins in 2006 were approximately 16.5 percent, which is well 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 moderated in 2006, but remained at levels significantly higher than years prior to 2005. Thus, net revenue for coal and nuclear units continued to be at levels sufficient to support new entry.

- The Modified Competitive Solution Method ("MCSM") triggered price adjustments more frequently in 2006. MCSM is a PUCT-approved mechanism that was in effect in 2005 and through September 2006 that provided for an *ex post* reduction to the resulting market prices when all dispatchable balancing energy was exhausted. The average number of MCSM intervals per month almost doubled to over 26 per month in 2006 compared to less than 16 per month in 2005 for the months in which MCSM was in effect.
- The competitive performance of the ERCOT market improved in 2006.

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, MCSM was eliminated by the new rules.

Unlike markets with a long-term capacity market, 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 for demand response and efficient incentives for new investment when required. During non-shortage conditions (*i.e.*, most of the time), the expectation of competitive market outcomes is no different in energy-only than in capacity markets.

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 1000 to 4000 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 2006 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 analysis in this section differs from similar analyses in prior reports in the following important respect. In prior reports, un-offered capacity calculations included capacity that existed but was not offered. They did not attempt to quantify the amount of un-offered capacity that was actually available, and practicable to offer, given the ERCOT scheduling timelines, operating rules and conditions, and technical or commercial limitations that might limit a QSE's ability to offer capacity in the ERCOT market. In contrast, the approach used for the analysis of un-offered capacity in this section is focused on online,

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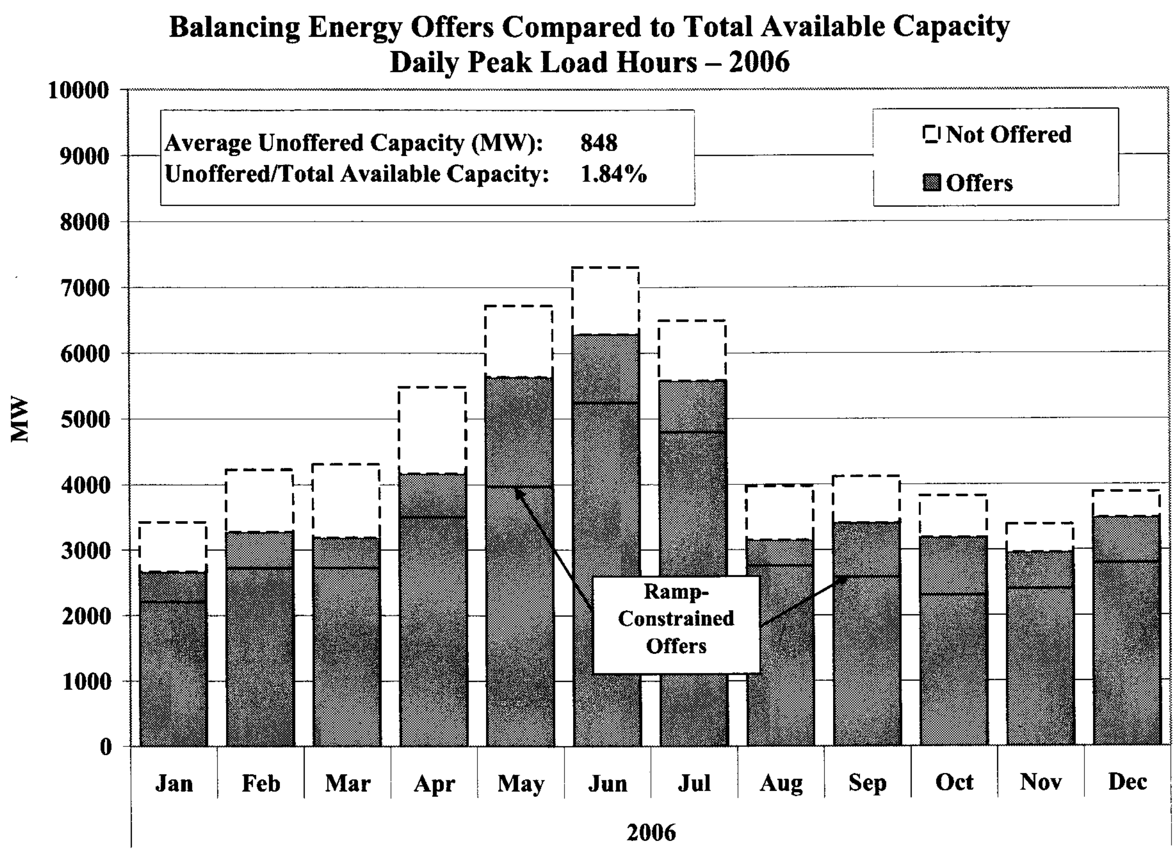
available capacity for which there is a reasonable expectation that the energy can be produced in light of the factors and considerations listed above.



In regard to the residual un-offered capacity, the report identifies several structural impediments that could not be specifically quantified in the figure above. These impediments are largely a function of the zonal market design and serve to explain the quantity of un-offered capacity that could not be specifically quantified in the figure above.

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 2006. 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.

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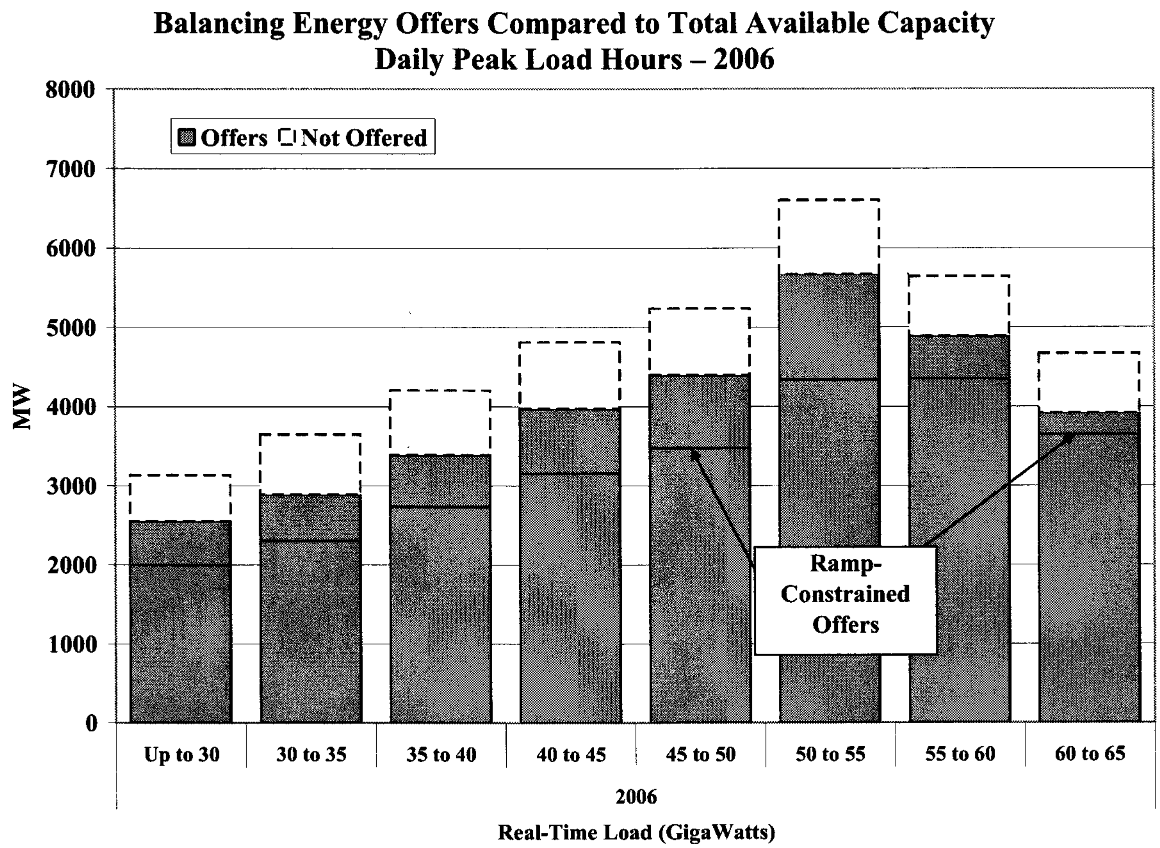


This figure indicates that in 2006, the average amount of capacity available to the balancing market increased gradually up to 55 GW of load and then declined at higher levels. The decline in balancing energy available at higher load levels is associated with the fact that scheduled generation increases 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.

4. Resource Plan Analysis

QSEs submit resource plans to inform ERCOT about which resources they plan to use to satisfy their energy and ancillary services obligations. While QSEs are expected to make their best effort to accurately forecast how they will operate their units, the resource plans are not financially binding. Resource plans are used by ERCOT in some of its reliability assessments before real-time and to make additional commitments to maintain reliability. Therefore, it is important for ERCOT to have accurate information in the resource plans that QSEs submit in order to avoid taking unnecessary and sometimes costly actions to maintain reliability.

Resource plans are not financially binding, yet they are used by ERCOT to make commitment decisions that can have significant cost implications. Hence, a market participant can affect ERCOT's actions and the revenue it receives by submitting resource plans that do not represent efficient generator commitment and dispatch. We analyzed market participants' resource plans to evaluate whether the market protocols may provide incentives for such strategic conduct. Specifically, we evaluated units that are frequently committed out-of-merit or frequently dispatched out-of-merit. Such units receive additional payments from ERCOT and we investigated whether market participants may engage in strategies to increase these payments.

This analysis indicates that most QSEs receiving substantial OOMC or OOME Up payments have commitment and scheduling patterns consistent with the market as a whole. However, some QSEs may delay the commitment of some resources that are frequently committed by ERCOT for reliability purposes or under-schedule resources that are frequently receive OOME Up instructions. In contrast, the analysis of units that are frequently called on for OOME Down indicates that these units are generally scheduled in a manner similar to the market as a whole.

The incentives for participants to submit resource plans that do not reflect anticipated real-time operations stem from the lack of nodal prices to signal the value of capacity and energy in local areas. In the absence of nodal prices, market participants may act strategically to garner additional uplift payments.

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 2006, the load served by ERCOT reached a peak of over 63 GW.[3] This was a relatively significant increase over previous years when the peak was approximately 60, 59, and 61 GW in 2003, 2004 and 2005, respectively. Changes in these 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, as evidenced by the rolling blackout events of April 17, 2006.

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 76 percent of generation capacity in ERCOT as a whole, and 86 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 more than 8 GW was mothballed during 2006 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 2006 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

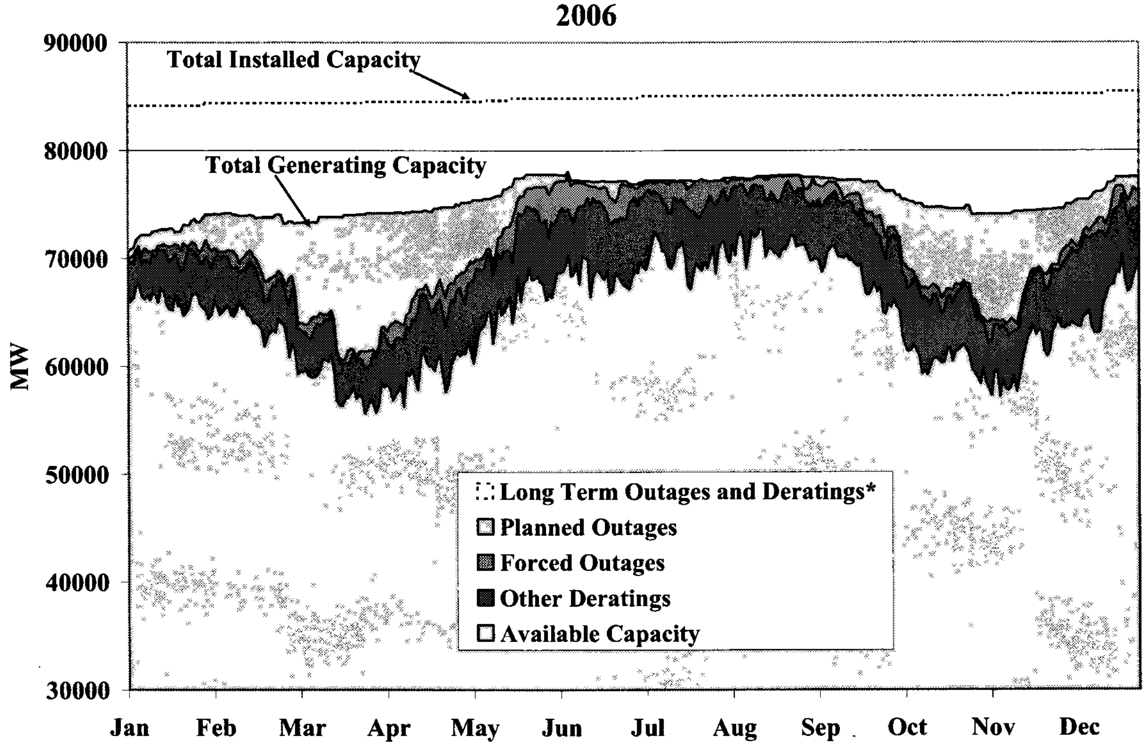
3 This value is the total load to be served in real-time as represented in ERCOT's Scheduling, Pricing and Dispatch software (including transmission and distribution losses), and may differ from settlement values.

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.

Short and Long-Term Deratings of Installed Capability 2006



* 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.

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The figure shows that long-term outages and deratings fluctuated between 6 GW and 13 GW. These long-term deratings reduce the effective resource margins in ERCOT from the levels reported above. Most of these deratings reflect:

- Resources out-of-service for extended periods due to maintenance requirements;
- Resources out-of-service for economic reasons (*e.g.*, mothballed units);
- Cogeneration resources typically used for purposes other than electricity generation; or
- Output ranges on available generating resources that are not capable of producing up to the full installed capability level.

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.

The "other deratings" shown in the figure ranged from an average of 7 percent during the summer in 2006 to as high as 12 percent in other months. These deratings include outages not reported or correctly logged by ERCOT and natural deratings due to high ambient temperature conditions and other factors. The overall pattern of outages and deratings is consistent with competitive expectations and does not raise significant concerns.

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 2,927 MW in 2006, which is approximately 8 percent of the average load in ERCOT. This is a significant decrease from the average of 4,313 MW in 2005 and 6,627 MW in 2004. These decreases can be attributed in part to the continued increase in ERCOT load with a relatively static available supply, fewer quick-start gas turbines that were qualified to provide balancing energy, and a continuation of the trend from previous years of ERCOT committing fewer units via OOMC instructions and RMR.

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 planned for implementation by 2009 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 2006, 1,985 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 1,835 MW at the end of 2005. Currently, LaaRs are permitted to supply up to 1,150 MW (50 percent) of the responsive reserves requirement. Although the participants with LaaRs resources are qualified to provide non-spinning reserves and up balancing energy in real-time, in 2006, they provided only about one percent of non-spinning reserves and none of the balancing energy. 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. In addition, prices in the balancing energy market have not been high enough to attract load participation in that market. 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 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.

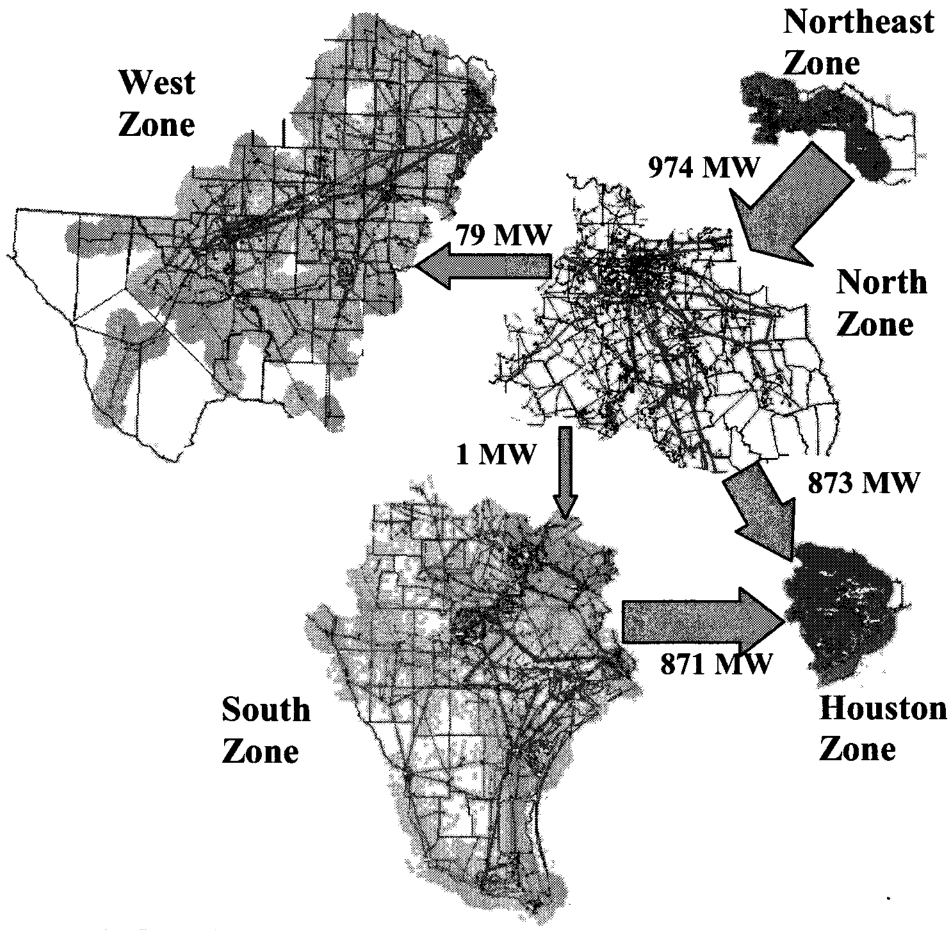
D. Transmission and Congestion

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 in order 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 five zone-based locations and six transmission interfaces. The transmission interfaces are referred to as Commercially Significant Constraints ("CSCs"). The following figure shows the average flows modeled in SPD during 2006 over each of these CSCs.

Average Modeled Flows on Commercially Significant Constraints 2006



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 79 MW, which is equivalent to saying that the average for the West-to-North CSC was *negative* 79 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, such as the North to West CSC that was implemented by ERCOT in 2005 to better manage congestion over that path.
- Based on modeled flows, Houston is a significant importer while the Northeast Zone and the South Zone export significant amounts of power.

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. In order 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 decreased considerably to $69 million in 2006, which reflects a decrease of $50 million from 2005. This increase was the result of less frequent congestion on the South-to-Houston, North-to-Houston, and South-to-North CSCs, as well as lower overall prices.

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

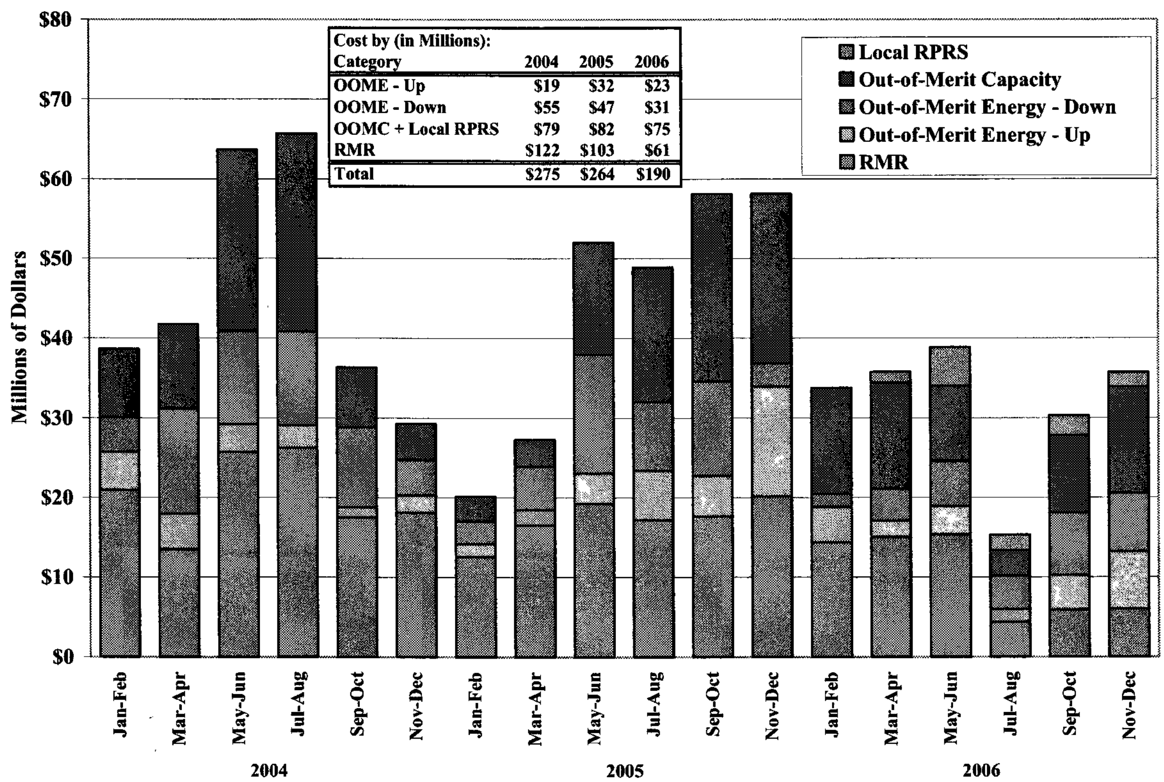
Participants in Texas can hedge against congestion in the balancing energy market by acquiring Transmission Congestion Rights ("TCRs") between zones which entitle the holder to payments equal to the difference in zonal balancing energy prices. Because the modeled limits for the CSC interfaces vary substantially, 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 decreased considerably to $7 million in 2006, down from $38 million in 2005. This reduction was primarily due to decreased interzonal congestion in 2006 and improved accuracy in the quantity of TCRs sold in the monthly auction.

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 2005, the annual and monthly TCR auctions substantially under-valued the TCRs in comparison to the balancing market congestion. In contrast to 2005, market participants over-estimated the annual value of congestion on the South to North, South to Houston, and North to Houston CSCs in 2006. 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 2006.

Expenses for Out-of-Merit Capacity and Energy 2004-2006



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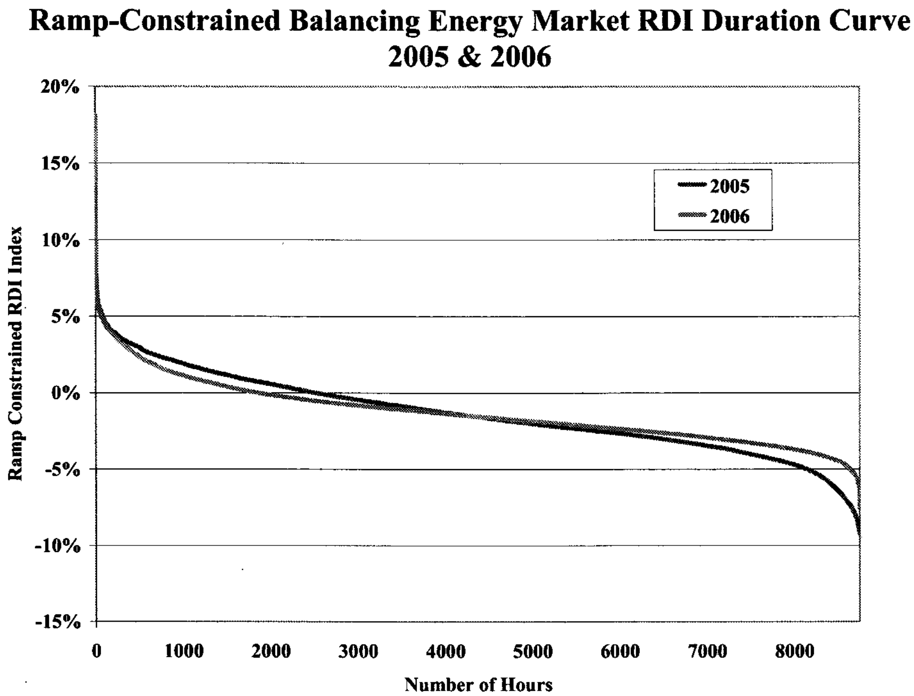
The results in the figure above show that overall uplift costs for RMR units, OOME units, and OOMC/Local RPRS units were relatively consistent between 2004 and 2005. The costs decreased by $74 million in 2006 from $264 million to $190 million, a reduction of 28 percent. There were substantial reductions to RMR cost due to the expiration of RMR agreements in 2006, which accounts for $42 million of the $74 million decrease from 2005 to 2006. Total OOME Up and OOME Down costs also decreased from $79 million in 2005 to $54 million in 2006, a reduction of 32 percent. This reduction is likely due to the continued improvements to the ERCOT transmission system resulting in less frequent local congestion, and the introduction of an enhanced replacement reserve procurement process by ERCOT in 2006.

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



In 2006, there were 1,861 hours (21.2 percent) when the balancing energy market RDI was greater than zero, which means a supplier was pivotal in the balancing energy market 21.2 percent of the time in 2006. In contrast, there were 2,525 hours (28.8 percent) when the balancing energy market RDI was positive in 2005. Hence, the frequency with which a supplier was pivotal in the balancing energy market decreased 26 percent in 2006 indicating that the overall competitiveness of the balancing energy market improved in 2006. Among other factors, this decrease can be attributed to an average reduction in up balancing energy deployments in 2006, which was influenced by the existence of the under-scheduled charges associated with the replacement reserve market.

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 physical and economic withholding in order to further evaluate competitive performance of the ERCOT market. Withholding patterns were examined relative to the level of demand and the size of each supplier's portfolio. Based on the analyses conducted in this area, the report found the overall output gap for both large and small suppliers was reduced considerably in 2006 as compared to 2005. Overall, we find that the competitive performance of the market improved in 2006.

I. REVIEW OF MARKET OUTCOMES

A. Balancing Energy Market

1. Balancing Energy Prices During 2006

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 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).[4] 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 2006.

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 2005 and 2006.[5] Balancing energy market prices were 24 percent lower in 2006 than in 2005, with the latter half of the year showing the largest reductions from 2005.

In 2005, natural gas prices began to rise significantly during the summer and remained at high levels through the end of the year. This increase was largely due to the effects of the hurricanes on the productive capability of the Gulf Coast region. However, natural gas prices settled to

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

5 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).

relatively lower levels in 2006, especially during the second half of the year. Natural gas is typically the marginal fuel in the ERCOT market. Hence, the changes in energy prices from 2005 to 2006 were largely a function of natural gas price movements.

Figure 1: Average Balancing Energy Market Prices 2005 & 2006

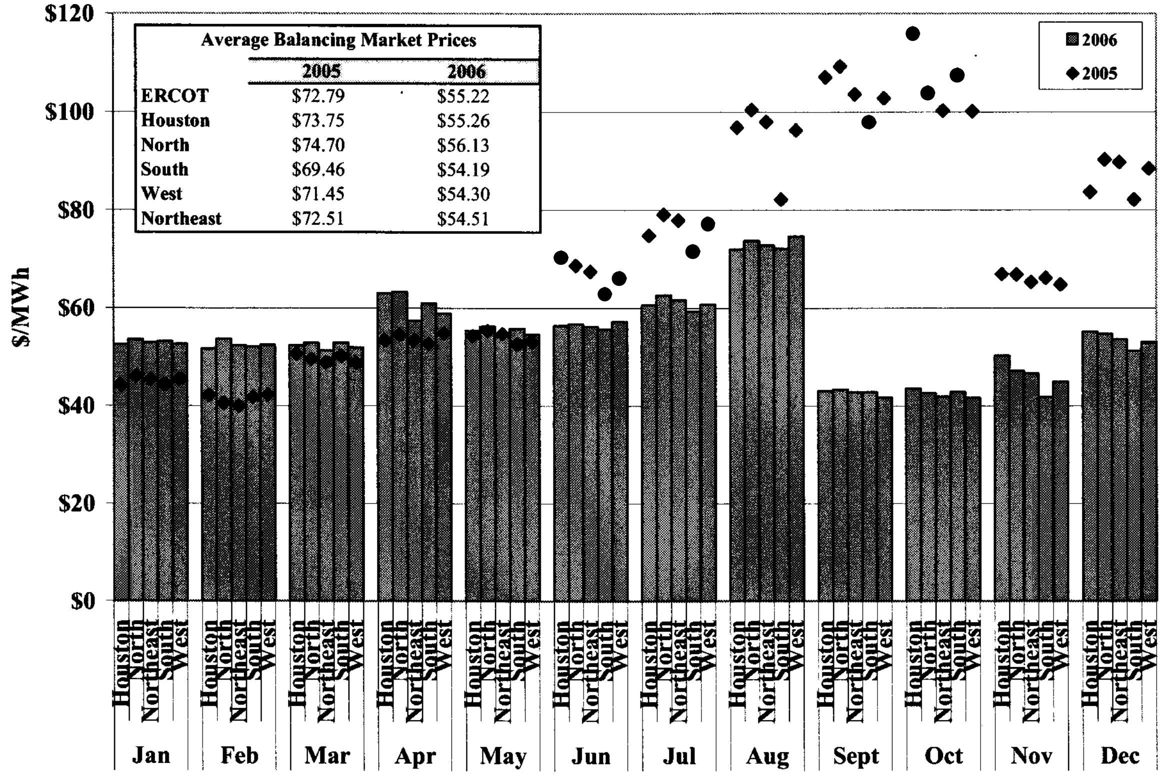


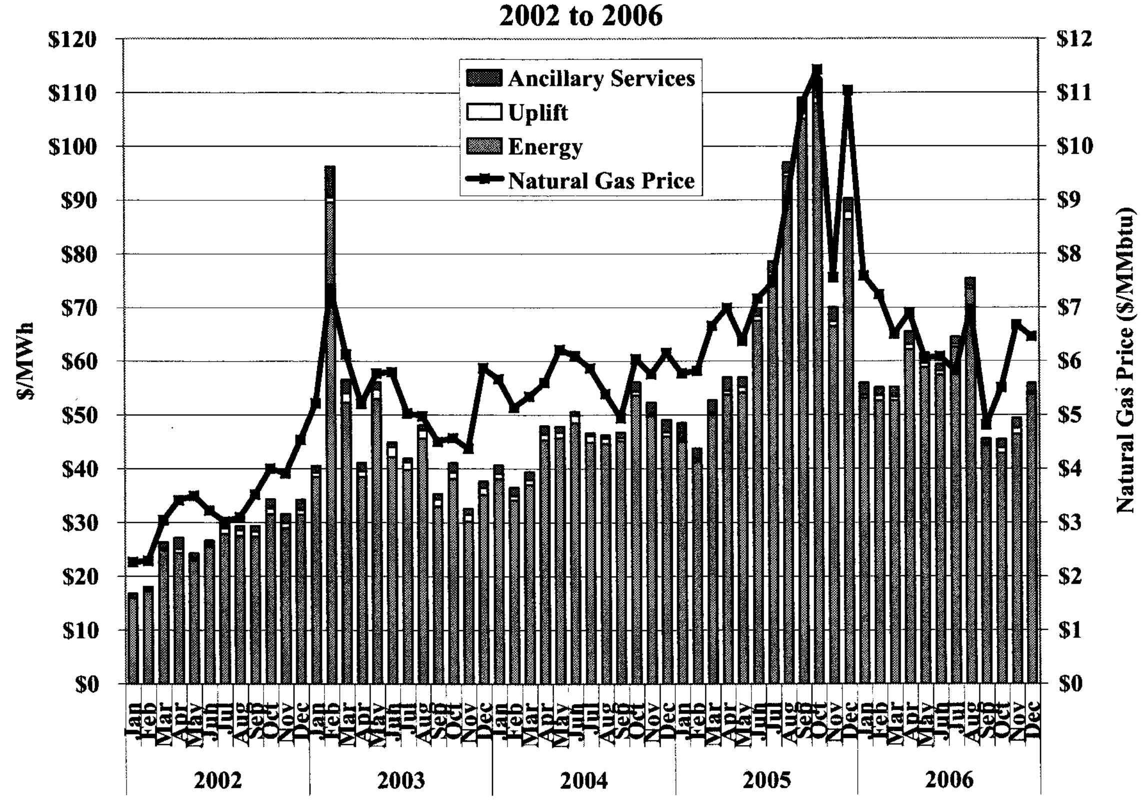
Figure 1 also shows that transmission congestion between zones decreased in ERCOT during 2006. The difference between the average North and South zones prices was approximately 3.5 percent in 2006 as compared to 7.5 percent in 2005. In individual months, the zonal price difference was also much smaller in 2006. For example, the average North zone price exceeded the South zone by approximately $18 per MWh in August 2005, while the difference was only $0.68 per MWh in August 2006.

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".[6] 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 2002 to 2006.

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 2002 to 2006



6 As discussed more below, 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.

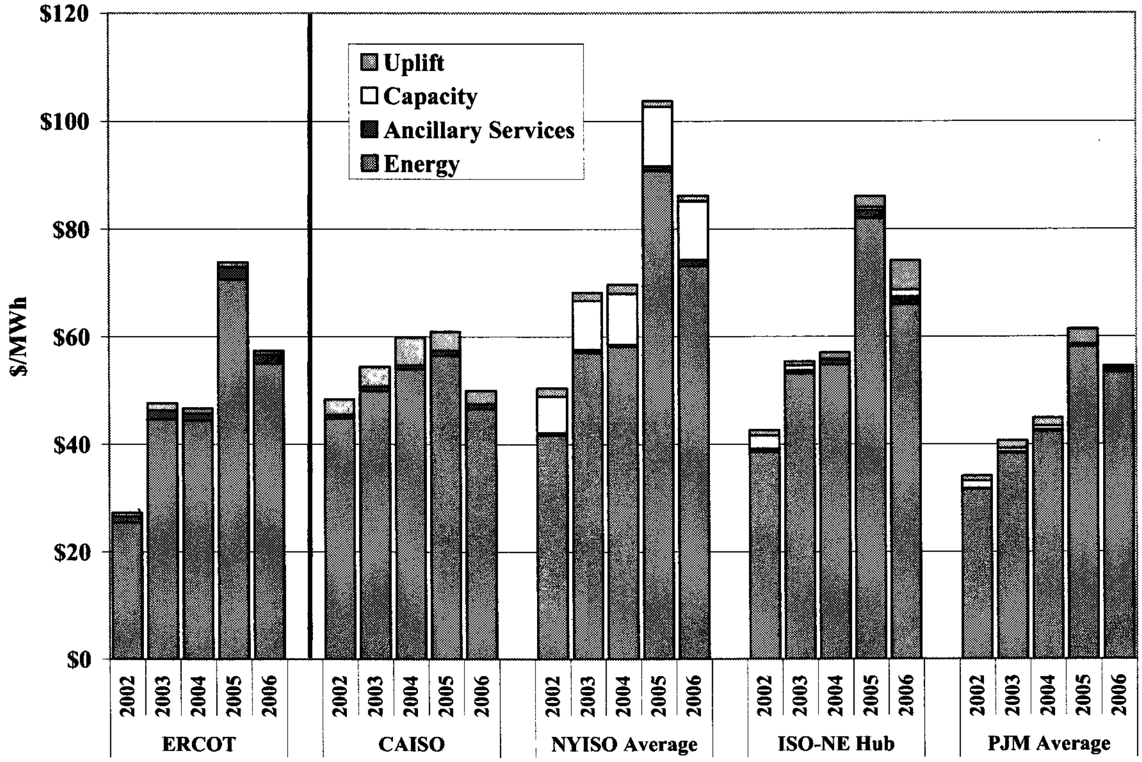
Figure 2 indicates that natural gas prices were a primary driver of the trends in electricity prices from 2002 to 2006. This is not surprising given that natural gas is the predominant fuel in ERCOT, especially among the generating units that most frequently set the balancing energy market prices. Natural 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. The larger increase in electricity prices and the higher number of price spikes in 2005, as discussed later in this subsection, was due, in part, to certain participant conduct that is the subject of a PUCT enforcement proceeding. 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.

Although fuel price fluctuations have been the dominant factor driving the decreases in electricity prices in 2006, fuel prices alone do not explain all of the price changes. At least three other factors contributed to price changes in 2006. First, ERCOT demand increased in 2006, while the supply remained relatively static. Second, ERCOT generally committed less excess capacity on a daily basis in 2006. Third, the overall competitive performance of the market improved in 2006 relative to 2005. The first two factors will tend to produce an upward pressure on prices in 2006 relative to 2005, and these factors are discussed in greater detail in Section III of this report. In contrast, the third factor will tend to lower prices and is examined 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 2005 to 2006, a 30 percent decrease in ancillary services costs result in a one percent decrease in the all-in price for electricity. Ancillary services prices began to decrease in late 2005 and remained lower throughout 2006. Generally, the ancillary services prices coincided with price movements in the balancing energy market, which is to be expected since the energy and ancillary services 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.

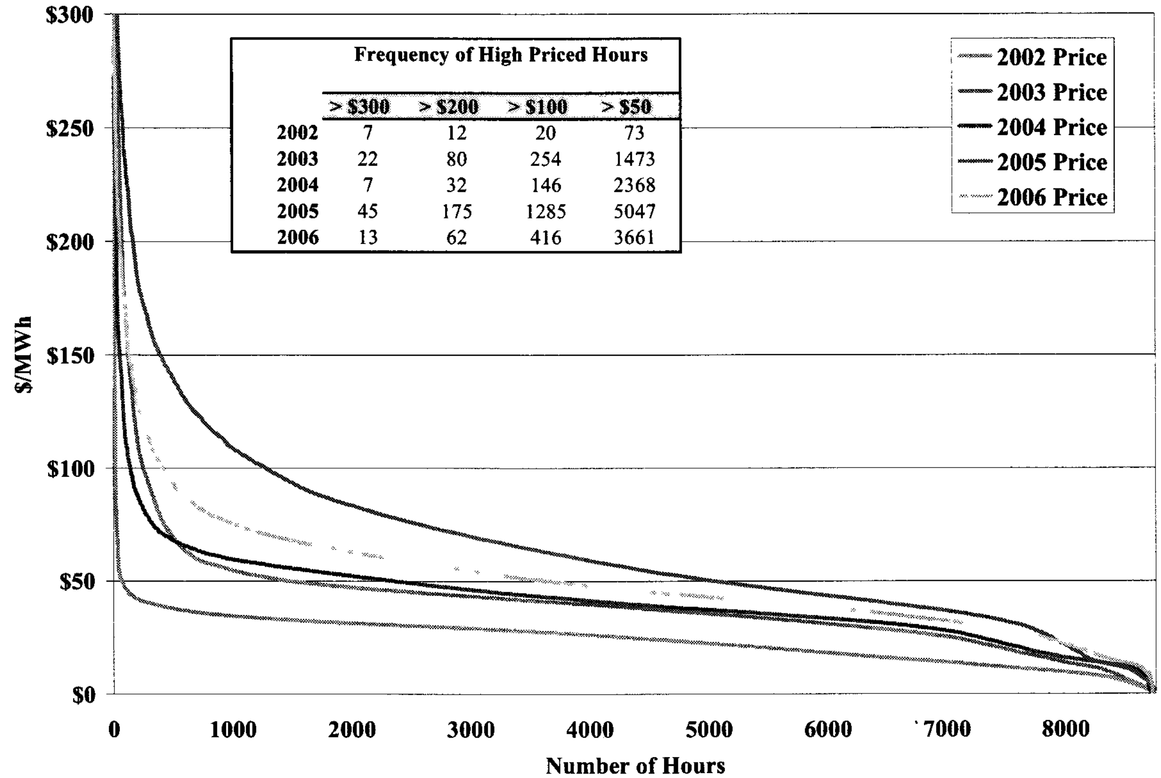
Figure 3: Comparison of All-in Prices Across Markets 2002 to 2006



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. Although the markets vary substantially in the portion of their generating capacity that is fueled by natural gas, these units are on the margin and setting the wholesale spot prices in a large share of the hours in each of the markets. The largest decreases in electricity prices occurred in ERCOT, indicating natural gas resources are on the margin more frequently in this market than other markets. PJM had the smallest percentage decrease in electricity price in 2006 from 2005. Coal-fired generation is on the margin in a larger share of the hours in PJM, making prices in that market less sensitive to changes in natural gas prices.

Figure 4 presents price duration curves for the ERCOT balancing energy market in each year from 2002 to 2006. 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 2002 to 2006



The figure shows that, with the exception of 2005, balancing energy prices were higher in 2006 than in prior years. Balancing energy prices exceeded $50 in more than 3,000 hours in 2006 compared to more than 5,000 hours in 2005, and approximately 2,000 hours in 2003 and 2004. These large year-to-year changes reflect the effects of higher fuel prices, which impact electricity prices in a broad range of hours. Higher natural gas prices raise the marginal production costs of the generating units that set the prices in the balancing energy market in a large share of the intervals.

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 2002 and 2006 at the highest price levels.

For example, 2003 experienced considerably more price spikes (*e.g.*, prices higher than $300) than 2004 or 2006 even though prices were higher on average in 2004 and 2006. The largest number of price spikes and the highest average price of any year from 2002 to 2006 occurred in 2005. To better observe the highest-priced hours during 2004 and 2006, the following analysis focuses on the frequency of price spikes in the balancing energy market. Figure 5 shows average prices and the number of price spikes in each month of 2004 and 2006. 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).

As the figure shows, the number of price spikes increased sharply after August 2004. There was an average of 38 price spike intervals per month in 2004 (each month has over 2,900 intervals). The number of price spike intervals more than quadrupled to 127 per month during 2005. Although the number went down in 2006 to 99, it was still more than double the number in 2004. 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 $2.23 per MWh during 2004 and $6.98 per MWh during 2005. In 2006, the impact was $4.68 per MWh. Even though price spikes account for a small portion of the total intervals, they have a significant impact on overall price levels.

Figure 5: Average Balancing Energy Prices and Number of Price Spikes 2004 to 2006

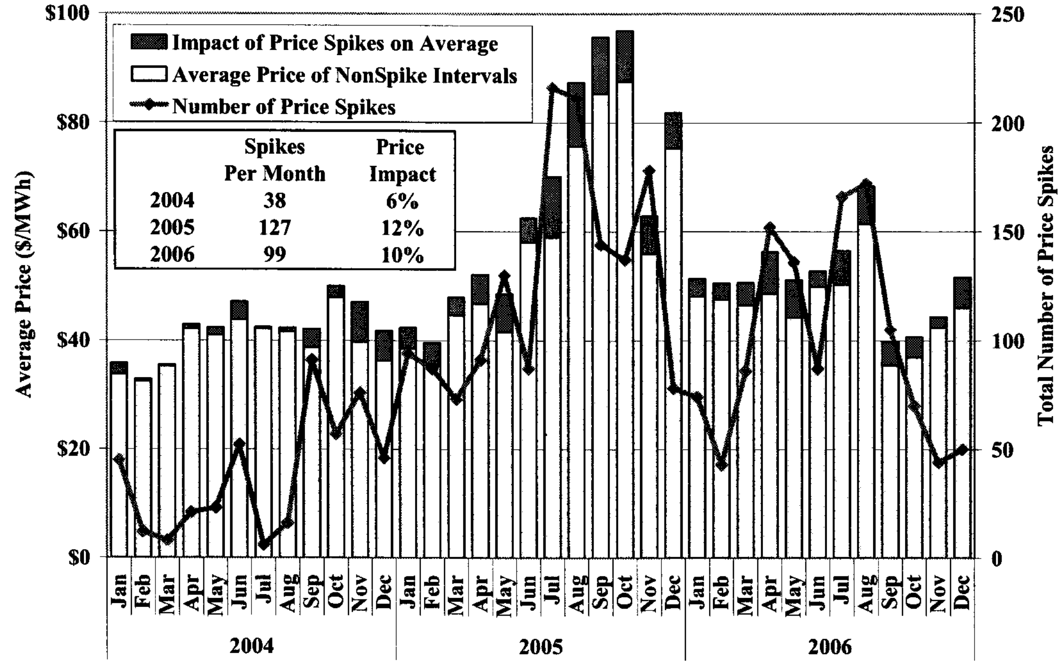


Figure 6: Average Regulation Up Prices and Number of Price Spikes 2004 to 2006

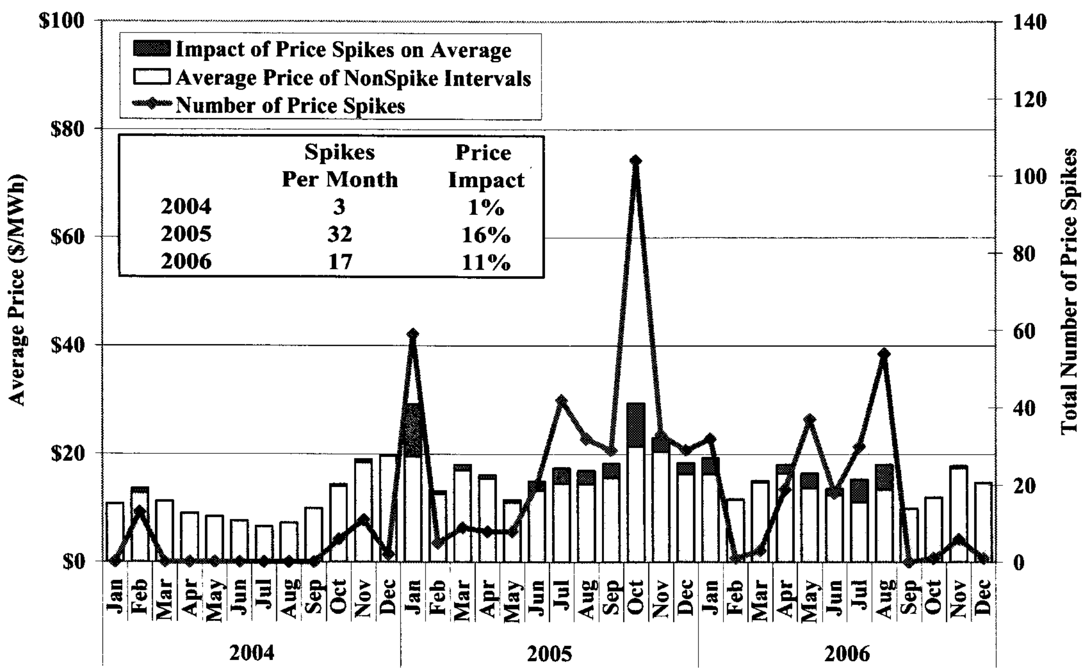


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Figure 7: Average Regulation Down Prices and Number of Price Spikes 2004 to 2006

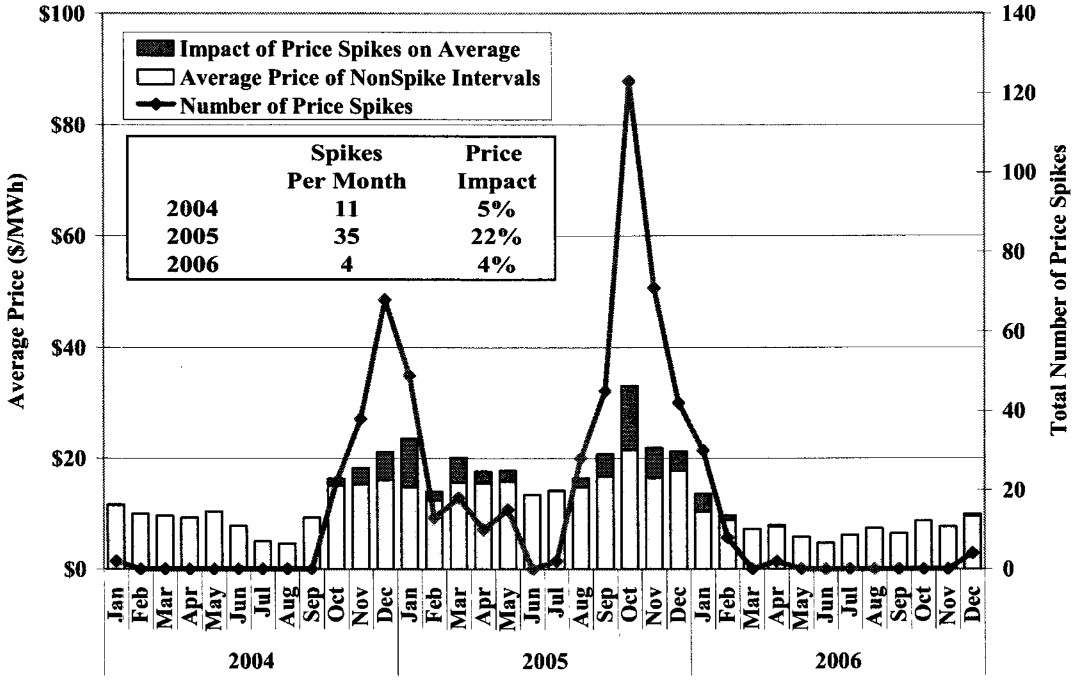
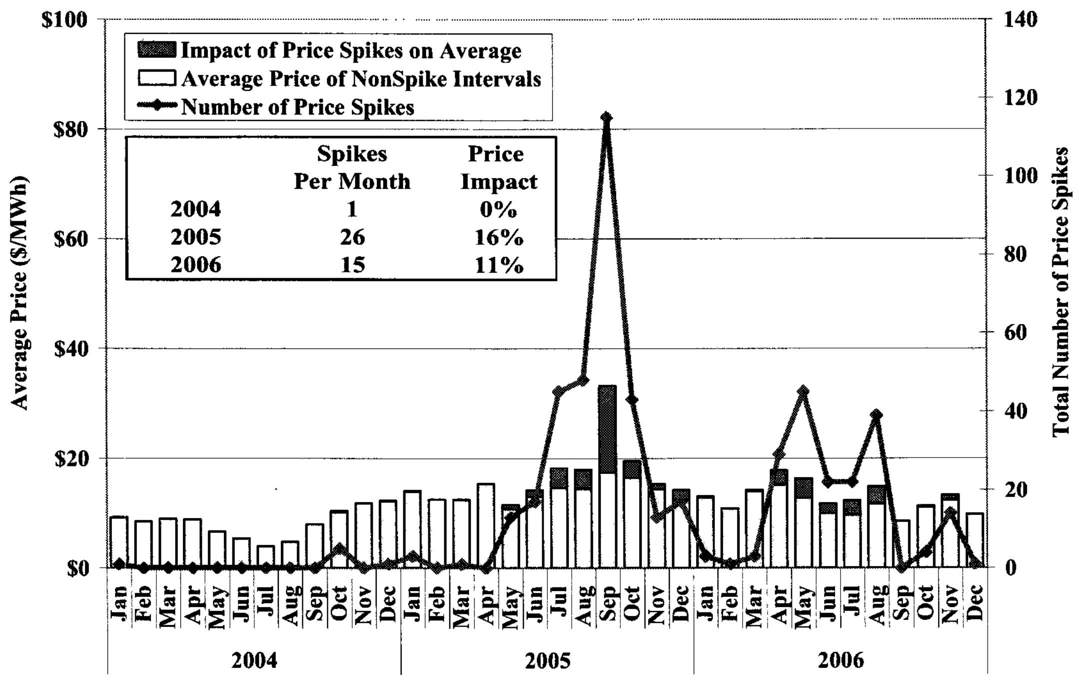


Figure 8: Average Responsive Reserve Prices and Number of Price Spikes 2004 to 2006



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Price spikes in the markets for ancillary services have also risen significantly over this period. During 2004, there were three price spike hours per month for regulation up, 11 for regulation down, and one for responsive reserves. However, in 2005, the number of price spike hours rose dramatically to 32 per month for regulation up, 35 per month for regulation down, and 26 per month for responsive reserves.[7] 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. Since the same resources are used to supply ancillary services and energy, increases in energy prices should lead to corresponding increases 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. The price spikes have generally become more frequent and have become a larger component of the average balancing energy and ancillary service prices. There are several factors that have contributed to the rise in price spikes that are analyzed in detail in subsequent sections of this report. 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.

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 includes two charts showing 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

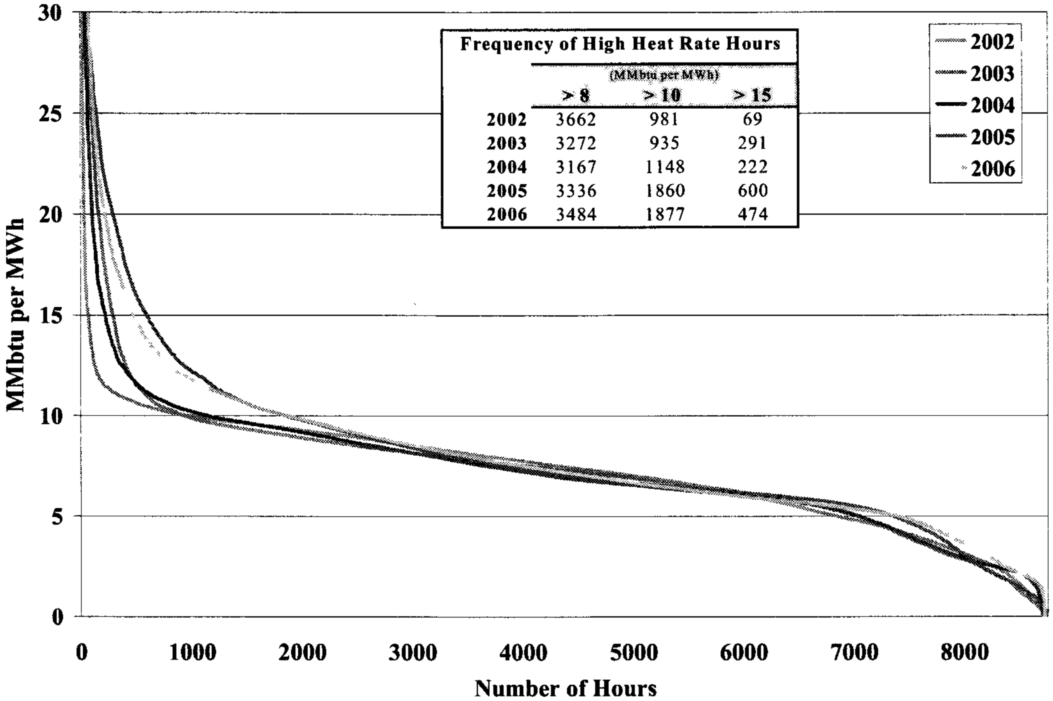
7 Price spikes are defined as hours where the price exceeds a threshold of $50 per MW for regulation up, regulation down, and responsive reserves.

Natural Gas Price.[8] 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 2002 to 2006.

In contrast to Figure 4, Figure 9 shows that the implied marginal heat rates were relatively consistent across the majority of hours from 2002 to 2006. 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 2002 to 2006 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 implied heat rate was over 10 was 1,148 in year 2003, whereas in 2005 and 2006 the number rose to 1,860 and 1,877, respectively. However, in 2006, the number of hours when the implied heat rate was over 15 dropped to 474 from 600 in 2005. This indicates that there are price differences that are due to factors other than changes in natural gas prices.

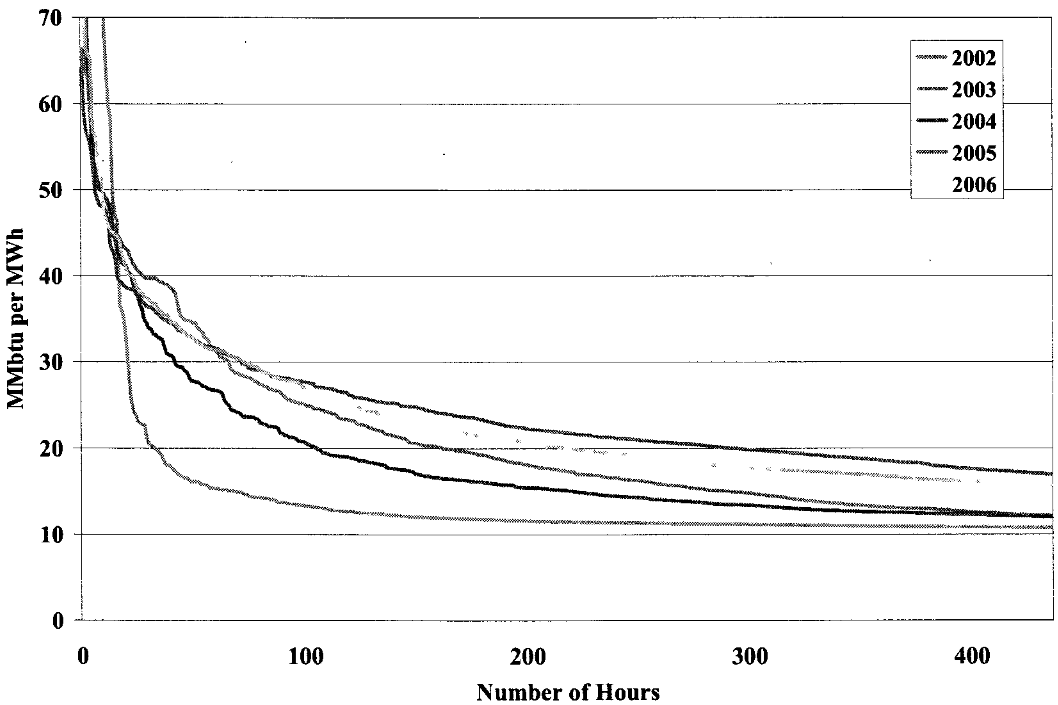
8 This methodology implicitly assumes that electricity prices move in direct proportion to changes in natural gas prices.

Figure 9: Implied Marginal Heat Rate Duration Curve
All Hours – 2002 to 2006



	> 8	> 10	> 15
2002	3662	981	69
2003	3272	935	291
2004	3167	1148	222
2005	3336	1860	600
2006	3484	1877	474

Top Five Percent of Hours in Each Year – 2002 to 2006



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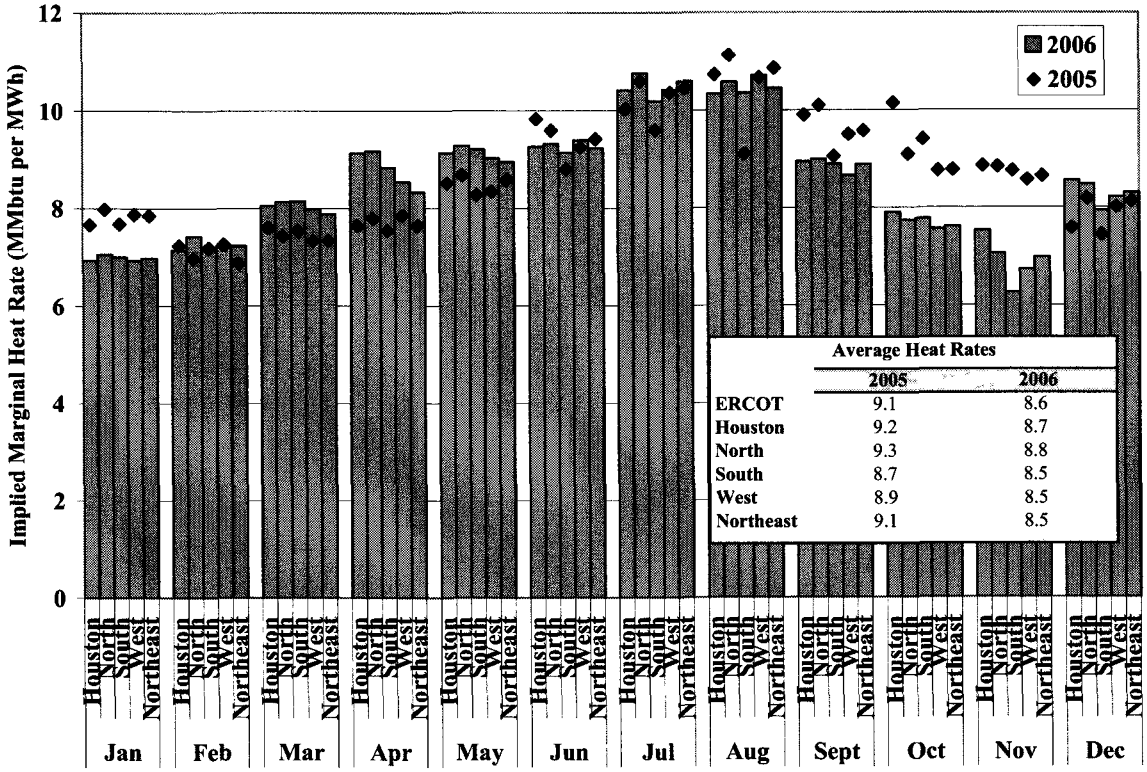
To better understand these differences, the next figure shows the implied marginal heat rates on a monthly basis in each of the ERCOT zones in 2005 and 2006. This figure is the fuel price-adjusted version of Figure 1 in the prior sub-section. Adjusted for gas price influence, Figure 10 shows that average implied heat rate for all hours of the year decreased by 5.5 percent from 9.1 in 2005 to 8.6 in 2006.

Figure 10: Monthly Average Implied Marginal Heat Rates 2005 & 2006



3. Price Convergence

One indicator of market performance is the extent to which forward and real-time spot prices converge over time. In ERCOT, there is no centralized day-ahead market so prices are formed in the day-ahead bilateral contract market. The real-time spot prices are formed in the balancing energy market. Forward prices will converge with real-time prices when two main conditions are in place: a) there are low barriers to shifting purchases and sales between the forward and real-time markets; and b) sufficient information is available to market participants to allow them to develop accurate expectations of future real-time prices. When these conditions are met, market participants can be expected to arbitrage predictable differences between forward prices

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and real-time spot prices by increasing net purchases in the lower-priced market and increasing net sales in the higher-priced market. This will tend to improve the convergence of the forward and real-time prices.

We believe these two conditions are largely satisfied in the current ERCOT market. Relaxed balanced schedules allow QSEs to increase and decrease their purchases in the balancing energy market. This flexibility should better enable them to arbitrage forward and real-time energy prices. While this should result in better price convergence, it should also reduce QSEs' total energy costs by allowing them to increase their energy purchases in the lower-priced market. However, volatility in balancing energy prices can create risks that affect convergence between forward prices and balancing energy prices. For example, risk-averse buyers will be willing to pay a premium to purchase energy in the bilateral market.

There are several ways to measure the degree of price convergence between forward and real-time markets. In this section, we measure two aspects of convergence. The first analysis investigates whether there are systematic differences in prices between forward markets and the real-time market. The second tests whether there is a large spread between real-time and forward prices on a daily basis.

To determine whether there are systematic differences between forward and real-time prices, we examine the difference between the average forward price[9] and the average balancing energy price in each month between 2004 and 2006. This reveals whether persistent and predictable differences exist between forward and real-time prices, which participants should arbitrage over the long-term.

In order to measure the short-term deviations between real-time and forward prices, we also calculate the average of the absolute value of the difference between the forward and real-time price on a daily basis during peak hours. It is calculated by taking the absolute value of the difference between a) the average daily peak period price from the balancing energy market (*i.e.*, the average of the 16 peak hours during weekdays) and b) the day-ahead peak hour bilateral price. This measure indicates the volatility of the daily price differences, which may be large

[9] Day-ahead bilateral prices are from Megawatt Daily.

even if the forward and balancing energy prices are the same on average. For instance, if forward prices are $70 per MWh on two consecutive days while real-time prices are $40 per MWh and $100 per MWh on the two days, the price difference between the forward market and the real-time market would be $30 per MWh on both days, while the difference in average prices would be $0 per MWh. These two statistics are shown in Figure 11 for each month between 2004 and 2006.

Figure 11 shows price convergence during peak periods (i.e. weekdays between 6 AM and 10 PM). This timeframe matches the definition of peak hours that are commonly traded in the forward market. During most of 2004, the average day-ahead price was consistent with the average balancing energy price. However, starting in September 2004 and continuing through 2005, it became common for the average balancing energy price to exceed the day-ahead price by a significant margin. In 2006, the average day-ahead price again became relatively consistent with the average balancing energy price. In the months of May, June, July and August of 2006, average day-ahead prices were higher than average balancing energy price, while in the other months of 2006, average day-ahead prices were exceeded by the average balancing energy prices, but by a much smaller margin on average than in 2005.

Figure 11: Convergence Between Forward and Real-Time Energy Prices 2004 to 2006

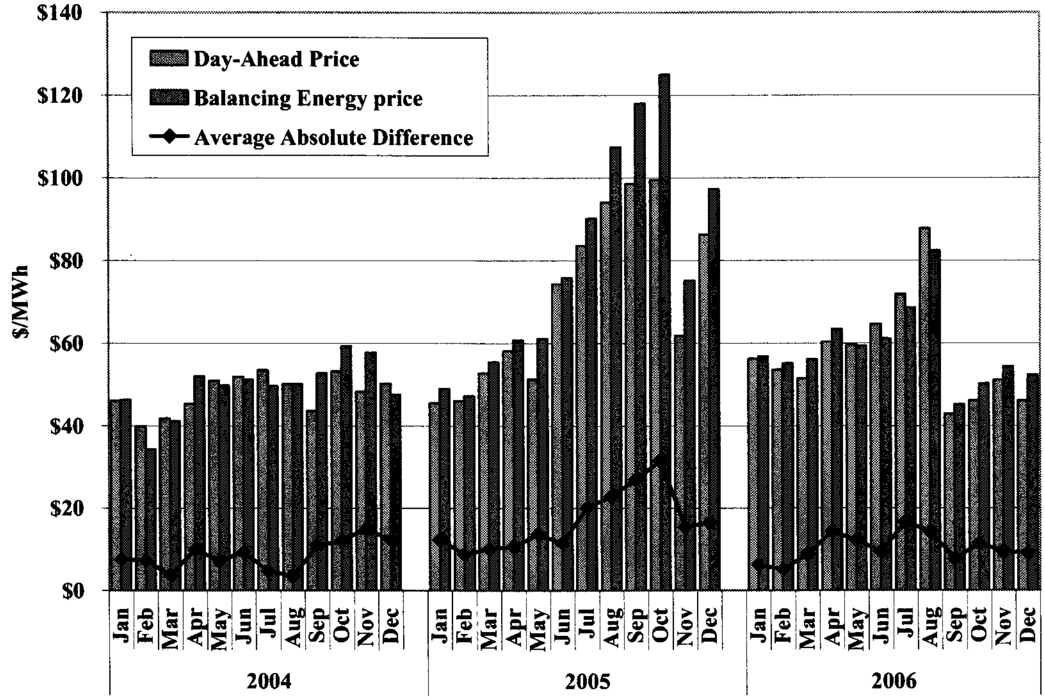

Figure 11 also shows that the average absolute price difference from 2004 to 2006. The difference (shown by the line) was relatively low during the first eight months of 2004 before rising considerably during the last four months. In 2005, the average absolute difference rose sharply in the summer and fall. In 2006, the average absolute difference dropped closer to the average level observed in 2004. The average absolute difference was $9 in 2004, $17 in 2005 and $10 in 2006. As noted above, the average absolute difference measures the volatility of the price differences.

The results in this section indicate that convergence between the day-ahead bilateral prices and the balancing energy prices has improved in 2006 from 2005. The frequency of price spikes in 2006 was less than in 2005, but still much greater than the price spike frequency in 2004. However, the average absolute difference between the day-ahead price and balancing energy price in 2006 returned closer to the average level observed in 2004.

4. Volume of Energy Traded in the Balancing Energy Market

In addition to signaling the value of power for market participants entering into forward contracts, the balancing energy market plays a role in governing real-time dispatch. This section examines the volume of activity in the balancing energy market.

The average amount of energy traded in ERCOT's balancing energy market is small relative to overall energy consumption. Most energy is purchased and sold through forward contracts that insulate participants from volatile spot prices. Because forward contracting does not precisely match generation with real-time load, there will be residual amounts of energy bought and sold in the balancing energy market. Moreover, the balancing energy market enables market participants to make efficient changes from their forward positions, such as replacing relatively expensive generation with lower-priced energy from the balancing energy market.

Hence, the balancing energy market will improve the economic efficiency of the dispatch of generation to the extent that market participants make their resources available in the balancing energy market. In the limit, if all available resources were offered competitively in the balancing energy market (to balance up or down), the prices in the current market would be identical to the prices obtained by clearing all power through a centralized spot market (even though most of the commodity currently settles bilaterally). It is rational for suppliers to offer resources in the balancing energy market even when they are fully contracted bilaterally, because they can increase their profit by reducing their output and supporting the bilateral sale with balancing energy purchases. Hence, the balancing energy market should govern the output of all resources, even though only a small portion of the energy is settled through the balancing energy market.

In addition to their role in governing real-time dispatch, balancing energy prices also provide a vital signal of the value of power for market participants entering into forward contracts. As discussed above, the spot prices emerging from the balancing energy market should directly affect forward contract prices, assuming that the market conditions and market rules allow the two markets to converge efficiently.

This section summarizes the volume of activity in the balancing energy market. Figure 12 shows the average quantities of balancing up and balancing down energy sold by suppliers in each

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