Barry T. Smitherman
Chairman

Donna L. Nelson
Commissioner

Kenneth W. Anderson, Jr.
Commissioner

Brian H. Lloyd
Executive Director

Rick Perry
Governor

Public Utility Commission of Texas

TO: Chairman Barry Smitherman
Commissioner Donna L. Nelson
Commissioner Kenneth W. Anderson, Jr.

FROM: Brian H. Lloyd
Executive Director

RE: Independent Market Monitor for the ERCOT Wholesale Market
Investigation of the ERCOT Energy Emergency Alert (EEA) Level 3 on February 2, 2011

DATE: April 25, 2011

As you are aware, on February 4, 2011, I directed the Independent Market Monitor (IMM) and Texas Reliability Entity (TRE) to investigate the ERCOT Energy Emergency Alert Level 3 that occurred during the extreme cold weather on February 2, 2011.

Attached is the IMM's report that specifically addressed the question of whether there was any evidence of market manipulation or market power abuse. While the IMM's report provides a timeline of events, including actions taken by ERCOT and power plant operators prior to the emergency event, it does not address non-compliance with reliability protocols and rules. These topics will be addressed in greater detail in the TRE report, with specific instances of violations subsequently brought to you as enforcement cases. I expect to receive a preliminary report from the TRE within the next several weeks, and will provide it to your offices at that time.

The IMM concluded that there was no evidence of market manipulation or market power abuse in relation to the widespread power plant outages that occurred the first week of February. Further the IMM found that the real-time and day-ahead wholesale markets for February 2 and February 3 operated efficiently with market prices appropriately reflecting the supply and demand conditions occurring on those days. The report also discusses how these prices are consistent with ERCOT's energy-only wholesale market design and how this market design provided beneficial incentives for generators to restore lost power plants as quickly as possible and for large consumers to voluntarily reduce their demand during the emergency.

Please let me know if you have any questions.

INVESTIGATION OF THE ERCOT ENERGY EMERGENCY ALERT LEVEL 3 ON FEBRUARY 2, 2011

POTOMAC ECONOMICS, LTD.

Independent Market Monitor for the
ERCOT Wholesale Market

April 21, 2011

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INTRODUCTION

In the early morning hours of February 2, 2011, the Electric Reliability Council of Texas ("ERCOT") region experienced extreme cold weather conditions, record electricity demand levels, and the loss of numerous electric generating facilities across the ERCOT region. These events combined to result in the declaration of Energy Emergency Alert ("EEA") Level 3 at 5:43 a.m., with the initial interruption of 1,000 MW of firm load at that time, and reaching 4,000 MW of firm load shed by 6:30 a.m. Subsequently, firm load was restored in 500 MW increments beginning shortly prior to 8:00 a.m., with all firm load restored shortly after 1:00 p.m. on February 2nd. Prior to the declaration of EEA Level 3, load resources contracted to provide responsive reserve service were deployed at approximately 5:20 a.m., and Emergency Interruptible Load Service ("EILS"), another contractual demand response service, was deployed concurrent with the declaration of EEA Level 3, at approximately 5:46 a.m.

On February 4, 2011, the Executive Director of the Public Utility Commission of Texas ("PUCT" or "Commission") directed Potomac Economics as the Commission's Independent Market Monitor ("IMM"), and the Texas Reliability Entity ("TRE") as the Commission's Reliability Monitor, to investigate the ERCOT EEA Level 3 that occurred on February 2, 2011, and subsequent related events and developments on February 3-4, 2011, including all preparations leading to the emergency event, as well as action taken once the event occurred, and focusing on the actions of ERCOT and the ERCOT market participants to determine whether all appropriate laws, rules, requirements and processes were followed.

The primary role of the IMM as the Commission's market monitor is to: (1) detect and prevent market manipulation strategies and market power abuses; and (2) evaluate the operations of the wholesale market and the current market rules and proposed changes to the market rules, and recommend measures to enhance market efficiency.[1]

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[1] Public Utility Regulatory Act, §39.1515(a); P.U.C. Subst. R. §25.365(c).

The primary role of the TRE as the Commission's reliability monitor is to monitor and investigate material occurrences of non-compliance with ERCOT procedures that have the potential to impede ERCOT operations, or represent a risk to system reliability.[2]

Given this division of responsibilities, this IMM report addresses the following two issues related to the ERCOT EEA Level 3 on February 2, 2011 and subsequent related events and developments on February 3-4, 2011: (1) whether market manipulation strategies or market power abuses were a cause or played a role in these events; and (2) whether the operations of the wholesale market and the existing market rules produced efficient market outcomes.

The review and analysis performed by the IMM and described in this report yields the following findings related to the events in the ERCOT wholesale market on and around February 2, 2011:

- Based on our review of the cause of each generating unit outage and/or capacity de-ration, as well as the financial positions of market participants, we do not find any evidence of market manipulation or market power abuse in relation to the widespread generating unit outages that resulted in the EEA3 event on February 2nd.
- Given the system conditions that materialized on February 2nd and 3rd, we find that the ERCOT real-time and day-ahead wholesale markets operated efficiently and the outcomes are consistent with the ERCOT energy-only wholesale market design.

Finally, because the review of the EEA3 event on February 2, 2011 is the subject of review by multiple entities and the IMM report is but one facet of this review, we have not at this time provided recommendations that may be beneficial in preventing a reoccurrence of the events experienced on and around February 2nd. We anticipate and are looking forward to participating in the development of a comprehensive set of actions that will serve to significantly improve the future reliable operation of the ERCOT grid in manners consistent with the competitive ERCOT market structure.

2 P.U.C. Subst. R. §25.503(j).

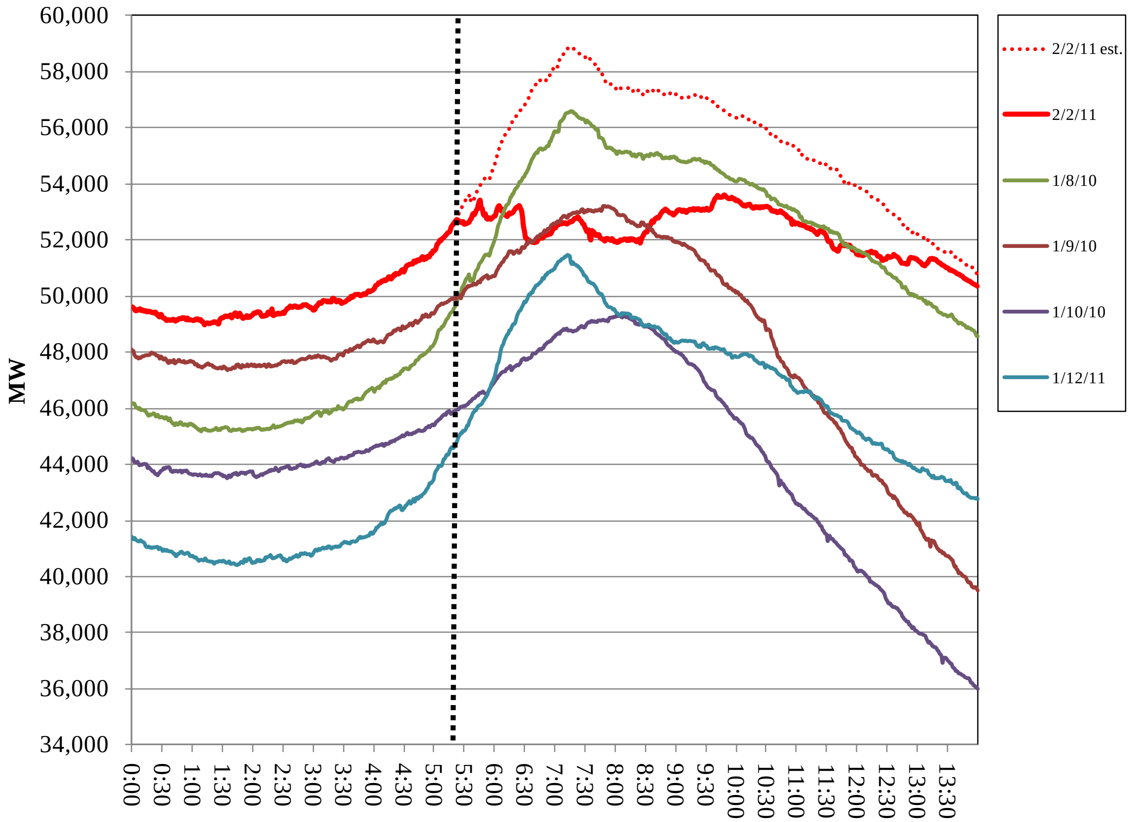
I. CHRONOLOGY OF EVENTS

In the early morning hours of February 2, 2011, the Electric Reliability Council of Texas (“ERCOT”) region experienced extreme cold weather conditions, record electricity demand levels, and the loss of numerous electric generating facilities across the ERCOT region. These events combined to result in the declaration of Energy Emergency Alert (“EEA”) Level 3 at 5:43 a.m., with the initial loss of 1,000 MW of firm load at that time, and reaching 4,000 MW of firm load shedding by 6:30 a.m. Subsequently, firm load was restored in 500 MW increments beginning shortly prior to 8:00 a.m., with all firm load restored shortly after 1:00 p.m. on February 2nd. Prior to the declaration of EEA Level 3, load resources providing contractual responsive reserve service were deployed at approximately 5:20 a.m., and Emergency Interruptible Load Service (“EILS”), another contractual demand response service, was deployed concurrent with the declaration of EEA Level 3, at approximately 5:46 a.m.

As stated above, the first stage of load shedding was initiated at 5:20 a.m. through the deployment of load resources contracted to provide responsive reserve service. Shown in Figure 1 are the five days through February 2, 2011 with the highest ERCOT electricity demand at 5:20 a.m. As of 5:20 a.m. on February 2nd, the demand for electricity was 2,760 MW higher than on any other day in the history of the of the ERCOT region at this same time, and was experiencing a rapid rate of growth as is typical on such cold winter mornings.

The demand curve for February 2, 2011 is noticeably distorted after 5:20 a.m. due to the various stages of load shedding that started at that time and remained in effect until just after 1:00 p.m., with the exception of approximately 470 MW of EILS deployments that remained in effect until approximately 10 a.m. on February 3rd.

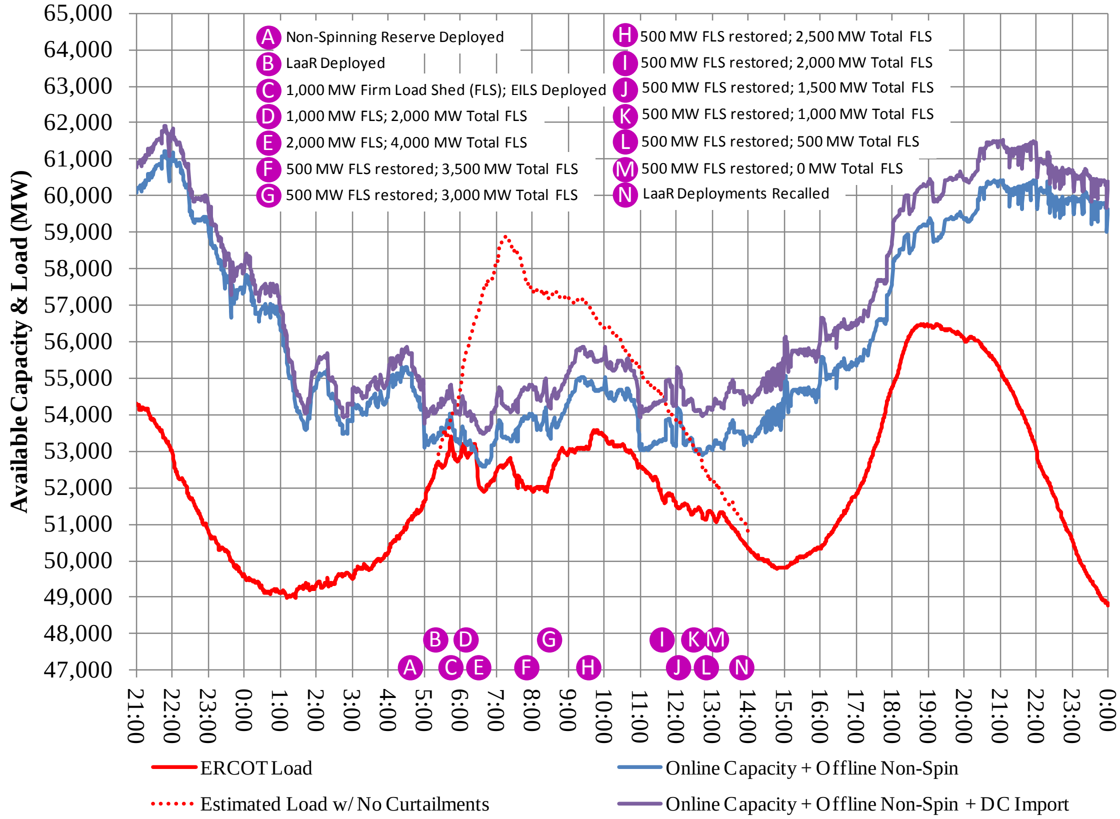
Figure 1: Top 5 ERCOT Loads at 05:20 through Feb. 2, 2011



Also shown in Figure 1 is the estimated load that would have materialized on February 2nd absent any load curtailments. This estimate is based on several factors, including the actual load and rate of load increase prior to the implementation of the first load curtailments, the load shape on similar days, and ERCOT load forecasts produced just after 3 a.m. on the morning of February 2nd. This estimate indicates that, absent curtailments, the demand in the ERCOT region would have approached 59,000 MW just after 7 a.m., or almost 2,300 MW higher than the previous record instantaneous demand for electricity experienced on January 8, 2010.

Figure 2 shows the ERCOT load, available generation capacity including scheduled off-line non-spinning reserves, and available generation capacity including scheduled off-line non-spinning reserves plus DC tie imports from 21:00 on February 1st through 24:00 on February 2nd. Also included in this chart are markers of key reliability actions taken by ERCOT through the course of this event.

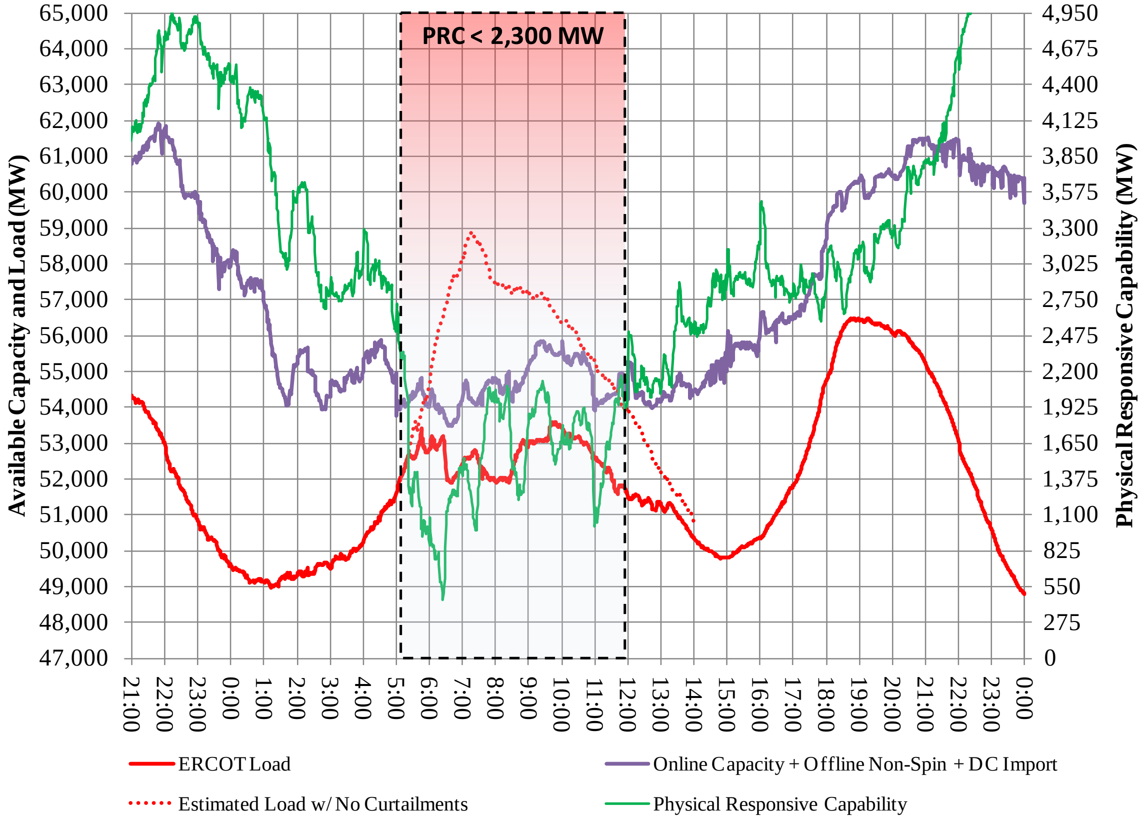
Figure 2: Timeline of ERCOT Reliability Actions



The data in Figure 2 show available capacity (including off-line non-spinning reserve and DC tie imports) of almost 62,000 MW at 10 p.m. on February 1st. After that time, available capacity steadily declined to a range of 54,000 and 55,800 MW between about 1:45 and 5:00 am on February 2nd. From about 5:45 a.m. through 6:30 a.m., available resources excluding DC tie imports were very close to the total ERCOT load, and ERCOT issued instructions to shed a total of 4,000 MW of firm load over this timeframe.

That the available resources margin was so low in relation to the total load underscores the magnitude of the system reliability issues experienced during this event. Figure 3 shows the available capacity, load and physical responsive reserve capability ("PRC") for the same time period as the data in Figure 2.

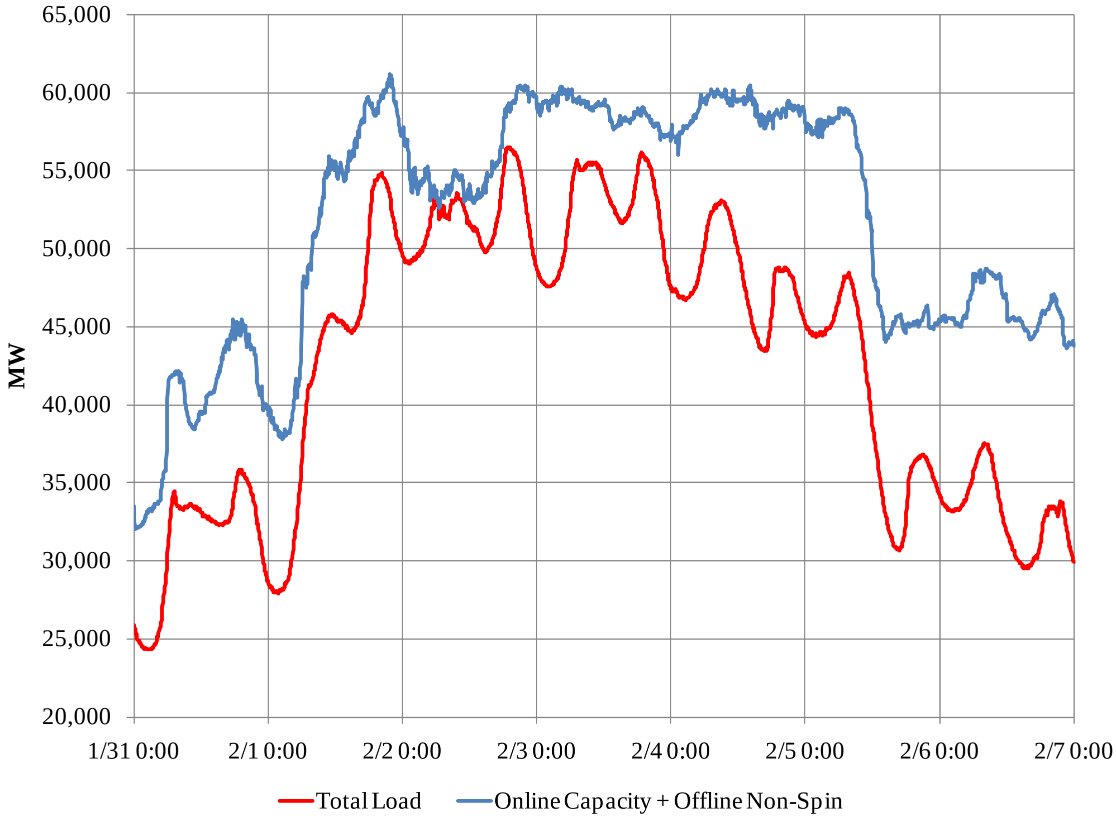
Figure 3: Available Capacity, Load and Reserves



To ensure reliable recovery from the loss of the two largest generators under normal conditions, ERCOT's minimum acceptable level of PRC is 2,300 MW. If PRC drops below 2,300 MW, ERCOT will initiate Energy Emergency Alert Level 1. As shown in Figure 3, PRC (on the right y-axis) was less than the ERCOT minimum level of 2,300 MW from just after 5 a.m. until approximately 12:00 p.m. on February 2nd, dropping as low as 445 MW at approximately 6:25 a.m.

To provide additional perspective on the capacity limitations experienced on February 2nd, Figure 4 shows the available capacity (online capacity plus offline non-spinning reserves) and the ERCOT load for the seven days from January 31 through February 6, 2011.

Figure 4: Seven Day View of ERCOT Available Capacity and Load



The data in Figure 4 highlight the highly unusual and extremely narrow gap between available capacity and actual load that was experienced on the morning of February 2, 2011 relative to other days of similar and much lower load levels. These data also highlight the successful efforts to return substantial generating capacity to service prior to the record peak demand on the evening of February 2nd and to sustain the availability of that capacity for the high electricity demands experienced again on February 3rd.

II. MARKET MANIPULATION/MARKET POWER ASSESSMENT

Section I provided a chronology of events on and around February 2, 2011 that showed an extremely large number of power plants in the ERCOT region tripping offline, failing to start, or experiencing de-rated output levels that, combined with the extremely high demand for electricity, led to supply shortages and the implementation of firm load shedding procedures for more than seven hours during the morning of February 2nd. As discussed in Section III, these shortage conditions were accompanied by scarcity level prices in the ERCOT wholesale market which, in the absence of market manipulation or the exercise of market power, is a result that is consistent with the ERCOT wholesale market design. Hence, as a necessary prelude to the assessment of the efficiency of wholesale market operations in Section III, this section provides an assessment of the reduced power plant capabilities that resulted in the electricity shortage conditions that materialized on February 2nd, specifically addressing the question of whether there is any evidence indicating that the market results were influenced by acts of market manipulation or the exercise of market power. In the context of the events that unfolded on February 2, 2011, the analysis in this section is focused on the question of whether available supply was artificially withheld from the market by means of economic or physical withholding.

A. Assessment of Economic and Physical Withholding

Economic withholding is characterized by an attempt to exercise market power through the submission of offers that are substantially greater than marginal cost. Potential economic withholding can be evaluated through the calculation of an "output gap," which is defined as the quantity of energy that is not being produced by in-service capacity even though the capacity is economic by a substantial margin given the spot market price. As discussed in Section III, during the shortage events on February 2nd, spot market prices remained at or near the system-wide cap of $3,000 per MWh during the timeframe that operating reserves were well below the minimum reliability threshold. Hence, all available capacity was being utilized, and therefore, by definition, there cannot be an output gap that would indicate economic withholding. For this reason, the remainder of this subsection will turn to the question of physical withholding.

Physical withholding occurs when a market participant makes resources unavailable for dispatch that are otherwise physically capable of providing energy and that are economic at prevailing market prices. This can be done by either intentionally de-rating a unit or declaring it as forced out of service. Generator de-ratings and forced outages are unavoidable and occur regularly on a day-to-day basis in the ERCOT region as well as other electricity markets. However, the magnitude of de-ratings and forced outages that occurred on and around February 2nd was significantly higher than normal. Therefore, a detailed review of the cause of each generating unit outage and de-rating is required to determine whether there is any evidence that points to potential physical withholding.

In support of this detailed assessment, the IMM reviewed the information listed in Table 1 obtained either directly from ERCOT systems and databases or through responses to information requests provided by market participants.

Table 1: Information Sources Relied Upon by the IMM

Information Source	Information Type
ERCOT Real-time Energy Management System (EMS) historian (PI)	Real-time ERCOT load, generation, spinning reserve, physical responsive reserve, DC tie flows, and individual generating unit data (MW output, resource status codes, high sustained limit, high ancillary service limits, high dispatch limits, base points, low sustained limits, low ancillary service limits, low dispatch limits, ancillary service capacity provision, and locational marginal prices).
Current Operating Plans	Planned hourly generating unit information, including resource name, qualified scheduling entity, resource status, ancillary service provision, and resource limits.
ERCOT Market Information System Reports	Day-ahead and hour-ahead Reliability Unit Commitment results
ERCOT Operator log books	Supervisor, Transmission Security, RUC, Real-time, DC Tie, Resource and Shift Engineers log books.
ERCOT Settlement data	Day ahead and real-time settlement data (volumes and dollars by participant and by location).
ERCOT Control Room telephone recordings	Recordings of incoming and outgoing telephone calls to/from the ERCOT control room.

ERCOT Oracle databases	Outage Scheduler data, Resource Limit Calculator data, Load Frequency Control data, transmission constraints and resource shift factors.
ERCOT Capacity, Demand and Reserves Report	List of generators, their location and installed capacity
Responses to Information requests issued by the IMM	Resource performance and availability data, market participant financial information.
Responses to information requests issued by the Texas Reliability Entity	Resource performance and availability data, preparatory, communication, and recovery efforts.
Responses to information requests issued by ERCOT	Preparatory and recovery efforts, resource performance and availability data.
Responses to information requests issued by the Federal Energy Regulatory Commission	Resource statistics, performance and availability data, timeline of event actions, preparatory, communication, and recovery efforts.
ERCOT public documents related to the February EEA3 Event	Various

Review of these data indicates that the scope of the outages and capacity de-ratings was widespread in geography, generating unit type, and by class of market participant. Generating unit outages occurred across all areas of the state and for all generating unit types except for nuclear units. The outages also affected all classes of unit owners, including private investors, municipal utilities, electric cooperatives, and river authorities. Weather-related generating unit outages began as early as the afternoon of February 1st and continued through February 4th, with the peak cumulative loss of capacity occurring during the morning hours of February 2nd during the early stages of the EEA3 event.

In preparation for the forecast extreme weather conditions, ERCOT took several actions in the days preceding February 2nd, including:

- On January 28-31, ERCOT coordinated the cancellation, withdrawal or delay of a number of planned transmission outages, including ten 345 kV lines, 27 138 kV lines, three 69 kV lines, two 345/138 kV autotransformers, and one 138/69 kV autotransformer.
- On January 31st, ERCOT ordered on-line one unit with a long start-up lead time.

- On the morning of January 31st, issued an Operating Condition Notice ("OCN") to all market participants advising that "a cold front is approaching with temperatures anticipated to be in mid to low 18 degree range and maximum temperature expected to remain near or below freezing impacting 50% or more of major metropolitan areas. Estimated starting time Tuesday 2/1/11 09:00."

- On the morning of February 1st, ERCOT issued an additional advisory "expecting temperatures in the teens to low 20F; maximum temperatures near or below freezing impacting 50% or more of major metro areas."

- On February 1st, ERCOT committed 13 generating resources through its reliability unit commitment processes.

In addition to our review of the causes of specific generator outages and de-rations, we also reviewed the actions generation resource owners took in preparation for the impending cold weather. Common preparatory actions included the following:

- Held plant site meetings to review ERCOT procedures and specific unit plans;
- Brought in relief crews to increase plant staffing;
- Prepared for operations on alternate fuel, including obtaining alternate fuel supply;
- Verified the operation of heat tracing equipment;
- Placed portable heaters in areas known to freeze to protect critical equipment, using tarps to provide wind protection;
- Checked equipment anti-freeze levels, filling where necessary;
- Drained fluids from non-essential equipment;
- Increased operation of standby equipment to prevent freezing;
- Increased the frequency of equipment monitoring.

Although a wide range of actions were undertaken by generation resource owners in preparation for the extreme weather conditions, it is clear from the unprecedented loss of generation capacity on the morning of February 2nd that many of these preparatory efforts were unsuccessful. This experience will serve to produce lessons learned and specific areas for improvement in the areas of generation resource weatherization and coordinated extreme weather planning.

One item that will likely be considered for potential improvement relates to the coordination of planned generation resource outages. The amount of capacity planned to be out of service for maintenance during the first week of February was generally consistent with the quantity of planned outages occurring at that time in previous years (excluding mothballed generation resources). However, there were two generating resources totaling approximately 1,500 MW of capacity with planned outages scheduled to begin on February 1st. While ERCOT does not have the authority to order the deferral of planned outages on such short notice, ERCOT can inquire with the resource owner about the possibility of deferring the outage. Given the issuance of the OCN and the procurement of long-lead time units beginning on January 31st, the initiation of such a dialogue would appear to have been a reasonable action, although we did not find any evidence that this occurred prior to the EEA event.[3] However, as the events of February 2nd were unfolding, ERCOT did approach a different generation owner about deferring the start of their planned outage of approximately 500 MW of capacity, which had been scheduled to begin on February 3rd. In this case the outage was deferred by approximately one week.

Overall, although the scope and magnitude of the generating unit outages on February 2nd was absolutely unprecedented, we do not find any evidence that indicates that the outages were the result of physical withholding.

B. Assessment of Profitability

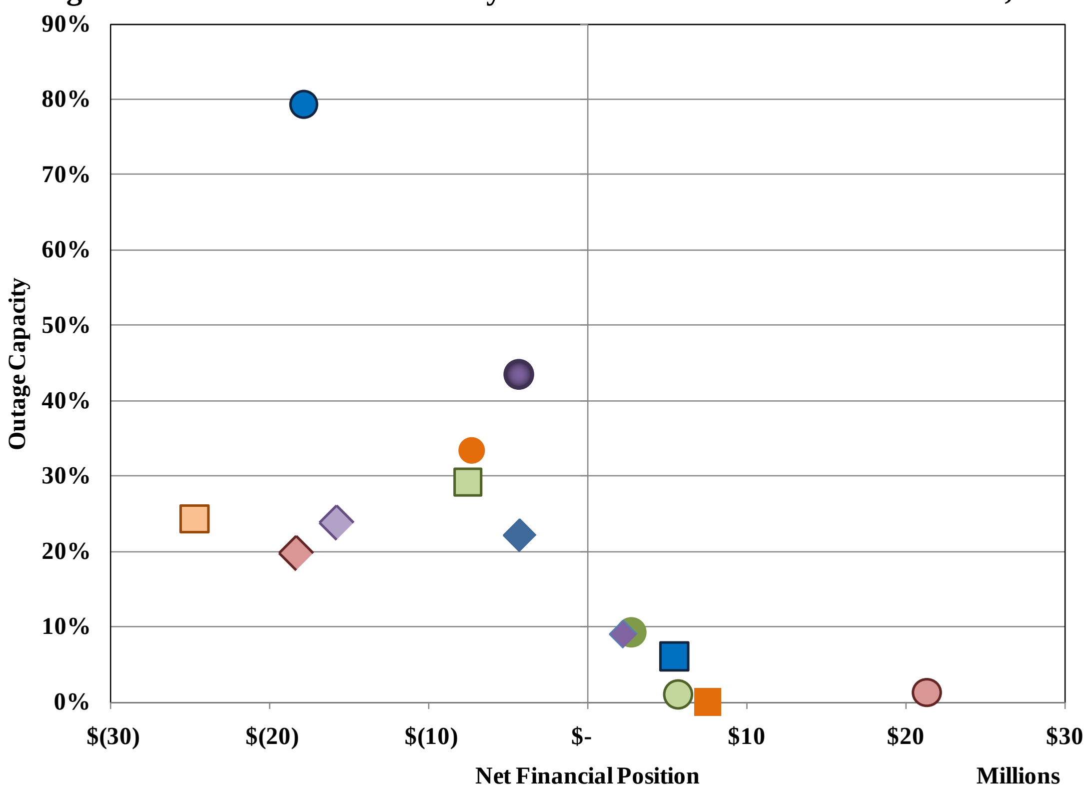
The analysis described in the prior subsection did not provide any indication of market manipulation or market power abuse in relation to the widespread generating unit outages that occurred on February 2nd. Another measure to provide additional insight related to

3 IMM discussions with this resource owner indicated that they may have been able to defer the outages depending on the timing of that decision. The resource owner considered deferring the outages prior to February 1st; however, forward market prices were not sufficient to justify the deferral of either outage. This explanation is consistent with the market conditions observed prior to February 2nd. On February 2nd, after consulting with ERCOT, this resource owner did initiate the process to return both of their plants to service from their planned outage condition. Some of the units were able to return to service on Feb. 4th. The first plant to completely return was operational on Feb. 5th. Although some of the units of the second plant operated for brief periods in the interim, the entire plant was completely returned to service the following week.

this finding is the relative profitability of market participants during these events and how it correlates with unit outages. Although an assessment of profitability in isolation is insufficient to draw conclusions related to market manipulation or market power, increased profitability is the primary motive associated with resource withholding strategies. Hence, a negative correlation between resource outages and profitability would provide increased confidence in the findings from the prior subsection that the outages were not the result of market manipulation strategies or market power abuses.

As discussed in Section III, real-time market prices on the morning of February 2nd were at or near the system-wide cap of $3,000 per MWh due to the short-supply conditions existing during the EEA event. Figure 5 shows the relationship between wholesale market profitability on February 2nd and availability of generation during the morning of February 2nd for market participants representing the largest fleets of generating resources.

Figure 5: Generation Availability and Net Financial Position on Feb. 2, 2011



The data in Figure 5 show that those market participants who were able to operate their generation fleet at greater than 90% availability during the morning of February 2nd were financially successful that day. In contrast, market participants affected by significant generation outages found themselves unprofitable that day.[4]

Day-ahead market prices for February 3rd were also affected by the conditions on February 2nd and were substantially higher than normal levels, as discussed in Section III. Although some market participants that lost money on February 2nd were able to recover much of their lost generating capacity and financial losses on February 3rd, none of the market participants that lost significant generating capacity and were unprofitable on February 2nd had financial gains on Feb. 3rd that significantly exceeded their losses on February 2nd.

4 The data in Figure 5 do not include market participants without physical generation resources or market participants operating only wind generation resources or relatively small fleets of non-wind generation resources. Outage capacity does not include planned outages.

III. WHOLESALE MARKET OPERATIONS ASSESSMENT

Having established in Section II that the events on February 2nd were not the result of market manipulation or an abuse of market power, this section provides an assessment of the second statutory charge of the IMM; that is, the efficiency of ERCOT wholesale market operations. This assessment must begin with a review of the fundamental wholesale market design elements that are specified by Commission rules and incorporated into the ERCOT Protocols and procedures.

A. Energy-Only vs. Capacity Markets

Most organized electricity markets, such as the PJM Interconnection, the New York ISO, and the New England ISO, have capacity markets that are designed to ensure long-term resource adequacy (*i.e.*, to maintain planning reserve margins at or above minimum requirements). In these markets, capacity resources are procured on a forward basis and receive compensation for the provision of capacity services subject to meeting certain capacity availability requirements. In addition to their energy requirements, load serving entities in these markets are obligated to pay for the costs incurred through the long-term capacity markets.

In contrast, the PUCT adopted rules in 2006 that define the parameters of the ERCOT energy-only market. These rules include a Scarcity Pricing Mechanism ("SPM") that relaxed the then-existing system-wide offer cap of $1,000 per MWh by gradually increasing it on a pre-defined schedule to $1,500 per MWh on March 1, 2007, $2,250 per MWh on March 1, 2008, and to $3,000 per MWh two months after the implementation of the nodal market. Additionally, market participants controlling less than five percent of the capacity in ERCOT are specifically defined as not possessing market power under the PUCT rules. Hence, these small participants may submit very high-priced offers that, per the PUCT rule, will not be deemed to be an exercise of market power under the PUCT rules. However, because of the competitive incentives faced by the small market participants, the quantity offered at such high prices – if any – is very small, and offers of such small quantities will only be selected as the system exhausts all available capacity beyond minimum operating reserves (*i.e.*, during shortage conditions). [5]

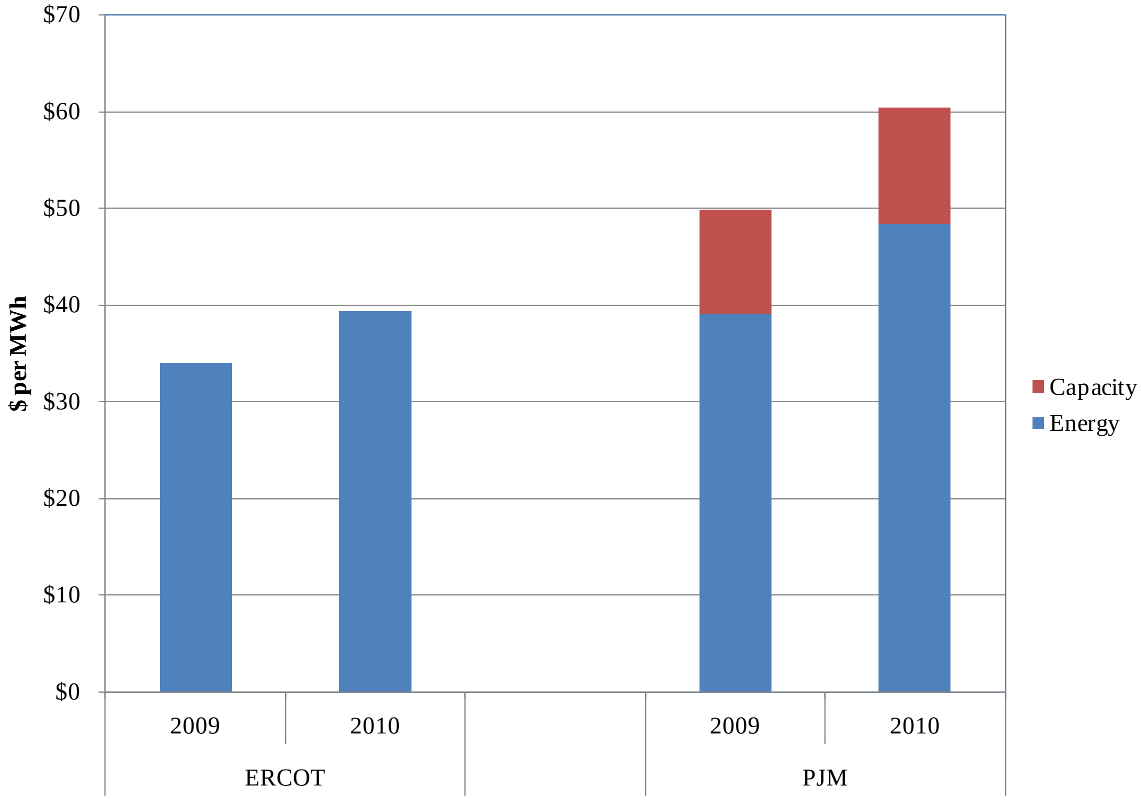
Unlike markets with a long-term capacity market where fixed capacity payments are made to resources across the entire year regardless of the relationship of supply and demand, the objective of the energy-only market design is to allow energy prices to rise significantly during legitimate shortage conditions (*i.e.*, when the available supply is insufficient to simultaneously meet both energy and operating reserve requirements). This allows an efficient price signal to be provided for supply and demand resources in the short-term, as well as signaling the longer-term need new supply and demand side investments. 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.

Hence, in an energy-only market, it is the expectation that both the magnitude of the energy price during shortage conditions and the frequency of shortage conditions will attract new investment when required. In other words, the higher the price during shortage conditions, the fewer shortage conditions that are required to provide the investment signal, and vice versa. Under ERCOT's energy-only construct, PUCT rules allow energy prices to rise as high as $3,000 per MWh. Implicit in the determination of this shortage pricing level is an assumption that the frequency of shortage conditions will average approximately 30 hours per year over the long-term (0.3 percent of the hours in an year), with some years experiencing a higher frequency of shortage conditions, and some years experiencing less. In other words, 30 hours per year of shortage conditions with prices at $3,000 per MWh produce revenue consistent with the levelized annual capital cost of a new peaking generation facility. Thus, the parameters of the energy-only market as defined in the PUCT rules are specifically designed to accomplish the same resource adequacy objectives of the capacity market mechanisms in other markets, except the means of doing so in the ERCOT market is achieved exclusively through energy prices.

5 Operating reserve shortages occur relatively infrequently as further discussed in this section, and do not typically involve firm load shedding as was the case on the morning of February 2, 2011.

Figure 6 shows the load-weighted average real-time energy and capacity prices for the ERCOT and PJM markets for 2009 and 2010. These data show that ERCOT's average energy price was lower than in PJM in both years, and that while ERCOT has no capacity market component, the PJM capacity cost component was $10.75 per MWh in 2009 and $12.19 per MWh in 2010.[6]

Figure 6: Load-Weighted Average Energy and Capacity Prices



For a residential customer that consumes approximately 1,000 kWh of energy per month, the data in Figure 6 indicate that customer would have paid more than $12 on his/her monthly bill in each month in 2010 for the capacity market in PJM. In contrast, the equivalent component of the PJM capacity market can be measured by the isolating the effect of price spikes during shortage conditions in the ERCOT energy prices. For example, if the number of shortage conditions with $3,000 per MWh price levels reached 30 hours per year in the ERCOT market, the effect on the annual average wholesale

6 ERCOT data are as calculated by the IMM based on ERCOT data. PJM data are from *PJM 2010 State of the Market Report, Volume I*, Monitoring Analytics, Table 1-7 (March 10, 2011).

electricity price would be approximately $10 per MWh. The shortage conditions during the morning of February 2, 2011 resulted in approximately six hours of shortage pricing; therefore, the effect of this event on the annual average wholesale electricity price will be an increase of approximately $2 per MWh. In contrast, for the entire month of January 2011, there were approximately 1.5 hours of shortage conditions, which would have the effect of increasing the annual average wholesale electricity price by approximately $0.38 per MWh.

The different cost allocation and pricing mechanisms also create different market incentives between capacity market and energy-only market structures. For example, the market outcomes on the morning of February 2, 2011 created substantial market incentives to maximize available generating capability, restore lost generating capability as quickly as possible, and to voluntarily reduce demand. In contrast, in a capacity market structure, the loss of generation on one day while meeting availability requirements during the remainder of the year would result in little, if any, loss of annual capacity market revenues. Further, because capacity markets have much lower energy price caps than in energy-only markets, the energy market exposure during shortage conditions is lower in capacity markets than in energy-only markets, thereby reducing the market incentives on the supply and demand sides to take extraordinary actions in response to reserve shortage conditions.

In summary, alternative mechanisms exist for ensuring long-term resource adequacy in competitive electricity markets. In most organized electricity markets, a form of capacity market has been implemented to achieve this objective. In the ERCOT market, the energy-only approach has been implemented. The energy-only approach is designed to allow energy prices to rise significantly higher during shortage conditions such that an efficient price signal is provided for supply and demand resources in the short-term, as well as signaling the longer-term need new supply and demand side investments. During non-shortage conditions (*i.e.*, more than 99 percent of the time), the expectation of competitive energy market outcomes is no different in energy-only than in capacity markets. Although reserve shortage conditions (and the associated price spikes) are only expected to occur during a small percentage of the hours in a year, such market outcomes are a critical component of the energy-only market design, and an energy-only market design without efficient shortage pricing is not sustainable over the long-term.

B. ERCOT Wholesale Market Outcomes on February 2-3, 2011

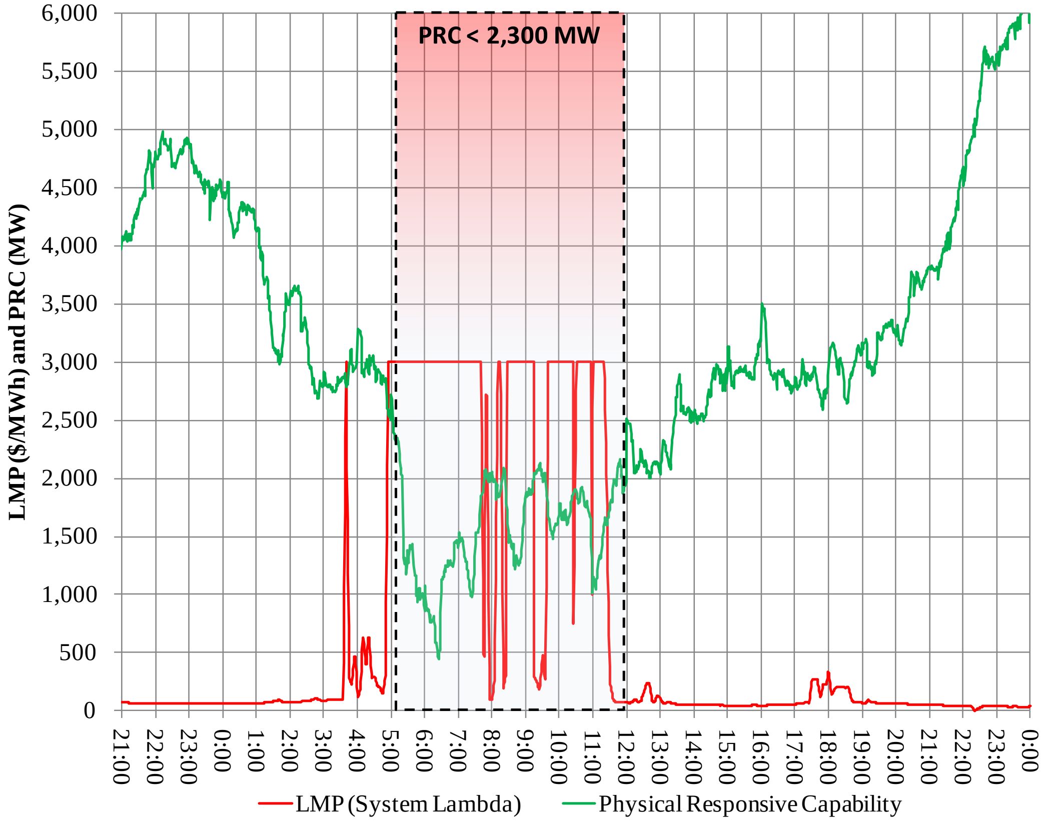
As a general principle, competitive and efficient market prices should be consistent with the marginal cost of the marginal action taken to satisfy the market's demand. In the vast majority of hours, the marginal cost of the marginal action is that associated with the dispatch of the last generator required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

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

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

During the morning of February 2, 2011, ERCOT operating reserve levels were reduced to perilously low levels for a sustained period of time. ERCOT's primary measure of overall operating reserves is Physical Responsive Reserve ("PRC"), and ERCOT will remain in various levels of EEA once PRC drops below 2,300 MW. Figure 7 shows the wholesale market prices and PRC from 21:00 on February 1 through 24:00 on February 2, 2011.

Figure 7: Prices and PRC (2/1/11 21:00 – 2/2/11 24:00)

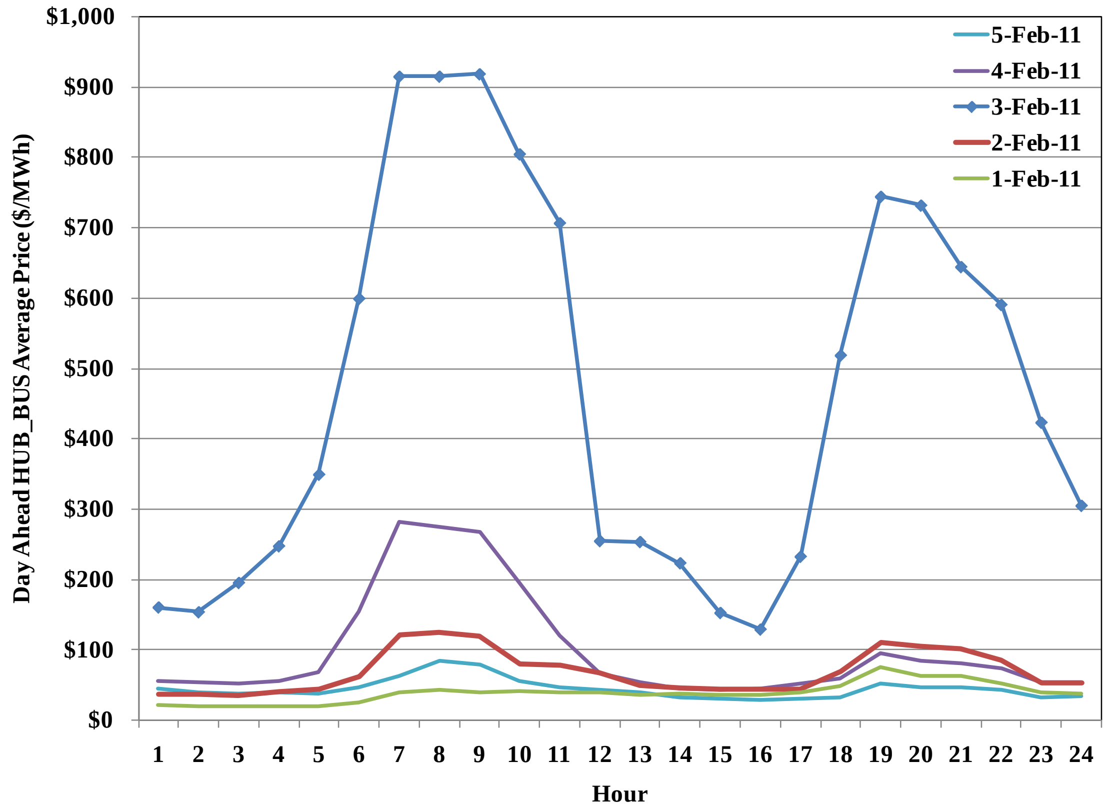


The data in Figure 7 show increased price volatility from 3:30 to 4:45 a.m. as system demand was increasing and generating units continued to be in various stages of tripping and starting. By 4:55 a.m., prices had reached a sustained level $3,000 per MWh, and PRC dropped below 2,300 MW by 5:10 a.m. PRC dropped to as low as 445 MW at 6:25 a.m., and remained consistently below the minimum 2,300 MW level until 12:00 p.m.

These wholesale market pricing outcomes are consistent with the ERCOT energy-only market design. The wholesale market prices began communicating the degradation in system reliability as early as 3:30 a.m. By 4:55 a.m. – 15 minutes prior to the reduction of PRC below the minimum acceptable level of 2,300 MW and 50 minutes prior to the first stage of firm load shedding – prices were consistently communicating the rapidly deteriorating system reliability conditions. Finally, as load levels naturally reduced and reserve levels were restored, prices dropped back to levels typical of non-shortage conditions.

The secondary effect of the conditions during the morning of February 2, 2011 was the effect on the day-ahead market for February 3, 2011. Figure 8 shows the hourly average day-ahead market energy prices for February 1st through the 5th.

Figure 8: Average Hourly Day-Ahead Prices for Feb. 1-5, 2011



Notable in Figure 8 is that, while somewhat higher than a typical day, the day-ahead prices for February 2nd are significantly lower than the real-time prices shown in Figure 7 for the same day. Figure 8 also shows that the day-ahead prices for February 3rd were substantially higher than on February 2nd and, in fact, represent the highest day-ahead market prices experienced since the implementation of the nodal market.

To better understand these day-ahead pricing outcomes for February 3rd requires a review of the day-ahead market function and timing. The ERCOT day-ahead market is not a mandatory market; rather, it is a voluntary market that consists of willing sellers that will be cleared for offers to sell energy at their offer price or higher and willing buyers that will be cleared for bids to buy at their bid price or lower. The day-ahead market is not limited to physical generation as sellers or physical load serving entities as buyers. In other words, any market participant – whether it has a physical position in the market or not – can participate in the day-ahead market and take a financial position against the real-time market. Because of the voluntary, financial nature of the day-ahead market, its outcomes are strongly driven by expectations of the real-time market performance for the following day.

On this point, an understanding of the timing of the day-ahead market execution is critical. The day-ahead market opens for bid/offer submission at 6:00 a.m. on the day prior to the operating day, and the submission window closes at 10:00 a.m. Thus, for the February 3rd day-ahead market, the submission window opened at 6:00 a.m. and closed at 10:00 a.m. on February 2nd. Thus, at the time that bids/offers were submitted for the February 3rd day-ahead market, ERCOT was in the middle of the EEA level 3 events on February 2nd. Considerable uncertainty regarding generating unit availability and system conditions for February 3rd existed at that time, while the forecast called for continued arctic conditions across the state and record electricity demand was again forecast for the ERCOT region.

On a typical day, the day-ahead market results for February 3rd would give rise to market performance concerns, just as the real-time results on February 2nd would also raise concerns on a typical day. However, the real-time system conditions on February 2nd were far from typical, with the market outcomes reflecting the underlying system reliability conditions, consistent with the energy-only market design, as previously discussed. Likewise, the day-ahead market outcomes for February 3rd were driven by the highly atypical uncertainties and risks facing both the supply and demand sides that existed at the time the day-ahead market submissions occurred, and the results are not unexpected given those considerations. Notably, while the day-ahead prices for February 3rd averaged $465.64 per MWh, day-ahead prices for February 4th and 5th averaged $99.56 and $44.68 per MWh, respectively, as the weather moderated resulting in decreased electricity demands and generation resources previously experiencing outages were returned to service. Although near-record electricity demand levels were again experienced on February 3rd, a substantial number of generating units that were forced out of service on February 2nd were able to return by the morning of February 3rd.

Real-time prices on February 3rd averaged approximately $112 per MWh, which is higher than a typical day but much lower than the day-ahead prices for that day.

Overall, we find that the real-time and day-ahead wholesale markets for February 2nd and 3rd operated efficiently given the system conditions and the outcomes are consistent with the ERCOT energy-only wholesale market design.