Public Utility Commission of Texas

Market and Reliability Issues Related to the Extreme Weather Event on February 24-26, 2003

Project No. 25937, PUC Investigation into Possible Manipulation of the ERCOT Market

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Executive Summary

This report contains the most recent analysis by the Market Oversight Division (MOD) of the system and market impacts caused by the extreme weather event of February 24-27, 2003. It is based on direct analysis of Electric Reliability Council of Texas (ERCOT) data, interviews with Market Participants, interviews with officials at ERCOT, and discussions with staff members of the Texas Railroad Commission (RRC) with oversight over intrastate natural gas pipeline utilities.

- *System Impact*. MOD believes the extreme weather event demonstrated the problems posed by inaccurate and outdated resource plans. ERCOT operators relied on the generation capacity shown in the resource plans they were given by all Qualified Scheduling Entities (QSEs). In many cases, however, the resource plans contained "hollow" numbers for generation capacity because natural gas shortages made it impossible for the plants to produce anywhere near the electricity they were scheduled to deliver. Effective deratings were in many cases not reported to ERCOT, which meant that operators were often trying to respond to frequency and schedule control error (SCE) problems by deploying resources that weren't really there. Although some Market Participants interviewed by MOD said ERCOT erred by not procuring more replacement reserves, the resource plans ERCOT had in hand said the system had plenty of generation available and that more replacement reserves would not be needed. Moreover, even if more replacement reserves had been procured, that capacity probably would not have been deployable either. Replacement reserves would have needed fuel in order to be deployed, yet if the additional fuel had been available, the scheduled resources probably would have been able to respond as directed by ERCOT.
- *Market Impact*. Prices spiked to $990 in the Up Balancing Energy Service (UBES) on February 24 and 25. As stated in MOD's initial report on the event, this price was the result of a "hockey stick" bid by one market participant – a single megawatt bid at $990, while the rest of the market participant's bid quantity was priced near marginal cost. MOD interviewed Market Participants who had submitted bids in excess of $300, and found that these bidders fell into two groups: those whose maximum bids were in the $300 to $500 range, and two who routinely submitted hockey stick bids of $990 or higher.[1] When asked to explain the reasons for their high bids, those in the first group cited high gas prices, unexpected forced plant outages, and their general inability to obtain natural gas on the intraday market on February 24 and 25. Those in the second group justified their $990 and $999 bids simply by saying such bids were not prohibited under the Protocols. The fact that these hockey stick bids set the market clearing price for energy (MCPE) had a ripple effect in the ancillary capacity service markets, where the MCPE is often used as an indicator of a generator's cost of replacement energy. Many QSEs who submitted ancillary

[1] One Market Participant who had routinely submitted a hockey stick during most intervals ceased to do so during the week of the extreme weather event.

capacity service bids above $900 told MOD they did so because of the high balancing energy prices they were seeing.

- *Recommendations*. Throughout this report, MOD recommends a number of policy actions, the most important of which are stricter enforcement of resource plan accuracy and implementation of the Competitive Solution Method proposed by Staff in Docket No. 24770.

MOD is still awaiting certain reports and other information that may shed more light on the effects of the extreme weather event. TXU Lone Star Pipeline is expected to finalize a report on curtailments and other issues affecting natural gas supplies during the extreme weather event, and MOD anticipates that this report will shed light on the fuel curtailments alleged by a number of generators. MOD is also awaiting documentation of extremely high intra-day gas prices that some generators said they had to pay on February 24th and 25th. In addition, data anomalies have clouded the picture of how much capacity was in fact on line and available during the weather event; MOD is continuing to work with ERCOT to obtain reliable figures for planned outages, forced outages, and available capacity.

Consequently, this report should not be regarded as MOD's final report on the February 24-27 extreme weather event. MOD will continue to gather information on the event as it becomes available, and will apprise the commission of any additional issues the new information may suggest.

ERCOT's Reliability Tools

ERCOT, as the single Control Area Operator, is responsible for maintaining the integrity of the ERCOT system. ERCOT has a defined set of communication tools that they employ in order to prevent the occurrence and minimize the magnitude of unreliable system conditions. These communications are issued by ERCOT to Transmission and Distribution Service Providers (TDSPs) and QSEs, and QSEs in turn notify the appropriate Resources and Load Serving Entities (LSEs).

It is important to note that ERCOT's role is to manage system integrity with no consideration or knowledge of the potential effect of their actions on market prices and also to allow for market mechanisms to resolve capacity insufficiency whenever possible.

The hierarchy of ERCOT's communication tools is shown in the left side of Table 1. In each subsequent level of communication, ERCOT has increasing authority to take actions not normally authorized. The key authority that ERCOT gains is the authority to issue Dispatch Instructions to QSEs and TDSPs. These Dispatch Instructions must be followed, as per the ERCOT Protocols: "Each TDSP and each QSE within the ERCOT System shall comply fully and promptly with valid Dispatch Instructions, unless in the sole and reasonable judgment of the TDSP or QSE, such compliance would create a threat to safety, risk of bodily harm or damage to the equipment, or is otherwise not in compliance with these Protocols."[2]

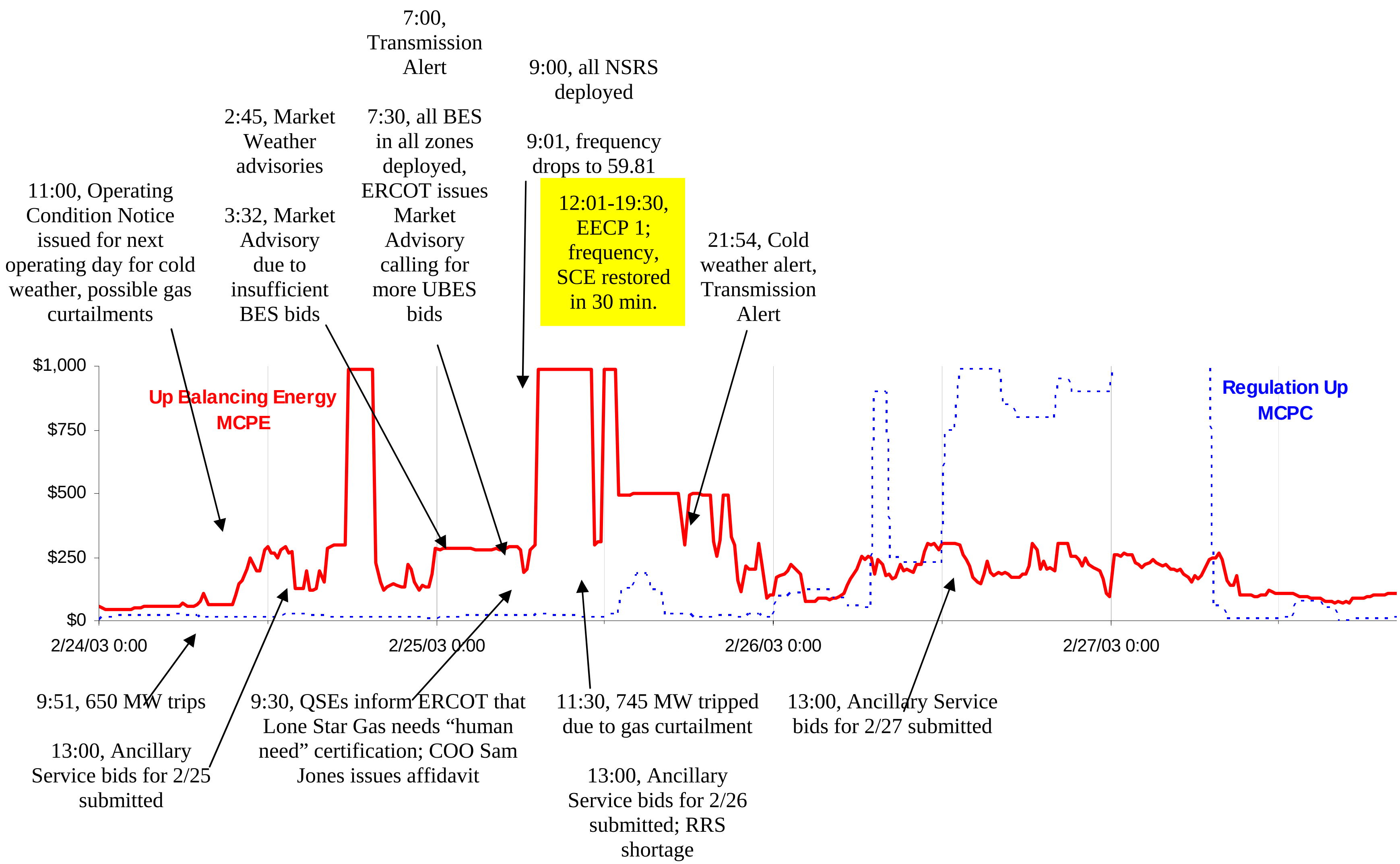
The right side of Table 1 shows the steps that ERCOT did take, ultimately leading to declaring an Emergency Condition and implementing Step 1 of the associated Emergency Electric Curtailment Plan (EECP). This information is contained in section 5.6 of the ERCOT Protocols.

[2] ERCOT Protocols, Section 5.4.4 (1). Unless otherwise noted, Protocol references are to the February 2003 version of the ERCOT Protocols.

Table 1: Sequence of ERCOT Emergency Authority

ERCOT's Additional Authority	Communication Tool/Step	Communications Issued
No additional authority	Operating Condition Notice	Feb 24th 11:00 - Issued Operating Condition Notice and cancelled planned transmission outages due to reports of gas curtailments
ERCOT may exercise its authority, in such circumstances, to increase Ancillary Service requirements above the quantities specified in the normal Day Ahead plan in accordance with scheduling procedures. ERCOT may also increase the Day Ahead market to Two Days Ahead.	Advisory	Feb 25th 02:45 - Market and Weather Advisories issued due to gas curtailments and weather
ERCOT must issue an Alert before acquiring Emergency Short Supply Regulation Services, Emergency Short Supply Responsive Reserve Services (RRS) or Emergency Short Supply Non-Spinning Reserve Services (NSRS). Corrective actions identified by ERCOT shall be communicated through Dispatch Instructions to TDSPs and/or QSEs required to implement the corrective action.	Alert	Several Alerts issued: to request more UBES bids & to inform that ERCOT was exceeding Transmission Limits to avoid reducing generation
Provide Dispatch Instructions to QSEs to start all Resources that are available in the time frame of the emergency (OOMC). Similarly, ERCOT will provide Dispatch Instructions to QSEs to suspend any ongoing generating unit or Resource performance testing and maximize Resource deployment (OOME) to increase Responsive Reserve levels on other Resources. QSEs intending to provide OOMC and OOME must comply as soon as practicable.	Emergency	Emergency Declared and EECP Step 1 Procedures in effect from 12:01 to 19:30 on Feb 25th All QSEs were requested to bring on line all available generation and bid it for BES

Figure 1: Timeline of Significant Events



Sequence of Events

On Friday, February 21, the weather forecast predicted a cold front moving over a large part of Texas. The cold front moved in earlier and was more severe than projected. Generation owners had nominated their gas needs for Monday, February 24, on the previous Friday, according to the normal nomination schedule. On Monday, with freezing temperature as far south as San Antonio, the actual demand for electricity exceeded ERCOT's forecast by 4218 MW. Market Participants had similarly missed the forecast. Owners of gas generation units found that they were short on gas and tried to acquire more gas on the intraday gas market. The demand for gas also increased as a result of an increased need for gas heating. The gas distribution companies had, in turn, under-estimated the demand for gas. As a result, gas supplies became hard to find, intra-day prices went up to $29 per MMBtu and possibly higher,[3] and there were reports of possible gas curtailments to generating units.

According to ERCOT Operations staff, at 18:00 hour on Monday, February 24, ERCOT began to experience insufficient Balancing Energy Service (BES) bids. ERCOT then issued a Market Alert, sent Verbal Dispatch Instructions (VDIs) to increase available energy and capacity, and ordered all Reliability Must Run (RMR) units raised to maximum outputs.

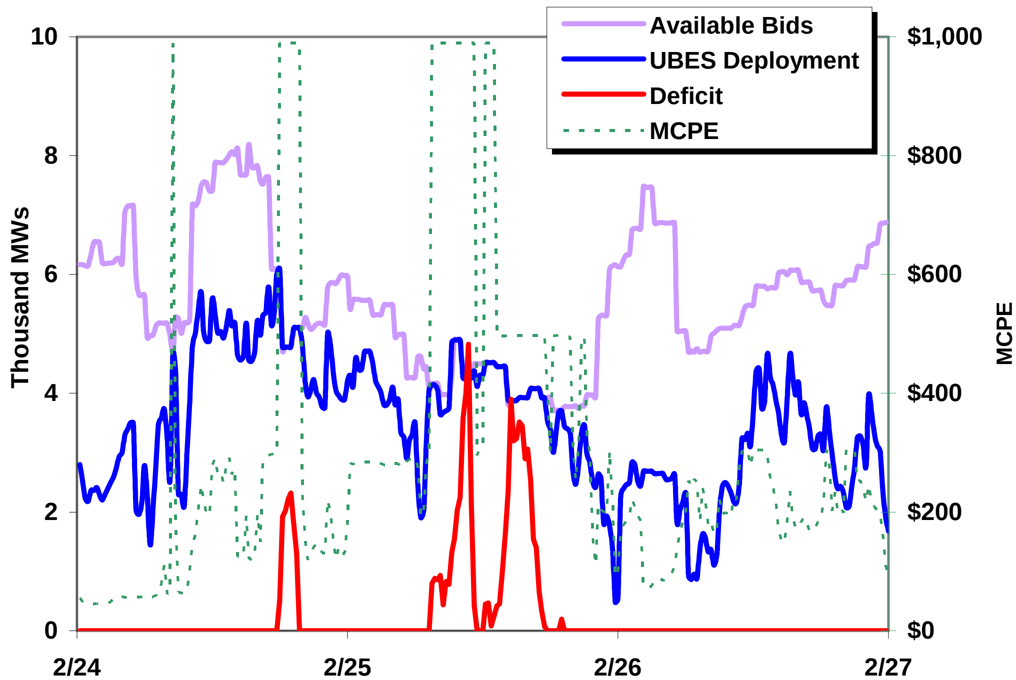
On Tuesday, February 25, temperatures in Dallas and Austin remained below freezing. At 7:30, 100% of the available UBES had been deployed. ERCOT issued a Market Advisory requesting more UBES bids. By 9:00, ERCOT was fully deploying all NSRS purchased, and VDIs were issued to keep the units on line past the procurement period. At the same time, gas companies started informing customers that they were activating tariff provisions to curtail gas for purposes other than "Human Need," although staff at the Texas Railroad Commission told MOD that TXU Lone Star Pipeline was the only intrastate gas company that actually curtailed customers. At the request of three QSEs, the ERCOT Chief Operating Officer signed affidavits stating that gas needed for generation met that qualification. At 9:08, gas curtailment to a power plant caused three units to trip, resulting in a loss of 745 MW of generation. Frequency dropped to 59.81 Hz and could not be restored. The ERCOT system control error (SCE) was -1,500 and increasing. At 12:01, ERCOT declared an EECP Step 1 and requested all QSEs to bring on all available generation and bid the energy into the Balancing Energy Market. ERCOT also verified that the DC ties were fully loaded with energy coming into ERCOT. After the EECP implementation, frequency and SCE were restored and the situation greatly improved within 30 minutes. The EECP Step 1 was terminated at 19:30.

As shown in Figure 2, the deficit in UBES bids on February 24, lasted from interval ending 18:00 to interval ending 19:45. During this window, the MCPE was set by a one MW bid at $990. On the 25th, ERCOT again exhausted the UBES bid stack and experienced a deficit in UBES bids during the intervals between 7:30 and 11:15, 12:15 and 17:30, and in the interval ending 19:00. During these intervals, the MCPE was again set by a one MW bid at $990 for all energy procured until 13:00, when the $990 bid was

[3] Generators representatives interviewed by MOD stated that in some cases, they had to pay up to $53 per MMBtu. MOD has not been able to verify these claims.

no longer present. MOD estimates that if the $990 bid had still been in the stack for the length of time that the bid deficit remained, the increased UBES costs would have been almost $10 million.

Figure 2: Timeline of the Events of February 24-26



The left scale measures the bid amounts in MW, whereas the right scale measures the bid price and MCPE in dollars.

The bid stack is exhausted when the total bids deployed (blue line) equal the total available bids (purple line). In those intervals, the MCPE (green line) is set by a one MW bid at $990 until 13:00 on February 25, and by a $500 bid thereafter.

Figure 2 also shows the magnitude of the bid deficits that were experienced (orange line.) On February 24, the bid deficit reached 2000 MW over a few intervals. On February 25, the bid deficit reached up to 4800 MW at one point. The deficit was made up by use of Non-Spinning Reserve, some Responsive Reserve, Regulation-Up and OOM instructions.

ERCOT's Ancillary Service Markets echoed the tight conditions and resulting high prices experienced in the Balancing Energy Market on the 24th and 25th. The effects on Ancillary Services prices lagged BES by one day, which is to be expected since bidding and clearing of Ancillary Services occurs in a day-ahead auction.

On Wednesday, February 26, bid prices in the RRS market reached a maximum of $999 and the daily average MCPC was $967. In the Up Regulation Services (URS) market, bid prices reached a maximum of $999 and the daily average MCPC was $852. Table 2 highlights the A/S price spikes of February 26. These price spikes were caused by a combination of decreased bid volumes along with high-priced bidding. The daily weighted average clearing prices for URS, Down Regulation Service (DRS), Responsive

Reserve Service (RRS), and Non-spinning Reserve Service (NSRS) before, during and after the weather event are shown in the following table.

Table 2: Daily Weighted Average Prices for Ancillary Services

	DRS	URS	RRS	NSRS	All AS
21-Feb-03	$8.00	$14.16	$16.49	NA	$13.98
22-Feb-03	$8.05	$15.10	$13.40	NA	$12.76
23-Feb-03	$9.12	$14.73	$9.30	NA	$10.76
24-Feb-03	$6.81	$15.36	$11.55	NA	$11.51
25-Feb-03	$11.68	$69.47	$15.47	$162.97	$39.35
26-Feb-03	$10.25	$851.57	$966.95	NA	$664.09
27-Feb-03	$11.00	$37.68	$14.83	NA	$18.74
28-Feb-03	$8.34	$17.99	$9.05	NA	$10.61

System Impact: Forecast Error

ERCOT's forecast on the 23rd for the 24th was 10% below the actual peak demand on the 24th (see Table 3). Its forecast on the 24th for the 25th was much closer, only 1.7% below the actual peak on the 25th. In the morning of the 25th, demand reached 42,263 MW and ERCOT increased its forecast for that day to 44,192 MW; however, the revised forecast turned out to be 4.2% above the actual peak demand. [4]

Table 3: Day Ahead Forecast Demand v. Actual

Forecast Made	Forecast For	Forecast Peak Demand	Actual Peak Demand	Forecast Error
Feb. 23	Feb. 24	37,811 MW	42,029 MW	-10.0%
Feb. 24	Feb. 25	41,975 MW	42,702 MW	-1.7%
Feb. 25	Feb. 25	44,192 MW	42,702 MW	4.2%

Generators base their gas supply needs on their forecast for the following day, and nominate gas to meet this expectation. On Friday, February 21 and again on Monday, February 24, most Market Participants missed the forecast and underestimated their actual load, causing generators to nominate insufficient gas in the day ahead and forcing them to look for intraday gas supplies. On the day of the 25th, using more accurate weather information, ERCOT's demand projection for that same day increased. However, it appears that significant load dropped as industrial customers in areas served by Lone Star Pipeline saw their gas supply curtailed and had to shut down their operations. Gas curtailments also affected some schools in the North region, while other schools closed due to icy conditions. Closings due to such gas curtailments and icy conditions resulted in a lower demand for electricity and moderated the effect of the energy shortages experienced on February 25.

Recommendation

- *ERCOT should improve its weather forecast and demand forecasts. MOD cautions, however, that better forecasting is no "silver bullet." Even the best weather modeling may not have been sufficient to prevent the system and market disturbances that occurred on February 24th and 25th.*

[4] Actual forecast numbers have not yet been confirmed as official by ERCOT.

System Impact: Natural Gas

Most power generators interviewed by MOD – as well as ERCOT operators who were communicating with those generators during the weather event – said that natural gas problems beyond the control of Market Participants led to the supply shortage that drove energy and capacity prices higher. Natural gas was suddenly in short supply, but equally significant was the fact that the structure of the natural gas market limited the way generators were able to respond to the fuel shortage in real time.

- *Depleted reserves*. The amount of natural gas in storage declined rapidly beginning in November 2002. A winter drawdown is normal, but this time the pace was so quick that by February reserves had gone from a five-year high to a five-year low in just four months.
- *Timeline for gas nominations*. Natural gas trading closes for the weekend, which means that fuel to generate power on Monday must be secured the prior Friday. If Friday's load forecasts are wrong, the natural gas market by and large cannot respond until Monday.
- *Fuel shortages and curtailments*. While there were in fact few complete curtailments of natural gas supplies to generators, delivery constraints often reduced the amount of power that some plants were capable of delivering to ERCOT.
- *Lack of on-site storage*. Natural gas pipeline companies have the bulk of their storage underground, but most of the old bundled electric utilities also had their own gas storage facilities. New independent power producers (IPPs) generally don't have their own gas storage, and power generation company (PGC) affiliates of the old bundled utilities told MOD that it is uneconomical to maintain such storage in a deregulated environment.

Depleted Reserves

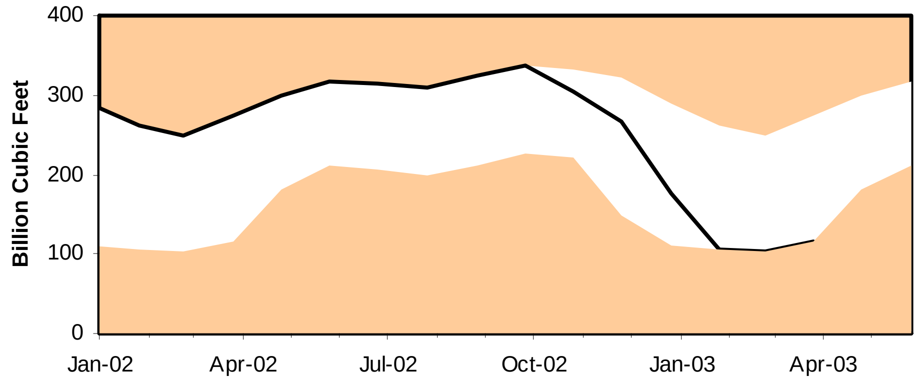
The amount of natural gas in storage had been dropping quickly for the four months prior to the February 24-27 weather event. (See Figure 3 and Figure 4.) By the end of January 2003, storage was about 60% of what it had been a year earlier both nationally and in Texas. Throughout February 2003, the reserve drawdown accelerated. Reserves in the U.S. interstate gas system declined by half during the month while Texas intrastate reserves fell by 40%.

Few reserves were available when the arctic front suddenly intensified the nationwide demand for natural gas on February 24th. Many power generators interviewed by MOD said they had grossly underestimated their fuel needs three days earlier, but when they turned to the intraday spot markets on February 24-27 to make up the difference, little natural gas was available at any price.

The increase in natural gas prices indicate how ill-prepared the nation's gas reserves were for the demand shock that began on February 24. Figure 5 shows that natural gas prices on the NYMEX tripled from the previous week, peaking at a record-high $18.85 per

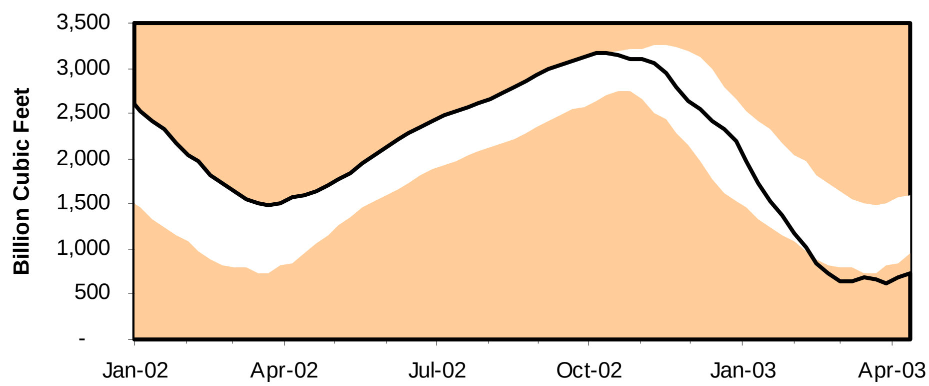
MMBtu on February 25th. Some power generators interviewed by MOD said that intraday prices – when they could find intraday supplies – were sometimes more than twice the NYMEX price.

Figure 3: Texas Intrastate Natural Gas in Storage



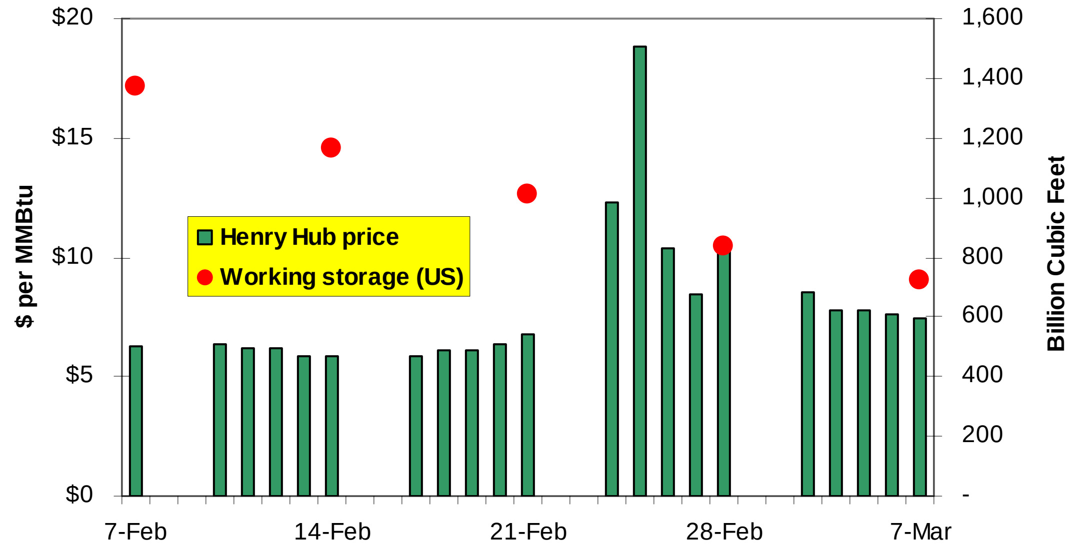
The white band represents the five-year range for end-of-month natural gas in storage from 1998 to 2002. Source: Texas Railroad Commission, "Gas Storage Statistics" (Internet, http://www.rrc.state.tx.us/divisions/gs/rap/storage-statistics/rapstrst.html)

Figure 4: U.S. Natural Gas in Storage



The white band represents the five-year range for end-of-week natural gas in storage from 1998 to 2002. Source: U.S. Energy Information Administration, Form EIA-912, "Weekly Underground Natural Gas Storage Report."

Figure 5: Daily Gas Prices and Weekly Storage



Timeline for Gas Nominations

Scheduling deliveries (or *nominations*) of bulk natural gas is only done Monday through Friday, therefore gas needed on a Monday must be scheduled three days ahead of time on Friday. When the gas trading day closed on Friday, February 21st, generators, other gas customers and to a large extent even the gas utilities themselves were unable to procure more supplies until the following Monday. The natural gas market was therefore incapable of responding to the sudden shortage because the market was closed.

Gas customers must pay a penalty if they take from the system more than they have nominated. The accounting is done monthly, however, and it is not uncommon for some industrial customers to "lean" on the pipeline: one week withdrawing more than they nominated, and then over-nominating the next week to net out the difference. The gas utility is usually indifferent as long as leaning doesn't affect its ability to manage its system.

Rapidly dwindling gas storage throughout the month of February caused pipeline owners to prevent customers from leaning on the system near the end of February, however. The RRC said that in some instances, the gas utility would not allow a customer to take gas that had been nominated. Consequently, the normal means by which power generators could cope with their weekend supply exposure – leaning on the system and making up the difference when the markets opened again on Monday – was not available to them when they needed it most.

Fuel Shortages and Curtailments

Although ERCOT and many power generators said they were anticipating natural gas curtailments on February 24 and 25, the only intrastate gas utility that actually shut off industrial customers was TXU Lone Star Pipeline. Those curtailments did not actually happen until February 25, when the company notified customers that it was activating its curtailment procedures.

A more serious problem was the overall reduction of natural gas supplies to power generators. One Market Participant interviewed by MOD said that its supply of natural gas was adequate to run only one of its site’s two gas-fired generating units. Another said that when ERCOT issued its EECP Step 1 at noon on February 25, operators told ERCOT that it only had enough fuel to run seven hours. Many other units were derated to significantly less than nameplate capacity because of low natural gas supplies, low pressure in the gas pipelines caused by rapid withdrawals, and cold-induced operating problems.

Full curtailment by natural gas utilities became an immediate possibility on February 25. TXU Lone Star Gas began notifying its customers that only “human needs” would be served until the supply crisis abated, and generators began notifying ERCOT that morning that they would be unable to meet some of their capacity and deployment obligations. According to ERCOT, most of the curtailments were in the North Zone, with a net loss of around 2,300 MW. (An estimated 5,500 MW was lost due to natural gas curtailments, but about 3,200 MW of that amount was restored when the units switched to fuel oil.)

All natural gas utilities under the jurisdiction of the RRC must file curtailment plans with the RRC. These curtailment plans must conform to a 1973 RRC order that prioritizes natural gas customers:

1. Deliveries for residences, hospitals, schools, churches and other human needs customers (highest priority, last to be curtailed).
2. Deliveries of gas to small industrials and regular commercial loads (defined as those customers using less than 3,000 MCF per day) and delivery of gas for use as pilot lights or in accessory or auxiliary equipment essential to avoid serious damage to industrial plants.
3. Large users of gas for fuel or as a raw material where an alternate cannot be used and operation and plant production would be curtailed or shut down completely when gas is curtailed.
4. Large users of gas for boiler fuel or other fuel users where alternate fuels can be used. This category is not to be determined by whether or not a user has actually installed alternate fuel facilities, but whether or not an alternate fuel "could" be used.
5. Interruptible sales made subject to interruption or curtailment at seller's sole discretion under contracts or tariffs which provide in effect for the sale of such gas as seller may be agreeable to selling and buyer may be agreeable to buying from time to time (lowest priority, first to be curtailed).

Electric generation falls under the fourth category – even new combined cycle gas turbines that are not designed to switch to fuel oil. However, TXU Lone Star contacted a number of power generators on the morning of February 25 to determine the percentage of generation that was for human needs. ERCOT Chief Operating Officer Sam Jones provided the gas utility with an affidavit certifying that all ERCOT generation that day was for human needs.

Lack of On-Site Storage

When utilities were still bundled, they could usually recover the cost of on-site natural gas storage. The incumbent PGCs affiliated with the old bundled utilities had that storage on hand during the February 24-27 weather event, as did some of the larger municipally owned utilities. New independent power producers, on the other hand, tended not to have their own storage facilities.

Having on-site gas storage gave some power generators a buffer against pipeline shortages, but in many cases the amounts were not enough to avoid supply problems altogether. Any volume in storage still had to be weighed against the uncertainty of how long the weather event would endure. In addition, some companies that had storage did not invest in the maintenance necessary to operate it near its capacity. Finally, some generators with storage said that high gas prices often made it economically imprudent to store gas.

According to IPPs interviewed by MOD, the economics of a new plant in a competitive wholesale environment preclude the capital expense of investing in natural gas storage; most prefer to manage their supply risk financially through hedging instruments rather than physically through storage.

Recommendation

- *Curtailment prioritization – collaborate with the RRC to determine a joint curtailment methodology for natural gas and electricity.*

System Impact: Alternative Fuel Switching

Texas has always had a significant portion of its electric generation fueled by natural gas, and historically much of the generation was "dual fueled", that is, it was capable of running on natural gas or fuel oil. Dual fuel capability has served as an important backstop for reliability in the event that natural gas was curtailed due to weather conditions or other supply disruptions. Despite the large amount of new generation that has been built in the state since 1995, the percentage of dual fuel capability has declined because independent power producers and other developers have chosen not to add dual fuel capabilities for economic reasons. Not only does dual fuel capability increase capital costs, but it implies the need to maintain oil inventory at the plant in order to take advantage of the alternate fuel capability. In some cases, the inclusion of oil-fired capability in a new plant may be prevented by environmental restrictions. Recent information from ERCOT indicates that 72.6% of installed capability in ERCOT is fueled by natural gas and 15.8% of this capability (11.5% of total installed capability) is dual fueled.

In response to the curtailments on February 24th and 25th, many units were switched from gas to fuel oil. Some experienced operating problems and most experienced some level of capacity derating. In one case, a fuel oil delivery mechanism malfunctioned, so that operators could deliver oil to one of two units, but not both (loss of 80 MW). In another case, two units tripped when operators tried to bring them up on oil. When they were finally restarted, they operated at a combined capacity of 150 MW instead of 328 MW. Even without operating problems, most units on oil experienced deratings which ranged from as little as a few percent to as much as much as 20 percent. ERCOT's preliminary estimate is that 5,500 MW of generating capacity was reduced due to gas curtailments and approximately 3,200 MW was regained on back-up fuel, an estimated net loss of 2,300 MW.

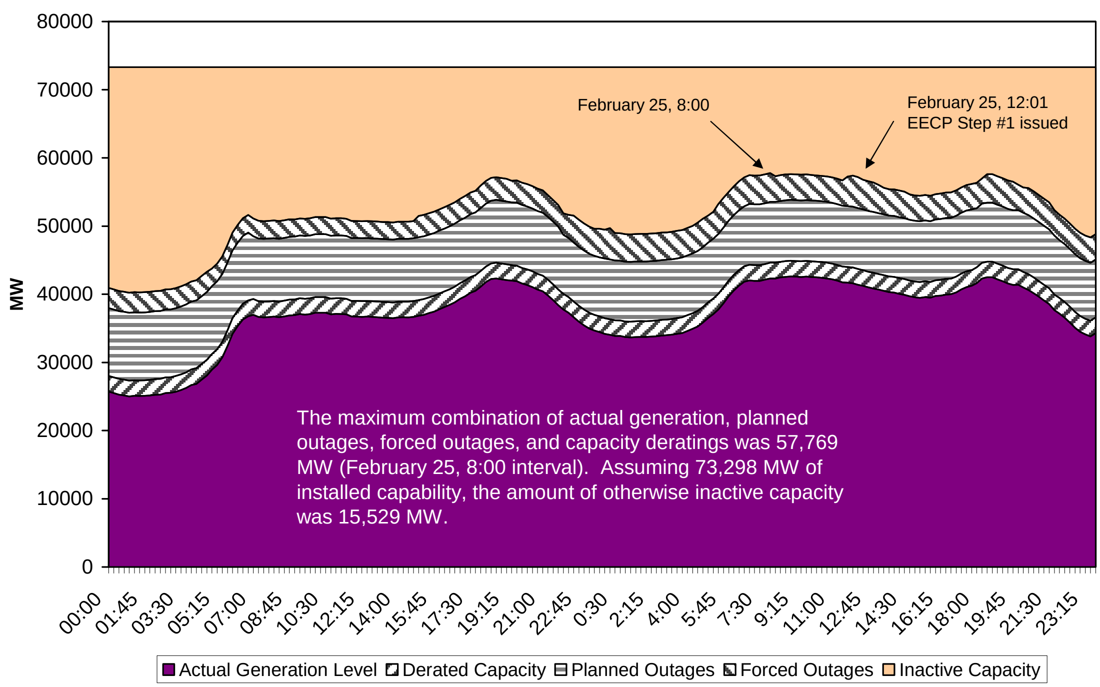
Recommendation

- *Consider providing financial incentives for fuel oil inventories that will be maintained for use by dual fueled generating units.*

System Impact: Outages

About 12,900 MW of capacity was out of service when February 24th began, including 9,900 MW on planned outage and 3,000 MW on forced outage. Planned outages declined to about 8,400 MW by the end of February 25th, but forced outages ranged from 2,600 MW to 4,700 MW during the two days. Although the outage level was significant, there was more than enough installed capacity to meet demand. The chart below shows installed capability in ERCOT of about 73,300 MW, which includes the DC ties but excludes mothballed plants and wind generation. The bottom area in the chart represents the actual generation level during the period which peaked at 42,613 MW in the 9:00 interval on the 25th. The second layer represents the 2300 MW of capacity lost due to gas curtailments and deratings. The third and fourth layers represent planned and forced outages, respectively. The blue layer at the top shows that there were more than 15,000 MW of installed capability that was not in operation or otherwise accounted for during the 24th and 25th.

Figure 6: Analysis of Installed Capacity on February 24-25, 2003



ERCOT issued the EECP Step #1 at 12:01 on the 25th which, in accordance with the Protocols, included dispatch instructions to QSEs to bring on line all available generation (OOMC) and bid it into the balancing energy market. After the EECP was issued, system frequency and SCE were restored to normal levels within 30 minutes. This indicates that the EECP Step #1 was effective in bringing more generation on line, but it raises the question of why more generation was not already on line, since balancing energy and ancillary service prices had already exceeded $900 in many intervals and ERCOT had previously issued several alerts and advisories. Staff is attempting to determine which plants were not on line during the period and why they were not in operation.

System Impact: Resource Plan Accuracy

Each QSE submits a Resource Plan to ERCOT in the day before the operating day, and it is obligated to keep this plan updated. The Resource Plan indicates the availability of each of the QSE's resources along with the planned operating level and operating limits of these resources.

A problem developed on February 25 because some of the Resources shown as available in the Resource Plan were in fact unavailable. Section 5.5.1 of the Protocols states:

> The QSE will notify ERCOT of an unplanned change in Resource status as soon as practicable following the change. The QSE representing the Resource will report any changes in Resource status to ERCOT in the Resource Plan by the beginning of the next hour following the change in status.

The operating level of the Resources was affected by the gas supply shortages and delivery problems, yet Resource Plans were not being properly updated by QSEs to keep ERCOT informed of the resulting changes in status. Non-compliance with the Resource Plan Update requirement can have serious consequences for ERCOT's ability to maintain reliability especially in times of severe weather conditions, as happened in this case. After conducting an analysis, the Frequency Control Task Force of ERCOT's Reliability and Operations Subcommittee (ROS) concluded[5]

> The data reviewed leads us to believe that during the hours of 0600 – 1200 on February 25th ERCOT as a whole was deficit and that ERCOT operations did not call for an EECP during this time due to invalid or not current data from the QSE resource plans.

MOD has reached the same conclusion based on our review of the data provided to us by ERCOT.

Recommendation

- *After the events of February 24-26, ERCOT started tracking and reporting on Resource Plan accuracy. The Protocols incentive and disincentive structure is ineffective in this area and the Commission should therefore consider applying meaningful penalties for Market Participants who do not comply with the Resource Plan update requirement.*
- *ERCOT also noted in discussion with MOD that the restriction on schedule and Resource Plan updates during the two-hour Operating Period is detrimental, and that real-time updates should be allowed during certain times. MOD supports this recommendation.*

[5] This conclusion was stated in a preliminary report given at the April ROS Meeting. The report can be found on ERCOT's website at http://www.ercot.com/calendar/2003calendar/Attachapr03/ROS04092003-24.doc.

Market Impacts

Up Balancing Energy Service

MOD interviewed several Market Participants who submitted bids above $300 during the extreme weather event. In those discussions, MOD staff was able to assess that, in many instances, the inclusion of high fuel costs in bids was responsible for the $300-$500 range Balancing Energy bids that were observed in the Balancing Energy market during those two days. The factors responsible for such high bids were:

- Intraday gas prices up to $29/MMBtu and possibly higher;
- Reduced efficiency of gas units operating with alternate fuel; and
- Some Market Participants were running older gas units with heat rates above 10,000 BTU that are normally not economical to run

With gas prices at $29, a new combined cycle gas unit with a heat rate of 7 MMBtu per KWh and operating at an optimal level of efficiency would have a production cost of roughly $203. An older gas unit with a heat rate of 12.5 would have a production cost of roughly $362. Deratings due to reductions in gas supplies would reduce the production efficiency of these units and increase their production costs.

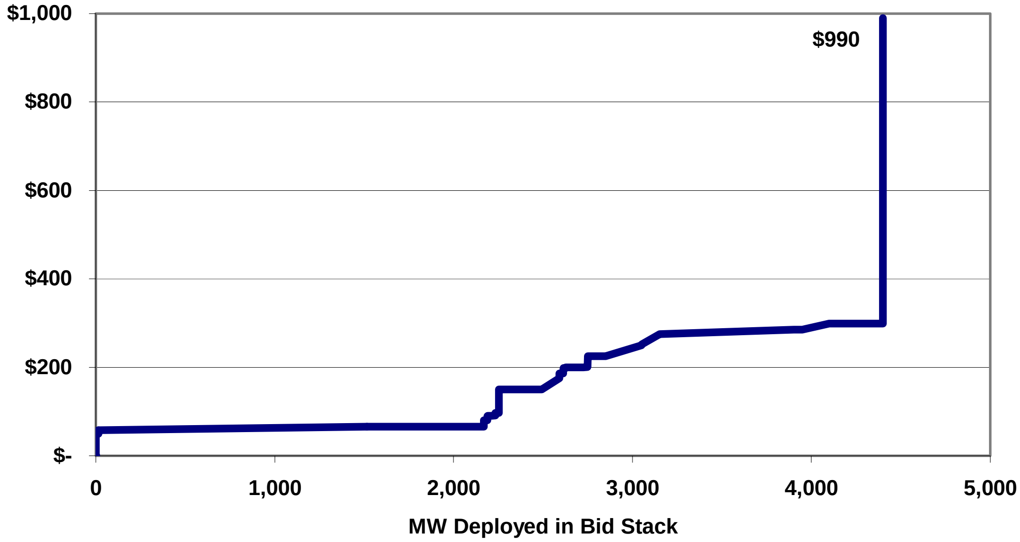
MOD concludes that bids in the $300-$500 range were consistent with market conditions at the time of the extreme weather event, although the possibility of market manipulation has not yet been ruled out. Moreover, many of the QSEs who bid in this range did so only on February 25 and did not exceed $300 on February 24. Some told MOD they were trying to stay below $300, because bids above that level result in the QSE being identified the next operating day as a high BES bidder.

Opportunistic Hockey Stick bidding

Two QSEs, however, bid well beyond the $300-$500 range indicated by market conditions. One had temporarily ceased placing its high bids prior to the weather event, while the other had high bids of $990 that set the MCPE during 28 intervals on February 24 and 25. Moreover, MOD found that both QSEs had been placing high bids routinely prior to the weather event. In both cases, the high bids exhibited the classic hockey stick pattern: a small quantity (one or two megawatts) bid at or near the maximum allowable price, with the rest of the bid curve priced near marginal cost.

When asked to explain their high bids, both pointed out that hockey stick bidding is not prohibited by either ERCOT or the commission. They acknowledged that the extreme bids did not reflect production costs during the weather event, but claimed that the sporadic windfall revenues were intended to improve the long-term profitability of a plant. Hockey stick bidding is being addressed in Docket Number 24770.

Figure 7: Hockey Stick Bidding on February 25, Interval Ending 8:00 a.m.



Down Balancing Energy Service

MOD analyzed how Down Balancing as well as Up Balancing bid prices were affected by the gas supply conditions and observed that some Market Participants submitted very high positive Down Balancing bid prices. This is a significant indication that these Market Participants were experiencing high production costs. For example, if a Market Participant submits a Down Balancing bid at $250/MWh, it indicates that its production costs are above $250/MWh, and that it would be willing to back off its own generation and buy from the market at $250 to meet its obligations. MOD observed that several Market Participants with Up Balancing bids above $300 had Down Balancing bids that reflected such high production costs. However, this behavior was not observed across all Market Participants, and some Market Participants' Down Balancing bids were not different than those they submit under normal conditions. When asked to explain such bids, these Market Participants often stated that they simply left their Down Balancing bids at their usual level while focusing on more pressing needs. MOD concluded that, although Down Balancing bids provide reliable evidence of high production costs that justify high bids in the Up Balancing market, the absence of such bids is not conclusive evidence unless other indicators are present to confirm improper behavior or market abuse.

Ancillary Capacity Services

ERCOT's Ancillary Capacity Service Markets echoed the tight conditions and resulting high prices experienced in the Balancing Energy Market on February 24 and 25. The effects on Ancillary Capacity Services prices lagged BES by one day, which is to be expected since bidding and clearing of Ancillary Services occurs in day-ahead auctions. The Day Ahead Market for February 25 was cleared by 13:30 on February 24 and the Market for February 26 is cleared by 13:30 on February 25 Ancillary Services displayed price spikes which were caused by a combination of decreased bid volumes along with high-priced bidding.

The following graphs show that there was a marked decrease in the total MWhs bid for RRS and URS. They also show that at the times when ERCOT procured all or almost all of the bid stacks, the prices spiked as high priced bids were struck.

Figure 8: Regulation Up Bid, Procured Volumes and Market Clearing Price

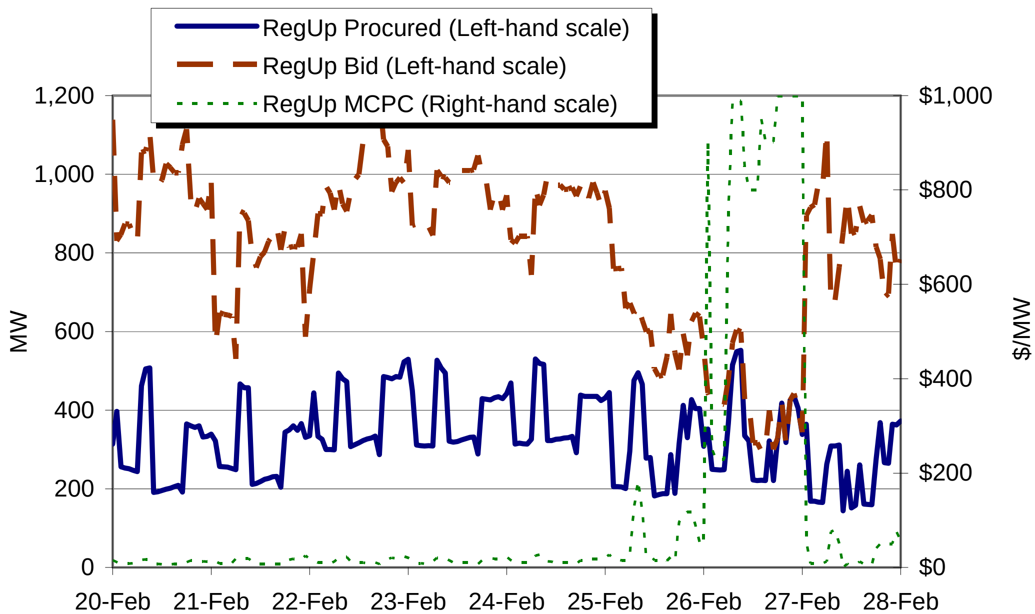
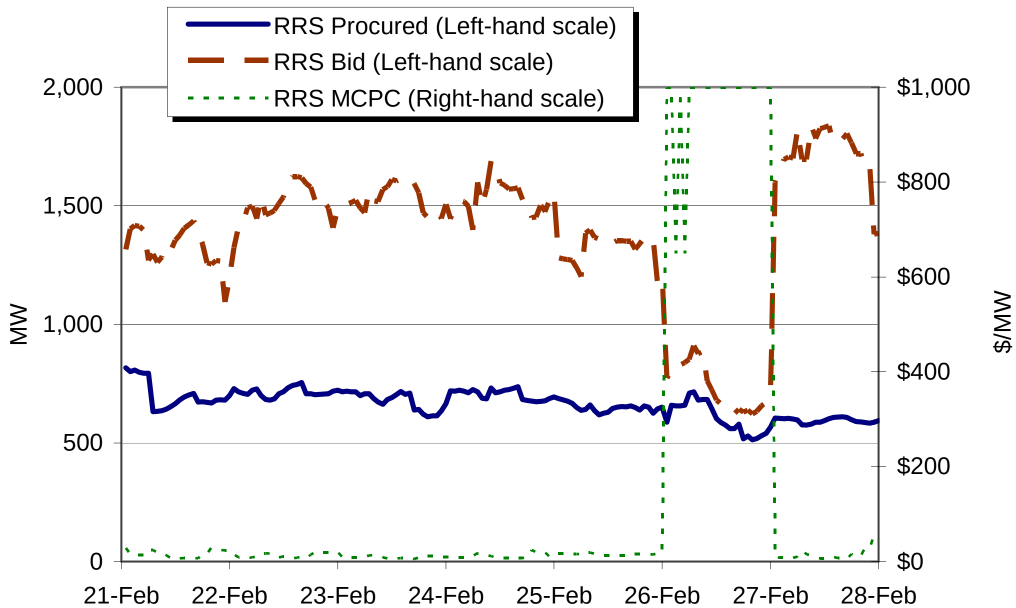


Figure 9: Responsive Reserves Bid, Procured Volumes and Market Clearing Price



Note that in Figure 9, the RRS bid quantity is overstated, because some bids in the RRS stack were struck for URS (these are bids that could be used for either URS or RRS).

During several hours on February 26, the RRS procurements were constrained by the available bids – there was insufficient capacity to procure all of the need in the first market. Because of known conditions and information from the QSEs that fuel availability was short, ERCOT made the decision not to open a second market. ERCOT issued a capacity insufficiency notice and logged the decision not to open a second market.

Ancillary Capacity Service bids placed on February 23 for February 24 did not reflect any abnormal conditions. URS and NSRS bids placed on the 24th for the 25th started to reflect some of the high gas prices experienced on the 24th. Bids placed on the 25th for the 26th, however, increased significantly and were close to the bid cap of $1000, fully reflecting the events of the 25th.

Several Market Participants interviewed by MOD indicated that the bid prices of February 26 included a risk premium that was due to the BES price spikes of the February 25. These Market Participants explained that the potential for plant outages was made more likely by the weather conditions and that if they were deployed and unable to meet their Ancillary Capacity Service commitments they would then be exposed to the $990 price in the Balancing Market.

The A/S price spikes of February 26 demonstrate that price spikes in the Balancing Market have a ripple effect that goes far beyond the direct impact they have in that market. The indirect costs to the market of the February 25 Hockey Stick bid of 1 MW that set the MCPE at $990 for several hours on that day are the high costs of A/S the market had to pay on February 26. A preliminary analysis estimates this indirect cost to be around $20 million.

Recommendation

- *In Docket No. 24770, Staff has proposed methods to deal with hockey stick bidding.*
- *MOD should further analyze the bid prices submitted by parties whose DBES bid prices were far apart from their UBES bid prices.*

Questions Relating to ERCOT's Actions and Responsibilities

Should ERCOT have declared an Emergency Condition sooner?

The Protocols contain criteria specifying when ERCOT can declare an Emergency Condition. One of these criteria is if a situation exists such that "ERCOT cannot maintain minimum reliability standards during the Operating Period using every Resource practicably obtainable from the market." [ERCOT Protocols 5.6.6 (1)] On the morning of February 25, frequency dropped to 59.81. ERCOT reports that it had deployed all available NSRS, was out of Balancing Energy and URS, had deployed 756 MW of RRS, and was unable to restore frequency. ERCOT then decided to declare EECP Step 1.

ERCOT data indicates that total obligations exceeded total online capacity from at least 6am to 9am on February 25 If this fact were known to ERCOT in real-time, they logically would have concluded that the resources available to them from the market were inadequate, especially since an Alert requesting additional BES bids had already been issued at 7:30am. However, indications are that ERCOT was not able to accurately determine the Total Online Capacity since Resource Plans were not being updated and capacity committed for Ancillary Services was not available as it should have been.

Declaring an Emergency sooner would have required QSEs to make all available generation available sooner. This may have prevented the price spikes at $990 which occurred in almost every interval from 6am to noon on February 25 One interviewed Market Participant stated that declaring the emergency sooner would have allowed some generators to operate outside of normal environmental limits and/or with alternate fuels sooner.

Should ERCOT have Acquired Replacement Reserves (RPRS)?

Several Market Participants have questioned whether ERCOT should have procured RPRS. Replacement Reserves are purchased by ERCOT in order to ensure the availability of adequate resources capable of providing additional Balancing Energy Service to ERCOT. A shortage of available Balancing Energy was experienced for eight 15-minute intervals on February 24 and thirty-nine 15-minute intervals on February 25 If ERCOT had procured RPRS, it potentially would have increased the amount of Balancing Energy Bids in the Balancing Market and reduced the need to order additional OOME. The decision to acquire Replacement Reserves is based on data from the Resource Plans regarding the level of capacity available to provide adequate Balancing Energy Service. The Resource Plans indicated that there was adequate available capacity and that therefore Replacement Reserves would not be needed. This underscores the need for accurate Resource Plans.

Should ERCOT have informed the TDSPs when it declared an emergency condition?

When the EECP Step 1 was declared, ERCOT made a hotline call to QSEs but did not contact the TDSPs. This was an oversight on ERCOT's part which did not appear to have had any negative consequences in this case.

Questions Relating to Market Participants' Actions and Responsibilities

MOD continues to analyze several unresolved issues. We have not yet received all of the data and information to answer these questions.

What is the meaning of "all Resources that are available in the time frame of the emergency" in this context?

The Protocols State that ERCOT will "Provide Dispatch Instructions to QSEs to start all Resources that are available in the time frame of the emergency (OOMC)." [ERCOT Protocols 5.6.6 (1)]

Does this mean: Available in Resource Plan? Available meaning functioning? Available meaning with reasonably priced gas? Is saving gas for a later time a valid excuse not to make these resources available? How is the "timeframe of the emergency" to be determined? This protocol provision should be clarified.

Did some QSEs not meet their Ancillary Services Obligations? Did a habitual practice of not meeting Ancillary Service Obligations negatively contribute to this event?

MOD is investigating this issue.

Did any plants remain offline that could have come online? If they did not do so, why?

MOD is investigating this issue.

Recommendations

- *ERCOT should communicate with both QSEs and TDSPs in the future when the system is under stress.*
- *Market Participants should support reliability of the system and if they do not, there should be consequences.*

Recommendations

- *After the events of February 24-26, ERCOT started tracking and reporting on Resource Plan accuracy. The Protocols incentive and disincentive structure is ineffective in this area and the Commission should therefore consider applying meaningful penalties for Market Participants who do not comply with the Resource Plan update requirement.*
- *ERCOT should communicate with both QSEs and TDSPs in the future when the system is under stress.*
- *In Docket No. 24770, Staff has proposed methods to deal with hockey stick bidding.*
- *MOD should further analyze the bid prices submitted by parties whose DBES bid prices were far apart from their UBES bid prices.*
- *ERCOT should improve its weather forecast and demand forecasts. MOD cautions, however, that better forecasting is no "silver bullet." Even the best weather modeling may not have been sufficient to prevent the system and market disturbances that occurred on February 24th and 25th.*
- *Curtailment prioritization – collaborate with the RRC to determine a joint curtailment methodology for natural gas and electricity.*
- *Market Participants should support reliability of the system and if they do not, there should be consequences.*
- *Consider providing financial incentives for fuel oil inventories that will be maintained for use by dual fueled generating units.*
- *ERCOT also noted in discussion with MOD that the restriction on schedule and Resource Plan updates during the two-hour Operating Period is detrimental, and that real-time updates should be allowed during certain times. MOD supports this recommendation.*