DOCKET NO. 40000
PUBLIC UTILITY COMMISSION OF TEXAS

2013 FEB 13 AM 11:23

COMMISSION PROCEEDING TO	§	THE PUBLIC UTILITY
ENSURE RESOURCE ADEQUACY	§	
IN ERCOT	§	COMMISSION OF TEXAS

FILING CLERK

COMMENTS OF MORGAN STANLEY CAPITAL GROUP INC. REGARDING RESOURCE ADEQUACY AND THE WORKSHOP OF JANUARY 24, 2013

Morgan Stanley Capital Group Inc. (Morgan Stanley) files these comments in response to the Workshop held by the Public Utility Commission of Texas (the "Commission") and the University of Texas on January 24, 2013 (the "Workshop"). The Workshop presented two plans to more appropriately price energy consumed when the market is experiencing reduced operational reserves and a subsequent higher risk of firm load shed. Morgan Stanley appreciates this opportunity to provide input into the process as the Commission reviews potential benefits and hazards of these two plans.

Summary of Conclusions

Of the two options under consideration, Morgan Stanley favors the Commission direct ERCOT to implement the plan developed by EDF SUEZ (Option A) as soon as possible. Option A will not only provide a more appropriate market signal for energy pricing when operational reserves are used, but also will significantly moderate the binary energy pricing outcomes the current design generates.

Background

The ERCOT market has faced challenges in achieving revenue sufficiency to support the development of new generation needed to supply the ever-increasing load in Texas. This problem has been colloquially described as "the missing money" or "the revenue gap". Through this proceeding and others, many of the contributing factors causing the missing money in ERCOT have been identified and actions have been taken to correct them. These include:

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- Increasing Energy and Ancillary Service Offer Caps to $5,000/MWh (June 1, 2013), $7,000/MWh (June 1, 2014), and finally $9,000/MWh (June 1, 2015);
- Moving of 500MWs of Non-Spinning Reserves ("NSRS") into Responsive Reserves ("RRS");
- Establishing floor prices for ancillary services to prevent price reversals;
- Approving Voluntary Mitigation Plans for certain stakeholders identified as capable of exercising market power; and
- Revising upward the Peaker Net Margin ("PNM") value and increasing the Lower Offer Cap ("LCAP") should the Peaker Net Margin value be reached.

Closing the Revenue Gap

These course corrections were adopted in order to close the revenue gap, but have so far failed to do so. Peaker Net Margin values have been calculated by Potomac Economics since 2008[1]. The margin calculation is based on the approximate revenues that would be received by a 10HR peaking unit if it were dispatched perfectly in the market without consideration of startup or minimum running costs. As such, it is not an exact estimation of revenues, but rather a general indicator of the revenue available to resources in the market. This shows that total revenues available range from about $45,000 to $125,000 over the five years.

After 2011, the market enhancements described above were made, and yet the Peaker Net Margin *decreased* to $33,952. It is important to note that the summer of 2012 was reported by ERCOT's Calvin Opheim as being *warmer* than average.

The reason for the low revenue result lies in the nature of the revisions. The bulk of the energy pricing changes only become effective when ERCOT experiences significant system shortages and reserves are being used to provide energy. In 2011, the market

[1] The calculations have been performed by Potomac Economics since 2008 and each year through 2011 can be found in Figure 65 of Potomac Economics', 2011 State of the Market Report.

experienced 28.5 hours of pricing at the offer cap. By comparison, in 2012 there were only 1.5 hours of prices at the cap even with the revisions incorporated into the market.

Thus, in the vast majority of weather conditions, mild to warmer than average, the system load does not rise to the level of needing energy from reserves, so the higher energy prices applied to those services do not materialize. It requires extreme weather, similar to that seen in 2011 to move load into a range where reserves provide a significant influence on energy pricing.

Binary Outcomes

The summer of 2011 raised alarms as the ERCOT market was perilously close to experiencing rolling blackouts in early August. The resource scarcity conditions demonstrated another facet of the market, the binary nature of energy pricing in ERCOT.

Resources in ERCOT have shown that they are very competitive. This has proven to be one of the beneficial changes of the deregulated market. However, when the resource stack becomes scarce, energy prices do not steadily increase in relation to increased reliability risk. Rather, they remain relatively low due to competitive forces, right up to the point of market exhaustion, and then rise sharply to the cap. For instance, on August 3, 2011, prices ranged from the mid $20 to mid $70/MWh range through interval ending 13:45. Over the next hour, prices rose sharply to the $3,000/MWh cap and remained at that level until ramping sharply back down to the high $50/MWh range in interval ending 1900. Similarly on June 26, 2012, prices rose from the low $50/MWh range in interval ending 1315 to over $1000/MWh in interval ending 1415, peaking near the $3,000/MWh cap by 1500.

Some volatility can be appropriately managed by the market. However, when energy price has the ability to move 2+ orders of magnitude over a day, the risk premiums an entity must charge become unwieldy. For instance, when the market reaches the $9,000/MWh offer cap level in 2015, a single 5 minute SCED interval can cause the price to increase $47/MWh, which could be roughly double what it would have been otherwise. A SCED interval can generate an extreme print like this any time the market becomes ramp limited or a large unit trips when operational reserves are not exceptionally robust, making the occurrences of such events rather random, as opposed to being broadly predictable when extreme conditions are likely. Thus, the risk premium needed to prevent loss from such an occurrence could outweigh the value of the underlying commodity.

Pending Credit Problems

The binary market structure could lead entities to forego paying the risk premium and risk the market outcomes in real time – a potentially disastrous result. Past events have shown how quickly established market participants can disappear entirely. Rapid price dislocations may cause parties to exercise contractual rights to collect margin, which if unmet within a short period (typically two business days), could result in defaults. This risk is magnified with increased price latitude. As with the bilateral market, ERCOT faces counterparty credit risk with each Qualified Scheduling Entity ("QSE") they face. The current margin requirements set forth in the Protocols appear inadequate given the latest increases in the offer caps and the binary nature of the market structure.

For instance, assume an entity has a 500MW uncovered obligation during the 16 peak hours of the market. That entity would have accumulated \$44 million in debt to ERCOT over August 3rd and 4th of 2011. If the \$3,000/MWh prints are revised up to \$9,000/MWh and none of the other market modifications are made, that obligation increases to around \$116 million. If this is 5,000MWs of accumulated load that is unhedged, the risk is over \$1 billion for the two days.

While these numbers are very large, they should not come as a surprise. The fundamental principles driving an energy only market anticipate that resources will go through years of under-recovery and over-recovery of capital but, over time, the market will find a point of reserve "equilibrium" when the average recovery supports new build economics. In the ERCOT market however, it appears that the market is structured such that several years of under-recovery (as noted by the PNM calculations) will be experienced, followed by one year, or more accurately, one month of significant over-recovery.

Assuming the PNM calculations are a fair representation of the values accruing to the market, it would appear that an additional $40,000/MW-yr is needed in most years to support new build economics. Assuming the market experiences 9 years of this level of revenue, the shortfalls must be made up in the 10^{th} year. This means that in year 10, the market has to provide approximately $400,000/MW-yr in revenues, with the bulk of those revenues coming in the month of August. Those pricing levels will test even the soundest of financial players in the market.

ERCOT is in the process of reviewing its credit standards, but it will be a significant challenge to provide appropriate market coverage. This is in part due to the fact that many market participants may not have the financial wherewithal to carry the collateral necessary to back their market positions. It is also very difficult to predict when the market may fall into a period of energy prices at the offer cap as relatively small variations in temperature can cause significant increases in demand. Further, as indicated by the events of 2011, once the market goes into that level of pricing, it can stay at that level for several hours. Margining procedures that provide sufficient protection for the market would be very expensive and frequently inaccurate. The engine would be forced to predict future market outcomes and could create many "false positives" that are not experienced in the market. Procedures that are not this stringent will leave the market potentially under-collateralized and exposed to participant defaults that, as described above, can be material.

Market defaults not only create disruptions to the market. The default allocation mechanism currently in operation in ERCOT works to unwind the revenues the market hopes to achieve to support new resource construction. This is due to the fact that the resource entities carry a portion of the burden of paying a default and are essentially paying themselves for a portion of the energy they provided during the high price event.

A better way

The Workshop looked at two approaches: Option A, a reserve pricing floor offered by GDF SUEZ, and Option B, a demand curve price adder developed by Dr. William Hogan.

As both proposals involve operating reserves in Real time, it is important to note the distinction between operating and planning reserves. Rolling blackouts occur when operating reserves are inadequate to meet current demand. Planning reserves are the long term target that, in concept, ensures sufficient availability of operating reserves throughout the year. Planning reserves margins are calculated in ERCOT's Capacity Demand and Reserve Report each year based on anticipated load conditions for the peak hour of the year. The reserve margin calculated intends to provide sufficient capacity during conditions where the load is higher than expected, or generation suffers forced outage.

As has been noted by Commissioner Anderson, ERCOT's two most recent rolling blackout events did not occur during the summer peak or even in the summer load period. Rather, one occurred during a hot day in April of 2006 when considerable generation was on maintenance outage. The other occurred during an extreme cold weather event in February of 2011 when several generation units were forced off line due mechanical problems. Sufficient capacity existed in the system during these events. However, the capacity could not be operated. He appropriately describes these as "Black Swan" events.

Option A

Option A is similar in form to the way the floors for ancillary services operate today. To increase revenues, it is recommended to slope the offer floors up to the cap (they are currently flat for NSRS) and increase the amount of reserves purchased in the market. This creates a "runway" in place of the "cliff" we have today. As the market moves into periods of fewer reserves, the energy price would be forced to a higher level than their current competitive levels by the reserve curve requirements. This creates more mid-range pricing and aids in replacing the "missing money" to the market. Both the pricing signals and overall increase in revenues are indicators to developers to begin projects.

The impact of the proposal depends heavily on the shape of the curve. The GDF SUEZ proposal suggests an increase in operating reserves of 3300MWs in order to achieve an equilibrium point of 13.75%. This is based on internal studies GDF SUEZ has performed that revise the current NSRS offer floors to a straight line curve starting at $1,000/MWh and continuing to $9,000/MWh. Morgan Stanley supports the use of a straight line curve as that provides the greatest moderation of the binary energy price outcomes, but would prefer a lower starting point to mitigate the likely step function that would occur as the market transitions into the use of NSRS.

Morgan Stanley would also propose using the models set up in the Brattle Study to verify these results. Brattle's model should be able to simulate the revised offer floor shape over several years to determine new revenue levels and the equilibrium reserve level achieved by the change. The shape and level of reserves can then be adjusted based on the Commission's policy desires. For example, regulators may seek an equilibrium point near the 13.75% reserve margin level, or some other level altogether. Using an assumed straight line shape, the NSRS offer floor can be revised to start at a price of $500/MWh and end at the offer cap. Then the number of reserves required can be adjusted as needed to achieve the desired reserve margin level.

The increase in operating reserves would not only increase resource revenues, but would also provide support to the system should it experience another Black Swan scenario. In the two events described, generation resources would likely have varied their maintenance schedules to be available for the increased ancillary service demand.

If it is desired to later move to a capacity market, this mechanism is fully compatible with that approach as it would aid in providing much of the revenue needed to sustain reserves. Thus it reduces the need for significant revenues from the capacity market.

The “runway” created by this approach will also curb many of the problems created by the current binary market design. This is where some care should be taken as to the quantity of reserves to which the curve applies. Year on year load and resource variations could cause the market to leap frog over the curve if it does not have sufficient depth. For example if load growth is expected to be approximately 1,000MWs per year, a reserve curve of 500MWs would be far too small. One could experience a year where the market does not achieve a single event on the reserve curve, sending no construction signals, while in the following year, several such events could not only get into the curve but frequently exhaust it at the system wide offer cap.

Cushioning the binary nature of the market will facilitate trading in ERCOT. As mentioned previously, the potential market consequences of a $9,000/MWh print could create serious market dislocations. When the price [consequences] of the risk outweighs the price of the underlying commodity, trading is impaired. The Option A approach would significantly decrease the risk premium required by the market and increase its liquidity.

Another benefit of the incremental nature of Option A is that it better supports demand response. Many of the providers of this service have difficulty responding to individual 5 minute SCED prices. If the slope is gradual enough, the market should not move rapidly into or out of the curve in single SCED intervals as is commonly seen today. Gradualism enhances price stability, thus allowing loads better economics for curtailment.

Since Option A utilizes current ERCOT systems it appears that it can be quickly and easily implemented. It should also be considered somewhat “tested” as the mechanism will work similar in fashion to the Power Balance Penalty Curve in operation in the ERCOT market today. For these reasons, Morgan Stanley prefers Option A.

Option B

Option B is a modification of the approach developed by Dr. William Hogan as a needed change for ERCOT’s pricing of reserve energy. The approach creates an adder that is tied to the reliability risk of energy service at varying levels of operating reserves. The adder is created by multiplying the Value of Lost Load ("VOLL"), by the probability of firm load shed at each level of operating reserves.

The adder, once calculated, would be incorporated into the energy price at each settlement point in the system. The adder would also be paid to all unloaded capacity in the system that is not already providing ancillary services. The latter aspect of the plan is a "fix" to the original proposal which requires real time co-optimization to ensure an appropriate payment stream.

This approach, while potentially providing sufficient revenues for new development, has a number of problems related to its implementation in the ERCOT market.

The shape of the curve will be critical to determining if this plan will increase revenues. The recommendation is not only to create the adder, but also remove all the existing pricing floors in the market. This means that relative to the current market design, the price of energy provided by NSRS could drop $80/MWh, and energy provided by RRS could drop $4,960/MWh (assuming a $5,000/MWh offer cap) when the existing floors are removed. If the reserve adder doesn't correct for these price reductions, the result will be *less* revenue for the market, not more.

A significant impediment to this approach will be the challenge of creating revenue at these levels using experiential data from ERCOT's operations. For instance, the curve developed by ERCOT as an example showed a 5% loss of load probability with 3,300MWs of reserves remaining on the system. This would indicate that for every 20 occurrences that the market drops to 3,300MWs of active reserves, ERCOT will suffer a firm load shed event. That does not appear to align itself with historical data. Using a VOLL of $5,000/MWh would set the adder price for this level at $250/MWh ($5,000*0.05). This is significantly lower than the price of $5,000/MWh that would be seen in the current market rules assuming that there are 500MWs of Regulation Up Service (URS) and 2,800MWs of Responsive Reserves (RRS) in the operational hour (priced at the system wide offer cap as required). So the estimated curve provided by ERCOT not only appears to overestimate the risk of firm load shed, it also provides a very low adder at those levels. A curve that better aligns itself with experiential outage data would appear to provide significantly *less* revenue for market resources than our current design, not more.

Option B does not require an increase in operating reserves as is recommended by Option A. Rather, it hopes that reserves will increase in response to the availability of the reserve payment. This is unlikely due to the low level of the adder when available reserves exceed existing ancillary service requirements. Such low revenue levels are unlikely to encourage resources to operate less efficiently to maintain reserves off the top of their unit.

Additional issues have been raised as to whether the curve would be dynamic or static. The nature of market operations points to a dynamic curve that accounts for variations in wind output, load ramping and capacity that is offline but available. These variables indicate higher or lower risk to the market, but are not part of a simple "operational capacity available" measure. Dynamic curves, however, would be exceptionally difficult to manage from a market standpoint as they can vary day to day and even hour to hour. Static curves would also be difficult if the curve is steeply inclined. When the market is on the incline, relatively small errors in reserve estimates can lead to errors of thousands of dollars in adder price.

The adder also creates market issues in that each resource must estimate what the adder will be at each hour of the day and incorporate that value into such resource's Day Ahead Market Offers. This must be done not only for energy, but for the ancillary service price as well to ensure the co-optimization of ancillary services day ahead works correctly. This could also lead to inefficiencies as various resources may have varying views of what the adder will be. Thus, an inefficient resource that inaccurately predicts a low adder may be dispatched before a more efficient unit that offers with a higher estimated adder.

Unlike Option A, the adder would not correct the binary market flaw, but rather exacerbate it. Removing the current offer floors could move the market back to the system offer structure that occurred in 2011 with higher offer caps. It appears that the adder curve will have a similar sharply increasing shape to it. Thus, a binary adder curve would be summed with a binary energy curve, exacerbating the binary energy price outcomes. This is a critical issue for market participation as the market will not be able to appropriately account for where the adder will move in real time. As the adder becomes more and more difficult to predict accurately, projecting market value becomes exceptionally difficult for the prompt summer and becomes essentially impossible for future years. As the risk increases, participation may drop as entities may decline to participate in the market. This saps trading volumes from the market that are essential for new development.

Option B also creates an uplift payment due to the payments for reserves that are not ancillary services. This is needed to appropriately align incentives for resources that would rather run at maximum output given the adder, but are marginally backed off due to their energy offer curve. The magnitude of this payment is unclear and depends largely on the shape of the adder curve. This is not necessary in Option A, as the price is explicit in the energy curve.

Implementation of Option B would be far more complex than A. The mechanism requires revisions to the pricing engine to incorporate a real time calculation of the adder and summation of that value into settlement point prices. The "reserve imbalance" that is contemplated in this option as well as the allocation of the imbalance must be worked into the settlement engine. New reporting requirements would also be needed so that the magnitude of the adder and uplift can be tracked.

Conclusions

Though both options appear to work toward the same goal, Morgan Stanley supports implementation of Option A. It provides fewer problems with implementation, fewer problems with market operations and represents evolution instead of revolution. Several issues have been raised with Option B. Since it is an untried concept, it is also unclear whether all the unintended consequences have been unearthed.

Option A is easier to manage from a market standpoint and significantly addresses the binary clearing price problem. At a minimum, it is recommended that Option A be implemented as the market continues to investigate moving to the full solution developed by Dr. Hogan, including real time energy and ancillary service co-optimization, or to a capacity market. It appears this solution can be implemented as early as summer of 2013 and can provide a strong new signal to the market.

Respectfully submitted,

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