Comments on Mitigating Local Market Power and Interim Measures For Intra-Zonal Congestion Management

Frank A. Wolak, Chairman; Brad Barber, Member;
James Bushnell, Member; Benjamin F. Hobbs, Member
Market Surveillance Committee of the California ISO

September 10, 2002

Introduction

The California Independent System Operator (CAISO) is currently appealing to the Federal Energy Regulatory Commission (the Commission) for the tools to deal with local market power problems associated with intra-zonal congestion management (AZCM). These two issues are so intimately related that it is more productive to address them in a combined solution. In particular, the combination of local market power and zonal congestion management has led to chronic problems with the intentional over-scheduling of generation at certain locations in the transmission network. This practice has come to be known as the "dec game." To provide meaningful relief to the reliability and economic costs associated with intra-zonal congestion, any measure approved by FERC must mitigate the local market power that greatly magnifies the severity of "dec game." The solutions approved to date, specifically those laid out in the Commission's July 17th order on California's MD02 market redesign Docket No. ER02-1656, do not adequately address this problem. Significant amounts of local market power can still be exercised under this mechanism. For this reason, the Commission should not defer implementing a solution to this problem until the end of the California market redesign process. This would create an intolerable delay in addressing unjust and unreasonable market outcomes, with serious near-term economic and reliability consequences for California.

The Problem: The Combination of Zonal Pricing *and* Local Market Power

Because the California ISO does not have the authority to mitigate the bids of market participants with local market power, intra-zonal congestion costs have been much more frequent and severe than projected at the start of market, with costs to the ISO now averaging over a million dollars per month. The largest source of intra-zonal congestion costs continues to be the "dec game," where generation unit owners are paid substantial sums for essentially doing nothing because of the local market power they possess.

This problem arises in circumstances where producers attempt to put too much power into a location on the grid. Under a locational pricing scheme with adequate pricing points, the locational price earned by such suppliers would be near zero or even negative. With forward market self-scheduling that only respects inter-zonal transmission constraints, producers schedule at whatever level they wish subject to inter-zonal transmission constraints. If the ISO subsequently needs to manage intra-zonal congestion, unit owners can offer to "buy back" their generation obligation from the ISO with a decremental energy (dec) bid. If firms were perfectly competitive, such bids would reflect the marginal costs avoided by not producing. However, in the vast majority of circumstances, firms possess local market power, meaning that they are aware of the fact that no other firm can relieve this intra-zonal constraint. Consequently, the ISO often has no choice but to accept dec bids at implausibly low, and often *negative*, prices. With a negative dec bid, the supplier is paid not to generate.

Under the system conditions when a generation unit owner knows that it is the only firm able to relieve an intra-zonal transmission constraint, it is not surprising that the ISO finds itself with too much power scheduled through these portions of its network. The source of the problem is economic, but the consequences threaten the reliability of the network. The magnitude of these economic and reliability consequences make it a problem that must be dealt with immediately, not deferred until the resolution of the market redesign process.

It is important to emphasize that although a locational marginal pricing scheme would largely eliminate the dec game, local market power problems will continue to exist in a different form. Under a locational marginal pricing scheme, local market power is exercised by withholding electricity from the market. This withholding will occur when a generation unit owner knows a certain amount of energy must be supplied by some of the units it owns or local demand will not be met because of transmission constraints into this area. Unless there is significant price-responsive demand at this location, there is no limit to the price that this unit owner can bid for the required amount of energy. Consequently, without the authority to mitigate the bids of this unit owner when it possesses local market power, there is no limit to price of energy at that location. For this reason, all of the US ISOs that use locational marginal pricing have mechanisms to mitigate the bids of generation unit owners with local market power.

The Solution: Mitigate the Perverse Economic Incentives that Create the Problem

Any solution to this local market power problem must reduce the magnitude of the profits that firms can earn from attempting to exercise it. If this market power is sufficiently mitigated, then these firms will find it profit-maximizing to schedule their units in a manner that reduces, rather than enhances the likelihood of intra-zonal congestion.

In its standard market design (SMD) proposals, the Commission has emphasized the need to mitigate the local market power of suppliers who are advantageously located within the network. However, because the SMD also emphasizes a high-resolution locational marginal pricing (LMP) scheme for transmission, there is no consideration of the peculiar ways in which local market power manifests itself under zonal congestion management schemes such as the one that currently exists in California. As discussed above, the focus of local market power mitigation measures under locational marginal pricing is on preventing certain suppliers from bidding unreasonably *high* prices. Even the market power mitigation components of the Reliability Must-Run (RMR) agreements in California focus only on this problem. These agreements were intended to cover system conditions when local market power mitigation is needed to prevent unreasonably high prices. But local market power most often manifests itself under the current California market design through suppliers bidding unreasonably *low* prices.[1] Therefore meaningful local market power regulation in California must mitigate offer prices in both of these directions.

Mitigating the bids on units required to provide intra-zonal congestion relief is a relatively simple means of addressing the most severe circumstances of the local market power problem.[2] The Commission has already approved the use of bid mitigation for such purposes in California, but several aspects of the measures outlined in the Commission's July 17th order make them ineffectual for the current California market design unless they are revised in the manner described below.

First, the usage of a *maximum* bid price threshold below which no mitigation would apply clearly fails to address the more severe problem of bids that are unreasonably *low*. Second, the mechanism described in the Commission's July 17th order allows bid ranges around the reference price that are in our opinion inappropriately loose for an application to a circumstance of local market power. A generation unit owner can exercise a sizeable amount of local market power and still not trigger the bid mitigation process in the Commission's July 17th order. This is particularly true for case of bidding unreasonably low. Bidding negative $30/MWh, the negative bid cap in the Commission's July 17th order, still allows a firm to be a paid substantial sum of money for submitting a day-ahead energy schedule that it knows is infeasible.

Our revisions to the process outlined in the July 17th order for immediate application addresses these shortcomings. We recommend applying a narrow band, no larger than ten percent, *in either direction* around the reference price as the threshold for mitigation in the circumstance of local market power because of intra-zonal congestion. In our view, a reasonable standard for when a firm possesses local market power is that it and one other firm are the only market participants with generating units able to solve this intra-zonal congestion constraint given the day-ahead energy schedules of all market participants. Furthermore, we would not recommend employing an initial bid-price threshold to trigger mitigation for local market power. This "less than three firms" criterion for determining whether a firm possesses local market power is our preferred condition for bid mitigation to occur. We also recommend using incremental production costs for thermal resources, rather than historic bids, as the basis for constructing the reference price.

---

[1] According to the CAISO, AZCM dec costs have been roughly 10 times the magnitude of AZCM inc costs over the last 2 years.

[2] Even with incremental and decremental bids that accurately reflect the operating costs of the plant, a firm may still have an incentive to inefficiently schedule power into a congested part of the network. If the zonal price were sufficiently above marginal cost, a firm could still profit from the difference between the zonal price and its 'dec' obligation. While the implementation of a higher resolution of locational marginal pricing is needed to completely eliminate these incentives, we believe that eliminating the most extreme profit opportunities through the mitigation of dec bids in manner we suggest will provide sufficient relief to the ISO.

Using bids in previous competitive periods as a reference price for mitigation can lead to distortions in the firm's bids during these hours because the firm may find it long- or medium-term profit-maximizing to influence its reference price during those hours. The potential for such distortions is a cause of the misgivings we hold about using AMP for system-wide mitigation. While such distortions may not be severe when combined with relatively broad conduct and impact thresholds, the linkage of bids across reference hours and mitigation hours would be much stronger with more narrow thresholds. Thus while an AMP mechanism might mitigate bids during hours of market power, it may also distort bids during hours in which the market is relatively competitive. For these reasons we feel that a cost-based reference price is most appropriate for local market power mitigation.[3]

Implementing a solution

The ISO has expressed growing concern about its ability to manage intra-zonal congestion in a reliable manner. Because of these concerns, the ISO has requested the ability to enforce advanced schedules that are feasible with regards to both intra-zonal as well as inter-zonal congestion.

We believe that by putting in place a mechanism that automatically mitigates the bids of unit owners with local market power, the economic incentive to intentionally submit infeasible schedules and the incidence of intra-zonal congestion will be significantly reduced. The negative reliability consequences of the CAISO of managing AZCM should also be less extreme. Simply maintaining the current procedure of relying on adjustments in the real-time energy market, but with mitigated bids for units with local market power would go a long way toward limiting the perverse incentives causing the problem. However, there is a legitimate concern that this still places too much pressure on the real-time market, with potentially serious consequences for reliability.

To deal with these reliability concerns, the CAISO could combine its desire to curtail overscheduled generation in advance with a process for achieving such curtailment in an efficient manner. Using the mitigated bids of units with local market power as intra-zonal adjustment bids could achieve this. Instead of curtailing schedules according to a pro-rata measure, the adjustments would occur in accordance with the ordering of these adjustment bids. Any curtailment scheme could be combined with a process that allows for suppliers to adjust their advance schedules voluntarily, giving them the opportunity to reach an efficient set of aggregate schedules through bilateral arrangements before the ISO would have to intervene. Specifically, after the close of the

[3] One might think that the firm may not recover its annual going forward fixed costs of operation if it is mitigated to this level too frequently. However, as noted above, we expect this mitigation to apply primarily to decremental energy bids, which are the prices that firms must purchase energy scheduled in the forward market back from the ISO. The vast majority of instances of bid mitigation for incremental energy should be covered by RMR contracts, which pay generators annual fixed payments to cover their going forward fixed costs. However, in the unlikely event that a plant does not recover its annual going forward fixed costs because of this local market power mitigation mechanism, the unit owner could apply to the Commission for ex post relief through an uplift payment from the ISO.

hour-ahead market, the ISO could use the mitigated adjustment bids for those units with local market power and the unmitigated adjustment bids of the remaining firms to compute final hour-ahead schedules that are feasible in terms of both intra-zonal and inter-zonal transmission constraints. In the event that suppliers submit hour-ahead schedules that are feasible from both an intra-zonal and inter-zonal perspective, this process would not be necessary. [4]

It is important to note that the implementation of locational marginal pricing that is part of the ultimate California market re-design process will not eliminate the local market power problem. It will only take a different form. Some scheme for mitigating local market power is still necessary. All the eastern ISOs have local market power mitigation schemes that are more rigorous than those proposed for California in the July 17th order. For example, the PJM ISO has an automatic mechanism that mitigates the bids of market participants that the ISO determines to possess local market power to their filed variable cost plus a 10 percent adder. Consequently, there is no reason to defer the solution of this problem to the completion of California market redesign process, because the ultimate solution to this problem and the present solution are the largely the same.

[4] As long as the ISO specifies in advance what will occur if generation unit owners fail to submit feasible, from an inter-zonal and intra-zonal perspective, hour-ahead schedules, trading among scheduling coordinators should take place to move closer to this outcome. For this reason, we recommend that the ISO to manage any remaining intra-zonal congestion at the end of the hour-ahead market to minimize the as-bid re-dispatch costs using both the mitigated bids of generation units with local market power and the bids of units without local market power, rather than the pro-rata allocation scheme proposed in Amendment 47. With this intra-zonal congestion management backstop in place, generation unit owners have very good idea what intra-zonal transmission capacity will be ultimately allocated to each generation unit owners. Trading among market participants could then take place to arrive at a fully feasible final schedule. Generating companies could reallocate capacity among their units or trade transmission capacity with other companies that would like to schedule generation out of a local area. In the event that this trading failed to yield fully feasible hour-ahead schedules, the backstop of minimizing as bid re-dispatch costs to compute feasible schedules would be implemented at the close of the hour-ahead market.