



Memorandum

To: ISO Operations Committee
From: Keith Casey, Director, Market Monitoring
cc: ISO Board of Governors, ISO Officers
Date: December 9, 2005
Re: Market Monitoring Report

This is a status report only. No Board Action is required.

As part of the CAISO's realignment process, market performance reporting to the Board of Governors has been transferred to the Department of Market Services. Going forward, the Market Monitoring Reports to the Board of Governors will focus on analysis of issues that may be impacting market performance or system reliability. The following provides a summary of the current issues being analyzed by the Department of Market Monitoring.

Raising the Damage Control Bid Cap from \$250/MWh to \$400/MWh.

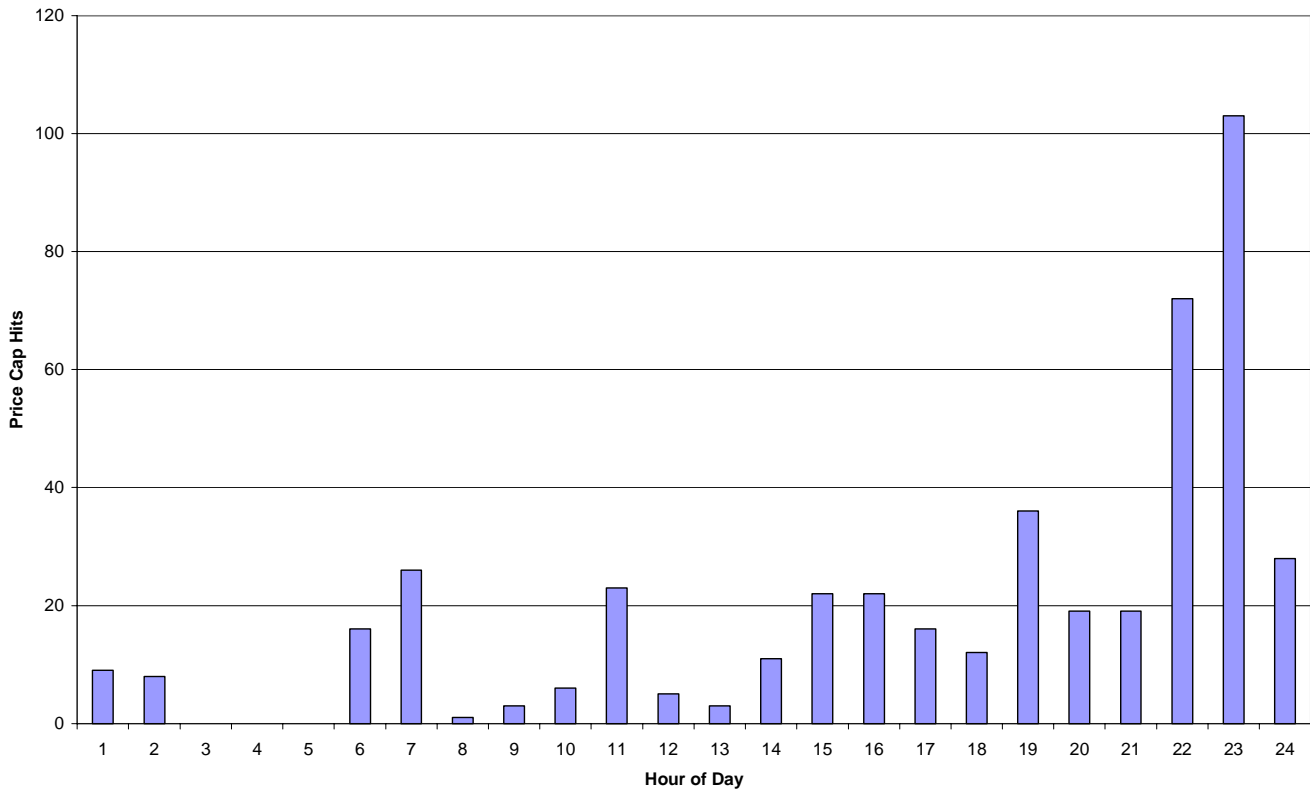
On November 9, 2005, in response to a request from the Department of Market Monitoring, the ISO Market Surveillance Committee (MSC) provided an Opinion on raising the level of the Damage Control Bid Cap (DCBC) on the real-time energy market. The current cap is a \$250/MWh "soft bid-cap", which means that accepted market bids above \$250/MWh are ineligible to set the market clearing price, are paid as-bid, and subject to cost-justification with FERC. The MSC recommends raising the bid cap to \$400/MWh based primarily on a concern that generation unit-level variable costs could approach or exceed the current cap level of \$250/MWh due to high and volatile natural gas prices. The MSC also noted that a \$400/MWh bid cap would be more comparable to a \$250 bid cap given the significant increase in natural gas prices since the \$250/MWh bid cap was originally established. Additionally, they argued a higher bid cap would further encourage the development of demand response programs.

The Department of Market Monitoring supports the MSC's recommendation. Market conditions have changed significantly since the 2000-2001 energy crisis. The California IOUs have largely hedged their exposure to spot market energy prices for summer 2006 through long-term forward energy contracts that are set at a fixed price or a price indexed to natural gas prices. This leaves the majority of the load in the ISO control area with very small cost exposure to spot market energy prices and shifts the spot market price risk to the supply side of the market, which provides suppliers with incentives to keep spot market prices low.

The high level of forward energy contracting in California has resulted in very low volumes of energy transacted in the real-time energy market. Over the past year, average underscheduling was only 2.1 percent of the total wholesale energy requirements. Although the real time market does experience occasional price spikes and market volumes above 5 percent of total wholesale energy requirements, primarily during periods of fast load ramps or unexpected high loads, the bid cap is seldom binding in these periods as there is generally a sufficient amount of bids provided under the cap. Raising the price cap would primarily impact those periods when the bid cap constrains the market clearing price. DMM analysis shows that 5-minute prices were at or just under the \$250 cap

in only 460 five-minute intervals since January 2005, which equates to approximately 0.5% of the total 5-minute intervals during that period. High real-time energy prices usually occur during periods of fast load or generation ramping (HE7, HE19, and HE 22-23), which can occur in any season, and high summer load periods (HE 14 through HE 18). The following chart shows the distribution of cap constrained price hours since January 2005.

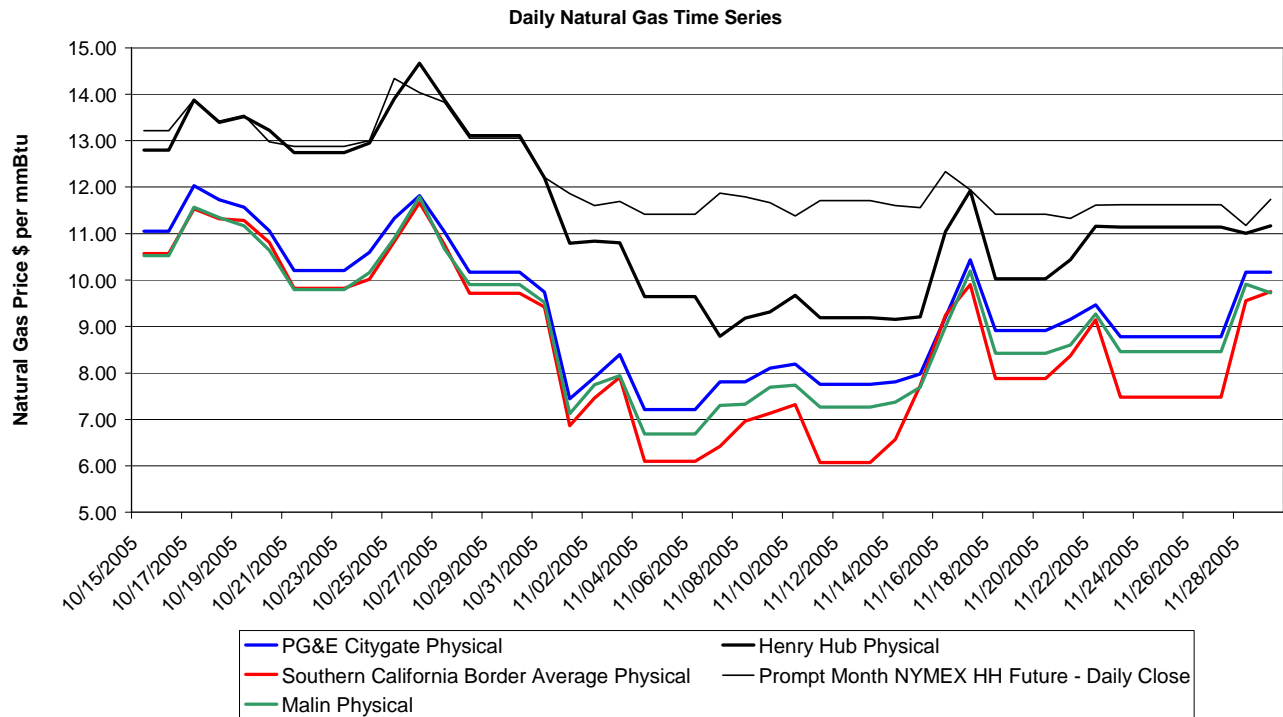
Figure 1. Number of SP26 Interval Prices at or near the \$250 Cap by Operating Hour¹
January - November 2005



The current \$250/MWh bid cap on the California ISO's real-time energy market was most recently established in October 2002 when natural gas prices were between \$3 and \$4/mmbtu. In recent months, concerns over tight natural gas supply have resulted in very high and volatile natural gas prices throughout the country. Natural gas spot prices in California recently reached as high as \$12/mmbtu and have been extremely volatile. Though natural gas prices have moderated in recent weeks, they could easily rebound higher during the critical winter heating demand months (December-March). The following chart shows the recent trend in natural gas physical and prompt month NYMEX futures prices since May 2005.

¹ This analysis uses a definition of a price cap hit as a price within \$1 of the \$250 price cap; i.e. at least \$249/MWh. The period of analysis was January 1 through November 14, 2005.

Figure 2. Daily Natural Gas Physical and Futures Prices



Given these significant changes in market conditions, DMM recommends that the real-time energy market Damage Control Bid Cap be increased from \$250/MWh to \$400/MWh. Raising the bid cap under current market conditions would provide several significant benefits to the California energy markets.

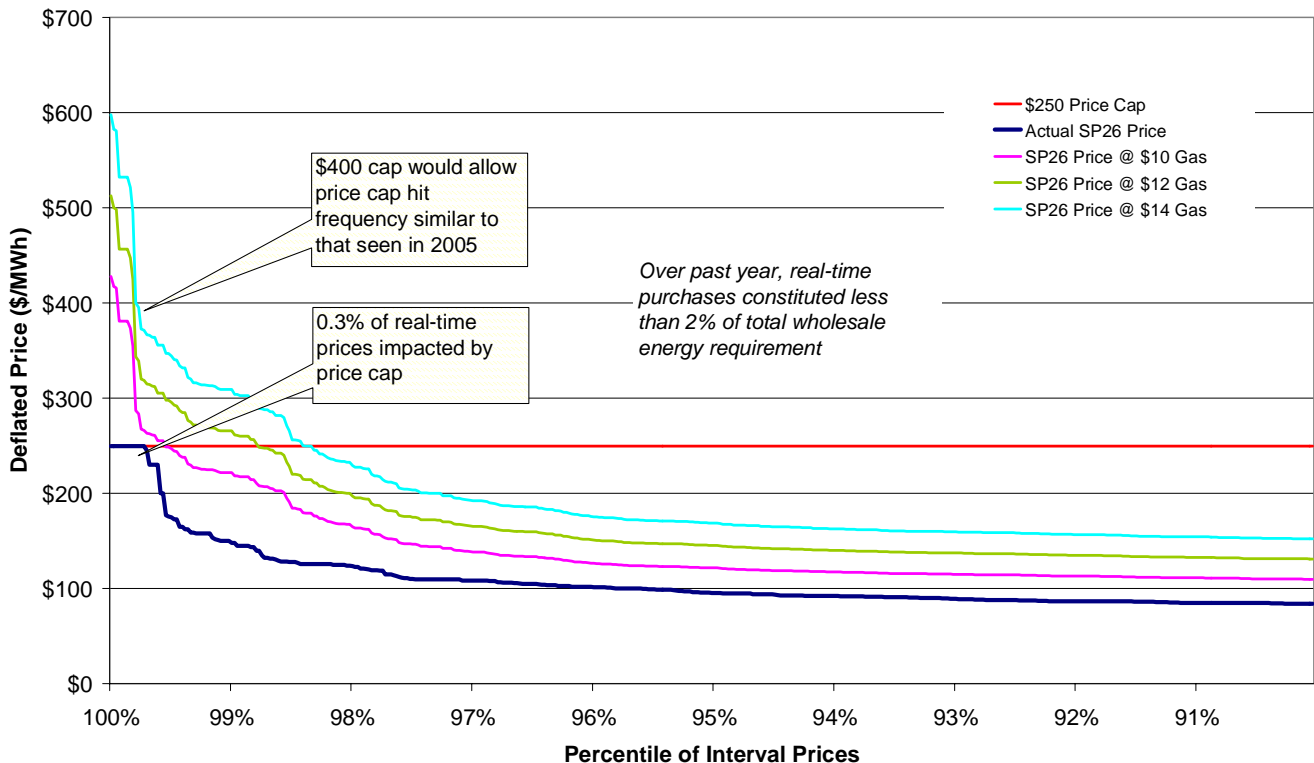
- A higher bid cap would provide several reliability benefits critical to maintaining reliable grid operation given the tight supply margins forecast for next summer.
 1. It would provide greater incentives for generator owners to maintain their units at a high level of availability so they mitigate the risk of experiencing a forced outage during a critical peak load hours.
 2. It would provide greater incentives for further development of demand response programs such as real-time pricing. Such demand programs would reduce reliance on high cost, environmentally unfriendly combustion turbines during critical peak demand hours and increase supply margins during peak load periods.
 3. It would promote reliability by providing greater fixed cost recovery for generating units during high demand periods when supply margins are tight and prices are at or near the bid cap. Several generating units in California are at risk of retirement due to insufficient fixed cost recovery. Moreover, some new generating units in the CAISO Control Area do not have long-term power contracts and a higher spot price during critical peak periods will help to make these units more economically viable.
 4. Should gas prices escalate significantly over the winter months in response to high gas heating demand or supply disruptions, a higher cap would not discourage suppliers, particularly importers, from selling into the California real-time energy market since they would be assured bid cost recovery for accepted bids above

\$250/MWh. A higher cap would also provide a greater incentive to internal suppliers with options of selling their output to external load through the western bilateral short-term energy markets to instead provide real-time energy bids to the CAISO.

- A higher bid cap would provide greater incentives for the LSEs to continue to minimize their spot market exposure by signing additional long-term power contracts.
- Finally, increasing the cap to \$400/MWh would provide a measured transition to the \$500/MWh energy bid cap scheduled to be invoked with the California ISO's new market design in February 2007.

As discussed above, over the past year the current \$250/MWh bid cap has been binding in only a small number of periods. However these periods are often the most critical times that real-time energy is needed to maintain system reliability. The following chart compares the actual price duration curve (prices stacked from highest to lowest) from May 2005 through September 2005 to price duration curves adjusted for higher gas prices.² As shown in the chart, the current bid cap impacted approximately 0.3 percent of interval prices during the past summer, and a higher cap would allow prices to reflect higher natural gas price levels. If gas prices over the next year are in the \$10/MMBTu range and the ISO experiences similar market conditions to this year, this analysis suggests real time prices would only exceed \$250/MWh in fewer than 0.5 percent of 5-minute pricing intervals seen in the summer of 2005, and high prices during these periods would be impacting a relatively small amount of demand.

Figure 3. SP26 Real-time Energy Market Clearing Price Duration Curves at Different Natural Gas Price Levels, May through September 2005



² Each interval price was deflated to using the formula: (price - \$4 O&M) * (comparison gas price / actual daily gas price) + \$4 O&M. Comparison gas prices used were \$10, \$12, and \$14/MMBTu.

Given the current market conditions discussed above, the DMM concludes that the reliability risks associated with not raising the cap far outweigh any risk of increased prices from a higher bid cap. As noted above, the spot market risk for load serving entities is minimal. Moreover, a higher bid cap is unlikely to have an appreciable effect in increasing the costs of bilateral energy contracts because load serving entities have indicated they have already contracted for the vast majority of their energy requirements for next summer and any additional new contracts would likely extend beyond 2006 and therefore would in any case be reflective of the \$500/MWh bid cap ordered by FERC to take effect upon implementation of MRTU in February 2007. Finally, any local market power concerns stemming from a higher bid cap and the potential of having must offer obligations revoked by FERC this summer, will be addressed by the current local market power mitigation measures. Should the exercise of local market power become more prevalent in 2006, for whatever reason, the adequacy of local market power mitigation measures will be assessed and to the extent the current mitigation is found to be inadequate, new mitigation measures will be proposed. In other words, maintaining a lower bid energy cap (i.e., \$250) would not be an adequate backstop for potentially inadequate local market power mitigation rules. If the current local market power mitigation rules were determined to be inadequate, DMM would seek to have them modified.

For these reasons, DMM agrees with the MSC and recommends that the real-time energy market bid cap be increased from a \$250/MWh soft cap to a \$400/MWh soft cap. In addition, DMM recommends the bid cap for adjustment bids used in the Day Ahead and Hour Ahead Congestion Management Markets also be increased to \$400/MWh and that the bid cap for the Ancillary Service Markets remains at \$250/MW.

Utilization of Contingency Reserves under MRTU

The following summarizes the key findings and recommendations of the Department of Market Monitoring's investigation into the reasons that ISO grid operators did not dispatch contingency reserves on the afternoon of August 25, 2005, a warm day with temperatures 14 degrees above forecast, during which the Pacific DC Intertie failed, resulting in 1,800 MW of shed load. During this event, the SP26 real-time market-clearing price was set at \$120.92/MWh and certain resources flagged as contingency reserve were dispatched out-of-sequence with bids as high as \$249.99/MWh. As previously reported last month, these contingency reserve bids should have been dispatched in-sequence and allowed to set the market clearing price. DMM reported this issue to Market Operations and they are in the process of correcting real-time market prices for that event. DMM further reviewed this issue to understand why it occurred and what could be done in the future to avoid a reoccurrence.

In discussing this issue with Market Operations, operators identified two issues with managing the use of contingency reserve bids:

1. Confusion due to multiple commodity price sheets for the same operating hour, and
2. Processing delays and manual entries associated with dispatching Contingency Reserve within RTMA

These two issues are discussed below:

1. Confusion due to multiple commodity price sheets for the same operating hour.

Problem: Prior to real time, operators print out commodity sheets from the software. These printed commodity sheets are hard copies of the lists of bids comprising the real-time market and are used for reference to allow operators to know which resources are dispatchable in the event that there is a computer malfunction in real time. Operators have three different commodity sheets for the operating hour:

- A sheet of *original bids*. This list consists of suppliers' actual bids submitted into the market. This sheet excludes proxy bids (i.e., filled-in bids, pursuant to the Must-Offer Obligation, from suppliers that did not actually submit bids)
- A sheet of *constrained supplemental bids*. This sheet includes bids for all dispatchable supplemental resources (including proxy bids) but excludes energy bids from procured contingency operating reserves.
- A sheet of *unconstrained supplemental bids*. This sheet includes bids for all supplemental resources, including proxy bids and bids from contingency operating reserve.

Operators indicated having multiple commodity sheets was confusing and creates the potential for operators to inadvertently dispatch resources from the wrong sheet.

Solution: Operators would prefer a single commodity stack with all resource information. This would enable them to know the available resources without inadvertently missing certain classes of resources.

2. Contingency Dispatch Usability and Delay

Problem: During a zonal contingency, as was the case during the August 25th event, operators must take several steps to dispatch contingency reserves within a constrained zone. In such a case, he or she must: 1) Switch from the commodity dispatch screen to the contingency flagging screen; 2) Manually un-select the individually resources outside the constrained zone so that the only contingency reserves released to the market are those in the constrained zone; and 3) Switch back to the commodity screen to dispatch.

When RTMA is working optimally, this entire sequence takes a few minutes. However, during a volatile situation such as a contingency, many users are impacting the computer server network and operators may experience significant system delays. This entire procedure can take many minutes, and at times operators' terminals may lock up completely.

Solution: A single button on the commodity dispatch screen should be able to dispatch all resources (including contingency only reserve bids) in a single congestion zone. Additionally, poor server system performance and delays of this magnitude should be considered unacceptable by the ISO and fixed. This is a critical time that RTMA needs to have high performance for the dispatching of dozens of units during a major event where time is critical. Switching between screens to set every flag to the right setting is time consuming. One button on the dispatch screen should be able to perform this function.

During the August 25th event, because a grid operator was concerned about the time it would take to dispatch contingency reserve utilizing the RTMA software contingency clearing function, they opted to dispatch manually using the commodity sheet. However, they inadvertently used the "constrained" sheet, which does not show contingency non-spinning reserve bids. These units were dispatched out-of-sequence only after the scheduling coordinator contacted the operator on the telephone to inform him that they were available. This type of situation could be avoided in the future if the solutions proposed above are adopted.

Intrazonal Congestion South of Pastoria

Recently, as loads have subsided in the central valley of California, significant intrazonal congestion has frequently occurred on the transmission system south of the Pastoria substation. During the period of September 1st through November 17th, redispatch costs totaled approximately \$5.23 million as a result of decremental dispatches to the

Pastoria (70 percent) and Big Creek (30 percent) generation stations to mitigate the congestion. DMM has been monitoring the situation closely given the lack of competition to relieve the congestion in the area. Under the current local market power mitigation rules, units dispatched out-of-sequence in the decremental direction are charged their decremental reference level, which is determined independently by Potomac Economics. Reference levels are generally established as the average price of accepted bids for the previous ninety days, unless there are no bids or the unit owner has requested a cost-based determination. In response to competitive problems with the Mexican border generation units and Miguel congestion beginning in the summer of 2003, the ISO worked with Potomac to institute a competitiveness screen for out-of-sequence decremental dispatch instructions. Under the screen, a generating unit must have at least 50 percent of their decremental bid volumes dispatched in-sequence over the previous ninety days to have their reference levels set by the bid-based methods. If less than 50 percent of their bids were dispatched in-sequence, Potomac will set their reference levels using the cost-based method.

Since congestion became prevalent south of Pastoria in mid-September, a significant amount of Pastoria's decremental dispatches have been out-of-sequence. DMM is consulting with Potomac to determine whether it is appropriate to implement cost-based reference levels for Pastoria. DMM is also working with the ISO's market and grid operations staff to verify that congestion mitigation in the area is being properly implemented under the ISO's operating procedure (M-401).

RTMA (Real-time Market Applications) Software Issues

\$250/MWh Damage Control Bid Cap Enforcement

In recent months, DMM uncovered the fact that RTMA damage control bid cap has not been enforced properly. Under the ISO Tariff, the current damage control bid cap allows a range from -\$30/MWh to \$250/MWh where the clearing price (MCP) for each 5-minute dispatch interval may be set. DMM has observed that while resources with bid prices equal to \$250/MWh were being dispatched by RTMA, the MCP was set at the next lowest marginal bid dispatched. Since RTMA was implemented in October 2004, there has not been a single instance of the MCP set to \$250/MWh. DMM raised this issue with Market Operations who performed an investigation. Market Operations determined that the root cause of the issue is the design inconsistency in RTMA software in handling a small internal adjustment of the price curve data of resource economic bids submitted by scheduling coordinators (SC). In effect, bids that were submitted at the bid cap of \$250/MWh were adjusted to \$250.001/MWh by the software and no longer eligible to set the market clearing price. Market Operations has identified 437 intervals (approximately 36 hours) where the price should have been set at \$250/MWh but was instead set at the next lowest priced marginal bid dispatched by RTMA. DMM estimates that the market impact of this issue to be between \$2 and \$3 million. The RTMA software will be corrected so that bids submitted at the price cap are eligible to set the market clearing price as specified by the ISO Tariff. Settlement reruns will also take place to account for the correct prices.

\$12/MWh Price Issue

As DMM reported last month in its RTMA Assessment, Market Operations identified instances of erroneous \$12/MWh prices being set by RTMA. After an investigation, they determined that \$12/MWh prices were being set by RTMA during instances in which all units dispatched were dispatched at their maximum ramping levels. The rules built into the RTMA software will not allow a unit that is ramped at its maximum ramp rate to set the market clearing price. In these instances the price is set to \$12/MWh. Market Operations has sent a proposed solution to this problem to ABB, the ISO's RTMA software vendor. The ISO has concluded that a software fix for this issue is too costly and the ISO will continue to reset these prices to the previous interval price in the ISO's 96-hour correction process. Since this issue

was uncovered, DMM has observed only 40 instances of erroneous \$12/MWh prices set by RTMA since it was implemented in October 2004.

\$0/MWh Price Issue

On July 31, 2005, Market Operations observed that the real-time market clearing price as determined by RTMA software were at \$0 for many of the 5-minute dispatch intervals between operating hours 2 through 10. Further investigation by CAISO Market Operations on RTMA save cases found that for those intervals with \$0 pricing as determined by ex-ante and ex-post pricing dispatches, the MCP determined by RTMA physical run were non-zero values, between \$5 and \$40.

Unable to explain these prices produced by RTMA, CAISO asked the RTMA vendor (ABB) to provide an explanation for the \$0 pricing phenomenon. They subsequently reported to CAISO that they found a software defect in the RTMA ex-ante (and ex-post) pricing dispatch component. This defect could cause, but not always, the lowering or the increasing of the value of MCP for settlement from the correct value. Moreover, the incorrect MCP is not necessary a \$0 value. This problem was corrected in the RTMA software in late October.

RCST Settlement

DMM has been involved in reviewing the Reliability Capacity Services Tariff (RCST) proposal offered by the Independent Energy Producers in their filed complaint to FERC concerning the current Must Offer requirements and generator revenue adequacy. Since the ongoing settlement discussions on this issue are subject to confidential treatment under FERC Rule 602, DMM has provided its recommendation on this issue in a separate confidential memorandum to the Board for the Board's Executive Session meeting on December 9th.