California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Keith Casey, Director, Market Monitoring

CC: ISO Officers

Date: April 12, 2007

Re: Market Monitoring Report

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

This month's Market Monitoring Report provides a brief overview and update on two key items: 1) Summary of the 2006 Annual Report on Market Issues and Performance, and 2) An assessment of market impacts associated with a recent software issue relating to the operation of the Real Time Market Application (RTMA).

1. 2006 Annual Report on Market Issues and Performance

Each year the Department of Market Monitoring publishes an annual report on the performance of markets administered by the CAISO. This memo provides a brief summary of the market performance highlights for 2006. Additionally, Attachment A to this Memo provides a summary of requests submitted by Stakeholders of issues they would like to see addressed in the report accompanied by a response by DMM indicating how these requests were addressed. A complete copy of the report will be provided to you separately.

From an operational standpoint, 2006 was a year of extremes with operational challenges in the spring due to excessive hydroelectric generation and in the summer due to a record breaking heat wave. Through it all, grid reliability and the markets fared very well. A well above average snowpack throughout California and the Pacific Northwest resulted in an abundance of hydroelectric generation production in the first half of the year. High volumes of hydroelectric production caused persistent over-generation conditions and unscheduled loop flow issues that created real-time operational challenges and caused a high degree of price volatility in the Real Time Market. The abundance of hydroelectric power coupled with lower natural gas prices also had a significant impact of reducing day-ahead spot energy prices. In the first half of the year, day-ahead energy prices in Southern California averaged approximately $51/MWh, compared to $84/MWh for the same period last year.

California's spot wholesale energy markets in 2006 were generally stable and competitive, similar to the past several years (2002-2005). One of the primary metrics that DMM uses to gauge overall market competitiveness is a 12-month Market Competitiveness Index (MCI), which represents a 12-month rolling average of the estimated hourly price-cost markups (i.e., the difference between actual energy prices and estimated "competitive" prices that are derived from cost-based simulations). DMM considers MCI values in the range of $5-$10/MWh to be reflective of a workably competitive market. The monthly MCI values estimated for 2006 were below $10/MWh in all months of the year. The average total wholesale cost of energy in 2006 was $47.55/MWh of load compared to $57.83/MWh in 2005. Total costs include the following components: forward scheduled energy, inter-zonal congestion, real-time imbalance energy, real-time out-of-sequence energy redispatch premium, net RMR costs, ancillary services, and ISO-related costs (transmission, reliability, and grid management charge). The decrease in the total costs in 2006 was primarily due to lower natural gas prices, especially compared to the high natural gas prices seen in the fourth quarter of 2005 when there was a sharp increase in natural gas prices due to the supply interruptions from the Gulf Coast hurricanes.

The CAISO Inter-Zonal Congestion Management market was also generally stable and competitive in 2006. Total inter-zonal congestion costs in 2006 were $56 million, slightly higher than the $54.6 million in 2005. The two most frequently congested transmission paths in 2005, the Pacific AC Intertie (PACI, formerly the California-Oregon Intertie, or COI) from the Northwest and Palo Verde branch group from the Southwest, remained the top two congested paths in 2006 with PACI being congested in 18% of the hours in the day-ahead market (the same congestion frequency as in 2005) and Palo Verde congested in 15% of the hours (compared to 23% in 2005). Of the internal paths, Path 26 was congested only 5% of hours (in the north-to-south direction), while Path 15 was congested in only 1% of hours. Congestion costs on Path 15 went from $2.2 million in 2005 to $1.9 million in 2006. Not surprisingly, Palo Verde had the highest congestion costs in 2006 at $17.1 million (compared to $19.8 million in 2005). Congestion costs on PACI totaled $12 million (compared to $6.7 million in 2005).

In the ancillary service markets, prices were stable throughout most of the year, and were mixed compared to last year depending on the service. The overall average ancillary service price in 2006 was slightly higher, at $11.12/MW, compared to last year's average of $10.72/MW. The average volume of each ancillary service purchased was quite similar to previous years. The frequency of bid insufficiency was lower in 2006 in all the ancillary service markets, however the percent of requirement that was deficient (the magnitude of the deficiency) was notably higher in 2006. A comparison of monthly insufficiency figures for both years shows that the CAISO experienced dramatically higher bid insufficiency during April, when the high hydroelectric output impacted ancillary service offers, and again in July, when record-setting peak load conditions left little excess capacity to be used for reserves.

One of the major success stories in 2006 is the continued reduction in intra-zonal congestion costs. In 2006, intra-zonal congestion costs totaled $207 million, compared to $222 million in 2005 and $426 million in 2004. Intra-zonal congestion cost is comprised of three components: 1) Minimum Load Cost Compensation (MLCC) for units denied Must-Offer Waivers, 2) RMR Costs, and 3) real-time redispatch costs. The main contributors to this decrease were a decline in MLCC costs from $114 million in 2005 to $109 million in 2006 and a decline in real-time redispatch costs from $36 million in 2005 to $17 million in 2006. RMR costs for intra-zonal congestion increased slightly in 2006 ($80 million in 2006, $72 million in 2005).

Though the CAISO markets and short-term bilateral energy markets were stable and competitive in 2005, low levels of new generation investment coupled with unit retirements, significant load growth, and record-setting peak load conditions have created reliability challenges for the Control Area during the peak summer season. During the peak heat wave period in July, the CAISO declared Stage 1 Emergencies on three days, and a Stage 2 Emergency on the 24th that resulted in roughly 800 MW of voluntary load curtailment. Low levels of new generation investment within Southern California coupled with significant load growth has resulted in a higher reliance on imported power from both the Southwest and Northwest. This dependence on imports, coupled with tight reserve margins, makes Southern California vulnerable to reliability problems should there be a major transmission outage (as occurred on August 25th of 2005 with the loss of the Pacific DC Intertie) or coincident large generator outages. Much of the existing generation within Southern California is comprised of older facilities that are prone to forced outages, especially under periods of prolonged operation as occurred during the extraordinarily long heat wave in July. Additional new generation investment and re-powering of older existing generation facilities would significantly improve summer reliability issues in Southern California.

DMM's financial assessment of the potential revenues a new generation facility could have earned in California's spot market in 2006 indicates potential spot market revenues fell short of the unit's annual fixed costs; however, for combined cycle units the spot market returns have improved for the second straight year. Despite this improvement, 2006 marks the fifth straight year that DMM's analysis found that estimated spot market revenues failed to provide sufficient fixed cost recovery for new generation investment. This result underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. Unfortunately, long-term energy contracting by the state's major investor owned utilities (IOUs) has been limited and the practice of relying heavily on short to medium term contracting perpetuates reliance on older inefficient generating units, particularly for local reliability needs. The addition this year of the California Public Utilities Commission's (CPUC) Resource Adequacy (RA) program has provided a vehicle for load-serving entities (LSEs) and suppliers to engage in longer-term contracting for capacity, as well as bundling capacity contracts with longer-term energy contracts to provide an effective hedge against potential spot market volatility.

While long-term contracting is critical for facilitating new investment, it must be coupled with appropriate deliverability and locational requirements to ensure new investment is occurring where it is needed. Implementation of the location-specific reliability requirements into the RA framework in 2007 should also help to facilitate new generation development in critical areas of the grid. Additionally, in a July 2006 CPUC ruling, the CPUC directed Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) to procure 1,500 MW and 2,200 MW of new generation, respectively, and to unbundle the capacity and energy products from this new generation. Under this decision, the capacity of the new generation would be allocated to each LSE in the IOU's service territory and count towards its RA requirements, with the costs of the capacity allocated similarly and the energy product auctioned off by a third party. The CPUC action was taken due to the urgency for new generation investment in California and the recognition that a more permanent long-term procurement structure, that effectively addresses the need for long-term procurement and retail competition, would not be completed for some time.

2. Software Issues and RTMA Operation

Starting in mid-March, several problems were identified with a new software system for managing inter-tie schedules – the Control Area Scheduler (CAS) – that was deployed in February. However, the operational and market impacts associated with these problems appear to have been limited by mitigation actions taken by Grid Operations staff. While these problems may have contributed somewhat to an increase in the frequency of price spikes in March, these price spikes appear to be the result of a variety of factors, including mitigation of high unscheduled energy flows, transmission outages, and other factors unrelated to the CAS software problems.

On February 14, 2007, the CAISO deployed a new software system for managing inter-tie schedules, named the Control Area Scheduler. The CAS system facilitates the process of creating, approving and curtailing inter-tie schedules by automating the process of matching inter-tie schedules with their associated "e-tags," ensuring tags are consistent with NERC-approved guidelines, and passing final approved schedules to the Real Time Market Application (RTMA) software.

In mid-March – about one month after deployment of CAS – dispatches issued by the RTMA software began to periodically appear inconsistent with the imbalance energy needs of the system. The primary result of these RTMA dispatches was increased use of the RTMA *load bias*, which allows CAISO Grid Operations to manually adjust the load forecast over the 2-hour "look ahead" period used by RTMA to determine real-time energy dispatches. In addition, the volatility of real-time prices and dispatches and frequency of price spikes appears to have increased somewhat during this period.

Initial investigation of these trends by CAISO Operations Information Technology (OIT) indicated that in some cases these problems were attributable to or exacerbated by delays in the timing of inter-tie scheduling information being passed from the CAS system to the RTMA software. The RTMA software dispatches hourly inter-tie bids and 5-minute dispatchable resources based on expected system conditions over a "look ahead" period of up to two hours. Thus, any delay in the passage or updating of inter-tie schedules passed from the CAS system to the RTMA software can have a significant impact on the efficiency of dispatches produced by RTMA. Upon review by OIT, several potential sources of delay in passage of inter-tie schedule from CAS to RTMA were identified. Modifications were made to address most of these problems by March 23, with several additional modifications being implemented at the end of March.

As shown in Figure 1, there has been a notable increase in the frequency of the load bias entered by Grid Operators in RTMA in March 2006 relative to previous months when CAS was in effect, particularly starting about March 12, which corresponds to the time that Grid Operations staff began reporting concerns with some RTMA dispatches that could be related to inter-tie schedules passed from CAS to RTMA. From March 12 through the end of the month, the load bias was utilized in 25% of the hours. This compares to an average usage of the bias of about 10% from January to the time CAS was implemented in February, and an average of 18% from the time CAS was implemented in February to March 12. However, during the last two weeks of March, 2007, the bias was utilized 28% of the time, reflecting the fact that during the early period of spring, system operations are traditionally highly volatile due to factors such as the beginning of early spring hydro runoff.

While the CAISO has a goal of reducing and limiting use of the load bias feature of RTMA, the load bias is designed to be used under these types of conditions, and it appears that the very active usage of the load bias by Grid Operations staff in March played a key role in mitigating the impact of the CAS issue and other factors which contributed to the volatility of system conditions in March.

As shown in Figure 2, the frequency of price spikes during March 2007 increased relative to March 2006, with most of these price spikes occurring in the last two weeks of March. During March 2007, real-time prices exceeded $250 in about 1.5% of intervals compared to about .5% of intervals during March 2006. However, the CAS issue appears to have most likely been a significant contributing factor to price spikes from March 12 to March 23, at which point initial modifications were implemented to address the CAS problem, and price spikes appear to be related to a variety of other conditions, as described below. From March 12 through March 23, prices in excess of $250 occurred during about 1.5% of 5-minute intervals, compared to about 1% of intervals during this same period of 2006.

DMM's review of market performance over this period – combined with findings of other CAISO departments' reviews of recent operational and software conditions – suggests that the relatively moderate increase in price spikes and volatility of RTMA dispatches in March are partly attributable to the problems in passage of inter-tie schedule from CAS to RTMA. However, the relatively moderate increase in the price spikes and volatility of RTMA dispatches in March can also be attributed to a number of other specific reasons, which include:

- *Unscheduled energy flows.* Starting in mid-March through the end of the month, unscheduled energy flows on CAISO-managed transmission have often required significant adjustments in inter-tie schedules and pre-dispatches during many hours. Specifically, unscheduled north-to-south flows have caused the CAISO to reduce imports in real time from the Northwest, and compensate by increasing imports from the Southwest and/or increasing reliance on generation from within the CAISO system. Since unscheduled flows can be highly unpredictable, actions taken to compensate for such flows can increase price volatility and the frequency of short-term price spikes.

- *Transmission outages.* Outages on the DC inter-tie (NOB) from March 26 – 30 appear to have contributed to price spikes during this period.

- *Declined pre-dispatches and negative uninstructed deviations.* Several specific price spikes in March appear to have been exacerbated by relatively large volumes of declined pre-dispatch instructions for interchange and negative uninstructed deviations by resources within the CAISO. When pre-dispatches issued by RTMA are declined, there is insufficient time for this information to be fed back into RTMA so that additional pre-dispatches may be issued. Similarly, while RTMA incorporates an algorithm for monitoring and forecasting uninstructed deviations by resources within the CAISO system, there can be a significant and unavoidable lag between the time relatively large negative deviations begin to occur and the time such deviations can be incorporated in the forecast of uninstructed deviations used by RTMA in determining dispatch instructions.

DMM does not believe it is possible to accurately disentangle the potential impact of the CAS software problems from other factors causing or contributing to price spikes. However, DMM believes additional costs associated with the CAS software problems would be minimal, due to the relatively small increase in prices that could be attributable to these problems and the very low volume of energy that was transacted in the Real Time Market during these hours.

Figure 1 Usage of RTMA Load Bias

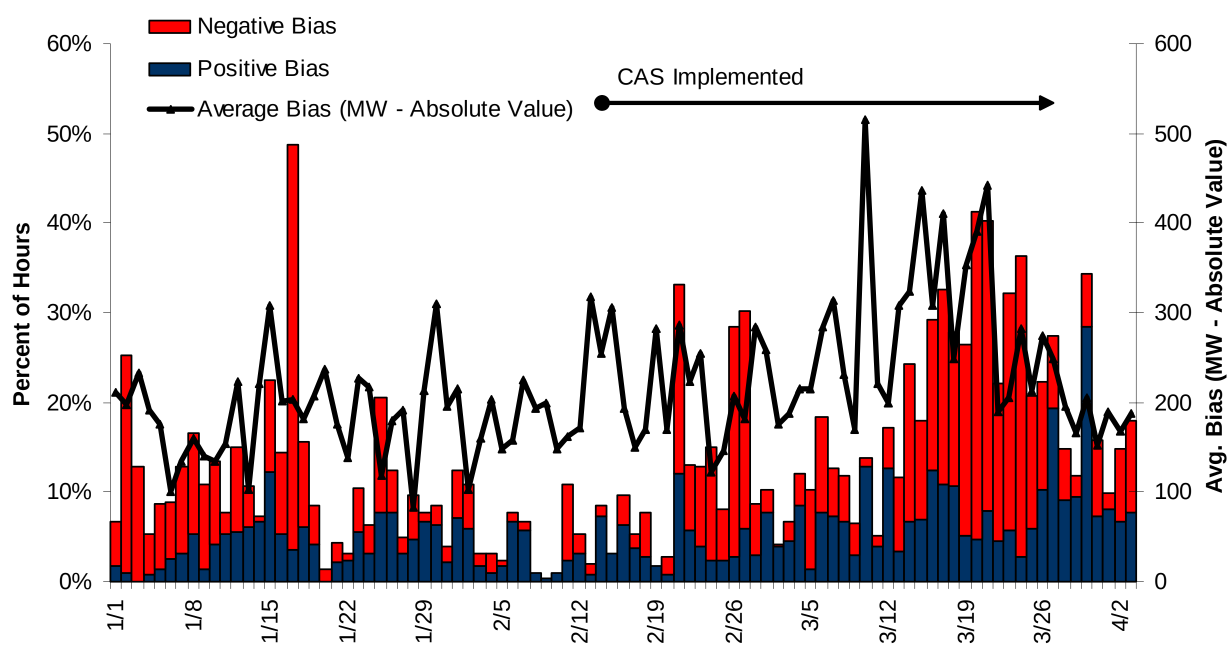

Figure 2 Frequency of Price Spikes (>$250) in the Real Time Market