California ISO
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California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Keith Casey, Director, Market Monitoring

CC: ISO Officers

Date: December 6, 2006

Re: Market Monitoring Report

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

EXECUTIVE SUMMARY

In this month's Market Monitoring Report, DMM is providing updates on two issues. The first issue concerns potential modifications to the CAISO day-ahead scheduling requirement (Amendment 72) and the second is an update on short-term market competitiveness.

Potential Modifications to Amendment 72

In October 2005, the CAISO filed Tariff Amendment 72, which required Scheduling Coordinators (SCs) to submit day-ahead schedules equal to at least 95% of their forecast demand for each hour of the next day. The 95% day-ahead scheduling requirement was designed to enhance reliability and reduce the need for the CAISO to take actions to protect against under-scheduling, such as requiring additional capacity to be on-line through Must-Offer Waiver denials.

Overall compliance with the 95% day-ahead scheduling requirement has been extremely high since spring 2006, particularly during peak hours.[1] However, some participants and CAISO operations staff have expressed concerns about the impacts and difficulty of compliance with the 95% scheduling requirement, particularly during off-peak and weekend hours. In response to these concerns, the CAISO has initiated a stakeholder process to identify and consider potential refinements to Amendment 72. The stakeholder process and a brief outline of the potential modifications to Amendment 72 are discussed in Section I below.

Update on Short-term Market Competitiveness

One of the main indices DMM uses to measure the overall competitiveness of California's wholesale energy market is the Short-term Market Competitiveness Index, which compares the average cost of short-term (day-ahead and day-of) bilateral energy purchases by California's three Investor Owned Utilities to a competitive benchmark price estimated by DMM. This index, which is also referred to as a price-to-cost mark-up, is calculated hourly but is reviewed based on monthly averages to get a more comprehensive picture of overall market performance. DMM recently updated this index for the first three quarters of 2006. Not surprisingly, this assessment found that California's short-term energy market was very competitive in 2006. The key findings from this analysis are the following:

- On average, the price-to-cost mark-up for the first three quarters of 2006 was approximately $4.50/MWh, or 8.5% over the estimated competitive price. Based on historical market performance (1998-2006), which included monthly mark-ups as high as $220/MWh during the energy crisis (2000-2001), average mark-ups below $5.00/MWh are considered very competitive.

- Price-to-cost mark-ups for short-term purchases were lower ($1 - $4 / MWh) during the late winter and spring of 2006 as an abundance of hydroelectric generation increased overall market competitiveness.

- Mark-ups increased significantly in June and July, to $8/MWh and $13/MWh respectively, as a result of significantly higher average load in June (compared to prior years) and the record-breaking heat wave in late July.

A final analysis of the short-term competitive index for 2006 will be provided in February 2007, once all of the IOU short-term procurement data are received for 2006. A more detailed description of the findings and study methodology is provided in Section II below.

I. Amendment 72 Day Ahead Scheduling Requirement

In October 2005, the CAISO filed Tariff Amendment 72, which required Scheduling Coordinators (SCs) to submit day-ahead schedules equal to at least 95% of their forecast demand for each hour of the next day. The 95% day-ahead scheduling requirement was designed to enhance reliability and reduce the need for the CAISO to take actions to protect against underscheduling, such as requiring additional capacity to be on-line through Must-Offer Waiver denials. The CAISO did not seek to include a penalty for failing to meet the 95% scheduling requirement in Amendment 72, and instead indicated that any failure to meet this requirement may be subject to enforcement by the Federal Regulatory Energy Commission (FERC) under FERC market rules, which include a general requirement that participants comply with all provisions of the CAISO Tariff. FERC approved Amendment 72 in November 2005.

Overall compliance with the 95% day-ahead scheduling requirement has been extremely high since spring 2006, particularly during peak hours.[1] However, some participants and CAISO operations staff have expressed concerns about the impacts and difficulty of compliance with the 95% scheduling requirement, particularly during off-peak and weekend hours. For example:

- Numerous participants have indicated that the bulk of bilateral market supply is only available in standard blocks of 16 peak hours or 8 off-peak hours, so that complying with the 95% scheduling requirement during all hours often requires SCs to over-procure and then over-schedule significant amounts of energy during off-peak hours.

- At the same time, CAISO operators have expressed concern that any over-scheduling during these off-peak hours due to Amendment 72 may negatively affect system reliability by exacerbating over-generation conditions. This impact was particularly evident this spring, when over-scheduling attributed to Amendment 72 – combined with other sources of unscheduled energy and uninstructed generation – created significant over-generation during many hours.

[1] A discussion of Amendment 72 compliance was provided in DMM's October 10, 2006 Market Monitoring Report memo to the CAISO Board (*http://www.caiso.com/188d/188d792d5a4a10.pdf*).

- Numerous participants have also expressed concern that under current CAISO Tariff provisions even infrequent and minor violations of the 95% scheduling requirement (and related load forecasting requirements) may be subject to investigation and potential sanction by FERC.[2]

In response to these concerns, the CAISO will be initiating a stakeholder process to identify and consider potential refinements to Amendment 72. Potential Tariff changes that would address the major concerns with Amendment 72 include the following:

- Modify the Tariff so that day-ahead schedules submitted by each SC are required to meet 95% of forecasted load only during peak hours (e.g., Monday through Saturday, Hours Ending 7 through 22). The exemption for Sundays may be designed to be non-applicable on Sundays that the CAISO issues a "Restricted Maintenance Operations" (i.e., "No-Touch") alert prior to the day-ahead scheduling deadline.

- Allow a threshold for limited non-compliance with the 95% scheduling requirement by individual SCs that would not be subject to sanction (e.g., an SC would be considered in compliance with the 95% scheduling requirement if they incurred no more than six hourly violations within a calendar month and none of those violations resulted in less than 93% of their day-ahead forecasted load being scheduled day-ahead).[3] The threshold exemption may be designed so as to be non-applicable on peak load days that the CAISO issues a "Restricted Maintenance Operations" (i.e., "No-Touch") alert prior to the day-ahead scheduling deadline.

- Clarify that day-ahead scheduling requirements apply to Preferred and Revised Preferred schedules submitted by each SC to the CAISO during the day-ahead scheduling process, rather than the Final Schedules for each SC that are published by the CAISO after adjustments made by the congestion management process.

The potential revisions to Amendment 72 noted above could be implemented without any modification to the CAISO's operational or market software systems, and would only require minimal adjustments to data analysis programs used by DMM to calculate and report potential non-compliance with day-ahead scheduling requirements on an *ex-post* basis.

The process for developing any changes to Amendment 72 will be conducted on a relatively accelerated timeframe, so that any changes may be effective prior to the spring months when problems related to over-generation tend to be highest. The specific steps in this process, which were outlined in a December 1, 2006 Market Notice, include the following:

- Development and distribution of whitepaper outlining issues with Amendment 72 and a draft straw proposal for changes to Amendment 72 (December 8, 2006)

- Submission of initial stakeholder comments on straw proposal (December 15, 2006)

- Conference call with stakeholders to discuss straw proposal and stakeholder comments (December 18 or 19, 2006)

- Submission of final stakeholder comments on straw proposal (January 5, 2006)

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[2] As discussed in DMM's October 10, 2006 Market Monitoring Report, under the CAISO Tariff, DMM has the authority to issue a penalty of $500 per day for failure to submit a day-ahead load forecast, but does not have the discretion to waive or reduce penalties for violations identified pursuant to this authority. Rather, as in the case of penalties for failure to meet outage generation reporting requirements, DMM may only submit a filing at FERC recommending that the Commission waive or reduce a penalty based on mitigating circumstances.

[3] A similar threshold for excusing limited non-compliance could also be established for the requirement that each SC submit a day-ahead demand forecast to the CAISO, which is subject to a $500 penalty directly by the CAISO.

- Development of CAISO recommendation to CAISO Board (January 10, 2007)
- Discussion and potential approval of Tariff modifications at CAISO Board Meeting (January 24-25, 2007)

The stakeholder process described in this memo would only address potential modifications to day-ahead scheduling requirements until implementation of MRTU. Pursuant to FERC's September 21, 2006 Order on MRTU, a separate stakeholder process is being conducted later in 2007 to address potential provisions to address under-scheduling under MRTU prior to successful implementation of convergence bidding. [4]

II. Short-term Market Competitive Index for January – September of 2006

Background and Results

DMM utilizes several indices to measure overall market performance in the California wholesale electricity markets. One of the main indices is the Short-term Market Competitiveness Index, which compares the average cost of actual short-term (day-ahead and day-of) bilateral energy purchases by California's three Investor Owned Utilities to a competitive benchmark price estimated by DMM. This index is calculated on an hourly basis but is averaged over a much longer time horizon (e.g., monthly) to get a more comprehensive picture of overall market performance. The Short-term Market Competitiveness Index (also referred to as a price-to-cost mark-up) is the difference between the actual price paid for wholesale electricity in the short-term bilateral market and an estimate of the marginal cost of the most expensive unit of energy needed to serve the amount of load that is scheduled prior to the real-time (imbalance) market. This marginal cost estimate is referred to as the "competitive price."

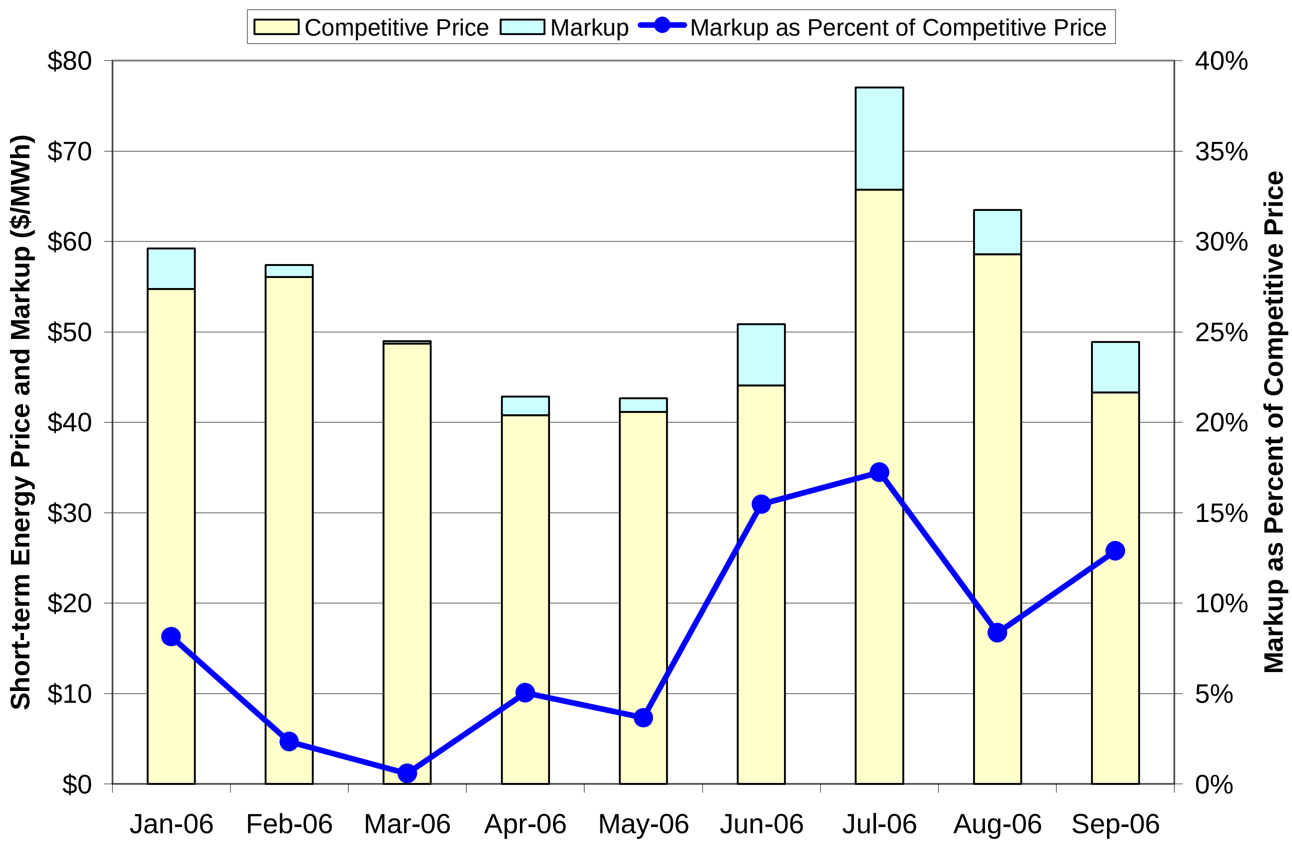
The analysis presented here focuses on monthly average price-to-cost mark-ups because the emphasis of this assessment is on overall long-term market competitiveness as opposed to hour-to-hour competitiveness. Another reason for focusing on monthly assessments is that hour-to-hour variations in estimated price-to-cost mark-ups may be the result of data or modeling deficiencies that may over- or under-predict market competitiveness in any particular hour. In fact, the preferred barometer for short-term market performance is the 12-Month Competitive Index (12-MCI), which represents a 12-month rolling average of the estimated monthly short-term energy mark-ups. DMM has been calculating the 12-MCI since 2001. During the height of the energy crisis, the 12-MCI was well above $60/MWh (i.e., short-term procurement costs were $60/MWh above estimated competitive prices). Since 2002, the 12-MCI has hovered between $0/MWh and $11/MWh. Given historical experience, DMM considers a 12-MCI in the range of $5 to $10/MWh to be a competitive range that reflects very little market power.

The monthly average estimated competitive price and mark-up are presented in Figure 1 along with the monthly average mark-up expressed as a percent of the estimated competitive price. The actual average price paid for short-term purchases is the sum of the competitive price and the mark-up (i.e., the entire height of the columns in Figure 1). Monthly average mark-ups have ranged from nearly 0% to 17%, with an average mark-up of 8.5% over this nine-month period. For comparison, monthly average mark-ups in 2005 ranged from 4% to 16%.

[4] The CAISO's filing on Amendment 72 indicated that the day-ahead scheduling requirement was viewed as a "stop gap" measure that the CAISO expects would be unnecessary and not be extended under MRTU once the Integrated Forward Market (IFM) and Residual Unit Commitment (RUC) processes were in place. However, FERC's September 21 Order on MRTU indicated that the FERC is concerned about the potential for day-ahead under-scheduling by LSEs in the absence of convergence bidding and/or any explicit day-ahead scheduling. Consequently, the Order directs the CAISO to develop and file interim measures, no later than 180 days prior to the effective date of MRTU Release 1, to address the potential economic incentive for LSEs to under-schedule in the Day Ahead Market until the successful implementation of convergence bidding has been achieved. (September 21 Order at 452, p.132).

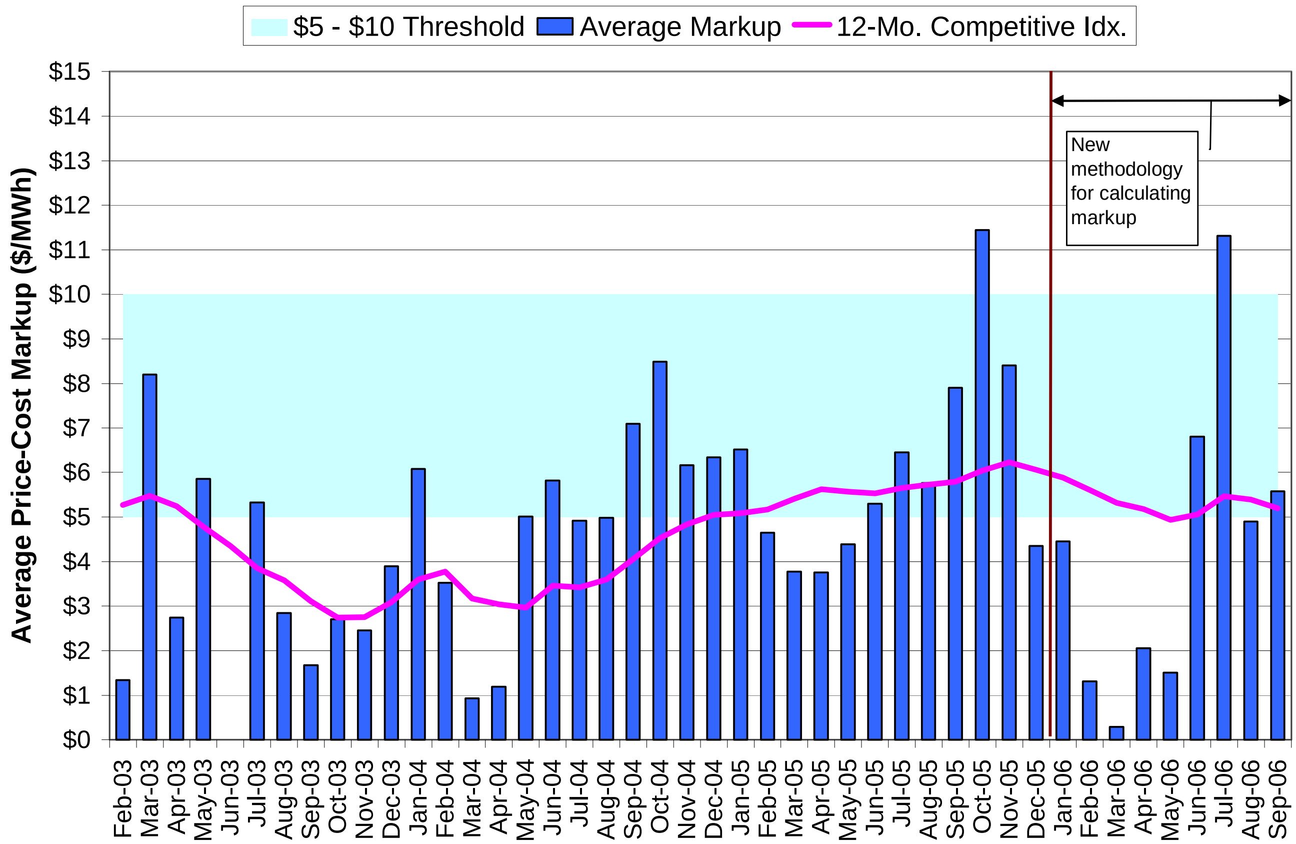
The estimated prices for spring and early summer are of particular interest in Figure 1. Heavy hydroelectric output during this period impacted wholesale electricity prices by displacing more expensive thermal generation. The result is a significant reduction in monthly average prices, as seen for April – May in Figure 1, and an increase in overall market competitiveness as indicated by the very low estimated price-to-cost mark-ups. Increased average loads in June (average daily loads were more than 3,000 MW higher in June 2006 than in June 2005) and a record-breaking heat wave in July resulted in higher short-term prices. In addition, the monthly average mark-up increased significantly, to above 15%, during June and July.

Figure 1 Monthly Average Short-Term Price and Price-to-Cost Mark-up (Jan – Sep 2006)



The monthly average mark-up values, and the 12-month rolling average of those monthly values (12-MCI), are presented in Figure 2 below. For the first three quarters of 2006, monthly short-term mark-up values were, on average, lower than the price-to-cost mark-ups observed for the same period in 2005. In fact, on a month-to-month basis, mark-ups have been lower in 2006 compared to 2005 for all months except for June and July. The 12-MCI has also been, on average, below levels seen in 2005 and has remained at the lower end of the $5/MWh - $10/MWh range throughout the first nine months of 2006, indicating a general condition of competitiveness in the short-term wholesale market in California.

Figure 2 Monthly Average Price-to-cost Mark-up and 12-month Competitive Index for February 2003 – September 2006



It is important to note that a finding that the energy market is very competitive does not mean that the market is optimally designed. For instance, DMM has previously reported on numerous deficiencies in the current market design that have attributed to reducing spot market revenue opportunities for generation and consequently reduced incentives for long-term contracting, which is critical for facilitating new generation investment. Noted deficiencies include the lack of locational marginal pricing (LMP) of energy, the absence of a formal reserve shortage scarcity pricing mechanism, and the lack of local capacity markets. The initial release of MRTU and subsequent enhancements should address most of these deficiencies and provide a much better market structure for facilitating generator revenue adequacy and new investment.

Note that the methodology used to calculate the monthly average mark-up values was changed from the previous methodology, beginning in January 2006. The change in methodology results in higher estimated monthly average mark-ups that more closely reflect daily short-term portfolio procurement decisions than did the prior methodology. This change is discussed in more detail in the next section.

Discussion of the Data, Simulation Model, and Mark-up Calculation

In general, the price-to-cost mark-up and 12-month competitive index have two primary components required for calculation: a representative market price for actual short-term purchases and a simulated competitive price to meet the amount of load that is met through day-ahead and day-of purchases. The representative actual market price for short-term purchases is calculated using actual procurement data provided by California's three IOUs.[5] The competitive price is simulated through economic dispatch using a simple two-zone (north and south) representation of the CAISO Control Area. Under this approach, imports from the northwest and southwest are represented as single interfaces in the north and south, respectively, with each interface represented by a single aggregate supplier.

The simulation model assumes that every available asset in the control area bids competitively (at marginal cost) and the portfolio of available resources clears against the total of actual historical hour-ahead generation schedules in each hour. Additional conditions were necessary to develop the estimated competitive price. Generating units are assigned unit commitment levels based on historical hour-ahead schedules. Hydroelectric units and pump storage units are optimally dispatched to reflect total metered output. Resources in the cogeneration, renewable, and QF classes, in addition to resources with unknown variable costs, were modeled to operate at their historical forward energy schedules. California imports are modeled to flow economically, bound by hourly inter-tie availability, and are priced at historical Powerdex hub price levels for the California-Oregon Border (COB) and Palo Verde (PV).

The simulation produces estimated hourly competitive prices for two zones within the CAISO Control Area. An hourly mark-up value is calculated for each hour within a day by taking the difference between the actual (proxy) short-term procurement unit cost and the estimated competitive price. These hourly values may be positive or negative. However, there is an important step in the calculation of price-to-cost mark-ups that takes place within each operating day.[6] Specifically, within a day, a daily weighted average mark-up is calculated using the hourly mark-up values weighted by the hourly procurement quantities. The daily average mark-up is then constrained to be non-negative. This is done to reflect the lumpy nature of short-term procurement practices where a supplier may sell a 16-hour block of energy in the day-ahead and, based on that supplier's forecast of prices for that day, the supplier may sell at a loss for some hours in that block but have this more than off-set by gains from other hours within that block sale, yielding a net gain across the entire block. Additionally, the daily netting of hourly gains and losses also implicitly adjusts for "forecast error" on the part of the parties involved in the short-term transactions. To the extent that actual average prices turn out to be different from expected average prices, this difference may result in a negative estimated mark-up. However, in measuring the competitiveness of the short-term wholesale market, we do not expect suppliers to intentionally sell energy across any given day at a price where they are not able to recover their marginal costs. In constructing an aggregate measure of competitiveness for a month, we do not want negative daily mark-up values impacting the monthly competitive metric where those negative daily values are likely due to "forecast error" and not competitive conditions in the short-term market. For these reasons, we bound the daily average mark-up estimate to be non-negative.

[5] There are hours for which no short-term procurement data were available for certain of the load serving entities that participated in the data provision. For these hours, proxy values for both price and quantity were used from neighboring hours for that load serving entity rather than omit that hour from the estimate since other load serving entities may have provided data for that hour.

[6] This netting of positive and negative hourly mark-up values within a day is a change from the methodology employed in prior years, where positive and negative values were netted across an entire month, and negative monthly mark-ups would then be truncated to zero. The monthly netting approach taken in prior years would have resulted in lower reported monthly mark-ups, as negative mark-up values from one day would have off-set positive mark-up values from another day within the same month.