California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Keith Casey, Director, Market Monitoring

Date: July 10, 2009

Re: ***Market Monitoring Report***

This memorandum does not require Board action.

At the ISO Board of Governors (the Board) meeting on May 18, 2009, the Department of Market Monitoring (DMM) provided a review of the performance of the new California Independent System Operator Corporation (the ISO) markets during the first month of operation. This review noted that while the overall performance of the new ISO markets was competitive and stable, the real time energy market did exhibit a high degree of price volatility, and average prices in this market tended to diverge from average day-ahead prices. Our review also included a list of recommendations that the ISO should consider to try to reduce excessive price volatility in the real-time market.

This report provides an update to the real-time market analyses presented to the Board in May and covers the first three months of market operation (April-June 2009). It starts with an assessment of price convergence across the ISO energy markets (Day Ahead, Hour Ahead Scheduling Process (HASP), and the 5-minute Real Time Dispatch (RTD)) and concludes with a review of trends in RTD price volatility. Our updated analysis shows a significant improvement in price convergence in June during the middle and later hours of the day but HASP prices continue to diverge during the early morning hours. Additionally, we show that while price volatility in May was similar to April, there was a significant improvement in June. This improvement is likely due to (1) the various actions the ISO has taken over the past two months to improve the quality of the real-time market model and associated input data and (2) the fact that many of the planned generation and transmission outages that were driving some of the price volatility in April and May were completed in June. Despite these improvements, price volatility from one 5-minute interval to another is found to be much higher than what is observed in other ISOs. We will be working with ISO market operations to conduct further analysis of this observation and consider potential options for addressing it going forward.

The analyses presented here will also be included in a quarterly report on market performance that DMM will be filing with the Federal Regulatory Energy Commission (FERC) in June. In addition to reporting on performance of the real-time market, the quarterly report will also

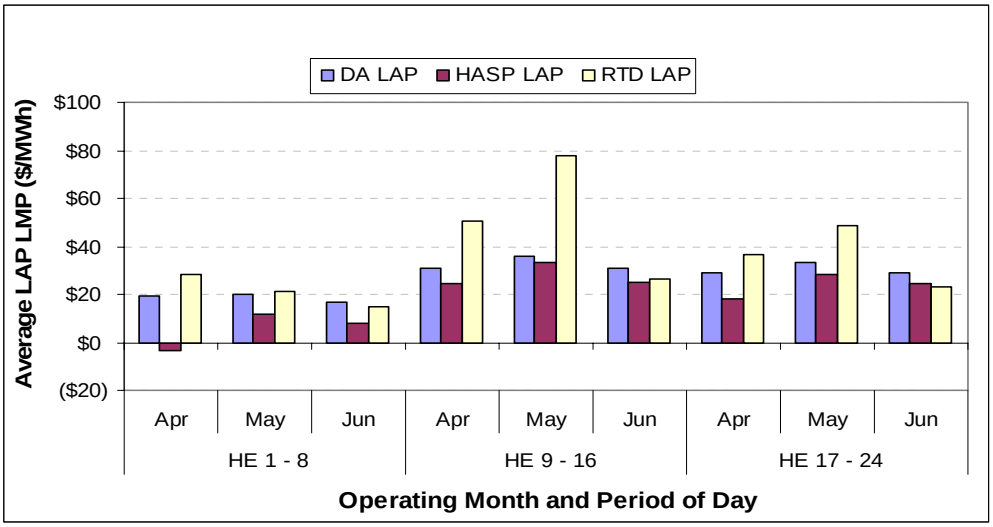
include an assessment of the effectiveness of the local market power mitigation procedures and a review of the use of exceptional dispatches.

Review of price convergence

One standard measure of market performance is the degree to which prices across the ISO's inter-temporal energy markets (Day-Ahead, HASP, and RTD) converge. A high degree of price convergence can provide market efficiency benefits in markets that are otherwise competitive and well functioning. The extent to which prices from inter-temporal energy markets converge depends on a variety of factors. Two legitimate reasons for why prices may diverge between the Day Ahead and Real Time Energy Markets are 1) difference in transaction costs (i.e., market costs not reflected in the market clearing price such as uplift costs and administrative fees) and 2) differences in market participant's risk tolerance for price volatility (e.g., a buyer in the Day Ahead Market may be willing to pay a price that is slightly higher than the expected real-time price in order to avoid the risk of being exposed to higher than expected real-time prices).

Price convergence can be measured and analyzed in a variety of ways. One approach is to examine how well average prices converge over an extended period. Figure 1 below provides such a comparison for the Southern California Edison (SCE) Load Aggregation Point LAP prices.[1]

Figure 1. Comparison of SCE LAP Prices



As evident in Figure 1, average LAP prices for SCE in the HASP tend to be significantly below day-ahead and real-time prices during the early morning hours (hours 1- 8). This divergence was

[1] For the sake of brevity, we focus here just on SCE LAP prices but much of this discussion would apply to the other two Default LAP prices (San Diego Gas & Electric (SDG&E) and Pacific Gas & Electric (PG&E)) with some important differences. Most notably, average SDG&E LAP prices for the RTD market were higher than SCE during the middle hours of the day due to greater congestion in the San Diego region. Conversely, average PG&E LAP prices for the RTD market during the middle part of the day were much more moderate than SCE as most of the high RTD prices in SCE were due to north-to-south congestion on Path 26, which separates the PG&E region from SCE.

most pronounced in April with the average HASP price for the SCE LAP being negative. There was significant improvement in HASP price convergence during the morning hours in May and June though the average HASP price for these periods was still well below the average day-ahead and RTD prices. A number of factors have contributed to the observed divergence in HASP prices during the morning hours. Three main factors are:

1) The load pattern across this period is relatively low but changes significantly from one hour to the next;

2) There is limited 5-minute dispatch capability (particularly in the decremental direction) due to units being off-line or at minimum operating levels; and

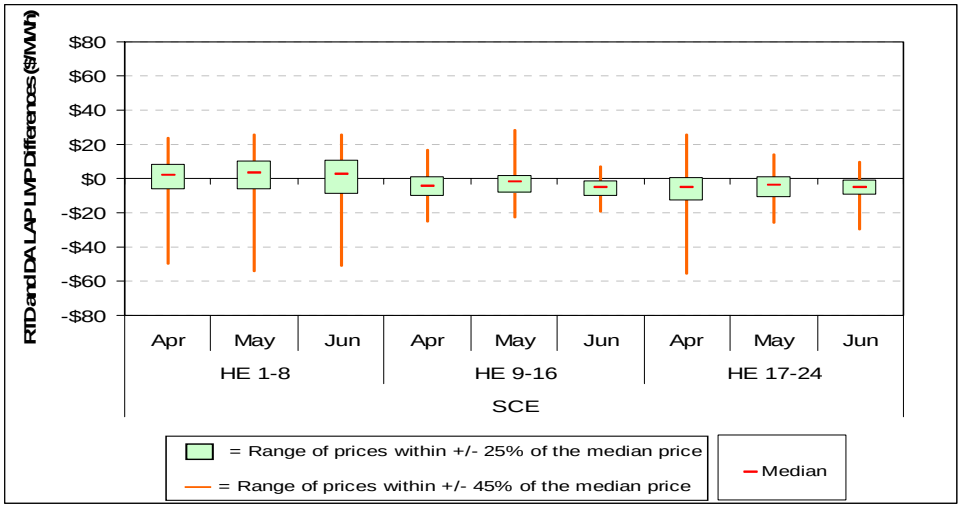
3) Load is typically scheduled at or near 100 percent of forecast.

To manage the sharp increase in load and supporting supply schedules during the early morning hours when 5-minute dispatchable supply is limited, ISO operators often bias the HASP load forecast downward. This has the effect of reducing day-ahead net-import schedules and positioning the subsequent 5-minute dispatch market (RTD) into more of an incremental dispatch mode. While the use of a negative load bias in HASP is critical for ensuring there is sufficient 5-minute dispatchable energy to manage the morning ramp, this practice tends to produce a predictable price divergence with average HASP prices that are typically well below day-ahead and RTD prices.

During the middle part of the day (hours 9 -16), average RTD LAP prices for SCE were significantly higher than day-ahead and HASP LAP prices, which tended to be more closely converged (Figure 1). Higher RTD prices during this period are due primarily to price spikes during market intervals when Path 26 (the major transmission path between northern and southern California) is congested and the southern region runs out of 5-minute dispatchable supply. Average RTD prices in June were much more closely aligned with day-ahead and HASP as price spikes were much less frequent in June. The latter part of the day (hours 17-24) shows a similar pattern but average RTD prices were not as extreme during April and May.

One limitation of examining price convergence through comparing monthly average prices is that they do not provide any information on the degree to which prices tend to converge on an hour-to-hour basis. For instance, if day-ahead prices were $20/MWh higher than RTD prices in half the hours of a month but $20/MWh lower in the other hours, a simple comparison of the average prices for the entire month would show the prices as being very similar. To provide insight into the hour-to-hour level of price convergence, Figure 2 shows a box-whisker plot representation of the distribution of hourly price differences between day-ahead and real-time (RTD) for the SCE LAP. The plots in Figure 2 show the median price difference (red hash line), the range of price differences within +/-25% of the median price difference (green box) and the range of price differences within +/- 45% of the median price difference (orange line). For a market with good price convergence, the median price difference should be near zero and the distribution of price differences around the median should be very concentrated and symmetric.

Figure 2. Distribution of Hourly SCE LAP Price Differences (RTD Price – DA Price)



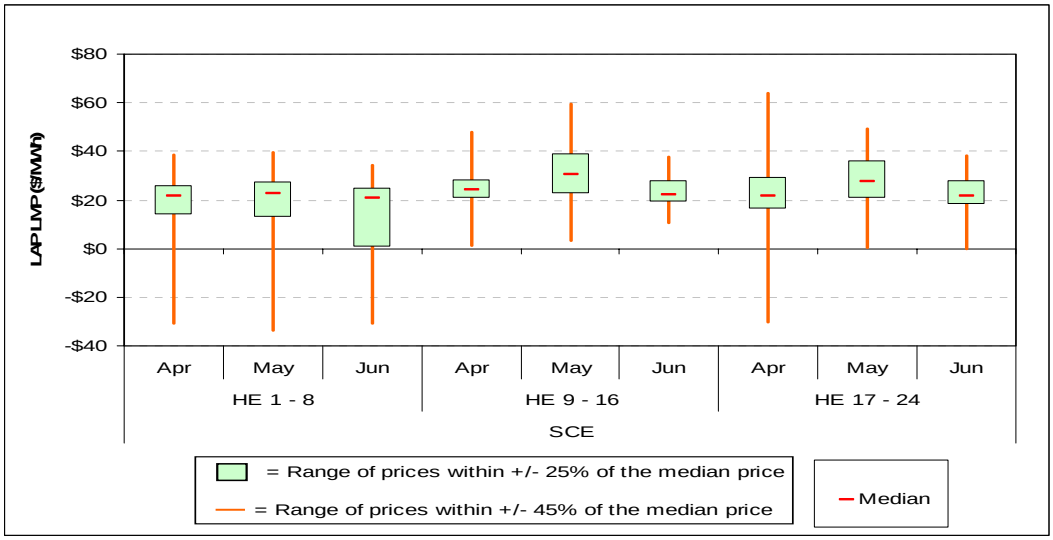
As evident in Figure 2, the median price difference for the SCE LAP price during the early morning hours is near zero (slightly positive) but has a fairly wide distribution that is skewed in the negative direction (i.e., observations where RTD Price < DA Price tend to involve larger price differences). The distribution of price differences during the mid-day (hours 9-16) and late-day (hours 17-24) have a negative median (i.e., these periods have more instances where RTD prices are less than day-ahead prices). Moreover, the central part of the distributions (+/- 25% of the median price difference) also tends to be in the negative range, which indicates that in roughly 75% of the cases, the RTD price is lower than the day-ahead price. These observations are particularly interesting for April and May because, as shown in Figure 1, the average RTD prices for these months during the mid-day and late-day periods were actually substantially higher than the average day-ahead price. These seemingly contradictory results are explained by the impact that extreme positive RTD LAP price spikes have in driving up the average RTD price. Even though extreme RTD prices (i.e., higher than $500/MWh) occurred only in 2.3% and 1.4% of the 5-minute pricing intervals in April and May, respectively (Figure 6), they were frequent enough to pull up the average RTD LAP prices above the day-ahead prices for these periods. This example demonstrates the value of examining price convergence from different perspectives (e.g., Figure 1 vs. Figure 2).

Review of price volatility

This section provides a brief summary of some observed trends in price volatility. As was discussed at the Board meeting on May 18, 2009, the real-time energy market in April was, at times, extremely volatile, with 5-minute prices exceeding $2,500/MWh in some intervals. Some of this volatility was caused by an unusually early heat wave during the third week of April, which led to high loads in southern California and congestion on some of the major south-to-north transmission paths. However, sporadic 5-minute price spikes continued through May but then moderated substantially in June.

Figure 3 below provides a box-whisker plot representation of the distribution of SCE RTD LAP prices for the past three months. SCE RTD LAP prices tend to show the greatest volatility in the early morning, with 90 percent of the prices (+/- 45 percent of the median price) generally falling within a rather wide dispersion of approximately $70/MWh (-$30/MWh to $40/MWh). Price distributions were fairly spread out in the mid-day and late-day periods as well (Figure 3). However, the price distributions became significantly more consolidated in June during these same periods.

Figure 3. SCE RTD LAP Price Distributions (April – June)



To provide some context on how the price distribution plots shown in Figure 3 compare with other ISOs/RTOs with locational marginal pricing (LMP) markets, Figure 4 shows a similar plot of zonal 5-minute prices in ISO New England for the week of May 11-15, 2009. For this particular week, which was randomly selected, 90 percent of ISO New England load zone prices for Massachusetts and Connecticut were generally within a $30-$40/MW range, which is similar to the observed SCE LAP price distributions for the mid-day to late-day periods of June (Figure 3).

Figure 4. ISO New England Price Distribution

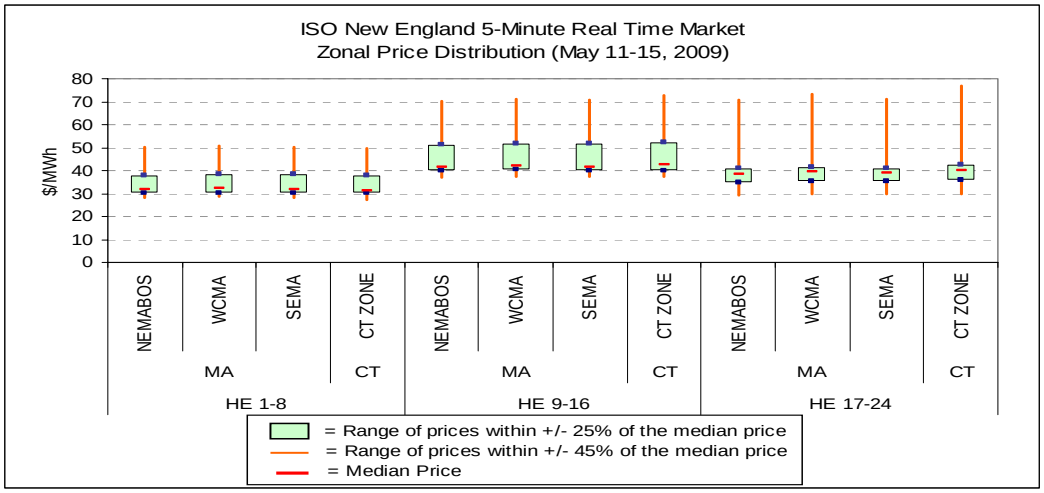
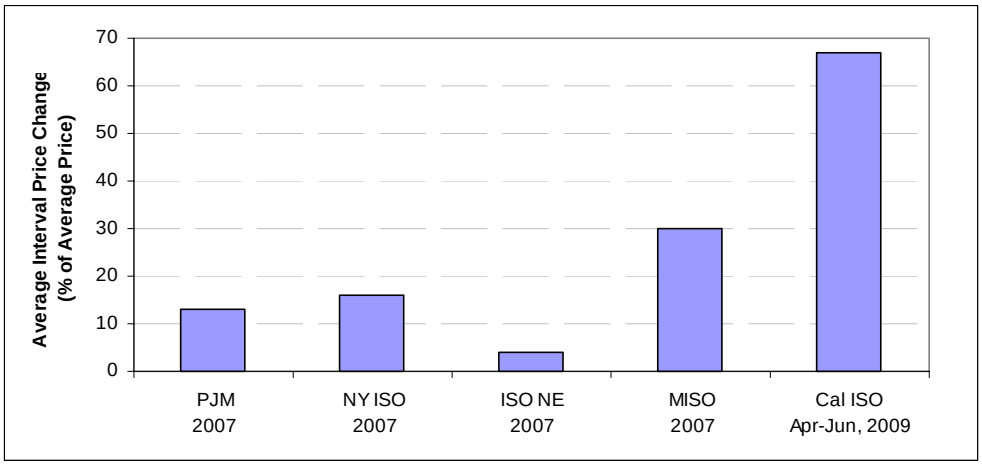


Figure 5 provides a different perspective on price volatility, which is to examine the extent to which prices change from one 5-minute interval to the next by calculating the average interval price change and expressing it as a percentage of the average price. We calculated this metric separately for the three Default LAP prices (SCE, SDG&E, and PGE) and show the average along with a comparison of the same metric for other ISOs.[2]

Figure 5. Five Minute Real-Time Price Volatility – Comparison with Other ISOs



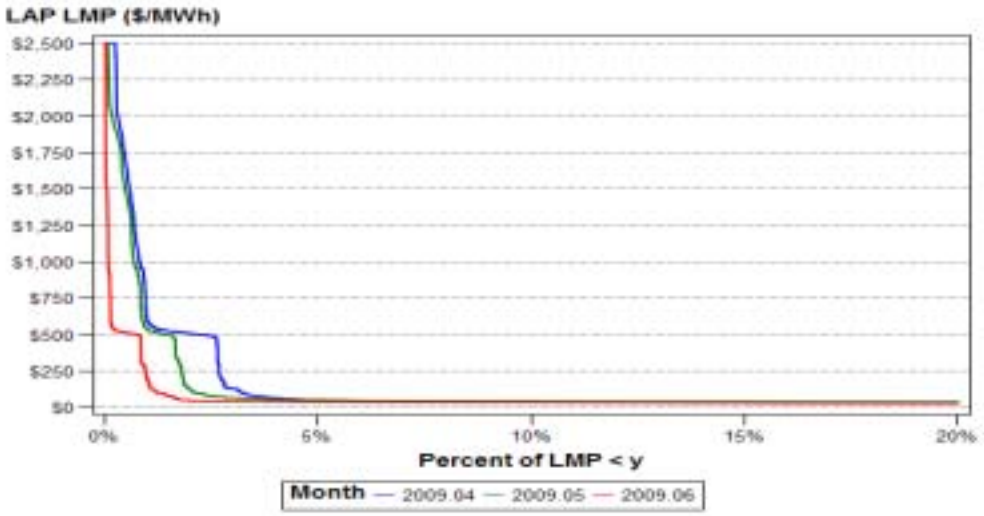
As evident in Figure 5, the interval-to-interval volatility of the California ISO 5-minute prices for the first three months of the new market is substantially greater than what has been observed in

[2] The data shown for other ISOs are from the *2007 State of the Market Report for the Midwest ISO*, prepared by Potomac Economics. The metrics for the other ISOs is calculated using several hub prices for each ISO – see Figure 35, page 46 of the report. (http://www.potomaceconomics.com/uploads/midwest_presentations/2007_State_of_the_Market_Report-Full_Text_07-08.pdf).

other ISOs.[3] Comparing price volatility in the nascent California ISO market to price volatility in more mature LMP markets may not be a fair comparison but it nonetheless provides some important context and basis for gauging future trends. Moreover, differences in observed interval-to-interval price volatility across various ISOs are likely due to important differences in particular aspects of each ISO's real-time market design and optimization features as well as differences in market characteristics such as dependency on inter-tie schedules, daily load profiles, and internal resource mix. In light of these factors, we do not view the comparison of price volatility shown in Figure 5 as a simple "less is better" exercise. Instead, it should be used as a basis for examining what aspects of the California ISO Real Time Market design are contributing to higher price volatility and assessing whether these features are desirable or need to be modified in some fashion.[4]

Finally, Figure 6 provides some insights into frequency and magnitude of extreme RTD prices. Specifically, Figure 6 shows that the frequency of extreme prices over $500/MWh has declined steadily from 2.3 percent in April to 1.4% in May and to 0.8 percent in June. This improvement is likely due to various enhancements the ISO has made to the real-time market such as improvements in the accuracy of the RTD load forecasts and in the use of load and transmission limit biasing. Additionally, many of the planned generation and transmission outages that were driving some of the price volatility in April and May were completed in June.

Figure 6. RTD LAP Price Duration Curves (Top 20 Percentile)



[3] The index shown in the chart for the California ISO (68%) was very consistent across all three LAPs and across all three months. We did see a significant decline in the absolute average interval price deviation in June for all three LAPs but we also saw a proportionate drop in the average price for June making the ratio virtually the same as prior months.

[4] For example, different ISOs have different means for utilizing energy from regulation reserves to manage periodic shortages of ramping energy. Many of the price spikes occurring in the ISO's 5-minute dispatch market (RTD) are due to shortages of ramping energy and therefore comparing how RTD utilizes energy from regulation reserves to practices in other ISOs might reveal opportunities for market enhancements that could appropriately reduce price volatility. In other cases, there may be differences in the California Real Time Market design that produce greater price volatility but are desirable.

In summary, this analysis shows that price volatility in the California ISO's Real Time Market did improve in June relative to April and May. Specifically, RTD LAP prices in June showed a much tighter price distribution with fewer extreme prices. However, price volatility from one 5-minute interval to the next is found to be much higher than what is observed in other ISOs. We will be working with the ISO to conduct further analysis of this observation and consider potential options for addressing it.