3. Real Time Market Performance

3.1 Overview

As noted in Chapter 1, 2005 marked the first full year of operation under the new Real Time Market Application (RTMA) software. The RTMA software was designed to address significant shortcomings in the prior real-time dispatch and pricing application (Balancing Energy and Ex-Post Pricing, BEEP).

RTMA is designed to receive bids to provide real-time energy, calculate the imbalance energy requirement for the next dispatch interval, and provide an economically optimized set of dispatch instructions to meet the imbalance energy need at least cost subject to resource and transmission grid constraints. Specific enhancements to BEEP that RTMA was designed to provide include:

- Replacement of the BEEP Target Price mechanism[1] with economic dispatch (or “market clearing”) of all incremental and decremental energy bids with “price overlap” (i.e., bids to sell energy (incremental energy bids) at a price lower than the price of bids to buy energy (decremental energy bids)).
- Enhanced treatment of resource operating constraints, such as ramp rates, forbidden operating ranges[2], minimum run times, and start-up times. In addition to lowering uninstructed deviations by increasing the overall feasibility of dispatch instructions, these improvements were necessary in order for the CAISO to gain approval to implement an Uninstructed Deviations Penalty (UDP) from the Federal Energy Regulatory Commission (FERC).
- Optimization of dispatch instructions based on a two-hour “look ahead” period, rather than dispatch of bids in economic merit order for each individual interval.
- Improved system responsiveness and efficiency due to use of a 5-minute dispatch interval, rather than the previous 10-minute interval.
- Increased reliance on automated dispatch instructions.

[1] Prior to RTMA, the Target Price mechanism was utilized by the CAISO to ensure that the system-wide bid curve representing decremental and incremental real-time energy bids submitted by all participants utilized by the BEEP software was monotonically non-decreasing. Prior to any adjustments by the Target Price mechanism, the system-wide bid curve representing decremental and incremental real-time energy bids submitted by all participants typically included some “price overlap,” or decremental bids with a bid a price higher than the bid price of some the incremental bids. Such a non-monotonic bid curve would result in real-time prices that increased as the CAISO switched from incing energy to decing energy. To avoid this, the CAISO developed a Target Price mechanism that would set the system bid curve for the overlapping portion of incremental and decremental bids of eligible resources equal to the bid price at the point where the overlapping bids intersect. This point is referred to as the “Target Price”. Initially, all resources (including imports) were eligible to set the Target Price. However, due to gaming potential with this open provision, eligibility to set the Target Price was later (October 2001) restricted to generating units with Participating Generator Agreement and loads with Participating Load Agreement; moreover only capacity that could be dispatched in 10 minutes could set the Target Price.

[2] Forbidden operating ranges are those operating ranges in which a resource may not operate for an extended period, but must run through as quickly as possible. A unit therefore may not provide regulation service within a forbidden operating region, because that could require the unit to operate within the forbidden region for some period of time.

The RTMA software uses a 120-minute time horizon to compare the load forecast, current and expected telemetry of resources in the CAISO Control Area, current and expected telemetry of transmission links to other control areas, and the current status of resources on Automatic Generation Control (AGC). From this information, RTMA will set generation levels for resources participating in the CAISO Real Time Market using an optimization that achieves least-cost dispatch while respecting generation and inter-zonal constraints.

A complementary software application, Security Constrained Unit Commitment (SCUC), determines the optimum short-term (i.e., one to two hours, the time from the current interval through the end of the next hour based on the current and next hour's bids) unit commitment of resources used in the RTMA. The SCUC software commits off-line resources with shorter start-up times into the Real Time Market for RTMA to dispatch, or, conversely, the SCUC software de-commits resources as required to prevent over-generation in real-time. The SCUC program runs prior to the beginning of the operating hour and performs an optimal hourly pre-dispatch for the next hour to meet the forecast imbalance energy requirements while minimizing the bid cost over the entire hour. The SCUC software also pre-dispatches (i.e., dispatches prior to the operating hour) hourly inter-tie bids.

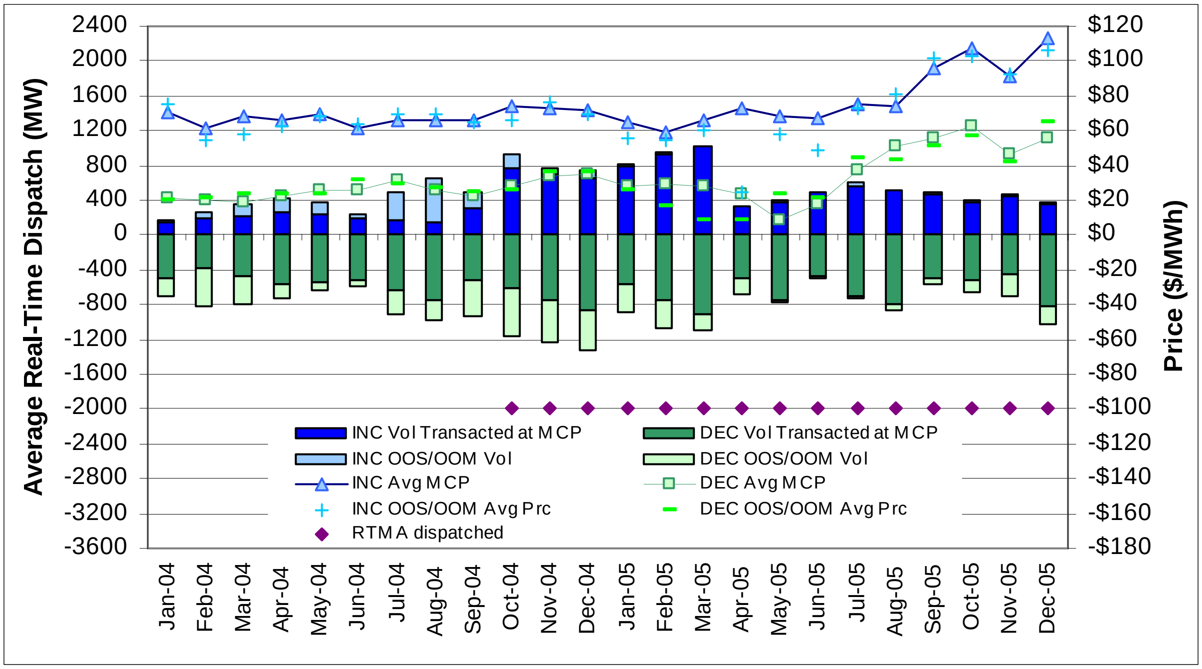
Since its implementation, several issues have been raised concerning RTMA performance. One of the major concerns cited is a perceived high degree of price and dispatch volatility. Section 3.2 provides a general review of RTMA prices and dispatch volumes compared to prior years. Section 3.3 provides a more in-depth assessment of RTMA performance. One notable aspect of RTMA – settlement rules for pre-dispatched inter-tie bids, was found to be particularly problematic in early 2005 and required a modification to the CAISO Tariff. A review of the impact from this Tariff change is provided in Section 3.3. Another important aspect of RTMA is a load bias feature that allows operators to manually adjust the load forecasts that are used to determine optimal dispatch in RTMA. A review of the relationship between the use of load bias and the use of regulation energy is examined in Section 3.3. One element of RTMA that has not been implemented is the penalty provisions for deviations from dispatch instructions (Uninstructed Deviation Penalty (UDP)). This element has not been implemented because uninstructed deviations have been relatively moderate since RTMA was implemented. An analysis of uninstructed deviations under RTMA is also provided in Section 3.3.

3.2 Real Time Market Trends

3.2.1 Prices and Volumes

Figure 3.1 shows monthly average prices and volumes for both incremental and decremental energy, both in and out-of-sequence (OOS), in 2004 and 2005. Monthly average prices for incremental energy in 2005 were stable, averaging between $60 and $80/MWh from January - August but increasing significantly in the September - December period due to the dramatic increase in natural gas prices resulting from the Gulf Coast hurricanes. Average monthly incremental prices during that four-month period ranged between $90 and $117/MWh. Average monthly prices for decremental energy were also stable, generally ranging between $20 and $40/MWh for most of 2005 but increasing to the $40 to $60 range in the August - December period. As in 2004, in-sequence dispatch volumes were overwhelmingly decremental in most months of 2005.

Figure 3.1 Monthly Average Dispatch Prices and Volumes (2004-2005)



Decremental volumes were significantly larger than incremental volumes in 2005, due in part to the presence of uninstructed energy and energy that was not recognized by RTMA. As these cause energy in the system above levels predicted from hour-ahead schedules and other CAISO-committed sources, RTMA must balance the system in real-time by decrementing resources below their schedules.

Figure 3.2 compares average annual Real Time Market prices by zone (NP15, SP15) for 2001 through 2005. Real-time prices were on average higher in 2005 than in the previous three years, but this was mainly due to a steady increase in natural gas prices over this period.

Figure 3.2 Average Annual Real-Time Prices by Zone (2001-2005)

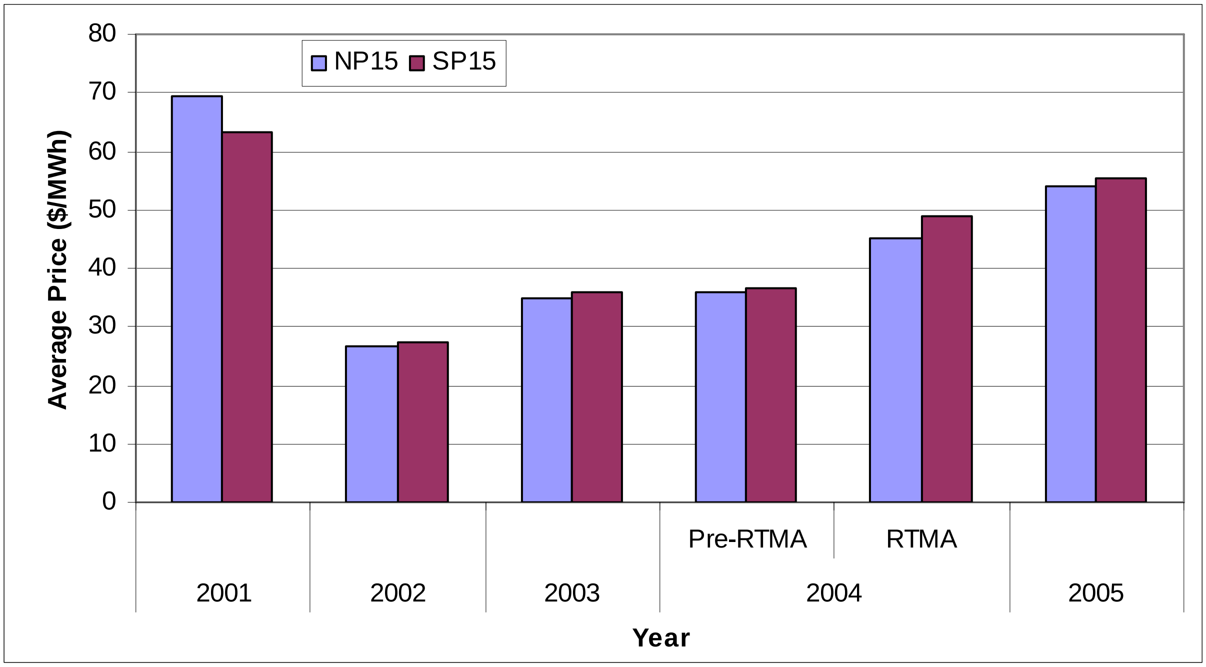


Figure 3.3 shows SP15 real-time price duration curves for 2003 through 2005 and indicates that real-time interval prices in 2005 were consistently higher than in the past two years, predominately because of higher natural gas prices. Figure 3.3 also shows that the Real Time Market posted a price of -$0.01/MWh in approximately 6 percent of intervals in 2005. This price was set by a hydroelectric resource when it had limited ability to reduce output due to a water management constraint. As real-time over-generation conditions were frequent in 2005, particularly during the spring runoff season (as discussed in Chapter 2), this unit was often marginal, as its bids were often large in volume, particularly when few other resources were available to be decremented, such as at night or during the morning ramp.

Figure 3.3 SP15 Price Duration Curves (2003-2005)

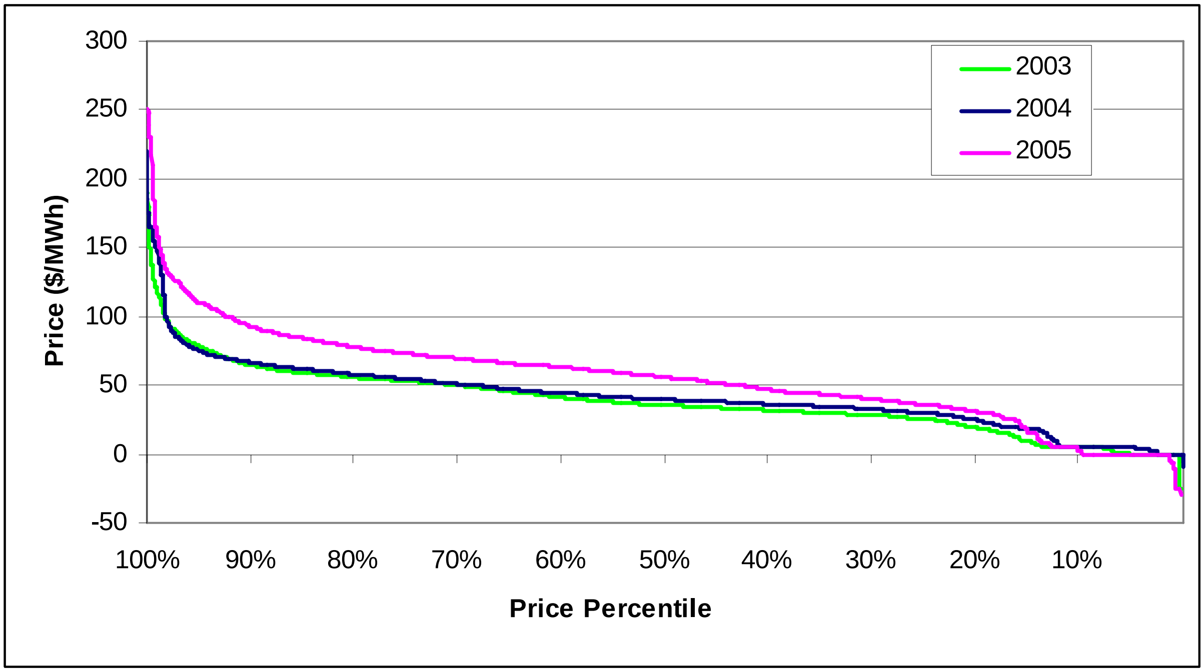
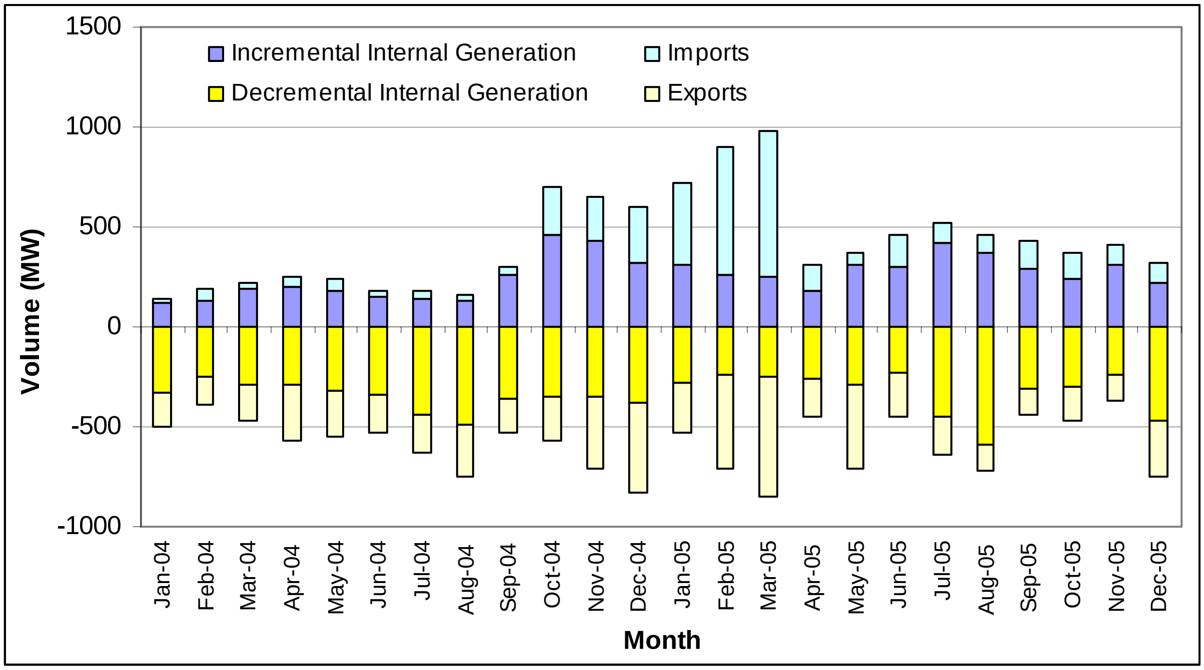


Figure 3.4 shows the monthly average dispatch volumes for internal generation, imports and exports for 2004 to 2005. With the exception of the four-month period of December 2004 - March 2005, internal resources constituted the majority of RTMA dispatches. The increase in inter-tie dispatches during the December 2004 - March 2005 time period is attributable to the "bid or better" settlement rules for inter-tie bids that are pre-dispatched under RTMA. This rule, coupled with the increasing volume of market clearing inter-tie bids, created significant market uplifts and resulted in a modification to the CAISO Tariff that replaced the "bid or better" settlement with an "as-bid" settlement rule. The impact of this rule change can be seen in Figure 3.4 by the highly pronounced decrease in inter-tie dispatch volumes beginning in April 2005. This issue is discussed in greater detail in Section 3.3.

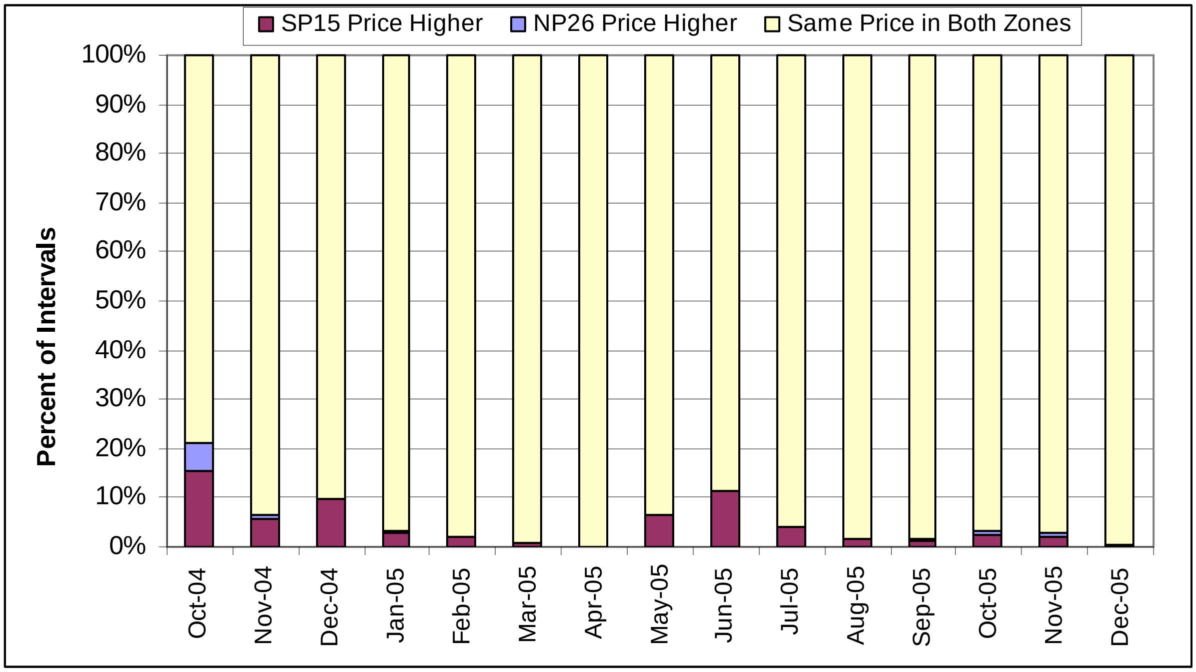
Figure 3.4 Monthly Average Dispatch Volumes for Internal Generation, Imports, and Exports (2004-2005)



3.2.2 Real-Time Inter-Zonal Congestion

Despite an increase in the north-to-south rating for Path 26 of 300 MW (3,400 to 3,700 MW) in May 2005, real-time north-to-south congestion periodically occurred on Path 26 throughout 2005, generally when loads were high in Southern California and lower cost generation was available in Northern California. Prices differed between NP26 and SP15 in approximately 3.1 percent of intervals in 2005 due to real-time congestion on Path 26 or limitations due to the Southern California Import Transmission Nomogram (SCIT). Prior to the upgrade of Path 15 in 2004, real-time congestion was generally in the south-to-north direction, which resulted in higher prices in NP26 and lower prices in SP15. However, since the Path 15 upgrade coupled with a significant amount of new generation in Northern California, congestion in the north-to-south direction has been more frequent. This typically occurred due to the Southern California Import Transmission (SCIT) constraint, which can be mitigated either by splitting the Real Time Market or by using out-of-sequence dispatches within SP15 (Intra-Zonal Congestion management). On other occasions, the CAISO market experienced real-time congestion in the north-to-south direction on Path 26, due to unscheduled counter-clockwise flow within the Western Interconnection. Figure 3.5 shows the monthly count of market splits since September 2004.

Figure 3.5 NP26-SP15 Market Price Splits (October 2004 - December 2005)



3.2.3 Periods of Market Stress

3.2.3.1 July 21-22 Stage Emergencies

An extended heat wave that began on July 11, 2005, continued unabated into August. With no break from high loads, forced generator outages increased during the third week in July contributing to the issuance of Stage 2 emergencies on July 21 and 22. System Conditions in Southern California were sufficiently severe to cause Path 26 to be overloaded in real-time despite the path having its north-to-south rating increased from 3,400 to 3,700 MW in May 2005.

On July 21, low voltage in the area of the Devers Substation near Palm Springs necessitated the declaration of a Stage 2 transmission emergency, as loads in Southern California reached a new peak of approximately 26,459 MW. The CAISO called upon utilities to drop interruptible loads in accordance with their service agreements when operating reserves fall below 5 percent of load. Meanwhile, the CAISO was only able to accept real-time bids from internal resources due to the low-voltage event, and thus declined bids from imports. The RTMA price remained at $120.22/MWh for most of the period between 1:40 and 3:05 pm, and then increased to $172.99/MWh for most of the period between 3:10 and 4:05 pm. The $120.22/MWh price was set by a new combined-cycle resource in SP15; the $172.99 price was set by a non-spinning reserve bid from a combustion turbine resource, also in SP15. Both resources had energy bids within the AMP Conduct Test thresholds.

On Friday, July 22, CAISO load approached 43,960 MW, considerably less than the system-wide record of 45,386 MW set on July 20. However, SP15 load was within 20 MW of its record load set on July 21. At approximately 1:48 pm, a neighboring control area lost a resource, causing an overload of Path 26. The CAISO declared a Stage 2 emergency, and called for interruptible and state water pump loads to be curtailed. From 1:40 to 3:50 pm, the RTMA market-clearing price within SP15 was $249.99/MWh, once cent below the soft bid cap. During this time, the zonal bid stack was fully dispatched. No Scheduling Coordinator submitted any real-time bids above $250/MWh during this price spike.

While the SP15 price was at $249.99/MWh, several units had bid in excess of their reference level thresholds, failing the AMP Conduct Test. However, all such units were located within NP15, where the market-clearing price ranged between $10 and $48.74/MWh, as units there were being decremented to relieve the congestion on Path 26.

Because the SP15 bid curve was relatively inelastic ("steep") at the dispatch level during this price spike, SP15 load would have had to drop only 50 MW or so to pull the price below $200/MWh, illustrating potential gains to Load Serving Entities (LSEs) and their customers from expanded load response programs that are triggered by the real-time price.

3.2.3.2 August 25 Load Shedding Event

Unexpected high loads resulting from temperatures that were 14 degrees above forecast in Southern California on August 25, combined with the sudden loss of the Pacific DC inter-tie, resulted in the loss of interruptible and firm load for a brief period. During this time, real-time prices reached $120.92/MWh, significantly below the $250/MWh price cap due to out-of-merit dispatch of higher priced contingency only bids.

DMM reviewed the dispatch procedures followed during the load shedding event on August 25 to determine why higher priced contingency only reserve bids that were dispatched out-of-merit during the critical hours were not cleared and eligible to set the Real Time Market price in SP15. Ancillary Service (A/S) energy bids marked as contingency reserve cannot be dispatched by the RTMA under normal conditions. The bid segments associated with contingency reserve are therefore unavailable for market dispatch or to set the price unless the contingency flag is cleared (i.e., a contingency occurs that enables operators to release the contingency reserve energy bids into the real-time market for dispatch). Had the contingency flag been cleared on these bids, making the associated energy eligible for in-merit dispatch and eligible to set the price, the RTMA price would have been set near the price cap of $250/MWh.

DMM raised this issue with Market Operations and based on the circumstances (no skipped bids and out-of-sequence dispatch of units that should have had their contingency flag cleared) recommended to Market Operations that prices be corrected to reflect the marginal unit dispatch during those intervals. Market Operations also reviewed the events and concurred that the marginal bid during certain dispatch intervals in hours ending 16 and 17 on August 25 should have been $249.99/MWh. As such, the interval prices were corrected.

3.2.4 Bidding Behavior

Figure 3.6 and Figure 3.7 respectively show profiles of incremental and decremental energy bids from internal resources in SP15 by bid price ranges for the period covering RTMA operation (October 2004 to December 2005). Most notable in Figure 3.6 is the significant increase in the percentage of higher priced incremental energy bids beginning in July 2005 and steadily increasing through the fall. This trend is largely attributable to the increase in natural gas prices that occurred during this period. Additionally, some resources bid very low prices for decremental energy, at times below $0/MWh, particularly during April - June 2005. The category in Figure 3.7 representing bids in the range of -$1/MWh to $0/MWh consisted largely of the -$0.01/MWh hydroelectric bids discussed in Section 3.2.1.

Figure 3.6 SP15 Incremental Energy Bids by Bid Price Bin: Oct-04 to Dec-05

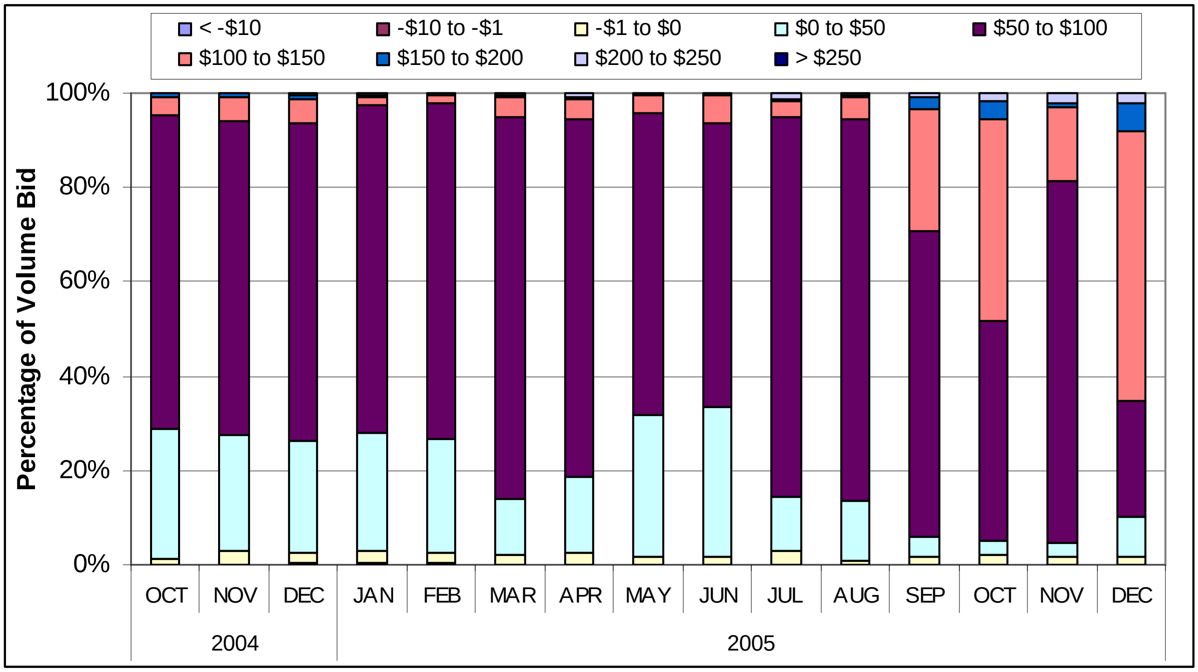
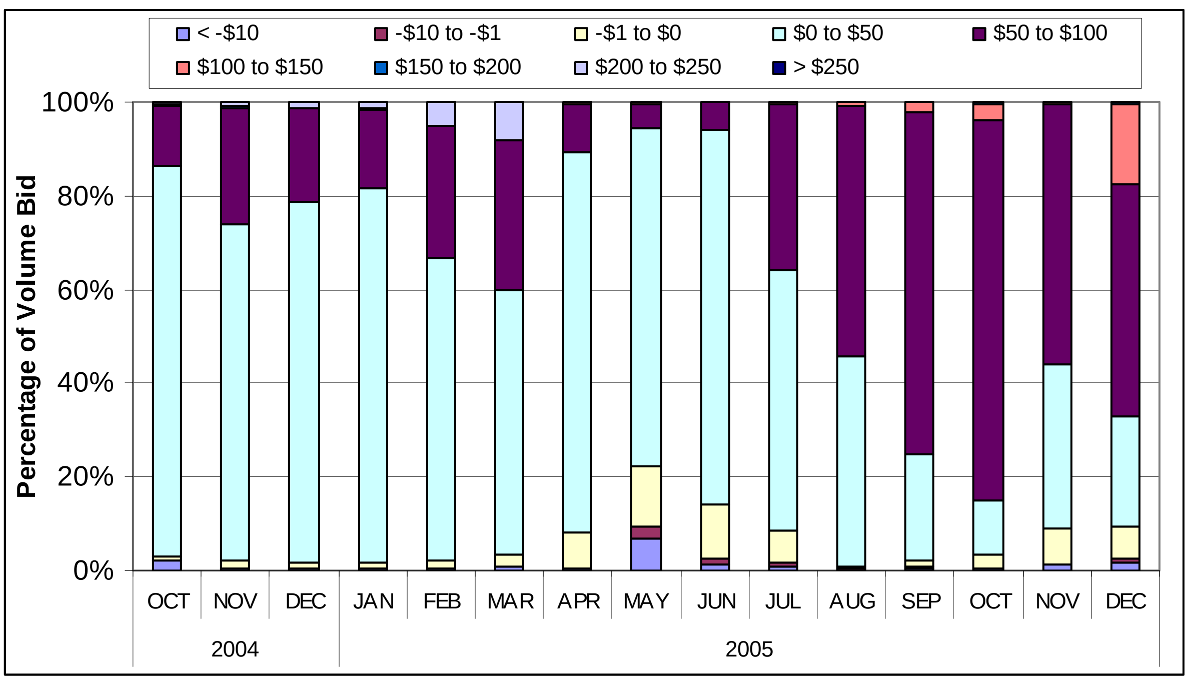


Figure 3.7 SP15 Decremental Energy Bids by Bid Price Bin: Oct-04 to Dec-05



Decremental bids below the price of $0/MWh were common, for a variety of reasons:

- Throughout the year, and particularly in the spring, certain hydroelectric resources faced spilling conditions due to high run-of-river water flows. Under these circumstances, reservoirs were full to capacity, and resource operators were admitting water into their generation turbines at the rate that water was flowing into the reservoir. In order to be decremented, resources would have had to divert water from their turbines over the spillway, effectively losing the potential energy for that volume of water.

- Certain gas-fired generators in California received operational flow orders requiring that generators face penalties if they fail to accept gas deliveries from pipelines. In the event that a generator does not have available gas storage, it may be required to run at its scheduled output, or incorporate these costs into its bids.
- Due largely to the binding SCIT Nomogram, a physical constraint on the instantaneous volume of imports into Southern California, Path 26 was congested in the north-to-south direction in real-time, resulting in divergent zonal prices. When the SCIT constraint is breached, it can be managed through out-of-sequence dispatches or real-time zonal congestion. In the latter case, the CAISO increments energy within SP15 and decrements within NP26, causing prices to diverge, and sending NP26 prices lower, sometimes below zero.
- During off-peak hours, particularly in the lowest-load hours of 1:00 to 5:00 am, few resources are on and generating above minimum operating capacity. As a result, few units are available to be decremented in these hours. This creates instances where competition is thin among the few providers of decremental energy during these hours.

3.3 Analysis of RTMA Performance

3.3.1 Relationship of Prices to Loads and Dispatches

In 2005, there were several occasions when very high peak summer demand conditions did not result in high real-time prices. These occurrences raised a concern that real-time prices were not well correlated with overall system conditions. This section examines this issue focusing on SP15 Real Time Market prices as this zone tended to have the greatest demand for incremental energy in 2005. A simple regression analysis for the peak month of July 2005 indicates that the SP15 real-time price exhibits a statistically significant positive relationship to both actual system loads and SP15 RTMA dispatch volumes, as would be expected (Table 2.1). These two explanatory variables, SP15 Dispatch Volume and Actual Load, explain approximately 48 percent of the variation in the SP15 real-time price.

Table 2.1 Regression of SP15 Real-Time Prices as a Function of Actual ISO System Load and SP15 Real-Time Dispatch Volume[3]

	Coefficient	t-statistic
Intercept	-13.8702	-11.1035
SP15 Dispatch Volume	0.0229	55.7868
Actual Load	0.0021	54.5312
Model R-square	0.48	
Observations	8928	

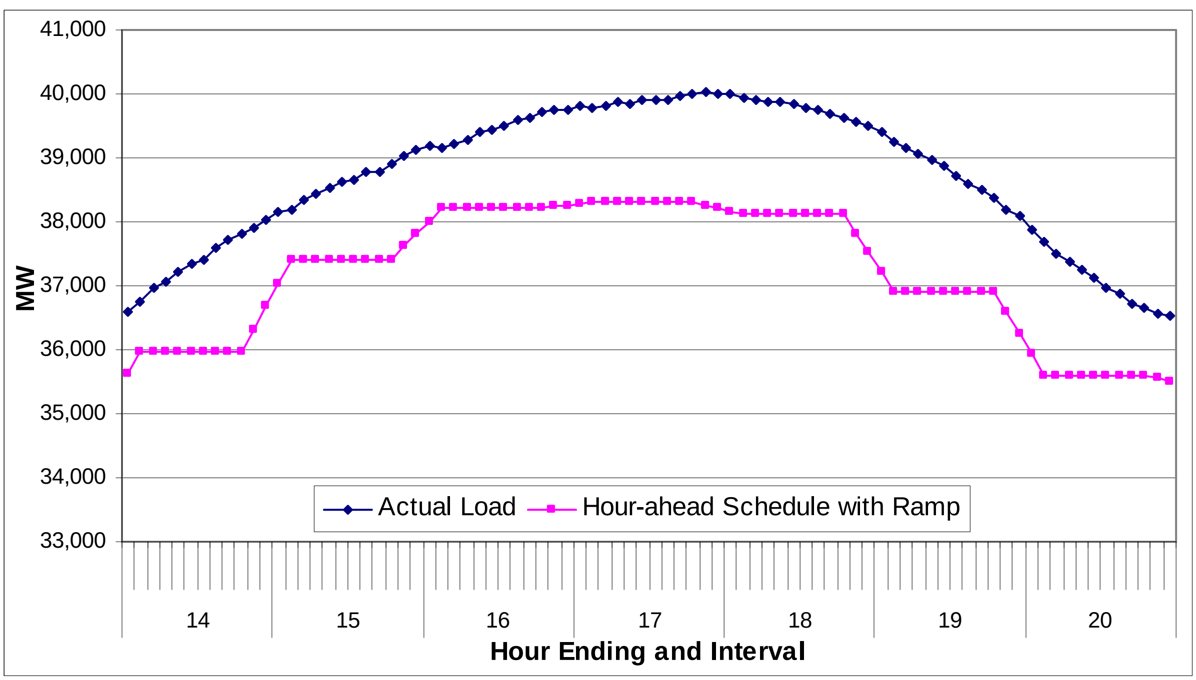
[3] Least-squares regression for all intervals, July 1-31, 2005.

While real-time prices are generally correlated with actual system loads, this is not always the case. In many instances in 2005, real-time prices were not always high during high-load periods. This tended to occur when the CAISO schedules were in excess of load, or when other types of energy were present. This can occur due either to inaccurate load forecasts, or to the following sources of energy, which Scheduling Coordinators cannot consistently account for when scheduling:

- Un-modeled and uninstructed energy;
- Minimum Load energy from resources retained under the Must-Offer Obligation; and
- Real-time RMR energy used to maintain reliability in the presence of transmission outages and other adverse grid events.

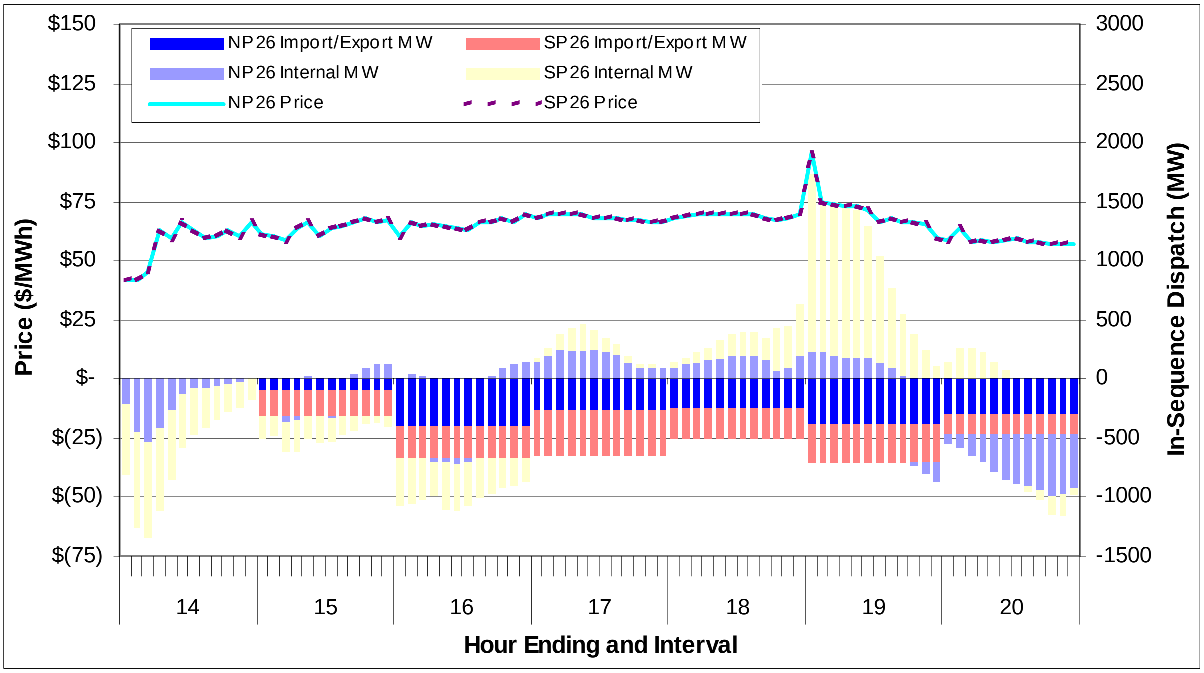
One example of such a day was Sunday, July 31, 2005, when CAISO system load ranged between 39,781 and 40,019 MW in Hour Ending 17:00 (between 4:00 and 5:00 pm). This hour represented one of the highest peak loads for Sundays in 2005, and was one of only three Sundays in 2005 that had a peak load above 40,000 MW. During this hour, Scheduling Coordinators had scheduled 38,309 MW, approximately 1,700 MW short of actual load. Figure 3.8 compares schedules and loads on the afternoon of July 31, 2005.

Figure 3.8 Hour-Ahead Schedule vs. Actual Load on the Afternoon of July 31, 2005



In this same hour, the system-wide real-time price ranged between $66.43 and $69.96/MWh. RTMA pre-dispatched approximately 656 MW of exports at the beginning of the hour, and then incremented between 97 and 458 MW of internal generation throughout the hour. Thus, the total net dispatch was actually negative. Figure 3.9 shows CAISO real-time in-sequence dispatch by zone on this same afternoon.

Figure 3.9 Real-Time Dispatch and Price on the Afternoon of July 31, 2005



Real-time energy prices were relatively low during this high-load period (Hour 17) due to unscheduled energy from a variety of sources. The total actual load as measured at the end of the hour ending 17 on July 31, 2005, was 40,019 MW. The approximate energy (average MW for the hour) used to meet that load is itemized in Table 3.1. The average net in-sequence dispatch (including pre-dispatched exports) was negative 385 MW. The CAISO also dispatched RMR capacity in this hour that provided approximately 1,174 MW of real-time energy. There was also an extra 175 MW of unscheduled resources at minimum load pursuant to the MOO, (which could have provided up to 3,954 MW of energy) and 40 MW of out-of-sequence energy dispatched. The remaining shortfall (703 MW) was met from regulation and uninstructed energy from small QF resources.

Table 3.1 Energy Generation Contribution by Type: July 31, 2005 - Hour Ending 17:00

Energy Type	Contribution (MW)
Hour-Ahead Scheduled	38,309
Net In-Sequence Dispatch (Avg.)	(382)
Real-Time RMR Dispatch	1,174
Minimum-Load (Must-Offer)	175
Out-of-Sequence Dispatch	40
Regulation and Uninstructed (Avg.)	703
Total Generation	**40,019**
Actual Load	**40,019**

This example demonstrates that unscheduled energy from RMR, must-offer waivers, and other sources can result in relatively low real-time prices despite large schedule shortfalls and high system loads.

3.3.2 Price and Dispatch Volatility

As previously discussed, RTMA was designed to address significant shortcomings in the prior real-time dispatch and pricing application (BEEP).[4] One of the major concerns raised about RTMA since its implementation is a perceived high degree of price and dispatch volatility. It should be noted that a real-time imbalance energy market is inherently volatile due to the fact that it is clearing supply and demand imbalances on nearly an instantaneous basis. A high degree of price and dispatch volatility is not necessarily indicative of poor performance. Rather, the question is whether the volatility is excessive relative to what is required to efficiently clear the real-time imbalances and overlapping bids.

In October 2005, DMM conducted an in-depth market performance assessment of RTMA.[5] One of the key findings of this assessment is that the volatility of 5-minute prices in the CAISO's Real Time Market (from one interval to another within each operating hour) has increased significantly since implementation of the RTMA software. In addition, the volatility of individual generating unit dispatches in the CAISO's Real Time Market has also increased significantly since implementation of RTMA. The detailed analyses of that report and some additional analyses of RTMA performance are provided below.

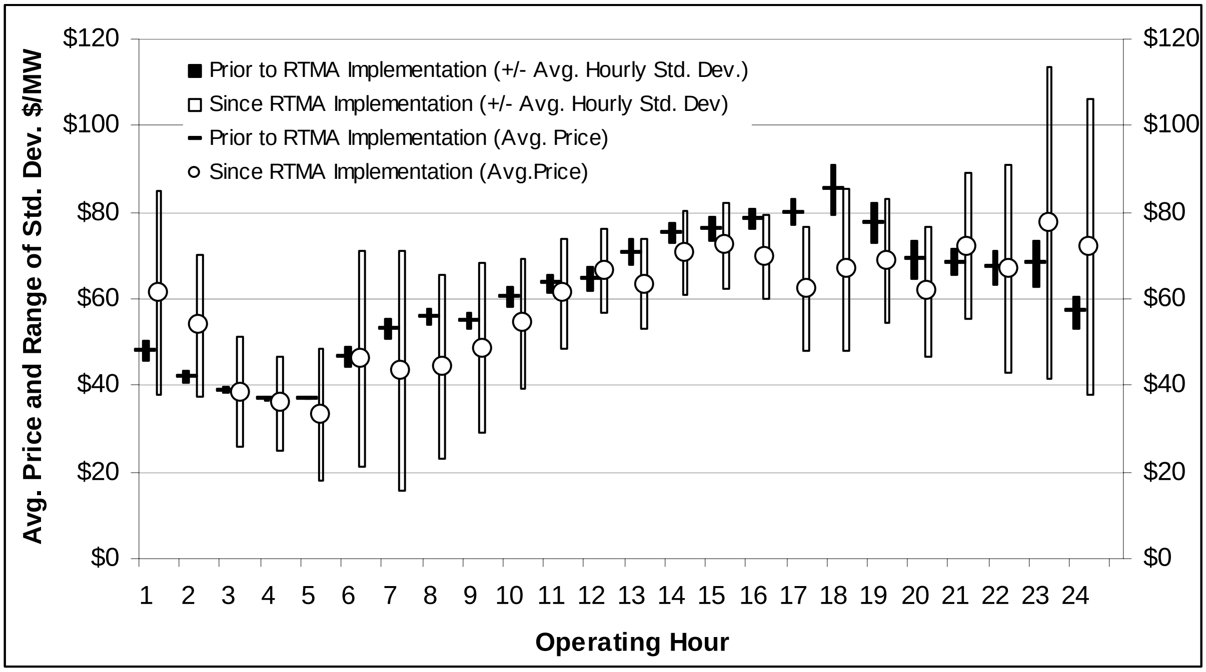
Figure 3.10 compares the average and range of RTMA interval prices for 2005 with the average and range of interval prices for the last 12-months of BEEP operation (October 2003 – September 2004). The range of prices for each hour shown in Figure 3.10 represents the average interval price for that hour, plus and minus the average standard deviation of interval prices within each operating hour.[6] As shown in Figure 3.10, overall prices have dropped slightly for most hours since RTMA was implemented, but the range of interval prices within each hour has increased significantly.

[4] Balancing Energy and Ex-Post Pricing (BEEP) software.

[5] Assessment of Real-time Market Application (RTMA) Performance, DMM Report, October 12, 2005 (http://www.caiso.com/docs/09003a6080/37/8c/09003a6080378c2c.pdf)

[6] The measure is designed to measure volatility of the prices for the pricing intervals in each hour (six 10-minute intervals in pre-RTMA and twelve 5-minute intervals under RTMA), rather than volatility in prices from day to day. Therefore, the standard deviation was first calculated for the interval prices within each hour. These individual hourly results were then averaged across the time period for each operating hour, 1-24.

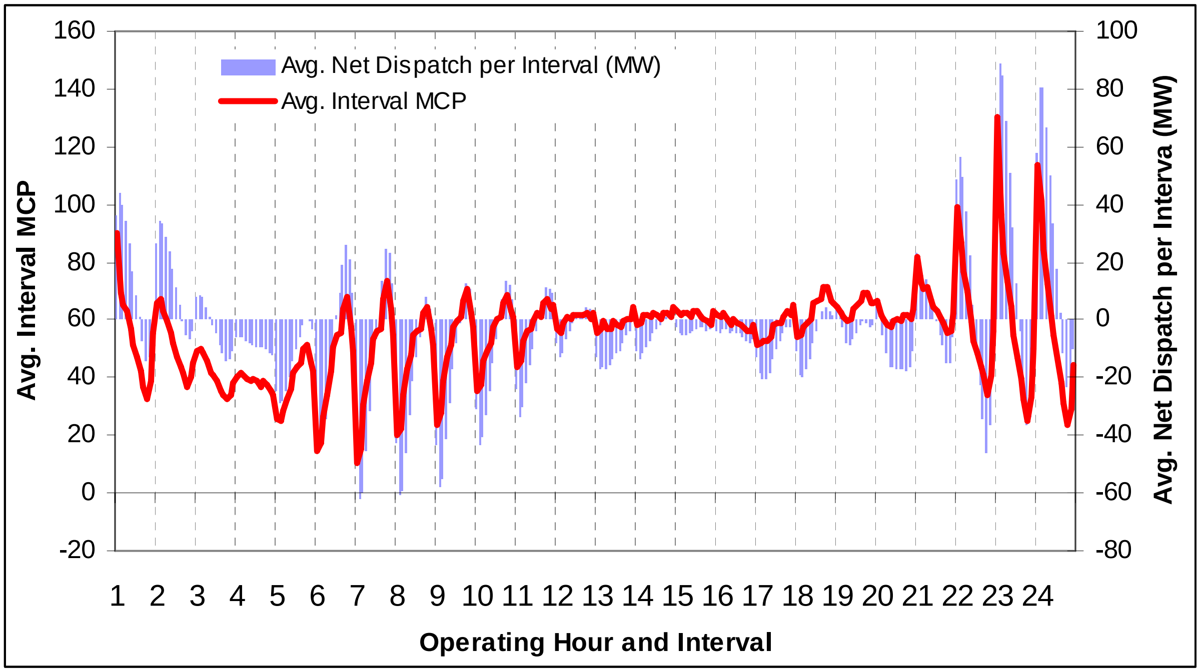
Figure 3.10 Average SP15 Hourly Prices and Standard Deviation Before (Oct 2003 – Sep 2004) and After (2005) RTMA Implementation



Analysis of price and dispatch data on a 5-minute interval basis shows that much of the intra-hour deviation of real-time prices under RTMA can be attributed to intra-hour fluctuations in demand for imbalance energy. As shown in Figure 3.11, there is a very close correlation between the intra-hour price deviations and net quantity of real-time energy dispatched each 5-minute interval since implementation of RTMA. Within each hour, prices are significantly higher when the CAISO is incrementing generation, and lower when the CAISO is decrementing generation. This pattern is especially noticeable during the morning and evening ramping hours, when the volatility of prices and imbalances within each hour are highest, as shown in more detail in Figure 3.13 and Figure 3.14, respectively.

During the morning ramp hours, prices tend to be lower during the first 15-minutes of each hour as the CAISO typically needs to decrement generation. During these intervals, the need to decrement generation stems from the fact that supply is ramping up to its new hourly schedule faster than the actual increase in loads during the first portion of each hour. Conversely, during evening ramp hours, the prices tend to be significantly higher during the first 15-minutes of each hour as the CAISO typically needs to increment generation. The need to increment generation during these intervals stems from the fact that supply is ramping down to its new hourly schedule faster than the actual decrease in loads during the first portion of each hour.

Figure 3.11 Intra-Hour Price Volatility Under RTMA in 2005



Not surprisingly, extreme RTMA interval prices (price spikes) tended to occur during the hours and intervals of the day that demand for imbalance energy was greatest. Most notably, prices spiked frequently in the first interval of the hour, as changes in supply output in response to hourly schedule changes fell out of synch with changes in actual load, and RTMA dispatched energy to correct for the difference. Another trend was regular spikes during the late-night ramp, particularly between 10:00 pm and midnight (hours ending 23:00 and 24:00). At 10:00 pm, peak-period bulk power contract deliveries end relatively abruptly in all seasons of the year, decreasing by several thousand megawatts in the course of one hour. Meanwhile, load ramps down more smoothly, and varies by season. As a result, RTMA tends to dispatch most or all resources to smooth the generation ramp change and more closely match it to load. Figure 3.12 shows the number of days in each hour and interval in which real-time prices exceeded \$200/MWh. Note that in interval 1 of hour ending 23:00 (between 10:00 and 11:00 pm), the price spiked on 70 of 365 days, or approximately 19 percent of the time, in 2005.

Figure 3.12 SP15 Incremental Price Spikes by Hour of Day and Interval in 2005

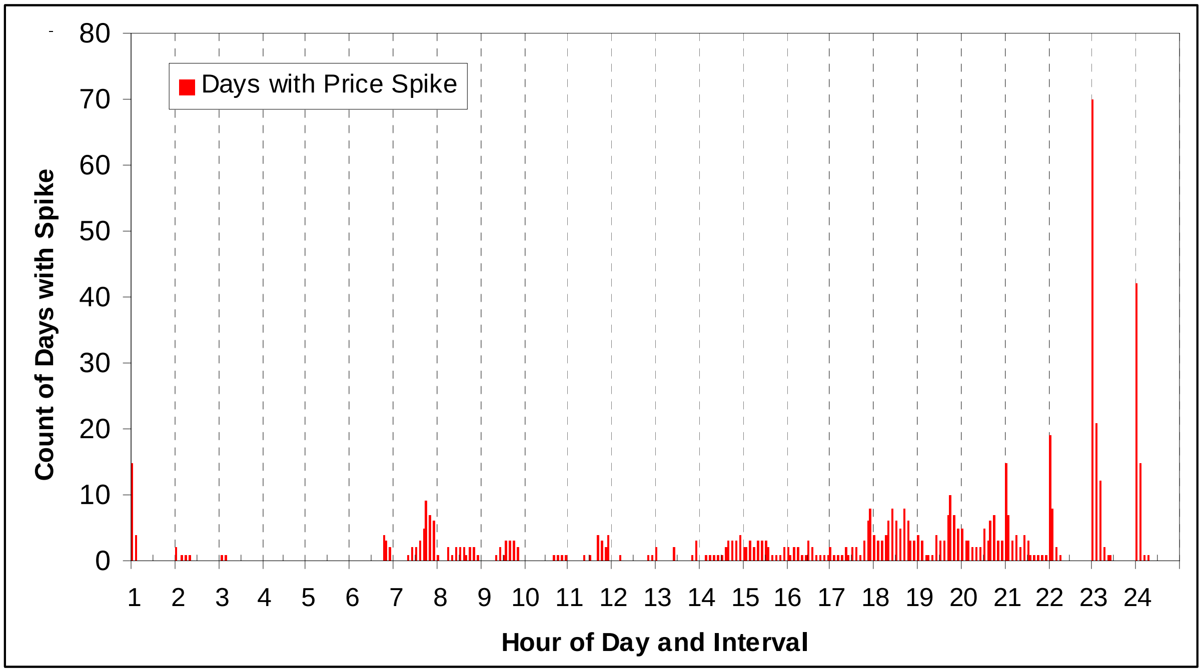


Figure 3.13 and Figure 3.14 below show average dispatch volumes and deviations of interval prices from the hourly average price for morning and late evening ramping hours in 2005.

Figure 3.13 Intra-Hour Price Volatility during Morning Ramping Hours (2005)

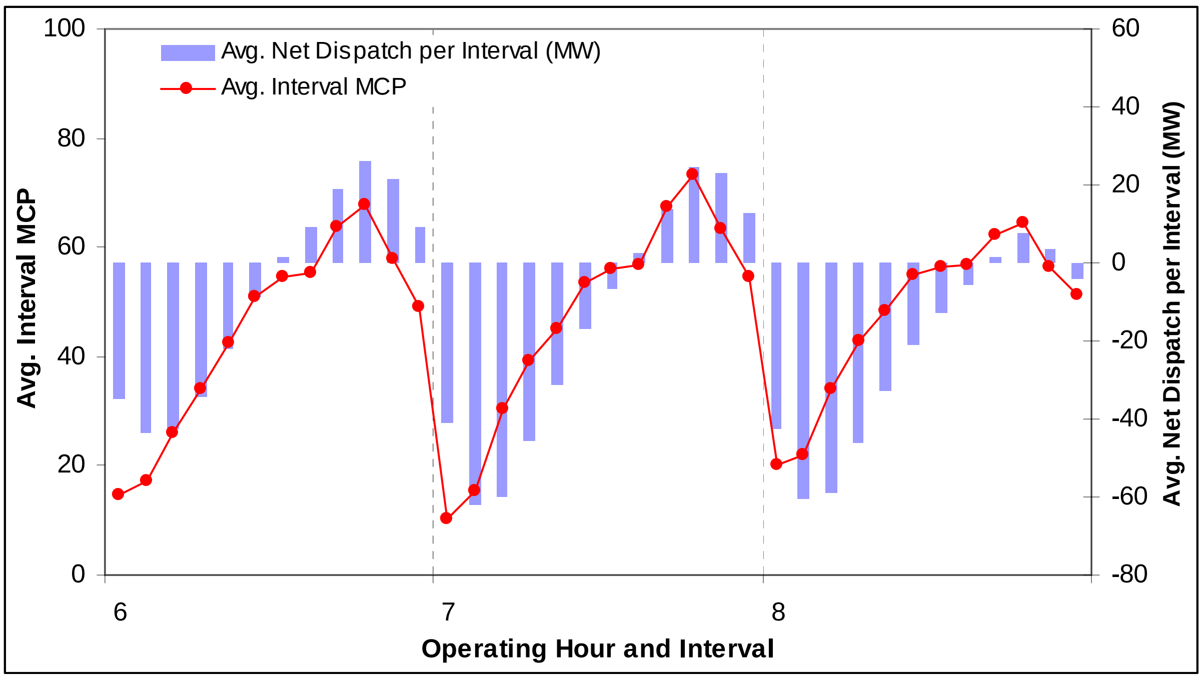
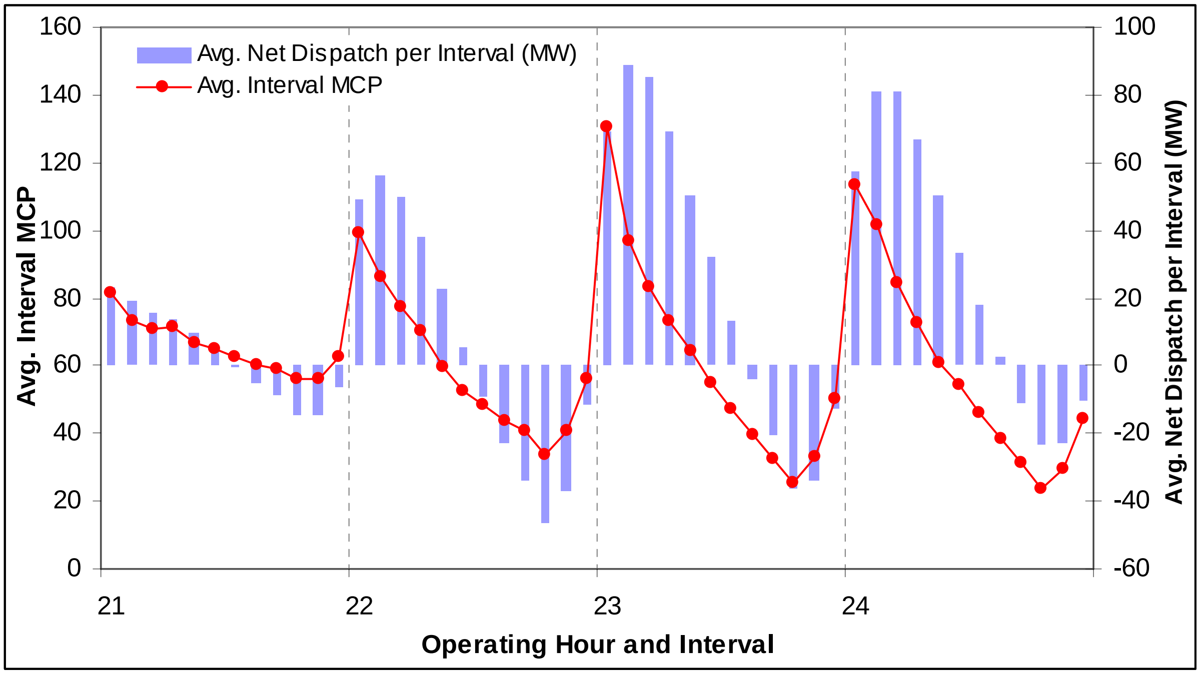
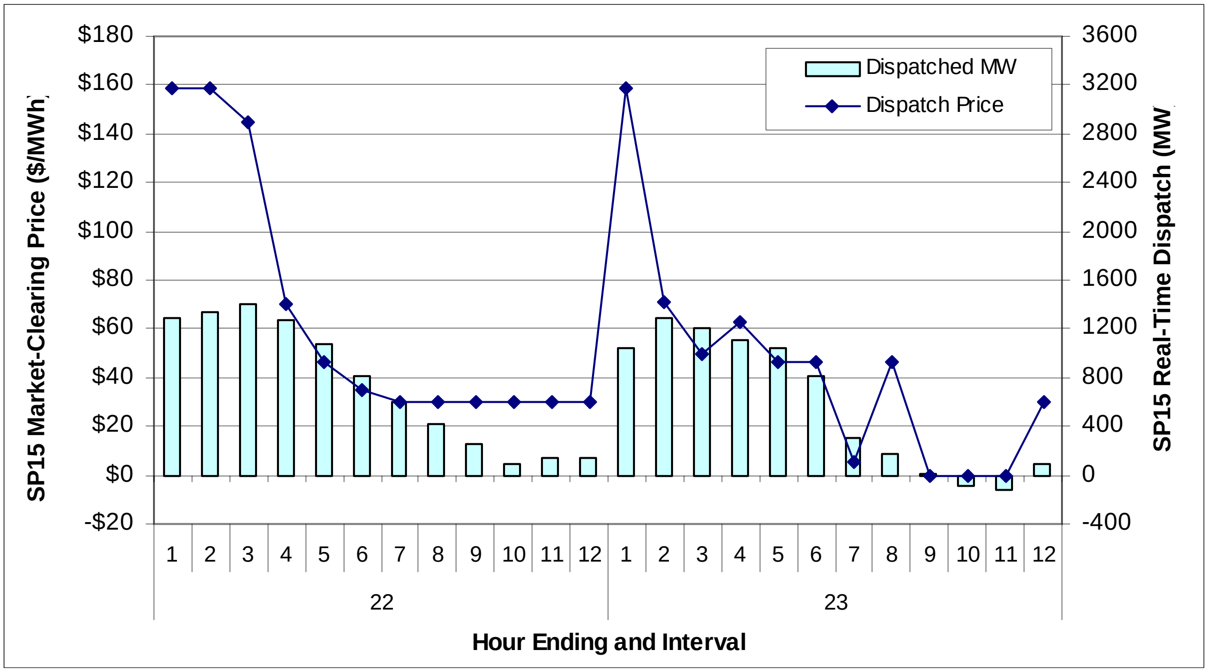


Figure 3.14 Intra-Hour Price Volatility during Evening Ramping Hours (2005)



Although demand for imbalance energy tends to peak in the second or third intervals of the evening hours (as shown in Figure 3.14 above), 5-minute prices tend to peak in the first interval and then drop in subsequent intervals through the hour. This trend can be attributed to changes in the available supply during each of these 5-minute intervals due to ramp limitations of lower priced resources. Figure 3.15 and Figure 3.16 below show an example of this using actual bid and dispatch data for an hour ending 23 in June 2005.

Figure 3.15 Dispatch and Pricing Example for Typical Evening Ramping Hours



As shown in Figure 3.15, the amount of imbalance energy dispatched during hour ending 23 rose sharply during the first interval with the price spiking to $159/MWh. While demand continues to rise in interval 2, the price dropped to $71/MWh. The cause of this pattern is illustrated in Figure 3.16 and Figure 3.17. As shown in Figure 3.16, the actual available supply of bids during the first 5-minute interval of an hour is often dramatically lower than the total amount of supply bids available over the entire operating hour. As shown in Figure 3.17, the supply of real-time energy bids during interval 2 is significantly higher than in interval 1 after taking into account ramp rates of each resource. During the first interval in this example hour, the price was set at $169/MWh by a fast-ramping resource dispatched to meet demand. During the second interval, however, additional energy was available from the lower cost resources, so that the higher cost bids are no longer needed to meet demand. As a result of this shift in the 5-minute supply curve, the price cleared at only $71/MWh during the second interval, despite the fact that demand for imbalance energy actually rose. This example also illustrates why some units may be receiving changes in dispatch direction, and why the number of units receiving a change in dispatch direction tends to be highest during the second interval of each hour.

Figure 3.16 Total Hourly Incremental Energy Supply vs. Ramp-Constrained Supply

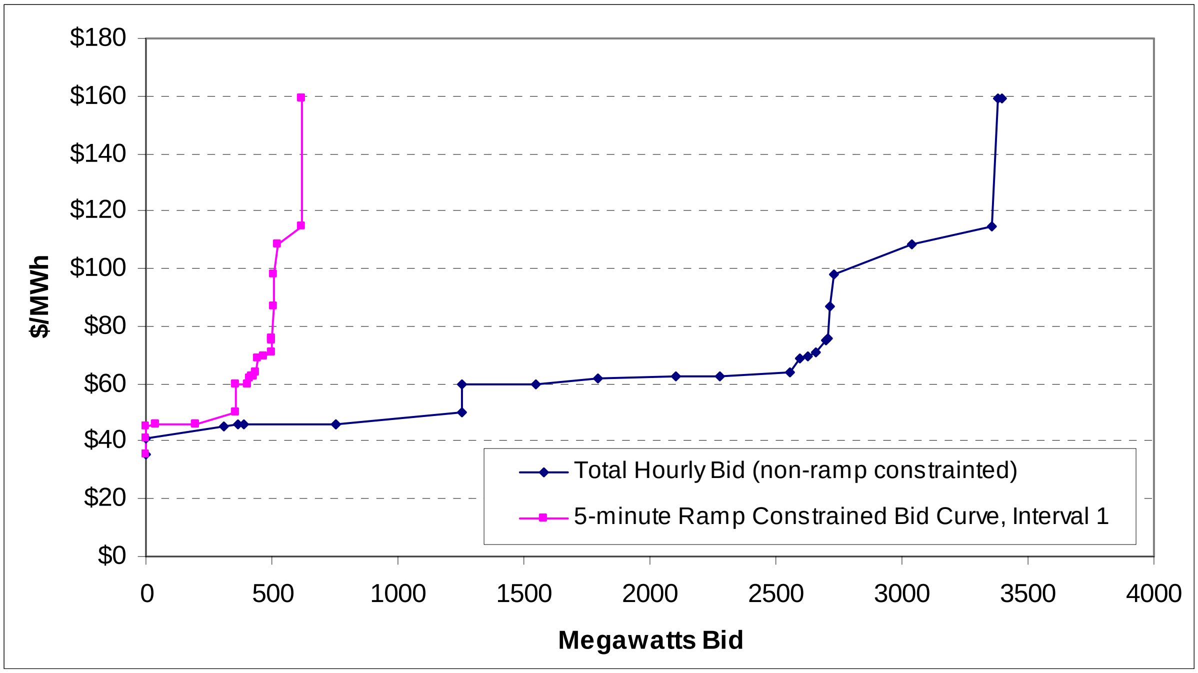
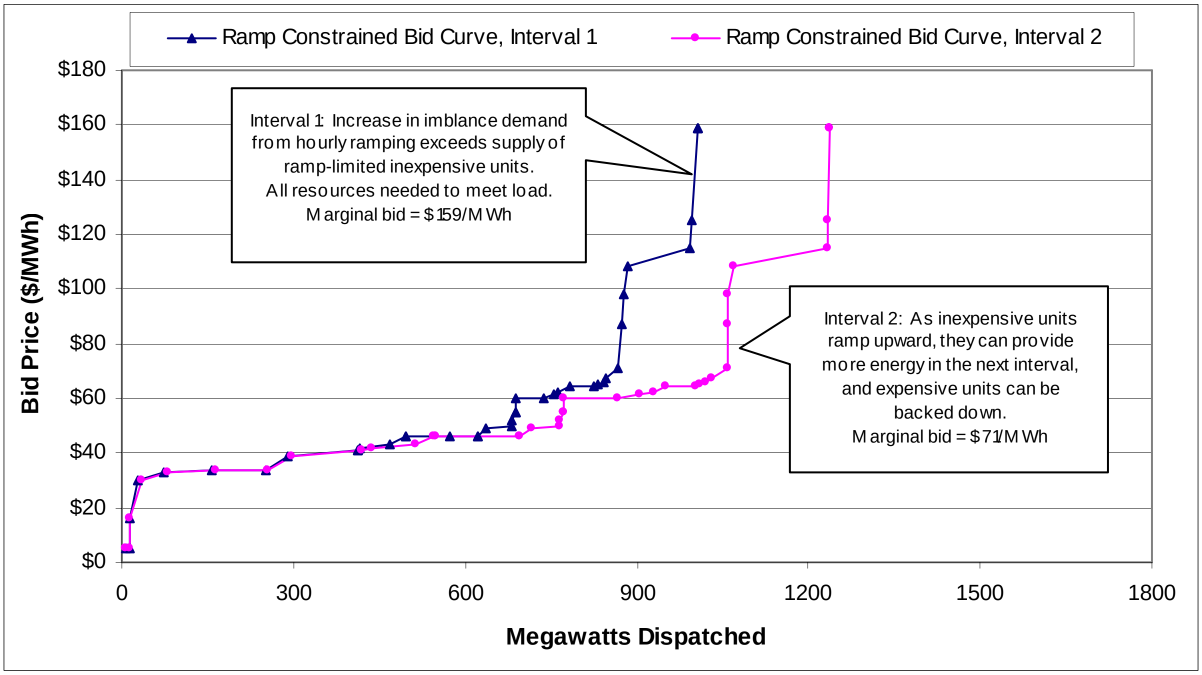


Figure 3.17 Ramp-Constrained Supply Available During Intervals 1 and 2



One of the major market design changes incorporated into the RTMA software was the economic dispatch or market clearing of all incremental and decremental bids for supplemental energy. Rather than simply dispatching the bids necessary to meet the projected imbalance of the CAISO system, RTMA dispatches all remaining incremental and decremental bids for supplemental energy with "overlapping" prices (i.e., incremental bids offered at a price lower than the price of decremental energy bids submitted by other participants). Analysis of RTMA dispatch data indicates that a large portion of energy dispatched in RTMA has been dispatched as part of the process of clearing real-time market bids, rather than to simply meet CAISO system imbalance needs. This indicates that this market design change may also be a significant cause of the increased volatility of prices and unit dispatches since implementation of RTMA.

In order to quantitatively assess the volatility of dispatches within each hour before and after RTMA, a measure of dispatch volatility was developed that counts the number of times each unit is dispatched by RTMA in a different direction than the previous RTMA dispatch within the same hour.[7] Under normal operating conditions, units may receive one or two switches in dispatch direction each hour. However, three or more switches in dispatch direction during any hour may indicate excessive volatility.

Based on this measure of dispatch volatility, the volatility of unit dispatches in the CAISO's Real Time Market does appears to have increased since implementation of RTMA. Figure 3.18 and Figure 3.19 show the average number of units that received a change in dispatch direction in each 5- or 10-minute interval of each operating hour before and after RTMA was implemented, respectively. As shown in these figures, there is a similar hourly and daily pattern in dispatches both before and after implementation of RTMA. At the beginning of each operating hour, a

[7] For example, if a unit is dispatched up in the first interval, and is then dispatched down in a subsequent interval within the same hour, the unit has received one "dispatch direction switch." If the same unit was then dispatched back up in yet another interval within the same hour, this would count as a second switch in dispatch direction that hour.

significant number of units are dispatched in a different direction, as new hourly schedules take effect. In addition, the number of units dispatched in a different direction increases significantly during the morning and evening ramping hours, during which the change in schedules and loads that must be met by imbalance energy is especially high. While these same patterns existed prior to implementation of RTMA, the overall number of units dispatched in different directions under RTMA has increased significantly across all intervals and hours of the day.

Figure 3.18 Average Number of Units Receiving Change in Dispatch Direction by Operating Hour and Interval (Pre-RTMA, October 2003- August 2004)

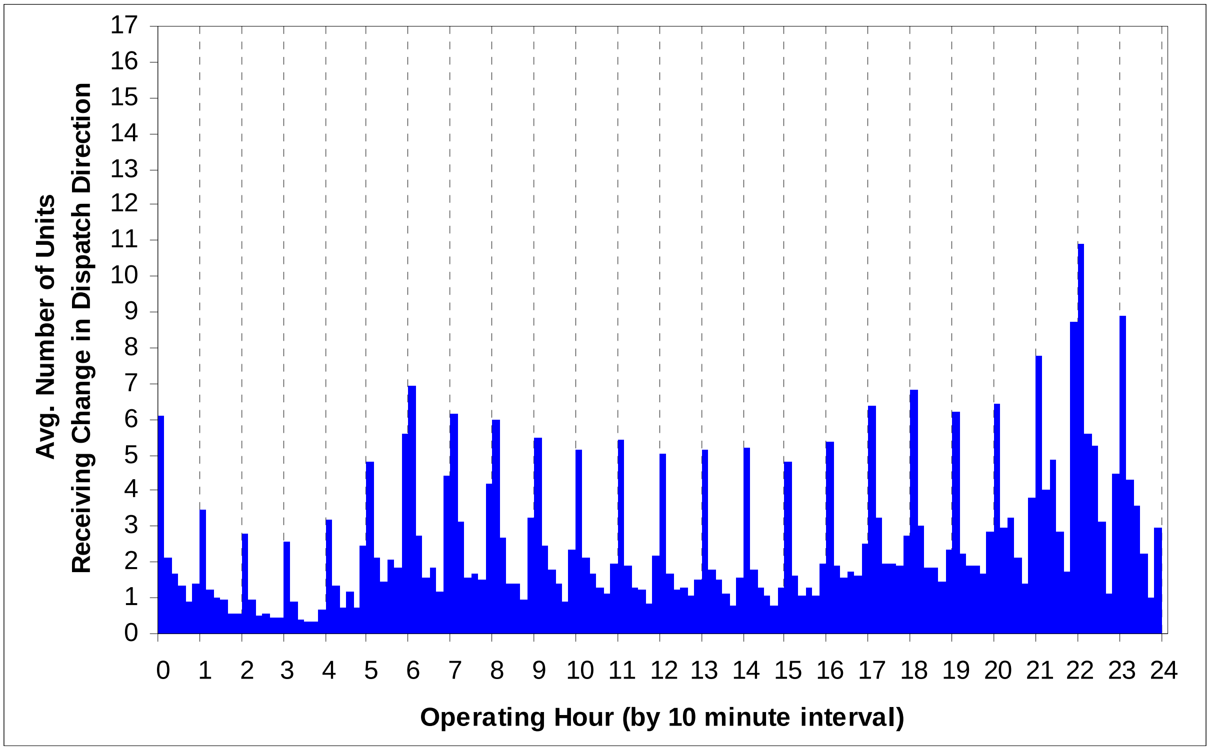


Figure 3.19 Average Number of Units Receiving Change in Dispatch Direction by Operating Hour and Interval (Post-RTMA, October 2004- August 2005)

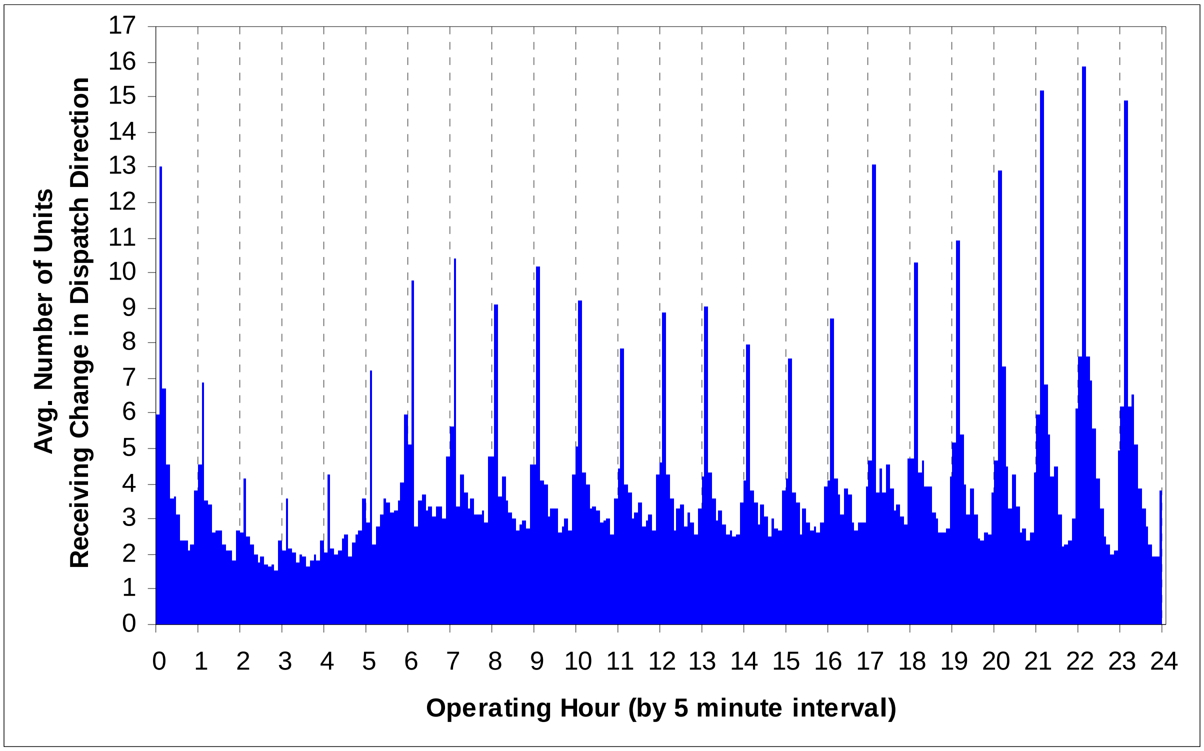


Figure 3.20 and Figure 3.21 show the average percent of units in each operating hour that experienced a change in dispatch direction for the period from October - August, before and after implementation of RTMA.

Figure 3.20 Percentage of Units Dispatched by BEEP with One or More Switches in Dispatch Direction each Hour (October 2003-August 2004)

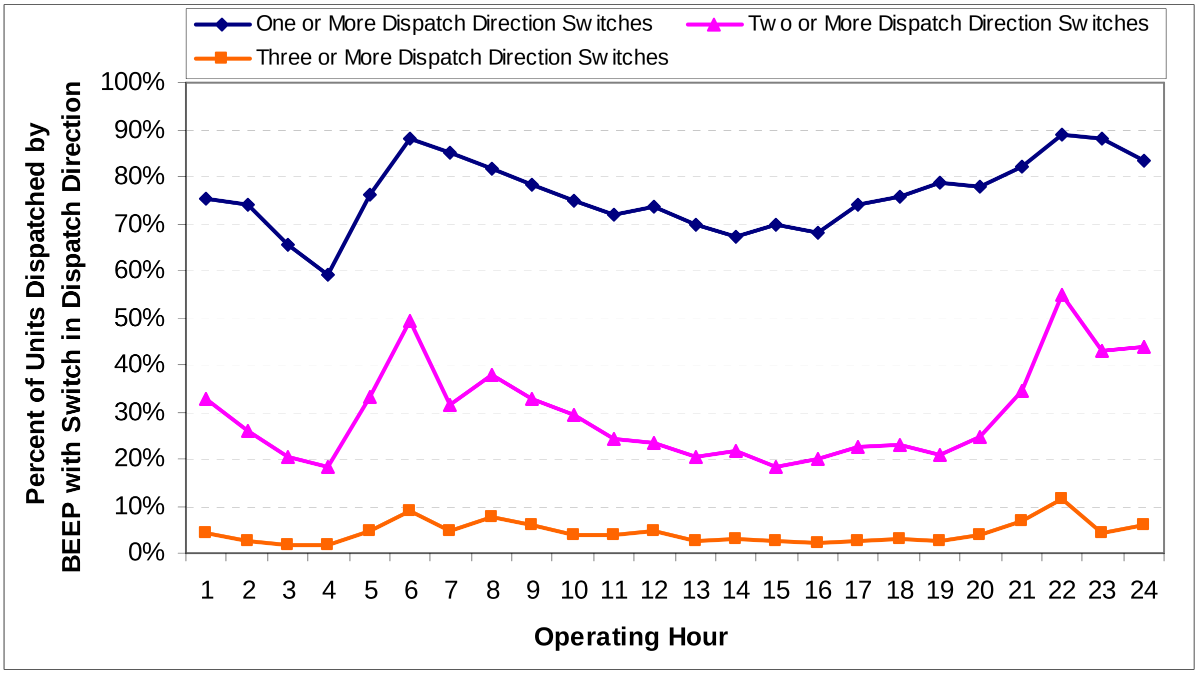
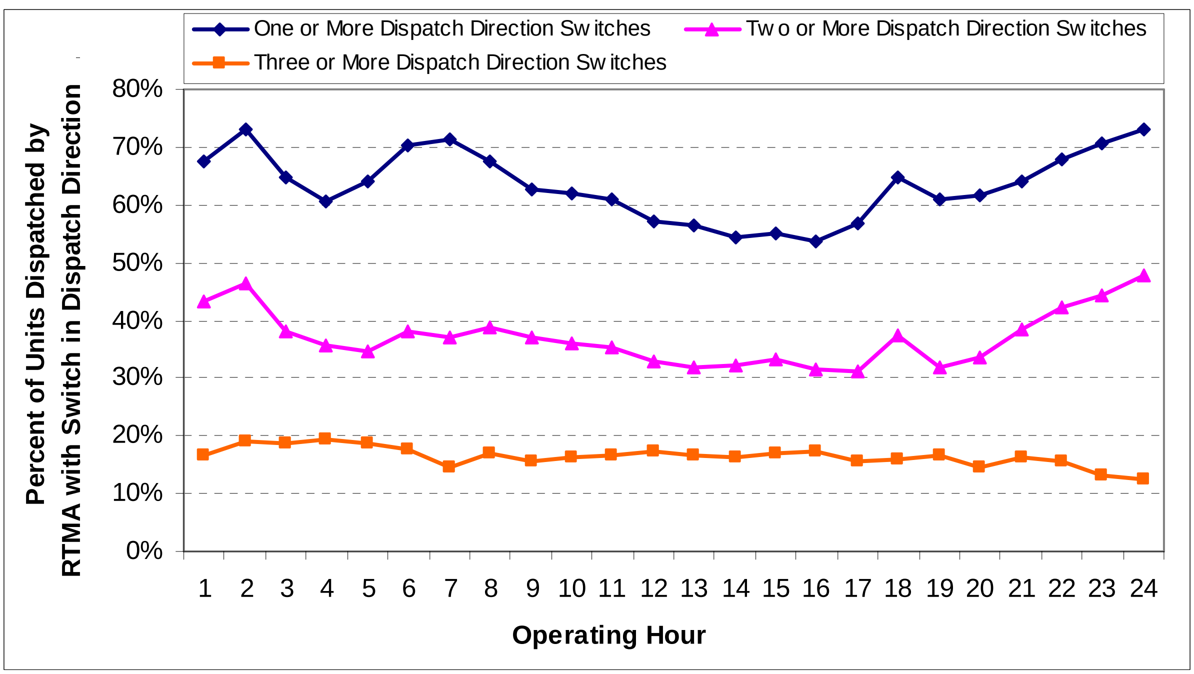


Figure 3.21 Percentage of Units Dispatched by RTMA with One or More Switches in Dispatch Direction each Hour (October 2004-August 2005)



3.3.3 Settlement of Pre-Dispatched Inter-tie Bids (Amendment 66)

As discussed in Chapter 1, the RTMA design included two significant modifications relating to the dispatch and settlement of import/export bids over inter-ties with neighboring control areas.

- **Market Clearing of Import/Export Bids**. One of the central features of RTMA was the establishment of a market clearing mechanism, under which bids for incremental energy to provide additional energy at a price lower than decremental bids to purchase energy would be dispatched or “cleared” against each other. The RTMA software applies this market-clearing algorithm to all remaining bids after bids needed to meet projected CAISO imbalance energy demand are accepted. This market clearing mechanism, which is incorporated in all other major ISO market designs, was incorporated into the RTMA software to promote greater economic efficiency, encourage participation in the CAISO Real Time Market, and avoid problems with the alternative “Target Price” mechanism previously employed to resolve incremental and decremental bids with such price overlap.
- **Bid or Better Settlement Rule for Import/Export Bids.** A second key feature of RTMA as initially implemented was settlement of pre-dispatched import/export bids on a “bid or better” basis. Under the “bid or better” settlement rule, hourly import bids pre-dispatched by the CAISO were paid the higher of their bid price or the ex-post MCP subsequently set during the operating hour by resources within the CAISO system dispatched on a 5-minute basis. Conversely, pre-dispatched export bids were charged the lower of their bid price or the ex-post MCP. This settlement rule was adopted to encourage participation in the Real Time Market by imports and exports, which are prohibited from setting the real-time market price under market rules established by the Federal Energy Regulatory Commission (FERC). Although RTMA pre-dispatches import/export bids that were anticipated to be lower/higher than the ex-post MCP, actual system conditions can frequently result in MCPs that are significantly lower/higher than import/export bids pre-dispatched. In cases when MCPs were lower/higher than bid prices of pre-dispatched import/export bids, additional payments or decreased charges applied to pre-dispatched import/export bids were recovered through uplift charges assessed to other CAISO participants based on uninstructed deviations and gross load.

In early 2005, the combination of these two new market design features resulted in an increasing volume of off-setting import/export bids being cleared in the CAISO markets, and increasing uplift charges being assessed under the “bid or better” settlement rule. Under the “bid or better” settlement rule, the CAISO incurred uplift charges whenever actual ex-post MCPs were either higher or lower than the projected prices used to clear import/export bids. For example, when ex-post MCPs were higher than the project prices used to clear import/export bids, uplifts were paid to pre-dispatched imports bid at prices in excess, but export bids cleared against these import bids were only charged the ex-post MCP. Conversely, when ex-post MCPs were lower than the project prices used to clear import/export bids, uplifts were paid to pre-dispatched exports bid at prices lower than the ex-post MCP, but import bids cleared against these export bids were paid the full ex-post MCP.

In spring 2005, this basic market design flaw was exacerbated by significant divergences between the projected prices used to clear import/export bids and the actual ex-post MCPs, which are based on an average of the actual 5-minute interval prices. One of the primary causes of this divergence was the way that the RTMA software accounted for uninstructed deviations by resources within the CAISO. Specifically, the initial RTMA software projected uninstructed deviations in future dispatch intervals by assuming that generation internal to the CAISO that was deviating from its schedule would seek to return to its scheduled operating level. This approach tended to underestimate positive uninstructed energy provided by many units, such as run-of-river hydro, Qualifying Facilities (QFs), and units operating at minimum load due to must-offer waiver denials. Since the RTMA software systematically underestimated uninstructed energy from these resources, ex-post MCPs tended to be significantly lower than projected prices used in pre-dispatching import/export bids. Combined with the basic design flaw of the “bid or better” settlement rule, this systematic price divergence created excessive uplift for export/import bids dispatched under the market-clearing feature of RTMA. This flaw in how uninstructed deviations were treated in RTMA was identified relatively quickly after RTMA implementation, but due to the lead-time for development and implementation of an enhanced algorithm this problem was not fixed until March 24, 2005.

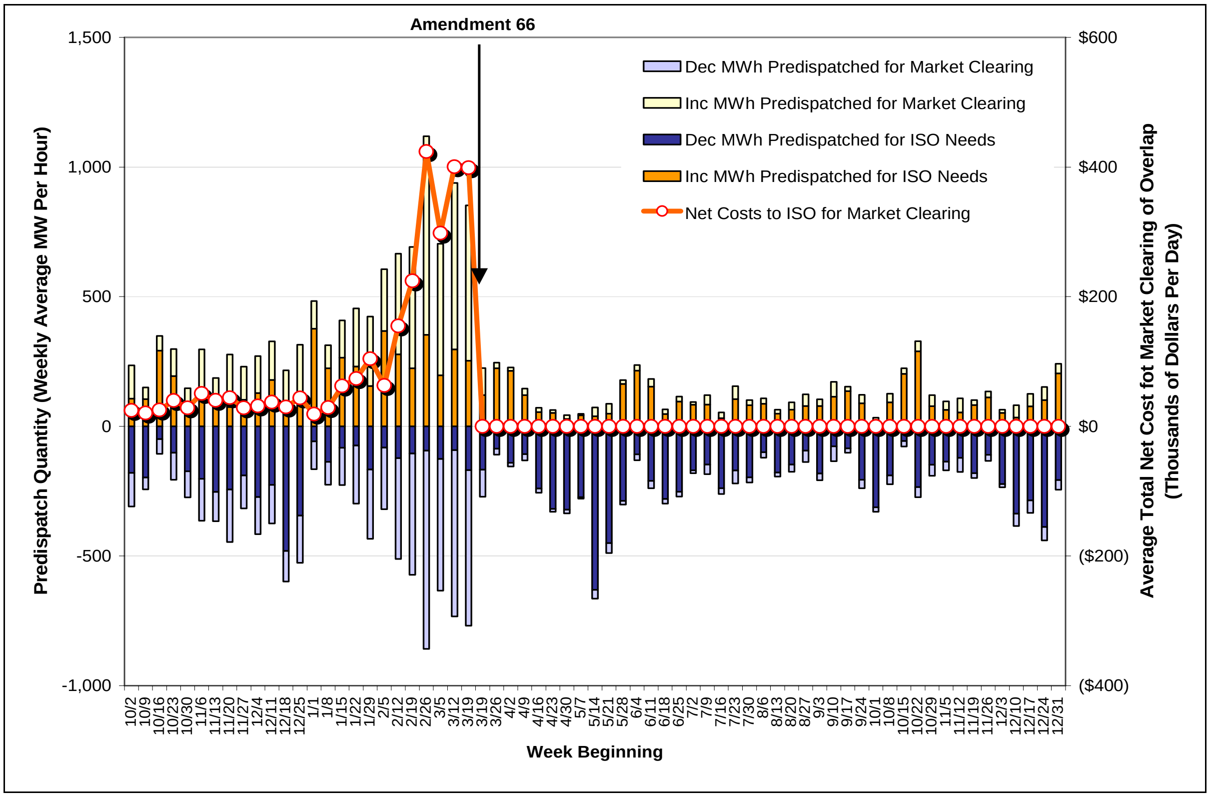
In addition, analysis of participant bidding behavior suggests that some market participants took advantage of these market design flaws and conditions by bidding imports and exports in a manner that increased the probability of having off-setting import and export bids accepted in the pre-dispatch, which resulted in uplift payments being made for the difference between bid prices and the ex-post MCP, despite the fact that no net energy was being delivered to the CAISO system as a result of these off-setting import and export bids.

As a result of the systematic and often excessive uplift charges incurred by off-setting import and export bids pre-dispatched as part of the market clearing feature of RTMA, the CAISO filed Amendment 66 with FERC to replace the “bid or better” settlement rule for pre-dispatched import/export bids to an “as-bid” market design. Under an “as-bid” settlement, pre-dispatched import bids are paid the bid price, while pre-dispatched export bids are charged the bid price. The change to an “as-bid” settlement rule was chosen by the CAISO as a second-best option, with a preferred option being settlement of all pre-dispatched import/export bids at a separate pre-dispatch MCP that would be applied to all hourly import bids pre-dispatched. However, the single price pre-dispatch market option could not be implemented without a significant delay and expenditure of resources.

Once Amendment 66 was implemented, the volume of bids dispatched for market-clearing (beyond bids pre-dispatched for meeting CAISO system imbalance needs) and the associated uplift costs declined dramatically (Figure 3.22). Total uplift costs incurred prior to the CAISO’s March 23 filing were estimated at $33.6 million, with about $18.6 million of these uplift costs attributable to clearing of overlapping (or offsetting) incremental and decremental bids under RTMA. Costs attributable to clearing of overlapping (or offsetting) incremental and decremental bids averaged about $400,000 per day in the month prior to Amendment 66.

The volume of offsetting incremental and decremental energy bids pre-dispatched by the CAISO to clear the market has also been dramatically reduced under the “as-bid” settlement rule. Since the effective date of Amendment 66 through the end of 2005, an average of only about 30 MW of off-setting incremental and decremental bids have been pre-dispatched each hour, as opposed to an average of about 600 MW per hour in the month prior to implementation of Amendment 66.

Figure 3.22 Average Hourly Volume of Bids Pre-Dispatched by the CAISO and Average Daily Costs to CAISO of Market Clearing



Another indication that significant improvements have been made in RTMA since the change from the "bid or better" to an "as-bid" settlement rule is that prices for pre-dispatched energy from import/export bids have tracked much more closely with Real Time Market prices set by resources within the CAISO system subsequently dispatched within each operating hour. Figure 3.23 and Figure 3.24 show the trend in volumes and net prices of incremental and decremental energy pre-dispatched to balance CAISO system demand, and compare the net prices for pre-dispatched incremental and decremental energy with the value of this pre-dispatched energy calculated using the corresponding hourly ex-post MCP set by resources dispatched within the CAISO system. As shown in Figure 3.23, prior to implementation of Amendment 66, the cost of pre-dispatched incremental energy (including uplifts) was often significantly higher than the value of this incremental energy as reflected in the MCPs set in the CAISO real-time 5-minute imbalance market. Similarly, as shown in Figure 3.24, prior to implementation of Amendment 66, the cost of pre-dispatched decremental energy (including uplifts) tended to be systematically lower than the value of this decremental energy calculated at the ex-post MCPs set in the CAISO real-time 5-minute imbalance market.

Figure 3.23 Total Net Cost Paid for Incremental Energy Pre-dispatched to Balance CAISO System Demand

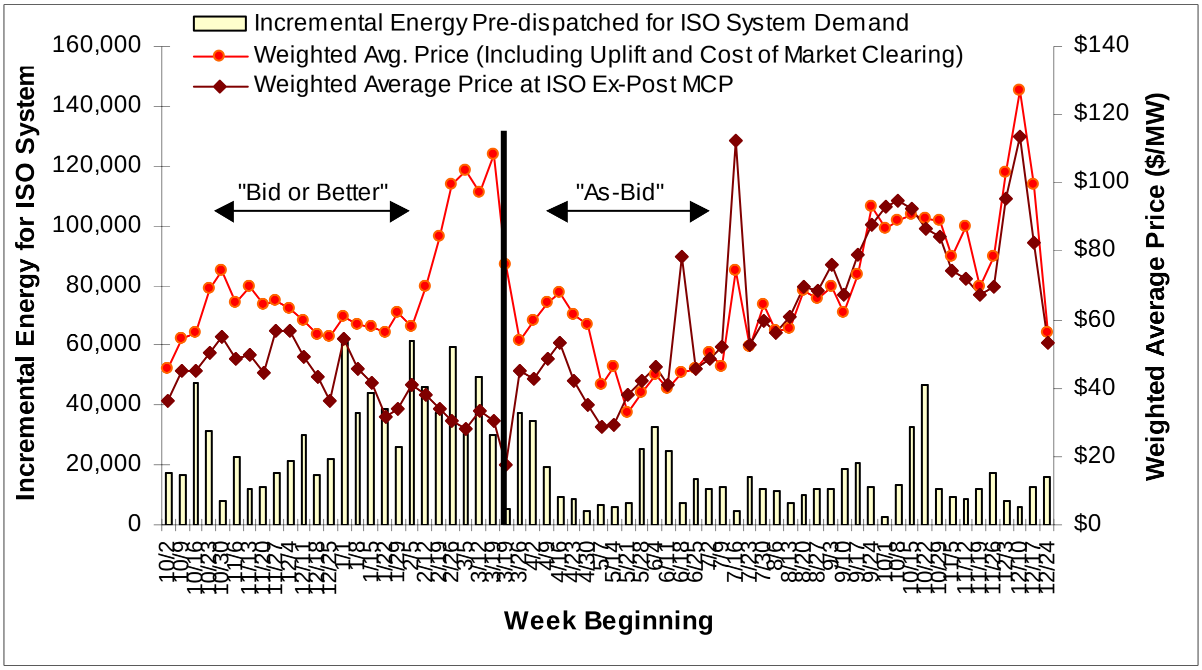
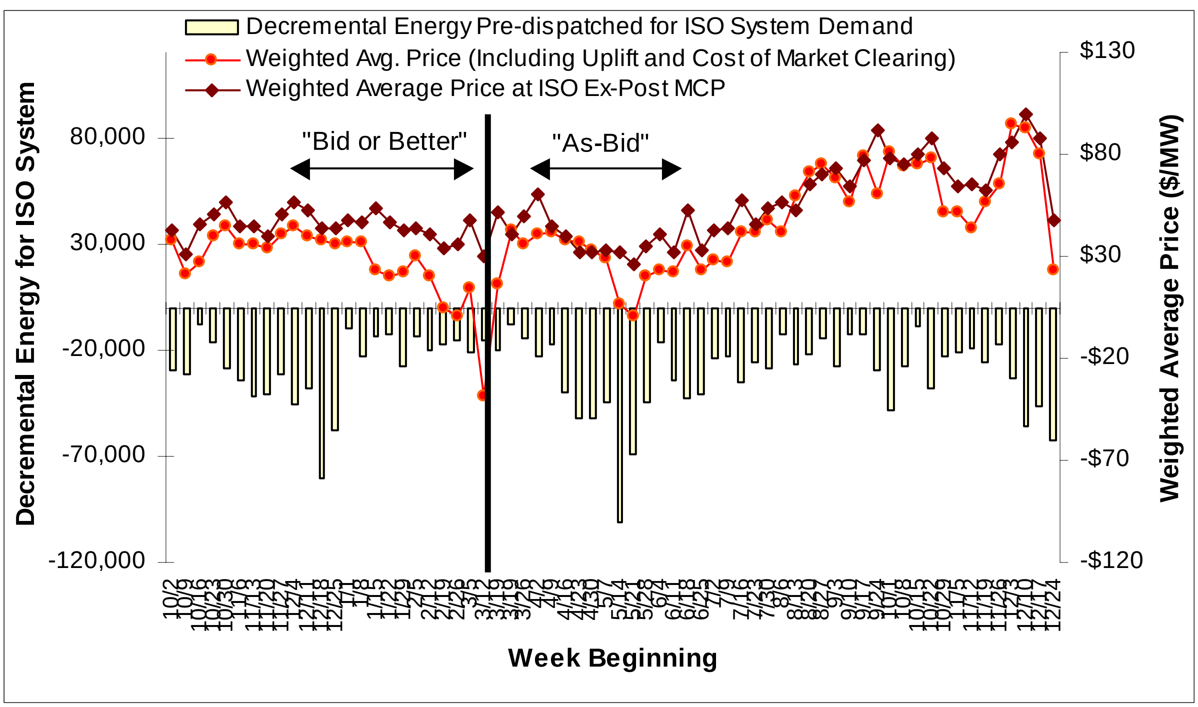


Figure 3.24 Total Net Price Received for Decremental Energy Pre-dispatched to Balance CAISO System Demand



The reduction in the difference between pre-dispatched energy costs and real-time MCPs is due to a combination of the elimination of uplift payments made under the “bid or better” settlement rule and the improved algorithm within RTMA used to account for uninstructed deviations by generating resources within the CAISO that was implemented at virtually the same time as the switch to an “as-bid” settlement rule on March 25, 2005. The divergence in pre-dispatch and real-time energy prices for incremental energy during mid-April to mid-June corresponds to a period when the CAISO needed to consistently decrement large volumes of resources to balance loads, due to a variety of seasonal conditions, such as low loads and inflexible output from hydro resources due to high spring runoff.

The replacement of the “bid or better” settlement rule with an “as-bid” settlement rule for imports/export created a concern among some market participants that this change would reduce the liquidity of import/export bids submitted to the CAISO market. To date, however, the CAISO has not experienced problems in terms of bid insufficiency or liquidity of incremental energy import bids since the switch to an “as-bid” market under Amendment 66. In fact, the volume of incremental energy bids has typically been higher this year than during the comparable period in 2004, and has consistently been well in excess of the quantity of bids actually pre-dispatched.

As shown in Figure 3.25, the volume of overall net imports scheduled or bid into the CAISO system remained comparable to pre-Amendment 66 levels throughout the summer months under the “as-bid” settlement rule. Net scheduled imports increased significantly, and the volume of incremental real-time energy bids remained far in excess of amounts of imports actually pre-dispatched. Similarly, as shown in Figure 3.26, the volume of decremental real-time energy export bids submitted to the CAISO Real Time Market increased and remained far in excess of amounts of imports actually pre-dispatched for most hours.

Bid prices for incremental energy from imports have increased and bid prices for decremental energy for export have decreased somewhat since implementation of Amendment 66 relative to bilateral market prices. However, this would be expected under an “as-bid” settlement rule, as participants adjust their bids to compensate for the expected value from uplift payments they previously received under the “bid-or-better” settlement rule. When the actual value of the additional benefits received under the “bid-or-better” settlement rule are incorporated into the analysis, bid prices for incremental energy imports and decremental energy exports both appear to have decreased moderately.

Figure 3.25 Net Scheduled Imports, Real-Time Energy Import Bid Volumes, and Pre-Dispatched Imports - Hourly Averages by Week (Peak Hours 13-20)

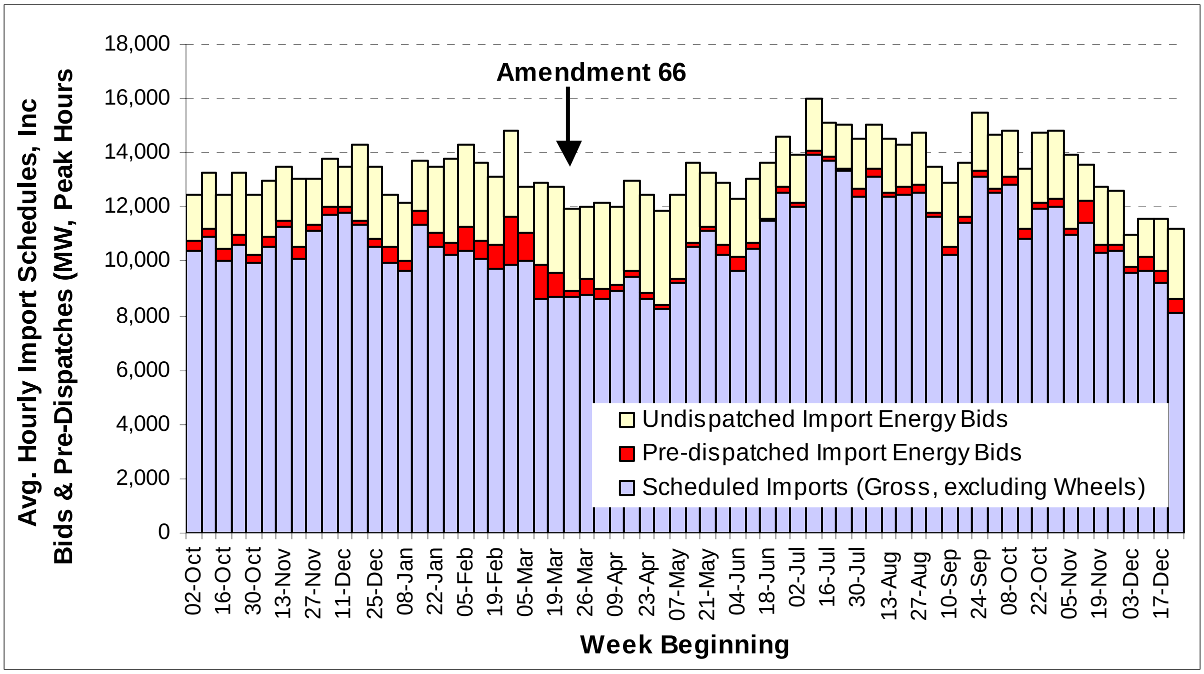
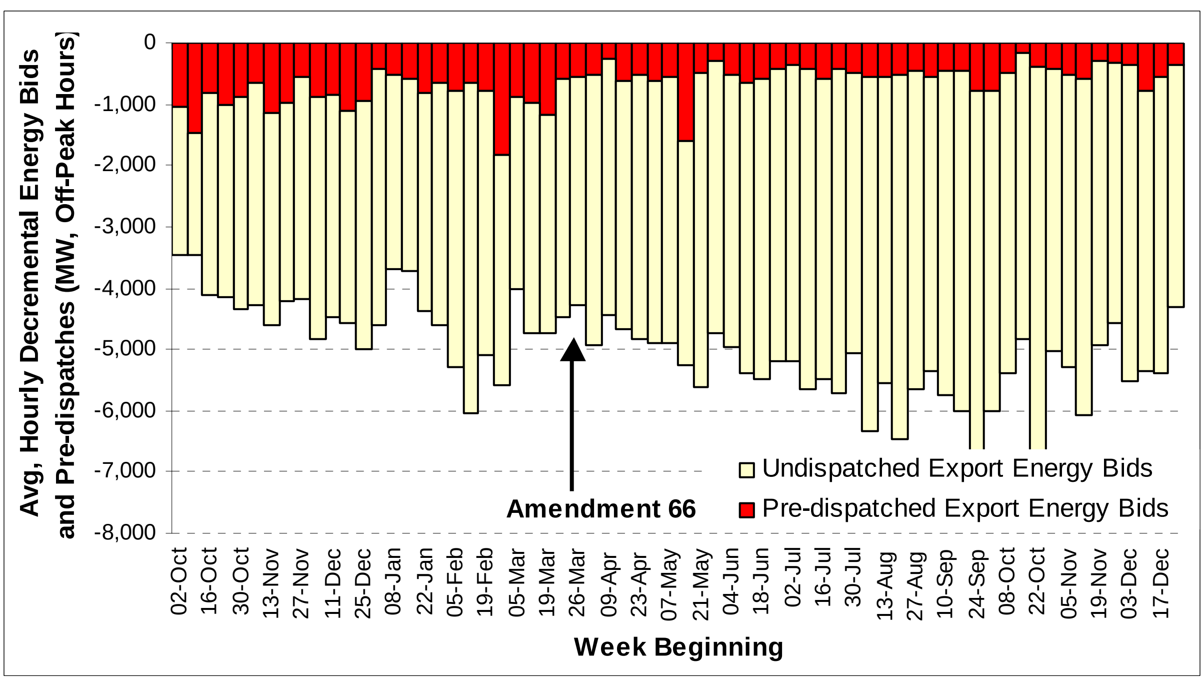


Figure 3.26 Real-Time Energy Export Bid Volumes And Pre-Dispatched Exports - Hourly Averages by Week (Off-Peak Hours 1-8)



3.3.4 RTMA Load Bias and Use of Regulation

The RTMA software has greatly reduced the frequency and degree of dispatcher judgment or intervention required to run the real-time imbalance market. For example, under the BEEP software, dispatchers calculated the imbalance requirement for the next 10-minute interval and communicated that requirement to the Grid Resource Coordinator who would then implement a specific dispatch solution to fulfill these requirements. Significant dispatcher knowledge and judgment was required to assess how to factor inputs such as: actual units start-up times, ramp rates, increased or decreased system load, known and anticipated imbalance energy needs, and conditions in future intervals. The RTMA software continues to allow for dispatcher adjustments, but focuses dispatcher input primarily on one single input: the *load bias*, which is an optional adjustment that can be entered by the dispatcher to RTMA's internally generated projection of imbalance energy requirements over the next one to two hour period.

Grid Operations has established an operational goal of utilizing a load bias in the RTMA software in no more than 40 percent of all intervals. As shown in Figure 3.27, while the type of load bias has varied significantly from month-to-month in response to system conditions, dispatchers have utilized the load bias in no more than about 40 percent of the intervals within each month of 2005 except for January. This represents a dramatic reduction following the first four months under RTMA (October 2004 - January 2005).[8]

Dispatchers utilize the load bias function of RTMA to account for actual system conditions or anticipated conditions within the next few intervals, which include:

- Returning regulating units to their Dispatch Operating Points or Preferred Operating Point (POP). This basic reliability requirement is required under the CAISO Tariff, and may be the most frequent reason for the use of load bias.
- Mitigating congestion on transmission inter-ties by over-generating to help reduce inter-tie loading.
- Mitigating intra-zonal congestion. When dispatchers determine that resources must be incremented or decremented in real-time for intra-zonal congestion, the load bias may be used to increase the response time of RTMA in adjusting other resources as needed to balance overall system loads and resources.
- Managing sudden increases or decreases in imbalance energy conditions as relatively large blocks of pump loads are turned off or on.
- Compensating for load forecast error. Dispatchers may utilize the load bias to compensate for very short-term load forecast error if RTMA's load forecast appears to be lagging or systemically off.
- Managing uninstructed deviations. While RTMA does forecast uninstructed deviations on an ongoing basis based on an enhanced algorithm, dispatchers may utilize the load bias to account for uninstructed deviations if RTMA treatment of uninstructed energy appears to be lagging or is systemically off.
- Facilitating more rapid response to an unplanned loss of a generation or transmission facility. The load bias may be used to compensate for a sudden loss of resources or transmission outage that may be known to dispatchers, but has not yet been registered or fully incorporated into RTMA.

[8] Actual load bias data are not available for the first month of RTMA (October 2004).

- Compensating for differences in unit ramping characteristics not accurately modeled in RTMA. For example, combined cycle and other thermal units may have temporary operating constraints that are not modeled in RTMA. To the extent that dispatchers are aware of these constraints and how they limit the ramping ability of a unit, the load bias may be used to compensate for the difference between automated RTMA dispatch instructions and the dispatchers' estimate of actual unit responses to these dispatches.
- Restoring operating reserve. If resources providing operating reserve have been dispatched to provide real-time energy, the load bias may be used to more quickly dispatch supplemental energy bids in order to restore operating reserve margins.
- Adjusting for known telemetry error. In the event that telemetry from a resource fails or is determined to be significantly in error, the load bias may be used to adjust for this error.
- Compensating for manual and automatic time error correction. When the system frequency is modified (i.e., above or below 60 Hz) to correct time errors within the CAISO control area, the load bias may be utilized to help maintain this adjusted frequency.

Under all of the situations described above, the use of the load bias would help maintain system reliability by achieving a better balance between loads and resources, reducing use of regulation resources, and reserving regulation capacity for use in responding to sudden system imbalances.[9] As described later in this section of the report, analysis of load bias usage patterns by DMM also indicates that the load bias is utilized primarily to reduce significant upward or downward deviations from the preferred operating point of resources providing regulation, and thereby maintain ramping capability of regulation capacity.

In order to encourage operators to limit adjustments to RTMA on a minute-by-minute basis, Grid Operations has established an operational goal of utilizing a load bias in the RTMA software no more than 40 percent of all 5-munite intervals. As shown in Figure 3.27, while the type of load bias has varied significantly from month to month in response to system conditions, Operations staff have utilized the load bias in no more than about 40 percent of the intervals within each month of 2005 except for January. This represents a dramatic reduction following the first four months under RTMA (October 2004 - January 2005).[10]

Operations staff have indicated that the load bias is utilized primarily to decrease the usage of upward and downward regulation energy, or the deviation of units providing regulation from their Preferred Operating Point (POP). During ramping intervals when such sudden changes in system imbalances in a specific direction are anticipated, Operations staff have also indicated that the bias may be utilized to cause usage of regulation resources to deviate somewhat from POP in the opposite direction of the anticipated change in the system imbalance, so that the range of regulation capacity available to respond to the anticipated change is increased.

Under the approach described by Operations staff, the load bias is used to help preserve regulation capacity for use in responding to sudden system imbalances, rather than a mechanism for "smoothing" out instructed energy dispatches issued through RTMA and the resulting market clearing prices. Analysis of load bias usage patterns by DMM also indicates that the load bias is utilized primarily to reduce significant upward or downward deviations from the preferred operating point of resources providing regulation, and thereby maintain ramping capability of regulation capacity.

[9] In many – if not most – of these situations, use of the load bias would be expected to reduce the overall system level deviation of regulation resources from their Preferred Operating Point (POP) during the same interval which the load bias was applied. However, in some cases, the load bias may be utilized to reduce anticipated regulation deviation in future intervals, rather than in the current interval.

[10] Actual load bias data are not available for the first month of RTMA (October 2004).

Figure 3.27 Utilization of Load Bias by Month (Percent of Intervals)

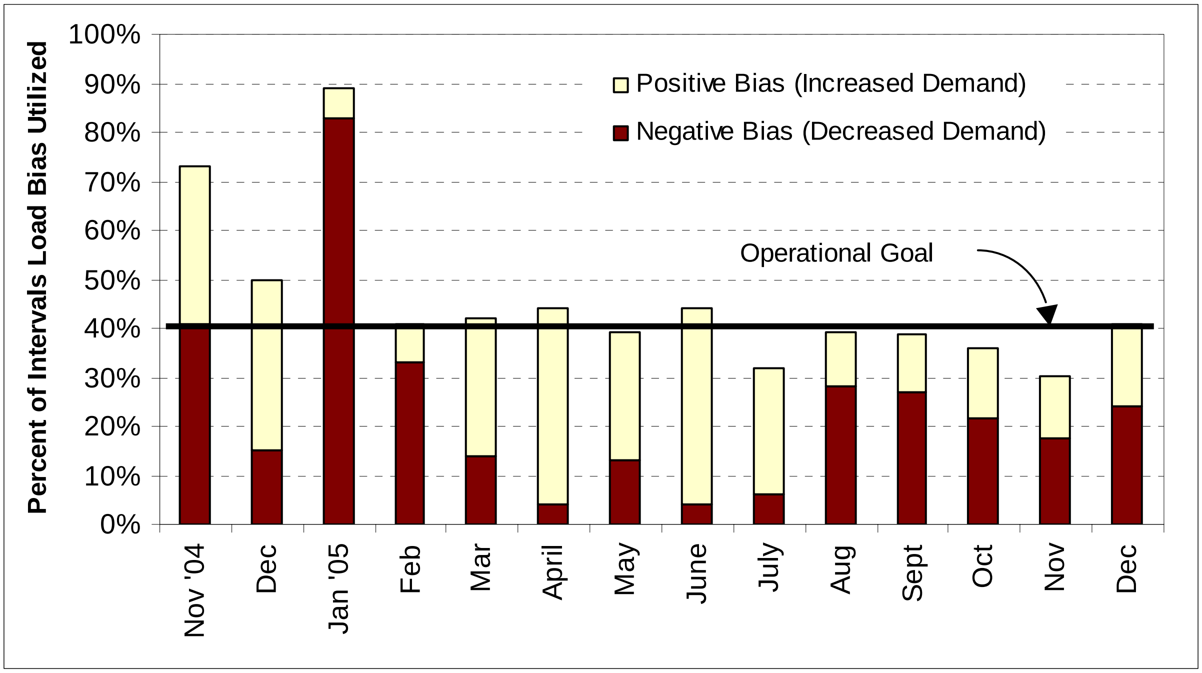
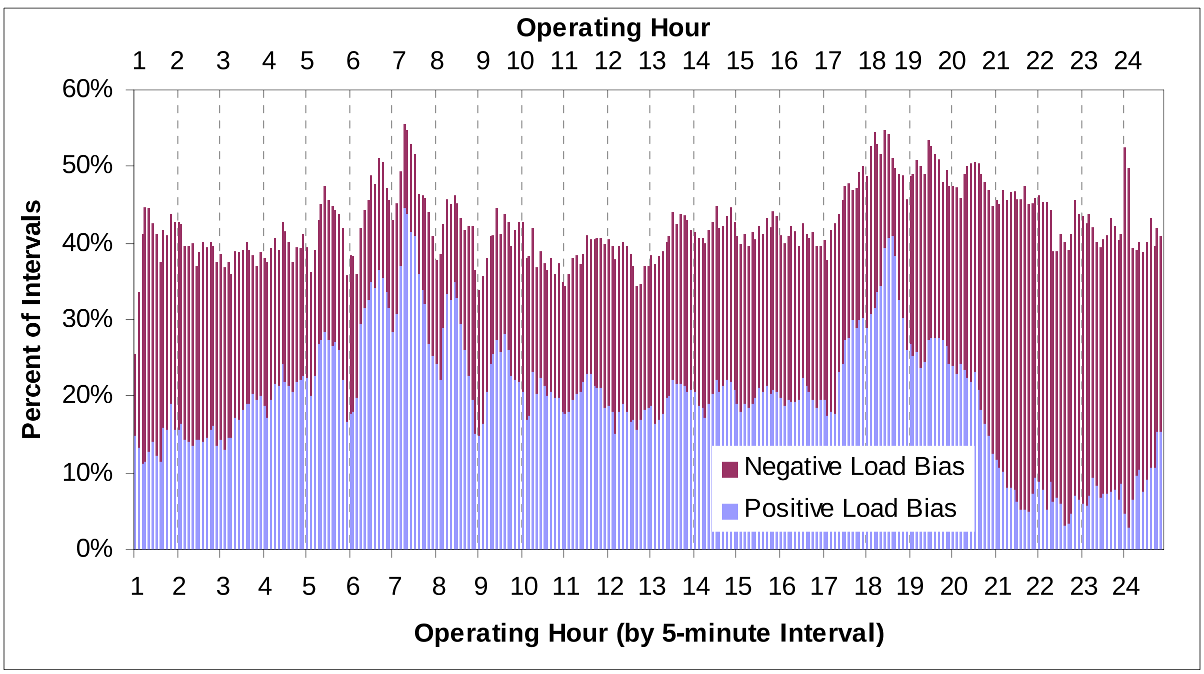


Figure 3.28 Utilization of Load Bias by Hour and Interval (2005)



Usage of the load bias is also relatively balanced across hours of the day, with usage reaching no more than about 50 percent during the morning and evening ramping hours, compared to no less than about 35 percent during other hours, as depicted in Figure 3.28. The load bias tends to be positive during the morning ramping hours (HE 6-8) and the peak evening hours (HE 17-18). During these hours, a positive load bias would tend to cause RTMA to increase dispatches of incremental energy, and thereby increase upward ramping capability of regulation resources by reducing usage of upward regulation or increasing usage of downward regulation. Conversely, as shown in Figure 3.28, load bias tends to be negative during the late evening ramping hours (HE 21-24). During these hours, a negative load bias would tend to cause RTMA to increase dispatches of decremental energy, and thereby increase downward ramping capability of regulation capacity by reducing usage of downward regulation or increasing usage of upward regulation.

More detailed analysis of the usage and impact of RTMA load bias was also performed by examining the load bias together with regulation usage on an interval-by-interval basis for the calendar year 2005. For this analysis, the impact of the load bias on regulation usage was approximated by calculating, for each interval, a counterfactual regulation deviation from POP that may have occurred if load bias had not been used. Specifically, it was assumed that each MW of load bias entered in an interval had a direct one-for-one impact on the amount of instructed energy dispatched through RTMA and, in turn, on regulation usage. For example, if a 100 MW positive load bias was entered during an interval when the actual regulation deviation was +150 MW, it is assumed that in the absence of the 100 MW positive load bias, 100 MW less of instructed energy would have been dispatched and the regulation deviation would have totaled +250 MW.[11] Summary results of this analysis are shown in Table 3.2, Figure 3.29, and Figure 3.30.

As shown in Table 3.2 and Figure 3.29, the actual average regulation deviation during the 44 percent of intervals when a positive or negative load bias was utilized (-16 and –51 MW, respectively) was relatively close to the actual average regulation deviation during the 58 percent of intervals when no load bias was utilized (-28 MW). However, if no load bias had been utilized during the 20 percent of intervals when a positive load bias was used, the average regulation deviation may have been as high as 229 MW. Similarly, if no load bias had been utilized during the 22 percent of intervals when a negative load bias was used, the average regulation deviation may have been as much as -255 MW.

[11] The general equation used to calculate the counterfactual regulation deviation each interval *t* is $Dev'_t = Dev_t + Bias_t$ The change in the absolute value of the regulation deviation from POP can then be calculated as Δ Abs (Dev_t) = Abs(Dev_t) - Abs(Dev'_t).

Table 3.2 Estimated Impact of Load Bias on Regulation Energy Usage and Regulation Deviation from POP (2005)

	Type of Load Bias		
	Positive	**Negative**	**None**
Percent of 10-minute Intervals	20%	22%	58%
Average Load Bias (MW)	229	-255	0
Average Regulation Deviation (MW)	-16	-51	-28
Average Regulation Deviation (MW) Without Bias	212	-306	-28
Average Absolute Deviation (MW) from POP	126	127	120
Average Absolute Deviation (MW) from POP Without Bias	234	316	N/A
Average Decrease in Absolute Deviation (MW) from POP due to Bias	108	189	N/A
Instructed Energy Dispatches during Interval			
Incremental Only	5%	4%	5%
Decremental Only	12%	7%	9%
Both - Net Incremental	43%	38%	39%
Both - Net Decremental	38%	51%	46%
Average Instructed Incremental Energy (MW)	307	280	282
Average Instructed Decremental Energy (MW)	-297	-352	-324

Figure 3.29 Potential Impact of Load Bias on Regulation Energy Usage (2005)

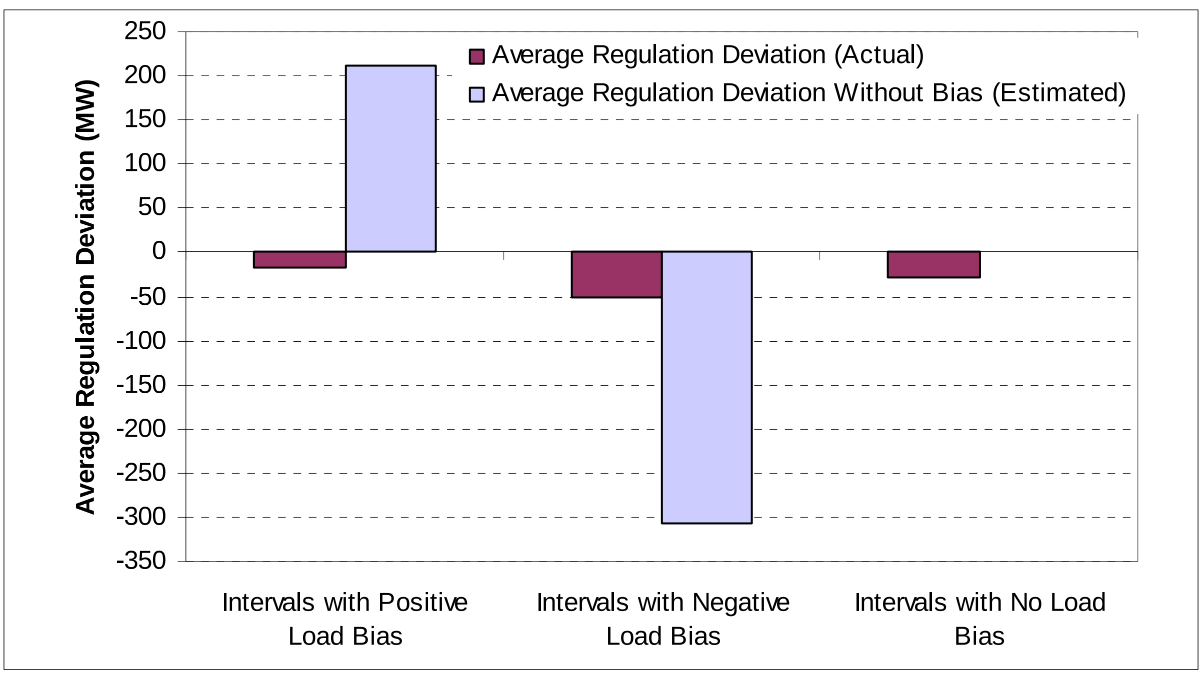


Figure 3.30 Potential Impact of Load Bias on Regulation Deviation from POP (January – December 2005)

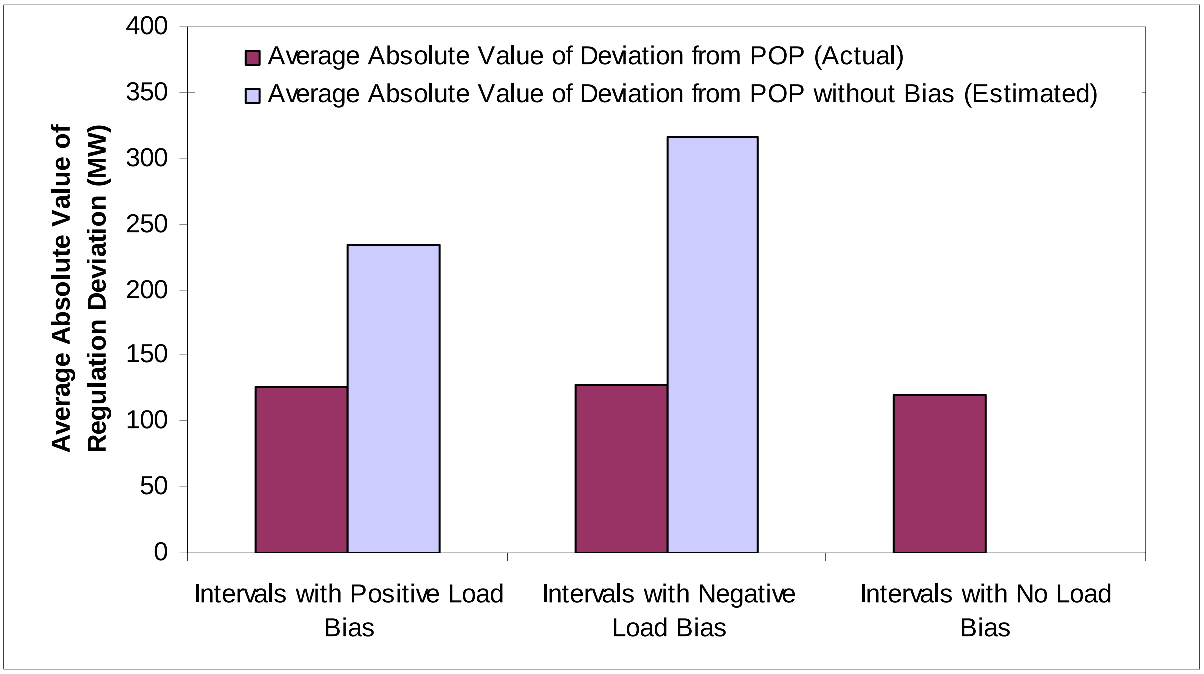


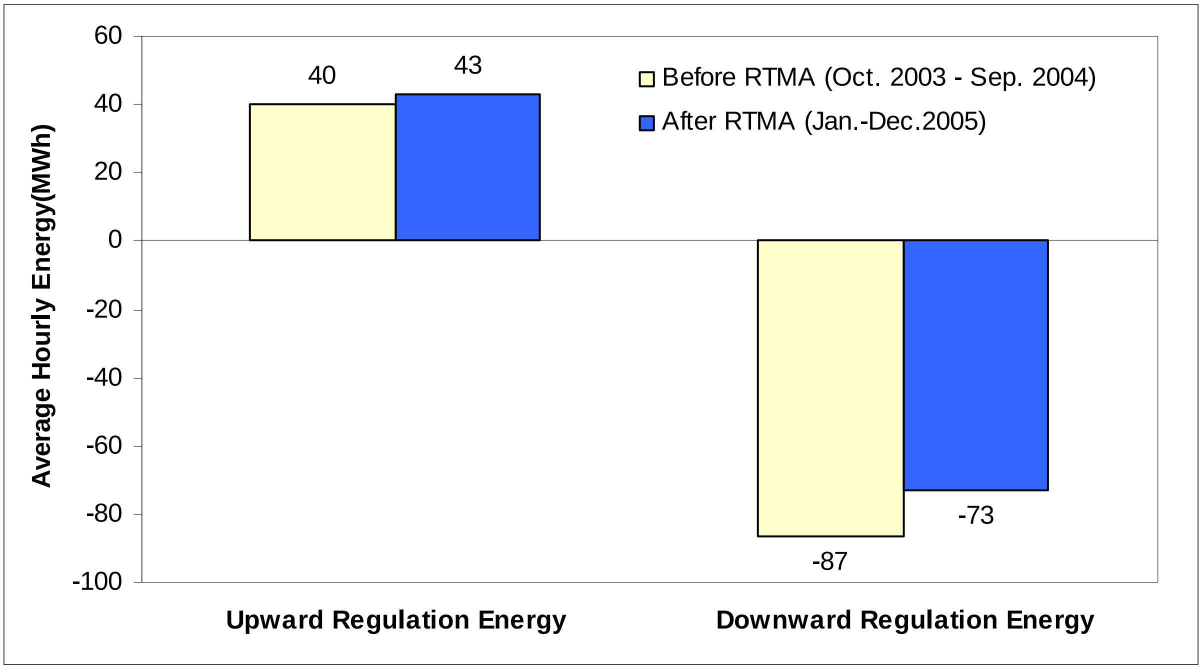
Table 3.2 and Figure 3.30 show a similar comparison of the absolute value of the actual regulation deviation from POP during these different intervals, along with the potential impact of the load bias in terms of decreasing the absolute regulation deviation from POP. Again, results suggest that the load bias was utilized in both the positive and negative direction to reduce the regulation deviation from POP during intervals when the average regulation deviation would have otherwise been relatively high as compared to intervals when no bias was used.

Examination of trends in instructed energy dispatches provides further indications that the load bias was used to manage regulation deviations, rather than as a mechanism for "smoothing" out instructed energy dispatches issued through RTMA and the resulting market clearing prices. If the load bias has been utilized to smooth prices by reducing RTMA dispatches, a positive load bias would tend to be used in intervals when RTMA was primarily decrementing generation, while a negative load bias would tend to be used in intervals when RTMA was primarily incrementing.[12] However, as shown in the bottom section of Table 3.2, no significant difference appears in the pattern of incremental and decremental energy dispatches between intervals when a load bias was used and no load bias was used.

While the load bias appears to have been used to decrease the usage of regulation capacity relative to levels that would have occurred under RTMA absent any load adjustments by operators, the overall usage of regulation in 2005 has not changed significantly in 2005 relative to the twelve month period prior to implementation of RTMA (October 2003-September 2004). As shown in Figure 3.31, average usage of upward regulation increased from about 40 MWh to 43 MWh, while usage of downward regulation dropped from about -87 MWh to -73 MWh in 2005.

[12] For example, during intervals when RTMA was incrementing generation, a negative load bias would reduce incremental instructed energy dispatches (and thereby reduce real price increases), and increase use of upward regulation in place of instructed incremental generation.

Figure 3.31 Change in Regulation Usage Since Implementation of RTMA



3.3.5 Uninstructed Deviations

3.3.5.1 Background

The Uninstructed Deviation Penalty (UDP) was a feature incorporated into MRTU Phase 1b[13] market design that was designed to provide an incentive for resources to follow their schedules and CAISO dispatch instructions. For generating units in the CAISO control area, UDP was to only apply to generating units with Participating Generator agreements with the CAISO. Some participating generating units were to be exempt from UDP, such as generating units required to run by environmental constraints, certain intermittent renewable resources, certain Qualifying Facilities, Condition 2 Reliability Must Run units, and generating units that are part of a load-following Metered Subsystem. UDP was also to apply to dynamically scheduled generating units located outside of the CAISO Control Area, and to non-dynamically scheduled imports to the extent Supplemental Energy dispatches made 40 minutes prior to the operating hour were declined.

For units subject to UDP, penalties would only apply to generator deviations that were above or below a deadband equal to the greater of 5 MW or 3 percent of a unit's maximum output level. For generation in excess of a resource's dispatch instructions[14] plus the aforementioned deadband, the planned UDP charge was to be the level of the deviation multiplied by 100 percent of the corresponding applicable market clearing price. Thus, this charge was designed to essentially offset the revenues earned from this uninstructed energy, so that no net payment was received for excess generation. For resources generating less than their dispatch instruction less the aforementioned deadband, the planned UDP charge was to be equal to the energy quantity of the deviation multiplied by 50 percent of the corresponding applicable market clearing price for under-generation. In this situation, the charge was designed so that generators paid a total of about 150 percent of the real-time market price for any scheduled or dispatched energy that was not generated.

When MTRU Phase 1b was implemented on October 1, 2004, UDP was planned to be implemented as a component of Phase 1b after an initial two-month grace period, during which the CAISO would provide market participants with the results of its UDP calculations, but would not actually charge the penalty. Compliance with dispatch instructions was thought to be particularly important under Phase 1b, because, in addition to previously existing concerns about the effect of uninstructed deviations on control area operations, Phase 1b's RTMA system was anticipated to produce a greater quantity of dispatches than the previously existing BEEP system due to fact that RTMA clears all overlapping bids among suppliers (in addition to dispatching energy needed to meet CAISO imbalance energy needs).

The UDP grace period was extended past the initially planned two months while the CAISO resolved a variety of issues related to implementation of RTMA and UDP. In May 2005, the CAISO decided to indefinitely defer implementing UDP because experience gained during the UDP grace period showed that there was a reasonable potential that the existing design of UDP, coupled with the characteristics of the CAISO market systems, would make it impossible for market participants operating generating units to avoid UDP in certain situations despite their best efforts. These circumstances included the following:

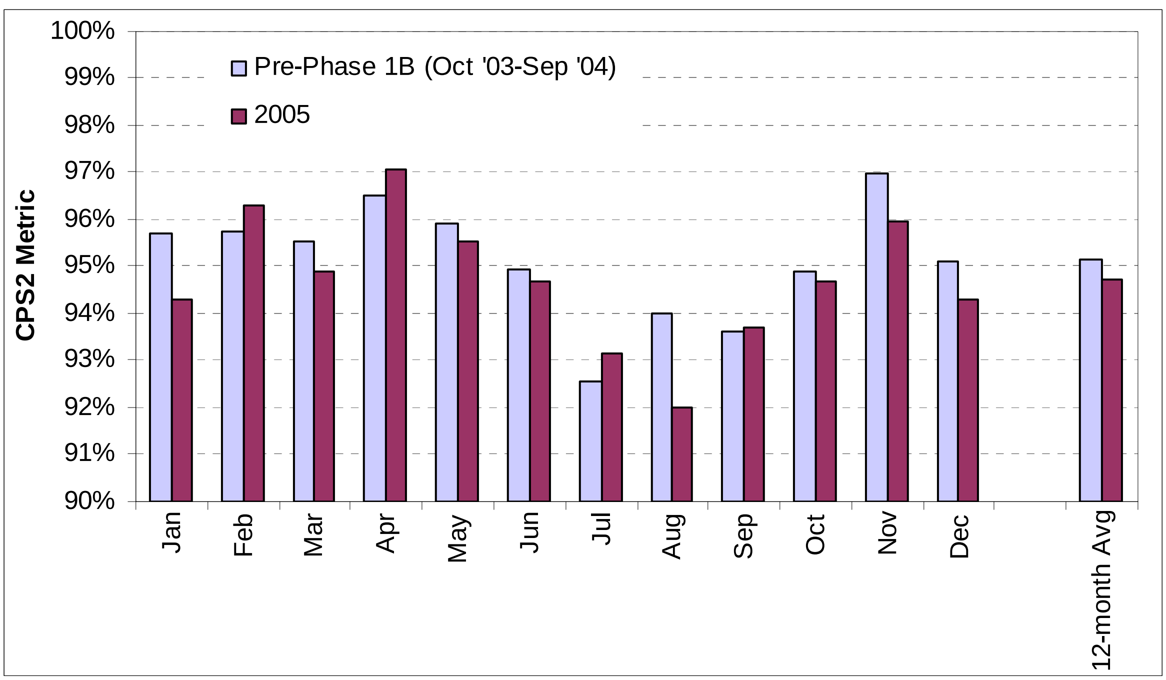
[13] "MRTU Phase 1b" refers to the October 1, 2004, implementation of RTMA and associated changes in market settlements, including UDP.

[14] CAISO dispatch instructions include dispatches to a resource's Final Hour-Ahead Schedule and dispatches for any Instructed Imbalance Energy.

- Many market participants maintained that dispatches generated by the RTMA system were difficult for generating units to follow because they were unpredictable and excessively volatile.
- RTMA dispatches do not accurately model the "steam inertia" characteristics of generating units when dispatch instructions reverse direction from the previous interval. This situation can result in generating units unavoidably deviating from dispatch instructions, often in excess of the UDP deadband.
- Many market participants maintained that reporting generating unit limitations in the CAISO outage reporting system was impractical to accomplish within a 30-minute timeframe that would be necessary to avoid UDP. These unit limitations include temporary changes to the unit's maximum or minimum output level, as well as other operating limitations such as the temporary inability of a combined cycle generating unit to begin ramping to greater output levels while the second stage of the unit is being brought into operation.

An additional factor considered in deferring implementation of UDP was that following implementation of Phase 1b, control area operations were reasonably stable without UDP, as indicated by control area performance metrics, including the CPS2 metric and the level of uninstructed deviation. For example, Figure 3.32 compares the CPS2 metric for Phase 1b operation in 2005 with the corresponding months from the 12-month period prior to Phase 1b. As shown in Figure 3.32, the monthly CPS2 metric shows no clear difference in CPS2 performance before and after Phase 1b's deployment.

Figure 3.32 Monthly CPS2 Metric



Another consideration in the decision to defer implementation of UDP was that the overall level and volatility of uninstructed deviations did not increase following implementation of Phase 1b and that implementing UDP would not significantly reduce any detrimental impacts that uninstructed deviation may have on system or market operations. The following sections of this report provide a quantitative analysis of actual trends and impacts of uninstructed deviations during 2005 – the first full calendar year since Phase 1b has been in effect – relative to a comparable time period immediately prior to implementation of Phase 1b in October 2004.

3.3.5.2 Methodology

This report examines trends in uninstructed deviations during 2005 based on three basic measures.

- *Volume of Uninstructed Deviations.* First, the total volume or magnitude of all uninstructed deviations on a system-wide level is important since this reflects the impact of uninstructed deviations on the overall quantity of incremental or decremental energy that the CAISO must dispatch to balance system loads and resources. For this analysis, the magnitude of system-level uninstructed deviations was measured by calculating the approximate net deviation in each 10-minute settlement interval of all generating units (including generating units not subject to UDP). For this analysis, the approximate deviation of each unit is first calculated for each interval. The net deviation on a system level of each interval is then calculated by summing up the approximate deviation of all generating units. This summation and netting of individual resource deviations reflects the fact that system and market operation are affected primarily by the net system-wide deviation, rather than deviations of individual resources. However, it is important to note that to the extent individual resource deviations create real-time congestion issues, individual resource deviations can be an operational concern as well.[15] Since the system level deviations can be either positive or negative each interval, the system level deviation each interval was converted to an absolute value for purposes of aggregating and comparing the magnitude of deviations over longer-term periods (e.g., by month).

- *Volatility of Uninstructed Deviations.* Second, the volatility of uninstructed deviations on a system-wide level from one interval to the next is also important since sudden and/or unpredictable changes in system level uninstructed deviations can have detrimental impacts on system and market operations. For this analysis, the volatility of uninstructed deviations was assessed based on the change in system level uninstructed deviations from each interval to the next. Again, since the system level deviations can be either positive or negative each interval, the change in system level deviation in each interval was converted to an absolute value for purposes of aggregating and comparing the volatility of deviations over longer-term periods (e.g., by month).

- *Potential Reduction in Uninstructed Deviations from Application of UDP Charges.* Finally, the potential reduction in the system level net deviation that may result if UDP charges were actually applied in the settlement process is examined. This analysis is based on the uninstructed energy quantities subject to UDP that are calculated by the CAISO as part of the participant advisory notices that continue to be made available to market participants as part of the advisory process developed for the initial UDP grace period. For this analysis, it is first assumed that during each interval each resource subject to UDP would reduce deviations to the deadband level at which no UDP charges would be

[15] This latter concern is one of the primary reasons the UDP design did not allow for netting of deviations across a market participant's entire portfolio and instead only allowed netting across generating units in very limited circumstances.

incurred. The system level net deviation was then recalculated each interval taking into account the assumed reduction in deviations by individual resources. It should be noted that this approach represents the upper bound of the potential reduction in the system level net deviation that result if UDP charges were applied, since it is not likely that all resources would be able to or would take action to modify their operations to eliminate UDP charges entirely.

For the first two analyses described above, uninstructed deviations is defined as the metered output of each generating unit, minus the unit's output due to scheduled generation and any instructed imbalance energy dispatches. This approach closely approximates how uninstructed energy is calculated for settlement purposes, but several adjustments were made in the calculation of instructed imbalance energy to account for differences and provide an equitable comparison between the Phase 1b and the pre-Phase 1b market designs and systems.[16] Units providing regulation were excluded from the analysis during the hours they were providing regulation since this energy is provided in response to CAISO operating instructions. As noted above, the analysis of the potential reduction in uninstructed deviations if the UDP were charged to participants is based on data calculated by the CAISO as part of the participant advisory notices sent as part of the advisory process developed for the initial UDP grace period.

The analysis includes only generating units located within the control area, which comprise more than 99 percent of the deviation subject to UDP. However, non-dynamically scheduled resources located outside the CAISO Control Area were not included because they are dispatched on an hourly basis and would not have deviations within the hour. Dynamically scheduled resources located outside the CAISO Control Area were not included because of difficulties reconciling naming conventions between the pre- and post-Phase 1b periods.

3.3.5.3 Results

Results of this analysis indicate that the volume and volatility of uninstructed deviations have not changed significantly in 2005 relative to the most recent comparable time period prior to implementation of Phase 1b, and that assessment of UDP charges may result in a relatively minor decrease in uninstructed deviations.

Figure 3.33 compares the magnitude of generating unit uninstructed deviations in January 2005 - December 2005 with the uninstructed deviations during the corresponding months from the 12-month period prior to Phase 1b (October 2003 - September 2004). Figure 3.33 also shows the percentage of settlement intervals in which the net system level deviation was positive (i.e., net generation exceeded the total amount of energy scheduled or dispatched from these units) during each of these months.

As shown Figure 3.33, the level of uninstructed deviation in 2005 has been relatively consistent with the level that existed prior to Phase 1b, with the net amount of uninstructed deviations averaging 384 MW in 2005 and averaging 368 MW in the 12 months prior to Phase 1b's implementation. These values were similar for both peak and off-peak periods in both 2005 and prior to Phase 1b. Both 2005 and the pre-Phase 1b period show a similar seasonal variation in

[16] The following items are dispatched as instructed imbalance energy by the Phase 1b systems but were not dispatched as instructed imbalance energy prior to Phase 1b: minimum load output during must-offer waiver denial periods; transmission loss self-provision; deviation from the standard 20-minute ramp during hourly schedule changes; and adjustments to output due to temporary limitations in a unit's minimum or maximum operating levels. These differences were accounted for by adding minimum load output to the instructed imbalance energy calculations for the pre-Phase 1b timeframe and subtracting transmission loss self-provision, ramping deviation, and adjustments to output due to temporary limitations from the instructed imbalance energy calculations for the Phase 1b timeframe.

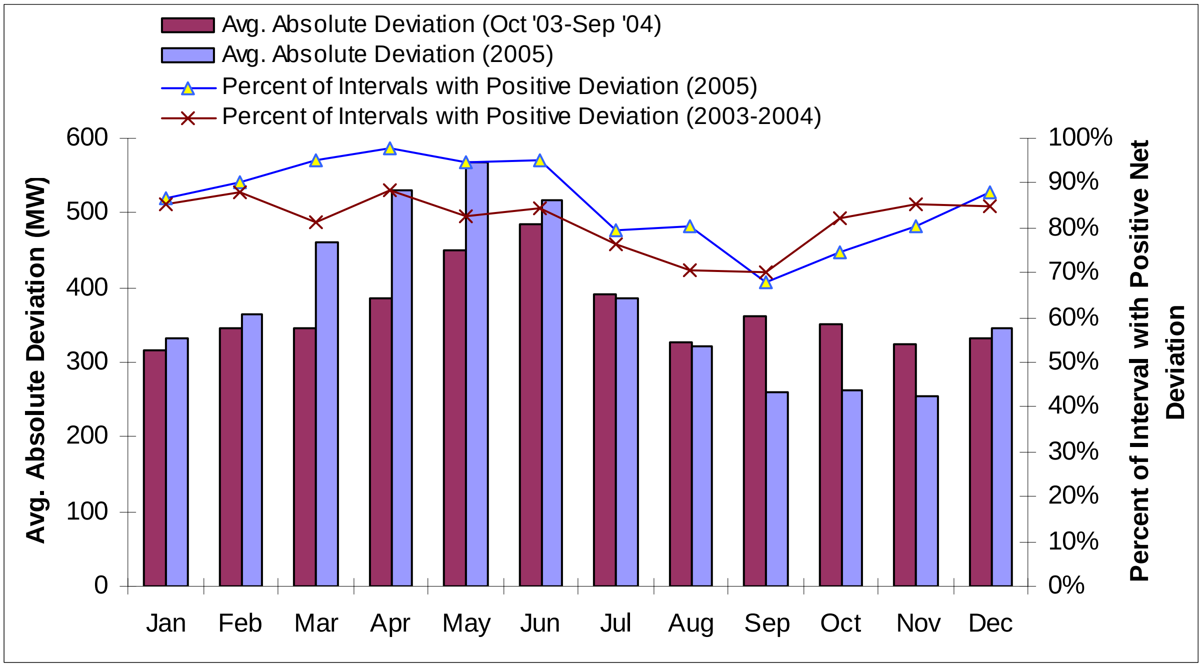
the magnitude of uninstructed deviation – relatively higher in the spring months and lower in the fall months. The higher deviation in the spring months is at least partially attributable to positive deviation of hydro units during the spring runoff period.

Figure 3.33 shows that in 2005, a relatively higher level of deviation existed in March - June, and a relatively lower level of deviation existed in September - November 2005, as compared to the corresponding months in the period before Phase 1b. These differences do not appear to represent any significant systematic deviations by any class of generating units, but rather appear to have resulted from the deviation of a limited number of generating units. For example, the relatively higher level of deviation seen in March - June 2005, compared to the corresponding pre-Phase 1b months, can be attributed to the deviation of a few large base-load non-gas-fired thermal and hydro generating units, as well as a number of Qualifying Facilities.

Figure 3.33 also shows that uninstructed deviations were predominately positive (i.e., generating more than schedule plus dispatch instructions) – the net deviation of generating units was positive in an average of 84 percent of settlement intervals throughout 2005 and the corresponding period prior to Phase 1b's implementation. This value was relatively consistent in the two periods. The prevalence of positive uninstructed deviation is likely explained by the fact that generating units are periodically operated without a schedule or dispatch instruction. This occurs when a generating unit owner does not shutdown a unit to avoid start-up/shutdown costs, if the operator anticipates the unit is to be needed again after a short period. Additionally, a number of units, such as hydro units and Qualifying Facilities must run unscheduled or above schedules due to environmental constraints or due to the nature of the energy source. This results in positive uninstructed deviation quantities that are relatively greater than the negative uninstructed deviation quantities resulting from units merely generating incrementally less than their scheduled or dispatched output level. Another contributor to net positive uninstructed deviation quantities is the generator output below a generator's minimum output level during start-up and shutdown periods, which is not dispatched as instructed imbalance energy.[17]

[17] Instructed imbalance energy is the incremental expected energy quantity corresponding to a CAISO dispatch to move a unit above or below its scheduled output level.

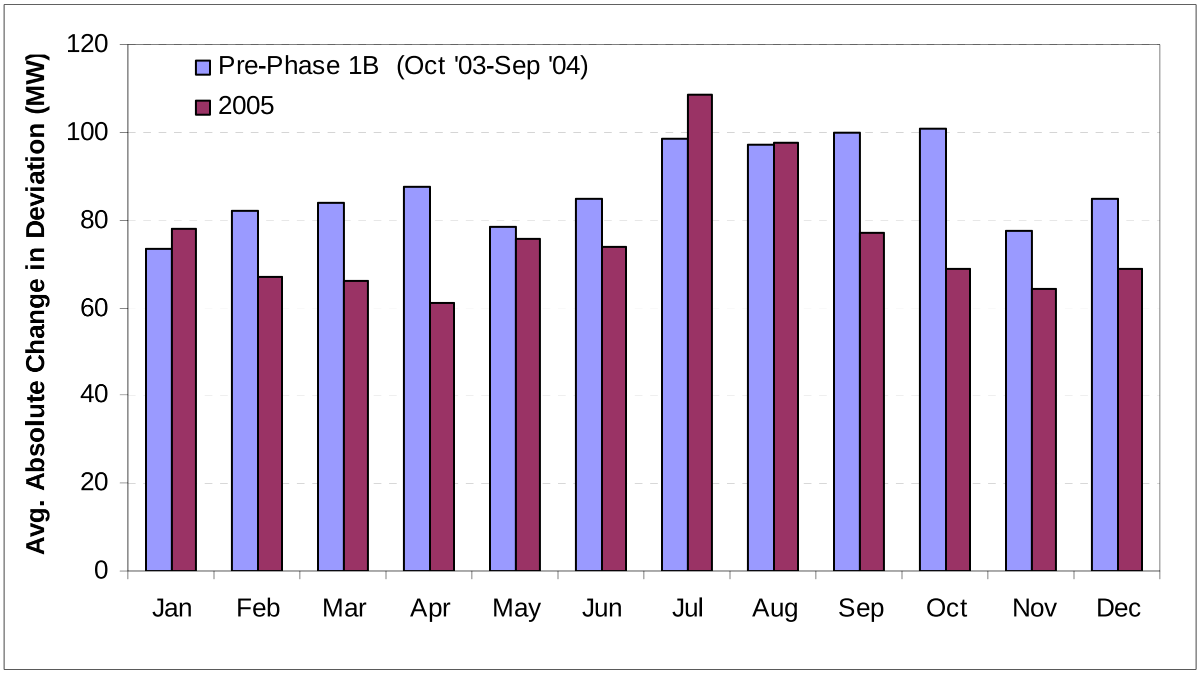
Figure 3.33 Average Absolute Value of Net Uninstructed Deviation (UD)



Market and control area operations are also affected by the settlement interval to settlement interval variation in the net amount of deviation. Figure 3.34 examines this variation, which is represented by the absolute value of the change in net generating unit deviations between 10-minute settlement intervals for January 2005 - December 2005 compared to the corresponding months from the 12-month period prior to Phase 1b (October 2003 - September 2004).

As Figure 3.34 shows, the settlement interval to settlement interval change in the net amount of uninstructed deviation in 2005 has been relatively consistent with the level that existed prior to Phase 1b. The seasonal variation in the between-settlement interval net deviation change is similar in the two periods, as well as the average magnitude of the variation in the two periods, averaging 76 MW in 2005 and averaging 87 MW in the 12 months prior to Phase 1b implementation.

Figure 3.34 Average Change in Net Uninstructed Deviation between 5-Minute Dispatch Intervals



The degree to which uninstructed deviations could be reduced by assessment of UDP charges is limited by a variety of factors previously noted:

- Only deviations outside the UDP deadband (5 MW or 3 percent of a unit's maximum output level) are subject to UDP;
- A variety of generation resources and situations are exempt from UDP charges;[18] and
- Compliance with schedules and dispatch instructions may in some cases be infeasible for generators.

The upper range of the potential reduction in system level uninstructed deviations that might result from assessment of UDP charges was quantified for this report based on calculations done by the CAISO as part of the participant advisory process developed for the initial UDP grace period, as described above. Results of this analysis are provided in Figure 3.35, which shows the portion of aggregate net uninstructed deviations that might be reduced if each unit subject to UDP modified its operations to avoid all UDP charges.[19]

As Figure 3.35 shows, the reduction in net system level deviations due to such compliance by each unit subject to UDP averages only about 51 MW or about 16 percent of the average 313 MW net deviation in 2005.[20]

[18] UDP exemptions include deviation of individual units within generating units aggregated for UDP purposes as long as the net aggregate deviation is within the deadband, and exemptions for deviations during start-up/shutdown periods, outages, and other factors.

[19] Note that this calculation is an approximation that assumes that the direction (i.e., positive or negative) of the net deviation subject to UDP is in the same direction as the aggregate net system deviation.

[20] The 313 MW average net deviation is less than the 384 MW average net deviation presented in Figure 3.33 because the 313 MW value was calculated using the current Phase 1b definition of instructed imbalance energy.

Figure 3.35 Maximum Potential Reduction in Net Deviation if UDP Charges Were Assessed and Total Net Aggregate Deviation (2005)

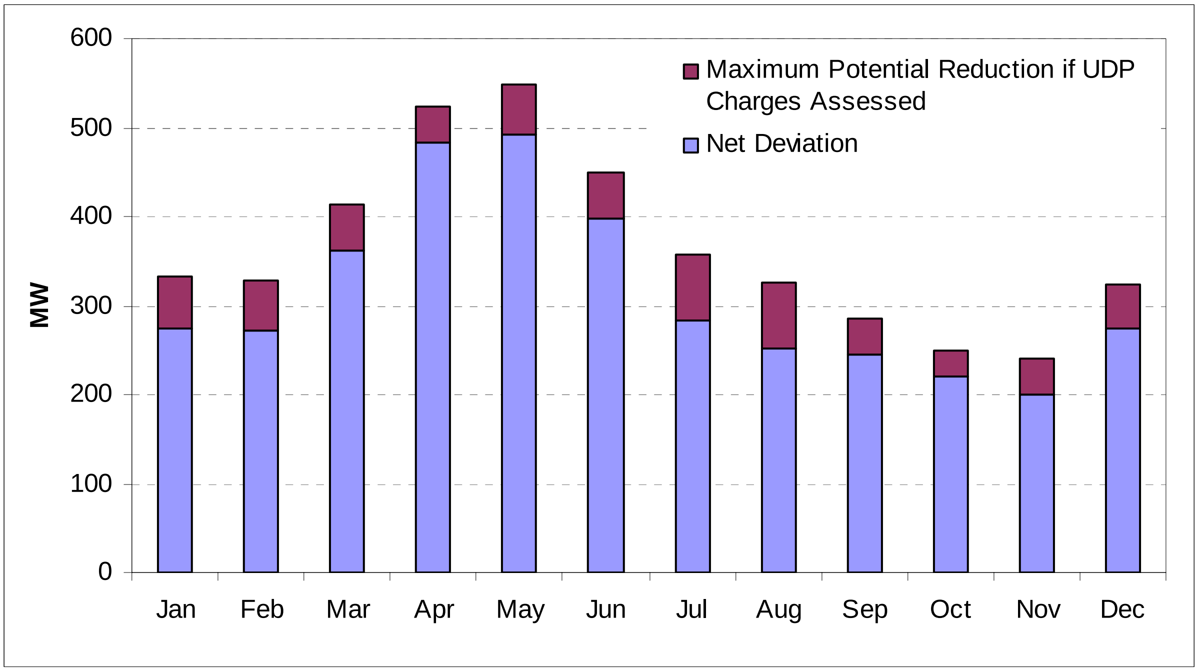
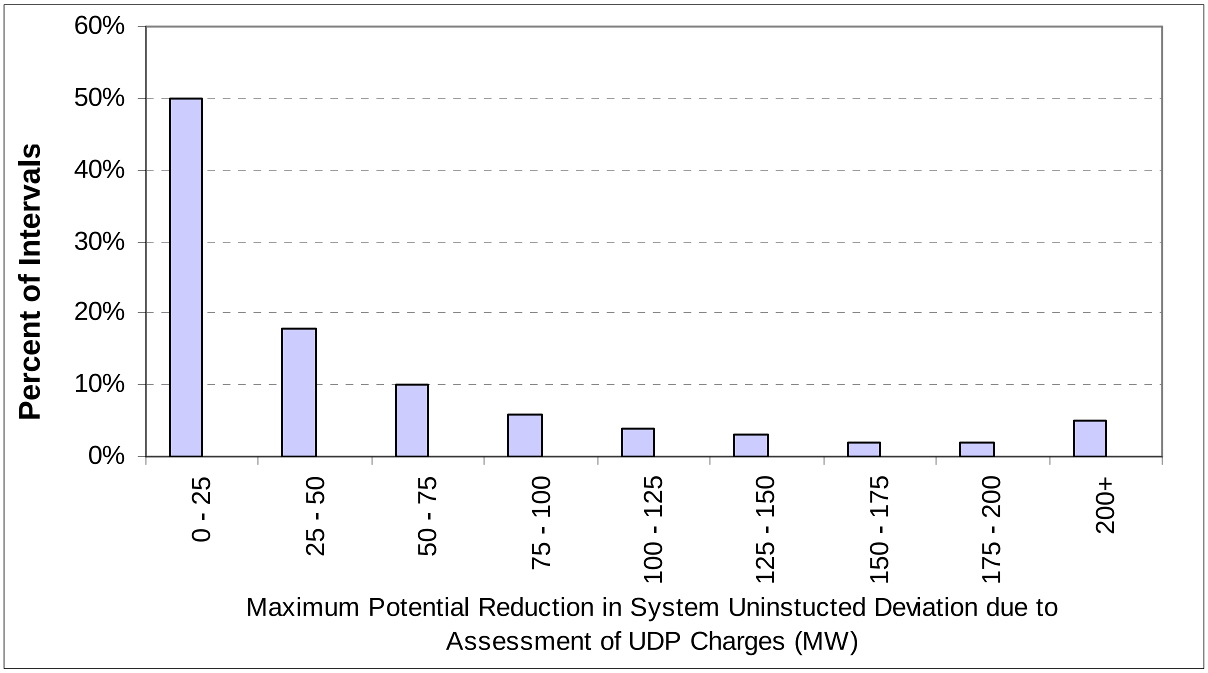


Figure 3.36 provides a histogram of the magnitude of the estimated maximum potential reduction in the net system deviation that might result from assessment of UDP charges on a 10-minute settlement interval basis. As Figure 3.36 shows, during about 50 percent of intervals this reduction would be 25 MW or less. The maximum potential reduction in net system deviation would be greater than 200 MW in only about 5 percent of intervals.

Figure 3.36 Maximum Potential Reduction in Net Aggregate Deviation if UDP Charges were Assessed (2005)



3.3.6 Summary and Conclusions

Much of the increase in price and dispatch volatility occurring since implementation of RTMA may be attributed to certain design features included in RTMA, which were developed to improve market efficiency. These include the following:

- **Real-Time Price Volatility and Fluctuations.** The volatility of 5-minute prices in the CAISO's Real Time Market (from one interval to another within each operating hour) has increased significantly since implementation of the RTMA software.
- **Volatility of Generating Unit Dispatches.** The volatility of individual generating unit dispatches in the CAISO's Real Time Market has also increased significantly since implementation of RTMA. This finding is consistent with feedback from several generation operators who have complained that their units are often "whipsawed", or dispatched in different directions excessively (i.e., dispatched up, then down and then back up, etc., within the same hour) under RTMA.
- **Regulation Capacity.** The overall amount of regulation capacity purchased and utilized by the CAISO does not appear to have been reduced since implementation of RTMA. While use of downward regulation capacity has decreased somewhat, use of upward regulation capacity has increased slightly. Thus, RTMA does not yet appear to have significantly reduced reliance on regulation energy to balance loads and resources.

- **Operator Bias of Load.** The performance of RTMA is also impacted by the frequency and magnitude of load bias that may be entered by Grid Operators (as an adjustment to RTMA's internally generated projections of imbalance energy requirements in subsequent intervals). The more the operator is able to rely on RTMA, the less manual bias may be needed. In order to encourage a balancing of the potential benefits of entering a load bias in RTMA with the goal of limiting reliance on this feature, Grid Operations has established an operational goal of utilizing a load bias in the RTMA software in no more than 40 percent of dispatch intervals. The frequency with which a manual bias has been entered into RTMA (during an operating hour) has fluctuated just above or below the operational limit of 40 percent of the dispatch intervals. DMM analyses suggest that the load bias was utilized in both the positive and negative direction to reduce the regulation deviation from POP during intervals when the average regulation deviation would have otherwise been relatively high as compared to intervals when no bias was used. Furthermore, the load bias appears to be used to manage regulation deviations, rather than as a mechanism for "smoothing" out instructed energy dispatches issued through RTMA and the resulting market clearing prices.

- **System Reliability.** The primary metric used to measure CAISO system reliability – the Control Performance Standard 2 (CPS2) – shows no clear change in reliability performance since implementation of RTMA as compared to the period prior to RTMA. However, it should be noted that RTMA software includes a variety of features (such as 5-minute vs. 10-minute dispatch, increased automation, and forward-looking dispatch algorithms) that may facilitate and improve real-time operations in ways that may not be reflected in CPS2 metrics. Any operational benefits from these RTMA features may need to be assessed based on more qualitative input from Operations staff.

- **Prices for Pre-dispatched Imports/Exports and Real-Time Energy.** One indication that significant improvements have been made in RTMA since implementation of some enhancements to the software in late March 2005 is that prices for pre-dispatched energy from import/exports bids have tracked much more closely with Real Time Market prices set by internal resources dispatched within each operating hour.

- **Uplift Payments for Internal Resources.** One of the key features of RTMA not incorporated in the previous Real Time Market software is that RTMA dispatches units based on anticipated system conditions and resource ramping constraints over a two-hour "look-ahead" period. Bids from internal resources dispatched in one interval to meet expected needs in future intervals do not set the Market-Clearing Price (MCP) for that interval, but are paid the real-time MCP for each interval and are eligible for bid cost recovery over the entire operating day. Over the first 10-months of RTMA (October 2004 - July 2005), about 9.5 percent of total incremental energy and 5 percent of decremental energy from units within the CAISO system were eligible for uplift payments. Total uplift payments actually paid for both incremental and decremental energy, after netting of market revenues over the operating day, have been about $8.6 million over the ten-month period of October 2004 - July 2005, or only about 1.2 percent of total transactions costs for instructed incremental and decremental energy for units within the CAISO system.

Much of the increase in price and dispatch volatility occurring since implementation of RTMA may be attributed to certain design features included in RTMA, which were developed to improve market efficiency:

- **Increased Reliance on Market Energy Bids versus Regulation.** RTMA is specifically designed to increase reliance on Real Time Market energy bids to follow short-term fluctuations in demand, which may otherwise be met by the use of regulation energy. During many periods, however, the supply of highly flexible, fast-ramping resources offered into the real-time market has been limited, so that increased reliance on bids necessarily results in higher price volatility. This is particularly true during the morning and evening ramping periods, when prices have been most volatile.
- **Prices Set by Marginal Bids Dispatched to Meet Imbalance Each Interval.** A second major market design change incorporated into the RTMA software was that prices under RTMA are set based on the bid of the marginal resource dispatched to meet demand within each interval, and that prices are not set by bids that may have been dispatched to meet demand in future or previous intervals (but are "constrained on" in an interval due to ramping constraints or minimum operating times, etc.) Prior to RTMA, the real-time MCP could be "stuck" for multiple intervals by a high bid that was dispatched in a previous interval, but was no longer indicative of the marginal unit dispatched in subsequent intervals. RTMA was specifically designed to eliminate the "stuck price" issue that existed in the prior BEEP software. This feature of RTMA may tend to lower overall real-time prices, but would also tend to increase price volatility.
- **Market Clearing of Incremental and Decremental Bids.** A third major market design change incorporated into the RTMA software was the economic dispatch or market clearing of all incremental and decremental bids for supplemental energy. Rather than simply dispatching the bids necessary to meet the projected imbalance of the CAISO system, RTMA dispatches all remaining incremental and decremental bids for supplemental energy with "overlapping" prices (i.e., incremental bids offered at a price lower than the price of decremental energy bids submitted by other participants). This feature was incorporated into RTMA to allow greater overall market efficiency, and to encourage participants to submit increased volumes of incremental and decremental bids. However, this feature of RTMA may also contribute to the increased volatility of dispatches and prices relative to the previous BEEP software.
- **Elimination of Target Price Mechanism.** Some of the increase in price volatility may also be attributable to the fact that the volatility of real-time prices prior to RTMA were often muted by the "Target Price" mechanism incorporated in the previous BEEP software. The clearing of incremental and decremental energy bids eliminated the need to rely on the "Target Price" mechanism, which had the effect of "flattening out" prices over portions of the real-time energy bid stack, and was criticized for making market prices less responsive to actual bid prices. Prior to implementation of RTMA, 10-minute real prices cleared at the Target Price for each hour in about 18 percent of all intervals. Under RTMA, prices during intervals when the Target Price would have previously set the price are now set by bids for incremental and decremental energy.

A real-time imbalance energy market is inherently volatile due to the fact that it is clearing supply and demand imbalances on nearly an instantaneous basis. Therefore, a high degree of price and dispatch volatility is not necessarily indicative of poor performance. Rather, the question is whether the volatility is excessive relative to what is required to efficiently clear the real-time imbalances and overlapping bids. Results from this analysis indicate that:

- Although RTMA has increased the volatility of prices and dispatches within each operating hour, this appears to be primarily the result of various features of RTMA designed to increase the responsiveness of prices and dispatches to system imbalance conditions in each 5-minute interval. Upon close examination, the fluctuations in prices and dispatches under RTMA closely mirror actual system imbalance conditions.
- Performance of RTMA seems to have improved since it was implemented on October 1, 2004, as numerous modifications have been made. For example, modification to the way RTMA projects uninstructed deviations dramatically improved convergence of prices for pre-dispatched bids on inter-ties and the Real Time Market price set by resources dispatched within the CAISO system during each hour.