California Independent
System Operator Corporation

California ISO

Quarterly Report on Market Issues and Performance

November 8, 2010

Prepared by: Department of Market Monitoring

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Executive summary

This report provides an overview of general market performance during the third quarter of 2010 (July – September). The report also provides more detailed analysis of two special issues:

- The continuing trend of decreased net imports in the hour-ahead market, which can exacerbate the need to increase procurement of imbalance energy in the 5-minute real-time market at higher prices.
- The effectiveness of the compensating injection feature in reconciling market schedules on major interties with actual flows in the hour-ahead and real-time markets.

Energy markets

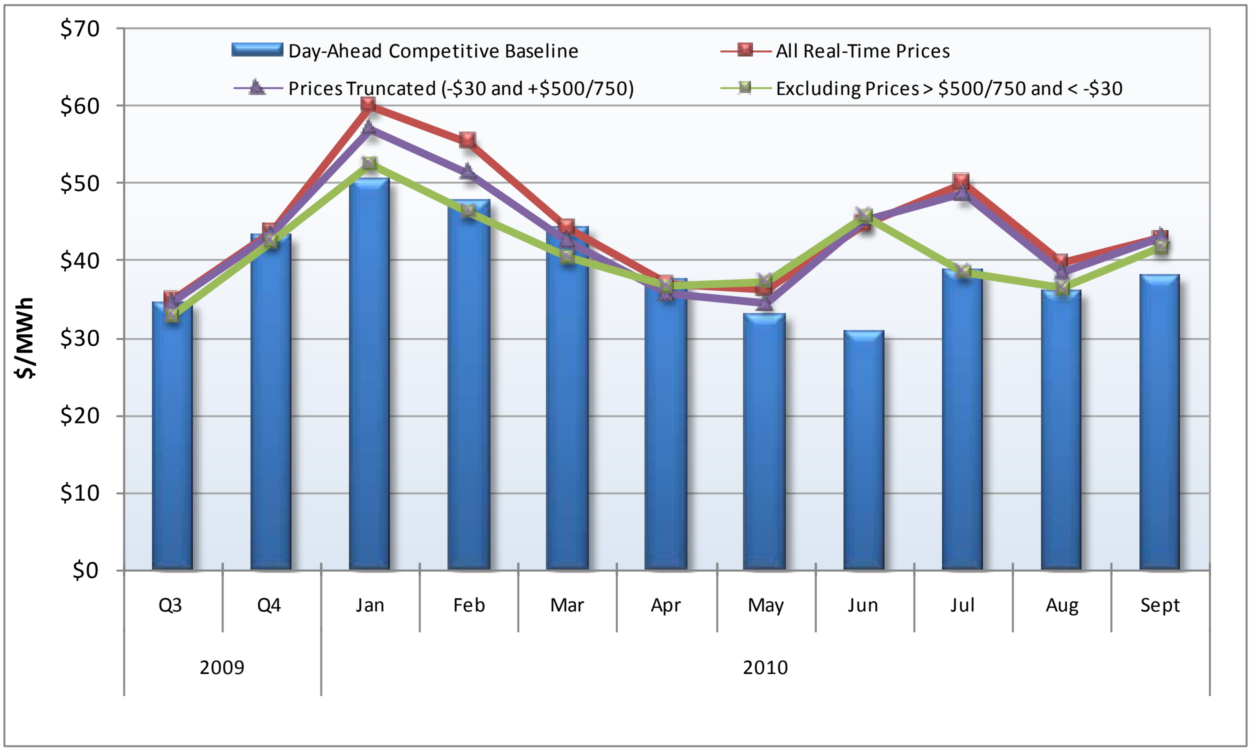
- The day-ahead integrated forward market has continued to be very stable and competitive, with a very high portion of load and supply being scheduled in the day-ahead market (e.g., typically 94 to 101 percent).
- Average energy prices in the day-ahead market during each month of the third quarter continued to be approximately equal to benchmark prices that DMM estimates would occur under highly competitive conditions.
- Average real-time energy prices for load aggregation points exceeded $500/MWh in about 1 percent of intervals in July. This was primarily the result of wildfires and related transmission de-rates in real-time that increased average real-time price at the SCE load aggregation point significantly above the competitive baseline price for the day-ahead market. However, as shown in Figure E.1, real-time market prices in the SCE area during August and September were close to competitive baseline levels.
- Real-time prices in the PG&E load aggregation point during each month of Q3 were approximately equal to competitive baseline levels.
- Because most energy is scheduled in the day-ahead market and such a small portion of overall energy is procured in the real-time market, higher average real-time prices have had minimal impact on overall wholesale energy costs.

Congestion

- Congestion on inter-ties from balancing areas adjacent to Northern California decreased in Q3 relative to Q2 2010. This is consistent with the drop-off in seasonal snowmelt and increased local demand in the Northwest.
- Congestion on inter-ties from balancing areas adjacent to Southern California was mixed. Congestion in Q3 on Palo Verde – the major inter-tie between California and the Southwest – remained about the same as in Q2, while congestion on Mead continued to fall off its highs set in Q1.
- The frequency of day-ahead congestion on constraints within the ISO was very low and had minimal impact on overall day-ahead energy prices in Q3. The SCE import limit, which was frequently

binding in prior winter months, continued to be binding less frequently in the summer. However, congestion along Path 26 and one of its component lines (Midway to Vincent) picked up in Q3 because of the impact of wildfires and increased loads in Southern California.

Figure E.1 Comparison of competitive baseline to real-time prices in SCE LAP



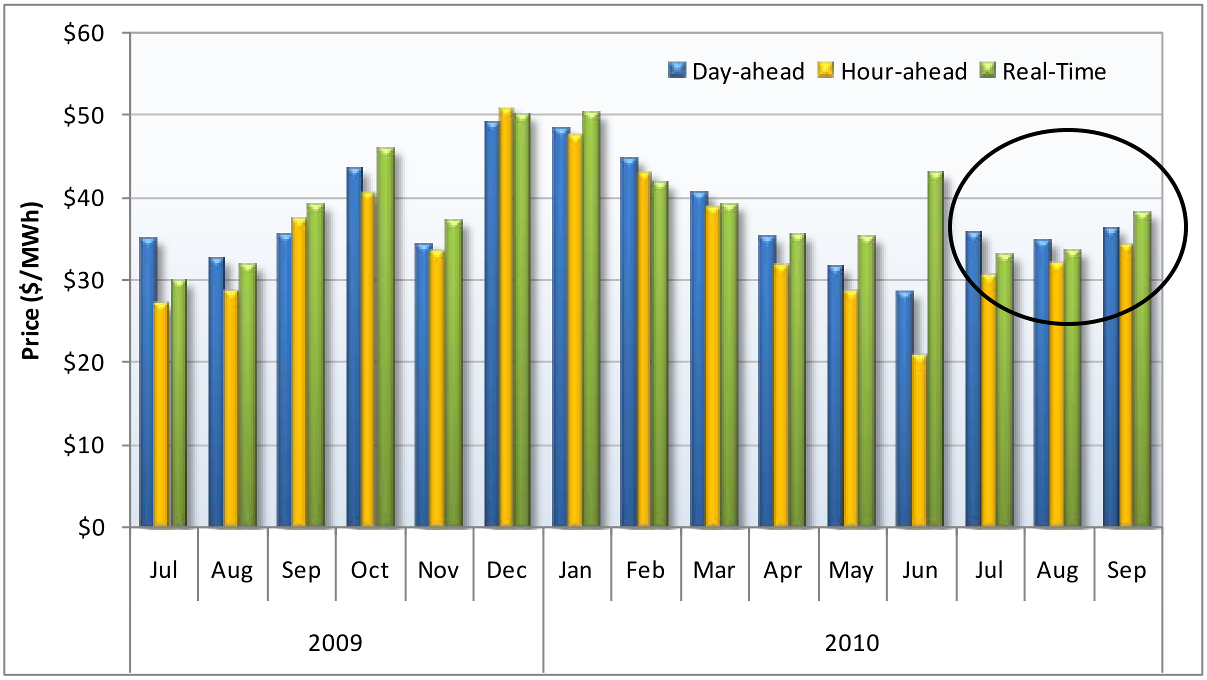
Ancillary services

- Ancillary services costs in Q3 totaled $23.2 million, an increase of almost 8.5 percent from the same quarter last year, but an 11 percent decrease from Q2. The increase in costs from Q3 2009 occurred mainly as a result of higher regulation and spin prices. The decrease from Q2 can be attributed to decreased prices of regulation and spin.
- In general, the average day-ahead market clearing price for regulation down, regulation up, and spin decreased each month during the third quarter. Non-spin prices trended upward during this time.
- The amount of self-scheduled capacity in Q3 for regulation and spin increased compared to the previous quarter, contributing to the decrease in day-ahead prices. In September 2010, regulation up obtained the lowest average day-ahead market clearing price since the start of the nodal markets in April 2009.

Divergence in hour-ahead scheduling process and real-time dispatch prices

Although overall price convergence improved in Q3 compared to Q2, prices in the hour-ahead scheduling process (HASP) continued to remain lower than prices in the 5-minute real-time dispatch (RTD) market in Q3, as shown in Figure E.2.

Figure E.2 Monthly average prices (all hours, PG&E LAP)



The tendency for 5-minute real-time prices to exceed hour-ahead prices is driven in large part by relatively short-term extreme price spikes that occur when the 5-minute real-time market software meets the system-wide power balance constraint with regulation resources rather than with energy resources. When this relaxation occurs, the software imposes a penalty price, which then affects the energy prices in the pricing run.[1] This constraint can occur in two different ways:

- When the market software dispatches regulation as supply to meet projected demand, this represents a "shortage" of dispatchable energy bids that causes prices to spike upwards to the $750/MWh bid cap.
- When the market software dispatches regulation down to balance supply with projected demand, this represents an "excess" of scheduled energy that causes prices to spike downwards to the -$30/MWh bid floor.

Figure E.3 shows monthly prices in all hours adjusted for the power balance constraint. Price convergence between hour-ahead and real-time prices improved in these hours, particularly in the months of April through June 2010. Moreover, after adjusting for these hours, there is also a day-ahead price premium to both the hour-ahead and real-time markets in most months.

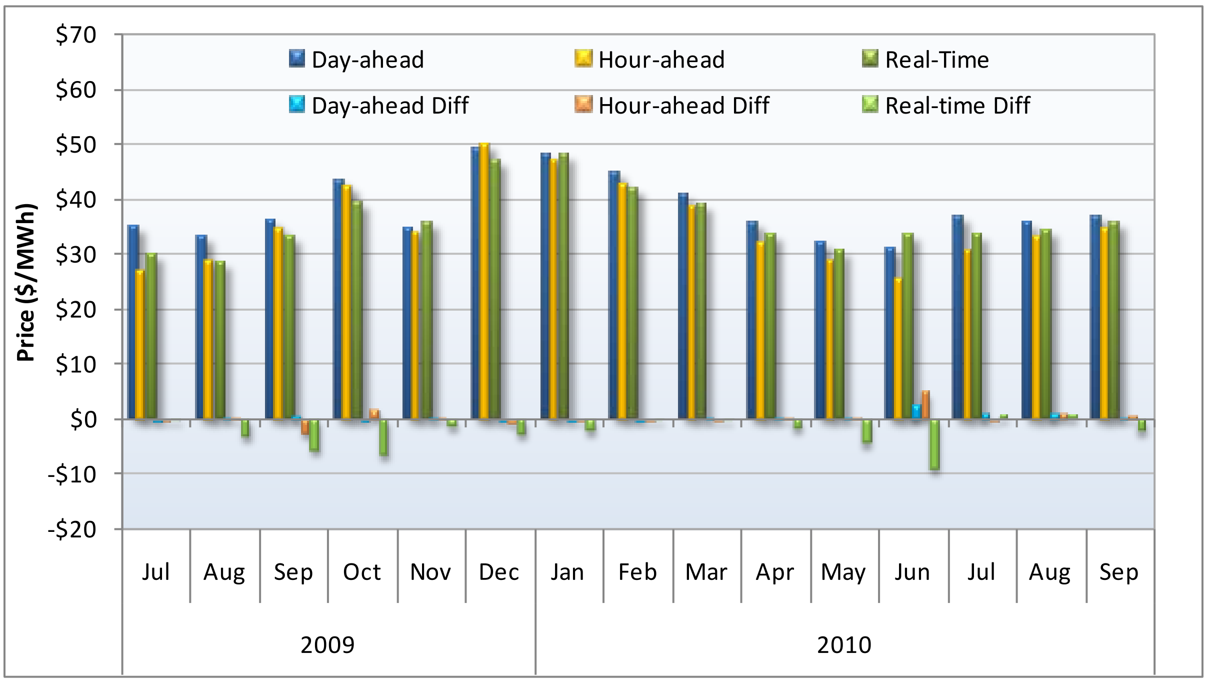
One of the major root causes of the divergence of prices in the hour-ahead and 5-minute real-time markets that has been identified involves the difference in load forecasts used in these two markets. Differences within the forecasting software may be a result of changing conditions between the

[1] The pricing penalty for supply being short of demand is set at the energy bid cap, which is currently set at $750/MWh, as specified by the Federal Energy Regulatory Commission. The energy bid cap and penalty price will increase to $1,000/MWh on April 1, 2011. The pricing penalty for supply being ahead of demand is set to -$35/MWh.

execution of the hour-ahead market and the real-time market. Load forecasts used in the software can also be adjusted by a load bias. Load bias occurs when operators change load assumptions to the forecast either explicitly or implicitly within the model. Load bias levels are not necessarily consistent between the hour-ahead and real-time forecasts. When taken together, load forecast differences and operator bias can lead to differences in price results between the hour-ahead and the real-time markets. The ISO should be able to address real-time price volatility and divergence through improved short-term forecasting and load adjustment processes.

Other factors influencing divergence include differences in real-time delivered energy from variable energy resources from hour-ahead forecast levels as well as other deviations in operational resources in real-time (e.g., due to outages and other factors). The ISO may be able to mitigate the impacts of factors that add variability and uncertainty in the real-time market by incorporating features that would ensure greater resource flexibility on a 5-minute basis.

Figure E.3 Change in monthly prices without hours when power balance constraints active (PG&E LAP, all hours)



Compensating injections

The California ISO transmission network is part of the Western Electricity Coordinating Council network. Throughout WECC, energy schedules between different balancing authority areas (BAAs) are based on energy scheduled under transmission rights or contract path flows. As a result, there might be discrepancies – or unscheduled flows – between these contract path flows and the actual flows between the ISO and neighboring BAAs.

In July 2010, the ISO implemented a new feature in the real-time software to manage these unscheduled flows in an automated manner using compensating injections.[2] Compensating injections are megawatt injections and withdrawals made in the ISO software at various locations external to the ISO to minimize unscheduled flows along the inter-ties in both the hour-ahead and 5-minute real-time markets.

DMM observes that net compensating injections range between positive and negative 100 MW during each interval. However, both the gross positive and negative compensating injections can add up to more than 4,000 MW in some intervals. On an individual inter-tie basis, DMM has observed in the ISO sample data that the compensating injections on major inter-ties have been only in the hundreds of megawatts.

As part of the implementation of compensating injections for reliability concerns, a limitation was imposed by a discount factor, which discounts the compensating injections at each location if the overall net system-level compensating injections are above certain thresholds.[3] If the net compensating injections are above some higher threshold, every individual compensating injection will be cancelled. Specifically:

- The intervals when the positive and negative compensating injections exceed 1,000 MW represent intervals no discounting was applied, so that the full impact of this feature was in effect. We refer to these intervals as Full CI intervals.
- The intervals when the positive and negative compensating injections are just under 1,000 MW represent intervals when the compensating injection feature was on but the discounting was applied. We refer to these intervals as Partial CI intervals, since the impact of this feature was partially in effect.
- The intervals when no compensating injections occurred represent intervals when compensating injections were cancelled or not generated as a result of functional failures of this software feature.

Based on the ISO's metrics and sample data for monitoring the performance of compensating injections on major inter-ties, DMM has identified several general trends:

- For intervals with Full CI, the differences between the market flows and actual flows are close to zero. This indicates that when compensating injections are not discounted, they are able to reduce the gaps between the scheduled and actual flows. Full CI accounted for roughly 26 percent of the intervals in Q3.
- For intervals with Partial CI or No CI, the gaps between market and actual flows persist. Because the discount factor is small, the intervals with Partial CI and the intervals with No CI are often indistinguishable from each other. Thus, the discount factor, which occurs in most intervals, greatly limits the capability and performance of compensating injections in tightening the flow gaps. Partial CI occurred in roughly 70 percent of the intervals in Q3, whereas CI was turned off in roughly 5 percent of the intervals in the quarter.

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[2] Technical Bulletin 2010-07-01, Compensating Injection in the ISO Real-time Market, July 16, 2010, http://www.caiso.com/27d4/27d4e73124db0.pdf.

[3] In the third quarter of 2010, the discount factor was 0.2 for net compensating injections between 50 MW and 500 MW in absolute value. Below 50 MW, compensating injections were not discounted; above 500 MW, all compensating injections were cancelled.

Recommendations:

Improve the consistency of hour-ahead and real-time prices and dispatches.

The trend of selling relatively large quantities of import/export energy in the hour-ahead scheduling process and then re-purchasing additional energy in the 5-minute market at higher prices remains one of the most critical areas for further improvement in the new market software and processes.

Many of the changes identified in the Q3 2009 and again in the Q2 2010 reports that might address this issue are still under development by the ISO. In several cases, implementation of these modifications was initially anticipated in the end of 2009 or early 2010, but implementation has been pushed back to Q4 2010. The status of these changes as well as other ISO actions is outlined below.

- As reported in DMM's reports for Q3 2009 and Q2 2010, the ISO is developing a new short-term forecasting tool that is designed to provide a more accurate and consistent forecast for both the hour-ahead scheduling process and the real-time market. In addition, this new forecast will specifically be designed to provide forecasts at the 15-minute and 5-minute level of granularity over the approximately two hour forecasting timeline needed for the hour-ahead and real-time markets. Implementation of this new forecasting tool is anticipated in the fourth quarter of 2010.

- In Q3 2009, the ISO assessed a variety of options that might mitigate the impacts of the differences in ways that inter-tie schedules and ramping of resources are modeled in hour-ahead compared to real-time. As an initial step, the ISO is developing enhancements that would modify the hour-ahead scheduling process to account for the imbalance energy difference that arises because it does not model how changes in net hourly inter-tie schedules are ramped in over a 20-minute period each operating hour. Testing of this enhancement is currently in progress. The target for release of this feature was moved several times, and is currently projected for the fourth quarter of 2010.

- The ISO is continuing to look for opportunities to improve how and when to adjust or bias the load forecasts used in the hour-ahead and 5-minute real-time markets. As part of this effort, the ISO is developing a more systematic procedure that gives the operator additional guidance to determine whether a bias should be removed or continued.

- In late July 2010, the ISO implemented the capability to produce automated compensating injections in the hour-ahead and 5-minute real-time market software. This feature is designed to automatically align flows produced by the market software with actual observed flows. This feature is expected to decrease the need for manual biasing of transmission limits, and may help to improve price convergence between the hour-ahead and 5-minute real-time markets. However, the effectiveness of compensating injections on improving price convergence has yet to be quantified due to data limitations, which are discussed below.

- As identified in DMM's Q2 2010 report, the ISO has begun a process to evaluate what products, if any, may be necessary to support renewable integration. These products could potentially address some of the issues related to low ramping capability, and could improve price convergence in certain instances.

- The ISO is considering whether additional constraints may be added to the market software to better ensure that there is sufficient committed flexibility to absorb the potential variation and uncertainty in actual real-time imbalance conditions.

While implementation of the changes identified above may improve price convergence, DMM believes the ISO should continue to seek to identify other potential sources of the divergence between prices and dispatches in the hour-ahead and real-time markets and how these may be addressed. Addressing sources of real-time price spikes and divergence due to forecasting and modeling issues becomes increasingly important with the scheduled implementation of convergence bidding in 2011. With convergence bidding, spikes in the real-time market may have a larger impact on the day-ahead market, where market cost impacts are larger.

DMM supports ISO efforts to identify methods to ensure that sufficient flexibility of resources are available to meet the variability and uncertainty of real-time conditions. DMM has observed that small variations can have large asymmetric impacts on real-time prices. The more flexibility built within the model, the better the ISO can respond to these real-time events.

Provide the data necessary to further test the effectiveness of compensating injections.

DMM recommends that the performance of compensating injections be assessed by comparing market flows both with and without compensating injections against actual flows, for both external inter-ties and major internal paths, over a period of time.

The current compensating injection software and monitoring efforts of the ISO are focused on inter-ties, under the assumption that improvements in modeled versus actual flows on the inter-ties will result in similar improvement on internal constraints within the ISO. However, the ISO does not currently capture the data needed to monitor the actual impact on internal constraints. Analysis of the difference between scheduled versus actual flows over longer time periods could provide insights into systematic patterns in unscheduled flows that might be incorporated into the day-ahead modeling process, rather than only the hour-ahead and real-time markets.

Such analysis is currently infeasible for several reasons. Actual flow data requires manual processing, which makes it too difficult for DMM to perform long-term analysis. In addition, the ISO captures data for market flows with compensating injections but not without compensating injections. Without this information, DMM is not able to determine if false congestion caused by market flow divergence has occurred as a result of over-compensating the market flows on internal paths. DMM is also not able to determine whether or not over-correction has occurred along the inter-ties.

When the data is available, DMM will perform additional analyses on congestion related concerns and report further on its findings.

1 Review of market performance

1.1 Energy market

Overall performance

This section provides an assessment of the overall performance of the integrated forward market and real-time energy market. Key findings include the following:

1. The day-ahead integrated forward market has continued to be very stable and competitive, with a very high portion of load and supply being scheduled in the day-ahead market (e.g., typically 94 to 101 percent).

2. Energy prices in the day-ahead market during each month of the third quarter continue to be approximately equal to benchmark prices estimated under perfectly competitive conditions.

3. Real-time energy prices exceeded $500/MWh in about 1 percent of intervals in July, primarily as a result of wildfires and related transmission de-rates in real-time, increasing average real-time price at the SCE load aggregation point significantly above the competitive baseline price for the day-ahead market. However, real-time market prices in August and September 2010 were close to competitive baseline levels.

Day-ahead scheduling of load

Load scheduled in the day-ahead market continues to be very high. As shown in Figure 1.1 and Figure 1.2, about 94 to 101 percent of real-time load was scheduled in the day-ahead market in Q3. This is consistent with levels of day-ahead scheduling in Q2.

The level of load scheduled in the day-ahead market can represent a key indicator of overall market efficiency and competitiveness. If the amount of load scheduled in the day-ahead market is close to the actual level of load in real-time, this generally indicates sufficient supply was made available and load bids effectively reflected market and system conditions. This generally allows for more efficient unit commitment and energy scheduling. High levels of load scheduling in the day-ahead market can also indicate that markets are competitive and that market power is being effectively mitigated. Finally, when load scheduled in the day-ahead is near actual load, the effect of extremely high or low real-time prices is low, because a relatively small portion of demand and supply is actually being settled at the real-time price.

For Q3, the percentage of actual real-time load scheduled in the day-ahead market corresponded well with real-time prices for hours ending 2 through 20. During these hours, a greater percentage of actual real-time load was scheduled in the day-ahead when real-time prices trended higher. A lower percentage of actual real-time load was scheduled in the day-ahead when real-time prices trended lower. Thus, the scheduling of load appears to be relative to the day-ahead and real-time price relationship.

As shown in Figure 1.1, a relatively higher percentage of load is scheduled in the day-ahead during the hours when loads begin to ramp down (hours ending 21 through 24 and hour ending 1), which is also when real-time prices have trended higher over the last two quarters.

Figure 1.1 Day-ahead load scheduling by operating hour (Q3 2010)

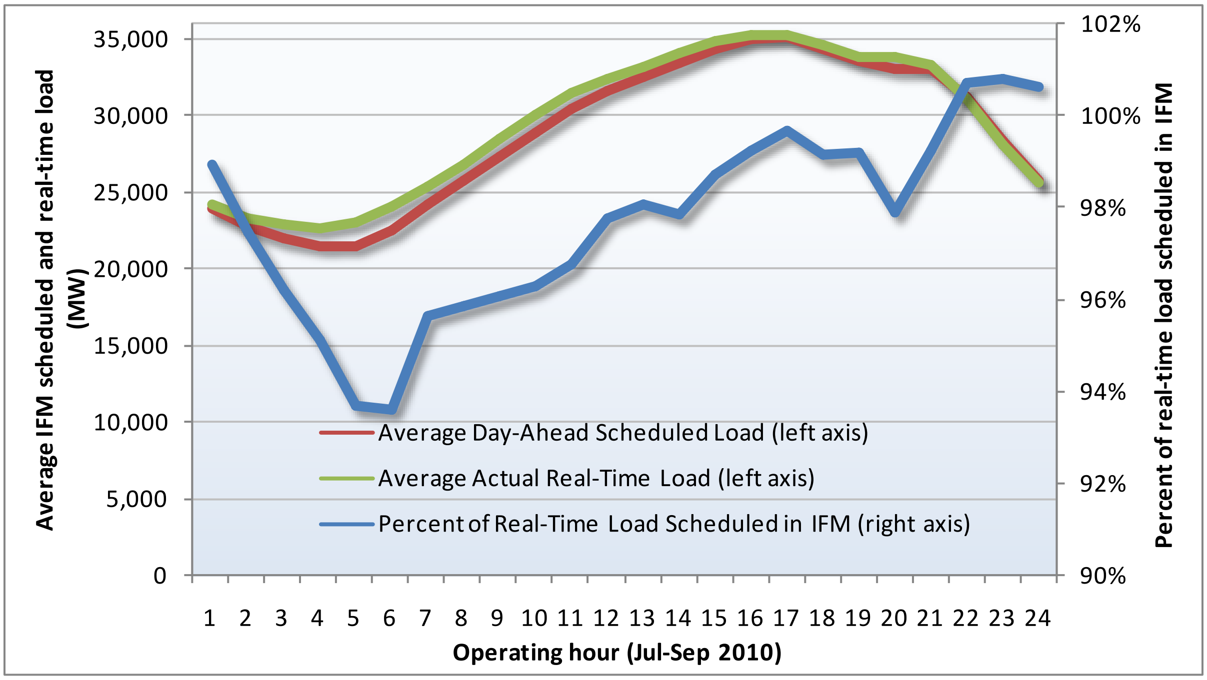
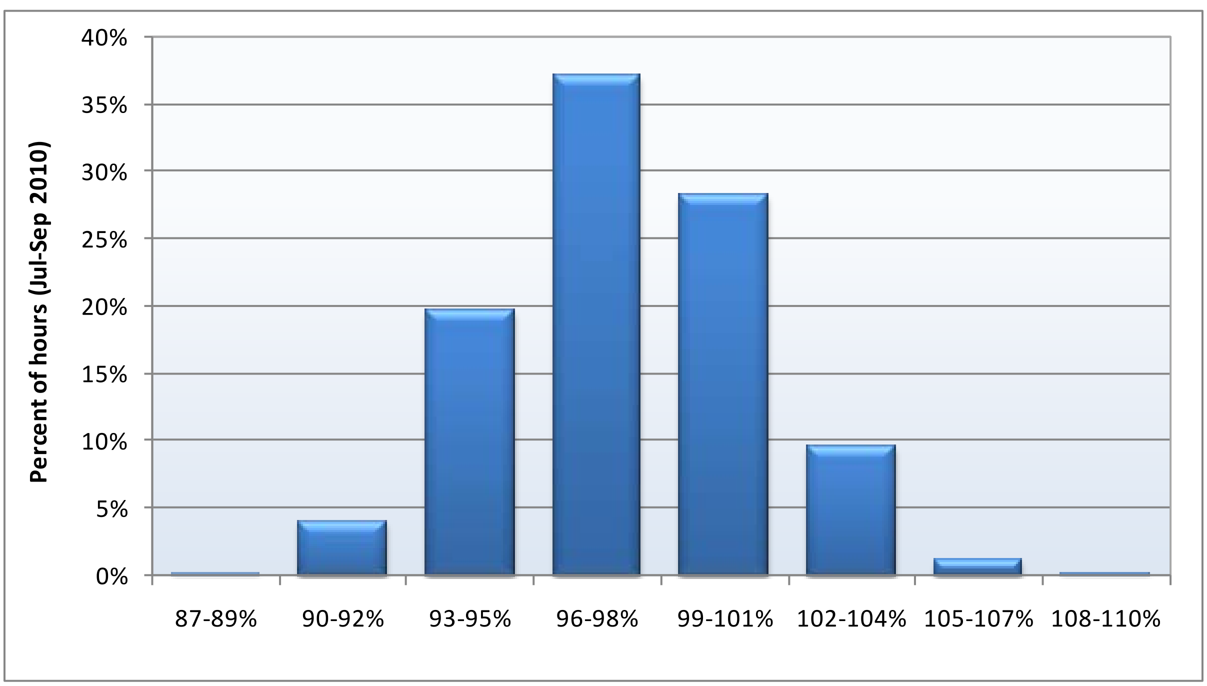


Figure 1.2 Percent of real-time load scheduled in the day-ahead (Q3 2010)



Market competitiveness

To assess the overall competitiveness of the energy market, DMM estimates competitive baseline prices as a benchmark for assessing actual market prices. This benchmark is calculated by re-simulating the market using the day-ahead market software with bids reflecting the actual marginal cost of gas-fired units. To calculate this baseline under the new market design, DMM replaces actual market bids submitted by gas-fired units with the default energy bids that would be used if a unit were subject to bid mitigation. A detailed description of the methodology is provided in DMM's Q4 2009 report.[4]

Figure 1.3 shows monthly summary results of this competitive baseline analysis for the SCE load aggregation point. The percentage difference between actual market prices and prices resulting under this competitive baseline scenario represents the *price-cost mark-up* index for the day-ahead market. As illustrated in Figure 1.3, the monthly price-cost mark-up ranged from 0 percent to -4 percent. Results for the PG&E and SDG&E load aggregation points are approximately equal to results for the SCE load aggregation point.

Overall, the mark-up index indicates that monthly prices are within competitive ranges for the quarter. The mark-up index for Q3 shows slightly negative price-cost mark-ups, which are attributable to the fact that a significant amount of generators bid slightly below their default energy bids. Because cost-based default energy bids include a 10 percent adder above fuel and variable costs, these relatively small negative mark-ups are indicative of a competitive market and reflect the fact that actual bids for many units are designed to cover fuel and variable costs, but do not include the additional 10 percent multiplier included in default energy bids.

Meanwhile, average prices were slightly higher during Q3 relative to Q2 in both the actual day-ahead market and the competitive baseline scenario results. This small increase can be explained by higher loads causing higher cost units to set prices for peak hours during Q3 compared to Q2. The slightly higher electricity prices in July are due to slightly higher natural gas prices during this month.

Real-time price spikes

While the frequency of real-time price spikes decreased in Q3 from the previous quarter, the overall level of price spikes increased compared to previous quarters (see Figure 1.4). The percent of intervals with real-time prices above $250/MWh decreased from 1.5 percent of intervals in Q2 to 0.9 percent of intervals in Q3. However, roughly 0.1 percent of intervals in Q3 had price spikes greater than $1,000/MWh (see red bars in Figure 1.4). The frequency of these extreme price spikes was more than in any other quarter over the past 15 months under the new market design. Additionally, the frequency of price spikes above $750/MWh was roughly the same in Q3 as in Q2.

The increase in extreme price spikes occurred primarily in the SCE and SDG&E areas and was due in large part to transmission de-rates in and along Path 26, which was threatened by wildfires during periods of high demand. As noted in Section 2, when extremely high prices occurred in the real-time market, these prices were primarily due to the power balance constraint and congestion.

[4] *Quarterly Report on Market Issues and Performance*, Department of Market Monitoring February 1, 2010, pp. 22-23, http://www.caiso.com/2730/2730ee1e71a10.pdf

Figure 1.3 Competitive baseline index for SCE LAP

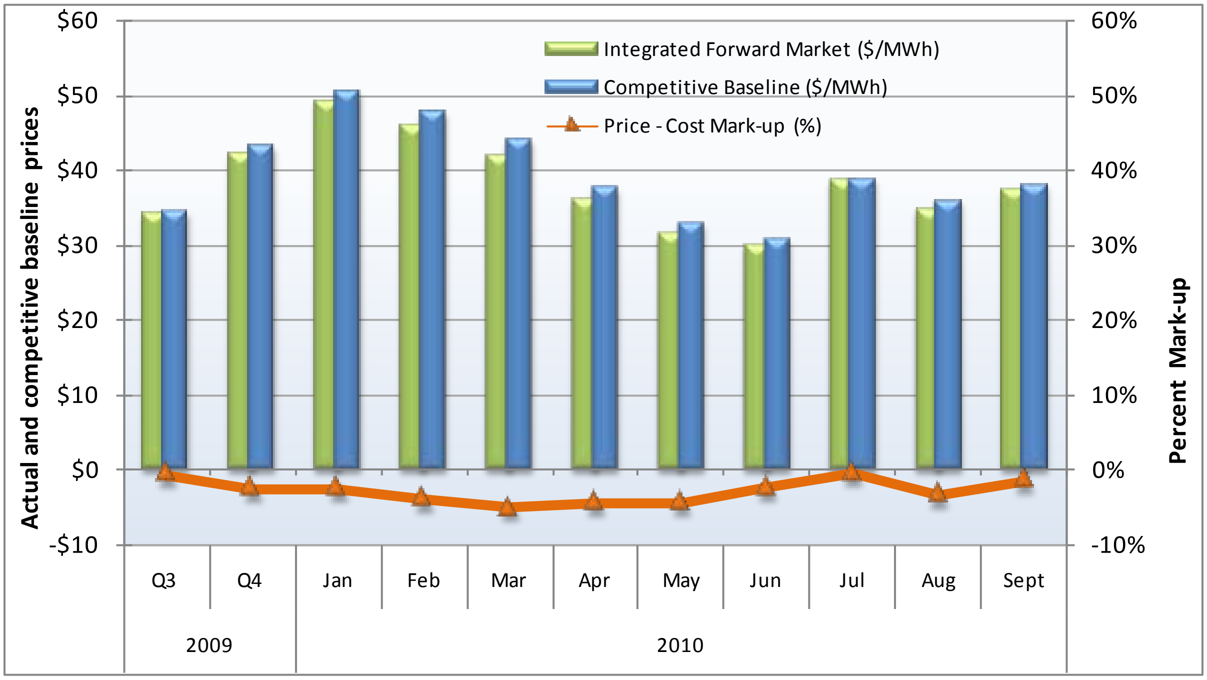


Figure 1.4 Real-time LAP price spike frequency by month

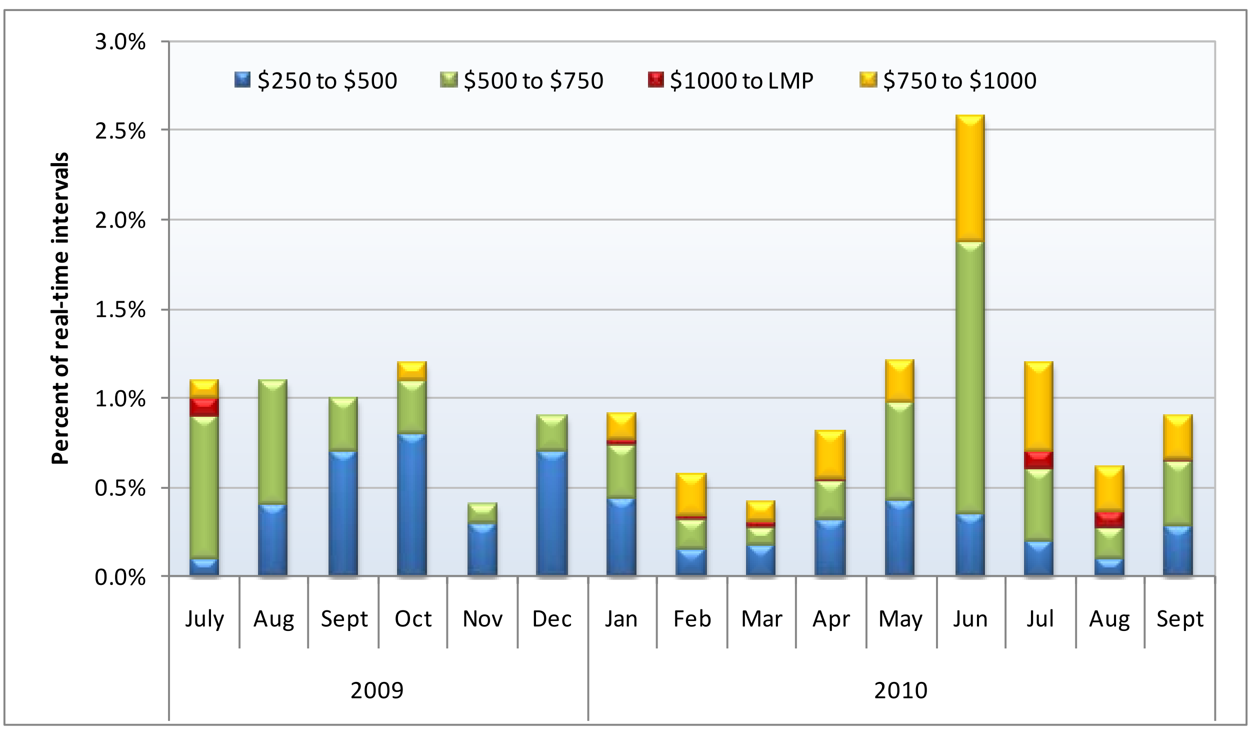


Figure 1.5 compares the competitive baseline price calculated by DMM using the day-ahead market software for the SCE area with three different averages of 5-minute real-time prices: (1) the average of all 5-minute prices (red line); (2) the average with extreme 5-minute prices truncated at the relevant bid cap (purple line); and (3) the average with all prices above or below the bid caps excluded (green line).[5] Comparing real-time prices with averages that have extreme prices truncated or excluded highlights the impact of extreme price spikes (or negative prices) on overall average prices. In addition, when comparing real-time prices to the competitive baseline prices computed by DMM, we believe it is appropriate to exclude such extreme prices given that real-time prices reflect 5-minute operating constraints that cannot be captured in the competitive baseline estimate produced using the day-ahead market software.

As shown in Figure 1.5, all three of these price comparisons for the SCE area were relatively close to the competitive baseline in August and September 2010. However, in July 2010, average real-time prices rose significantly above the competitive baseline. This price difference can be attributed to extreme real-time prices above the $750/MWh bid cap in the SCE area during July.[6] Most of these extreme real-time prices were driven by specific events, such as wildfire-related transmission de-rates and outages, generation outages, and, on some days, higher than expected real-time demand.

As shown in Figure 1.5, when extremely high or low real-time prices (greater than the respective bid cap of $500/$750 or less than -$30) are excluded, average real-time prices for each of the three months are essentially equal to the competitive baseline estimate. The SDG&E load aggregation point exhibits similar trends as SCE concerning real-time prices and competitive baseline.

As shown in Figure 1.6, real-time prices in the PG&E area were slightly below competitive baseline in July. This is attributable to transmission de-rates resulting in north-to-south congestion on Path 26, which causes prices in the PG&E area to decrease relative to the SCE and SDG&E prices.

[5] Prior to April 1, 2010, prices above the $500/MWh energy bid cap in effect during this period are truncated or excluded. After April 1, 2010, prices above the $750/MWh energy bid cap are truncated or excluded.

[6] Data for the chart equivalent to Figure 1.5 appearing in the Q2 report had a coding error. The error resulted in the yellow line showing the average prices with prices above $500 and below -$30 removed (rather than above $750 and below -$30 removed) for April, May, and June 2010. Figure 1.5 in this report provides the corrected data for the Q2 2010 yellow line (now green). The correction marginally increased the average price with extreme prices removed number for April and May. However, only removing prices above $750, rather than prices above $500, increased the Excluding Prices average price for the month of June to be roughly equal to the average real-time price with no prices removed. Extreme prices above $500/MWh caused the average real-time prices to exceed the day-ahead competitive baseline in June. The Q2 report's figure shows that removing prices above $500 and below -$30 results in real-time prices roughly equal to the day-ahead competitive baseline in June.

Figure 1.5 Comparison of competitive baseline to real-time prices in SCE LAP

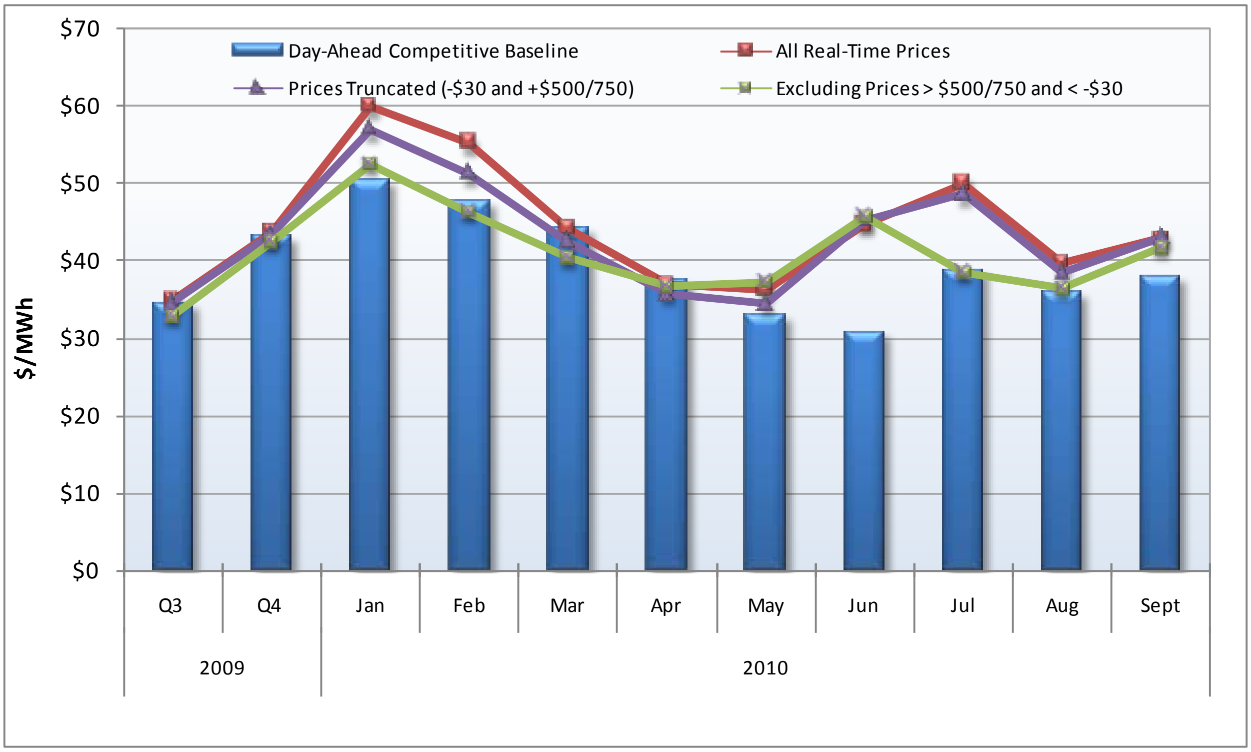
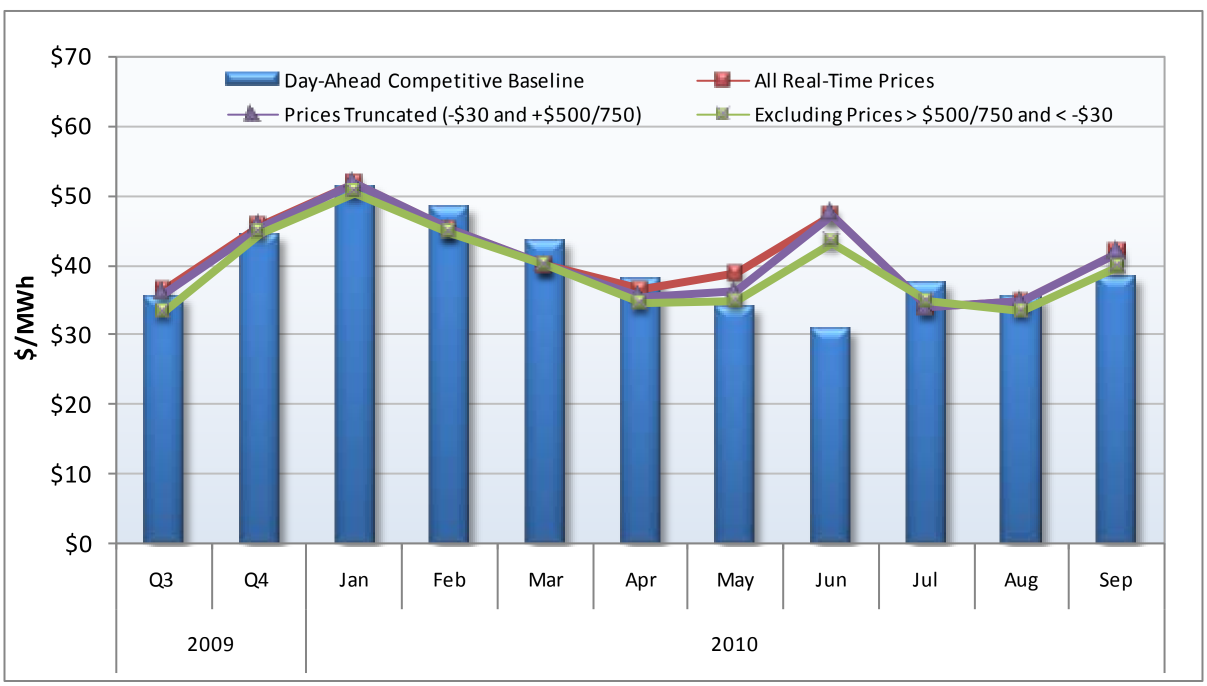


Figure 1.6 Comparison of competitive baseline to real-time prices in PG&E LAP



Monthly average prices

Average on-peak and off-peak prices throughout the ISO system in both the day-ahead and real-time markets were higher in the third quarter than in the second quarter due to higher loads.

In the SCE load aggregation point, monthly average peak prices in the 5-minute real-time market were higher than prices in the day-ahead and hour-ahead markets in the months of July through September 2010, as illustrated in Figure 1.7 and Figure 1.8. The increase in 5-minute real-time prices was primarily driven by specific events, such as wildfire-related transmission de-rates and outages, generation outages, and higher than expected real-time demand on some days.

During off-peak hours, monthly average prices in the SCE area were slightly higher for the real-time market than prices in the day-ahead and hour-ahead markets in July 2010 and slightly lower in August and September. These results were a significant shift from the prices in Q2 and can be attributed to changes in self-scheduling resources relative to load and ramping conditions. Day-ahead and hour-ahead prices trended upward in Q3 compared to Q2.

Energy prices in the PG&E and SDG&E load aggregation points experienced a similar trend across the quarter as the SCE load aggregation point for the three markets. Figure 1.9 shows price convergence between the hour-ahead and real-time markets for the PG&E load aggregation point. Overall, price convergence was significantly better in Q3 compared to the previous quarter, particularly June.

Figure 1.7 Monthly average LMPs for the SCE LAP (peak hours)

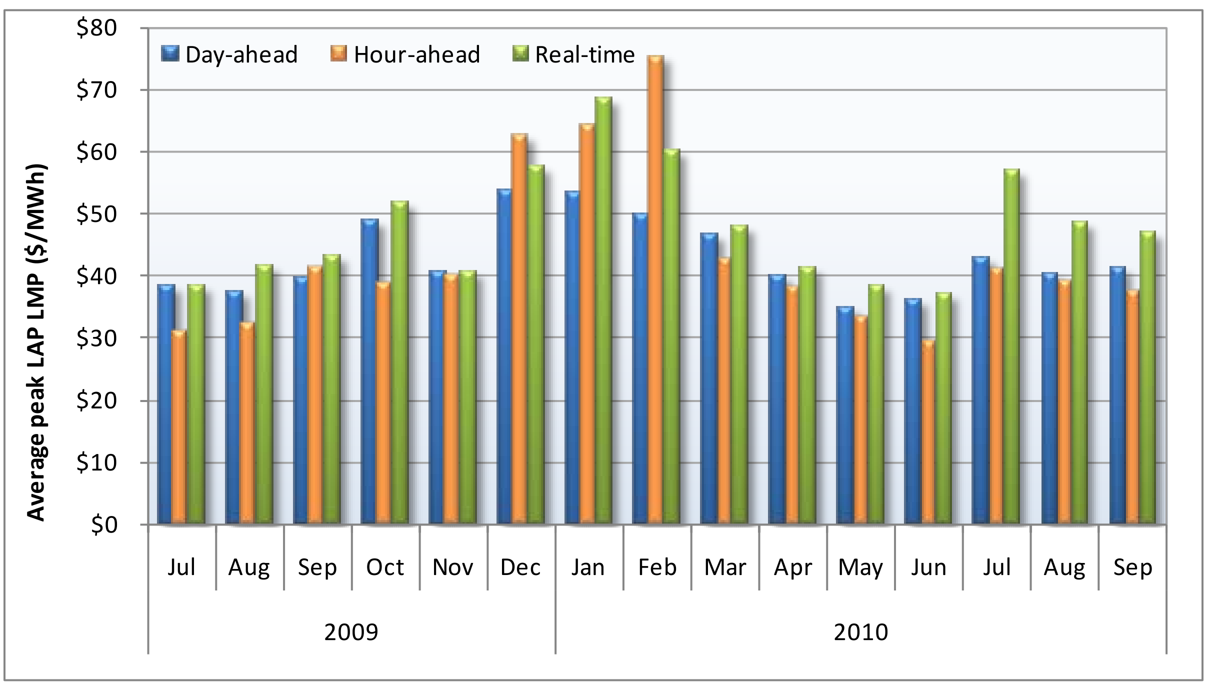


Figure 1.8 Monthly average LMPs for the SCE LAP (off-peak hours)

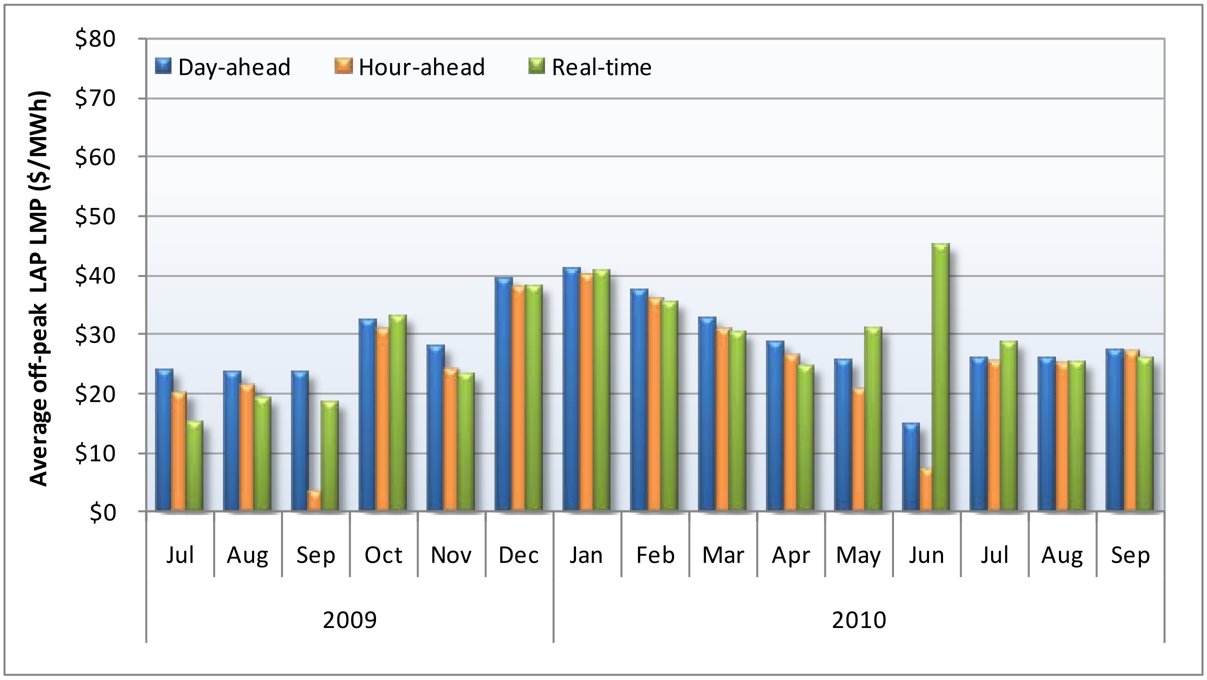
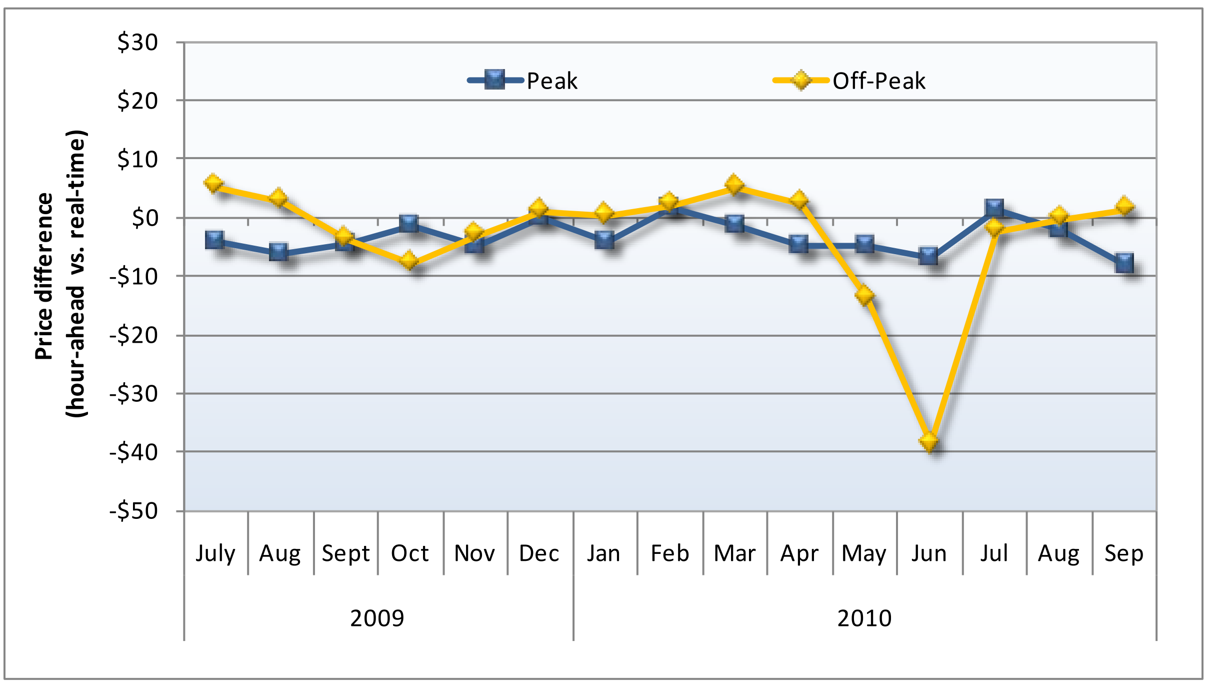


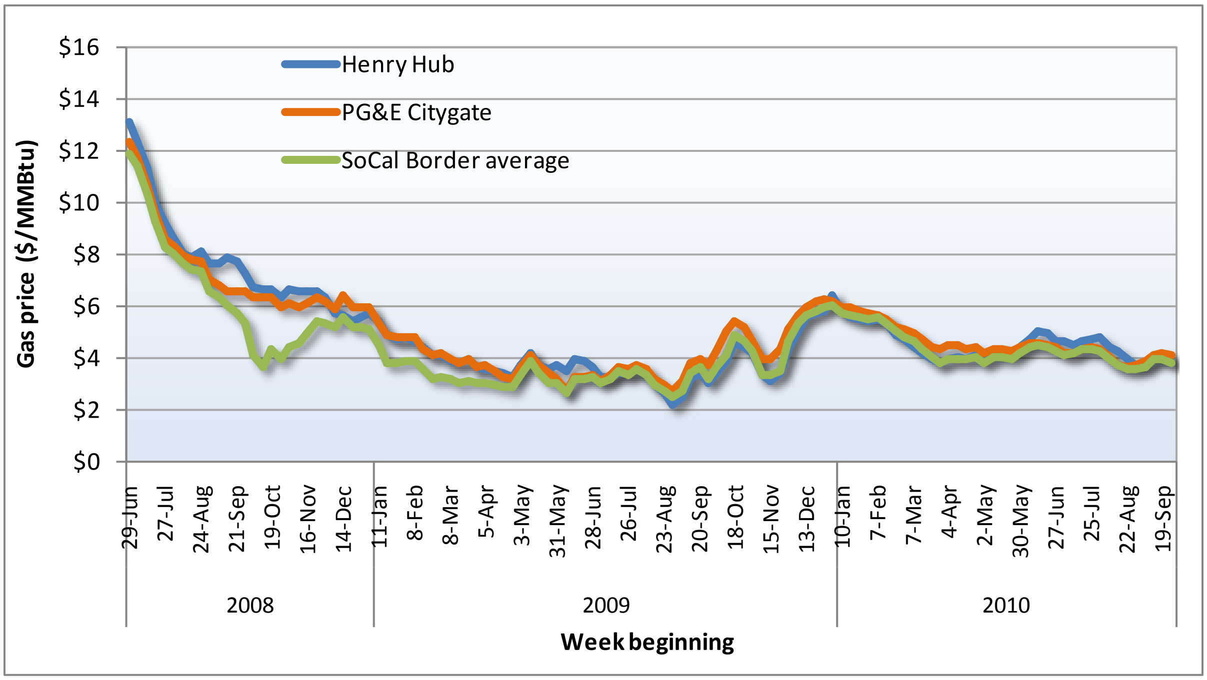
Figure 1.9 Convergence between hour-ahead and real-time LMPs – PG&E LAP



Natural gas prices

Weekly natural gas prices in California ranged from just over $3.50/MMBtu to just under $4.50/MMBtu during the third quarter. Compared to the third quarter 2009, weekly third quarter 2010 California natural gas prices increased about $0.75/MMBtu (over 20 percent), following the overall change in the natural gas commodity price at the Henry Hub. Even though natural gas prices were up compared to last year, the third quarter natural gas prices in California were the lowest so far this year, with 2010 lows achieved in late August. As is common, the PG&E Citygate prices were a premium to the SoCal Border average prices, averaging $0.15/MMBtu above the SoCal Border average for the quarter.

Figure 1.10 Natural gas prices



1.2 Congestion

Congestion on external interfaces and scheduling limits

Figure 1.11 and Figure 1.12 provide a comparison of the hours of day-ahead congestion on major inter-ties in the north and south of the ISO system, respectively, on a quarterly basis from Q3 2009 through Q3 2010. Table 1.1 provides the frequency of congestion and average shadow price on the inter-ties and scheduling limits in the day-ahead market in Q3 2010.

The frequency of congestion on inter-ties with other regions was down on most inter-ties in Q3 2010. However, while congestion fell on many inter-ties, congestion increased on some inter-ties compared to previous quarters.

- In the north, the frequency of congestion in Q3 significantly decreased for the Silver Peak, NOB, PACI and Summit inter-ties compared to Q2.

- In the south, the frequency of congestion in Q3 significantly decreased for the Mead inter-tie and was similar for the Palo Verde inter-tie compared to Q2.

Key trends in Table 1.1 include the following:

- The **Mead inter-tie** was congested 19 percent of the time in the day-ahead market in the third quarter. The congestion occurred mostly during the peak hours. The average shadow price on this inter-tie was relatively low at $5/MWh. The frequency of day-ahead congestion on Mead in Q3 was moderately higher than Q3 2009, but significantly lower than in Q1 and Q2 2010. Even when congestion occurred on the Mead inter-tie, there were often significant quantities of unused capacity reserved for existing transmission contracts and transmission ownership rights. These transmission rights are reserved until after the completion of the hour-ahead market unless they are released by the participant prior to the running of the market. The participant may choose to schedule or not schedule power on the reserved transmission. This reduces the amount of transmission capacity available for the market, regardless of whether or not the capacity is used by the participant.

Figure 1.11 Frequency of day-ahead congestion on major northern inter-ties

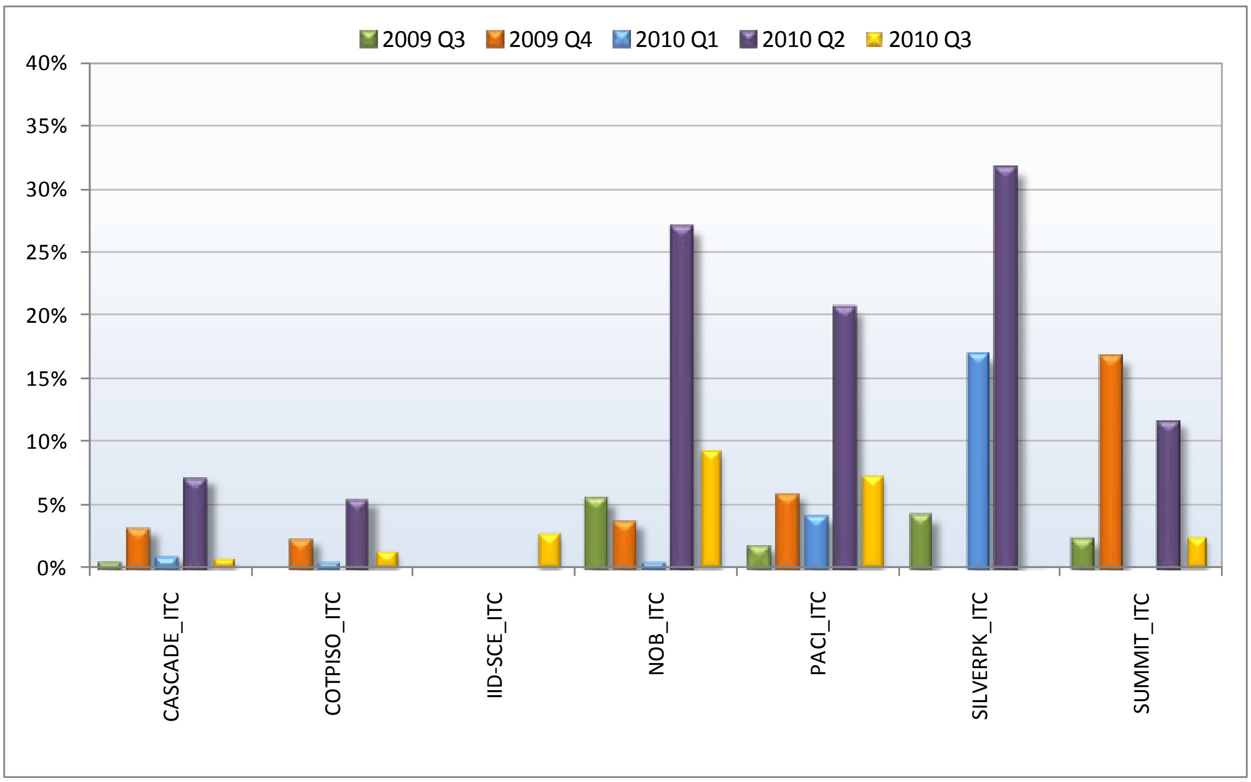
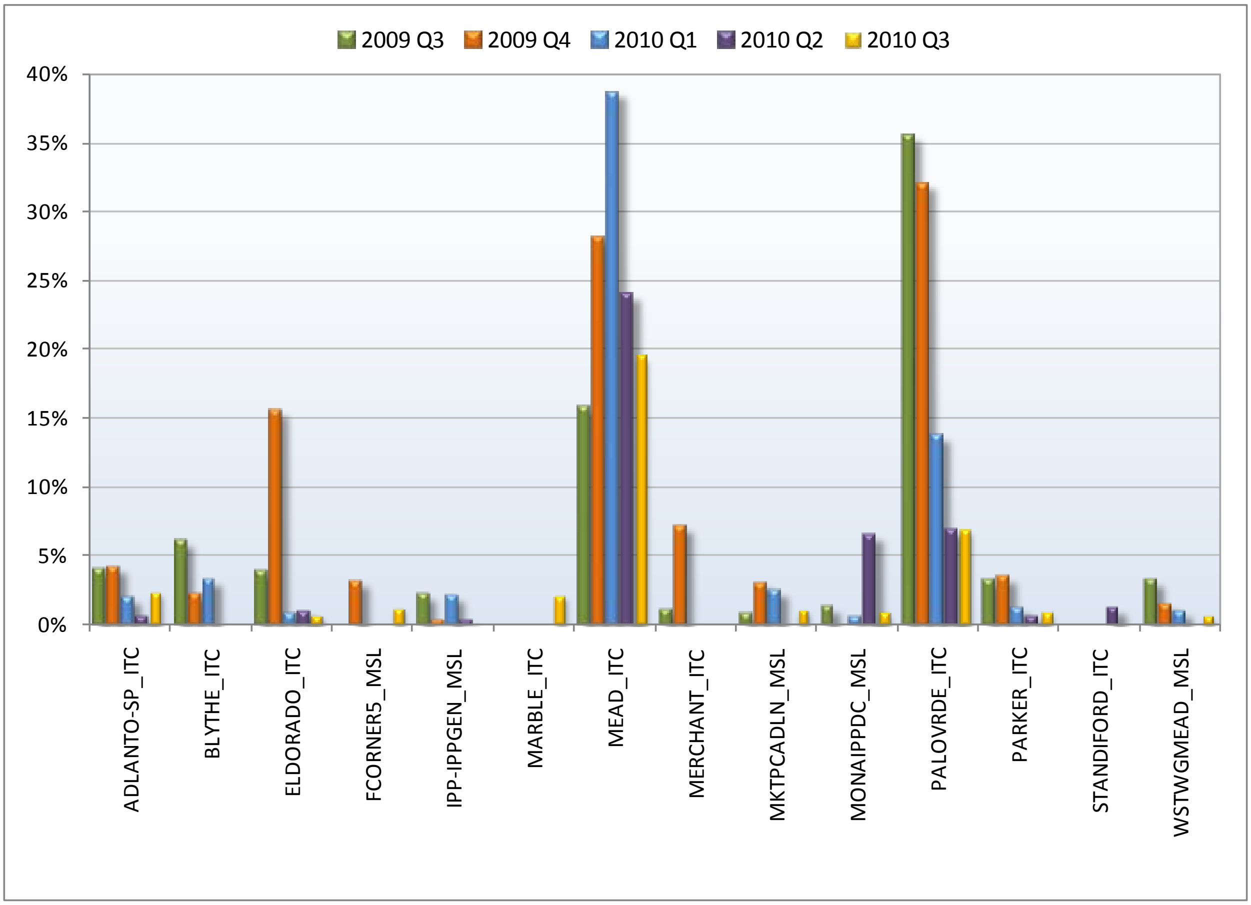


Figure 1.12 Frequency of day-ahead congestion on major southern inter-ties



- The frequency of the **NOB inter-tie** day-ahead congestion significantly decreased in Q3 compared to the previous quarter. During the quarter, NOB was congested approximately 9 percent of the time, with an average shadow price during hours of congestion of $14/MWh. The **PACI inter-tie** was congested 7 percent of the time in the day-ahead market, with an average shadow price of $11/MWh. The congestion levels on these inter-ties were influenced by de-rates and transmission outages, including the outage of Marion-Lane #1 500 kV line; and by the seasonal decline of hydro-electric generation in the Northwest and increased local demand.

- The **Silver Peak inter-tie** was congested 0.01 percent of the time in the day-ahead market in Q3. This is a dramatic decrease from Q2, when the line was congested 31 percent of the time due to line maintenance. This maintenance was completed at the end of May 2010. The average shadow price when this line was congested was $1/MWh.

- The frequency of day-ahead congestion on the **Palo Verde inter-tie** increased slightly (0.06 percent) in Q3 from its previous record low level in the new market in Q2. During Q3, Palo Verde was congested 7 percent of the time, with an average shadow price of $7/MWh. Palo Verde congestion was primarily a result of planned outages and line maintenance.

Table 1.1 Frequency of IFM congestion and average shadow prices of inter-ties (Q3 2010)

Name	Congestion Frequency	Avg. Shadow Price ($/MWh)
ADLANTO-SP_ITC	2%	$5
CASCADE_ITC	0.6%	$10
COTPISO_ITC	1%	$10
ELDORADO_ITC	0.7%	$3
FCORNER5_MSL	1%	$15
IID-SCE_ITC	3%	$59
MARBLE_ITC	2%	$66
MEAD_ITC	19%	$5
MKTPCADLN_MSL	1%	$21
MONAIPPDC_MSL	1%	$4
NOB_ITC	9%	$14
PACI_ITC	7%	$11
PALOVRDE_ITC	7%	$7
PARKER_ITC	1%	$63
SILVERPK_ITC	0.1%	$1
STANDIFORD_ITC	1%	$721
SUMMIT_ITC	2%	$27
WSTWGMEAD_MSL	1%	$18

Congestion on internal constraints

Figure 1.13 shows the impact of congestion on specific internal constraints on average day-ahead LMPs for the three load aggregation points during the hours when congestion occurred. Constraints shown in Figure 1.13 include either congested internal flowgates and nomograms in the day-ahead market greater than 0.1 percent, or those that had an impact on an LMP of at least ±$0.90/MWh.

As shown in Figure 1.13, congestion on some constraints had a significant impact on prices in the different load aggregation points during hours of congestion. However, because the frequency of internal congestion was low, congestion had a minimal impact on overall day-ahead energy prices in Q3. Other findings include:

- Spring Mi-Wuk 115 kV (Line) was congested approximately 13 percent of the time. While this constraint was frequently binding in Q3, this constraint had only a minimal effect on the load aggregation point congestion. This line is a radial generation tie with capacity less than that of the hydro-electric generation tied to it. When the flowgate is congested, the hydro units can respond to prices, or, in the extreme, spill water when backed down. The nodal LMP on the generation side of the flowgate is low even when the system marginal energy component is high, resulting in a high LMP congestion component.

- Path 26 branch group was congested almost 2 percent of the time due to de-rates associated with wildfires. Congestion averaged $2.62/MWh for both the SCE and SDG&E load aggregation point LMPs during congested hours. The effect on PG&E was negative.

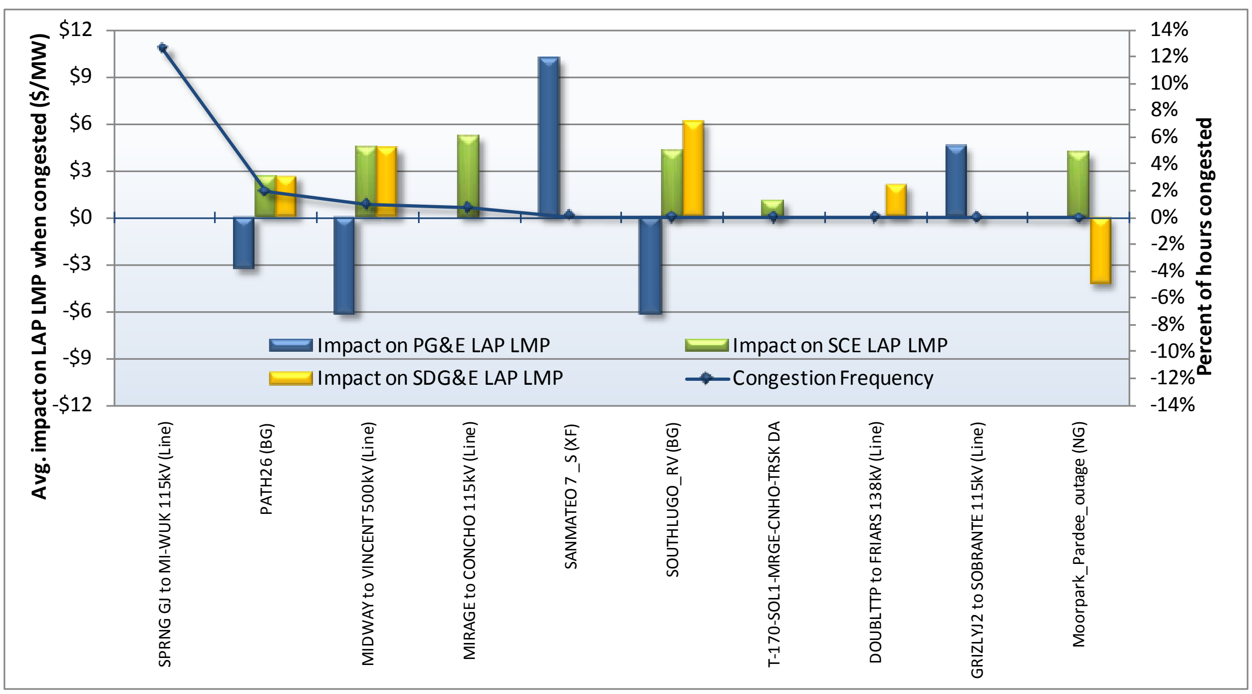
- Midway to Vincent 500 kV (Line), a component of Path 26, was congested roughly 1 percent of the time due primarily to wildfires and planned outages. The effect of the constraint on the SDG&E and SCE load aggregation point LMPs averaged $4.41/MWh during congested hours respectively. The effect on the load aggregation point LMPs for PG&E was negative.

- Mirage to Concho 115 kV (Line) was congested 0.8 percent of the time due to outages on the Mirage-Tamarisk 115 kV line. Congestion on this line averaged $5.14/MWh on the SCE load aggregation point LMPs during congested hours. This had no effect on load aggregation point LMPs for SDG&E and PG&E.

- San Mateo 7 S transformer was congested 0.23 percent of the time due to planned work in August. Congestion on the PG&E load aggregation point for San Mateo 7 S averaged $10.14/MWh. This transformer had no effect on load aggregation point LMPs for SDG&E and SCE.

- SouthLugo RV import percent branch group limit was congested 0.18 percent of the time. Congestion on this constraint averaged $4.25/MWh at the SCE load aggregation point LMPs and $6.12 at the SDG&E load aggregation point LMPs during hours when this constraint was binding. The PG&E load aggregation point LMPs were negatively affected when the constraint was binding, indicating that the prices in PG&E were lower relative to both the SCE and SDG&E area LMPs and the system marginal energy cost.

Figure 1.13 Effect of congestion on internal constraints on LAP LMPs (Q3 2010)



Conforming transmission constraint limits

Constraint limits in the market software are sometimes adjusted or conformed to account for differences in flows calculated by the market model and actual flows observed in real-time. The total number of conformed transmission constraints handled by the operators was small, and in Q3, the total number of hours conformed was also relatively low.

Constraints tended to be conformed in the upward direction in real-time, increasing the limit on those constraints. This is typically done when the flow calculated by the market is significantly above the actual flow indicated through the energy management system. In such cases, the market is indicating a higher degree of scarcity of transmission capacity than actually exists. Grid operators conform the constraint limit upward to more accurately reflect the available transmission capacity on the constraint. This practice avoids instances where the constraint artificially binds in the market and impacts prices when transmission was not in fact scarce.

Operation engineers review congestion in the day-ahead market on a regular basis to identify the potential need for conforming. However, transmission constraints were rarely conformed in the day-ahead market. Table 1.2 lists all flowgates and nomograms that were conformed in the day-ahead market, along with the percentage of hours that each was conformed, the average conformed limit, the percentage of hours in which it was binding while conforming was applied, and the average of the shadow price. As shown in Table 1.2:

- Only six constraints were conformed in the day-ahead market more than one percent of the time.
- One constraint was conformed down, on average, to 93 percent of its operating limit, primarily to maintain a safe operating reserve margin.
- Five constraints were conformed up to avoid inappropriate congestion.

Table 1.2 Day-ahead conforming limits and congestion frequencies for flowgates (Q3 2010)

Flowgate Name	Conformed Hours	Average Conformed Limit	Congested Intervals	Average Shadow Price
SANBRDNO to DEVERS 230kV (Line)	4%	93%		
COTWDPGE to WHEELBR 115kV (Line)	3%	107%		
T-170-SOL1-MRGE-CNHO-TRSK DA	2%	108%		
MISSON to POTRERO 115kV (Line)	1%	120%		
MIRAGE to CONCHO 115kV (Line)	1%	110%	0.3%	678
SN LS OB to SNTA MRA 115kV (Line)	1%	110%		

Table 1.3 lists flowgates and nomograms that were conformed in the real-time market, along with the percentage of hours that each was conformed, the average conformed limit, the percentage of hours in which it was binding while conforming was applied, and the average of the shadow price. The statistics presented in this table are calculated only for intervals in which the conforming action moved the effective limit from the actual limit. For most of these transmission lines, the conforming level was maintained at a relatively constant level during the period in which they were conformed. There was strong consistency in conforming within the real-time markets (hour-ahead scheduling process and real-time dispatch) in both frequency and level of adjustment.

Table 1.3 Real-time congestion frequency and conforming limits for flowgates (Q3 2010)

Flowgate Name	Conformed Intervals	Conformed Upward				Conformed Downward			
		Conformed Interval	Average Conformed Limit	Congested Intervals	Average Shadow Price	Conformed Interval	Average Conformed Limit	Congested Intervals	Average Shadow Price
SPRNG GJ to MI-WUK 115kV (Line)	37%	0.2%	101%			37%	92%	30.6%	$57
STANISLS to RVRBK J2 115kV (Line)	22%	22%	110%						
HIGGINS to BELL PGE 115kV (Line)	22%	22%	110%						
SCE_PCT_IMP (BG)	22%	22%	120%						
PATH26 (BG)	12%	3%	106%	0.09%	$19	9%	81%	2.8%	$172
LARKIN to POTRERO 115kV (Line)	11%	11%	116%						
MIDWAY to VINCENT 500kV (Line)	8%	8%	114%	0.06%	$23	0%	99%		
T-170-SOL1-MRGE-CNHO-TRSK	6%	1%	106%			5%	94%	1.8%	$832
SANMATEO to RAVENSWD 115kV (Line)	5%	5%	123%	0.14%	$380				
MARTIN-MILBRA_1 (NG)	3%	1%	111%			2.0%	94%	0.7%	$224

Of the 10 constraints listed in Table 1.3, operators conformed all 10 constraints in the upward direction to avoid congestion occurring in the market that was not actually occurring based on observed flows. Operators conformed the Path 26 branch group, T-170-SOL1-MRGE-CNHO-TRSK (Mirage-Tamarisk local area – special load relief), the Martin-Milbra nomogram, and the Spring Mi-Wuk 115 kV line downward. Operators tend to conform down the operating limit of these major transmission lines in order to maintain an adequate reliability margin. The reliability margin ensures the flow on the grid line stays within the line's operating limits even when sudden unpredictable changes in flows occur.

Table 1.3 shows that constraints were rarely congested during the intervals that their operating limits were conformed upward. Most of the congestion occurred when downward conforming was applied. The frequency of congestion during these instances was low overall, with the exception of congestion on the Spring Mi-Wuk 115 kV line. When ratings were conformed down, the actual real-time flows were approaching the constraint operating limit more rapidly than the market real-time flow, and in some cases even exceeded the limit. In these circumstances, operators conform the constraint limit downward to get the market to manage flows by dispatching resources to relieve the constraint at a lower limit.

1.3 Exceptional dispatch

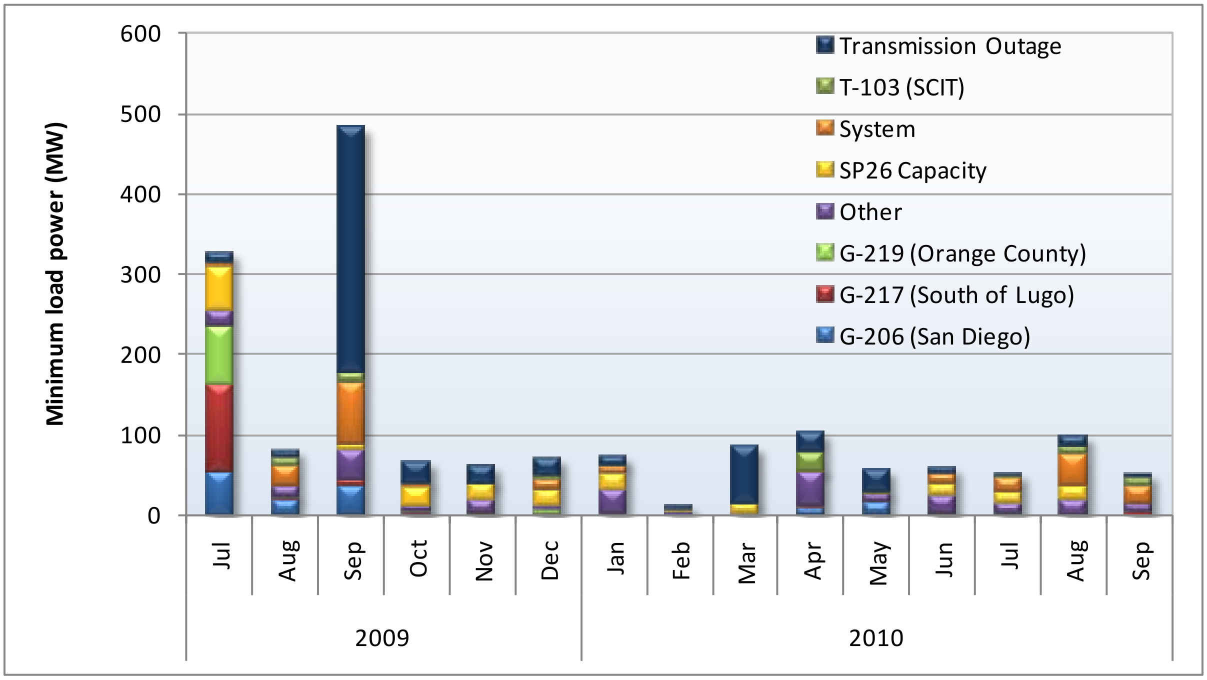
Minimum-output power from generation committed through exceptional dispatch averaged approximately 67 MW across the quarter. This level was less than in the previous quarter and dramatically less than the levels from the same quarter a year ago. Minimum-output power from resources committed via exceptional dispatches ranged in the quarter between a maximum per month average of approximately 99 MW and a minimum average of approximately 50 MW.

Figure 1.14 shows monthly average power from minimum-output generation committed through exceptional dispatch. Exceptional dispatches for system capacity increased relative to the prior quarter. Operators issue system capacity exceptional dispatches to ensure the online capacity is adequate to manage worst-case load and outage scenarios. Therefore, the need for system capacity exceptional dispatches increases as the load approaches annual peaks.

Exceptional dispatches for transmission outages decreased in September relative to months in prior outage seasons. Software enhancements, such as minimum online commitment constraints, aided this reduction.

The bulk of energy from exceptional dispatches continued to result from the minimum load energy from unit commitments. Average in-sequence and out-of-sequence exceptional dispatch power increased slightly from the previous quarter, but decreased relative to Q3 2009. Overall, total energy from exceptional dispatches remained less than 0.5 percent of total load.

Figure 1.14 Monthly average minimum-output power from generation committed through exceptional dispatch



1.4 Ancillary services

Ancillary services costs in Q3 totaled $23.2 million, an increase of almost 8.5 percent from the same quarter last year, but an 11 percent decrease from Q2 2010. Day-ahead ancillary service prices also trended downward for most reserve types in each month of the quarter.

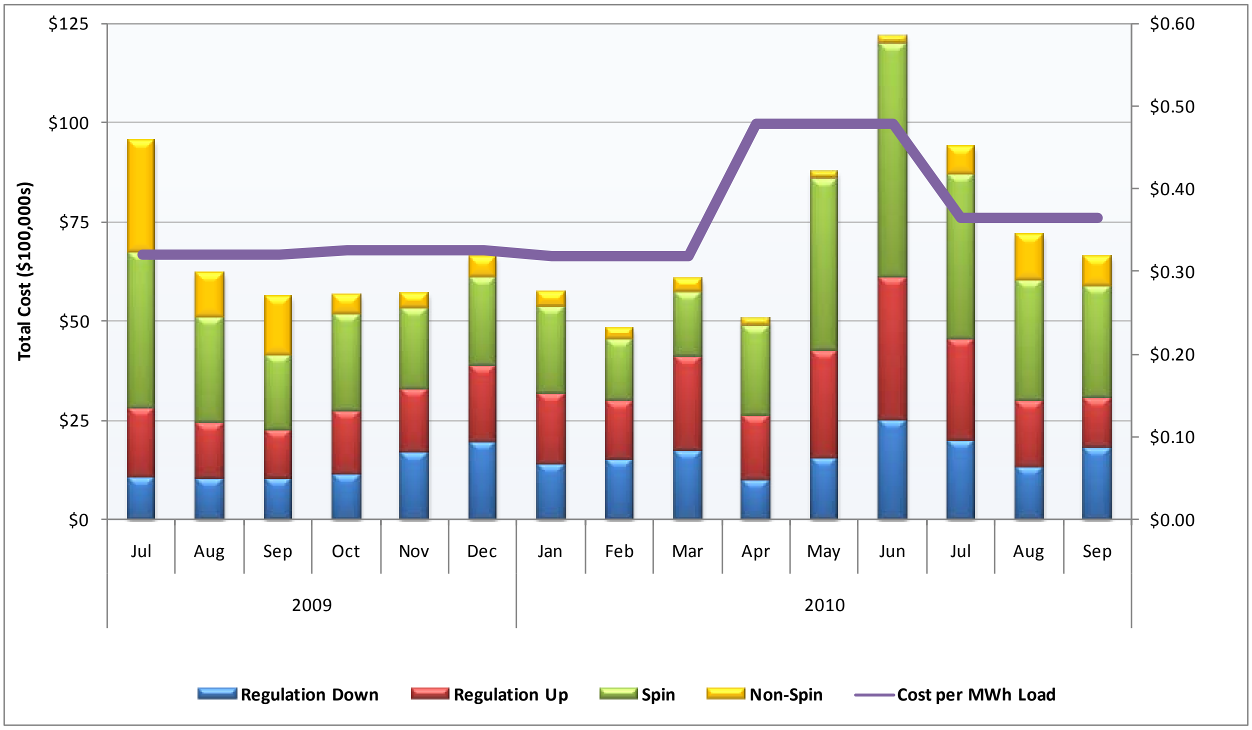
Figure 1.15 shows the total cost of procuring all four products by month from July 2009 through September 2010.[7] Key trends in the ancillary service market over this 15-month period include the following:

- The total cost of ancillary services decreased by $2.85 million from Q2 2010, mainly as a result of decreased prices of regulation and spin.

[7] The total cost figures from July 2009 through September 2010 account for day-ahead capacity that is unavailable in real-time and charged back to the specific unit(s) at the average of the real-time price. Resources that sell ancillary services receive the prices for all regions within which they are located. For example, a resource located in SP26 and selling spinning reserve will receive the ancillary service price for the SP26, ISO, SP26 Expanded, and ISO Expanded regions. Ancillary services have been procured from four of the 10 pre-defined regions, ISO, ISO Expanded, South of Path 26, and South of Path 26 Expanded regions, in the day-ahead and real-time pre-dispatch markets.

- The total cost of ancillary services increased by $1.8 million from Q3 2009, mainly as a result of higher regulation and spin prices. The higher prices can be attributed to slightly higher bids as well as higher energy prices resulting in more lost opportunity cost impacting the ancillary service prices.
- The cost of ancillary services per MWh of load served for Q3 2010 was $0.36/MWh, roughly a 25 percent decrease from the previous quarter and a 12 percent increase from Q3 2009.

Figure 1.15 Ancillary service cost by month



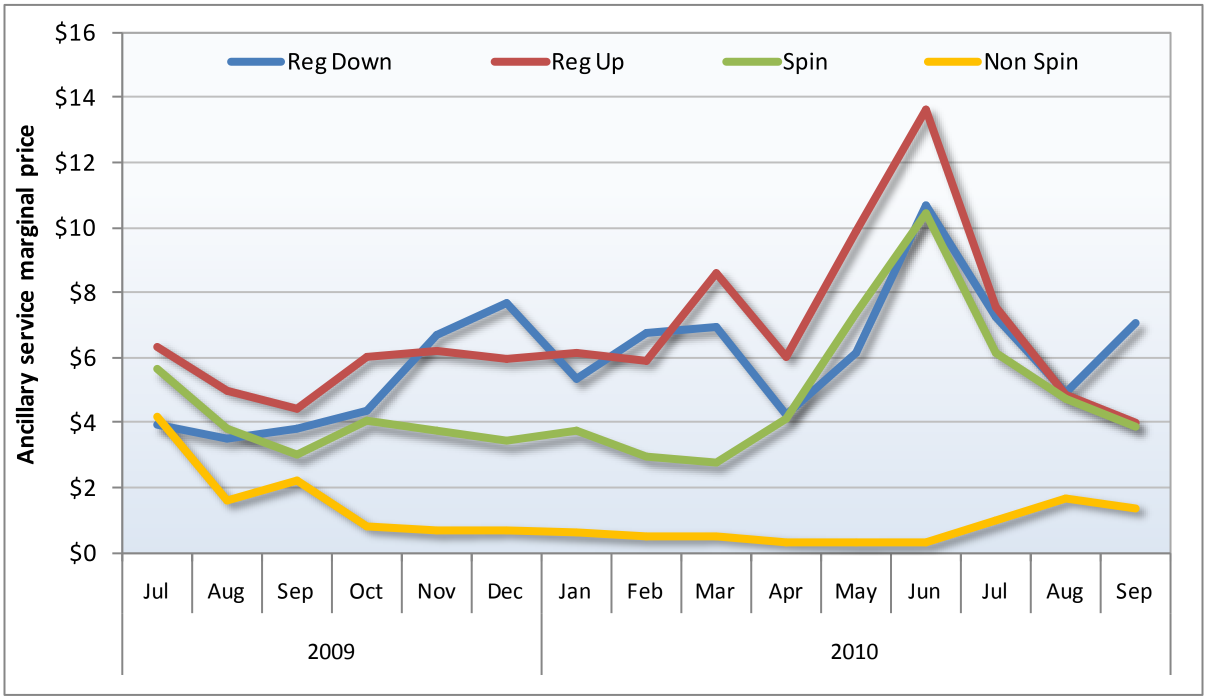
Resources providing ancillary services receive a market clearing price in both the day-ahead and real-time markets.[8] Figure 1.16 shows the weighted average market clearing prices for each ancillary service product by month in the day-ahead market. Day-ahead prices ranged from approximately $1/MW to $7.50/MW. Key findings from Figure 1.16 include the following:

- In general, the average day-ahead market clearing price for regulation down, regulation up and spin decreased each month during the third quarter. Non-spin prices trended upward during this quarter.
- The amount of self-scheduled capacity in Q3 for regulation and spin increased compared to the previous quarter, contributing to the decrease in day-ahead prices.
- In general, day-ahead prices in Q3 were slightly higher than the day-ahead prices from the same quarter last year. This can be attributable to slightly higher bids as well as higher energy prices

[8] Capacity payments in the real-time market are only for incremental capacity above the day-ahead award.

increasing the lost opportunity cost. In September 2010, regulation up obtained the lowest average day-ahead market clearing price since the start of the nodal markets in April 2009.

Figure 1.16 Day-ahead ancillary service market clearing prices



2 Price convergence

A key measure of overall performance of the ISO energy markets is the degree to which prices across these markets converge. A high degree of price convergence is an indicator of potential market efficiency, as it suggests that resource commitment and dispatch decisions are being optimized across the markets within the ISO, as well as between the ISO and neighboring control areas.

As discussed in DMM's previous quarterly reports, divergence in the hour-ahead scheduling process and real-time dispatch can create substantial uplifts that must be recovered from load-serving entities through the Real-Time Imbalance Energy Offset charge (Charge Code 6477). This occurs when the ISO tends to export relatively large quantities of additional energy in the hour-ahead scheduling process (at low prices), and then dispatch additional energy within the ISO in real-time dispatch (at significantly higher prices). This pattern of "selling low" in the hour-ahead and "buying high" in real-time has created substantial revenue imbalances that were recovered based on each participant's metered loads through Real-Time Imbalance Energy Offset charges.

DMM has identified that price divergence between the hour-ahead and real-time represents one of the most critical areas for further improvement in the new market software and processes. This section updates the analysis of price convergence through the third quarter and focuses on specific hours driving price divergence. Overall, price divergence remains a problem, particularly with respect to the divergence of hour-ahead and real-time prices.

Potential root causes of this trend and some steps being pursued by the ISO to reduce these price divergences were discussed in DMM's previous quarterly reports.[9] Most of these modifications have yet to be incorporated into the market software.

2.1 Price divergence

In the third quarter of 2010, there was significant congestion driving prices in the SCE and SDG&E areas up relative to the PG&E area. This congestion was often related to wildfires and de-rates in transmission capability. As a result, PG&E prices are more representative of systematic issues affecting price divergence rather than this type of extreme event.

Figure 2.1 and Figure 2.2 show monthly average prices for on-peak periods and off-peak periods for the PG&E load aggregation point, respectively. Key trends in these figures include:

- Prices in the hour-head market used to dispatch and settle imports and exports have tended to be systematically lower than prices in the 5-minute real-time market.
- During peak hours, prices in the 5-minute real-time market have tracked day-ahead prices closely during most months, but exceeded day-ahead prices during some months.
- During off-peak hours, the trends are less consistent. Prices in the real-time market tracked day-ahead prices closely during most months, but exceeded day-ahead prices during some months.

[9] *Quarterly Report on Market Issues and Performance*, Revised December 23, 2009; covering July through September, 2009, http://www.caiso.com/2425/2425f4d463570.html; and *Quarterly Report on Market Issues and Performance*, August 11, 2010; covering April through June, 2010, http://www.caiso.com/27ef/27ef9dc058db0.pdf.

Figure 2.1 Comparison of PG&E load aggregation point LMPs
On-peak – Excluding prices > $1,000 and < -$500

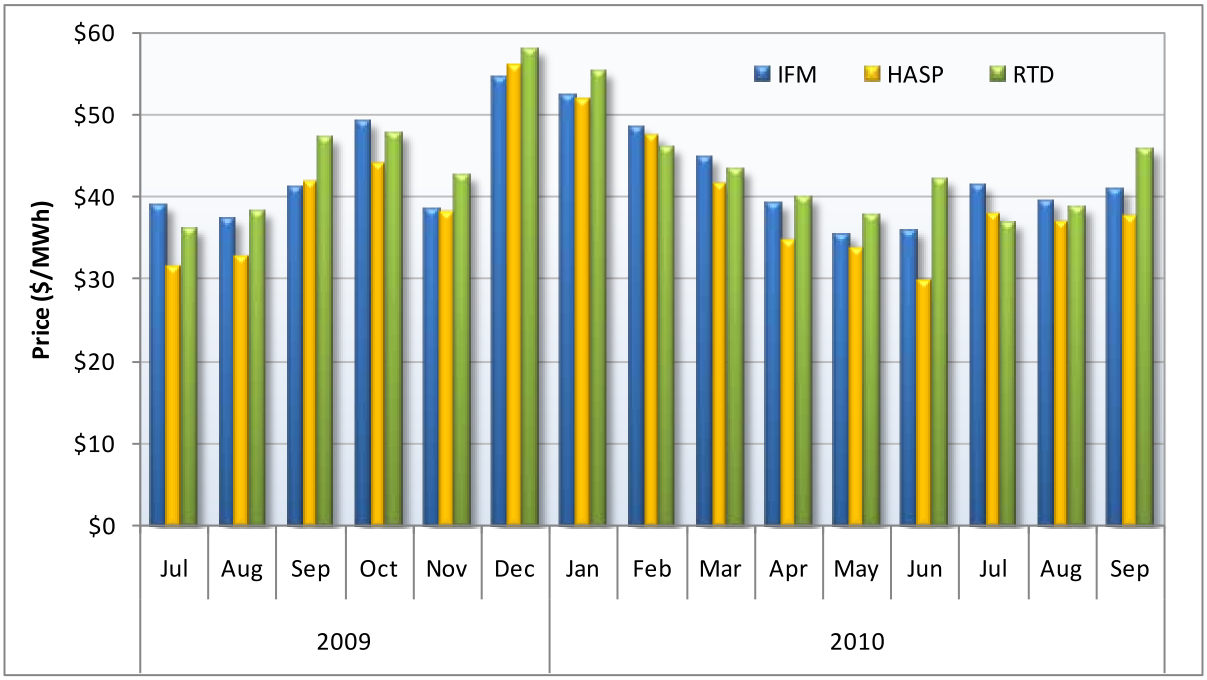
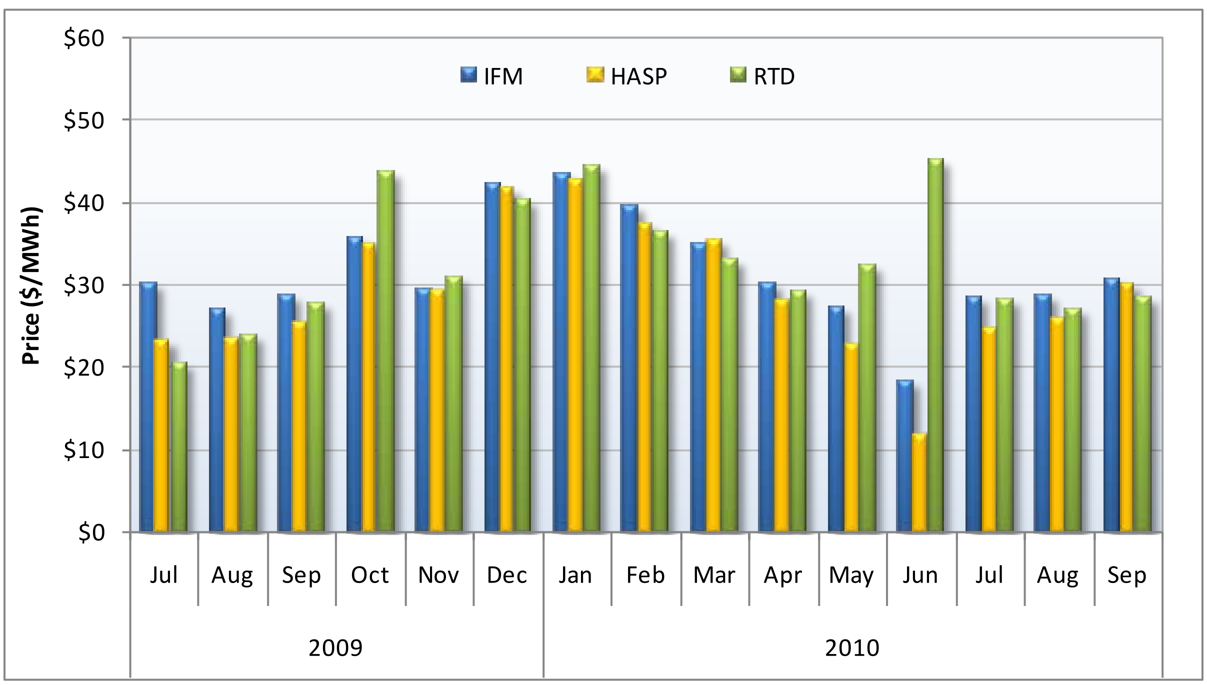


Figure 2.2 Comparison of PG&E load aggregation point LMPs
Off-peak – Excluding prices > $1,000 and < -$500



Power balance constraints

The tendency for 5-minute real-time prices to exceed hour-ahead prices is driven in large part by extreme price spikes in the real-time market that occur when the market software meets the system-wide power balance constraint with regulation resources rather than with energy resources. When this relaxation occurs, the system imposes a penalty price, which then affects the energy prices in the pricing run.[10] This constraint can occur in two different ways:

- When the market software dispatches regulation as supply to meet projected demand, this represents a “shortage” constraint that causes prices to spike upwards to the $750/MWh bid cap.
- When the market software dispatches regulation down to balance supply with projected demand, this represents an “excess” constraint that causes prices to spike downwards to the -$30/MWh bid floor.

Figure 2.3 shows the frequency of these two types of power balance constraints in the real-time markets from the beginning of the third quarter 2009. The power balance constraints have never occurred in either the day-ahead or the hour-ahead markets. As shown in Figure 2.3:

- Constraint activity due to shortage relaxations have ranged from 0.1 percent to 2 percent of the intervals of each month since July 2009. In the third quarter 2010, prices spiked up due to shortage relaxations during about 1 percent of all 5-minute intervals, with relaxations occurring in about 3 percent of all hours. This reflects the fact that constraints generally occur during only a few intervals of any individual hour.
- Constraint activity due to excess relaxations of energy peaked in June 2010, with relaxations occurring in about 6 percent of intervals. In the third quarter 2010, prices spiked down due to excess constraints during 3 percent of all 5-minute intervals, with constraints occurring in 10 percent of all hours.

Figure 2.4 shows monthly on-peak prices in the energy markets after the hours with power balance constraints have been removed from each market, along with the change in monthly price differences in these markets due to exclusion of these intervals.[11] The largest changes occurred in the real-time market, improving price convergence between the hour-ahead and real-time markets. In particular, changes in real-time prices were largest in the months of September 2009 and 2010, with real-time prices averaging over $9/MWh and $8/MWh lower during these months, respectively. Moreover, after adjusting for the power balance constraint, there is also a day-ahead on-peak price premium to both the hour-ahead and real-time markets in most months.

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[10] The pricing penalty for supply being short of demand is set to the energy bid cap, which is currently set at $750/MWh, as specified by the Federal Energy Regulatory Commission. The energy bid cap and penalty price will increase to $1,000/MWh on April 1, 2011. The pricing penalty for supply being ahead of demand is set to -$35/MWh.

[11] In order to keep consistency of averaging across the day-ahead, hour-ahead and real-time markets, each hour was removed from all three markets when a power balance constraint was active in real-time. The percentage of hours with power balance constraints is higher than the percentage of intervals with power balance constraints as it is common for only a small number of intervals with power balance constraints to occur within an hour. For instance, in June 2010, a total of 8 percent of the intervals had either an excess or shortage power balance constraint, whereas the percentage of hours affected by the power balance constraint in June 2010 was over 22 percent.

Figure 2.3 Frequency of power balance constraints in real-time intervals

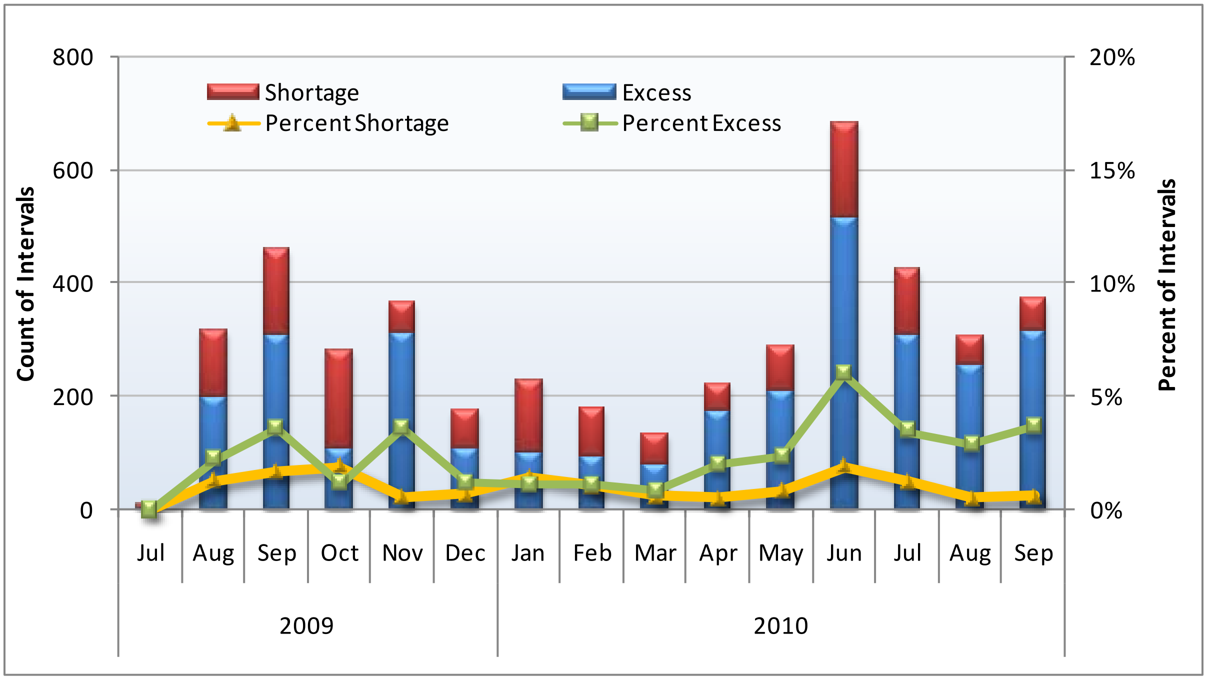


Figure 2.5 highlights the degree to which monthly average real-time prices during peak hours have tended to exceed hour-ahead prices, and the degree to which this divergence is caused by extreme prices during the relatively small percentage of intervals when power balance constraints are active.

Figure 2.6 shows that price convergence also improves during off-peak hours when hours in which the power balance constraints are active are removed. For instance, with these intervals excluded, real-time off-peak prices are significantly lower in October 2009, and in May and June 2010, improving price convergence with the hour-ahead market. In other months, such as August 2010, real-time average off-peak prices increased and were closer to the day-ahead off-peak prices.

Figure 2.7 highlights the degree to which monthly average real-time prices during off-peak hours have tended to exceed hour-ahead prices, and the degree to which this divergence is caused by extreme prices during the relatively small percentage intervals when the power balance constraints are active.

Figure 2.4 Change in monthly prices without hours when power balance constraints active (PG&E LAP, Peak hours)

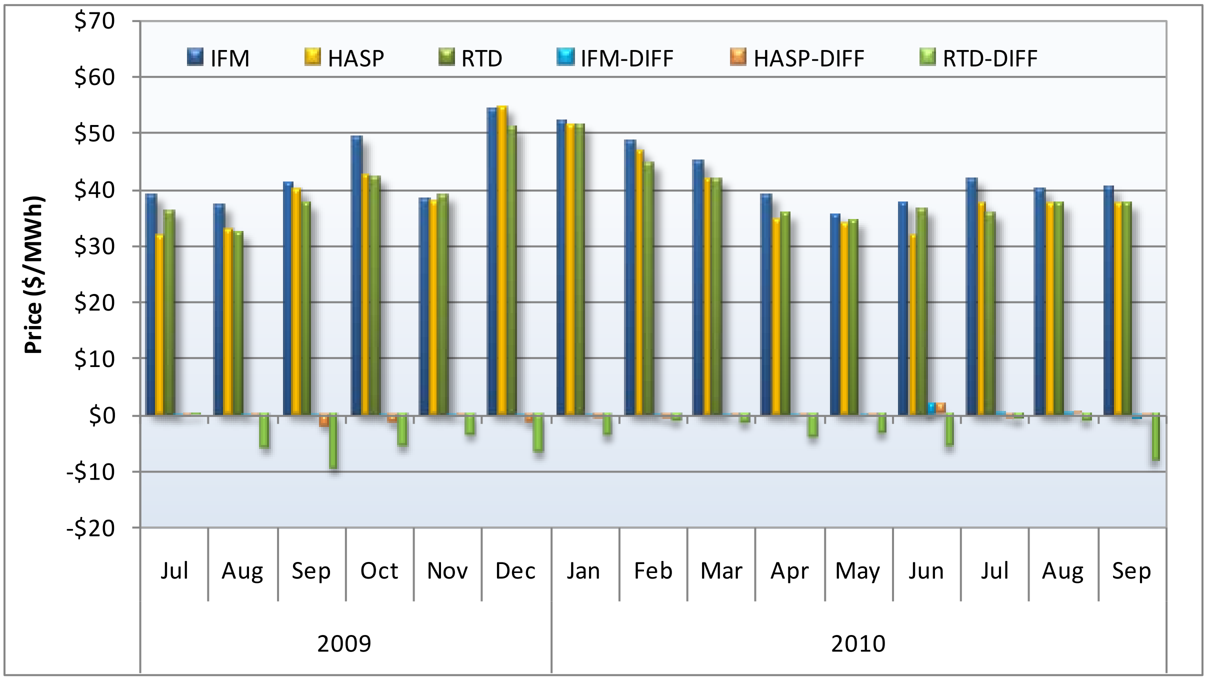


Figure 2.5 Difference in RTD and HASP without hours when power balance constraints active (PG&E LAP, Peak hours)

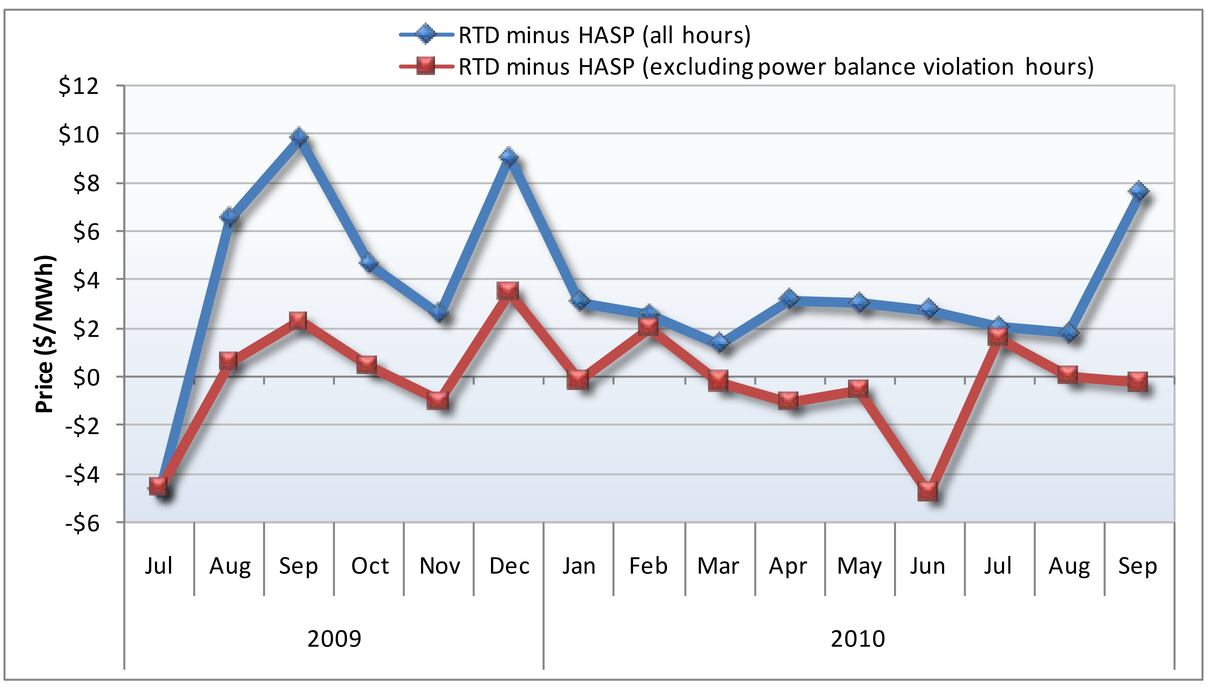


Figure 2.6 Change in monthly prices without hours when power balance constraints active (PG&E LAP, Off-peak hours)

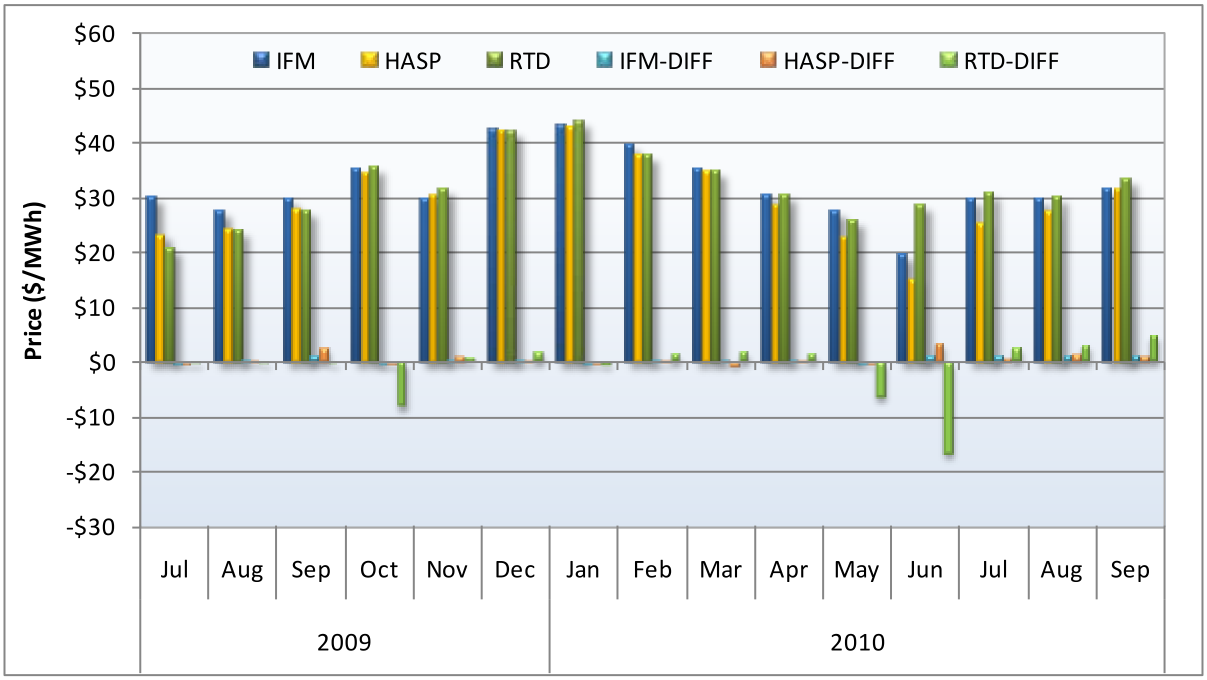
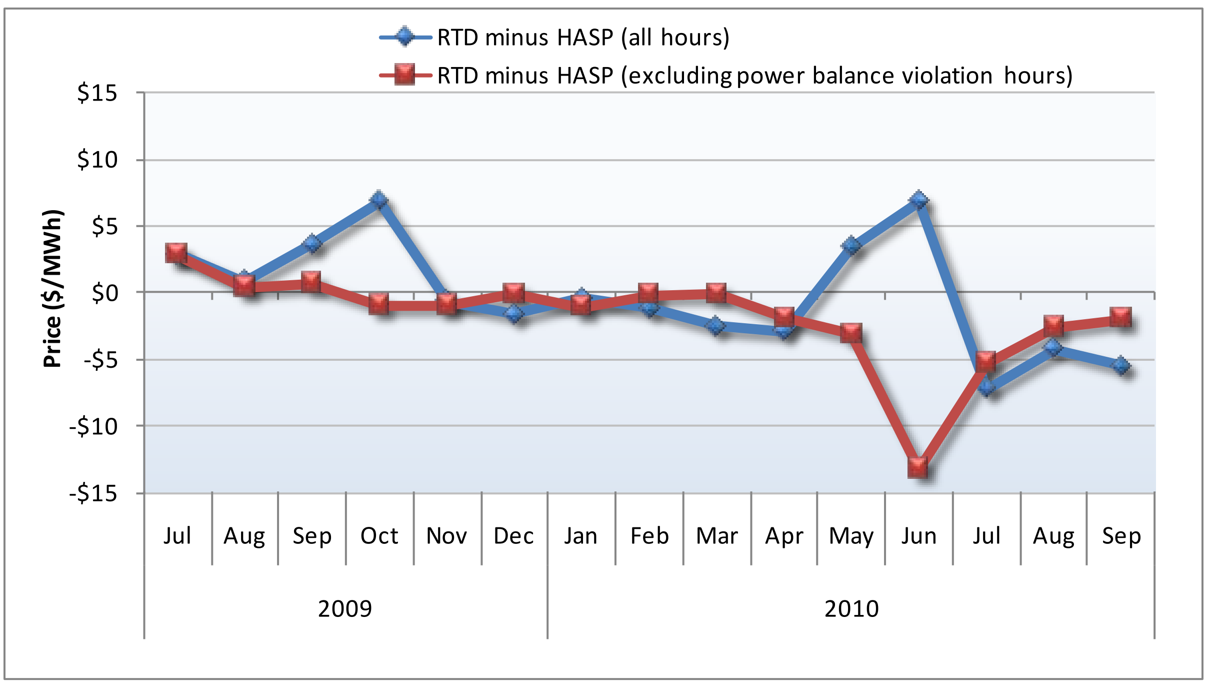
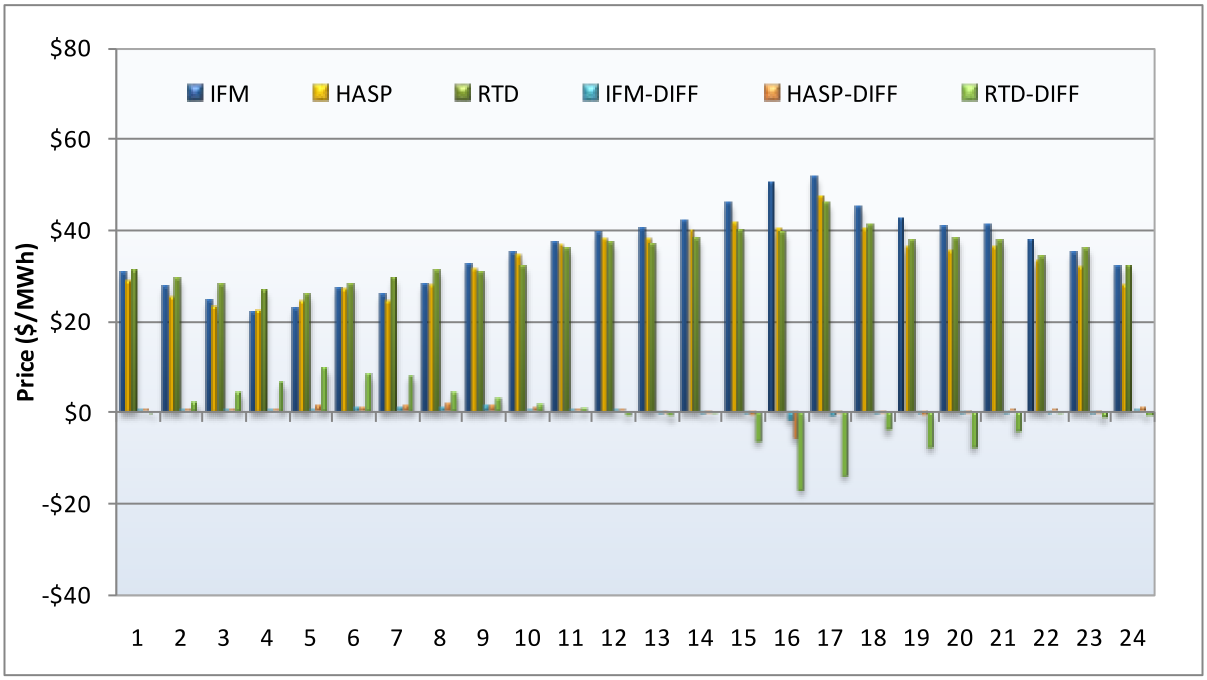


Figure 2.7 Difference in RTD and HASP without hours when power balance constraints active (PG&E LAP, Off-peak hours)



From an hourly perspective, prices tend to increase and decrease depending on whether a shortage or excess power balance constraint occurred. Figure 2.8 shows that most positive price differences occurred during off-peak hours in the third quarter, whereas most negative price differences occurred in on-peak hours. Indeed, most excess power balance constraints occurred in off-peak hours in Q3, whereas shortage constraints occurred most frequently in on-peak hours.

Figure 2.8 Changes in hourly PG&E prices when power balance constraint hours removed (Q3 2010)



Factors influencing divergence

One of the actionable root causes of the divergence of prices in the hour-ahead and 5-minute real-time markets that has been identified involves the difference in load forecasts used in these two markets. Differences within the forecasting software may be a result of changing conditions between the execution of the hour-ahead market and the real-time market. Load forecasts used in the software can also be adjusted by a load bias. Load bias occurs when operators change load assumptions to the forecast either explicitly or implicitly within the model. Load bias levels are not necessarily consistent between the hour-ahead and real-time forecasts. When taken together, the load forecast differences and operator bias can lead to differences in price results between the hour-ahead market and the real-time market.

Other factors influencing divergence include differences in real-time delivered energy from variable energy resources from hour-ahead forecast levels as well as other deviations in operational resources in real-time. Addressing these issues that add variability and uncertainty, in addition to the forecast issues, by better ensuring sufficient resource flexibility can also improve price convergence results.

2.2 Costs associated with price divergence

Divergence in prices can pose unnecessary additional inefficiencies and costs on the system. When net imports decrease in the hour-ahead scheduling process, but real-time imbalance energy increases, the decrease in net imports may be inefficient.[12] Such reductions are inefficient if hour-ahead prices are systematically lower than real-time prices, so that the ISO is selling energy in the hour-ahead at a low price and then purchasing additional energy in real-time at a higher price. This can also create substantial uplifts that must be recovered from load-serving entities through the Real-Time Imbalance Energy Offset.[13]

Decreased net imports in the hour-ahead scheduling process

When hour-ahead prices are systematically lower than day-ahead prices, holding all else constant, net imports are likely to decrease in the hour-ahead scheduling process. In the hour-ahead scheduling process, participants can directly increase or decrease their final day-ahead import and export schedules and bid prices, and submit additional import and export bids. However, even if participants do not modify their day-ahead import or export bids in the hour-ahead, net imports may decrease if the hour-ahead price is lower than the day-ahead price. If hour-ahead prices are lower, fewer imports that cleared the day-ahead market may “re-clear” in the hour-ahead scheduling process. Additional exports that did not clear in the day-ahead may also clear in the hour-ahead.

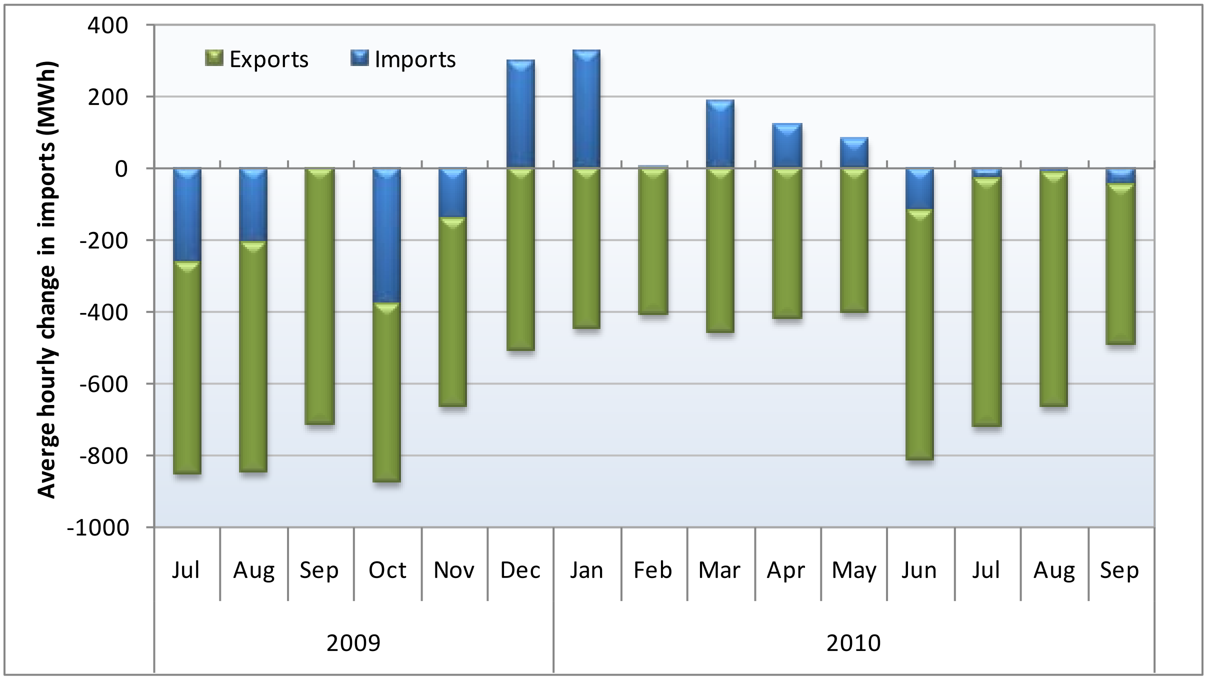
Since hour-ahead prices have often been lower than day-ahead prices under the new market design, the amount of imports originally scheduled in the day-ahead that “re-clear” the hour-ahead scheduling process often decreases and the amount of additional exports that clear increases in the hour-ahead. Additional export bids (beyond those submitted in the day-ahead market) have also tended to be submitted and cleared in the hour-ahead. This likely reflects participants’ expectation that during many periods prices will be relatively low in the hour-ahead compared to prices in the day-ahead market or the regional bilateral markets. This additional demand for exports tends to increase the hour-ahead price relative to a case where no additional exports were made. However, despite this additional demand for exports, hour-ahead prices have tended to be significantly lower than day-ahead and 5-minute real-time prices.

Figure 2.9 shows that, on average, hourly net imports decrease in the hour-ahead from day-ahead levels in every month. The decrease in net imports is primarily due to increased exports, which accounted for about 95 percent of the overall decrease in net import in the hour-ahead market in the third quarter. The increase in exports in the hour-ahead from the day-ahead in June 2010 was second only to the increase in exports in September 2009. Export activity in the hour-ahead market remained almost as high in July 2010 as in June 2010, declined slightly in August 2010, and then fell off in September 2010.

[12] The inter-tie prices are relative to prices in neighboring systems. If prices outside of the ISO system are higher, it makes economic sense for net imports to decrease in the hour-ahead scheduling process. This can be accomplished by either reducing imports or increasing exports.

[13] More information about the Real-Time Imbalance Energy Offset charge can be found on the ISO website at http://www.caiso.com/2406/2406e2a640420.html.

Figure 2.9 Change in net imports in hour-ahead relative to final day-ahead schedules



Costs of decreased net imports in the hour-ahead scheduling process

When net imports decrease in the hour-ahead, but real-time imbalance energy increases, this indicates that the decreased imports in the hour-ahead are likely to have increased the need to dispatch imbalance energy in real-time.[14] Figure 2.10 shows DMM's estimate of the average hourly decrease in hour-ahead net imports that were subsequently re-procured by the real-time dispatch by month.[15] After peaking in June 2010, the average decrease in imports in the hour-ahead, which were subsequently re-procured by the real-time dispatch with imbalance energy, fell by over 100 MW on average from July 2010 to September 2010, finishing at just above 500 MW. As shown in Figure 2.10, the average decrease in net imports remained several times greater in the southern zone (SP15) than in the northern zone (NP15).

[14] In some cases, reductions in net import may be necessary in the hour-ahead scheduling process to manage congestion or reduce supply due to energy not scheduled in the day-ahead market, such as renewable generation or unscheduled start-up or minimum load energy from thermal units. The hour-ahead software should take this energy into account and seek to optimize prices between imports/exports adjusted in the hour-ahead and subsequent dispatches and prices in the 5-minute real-time market.

[15] DMM estimates the hourly decrease in hour-ahead net imports that were subsequently re-procured by the real-time dispatch by month based on the difference between the decrease in net imports each hour with the amount of energy dispatched in the 5-minute market during that hour. For instance, if the net imports were decreased by 500 MW in the hour-ahead, and 700 MW of net incremental energy was dispatched in the 5-minute market that hour, the entire 500 MW decrease of net imports in hour-ahead was re-procured in the 5-minute market. If net imports were decreased by 500 MW in the hour-ahead, but only 200 MW of net incremental energy was dispatched in the 5-minute market that hour, then only 200 MW of the decrease of net imports in hour-ahead was counted as being re-procured in the 5-minute market.

Figure 2.10 Comparison of imbalance energy increases due to decreasing net imports in HASP

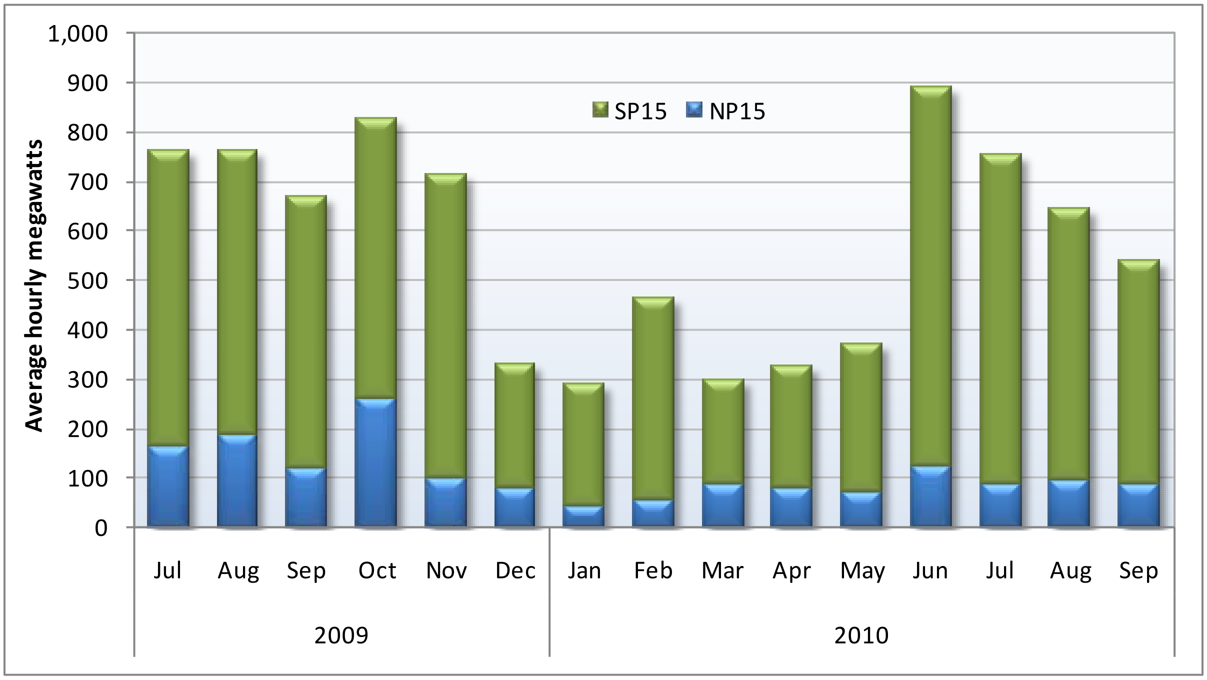


Figure 2.11 shows the estimated costs of additional imbalance energy because of decreasing net imports in the hour-ahead and increasing procurement of imbalance energy in real-time at a higher price.[16] The largest values were at the very start of the new market and again in June 2010. The estimated costs fell from just under $23.5 million in June 2010 to $8.5 million in July 2010 and then to around $5 million in August and September 2010.

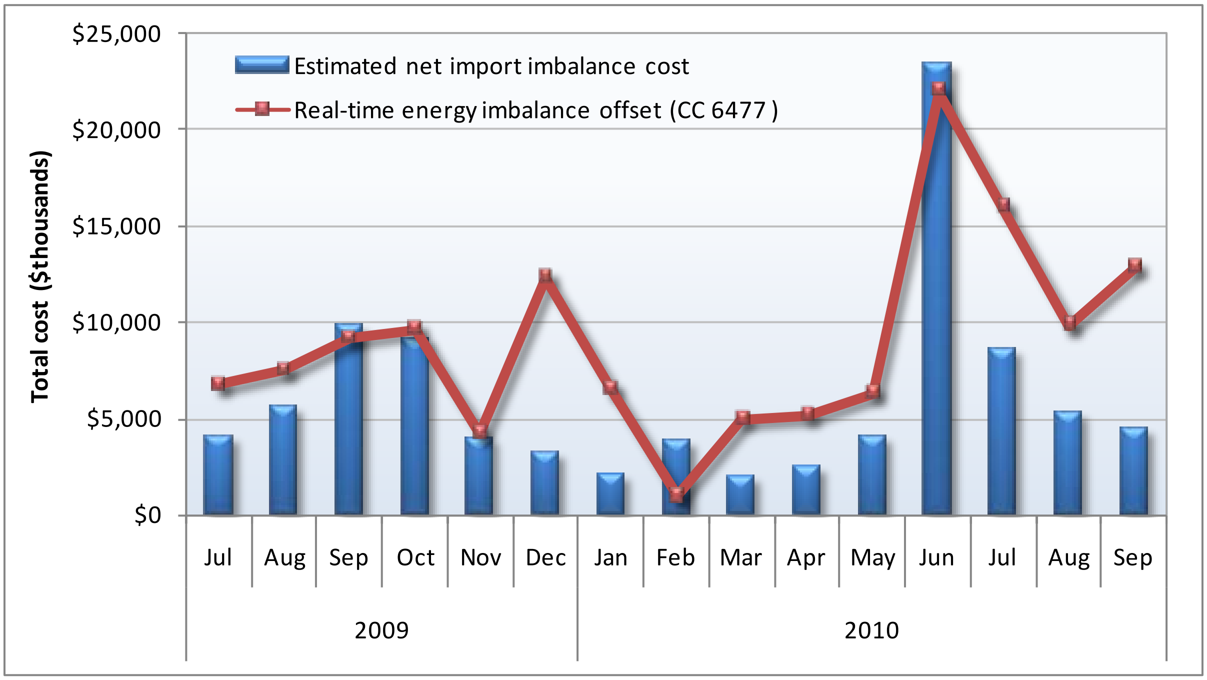
In the third quarter, there were 12 days where the real-time energy imbalance offset charge was greater than $750,000 per day, accounting for nearly 50 percent of the total quarterly charges. During Q3, price differences and resulting imbalance energy revenue shortfalls can be attributed to a combination of major isolated events (including wildfires, transmission outages and de-rates), generation outages, differences in real-time forecast load compared to day-ahead forecast load, and forecasting limitations.[17] In contrast, many of the events in Q2 were a result of shortages in ramping resources, particularly in off-peak hours, because of a high proportion of self-scheduled generation and low loads.[18]

[16] DMM estimates these costs based on (1) the decrease in hour-ahead net imports that were subsequently re-procured in real-time, and (2) the difference in hour-ahead versus real-time prices during the corresponding hour. This estimate is only one element of the Real-Time Imbalance Energy Offset charge and, therefore, will differ from the total value of the charge for various reasons. Further detail on the different elements contained within the charge can be found in the following report: http://www.caiso.com/2416/2416e7a84a9b0.pdf.

[17] Wildfires and related transmission outages and de-rates affected five of the days, accounting for $8.4 million. Generation outages and de-rates affected three of the days, accounting for $3.2 million. Significant increases in real-time load compared to day-ahead forecast load affected two days, accounting for $2.9 million. One day was affected by transmission de-rates due to problems in a control area outside of the ISO system, totaling $1.5 million, and the final day was affected by load forecasting problems and a large negative HASP price over -$1,600/MWh that accounted for $2.7 million.

[18] There were 10 days in the second quarter of 2010 where the real-time energy imbalance offset charge was greater than $750,000 per day, accounting for nearly 50 percent of the quarterly charges. June 11, 2010 accounted for roughly $3.1 million and June 20, 2010 accounted for $2.8 million alone.

Figure 2.11 Estimated imbalance costs due to decreased net HASP imports reprocured in RTD market at higher price



2.3 Actions taken to mitigate root causes of systematic price divergence

Many of the changes identified in DMM's Q2 2010 report have been delayed and are still under development by the ISO. The status of these changes as well as other ISO actions is outlined below.

- As reported in DMM's reports for Q3 2009 and Q2 2010, the ISO is developing a new short-term forecasting tool that is designed to provide a more accurate and consistent forecast for both the hour-ahead scheduling process and the real-time market. In addition, this new forecast will specifically be designed to provide forecasts at the 15-minute and 5-minute level of granularity over the approximately two hour forecasting timeline needed for the hour-ahead and real-time markets. Implementation of this new forecasting tool is anticipated in the fourth quarter of 2010.

- In Q3 2009, the ISO assessed a variety of options that might mitigate the impacts of the differences in ways that inter-tie schedules and ramping of resources are modeled in hour-ahead compared to real-time. As an initial step, the ISO is developing enhancements that would modify the hour-ahead scheduling process to account for the imbalance energy difference that arises due to the fact that it does not model how changes in net hourly inter-tie schedules are ramped in over a 20-minute period each operating hour. Testing of this enhancement is currently in progress. The target for release has also been moved from the third quarter of 2010 to the fourth quarter of 2010.

- The ISO is continuing to look for opportunities to improve how and when to bias the system. As part of this effort, the ISO is developing a more systematic procedure that gives the operator more guidance to determine whether a bias should be removed or continued.

- In late July 2010, the ISO implemented the capability to produce automated compensating injections in the hour-ahead and 5-minute real-time market software. This feature is designed to automatically align flows produced by the market software with actual observed flows. This feature is expected to decrease the need for manual biasing of transmission limits, and may help to improve price convergence between the hour-ahead and 5-minute real-time markets. The performance of compensating injections is discussed in further detail in Section 3.

- As identified in DMM's Q2 2010 report, the ISO has begun a process to evaluate what products, if any, may be necessary to support renewable integration. These products could potentially address some of the issues related to low ramping capability, which can affect price convergence in certain instances.

- The ISO is considering what, if any, additional constraints may be necessary to better ensure that there is sufficient committed flexibility to absorb the potential variation and uncertainty in actual real-time imbalance conditions.

Improving price convergence, particularly with respect to the hour-ahead and real-time markets, remains one of the most critical areas for further improvement in the market software and processes. While implementation of the changes identified above may improve price convergence, DMM believes the ISO should continue to seek to identify other potential sources of the divergence between prices and dispatches in the hour-ahead and real-time markets and how these may be addressed. Addressing sources of real-time price spikes and divergence due to forecasting and modeling issues becomes increasingly important with the scheduled implementation of convergence bidding in 2011. With convergence bidding, spikes in the real-time market may have a larger impact on the day-ahead market, where market cost impacts are larger.

Furthermore, DMM supports ISO efforts to identify methods to ensure that sufficient flexibility of resources are available to meet the variability and uncertainty of real-time conditions. DMM has observed that small variations can have large asymmetric impacts on real-time prices. The more flexibility built within the model, the better the ISO can respond to these real-time events.

3 Special issues – compensating injections

The California ISO transmission network is part of the Western Electricity Coordinating Council network. Throughout WECC, energy schedules between different balancing authority areas (BAAs) are based on energy scheduled under transmission rights or *contract path* flows. As a result, there might be discrepancies – or unscheduled flows – between these contract path flows and the actual flows between the ISO and neighboring BAAs.

In July 2010, the ISO implemented a new feature in the real-time software to manage these unscheduled flows in an automated manner using compensating injections (CI).[19] Compensating injections are megawatt injections and withdrawals made in the ISO software at various locations external to the ISO to minimize unscheduled flows along the inter-ties. Compensating injections are determined in the real-time pre-dispatch run made every 15 minutes, and are then included in both the hour-ahead and 5-minute real-time markets.

DMM has access to limited data for use in assessing the performance and impact of compensating injections. However, Figure 3.1 and Figure 3.2 provide data for one sample day (September 30, 2010), which illustrates how compensating injections typically perform in the market.

The red and green bars in Figure 3.1 show the total gross positive and negative compensating injections, respectively, while the blue line shows the total net value of these positive and negative compensating injections by interval on this sample day.

As shown in Table 3.1, the net compensating injections range between positive and negative 100 MW during each interval. However, both the positive and negative compensating injections can add up to more than 4,000 MW in some intervals. Such large values of the total positive and negative compensating injections reflect a large amount of positive and negative unscheduled flows between the ISO and neighboring BAAs on individual inter-ties.

The net compensating injection values are of a much smaller magnitude (less than 100 MW in absolute value), but can impose operational challenges by interacting with the Area Control Error. The ACE is a measure of the instantaneous matching of supply and demand on a system-wide basis, which is used as a critical means of managing system reliability. To avoid creating problems with the ACE, the software limited the net impact of compensating injections to be no more than an absolute difference of 100 MW.

This limitation is imposed by a discount factor, which discounts the compensating injections at each location if the overall net system-level compensating injections are above certain thresholds.[20] If the net compensating injections are above some higher threshold, every individual compensating injection will be cancelled. These thresholds and discount factors result in the step-wise pattern of the total positive and negative compensating injection amounts in Figure 3.1. Specifically:

[19] Technical Bulletin 2010-07-01, Compensating Injection in the ISO Real-time Market, July 16, 2010, http://www.caiso.com/27d4/27d4e73124db0.pdf.

[20] In the third quarter of 2010, the discount factor was 0.2 for net compensating injections between 50 MW and 500 MW in absolute value. Below 50 MW, compensating injections were not discounted; above 500 MW, all compensating injections were cancelled.

- The intervals when the positive and negative compensating injections exceed 1,000 MW represent intervals no discounting was applied, so that the full impact of this feature was in effect. As noted in Figure 3.1, we refer to these intervals as Full CI intervals.
- The intervals when the positive and negative compensating injections are just under 1,000 MW represent intervals when the compensating injection feature was on but the discounting was applied. We refer to these intervals as Partial CI intervals, since the impact of this feature was partially in effect.
- The intervals when no compensating injections occurred represent intervals when compensating injections were cancelled or not generated because of functional failures of this software feature.

Table 3.1 summarizes the level of compensating injections under these three categories for intervals in the third quarter since this feature was activated in July. As shown in Table 3.1, no compensating injection was in effect about 5 percent of the intervals in this period. About 26 percent of intervals had Full CI, while 70 percent of intervals had Partial CI during this period. The hourly average net compensating injection was 2.3 MW. During intervals when compensating injections were fully in effect, the total positive and negative compensating injection averaged roughly ±4,000 MW, compared to about ±800 MW during Partial CI intervals when the discounting was in effect.

The purpose of compensating injections is to minimize the gaps between the contract path flows scheduled in the market and the actual flows along the inter-ties. Figure 3.2 shows the differences of the market flows and actual flows for September 30, 2010 on three major inter-ties – Malin, Sylmar, and Palo Verde. These three inter-ties are at different locations in the ISO, and therefore provide an indication of the performance of the compensating injection feature in different key locations.

Table 3.1 Summary of compensating injections

Q3 2010	# of Intervals	Percentage	Average Net	Average Absolute Net	Maximum Net	Minimum Net	Average Postive	Average Negative
CI Off	299	5%	0.0	0	0	0	0	0
Full CI	1,532	26%	1.3	24	50	-50	4,069	-4,067
Partial CI	4,176	70%	2.9	32	100	-99	818	-815
All CI	6,007	100%	2.3	28	100	-99	1,606	-1,604

Figure 3.1 Compensating injection levels (September 30, 2010)

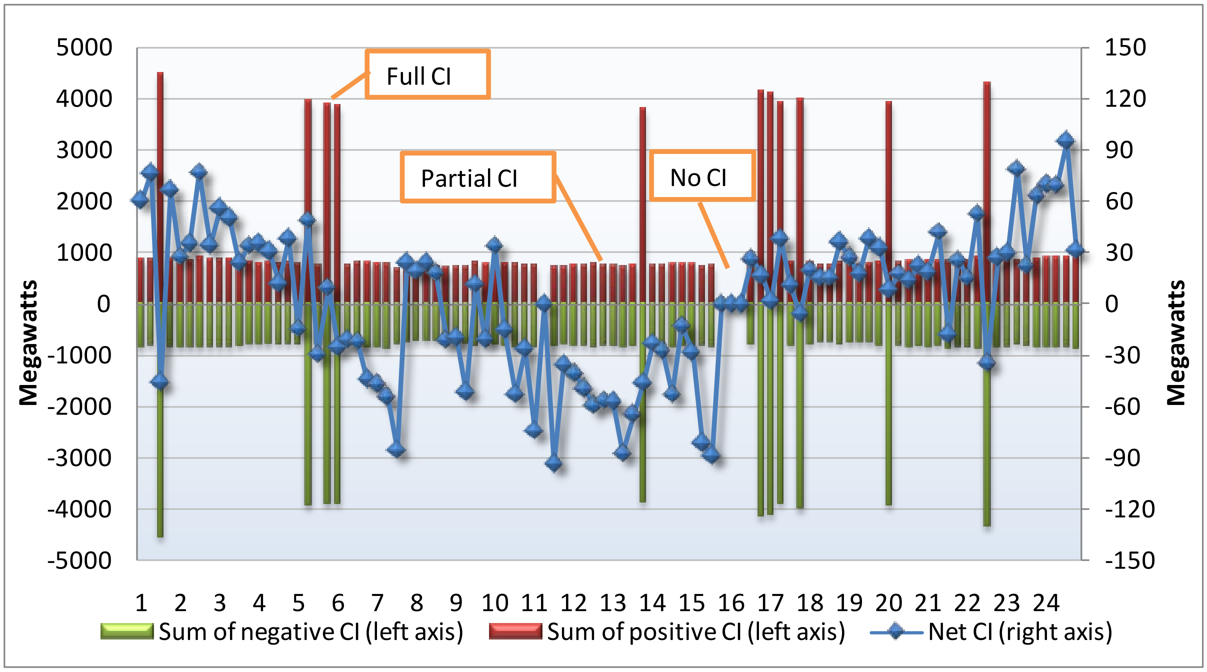
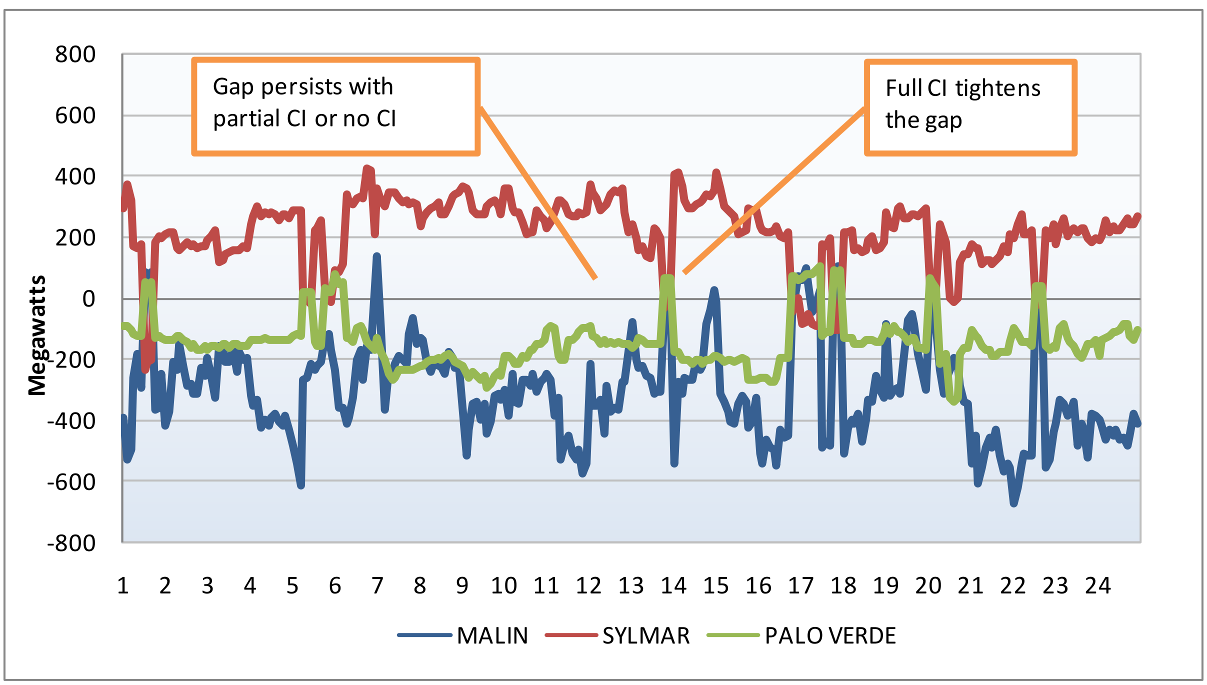


Figure 3.2 Difference between market flows and actual flows on selected inter-ties (September 30, 2010)



Correlating Figure 3.2 with Figure 3.1 provides a means of assessing the impact of compensating injections on the accuracy of the modeled flows over each of these inter-ties after inclusion of the compensating injections.

- For intervals with Full CI, the differences between the market flows and actual flows are close to zero. This indicates that when compensating injections are not discounted, they are able to reduce the gaps between the scheduled and actual flows.
- For intervals with Partial CI or No CI, the gaps between market and actual flows persist, ranging from about -600 to 400 MW. Due to the discount factor being small, the intervals with Partial CI and the intervals with no compensating injections are almost indistinguishable from each other. The discount factor greatly limits the capability and performance of compensating injections in tightening the flow gaps.

The ISO is working on approaches to relax the discount factor without causing significant operational issues, and thus improve the overall performance of compensating injections.[21]

DMM's review of the available data for sample days – as described above – indicates that when the Full CI feature is on, compensating injections significantly reduce the difference between modeled versus actual flows on the major inter-ties. Ideally, however, DMM would like to benchmark the performance of compensating injections by comparing market flows both *with* and *without* compensating injections against actual flows, for both external inter-ties and major internal paths, over a much longer period.

The compensating injection software and monitoring efforts of the ISO are focused on inter-ties, under the assumption that improvements in modeled versus actual flows on the inter-ties will result in similar improvement on internal constraints within the ISO. However, the ISO does not currently capture data needed to monitor the actual impact on internal constraints. Analysis of the difference between modeled versus actual flows over longer time periods could provide insights into systematic patterns in unscheduled flows that might be incorporated into the day-ahead modeling process, rather than only the hour-ahead and real-time markets.

Such analysis is currently infeasible for several reasons. Actual flow data requires manual processing, which makes is too difficult for DMM to perform long-term analysis. In addition, the ISO captures data for market flows with compensating injections but not without compensating injections. Without this information, DMM is not able to determine if false congestion caused by market flow divergence has occurred because of over-compensating the market flows on internal paths. DMM is also not able to determine whether over-correction has occurred along the inter-ties.

Going forward, DMM will continue to review the ISO metrics and the performance of compensating injections. Furthermore, the ISO has indicated that it will look to capture the missing data elements needed to monitor for false congestion and over-correction. When the data is available, DMM will perform additional analyses on congestion related concerns and report further on its findings.

[21] The ISO changed the discount factor on October 12, 2010. The effects of this change are still under review.