California Independent
System Operator Corporation

California ISO

Quarterly Report on Market Issues and Performance

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Executive summary

This report provides an overview of general market performance during the fourth quarter of 2010 (October – December).

Energy market performance

- In the fourth quarter of 2010, the day-ahead integrated forward market has continued to be stable and competitive. The level of load and supply scheduled in the day-ahead market continued to be within a few percentages of actual loads most hours. Average day-ahead energy prices continued to be approximately equal to benchmark prices that DMM estimates would occur under highly competitive conditions.
- In the 5-minute real-time market, average prices rose significantly above prices in the day-ahead and hour-ahead markets. Average real-time prices were driven up by a marked increase in brief but extreme price spikes near or above the $750/MWh bid cap. Most of these high prices were attributable to minor shortages of upward ramping capacity during these intervals.
- These high real-time price spikes generally do not reflect an underlying shortage of total potential capacity or uncompetitive bidding by suppliers, and may be avoided by further modeling and dispatch improvements that increase the accuracy and flexibility of real-time dispatches. The ISO has been developing several such improvements that appear to have the potential to lower the frequency of such extreme price spikes and improve hour-ahead and real-time market performance.
- The divergence of 5-minute real-time prices from hour-ahead market prices also continues to impose unnecessary additional inefficiencies and costs on the system. This occurs because net imports continue to be decreased in the hour-ahead market at low prices, which increases the additional incremental energy then purchased in the 5-minute real-time market at higher prices. The net cost of "selling low" in the hour-ahead market and "buying high" in real time must be recovered from load-serving entities through the real-time imbalance energy offset charge. In the fourth quarter, DMM estimates that this trend accounted for as much as $24 million in real-time imbalance energy offset charges.
- Overall, congestion within the ISO system had minimal impact on overall prices. On several days, however, prices caused by extreme congestion within the San Diego load aggregation point reached prices up to $6,000/MWh in multiple intervals. Many spikes were precipitated by generator and transmission outages that caused transmission paths into San Diego to be de-rated and manually adjusted in real time. Further exacerbating these high prices was the combined effect of several details of how congestion is modeled in the real-time software. Although high prices created by these modeling details have been very infrequent, the ISO is considering enhancements that would prevent or reduce such extreme prices when they are not reflective of actual underlying system conditions.

Multi-stage generating resources

The ISO implemented functionality for multi-stage generating units on December 7, 2010. At this time, DMM has limited market and operating data upon which to assess the performance of this new market feature. A limited number of generating units initially opted to participate as multi-stage generators. Several resources switched back to operating as conventional generating units in the first month. More recently, however, numerous other generating units have opted to begin operating as multi-stage generating units, so that the overall number of units using this new market enhancement has increased slightly since implementation.

Refinements in the new software are being initiated to address problems observed during this initial implementation period. DMM believes that a more meaningful assessment of this functionality can be made after these refinements are implemented and unit owners gain more experience bidding and scheduling as multi-stage generation units.

Addressing energy market performance issues

The ISO is implementing several key measures aimed at improving the consistency of hour-ahead and real-time prices and reducing the incidence of ramping capacity shortages in the 5-minute market. Although many were delayed for an early 2010 deployment, many now appear close to final implementation. An update on these items is provided below:

- **Compensating Injections.** 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. In mid-October 2010, the parameter settings for this software feature were adjusted to improve performance. Based on the limited amount of compensating injections data available from the ISO, DMM has found that these adjustments did improve the performance of this software feature.

- **Improving the forecast used in the hour-ahead and 15-minute pre-dispatch processes.** As noted in previous DMM reports, the ISO is continuing to develop a new short-term forecasting tool designed to provide more accurate and consistent forecasts for the hour-ahead and the real-time markets. Expected in 2010, implementing this new forecasting tool is now scheduled for February 2011.

- **Providing improved guidance to the operators regarding manual load adjustment practices.** The ISO has indicated it is seeking 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 has provided additional training and guidance to market operators on using load adjustments. The ISO is also developing a more systematic procedure that gives operators additional guidance to determine whether a load adjustment should be removed or continued. In addition, the new load forecasting tool should reduce the need for such manual adjustments. Additional recommendations relating to load forecasting and manual adjustments are provided in the final section of this summary and Section 1.3 of this report.

- **Accounting for inter-tie ramping requirements in the hour-ahead scheduling process.** This enhancement will modify the hour-ahead market to account for ramping energy needed from the 5-minute real-time market to adjust to changes in the net import and export schedules each hour. This enhancement was implemented from December 3 until December 23, 2010, but was suspended in order to refine the rules for how this constraint impacts prices used to settle imports and exports when it is binding. This feature was re-activated January 27, 2011. As noted in the December 2 market notice announcing the initial implementation of this modification, this feature "will not be visible to market participants; however, future market reports will provide information about how this feature is working to improve HASP to RTD price convergence."[1] DMM has not been able to assess the impact of this modification at this time, but has initiated discussions with the ISO regarding how to assess the impacts of this feature.

- **Adding a new flexible ramping capacity constraint.** In early 2011, the ISO is seeking to implement a new flexible ramping constraint in the hour-ahead and 15-minute pre-dispatch processes. The flexible ramping constraint will require that the software optimization results include a pre-specified amount of additional ramping capacity (beyond levels needed to simply meet the energy forecast). This new constraint is designed to ensure that sufficient upward and downward ramping capability from 5-minute dispatchable resources is committed and available to balance loads and supply on a 5-minute basis, taking into account the potential variability in actual system conditions. When applied in the hour-ahead market, this constraint may cause the level of net imports to better align with internal ramping energy needs. When applied in the 15-minute pre-dispatch process, this constraint may trigger commitment of fast start units when additional upward ramping capacity is needed.

- **Unit start-up profiles.** Currently, when a generating unit is scheduled to start up, the market software does not account for the energy generated while the unit is ramping up to its minimum load level. On a system-wide basis, this can create several hundred megawatts of unscheduled energy during the early morning hours. Operators currently seek to compensate for this through manual load adjustments. The ISO is developing software enhancements to model the unscheduled energy expected from units starting up. The ISO expects to implement this enhancement in the second quarter of 2011.

- **Adaptive control enhancements.** The ISO has a mid-term initiative in 2011 to develop adaptive control enhancements that will predict and account for various specific sources of uninstructed deviations. A simpler feature incorporated in the new market software to account for uninstructed deviations was disabled due to performance issues. Operators now must make uninstructed deviations adjustments, as appropriate, by using manual load biases.

Recommendations

- **Modeling enhancements to improve price convergence**. DMM believes each of these initiatives represent important steps that will help reduce extreme price spikes due to short-term shortages of ramping capacity, which in turn will help promote convergence of average hour-ahead and real-time prices. DMM recommends that the ISO continue to address the factors contributing to price divergence through these types of modeling and operational improvements even after the implementation of convergence bidding in February. Convergence bidding may reduce the recent divergence of hour-ahead and real-time prices. However, modeling and operational enhancements are a more economically efficient means of reducing extreme price variations and divergences.

- **Manual load adjustments.** DMM has identified some cases in which it appears that manual load adjustments may have contributed – in retrospect – to the shortages of upward energy resulting in relaxation of the power balance constraint and extreme price spikes. For example, this can occur when the hour-ahead load forecast is biased significantly downwards, and when the real-time forecast is suddenly biased upwards. As noted above, operators use load adjustments to account for anticipated unscheduled energy and uninstructed deviations by generation, as well as load

[1] Market Notice, December 2, 2010, Hourly Inter-tie Ramping Production Deployment 12/03/10.

uncertainty. DMM recognizes that these factors are often difficult to predict. However, based on these observations, DMM has recommended that the ISO continue to improve how and when to adjust or bias the load forecasts used in the hour-ahead and 5-minute real-time markets. The ISO has indicated it is developing a more systematic procedure that gives operators additional guidance in determining whether to remove or continue a load adjustment.

- **New load forecasting tool and tracking of manual load adjustments.** As noted above, the ISO is continuing development of a new short-term forecasting tool that it hopes to implement in February 2011. Upon implementation, DMM is recommending that the ISO keep a database of manual adjustments made to this forecast in the hour-ahead and real-time software.[2] DMM believes this data may provide a basis for more systematic analysis and improvements of manual load adjustment practices and perhaps the load forecasting tool itself. Also, these data will be needed to determine the extent to which any new load forecasting tool reduces the need for manual adjustments and its accuracy prior to any such adjustments.
- **San Diego congestion.** DMM is highly supportive of modeling enhancements that would prevent the type of extreme prices that occurred in the San Diego area in the fourth quarter. Although the conditions that cause such high prices have been very infrequent, such modeling enhancements would allow prices to increase significantly when congestion occurs but would produce prices that are more reflective of actual underlying system conditions.

[2] Currently, only a portion of the manual load adjustments are saved in the software database. Other manual adjustments are made to the forecast, but are recorded only in a separate spreadsheet format that cannot be readily used for analysis.

1 Energy market performance

Day-ahead market

In the fourth quarter of 2010, the day-ahead integrated forward market continued to be stable and competitive. The level of load and supply scheduled in the day-ahead market continued to be within a few percentages of actual loads for most hours. Average energy prices in the day-ahead market during each month of the fourth quarter continued to be approximately equal to benchmark prices that DMM estimates would occur under highly competitive conditions.

Real-time market

In the 5-minute real-time market, average prices rose significantly above prices in the day-ahead and hour-ahead markets. Average real-time prices were driven up by a marked increase in short but extreme price spikes. Most of these high prices were attributable to minor system level shortages of upward ramping capacity during these intervals. The price spikes generally do not reflect an underlying shortage of total potential capacity or uncompetitive bidding by suppliers, and may be avoided by further modeling and dispatch improvements that increase the accuracy and flexibility of real-time dispatches. This chapter focuses on a more detailed examination of this issue.

Congestion

Overall, congestion within the ISO system had minimal impact on overall prices. However, on five days in December, the San Diego load aggregation point reached prices ranging from $259 to $2,192/MWh for multiple hours.[3] Many of these price spikes were precipitated by generation and transmission outages that caused transmission paths into the San Diego area to be de-rated and manually adjusted in real-time.[4]

On these days, extremely high shadow prices occurred during numerous intervals when the market software issued an extreme re-dispatch of units located outside of San Diego in order to reduce modeled flows on the congested branch groups into San Diego. As described in two prior ISO technical bulletins, in cases such as this the lossless shift factors used in the market optimization can adjust resource schedules in ways that appear to be more effective in solving transmission constraints than they really are. This can result in extremely inefficient dispatch among resources where large amounts of re-dispatch provide very small congestion relief (which, in reality, may not even occur).[5] On one of these days, the impact of these high prices was further magnified when congestion occurred

[3] High prices occurred in San Diego because of large congestion values on December 22 in hours ending 18 and 19, December 23 in hour ending 20, December 25 in hours ending 18 and 19, December 28 in hours ending 18 and 20, and on December 29 in hours ending 11, 12, and 18. San Diego congestion exceeded $6,000/MWh for several intervals on December 22 hour ending 18 and December 29 hours ending 11 and 12.

[4] A fire at a generation station on December 22 caused both generation and transmission outages.

[5] *Technical Bulletin 2009-05-02: SDG&E Constrained 5-minute Default LAP Price on 4/19/09*, May 20, 2009, *http://www.caiso.com/23b4/23b4caaf479b0.pdf*.; and

Technical Bulletin 2009-06-03, Comparison of Lossy versus Lossless Shift Factors in the ISO Market Optimizations, June 15, 2009, http://www.caiso.com/23ce/23cec5cd70160.pdf.

simultaneously on the two major overlapping branch groups limiting imports into San Diego (SDGEIMP_BG and SDGE_CFEIMP_BG).[6]

Upon reviewing these pricing events, the ISO determined that on a going forward basis, because of the significant degree of overlap between these two major branch groups limiting imports into San Diego, it would be more appropriate to enforce only one of the two constraints at one time in the market model. Currently, the SDGE_CFEIMP_BG is enforced due to seasonal effects. With this approach, the flows on the other branch group would be closely monitored by operators and would only be enforced in real-time if deemed necessary.

The ISO is also considering options that could produce more efficient and less extreme real-time re-dispatch and pricing outcomes in cases when the use of lossless shift factors would otherwise result in the type of extreme re-dispatch and pricing that has been periodically observed because of congestion into the San Diego area.[7]

- One option would be to use “lossy” shift factors that reflect estimated losses.[8]
- A second option would be to measure the combined effectiveness of different resources re-dispatched and limit the re-dispatch accordingly. Currently, all individual resources with a shift-factor effectiveness of at least a threshold of 2 percent may be re-dispatched to relieve congestion.
- The third option is to set the transmission relaxation parameter for transmission constraints that are closed interfaces (SDGE IMP, SCE IMP) to near the $750/MWh bid cap rather than the current value of $5,000.[9] This option could be implemented by simply re-setting current software parameters, but would require a tariff modification.

1.1 Energy market prices

Figure 1.1 and Figure 1.2 show monthly average prices for on-peak periods and off-peak periods for the PG&E load aggregation point, respectively. As shown in these figures:

- Prices in the hour-ahead market used to dispatch and settle imports and exports tended to be systematically lower than prices in the 5-minute real-time market.

[6] Prices were corrected on December 29 to adjust for duplicative congestion on the SDGEIMP_BG. See the weekly price corrections report for further details (http://www.caiso.com/2b03/2b039ac027650.pdf).

[7] In 2009, to reduce these inefficient dispatch results, the ISO allowed the constraint that could not be resolved in the scheduling run to relax up to 5 MW in real-time in the pricing run. As DMM understands, the more recent cases observed represent solutions that can be resolved in the scheduling run and are not relaxed in the pricing run.

[8] See *Technical Bulleting 2009-06-03, Comparison of Lossy versus Lossless Shift Factors in the ISO Market Optimizations*, June 15, 2009, http://www.caiso.com/23ce/23cec5cd70160.pdf.

[9] The rationale for lowering this parameter only for closed interfaces is that there are no network effects for these transmission constraints, and, therefore, there is no possibility that relaxing the constraint at the lower price would prevent the dispatch of a resource effective at relieving the constraint. The specific value for relaxing these constraints might be set based on the largest spread between possible economic bids that could be re-dispatched to relieve congestion (e.g., $750-(-$30) = $780).

Figure 1.1 Average monthly on-peak prices - PG&E load aggregation point
Excluding prices > $1,000 and < -$500

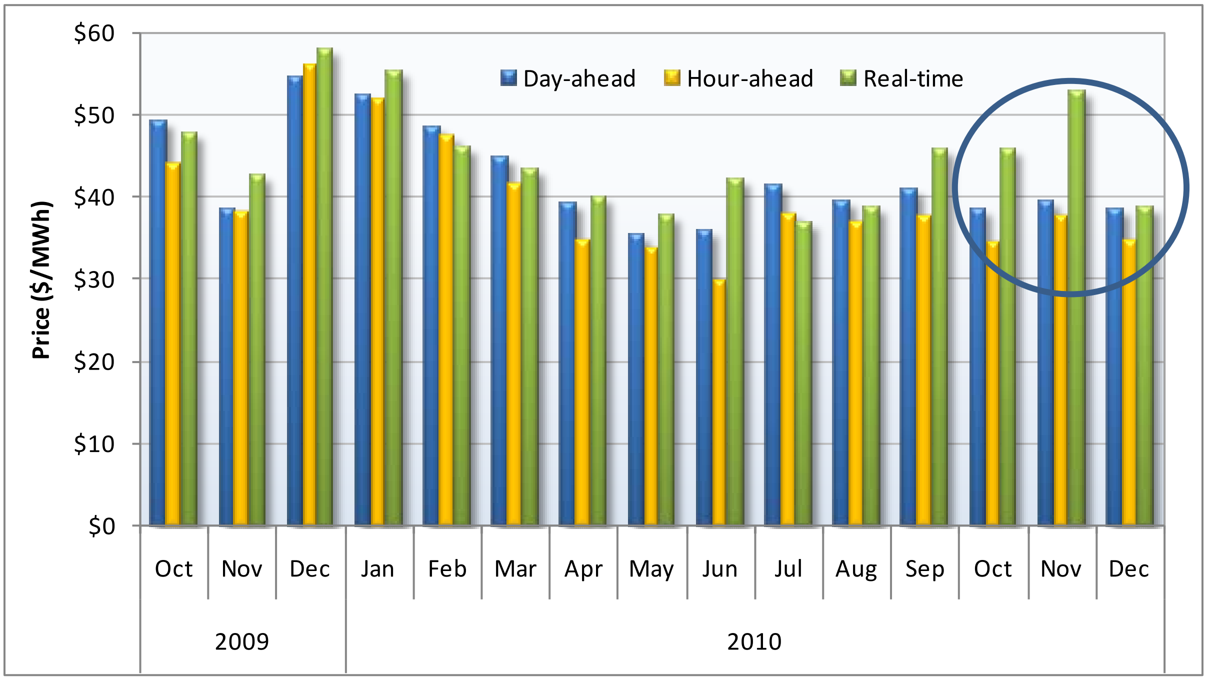
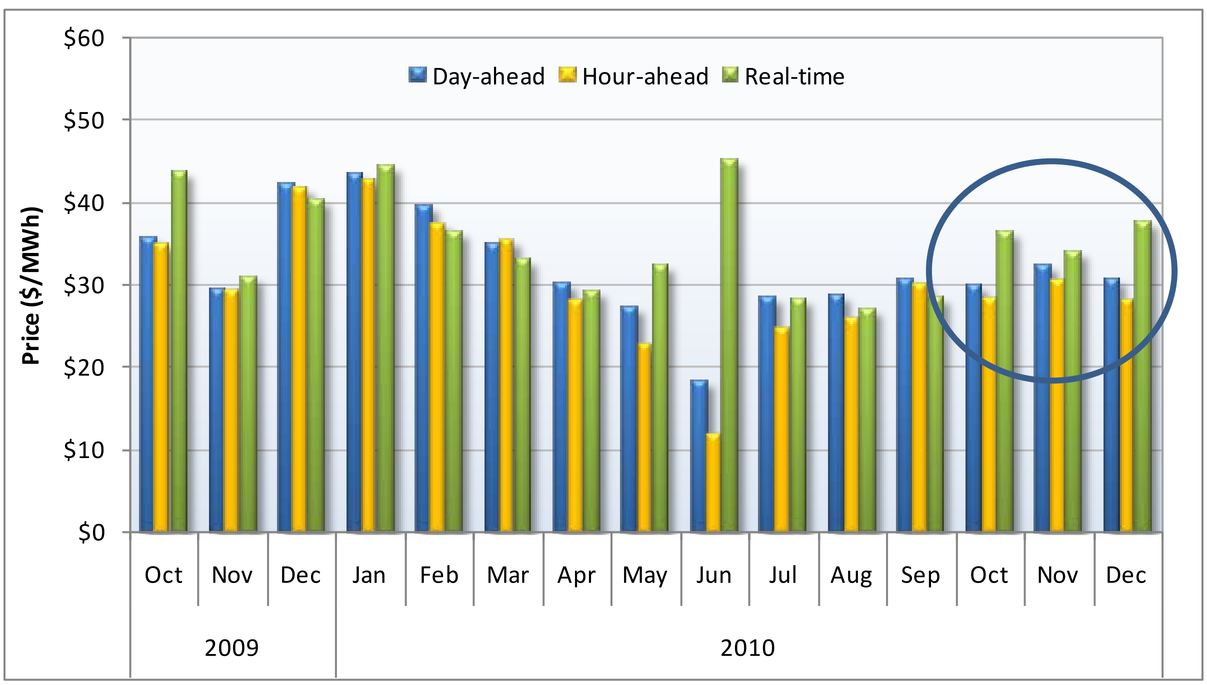


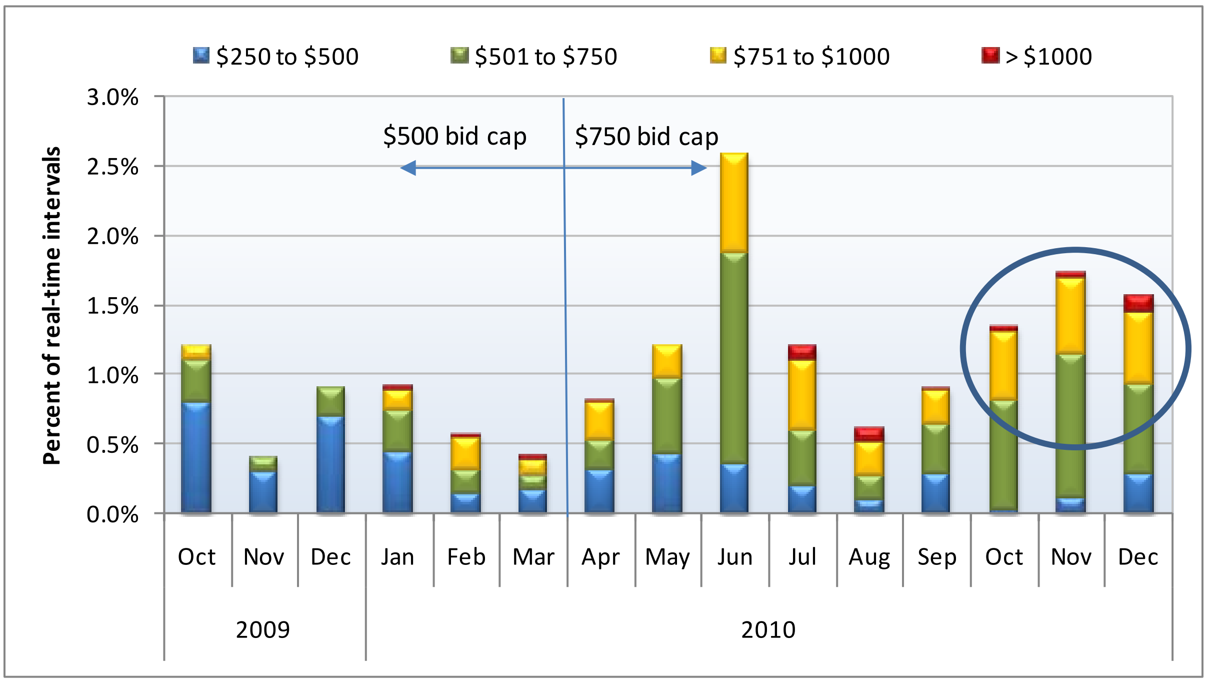
Figure 1.2 Average monthly off-peak prices - PG&E load aggregation point
Excluding prices > $1,000 and < -$500



- During peak hours, average prices in the 5-minute real-time market were significantly higher than day-ahead prices in October and November, but tracked day-ahead prices closely during December.
- During off-peak hours, prices in the real-time market were significantly higher than day-ahead prices in all three months of the fourth quarter of 2010.

The increase in average real-time energy market prices in the fourth quarter of 2010 was driven by a significant increase in extreme price spikes near or above the $750/MWh bid cap. As summarized in Figure 1.3, these price spikes occurred less than 1.5 percent of hours. Without these extreme price spikes, average peak prices in the real-time market would have tracked very closely with the average hour-ahead prices shown in Figure 1.9. Average real-time prices would also have been slightly lower than average day-ahead prices if these extreme price spikes did not occur during these few intervals.

Figure 1.3 Frequency of price spikes (All LAP areas)



In the fourth quarter of 2010, most of the high real-time price spikes lasted just a few 5-minute intervals and were attributable to minor short-term insufficiencies of energy bids that could be dispatched due to 5-minute ramping limitations. One major factor that tends to create shortages of ramping capacity is the fundamental discrepancy between the 15-minute intervals used in the hour-ahead scheduling and 15-minute pre-dispatch, and the 5-minute dispatch intervals used in the real-time market. For example, schedules produced by the 15-minute optimization may not provide for sufficient ramping capabilities needed to balance loads and generation during the three 5-minute intervals within this period.

Other specific factors observed to have caused or contributed to significant changes in imbalance energy needs between the hour-ahead and 15-minute pre-dispatch processes and the 5-minute market include the following:

- Differences between the load forecasts used in the hour-ahead and 15-minute pre-dispatch processes and the 5-minute real-time dispatch;
- Manual adjustments to these load forecasts, which may sometimes exacerbate price spikes by increasing load forecast differences or creating sudden changes in forecasted loads;
- Resource deviations including variable energy resources delivering more or less than forecast;
- Resources shutting down without sufficient notice;[10]
- Resources being constrained by their forbidden operating region or slow ramping regions not modeled in the market software;
- Imports awarded in day-ahead or hour-ahead market that are not delivered (i.e., e-tagged);
- Contingency events, such as unit or transmission outages; and
- During some periods, decreased flexibility of hydro resources due to high hydro run-off.

With additional constraints being incorporated into the day-ahead market and the reduction of exceptional dispatches, the system also has less surplus flexibility available to meet changes from expected conditions due to any of these factors. Steps by the ISO to decrease the uncertainty associated with these factors and increase the flexibility of the real-time market to respond to these factors are discussed in later sections of this chapter.

1.2 System power balance constraint

When insufficient incremental or decremental energy can be dispatched to meet estimated demand during any interval, the system-wide *power balance constraint* of the 5-minute real-time software is relaxed. This constraint requires dispatched supply to meet estimated load on a system-wide level during all 5-minute intervals. Relaxing the power balance constraint occurs under two different conditions:

- When insufficient incremental energy is available for 5-minute dispatch, the real-time software relaxes this constraint in the scheduling run using penalty prices of $750 for the first 350 MW and $6,500 thereafter.[11] In the pricing run, a penalty price of $750 is used. This causes prices to spike to

[10] *Operating Procedure T-113, Scheduled and Forced Outages, Section 3-8*, http://www.caiso.com/docs/2002/01/29/2002012913333822467.pdf.

[11] As explained pending modification to the *Business Practice Manual for Market Operations*:

> To reflect the role regulation plays in balancing the system when economic bids are exhausted, the ISO allows the system power balance constraint to relax by as much as +/-350MW in the real-time dispatch process at a price of $750 in the upward direction in the scheduling and pricing run and at price of -$35 in the downward direction in the scheduling and pricing run. The -$35 price used in the downward direction is used to allow for coordinated dispatch of bids that may exist near or below the soft bid floor. (PRR 360 published November 17, 2010)

As explained in the current *Business Practice Manual for Market Operations*, the $6,500/MW parameter for relaxing the power balance constraint is set at a high value in order to “achieve high priority in serving forecast load and exports that utilize non-RA capacity.” *Business Practice Manual for Market Operations*, Version 15, Revised: December 21, 2010, p.143.

the $750/MWh bid cap or above.[12]

- When insufficient decremental energy is available for 5-minute dispatch, the software relaxes this constraint in the scheduling using a penalty price of -$35 for the first 350 MW. After this, different types of self-scheduled energy may be curtailed at penalty prices beginning at -$825. In the pricing run, a penalty price of -$35 is used. This causes prices to drop down to or below the "soft" floor for energy bids set at -$30/MWh.

In practice, when brief insufficiencies of incremental or decremental energy bids that can be dispatched to meet this system energy constraint occur in the market software, there may not be an issue with the actual physical balance of system loads and generation. This is because the real-time market software is not a perfect representation of actual 5-minute conditions. To the extent an imbalance in loads and generation actually does exist during these intervals, units providing upward regulation provide any additional energy needed to balance loads and generation.

- Figure 1.4 and Figure 1.5 show the frequency with which the power balance constraint was relaxed in the 5-minute real-time market software since the fourth quarter of 2009. The power balance constraints have never been relaxed in the day-ahead or the hour-ahead markets. As shown in Figure 1.4, the power balance constraint was relaxed due to insufficiencies of dispatchable incremental energy in about 1.5 percent of all 5-minute intervals during the fourth quarter 2010. This represents a notable increase from most previous months. As discussed later in this report, the impact of this trend on average real-time prices was also the highest of any quarter since the bid cap and penalty prices used in the pricing run when this relaxation occurs was raised from $500/MWh to $750/MWh in April 2010.

- As shown in Figure 1.5, the power balance constraint was relaxed due to insufficiencies of dispatchable decremental energy in about 1 percent of all 5-minute intervals during the fourth quarter 2010. This represents a drop compared to most previous months. When the power balance constraint is relaxed under these conditions, the downward impact on average prices is also less significant because prices only drop towards or to the -$30/MWh bid floor. However, DMM notes that the ISO recently proposed lowering this bid floor to -$500/MWh in 2012 and even lower in the following years. DMM has expressed concern about this proposal, due in part to the impact this would have when the power balance constraint was relaxed because of short-term insufficiencies of dispatchable downward energy bids that can be created by software modeling issues.[13]

[12] If a significant level of relaxation has occurred, the resulting prices are approximately equal to the $750/MWh bid cap. If a relatively minor degree of relaxation has occurred, prices in the pricing run may fall below the $750/MWh bid cap and would be set by marginal bids actually dispatched. This results from the fact that in the pricing run, a number of other constraints are relaxed slightly and other extremely high or low penalty prices enforced in the scheduling run are replaced with the $750/MWh bid cap and -$30/MWh bid floor.

[13] See DMM comments on Phase 1 of the Integration market initiative at http://www.caiso.com/2b11/2b11a5a872c80.pdf.

Figure 1.4 Relaxation of power balance constraint due to insufficient upward ramping capacity

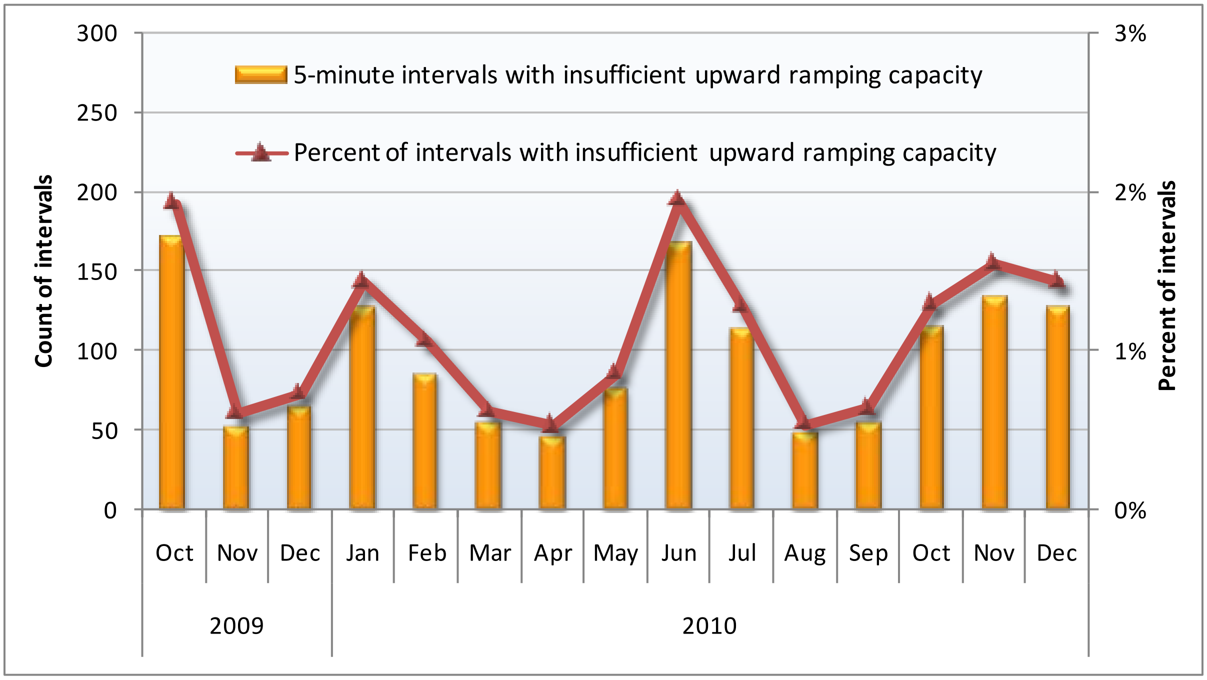


Figure 1.5 Relaxation of power balance constraint due to insufficient downward ramping capacity

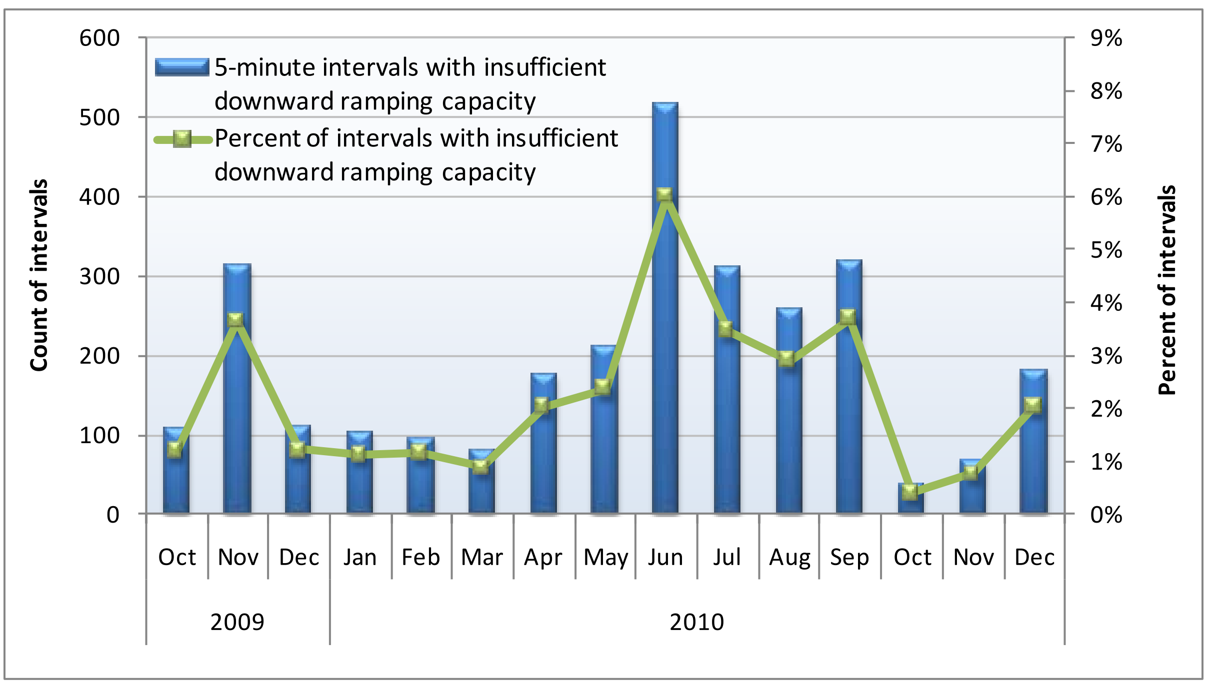


Figure 1.6 and Figure 1.7 provide more detailed information on the intervals in which the power balance constraint was relaxed in the fourth quarter of 2010. Figure 1.6 shows the percentage of intervals that the power balance constraint was relaxed by hour. As shown in Figure 1.6:

- Shortages of upward ramping capacity caused the power balance constraint to become binding most frequently during peak hours when system loads were highest and changing at a relatively high rate.[14]

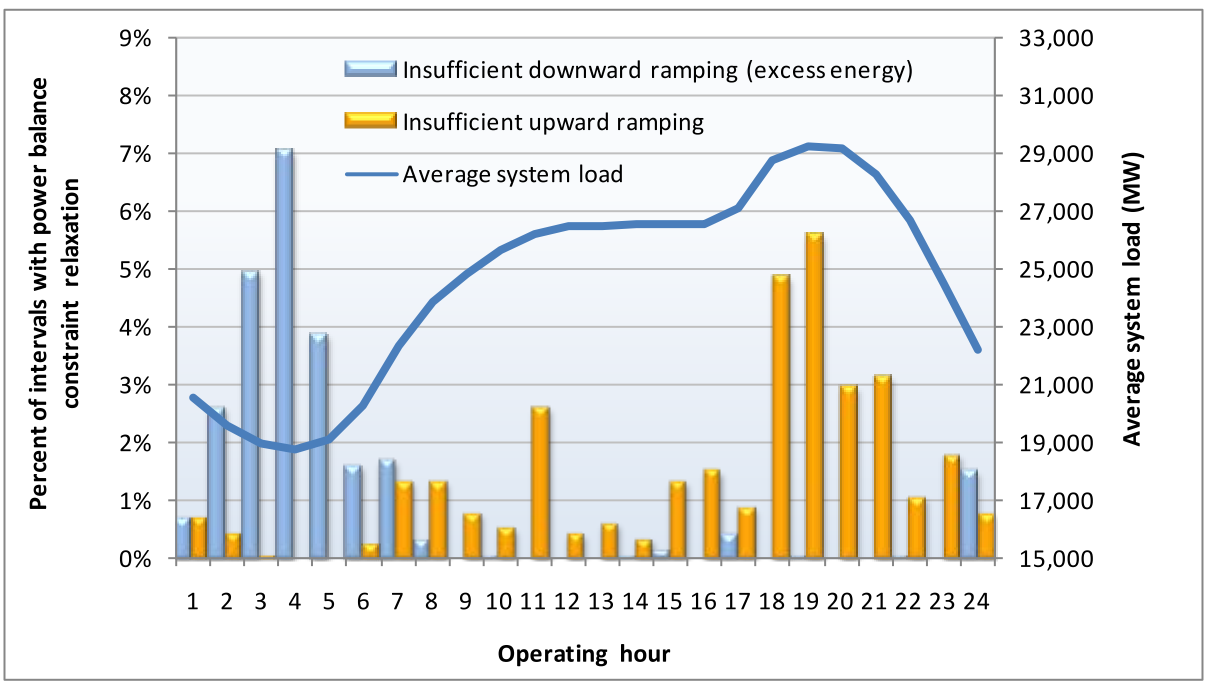
- Overall, the power balance constraint was binding because of shortages of upward ramping in about 1.5 percent of intervals during the fourth quarter of 2010. However, during the system peak load hours of 18 through 21, prices spiked because of shortages of upward ramping in about 3 to 5 percent of intervals.

Figure 1.7 shows the number of consecutive 5-minute intervals that shortages of upward ramping capacity existed in the fourth quarter of 2010. As shown in Figure 1.7:

- About three-fourths of price spikes because of shortages of upward ramping capacity persist for only one to three 5-minute intervals (or 5 to 15 minutes).

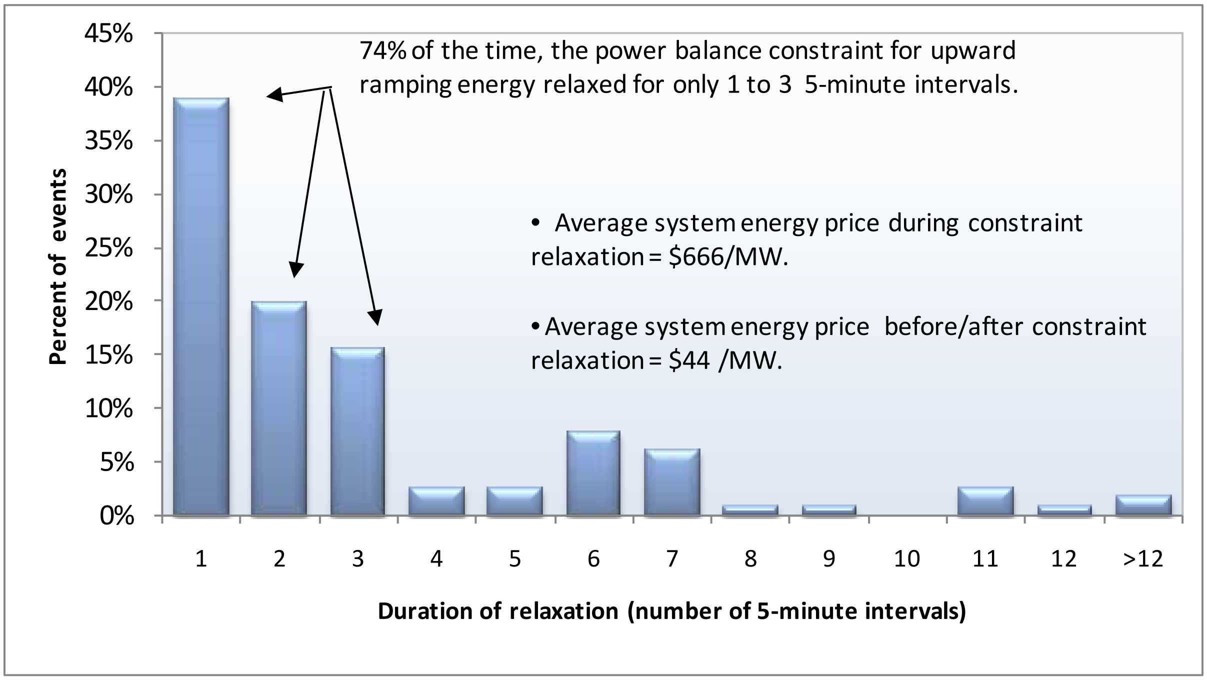
- During intervals when price spikes occurred because of these short-term shortages of upward ramping capacity, system energy prices averaged $666/MWh. This compares to an average system energy price of only $44/MWh in the intervals before and after these price spikes.

Figure 1.6 Relaxation of power balance constraint by hour (October – December 2010)



[14] During off-peak hours, the power balance constraint has been binding due to shortages of downward ramping capacity. However, shortages of downward ramping do not create prices lower than the -$30/MWh bid floor which is in effect for real-time energy bids.

Figure 1.7 Duration of energy balance constraint relaxation of events (October – December 2010)



1.3 Load forecasting and manual adjustments

One of the primary contributing factors to divergence of prices in the hour-ahead and 5-minute real-time markets involves the difference in load forecasts used in these two markets. For example, if system demand is under-forecasted in the hour-ahead market, the market software may dispatch imports and exports in a way that decreases the supply of available upward ramping capacity within the ISO during the 5-minute market. Similarly, if the load forecast is suddenly increased in the 5-minute real-time market, this can create a brief shortfall in the upward ramping energy available to meet the increased load forecast.

Some of the differences in these forecasts may be due to changing conditions between the execution of the hour-ahead market and the real-time market. However, operators can also manually adjust load forecasts used in the software. This is known as a *load bias*.

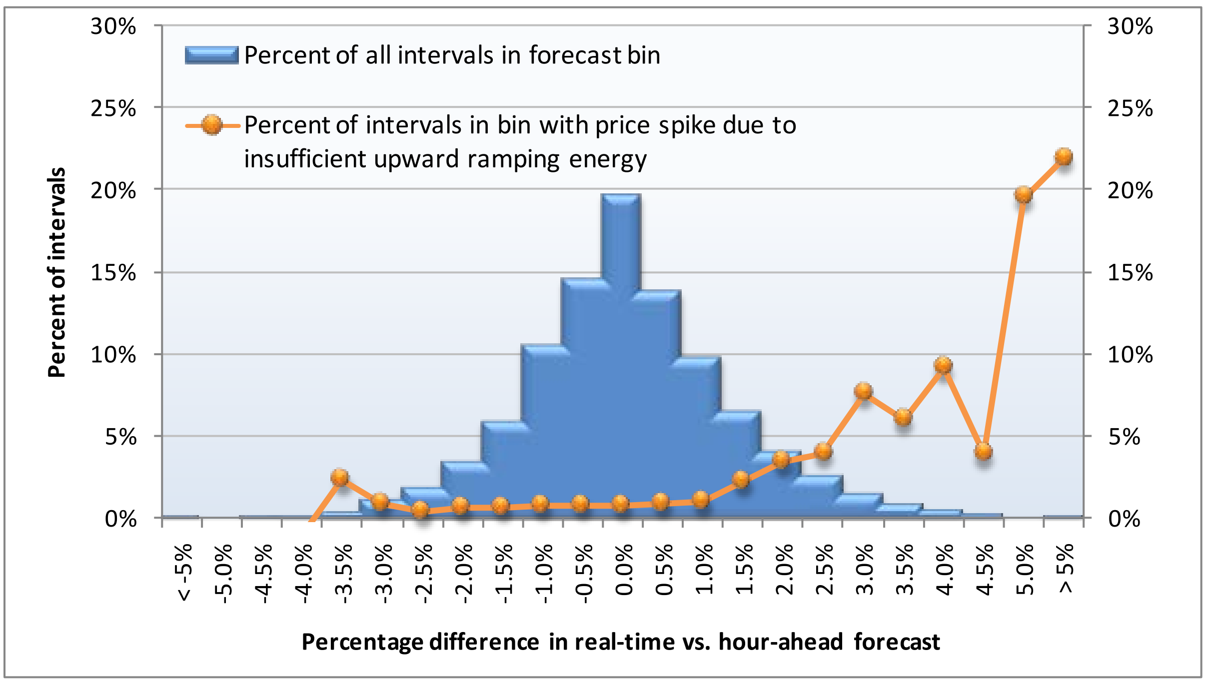
Load bias levels are not necessarily consistent between the hour-ahead and real-time forecasts. This can contribute to differences in price results between the hour-ahead market and the real-time market and short but extreme price spikes in the 5-minute market.

Figure 1.8 provides a histogram of the difference in the load forecast used in the hour-ahead market and the 5-minute load forecast in the fourth quarter of 2010. The bins represented by the blue bars show the distribution of this difference as a percentage of the real-time forecast. The line shows the percentage of intervals within each of these bids that the energy balance constraint was relaxed due to insufficient upward ramping energy. Load forecast data include manual adjustments. As shown in Figure 1.8:

- During most hours (81 percent), the load forecast used in the hour-ahead market was within ±2 percent of the 5-minute load forecast. During these hours, shortages of upward ramping capacity rarely occurred.
- Most shortages of upward ramping capacity (75 percent) occurred when the 5-minute load forecast exceeded the load forecast used in the hour-ahead scheduling process by 2 percent or more.
- As the degree to which real-time loads were under-forecasted in the hour-ahead market increases, the incidence of price spikes due to shortages of upward ramping capacity also increases significantly.

DMM has identified some cases in which it appears that manual load adjustments may have contributed to the shortages of upward energy resulting in relaxation of the power balance constraint and extreme price spikes. For example, this can occur when the hour-ahead load forecast is biased significantly downwards, and when the real-time forecast is suddenly biased upwards. The more extreme differences in the hour-ahead and real-time forecasts in Figure 1.8 are likely to reflect cases in which such biasing occurred.

Figure 1.8 Difference in hour-ahead and real-time forecast



Based on these observations, DMM has recommended that the ISO seek to improve how and when to adjust or bias the load forecasts used in the hour-ahead and 5-minute real-time markets. The ISO is developing a more systematic procedure that gives operators additional guidance to determine whether a load adjustment should be removed or continued.

The ISO is continuing development of a new short-term forecasting tool designed to provide a more accurate and consistent forecast for the hour-ahead scheduling process and the real-time market. This tool will provide forecasts at the 15-minute and 5-minute levels. The current load forecasting tool provides 30-minute forecasts, from which more granular forecasts are developed by simple interpolation. This new forecasting tool was expected in 2010, but implementation is now scheduled for February 2011.

When the ISO implements this tool, DMM is recommending that the ISO keep a database of manual adjustments made to this forecast in the hour-ahead and real-time software.[15] DMM believes this data may provide a basis for more systematic analysis and improvements of manual load adjustment practices and perhaps the load forecasting tool itself. Also, these data will be needed to determine the extent to which any new load forecasting tool reduces the need for manual adjustments and its accuracy prior to any such adjustments.

1.4 Impact of power balance constraint

As noted in Section 1.2, the power balance constraint was relaxed due to insufficient incremental energy during 1.5 percent of intervals in the fourth quarter of 2010. Price spikes during these intervals had a significant impact on overall average real-time prices due to the $750/MWh bid cap and penalty prices used in the pricing run when this relaxation occurs.

Figure 1.9 and Figure 1.10 highlight the degree to which the divergence of monthly average real-time prices during peak hours were caused by extreme prices during the small percentage of intervals when power balance constraint relaxations occur. With these intervals excluded, real-time prices during peak hours were approximately equal to hour-ahead prices. As shown in these figures, the impact of intervals when the power balance constraint needed to be relaxed became especially high in the fall months of 2010. This reflects the increased frequency with which this constraint needed to be relaxed and the higher magnitude of price spikes when this occurs because of the higher $750/MWh bid cap that took effect in April 2010.

Figure 1.11 and Figure 1.12 provide a similar comparison of the impact of prices during intervals when the power balance constraint needed to be relaxed during off-peak hours. With these intervals excluded, real-time off-peak prices are significantly lower in all three months of the fourth quarter 2010, and are relatively close to hour-ahead market prices.

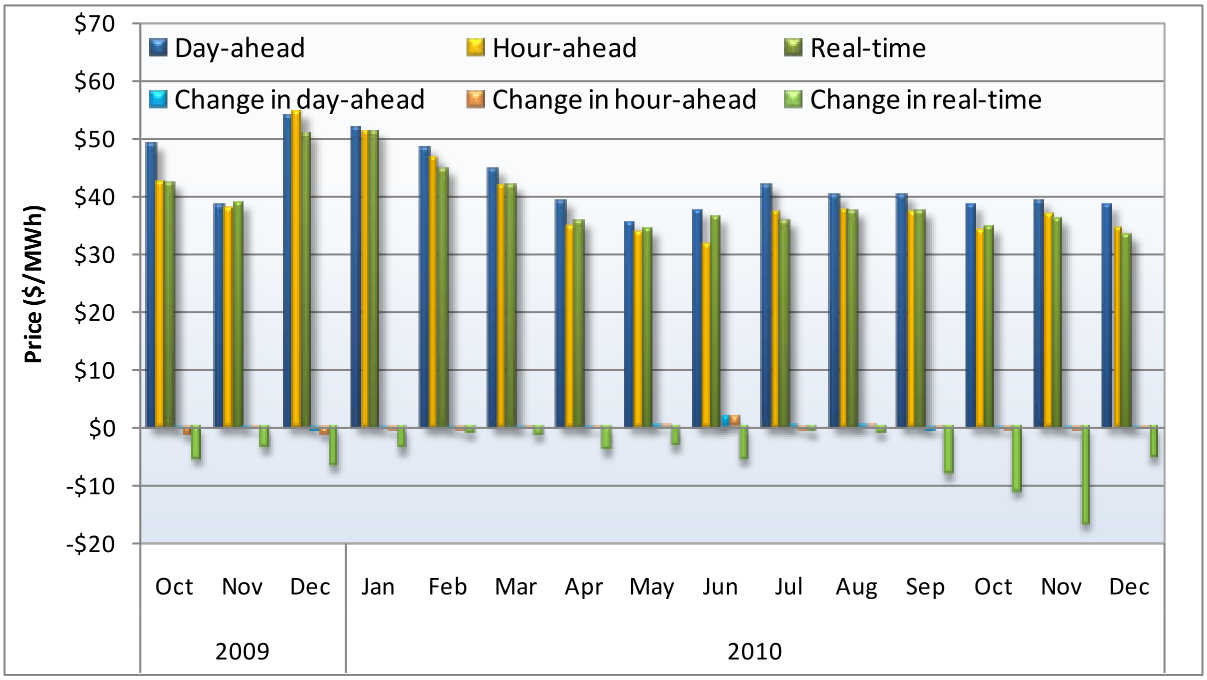
Figure 1.13 highlights the impact of prices during intervals when the power balance constraint needed to be relaxed for hourly prices in the fourth quarter of 2010. The most significant impact on real-time prices occurred during hours when the power balance constraint was relaxed because of insufficient incremental energy, as previously shown in Figure 1.6. Although the power balance constraint was relaxed because of excess energy a comparable percentage of morning hours (as shown in Figure 1.6), this did not have a significant impact on the difference in hour-ahead and real-time prices during these hours, as shown in Figure 1.13. This reflects the fact that under the current -$30/MWh bid floor, prices generally do not drop below -$30/MWh when the power balance constraint was relaxed because of excess energy.

[15] Currently, only a portion of the manual load adjustments are saved in the software database. Other manual adjustments are made to the forecast, but are recorded only in a separate spreadsheet format that cannot be readily used for analysis.

1.5 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 market, but real-time imbalance energy increases, the decrease in net imports may be inefficient.[16] 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 dispatching 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 charge.[17]

Figure 1.9 Change in monthly prices excluding hours when power balance constraint relaxed (PG&E LAP, peak hours)



[16] 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.

[17] 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 1.10 Difference in monthly hour-ahead and real-time prices excluding hours when power balance constraint relaxed (PG&E LAP, peak hours)

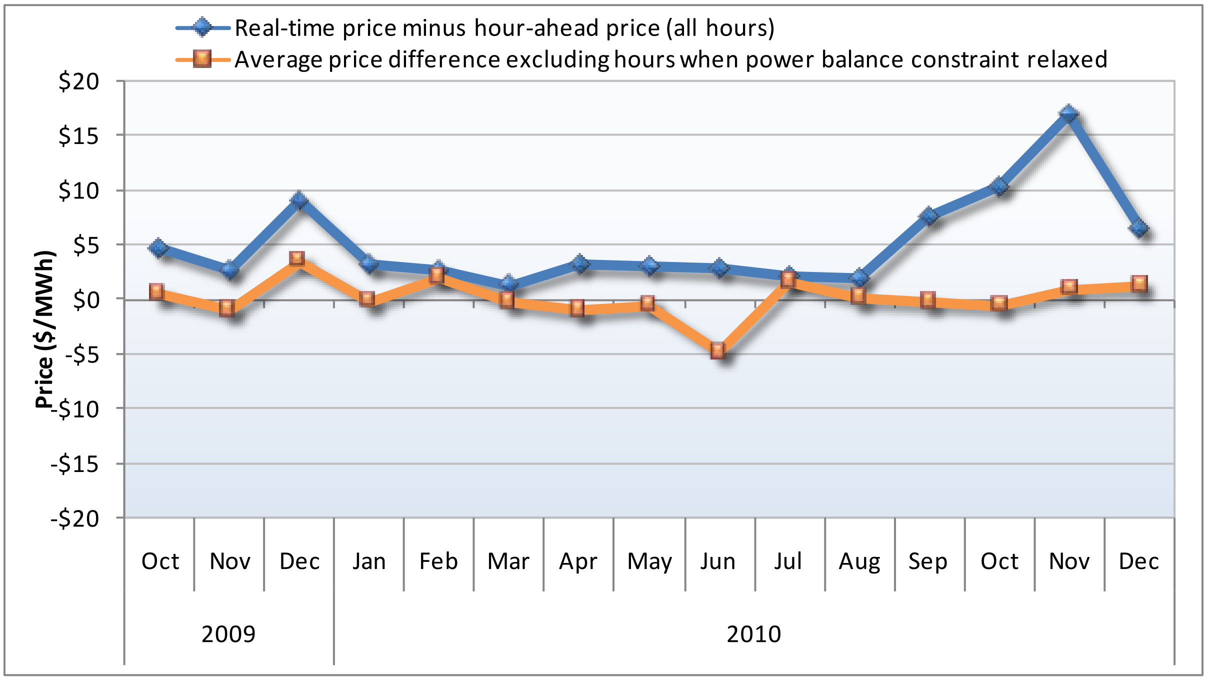


Figure 1.11 Change in monthly prices excluding hours when power balance constraint relaxed (PG&E LAP, off-peak hours)

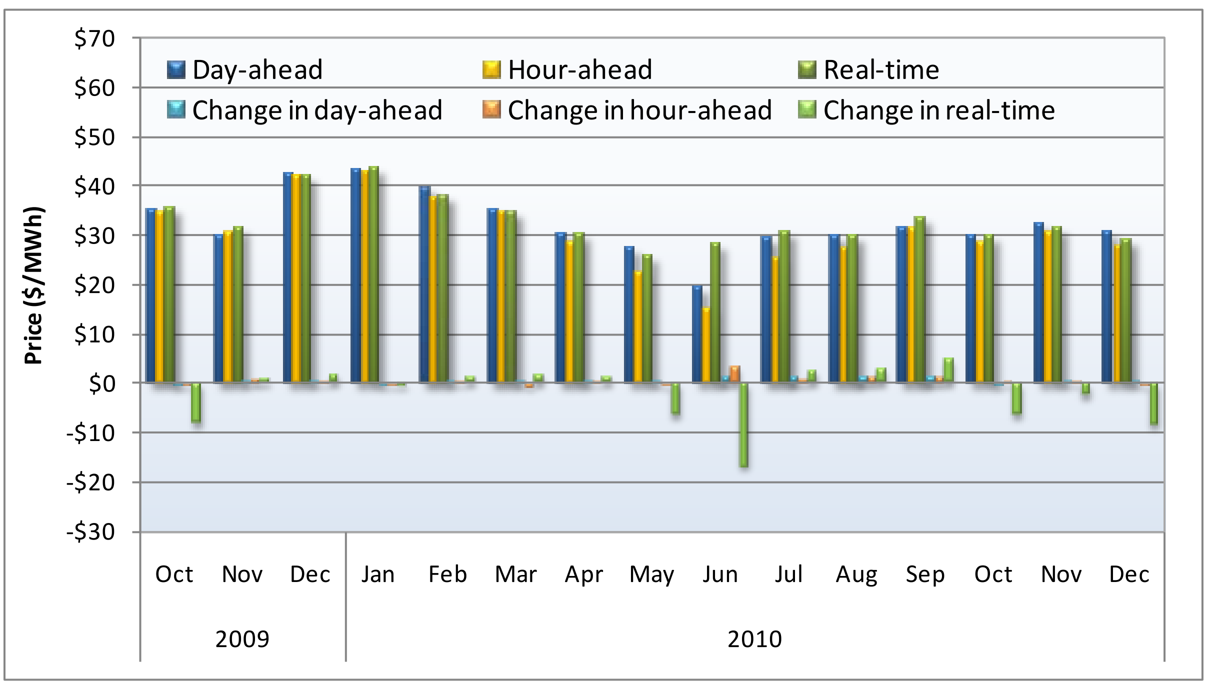


Figure 1.12 Difference in monthly hour-ahead and real-time prices excluding hours when power balance constraints relaxed (PG&E LAP, off-peak hours)

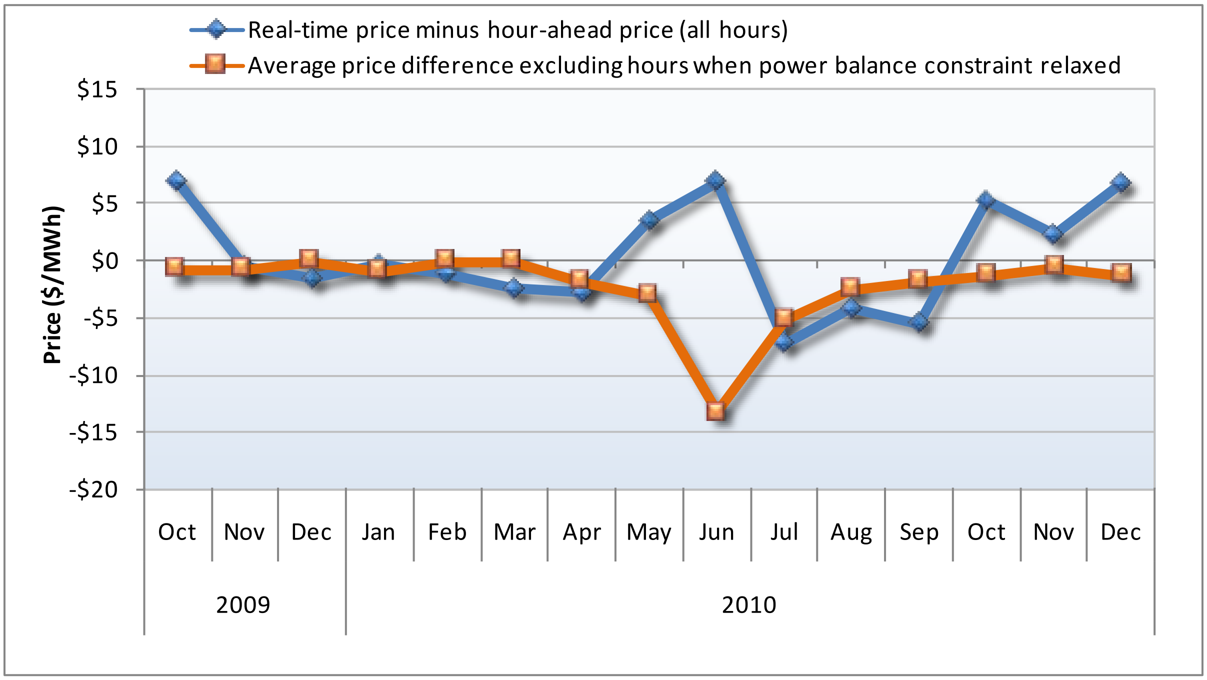
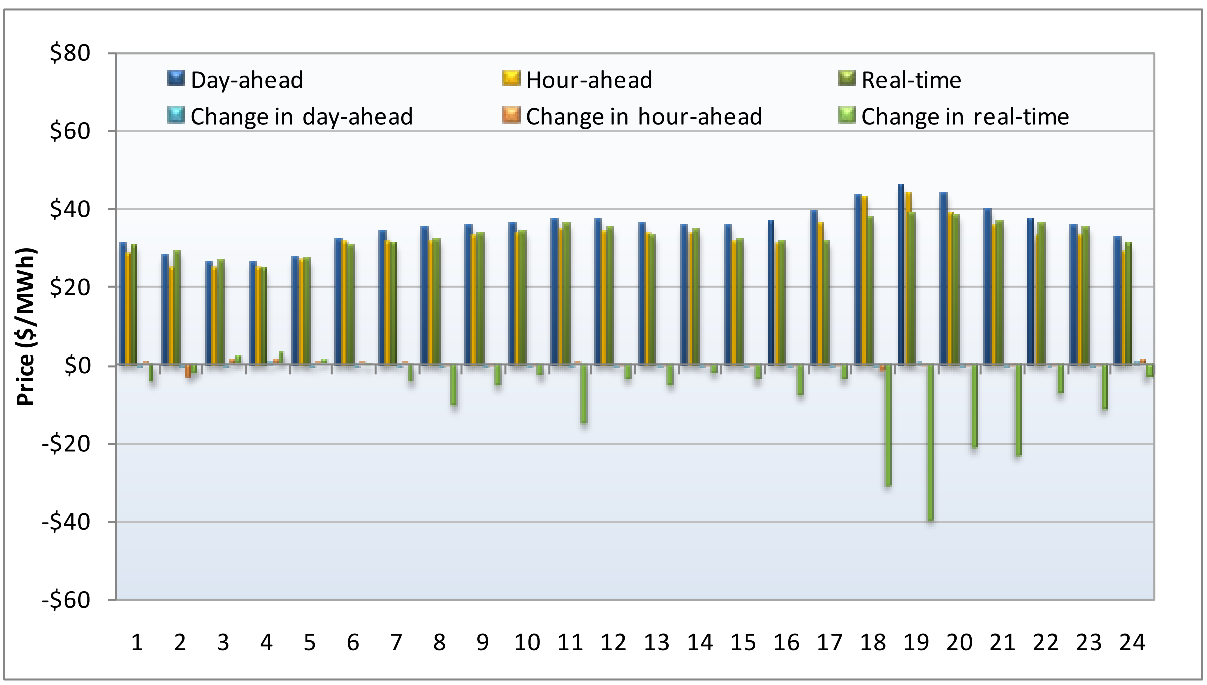


Figure 1.13 Change in average hourly price excluding hours when power balance constraint relaxed (PG&E LAP, off-peak hours Q4 2010)



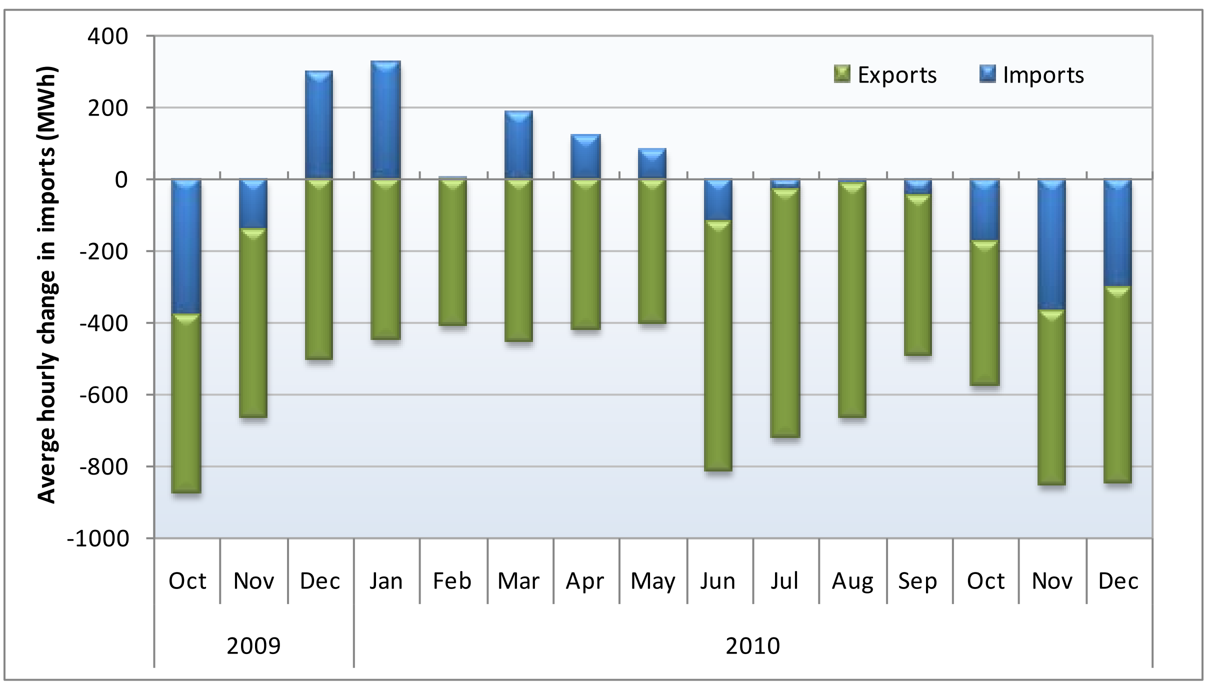
Decreased net imports in the hour-ahead market

When hour-ahead prices are low, net imports are likely to decrease in the hour-ahead market. In the hour-ahead market, 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 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 may also clear in the hour-ahead when prices are low.

Since hour-ahead prices have been systematically lower than day-ahead prices under the new market, 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 1.14 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 because of increased exports. However, in the fourth quarter decreases in net imports played its largest role since the start of the new market, accounting for roughly 37 percent of the decrease in net imports in the hour-ahead market in the fourth quarter compared to only 5 percent in the third quarter. Export levels in the fourth quarter 2010 were the second lowest to the first quarter of 2010.

Figure 1.14 Change in net imports in hour-ahead relative to final day-ahead schedules



Costs of decreased net imports in the hour-ahead market

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.[18] The green bars in Figure 1.15 show 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. The lines in Figure 1.15 compare the corresponding weighted average prices at which this decrease in net imports was settled in the hour-ahead market and the weighted average prices for additional energy procured in the real-time market during each month.[19] Together, the hourly decrease in hour-ahead net imports and the difference in hour-ahead and real-time prices produce the estimated imbalance energy costs. The total costs are ultimately determined by the quantity that is reduced in the hour-ahead process and then re-procured in real-time, combined with the difference in prices in these two markets.

As shown in Figure 1.15, the estimated quantities of reduced imports resulting in higher real-time energy purchases peaked in June 2010 after remaining relatively low in the first half of 2010. This quantity declined for several months, but then increased in November 2010.[20] Average weighted price differences between the hour-ahead and real-time markets also peaked in June 2010 at roughly $37/MWh, and then averaged around $15/MWh for the remainder of the year.

[18] In some cases, reductions in net import may be necessary in the hour-ahead scheduling process to manage congestion or reduce supply because of 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 and exports adjusted in the hour-ahead and subsequent dispatches and prices in the 5-minute real-time market.

[19] 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.

[20] Some DMM metrics were affected by undocumented changes made to data table structures when the multi-stage generator project was launched in early December. The results for December have been left blank for these metrics until they can be correctly calculated.

Figure 1.15 Monthly average quantity and prices of net import reductions in hour-ahead scheduling process and resulting increase in real-time energy dispatched

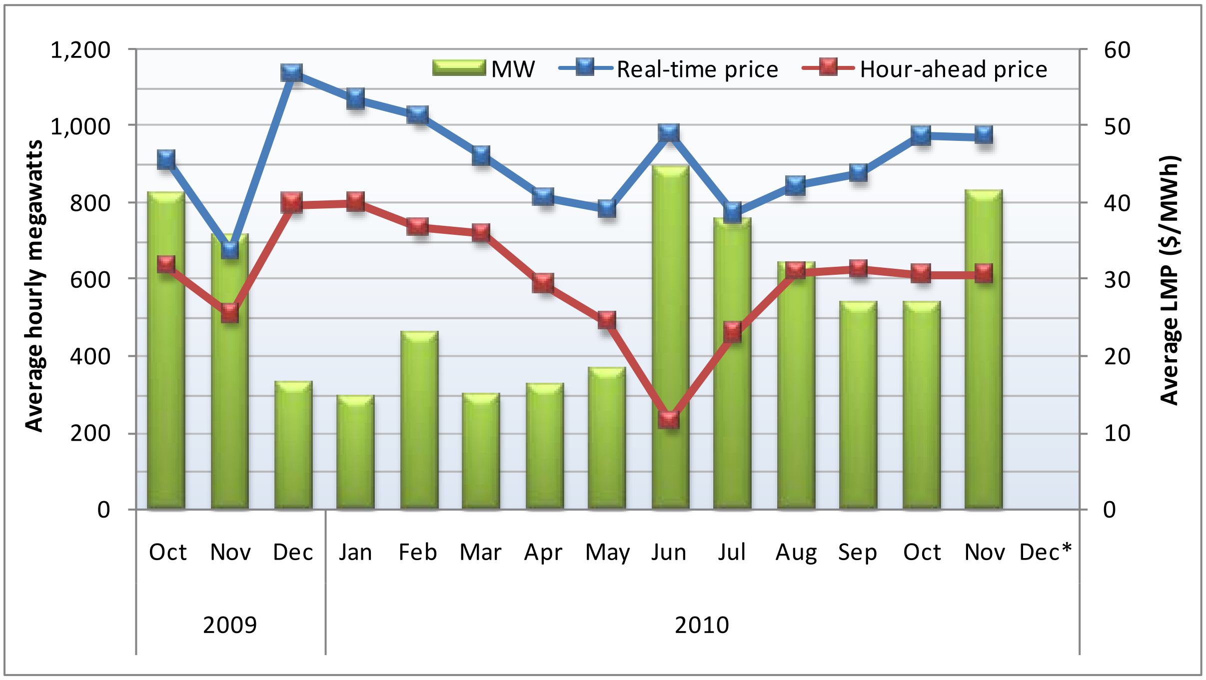


Figure 1.16 shows the estimated costs of additional imbalance energy because of decreasing net imports in the hour-ahead and increasing procurement of imbalance energy in real-time at a higher price.[21] The largest values were at the very start of the new market and in June 2010. The estimated costs fell from just under $23.5 million in June to around $5 million in September and then increased to over $9.5 million in November.[22] In the fourth quarter, DMM estimates that these costs accounted for as much as $24 million in real-time imbalance energy offset charges, approximately $0.44/MWh.[23] There were 11 days where the real-time energy imbalance offset charge was greater than $750,000 per day, accounting for over 40 percent of the total quarterly real-time energy offset charges for the quarter.[24]

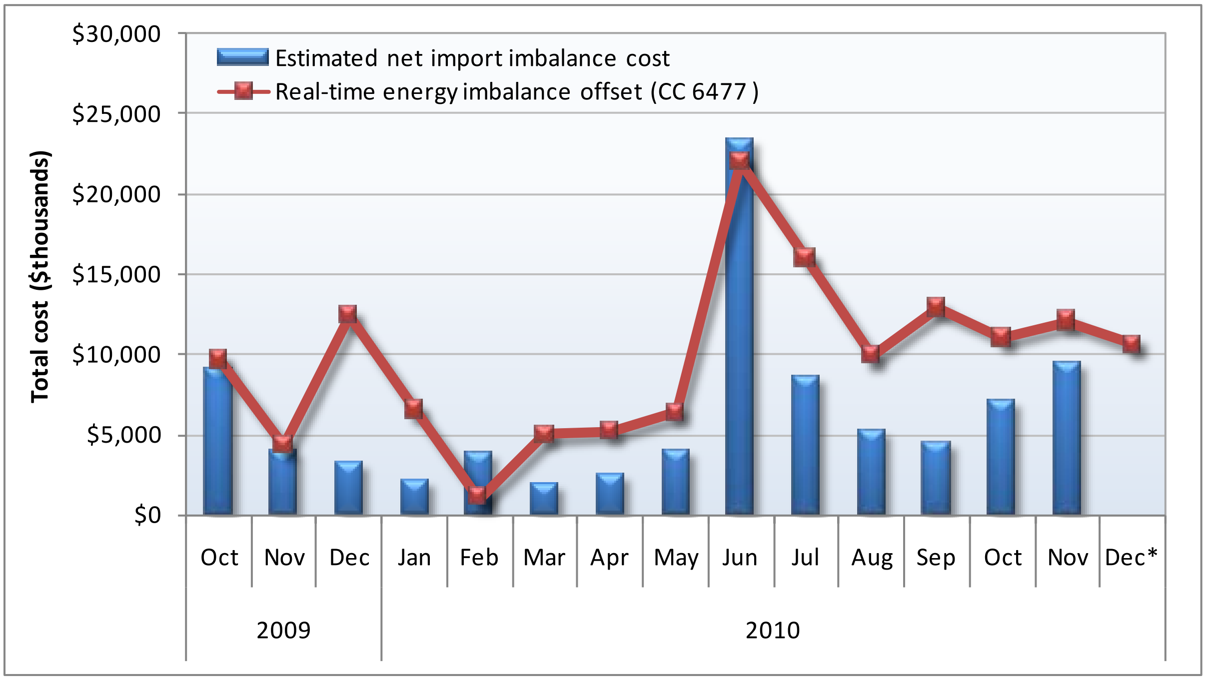
[21] DMM estimates these costs based on (1) the decrease in hour-ahead net imports that were subsequently re-procured in real-time, and (2) the difference in hour-ahead versus real-time prices during the corresponding hour. This estimate is only one element of the real-time imbalance energy offset charge 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.

[22] See footnote 20 for explanation of December results.

[23] We assumed costs in December would be similar to costs in October.

[24] November 29, 2010 accounted for roughly $3.7 million alone.

Figure 1.16 Estimated imbalance costs because of decreased net hour-ahead imports requiring dispatch of additional energy in 5-minute market at higher price



1.6 Initiatives to improve market performance

The ISO is implementing several key measures aimed at improving the consistency of hour-ahead and real-time prices and reducing the incidence of ramping capacity shortages in the 5-minute market. Although many were delayed for an early 2010 deployment, many now appear close to final implementation. An update on these items is provided below:

- **Compensating Injections.** 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 automatically aligns flows produced by the market software with actual observed flows. In mid-October 2010, the parameter settings were adjusted to improve performance. The changes in the performance of compensating injections are discussed in further detail in Section 2.4 of this report.

- **Improving the forecast used in the hour-ahead and 15-minute pre-dispatch processes.** As previously noted, the ISO is developing a new short-term forecasting tool designed to provide a more accurate and consistent forecast for the hour-ahead scheduling process and the real-time market. This new forecasting tool was expected in 2010, but is now scheduled for February 2011.

- **Providing improved guidance to the operators regarding manual load adjustment practices.** The ISO is seeking 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 has provided additional training and guidance to market operators on using load adjustments. The ISO is also developing a more systematic procedure that gives operators additional guidance to determine whether to remove or continue a load adjustment. In addition, the new load forecasting tool should reduce the need for manual adjustments.

- **Accounting for inter-tie ramping requirements in the hour-ahead scheduling process.** This enhancement will modify the hour-ahead scheduling process to account for ramping energy needed from the 5-minute real-time market to adjust to changes in the net import and export schedules each hour. In use December 3 until December 23, 2010, it was suspended to refine the rules for how this constraint impacts prices used to settle imports and exports when it is binding. This feature was re-activated January 27, 2011. As noted in a December 2 market notice, this feature "will not be visible to market participants; however, future market reports will provide information about how this feature is working to improve HASP to RTD price convergence."[25] DMM has not been able to assess the impact of this modification at this time, but is discussing with the ISO how to assess the impacts of this feature by re-simulating the hour-ahead market for a sample of hours with and without this constraint.[26]

- **Reinforce the requirement to provide timely information on resource outages and limitations.** In November the ISO modified operating procedures for scheduled and forced outages to clarify and reinforce the obligation for resources to submit information about resource limitations or unavailability prior to the start of the hour-ahead scheduling process.[27]

- **Adding a new flexible ramping capacity constraint.** In early 2011, the ISO plans to implement a flexible ramping constraint in the hour-ahead and 15-minute pre-dispatch process. The flexible ramping constraint will require that the software optimization results include a pre-specified amount of additional ramping capacity (beyond levels needed to simply meet the energy forecast). This new constraint is designed to ensure that sufficient upward and downward ramping capability from 5-minute dispatchable resources is committed and available to balance loads and supply on a 5-minute basis, taking into account the potential variability in actual system conditions. When applied in the hour-ahead market, this constraint may help better align net import levels with internal ramping energy needs. When applied in the 15-minute pre-dispatch process, this constraint may trigger commitment of fast start units when additional upward ramping capacity is needed.

- **Unit start-up profiles.** Currently, when a generating unit is scheduled to start up, the market software does not account for the energy generated while the unit is ramping up to its minimum load level. On a system-wide basis, this can create several hundred megawatts of unscheduled energy during the early morning hours. Operators currently seek to compensate for this through manual load adjustments. The ISO is developing software enhancements to model the unscheduled energy and expects to implement this enhancement in the second quarter of 2011.

- **Adaptive control enhancements.** The ISO has a mid-term initiative in 2011 to develop adaptive control enhancements that will predict and account for other various specific sources of uninstructed deviations. A simpler feature incorporated in the new market software to account for uninstructed deviations was disabled due to performance issues. Operators now must make uninstructed deviations adjustments, as appropriate, by using manual load biases.

[25] Market Notice, December 2, 2010, Hourly Intertie Ramping Production Deployment 12/03/10.

[26] See more detailed discussion in Section 2.1 of this report.

[27] *Operating Procedure T-113, Scheduled and Forced Outages, Section 3.8*, http://www.caiso.com/docs/2002/01/29/2002012913333822467.pdf.

DMM believes each of these initiatives represent important steps that will help reduce extreme price spikes because of short-term shortages of ramping capacity, which in turn will help promote convergence of average hour-ahead and real-time prices. DMM recommends that the ISO continues to address the factors contributing to price divergence directly through these types of modeling and operational improvements even after the implementation of convergence bidding in February. Convergence bidding may reduce the recent divergence of hour-ahead and real-time prices. However, modeling and operational enhancements are a more economically efficient means of reducing extreme price variations and divergences.

2 Software modifications

The ISO implemented several significant software related changes in the fourth quarter. These changes included new features that:

- Account for inter-tie ramping in the hour-ahead market (commonly referred to as hourly inter-tie ramping or HIR);
- Provide scarcity pricing signals for ancillary services in the real-time market; and
- Better optimize multi-stage generating (MSG) units in the market software.

In addition, the ISO modified the parameters for the compensating injections feature that was launched in July to improve performance.

2.1 Hourly inter-tie ramping

The hourly inter-tie ramping feature modified the hour-ahead scheduling process to account for inter-tie ramping requirements. Initially, only the 5-minute market software accounted for changes in net imports along the inter-ties. The new hourly inter-tie ramping feature makes the hour-ahead market and 5-minute markets more consistent across the hour by modifying the hour-ahead market to account for the 20-minute ramping period between hours.

Implemented from December 3 until December 23, 2010, it was suspended to refine the rules for how this ramping constraint affects prices used to settle imports and exports when it is binding. The ISO reactivated this feature on January 27, 2011. As noted in a December 2 market notice, this feature "will not be visible to market participants; however, future market reports will provide information about how this feature is working to improve HASP to RTD price convergence."[28] DMM has not been able to assess the impact of this modification at this time, but is discussing with the ISO how to assess the impacts of this feature by re-simulating the hour-ahead market for a sample of hours with and without this constraint.[29]

[28] Market Notice, December 2, 2010, Hourly Intertie Ramping Production Deployment 12/03/10.

[29] Specifically, DMM is suggesting to re-run the hour-ahead market with this constraint added for a sample of hours, including some when the power balance constraint was relaxed in the real-time market due to insufficient upward and downward ramping capacity. Results of these re-runs would be assessed to determine if (1) the change in inter-tie prices reduced price divergence, and/or (2) the change in net imports due to the constraint resulted in the additional type of ramping capacity in the 5-minute market during that hour (e.g., upward and downward ramping capacity). With this approach, it should be noted that re-running the 5-minute market with adjusted interchange schedules would not be practical or necessarily provide an accurate indication of the actual impact on the 5-minute market results. Rather, the general nature of the impact on the 5-minute market results would be assumed based on the change in net interchange schedules because of the constraint. For example, if the constraint was found to have increased net imports or reduced any increase in hourly interchange schedules, this would provide an indication that the constraint increased the supply of upward ramping or decreased the need for upward ramping in the 5-minute real-time market.

2.2 Scarcity pricing of ancillary services

Scarcity pricing of ancillary services in the real-time pre-dispatch process was implemented on December 14, 2010. When there are ancillary services deficiencies in this process, the scarcity pricing mechanism administratively sets the ancillary service price. The price level accounts for both the quality and location of the reserve and sets the price for each ancillary service product and region appropriately.

Scarcity pricing only indirectly affects energy market pricing outcomes in real-time. Ancillary services are only procured in the real-time market as part of the real-time pre-dispatch process, which is run every 15 minutes. This process also commits quick start-units and schedules inter-tie resources. The real-time pre-dispatch, however, does not set real-time prices for internal energy resources. Therefore, to the extent that tradeoffs exists that affect the commitment of quick start units and inter-tie resources, these results will indirectly influence the energy market prices for internal resources in the 5-minute real-time dispatch market, but will not directly affect these prices.

Scarcity pricing of ancillary services in the pre-dispatch process was activated inappropriately on December 19 and 23 although no shortage of ancillary services existed.[30] Both instances occurred because of separate software patch installations, and for December 23, the published ancillary service prices were reverted back to the day-ahead results. The software patch issues appear to be resolved as no further instances of false scarcity pricing of ancillary services has occurred since December 23.

DMM will continue to monitor the application of scarcity pricing of ancillary services in the real-time market and will report on any significant events in subsequent reports.

2.3 Multi-stage generating units

The ISO implemented functionality for multi-stage generating units on December 7, 2010. At this time, DMM has limited market and operating data upon which to assess the performance of this new market feature. However, initial monitoring results indicate the following:

- Due to the uncertainties associated with this new market feature, only 11 generating units (representing 4,556 MW of total capacity) chose to operate as multi-stage generating units upon software implementation. Several major combined cycle generating units switched back to being modeled as single configuration generating units within the first month. More recently, however, numerous other resources have opted to begin operating as multi-stage generating units, making the overall number of units using this new market enhancement slightly higher than when it was first implemented.
- In some cases, it appears that the new functionality's performance may improve as unit owners learn how to adjust bids for energy and the costs of starting up and transitioning between different unit configurations.
- Modeling and bidding issues with this functionality led to a notable increase in exceptional dispatches and blocked dispatch instructions for resources operating as multi-stage generating units in the weeks following implementation. In most cases, these exceptional dispatches appear to have

[30] Ancillary service scarcity pricing was triggered incorrectly on December 19 in multiple intervals in the real-time market runs during hour ending 18 and for multiple intervals in hours ending 1 and 2 on December 23.

been issued to override a dispatch from the market software in order to transition a unit to a new configuration or to keep the unit in its current configuration. The frequency of exceptional dispatch appears to have decreased as the software issues were resolved and operators and participants gained more experience with the new functionality.

- Bid cost recovery payments appear to have increased somewhat for resources operating as multi-stage generating units. Final settlement data for these payments are not available at this time.
- Numerous refinements in the new software have been initiated to address issues observed during the implementation period. The number of new software issues appears to be dropping significantly.

Over the longer run, there are several measures that will provide an indication as to how well this market feature is working:

- The frequency of exceptional dispatches and blocked dispatch instructions issued for multi-stage generating resources. To the extent the market dispatch improves because of this functionality, we would expect to see less frequent need for manual intervention to control these units.
- The frequency with which generation owners use the ISO's outage management system (Scheduling and Logging for ISO of California or SLIC) to manage start up, shutdown, and configuration changes by entering temporary adjustments to their unit operating characteristics. The need for such adjustments should decrease for multi-stage generating units.
- A decrease in self scheduling would provide an indicator that this feature is committing, de-committing and dispatching multi-stage generating resources in a fashion consistent with what the resource schedulers believe is profitable, efficient and consistent with their units' operational capabilities and requirements.
- Bid cost recovery payments made to multi-stage generating resources. Higher payments after implementation could indicate that resources were subject to uneconomic commitments or dispatches more than before implementing this functionality.
- Feedback from the resource schedulers that they have observed commitment and dispatch among the resource configurations that is profitable, efficient and consistent with their units' operational capabilities and requirements. One of the key types of feedback may be the number of units that eventually choose to operate as multi-stage generating units.

The ISO has committed to monitoring the impacts and effectiveness of the multi-stage generating units. DMM will also seek to provide an assessment of this new market feature in future market reports.

2.4 Compensating injections

Background

In July 2010, the ISO re-implemented a new feature in the real-time software to manage unscheduled flows along the inter-ties in an automated manner using compensating injections.[31] Compensating injections are pseudo megawatt injections and withdrawals made in the ISO software at various locations external to the ISO that act to minimize unscheduled flows. The 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.

Prior to implementation of compensating injections, the ISO had identified that net compensating injection values (less than 100 MW in absolute value) can impose operational challenges by interacting with the Area Control Error. The ACE is a measure of the instantaneous difference in matching 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 reduces the compensating injections at each location if the overall net system-level compensating injections are above certain thresholds. If the net compensating injections are above some higher threshold, every individual compensating injection will be cancelled.

In previous market reports, DMM recommended that prior to re-implementing compensating injections, the ISO should establish plans for monitoring the impact of this software feature and modifying software settings as needed.

As noted in the 2010 third quarter report, DMM has access to limited data for use in assessing the performance and impact of compensating injections. DMM's review of the available data for one sample day after the third quarter re-implementation indicated that when fully on, the resulting compensating injections significantly reduce the difference between modeled versus actual flows on the major inter-ties. However, as indicated in DMM's report for the third quarter of 2010, the initial software settings resulted in this feature being fully on only about 26 percent of all intervals.[32]

On October 12, 2010, the ISO modified the feature by adjusting the parameters that discount the amount of injections on the system under certain conditions. The goal was to allow compensating injections to be in full effect for a higher portion of the time than what was being observed under the initial parameter settings.

Analysis

After gaining experience with compensating injections throughout the late summer and early fall, the ISO decided to adjust the parameters in October to improve overall performance of the feature. The discount factor was increased from 0.2 to 0.3 for net compensating injections between 100 MW and

[31] *Technical Bulletin 2010-07-01, Compensating Injection in the ISO Real-time Market, July 16, 2010, http://www.caiso.com/27d4/27d4e73124db0.pdf.* As noted in prior DMM reports, the ISO initially implemented compensating injections in October 2009, but turned off this feature in November 2009 until further refinements were made.

[32] See *Quarterly Report on Market Issues and Performance*, November 8, 2010, pp. 39-42. http://www.caiso.com/2848/2848983817680.pdf.

335 MW. In addition, the level at which discounting begins was increased from 50 MW to 100 MW, and the level at which they are cancelled was decreased from 500 MW to 335 MW.

These thresholds and discount factors result in the large deviations in average positive and negative injections from interval to interval.[33] Specifically:

- The intervals when the positive and negative compensating injections exceed 1,500 MW represent intervals where no discounting was applied, so that the full impact of this feature was in effect. As noted in Table 2.1 and Table 2.2 below, we refer to these intervals as "full compensating injection" intervals.
- The intervals when the positive and negative injections are just under 1,500 MW represent when the feature was on but the discounting was applied. We refer to these intervals as "partial compensating injection" intervals, since the impact of this feature was partially in effect.
- The intervals when no injections occurred represent when injections were cancelled or not generated because of functional failures of this software feature.

Table 2.1 shows results for the first phase of the implementation from July 27 through October 11. Table 2.2 shows results from the second phase, October 12 through December 1.

Table 2.1 Summary of compensating injections (July 27 – October 11)

	# of Intervals	Percentage	Average Positive	Average Negative	Average Net	Average Absolute Net	Maximum Net	Minimum Net
Compensating Injections Off	338	5%	0	0	0.0	0	0	0
Full Compensating Injections	1,837	26%	4,050	-4,050	0.8	25	50	-50
Partial Compensating Injections	4,887	69%	811	-809	1.8	32	100	-99
All Compensating Injections	7,062	100%	1,696	-1,694	1.5	30	100	-99

Table 2.2 Summary of compensating injections (October 12 – December 31)

	# of Intervals	Percentage	Average Positive	Average Negative	Average Net	Average Absolute Net	Maximum Net	Minimum Net
Compensating Injections Off	929	13%	0	0	0.0	0	0	0
Full Compensating Injections	3,608	49%	3,984	-3,975	9.1	48	100	-100
Partial Compensating Injections	2,811	38%	1,255	-1,245	10.7	54	100	-100
All Compensating Injections	7,348	100%	2,789	-2,779	9.8	50	100	-100

As expected, the implementation of the new parameters on October 12 significantly increased the level and frequency of compensating injections:

[33] See Figure 3.1 in the *Quarterly Report on Market Issues and Performance*, November 8, 2010; covering July through September, 2010, http://www.caiso.com/2848/2848983817680.pdf.

- The percentage of intervals with full compensating injections increased from 26 percent to 49 percent; and
- The percentage of intervals with partial compensating injections decreased from 69 percent to 38 percent.

These changes resulted from the increase in the level where discounting compensating injections begin, which was increased from 50 MW to 100 MW. In addition:

- The percentage of intervals with no injections increased from 5 percent to 13 percent. This can be associated with the decrease in the level at which compensating injections are cancelled, which was decreased from 500 MW to 335 MW.

A comparison of Table 2.1 and Table 2.2 also shows that the new discount parameter increased the average levels of positive and negative injections for partial compensating injection intervals as well. For example, positive injections for partial compensating injections went from 811 MW in the first period to 1,255 MW in the second. Similar trends also existed for negative partial compensating injections values. These changes can be attributed to the increase in the discount factor from 0.2 to 0.3.

Recommendations

The compensating injection software and the ISO monitoring efforts 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. 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.

Deeper analysis using the current ISO approach is currently infeasible for several reasons. Data on metered flows requires extensive manual processing, which makes it too difficult for DMM or other ISO staff to perform long-term analysis. In addition, the ISO captures data for total market flows with compensating injections, but does not capture data on the contributions of compensating injections to these total market flows. Without this information, DMM is not able to determine if false congestion caused by market flow divergence may occur 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’s metrics and the performance of compensating injections. Furthermore, the ISO has indicated that it will look into capturing 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.

The ISO has indicated it plans to make further enhancements to the compensating injection algorithm. These enhancements will focus on applying the discount parameters to either the positive or negative injections to keep net flows below a target threshold. This differs from the current approach that applies the discount factor to both the positive and negative injections. DMM recommends that any further modifications to compensating injections be documented, discussed in detail and ultimately described for participants in a technical bulletin.