California Independent System Operator Corporation

California ISO

Q3 2013 Report on Market Issues and Performance

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Executive summary

This report provides an overview of general market performance during the third quarter of 2013 (July – September) by the Department of Market Monitoring (DMM). Key trends in market performance include the following:

- Electricity market prices in the first nine months have been about 54 percent higher than during the same period in 2012 for several reasons:
    - Gas prices have risen about 40 percent in the first nine months from the unusually low gas prices that occurred in 2012. This accounts for most of the increase in prices.
    - Most of the remaining increase in electricity market prices in the first nine months of 2013 can be attributed to implementation of the state's greenhouse gas cap-and-trade program. DMM estimates day-ahead market prices for the first nine months were about $5.50/MWh higher with implementation of this program.[1]
    - Another factor causing upward pressure on electricity market prices includes a decrease in hydro-electric generation for the first nine months of 2013 compared to the year before. In the third quarter, hydro-electric generation was 20 percent lower than in 2012.
- In August, real-time prices were significantly higher than day-ahead prices due to wildfires and high loads.
- In July and September, average real-time price levels were lower than both day-ahead and hour-ahead prices. This represents the continuation of a trend that started in April which has been driven by a drop in extremely high real-time price spikes and increased frequency of negative real-time prices. Higher levels of intermittent generation deliveries in real time that were not scheduled in the day-ahead have contributed to lower real-time prices during many hours since spring of this year.
- Hour-ahead prices were higher than real-time prices in all three months. Hour-ahead prices in August were also affected by wildfires and periods of high load.
- Congestion continued to impact overall energy prices, raising day-ahead prices in the Southern California Edison area by around 2 percent while lowering prices in other areas. Most of this price impact was driven by congestion on the constraint that limits the amount of load within the SCE area that can be met by flows into this area.[2]
- Real-time energy and congestion imbalance offset charges were essentially unchanged compared to the second quarter. Charges were primarily due to large costs incurred on just two days due to loop flows and forced outages, including wildfires and other special system conditions. Energy imbalance costs have decreased slightly in the third quarter of 2013 compared to the same period in 2012, $14

[1] This $5.50/MWh price impact is highly consistent with the cost of carbon emission credits and the efficiency of gas units typically setting prices in the day-ahead market during this period. The impact of higher wholesale prices on retail electric rates will depend on policies adopted by the California Public Utilities Commission (CPUC) and other state entities. Under a 2012 CPUC decision, revenue from carbon emission allowances sold at auction will be used to offset impacts on retail costs. More detailed information on this issue is provided in Section 3.2 of this report.

[2] This constraint has been removed from the markets as noted in the Market Notice on September 20, 2013. Un-enforcement of the SCE_PCT_IMP_BG constraint was effective October 1, 2013. For more information, see http://www.caiso.com/Documents/ResendUn-enforcement-SCE_PCT_IMP_BGConstraintSep20_2013.htm.

million from $16 million respectively. However, congestion imbalance costs in the third quarter have decreased significantly to about $40 million compared to $100 million from the same quarter in the previous year.

- Overall bid cost recovery payments decreased mainly because of decreases in unit commitment resulting from reduced use of minimum online constraints and exceptional dispatches.
- The amount of convergence (or virtual) bids and net virtual supply positions clearing the market increased in July but started to reduce in August and September, continuing a trend that began in May. Real-time prices were generally lower than day-ahead prices, which increased revenues paid to participants with virtual supply positions.
- Convergence bidders were paid revenues of about $5.5 million, down from about $14 million in the second quarter. The third quarter profits were mainly from net virtual supply positions. However, virtual supply positions were allocated bid cost recovery charges of around $2.7 million in the last two quarters. Taking these charges into account, net overall revenues received by virtual bidders in the third quarter were about $2.9 million compared to about $11 million in the second quarter.
- Total payments for flexible ramping resources were around $3 million, down from around $7 million in the second quarter of 2013. Flexible ramping costs in the first three quarters of 2013 were around $20 million, compared to about $17 million for the same period in 2012. Most payments for ramping capacity occurred during the evening peak hours.
- Under the new real-time market design being implemented in spring 2014, most real-time energy will be dispatched and settled on a 15-minute basis. In 2013, average system energy prices in the 15-minute pre-dispatch market were 19 percent higher than day-ahead prices and 26 percent higher than 5-minute real-time prices. This appears related, in part, to the flexible ramping constraint. When the new 15-minute real-time market is implemented in spring 2014, such price divergence could result in significant market inefficiencies. DMM is recommending the ISO play a high priority on addressing this issue prior to implementation of the new 15-minute real-time market design.
- The volume of imports offered and clearing the market decreased by about 6 percent and 18 percent, respectively, in the third quarter compared to the same period in 2012. This follows a period of increases in imports during the first half of 2013. The decrease in imports in the third quarter appears to have been driven by decreases in hydro generation in the Pacific Northwest and increases in power prices at the Mid-Columbia and Palo Verde trading hubs.
- The ISO implemented the pay-for-performance regulation products (also known as *mileage*) on June 1, 2013. Mileage up and mileage down are separate regulation products and are procured in both the day-ahead and real-time markets along with other ancillary services. Mileage prices were low in both directions in the third quarter. In the day-ahead market, mileage prices averaged $0.10 for mileage down and $0.05 for mileage up, while the real-time mileage prices averaged $0.04 for both mileage down and mileage up. Total mileage payments were $203,000 for the quarter.
- The ISO implemented enhancements to local market power mitigation procedures in the real-time market on May 1, 2013. The new real-time procedure dynamically evaluates transmission congestion and competitiveness based on projected system and market conditions about 35 to 75 minutes before each 5-minute market run. DMM's analysis of these new procedures includes the following findings and recommendations:

- While this new real-time procedure is much more accurate than the prior approach, differences often exist between projections of congestion during the pre-market mitigation runs and the actual 5-minute market runs.
- In practice, these differences have not had a significant impact on bid mitigation or the degree of protection against local market power for several reasons. In most cases, constraints on which congestion differences occurred are structurally competitive, so mitigation would not have been triggered. In addition, because of very competitive bidding in the market, only a very few resources had bids that would have been lowered when subject to mitigation.
- These differences in congestion could have a much more significant impact on overall market prices and efficiency when the ISO implements a 15-minute real-time market in spring 2014. Specifically, such differences could create systematic divergence of 15-minute and 5-minute real-time prices. Consequently, DMM is recommending the ISO perform analysis to better understand and mitigate the causes for differences in projected and actual real-time congestion.

As noted above, two key recommendations in this report involve the need to address the significant price and congestion differences occurring between the 15-minute real-time pre-dispatch process and other markets. When the new 15-minute real-time market is implemented in spring 2014, results of this 15-minute dispatch process will have a major impact on market efficiency and settlements. Therefore, DMM is recommending the ISO play a high priority on addressing these issues prior to implementation of the new 15-minute real-time market design.

Energy market performance

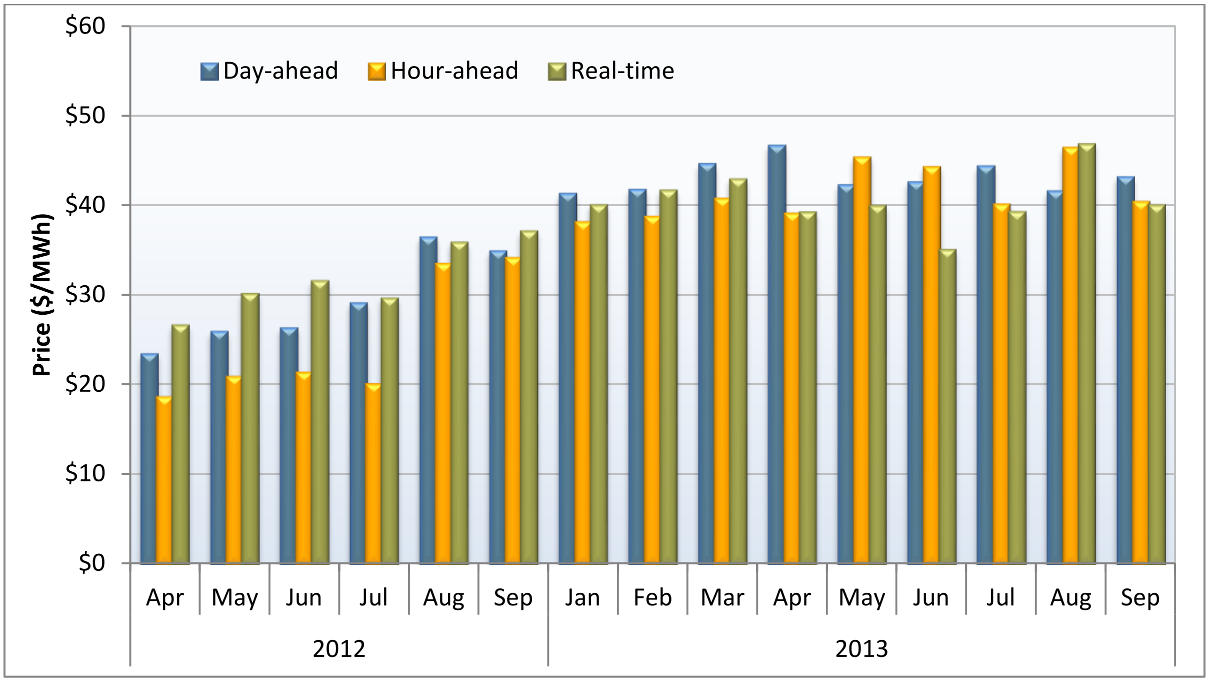
This section provides a more detailed summary of energy market performance in the third quarter.

Price levels remain higher in 2013 compared to 2012. Average system energy prices in the ISO markets remained higher in the third quarter compared to price levels in 2012 (see Figure E.1). This increase is primarily the result of an almost 30 percent increase in regional natural gas prices in the third quarter. Most of the remainder of the increase in prices can be attributed to compliance costs associated with the state's cap-and-trade program. DMM estimates that the cap-and-trade program has added about $5.50/MWh to the system energy price in the third quarter. Another factor causing upward pressure on electricity market prices was a decrease in hydro-electric generation, around 20 percent for the same period.

Increased divergence between average day-ahead and real-time system energy prices. Average system energy prices in the real-time market (excluding congestion) were systematically lower than average prices in the day-ahead market (see Figure E.1) for the quarter. Prices in August were higher because of wildfire related transmission outages and higher load at the end of the month. The overall price divergence was due in part to substantial amounts of wind and solar energy in the real-time market that was not scheduled in the day-ahead. Also, energy from units committed after the day-ahead market through the residual unit commitment process and exceptional dispatches contributed to this divergence.

Divergence between day-ahead and hour-ahead system energy prices. Average system energy prices in the hour-ahead market were lower than day-ahead prices in July and September, as seen in Figure E.1. August hour-ahead prices were greater than day-ahead prices because of a relatively small number of hours with extremely high hour-ahead prices due to wildfires and high load.

Figure E.1 Average monthly system marginal energy prices (all hours)



Congestion continued to influence day-ahead and real-time prices. Congestion within the ISO system continued to impact overall prices in the third quarter in the day-ahead and real-time markets. Congestion affected overall day-ahead market prices by about 1 to 2 percent and real-time market prices by 2 to 3 percent. For the quarter, congestion caused Southern California Edison and San Diego Gas & Electric prices to increase, while causing overall prices in the Pacific Gas and Electric area to decrease. Import limitations into Southern California Edison primarily contributed to these congestion patterns.[3]

Real-time congestion and energy imbalance offset costs remained unchanged. Real-time congestion imbalance offset costs totaled about $41 million in the third quarter (Section 1.5). This is essentially unchanged from the previous quarter. More than one quarter of these offset costs occurred on only two days due to unscheduled flows and actual load differing from day-ahead forecast. Real-time energy imbalance offset costs also remained relatively unchanged at $14 million, slightly down from about $15 million from the previous quarter.

Bid cost recovery payments decreased. Bid cost recovery payments totaled around $26 million in the third quarter, compared to $33 million in the second quarter. The reduced use of minimum online commitments and exceptional dispatch commitments for summer testing caused lower day-ahead and real-time bid cost recovery payments compared to the second quarter. Day-ahead and real-time bid cost recovery payments totaled around $21 million. The residual unit commitment portion of bid cost recovery payments decreased in the third quarter, dropping to around $5 million. ISO operators have

[3] This constraint has been removed from the market as indicated by the Market Notice on September 20, 2013. Un-enforcement of SCE_PCT_IMP_BG constraint was effective October 1, 2013. For more information, see: http://www.caiso.com/Documents/ResendUn-enforcement-SCE_PCT_IMP_BGConstraintSep20_2013.htm.

continued making adjustments to the system or regional residual unit commitment requirements to mitigate potential contingencies, though began to account for forecasted renewables as part of this process. Virtual supply positions were allocated $2.7 million of the $5 million in bid cost recovery charges for residual unit commitment.

Flexible ramping constraint payments decreased. The flexible ramping constraint is designed to help mitigate short-term deviations in load and supply between the real-time commitment and dispatch models (such as load and wind forecast variations and deviations between generation schedules and output). The constraint procures ramping capacity in the 15-minute real-time pre-dispatch that is subsequently made available for use in the 5-minute real-time dispatch. The total payments to generators for the flexible ramping constraint were around $3 million, compared to around $7 million in the previous quarter. By comparison, payments for spinning reserve totaled about $9.5 million for the same period. The ISO operators continued to keep the flexible ramping requirement high more consistently during the ramping periods of the day in the third quarter.

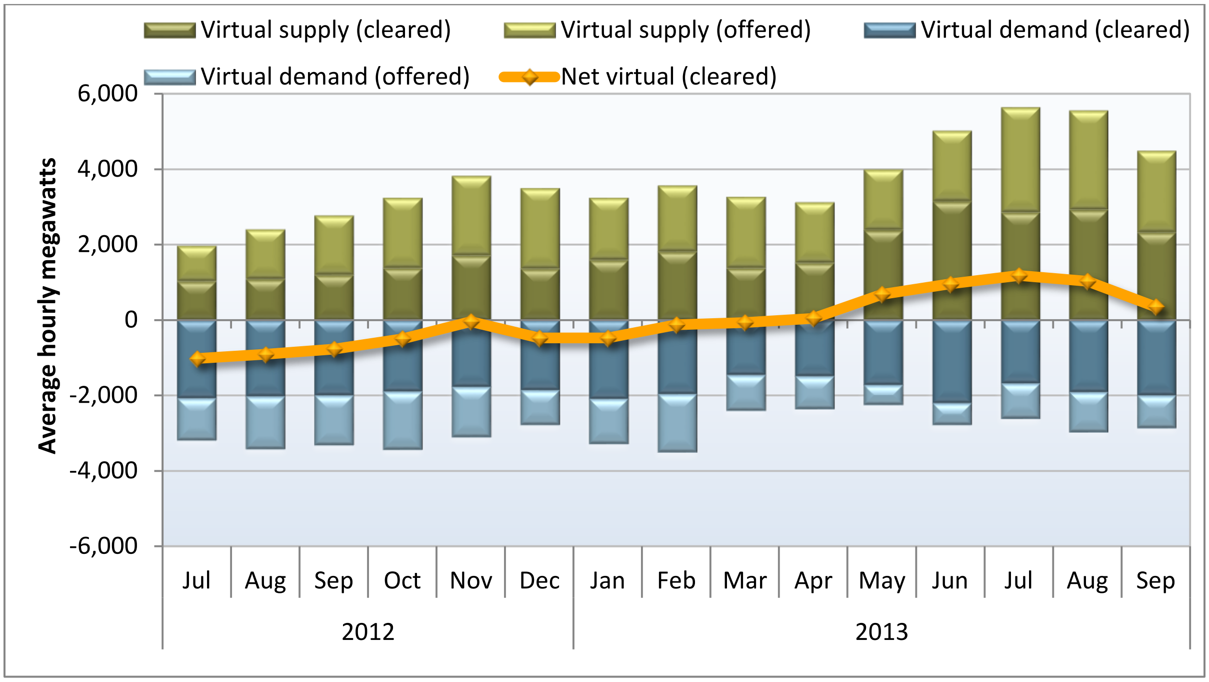
Convergence bidding

Convergence bidding provides a mechanism for participants to hedge or speculate based on potential price differences of congestion at different locations or in system energy prices between the day-ahead and real-time markets. Convergence bidding was first implemented in February 2011. On November 2011, convergence bidding was temporarily suspended on the inter-ties. On May 2, 2013, the FERC made this decision permanent under certain conditions. Convergence bidding activity was marked by several key trends in the third quarter.

Amount of cleared convergence bids reached its highest values since April 2011. Average hourly cleared volumes increased to 4,560 MW in the third quarter from 4,150 MW in the second quarter. In net, virtual positions were primarily virtual supply. Even with these high levels of cleared convergence bids, price divergence remained between the day-ahead and real-time markets (see Figure E.2).

Continued convergence bidding designed to take advantage of congestion. Market participants can hedge (or speculate) on potential congestion between points within the ISO system by placing an equal amount of virtual demand and supply bids at different internal locations during the same hour. This type of offsetting virtual position at internal locations accounted for an average of about 1,500 MW per hour of virtual demand offset by over 1,500 MW of virtual supply at other locations in the third quarter, up from 1,420 MW in the second quarter. These offsetting bids represented over 67 percent of all cleared bids in the third quarter, or about the same as in the prior quarter.

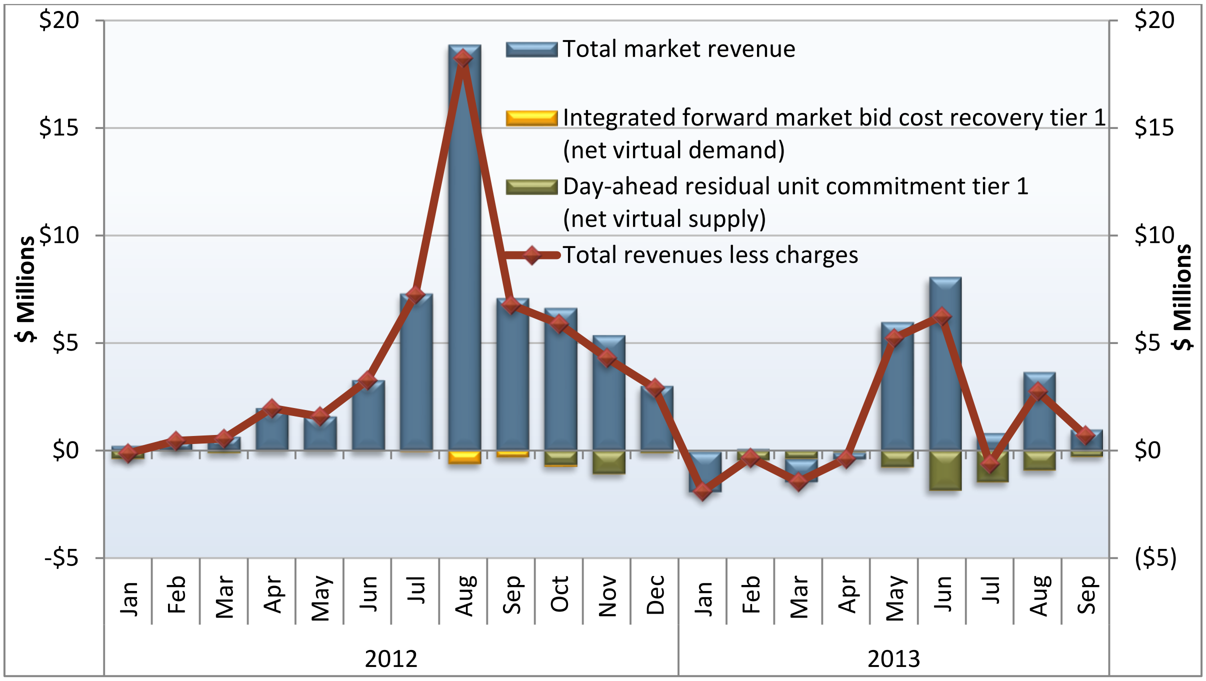
Figure E.2 Monthly average virtual bids offered and cleared



Decreased net revenues associated with virtual supply positions. Based only on virtual bidding settlements relating to differences in day-ahead and real-time market prices, virtual supply received net revenues of about \$8.3 million, while virtual demand accounted for a loss of around \$2.7 million. This represents net revenues of about \$5.5 million due to profits from net virtual supply positions. However, virtual supply positions were allocated bid cost recovery charges resulting from residual unit commitment of around \$2.7 million. Taking these charges into account, net overall revenues received by virtual bidders were about \$2.9 million.

Increase in bid cost recovery charges allocated to virtual supply positions. As shown in Figure E.3, the amount of bid cost recovery charges resulting from residual unit commitment allocated to virtual supply positions has been very low throughout 2012 and early 2013. However, starting in February bid cost recovery allocation to net virtual suppliers increased and often had a major impact on the overall net profitability of virtual bidding. This reflects a combination of two factors. First, starting in late 2012 bid cost recovery payments for residual unit commitment started to increase significantly. Then, starting in early 2013, net virtual supply began to increase in volume and account for a large portion of the transactions to which these bid cost recovery payments are allocated.

Figure E.3 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and residual unit commitment tier 1



Special issues

Market performance during heat waves, wildfires and other events. The ISO market experienced a system-wide heat wave between June 27 and July 3. Overall, the ISO systems and markets performed well under stressed conditions. There were also two wildfires which impacted the grid during other periods. The Rim Fire, one of the largest in California history, started on August 17 and lasted for weeks but had only a minimal impact on grid operations. The Spring Peak Fire impacted the grid on August 18 and 19 and caused outages on some transmission lines, with a significant impact to the Pacific DC Intertie (Path 65). This occurred in conjunction with high loads and resulted in sustained periods of real-time price spikes on these two days. The ISO also experienced software issues that impacted the real-time market for September 17 and 18. These software issues resulted in price corrections for numerous real-time prices.

Effect of cap and trade on ISO markets. Resources in the ISO market became subject to the state's greenhouse gas cap-and-trade program in January 2013. The cost of greenhouse gas allowances in bilateral markets fell in the third quarter to an average of $13.27/mtCO$_2$e and ended the quarter at slightly over $12.00/mtCO$_2$e.[4] This is down from the first and second quarter prices, when emission costs averaged $14.55/mtCO$_2$e and $14.59/MtCO$_2$e, respectively. DMM estimates that these greenhouse gas compliance costs have increased the average wholesale electricity price in 2013 by about $5.50/MWh. This is consistent with the additional emissions costs for gas units typically setting prices in the ISO market. In addition, the total amount of imports offered to the market decreased for

[4] mtCO$_2$e stands for metric tons of carbon dioxide equivalent, a standard emissions measurement.

each month in the third quarter of 2013 compared to the third quarter of 2012. During this period, imports offered decreased by 6 percent compared to the same period in 2012. Decreases in offered and cleared import megawatts are slightly larger coming from the north. These changes may be due to decreases in hydro-electric generation in the Pacific Northwest and increases in power prices at the Mid-Columbia and Palo Verde trading hubs.

Implementation of the regulation pay-for-performance (mileage) product. In June, the ISO implemented the pay-for-performance regulation product, often referred to as *mileage*, to complement the existing frequency regulation capacity markets. As in June, mileage costs in the third quarter represent a small part of the regulation market settlement. In the day-ahead market, mileage prices averaged $0.10 for mileage down and $0.05 for mileage up, while the real-time mileage prices averaged $0.04 for both mileage down and mileage up. Total costs of the mileage system reached about $203,000 for the quarter, compared to over $6 million for regulation capacity. Mileage payments for the third quarter were estimated at $40,700 for mileage up and $163,700 for mileage down. This represents a modest increase in monthly payments when compared to June. Monthly average mileage up payments increased by about 17 percent and mileage down payments increased by about 4 percent compared to June.

Enhancements to the real-time local market power mitigation procedure. The new local market power mitigation procedure dynamically evaluates competitiveness based on actual system and market conditions. One of the main enhancements was the improved mitigation trigger. DMM's analysis shows that in the third quarter the accuracy of congestion prediction remained very high in the day-ahead market (91 percent compared to 84 percent in the second quarter). However, the consistency of projected versus actual congestion in the real-time market remained much lower (55 percent versus 49 percent in the second quarter). Thus, this represents a modest improvement from the previous quarter.

Much of the prediction error in the real-time market was due to the differences in model inputs between the 15-minute real-time pre-dispatch mitigation run and the 5-minute market run. This is because the mitigation processes for the 15-minute real-time pre-dispatch run roughly 35 to 75 minutes before the 5-minute market runs. In practice, these differences in projected and actual real-time congestion have not had a significant impact on bid mitigation since only a very few resources have bids actually mitigated, due to very competitive bidding in the market. However, these differences in congestion could have a much more significant impact on overall market prices and efficiency when the ISO implements a 15-minute real-time market in spring 2014. Specifically, such differences could create systematic divergence of 15-minute and 5-minute real-time prices. Consequently, DMM is recommending the ISO perform analysis to better understand and mitigate the causes for differences in projected and actual real-time congestion.

1 Market performance

This section highlights key performance indicators of the markets in the third quarter:

- Higher real-time prices in August due to wildfires and periods of high load.
- Systemically higher day-ahead prices than real-time prices in July and September, during both peak and off-peak hours. This represents continuation of a trend that began in April.
- Higher hour-ahead prices than real-time prices in all three months. Hour-ahead prices in August were also affected by wildfires and periods of high load.
- Continued low overall frequency of high real-time price spikes.
- Decreased frequency of negative real-time prices and reduced periods of over-generation.
- More consistency of congestion between the day-ahead and real-time markets.
- Continued high real-time imbalance offset costs, driven by higher congestion imbalance offset costs. However, these costs were significantly lower than the third quarter of 2012.
- Decreased bid cost recovery payments, resulting from reduced levels of minimum online commitments and exceptional dispatches.

1.1 Energy market performance

This section assesses the efficiency of the energy market based on an analysis of the system energy component of day-ahead, hour-ahead and real-time market prices. Price convergence between these markets may help promote efficient commitment of internal and external generating resources.

Average real-time price levels were lower than both day-ahead and hour-ahead prices for the quarter in July and September. In August, average real-time prices were driven higher than day-ahead prices due to the impact of wildfires and high loads. Figure 1.1 and Figure 1.2 show monthly system marginal energy prices for peak and off-peak periods, respectively.

- On a monthly average basis, peak hour-ahead prices were about $5/MWh lower than day-ahead prices in July and September, but were higher in August by about $9/MWh. These higher values for the peak hours were a result of a relatively small number of hours (around 30 to 40) where hour-ahead prices significantly exceeded day-ahead prices. When these prices are excluded, the results indicate a greater convergence between the day-ahead and hour-ahead prices. Off-peak hour-ahead prices were about $1/MWh lower than day-ahead for the entire period.
- In July and September, average system prices in the 5-minute real-time market were lower than day-ahead market prices by about $6/MWh during peak periods and about $1/MWh during off-peak periods. In August, real-time prices were higher than day-ahead prices by about $5/MWh during peak and off-peak periods. Factors contributing to the price differences between the day-ahead and real-time markets include modeling differences between the day-ahead and real-time markets and increased real-time generation from variable generation including wind and solar resources.

- Except for peak hours in August, average system prices in the 5-minute real-time market were not significantly different from hour-ahead prices during peak and off-peak periods. The largest average difference was $5/MWh and occurred during the off-peak hours in August.

Figure 1.1 Average monthly on-peak prices – system marginal energy price

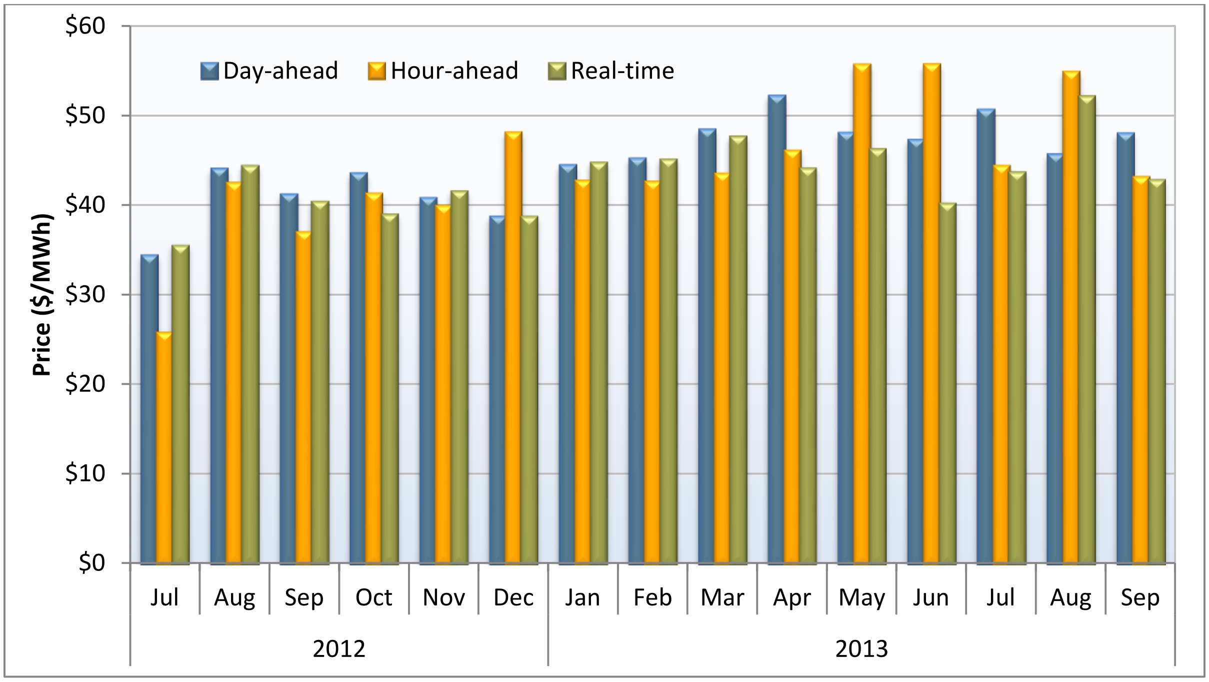


Figure 1.2 Average monthly off-peak prices – system marginal energy price

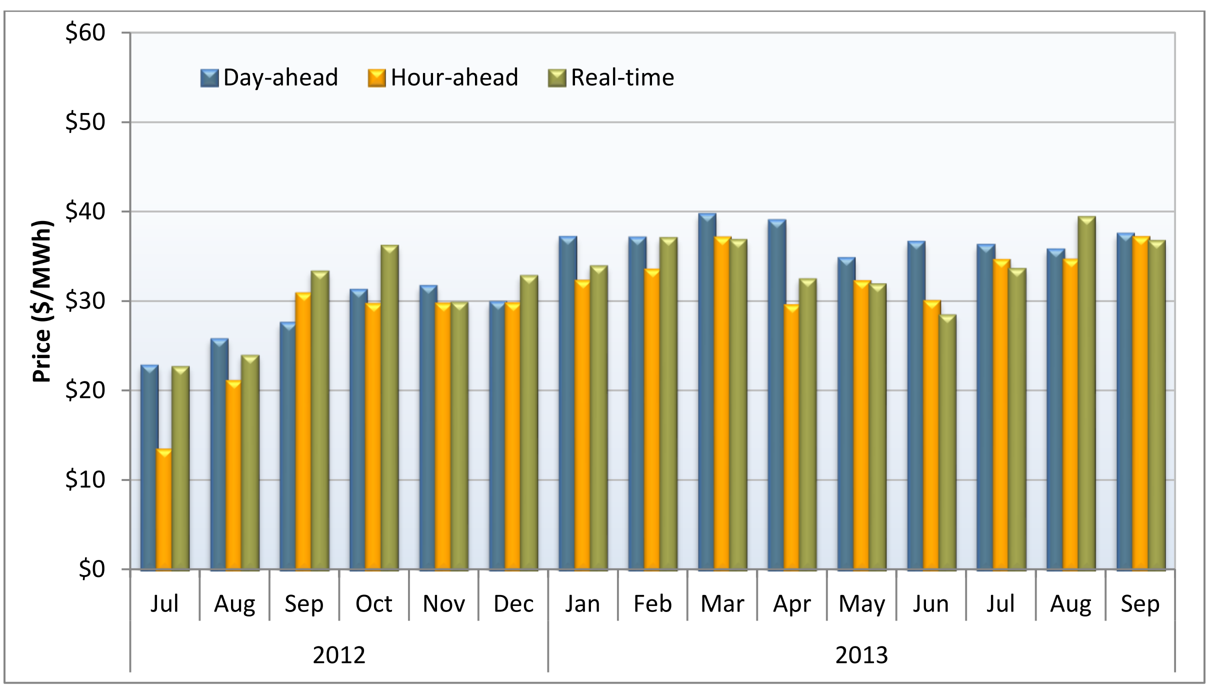


Figure 1.1 and Figure 1.2 show price divergence among average day-ahead, hour-ahead and real-time prices by month during the third quarter. The systematic difference in the renewable energy schedules between the day-ahead and real-time markets is one of the factors contributing to the relatively lower real-time prices. Average real-time wind generation was 550 MW higher than day-ahead schedules, reaching above 1,900 MW in some hours. Average real-time solar generation in peak hours was around 200 MW higher than day-ahead schedules, reaching up to 1,000 MW in some hours.

Post day-ahead residual unit commitments and exceptional dispatch commitments also contributed to relatively low real-time prices. Energy from residual unit commitments averaged around 62 MW, reaching above 1,000 MW in a few hours.[5] Energy from exceptional dispatch commitments averaged around 65 MW, reaching nearly 580 MW in some hours.

Figure 1.3 and Figure 1.4 further illustrate the differences between prices in the third quarter. In Figure 1.3, the average hourly hour-ahead prices for the third quarter were lower than day-ahead prices in most hours, except for hours ending 1 and 16.[6] Real-time prices were higher than hour-ahead prices in 11 hours, averaging about $4/MWh higher in these hours. Day-ahead prices exceeded real-time prices in 17 hours. The average price difference was nearly $3/MWh in hours where day-ahead prices exceeded real-time prices.

Figure 1.4 highlights the magnitude of the system marginal price differences for all hours in the day-ahead and real-time markets based on a simple average of price differences in these markets.[7] The figure shows that the simple average price difference between the day-ahead and real-time markets (green line) was near zero all through the second half of 2012 through March 2013. Beginning in April, the chart shows that day-ahead prices were increasingly higher than real-time prices. This increase can be attributed in part to the increased frequency of negative prices during early morning hours and decreased frequency of price spikes during peak hours. In June, day-ahead prices exceeded real-time prices by about $15/MWh, the largest difference since January 2011. This trend continued in the third quarter with the exception of August. In August, real-time system energy prices exceeded day-ahead prices by $5/MWh, driven by significant forced transmission outages in real-time related to wildfires and to periods of higher demand at the end of the month.

Figure 1.4 also shows the average absolute price difference between the day-ahead and real-time markets (gold line).[8] Even though the simple average was near zero for the second half of 2012 and the first quarter of 2013, the absolute average difference indicated that the overall magnitude of the differences was higher during this period than in the third quarter of 2013. Thus, the simple average masks the nature of the differences indicating convergence overall, when there are offsetting positive

[5] More than half of the capacity committed by the residual unit commitment was from long-start units.

[6] The largest price difference was in hour ending 16, when the hour-ahead prices exceeded the day-ahead price by about $27/MWh. This was greatly influenced by extreme hour-ahead prices in hour ending 16 on August 30, when the ISO adjusted the limit of the SCIT_BG due to a large load forecast error. When this outlier is removed, the average hour-ahead price is reduced by about $23/MWh.

[7] Historically, this chart has shown the simple and absolute average differences between hour-ahead and real-time prices.

[8] By taking the absolute value, the direction of the difference is eliminated and only the magnitude of the difference remains. Mathematically, this measure will always exceed the simple average of price differences shown in Figure 1.4 if both negative as well as positive price differences occur. If the magnitude decreases, price convergence would be improving. If the magnitude increases, price convergence would be getting worse. DMM does not anticipate that the average absolute price convergence should be zero. This metric is considered secondary to the simple average metrics and helps to further interpret price convergence.

and negative differences in different hours. In the third quarter, the absolute average difference was about $12/MWh down from $20/MWh in the previous quarter. This is the lowest absolute quarterly price difference since the first quarter of 2012.

Figure 1.3 Hourly comparison of system marginal energy prices (July – September)

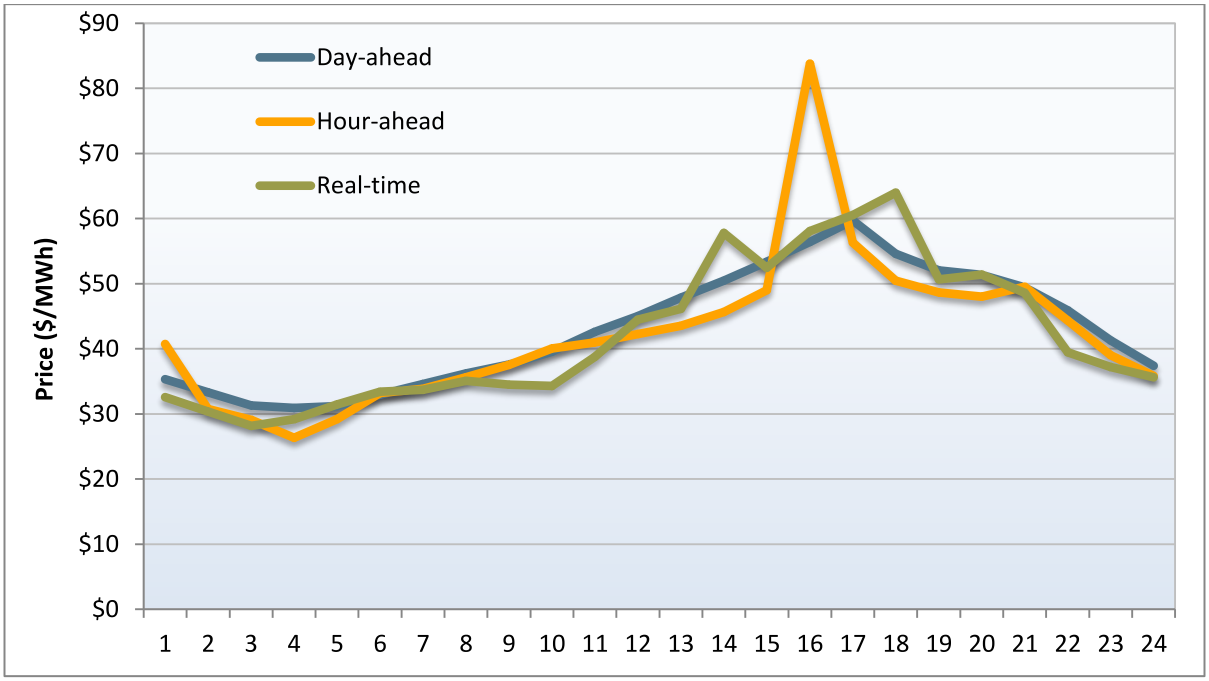
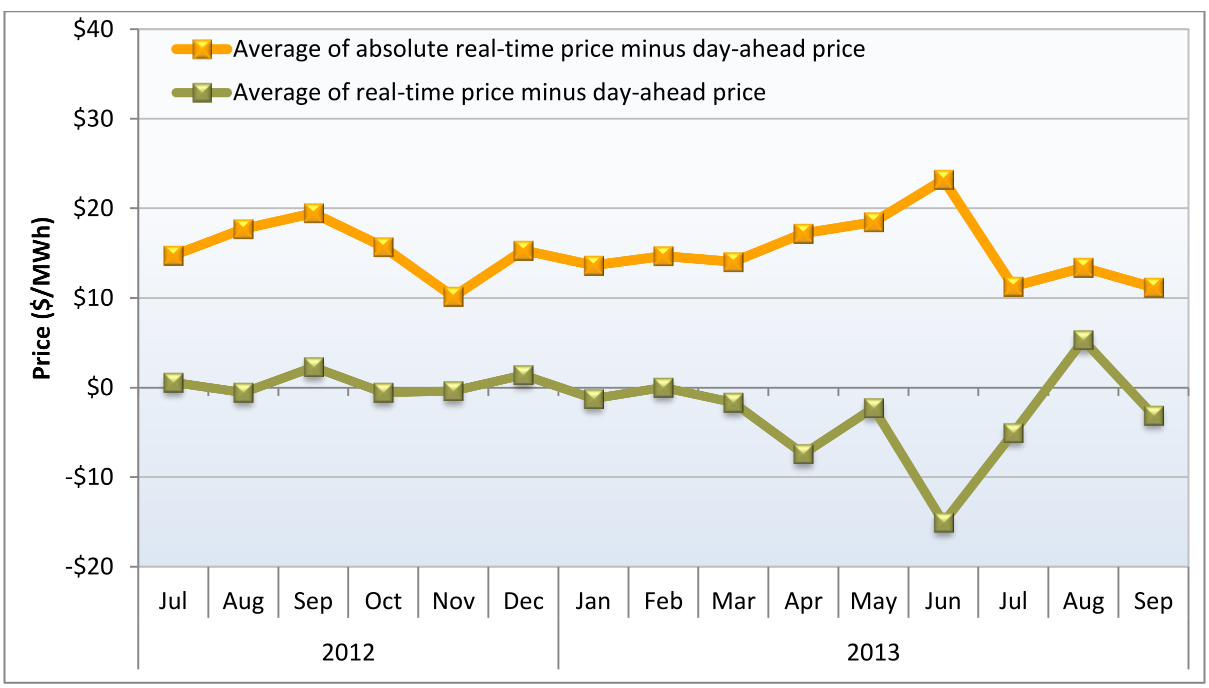


Figure 1.4 Difference in monthly day-ahead and real-time prices based on simple average and absolute average of price differences (system marginal energy, all hours)



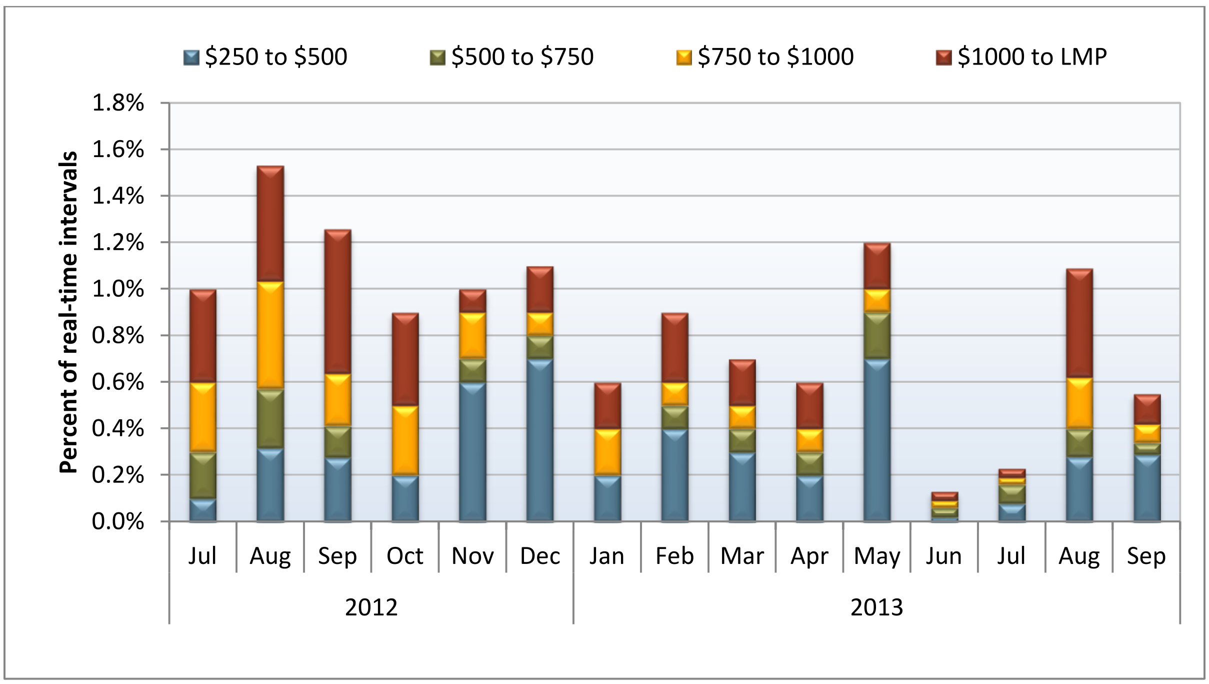
1.2 Real-time price variability

Real-time market prices historically have been very variable, which is highlighted in this section along with reasons why the variability occurs.

Figure 1.5 shows the frequency of price spikes that occur in each investor-owned utility area in the real-time market. In the third quarter, the frequency was essentially unchanged from the second quarter at about 0.6 percent. This occurred even with a significant increase in the frequency of all categories of real-time price spikes in August due to wildfires and subsequent transmission line outages, as well as high system load conditions at the end of the month.

As in the previous two quarters, the ISO continued to increase the flexible ramping constraint requirements during the evening ramping hours. Following the trend of the second quarter, the total frequency of price spikes was slightly downward, with the exception of price spikes in the $1,000/MWh category in August. The greatest portion of the price spikes in this category was related to system energy shortages and extreme congestion due to transmission line outages.

Figure 1.5 Frequency of price spikes (all LAP areas)



The number of power balance constraint relaxation intervals resulting from insufficient upward ramping capacity decreased slightly in the third quarter compared to the previous quarter and the same months last year, as seen in Figure 1.6. Power balance relaxations can also occur in the presence of congestion. In the third quarter, only 2 percent of the upward ramping capacity relaxations, shown in Figure 1.6, resulted from extreme regional congestion compared to about 30 percent in the second quarter and about 60 percent in the first quarter.[9]

There was also a notable decrease in the number of power balance constraint relaxations from infeasible decremental energy in the third quarter relative to the second quarter and the third quarter of 2012, as shown in

Figure 1.7.[10] This is a result of a lower share of real-time generation from variable resources, seasonal decreases in hydro-electric generation and higher off-peak loads. Almost all of these power balance constraint relaxations resulted from system-wide over-generation conditions.

Around 50 percent of high real-time prices were caused by congestion or a combination of power balance constraint relaxations and congestion in the third quarter. About 46 percent of these prices can be attributed to congestion alone, while about 45 percent were a result of system-wide power balance relaxations. High priced bids resulted in only 4 percent of the high prices in the quarter. Figure 1.8 highlights the different factors driving high real-time prices at a regional level. The prices in this figure include all intervals in which the real-time price for a load aggregation point approached the bid cap.[11]

[9] Sometimes extreme congestion on constraints within the ISO system can limit the availability of significant amounts of supply. This can cause system-wide limitations in upward ramping capacity, and thus cause relaxations in the power balance constraint. In these cases, the cost of relaxing the system power balance constraint is less expensive than the cost of relaxing the internal constraint. Therefore, the system power balance constraint is relaxed to deal with upward ramping limitations in the congested portion of the ISO system. This is primarily true for large regional constraints. For very small local constraints, the opposite is true. In the case of local constraints, the cost of relaxing the local constraint is less expensive than the cost of relaxing the system power balance constraint. Thus, the local constraint is relaxed instead of the power balance constraint.

[10] When these downward ramping limitations occur, the real-time system energy price is set by a penalty parameter equal to -$35/MWh, just below the bid floor of -$30/MWh.

[11] The analysis behind this figure reviews price spikes above $700/MWh.

Figure 1.6 Relaxation of power balance constraint because of insufficient upward ramping capacity

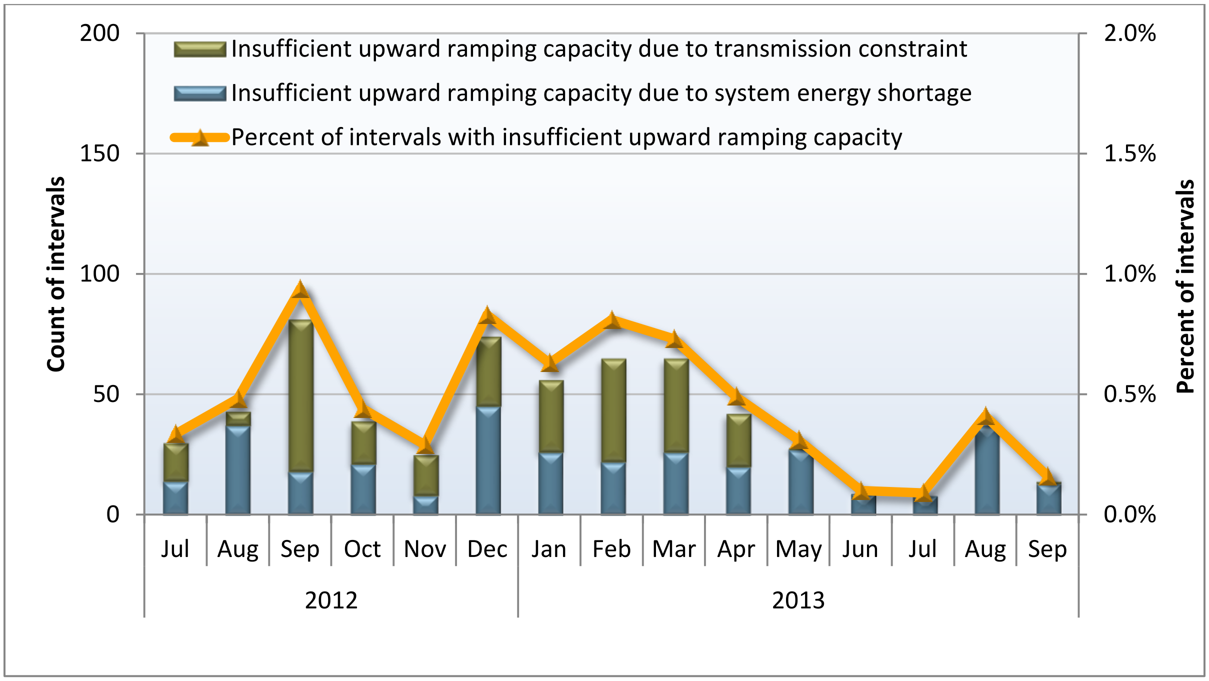


Figure 1.7 Relaxation of power balance constraint because of insufficient downward ramping capacity

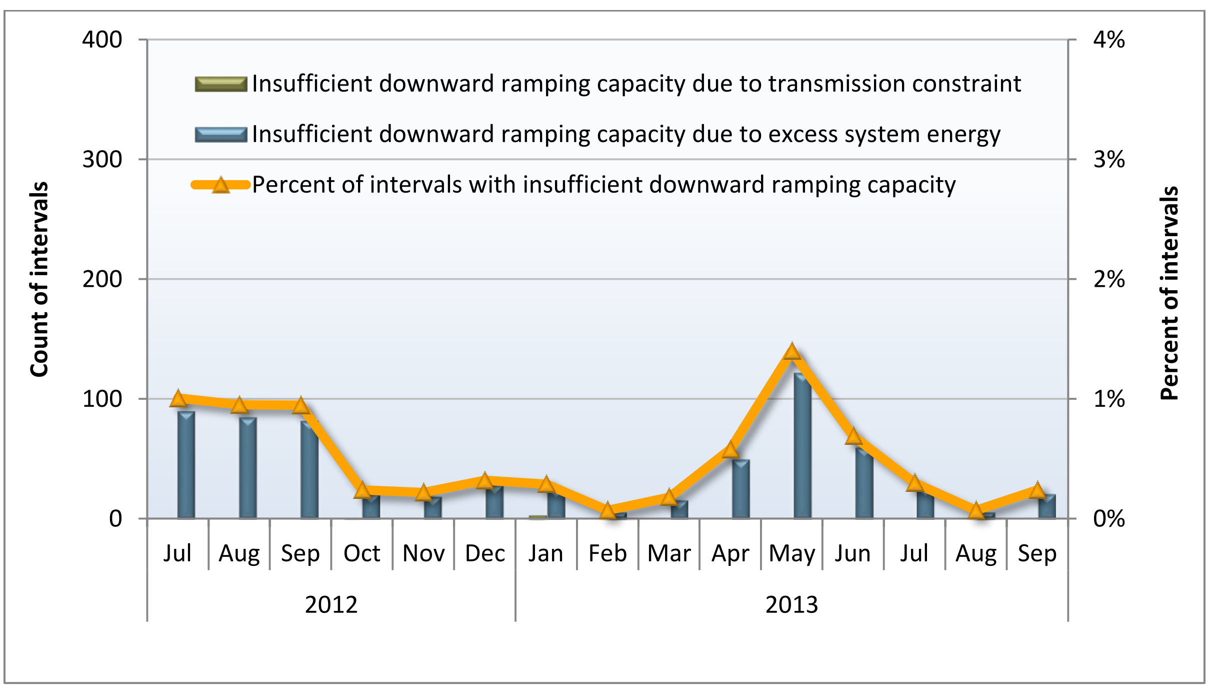
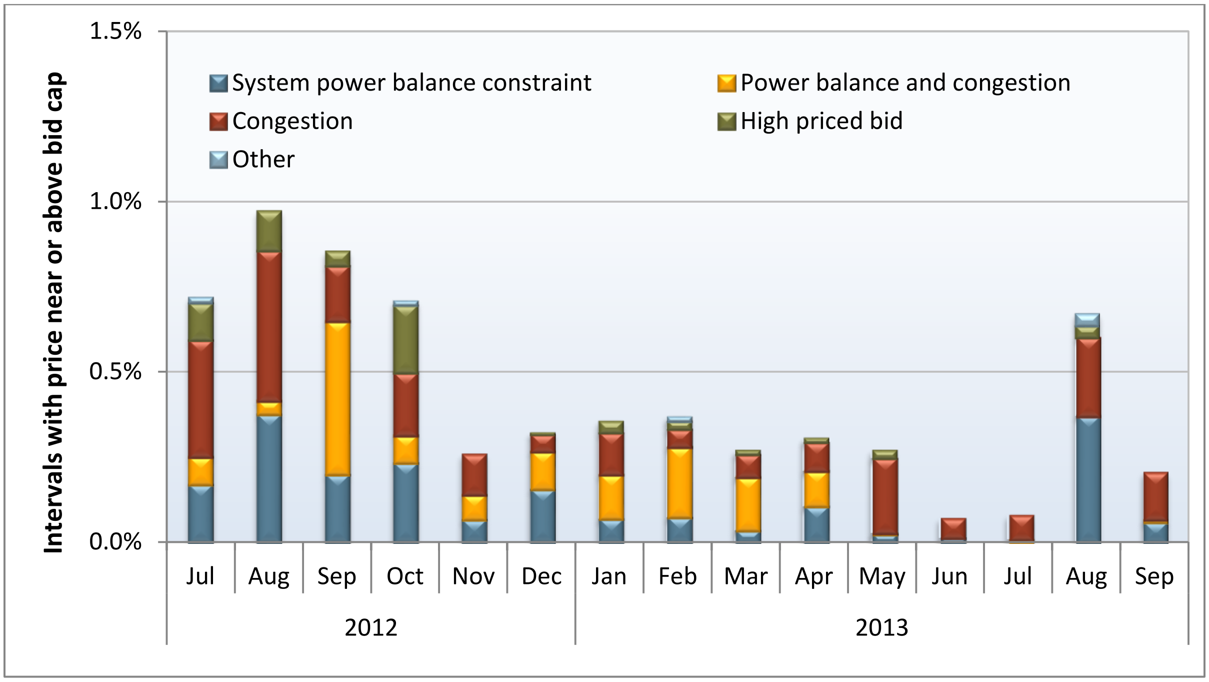


Figure 1.8 Factors causing high real-time prices



Power balance constraint relaxations at the interval level can significantly affect average real-time market prices over longer periods of time, such as a month. This is particularly true when positive power balance constraint relaxations occur, often resulting in system prices at $1,000/MWh. Furthermore, average prices are also affected by negative power balance constraints due to over-generation, resulting in prices at -$30/MWh.

As shown in previous reports, controlling for power balance constraint relaxations can be helpful in showing the underlying nature of the price relationship between market prices.[12] After removing all hours with a real-time power balance constraint between January 2011 and September 2013, results show that the real time system marginal energy prices in peak hours have been consistently lower than day-ahead peak prices (see Figure 1.9). Off-peak prices in the day-ahead and real-time markets, as seen in Figure 1.10, have displayed a much more consistent relationship, with the exception of the first four months of 2013.

[12] For further information see *2010 Annual Report on Market Issues and Performance*, Department of Market Monitoring, Section 8.6, http://www.caiso.com/2b66/2b66baa562860.pdf.

Figure 1.9 Peak average system marginal energy prices excluding power balance constraint

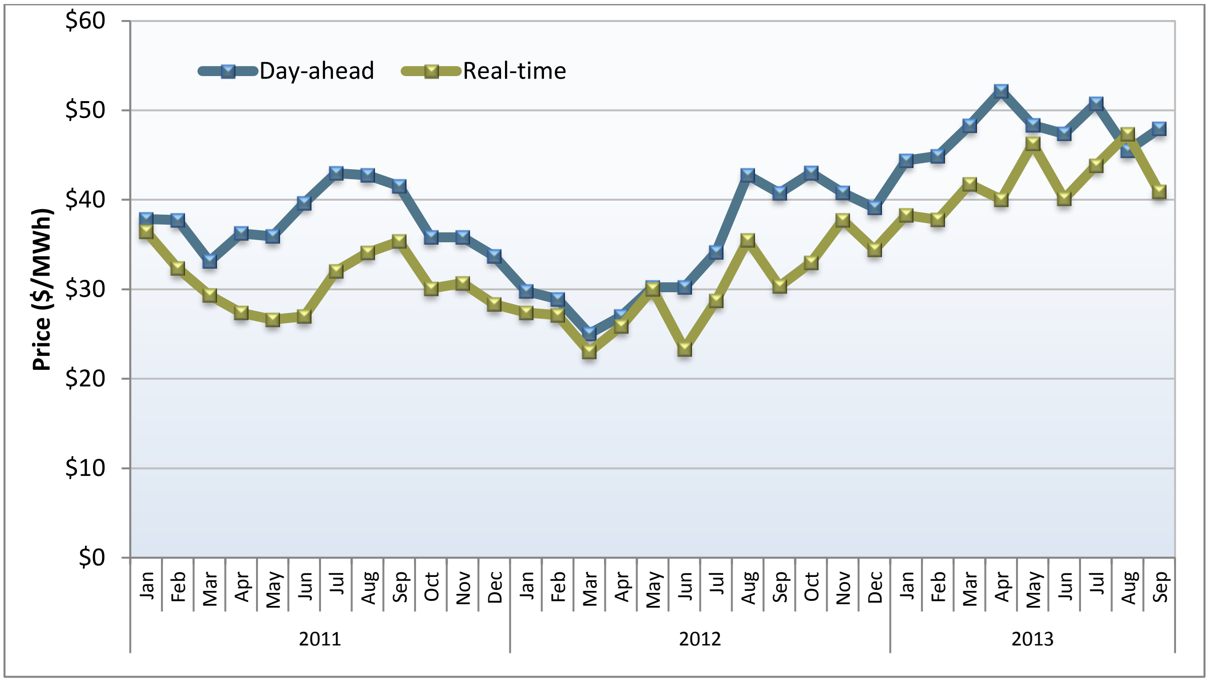
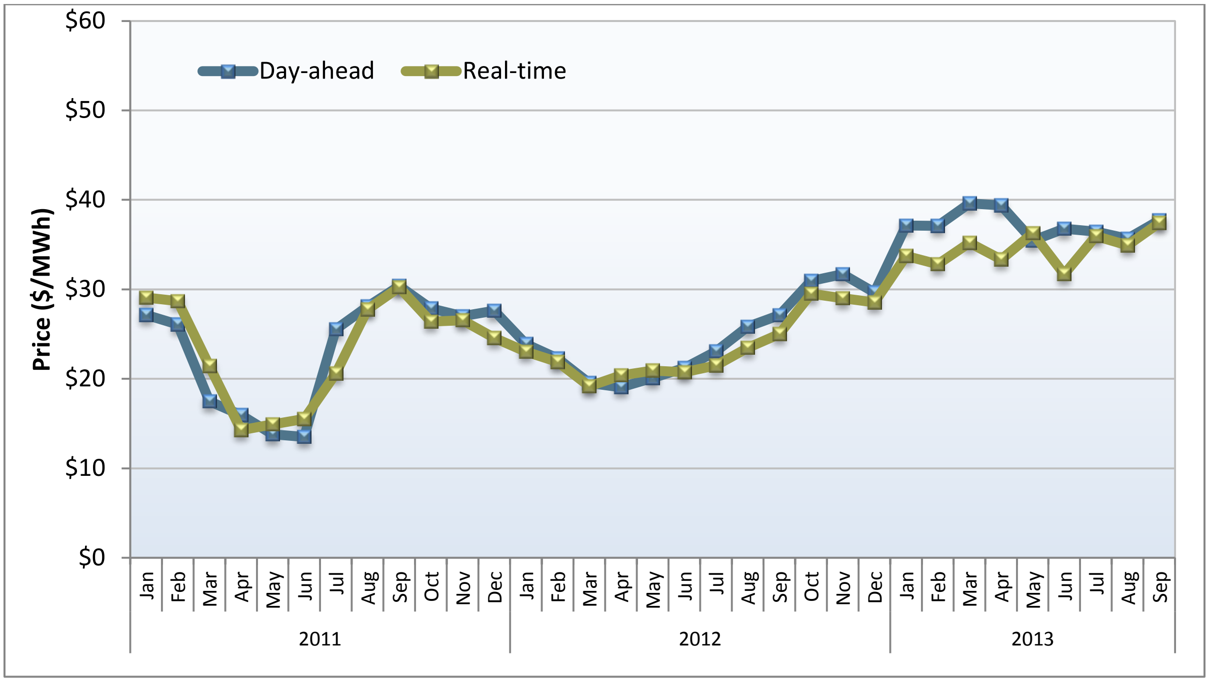


Figure 1.10 Off-peak average system marginal energy prices excluding power balance constraint



1.3 Flexible ramping constraint performance

This section highlights the performance of the flexible ramping constraint over the last quarter. Key trends include the following:

- Flexible ramping costs were around $3 million in the third quarter, down from around $7 million in the second quarter. Flexible ramping costs in the first three quarters of 2013 were around $20 million, while the costs in the same period in 2012 were about $17 million.[13]
- The ISO operators increased the flexible ramping requirement consistently during the morning and evening ramping periods of the day in the third quarter, averaging nearly 600 MW during ramping hours. This caused both the procurement level and flexible ramping shadow prices to remain high. This pattern was similar to the flexible ramping requirements in the previous quarter.
- Overall, more than half of the flexible ramping capacity was procured in the northern part of the state, which can be stranded when congestion occurs in the southern part of the state.

[13] In November 2012, the ISO implemented changes to the settlement rules for the flexible ramping constraint. These changes have been incorporated in the revenue calculations. See the following document for further details: http://www.caiso.com/Documents/October242012Amendment-ImplementFlexibleRampingConstraint-DocketNoER12-50-000.pdf.

Background

In December 2011, the ISO began enforcing the flexible ramping constraint in the upward ramping direction in the 15-minute real-time pre-dispatch and the 5-minute real-time dispatch markets. The constraint is only applied to internal generation and proxy demand response resources and not to external resources. The default requirement is currently set to around 300 MW, but is frequently adjusted up to 900 MW, typically in the morning and evening ramping hours.

If there is sufficient capacity already online, the ISO does not commit additional resources in the system, which often leads to a low (or often zero) shadow price for the procured flexible ramping capacity. During intervals when there is not enough 15-minute dispatchable capacity available among the committed units, the ISO can commit additional resources (mostly short-start units) for energy to free up capacity from the existing set of resources. Units committed to meet the flexible ramping requirement can be eligible for bid cost recovery payments in real-time. A procurement shortfall of flexible ramping capacity will occur where there is a shortage of available supply bids to meet the flexible ramping requirement or when there is energy scarcity in the 15-minute real-time pre-dispatch.[14]

Payments to the generators

Total payments for flexible ramping resources in the third quarter were around $3 million, down from about $7 million and $10 million in the second and first quarters, respectively.[15]

Table 1.1 provides a review of monthly flexible ramping constraint activity in the 15-minute real-time market since mid-2012. The table highlights the following:

- The frequency of intervals where the flexible ramping constraint was binding was around 10 percent, down from 12 percent in the previous quarter.
- The frequency of procurement shortfalls was 0.4 percent of all 15-minute intervals in the third quarter, down from 1.6 percent in the previous quarter.
- The total payments to generators for the flexible ramping constraint were around $3 million, down from around $7 million in the previous quarter.
- The average shadow price when the flexible ramping constraint was binding was about $38/MWh, down from $65/MWh in the previous quarter.[16]

Most payments for ramping capacity occurred during the evening peak hours. Figure 1.11 shows the hourly flexible ramping payment distribution during the third quarter broken down by technology type. As shown in the graph, the highest payment periods were during hours ending 15 through 18. Natural gas-fired capacity accounted for about 41 percent of these payments with hydro-electric capacity accounting for 58 percent.

[14] The penalty price associated with procurement shortfalls is set to just under $250.

[15] There are also secondary costs, such as those related to bid cost recovery payments to cover the commitment costs of the units committed by the constraint and additional ancillary services payments. Assessment of these costs are complex and beyond the scope of this analysis.

[16] DMM enhanced the analysis for average shadow price for the flexible ramping constraint which resulted in an increase from what was reported for the second quarter from approximately $57/MWh to about $65/MWh.

Table 1.1 Flexible ramping constraint monthly summary

Year	Month	Total payments to generators ($ millions)	15-minute intervals constraint was binding (%)	15-minute intervals with procurement shortfall (%)	Average shadow price when binding ($/MWh)
2012	Jul	$1.00	8%	1.4%	$62.13
2012	Aug	$0.76	7%	1.2%	$65.02
2012	Sep	$1.00	13%	0.8%	$38.47
2012	Oct	$0.93	9%	1.0%	$46.01
2012	Nov	$0.23	4%	0.5%	$44.85
2012	Dec	$1.09	9%	1.6%	$72.60
2013	Jan	$1.62	14%	2.2%	$58.61
2013	Feb	$3.45	19%	2.0%	$57.90
2013	Mar	$4.85	19%	3.1%	$68.39
2013	Apr	$2.51	15%	1.6%	$54.62
2013	May	$2.73	13%	2.0%	$68.50
2013	Jun	$1.95	9%	1.3%	$72.97
2013	Jul	$0.90	10%	0.4%	$36.19
2013	Aug	$1.51	14%	0.7%	$42.22
2013	Sep	$0.84	7%	0.2%	$34.83

Figure 1.11 Hourly flexible ramping constraint payments to generators (July – September)

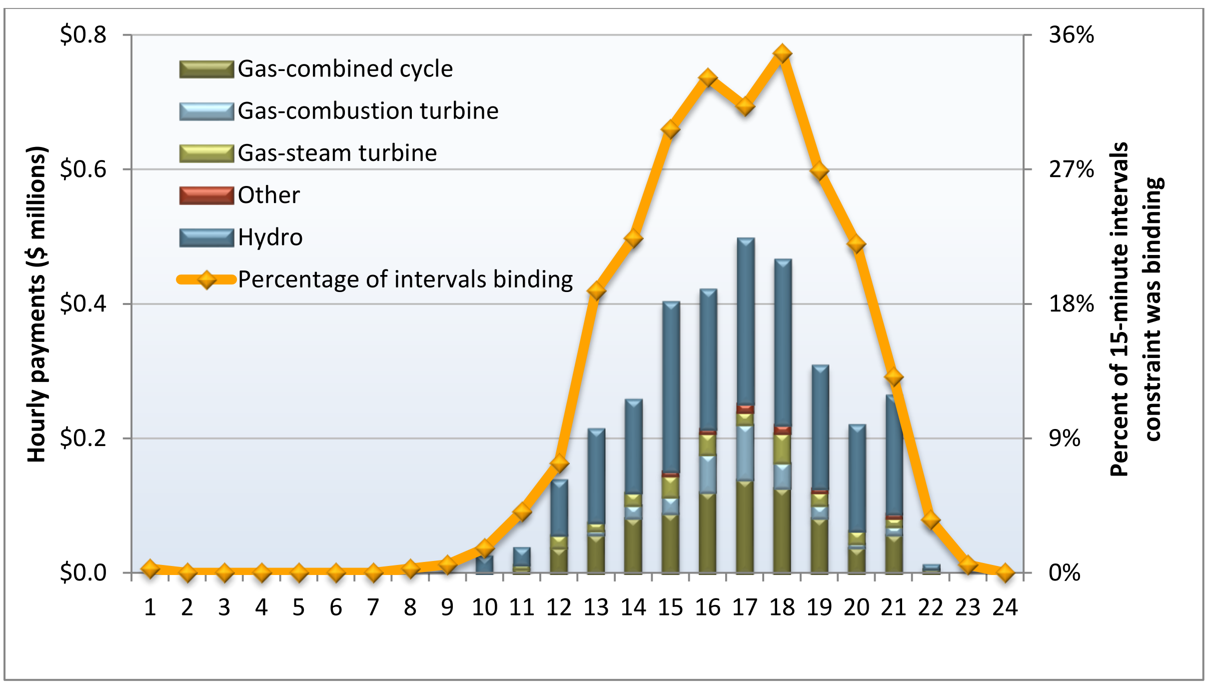
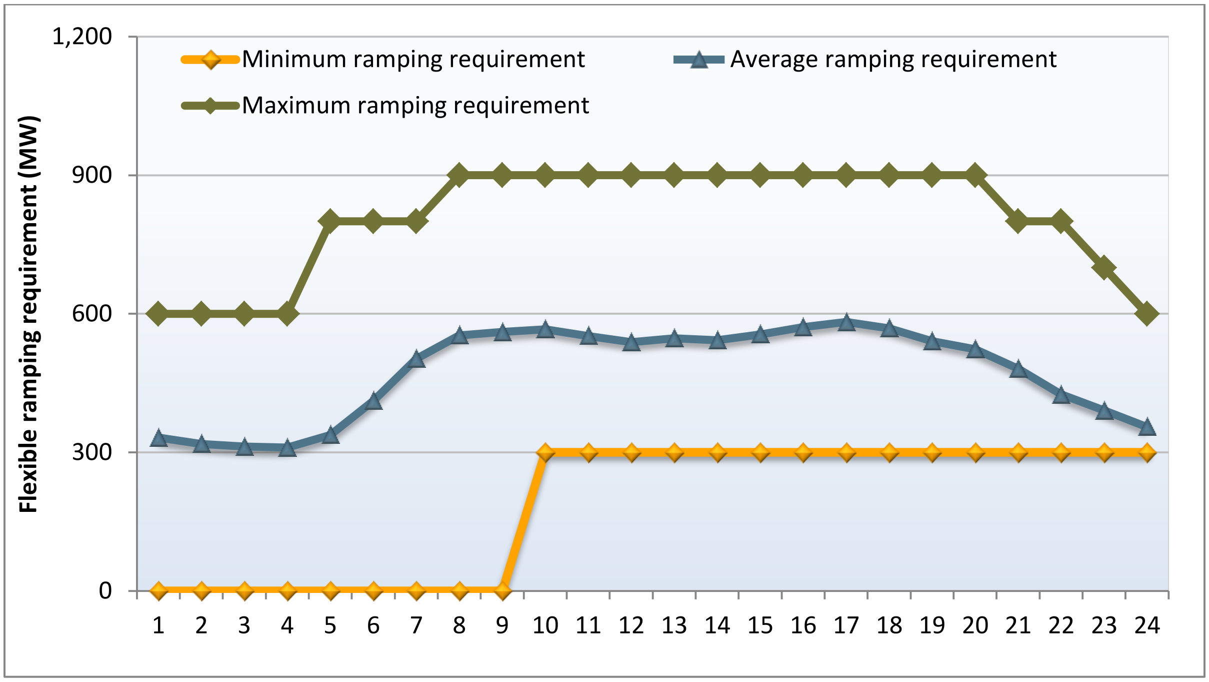


Figure 1.12 Hourly average flexible ramping requirement values (July – September)



The ISO continues its efforts to decrease the frequency and volume of exceptional dispatch. As a result, ISO operators used other market tools such as the flexible ramping constraint to deal with reliability concerns. Figure 1.12 shows the hourly average flexible ramping requirement values in the third quarter. The hourly ramping requirement ranged from a minimum of 0 MW to a maximum of 900 MW. On average, the requirement was set to around 300 MW in the pre-dawn early morning hours and nearly 600 MW in the morning and evening load-ramping hours. This pattern was similar to the flexible ramping requirements in the previous quarter, although there appears to be a slight decline in levels during the morning ramp and evening peak hours.

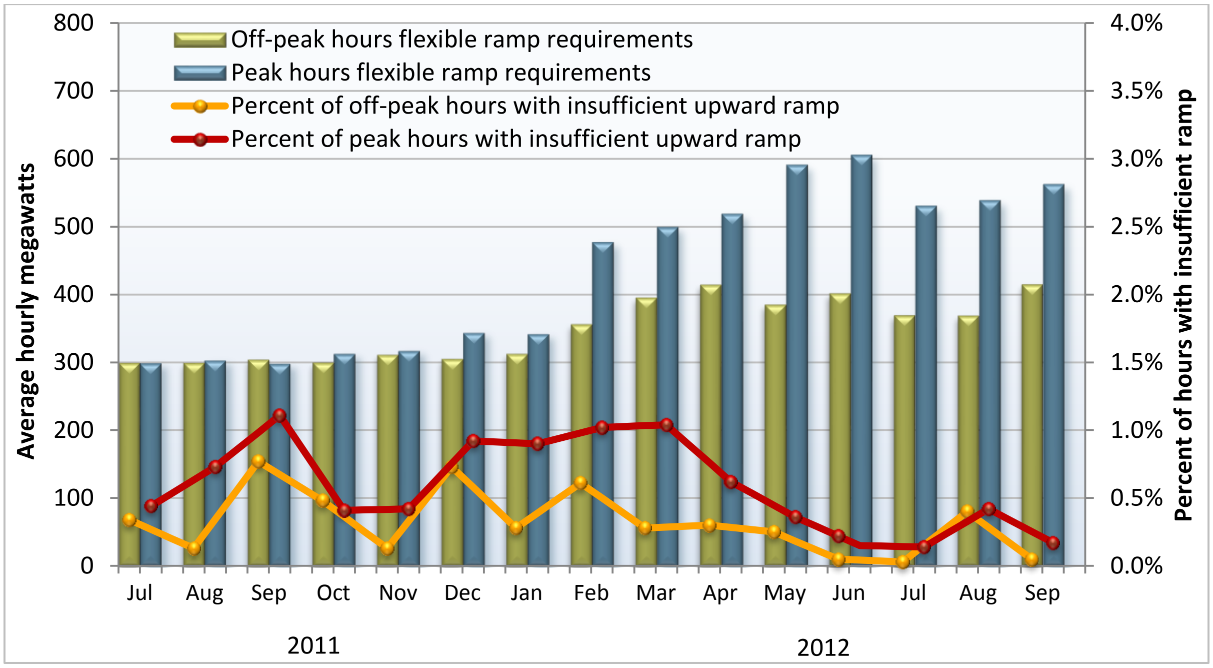
Real-time utilization of flexible ramping capacity

A measure of the potential effectiveness of the flexible ramping constraint in terms of procuring ramping capacity when needed is the actual usage of this ramping capacity in real time. DMM uses the ISO's methodology along with settlement data to calculate the utilization of flexible ramping capacity. The metric determines how much of the procured flexible ramping capacity in the 15-minute real-time pre-dispatch was used in the 5-minute real-time dispatch. The utilization of flexible ramping capacity is a function of prevailing system conditions, including load and generation levels. The average utilization of procured flexible ramping capacity ranged from 13 percent in the early morning to 41 percent in the evening. This pattern was similar to the previous quarter and the overall pattern in 2012.

Another measure is to review the relationship between the frequency of upward ramping infeasibilities in the real-time market and the flexible ramping constraint requirement level. Figure 1.13 shows the monthly average flexible ramping requirements, as well as percent of insufficient ramp, both in peak and off-peak hours. The green bars represent flexible ramp requirements during off-peak hours, while the blue bars represent flexible ramp requirements during peak hours. The frequency of upward ramp shortages during peak and off-peak hours are represented by the red and yellow line, respectively.

Since February 2013, the ISO increased flexible ramping requirements for peak hours to about 550 MW and off-peak requirements to about 400 MW from about 300 MW in earlier months. The frequency of insufficient upward ramp infeasibilities were higher during peak hours, but decreased substantially as the amount of flexible ramp increased.

Figure 1.13 Flexible ramping requirements and frequency of insufficient ramp intervals



The flexible ramping constraint and 15-minute real-time pre-dispatch prices

The 15-minute pre-dispatch market currently produces non-binding energy prices. While energy prices are non-binding, ancillary services prices and flexible ramping shadow prices are binding for settlement purposes.

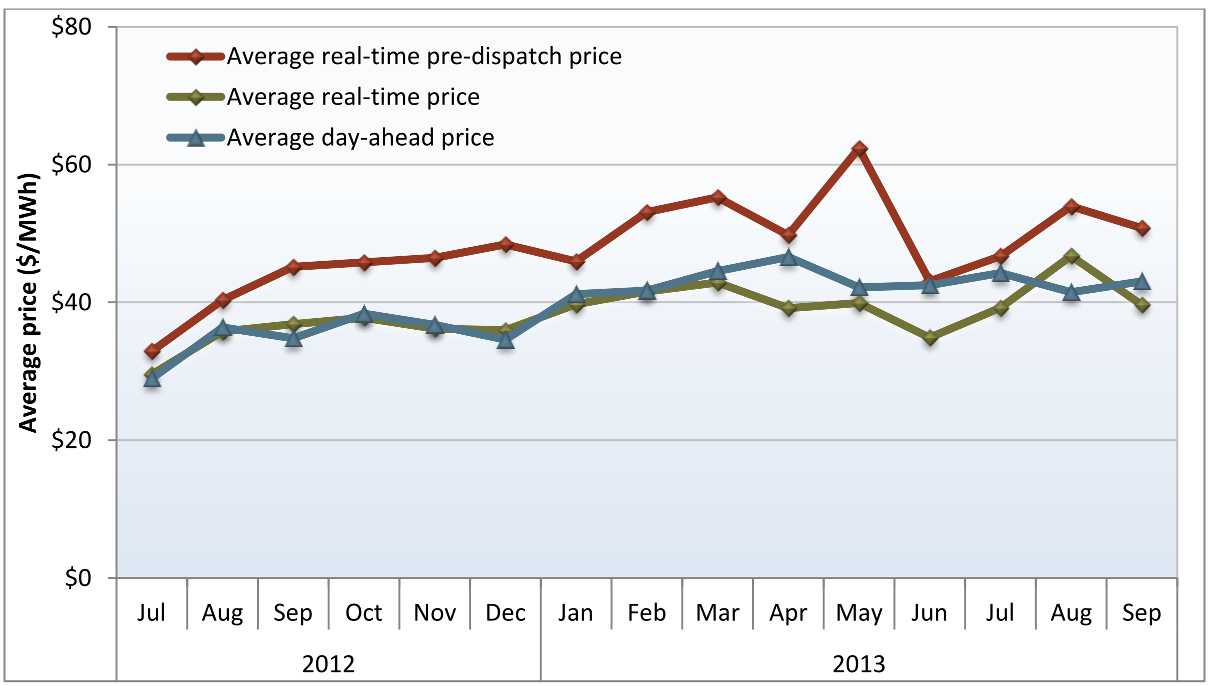
FERC Order No. 764 required that all FERC-jurisdictional transmission providers provide the opportunity for intra-hour schedule changes in 15 minute increments.[17] This requirement is instrumental to facilitating these proposed enhancements that will create a market structure oriented around renewable resources while also eliminating existing market inefficiencies. Implementation at the ISO is anticipated in the spring of 2014.

[17] On June 22, 2012, FERC approved Order 764 to remove barriers to the integration of variable energy resources by requiring each transmission provider to: (1) offer an option to schedule energy with 15-minute granularity; and (2) require variable energy resources to provide meteorological and forced outage data for the purpose of power production forecasting. Draft Final Proposal - FERC Order No. 764 Market Changes. For more information, see http://www.caiso.com/informed/Pages/StakeholderProcesses/FERCOrderNo764MarketChanges.aspx.

As part of the effort to address the FERC order, the ISO has taken this opportunity to make additional changes in the hour-ahead and real-time markets. Specifically, the ISO is proposing to change inter-tie scheduling and settlement from an hourly to a 15-minute basis, and to also establish a 15-minute settlement for internal resources and convergence bids. The proposal also includes retaining the existing 5-minute dispatch to provide real-time balancing.

Currently, the 15-minute pre-dispatch market prices are affected by the flexible ramping constraint as well as other differences between the 15- and 5-minute markets, including load forecast and operator adjustments. Figure 1.14 compares the 15-minute real-time pre-dispatch prices (red line), average real-time prices (green line) and average day-ahead price (blue line).[18] As shown in this figure, the real-time pre-dispatch prices are consistently higher than both the day-ahead and 5-minute real-time market prices. In 2013, the 15-minute real-time pre-dispatch prices exceeded day-ahead prices by about 19 percent and 5-minute real-time prices by about 26 percent. The ISO is looking into these differences and expects to make any necessary changes to address the underlying causes of this divergence. DMM is recommending the ISO play a high priority on addressing this issue prior to implementation of the new 15-minute real-time market design in spring 2014.

Figure 1.14 Average system marginal 15-minute real-time pre-dispatch compared to day-ahead and real-time prices



1.4 Congestion

Congestion within the ISO system in the third quarter affected overall prices less in the day-ahead and real-time markets than in the second quarter. However, congestion continued to impact the market,

[18] Energy prices in the 15-minute pre-dispatch market are not currently subject to the same rigorous price validation and correction process as in other markets and may include intervals that would otherwise be corrected.

particularly into the Southern California Edison area. Much of the congestion was related to adjustments of the flows on the SCE percent import branch group constraint (SCE_PCT_IMP_BG),[19] retirement of San Onofre Nuclear Generating Station (SONGS) units 2 and 3 and other generation and transmission events.

The impact of congestion on any constraint on each pricing node in the ISO system can be calculated by summing the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation can be done for individual nodes, as well as groups of nodes that represent different load aggregation points or local capacity areas.

Congestion on constraints in Southern California often increases prices within the Southern California Edison and San Diego Gas & Electric areas, but decreases prices in the Pacific Gas and Electric area. Congestion in Northern California often has the opposite effect. Also, the price impacts on individual constraints can differ between the day-ahead and real-time markets, as seen in the following sections.

1.4.1 Congestion impacts of individual constraints

Day-ahead congestion

Historically, congestion in the day-ahead market generally occurs more frequently but with a lower impact than the real-time market. Table 1.2 provides information related to the frequency and magnitude of day-ahead market congestion.

In the PG&E area, 30875_MC CALL_230_30880_HENTAP2_230_BR_1_1 was the most congested constraint. This constraint was binding in nearly 30 percent of hours. During these hours, prices in the PG&E area increased by about $0.59/MWh and prices in the SCE and SDG&E areas decreased by about $0.42/MWh. The McCall system is heavily dependent on imports from the 230 kV system through McCall, Herndon, Henrietta banks, and local hydro generation. The constraint is adjusted to protect thermal overload of the Gates-McCall 230 kV line for the contingency loss of Panoche-Helms 230 kV line. The second most congested constraint in the PG&E area was 6110_TM_BNK_FLO_TMS_DLO_NG at nearly 20 percent of hours. This was primarily due to wildfires.[20]

The 24087_MAGUNDEN_230_24153_VESTAL_230_BR_2_1 constraint was the most congested constraint in the SCE area and was primarily adjusted for reliability. This constraint was congested in about 23 percent of the hours in the third quarter, up from about one percent in the previous quarter. When congestion occurred on this constraint, prices in the SCE area increased by about $0.93/MWh and decreased for SDG&E and PG&E areas by about $0.30/MWh. The second most congested constraint in the SCE area, at about 16 percent, was the SCE_PCT_IMP_BG.[21] When congestion occurred on this

[19] This constraint has been removed from the markets as indicated in the Market Notice on September 20, 2013. Un-enforcement of SCE_PCT_IMP_BG constraint was effective October 1, 2013. For more information, see: http://www.caiso.com/Documents/ResendUn-enforcement-SCE_PCT_IMP_BGConstraintSep20_2013.htm.

[20] This is a nomogram in the COI Master Operating Procedure (#6110). This procedure specifies system operating limits (SOL) and provides both normal and contingency operations, and background and guidance for all COI related paths. Specifically, this nomogram is for the double loss of 500 kV lines Table Mountain-Tesla and Table Mountain-Vaca to protect for the Table Mountain 500/230 kV XFMR bank.

[21] This constraint has been removed from the market as noticed by the ISO on September 20, 2013. Un-enforcement of the constraint was effective October 1, 2013. For more information, see http://www.caiso.com/Documents/ResendUn-enforcement-SCE_PCT_IMP_BGConstraintSep20_2013.htm.

constraint, prices in the SCE area increased about $2.20/MWh and decreased for SDG&E and PG&E areas about $2/MWh. This constraint was directly affected by the SONGS retirement.

In the San Diego area, the most congested constraint was 7820_TL 230S_OVERLOAD_NG. This constraint was binding in almost 12 percent of the hours and increased prices in the SDG&E area by $5.31/MWh, while decreasing prices in the PG&E area by $0.59/MWh. This nomogram protects the Imperial Valley-El Centro 230 kV line for a loss of the Imperial Valley-North Gila 500 kV line. Other significant binding constraints in the third quarter included the T-135 VICTVLUGO constraint to protect the Lugo-Victorville 500 kV line from overloading, the SouthBay-Otay 69 kV line for a loss of the Miguel-Border 69 kV line, and the Serrano transformer flowgate which protects the Serrano 500/220 kV transformer for a contingency on the parallel transformer.

As shown in Table 1.2, with the exception of the SCE_PCT_IMP_BG, 7820_TL 230S_OVERLOAD_NG and the McCall-Hentap constraints, internal congestion occurred infrequently and typically had a minimal impact on overall day-ahead energy prices.

Table 1.2 Impact of congestion on day-ahead prices by load aggregation point in congested hours

		Frequency			Q1			Q2			Q3		
Area	Constraint	Q1	Q2	Q3	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1		1.9%	28.2%				$0.57	-$0.45	-$0.45	$0.59	-$0.42	-$0.42
	6110_TM_BNK_FLO_TMS_DLO_NG		0.6%	19.0%				$0.39			$0.94	-$0.88	-$0.88
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1			0.7%							$1.08	-$0.84	-$0.84
	PATH15_BG	7.7%	9.8%	0.5%	$1.68	-$1.43	-$1.43	$1.60	-$1.32	-$1.32	$2.26	-$1.86	-$1.86
	LOSBANOSNORTH_BG		1.2%	0.1%				$2.74	-$2.09	-$2.09	$1.66	-$1.60	-$1.60
	30735_METCALF _230_30042_METCALF _500_XF_13		1.3%					$2.26	-$1.92	-$1.92			
SCE	24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1		0.8%	22.8%	-$0.11	$2.14	-$0.11				-$0.30	$0.93	-$0.30
	SCE_PCT_IMP_BG	71.2%	51.2%	16.3%	-$3.93	$4.85	-$3.89	-$3.66	$4.29	-$3.63	-$2.00	$2.20	-$1.89
	BARRE-LEWIS_NG	23.9%	5.3%	5.2%	-$1.32	$1.84	$0.21	-$1.06	$1.29	$0.91	-$0.40	$0.51	$0.15
	PATH26_BG	1.1%		1.9%	-$1.83	$1.47	$1.47				-$3.08	$1.97	$1.97
	SLIC 2146366_VINCENTBUS			0.3%							-$3.14	$2.18	$2.57
	SLIC 2088287_BARRE-LEWIS_NG	0.7%			-$1.28	$2.13							
SDG&E	7820_TL 230S_OVERLOAD_NG		13.6%	11.8%				-$1.01		$7.69	-$0.59		$5.31
	T-135 VICTVLUGO_LGVNDLO_NG			4.3%							-$2.14	$1.40	$1.75
	22768_SOUTHBAY_69.0_22604_OTAY _69.0_BR_2 _1		5.5%	2.9%						$0.96			$0.26
	22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1		0.1%	1.5%						$1.18			$1.31
	SOUTHLUGO_RV_BG	0.4%	3.3%	0.7%	-$3.24	$2.47	$4.42	-$5.15	$3.56	$5.43	-$4.60	$2.94	$4.33
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P		0.9%	0.3%				-$3.53	$1.88	$7.28	-$1.08	$0.64	$2.41
	SLIC 2148149 TL23050_NG			0.3%									$11.36
	24016_BARRE _230_24044_ELLIS _230_BR_3 _1		0.7%	0.1%				-$0.47		$2.34	-$0.27		$1.19
	SDGE_PCT_UF_IMP_BG		2.2%					-$0.76	-$0.76	$7.58			
	24016_BARRE _230_24044_ELLIS _230_BR_1 _1		1.7%					-$2.46	-$0.67	$15.70			
	SLIC 2122013 BARRE-ELLIS-230S_NG		1.6%					-$0.46		$4.91			
	24016_BARRE _230_24044_ELLIS _230_BR_4 _1		1.6%					-$0.45		$2.17			
	7830_SXCYN_CHILLS_NG	0.1%	1.3%				$0.56			$9.51			
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P		0.8%					-$3.02	$1.67	$6.02			
	SLIC 2077347 TL50003_NG		0.6%							$6.05			
	SLIC 2067610 TL50001_NG		0.6%							$12.23			
	SLIC 2122013 Barre-Ellis DLO		0.6%					-$2.54		$15.20			
	SLIC 2111709_IV500North_BUS_NG		0.5%							$20.93			
	SLIC 2122013 Barre-Ellis DLO_20		0.4%					-$1.97		$12.42			
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	3.4%	0.2%				$4.27			$6.81			
	IVALLYBANK_XFBG	2.6%					$0.84						
	SLIC 2051445 TL23050_NG	2.3%					$6.31						
	SLIC 2090466 and 2090467 SOL	2.3%					$15.29						
	SLIC 2112931 EL CENTRO BK1_NG	1.2%					$5.05						
	MIGUEL_BKs_MXFLW_NG	0.4%			-$1.04		$11.65						
	24138_SERRANO _500_24137_SERRANO _230_XF_3	0.4%			-$17.48		$41.61						
	SLIC 2094078 IV Bank81_NG	0.2%			-$3.54		$24.91						

Real-time congestion

Congestion in the real-time market differs from the day-ahead market in that real-time congestion occurs less frequently overall, but often with a larger price effect in the intervals when it occurs. Table 1.3 shows the frequency and magnitude of congestion in the third quarter.

Table 1.3 Impact of congestion on real-time prices by load aggregation point in congested intervals

		Frequency			Q1			Q2			Q3		
Area	**Constraint**	**Q1**	**Q2**	**Q3**	**PG&E**	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**
PG&E	30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1		1.0%	14.4%				$1.21	-$1.20	-$1.20	$1.25	-$1.47	-$1.47
	6110_TM_BNK_FLO_TMS_DLO_NG		1.2%	1.9%				$7.51	-$3.80	-$3.80	$5.63	-$6.85	-$6.85
	PATH15_S-N	2.1%	4.5%	1.0%	$52.05	-$43.98	-$43.98	$17.53	-$14.29	-$14.29	$12.27	-$9.59	-$9.59
	30055_GATES1 _500_30900_GATES _230_XF_11_P		0.2%	0.4%				$7.58	-$6.64	-$6.64	$3.52	-$3.50	-$3.50
	LBN_S-N		0.9%	0.2%				$28.13	-$23.22	-$23.22	$43.77	-$34.82	-$34.82
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1			0.2%							$14.19	-$10.92	-$10.92
	TRACY500_BG		2.3%					-$9.51	$7.42	$7.42			
	30735_METCALF _230_30042_METCALF _500_XF_13		2.2%					$29.35	-$31.17	-$31.17			
	30735_METCALF _230_30750_MOSSLD _230_BR_1 _1		0.6%					$23.95	-$23.75	-$23.75			
	T-135 VICTVLUGO_PVDV_NG	0.1%	0.01%		$33.40	-$38.73		$1.06		-$1.57			
SCE	SCE_PCT_IMP_BG	10.0%	2.2%	2.4%	-$33.78	$41.04	-$33.48	-$47.91	$58.30	-$47.41	-$16.30	$17.84	-$13.31
	BARRE-LEWIS_NG	5.4%	0.2%	2.2%	-$8.62	$5.60	-$6.64	-$5.70	$5.30	$1.97	-$2.60	$2.20	
	PATH26_N-S	2.0%	1.2%	1.0%	-$23.96	$19.63	$19.63	-$72.06	$58.65	$58.65	-$25.07	$17.70	$17.70
	24155_VINCENT _230_24091_MESA CAL_230_BR_1 _1		0.4%					-$11.16	$9.31	$8.74			
	PATH15_N-S	0.03%			-$56.37	$47.06	$47.06						
SDG&E	7820_TL 230S_OVERLOAD_NG	0.4%	2.6%	1.6%			$29.90	-$1.75		$34.48	-$4.82		$36.06
	SOUTH_OF_LUGO		0.4%	0.3%				-$20.66	$16.05	$22.56	-$81.01	$57.91	$93.04
	SLIC 2161499 DEVERS-VISTA 2_NG			0.34%							-$46.58	$33.15	$76.75
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.1%	0.4%	0.3%	-$37.04		$92.29	-$23.63	$14.79	$51.60	-$8.27	$6.54	$18.73
	24138_SERRANO _500_24137_SERRANO _230_XF_3	0.1%		0.2%	-$32.00		$80.19				-$10.43	$5.24	$18.47
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P			0.1%							-$21.51	$10.35	$38.20
	22342_HDWSH _500_22536_N.GILA _500_BR_1 _1		0.2%	0.05%				-$8.74		$55.06	-$2.09		$14.07
	SOUTHLUGO_RV_BG	0.01%	0.2%	0.03%	-$2.45	$1.74	$3.24	-$157.14	$110.45	$160.42	-$67.97	$61.86	$79.45
	SLIC 2122013 Barre-Ellis DLO_16		0.6%					-$3.44	-$0.90	$23.02			
	SLIC 2122013 Barre-Ellis DLO_17		0.6%					-$4.49	-$1.25	$29.85			
	SLIC 2122013 Barre-Ellis DLO_21		0.5%					-$2.20		$14.49			
	SLIC 2077347 TL50003_NG		0.5%					$0.83		$54.19			
	24016_BARRE _230_24044_ELLIS _230_BR_1 _1		0.4%					-$1.52	-$0.55	$9.86			
	7830_SXCYN_CHILLS_NG		0.3%							$19.99			
	SLIC 2126995 SONGS_NG1		0.1%					-$47.35		$441.78			
	SDGE_PCT_UF_IMP_BG		0.1%					-$13.32	-$13.32	$141.64			
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _2	0.03%			-$320.31	$267.35	$267.35						
	IVALLYBANK_XFBG	3.1%					$2.55						
	7830_TL 230S_IV-SX-OUT_NG	0.5%					$51.47						
	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	0.4%			-$2.22	-$5.25	$15.46						
	SLIC 2090466 and 2090467 SOL	0.3%					$30.74						
	SLIC 2051445 TL23050_NG	0.2%					$46.55						
	SLIC 2112931 EL CENTRO BK1_NG	0.2%					$49.40						

Overall, the most congested constraint was 30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1 located in the PG&E area, which was binding about 14 percent of the time in the third quarter. This constraint increased prices by about $1.25/MWh in the PG&E area and decreased prices in the SCE and SDG&E areas by $1.47/MWh. This constraint was influenced by imports from the 230 kV system through McCall, Herndon, Henrietta banks, and local hydro generation.

The second most congested constraint in the quarter was in the Southern California Edison area, the SCE_PCT_IMP_BG, with congestion in nearly 2.4 percent of the intervals. This constraint alone increased the prices in the SCE area by $17.84/MWh in congested periods, while prices in the PG&E and SDG&E area decreased by $16.30/MWh and $13.31/MWh, respectively. This constraint was directly affected by the SONGS retirement, variable resource output, generation outages and derates.

Prices in the San Diego area were affected by multiple constraints. The 7820_TL 230S_OVERLOAD_NG nomogram drove the prices in the SDG&E area up by about $36/MWh and decreased the PG&E area prices by $5/MWh. The other remaining constraints in the SDG&E area were binding in less than 0.5 percent of the intervals, but had significant price impact on the SDG&E area prices when they were binding. These constraints include the Serrano transformer, the T-135 VICTVLUGO and the Southbay-Otay nomograms, and the South of Lugo branch group.

Overall, congestion occurred more frequently in the day-ahead market compared to the real-time market, as shown by a comparison of Table 1.2 and Table 1.3. In the third quarter, the price impact on the most significant binding elements is larger in the real-time market than the day-ahead market. For instance, the 30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1 constraint was binding in roughly 28 percent of the hours in the day-ahead market compared to around 14 percent of intervals in the real-time market. While this constraint increased day-ahead prices in the PG&E area by nearly $0.59/MWh, it increased prices by over $1.25/MWh in the real-time market. A similar pattern can also be seen with the 7820_TL 230S_OVERLOAD_NG constraint.

Differences in congestion in the day-ahead and real-time markets occur as system conditions change, virtual bids liquidate, and constraints are adjusted to account for discrepancies between market and actual flow and to provide a reliability margin.

1.4.2 Congestion impact on average prices

This section provides an assessment of differences on overall average prices in the day-ahead and real-time markets caused by congestion between different areas of the ISO system. Unlike the analysis provided in the previous section, this assessment is based on the average congestion component of the price as a percent of the total price during all congested and non-congested hours. This approach shows the impact of congestion taking into account the frequency that congestion occurs, as well as the magnitude of the impact that congestion has when it occurs.[22] The price impact of congestion in all hours in the third quarter was less in the day-ahead market than the real-time market.[23]

Day-ahead price impacts

Table 1.4 shows the overall impact of day-ahead congestion on average prices in each load area in the third quarter by constraint.

The SCE_PCT_IMP_BG increased day-ahead prices in the SCE area above system average prices by $0.36/MWh or 0.8 percent, down from $2.20/MWh (4.8 percent) in the previous quarter. Prices decreased by about $0.32/MWh (0.8 percent) in the PG&E and SDG&E areas. This constraint is designed to ensure that enough generation is available to balance demand from units within the SCE area in the event of a severe under-frequency event that would result in the SCE area being separated from the rest of the interconnection.[24]

In the SDG&E area, the 7820_TL 230S_OVERLOAD_NG increased prices by $0.63/MWh or 1.4 percent and decreased PG&E area prices by $0.04/MWh or 0.1 percent with no significant price impact on SCE area prices.

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[22] In addition, this approach identifies price differences caused by congestion without including price differences that result from variations in transmission losses at different locations.

[23] As mentioned before, congestion in the real-time market often has a larger price effect in intervals when it occurs. However, the overall price impact of congestion depends on the frequency of congestion along with the magnitude of the price effect.

[24] This constraint has been un-enforced in the model. See footnote 19 for further detail.

The day-ahead prices in the PG&E area were driven by the 30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1 and the 6110_TM_BNK_FLO_TMS_DLO_NG nomograms. These nomograms increased prices by $0.18/MWh or around 0.4 percent. The 30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1 was influenced by imports from the 230 kV system through McCall, Herndon, Henrietta banks, and local hydro generation. The 6110_TM_BNK_FLO_TMS_DLO_NG nomogram was conformed due to wildfires.

The overall impact of congestion on day-ahead prices in the PG&E area decreased prices by about $0.30/MWh or about 0.7 percent from the system average. This occurred because prices in the PG&E area were lower when congestion occurred on the constraints limiting flows into the SCE and SDG&E areas.

Table 1.4 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
SCE_PCT_IMP_BG	-$0.33	-0.77%	$0.36	0.82%	-$0.31	-0.70%
7820_TL 230S_OVERLOAD_NG	-$0.04	-0.10%			$0.63	1.41%
6110_TM_BNK_FLO_TMS_DLO_NG	$0.18	0.42%	-$0.04	-0.10%	-$0.04	-0.10%
T-135 VICTVLUGO_LGVNDLO_NG	-$0.09	-0.21%	$0.06	0.14%	$0.07	0.17%
24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1			$0.21	0.49%		
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	$0.17	0.39%	-$0.02	-0.04%	-$0.02	-0.04%
PATH26_BG	-$0.06	-0.13%	$0.04	0.08%	$0.04	0.08%
SOUTHLUGO_RV_BG	-$0.03	-0.08%	$0.02	0.05%	$0.03	0.07%
BARRE-LEWIS_NG	-$0.02	-0.05%	$0.03	0.06%	$0.00	0.00%
SLIC 2148149 TL23050_NG					$0.03	0.07%
PATH15_BG	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
SLIC 2146366_VINCENTBUS	-$0.01	-0.02%	$0.01	0.01%	$0.01	0.02%
22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1					$0.02	0.05%
30790_PANOCHE _230_30900_GATES _230_BR_1 _1	$0.01	0.02%	-$0.01	-0.01%	-$0.01	-0.01%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	$0.00	-0.01%			$0.01	0.02%
22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1					$0.01	0.02%
Other	-$0.09	-0.20%	$0.09	0.21%	$0.01	0.03%
Total	-$0.30	-0.7%	$0.74	1.7%	$0.47	1.1%

Real-time price impacts

Table 1.5 shows the overall impact of real-time congestion on average prices in each load area in the third quarter by constraint.

Congestion drove prices in the SCE area above system average prices by about $1.38/MWh or 3.2 percent. Most of this increase was driven by congestion on the SCIT_BG, which increased prices in the SCE area by $0.76/MWh (1.8 percent). Another major driver of congestion was the SCE_PCT_IMP_BG constraint due to limits on the percentage of load in the SCE area that can be met by total flows on all transmission paths into the SCE area.

Prices in the San Diego area were impacted the most by congestion associated with the SCIT_BG, SOUTH_OF_LUGO and 7820_TL 230S_OVERLOAD_NG constraints. These three constraints drove San Diego area prices above the system average by nearly 4 percent or about $1.60/MWh.

The overall impact of congestion on prices in the PG&E area was to decrease prices from the system average by about $1/MWh or about 2.6 percent. Prices in the PG&E area are lowered when congestion occurs on the constraints that limit flows in the north-to-south direction (e.g., PATH26_N-S) and on constraints limiting flows into the SCE (e.g., SCIT_BG and SCE_PCT_IMP_BG) and SDG&E areas.

Table 1.5 Impact of congestion on overall real-time prices

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
SCIT_BG	-$1.05	-2.56%	$0.76	1.75%	$0.82	1.89%
SCE_PCT_IMP_BG	-$0.39	-0.96%	$0.43	0.99%	-$0.32	-0.73%
SOUTH_OF_LUGO	-$0.28	-0.68%	$0.20	0.46%	$0.32	0.74%
7820_TL 230S_OVERLOAD_NG	-$0.05	-0.13%			$0.57	1.31%
PATH26_N-S	-$0.24	-0.59%	$0.17	0.39%	$0.17	0.39%
SLIC 2161499 DEVERS-VISTA 2_NG	-$0.14	-0.34%	$0.08	0.19%	$0.26	0.61%
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	$0.18	0.44%	-$0.12	-0.28%	-$0.12	-0.28%
6110_TM_BNK_FLO_TMS_DLO_NG	$0.11	0.27%	-$0.11	-0.26%	-$0.11	-0.26%
PATH15_S-N	$0.13	0.32%	-$0.10	-0.23%	-$0.10	-0.23%
LBN_S-N	$0.08	0.19%	-$0.06	-0.14%	-$0.06	-0.14%
BARRE-LEWIS_NG	-$0.05	-0.13%	$0.05	0.11%		
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.02	-0.06%	$0.02	0.04%	$0.06	0.13%
22841_PICOTAP _138_22396_LAGNA NL_138_BR_1 _1	-$0.04	-0.09%	$0.03	0.07%	$0.03	0.06%
T-133 METCALF_NG	-$0.03	-0.07%	$0.03	0.06%	$0.03	0.06%
24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.02	-0.05%	$0.01	0.02%	$0.04	0.09%
T-163-Magunden-Pastoria_NG			$0.01	0.03%	-$0.05	-0.12%
34774_MIDWAY _115_34780_CYMRIC _115_BR_1 _1	-$0.02	-0.06%	$0.02	0.04%	$0.02	0.04%
24138_SERRANO _500_24137_SERRANO _230_XF_3	-$0.02	-0.04%	$0.01	0.02%	$0.03	0.07%
SOUTHLUGO_RV_BG	-$0.02	-0.04%	$0.02	0.04%	$0.02	0.05%
30790_PANOCHE _230_30900_GATES _230_BR_1 _1	$0.02	0.05%	-$0.02	-0.04%	-$0.02	-0.04%
30055_GATES1 _500_30900_GATES _230_XF_11_P	$0.02	0.04%	-$0.01	-0.03%	-$0.01	-0.03%
PRLBLM_EDMNTN_BG	-$0.01	-0.04%	-$0.01	-0.03%	-$0.01	-0.03%
34774_MIDWAY _115_30970_MIDWAY _230_XF_2	-$0.01	-0.03%	$0.01	0.03%	$0.01	0.03%
30970_MIDWAY _230_30060_MIDWAY _500_XF_12	-$0.01	-0.03%	$0.01	0.03%	$0.01	0.03%
24807_MIRAGE _115_24819_CONCHO _115_BR_1 _1	-$0.02	-0.04%	-$0.02	-0.05%		
34774_MIDWAY _115_30970_MIDWAY _230_XF_3	-$0.01	-0.03%	$0.01	0.03%	$0.01	0.03%
7230 SOL_3_NG_SUM	-$0.01	-0.03%	$0.01	0.02%	$0.01	0.03%
22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1					-$0.03	-0.06%
30915_MORROBAY_230_30916_SOLARSS _230_BR_1A_1	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1					$0.02	0.05%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					$0.02	0.05%
SLIC 2148149 TL23050_NG					$0.02	0.05%
Other	$0.85	2.07%	-$0.02	-0.05%	-$0.62	-1.42%
Total	-$1.06	-2.6%	$1.38	3.2%	$0.97	2.2%

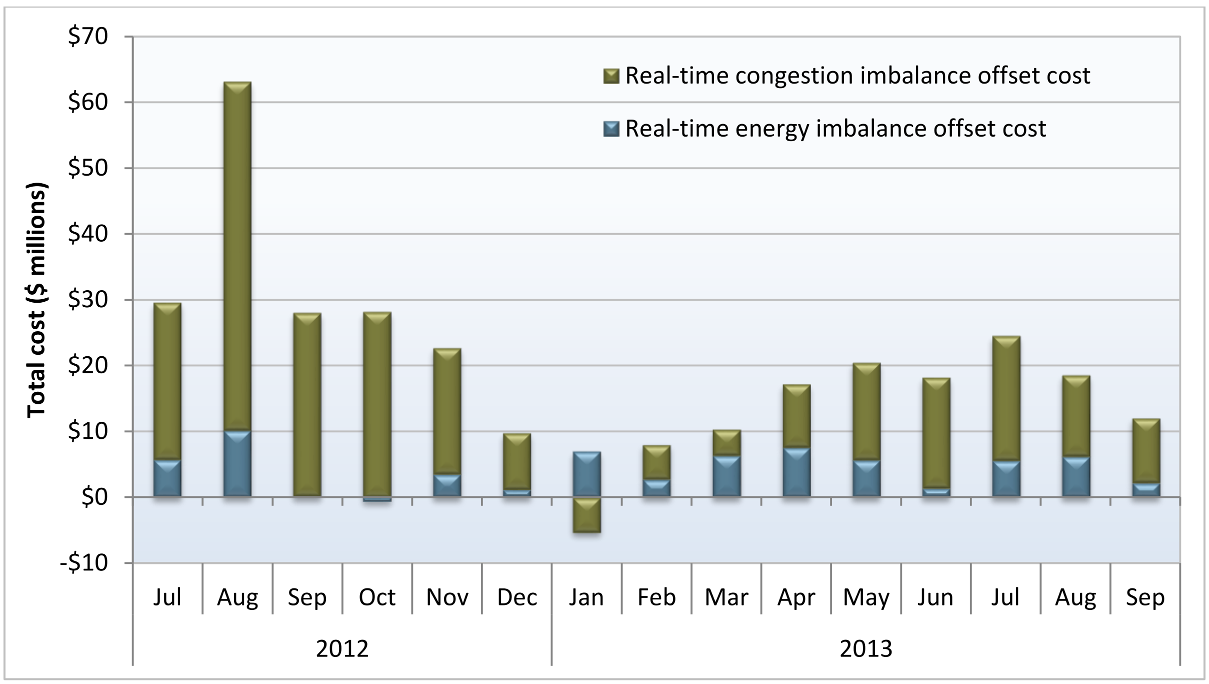
Overall, most significant real-time congestion occurred less frequently than day-ahead congestion. Its overall price impact was similar to what occurred in the previous quarter. As mentioned earlier, the differences in congestion can be attributed to differences in market conditions and changes associated with conforming line limits to make market flows reflect actual flows, as well as to provide a reliability margin.

In terms of both simple and absolute averages, congestion differences have reduced substantially between the day-ahead and real-time markets in the third quarter compared to the previous quarter, as the frequency and impact of congestion decreased. Congestion differences also decreased between day-ahead and hour-ahead markets as hour-ahead prices decreased somewhat during peak hours in the third quarter.

1.5 Real-time imbalance offset costs

Real-time imbalance offset costs totaled about $55 million, a slight decrease from $56 million in the second quarter. This was slightly above the average quarterly offset cost for 2011 and 2012 of about $50 million. Congestion offset costs accounted for approximately 75 percent of the total imbalance costs during this quarter, totaling about $41 million (see Figure 1.15). The remaining $14 million were incurred through energy imbalance offset costs, which remained relatively consistent with previous periods.

Figure 1.15 Real-time imbalance offset costs



Real-time congestion offset costs were primarily due to unscheduled flows and market modeling differences. Together, costs incurred on two days account for more than one quarter of congestion offset costs for the quarter.

- On July 4, congestion offset costs reached $6.4 million due to unscheduled flows which affected the shadow value on a single constraint substantially between the hour-ahead and real-time markets.

- On August 30, congestion offset costs reached $4.2 million. On this date, actual load differed substantially from day-ahead forecasts. Increased demand in the hour-ahead market resulted in shadow prices on some constraints substantially above the real-time shadow price cap.[25]

The 11 days with the next highest real-time congestion offset cost accounted for a combined total of about $21 million.

The ISO's efforts to address systematic modeling differences between the day-ahead and real-time markets, including better alignment of day-ahead and real-time transmission limits and modification of the constraint relaxation parameter, have contributed to reducing real-time imbalance costs compared to the summer of 2012. This appears to have significantly improved imbalance congestion offset costs between 2012 and 2013 as real-time congestion imbalance costs were $100 million in the third quarter of 2012 and just over $40 million in the third quarter of 2013. Even with these improvements, the possibility of high real-time imbalance offset costs continues to exist.

1.6 Residual unit commitment

Although residual unit commitment volumes remained relatively high in the third quarter, the direct costs of procuring residual unit commitment capacity fell dramatically. The direct costs of procuring residual unit commitment capacity ($200,000) were lower in the third quarter of 2013 than in any quarter since the third quarter of 2012. As in prior quarters, increased residual unit commitment costs have primarily been driven by an increase in residual unit commitment requirements driven by liquidation of cleared net virtual supply.

Much of this capacity does not incur direct costs but does account for a portion of the bid cost recovery payments discussed in further detail in Section 2.2. Figure 1.16 illustrates average hourly direct non-resource adequacy costs by month in addition to the average hourly residual unit commitment procurement, categorized as either non-resource adequacy or resource adequacy and minimum load.

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity online or reserved to meet forecast load in real time. The residual unit commitment market is run right after the day-ahead market and procures capacity sufficient to bridge the gap between the physical capacity that cleared in the day-ahead market and the day-ahead forecast load. ISO operators are able to increase the amount of residual unit commitment requirements for reliability purposes and have used this tool frequently in 2013.

As illustrated in Figure 1.17, residual unit commitment procurement appears to be driven in large part by the need to replace cleared net virtual supply bids which will not appear in the real-time market. On average, cleared virtual supply (green bar) has had a greater presence in the third quarter of 2013 than it did in the same quarter of 2012. Operator adjustments to the residual unit commitment process (red bar) have also played a part in the growth of residual unit commitment procurement. The increase in the residual unit commitment requirement made by operators during 2013 was partly related to decreased reliance on exceptional dispatch, which increased the use of alternative means of ensuring

[25] This is due to differences in constraint shadow prices in the hour-ahead and 5-minute markets. For instance, the cap on real-time shadow prices is $1,500, whereas the cap on hour-ahead market shadow prices is $5,000. For more detail and analysis see the discussion paper "Real-time Revenue Imbalance in California ISO Markets" at: http://www.caiso.com/Documents/DiscussionPaper-Real-timeRevenueImbalance_CaliforniaISO_Markets.pdf.

adequate capacity and ramping in real time. However, beginning in the third quarter of 2013, the ISO began factoring in forecasted variable generation in the residual unit commitment process, reducing the volume of operator adjustments.

Figure 1.16 Residual unit commitment costs and volume

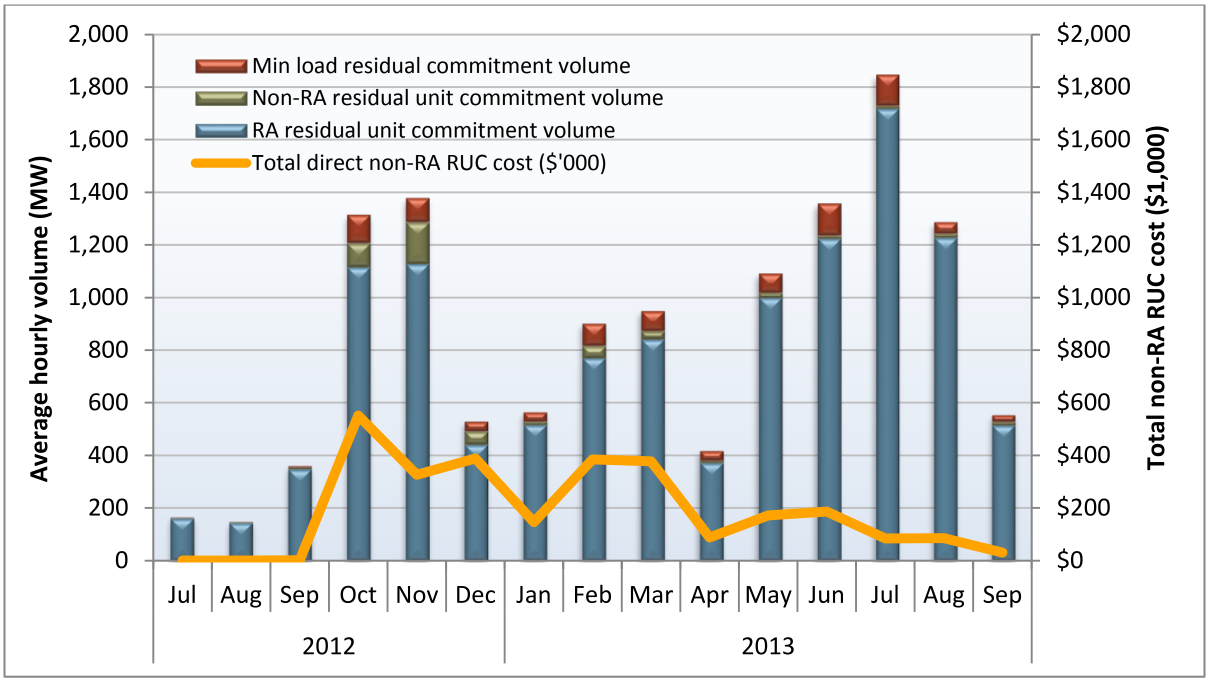
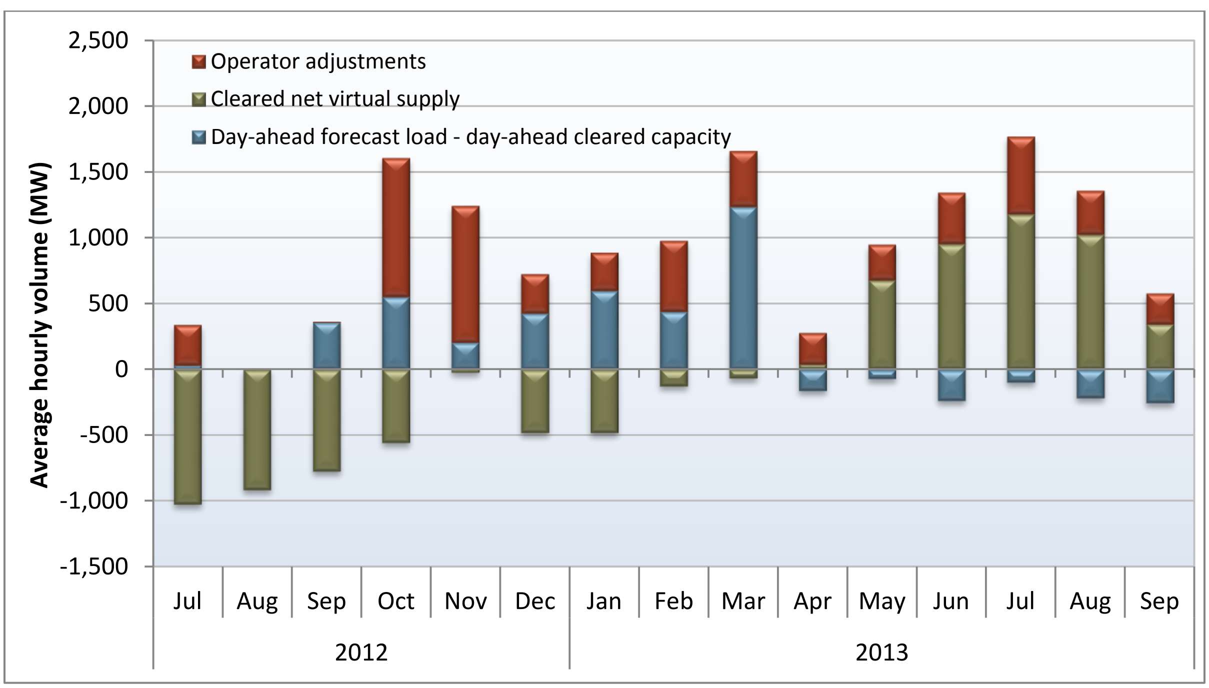


Figure 1.17 Determinants of residual unit commitment procurement



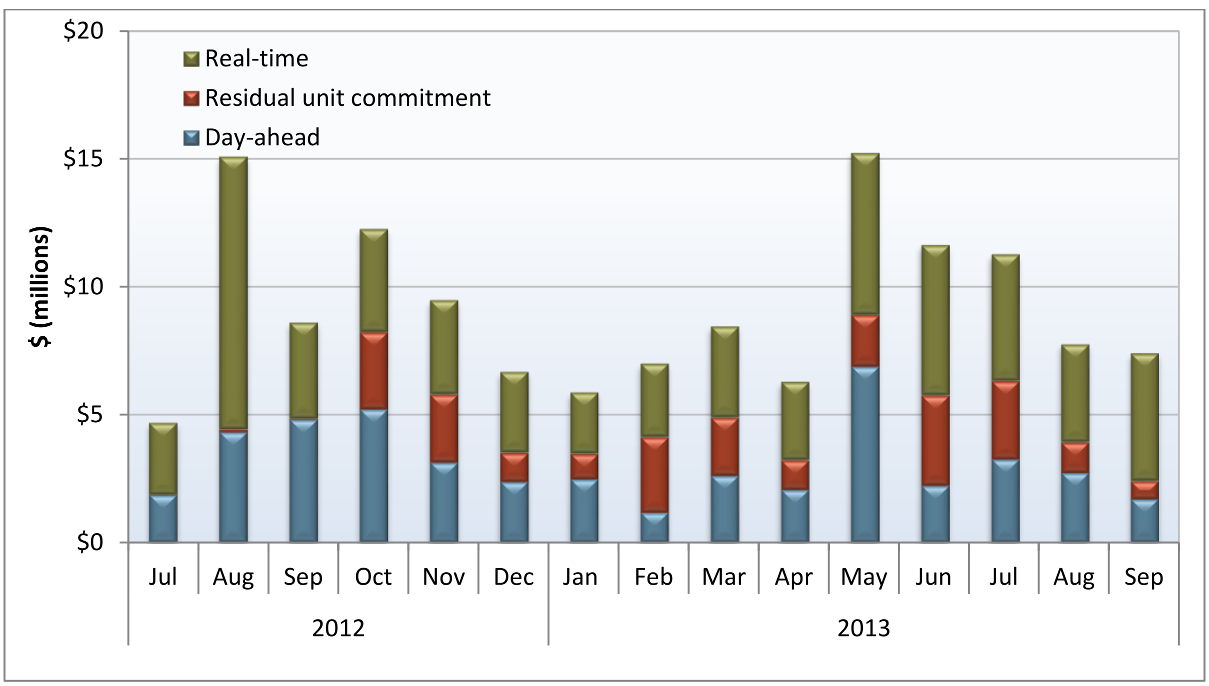
The day-ahead forecasted load versus cleared day-ahead capacity (blue bar) represents the difference in cleared supply (both physical and virtual) compared to the ISO's forecast of load. Beginning in April 2013, this has had the effect of reducing the need for additional residual unit commitment, though historically has played a larger role in residual unit commitment.

1.7 Bid cost recovery payments

Bid cost recovery payments are designed to ensure that generators receive enough market revenues to cover the cost of all their bids when dispatched by the ISO.[26] Bid cost recovery payments totaled around $26 million in the third quarter, compared to $33 million in the second quarter (see Figure 1.18 for a monthly breakdown).

The reduced use of minimum online commitments and exceptional dispatch commitments for summer testing helped lower day-ahead and real-time bid cost recovery payments compared to the second quarter. The portion of bid cost recovery resulting from residual unit commitment decreased in the third quarter, dropping to around $5 million. Bid cost recovery payments from day-ahead commitments decreased from over $11 million in the second quarter to $7.7 million in the third quarter. Around $7 million of the real-time commitment costs resulted from unit commitments through exceptional dispatch.

Figure 1.18 Monthly bid cost recovery payments



[26] Bid cost recovery covers the bids for start-up, minimum load, ancillary services, residual unit commitment availability, and day-ahead and real-time energy.

Bid cost recovery payments for residual unit commitment costs mainly resulted from increased scheduled virtual supply and operator adjustments to the residual unit commitment requirements due to load forecast and variable resource generation uncertainty. Similar to the last quarter, the net virtual position was virtual supply in the majority of hours (see Section 2.1) When the market clears net virtual supply, the residual unit commitment process will replace the virtual supply with physical resources not committed in the day-ahead market. This situation contributed to virtual bidders accounting for over 50 percent ($2.7 million) of the residual unit commitment payments in the quarter (for further detail see Section 2.2).

ISO operators have continued making adjustments to the system or regional residual unit commitment requirements to mitigate potential contingencies. These changes were concentrated in the late afternoon and early evening hours during the steep ramping period in real time. Frequently, units were committed in the residual unit commitment process to meet these system needs. However, these units were at times uneconomic in real time, requiring recovery of their bid costs.

2 Convergence bidding

Virtual bidding is a part of the Federal Energy Regulatory Commission's standard market design and is in place at all other ISOs with day-ahead energy markets. In the California ISO markets, virtual bidding is formally referred to as *convergence bidding*. The ISO implemented convergence bidding in the day-ahead market on February 1, 2011. Virtual bidding on inter-ties was temporarily suspended on November 28, 2011.[27] On May 2, 2013, FERC issued an order conditionally accepting elimination of the convergence bidding on inter-ties.[28]

When convergence bids are profitable, they may increase market efficiency by improving day-ahead unit commitment and scheduling. Convergence bidding also provides a mechanism for participants to hedge or speculate against price differences in the two following circumstances:

- price differences between the day-ahead and real-time markets; and
- congestion at different locations.

Participants engaging in convergence bidding continued to receive more money from the ISO markets than what they paid into the ISO markets in the third quarter. Total net revenues for convergence bidding positions during this quarter were around $5.5 million. Virtual supply generated net revenues of about $8.3 million, while virtual demand accounted for a loss of around $2.7 million. However, the total payment to convergence bidders is reduced to $2.9 million after taking into account virtual bidding bid cost recovery charges of around $2.7 million for the quarter.

Most of the positive revenues resulted from offsetting virtual demand and supply bids at different internal locations designed to profit from higher anticipated congestion between these locations in real-time. This type of offsetting internal bids represented over 67 percent of all accepted virtual bids in the third quarter, about the same as in the previous quarter

Trading volumes reached the highest level since April 2011. Total hourly trading volumes increased to 4,560 MW in the third quarter from 4,150 MW in the second quarter. Internal virtual supply averaged around 2,700 MW while virtual demand averaged around 1,850 MW during each hour of the quarter. Thus, the average hourly net virtual position in the third quarter was 850 MW of virtual supply, an increase from 550 MW of virtual supply in the previous quarter.

Net virtual demand within the ISO may help to increase market efficiency by increasing the efficiency of day-ahead unit commitment and scheduling, and reducing real-time prices. For the quarter, the net revenues for the net virtual demand positions were negative. Net revenues from virtual supply were positive as prices were generally higher in the day-ahead market than the real-time market, as shown in Section 1.1. Even with the high volumes of virtual supply in the third quarter, prices in the day-ahead market continued to be systematically higher than in the real-time market in July and September.

[27] See 137 FERC ¶ 61,157 (2011) accepting and temporarily suspending convergence bidding at the inter-ties subject to the outcome of a technical conference and a further commission order. More information can also be found under FERC docket number ER11-4580-000.

[28] See 143 FERC ¶ 61,157 (2013) conditionally accepting elimination of inter-tie convergence bidding. In the order, FERC indicated that the ISO should address within a year the issue of structural separation between the hour-ahead and real-time markets or explain why it has not done so before it reevaluates the efficiency of convergence bidding on inter-ties.

Background

Convergence bidding allows participants to place purely financial bids for supply or demand in the day-ahead energy market. These virtual supply and demand bids are treated similar to physical supply and demand in the day-ahead market. However, all virtual bids clearing the day-ahead market are removed from the hour-ahead and real-time markets, which are dispatched based only on physical supply and demand. Virtual bids accepted in the day-ahead market are liquidated financially in the real-time market as follows:

- Participants with virtual demand bids accepted in the day-ahead market pay the day-ahead price for this virtual demand. Virtual demand, at points within the ISO, is then paid the real-time price for these bids.
- Participants with accepted virtual supply bids are paid the day-ahead price for this virtual supply. Virtual supply, at points within the ISO, is then charged the real-time price.

Thus, virtual bidding allows participants to profit from any difference between day-ahead and real-time prices. In theory, as participants take advantage of opportunities to profit through convergence bids, this activity should tend to make prices in these different markets closer as illustrated by the following:

- If prices in the real-time market tend to be higher than day-ahead market prices, convergence bidders will seek to arbitrage this price difference by placing virtual demand bids. Virtual demand will raise load in the day-ahead market and thereby increase prices. This increase in load and prices could also lead to the commitment of additional physical generating units in the day-ahead market, which in turn could tend to reduce average real-time prices. In this scenario, virtual demand could help improve price convergence by increasing day-ahead prices and reducing real-time prices.
- If real-time market prices tend to be lower than day-ahead market prices, convergence bidders will seek to profit by placing virtual supply bids. Virtual supply will tend to lower day-ahead prices by increasing supply in the day-ahead market. This increase in virtual supply and decrease in day-ahead prices could also reduce the amount of physical supply committed and scheduled in the day-ahead market.[29] This would tend to increase average real-time prices. In this scenario, virtual supply could help improve price convergence by reducing day-ahead prices and increasing real-time prices.

The degree to which convergence bidding has actually increased market efficiency by improving unit commitment and dispatches has not been entirely assessed. However, there are settlement charges associated with virtual bidding that may provide a challenge to price convergence between the day-ahead and real-time markets.

2.1 Convergence bidding trends

As with the previous quarter, trading volume again reached the highest level since April 2011. Total hourly trading volumes increased to 4,560 MW in the third quarter from 4,150 MW in the second quarter.

[29] This will not create a reliability issue as the residual unit commitment process occurs after the integrated forward market run. The residual unit commitment process removes convergence bids and re-solves the market to the ISO forecasted load. If additional units are needed, the residual unit commitment process will commit more resources.

Figure 2.1 shows the monthly quantities of virtual demand and supply offered and cleared in the market. Figure 2.2 illustrates an hourly distribution of the offered and cleared volumes over the quarter. As shown in these figures:

- On average, 57 percent of virtual supply and demand bids offered into the market cleared in the third quarter compared to 63 percent in the previous quarter.
- Cleared volumes of virtual supply outweighed cleared virtual demand in the third quarter by around 850 MW on average. This relationship is similar to the second quarter when virtual supply outweighed virtual demand by about 550 MW.
- Similar to the previous quarter, virtual supply exceeded virtual demand during both peak and off-peak hours. Virtual supply exceeded virtual demand during peak hours by about 630 MW, and during off-peak hours by about 1,280 MW.

Figure 2.1 Monthly average virtual bids offered and cleared

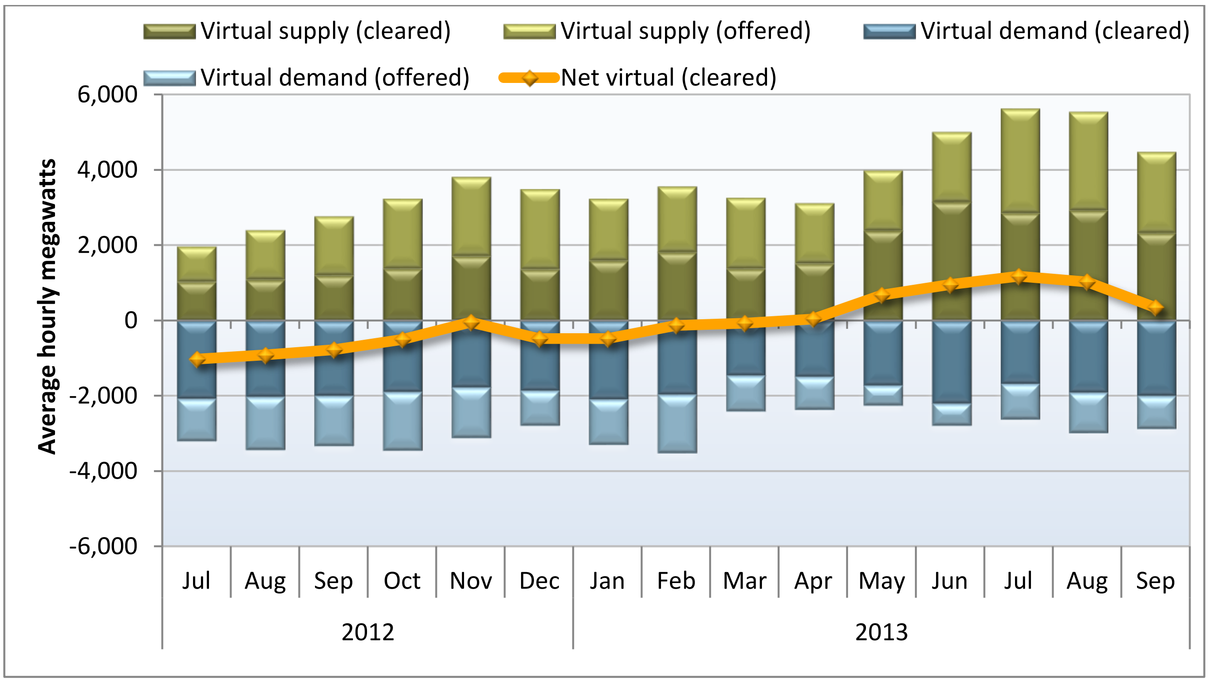
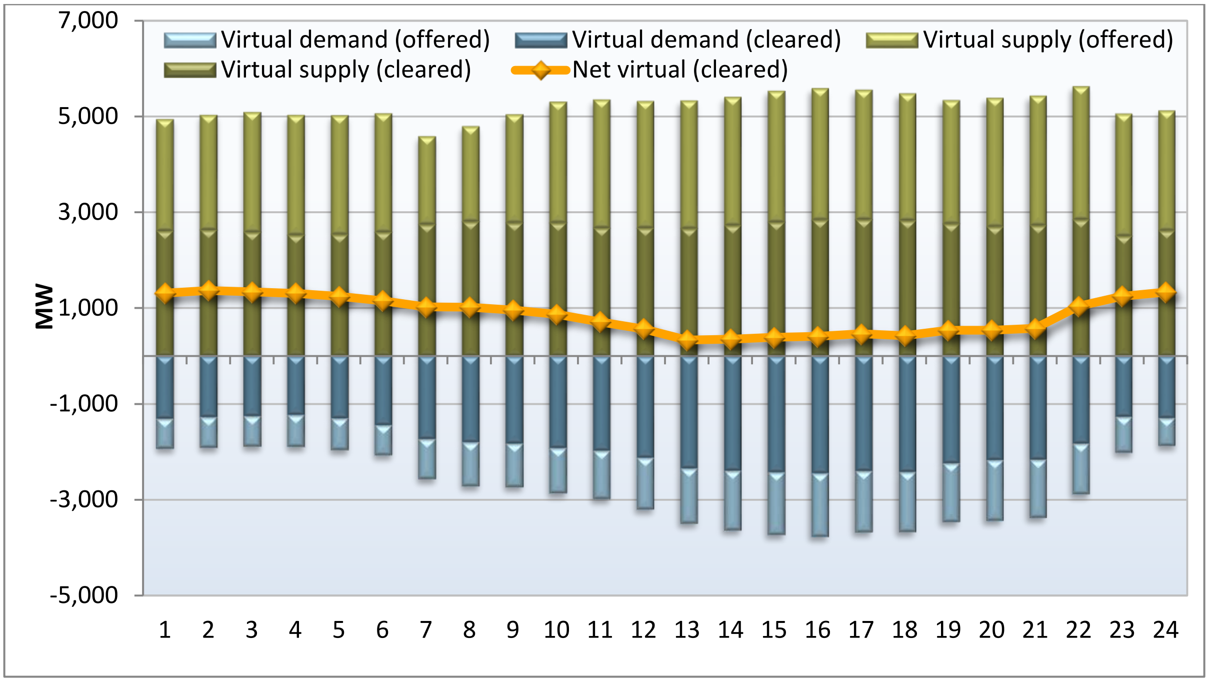


Figure 2.2 Hourly offered and cleared virtual activity (July – September)



Consistency of price differences and volumes

Convergence bidding is designed to bring together day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between the two markets. Net convergence bidding volumes were consistent in 22 hours in July. However, the August and September net convergence bidding volumes were increasingly more inconsistent with price differences between the day-ahead and real-time markets, with only 14 hours in September consistent with price differences.

Figure 2.3 compares cleared convergence bidding volumes with the volume weighted average price differences at which these virtual bids were settled. The difference between day-ahead and real-time prices shown in this figure represents the average price difference weighted by the amount of virtual bids clearing at different internal locations.

When the red line is positive, it indicates that the weighted average price charged for internal virtual demand in the day-ahead market was higher than the weighted average real-time price paid for this virtual demand. When positive, it indicates that a virtual demand strategy was not profitable and, thus, was directionally inconsistent with weighted average price differences.

The overall virtual demand volumes continued to be inconsistent with weighted average price difference for the hours in which virtual demand cleared the market in each month except for August. Wildfires, high loads and transmission outages caused extremely high real-time prices on a few days in August, which made overall virtual demand positions in August profitable.

During months when the yellow line is positive, this indicates that the weighted average price paid for internal virtual supply in the day-ahead market was higher than the weighted average real-time price charged when this virtual supply was liquidated in the real-time market. On average, virtual supply positions at internal locations has been consistently profitable since July 2012.

As noted earlier, a large portion of the internal virtual supply clearing the market was paired with internal demand bids at different internal locations by the same market participant. Such offsetting virtual supply and demand bids are likely used as a way of hedging or speculating from internal congestion within the ISO as well as avoiding bid cost recovery settlement charges.[30] When virtual supply and demand bids are paired in this way, one of these bids may be unprofitable independently, but the combined bids may break even or be profitable due to congestion.

Figure 2.3 Convergence bidding volumes and weighted price differences at internal locations

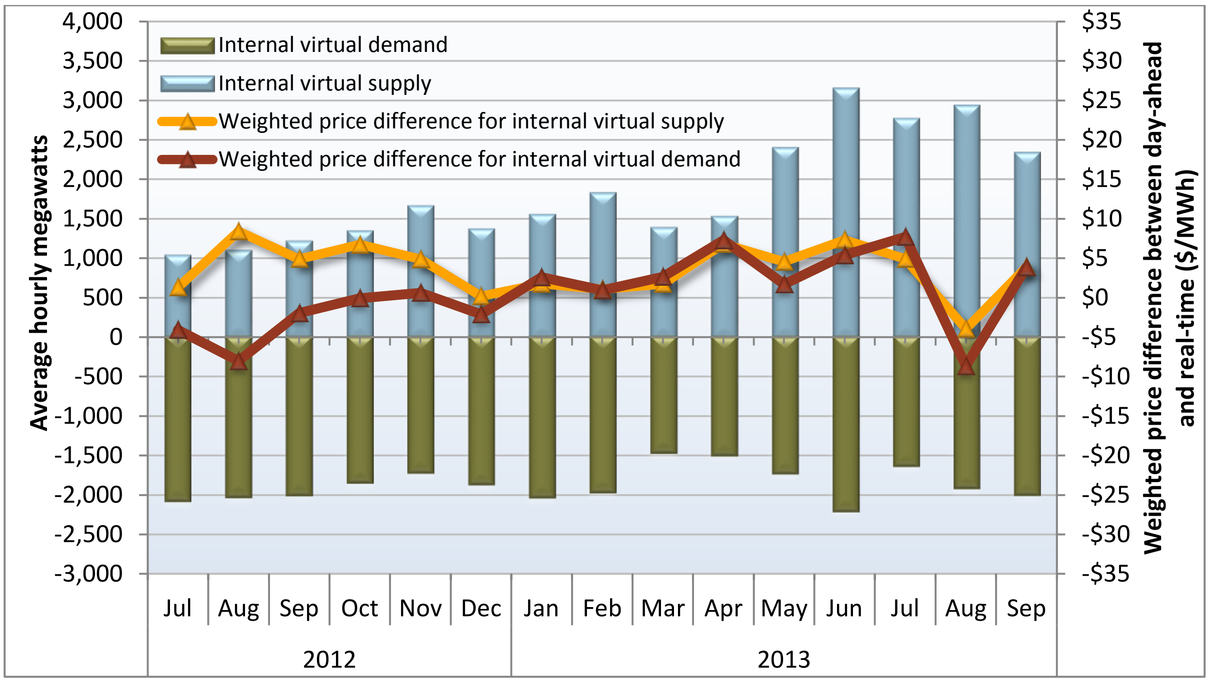


Figure 2.4, Figure 2.5 and Figure 2.6 show average hourly net cleared convergence bidding volumes compared to the difference in the day-ahead and real-time system marginal energy prices in July, August and September, respectively. The blue bars represent the net cleared internal virtual position, whereas the green line represents the difference between the day-ahead and real-time system marginal energy prices. Historically, market participants have bid virtual demand in peak hours in anticipation of real-time price spikes. Even though these spikes do not occur often, the revenues have historically outweighed losses that happened otherwise. However, the frequency of the systematic price spikes have reduced (see Section 1.2) and virtual bidding positions have shifted to being primarily virtual supply in the peak hours.

[30] Please refer to the section at the end of the chapter for detailed analysis of bid cost recovery charges to convergence bidders.

- As shown in Figure 2.4, convergence bidding volumes in July were consistent with price differences in most hours. In total, there were 22 hours where net convergence bidding volumes were consistent with day-ahead and real-time price differences.
- In August, as seen in Figure 2.5, convergence bidding volumes began to be less consistent with differences between day-ahead and real-time prices. There were 15 hours where net convergence bidding volumes were consistent with day-ahead and real-time price differences. Wildfires along with high loads and transmission outages on a few days in August caused extremely high real-time prices in the peak load hours. Since net virtual positions were virtual supply in these hours, high real-time prices caused losses from virtual supply positions.
- Figure 2.6 illustrates similar consistency for net virtual positions in September compared to August. In total, there were only 14 hours where net convergence bidding volumes were consistent with day-ahead and real-time price differences. Similar to August, inconsistencies occurred in the peak load hours.

Figure 2.4 Hourly convergence bidding volumes and prices – July

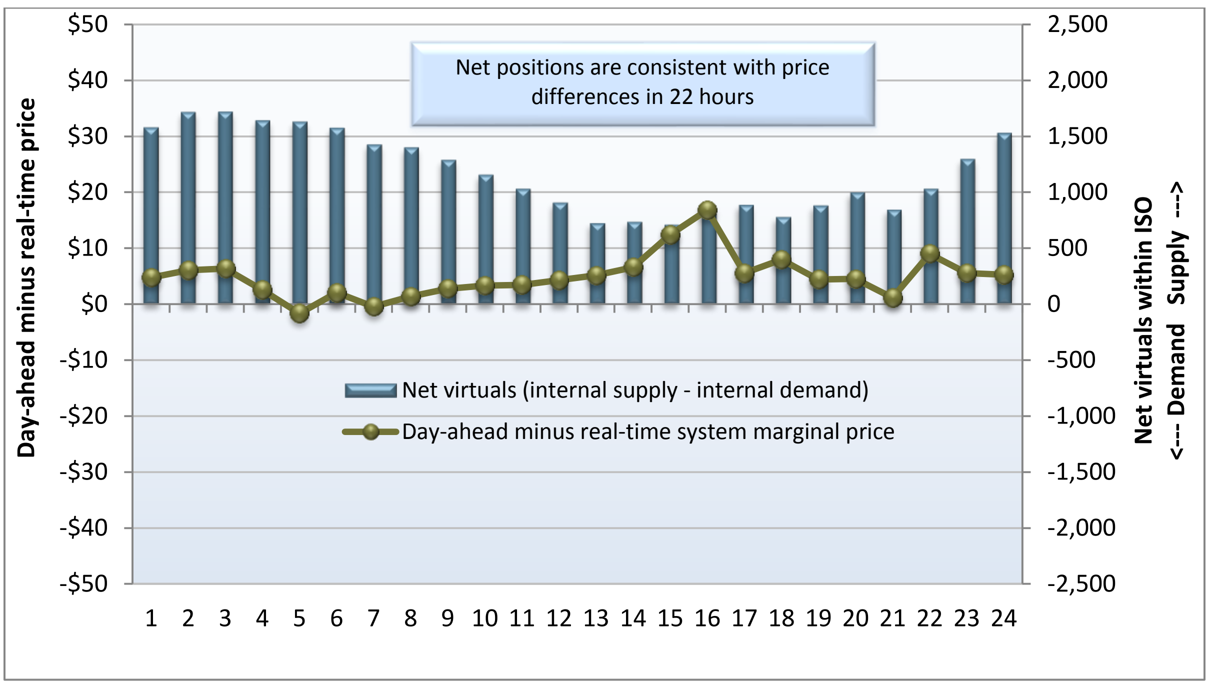


Figure 2.5 Hourly convergence bidding volumes and prices – August

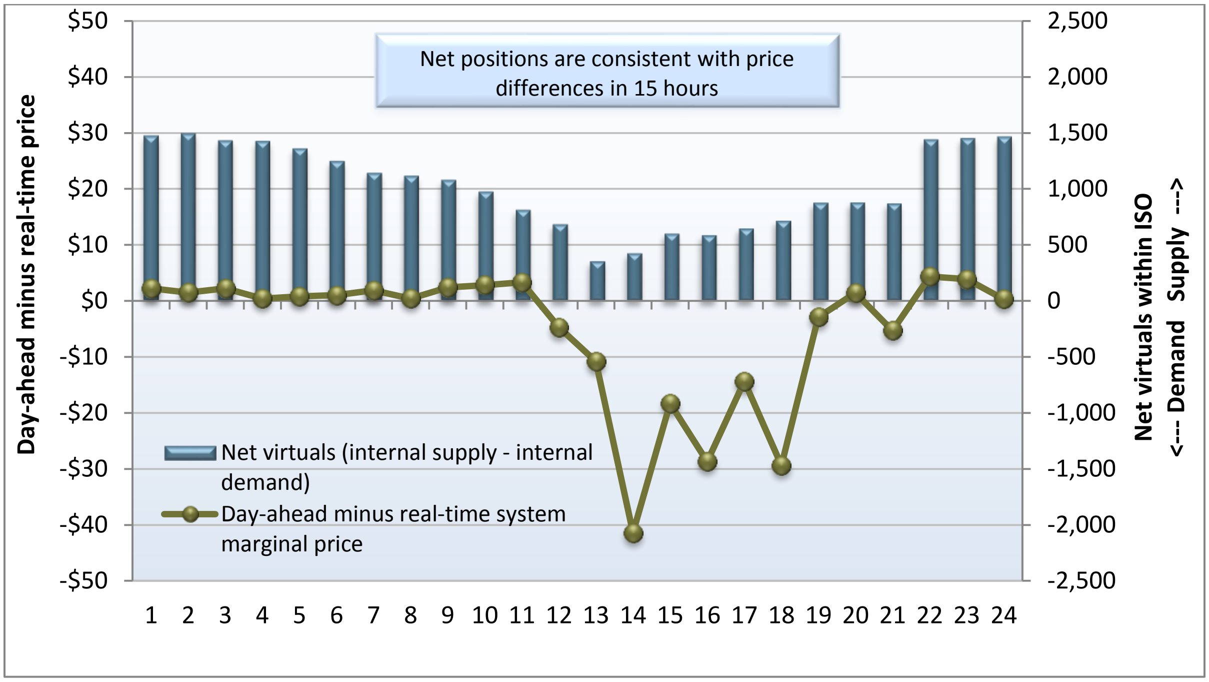
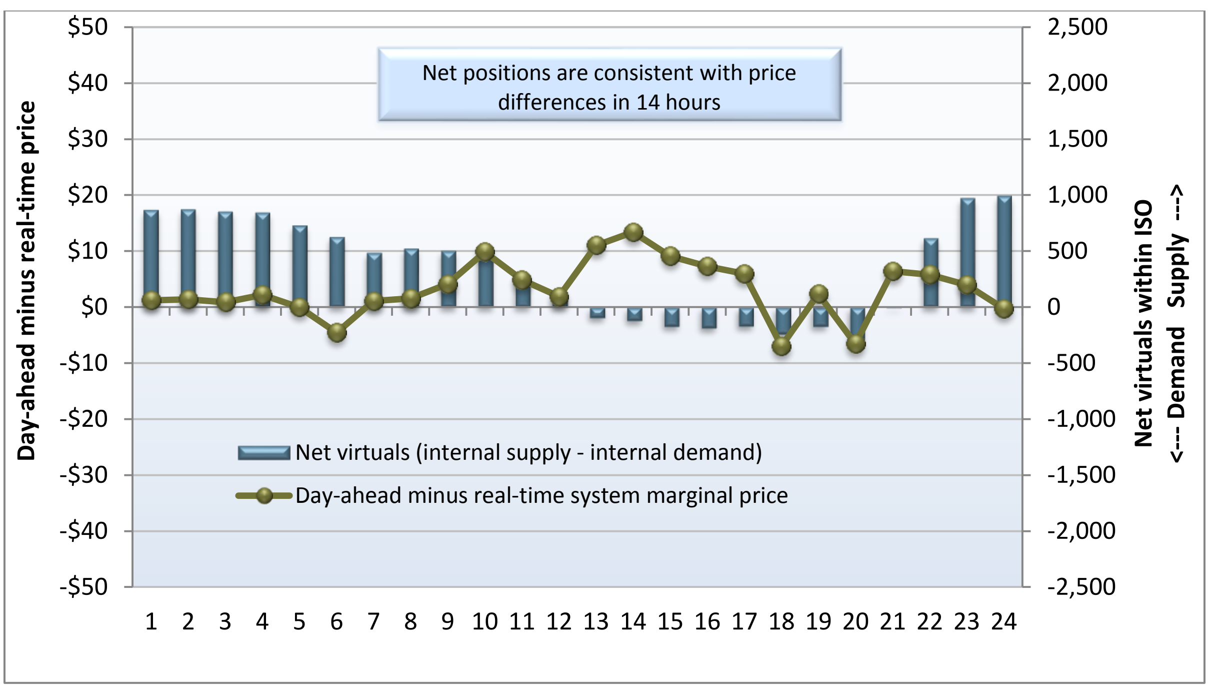


Figure 2.6 Hourly convergence bidding volumes and prices – September



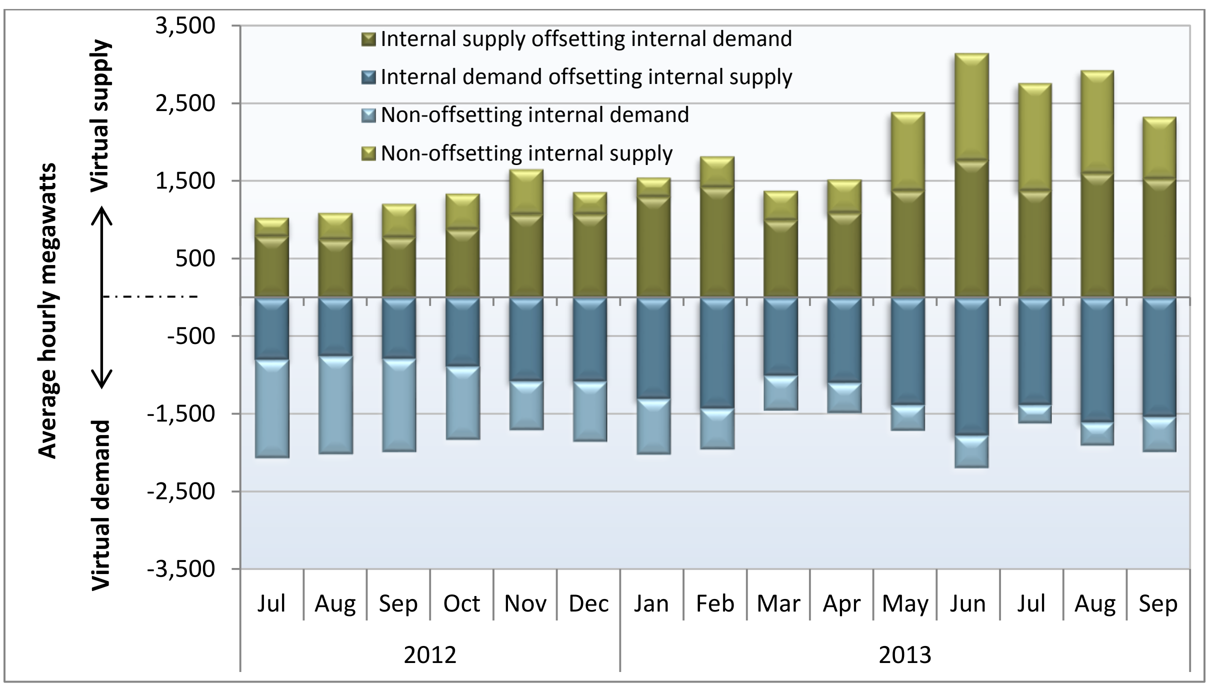
Offsetting virtual supply and demand bids at internal points

Market participants can also hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO system by placing virtual demand and supply bids at different internal locations during the same hour. These virtual demand and supply bids offset each other in terms of system energy. However, the combination of these offsetting bids can be profitable if there are differences in congestion in the day-ahead and real-time markets between these two locations.

The majority of cleared virtual bids in the third quarter were related to offsetting bids. However, the amount of non-offsetting internal supply increased dramatically since the first quarter. Figure 2.7 shows the average hourly volume of offsetting virtual supply and demand positions at internal locations. The dark blue and dark green bars represent the average hourly overlap between internal demand and internal supply by the same participants. The light green bars represent the remaining portion of internal virtual supply that was not offset by internal virtual demand by the same participants. The light blue bars represent the remaining portion of internal virtual demand that was not offset by internal virtual supply by the same participants.

As shown in Figure 2.7, offsetting virtual positions at internal locations accounted for an average of about 1,500 MW of virtual demand offset by 1,500 MW of virtual supply in each hour of the third quarter. These offsetting bids represent over 67 percent of all cleared internal virtual bids in the third quarter, about the same as in the previous quarter. This suggests that virtual bidding continues to be used to hedge or profit from internal congestion.

Figure 2.7 Average hourly offsetting virtual supply and demand positions by same participants



2.2 Convergence bidding revenues

This section highlights sources of net revenues (or payments) received (or paid) by convergence bidders. As with the previous quarter, participants engaged in convergence bidding received more money from the ISO markets than what they paid into the ISO markets in the third quarter. This resulted in positive net revenues of about $5.5 million, with most of the positive revenues associated with virtual supply bids.

Figure 2.8 Total monthly net revenues paid from convergence bidding

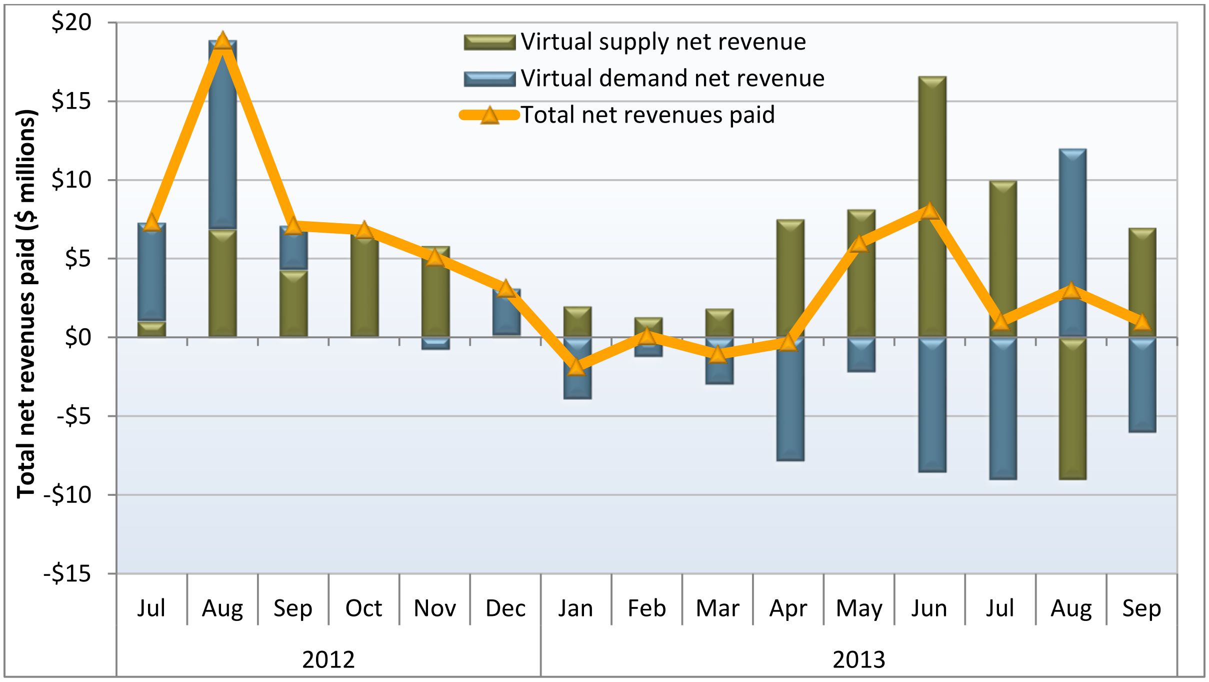


Figure 2.8 shows total monthly net revenues for cleared virtual supply and demand. This figure shows the following:

- Virtual supply revenues were profitable in every month except for August where real-time prices were extremely high on a few days. Virtual supply revenues can be attributed to day-ahead prices being generally higher than real-time prices.
- Virtual demand was profitable only in August. In total, virtual demand accounted for approximately $2.7 million in net payments to the ISO markets.
- Although trading volume reached the highest level since April 2011, total net revenues paid to virtual bidders decreased significantly from the previous quarter. This change was driven by losses on both virtual supply and demand positions.
- In the third quarter, convergence bidders were paid close to $2.9 million, after taking into account virtual bid cost recovery charges of around $2.7 million for the quarter. The net revenues from the market were about $5.5 million in this quarter, compared to about $14 million in the previous quarter. Virtual supply generated net revenues of about $8.3 million, while virtual demand accounted for a loss of around $2.7 million.

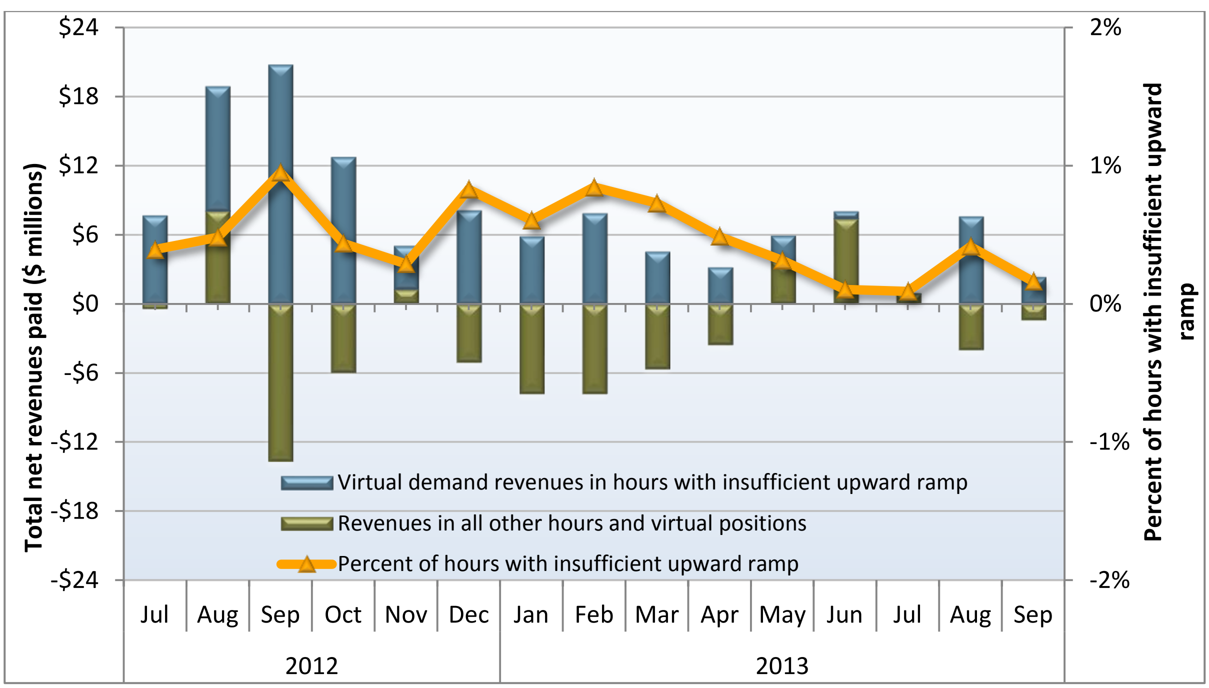
Net revenues at internal scheduling points

In the third quarter, the cleared share of virtual demand accounted for about 66 percent of bid-in virtual demand at internal locations, down from 73 percent in the previous quarter. Virtual demand bids at internal nodes are profitable when real-time prices spike in the 5-minute real-time market. Almost all net revenues paid for these internal virtual demand positions have resulted from a relatively small portion of intervals when the system power balance constraint becomes binding because of insufficient upward ramping capacity or with congestion. Virtual supply bids are profitable when real-time prices drop below day-ahead prices. Historically, this has happened during off-peak hours when over-generation can drive the real-time prices down.

Figure 2.9 compares total net revenues paid out for internal virtual bids during hours when the power balance constraint was relaxed because of short-term shortages of upward ramping capacity with the overall net revenues of internal virtual bids during all other hours. As shown in Figure 2.9:

- Although upward ramping capacity was insufficient in under 0.5 percent of the hours in the quarter, these hours accounted for all net revenues paid for internal virtual demand. Revenues paid for virtual demand during these brief but extreme price spikes can be high enough to outweigh losses when the day-ahead price exceeds the real-time market price. However, as with the first two quarters, third quarter revenues paid out during these periods were not sufficient to offset virtual demand losses in other periods.
- Total net revenues were around $5.5 million. Virtual demand net revenues were around $10 million during intervals of insufficient upward ramp. Virtual revenues in all other intervals were around $4.5 million losses, driven by positive revenues of about $8.3 million in virtual supply and negative revenues of $13 million in virtual demand in the third quarter.

Figure 2.9 Net revenues paid for convergence bids at internal scheduling points during hours with energy power balance constraint relaxations due to shortages of upward ramping



Real-time price spikes are typically associated with brief shortages of ramping capacity. Virtual demand at internal scheduling points can potentially result in additional capacity being committed and available in the real-time market. In practice, however, the impact of internal virtual demand on real-time price spikes appears to have been limited by a number of factors:

- As discussed in prior sections of this chapter, the impact of virtual internal demand in the day-ahead market was offset significantly by virtual supply.
- Any additional capacity potentially made available by convergence bidding may not be enough to address the short-term ramping limitations in the real-time market.

Also, in the event of over-generation, real-time prices can be negative, but rarely fall below the bid floor of -$30/MWh. This diminishes the risk of market participants losing substantial money by bidding virtual demand as well as reduces the potential benefits to virtual supply bids at internal nodes.

Net revenues and volumes by participant type

DMM's analysis finds that most convergence bidding activity is conducted by entities engaging in pure financial trading that do not serve load or transact physical supply. These entities accounted for $4.7 million (58 percent) of the total convergence bidding settlements and a vast majority of both gains and losses in the third quarter.

Table 2.1 compares the distribution of convergence bidding volumes and revenues among different groups of convergence bidding participants. The trading volumes show cleared virtual positions along with the corresponding net revenues in millions of dollars.

DMM has defined financial entities as speculators who own no physical power and participate in only the convergence bidding and congestion revenue rights markets. Physical generation and load are represented by participants that primarily participate in the ISO markets as physical generators and load-serving entities, respectively. Marketers include participants on the inter-ties and participants whose portfolios are not primarily focused on physical or financial participation in the ISO market.

As shown in Table 2.1, financial participants represent the largest segment of the virtual market, accounting for about 74 percent of volumes and about 58 percent of settlement dollars. Marketers represent about 12 percent of the trading volumes and 16 percent of the settlement dollars. Generation owners and load-serving entities represent a small segment of the virtual market in terms of volumes (about 14 percent); however, they have around 26 percent of settlements. Physical participant positions in aggregate were profitable due to revenues from both virtual supply and demand positions.

Table 2.1 Convergence bidding volumes and revenues by participant type (July – September)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	397	440	837	-$1.7	$6.8	$4.7
Marketer	48	91	138	-$1.4	$0.1	-$1.3
Physical generation	13	72	85	$0.6	$0.4	$1.1
Physical load	1	68	69	-$0.1	$1.2	$1.1
Total	**459**	**671**	**1,130**	**-$2.7**	**$8.5**	**$5.5**

Virtual bid cost recovery charges

As previously noted, virtual supply and demand bids are treated similar to physical supply and demand in the day-ahead market. However, virtual bids are excluded from the day-ahead market processes for price mitigation and grid reliability (local market power mitigation and residual unit commitment). This impacts how physical supply is committed in both the integrated forward market and in the residual unit commitment process.[31] When the ISO commits units, it may pay market participants through the bid cost recovery mechanism to ensure that market participants are able to recover start-up costs, minimum load costs, transition costs, and energy bid costs.[32]

Since virtual bids can influence unit commitment, they share in the associated costs with physical resources. Specifically, virtual bids can be charged for bid cost recovery payments in two charge codes.[33]

- Integrated forward market bid cost recovery tier 1 allocation[34] addresses costs associated with situations when the market clears with positive net virtual demand. In this case, virtual demand leads to increased unit commitment in the day-ahead market, which may not be economic.
- Day-ahead residual unit commitment tier 1 allocation[35] relates to situations where the day-ahead market clears with positive net virtual supply. In this case, virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in the residual unit commitment, which may not be economic.

As shown in Figure 2.10, the day-ahead residual unit commitment tier 1 allocation charge associated with virtual bids was highest throughout the summer months, reaching a peak of nearly 16 percent of total bid cost recovery charges in June. However, the percent decreased in September, falling to around

[31] If physical generation resources clearing the day-ahead energy market are less than the ISO's forecasted demand, the residual unit commitment process ensures that enough additional physical capacity is available to meet the forecasted demand. Convergence bidding increases unit commitment requirements to ensure sufficient generation in real time when the net position is virtual supply. The opposite is true when virtual demand exceeds virtual supply.

[32] Generating units, pumped-storage units, or resource-specific system resources are eligible for receiving bid cost recovery payments.

[33] Both charge codes are calculated by hour and charged on a daily basis.

[34] Total integrated forward market (IFM) load and convergence bidding entities with a net virtual demand position may be charged an IFM Tier 1 uplift charge. This is triggered when the system-wide virtual demand is positive. Market participants with portfolios that clear with positive net virtual demand are charged. Market participants will not be charged if physical demand plus virtual demand minus virtual supply is equal to or less than measured demand. Specifically, the uplift obligation for virtual demand is based on how much additional unit commitment was driven by net virtual demand that resulted in the integrated forward market clearing above what was needed to satisfy measured demand. Physical load and virtual demand pay the same IFM uplift rate. The rate is calculated on an hourly basis and charged daily. For further detail, see Business Practice Manual configuration guides for charge code (CC) 6636, IFM Bid Cost Recovery Tier1 Allocation_5.1a: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

[35] There are two payments associated with the day-ahead residual unit commitment. One is the residual unit commitment availability payment at the residual unit commitment price, and the other is residual unit commitment bid cost recovery. During the day-ahead market, if the scheduled demand is less than the forecast, residual unit commitment availability is procured to ensure that enough committed capacity is available and online to meet the forecasted demand. Awarded capacity is paid at the residual price. The residual unit commitment bid cost recovery uplift obligation is allocated when system-wide net virtual supply is positive. The virtual supply obligation to pay a residual unit commitment bid cost recovery tier 1 uplift is based on the pro-rata share of the total obligation as determined by market participants' total net virtual supply awards. Allocation of residual unit commitment compensation costs is calculated by hour and charged by the day. For further detail, see Business Practice Manual configuration guides for charge code (CC) 6806, Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocation_5.5: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

four percent. This is consistent with the decreases in net virtual supply volumes in September (see Figure 2.1). The integrated forward market bid cost recovery costs associated with net virtual demand were highest in the third quarter of 2012 when the market was significantly net virtual demand.

Figure 2.11 shows estimated total convergence bidding revenues, total revenues less bid cost recovery charges and costs associated with the two bid cost recovery charge codes. The total convergence bidding bid cost recovery costs for the third quarter were close to $2.7 million. As noted earlier, the total estimated net revenue for convergence bidding was around $5.5 million. Combined with the convergence bidding bid cost recovery costs, the total adjusted revenue from convergence bidders was around $2.9 million.

Figure 2.10 Convergence bidding costs associated with bid cost recovery tier 1 and residual unit commitment tier 1 as a percent of total bid cost recovery

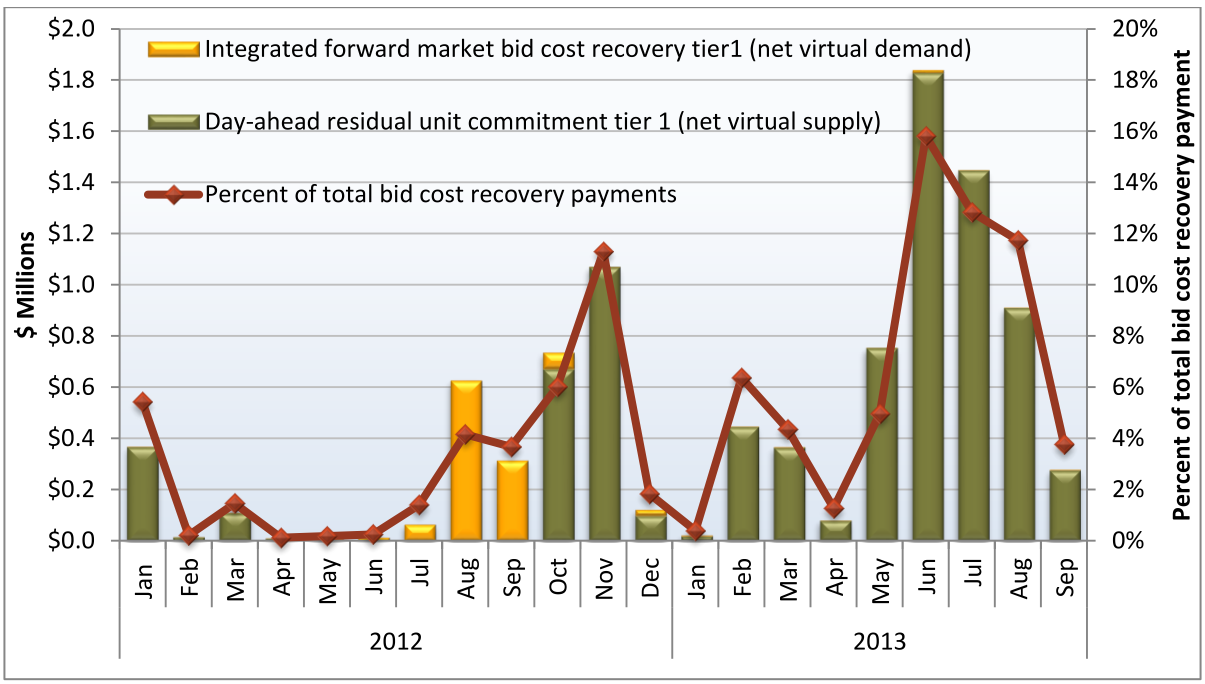
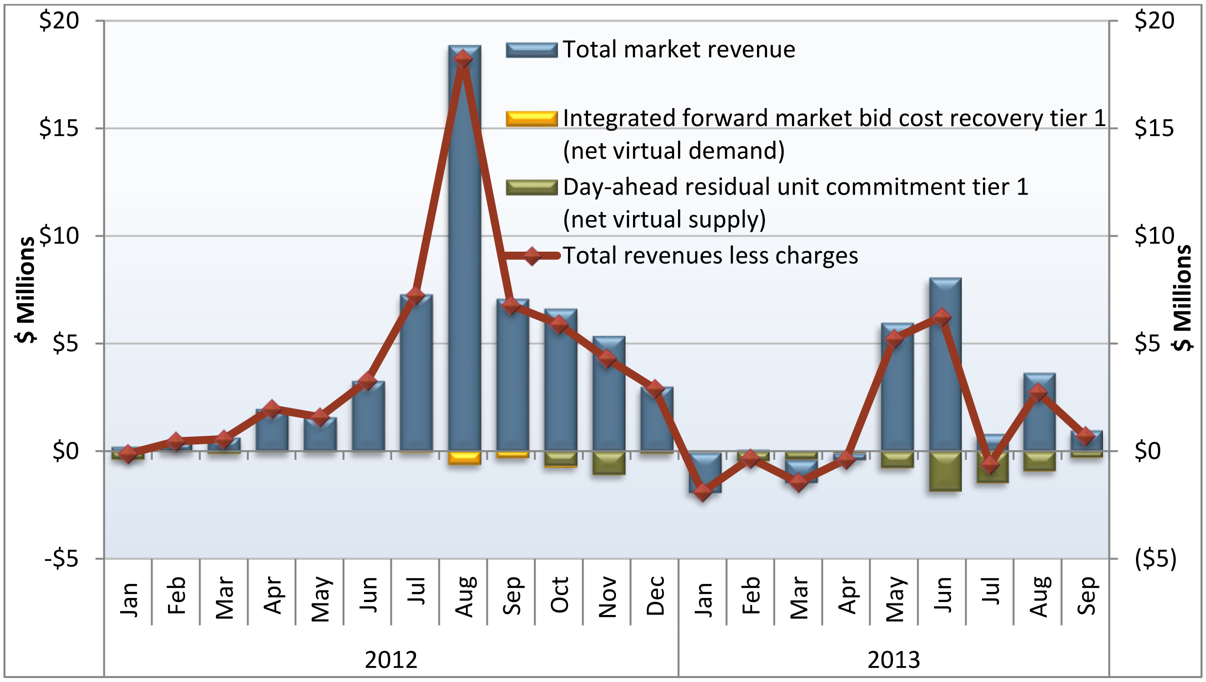


Figure 2.11 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and residual unit commitment tier 1



3 Special Issues

3.1 Market performance during heat waves, wildfires and other events

The ISO market experienced a system-wide heat wave between June 27 and July 3. The ISO systems and markets performed well under stressed conditions.

There were also two wildfires which impacted the ISO grid. The Rim Fire, one of the largest in California history, started on August 17 and lasted for weeks but had only a minimal impact on grid operations. The Spring Peak Fire impacted the grid on August 18 and 19 and caused outages on some transmission lines, specifically impacting the Pacific DC Intertie (Path 65). This occurred in conjunction with high loads and resulted in multiple periods of high real-time prices on these two days.

On September 17, the ISO experienced software issues that affected the real-time market during implementation of the ISO's new network model, which incorporated additions and modifications of new transmission. These software issues resulted in price corrections for numerous real-time intervals on September 17 and 18.

Summer heat wave: June 27 through July 3

Peak loads from June 27 through July 3 were above 40,000 MW, reaching the annual peak for 2013 at 45,058 megawatts on July 1.[36] As a preliminary precaution, the ISO issued Flex Alerts for Northern California on July 1 and July 2.[37] The ISO also implemented its Restricted Maintenance Operations procedure, where market participants are cautioned to avoid actions that may jeopardize generator or transmission availability.[38]

During the heat wave, day-ahead market prices averaged around $59/MWh and real-time prices averaged around $41/MWh. In contrast to heat waves in previous years, the real-time market did not experience any significant price spikes around $1,000/MWh and prices reached around $500/MWh in only a few intervals. However, the real-time market experienced negative prices in several intervals in the early morning. Commitments to meet peak load in the morning ramping hours contributed to the negative prices in the early morning hours.

Overall, the reason for the lower real-time market prices can be attributed to lower actual load in the real-time market compared to forecasted load in the day-ahead market. For instance, peak loads were considerably less than forecast due to a number of contributing factors including cloud cover that reduced the intense heat in the south and on the coast, lower than anticipated temperatures, utility-

[36] The ISO's 1-in-2 year forecast for 2013 was 47,413 MW.

[37] A Flex Alert is an urgent call to consumers to immediately conserve electricity in the peak hours and shift demand to the hours typically after 6:00 p.m. Flex Alerts are based on the ISO's load forecast and its assessment of potential contingencies, and ideally they are issued a day in advance to give consumers an early notice to take action. For more information see http://www.flexalert.org/what-is-flex-alert#success.

[38] The Restricted Maintenance Operations procedure is a part of operating procedure 4420 - System Emergency. The procedure requires participating transmission owners, scheduling coordinators and generators obtain permission from the ISO to go ahead with pre-scheduled or planned work, regardless of whether prior approvals were obtained from the ISO. Details of operating procedure 4420 can be found at http://www.caiso.com/Documents/4420.pdf.

initiated demand response programs, and the Flex Alert in Northern California.[39] Furthermore, day-ahead load was increased by virtual demand positions anticipating tight supply and demand conditions in real time. Accordingly, the real-time market did not face any significant ramping or supply issues and, as a result, there were only a few price surges in the real-time market.

Overall, the hour-ahead market did not have significant issues during the heat wave period, with the exception of June 28. On this day, temperatures and loads throughout the west were extremely high. During the mid-day and afternoon hours, some of the inter-tie imports into the ISO system declined their hour-ahead energy schedules. The decline amounts reached up to 1,000 MW. This created reliability concerns given the large unanticipated decrease in imports and tight overall supply conditions throughout the west. As a result, ISO operators made manual adjustments to the load levels in the hour-ahead market to prevent potential reliability problems from occurring in real time. These adjustments reached up to almost 3,000 MW in hour ending 16.

These load adjustments exacerbated hour-ahead congestion in Northern California. For instance, hour-ahead prices in the PG&E area ranged between $2,000/MWh and $4,000/MWh for several intervals from hour ending 13 through hour ending 17, reaching above $5,000/MWh in a few intervals. During this period, prices in the other areas increased up to $700/MWh.

August wildfires

Two wildfires in August affected ISO operations. The first one was the Rim Fire which started on August 17. Although it was the third largest wildfire in California history and continued for several weeks, it had minimal overall impact on grid operations.[40] The Spring Peak Fire affected the grid on August 18 and 19, and caused the loss of one of the major interfaces from the Northwest, the Pacific DC Intertie (Path 65). This transmission line outage, along with high loads, resulted in sustained real-time price spikes in all ISO areas for almost two hours on August 18. Average real-time prices were around $107/MWh and $83/MWh on August 18 and 19, respectively. The maximum real-time prices were around $900/MWh on the 18th and around $550/MWh on the 19th.

Software issues during model implementation

The ISO experienced software issues that impacted the real-time market for September 17 and 18. The issues were related to implementation of the new network model for the September 19 release date. During the transition to this new model, a software issue caused incorrect mapping of market data which resulted in invalid market results. These issues affected the real-time market from hour ending 21 on September 17 through hour ending 5 on September 18 and hour ending 21 through 24 on September 18. Prices for the real-time market were corrected by the ISO price validation team. The ISO resolved the software issues for the day-ahead market results prior to publication for these trade dates.

[39] The utilities estimated a decrease of around 400 MW in load on average during the afternoon peak hours as a result of demand response programs during this period.

[40] Although there were concerns of the potential for significant issues, the fire did not have an immediate or lasting negative impact on the Hetch Hetchy electric or water supply for San Francisco.

3.2 California greenhouse gas allowance market

Generating resources became subject to California's greenhouse gas cap-and-trade program compliance requirements starting on January 1, 2013. This section highlights the impact of these requirements in the first three quarters of 2013. These highlights include the following:

- The cost of greenhouse gas emissions permits fell in the third quarter to an average of \$13.27/mtCO_2e and ended the quarter at slightly over \$12.00/mtCO_2e. This is down from the first and second quarter prices, which averaged \$14.55/mtCO_2e and \$14.59/MtCO_2e, respectively.[41]
- The total amount of import megawatts offered to the market decreased by 6 percent for the third quarter in 2013 compared to the third quarter of 2012. This follows increases in the first half of the year where the total amount of import megawatts offered to the market increased for each month in 2013 compared to the first half of 2012. The third quarter 2013 imports offered in the market are higher than in the third quarters of 2011 and 2010, and represent a small decrease in import offers historically.
- Based on statistical analysis of changes in day-ahead market energy prices following cap-and-trade implementation, DMM estimates that average wholesale prices are about \$5.50/MWh higher due to cap-and-trade compliance costs for year-to-date. This is consistent with the emissions costs for gas units typically setting prices in the ISO market.

Background

California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, directs the California Air Resources Board (CARB) to develop regulation to reduce greenhouse gas emissions to 1990 levels by 2020. The cap-and-trade program is one of a suite of regulatory measures adopted by CARB to achieve this goal.

The cap-and-trade program covers major sources of greenhouse gas emissions including power plants.[42] The program includes an enforceable emissions cap that will decline over time. California will directly distribute and auction allowances, which are tradable permits equal to the emissions allowed under the cap.

The impact of higher wholesale prices on retail electric rates will depend on policies adopted by the CPUC and other state entities. As part of the cap-and-trade program, the CARB allocated allowances to the state's electric distribution utilities to help compensate electricity customers for the costs that will be incurred under cap and trade. The investor-owned electric utilities are required to sell all of their allowances at CARB's quarterly auctions, and the proceeds from the auction are to be used for the

[41] mtCO_2e stands for metric tons of carbon dioxide equivalent, a standard emissions measurement.

[42] The cap-and-trade program covers major sources of greenhouse gas emissions in California such as refineries, power plants, industrial facilities, and transportation fuels. For the electricity sector, the covered entity is the first deliverer of electricity. The first deliverer is defined in the regulation as the operator of an in-state electricity generator, or an electricity importer. The compliance obligation for first deliverers is based on the emissions that are a result of the electricity they place on the grid. The threshold for inclusion in the program for electricity generated from an in-state facility, and for imported electricity from a specified source, is 25,000 metric tons of annual greenhouse gas emissions. For imported electricity from unspecified sources, there is no threshold and all emissions are covered.

benefit of retail ratepayers, consistent with the goals of AB 32. Under a 2012 CPUC decision, revenue from carbon emission allowances sold at auction will be used to offset impacts on retail costs.[43]

One allowance represents one metric ton of CO_2e. Sources under the cap are required to surrender allowances and offsets equal to their emissions at the end of each compliance period, with a partial annual surrender in the interim years. Imports from unspecified sources and electric generation resources emitting more than 25,000 metric tons of greenhouse gas annually, either within California or as imports into California, are covered under the first phase of the cap-and-trade program, which started on January 1, 2012, with enforceable compliance obligations beginning with emissions during 2013.

AB 32 requires CARB to minimize *leakage*, which is a reduction in greenhouse gas emissions within California that is offset by an increase in greenhouse gas emissions outside of California. The cap-and-trade program limits leakage in part by prohibiting *resource shuffling*, or substituting imports of lower gas emitting resources for imports actually sourced from higher emitting resources to avoid the cost of allowances. Proposed cap-and-trade regulation changes that incorporate resource shuffling definitions into the regulation and clarify resource shuffling safe harbors were released in draft form in July and presented to CARB's board for public comment and consideration on October 25.[44] The proposed rule changes would also permanently eliminate a temporarily waived requirement that market participants attest each year that they have not engaged in resource shuffling.[45]

Generators and importers that are covered by the regulations are required to submit allowances covering 30 percent of emissions in each year and the remainder of their emissions in the final year of each three year compliance period. In addition to allowances, covered generators and importers may submit emissions offsets to cover up to 8 percent of their emissions.[46] The total cap on emissions is set to decline 2 percent annually through 2014 and then about 3 percent annually through 2020.

Allowances are available at quarterly auctions held by the Air Resources Board and may also be traded bilaterally. In addition, financial derivatives based on allowance prices are traded on public exchanges such as the InterContinental Exchange (ICE). Allowances are associated with a specific year, which is known as the *vintage*. Allowances are *bankable*, meaning that an allowance may be submitted for compliance in years subsequent to the vintage of the allowance.[47] *Borrowing* of allowances is not

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[43] Pursuant to CPUC decision Docket #R.11-03-012, the investor-owned utilities will distribute this revenue to emissions-intensive and trade-exposed businesses, to small businesses, and to residential ratepayers to mitigate carbon costs. Remaining revenues will be given to residential customers as an equal semi-annual bill credit. See http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M039/K594/39594673.PDF.

[44] The proposed regulation changes are posted here: http://www.arb.ca.gov/cc/capandtrade/meetings/071813/ct_reg_2013_discussion_draft.pdf. A presentation describing the proposed cap-and-trade program regulation changes is available here: http://www.arb.ca.gov/cc/capandtrade/meetings/071813/workshoppresentation.pdf. The draft resolution presented at the October 25 CARB board meeting is available here: http://www.arb.ca.gov/cc/capandtrade/oct-25-drft-brd-res.pdf. Also, see CARB Regulatory Guidance document: *What is Resource Shuffling*, dated November 2012: http://www.arb.ca.gov/cc/capandtrade/guidance/appendix_a.pdf.

[45] See proposed regulation cited above and the letter from the CARB Chairman Mary Nichols to Commissioner Moeller of the Federal Energy Regulatory Commission dated August 16, 2012: http://www.arb.ca.gov/newsrel/images/2012/response.pdf.

[46] The first offsets were issued in September: http://www.arb.ca.gov/newsrel/newsrelease.php?id=504.

[47] For example, a vintage 2013 allowance may be used for compliance during either the first (2013-2014), second (2015-2017), or third (2018-2020) compliance periods.

allowed, meaning that permits for future years cannot satisfy compliance requirements in an earlier year.[48]

The cap-and-trade program affects wholesale electricity market prices in two ways. First, market participants covered by the program will presumably increase bids to account for the incremental cost of greenhouse gas allowances. Second, the ISO amended its tariff, effective January 1, 2013, to include greenhouse gas compliance cost in the calculation of each of the following:

- Resource commitment costs (start-up and minimum load costs);
- Default energy bids, which are bids used in the automated local market power mitigation process; and
- Generated bids (bids generated on behalf of resource adequacy resources and as otherwise specified in the ISO tariff).[49]

The ISO uses a calculated greenhouse gas allowance index price as a daily measure of the cost of greenhouse gas allowances. The ISO greenhouse gas allowance price is calculated as the average of two market based indices.[50] Daily values of the ISO greenhouse gas allowance index are plotted in Figure 3.1. In the third quarter, allowance costs fell to an average \$13.27/mtCO_2e, ending the quarter at only slightly over \$12.00/mtCO_2e.

[48] The proposed cap-and-trade regulation changes add an exception to allow limited borrowing for *true-up* allowances, allowances allocated for production changes or allowance allocation not properly accounted for in prior allocations. http://www.arb.ca.gov/cc/capandtrade/meetings/071813/ct_reg_2013_discussion_draft.pdf.

[49] Details on each of the calculations may be found in the ISO Business Practice Manual for Market Instruments, Appendix K: http://bpmcm.caiso.com/BPM Document Library/Market Instruments/BPM_for_Market_Instruments_v26_clean.doc.

[50] The indices are ICE and ARGUS Air Daily. As the ISO noted in a market notice issued on May 8, the ICE index is a settlement price but the ARGUS price was updated from a settlement price to a volume weighted price in mid-April of this year. For more information, see the ISO notice: http://www.caiso.com/Documents/GreenhouseGasAllowancePriceSourcesRevisedMay8_2013.htm.

Figure 3.1 ISO's greenhouse gas allowance price index

Effects in import levels and participation

Nearly 30 percent of ISO load was served by imports from outside the ISO system in 2012, with most of these imports coming from outside California.[51] Prior to the implementation of the cap-and-trade program, stakeholders and regulators were concerned that certain rules related to resource shuffling would result in reduced imports into California as some participants would elect to no longer import.[52] Ultimately, while the mix of participants that import power into California has changed slightly in 2013, the levels of imports have increased in the first nine months of 2013, compared to the same period in 2012.[53] However, in the third quarter, the total amount of import megawatts offered to the market decreased by 6 percent compared to the same period in 2012.

Figure 3.2 shows the amount of megawatts bid in at inter-ties and cleared in the day-ahead market in the first three quarters of 2012 and 2013.[54] Percentages in the boxes in Figure 3.2 highlight the percentage change in total volume of import bids offered each month in 2013 compared to the same month in 2012. In the first half, the total amount of import megawatts offered to the market increased for each month in 2013 compared to the first half of 2012. Import megawatts offered increased by

[51] See the DMM *2012 Annual Report on Market Issues and Performance*, Section 1.2 on supply conditions: http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf.

[52] See the August 6 letter from FERC Commissioner Moeller to Governor Brown: http://www.ferc.gov/about/com-mem/moeller/moeller-08-06-12.pdf.

[53] There were a small number of participants, specifically, public entities, and their associated imports into California, which explicitly stopped importing as a result of the program. However, new market entrants have begun to import into California and include a mix of public entities and private companies. In total, the new entrant imports exceeded the quantity of megawatts that were associated with the participants that are no longer importing into California.

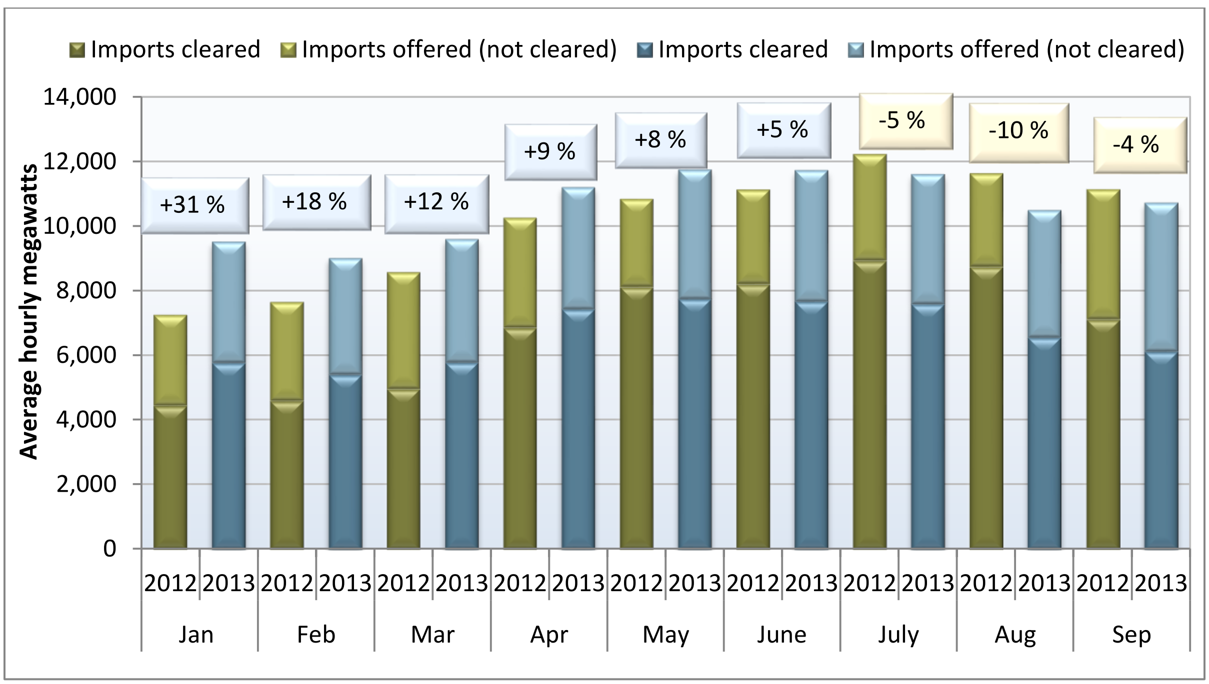
[54] This analysis excludes imports from dynamic system units and wheels.

around 13 percent in the first six months of 2013 compared to the same period in 2012. However, in the third quarter, the total amount of import megawatts offered to the market decreased for each month in 2013 compared to the third quarter of 2012.

In the third quarter, imports offered decreased by 6 percent compared to the same period in 2012, but remain higher than imports offered in the third quarters of 2011 and 2010. DMM does not attribute the drop in third quarter 2013 offered imports to the cap-and-trade program as there are many other potential factors driving this change. While DMM does not have detailed information with respect to supply and demand conditions outside of the ISO, DMM is aware that hydro-electric generation in the Pacific Northwest was lower in 2013 compared to 2012 and could help explain part of this change.

As shown by the darker bars in Figure 3.3, the volume of import bids that cleared the market increased in the first four months of 2013 compared to 2012 and decreased in the remaining five months. In the third quarter of 2013, import megawatts cleared in the market decreased by around 18 percent compared to the third quarter of 2012. This change is likely to be affected by relative price differences between prices inside and outside of California. DMM observed that bilateral prices at the Mid-Columbia and Palo Verde hubs were much closer to California hub prices in July and August than during other parts of the year and could potentially explain part of the change in cleared imports.

Figure 3.2 Inter-tie imports offered and cleared in the day-ahead market[55]



In the third quarter, the decreases in offered and cleared import megawatts are slightly larger coming from the north. This may be due to several factors including reduced hydro generation in the Pacific

[55] Percentages in the boxes highlight the percentage change in total volume of import bids offered each month in 2013 compared to the same month in 2012.

Northwest and demand conditions inside and outside of California as well as prices inside and outside the ISO system. For the year, import megawatts offered increased by 5 percent and import megawatts cleared in the market decreased by 3 percent during the first 9 months of 2013 compared to 2012.

Bid prices for imports have increased notably in the first nine months of 2013 compared to 2012. However, DMM attributes most of this increase to the increase in gas prices, which have risen by about 40 percent over this period. Given the significant change in gas prices over this period, DMM has not sought to quantify the portion of higher import bid prices that may be attributable to greenhouse gas allowance costs.

Changes in market prices

Greenhouse gas compliance costs are expected to increase wholesale electricity costs as both market participant bids and the ISO's own calculation of default energy bids, resource commitment costs and generated bids increase to reflect the additional incremental variable cost of greenhouse gas compliance.

DMM has adopted a statistical approach to estimate the impact of greenhouse gas costs on day-ahead market prices during the first three quarters of greenhouse gas compliance. This approach relies on the comparison of market data before cap-and-trade implementation with data from 2013.[56] DMM used a similar model in the first quarter, but improved upon it to control for exogenous differences in generation availability (wind, for example) and other factors.[57] The improved model allows us to broaden the time period of analysis to include the second and third quarters of 2013. For the third quarter analysis, DMM has limited the sample to days in which the implied heat rate in every hour is less than 20,000 Btu/kWh.[58]

The energy price DMM chose to analyze was the day-ahead system marginal energy cost.[59] DMM chose to analyze changes in this value to limit the effects of transmission congestion when trying to isolate the effect of the greenhouse gas costs. While the system marginal energy cost does not eliminate transmission congestion effects, it can act as a reasonable benchmark for system prices.[60]

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[56] As demonstrated in Figure 3.3, the ISO's estimated greenhouse gas compliance cost does not exhibit sufficient variation to determine the impact based on minor fluctuations in this value alone.

[57] A summary of our earlier analysis is available in the *Quarterly Report on Market Issues and Performance* for Q1 2013: http://www.caiso.com/Documents/2013FirstQuarterReport-MarketIssues_Performance-May2013.pdf.

[58] This selection eliminates 29 days in the 21 month period containing hours that DMM has determined to be outliers. In these hours, the day-ahead system marginal energy cost exceeds the marginal gas and greenhouse gas emissions cost of units with a heat rate of 20,000 Btu/kWh, a value far above the heat rate of all but a very few peaking gas units in the ISO market. In each hour, the greenhouse gas adjusted implied heat rate is calculated by dividing the system marginal energy costs by the sum of a weighted average gas price and an estimated greenhouse gas cost. In each hour, the gas price is a weighted average of three regional gas price indices (weights are given in parentheses): PGE2 (0.4), SCE1 (0.5), and SCE2 (0.1). These gas price indices are used by the ISO in calculating default energy bids and other market calculations. The estimated greenhouse gas cost is calculated as the product of the ISO's daily greenhouse gas allowance cost and 0.053165, the EPA's default emissions rate. Prices in the outlying hours may be driven by factors other than incremental variable cost, and as such, an alternative to DMM's model might be more appropriate to explain changes in price in this subset of hours.

[59] This is the energy component of each of the locational marginal prices within the ISO system and excludes both congestion and transmission loss related costs.

[60] For further discussion on the system marginal energy price, please see Appendix C of the ISO tariff: http://www.caiso.com/Documents/CombinedConformedTariff_Mar20_2013.pdf.

DMM estimates the impact of greenhouse gas compliance on wholesale energy prices by estimating average daily system energy prices as a linear function of a measure of greenhouse gas compliance cost, gas price indices, indicator variables for holidays, Saturday, and Sunday, and a non-linear function of expected load, scheduled generation availability for fuel types that we assume to be exogenous (hydro, wind, solar, geo-thermal, and nuclear), and imports (as modeled by exogenous gas price indices).[61] The model estimated here differs slightly from the model estimated in the second quarter because it includes an additional nonlinear load measure.

$$\begin{aligned}\text{Average Electricity Price} = {} & \beta_0 + \beta_1\text{GHG} + \beta_2\text{Load} + \beta_3\text{Load}^2 + \beta_4\text{Load}^3 + \beta_5\text{Gas}_{\text{PGE}} + \\ & \beta_6\text{Gas}_{\text{SCE1}} + \beta_7\text{Gas}_{\text{SCE2}} + \beta_8\text{Gas}_{\text{SDG2}} + \beta_9\text{Holiday} + \\ & \beta_{10}\text{Saturday} + \beta_{11}\text{Sunday} + \beta_{12}\text{Wind} + \beta_{13}\text{Wind}^2 + \beta_{14}\text{Solar} + \\ & \beta_{15}\text{Solar}^2 + \beta_{16}\text{Hydro} + \beta_{17}\text{Hydro}^2 + \beta_{18}\text{Nuclear} + \beta_{19}\text{Nuclear}^2 + \\ & \beta_{20}\text{Geothermal} + \beta_{21}\text{Geothermal}^2 + \beta_{22}\text{Imports\_IV} + \\ & \beta_{23}\text{Imports\_IV}^2 + \varepsilon\end{aligned}$$

Using this model, DMM estimates that in the first nine months of 2013 the average impact of greenhouse gas compliance was about \$5.50/MWh or \$0.39 per dollar of the allowance price.[62] DMM also performed this analysis by quarter, noting that the average impact declines as system demand

[61] If import supply is elastic, imports may be endogenous. That is, scheduled imports may themselves be a function of electricity prices. Including an endogenous variable in the regression could bias our results, so DMM has used an instrumental variable approach to estimate the impact of greenhouse gas emission costs in a consistent manner. A useful set of instruments has two properties. First, the set should be a powerful predictor of the endogenous factor: imports. Second, the instruments should not be endogenous themselves. For this analysis, DMM uses daily gas price indices for multiple hubs outside of the ISO to instrument import levels. DMM's model is estimated using two stage least squares estimated with the ivreg() function of the AER package (Christian Kleiber and Achim Zeileis (2008). Applied Econometrics with R. New York: Springer-Verlag. ISBN 978-0-387-77316-2. http://CRAN.R-project.org/package=AER.) available in R (R Core Team (2013). R: A language and environment for statistical computing. R Foundation for Statistical Computing, Vienna, Austria. http://www.R-project.org/.)

[62] Two alternative greenhouse gas measures are used. The first is an indicator variable equal to 1 in the greenhouse gas compliance period and 0 before that period. In this case, the coefficient estimate (β_1 in the equation above) may be interpreted as the estimated average impact of greenhouse gas compliance on electricity prices (\$/MWh). The second greenhouse gas measure is the ISO's index of the greenhouse gas allowance value, set equal to zero before the compliance period. In this case, the coefficient estimate may be interpreted as the estimated impact of greenhouse gas compliance per allowance cost (\$/MWh divided by \$/mtCO_2e). DMM's regression results are based on values from January 2012 through June 2013 to limit bias introduced by factors not yet included in the model. Load is the ISO's hourly day-ahead forecast of ISO load. We assume that the load forecast, which is based on weather indices and historical time series data, is not price responsive in the short-term, which allows us to estimate this model using ordinary least squares, rather than as a system of demand and supply equations. We also assume that the greenhouse gas allowance index price is exogenous rather than endogenously determined by electricity prices. Resource specific day-ahead schedules are summed by fuel type to calculate generation from wind, geothermal, nuclear, solar, hydro, and import sources. As discussed in footnote 61 imports are estimated as a linear function of the remaining exogenous independent variables and instrumented by multiple gas price indices outside of California.

increases: \$6.14 in the first quarter, \$7.48 in the second, and \$3.71 in the third.[63] Although rough, our model predicts the average ISO day-ahead system energy prices fairly well, explaining approximately 94 percent of the variation in this measure in both models.[64] This analysis may be refined as further data becomes available.

The statistical approach outlined above produces estimates that are somewhat consistent with expectations of the impact of greenhouse gas compliance costs on wholesale electricity costs during a period when market prices are being set close to the marginal operating cost of relatively efficient units. For example, a gas-fired unit with a heat rate of 8,000 Btu/kWh would have an expected emissions cost of 42.5 cents per dollar of greenhouse gas allowance costs. The 39 cents per dollar of the allowance price estimate represents the additional emissions cost of a unit with a heat rate of 7,304 Btu/kWh.[65]

Figure 3.3 illustrates average monthly implied heat rates with and without an adjustment for greenhouse gas compliance costs. The implied heat rate is a standard measure of the maximum heat rate that would be profitable to operate given electricity prices and fuel costs, ignoring all non-fuel costs. The implied heat rate is calculated by dividing the electricity price, in this case the hourly day-ahead system marginal energy price, by fuel price. Because natural gas is often on the margin in the ISO market, we use a weighted average of daily natural gas prices.[66]

DMM calculates the implied heat rate adjusted for greenhouse gas compliance costs by subtracting our estimate of the greenhouse gas compliance cost price impact derived above from the energy price and then dividing the result by the gas price index. In this case, DMM chose to use quarterly estimates of the greenhouse gas impact: \$0.415 per dollar of allowance cost in the first quarter, \$0.501 in the second quarter, and \$0.294 in the third quarter.[67] DMM has noted that, as seen in the quarterly estimates, the greenhouse gas impact appears to be negatively correlated with periods of high load.

The implied heat rate analysis illustrated above shows that changes in gas prices and greenhouse gas compliance costs account for almost all of the electricity price increase between the first 9 months of 2012 and 2013. Adjusted implied heat rates are substantially lower in the third quarter of 2013 than they were in the third quarter of 2012.

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[63] These estimates were generated by using a set of three quarterly indicator variables multiplied by the greenhouse gas measure in place of single greenhouse gas measure.

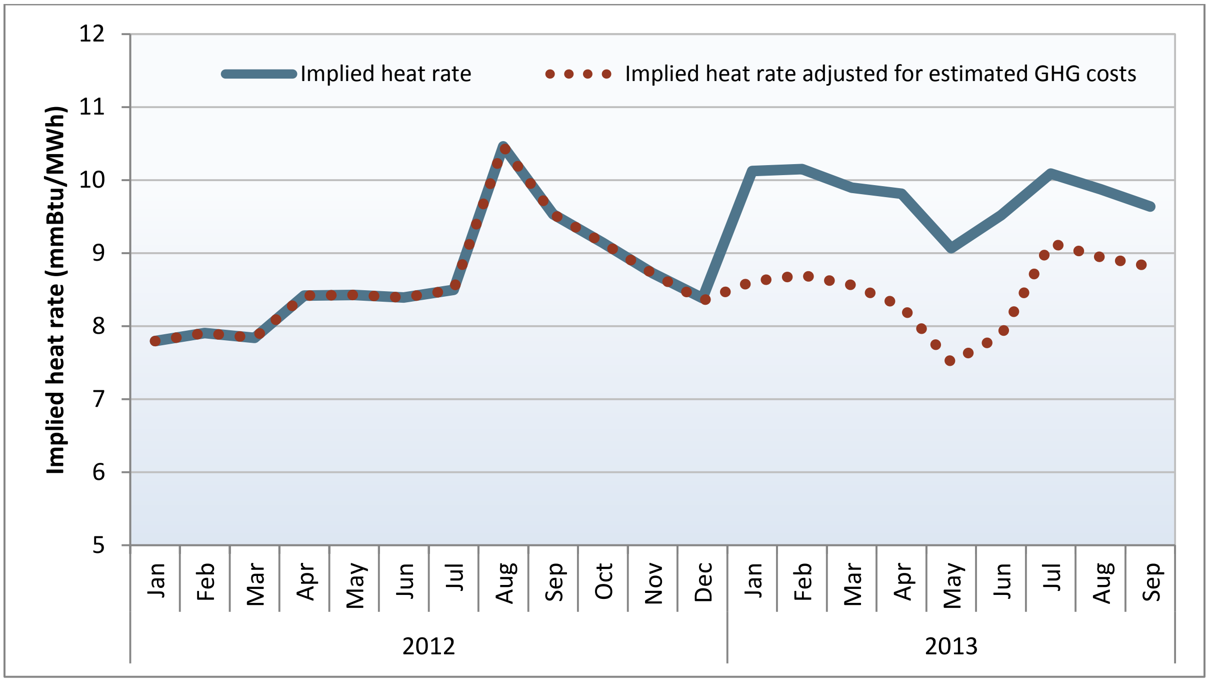
[64] In the first case, R^2 = 0.9435 and the adjusted R^2 = 0.9411. In the second case, R^2 = 0.9442 and the adjusted R^2 = 0.9419.

[65] 0.0530731 $mtCO_2e$ /MMBtu x 8,000 Btu/kWh = \$0.425/\$ Greenhouse gas allowance price. The emissions factor, 0.0530731 $mtCO_2e$ /MMBtu , is calculated as follows: 53.02 kg CO2/MMBtu + [(0.001 kg CH4/mmBtu)*21 kg CO2/kg CH4)] + [0.0001 kgN2O/mmBtu *310 kg CO2/kg N2O)] = 53.0731. The N20 and CH4 global warming potential values (310 and 21, respectively) are from table A1 of http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl. Default emissions factors are available in tables C1 and C2 of the same source. DMM thanks ARB staff for their assistance with this calculation. 0.38767 divided by 0.0530731 = 7.304454.

[66] For this calculation, DMM is using a weighted average of three regional gas price indices (weights are given in parentheses): PGE2 (0.4), SCE1 (0.5), and SCE2 (0.1). These gas price indices are used by the ISO in calculating default energy bids and other market calculations.

[67] These estimates were generated by using a set of three quarterly indicator variables multiplied by the greenhouse gas measure in place of single greenhouse gas measure.

Figure 3.3 Implied heat rates with and without greenhouse gas compliance costs



3.3 Pay-for-performance regulation (mileage)

Summary

The ISO implemented the pay-for-performance regulation product, often referred to as *mileage*, in June to complement the existing frequency regulation markets. In the first full quarter of operation, mileage continued to be a small part of the regulation market settlement, as it had been in the first month.

Mileage prices averaged about $0.06 per MW of mileage, and total costs of the mileage system reached about $203,000 for the quarter, compared to over $6 million for regulation. The small settlement impact was driven by low prices. This pattern reflects only four months of operation for this new product, all of which were during the summer period. The extent to which low prices and low overall settlement impact will persist cannot be derived from the analysis presented in this section. This may be due to seasonality as well as market participants becoming more familiar with this new product.

Market outcomes in the first four months of this new product show a clear pattern where the ISO uses significantly more of the regulation down service via instructed mileage than the regulation up service.

Some possible explanations for the greater use of energy from regulation down include the following:

- unscheduled flows into the ISO system;
- variability between load forecasts and actual load; and
- differences in ramping capabilities between ramping up and ramping down for resources within the ISO market.

The pay-for-performance regulation (mileage) product

FERC issued Order 755 in October 2011 to address what it perceived as undue discrimination in procurement and compensation for regulation in the wholesale electricity markets. The order explains that the greater provision of frequency regulation services from faster, better performing resources was not recognized in the RTO and ISO markets. To remedy this situation, the FERC ordered that each ISO and RTO institute a market-based system that compensates regulation performance.[68]

The ISO implemented the pay-for-performance regulation product on June 1, 2013. The product is *directional*, meaning that mileage up and mileage down are separate services. These services are procured in both the day-ahead and real-time markets along with other ancillary services.

The term *mileage* refers to the amount of movement that a resource performs while providing regulation service to the ISO system. Energy deployments of regulation service are measured across four-second intervals. Previously, units were compensated for regulation capacity and then also paid the market price for the real-time net energy they provided while performing regulation services on ten-minute intervals. As automatic generation control (AGC) signals are sent every four seconds, the compensation of regulation capacity and energy over the settlement period does not reflect the quality of the regulation service that the generator provides in responding to the control signal.

Resources that sell mileage in the ISO market under the new program receive a payment for the awarded regulation capacity in a similar manner as before, but also receive a payment for the amount of up and down movement they actually deliver. Thus, mileage is a measure of the service that is derived from resources providing regulation capacity.

While units submit separate offer prices for regulation capacity and mileage, the mileage product is procured from the set of resources that have also sold regulation capacity. The joint procurement results in the market preferring to procure regulation from units that can move quickly and follow the regulation signal accurately. Resources that are eligible to provide regulation can bid into the mileage market at a price ranging from $0 to $50 per megawatt of mileage, where each megawatt of mileage represents one megawatt of regulation service provided in a given direction.

According to the market design, any resource should be able to provide a quantity of mileage at least equal to its regulation capacity. In other words, if a resource provides 10 MW of regulation, it must be able to change its output by at least 10 MW.[69] Since mileage is measured over an hour, and can consist of both up and down movement, it is also possible that a regulation resource may provide significantly more total movement in an hour than is indicated by its regulation capacity.

The amount of mileage a unit may sell is determined by the resource's history of accurately following AGC signals and its ramp rate. Resources do not respond perfectly to the AGC signal, so the amount of mileage that is instructed is not the same as what is delivered. Settlements are based on the adjusted mileage, with corrections for measured accuracy.

The total system requirement for mileage for each trading hour is determined using a rolling average of the amount of instructed mileage in that hour over the last seven days scaled by the amount of regulation procured in each hour. A historical measure is used because it is not possible to know in

[68] For further detail, see 18 C.F.R. § 35.28(g)(3) http://www.ferc.gov/whats-new/comm-meet/2011/102011/E-28.pdf.

[69] As part of the pay-for-performance design, the definition of regulation capacity available from a given resource was standardized to be equal to the amount that the resource can ramp in ten minutes.

advance how much movement will be required of the regulating resources. This means that the amount of mileage procured in the market is an estimate of the system need for that hour and will differ from the amount of mileage that is actually provided.

Mileage market performance

Mileage prices were low in both directions in the third quarter, averaging $0.10 for mileage down and $0.05 for mileage up in the day-ahead market. In June, the average price for mileage down was $0.16 and mileage up was $0.03.

Real-time mileage prices were similarly low, averaging $0.04 for mileage down and $0.04 for mileage up. Average mileage down payments decreased from June levels of $0.09 while mileage up remained relatively unchanged.

Mileage payments for the third quarter were estimated at $40,700 for mileage up and $163,700 for mileage down. This represents an increase in per-month payments when compared to June. On a per-month basis, mileage up payments increased by about 17 percent and mileage down payments increased by about 4 percent.

Peak prices for mileage up were seen primarily in off-peak hours, with hours ending 1 and 24 being the highest at $0.30 and $0.24 respectively. This is counter to the observation from June where peak prices for mileage up corresponded to peak energy demand. Peak prices for mileage down occurred during the early morning ramping period, with a high of $0.43 during hour ending 9.

Figure 3.4 shows the average hourly levels of adjusted upward mileage for the third quarter, as well as the average mileage up price and regulation up price in each hour from the day-ahead market.[70] System needs for regulation up service in the form of mileage peaked in hour ending 7 at about 800 MW of mileage up, an increase from 677 MW for the same peak hour in June. The price for mileage up did not reach a peak at this hour at $0.13 per megawatt of service; however, it was above the average. Similar to last quarter, the prices for mileage up and regulation up have a countercyclical relationship. During hours when regulation up prices were high, mileage up prices tended to be low, and vice versa.

While there are reasons that the mileage up price and the regulation up price would respond differently in the face of peak energy demand, it is somewhat counterintuitive to see that mileage up prices average at or near zero during peak ramping and energy use hours for the quarter.

[70] Adjusted mileage is the instructed mileage corrected for resource under-response. It does not exactly represent service rendered to the system, but is indicative of regulation service demands. The term *actual mileage* throughout the document also means the same.

Figure 3.4 Mileage up price and adjusted quantity

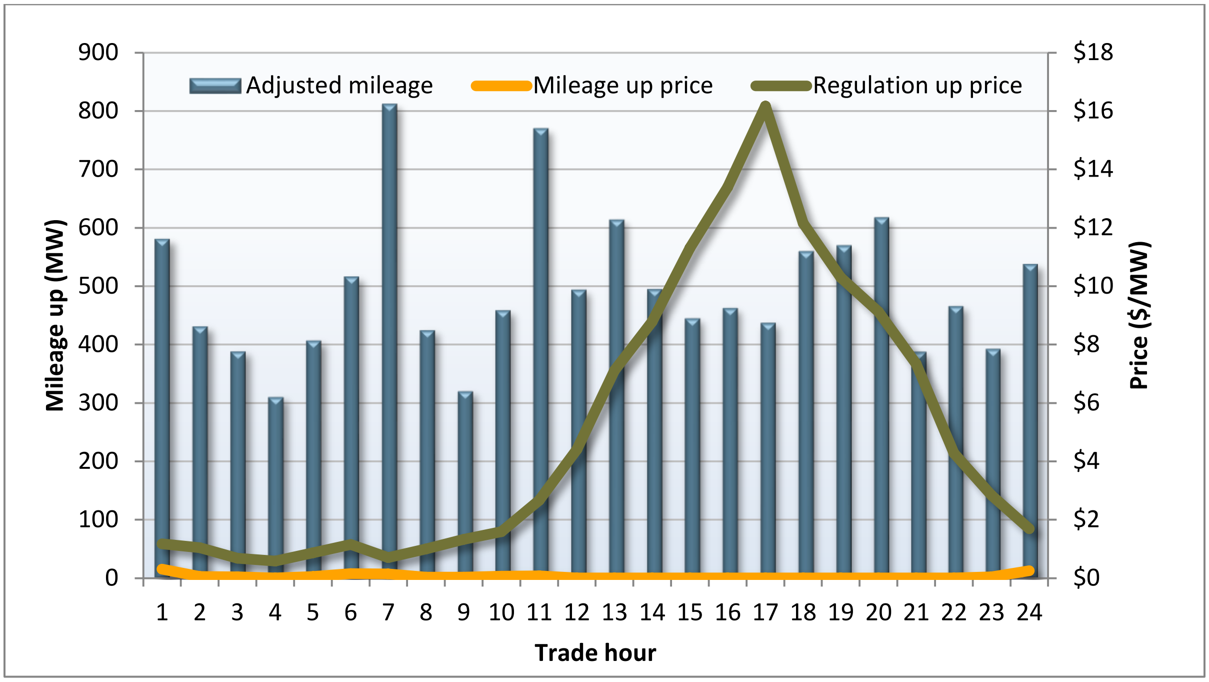


Figure 3.5 Mileage down price and adjusted quantity

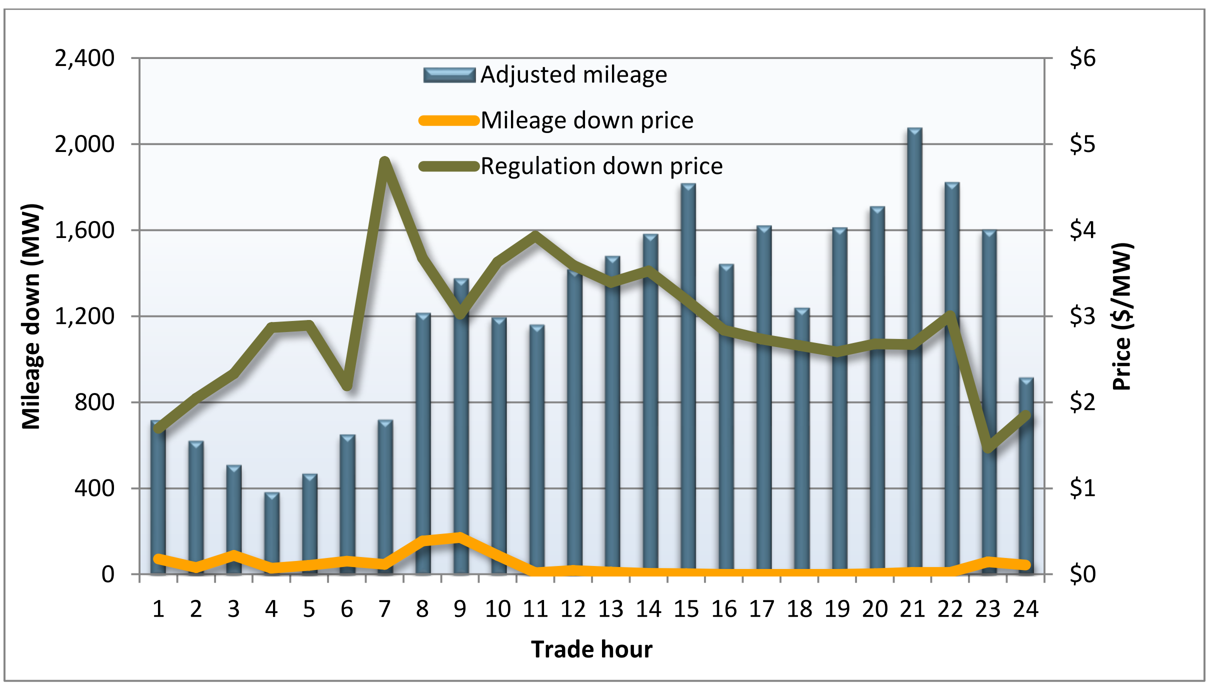


Figure 3.5 shows the monthly average of adjusted mileage down throughout the day, as well as the averages of the mileage down prices and the price of regulation down reserves from the day-ahead market. Downward mileage was most valuable during the morning ramping period, as evidenced by the higher prices in hours ending 8 and 9. Even though prices were high in those hours, the quantities of mileage down averaged 1,200 MW for each hour.

Adjusted mileage down quantity peaked at hour ending 21 with an average of 2,078 MW of adjusted mileage, an increase from the June peak hour 22 with 1,913 MW. For hour ending 21, the average price was about $0.02 per MW of mileage compared to $0.10 in June. The divergence between instances of high prices and high quantity demanded is related to the fact that mileage down is supplied as a secondary product. Available quantity can become scarce when the primary product is scarce, or when the mix of resources providing the primary product is not highly capable of delivering the secondary product. In both cases, it is the market for the primary product that determines how much mileage is available.

Similar to June, significant amounts of regulation were procured and produced on average per hour in both directions throughout the day, even at times when mileage prices were at or near zero. One of the conditions that allowed for frequent zero prices was a robust supply of zero price mileage available to the ISO market. In order to be procured, these mileage bids must be tied to regulation bids that also clear the market.

Figure 3.6 shows the quantities of mileage up that were required by the market, procured by the market, and the adjusted quantity that represents system instructions to resources. Upward mileage is often procured at a zero price, which allows the system to procure more than the market requirement without additional cost.

The price of mileage down is less frequently near zero than mileage up prices. This can be seen in Figure 3.7 where the procured quantity of mileage down was very close to the required quantity, on average, through much of the day. The mileage down price was $0 most frequently during hours ending 14 through 20, and over-procurement of mileage down was most often seen at those times.

System volumes for mileage down continue to be noticeably higher than system volumes for mileage up. Some difference is to be expected, but the volume of mileage down is more than twice that of mileage up. At this time it is difficult to assess potential causes and impacts given the relatively short period this market has been operating. However, the difference appears to be systematic, and could potentially be a result of several factors, including the following:

- unscheduled flows into the ISO system;
- variability between load forecasts and actual load; and
- differences in ramping capabilities between ramping up and ramping down for resources within the ISO market.

DMM continues to closely monitor the mileage product to help inform the ISO in setting regulation reserve requirements at different times of the day and year.

Figure 3.6 Mileage up quantity required, procured, and adjusted

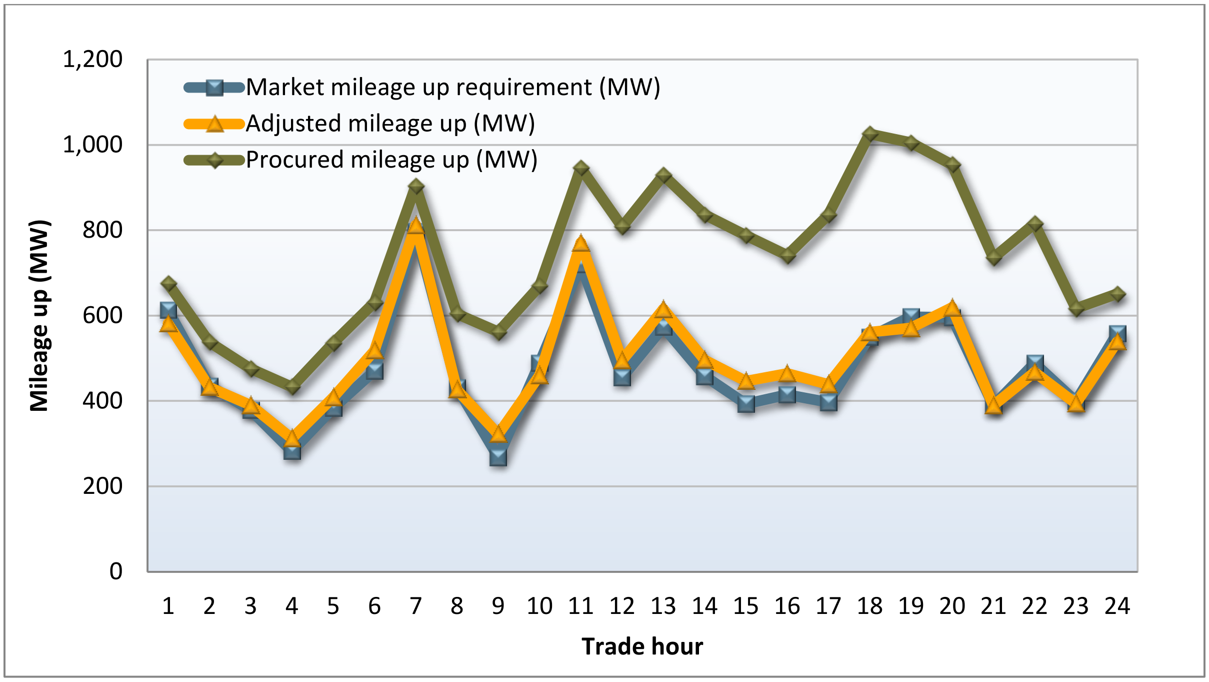
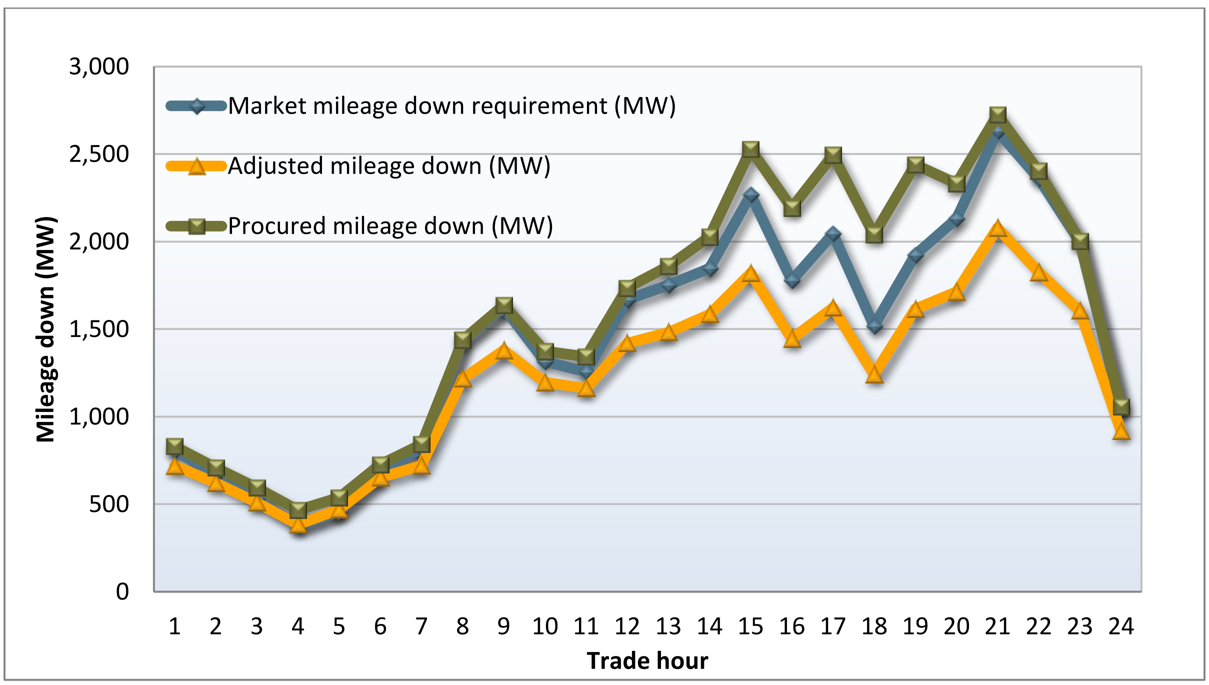


Figure 3.7 Mileage down quantity required, procured, and adjusted



Performance accuracy

In the last quarterly report, DMM identified a performance accuracy issue where many resources were falling short of the 50 percent accuracy benchmark for regulation providers. This criteria was established as part of the pay-for-performance program. Since the last quarterly report, the ISO has started a process to review the methods of instructing resources receiving an AGC signal, as well as the appropriateness of the accuracy measurements and calculations.

Similar to June, the system accuracy in the third quarter was, on average, 40 percent in the up direction and 52 percent in the down direction. When weighted by mileage instructed in each period, the accuracy measurements are 53 percent and 62 percent for mileage up and down, respectively. This appears to be a more meaningful measurement and it is under consideration by the ISO.

The measurement of accuracy and performance benchmark appears to qualify the majority of units for decertification. The appropriateness of this performance accuracy measure relative to operational needs is currently being reviewed by the ISO since the implications are not supported by operational experience. ISO has not experienced frequency violations in proportion to what would be inferred by the poor performance as measured by the accuracy metric.

The decertification provision, along with in-market performance incentives, was intended to remove extremely slow or poor performing resources from the regulation market. The high failure rate indicated by the performance measures would result in the majority of regulating resources being decertified which could lead to relative scarcity of regulation capacity. In order to achieve the goal of explicitly valuing the mileage resulting from regulation it is important to rely on a performance measure that accurately reflects the resource's performance relative to both the reliability need as well as the instruction issued by the ISO. Decertification of the large pool of resources that have not met the performance threshold may represent an unnecessary increase in the cost of regulation. On the other hand, failure to decertify poorly performing resources can keep supply margins deceptively high and result in low market prices for regulation and mileage that do not incent the responsiveness the ISO anticipates needing in the future.

Potential market issues

During the development of the pay-for-performance program, a gaming opportunity was identified by DMM and by the ISO Market Surveillance Committee. The potential opportunity stems from the linked nature of mileage and regulation bids and the possibility that an entity could use a below-cost bid for one product to make excess profits from the other linked product. DMM has not observed this strategy successfully employed but continues to monitor for this potential opportunity, e.g., the relationship between mileage revenue and regulation revenue.

Similar to June, the overall mileage costs for the quarter were about 3 percent of regulation costs. This is counter to what would be expected in the case of the type of manipulation that was the subject of those concerns. DMM believes that the steady supply of low priced bids for regulation and mileage have helped prevent this type of behavior, as was noted in DMM's March 2012 memo to the ISO Board.[71]

[71] The board memo can be found at http://www.caiso.com/Documents/Department_MarketMonitoringReport-MAR2012.pdf.

3.4 Performance of new local market power mitigation procedures

In May 2013, the California ISO implemented the second phase of the new competitiveness assessment and mitigation mechanism to address local market power. Together with the first phase implemented on April 11, 2012, this completes the transition to the new procedure. The new procedure evaluates transmission competitiveness dynamically based on actual system and market conditions, and triggers bid mitigation for generation units based on the impact that non-competitive transmission constraints have on the unit's locational price.[72] The previous methodology was based on a static evaluation of the competitiveness of supply for congestion relief under which most constraints were deemed uncompetitive by default.

Background

Local market power is created by two factors: congestion that limits the supply of imported electricity into the congested area, and insufficient or concentrated control of supply within the congested area.

The dynamic competitive path assessment (DCPA) identifies where local market power may exist by first projecting when congestion may occur on constraints during the day-ahead or real-time market run through a special pre-market run or *mitigation run* of the market software. If congestion is projected to occur, the structural competitiveness of the supply of resources that can relieve this congestion is assessed using a three pivotal supplier test. Bids for these supply resources are subject to mitigation only if this test indicates the constraint on which these resources can relieve congestion is structurally non-competitive.

Thus, the frequency of mitigation and overall accuracy of the new local market power mitigation procedures depend on a combination of two factors: (1) the accuracy of how well the mitigation run predicts when congestion occurs in the market run, and (2) the portion of constraints which are congested in the mitigation or market run which are structurally non-competitive. The way in which DMM has used this framework to assess the overall accuracy of new mitigation procedures is shown graphically in Table 3.1.

As shown in Table 3.1, when congestion is *over-identified*, or is projected to occur in the mitigation run but does not occur in the market, mitigation is not applied when the congested constraint is deemed to be competitive. When congestion is over-identified, mitigation is only applied when the congested constraint is deemed to be non-competitive. This has sometimes been referred to as *unnecessary mitigation*. As described later in this section, the frequency of such unnecessary mitigation has been extremely low in both the day-ahead and real-time markets under the new mitigation procedures.

When congestion is *under-identified*, or is not projected to occur in the mitigation run but then occurs in the market, this only results in inaccurate mitigation when the congested constraint would have been deemed structurally non-competitive. In these cases, mitigation should be applied but is not. This is also referred to as *under-mitigation*. As described later in this section, the frequency of this type of lack of mitigation has also been extremely low in both the day-ahead and real-time markets under the new mitigation procedures.

[72] Further detailed information on the local market power mitigation implementation and related activities can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/LocalMarketPowerMitigationEnhancements.aspx.

Table 3.1 Framework for analysis of local market power mitigation accuracy

Congestion Prediction (mitigation run vs. market)	Dynamic Competitive Path Assessment Results Competitive	Non-Competitive
Consistent (congested in mitigation and market runs)	No mitigation	Correct mitigation
Over-identified (congestion in mitigation run, but not market)	No mitigation	**Mitigation applied, but not needed**
Under-identified (no congestion in mitigation run, but market congestion)	No mitigation	**Mitigation needed, but not applied**

The following sections present results of an assessment of the overall accuracy of the new mitigation procedures using this framework. The analysis is based on market results from July 1 through September 30, 2013.

One limitation of this framework is that when congestion is not identified in the mitigation run but then occurs in the market run (referred to in this report as *under identification*), the market software does not provide results of the three pivotal supplier test that can be used to determine if the constraint was competitive or non-competitive. However, as discussed in the following sections, other analysis by DMM indicates that constraints on which congestion occurs are structurally competitive a very high portion of time (about 85 percent). In this report, illustrate how these results can be used to estimate the overall portion of times in which under-mitigation occurs as a result of under-identification of congestion in the market run.

Day-ahead market

In the day-ahead market, the mitigation run is performed immediately before the actual market run and uses the same initial input data – except for bids that are mitigated as a result of the market power mitigation run. Because of this, DMM has found that the frequency of congestion projected in the day-ahead mitigation run is highly consistent with actual congestion that occurs in the subsequent day-ahead market.

As shown in Table 3.2, when congestion occurred during the study period, congestion occurred in both the day-ahead mitigation and market run about 91 percent of time. However, these congested constraints were deemed competitive about 86 percent of the time, so that bid mitigation was applied to resources that could relieve this congestion in only about 14 percent of these intervals.[73]

About 4 percent of the time constraints were congested in the day-ahead mitigation run but not in the day-ahead market. However, since these congested constraints were deemed competitive most of the time (72 percent), bid mitigation was applied when no congestion occurred in the day-ahead market only about 1 percent of the total times that congestion occurred.

[73] 6,294 ÷ 7,312 = 86 percent.

Table 3.2 Consistency of congestion and competitiveness of constraints in day-ahead local market power mitigation process[74]

	Dynamic Competitive Path Assessment Results					
	Competitive		Non-Competitive		Total	
*Congestion Prediction**	# constraint hours	% total	# constraint hours	% total	# constraint hours	% total
Consistent (congested)	6,294	78%	1,018	13%	7,312	91%
Over-identified	236	3%	90	1%	326	4%
Under-identified	---	---	---	---	401	5%
	6,530	**85%**	**1,108**	**15%**	**8,039**	**100%**

Congestion Prediction:
Consistent = congestion in mitigation and market runs.
Over-identified = Congestion in mitigation run, but no congestion in market.
Under-identified = No congestion in mitigation run, but congestion in market.

It should also be noted that over-identification of congestion does not necessarily subject resources to bid mitigation unnecessarily. In some cases, lowering of bids through bid mitigation prior to the market run may cause congestion not to occur in the day-ahead market run.

As show in Table 3.2, about 5 percent of the time congestion occurred, constraints were congested in the day-ahead market run but not in the day-ahead mitigation run. As previously noted, when congestion is not identified in the mitigation run but then occurs in the market run, the market software does not provide results of the three pivotal supplier test that can be used to determine if the constraint was competitive or non-competitive. However, data from other hours when congestion occurs in the day-ahead market during the mitigation run indicate that constraints are structurally noncompetitive a relatively low portion of time (about 13 percent). This suggests that the frequency of under-mitigation is extremely low and is less than 1 percent of intervals when congestion occurs.[75]

Real-time market

The real-time mitigation process is performed in the real-time pre-dispatch market about 35 minutes before the 5-minute real-time market run. As a result, there may be considerable differences in the model inputs such as load, generation output, transmission limits, generation and transmission outages, and other factors. The differences in model inputs between the mitigation run and the 5-minute market

[74] These figures represent instances where internal paths were congested in the mitigation run, the market run, or both. Instances where a line was not congested in either the mitigation or market runs are not included. This is due to the large number of transmission constraints and the relative infrequency of congestion. The mitigation run consistently predicts no congestion in the market run in a very large number of instances.

[75] For example, 5 percent x 15 percent = 0.75 percent

run can reduce the accuracy of prediction of congestion by the mitigation runs. In turn, this can impact the accuracy of the process to identify local market power and consequently impact the potential accuracy of the mitigation process.

Results of this analysis show that the accuracy of congestion prediction is notably lower in the real-time local market power mitigation process than in the day-ahead. However, since most congested constraints are deemed competitive in the real-time process, the overall impact of less accurate prediction of congestion is still very low in the real-time market.[76]

As shown in Table 3.3, congestion occurred in both the real-time mitigation and market runs about 55 percent of all intervals in which congestion occurred in the real-time process. This represents an improvement from 49 percent in the second quarter. It is unclear if this slight improvement reflects underlying fundamental or temporary factors.

About 29 percent of the time constraints were congested in the real-time mitigation run but not in the real-time market. However, since these congested constraints were deemed competitive most of the time, bid mitigation was applied when no congestion occurred in the real-time market only about 4 percent of the total intervals in which congestion occurred.

Table 3.3 Consistency of congestion and competitiveness of constraints in real-time local market power mitigation process[77]

	Dynamic Competitive Path Assessment Results					
	Competitive		Non-Competitive		Total	
*Congestion Prediction**	# constraint intervals	% total	# constraint intervals	% total	# constraint intervals	% total
Consistent (congested)	6,847	48%	896	6%	7,743	55%
Over-identified	3,468	25%	611	4%	4,079	29%
Under-identified	---	---	---	---	2,309	16%
	10,315	**87%**	**1,507**	**13%**	**14,131**	**100%**

Congestion Prediction:
Consistent = congestion in mitigation and market runs.
Over-identified = Congestion in mitigation run, but no congestion in market.
Under-identified = No congestion in mitigation run, but congestion in market.

[76] The congestion prediction and mitigation accuracy figures reported omit cases where the mitigation run correctly predicted no congestion on specific constraints in the subsequent real-time market run. Considering only the critical constraint list (flow ≥ 85 percent of limit), the mitigation run correctly predicted no congestion in 5-minute real-time market 95 percent of the time. These instances are omitted from our statistics because they represent instances where there is no accuracy consequence that would not be accounted for in another category. Also, these cases are sufficiently large in number that when included they distort the relative accuracy of the categories that do have market consequences.

[77] The comparison in this table is between the real-time mitigation process that takes place in the real-time unit commitment process 37.5 minutes before the trade interval and the corresponding 5-minute trade intervals. Evaluation adheres to the "balance of hour" approach that is applied to bid mitigation. For example, if a constraint is congested in 15-minute trade interval 2 in the mitigation run and is also congested in 15-minute trade interval 2, 3, or 4 of real-time dispatch then the congestion is considered as correctly identified in the mitigation process.

As shown in Table 3.3, about 16 percent of the time congestion occurred, constraints were congested in the real-time market run but not in the real-time mitigation run. As previously noted, for these intervals the market software does not provide results of the three pivotal supplier test, so data are not available to determine if the constraint was competitive or non-competitive. However, data from other hours when congestion occurs in the real-time market during the mitigation run indicate that constraints are structurally non-competitive a relatively low portion of time (about 13 percent). This suggests that the frequency of under-mitigation is extremely low and is about 2 percent of intervals when congestion occurs.[78]

Impact of mitigation on bid prices

Under the new mitigation procedures, bids are subject to mitigation if the resource can relieve congestion on a constraint on which congestion is projected to occur and which has been found to be structurally uncompetitive in the dynamic competitive path assessment. However, bids subject to mitigation are not automatically lowered. Bids are only lowered if they exceed the higher of (1) the resource's default energy bid (DEB), which is designed to reflect its marginal operating costs, or (2) a competitive price that is calculated from the pre-market mitigation run that is designed to exclude the potential effects of local market power.[79] In practice, DMM has found that under the new mitigation procedures, the bid mitigation floor is often set by the calculated competitive price and only a small proportion of units subject to mitigation actually see their offer price reduced as a result of this process.

Figure 3.8 shows the average percentage of all units subject to mitigation each interval under the new real-time local market power mitigation procedures by day. The vertical axis indicates the percentage of all units with bids subject to mitigation. The bars in Figure 3.8 categorize these units based on whether the units' bids were actually mitigated (lowered) or not. The bars categorize cases when units were subject to mitigation in terms of two key factors: (1) whether or not the offer price was lowered as a result of mitigation and (2) which of the two mitigation floors determined the mitigated price (i.e., default energy bid or competitive price).

As shown in Figure 3.8, the percentage of all units subject to mitigation each interval was extremely low most days and exceeded about 5 percent on only three days, during which an average of about 8 to 11 percent of units were subject to mitigation each interval. In most cases, bids subject to mitigation are not lowered since these bids are lower than the units' default energy bids (see green bars). The blue bars show cases where bids were not lowered since the competitive locational price was greater than the unit's bid price.

Cases where the unit's bid price was actually lowered as a result of mitigation were less than 1 percent of instances (see the yellow and red bar segments). The yellow bar segments show that in cases where the bid price was lowered, the bids were lowered to the competitive locational price, since this price was greater than the unit's default energy bid. The red bar segments show the frequency of instances where the unit's bid price was lowered to its default energy bid, which was greater than the calculated competitive price. The frequency of this category is so low that it is essentially undetectable in Figure 3.8. A more detailed summary of the frequency of units which had their bids lowered as a result of

[78] For example, 16 percent x 13 percent = 2 percent

[79] Bids are not mitigated to a higher price, so if the original offer price is below the higher of the default energy bid and the competitive price, then the bid price is not changed by the mitigation process.

mitigation is provided in Figure 3.9. As shown in this figure, the average number of units having bids lowered each interval by mitigation was very low through the summer period.

Figure 3.8 Percent of units subject to mitigation under new real-time procedures

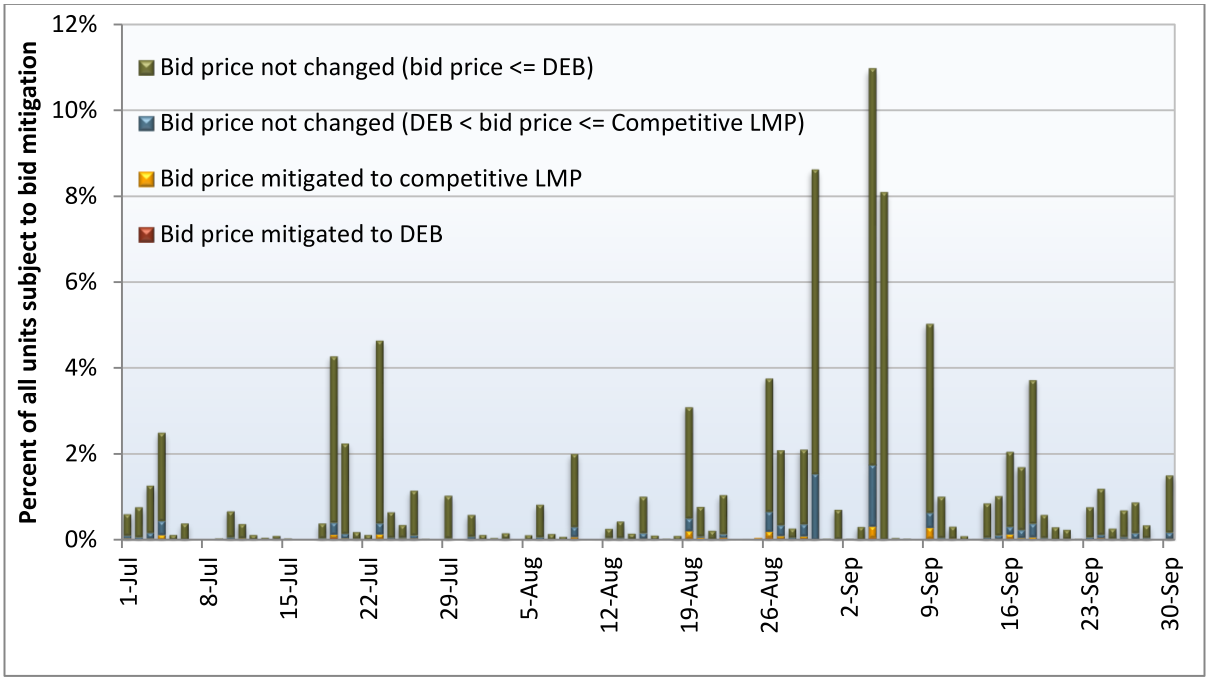
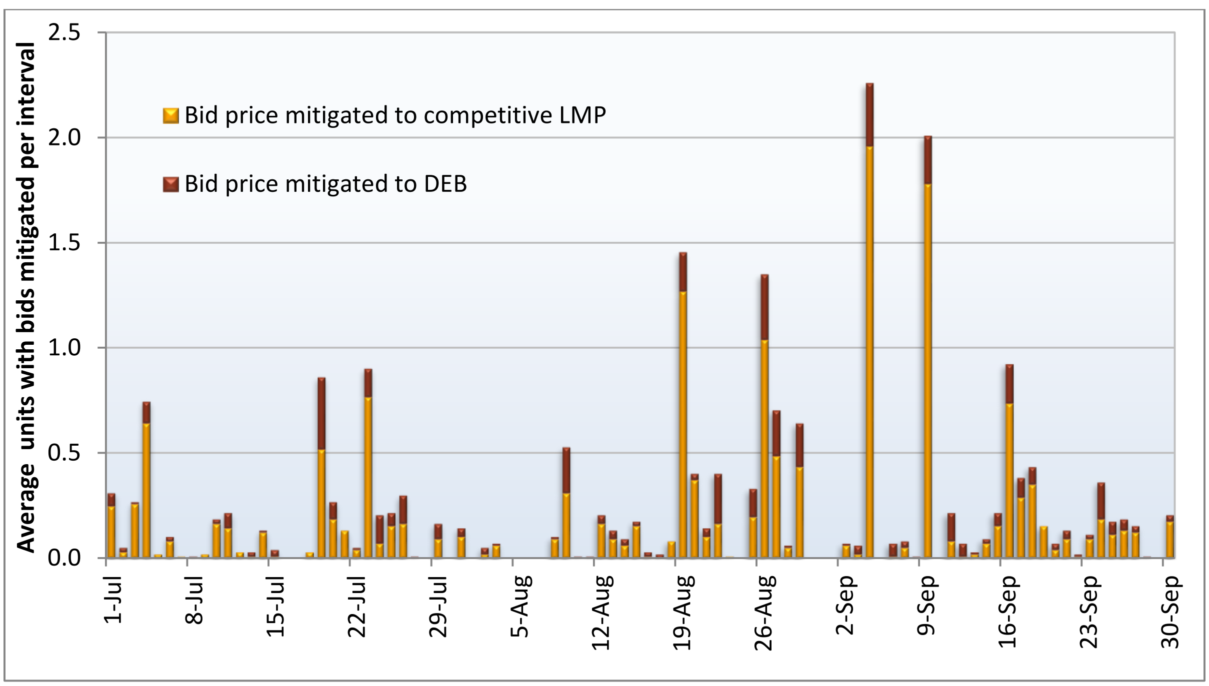


Figure 3.9 Average number of units with bids mitigated under new real-time procedures



Conclusions

While the new real-time procedure is much more accurate than the prior approach, differences often exist between projections of congestion during the pre-market mitigation runs and the actual 5-minute market runs. In practice, these differences have not had a significant impact on bid mitigation or the degree of protection against local market power for several reasons. In most cases, constraints on which congestion differences occurred are structurally competitive, so that mitigation would not be triggered. In addition, due to very competitive bidding in the market, only a very few resources have bids that would be lowered when subject to mitigation.

These differences in congestion could have a much more significant impact on overall market prices and efficiency when the ISO implements a 15-minute real-time market in spring 2014. Specifically, such differences could create systematic divergence of 15-minute and 5-minute real-time prices. Consequently, DMM is recommending the ISO perform analysis to better understand and mitigate the causes for differences in projected and actual real-time congestion.