California ISO

Shaping a Renewed Future

California ISO

Quarterly Report on Market Issues and Performance

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Prepared by: Department of Market Monitoring

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Executive summary

This report provides an overview of general market performance during the second quarter of 2011 (April – June) by the Department of Market Monitoring (DMM).

Energy market performance

- In the 5-minute real-time market, average prices remained above prices in the day-ahead and hour-ahead markets for off-peak hours in the second quarter, particularly in April and June. Average on-peak real-time prices were much closer to day-ahead and hour-ahead prices in April and May, but were much lower than both day-ahead and hour-ahead prices in June.

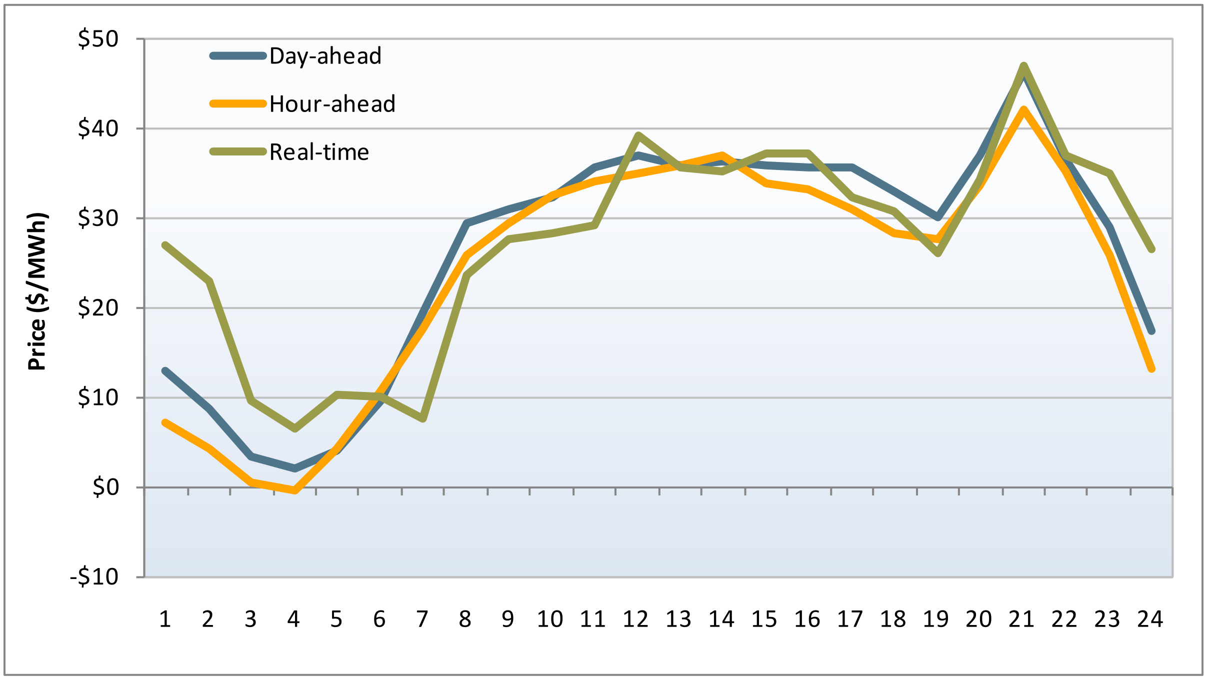
- When averaged for both peak and off-peak periods for the month, hour-ahead and real-time market price convergence improved in the second quarter, most notably in May. However, this improvement is a result of averaging price differences over the day. In some hours, real-time prices were systematically lower than hour-ahead prices and in other hours real-time prices were systematically higher than hour-ahead prices (see Figure E.1). Thus, even though overall peak and off-peak prices appear to converge for this period, systematic price divergences continued to persist in some hours.

- Higher average real-time prices for off-peak periods continued to be driven by short but extreme price spikes. Most of these high prices were attributable to minor system level shortages of upward ramping capacity during one or two consecutive 5-minute intervals. These price spikes generally do not reflect an underlying shortage of total potential capacity and may be avoided by further modeling and dispatch improvements that increase the accuracy and flexibility of real-time dispatches. The volume of price spikes were reduced in the second quarter this year compared to the second quarter last year as a result of various modeling and procedural changes made by the ISO.

- The divergence of 5-minute real-time prices from hour-ahead market prices also continues to impose unnecessary additional inefficiencies and costs on the system. This occurs when net physical and virtual imports at inter-ties settle against prices that differ from physical generation and virtual bids at internal locations. Real-time imbalance energy offset charges have totaled roughly $76 million since convergence bidding began in February 2011. DMM estimates that convergence bidding contributed to $43 million of these costs, with $19 million coming during the second quarter. In May, real-time imbalance energy offset costs associated with convergence bidding were lower than in other months. The imbalance costs in May were driven by imbalances from uninstructed and unaccounted for energy costs. The volumes of offsetting virtual bidding positions were also low in May.

- Congestion within the ISO system had minimal impact on overall prices. However, day-ahead congestion continued to occur more frequently than congestion in the real-time market, particularly on constraints relating to imports into the Southern California Edison and San Diego Gas and Electric areas. This increase in day-ahead congestion coincided with implementation of virtual bidding on February 1, 2011, and continued through the second quarter. DMM continues to evaluate the extent that this congestion was attributable to convergence bidding rather than generation and transmission outages.

Figure E.1 Hourly comparison of PG&E load aggregation point prices – Q2 2011



- Scarcity pricing of ancillary services was triggered in a dozen 15-minute real-time pre-dispatch intervals in the second quarter. As is common for this time of year, loads reached their seasonal spring lows and hydro-electric units provided energy rather than bid into the ancillary services markets. Both of these factors combined to reduce the available real-time supply of ancillary services. As a result, there was less online flexibility of supply to counteract events that occurred in real-time, such as unit de-rates and outages.

Convergence bidding

The ISO implemented functionality for convergence (or virtual) bidding in the day-ahead market for February 1, 2011. Convergence bidding is designed to allow any creditworthy entity, regardless of whether or not they own physical load or generation, to place bids to buy power and offers to sell power into the day-ahead market. As these bids are only virtual and not physical, they will liquidate in real-time and cause the physical system to re-dispatch accordingly.

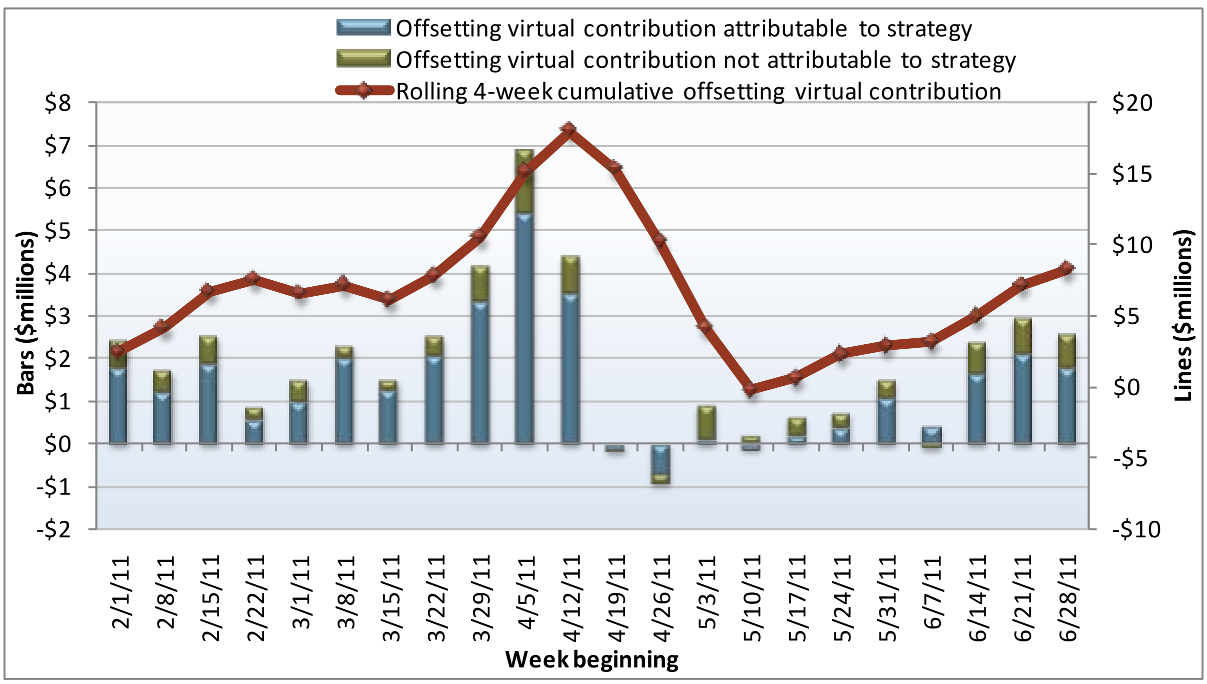
Convergence bidders profit by arbitraging the difference between day-ahead and real-time prices. In theory, as participants take advantage of opportunities to profit through convergence bids, this activity should drive real-time and day-ahead prices closer. While average price convergence appears to have improved since February 2011, this improvement is a result of averaging hourly prices over the day. In some hours, real-time prices still tend to be higher than day-ahead and hour-ahead prices, and in other hours, real-time prices are lower. These systematic price differences continue to make convergence bidding highly profitable.

Convergence bidding has been marked by two key trends over the course of the first few months.

- The vast majority of virtual supply clearing the market is imports on inter-ties, whereas the bulk of cleared virtual demand has been at internal locations. This pattern has remained constant since the start of convergence bidding in February.
- The volume of virtual bids clearing the market increased steadily over the first few months until the second half of April. Afterwards, volumes dropped precipitously and then began to increase steadily through June.

The increase in volumes of virtual bids provided little value in terms of price convergence or market efficiency because virtual demand was met with virtual supply. Specifically, individual participants bid in positions at inter-ties that offset their positions at internal nodes. The use of this strategy receded in late April and May but began to increase again in June. As a result, real-time imbalance charges associated with the offsetting strategy increased at the end of the second quarter (see Figure E.2).

Figure E.2 Contribution of offsetting virtual supply and demand to real-time imbalance charges by week[1]



Over the course of the second quarter, net revenues paid out to convergence bidding entities totaled almost $19 million – or just over the $16 million paid to convergence bidding entities in February and

[1] Figures E.2, 2.7, 2.8, 2.10, 2.11, 2.12, and 2.13 were revised on 8/24/2011. The original figures were calculated from data in the ISO's Enterprise Data Repository (EDR), which does not include price correction data. DMM developed a separate process to incorporate the price corrections made by the ISO as part of the settlement process and then updated these figures. With the exception of Figure 2.12, the changes were minimal. In Figure 2.12, convergence bidding results for the month of May changed from negative $4 million to negative $300,000. This change was the result of extreme negative prices (-$10,000/MWh) on May 27 hour ending 1 that were corrected as part of the ISO settlement process.

March. DMM's assessment of convergence bidding over the first five months is that convergence bidding has had little or no benefit in terms of helping to improve price convergence or the efficiency of day-ahead unit commitment decisions. Meanwhile, convergence bidding has added to energy imbalance offset costs that are ultimately allocated to load-serving entities.

Since 2009, DMM has indicated that the systematic difference in hour-ahead and 5-minute real-time prices has represented one of the most significant sources of inefficiency in the ISO's new market and has expressed concern that this trend is attributable to systematic differences in the inputs and models used in the different markets and may persist unless specifically addressed though enhanced modeling and operational practices. In 2010, the ISO indicated that addressing this price divergence would be a high priority and identified numerous software and modeling enhancements the ISO felt would improve price convergence. In addition to these modeling enhancements, DMM recommended that the ISO also implement improved operational procedures or guidelines for manual adjustments to the load forecast made by system operators that have a significant impact on price convergence between the hour-ahead and 5-minute real-time markets.

Numerous modeling and operational improvements have been made by the ISO. While it appears these changes have resulted in some improvements in price convergence, significant and systematic differences in hour-ahead and real-time prices persist, even after implementation of convergence bidding. This provides further evidence that more fundamental structural aspects of the current market design tend to create systematic differences in hour-ahead and real-time prices. Therefore, DMM believes it is becoming increasing apparent that more fundamental modifications to the hour-ahead and real-time market design will be needed to resolve the problems created by this price divergence.

Recommendations

- **Modeling enhancements to improve price convergence**. DMM believes that current ISO initiatives to improve price convergence between the hour-ahead and real-time markets represent important steps that will help reduce extreme price spikes due to short-term shortages of ramping capacity. Virtual bidding has not resolved the issue of real-time price convergence. Therefore, improving price convergence through modeling and operational enhancements remains a crucial approach to addressing this problem.

- **Address offsetting virtual bidding strategy**. DMM supports the ISO's proposal to suspend virtual bidding at the inter-ties. Specifically, participants taking offsetting positions of virtual supply at inter-ties and virtual demand at internal locations appear to result in higher real-time imbalance charges without contributing to price convergence or market efficiency. The strategy provides little or no increase in efficiency or reliability as these offsetting virtual supply and demand positions do not increase day-ahead unit commitment. Rather, the strategy simply allows some participants to profit from price divergence between the hour-ahead and 5-minute real-time markets. As long as participants can bid in offsetting virtual supply bids on the inter-ties and virtual demand bids on internal nodes, this strategy will likely continue to inflate real-time energy imbalance charges when price divergence occurs between the hour-ahead and real-time markets.

- **Other market design options.** One long-term solution for minimizing these offset charges is to redesign the real-time market so that all external and internal resources are scheduled and settled in the same market. However, the implementation of such a redesign is likely several years away. DMM believes that even with the removal of virtual bidding at the inter-ties, these offset charges may be significant enough to warrant further action prior to the implementation of the real-time market redesign as part of the renewable integration initiative. Therefore, DMM recommends that the ISO continue to consider a phased approach that would start with the elimination of virtual bidding at the interties, as well as a second phase to address remaining issues with physical inter-tie schedules. In particular, DMM believes the ISO should continue to consider the merits of the NYISO's real-time method for settling inter-tie schedules.

1 Market performance

Day-ahead market

DMM continues to evaluate the competitiveness of the day-ahead integrated forward market in the first and second quarters of 2011.[2]

Real-time market

In the 5-minute real-time market, average prices remained significantly above prices in the day-ahead and hour-ahead markets for off-peak hours in the second quarter. Higher average real-time prices continued to be driven by short but extreme price spikes. Most of these high prices were attributable to minor system level shortages of upward ramping capacity during one or two consecutive 5-minute intervals. These price spikes generally do not reflect an underlying shortage of total potential capacity and may be avoided by further modeling and dispatch improvements that increase the accuracy and flexibility of real-time dispatches. Average on-peak real-time prices were much closer to day-ahead and hour-ahead prices in April and May, but were much lower than both day-ahead and hour-ahead prices in June.

Congestion

Congestion within the ISO system had minimal impact on overall prices. However, day-ahead congestion continued to occur more frequently than congestion in the real-time market, particularly on constraints relating to imports into the Southern California Edison and San Diego Gas and Electric areas. This increase in day-ahead congestion coincided with implementation of virtual bidding on February 1, 2011, and continued through the second quarter. DMM continues to evaluate the extent that this congestion was attributable to convergence bidding versus generation and transmission outages.

Ancillary services

Scarcity pricing of ancillary services was triggered regionally in a dozen 15-minute real-time pre-dispatch intervals in the second quarter. As is common, loads reached their seasonal spring lows and hydro-electric units generated rather than bid into the ancillary services market. Both of these factors combined to reduce the available real-time supply of ancillary services. As a result, there was less online flexibility of supply to counteract events that occurred in real-time, such as unit de-rates and outages.

[2] DMM has previously had the ability to rerun the ISO market software to assess the competitiveness of the day-ahead market. However, as noted in DMM Q1 2011 report, DMM was not able to conduct this analysis so far in Q1 2011 due to problems with the software system provided by the ISO to DMM for this analysis. In Q2, DMM continued to be unable to perform this analysis due to continued problems with the market software system, as well as some enhancements to the methodology for calculating the competitive market baseline being made by DMM. DMM anticipates being able to have competitiveness metrics completed for the next quarterly report.

1.1 Energy market performance

Figure 1.1 and Figure 1.2, below, show monthly average prices for on-peak periods and off-peak periods for the PG&E load aggregation point, respectively.

Figure 1.1 Average monthly on-peak prices - PG&E load aggregation point

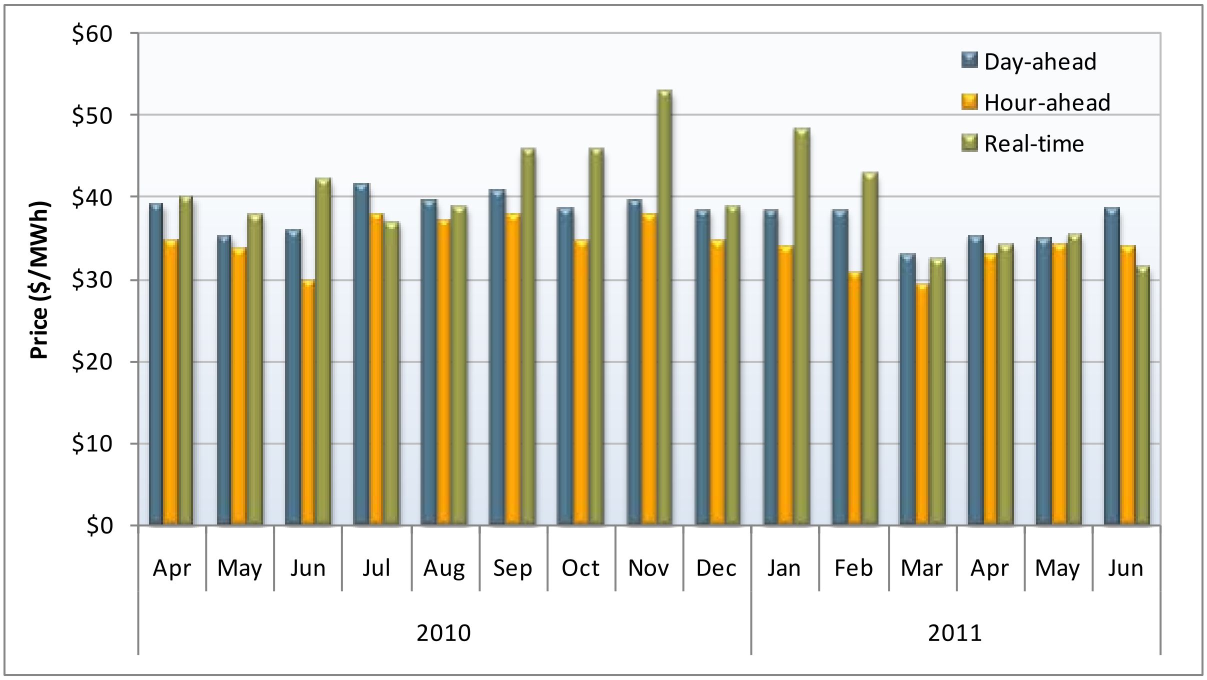
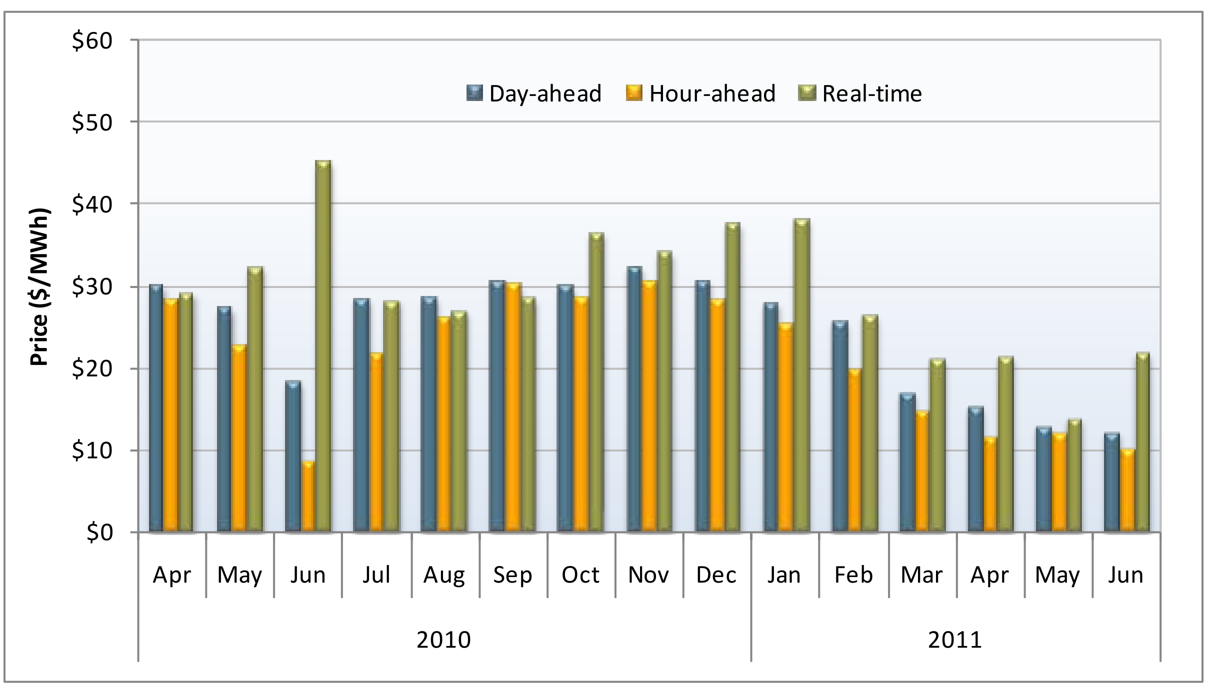


Figure 1.2 Average monthly off-peak prices - PG&E load aggregation point



- Hour-ahead market prices tended to be lower than peak and off-peak prices in the 5-minute real-time market. Hour-ahead market prices are used to settle physical imports and exports as well as virtual supply and demand bids on the inter-ties.

- During peak hours, average prices in the 5-minute real-time market were fairly close to day-ahead and hour-ahead prices in April and May. However, real-time prices were lower than both day-ahead and hour-ahead prices in June.

- During off-peak hours, prices in the 5-minute real-time market were significantly higher than day-ahead and hour-ahead prices in both April and June. Average off-peak real-time prices tracked closer to day-ahead and hour-ahead prices in May.

Figure 1.1 and Figure 1.2 suggest that hour-ahead and real-time market price convergence improved in the second quarter, most notably in May. However, this improvement is a result of averaging price differences over the day. In some hours, real-time prices were lower than hour-ahead prices and in other hours real-time prices were higher than hour-ahead prices. When averaged together, prices appear to converge, but in reality, price divergence in some hours offset price divergence in other hours.

Figure 1.3 and Figure 1.4 indicate hourly variations in price divergence:

- Figure 1.3 shows average hourly prices for the second quarter.[3] Real-time prices were higher than day-ahead and hour-ahead prices in the early morning hours (1 through 5) and late evening hours (21 through 24). In hours 7 through 11 and in hour 19, real-time prices were often much lower than both day-ahead and hour-ahead prices.

- Figure 1.4 highlights the magnitude of these differences by taking the average of the absolute difference in prices in the hour-ahead and real-time markets.[4] When taking the straight average of prices (green line), price convergence appears to have improved significantly since January. However, when the average absolute differences are taken into account, the magnitude of price differences began to increase in March, indicating that price divergence has grown. Indeed, the absolute price divergence in the second quarter of 2011 is second only to the absolute price divergence in the second quarter of 2009, at the start of the nodal market. While average differences between hour-ahead and real-time prices fell to a low of almost $1.50/MWh in May, the average absolute difference in prices was approximately $19.50/MWh for the same month.

[3] The monthly trends for April, May and June were similar and are not lost in this averaging.

[4] By taking the absolute value, the direction of the difference is eliminated and only the magnitude of the difference remains. If the magnitude decreases, price convergence would be improving. If the magnitude increases, prices convergence would be getting worse.

Figure 1.3 Hourly comparison of PG&E load aggregation point prices – Q2 2011

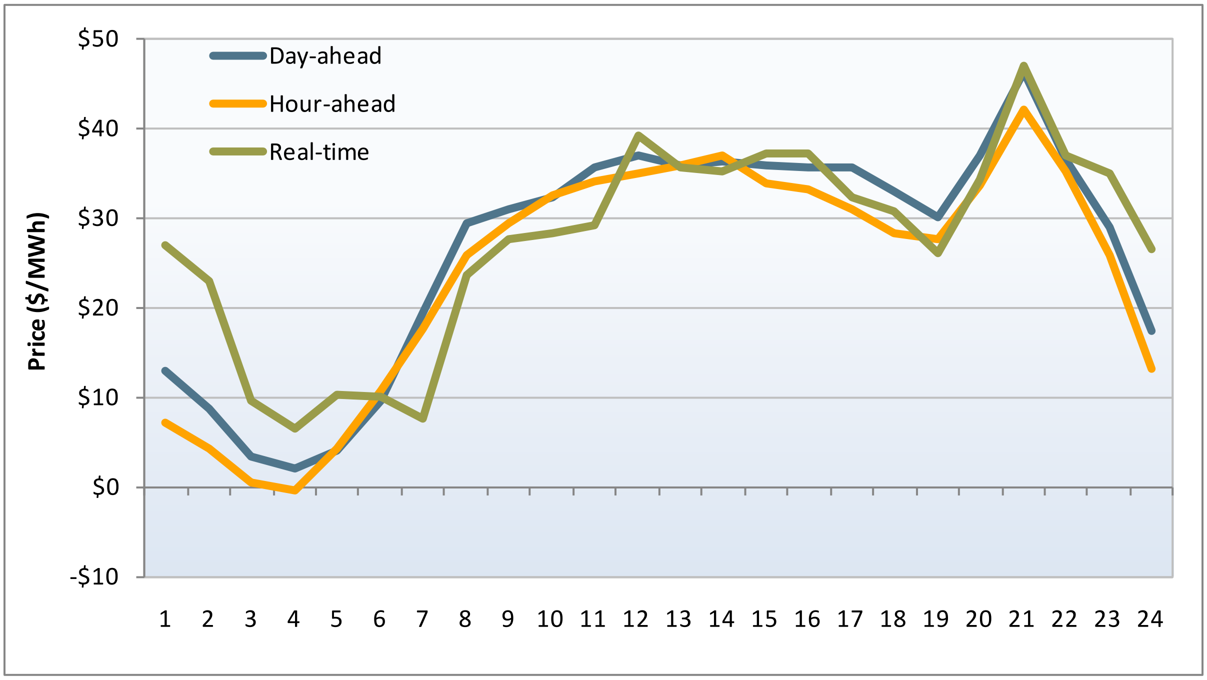
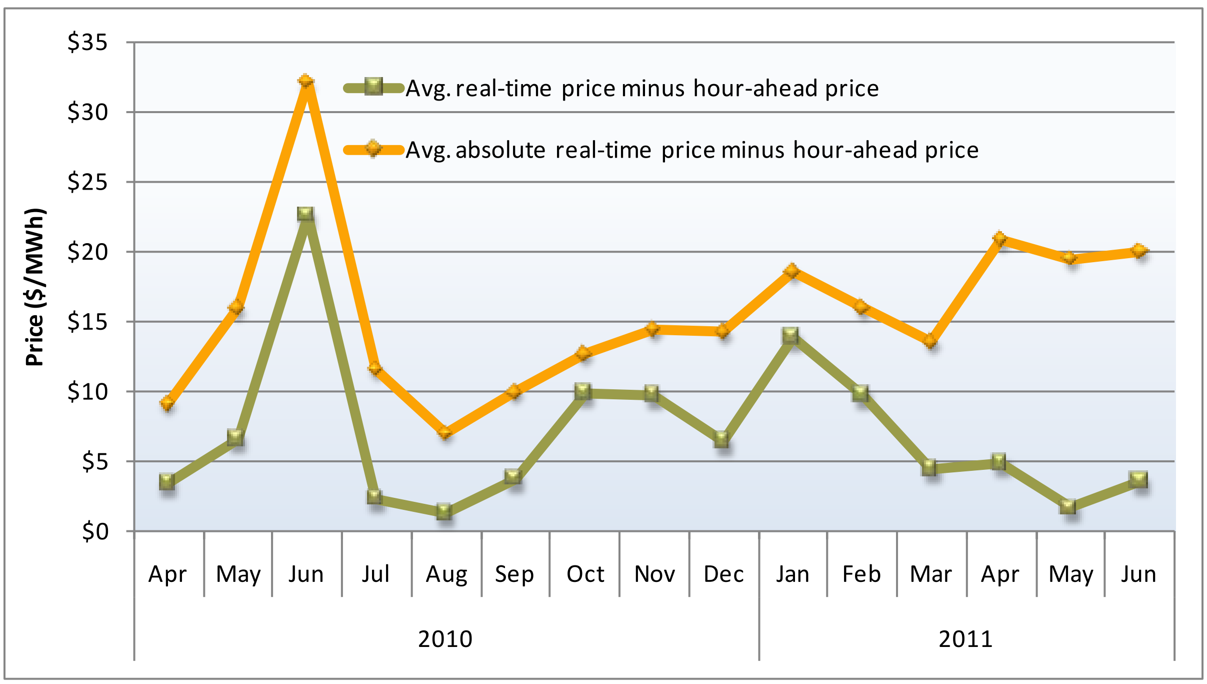


Figure 1.4 Difference in monthly hour-ahead and real-time prices when taking a simple average and absolute average of price differences (PG&E LAP, all hours)



1.2 Power balance constraint

The system-wide power balance constraint continues to contribute to both high real-time positive and negative prices. Figure 1.5 and Figure 1.6 show the frequency the power balance constraint was relaxed in the 5-minute real-time market software since the second quarter of 2010.

- Figure 1.5 shows that insufficiencies of dispatchable incremental energy caused the power balance constraint to be relaxed slightly below 1 percent of all 5-minute intervals in the second quarter of 2011. The second quarter figure is down when compared to both the first quarter of the year and the second quarter of 2010. Most notably, the number of instances fell by about 1 percent from June 2010 to June 2011. This reduction can be attributed to changes in operational procedures and software enhancements since last year, particularly those related to load adjustments.

- Figure 1.6 indicates that since February there has been a general decreasing trend in the number of power balance constraint relaxations in the 5-minute intervals because of insufficiencies of dispatchable decremental energy. The June 2011 values indicate a significant decline in the number of relaxations compared to the June 2010 values. This improvement can also be attributed to changes in operational procedures and software enhancements. Specifically, the ISO implemented in the second quarter new procedures to account for generation shut-down procedures, as well as initiated a new load forecasting tool that provides better sub-hourly load granularity.[5]

Figure 1.7 provides more detailed information on the intervals in which the power balance constraint was relaxed because of insufficient upward ramp in the second quarter of 2011. As shown in Figure 1.7:

- Power balance constraint relaxations from shortages of upward ramping capacity were dispersed over different hours of the day in the second quarter of 2011. This is a contrast to the first quarter where relaxations took place frequently during morning and evening ramp hours of 7, 8, 18 and 19. In the second quarter, the ISO changed the operational procedures related to hour-ahead load adjustments. Specifically, the ISO started new hour-ahead forecast adjustment procedures where the operators adjust hour-ahead load during ramping hours by approximately 25 percent of the load change and adjust hour-ahead load by approximately 2 percent of the forecast across peaks.[6] By procuring more capacity in the hour-ahead market, the intent of these adjustments was to address ramping deficiencies in the 5-minute real-time market.

[5] This new load forecasting tool has had significant stability issues in the third quarter leading to an inappropriate increase in price spike activity. These issues will be addressed in the next DMM quarterly report.

[6] These procedural guidelines for adjustment are for normal conditions. Operators may adjust by more or less to account for other anticipated system conditions.

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

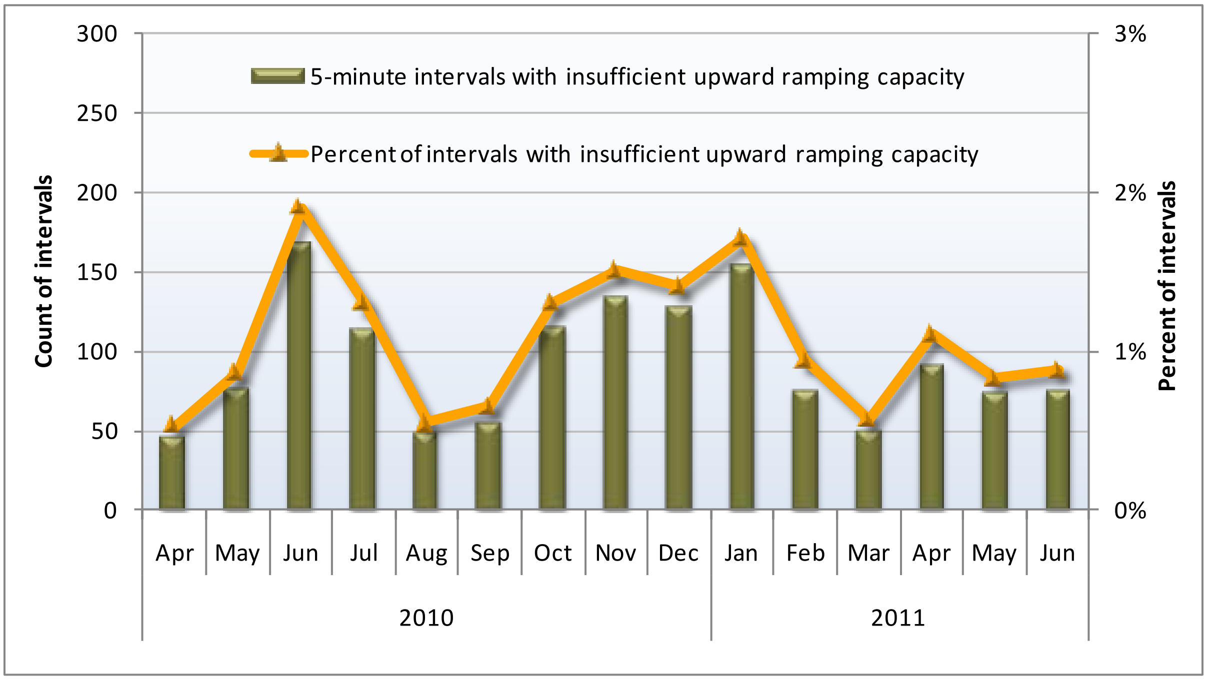


Figure 1.6 Relaxation of power balance constraint due to insufficient downward ramping capacity

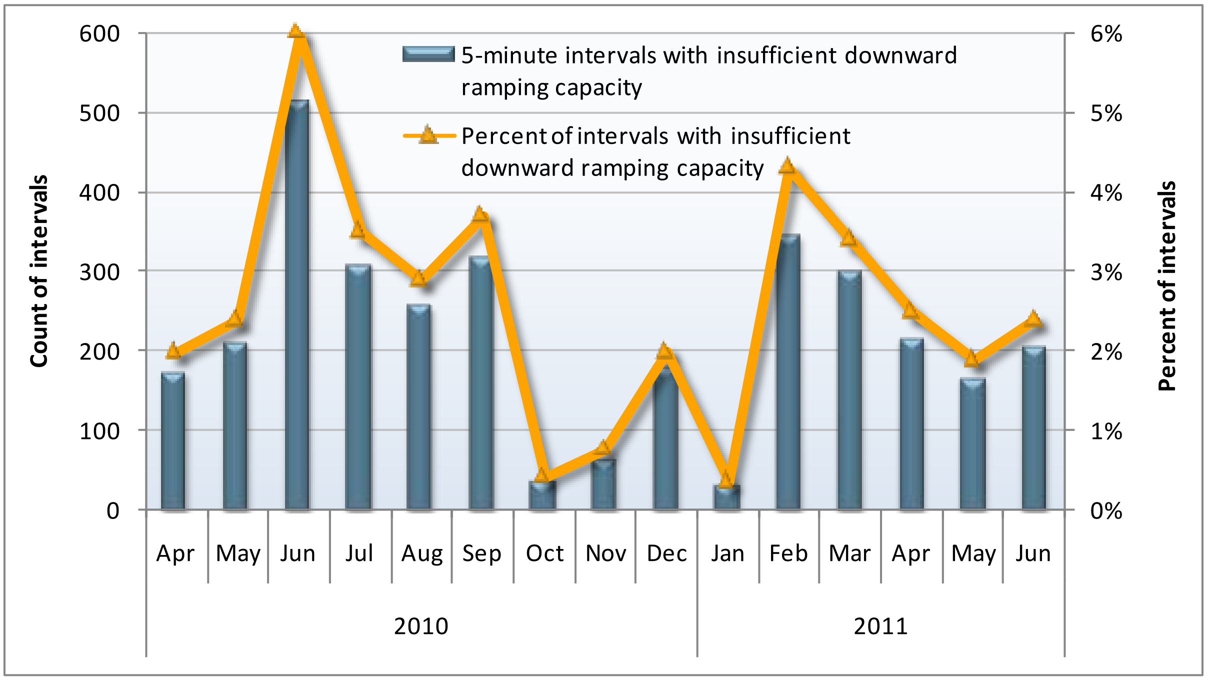
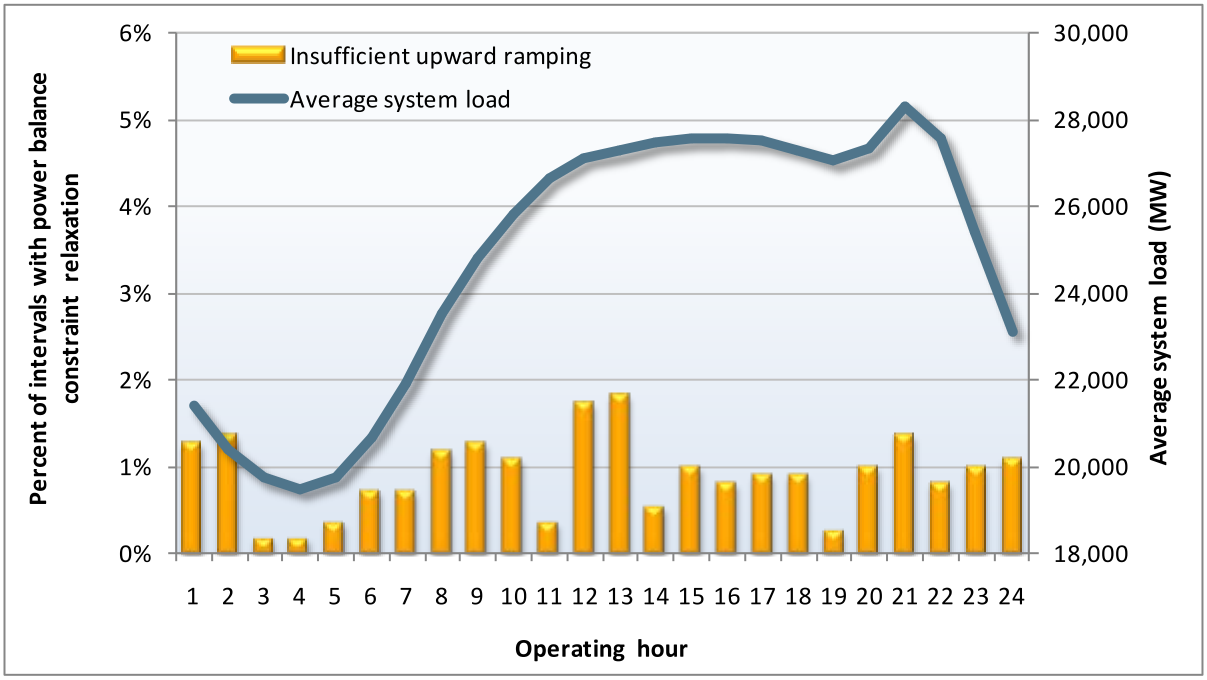


Figure 1.7 Relaxation of power balance constraint by hour (April – June 2011)



The power balance constraint was relaxed because of insufficient incremental energy less than 1 percent of intervals in the second quarter. Price spikes during these intervals continued to have a significant impact on overall average real-time prices due to the bid cap and penalty prices used in the pricing run when this relaxation occurs.

Figure 1.8 and Figure 1.9 highlight the degree to which the divergence of monthly average real-time prices during all hours was caused by extreme prices during the small percentage of intervals when power balance constraint relaxations occurred. With these intervals excluded, real-time prices were less than average day-ahead and hourly prices during the second quarter. Indeed, after correcting for these intervals, May had the largest negative spread in hour-ahead and real-time prices since the market began in April 2009.

Figure 1.8 Change in monthly prices excluding hours when power balance constraint relaxed (PG&E LAP, all hours)

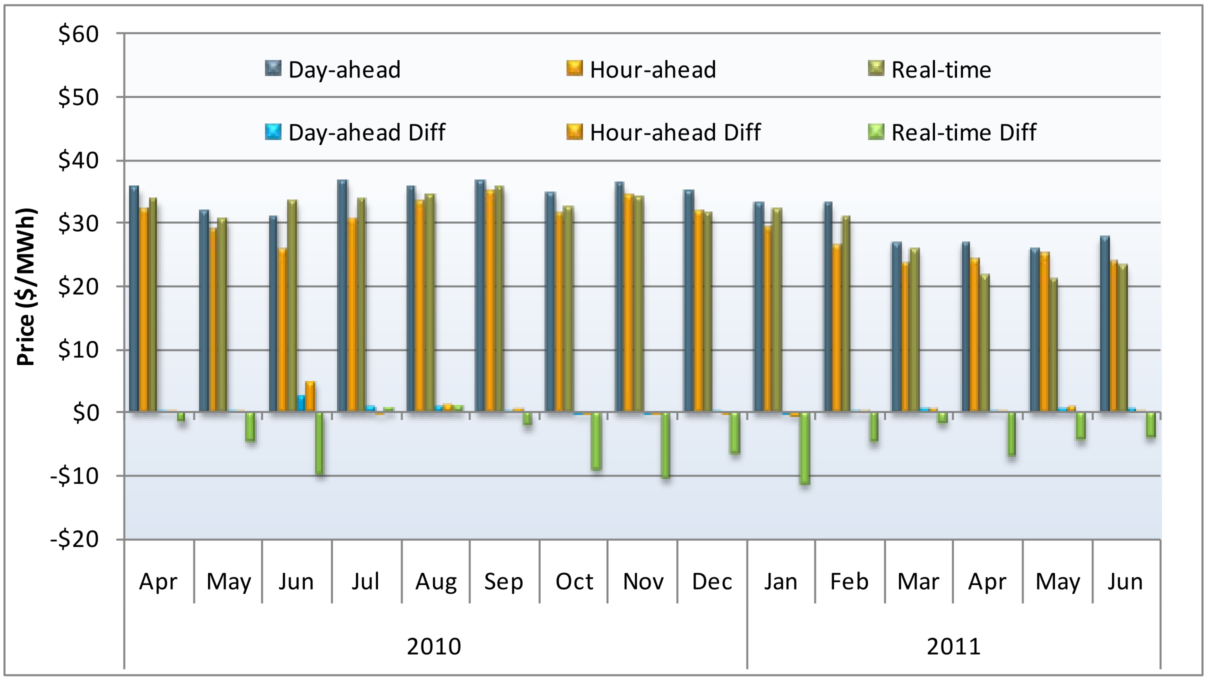
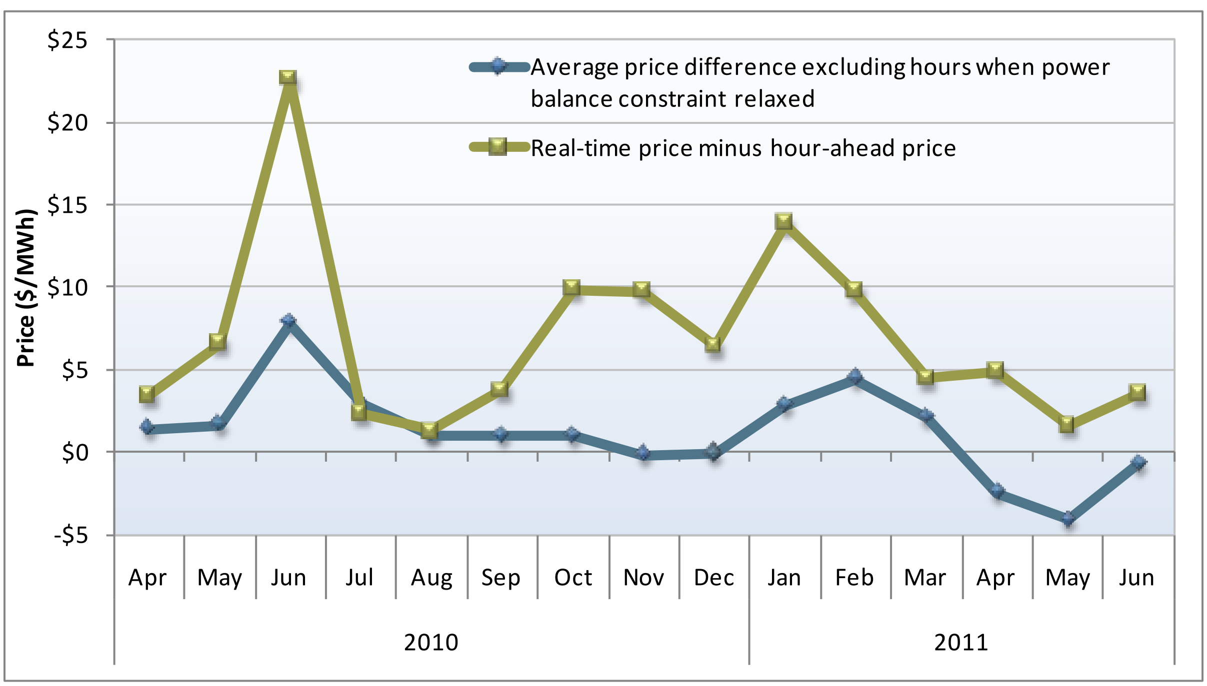


Figure 1.9 Difference in monthly hour-ahead and real-time prices excluding hours when power balance constraint relaxed (PG&E LAP, all hours)

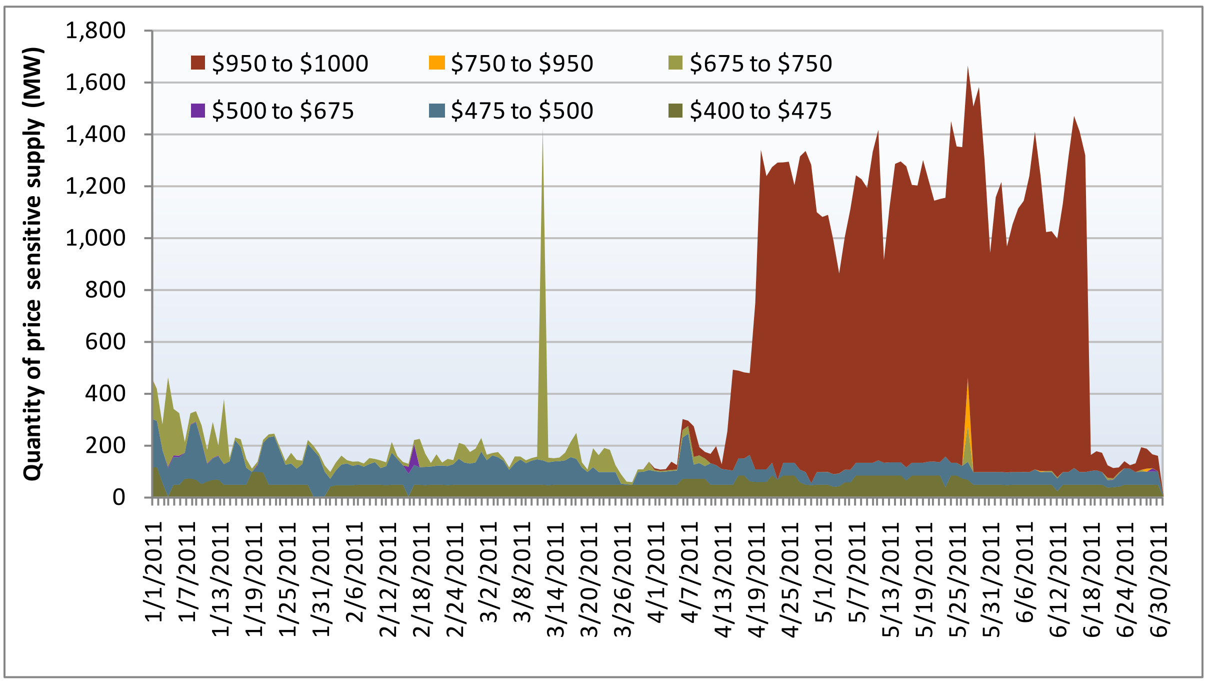


1.3 Increase in the bid cap

On April 1, the energy market bid cap was increased to $1,000/MWh from $750/MWh. Figure 1.10 shows that the volume of real-time energy bid at or near these bid caps increased dramatically in mid-April and declined sharply in mid-June. DMM attributes this increase in supply offered near the bid cap to market behavior identified in an emergency tariff filing with the Federal Energy Regulatory Commission on June 22, 2011.[7] The amount of capacity bid at or near the $1,000/MWh bid cap declined just before this filing was made.

The volume of supply bid at or near the cap was consistent with the pattern in Figure 1.10 during most hours with the exception of the last few hours of the day. In these hours, there were fewer bids at the bid cap, consistent with the strategy outlined in the ISO's June 22 filing. The strategy outlined in the filing was intended to increase bid cost recovery payments, not real-time prices.[8] As such, much of the generation bid near the cap was ramp limited and therefore unable to set price.

Figure 1.10 Real-time bids by price bin: all hours



Even though the bidding behavior around the bid cap changed dramatically from mid-April through mid-June, the frequency of price spikes did not increase relative to other periods. As summarized in Figure 1.11, the frequency of price spikes occurred in roughly 1 percent of the time in the second quarter. This was significantly less than the frequency during the second quarter of 2010 and less than the frequency of price spikes in the first quarter of 2011.

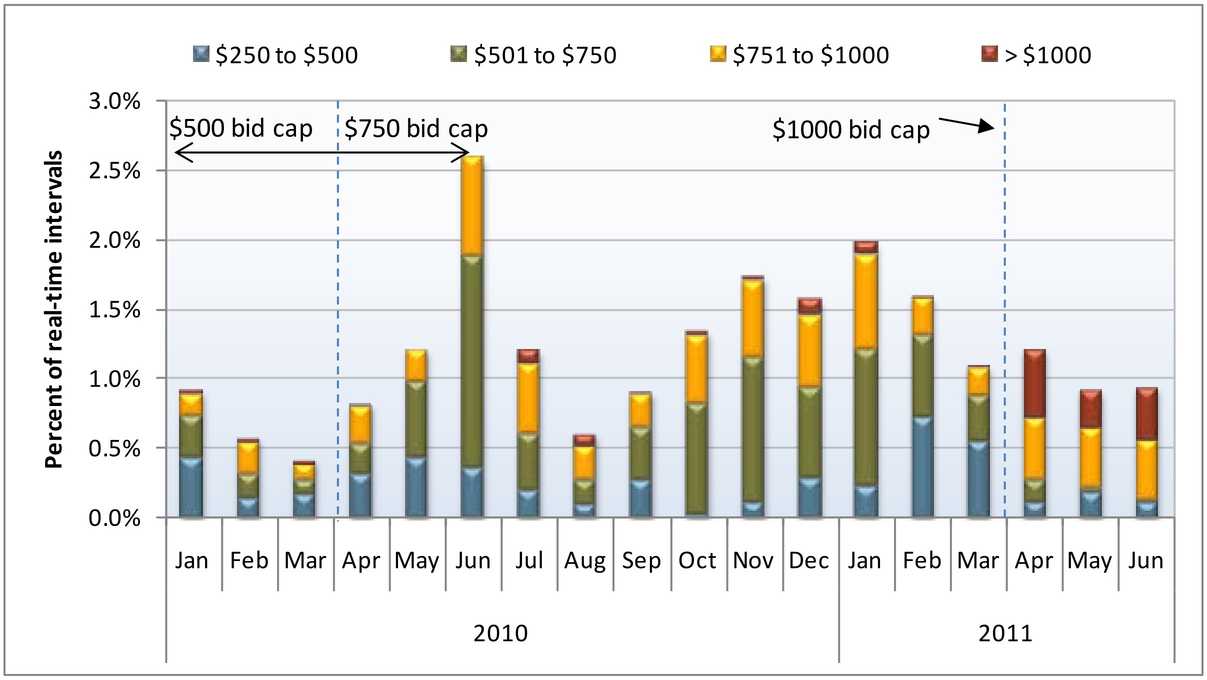
While the frequency was fairly consistent and to some extent lower than in previous periods, the magnitude of price spikes increased in the second quarter. Notably, the frequency of price spikes above

7 See FERC Docket No. ER11-3856.

8 Bid cost recovery payments increased as a result of the strategy. After the bid behavior changed in mid-June, bid cost recovery payments fell.

$1,000/MWh was as high as during the first quarter of the nodal market (April – June 2009). DMM attributes this change in magnitude to the increase in the bid cap to $1,000/MWh and its relationship to the power balance constraint relaxation penalty price rather than to changes in participant behavior. Indeed, in 2010, DMM observed a shift in magnitude of price spikes over $500/MWh after the bid increase to $750/MWh on April 1, 2010.

Figure 1.11 Frequency of price spikes (all LAP areas)

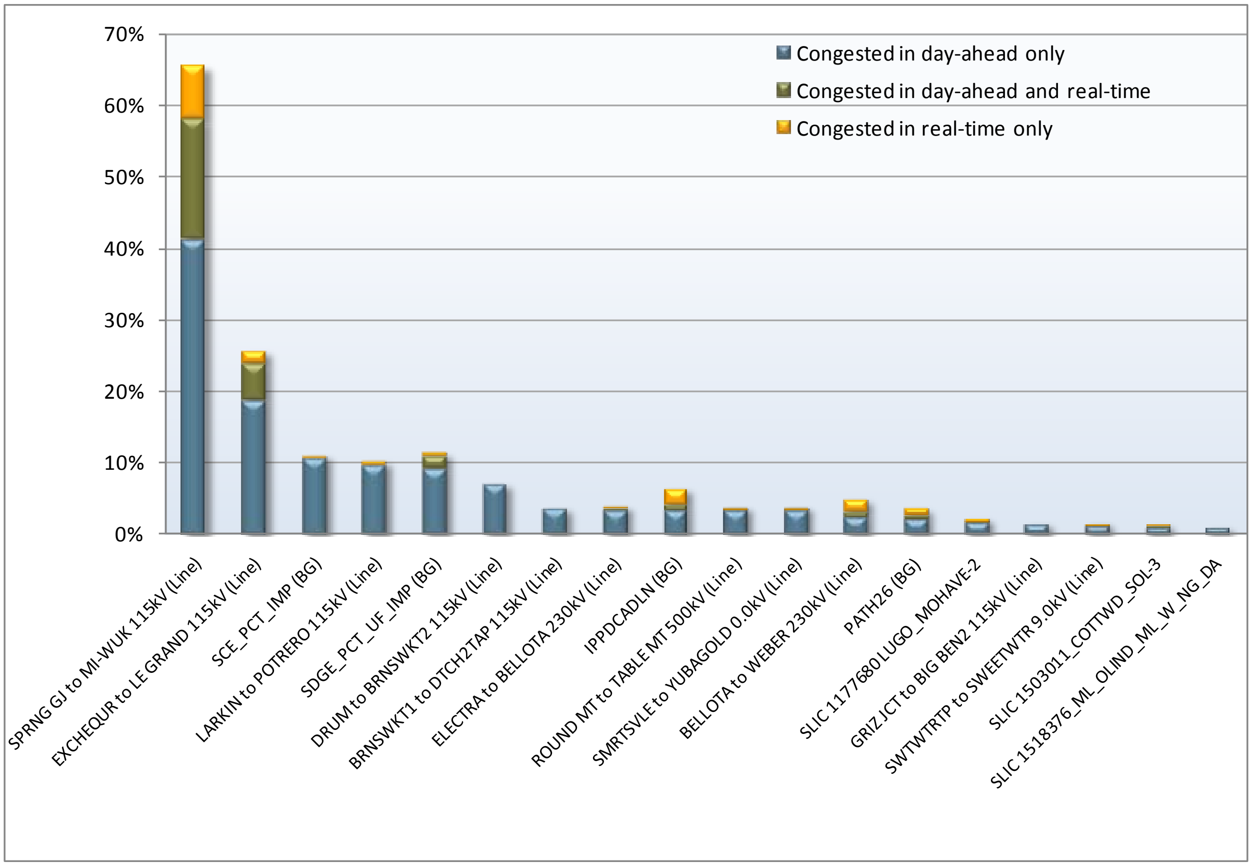


1.4 Congestion

Congestion within the ISO system had minimal impact on overall prices. However, the frequency of day-ahead congestion increased, particularly on constraints in generation pockets and those relating to imports into the Southern California Edison and San Diego Gas and Electric areas. Moreover, congestion in the day-ahead market did not usually materialize in the real-time market. This increase in day-ahead congestion coincided with implementation of virtual bidding on February 1, 2011, and has continued through the second quarter. DMM continues to evaluate the extent that this increase in congestion was attributable to convergence bidding as opposed to other factors such as generation and transmission outages.[9]

[9] DMM has limited ability to assess the impact of virtual bidding on congestion due to problems with re-running the day-ahead market software, as noted in footnote 1.

Figure 1.12 Consistency of congestion in day-ahead and real-time markets (April - June 2011)



The Spring GJ to Mi-Wuk 115 kV (line) has historically been the most frequently congested constraint during the spring and early summer months, though this constraint has only a minimal effect on PG&E congestion. This line is a radial generation tie with capacity less than that of the hydro generation tied to it. During the hydro runoff season, which occurs in the second quarter, generation becomes trapped behind the Spring Mi-Wuk flowgate. When the flowgate is congested, the hydro units can respond to prices, or, in the extreme, spill water when backed down. The nodal LMP on the generation side of the flowgate is low even when the system marginal energy component is high, resulting in a high LMP congestion component.

Similar generation pocket constraints include Exchequr to Le Grand 115 kV (line), Drum to Brnswkt2 115 kV (line), Brnswkt1 to Dtch2tap 230 kV (line), Electra to Bellota 230 kV (line), Smrtsvle to Yubagold 60 kV (line), Grizjct to Bigben2 115 kV (line) and Swtwtrtp to Sweetwtr 9 kV (line).

Outages on the Southwest Powerlink (SWPL) (North Gila-Hassayampa and Imperial Valley-Miguel) contributed to congestion into the SCE and SDG&E areas. When outages occur on SWPL, the internal San Diego percent of generation requirement increases to 30 percent from 25 percent. Limits are also placed on the South of SONGS transmission lines. Congestion in the SCE area was also increased by manual reductions (or conforming) of transmission limits for reliability reasons, and by local outages (e.g., Mira Loma-Olinda 220 kV Line).

Congestion on the Larkin to Potrero 115 kV constraint was related to a number of outages in connection with the A-X #1 115 kV cable work.

1.5 Scarcity pricing of ancillary services

Scarcity pricing of ancillary services occurs when the market optimization is unable to meet reserve requirements. Table 1.1 highlights the specific intervals with scarcity of ancillary services in the real-time pre-dispatch market, the scarce ancillary service and the MW shortfall. In total, there were a dozen intervals where scarcity pricing of ancillary services was triggered in the second quarter. Only spinning reserves and regulation up markets were short by up to 23 MW and 29 MW, respectively.

Table 1.1 Ancillary service scarcity events (April 2011 – June 2011)

Date	Time	Ancillary service	Region affected	MW Shortfall
4/29/2011	5:15	Spin	SP 26	7.1
5/15/2011	0:15	Spin	SP 26 Expanded	2.6
5/23/2011	7:00	Spin	SP 26 Expanded	22.8
5/26/2011	7:15	Spin	SP 26	9.1
6/10/2011	6:00 - 6:45	Reg Up	SP 26 Expanded	16.5
6/16/2011	6:00 - 6:30	Reg Up	SP 26 Expanded	28.9
6/16/2011	6:45	Reg Up	SP 26 Expanded	6.5

In comparison to the first three months of the year, there were fewer hydro resources offering ancillary services in the market during the second quarter. This reduction of resources can be attributed to the following factors:

- There was a large amount of snowpack this year (approximately 160 percent of historical average). As a result, hydro-electric generators produced energy rather than offering ancillary services into the market.
- Loads reached their seasonal lows. This had the effect of decreasing the amount of net committed resources in the market, reducing the available online supply of ancillary services in the market.

These two factors taken together with normal system conditions, including de-rates and forced outages of generation, caused the scarcity of ancillary services during a dozen 15-minute intervals in the quarter. All of these events were concentrated in either SP26 or SP26 expanded ancillary service sub-regions. There were no scarcity events in the CAISO or CAISO expanded regions.

The overall direct market effect of these scarcity events on ancillary service costs was just under $150,000. Indirectly, there is likely to have been unit commitment in the real-time pre-dispatch process that may not have occurred otherwise. However, no real-time generation received the 15-minute real-time pre-dispatch energy prices. Real-time generation settles against the 5-minute real-time prices, which are, at this time, not directly influenced by the scarcity pricing.

2 Convergence bidding

Convergence bidding was implemented in the day-ahead market for February 1, 2011. Net revenues for convergence bidding entities have been just over $34 million for the first five months of this new market feature (February through June). However, DMM's assessment has found little evidence that convergence bidding has helped price convergence or increased the efficiency of day-ahead unit commitment decisions. Meanwhile, convergence bidding has added to energy imbalance offset costs that are ultimately allocated to demand.

As shown in Section 1, average price convergence did appear to improve, particularly in the month of May. However, on an hourly basis, prices in real-time overshot day-ahead and hour-ahead prices in some hours and undershot in others, indicating that convergence was only achieved through averaging.

Background

Convergence bidding is designed to allow any creditworthy entity, regardless of whether or not they own physical load or generation, to place bids to buy power and offers to sell power into the day-ahead market. As these bids are only virtual and not physical, they will liquidate in real-time and cause the physical system to re-dispatch accordingly.

In theory, these participants profit by arbitraging the difference between day-ahead and real-time prices. As participants take advantage of opportunities to profit through convergence bids, this activity should drive real-time and day-ahead prices closer. The following illustrates how virtual demand and supply are designed to work.

- If prices are higher in the real-time market relative to the day-ahead market, convergence bidders should place virtual demand bids. Virtual demand will raise load in the day-ahead, which could lead to additional unit commitment. This additional unit commitment would occur because of higher prices in the day-ahead market. This additional unit commitment would be available in real-time and would have a dampening effect on real-time prices. The virtual demand would then be paid the difference between the real-time price and the day-ahead price for each virtual megawatt.

- If prices are lower in the real-time market relative to the day-ahead market, convergence bidders should place virtual supply bids. Virtual supply will displace the supply of physical generation in the day-ahead and could lead to units being committed lower on their bid curves, or potentially even displace of additional unit commitments.[10] This reduction in physical commitment would occur because of lower prices in the day-ahead market. In real-time, these virtual supply resources would not materialize and should therefore have an elevating effect on real-time prices. The virtual supply would then be paid the difference between the real-time price and the day-ahead price for each virtual megawatt.

The California market does have a unique feature that makes it different from most other ISOs and RTOs. California's market design re-optimizes imports and exports in an hour-ahead market. These

[10] This will not create a reliability issue as the residual unit commitment process occurs after the integrated forward market runs. 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 these resources.

inter-tie resources settle against hour-ahead prices rather than 5-minute real-time prices. The same is true for convergence bids on the inter-ties. These bids also settle against hour-ahead prices and not 5-minute real-time prices.

As shown in Section 2.1.2, this feature of the ISO market design has led to a particular convergence bidding strategy that has been exploited when prices diverge between the hour-ahead and real-time markets. While this virtual bidding strategy has been highly profitable and has increased revenue imbalances allocated to load-serving entities, it does not appear to have provided any significant benefits in terms of helping to converge prices in the hour-ahead and 5-minute real-time markets.

2.1 Convergence bidding activity

Convergence bidding has had two distinct elements over the course of the first few months. Initially, volumes increased steadily over the first few months until the second half of April. Afterwards, volumes dropped precipitously and then began to increase steadily through June. Second, the vast majority of virtual supply positions are found on inter-ties, whereas virtual demand positions are most often on internal locations. This activity is outlined below.

2.1.1 Increase in convergence bidding volumes

Convergence bidding volumes increased steadily from the start of convergence bidding on February 1 until mid-April. In the second quarter, convergence bidding volumes were generally lower than in the first two months, though trading activity increased steadily after falling off in mid-April. Figure 2.1 and Figure 2.2 show the quantities of both virtual demand and supply offered and cleared in the market.

As shown in Figure 2.1:

- On average, roughly 60 percent of virtual supply and demand bids cleared in the first five months of convergence bidding.
- With the exception of the very first week of convergence bidding, cleared virtual supply has outweighed cleared virtual demand on average by over 580 MW.

As shown in Figure 2.2:

- Virtual supply exceeds virtual demand in every hour except the late evening ramp down hours ending 23 and 24.
- The total volume of offered and cleared virtual bids is consistent for much of the day with the exception of the early morning hours ending 3 through 7.

Figure 2.1 Weekly average offered and cleared virtual activity

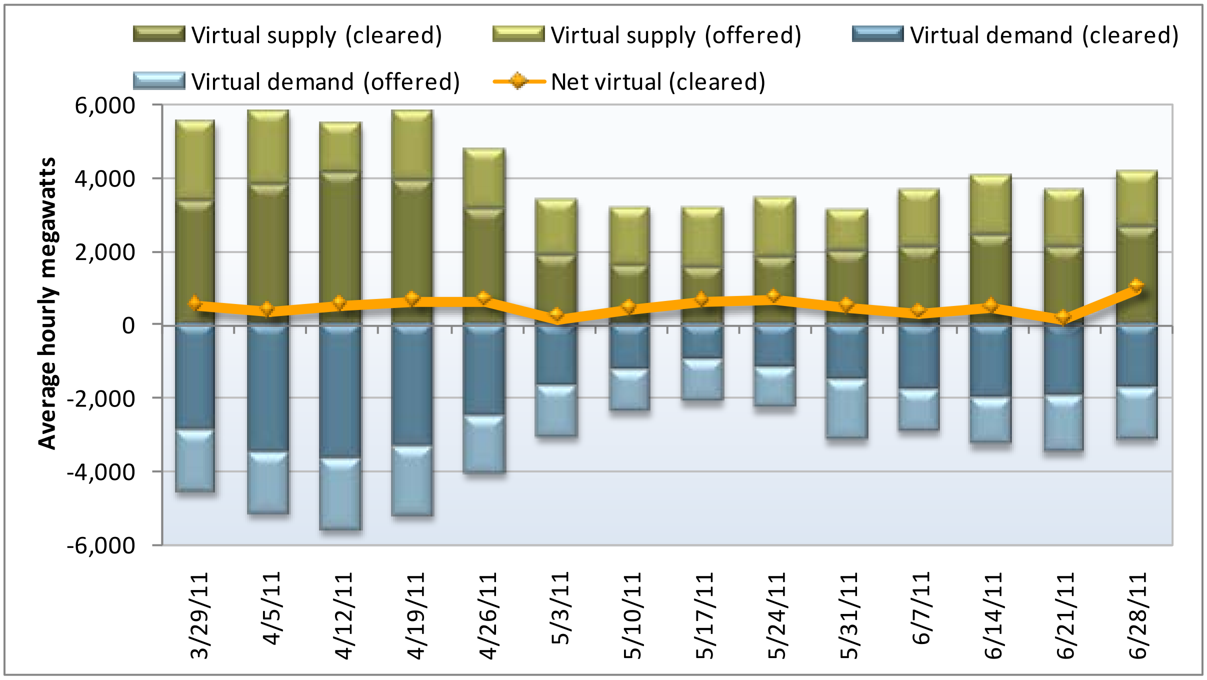
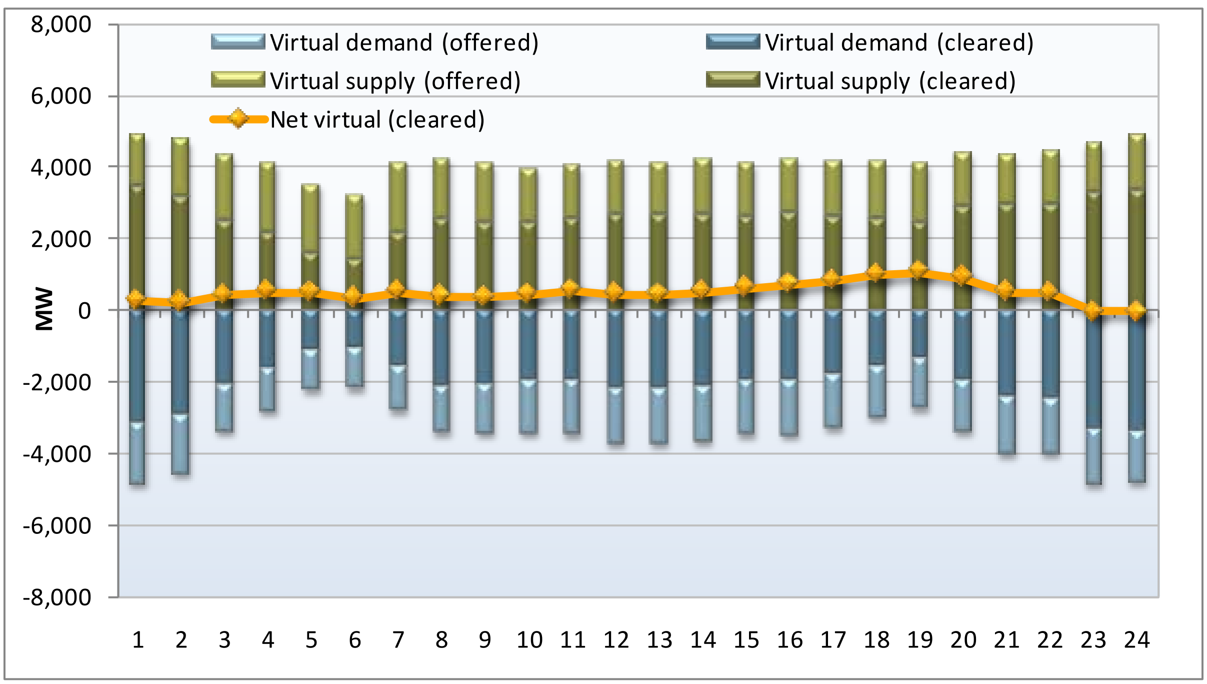


Figure 2.2 Hourly offered and cleared virtual activity (May – June 2011)



2.1.2 Virtual supply at the inter-ties and virtual demand at internal nodes

The difference between convergence bidding positions at the inter-ties and at internal nodes shows a distinctive pattern. As shown in Figure 2.3, convergence bidding on inter-ties (shown in green) is weighted towards virtual supply and convergence bidding on internal locations (shown in blue) is weighted towards virtual demand.

Numerous market participants have employed a strategy where they place virtual supply positions at the inter-ties and then place an equal and opposite virtual demand position at internal locations. Figure 2.4 shows the volume of these overlapping positions. The blue bars represent the weekly average megawatts associated with this strategy, whereas the green bars represent offsetting positions attributable to different convergence bidding entities placing offsetting positions. While there was a sharp drop off in this strategy in mid-April and into May, the volume of megawatts again began to increase at the end of May and into June.

Figure 2.3 Weekly net cleared inter-tie and internal positions

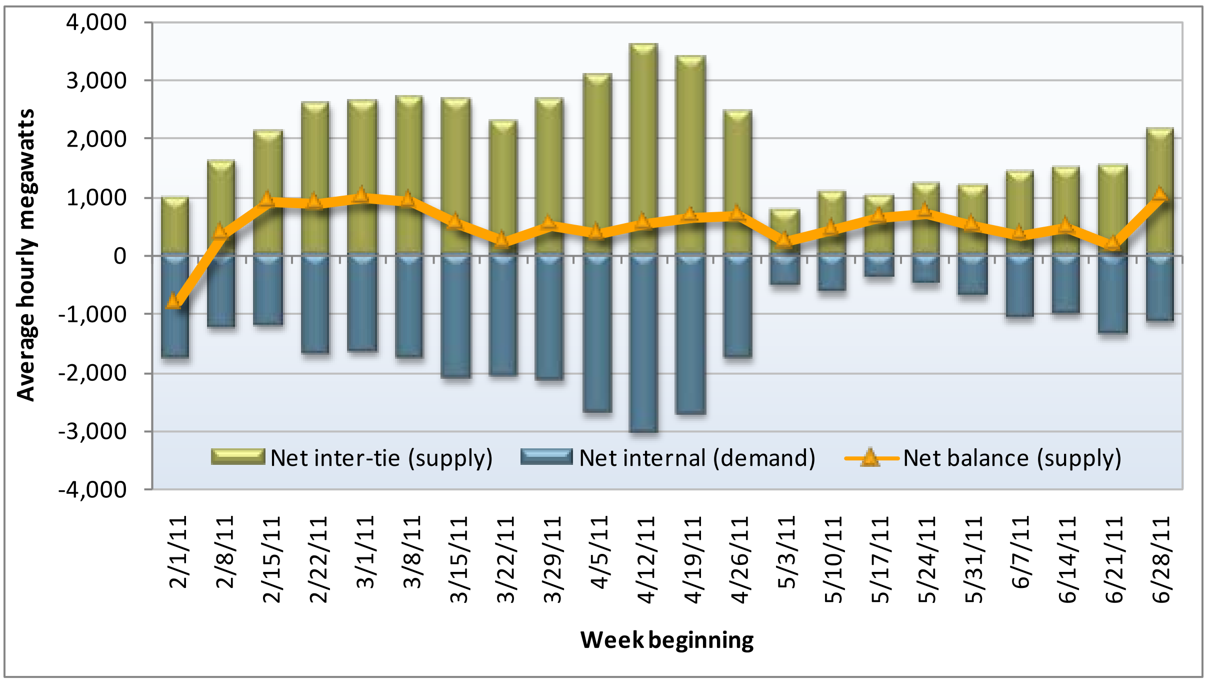
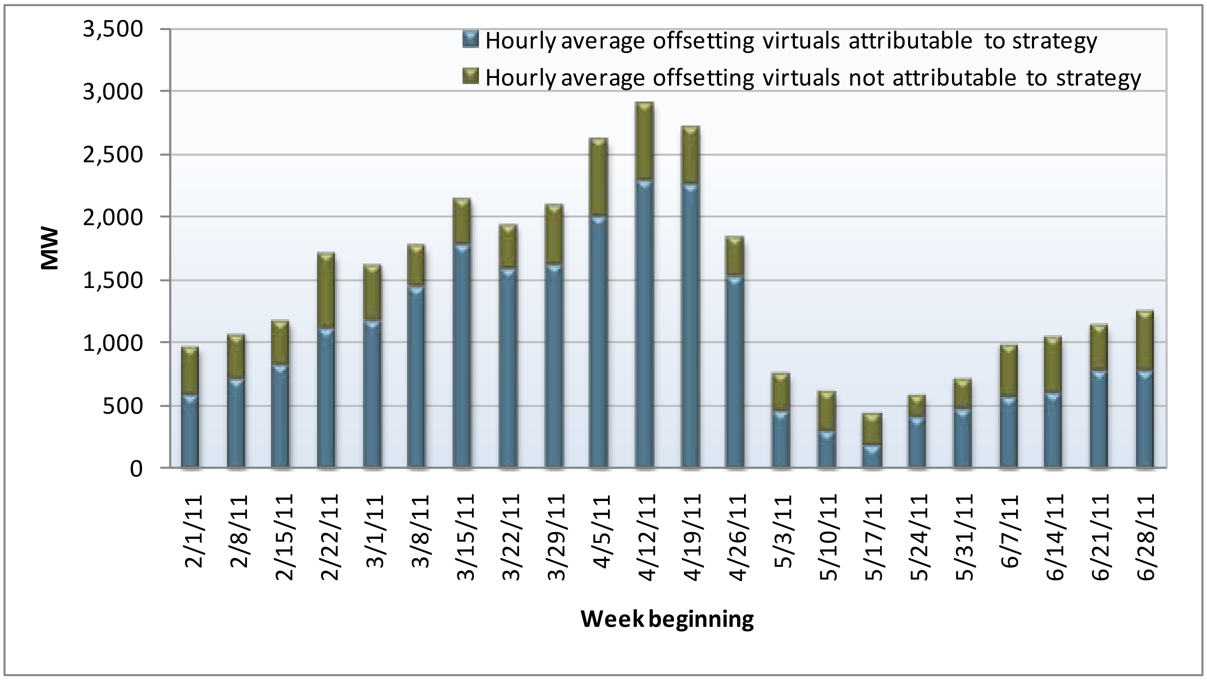


Figure 2.4 Portion of cleared virtual bids attributable to offsetting virtual bids submitted by same participant (virtual imports plus virtual internal demand)



As noted above, convergence bidding at the inter-ties settles against the hour-ahead market prices, whereas convergence bidding at internal nodes settles against the 5-minute real-time market prices. If prices in the hour-ahead market were consistent with 5-minute real-time market prices this would not create cause for concern. Yet, as shown in the next section, prices between these markets have been markedly different for much of the first five months. This has led to substantial uplifts that are outlined further in Section 2.2.3.

2.2 Convergence bidding effects on market

If convergence bidding is working as intended, day-ahead, hour-ahead and 5-minute real-time market prices should converge. Figure 2.5 shows weekly average prices at the PG&E load aggregation point.

- In February and March there appears to be signs of price convergence as real-time prices (green line) become closer to the day-ahead prices (orange line), while the hour-ahead prices (blue line) come closer to the day-ahead prices.
- Since the end of March and to the end of June, prices diverge substantially. Contributing factors for the price divergence include the frequency of power balance constraint relaxations and the increase in the bid cap from $750/MWh to $1,000/MWh, as well as generation and transmission outages.
- Since April real-time price volatility increased steadily. Unlike the first quarter, real-time prices fluctuated around day-ahead and hour-ahead prices. Averaged over the month, they may give a false sense of convergence, but as noted in Section 1, average absolute prices have diverged significantly starting in March.

Figure 2.5 Weekly average prices PG&E load aggregation point – all hours

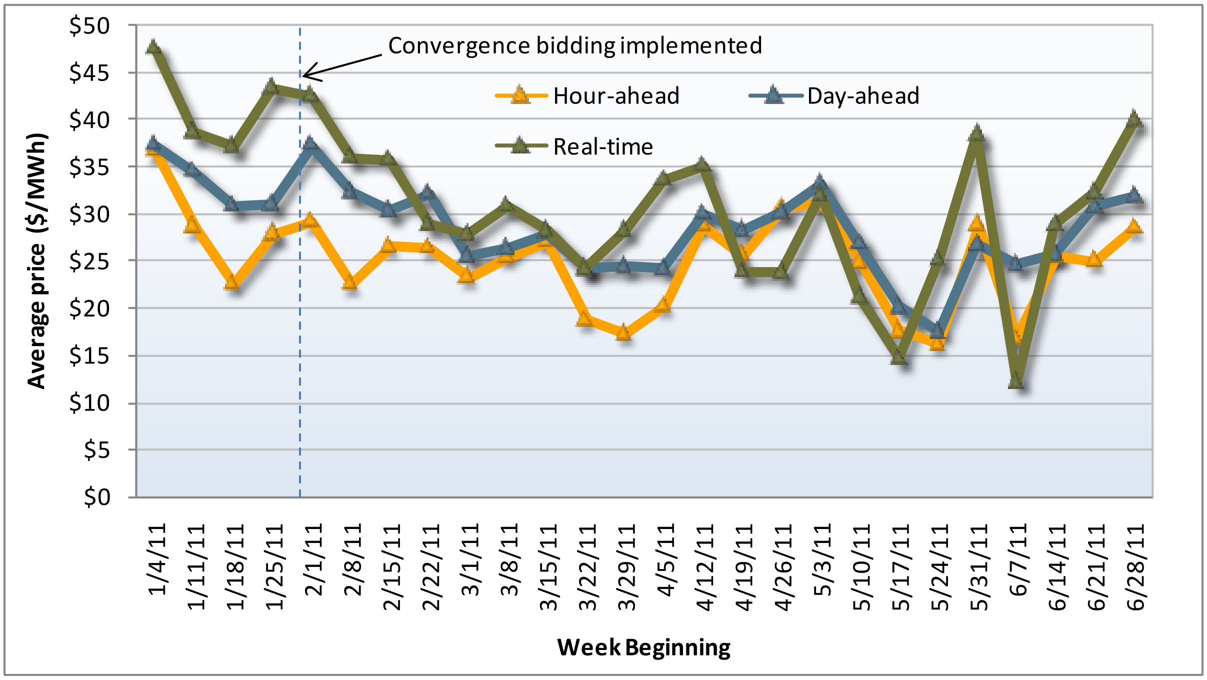


Figure 2.6 Weekly average difference between real-time and hour-ahead prices (PG&E LAP)

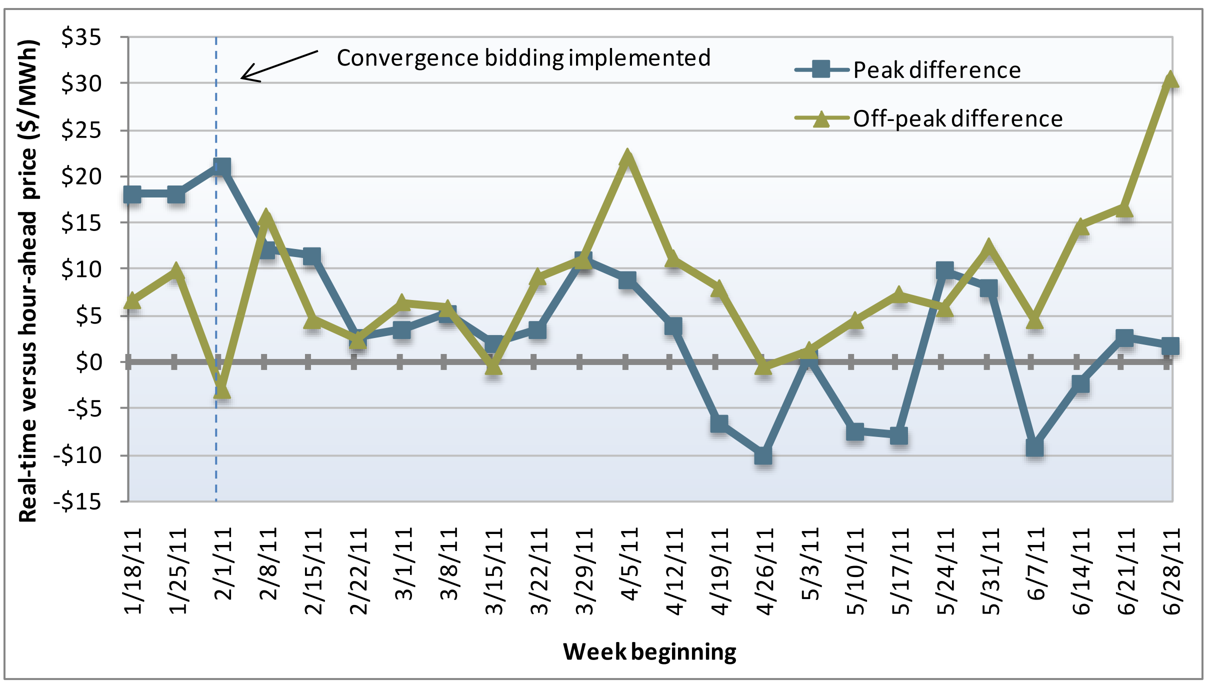
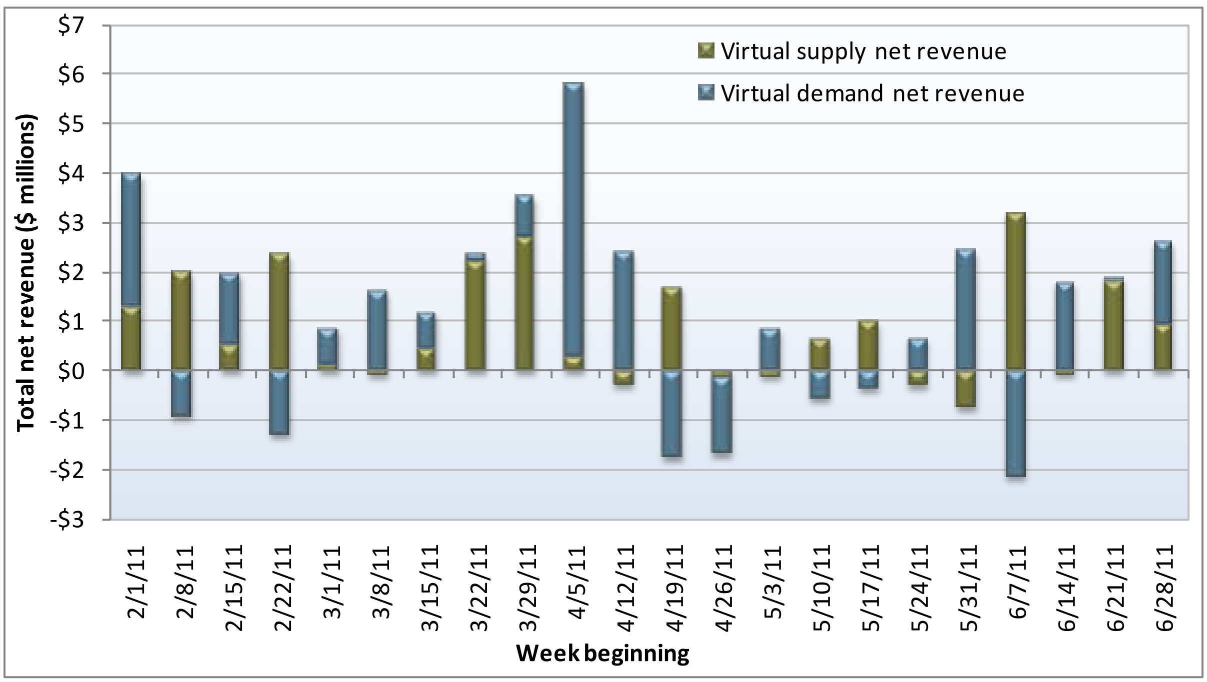


Figure 2.6 compares the difference between prices in the hour-ahead and 5-minute real-time markets for peak and off-peak periods. Figure 2.6 shows that the price difference fell in February and was near zero for much of March. Prices diverged again at the end of March and even more into June. By the end of June, peak price differences were near zero and off-peak prices exceeded real-time prices.

2.2.1 Net profits from convergence bidding

With the exception of the end of April and May, the total net profits paid to convergence bidding entities have been positive. Over the course of the second quarter, net revenues paid out to convergence bidding entities totaled almost $19 million, just over the $16 million paid to convergence bidding entities in February and March. Figure 2.7 shows weekly convergence bidding net revenues for both virtual demand and virtual supply positions. Frequently, both virtual supply and virtual demand positions have led to positive net revenues. This is because inter-tie bids and internal bids settle against hour-ahead and 5-minute real-time market prices, respectively. Moreover, these prices most often move in different directions relative to day-ahead prices.

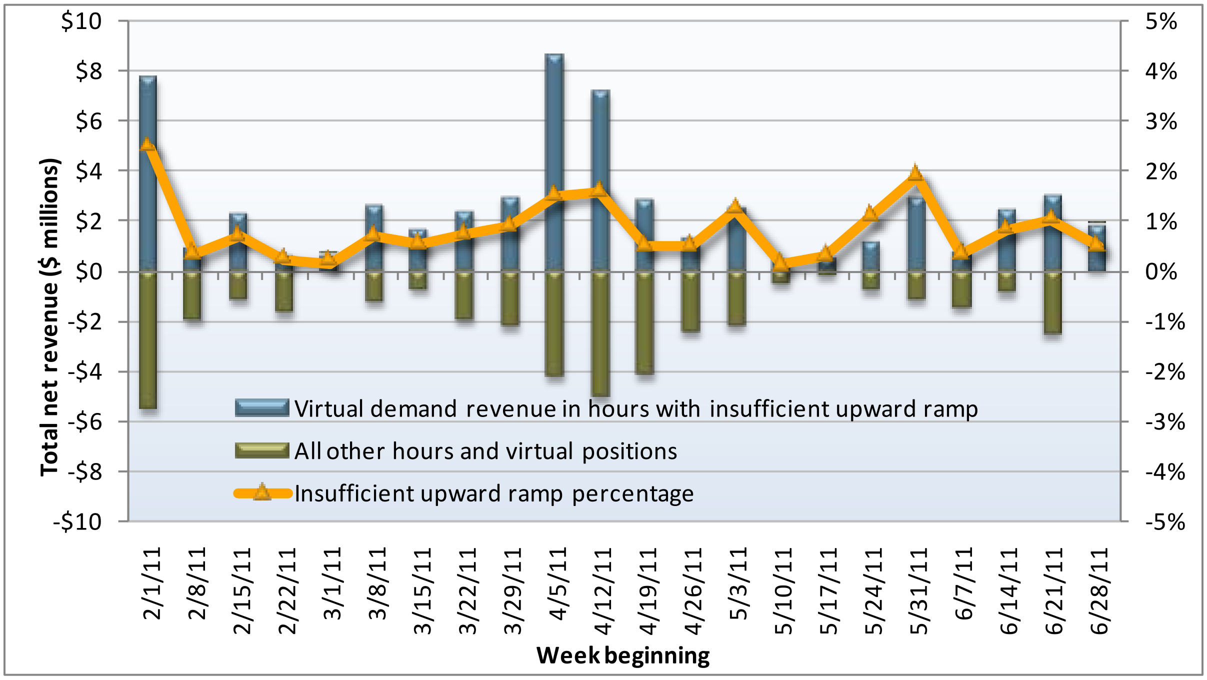
Figure 2.7 Total weekly convergence bidding net revenues



Net revenues on internal nodes

Approximately 80 percent of virtual demand bids clear at internal locations. Virtual demand bids at internal nodes are profitable when real-time prices spike in the 5-minute real-time market. Intervals when the system power balance constraint relaxes account for almost all of the positive revenues for internal virtual demand positions, as shown in Figure 2.8. As noted in Section 1, when the power balance constraint is relaxed, the system marginal energy component of the price is set to the bid cap, which was $750/MWh in the first two months of convergence bidding and increased to $1,000/MWh on April 1. Net revenues received from these brief but extreme price spikes are typically high enough to outweigh losses when the day-ahead price exceeds the real-time market price. In fact, having a single 5-minute interval price spike can yield enough aggregate income to compensate losses in the remaining intervals of the hour.

Figure 2.8 Convergence bidding revenues at internal nodes



These price spikes are typically associated with brief shortages of ramping capacity. Convergence bidding can potentially add additional capacity, but that capacity may not be enough to address the ramping limitations. Moreover, in the event of over generation, real-time prices can be negative, but they never go 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.

2.2.2 Changes in unit commitment

In the day-ahead market, if scheduled demand is less than the ISO forecasted demand, the residual unit commitment process procures additional capacity to meet the forecasted demand as well as any forecasted shortfalls of minimum generation requirements.

Cleared virtual supply often outweighs cleared virtual demand and, as a result, more units are committed in the residual unit commitment process. Accordingly, more residual unit commitment capacity is needed to replace the net virtual supply with physical supply. This situation is likely to increase the direct costs and bid cost recovery payments associated with residual unit commitment.

In the second quarter of 2011, total direct residual unit commitment costs totaled $250,000 compared to a 2010 total of $83,000. Since convergence bidding started in February, direct residual unit commitment costs have totaled around $385,000. Bid cost recovery payments for the residual unit commitment capacity amounted to over $900,000 in the second quarter compared to $1.4 million in all of 2010.[11]

2.2.3 Costs associated with continued price divergence and convergence bidding

Divergence in prices can pose unnecessary additional inefficiencies and costs on the system. When net imports decrease in the hour-ahead market, but real-time imbalance energy increases, the decrease in net imports may be inefficient.[12] Moreover, if net virtual supply on the inter-ties outweighs net virtual demand on internal nodes, and real-time imbalance energy increases, this may also be inefficient.

Such reductions are inefficient if hour-ahead prices are systematically lower than real-time prices, so that the ISO is selling both physical and virtual supply in the hour-ahead at a low price and then dispatching additional energy in real-time at a higher price. Conversely, if both physical supply and virtual demand are purchased in the hour-ahead market at high prices and then additional energy is dispatched in real-time at lower prices, this can also create imbalances. These situations can create substantial uplifts that must be recovered from load-serving entities through the real-time imbalance energy offset charge.[13]

Physical net imports in the hour-ahead market relative to day-ahead market

Historically, hour-ahead market prices have been lower than both day-ahead and real-time market prices. However, over the course of the last few months, hour-ahead prices have become more in line with real-time prices and closer to day-ahead prices (as shown in Section 1). This has coincided with the change in operational load adjustment patterns whereby loads are adjusted upward systematically in the hour-ahead market to compensate for modeling discrepancies.[14] Correspondingly, there has been a shift in the hour-ahead market from reducing net imports, to increasing net imports on average.[15]

Figure 2.9 shows hourly average differences of scheduled physical hour-ahead market imports and exports from the scheduled day-ahead imports and exports. Continuing the trend started in March, the average change in physical imports has outweighed the average change in physical exports in the hour-ahead market. As a result, net physical imports increased in the hour-ahead market by an average of just over 200 MW in the second quarter. For the same period, net virtual supply has outweighed net virtual demand by roughly 580 MW since convergence bidding started in February.

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11 In the first half of 2011, net bid cost recovery payments associated with all energy, ancillary services and residual unit commitment markets were significantly higher relative to the same period in 2010. After the ISO's emergency tariff filing in June, the payments began to decrease.

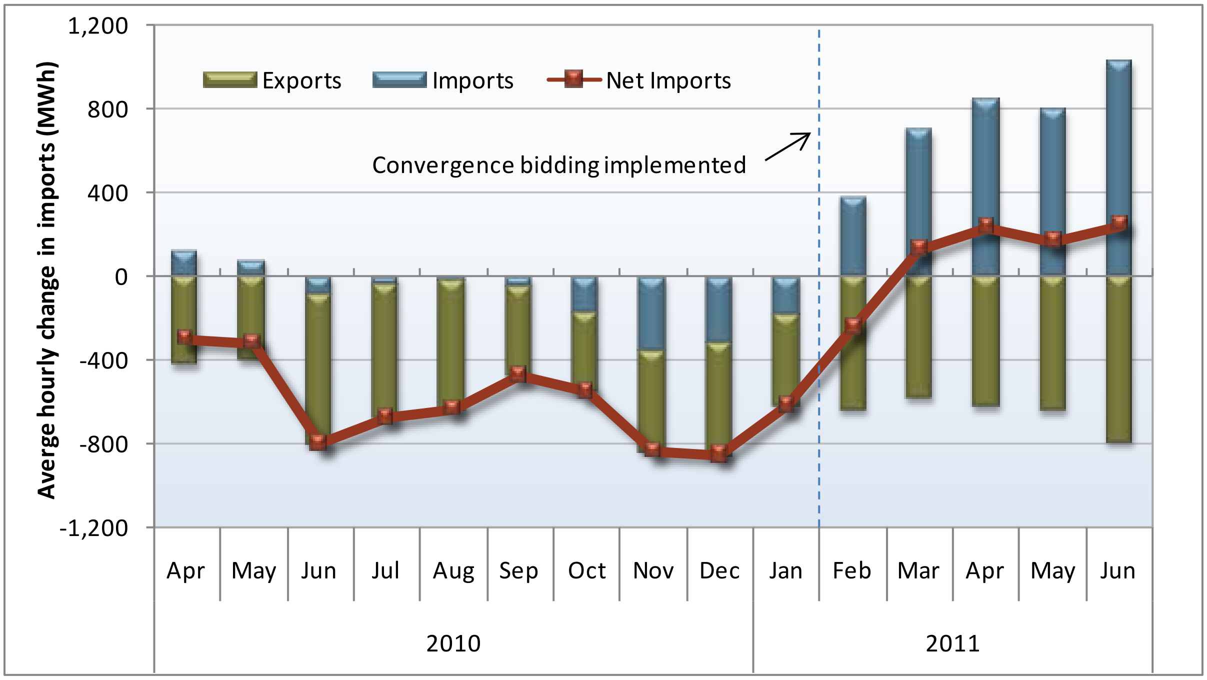
12 The inter-tie prices are relative to prices in neighboring systems. If prices outside of the ISO system are higher, it makes economic sense for net imports to decrease in the hour-ahead scheduling process. This can be accomplished by either reducing imports or increasing exports.

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

14 See Section 1.2 for more detail on the load adjustment procedures.

15 At this time, DMM has not been able to determine the extent that the load adjustments have led to increased net imports relative to the actions of convergence bidding.

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



Costs of differences in physical net imports in the hour-ahead relative to real-time market

Real-time energy imbalances can occur when physical net imports decrease at hour-ahead prices that are lower than real-time prices when the real-time dispatch energy increases. Imbalances can also increase when physical net imports increase at hour-ahead prices that are higher than real-time prices when the real-time dispatch energy decreases. In both cases the ISO procures energy in the higher cost market and sells off energy in the lower cost market.[16] The effects of these movements are outlined below.

A. Costs of decreases in physical net imports in the hour-ahead relative to real-time market

When physical net imports decrease in the hour-ahead and real-time imbalance energy increases, the decreased imports in the hour-ahead are likely to have increased the need to dispatch imbalance energy in real-time.[17] This scenario occurred in almost 59 percent of the hours in the second quarter.

The blue bars in Figure 2.10 show DMM's estimate of the average hourly decrease in hour-ahead net imports that were subsequently re-procured by the real-time dispatch by month. The lines in Figure 2.10 compare the corresponding weighted average prices at which this decrease in net imports was

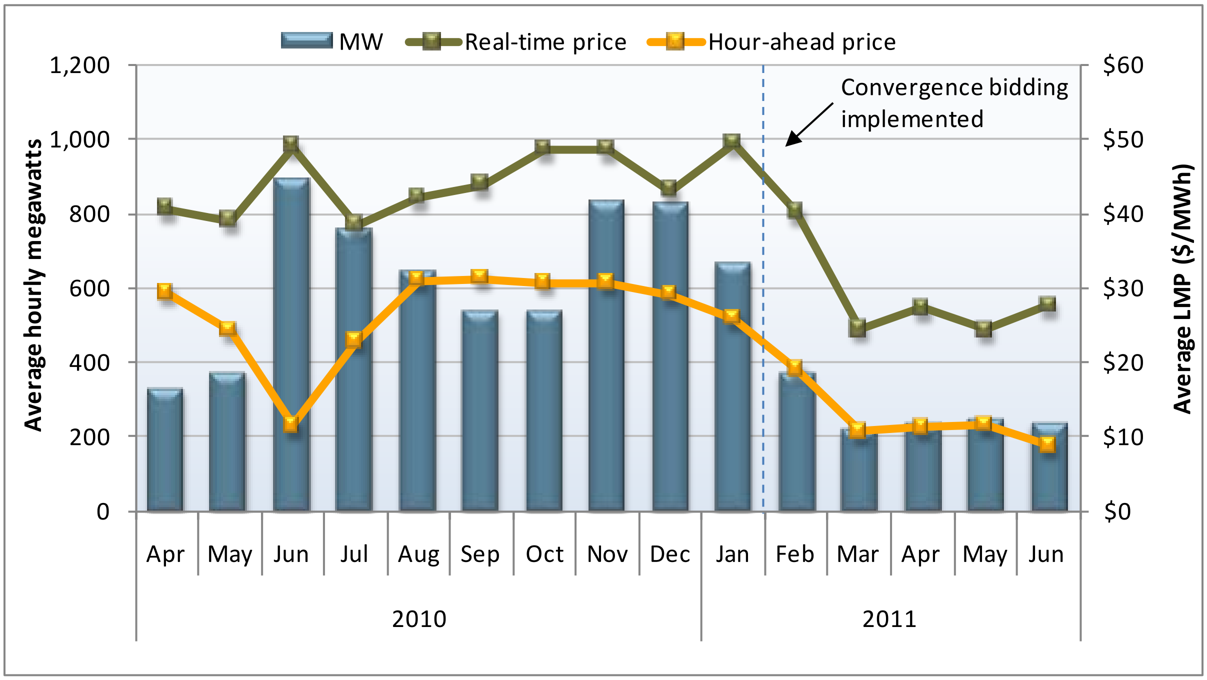
[16] When physical net imports in the hour-ahead market and real-time dispatch energy move in the same direction, no real-time imbalance is attributable to changes in physical net imports.

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

settled in the hour-ahead market and the weighted average prices for additional energy procured in the real-time market during each month.[18] Together, the hourly decrease in hour-ahead net imports and the difference in hour-ahead and real-time prices produce the estimated imbalance energy costs. The total costs are determined by the quantity that is reduced in the hour-ahead market and then re-procured in the 5-minute real-time market, combined with the difference in prices in these two markets.

As shown in Figure 2.10, there has been a slight decrease in the price divergence between hour-ahead and 5-minute real-time market prices in the second quarter of 2011 compared to the second quarter of 2010. The average price difference in the second quarter of 2011 was around $16/MWh with a diminished average quantity of about 238 MW compared to $21/MWh and 528 MW in the second quarter of 2010.

Figure 2.10 Monthly average quantity and prices of net import reductions in the hour-ahead market and resulting increase in real-time energy dispatched



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

B. Cost of increases in physical net imports in the hour-ahead relative to real-time market

When physical net imports increase in the hour-ahead and real-time imbalance energy decreases, the increased imports in the hour-ahead may have increased the need to dispatch decremental imbalance energy in real-time. This scenario occurred in over 17 percent of the hours in the second quarter.

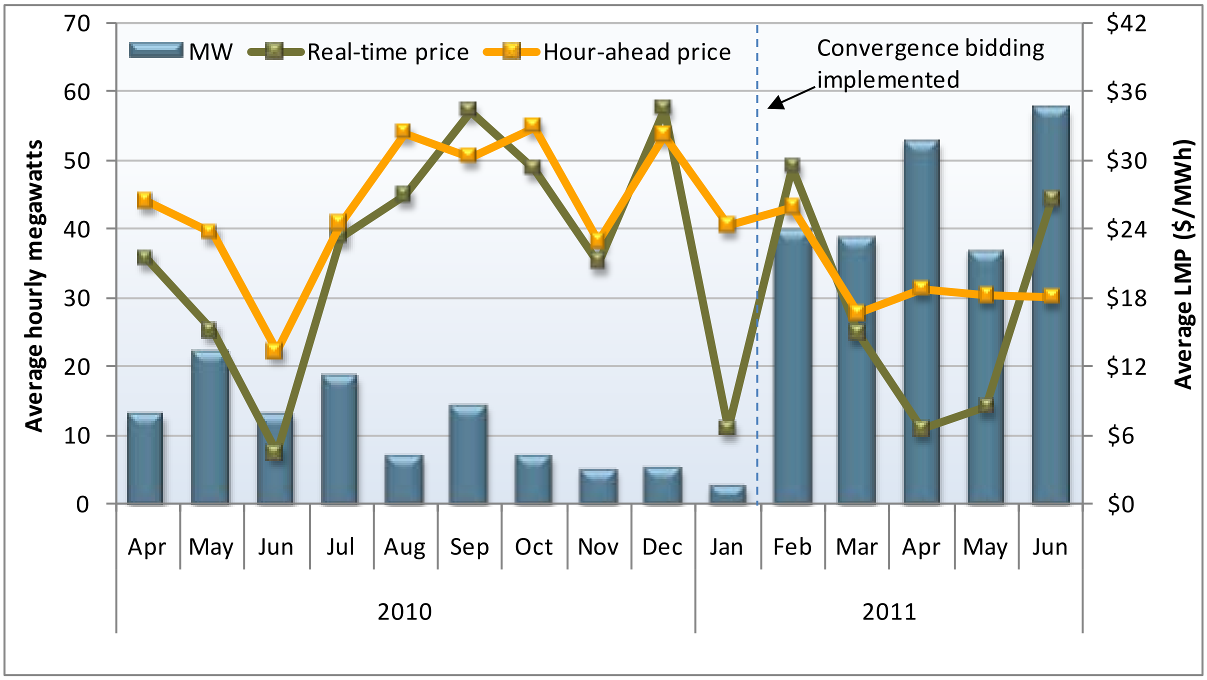
The blue bars in Figure 2.11 show DMM's estimate of the average hourly increase in hour-ahead net imports that were subsequently re-sold by the real-time dispatch by month. The lines in Figure 2.11 compare the corresponding weighted average prices at which this increase in net imports was settled in the hour-ahead market and the weighted average prices for additional energy sold in the real-time market during each month.[19] Together, the hourly increase in hour-ahead net imports and the difference in hour-ahead and real-time prices produce the estimated imbalance energy costs. The total costs are ultimately determined by the quantity that is increased in the hour-ahead market and then sold in the 5-minute real-time market, combined with the difference in prices in these two markets.

The average hourly volume of dispatch energy sold has more than quadrupled since the launch of convergence bidding in February this year, from an average of roughly 11 MW for the year prior to convergence bidding to 45 MW after. Average prices in the hour-ahead market were higher than the real-time market during most of the months. This also contributes to the imbalance cost as energy that is purchased in the hour-ahead market at higher prices is sold off in the real-time market at lower prices. Historically these volumes have been low and the relative price differences fairly tight and the effect on overall imbalance changes have been low. However, as shown in Figure 2.11, the average hour-ahead and real-time prices diverged in April and May 2011, with the hour-ahead price exceeding the real-time price by about $11/MWh, at volumes higher than the historical average.

Overall, this has been and remains a relatively small contributor to the real-time energy imbalance costs. However, as the hour-ahead market takes in more net imports and as the hour-ahead price exceeds the real-time price, this situation can also increase real-time imbalance energy costs.

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

Figure 2.11 Monthly average quantity and prices of net import increases in the hour-ahead market and resulting decrease in real-time energy dispatched



Real-time energy imbalance costs

Figure 2.12 shows the estimated costs of additional imbalance energy because of changes in net imports in the hour-ahead that is offset by imbalance energy in real-time at a different price.[20] With the introduction of convergence bidding in February 2011, these costs changed substantially and have been replaced by a virtual bidding imbalance cost. This virtual bidding imbalance cost is related to liquidating virtual positions on the inter-ties at different prices from internal virtual positions in the 5-minute real-time market.

The total convergence bidding imbalance cost during the first five months (February – June) was around $43 million. In the month of May, convergence bidding provided a small net credit to real-time energy imbalance costs of about $300,000. This is different from the overall trend and can be attributed to a difference of about $6 million between the hour-ahead payments made to the ISO for net virtual supply on the inter-ties and real-time payments made by the ISO on the net internal virtual demand. Because the hour-ahead and real-time prices were close during the month (a difference of about $3/MWh in energy prices on average), the additional payments from convergence bidding to the ISO can be attributed to a net higher volume of virtual supply on the ties in comparison to the internal virtual demand. On average, there were nearly twice as many virtual supply megawatts on inter-ties than internal virtual demand megawatts.

[20] DMM estimates these costs based on the following: 1) the decrease in hour-ahead net imports that were subsequently re-procured in real-time; 2) the increase in hour-ahead imports that were subsequently sold in real-time; and 3) the difference in hour-ahead versus real-time prices during the corresponding hour. This cost estimate is only one element of the real-time imbalance energy offset charge and, therefore, will differ from the total value of the charge for various reasons. Further detail on the different elements contained within the charge can be found in the following report: http://www.caiso.com/2416/2416e7a84a9b0.pdf.

Overall, there were almost $10 million in imbalance costs during the month of May. More than half of this value can be attributed to two factors:

- Imbalance cost attributed to the uninstructed imbalance energy (UIE);[21]
- Imbalance cost because of unaccounted for energy (UFE) dispatches in the real-time market.[22]

With May as an exception, the remaining months show substantial real-time imbalance charges because of convergence bidding activity. The ISO has initiated a stakeholder process to address issues related to convergence bidding and the real-time energy imbalance offset charge.[23] DMM supports this ISO stakeholder initiative and will provide any further comments as part of the stakeholder process.

Figure 2.12 Estimated imbalance costs due to changes in physical and virtual hour-ahead net imports at different prices than physical and virtual dispatch in the 5-minute market[24]

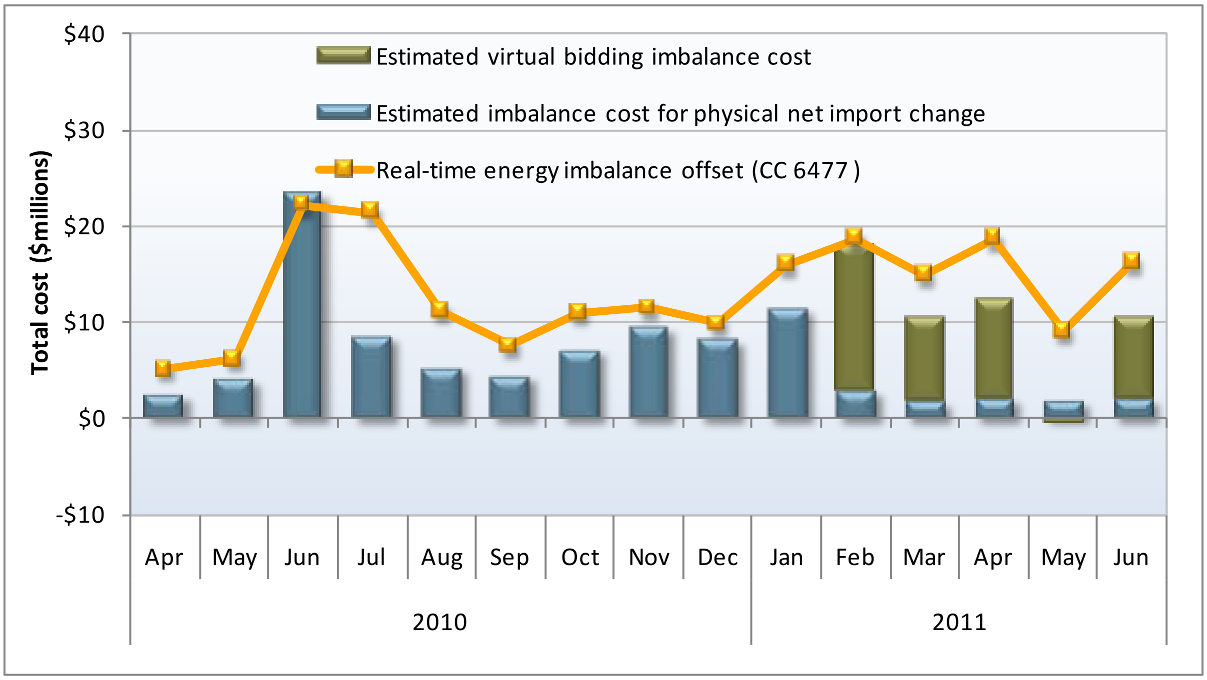


Figure 2.13 shows the breakdown of the estimated real-time imbalance cost associated with offsetting virtual supply on inter-ties and virtual demand at internal locations. The vast majority of the real-time

[21] Uninstructed imbalance energy includes generation that is self-committed or dispatched outside of the ISO market mechanism.

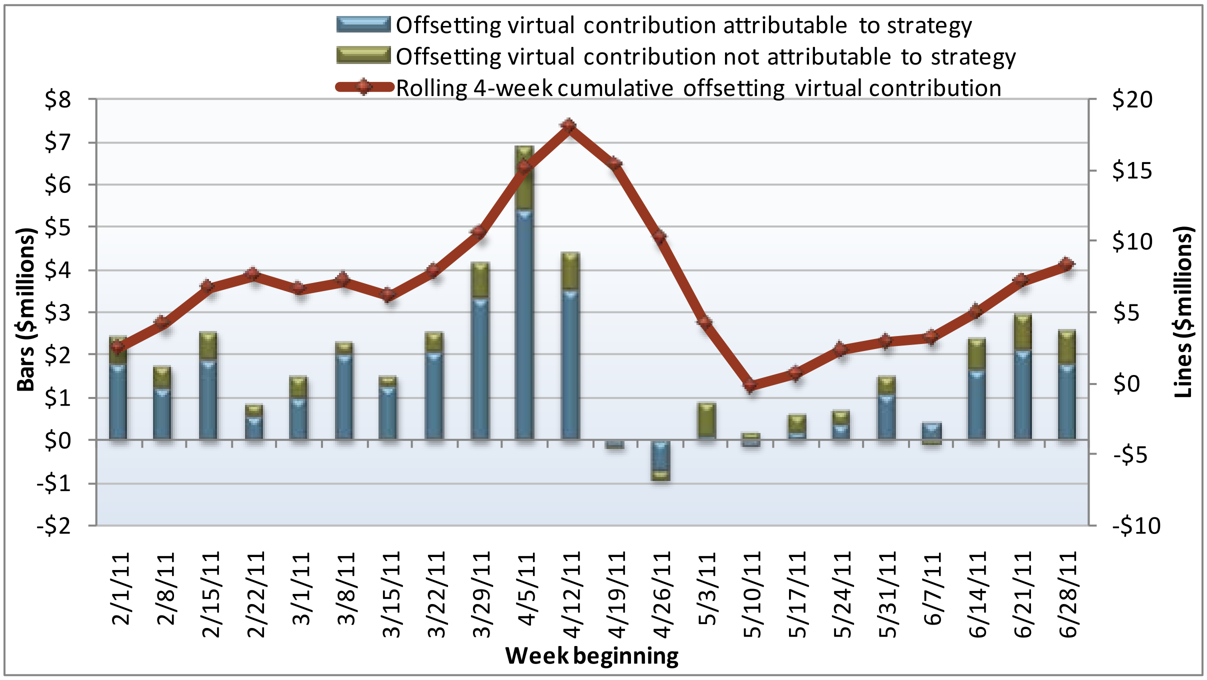
[22] Unaccounted for energy is attributable to meter measurement errors, power flow modeling errors, energy theft, statistical load profile errors, and distribution loss deviations.

[23] See the following for more information: http://www.caiso.com/informed/Pages/StakeholderProcesses/RealTimeImbalanceEnergyOffset2011.aspx.

[24] This figure was revised on 8/24/2011. The original figure was calculated from data in the ISO's Enterprise Data Repository (EDR), which does not include price correction data. DMM developed a separate process to incorporate the price corrections made by the ISO as part of the settlement process and then updated these figures. Convergence bidding results for the month of May changed from negative $4 million to negative $300,000. This change was the result of extreme negative prices (-$10,000/MWh) on May 27 hour ending 1 that were corrected as part of the ISO settlement process.

imbalance created by convergence bidding is associated with offsetting virtual positions. Over the course of the first five months of convergence bidding, this has resulted in roughly $42 million in real-time imbalance charges, approximately $11 million of which were after the shift in mid-April. Real-time energy imbalance charges associated with participants offsetting their own positions accounted for $31 million over the first five months, representing about 75 percent of the total offsetting positions.

Figure 2.13 Contribution of offsetting virtual supply and demand to real-time imbalance charges by week



2.2.4 Congestion revenue right settlement rule

The congestion revenue right (CRR) settlement rule was implemented to help deter the potential use of virtual bidding to increase payments for congestion revenue rights. The rule limits revenues from CRRs that have been increased by the strategic use of convergence bids.[25] This rule is to recapture, where warranted, the increase in CRR revenues to CRR holders that are attributable to that participant or affiliate's convergence bidding strategy. A four step approach is used to determine if the settlement rule will be applied:[26]

1. Calculate combined impact of participant's portfolio of virtual bids on flows of constraint for each hour;

2. Determine hours where participant's portfolio of virtual bids significantly impacted constraint;

[25] This rule is very similar to the rules in other RTOs and ISOs used to limit the effects of virtual bidding on financial transmission rights (FTRs).

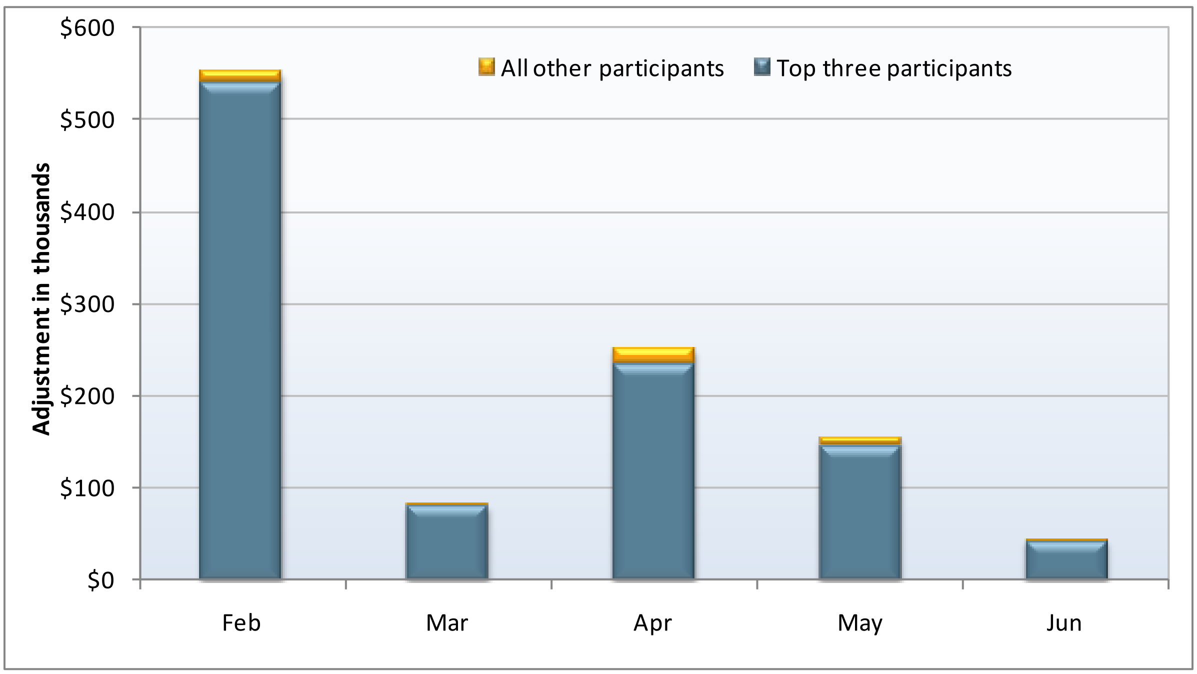
[26] *External Business Requirements Specification, Convergence Bidding*, December 01 2009, http://www.caiso.com/2478/24788f756dfc0.pdf.

3. Compare constraint's impact on day-ahead value of participant's CRR portfolio to the constraint's impact on real-time value of participant's CRR portfolio; and
4. Apply CRR payment adjustment (netted by constraint, period — peak and off-peak, and day).

From February through June, DMM estimates the total sum of revenue attributed to the settlement rule to be roughly $1 million. June was the month with the least amount of adjustment at less than $50,000. These payments were removed from the congestion revenues paid to the specific congestion revenue rights holders that impacted the congestion. In total, these revenues represented less than 1 percent of all revenues to congestion revenue rights for the period.

Figure 2.14 shows the monthly combination of peak and off-peak periods. This figure highlights that almost all of the revenues associated with the settlement rule were concentrated on three market participants. The top three highest ranking market participants were similar over the period but their ranking varied month by month.

Figure 2.14 Congestion revenue right settlement rule: peak and off-peak periods



2.3 Recommendations

DMM is supportive of the ISO's proposal to eliminate virtual bidding at the inter-ties as a short-term option for reducing real-time energy imbalance costs. Convergence bidding has not resolved the issue of real-time price convergence and has contributed to high real-time energy imbalance costs. Until price convergence can be reached through more effective modeling or structural changes between these two markets, convergence bidders can continue to take advantage of these differences between the hour-ahead and real-time markets. As long as these systematic price differences continue, participants can bid in offsetting virtual supply bids on the inter-ties and virtual demand bids on internal nodes. This strategy will continue to impose unnecessary costs to the market while providing little or no market or reliability benefits.