California ISO

California Independent System Operator Corporation

California ISO

Q2 2015 Report on Market Issues and Performance

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Executive summary

This report covers general market performance during the second quarter of 2015 (April – June). During this quarter, there were two events that significantly impacted market results.

- First, a planned outage of Path 15 reduced available transmission capacity between Northern and Southern California throughout much of the quarter, impacting prices, congestion, uplifts, and virtual bidding revenues.
- Second, sustained high real-time prices during peak hours ending 16 through 20 occurred on June 8 because of higher than anticipated loads throughout the ISO system. This also affected prices, uplifts and virtual bids.

Together, these two items explain much of the market results throughout this reporting period. Other highlights in the second quarter include the following:

- Energy market prices remained highly competitive in the second quarter. The overall combined wholesale cost of energy was just slightly below prices that the Department of Market Monitoring (DMM) estimates would result under highly competitive conditions when suppliers bid at or near marginal costs.
- Day-ahead prices in April and May continued at low levels in both peak and off-peak periods. This was primarily driven by low natural gas prices. Day-ahead prices increased in June as loads and gas prices increased.
- Real-time prices continued to be consistently lower than day-ahead prices. Average monthly peak and off-peak prices were lower in real time than in the day-ahead market except during peak hours in June, when extremely high real-time prices during five hours on June 8 drove monthly average real-time prices above average monthly day-ahead prices. Monthly average 15-minute and 5-minute market prices tracked closely in all months of the quarter for both peak and off-peak hours.
- Negative prices occurred with increased frequency in the real-time market at load aggregation point (LAP) levels during about 5 percent of 15-minute intervals and about 8 percent of 5-minute intervals. Factors contributing to the increase in negative real-time prices included congestion on Path 15, low loads, and increased output from wind and solar resources.
- Frequent congestion in the south-to-north direction on Path 15 occurred from mid-March until early June because of planned transmission outages. This congestion drove prices in the Pacific Gas and Electric area significantly higher, and pushed prices in the Southern California Edison and San Diego Gas and Electric areas significantly lower.
- Congestion on constraints within the ISO system increased overall average day-ahead and 15-minute prices in the PG&E area by about 5.3 percent and 2.8 percent, respectively. Compared to the previous quarter, congestion had a much larger negative price impact in the SDG&E and SCE areas, decreasing prices in these areas by over 3 percent. These results were driven primarily by south-to-north congestion on Path 15.
- Revenue inadequacy from congestion revenue rights revenues remained relatively high at $45 million in the second quarter of 2015, compared to $56 million from the second quarter of 2014. In 2014, the ISO took several measures to reduce revenue inadequacy. While accumulating at a slower

pace than 2014, revenue inadequacy in the first six months of 2015 remains elevated at about $60 million.[1] DMM recommends that the ISO continue to investigate measures to address revenue inadequacy issues, which includes the alternative allocation of revenue inadequacy costs to congestion revenue rights holders on a constraint specific basis. This alternative allocation method would limit the amount of revenues that could be transferred from load-serving entities to congestion revenue rights holders through uplift. Moreover, this allocation method would reduce the incentive for entities purchasing congestion revenue rights to target modeling differences that create revenue inadequacy costs.[2]

- Bid cost recovery payments were around $26.2 million in the second quarter of 2015, compared to $23.5 million in the second quarter of 2014 and $12 million in the first quarter of 2015. This increase is partly related to minimum online constraints in place because of the Path 15 outages.
- Net revenues received by convergence bidders were about $8.4 million in the second quarter. Virtual demand positions were more profitable than virtual supply positions because of significant net revenues earned by virtual demand on just one day, June 8, due to the high prices in real time compared to the prices in day-ahead.
- Almost all imports scheduled in the day-ahead market continue to be self-scheduled in real time rather than re-bid in the real-time market. This overall trend has continued since FERC Order No. 764 market changes were implemented in May 2014.
- The volume of 15-minute dispatchable import bids increased by 48 percent compared to the first quarter, averaging 413 MW each hour in the second quarter. In addition, 15-minute dispatchable economic export bids increased to an average of 190 MW in the second quarter, compared to 55 MW in the first quarter. However, 15-minute dispatchable bids continued to be submitted by a small number of scheduling coordinators on just three inter-ties (Malin, Palo Verde and Rancho Seco).
- During most intervals, prices in the energy imbalance market remained highly competitive and have been set by bids closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation. However, during a relatively small portion of intervals, energy or flexible ramping constraints have had to be relaxed for the market software to balance modeled supply and demand. Overall performance of the EIM is analyzed in detail in Section 3.

[1] Auction revenues totaled just under $64 million for the first half of 2015 resulting in a positive balance of almost $4 million when using auction revenues to address revenue inadequacy.

[2] *Allocating CRR Revenue Inadequacy by Constraint to CRR Holders*, Department of Market Monitoring, October 6, 2014: http://www.caiso.com/Documents/AllocatingCRRRevenueInadequacy-Constraint-CRRHolders_DMMWhitePaper.pdf.

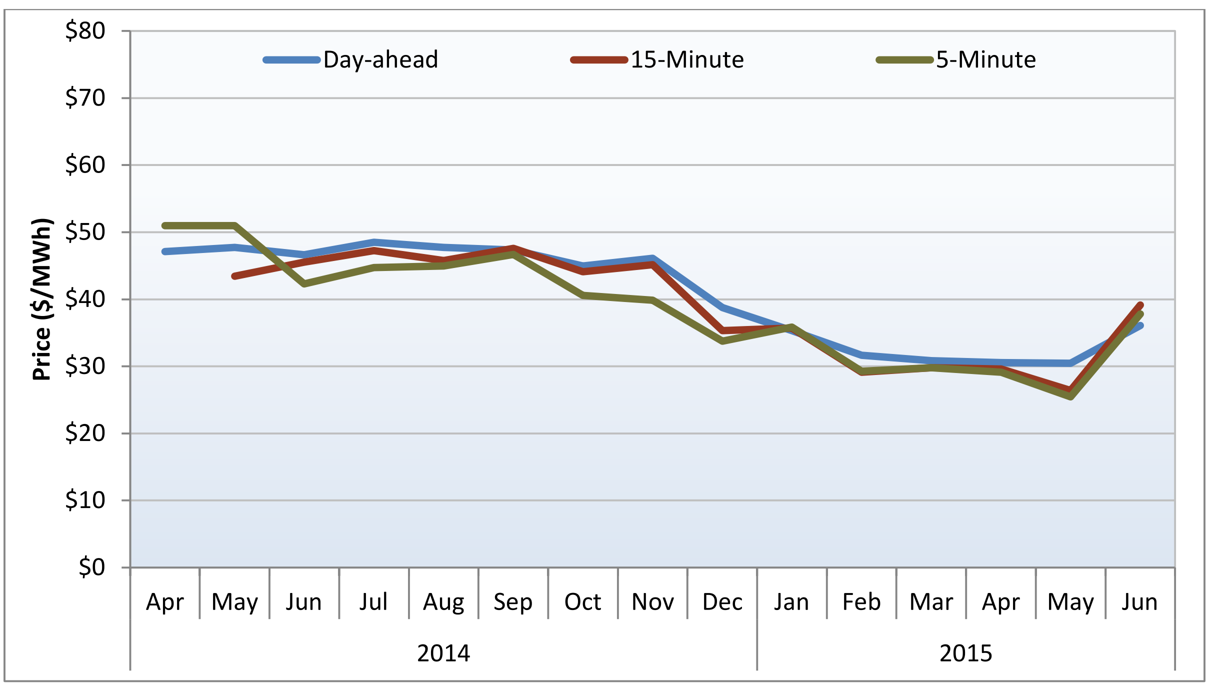
Energy market performance

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

Energy prices remained close to DMM's competitive baseline price. Average load-weighted prices in the day-ahead market were slightly lower than the simulated competitive baseline prices that DMM estimates would prevail under highly competitive conditions. Prices in the real-time market were just over competitive baseline prices in June, which were driven by several hours of high prices on June 8, and lower in the remaining months of the quarter.

Prices increased in June as temperatures and loads increased. Average day-ahead prices were higher than real-time prices in all peak and off-peak periods in the quarter except during peak hours in June, when extremely high real-time prices during five hours on June 8 drove monthly average real-time prices above average monthly day-ahead prices. Prices decreased in May and increased in June during the second quarter, while remaining lower than the second quarter of 2014 (see Figure E.1). Day-ahead prices in April and May were lower than in any month of the past 15 months, in both peak and off-peak periods. Average peak system prices in the 15-minute and 5-minute markets were lower than day-ahead market prices in April and May. Compared to the second quarter of 2014, hour-ahead prices tracked other real-time prices much more closely.

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



The frequency of negative prices increased in May and dropped in June. The frequency of negative load area prices was notably high in May in both the 15-minute and 5-minute markets, but decreased substantially in June. Negative prices occurred at load aggregation point levels in about 5 percent of 15-minute market intervals and 8 percent of 5-minute market intervals. Negative prices occurred in the late morning and early afternoon hours. This pattern occurred in the 15-minute market and even more so in the 5-minute market, especially on weekends. Factors contributing to the increase in negative real-time prices included transmission outages reducing Path 15 transmission capacity, low seasonal loads, and increased output from wind and particularly solar resources. Net loads were occasionally lowest during the early afternoon hours when solar generation was highest rather than during the overnight hours when loads were lowest.

Upward price spikes remained low. Price spikes above $250/MWh in the 15-minute market occurred in only 0.2 percent of intervals during the second quarter, an increase from 0.1 percent in the previous quarter. The frequency of price spikes over $250/MWh in the 5-minute market was 0.7 percent, the same as in the previous quarter. The majority of the upward volatility in both markets occurred on June 8.

Continued Path 15 congestion raised prices in the PG&E area. Frequent congestion in the south-to-north direction on Path 15 began in mid-March and continued until early June due to planned transmission outages. When south-to-north congestion on Path 15 occurred in the day-ahead market, prices were increased in the PG&E area by about $4.50/MWh and decreased in the SCE and SDG&E areas by about $3.70/MWh. Congestion on Path 15 occurred in the 15-minute market only about one-fifth as often as in the day-ahead market, but when it occurred increased prices in the PG&E area by about $14/MWh while prices decreased in the SCE and SDG&E areas by about $14/MWh.

Congestion revenue right revenue inadequacy remained elevated. Revenue inadequacy before accounting for auction revenues remained relatively high at $45 million in the second quarter of 2015, compared to $56 million from the second quarter of 2014. The balancing account deficit, which includes auction revenues, fell from $29 million in the second quarter of 2014 to $8 million in 2015 largely due to increased auction revenues. Second quarter revenue inadequacy in 2015 occurred with significantly less day-ahead market congestion rent of $38 million in 2015 compared to $168 million in 2014.

In 2014, with annual revenue inadequacy of nearly $200 million and a balancing account deficit of about $95 million, the ISO took several measures to reduce revenue inadequacy. While revenue inadequacy is accumulating at a slower pace than 2014, in the first six months of 2015 it remains elevated at about $60 million. DMM recommends that the ISO continue to investigate measures to address revenue inadequacy issues including the alternative allocation of revenue inadequacy costs to congestion revenue rights holders on a constraint specific basis. This alternative allocation method would limit the amount of revenues that could be transferred from load-serving entities to congestion revenue rights holders through uplift. Moreover, this allocation method would reduce the incentive for entities purchasing congestion revenue rights to target modeling differences that create revenue inadequacy costs.[3]

Bid cost recovery increased. Bid cost recovery payments were around $26.2 million in the second quarter of 2015, compared to $12 million in the first quarter of 2015 and $23.5 million in the second quarter of 2014. Day-ahead bid cost recovery payments increased in May as a result of minimum online constraints, particularly those related to the Path 15 planned outages. Real-time market bid cost recovery payments were higher in June and are currently under review by the ISO and DMM.

Real-time imbalance offset costs increased. Total offset costs were about $31 million in the second quarter of 2015, compared to $81 million in the second quarter of 2014 and $6 million in the first

[3] *Allocating CRR Revenue Inadequacy by Constraint to CRR Holders*, Department of Market Monitoring, October 6, 2014: http://www.caiso.com/Documents/AllocatingCRRRevenueInadequacy-Constraint-CRRHolders_DMMWhitePaper.pdf.

quarter of 2015. Total real-time imbalance offset costs in the second quarter were the sum of approximately $19 million in energy imbalance offset costs, $11 million in congestion imbalance offset costs, and $1 million in loss imbalance offset costs.

Ancillary service scarcity pricing was triggered in the day-ahead market. Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, implemented in December 2010, the ISO pays a pre-determined scarcity price for ancillary services procured during scarcity event intervals. For the first time in the day-ahead market, the ISO experienced a day-ahead ancillary service scarcity event on May 24 for a shortfall of regulation down. Path 15 congestion, low seasonal loads, and significant amounts of renewable generation likely contributed to the difficulty of committing more resources to provide regulation down.

Ancillary service scarcity events also occurred in the real-time market on May 24 for both spinning reserves and regulation down in SP26. During the second quarter, ancillary service scarcity pricing events in the 15-minute market also occurred for regulation up and regulation down on April 21 and for regulation down on May 17.

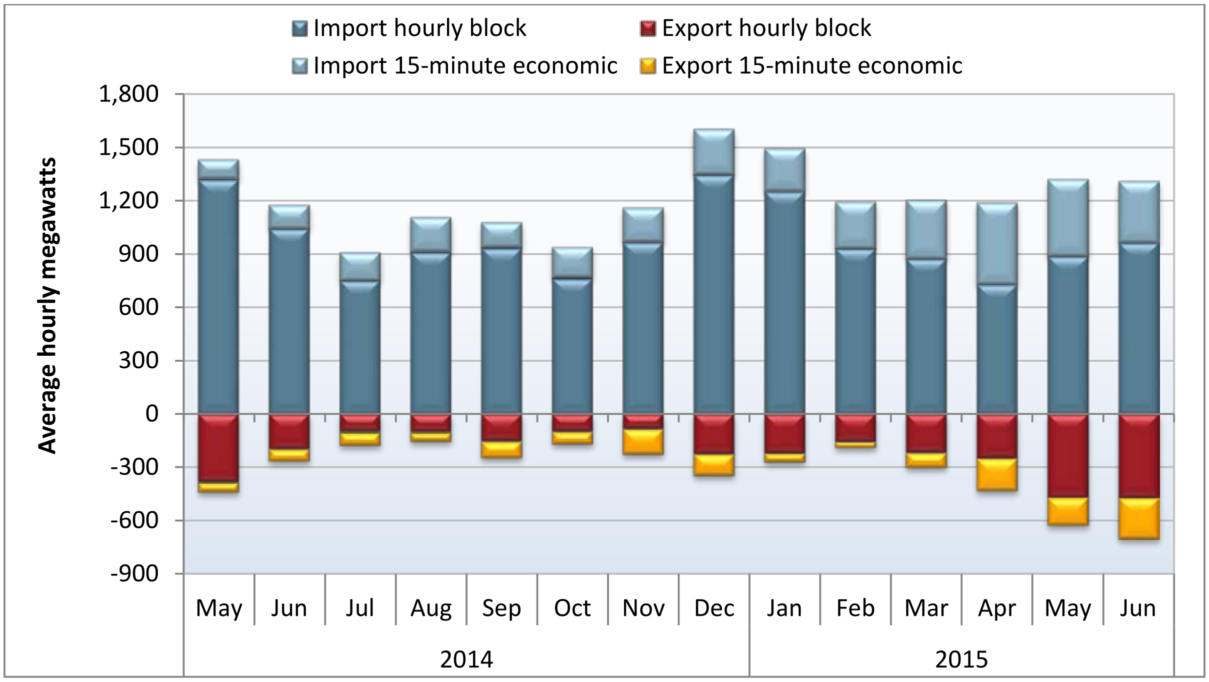
Special issues

New flexible ramping requirement tool increased requirement volatility. The ISO automated the flexible ramping constraint requirement in late March with the implementation of the balancing area ramp requirement (BARR) tool. Because the calculation only uses a very limited set of historical observations, there was very high variability in the flexible ramping requirements from one interval to the next in both the ISO and EIM areas. DMM and other ISO staff recommended increasing the set of observations used to calculate the requirement – preferably by grouping surrounding intervals together – to increase the accuracy of the calculation and reduce the high level of variability due to random variations in historical data. Both DMM and other ISO staff are concerned that the high volatility of flexible ramping constraint requirements that have resulted since implementing the ramping tool reflects requirements that are unnecessarily high in some intervals and too low compared to the actual potential demand for ramping capacity in other intervals.

Economic bids on inter-ties in the 15-minute market increased. When 15-minute scheduling on inter-ties was implemented in May 2014, there was a significant decrease in the amount of inter-tie bids into the real-time market as well as an increase in the volume of self-scheduled inter-tie transactions. While this overall trend has continued into the second quarter, real-time economic bidding, particularly of exports, increased in the second quarter (see Figure E.2). However, 15-minute dispatchable bids continued to be submitted by a small number of scheduling coordinators on just three inter-ties (Malin, Palo Verde and Rancho Seco).

Of the economic inter-tie bids in the real-time markets, about 32 percent of import bids and 33 percent of export bids were available for dispatch on a 15-minute basis. The remaining bids were for fixed hourly blocks. The volume of 15-minute dispatchable import bids increased by 48 percent compared to the first quarter, averaging 413 MW each hour in the second quarter. 15-minute dispatchable economic export bids increased to an average of 190 MW in the second quarter, compared to 55 MW in the first quarter. The volume of 15-minute economic bids in the second quarter was the highest quarterly value since 15-minute inter-tie bidding began in May 2014.

Figure E.2 Economic import and export bids by bidding option



1 Market performance

This section highlights key performance indicators of market performance in the second quarter.

- Day-ahead prices in April and May continued to remain low compared to previous periods, in both peak and off-peak periods, as natural gas prices continued to fall. However, prices increased in June as loads increased due to warmer temperatures and as gas prices increased.
- Monthly average 15-minute and 5-minute market prices tracked closely in all months of the quarter for both peak and off-peak hours. They were lower than day-ahead prices in April and May but higher than day-ahead prices in June. The increase in average prices in real time is related to scarcity events on June 8, which resulted in a period of high prices for multiple hours.
- In the second quarter, price spikes were mostly driven by tight supply conditions on June 8 due to higher than anticipated heat throughout much of the ISO system. While prices above $250/MWh occurred in only about 0.2 percent of intervals in the 15-minute market, almost all of the high prices in the quarter occurred on June 8. In the 5-minute market, about 0.7 percent of intervals had price spikes, with many of these also occurring on June 8.
- In the 15-minute market, negative prices at load aggregation points (LAPs) were observed in about 5 percent of intervals. Negative prices were more frequent in the 5-minute market, occurring in about 8 percent of intervals. This is an increase from previous periods and was driven by an increase in negative prices, particularly in May. Factors contributing to the increase in negative real-time prices included congestion on Path 15, low loads, and increased output from wind and solar resources.
- Congestion in the south-to-north direction on Path 15 had a significant impact on prices in the ISO for the quarter in both the day-ahead and real-time markets. The Path 15 congestion increased prices in the PG&E area by an average of 4.6 percent in the day-ahead market and 2.6 percent in the 15-minute market, and decreased prices in the SCE and SDG&E areas by about 4.5 percent in the day-ahead market and 3.3 percent in the 15-minute market, respectively.
- Flexible ramping constraint payments were around $0.8 million in the second quarter, up from $0.4 million from the previous quarter. This increase occurred as fixes to the flexible ramping constraint credit were implemented in February. This resulted in a higher frequency of binding intervals.
- Bid cost recovery payments were just above $26 million in the second quarter, compared to $23.5 million in the second quarter of 2014 and $12 million in the first quarter of 2015. This increase is primarily attributable to increases in day-ahead bid cost recovery related to minimum online constraints. A primary minimum online constraint was for NP15 capacity related to planned outages on Path 15.
- Real-time imbalance offset costs increased to $31 million in the second quarter, up from a historic low of $6 million in the first quarter, but down from $81 million in the second quarter of 2014. June 8 had a significant effect on real-time imbalance offset costs; real-time congestion offset costs were a credit of $4 million, whereas real-time energy imbalance offset costs were a debit of almost half of the monthly $11 million total for June.
- Cleared hourly volumes of virtual supply outweighed cleared virtual demand by about 800 MW on average, an increase from 360 MW of net virtual supply in the previous quarter. Total convergence

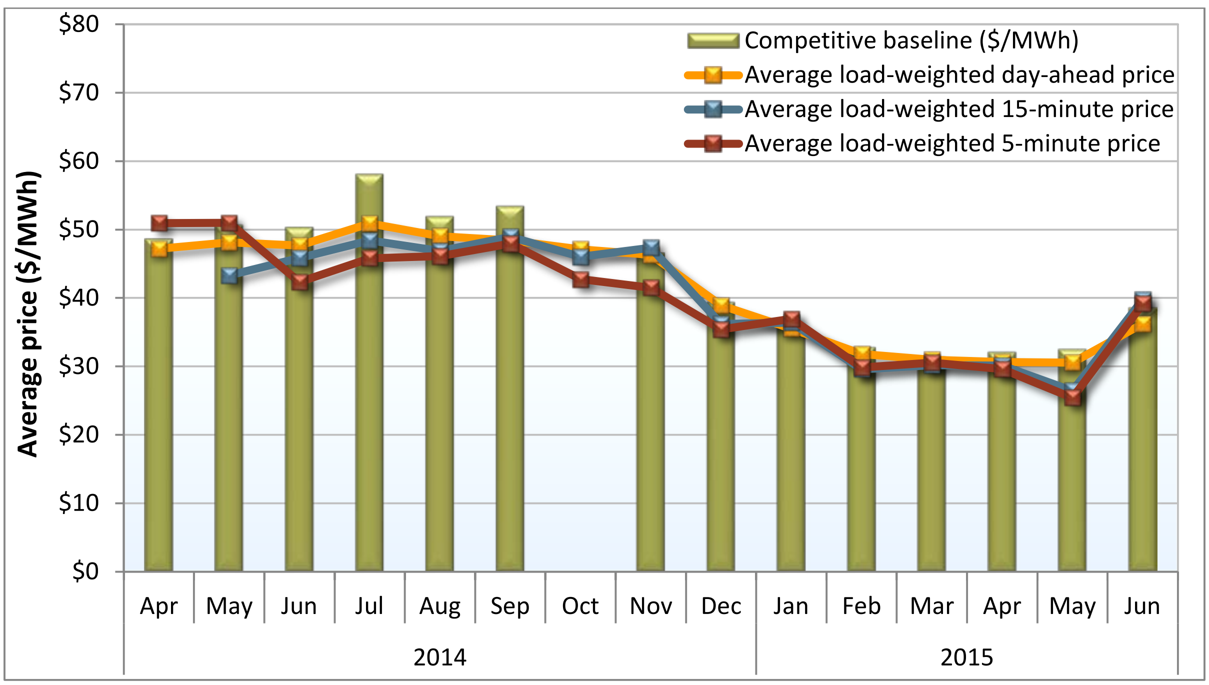
bidding revenue for the quarter, adjusted for bid cost recovery costs, was about $8.4 million, an increase from about $2.2 million in the previous quarter.

1.1 Overall market competitiveness

To assess the competitiveness of the ISO energy markets, DMM compares actual market prices to competitive benchmark prices we estimate would result under highly competitive conditions. DMM estimates competitive baseline prices by re-simulating the market using the day-ahead market software with bids reflecting the actual marginal cost of gas-fired units, no convergence bids and actual load.[4]

Figure 1.1 compares this competitive baseline price to load-weighted prices in the day-ahead, 15-minute and 5-minute real-time markets. When comparing these prices, it is important to note that baseline prices are calculated using the day-ahead market software under highly competitive conditions, which do not reflect all of the system conditions and limitations that impact real-time prices.

Figure 1.1 Comparison of competitive baseline with day-ahead and real-time load-weighted prices



As shown in Figure 1.1, prices in the day-ahead market were slightly lower than competitive baseline prices in all months in the second quarter. Prices in the real-time market were just over competitive

[4] The competitive baseline is a scenario setting the bids for gas-fired generation equal to default energy bids (DEBs), removing convergence bids and setting system demand to actual system load. This scenario represents the combination of perfect load forecast along with physical and competitive bidding of price-setting resources, and is calculated using DMM's version of the actual market software. DMM was unable to calculate the competitive baseline for October 2014 because of implementation issues with transitioning the systems to the fall market software version.

baseline prices in June, driven by tight supply conditions and high prices on June 8,[5] and lower in the remaining months of the quarter.

DMM also calculates an overall price-cost mark-up by comparing competitive baseline energy prices to total average wholesale energy prices.[6] Total wholesale energy prices used in this analysis represent a load-weighted average price of all energy transactions in the day-ahead, 15-minute and 5-minute real-time markets.[7] The overall combined average of market prices was about $2/MWh or about 6 percent lower than the competitive baseline price in the second quarter of 2015, which is slightly lower than the second quarter of 2014 at just under 4 percent.

1.2 Energy market performance

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

Figure 1.2 and Figure 1.3 show monthly system marginal energy prices for peak and off-peak periods, respectively. As seen in these figures, average day-ahead price levels were higher than real-time prices in most peak and off-peak periods in the quarter except during peak hours in June. Prices decreased in May and increased in June during the second quarter, while remaining lower than the second quarter of 2014.

Overall, price levels followed the changes in natural gas prices. However, the increase in real-time prices in June was primarily driven by price events on June 8 which was driven by higher than anticipated heat. The events on June 8 are discussed in further detail below.

- Average day-ahead prices were about the same in April and May then increased in June. Day-ahead prices in April and May were lower than in any month of the past 15 months, in both peak ($32/MWh) and off-peak ($28/MWh) periods. In June, day-ahead prices were $40/MWh during peak period and $31/MWh for off-peak period. Overall, day-ahead prices were mostly higher than hour-ahead, 15-minute and 5-minute market prices for the quarter.

- In the second quarter, average peak system prices in the 15-minute market were lower than day-ahead prices in April by about $1/MWh and in May by about $4/MWh. The 15-minute market average peak system prices turned higher than day-ahead prices in June by about $6/MWh. Off-peak 15-minute prices were lower than day-ahead prices in all three months.

[5] Details on the June 8 events are discussed in Section 1.2.

[6] DMM calculates the price-cost mark-up index as the percentage difference between actual market prices and prices resulting under this competitive baseline scenario. For example, if market prices averaged $55/MWh during a month and the competitive baseline price was $50/MWh, this would represent a price-cost mark-up of 10 percent.

[7] The wholesale costs of energy are pro-rated calculations of the day-ahead, 15-minute and 5-minute prices weighted by the corresponding forecasted load.

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

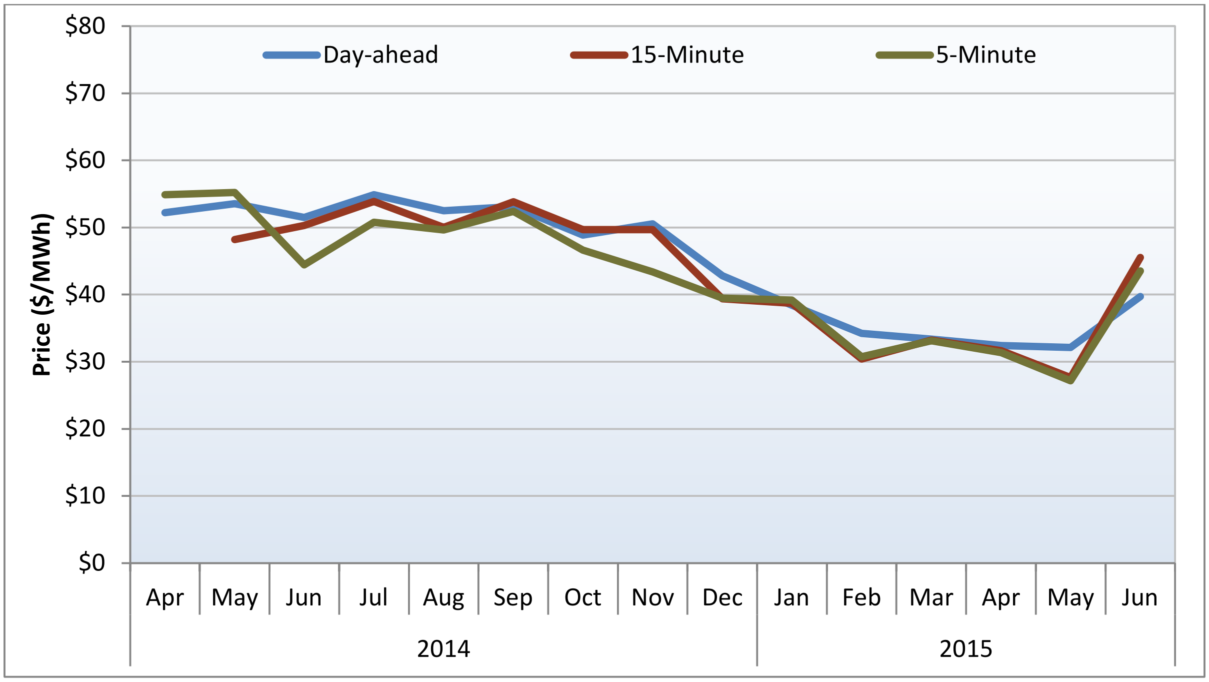
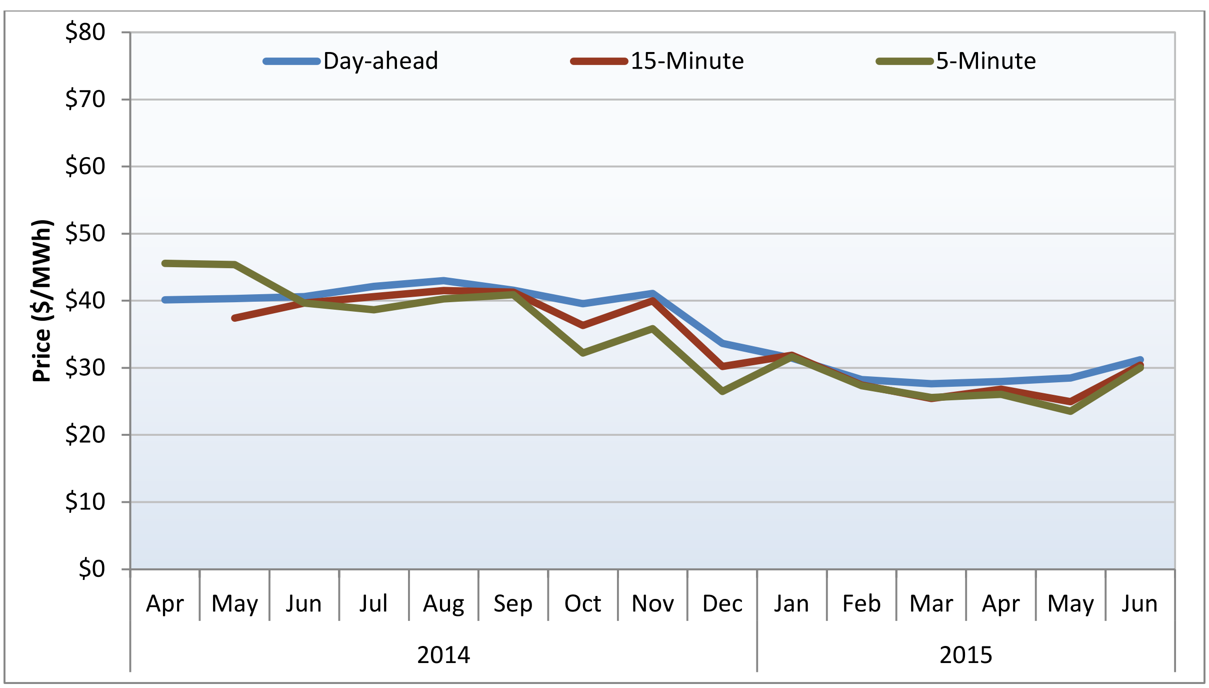


Figure 1.3 Average monthly off-peak prices – system marginal energy price



- The 5-minute market prices trended similar to the 15-minute market prices in the second quarter. Peak period average system prices in the 5-minute market were lower than day-ahead market prices in April and May and higher in June. In off-peak periods, 5-minute prices were lower than day-ahead prices during the entire quarter.

- On a monthly average basis, hour-ahead prices were lower than day-ahead prices in April and May and slightly higher in June. The average difference between day-ahead and hour-ahead prices was about $1/MWh for peak hours and about $2/MWh for off-peak hours. Compared to the second quarter of 2014, hour-ahead prices in the second quarter of 2015 tracked other real-time prices much more closely.

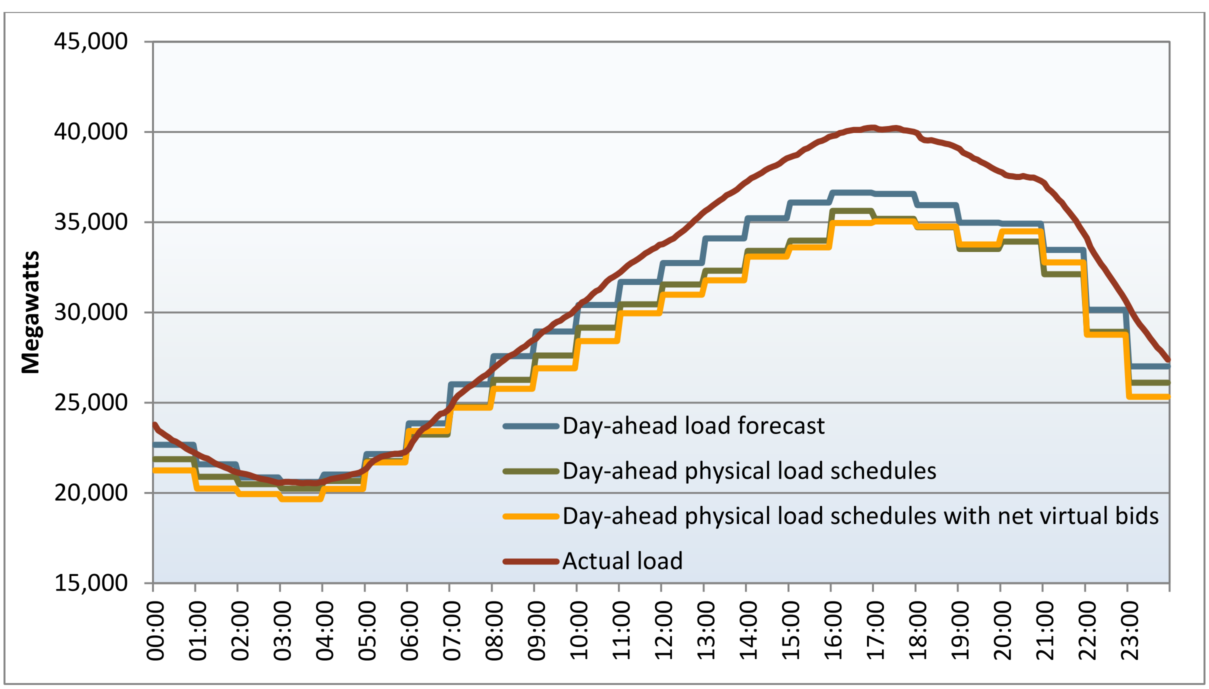
Description of June 8 events

The frequency of high prices above $250/MWh in the 15-minute market increased substantially in June compared to previous months, as seen in Section 1.3 below. All of these high priced 15-minute intervals occurred during one 5-hour period – hours ending 16 through 20 on June 8 – and averaged over $750/MWh during these hours. In addition, prices in the 5-minute market exceeded $250/MWh for much of this afternoon, averaging about $570/MWh. This accounted for more than half of all high priced 5-minute intervals in June.

As noted earlier, average energy prices were also noticeably affected by the high real-time prices on this day. If June 8 is excluded from the average monthly prices shown in Figure 1.2, average peak real-time prices for June would be below the day-ahead average, as they were in April and May.

The prolonged period of high prices in the real-time markets on June 8 was primarily a result of real-time load significantly exceeding the amount forecasted and scheduled in the day-ahead market (see Figure 1.4). Actual load (red line) peaked at over 40,200 MW for the ISO in hour ending 18, which was about 3,600 MW higher than the day-ahead ISO forecast (blue line) used for that hour. Moreover, the load procured by participants (green line) was below the ISO forecast by about 1,500 MW in hour ending 18 and net virtual bids did not anticipate the conditions (as seen in the gold line).

Figure 1.4 Comparison of day-ahead load and actual load on June 8, 2015



The higher than anticipated loads were primarily due to higher than anticipated temperatures throughout California on this day. Average temperatures were 4 degrees higher than forecasted day-ahead. In addition, wind generation was lower than anticipated throughout the afternoon and evening hours.

Due to these extreme conditions, the ISO experienced an increase in model infeasibilities in both the 5-minute and 15-minute markets. There were a total of 25 intervals in the 5-minute market with power balance relaxations on June 8. In the 15-minute market, there were 3 intervals with solution infeasibilities, but the power balance constraint was not relaxed in these cases.

Since ISO operators adjusted the load upwards in order to bring additional generation on-line, many of the intervals with power balance constraint relaxations in the 5-minute market were affected by the load bias limiter.[8] Therefore, prices in these intervals were determined by the last dispatched economic bid instead of a penalty price. In the 5-minute market, the load bias limiter was active and adjusted the price down accordingly.

During the 3 intervals with market infeasibilities in the 15-minute market, the load bias limiter did not trigger because the ISO market model resolved the power balance infeasibility by cutting exports. The current penalty parameter for cutting exports in the 15-minute market is set to $1,050, whereas the power balance constraint relaxation is set at $1,100. Because the load bias limiter triggers off of power balance constraint relaxations, it was not triggered on this day and prices were set by the penalty parameter in these intervals.

Congestion affected load area prices

Figure 1.5 and Figure 1.6 show the day-ahead and 15-minute market average hourly prices, respectively, at the PG&E, SCE and SDG&E areas in the second quarter. The price separation between PG&E area and Southern California during most peak hours is very noticeable in both markets, with average differences of about $5/MWh in day-ahead peak hours and $9/MWh in 15-minute peak hours.

This separation is largely caused by congestion on Path 15 from Southern California to Northern California, which caused PG&E prices to increase and SCE and SDG&E prices to decrease. The congestion was driven primarily by transmission outages and derates that reduced the line capacity by an average of about 40 percent. Moreover, low seasonal loads combined with a higher portion of solar generation on the system also contributed to the congestion.

[8] For further discussion of the load bias limiter, see DMM's *2014 Annual Report on Market Issues and Performance*, pp. 82-83: http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

Figure 1.5 Hourly comparison of day-ahead market load area prices

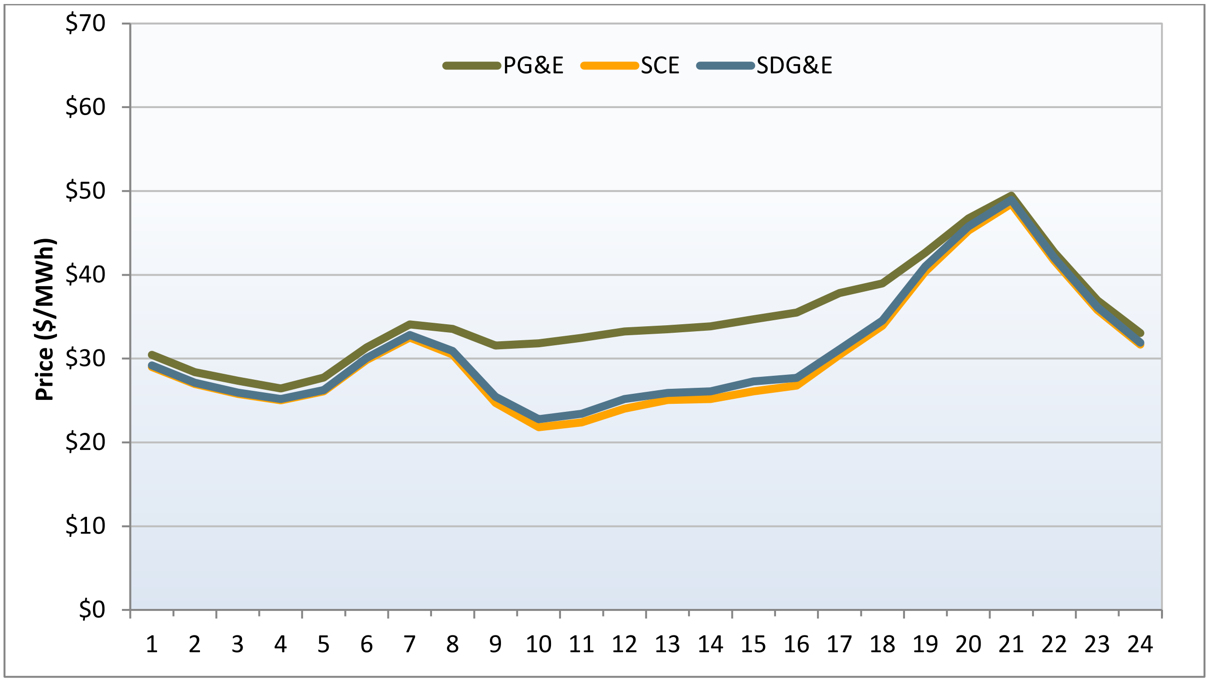
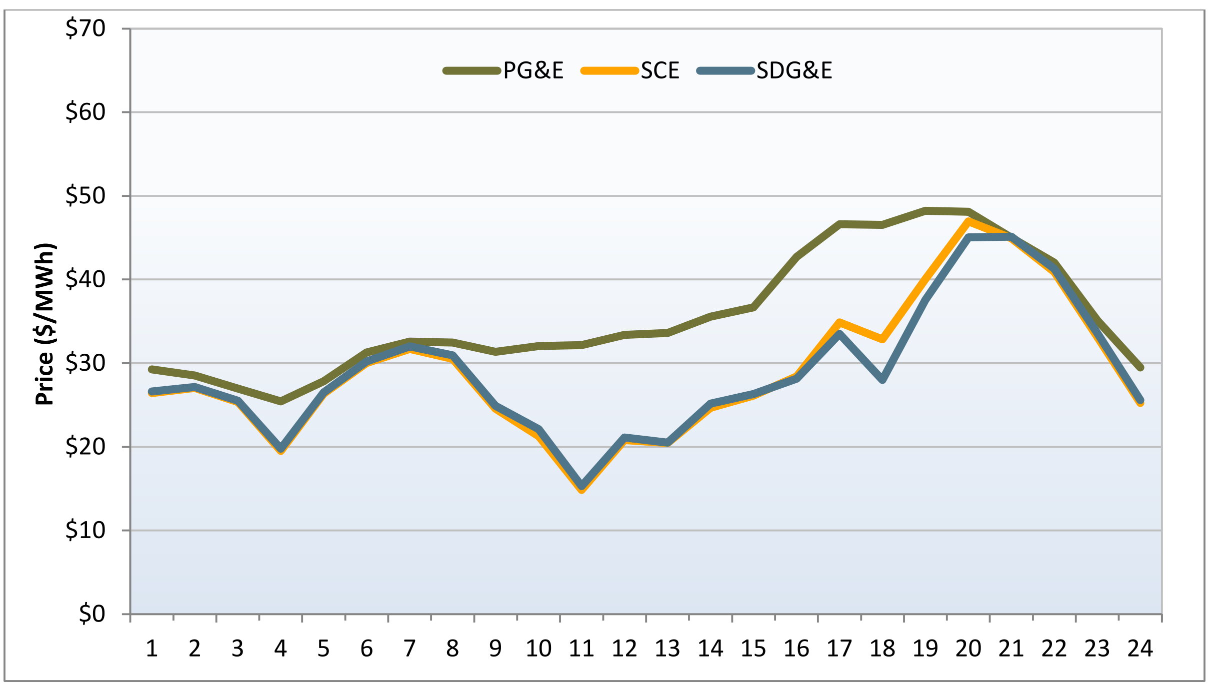


Figure 1.6 Hourly comparison of 15-minute market load area prices



1.3 Real-time price variability

Real-time market prices can be highly volatile with periods of extreme positive and negative price spikes. As noted above, a short period of volatility can have a significant impact on average prices. Both the frequency of positive and negative price spikes increased in both the 15-minute and 5-minute markets in the second quarter compared to previous periods.

Frequency of price spikes

Overall, positive price spikes were relatively infrequent in both the 15-minute and 5-minute markets in the second quarter. Prices above $250/MWh were observed in about 0.2 percent of intervals in the 15-minute market, a 0.1 percent increase from the previous quarter. This increase is mainly attributable to the price spikes caused by the June 8 events described in Section 1.2. The months of April and May had the lowest frequency of positive price spikes (around 0.03 percent) since the implementation of the 15-minute market in May last year, as shown in Figure 1.7.

Figure 1.8 shows the frequency of positive price spikes occurring in the 5-minute market. In the second quarter, the frequency of price spikes was about 0.7 percent, which was the same as in the previous quarter. The overall frequency of 5-minute price spikes was slightly higher compared to previous periods. This was mostly driven by an increase in the frequency of price spikes above $750/MWh, which accounted for 0.4 percent of intervals during the quarter. This also was greatly affected by the events on June 8.

As with previous quarters, negatively priced intervals were more frequent than high price intervals during the second quarter. In the 15-minute market, negative prices were observed in 5 percent of intervals during the quarter, an increase from 2 percent in the previous quarter. Negative prices were even more frequent in the 5-minute market, occurring in about 8 percent of intervals, compared to 6 percent in the first quarter.

Figure 1.9 shows the frequency of negative price spikes since May 2014 in the 15-minute market. Figure 1.10 shows the frequency of negative price spikes in the 5-minute market for the past 15 months. May had the highest frequency of negative prices in both markets. About 9 percent of intervals in the 15-minute market in May had negative prices, while 13 percent of intervals in the 5-minute market in May were negative. Negative prices in June occurred in 1.2 percent of intervals in the 15-minute market and 3.5 percent of intervals in the 5-minute market, among the lowest frequencies of negative price spikes in their respective periods.

Figure 1.7 Frequency of positive 15-minute price spikes (all LAP areas)

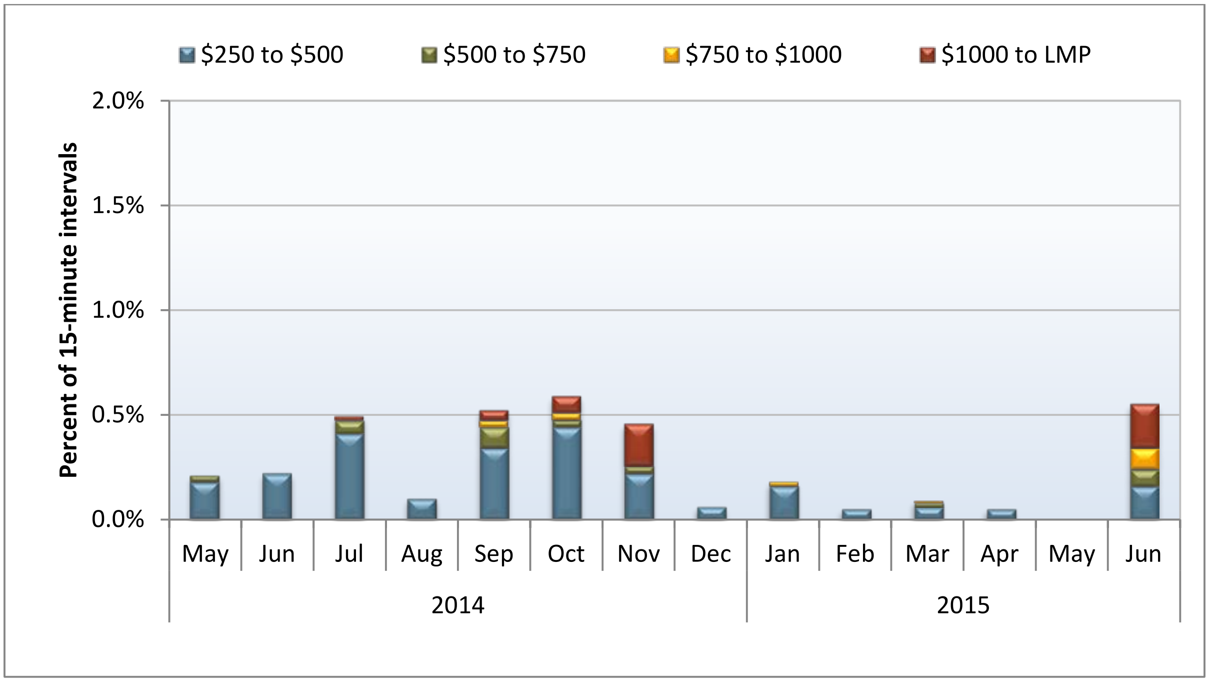


Figure 1.8 Frequency of positive 5-minute price spikes (all LAP areas)

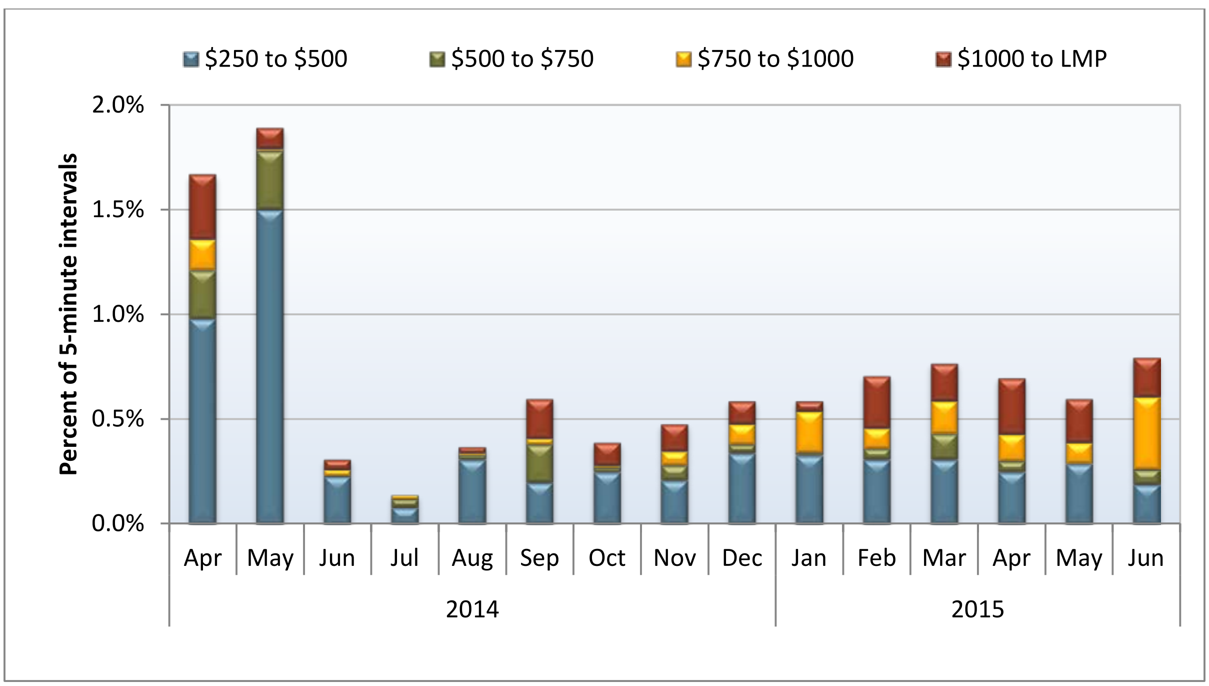


Figure 1.9 Frequency of negative 15-minute price spikes (all LAP areas)

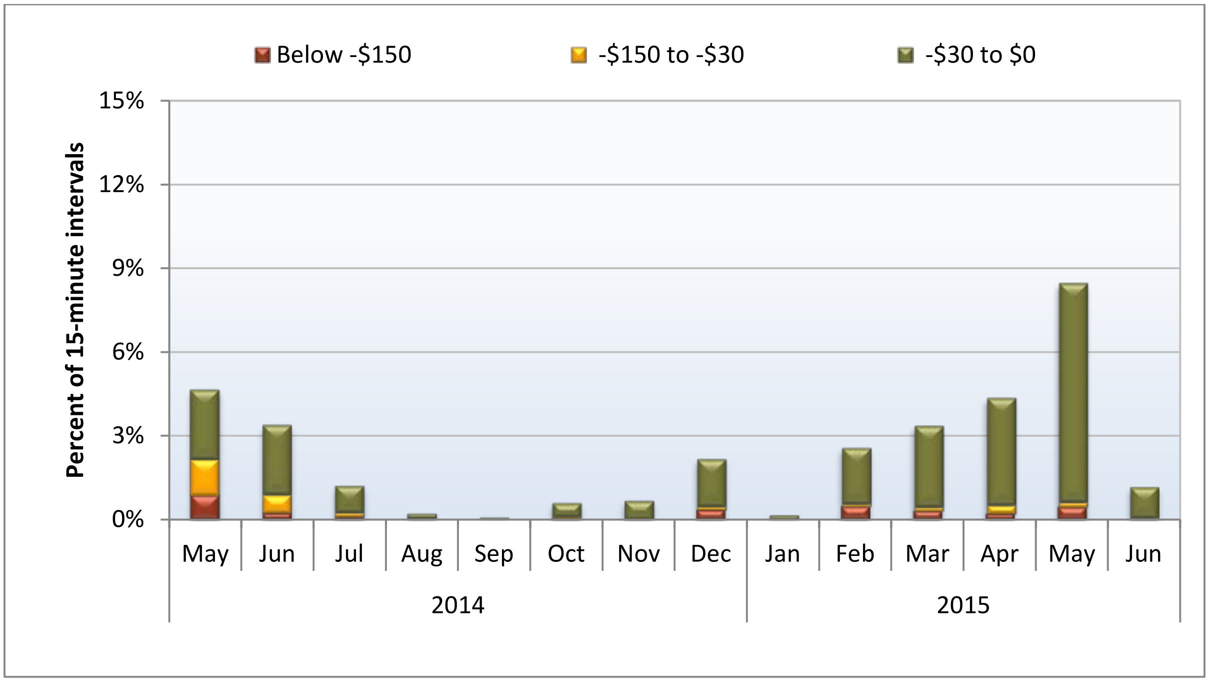
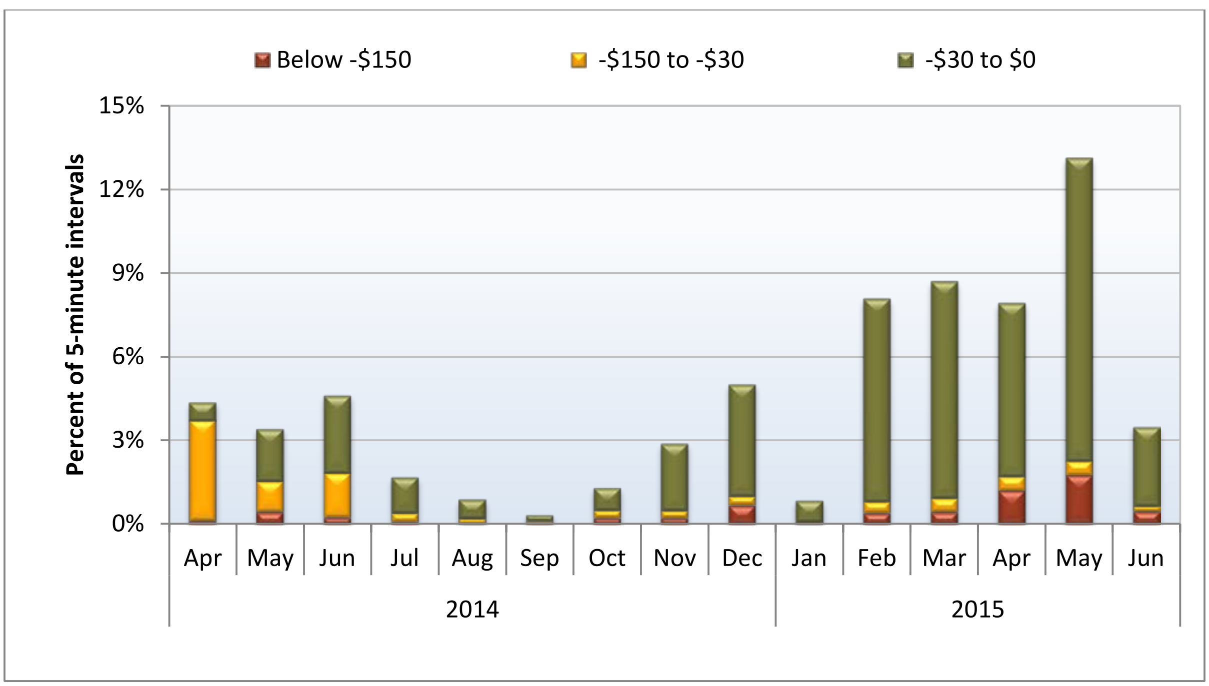


Figure 1.10 Frequency of negative 5-minute price spikes (all LAP areas)



Causes for negative prices

Several factors may contribute to negative prices in real-time markets. The following analysis categorizes the causes as follows:

- **Power balance constraint** – During these intervals the power balance constraint was relaxed and the congestion component was less than 50 percent of the price.
- **Power balance constraint and congestion** – These prices occurred when the power balance constraint was relaxed and the congestion component was more than 50 percent of the price. In these cases, the congestion component was negative.
- **Congestion** – These negative prices occurred when the power balance constraint was not relaxed and the negative congestion component accounted for more than half the negative price.
- **Low priced bid** – During these intervals, the energy component was between -\$150/MWh and \$0/MWh, the congestion component accounted for less than 50 percent of the negative price, and a negatively priced bid was dispatched.
- **Other** – The negative price was not caused by any of the conditions described above.

During the second quarter, most negative prices were caused by congestion in both 15-minute and 5-minute markets, particularly in May, as illustrated in Figure 1.11 and Figure 1.12. In the 15-minute market, negative prices from congestion accounted for 90 percent of the total number of intervals with negative prices, compared to only 33 percent in the first quarter. In the 5-minute market, negative prices from either congestion or both power balance constraint and congestion totaled 63 percent of negative price intervals, compared to 16 percent during the first quarter. This pattern is different from previous periods when the negative prices mostly resulted from negative priced bids, which is also reflected by the increase in frequency of prices below -\$30/MWh. The congestion during this period was primarily related to congestion on Path 15.

Figure 1.11 Factors causing negative 15-minute prices (all LAP areas)

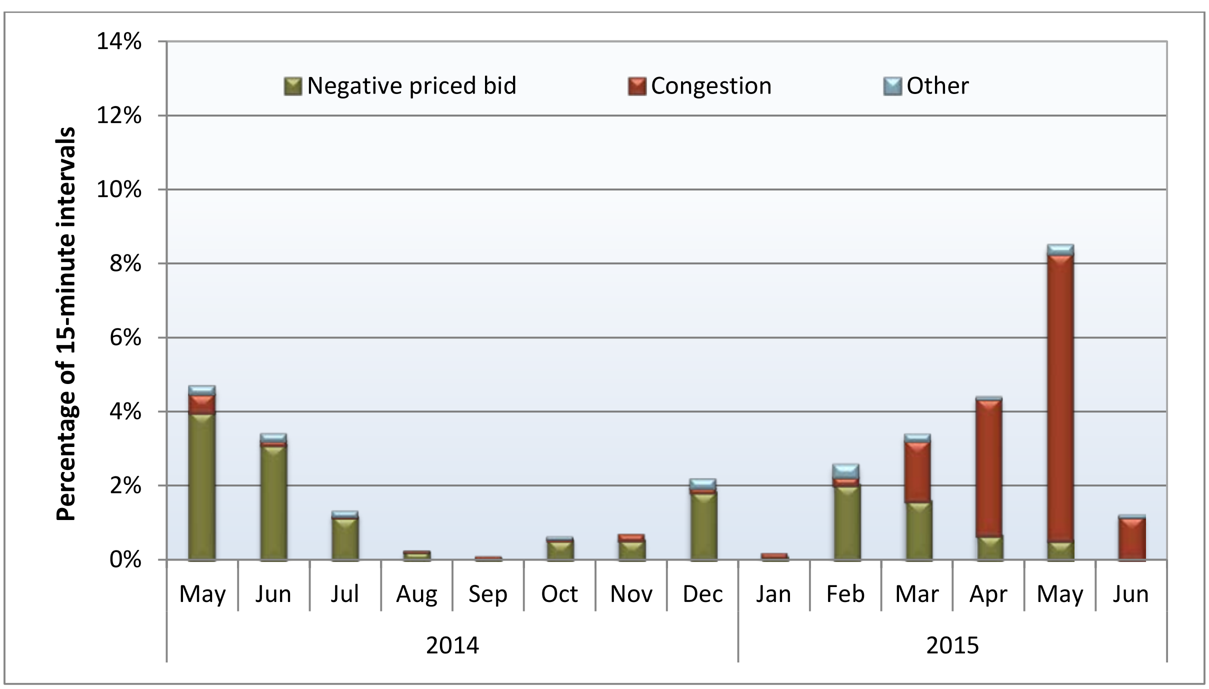
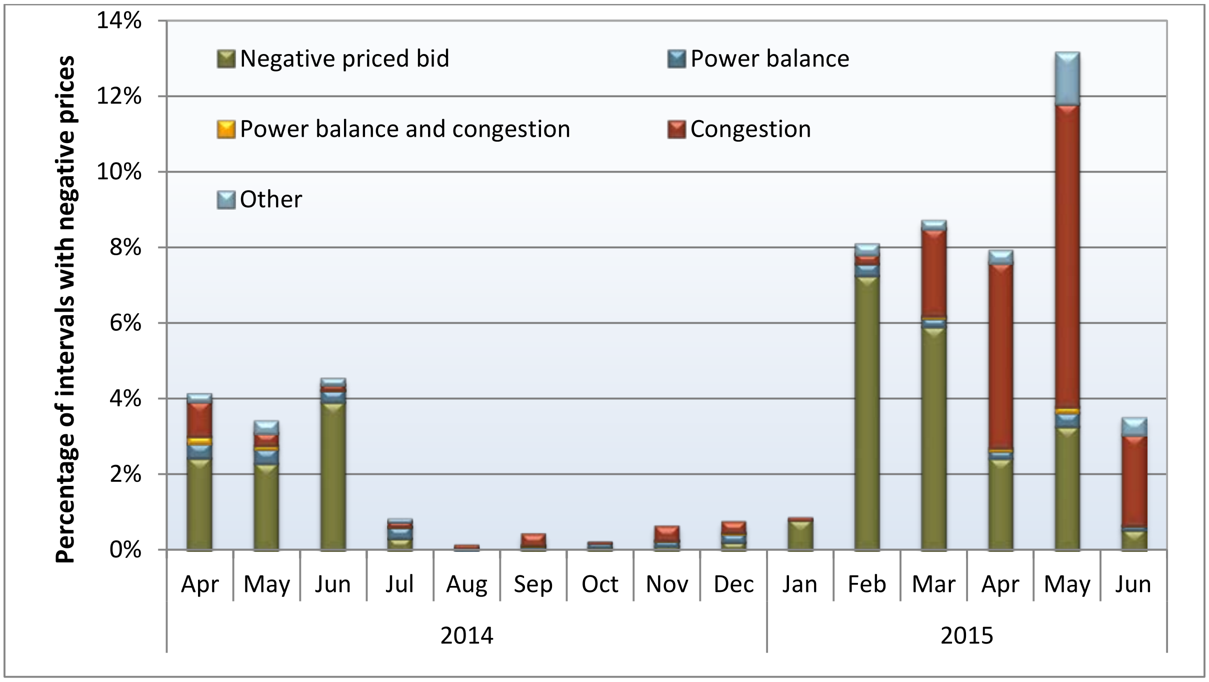


Figure 1.12 Factors causing negative 5-minute prices (all LAP areas)



Hourly frequency of negative prices

Negative prices typically occurred in the late morning and early afternoon hours. This pattern occurred in the 15-minute market (Figure 1.13) and even more so in the 5-minute market (Figure 1.14). Moreover, it was more pronounced on weekends than on weekdays. The increase in negative prices occurred as a result of a combination of factors including: transmission outages reducing Path 15 transmission capacity, low seasonal loads, and higher renewable generation from wind and particularly solar.

Net loads were occasionally lowest during the early afternoon hours when solar generation was highest rather than during the overnight hours when loads were lowest.[9] These low net loads, along with thermal resources preparing for the steep evening net load ramp, contributed to the increase in negative prices in the second quarter.

In previous years with good hydro conditions, hydro played a role in contributing to conditions that caused negative prices. However, hydro-electric generation output was low in the second quarter because of severe drought conditions and, thus, was not a significant factor in contributing to these pricing patterns. The low hydro-electric conditions may have helped to reduce the incidence of negative prices that otherwise may have occurred.

[9] Net load represents actual load minus solar and wind output.

Figure 1.13 Frequency of negative 15-minute prices by hour (all LAP areas)

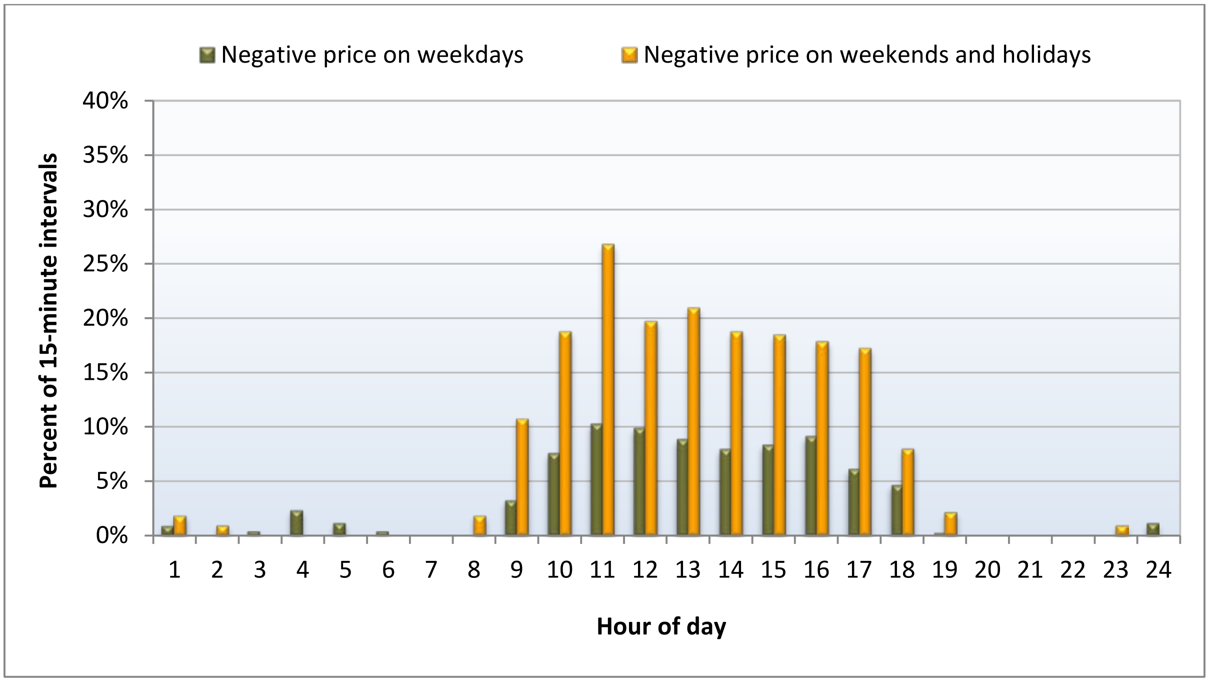
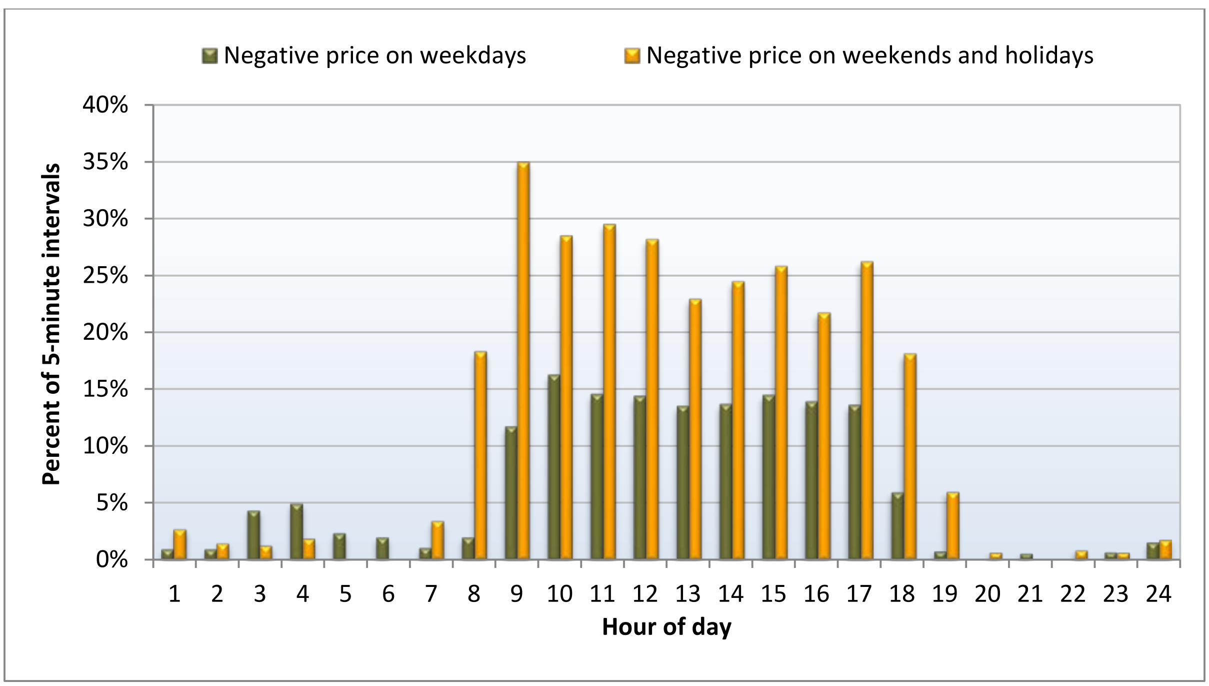


Figure 1.14 Frequency of negative 5-minute prices by hour (all LAP areas)



1.4 Congestion

Congestion on constraints within the ISO system increased overall average day-ahead and 15-minute prices in the PG&E area by about 5 percent and 2.5 percent, respectively. Compared to the previous quarter, congestion had a much larger negative price impact in the SDG&E and SCE areas, affecting prices by about -$1.50/MWh and -$1.30/MWh respectively.

Much of the congestion was related to planned transmission outages associated with Path 15, which began in mid-March and continued to early June. Further contributing to the congestion were lower loads and a high level of renewable generation south of Path 15, particularly from solar resources. Renewable resources were decrementally dispatched at times and frequently set low prices in Southern California.

When south-to-north congestion on Path 15 occurred in the day-ahead market, prices increased in the PG&E area by about $4.50/MWh and decreased in the SCE and SDG&E areas by about $3.70/MWh. Congestion on Path 15 occurred in the 15-minute market only about one-fifth as often as in the day-ahead, but it increased prices in the PG&E area by about $14/MWh while decreasing prices in the SCE and SDG&E areas by about $14/MWh.

1.4.1 Congestion impacts of individual constraints

Day-ahead congestion

Compared to the previous quarter, the frequency and impact of congestion in the day-ahead market increased in the first quarter.

In the PG&E area, the Path 15 constraints were the most congested constraints in the day-ahead market (see Table 1.1).[10] Combined, these constraints were binding in about 37 percent of hours. Many of these hours were peak hours. During these hours, prices in the PG&E area increased by about $4.50/MWh while prices in the SCE and SDG&E areas decreased by about $3.70/MWh. This congestion occurred mainly due to planned maintenance, anticipated variable resource deviation and unscheduled flows on the California-Oregon Intertie (COI).

Overall congestion in the SDG&E area decreased for the quarter. The 22356_IMPRLVLY_230_ 21025_ELCENTRO_230_BR_1_1 and 2122192_DOUBLTTP_138_22300_FRIARS_138_BR_1 _1 constraints were binding with the highest frequency and had a negative $2/MWh impact on SDG&E area prices, while having only a negligible impact on SCE and PG&E area prices. The third most binding constraint to impact the SDG&E area, caused by planned area outages, was 22462_ML60 TAP_138_22772_ SOUTHBAY_138_BR_1_1. This constraint was binding in about 1.3 percent of the hours and solely affected the SDG&E area prices, increasing them by about $9.20/MWh for the quarter.

[10] The ISO converted the Path 15 constraint from a branch group to a nomogram in the day-ahead market, effective on May 21. The change was expected to increase efficiency and reliability of the system. More detail on the PATH15_NG constraint can be found in the following ISO market notice (http://www.caiso.com/Documents/Enforcement-Path15-NomogramConstraint.htm) and the Operating Procedure 3610 available at: http://www.caiso.com/Documents/3610.pdf.

Table 1.1 Impact of congestion on day-ahead prices by load aggregation point in congested hours

		Frequency		Q1			Q2		
Area	**Constraint**	**Q1**	**Q2**	**PG&E**	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**
PG&E	PATH15_BG	6.2%	27.6%	$4.02	-$3.29	-$3.06	$4.54	-$3.86	-$3.64
	PATH15_S-N		9.1%				$4.05	-$3.65	-$3.42
	30055_GATES1 _500_30900_GATES _230_XF_11_P		2.7%				$0.70	-$0.60	-$0.59
	30751_MOSSLDB _230_30750_MOSSLD _230_BR_1 _1		2.3%				$1.97	-$1.72	-$1.63
	35922_MOSSLD _115_30751_MOSSLDB _230_XF_1		1.5%				$2.02		
	35922_MOSSLD _115_30751_MOSSLDB _230_XF_2		1.3%				$4.13	-$6.42	-$6.20
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1		0.6%				$2.96	-$1.36	
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3		0.3%				$4.13	-$3.82	-$3.62
SCE	24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1		2.2%					$0.49	
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1		0.8%				-$1.78	$2.51	-$0.41
	22716_SANLUSRY_230_22504_MISSION _230_BR_2 _1		0.2%					$0.70	-$5.89
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.9%		-$0.74	$1.00	-$0.59			
SDG&E	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1		2.8%						-$2.14
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1		2.4%						-$2.11
	22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1		1.3%						$9.18
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	4.2%	1.3%			-$0.47	-$0.72		$1.17
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1		0.9%				-$0.41	$0.49	$0.40
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	9.0%	0.8%	-$0.95	$0.92	$1.51	-$1.78	$2.51	-$0.41
	SLIC 2584248 50002_OOS_TDM		0.6%						$4.70
	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1		0.6%						$5.26
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		0.3%				-$5.06	$3.49	$7.21
	22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1	24.7%				$5.04			
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	13.1%		-$2.80	$1.70	$5.15			
	IVALLY-ELCNTO_230_BR_1_1	1.7%		-$0.05		$1.47			
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	1.5%		-$3.81	$2.35	$6.50			
	22768_SOUTHBAY_69.0_22772_SOUTHBAY_138_XF_1	0.5%				$6.85			

The 24087_MAGUNDEN_230_24153_VESTAL_230_BR_2_1 constraint was the most binding constraint in the SCE area in the second quarter at 2.2 percent of hours due to contingencies. This constraint solely impacted prices in the SCE area, and increasing them by about $0.50/MWh. The 24016_BARRE_230 _24154_VILLA PK_230_BR_1_1 constraint was the second most binding constraint at 0.8 percent of hours. This constraint, when binding, increased SCE area prices by about $2.50/MWh and decreased prices in the PG&E and SDG&E areas by about $1.80/MWh and $0.40/MWh, respectively.

15-minute market congestion

Congestion in the 15-minute market occurred less frequently than in the day-ahead market, but often had a larger price effect. Table 1.2 shows the frequency and magnitude of 15-minute market congestion in the quarter.

The PATH15_S-N constraint was the top binding constraint for the quarter and had the greatest price impact on the PG&E area. This constraint was binding in about 6.7 percent of the intervals in the quarter and increased prices in the PG&E area by about $14.16/MWh while decreasing prices in the SCE and SDG&E areas by about $14.62/MWh and $13.81/MWh, respectively.

Table 1.2 Impact of congestion on 15-minute prices by load aggregation point in congested intervals

Area	Constraint	Frequency		Q1			Q2		
		Q1	Q2	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	PATH15_S-N	1.0%	6.7%	$16.27	-$16.36	-$15.30	$14.16	-$14.62	-$13.81
	30751_MOSSLDB _230_30750_MOSSLD _230_BR_1 _1		0.3%				$6.59	-$6.62	-$6.29
	6110_SOL10_NG		0.2%				$4.96	$2.13	$1.50
	PATH15_BG	0.2%		$5.87	-$6.08	-$5.72			
SCE	24087_MAGUNDEN_230_24153_VESTAL _230_BR_1 _1		0.5%						$14.09
	SLIC 2584248 50002_SCIT		0.1%				-$4.18	$9.51	$9.92
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1		0.1%					$3.57	-$30.20
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.5%		-$3.09	$7.15	$3.45			
	PATH26_N-S	0.1%		-$46.75	$44.20	$41.92			
SDG&E	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1		0.1%				-$5.92	$16.52	$2.76
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1		0.1%					$9.67	-$100.16
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		0.1%				-$5.35	$5.99	$10.80
	SDGEIMP_BG		0.1%				-$1.74	-$1.74	$24.03
	22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1	2.7%				$14.80			
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	1.7%		-$7.01	$8.42	$19.96			
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.5%		-$9.33	$10.25	$25.01			

Overall, congestion occurred more frequently in the day-ahead market than in the 15-minute market, but had a smaller price impact when binding. In the quarter, the price impact on the most significant binding elements was larger in the 15-minute market than the day-ahead market. For instance, the combined frequency of the Path 15 constraints in the day-ahead market was roughly 37 percent of hours in the day-ahead market compared to around 6.7 percent of intervals in the 15-minute market. While Path 15 congestion increased day-ahead prices in the PG&E area by about $4.50/MWh, it increased prices in the PG&E area by about $14/MWh in the 15-minute market.

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 flows and to provide a reliability margin.

1.4.2 Impact of congestion on average prices

This section provides an assessment of differences between overall average regional prices in the day-ahead and 15-minute 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 when taking into account both the frequency with which congestion occurs and the magnitude of the impact.[11] The congestion price impact differs across load areas and markets.

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 for groups of nodes that represent different load aggregation points or local capacity areas.

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

Day-ahead price impacts

Table 1.3 shows the overall impact of day-ahead congestion on average prices in each load area in the quarter by constraint.

For the quarter, congestion effects in the day-ahead market were mixed as prices increased in the PG&E area and decreased in the SDG&E and SCE areas. Congestion in the day-ahead market had a significant impact in the PG&E area, where it increased prices by about 5.3 percent ($1.84/MWh). In the SCE and SDG&E areas overall prices decreased, by 4.8 percent ($1.47/MWh) and 4.1 percent ($1.28/MWh), respectively.

The constraints related to Path 15, PATH15_BG and PATH15_S-N, had the largest overall impact on prices in the quarter. These constraints increased prices in the PG&E area by about $1.62/MWh (4.7 percent) and decreased prices in the SCE and SDG&E areas by $1.39/MWh (4.6 percent) and $1.31/MWh (4.3 percent), respectively. As noted earlier, the Path 15 congestion was related to planned transmission outages that occurred throughout much of the quarter.

Table 1.3 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
PATH15_BG	$1.25	3.60%	-$1.06	-3.51%	-$1.00	-3.25%
PATH15_S-N	$0.37	1.06%	-$0.33	-1.09%	-$0.31	-1.01%
35922_MOSSLD _115_30751_MOSSLDB _230_XF_2	$0.06	0.16%	-$0.04	-0.12%	-$0.03	-0.11%
30751_MOSSLDB _230_30750_MOSSLD _230_BR_1 _1	$0.05	0.13%	-$0.04	-0.13%	-$0.04	-0.12%
22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1					$0.12	0.38%
22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1					-$0.06	-0.20%
30055_GATES1 _500_30900_GATES _230_XF_11_P	$0.02	0.05%	-$0.02	-0.05%	-$0.02	-0.05%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.05	-0.16%
24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1	-$0.01	-0.04%	$0.01	0.03%	$0.02	0.06%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.01	-0.04%	$0.02	0.06%	$0.00	-0.01%
30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.01	0.03%	-$0.01	-0.04%	-$0.01	-0.03%
22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1					$0.03	0.10%
35922_MOSSLD _115_30751_MOSSLDB _230_XF_1	$0.03	0.09%				
SLIC 2584248 50002_OOS_TDM					$0.03	0.10%
30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1	$0.02	0.06%				
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.00	0.00%			$0.02	0.05%
22716_SANLUSRY_230_22504_MISSION _230_BR_2 _1					-$0.01	-0.04%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1						
24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1			$0.01	0.04%		
Other	$0.07	0.20%	-$0.01	-0.05%	$0.04	0.12%
Total	$1.84	5.3%	-$1.47	-4.8%	-$1.28	-4.1%

15-minute price impacts

Table 1.4 shows the overall impact of 15-minute congestion on average prices in each load area in the quarter by constraint. The overall impact of congestion elevated the PG&E area price by about $1/MWh (2.8 percent) and decreased the SCE and SDG&E area prices by about $0.9/MWh or 3 percent and about $1/MWh or 3.6 percent respectively. The most pronounced congestion was related to Path 15 congestion. The overall impact on 15-minute prices of this congestion, however, was slightly less than on day-ahead prices (e.g., 2.6 percent of 15-minute prices versus 3.6 percent of day-ahead prices).

Table 1.4 Impact of congestion on overall 15-minute prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
PATH15_S-N	$0.94	2.65%	-$0.97	-3.36%	-$0.92	-3.19%
22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1			$0.01	0.03%	-$0.14	-0.48%
24087_MAGUNDEN_230_24153_VESTAL _230_BR_1 _1			$0.07	0.23%		
30751_MOSSLDB _230_30750_MOSSLD _230_BR_1 _1	$0.02	0.05%	-$0.02	-0.06%	-$0.02	-0.06%
22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1					-$0.03	-0.09%
SLIC 2584248 50002_SCIT			$0.01	0.03%	$0.01	0.03%
99010_VELAS-LB_230_24076_LAGUBELL_230_BR_1 _1			$0.01	0.05%		
SDGEIMP_BG					$0.02	0.06%
6110_SOL10_NG	$0.01	0.03%	$0.01	0.02%		
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.01	-0.01%	$0.01	0.04%		
24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1			$0.01	0.02%	$0.01	0.03%
Other	$0.05	0.13%			$0.01	0.03%
Total	$1.00	2.82%	-$0.87	-3.00%	-$1.05	-3.64%

1.5 Congestion revenue rights revenue adequacy

Congestion revenue rights are forward contracts on transmission capacity that settle on day-ahead congestion prices.[12] Congestion revenue right payments exceeded day-ahead market congestion rent collections in the second quarter leading to $44.5 million in revenue inadequacy before accounting for auction revenues.[13] This resulted in an $8.2 million deficit to the congestion revenue rights balancing account – which includes auction revenues – during the second quarter.

Background

The market for congestion revenue rights is designed so that congestion rent collected from the day-ahead market should be sufficient to cover payments to congestion revenue rights holders. This is referred to as revenue adequacy.[14] Day-ahead congestion rents and congestion revenue right entitlement payments are placed in a balancing account. All revenues from the annual and monthly auction processes are also added to the balancing account which offsets deficits due to revenue

[12] The *2014 Annual Report on Market Issues and Performance* offers general background information on congestion revenue rights. For more information, see: http://www.caiso.com/Documents/DMM_Q1_2015_Report_Final.pdf.

[13] Congested constraints can cause the amount paid for consuming power to exceed the amount paid for providing the power. This difference in payments is congestion rent.

[14] For a more detailed explanation of congestion revenue rights revenue adequacy and the simultaneous feasibility test, please see the ISO's 2014 reports on congestion revenue rights at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=6E3E0602-9DF9-4F7F-8557-3D7C99DCCBE8.

inadequacy, if needed. Monthly balancing account shortfalls or surpluses are allocated to measured demand.

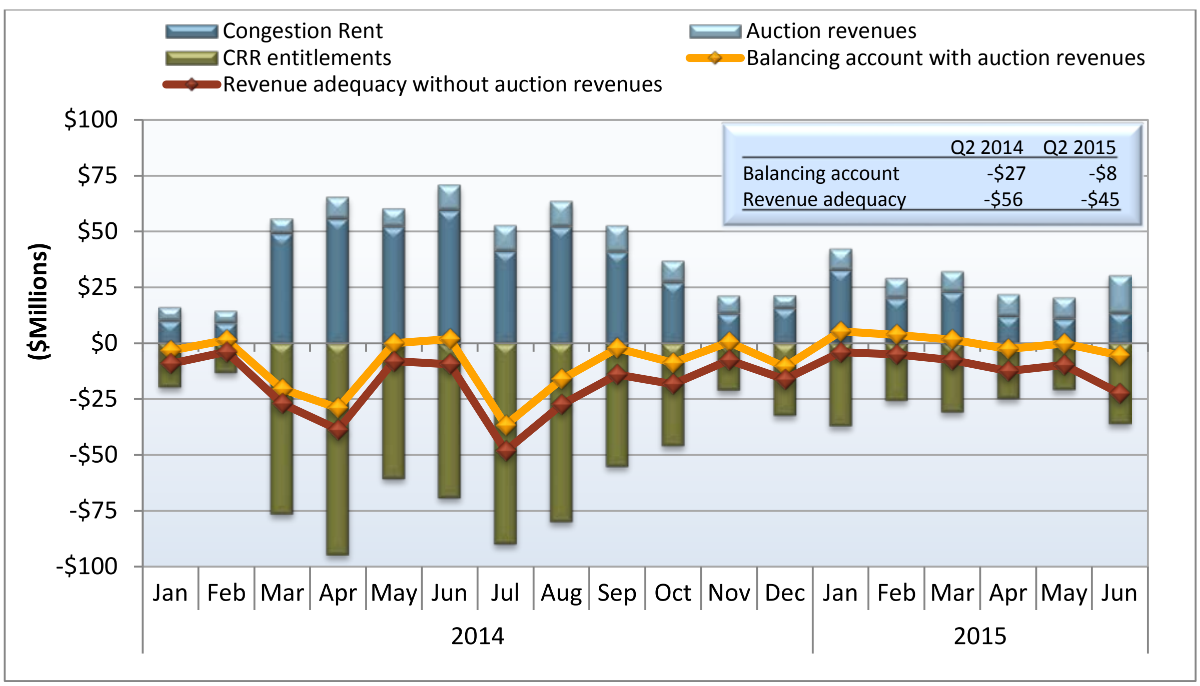
Revenue inadequacy, or when congestion rents are insufficient to cover payments to congestion revenue rights, can occur for a variety of reasons. Differences between the network transmission model used in the congestion revenue rights process and the final day-ahead market model is one of the major causes of revenue inadequacy. When there is less capacity available across a transmission constraint in the day-ahead market than the congestion revenue rights auction, the amount of congestion rent the day-ahead market can collect can be below the amount of congestion revenue right entitlements.

Revenue adequacy

Figure 1.16 shows the monthly revenues, payments, revenue adequacy, and balancing account values from January 2014 through June 2015.

- The dark blue bars represent day-ahead market congestion rent.
- The light blue bars show net revenues from the annual and monthly auctions for congestion revenue rights corresponding to each quarter. This includes revenues paid for positively priced congestion revenue rights in the direction of expected prevailing congestion, less payment made to entities purchasing negatively priced counter-flow congestion revenue rights.[15]

Figure 1.15 Monthly revenue adequacy



- The dark green bars show net payments made to holders of congestion revenue rights. This includes payments made to holders of rights in the prevailing direction of congestion plus revenues collected from entities holding counter-flow congestion revenue rights.

[15] Auction revenues from the seasonal auctions are divided into the months within the seasonal term based on the number of hours in each month for the congestion revenue right type (peak or off-peak).

- The orange line shows the monthly balancing account value which includes auction revenues.
- The red line shows the monthly revenue adequacy which excludes auction revenues.

As seen in Figure 1.15, revenue inadequacy before accounting for auction revenues in the second quarter was $45 million, down 20 percent from a shortfall of $56 million in the second quarter of 2014. The balancing account deficit improved by 70 percent to $8 million largely due to auction revenues increasing to $37 million in the second quarter of 2015 from $29 million in the second quarter of 2014.

However, second quarter revenue inadequacy in 2015 occurred with significantly less day-ahead market congestion rent ($38 million) in 2015 compared to the second quarter of 2014 ($168 million). As a percent of day-ahead congestion rents, second quarter congestion revenue right entitlements increased to about 220 percent in 2015 from 130 percent in 2014. So while in absolute dollar terms revenue inadequacy improved, revenue inadequacy increased as a percent of congestion rent.

Components of congestion revenue rights balancing account by market participant type

Table 1.5 compares the distribution of individual components of congestion revenue rights balancing account among different groups of congestion revenue rights holders and shows the final balance of revenue adequacy account for each participant type.[16] The columns include the following:

- **Net day-ahead congestion rents:** The congestion rent collections in the day-ahead market from market participants net of congestion rents passed through to existing transmission contracts and transmission ownership rights.
- **CRR settlement rule:** Charges from the congestion revenue rights settlement rule mechanism.[17]
- **CRR auction revenues:** The net revenues from the annual and monthly congestion revenue rights auctions.
- **CRR entitlements:** Net payments made to holders of congestion revenue rights, which include payments made to holders of rights in the prevailing direction of congestion plus revenues collected from entities purchasing counter-flow congestion revenue rights.
- **Final CRR account balance**: The sum of the first three columns, which represent collections made by the ISO, minus CRR entitlements which are paid out by the ISO.

For purposes of this analysis, congestion revenue rights holders are categorized as follows:

- Balancing authority areas outside the ISO system.
- Financial entities that own no physical power in the ISO system and participate in only the convergence bidding and congestion revenue rights markets.

[16] ISO's final account balance in the table shows the difference between payments to the ISO and payments by the ISO. A negative balance means that the ISO paid more to the market participants than it received from them.

[17] If a market participant's convergence bidding positions impact the power flow and congestion on a constraint by a certain percentage and increase the value of the congestion revenue rights for the market participant, the ISO adjusts the payment by reducing the value of the congestion revenue rights.

- Marketers that participate by scheduling imports or exports on inter-ties and whose portfolios are not primarily focused on physical or financial participation in the ISO markets.
- Physical generators who primarily participate in the ISO as physical generators.
- Physical load or entities who primarily participate in the ISO as load-serving entities.

As shown in Table 1.5, financial participants received the largest share of net revenues, collecting net revenues of nearly $11 million in the second quarter of 2015. These financial entities bid heavily in the monthly auctions, speculating on and responding to congestion trends. Subtracting the day-ahead congestion from the revenues of financial participants can be misleading when trying to determine the profitability of the congestion revenue right positions. This is because the day-ahead congestion costs for financial participants are incurred primarily to procure convergence bidding positions.[18] Overall, financial participants earned over $17 million by purchasing transmission rights in the congestion revenue right auction for about $12 million and selling them for $30 million.

Load-serving entities collected net revenues of $4.1 million. Most of these revenues resulted from allocations of congestion revenue rights made based on the volume of load served and auction revenues from counter-flow positions.[19] Load-serving entities on net used counter-flow positions to sell allocated rights back to the congestion revenue right auction. Marketers and physical generation on net contributed $7 million and $2 million, respectively, in payments into the balancing account.

Table 1.5 Components of CRR balancing account by market participant type (April – June)

Trading entities	Payments to the CRR Balancing Account ($ millions)				
	Net day-ahead congestion rents	CRR settlement rule	CRR auction revenues	CRR entitlements	Final CRR account balance
Balancing authority	-$1.4			-$1.7	**-$3.1**
Financial	$6.8	$0.1	$12.6	-$30.2	**-$10.7**
Marketer	$2.2	$0.0	$20.5	-$15.3	**$7.5**
Physical generation	$2.7	$0.0	$6.2	-$6.6	**$2.3**
Physical load	$27.2	$0.1	-$3.0	-$28.4	**-$4.1**
Total	**$37.6**	**$0.2**	**$36.3**	**-$82.2**	**-$8.2**

Measures to reduce revenue inadequacy

The ISO in 2014 took measures to reduce revenue inadequacy, which are noted below.

[18] Convergence bid positions could be net virtual supply or demand in the day-ahead market that are reversed in the real-time to arbitrage overall prices. Convergence bids can also be used to purchase transmission rights in the day-ahead market to sell to the real-time market similar to the purchase of transmission rights in the congestion revenue rights auction to sell to the day-ahead market.

[19] Negative auction revenues in Table 2.1 represent payments for the cleared counter-flow positions.

- Extending a breakeven point analysis used on inter-ties to internal constraints. Under this approach the constraint used in the current monthly or annual auction is limited by the breakeven limit that would have made the constraint congestion revenue rights payments equal the congestion rent collected by the constraint over the previous corresponding time interval (i.e., for the monthly auction, this represents the limit needed to breakeven for the constraint in the previous month).

- Increased the number of contingency cases enforced in the annual congestion revenue rights process. Contingency cases are various events that could occur which will affect the flows on the transmission system. Flows over transmission elements could be constrained by different limits under different contingencies. The combination of transmission element and contingency case form the constraint used in the day-ahead market.

- Enforced a few additional nodal constraints in the congestion revenue rights processes. Nodal constraints restrict the amount of power that can be injected or withdrawn from a node in the day-ahead market. Nodal constraints can contribute to congestion revenue rights entitlement payments and day-ahead market congestion rent in the same manner as other transmission elements.[20]

While the ISO efforts likely reduced revenue inadequacy, it still appears to be an issue in the first half of 2015. DMM noted in a 2014 whitepaper that there are a variety of unavoidable modeling issues that can create discrepancies in the network transmission model that is used in the congestion revenue rights process and the final day-ahead market model.[21] These issues include planned and unexpected transmission outages and de-rates occurring after the final congestion revenue rights model is finalized; granularity differences between the congestion revenue rights process and day-ahead market (i.e., monthly versus hourly); and unsettled flows in the day-ahead market that cannot readily be accounted for in the congestion revenue rights process.

DMM proposed a general methodology that could be used to allocate revenue inadequacy costs back to holders of congestion revenue rights on an interval and constraint specific basis.[22] This alternative allocation approach would limit the total amount of revenues that can be transferred from load-serving entities to congestion revenue rights holders through uplift. Moreover, this allocation method could reduce the incentive for entities purchasing congestion revenue rights to target modeling differences that create revenue inadequacy costs. Given the continued revenue inadequacy issues in the first half of 2015, the ISO could consider this alternative allocation methodology and other additional measures to address revenue inadequacy.

1.6 Bid cost recovery

Overall bid cost recovery payments for 2015 have been low, as seen in Figure 1.16. We estimate total bid cost recovery payments for the second quarter at about $26.2 million. This is an increase from

[20] For more information on nodal constraints, see the discussion in Section 4.2 of the following straw proposal: http://www.caiso.com/Documents/RevisedStrawProposal-PriceInconsistencyMarketEnhancements.pdf, and technical bulletin: http://www.caiso.com/Documents/ConvergenceBiddingTechnicalStatusUpdate.pdf. Nodal group constraint information can be found on the ISO OASIS website (oasis.caiso.com) under Prices and then Nodal Group Constraints.

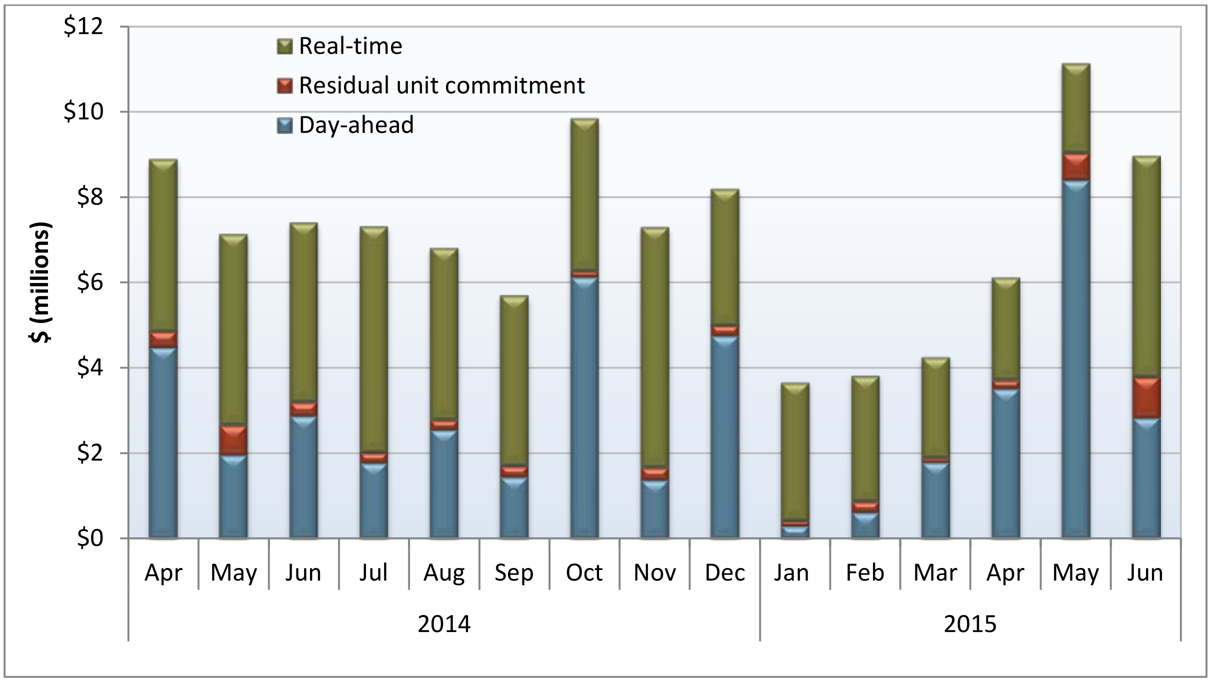
[21] The whitepaper can be found here: http://www.caiso.com/Documents/AllocatingCRRRevenueInadequacy-Constraint-CRRHolders_DMMWhitePaper.pdf.

[22] Ibid.

about $23.5 million in the same quarter last year and from $12 million in the first quarter of this year. High levels of payments for day-ahead bid cost recovery were recorded in May, estimated at over $8 million, with about $7 million for resources that were able to relieve minimum online constraints, particularly the minimum online constraint for NP15 capacity related to planned outages on Path 15.[23]

Real-time market bid cost recovery payments were higher in June than they had been since last November, but were not out of line with historical values. This increase from recent months is due to a handful of specific situations that are currently under review by DMM and the ISO.

Figure 1.16 Monthly bid cost recovery payments



1.7 Real-time imbalance offset costs

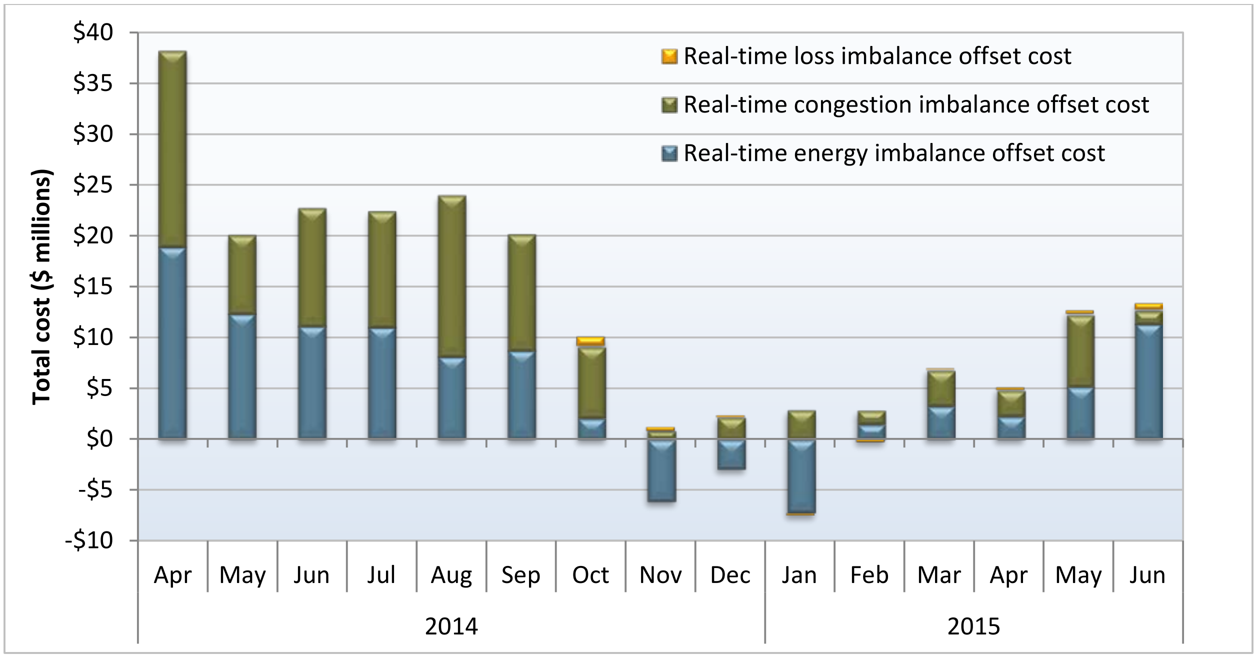
Real-time imbalance offset costs within the ISO system increased in the second quarter and totaled about $31 million, compared to $81 million in the second quarter of 2014 and $6 million in the first quarter of 2015. Total real-time imbalance offset costs in the second quarter were the sum of approximately $1 million in real-time imbalance loss offset cost, $11 million in congestion imbalance offset cost, and $19 million in energy imbalance offset cost. Values reported here are the most current reported settlement imbalance charges, but are subject to change.

Figure 1.17 reports monthly real-time imbalance offset costs including real-time energy imbalance offset, real-time congestion imbalance offset and real-time imbalance loss offset costs. Until October 1, the ISO aggregated real-time loss imbalance offset costs with real-time energy imbalance costs. The

[23] This minimum online constraint was noticed to the market on March 17: http://www.caiso.com/Documents/EnforcementofMinimumOnlineCommitmentConstraintforNP15Area31815-53115.htm.

second quarter loss imbalance offset was a cost of $1.1 million compared to a credit of $0.3 million in the first quarter of 2015.

Figure 1.17 Real-time imbalance offset costs



Congestion imbalance offset costs fell substantially in the fourth quarter of 2014, and have remained flat in the first half of 2015. Real-time congestion imbalance offset costs were $11 million in the second quarter of 2015 compared to $8 million in the first quarter. The current estimated cost remains at a level lower than any quarter since the first quarter of 2013. Although real-time congestion imbalance offset costs have remained stable, real-time congestion due to conditions unanticipated in the day-ahead market can still result in substantial imbalance offsets. The increase in real-time congestion imbalance offset costs in May 2015 is attributable to three particular days and two constraints on which flow limits were reduced in real time.[24] Real-time congestion imbalance offset costs in June were held down by the results on June 8, which saw a credit to real-time congestion imbalance offset of approximately $4 million.

Real-time imbalance energy offset costs were elevated in June 2015. However, over half of the $11 million monthly total in June was due to the events on June 8. As noted earlier, real-time load was significantly higher than the day-ahead forecast. This resulted in multiple intervals of power balance shortage relaxations and corresponding high prices in the real-time markets. These factors contributed to the real-time imbalance energy offset costs on June 8.

The settlement values reported for the real-time energy imbalance offset include several components that are offset by settlement values elsewhere in the market and thus are not true uplift costs. These

[24] On May 3, the PATH15_S-N constraint had significantly more congestion in real time than in the day-ahead and accounted for over $1 million in real-time congestion imbalance offset cost. On May 30 and 31, the 30515_WARNERVL_230_30800_ WILSON_230_BR_1_1 constraint was conformed in real time and accounted for $1 to $2 million per day in real-time congestion imbalance offset cost.

values are inflated when real-time prices are elevated, such as occurred on June 8. For example, transmission loss obligation charges for transmission loss paybacks are currently allocated to measured demand through a separate settlements process. When a scheduling coordinator schedules imports involving certain transmission access outside of the ISO, losses associated with these imports are paid back to the appropriate balancing authority area in the form of energy. Transmission loss obligation charges to the scheduling coordinator reflect the amount paid to ISO generators to provide the transmission loss payback energy.

1.8 Convergence bidding

Participants engaging in convergence bidding continued to earn positive returns in the second quarter. The net revenues from the market in these three months were about $9.5 million. Virtual supply generated net revenues of about $1.2 million while virtual demand accounted for approximately $8.3 million. The total payment to convergence bidders fell slightly, to about $8.4 million, after taking into account virtual bidding bid cost recovery charges of $1.1 million.

Offsetting virtual demand with supply bids at different locations is designed to profit from higher anticipated congestion between these locations in the real-time market. This type of offsetting bid represented about 54 percent of all accepted virtual bids in the second quarter, a decrease from 58 percent in the previous quarter.

Total hourly trading volumes increased in the second quarter to about 3,100 MW from 2,400 MW in the previous quarter. Virtual supply averaged around 1,950 MW while virtual demand averaged around 1,150 MW during each hour of the quarter. Cleared hourly volumes of virtual supply outweighed cleared virtual demand by about 800 MW on average, an increase from 360 MW of net virtual supply in the previous quarter.

Net revenues for most of the second quarter were positive from both net virtual supply positions and net virtual demand positions. Although prices were generally higher in the day-ahead market than the 15-minute market, which benefits virtual supply positions, price spikes in the 15-minute market on June 8 lead to virtual demand positions being profitable for the quarter and significantly reduced the profitability of virtual supply positions.[25]

1.8.1 Convergence bidding trends

Total hourly trading volumes increased in the second quarter to 3,100 MW from 2,400 MW in the previous quarter. These volumes had remained relatively stable for the last few quarters. On average, about 47 percent of virtual supply and demand bids offered into the market cleared in the second quarter, which is up from 40 percent in the first quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 800 MW on average, which is an increase from 360 MW of net virtual supply in the previous quarter. Virtual supply exceeded virtual demand during both peak and off-peak hours, by about 700 MW and 995 MW, respectively. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply in hours ending 20 and 21 with the highest net virtual demand occurring in hour ending 21 at

[25] For additional background please refer to Section 3.6 Convergence bidding in the *Q4 2014 Report on Market Issues and Performance*: http://www.caiso.com/Documents/2014FourthQuarterReport_MarketIssuesandPerformance_March2015.pdf.

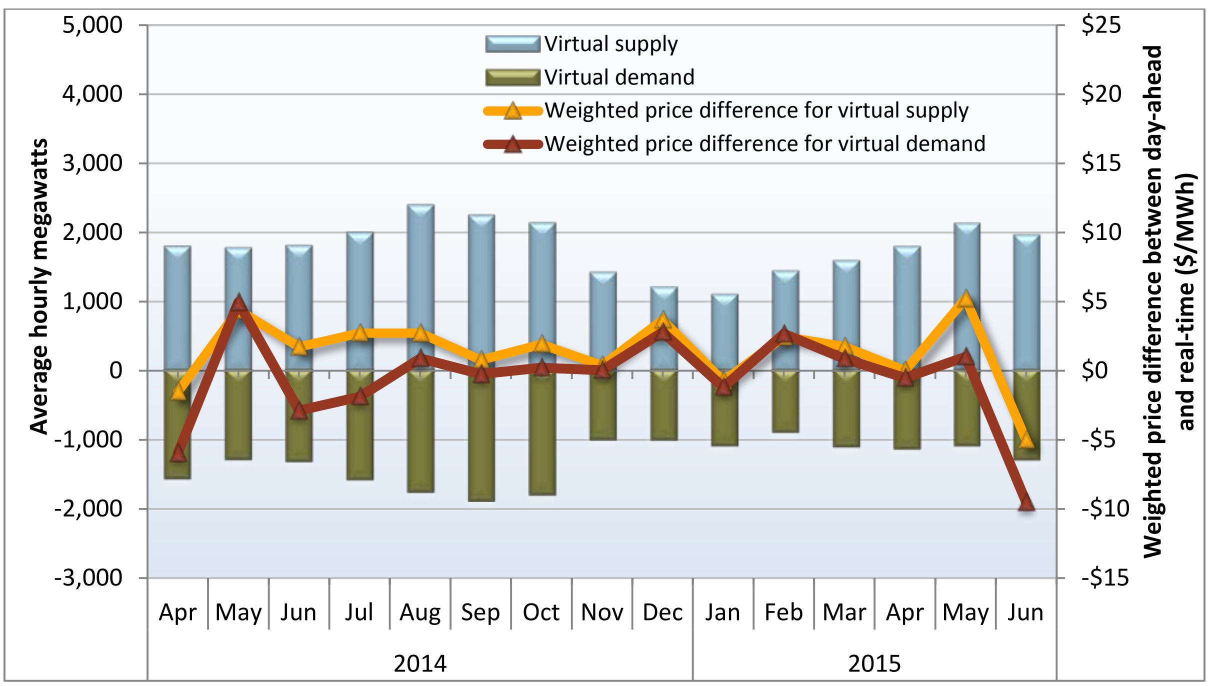
about 140 MW. In 22 of 24 hours, net cleared virtual supply exceeded net cleared demand. The highest net cleared virtual supply hour was hour ending 24 at about 1,300 MW.

Consistency of price differences and volumes

Convergence bidding is designed to align 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. For the quarter, net convergence bidding volumes were consistent with price differences between the day-ahead and real-time markets for an average of 12 hours. By month for the quarter, net convergence bidding volumes were consistent with price differences between the day-ahead and real-time markets for an average of 17, 23 and 8 hours for April, May and June, respectively.

Figure 1.18 compares cleared convergence bidding volumes with the volume-weighted average price difference where the 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 locations.

Figure 1.18 Convergence bidding volumes and weighted price differences



When the red line is positive, it indicates that the weighted average price charged for 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.

Virtual demand volumes for the months of April and June were consistent with weighted average price differences for the hours in which virtual demand cleared the market and, thus, were profitable. However, virtual demand positions in May were unprofitable as they were inconsistent with the weighted average price differences.

The yellow line in Figure 1.18 represents the difference between the day-ahead price paid to virtual supply and the real-time market price at which virtual supply positions are liquidated, weighted by cleared virtual supply bids by time interval and location. Virtual supply positions in the first quarter were on average profitable in April and May, but not in June.

Offsetting virtual supply and demand bids

Market participants can 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 locations during the same hour. These virtual demand and supply bids offset each other in terms of system energy and are not exposed to bid cost recovery settlement charges. 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 differences between the day-ahead and real-time markets.

The majority of cleared virtual bids in the first quarter were offsetting bids. Offsetting virtual positions accounted for an average of about 830 MW of virtual demand offset by 830 MW of virtual supply in each hour of the second quarter. These offsetting bids represent about 54 percent of all cleared virtual bids in the second quarter, which is a decrease from 58 percent in the previous quarter. This suggests that virtual bidding continues to be used to hedge or profit from congestion.

1.8.2 Convergence bidding revenues

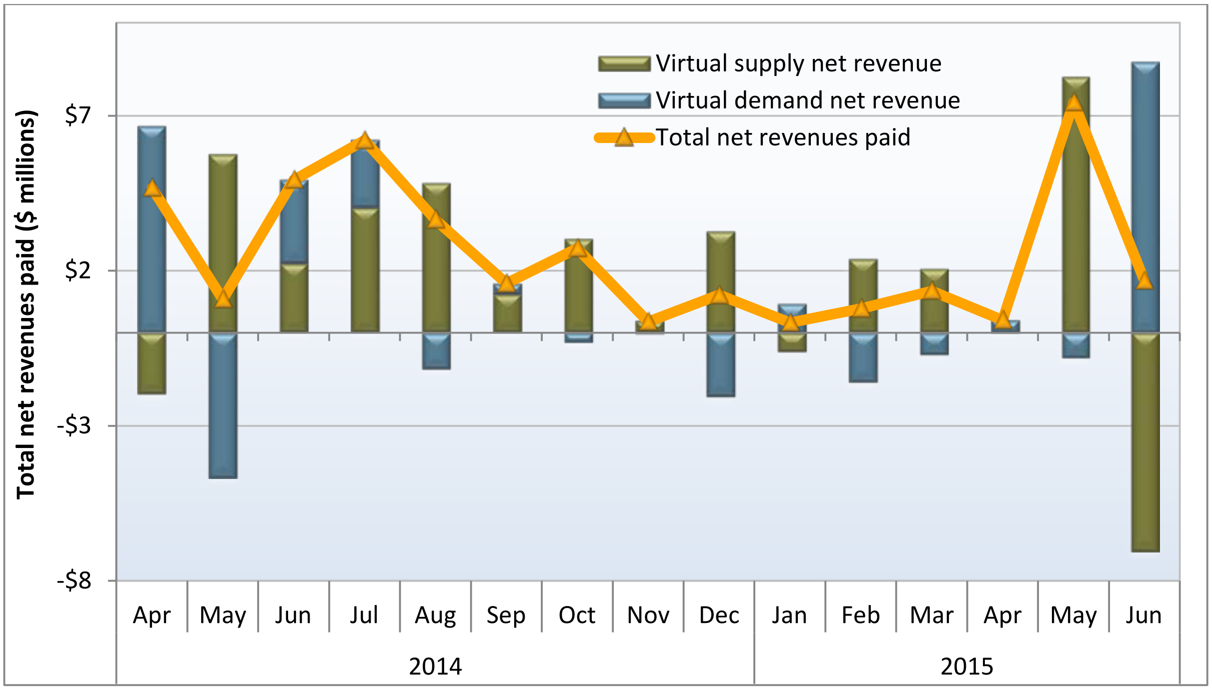
This section highlights sources of net revenues (or payments) received (or paid) by convergence bidders in the first quarter. Similar to the previous quarter, convergence bidding participants earned positive revenue. In the first quarter, net revenues were about $9.5 million from revenue collected on both virtual supply and demand positions.

Figure 1.19 shows total monthly net revenues for cleared virtual supply and demand. This figure shows the following:

- The net revenues from the market were about $9.5 million in the first quarter, compared to about $10.7 million in the same quarter in 2014, and $2.5 million in the previous quarter.
- Virtual supply revenues were most profitable in May as day-ahead prices were generally higher than 15-minute market prices. This was followed by the least profitable month of June with -$7 million, mainly due to losses on June 8. In total, virtual supply accounted for net payments of about $1.2 million during the quarter.
- Virtual demand revenues were very low or negative in April and May but were very profitable in June, associated with the price spikes on June 8 ($10.8 million). In total, virtual demand accounted for around $8.3 million in net payments to the market for the quarter.
- Excluding June 8 from the calculations would have resulted in virtual demand making payments of nearly $2.5 million rather than receiving a net payment of $8.3 million. Virtual supply payments would increase nearly ten-fold to a total net payment of $12 million for the quarter without June 8.

- Convergence bidders were paid about $8.4 million after subtracting virtual bidding bid cost recovery charges of $1.1 million for the quarter.[26] The costs were about $0.16 million, $0.43 million and $0.51 million in April, May and June, respectively.

Figure 1.19 Total monthly net revenues paid from convergence bidding



Net revenues and volumes by participant type

Table 1.6 compares the distribution of convergence bidding cleared volumes and net revenues in millions of dollars among different groups of convergence bidding participants.[27] As shown in Table 1.6, financial entities represent the largest segment of the virtual bidding market in terms of volume, accounting for about 48 percent of volumes and about 60 percent of settlement dollars. Marketers represent about 32 percent of the trading volumes and 36 percent of the settlement dollars. Generation owners and load-serving entities represent a smaller segment of the virtual market in terms of volumes (about 20 percent) and an even smaller segment of the settlements portion (3 percent).

[26] Further detail on bid cost recovery and convergence bidding can be found here: http://www.caiso.com/Documents/DMM_Q1_2015_Report_Final.pdf.

[27] DMM has defined financial entities as participants who own no physical power and participate in the convergence bidding and congestion revenue rights markets only. 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.

Table 1.6 Convergence bidding volumes and revenues by participant type (April – June)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	683	800	1,485	$5.53	$0.26	$5.79
Marketer	358	632	990	$2.14	$1.28	$3.42
Physical generation	1	352	353	-$0.01	-$0.04	-$0.04
Physical load	111	170	281	$0.67	-$0.31	$0.36
Total	**1,153**	**1,955**	**3,109**	**$8.3**	**$1.2**	**$9.5**

1.9 Ancillary service scarcity pricing events

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, implemented in December 2010, the ISO pays a pre-determined scarcity price for ancillary services procured during scarcity event intervals.

On May 24, for the first time since implementation of scarcity pricing in December 2010, the ISO experienced an ancillary service scarcity event in the day-ahead market. Regulation down procurement fell 0.35 MW short of the requirement in hours ending 9 through 17 in the SP 26 region. On this day, Southern California experienced near zero to slightly negative energy prices in the day-ahead market because of Path 15 congestion in combination with low seasonal loads and significant amounts of renewable generation. This likely contributed to the difficulty of committing more resources to provide regulation down. Ancillary service scarcity events also occurred in the real-time market on May 24 for both spinning reserves and regulation down in SP 26. For regulation down, the shortfall was 0.35 MW during two 15-minute intervals. There were five 15-minute intervals with insufficient procurement of spinning reserve, with the shortfall ranging from about 1 MW to almost 6 MW.

During the second quarter, ancillary service scarcity pricing events in the 15-minute market also occurred for regulation up and regulation down on April 21 and for regulation down on May 17.

2 Special Issues

2.1 Inter-tie bidding and scheduling

After implementing 15-minute scheduling on the inter-ties in May 2014, there was a significant decrease in the amount of inter-tie bids offered into the real-time market as well as an increase in the volume of self-scheduled inter-tie transactions. Overall, this trend held into 2015, though real-time economic bidding, particularly of exports, increased in the second quarter.

Figure 2.1 shows the level of self-scheduled imports and exports compared to the total offered imports and exports in the real-time markets. As seen in the figure, most real time inter-tie import bids remained self-scheduled. Around 80 percent of import bids and 31 percent of export bids in the hour-ahead market were self-schedules in the second quarter. In the first quarter of 2014, before the implementation of FERC Order No. 764, 49 percent of import bids and 8 percent of export bids were self-scheduled in the hour-ahead market. Figure 2.1 also shows that the volume of import bids decreased slightly in the real-time markets compared to the first quarter, whereas the amount of economic export bids increased.

Figure 2.1 Volume of self-scheduled and economic import and export bids in the real-time market

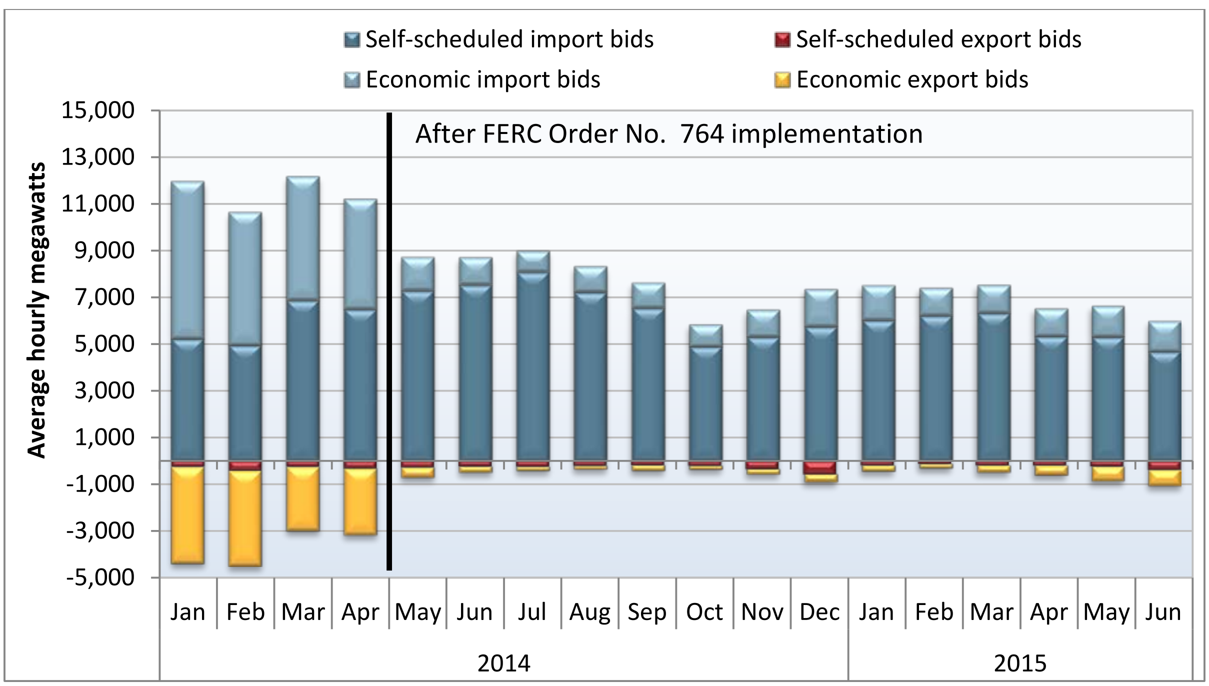
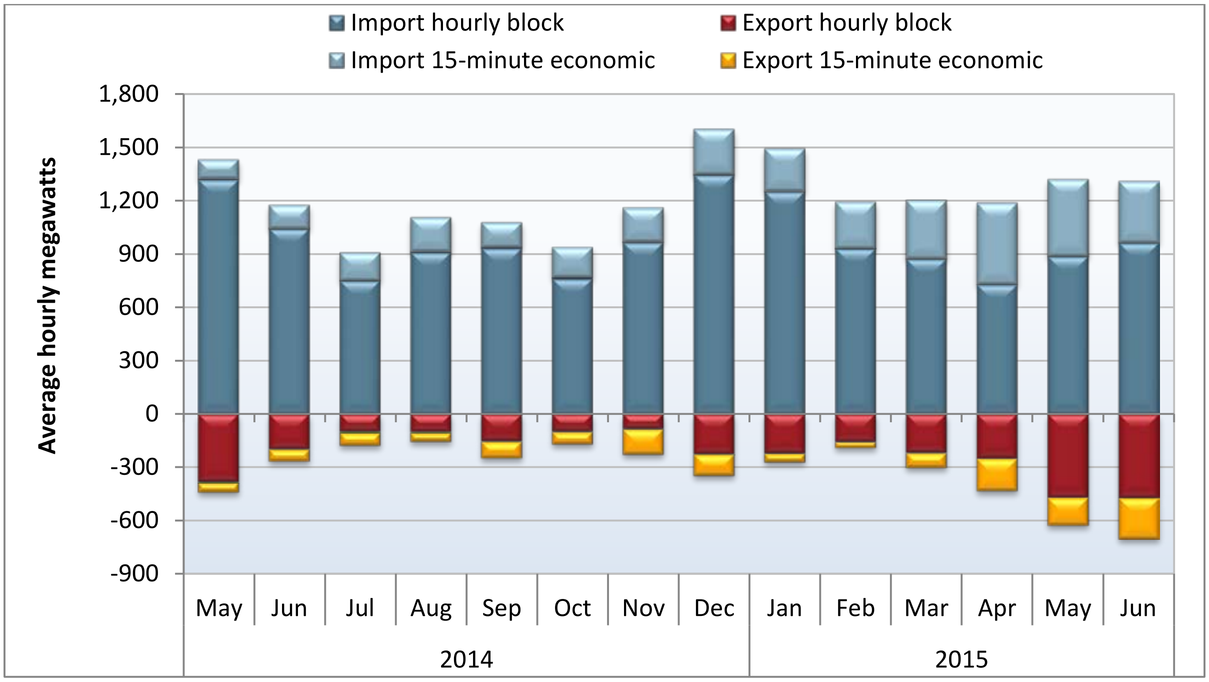


Figure 2.2 Economic import and export bids by bidding option



Most of the real-time economic bids on the inter-ties remained in the hour-ahead market in the second quarter, though the share of 15-minute inter-tie bids grew. In the second quarter, around 68 percent of economic import bids and around 67 percent of economic export bids were hourly block bids.[28] This is lower than the first quarter when 83 percent of economics imports bids and around 80 percent of economic export bids were bid in as hourly blocks. The remaining 32 percent of economic import bids and 33 percent of economic export bids were 15-minute economic bids, as shown in Figure 2.2. This is up from 17 percent of economic import bids and 20 percent of economic export bids in the 15-minute market in the first quarter.

The volume of 15-minute dispatchable import bids increased by 48 percent compared to the first quarter, averaging 413 MW each hour in the second quarter. 15-minute dispatchable economic export bids increased to an average of 190 MW, compared to 55 MW in the first quarter. The volume of 15-minute economic bids in the second quarter was the highest quarterly value since 15-minute import bidding began in May 2014.

Figure 2.3 shows the hourly average amount of 15-minute dispatchable economic import and export bids by inter-tie, with each color representing a different scheduling coordinator. These bids were concentrated on three inter-ties and submitted by a small number of scheduling coordinators. The majority of these scheduling coordinators are external balancing authority areas, as seen in Table 2.1. This lack of liquidity on the inter-ties in the 15-minute market may, as discussed in a recent DMM special report, be problematic if convergence bidding on the inter-ties is reintroduced.[29]

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[28] As with previous quarters, participants seldom used the hourly economic bid block option with a single intra-hour economic schedule change on the inter-ties.

[29] The DMM report on potential issues with implementing convergence bidding on the inter-ties can be found here: http://www.caiso.com/Documents/DMMReport-ConvergenceBiddingonInterties.pdf. The analysis in the special report included bids by tie-generators, which are excluded from the analysis in this section.

Figure 2.3 15-minute dispatchable economic bids by inter-tie and scheduling coordinator (Q2 2015)

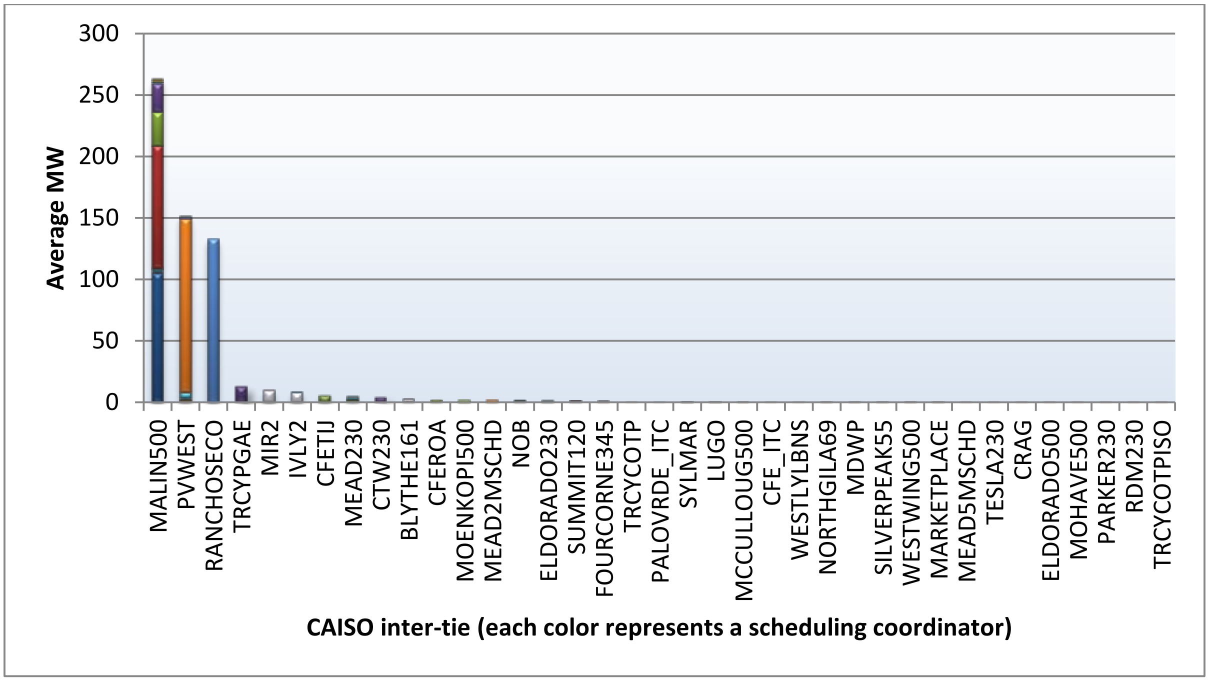


Table 2.1 15-minute dispatchable economic bids by scheduling coordinator type (Q2 2015)

Trading entities	Import bids			Export bids		
	Average MW per hour	Percent of total	Change from Q1 (MW/h)	Average MW per hour	Percent of total	Change from Q1 (MW/h)
External BAA	284	69%	54	176	93%	122
Marketer	110	27%	87	9	5%	9
Physical load	16	4%	16	3	1%	3
Physical generation	4	1%	-23	3	1%	2
Total	**413**	**100%**	**134**	**190**	**100%**	**135**

2.2 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 $770,000 in the second quarter, up from around $400,000 in the previous quarter. This increase is primarily attributable to changes in application of the flexible ramping credit in the first quarter.[30]
- Most payments occurred during evening peak hours. Natural gas-fired capacity accounted for about 39 percent of these payments with hydro-electric capacity accounting for 58 percent.
- The flexible ramping requirement was, on average, set to over 300 MW in the ISO, about 49 MW in PacifiCorp East, and about 44 MW in PacifiCorp West.

Background

The ISO began enforcing the flexible ramping constraint in the upward ramping direction in the 15-minute market in December 2011.[31] The constraint is applied to internal generation, dynamic inter-ties and proxy demand response resources within the ISO balancing area, as well as the EIM balancing areas beginning in November 2014.

If sufficient capacity is on line, the ISO software 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 software 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 the 15-minute market. A procurement shortfall of flexible ramping capacity will occur when there is a shortage of available supply bids to meet the flexible ramping requirement or when there is energy scarcity in the 15-minute market.[32]

The ISO on March 30 implemented an automated tool to set the flexible ramping requirement in both the ISO and PacifiCorp balancing areas. This tool is described in further detail below. For the second quarter, the overall average of the flexible ramping requirement in the ISO was just above 300 MW, which is similar to the average for the first quarter. Compared to the first quarter, the average requirement in the second quarter was higher during peak hours and lower during off-peak hours.

The constraint is also applied to each EIM balancing authority area and to grouped combinations of balancing authority areas. In total, there are seven flexible ramping constraints used in the model.[33] On average the flexible ramping requirement was set to about 49 MW in PacifiCorp East and about 44 MW in PacifiCorp West in the second quarter.

Originally, the ISO also applied a credit to the flexible ramping requirements when the EIM was launched. However, issues with this credit affected the performance of the flexible ramping constraint,

[30] The ISO made a series of fixes in February that appear to have addressed implementation issues with the flexible ramping credit.

[31] The flexible ramping constraint is also binding in the second, but not the first, interval of the 5-minute real-time market.

[32] The penalty price associated with procurement shortfalls was set to $247 before January 15, 2015. Beginning January 15, the penalty price is now set to $60. For more information, see: http://www.caiso.com/Documents/Dec18_2014_OrderAcceptingFlexibleRampingConstraintParameterAmendment_ER15-50.pdf.

[33] The seven combinations include: ISO area, PacifiCorp East area, PacifiCorp West area, the combined PacifiCorp East and West areas, the ISO area combined with the PacifiCorp East area, the ISO area combined with the PacifiCorp West area, and the ISO area combined with both the PacifiCorp East and West areas.

and in turn affected the procurement and pricing associated with the flexible ramping constraint.[34] The ISO made several fixes in February and, ultimately, the flexible ramping credit has had little to no impact on the requirement since the fixes were implemented.

Balancing area ramp requirement tool

The balancing area ramp requirement (BARR) tool was implemented in the 15-minute market on March 30. The new tool automatically calculates the ramping requirement in the ISO and EIM balancing areas that is used in the flexible ramping constraint calculation.

Prior to implementing this ramping tool, the ISO and EIM operators directly set the ramping requirement based on observed utilization patterns. In the ISO region, the default requirement was set to 300 MW and was often increased during both the morning and evening ramping periods to over 400 MW. The ramping requirements in EIM were set at about 25 MW to 40 MW in the PacifiCorp West and East areas, respectively, and were adjusted infrequently.

Initially, when the ramping tool was implemented it looked at 20 observations for each 15-minute interval and took the 95 percentile observation (i.e., the 19th highest observation out of 20 observations).[35] The ISO then set the actual requirement by limiting the result of the automated calculation to be no lower than 80 MW and no higher than 500 MW.

The same calculations were applied to the EIM areas with different maximum and minimum values. The maximum value in PacifiCorp West was 100 MW and the minimum value was 20 MW. The maximum value in PacifiCorp East was 150 MW and the lowest value was set to 20 MW.

Because the calculation only uses a very limited set of historical observations, there was very high variability in the flexible ramping requirements from one interval to the next in both the ISO and EIM areas (see Figure 2.4). DMM and other ISO staff recommended increasing the set of observations used to calculate the requirement – preferably by grouping surrounding intervals together – to increase the accuracy of the calculation and reduce the high level of variability due to random variations in historical data. Both DMM and other ISO staff are concerned that the high volatility of flexible ramping constraint requirements that have resulted since implementing the ramping tool reflects requirements that are unnecessarily high in some intervals and too low compared to the actual potential demand for ramping capacity in other intervals.

To implement a change quickly, the ISO increased the number of observations for each interval from 20 to 40 intervals by increasing the number of days the ISO looked back to perform the calculation as each interval was calculated as a unique observation. Consistent with the original recommendation, both DMM and the ISO staff recommended increasing the number of observations by grouping the ramping requirements across periods of the day (e.g., off-peak intervals). This change is currently being evaluated to determine what groupings of intervals would be most appropriate.

In the meantime, the ISO also increased the minimum values in the ISO and EIM areas to help reduce the magnitude of the downward changes in the requirement during many intervals. The current minimum values are set to 300 MW in the ISO, 60 MW in PacifiCorp West and 80 MW in PacifiCorp East.

[34] Greater detail on issues with the flexible ramping requirement credit system can be found in DMM's *Q4 2014 Report on Market Issues and Performance*, pp. 36-39: http://www.caiso.com/Documents/2014FourthQuarterReport_MarketIssuesandPerformance_March2015.pdf.

[35] Weekend days are considered as separate observations from weekdays.

The maximum values were also changed slightly over the course of the quarter in the EIM areas, but are now the same as those used upon implementation of the tool in March.

Figure 2.4 ISO area 15-minute flexible ramping requirement (March 25 through April 4)

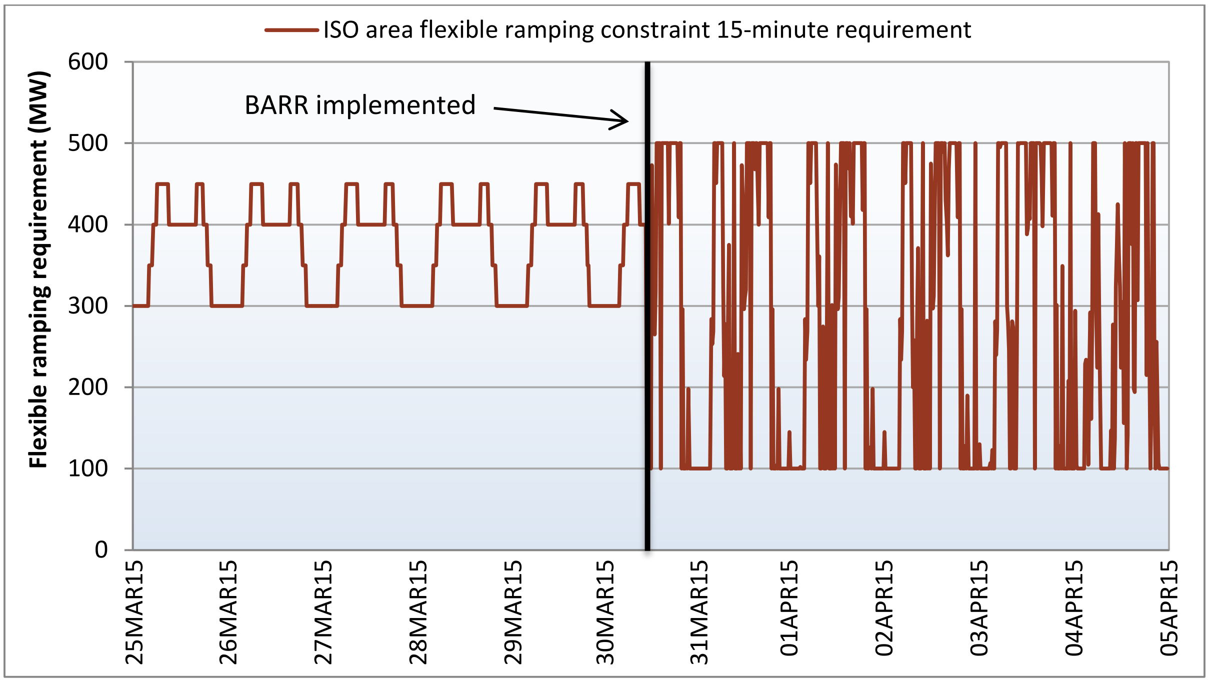


Figure 2.4 shows the ISO flexible ramping requirements for each 15-minute interval for March 25 through April 4. This sample of days shows how the flexible ramping requirements changed when the balancing area ramp requirement tool was implemented on March 30. As seen in Figure 2.4, not only did the range of the requirements increase, but the variability from interval to interval also increased.

Table 2.2 through Table 2.4 show the average amount, range and volatility of the flexible ramping constraint requirements by month for the ISO and PacifiCorp balancing areas. Volatility is measured as the standard deviation of the percent change in the requirements between intervals. A higher volatility implies more frequent and/or larger changes in the requirement from one interval to the next.

As shown in Table 2.2 through Table 2.4, the volatility of flexible ramping requirements increased significantly after implementing the balancing area ramp requirement tool. As previously noted, DMM is concerned that the high volatility of flexible ramping constraint requirements that have resulted since then reflect requirements that are unnecessarily high in some intervals and too low compared to the actual potential demand for ramping capacity in other intervals.

Table 2.2 Flexible ramping requirement and volatility (ISO)

Month	Requirement (MW) Avg	Min	Max	Volatility*	Percent of intervals Req = Lower bound	Req = Upper bound	Req <> bounds
Jan	373	300	450	3%			
Feb	373	300	450	3%			
Mar	369	100	500	25%			
Apr	269	80	500	116%	36%	27%	64%
May	300	80	500	141%	36%	41%	77%
Jun	350	80	500	73%	23%	47%	70%

Table 2.3 Flexible ramping requirement and volatility (PACE)

Month	Requirement (MW) Avg	Min	Max	Volatility*	Percent of intervals Req = Lower bound	Req = Upper bound	Req <> bounds
Jan	33	30	40	5%			
Feb	33	30	40	5%			
Mar	33	20	150	28%			
Apr	44	20	150	102%	55%	12%	67%
May	39	20	100	98%	62%	14%	76%
Jun	63	20	150	70%	53%	7%	60%

Table 2.4 Flexible ramping requirement and volatility (PACW)

Month	Requirement (MW) Avg	Min	Max	Volatility*	Percent of intervals Req = Lower bound	Req = Upper bound	Req <> bounds
Jan	26	25	30	3%			
Feb	26	25	30	3%			
Mar	27	20	100	25%			
Apr	47	10	100	116%	18%	55%	73%
May	32	10	50	141%	36%	45%	81%
Jun	54	10	100	73%	48%	18%	66%

***Volatility measured as the standard deviation of the percent change in the requirements between intervals.**

This increase in volatility occurred despite minimum and maximum limits that the ISO placed on the requirements calculated by the ramping tool algorithm. As shown in the right hand columns of Table 2.2 through Table 2.4, flexible ramping requirements are being set at these minimum and maximum limits in 60 to 80 percent of intervals, indicating that the ramping tool is calculating requirements outside of these ranges during most intervals. DMM believes this provides further indication that modifications to the ramping tool should be considered.

Flexible ramping procurement costs

Total payments for flexible ramping resources in the second quarter were around $770,000, up from around $400,000 in the previous quarter.[36] Table 2.5 provides a review of monthly flexible ramping constraint activity in the 15-minute market.[37] Given that the flexible ramping constraint was never binding in January, likely due to the incorrect application of the flexible ramping credit, it is more informative to compare the second quarter averages to the averages for February and March than to the averages for the whole first quarter. The table highlights the following:

- The flexible ramping constraint was binding in around 6 percent of intervals in the second quarter, which is roughly equal to the average for February and March.
- The frequency of procurement shortfalls decreased slightly to 0.8 percent for all 15-minute intervals compared to 0.9 percent in February and March.
- The average shadow price when the flexible ramping constraint was binding was about $18/MWh, a slight decrease from about $21/MWh in February and March.

Table 2.5 Flexible ramping constraint monthly summary

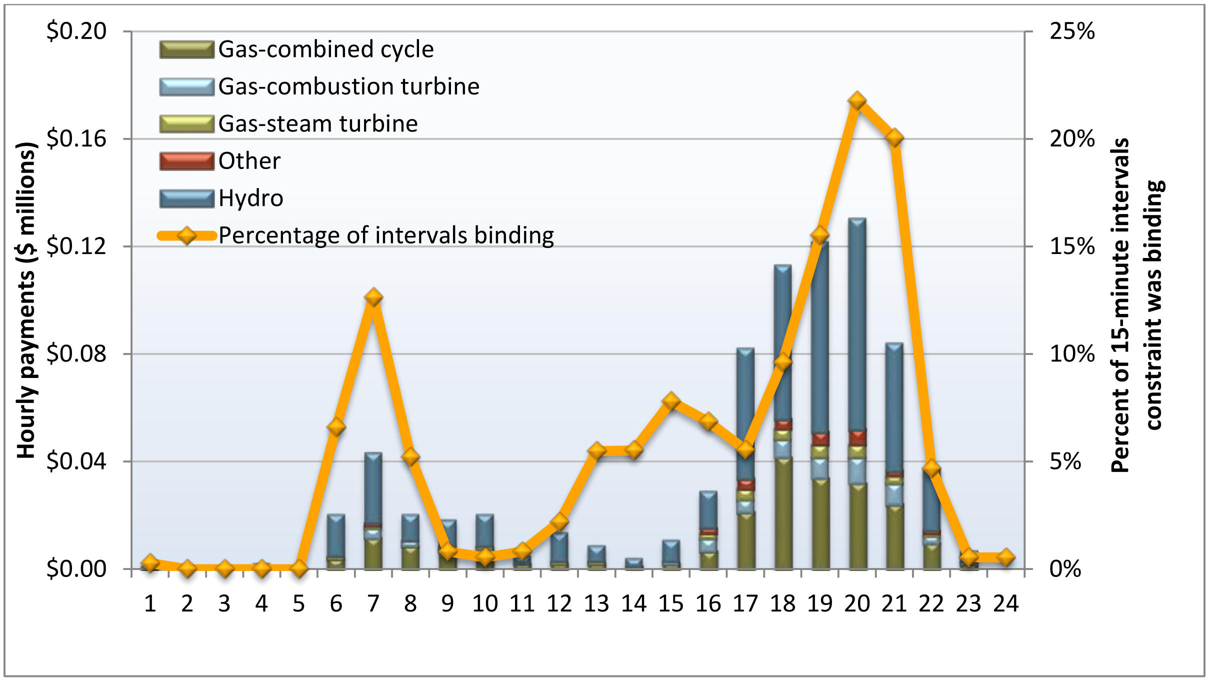
Year	Month	Total payments to generators ($ millions)	15-minute intervals constraint was binding (%)	15-minute intervals with procurement shortfall (%)	Average shadow price when binding ($/MWh)
2014	Jul	$0.25	3%	0.1%	$49.23
2014	Aug	$0.11	3%	0.1%	$25.06
2014	Sep	$0.21	4%	0.1%	$33.10
2014	Oct	$0.42	4%	0.4%	$41.84
2014	Nov	$0.19	1%	0.2%	$74.48
2014	Dec	$0.02	0%	0.0%	$0.00
2015	Jan	$0.04	0%	0.0%	$0.00
2015	Feb	$0.10	6%	0.5%	$15.61
2015	Mar	$0.26	7%	1.3%	$26.15
2015	Apr	$0.32	8%	1.3%	$18.95
2015	May	$0.09	3%	0.2%	$13.86
2015	Jun	$0.36	6%	1.0%	$20.11

[36] 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 is complex and beyond the scope of this analysis.

[37] DMM had problems with data availability between October 16 and October 30, 2014, and thus did not include the data from that period in the calculation.

Most payments for ramping capacity occurred during the evening peak hours. Figure 2.5 shows the hourly flexible ramping payment by technology type during the first quarter. As shown in the figure, the highest payment periods were in hours ending 7 and 17 through 21. Natural gas-fired capacity accounted for about 39 percent of these payments with hydro-electric capacity accounting for 58 percent.

Figure 2.5 Hourly flexible ramping constraint payments to generators (April – June)



3 Energy imbalance market

This section covers the energy imbalance market performance in the second quarter. Below are key observations and findings.

- Prices in the EIM during most intervals have been highly competitive and set by bids closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation. However, during a relatively small portion of intervals, energy or flexible ramping constraints have had to be relaxed for the market software to balance modeled supply and demand.
- The frequency of intervals in which the power balance and flexible ramping constraints have been relaxed dropped notably in PacifiCorp East in the 15-minute market in May and June, and in the 5-minute market in June. In PacifiCorp West the trend was mixed with increased frequency of constraint relaxations in the 15-minute market in April and June, and increased power balance relaxations in the 5-minute market in May.
- In the 15-minute market, price discovery was not as necessary in both PacifiCorp areas in May and June to keep average prices equal to the bilateral market price indices as average EIM prices were either at or below the bilateral market prices. For the most part in the 5-minute market, price discovery provisions helped to keep EIM prices in both PacifiCorp areas about equal to the bilateral market price indices that were used to set prices prior to EIM implementation.
- The ISO implemented the balancing area ramp requirement tool in late March which automated the calculation of the flexible ramping requirements (see Section 2.2). This change appears to have contributed to increases in violations of the flexible ramping constraint in April. DMM and the ISO have provided feedback and recommendations to the development team on how to improve the performance of this new tool.

3.1 Background

The energy imbalance market became financially binding with its first participant on November 1, 2014. Balancing authority areas outside of the ISO balancing area can now voluntarily take part in the ISO's real-time market. The energy imbalance market is expected to achieve benefits for customers and facilitate integration of higher levels of renewable generation.[38]

The EIM includes both 15-minute and 5-minute financially binding schedules and settlement. Energy imbalances between 15-minute schedules and base (pre-market) schedules settle at the 15-minute market prices, and energy imbalances between 15-minute schedules and 5-minute schedules settle at 5-minute market prices. With the EIM, the ISO also modified the flexible ramping constraint construct. This is outlined in further detail in Section 2.2.

[38] *Benefits for Participating in EIM* report Feb. 11, 2015: http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ4_2014.pdf, April 30, 2015: http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ1_2015.pdf, and July 30, 2015: http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ2_2015.pdf.

During the initial EIM implementation, the amount of capacity available through the market clearing process was restricted and imbalance needs were exaggerated in ways that are not reflective of actual economic and operational conditions. This caused the need to relax ramping and system energy balance constraints in the market software more frequently than expected to enable the market to clear. The factors contributing to the need for constraint relaxation and steps being taken to address these issues have been addressed by the ISO as noted in its reports submitted to FERC.[39] When relaxing the power balance constraint for an EIM area, prices could be set based on the $1,000/MWh penalty price for this constraint used in the pricing run of the market model.

After review, the ISO determined that many of these outcomes were inconsistent with actual conditions. Consequently, on November 13, 2014, the ISO filed with federal regulators special *price discovery* measures to set prices based on the last dispatched bid price rather than penalty prices for various constraints.[40] FERC approved measures on December 1 with an effective date of November 14, 2014. In addition, FERC ordered that the ISO and the Department of Market Monitoring provide reports every 30 days during the period of the waiver that outlines the issues driving the need for the EIM tariff waiver.[41] On March 16, 2015, FERC extended the waiver for an additional 90 days and, in addition, extended the reporting requirements.[42] On June 19, FERC further extended the waiver period and reporting requirements until the ISO can implement longer term solutions.[43]

3.2 Energy imbalance market performance

Prices in the EIM during most intervals have been highly competitive and have been set by bids closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation. However, during a relatively small portion of intervals, energy or flexible ramping constraints have had to be relaxed for the market software to balance modeled supply and demand. Figure 3.1 and Figure 3.2 provide a monthly summary of the frequency of constraint relaxation (red and

[39] The ISO *Energy Imbalance Market Pricing Waiver Report*s can be found here:
http://www.caiso.com/Documents/Dec15_2014_EnergyImbalanceMarketPerformanceReport_ER15-402.pdf,
http://www.caiso.com/Documents/Jan15_2015_EnergyImbalanceMarket_REPORT_ER15-402.pdf,
http://www.caiso.com/Documents/Feb19_2015_EIM_Informational_Report_ER15-402.pdf,
http://www.caiso.com/Documents/Mar26_2015_EIM_InformationalRpt_Feb13-Mar16_2015_ER15-402.pdf,
http://www.caiso.com/Documents/Apr24_2015_March2015_EnergyImbalanceMarket_PriceWaiverReport_ER15-402.pdf,
http://www.caiso.com/Documents/Jun3_2015_April2015_EnergyImbalanceMarketPriceWaiverReport_ER15-402.pdf, and
http://www.caiso.com/Documents/Jul14_2015_May2015_EIM_PriceWaiverReport_ER15-402.pdf .

[40] For further details, see http://www.caiso.com/Documents/Nov13_2014_PetitionWaiver_EIM_ER15-402.pdf.

[41] The DMM filings can be found here:
http://www.caiso.com/Documents/Dec18_2014_DMMReport_EIMPerformance_November2014_ER15-402.pdf,
http://www.caiso.com/Documents/Jan23_2015_DMMAssessment_December2014EIMPerformance.pdf,
http://www.caiso.com/Documents/Mar4_2015_DMMAssessment_EIMInformationalReport_Jan-Feb2015_ER15-402.pdf,
http://www.caiso.com/Documents/Apr2_2015_DMM_AssessmentPerformance_EIM-Feb13-Mar16_2015_ER15-402.pdf,
http://www.caiso.com/Documents/May7_2015_DMM_Report_Performance_Issues_EIM_March2015_ER15-402.pdf,
http://www.caiso.com/Documents/Jun12_2015_DMM_Report_Performance_Issues_EIM_April2015_ER15-402.pdf, and
https://www.caiso.com/Documents/Jul28_2015_DMMReport_Performance_Issues_EIM_May2015_ER15-402.pdf.

[42] The March 16 order can be found here:
http://www.caiso.com/Documents/Mar16_2015_OrderRejectingEIMTransitionPeriodPricingAmendment_ER15-861.pdf.

[43] The June 19 order can be found here: http://www.caiso.com/Documents/Jun19_2015_OrderGrantingMotion_Relief-EIMTransitionPeriodPrices_ER15-861_EL15-53.pdf.

gold bars), average prices with (red line) and without price discovery (dashed red line), and bilateral market prices (blue line) for PacifiCorp East and PacifiCorp West, respectively.

As shown in Figure 3.1, the frequency of constraint relaxations in the 15-minute market in PacifiCorp East was relatively high in April and then decreased in May and June. After mid-April, the frequency of constraint relaxations declined significantly through the rest of the quarter. As shown in Figure 3.2, the frequency of constraint relaxations in the 15-minute market in PacifiCorp West increased in April from March, but dropped substantially during May then increased again in June. The increases in violations of the flexible ramping constraint in April are likely the result of changes to the flexible ramping constraint requirements.[44]

These two figures also show average daily prices in the 15-minute market with and without the special price discovery mechanism being applied to mitigate prices in PacifiCorp East and PacifiCorp West, respectively. In addition, the figures also provide a comparison of EIM prices to bilateral market price indices that were used to set prices in the PacifiCorp areas prior to EIM implementation.[45] The analysis shows that without the price discovery provisions being applied in EIM, average daily prices would have exceeded the bilateral market price index reflective of prices for imbalance energy in both PacifiCorp areas until May. In May and June, the 15-minute market prices would have tracked much more closely with bilateral market prices, or even were below them, without price discovery. This is related to the fact that there have been significantly fewer constraint violations, particularly power balance relaxations, over the past couple months.

Figure 3.3 and Figure 3.4 provide the same monthly summary for daily average prices in the 5-minute market. As shown in these figures, the need to relax the power balance constraint in the 5-minute market has also declined in the second quarter, particularly in the PacifiCorp West area compared to the beginning of EIM. This reflects that the supply of ramping capacity within PacifiCorp has improved in the 5-minute market.

The higher frequency of power balance constraint relaxations in the 5-minute market reflects that incremental transfers into PacifiCorp from the ISO in the 5-minute market had been essentially prevented from occurring during almost all intervals until the beginning of February. The dynamic transfer constraint, which constrains the extent to which transfers between PacifiCorp and the ISO scheduled in the 15-minute market can change in the 5-minute market, was set to a limit of less than 0.003 MW during most 5-minute market intervals until early February.

Since early February, the dynamic transfer capability limits now allow 15-minute EIM transfer schedules on COI to be modified by about ±11 MW during peak hours and about ±110 MW during off-peak hours. This appears to have helped reduce the frequency of power balance relaxations in the 5-minute market in PacifiCorp West.

As shown in Figure 3.1 through Figure 3.4, the price discovery mechanism approved under FERC's December 1 order has effectively mitigated the impact of constraint relaxation on market prices, though played a reduced role in affecting market outcomes in the second quarter.

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[44] See Section 2.2 for further detail on the changes to the flexible ramping constraint requirement.

[45] The bilateral market index represents a daily average of peak and off-peak prices for four major western trading hubs (California Oregon Border, Mid-Columbia, Palo Verde and Four Corners). Prior to EIM implementation, DMM identified this bilateral price index to stakeholders and regulators as a benchmark DMM would use to assess the competitiveness and overall performance of EIM.

Figure 3.1 Frequency of constraint relaxation and average prices by month PacifiCorp East - 15-minute market

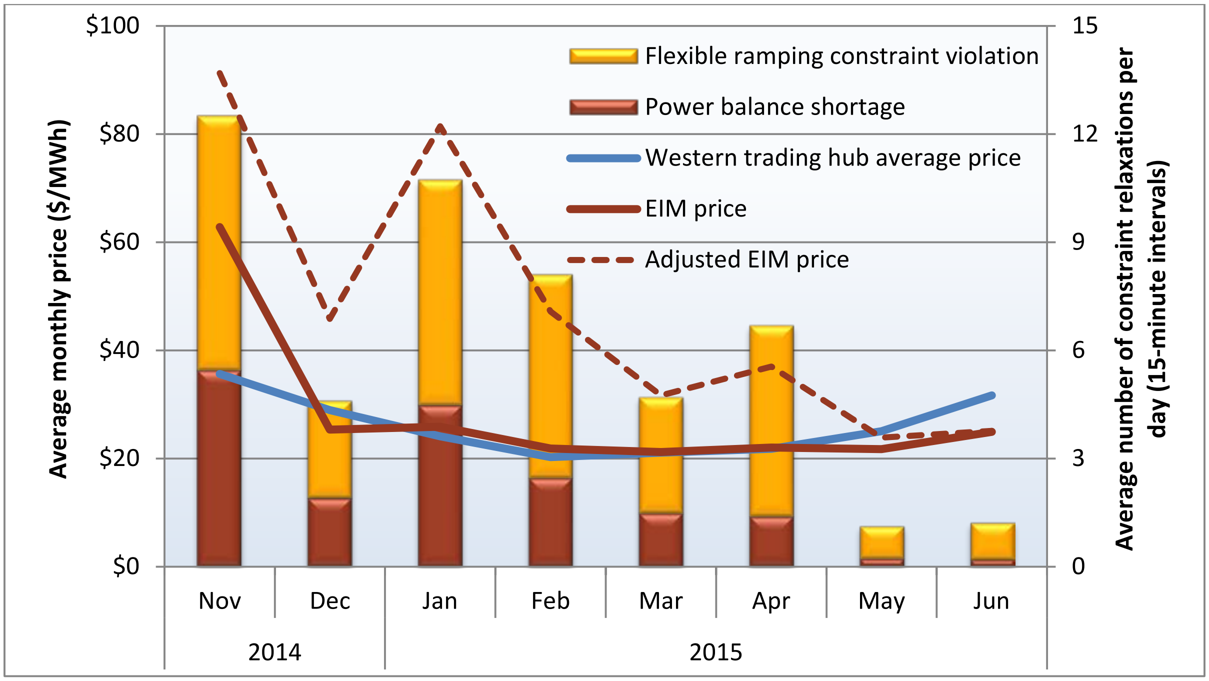

Figure 3.2 Frequency of constraint relaxation and average prices by month PacifiCorp West - 15-minute market

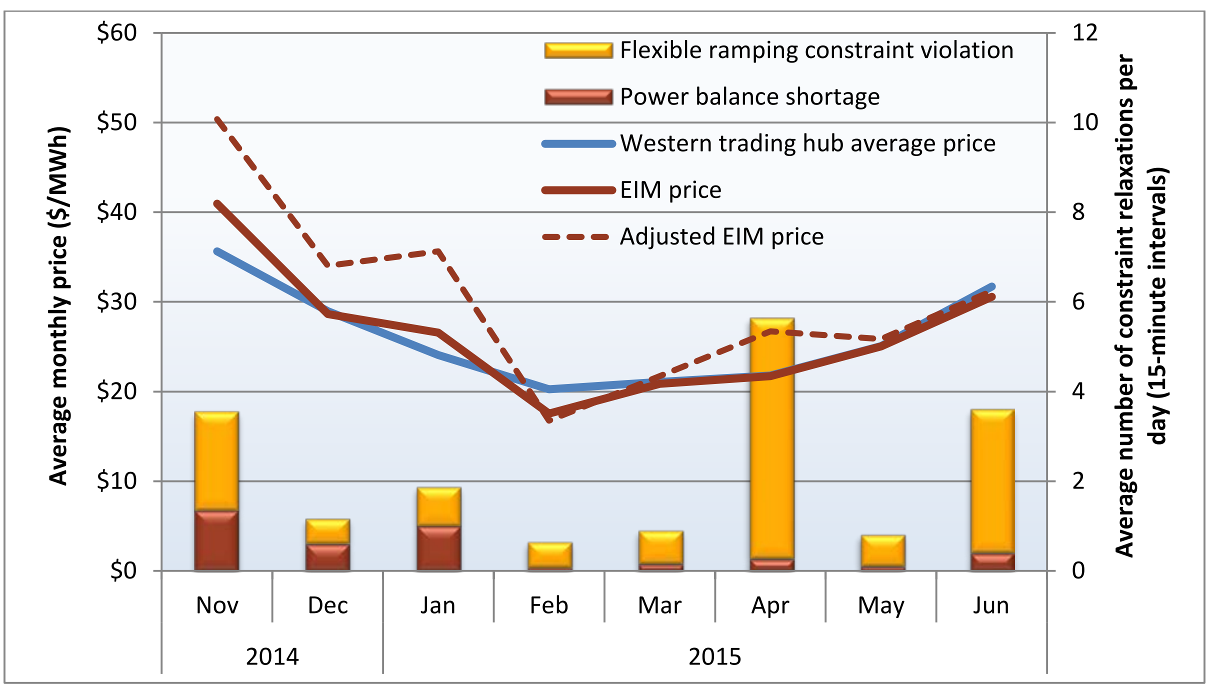

Figure 3.3 Frequency of constraint relaxation and average prices by month PacifiCorp East - 5-minute market

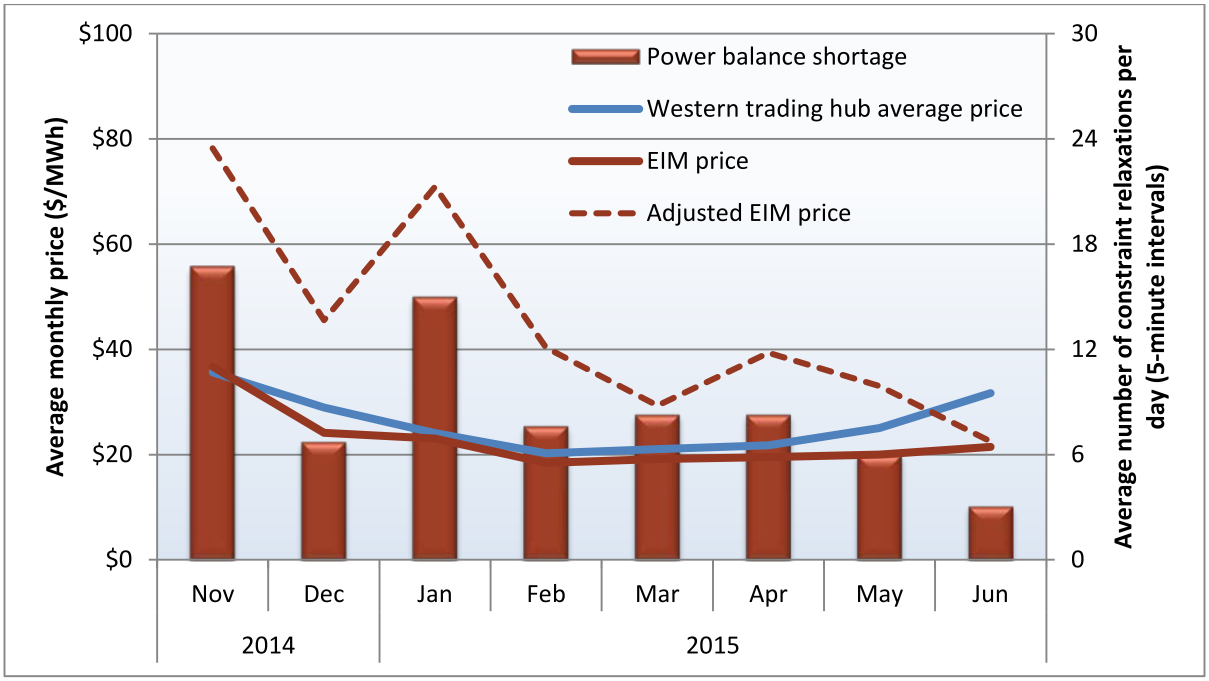

Figure 3.4 Frequency of constraint relaxation and average prices by month PacifiCorp West - 5-minute market