California Independent System Operator Corporation

California ISO

Q1 2015 Report on Market Issues and Performance

June 10, 2015

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Executive summary

This report provides highlights of significant market changes and general market performance during the first quarter of 2015 (January – March).

- Energy market prices remained highly competitive in the first 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. This result is consistent with previous periods in 2014.
- Day-ahead prices in the first quarter decreased compared to the fourth quarter of 2014 in both peak and off-peak periods. This was primarily driven by falling natural gas prices.
- Real-time prices were lower than day-ahead prices for most of the quarter. 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, in about 2 percent of 15-minute intervals and about 6 percent of 5-minute intervals. Factors contributing to the increase in negative real-time prices included low loads, increased output from wind and solar resources, and congestion.
- Congestion on constraints within the ISO system increased overall average day-ahead and 15-minute prices in the San Diego Gas and Electric area by about 6 percent and 2.5 percent, respectively. Congestion had a relatively small overall net impact on prices in the Pacific Gas and Electric and Southern California Edison areas.
- Toward the end of the first quarter, frequent congestion in the south-to-north direction on Path 15 began to occur because of planned transmission outages which have continued into the second quarter. This congestion drives prices in PG&E significantly higher, and drives prices in the SCE and SDG&E area significantly lower.
- Real-time imbalance offset costs are currently estimated to total about $6 million in the first quarter of 2015, compared to $42 million in the first quarter of 2014 and $2 million in the fourth quarter of 2014. This is a continuation of the low levels achieved in the fourth quarter of 2014.
- Bid cost recovery payments were around $12 million in the first quarter of 2015, compared to $25 million in the fourth quarter of 2014 and $21 million in the first quarter of 2014. This is the lowest level of bid cost recovery payments in nearly 5 years.
- Net revenues received by convergence bidders, after accounting for bid cost recovery charges, were about $2.2 million in the first quarter. Net revenues from net virtual supply positions were positive as prices were generally higher in the day-ahead market than the 15-minute market and there were few instances of elevated prices in the 15-minute market.
- Flexible ramping constraint payments were around $0.4 million in the first quarter, down slightly from the previous quarter. As in December 2014, the flexible ramping constraint was not binding in January due to several errors in how enhancements were implemented in the market software. The

ISO implemented several fixes correcting the errors in February. Subsequently, the constraint was binding more frequently.

- Almost all imports scheduled in the day-ahead market continue to be self-scheduled in the real-time market rather than re-bid in the real-time market. This overall trend has continued since the FERC Order No. 764 market changes were implemented in May 2014.

- Submission of economic bids on inter-ties in the 15-minute market increased in the first quarter, but still remained relatively low. The volume of 15-minute dispatchable import bids increased by 19 percent compared to the fourth quarter, but still averaged only 215 MW each hour in the first quarter. This increase may in part be related to the Bonneville Power Administration implementing 15-minute scheduling in the fourth quarter of 2014. On many inter-ties, however, there are still no 15-minute economic import bids.

- The ISO fully implemented the energy imbalance market (EIM) on November 1. During most intervals, prices in the EIM 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 of this report.

Energy market performance

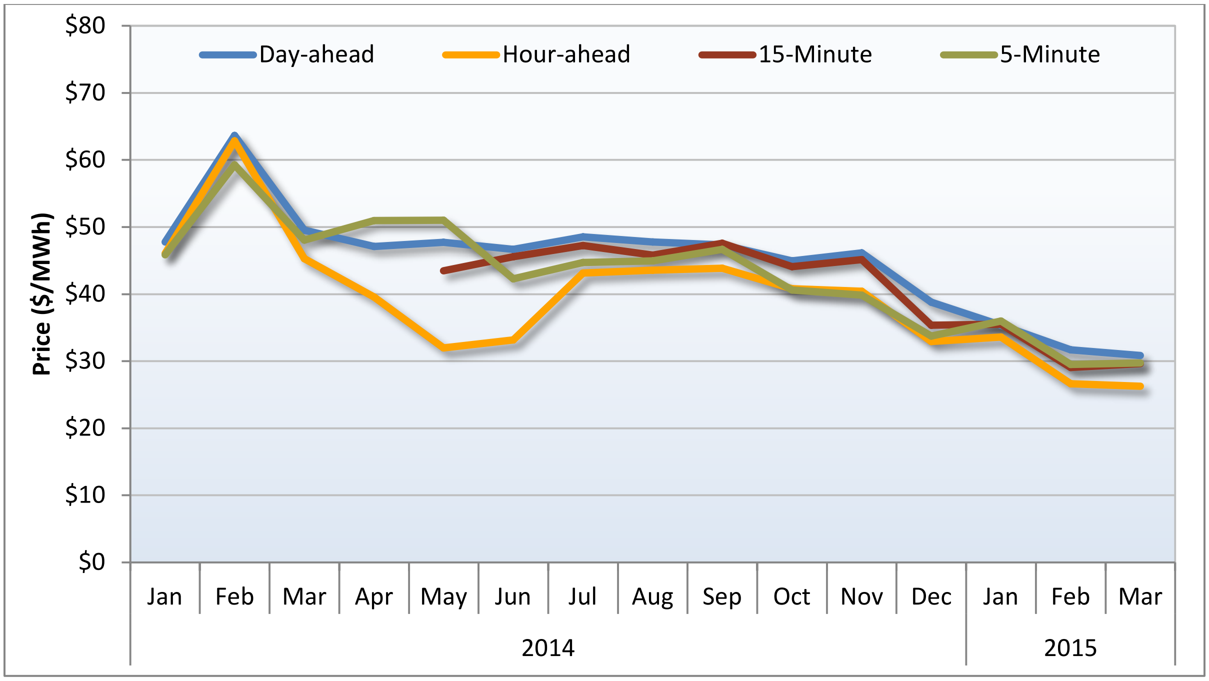
This section provides a more detailed summary of energy market performance in the first quarter.

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 January, and slightly below in the remaining months of the quarter.

Prices converged between average day-ahead and real-time system energy prices. The average difference between the day-ahead market price and prices in all three real-time markets decreased in the first quarter of 2015. Average system energy prices in the 15-minute market (excluding congestion) were lower than average prices in the day-ahead market in February and March, and very similar to day-ahead prices in January (see Figure E.1). The 5-minute market prices were on average very close to the 15-minute market prices throughout the quarter. Hour-ahead market prices were consistently lower than prices in all other markets. The hour-ahead market is the first real-time market impacted by any unscheduled generation changes, particularly from wind and solar. There is also a large volume of self-scheduled energy on the inter-ties in the hour-ahead market. The combination of these factors can create limited maneuverability and low prices in the hour-ahead market. However, hour-ahead prices are no longer used for financial settlement since implementation of the 15-minute market in May 2014.

The frequency of negative prices increased. The frequency of negative prices was relatively low in January in both the 15-minute and 5-minute markets, but increased substantially in February and March. Negative prices occurred in about 2 percent of 15-minute market intervals and 6 percent of 5-minute market intervals, or about twice as frequently as in the previous quarter. Negative prices occurred both in the early morning hours and also 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 low loads, increased output from wind and solar resources, and congestion. 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.

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



Upward price spikes remained low. Price spikes above $250/MWh in the 15-minute market occurred in only 0.1 percent of intervals during the first quarter, a decrease from 0.4 percent in the previous quarter. The frequency of price spikes over $250/MWh in the 5-minute market increased to 0.7 percent compared to 0.5 percent in the previous quarter.

Congestion increased prices significantly in the San Diego area. Congestion on constraints within the ISO system increased overall average day-ahead and 15-minute prices in the SDG&E area by about 6 percent and 2.5 percent, respectively. Congestion had a relatively small overall net impact on prices in the PG&E and SCE areas.

Path 15 congestion raised prices in the PG&E area at the end of the quarter. Toward the end of the first quarter, frequent congestion in the south-to-north direction on Path 15 began to occur due to planned transmission outages which have continued into the second quarter. 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/MWh and decreased in the SCE and SDG&E areas by about $3/MWh. Congestion on Path 15 occurred in the 15-minute market only about one-sixth as often as in the day-ahead market, but increased prices in the PG&E area by about $16/MWh while decreasing prices in the SCE and SDG&E areas by about $16/MWh when it occurred.

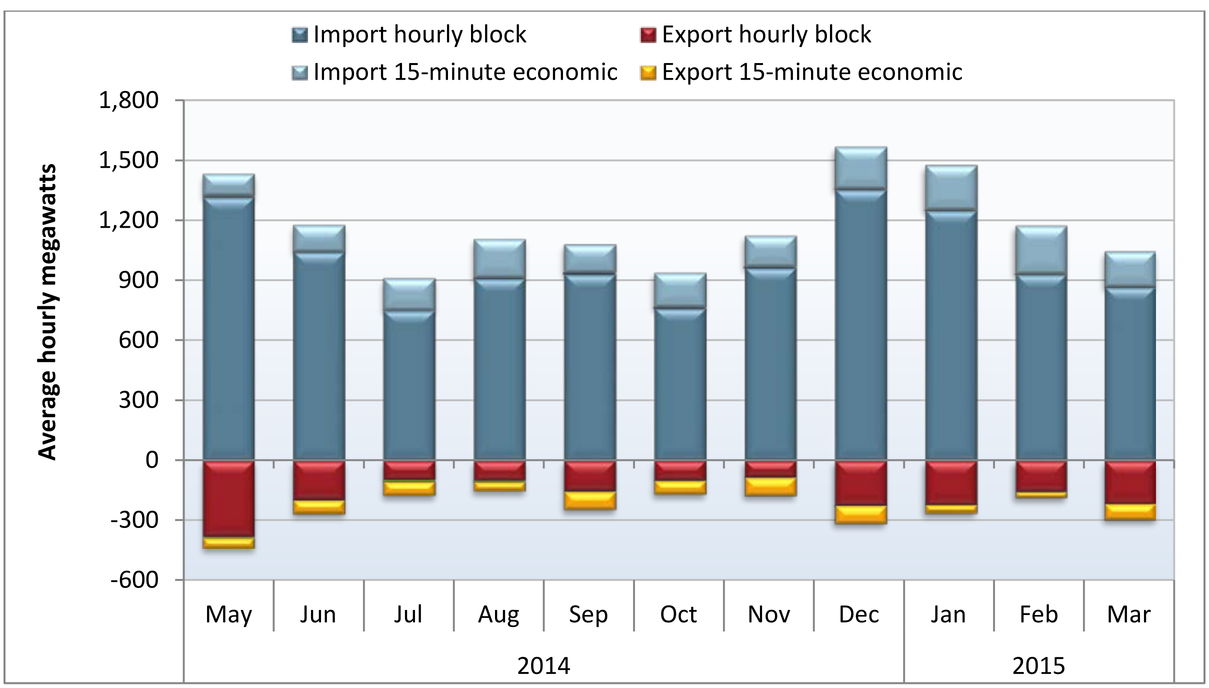
Real-time congestion and energy imbalance offset costs remained low. Real-time imbalance offset costs are currently estimated to be low, maintaining the historically low levels achieved in the fourth quarter of 2014 within the ISO. Total offset costs totaled about $6 million in the first quarter of 2015, compared to $42 million in the first quarter of 2014 and $2 million in the fourth quarter of 2014. Total real-time imbalance offset costs in the first quarter were the sum of approximately $8 million in congestion imbalance offset costs and an estimated credit of $2 million in energy imbalance offset costs for a net imbalance cost of $6 million.

Flexible ramping constraint payments remained low. Flexible ramping constraint payments in the first quarter decreased to $0.4 million compared to $0.6 million in the previous quarter. The constraint was not binding for any interval in January, which was likely due to the ISO's incorrect application of the flexible ramping credit. In early February, the ISO made several fixes to the flexible ramping constraint. As a result, the constraint was active in February and March with an average shadow price when the constraint was binding of $16/MWh in February and $26/MWh in March in the ISO balancing area. In late March, the ISO implemented a new tool that automated the calculation of the flexible ramping requirement. Further details on this new tool will be discussed in a subsequent quarterly report.

Real-time economic import and export bid quantities remained relatively low. The amount of inter-tie imports and exports cleared between the day-ahead and real-time markets has not changed considerably since implementing 15-minute inter-tie scheduling in May 2014. However, the amount of economic bids (versus self-schedules) on inter-ties in the real-time market decreased significantly upon implementation of the 15-minute market, while self-scheduling increased. On many inter-ties, there are still no 15-minute economic import bids. This overall trend continued in the first quarter.

Economic bids on inter-ties increased somewhat in the 15-minute market in the first quarter (see Figure E.2). Of the economic inter-tie bids in the real-time markets, about 17 percent of import bids and 20 percent of export bids were available for dispatch on a 15-minute basis, with the remaining bids being bids for fixed hourly blocks. The volume of 15-minute dispatchable import bids increased by 19 percent compared to the fourth quarter, but still averaged only 215 MW each hour in the first quarter. This increase may be in part related to the Bonneville Power Administration's implementation of 15-minute scheduling in the fourth quarter of 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 first quarter.

- Day-ahead prices in the first quarter decreased compared to the fourth quarter of 2014, both in peak and off-peak periods. This was primarily driven by falling natural gas prices.
- Monthly average 15-minute and 5-minute market prices were similar to each other in all months of the quarter for both peak and off-peak hours. They were lower than day-ahead prices but higher than hour-ahead prices for most of the quarter.
- In the first quarter, price spikes were relatively infrequent, with prices above $250/MWh in about 0.1 percent of intervals in the 15-minute market and about 0.7 percent of intervals in the 5-minute market.
- In the 15-minute market, negative prices were observed in about 2 percent of intervals. Negative prices were more frequent in the 5-minute market, occurring in about 6 percent of intervals. In March, negative prices occurred in almost 8 percent of intervals in the 5-minute market. Factors contributing to the increase in negative real-time prices included low loads, increased output from wind and solar resources, and congestion.
- Congestion on constraints within the ISO system increased overall average day-ahead and 15-minute prices in the SDG&E area by about 6 percent and 2.5 percent, respectively. Congestion had a relatively small overall net impact on prices in the PG&E and SCE areas.
- Flexible ramping constraint payments were around $0.4 million in the first quarter, down slightly from the previous quarter. As occurred in December, the flexible ramping constraint was not binding in January. The ISO implemented several fixes in February; subsequently, the flexible ramping constraint was binding more frequently.
- Real-time imbalance offset costs are currently estimated to be low, maintaining the historically low levels achieved in the fourth quarter of 2014. Total offset costs totaled about $6 million in the first quarter of 2015, compared to $42 million in the first quarter of 2014 and $2 million in the fourth quarter of 2014.
- Cleared hourly volumes of virtual supply outweighed cleared virtual demand by about 360 MW on average, an increase from 330 MW of net virtual supply in the previous quarter. Total convergence bidding revenue for the quarter, adjusted for bid cost recovery costs, was about $2.2 million, a decrease from about $4 million in the previous quarter.

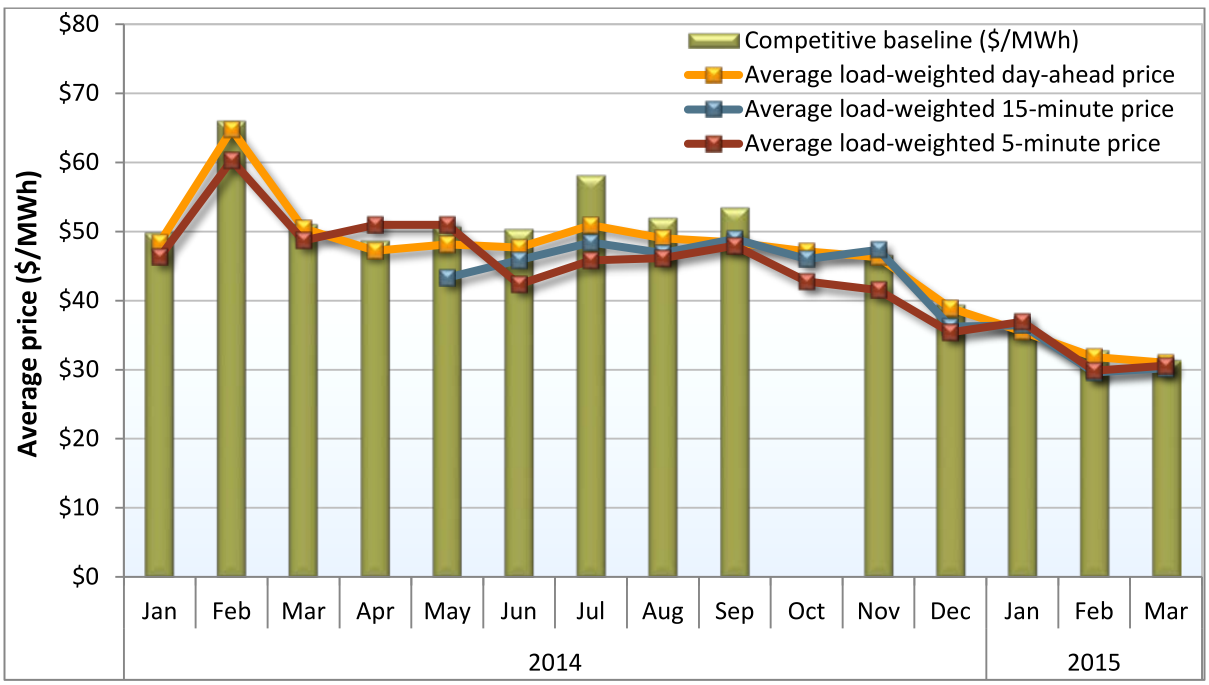
1.1 Overall market competitiveness

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.[1]

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.

As shown in Figure 1.1, prices in the day-ahead market were slightly lower than competitive baseline prices in all months in the first quarter. Prices in the real-time market were just over competitive baseline prices in January, and slightly below in the remaining months of the quarter.

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



DMM also calculates an overall price-cost mark-up by comparing competitive baseline energy prices to total average wholesale energy prices.[2] Total wholesale energy prices used in this analysis represent a

[1] 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.

[2] 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.

load-weighted average price of all energy transactions in the day-ahead, 15-minute and 5-minute real-time markets.[3]

The overall combined average of market prices was about $0.75/MWh or just over 2 percent lower than the competitive baseline price in the first quarter of 2015, which is similar to the first quarter of 2014 at just under 3 percent.

1.2 Energy market performance

This section assesses the efficiency of the energy market based on an analysis of the system energy component 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. Overall, prices decreased in the first quarter, compared to the previous quarter and the first quarter of 2014. This decrease is primarily driven by decreases in natural gas prices.

- Average day-ahead prices decreased in every month of the first quarter, compared to the previous months. Day-ahead prices in March were lower than in any month of the past 15 months, in both peak ($33/MWh) and off-peak ($28/MWh) periods. Overall, day-ahead prices were higher than hour-ahead, 15-minute and 5-minute market prices for the quarter.

- In the first quarter, average peak system prices in the 15-minute market were lower than day-ahead prices by $1.50/MWh. The average difference was small in January and March (about $0.20/MWh) and larger ($4/MWh) in February. Off-peak 15-minute prices were somewhat higher than day-ahead prices in January and lower in February and March.

- Peak period average system prices in the 5-minute market were higher than day-ahead market prices in January and lower in February and March, similar to 15-minute prices. In January, 5-minute prices in off-peak periods were roughly equal to day-ahead prices, while they were about $1/MWh lower in February and almost $2/MWh lower in March.

- On a monthly average basis, hour-ahead prices were lower than day-ahead, 15-minute and 5-minute market prices throughout the first quarter. The average difference between day-ahead and hour-ahead prices was about $4/MWh for peak hours and about $3/MWh for off-peak hours.

[3] The wholesale costs of energy are pro-rated calculations of the day-ahead, hour-ahead and real-time prices weighted by the corresponding forecasted load. Beginning in May 2014, the calculation pro-rates day-ahead, 15-minute and 5-minute prices weighted by the corresponding forecasted load. The month of October 2014 has been excluded from this calculation because of implementation issues with transitioning the systems to the fall market software version.

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

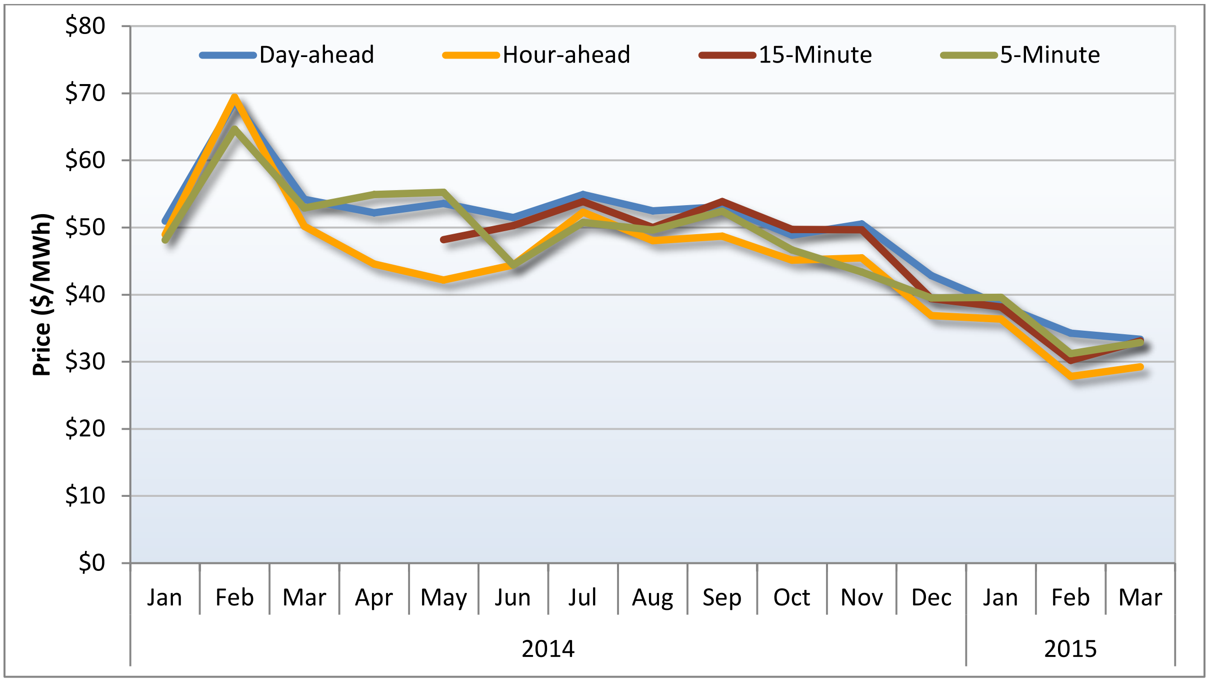


Figure 1.3 Average monthly off-peak prices – system marginal energy price

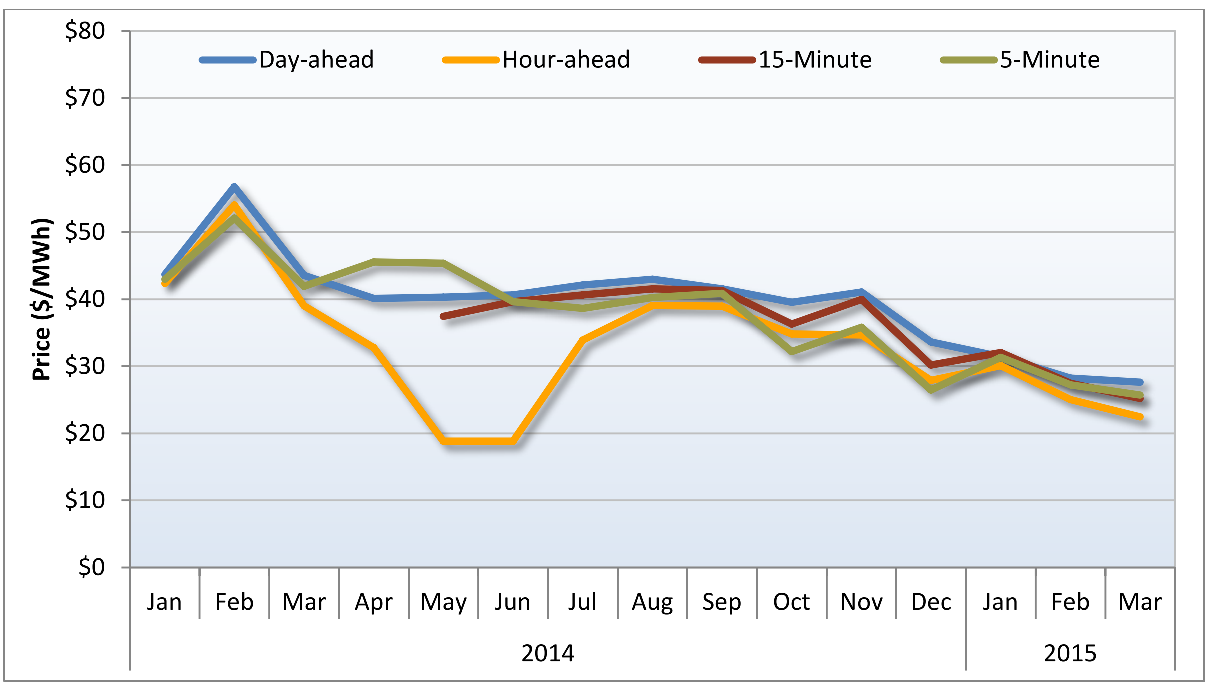


Figure 1.4 Hourly comparison of system marginal energy prices (January - March)

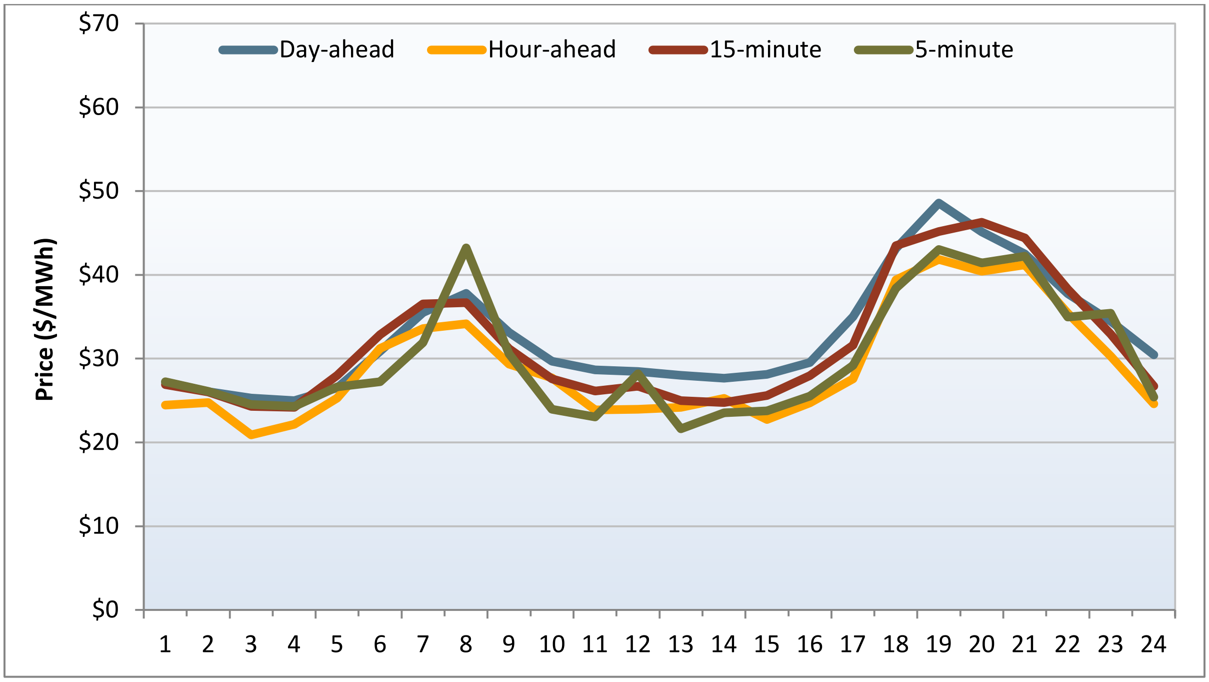


Figure 1.4 further illustrates the market prices on an hourly basis in the first quarter. Notably, prices in the three real-time markets were less than the day-ahead prices in the late morning and early afternoon hours (hours ending 10 through 15). Solar generation typically peaks during this period, driving net loads down.[4]

Prices in the 5-minute market increased the most during the morning ramping period and were higher than the other three markets in hour ending 8. As discussed in Section 1.3, prices in the 5-minute market are more volatile compared to the other markets. In the first quarter, hour ending 8 experienced many positive and relatively few negative price spikes in the 5-minute market, resulting in high average prices for this hour. In contrast, 5-minute market prices were lower compared to 15-minute market prices during the evening peak period (hours ending 17 through 20).

1.3 Real-time price variability

Historically, 5-minute real-time market prices have been highly volatile with periods of extreme positive and negative price spikes. In many instances, this price variability was the result of relaxing the power balance constraint to resolve the feasibility of the dispatch.[5] Upon implementing the new 15-minute market in May 2014, price variability in the 5-minute market has a lower impact as there is less settlement using the 5-minute real-time price.

[4] Net loads are the difference between system load, and solar and wind generation.

[5] Greater detail on system power balance constraints can be found in DMM's *2014 Annual Report on Market Issues and Performance*: http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

Overall, positive price spikes were relatively infrequent in both the 15-minute and 5-minute markets in the first quarter. Prices above $250/MWh were observed in about 0.1 percent of intervals in the 15-minute market, down from 0.4 percent in the previous quarter. The first quarter had the lowest frequency of 15-minute price spikes since implementing the market in May 2014, as shown in Figure 1.5.

Figure 1.6 shows the frequency of positive price spikes occurring in the 5-minute market. In the first quarter, the frequency of price spikes was about 0.7 percent, up from 0.5 percent 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 0.3 percent of intervals during the quarter.

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

Figure 1.7 shows the frequency of negative price spikes since May 2014 in the 15-minute market. Figure 1.8 shows the frequency of negative price spikes in the 5-minute market for the past 15 months. Negative prices in January occurred in only 0.2 percent of intervals in the 15-minute market and 0.9 percent of intervals in the 5-minute market. These were among the lowest frequencies of negative price spikes in their respective periods. In contrast, February and March showed significant increases in the frequency of negative prices in both markets. In the 15-minute market, about 3 percent of intervals in February and March had negative prices, whereas just over 8 percent of intervals in February and March were negative in the 5-minute market.

Negative prices typically occurred both in the early morning hours and also 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. The increase in negative prices occurred as a result of a combination of factors including: low seasonal loads, higher renewable generation from both solar and wind, and transmission outages reducing Path 15 transmission capacity. 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.[6] 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 first 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 first quarter because of drought conditions and thus was not a significant factor in contributing to these pricing patterns, possibly helping to reduce the incidence of negative prices that otherwise may have occurred.

Most negative prices in both the 15-minute and 5-minute markets were between -$30/MWh and $0/MWh, and were set by bids rather than by a penalty parameter.

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

Figure 1.5 Frequency of positive 15-minute price spikes (all LAP areas)

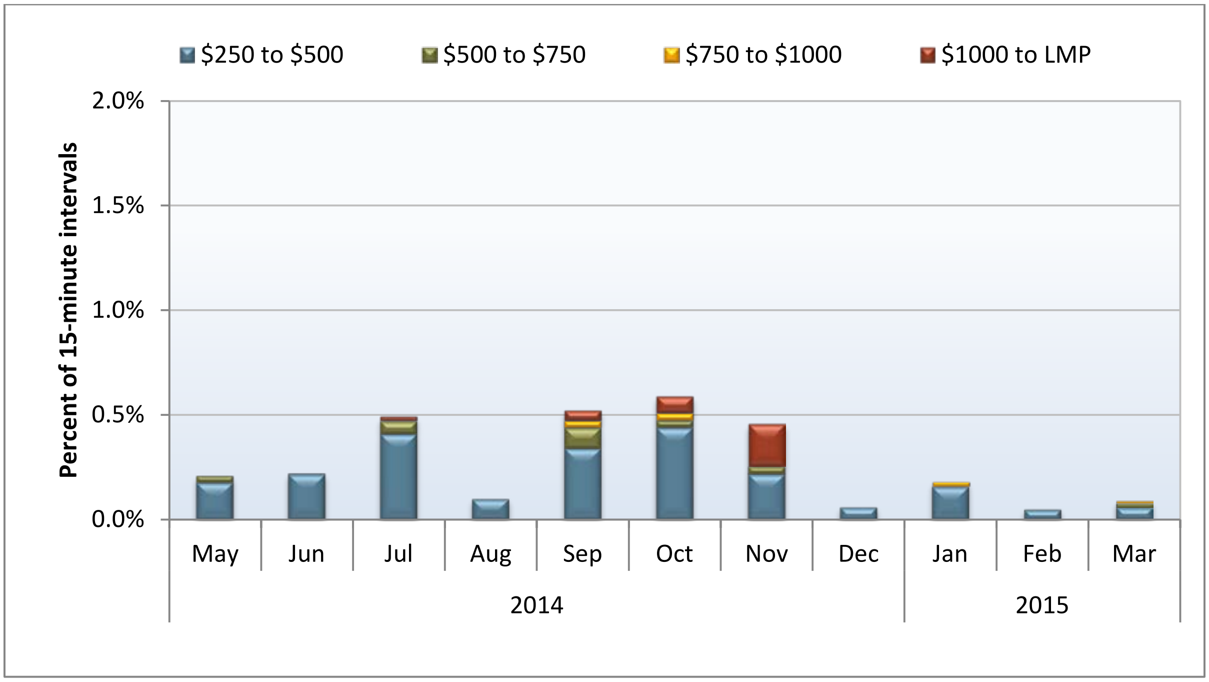


Figure 1.6 Frequency of positive 5-minute price spikes (all LAP areas)

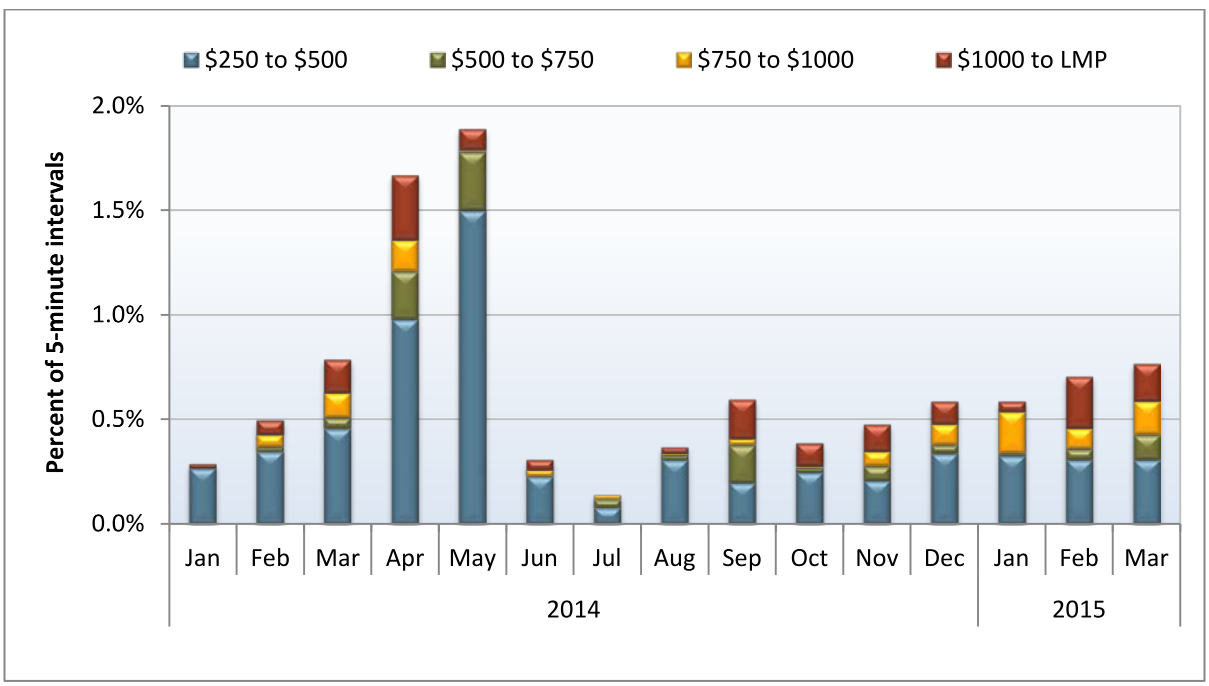


Figure 1.7 Frequency of negative 15-minute price spikes (all LAP areas)

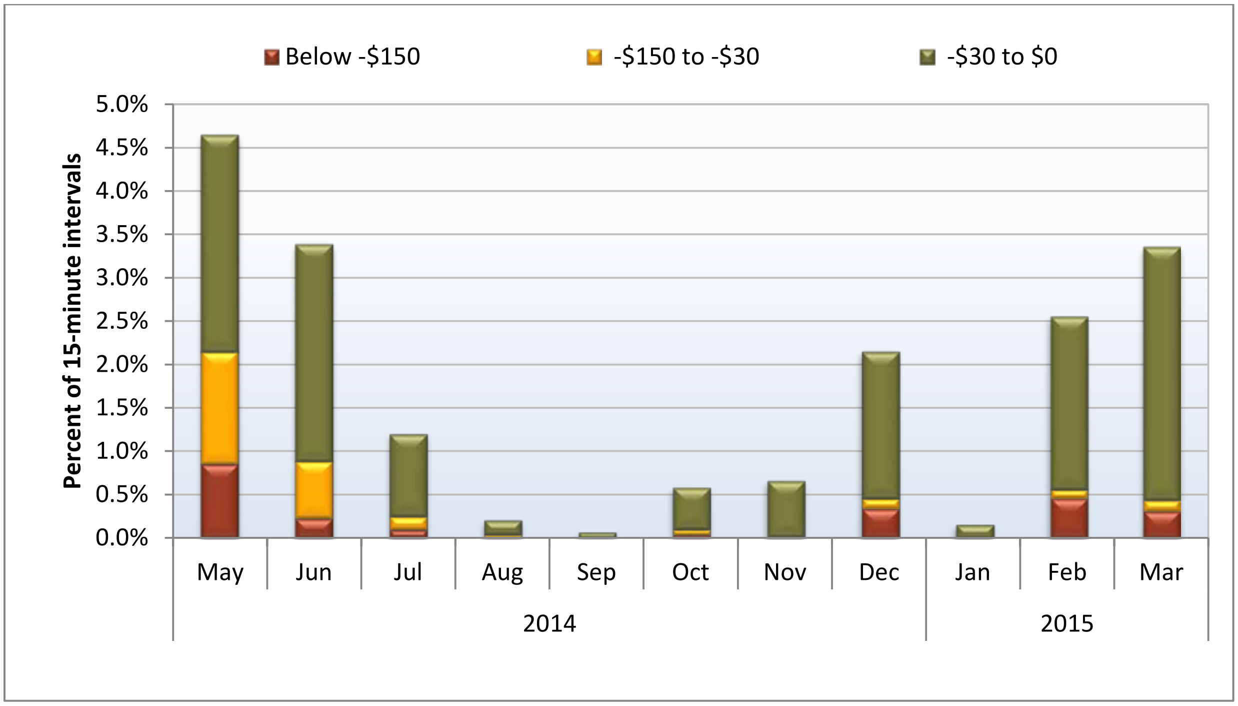
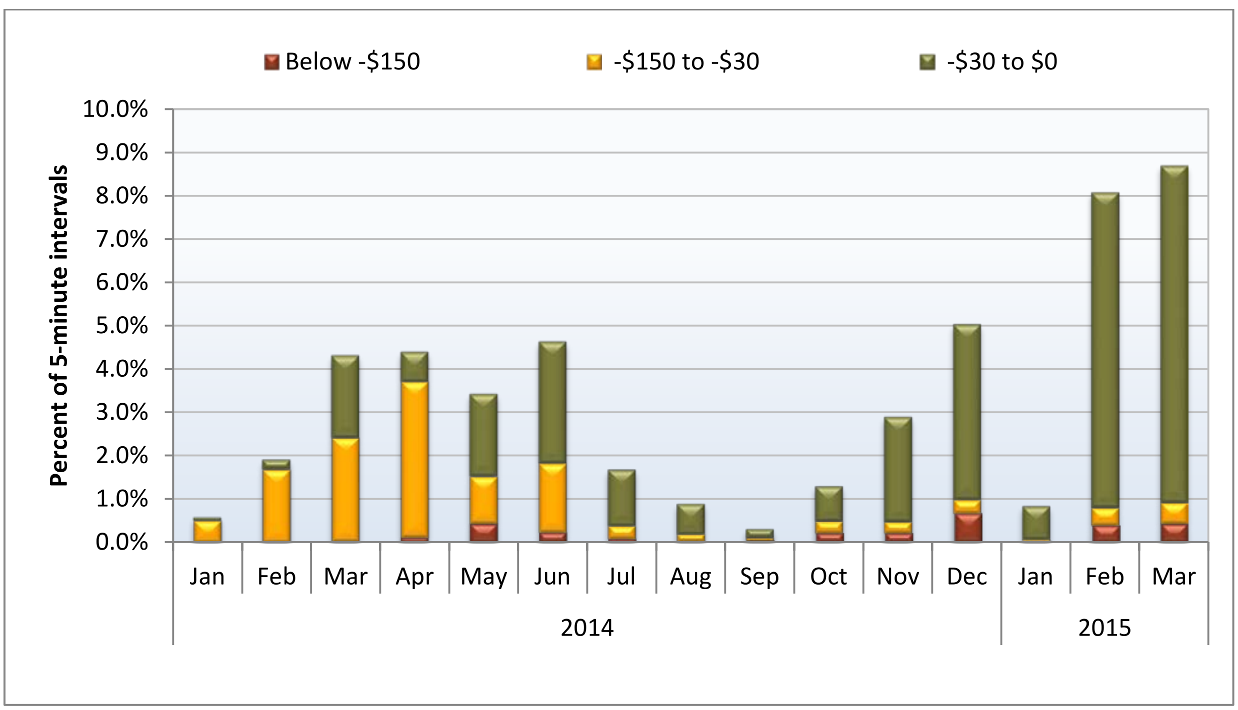


Figure 1.8 Frequency of negative 5-minute price spikes (all LAP areas)



1.4 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 $400,000 in the first quarter, down from around $630,000 in the previous quarter. The lower costs were related to issues associated with the flexible ramping credit, which was implemented along with the energy imbalance market in November.[7]
- Most payments occurred during evening peak hours. Natural gas-fired capacity accounted for about 52 percent of these payments with hydro-electric capacity accounting for 45 percent.
- ISO operators adjusted the ISO balancing area flexible ramping requirement to 450 MW consistently during the morning and evening ramping periods during the first quarter. The requirement was typically set to 300 MW during the off-peak hours and 400 MW during the middle of the day.[8]
- The flexible ramping requirement was set to a little over 30 MW in PacifiCorp East and to a little over 25 MW in PacifiCorp West for most of the day. These requirements were adjusted higher during the morning and evening peak hours, but remained fairly constant throughout the day.

Background

The ISO began enforcing the flexible ramping constraint in the upward ramping direction in the 15-minute market in December 2011.[9] 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. Operators adjust the flexible ramping requirement level to ensure enough upward ramping flexibility, particularly during ramping periods. In the first quarter of 2015, ISO operators typically set the requirement for the ISO balancing area to 300 MW during the off-peak hours. They gradually moved this to 450 MW in the morning and evening ramping periods and set the requirement to 400 MW during the day.

If sufficient capacity is online, 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.[10]

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[7] The ISO made a series of fixes in February that appear to have addressed the implementation issues.

[8] Beginning on March 30, the ISO implemented an automated tool that now sets the flexible ramping requirements in both the ISO and PacifiCorp balancing areas. DMM plans to report on this new feature in a subsequent report.

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

[10] 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.

The constraint is now also applied to each EIM balancing authority area and as grouped combinations of balancing authority areas. In total, there are seven flexible ramping constraints used in the model.[11] On average the flexible ramping requirement was set to a little above 30 MW in PacifiCorp East for most of the day and adjusted up to 150 MW during the morning and evening peak hours. In PacifiCorp West, the requirement was set to a little over 25 MW for most of the day and adjusted up to 100 MW during the morning and evening peak hours.

Originally, the ISO also applied a credit to the flexible ramping requirements when the EIM was launched. However, as mentioned in the previous DMM quarterly report, issues with this credit affected the performance of the flexible ramping constraint, and in turn affected the procurement and pricing associated with the flexible ramping constraint.[12] The ISO made several fixes in February and, ultimately, the flexible ramping credit is no longer applied.

Furthermore, the ISO enhanced how the flexible ramping constraint was set in both the ISO and in the EIM balancing areas in late March. The ISO implemented a new tool that automated the calculation of the flexible ramping requirements for each balancing area.[13] Further details on this new tool will be discussed in a subsequent quarterly report.

Flexible ramping procurement costs

Total payments for flexible ramping resources in the first quarter were around $400,000, down from around $630,000 in the previous quarter.[14] Table 1.1 provides a review of monthly flexible ramping constraint activity in the 15-minute market.[15] The table highlights the following:

- The flexible ramping constraint was binding in around 4 percent of intervals, up from 2 percent in the previous quarter.
- The frequency of procurement shortfalls increased to 0.6 percent for all 15-minute intervals compared to 0.2 percent in the previous quarter.
- The average shadow price when the flexible ramping constraint was binding was about $16/MWh in February and $26/MWh in March, lower than the average $58/MWh in the previous quarter when the flexible ramping constraint was binding.
- The average shadow price in January was $0/MWh because the constraint was not binding in any interval during the month for the ISO balancing area. This outcome is likely due to the incorrect application of the flexible ramping credit. The flexible ramping credit significantly decreased the

[11] 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.

[12] 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.

[13] The tool is known as the *Balance Area Ramping Requirements* (BARR) tool.

[14] 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.

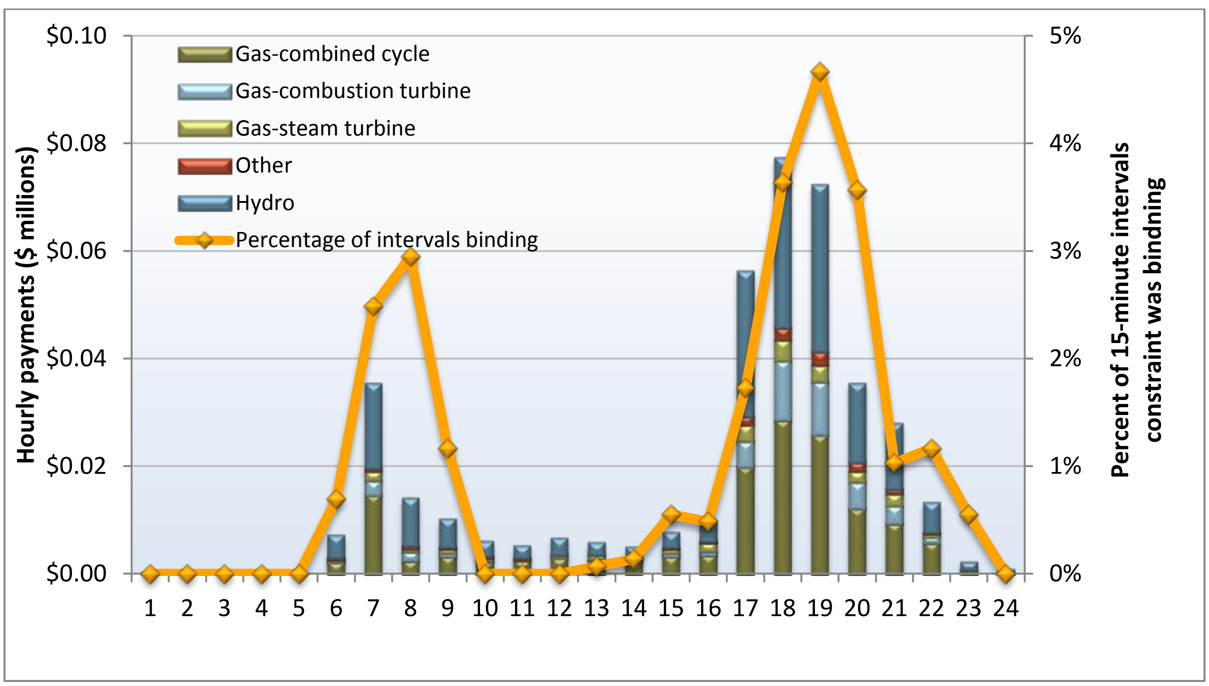
[15] DMM had problems with data availability between October 16 and October 30, 2014, and thus did not include the data from that period in the calculation.

flexible ramping requirement, which in turn reduced the level of procured flexible ramping capacity after the launch of the EIM market.

Table 1.1 Flexible ramping constraint monthly summary

Year	Month	Total payments to generators ($ millions)	15-minute intervals constraint was binding (%)	15-minute intervals with procurement shortfall (%)	Average shadow price when binding ($/MWh)
2014	Apr	$1.32	11%	0.8%	$44.59
2014	May	$0.72	7%	0.1%	$28.96
2014	Jun	$0.25	4%	0.1%	$25.97
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

Figure 1.9 Hourly flexible ramping constraint payments to generators (January - March)



Most payments for ramping capacity occurred during the evening peak hours. Figure 1.9 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 between 17 and 21. Natural gas-fired capacity accounted for about 52 percent of these payments with hydro-electric capacity accounting for 45 percent.

1.5 Congestion

Congestion on constraints within the ISO system increased overall average day-ahead and 15-minute prices in the SDG&E area by about 6 percent and 2.5 percent, respectively. Congestion had a relatively small overall net impact on prices in the PG&E and SCE areas. Much of the congestion was related to unscheduled flows and planned outages.

Toward the end of the first quarter, frequent congestion in the south-to-north direction on Path 15 began to occur due to planned transmission outages, which have continued into the second quarter. Further contributing to but not the main cause of the congestion was the high level of renewable generation south of Path 15 as renewable resources were economically curtailed at times and set low prices in the markets.

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/MWh and decreased in the SCE and SDG&E areas by about $3/MWh. Congestion on Path 15 occurred in the 15-minute market only about one-sixth as often as in the day-ahead, but increased prices in the PG&E area by about $16/MWh while decreasing prices in the SCE and SDG&E areas by about $16/MWh when congestion occurred.

1.5.1 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, PATH15_BG was the most congested constraint in the day-ahead market (see Table 1.2). This constraint was binding in about 6.2 percent of hours. During these hours, prices in the PG&E area increased by about $4/MWh while prices in the SCE and SDG&E areas decreased by over $3/MWh. This congestion occurred mainly due to planned maintenance, anticipated variable resource deviation and unscheduled flows on the California-Oregon Intertie (COI).

In the SDG&E area, the constraint with the largest impact in the quarter was 22835_SXTAP2_230_22504 _MISSION_230_BR_1_1. This constraint was binding in about 25 percent of hours and only affected the SDG&E area prices by $5/MWh. This constraint is intended to protect the Sycamore Canyon Tap – Mission 230 kV line. The second most binding constraint to impact the SDG&E area, caused by planned outages in the SCE area, was 24138_SERRANO_500_24137_SERRANO_230_XF_1_P. This constraint increased the SDG&E and SCE area prices by about $5.15/MWh and $1.70/MWh, respectively, while decreasing the PG&E area prices by about $2.80/MWh for the quarter. Also, the 24138_SERRANO _500_24137_SERRANO_230_XF_2_P constraint had similar price impacts but with less frequency (1.5 percent) for the quarter.

Similar to the last quarter, the Barre – Villa Park 220 kV line was the most binding constraint in the SCE area. The constraint is to protect for thermal overload from the contingency loss of the Barre – Lewis 220 kV line. This constraint was congested in about 2 percent of hours due to contingencies. When this constraint was binding, PG&E area prices decreased by about $0.75/MWh, while prices increased in the SCE area by about $1/MWh and in the SDG&E area by about $0.60/MWh.

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

Area	Constraint	Frequency	Q1		
		Q1	PG&E	SCE	SDG&E
PG&E	PATH15_BG	6.2%	$4.02	-$3.29	-$3.06
SCE	24016_BARRE _230_25201_LEWIS _230_BR_1_1	1.9%	-$0.74	$1.00	-$0.59
SDG&E	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
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	9.0%	-$0.95	$0.92	$1.51
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	4.2%			-$0.47
	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

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 1.3 shows the frequency and magnitude of 15-minute market congestion in the quarter.

The top two binding constraints for the quarter had the greatest price impact on the SDG&E area, 22835_SXTAP2_230_22504_MISSION_230_BR_1_1 and 24138_SERRANO_500_24137_SERRANO _230_XF_1_P. These constraints were binding in about 2.7 percent and 1.7 percent of the intervals in the quarter. The PATH15_S-N constraint was binding in about 1 percent of intervals and increased prices in the PG&E area by about $16.30/MWh while decreasing prices in the SCE and SDG&E areas by about $16.30/MWh and $15.30/MWh, respectively.

Table 1.3 Impact of congestion on 15-minute prices by load aggregation point in congested intervals

Area	Constraint	Frequency	Q1		
		Q1	PG&E	SCE	SDG&E
PG&E	PATH15_S-N	1.0%	$16.27	-$16.36	-$15.30
	PATH15_BG	0.2%	$5.87	-$6.08	-$5.72
SCE	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	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

22835_SXTAP2_230_22504_MISSION_230_BR_1_1 constraint was binding in roughly 25 percent of hours in the day-ahead market compared to around 2.7 percent of intervals in the 15-minute market. While this constraint increased day-ahead prices in the SDG&E area by about $5/MWh, it increased prices by about $15/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.

1.5.2 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.[16] 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.

Day-ahead price impacts

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

Table 1.4 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.37	-1.12%	$0.22	0.68%	$0.68	1.94%
22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1					$1.25	3.59%
PATH15_BG	$0.25	0.76%	-$0.20	-0.62%	-$0.19	-0.54%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.09	-0.26%	$0.08	0.26%	$0.11	0.33%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.06	-0.18%	$0.04	0.11%	$0.10	0.29%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.04%	$0.02	0.06%		
22768_SOUTHBAY_69.0_22772_SOUTHBAY_138_XF_1					$0.03	0.09%
IVALLY-ELCNTO_230_BR_1_1					$0.03	0.07%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1					-$0.02	-0.06%
22420_SILVERGT_69.0_22430_SILVERGT_230_XF_2					$0.01	0.03%
Other	$0.01	0.03%	$0.01	0.02%	$0.03	0.10%
Total	-$0.26	-0.8%	$0.16	0.5%	$2.02	5.8%

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

For the quarter, congestion in the day-ahead market was mixed as prices increased in the SDG&E and SCE areas and slightly decreased in the PG&E area. Congestion in the day-ahead market had a significant impact in the SDG&E area, where it increased prices by about 5.8 percent ($2.02/MWh). In the PG&E area, prices slightly decreased by 0.8 percent ($0.26/MWh), and prices in the SCE area slightly increased by 0.5 percent ($0.16/MWh).

The 22835_SXTAP2_230_22504_MISSION_230_BR_1_1 constraint had the largest overall impact on prices in the quarter. This constraint increased prices in the SDG&E area by $1.25/MWh (3.6 percent) and did not have a significant impact in the other areas. The 24138_SERRANO_500_24137_SERRANO _230_XF_1_P constraint also had the greatest price impact on the SCE area.

In the PG&E area, the PATH15_BG constraint increased prices by $0.25/MWh (0.8 percent), and decreased prices in the SDG&E and SCE areas by about $0.20/MWh.

15-minute price impacts

Table 1.5 shows the overall impact of 15-minute congestion on average prices in each load area in the quarter by constraint.[17] The overall impact of congestion elevated the SDG&E area price by about $0.84/MWh (2.5 percent) and SCE area prices by about $0.12/MWh or 0.4 percent, and decreased PG&E area prices by about $0.06/MWh or 0.2 percent. The most pronounced congestion was related to planned outages impacting the Serrano transformers and the Mission 230 kV line.

Table 1.5 Impact of congestion on overall 15-minute prices

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.12	-0.38%	$0.15	0.46%	$0.35	1.02%
PATH15_S-N	$0.17	0.52%	-$0.17	-0.53%	-$0.16	-0.46%
22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1					$0.40	1.17%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.05	-0.15%	$0.05	0.16%	$0.13	0.37%
PATH26_N-S	-$0.04	-0.12%	$0.04	0.11%	$0.03	0.10%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.02	-0.05%	$0.04	0.12%	$0.01	0.04%
PATH15_BG	$0.01	0.04%	-$0.01	-0.04%	-$0.01	-0.03%
25201_LEWIS _230_24154_VILLA PK_230_BR_1 _1	-$0.01	-0.02%	$0.01	0.02%	$0.02	0.05%
PATH15_N-S	-$0.01	-0.02%	$0.01	0.02%	$0.01	0.02%
Other			$0.01	0.04%	$0.07	0.20%
Total	-$0.06	-0.18%	$0.12	0.38%	$0.84	2.47%

1.6 Real-time imbalance offset costs

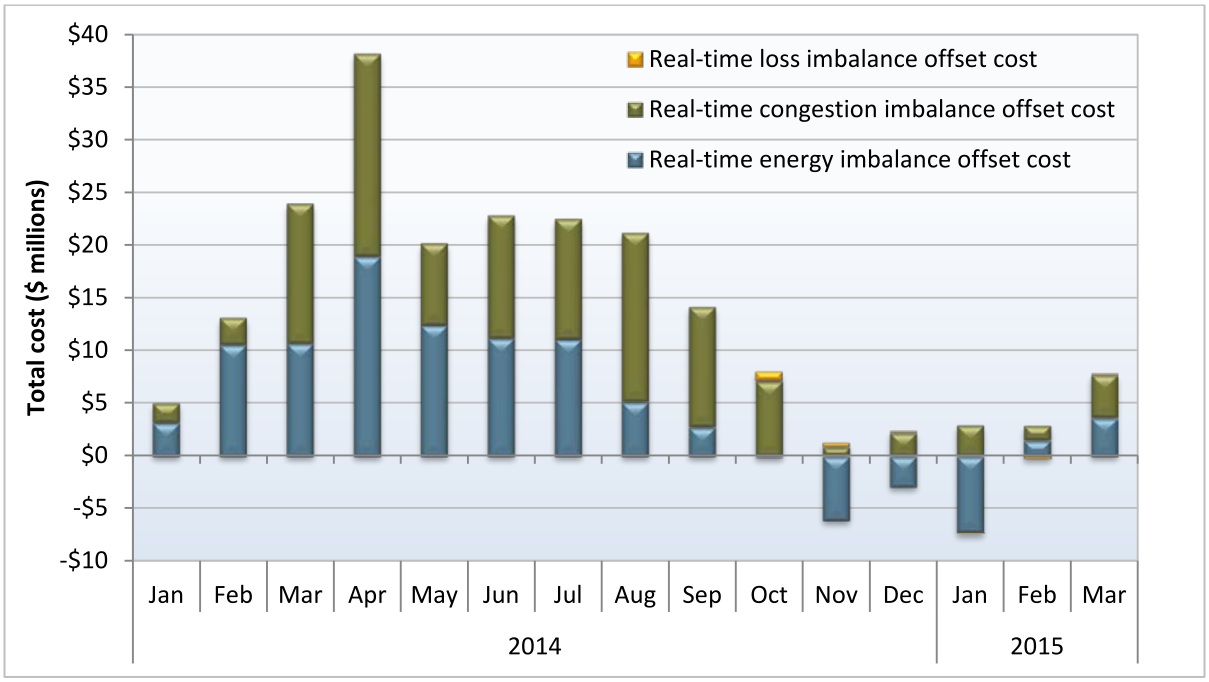
Real-time imbalance offset costs within the ISO system are currently estimated to be low, thus maintaining the historically low levels achieved in the fourth quarter of 2014. Total offset costs totaled about $6 million in the first quarter of 2015, compared to $42 million in the first quarter of 2014 and $2 million in the fourth quarter of 2014. Total real-time imbalance offset costs in the first quarter were the sum of approximately $8 million in congestion imbalance offset costs and an estimated credit of $2

[17] Due to data issues, details on specific constraints could not be calculated and were included in the 'other' category.

million in energy imbalance offset costs. Values reported here are the most current reported settlement imbalance charges, but are subject to change.[18]

Figure 1.10 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 loss imbalance offset was a credit of $0.3 million which accounted for approximately -5 percent of the total imbalance offset cost this quarter.

Figure 1.10 Real-time imbalance offset costs



Congestion imbalance offset costs fell substantially from $39 million in the second and third quarters of 2014 to $10 million in the fourth quarter and $8 million in the first quarter of 2015. The current estimated cost is lower than any quarter since the first quarter of 2013. Low real-time imbalance congestion offset is consistent with the low impact and frequency of real-time congestion this quarter. Although real-time congestion imbalance offset costs were low this quarter, real-time congestion due to conditions unanticipated in the day-ahead market can still result in substantial imbalance offsets. Two days this quarter are currently estimated to have real-time imbalance congestion offset costs over $1 million.

18 In addition to the routine causes for recalculation, the ISO has determined that a metering error resulted in under-metering of actual power flow over a handful of inter-ties. Offset costs calculated on the basis of under-metered flow will be corrected. The inter-tie meter difference from actual flow is estimated to have generated approximately $19 million of real-time imbalance energy offset between June and August of 2014 alone. The ISO has resolved the inter-tie metering issue. Revised settlements will reflect this change following the normal settlements timeline.

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. 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.

1.7 Convergence bidding

Beginning in May 2014, convergence bids switched from settling against the 5-minute real-time prices to the 15-minute real-time prices for internal locations, and switched from hour-ahead prices to 15-minute prices for inter-ties.[19] All numbers reported in this section reflect the prevailing settlement rules at the time the market ran.

Participants engaging in convergence bidding continued to earn positive returns in the first quarter. The net revenues from the market in these three months were about $2.5 million. Virtual supply generated net revenues of about $3.8 million, while virtual demand accounted for approximately $1.3 million in net payments to the market. The total payment to convergence bidders fell slightly, to about $2.2 million, after taking into account virtual bidding bid cost recovery charges of $0.27 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 58 percent of all accepted virtual bids in the first quarter, a decrease from 65 percent in the previous quarter.

Total hourly trading volumes decreased in the first quarter to about 2,400 MW from 2,800 MW in the previous quarter. Virtual supply averaged around 1,400 MW while virtual demand averaged around 1,000 MW during each hour of the quarter. Cleared hourly volumes of virtual supply outweighed cleared virtual demand by about 360 MW on average, an increase from 330 MW of net virtual supply in the previous quarter.

[19] Virtual bidding at the inter-ties was suspended in late 2011 but was to be gradually reintroduced with the 2014 spring systems software release. The virtual bidding position limit was to be set at 5 percent on the inter-ties beginning in May 2015. However, in April 2015, the ISO requested a waiver for the requirement to re-implement virtual bidding on inter-ties for up to an additional 12-month period. The ISO was concerned that reintroducing inter-tie virtual bidding in light of the observed lack of liquidity in economic bidding in the ISO's 15-minute market would decrease economic efficiency, based on a supplemental report completed by DMM analyzing the connection between 15-minute market economic bids at the inter-ties and inter-tie virtual bidding. FERC granted a temporary waiver delaying implementation of convergence bidding on the inter-ties pending further review and a subsequent order. For more information, see: http://www.caiso.com/Documents/Apr29_2015_OrderGrantingWaiverRequest_IntertieVirtualBidding_ER15-1451_ER14-480.pdf.

Net revenues for most of the first quarter were positive from net virtual supply positions and negative from net virtual demand positions as prices were generally higher in the day-ahead market than the 15-minute market.[20]

1.7.1 Convergence bidding trends

Total hourly trading volumes decreased in the first quarter to 2,400 MW from 2,800 MW in the previous quarter. These volumes have remained relatively stable for the last few quarters. On average, about 40 percent of virtual supply and demand bids offered into the market cleared in the first quarter, which is down from 49 percent in the fourth quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 360 MW on average, which is an increase from 330 MW of net virtual supply in the previous quarter. Virtual supply exceeded virtual demand during both peak and off-peak hours, by about 290 MW and 470 MW, respectively. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply in hours ending 6 to 8 and 18 to 21, with the highest net virtual demand occurring in hour ending 18 at about 400 MW. In the remaining hours, net cleared virtual supply exceeded net cleared demand. The highest net cleared virtual supply hour was hour ending 24 at about 910 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 19 hours.

Figure 1.11 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.

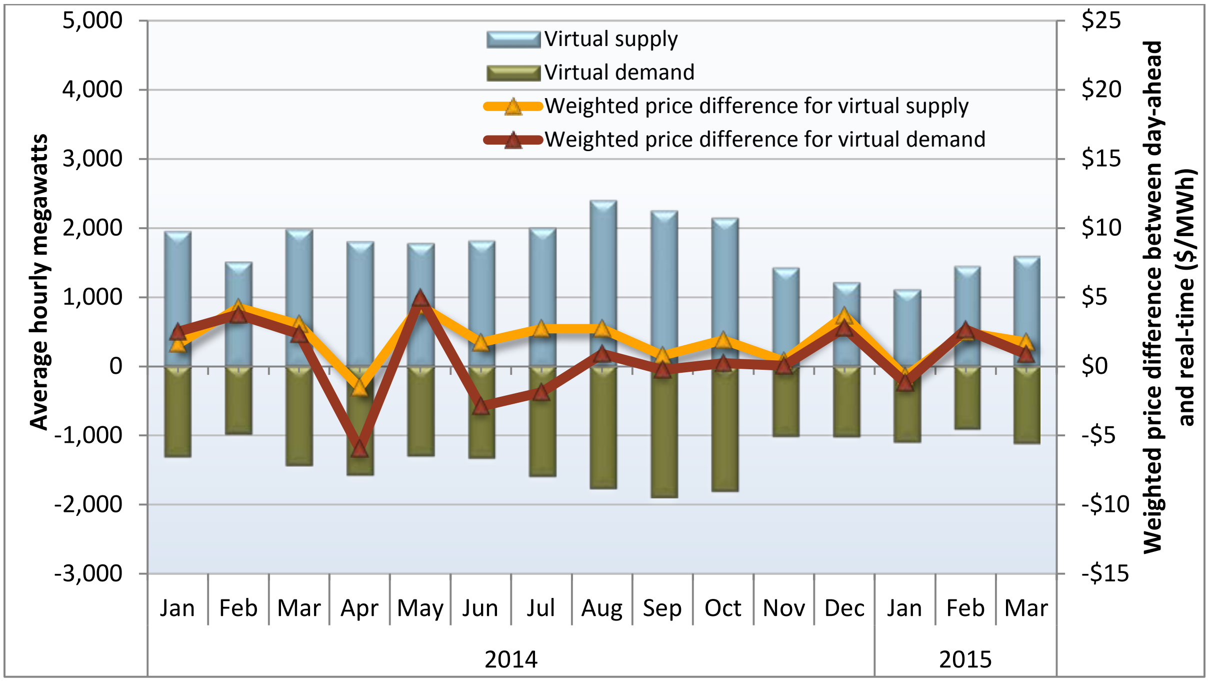
When the red line is positive, it indicates that the weighted average price charged for virtual demand in the day-ahead market was higher than the weighted average real-time price paid for this virtual demand. When positive, it indicates that a virtual demand strategy was not profitable, and thus was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

Virtual demand volumes for the months of February and March were inconsistent with weighted average price differences for the hours in which virtual demand cleared the market and, thus, were not profitable. However, virtual demand positions in January were slightly profitable as they were consistent with the weighted average price differences.

The yellow line in Figure 1.11 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 February and March, but not in January.

[20] 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.

Figure 1.11 Convergence bidding volumes and weighted price differences



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.[21] 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 690 MW of virtual demand offset by 690 MW of virtual supply in each hour of the first quarter. These offsetting bids represent about 58 percent of all cleared virtual bids in the first quarter, which is a decrease from 65 percent in the previous quarter. This suggests that virtual bidding continues to be used to hedge or profit from congestion.

1.7.2 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

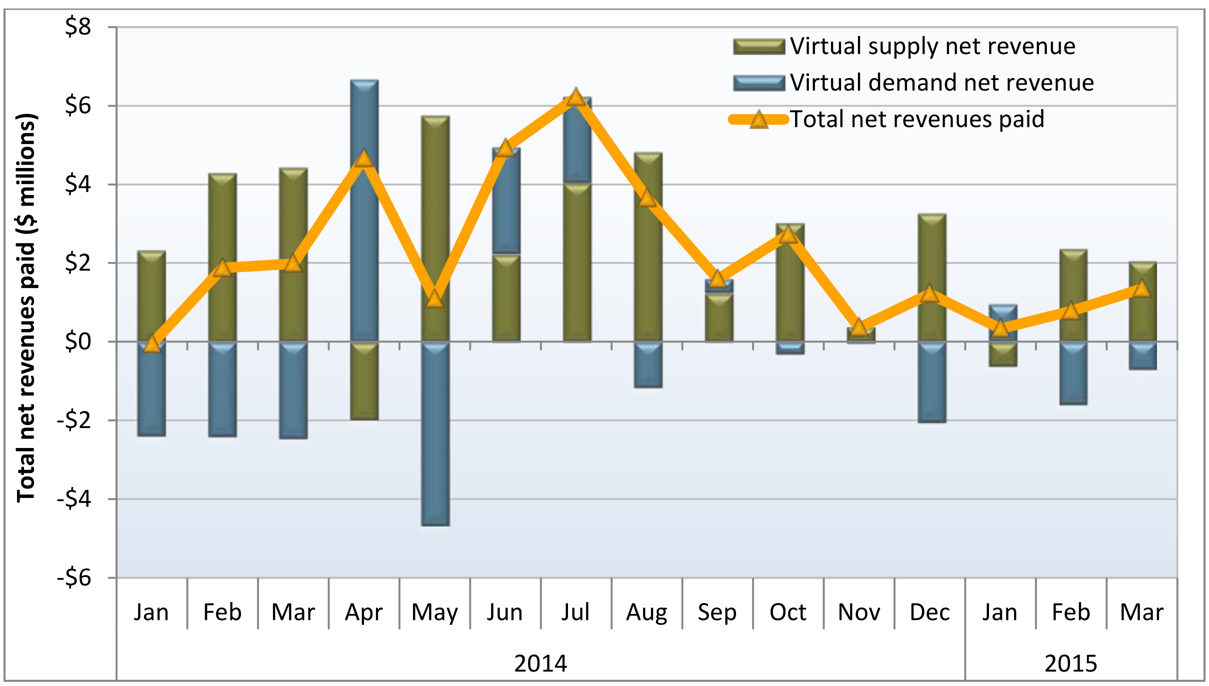
[21] Please refer to the discussion at the end of this section for detailed analysis of bid cost recovery charges to convergence bidders.

revenue. In the first quarter, net revenues were about $2.5 million from revenue collected on both virtual supply and demand positions.

Figure 1.12 shows total monthly net revenues for cleared virtual supply and demand. This figure shows the following:

- The net revenues from the market were about $2.5 million in the first quarter, compared to about $3.8 million in the same quarter in 2014 and $4.3 million in the previous quarter.
- Virtual supply revenues were most profitable in February as day-ahead prices were generally higher than 15-minute market prices. In total, virtual supply accounted for net payments of about $3.8 million during the quarter.
- Virtual demand revenues were negative in February and March and positive in January. In total, virtual demand accounted for around $1.3 million in net payments to the market for the quarter.
- Convergence bidders were paid about $2.2 million, after subtracting virtual bidding bid cost recovery charges of $0.27 million for the quarter.

Figure 1.12 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.[22] As shown in Table 1.6, financial entities represent the largest segment of the virtual market in terms of volume, accounting for about 54 percent of volumes and about 38 percent of settlement dollars. Marketers represent about 32 percent of the trading volumes and 40 percent of the settlement dollars. Generation owners and load-serving entities represent a small segment of the virtual market in terms of volumes (about 14 percent) but a larger segment of the settlements portion (22 percent).

Table 1.6 Convergence bidding volumes and revenues by participant type (January – March)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	602	685	1,287	-$0.63	$1.56	$0.94
Marketer	329	437	765	-$0.13	$1.11	$0.98
Physical generation	84	108	192	-$0.58	$0.67	$0.09
Physical load	2	139	142	$0.00	$0.46	$0.45
Total	**1,017**	**1,369**	**2,386**	**-$1.3**	**$3.8**	**$2.5**

Virtual bid cost recovery charges

As previously noted, virtual supply and demand bids are treated similarly to physical supply and demand in the day-ahead market. However, virtual bids are excluded from the day-ahead market processes for price mitigation and grid reliability (local market power mitigation and residual unit commitment). This impacts how physical supply is committed in both the integrated forward market and in the residual unit commitment process.[23] When the ISO commits units, it may pay market participants through the bid cost recovery mechanism to ensure that market participants are able to recover start-up costs, minimum load costs, transition costs and energy bid costs.[24]

Because virtual bids can influence unit commitment, they share in the associated costs. Specifically, virtual bids can be charged for bid cost recovery payments under two charge codes.[25]

[22] 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.

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

[24] Generating units, pumped-storage units, or resource-specific system resources are eligible to receive bid cost recovery payments.

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

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.[26] In this case, virtual demand leads to increased unit commitment in the day-ahead market, which may not be economic.
- Day-ahead residual unit commitment tier 1 allocation relates to situations where the day-ahead market clears with positive net virtual supply.[27] In this case, virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in the residual unit commitment, which may not be economic.

The costs associated with the two bid cost recovery charge codes for the first quarter totaled only about $0.27 million. The costs were about $0.08 million, $0.12 million and $0.08 million in January, February and March, respectively. As noted earlier, the total estimated net revenue for convergence bidding was around $2.5 million for this period. Total convergence bidding revenue is reduced to about $2.2 million when accounting for this adjustment.

[26] For further detail, see Business Practice Manual configuration guides for charge code (CC) 6636, IFM Bid Cost Recovery Tier1 Allocation_5.1a: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

[27] For further detail, see Business Practice Manual configuration guides for charge code (CC) 6806, Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocation_5.5: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

2 Special Issues

2.1 Inter-tie bidding and scheduling

The amount of inter-tie imports and exports cleared between the day-ahead and real-time markets has not changed considerably after implementation of 15-minute scheduling on the inter-ties in May 2014.[28] However, there was a significant decrease in the amount of inter-tie bids offered into the real-time market and a corresponding increase in the volume of self-scheduled inter-tie transactions. This overall trend continued into the first quarter.

Figure 2.1 and Figure 2.2 show the level of self-scheduled imports and exports compared to the total offered imports and exports in the day-ahead and real-time markets. Initially, the market experienced a considerable increase in the quantity of self-scheduled inter-tie import bids in both the day-ahead and real-time markets following implementation of the new inter-tie rules. In the second part of 2014 and first quarter of 2015, the quantity and share of self-scheduled import bids in the day-ahead market decreased to levels similar to before the market changes in May. Day-ahead self-scheduled export levels remained at negligible levels in the first quarter.

In the real-time market, most of the inter-tie import bids remained self-scheduled. Around 83 percent of import bids and 40 percent of export bids in the hour-ahead market were self-schedules in the first quarter. In the first quarter of 2014, 49 percent of import bids and 8 percent of export bids were self-scheduled in the hour-ahead market.

Figure 2.1 and Figure 2.2 also show that the increasing trend in the volume of both import and export bids at the end of 2014 did not continue in the first quarter of 2015. This may be related to the severe drought conditions throughout the West or other potential factors.

Most of the economic bids on the inter-ties remained in the hour-ahead market. In the first quarter, around 83 percent of economic import bids and around 80 percent of economic export bids were hourly block bids. Inter-tie resources seldom used the hourly economic bid block option with a single intra-hour economic schedule change. Around 17 percent of economic import bids and 20 percent of economic export bids were 15-minute economic bids, as shown in Figure 2.3. The volume of 15-minute dispatchable import bids increased by 19 percent compared to the fourth quarter, averaging 215 MW each hour in the first quarter. Both the percentage and volume of 15-minute economic import bids in the first quarter were the highest quarterly values since 15-minute import bidding began in May 2014.

[28] 15-minute changes are not allowed on the PDCI and IPPDC inter-ties.

Figure 2.1 Volume of self-scheduled and economic import and export bids in the day-ahead market

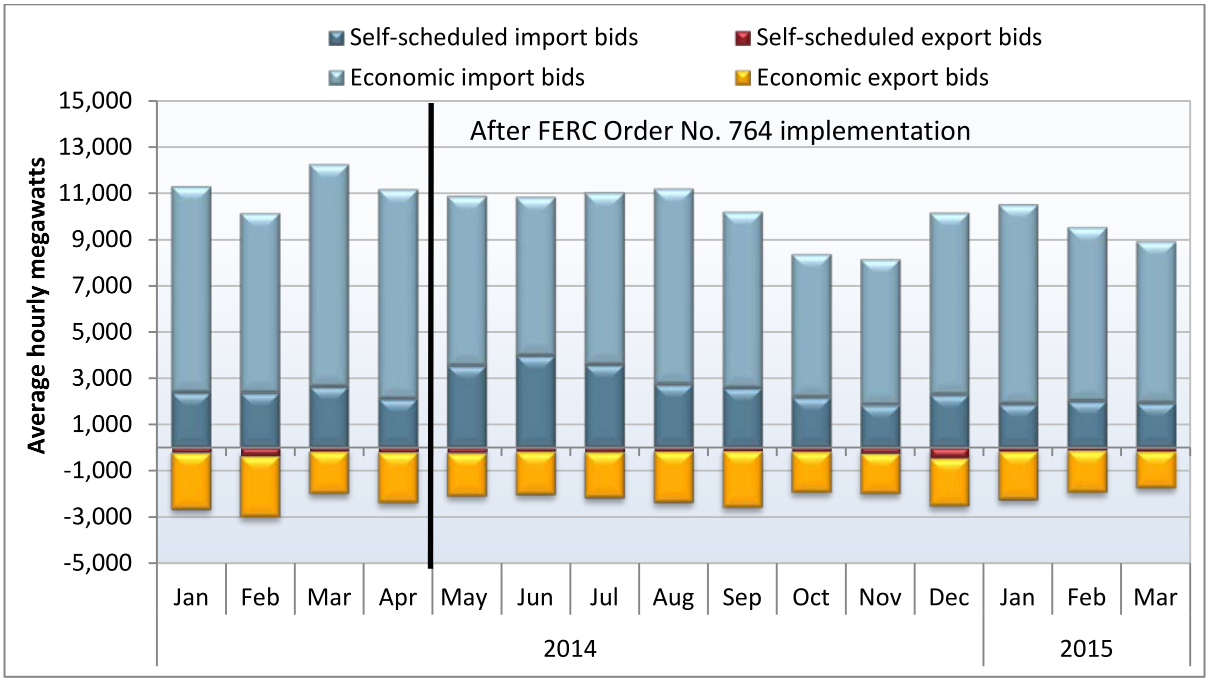


Figure 2.2 Volume of self-scheduled and economic import and export bids in the real-time market

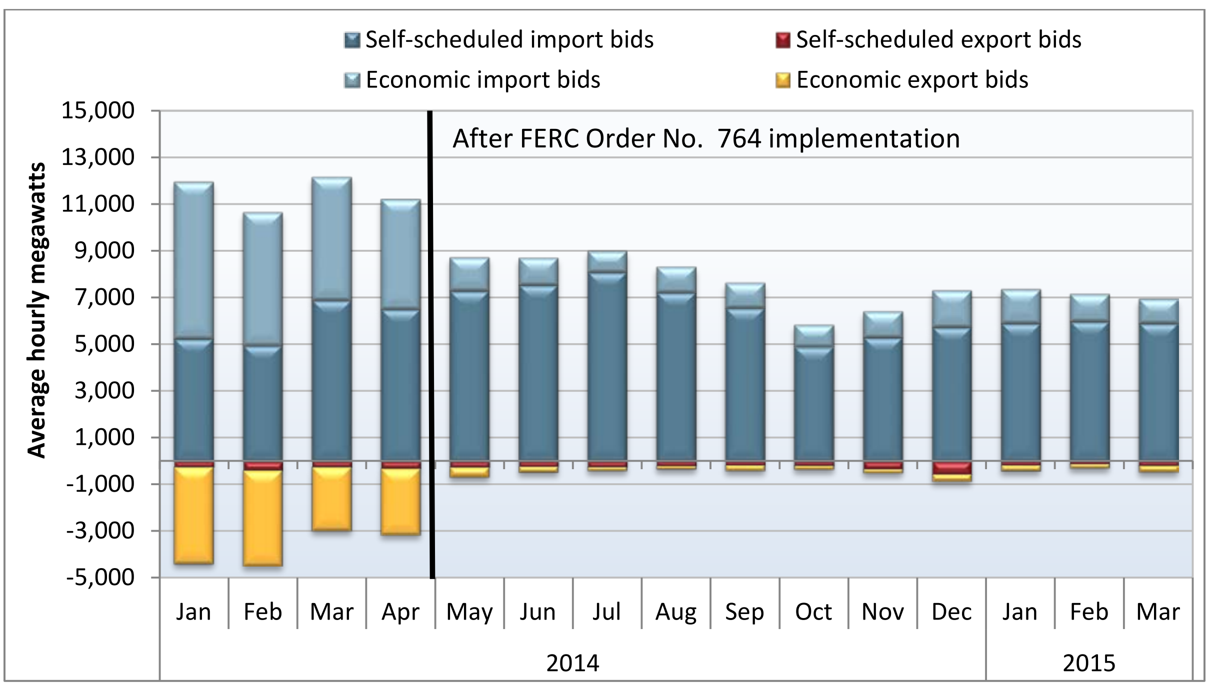
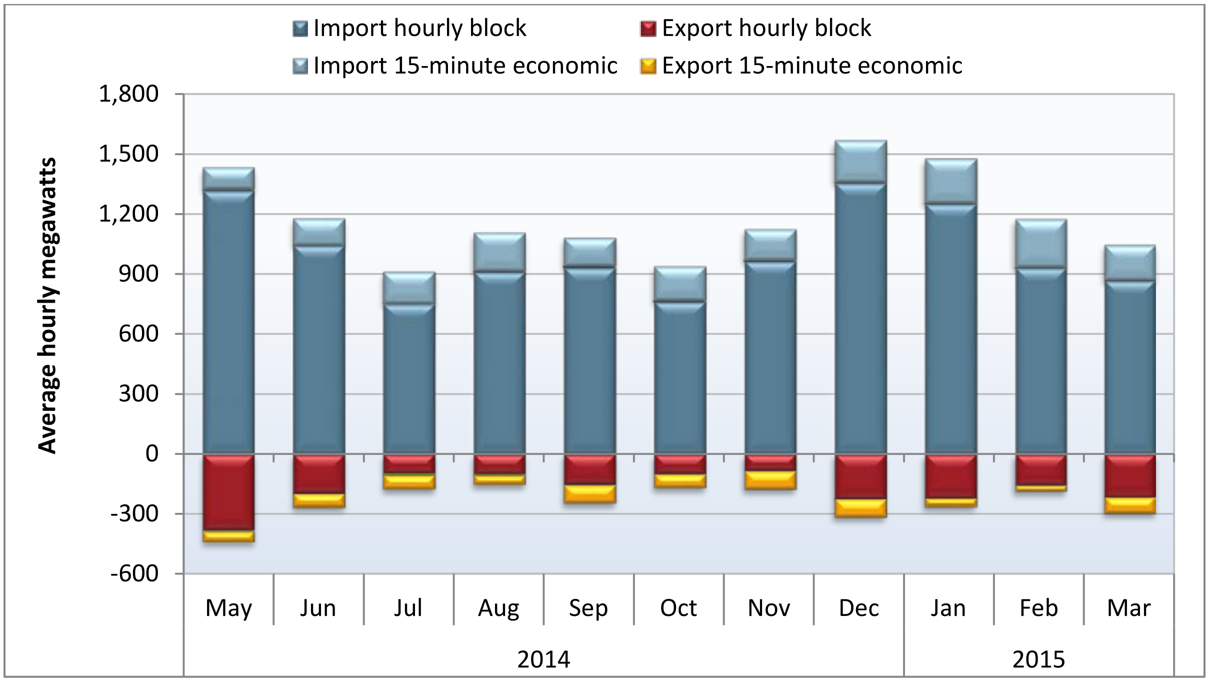


Figure 2.3 Economic import and export bids by bidding option



3 Energy imbalance market

This section covers the energy imbalance market performance in the first 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 both the 15-minute and 5-minute markets in February and March. In PacifiCorp West this downward trend continued in the 5-minute market, while the frequency of constraint relaxations was low overall in the 15-minute market in February and March.
- With price discovery provisions, EIM prices in both PacifiCorp areas have been kept about equal to the bilateral market price indices that were used to set prices prior to EIM implementation.
- Several problems with how the flexible ramping constraint was implemented as part of the EIM design were identified and have been mitigated. These issues reduced the quantity of flexible ramping required and consequently procured and prevented the flexible ramping constraint from being binding in the ISO market. These issues appear to have been mitigated by changes made by the ISO in February 2015.
- The frequency of manual dispatches fell each month since EIM went live in November 2014. This trend has continued in the first quarter. Incremental manual dispatches occurred in 36 percent of 15-minute intervals over the month of November 2014, falling to 9 percent of 15-minute intervals in March 2015. Decremental manual dispatches fell similarly from 30 percent of 15-minute intervals in November 2014 to 7 percent of 15-minute intervals in March 2015.
- The volume of EIM manual dispatches has also decreased consistently for EIM participating and non-participating resources, with decreases in both incremental and decremental manual dispatches. Average hourly incremental manual dispatch energy has fallen from 33 MW in November 2014 to 5 MW in March 2015. Decremental manual dispatch energy has declined from 34 MW in November 2014 to 3 MW in March 2015.

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.[29]

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

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 1.4.

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.[30] 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 for and FERC approved special *price discovery* measures to set prices based on the last dispatched bid price rather than penalty prices for various constraints.[31] FERC approved the filing 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, outlining the issues driving the need for the EIM tariff waiver.[32] On March 16, 2015, FERC extended the waiver for an additional 90 days and, in addition, extended the reporting requirements.[33]

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.

[30] *Energy Imbalance Market Pricing Waiver Report*, December 15, 2014, January 15, 2015, February 19, 2015, March 26, 2015 and April 24, 2015: 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, and http://www.caiso.com/Documents/Apr24_2015_March2015_EnergyImbalanceMarket_PriceWaiverReport_ER15-402.pdf.

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

[32] 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, and http://www.caiso.com/Documents/May7_2015_DMM_Report_Performance_Issues_EIM_March2015_ER15-402.pdf.

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

Figure 3.1 and Figure 3.2 provide a weekly summary of the frequency of constraint relaxation (red and 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 November and then again in January. After mid-January, 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 dropped substantially during November then increased in late December and into January. After this period, the frequency of constraint relaxations declined significantly and consistently through the rest of the period.

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. These 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.[34] These figures show that without the price discovery provisions being applied in EIM, average daily prices would consistently exceed the bilateral market price index reflective of prices for imbalance energy in the PacifiCorp areas prior to EIM. However, with price discovery, EIM prices track very closely with this bilateral price index.

Figure 3.3 and Figure 3.4 provide the same weekly summary for the 5-minute market. As shown in these figures, the need to relax the power balance constraint in the 5-minute market has also remained relatively high, particularly in the PacifiCorp East area, since EIM implementation. This reflects the fact that in the 5-minute market the supply of ramping capacity within PacifiCorp is more constrained than in the 15-minute market.

The higher frequency of power balance constraint relaxations in the 5-minute market also reflects the fact 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 first week of February. The dynamic transfer constraint (DTC), 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 since this change was implemented.

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.

[34] 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 week PacifiCorp East - 15-minute market

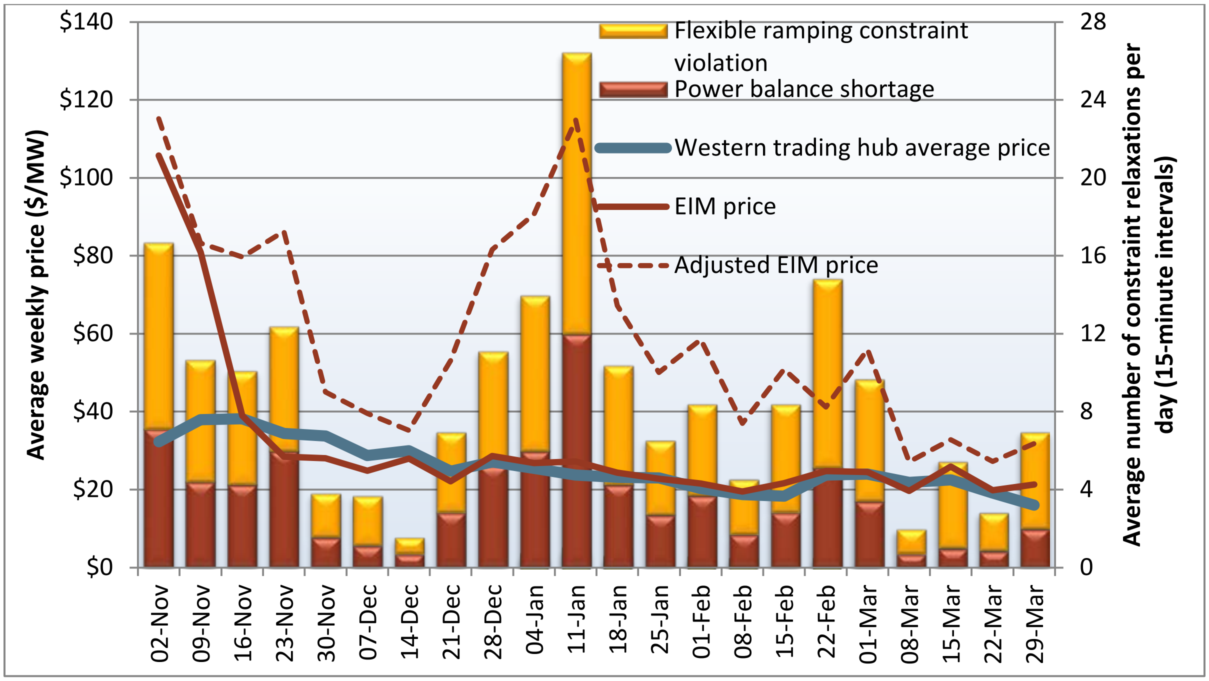


Figure 3.2 Frequency of constraint relaxation and average prices by week PacifiCorp West - 15-minute market

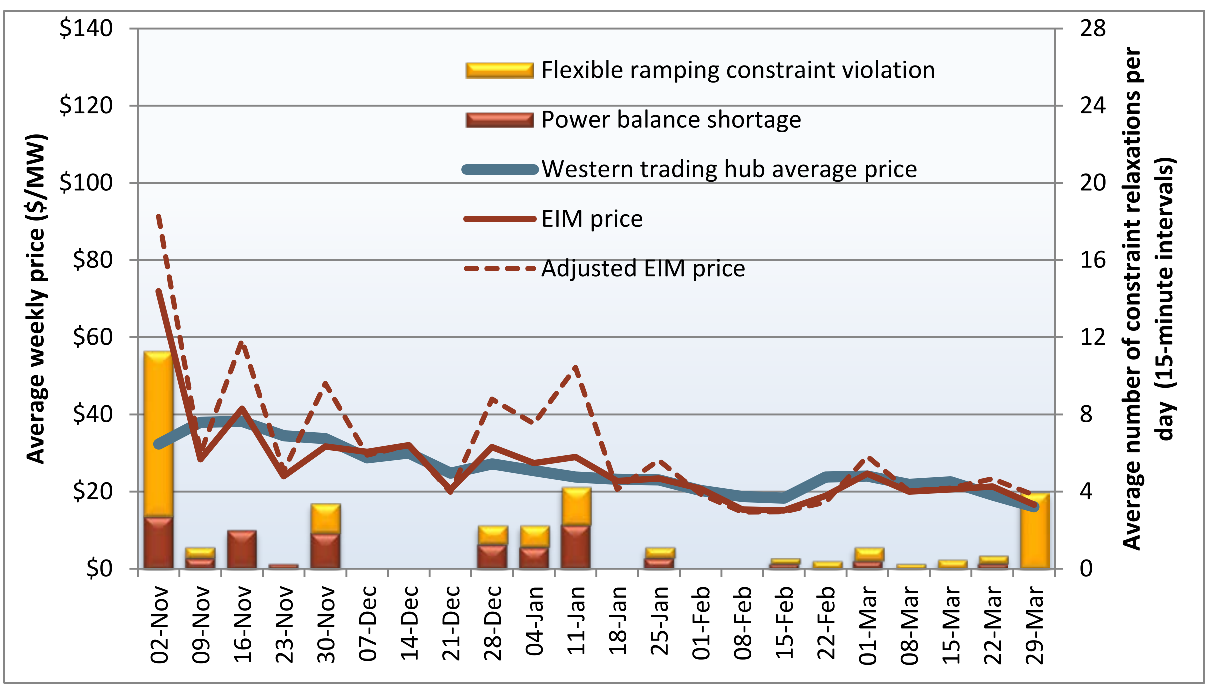


Figure 3.3 Frequency of constraint relaxation and average prices by week PacifiCorp East - 5-minute market

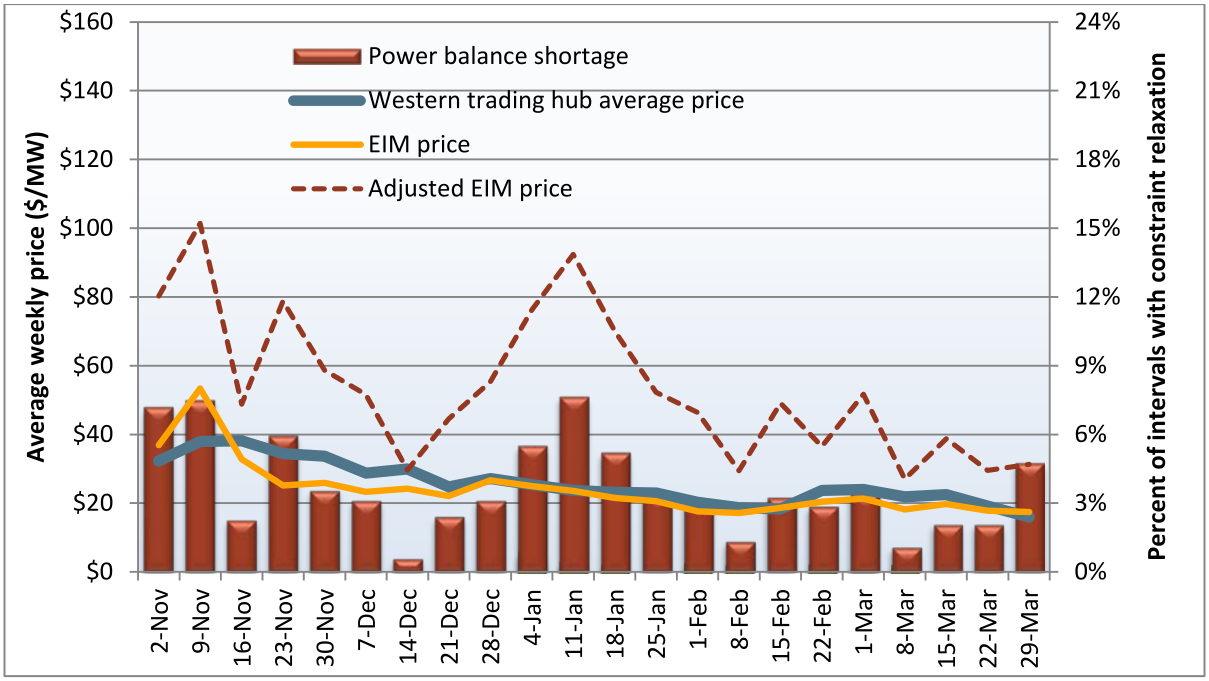
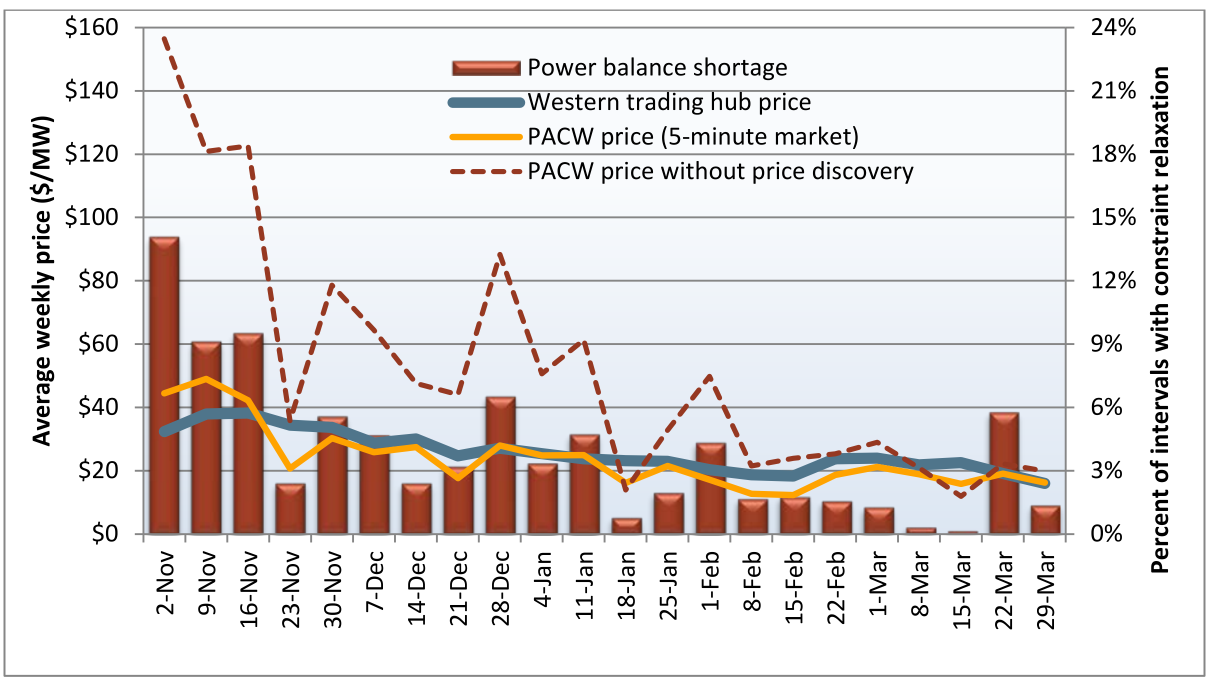


Figure 3.4 Frequency of constraint relaxation and average prices by week PacifiCorp West - 5-minute market



Manual dispatch trends

An EIM entity may issue manual dispatches for participating or non-participating resources as part of its reliability function.[35] The timing and frequency of these dispatches are determined by the EIM entity rather than by the resource or the ISO. EIM manual dispatches may be issued to address system reliability concerns, reflect resource operation restrictions that are not otherwise reflected in the market, and to manage congestion as required.

Manual dispatches may be issued in both the upward (incremental) or downward (decremental) directions. Incremental manual dispatch refers to a manually dispatched quantity greater than the final base schedule submitted by the EIM entity 40 minutes before the operating hour. Decremental manual dispatch refers to a manual dispatch quantity less than the final base schedule. All incremental or decremental energy from manual dispatches is settled at the EIM market price rather than based on the resource's energy bid price.

The frequency and volume of incremental and decremental manual dispatch of EIM participating and non-participating resources fell consistently each month between November 2014 and March 2015.[36]

The frequency of manual dispatches has fallen each month since EIM went live in November 2014. This trend has continued in the first quarter of 2015. Figure 3.5 shows the percentage of intervals in the 15-minute market where an incremental or decremental EIM manual dispatch was active. Incremental manual dispatches occurred in 36 percent of 15-minute intervals over the month of November 2014, falling to 9 percent of 15-minute intervals in March 2015. Decremental manual dispatches fell similarly from 30 percent of 15-minute intervals in November 2014 to 7 percent of 15-minute intervals in March 2015.

The volume of EIM manual dispatches has also decreased consistently for EIM participating and non-participating resources, with decreases in both incremental and decremental manual dispatches (Figure 3.6). Average hourly incremental manual dispatch energy has fallen from 33 MW in November 2014 to 5 MW in March 2015. Decremental manual dispatch energy has declined from 34 MW in November 2014 to 3 MW in March 2015.

The decline in manual dispatch may reflect improved market performance and increased EIM resource participation. Further, many EIM manual dispatches in this period were issued to address issues with resource outages, minimum output re-rates, or other operation restrictions that are not otherwise reflected in the market. Thus, improved ability of the EIM entity to manage these issues in the ISO's outage management system (webOMS) may have played a role in decreasing EIM manual dispatches over this period.

[35] An EIM entity is a balancing authority area that is not a full member of the ISO, which represents one or more EIM transmission service providers who have made transmission available and elects to participate in the EIM. EIM manual dispatch is analogous to ISO exceptional dispatch, except that EIM manual dispatch can only be issued by the EIM entity and not the ISO. Further, EIM manual dispatch settles as imbalance energy and has no specific exceptional dispatch settlement.

[36] This analysis is based on manual dispatches that were reported to and recorded by the ISO systems. To the extent that manual dispatches were not correctly reported, this will not be reflected in this analysis. However, unreported manual dispatches are likely to have decreased over time.

Figure 3.5 EIM manual dispatch frequency - coal, gas, and hydro resources

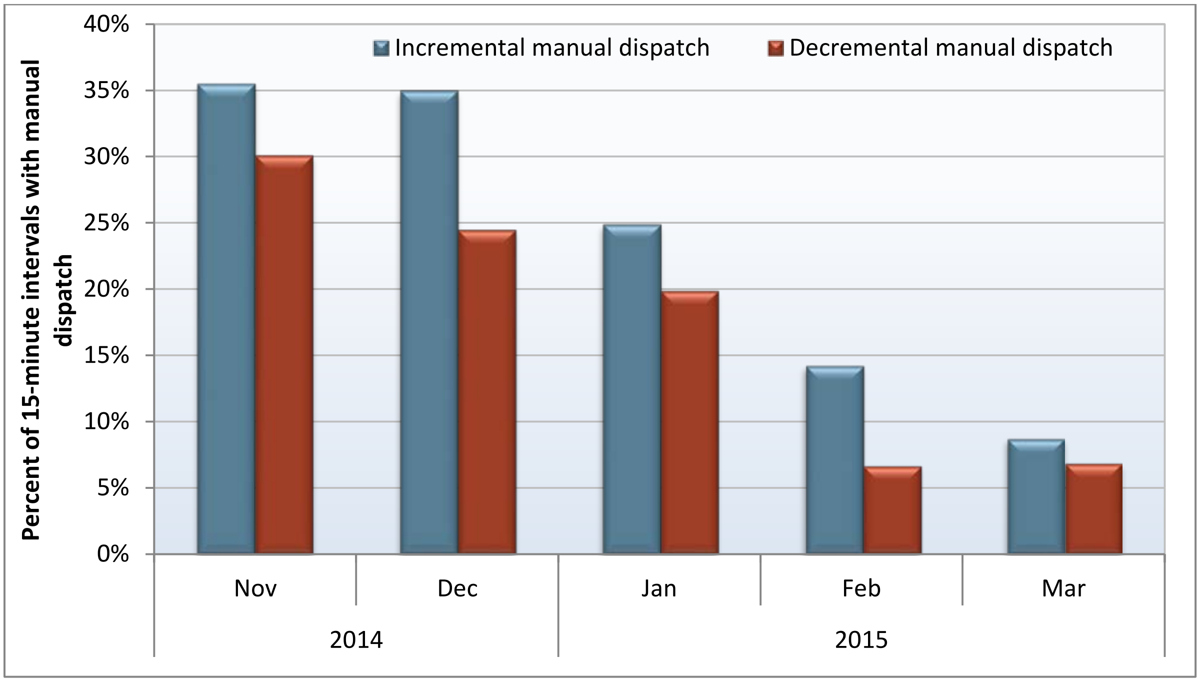
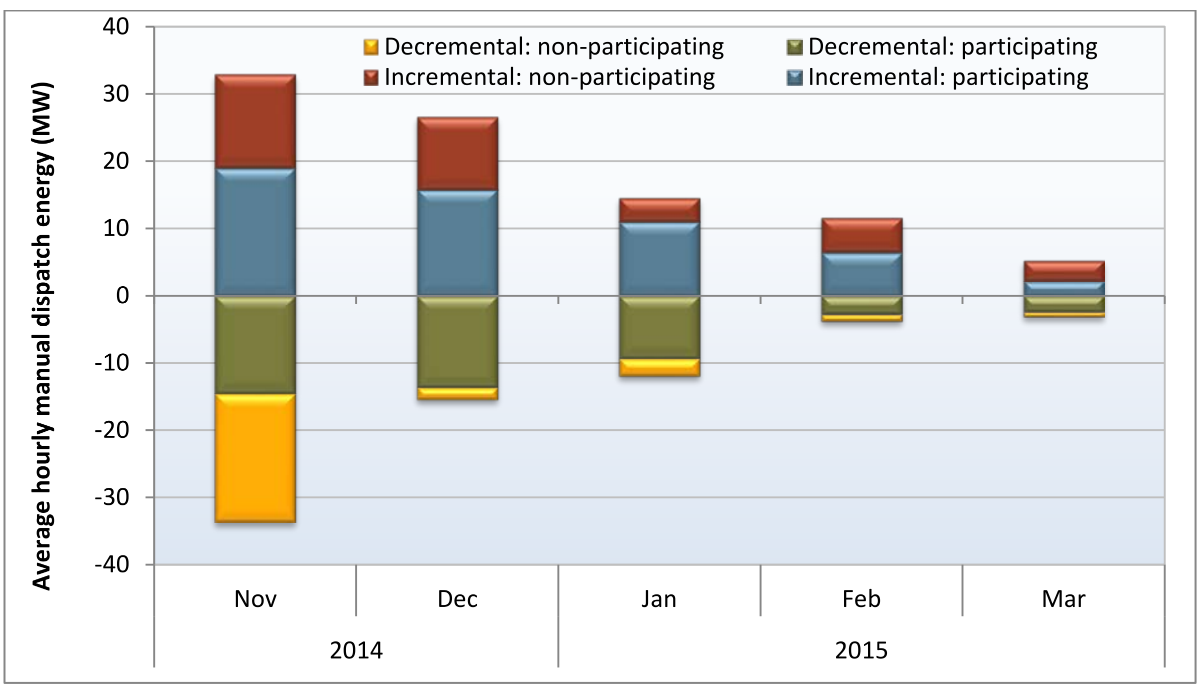


Figure 3.6 EIM manual dispatch volume - coal, gas, and hydro resources



Internal constraints within the PacifiCorp balancing authority area were not generally submitted by the EIM entity for enforcement in the EIM market model until the end of the first quarter. However, DMM's review of operator logs associated with EIM manual dispatches indicates that manual dispatches have rarely, if ever, been used to manage internal transmission constraints. The EIM entity in 2015 has begun to provide additional internal constraints for enforcement in the EIM market model to allow internal congestion management by the EIM software in the event internal congestion begins to occur under late spring and summer load and supply conditions.

The bid prices and marginal costs of EIM participating resources receiving incremental manual dispatch have generally been well-aligned with 15-minute prices at the time of the manual dispatch. Figure 3.7 and Figure 3.8 show volume-weighted average bids and 15-minute prices for incremental manual dispatch, as well as distributions of the amount by which incremental manual dispatch bids exceeded the 15-minute price.[37] Where the manually dispatched output level was not bid in to the market, default energy bids used in mitigation were used for this analysis. These figures are only based on manual dispatches issued to participating resources because non-participating resources do not have bids submitted in the market or default energy bids.

As shown in Figure 3.7 and Figure 3.8, the weighted average bid for manually dispatched energy (red lines) was close to the weighted average 15-minute price (yellow lines), with some exception in the PacifiCorp East area in November 2014, and in the PacifiCorp West area in November 2014 and January 2015. Some separation between weighted average bids and 15-minute prices occurred in November 2014 and January 2015. This difference in November 2014 was driven by the fact that market clearing prices in both EIM areas were elevated in comparison with other months, while the weighted average bids remained relatively constant. In January 2015, this difference was driven by intervals with negative prices in the PacifiCorp West area, which resulted in a weighted average 15-minute price of only $9/MWh compared to a weighted average bid price of $24/MWh.

The bars in Figure 3.7 and Figure 3.8 show the amount by which incremental manual dispatch bids exceeded the 15-minute price. As shown in these figures, a significant portion of manual dispatches were issued for resources with energy bid prices that were less than the 15-minute price. There are a variety of reasons these lower priced bids were not dispatched by the market software. As previously noted, many EIM manual dispatches in this period were issued to address issues with resource outages, minimum output re-rates, or other operation restrictions that are not otherwise reflected in the market software. For example, a resource with lower priced bids that was manually dispatched could have been unavailable for dispatch by the market software due a misreported outage or other problem associated with the outage management system (webOMS). In other cases, bids less than the 15-minute price in these figures represent default energy bids for capacity that was not bid into the market.

[37] Bids used in this analysis are unmitigated input bids for the highest output level of the incremental manual dispatch.

Figure 3.7 Incremental manual dispatch difference between bid and 15-minute price PacifiCorp East (PACE)[38]

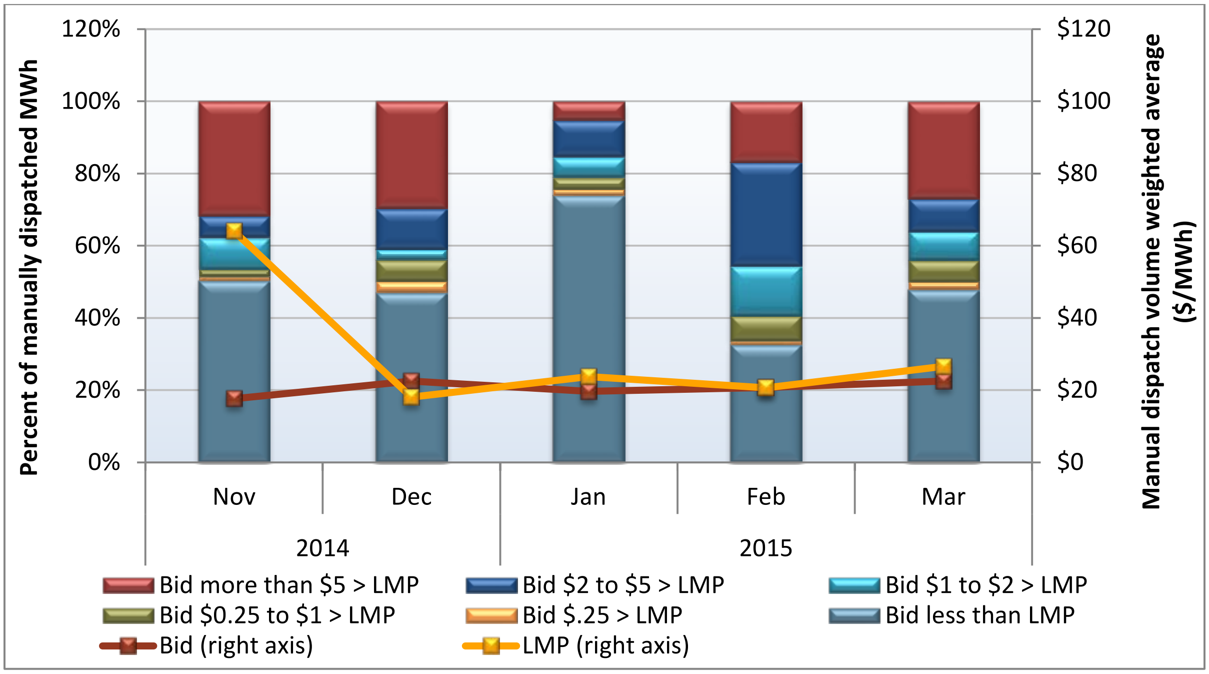
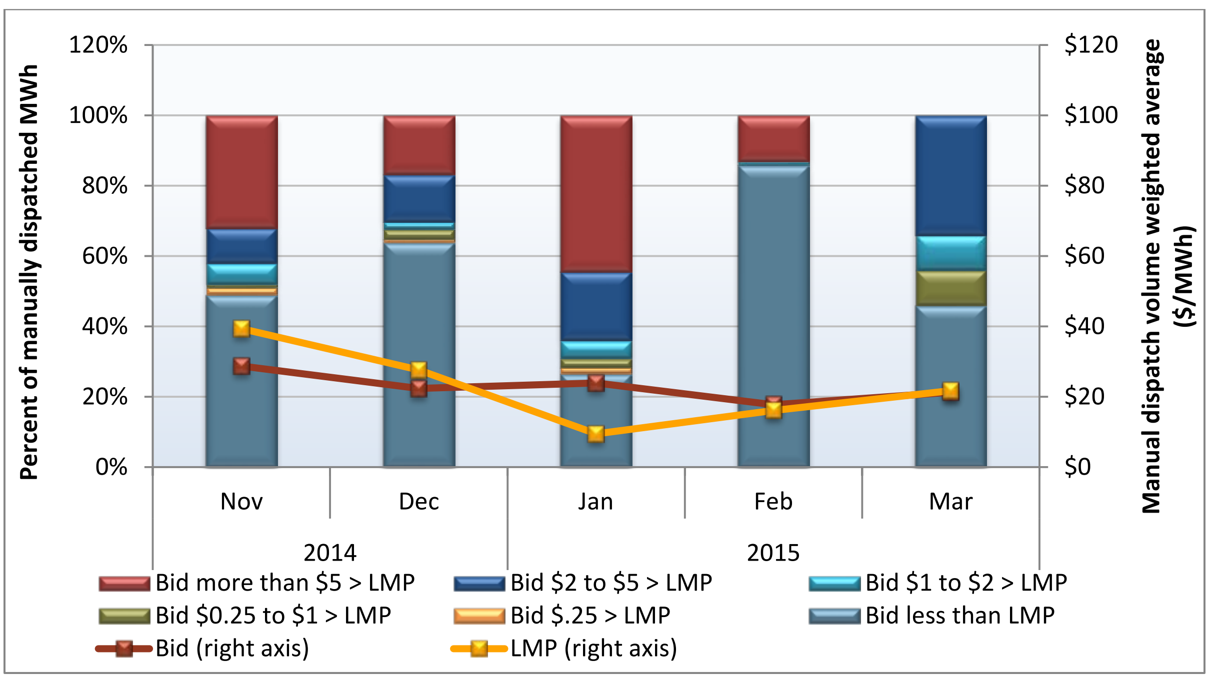


Figure 3.8 Incremental manual dispatch difference between bid and 15-minute price PacifiCorp West (PACW)



[38] These figures represent EIM participating coal, gas, and hydro resources. Default energy bids were used when the manual dispatch output level had no bid.