California Independent System Operator Corporation

California ISO

Q1 2017 Report on Market Issues and Performance

July 10, 2017

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Executive summary

This report covers market performance during the first quarter of 2017 (January – March). Key highlights during this quarter include the following:

- For the first time, negative prices were relatively frequent in the day-ahead market. Prices fell below zero in over 50 hours in the first quarter, around 10 percent of hours between hours ending 11 and 15. The frequency of negative prices increased in the real-time market as well, reaching about 10 percent of intervals in the 15-minute market and 13 percent of intervals in the 5-minute market.
- The ISO enforced two of the Aliso gas nomograms on four days in January. This appears to have had minimal impact on the market. These constraints do not appear to have been sufficient, on their own, to limit gas burn from participating gas resources.
- DMM is recommending refinements in the Aliso Canyon measures adopted last year. In addition to gas nomogram refinements required to effectively limit gas burn, DMM has recommended that the ISO review and reduce Aliso Canyon related gas bid adders used in the real-time market. In addition, the effectiveness of the ISO's market power mitigation procedures may be adversely affected if operators enforce the gas burn constraints. Including the impacts of any and all gas nomograms in the automated dynamic competitive path assessment should be a necessary precursor to any decision to extend the nomograms beyond their current use and sunset date.
- In October 2016, Arizona Public Service (APS) and Puget Sound Energy (PSE) joined the energy imbalance market, adding a significant amount of transfer capacity. Given the significant amount of transfer capacity between Arizona Public Service and the ISO, there was little congestion between these regions. Arizona Public Service also added significant transfers with PacifiCorp East and there was minimal congestion between these regions. Energy imbalance market prices in the Arizona Public Service area were close to those observed in NV Energy, PacifiCorp East and the ISO during the quarter.
- Energy imbalance market prices in Puget Sound Energy were similar to prices in PacifiCorp West. Puget Sound Energy is connected to the energy imbalance market by 300 MW of transfer capacity into and out of PacifiCorp West. These transfers did not limit flows in most cases, which resulted in little congestion between these regions and similar prices.
- There continued to be congestion in the energy imbalance market from PacifiCorp West toward the ISO and PacifiCorp East. This caused price separation between these two areas and the rest of the energy imbalance market. Prices in Puget Sound Energy and PacifiCorp West were lower than those in the ISO and other energy imbalance areas as a result of this congestion.
- Payments for flexible capacity increased since implementation of the flexible ramping product, but still remain low at less than $0.14/MWh of load. Total payments for flexible ramping capacity in the first quarter were about $9.2 million, almost twice payments in the fourth quarter of 2016 which totaled about $5 million.

Other key highlights are summarized here and further detail is provided below.

- Average day-ahead and real-time prices were competitive compared to benchmark prices and were lower than price levels in the previous quarter because of increased output from renewable resources and relatively low load.
- Average prices in the day-ahead market continued to be higher than 15-minute market prices for the quarter.
- Price spikes were relatively infrequent in both the 15-minute and 5-minute markets. Prices above $250/MWh were observed in only about 0.1 percent of intervals in the 15-minute market and 0.6 percent of intervals in the 5-minute market.
- During the first quarter of 2017, congestion revenue rights auction revenues were $12 million less than congestion payments made to non-load serving entities purchasing these rights. This represents about $0.65 in auction revenues paid to transmission ratepayers for every dollar paid to auctioned rights holders, comparable to the first quarter of 2016.
- Day-ahead congestion in the San Diego Gas and Electric areas increased prices by over $1/MWh for the quarter, but had less impact on prices in the Southern California Edison and Pacific Gas and Electric load areas.
- Bid cost recovery payments were $22 million in the first quarter, up from $19 million in the prior quarter. Real-time bid cost recovery remains the largest category of bid cost recovery and totaled about $13 million. An increase in bid cost recovery payments for residual unit commitment accounts for much of the increase.
- Convergence bidding was slightly unprofitable for the second consecutive quarter after accounting for bid cost recovery charges. Total net revenues for entities engaging in convergence bidding during this quarter were about negative $0.1 million, a smaller loss than the $2.6 million loss in the fourth quarter of 2016. In addition, the percent of virtual supply and demand bids offered into the market that cleared decreased to a record low at about 31 percent, down from 37 percent in the prior quarter.
- The ISO and Puget Sound Energy were net importers in the energy imbalance market, while PacifiCorp East and PacifiCorp West tended to be net exporters. NV Energy and Arizona Public Service were slight net exporters, exporting slightly more than they imported over the quarter. However, the direction and volume of transfers between the ISO and different energy imbalance market areas fluctuated significantly based on actual real-time market conditions.
- The available balancing capacity mechanism continued to have a limited impact on addressing power balance constraint relaxations in the first quarter. NV Energy and Puget Sound Energy offered available balancing capacity into the market for most hours during the quarter, while PacifiCorp East and PacifiCorp West did so infrequently. Arizona Public Service offered available balancing capacity less frequently than in prior quarters.
- Load adjustments in energy imbalance market areas were typically smaller in magnitude, but generally larger as a percentage of area load, than adjustments in the ISO. Overall, load adjustments were typically positive in PacifiCorp East, NV Energy, Arizona Public Service and the ISO, while load adjustments in PacifiCorp West were typically negative. Puget Sound Energy made adjustments infrequently in either direction. Arizona Public Service operators adjusted the load

forecast significantly more frequently during the first quarter than in previous quarters, at about 40 percent of the real-time intervals

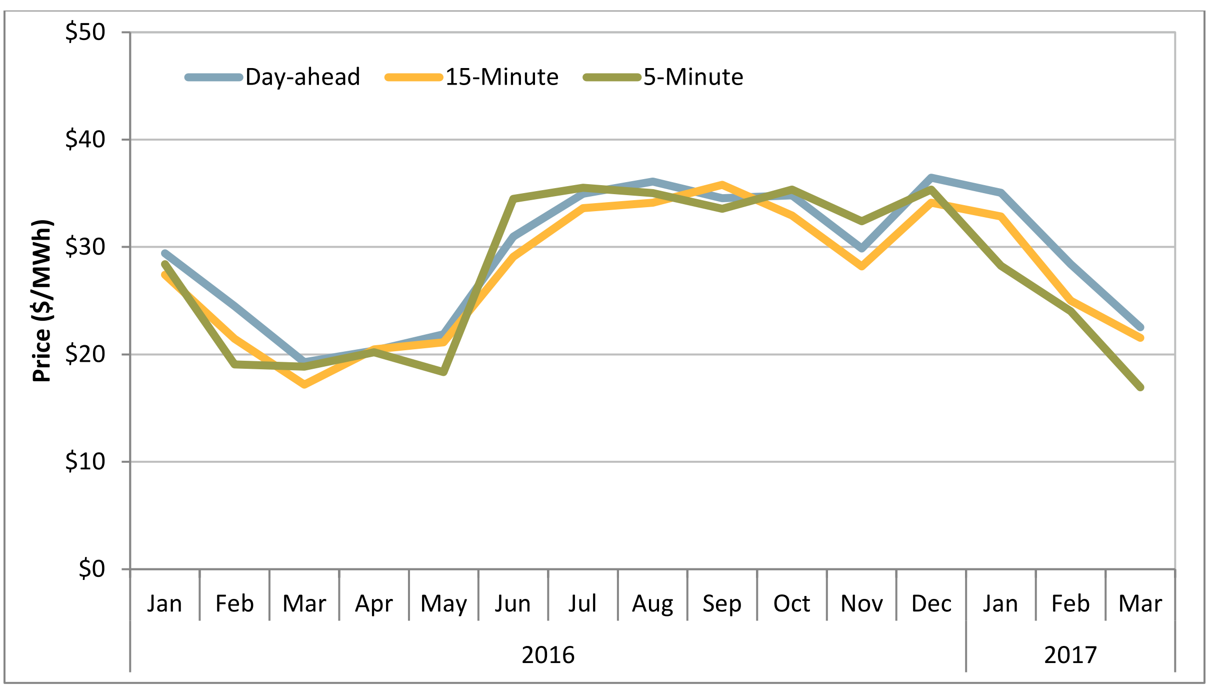
- As part of a set of temporary measures related to Aliso Canyon, the ISO began using a more up-to-date source for calculating the natural gas price index used by the day-ahead market. This update removed a one-day lag in the natural gas price information used in the day-ahead market, and greatly improved the accuracy of the ISO's index.
- DMM had not found any systematic need for the real-time commitment cost and incremental energy natural gas cost scalars used to increase bid caps, which were implemented as Aliso Canyon mitigation measures. DMM is recommending that the ISO review and reduce these scalars.

Energy market performance

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

Average energy prices decreased dramatically during the first quarter of 2017. Monthly average day-ahead energy prices decreased from around $35/MWh in December to less than around $23/MWh in March. This coincided with increased output from renewable resources and relatively low loads. Prices in the 15-minute market continued to be consistently lower than day-ahead prices and moved in about the same direction and magnitude of day-ahead prices each month. Prices in the 5-minute market were lower than both day-ahead and 15-minute market prices during each month of the quarter. On average, 5-minute market prices in March were notably low at about $17/MWh. This was the lowest average monthly 5-minute market price during the past several years.

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



Price spikes were relatively infrequent in both the 15-minute and five-minute markets. As shown in Figure E.1, average prices in the 5-minute market were lower than both day-ahead and 15-minute market prices in each month this quarter. Prices above $250/MWh were observed in only about 0.1 percent of intervals in the 15-minute market and 0.6 percent of intervals in the 5-minute market. Prices higher than $750/MWh occurred during about 0.4 percent of intervals during the quarter in the 5-minute market, compared to 0.6 percent of intervals in the previous quarter and 0.3 percent of intervals in the first quarter of 2016. These high prices largely resulted from resource ramping limitations during periods when solar generation ramped off-line and system load increased toward evening peaks

Negative prices occurred more frequently in both the day-ahead and real-time markets. For the first time, negative prices were relatively frequent in the day-ahead market. Prices fell below zero in over 50 hours in the first quarter, around 10 percent of hours between hours ending 11 and 15. The frequency of negative prices increased in the real-time market as well, reaching about 10 percent of intervals in the 15-minute market and 13 percent of intervals in the 5-minute market. Lower prices during the middle of the day corresponded to periods when low-priced solar generation was greatest, and net demand was lowest. Solar generation continued to grow in the ISO during the quarter as utility scale solar set a new record at around 9,700 MW on March 28. There continue to be few intervals when the price was below -$50/MWh or less, and the price was almost never set by the power balance constraint penalty parameter for excess generation at -$155/MWh.

Congestion was low in the day-ahead market. Day-ahead congestion in the San Diego Gas and Electric area increased prices by about $1/MWh during the quarter. This congestion was because of enforcement of operating procedures to mitigate for contingencies and adjustments to transfer limits to account for outages. Day-ahead congestion had little overall impact on market prices in the Southern California Edison and Pacific Gas and Electric load areas. Congestion in the 15-minute market occurred less frequently than in the day-ahead market, but had larger effects on prices, similar to prior quarters. Overall, congestion had the largest impact on San Diego Gas and Electric, where the Crosstrip constraint bound somewhat frequently.

Auction revenues from congestion revenue rights continue to fall short of payments made by ratepayers this quarter. In the first quarter of 2017, congestion revenue rights auction revenues were $12 million less than congestion payments made to non-load-serving entities purchasing these congestion revenue rights. This represents only $0.65 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, down slightly from $0.68, the annual average in 2016. Financial participants continued to earn the highest profits at $10 million (paying 52 cents in the auction per dollar of congestion revenue rights revenue), followed by marketers at $1.5 million (paying 86 cents per dollar of revenue), then generators at $0.5 million (paying 83 cents per dollar of revenue). Load-serving entities gained about $1 million from rights they explicitly sold in the auction in first quarter of 2017, up from negative $0.20 million in the same quarter of 2016.

Bid cost recovery payments increased. Overall bid cost recovery payments were $22 million in the quarter, somewhat higher than the quarterly average for 2016. Real-time bid cost recovery remains the largest category of bid cost recovery and totaled about $13 million in the first quarter, up from $11 million in the last quarter. At $4 million, day-ahead bid cost recovery payments continued to be low. Bid cost recovery payments for residual unit commitment totaled about $5 million, accounting for a large part of the increase in bid cost recovery payments this quarter.

Virtual bidding revenues were negative. Net revenues, after accounting for bid cost recovery charges, increased to negative $0.1 (a payment) from negative $2.6 million in the fourth quarter. Revenues for virtual supply and demand totaled $4.6 million, which was smaller than bid cost recovery charges of $4.7 million. Total cleared virtual volume continued to decrease in the first quarter to about 2,100 MW on average compared to 2,600 MW in the previous quarter.

Special issues

The ISO has moved forward on recommendations from DMM on the load bias limiter. DMM has provided recommendations to the ISO on how the load bias limiter feature might be enhanced to better reflect the impact of excessive load adjustments on creating power balance relaxations. Specifically, DMM has recommended considering the adjustment based on a combination of factors including the *change* in load adjustment from one interval to the next and the *duration* of an adjustment rather than solely the *absolute* value of any load adjustment. The ISO hosted a call with stakeholders regarding implementing these changes and posted a white paper on the ISO website outlining the proposed changes.[1] DMM is supportive of the proposed changes and has posted a whitepaper assessing their impact.[2]

The load bias limiter decreased average 5-minute market prices in the ISO by around $2/MWh during the quarter and had a small impact on energy imbalance market prices. Had the proposed load bias limiter been active during the quarter instead of the current load bias limiter, it would have decreased 5-minute market prices in the ISO by around $0.50/MWh, significantly less than the current load bias limiter.

The flexible ramping product was implemented in November. The flexible ramping product replaced the flexible ramping constraint on November 1. The flexible ramping product differs from the flexible ramping constraint in several important ways. First, the constraint procured flexibility in only the upward direction in the 15-minute market, whereas the new mechanism procures flexibility up and down in both the 5-minute and 15-minute markets. Second, the amount of flexibility procured and the willingness to pay for the flexibility procured by the new product is determined by a sloped demand curve, rather than a set price-quantity pair at $60/MWh. Third, the new mechanism compensates units providing flexibility, and charges resources that are creating more need for flexibility.

A demand curve is generated for the ISO area, each balancing area in the energy imbalance market, and the aggregate of all areas.[3] Each specific curve is calculated as the expected cost of a power balance relaxation for each amount of flexible capacity procured for that region. The probability of a power balance constraint relaxation is calculated using historical net load forecast error, and not historical ramping needs. For more information about the flexible ramping product and the calculation of the flexible ramping product demand curves, see DMM's 2016 annual report.[4]

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1 *Load Conformance Limiter Enhancement*, December 28, 2016: http://www.caiso.com/Documents/TechnicalBulletin_LoadConformanceLimiterEnhancement.pdf.

2 *Comments on the Load Conformance Limiter Enhancement,* Department of Market Monitoring, May 19, 2017. http://www.caiso.com/Documents/DMMComments-LoadConformanceLimiterEnhancement.pdf

3 See Section 4.1 of this report for additional details about formation of the flexible ramping product demand curves.

4 *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, pp. 109-120: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

Although flexible ramping payments increased with the implementation of the flexible ramping product, payments per megawatt-hour of load remained low.[5] Average net payments per megawatt-hour of load during the first quarter were about $0.11/MWh, an increase from about $0.07/MWh during November and December. Total payments to generators increased following implementation of the flexible ramping product, and continued to increase in the first quarter. Total payments for flexible ramping capacity in the first quarter were about $9.2 million. About 52 percent of payments during the quarter were to ISO generators, which reflects the majority of flexible ramping capacity awards.

DMM is recommending refinements in special Aliso Canyon measures adopted last year. Following a significant natural gas leak in late 2015, the injection and withdrawal capabilities of the Aliso Canyon natural gas storage facility in Southern California were severely restricted. The ISO has developed a set of operational tools to manage potential gas system limitations that allows operators to restrict the gas burn of ISO natural gas-fired generating units. In the first quarter of 2017, the ISO enforced two gas constraints (San Diego Gas and Electric system and the broader Southern California Gas Company system) on four days, from January 23 -26. These constraints do not appear to have been sufficient, on their own, to limit gas burn from participating gas resources.

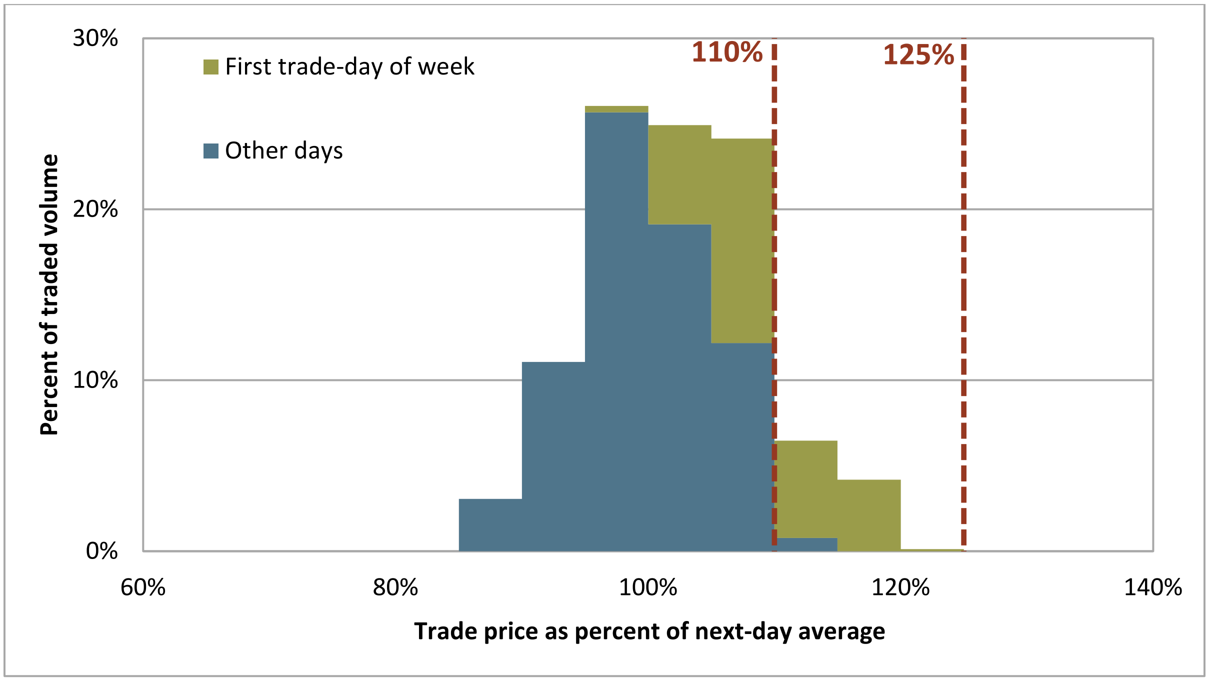
The effectiveness of the ISO's market power mitigation procedures may be adversely affected if operators enforce the gas burn constraints. The gas burn constraints would limit the amount of generation available to relieve congestion on a transmission constraint in a way that market power mitigation procedures would not account for. A transmission path may therefore be deemed competitive when in fact the amount of supply that can be dispatched to relieve congestion on these constraints is more restricted and uncompetitive because of the constraints. To address this limitation, the temporary tariff amendments include the authority for the ISO to deem transmission paths uncompetitive. Because of the limited use of the gas burn constraints during 2016 and 2017, this feature was also not used.

The existing manual dynamic competitive path assessment override process was meant to function as an emergency stop gap measure. It is a reactive process that is both less transparent and less capable than an automated process would be. Including the impacts of any and all gas nomograms in the automated dynamic competitive path assessment should be a necessary precursor to any decision to extend the nomograms beyond their current use and sunset date.

The Aliso measures also include the addition of real-time gas price scalar adjustments for the fuel component of default energy bids (25 percent) and commitment costs bids (75 percent). DMM's analysis of same day natural gas prices in Southern California in the first quarter shows that these adders caused gas prices used to calculate bid caps to exceed prices of all but a very small portion of natural gas transactions. Figure E.2 shows same-day trade prices for the SoCal Citygate during January through March 2017 compared to the next-day average price. Only 10 percent of traded volume on ICE exceeded the normal 110 percent scalar adder at the SoCal Citygate and none of the traded volume exceeded the 125 percent adder. Figure E.2 also shows that the majority of trades above the 110 percent level occurred on days that were the first trading day of the week, which was typically a Monday (as shown in green on the chart). Hence, this analysis shows that there was a very limited need for the increased bidding flexibility created by raising the commitment cost and default energy bid caps during the first quarter. DMM has recommended to the ISO that it review and reduce Aliso Canyon related gas bid adders used in the real-time market.

[5] Load is measured as the total load in the ISO and energy imbalance market areas.

Figure E.2 Same-day trade prices compared to next-day index (January – March)



Net Import lack flexibility in real-time. During the quarter imports accounted for the greatest share of average hourly generation in the real-time market at over 6,000 MW. However, the portion of these imports bid into the 15-minute market and available to receive dispatch instructions only totaled about 500 MW (7 percent) per hour on average. By contrast, gas generation provided the most flexibility in the ISO, with about 3,000 MW (81 percent) per hour on average. Solar generation offered greater economic flexibility than imports, despite its intermittent nature. Similarly, a greater proportion of both solar and wind resources were bid flexibly into the 15-minute market. As more renewable generation is added to the generation fleet in California to meet renewable portfolio standard goals, economic bids for imports can help the market resolve surplus supply conditions and avoid curtailment of self-schedules.

1 Market performance

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

- For the first time, negative prices were relatively frequent in the day-ahead market. Prices fell below zero in over 50 hours in the first quarter, all during midday hours when solar generation was greatest. Day-ahead prices were negative in around 10 percent of hours between hours ending 11 and 15. Real-time prices during the quarter were negative during about 10 percent of intervals in the 15-minute market and 13 percent of intervals in the 5-minute market.

- Despite an increased frequency of negative day-ahead and real-time prices, average prices during the quarter remained higher than the first quarter of 2016. This was primarily the result of increased natural gas prices from early 2016.

- Average day-ahead, 15-minute, and 5-minute market prices declined through the quarter. Lower prices at the end of the quarter were the result of increased hydro and solar generation combined with seasonally low loads.

- Solar generation increased to about 6,000 MW per hour during the midday hours, and a new peak solar output was set at about 9,700 MW in March.

- Average day-ahead prices continued to be about $2/MWh above 15-minute prices during the quarter, resulting from more solar availability in the real-time market than the day-ahead market.

- The frequency of negative prices in the 15-minute and 5-minute markets increased significantly during the quarter, particularly in March when prices below $0/MWh occurred during about 16 percent and 21 percent of intervals, respectively. As a result, prices in the 5-minute market were lower than day-ahead and 15-minute market prices during most hours in the quarter, and about $4/MWh lower in March. The frequency of negative prices in the 5-minute market in March was higher than any month in ISO history.

- During the first quarter of 2017, congestion revenue rights auction revenues were $12 million less than congestion payments made to non-load serving entities purchasing these rights. This represents about $0.65 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, comparable to the first quarter of 2016.

- In the day-ahead and 15-minute markets, congestion increased prices in the San Diego Gas and Electric area. Real-time congestion increased San Diego Gas and Electric area prices by more than $1/MWh (4 percent) in the 5-minute market and about 2 percent in the 15-minute market. The main driver was enforcement of the Crosstrip nomogram, which prevents overload on parallel 230 kV lines when there is a contingency on a third constraint: the TL50001 line (Imperial Valley – Miguel 500 kV).

- Bid cost recovery payments were $22 million in the first quarter, slightly higher than average costs in 2016. Real-time bid cost recovery remains the largest category of bid cost recovery and totaled about $13 million, comparable to average real-time costs in 2016.

- For the second consecutive quarter convergence bidding was slightly unprofitable, after accounting for bid cost recovery charges, with losses totaling about $100,000. The percent of virtual supply and demand bids offered into the market that cleared and related average hourly volume cleared decreased to a record low at about 31 percent and 2,100 MW, respectively.

1.1 Energy market performance

Energy market prices

This section assesses energy market efficiency 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 1.1 shows average monthly system marginal energy prices during all hours. As seen in this figure, average prices decreased significantly during the first quarter. Prices decreased relative to the previous quarter due to increased output from renewable resources and relatively low loads. However, prices in the first quarter of 2017 were high relative to the same quarter of 2016. This was primarily the result of increased natural gas prices.

- Average day-ahead, 15-minute, and 5-minute market prices decreased during every month of the first quarter from around $35/MWh in December 2016 to less than $23/MWh in March 2017.
- Day-ahead market prices continued to be higher than 15-minute market prices, averaging about $2/MWh above 15-minute market prices during the quarter.
- Average 5-minute market prices were lower than day-ahead and 15-minute market prices during all months of the quarter. 5-minute market prices in March were notably low at about $17/MWh. This was the lowest average monthly 5-minute market price during the past several years.

Figure 1.2 illustrates system marginal energy prices on an hourly basis in the first quarter compared to average hourly net load.[6] Prices in this figure generally follow the net load pattern; energy prices were lowest during the early morning, mid-day, and late evening hours, and were highest during the morning and evening peak load hours. Lower prices during the middle of the day corresponded to periods when low-priced solar generation was greatest, and net demand was lowest.

Solar generation continued to grow in the ISO during the quarter as utility scale solar set a new record at around 9,700 MW on March 28. As additional solar is built and interconnected with the system, net loads and average system prices during the middle of the day may continue to decrease. This is a result of less expensive units setting prices during periods when net demand is lower, driven by increases in solar or other renewable generation.

Figure 1.2 also shows that average prices in the day-ahead market were higher than 15-minute market prices during most hours of the day. Notably, prices in the day-ahead market were higher than 15-minute prices in hours ending 11 through 16. In these hours, day-ahead prices averaged about $4/MWh higher than 15-minute market prices because of additional solar generation bidding or scheduling into the real-time market compared to the day-ahead market. During hours ending 8 through 10, average prices in the 5-minute market were about $17/MWh lower than day-ahead and 15-minute market prices because of over-supply conditions from solar generation ramping up and south-to-north congestion.

6 Net load is calculated by subtracting the generation produced by wind and solar that is directly connected to the ISO grid from actual load.

Figure 1.1 Average monthly prices (all hours) – system marginal energy price

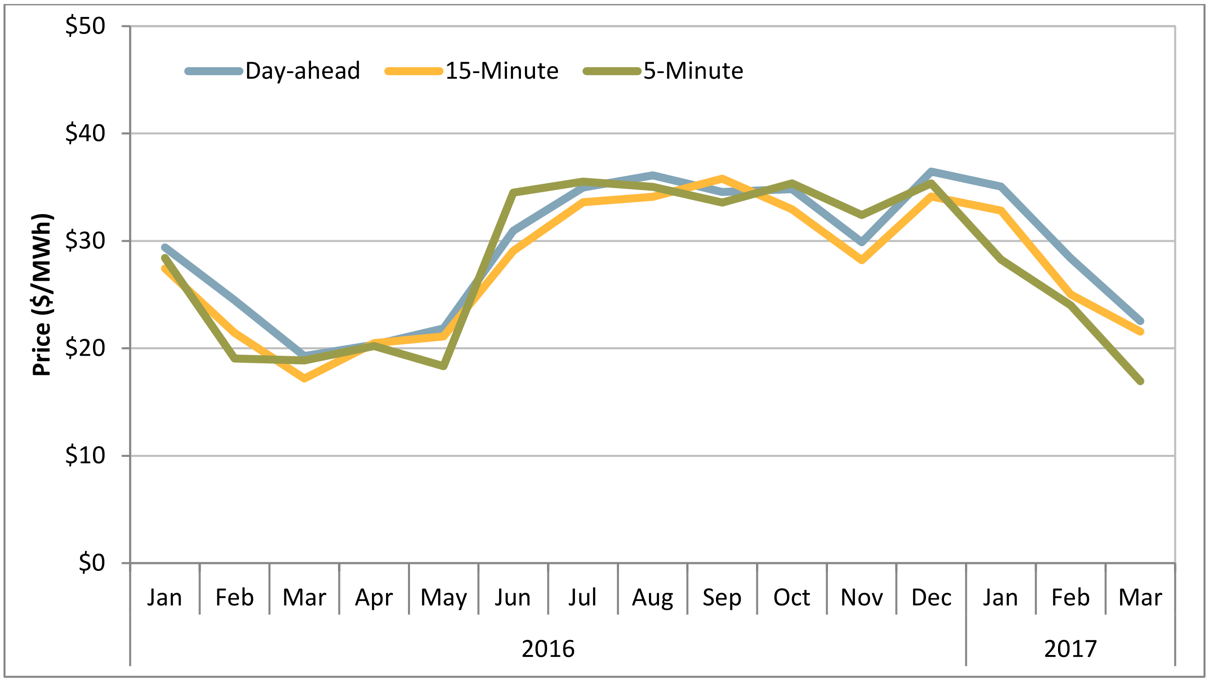
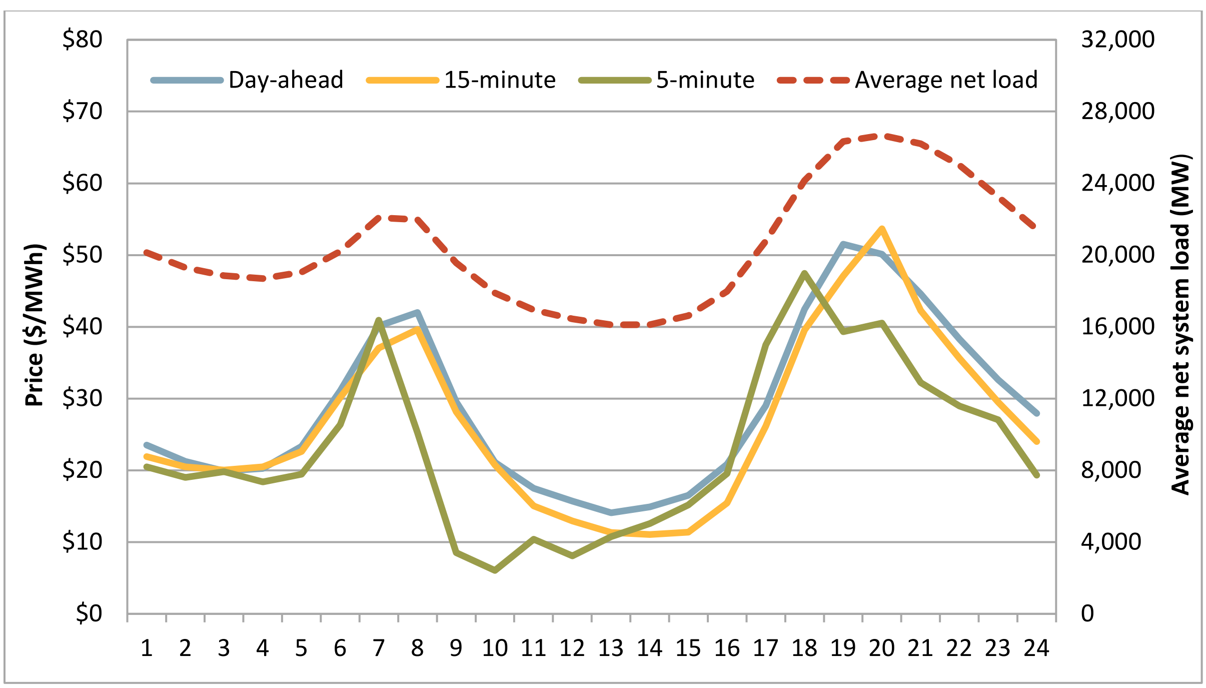


Figure 1.2 Hourly system marginal energy prices



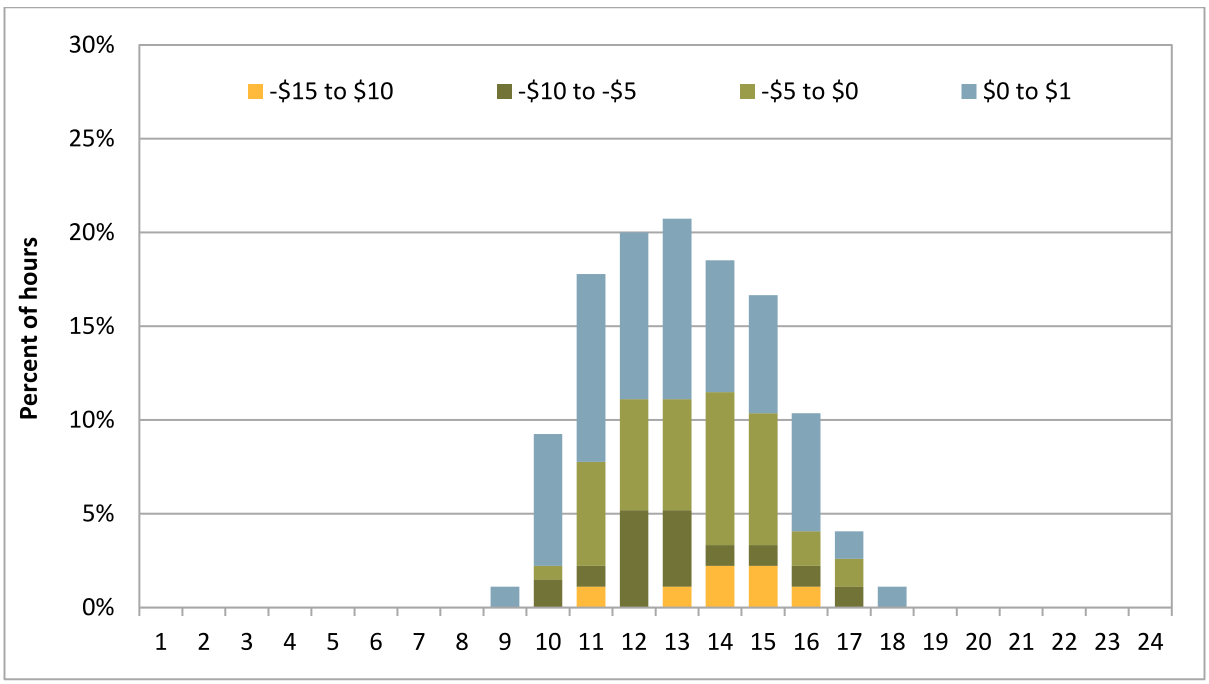
Negative day-ahead market prices

Negative prices were relatively frequent in the day-ahead market during the first quarter. There were 51 hours when day-ahead prices were negative, about 2 percent of all hours in the quarter. In comparison, day-ahead market system marginal energy prices were negative during only three hours during all of 2016. More frequent negative prices in the day-ahead market were the result of additional installed renewable capacity and additional generation from hydro resources.

Figure 1.3 shows the frequency of negative prices near or below $0/MWh in the day-ahead market by hour during the first quarter. Negative prices in the day-ahead market occurred during midday hours in late February and all of March, when solar generation was greatest and loads were seasonally mild. During the first quarter, day-ahead prices were negative during around 10 percent of hours between hours 11 through 15. Negative prices occurred more frequently on weekends when loads were lower.

During the majority of hours that day-ahead prices were negative, prices in the real-time market continued to be more negative. Negative prices in the day-ahead market during the quarter reflected real-time prices.

Figure 1.3 Hourly frequency of day-ahead prices near or below $0/MWh



1.2 Real-time price variability

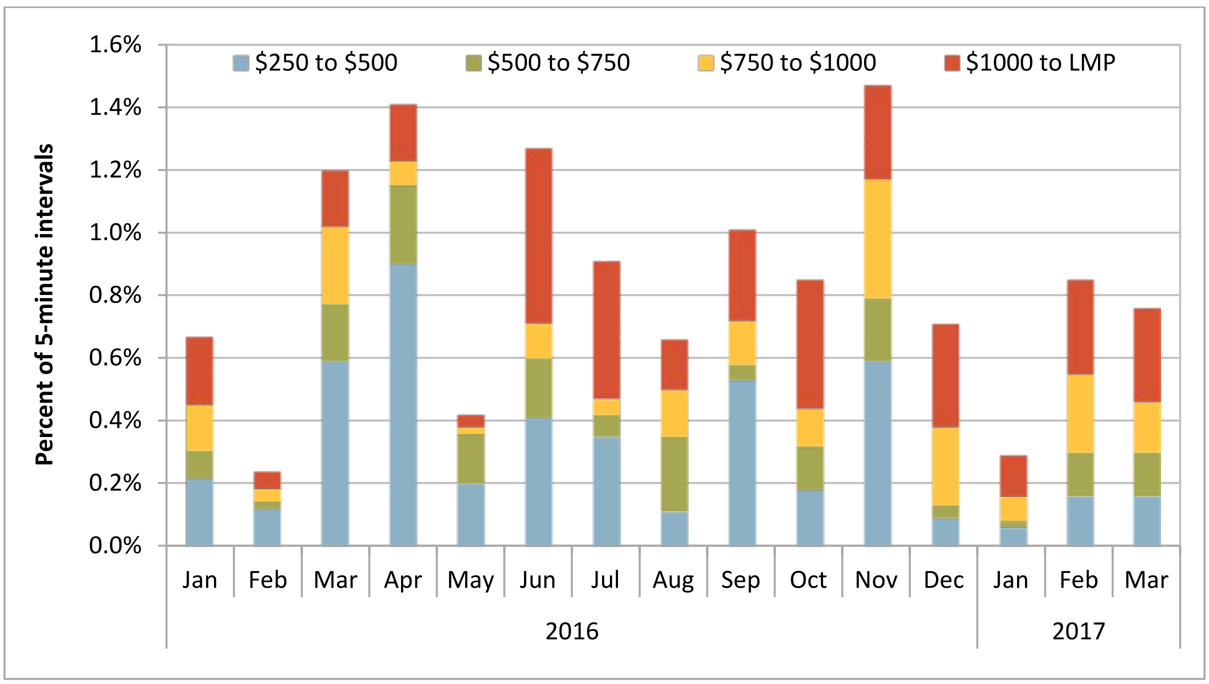
Real-time market prices can be highly volatile with periods of extreme positive and negative prices. Even a short period of extremely high or low prices can have a significant impact on average prices. During the quarter, most of the extreme prices occurred as a result of very high or negatively priced bids clearing the market. In some instances, extremely high or low prices were the result of relaxing the power balance constraint to resolve the feasibility of the dispatch.

High prices

The frequency of high prices during the first quarter decreased in the 15-minute and 5-minute markets compared to the prior quarter. Figure 1.4 shows the frequency of positive price spikes occurring in the 5-minute market by month. Prices above $250/MWh were observed in only about 0.1 percent of intervals in the 15-minute market and 0.6 percent of intervals in the 5-minute market.

Prices higher than $750/MWh occurred during about 0.4 percent of intervals during the quarter in the 5-minute market, compared to 0.6 percent of intervals in the previous quarter and 0.3 percent of intervals in the first quarter of 2016. Price spikes greater than $750/MWh occurred most frequently during hours ending 17 and 18, at more than 2 percent of intervals. These high prices largely resulted from resource ramping limitations during periods when solar generation ramped off-line and system load increased toward evening peaks. During these intervals, steep increases in net load exceeded flexible ramping capacity procured through the flexible ramping product and required the power balance constraint to be relaxed because of insufficient available incremental energy.

Figure 1.4 Frequency of high 5-minute prices by month



Negative prices

When a generator is dispatched down economically the market arrives at a solution by matching supply and demand. Units with negative bids can be dispatched down accordingly. During these intervals the market continues to function efficiently, and the least expensive generation serves load, while more expensive generation is dispatched down.

When the supply of economic bids to decrease energy are exhausted, the power balance constraint can be relaxed up to the regulation requirement to reflect the role regulation plays in balancing the system. Past this, self-scheduled generation can be curtailed including self-scheduled wind and solar output.

During nearly all of the intervals in the first quarter when prices were negative, the market economically dispatched generation down and did not have to curtail self-scheduled generation.

The frequency of negative prices increased significantly in both the 15-minute and 5-minute markets during the first quarter, compared to the prior quarter and the first quarter of 2016. Similar to the negative day-ahead prices discussed above, this increase was driven by a growth in installed renewable capacity and increased hydro generation. Most of the negative prices in the 15-minute and 5-minute markets were between -$50/MWh and $0/MWh and were the result of economic bids from renewable generation, particularly solar resources, setting market prices. Prices were negative in the 15-minute market during about 10 percent of intervals, and about 13 percent of 5-minute intervals during the quarter.

Figure 1.5 shows the frequency of negative prices in the 5-minute market by month.[7] Negative prices were most frequent in March, at about 20 percent of intervals, when loads were lowest while hydro and solar generation were greatest. This was the highest frequency of negative prices observed during any single month since 2009.

During the first quarter, the frequency of prices near or below the -$150/MWh floor continued to occur infrequently at about 0.2 percent of 5-minute intervals. This indicates a low frequency of intervals when the supply of bids to decrease energy were exhausted and the potential need for self-scheduled generation to be curtailed. In many of these intervals, significant south-to-north congestion limited the amount of available generation with downward flexibility and resulted in power balance constraint relaxations to the regulation requirement. This congestion was driven by adjustments to transmission transfer limits to account for outages.

Figure 1.6 shows the frequency of negative prices by hour in the 5-minute market during the quarter. Negative prices were frequent between hours 9 and 17, when net demand was low and solar generation was greatest. During these hours negative prices occurred during about 23 percent of intervals in the 15-minute market and 32 percent of intervals in the 5-minute market. Solar generation set a new record at about 9,700 MW and averaged just over 6,000 MW during midday hours, compared to about 5,000 during the first quarter of 2016.

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7 Corresponding values for the 15-minute market with Figure 1.5 and Figure 1.6 show a similar pattern but lower percentages of intervals.

Figure 1.5 Frequency of negative 5-minute prices by month

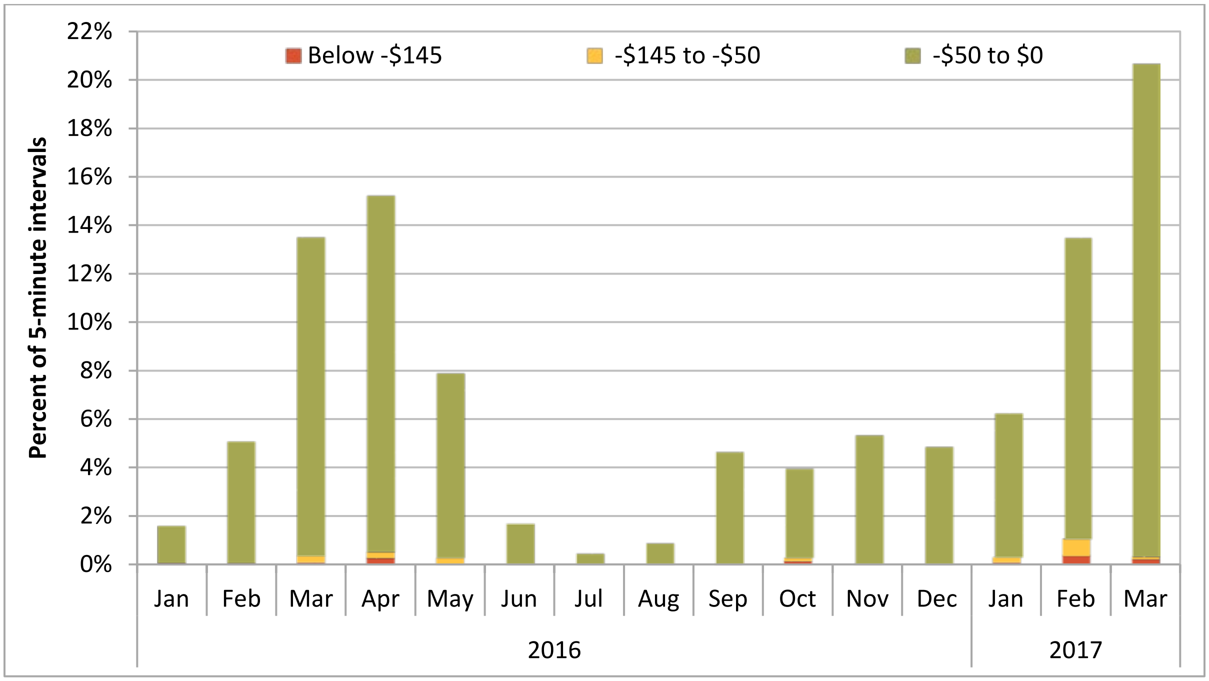
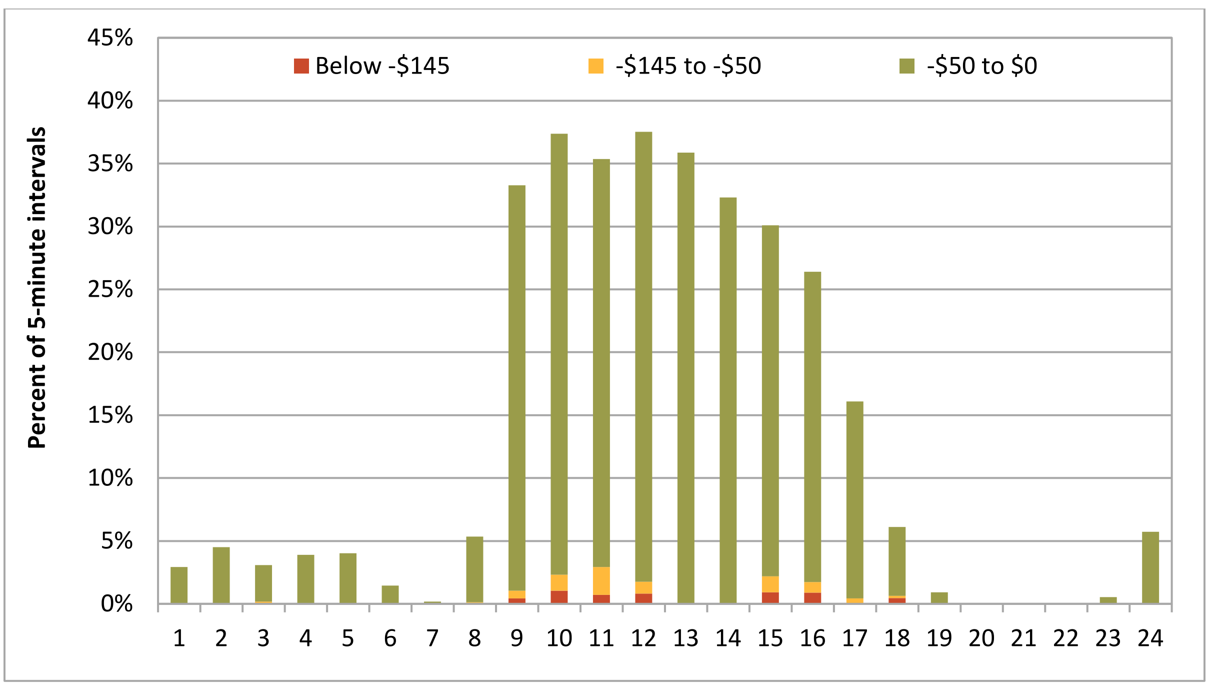


Figure 1.6 Hourly frequency of negative 5-minute prices (January – March)

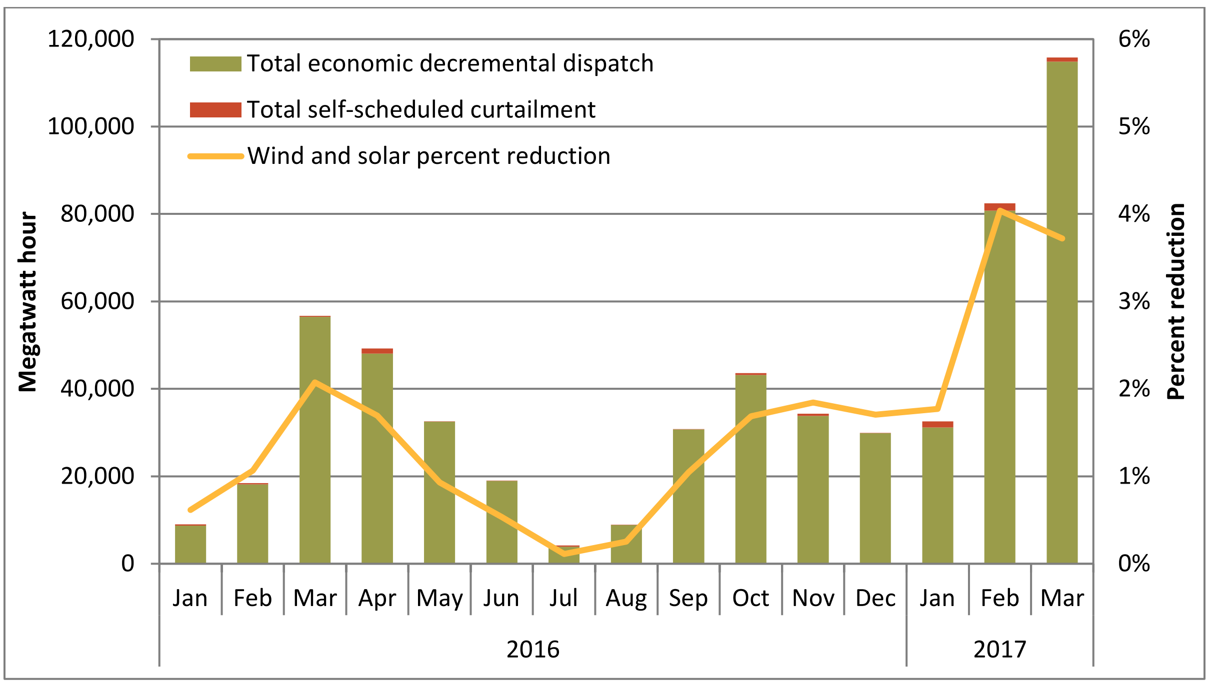


As discussed earlier, the market can resolve oversupply conditions by decrementally dispatching generation. Dispatching wind and solar generation decrementally reduces the output of these resources from their forecasted output level. However, the supply of bids to decrease energy can be exhausted. When sufficient downward ramping capacity is not available during real-time dispatch, the software relaxes the power balance constraint up to 30 MW. After which, self-scheduled generation can be curtailed including self-scheduled wind and solar generation.

Renewable output can be reduced by decrementally dispatching renewable generation and also by curtailing self-scheduled renewable generation. Figure 1.7 shows the total quantity of wind and solar in the ISO that was dispatched down economically as well as curtailments of self-scheduled wind and solar generation. The figure also include these quantities as a percent of total wind and solar forecasts.

Figure 1.7 shows that nearly all of the reductions in wind and solar were economic downward dispatches rather than self-scheduled curtailments. The majority of decremental dispatches to renewable resources were to solar generation, primarily because market participants bid more economic downward capacity for solar than for wind. Because of the increased frequency of negative real-time prices, the total quantity of decremental dispatches to wind and solar generation increased significantly during the first quarter, particularly in February and March where wind and solar output was reduced by around 4 percent from forecast.

Figure 1.7 ISO reduction of wind and solar generation by month



The ISO has released daily and monthly curtailment amounts on the ISO website.[8] Reported quantities describe different measurements than the curtailment amounts reported by DMM in Figure 1.7. In particular, the ISO's curtailment amounts account for upward ramping limitations on wind and solar resources within each 5-minute interval. So, for example, it may not be ramp feasible for a renewable resource to be dispatched back up to its forecast in a single interval after several consecutive intervals of

8 For further information on these amounts see: http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.

downward dispatch. In this case, the ISO calculates curtailment as the difference between the maximum ramp-feasible dispatch level and market dispatch in any interval. DMM's analysis of downward dispatch in any interval accounts for the total dispatch below forecast. This reflects the total reduction in wind and solar generation as a result of oversupply conditions in the market.

1.3 Congestion

In the day-ahead and real-time markets, the overall impact of congestion on load area prices was higher in the first quarter of 2017 compared to the fourth quarter of 2016. Congestion had the largest impact on San Diego Gas and Electric, where the Crosstrip constraint bound somewhat frequently. The Crosstrip nomogram prevents overload on parallel 230 kV lines when there is a contingency on a third constraint: the TL50001 line (Imperial Valley – Miguel 500 kV). The Crosstrip constraint began appearing after a market update in December.[9]

Congestion in the 15-minute market occurred less frequently than in the day-ahead market, but had larger effects on prices, similar to prior quarters. Total congestion impacts at San Diego Gas and Electric increased prices by over $1/MWh (4 percent) in the day-ahead market and about half that in the 15-minute market.

1.3.1 Congestion impacts of individual constraints

Day-ahead congestion

The overall frequency of congestion declined in the day-ahead market.[10] The most frequently binding constraint in the Pacific Gas and Electric area was the set of Path 15 constraints which bound in the south-to-north direction in the first quarter during a total of 7 percent of all hours.[11] When these Path 15 constraints bound, the combined average impact increased Pacific Gas and Electric area prices by about $5/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by about $4/MWh. This congestion was primarily the result of operator adjustments to path limits to mitigate for transmission line outages.

In the San Diego Gas and Electric area, most of the congestion in the first quarter of 2017 was due to the Crosstrip (23040_CROSSTRIP) and Imperial valley- (7820_TL23040_IV_SPS_NG) constraints which are modeled to mitigate for the contingency of TL50001 (Imperial Valley – Miguel 500 kV line). An outage on this line could cause overload on the underlying parallel 230kV lines which would then cause remedial action schemes (RAS) to Crosstrip and open up another 230kV line. These constraints were binding during approximately 28 percent of hours, having a combined price impact of $8/MWh in the San Diego Gas and Electric area and no impact on Southern California Edison area.

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9 The Crosstrip nomogram was discussed in the March, 2017, Market Performance and Planning Forum, slides 4-6: http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum-Mar14_2017.pdf.

10 *Q4 2016 Report on Market Issues and Performance*, March 2017, pp. 16: http://www.caiso.com/Documents/2016FourthQuarterReport-MarketIssuesandPerformanceMarch2017.pdf

11 Path 15 constraints include the frequency and average price impact of PATH15_S-N, OMS 4583153_PATH15_S-N, OMS_4444156_Path15_S_N, OMS 4436916_PATH15_S-N constraints.

Table 1.1 Impact of congestion on day-ahead prices during congested hours[12]

Area	Constraint	Frequency	Q1		
		Q1	PG&E	SCE	SDG&E
PG&E	PATH15_S-N	7.1%	$5.07	-$4.09	-$3.79
	OMS_4654659_LBN_S_N	0.6%	$1.25	-$0.97	-$0.91
	OMS 4621181 LBN_S-N	0.4%	$10.32	-$8.60	-$7.90
SDG&E	23040_CROSSTRIP	15.9%	-$0.22		$3.10
	7820_TL23040_IV_SPS_NG	12.0%	-$0.31		$4.65
	22596_OLD TOWN_230_22504_MISSION _230_BR_1 _1	2.4%			$3.47
	7820_TL 230S_OVERLOAD_NG	2.1%	-$0.17		$2.07
	IID-SCE_BG	1.8%			-$1.24
	92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1	1.6%	-$1.03		$7.27
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	1.5%			-$0.63
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	1.3%			$2.60
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	1.1%			-$3.23
	22865_GRNT HLL_138_22852_TELECYN _138_BR_1 _1	0.9%			$1.90
	OMS 4622069 TL50003	0.6%	-$2.22		$26.39
	OMS 4585329 TL50001_NG	0.5%	-$0.56		$8.30
	OMS 4608811 MG_BK80_NG	0.4%	-$0.10		$2.76

15-minute market congestion

Congestion in the 15-minute market occurred less frequently than in the day-ahead market, but often had larger effects on prices. This is typical of congestion patterns in the real-time market and is similar to patterns in recent quarters. Table 1.2 shows the frequency and magnitude of 15-minute market congestion for the quarter.

In the Pacific Gas and Electric area, similar to the day-ahead market, Path 15 constraints (PATH15_S-N, OMS 4687953_P15_S-N) bound most frequently in the south-to-north direction during the first quarter at about 3 percent of intervals. When Path 15 bound it increased Pacific Gas and Electric area prices on an average by about $13/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by on an average $14/MWh. These constraints bound primarily because of adjustments to transfer limits to account for nearby outages.

In the Southern California Edison area, Path 26 in the north-to-south direction bound frequently at 0.5 percent of the intervals. When it bound, it increased Southern California Edison and San Diego Gas and Electric area prices by about $12/MWh and $11/MWh, respectively while decreasing Pacific Gas and Electric area price by $14/MWh. It was binding because the Path 26 limit was reduced to account for a forced outage on the Midway – Whirlwind 500 kV line.

Similarly, in the San Diego Gas and Electric area, as mentioned earlier, the crosstrip constraint bound most frequently at about 5 percent of all intervals. When binding, it increased San Diego Gas and

[12] This chart shows impacts on load aggregation point prices for constraints binding during more than 0.3 percent of the intervals during the quarter.

Electric area prices by about $11/MWh and had no effect on Pacific Gas and Electric and Southern California Edison load area prices.

As shown in Table 1.2, in the 15-minute market, frequently binding constraints in the ISO such as the Path 15, Path 26 and Crosstrip constraints have had a significant impact on energy imbalance market area prices. The frequency and impact of congestion in the 5-minute is similar to that of 15-minute market.

Table 1.2 Impact of congestion on 15-minute prices during congested intervals[13]

		Frequency	Q1							
Area	**Constraint**	**Q1**	**PG&E**	**SCE**	**SDG&E**	**PACE**	**PACW**	**NEVP**	**PSEI**	**AZPS**
PG&E	PATH15_S-N	2.4%	$15.25	-$16.22	-$15.28	$0.06	$15.54	-$7.18	$15.28	-$13.38
	6110_TMS_DLO	0.8%	$2.54	$3.39	$3.08	-$2.13	-$14.55		-$14.45	$1.65
	OMS 4621181 LBN_S-N	0.4%	$25.62	-$33.28	-$31.51	$2.55	$35.12	-$13.49	$34.55	-$28.28
	OMS 4687953_P15_S-N	0.3%	$10.58	-$12.56	-$11.99	$0.35	$11.42	-$3.77	$11.24	-$10.71
SCE	PATH26_N-S	0.5%	-$14.03	$11.82	$11.19	$1.18	-$9.50	$5.54	-$9.33	$9.95
SDG&E	23040_CROSSTRIP	5.0%			$11.11	-$0.98		-$0.75		-$2.48
	7820_TL 230S_OVERLOAD_NG	1.5%		$0.65	$12.64	-$1.40	-$0.94	-$1.02	-$0.68	-$3.22
	92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1	0.8%			$18.81	-$3.40		-$2.74		-$7.72
	OMS 4622069 TL50003	0.3%		$1.05	$42.46	-$5.11		-$3.70		-$19.91

1.3.2 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. The analysis provided in the previous section focused only on hours where congestion was present. This section is based on the average congestion component as a percent of the total price during all congested and non-congested intervals. This approach shows the impact of congestion when taking into account both the frequency with which congestion occurs and the magnitude of the impact.[14] The congestion price impact differs across load areas and markets.

The impact of congestion 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 1.3 shows the overall impact of day-ahead congestion on average prices in each load area during the quarter by constraint.[15] The impact of congestion increased San Diego Gas and Electric and Pacific Gas and Electric area prices by about $1.23/MWh (4 percent) and $0.26/MWh (0.9 percent),

13 Details on constraints binding in less than 0.3 percent of the intervals have not been reported.

14 This approach identifies price differences caused by congestion and does not include price differences that result from transmission losses at different locations.

15 Details on constraints with shift factors less than two percent have been grouped in the 'other' category.

respectively, and decreased Southern California Edison area prices by about $0.30/MWh (1 percent). In the San Diego Gas and Electric area, the constraints (7820_TL23040_IV_SPS_NG and 23040_CROSSTRIP) had a combined price impact of $1/MWh. In the Pacific Gas and Electric area, the Path 15 constraint in the south-to-north direction had a price impact of $0.25/MWh.

Table 1.3 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
PATH15_S-N	$0.25	0.83%	-$0.21	-0.74%	-$0.19	-0.64%
7820_TL23040_IV_SPS_NG	-$0.04	-0.13%			$0.56	1.88%
23040_CROSSTRIP	-$0.03	-0.12%			$0.49	1.66%
OMS 4622069 TL50003	-$0.01	-0.04%			$0.15	0.49%
92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1	-$0.02	-0.06%			$0.11	0.39%
OMS 4621181 LBN_S-N	$0.04	0.15%	-$0.04	-0.13%	-$0.03	-0.11%
22596_OLD TOWN_230_22504_MISSION _230_BR_1 _1					$0.08	0.28%
OMS 4583153_PATH15_S-N	$0.03	0.10%	-$0.02	-0.08%	-$0.02	-0.07%
7820_TL 230S_OVERLOAD_NG	$0.00	-0.01%			$0.04	0.15%
OMS 4585329 TL50001_NG	$0.00	-0.01%			$0.04	0.13%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.04	-0.12%
22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1					$0.03	0.11%
OMS_4444156_Path15_S_N	$0.01	0.04%	-$0.01	-0.03%	-$0.01	-0.03%
IID-SCE_BG					-$0.02	-0.07%
OMS_4654659_LBN_S_N	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
22865_GRNT HLL_138_22852_TELECYN _138_BR_1 _1					$0.02	0.06%
OMS 4436916_PATH15_S-N	$0.01	0.02%	$0.00	-0.02%	$0.00	-0.01%
30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	$0.00	0.02%	$0.00	-0.01%	$0.00	-0.01%
OMS 4608811 MG_BK80_NG	$0.00	0.00%			$0.01	0.03%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1					-$0.01	-0.03%
Other	$0.02	0.07%	-$0.02	-0.05%	$0.02	0.08%
Total	**$0.26**	**0.88%**	**-$0.30**	**-1.08%**	**$1.23**	**4.13%**

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.[16] Congestion during the first quarter increased San Diego Gas and Electric and Pacific Gas and Electric area prices by about $0.60/MWh (2 percent) and $0.50/MWh (2 percent), respectively, and decreased Southern California Edison area prices by about $0.50/MWh (2 percent). Similar to the day-ahead market, Path 15 constraint in the south-to-north direction had an impact on all of the load area prices. Surplus generation during high solar periods and operator adjustments to the Path 15 limit to account for transmission outages are the main drivers for congestion on Path 15. The largest price impact in the San Diego Gas and Electric area is due to Crosstrip nomograms with a combined effect of approximately $0.75/MWh.

16 Details on constraints with shift factors less than two percent have been grouped in the 'other' category.

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	$0.36	1.30%	-$0.39	-1.48%	-$0.36	-1.33%
23040_CROSSTRIP					$0.56	2.04%
OMS 4621181 LBN_S-N	$0.09	0.32%	-$0.12	-0.45%	-$0.11	-0.40%
7820_TL 230S_OVERLOAD_NG			$0.01	0.04%	$0.19	0.68%
PATH26_N-S	-$0.07	-0.26%	$0.06	0.24%	$0.06	0.21%
92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1					$0.14	0.52%
OMS 4622069 TL50003			$0.00	0.00%	$0.13	0.49%
OMS 4687953_P15_S-N	$0.03	0.11%	-$0.04	-0.13%	-$0.03	-0.12%
6110_TMS_DLO	$0.02	0.07%	$0.03	0.11%	$0.03	0.09%
OMS_4654659_LBN_S_N	$0.02	0.08%	-$0.02	-0.09%	-$0.02	-0.08%
LBN_S-N	$0.02	0.05%	-$0.02	-0.07%	-$0.02	-0.07%
6310_SOL3_NG_WIN	$0.03	0.09%	-$0.01	-0.05%	-$0.01	-0.04%
22596_OLD TOWN_230_22504_MISSION _230_BR_1 _1					$0.03	0.12%
7820_TL23040_IV_SPS_NG					$0.03	0.11%
Other	$0.03	0.10%	-$0.01	-0.03%	$0.03	0.11%
Total	**$0.52**	**1.86%**	**-$0.50**	**-1.92%**	**$0.63**	**2.32%**

Internal congestion in the energy imbalance market

Table 1.5 shows the frequency of congestion on internal constraints in the energy imbalance market since 2014. During the first quarter of 2017, internal congestion in PacifiCorp East increased slightly compared to previous quarter. Congestion in PacifiCorp East was mainly a result of a modelling enhancement that went in place in the fall of 2016 which resulted in a single constraint binding during most of the 16 percent of intervals in the 15-minute and 17 percent of the intervals in the 5-minute market. In the NV Energy area, the frequency of binding constraints increased significantly to about 10 percent and 12 percent in the 15-minute and 5-minute markets, respectively. This is because NV Energy is actively adjusting transmission elements for accuracy of line ratings and outages. In the rest of the energy imbalance market areas, internal congestion was low, even after an increased number of constraints were enforced following FERC's November 19, 2015, Order.[17]

Persistent low congestion may be a result of the following:

- Each energy imbalance market area may be incorporating some degree of congestion management in their process when making forward unit commitments and developing base schedules.
- Bids may be structured in such a way as to limit or prevent congestion within an energy imbalance market area.

[17] *Order on Proposed Market-Based Rate Tariff Changes*, November 19, 2015, ER15-2281-000: https://www.ferc.gov/whats-new/comm-meet/2015/111915/E-5.pdf.

- Within the PacifiCorp areas, physical limits on local constraints, which are modeled in the full network model, may not be fully reflective of contractual limits that may be enforced through generating base schedules and the amount offered from some resources.

These reasons appear plausible because almost all of the generation within each energy imbalance market area is scheduled by a single entity.

Table 1.5 Percent of intervals with congestion on internal EIM constraints

	2014	2015				2016				2017
	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
15-minute market (FMM)										
PacifiCorp East	0.1%	0.2%	0.2%	0.5%	2.6%	2.2%	0.2%	1.3%	14.9%	16.1%
PacifiCorp West	0.1%	0.0%	0.0%	0.2%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%
NV Energy					0.0%	0.0%	0.1%	0.3%	3.2%	10.3%
Puget Sound Energy									0.0%	0.0%
Arizona Public Service									0.0%	0.0%
5-minute market (RTD)										
PacifiCorp East	0.0%	0.3%	0.2%	0.4%	2.3%	2.2%	0.2%	1.3%	15.2%	17.1%
PacifiCorp West	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.0%
NV Energy					0.0%	0.0%	0.2%	0.3%	3.2%	11.7%
Puget Sound Energy									0.0%	0.0%
Arizona Public Service									0.0%	0.0%

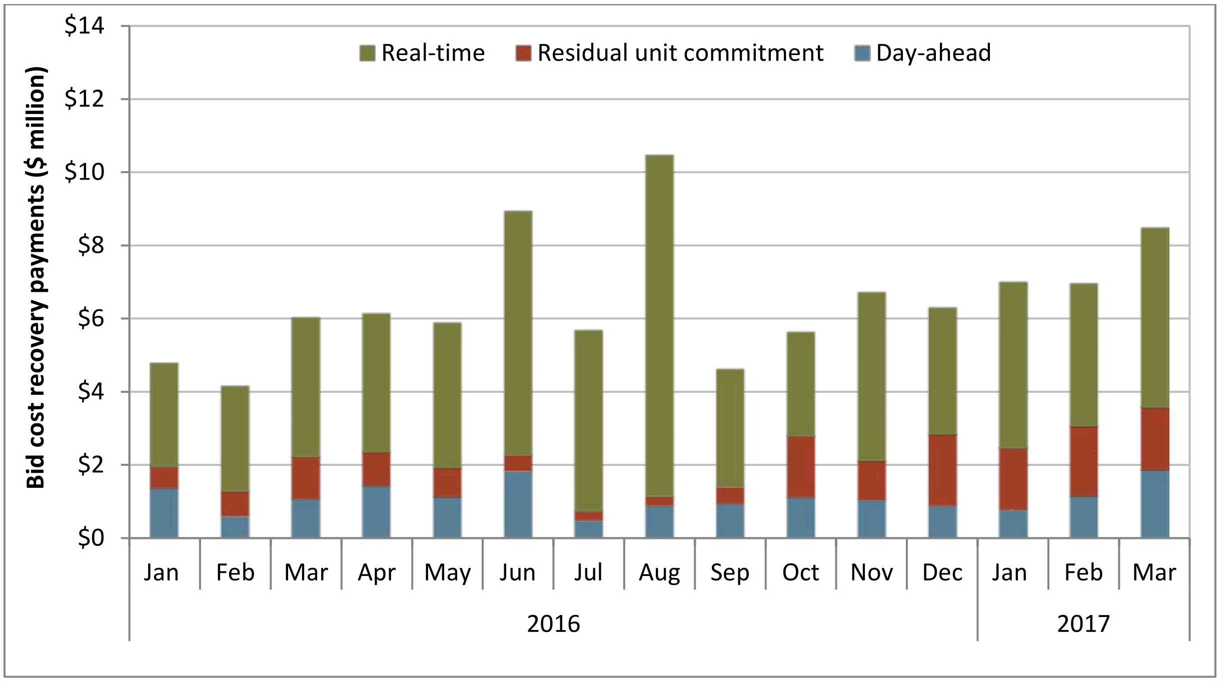
1.4 Bid cost recovery

Estimated bid cost recovery payments for the first quarter totaled about $22 million. This is higher than bid cost recovery payments made each quarter last year. This amount was significantly larger than the total bid cost recovery in the first quarter 2016, when the payments totaled about $15 million, one of the lowest totals in the last five years. The increase in overall bid cost recovery was driven by an increase in bid cost recovery for residual unit commitment.

Bid cost recovery attributed to the day-ahead market totaled about $4 million, or about $1 million larger than the prior quarter and the same quarter during the prior year. In the first quarter, bid cost recovery payments for residual unit commitment totaled about $5 million, the highest amount since 2015. Bid cost recovery payments attributed to the residual unit commitment process were primarily paid to a handful of units, and the costs were spread out relatively evenly over the quarter.

Bid cost recovery attributed to the real-time market totaled about $13 million, comparable to quarterly real-time bid cost recovery payments in 2016. Real-time bid cost recovery payments continued to be somewhat uniformly distributed throughout the quarter with no specific days where payments were particularly large. These real-time bid cost recovery payments were paid to a number of units in the real-time market whose payments were less than variable costs. There was little concentration on particular units and much of these payments did not originate from exceptional dispatches or minimum online commitments.

Figure 1.8 Monthly bid cost recovery payments



1.5 Convergence bidding

Convergence bidding was slightly unprofitable overall during the first quarter, similar to the previous quarter. This was the first time consecutive quarters were not profitable for virtual bidding since its implementation in 2011. Net revenues from the market during the quarter were about $4.6 million. Virtual supply generated net revenues of about $7.3 million, while virtual demand accounted for approximately $2.7 million in net payments to the market. However, combined net revenues for virtual supply and demand totaled negative $0.1 million (payments) after including about $4.7 million of virtual bidding bid cost recovery charges.

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 only about 32 percent of all accepted virtual bids in the first quarter, down from 49 percent in the previous quarter.

Average hourly cleared volumes continued to decrease in the first quarter to about 2,100 MW from about 2,600 MW during the previous quarter. Virtual supply averaged around 1,500 MW while virtual demand averaged around 600 MW during each hour of the quarter, both decreases from the previous quarter.

1.5.1 Convergence bidding trends

Average hourly cleared virtual supply and virtual demand volume continued to decrease in the first quarter to about 2,100 MW from about 2,600 MW during the previous quarter. On average, only about 31 percent of virtual supply and demand bids offered into the market cleared in the first quarter, which is down from 37 percent in the previous quarter. This continues a trend of less cleared volume since the third quarter of 2015 and reflects the lowest quarterly percentage and amount cleared since convergence bidding began in 2011.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 850 MW on average, which increased from 630 MW of net virtual supply in the previous quarter. Virtual supply exceeded virtual demand during both peak and off-peak hours by about 960 MW and 620 MW, respectively. On average for the quarter, net cleared virtual supply exceeded net cleared virtual demand during all hours. The highest net cleared virtual supply hour was hour ending 16 when around 1,550 MW more virtual supply cleared than virtual demand.

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 average price differences between the day-ahead and real-time markets during 22 of 24 hours.

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 because of congestion differences between the day-ahead and real-time markets.

Offsetting virtual positions accounted for an average of about 340 MW of virtual demand offset by 340 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 32 percent of all cleared virtual bids in the first quarter, down from about 49 percent in the previous quarter. This is the lowest quarterly proportion observed in the past five years and continued a downward trend in the proportion of offsetting bids in the market.

1.5.2 Convergence bidding revenues

Participants engaged in convergence bidding in the first quarter paid slightly more into the ISO markets than they received *after* accounting for bid cost recovery charges. This resulted in net payments of about $0.1 million. Revenues before accounting for bid cost recovery charges were $4.6 million. Thus, the net payments by virtual bids were driven primarily by charges associated with bid cost recovery payments.

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.[18] 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, minimum load, transition, and energy bid costs.

Because virtual bids can influence unit commitment, they share any associated costs. Specifically, virtual bids can be charged bid cost recovery payments under two charge codes.

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

Figure 1.9 shows total monthly net revenues for virtual supply (green bar), total net revenues for virtual demand (blue bar), the total amount paid for bid cost recovery charges (red bar), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line). This chart shows that residual unit commitment costs paid for by convergence bidders increased from the previous quarter, as a result of higher overall residual unit commitment costs during the first quarter.

Before accounting for bid cost recovery charges:

- Total market revenues were positive during all three months in the quarter. Monthly net revenues during the first quarter totaled about $4.6 million, compared to about $2.8 million during the same quarter in 2016, and about $1.3 million during the previous quarter.
- Virtual supply was profitable during all three months of the quarter as day-ahead prices were generally higher than 15-minute market prices. In total, virtual supply generated net revenues of about $7.3 million during the quarter before accounting for bid cost recovery charges.
- Virtual demand revenues were negative in all three months of the quarter. In total, virtual demand accounted for around $2.7 million in net payments to the market for the quarter.

After accounting for bid cost recovery charges:

- Convergence bidders paid about $0.1 million after subtracting bid cost recovery charges of about $4.7 million for the quarter.[19,20] Bid cost recovery charges were about $1.3 million in January and about $1.7 million in both February and March.

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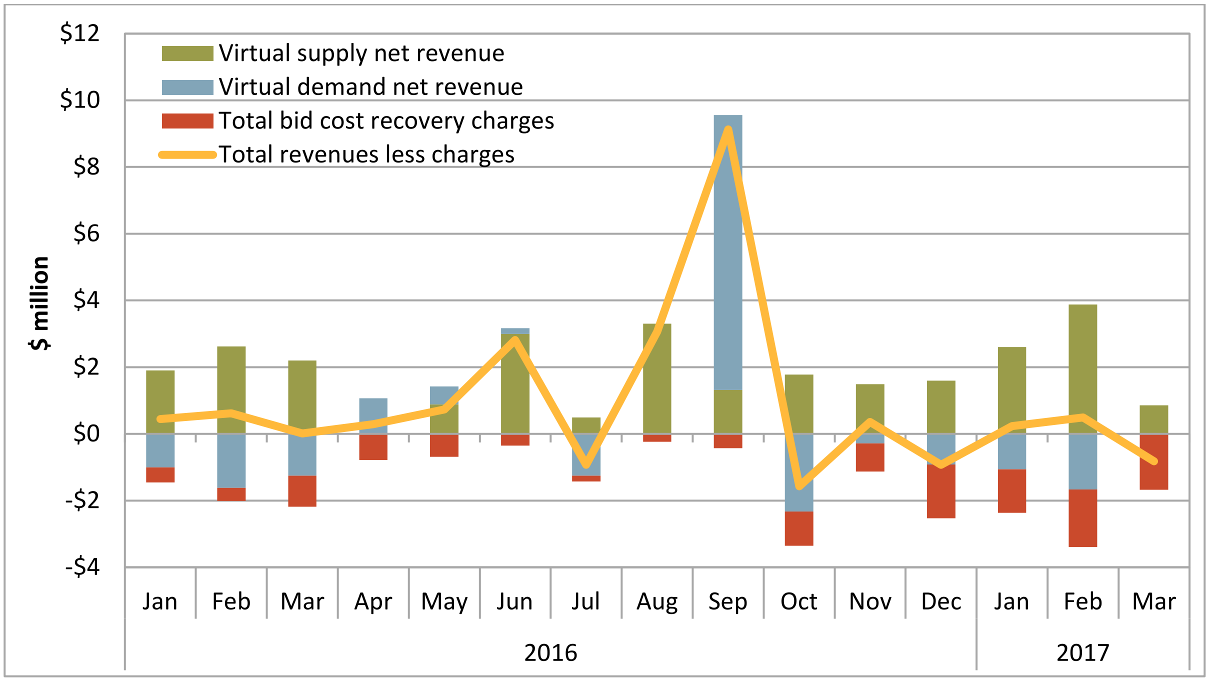
[18] If physically generating resources clearing in the day-ahead energy market are less than the ISO's forecasted demand, the residual unit commitment process ensures that enough additional physical capacity is available to meet the forecast demand. Convergence bidding increases unit commitment requirements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

[19] Further detail on bid cost recovery and convergence bidding can be found here, p.25: http://www.caiso.com/Documents/DMM_Q1_2015_Report_Final.pdf.

[20] Business Practice Manual configuration guide has been updated for CC 6806, day-ahead residual unit commitment tier 1 allocation, to ensure that the residual unit commitment obligations do not receive excess residual unit commitment tier 1 charges or payments. For additional information on how this allocation may impact bid cost recovery, refer to page 3: BPM Change Management Proposed Revision Request.

Figure 1.9 Convergence bidding revenues and bid cost recovery charges



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 in the first quarter.[21] As shown in Table 1.6, financial entities represented the largest segment of the virtual bidding market in terms of volume, accounting for about 49 percent of volume, but only about 33 percent of settlement revenue. Marketers represented about 37 percent of the trading volumes, but a high 44 percent of the settlement revenue. Generation owners and load-serving entities represented a smaller segment of the virtual market in terms of volumes (about 14 percent) and settlement dollars (about 23 percent).

[21] 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 interties 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

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	340	679	1,019	-$2.04	$3.55	$1.51
Marketer	253	513	766	-$0.71	$2.73	$2.02
Physical load	0	189	189	$0.00	$0.73	$0.73
Physical generation	22	82	104	$0.00	$0.33	$0.34
Total	**615**	**1,463**	**2,078**	**-$2.7**	**$7.3**	**$4.6**

1.6 Congestion revenue rights

As discussed in DMM's 2016 annual report, since 2012 electric ratepayers – who ultimately pay for the cost of transmission managed by the ISO – received an average of about $114 million less per year in revenues from the congestion revenue rights auction compared to the congestion payments made to entities purchasing these rights.[22] During the first quarter of 2017, congestion revenue rights auction revenues were $12 million less than congestion payments made to non-load-serving entities purchasing these congestion revenue rights. This represents $0.65 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, which is slightly higher than $0.63 during the first quarter of 2016.

Background

Congestion revenue rights are paid (or charged), for each megawatt held, the difference between the hourly day-ahead congestion prices at the sink and source node defining the right. These rights can have monthly or seasonal (quarterly) terms, and can include on-peak or off-peak hourly prices. Congestion revenue rights are allocated to entities serving load. Congestion revenue rights can also be procured in monthly and seasonal auctions.

The owners of transmission – or entities paying for the cost of building and maintaining transmission – are entitled to congestion revenues associated with transmission capacity in the day-ahead market. In the ISO, most transmission is paid for by ratepayers of the state's investor-owned utilities and other load-serving entities through the transmission access charge (TAC).[23] The ISO charges load-serving entities the transmission access charge in order to reimburse the entity that builds each transmission line for the costs incurred.

[22] *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2017, pp. 191-204, 243-245: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

[23] Some ISO transmission is built or owned by other entities such as merchant transmission operators. The revenues from transmission not owned or paid for by load-serving entities gets paid directly to the owners through transmission ownership rights or existing transmission contracts. The analysis in this section is not applicable to this transmission. Instead, this analysis focuses on transmission that is owned or paid for by load-serving entities only.

Load-serving entities then pass that transmission access charge through to ratepayers in their customers' electricity bills. Therefore, these ratepayers are entitled to the revenues from this transmission. When auction revenues are less than payments to other entities purchasing congestion revenue rights at auction, the difference between auction revenues and congestion payments represents a loss to ratepayers. The losses therefore cause ratepayers, who ultimately pay for the transmission, to receive less than the full value of their day-ahead transmission rights.

As explained in DMM's 2016 annual report, DMM believes that the ratepayer gains or losses from the auction is the appropriate metric for assessing the congestion revenue right auction.[24]

Analysis of congestion revenue right auction returns

As described above, the performance of the congestion revenue rights auction can be assessed by comparing the auction revenues ratepayers received to the ratepayer payments to non-load-serving entities purchasing congestion revenue rights in the auction. Note that payments and charges to ratepayers are through load-serving entities. Figure 1.10 compares the following:

- auction revenues received by ratepayers from non-load-serving entities purchasing congestion revenue rights in the auction (blue bars on left axis);
- net payments from ratepayers to non-load-serving entities purchasing congestion revenue rights in the auction (green bars on left axis); and
- auction revenues received by ratepayers as a percentage of the net payments to non-load-serving entities purchasing congestion revenue rights in the auction (yellow line on right axis).

Ratepayers lost a total of $12 million during first quarter of 2017 as payments to auctioned congestion revenue rights holders exceeded auction revenues. This was a slight increase from nearly $11 million ratepayers lost during the same quarter in 2016.

Auction revenues were only 65 percent of payments made to non-load-serving entities during first quarter of 2017, slightly up from 63 percent during first quarter of 2016.

[24] *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2017, pp. 243-245: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

Figure 1.10 Auction revenues and payments to non-load-serving entities

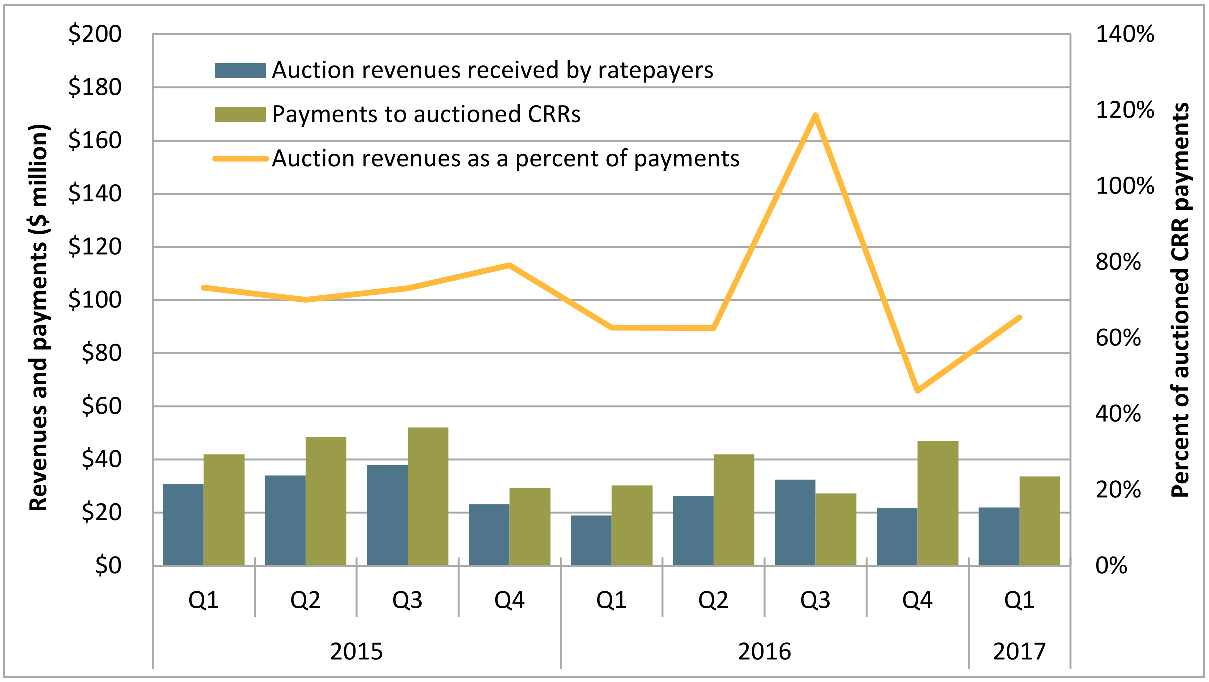


Figure 1.11 through Figure 1.14 show quarterly auction revenues paid to all entities purchasing rights in the auction compared to payments they received broken out by the following entity types:

- Financial entities participate in the ISO markets only through the convergence bidding and congestion revenue right products.
- Marketers participate in the ISO energy markets primarily through intertie transactions, rather than generators or loads internal to the ISO.
- Physical generation and load have generators and loads within the ISO footprint.

Figure 1.11 through Figure 1.14 show congestion revenue right auction results for all four participant types: financial, marketer, generator, and load-serving entity. Similar to Figure 1.10, these charts show quarterly auction revenues and congestion revenue rights payments from 2015 through the first quarter of 2017. Highlights from these figures show the following for the first quarter of 2017:

- Financial entities continued to have the highest profits between the entity types, at approximately $10 million. This was an increase from $8 million in first quarter of 2016. Marketer profits were $1.5 million, slightly lower than $1.9 million in 2016. Generator profits were half a million, down from $1.3 million in the first quarter of 2016.
- Financial entities paid 52 cents in auction revenue per dollar received similar to that of 2016. Generators also paid 83 cents, up from 57 cents in 2016. Marketers paid 86 cents, which was close to what they paid in 2016.
- Load-serving entities were the only auction participant type that, on net, continued to sell rights into the auction from explicit bidding. Load-serving entities gained about $1 million from rights they explicitly sold in the auction in first quarter of 2017, up from negative $0.20 million in the same quarter of 2016.

Figure 1.11 Auction revenues and payments (financial entities)

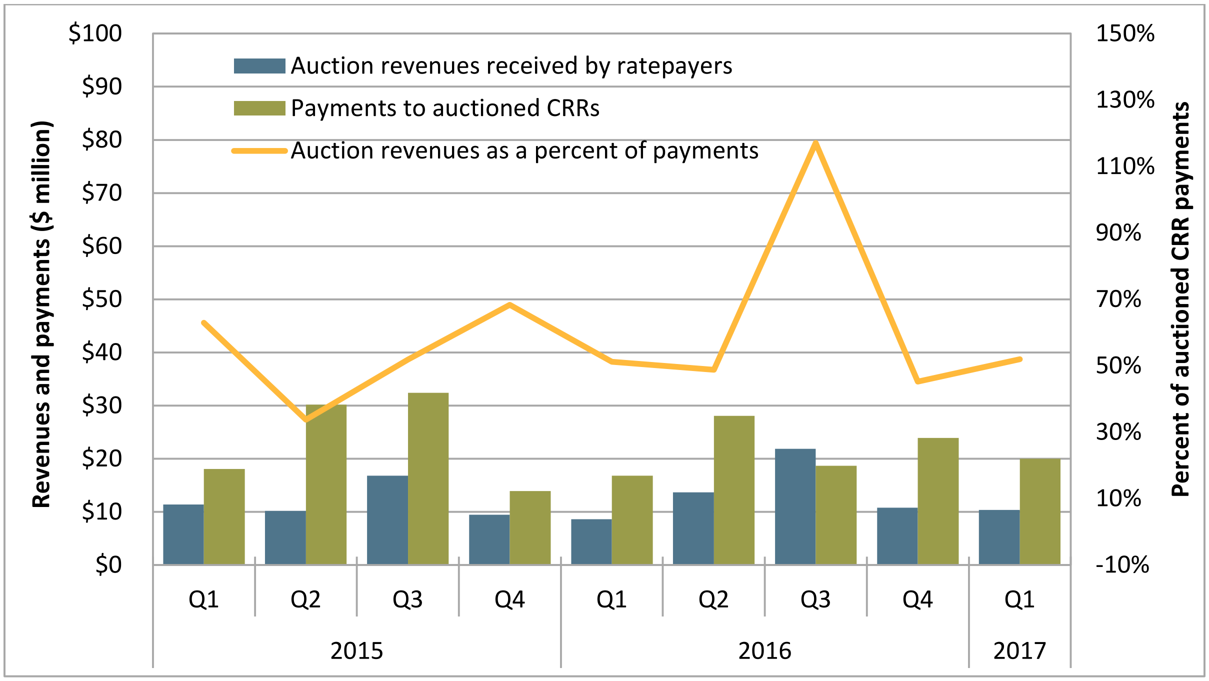


Figure 1.12 Auction revenues and payments (marketers)

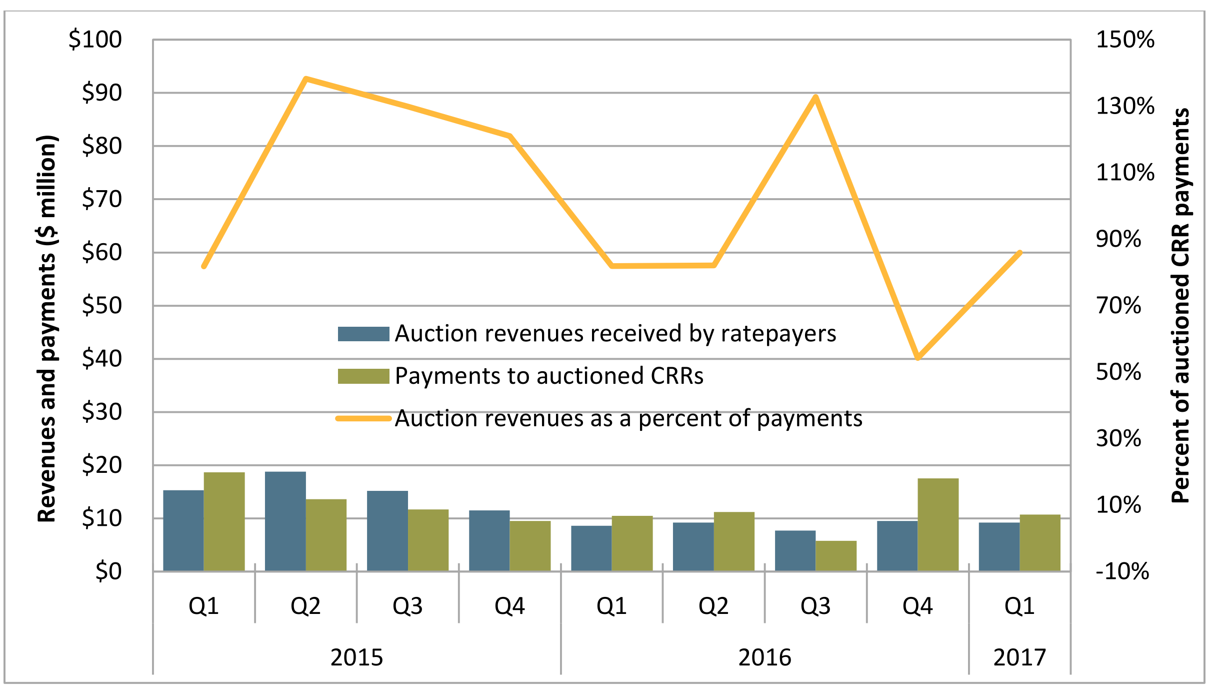


Figure 1.13 Auction revenues and payments (generators)

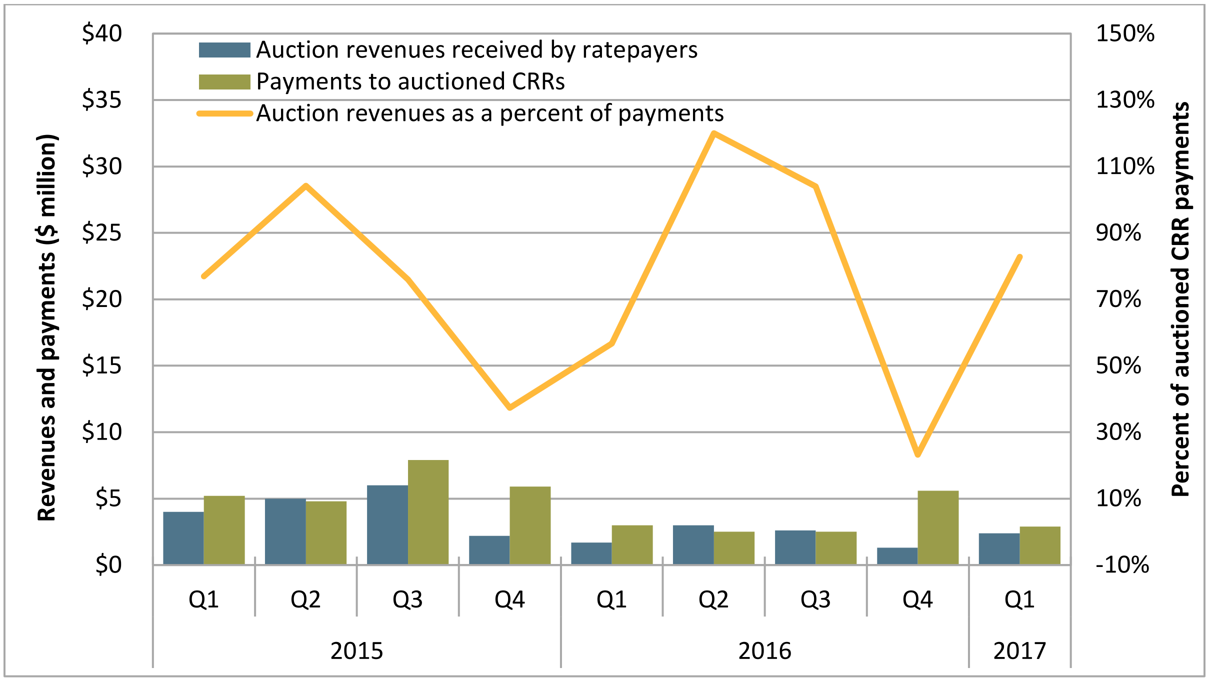
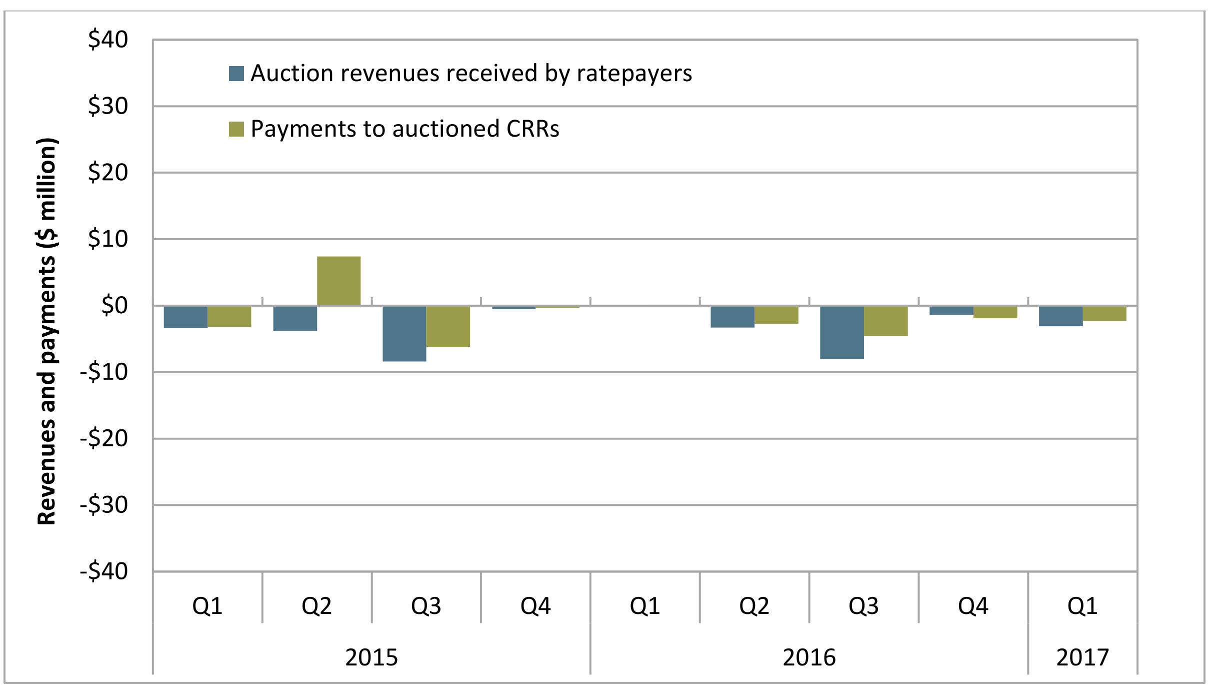


Figure 1.14 Auction revenues and payments (load-serving entities)



Potential improvements to the congestion revenue rights auction

DMM believes that the trend of revenues being transferred from electric ratepayers to other entities warrants reassessing the standard electricity market design assumption that ISOs should auction off these financial instruments on behalf of ratepayers after the congestion revenue right allocations.[25] DMM believes the current auction is unnecessary and could be eliminated. If the ISO believes it is beneficial to the market to facilitate hedging, DMM believes the current auction format should be changed to a *market* for congestion revenue rights or locational price swaps based on bids submitted by entities willing to buy or sell congestion revenue rights.

In response to DMM's recommendation at the June 2016 Board of Governors meeting, ISO management indicated the ISO would consider scheduling an initiative on this issue and included it in the 2017 stakeholder initiative catalog.[26] The ISO is currently planning an initiative to investigate congestion revenue rights auction efficiency slated for the latter half of 2017.[27]

[25] DMM whitepaper on *Shortcomings in the congestion revenue right auction design*, November 28, 2016*:* http://www.caiso.com/Documents/DMM-WhitePaper-Shortcomings-CongestionRevenueRightAuctionDesign.pdf.

[26] 2017 *Stakeholder initiatives catalog*, November 4, 2016, p.27: http://www.caiso.com/Documents/RevisedDraft_2017StakeholderInitiativesCatalog.pdf.

[27] *Policy update – Market performance and planning forum*, January 18, 2017, p.71: http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum_Jan18_2017.pdf.

2 Energy imbalance market

This section covers the energy imbalance market performance during the first quarter. Key observations and findings include the following.

- Overall prices continued to be uniform between PacifiCorp East, NV Energy, Arizona Public Service, and the ISO during most intervals. Price separation that did occur was primarily due to flexible ramping sufficiency test failures and market interruptions.
- Prices in PacifiCorp West and Puget Sound Energy were often lower than the other energy imbalance market areas because of continued congestion from PacifiCorp West into the ISO and PacifiCorp East.
- In early March, the ISO declared an interruption for NV Energy participation in the real-time market. This occurred as a result of a planned outage on a major transmission line that connects the Northern and Southern NV Energy systems. The interruption was declared to allow NV Energy to maintain reliability within their area. A market interruption was also declared for Arizona Public Service for 13 hours on March 17.
- Transition period pricing had significant impacts on prices in Arizona Public Service. Without this mechanism prices would have been less than $10/MWh in both real-time markets, compared to actual average real-time prices of about $18/MWh. The power balance constraint bound frequently because of excess generation during hours when the flexible ramping sufficiency test failed.
- The frequency of valid over-supply power balance constraint infeasibilities in Arizona Public Service increased significantly from the previous quarter. Most of these infeasibilities occurred during intervals when exports were limited from the area because of flexible ramping sufficiency test failures which constrain exports. However, because of special transition period pricing, in place during the quarter for Puget Sound Energy and Arizona Public Service, prices in these areas did not reflect penalty-based pricing.
- The majority of power balance constraint relaxations during the quarter, across all of the energy imbalance market balancing areas, occurred during hours when the area failed the flexible ramping sufficiency test. Balancing areas continued to fail the sufficiency tests frequently. In particular, Arizona Public Service failed the downward sufficiency test very frequently, in over 26 percent of all hours during the quarter.
- The ISO and Puget Sound Energy were net importers in the energy imbalance market, while PacifiCorp areas tended to be net exporters. The direction and volume of transfers between the ISO and different energy imbalance market areas fluctuated significantly based on actual real-time market conditions.
- The available balancing capacity mechanism continued to have a limited impact on reducing the number of power balance constraint relaxations in the first quarter. NV Energy and Puget Sound Energy offered available balancing capacity into the market for most hours in the first quarter, while PacifiCorp East and PacifiCorp West did so infrequently. Arizona offered available balancing capacity less frequently than in prior quarters.

2.1 Energy imbalance market performance

Energy imbalance market prices

Overall prices across all of the energy imbalance market areas decreased during the first quarter, reflecting seasonal system conditions. In general, prices in the energy imbalance market differed between two distinct regions. Average prices in the first region – including PacifiCorp East, NV Energy and Arizona Public Service – tended to be similar to each other and the ISO because of large transfer capacities and little congestion. However, there was some price separation within this region in part because of flexible ramping sufficiency test failures and market interruptions. Prices in the second region – including PacifiCorp West, and Puget Sound Energy – tended to be different than those in the first and the ISO because of limited transfer capability between PacifiCorp West and PacifiCorp East and between the ISO.

Between the evenings of March 6 and March 10, the ISO declared an interruption of NV Energy participation in the real-time market. This occurred as a result of a planned outage on a major transmission line that connects the Northern and Southern NV Energy systems. During this period, energy imbalance market transfers were locked to and from NV Energy. During this time energy imbalance market prices in NV Energy were set by administrative pricing rules that use the last valid 15-minute market and 5-minute market price before the interruption. These rules set prices at about $18/MWh and $45/MWh in the 15-minute and 5-minute markets, respectively, during the interruption period.[28] Additionally, on March 17 a market interruption was declared for Arizona Public Service for 13 hours. During the interruption, transfers were locked and administrative pricing rules were also applied, which set prices at about $16/MWh in the 15-miniute market and about $12/MWh in the 5-minute market.[29]

Figure 2.1 shows hourly average combined 5-minute prices for PacifiCorp East, NV Energy, and Arizona Public Service as well as combined prices for PacifiCorp West and Puget Sound Energy.[30] The figures also show 5-minute market prices for Southern California Edison and Pacific Gas and Electric for comparison with the ISO. Lower hourly prices for PacifiCorp East, NV Energy, and Arizona Public Service than the ISO were mostly the result of greenhouse gas prices, but otherwise tracked closely to system prices.[31]

Prices in PacifiCorp West and Puget Sound Energy often formed a second pricing region. As shown in Figure 2.1, prices here during the morning and evening peak net load periods were often less than prices in the ISO because of limited transmission available from PacifiCorp West into the ISO and PacifiCorp East. Similarly, during the middle of the day, when negative prices reflected oversupply

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[28] At the time of the market interruption a new methodology for administrative pricing had been approved, but not yet implemented in the ISO tariff. During an extended interruption of participation by an Energy Imbalance Market entity in the real-time market when both 15-minute market and 5-minute market results are unavailable, the ISO will use the price specified in the entity's open access transmission tariff as the locational marginal price. For further information see January 30, 2017, *Order Accepting Tariff Revisions – Administrative Pricing Enhancements*: https://www.caiso.com/Documents/Jan30_2017_OrderAcceptingTariffAmendment-AdministrativePricingEnhancements_ER17-415.pdf.

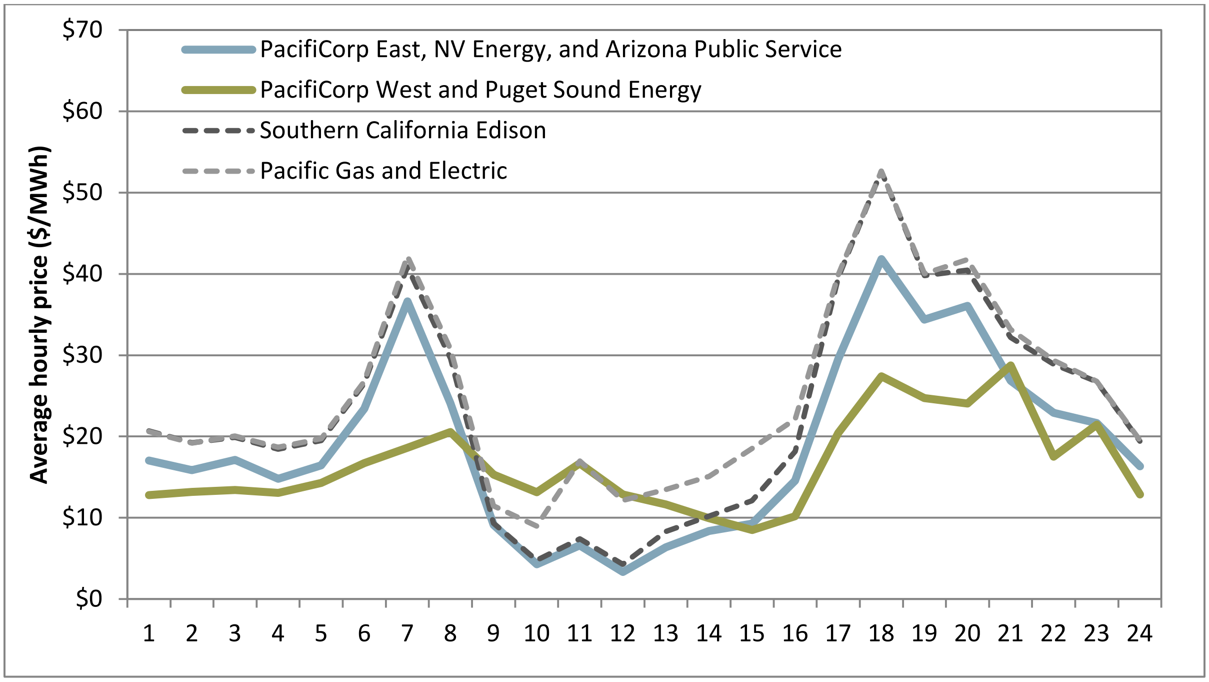
[29] The market interruption in Arizona Public Service was declared because base schedules on interties were not updating.

[30] The individual balancing areas were grouped this way because of similar hourly pricing. Hourly 15-minute market prices show a similar pattern but at higher prices between hours ending 8 through 12 and 20 through 24.

[31] Greenhouse gas prices were typically just over $5/MWh, and were applied to an energy imbalance area when energy was deemed delivered from that area into the ISO.

conditions, prices in PacifiCorp West and Puget Sound Energy were often larger because of congestion into PacifiCorp West.

Figure 2.1 Hourly 5-minute market prices (January – March)



Power balance constraint

When the power balance constraint is relaxed because of insufficient upward ramping capacity (shortage or under-supply), prices could be set using the $1,000/MWh penalty price. Power balance constraint relaxation due to insufficient downward ramping capacity (surplus or over-supply) can set prices at -$155/MWh in the pricing run. Transition period pricing, when active, sets the market price based on the last price bid into the market by a unit when the power balance constraint is relaxed. This mechanism was in effect for Puget Sound Energy and Arizona Public Service throughout the first quarter and expired at the end of March 2017 following their six-month transition period.

During the first quarter, valid under-supply infeasibilities were relatively infrequent, particularly in comparison to levels observed in the energy imbalance market in 2015. Valid under-supply infeasibilities occurred during less than 0.2 percent of intervals in the 5-minute market in each of the energy imbalance market balancing areas. Under-supply infeasibilities in the 15-minute market were less frequent.

As shown in Figure 2.2, the frequency of valid over-supply infeasibilities in Arizona Public Service increased significantly from the previous quarter. Valid-over-supply infeasibilities in Arizona Public Service occurred during about 7 percent of 15-minute intervals and 9 percent of 5-minute intervals during the first quarter, up from about 1 percent of intervals in both markets during the fourth quarter of 2016. However, because special transition pricing was in effect in this area during the quarter, prices during the power balance constraint relaxations were not set at the -$155/MWh penalty parameter for over-supply infeasibilities.

Figure 2.2 Frequency of over-supply power balance constraint relaxation Arizona Public Service

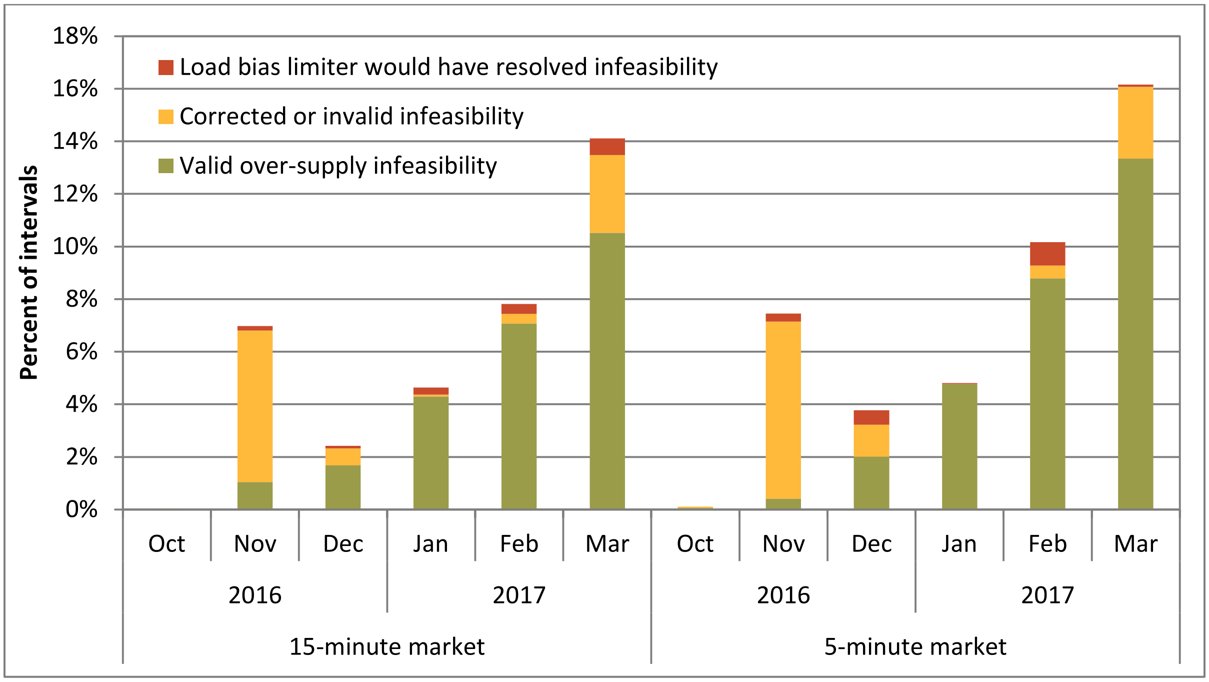


Table 2.1 shows estimated prices in Puget Sound Energy and Arizona Public Service if transition period pricing had not been in effect and prices were set at the penalty parameters during intervals when the power balance constraint was relaxed. This calculation accounts for intervals when the load bias limiter would have triggered and set prices the same as transition period pricing. In particular, transition period pricing increased prices in Arizona Public Service by over $10/MWh in the 15-minute and 5-minute markets. This was the result of frequent over-supply infeasibilities and the associated penalty price (-$155/MWh) that were avoided with the transition period pricing mechanism in place. Transition period pricing decreased prices by around $0.40/MWh and $1.80/MWh in the 15-minute market and 5-minute market in Puget Sound Energy, respectively.

Table 2.1 Impact of transition period pricing on EIM prices (January – March)

	Average EIM price	Estimated EIM price without transition period pricing	Estimated impact of transition period pricing	
			Dollars	Percent
Puget Sound Energy				
15-minute market (FMM)	$18.75	$19.16	-$0.41	-2.1%
5-minute market (RTD)	$15.54	$17.31	-$1.77	-10.2%
Arizona Public Service				
15-minute market (FMM)	$19.45	$8.64	$10.81	125%
5-minute market (RTD)	$17.44	$5.13	$12.31	240%

Available balancing capacity

The ISO implemented the available balancing capacity (ABC) mechanism in the energy imbalance market in late March 2016. This enhancement allows for market recognition and accounting of capacity that entities in these areas have available for reliable system operations, but is not bid into the market. Available balancing capacity is identified as upward capacity (to increase generation) or downward capacity (to decrease generation) by each energy imbalance market entity in their hourly resource plans. The available balancing capacity mechanism enables the ISO system software to deploy such capacity through the energy imbalance market, and prevent market infeasibilities that may arise without availability of this capacity.[32]

In this report, DMM provides a short summary of the available balancing capacity mechanism since it was implemented in March 2016, and highlights issues from the first quarter of 2017. FERC's December 17, 2015, Order on the available balancing capacity proposal requires that the ISO submit quarterly reports on its performance.[33] The ISO filed the initial report with FERC on November 10, 2016 and a second report on May 30, 2017.[34]

Figure 2.3 and Figure 2.4 summarize the frequency of upward and downward available balancing capacity offered by each energy imbalance market area. Capacity in the upward and downward directions in the NV Energy and Puget Sound Energy areas continued to be offered in almost all hours of the first quarter. The frequency of offered capacity in the PacifiCorp East area increased in the first quarter, but remained low. The frequency of offered capacity in PacifiCorp West was lower overall, with upward capacity offered more frequently at the beginning of the quarter, and downward capacity falling to negligible levels in all months of the quarter.

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32 See *Order Accepting Compliance Filing – Available Balancing Capacity* (ER15-861-006), December 17, 2015: http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf.

33 Ibid.

34 *EIM Available Balancing Capacity Report for March 23 – June 30, 2016* (ER15-861), November 10, 2016: http://www.caiso.com/Documents/Nov10_2016_EIM_AvailableBalancingCapacityQuarterlyReport_March23-June30_2016_ER15-861.pdf.

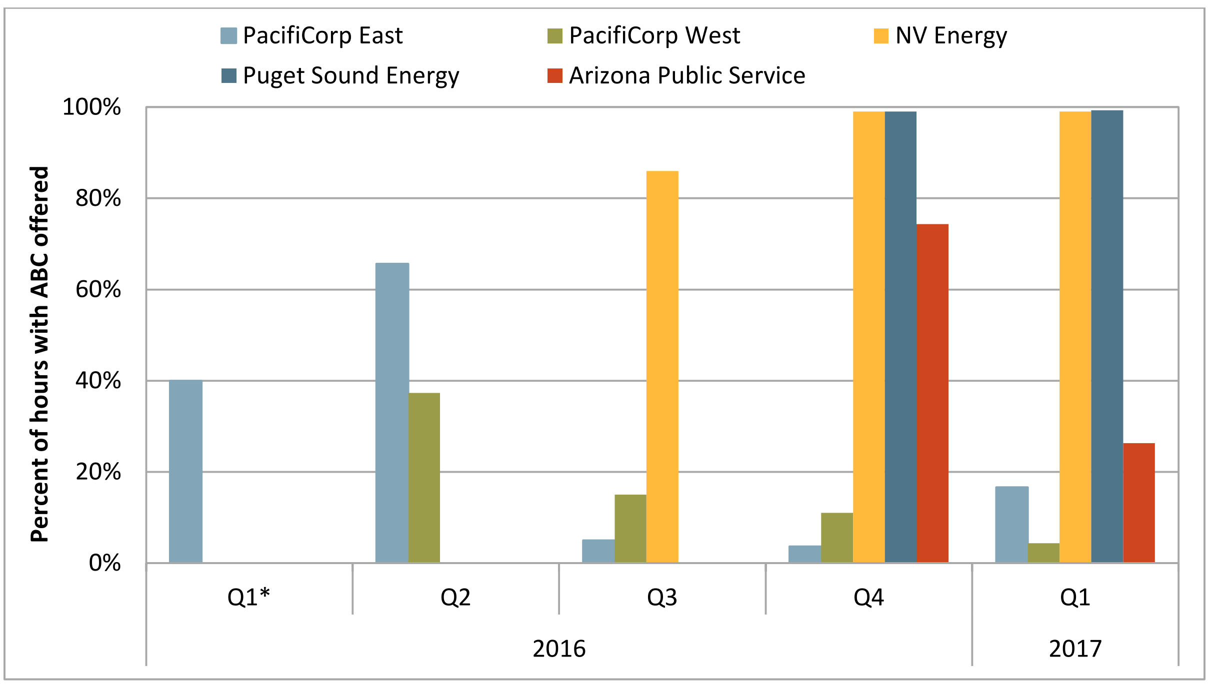
EIM Available Balancing Capacity Report for July 1 – September 30, 2016 (ER15-861), May 30, 2017: http://www.caiso.com/Documents/May30_2017_EIMABCQuarterlyReport_Jul1-Sep30_2016_ER15-861.pdf.

The frequency of upward available balancing capacity offered in the PacifiCorp East area in the first quarter rose from 3 percent of hours in January to more than 20 percent of hours in February and March. In PacifiCorp West, the highest frequency of upward available balancing capacity offered in the first quarter was in January, at 13 percent of hours, none was offered in February or March.

Downward available balancing capacity was offered in PacifiCorp East during 23 percent of hours in March, up from about 1 percent earlier in the quarter. Downward available balancing capacity was not offered in PacifiCorp West in January or February and was only offered in 1 percent of hours in March.

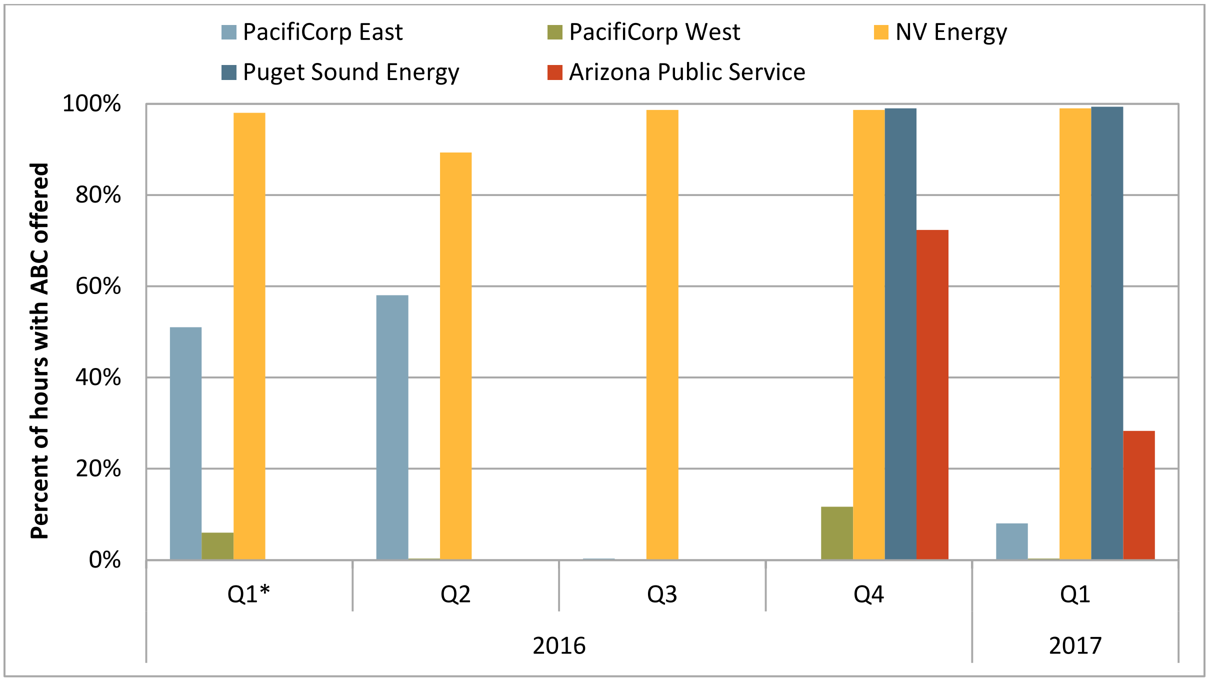
Upward and downward available balancing capacity offered in the Arizona Public Service area declined compared to prior quarters, continuing a trend that began in the fourth quarter of 2016. Frequency of upward and downward available balancing capacity offered in the Arizona Public Service was highest in January with capacity offered in 35 and 33 percent of hours, respectively. In February and March these figures feel to approximately 24 percent of hours.

Figure 2.3 Frequency of upward available balancing capacity offered



* Q1 2016 only includes data from March 23 - 31, 2016.

Figure 2.4 Frequency of downward available balancing capacity offered



* Q1 2016 only includes data from March 23 - 31, 2016.

Available balancing capacity is offered to the market on an hourly basis. The design of the available balancing capacity mechanism is to dispatch offered capacity for the purpose of resolving infeasibilities within the energy imbalance market balancing authority area offering the capacity, and for such capacity to participate in congestion management when dispatched. When available balancing capacity was offered in an energy imbalance market area in the first quarter, the amount offered typically ranged from 40 MW to 90 MW. The reported frequency of available balancing capacity dispatch remained relatively infrequent in the first quarter.

In all energy imbalance market balancing authority areas, the greatest frequency of reported available balancing capacity dispatch in the first quarter occurred in the month of March in the NV Energy area. For the PacifiCorp areas and the Puget Sound Energy area, available balancing capacity dispatched in either direction was reported during less than 1 percent of 5-minute intervals in the first quarter. In the NV Energy area, the dispatch of downward capacity averaged 1 percent of 5-minute intervals over the quarter.

Dispatch of upward capacity occurred during 5 percent of 5-minute intervals in March, and in less than 1 percent of 5-minute intervals in January and February. Downward capacity was reported to be dispatched in the Arizona Public Service area in 3 percent of 5-minute intervals in March, and 1 percent of intervals in January and February. Dispatch of upward capacity in this area was reported in less than 1 percent of intervals in the first quarter.

While the reported dispatch of available balancing capacity was infrequent, the number of instances of dispatch for the purpose of resolving infeasibilities as intended may be fewer. In addition, there may be instances where capacity was available, and dispatch may have been expected, but did not occur.

DMM is aware of instances where megawatt quantities reported as dispatched available balancing capacity may not actually represent capacity dispatched to resolve an infeasibility within a balancing authority area. These apparent dispatches may be, for example, the result of a resource ramping up or down and crossing the capacity range designated as available balancing capacity in the process. Additionally, DMM has observed instances where capacity is not dispatched when expected. Resource ramping limitations may be one explanation for such outcomes.

DMM continues to work with the ISO to better understand all potential reasons for which a given market quantity may be reported as dispatched available balancing capacity. This includes the potential reasons discussed here, as well as any potential reporting issues on quantities of available balancing capacity dispatch.[35] Such understanding may facilitate more detailed analysis by DMM at a later time.

2.2 Flexible ramping sufficiency test

The flexible ramping sufficiency test ensures that each balancing area has enough ramping resources over an hour to meet expected upward and downward ramping needs. The test is designed to ensure that each energy imbalance market area has sufficient ramping capacity to meet real-time market requirements without relying on transfers from other balancing areas. This test is performed prior to each operating hour.

When the energy imbalance market was initially implemented there was an upward ramping sufficiency test. In November 2016, the ISO implemented an additional downward ramping sufficiency test in the market with the introduction of the flexible ramping product, which replaced the flexible ramping constraint. If an area fails the upward sufficiency test, energy imbalance market imports cannot be increased.[36] Similarly, if an area fails the downward sufficiency test, exports cannot be increased. In addition to the sufficiency test, each area is also subject to a capacity test. If an area fails the capacity test, then the flexible ramping sufficiency test automatically fails as a result.[37]

When the flexible ramping sufficiency test was initially implemented requirements were determined from procurement targets for the flexible ramping constraint. The flexible ramping constraint was replaced in November, 2016 by the flexible ramping product. Unlike the flexible ramping constraint, the flexible ramping product uses a demand curve, rather than a fixed target, when procuring flexibility. When the ISO switched to the flexible ramping product, they began using the maximum requirement from the demand curve for the sufficiency test, instead of the old targets from the constraint.[38] DMM asked the ISO to reconsider how it uses the maximum point from the demand curve for the sufficiency tests, as they can change dramatically from hour to hour and they can be significantly larger than old requirements.

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35 The ISO implemented a fix in early October 2016 to resolve some issues where available balancing capacity was reported as dispatched but a dispatch did not occur.

36 *Business Practice Manual for the Energy Imbalance Market*, August 30, 2016, p. 45-52: https://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V6_clean.docx.

37 *Business Practice Manual for the Energy Imbalance Market*, August 30, 2016, p. 45.

38 For further detail, see DMM's presentation on January 18, 2017, to the Market Performance and Planning forum on the calculation of the flexible ramping sufficiency requirement: http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum_Jan18_2017.pdf.

Limiting transfers can impact the frequency of power balance constraint relaxations and, thus, price separation across balancing areas. The majority of power balance constraint relaxations during the quarter, across all of the energy imbalance market balancing areas, occurred during hours when the area failed the flexible ramping sufficiency test. Constraining transfer capability may also impact the efficiency of the energy imbalance market by limiting transfers into and out of a balancing area that could potentially provide benefits to other balancing areas.

Figure 2.5 shows the average number of hours per day in which an energy imbalance market area failed the sufficiency test in the upward direction. As shown in Figure 2.5, balancing areas continued to fail the upward sufficiency test frequently during the first quarter. In particular, PacifiCorp West and NV Energy failed the upward flexible ramping sufficiency test during more than 4 percent of hours in the quarter. However, the majority of failed upward sufficiency tests by NV Energy occurred during its market interruption and therefore did not have any market impacts because administrative pricing was in place.

Figure 2.6 provides the same information for sufficiency tests in the downward direction. This figure highlights the prevalence of Arizona Public Service downward sufficiency test failures: about 26 percent of all hours.

Figure 2.5 Frequency of upward failed sufficiency tests by month

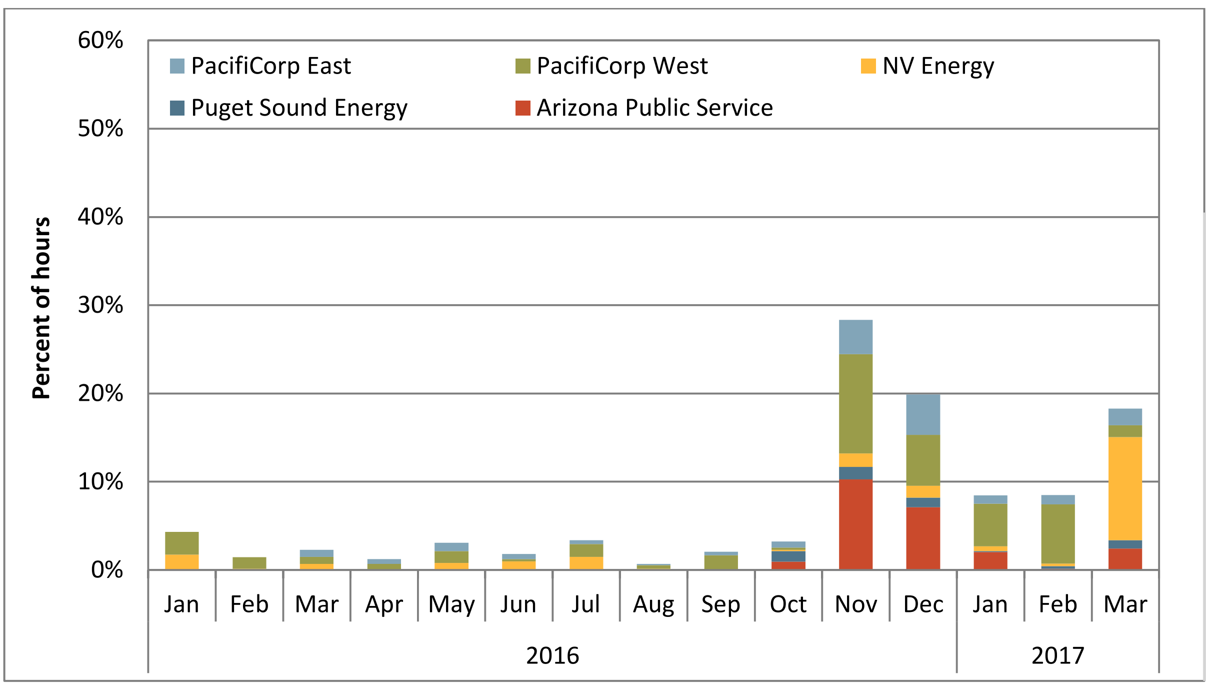
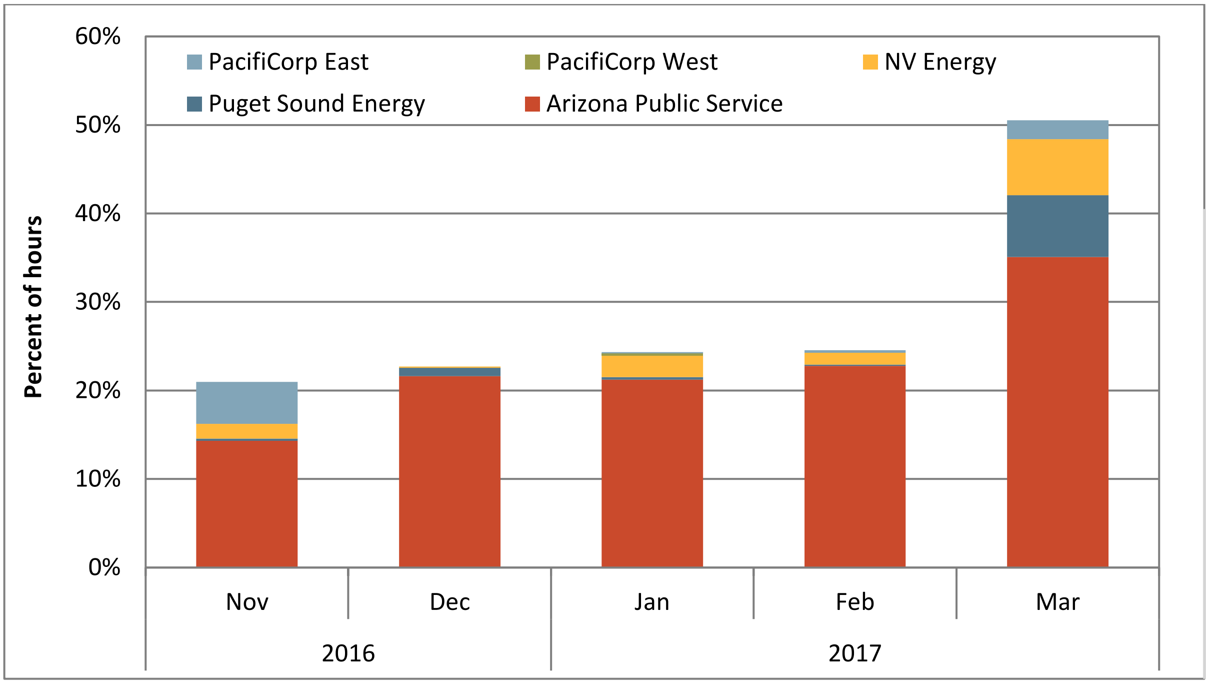


Figure 2.6 Frequency of downward failed sufficiency tests by month



2.3 Energy imbalance market transfers

The real-time market software solves a large cost minimization problem for dispatch instructions to generation considering all of the resources available to the market, including those in the energy imbalance market areas and the ISO. This software also considers a number of constraints including transmission availability between balancing areas within the energy imbalance market. Because of real-time differences in system conditions, real-time schedules for generation are frequently different than day-ahead schedules for resources in the ISO and base schedules for resources in the energy imbalance market. When aggregated, these differences can cause large changes in scheduled flows between balancing areas in the real-time market, or *energy transfers,* between areas. These transfers may represent the market software electing to use lower cost generation in one area in lieu of higher cost generation in another area, and thus reduce the overall cost to meet load for the in the energy imbalance market. This section includes results for energy transfers between energy imbalance market areas, which is one of the key sources of value that the energy imbalance market provides.[39]

Table 2.2 shows the percentage of intervals that each energy imbalance market area and the ISO either exported or imported energy on net and the associated quantity in the 5-minute market. Table 2.3 shows detail about how frequently congestion occurred in any energy imbalance area.[40] These tables show that scheduled transfers tended to flow out of the PacifiCorp areas and into the ISO and Puget

[39] In prior quarterly reports, DMM has shown real-time energy flows within the energy imbalance market. These figures show real-time energy market flows net of all base schedules.

[40] This table removes all intervals when congestion could be caused by greenhouse gas compliance costs, these are usually about $5/MWh.

Sound Energy areas during the majority of intervals and that there was very little congestion between the ISO and most areas in the energy imbalance market.

Table 2.2 shows that the ISO and Puget Sound Energy were net importers during the quarter, and that they imported greater quantities of energy than when exporting. Similarly, PacifiCorp East and PacifiCorp West tended to export energy more frequently than they imported, and when they exported they tended to export greater quantities of energy than while importing during the quarter. NV Energy and Arizona Public Service were slight net exporters, exporting slightly more than they imported over the quarter.

Table 2.3 shows that there was little congestion between the ISO, NV Energy, PacifiCorp East, and Arizona Public Service. It also shows that there was some congestion between PacifiCorp West and the ISO and between PacifiCorp West and PacifiCorp East. These patterns caused local prices in the ISO, PacifiCorp East, NV Energy and Arizona Public Service to be set close to the system price during most intervals. Congestion around PacifiCorp West caused 5-minute prices in PacifiCorp West and Puget Sound Energy to differ frequently from system prices and prices in other energy imbalance market areas. When system prices were higher, constraints out of PacifiCorp West into the ISO and PacifiCorp East bound frequently and caused price separation between the PacifiCorp West and Puget Sound Energy areas and prices in the other energy imbalance market areas. Similarly, when system prices were lower, constraints into PacifiCorp West bound and caused price separation.

Table 2.2 Average net energy imbalance market transfer (January – March)

EIM participant	Net importer frequency	Net importer flows	Net exporter frequency	Net exporter flows
ISO	64%	-284	35%	202
PacifiCorp East	34%	-87	66%	181
PacifiCorp West	39%	-53	61%	83
NV Energy	48%	-88	51%	85
Puget Sound Energy	64%	-76	35%	28
Arizona Public Service	49%	-53	50%	63

Table 2.3 Congestion status and flows in EIM (January – March)[41]

	Congested toward ISO	Congested from ISO
PacifiCorp East	7%	1%
PacifiCorp West	30%	14%
NV Energy	4%	3%
Puget Sound Energy	30%	15%
Arizona Public Service	6%	3%

Different areas in the energy imbalance market exhibited different hourly transfer patterns. Generally, the ISO exported energy during the middle of the day, when solar generation was greatest, and imported energy during the morning hours and evening hours. Many of the flows between the ISO and energy imbalance market areas mirrored this pattern. Energy transfers in each area were driven by the resource mix and relative prices during these times of the day.

Figure 2.7 through Figure 2.9 shows detail about how energy transfers moved between NV Energy, Arizona Public Service, and Puget Sound Energy, respectively, and neighboring areas with transfer capability on an hourly basis during the quarter. Figure 2.7 shows that NV Energy transferred energy to PacifiCorp East during peak solar hours, and received transfers from the ISO during the same hours. Then, during evening hours this was reversed and transfers were received from PacifiCorp East and sent to the ISO in the evening hours. In the early morning hours, NV Energy transferred small amounts of energy out of the area on net.

41 Table 2.3 shows 5-minute market congestion between PacifiCorp West and the ISO inclusive of the transfer constraint and the constraint governing flows into the ISO on the Malin 500 kV constraint. These 5-minute constraints account for the dynamic limits imposed on transfers between the ISO and PacifiCorp West.

Figure 2.7 Average hourly imports into NV Energy (January – March)

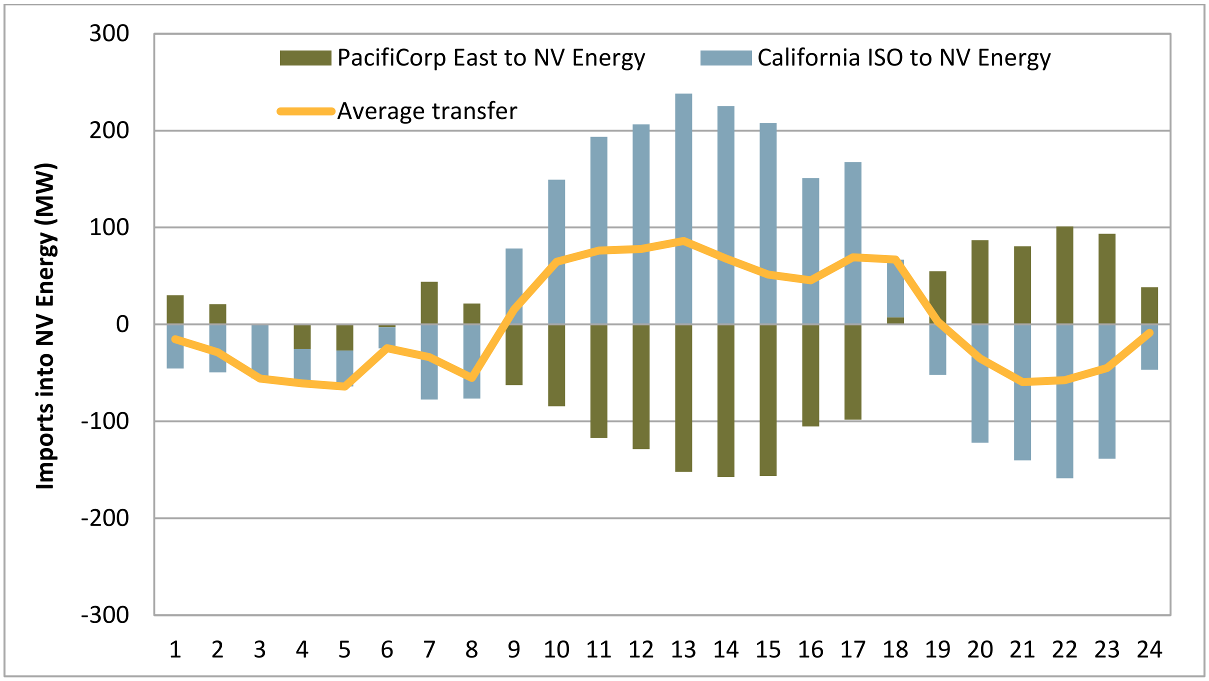


Figure 2.8 shows similar information, but for Arizona Public Service rather than NV Energy. This chart shows that Arizona Public Service transferred the most energy during the evening hours of the day and transferred when energy was transferred to the ISO and from PacifiCorp East. Transfers were lighter on average during other hours, where in the morning flows were in the same direction and during peak solar hours transfers tended to come from the ISO and go to PacifiCorp East.

Figure 2.9 shows average transfers between PacifiCorp West and the ISO, Puget Sound Energy, and PacifiCorp East. This figure shows similar patterns as the other figures in this section, where transfers tended to move in from the ISO during peak solar hours and to the ISO during morning and evening hours. For most hours of the day, including the late afternoon through morning, PacifiCorp West tended to import energy from Puget Sound Energy and export to the ISO, indicating electricity moved in a north-to-south direction. During peak solar hours of the day the reverse was true, and PacifiCorp West imported energy from the ISO and exported to Puget Sound Energy. Figure 2.9 shows that PacifiCorp West always receives imports from PacifiCorp East. This is a byproduct of the transfer limits imposed between the two areas that specify that transfers only occur in the east-to-west direction between these two areas.

Figure 2.8 Average hourly imports into Arizona Public (January – March)

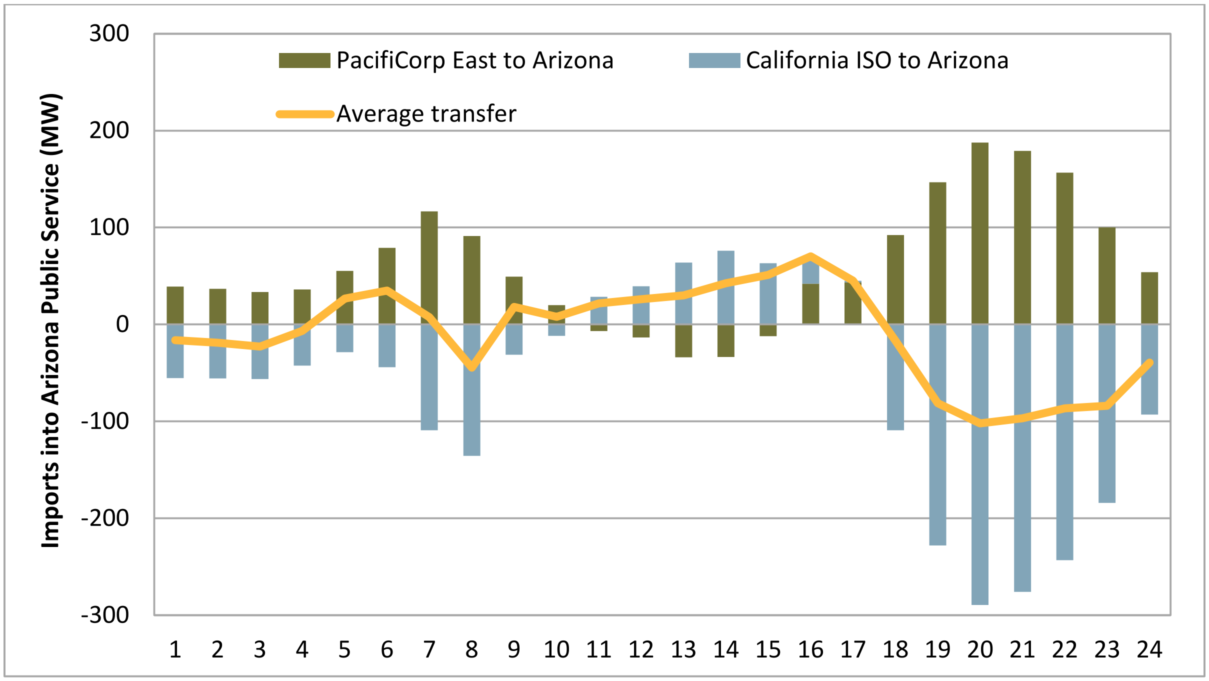
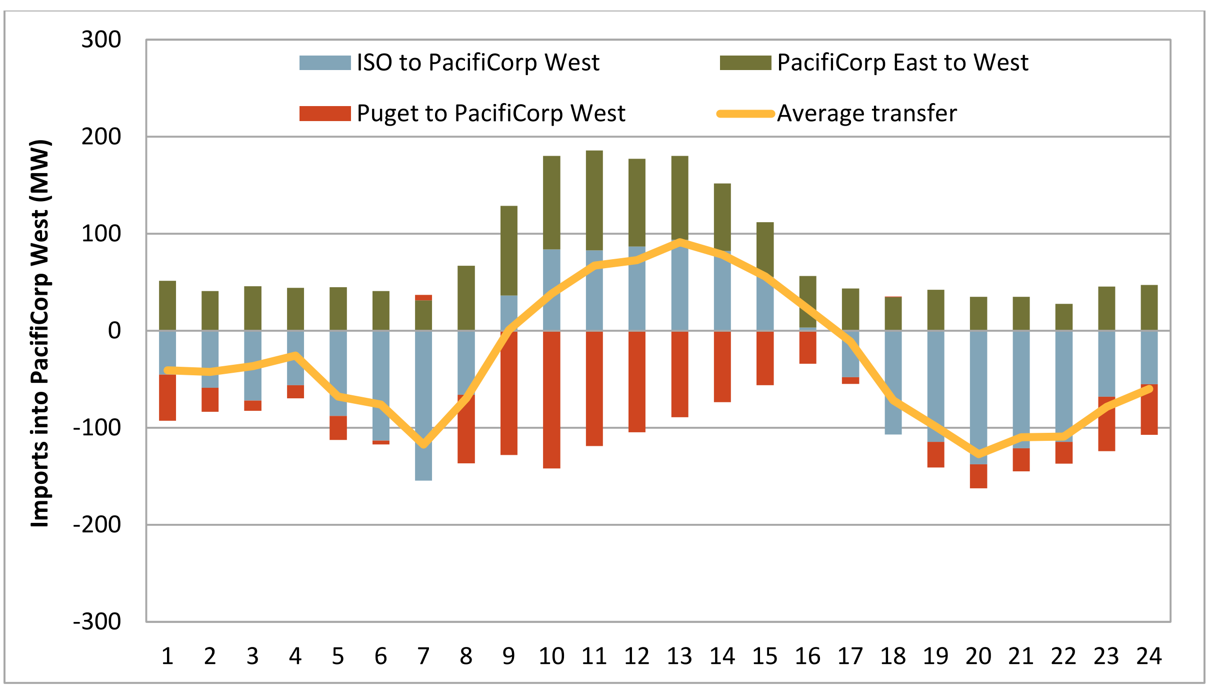


Figure 2.9 Average hourly imports into PacifiCorp West (January – March)



3 Load adjustments

This section provides a summary of load adjustments during the first quarter. Key trends include the following:

- Overall, load adjustments were typically positive in PacifiCorp East, NV Energy, Arizona Public Service and the ISO, while load adjustments in PacifiCorp West were typically negative. Puget Sound Energy made adjustments infrequently in either direction.
- Arizona Public Service operators adjusted the load forecast significantly more frequently during the first quarter than in previous quarters, at about 40 percent of the real-time intervals.
- The reasons selected most often for load adjustments differed significantly across the energy imbalance market areas. PacifiCorp East adjusted load primarily for generation deviation, PacifiCorp West for automatic time error correction, NV Energy for reliability based control, and Arizona Public Service and Puget Sound Energy for load forecast deviation.[42]
- The load bias limiter had a small impact on energy imbalance market prices during the first quarter. However, the load bias limiter decreased average 5-minute market prices in the ISO by around $2/MWh during the quarter.
- DMM provided recommendations to the ISO for enhancements to the load bias limiter feature to limit adjustments only when a *change* in load adjustment causes a power balance constraint relaxation, rather than solely the *magnitude* of the load adjustment. DMM made this recommendation because adjustments are sometimes entered and not updated for long periods of time. The ISO posted a technical bulletin in December announcing that they intend to implement this change. Had the proposed load bias limiter been active during the quarter instead of the current load bias limiter, it would have decreased 5-minute market prices in the ISO by around $0.50/MWh, significantly less than the current load bias limiter.

Background

Operators in the ISO and energy imbalance market can manually modify load forecasts used in the market through a load adjustment. Load adjustments are also sometimes referred to as *load bias* or *load conformance*. These adjustments are used to account for potential modeling inconsistencies and inaccuracies. Specifically, operators listed multiple reasons for use of load adjustments including managing load and generation deviations, automatic time error corrections, scheduled interchange variations, reliability events, and software issues.

The ISO enhanced the real-time market software in December 2012 to limit load forecast adjustments made by operators to only the available amount of system ramp. Beyond this level of load adjustment a shortage occur and triggers penalty pricing when the power balance constraint is relaxed, without achieving any increase in actual system energy. With this software enhancement, known as the *load*

[42] Automatic time error correction is used to maintain interconnection frequency and to ensure that time error corrections and primary inadvertent interchange payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection. For more information refer to WECC Reliability Standards here: http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-004-WECC-02.pdf.

bias limiter, load adjustments made by operators are less likely to have extreme effects on market prices. This tool was extended to the energy imbalance market balancing areas in March 2015.

Frequency and size of load adjustments

Figure 3.1 and Figure 3.2 show the frequency of positive and negative load forecast adjustments for PacifiCorp East, PacifiCorp West, NV Energy, Puget Sound Energy, and Arizona Public Service during the previous six months for the 15-minute and 5-minute markets, respectively. The same data for the ISO is provided as a point of comparison and reference.

Table 3.1 summarizes the average frequency and size of positive and negative load forecast adjustments in the 15-minute and 5-minute markets during the first quarter. Overall, load adjustments were typically positive in PacifiCorp East, NV Energy, Arizona Public Service and the ISO, while negative load adjustments were frequently negative in PacifiCorp West. Puget Sound Energy adjusted the load forecast in either direction much less frequently than the other areas during the quarter. Table 3.1 also includes the average absolute positive and negative load adjustment as a percentage of area load.

PacifiCorp East operators entered positive load adjustments more frequently during the first quarter at about 23 percent of 15-minute intervals and 44 percent of 5-minute intervals. This continues a trend observed in the previous quarter. During intervals with positive adjustments, the amounts averaged around 108 MW from PacifiCorp East (about 2 percent of area load) during the quarter, as shown in Table 3.1.

PacifiCorp West continued to primarily adjust loads in the downward direction in the first quarter, during about 40 percent of intervals in the 15-minute market and 53 percent of intervals in the 5-minute market. These negative adjustments averaged around -54 MW in the real-time markets, or about 2 percent of area load.

In the NV Energy area, load adjustments in the 15-minute market were primarily positive, occurring during 24 percent of intervals, compared to 2 percent of intervals in the negative direction. These 15-minute market adjustments generally followed the load pattern with less frequent positive adjustments during the early morning and late evening hours and more frequent positive adjustments during the evening peak load hours. However, in the 5-minute market, negative load adjustments were entered much more frequently, during 25 percent of intervals, at an average of -69 MW. Positive adjustments averaged almost 100 MW in the 15-minute market and around 62 MW in the 5-minute market.

Arizona Public Service adjusted the load forecast significantly more frequently during the first quarter during about 40 percent of 15-minute and 5-minute intervals, compared to 15 percent of intervals in the prior quarter. In addition, as a percent of total area load, average load adjustments by Arizona Public Service were larger in magnitude compared to other areas, at around 4 percent of area load. The majority of these adjustments were positive and typically followed the area’s load curve with more frequent and larger adjustments during the morning and evening peak load hours.

Puget Sound Energy adjusted the load forecast in either direction much less frequently than other areas, during about 9 percent of 15-minute intervals and 17 percent of 5-minute intervals. Because of the low frequency of load adjustments by Puget Sound Energy operators, average hourly net load adjustments were very low during the quarter.

Figure 3.1 Average frequency of positive and negative load adjustments by BAA (15-minute market)

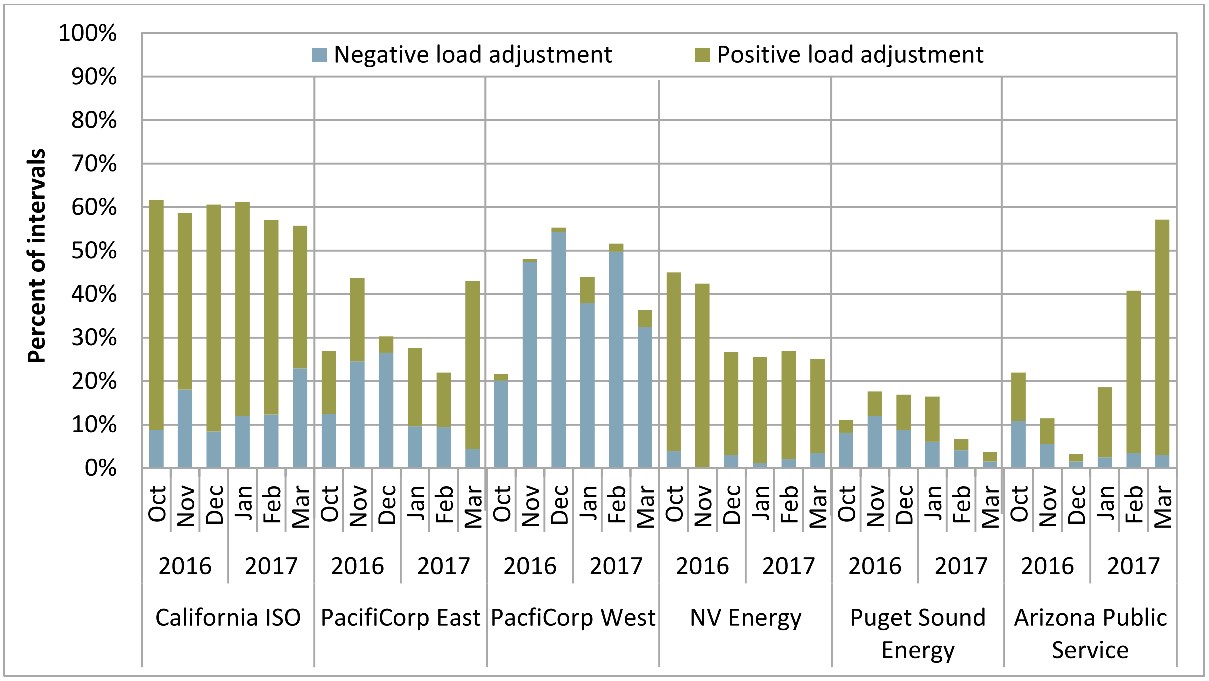


Figure 3.2 Average frequency of positive and negative load adjustments by BAA (5-minute market)

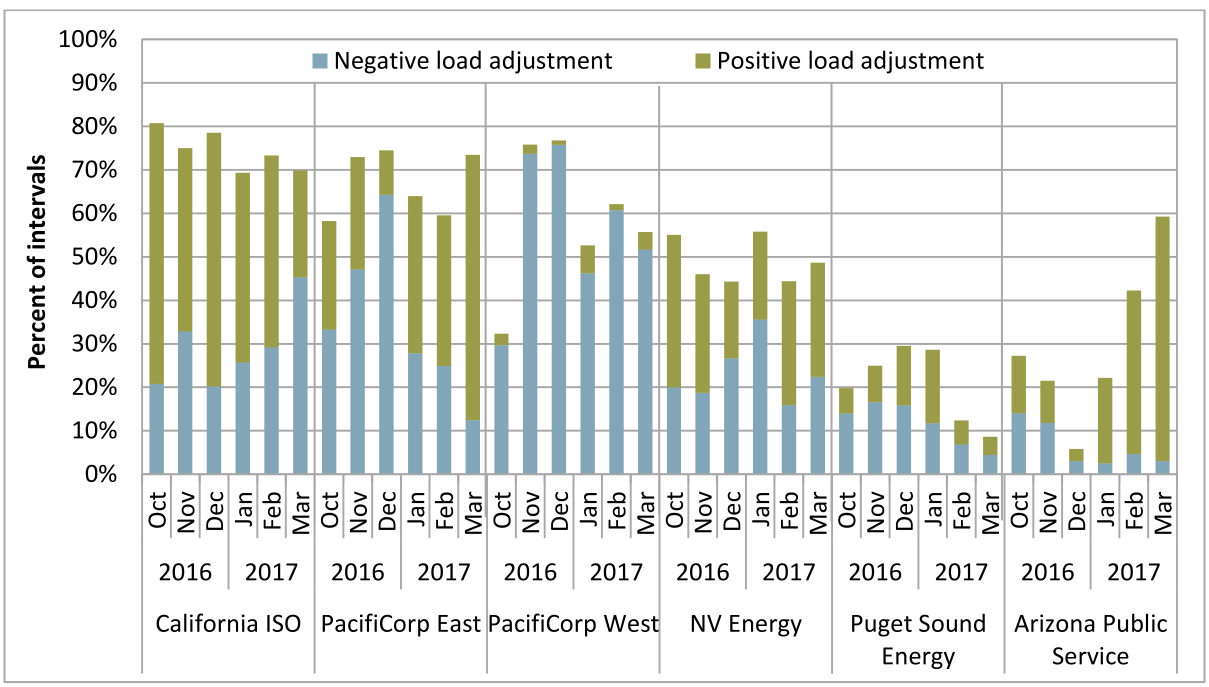


Table 3.1 Average frequency and size of load adjustments (January – March)

	Positive load adjustments			Negative load adjustments			Average hourly bias MW
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO							
15-minute market	42%	502	2.0%	16%	-340	1.5%	158
5-minute market	37%	329	1.4%	33%	-348	1.5%	6
PacifiCorp East							
15-minute market	23%	107	2.2%	8%	-109	2.1%	17
5-minute market	44%	109	2.2%	22%	-100	2.0%	27
PacifiCorp West							
15-minute market	4%	44	1.5%	40%	-52	2.0%	-19
5-minute market	4%	49	1.7%	53%	-56	2.2%	-28
NV Energy							
15-minute market	24%	98	2.6%	2%	-120	3.5%	20
5-minute market	25%	62	1.7%	25%	-69	2.0%	-2
Puget Sound Energy							
15-minute market	5%	67	1.8%	4%	-62	2.0%	1
5-minute market	9%	67	1.9%	8%	-62	2.0%	1
Arizona Public Service							
15-minute market	36%	116	4.0%	3%	-109	4.2%	38
5-minute market	38%	127	4.4%	3%	-105	4.1%	45

Reasons for load adjustments

When the available balancing capacity mechanism was implemented the ISO developed a feature for operators to log pre-specified reasons for making load adjustments using a drop down menu. Operators in the energy imbalance market began regularly logging reasons for adjustments in the 15-minute and 5-minute markets at the beginning of April. These reasons are summarized below.

Reasons for load adjustment in the ISO were classified into four groups:

- load deviation (differences between the load value in the market and actual or expected load);
- resource deviation (difference between resource dispatch operating targets and actual or expected output);
- reliability event (managing transmission exceedance or operating reserves); and
- software issue (errors in market inputs usually driven by other software).

Reasons for load adjustment in the energy imbalance market included:

- load forecast deviation (load deviation from the forecast);
- generation deviation (includes deviation in forecast for variable energy resources, generator startup or shutdown resulting in generation below its minimum operating level, and generation testing);

- reliability based control (informing the market of a need for generation increase or decrease to comply with the balancing authority area limit standard);
- automatic time error correction (informing the market of automatic generation control deviation from zero area control error due to automatic time error correction); and
- schedule interchange variation (changes in scheduled interchange within 40 minutes prior to the interval).

When operators enter a load adjustment duration and quantity, operators have the option to select a reason for the load adjustment from a list of predefined reasons.[43] In addition, operators have the ability to include details about why a load adjustment was entered in a free-form text box. If operators enter a load adjustment for more than one reason, they have the ability to select only one preset reason from the list. However, additional reasons can be entered in the free-form text box. Logging additional details or reasons through the text box is optional.

During the quarter, PacifiCorp operators were more likely to include additional detail in the 5-minute market than in the 15-minute market. PacifiCorp East operators entered information in the free-form text box during about 67 percent of 5-minute intervals when load adjustments were entered, while PacifiCorp West operators entered additional information during about 47 percent of 5-minute market adjustments. PacifiCorp frequently used this feature to cite additional reasons beyond the single reason selected from the predefined list. Operators in NV Energy used the additional details text box very frequently, including additional information during around 95 percent of 15-minute and 5-minute intervals when load adjustments were entered. Puget Sound Energy used the free-form text box during about 19 percent of the time load was adjusted in the real-time market, while Arizona Public Service rarely used this feature, including additional details only about 3 percent of the time.

At this time, the only method for evaluating additional details about the load adjustment, including details about reliability needs and alternative options evaluated prior to entering a load adjustment, is with the free-form text box. There is no secondary drop down function for operators to track these details. DMM has not observed input in the free-form text box that addresses alternative options to load adjustments considered, and therefore cannot provide any additional information on them at this time. DMM recommends that the ISO modify its tool to allow operators to enter this information or to provide for another process to capture it.

Figure 3.3 and Figure 3.4 show the frequency of load adjustments in the energy imbalance market areas by the reason selected for the adjustment during the previous six months for the 15-minute and 5-minute markets, respectively.[44] During the first quarter, the reasons selected varied significantly between energy imbalance market entities.

PacifiCorp East selected generation deviation frequently, during about 61 percent of 15-minute and 5-minute load adjustments. These actions were often made to account for wind and solar deviation.

[43] In the energy imbalance market, in addition to four commonly listed reasons, four less frequently used options are: disturbance response, stranded load, stranded generation, and other event.

[44] Analysis was completed for intervals when a bias was entered and a particular reason from the predefined list was specifically selected. They do not include intervals when the reason, also from the list, was indirectly logged as an additional detail in the free-form text box.

During this quarter, PacifiCorp East operators also continued to select schedule interchange variation regularly, during about 24 percent of 15-minute and 5-minute load adjustments.

PacifiCorp West operators primarily selected automatic time error correction. This item was selected for about 53 percent of 15-minute and 5-minute load adjustments to account for inadvertent energy. In addition, PacifiCorp West adjusted the load forecast frequently for generation deviation (for about 25 percent of adjustments) and schedule interchange variation (for about 17 percent of adjustments).

In NV Energy, operators continued to adjust load most frequently for reliability based control. Through the free-form text box, operators indicated that this option was primarily selected when the load adjustment was used to adjust generation to comply with the balancing authority area limit standards. NV Energy operators selected reliability based control during about 91 percent of intervals with load adjustments.

Puget Sound Energy selected load forecast deviation most often. Puget Sound Energy chose load forecast deviation during about 90 percent of 15-minute market and 5-minute market load adjustments. However, Puget Sound Energy made load forecast adjustments very infrequently during the first quarter, particularly in February and March.

As mentioned earlier, Arizona Public Service adjusted the load forecast more frequently during the quarter. These adjustments were most frequently for load forecast deviation and generation deviation, during about 47 percent and 38 percent of load adjustments, respectively. However, Arizona Public Service regularly did not select a reason from the predefined list during the first quarter, during almost 10 percent of 15-minute market and 5-minute market load adjustments.

Figure 3.3 Frequency of load forecast adjustments by reason (15-minute market)

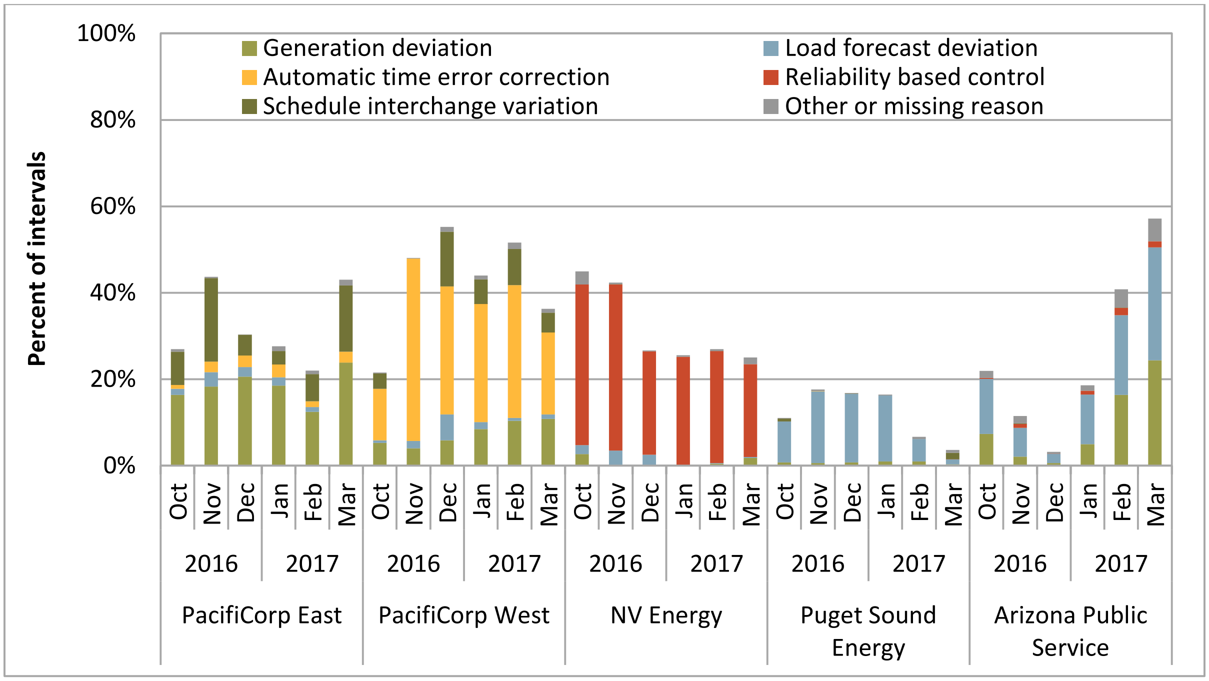
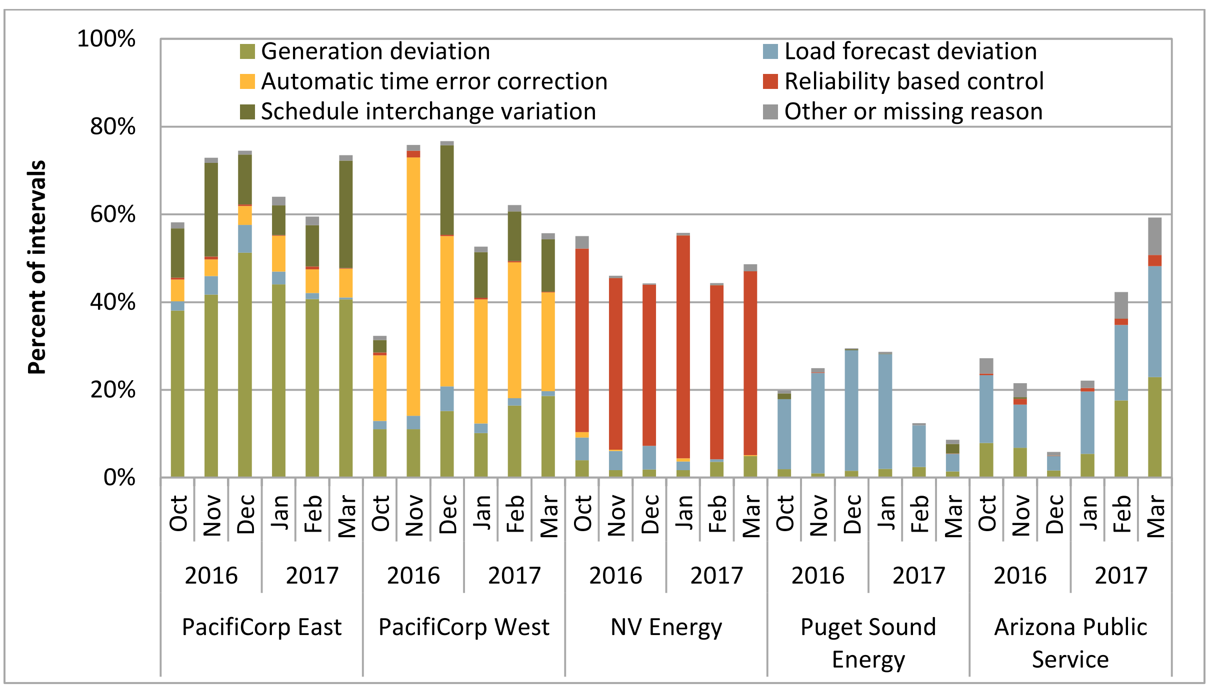


Figure 3.4 Frequency of load forecast adjustments by reason (5-minute market)



Impact of load adjustments on prices

The impacts that load adjustments have on prices can range widely and cannot be readily determined or estimated. When load is adjusted upwards, this tends to put upward pressure on prices in the immediate intervals by increasing the demand forecast. However, this upward adjustment may actually help to decrease prices in subsequent intervals by ramping up generation and making more supply available in subsequent periods. Likewise, downward adjustments can lower prices in immediate intervals, but may decrease supply and increase prices in subsequent intervals.

The impact of the load adjustment can be quantitatively assessed in cases when the load bias limiter is triggered.[45] The ISO implemented this feature to limit the effect of load adjustments on prices when adjustments cause power balance constraint relaxations. Prior to the pricing run, the ISO software performs a test to see if operator load adjustments contributed to the relaxation of the power balance constraint in the scheduling run. Specifically, the software compares the magnitude and direction of the power balance relaxation to the operator load adjustment for both shortage and excess events. If the load adjustment exceeds the quantity of the relaxation in the same direction, the size of the load adjustment is automatically reduced in the pricing run to prevent the shortage or excess.

When the load bias limiter is triggered it results in a market solution in the pricing run such that the price is set by the last economic unit dispatched, rather than the $1,000/MWh penalty price for under-supply power balance relaxations or the -$155/MWh penalty price for over-supply power balance relaxations. The functionality of the load bias limiter is similar to the transition period pricing feature that was in effect in Puget Sound Energy and Arizona Public Service during the first quarter, as they both set price to the offer price of the last dispatched resource during power balance relaxations.[46]

Table 3.2 shows the estimated net impact of the load bias limiter on energy imbalance market prices during the first quarter. Puget Sound Energy and Arizona Public Service are not included in this table because the load bias limiter did not impact prices in these areas because transition period pricing was in place that sets the price for *all* power balance constraint relaxations to the price of the last dispatched resource. However, had transition period pricing not been in effect, DMM estimates that the load bias limiter would have decreased 5-minute market prices in the Puget Sound Energy and Arizona Public Service areas by around $0.60/MWh and $0.90/MWh, respectively.

Depending on the frequency of power balance constraint relaxations and load adjustment activity, the load bias limiter generally has a net impact that decreases average prices by mitigating potential $1,000/MWh penalty prices from under-supply infeasibilities. For NV Energy, PacifiCorp West and PacifiCorp East, the overall impact of the load bias limiter was small during the quarter, decreasing average 15-minute and 5-minute prices by less than $0.50/MWh.

In prior quarterly and annual reports, DMM recommended that the ISO consider modifying the load bias limiter to focus on instances where power balance relaxations occur as the result of a *change* in load adjustments, rather than solely the *magnitude* of the adjustment. In December the ISO released a technical bulletin announcing that they intend to implement this change. This was followed by a

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45 This is also sometimes referred to as the load conformance limiter or the load adjustment limiter.

46 The transition period pricing feature is active for the first six months of market operation for new energy imbalance market entities and expired for Puget Sound Energy and Arizona Public Service at the end of the March.

stakeholder call in early January to review the proposed enhancement.[47] Generally, the proposed logic states that only changes in the load adjustment greater than changes in the power balance relaxation would trigger the limiter. However, the proposed logic has a memory component that can allow a single load adjustment to trigger the limiter as long as the shortage does not increase. DMM provided comments in support of this proposal on May 19.[48]

Table 3.2 also includes average estimated prices during the first quarter if the proposed load bias limiter was active instead of the current load bias limiter. Overall, the proposed load bias limiter would have resulted in a smaller impact on prices during the quarter than the current load bias limiter because of fewer under-supply infeasibilities resolved. The proposed load bias limiter logic would have decreased prices in the ISO by around $0.50/MWh, and the current load bias limiter decreased average prices in the ISO by about $2/MWh.[49]

Table 3.2 Impact of load bias limiter on prices (January – March)

	Average price	Average estimated price without the load bias limiter	Estimated impact of current load bias limiter	Average estimated price with the proposed load bias limiter	Estimated impact of proposed load bias limiter
PacifiCorp East					
15-minute market (FMM)	$21.07	$21.15	-$0.08	$21.15	$0.00
5-minute market (RTD)	$17.78	$18.03	-$0.25	$17.89	-$0.14
PacifiCorp West					
15-minute market (FMM)	$21.72	$21.96	-$0.25	$21.81	-$0.16
5-minute market (RTD)	$17.64	$17.84	-$0.20	$17.62	-$0.22
NV Energy					
15-minute market (FMM)	$23.98	$24.17	-$0.19	$24.09	-$0.07
5-minute market (RTD)	$21.89	$22.30	-$0.41	$22.02	-$0.28
California ISO (LAP average)					
15-minute market (FMM)	$26.79	$26.79	$0.00	$26.79	$0.00
5-minute market (RTD)	$24.20	$26.27	-$2.08	$25.79	-$0.49

47 The *Load Conformance Limiter Enhancement – Technical Bulletin* (December 28, 2016) can be found here: http://www.caiso.com/Documents/TechnicalBulletin_LoadConformanceLimiterEnhancement.pdf.

48 *Comments on the Load Conformance Limiter Enhancement*, Department of Market Monitoring, (May 19, 2017) can be found here: http://www.caiso.com/Documents/DMMComments-LoadConformanceLimiterEnhancement.pdf.

49 The California ISO prices reflect a simple average over the three major DLAPs: PG&E, SDG&E, and SCE. The impacts of the load bias limiter did not vary much between these areas.

4 Special issues

This section provides information about the following three special issues:

- The ISO implemented the flexible ramping product on November 1, 2016. The flexible ramping product differs from the former flexible ramping constraint by compensating or charging for forecast ramping movements, procuring flexible capacity using a demand curve and procuring for both upward and downward ramping needs. Overall costs for flexible ramping remained low, at less than $0.14/MWh of load.

- As part of a set of temporary measures related to Aliso Canyon, the ISO began using a more up-to-date source for calculating its natural gas price index used by the day-ahead market. This update removed a one-day lag in the natural gas price information used in the day-ahead market, and greatly improved the accuracy of the ISO's index. DMM's analysis of same day natural gas price volatility in Southern California during the first quarter of 2017 and 2016 shows that additional bidding flexibility has been sufficient to cover the vast majority of same day natural gas transaction prices. DMM has recommended to the ISO that it review and reduce the special gas price adders being applied to commitment costs and default energy bids used in the real-time market.

- During the quarter imports accounted for the greatest share of average hourly generation in the real-time market at over 6,000 MW. However, the portion of these imports bid into the 15-minute market and available to receive dispatch instructions only totaled about 500 MW (7 percent) per hour on average. There were a significantly greater proportion of economic bids for imports and exports in the day-ahead market than in the real-time market. On average, economic bids made up about 80 percent of imports and exports in the day-ahead market, while self-schedules made up the remaining 20 percent.

4.1 Flexible ramping

This section provides information about market outcomes for the flexible ramping product during the first quarter.

Background

On November 1, 2016, the ISO implemented a new market feature for procuring real-time flexible ramping capacity known as the flexible ramping product. The product replaced the previous procurement mechanism, called the flexible ramping constraint. The flexible ramping product differs from the flexible ramping constraint in several important ways.

First, while the constraint procured only upward flexible capacity in the 15-minute market, the product procures both upward and downward flexible capacity, in both the 15-minute and the 5-minute markets. As with the constraint, the procurement in the 15-minute market is intended to ensure that enough ramping capacity is available to meet the needs of both the upcoming 15-minute market runs, and the corresponding 5-minute market runs for the same time period. The procurement in the 5-minute market aims to ensure that enough ramping capacity is available to handle differences between consecutive 5-minute market intervals.

Second, the amount of flexible capacity that the product procures is determined from a demand curve instead of from a fixed requirement. This means that the amount of flexible capacity procured in a given market interval will depend on the willingness-to-pay for procuring flexible capacity in that interval derived from the demand curve.

Third, the shadow prices for the flexible ramping product are used not only for compensating resources that are counted towards meeting the flexible ramping capacity demand, but also to pay or charge resources for their forecasted ramping movement.

Flexible ramping product demand curves

The ISO procures flexible ramping capacity using demand curves, such that the amount of flexible ramping capacity procured in a given interval depends on the cost of procuring flexible capacity in that interval. The demand curves, which represent the ISO's willingness-to-pay for flexible ramping capacity, reflect the expected reduction in power balance constraint relaxation costs from an increase in the amount of procured flexible ramping capacity.

The demand curves are calculated independently for each hour of the day, and differ by market (15-minute and 5-minute) and direction (upward ramping and downward ramping). Further, there are separate demand curves calculated for each energy imbalance market area, in addition to a system-level demand curve. For more information about the flexible ramping product and the calculation of the flexible ramping product demand curves, see DMM's 2016 annual report.[50]

The demand curves used in the first quarter of 2017 were similar to those used during November and December, 2016. Average demand for upward ramping in the 15-minute market at the system-level was about 810 MW at $0/MWh and about 550 MW at $100/MWh. In the downward direction, average system-level demand was about 720 MW at $0/MWh and about 40 MW at $100/MWh.

Demand for flexible ramping capacity in the 5-minute market in the first quarter remained lower than demand in the 15-minute market. At the system level, average upward demand was about 150 MW at $0/MWh and about 120 MW at $100/MWh. In the downward direction, average system-level demand was about 110 MW at $0/MWh and about 10 MW at $100/MWh.

Market outcomes for flexible ramping product

This section describes the amount of flexible ramping capacity that was procured in the first quarter, and the corresponding flexible ramping shadow prices.

A sufficiently large amount of flexible ramping capacity sometimes was committed by the market regardless of the demand for the flexible ramping product. In such intervals, the demand curves did not bind and the flexible ramping shadow price was $0/MWh. Figure 4.1 shows the percent of intervals when the system-level flexible ramping demand curve bound, and had a positive shadow price, in the 15-minute market during the first quarter.

In the first quarter, the system-level demand curves continued to bind more frequently in the upward direction than in the downward direction. However, the frequency in the downward direction increased compared to November and December. The system-level downward demand curves bound in about 11

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[50] *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, pp. 109-120: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

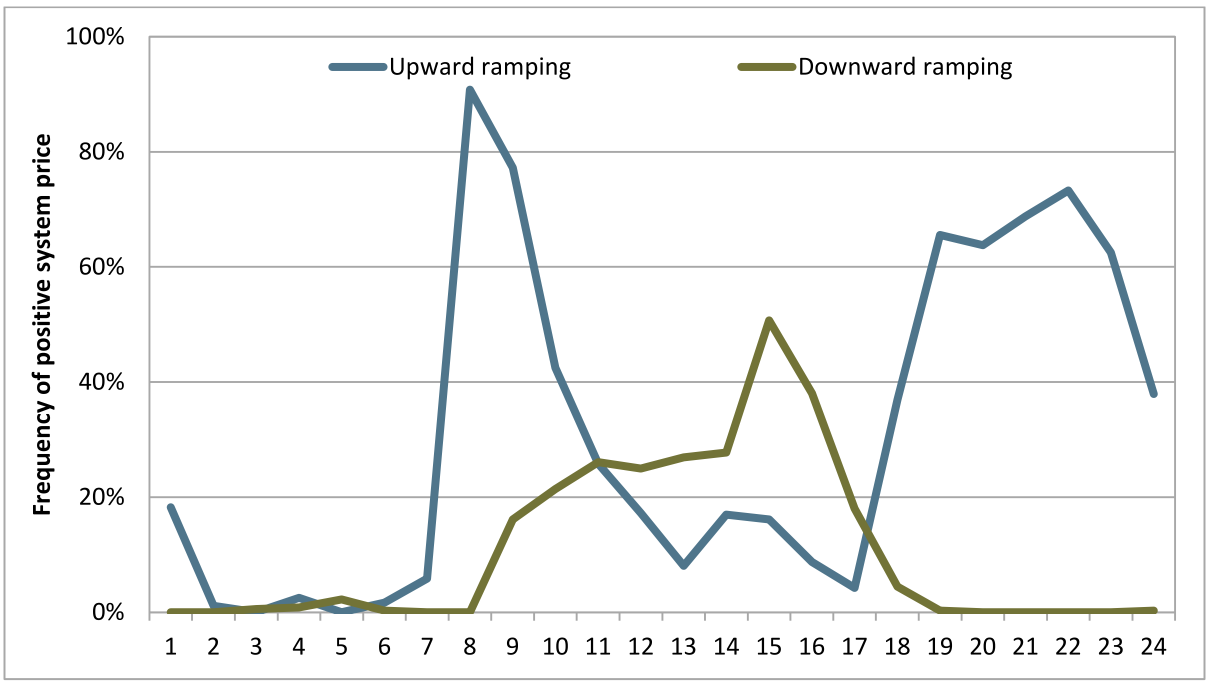
percent of 15-minute intervals during the first quarter, compared to about 3 percent during November and December. As seen in Figure 4.1, the downward demand curves were mostly binding during hours with high levels of solar generation.

In the upward direction, non-zero system-level flexible ramping prices were observed in the 15-minute market in about 31 percent of intervals, a slight increase compared to 30 percent of intervals in during November and December. Figure 4.1 shows that positive prices in the upward direction were most frequent in the morning and evening hours. This coincides with higher levels of demand for upward flexible ramping capacity during those hours.

The average system-level shadow price when the demand curve was binding in the 15-minute market during the first quarter was $11/MWh in the upward direction and $6/MWh in the downward direction.

In the 5-minute market, system-level flexible ramping prices were positive during less than 1 percent of intervals in both the upward and downward direction. This is because the quantity of flexible ramping capacity demanded in the 5-minute market was significantly lower than in the 15-minute market.

Figure 4.1 Hourly frequency of positive 15-minute market flexible ramping shadow price (January – March)



In addition to the system-level shadow price, an area-specific demand curve may be binding, creating an additional price for resources in that area. These demand curves continued to be infrequently binding for most areas during the first quarter.

Table 4.1 shows the percent of intervals with positive flexible ramping shadow prices, and the average flexible ramping shadow price for intervals when the price was positive, for the first quarter. This is shown for both the 15-minute and 5-minute markets and for each energy imbalance market area, as well as the system-level energy imbalance market area.

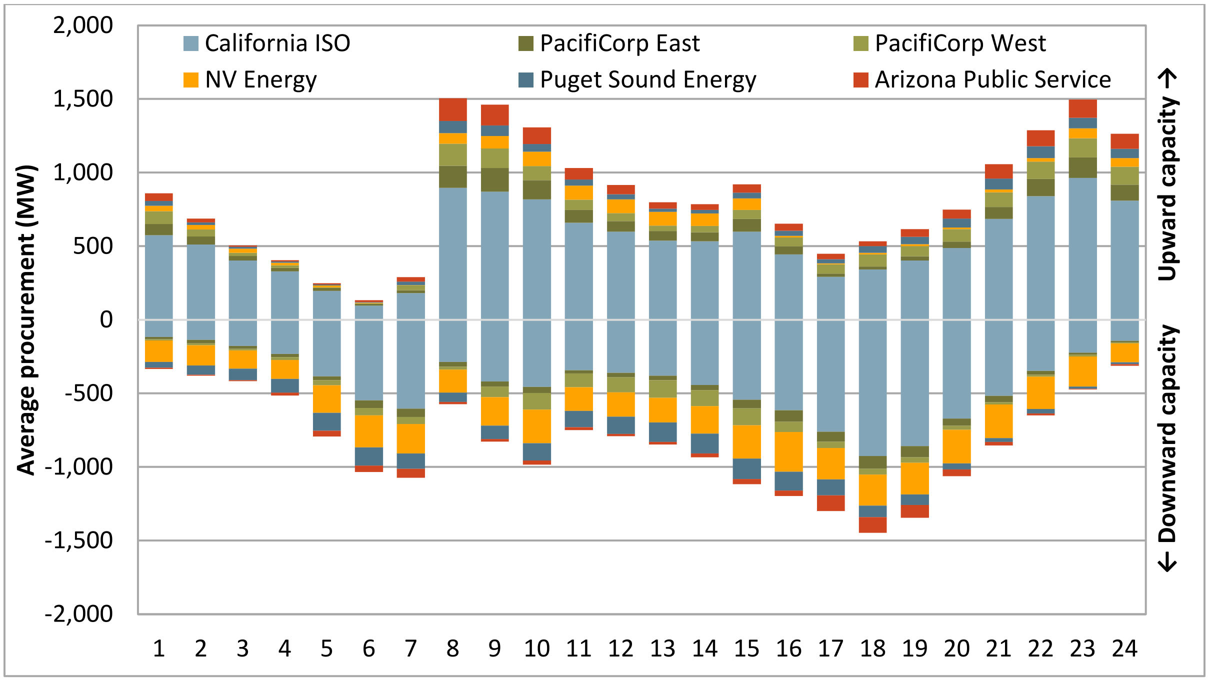
Table 4.1 Flexible ramping product shadow prices (January – March)

	Positive upward flex ramp shadow price (percent of intervals)	Average upward flex ramp shadow price ($/MWh)	Positive downward flex ramp shadow price (percent of intervals)	Average downward flex ramp shadow price ($/MWh)
PacifiCorp East				
15-minute market (FMM)	1.2%	$34	2.8%	$10
5-minute market (RTD)	0.1%	$98	0.1%	$40
PacifiCorp West				
15-minute market (FMM)	2.1%	$58	0.5%	$5
5-minute market (RTD)	0.7%	$101	0.1%	$13
NV Energy				
15-minute market (FMM)	0.5%	$124	1.4%	$34
5-minute market (RTD)	0.2%	$170	1.0%	$46
Puget Sound Energy				
15-minute market (FMM)	1.5%	$42	0.9%	$20
5-minute market (RTD)	0.2%	$65	0.1%	$55
Arizona Public Service				
15-minute market (FMM)	1.6%	$53	12.4%	$31
5-minute market (RTD)	0.1%	$96	2.7%	$29
California ISO				
15-minute market (FMM)	0.3%	$7	0.3%	$7
5-minute market (RTD)	0.0%	$11	0.0%	N/A
EIM area				
15-minute market (FMM)	31.1%	$11	10.8%	$6
5-minute market (RTD)	0.4%	$34	0.2%	$3

Figure 4.2 shows the hourly average amount of flexible ramping capacity procured in the 15-minute market during the first quarter. This capacity may have been procured to satisfy system-level demand, an area-specific demand, or both. The different colors indicate from which area the capacity was procured. The positive bars show procurement for upward flexible ramping, and the negative bars for downward flexible ramping. The hourly procurement profile is similar to the hourly profile of the system-level demand curves. This reflects that most of the flexible ramping capacity was procured to meet the system-level demand curve.

Overall, the ISO procured an average of about 810 MW of upward capacity and 780 MW of downward capacity in the 15-minute market during the first quarter. This represents a small decrease compared to November and December. The total average quantity of flexible ramping capacity procured in the 5-minute market was about 180 MW in the upward direction and 220 MW in the downward direction.

Figure 4.2 Hourly average flexible ramping capacity procurement in 15-minute market (January – March)



Flexible ramping procurement costs

Generation capacity that satisfied the demand for flexible ramping capacity received payments based on the flexible ramping shadow price. In addition, the flexible ramping shadow price is also used to pay or charge for forecast ramping movements. This means that a generator that was given an advisory dispatch by the market to increase output was paid the upward flexible ramping price and charged the downward flexible ramping price. Similarly, a generator that was forecasted to decrease output was charged the upward flexible ramping price and paid the downward flexible ramping price.[51]

The total net capacity payments to resources used to satisfy the demand for flexible ramping capacity typically are positive. The total net payments for forecasted movements may be either positive or negative, depending on market outcomes.

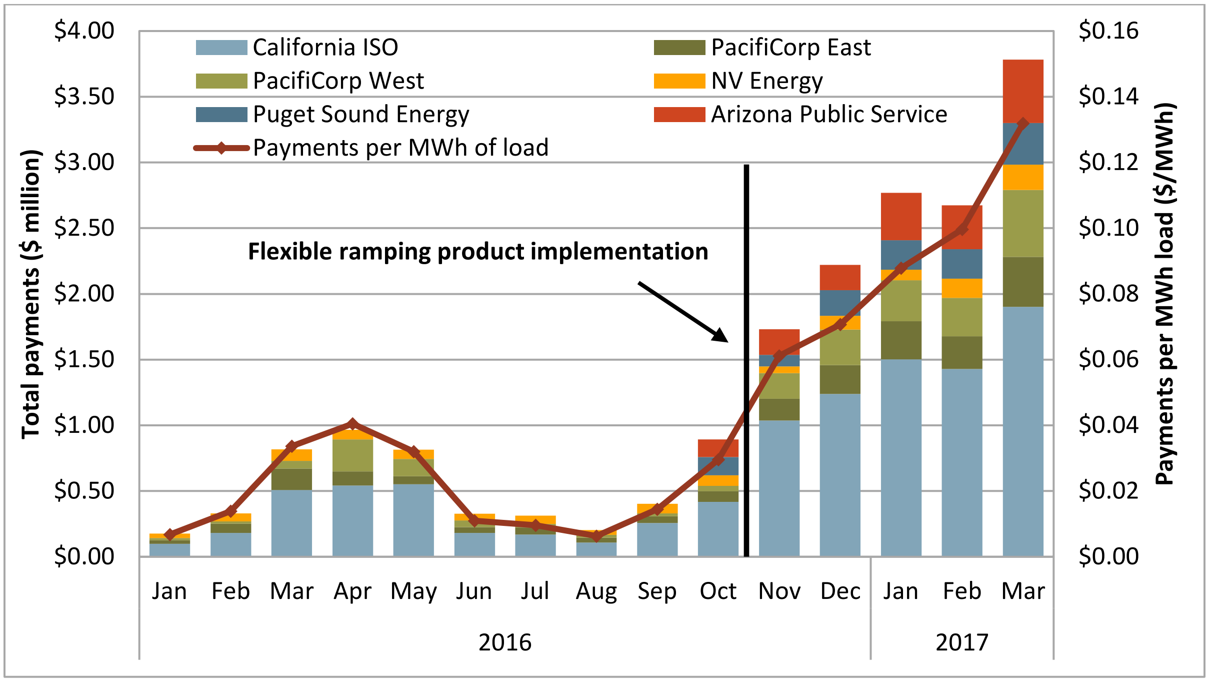
Figure 4.3 shows the total net payments to generators for flexible ramping capacity by month and balancing area.[52] For the time period before the flexible ramping product was implemented in

[51] More information about the settlement principles can be found in the ISO's *Revised Draft Final Proposal for the Flexible Ramping Product*, December 2015: http://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

[52] Secondary costs, such as costs associated with impacts of flexible ramping procurement on energy costs, bid cost recovery payments or ancillary service payments are not included in these calculations. Assessment of these costs is complex and beyond the scope of this analysis.

November 2016, Figure 4.3 shows net payments to generators from the flexible ramping constraint.[53] The values for November, 2016 and onward reflect net payments to generators from the flexible ramping product. This includes the total net amount paid for upward and downward flexible ramping capacity in both the 15-minute and 5-minute markets. Payments for forecasted movements are not included.[54]

Figure 4.3 Monthly flexible ramping payments by balancing area



As shown in Figure 4.3, total payments to generators increased following implementation of the flexible ramping product, and continued to increase in the first quarter. Total payments for flexible ramping capacity in the first quarter were about $9.2 million. About 52 percent of payments during the quarter were to ISO generators, which reflects the majority of flexible ramping capacity awards.

Although flexible ramping payments increased with the implementation of the flexible ramping product, payments per megawatt-hour of load remained low.[55] Average net payments per megawatt-hour of load during the first quarter were about $0.11/MWh, an increase from about $0.07/MWh during November and December.

53 Rescissions for non-performance have been excluded.

54 A prior version of this figure was shown in DMM's Q4 2016 report. The prior version included net payments for both capacity and forecasted movements. However, because of an error in the ISO's settlement calculations, the forecasted movement component of this value was inaccurate. In this version, the forecasted movement component has been excluded. The values in this section therefore differ slightly from those reported in the Q4 report.

55 Load is measured as the total load in the ISO and energy imbalance market areas.

Areas of continued review

The method used to calculate the flexible ramping demand curves represents an improvement compared to the method that was used for determining the flexible ramping constraint requirements. Nevertheless, there may be possibilities for additional enhancements after further study of the flexible ramping product. For example, it might be beneficial to base the demand curves on a larger sample of net load forecast errors.

Further, in the current implementation of the flexible ramping product, the demand curves for individual balancing areas are included in the constraint for system-level procurement. DMM believes that this implementation approach leads to system-level procurement of flexible ramping capacity, and associated flexible ramping shadow prices, that are lower than what would be consistent with the system-level flexible ramping demand curves.

For additional information about these topics, see DMM's 2016 annual report.[56]

4.2 Aliso Canyon gas-electric coordination

Following a significant natural gas leak in late 2015, the injection and withdrawal capabilities of the Aliso Canyon natural gas storage facility in Southern California were severely restricted. These restrictions impact the ability of pipeline operators to manage real-time natural gas supply and demand deviations, which in turn could have impacts on the real-time flexibility of natural gas-fired electric generators in Southern California. This primarily impacts resources operated in the Southern California Gas Company (SoCalGas) and San Diego Gas and Electric (SDG&E) service areas, collectively referred to as the SoCalGas system.

The ISO, Los Angeles Department of Water and Power, California Energy Commission and California Public Utilities Commission published a risk assessment and technical report in April 2016 finding that the limited operability of Aliso Canyon posed a significant risk to electric reliability during the summer months of 2016.[57] To address these reliability concerns, these agencies took many steps to manage system conditions, including the ISO which filed for FERC approval of several temporary tariff amendments in May 2016.[58] These tariff amendments, which are described in further detail below, were approved by FERC on June 1 and remained in effect until November 30, 2016.[59]

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56 *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, pp. 109-120: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

57 *Aliso Canyon Risk Assessment Technical Report*, April 5, 2016: http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf.

58 *Tariff Amendment to Enhance Gas-Electric Coordination to Address Risks Posed by Limited Operability of Aliso Canyon Natural Gas Storage Facility*, May 9, 2016: http://www.caiso.com/Documents/May9_2016_TariffAmendment_EnhanceGas-ElectricCoordination_LimitedOperation_AlisoCanyonNaturalGasStorageFacility_ER16-1649.pdf.

59 FERC order accepting tariff revisions, subject to condition, and establishing a technical conference: http://www.caiso.com/Documents/Jun1_2016_OrderAcceptingTariffRevisions_Establishing_TechnicalConference_AlisoCanyon_ER16-1649.pdf.

Other actions included SoCalGas adjusting its natural gas balancing rules to provide stronger incentives for natural gas customers, such as electric generators, to align their natural gas purchases and burns. Furthermore, electric operators and gas system operators developed enhanced coordination procedures that were used throughout the summer. Finally, relatively well-forecasted load and weather conditions may also have contributed to ensuring reliable conditions this past summer.

A follow-up risk assessment study, focusing on the upcoming winter months, was published in August.[60] In September, FERC organized a technical conference where both the ISO and DMM discussed the effectiveness of the temporary Aliso Canyon measures.[61] Following these studies and discussions, the ISO in October 2016 filed for FERC approval to allow most of the tariff amendments to remain in effect through November 30, 2017.[62] DMM filed comments that, overall, were supportive of the ISO's filing, but also recommended additional enhancements including making the update of natural gas prices for the day-ahead permanent and applying mitigation to exceptional dispatches that are made to manage natural gas limitations.[63] FERC approved the extension on November 28, 2016.[64]

The ISO has initiated a stakeholder process, Aliso Canyon gas-electric coordination phase 3, which proposes extending some of the Aliso Canyon measures in perpetuity and allowing these measures to be applied both across the ISO and Energy Imbalance Market footprint.[65]

Operational tools and corresponding mitigation measures

The ISO has developed a set of operational tools to manage potential gas system limitations that allows operators to restrict the gas burn of ISO natural gas-fired generating units. The tools, which were implemented as a set of nomogram constraints, can be used to limit either the total gas burn or deviations in gas burn compared to day-ahead schedules. These tools were available to operators beginning June 2, 2016.[66]

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[60] *Aliso Canyon Winter Risk Assessment Technical Report*, August 23, 2016: http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-02/TN212913_20160823T090035_Aliso_Canyon_Winter_Risk_Assessment_Technical_Report.pdf.

[61] The technical conference agenda and presentations can be found here: https://www.ferc.gov/eventcalendar/EventDetails.aspx?ID=8413&CalType=.

[62] *Filing to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility*, October 14, 2016: http://www.caiso.com/Documents/Oct14_2016_TariffAmendment_AlisoCanyonGasElectricCoordination_Phase2_ER17-110.pdf.

[63] *Comments of the Department of Market Monitoring of the California Independent System Operator on the Tariff Amendment Filed to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility*, Department of Market Monitoring, October 19, 2016, FERC Docket No. ER17-110-000.

[64] FERC order accepting tariff revisions, subject to condition: http://www.caiso.com/Documents/Nov28_2016_OrderAcceptingTariffAmendment_AlisoCanyonElectricGasCoordinationPhase2_ER17-110.pdf.

[65] Further information on this stakeholder process is available here: http://www.caiso.com/informed/Pages/StakeholderProcesses/AlisoCanyonGasElectricCoordination.aspx

[66] Refer to *Operating Procedure 4120C used during SoCalGas area limitations or outages:* http://www.caiso.com/Documents/4120C.pdf.

In the first quarter of 2017, the ISO enforced two gas constraints (San Diego Gas and Electric system and the broader Southern California Gas Company system) on four days, from January 23 -26. These constraints do not appear to have been sufficient, on their own, to limit gas burn from participating gas resources. As presented in the Market Performance and Planning Forum, shadow prices of each nomogram were either zero or set at the penalty price for most intervals, indicating that these constraint were likely to be either relaxed or not binding at all.[67] The activation of these constraints had a very limited impact on market outcomes.

Operators did not elect to enforce these constraints at all during the second or third quarters of 2016. In the fourth quarter, ISO operators temporarily used the functionality as a precautionary measure when managing a specific pipeline maintenance outage in the San Diego area. This had a very limited impact on market outcomes.

The effectiveness of the ISO's market power mitigation procedures may be adversely affected if operators enforce the gas burn constraints. The gas burn constraints would limit the amount of generation available to relieve congestion on a transmission constraint in a way that market power mitigation procedures would not account for. A transmission path may therefore be deemed competitive when in fact the amount of supply that can be dispatched to relieve congestion on these constraints is more restricted and uncompetitive because of the constraints. To address this limitation, the temporary tariff amendments include the authority for the ISO to deem transmission paths uncompetitive. Because of the limited use of the gas burn constraints during 2016 and 2017, this feature was also not used.

The existing manual dynamic competitive path assessment override process was meant to function as an emergency stop gap measure. It is a reactive process that is both less transparent and less capable than an automated process would be. Including the impacts of any and all gas nomograms in the automated dynamic competitive path assessment should be a necessary precursor to any decision to extend the nomograms beyond their current use and sunset date.

The tariff amendments also included the ability of the ISO to limit or suspend virtual bidding. A restriction on virtual bidding may be necessary if operators choose to reserve transmission capacity in the day-ahead market for use in the real-time market or if operators need to use the gas nomogram constraints differently in the day-ahead and real-time markets as these actions could cause systematic and predictable price differences between day-ahead and real-time prices. Virtual bidders could take advantage of such price differences, which may undo the intent of virtual bidding and could have negative impacts on market efficiency. Because the ISO did not implemented the gas constraints on a limited basis and did not limit flows on internal transmission, there was no need to consider suspending virtual bidding.

The ISO has requested to temporarily keep the ability to use the maximum gas limit constraint. As such, having the ability to suspend virtual bidding remains an important tool to protect against potential market inefficiencies, should they arise.

Additional bidding flexibility for SoCalGas resources

Starting July 6, to allow natural gas-fired generators in the SoCalGas system to reflect higher same day natural gas prices and to avoid having these resources dispatched for system needs in the event of

[67] http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum-Mar14_2017.pdf

constrained gas conditions in Southern California, the ISO adjusted the gas price indices used to calculate the commitment cost caps and default energy bids in the real-time market for natural gas-fired generators on the SoCalGas systems. A 75 percent adder was included in the fuel cost component used for calculating proxy commitment costs for resources on the SoCalGas systems in real time. The ISO also included a 25 percent adder for the fuel cost component of default energy bids in the real-time market. The 75 percent and 25 percent adders implemented by the ISO were based on analysis presented by DMM in its comments on the final Aliso Canyon gas-electric coordination proposal.[68]

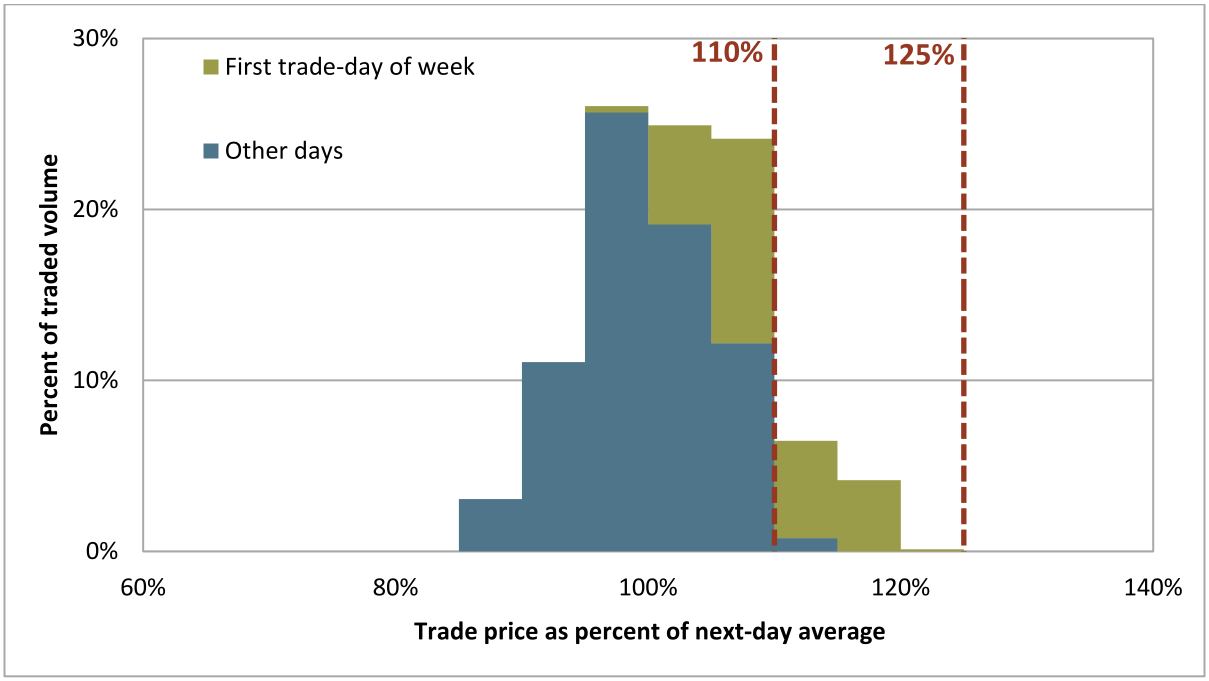
DMM's analysis of same day natural gas price volatility in Southern California during the first quarter of 2017 and 2016 shows that this additional flexibility has been sufficient to cover the vast majority of same day natural gas transaction prices. For example, of the same day traded volume observed on the InterContinental Exchange (ICE) at the SoCal Citygate during June through December, 74 percent was less than 10 percent higher than the next day index and 98.6 percent of same day traded volume was less than 25 percent higher than the next day index price. Thus, there was a very limited need overall for the increased bidding flexibility. A more detailed analysis and discussion of the increased bidding flexibility, focusing on the summer months of 2016, is available in DMM's comments to the ISO's October FERC filing.[69]

DMM's analysis of same day natural gas prices in Southern California in the first quarter shows that these adders caused gas prices used to calculate bid caps to exceed prices of all but a very small portion of natural gas transactions. Figure 4.4 shows same-day trade prices for the SoCal Citygate during January through March 2017 compared to the next-day average price. Only 10 percent of traded volume on ICE exceeded the normal 110 percent scalar adder at the SoCal Citygate and none of the traded volume exceeded the 125 percent adder. Figure 4.4 also shows that the majority of trades above the 110 percent level occurred on days that were the first trading day of the week, which was typically a Monday (as shown in green on the chart). Hence, this analysis shows that there was a very limited need for the increased bidding flexibility created by raising the commitment cost and default energy bid caps during the first quarter. DMM has recommended to the ISO that it significantly reduce the special Aliso Canyon gas price adders being applied to commitment cost and default energy bids used in the real-time market.

68 *Comments on Final Aliso Canyon Gas-Electric Coordination Proposal*, Department of Market Monitoring, May 6, 2016: http://www.caiso.com/Documents/DMMComments_AlisoCanyonGas_ElectricCoordinationRevisedDraftFinalProposal.pdf.

69 *Comments of the Department of Market Monitoring of the California Independent System Operator on the Tariff Amendment Filed to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility*, Department of Market Monitoring, October 19, 2016, FERC Docket No. ER17-110-000, pp. 7-9.

Figure 4.4 Same-day trade prices compared to next-day index (January – March)



Resources were also granted the ability to rebid their commitment costs in the real-time market, except for hours with day-ahead schedules or hours spanning minimum run times if committed in the real-time market. This ability was activated on June 2. As discussed in DMM's comments to the ISO's October filing, almost all of the capacity that made use of the ability to rebid commitment costs with the additional headroom during the summer months were bid in by one scheduling coordinator and the bidding pattern did not appear linked to same day price movements.

More timely natural gas prices for the day-ahead market

In addition to the tools described above, the ISO asked in its May FERC filing for permission to use a more timely natural gas price for calculating default energy bids and proxy commitment costs in the day-ahead market. With this modification, the ISO is basing natural gas price indices on next-day trades from the morning of the day-ahead market run instead of indices from the prior day.

The target implementation date for this measure was July 6. However, the ISO was not able to confirm that this price would be consistent with a FERC policy statement on natural gas indices.[70] FERC issued an order on this motion for clarification on October 20, confirming that the price update is consistent with the policy statement.[71] Consequently, the ISO implemented the new methodology on October 22, 2016.

70 For more information see the following limited tariff waiver petition: http://www.caiso.com/Documents/Jul12016_AlisoCanyonLtdTariffWaiverPetition_ER16-1649.pdf.

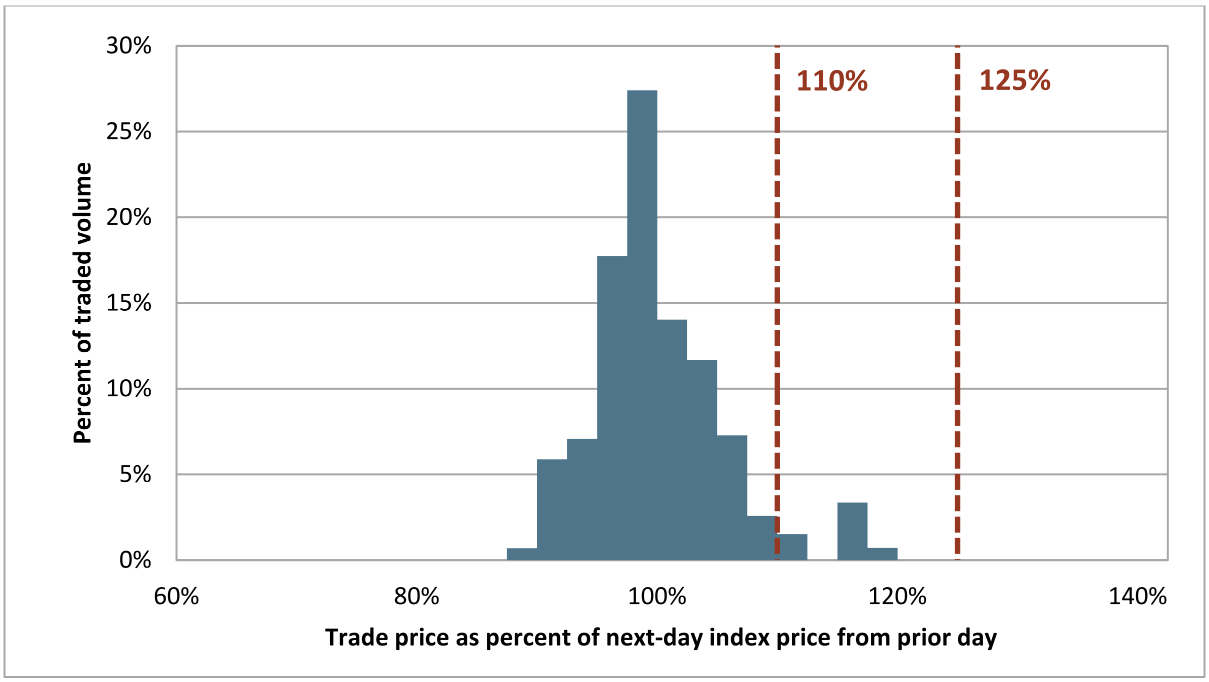
71 FERC order granting petition for extension of limited waiver and dismissing motion for clarification, October 20, 2016: http://www.caiso.com/Documents/Oct20_2016_OrderGrantingPetition_Extension_LimitedWaiver_DismissingMotion_Clarification_ER16-1649.pdf.

DMM was very supportive of this change and recommended in its October 20 filing that this be permanently extended.[72]

Figure 4.5 and Figure 4.6 illustrate the benefit of using the updated natural gas price index. Figure 4.5 shows next-day trade prices reported on ICE for the SoCal Citygate during the first quarter, compared to the next day price index previously used in the day-ahead market which was lagged by one trade day. As shown in Figure 4.5, about 6 percent of next day trades were at a price in excess of the 10 percent adder normally included in default energy bids. None of the next day trades were in excess of the 25 percent headroom normally included in commitment cost bid caps.

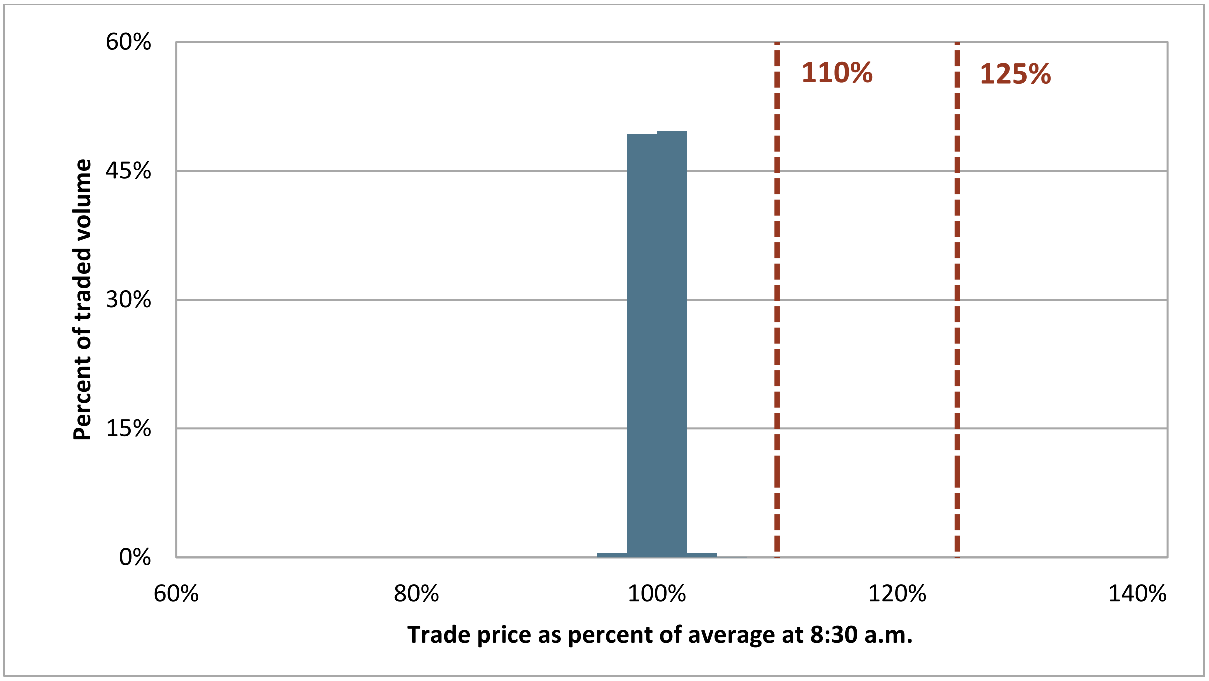
Figure 4.6 shows the same data but compares the price of each trade to a weighted average of trades reported on ICE before 8:30 am, just before the ISO runs the day-ahead market. This represents the updated method that the ISO is currently using. As shown in Figure 4.6, all trade prices are now within the 10 percent adder normally included in default energy bids.

Figure 4.5 Next-day trade prices compared to next-day index from prior day (January - March)



[72] *Comments of the Department of Market Monitoring of the California Independent System Operator on the Tariff Amendment Filed to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility*, Department of Market Monitoring, October 19, 2016, FERC Docket No. ER17-110-000, pp. 1-2.

Figure 4.6 Next-day trade prices compared to updated next-day average price (January - March)



Exceptional dispatch mitigation

While the ISO only made very limited use of the operational tools to manage gas limitations in 2016, it did use exceptional dispatches to help manage a broader set of conditions affecting gas supply in Southern California, including on December 17 and 18. However, at this time, the ISO is not able to mitigate exceptional dispatches for gas constraints, only noncompetitive transmission constraints and a few other specific reasons. As part of our FERC filing on October 20, DMM recommended that upward and downward exceptional dispatches issued to manage Aliso Canyon gas issues be considered non-competitive and subject to market power mitigation because of the potential for high market concentration of resources that could be exceptionally dispatched to address the gas constraints.[73] The ISO has included mitigation of exceptional dispatches as one of the topics to be addressed in the Commitment Costs and Default Energy Bid Enhancements stakeholder process.[74]

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[73] *Comments of the Department of Market Monitoring of the California Independent System Operator on the Tariff Amendment Filed to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility*, Department of Market Monitoring, October 19, 2016, FERC Docket No. ER17-110-000, pp. 12-17.

[74] *Commitment Costs and Default Energy Bid Enhancements Issue Paper*, November 18, 2016: http://www.caiso.com/Documents/IssuePaper_CommitmentCost_DefaultEnergyBidEnhancements.pdf.

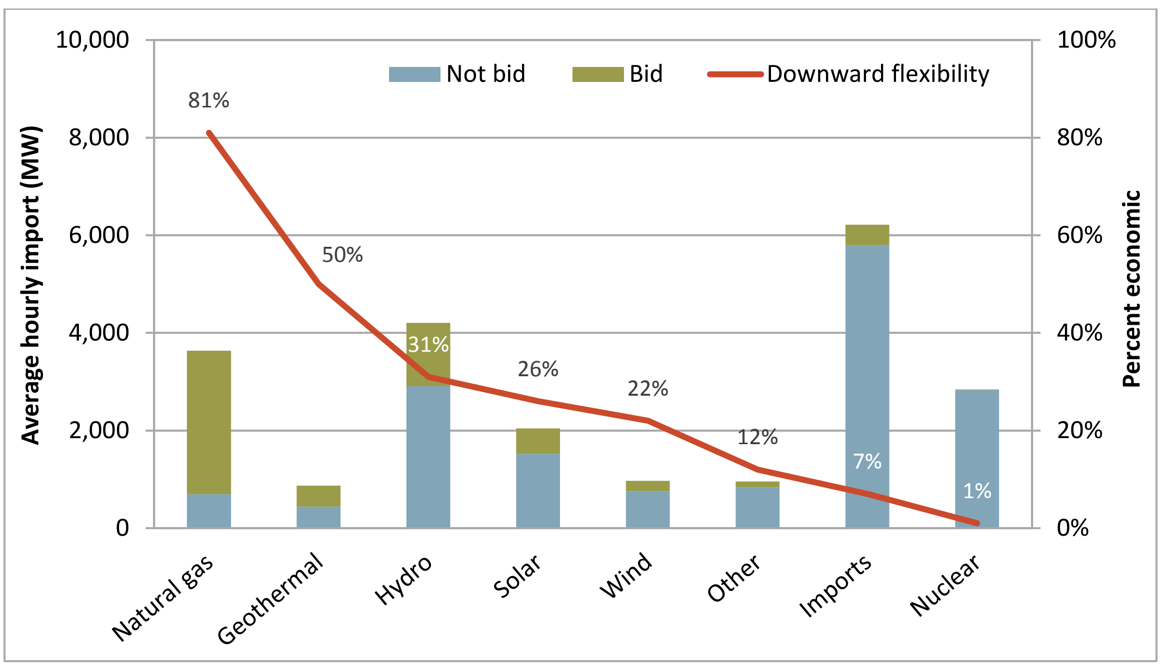
4.3 Net import flexibility

This section compares the availability of economic bids for imports and exports into and out of the ISO excluding self-schedules. As more renewable generation is added to the generation fleet in California to meet renewable portfolio standard goals economic bids for imports can help the market resolve surplus supply conditions and avoid curtailment of self-schedules. Sufficient economic bids from imports in the real-time market may reduce the number of intervals that the power balance constraint is relaxed and penalty parameters are used to set prices.

Figure 4.7 and Figure 4.8 show the current amount of flexibility for imports and exports in the real-time market. Figure 4.7 shows the real-time downward flexibility by fuel type within the ISO. During the quarter imports accounted for the greatest share of average hourly generation in the real-time market at over 6,000 MW. However, the portion of these imports bid into the 15-minute market and available to receive dispatch instructions only totaled about 500 MW (7 percent) per hour on average. By contrast, gas generation provided the most flexibility in the ISO, with about 3,000 MW (81 percent) per hour on average. Solar generation offered greater economic flexibility than imports, despite its intermittent nature. Similarly, a greater proportion of both solar and wind resources were bid flexibly into the 15-minute market.

Figure 4.8 shows quantities for imports and exports in the ISO during 2016 and the first quarter of 2017, and the proportion bid in flexibly or self-scheduled. For the first quarter of 2017, the portion of economic bids dropped to around 19 per cent on average.[75]

Figure 4.7 Average hourly real-time economic bids by generation type (January – March)



[75] The definition of 'bid' and 'not bid' in Figure 4.7 is not equivalent to 'self-scheduled' and 'economic bid' in Figure 4.8. There may be inflexible portions of economic bids, which is not captured in the simple 'self-scheduled' versus 'economic' dichotomy. This explains why the percent economic is lower in Figure 4.7. Figure 4.10 includes bids above $950/MWh and below -$135/MWh.

Figure 4.8 Average hourly real-time import and export bids (15-minute market)

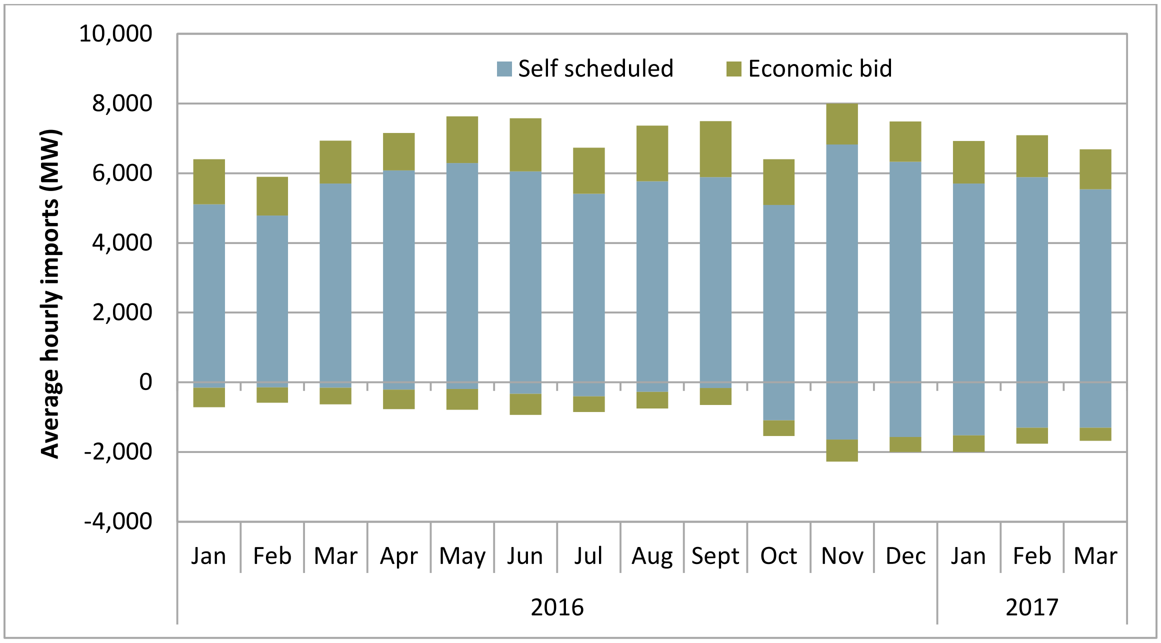
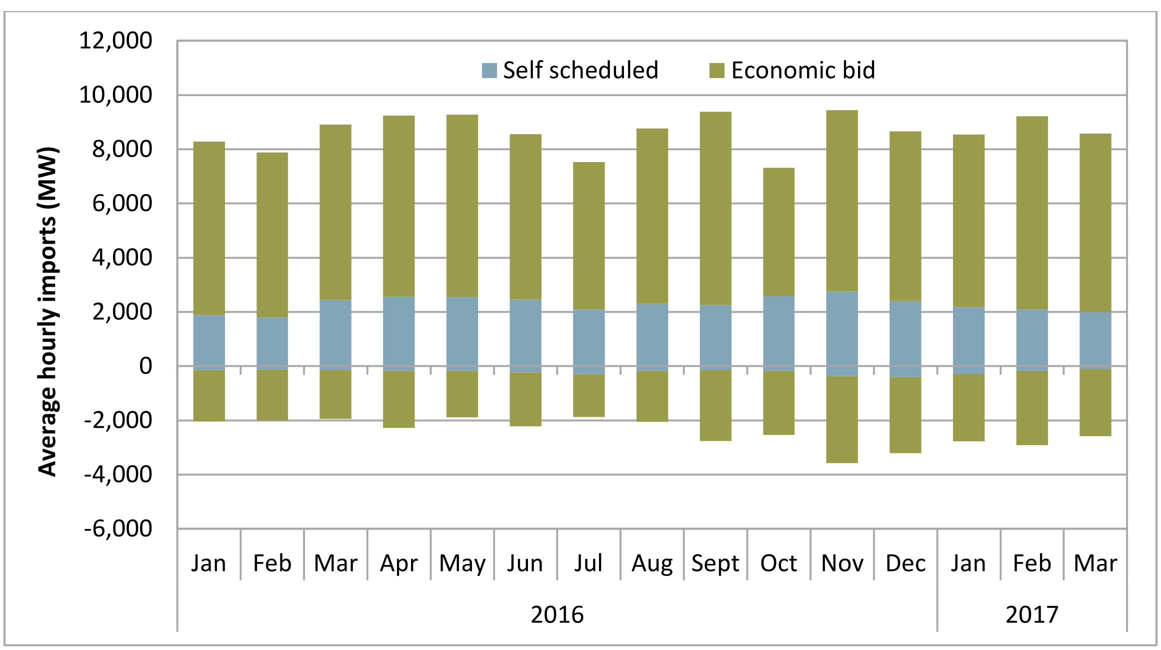


Figure 4.9 shows the same information for day-ahead bids for imports and exports beginning in 2016. There were a significantly greater proportion of economic bids for imports and exports in the day-ahead market than in the real-time market. On average, economic bids made up about 80 percent of imports and exports in the day-ahead market, while self-schedules made up the remaining 20 percent.

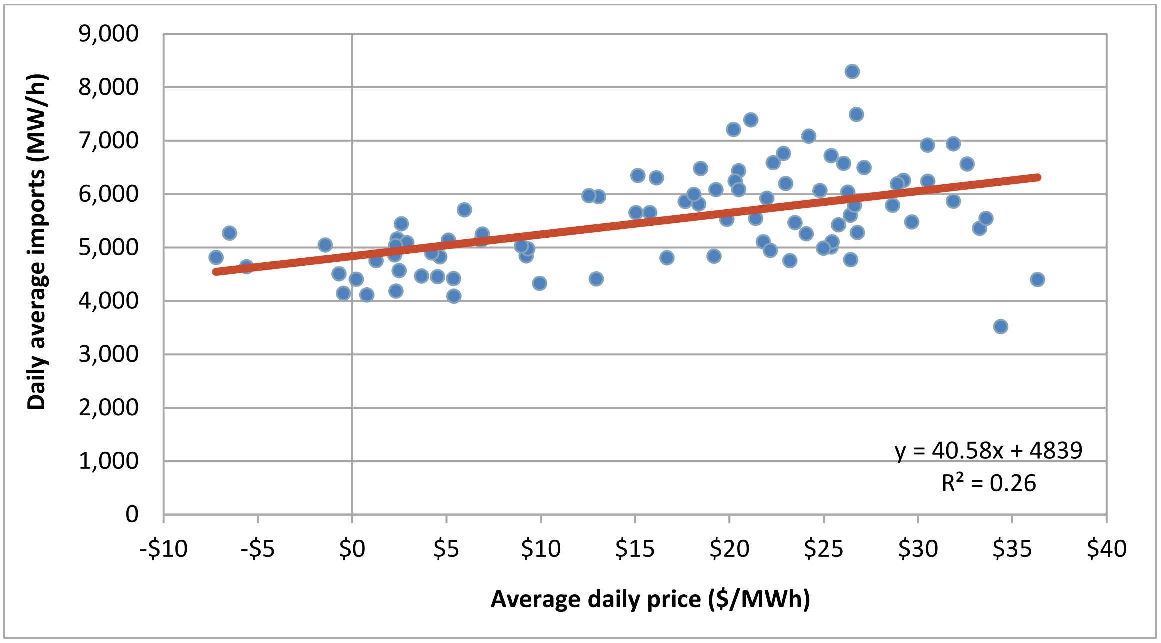
Figure 4.9 Average hourly day-ahead import and export bids



Economic flexibility for imports and exports in the day-ahead market may help relieve oversupply conditions occurring during midday hours when solar generation is greatest. Figure 4.10 shows a scatter plot of cleared prices in the day-ahead market and total imports into the ISO, as well as a trend line fitted to the data. This shows that when prices in the day-ahead market decreased the total amount of net imports to the ISO also decreased.

The red line is a simple linear regression of average hourly net imports against price.[76] This shows that for each one dollar reduction in price net imports decreased by about 40 MW and that the day-ahead market provides the opportunity for imports to conform to market conditions, including oversupply.

Figure 4.10 Daily cleared net imports and day-ahead prices (Hours 9 – 16)



[76] The regression in Figure 4.10 is indicative of the relationship between net imports and price in the day-ahead market. However, a more accurate price coefficient may be produced by including additional covariates such as daily average hourly load and peak load, considering individual data points instead of daily averages, and properly addressing heteroscedasticity and the shape of the distribution.