California ISO

California Independent System Operator Corporation

California ISO

Q3 2017 Report on Market Issues and Performance

December 8, 2017

Department of Market Monitoring

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Executive summary

This report covers market performance during the third quarter of 2017 (July – September). Key highlights during this quarter include the following:

- The ISO market experienced two system-wide heat waves and very high loads at the beginning of August and at the end of August continuing into early September. System load peaked at 50,116 MW on September 1, almost reaching the all-time system high: 50,270 MW on July 24, 2006.
- Day-ahead prices reached historic highs. On September 1, system marginal energy prices in the day-ahead market reached were greater than $200/MWh during a four-hour period and over $770/MWh in one hour.
- The frequency of price spikes in the 15-minute and 5-minute markets increased during the quarter.
- Total wholesale energy costs for year-to-date 2017, normalized for gas and greenhouse gas prices, remain very close to totals from 2016. Higher gas prices resulted in larger overall costs to deliver energy in 2017. On the peak load day in September, prices in the day-ahead market were significantly higher than prices in the bilateral markets.
- Analysis by the Department of Market Monitoring (DMM) of same-day natural gas price volatility in Southern California year-to-date in 2017 shows that there has been a very limited need for the increased bidding flexibility created by raising commitment cost and default energy bid caps. Following a recommendation by DMM to address this issue, the ISO reduced the Aliso Canyon real-time gas scalars to zero beginning August 1, 2017, raising them again on a temporary basis from August 4 through August 7, 2017.
- On June 14, the ISO began increasing operating reserve requirements during midday hours to account for solar generation inverter fault response in the system by using an existing functionality within the software that allows operators to increase the requirement by a specified percent of the load forecast. The ISO frequently increased operating reserve requirements for hours ending 9 through 16 by 1.5 percent of the load forecast between July 1 and September 18. This increase was equal to roughly 25 percent of utility-scale solar generation. Starting on September 19, the upward adjustments were removed after the ISO indicated that remediation of the underlying solar response to fault conditions had been partially addressed such that the 25 percent solar criteria was reduced to 15 percent.
- During the third quarter of 2017, auction revenues were $9 million less than congestion payments made to non-load-serving entities purchasing these rights, thus increasing the year-to-date ratepayer losses to $38 million. Losses in the third quarter represent $0.72 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders. Total ratepayer losses from the congestion revenue rights auction were larger than $680 million since the market began in 2009.[1]

[1] *Summary of Testimony of Eric Hildebrandt, PhD*, Committee on Energy and Commerce Subcommittee on Energy United States House of Representatives, November 29, 2017: http://docs.house.gov/meetings/IF/IF03/20171129/106663/HHRG-115-IF03-Wstate-HildebrandtE-20171129.pdf

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

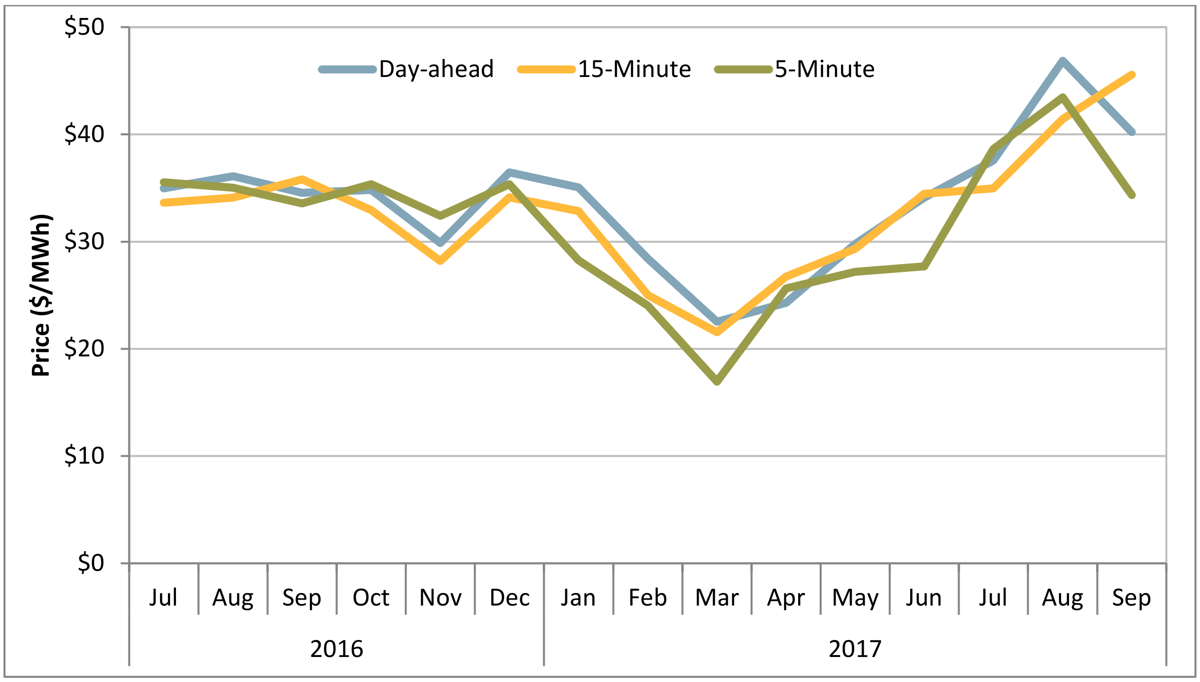
- Average 15-minute market prices increased during every month of the third quarter from around $34/MWh in June to over $45/MWh in September. Average day-ahead and 5-minute market prices also increased overall due to seasonally higher temperatures and loads.
- In the day-ahead market, the impact of congestion was low on Pacific Gas and Electric and Southern California Edison area prices, but decreased prices in the San Diego Gas and Electric area by about $0.80/MWh (2 percent). In the 15-minute market, congestion increased Pacific Gas and Electric and Southern California Edison area prices by about $1.20/MWh and $0.50/MWh respectively, and decreased San Diego Gas and Electric area prices by about $0.40/MWh.
- Bid cost recovery payments were about $30 million in the third quarter, compared to $21 million during the same quarter during 2016. Real-time bid cost recovery remained the largest category and totaled about $24 million, a significant portion from a few specific days.
- Net revenues for convergence bidders before accounting for bid cost recovery charges were about $3.3 million. Net revenues for virtual supply and demand fell to about $1.6 million after including about $1.7 million of virtual bidding bid cost recovery charges.
- Total payments for flexible ramping capacity in the third quarter with the flexible ramping product were about $5.1 million, down from $7.5 million in the previous quarter. About 55 percent of payments during the quarter were to ISO generators, which reflects the majority of flexible ramping capacity awards.
- The ISO continued to rely on imports dispatched after the day-ahead market to meet load in peak periods. A substantial increase in load adjustment in the hour-ahead and fifteen minute markets during peak hours is correlated with incremental increases in net imports into the ISO. The ISO also issued manual dispatches on the interties for system reliability on 12 days thus far in 2017.
- Average prices in PacifiCorp East, NV Energy, and Arizona Public Service were often similar to each other and the ISO during most hours. However, in other hours, one or more of these areas failed the flexible ramping sufficiency test or reached their transfer limits which created price separation. 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.
- Balancing areas failed the flexible ramping sufficiency tests less frequently overall during the quarter. In particular, Puget Sound Energy failed the downward sufficiency test in less than 1 percent of hours during the quarter, compared to about 13 percent of hours in the previous quarter. However, NV Energy failed the tests more frequently, during over 5 percent of hours in the upward direction and over 3 percent of hours in the downward direction.
- Overall, load adjustments were typically positive in PacifiCorp East, Arizona Public Service and the ISO, while negative load adjustments were frequent in PacifiCorp West and Puget Sound Energy. NV Energy load adjustments were typically positive in the 15-minute market and negative in the 5-minute market.

Energy market performance

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

Average energy prices rose during the third quarter. In August, average day-ahead prices reached about $47/MWh. This was the highest average monthly day-ahead price since 2014. Day-ahead prices were high in the other months of the quarter as well, averaging $38/MWh in July and $40/MWh in September. This coincided with seasonally higher temperatures and associated higher loads. Prices were also high in both the 15-minute and 5-minute markets. Average prices in the 15-minute market were lower than prices in the day-ahead market in July and August but increased to $46/MWh in September, more than $5/MWh above the day-ahead price. Prices in the 5-minute market were lower than both day-ahead and 15-minute market prices on average during the quarter. In June, average 5-minute prices were higher than both day-ahead and 15-minute prices.

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



The day-ahead system marginal energy price reached $770/MWh for hour ending 19 on September 1, an historic high. The ISO market experienced two system-wide heat waves and associated high loads at the beginning of August and at the end of August continuing into early September. During these periods, daily peak loads and day-ahead system marginal energy prices were very high. On September 1, load peaked at 50,116 MW. On August 1, August 2, August 28, August 29, August 31 and September 1, the day-ahead market experienced very high system marginal energy prices greater than $250/MWh in hours ending 19 and 20 when load net of wind and solar was highest. On September 1, when loads were highest, the day-ahead system marginal energy price peaked at around $770/MWh. These outcomes were primarily driven by tight supply conditions as a result of a number of factors in combination with high demand while a significant amount of solar production is ramping down during sunset hours.

Day-ahead market prices appear competitive in most but not all hours of the third quarter. Total wholesale energy costs for year-to-date 2017, normalized for gas and greenhouse gas prices, remain very close to totals from 2016. Higher gas prices resulted in larger overall costs to deliver energy in 2017 and explained much of the increase from 2016. On the peak load day in the beginning of September, prices in the day-ahead market were significantly higher than prices in the bilateral markets. This and other high load days in the quarter also coincided with hours when the residual supply index was lowest. On most days, prices in the ISO reflect typical premiums, from greenhouse gas costs within the state, over average bilateral prices for energy traded at the Palo Verde and Mid-Columbia hubs.

Price spikes were observed relatively frequently in both the 15-minute and 5-minute markets. The frequency of high prices in the 15-minute market increased significantly during the quarter, particularly during September when prices above $250/MWh occurred during almost 1.5 percent of intervals. These high prices mostly occurred on a small number of days during periods when “net load” (load net of wind and solar) was very high, Hours 19-21. The frequency of price spikes in the 5-minute market greater than $250/MWh also increased from the previous quarter to almost 1.2 percent of intervals, up from 0.9 percent of intervals in the previous quarter. In addition, the frequency of more extreme 5-minute prices larger than $750/MWh continued to increase to almost 0.8 percent of intervals during the quarter. The load bias limiter triggered during most extreme price intervals with a resulting price near the $1,000/MWh bid cap in both the 15-minute and 5-minute markets due to the presence of high economic bids.

Congestion reduced prices in the San Diego Gas and Electric area but had little impact elsewhere. In the day-ahead market, the impact of congestion was low on Pacific Gas and Electric and Southern California Edison area prices, but decreased prices in the San Diego Gas and Electric area by about $0.80/MWh (2 percent). In the 15-minute market, congestion increased Pacific Gas and Electric and Southern California Edison area prices by about $1.20/MWh and $0.50/MWh respectively, and decreased San Diego Gas and Electric area prices by about $0.40/MWh. Frequent congestion on the Doublet Tap-Friars 138 kV constraint created a generation pocket, or an export constrained area, and resulted in lower prices in San Diego.

Bid cost recovery payments increased. Overall bid cost recovery payments were $30 million in the quarter, slightly higher than costs during the prior quarter this year and significantly higher than the $21 million cost during the same quarter of 2016. Real-time bid cost recovery remains the largest category and totaled about $24 million in the third quarter, up from $21 million in the last quarter. Bid cost recovery attributed to the day-ahead market totaled about $3 million while payments for residual unit commitment totaled about $2.5 million.

Virtual supply revenues were negative. Convergence bidding was profitable overall during the third quarter with combined net revenues of about $1.6 million after accounting for bid cost recovery charges. However, total virtual supply accounted for around $0.9 million in net payments to the market for the quarter, before accounting for bid cost recovery charges. This was only the third quarter that virtual supply was not profitable overall since implementation of convergence bidding in February 2011.

Auction revenues from congestion revenue rights continue to fall short of payments made by ratepayers this quarter. In the third quarter of 2017, congestion revenue rights auction revenues were $9 million less than congestion payments made to non-load-serving entities purchasing these rights. This represents only $0.72 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, an increase from the annual average of $0.65 in 2016. Financial participants continued to garner the highest profits, netting $11 million (paying 55 cents in the auction per dollar of congestion revenue rights revenue). Generators lost about $0.6 million (paying $1.4 per dollar of revenue), while marketers lost $1 million (paying $1.1 per dollar of revenue). Load-serving entities gained about $0.8 million from rights they explicitly sold in the auction in the third quarter of 2017, down from about $3.4 million in the same quarter of 2016.

Special issues

Measures of system level market power in the ISO's day-ahead market indicate an increased frequency of hours in which competitive supply was insufficient to meet demand. The residual supply index with the three largest suppliers removed (RSI_3) was less than 1 during about 60 hours through the end of September, or about double the number of hours in 2016. The index was less than 1 during about 20 hours with the two largest suppliers removed (RSI_2), compared to only 2 hours in 2016. The RSI_1 value was only less than 1 during 1 hour. The hourly RSI_3 value reached as low as 0.86 in 2017, compared to about 0.92 in 2016. These hours include those in which the ISO's market has observed historically high day-ahead prices.

The ISO has determined that a software error caused pre-mitigation prices to be unreasonably low on June 21 and other days. As reported in DMM's second quarter report, on June 21, system marginal prices in the binding integrated forward market run, following mitigation, were significantly higher than in the market power mitigation run.[2] Similar discrepancies have occurred on other days in both the day-ahead and real-time markets. Since publication of that report, the ISO has determined that a software error introduced in 2016 resulted in infeasible energy and ancillary service awards for resources in the market power mitigation run but not the binding market run in the day-ahead market. The software error resulted in an erroneous increase in supply available in the market power mitigation run, causing prices in that run to be lower than they would have been had all awarded schedules been feasible. The ISO is currently evaluating the impact of this error on the market power mitigation process on affected days. The error was eliminated effective July 22, 2017, in the day-ahead market.

The ISO reduced the special Aliso Canyon gas price scalars to zero. The measures adopted by the ISO in response to the Aliso issue included the addition of real-time gas price scalar adjustments for the fuel component of default energy bids (25 percent) and commitment cost bids (75 percent). DMM's analysis of same day natural gas prices in Southern California since these scalars were implemented in July 2016 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. Based on this analysis, DMM recommended the ISO review this issue and lower the scalars. Starting on August 1, the ISO reduced the special Aliso Canyon gas price scalars being applied to commitment cost and default energy bids in the real-time market to zero. Following a curtailment watch issued by SoCalGas due to an unplanned pipeline outage, the ISO adjusted the scalars to 75 percent and 25 percent for commitment cost and default energy bid calculation effective August 4, 2017.[3] During the days when the scalars were active, same day prices on the Intercontinental Exchange were trading below the next day index. Effective August 8, 2017, the ISO lowered the scalars back to zero for commitment cost and default energy bid calculation based on the gas supply conditions and levels of load in the ISO system.

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[2] *Q2 2017 Report on Market Issues and Performance*, September 25, 2017: http://www.caiso.com/Documents/2017SecondQuarterReport-MarketIssuesandPerformance-September2017.pdf

[3] *Market Notice - Adjustment of Gas Price Index Scaling Factors*, August 3,2017: http://www.caiso.com/Documents/Adjustment_GasPriceIndexScalingFactors080317.html

Resource adequacy capacity showings were sufficient to meet load on some but not all days in the third quarter. Peak loads on September 1 and September 2 were above 47,000 MW with loads reaching over 50,000 MW on September 1, significantly larger than system resource adequacy requirements which decreased from about 50,000 MW in August to about 46,000 MW in September. Actual resource adequacy procurement on both days was just below 47,000 MW, with over 43,000 MW (96 percent) available in the day-ahead market during the peak load hour on September 1 and about 42,000 MW (92 percent) available on September 2. On average, less than 95 percent of the resource adequacy capacity shown in the quarter was available in the day-ahead market. The resource adequacy availability incentive mechanism (RAAIM) became effective in April. The ISO identified a number of issues with the mechanism and is working to correct them. Some of these changes will be put in place in the fall software release and applied retroactively to settlement from the effective date in April 2017 forward, and some will be released at a later date and applied proactively. A single intra-monthly capacity procurement designation was accepted by a scheduling coordinator during the quarter.

Key recommendations

Develop enhancement to avoid lowering system-level flexible ramping product prices and procured quantities when inappropriate. In the initial implementation of the flexible ramping product, demand curves for individual balancing areas were 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. This aspect of the flexible ramping product was active throughout the second quarter. The ISO implemented a software change on July 13, 2017, to limit the use of demand curves from individual balancing areas to zero when sufficient transfer capability connected the area with system conditions. However, the implementation of this enhancement has resulted in market outcomes in which resources providing flexible ramping capacity received lower payments based on the balancing area specific demand curve rather than the system-level demand curve.

Further review the impact of the identified software error in the market power mitigation run on the accuracy of mitigation in the day-ahead market. The ISO has reported to DMM that the identified software error was in place from August 17, 2016, through July 20, 2017. The reported error allowed combined energy and ancillary service awards in violation of available capacity in the market power mitigation run in some cases. Further research is needed to determine the impact of the software error on the automated mitigation process during that time. If possible, DMM requests that the ISO include a replication of market results as part of the ISO's review.

Develop the capability to update gas prices in real-time rather than continuing use of gas cost scalars. Since the ISO lowered the gas cost scalars to 100 percent on August 1, 2017, the ISO has temporarily re-set the gas scalars back to the 175 percent and 125 percent default levels on three occasions, the first described above and the second two in the fourth quarter. DMM believes each of these events highlights the problems associated with use of the gas cost scalars as a tool to help ensure reliability while effectively mitigating market power. The first is the delay in activating and deactivating scalars in response to real time gas conditions. The second is the challenge of matching fixed increased scalars to real-time gas price increases. Both events also highlight the need for the ISO to develop the capability to update gas prices used in the real-time market based on same day gas market price information that is available each morning, as recommended by DMM.[4]

[4] Further detail on DMM's recommendation is available in DMM's comments on the ISO's recent tariff filing to extend Aliso provisions: http://www.caiso.com/Documents/Oct26_2017_DMMComments-AlisoCanyonElectric-GasCoordinationPhase3_ER17-2568.pdf

1 Market performance

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

- Average 15-minute market prices increased during every month of the third quarter from around $34/MWh in June to over $45/MWh in September. Average day-ahead and 5-minute market prices also increased overall due to seasonally higher temperatures and loads.

- The ISO market experienced two system-wide heat waves and associated high loads at the beginning of August and at the end of August continuing into early September. During these periods, daily peak loads and day-ahead system marginal energy prices were very high. On September 1, load peaked at 50,116 MW and day-ahead prices peaked at around $770/MWh.

- The frequency of high prices in the 15-minute market increased significantly during the quarter, particularly during September when prices above $250/MWh occurred during almost 1.5 percent of intervals. These high prices mostly occurred on a small number of days during periods when load net of wind and solar was very high.

- In the day-ahead market, the impact of congestion was low on Pacific Gas and Electric and Southern California Edison area prices, but decreased prices in the San Diego Gas and Electric area by about $0.80/MWh (2 percent). In the 15-minute market, congestion increased Pacific Gas and Electric and Southern California Edison area prices by about $1.20/MWh and $0.50/MWh, respectively, and decreased San Diego Gas and Electric area prices by about $0.40/MWh. Frequent congestion on the Doublet Tap-Friars 138 kV constraint created a generation pocket, or an export constrained area, and resulted in lower prices in San Diego.

- The ISO frequently increased operating reserve requirements for hours ending 9 through 16 by 1.5 percent of the load forecast between July 1 and September 18. This increase was equal to roughly 25 percent of utility-scale solar generation.

- Total bid cost recovery payments for the third quarter were about $30 million. This amount was slightly higher than the total amount of bid cost recovery in the previous quarter but much higher than the third quarter of 2016, when it was about $21 million. A significant amount of the bid cost recovery payments were accrued in the real-time market during July and August.

- Convergence bidding was profitable during the third quarter with combined net revenues of about $1.6 million after accounting for bid cost recovery charges. However, virtual supply continued to be unprofitable for the second consecutive quarter and only the third quarter since implementation in February 2011.

- During the third quarter of 2017, auction revenues were $9 million less than congestion payments made to non-load-serving entities purchasing these rights, thus increasing the year-to-date ratepayer losses to $38 million. Losses in the third quarter represent $0.72 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders. Total ratepayer losses from the congestion revenue rights auction were larger than $680 million since the market began in 2009.

- On July 13, 2017, an adjustment was made to limit the use of flexible ramping product demand curves from individual balancing areas to zero when sufficient transfer capability connected the area with system conditions. However, since this adjustment was made, resources providing flexible ramping capacity received lower payments based on the area-specific demand curve rather than the system-level demand curve in many intervals when sufficient transfer capacity was present.

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 continued to increase overall during the third quarter. Prices increased relative to the previous quarter because of seasonally higher temperatures and associated higher loads.

- Average 15-minute market prices increased during every month of the third quarter from around $34/MWh in June to over $45/MWh in September. Average 15-minute market prices in September were higher than day-ahead and 5-minute market prices by about $5/MWh and $11/MWh, respectively.
- Average day-ahead and 5-minute market prices increased in July and August, then decreased in September. In August, average day-ahead prices reached about $47/MWh. This was the highest average monthly day-ahead price since 2014.

Figure 1.2 illustrates system marginal energy prices on an hourly basis in the third quarter compared to average hourly net load.[5] Prices in this figure generally follow the net load pattern with the highest energy prices occurring during the evening peak load hours. In particular, prices were highest during hours ending 18 through 20. Further, average 15-minute market prices were about $10/MWh higher than average day-ahead and 5-minute market prices in hour ending 19. Under-supply infeasibilities in the 15-minute market during some of the highest load periods of the quarter increased prices in the 15-minute market.

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5 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

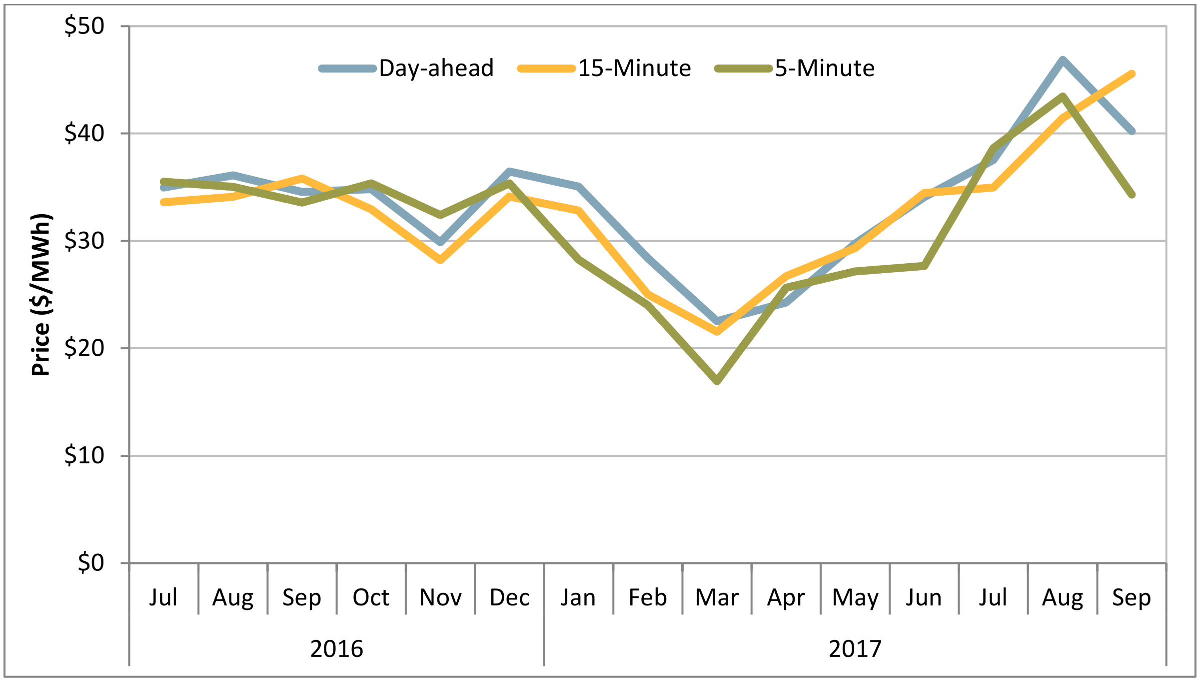
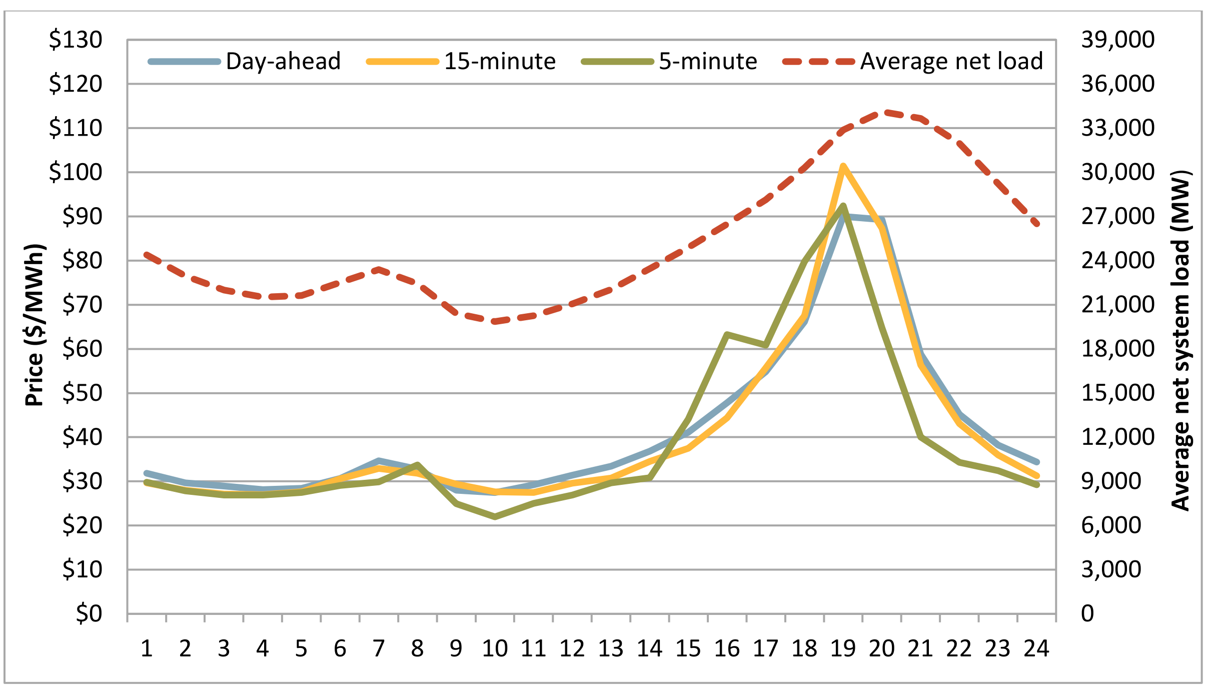


Figure 1.2 Hourly system marginal energy prices



Market competitiveness

In this section we review the competitiveness of the market and study the existence of potential market power with regard to the formation of day-ahead prices. The results of this study are outlined below.

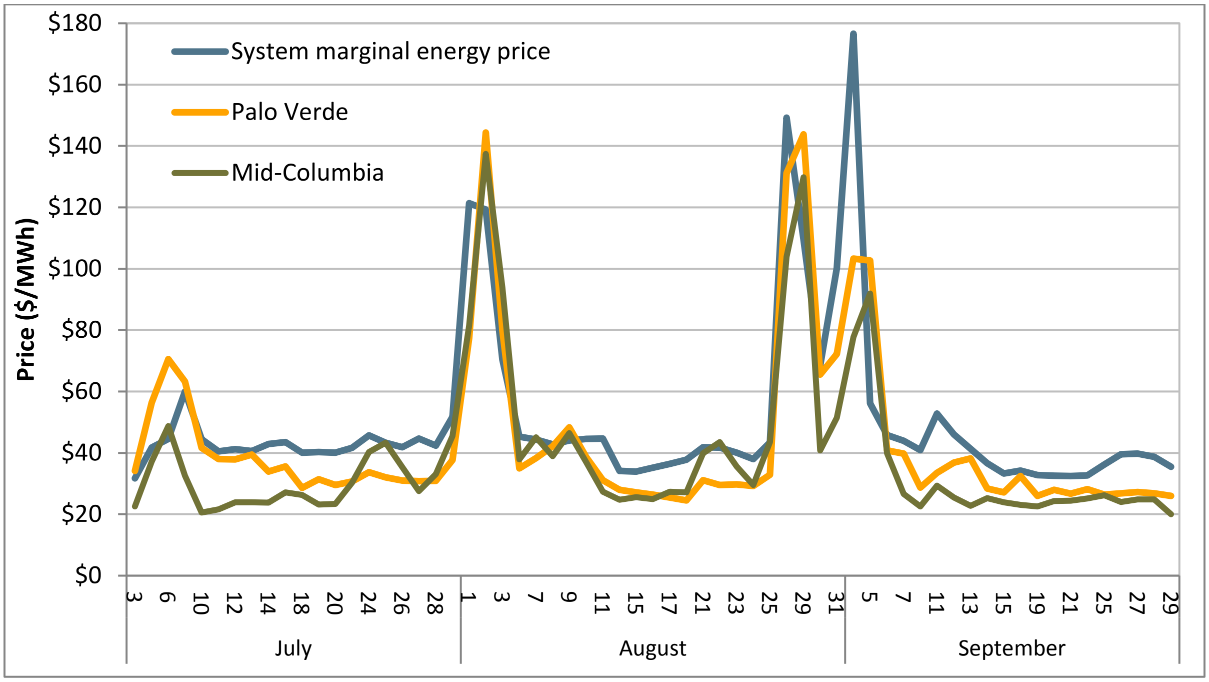
- Overall competitiveness in the day-ahead market remains strong. Higher gas prices resulted in larger overall costs to deliver energy in 2017 and explained much of the increase from 2016. Total wholesale energy costs for year-to-date 2017, normalized for gas prices, remain very close to totals from 2016.
- During a few days in the beginning of September, prices in the day-ahead market were significantly higher than prices in the bilateral markets. These days also coincided with hours when the residual supply index was lowest.
- Prices in the ISO reflect typical premiums, from greenhouse gas costs within the state, over average bilateral prices for energy traded at the Palo Verde and Mid-Columbia hubs.

Figure 1.3 shows day-ahead system marginal energy costs (SMEC) for energy in the ISO, as well as average peak energy prices traded at the Palo Verde and Mid-Columbia hubs outside of the California ISO market, for the quarter.[6] The chart shows that prices at Mid-Columbia were consistently lower than prices at Palo Verde, and that prices at Palo Verde were consistently lower than prices in the ISO. This is consistent with historical trends, where prices at hubs in the north tend to be lower than prices in the south, and prices in California tend to be higher than prices outside of California because of the greenhouse gas costs associated with generating energy in California or delivering energy into the state.

On most days average ISO prices were not significantly higher than greenhouse gas costs. One notable exception was September 1, when ISO prices averaged more than $175/MWh and prices at Mid-Columbia were only about $80/MWh. On average, prices were about $7/MWh higher in the ISO than at Palo Verde, a difference that is due in part to greenhouse gas compliance costs.

[6] Day-ahead system marginal energy costs only include the peak hours, for comparison purposes to the peak bilateral prices.

Figure 1.3 Daily system and bilateral market prices (July - September)



In addition to review of bilateral prices outside of the ISO, total wholesale cost to serve load in the market provides an additional measure of market competitiveness.[7] Extending the total costs during the first three quarters of 2017 through the end of the year would result in an estimated total cost to serve market load in 2017 of about $9.2 billion, compared to about $7.4 billion in 2016. These costs were just over $40/MWh for the first three quarters, compared to about $34/MWh in 2016. This is illustrated in Figure 1.4, where the blue bars represent nominal costs and show an increase from 2016 to 2017. Higher gas prices in California explain most of the differences in costs between the two years. The green line in this figure shows that average gas prices increased from about $2.63/MMBtu in 2016 to about $3.22/MMBtu during the first three quarters of 2017.[8] The gold bar in Figure 1.4 shows that wholesale energy costs to serve load normalized for changes in natural gas and greenhouse gas costs remained relatively stable from 2016 to 2017.

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7 The methodology for calculating the total wholesale energy cost is outlined in DMM's 2016 annual report (pp 60-61): http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

8 DMM uses a blend of natural gas prices at PG&E Citygate and SoCal Citygate during the period for this calculation. We normalize costs with a weighted natural gas and greenhouse gas cost because the marginal generating unit continues to be natural gas for a majority of intervals and the greenhouse gas is applicable to marginal prices and changes in these prices over time.

Figure 1.4 Total annual wholesale costs per MWh of load (2013-2017YTD)

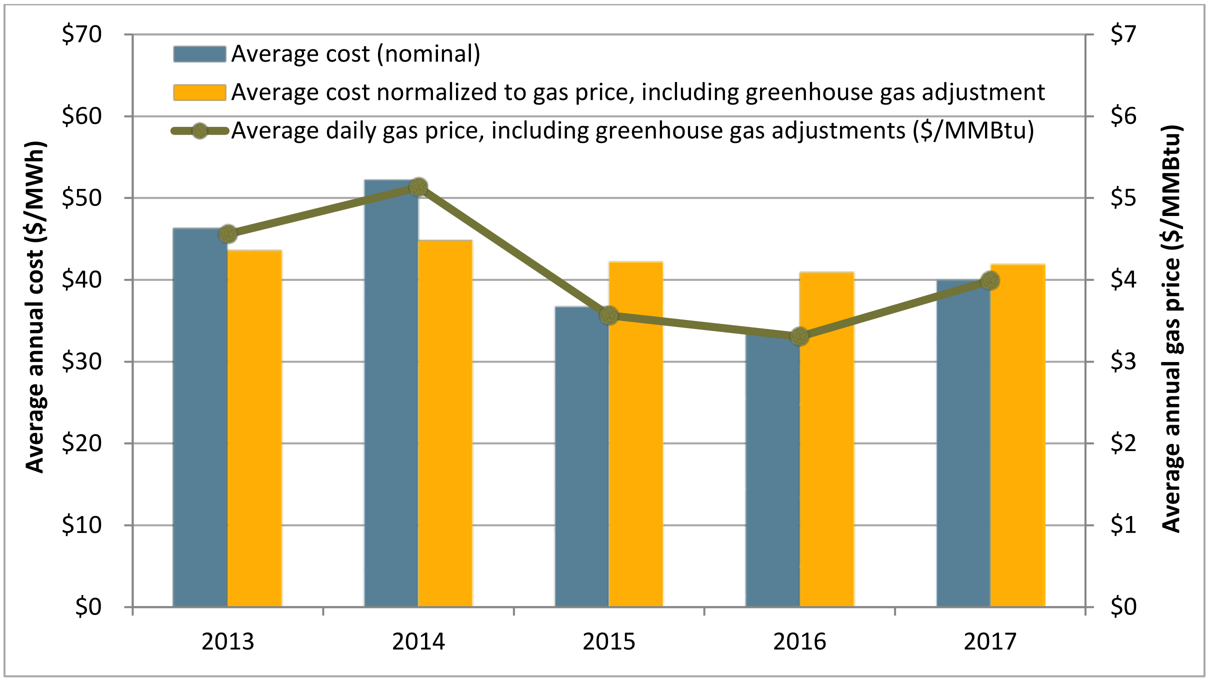

Table 1.1 provides annual summaries of nominal total wholesale costs by category from 2013 through the third quarter of 2017. Costs for energy procured in the day-ahead market continued to make up a majority (91 percent) of the total cost to deliver energy to the market, followed by costs from the real-time market (5 percent). These proportions are consistent with data from prior years. Higher costs through the third quarter of 2017, of about $6/MWh, resulted in higher total wholesale energy costs in the market compared to 2016. Real-time energy prices also increased, by just under $1/MWh, during the same time period.

Table 1.1 Estimated average wholesale energy cost per total MWh (2013-2017YTD)

	2013	2014	2015	2016	2017	Change '16-'17
Day-ahead energy costs	$ 44.14	$ 48.57	$ 34.54	$ 30.70	$ 36.33	$ 5.62
Real-time energy costs (incl. flex ramp)	$ 0.57	$ 1.98	$ 0.69	$ 1.02	$ 1.83	$ 0.81
Grid management charge	$ 0.80	$ 0.80	$ 0.80	$ 0.81	$ 0.81	$ 0.01
Bid cost recovery costs	$ 0.47	$ 0.40	$ 0.39	$ 0.33	$ 0.35	$ 0.02
Reliability costs (RMR and CPM)	$ 0.10	$ 0.14	$ 0.12	$ 0.11	$ 0.08	$ (0.03)
Average total energy costs	**$ 46.08**	**$ 51.89**	**$ 36.54**	**$ 32.97**	**$ 39.39**	**$ 6.43**
Reserve costs (AS and RUC)	$ 0.26	$ 0.30	$ 0.27	$ 0.54	$ 0.64	$ 0.10
Average total costs of energy and reserve	**$ 46.34**	**$ 52.19**	**$ 36.81**	**$ 33.50**	**$ 40.03**	**$ 6.53**

1.2 High load and price days in August and September

Supply and demand curves

The ISO market experienced two system-wide heat waves and associated high loads at the beginning of August and at the end of August continuing into early September. During these periods, daily peak loads were above 44,000 MW. On August 1, August 2, August 28, August 29, August 31 and September 1, the day-ahead market experienced very high system marginal energy prices greater than $250/MWh in hours ending 19 and 20 when load net of wind and solar was highest. On September 1, when loads were highest, the day-ahead system marginal energy price peaked at around $770/MWh.

The following section looks at some of the factors leading up to the high day-ahead prices during these two periods. High prices were primarily due to tight supply conditions in combination with high demand associated with the extreme temperatures.

Figure 1.5 shows the cumulative incremental bids from generation, imports, and virtual supply for hour ending 19 on August 1 and August 2 relative to the days leading up to it.[9] On August 1, there was a downward shift in supply bids in the day-ahead market during these peak net load hours due to reductions in variable energy resource forecasts, imports, and virtual supply bids. The combination of these factors resulted in a thinner bid stack during a period with already stressed conditions due to the heat. For hour ending 19, there were around 5,200 MW fewer incremental bids from these sources at or below $100/MWh on August 1 than were available on the previous day.

In particular, there was a significant downward shift in the quantity of imports offered in the day-ahead market during the high net load hour. Between July 30 and August 1, imports offered in the day-ahead market decreased by over 5,600 MW. During these days, temperatures and loads across the west were extremely high which caused tight supply conditions and high prices throughout the entire region and influenced these changes in intertie activity. Further, wind and solar forecasts were lower going into August 1 along with a significant downward shift of virtual supply bids.

Figure 1.6 provides the same information on supply bids for August 26 through September 1. Between August 28 and September 2 peak loads were extremely high at above 46,000 MW with loads on September 1 reaching over 50,000 MW. During hours ending 19 and 20 on these days, when load net of wind and solar was highest, topping 45,000 MW, prices in the day-ahead market also peaked. As shown in Figure 1.6, supply offered into the day-ahead market during the high net load hour was lowest on August 28 and September 1 for this period. This coincides with the days in which prices in the day-ahead market were highest. Imports offered in the day-ahead market decreased significantly in the days leading up to August 28 but returned on August 30 through the end of the heat wave. The key hours on September 1 experienced a large downward shift in virtual supply bids, but were otherwise more impacted by the significantly higher load.

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[9] Figure 1.5 and Figure 1.6 only show the incremental amounts for each bid and therefore do not account for the generation associated with the minimum operating levels of the resources. Self-scheduled generation and imports are depicted on the chart at -$190/MWh for illustrative purposes.

Figure 1.5 Comparison of incremental supply bids between July 30 and August 2, 2017 (Hour 19)

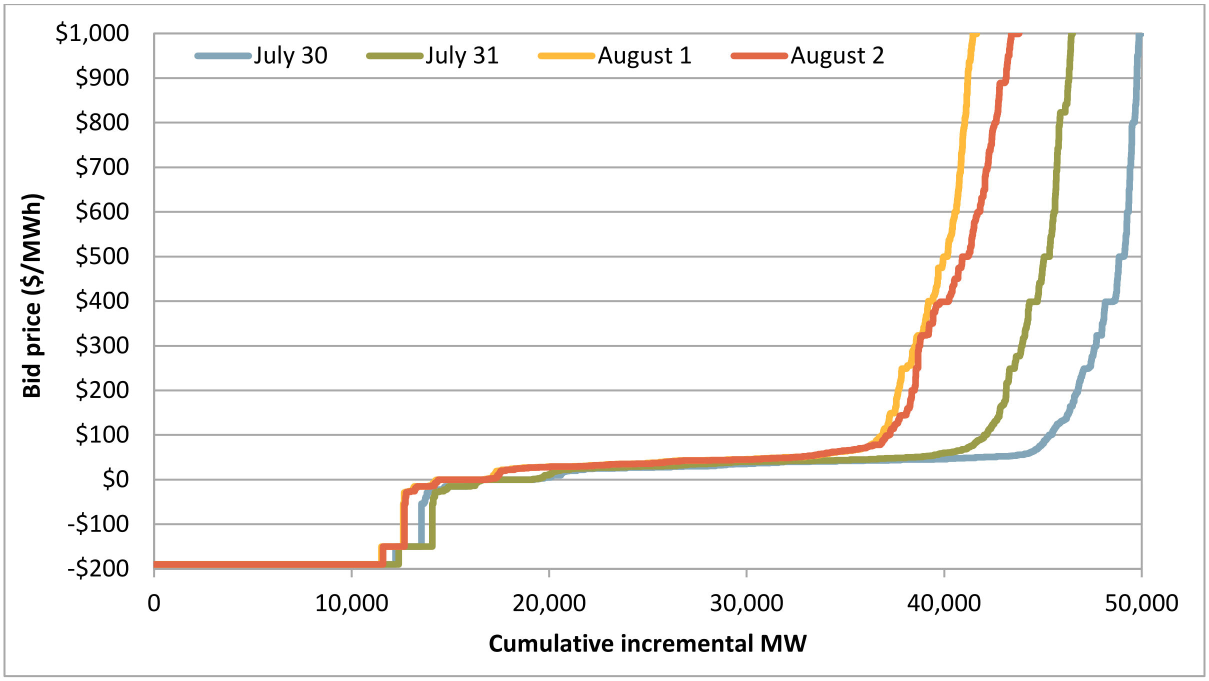
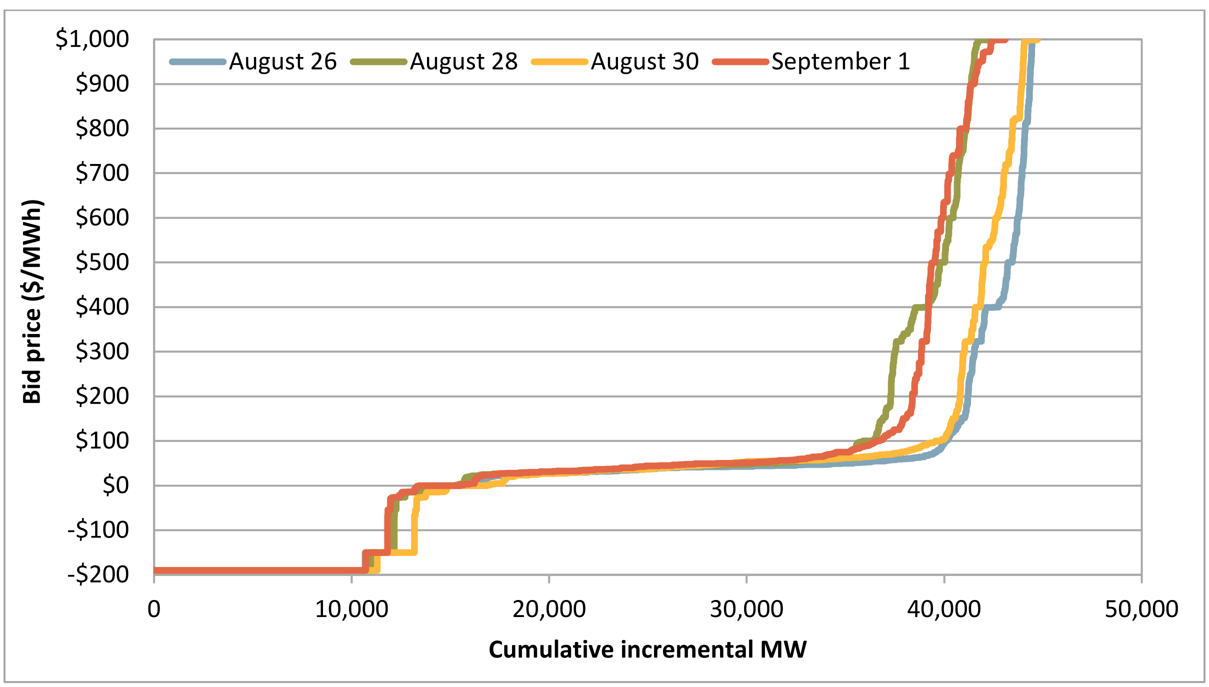


Figure 1.6 Comparison of incremental supply bids between August 26 and September 1, 2017 (Hour 19)



Load forecast adjustments

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*. Recently, the ISO has begun using the term *imbalance conformance* to describe these adjustments. Load forecast 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.[10] DMM will continue to use the terms load forecast adjustment and load bias limiter for consistency with prior reports.

Frequency and size of load adjustments, generation/import prices and imports

Compared to the prior year, load forecast adjustment in the ISO's hour-ahead and 15-minute markets increased dramatically in 2017. The 5-minute market load forecast adjustment decreased, relative to the same quarter in 2016. Figure 1.7 shows the average hourly load adjustment profile for the hour-ahead, 15-minute and 5-minute markets for the third quarter 2017 and 2016. The general shape and direction of load adjustments were similar for hour-ahead and 15-minute adjustments, but there was a nearly two fold increase in quantity relative to 2016.

Load adjustments in the hour-ahead and 15-minute markets are very similar to each other throughout the day. But, unlike the third quarter of 2016, 5-minute market adjustments differ dramatically from other markets for nearly all hours of the day. The largest positive deviations between the 5-minute and other markets were observed in hours ending 20 and 21 when the hour-ahead and 15-minute adjustments exceeded the 5-minute adjustments by around 800 MW and 930 MW, respectively. The largest negative adjustments occurred in hours ending 8, 9, and 10, 450 MW, 630 MW and 430 MW, respectively. Both positive and negative adjustments are often associated with over-forecasted load, changes in expected renewable generation as well as morning or evening net load ramp.

Average locational marginal pricing for the day-ahead, hour-ahead and 15-minute markets at the intertie nodes is shown by hour for the quarter in Figure 1.8. Prices in the 15-minute market are significantly higher than both day-ahead and hour-ahead prices across the peak. For nearly all hours, prices in the hour-ahead and 15-minute markets are higher than the day-ahead market, particularly in hours where large load adjustments occur.

[10] Additional detail can be found in Section 9, Market Adjustments, in the *2016 Annual Report on Market Issues and Performance*, which is available on the ISO website at: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf

Figure 1.7 Average 3rd quarter hourly load adjustment (2016 – 2017)

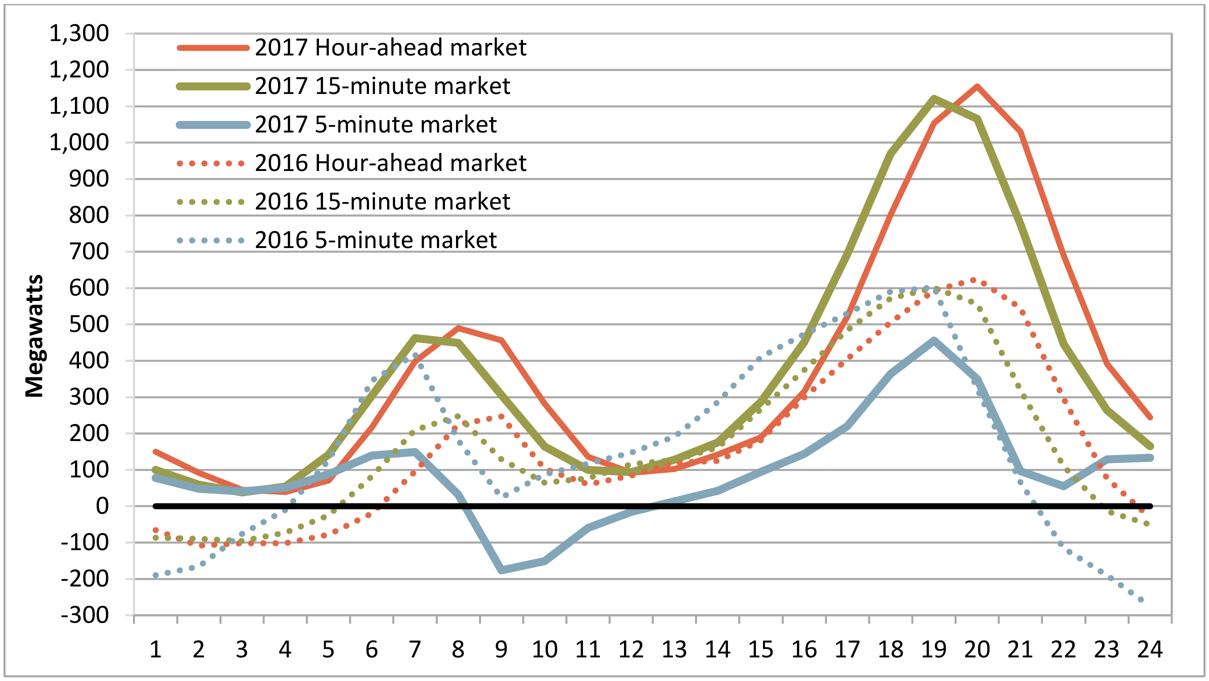
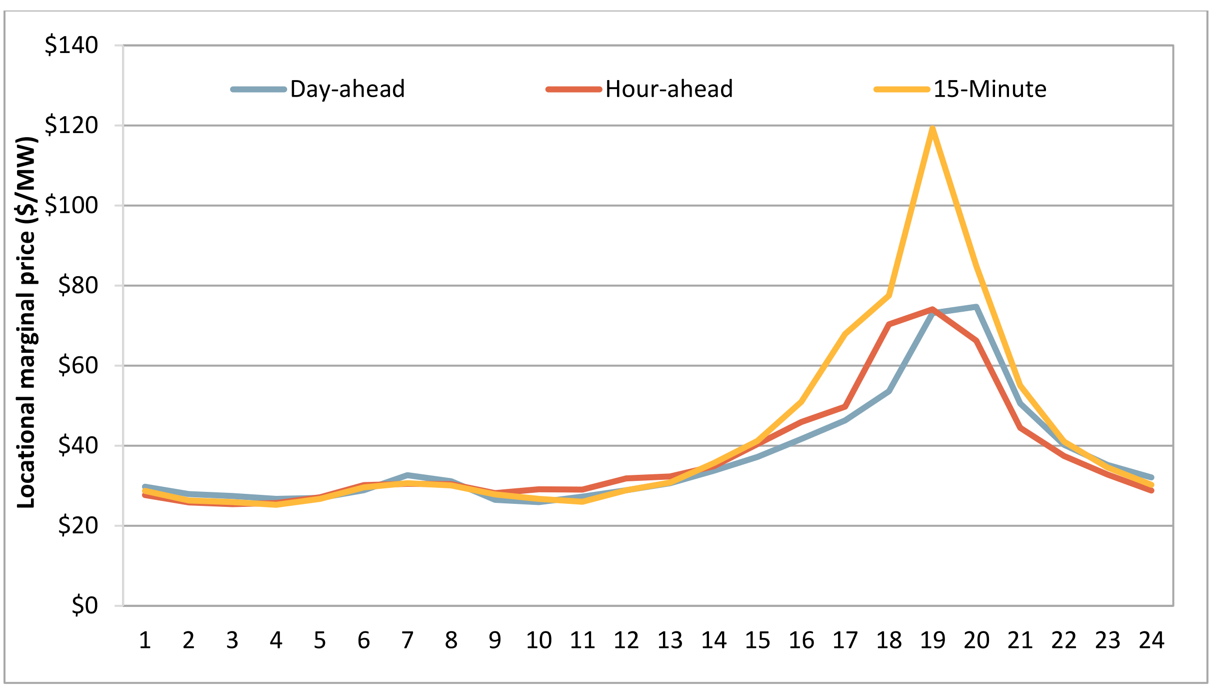


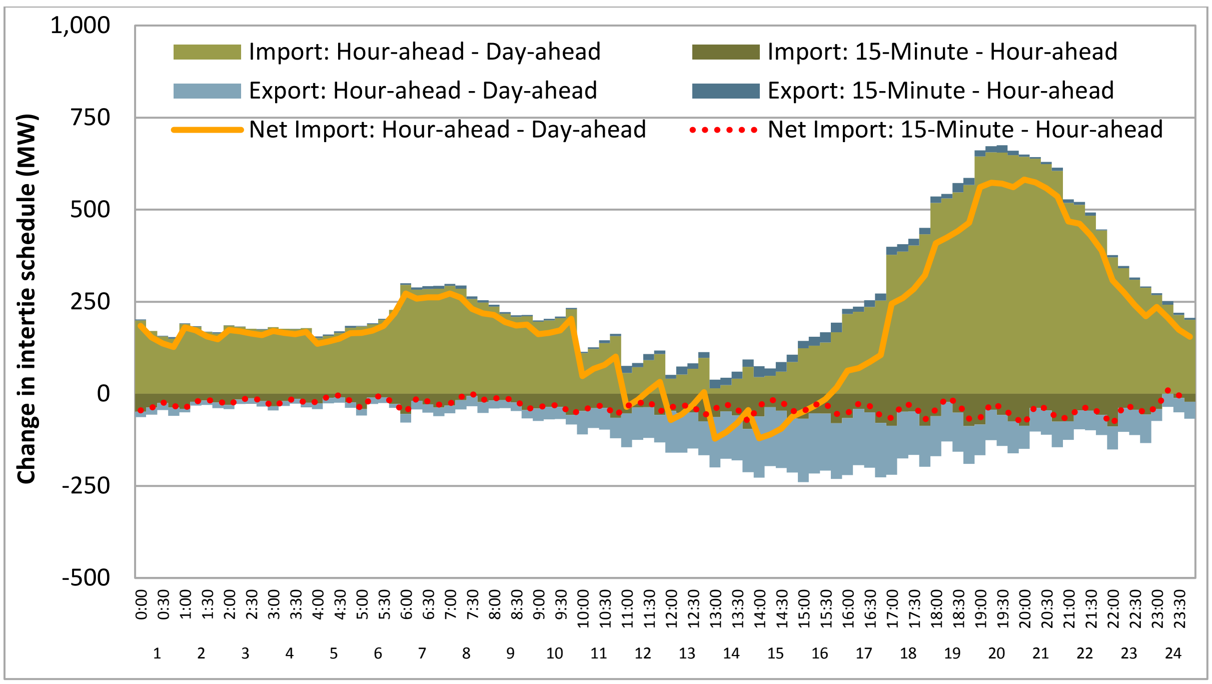
Figure 1.8 Intertie – average locational marginal pricing



Real-time incremental dispatch of imports appears consistent with both pricing and load adjustments, with most incremental commitment of imports occurring in the hour-ahead market. On average, over

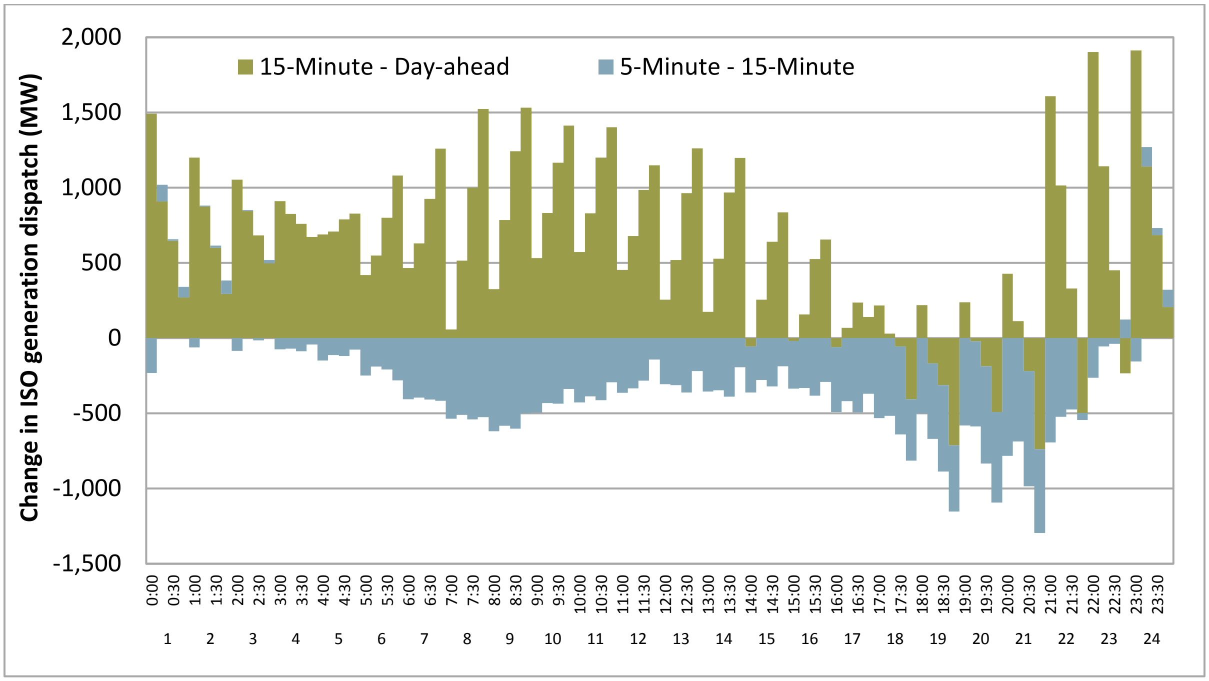
500 MW of net interchange is committed across the peak load adjustment hours of the day. The light green area in Figure 1.9 shows the average incremental increase in imports between the day-ahead and hour-ahead markets. The light blue area shows the incremental change in exports between the day-ahead and hour-ahead markets where an increased export is displayed as a negative value. The yellow line shows the change in net interchange, summing the effects of increased imports and increased exports. The red dotted line represents the change in net interchange between the 15-minute and hour-ahead markets and is the sum of incremental decreases in imports (dark green) and exports (dark blue). These are lower values relative to the changes observed between the day-ahead and the hour ahead.

Figure 1.9 Net interchange dispatch volume



Incremental dispatch of internal generation decreases between the day-ahead and 15-minute real-time market on average in most intervals across the peak. Figure 1.10 displays the average incremental change for internal generators between the day-ahead and the 15-minute market in green and between the 15-minute market and the 5-minute market in blue. Decreased physical generation appears to be offset by increases in imported energy on the interties, as shown in Figure 1.9.

Figure 1.10 Imbalance generation dispatch volume



Peak load and resource adequacy requirements and performance

Resource adequacy capacity showings were sufficient to meet load on some but not all days in the third quarter. Peak loads on September 1 and September 2 were above 47,000 MW with loads reaching over 50,000 MW on September 1, significantly larger than system resource adequacy requirements which decreased from about 50,000 MW in August to about 46,000 MW in September. Figure 1.11 shows daily peak loads and forecasts, as the solid blue and green lines, from August 28 through September 6. Peak loads on September 1 and September 2 were above 47,000 MW with loads reaching over 50,000 MW on September 1. These loads were significantly larger than system resource adequacy requirements, shown by the dashed yellow line, which decreased from about 50,000 MW in August to about 46,000 MW in September. Actual resource adequacy procurement on both days was just below 47,000 MW, with over 43,000 MW (96 percent) available in the day-ahead market during the peak load hour on September 1 and about 42,000 MW (92 percent) available on September 2.

The ISO works with the California Public Utilities Commission and other local regulatory authorities to set system level resource adequacy requirements. System resource adequacy provisions require load-serving entities to procure generation capacity to meet forecasted peak load in each month plus a planning reserve margin, which is generally 15 percent of peak load.[11] Load-serving entities meet this requirement by providing resource adequacy showings to the ISO on a year-ahead basis due in October

[11] The peak load plus planning reserve margin is designed to include the additional operating reserve needed to meet peak load with an allowance for outages and other resource limitations.

and provide 12 month-ahead showings during the compliance year. Resource adequacy capacity must then be bid into the ISO markets through a must-offer requirement.

System resource adequacy requirements for September were substantially less than 115 percent of the ISO's 2017 1-in-2 year forecast of peak load, 53,908 MW.[12] During these high load days in September, the sum of monthly 1-in-2 peak load estimates for resource adequacy requirements provided by the California Energy Commission was 48,400 MW. This was less than both day-ahead forecast and loads on both days. Some load-serving entities have resource adequacy requirements calculated with a planning reserve margin of less than 15 percent.

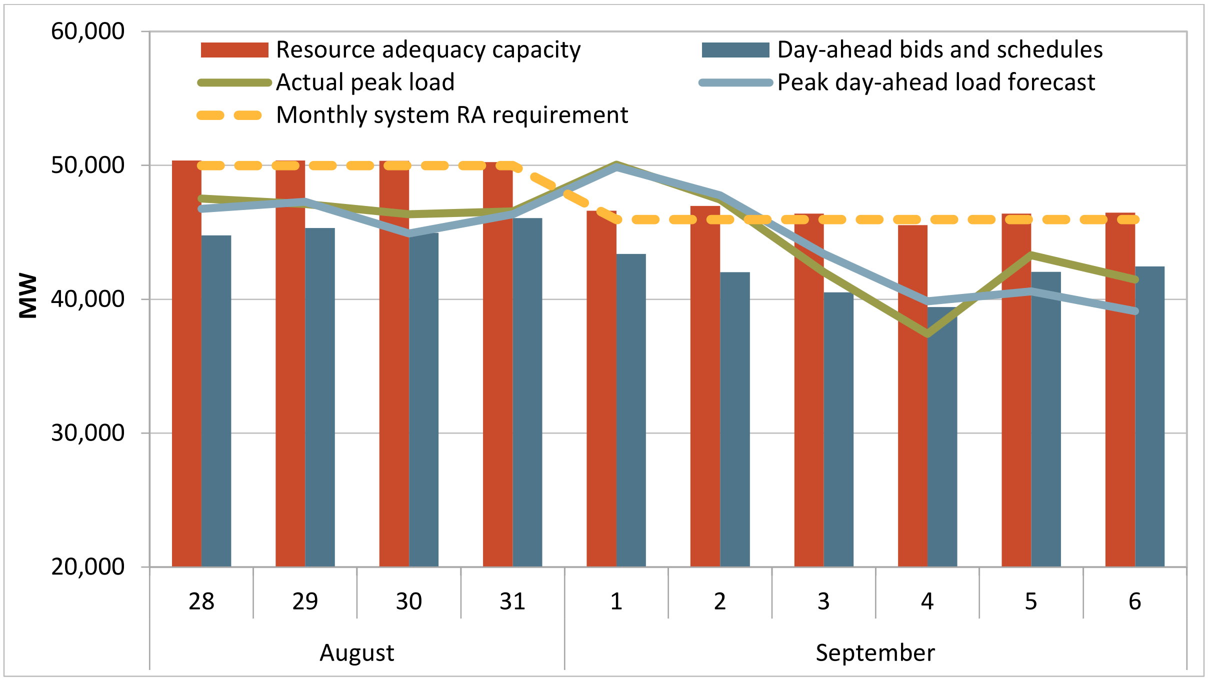
The red bars in Figure 1.11 show the total amount of resource adequacy capacity used to meet resource adequacy requirements in September. Scheduling coordinators are incentivized to make resource adequacy capacity available in the market during only *availability assessment hours* through the resource adequacy availability incentive mechanism.[13] For September, these are for hours ending 14 through 18 on non-weekend days. These hours do not necessarily align with hours when loads are highest. In particular, the availability assessment hours exclude two of the highest load hours including hours ending 19 and 20.

The blue bars in Figure 1.11 show the amount of resource adequacy capacity that was available in the day-ahead market through either a self-schedule or an economic bid during the peak load hour of the day. Differences between the resource adequacy capacity (red bars) and the available resource adequacy capacity in the day-ahead market (blue bars) were mostly driven by solar, wind, hydro, and nuclear resources, which have particular operating limitations.

[12] A similar note was made in the 2017 Q2 report regarding resource adequacy requirements for June: http://www.caiso.com/Documents/2017SecondQuarterReport-MarketIssuesandPerformance-September2017.pdf.

[13] See Section 3.3.2 for further discussion on the resource adequacy availability incentive mechanism.

Figure 1.11 Daily peak load, resource adequacy capacity, and planning forecast



Exceptional dispatch

Exceptional dispatches are unit commitments or energy dispatches issued by operators when they determine that market optimization results may not sufficiently address a particular reliability issue or constraint. This type of dispatch is sometimes referred to as an out-of-market dispatch. While exceptional dispatches are necessary for reliability, they may create uplift costs not fully recovered through market prices, affect market prices, and create opportunities for the exercise of temporal market power by suppliers.

Exceptional dispatches can be grouped into three distinct categories:

- **Unit commitment** — Exceptional dispatches can be used to instruct a generating unit to start up or continue operating at minimum operating levels. Exceptional dispatches can also be used to commit a multi-stage generating resource to a particular configuration. Almost all of these unit commitments are made after the day-ahead market to resolve reliability issues not met by unit commitments resulting from the day-ahead market model optimization.

- **In-sequence real-time energy** — Exceptional dispatches are also issued in the real-time market to ensure that a unit generates above its minimum operating level. This report refers to energy that would likely have cleared the market without an exceptional dispatch (i.e., that has an energy bid price below the market clearing price) as *in-sequence* real-time energy.

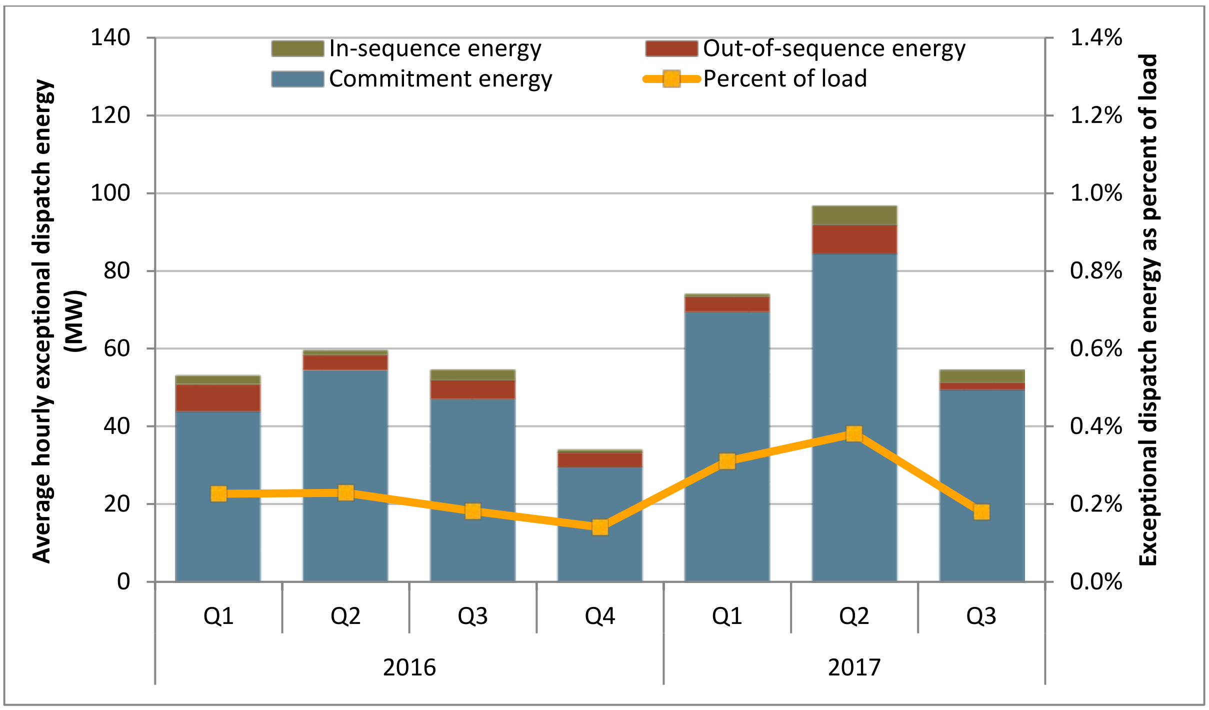
- **Out-of-sequence real-time energy** — Exceptional dispatches may also result in *out-of-sequence* real-time energy. This occurs when exceptional dispatch energy has an energy bid priced above the market clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to the local market power mitigation provisions in the ISO tariff, this energy is considered out-of-sequence if the unit's default energy bid used in mitigation is above the market clearing price.

Summary of exceptional dispatch

Energy from exceptional dispatch continues to account for a relatively low portion of total system loads. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged about 0.3 percent of system loads in 2017 through the first three quarters. This was higher than the total percent of energy exceptionally dispatched in 2016, which was about 0.2 percent of system load.

Total energy resulting from all types of exceptional dispatch increased by approximately 40 percent in the first three quarters of 2017 from the similar time period in 2016, as shown in Figure 1.12.[14] The percentage of total exceptional dispatch energy from minimum load energy accounted for about 90 percent of all exceptional dispatch energy in 2017. About 6 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 4 percent was from in-sequence energy.

Figure 1.12 Average hourly energy from exceptional dispatch



Although exceptional dispatches are priced and paid outside of the market, they can affect the market clearing price for energy. Energy resulting from exceptional dispatch effectively reduces the remaining load to be met by the rest of the supply. This can reduce market prices relative to a case where no exceptional dispatch was made. However, most exceptional dispatches appear to be made to resolve

[14] All exceptional dispatch data are estimates derived from Market Quality System (MQS) data, market prices, dispatch data, bid submissions, and default energy bid data. DMM's methodology for calculating exceptional dispatch energy and costs has been revised and refined since previous reports. Exceptional dispatch data reflected in this report may differ from previous annual and quarterly reports as a result of these enhancements.

specific constraints that would make energy from these exceptional dispatches ineligible to set the market price for energy if these constraints were incorporated in the market model.

The bulk of energy from exceptional dispatches is minimum load energy from unit commitments. Energy from this type of exceptional dispatch would not be eligible to set market prices even if incorporated in the market model. In addition, because exceptional dispatches occur after the day-ahead market, energy from these exceptional dispatches primarily affects the real-time market. If energy needed to meet these constraints was included in the day-ahead market, prices in the day-ahead market could be lower.

Manual dispatch on the interties

Exceptional dispatches on the interties are often referred to as 'manual dispatches'. Between May and September there were just over 100 manual dispatches on the interties that spanned 12 days and dispatched about 15,300 MWh. The largest daily quantities occurred on September 1, 2017, and September 2, 2017, about 6,100 and 5,900 MWh, respectively. These dispatches occurred between hours ending 16 and 22, but were concentrated in hours ending 18, 19 and 20. The single largest hour of manual dispatch occurred on hour-ending 19 on September 1, totaling 1,700 MW. The ISO has developed specific operating procedures documenting the determination of need and acquisition process.[15]

As with an exceptional dispatch for generator unit commitment or energy dispatches by operators, manual dispatches on the interties are used to maintain/re-establish operating reserves, meet energy over/under-generation events and procure additional energy or reduce excess energy not awarded by the market. Prior to 2017, manual dispatches on the interties were primarily issued in the event of an hour-ahead scheduling process (HASP) or real-time market failure, transmission outage, market software limitation/anomaly, or System Emergency (or prevention thereof). The use of manual dispatch appears to have become more common in 2017 to address system reliability on high load days, often associated with the evening net load peak ramp down hours.

The price[16] of a manual dispatch typically falls into one of three categories:

- **Bid or better** – Bid price or 5-minute market clearing price at the tie point pricing node, whichever is higher.
- **Fixed price –** Fixed price agreed upon between the ISO and the market participant.
- **Fixed price with floor –** Fixed price minimum level. The highest of the fixed price or the 5-minute market clearing price at the tie point pricing node.

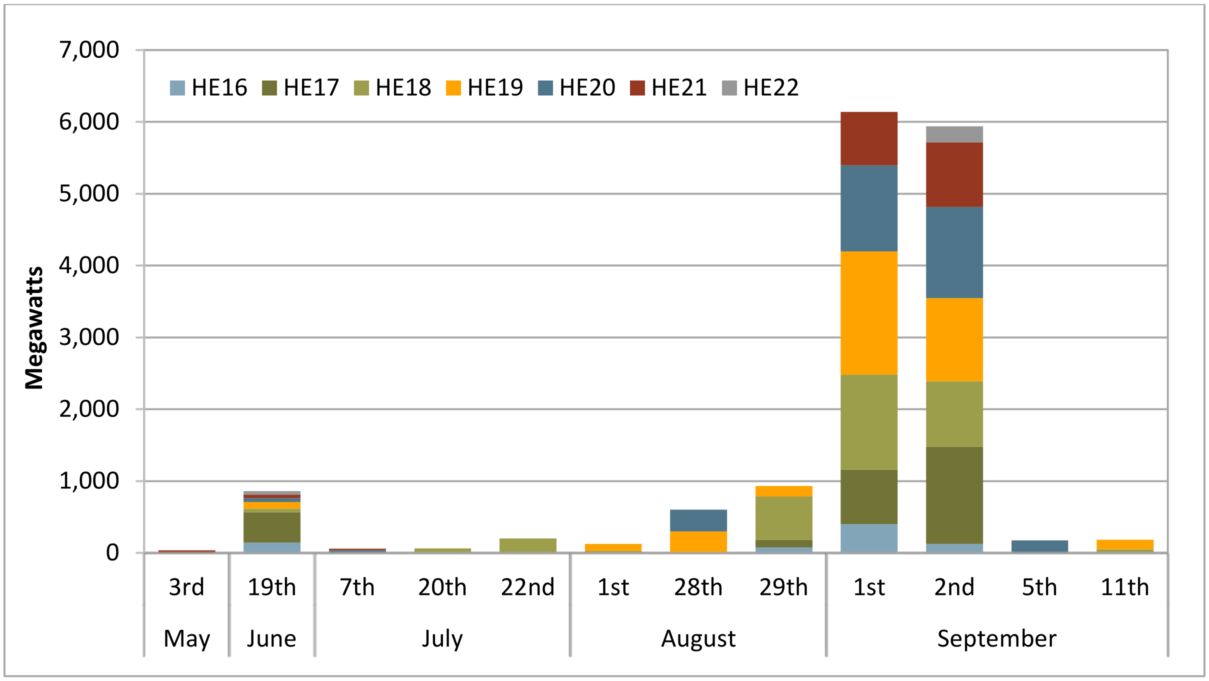
Of the approximate 15,300 MWh in the May to September time period, 'bid or better' accounted for about 54 percent of the total, 'fixed' price 14 percent and 'fixed price with floor' about 31 percent. On the two highest manual dispatch days when about 12,000 MWh were manually dispatched, 50 percent were 'bid or better', only 10 percent were 'fixed price' and 40 percent were 'fixed price with floor'.

15 *Manual Dispatch on Interties*, Operating Procedure 2530 (https://www.caiso.com/Documents/2530.pdf), *Real-Time Market Activities*, Operating Procedure 2210 (https://www.caiso.com/Documents/2210.pdf), and *System Emergency,* Operating Procedure 4420 (https://www.caiso.com/Documents/4420.pdf).

16 Purchases or sales of manual dispatch energy are settled consistent with the ISO tariff and Business Practice Manuals.

DMM estimates the direct revenues paid to market participants to be approximately $5 million for the May to September time period. However, total incremental revenue is about $1.5 million compared to a 'what if' price in the 15-minute market. The two highest direct revenue days were September 1 and September 2, 2017, which equate to about 32 percent and 40 percent of total costs for the period. Nearly 70 percent of all manual dispatch costs were in hours ending 18, 19 and 20 with $1.14 million, $1.39 million and $0.98 million, respectively.

Figure 1.13 Hourly manual dispatch volume on select days (May – September)



1.3 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 third quarter, the frequency of high prices increased in both the 15-minute and 5-minute markets while the frequency of negative prices decreased significantly.

During the quarter, most of the high prices occurred as a result of high bids clearing the market. In many instances, extremely high bids cleared the market after the load bias limiter resolved an infeasibility.

High prices

As shown in Figure 1.14, the frequency of high prices in the 15-minute market increased significantly during the quarter, particularly during September when prices above $250/MWh occurred during almost 1.5 percent of 15-minute intervals. High prices in the 15-minute market were concentrated on a small number of days during periods when load net of wind and solar was very high, typically between hours ending 18 and 20.

In addition, the frequency of larger price spikes greater than $750/MWh in the 15-minute market also increased from the previous quarter. During many of these intervals, the power balance constraint was relaxed due to insufficient incremental energy (shortage).

Further, the conditions for the load bias limiter were met during almost all of these intervals with infeasibilities. Specifically, if the operator load adjustment exceeds the size of the power balance constraint infeasibility and in the same direction, the size of the load adjustment is automatically reduced and the price is set by the last dispatched economic bid rather than the penalty parameter for the relaxation, for instance the $1,000/MWh price for a shortage. However, during most of the under-supply infeasibilities in the third quarter, accessible economic bids near the bid cap of $1,000/MWh were dispatched such that the resulting price was near the penalty parameter.

As shown in Figure 1.15, the frequency of price spikes in the 5-minute market greater than $250/MWh also increased from the previous quarter to almost 1.2 percent of intervals, up from 0.9 percent of intervals in the previous quarter. In addition the frequency of more extreme 5-minute prices larger than $750/MWh continued to increase to almost 0.8 percent of intervals during the quarter. Similar to the 15-minute market, the load bias limiter triggered during most of these intervals with a resulting price near the $1,000/MWh bid cap.

Figure 1.14 Frequency of high 15-minute prices by month

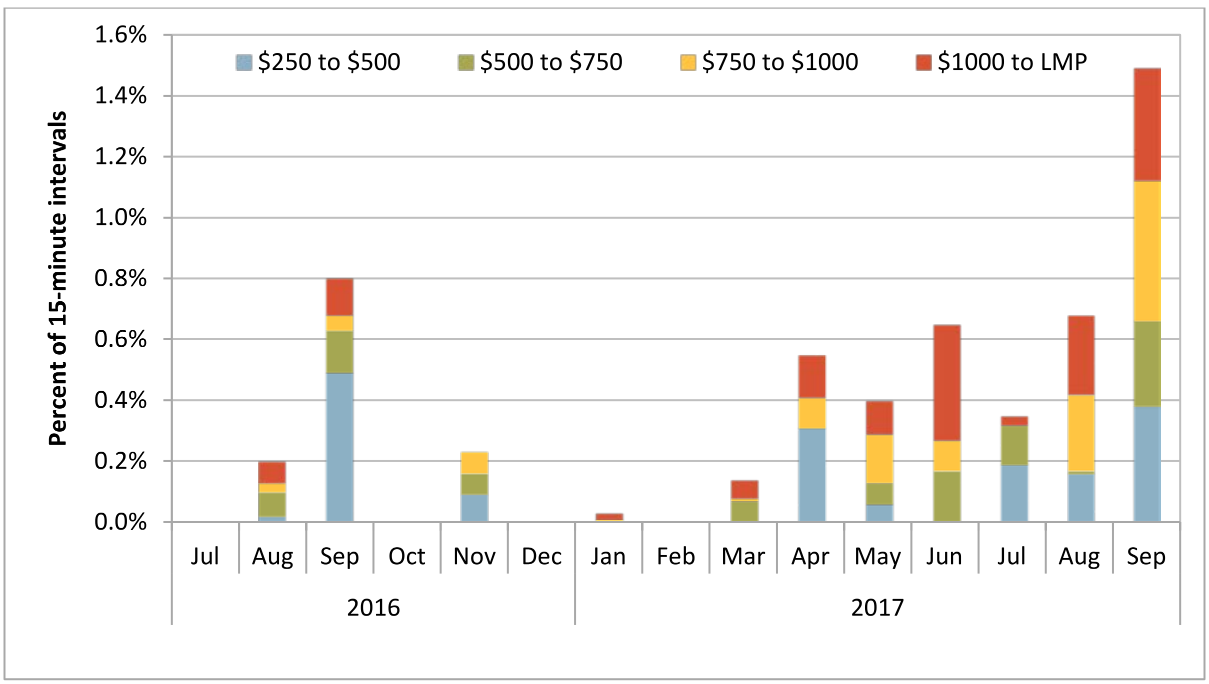
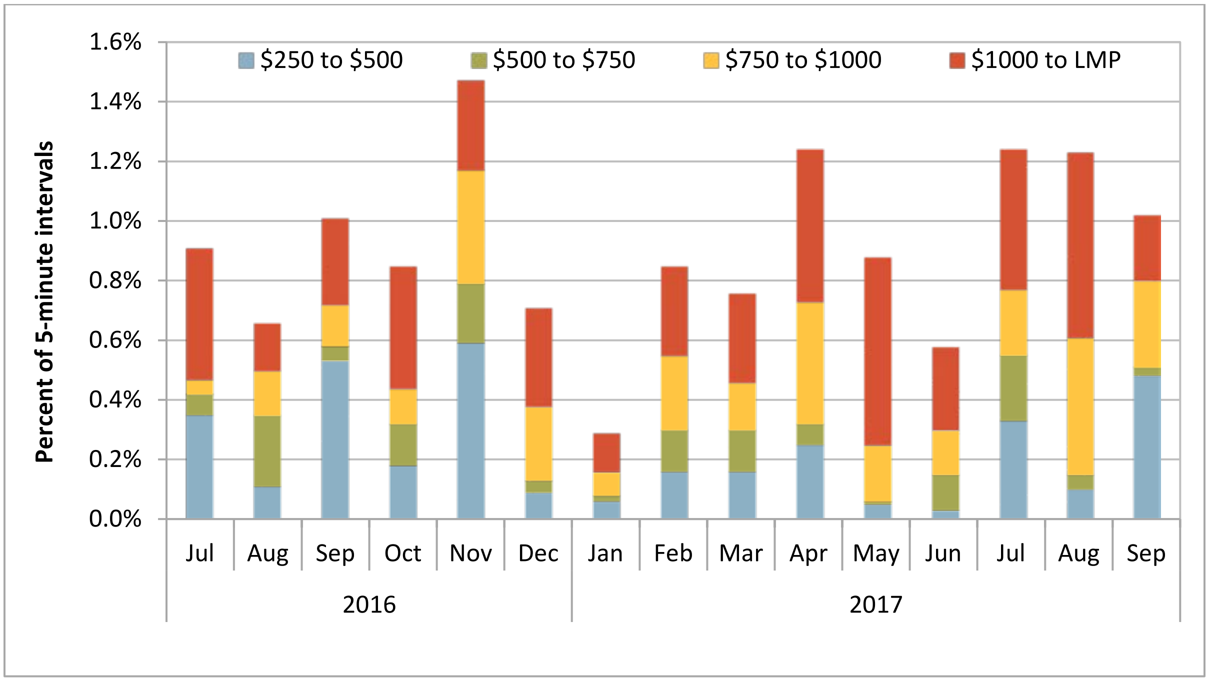


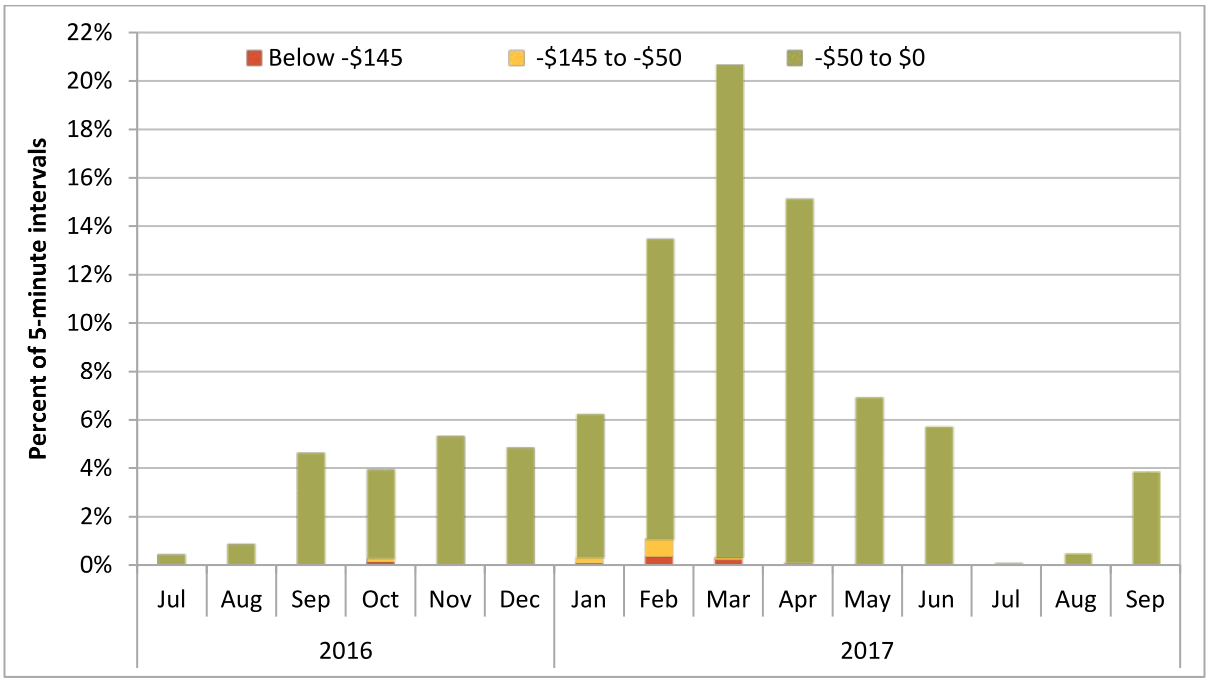
Figure 1.15 Frequency of high 5-minute prices by month



Negative prices

The frequency of negative prices decreased significantly in the 15-minute and 5-minute markets in the third quarter compared to the prior quarter, consistent with increases in seasonal load. Figure 1.16 shows the frequency of negative prices in the 5-minute market by month.[17] Negative prices occurred in about 0.3 percent of intervals in the 15-minute market and around 1.5 percent of intervals in the 5-minute market. These were most frequent between hours ending 9 and 16 during the second half of September when loads net of wind and solar were lower. However, prices did not reach below -$30/MWh for any of the three main load aggregation points during the quarter.

Figure 1.16 Frequency of negative 5-minute prices by month



1.4 Congestion

In the day-ahead market, the impact of congestion was low on Pacific Gas and Electric and Southern California Edison area prices but had a considerable negative impact on San Diego Gas and Electric area decreasing prices by about $0.80/MWh (2 percent). In the 15-minute market, congestion increased Pacific Gas and Electric and Southern California Edison area prices by about $1.20/MWh and $0.50/MWh, respectively, and decreased San Diego Gas and Electric area prices by about $0.40/MWh. The negative impact of congestion in the San Diego Gas and Electric area is due to a frequently binding Doublet Tap-Friars 138 kV constraint which is creating a generation pocket or an export constrained area.

[17] Corresponding values for the 15-minute market with Figure 1.16 show a similar pattern but higher percentages of intervals.

1.4.1 Congestion impacts of individual constraints

Day-ahead congestion

In the third quarter of 2017, the overall frequency of congestion increased in the day-ahead market compared to the previous quarter.[18] The most frequently binding constraint in the Pacific Gas and Electric area was the Metcalf constraint, which bound during a total of 3 percent of all hours. When this constraint bound, the impact increased Pacific Gas and Electric area prices by about $2/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by approximately $1.3/MWh. This congestion was primarily the result of an outage on the Metcalf #13 500/230 kV transformer bank.

In the Southern California Edison area, Barre – Villa Park constraint was the most frequently binding constraint. During the first half of the third quarter, this constraint was binding because an operating procedure was in effect to mitigate for the loss of Barre – Lewis 230 kV line. For the later part, it bound because of an outage on San Onofre-Serrano 220 kV line. This constraint was binding in 8 percent of the intervals and increased Southern California Edison and San Diego Gas and Electric area prices by $1/MWh and $4/MWh, respectively, and decreased Pacific Gas and Electric area prices by about $1.3/MWh.

In the San Diego Gas and Electric area, Double Tap-Friars 138 kV constraint bound most frequently during approximately 35 percent of hours with a negative price impact of $3.7/MWh. A major reason for congestion on this constraint is the loss of Penasquitos-Old Town 230 line.

Table 1.2 Impact of congestion on day-ahead prices during congested hours[19]

		Frequency	Q3		
Area	**Constraint**	**Q3**	**PG&E**	**SCE**	**SDG&E**
PG&E	30735_METCALF _230_30042_METCALF _500_XF_12	2.7%	$1.71	-$1.30	-$1.29
	RM_TM12_NG	2.2%	$10.91		-$2.28
	6310_CP6_NG	2.0%	$1.90	-$1.38	-$1.18
	30735_METCALF _230_30042_METCALF _500_XF_13	0.8%	$1.27	-$0.85	-$0.84
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	7.6%	-$1.27	$1.03	$3.55
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	6.4%	-$5.27	$0.55	-$1.01
	6310_CP3_NG	1.4%	-$0.39	$0.31	$0.28
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.0%	-$0.86	$0.99	$0.37
SDG&E	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	34.6%			-$3.67
	7820_TL 230S_OVERLOAD_NG	8.0%	-$0.32	$0.11	$3.96
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1	2.4%			$0.99
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1	1.2%			$5.53
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	1.0%			$2.50
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1	0.5%	$0.27	$0.56	-$5.02

[18] *Q2 2017 Report on Market Issues and Performance*, September 2017, pp. 24: http://www.caiso.com/Documents/2017SecondQuarterReport-MarketIssuesandPerformance-September2017.pdf

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

15-minute market congestion

In the 15-minute market, congestion on most constraints 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 1.3 shows the frequency and magnitude of 15-minute market congestion for the quarter.

In the Pacific Gas and Electric area, Round MountainTable Mountain nomogram bound most frequently during the third quarter at about 3 percent of intervals. When binding, it increased Pacific Gas and Electric area, Southern California Edison and San Diego Gas and Electric area prices by about $17/MWh, $6/MWh and $3/MWh, respectively. This nomogram is enforced to mitigate for the loss of either the Round Mountain – Table Mountain #1 or #2 lines. It was binding in the 15-minute market because the limit on the nomogram was conformed down to align with the real-time flows.

In the Southern California Edison area, Barre – Villa Park constraint bound frequently at 4 percent of intervals. When it bound, it increased Southern California Edison and San Diego Gas and Electric area prices by about $6/MWh and $11/MWh, respectively while decreasing Pacific Gas and Electric area prices by $4/MWh.

Similarly, in the San Diego Gas and Electric area, as mentioned earlier, Doublet Tap - Friars constraint bound most frequently at about 11 percent of all intervals. This constraint was binding due to an overload in the real-time contingency analysis (RTCA) run for the loss of Penasquitos-Old Town 230 line. When binding, the constraint created a generation pocket and decreased San Diego Gas and Electric area prices by about $8/MWh.

As shown in Table 1.3, frequently binding constraints in the ISO such as the Barre – Villa Park and Round Mountain – Table Mountain constraints have had a significant impact on 15-minute energy imbalance market area prices. The frequency and impact of congestion in the 5-minute market is similar to that of the 15-minute market.

Table 1.3 Impact of congestion on 15-minute prices during congested intervals[20]

		Frequency	Q3							
Area	Constraint	Q3	PG&E	SCE	SDG&E	PACE	PACW	NEVP	PSEI	AZPS
PG&E	RM_TM12_NG	3.0%	$16.96	$6.39	$3.23	-$24.15	-$51.79		-$51.74	
	30735_METCALF _230_30042_METCALF _500_XF_12	1.2%	$20.01	-$8.76	-$8.66	-$7.48	-$6.77	-$7.92	-$6.80	-$8.56
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _2	1.2%	-$12.12	$8.53	$8.17	-$0.72	-$9.74	$4.53	-$9.64	$7.22
	6310_CP6_NG	1.1%	$4.23	-$5.81	-$5.36	$1.45	$7.83	-$1.30	$7.69	-$4.55
	30735_METCALF _230_30042_METCALF _500_XF_13	0.8%	$26.32	-$10.49	-$10.44	-$9.74	-$9.32	-$9.74	-$9.34	-$10.36
	OMS_4864567_CP1	0.4%	$5.35	-$3.72	-$3.52	$0.45	$2.75	-$2.04	$2.74	-$3.17
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	4.0%	-$3.88	$5.45	$10.81	-$3.47	-$3.36	-$4.16	-$3.35	-$3.60
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	1.6%	$12.58	$16.97	$29.09	-$21.74	$1.15	-$46.42	$0.79	-$38.87
	6510_CP1_NG	0.4%	-$3.92	$8.79	$9.74	-$6.99	-$4.72	-$3.71	-$4.72	-$15.20
	6410_CP1_NG	0.4%	-$11.01	$6.74	$6.72	-$1.49	-$8.59	$3.64	-$8.38	$5.84
SDG&E	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	10.6%			-$8.41					-$5.47
	7820_TL 230S_OVERLOAD_NG	2.4%		$0.48	$10.27	-$1.03	-$0.45	-$0.95	-$0.47	-$2.30
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1	0.8%	$1.56	$2.82	-$18.88		$1.32		$1.28	-$3.47

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

1.4.2 Impact of congestion on average prices

This section provides an assessment of differences between overall average regional prices in the day-ahead and 15-minute markets caused by congestion between different areas of the ISO system. 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.[21] 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 1.4 shows the overall impact of day-ahead congestion on average prices in each load area during the quarter by constraint.[22] The impact of congestion was low on Pacific Gas and Electric and Southern California Edison area prices but had a considerable negative impact on San Diego Gas and Electric area decreasing prices by about $0.80/MWh (2 percent). As mentioned earlier, Doublet Tap – Friars constraint had a major negative impact on San Diego Gas and Electric area prices.

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

[22] Details on constraints with shift factors less than 2 percent have been grouped in the 'other' category.

Table 1.4 Impact of congestion on overall day-ahead prices

Constraint	PG&E $/MWh	PG&E Percent	SCE $/MWh	SCE Percent	SDG&E $/MWh	SDG&E Percent
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$1.27	-3.09%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.10	-0.23%	$0.08	0.19%	$0.18	0.44%
7820_TL 230S_OVERLOAD_NG	-$0.03	-0.06%	$0.00	0.00%	$0.32	0.77%
30735_METCALF _230_30042_METCALF _500_XF_12	$0.05	0.11%	-$0.04	-0.09%	-$0.04	-0.09%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	-$0.01	-0.03%	$0.03	0.07%	-$0.06	-0.16%
6310_CP6_NG	$0.04	0.09%	-$0.03	-0.07%	-$0.02	-0.06%
RM_TM12_NG	$0.04	0.08%			-$0.05	-0.12%
22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1					$0.07	0.17%
6510_CP1_NG	-$0.01	-0.03%	$0.01	0.02%	$0.01	0.02%
22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1	$0.00	0.00%	$0.00	0.01%	-$0.02	-0.06%
30735_METCALF _230_30042_METCALF _500_XF_13	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1					$0.02	0.06%
22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1					$0.02	0.06%
22824_SWTWTRTP_69.0_22820_SWEETWTR_69.0_BR_1 _1					$0.02	0.05%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.02%	$0.01	0.02%	$0.00	0.00%
22476_MIGUELTP_69.0_22456_MIGUEL _69.0_BR_1 _1					$0.02	0.04%
6310_CP3_NG	-$0.01	-0.01%	$0.00	0.01%	$0.00	0.01%
OMS_4864567_CP1	$0.01	0.01%	$0.00	-0.01%	$0.00	-0.01%
Other	$0.05	0.11%	-$0.02	-0.05%	$0.00	-0.01%
Total	**$0.02**	**0.05%**	**$0.04**	**0.09%**	**-$0.81**	**-1.98%**

15-minute price impacts

Table 1.5 shows the overall impact of 15-minute congestion on average prices in each load area in the quarter by constraint.[23] Congestion during the third quarter increased Pacific Gas and Electric and Southern California Edison area prices by about $1.20/MWh (2.8 percent) and $0.50/MWh (1.2 percent), respectively, and decreased San Diego Gas and Electric area prices by about $0.40/MWh (1.1 percent). Compared to the previous quarter, congestion impact on Pacific Gas and Electric area prices almost doubled. This is because the Round Mountain-Table Mountain nomogram (RM_TM12_NG) was conformed down to align with real-time flows. Similar to the day-ahead market, Doublet Tap-Friars constraint had a major negative impact on San Diego Gas and Electric area prices. This constraint was binding because of an overload in the RTCA run for the loss of Penasquitos-Old Town 230 line.

[23] Details on constraints with shift factors less than 2 percent have been grouped in the 'other' category.

Table 1.5 Impact of congestion on overall 15-minute prices

Constraint	PG&E		SCE		SDG&E	
	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.89	-2.19%
RM_TM12_NG	$0.52	1.20%	$0.19	0.47%	$0.08	0.18%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.09	-0.20%	$0.22	0.53%	$0.42	1.04%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.20	0.45%	$0.26	0.64%	$0.07	0.16%
30735_METCALF _230_30042_METCALF _500_XF_12	$0.25	0.58%	-$0.11	-0.26%	-$0.11	-0.26%
30735_METCALF _230_30042_METCALF _500_XF_13	$0.20	0.46%	-$0.08	-0.19%	-$0.08	-0.19%
30060_MIDWAY _500_24156_VINCENT _500_BR_2 _2	-$0.14	-0.33%	$0.10	0.24%	$0.10	0.24%
7820_TL 230S_OVERLOAD_NG			$0.01	0.02%	$0.24	0.60%
22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1	$0.01	0.03%	$0.02	0.05%	-$0.15	-0.37%
37585_TRCY PMP_230_30625_TESLA D _230_BR_2 _1	$0.09	0.22%	-$0.04	-0.10%	-$0.04	-0.10%
6310_CP6_NG	$0.05	0.11%	-$0.07	-0.16%	-$0.06	-0.15%
6410_CP1_NG	-$0.04	-0.10%	$0.03	0.06%	$0.03	0.06%
6510_CP1_NG	-$0.02	-0.04%	$0.03	0.08%	$0.04	0.09%
OMS_4864567_CP1	$0.02	0.05%	-$0.02	-0.04%	-$0.01	-0.03%
6310_CP8_NG	$0.02	0.04%	-$0.01	-0.03%	-$0.01	-0.03%
OP-6610_ELD-LUGO	$0.01	0.03%	$0.02	0.04%	$0.01	0.02%
30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.01	0.02%	-$0.01	-0.03%	-$0.01	-0.03%
Other	$0.14	0.32%	-$0.06	-0.16%	-$0.04	-0.11%
Total	**$1.22**	**2.84%**	**$0.48**	**1.17%**	**-$0.44**	**-1.07%**

Internal congestion in the energy imbalance market

Table 1.6 shows the frequency of congestion on internal constraints in the energy imbalance market since 2014. Compared to the previous quarter, internal congestion in NV Energy increased significantly in the third quarter of 2017. In the 15-minute market, congestion increased from 2 percent to 8 percent in the NV Energy area. Frequency of congestion followed a similar trend in the 5-minute market. 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.[24]

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.

[24] *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 1.6 Percent of intervals with congestion on internal EIM constraints

	2014	2015				2016				2017		
	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3
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%	4.3%	5.1%
PacifiCorp West	0.1%	0.0%	0.0%	0.2%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%	0.0%
NV Energy					0.0%	0.0%	0.1%	0.3%	3.2%	10.3%	1.8%	7.6%
Puget Sound Energy									0.0%	0.0%	0.0%	0.0%
Arizona Public Service									0.0%	0.0%	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%	3.3%	4.5%
PacifiCorp West	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.0%	0.1%	0.0%
NV Energy					0.0%	0.0%	0.2%	0.3%	3.2%	11.7%	1.6%	7.1%
Puget Sound Energy									0.0%	0.0%	0.0%	0.0%
Arizona Public Service									0.0%	0.0%	0.0%	0.0%

1.4.3 Congestion on interties

Table 1.7 provides a detailed summary of congestion frequency on major interties with total congestion charges in the day-ahead and hour-ahead markets. The import congestion charges reported in the table are the products of the shadow prices times the binding limit for the intertie constraint. For a supplier or load-serving entity trying to import power over a congested intertie, the congestion price represents a decrease in the price for imports into the ISO. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside of the ISO at points corresponding to these interties.

The table highlights the following:

- In the third quarter of 2017, the congestion on the major interties decreased significantly in both day-ahead and hour-ahead markets compared to the second quarter of 2017.
- In the day-ahead market, total congestion costs on the Nevada/Oregon Border and the Malin 500 intertie increased to about $90 million through the third quarter of 2017. These charges have already surpassed the $76 million incurred in 2016. This is driven by increased hydro-electric generation imported into the ISO from the Northwest and Northern California in 2017.

Table 1.7 Summary of import congestion in day-ahead and hour-ahead market on major interties (2016-2017)

		Frequency of import congestion							Import congestion charges ($ million)						
		2016				2017			2016				2017		
Market	Intertie	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q1	Q2	Q3	Q4	Q1	Q2	Q3
Day-ahead	PACI/Malin 500	34%	36%	17%	41%	42%	39%	11%	$11.41	$12.39	$5.81	$21.54	$14.30	$28.62	$6.13
	NOB	22%	42%	16%	26%	21%	54%	24%	$5.00	$6.34	$4.07	$8.94	$6.38	$25.10	$8.55
	IPP Utah	18%	3%	14%	18%	9%	12%	18%	$0.31	$0.03	$0.18	$0.29	$0.15	$0.31	$0.44
	Palo Verde	0.4%	0.1%	2.7%	17.4%	0%	0.9%	0.9%	$0.13	$0.01	$1.34	$11.47	$0.17	$0.33	$0.58
Hour-ahead	PACI/Malin 500	48%	47%	30%	61%	56%	53%	35%	$27.03	$31.84	$17.63	$37.72	$28.30	$48.35	$34.96
	NOB	11%	15%	11%	14%	15%	28%	10%	$10.94	$12.30	$8.89	$35.69	$19.55	$59.61	$9.89
	IPP Utah	3%	1%	3%	6%	2%	6%	2%	$0.38	$0.15	$0.73	$3.28	$1.18	$3.29	$0.78
	Palo Verde	1%	0.3%	5%	18%	0%	1%	1%	$0.50	$0.17	$10.42	$2.60	$0.00	$0.01	$0.00

1.5 Ancillary Services

1.5.1 Ancillary service requirements

The ISO procures four ancillary services in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (WECC) minimum operating reliability criteria and North American Electric Reliability Corporation's (NERC) control performance standards.

Operating reserve requirements

In compliance with FERC Order No. 789, the ISO modified its operating reserve requirement in October 2014 to be consistent with WECC's new operating reserve standards. Since October 2014, procurement requirements in real-time for operating reserves have typically been set to the maximum of the following: (1) the sum of 3 percent of the load forecast and 3 percent of generation and (2) the single most severe contingency. Day-ahead operating reserve requirements have typically been set to the maximum of (1) about 6.3 percent of the load forecast and (2) the single most severe contingency. Further, operators can increase the percent specified for the load forecast component of the calculations to exceed reliability requirements. The total operating reserve requirements are then typically split equally between spinning and non-spinning reserves.

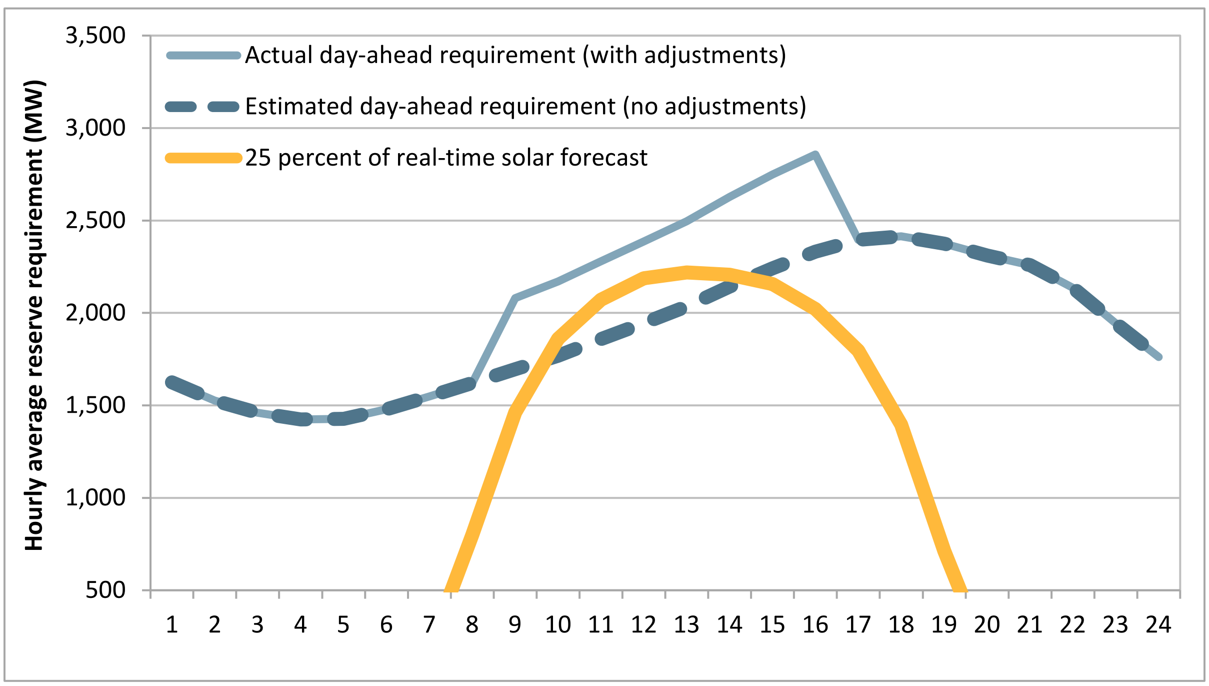
On June 8, the North American Electric Reliability Corporation published a report that found a previously unknown reliability risk related to a frequency measurement error that can potentially cause a large loss of solar generation. Although the WECC and NERC requirements did not change, the ISO made an upward adjustment to the operating reserve requirements starting with trade date June 14 to account for a potential loss of solar generation in the system. The ISO has indicated that the new total operating reserve requirements were set to the maximum of (1) the NERC or WECC required operating reserves and (2) up to 25 percent of total solar production.[25]

[25] *Market Notice – California ISO Temporary Increase Procurement of Operating Reserves*, July 12, 2017: http://www.caiso.com/Documents/CaliforniaISOTemporaryIncreaseProcurement-OperatingReserves.html

However, this functionality does not currently exist in the software. Instead, beginning on June 14, operators have increased the percent specified for the load forecast component of the calculation during midday hours to very roughly meet the new solar criteria using the existing tools available within the software. Between July 1 and September 18, day-ahead and real-time operating reserve requirements have been frequently increased upward by 1.5 percent of the load forecast between hours ending 9 and 16.[26] Starting on September 19, the upward adjustments were removed after the ISO indicated issue remediation had occurred such that the 25 percent solar criteria was reduced to 15 percent.[27]

Figure 1.17 shows *actual* hourly average operating reserve requirements between July 1 and September 18 with the application of the load forecast adders as well as *estimated* hourly average operating reserve requirements during the same period without any adjustment to the requirement.[28] The figure also includes 25 percent of real-time solar forecasts as a point of comparison. Between July 1 and September 18, the application of these load-based adjustments has often resulted in requirements that are higher than what would be expected using 25 percent of solar.

Figure 1.17 Hourly average operating reserve requirements (July 1 – September 18)



26 The upward adjustments to the operating reserve requirements were manually reduced to 0.5 percent of the load forecast between August 30 and September 3 when loads were very high.

27 *Adjustment to Temporary Increase of Daily Operating Reserves Procurement,* September 14, 2017: http://www.caiso.com/Documents/Adjustment_TemporaryIncrease_DailyOperatingReservesProcurement.html

28 The load forecast adders applied in day-ahead have also been typically applied in real-time for the same hours. In Figure 1.17, corresponding values for the real-time requirement are not included, but show a similar pattern, though at slightly lower values.

Regulation requirements and scarcity

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service pricing mechanism, implemented in December 2010, the ISO pays a pre-determined scarcity price for ancillary services procured during scarcity events. The scarcity prices are determined by a scarcity demand curve, such that the scarcity price is higher when the procurement shortfall is larger.

The ISO experienced 10 intervals of ancillary service scarcity pricing in the real-time market during the third quarter.[29] The 8 intervals of scarcity pricing that occurred on August 21 were the result of differences between the reserve requirements for the internal ISO sub-region and the broader expanded ISO region which encompasses it.

The ISO can procure ancillary services in the day-ahead and real-time markets from 10 predefined regions. During the third quarter, only four of these regions were utilized: ISO, expanded ISO, south of Path 26, and expanded south of Path 26. The expanded regions are identical to the internal regions but include interties. Each of these regions then have minimum and maximum requirements set for procurement of ancillary services where the internal regions are all nested within the system and corresponding expanded regions. Ancillary service requirements are then met by both internal resources and imports where imports are indirectly limited by the minimum requirements from the non-expanded regions.

On October 10, 2016, the ISO began using a new method for determining regulation procurement requirements.[30] The new method was implemented in response to growing needs for regulation to balance variable renewable generation. With the new method, each hour is calculated independently, based on observed regulation needs during the same month in the previous year. During the third quarter, the minimum day-ahead and real-time requirements averaged about 315 MW for both regulation up and regulation down for the expanded system region.

Furthermore, the ISO can adjust requirements manually for periods when conditions indicate higher net load variability. During the solar eclipse on August 21 regulation requirements were increased for the expanded system region. Regulation down minimum requirements for the expanded ISO region were increased for hours ending 10 through 12 to 400 MW, 800 MW, and 1,000 MW, respectively. However, corresponding adjustments to the maximum requirements for the ISO (non-expanded) region were not active in real time. As a result, the market was not able to procure additional regulation down from internal generation in the ISO region to meet the increased expanded ISO region minimum requirements. This created regulation down scarcity in real time where the regulation down scarcity price in the expanded ISO region was $700/MWh while the corresponding price in the ISO (non-expanded) region was around negative $700/MWh. However, this had a minimal financial impact because of the small volume of incremental real-time regulation down awards for non-internal resources during this period.

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[29] Regulation down scarcity, August 21, 2017: http://www.caiso.com/Documents/Notification-AncillaryServicesScarcityEvent-August21_2017.html.
Regulation up scarcity, September 11-12, 2017: http://www.caiso.com/Documents/Notification-AncillaryServicesScarcityEvent-September11-12_2017.html.

[30] The new methodology was initially implemented only in the day-ahead market because of software limitations. The ISO began using the new methodology in real time in January 2017.

1.6 Bid cost recovery

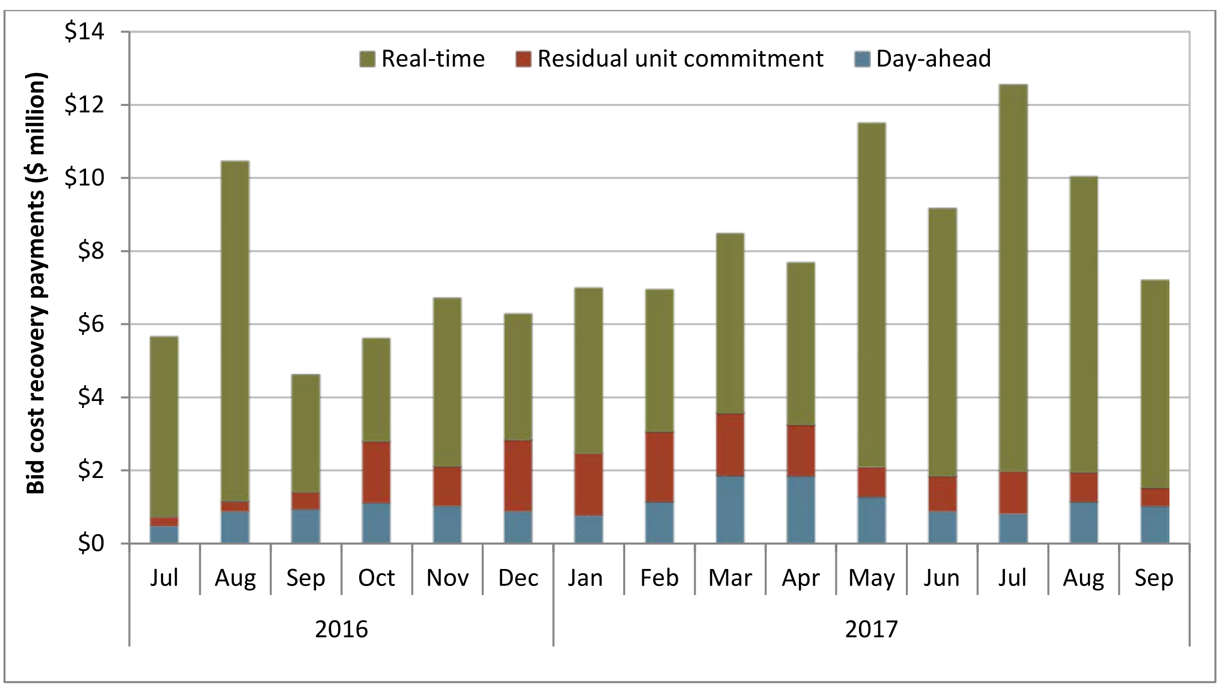
Estimated bid cost recovery payments for the third quarter totaled about $30 million. This amount was slightly higher than the total amount of bid cost recovery in the previous quarter and significantly higher than the third quarter of 2016, when it was about $21 million. A significant amount of the bid cost recovery payments were accrued in the real-time market during the months of July and August.

Bid cost recovery attributed to the day-ahead market totaled about $3 million, which is $1 million lower than the prior quarter. Bid cost recovery payments for residual unit commitment during the quarter totaled about $2.5 million, or about the same as average payments from the prior year.

Bid cost recovery attributed to the real-time market totaled about $24 million, or about $3 million larger than payments in the second quarter of 2017, and $7 million larger than payments in the third quarter of 2016. In July, real-time payments were over $10 million with real-time payments totaling more than $7 million between July 6 and July 20. In addition, there were several other days during the month when payments were unusually high. Real-time bid cost recovery payments during July were higher than any other month since 2011. On August 28, real-time bid cost recovery payments totaled about $2 million. This was due to a single resource buying back its day-ahead schedule at high real-time prices causing about $1 million in real-time bid cost recovery payments for that resource.

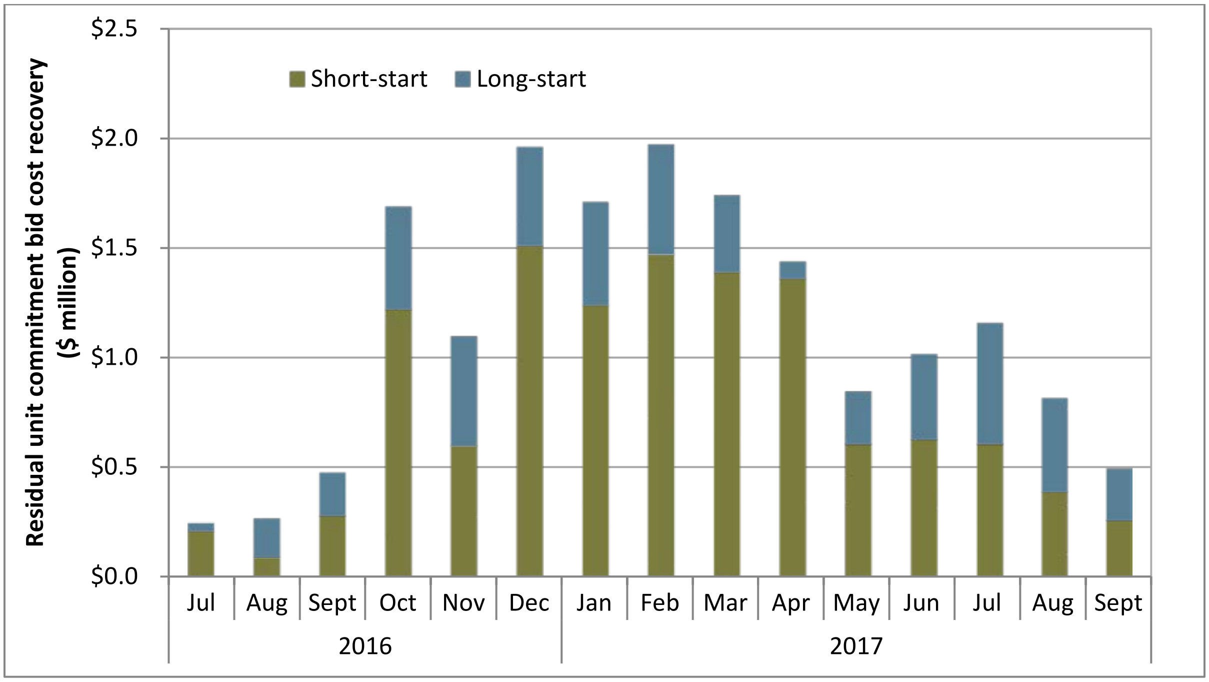
As shown in Figure 1.19, after netting against real-time revenues in the third quarter of 2017, short-start and long-start resources received about $1.3 million and $1.2 million, respectively, for residual unit commitment bid cost recovery payments, which was slightly down from about a total of $3.3 million in the prior quarter.[31]

Figure 1.18 Monthly bid cost recovery payments



[31] Residual unit commitment bid cost recovery charges are calculated by netting residual unit commitment shortfalls with real-time surpluses in revenue. The same methodology is used in calculating virtual bidding bid cost recovery charges.

Figure 1.19 Residual unit commitment bid cost recovery payments by commitment type



1.7 Convergence bidding

Convergence bidding was slightly profitable overall during the third quarter. However, virtual supply continued to be unprofitable for the second consecutive quarter. Net revenues from the market during the quarter were about $3.3 million. Virtual demand generated net revenues of about $4.2 million, while virtual supply accounted for approximately $0.9 million in net payments to the market. Combined net revenues for virtual supply and demand fell to about $1.6 million after including about $1.7 million of virtual bidding bid cost recovery charges.

1.7.1 Convergence bidding trends

Average hourly cleared volumes increased slightly in the third quarter to about 2,400 MW from about 2,300 MW during the previous quarter. Average hourly virtual supply increased during the quarter to about 1,600 MW compared to around 1,400 MW in the previous quarter. Virtual demand averaged around 800 MW during each hour of the quarter, down slightly from around 900 MW in the previous quarter. On average, about 36 percent of virtual supply and demand bids offered into the market cleared in the third quarter, which is down slightly from 37 percent in the previous quarter and 43 percent in the third quarter of 2016.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 780 MW on average, which increased from 560 MW of net virtual supply in the previous quarter. On average for the quarter, net cleared virtual supply exceeded net cleared virtual demand during all hours. Net cleared virtual supply was highest during the midday hours ending 10 through 15 when more than 1,000 MW more virtual supply cleared than virtual demand on average.

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 19 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 480 MW of virtual demand offset by 480 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 40 percent of all cleared virtual bids in the third quarter, down slightly from about 41 percent in the previous quarter.

1.7.2 Convergence bidding revenues

Participants engaged in convergence bidding in the third quarter were slightly profitable overall. Net revenues for convergence bidders before accounting for bid cost recovery charges were about $3.3 million. Net revenues for virtual supply and demand fell to about $1.6 million after including about $1.7 million of virtual bidding bid cost recovery charges.

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.[32] 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

[32] 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.

commitment in the day-ahead market and increased unit commitment in the residual unit commitment, which may not be economic.

Figure 1.20 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 third quarter totaled about $3.3 million, compared to about $12.1 million during the same quarter in 2016, and about $4.2 million during the previous quarter.
- Virtual supply net revenues were positive in July and August but were negative in September. In total, virtual supply accounted for around $0.9 million in net payments to the market for the quarter, before accounting for bid cost recovery charges. This was the second consecutive quarter virtual supply was not profitable and only the third quarter overall since convergence bidding began in 2011.
- Virtual demand net revenues were negative in July and August but were positive in September. In total, virtual demand generated net revenues of about $4.2 million during the quarter.

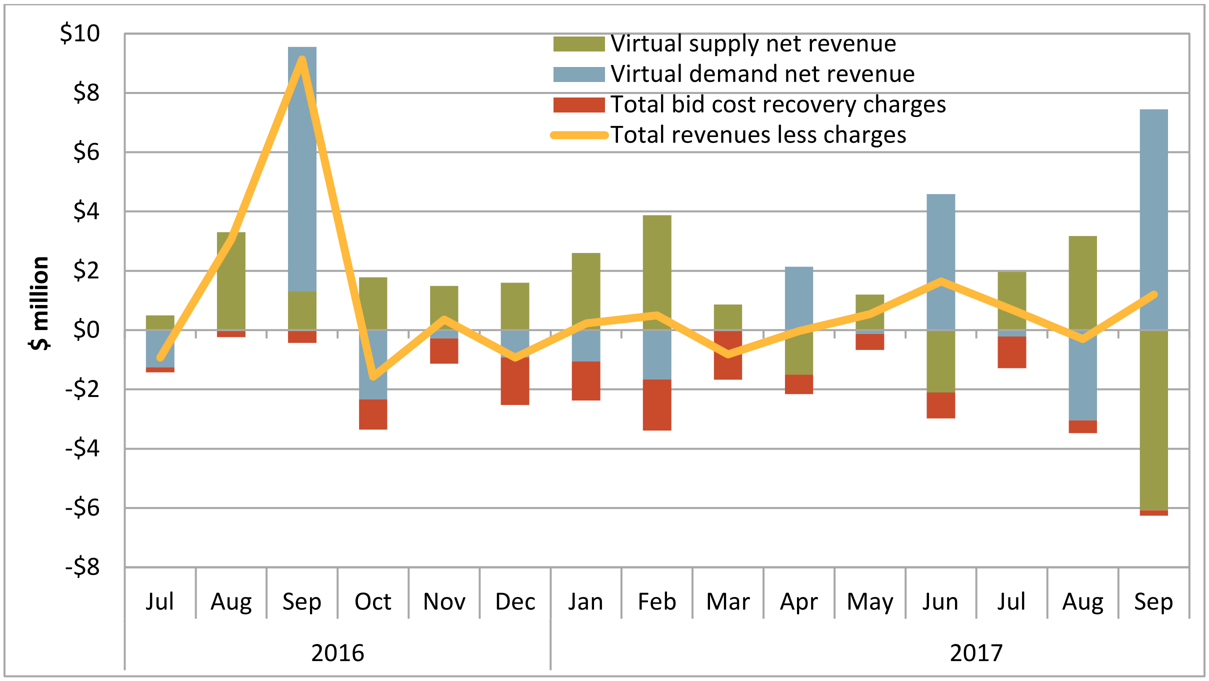
After accounting for bid cost recovery charges:

- Convergence bidders were paid about $1.6 million after subtracting bid cost recovery charges of about $1.7 million for the quarter.[33,34] Bid cost recovery charges were about $1.1 million in July, $0.4 million in August, and $0.2 million in September.

[33] 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.

[34] 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 1.20 Convergence bidding revenues and bid cost recovery charges



Net revenues and volumes by participant type

Table 1.8 compares the distribution of convergence bidding cleared volumes and net revenues, in millions of dollars, among different groups of convergence bidding participants in the third quarter.[35] Financial entities represented the largest segment of the virtual bidding market, accounting for about 61 percent of volume and a majority of settlement revenue. Marketers represented about 27 percent of the trading volumes, but a very small segment of settlement revenue. Generation owners and load-serving entities represented a smaller segment of the virtual market in terms of volumes at about 12 percent. In addition, generation owners and load-serving entities accounted for around $0.3 million in net payments to the market.

[35] 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 1.8 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	553	918	1,471	$4.38	-$0.86	$3.52
Marketer	239	407	646	$0.07	$0.01	$0.08
Physical load	0	263	263	$0.00	-$0.01	-$0.01
Physical generation	18	2	20	-$0.25	-$0.08	-$0.33
Total	**810**	**1,589**	**2,399**	**$4.2**	**-$0.9**	**$3.3**

1.8 Congestion revenue rights

Since 2009, electric ratepayers – who ultimately pay for the cost of transmission managed by the ISO – received an average of about $75 million less per year in revenues from the congestion revenue rights auction compared to the congestion payments made to entities purchasing these rights.[36] Total ratepayer losses since 2009 in the auction surpassed $680 million this quarter. During the third quarter of 2017, congestion revenue rights auction revenues were $9 million less than congestion payments made to non-load-serving entities purchasing these rights, thus increasing the year-to-date ratepayer losses to $38 million. These losses in the third quarter represent $0.72 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, which is lower than $1.2 during the same 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).[37] 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.

36 *Summary of Testimony of Eric Hildebrandt, PhD*, Committee on Energy and Commerce Subcommittee on Energy United States House of Representatives, November 29, 2017: http://docs.house.gov/meetings/IF/IF03/20171129/106663/HHRG-115-IF03-Wstate-HildebrandtE-20171129.pdf

37 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.[38]

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 1.21 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 $9 million during the third quarter of 2017 as payments to auctioned congestion revenue rights holders exceeded auction revenues. During the same quarter in 2016, auction revenues exceeded payments to congestion revenue rights holders and ratepayers gained $5 million.

Auction revenues were 72 percent of payments made to non-load-serving entities during third the quarter of 2017, down from 119 percent during the third quarter of 2016.

38 *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 1.21 Auction revenues and payments to non-load-serving entities

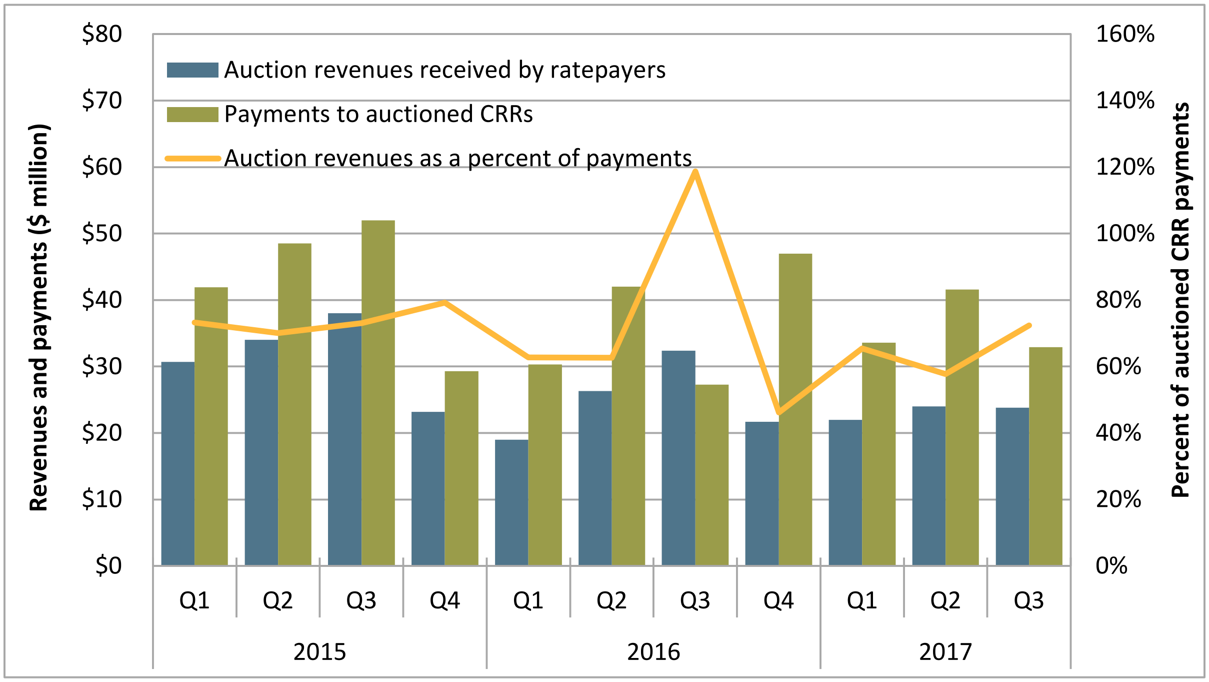


Figure 1.22 through Figure 1.25 show quarterly auction revenues paid to all entities purchasing rights in the auction compared to payments they received broken out by the following entity types:

- 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.

Similar to Figure 1.21, these charts show quarterly auction revenues and congestion revenue rights payments from 2015 through the third quarter of 2017. Highlights from these figures show the following for the third quarter of 2017.

- Financial entities continued to have the highest profits between the entity types, at approximately $11 million. This was an increase from $3 million they lost during the third quarter of 2016. Marketer losses were $1 million, up from a $2 million loss during the same quarter in 2016. Generators lost $0.6 million compared to a loss of $0.1 million in the third quarter of 2016.
- Financial entities paid 55 cents in auction revenue per dollar received compared to $1.20 paid in 2016. Generators paid $1.40 per dollar received, up from $1.00 in 2016. Marketers paid $1.10, down from $1.30 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 $0.80 million from rights they explicitly sold in the auction in the third quarter of 2017, down from $3.4 million in the same quarter of 2016.

Figure 1.22 Auction revenues and payments (financial entities)

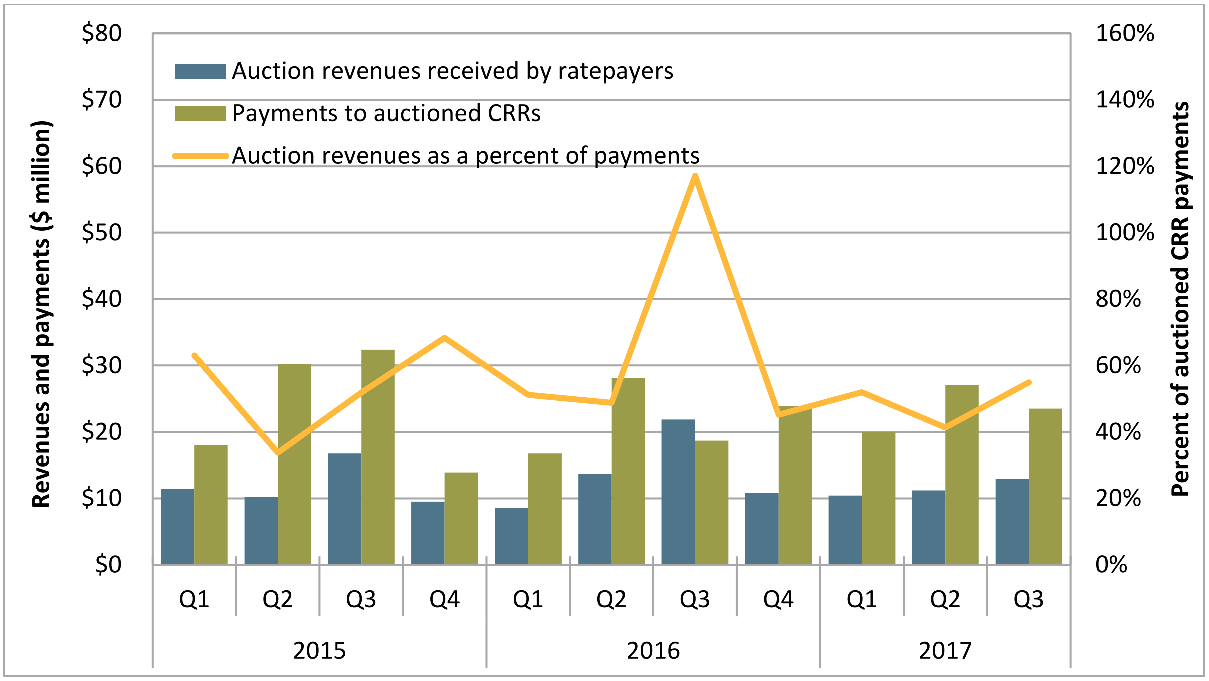


Figure 1.23 Auction revenues and payments (marketers)

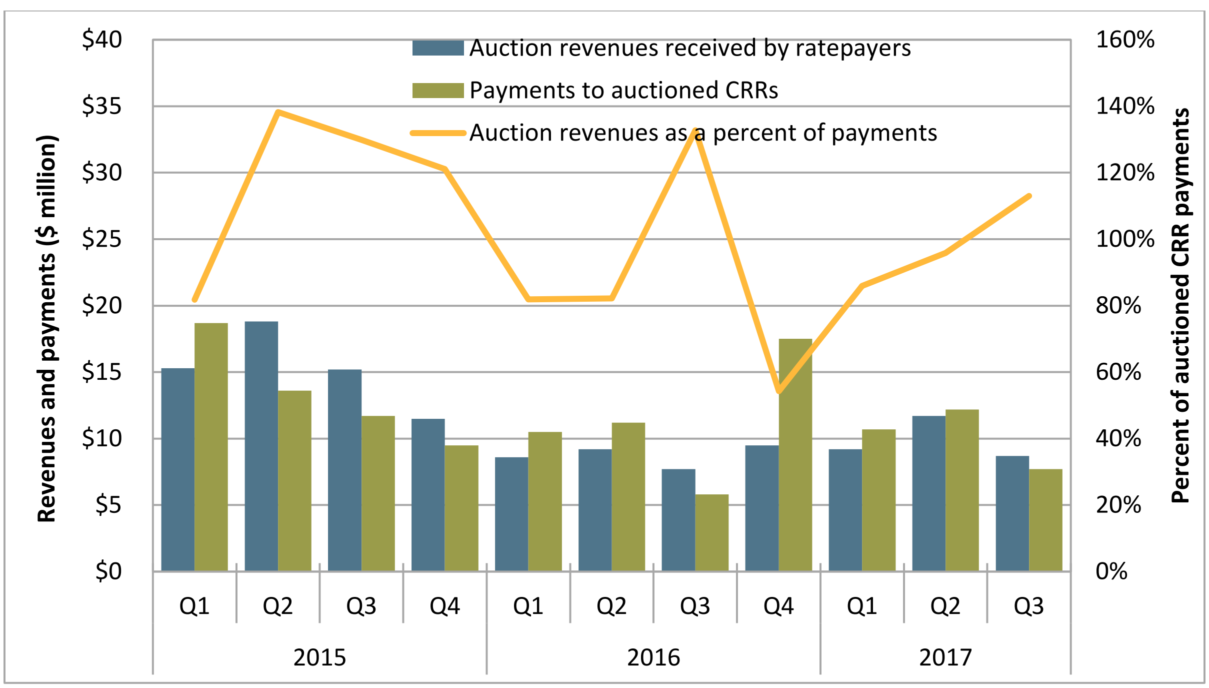


Figure 1.24 Auction revenues and payments (generators)

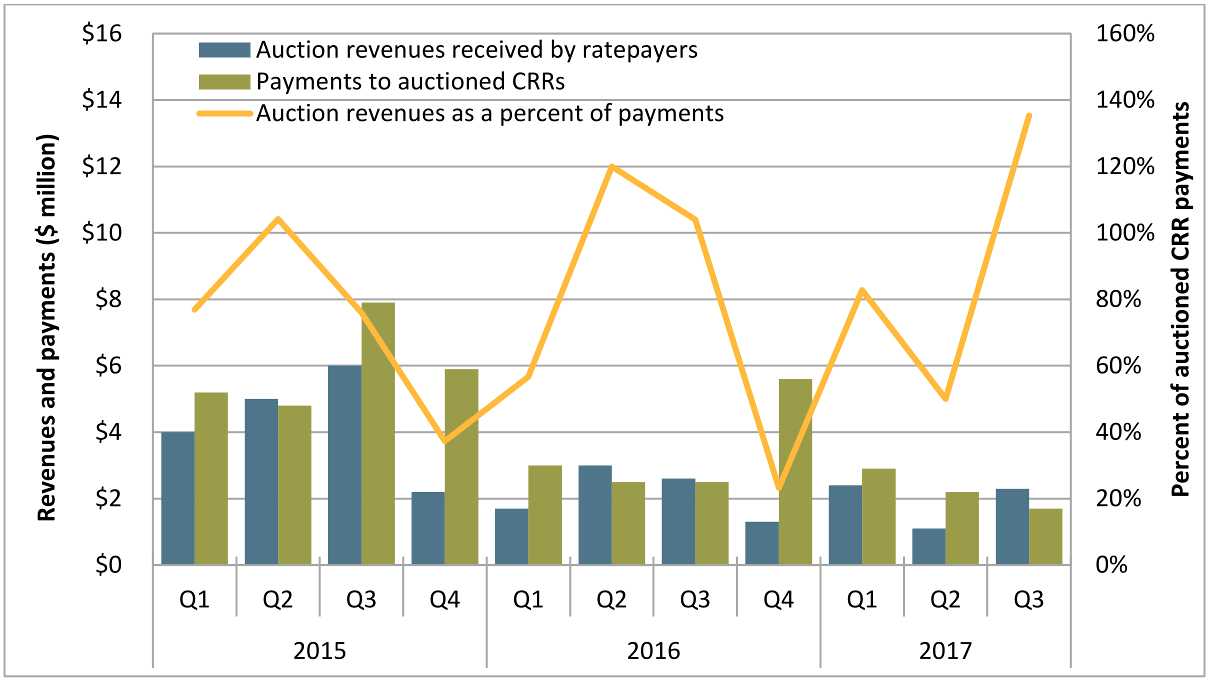
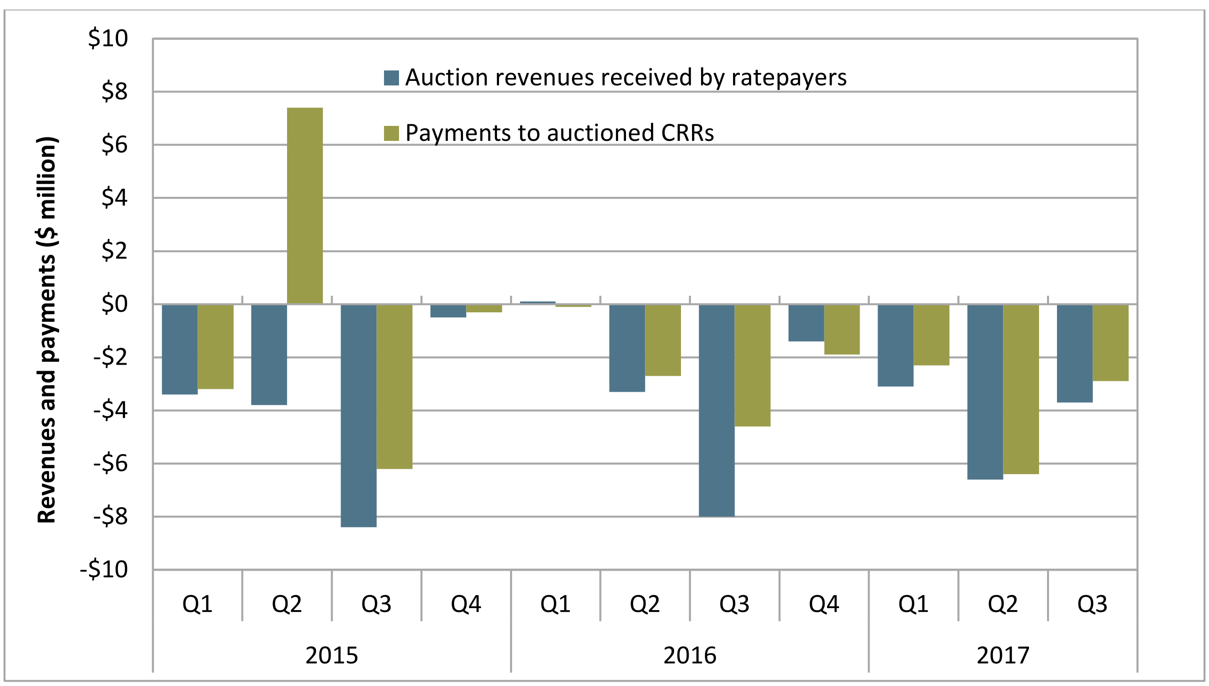


Figure 1.25 Auction revenues and payments (load-serving entities)



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.[39] DMM believes the current auction is unnecessary and could be eliminated.[40] 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 started the initiative "Congestion revenue rights auction efficiency" and adopted a two phase approach.[41] An analysis phase, in which the ISO will analyze the differences between auction prices and payouts in the congestion revenue rights market and the policy development phase, in which the ISO will consider potential policy changes. The ISO published its analysis of the congestion revenue rights auction performance on November 21, 2017 and has scheduled a working group meeting on December 19, 2017.[42] Congestion revenue rights working group will then review the results and discuss issues subsequently leading to an issue paper in February 2018.

1.9 Flexible ramping product

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

Background

The ISO implemented a new market feature on November 1, 2016, 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, 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 run and the corresponding 5-minute market runs for the same time period. Procurement in the 5-minute market aims to ensure that enough ramping capacity is available to handle differences between consecutive 5-minute market intervals.

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

[40] DMM whitepaper on *Market alternatives to the congestion revenue rights auction*, November 27, 2017. http://www.caiso.com/Documents/Market_Alternatives_CongestionRevenueRightsAuction-Nov27_2017.pdf

[41] ISO stakeholder processes – Congestion revenue rights auction efficiency: http://www.caiso.com/informed/Pages/StakeholderProcesses/CongestionRevenueRightsAuctionEfficiency.aspx

[42] Congestion Revenue Rights Auction Efficiency Analysis , November 21, 2017: http://www.caiso.com/Documents/CRRAuctionAnalysisReport.pdf

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 that represent the ISO's willingness-to-pay for flexible ramping capacity. The demand curves allow the market optimization to consider the trade-off between the cost of procuring additional flexible ramping capacity and the expected reduction in power balance constraint violation costs with the additional 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).[43] Further, there are separate demand curves calculated for each energy imbalance market area in addition to a system-level demand curve.

The flexible ramping product is incorporated into the ISO's market optimization as a constraint. In this approach, the demand curves are first entered into the market software as segments of *relaxation capacity* that reflect the expected cost of a power balance constraint violation for the level of foregone capacity procurement. The full length of the demand curve (or uncertainty) is then treated as a requirement and is met in every interval through a combination of flexible ramping capacity procurement or relaxation capacity.[44]

The system-level demand curve is always enforced in the market. However, the uncertainty requirement for the individual balancing areas is reduced in every interval by their transfer capability.[45] The demand curves for the individual areas are therefore binding when insufficient transfer capability is present, which indicates that the area is unable to benefit from the flexible capacity from other areas. When the uncertainty requirement for all of the individual areas is zero, then only the system-level uncertainty requirement is active.

Figure 1.26 shows the percent of intervals during the third quarter in each energy imbalance market area in which the area-specific uncertainty requirement was reduced to zero. For each area, the area-specific upward and downward uncertainty requirement was reduced to zero in more than 90 percent of 15-minute and 5-minute intervals. In effect, only the system-level uncertainty requirement was

[43] The demand curves are calculated from historical net load forecast error data. Weekdays use data for the same hour from the last 40 weekdays. For weekends, the last 20 weekend days are used. Additional information about the construction of the demand curves was provided by the ISO at the December 7, 2016, Market Performance and Planning Forum (pp. 24-50): http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum-Dec7_2016.pdf.

[44] While the uncertainty requirement is commonly referred to as a requirement, DMM notes that this value reflects the end point of the demand curve, or the maximum amount of flexible capacity the market is willing to pay for, rather than a hard requirement.

[45] In each interval, the upward uncertainty requirement is reduced by net import capability while the downward uncertainty requirement is reduced by net export capability. If the balancing authority area fails the flexible ramping sufficiency test in the corresponding direction, the uncertainty requirement will not include this reduction.

active in 83 percent of 15-minute intervals and 92 percent of 5-minute intervals. In the remaining intervals, one or more areas failed the flexible ramping sufficiency test or did not have sufficient transfer capability to cover the uncertainty requirement.

Since the implementation of the flexible ramping product, the demand curves for individual balancing areas are included in the constraint for system-level procurement. Initially, segments of relaxation capacity from the individual balancing area demand curves could be used to meet system-level uncertainty even when the uncertainty requirements for the individual balancing areas was reduced to zero. DMM believes that this implementation approach resulted in system-level procurement of flexible ramping capacity and associated flexible ramping shadow prices that were lower than what would be consistent using the system-level demand curves alone.

However, an adjustment was made on July 13 to limit the use of demand curves from individual balancing areas in meeting system-level uncertainty when sufficient transfer capability connected the area with system conditions. This enhancement was expected to avoid lowering system-level flexible ramping product prices and procured quantities in intervals when market conditions indicate that there was no need to procure any area-specific flexible ramping capacity. However, since this change was implemented, there are many intervals when resources providing ramping capacity received payments based on the first segment of their area-specific demand curve rather than the shadow price associated with the system demand curve.

When system-level capacity procurement is foregone through relaxation capacity, the system-level demand curve will be binding with a positive shadow price. Further, an area-specific demand curve may also be binding, creating a separate price for resources in that area. Resources providing flexible ramping capacity receive payments based on the combined shadow price, the sum of the system and area-specific shadow price.

Figure 1.27 shows the average combined system and area-specific shadow price when system-level flexible ramping capacity is foregone (relaxation) for the upward direction in the 15-minute market.[46] For simplicity, intervals in which one or more areas failed the flexible ramping sufficiency test or did not have sufficient transfer capability are excluded. The solid gray line shows the average system shadow price on its own. The dotted gray line shows the expected average shadow price for the level of flexible ramping capacity procured if only the system demand curve was used.[47] As shown in the figure, before July 13, all resources providing ramping capacity when only the system demand curve was binding were paid uniformly based on the system shadow price alone, though at levels below what would be expected (as discussed above).

Since August, DMM has observed intervals when the system demand curves are binding where the area specific demand curves are also binding at a negative shadow price such that the net of the system shadow price and the area-specific shadow price is equal to the price associated with relaxing the first segment of the area's demand curve. In most of these intervals, sufficient transfer capability between all of the energy imbalance market areas was available such that only the system demand curve was expected to be binding. In these instances, resources that provided ramping capacity received

[46] Corresponding values for the 5-minute market or downward direction are omitted because of less frequent occurrence of foregone flexible ramping capacity but show a similar pattern.

[47] This reflects the shadow price indicated by the demand curve with the actual amount of flexible ramping capacity procured. However, had the demand curves for the individual balancing areas not been included in the constraint for system-level procurement, the optimization would have likely procured more flexible ramping capacity at a therefore lower shadow price.

payments based on the first segment of the area-specific demand curve rather than the shadow price associated with the system demand curve. DMM continues to recommend that the ISO work with DMM and stakeholders to determine an appropriate enhancement that could avoid lowering system-level flexible ramping product prices and procured quantities.

Figure 1.26 Frequency of zero MW length area-specific demand curves (July – September)

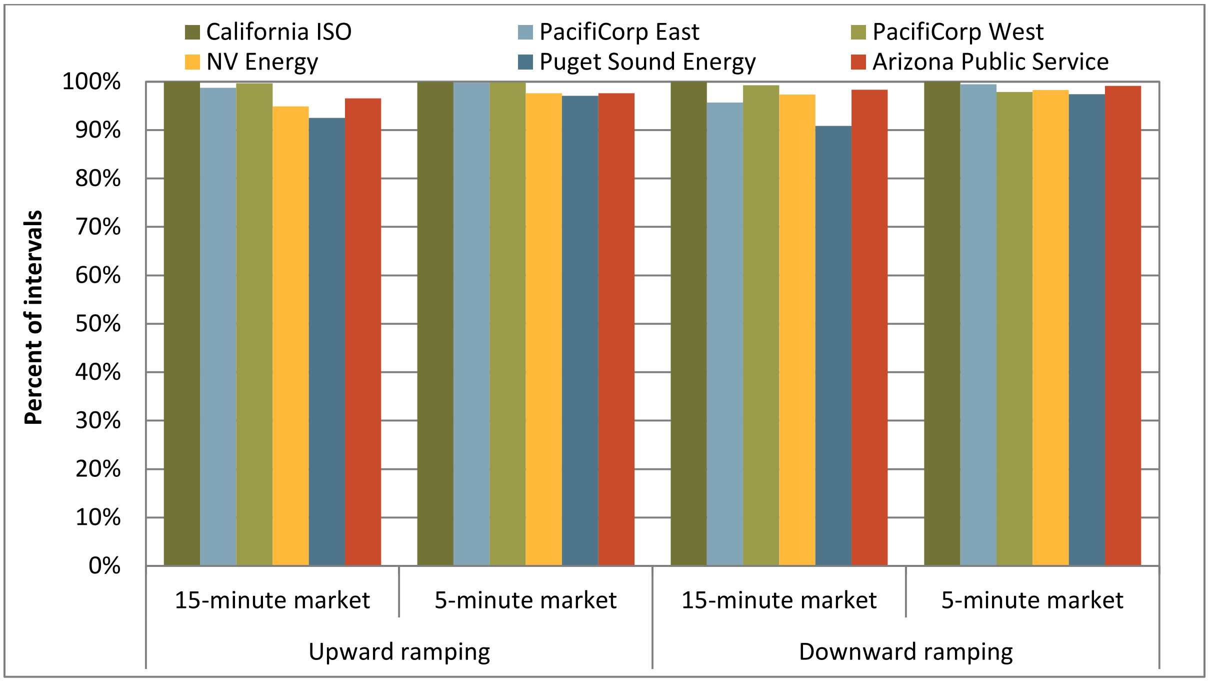
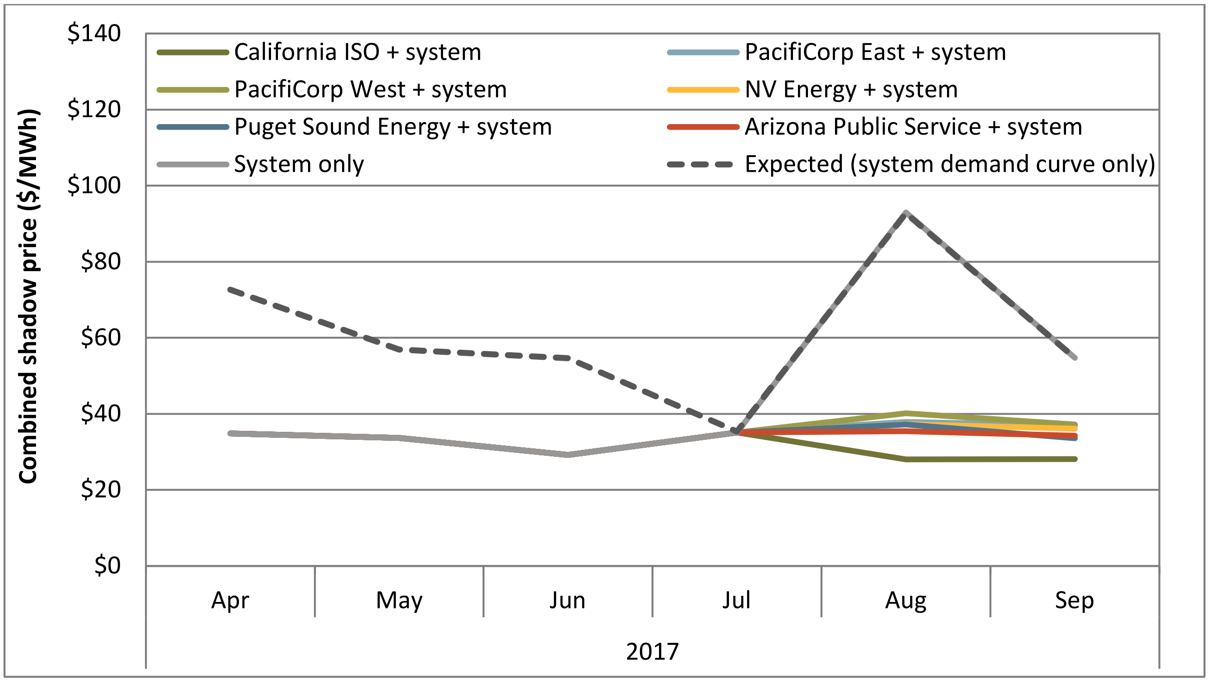


Figure 1.27 Average combined shadow price with foregone system-level flexible ramping capacity



Market outcomes for flexible ramping product

This section describes the amount of flexible ramping capacity that was procured in the third quarter, and the corresponding flexible ramping shadow prices. The flexible ramping product procurement and shadow prices are determined from the demand curves. When the shadow price is $0/MWh, at least the full length of the demand curve is procured for that interval. This reflects that flexible ramping capacity was readily available relative to the need for it such that there was no cost associated with the level of procurement.

Figure 1.28 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 third quarter. In the third quarter, the system-level demand curves bound much more frequently in the upward direction than in the downward direction. The system-level downward demand curves bound in less than 1 percent of 15-minute intervals during the third quarter, compared to about 7 percent during the second quarter.

In the upward direction, positive system-level flexible ramping prices were observed in the 15-minute market in about 24 percent of intervals. Figure 1.28 shows that positive prices in the upward direction were most frequent between hours ending 20 and 24. This coincides with periods with higher levels of demand for upward flexible ramping capacity.

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 1.28 Hourly frequency of positive 15-minute market flexible ramping shadow price (July - September)

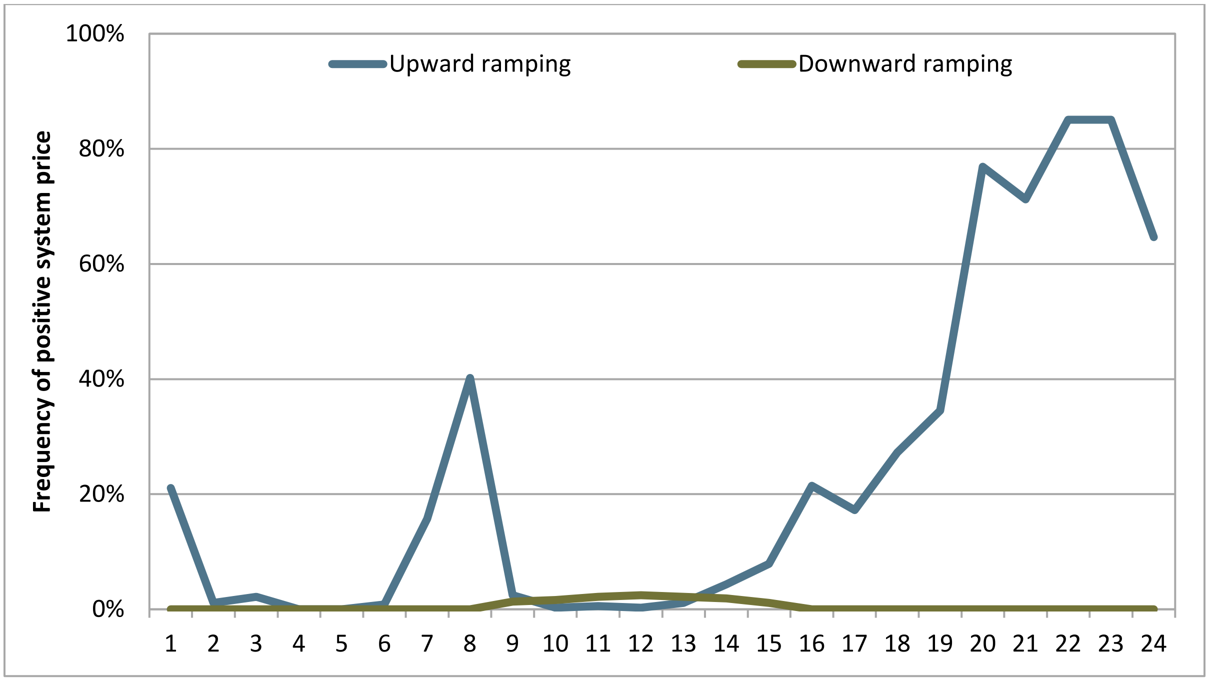
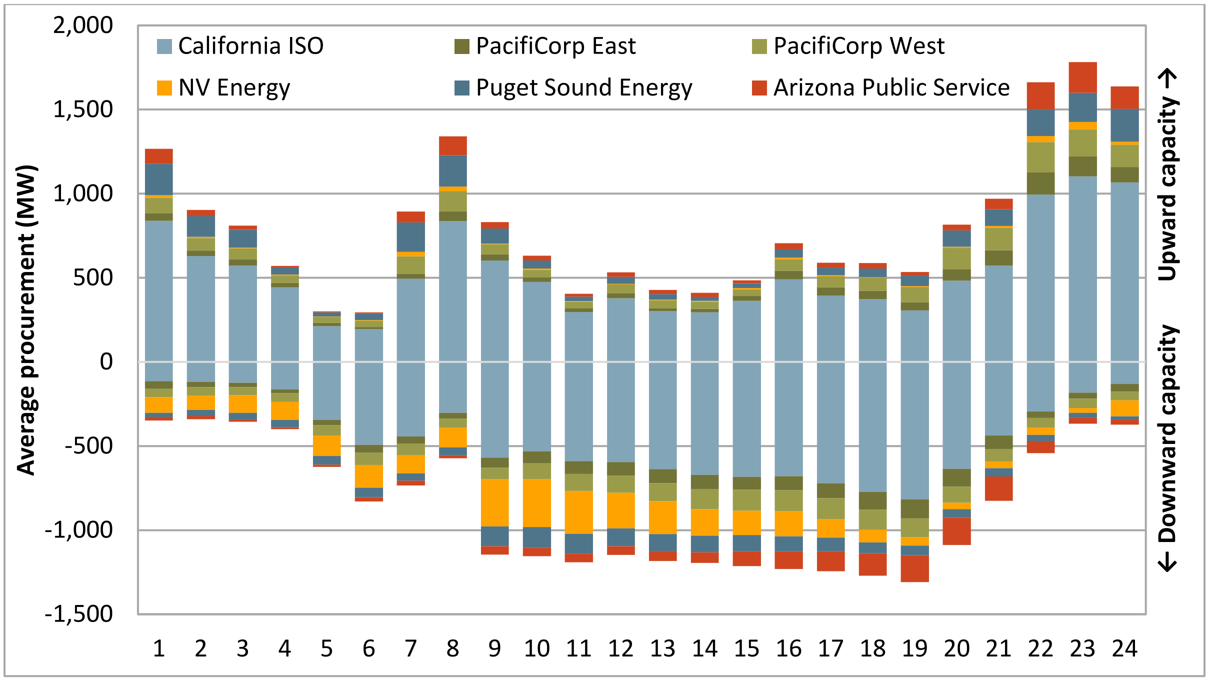


Figure 1.29 shows the hourly average amount of flexible ramping capacity procured in the 15-minute market during the third quarter. This capacity may have been procured to satisfy system-level demand, an area-specific demand, or both. The different colors indicate from which area the capacity was procured. 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 system-level uncertainty needs.

Overall, the ISO procured an hourly average of about 810 MW of upward capacity and 860 MW of downward capacity in the 15-minute market during the third quarter. Compared to the second quarter, this represents a small increase in upward capacity and about the same amount in downward capacity. The total hourly average quantity of flexible ramping capacity procured in the 5-minute market was about 210 MW in the upward direction and 280 MW in the downward direction.

Figure 1.29 Hourly average flexible ramping capacity procurement in 15-minute market (July – September)



Flexible ramping procurement costs

Generation capacity that satisfied the demand for flexible ramping capacity received payments based on the combined system and area-specific flexible ramping shadow price. In addition, the combined 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.[48]

The total 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 1.30 shows the total net payments to generators for flexible ramping capacity by month and balancing area.[49] For the time period before the flexible ramping product was implemented in

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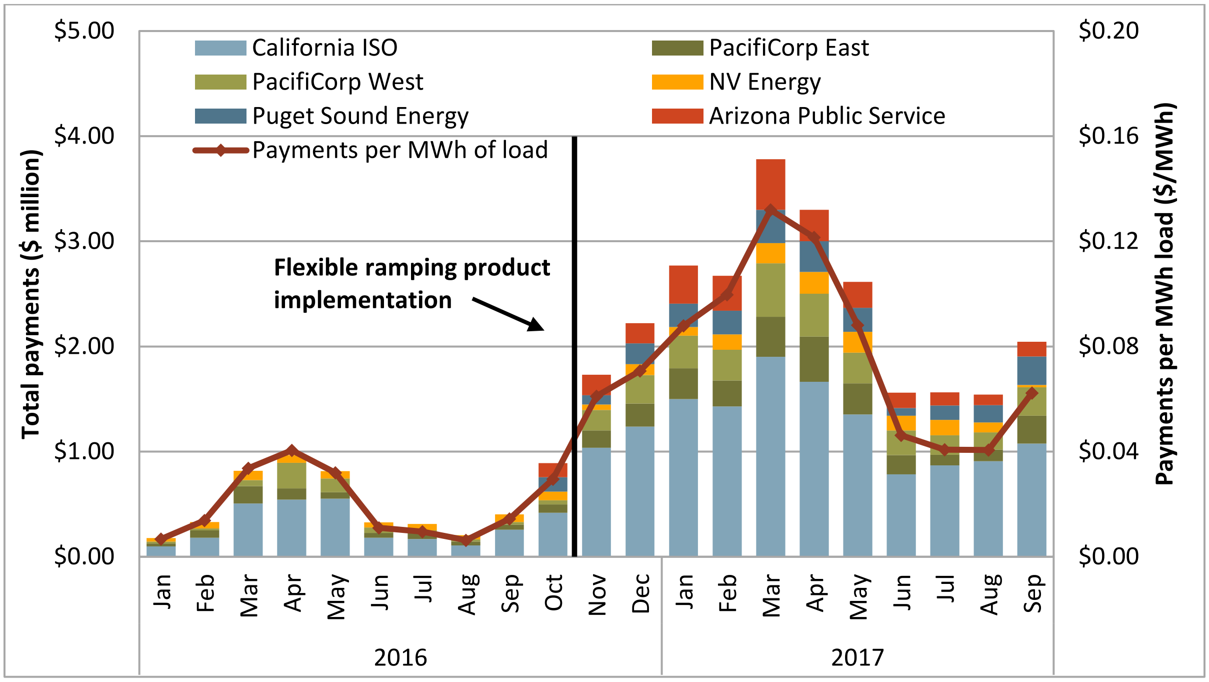
48 More information about the settlement principles can be found in the ISO's *Revised Draft Final Proposal for the Flexible Ramping Product*, December 2015: http://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

49 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 1.30 shows net payments to generators from the flexible ramping constraint.[50] 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.

Figure 1.30 Monthly flexible ramping payments by balancing area



As shown in Figure 1.30, total payments to generators have been higher following the implementation of the flexible ramping product. Total payments for flexible ramping capacity in the third quarter were about $5.1 million. Compared to the second quarter of 2017, total payments decreased from about $7.5 million. A similar seasonal pattern can be seen for the flexible ramping constraint payments over the summer of 2016. About 55 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.[51] Average net payments per megawatt-hour of load during the third quarter were about $0.05/MWh, a decrease from about $0.09/MWh for the second quarter.

50 Rescissions for non-performance have been excluded.

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

2 Energy imbalance market

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

- Average prices in PacifiCorp East, NV Energy, and Arizona Public Service were often similar to each other and the ISO during most hours. However, in other hours, one or more of these areas failed the flexible ramping sufficiency test or reached their transfer limits that created price separation.
- 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.
- The ISO and Arizona Public Service were net importers during the quarter. The PacifiCorp areas and NV Energy tended to export energy during the quarter.
- Valid under-supply infeasibilities were very infrequent during the third quarter, occurring in less than 0.5 percent of intervals in the 15-minute and 5-minute markets in each of the energy imbalance market balancing areas. In addition, the frequency of valid over-supply infeasibilities in Arizona Public Service continued to decrease to less than 0.4 percent of intervals, compared to around 3 percent of intervals in the previous quarter.
- Overall, load adjustments were typically positive in PacifiCorp East, Arizona Public Service and the ISO, while negative load adjustments were frequent in PacifiCorp West and Puget Sound Energy. NV Energy load adjustments were typically positive in the 15-minute market and negative in the 5-minute market.
- Balancing areas failed the flexible ramping sufficiency tests less frequently overall during the quarter. In particular, Puget Sound Energy failed the downward sufficiency test in less than 1 percent of hours during the quarter, compared to about 13 percent of hours in the previous quarter. However, NV Energy failed the tests more frequently in over 5 percent of hours in the upward direction and over 3 percent of hours in the downward direction.
- DMM notes that the use of net import capability and net export capability in the sufficiency test, as a function of the sufficiency test result in the previous hour, can block balancing areas from the benefit of a lower uncertainty requirement. DMM recommends that the ISO revaluate this interaction in a manner that does not impact the independence of consecutive hourly sufficiency tests.

2.1 Energy imbalance market performance

Energy imbalance market prices

During most hours, prices in the energy imbalance market differed between two distinct regions. Prices in the first region – including PacifiCorp East, NV Energy and Arizona Public Service – were often similar to each other and the ISO because of large transfer capacities and little congestion. However, there was some price separation within this region, particularly during hours ending 17 through 21. In many of these cases, one or more of these areas failed the flexible ramping sufficiency test that limited transfers and created price separation between the balancing areas. In other instances, export limits bound during periods when prices in the surrounding balancing areas were high.

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 transmission available between PacifiCorp West and the ISO as well as between PacifiCorp West and PacifiCorp East.

Figure 2.1 and Figure 2.2 show real-time prices for PacifiCorp East, NV Energy, and Arizona Public Service as well as hourly average combined prices for PacifiCorp West and Puget Sound Energy. PacifiCorp West and Puget Sound Energy were grouped this way because of very similar average hourly pricing. The figures also show prices for Southern California Edison for comparison with the ISO. Average prices for PacifiCorp East, NV Energy, and Arizona Public Service tracked closely to system prices during most hours. However, hourly average prices in PacifiCorp East were significantly lower than hourly average prices in NV Energy, Arizona Public Service and the ISO during hours ending 17 through 21. This was in part driven by several days when energy imbalance market transfers out of PacifiCorp East reached their limits.

Prices in PacifiCorp West and Puget Sound Energy often formed a second pricing region. As shown in Figure 2.1, prices here were often less than prices in the ISO because of limited transfer capability from PacifiCorp West into the ISO and PacifiCorp East.

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. When the load bias limiter is triggered, the infeasibility is resolved and prices are instead set by the last dispatched bid rather than the penalty parameters for under-supply and over-supply.

During the third quarter, valid under-supply infeasibilities were very infrequent. Valid under-supply infeasibilities occurred during less than 0.5 percent of intervals in the 15-minute 5-minute markets in each of the energy imbalance market balancing areas. In addition, the frequency of valid over-supply infeasibilities in Arizona Public Service continued to decrease to less than 0.4 percent of intervals, compared to around 3 percent of intervals in the previous quarter.

Figure 2.1 Hourly 15-minute market prices (July – September)

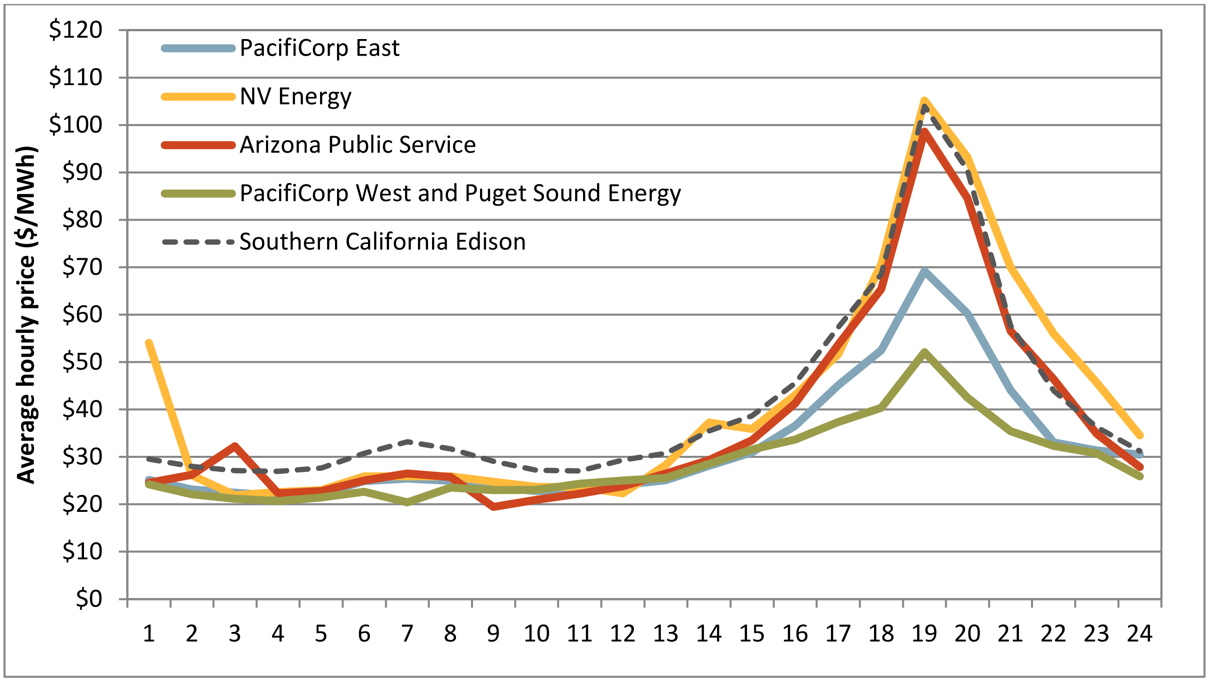
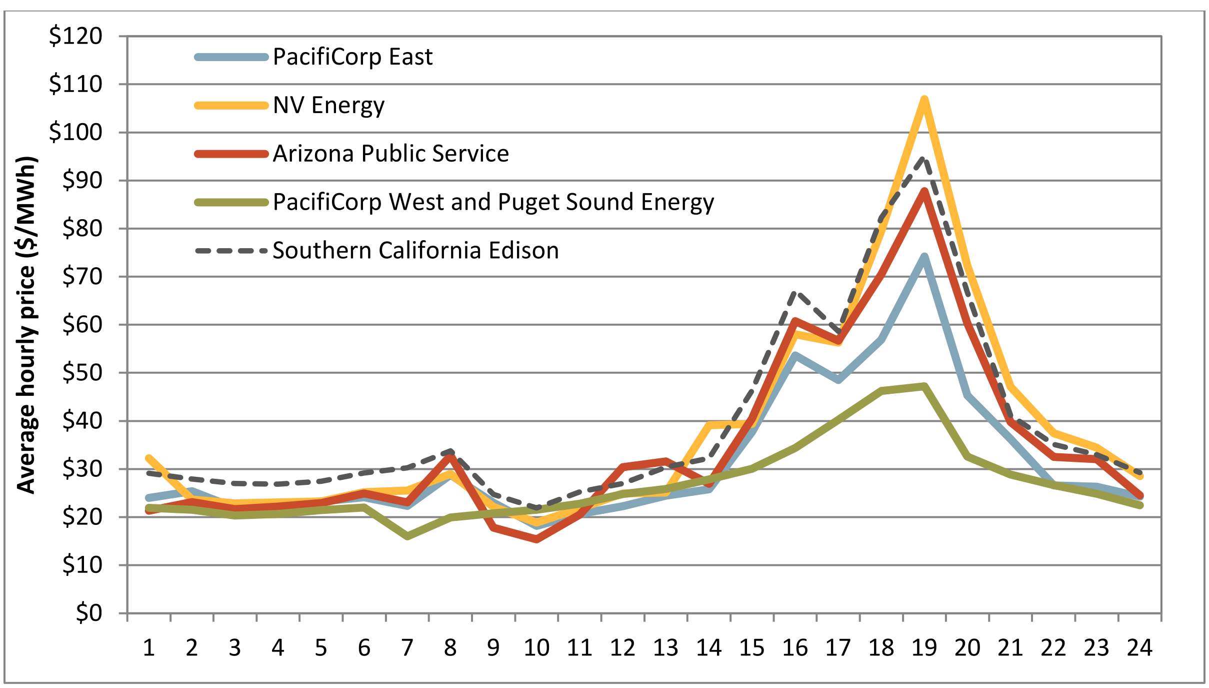


Figure 2.2 Hourly 5-minute market prices (July – September)



2.2 Flexible ramping sufficiency test

The flexible ramping sufficiency test ensures that each balancing area has enough ramping resources over each 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.

When the energy imbalance market was initially implemented there was an upward ramping sufficiency test. The ISO implemented in November 2016 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.[52] 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.[53]

Sufficiency test results

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 2.3 and Figure 2.4 show the average percent of hours in which an energy imbalance market area failed the sufficiency test in the upward and downward direction, respectively. Overall, areas failed the tests less frequently during the third quarter. In particular, Puget Sound Energy failed the downward sufficiency test in less than 1 percent of hours during the quarter, compared to about 13 percent of hours in the previous quarter. However, NV Energy failed the tests more frequently in over 5 percent of hours in the upward direction and over 3 percent of hours in the downward direction.

52 *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.

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

Figure 2.3 Frequency of upward failed sufficiency tests by month

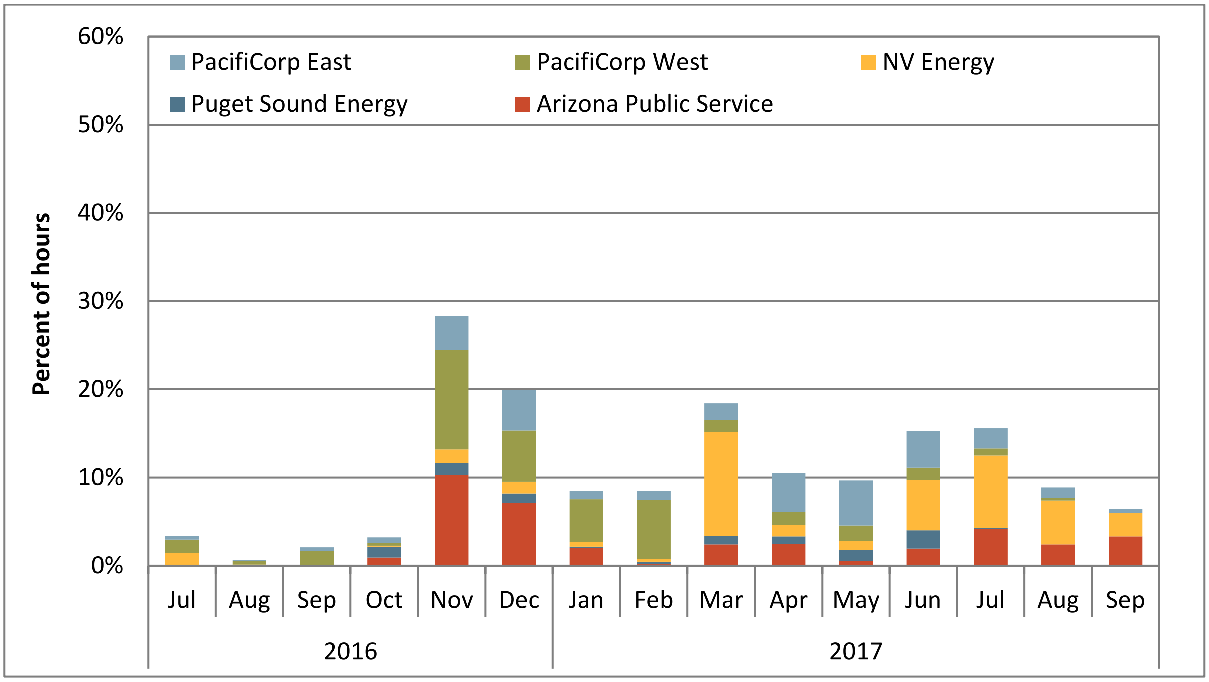
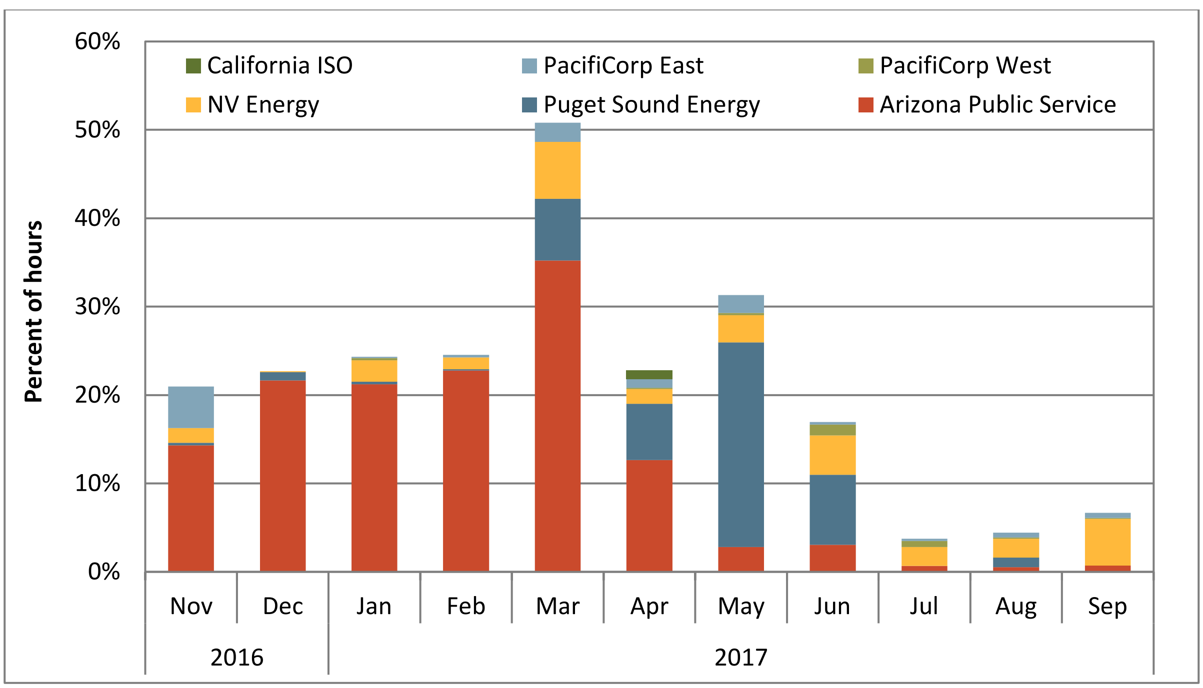


Figure 2.4 Frequency of downward failed sufficiency tests by month



Recommendations and areas of continued review

In order to pass the hourly flexible ramping sufficiency test in a given direction (upward or downward), the balancing area needs to show sufficient ramping capability from the start of the hour to each of the four 15-minute intervals in the hour. The area must pass all four 15-minute interval tests in order to pass the hourly flexible ramping sufficiency test for upward and downward ramping.

The requirement for the flexible ramping sufficiency test is calculated as the forecasted change in load plus the uncertainty requirement minus two discounts, diversity benefit and flexible ramping credits. The diversity benefit reflects that system-level flexible ramping needs are typically smaller than the sum of the individual balancing area flexible ramping needs because of reduced uncertainty across a larger footprint. As a result, balancing areas receive a prorated diversity benefit discount based on this proportion. In addition, credits reflect the ability to reduce exports to increase upward ramping capability or reduce imports to increase downward ramping capability. Further, the reduction in the sufficiency test requirement because of any diversity benefit or flexible ramping credit is capped by the area's net import capability for the upward direction or net export capability for the downward direction.[54]

The credits, net import capability, and net export capability are calculated from the energy imbalance market transfers and limits in the last binding 15-minute interval prior to the hour that is being tested. In most hours, net import (or export) capability is then calculated as the difference between total import (or export) limits and the net energy imbalance market transfer in that final 15-minute interval. However, if the balancing area failed the sufficiency test in the previous hour, net import or export capability – pulled from the last binding 15-minute interval – will be based on the limited transfer quantity as a result of failing the test rather than total energy imbalance market import and export limits.

DMM notes that the use of net import capability and net export capability in the sufficiency test, as a function of the sufficiency test result in the previous hour, can impact the ability of balancing areas to realize the benefits of increased resource diversity. In particular, balancing areas with otherwise sufficient transfer capability can be blocked from the benefit of a lower uncertainty requirement (as a result of less uncertainty spread over a larger area), regardless of the upper operating limits on the area's energy imbalance market transfers. DMM recommends that the ISO revaluate this interaction in a manner that does not impact the independence of consecutive hourly sufficiency tests.

Second, 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. 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 the old requirements.

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

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. 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*. 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, thus reducing the overall cost to meet load in the energy imbalance market. This section includes results for energy transfers between areas, which is one of the key sources of value that the energy imbalance market provides.[55]

Table 2.1 shows the percentage of intervals that each energy imbalance market area and the ISO either exported or imported energy on net and the associated average quantity in the 5-minute market. Table 2.2 shows detail about how frequently congestion occurred between any energy imbalance areas.[56] These tables show that scheduled transfers typically flowed into the ISO and Arizona Public Service and energy typically flowed out of the PacifiCorp areas and NV Energy.

Table 2.1 shows that the ISO and Arizona Public Service were net importers during the quarter, and that both areas transferred significantly greater quantities of energy while importing than while exporting. The PacifiCorp areas and NV Energy tended to export energy during the quarter. High loads and less expensive generation available outside of the ISO during the quarter made it economic for the ISO to import more energy from the energy imbalance market areas.

Table 2.2 shows there was some congestion in the 5-minute market in the direction of the ISO. Historically, there has been frequent congestion from the PacifiCorp West and Puget Sound Energy areas in the direction of the ISO. The frequency observed this quarter is consistent with these values. Congestion for exports from PacifiCorp West to the ISO caused 5-minute prices in PacifiCorp West and Puget Sound Energy to differ frequently from system prices and prices in the other energy imbalance market areas. When system prices were high, 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.

Congestion from the other energy imbalance areas, including PacifiCorp East, NV Energy and Arizona Public Service, toward the ISO was higher this quarter than in prior quarters. This may be because of increased transfers to the ISO during the quarter. Table 2.2 also shows that there continued to be little congestion from the ISO to other areas. In fact, there continues to be almost no congestion from the ISO to PacifiCorp East, NV Energy, or Arizona Public Service.

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[55] 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.

[56] This table removes all intervals when congestion could be caused by greenhouse gas compliance costs, which are usually about $6/MWh.

Table 2.1 Average net energy imbalance market transfer (July – September)

EIM participant	Net importer frequency	Net importer flows	Net exporter frequency	Net exporter flows
ISO	74%	-313	26%	171
PacifiCorp East	31%	-73	69%	176
PacifiCorp West	34%	-40	66%	93
NV Energy	39%	-79	61%	122
Puget Sound Energy	50%	-57	50%	55
Arizona Public Service	56%	-152	44%	97

Table 2.2 Congestion status and flows in EIM (July – September)[57]

	Congested toward ISO	Congested from ISO
PacifiCorp East	19%	0%
PacifiCorp West	31%	8%
NV Energy	18%	2%
Puget Sound Energy	31%	9%
Arizona Public Service	18%	2%

Different areas in the energy imbalance market exhibited different hourly transfer patterns. Generally, the ISO exported energy during the peak solar hours of the day and imported during other hours. Energy transfers in each area were driven by the resource mix and relative prices during these times of the day.

Figure 2.5 through Figure 2.7 show details about how energy transfers moved between NV Energy, Arizona Public Service, and PacifiCorp West, respectively, and neighboring areas on an hourly basis during the quarter. Figure 2.5 shows that NV Energy typically was an importer in the afternoon, while receiving imports from the ISO. It also shows that NV energy was a net exporter, on average, during almost all other hours of the day. In the morning hours NV Energy generally would be exporting to PacifiCorp East and the ISO, while in the evening hours the area would typically be exporting to the ISO while importing from PacifiCorp East.

Figure 2.6 shows similar information, but for Arizona Public Service rather than NV Energy. This chart shows that Arizona Public Service was a net importer during the middle of the day, a net exporter in the evening and was relatively neutral during the morning hours. In the morning Arizona Public Service imported energy from PacifiCorp East and exported energy to the ISO, in the middle of the day they

57 Table 2.2 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.

imported from both the ISO and PacifiCorp East, and during the evening they would import some energy from PacifiCorp East and export more to the ISO, on average.

Figure 2.7 shows average transfers between PacifiCorp West and the neighboring areas: Puget Sound Energy, PacifiCorp East, and the ISO. This figure shows that PacifiCorp West was generally a net exporter during almost all hours of the day. On average during all hours of the day, PacifiCorp West tended to export energy to the ISO and import from PacifiCorp East. Transfers from PacifiCorp East are a byproduct of the transfer limits imposed between the two areas, which specify that transfers only occur in the east-to-west direction between these two areas. This figure also shows that PacifiCorp West usually imported from Puget Sound Energy in the morning and exported to Puget Sound Energy during the evening hours.

Figure 2.5 Average hourly imports into NV Energy (July – September)

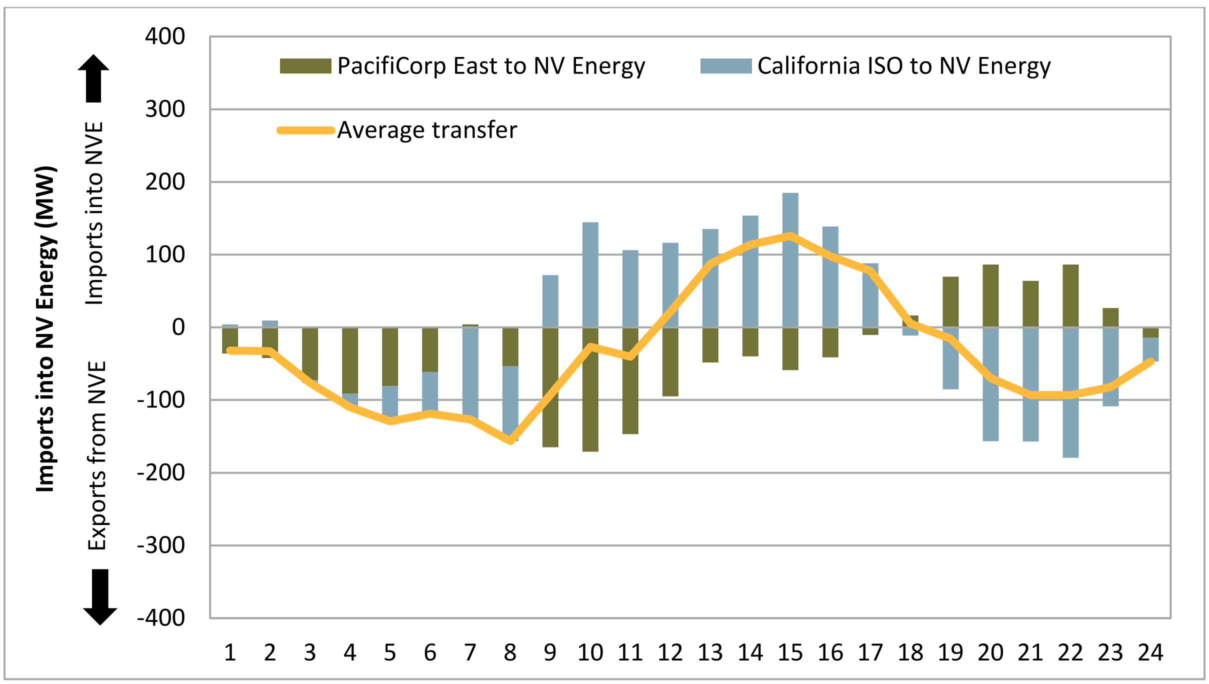


Figure 2.6 Average hourly imports into Arizona Public Service (July – September)

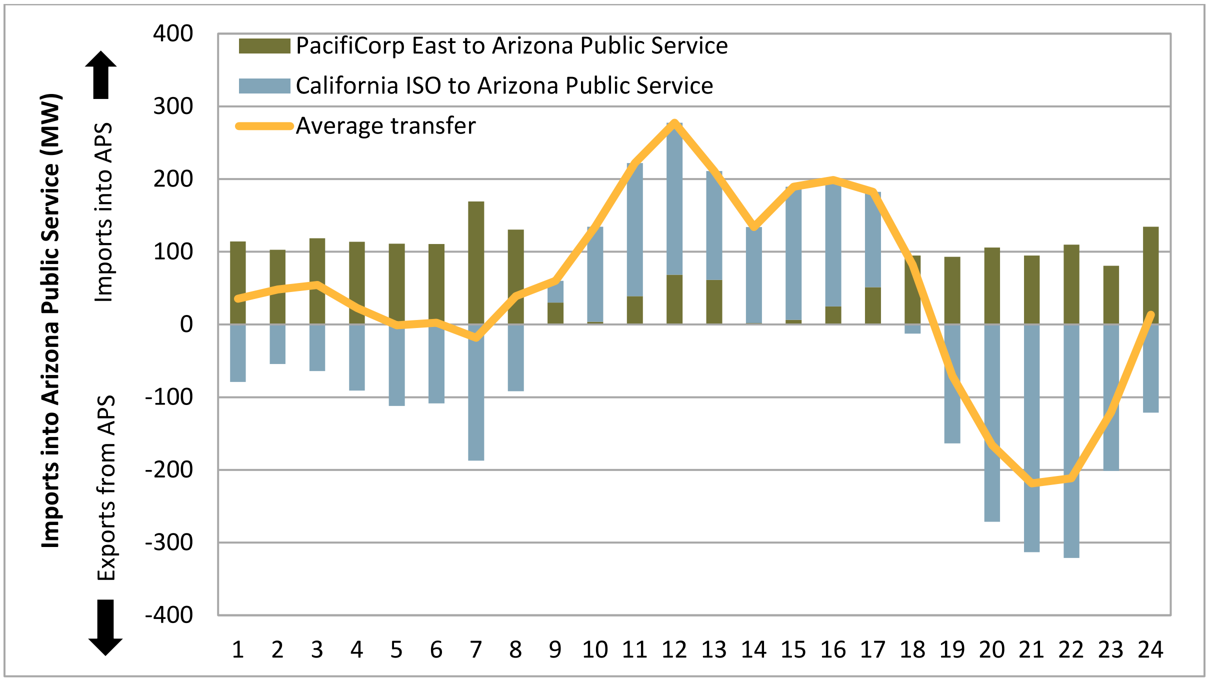
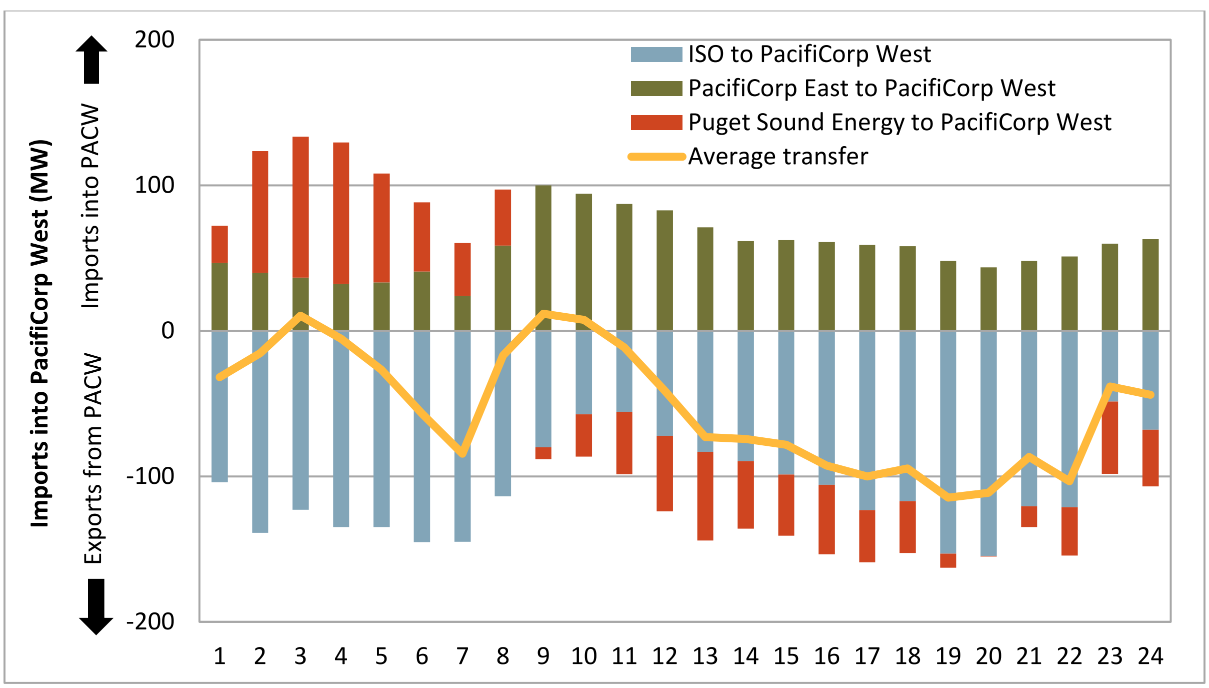


Figure 2.7 Average hourly imports into PacifiCorp West (July – September)



2.4 Load adjustments

Table 2.3 summarizes the average frequency and size of positive and negative load forecast adjustments for PacifiCorp East, PacifiCorp West, NV Energy, Puget Sound Energy, and Arizona Public Service during the third quarter for the 15-minute and 5-minute markets. The same data for the ISO is provided as a point of comparison and reference. Overall, load adjustments were typically positive in PacifiCorp East, Arizona Public Service and the ISO, while load adjustments were frequently negative in PacifiCorp West and Puget Sound Energy. NV Energy load adjustments were typically positive in the 15-minute market and negative in the 5-minute market.

Table 2.3 also includes the average absolute positive and negative load adjustment as a percent of area load. In particular, average load adjustments by Arizona Public Service, as a percent of total area load, were larger in magnitude compared to other areas. 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.

Table 2.3 Average frequency and size of load adjustments (July - September)

	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	57%	674	2.0%	6%	-328	1.2%	367
5-minute market	48%	370	1.1%	29%	-289	1.1%	97
PacifiCorp East							
15-minute market	11%	87	1.4%	4%	-85	1.5%	7
5-minute market	37%	83	1.4%	15%	-76	1.3%	19
PacifiCorp West							
15-minute market	3%	56	2.3%	4%	-42	1.8%	0
5-minute market	6%	55	2.3%	22%	-47	2.2%	-7
NV Energy							
15-minute market	15%	90	1.5%	5%	-136	2.7%	7
5-minute market	22%	63	1.1%	32%	-105	2.1%	-20
Puget Sound Energy							
15-minute market	3%	45	1.5%	14%	-66	2.9%	-8
5-minute market	4%	51	1.8%	21%	-65	2.8%	-11
Arizona Public Service							
15-minute market	91%	155	3.5%	4%	-317	8.0%	129
5-minute market	90%	155	3.5%	4%	-356	9.1%	126

3 Special issues

This section provides information about the following special issues:

- Measures of system-level market power in the day-ahead market indicate an increased frequency of hours in which competitive supply was insufficient to meet demand, as measured using the residual supply index removing either 2 or 3 pivotal suppliers. These hours include those in which the ISO market has observed historically high day-ahead prices.
- As reported in DMM's prior quarterly report, on June 21, system marginal prices in the binding integrated forward market run, following mitigation, were significantly higher than in the market power mitigation run.[58] This has occurred on other days as well. Since publication of that report, the ISO has determined that a software error introduced in 2016 resulted in infeasible energy and ancillary service awards for resources in the market power mitigation run but not the binding market run in the day-ahead market. The software error resulted in an erroneous increase in supply available in the market power mitigation run, causing prices in that run to be lower than they would have been had all awarded schedules been feasible. The ISO is currently evaluating the impact of this error on the market power mitigation process on affected days. The error was eliminated effective July 22, 2017, in the day-ahead market.
- DMM's analysis of same-day natural gas price volatility in Southern California during the first three quarters of 2017 shows that there was a very limited need for the increased bidding flexibility created by raising the commitment cost and default energy bid caps. Following DMM's analysis and recommendations, the ISO decided to reduce to zero the special Aliso Canyon gas price scalars which are being used in the real-time market. This change went into effect in the market starting August 1, 2017.
- During the first three quarters of the year, resource adequacy availability peaked in July at 93 percent.
- The resource adequacy availability incentive mechanism (RAAIM) became effective in April. The ISO identified a number of issues with the mechanism and is working to correct them. Some of these changes will be put in place in the fall software release and applied retroactively to penalties from April through implementation, and some will be released at a later date and will be applied proactively.
- There was one designation under the capacity procurement mechanism in the third quarter of 2017, which was triggered by exceptional dispatch in the intra-monthly competitive solicitation process. The designation for the El Cajon resource was a result of the competitive solicitation process where the scheduling coordinator submitted bids, and this particular unit's bid was submitted at the $6.31/kW-month soft cap. This capacity was requested via exceptional dispatch for relief on a local line in the San Diego area. Several additional designations were declined by one scheduling coordinator.

[58] *Q2 2017 Report on Market Issues and Performance*, September 2017: http://www.caiso.com/Documents/2017SecondQuarterReport-MarketIssuesandPerformance-September2017.pdf

3.1 Structural measures of market competitiveness

Market structure refers to the ownership of available supply in the market. The structural competitiveness of electric markets is often assessed using two related quantitative measures: the *pivotal supplier test* and the *residual supply index*. Both of these measures assess the sufficiency of supply available to meet demand after removing the capacity owned or controlled by one or more entities.

- **Pivotal supplier test**. If supply is insufficient to meet demand with the supply of any individual supplier removed, then this supplier is pivotal. This is referred to as a single pivotal supplier test. The two-pivotal supplier test is performed by removing supply owned or controlled by the two largest suppliers. For the three-pivotal test, supply of the three largest suppliers is removed.
- **Residual supply index**. The residual supply index is the ratio of supply from non-pivotal suppliers to demand.[59]

In the electric industry, measures based on the two or three pivotal suppliers are often used as measures of competitiveness because of the potential for oligopolistic bidding behavior. This potential is high in the electric industry because the demand for electricity is highly inelastic, and competition from new sources of supply is limited by long lead times and regulatory barriers for building new generation.

In this report the measure RSI_1 refers to the residual supply index calculated by excluding the largest supplier. The RSI_2 measure refers to the same calculation with the two largest suppliers excluded, and RSI_3 with the three largest supplier excluded.[60]

The frequency of hours with residual supply less than demand in the day-ahead market increased relative to 2016. Figure 3.1 shows the hourly residual supply index for the day-ahead energy market in the ISO for 2017 through the end of the third quarter. This analysis is based on system energy only and ignores potential transmission limitations.[61] Results are only shown for the 500 hours when each residual supply index was lowest.

As shown in Figure 3.1, the residual supply index with the three largest suppliers removed (RSI_3) was less than 1 during about 60 hours, or about double the number of hours in 2016. The index was less than 1 during about 20 hours with the two largest suppliers removed (RSI_2), compared to only 2 hours in 2016. The RSI_1 value was only less than 1 during 1 hour. The hourly RSI_3 value reached as low as 0.86 in 2017, compared to about 0.92 in 2016.

The residual supply index values reflect load conditions, generation availability, and resource ownership or control. Some generating units have tolling contracts, which transfer the control from unit owners to load-serving entities. These tolling contracts improve overall structural competitiveness in the operating period versus the study period.

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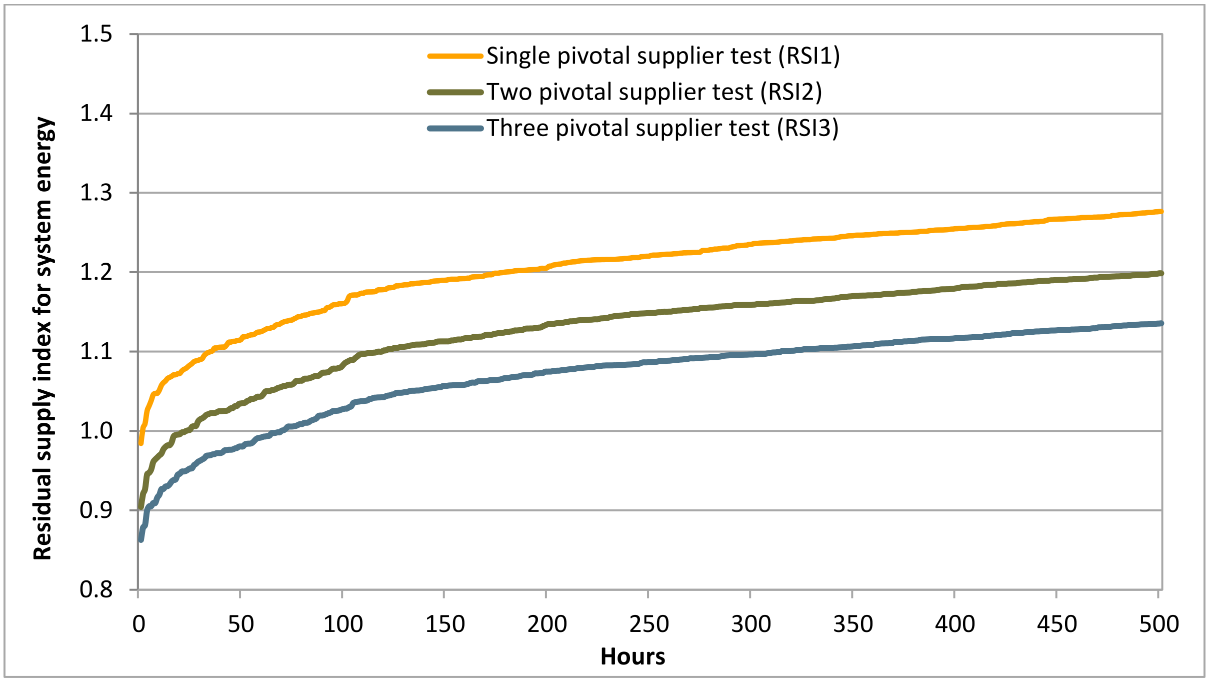
59 For instance, assume demand equals 100 MW and the total available supply equals 120 MW. If one supplier owns 30 MW of this supply, the residual supply index equals 0.90, or (120-30)/100.

60 A detailed description of the residual supply index was provided in Appendix A of DMM's 2009 annual report. http://www.caiso.com/Documents/2009AnnualReportonMarketIssuesandPerformance.pdf.

61 All internal supply bid into the day-ahead market is used in this calculation. Imports are assumed to be limited to 12,000 MW. Demand includes actual system load plus ancillary services.

The specific hours during 2017 that the residual supply index with the three largest suppliers excluded was below 1 were highly concentrated on a small number of days. There were about 60 hours where this measure was less than 1, and of those hours more than half were between the days of August 28 and September 3. These hours were primarily the peak load hours of the day, and these days made up all but three of the lowest 20 hours for this measure. Similarly, there were multiple hours where this measure was less than 1 between June 19 and June 21. This set of hours includes those with historically high day-ahead prices discussed in Chapter 1 of this report.

Figure 3.1 Residual supply index for day-ahead energy (January - September)



3.2 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.

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.[62]

In the third quarter of 2017, following a curtailment watch issued by SoCalGas on August 3, 2017, the ISO enforced two gas constraints (Inland and LA basin areas) in the real-time market from hours ending 17 through 24 on August 3 and a few intervals in hour ending 1 on August 4. Prior to this, the ISO enforced two gas constraints (San Diego Gas and Electric system and the broader Southern California Gas Company system) on four days in 2017, from January 23-26.

Additional bidding flexibility for SoCalGas resources

Starting July 6, 2016, 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 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.[63]

DMM's analysis of same-day natural gas prices in Southern California in the third quarter of 2017 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 3.2 shows same-day trade prices for the SoCal Citygate during July through September 2017 compared to the next-day average price. About 20 percent of traded volume on the Intercontinental Exchange (ICE) exceeded the normal 10 percent scalar adder at the SoCal Citygate and 2 percent of the traded volume exceeded the 25 percent adder. Same day prices higher than 125 percent of the next day index correspond to the days when the loads were significantly higher across California during the end of August and the first few days of September.

Figure 3.2 also shows that the majority of trades above the 10 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). Similar to the second quarter, 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 third quarter.

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

[63] *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.

Following DMM's analysis and recommendations, the ISO has decided to reduce to zero the special Aliso Canyon gas price scalars that are being applied to commitment cost and default energy bids used in the real-time market.[64] This change went into effect in the market starting August 1, 2017.[65]

Following a curtailment watch issued by SoCalGas due to an unplanned pipeline outage, the ISO adjusted the scalars to 75 percent and 25 percent for commitment cost and default energy bid calculation effective August 4, 2017.[66] During the days when the scalars were active, same day prices on ICE were trading below the next day index. Effective August 8, 2017, the ISO lowered the scalars back to zero for commitment cost and default energy bid calculation based on the gas supply conditions and levels of load in the ISO system.[67]

Figure 3.3 shows the comparison between SoCal Citygate next day index and same day price distribution before and after the scalars were active from July 28 through August 10, 2017. The red line represents the next day index without any scalar and the dashed orange and red lines represent 125 percent of the next day index and 175 percent of the next day index used in the default energy bids and commitment cost caps, respectively. Same day prices from ICE are represented as a green box and whisker plot which shows a tight distribution around the corresponding next day index. As shown in Figure 3.3, after the scalars were raised to 175 percent and 125 percent beginning in the real-time market on August 4, actual same day gas prices continued to stay about equal to the next day gas index.

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64 *Comments on Aliso Canyon Gas-Electric Coordination Phase 3 Draft Final Proposal*, Department of Market Monitoring, June 30, 2017: http://www.caiso.com/Documents/DMMComments_AlisoCanyonGas_ElectricCoordinationPhase3DraftFinalProposal.pdf

65 *Market Notice - Adjustment of Gas Price Index Scaling Factors*, July 31,2017: http://www.caiso.com/Documents/Adjustment_GasPriceIndexScalingFactors.html

66 *Market Notice - Adjustment of Gas Price Index Scaling Factors*, August 3,2017: http://www.caiso.com/Documents/Adjustment_GasPriceIndexScalingFactors080317.html

67 *Market Notice - Adjustment of Gas Price Index Scaling Factors*, August 7,2017: http://www.caiso.com/Documents/Adjustment-GasPriceIndexScalingFactorsEffective080817.html

Figure 3.2 Same-day trade prices compared to next-day index (July – September)

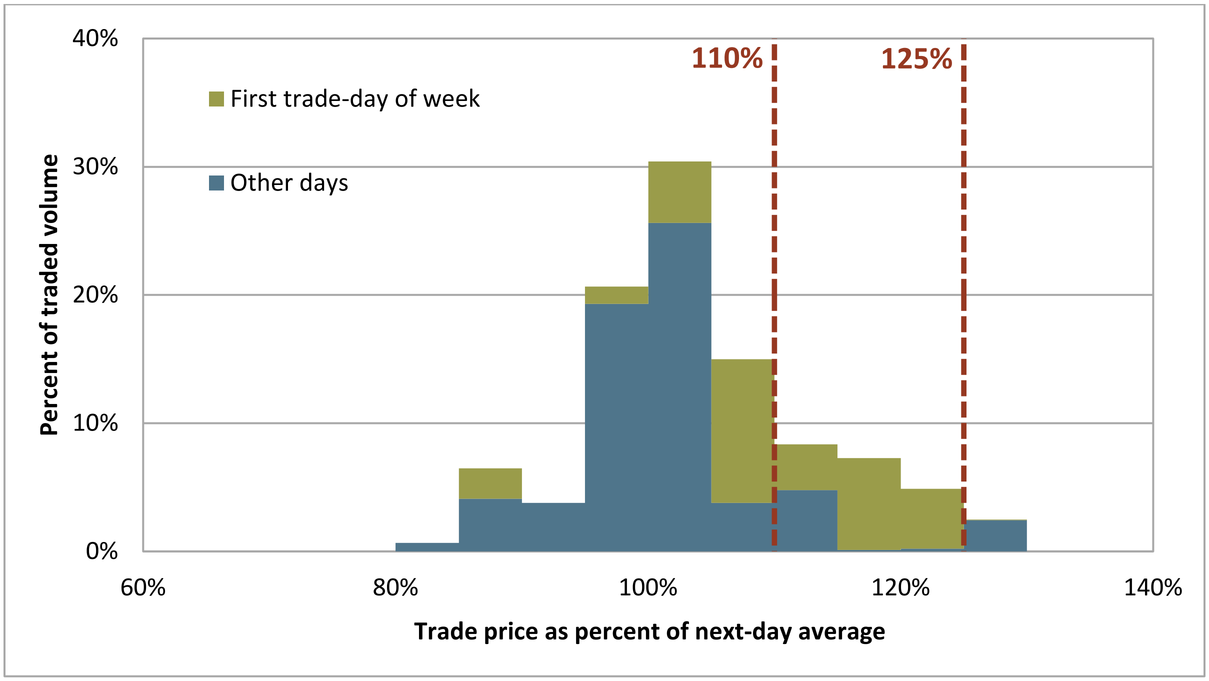
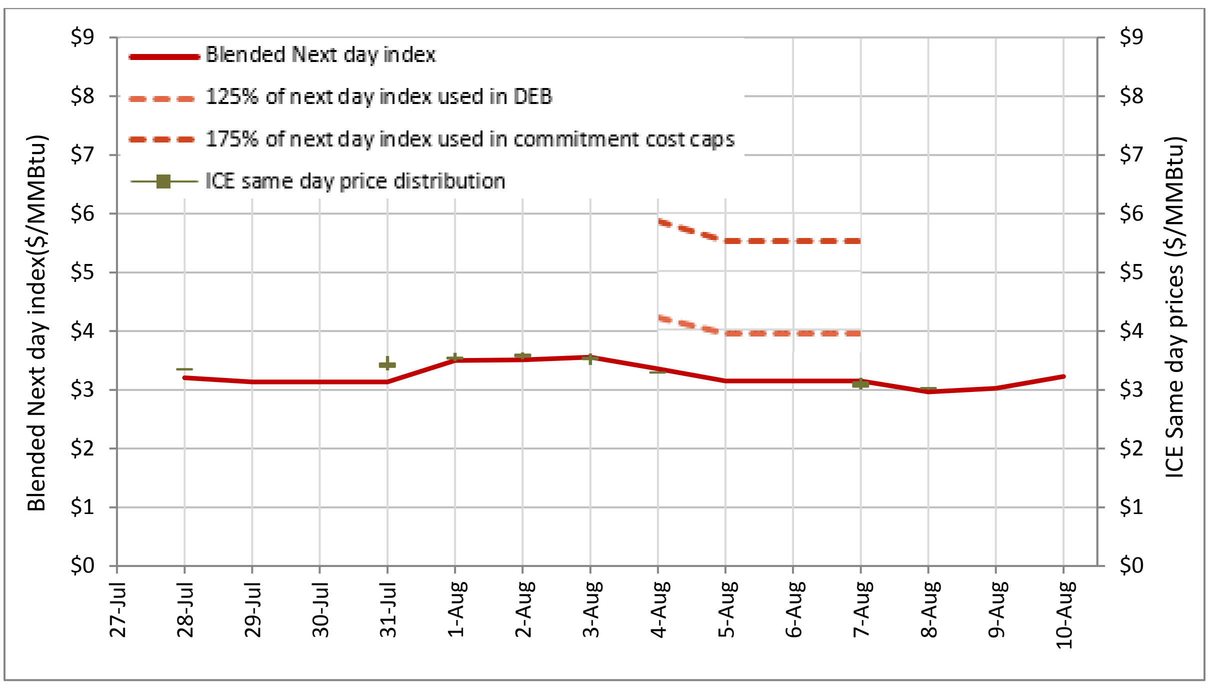


Figure 3.3 SoCal Citygate next day index verses ICE same day price distribution



More timely natural gas prices for the day-ahead market

Through its May 2016 FERC filing, the ISO also received authority 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.

Figure 3.4 and Figure 3.5 illustrate the benefit of using the updated natural gas price index in the third quarter of 2017. Figure 3.4 shows next-day trade prices reported on ICE for the SoCal Citygate during the third 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 3.4, about 12 percent of next-day trades were at a price in excess of the 10 percent adder normally included in default energy bids. About 2 percent of the next-day trades were in excess of the 25 percent headroom normally included in commitment cost bid caps.

Figure 3.5 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 3.5, all trade prices are now within the 10 percent adder normally included in default energy bids.

Figure 3.4 Next-day trade prices compared to next-day index from prior day (July - September)

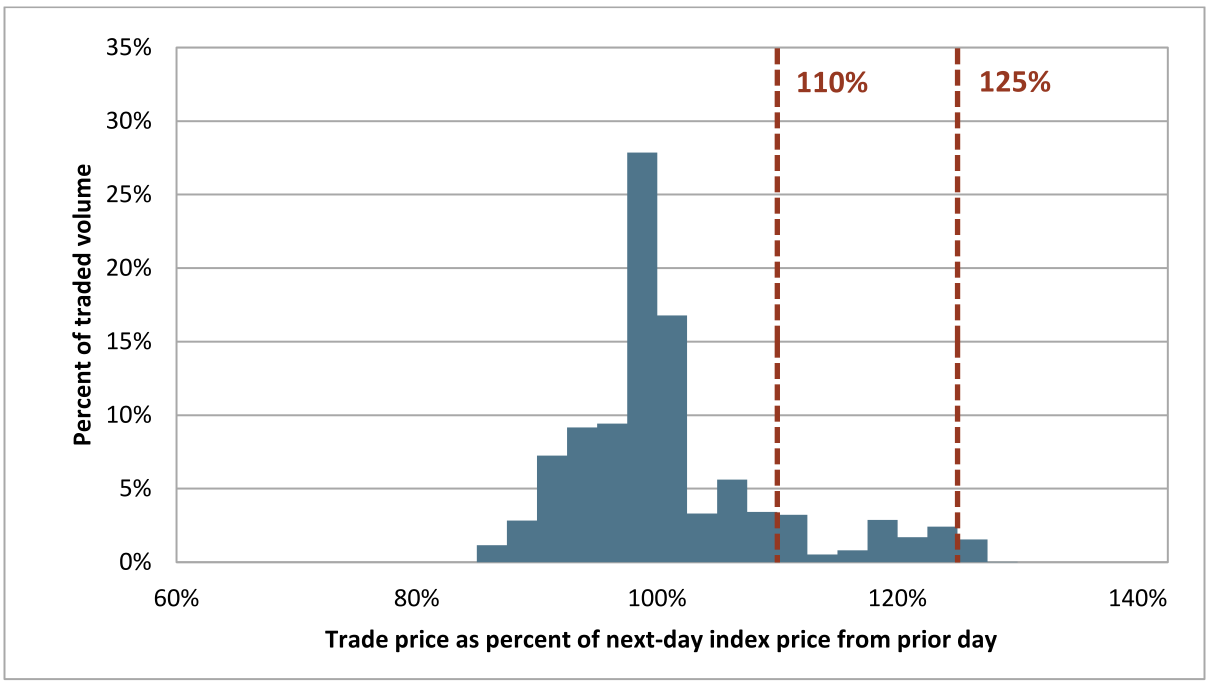
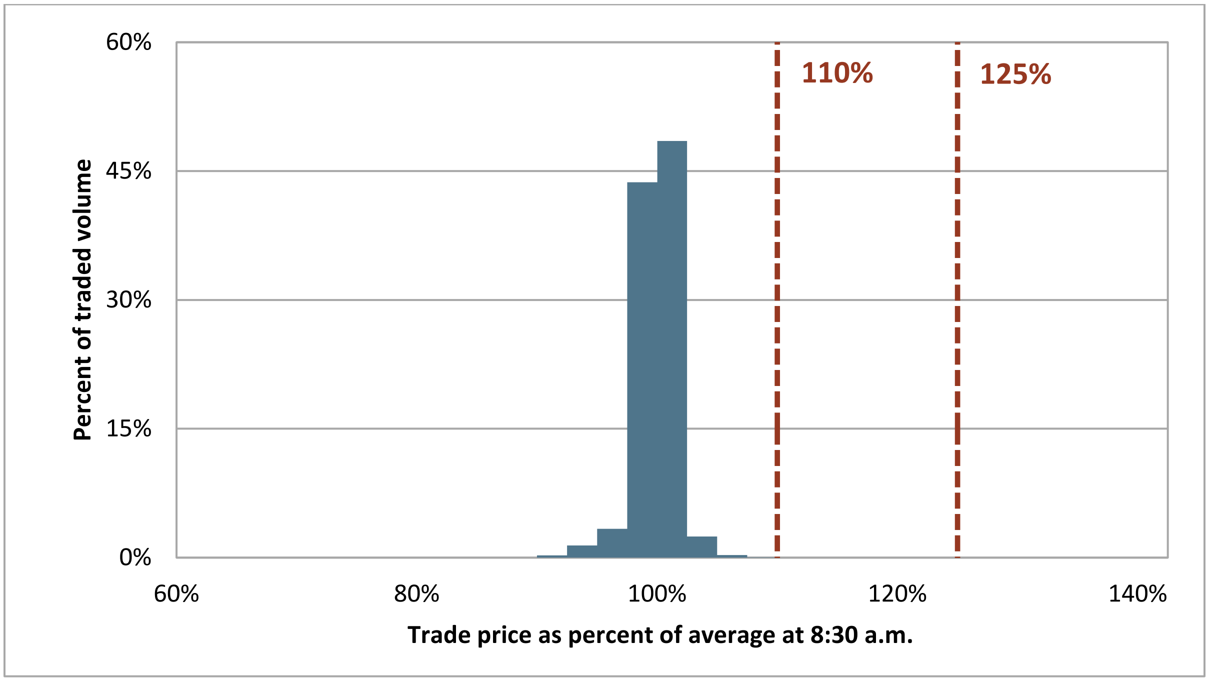


Figure 3.5 Next-day trade prices compared to updated next-day average price (July - September)



3.3 Resource adequacy

3.3.1 System resource adequacy availability

Load-serving entities procure resource adequacy capacity to meet system-level requirements. Scheduling coordinators are then incentivized to make resource adequacy capacity available in the market during *availability assessment hours* through the resource adequacy availability incentive mechanism. These are hours ending 14 through 18 during April through October, and hours ending 17 through 21 during the remainder of the year.[68]

A high portion of resource adequacy capacity was available to the market throughout the first half of 2017. Figure 3.6 summarizes the average monthly amount of resource adequacy capacity available in the day-ahead and real-time markets during the availability assessment hours. The red line shows the total amount of resource adequacy capacity used to meet requirements. The bars show the amount of resource adequacy capacity that was self-scheduled or bid in the day-ahead and real-time markets.[69]

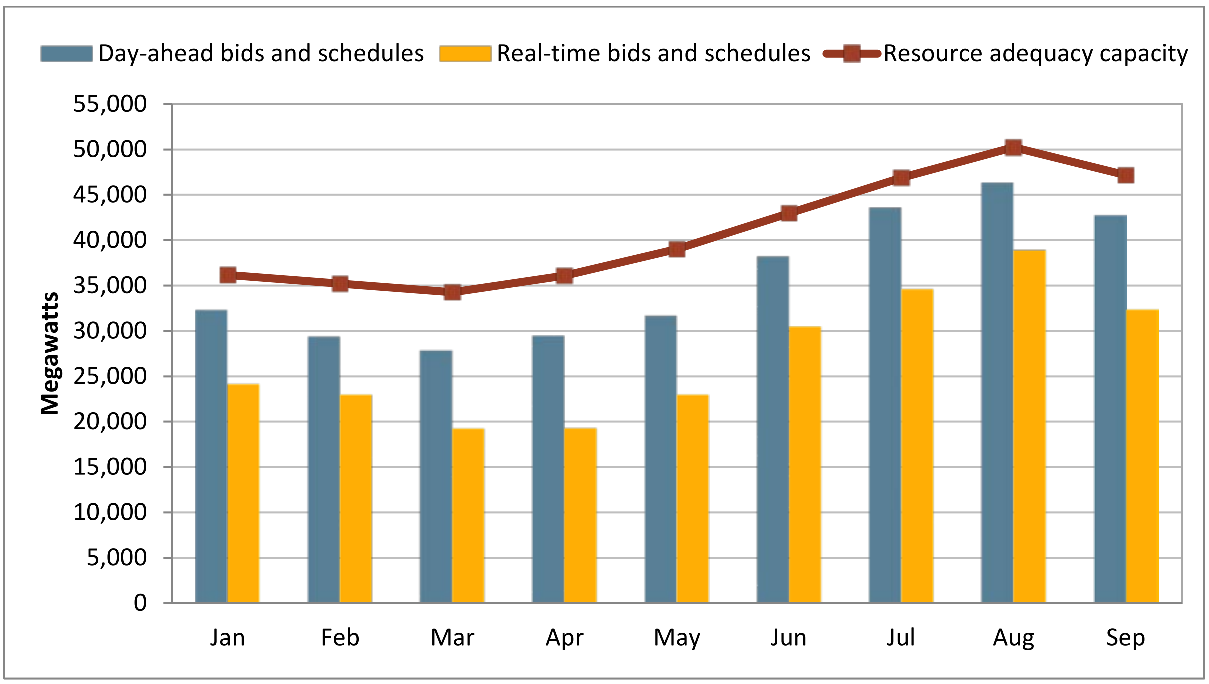
Key findings of this analysis include the following:

68 In April, the ISO began an initiative through the business practice manual change management process to change the resource adequacy availability hours for the 2018 year, but ultimately did not. This process is documented here: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=986.

69 These amounts are calculated as the hourly average of total bids and schedules available to each of these markets during the resource adequacy standard capacity product *availability assessment hours* during each month.

- In July, an average of 93 percent of resource adequacy capacity was available in the day-ahead market, the highest percentage of any month in 2017 through the end of the third quarter. A total of just over 50,200 MW was shown in August. An average of 92 percent of this capacity was available in the day-ahead market.
- Solar generation accounts for much of the difference between procured resource adequacy capacity and the amount self-scheduled or bid in the day-ahead market during the availability assessment hours. Resource adequacy capacity availability from variable energy resources is limited by generation forecasts. In particular, the hours reflected in Figure 3.6 tend to be during times of the day when solar generation is ramping off or unavailable completely, and therefore not available in the day-ahead market.
- Figure 3.6 also shows that a smaller portion of resource adequacy capacity was available in the real-time market. This is primarily because many long-start gas-fired units are not available in the real-time market if they are not committed in the day-ahead energy market or residual unit commitment process.

Figure 3.6 Monthly resource adequacy capacity scheduled and bid into ISO markets (2017)



3.3.2 Resource adequacy availability incentive mechanism

The reliability services initiative is a two-phase initiative focusing on the ISO's rules and processes relating to the resource adequacy program. Issues addressed in this initiative include resource adequacy rules for replacement and substitute capacity, definitions and qualifying criteria for new technology resources, and a compliance mechanism for resource adequacy resources. The first stage of the initiative was approved by FERC in October 2015 and implementation began in 2016.

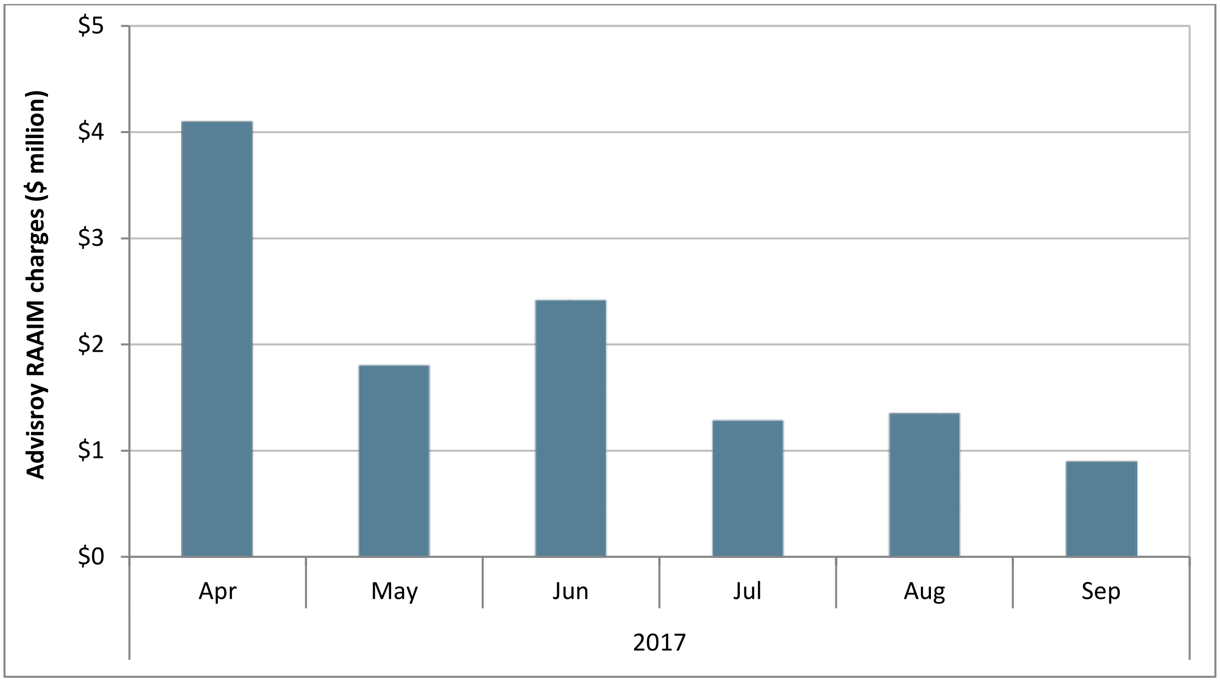
The reliability services initiative included the creation of the resource adequacy availability incentive mechanism (RAAIM), which is a compliance measurement mechanism that is meant to incentivize units to provide energy bids in the day-ahead and real-time markets at or above must-offer obligations. This mechanism differs from the previous standard capacity product (SCP) mechanism in numerous ways, most notably by measuring availability by compliance with a resource's must-offer obligation instead of whether or not the resource was on outage. The basic concept of the must-offer obligation is that a resource must be available to the market, through self-scheduling or by submitting bids. This change allows for evaluation of more detailed must-offer obligation of flexible resource adequacy resources.

Although the new availability incentive mechanism was implemented on November 1, 2016, settlement results were not scheduled to be financially binding until April 2017. Advisory results were provided to scheduling coordinators for review in the interim. In the absence of financially binding resource adequacy performance penalties, resources faced no financial penalty for failure to bid into the ISO's markets in accordance with their must-offer obligation, although their tariff obligation to do so remained.

During the interval when advisory results were being published, the ISO identified a number of issues with the current implementation of the availability incentive mechanism, some of which have already been addressed, and some of which will be addressed with software updates in the fall release. The ISO will continue to produce advisory settlement totals using the current mechanism. These calculations will become financially binding, retroactively, beginning on April 1, with regular settlements restatements after the software changes are implemented in November.

Figure 3.7 shows the total amount of monthly advisory charges for the resource adequacy availability incentive mechanism between April and September. Over $4 million of these charges were accumulated in April, the first month that settlements will be binding. The total amount of advisory payments during these six months totaled about $12 million.

Figure 3.7 Advisory incentive mechanism charges (April – September)[70]



Further enhancements

In addition to the changes that the ISO is implementing in November, there is an additional defect in the way that this mechanism calculates payments for resources that impacts awards for both flexible and system resource adequacy. The ISO released a white paper outlining the details of this defect and the solution they wish to pursue.[71] The ISO plans to implement changes to the mechanism in the spring of 2018. All changes implemented at that time will be effective going forward, and will not be retroactively applied to any settlements totals.

3.3.3 Capacity procurement mechanism

The capacity procurement mechanism within the ISO tariff provides backstop procurement authority to ensure that the ISO will have sufficient capacity available to maintain reliable grid operations. This mechanism establishes a price at which the ISO can procure backstop capacity to meet local resource adequacy capacity requirements that are not met through bilateral purchases. This backstop authority also mitigates the potential exercise of locational market power by resources needed to meet local reliability requirements.

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70 Payments reported in here will be subject to change per the enhancements effective retroactively that will be implemented in November 2017 with the fall software release.

71 *Resource Adequacy Availability Incentive Mechanism Modification White Paper*, August 31, 2017. http://www.caiso.com/Documents/WhitePaper-RAAIMCalculationModifications.pdf.

The ISO's capacity procurement mechanism tariff authority expired in 2016 and was replaced with a new approach. FERC instructed the ISO in a 2011 order to develop enhanced backstop provisions that would do the following:

1) procure capacity at a price that accounts for market conditions that change over time;

2) provide a reasonable opportunity for suppliers to recover fixed costs; and

3) support incremental investment for existing resources to perform long-term maintenance or make improvements that are necessary to satisfy environmental requirements or address reliability needs associated with renewable resource integration.

In response, the ISO proposed replacement of the administrative rate with a competitive bid solicitation process to determine the backstop capacity procurement price for the mechanism. DMM supported the tariff revision as a means of balancing the ISO's need to procure backstop capacity for reliability and mitigate potential local market power with the broader goal of providing an incentive for capacity to be met by resource adequacy capacity procured in the bilateral market. In October 2015, FERC issued an order accepting the ISO's proposed tariff revisions amending the existing capacity procurement mechanism.[72]

The amended capacity procurement mechanism implemented on November 1 is designed to allow competition between different resources that may meet capacity needs when possible. The new program allows resources to submit bids for capacity through a competitive solicitation process. The ISO will look to those bids first, when possible, to fulfill procurement needs.

The tariff revisions include a soft offer cap initially set at $75.68/kW-year (or $6.31/kW-month) by adding a 20 percent premium to the estimated going-forward fixed costs for a mid-cost 550 MW combined cycle resource with duct firing, as estimated in a 2014 report by the California Energy Commission.[73] However, a supplier may apply to FERC to cost-justify a price higher than the soft offer cap prior to offering the resource into the competitive solicitation process or after receiving a capacity procurement mechanism designation by the ISO.

Scheduling coordinators may submit competitive solicitation process bids for three offer types: yearly, monthly and intra-monthly. In each case, the quantity offered is limited to the difference between the resource's maximum capacity and capacity already procured as either resource adequacy capacity or through the ISO's capacity procurement mechanism.

The ISO inserts bids significantly above the soft offer cap for each resource with qualified resource adequacy capacity not offered in the competitive solicitation process up to the maximum capacity of each resource as additional capacity that could be procured. If capacity in the ISO generated bid range receives a designation through the capacity procurement mechanism, the clearing price will be set at the soft offer cap. A scheduling coordinator receiving a designation for capacity with an ISO generated bid may choose to decline that designation within 24 hours of receiving notice by electronic mail.

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[72] *Order Accepting CAISO's Proposed Capacity Procurement Mechanism Tariff Revisions* (ER15-1783), October 1, 2015: http://www.caiso.com/Documents/Oct1_2015_OrderAcceptingTariffRevisions_CapacityProcurementMechanism_ER15-1783.pdf.

[73] Rhyne, Ivin, Joel Klein. 2014. *Estimated Cost of New Renewable and Fossil Generation in California*. California Energy Commission. CEC-200-2014-003-SD.: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SD.pdf

The ISO uses the competitive solicitation process to procure backstop capacity in three distinct processes. First, if insufficient cumulative system, local, or flexible capacity is shown in annual resource adequacy plans the ISO may procure backstop capacity through an annual competitive solicitation process using annual bids. The annual process may also be used to procure backstop capacity to resolve a collective deficiency in any local area.

Second, the ISO may procure backstop capacity through a monthly competitive solicitation process in the event that insufficient cumulative capacity is shown in monthly resource adequacy plans for local, system or flexible resource adequacy. The monthly process may also be used to procure backstop capacity in the event that cumulative system capacity is insufficient because of planned outages.

Third, the intra-monthly competitive solicitation process can be triggered by exceptional dispatch or other significant events. Capacity procurement mechanism designations for risk of retirement are not included in the annual, monthly or intra-monthly competitive solicitation processes.

There was a single capacity procurement mechanism designation issued in the third quarter of 2017, which was triggered by exceptional dispatch in the intra-monthly competitive solicitation process. The designation for the El Cajon resource was a result of the competitive solicitation process where the scheduling coordinator submitted bids, and this particular unit's bid was submitted at the $6.31/kW-month soft cap. This capacity was requested via exceptional dispatch for relief on a local line in the San Diego area.

Several additional designations were declined by one scheduling coordinator. Scheduling coordinators that received exceptional dispatch instructions for capacity not designated through the resource adequacy process may decline a capacity procurement mechanism designation by contacting the ISO through appropriate channels within 24 hours. If the designation occurred during business hours, a scheduling coordinator may receive a courtesy notice of a designation via electronic mail. A scheduling coordinator may choose to decline a designation to avoid the associated must-offer obligation and reduce capacity costs passed to a single transmission access charge area or to the system as a whole.

The total estimated cost of capacity procurement mechanism designations issued in the third quarter was less than $0.4 million. The total cost was charged to the San Diego area, and there were no payments allocated across the entire system.

Table 3.1 Capacity procurement mechanism costs

Resource	CPM desicgnation (MW)	CPM deisgnation dates	Price ($/kW-mon)	Estimated cost ($ million)	Local capacity area	Exceptional dispatch CPM trigger
El Cajon Energy Center	24.87	7/27-8/31	$6.31	$0.37	SDG&E	Physical overload on local line

Additional improvements

Though DMM believes that this mechanism is a significant improvement over the previous standard capacity product, it could be further improved by incorporating a measure of performance. It is problematic to rely solely on market bids as a measure for compliance because a resource could offer into the market without necessarily having the ability to perform. The ISO, in consultation with local regulatory agencies, specifies the criteria for resource characteristics and locations that will ensure system reliability. However, if resource adequacy resources do not perform according to the characteristics the ISO assumes for the resources, the resource adequacy process may not ensure system reliability. Therefore, DMM encourages the ISO to consider performance based enhancements to this mechanism to penalize resources that cannot consistently perform at the standards the ISO assumes for the resources in the ISO's reliability studies.

DMM continues to be concerned about the mechanism's penalty price. The ISO set the penalty price for not meeting availability standards at 60 percent of the soft offer cap for the capacity procurement mechanism. As DMM has noted in past annual reports, if the cost of replacement capacity approaches the soft offer cap, it will be less costly for generating unit owners to pay the penalty rather than provide substitute capacity. This could decrease reliability and increase the probability of costly backstop procurement. DMM recommends that the ISO monitor this issue now that the new incentive mechanism is implemented.