Q2 Report on Market Issues and Performance

September 5, 2019

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California Independent System Operator

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Executive summary

This report covers market performance during the second quarter of 2019 (April – June). Key highlights during this quarter include the following:

- The total estimated wholesale cost of serving load in the second quarter of 2019 was about $1.4 billion or about $27/MWh. This 11 percent decrease relative to the second quarter of 2018 was driven by high availability of hydroelectric, wind and solar resources. After adjusting for natural gas costs and changes in greenhouse gas prices, wholesale electric costs decreased by about 11 percent to $30/MWh from $34/MWh.
- Average quarterly day-ahead prices were significantly lower than both 15-minute and 5-minute prices for the first time since 2014. Day-ahead prices averaged $23/MWh for the quarter while 15-minute and 5-minute prices averaged $26/MWh and $30/MWh, respectively (Figure E.1). Average prices decreased substantially from the first quarter to levels similar to the second quarter of 2018, driven by decreased gas prices and increased hydroelectric and renewable production. Day-ahead prices remained higher than real-time prices in most hours, but average quarterly real-time prices were driven up by real-time price spikes.
- Congestion revenue rights auction revenues were $6.6 million less than payments made to non-load-serving entities purchasing these rights during the second quarter (Figure E.2). Payments to financial entities and generation owners purchasing congestion revenue rights exceeded auction revenues by about $7.6 million and $0.2 million, respectively. However, energy marketers paid over $1 million more in auction revenues than the revenues they received from these rights.
- The decrease in losses to transmission ratepayers from sales of congestion revenue rights, relative to $17 million loss in the second quarter of 2018, is due in part to changes to the auction implemented by the ISO in 2019 which limit the source and sink of congestion revenue rights that can be purchased in the auction (Track 1A).[1] In addition, based on current settlement records, DMM estimates that changes in the settlement of congestion revenue rights made under Track 1B reduced losses to transmission ratepayers from sales of congestion revenue rights by about $5.5 million.
- Total bid cost recovery payments for the second quarter were about $27 million, or about $6 million higher than the second quarter of 2018. Bid cost recovery costs increased to 1.8 percent of total wholesale energy cost from 1.1 percent in the same quarter of 2018. From June 10 through 12, real-time payments were about $5 million due to relatively high loads and high system energy prices.[2]
- The frequency of negative prices in the 15-minute and 5-minute markets increased during the second quarter relative to the previous quarter and the same quarter of 2018, occurring in about 10 percent of 15-minute intervals and 13 percent of 5-minute intervals in April and May. Negative day-ahead prices occurred during an average of about 3.5 percent of hours throughout the quarter and a monthly high of about 5.4 percent of hours in April.

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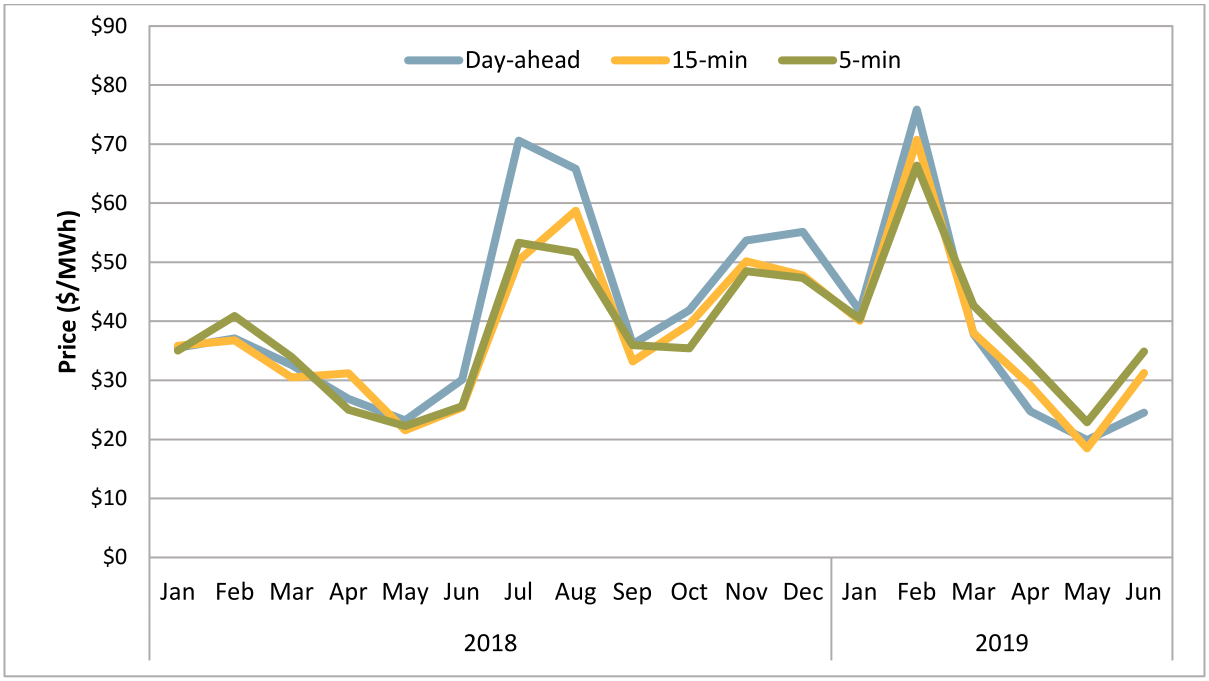
1 An explanation of these changes is available in DMM's 2018 Annual Report on Market Issues & Performance, Section 8.4, available here: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

2 All values reported are based on current settlements and may be resettled at a later date. DMM anticipates a significant reduction in payments on these dates in resettlement.

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



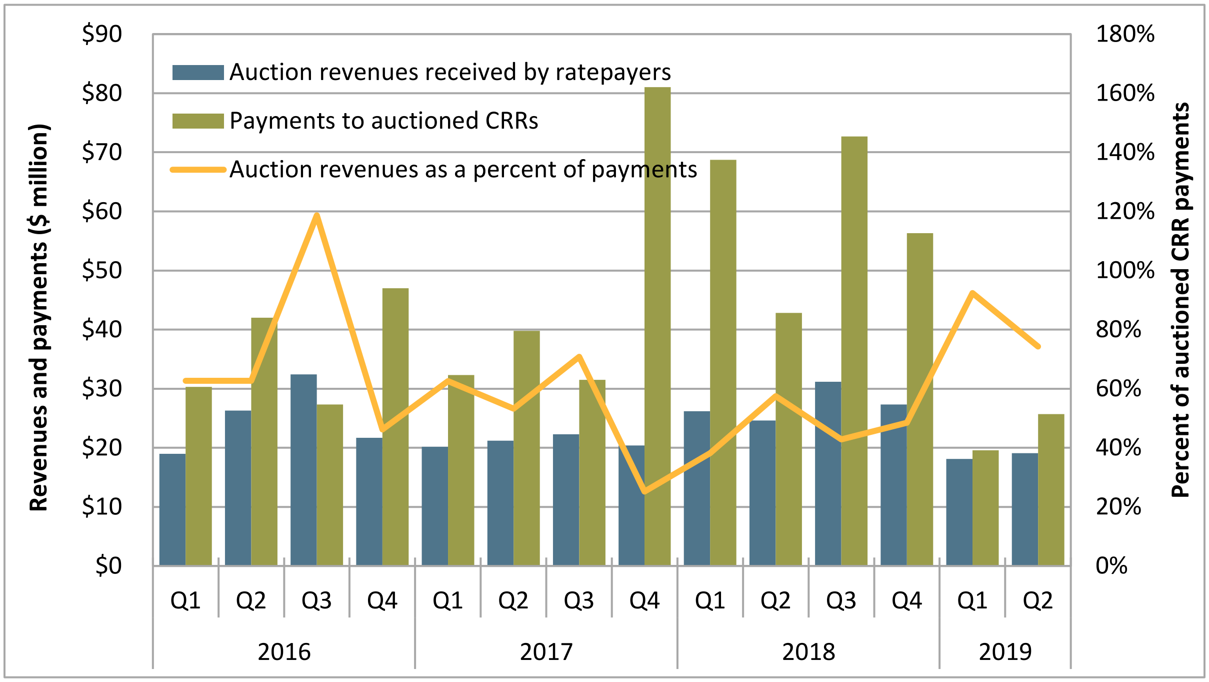
- Reductions in wind and solar generation due to downward dispatch during intervals with negative real-times pices increased significantly, exceeding 4 percent in April and May. Curtailment of self-schedules remained low relative to the amount of economic downward dispatch. All curtailments of self-scheduled wind and solar energy were due to localized congestion.

- Incremental energy subject to local market power mitigation increased significantly in the second quarter of 2019 compared to the same quarter in 2018 in both the day-ahead and 15-minute markets. This is partly due to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers. In the day-ahead market, the average incremental energy subject to mitigation increased to about 1,400 MW per hour in the second quarter of 2019 compared to 360 MW per hour in the same quarter of 2018. About 230 MW per hour of this incremental energy had bids lowered due to mitigation compared to 111 MW per hour in 2018.

- Total energy resulting from all types of exceptional dispatch nearly tripled in the second quarter of 2019 compared to the same quarter in 2018, averaging 0.11 percent of system load. Minimum load energy from exceptional dispatch unit commitments in the second quarter was nearly 2.5 times higher than the second quarter of the prior year. In the second quarter, out-of-sequence energy costs were $1.7 million, while commitment costs for exceptional dispatch paid through bid cost recovery were $3.6 million.

- Costs for ancillary services increased during the second quarter to about $58 million, compared to about $45 million in the previous quarter and $49 million during the same quarter in 2018. Regulation requirements increased over both the prior quarter and the second quarter of 2018 as did associated costs.

Figure E.2 Auction revenues and payments to non-load-serving entities



- Virtual demand was profitable on a quarterly basis for the first time since 2017 due to sustained high 15-minute market prices on June 10 and 11 when real-time load was up to 2.5 GW above day-ahead forecasts across peak hours on both days. Virtual bidders received about $20.1 million after subtracting bid cost recovery charges of about $0.9 million for the quarter.

- Beginning in May, commitment cost bid caps and generated and default energy bids have included calculated opportunity costs for use-limited resources with qualifying limitations. Capacity with non-zero opportunity costs for start limits totaled about 1,600 MW in May and 2,000 MW in June. About 48 percent of this capacity is restricted due to contractual limits. Capacity with non-zero opportunity costs associated with run hour limits totaled about 345 MW in May and 540 MW in June.

- The Balancing Authority of Northern California (BANC) joined the energy imbalance market on April 3, 2019. BANC participates in the energy imbalance market with the Sacramento Municipal Utility District as a member within the balancing area.

- In the energy imbalance market, the ISO implemented an enhancement on May 6, 2019, which evaluates sufficiency test results and potentially limits transfers on a 15-minute interval basis rather than for the entire hour. This decreased the frequency in which energy imbalance market areas failed the upward or downward sufficiency test.

- Recent changes in the load conformance limiter significantly reduced the frequency in which the conformance limiter triggered for under-supply conditions for Arizona Public Service during the second quarter. Instead, prices for the Arizona Public Service area were often set at the $1,000/MWh penalty parameter in these instances.

1 Market Performance

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

- The total estimated wholesale cost of serving load in the second quarter of 2019 was about $1.4 billion or about $27/MWh. This represents an 11 percent decrease compared to the second quarter of 2018, which was driven primarily by high availability of hydroelectric, wind and solar resources. After adjusting for natural gas costs and changes in greenhouse gas prices, wholesale electric costs decreased by about 11 percent to $30/MWh from $34/MWh.

- Average day-ahead prices were lower than 15-minute and 5-minute prices for the first quarter since 2014. Day-ahead prices averaged $23/MWh for the quarter while 15-minute and 5-minute prices averaged $26/MWh and $30/MWh, respectively. Average prices decreased from the first quarter to levels similar to the second quarter of 2018, driven by decreased gas prices and increased hydroelectric and renewable production. Day-ahead prices remained higher than real-time prices in most hours, but average quarterly real-time prices were driven up by real-time price spikes.

- The frequency of negative prices in the 15-minute and 5-minute markets increased during the second quarter relative to the previous quarter and the same quarter of 2018, occurring during around 10 percent of 15-minute intervals and 13 percent of 5-minute intervals in April and May.

- Reductions in wind and solar generation due to downward dispatch during intervals with negative real-times pices increased significantly compared to previous quarters, exceeding 4 percent in April and May. Curtailment of self-schedules remains very low relative to economic downward dispatch. Curtailments of self-scheduled wind and solar energy were due to localized congestion.

- Total bid cost recovery payments for the second quarter were about $27 million, about 1.8 percent of wholesale energy cost. This amount was $3 million lower than payments in the previous quarter and about $6 million higher than the second quarter of 2018.

- Incremental energy subject to mitigation increased significantly in the second quarter of 2019 compared to the same quarter in 2018 in both the day-ahead and 15-minute markets. This is partly due to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers.

- Total energy resulting from all types of exceptional dispatch increased nearly threefold in the second quarter of 2019 compared to the same quarter in 2018, averaging 0.11 percent of system load in the second quarter.

- During the second quarter of 2019, congestion revenue rights auction revenues were $6.6 million less than payments made to non-load-serving entities purchasing these rights. Payments to financial entities and generation owners purchasing congestion revenue rights exceeded auction revenues by about $7.6 million and $0.2 million, respectively. However, energy marketers paid over $1 million more in auction revenues than the revenues they received from these congestion revenue rights.

- Costs for ancillary services increased during the second quarter. Costs for ancillary services totaled about $58 million during the second quarter, compared to about $45 million in the previous quarter and $49 million during the same quarter in 2018. Regulation requirements increased over both the prior quarter and the second quarter of 2018 as did associated costs.

1.1 Supply conditions

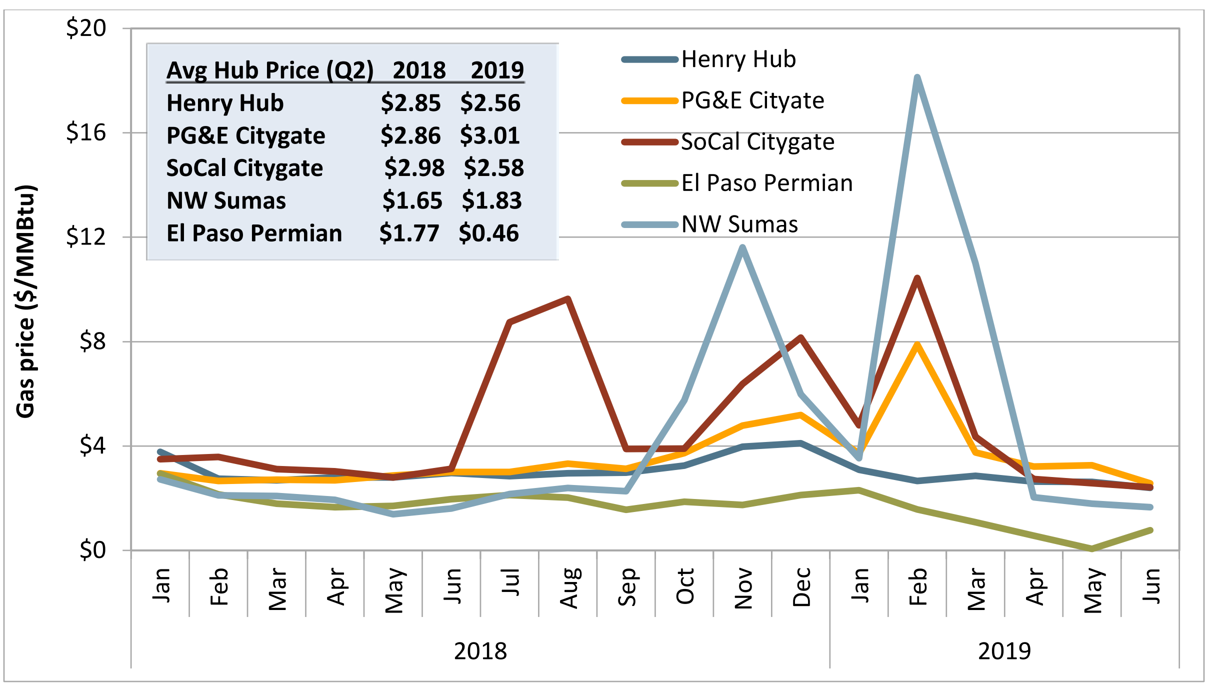
Natural gas prices

Electricity prices in western states typically follow natural gas price trends because natural gas units are often the marginal source of generation in the ISO and other regional markets. During the second quarter of 2019, natural gas prices have remained low across major gas trading hubs in the west, similar to the same quarter in 2018. Lower natural gas prices coupled with increased renewable energy production led to low overall system marginal energy prices across the ISO footprint.

Figure 1.1 shows monthly average natural gas prices at key delivery points across the west - PG&E Citygate, SoCal Citygate, Northwest Sumas, El Paso Permian as well as for the Henry Hub trading point, which acts as a point of reference for the national market for natural gas. As shown in the figure, natural gas prices fell sharply in the second quarter of 2019 for all the hubs.

Prices at SoCal Citygate gas hub averaged $2.58/MMBtu compared to $2.98/MMBtu in the second quarter of 2018. Prices remained low throughout the quarter because seasonal temperatures drove gas demand down in the SoCal area. Pipeline constraints on the SoCalGas system continued to impact SoCal Citygate hub prices. SoCalGas has delayed returning line L235-2, which delivers natural gas into SoCalGas's Northern Zone, to August 29, 2019. Hence, these continued supply constraints on the system will exist throughout the summer demand season. SoCal Citygate prices often impact overall system prices because 1) there are large numbers of natural gas resources in the south, and 2) these resources can set system prices in the absence of congestion.

Figure 1.1 Monthly average natural gas prices



PG&E Citygate gas prices have also remained low, but trended slightly higher than SoCal Citygate during the second quarter. Northwest Sumas gas hub in the Pacific Northwest saw a sharp decline in gas prices compared to the previous quarter. This is due to moderate shoulder season demand and increased hydropower generation.

Permian basin prices were low and occasionally negative for most of the second quarter. This price drop is related to a force majeure on El Paso Natural Gas's pipeline because of a potential leak. This outage led to a constraint on takeaway capacity out of the Permian basin thus putting downward pressure on gas prices.

Generation by fuel type

Figure 1.2 shows generation by fuel type over the day. Nuclear, bio-based resources, and geothermal resources remain constant, comprising about 4,300 MW of inflexible base generation. In hours ending 18 through 21, as solar ramps down, the resources primarily being used to meet the evening peak include hydro, natural gas, and imports.

Figure 1.3 shows hourly variation of generation by fuel group, driven by hourly variation of solar production. Generation from imports varied most over the day. During the peak, gas resources produced the most energy of any resource type. Hydroelectric generation also varied, though less than imports and natural gas. Finally, average wind generation complements solar production, generating more in the early morning and late evening, and less in the middle of the day. There is little variability from other resources on an hourly basis.

Figure 1.2 Average hourly generation by fuel type

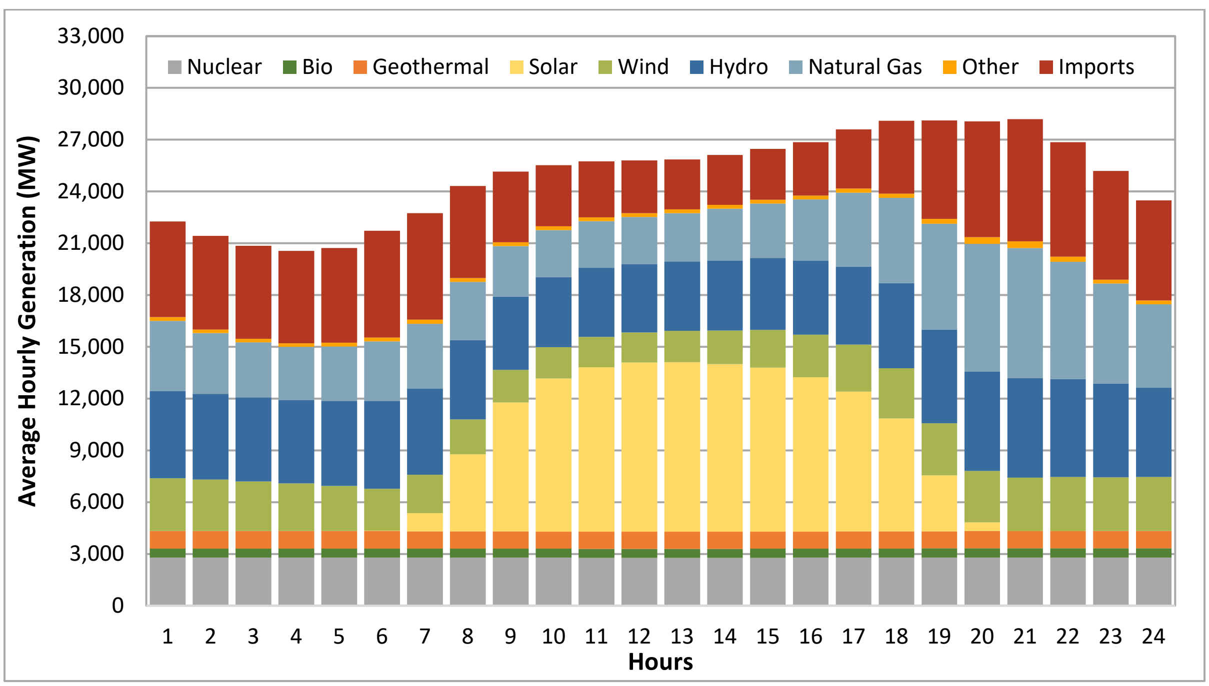
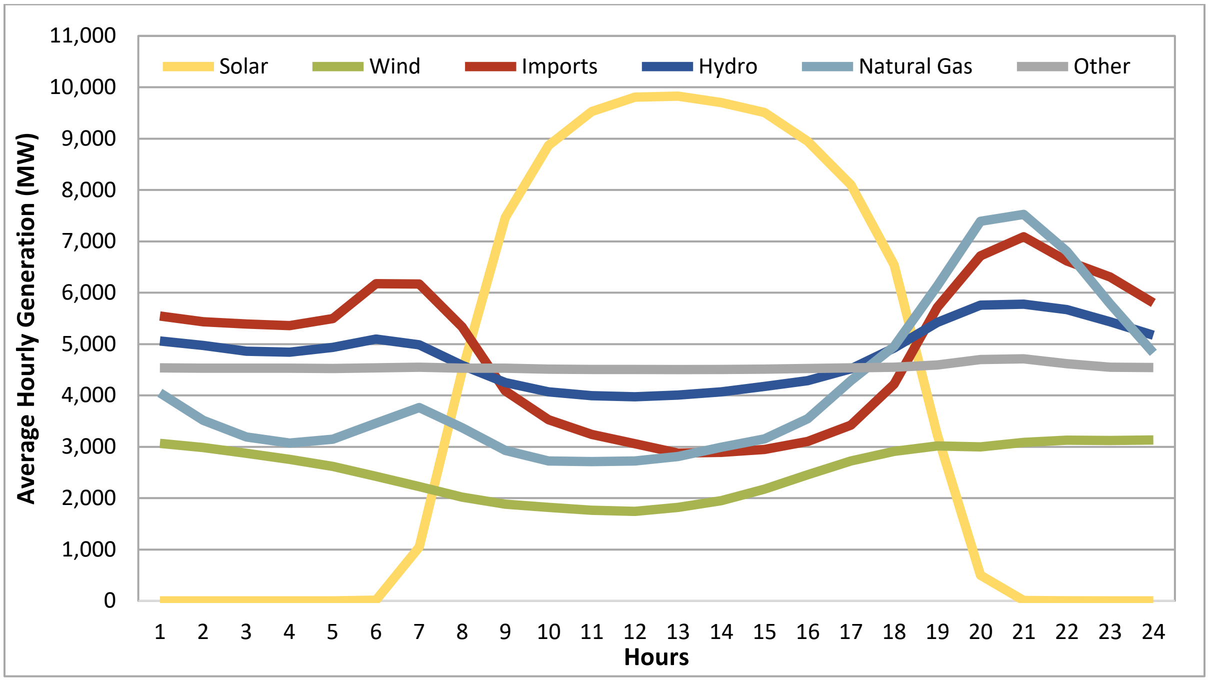


Figure 1.3 Variation in generation by fuel type



Variable renewable generation

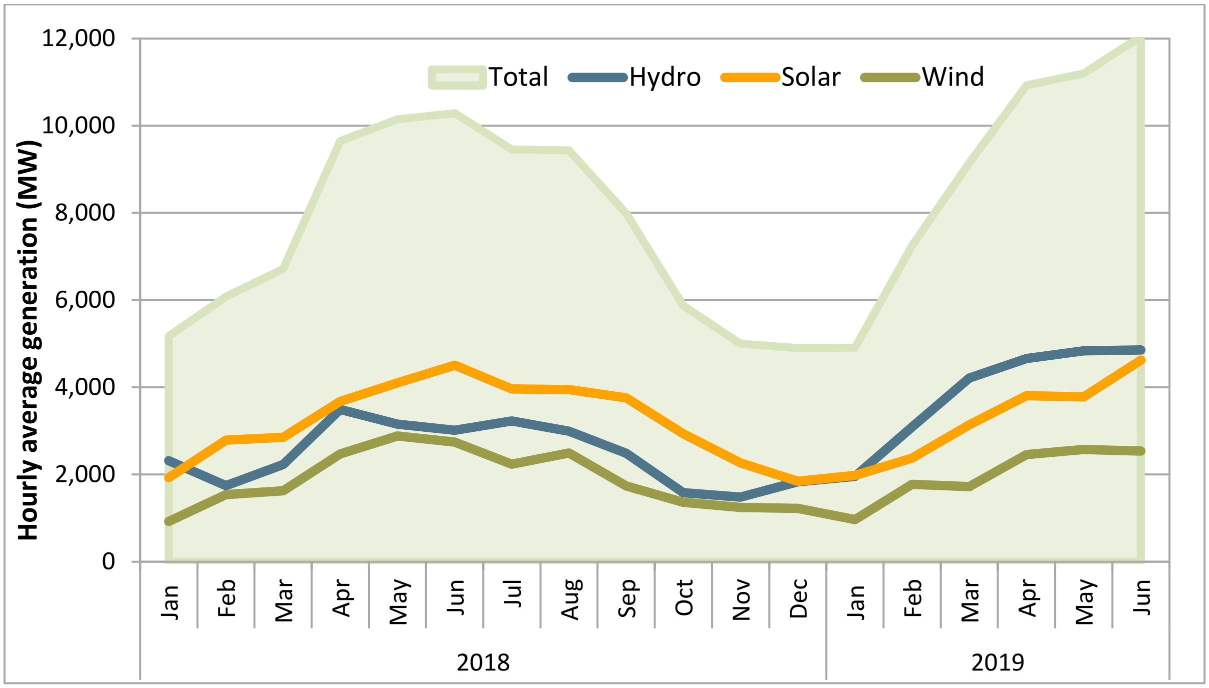
Total generation from hydroelectric, solar, and wind resources increased compared to the previous quarter and compared to the same quarter of 2018. This was primarily due to increased snow melt and therefore greater availability of hydroelectric production. Compared to 2018, hydroelectric production in the second quarter increased by roughly 49 percent. As of April 1, the statewide weighted average snowpack in California was 175 percent of normal compared to 58 percent of normal on April 1, 2018.[3]

Wind and solar production increased compared to the first quarter of 2019. Compared to 2018, however, wind and solar production decreased slightly, despite increases in installed capacity from the previous year. This was partially due to greater economic downward dispatch of both resources. In April and May 2019, solar and wind downward dispatch again reached record levels, roughly 200,000 and 230,000 MWh, respectively, which is presented in Section 1.5.

The availability of variable resources contributes to patterns in prices both seasonally and hourly. The increase in renewable production compared to the previous quarter contributed to lower wholesale electricity prices due to the low marginal cost of renewables relative to other resources. The 48 percent increase in hydroelectric output is one contributing factor to this trend.

3 For snowpack information, please see California Cooperative Snow Survey's Snow Course Measurements on the California Department of Water Resources website: https://cdec.water.ca.gov/snow/current/snow/.

Figure 1.4 Average hourly hydroelectric, wind, and solar generation by month

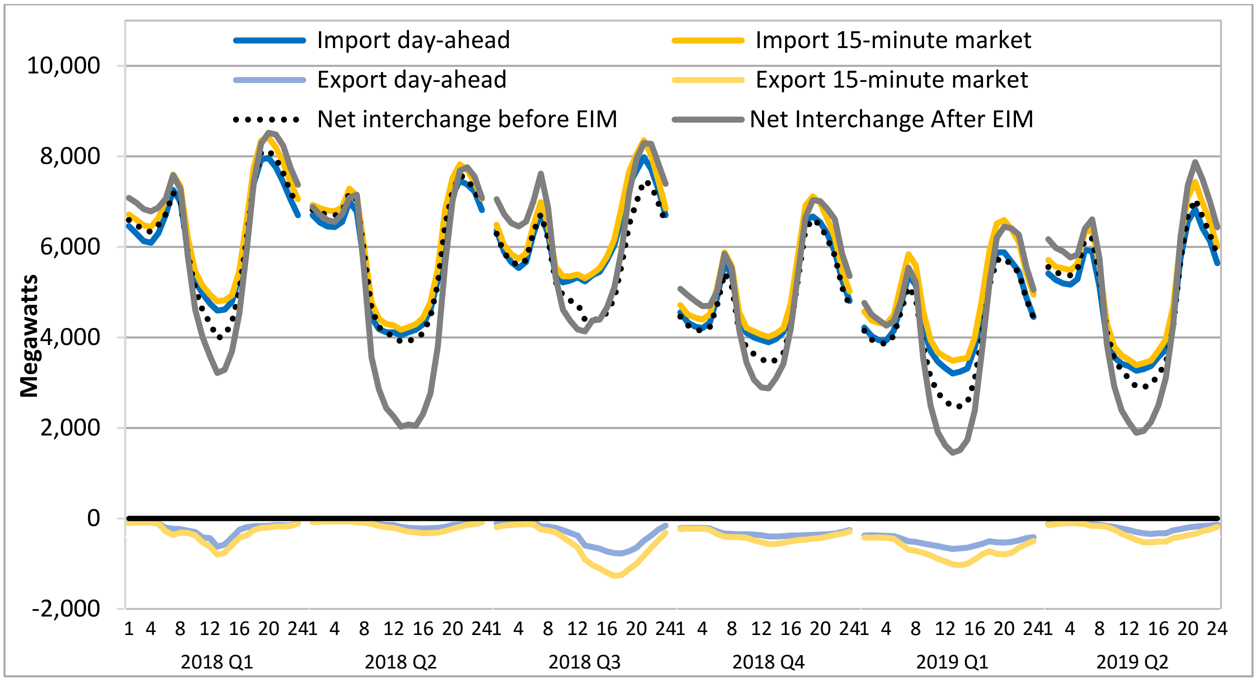


Imports and exports

As shown in Figure 1.5, average hourly cleared imports (shown in dark blue and dark yellow), peaked at about 7,800 MW in hour ending 21, similar to the roughly 7,700 MW in the same quarter of 2018. The greatest import transfer into the ISO from the energy imbalance market occurred in hour ending 21 at about 830 MW. Exports (shown as negative numbers below the horizontal axis in pale blue and yellow), decreased from the previous quarter, peaking at about 530 MW in hour ending 14 and 15. The average net interchange excluding energy imbalance market transfers (shown in dashes), is based on meter data and averaged by hour and quarter. The solid grey line adds incremental energy imbalance market interchange, which reached a low point of about 1,900 MW in hour ending 13 and 14.

The data for Figure 1.5 has been substantially updated and revised from the previous report. This impacted the 2018 results as well as the first quarter of 2019, changing the average from a few hours in the middle of the day with net exports to a net importer in all hours. Nevertheless, the first quarter of 2019 did have the lowest average hours of net imports for the period, followed closely by the second quarter in 2018 and 2019.

Figure 1.5 Average hourly net interchange by quarter



1.2 Energy market performance

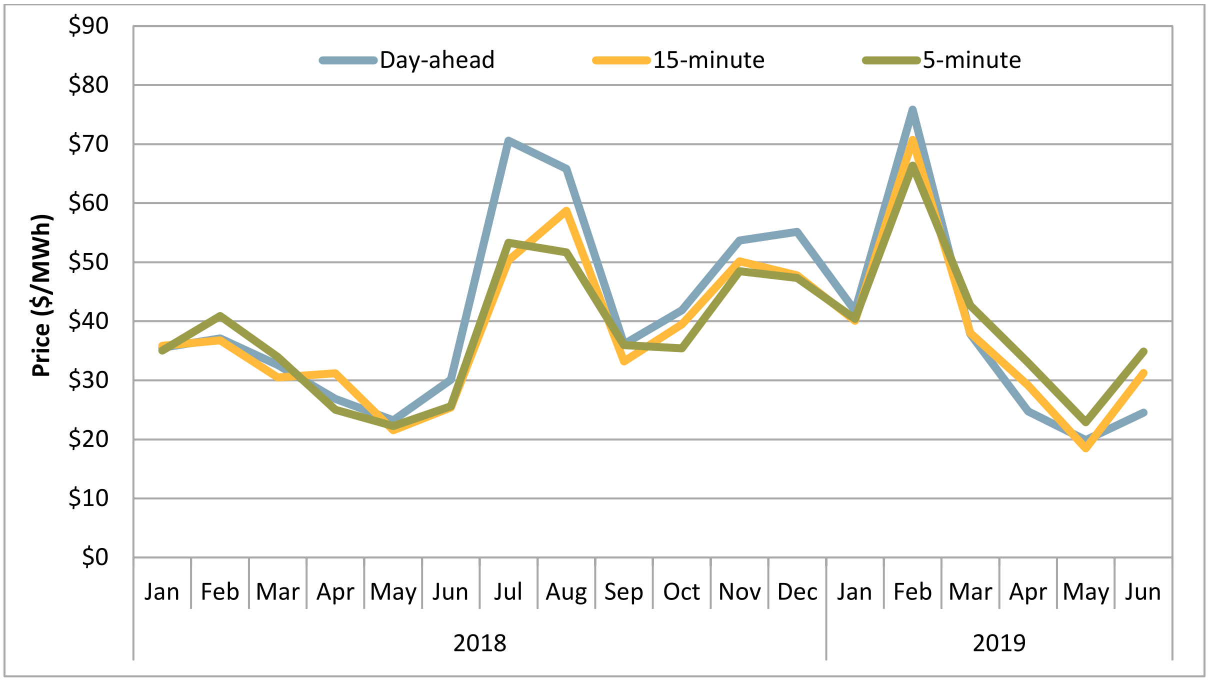
Energy market prices

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 1.6 shows load-weighted average monthly energy prices during all hours across the three largest load aggregation points in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric).[4] Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) from January 2018 to June 2019.

4 DMM typically weights prices at load aggregation points by schedules in each market. Due to data issues, however, prices reported here are weighted by actual load measurements at load aggregation points.

Figure 1.6 Average monthly system marginal energy prices (all hours)



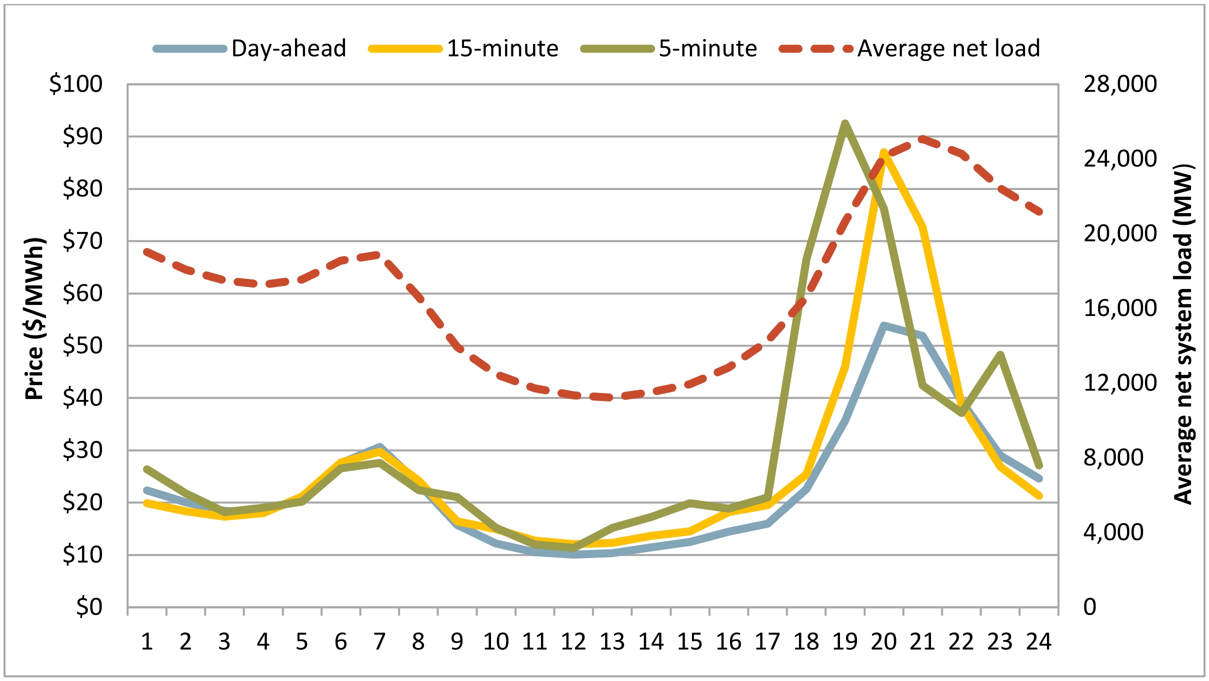
Prices decreased significantly from the first quarter to the second quarter of 2019. Average day-ahead prices decreased by 56 percent, 15-minute prices decreased by 47 percent, and 5-minute prices decreased by 39 percent. These lower second quarter prices were driven by low gas prices as well as an increase in production from renewable resources when compared to the first quarter. Energy prices were similar to the second quarter of 2018.

Average day-ahead prices were lower than 15-minute and 5-minute prices during the second quarter of 2019. Day-ahead prices averaged $23/MWh for the quarter while 15-minute and 5-minute prices averaged $26/MWh and $30/MWh respectively. This is a change from the typical pattern of higher day-ahead prices during most months since 2014.

Figure 1.7 illustrates load-weighted average energy prices on an hourly basis in the second quarter compared to average hourly net load.[5] Average hourly prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) and are measured by the left axis while average hourly net load (red dashed line) is measured by the right axis.

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 1.7 **Hourly load-weighted average marginal energy prices**



Average hourly prices in the second quarter continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours with prices peaking in hours ending 19 and 20. These hours had the greatest price divergence between the markets where 15-minute and 5-minute average hourly prices were significantly higher than day-ahead prices. High prices in the 15-minute and 5-minute markets that contributed to the large spikes in the evening peak hours tend to be associated with power balance constraint violations in the second quarter.

1.3 Wholesale energy cost

Total wholesale cost to serve load in the ISO market during the second quarter of 2019 was about $1.4 billion, compared to about $1.6 billion in the same quarter of 2018. The average cost per megawatt-hour of load decreased 11 percent to about $27/MWh for the second quarter from $31/MWh in the same quarter of 2018 (nominal costs shown in blue bars in Figure 1.8).

In previous quarters, changes in gas prices typically drive changes in the wholesale cost to serve load. In the second quarter of 2019, gas prices had less of an impact on cost differences when comparing with the same quarter in 2018. Volume-weighted gas prices were about the same in the second quarter of both 2018 and 2019 at about $3.73/MMBtu. The decrease in costs compared to the second quarter of 2018 was driven by low and often negative prices during a spring with high availability of hydroelectric, wind and solar resources, along with record levels of renewable curtailment.

When normalizing for changes in natural gas and greenhouse gas costs using the 2010 gas price which is used as a reference year, the gold bar in Figure 1.8 shows the wholesale energy costs to serve load decreased by 11 percent when comparing to the same quarter in 2018, from about $34/MWh to about $30/MWh, while the average daily gas price remained about the same as the second quarter of 2018.

Figure 1.8 Total quarterly wholesale costs per MWh of load

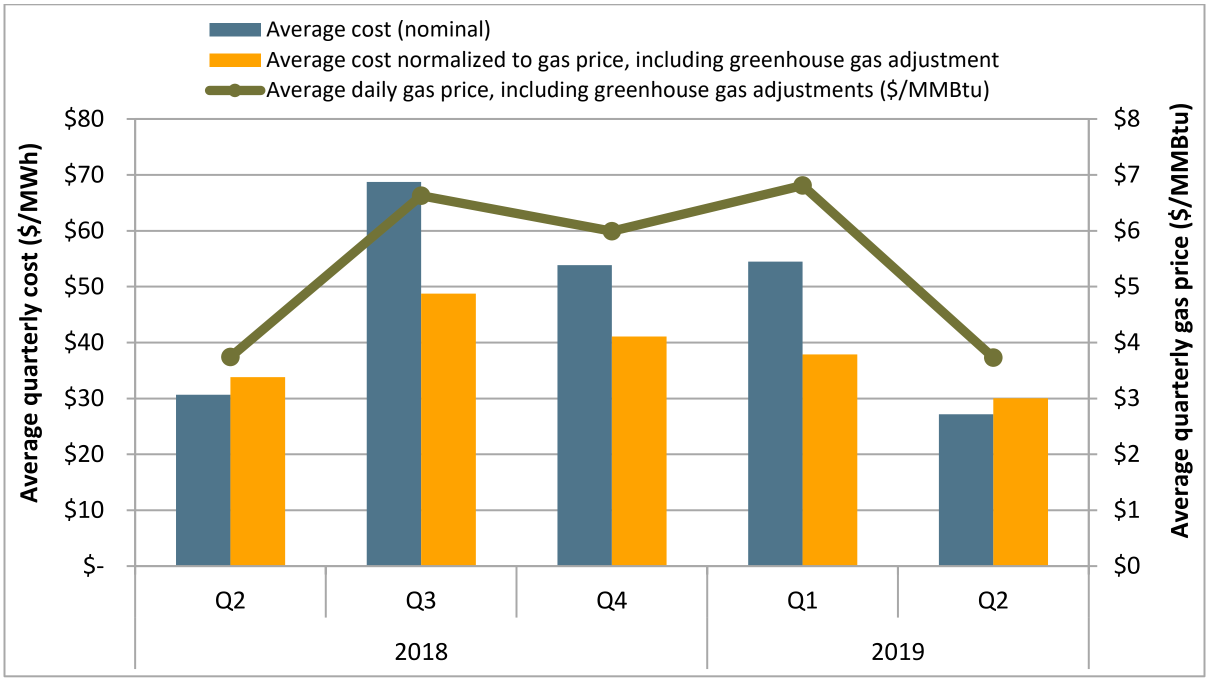


Table 1.1 provides quarterly summaries of nominal total wholesale costs by category. Costs for energy procured in the day-ahead market continued to make up a majority (88 percent) of the total cost to deliver energy to the market, similar to the second quarter of 2018 but a decrease from 95 percent in the previous quarter. Real-time market costs increased to almost 4.5 percent of the total cost from about 2 percent in the same quarter of 2018 and less than 1 percent in the first quarter of 2019. Bid cost recovery costs increased to 1.8 percent of total cost from 1.0 percent in the previous quarter and 1.1 percent in the same quarter of 2018. Costs for reliability remained low at about 0.2 percent in the second quarter of 2019 compared to about 2.2 percent of total costs in the same quarter in 2018. Reserve costs increased slightly to about 4.2 percent of total costs.

Table 1.1 Estimated average wholesale energy costs per MWh

	Q2 2018	Q3 2018	Q4 2018	Q1 2019	Q2 2019	Change Q2 2018-Q2 2019
Day-ahead energy costs	$ 27.66	$ 64.52	$ 51.44	$ 52.24	$ 23.89	$ (3.77)
Real-time energy costs (incl. flex ramp)	$ 0.60	$ 0.69	$ 0.00	$ 0.25	$ 1.20	$ 0.60
Grid management charge	$ 0.43	$ 0.43	$ 0.43	$ 0.42	$ 0.42	$ (0.01)
Bid cost recovery costs	$ 0.34	$ 1.27	$ 0.54	$ 0.56	$ 0.48	$ 0.14
Reliability costs (RMR and CPM)	$ 0.68	$ 0.63	$ 0.90	$ 0.06	$ 0.05	$ (0.63)
Average total energy costs	**$ 29.71**	**$ 67.54**	**$ 53.32**	**$ 53.53**	**$ 26.04**	**$ (3.67)**
Reserve costs (AS and RUC)	$ 0.95	$ 1.19	$ 0.53	$ 0.94	$ 1.14	$ 0.19
Average total costs of energy and reserve	**$ 30.66**	**$ 68.73**	**$ 53.85**	**$ 54.47**	**$ 27.19**	**$ (3.47)**

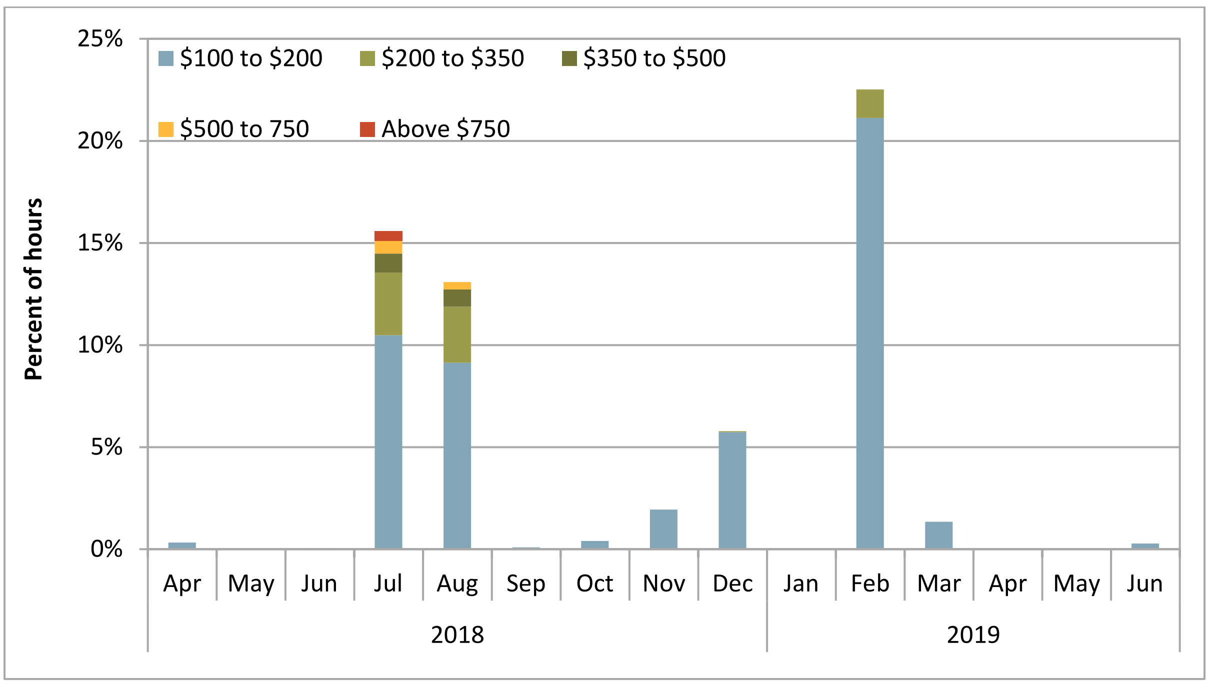
1.4 Day-ahead price variability

High prices

Figure 1.9 shows the frequency of day-ahead market prices in various high priced ranges from April 2018 to June 2019. There was a significant decrease in the frequency of hours with high day-ahead prices between the first and second quarter of 2019. Prices greater than $100/MWh occurred during about 8 percent of hours in the first quarter of 2019 compared to only 0.1 percent of hours in the second quarter.

The higher frequency of high energy prices in the first quarter was driven primarily by high natural gas prices in February. Lower natural gas prices and increased renewable production helped decrease the occurrence of large price spikes in the second quarter. The frequency of high day-ahead prices in this quarter was similar to the frequency in the same quarter of 2018.

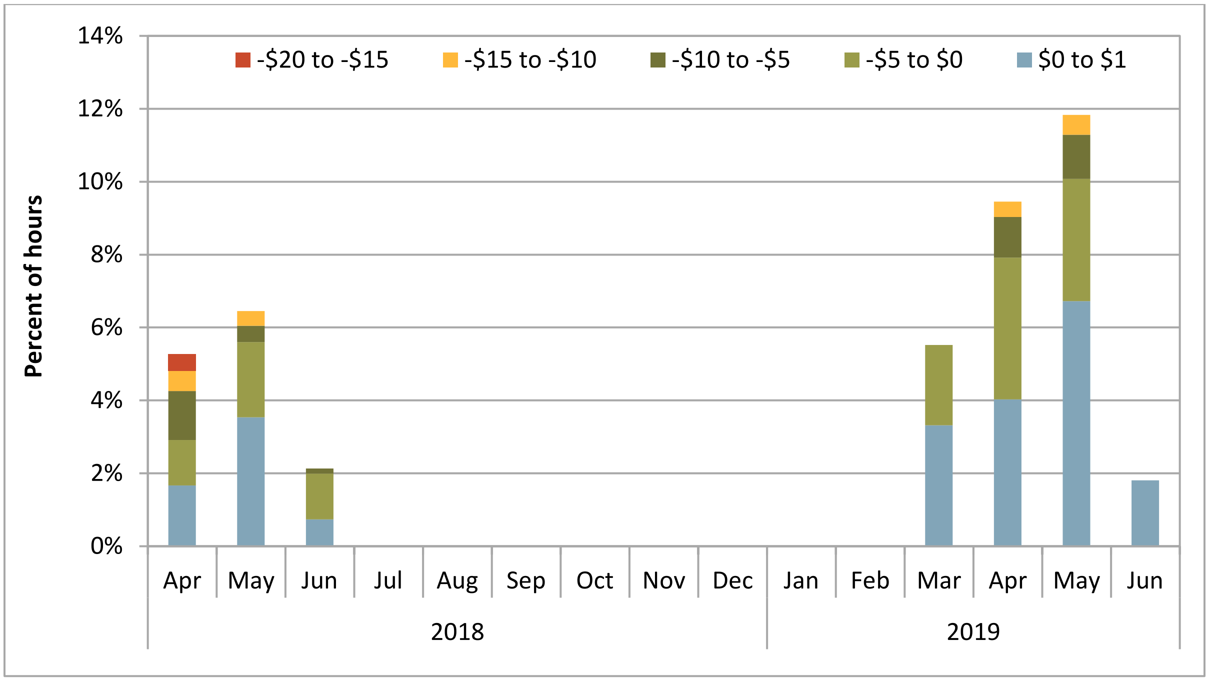
Figure 1.9 Frequency of high day-ahead prices (MWh) by month



Negative prices

Figure 1.10 shows the frequency of day-ahead market prices in various low priced ranges from April 2018 to June 2019. Similar to 2018, there was a moderate amount of hours in the second quarter of 2019 that experienced negative prices in the day-ahead market. Negative prices occurred during an average of about 3.5 percent of hours throughout the quarter with a high of about 5.4 percent in April to a low of about 0 percent in June. Negative day-ahead prices primarily occurred during mid-day hours of the second quarter when generation from solar was at its peak in conjunction with relatively low load conditions.

Figure 1.10 Frequency of negative day-ahead prices (MWh) by month



1.5 Real-time price variability

Real-time market prices can be volatile with periods of extreme positive or negative prices. Even a short period of extremely high or low prices can significantly impact average prices. During the second quarter of 2019, the frequency of negative prices was significantly higher than both the previous quarter and the second quarter of 2018. Similarly, the frequency of high prices in the 15-minute and 5-minute markets was higher than both previous quarter and the second quarter of 2018.

During the quarter, many of the high prices were set by the $1,000/MWh penalty parameter for an under-supply power balance constraint relaxation. In other instances, high prices occurred as a result of high bids clearing the market.

High prices

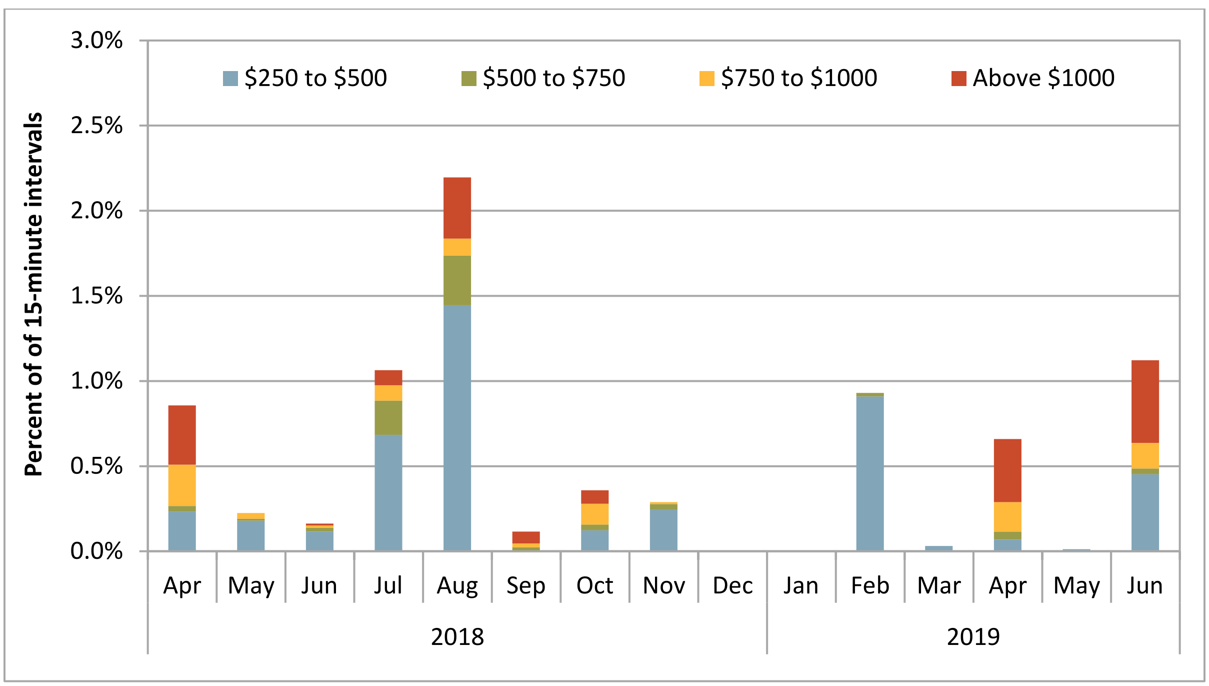
Figure 1.11 and Figure 1.12 show the frequency of prices above $250/MWh across the three largest load aggregation points in the ISO. As shown in Figure 1.11, the frequency of high prices in the 15-minute market greater than $750/MWh increased to around 0.4 percent of intervals during the quarter. The majority of these prices were set by under-supply infeasibilities that occurred in April and June.

On both June 10 and 11, real-time load was up to 2,500 MW above the day-ahead forecast across peak hours and 15-minute market prices were about $1,000/MWh for most intervals in hours ending 19 and 20. On June 10, high 15-minute market prices at the peak extended through hour ending 21. High real-time prices on these two days account for the increased quarterly frequency of high 15-minute market prices and profitability of virtual demand positions in the second quarter.

Figure 1.12 shows the frequency of high prices in the 5-minute market. The frequency of price spikes greater than $250/MWh in the 5-minute market was about 1.4 percent of intervals in the second quarter, compared to around 0.7 percent of intervals in same quarter of 2018. Further, the frequency of more extreme 5-minute market prices larger than $750/MWh increased during the quarter, particularly during April and June when they occurred during roughly 1 percent of 5-minute intervals.

Figure 1.13 shows the corresponding frequency of under-supply infeasibilities in the 5-minute market. Under-supply infeasibilities were more frequent in the second quarter, during around 0.4 percent of 5-minute market intervals and 0.2 percent of 15-minute market intervals. Infeasibilities resolved by the load conformance limiter continued to be very infrequent, a trend that began in the last quarter with the implementation of the enhancement to the limiter at the end of February.[6] However, the changes to the load conformance limiter did not have a significant impact on prices in the ISO. This is because in most intervals when the limiter triggers in the ISO, the highest priced bids dispatched are often at or near the $1,000/MWh bid cap such that the resulting price is often very similar with or without the limiter.

Figure 1.11 Frequency of high 15-minute prices by month (ISO LAP areas)



6 With the enhancement, the load conformance limiter triggers by a measure based on the change in load adjustment from one interval to the next, rather than the total level of load adjustment. For more information on the load conformance limiter enhancement, see Section 2.4.

Figure 1.12 Frequency of high 5-minute prices by month (ISO LAP areas)

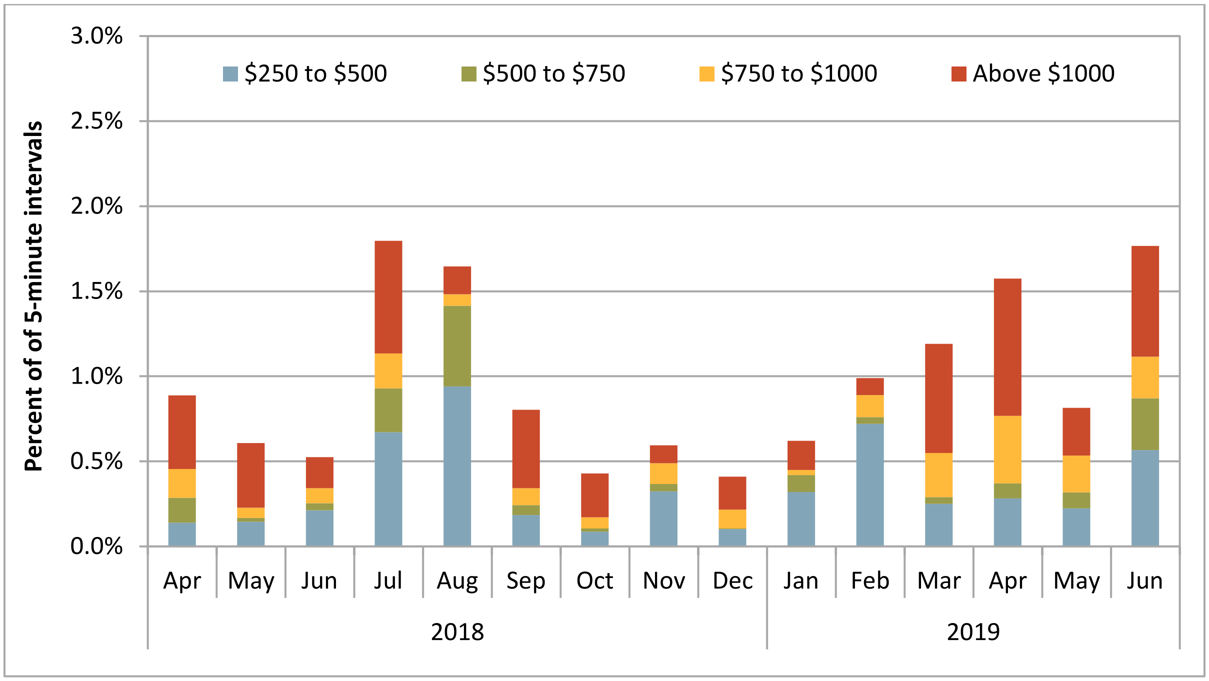
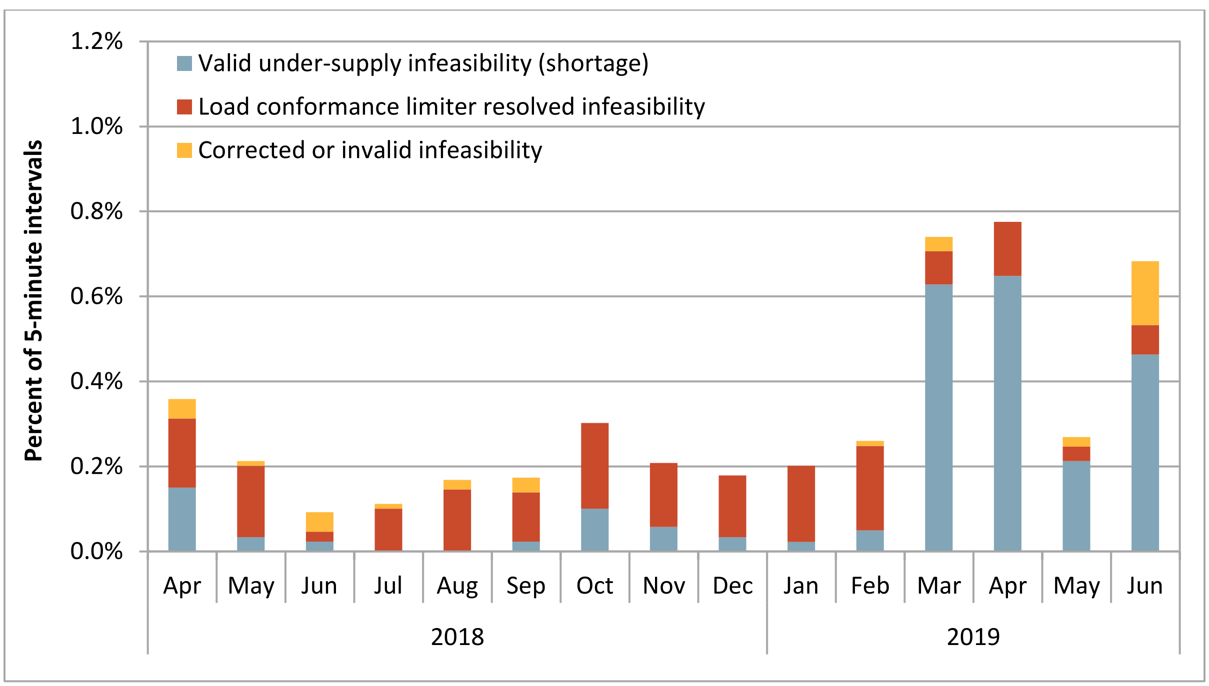


Figure 1.13 Frequency of under-supply power balance constraint infeasibilities (5-minute market)

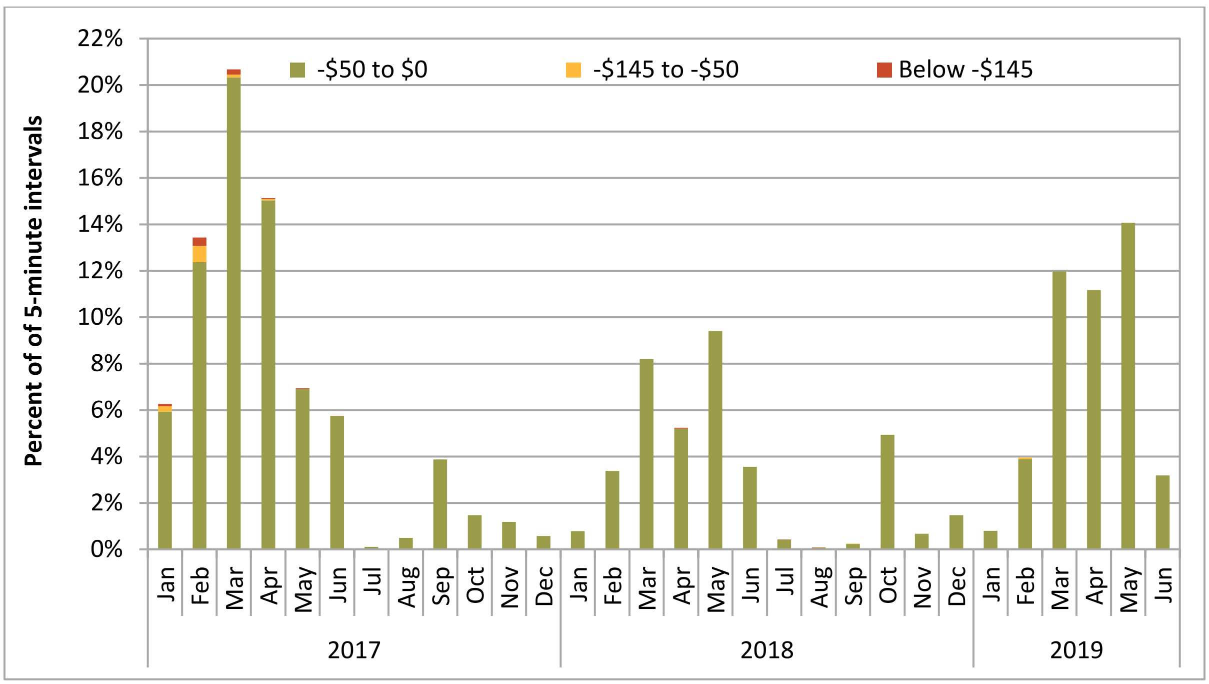


Negative prices

Figure 1.14 shows the frequency of negative prices in the 5-minute market by month across the three largest load aggregation points in the ISO.[7] The frequency of negative prices in the 15-minute and 5-minute markets increased during the second quarter relative to the previous three months and the same quarter of 2018. Negative prices during April and May occurred during around 10 percent of 15-minute intervals and 13 percent of 5-minute intervals. Prices never reached below negative $50/MWh for any of the three load aggregation points during the quarter in either the 15-minute or 5-minute markets. Further, there were no intervals when the power balance constraint was relaxed because of excess energy during the quarter.

Instead, negative prices were typically set by wind and solar resources reflecting their relatively low marginal costs. During the second quarter, this was most frequent between hours ending 9 and 17 when loads, net of wind and solar, were lowest.

Figure 1.14 Frequency of negative 5-minute prices by month (ISO LAP areas)



Reduction in wind and solar generation

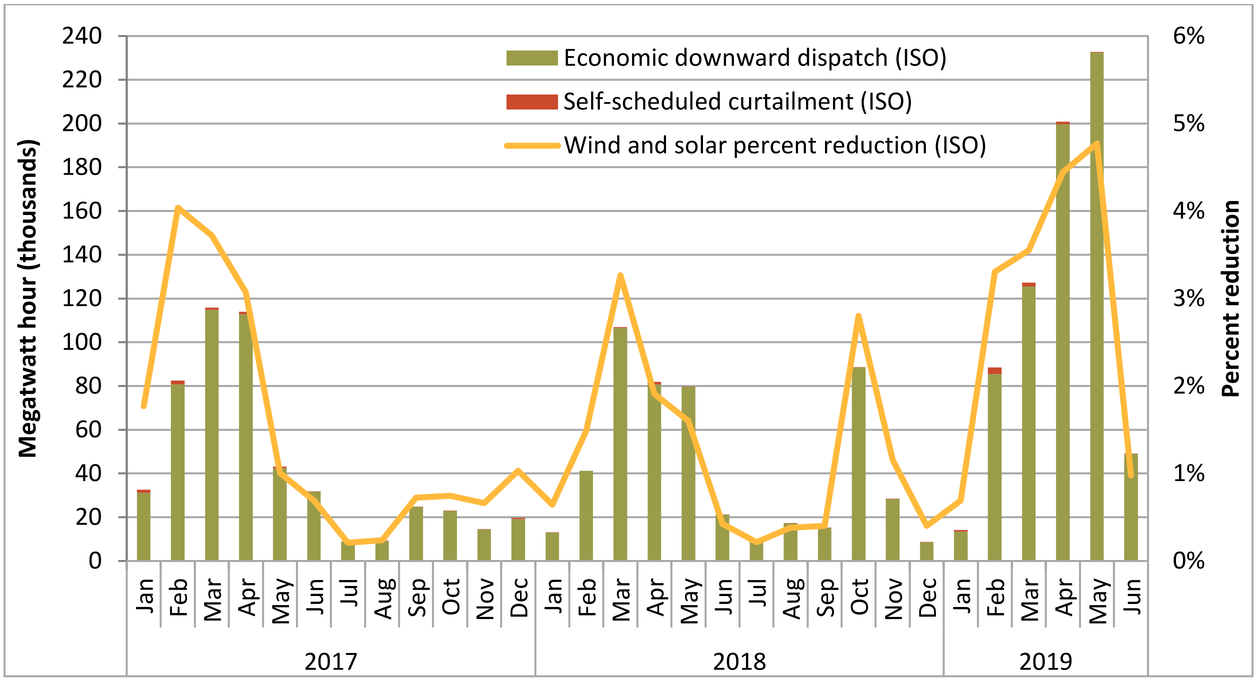
As shown in Figure 1.15, reductions in wind and solar generation as a result of economic downward dispatch and self-schedule curtailment increased significantly compared to previous quarters. Reduction in wind and solar generation can be explained by a combination of factors including negative prices, availability of hydroelectric resources, load conditions, export capability, and the amount of wind and solar bidding economically into the ISO markets.

7 Corresponding values for the 15-minute market show a similar pattern but at a lower frequency.

In 2019, hydroelectric production was high, similar to production in 2017. Wind and solar capacity on the system increased. The percent of wind and solar reduction as a percent of total possible production increased, as shown in Figure 1.15. Average loads for March, April, and May were lower than the same months in 2017 and 2018 and the ISO system saw some of the lowest net loads ever observed. There was also a high frequency of negative prices.

Curtailment of self-schedules (shown in red on Figure 1.15) remains very low relative to the amount of economic downward dispatch. All of the curtailments of self-scheduled wind and solar energy during the quarter were due to localized congestion.

Figure 1.15 Reduction in wind and solar generation by month



1.6 Convergence bidding

Convergence bidding was profitable overall during the second quarter. For the first time in five quarters, virtual demand was profitable. Virtual demand generated revenues of about $26.4 million while, before accounting for bid cost recovery charges, virtual supply generated net revenues of a loss of $5.4 million. Combined net revenues for virtual supply and demand fell to about $20 million after including about $1 million of virtual bidding bid cost recovery charges.

1.6.1 Convergence bidding trends

Average hourly cleared volumes were about 3,500 MW, an increase of about 400 MW from the previous quarter. Average hourly virtual supply remained similar to the previous quarter at about 2,000 MW. Virtual demand averaged around 1,500 MW during each hour of the quarter, a 400 MW increase from the previous quarter. On average, about 30 percent of virtual supply and demand bids offered into the market cleared in the quarter, which is about the same as in the previous quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 460 MW on average, a decrease from 940 MW of net virtual supply in the previous quarter. On average for the quarter, net cleared virtual demand only exceeded net cleared virtual supply during hours ending 17, 19 and 20. In the remaining 21 hours, net cleared virtual supply exceeded net cleared virtual demand. Cleared virtual supply exceeded virtual demand by 1,000 MW during hours ending 22 through 24.

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 14 of 24 hours. The majority of the inconsistent volumes occurred between hours ending 9 and 16.

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 860 MW of virtual demand offset by 860 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 50 percent of all cleared virtual bids in the second quarter, up from about 44 percent in the previous quarter.

1.6.2 Convergence bidding revenues

Participants engaged in convergence bidding in the second quarter were profitable overall. Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $21 million. Net revenues for virtual supply and demand fell to about $20 million after including about $1 million of virtual bidding bid cost recovery charges.[8] This slight decline is due primarily to bid cost recovery charges associated with virtual supply.

Figure 1.16 shows total monthly net revenues for virtual supply (green bars), total net revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line).

Before accounting for bid cost recovery charges:

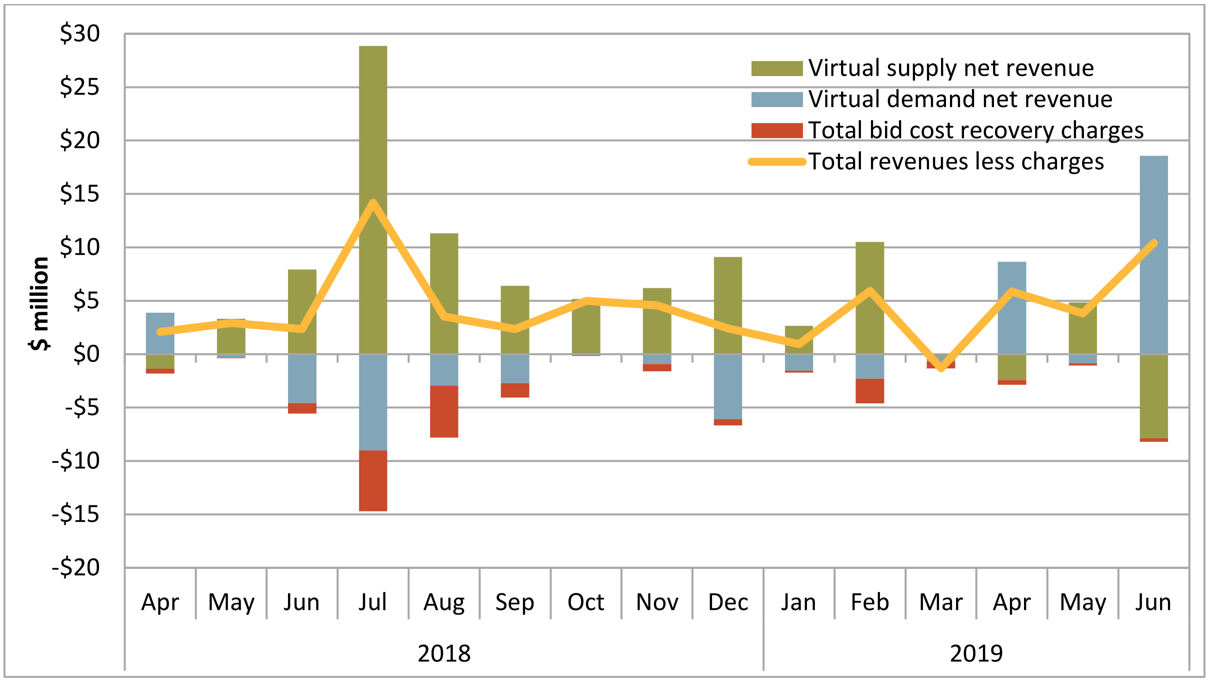
- Total market revenues were positive during all months of the quarter. Net revenues during the second quarter totaled about $21 million, compared to about $8.9 million during the same quarter in 2018, and about $8.7 million during the previous quarter.
- Virtual demand net revenues were positive in April and June and slightly negative in May. In total, virtual demand generated positive net revenues of about $26.4 million for the quarter. This was the

[8] For more information on how bid cost recovery charges are allocated please refer to the *Q3 2017 Report on Market Issues and Performance*, December 2017, pp. 40-41: http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf.

first quarter since the fourth quarter of 2017 that virtual demand net revenues were positive, primarily due to positive net virtual demand revenues on April 24, June 10 and June 11, 2019.

- Virtual supply net revenues were positive in May and negative in April and June. In total, virtual supply generated negative net revenues of nearly $5.4 million. This was primarily due to virtual supply losses on April 24, June 10 and June 11, 2019.

Figure 1.16 Convergence bidding revenues and bid cost recovery charges



After accounting for bid cost recovery charges:

- Convergence bidders received about $20.1 million after subtracting bid cost recovery charges of about $0.9 million for the quarter.[9,10] Bid cost recovery charges were about $0.5 million in April, $0.2 million in May and $0.3 million in June.

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9 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.

10 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.

Net revenues and volumes by participant type

Table 1.2 compares the distribution of convergence bidding cleared volumes and net revenues, in millions of dollars, among different groups of convergence bidding participants in the quarter.[11] Financial entities represented the largest segment of the virtual bidding market, accounting for about 70 percent of volume and 60 percent of settlement revenue. Marketers represented about 29 percent of the trading volumes and about 37 percent of settlement revenue. Generation owners and load-serving entities represented a smaller segment of the virtual market in terms of both volumes and settlement revenue, at about 3 percent and 4 percent respectively. Generation owners and load-serving entities accounted for around $0.75 million of net revenues in the market.

Table 1.2 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	1,104	1,290	2,394	$15.46	-$2.97	$12.48
Marketer	374	592	967	$9.81	-$2.10	$7.71
Physical load	0	38	38	$0.00	-$0.07	-$0.07
Physical generation	16	36	52	$1.11	-$0.29	$0.82
Total	**1,494**	**1,956**	**3,451**	**$26.4**	**-$5.4**	**$20.9**

1.7 Residual unit commitment

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real time. The residual unit commitment market is run immediately after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of load cleared in the day-ahead market and the day-ahead forecast load. ISO operators are able to increase residual unit commitment requirements. Use of this tool increased in June 2019.

As illustrated in Figure 1.17, residual unit commitment procurement appears to be driven in part by the need to replace cleared net virtual supply bids, which can offset physical supply in the day-ahead market run. On average, cleared virtual supply (green bar) was about 16 percent higher in the second quarter of 2019 than in the same quarter of 2018.

ISO operators were able to increase the amount of residual unit commitment requirements primarily due to load forecast uncertainty and weather change concerns. This tool, noted as operator adjustments (red bar) in the figure, was used in June averaging about 296 MW per hour.

Residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of variable energy resources and the forecast output of these renewable resources. This intermittent resource adjustment reduces residual unit commitment procurement

[11] 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.

targets by the estimated under-scheduling of renewable resources in the day-ahead market. It is represented by the yellow bar in Figure 1.17.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar) represents the difference in cleared supply (both physical and virtual) compared to the ISO's load forecast. On average, this factor contributed towards decreased residual unit commitment in the second quarter of 2019.

Figure 1.17 Determinants of residual unit commitment procurement

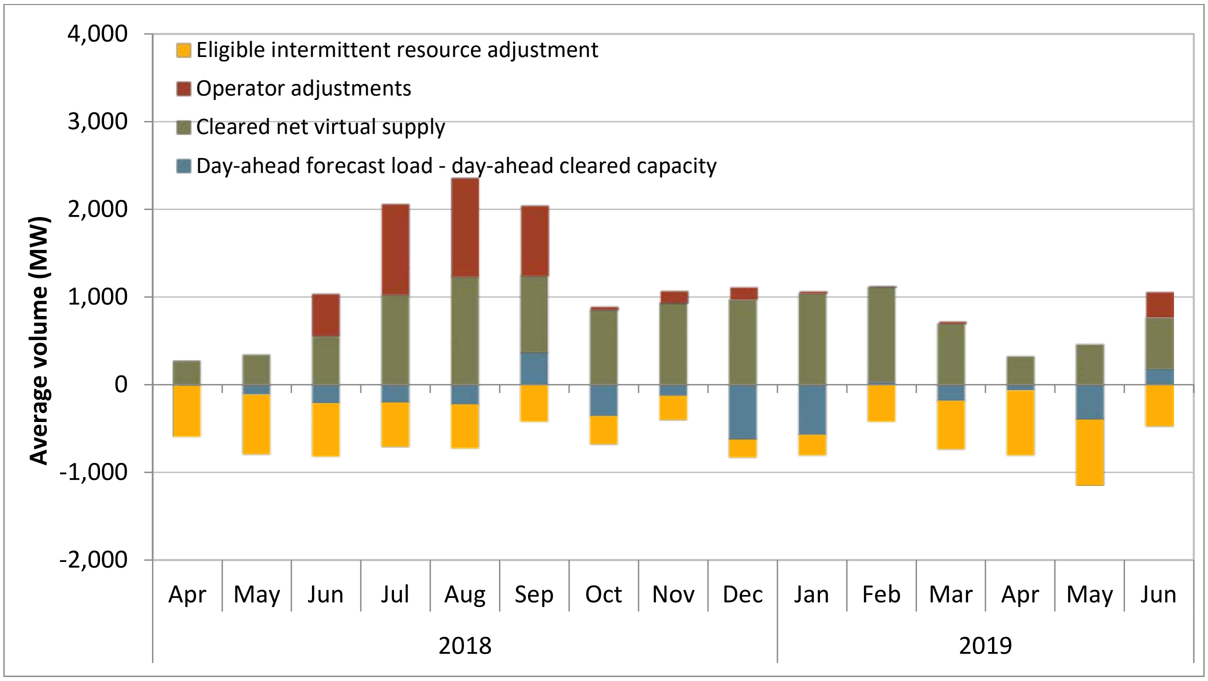
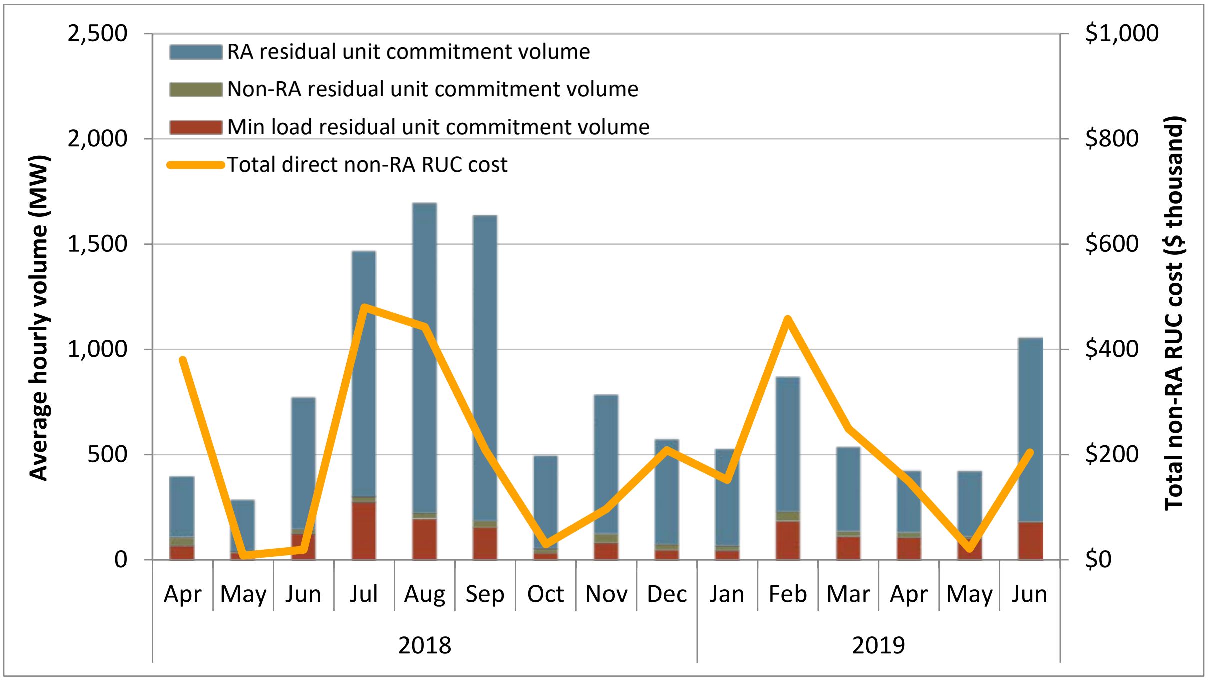


Figure 1.18 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. The figure shows increased residual unit commitment volumes and costs in June 2019 due to relatively high requirements. Total residual unit commitment procurement increased to about 632 MW per hour in the second quarter of 2019 from an average of 483 MW in the same quarter of 2018. Of the 632 MW per hour capacity, the capacity committed to operate at minimum load averaged about 130 MW each hour compared to 77 MW in the second quarter of 2018.

Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units committed in this process receive capacity payments.[12] The total direct cost of non-resource adequacy residual unit commitment, represented by the gold line in Figure 1.18, in the second quarter of 2019 was similar compared to 2018.

12 If committed, resource adequacy units may receive bid cost recovery payments in addition to resource adequacy payments.

Figure 1.18 Residual unit commitment costs and volume



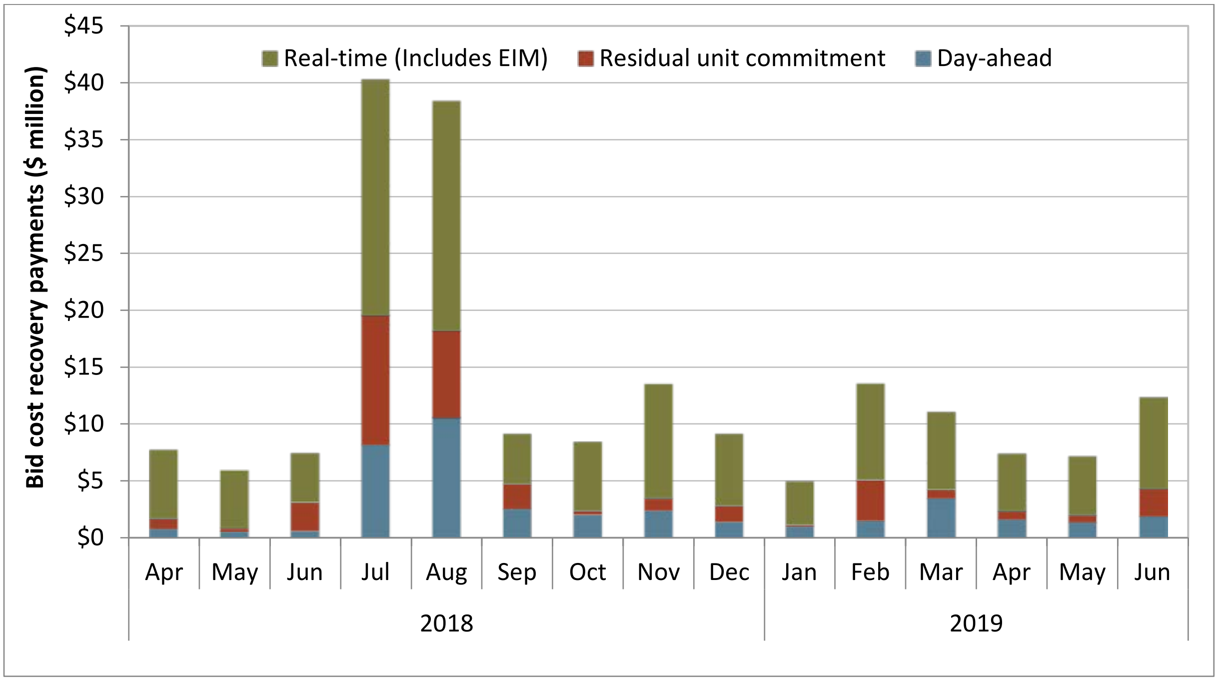
1.8 Bid cost recovery

Estimated bid cost recovery payments for the second quarter of 2019 totaled about $27 million. This amount was $3 million lower than the total amount of bid cost recovery in the previous quarter and about $6 million higher than the second quarter of 2018.

Bid cost recovery attributed to the day-ahead market totaled about $5 million, about $1 million less than the prior quarter. Bid cost recovery payments for residual unit commitment during the quarter totaled about $3.8 million, compared to $4.5 million in the prior quarter. Bid cost recovery attributed to the real-time market totaled about $18 million, or about $2.5 million higher than payments in the second quarter of 2018 and $1 million lower than payments in the first quarter of 2019. Bid cost recovery costs increased to 1.8 percent of total wholesale energy cost from 1.0 percent in the previous quarter and 1.1 percent in the same quarter of 2018.

From June 10 through 12, these real-time payments were about $5 million due to relatively high loads and high system energy prices.

Figure 1.19 Monthly bid cost recovery payments



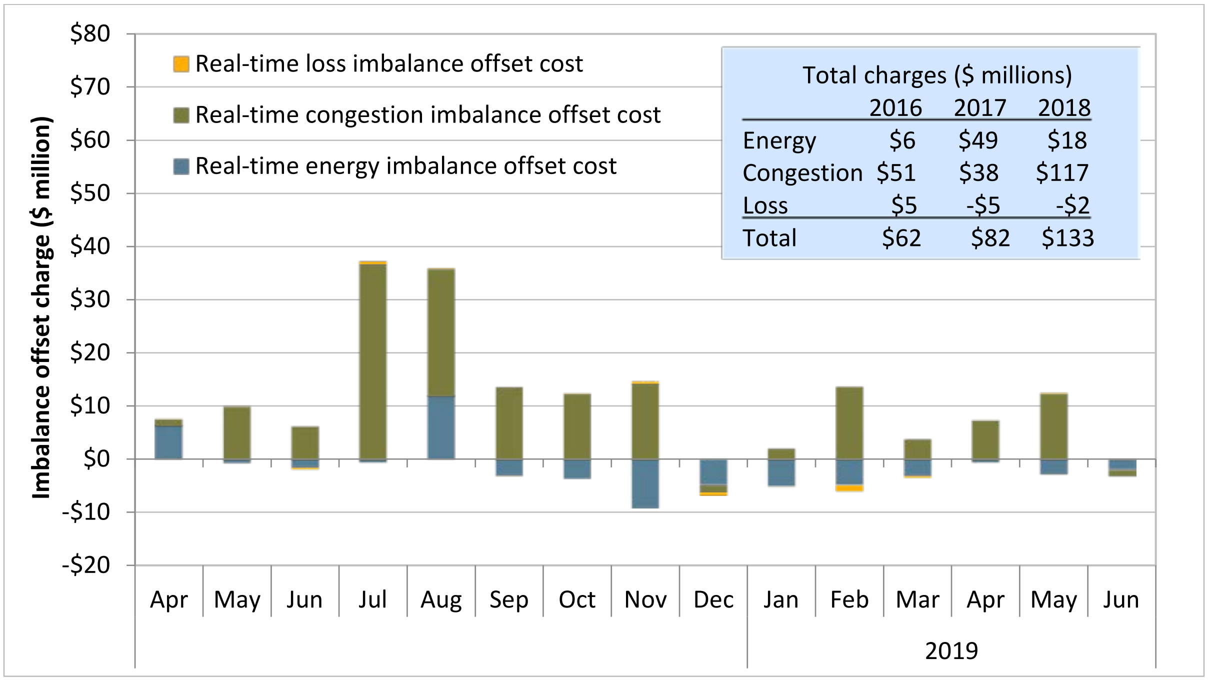
1.9 Real-time imbalance offset costs

Total real-time imbalance offset costs increased by 61 percent from $82 to $132 million between 2017 and 2018. Much of this increase appears to have been caused by persistent and significant reductions in constraint limits made by grid operators in the 15-minute market relative to higher limits used in the day-ahead market. Second quarter imbalance offset costs totaled $14 million, the sum of $19 million congestion offset costs less $5 million energy offset and $0.3 million loss offset. High real-time congestion imbalance offset costs were again associated with significant reductions in constraint limits in the 15-minute market relative to higher limits in the day-ahead market.

The real-time imbalance offset charge consists of three components. Any revenue imbalance from the energy components of real-time energy settlement prices is collected through the *real-time imbalance energy offset charge* (RTIEO). Any revenue imbalance from the congestion component of these real-time energy settlement prices is recovered through the *real-time congestion imbalance offset charge* (RTCIO). Any revenue imbalance from the loss component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge*.

The real-time imbalance offset cost is the difference between the total money paid out by the ISO and the total money collected by the ISO for energy settled in the real-time energy markets. Historically, this included energy settled at hour-ahead and 5-minute prices. The ISO implemented market changes related to FERC Order No. 764 in May 2014, which included a financially binding 15-minute market. Following this change, real-time imbalance offsets include energy settled at 15-minute and 5-minute prices. Within the ISO system, the charge is allocated as an uplift to measured demand (i.e., physical load plus exports).

Figure 1.20 Real-time imbalance offset costs



1.10 Congestion

This section provides an assessment of the frequency and impact of congestion on prices in the day-ahead and 15-minute markets. It assesses both the impact of congestion on local areas in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric) as well as on energy imbalance market entities.

Congestion in a nodal energy market occurs when the market model determines that flows have reached or exceeded the limit of a transmission constraint. Within areas where flows are constrained by limited transmission, higher cost generation is dispatched to meet demand. Outside of these transmission constrained areas, demand is met by lower cost generation. This results in higher prices within congested regions and lower prices in unconstrained regions.

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.[13]

Color shading is used in the tables to help distinguish patterns in the impacts of constraints. Orange coloring indicates a positive impact to prices, while blue coloring indicates a negative impact. The stronger the color of the shading, the greater the impact in either the positive or negative direction.

[13] This approach does not include price differences that result from transmission losses.

1.10.1 Congestion in the day-ahead market

In the day-ahead market, congestion frequency is typically higher than in the 15-minute market, but price impacts tend to be lower. The congestion pattern in this quarter reflects this overall trend.

Impact of congestion to overall prices in each load area

Figure 1.21 shows the overall impact of congestion on day-ahead prices in each load area for each quarter in 2018 and 2019.[14] Figure 1.22 shows the frequency of congestion. Highlights for this quarter include:

- The overall net impact to price separation as well as the frequency of congestion was low relative to the same quarter in 2018 and slightly higher than in the first quarter of 2019. Similar to previous quarters, the frequency of congestion was highest in SDG&E.
- Congestion resulted in a net increase to SCE and SDG&E prices by $0.09/MWh (0.4 percent) and $2/MWh (8.5 percent), respectively, and a net decrease to prices in PG&E by $0.13/MWh (0.6 percent).
- Congestion impacted PG&E prices in both directions, increasing prices in about 16 percent of intervals and decreasing prices in about 17 percent of intervals. For SCE and SDG&E, congestion primarily increased prices.
- The primary constraints impacting price separation in the day-ahead market were the Ocotillo-Suncrest 500 kV line outage nomogram and the Imperial Valley nomogram.

Additional information regarding the impact of congestion from individual constraints and the cause of congestion for constraints that had the largest impact on price separation is below.

14 The values in the figure represent the net impact of constraints on prices. Congestion sometimes increased and sometimes decreased values in each of the areas.

Figure 1.21 Overall impact of congestion on price separation in the day-ahead market

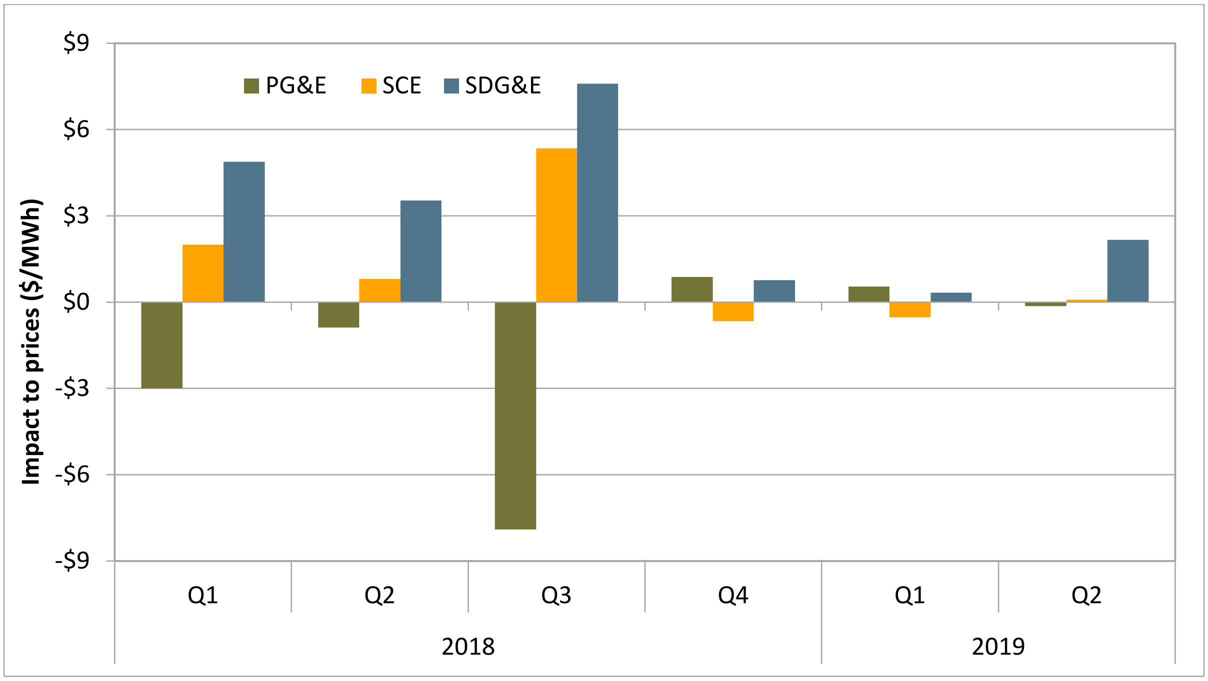


Figure 1.22 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)

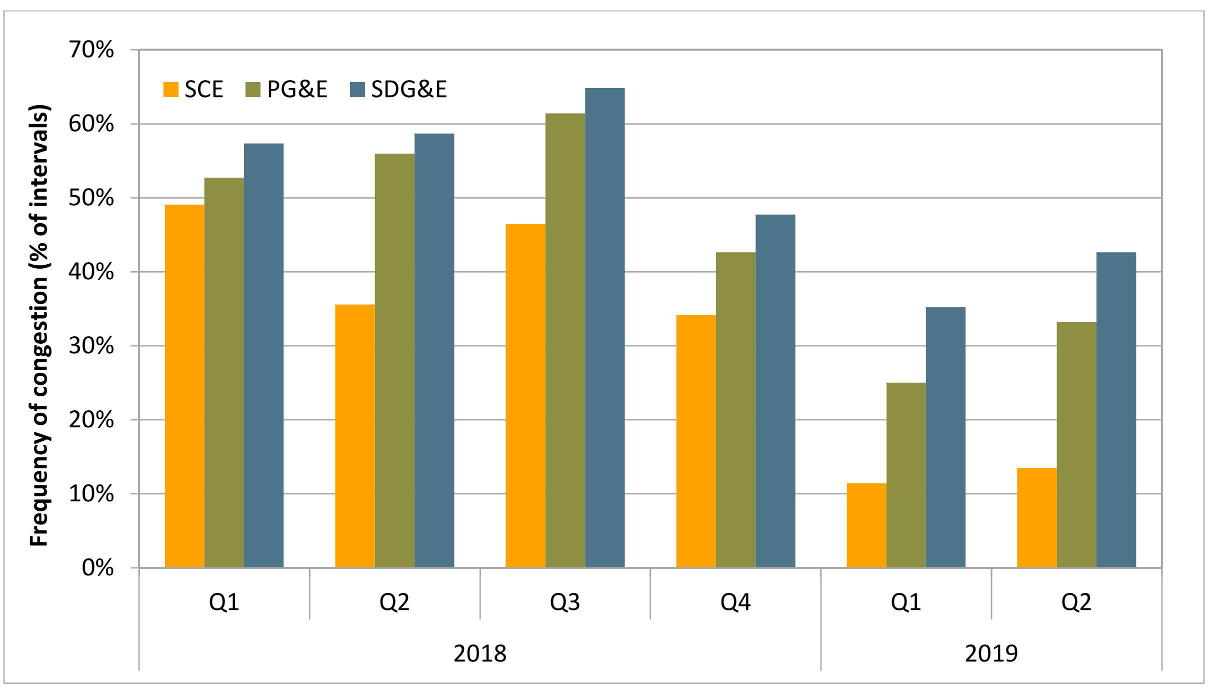
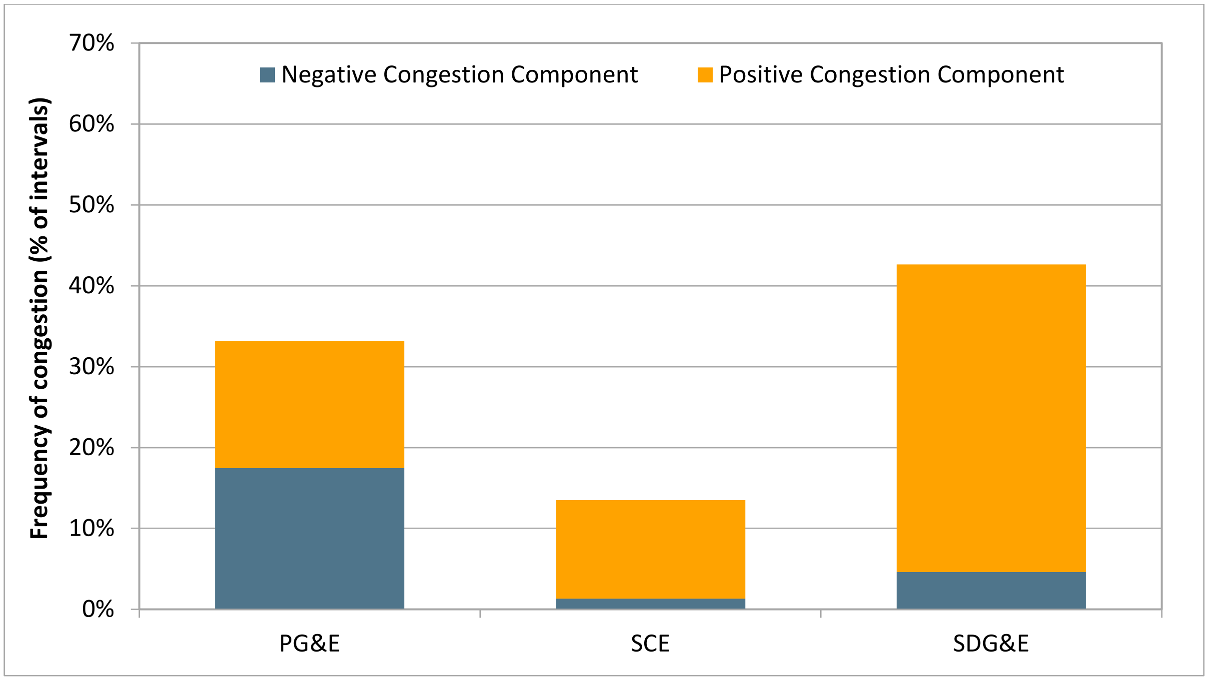


Figure 1.23 Percent of hours with congestion increasing versus decreasing day-ahead prices in the second quarter (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.3 breaks down the impact to price separation in the second quarter by constraint.[15] Table 1.4 shows the impact of congestion from each constraint *only during congested intervals,* where the number of congested intervals is presented separately as frequency. The constraints that had the greatest impact on price separation for the quarter were the Ocotillo-Suncrest 500 kV line outage nomogram, the Imperial Valley nomogram, and, in the PG&E area, the Midway-Vincent 500 kV line.

Ocotillo-Suncrest 500 kV line outage nomogram

The Ocotillo-Suncrest 500 kV line outage nomogram (OMS 6840921_TL50003_NG) bound infrequently in the second quarter, during about 2 percent of intervals. However, when binding, it had a significant impact on price separation, increasing SDG&E prices by about $29/MWh and decreasing PG&E prices by about $3/MWh. Overall for the quarter, the nomogram increased SDG&E prices by $0.63/MWh (2.5 percent) and decreased PG&E prices by $0.06/MWh (0.28 percent). This nomogram was enforced due to a planned outage on the Ocotillo-Suncrest 500 kV line, which was on outage only for 3 days in early April.

Imperial Valley nomogram

The Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) bound frequently in the second quarter, during about 12 percent of hours. When binding, it increased SDG&E prices by about $3/MWh. Over the entire quarter, it increased SDG&E prices by about $0.33/MWh (1.3 percent). The nomogram is enforced to mitigate for the loss of the Imperial Valley-North Gila 500 kV line. In the 2017-2018 transmission

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

planning cycle, an upgrade to the Imperial Valley-El Centro 230 kV S-Line was approved. The project, which is planned to be complete in 2021, will help to alleviate congestion in this area.

Midway-Vincent 500 kV line

In the PG&E area, congestion on the Midway-Vincent 500 kV line (30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3) bound infrequently during about 0.5 percent of hours. When binding, it increased prices in SDG&E and SCE by about $4/MWh and decreased prices in PG&E by about $5/MWh. Overall for the quarter, the constraint did not have a large impact on price separation, though it is interesting to note that the direction of congestion on this line changed on average from the previous quarter. This constraint bound primarily due to a series of planned and forced outages in late June that continued into July.

Table 1.3 Impact of congestion on overall day-ahead prices

Constraint Location	Constraint	PG&E		SCE		SDG&E	
		$ per MWh	Percent	$ per MWh	Percent	$ per MWh	Percent
PG&E	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.03	0.15%	-$0.01	-0.02%	$0.00	-0.02%
	6310_LBN_NRAS	$0.01	0.04%	-$0.01	-0.03%	-$0.01	-0.03%
	30580_ALTM MDW_230_30625_TESLA D _230_BR_1 _1	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.02	-0.11%	$0.02	0.09%	$0.02	0.08%
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.03	-0.11%	$0.03	0.14%	$0.00	0.01%
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	-$0.01	-0.04%	$0.02	0.11%	$0.01	0.02%
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.03%	$0.01	0.05%	$0.00	0.00%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	-$0.01	-0.03%	$0.00	0.00%	$0.02	0.08%
SDG&E	OMS 6840921_TL50003_NG	-$0.06	-0.28%	$0.00	0.00%	$0.63	2.49%
	7820_TL 230S_OVERLOAD_NG	-$0.03	-0.12%	$0.00	0.00%	$0.33	1.28%
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1	-$0.01	-0.05%	$0.00	0.00%	$0.24	0.93%
	MIGUEL_BKs_MXFLW_NG	-$0.01	-0.03%	$0.00	0.00%	$0.19	0.77%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P	-$0.02	-0.10%	$0.00	0.00%	$0.16	0.64%
	22873_VINE SUB_69.0_22380_KETTNER _69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.14	0.54%
	22592_OLD TOWN_69.0_22873_VINE SUB_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.12	0.48%
	OMS 7020096_50001_OOS_NG	-$0.01	-0.02%	$0.00	0.00%	$0.07	0.29%
	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_81	$0.00	0.00%	$0.00	0.00%	$0.06	0.25%
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.05	0.21%
	22592_OLD TOWN_69.0_22596_OLD TOWN_230_XF_1	$0.00	0.00%	$0.00	0.00%	$0.02	0.09%
	22692_ROSCYNTP_69.0_22696_ROSE CYN_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.01	0.06%
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.01	0.05%
	7820_TL23040_IV_SPS_NG	$0.00	0.00%	$0.00	0.00%	$0.01	0.04%
Other		$0.03	0.13%	$0.02	0.09%	$0.07	0.27%
Total		**-$0.13**	**-0.58%**	**$0.09**	**0.40%**	**$2.16**	**8.51%**

Table 1.4 Impact of congestion on day-ahead prices during congested hours[16]

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	1.9%	$1.81	-$2.99	-$2.69
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	0.5%	-$5.22	$4.37	$4.17
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	2.3%	-$1.09	$1.38	$0.61
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	2.1%	-$1.00	$1.17	$1.43
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	1.2%	-$0.62	$0.29	$1.62
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	0.5%	-$1.63	$2.23	$0.37
SDG&E	7820_TL 230S_OVERLOAD_NG	12.4%	-$0.22	$0.00	$2.62
	22873_VINE SUB_69.0_22380_KETTNER _69.0_BR_1 _1	5.3%	$0.00	$0.00	$2.61
	22592_OLD TOWN_69.0_22873_VINE SUB_69.0_BR_1 _1	4.5%	$0.00	$0.00	$2.69
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1	3.0%	-$2.13	$0.00	$7.95
	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_81	2.4%	$0.00	$0.00	$2.63
	OMS 6840921_TL50003_NG	2.2%	-$2.98	$0.00	$29.42
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P	1.8%	-$1.32	$0.00	$9.12
	MIGUEL_BKs_MXFLW_NG	1.5%	-$0.94	$0.00	$13.27
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	0.7%	$0.00	$0.00	$7.30
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	0.6%	$0.00	$0.00	$2.16
	OMS 7020096_50001_OOS_NG	0.6%	-$0.88	$0.00	$12.22
	7820_TL23040_IV_SPS_NG	0.4%	-$0.14	$0.00	$2.66
	22592_OLD TOWN_69.0_22596_OLD TOWN_230_XF_1	0.3%	$0.00	$0.00	$7.42

1.10.2 Congestion in the 15-minute market

In the 15-minute market, congestion frequency is typically lower than in the day-ahead market, but price impacts tend to be higher. The congestion pattern in this quarter reflects this overall trend.

Impact of congestion to overall prices in each load area

Figure 1.24 shows the overall impact of congestion on 15-minute prices in each load area for each quarter of 2018 and 2019. Figure 1.25 shows the frequency of congestion. Highlights for this quarter include:

- The overall net impact to price separation of congestion was higher in the second quarter of 2019 compared to the first, but lower than in the same quarter of 2018. However, the frequency of congestion in the second quarter was lower compared to all prior quarters of 2018 and 2019, unlike the day-ahead market where congestion frequency was higher in the second quarter than the first quarter of 2019. This was potentially due in part to regional differences between gas prices across the west in the first quarter; in the second quarter, the quarterly congestion impact was the result of congestion on June 10 and 11 when loads and flows into California were very high.

16 This table shows impacts on load aggregation point prices for constraints binding during more than 0.3 percent of the intervals during the quarter.

- Congestion resulted in a net increase to PG&E, SCE, SDG&E, BANC, and AZPS prices by about $2/MWh on average, and a net decrease to prices in NEVP, PACE, IPCO, PACW, PGE, PSEI, and PWRX by about $3/MWh on average. This impact was somewhat similar to the second quarter of 2018.
- Across the EIM load areas congestion primarily decreased prices, while congestion primarily increased prices in California. This can be seen in both the impact of congestion and frequency of positive and negative congestion impact. The frequency of congestion was highest in Powerex (56 percent of intervals), where congestion sometimes increased prices (31 percent of intervals) and also decreased prices (25 percent of intervals).
- The primary constraints impacting price separation in the 15-minute market were the Eldorado-Lugo nomogram, the Colorado River-Palo Verde 500 kV line outage nomogram, and the Indian Spring-Round Mountain 500 kV line outage nomogram.

Additional information regarding the impact of congestion from individual constraints and the cause of congestion for constraints that had the largest impact on price separation is below.

Figure 1.24 Overall impact of congestion on price separation in the 15-minute market

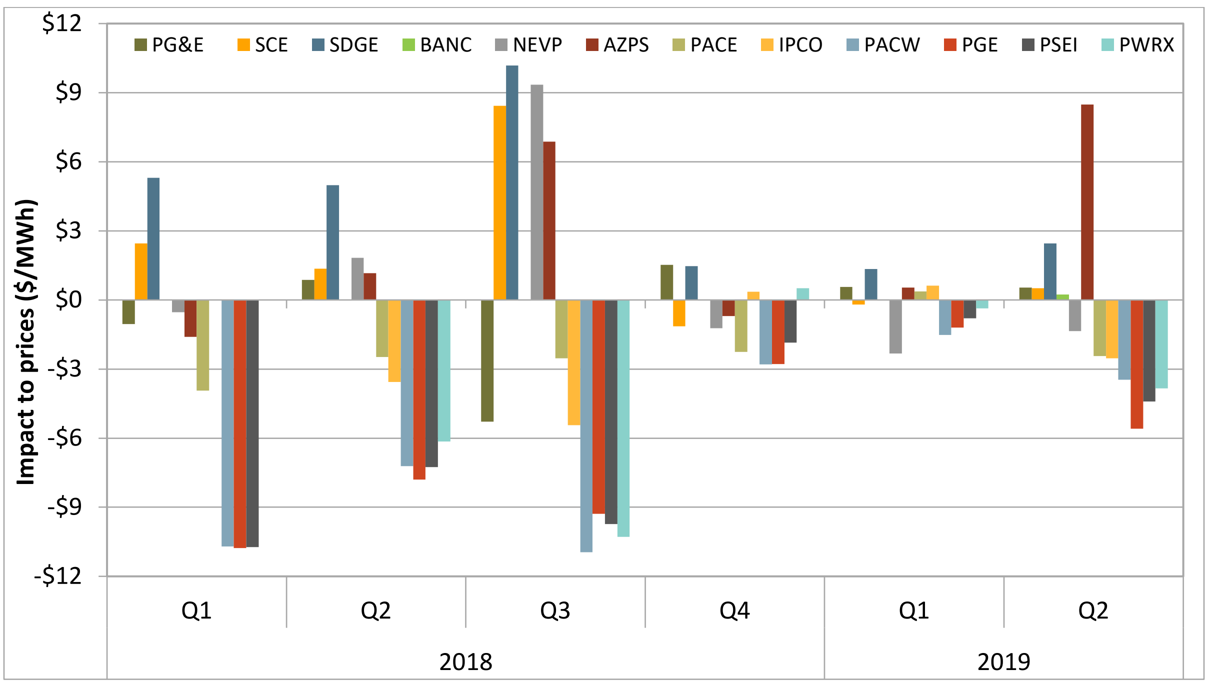


Figure 1.25 Percent of intervals with congestion increasing versus decreasing fifteen-minute prices in the second quarter (>$0.05/MWh)

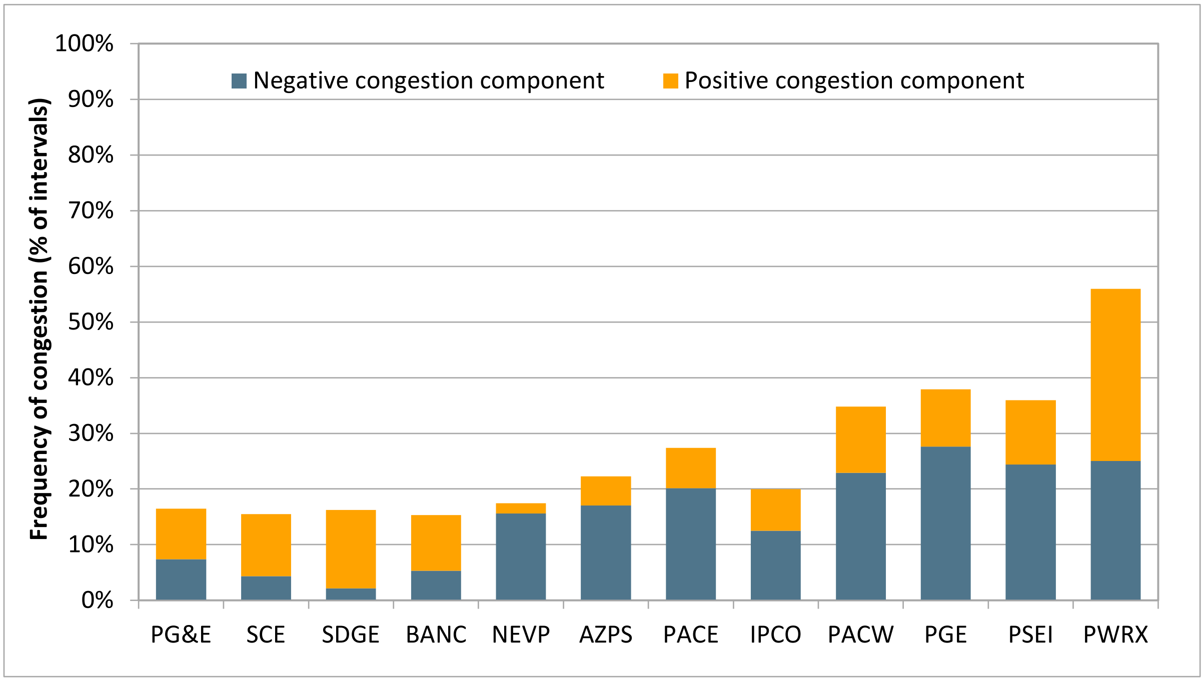
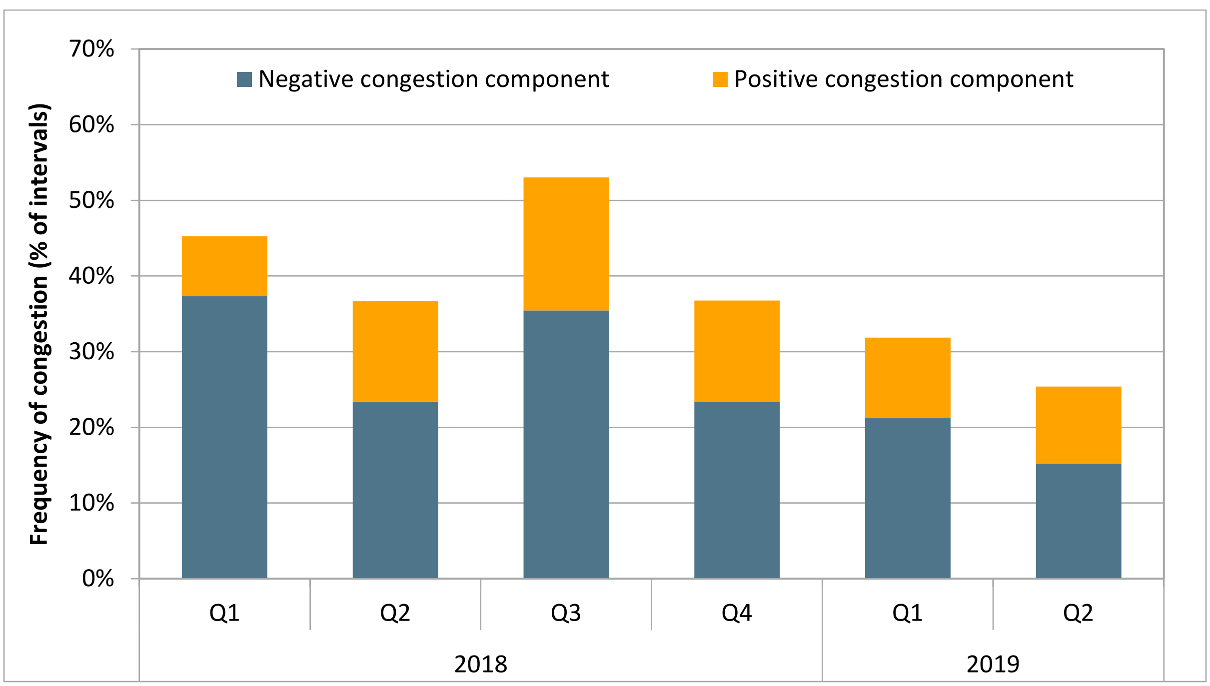


Figure 1.26 Percent of intervals with congestion impacting 15-minute prices (quarterly average of load areas)



Impact of congestion from individual constraints

Table 1.5 shows the overall impact (during all intervals) of congestion on average 15-minute prices in each load area. Table 1.6 shows the impact of congestion from each constraint *only during congested intervals,* where the number of congested intervals is presented separately as frequency. The color scales in the table below apply only to the individual constraints (excludes 'other' in Table 1.5). The category labeled "other" includes the impact of EIM transfer constraints and power balance constraint (PBC) violations, which often have the greatest impact on price separation for EIM areas. Transfer constraints and PBC violations are discussed in greater depth in Chapter 2. This section will focus on the individual flow-based constraints.

The constraints that had the greatest impact on price separation in the 15-minute market were the Eldorado-Lugo nomogram, the Colorado River-Palo Verde 500 kV line outage nomogram, and the Indian Spring-Round Mountain 500 kV line outage nomogram.

Eldorado - Lugo nomogram

The Eldorado-Lugo nomogram (OP-6610_ELD-LUGO) bound infrequently in the second quarter, during about 0.4 percent of intervals. However, when binding, it had a significant impact on price separation, increasing prices in California by about $30/MWh on average and decreasing prices in the southwest and east of California by about $12/MWh on average. Overall for the quarter, the nomogram increased prices in California by about $0.13/MWh on average and decreased prices in the southwest and east of California by about $0.35/MWh on average. This nomogram bound in particular on two days in June when loads in California were at their peak and flows into California were constrained.

Colorado River-Palo Verde 500 kV line outage nomogram

The Colorado River-Palo Verde 500 kV line outage nomogram (OMS 7228298_OP-6610) also bound infrequently in the second quarter, during about 1.2 percent of intervals. When binding, it increased prices in California by about $6/MWh on average and decreased prices in the southwest and east of California by about $8/MWh on average. Overall for the quarter, the nomogram increased prices in California by about $0.07/MWh on average and decreased prices in the southwest and east of California by about $0.15/MWh on average. This nomogram was enforced due to a planned outage on the Colorado River-Palo Verde 500 kV line, which was on outage for 4 days in May.

Indian Spring-Round Mountain 500 kV line outage nomogram

Congestion on the Indian Spring-Round Mountain 500 kV line (30010_INDSPRNG_500_30005_ROUND MT_500_BR_2 _1) bound infrequently during less than 0.3 percent of intervals. Overall for the quarter, the nomogram increased prices in California and Arizona by about $0.04/MWh on average and decreased prices throughout the rest of the EIM by about $0.09/MWh on average. Similar to the Eldorado-Lugo nomogram, this line bound in particular on two days in June when loads in California were at their peak and flows into California were constrained.

Table 1.5 Impact of congestion on overall 15-minute prices

Constr. Location	Constraint	PG&E	SCE	SDGE	BANC	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX
NEVP	ETY 120TXF					$0.03		-$0.01	-$0.01				
	FCN-RBS #3428		$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00
	FCN XF#2					-$0.04			$0.04				
PACE	WYOMING_EXPORT							-$0.07					
	PATH_C	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PG&E	30335_ATLANTC _230_30337_GOLDHILL_230_BR_1 _1				$0.21					-$0.05	-$0.05	-$0.03	-$0.02
	30622_EIGHT MI_230_30624_TESLA E _230_BR_1 _1				-$0.16								
	30500_BELLOTA _230_30515_WARNERVL_230_BR_1 _1				$0.10								
	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1				$0.00	-$0.04							
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1				$0.00	-$0.03							
	7430_CP6_NG_NEW				$0.03								
	30330_RIO OSO _230_30337_GOLDHILL_230_BR_1 _1				$0.01					$0.00	$0.00	$0.00	$0.00
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1		-$0.03	-$0.01			-$0.01						
	30010_INDSPRNG_500_30005_ROUND MT_500_BR_2 _1	$0.06	$0.03	$0.03	$0.06		$0.02	-$0.05	-$0.08	-$0.10	-$0.10	-$0.10	-$0.10
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	$0.05			$0.09				-$0.02	-$0.07	-$0.08	-$0.08	-$0.08
	30635_NWK DIST_230_30731_LS ESTRS_230_BR_1 _1	$0.05											
	RM_TM12_NG	$0.04	$0.02	$0.02	$0.03		$0.02	-$0.03	-$0.05	-$0.07	-$0.07	-$0.07	-$0.07
	6310_LBS_NRAS	$0.03	-$0.05	-$0.05	$0.05	-$0.03	-$0.04	$0.00	$0.01	$0.03	$0.03	$0.03	$0.03
	30105_COTTNWD _230_30245_ROUND MT_230_BR_2 _1	$0.03			$0.05			$0.00	-$0.04	-$0.05	-$0.05	-$0.05	-$0.05
	6310_MWN_NRAS	$0.01	-$0.01	-$0.01	$0.01	-$0.01	-$0.01		$0.00	$0.01	$0.01	$0.01	$0.01
	30523_CC SUB _230_30525_C.COSTA _230_BR_1 _1	$0.01						-$0.05	-$0.05	-$0.06	-$0.06	-$0.06	-$0.06
	6310_LBN_NRAS	$0.00	-$0.01	-$0.01	$0.01	-$0.01	-$0.01	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.00	-$0.01	-$0.01	$0.01	$0.00	-$0.01		$0.00	$0.01	$0.01	$0.01	$0.01
	RM_TM21_NG	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01
	6110_SOL10_NG	$0.00	$0.00	$0.00	$0.01		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.03	$0.03	$0.02	-$0.02	$0.01	$0.02	$0.00	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02
SCE	OP-6610_ELD-LUGO	$0.20	$0.14	$0.00	$0.18	-$0.57	-$0.47	-$0.27	-$0.10				
	OMS 7228298_OP-6610	$0.07	$0.11	$0.04	$0.06	-$0.20	-$0.21	-$0.12	-$0.05				
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.02	$0.09	$0.05	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	7750_DV2_N2DV500_NG		$0.06			-$0.03	-$0.15	-$0.04					
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	$0.00	$0.02	$0.01	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	7750_D-ECASCO_OOS_CP6_NG	$0.06	-$0.02	$0.03	$0.04	-$0.03	-$0.28	-$0.07					
SDG&E	MIGUEL_BKs_MXFLW_NG			$0.41			-$0.17	-$0.03					
	7820_TL 230S_OVERLOAD_NG		$0.03	$0.36	$0.00	-$0.03	-$0.08	-$0.03	$0.00	$0.00	$0.00	$0.00	$0.00
	7820_TL23040_IV_SPS_NG		$0.00	$0.28		$0.00	-$0.02	$0.00					
	OMS 6840921_TL50003_NG		$0.01	$0.23		-$0.02	-$0.07	-$0.02	-$0.01				
	24138_SERRANO _500_24137_SERRANO _230_XF_3	$0.00	$0.08	$0.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1			$0.16									
	22592_OLD TOWN_69.0_22873_VINE SUB_69.0_BR_1 _1			$0.15									
	OMS_7042181_TL23054_NG			$0.14		-$0.01	-$0.05	-$0.01					
	OMS 7020096_50001_OOS_NG		$0.00	$0.07		$0.00	-$0.01						
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P			$0.06		-$0.01	-$0.02						
	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_81			$0.05									
	22357_IV PFC1 _230_22358_IV PFC _230_PS_1			$0.04									
	22609_OTAYMESA_230_22467_MLSXTAP _230_BR_1 _1			$0.04									
	OMS_7058572_TL23055_NG			$0.03		$0.00	-$0.01	$0.00					
	OMS_7203296_TL23055_NG		$0.00	$0.03		$0.00	-$0.01	$0.00					
	22536_N.GILA _500_22360_IMPRLVLY_500_BR_1 _1		$0.00	$0.02		$0.00	-$0.01	$0.00	$0.00				
	OMS_7203286_TL23054_NG		$0.00	$0.02		$0.00	-$0.01	$0.00					
	92321_SYCA TP2_230_22832_SYCAMORE_230_BR_2 _1			$0.02			-$0.01						
	22873_VINE SUB_69.0_22380_KETTNER _69.0_BR_1 _1			$0.02									
	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1			$0.01			-$0.01						
Other		-$0.04	$0.02	$0.01	-$0.53	-$0.31	$10.10	-$1.58	-$2.13	-$3.07	-$5.19	-$4.02	-$3.47
Total		**$0.54**	**$0.51**	**$2.46**	**$0.22**	**-$1.36**	**$8.48**	**-$2.43**	**-$2.53**	**-$3.47**	**-$5.59**	**-$4.41**	**-$3.84**

Table 1.6 Impact of congestion on 15-minute prices in the ISO during congested intervals[17]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDGE	BANC	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX
PACE	WYOMING_EXPORT	3.7%							-$2.04					
PG&E	30523_CC SUB _230_30525_C.COSTA _230_BR_1 _1	2.7%	$1.20						-$1.94	-$2.12	-$2.11	-$2.10	-$2.09	-$2.10
	30622_EIGHT MI_230_30624_TESLA E _230_BR_1 _1	1.7%				-$9.39								
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	1.2%		-$2.82	-$2.33			-$2.12						
	30500_BELLOTA _230_30515_WARNERVL_230_BR_1 _1	0.9%				$11.68								
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	0.8%	$10.10			$11.32				-$8.58	-$11.52	-$12.09	-$11.87	-$11.72
	30105_COTTNWD _230_30245_ROUND MT_230_BR_2 _1	0.7%	$5.37			$6.61			-$3.04	-$5.34	-$6.46	-$6.74	-$6.64	-$6.58
	RM_TM12_NG	0.7%	$6.53	$3.76	$3.32	$4.68		$2.45	-$4.25	-$7.29	-$10.00	-$10.06	-$10.06	-$10.06
	30335_ATLANTC _230_30337_GOLDHILL_230_BR_1 _1	0.6%				$37.52					-$23.03	-$23.11	-$21.11	-$19.04
	6110_SOL10_NG	0.4%	$1.12	$0.76	$0.73	$1.71		$0.60	-$0.69	-$0.88	-$1.09	-$1.09	-$1.09	-$1.09
	6310_LBS_NRAS	0.4%	$8.48	-$12.51	-$11.83	$11.35	-$6.36	-$10.55	-$0.82	$3.52	$7.48	$7.17	$7.17	$7.17
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	0.4%	-$6.45	$6.46	$6.16	-$6.08	$3.48	$5.44	$0.06	-$2.31	-$4.38	-$4.29	-$4.29	-$4.29
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1	0.3%				$15.09	-$8.07							
	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1	0.3%				$13.64	-$12.03							
SCE	7750_D-ECASCO_OOS_CP6_NG	3.3%	$1.75	-$1.21	$1.46	$1.45	-$2.38	-$8.41	-$2.13					
	7750_DV2_N2DV500_NG	2.0%		$2.87			-$1.72	-$7.17	-$2.03					
	OMS 7228298_OP-6610	1.2%	$5.98	$8.51	$3.47	$5.04	-$16.26	-$16.81	-$9.40	-$4.23				
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	0.6%	-$4.83	$15.07	$9.22	-$4.83	-$4.64	-$4.83	-$4.63	-$4.63	-$4.83	-$4.83	-$4.83	-$4.83
	OP-6610_ELD-LUGO	0.4%	$45.15	$31.81	$1.36	$39.75	-$128.52	-$104.35	-$60.92	-$23.12				
SDG&E	7820_TL 230S_OVERLOAD_NG	2.2%		$1.22	$16.40	-$0.88	-$1.21	-$3.72	-$1.44	-$0.56	-$1.07	-$0.88	-$0.88	-$0.82
	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_81	1.5%			$3.18									
	7820_TL23040_IV_SPS_NG	1.3%		$0.72	$21.61		-$0.68	-$1.92	-$0.70					
	MIGUEL_BKs_MXFLW_NG	1.2%			$33.55			-$14.09	-$2.69					
	22592_OLD TOWN_69.0_22873_VINE SUB_69.0_BR_1 _1	1.1%			$13.62									
	OMS 6840921_TL50003_NG	1.0%		$1.37	$23.04		-$1.63	-$6.48	-$2.25	-$1.40				
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1	0.8%			$19.90									
	24138_SERRANO _500_24137_SERRANO _230_XF_3	0.7%	-$3.19	$11.16	$27.41	-$3.19	-$3.19	-$3.19	-$3.19	-$3.19	-$3.19	-$3.19	-$3.19	-$3.19
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P	0.4%			$14.38		-$1.69	-$4.70						
	OMS_7042181_TL23054_NG	0.3%			$40.20		-$2.10	-$13.76	-$2.33					
	OMS 7020096_50001_OOS_NG	0.3%		$1.15	$21.37		-$1.11	-$3.51						

1.11 Ancillary services

1.11.1 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.

The ISO can procure ancillary services in the day-ahead and real-time markets from the internal system region, expanded system region, four internal sub-regions, and four corresponding expanded sub-regions. The expanded regions are identical to the corresponding internal regions but include interties. Each of these regions can have minimum requirements set for procurement of ancillary services where the internal sub-regions are all nested within the system and corresponding expanded regions. Therefore, ancillary services procured in a more inward region also count toward meeting the minimum

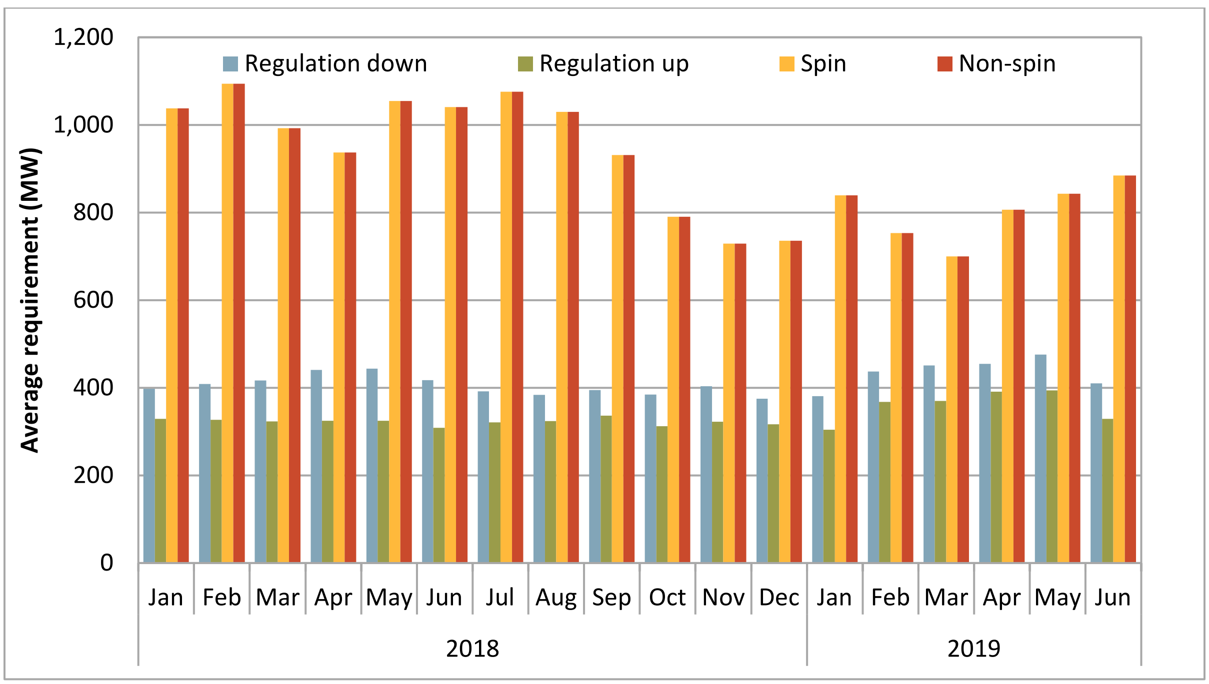
17 Details on constraints binding in less than 0.3 percent of the intervals have not been reported.

requirement of the outer region. Ancillary service requirements are then met by both internal resources and imports where imports are indirectly limited by the minimum requirements from the internal regions.

Operating reserve requirements in the day-ahead market are typically set by the maximum of (1) 6.3 percent of the load forecast, (2) the most severe single contingency and (3) 15 percent of forecasted solar production. Operating reserve requirements in real-time are calculated similarly except using 3 percent of the load forecast and 3 percent of generation instead of 6.3 percent of the load forecast. Projected schedules on the Pacific DC intertie that sink in the ISO balancing area (which can include a higher volume than the share that sinks directly in the ISO) often serve as the most severe single contingency.

Figure 1.27 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. As shown in the figure, average spinning and non-spinning operating reserve requirements increased in each of April, May, and June. Operating reserve requirements during the quarter were highest during the early morning and late evening hours. In particular, Pacific DC intertie schedules frequently set the operating reserve requirement during these hours as the most severe single contingency.

Figure 1.27 Average monthly day-ahead ancillary service requirements

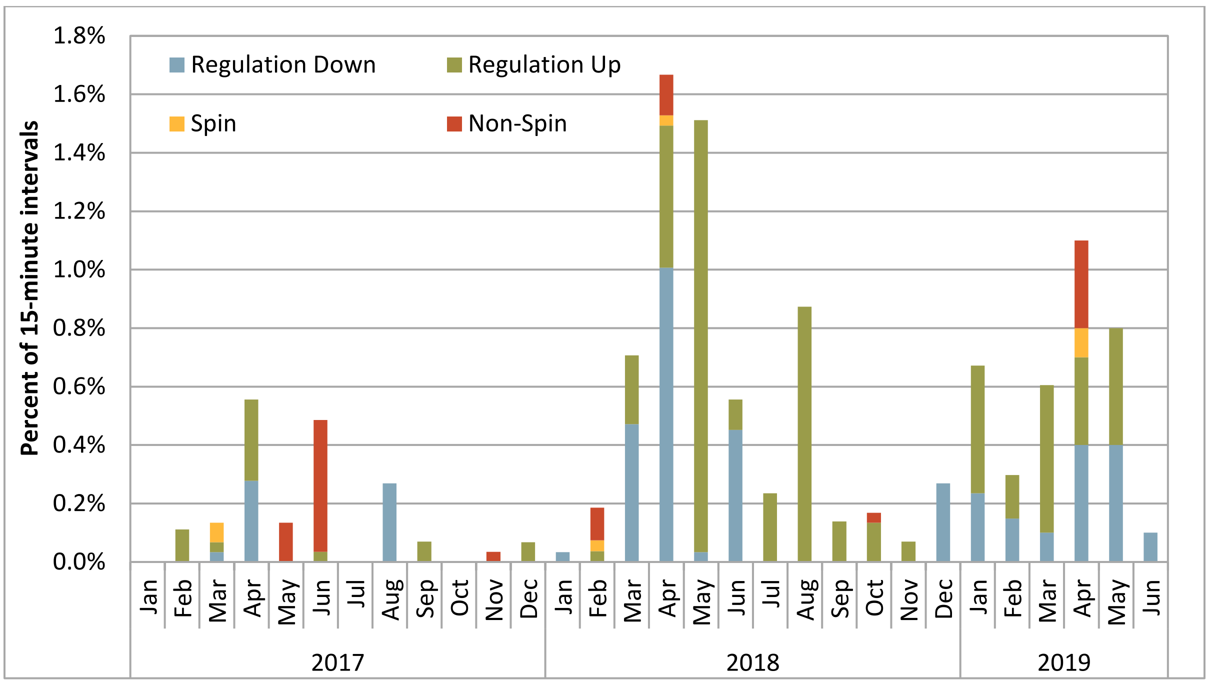


1.11.2 Ancillary service scarcity

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

As shown in Figure 1.28 the number of intervals with scarcity pricing increased during the second quarter, particularly from the shortage of spinning and non-spinning reserve. However, ancillary service scarcity intervals were much less frequent in comparison to the second quarter of 2018. During the second quarter of 2019, around 63 percent of the scarcity intervals occurred in the expanded system region, 27 percent in the expanded South of Path 26 region, and the remaining 10 percent in the expanded North of Path 26 region.

Figure 1.28 Frequency of ancillary service scarcities (15-minute market)

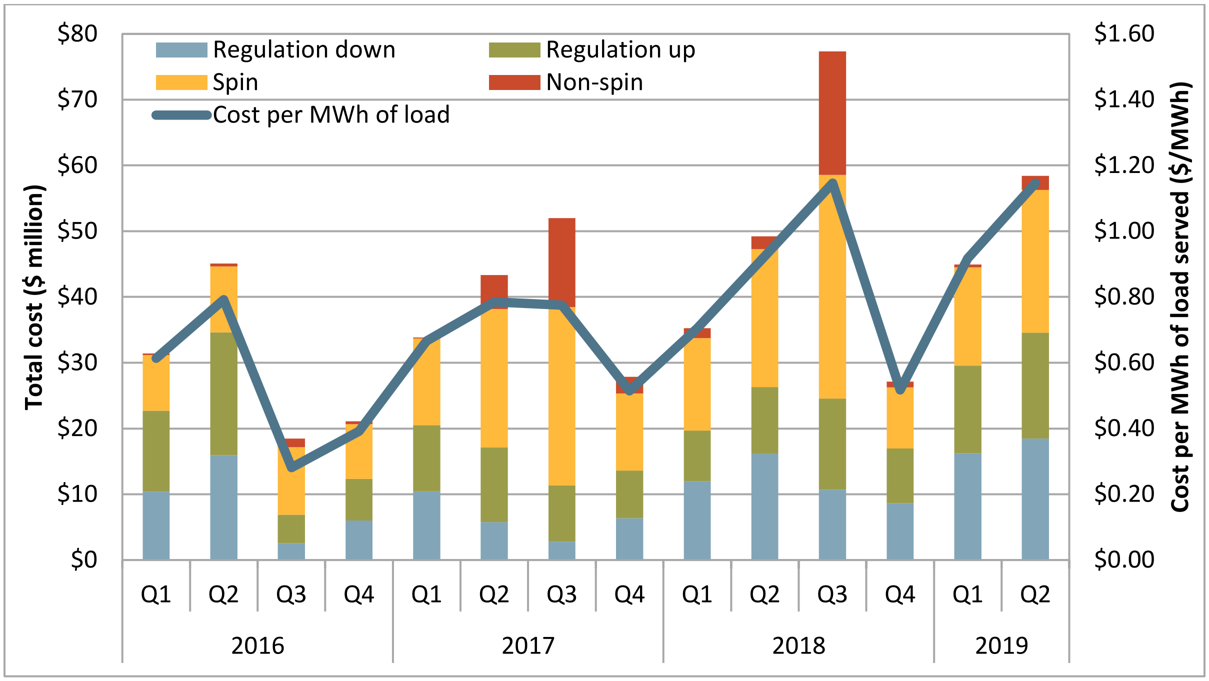


1.11.3 Ancillary service costs

Costs for ancillary services increased during the second quarter to about $58 million, compared to about $45 million in the previous quarter and $49 million during the same quarter in 2018.

Figure 1.29 shows the total cost of procuring ancillary service products by quarter and the total ancillary service cost for each megawatt-hour of load served. In particular, total payments associated with spinning reserve increased by around $7 million from the previous quarter. Total payments associated with regulation down, regulation up, and non-spinning reserve each increased by roughly $2 to $3 million from the previous quarter.

Figure 1.29 Ancillary service cost by product



1.12 Load forecast adjustments

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*. The ISO uses 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.[18] 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

The dramatic increase in load forecast adjustments during the steep morning and evening net load ramp periods in the ISO's hour-ahead and 15-minute markets in 2017 appears to have continued throughout 2018 and into the third quarter of 2019. Adjustments during the mid-day period also increased for these markets for the same time period but, on average by hour, changed from a negative adjustment to positive. In general, load forecast adjustments for the 5-minute market increased throughout the day

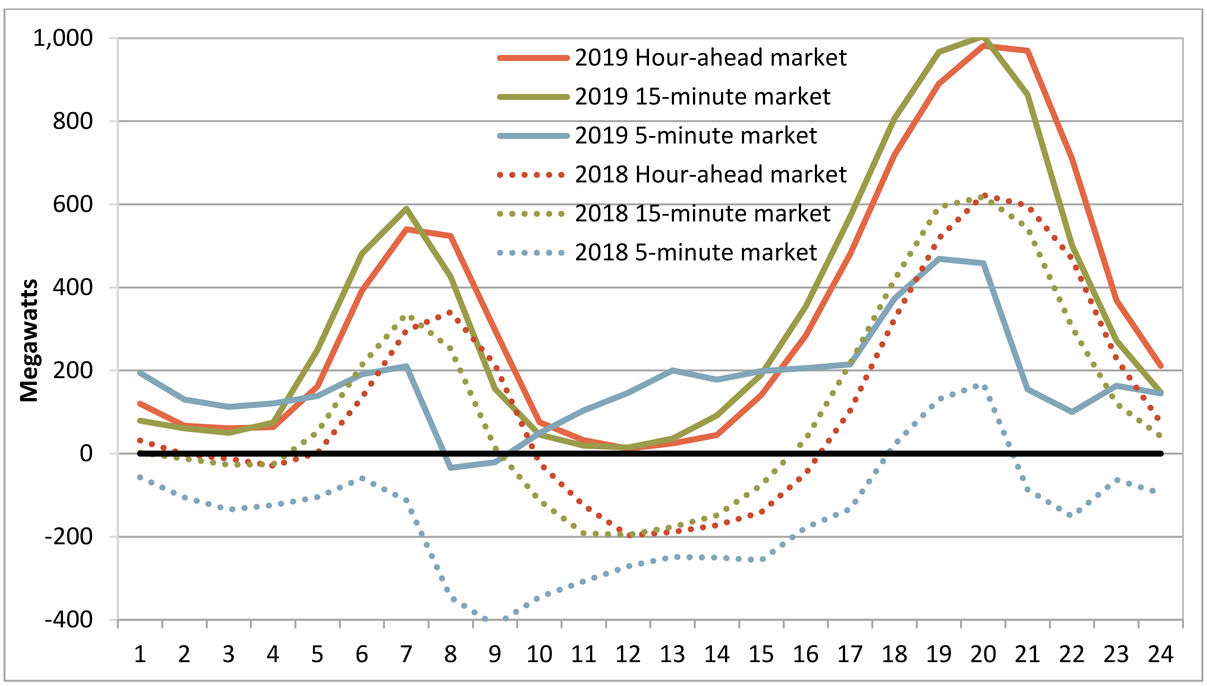
18 Additional detail can be found in Section 9, Market Adjustments, in the *2016 Annual Report on Market Issues and Performance*, which is available on the ISO website at: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf

and remained positive when comparing the second quarter of 2019 with the same period in 2018. Figure 1.30 shows the average hourly load adjustment profile for the hour-ahead, 15-minute and 5-minute markets for the second quarter in 2019 and 2018.

Load adjustments in the hour-ahead and 15-minute markets are very similar to each other throughout the day. But, like the previous year, the 2019 5-minute market adjustments differ dramatically from other markets for nearly all hours of the day. Unlike the same quarter in 2018 where the daily average hourly adjustment was about 150 MW in the negative direction, the average hourly adjustment for the second quarter of 2019 was about 175 MW in the positive direction with only slight negative conformance on average in hour-ending 8 and 9. In the hour-ahead and 15-minute markets the lowest adjustment period was in the mid-day hours as well as early morning/late evening. The lowest adjustment period in the 5-minute market was in hour-ending 8 and 9.

The shape of the adjustments for the 5-minute market was similar to the other markets with the exception of the mid-day period where adjustments reached up to 200 MW, while the hour-ahead and 15-minute market adjustments were close to 0 MW. However, this changed sharply surrounding the morning and evening ramp periods, when the average hourly adjustment was up to 1,000 MW in hour-ending 19 for the hour-ahead and 15-minute markets whereas the load adjustment in the 5-minute market was closer to 400 MW. Adjustments are often associated with over/under-forecasted load, changes in expected renewable generation, and morning or evening net load ramp periods.

Figure 1.30 Average hourly load adjustment (Q2 2018 – Q2 2019)



1.13 Local market power mitigation

Incremental energy subject to mitigation increased significantly in the second quarter of 2019 compared to the same quarter in 2018 in both the day-ahead and 15-minute markets. This is due, in part, to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers.

Background

The ISO's automated local market power mitigation (LMPM) procedures have been enhanced in numerous ways since 2012 to more accurately identify and mitigate resources with the ability to exercise local market power in the day-ahead and real-time markets. The ISO is currently working on further enhancements to real-time market power mitigation processes to be implemented in fall 2019. As part of this policy, the ISO is proposing several measures including prevention of flow reversal by eliminating balance of hour mitigation and providing an option for energy imbalance market areas to limit exports when mitigation is triggered due to import congestion.[19]

The impact on market prices of bids that were actually mitigated can only be assessed precisely by re-running the market software without bid mitigation. However, DMM does not have the ability to re-run the day-ahead and real-time market software to perform such analysis. Instead, DMM has developed a variety of metrics to estimate the frequency with which mitigation was triggered and the effect of this mitigation on each unit's energy bids and dispatch levels. These metrics identify bids lowered from mitigation each hour and also estimate the additional energy dispatched from these price changes.[20]

The following sections provide analysis on the frequency and impact of bid mitigation in day-ahead and real-time markets, for the ISO's balancing authority area.

Frequency and impact of automated bid mitigation

As shown in Figure 1.31, in the day-ahead market, the average incremental energy subject to mitigation increased to about 1,400 MW in the second quarter of 2019 compared to 360 MW in the same quarter of 2018. About 230 MW of this incremental energy had bids lowered due to mitigation compared to 111 MW in 2018. As a result, there was a very insignificant increase in dispatch, similar to that of 2018.

Figure 1.32 shows the same metrics but for the ISO's 15-minute and 5-minute markets. As shown in the figure, the average incremental energy subject to mitigation in the ISO is consistently higher in the 5-minute than in the 15-minute market. An average of 365 MW in each hour was subject to 15-minute market mitigation in the second quarter of 2019, compared to 154 MW in the same quarter in 2018. In the 5-minute market, an average of 523 MW was subject to mitigation compared to 938 MW in 2018.

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19 Draft final proposal, *Local market power mitigation enhancements*, January 31, 2019: http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements-UpdatedJan31_2019.pdf

20 The methodology has been updated to show incremental energy instead of units that have been subject to automated bid mitigation. This metric also captures carry over mitigation (balance of hour mitigation) in 15-minute and 5-minute markets by comparing the market participant submitted bid at the top of each hour (in the 15-minute market) to the bid used in each interval of 15-minute and 5-minute market runs.

Of the incremental energy subject to mitigation in the 15-minute and 5-minute markets, the relative percentage of incremental energy with bid price lowered due to mitigation increased in the second quarter of 2019 compared to 2018. Potential increase in 15-minute and 5-minute schedules from bid mitigation was minimal, similar to the second quarter of 2018.

Figure 1.31 Average incremental energy mitigated in day-ahead market

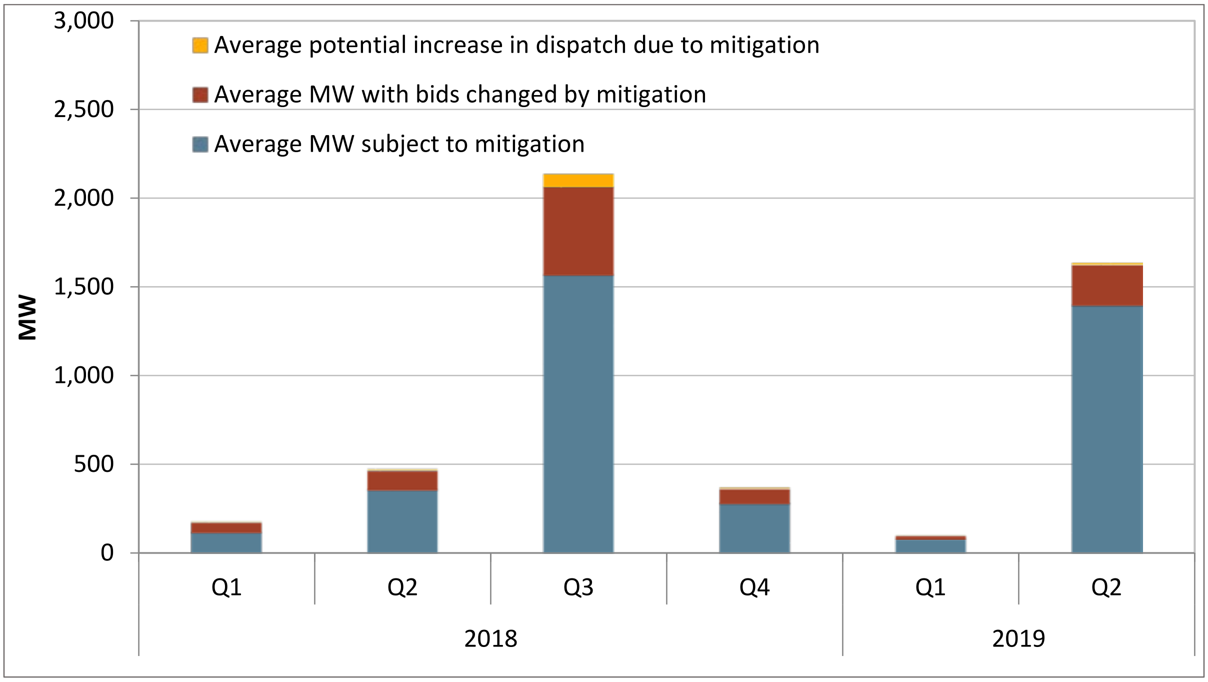
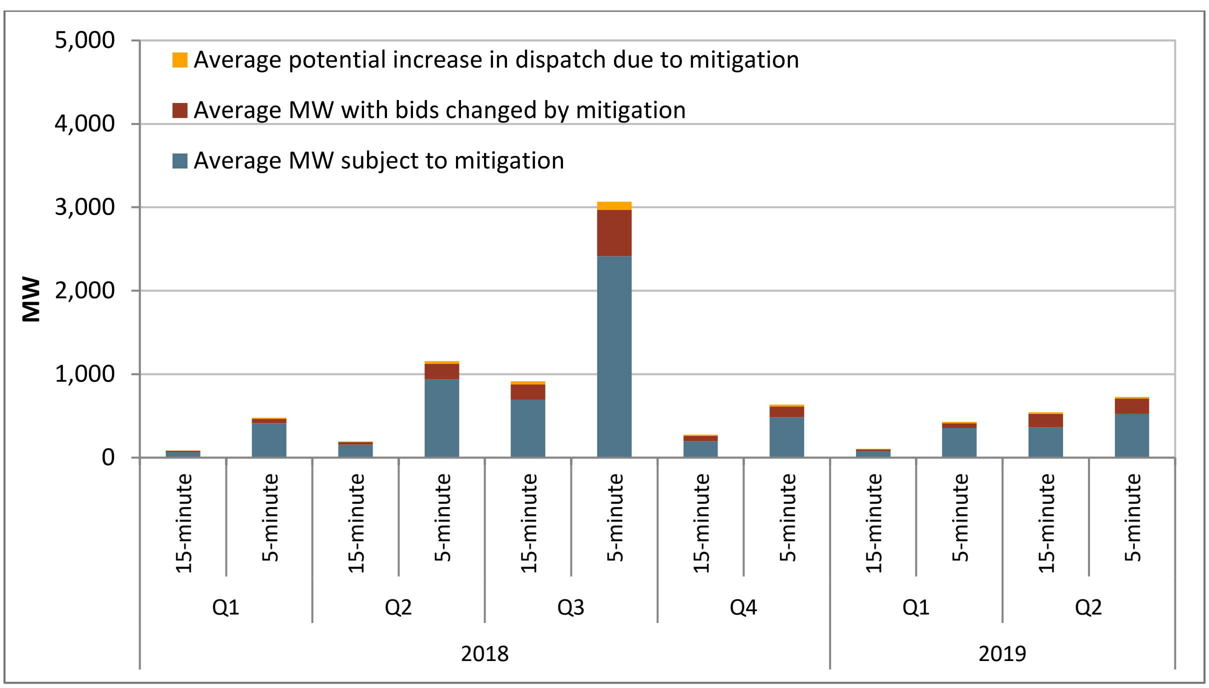


Figure 1.32 Average incremental energy mitigated in real-time market (ISO)



1.14 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 continued to account for a relatively low portion of total system loads. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 0.11 percent of system load in the second quarter.

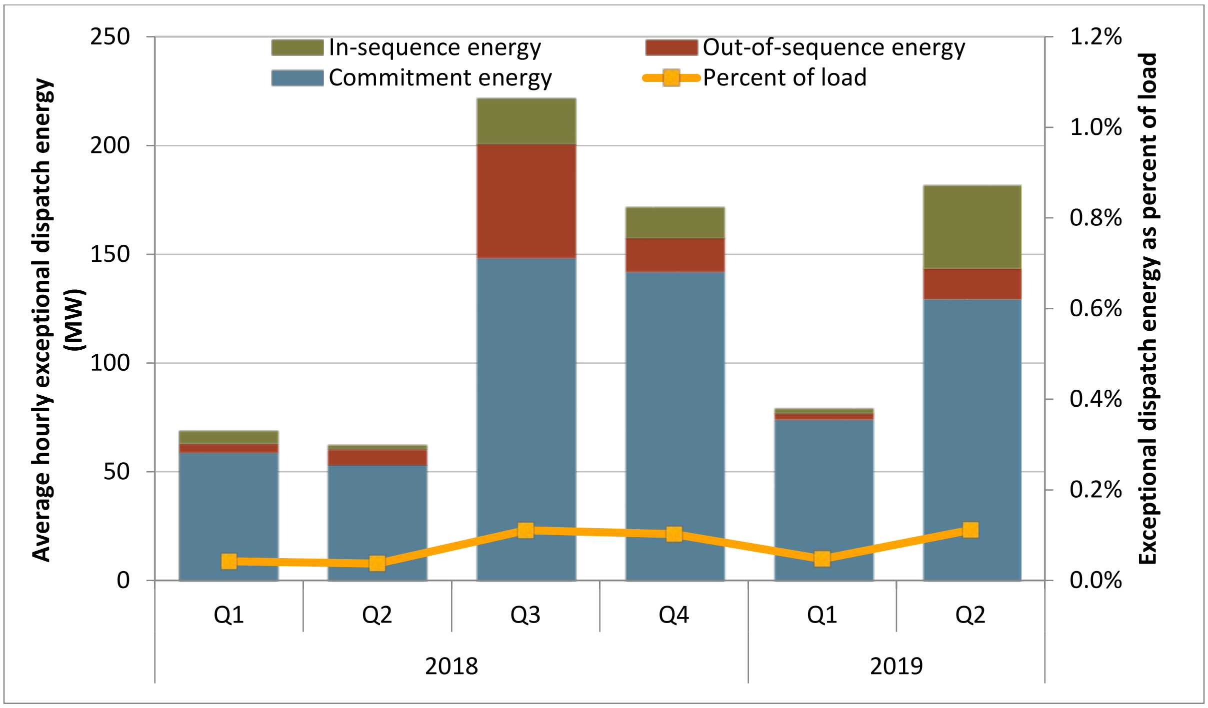
Total energy resulting from all types of exceptional dispatch increased nearly threefold in the second quarter of 2019 compared to the same quarter in 2018, as shown in Figure 1.33.[21] Exceptional dispatches for unit commitments accounted for about 71 percent of all exceptional dispatch energy in this quarter. About 8 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 21 percent was from in-sequence energy.

Although energy from exceptional dispatches cannot directly set market prices, the volume of energy form exceptional dispatches can affect the market clearing price for energy. Energy resulting from exceptional dispatch effectively reduces the remaining load to be met by other supply. This can reduce market prices relative to a case where no exceptional dispatch was made.

[21] 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.

For instance, as discussed later in this section, 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.

Figure 1.33 Average hourly energy from exceptional dispatch

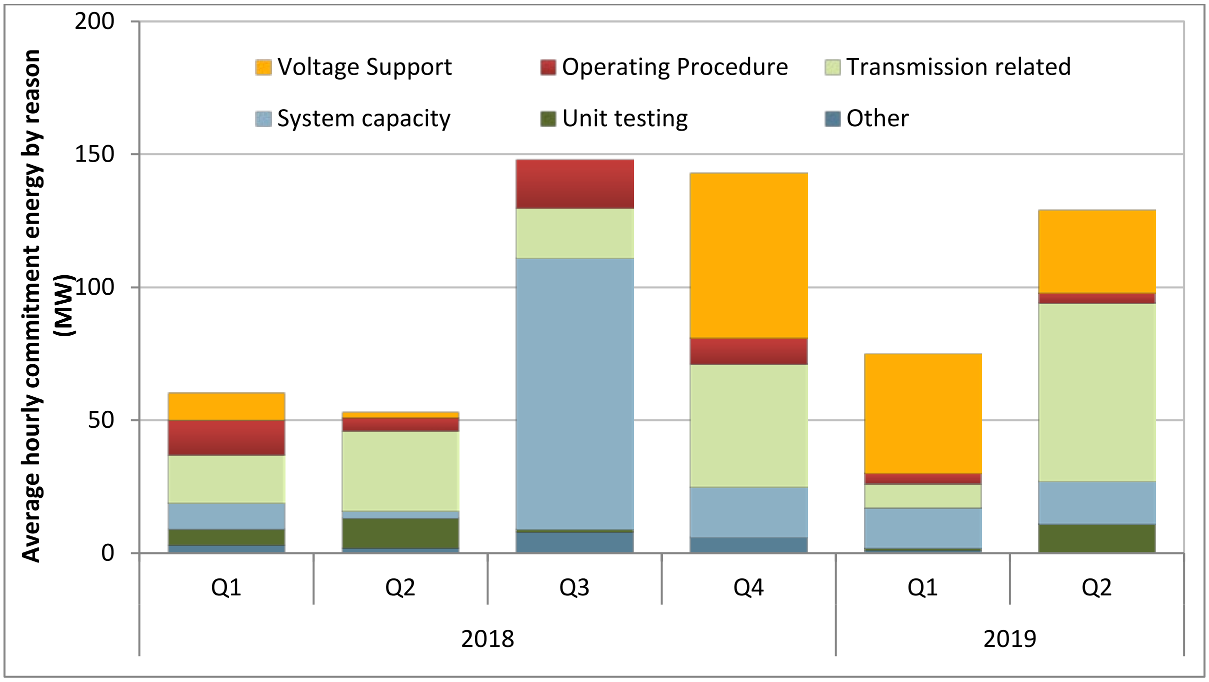


Exceptional dispatches for unit commitment

The ISO sometimes finds instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements not directly incorporated in the day-ahead market model. Alternatively, a scheduling coordinator may wish to operate a resource out-of-market for purposes of unit testing. In these instances, the ISO may commit additional capacity by issuing an exceptional dispatch for resources to come on-line and operate at minimum load, or for resources to operate at the minimum output of a specific multi-stage generator configuration.

Minimum load energy from exceptional dispatch unit commitments in the second quarter was nearly 2.5 times higher than the second quarter of the prior year. Elevated levels of exceptional dispatch unit commitment were driven by an increase in transmission related exceptional dispatches. The most frequent reason given for transmission related exceptional dispatches was to address planned transmission outages.

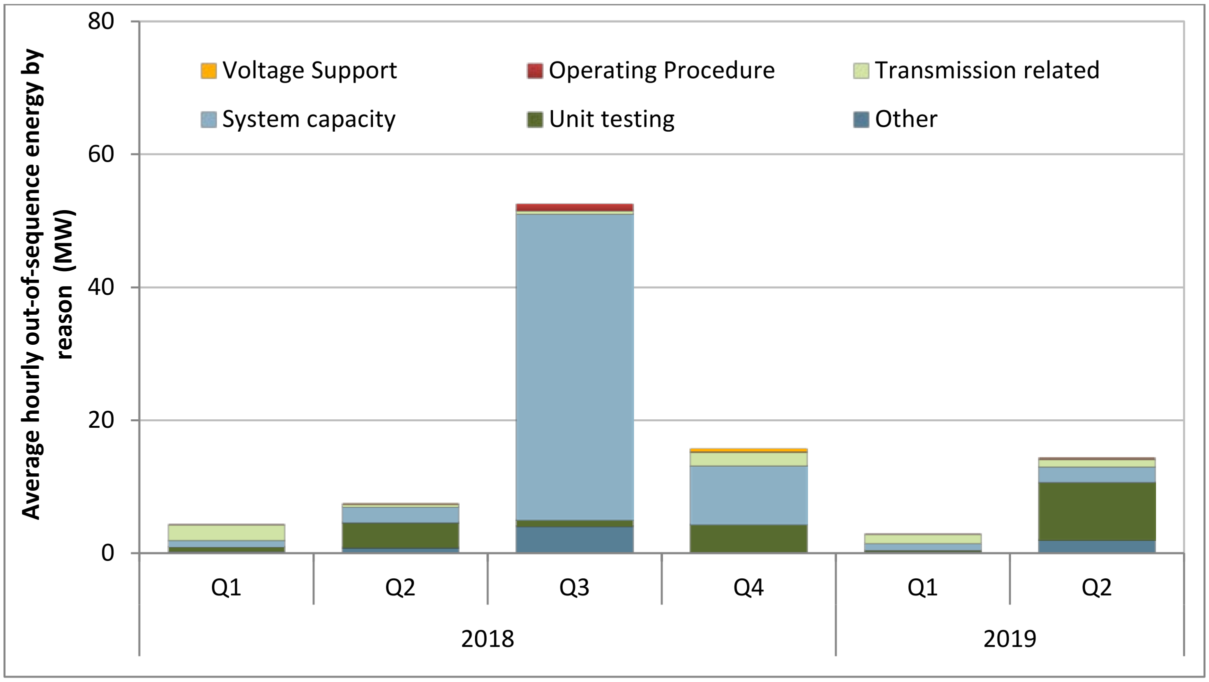
Figure 1.34 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch more than quintupled in this quarter compared to the same quarter in 2018. As previously illustrated in Figure 1.33, about 27 percent of this exceptional dispatch energy was out-of-sequence, meaning the bid price (or default energy bid if mitigated, or if the resource did not submit a bid) was greater than the locational market clearing price. Figure 1.35 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2018 and 2019. Most of the out-of-sequence energy in the second quarter was exceptionally dispatched for unit testing purposes.

Figure 1.35 Out-of-sequence exceptional dispatch energy by reason



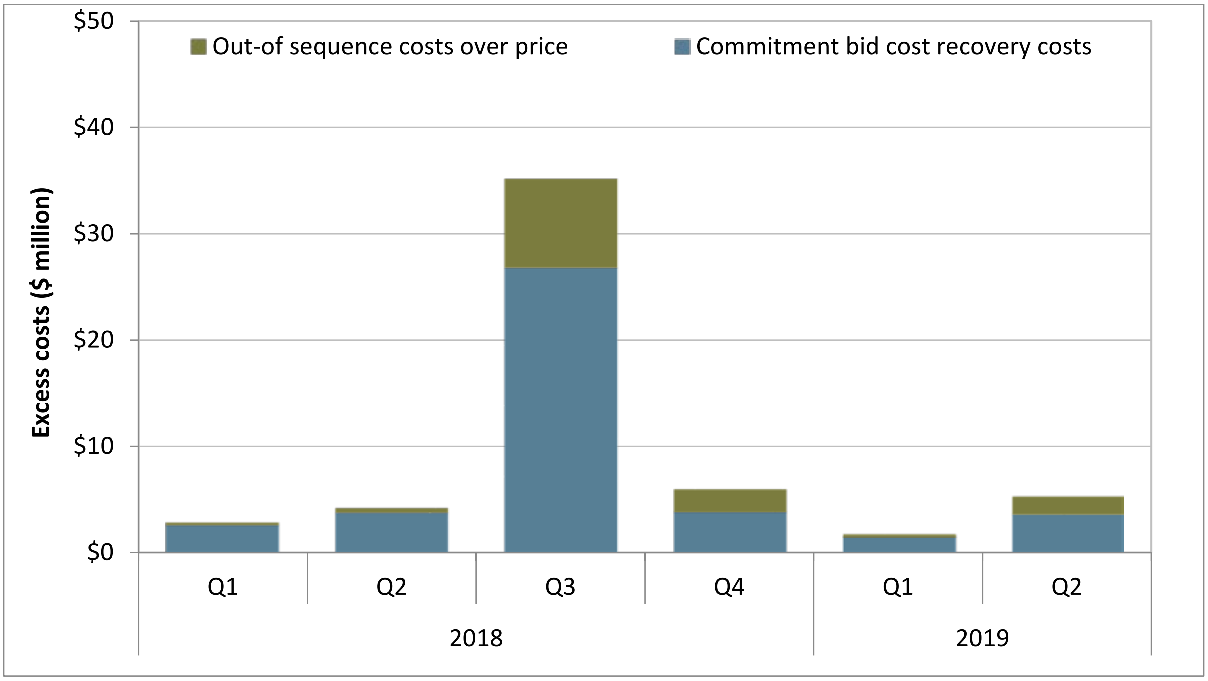
Exceptional dispatch costs

Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

- Units committed through exceptional dispatch that do not recover their start-up and minimum load bid costs through market sales can receive bid cost recovery for these costs.
- Units exceptionally dispatched for real-time energy out-of-sequence may be eligible to receive an additional payment to cover the difference in their market bid price and their locational marginal energy price.

Figure 1.36 shows the estimated costs for unit commitment and additional energy resulting from exceptional dispatches in excess of the market price for this energy. In the second quarter, out-of-sequence energy costs were $1.7 million, while commitment costs for exceptional dispatch paid through bid cost recovery were $3.6 million.

Figure 1.36 Excess exceptional dispatch cost by type



Manual dispatch on the interties

Exceptional dispatches on the interties are referred to by the ISO operators as *manual dispatches*. DMM, in previous annual reports, cautioned when the ISO procures imports out-of-market at prices higher than the 15-minute price paid for other imports that this can encourage economic and physical withholding of available imports.[22] DMM also recommended that the ISO improve its logging of manual dispatches to ensure proper settlement and allow tracking and monitoring. In 2018, the ISO implemented improved procedures, training and logging which appear to have been effective at ensuring proper settlement and allowing better tracking and monitoring of manual dispatches of imports.

In the first quarter, there were 37 instances of manual dispatches totaling about 4,900 MWh. All but three instances (totaling 425 MWh) were associated with emergency assistance to another balancing authority. The non-emergency assistance manual dispatches occurred on one day and one hour, January 12, 2019, for hour-ending 19. Emergency assistance manual dispatches occurred on 12 days and the hours ranged throughout the day. The greatest manual dispatch level was in hour-ending 10, totaling nearly 900 MWh, of which 640 MWh were on May 1, 2019.

In the second quarter, the number of instances of manual dispatches decreased; however, the total dispatch levels increased. There were 17 instances of manual dispatches on the ties which accounted for about 5,100 MWh. Nearly 60 percent of these were export dispatches for emergency assistance to another balancing authority. These occurred on nine days and typically in morning and evening ramp hours. Non-emergency assistance manual dispatches occurred on only three days in June (10, 11, 12) in hours-ending 17 to 21. In total, hour-ending 21 experienced the highest amount of manual dispatches

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22 *2017 Annual Report on Market Issues and Performance*, pp.206-207: http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf

for the quarter with emergency and non-emergency manual dispatch at 510 MWh and 1,250 MWh, respectively.

1.15 Congestion revenue rights

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.

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

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 cause ratepayers, who ultimately pay for the transmission, to receive less than the full value of their day-ahead transmission rights.

In the ten years since the start of the congestion revenue rights auction in 2009, auction revenues from rights sold in the auction have consistently been well below the congestion revenues paid out to entities purchasing these rights. Through 2018, transmission ratepayers have lost about $860 million in congestion revenues paid out in excess of revenues received from the auction. This represents only about 50 cents in auction revenues for every dollar paid to congestion revenue rights holders. Most of these profits have been received by financial entities that do not sell power or serve load in the ISO.[24]

Congestion revenue rights auction modifications

In 2016, DMM began recommending the ISO modify or eliminate the congestion revenue rights auction to reduce the losses to transmission ratepayers from congestion revenue rights sold in the auction. In 2018, the ISO proposed several changes to the congestion revenue rights auction design in order to reduce the systematic losses which have occurred from congestion revenue rights sold in the auction.

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

[24] A more detailed discussion of congestion revenue rights is provided in DMM's *2018 Annual Report on Market Issues and Performance* (pp.197-205). http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

- **Track 1A.** The first major change significantly reduces the number and pairs of nodes at which congestion revenue rights can be purchased in the auction.[25] This change was designed to limit rights sold in the auction to pairs of nodes at which physical generation and load is located, which in some cases may be purchased as hedge for actual sales and trading of energy.

- **Track 1B.** The second major change limits the net payments to congestion revenue right holders if payments to congestion revenue rights exceed associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis.[26]

These tariff changes were implemented by the ISO beginning with the annual and monthly auctions for 2019.

Congestion revenue right auction returns

Auctioned congestion revenue rights profitability or ratepayer losses are calculated as payments received by buyers of auctioned rights less the auction price and estimated offsets charged to auctioned congestion revenue rights. Based on this framework, ratepayers lost about $6.6 million during the second quarter of 2019 as payments to auctioned congestion revenue rights holders exceeded auction revenues. This compares to average losses of $18 million in the second quarter of the prior three years. As shown in Figure 1.37, auction revenues were 74 percent of payments made to non-load-serving entities during the second quarter of 2019, up from 57 percent during the same quarter in 2018.

Financial entities (which do not schedule or trade physical power or serve load) continued to have the highest profits among the entity types, at approximately $7.6 million. This was a decrease from $12.5 million profits during the second quarter of 2018. Energy marketers lost about $1.2 million, down from over $4 million profit during the same quarter in 2018. Generators' profits were about $0.2 million compared to $1.7 million in the second quarter of 2018.

The reduction in losses from the congestion revenue rights in the auction in the second quarter was due to a combination of at least three factors:

- Changes implemented by the ISO in 2019 which limit the source and sink of congestion revenue rights that can be purchased in the auction (Track 1A).[27]

- Changes in the settlement of congestion revenue rights implemented in 2019 (Track 1B).

- A significant drop in the impact and direction of congestion on day-ahead prices compared to Q2 in prior years.

The impact of Track 1A changes limiting the types of congestion revenue rights sold in the auction cannot be directly quantified. However, based on current settlement records, DMM estimates that changes in the settlement of congestion revenue rights made under Track 1B reduced losses to transmission ratepayers from sales of congestion revenue rights by about $5.5 million. A more detailed

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[25] See *FERC Order on Tariff Amendment - Congestion Revenue Rights Auction Efficiency Track 1A,* April 11, 2018*:* http://www.caiso.com/Documents/Apr11_2018_TariffAmendment-CRRAuctionEfficiencyTrack1A_ER18-1344.pdf

[26] See *FERC Order on Tariff Amendment - Congestion Revenue Rights Auction Efficiency Track 1B,* November 9, 2018*:* http://www.caiso.com/Documents/Nov9-2018-OrderAcceptingTariffRevisions-CRRTrack1BModification-ER19-26.pdf

[27] An explanation of these changes is available in DMM's *2018 Annual Report on Market Issues and Performance*, Section 8.4, available here: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

description of these Track 1B changes and how the impact of these changes is estimated is provided in a later section of this report.

The impact of the drop in congestion and change in congestion patterns in 2019 on transmission ratepayer losses from congestion revenue rights in the second quarter cannot be directly quantified. However, as shown by Figure 1.21 and Figure 1.22 in the section of this report on congestion, there was a very significant drop in the impact and direction of congestion on day-ahead prices compared to the same quarter in 2018.[28]

As shown in Figure 1.21, day-ahead congestion drove average prices in the PG&E area down by about $0.90/MWh in the second quarter of 2018, compared to about $0.13/MWh in the second quarter of this year. In the SCE area, congestion drove average day-ahead prices up by about $0.80/MWh in the second quarter of 2018 compared to about $0.10/MWh in the second quarter of this year.

The significant drop in congestion during the second quarter of 2019 compared to prior years is also reflected in Figure 1.37 and Figure 1.38. Prior to offset adjustments related to Track 1B of about $5.5 million, payments to auctioned rights holders totaled about $31.2 million in the second quarter of 2019. This is about 27 percent lower than the average of about $43 million in the second quarter of each of the prior four years (2015-2018).

28 See Figure 1.21 and Figure 1.22 on page 28 of this report.

Figure 1.37 Auction revenues and payments to non-load-serving entities

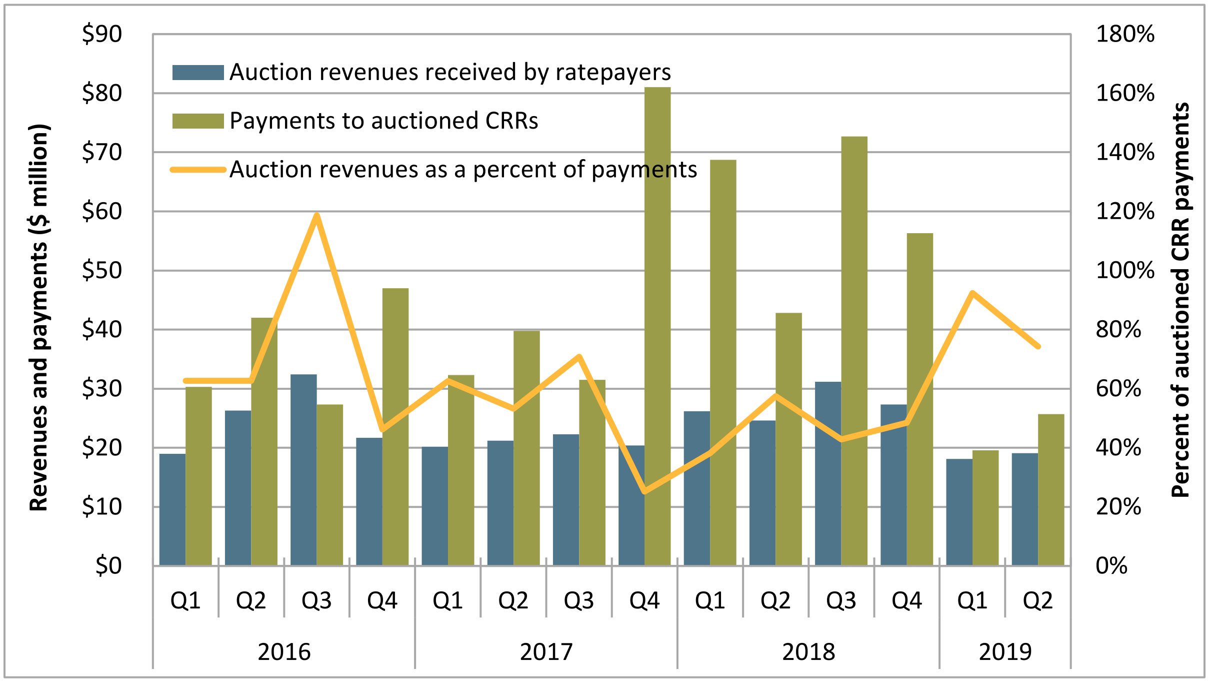
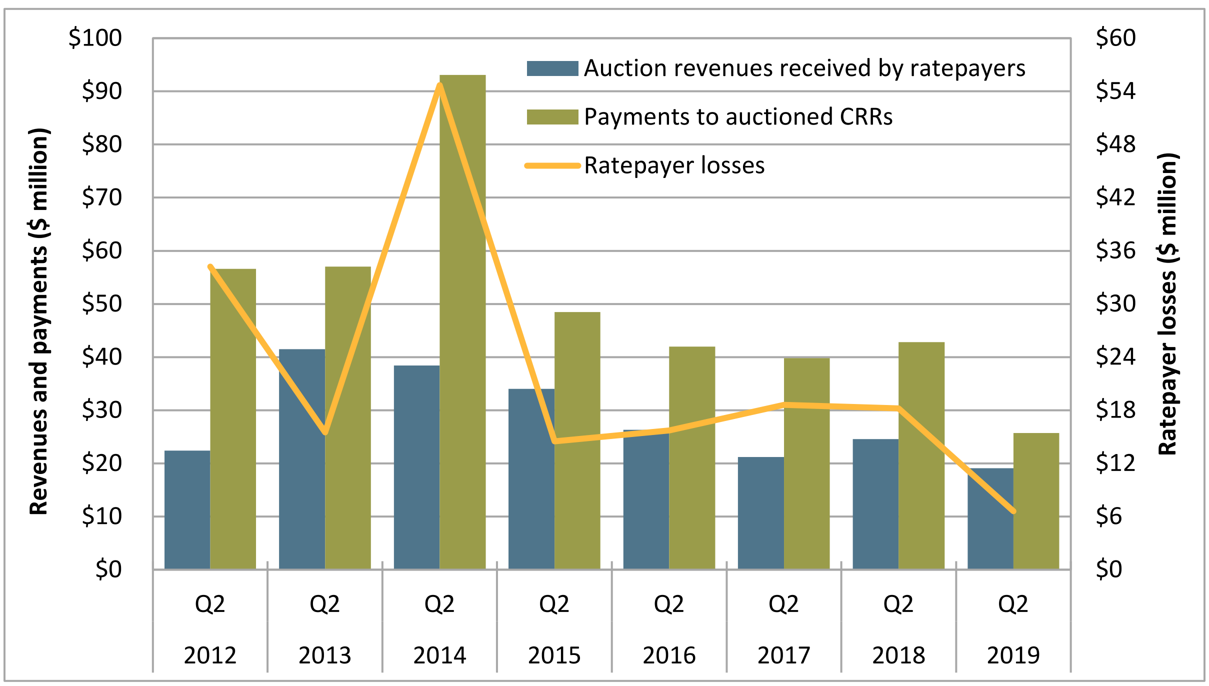


Figure 1.38 Q2 auction revenues and payments to non-load-serving entities (2012-2019)



Impact of Track 1B changes

Under changes made under the ISO's Track 1B filing, starting on January 1, 2019, congestion revenue rights are paid only up to the amount of congestion rent actually collected on the constraints underlying the congestion revenue right source and sink marginal congestion components (MCC). The total congestion revenue rights payments, netted by scheduling coordinator from each constraint, are calculated over the month. The total congestion rent is calculated by constraint and compared to the total congestion revenue rights payments across all scheduling coordinators from the constraint. If the congestion revenue rights payments are greater than the congestion rent collected for a constraint, the difference is charged as an offset to the scheduling coordinators with net positive flows on the constraint.

Based on current settlement records, DMM estimates that the changes made under Track 1B described above reduced losses to transmission ratepayers from sales of congestion revenue rights by about $5.5 million.

1.16 Flexible ramping product

Background

The flexible ramping product is designed to enhance reliability and market performance by procuring flexible ramping capacity in the real-time market to help manage volatility and uncertainty of real-time imbalance demand. The amount of flexible capacity the product procures is derived from a demand curve which reflects a calculation of the optimal willingness-to-pay for that flexible 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 violation costs.

The flexible ramping product procures both upward and downward flexible capacity, in both the 15-minute and 5-minute markets. 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 three 5-minute market runs with that 15-minute interval. Procurement in the 5-minute market is aimed at ensuring that enough ramping capacity is available to manage differences between consecutive 5-minute market intervals.

Market outcomes for flexible ramping product

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

Figure 1.39 shows the percent of intervals that the system-level flexible ramping demand curve bound and had a positive shadow price in the 15-minute market. In the second quarter, there was an increased frequency in binding shadow prices. The 15-minute market system-level demand curves bound in around 10 percent of intervals in the upward direction and 4 percent of intervals in the downward direction during the quarter. In the 5-minute market, the system-level demand curves bound in less than 0.2 percent of intervals in each direction.

Figure 1.39 Monthly frequency of positive 15-minute market flexible ramping shadow price

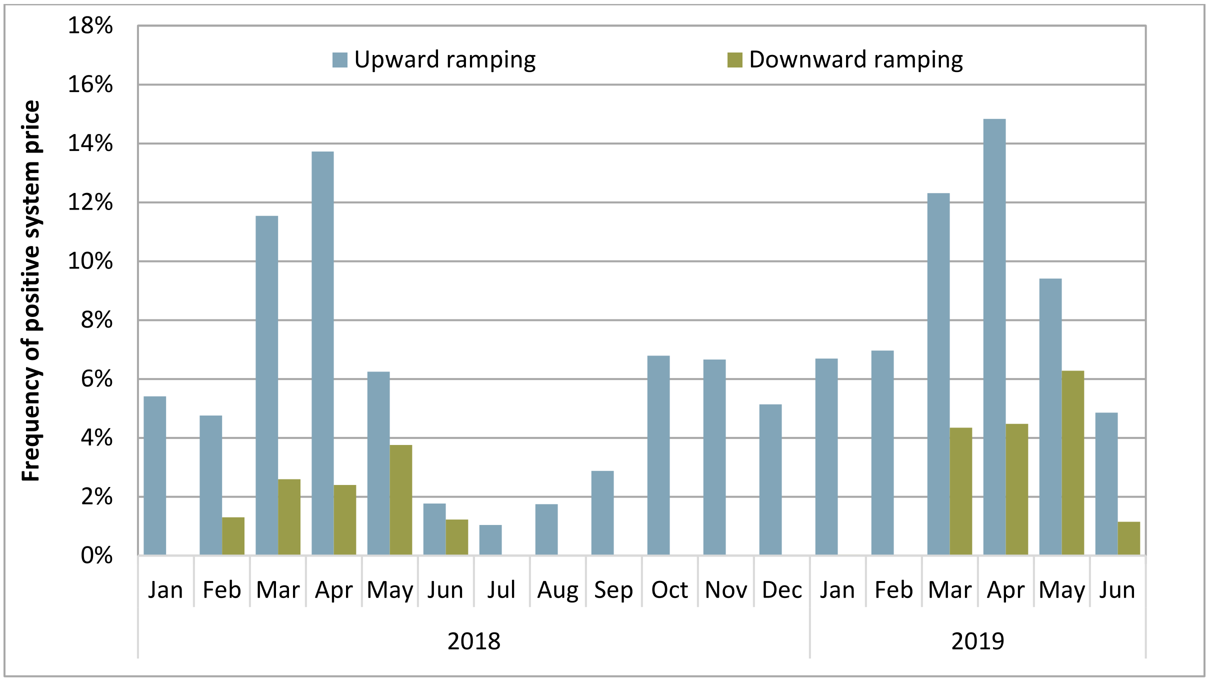


Figure 1.40 shows the hourly average amount of flexible ramping capacity procured in the 15-minute market during the second quarter. This capacity may have been procured to satisfy system-level demand, area-specific demand, or both. The positive bars show procurement for upward flexible ramping capacity, and the negative bars show procurement for downward flexible ramping capacity. The hourly procurement profile is very similar to the profile of the system-level demand curves, and reflects that most of the flexible ramping capacity was procured to meet system-level uncertainty needs. Overall, the market procured an hourly average of about 1,050 MW of upward ramping capacity and 1,040 MW of downward capacity in the 15-minute market during the second quarter.

Figure 1.41 shows the same information for flexible ramping capacity procured in the 5-minute market. During the quarter, system uncertainty requirements (and many of the BAA-specific uncertainty requirements) were high for hour-ending one in the 5-minute market. This is the result of a data issue which impacted particular net load error observations used in the uncertainty calculation. These observations dropped out of the historical uncertainty distributions in June. The higher requirements did not have a large impact on market outcomes as the flexible ramping demand curves were rarely binding in hour-ending one as flexible ramping capacity was typically readily available during this hour.

Figure 1.40 Hourly average flexible ramping capacity procurement in 15-minute market (April – June)

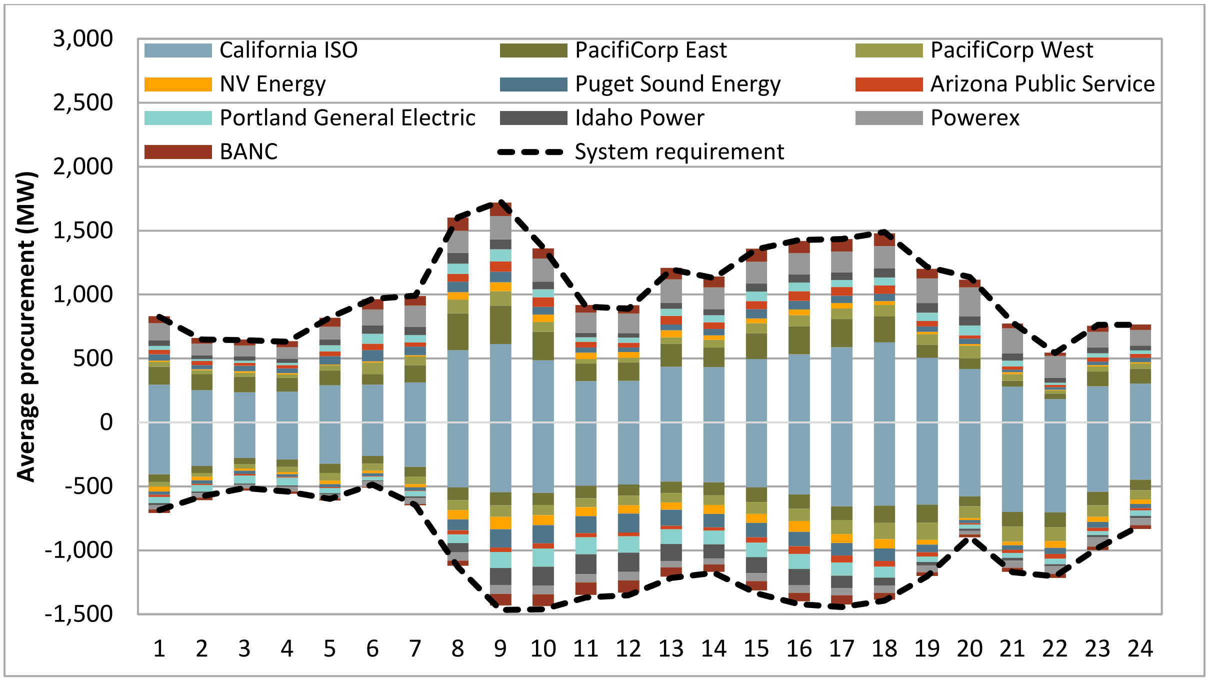
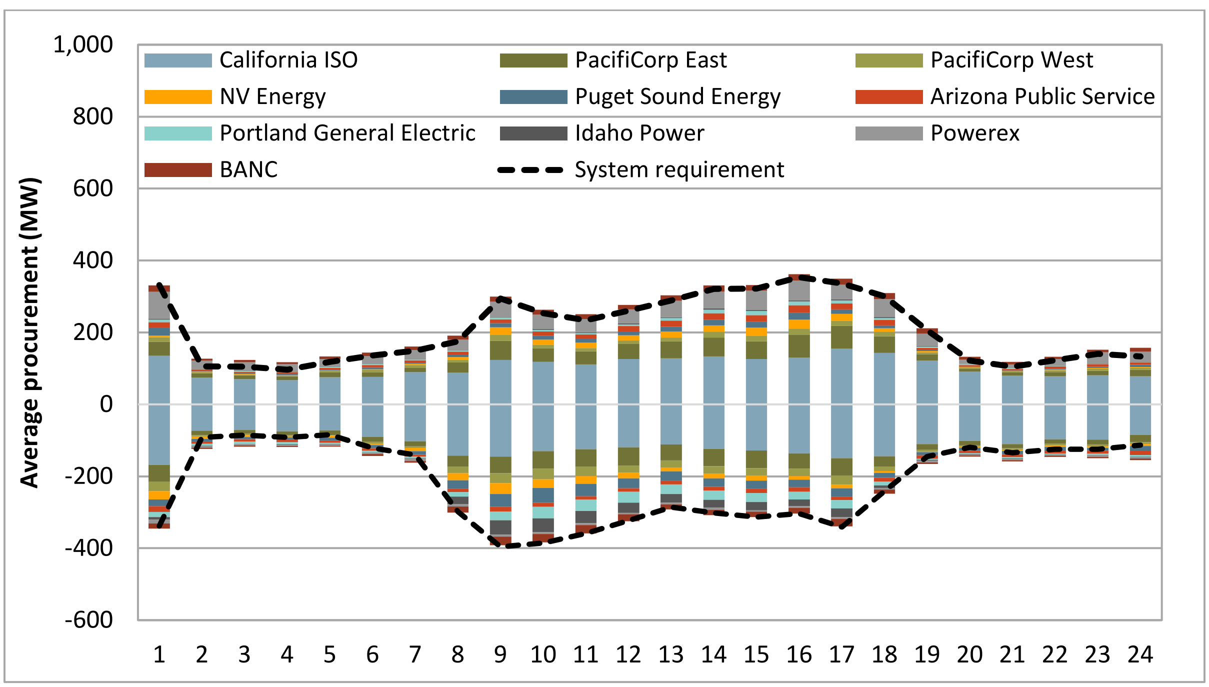


Figure 1.41 Hourly average flexible ramping capacity procurement in 5-minute market (April – June)



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 was also used to pay or charge for forecasted 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 forecast to decrease output was charged the upward flexible ramping price and paid the downward flexible ramping price.[29]

Figure 1.42 shows the total net payments to generators for flexible ramping capacity from the flexible ramping product by month. 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 forecast movements are not included.

Total net payments to generators in the ISO and energy imbalance market areas for providing flexible ramping capacity were around $2.1 million, similar to the previous quarter. Total payments to generators in the ISO were around $0.8 million, compared to $1.3 million for the energy imbalance market areas outside of the ISO. Net payments to NV Energy for flexible ramping capacity were negative during the second quarter.[30]

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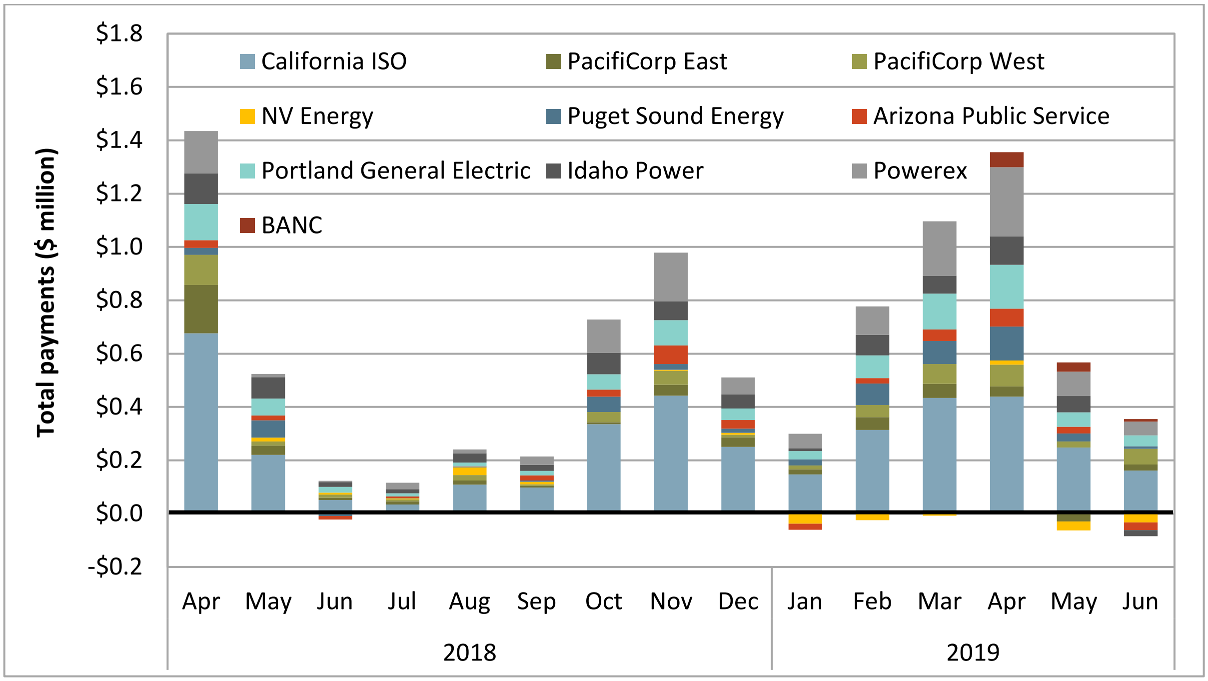
29 More information about the settlement principles can be found in the ISO's *Revised Draft Final Proposal for the Flexible Ramping Product*, December 2015: http://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

30 Flexible ramping capacity is settled as the sum of: (1) the 15-minute market uncertainty award times the combined system and area-specific 15-minute market shadow price, and (2) the *incremental* 5-minute market uncertainty award times the combined system and area-specific 5-minute market shadow price. A negative incremental award from the 15-minute market to the 5-minute market can contribute to negative net payments.

Figure 1.42 Monthly flexible ramping payments by balancing area



2 Energy imbalance market

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

- The Balancing Authority of Northern California (BANC) joined the energy imbalance market on April 3, 2019. BANC participates in the market with the Sacramento Municipal Utility District as a member within the balancing area.
- The ISO implemented an enhancement on May 6, 2019, which evaluates sufficiency test results and potentially limits transfers on a 15-minute interval basis rather than for the entire hour. This decreased the frequency in which energy imbalance market areas failed the upward or downward sufficiency test.
- Export transmission capacity from Powerex and Portland General Electric toward the ISO was often limited in both the 15-minute and 5-minute markets. Export limits from Powerex toward the ISO were set to zero during 97 percent of 15-minute market intervals and 93 percent of 5-minute market intervals. Similarly, export limits from Portland General Electric toward the ISO were set to zero during 78 percent of 15-minute intervals and 92 percent of 5-minute intervals during the quarter.
- The enhancement for the load conformance limiter significantly reduced the frequency in which the conformance limiter triggered for under-supply conditions for Arizona Public Service during the second quarter. Instead, prices for the Arizona Public Service area were often set at the $1,000/MWh penalty parameter in these instances.
- In November 2018, the ISO implemented a revised energy imbalance market greenhouse gas bid design, addressing concerns that the previous design did not capture the full impact of energy imbalance market imports into California on global greenhouse gas emissions for compliance with California's cap-and-trade regulation. Following implementation of these changes, which limited greenhouse gas bid capacity to the differences between base schedule and energy dispatch, the weighted average greenhouse gas cost increased as the deemed delivered resources shifted from lower to higher greenhouse gas emissions.

2.1 Energy imbalance market performance

Energy imbalance market prices

The Balancing Authority of Northern California (BANC) joined the energy imbalance market on April 3, 2019. BANC participates in the market with the Sacramento Municipal Utility District as a member within the balancing area. Prices in the BANC area tracked very similarly to prices in the ISO as a result of significant transfer capability and little congestion between the areas.

Figure 2.1 and Figure 2.2 show real-time prices for the energy imbalance market between April 3 and June 30, 2019. Several balancing areas were grouped together because of similar average hourly pricing. The figures also show prices at the Pacific Gas and Electric default load aggregation point as a point of comparison.

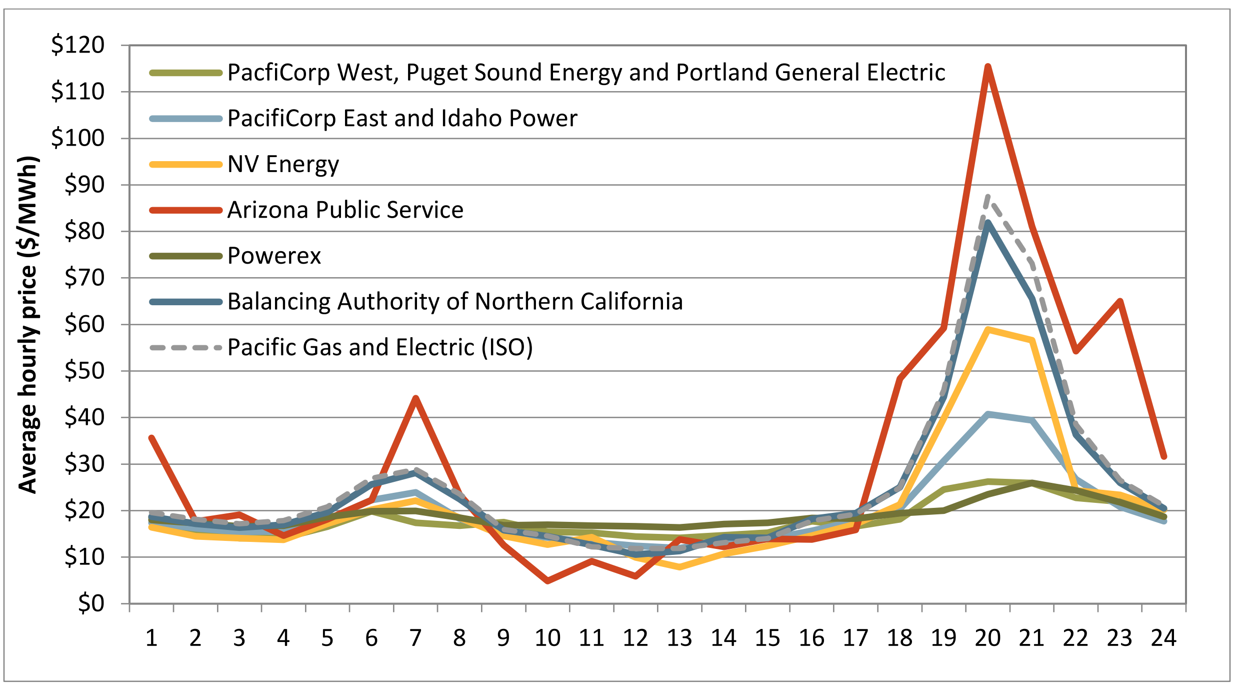
During peak system load hours, prices in the Northwest region including PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex were regularly lower than those in the ISO and other balancing areas because of limited transfer capability out of this region. Further, prices in the Powerex area were often different from prices in ISO and the other Northwest areas as a result of very limited transfer capability into or out of the area during the second quarter.

Prices in PacifiCorp East and Idaho Power were often similar to each other and lower than prices in the ISO. As shown in Figure 2.1 and Figure 2.2, price separation between these areas and the ISO was most pronounced during peak load hours when transfers from PacifiCorp East and Idaho Power into the ISO hit export limits.

Between April 23 and May 3, the ISO declared a separation of NV Energy from the market. This occurred as a result of a planned transmission outage. During this period, energy imbalance market transfers associated with NV Energy were locked, and prices in NV Energy were set by administrative pricing.

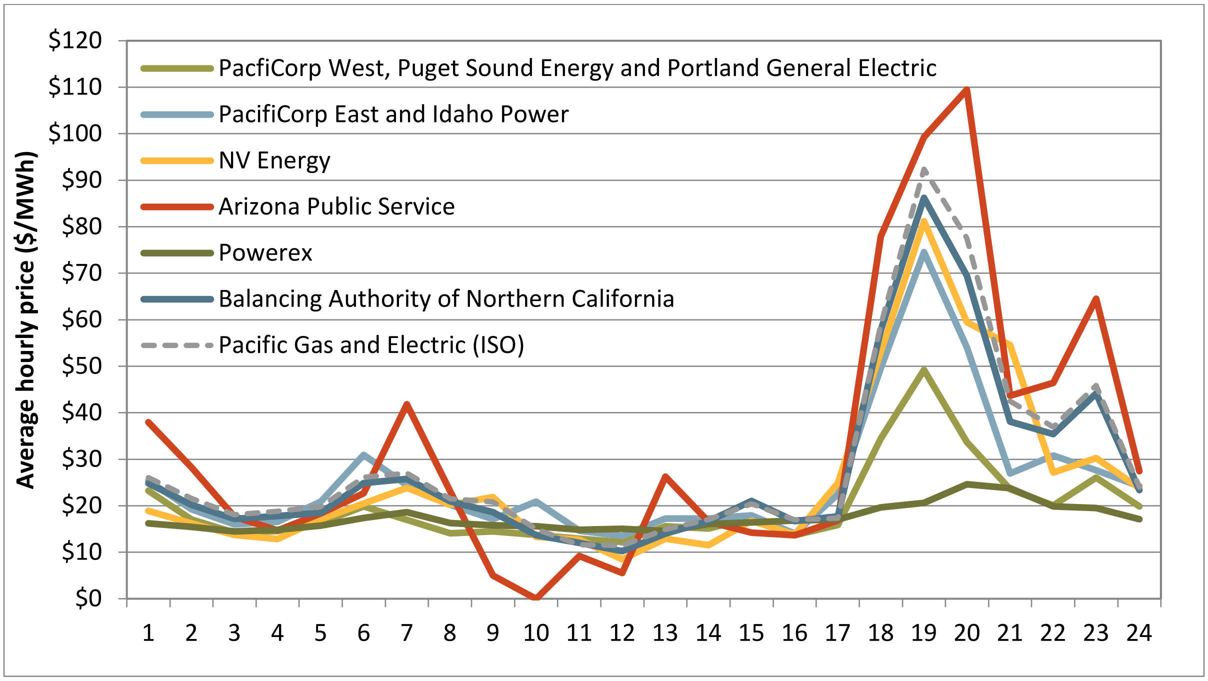
Average real-time prices for Arizona Public Service were significantly higher than prices in the ISO between hours ending 18 and 24. This was mostly due to a number of flexible ramping sufficiency test failures and subsequent under-supply power balance constraint relaxations. The majority of these infeasibilities were not resolved by the enhanced load conformance limiter and were therefore priced at the penalty parameter of $1,000/MWh.[31]

Figure 2.1 Hourly 15-minute market prices (April 3 – June 30)



[31] See section 2.4 for further details on the load conformance limiter enhancement and its impact.

Figure 2.2 Hourly 5-minute market prices (April – June)



Energy imbalance market wholesale energy cost

In the energy imbalance market, total estimated wholesale cost to serve load, excluding the ISO, was about -$2 million or -$0.02/MWh in the second quarter of 2019, a decrease from about $9 million or $0.15/MWh in the same quarter of 2018.

As shown in Figure 2.3 and Table 2.1, real-time energy costs contributed the largest portion of the costs, while imbalance offset costs typically reduced costs overall. Real-time energy costs per megawatt-hour of total load decreased by about 42 percent from the same quarter in 2018, while imbalance offset and other costs remained about the same. In the energy imbalance market, offset costs paid to non-California balancing areas include payments to offset greenhouse gas cap-and-trade obligations incurred due to market dispatch.

Figure 2.3 Total EIM quarterly wholesale costs per MWh of load

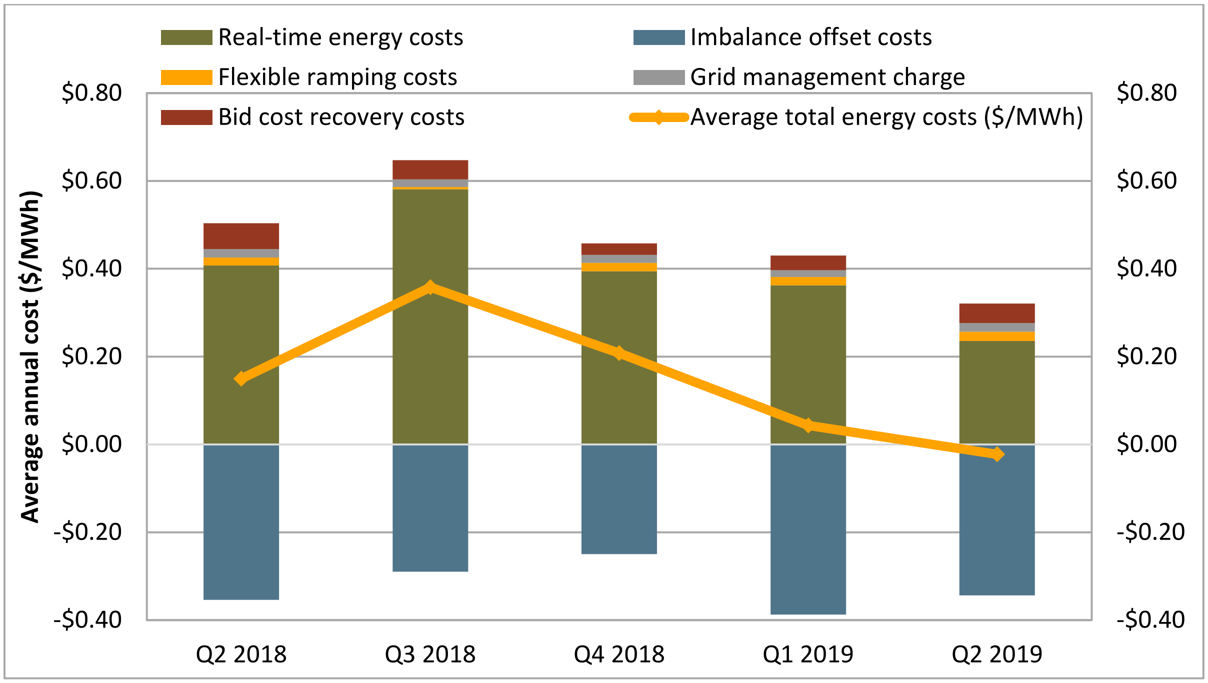


Table 2.1 Estimated average EIM wholesale energy costs per MWh

	Q2 2018	Q3 2018	Q4 2018	Q1 2019	Q2 2019	Change Q2 2018-Q2 2019
Real-time energy costs	$ 0.41	$ 0.58	$ 0.39	$ 0.36	$ 0.24	$ (0.17)
Imbalance offset costs	$ (0.35)	$ (0.29)	$ (0.25)	$ (0.39)	$ (0.34)	$ 0.01
Flexible ramping costs	$ 0.02	$ 0.00	$ 0.02	$ 0.02	$ 0.02	$ 0.00
Grid management charge	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.00
Bid cost recovery costs	$ 0.06	$ 0.04	$ 0.03	$ 0.03	$ 0.04	$ (0.01)
Average total energy costs ($/MWh)	**$ 0.15**	**$ 0.36**	**$ 0.21**	**$ 0.04**	**$ (0.02)**	**$ (0.17)**

2.2 Flexible ramping sufficiency test

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

If an area fails the upward sufficiency test, energy imbalance market transfers into that area cannot be increased.[32] Similarly, if an area fails the downward sufficiency test, transfers out of that area cannot be increased. An area will also fail the flexible ramping sufficiency test for when the capacity test fails for the specific direction. The capacity test is a test designed to ensure that there are sufficient incremental or decremental economic energy bids above or below the base schedules to meet the demand forecast.[33]

The flexible ramping sufficiency test requires balancing areas to show sufficient ramping capability from the start of the hour to each of the four 15-minute intervals within the hour. Previously, a failure of any of these four 15-minute interval sub-tests would result in a failure of the sufficiency test and limit transfers for the entire hour. The ISO implemented an enhancement on May 6, 2019, which evaluates sufficiency test results and potentially limits transfers on a 15-minute interval basis rather than for the entire hour. This decreased the frequency in which energy imbalance market areas failed the upward or downward sufficiency test.

Figure 2.4 and Figure 2.5 show the percent of *intervals* in which an energy imbalance market area failed the sufficiency test in the upward or downward direction.[34] Since May 6, the figures reflect that the flexible ramping sufficiency test evaluates sufficient ramping capability in 15-minute increments rather than hourly increments. During the quarter, Arizona Public Service failed the upward sufficiency test during 9 percent of intervals during April, compared to around 2 percent of intervals in May and 1 percent of intervals during June.

Failures of the sufficiency test are important because these outcomes limit transfer capability. Constraining transfer capability may 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. Reduced transfer capability also impacts the ability for an area to balance load, as there is less availability to import from or export to neighboring areas. This can result in local prices being set at power balance constraint penalty parameters.

32 If an area fails the upward sufficiency test, net EIM imports (negative) cannot exceed the lower of either the base transfer or optimal transfer from the last 15-minute interval. Similarly, if an area fails the downward sufficiency test, net EIM exports are capped at the higher of either the base transfer or optimal transfer from the last 15-minute interval.

33 *Business Practice Manual for the Energy Imbalance Market*, February 28, 2019, p. 50.

34 Intervals in which an energy imbalance market entity is entirely disconnected from the market (market interruption) are removed.

Figure 2.4 Frequency of upward failed sufficiency tests by month

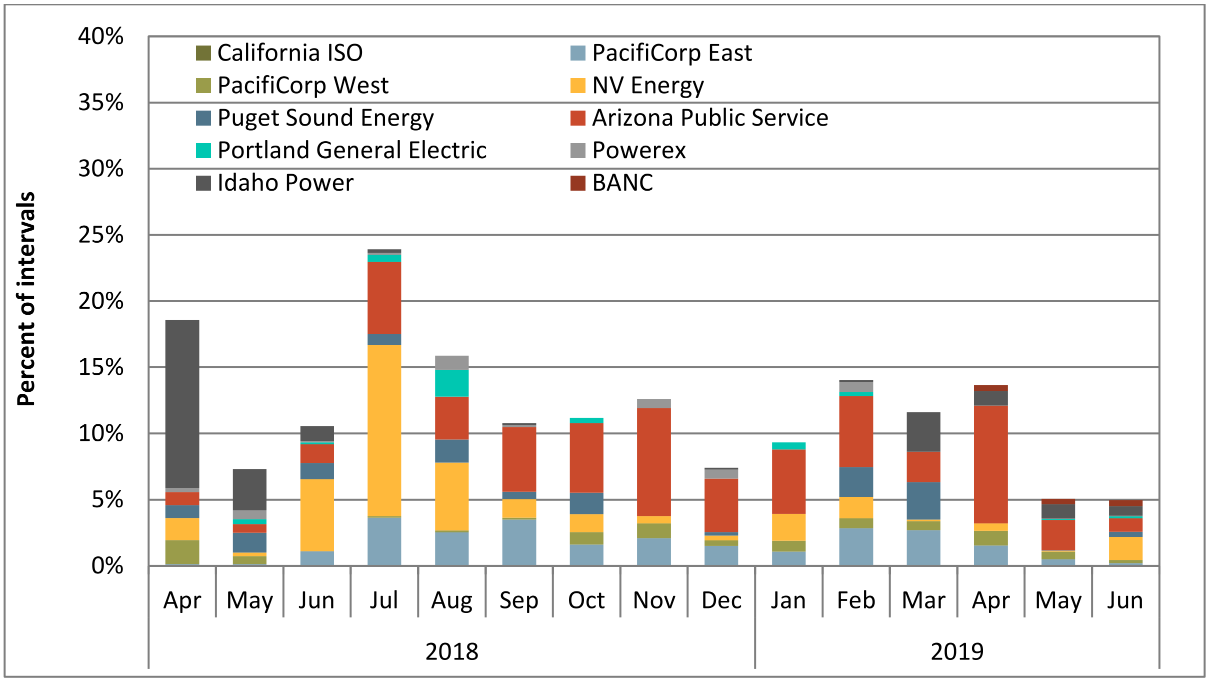
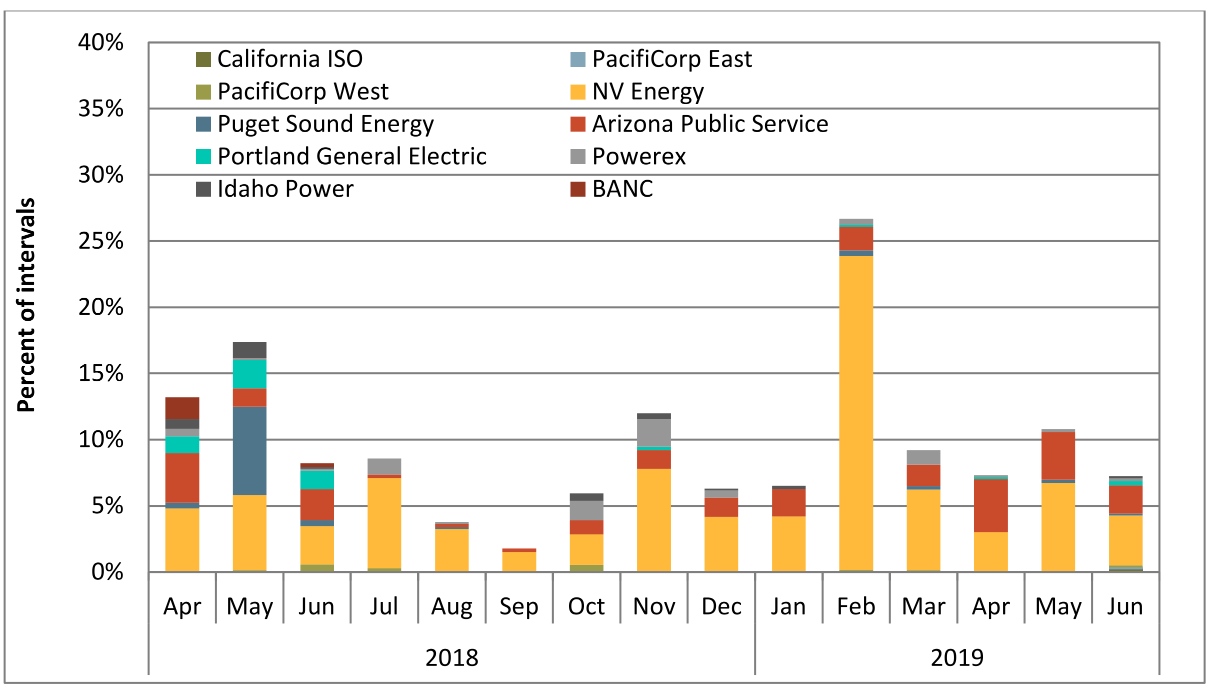


Figure 2.5 Frequency of downward failed sufficiency tests by month

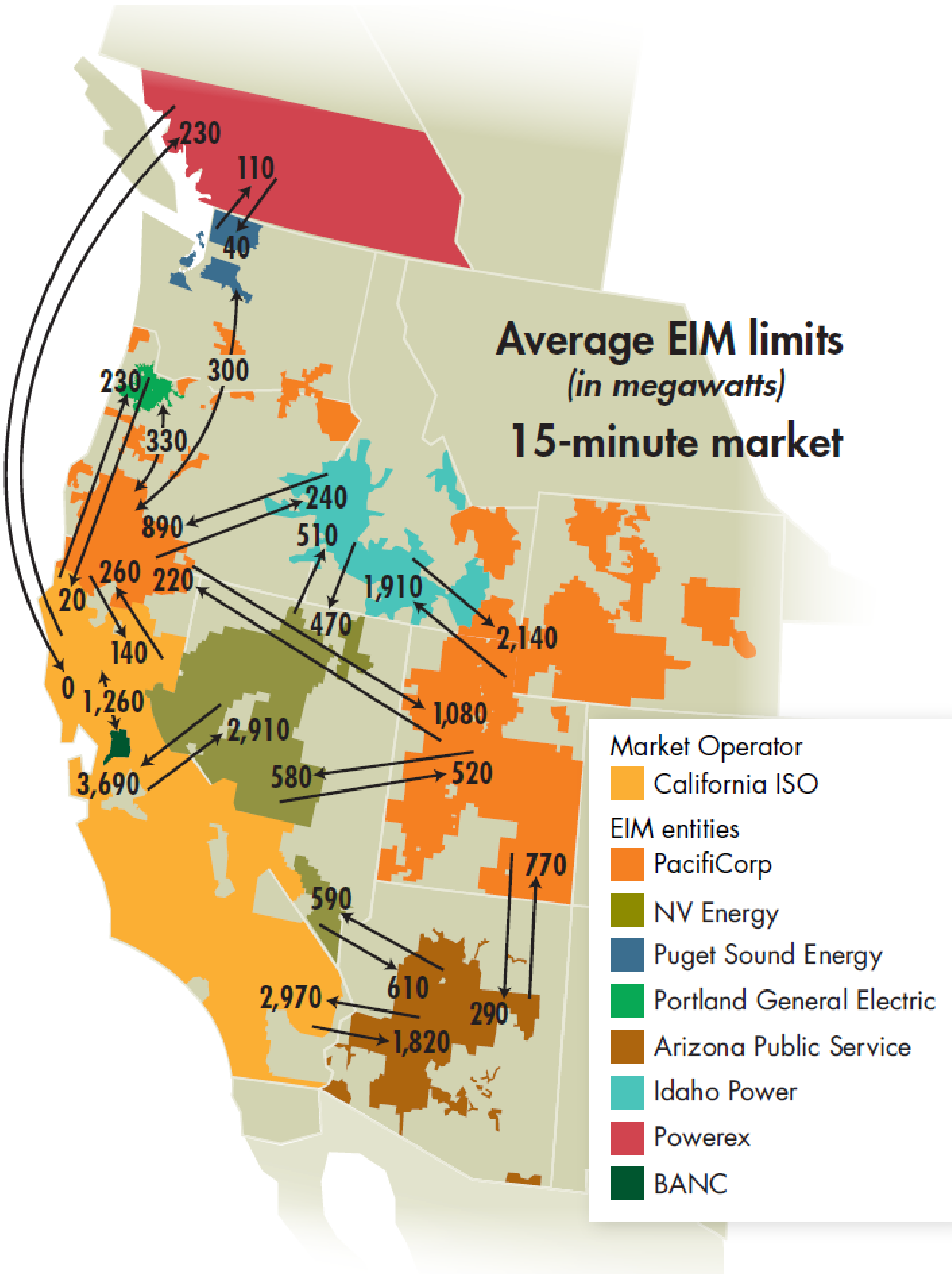


2.3 Energy imbalance market transfers

Energy imbalance market transfer limits

One of the key benefits of the energy imbalance market is the ability to transfer energy between areas in the 15-minute and 5-minute markets. Figure 2.6 shows average 15-minute market limits between each of the energy imbalance market areas between April 3 and June 30, 2019. The map shows that there was significant transfer capability between the ISO, NV Energy, Arizona Public Service, and BANC. Transfer capability between these areas, PacifiCorp East and Idaho Power was lower but still significant. These limits allowed energy to flow between these areas with relatively little congestion. Transfer capability was more limited between the ISO and the Northwest areas which include PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex. In particular, export limits from Powerex toward the ISO were set to zero during 97 percent of 15-minute market intervals and 93 percent of 5-minute market intervals. Similarly, export limits from Portland General Electric toward the ISO were set to zero during 78 percent of 15-minute intervals and 92 percent of 5-minute intervals during the second quarter.

Figure 2.6 Average 15-minute market energy imbalance market limits (April 3 – June 30)



Hourly energy imbalance market transfers

As highlighted in this section, transfers in the energy imbalance market are now marked by distinct daily and seasonable patterns which reflect differences in regional supply conditions and transfer limitations.

Figure 2.7 compares average hourly imports (negative values) and exports (positive values) between the ISO and other energy imbalance market areas during the last five quarters in the 15-minute market.[35] The bars show the average hourly transfers with the connecting areas. The gray line shows the average hourly net transfer.

In the second quarter of 2019, average exports during the middle of the day from the ISO were higher overall compared to both the previous quarter and the second quarter of the previous year. In particular, exports from the ISO towards areas in the Northwest increased from the previous year. The addition of the Balancing Authority of Northern California in the energy imbalance market at the beginning of April also contributed to higher exports from the ISO during the middle of the day. The California ISO exported around 60 MW on average to the BANC area during midday hours between April 3 and June 30.

Figure 2.7 California ISO - average hourly 15-minute market transfer

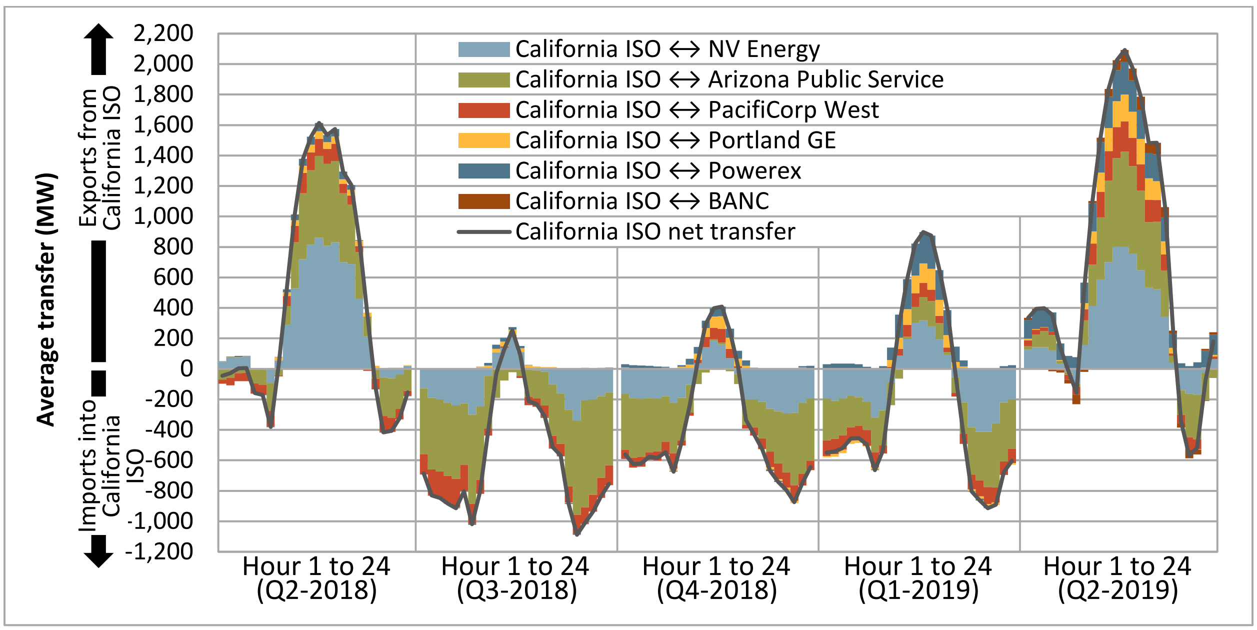


Figure 2.8 through Figure 2.12 show the same information on imports and exports for NV Energy, Arizona Public Service, Idaho Power, PacifiCorp West, and Powerex in the 15-minute market.[36] The amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[37]

35 Average transfers for the second quarter of 2019 include April 3 to June 30 only, and therefore reflect transfers after the Balancing Authority of Northern California joined the energy imbalance market.

36 Figures showing transfer information from the perspective of PacifiCorp East, Puget Sound Energy, Portland General Electric, and BANC are not explicitly included, but are represented in Figure 2.7 through Figure 2.12.

37 Base schedules on EIM transfer system resources are fixed bilateral transactions between EIM entities.

As shown in Figure 2.7, a large portion of the ISO's transfer capability in the energy imbalance market is with NV Energy and Arizona Public Service. Per Figure 2.8 and Figure 2.9, NV Energy and Arizona Public Service in the second quarter were generally net importers during the middle of the day in periods when ISO load net of solar generation was lowest.

Figure 2.10 shows the hourly 15-minute market transfer pattern between Idaho Power and neighboring areas, net of all base schedules. Idaho Power has transfer capacity between PacifiCorp West, PacifiCorp East, and NV Energy. On average during the second quarter, Idaho Power base scheduled around 650 MW in imports from PacifiCorp East and 600 MW in exports to PacifiCorp West. As shown in Figure 2.10, dynamic transfers were much lower during the quarter.

Figure 2.8 NV Energy – average hourly 15-minute market transfer

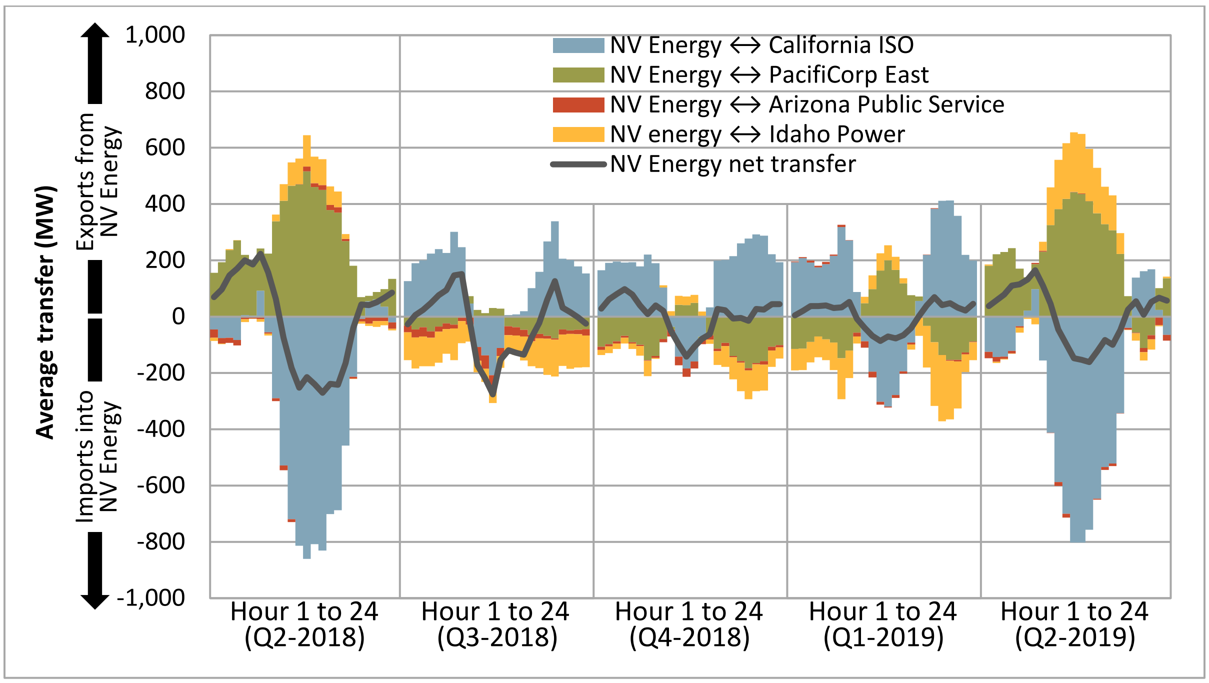


Figure 2.9 Arizona Public Service – average hourly 15-minute market transfer

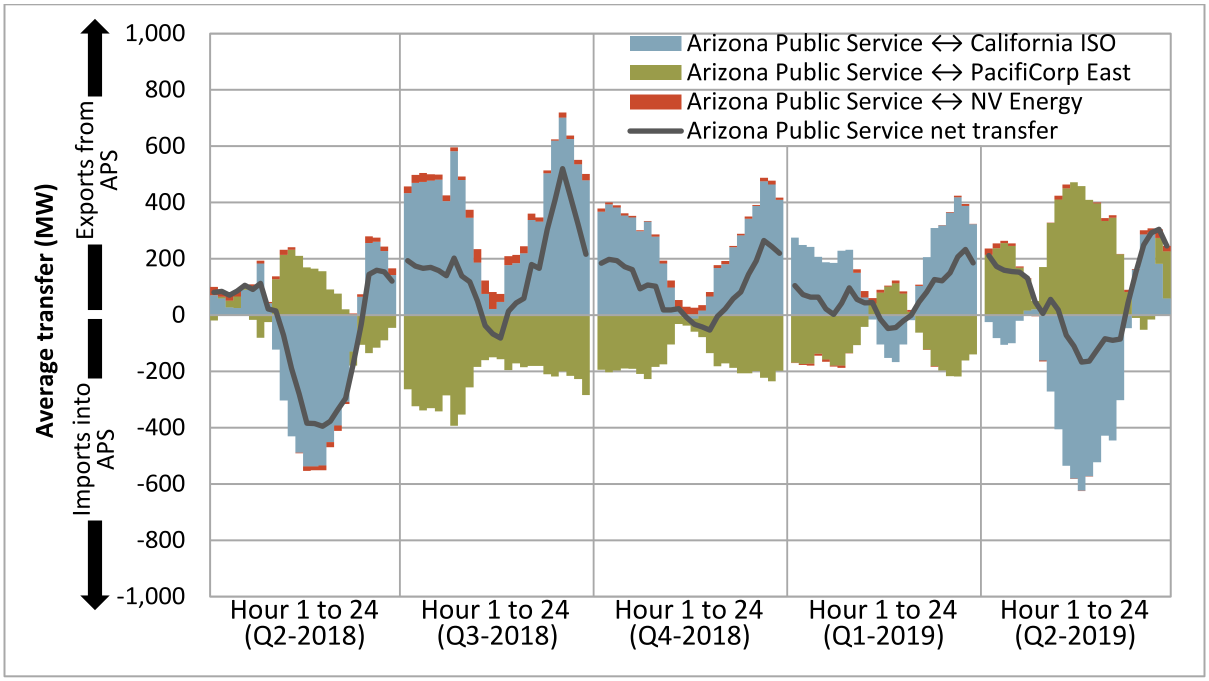


Figure 2.10 Idaho Power – average hourly 15-minute market transfer

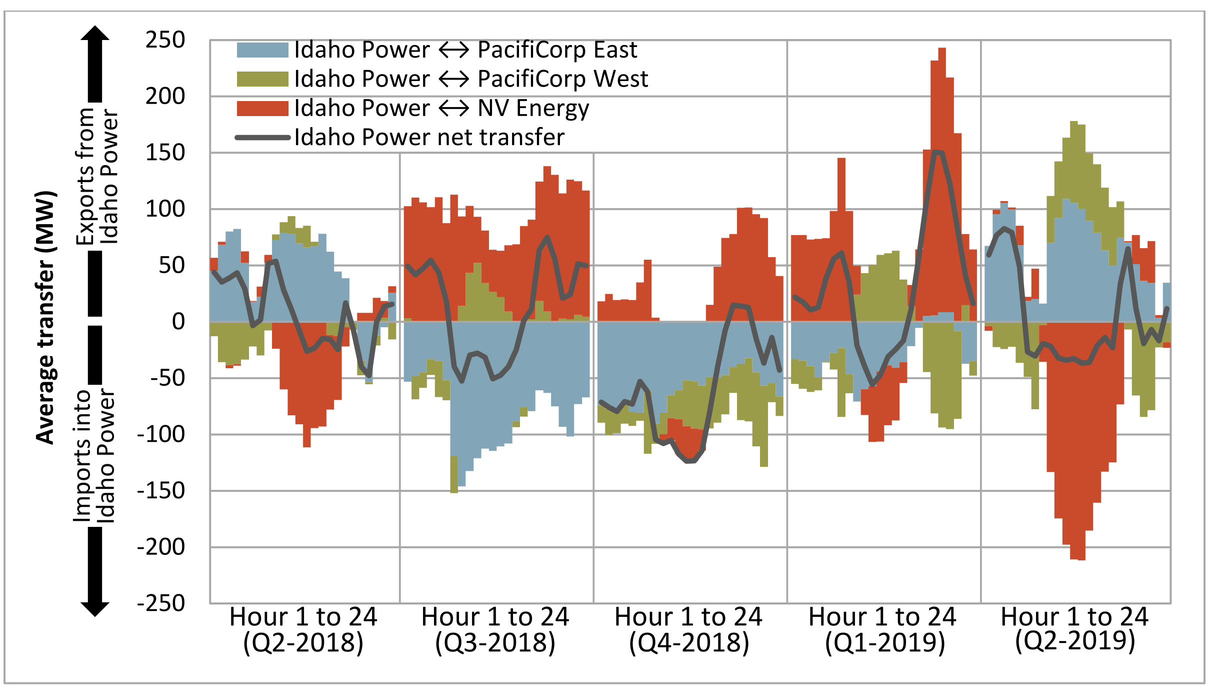


Figure 2.11 shows the hourly 15-minute market transfer pattern between PacifiCorp West and neighboring areas during the last five quarters. PacifiCorp West has transfer capacity between the ISO, PacifiCorp East, Puget Sound Energy, Portland General Electric, and Idaho Power. Similar to previous quarters, most of the transfers with Idaho Power and PacifiCorp East were base scheduled in the market, so therefore fixed. PacifiCorp West base scheduled roughly 1,100 MW in exports to PacifiCorp East on average during the second quarter. However, net of all base schedules, PacifiCorp West imported around 50 MW on average from PacifiCorp East.

Figure 2.12 shows average hourly 15-minute market imports and exports into and out of Powerex. During the second quarter of 2019, export transmission capacity from Powerex toward the ISO was often limited in both the 15-minute and 5-minute markets. Export limits from Powerex toward the ISO were set to zero during 97 percent of 15-minute market intervals and 93 percent of 5-minute market intervals. However, average import limits into the Powerex area from the ISO were roughly 300 MW in midday hours.

Similarly, export limits from Portland General Electric toward the ISO were set to zero during 78 percent of 15-minute intervals and 92 percent of 5-minute intervals during the second quarter. Average import limits into the Portland General Electric area from the ISO were over 200 MW in both the 15-minute and 5-minute markets.

Figure 2.11 PacifiCorp West – average hourly 15-minute market transfer

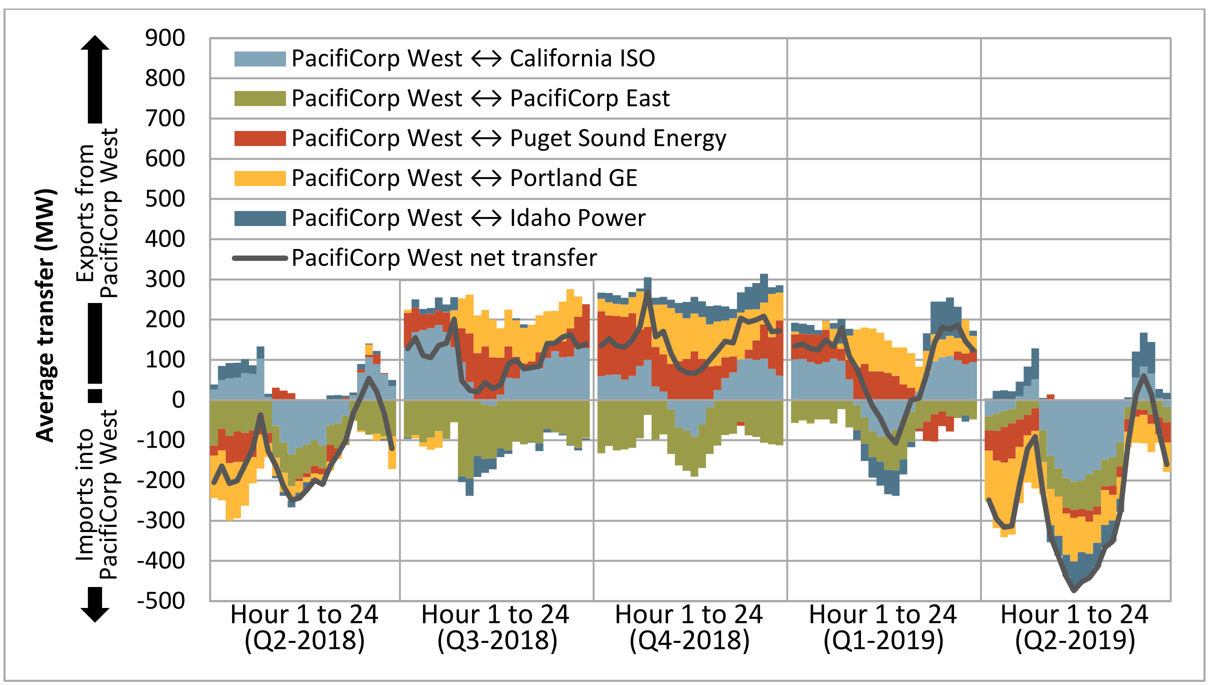
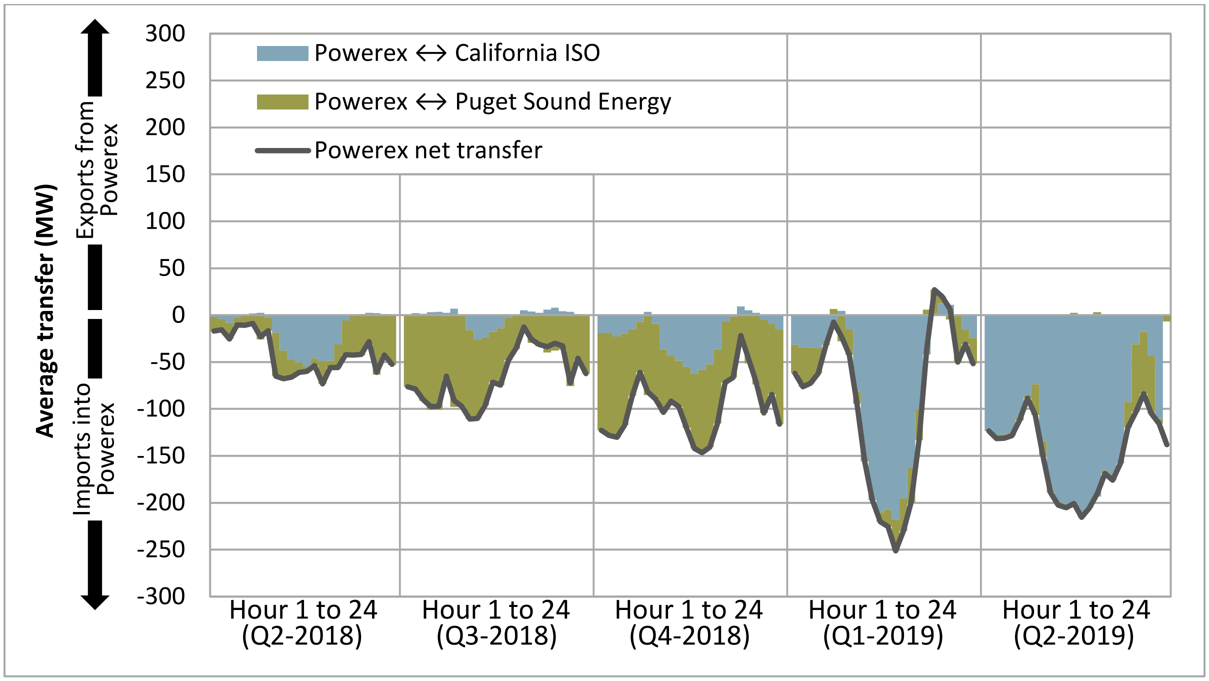


Figure 2.12 Powerex – average hourly 15-minute market transfer



Inter-balancing area congestion

Congestion between an energy imbalance market area and the ISO causes price separation.

Table 2.2 shows the percent of 15-minute and 5-minute market intervals when there was congestion on the transfer constraints into or out of an energy imbalance market area, relative to prevailing system prices in the ISO.[38]

During intervals when there is net import congestion into an energy imbalance market area, the ISO market software triggers local market power mitigation in that area.[39] Table 2.2 includes the frequency in which transfer limits bound from the ISO into the other balancing areas. For example, the highest frequency of such congestion was from the ISO into the Powerex area, during 32 percent of 15-minute market intervals and 42 percent of 5-minute market intervals during the second quarter.

38 Greenhouse gas prices can contribute to lower energy imbalance market prices relative to those inside the ISO. The current methodology uses prevailing greenhouse gas prices in each interval to account for and omit price separation that is the result of greenhouse gas prices only. Intervals in which an energy imbalance market entity is entirely disconnected from the market (market interruption) are removed.

39 Structural market power may exist if the demand for imbalance energy within a balancing area exceeds the transfer capacity into that balancing area from the ISO or other competitive markets.

Table 2.2 Frequency of congestion in the energy imbalance market (April – June 30)

	15-minute market		5-minute market	
	Congested toward ISO	Congested from ISO	Congested toward ISO	Congested from ISO
BANC	2%	2%	2%	2%
NV Energy	3%	1%	3%	1%
Arizona Public Service	3%	4%	2%	2%
PacifiCorp East	4%	7%	2%	5%
Idaho Power	4%	7%	2%	5%
PacifiCorp West	17%	11%	14%	8%
Portland General Electric	23%	10%	20%	6%
Puget Sound Energy	19%	12%	16%	9%
Powerex	21%	32%	34%	42%

As shown in the table, the highest frequency of congestion in the energy imbalance market continued to be from the Northwest areas in the direction toward the ISO. Congestion in the 15-minute market in the direction toward the ISO occurred during roughly 20 percent of intervals from PacifiCorp West, Portland General Electric, Puget Sound Energy and Powerex. In the 5-minute market, the Powerex area was congested toward the ISO more frequently than the other Northwest areas, during around 34 percent of intervals.

Table 2.2 also shows that congestion in either direction between BANC, NV Energy, Arizona Public Service, PacifiCorp East, Idaho Power, or the ISO area was infrequent during the second quarter. Congestion that did occur between these areas was often the result of a failed upward or downward sufficiency test, which limited transfer capability.

2.4 Load adjustments in the energy imbalance market

Frequency and size of load adjustments

Table 2.3 summarizes the average frequency and size of positive and negative load adjustments entered by operators in the energy imbalance market for the 15-minute and 5-minute markets during the second quarter.[40] The same data for the ISO is provided as a point of reference. In particular, Arizona Public Service entered positive load adjustments in around 85 percent of 15-minute and 5-minute intervals, at an average of around 100 MW (or around 3 percent of the area's load). Nearly all energy imbalance market entities had a greater frequency of 5-minute market load adjustments than 15-minute market load adjustments during the second quarter.

[40] Load adjustments are sometimes referred to as *load bias* or *load conformance*. The ISO uses the term *imbalance conformance* to describe this process.

Table 2.3 Average frequency and size of load adjustments (April - June)

	Positive load adjustments			Negative load adjustments			Average hourly adjustment MW
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO							
15-minute market	55%	621	2.5%	3%	-296	1.5%	336
5-minute market	64%	307	1.3%	10%	-225	1.0%	175
PacifiCorp East							
15-minute market	0%	N/A	N/A	15%	-60	1.3%	-9
5-minute market	9%	78	1.5%	48%	-90	1.9%	-36
PacifiCorp West							
15-minute market	0.1%	50	2.2%	8%	-46	2.3%	-3
5-minute market	3%	46	2.2%	35%	-47	2.3%	-15
NV Energy							
15-minute market	1%	122	3.1%	3%	-145	4.2%	-3
5-minute market	9%	75	1.7%	20%	-114	3.1%	-16
Puget Sound Energy							
15-minute market	0.1%	57	2.1%	12%	-32	1.3%	-4
5-minute market	2%	40	1.5%	45%	-34	1.4%	-15
Arizona Public Service							
15-minute market	85%	102	3.1%	7%	-74	2.7%	81
5-minute market	85%	102	3.1%	7%	-73	2.8%	81
Portland General Electric							
15-minute market	0.2%	43	2.0%	0.2%	-68	3.1%	0
5-minute market	20%	24	1.2%	1%	-53	2.4%	4
Idaho Power							
15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
5-minute market	12%	48	2.4%	2%	-57	3.2%	5
BANC							
15-minute market	0.4%	46	2.3%	0.2%	-33	3.0%	0
5-minute market	0.9%	45	2.5%	0.5%	-35	3.1%	0

Load conformance limiter enhancement

The load conformance limiter works the same way in the energy imbalance market as it does in the ISO. It reduces the impact of an excessive load adjustment on market prices when it is considered to have caused a power balance constraint relaxation. Previously, if the operator load adjustment exceeded the size of a power balance constraint and in the same direction, the size of the adjustment was automatically reduced and the price was set by the last economic signal rather than the penalty parameter for the relaxation, for instance the $1,000/MWh price for a shortage. However, there have been instances in which the application of this logic did not appear to reflect actual conditions such as periods when a persistent load conformance across multiple intervals would resolve smaller infeasibilities that did not appear to be caused by the level of load adjustment.

The ISO implemented an enhancement to the load conformance limiter, effective February 27, 2019. With the enhancement, the load conformance limiter triggers by a measure based on the change in load adjustment from one interval to the next, rather than the total level of load adjustment. DMM's monitoring and review of real-time market performance suggests that the enhanced logic for the load conformance limiter is likely to better capture the cause-and-effect relationship between an excessive operator adjustment and an infeasibility. Previous analysis by DMM showed that this change is expected to significantly reduce the frequency in which the limiter triggers.[41]

Figure 2.13 shows the frequency of infeasibilities in the 5-minute market during the second quarter in which the current (enhanced) conformance limiter triggered and/or the previous limiter would have triggered.[42] The green bars represent intervals when the current limiter did not trigger, but would have under the previous approach. For intervals with ramping shortages in this category, the current approach increases prices relative to the previous method since prices would have been set by an economic bid under the previous approach, but were instead set by the $1,000/MWh penalty parameter. The red bars represent intervals when the current limiter triggered, but would not have under the previous approach. These intervals were infrequent during the quarter.

Under current market conditions, the enhancement to the conformance limiter is not expected to have a significant impact on average prices in the ISO. This is because in most intervals when the limiter triggers in the ISO, the highest priced bids dispatched are often at or near the $1,000/MWh bid cap such that the resulting price is often very similar with or without the limiter.

However, the changes to the conformance limiter can have a significant impact on prices for some of the energy imbalance market areas. As shown in Figure 2.13, the enhancement significantly reduced the frequency in which the conformance limiter triggered for under-supply conditions for Arizona Public Service during the second quarter. Instead, prices for the Arizona Public Service area were often set at the $1,000/MWh penalty parameter in these instances.

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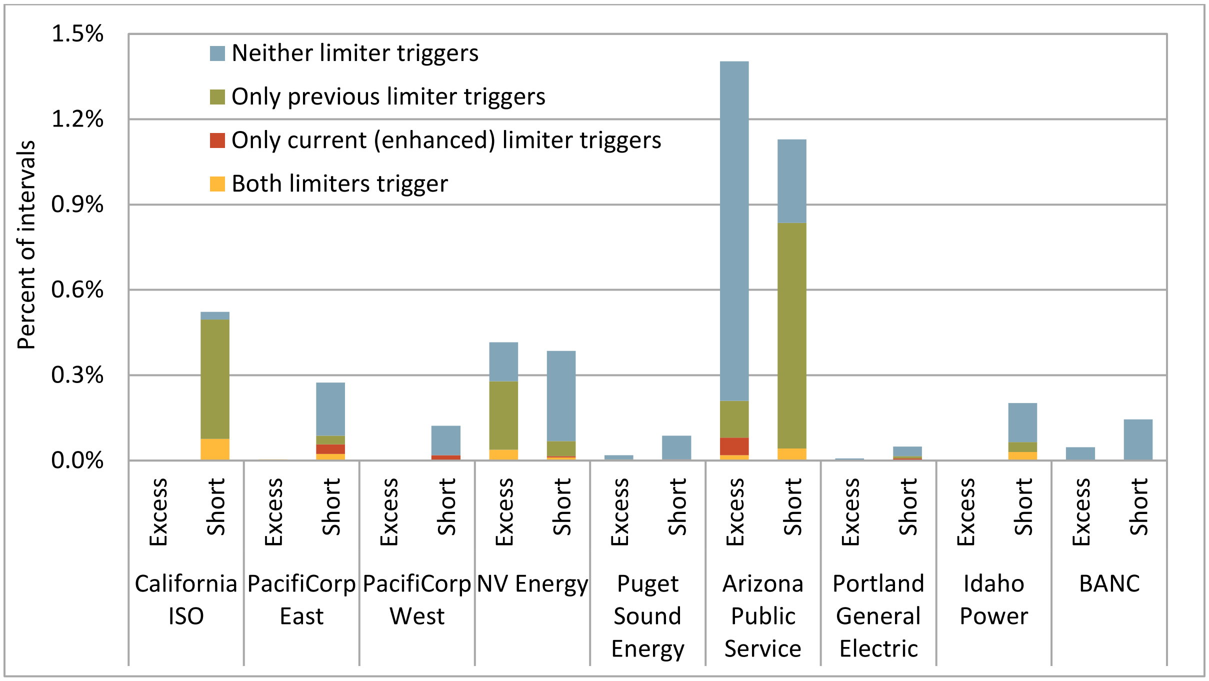
[41] *EIM power balance constraint relaxation and imbalance conformance limiter*, Department of Market Monitoring, January 18, 2019. http://www.caiso.com/Documents/EIMpowerbalanceconstraintrelaxationandimbalanceconformancelimiter.pdf

[42] In the figure, intervals when the power balance constraint needed to be relaxed due to excess supply are labeled *Excess*. Intervals when the power balance constraint needed to be relaxed due to a shortage of upward ramping capability are labeled *Short*.

Figure 2.13 Frequency of load conformance limiter in the 5-minute market (April - June)



2.5 Greenhouse gas in the energy imbalance market

Background

Under the current energy imbalance market design, all energy transferred into the ISO to serve ISO load through an energy imbalance market transfer is subject to California's cap-and-trade regulation.[43] Under the energy imbalance market design, a participating resource submits a separate bid representing the cost of compliance for its energy attributed to the participating resource as serving ISO load. The energy imbalance market optimization minimizes costs of serving load in both the ISO and energy imbalance market taking into account greenhouse gas compliance cost for all energy deemed delivered to California. The energy imbalance market greenhouse gas price in each 15-minute or 5-minute interval is set at the greenhouse gas bid of the marginal megawatt attributed as serving ISO load. This information serves as the basis for greenhouse gas compliance obligations under California's cap-and-trade program.

This greenhouse gas revenue is returned to participating resource scheduling coordinators with energy that is deemed delivered as compensation for compliance obligations. The revenue is equal to the cleared 15-minute market quantity priced at the 15-minute price plus the incremental greenhouse gas dispatch in the 5-minute market valued at the 5-minute market price. Incremental dispatch in the 5-minute market may be either positive or negative.

43 Further information on energy imbalance market entity obligations under the California Air Resources Board cap-and-trade regulation is available in a posted FAQ on ARB's website here: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/eim-faqs.pdf.

As of November 2018, the ISO implemented a new policy change to address the concerns that the market design was not capturing the full greenhouse gas effect of energy imbalance market imports into California to serve ISO load for compliance with California's cap-and-trade regulation.[44] The amount of capacity that can be deemed delivered to California will now be limited to the upper economic bid limit of a resource minus the resource's base schedule. Since the policy change in November, there have been notable changes in the greenhouse gas price in the energy imbalance market discussed below.

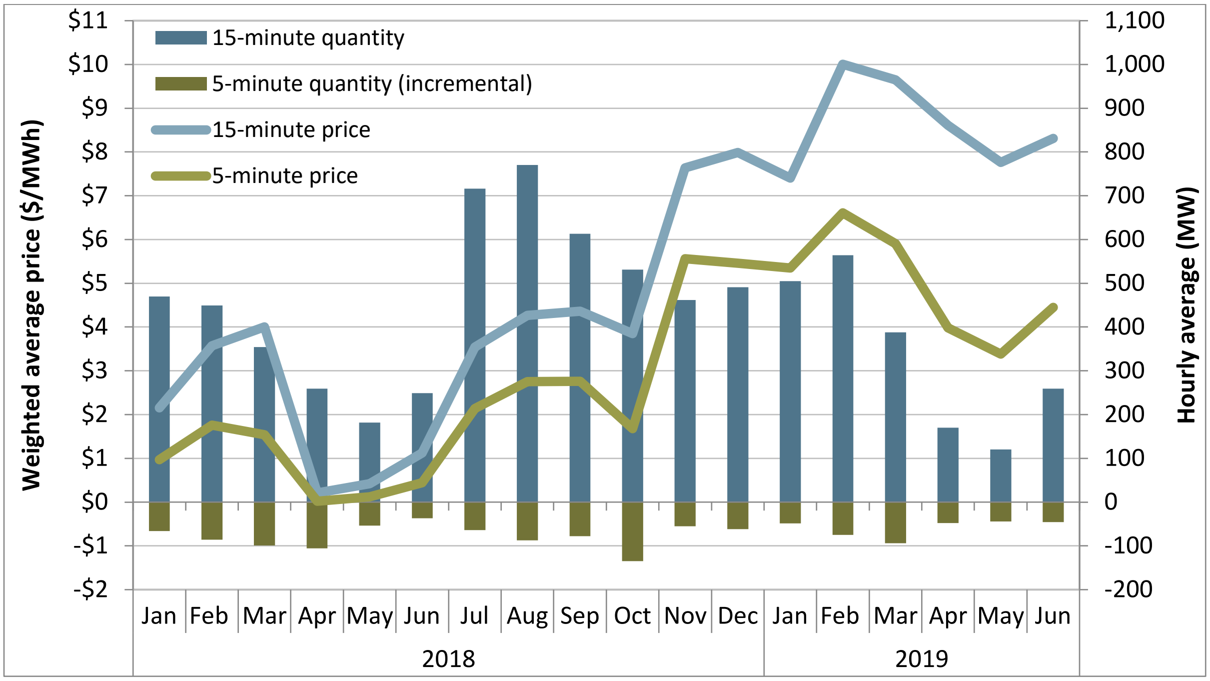
Greenhouse gas prices

Figure 2.14 shows monthly average cleared energy imbalance market greenhouse gas prices and hourly average quantities for transfers serving ISO load settled in the energy imbalance market in the second quarter of 2019. Weighted average prices are calculated using 15-minute deemed delivered megawatts as weights in the 15-minute market and the absolute value of incremental 5-minute greenhouse gas dispatch in the 5-minute market. Hourly average 15-minute and 5-minute deemed delivered quantities are represented by the blue and green bars in the chart, respectively.

Weighted 15-minute greenhouse gas prices averaged around $8/MWh for each month of the second quarter while 5-minute prices averaged around $4/MWh. Prior to the policy change in November 2018, monthly greenhouse gas prices from January to October averaged around $2.75/MWh in the 15-minute market and $1.40/MWh in the 5-minute market. The increase in greenhouse gas prices relative to last year was likely the result of the policy change, which limits the energy imbalance market capacity that can be deemed delivered to California and results in higher emitting resources setting the price. Another potential contribution to the increase in the energy imbalance market greenhouse gas price compared to 2018 is a notable increase in the market clearing price of the California Air Resources Board quarterly auction for emission allowances.

[44] Further information on the energy imbalance market greenhouse gas enhancements proposal can be found here: http://www.caiso.com/Documents/ThirdRevisedDraftFinalProposal-EnergyImbalanceMarketGreenhouseGasEnhancements.pdf

Figure 2.14 Energy imbalance market greenhouse gas price and cleared quantity

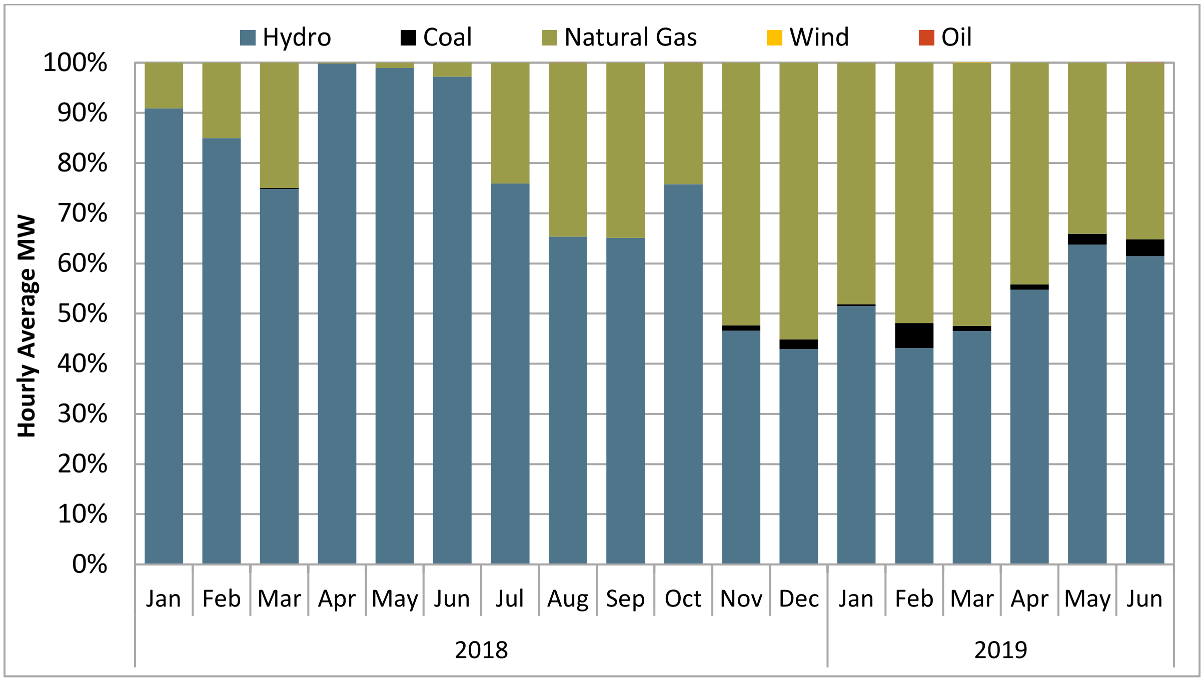


DMM estimates the total profit accruing for greenhouse gas bids attributed to energy imbalance market participating resources serving ISO load by subtracting estimated compliance costs from greenhouse gas revenue calculated in each interval. This value totaled around $1.9 million in the second quarter, compared to roughly $280 thousand in the second quarter of the previous year.

Energy delivered to California by fuel type

Figure 2.15 shows the hourly average energy deemed delivered to California by fuel type in the second quarter. About 38 percent of energy imbalance market greenhouse gas compliance obligations were assigned to gas resources, a sharp increase from 2 percent in the second quarter of the previous year. Hydroelectric resources accounted for about 47 percent of total energy delivered to California which decreased from around 98 percent in the same quarter of 2018. Additionally, energy originating from coal resources has increased since the policy change, but only accounted for around 2 percent of energy delivered in the second quarter, similar to the first quarter of 2019.

Figure 2.15 Hourly average EIM greenhouse gas megawatts by fuel type

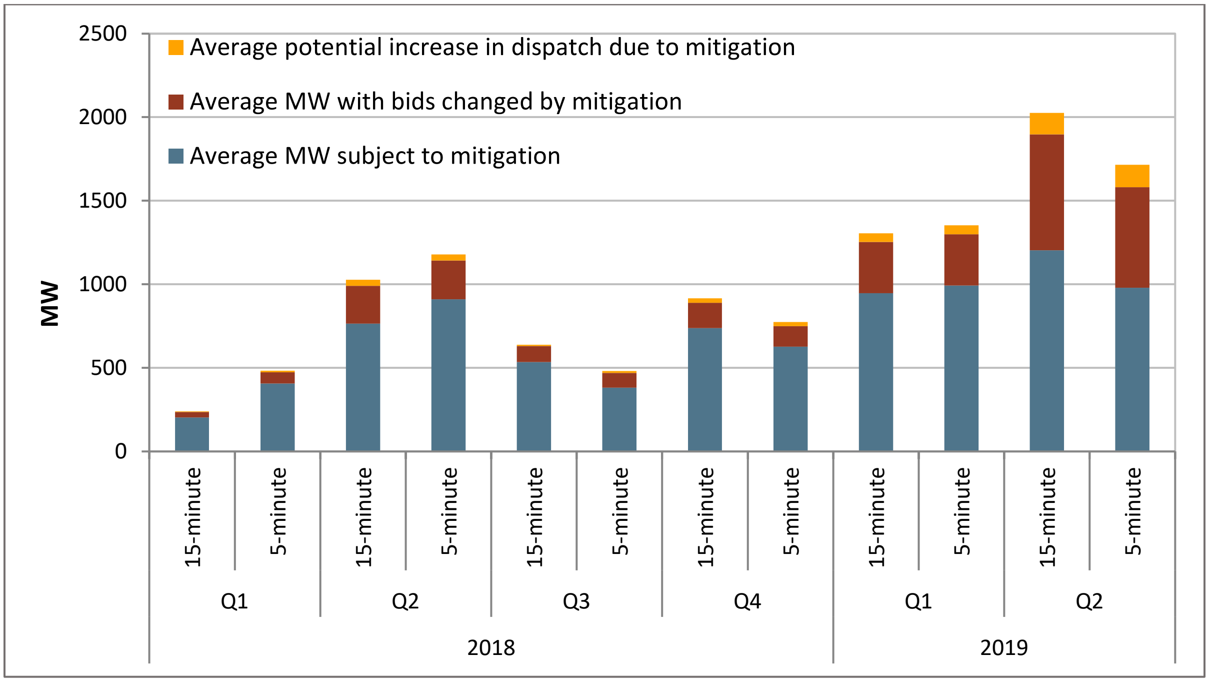


2.6 Mitigation in the energy imbalance market

Figure 2.16 highlights the frequency and volume of 15-minute and 5-minute market mitigation in all the balancing authority areas in the energy imbalance market:

- As shown in the figure, average incremental energy subject to mitigation in the energy imbalance market increased significantly in the second quarter of 2019 in the 15-minute market, compared to 2018.
- Of the megawatts that were subject to mitigation, about 60 percent had their bids lowered due to 15-minute and 5-minute market mitigation in the second quarter of 2019. This is considerably higher from the same quarter in 2018.
- As a result of increased bid mitigation in the second quarter of 2019, the potential increase in both 15-minute and 5-minute dispatch also increased in the energy imbalance market areas.

Figure 2.16 Average incremental energy mitigated in real-time market (EIM)



3 Special Issues

This section provides information about the following special issues:

- The ISO did not enforce any total gas burn constraints on the SoCalGas region in either the day-ahead or real-time markets. DMM continues to recommend that gas use limits be set for individual intervals based on the shape of net loads or actual gas usage over the course of the day. This modification could allow the gas limits to be highest during the ramping hours when gas units are needed most to meet ramping needs.
- If real-time gas prices had been updated to same-day prices, about 99 percent of the same-day trades at SoCal Citygate would have been at or below the 10 percent adder included in default energy bids used in mitigation.
- Without real-time gas price updating, about 89 percent of traded volume was at or below the normal 25 percent adder and 75 percent was at or below the 10 percent adder at SoCal Citygate.
- Beginning in May, commitment cost bid caps and generated and default energy bids have included calculated opportunity costs for use-limited resources with qualifying limitations. Capacity with non-zero opportunity costs associated with start limits was about 1,600 MW in May and 2,000 MW in June. About 48 percent of this capacity is restricted due to contractual limits. Positive opportunity costs related to run hour and energy limits were solely from exogenous limits. The capacity associated with run hour limits was about 345 MW in May and 540 MW in June. The capacity associated with energy limits with positive opportunity costs was about 4,700 MW in May and 5,000 MW in June.

3.1 Gas burn constraints

On September 28, 2018, the ISO filed tariff amendments to extend Aliso Canyon provisions until December 31, 2019.[45] One of these measures was to have the authority to enforce gas burn constraints (or nomograms) in the ISO energy markets to directly limit gas usage by groups of power plants in the SoCalGas system.

DMM supported temporary extension of the ISO's ability to enforce a maximum gas constraint for groups of units in the SoCalGas system, but continues to recommend that the ISO refine how it utilizes the maximum gas constraint and improve how gas usage constraint limits are set and adjusted in real-time.[46]

In the second quarter of 2019, the ISO did not enforce any gas burn constraints in either the day-ahead or real-time markets. When they were enforced in the first quarter, it did not appear that enhancements

45 Tariff Amendment - Aliso Canyon Gas-Electric Coordination Phase 4 (ER18-2520), September 28, 2018: http://www.caiso.com/Documents/Sep28-2018-TariffAmendment-AlisoCanyonGas-ElectricCoordination-Phase4-ER18-2520.pdf

46 FERC filing - Comments on Aliso Canyon Gas-Electric Coordination Phase 4 (ER18-2520), Department of Market Monitoring, October 19,2018: http://www.caiso.com/Documents/CommentsoftheDepartmentofMarketMonitoirng-Aliso4-Oct192018.pdf

had been implemented that address DMM's key recommendations about how to set and adjust the gas constraints. Specifically, daily gas use limits were implemented as constraints on each interval of the ISO markets, with gas use limits for each interval being set by allocating daily use limits based on the shape of total system loads over the day. DMM has recommended setting gas use limits for individual intervals based more on the shape of net loads or actual gas usage over the course of the day. This modification could allow the gas limits to be highest during the ramping hours when gas units are needed most to meet ramping needs.[47]

3.2 Updating natural gas prices in the real-time market

DMM continues to recommend that the ISO develop the ability to adjust gas prices used in the real-time market based on observed prices on Intercontinental Exchange (ICE) the morning of each operating day. This approach would closely align the gas price used in the real-time market with the actual costs for gas purchased in the same-day gas market.[48]

Figure 3.1 shows ICE same-day natural gas trade prices at SoCal Citygate compared to the next-day average price in the second quarter of 2019. At SoCal Citygate, about 11 percent of traded volume exceeded the normal 25 percent adder and an additional 13 percent of the traded volume exceeded the 10 percent adder. Prices were less volatile and are of lower magnitude during this quarter primarily due to lower seasonal gas demand. Refer to Section 1.1 for more detailed information on natural gas prices.

These figures further show that a significant portion of same-day traded volume that was more than 10 percent higher than the next-day average occurred on the first trade day of the week. These trades are represented by the green bars. Same-day trades for the first trade day of the week (which is typically a Monday, unless the Monday is a holiday) are more likely to exceed the next-day average because, in the next-day market, the first day of the week is traded as a package together with the weekend. The next-day prices for these weekend packages are typically somewhat lower than for weekdays.

[47] DMM's *2018 Annual Report on Market Issues and Performance*, Section 11.4, available here: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

[48] *Decision on Commitment costs and default energy bids enhancements proposal,* Department of Market Monitoring board memo, March 2018: http://www.caiso.com/Documents/Decision_CCDEBEProposal-Department_MarketMonitoringMemo-Mar2018.pdf

Figure 3.1 SoCal Citygate same-day trade prices compared to next-day index (April – June)

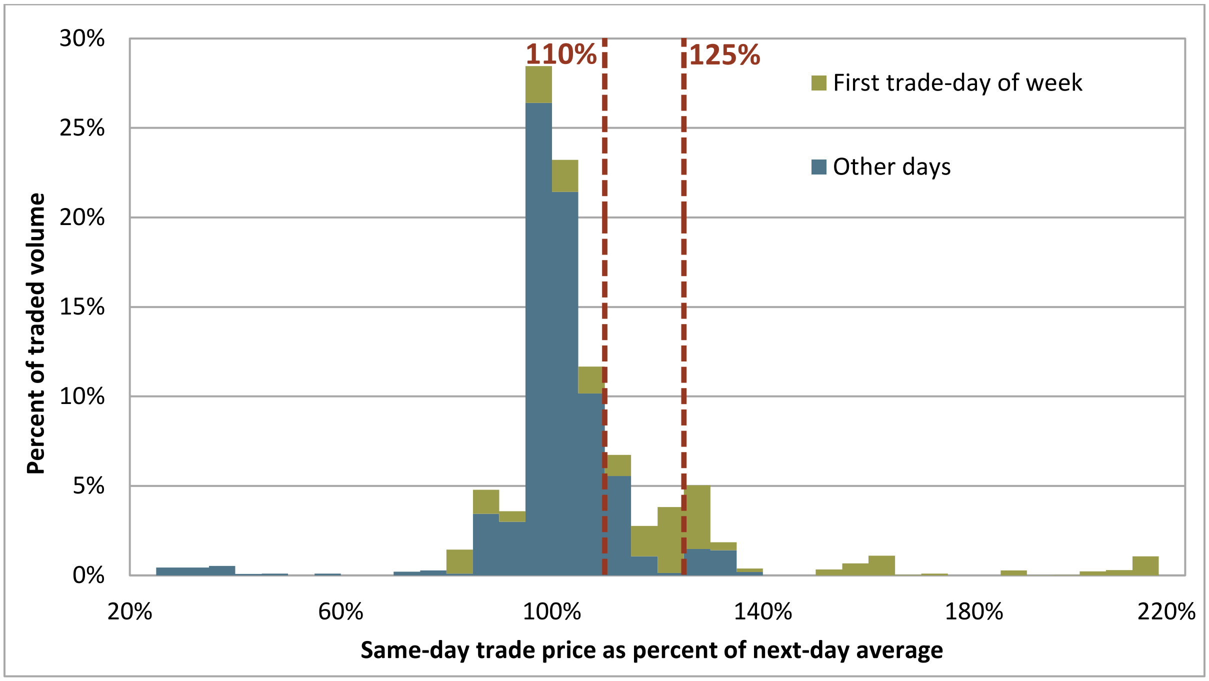
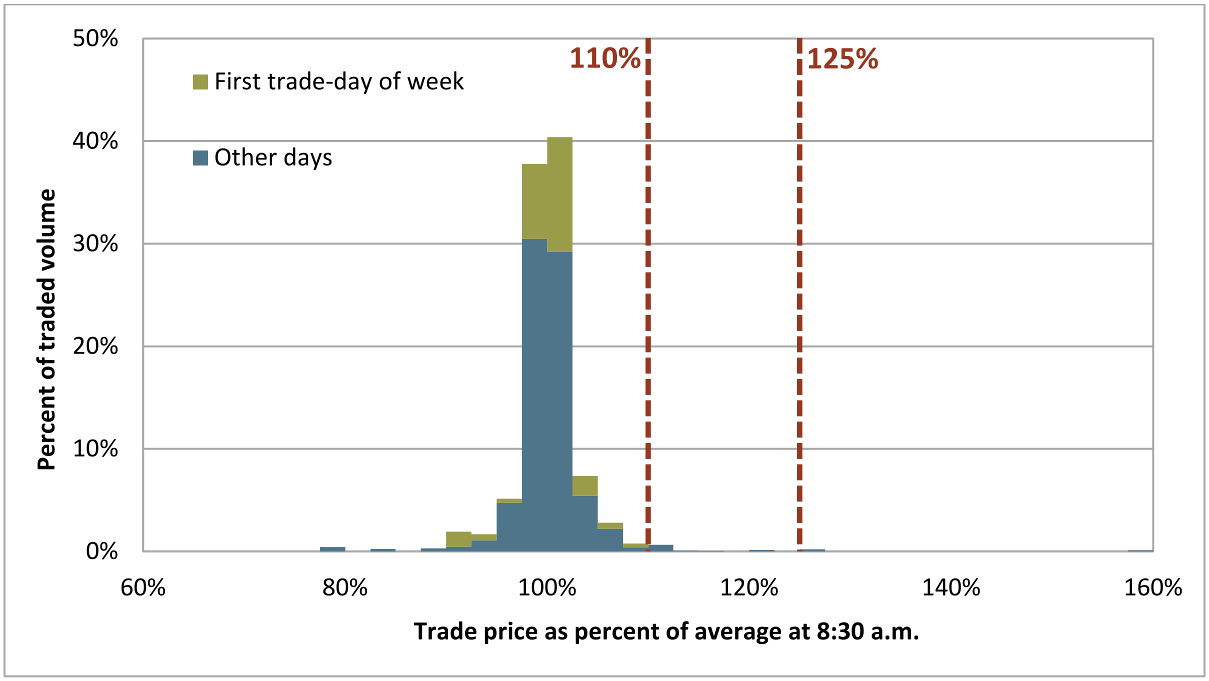


Figure 3.2 compares the price of each same-day trade at SoCal Citygate to an updated volume-weighted average price of same-day trades reported on ICE before 8:30 am. This reflects gas prices that would be used for the real-time market under DMM's recommendation.

For the second quarter of 2019, the figure shows that if the real-time gas prices were updated using an updated same-day price, about 99 percent of the same-day trades at SoCal Citygate would have been at or below the 10 percent adder included in default energy bids used in mitigation. About 1 percent of the traded volume would have exceeded the 10 percent adder, but still would have been less than the 25 percent adder normally included in commitment cost caps. An insignificant amount of the same-day traded volume would have exceeded the 25 percent adder.

Figure 3.2 SoCal Citygate same-day prices as a percent of updated same-day averages (Apr - Jun)



The ISO did not include DMM's recommendation to update gas prices used in calculating bid caps for the real-time market in the proposed commitment cost and default energy bid enhancement (CCDEBE) that was approved by the ISO Board in May 2018. However, in 2019, the ISO subsequently included provisions to update bid caps using same-day gas prices as part of the local market power mitigation enhancements initiative. Under this revised proposal*, reasonableness thresholds* used to automatically approve generators' requests to increase bid caps will be updated if the same-day gas price for a fuel region exceeds 10 percent of the next-day index for the same gas flow day.[49]

Updated natural gas prices for the day-ahead market

FERC's November 26, 2018, order extended the ISO's authority to use more timely natural gas prices for calculating default energy bids and proxy commitment costs in the day-ahead market through December 31, 2019. Under this extension, the ISO updates the gas price on next-day trades from the morning of the day-ahead market run instead of using indices from the prior day.[50] DMM is very supportive of this change and recommends that this be permanently extended. As part of the

[49] Draft final proposal, Local Market Power Mitigation Enhancements, February 1, 2019: http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements-UpdatedJan31_2019.pdf

[50] This market modification uses weighted average price of next-day trades at SoCal Citygate before 8:30 am from Intercontinental Exchange (ICE). These are next-day trades that occur prior to the ISO beginning the day-ahead market run.

commitment cost and default energy bid enhancements initiative, the ISO has proposed to make this a permanent measure.[51]

As part of the local market power mitigation enhancements initiative, the ISO plans to use updated Monday-only gas price index in the day-ahead market for Mondays only and when available.[52]

Figure 3.3 and Figure 3.4 illustrate the benefit of using the updated natural gas price index in the second quarter of 2019. Figure 3.3 shows next-day trade prices reported on ICE for SoCal Citygate during the second 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 3.3, about 9 percent of the next-day trades were in excess of the 25 percent headroom normally included in commitment cost bid caps. An additional 13 percent of next-day trades were at a price in excess of the 10 percent adder normally included in default energy bids.

Figure 3.4 shows the same data but compares the price of each next-day trade to a weighted average price of next-day 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 3.4, a very insignificant amount of traded volume exceeded the 10 percent adder included in default energy bids. None of the volume exceeded the 25 percent adder included in the commitment cost caps. This shows that the methodology currently in place is significantly more reflective of next-day trading prices than the methodology that was in place prior to the Aliso measure.

51 Second Revised Draft Final Proposal - Commitment Costs and Default Energy Bid Enhancements, March 2018: http://www.caiso.com/Documents/SecondRevisedDraftFinalProposal-CommitmentCosts-DefaultEnergyBidEnhancements.pdf

52 *White paper – Temporary use of gas price index for day-ahead market*, January 11, 2019: http://www.caiso.com/Documents/WhitePaper-TemporaryUse-GasPriceIndex-Day-AheadMarket.pdf

Figure 3.3 Next-day trade prices compared to next-day index from prior day (Apr - Jun)

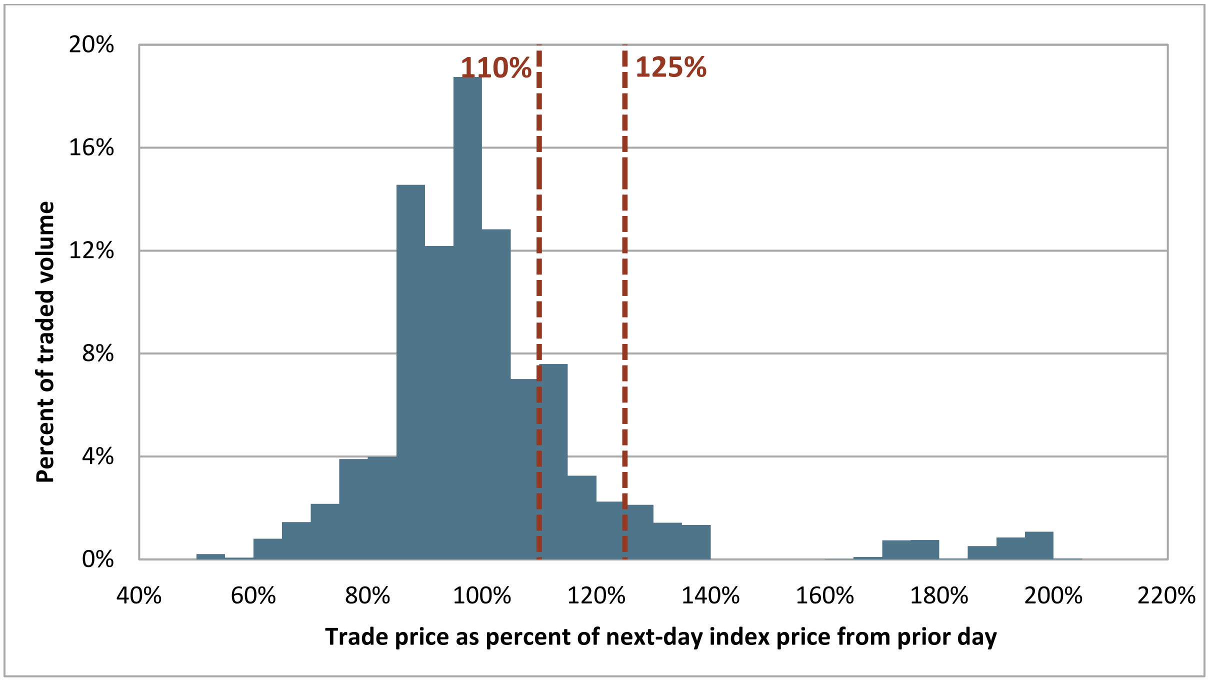
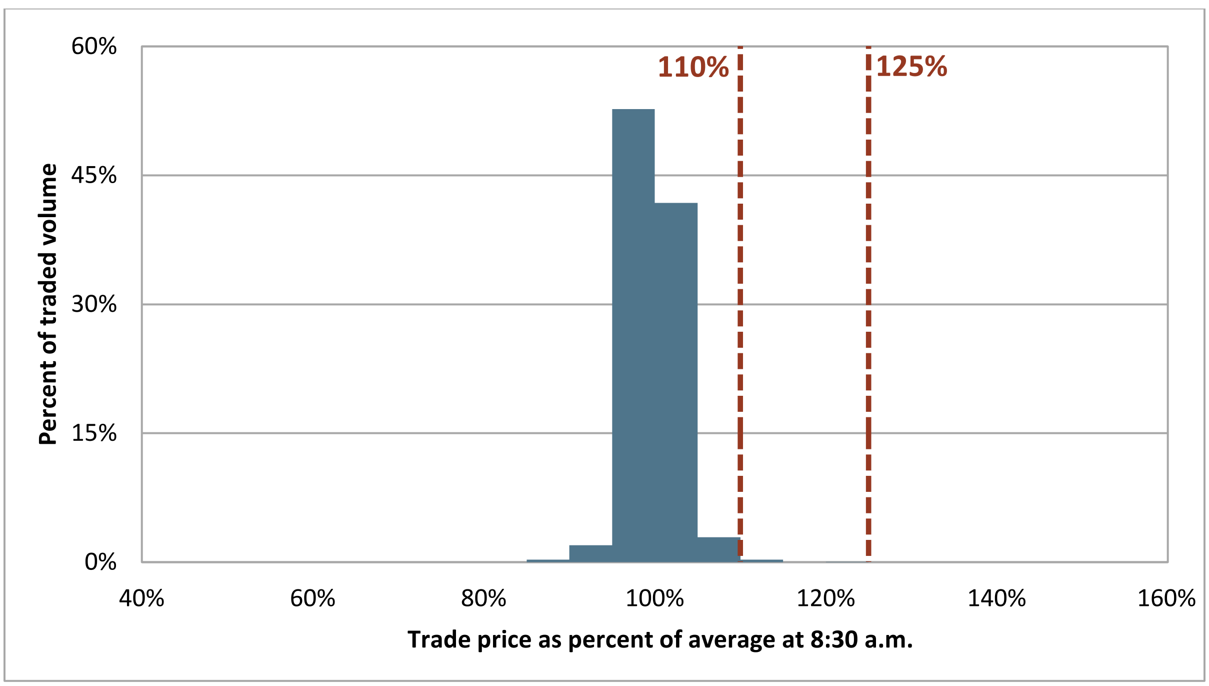


Figure 3.4 Next-day trade prices compared to updated next-day average price (Apr - Jun)



3.3 CCE3 opportunity cost implementation

Many resources that participate in the ISO market are subject to limitations on their operating activity. An example would be local air quality regulation that limits generator emissions over the course of a year. These limits are often defined through periods that extend beyond the ISO's market optimization horizon and are consequently not captured in optimal market dispatch decisions. Previously, it was up to scheduling coordinators to determine when to use these resources given their use limitations. Market optimization solutions that can only account for these limits indirectly may not be as efficient as those that result from an optimization model that can account for resource use limitations.

In early 2016, the ISO gained Board approval of Commitment Cost Enhancements Phase 3 (CCE3), an initiative to implement an opportunity cost methodology for use-limited resources that reflects eligible limitations to be used in commitment cost bids and variable cost default energy bids.[53] In this initiative, opportunity costs are calculated for start, run hour, and energy limitations based on the profits a use-limited resource would forgo in the future due to present commitment and dispatch decisions. The goal of this initiative is to bridge the gap between resource limitation periods and the market optimization horizon to simultaneously allow use-limited resources to bid more frequently in the market and to allow the market to determine the optimal dispatch of available resources.

This initiative was implemented in the second quarter of 2019 with the use of opportunity cost adders beginning in May. Resource use limits were based on registered exogenous (i.e., limits imposed on resources from outside parties, such as air quality regulation) as well as contractual limits. Both DMM and the ISO believe that economic limits that originate from commercial power contracts are not appropriate for calculating opportunity cost adders. However, FERC approved the ISO's proposal to allow a three-year exemption that allows contractual limitations that were agreed upon before January 1, 2015, to contribute to opportunity cost adders.[54] DMM maintains that it is inefficient and inequitable to treat contractual limitations as actual physical or environmental limitations when calculating market optimization inputs.

Capacity associated with opportunity costs

Resources that qualify as use-limited receive a calculated opportunity cost adder to be included in their commitment cost and variable cost default energy bids based on expectations of future profit. The opportunity cost calculation methodology estimates the foregone profits of the last start, run hour and/or energy megawatt-hour assuming the resource is committed when most valued. Hence, resources will only receive a non-zero opportunity cost if their qualified use limit is binding over the specified optimization time horizon.

Figure 3.5 shows the megawatt capacity that is associated with use-limited resources' start, run hour, and energy limit opportunity costs for May and June of 2019.[55] This capacity is categorized by whether

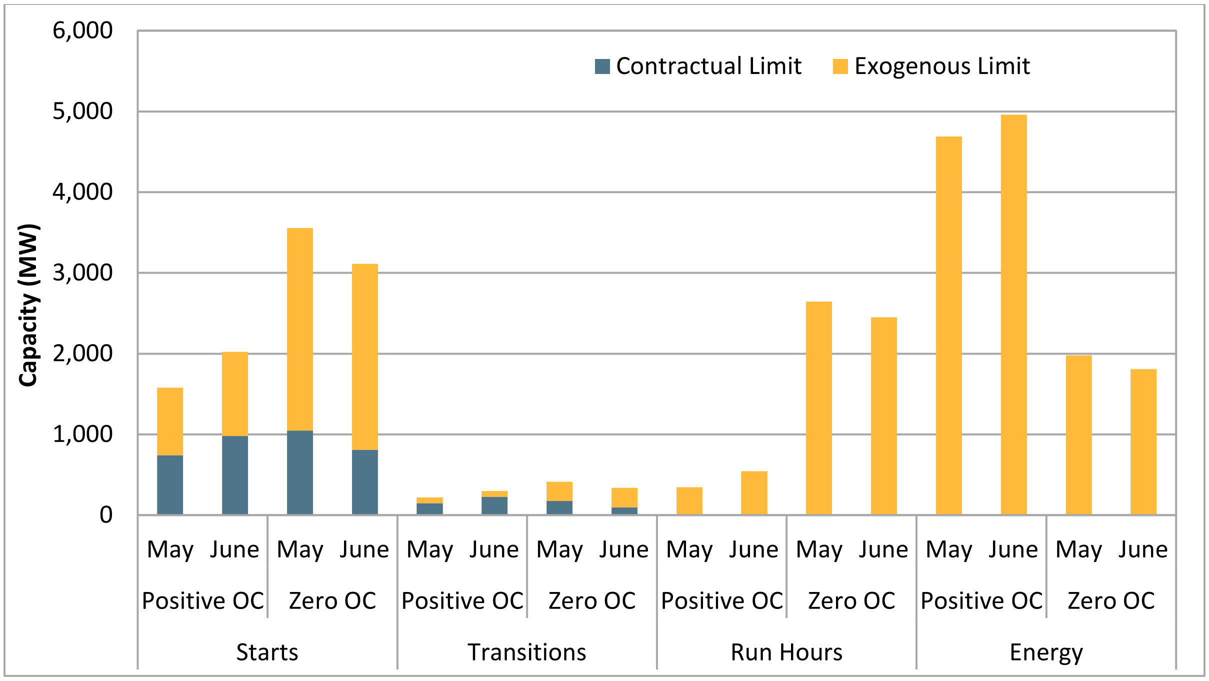
[53] *Commitment Cost Enhancements Phase 3 Draft Final Proposal*, February 17, 2016: http://www.caiso.com/Documents/DraftFinalProposal-CommitmentCostEnhancementsPhase3.pdf

[54] *Annual Report on Market Issues and Performance*, May, 2018: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

[55] For multi-stage generating resources, transitions are counted towards start limits based on implied starts that the resource incurs due to transitioning from a lower configuration to a higher configuration. Hence, transition opportunity cost is calculated as the difference between start opportunity costs of higher and lower configurations.

the limit resulted in a non-zero opportunity cost (Positive OC) or an opportunity cost value of zero (Zero OC) as well as by whether the limit was contractual or exogenous.

Figure 3.5 Capacity from resources with use-limit opportunity costs



Positive opportunity costs associated with start limits included both contractual and exogenous limits in May and June. The capacity associated with start limits with positive opportunity costs was about 1,600 MW in May and 2,000 MW in June.[56] About 48 percent of this capacity is restricted due to contractual limits. The capacity associated with multi-stage generating resources' positive start opportunity costs associated with transitions was about 220 MW in May and 300 MW in June.[57] About 72 percent of this capacity is restricted due to contractual limits. Resources with positive start and transition opportunity costs over this period were almost entirely gas units.

Positive opportunity costs related to run hour and energy limits were solely from exogenous limits. The capacity associated with run hour limits was about 345 MW in May and 540 MW in June.[58] The capacity associated with energy limits with positive opportunity costs was about 4,700 MW in May and 5,000

56 The capacity associated with a start limit for each resource is the resource's Pmax. For multi-stage generating resources, this is the largest Pmax of the startable configurations.

57 For multi-stage generating (MSG) resources, the capacity associated with transitions is calculated by taking the largest megawatt difference between output ranges of configurations that can be transitioned to in the upward direction. For resources whose configuration output ranges do not overlap (e.g., lower configuration Pmax < higher configuration Pmin), this is the maximum difference between the lower configuration Pmax and the higher configuration Pmin of configurations that can be transitioned to in the upward direction. For resources whose configuration output levels overlap (e.g. lower configuration Pmax > higher configuration Pmin), this is the largest difference in Pmins between all configurations that can be transitioned to in the upward direction.

58 The capacity associated with run hour limits for each resource is the resource's Pmax.

MW in June.[59] Resources with positive run hour opportunity costs were mostly gas units with some demand response units, while resources with positive energy opportunity costs were mostly hydro units with some gas units.

There was also a significant amount of capacity that had zero opportunity costs in May and June of 2019. This capacity comes from resources that qualified for opportunity cost calculations, but their start, run hour, or energy limits were not binding in either May or June. There was over 16,000 MW of capacity with zero opportunity costs during these months. Most of this capacity was from start and run hour limits. Though this capacity had zero opportunity costs during this period, the opportunity cost could turn positive at some point based on the interaction between resource dispatch activity and the limitation horizon.

Resource adequacy

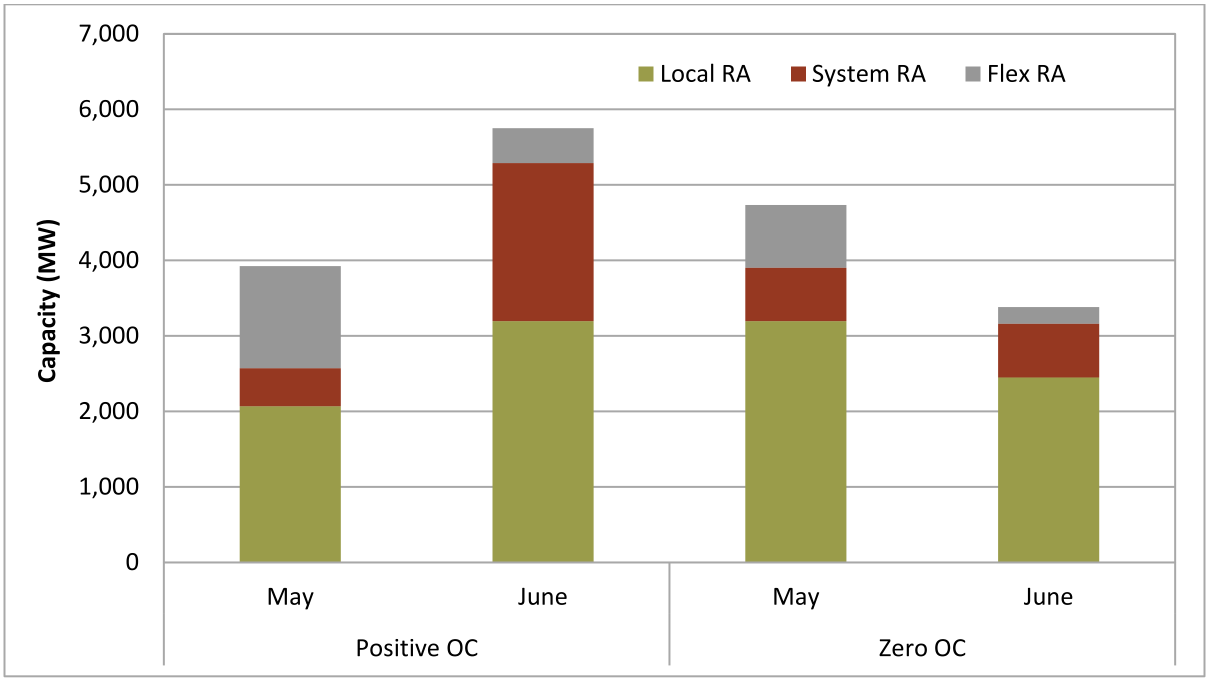
Use-limited resources are eligible to provide resource adequacy capacity if they are shown on a load-serving entity's annual or monthly supply plan. These resources are subject to resource adequacy must-offer obligations as well as resource adequacy availability incentive mechanism (RAAIM) charges associated with bid activity during the availability assessment hours. Use-limited resources can be exempt from RAAIM for the remainder of the month that the resource has reached its limitation by submitting use-limited related outage cards.[60] This provides a tradeoff between scenarios where resource adequacy rules allow for a greater mix of capacity for reliability needs in the ISO than there would be without use-limited resources, but not all resource adequacy capacity may be available in the market during critical times if the calculated opportunity costs and outage card usage do not manage resources' limits efficiently.

Figure 3.6 shows the megawatt capacity of use-limited resources that are contracted to supply local, system, and flexible resource adequacy according to load-serving entity month-ahead supply plans for May and June of 2019. This capacity is grouped according to whether the resources had a positive opportunity cost for at least one limit type (starts, transitions, run hours, or energy) and those that have a zero value for their opportunity cost due to a non-binding limit.

59 The capacity associated with energy limits for each resource was calculated by subtracting the resource's Pmin from its Pmax. For multi-stage generating units whose configuration output ranges may or may not overlap, this was calculated as the minimum between the sum of configuration output ranges (i.e., the sum of each configuration Pmax minus each configuration Pmin) and the difference of the resource Pmax and Pmin.

60 If the resource is still on outage in the subsequent month after they reach their limit, the resource will be subject to RAAIM unless substitute capacity has been provided.

Figure 3.6 Resource adequacy capacity with use-limit opportunity costs



Use-limited resources provided about 8,700 MW of resource adequacy capacity in May and about 9,100 MW in June. Of this capacity, about 4,000 MW in May and 5,800 MW in June had a positive opportunity cost. The majority of this capacity during May and June, about 61 percent, was provided for local resource adequacy, while 23 percent and 16 percent was provided for system and flexible resource adequacy, respectively.

Outages

To complement the addition of opportunity costs to commitment cost bids to help manage resource usage, the ISO designated use-limited related outage cards. There are multiple purposes of use-limit outage cards. These are to help prevent resources from reaching their limit prematurely in the event the calculated opportunity costs are ineffective in managing their limit, to indicate a use-limited resource has reached its limit and is exempt from RAAIM if they are a resource adequacy resource, and to allow demand response programs to take "fatigue" breaks.

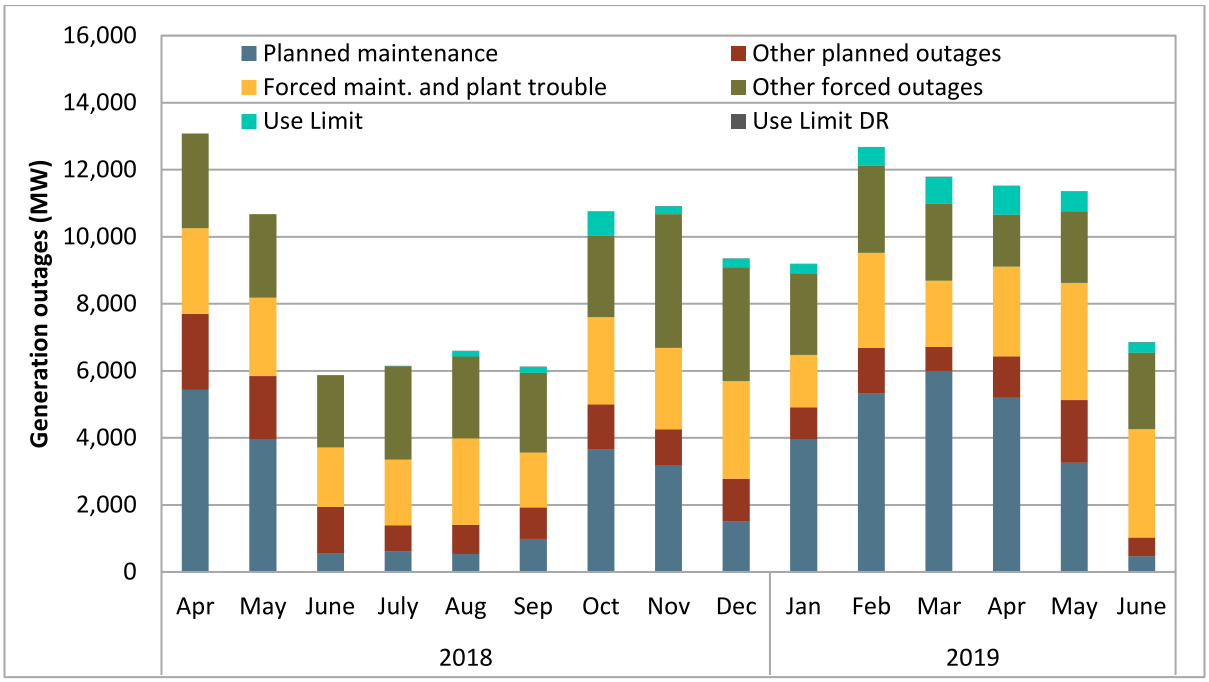
Scheduling coordinators must choose an appropriate "nature of work" category when submitting an outage card for a resource. The nature of work categories related to use limits are as follows:

- Annual use limit reached – this outage card is to be used when a use-limited resource with an annual limit has reached its annual limit.
- Month use limit reached – this outage card is to be used when a use-limited resource with a month limit has reached its month limit.
- Other use limit reached – this outage card is to be used when a use-limited resource with a limit time horizon greater than a month and less than a year reaches its limit.

- Short term use limit reached – this outage card can be used either when a use-limited resource is at risk of reaching its limitation prematurely due to the ineffectiveness of opportunity cost adders to commitment costs or variable cost default energy bids in managing a resource's limit or when a proxy demand response or reliability demand response resource needs a "fatigue" break after being dispatched for a certain number of hours and consecutive days.

Figure 3.7 shows the monthly averages of maximum daily outages broken out by type during peak hours. This figure shows the amount of megawatt capacity from resources that took outages specifically related to use limits as well as for other outage types such as planned maintenance, other planned outages, forced maintenance and plant trouble, and other forced outages.

Figure 3.7 Average of maximum daily generation outages by type - peak hours



Scheduling coordinators started using outage cards related to demand response use limits (dark purple) and other use limits (light blue) in July 2018. The proportion of total capacity on outage from use-limited resources ranges from 0.3 percent to 7.5 percent per month. Average daily maximum capacity on use limit outage peaked at about 850 MW in April. Similar to planned outages, outages related to use limits appear to be less prevalent during summer months when loads are high and system capacity is tight. Conversely, outages related to use limits are more prevalent during months when system capacity is well above load.