Q4 2019 Report on Market Issues and Performance

February 28, 2020

Department of Market Monitoring

California Independent System Operator

TABLE OF CONTENTS

Executive summary

This report covers market performance during the fourth quarter of 2019 (October - December). Key highlights during this quarter include the following:

- **Market prices** remained highly competitive in the fourth quarter due to a combination of favorable market and system conditions, although an increase in gas prices led to higher wholesale electric costs. Electricity prices increased slightly from the third quarter to the fourth quarter of 2019, with average day-ahead prices ($42/MWh) greater than both 15-minute ($40/MWh) and 5-minute prices ($36/MWh) (Figure E.1).
- **The total estimated wholesale cost of serving ISO load** in the fourth quarter of 2019 was about $2.3 billion ($44/MWh), a decrease from $2.8 billion ($54/MWh) in the same quarter of 2018. After adjusting for natural gas costs and changes in greenhouse gas prices, wholesale electric costs decreased by less than 4 percent to $40/MWh in the fourth quarter from $41/MWh in the same quarter in 2018.
- **Gas prices** were lower in the fourth quarter compared to Q4 2018 at both SoCal and PG&E Citygates, following the return to service of gas pipeline capacity that had been out of service since 2017. Changes to Operational Flow Order (OFO) and Aliso Canyon Storage withdrawal protocols also helped to lower gas prices. The drop in gas prices compared to last year contributed to lower wholesale energy costs relative to the fourth quarter of 2018.
- **Real-time offset costs** increased in the fourth quarter to $50 million. Real-time offset costs totaled $101 million in 2019, with $97 million in real-time imbalance congestion offset costs. Reductions in transmission constraint limits below day-ahead limits made in the 15-minute market continued to be a major driver of congestion imbalance charges.
- **Congestion revenue rights** auction revenues were $22.1 million less than payments made to non-load-serving entities during the fourth quarter of 2019. Auction revenues were 46 percent of payments made to non-load-serving entities during the fourth quarter of 2019, slightly down from 48 percent during the same quarter in 2018 (Figure E.2). For the year, ratepayer losses from sales of congestion revenue rights totaled about $34 million, down from $131 million in 2018. The reduction in losses was driven by a combination of the changes implemented by the ISO in 2019, along with a significant drop in day-ahead market congestion.
- **Load forecast adjustments** reached 1,100 MW during the peak net load ramp hour, on average, in the fourth quarter, continuing the increase in operator use of imbalance conformance that began in 2017.

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

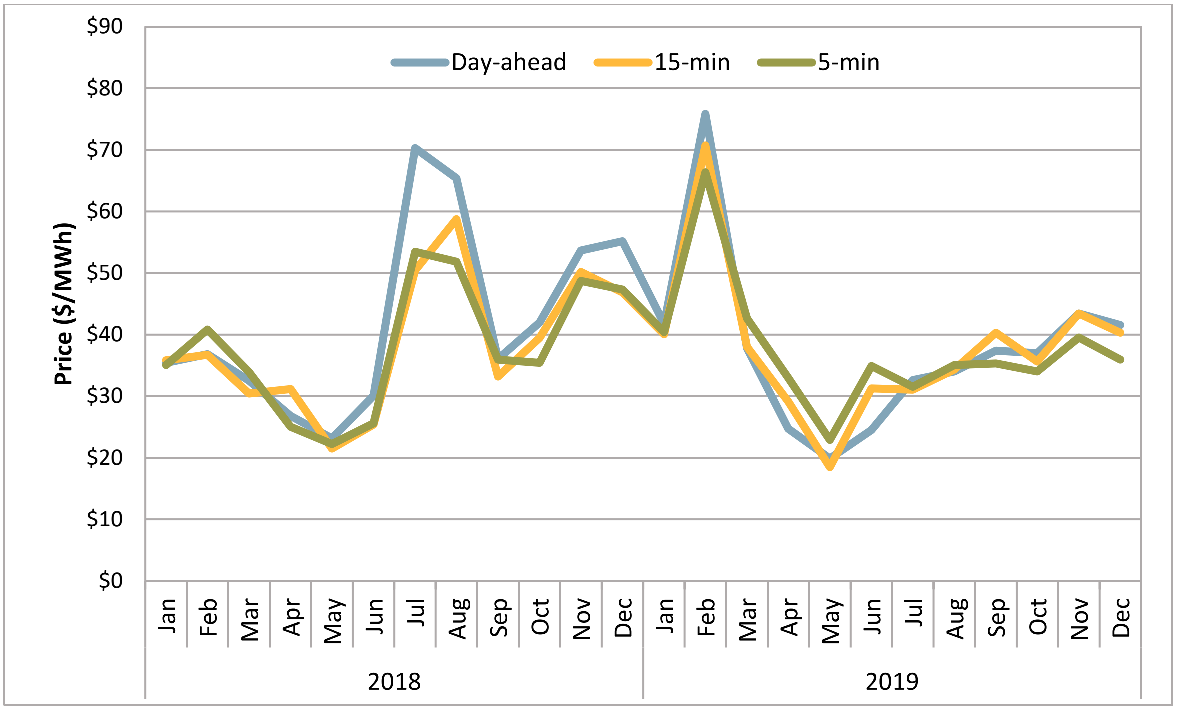
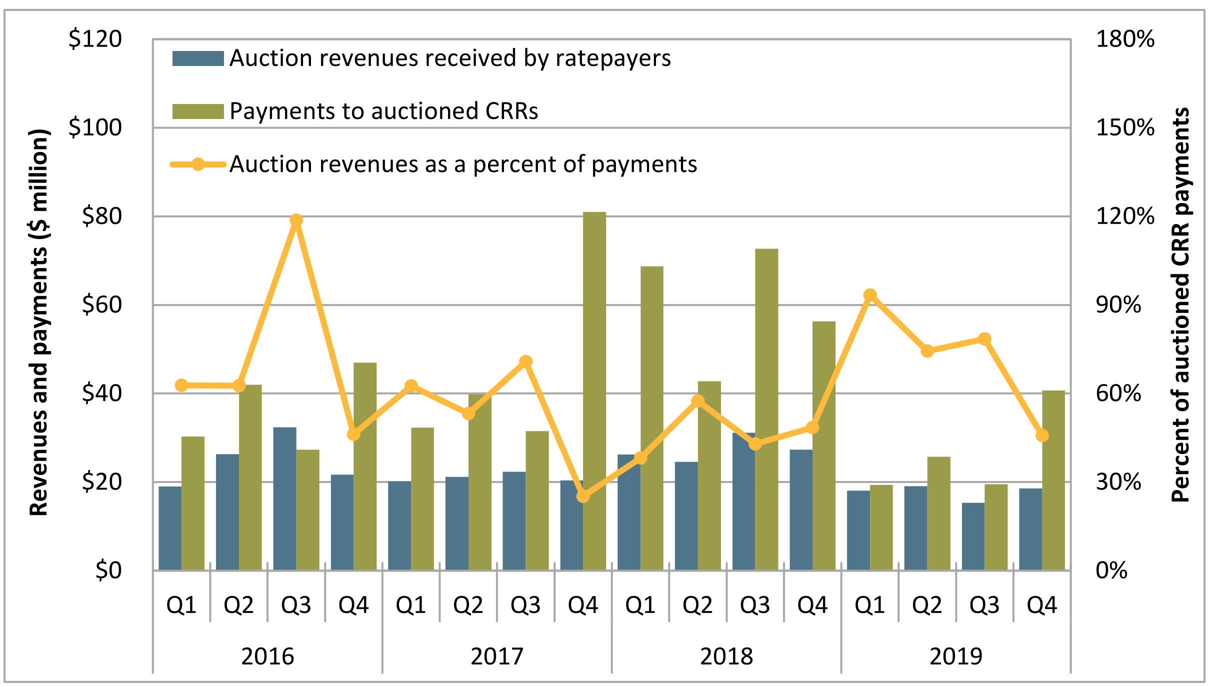


Figure E.2 Auction revenues and payments to non-load-serving entities



Western energy imbalance market

- **Prices in the Northwest region**, which includes PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex, were regularly lower than prices in the ISO and other balancing areas due to limited transfer capability out of this region during peak system load hours.
- **Sufficiency test failures and subsequent under-supply power balance constraint relaxations** drove average real-time prices for Arizona Public Service higher. With the modified load conformance limiter implemented in February 2019, almost all intervals with power balance relaxations were priced at the penalty parameter of $1,000/MWh.
- **Congestion imbalance deficits related to base schedules** remained very low in the fourth quarter. Balancing areas may allocate these imbalances to third party customers and others. Historically, PacifiCorp East is the only area to have had significant base schedule related congestion imbalance deficits which occurred primarily in late 2017 and early 2018.
- **Western EIM greenhouse gas** prices increased as the deemed delivered resources shifted from lower to higher greenhouse gas emissions. In November 2018, the ISO implemented a revised EIM greenhouse gas bid design which limited greenhouse gas bid capacity to the differences between base schedule and available capacity. The weighted average greenhouse gas cost increased as the deemed delivered resources shifted from hydroelectric to natural gas.

Special issues

Energy storage and distributed energy resources phase 3 implementation

- **Implementation of the energy storage and distributed energy resources phase 3** initiative had little impact. This initiative created two new demand response dispatch options (hourly and 15-minute) and removed the single load-serving entity aggregation requirement which was expected to decrease the registration of demand response resources sized less than 1 MW. Thus far, implementation of this initiative on November 13 has had little impact due to both low utilization of new dispatch options and the continued registration of resources sized less than 1 MW.

Local market power mitigation enhancements implementation

- **Elimination of carryover mitigation in the ISO** reduced rates of mitigation in the real-time market. One of the local market power mitigation enhancements approved by the Federal Energy Regulatory Commission was the elimination of carryover mitigation, the practice of mitigating a resource in subsequent market intervals only because the resource was mitigated in a prior interval of the same hour which had applied to mitigation in both the 15-minute and 5-minute real-time markets. Rates of real-time mitigation in the ISO were similar to the prior fourth quarter while rates of day-ahead mitigation, which was not affected by carryover mitigation, increased. Rates of mitigation in all markets remained low.
- **Elimination of carryover mitigation in the Western EIM** also reduced rates of mitigation. Rates of mitigation in the Western EIM were lower than the previous fourth quarter and remained very low.
- **A new default energy bid option, the hydro default energy bid** became available as part of the local market power mitigation enhancements initiative, implemented on November 13. By the end of

2019, only a small portion of the eligible capacity had selected the new hydro default energy bid. Most capacity that has selected this option is registered with 12 months of storage and located within the California ISO balancing area.

Gas usage constraints

- **Gas usage constraints** were enforced in the SoCalGas region in the fourth quarter but bound infrequently. DMM continues to recommend that gas use limits be set 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.

System market power

- **The price-cost markup** averaged $0.71/MWh or just under 2 percent for 2019. This slight positive markup indicates that prices have been very competitive overall for the year.

- **Market power** has had a very limited effect on system market prices even during hours when the ISO system was structurally uncompetitive. However, DMM has expressed concern that market conditions may evolve in a way that will increase the potential for system-level market power. DMM supports the ISO's proposal to continue with an initiative to design system market power mitigation and looks forward to working with the ISO throughout that process.

- **DMM continues to recommend** several other market design changes that may help mitigate system market power beyond the bid mitigation options being examined as part of this initiative. These include consideration of options that would increase the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time. DMM also continues to recommend that the ISO's plan for implementing FERC Order 831 include provisions to (1) ensure that import bids over $1,000/MWh are subject to ex ante cost justification and (2) avoid setting penalty prices at $2,000/MWh except when needed to implement the provisions of Order 831.

1 Market performance

This section highlights key indicators of market performance in the fourth quarter:

- **Market prices** were highly competitive in the fourth quarter due to a combination of favorable market and system conditions although higher gas prices led to an increase in wholesale electric costs compared to the previous quarter.

- **The total estimated wholesale cost of serving load** in the fourth quarter of 2019 was about $2.3 billion ($44/MWh), a decrease from $2.8 billion ($54/MWh) in the same quarter of 2018. After adjusting for natural gas costs and changes in greenhouse gas prices, wholesale electric costs decreased by less than 4 percent to $40/MWh from $41/MWh.

- **Gas prices** were lower in the fourth quarter compared to Q4 2018 at both SoCal and PG&E Citygates, following the return to service of gas pipeline capacity that had been out of service since 2017, as well as other changes to Operational Flow Order (OFO) and Aliso Canyon Storage withdrawal protocols. The drop in gas prices compared to last year contributed to lower wholesale energy costs relative to the fourth quarter of 2018.

- **Renewable production** fell by 43 percent contributing to higher wholesale energy costs relative to the previous quarter.

- **Electricity prices** increased slightly from the third quarter to the fourth quarter of 2019, with average day-ahead prices ($42/MWh) greater than both 15-minute ($40/MWh) and 5-minute prices ($36/MWh).

- **Flexible ramping product** system level prices were zero for more than 95 percent of intervals in the 15-minute market and more than 99 percent of intervals in the 5-minute market in the upward direction. Prices were zero in all intervals in the downward direction in both markets at the system level. Some resources supplying flexible ramping product capacity are not able to resolve system level uncertainty because of resource characteristics or congestion, reducing the efficacy with which the product can manage net load volatility or prevent power balance violations.

- **Bid cost recovery payments** for the fourth quarter of 2019 totaled about $27 million, or about $21 million less than the previous quarter and similar to the fourth quarter of 2018.

- **Congestion.** The overall net impact and frequency of congestion on load was low in both the day-ahead and real-time markets. The frequency of congestion was highest in SDG&E.

- **Real-time offset costs** increased in the fourth quarter to $50 million. Real-time offset costs totaled $101 million in 2019, with $97 million in real-time imbalance congestion offset costs. Reductions in transmission constraint limits below day-ahead limits made in the 15-minute market continued to be a major driver of congestion imbalance charges.

- **Congestion revenue rights** auction revenues were $22.1 million less than payments made to non-load-serving entities during the fourth quarter of 2019. Auction revenues were 46 percent of payments made to non-load-serving entities during the fourth quarter of 2019, slightly down from 48 percent during the same quarter in 2018. In 2019, ratepayer losses from sales of congestion revenue rights totaled about $34 million, or about 68 cents in auction revenue per dollar paid out to congestion revenue rights purchased in the auction in 2019. Financial entities, which do not serve load or provide supply in the ISO markets, received profits of about $33 million and paid 55 cents in auction revenues per dollar of payments received.

- **Ancillary services** costs decreased during the fourth quarter to about $23 million, compared to about $28 million in the previous quarter, despite an atypically high number of intervals with scarcity pricing.
- **Load forecast adjustments** made by system operators reached an average of 1,100 MW during the peak net load ramp hour in the fourth quarter, continuing a dramatic increase in operator use of imbalance conformance that began in 2017.

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 fourth quarter of 2019, natural gas prices increased across major gas trading hubs in the west. This increase in natural gas prices increased system marginal energy prices across the ISO footprint during the fourth quarter.

Figure 1.1 shows monthly average natural gas prices at key delivery points across the west including PG&E Citygate, SoCal Citygate, Northwest Sumas, El Paso Permian and 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 at SoCal Citygate and Northwest Sumas declined sharply in the fourth quarter when compared to the same quarter in 2018.

Prices at the SoCal Citygate gas hub averaged $4.49/MMBtu compared to $6.14/MMBtu in the fourth quarter of 2018. Key factors contributing to these lower SoCal Citygate mid-winter prices in 2019 include:

- On September 17, the California Public Utilities Commission (CPUC) urged Southern California Gas Company (SoCalGas) to increase injections of natural gas at its underground storage fields to prepare for winter.[1]
- On October 14, SoCalGas announced the completion of the Line 235-2 maintenance and its return to service at reduced pressure. This line has been out of service since October 2, 2017, causing significant supply constraints, which increased SoCal Citygate gas prices during the outage.
- The return of 270 million cubic feet per day of capacity at Topock and Needles, which supports access to lower cost natural gas supplies in the San Juan and Permian Basins.

[1] Southern California Daily Energy Report: https://www.eia.gov/special/disruptions/socal/summer/#commentary

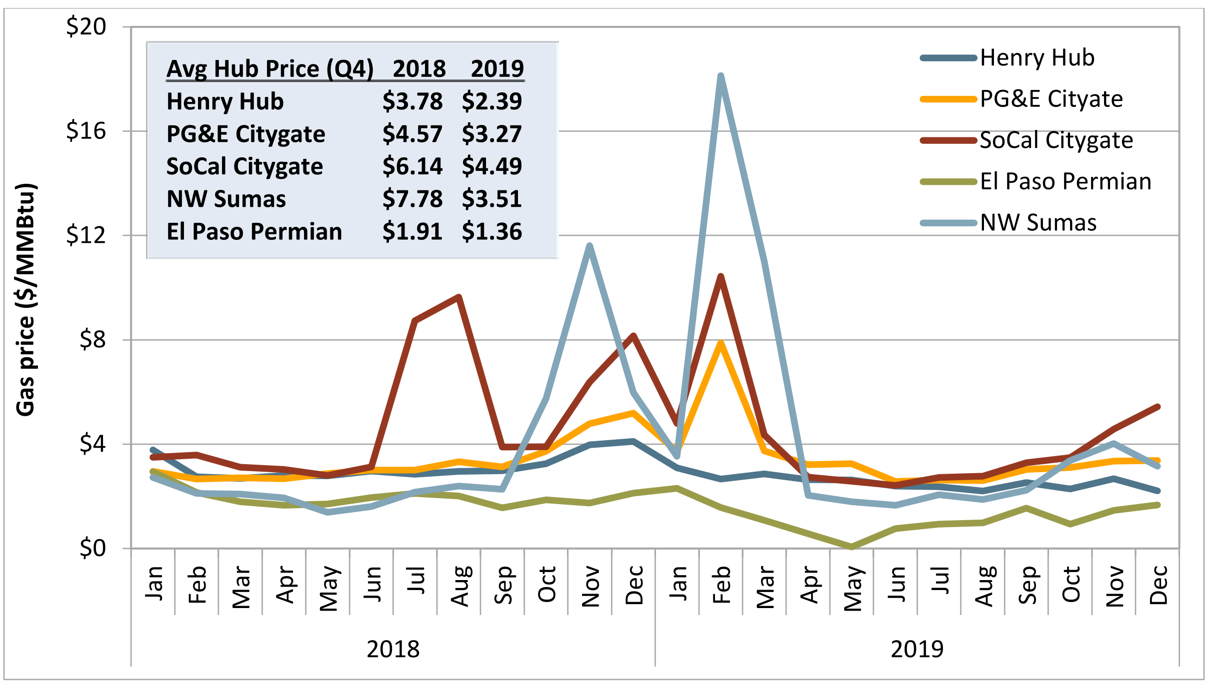
- The CPUC granting SoCalGas more flexibility this winter to withdraw from the Aliso Canyon natural gas storage facility. During the past few winters, Aliso Canyon was only available for withdrawals as a last resort.[2]

High SoCal Citygate prices during late November and December 2019 are a result of colder-than-normal temperatures and maintenance at SoCalGas storage facilities. During the maintenance, SoCalGas withdrew natural gas from the Aliso Canyon facility under the new withdrawal protocol. SoCal Citygate prices often impact overall electric 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.

Northwest Sumas prices have also declined compared to the fourth quarter in 2018. On November 28, the Canada Energy Regulator approved the Enbridge Westcoast line to return to full operating pressure, following an October 2018 explosion.

Permian prices initially started to rise because a new pipeline entered into service, providing additional take-away capacity and relieving a shortage due to a force majeure on El Paso Natural Gas's pipeline. However, natural gas production in the region has increased, exhausting the newly available capacity and resulting in ongoing export constraints that placed downward pressure on prices.

Figure 1.1 Monthly average natural gas prices



Avg Hub Price (Q4)	2018	2019
Henry Hub	$3.78	$2.39
PG&E Citygate	$4.57	$3.27
SoCal Citygate	$6.14	$4.49
NW Sumas	$7.78	$3.51
El Paso Permian	$1.91	$1.36

Monthly variation in hydroelectric, wind, and solar

In the fourth quarter, total generation from hydroelectric, solar, and wind resources decreased by about 43 percent compared to the previous quarter. Generation from these resources tends to peak in the

2 Aliso Canyon Withdrawal Protocol, July 23, 2019: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/UpdatedWithdrawalProtocol_2019-07-23%20-%20v2.pdf

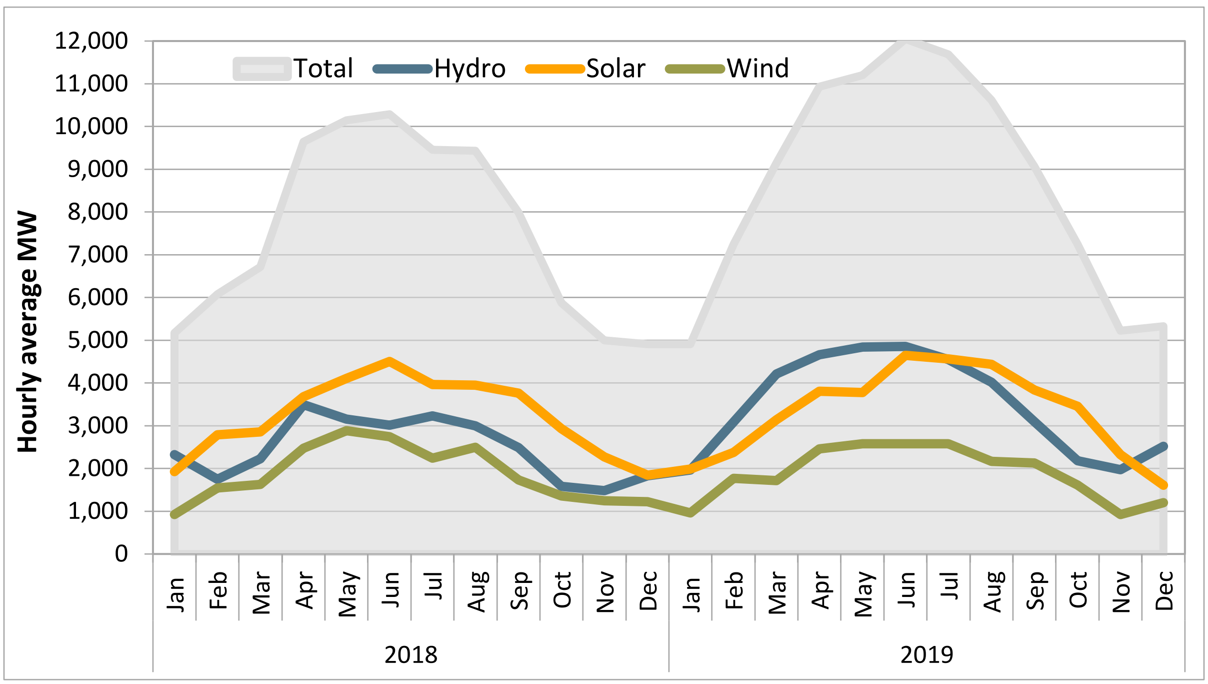
second quarter. Total generation increased by 13 percent compared to the same quarter in 2018, primarily due to greater availability of hydroelectric resources in addition to continued capacity additions of wind and solar.

Compared to 2018, hydroelectric production in the fourth quarter increased by roughly 36 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] Compared to the previous quarter, hydroelectric generation decreased 43 percent.

Compared to the fourth quarter of 2018, solar production increased by about 5 percent while wind production decreased by about 2 percent. Compared to the third quarter of 2019, solar and wind production decreased by about 44 percent.

The availability of variable resources contributes to patterns in prices both seasonally and hourly due to their low marginal cost relative to other resources. The 43 percent decrease in production from these resources contributed to higher wholesale electricity prices relative to the previous quarter just as the 13 percent increase in production contributed to lower costs relative to the fourth quarter of 2018.

Figure 1.2 Average hourly hydroelectric, wind, and solar generation by month



Generation by fuel type

Figure 1.3 shows average hourly generation for the quarter by fuel type. In the fourth quarter, lower loads and lower solar and hydroelectric generation resulted in significantly more production from natural gas relative to other resource types compared to the third quarter. Generation from imports decreased, likely related to lower availability of hydroelectric resources outside of California. Generation

[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/.

from nuclear, bio-based resources, and geothermal resources decreased compared to the previous quarter, comprising about 3,100 MW of inflexible base generation. Generation from 'other' resources, including coal, battery storage, demand response, and additional non-gas technologies, increased in this quarter, but continues to be a small share of generation (about 370 MW on average).

Figure 1.3 Average hourly generation by fuel type (Q4 2019)

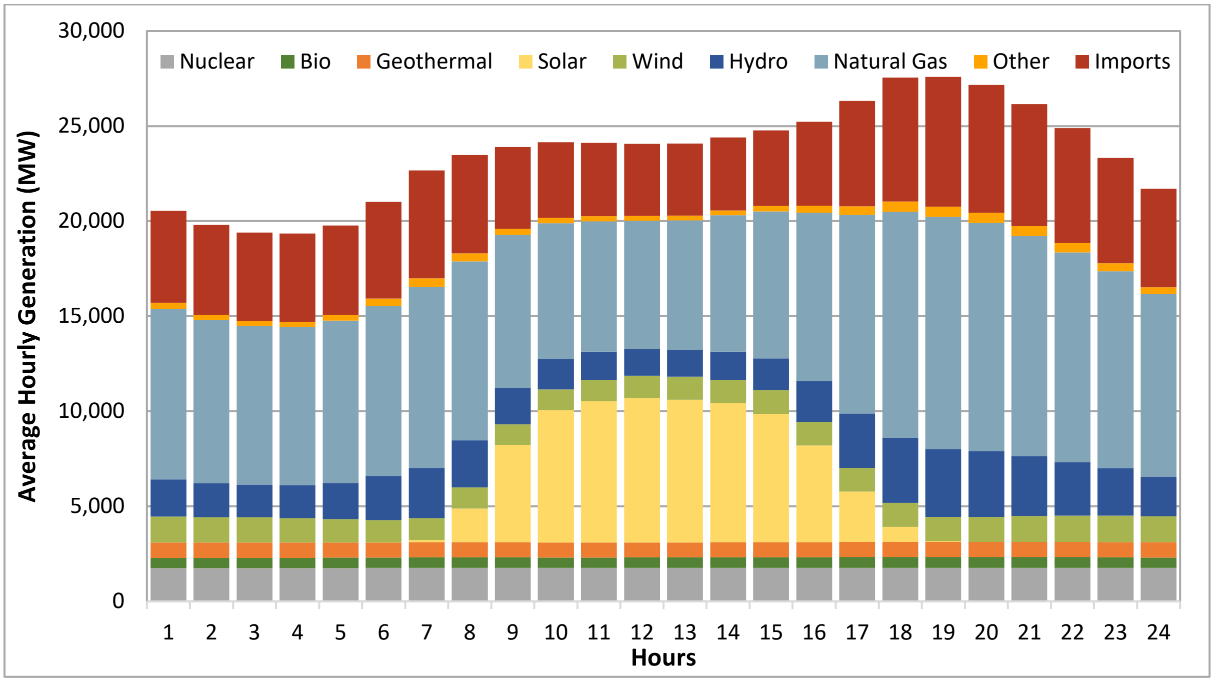
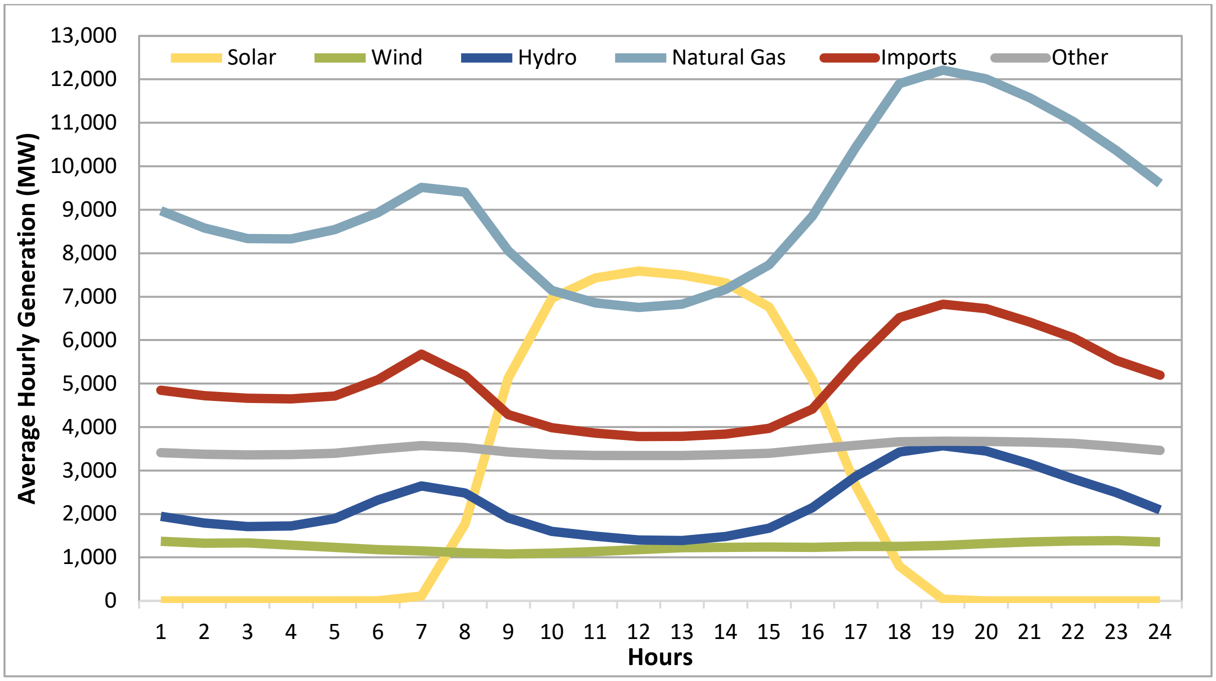


Figure 1.4 shows hourly variation of generation by fuel group, driven by hourly variation of solar production. In the fourth quarter, natural gas varied most over the day and produced significantly more than any resource during the peak net load hours, similar to previous quarters. Compared to the previous quarter, net imports and hydroelectric generation varied more significantly over the day, ramping up for the morning and evening net load peaks, and backing down when solar was producing.

Unlike the previous quarter, imports consistently produced more than hydroelectric resources throughout the day. Wind generation typically complements solar production by generating more in the early morning and late evening, and less in the middle of the day. In the fourth quarter, however, wind generation did not follow this pattern on average. There continued to be little variability from resources in the "other" category on an hourly basis.[4]

[4] In this figure, the 'Other' category contains nuclear, geothermal, bio-based resources, coal, battery storage, demand response, and additional resources of unique technologies.

Figure 1.4 Hourly variation in generation by fuel type (Q4 2019)



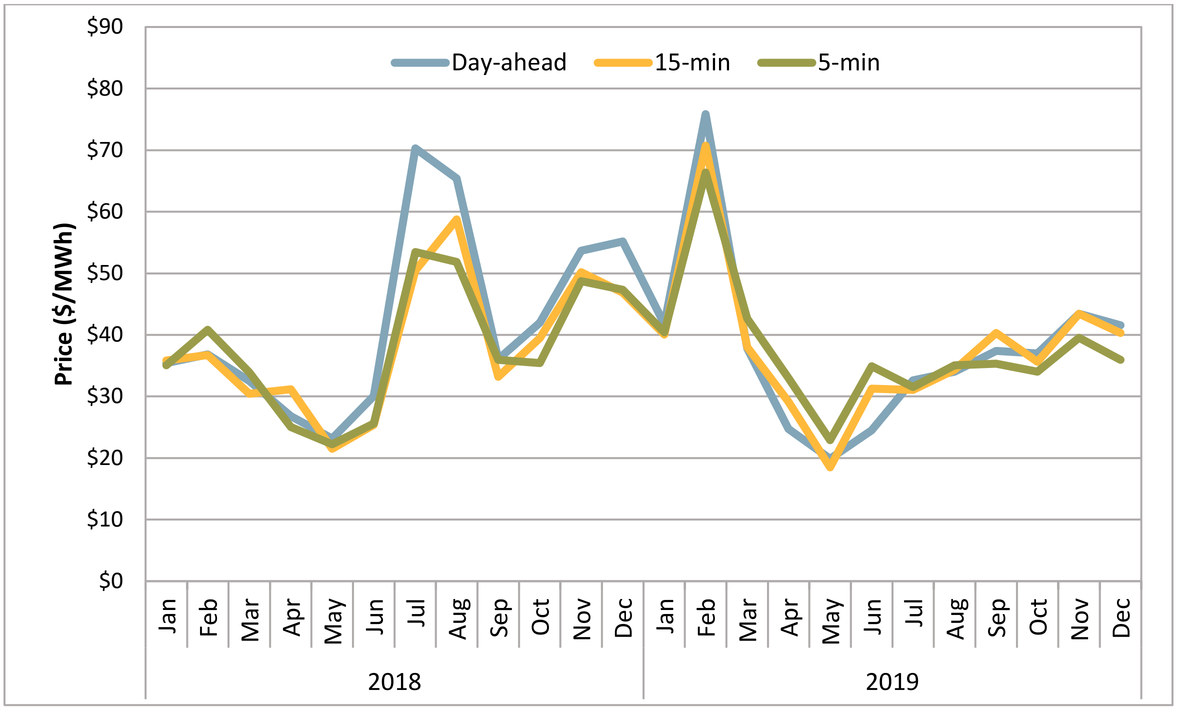
1.2 Energy market performance

1.2.1 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 1.5 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). Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) from January 2018 to December 2019.

Figure 1.5 Average monthly system marginal energy prices (all hours)



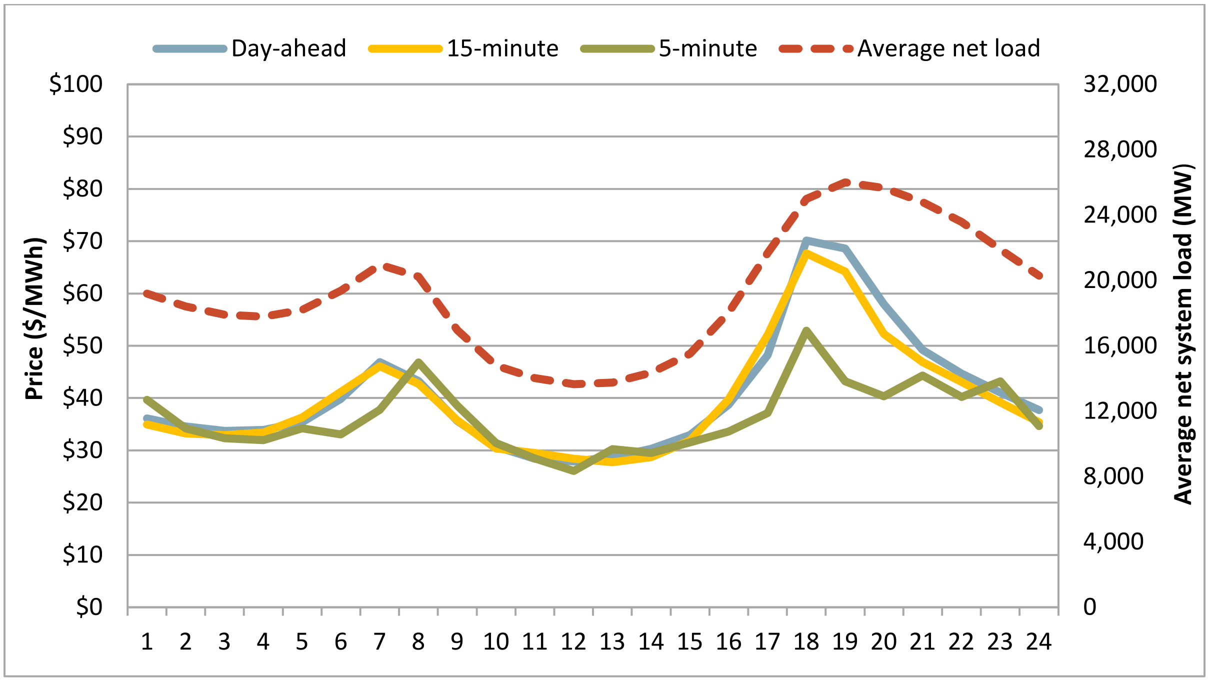
Prices increased slightly from the third quarter to the fourth quarter of 2019. Average day-ahead prices increased by 17 percent, 15-minute prices increased by 13 percent, and 5-minute prices increased by 7 percent. Although average prices in all three markets have been steadily rising since the second quarter of 2019, prices remain well below those experienced between the third quarter of 2018 and the first quarter of 2019 when natural gas prices spiked in multiple trading hubs across the West.

Average day-ahead prices were greater than the 15-minute and 5-minute market prices during the fourth quarter. Day-ahead prices averaged about $42/MWh, 15-minute prices averaged $40/MWh, and 5-minute prices averaged $36/MWh over the quarter. This relationship between market prices had been the general trend since 2014, before a reversal during the first two quarters of 2019 when day-ahead prices were below real-time prices.

Figure 1.6 illustrates load-weighted average energy prices on an hourly basis in the fourth 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 1.6 Hourly load-weighted average marginal energy prices

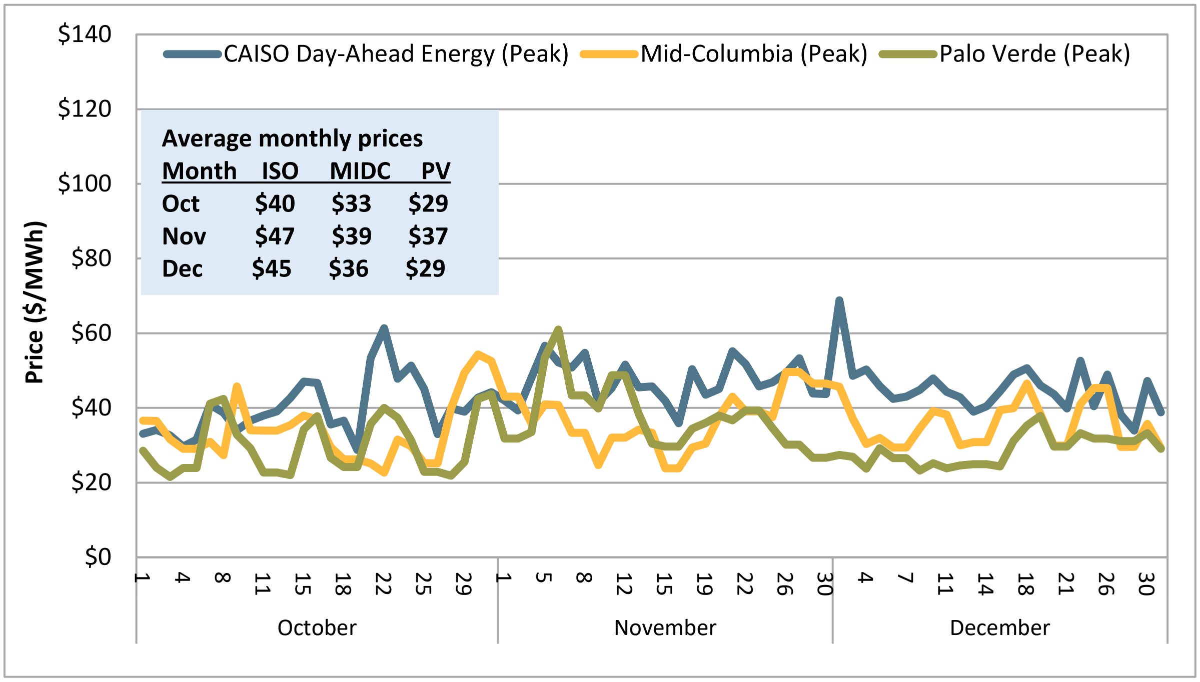


Average hourly prices in the fourth quarter continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours, particularly hours ending 18 and 19. The greatest price divergence between the markets coincided with the evening peak during hours ending 17 to 20. In hour ending 19, average prices in both the day-ahead and 15-minute markets exceeded 5-minute prices by more than $20/MWh. The difference between the day-ahead and 15-minute markets from the 5-minute market was at least $11/MWh for hours ending 17, 18, and 20. A similar price divergence pattern also occurred during the third quarter of 2019.

1.2.2 Bilateral price comparison

Average prices in the ISO, across all hours in the fourth quarter, were greater on average than prices at Mid-Columbia and Palo Verde, reflecting transmission constraints as well as greenhouse gas compliance costs. Figure 1.7 shows day-ahead weighted average prices across the three largest load aggregation points (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric) in the ISO, as well as average peak energy prices at the Palo Verde and Mid-Columbia hubs outside of the ISO market.

Figure 1.7 Daily system and bilateral market prices (Oct – Dec)



Average prices in the ISO and trade hubs were calculated during peak hours (hours ending 7 through 22) for all days excluding Sundays and holidays. In a reversal from the third quarter, daily ISO system prices in the fourth quarter were generally higher than both bilateral hub prices. Daily energy prices at Palo Verde were higher than ISO prices only about 5 percent of the time, while Mid-Columbia prices were higher than ISO prices only about 16 percent of the time during the quarter.

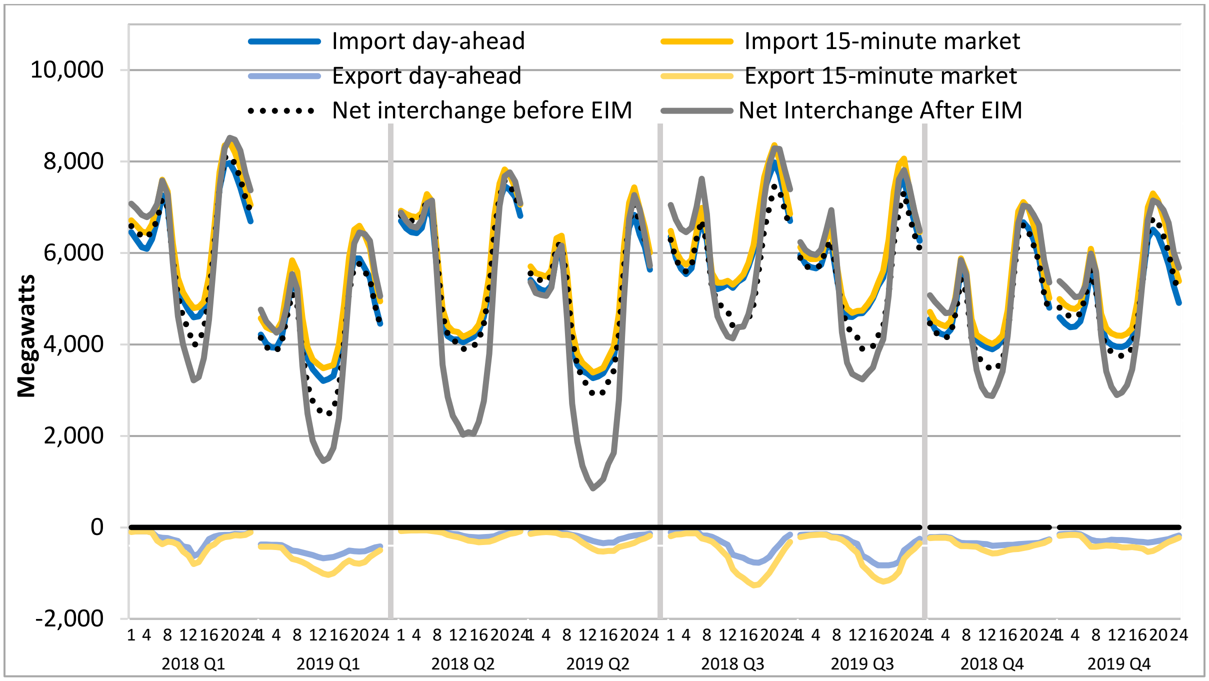
Average day-ahead prices in the ISO were also compared to hourly energy prices traded at Mid-Columbia and Palo Verde hubs for all hours of the quarter using data published by Powerdex. Average hourly prices in the ISO were greater than prices in Mid-Columbia and Palo Verde by $6.57/MWh and $10.36/MWh, respectively.

Imports and exports

As shown in Figure 1.8, average hourly cleared imports (shown in dark blue and dark yellow) peaked at the same time and approximately the same volumes as the same quarter from the previous year. Fourth quarter peak imports in the day-ahead (dark blue line) increased slightly from about 7,050 MW to 7,150 MW compared to the same period the previous year. For the same comparable period the peak 15-minute (dark yellow line) cleared imports also slightly increased from about 7,100 MW to 7,300 MW.

The greatest import transfer into the ISO from the EIM occurred in hour ending 22 at about 650 MW. Exports (shown as negative numbers below the horizontal axis in pale blue and yellow), decreased slightly from the same quarter in 2018, peaking at about 320 MW in hour ending 16 through 19. The average net interchange, excluding EIM transfers (shown in dashes), is based on meter data and averaged by hour and quarter. The solid grey line adds incremental EIM interchange, which reached a low point of about 2,900 MW in hour ending 12.

Figure 1.8 Average hourly net interchange by quarter



1.3 Wholesale energy cost

Total wholesale cost to serve load in the ISO market during the fourth quarter of 2019 was about $2.3 billion, down from about $2.8 billion in the same quarter of 2018. The average cost per megawatt-hour of load decreased 18 percent to about $44/MWh for the fourth quarter from $54/MWh in the same quarter of 2018 (nominal costs shown in blue bars in Figure 1.9).

The decrease in average wholesale electric prices is primarily from a 19 percent decrease in natural gas prices compared to the same quarter in 2018. Load-weighted gas prices decreased to about $4.85/MMBtu, a 19 percent decrease from about $5.99/MMBtu in the same quarter of 2018. When normalizing for changes in natural gas and greenhouse gas costs using the 2010 gas price as a reference year, the gold bar in Figure 1.9 shows the wholesale energy costs to serve load decreased by 4 percent to about $40/MWh from about $41/MWh in the same quarter of 2018. In addition to lower natural gas costs, increased production from hydroelectric and solar resources contributed to lower wholesale energy costs this quarter.

Figure 1.9 Total quarterly wholesale costs per MWh of load

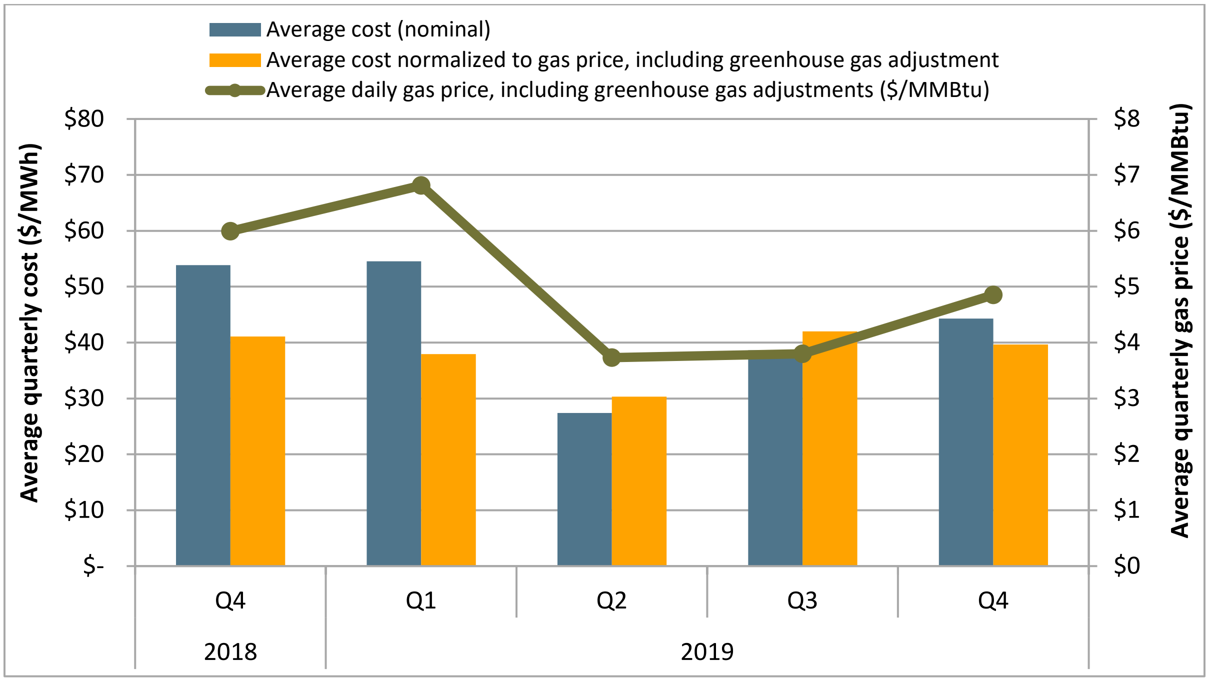


Table 1.1 provides quarterly summaries of nominal total wholesale costs by category. Costs for energy procured in the day-ahead market continued to make up a majority (93 percent) of the total cost to deliver energy to the market, similar to the previous quarter and the fourth quarter of 2018. Real-time market costs increased to about 3 percent of the total cost from about 2.5 percent in the previous quarter. Bid cost recovery costs were about 1 percent of total cost, a decrease from the previous quarter but similar to the same quarter of 2018. Costs for reliability remained low at about 0.1 percent, and reserve costs decreased slightly to about 1.1 percent of total costs.

Table 1.1 Estimated average wholesale energy costs per MWh

	Q4 2018	Q1 2019	Q2 2019	Q3 2019	Q4 2019	Change Q4 2018-Q4 2019
Day-ahead energy costs	$ 51.46	$ 52.23	$ 23.97	$ 35.94	$ 41.35	$ (10.11)
Real-time energy costs (incl. flex ramp)	$ 0.01	$ 0.30	$ 1.28	$ 0.98	$ 1.44	$ 1.44
Grid management charge	$ 0.48	$ 0.46	$ 0.47	$ 0.45	$ 0.46	$ (0.02)
Bid cost recovery costs	$ 0.48	$ 0.56	$ 0.50	$ 0.72	$ 0.47	$ (0.01)
Reliability costs (RMR and CPM)	$ 0.90	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ (0.83)
Average total energy costs	**$ 53.32**	**$ 53.60**	**$ 26.28**	**$ 38.15**	**$ 43.78**	**$ (9.54)**
Reserve costs (AS and RUC)	$ 0.53	$ 0.94	$ 1.15	$ 0.46	$ 0.49	$ (0.05)
Average total costs of energy and reserve	**$ 53.85**	**$ 54.54**	**$ 27.42**	**$ 38.61**	**$ 44.27**	**$ (9.59)**

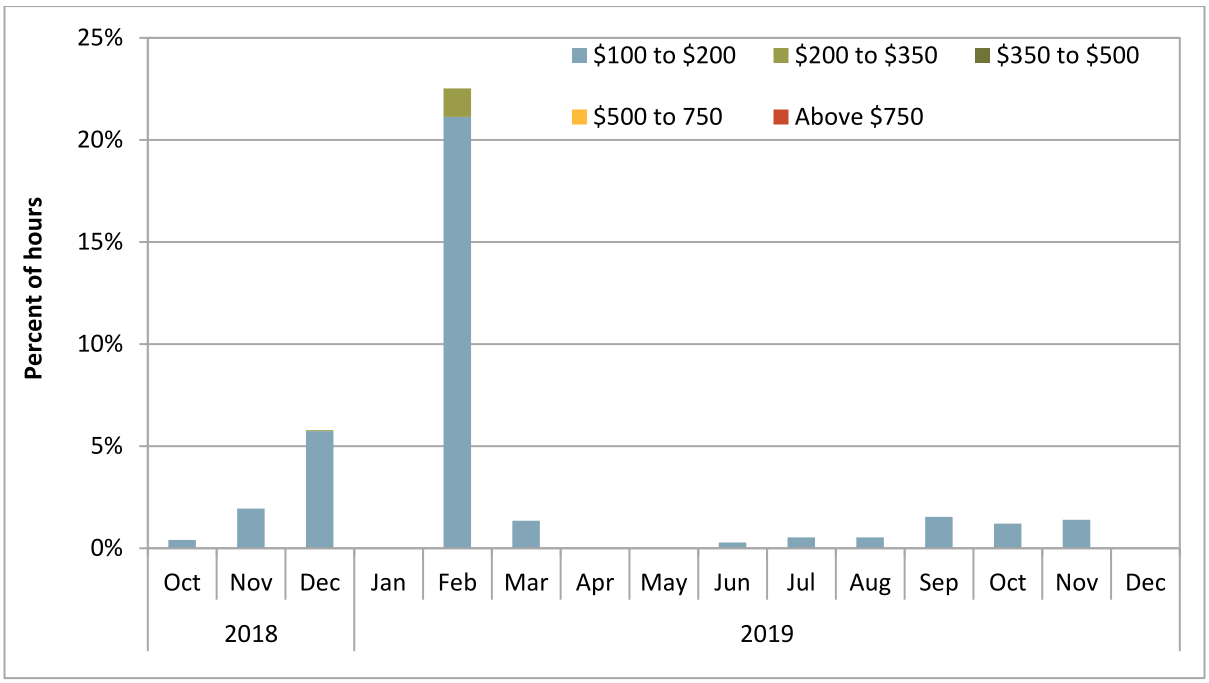
1.4 Day-ahead price variability

High prices

Figure 1.10 shows the frequency of day-ahead market prices in various high priced ranges from October 2018 to December 2019. The frequency of hours with high day-ahead prices was similar between the third and fourth quarters of 2019. Prices greater than $100/MWh occurred during 1 percent of hours in each quarter.

The frequency of high day-ahead price spikes in the fourth quarter of 2019 was slightly lower than during the same quarter of the previous year, when prices above $100/MWh occurred more frequently.

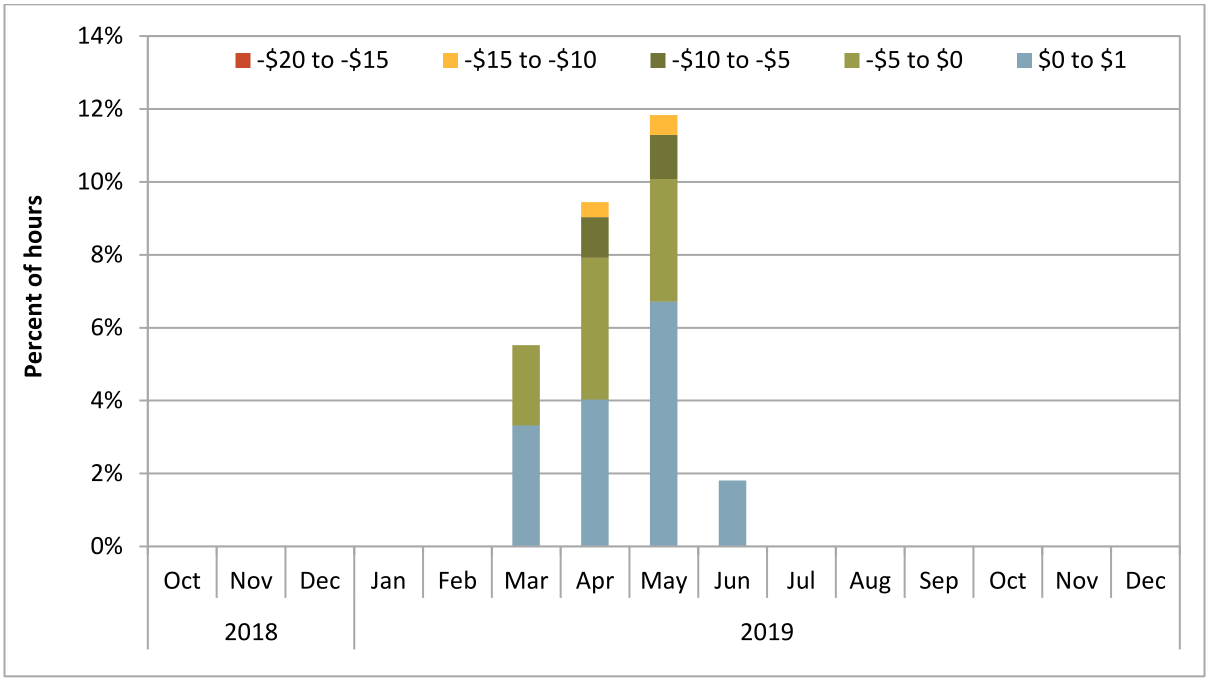
Figure 1.10 Frequency of high day-ahead prices (MWh) by month



Negative prices

Figure 1.11 shows the frequency of day-ahead market prices in various low priced ranges from October 2018 to December 2019. Unlike the first two quarters of 2019, there were no negative day-ahead prices in the fourth quarter, even during the mid-day hours when generation from solar was at its peak with relatively low loads. This result is similar to the frequency of negative day-ahead prices from the third quarter of 2019 as well as the same quarter of the previous year.

Figure 1.11 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 fourth quarter of 2019, the frequency of high real-time prices was low, similar to the previous quarter. This was in part due to a low frequency of under-supply infeasibilities during the quarter. There were no under-supply infeasibilities in either the 15-minute market or the 5-minute market during December.

High prices

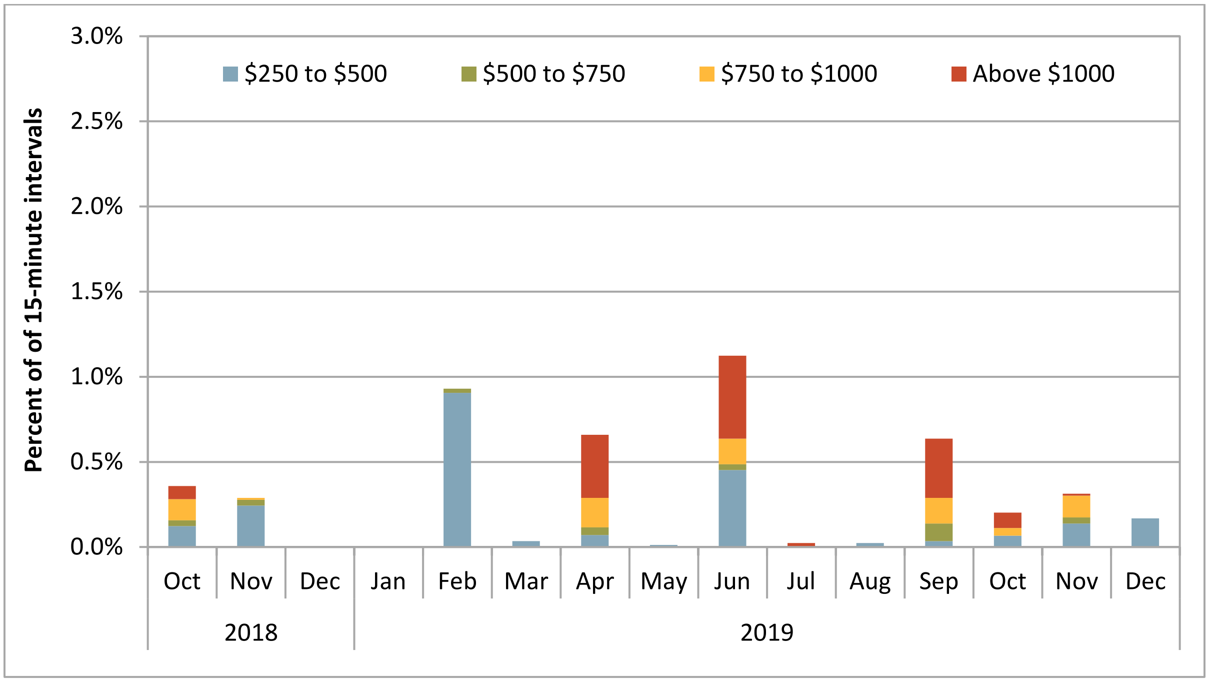
Figure 1.12 and Figure 1.13 show the frequency of prices above $250/MWh across the three largest load aggregation points (LAP) in the ISO. As shown in Figure 1.12, the occurrence of high prices in the 15-minute market greater than $250/MWh was very infrequent during the fourth quarter. Under-supply infeasibilities for the quarter in the 15-minute market were isolated to only two intervals in October.

Figure 1.13 shows the frequency of high prices in the 5-minute market. During the fourth quarter, the frequency of price spikes greater than $250/MWh in the 5-minute market occurred during less than 0.5 percent of intervals, similar to the previous quarter.

Figure 1.14 shows the corresponding frequency of under-supply infeasibilities in the 5-minute market. Valid under-supply infeasibilities were very infrequent in the fourth quarter, occurring during less than 0.1 percent of 5-minute market intervals. In particular, there were no valid undersupply infeasibilities in the 5-minute market during December.

Infeasibilities resolved by the load conformance limiter continued to be very infrequent, a trend that began in the first quarter with the implementation of the enhancement to the limiter at the end of February 2019.[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 1.12 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 1.13 Frequency of high 5-minute prices by month (ISO LAP areas)

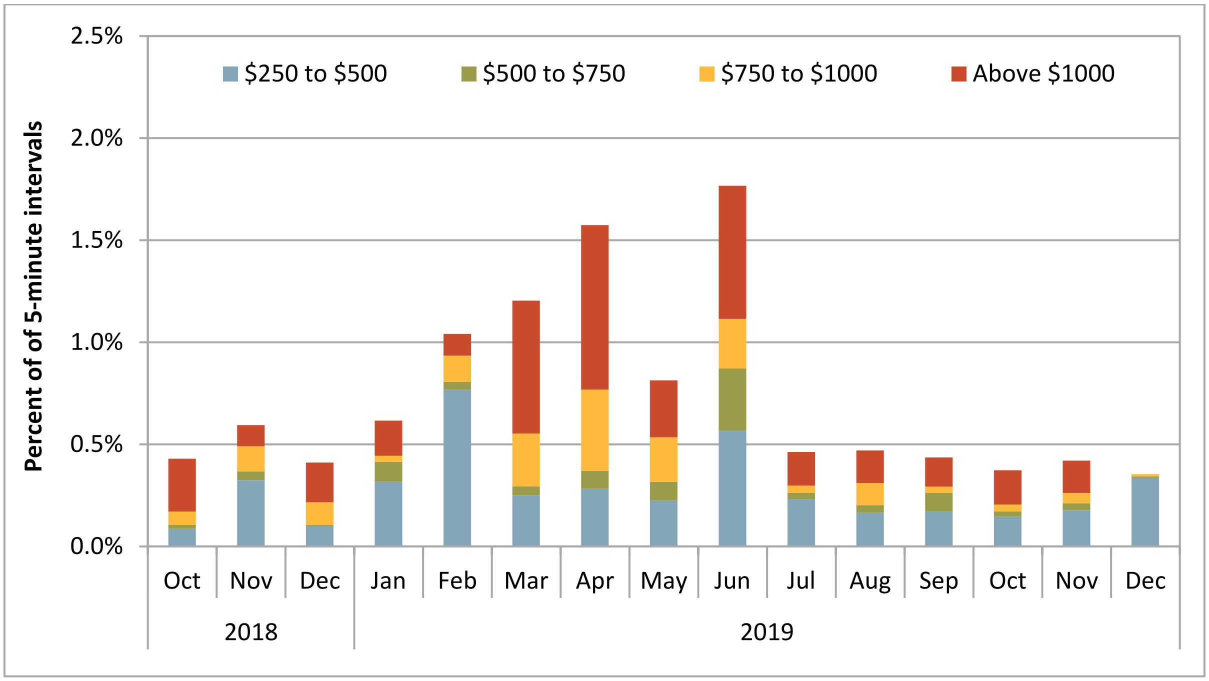
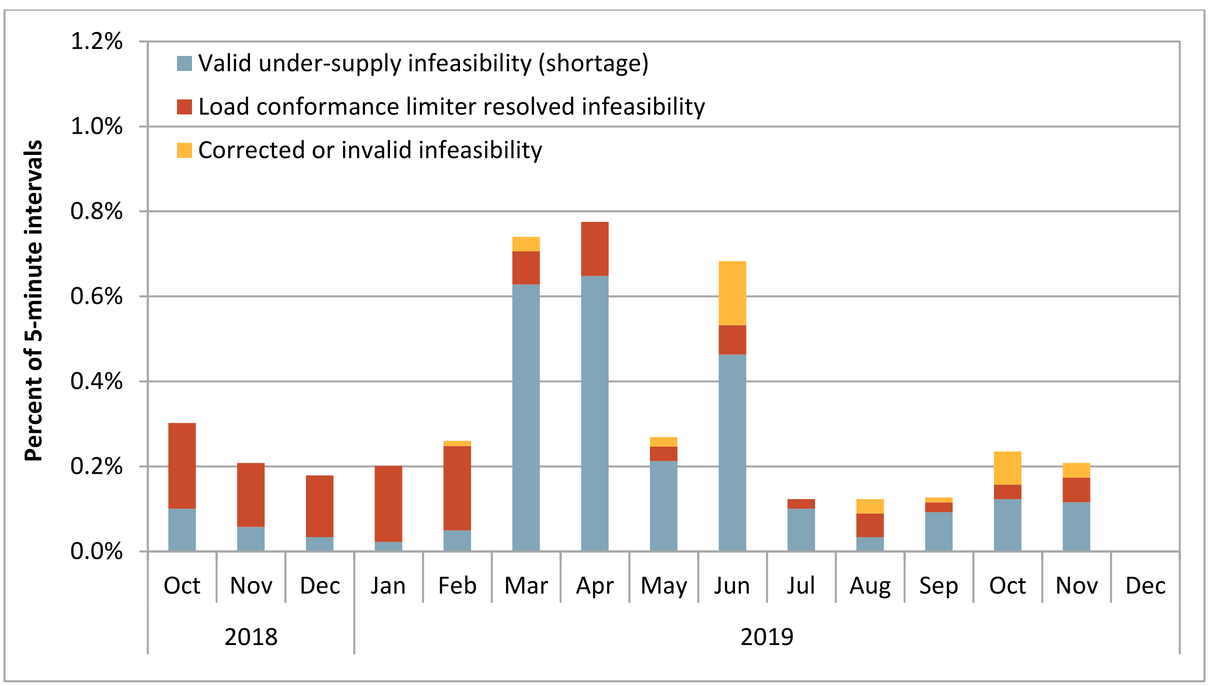


Figure 1.14 Frequency of under-supply power balance constraint infeasibilities (5-minute market)

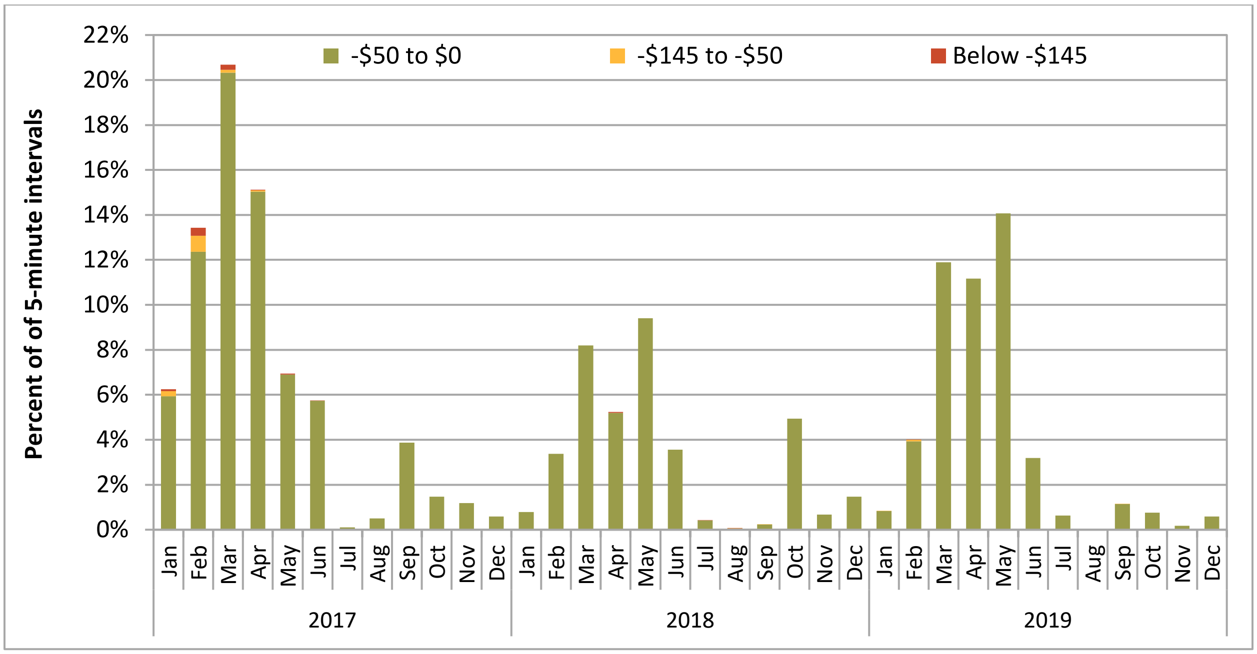


Negative prices

Figure 1.15 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 continued to be very low during the fourth quarter of 2019, occurring during less than 1 percent of intervals. 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 economic bids from wind and solar resources reflecting their relatively low marginal costs. During the fourth quarter, this was most frequent between hours ending 10 and 15 when loads, net of wind and solar, were lowest.

Figure 1.15 Frequency of negative 5-minute prices by month (ISO LAP areas)



1.6 Flexible ramping product

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 within that 15-minute interval. Procurement in the 5-minute

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

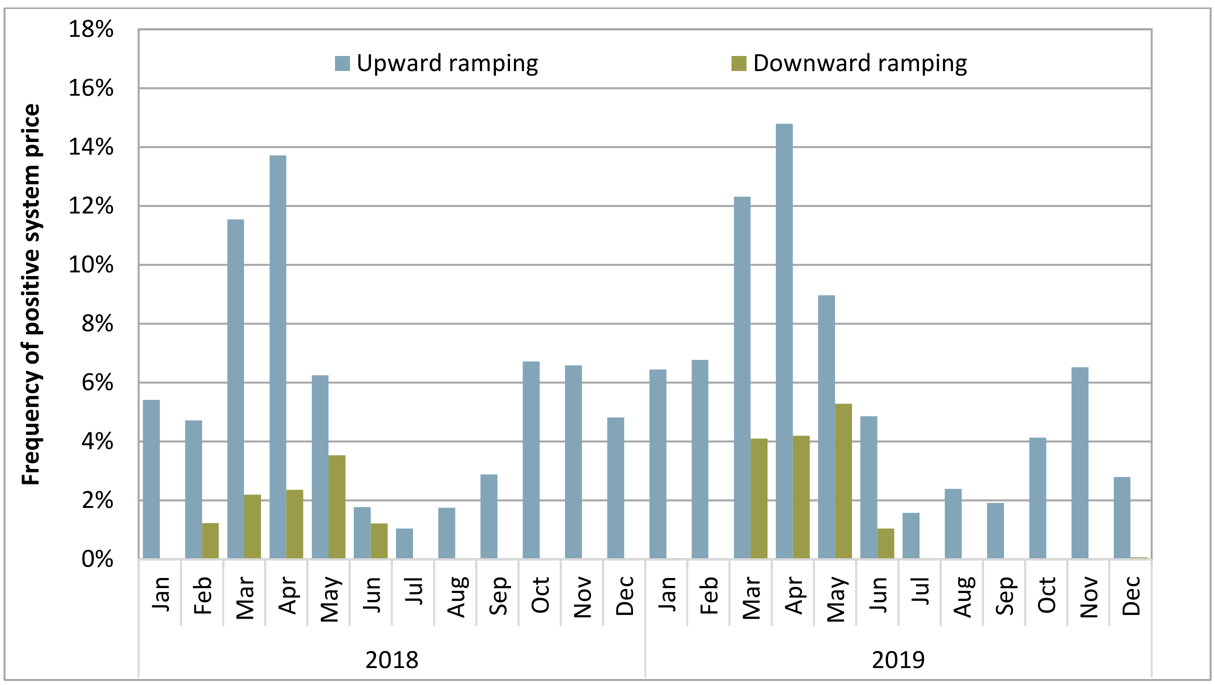
market is designed to ensure that enough ramping capacity is available to manage differences between consecutive 5-minute market intervals.

1.6.1 Flexible ramping product prices

This section describes the amount of flexible ramping capacity that was procured in the fourth quarter, and 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 1.16 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 fourth quarter, there was an increased frequency in nonzero shadow prices. The 15-minute market system-level demand curves bound in around 4.5 percent of intervals in the upward direction during the quarter. In the 5-minute market, the system-level demand curves bound in less than 0.1 percent of intervals.

Figure 1.16 Monthly frequency of positive 15-minute market flexible ramping shadow price



1.6.2 Flexible ramping product costs

Flexible ramping capacity that satisfy the demand for upward and downward uncertainty receive payments based on the combined system and area-specific flexible ramping shadow price. In addition, the combined flexible ramping shadow price is used to pay or charge for forecasted ramping movements. This means 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.[8] The following section looks at flexible ramping product payments from three different perspectives: (1) by payment type, (2) by area, and (3) by fuel type.

Figure 1.17 shows the total monthly net payments to resources from the flexible ramping product, including both payments for flexible ramping capacity to meet upward and downward uncertainty as well as payments for forecasted movements. Payments for upward uncertainty were up from the previous quarter, consistent with a higher frequency of nonzero prices for flexible ramping capacity. Total uncertainty payments to generators in the ISO and the EIM for providing flexible ramping capacity during the fourth quarter were around $1.5 million, compared to around $0.6 million in the previous quarter.

Figure 1.17 Monthly flexible ramping product payments by type

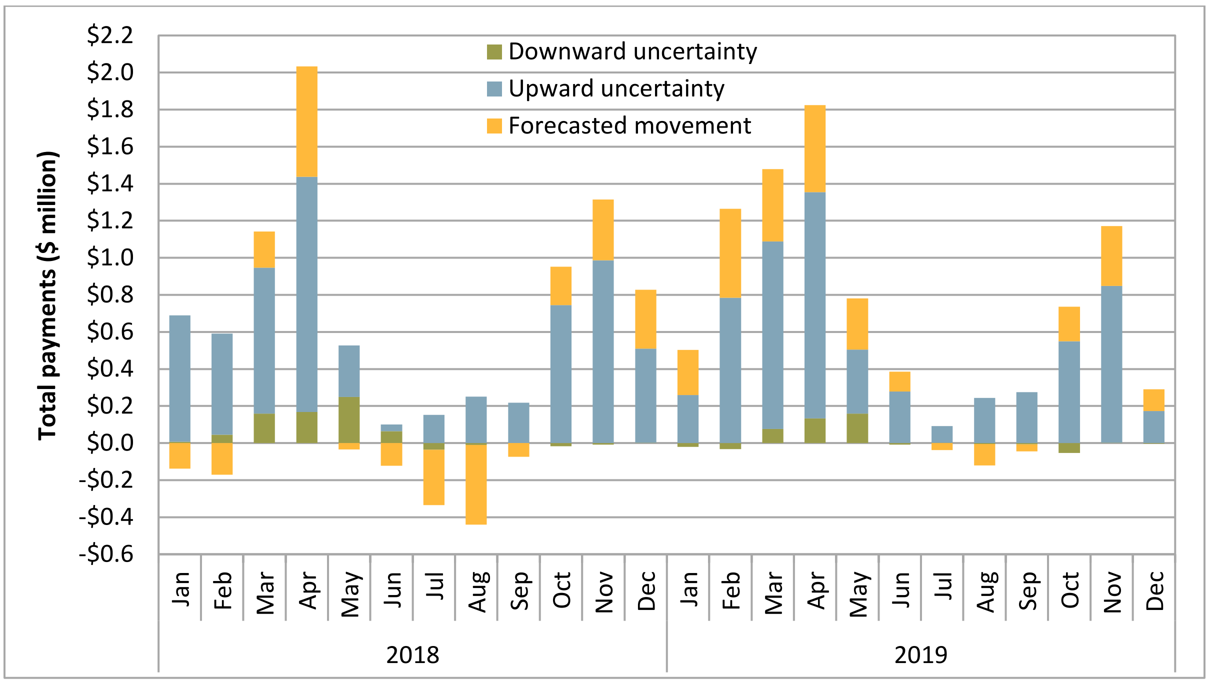


Figure 1.18 and Figure 1.19 do not include payments for forecasted movements and therefore only reflect payments to generators for upward and downward ramping capacity to meet uncertainty needs.

Figure 1.18 shows these payments by area, arranged generally by geographic location. Payments for this capacity may have been procured to satisfy system-level demand, area-specific demand, or both. During 2019, 42 percent of payments for flexible ramping capacity have been to resources internal to the ISO while 45 percent of payments have been to areas in the Northwest region that includes PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex. In both cases, the large majority of payments have been for system uncertainty needs rather than area-specific uncertainty needs.

8 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.

Figure 1.18 Monthly flexible ramping product uncertainty payments by area

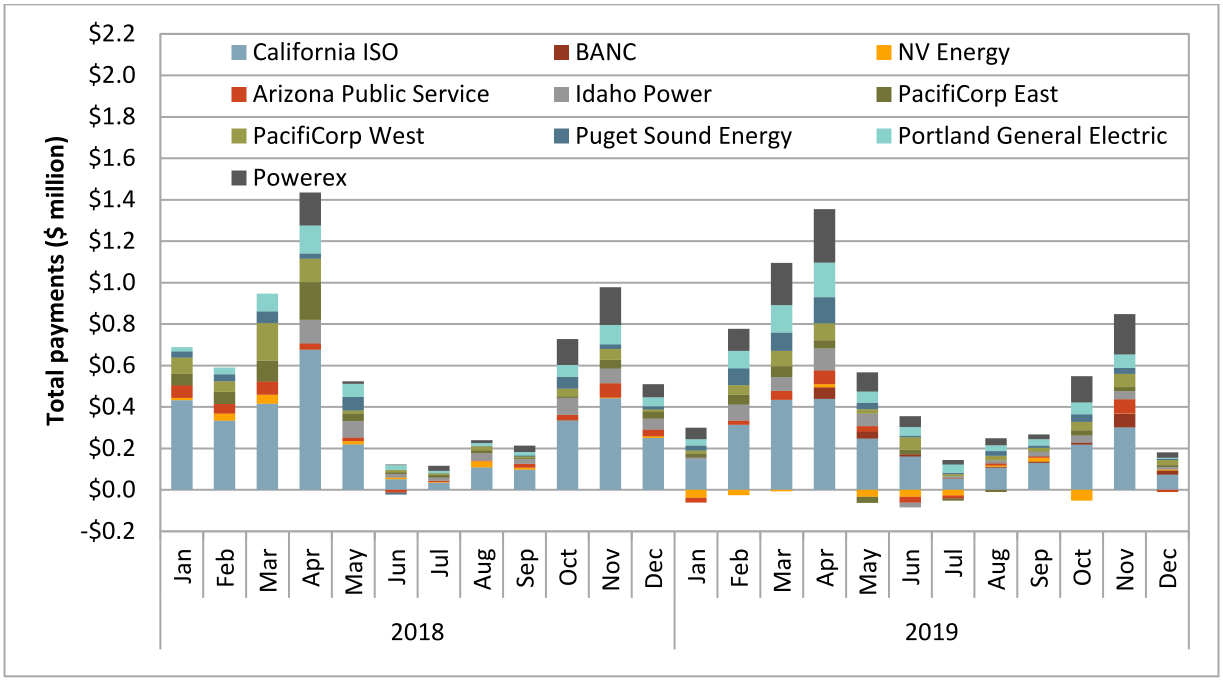


Figure 1.19 Monthly flexible ramping product uncertainty payments by fuel type

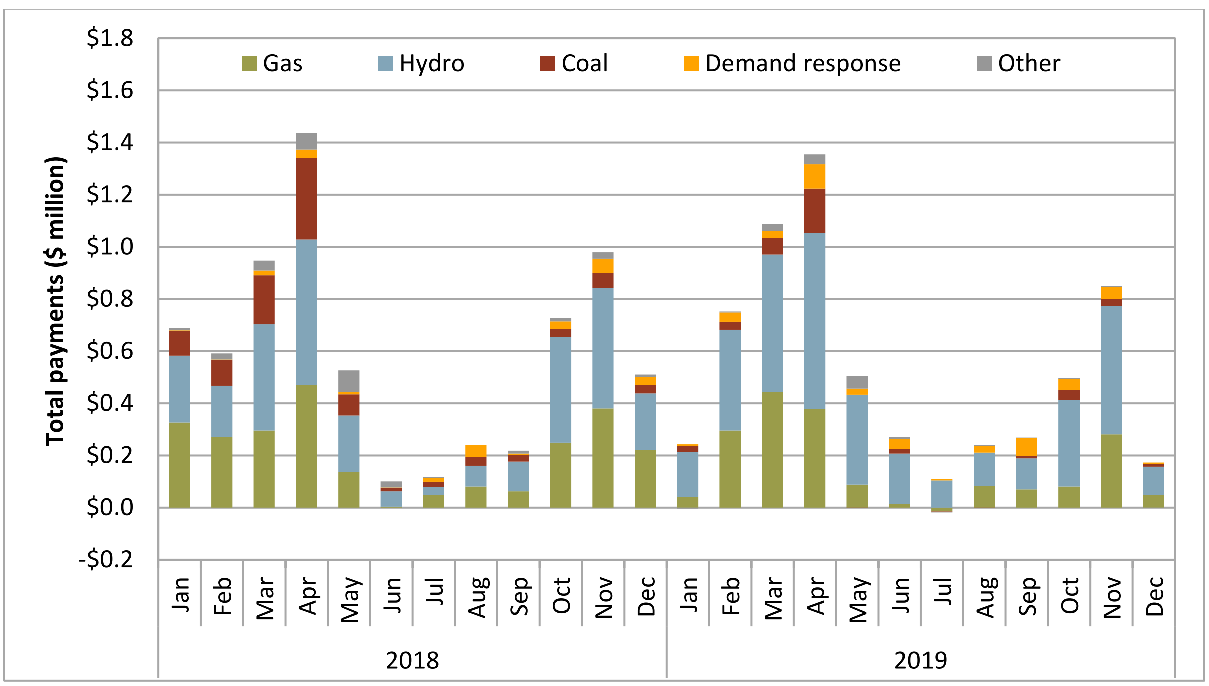


Figure 1.19 shows the same information by fuel type. In 2019, around 57 percent of flexible capacity payments for upward and downward uncertainty have been to hydroelectric generators. Similarly, 29 percent of payments have been to gas resources while roughly 6 percent of payments have been to each of coal and proxy demand response units. Procuring ramping capacity from proxy demand response units presents an issue because of the ability of these resources to respond to isolated 5-minute dispatches.

1.6.3 Flexible ramping product procurement

One of the key objectives of the flexible ramping product is to address the challenges of maintaining power balance in real-time between supply and demand. The flexible ramping product allows the market to account and procure for uncertainty surrounding a forecasted value that could otherwise result in an infeasibility. However, procurement of flexible ramping capacity from resources that are not able to meet system uncertainty — either because of resource characteristics or congestion — can reduce the effectiveness of the flexible ramping product to both manage net load volatility and prevent power balance violations.

In particular, procurement from proxy demand response resources and from resources stranded behind transfer constraints (particularly in the Northwest) can contribute to lower deliverability of flexible ramping capacity at the system level and suppress the true opportunity cost of providing such capacity instead of energy.[9]

Figure 1.20 shows the average upward ramping capacity procured in the 5-minute market by fuel type in the interval prior to any system under-supply infeasibility (or period of consecutive infeasibilities).[10] The dotted line shows the underlying number of under-supply infeasibility periods in each month. The bars show the average procurement of upward ramping capacity by fuel type in the interval prior to these periods. During October 2019, upward flexible ramping capacity awards to demand response resources made up 15 percent of procurement in the interval prior to infeasibility periods. In November, this was down to around 1 percent. There were no under-supply infeasibilities in December.

Figure 1.21 shows the same procurement information as Figure 1.20, except by area instead of fuel type. During the fourth quarter, flexible ramping capacity awards to resources in the Northwest region made up 55 percent of procurement in the interval prior to under-supply infeasibility periods.

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9 For more detailed information on these issues, see Section 3.1.3 in DMM's *Q3 2019 Report on Market Issues and Performance*, December 5, 2019: http://www.caiso.com/Documents/2019ThirdQuarterReportonMarketIssuesandPerformance.pdf.

10 For under-supply infeasibility periods lasting longer in duration than one 5-minute interval, only procurement in the interval prior to these periods is summarized in these figures.

Figure 1.20 Average 5-minute market upward ramping capacity procurement prior to under-supply infeasibility periods - by fuel type

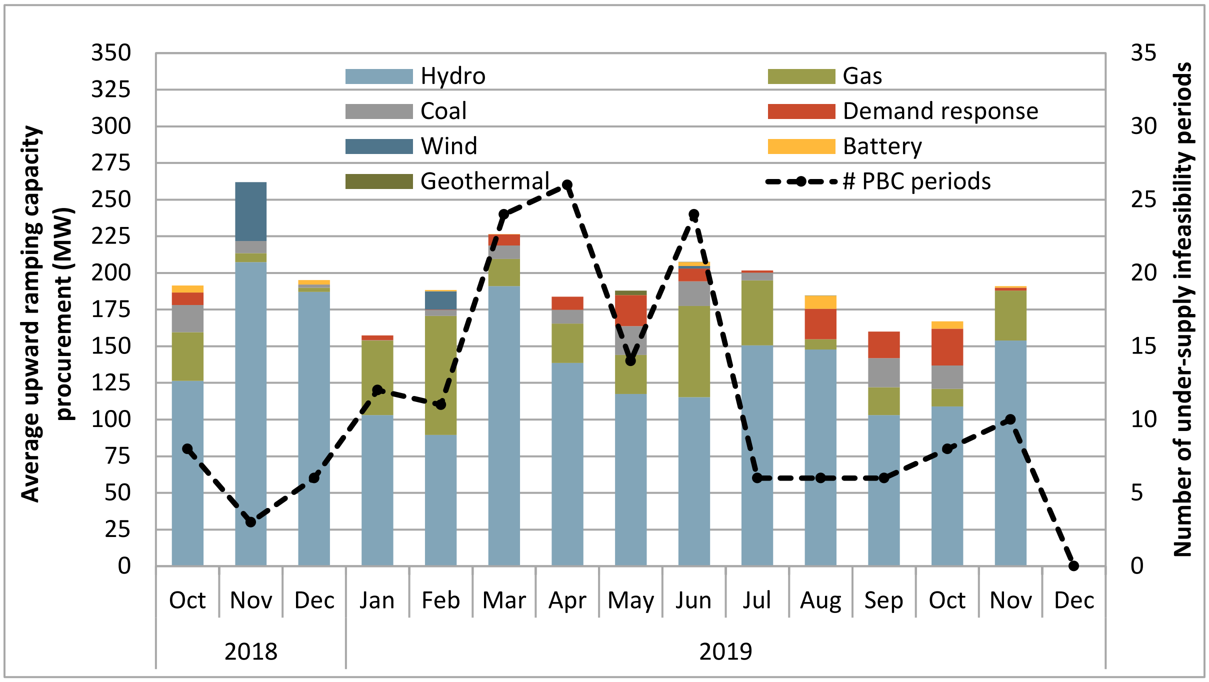
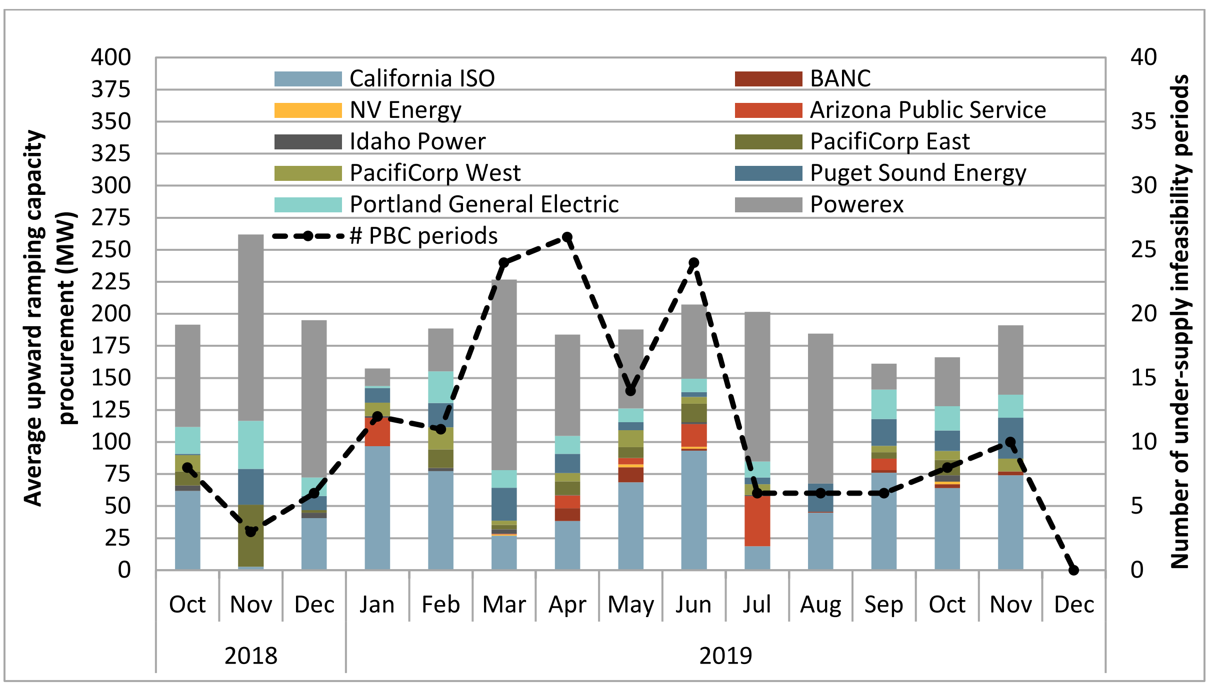


Figure 1.21 Average 5-minute market upward ramping capacity procurement prior to under-supply infeasibility periods - by area



1.7 Convergence bidding

Convergence bidding was profitable overall for both virtual demand and virtual supply bids for the fourth quarter. Combined net revenue for virtual supply and demand was about $5.5 million after including about $2.2 million of virtual bidding bid cost recovery charges. Virtual demand generated revenues of about $0.1 million. Before accounting for bid cost recovery charges, virtual supply generated net revenues of $7.6 million.

1.7.1 Convergence bidding trends

Average hourly cleared volumes were about 3,200 MW, a decrease of about 200 MW from the previous quarter. Average hourly virtual supply remained similar to the previous quarter at about 1,900 MW. Virtual demand averaged around 1,300 MW during each hour of the quarter, a 100 MW decrease from the previous quarter. On average, about 25 percent of virtual supply and demand bids offered into the market cleared in the quarter, down from 30 percent in the previous quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 560 MW on average, an increase from 540 MW of net virtual supply in the previous quarter. On average for the quarter, net cleared virtual demand only exceeded net cleared virtual supply in hours ending 6 and between 17 and 20. In the remaining 19 hours, net cleared virtual supply exceeded net cleared virtual demand. Similar to the previous quarter, cleared virtual supply exceeded virtual demand by 1,000 MW during hours ending 21 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 19 of 24 hours. The majority of the inconsistent volumes occurred between hours ending 5, 11, 16, 18 and 19.

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 780 MW of virtual demand offset by 780 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 49 percent of all cleared virtual bids in the fourth quarter, a decrease of about 1 percent from the previous quarter.

1.7.2 Convergence bidding revenues

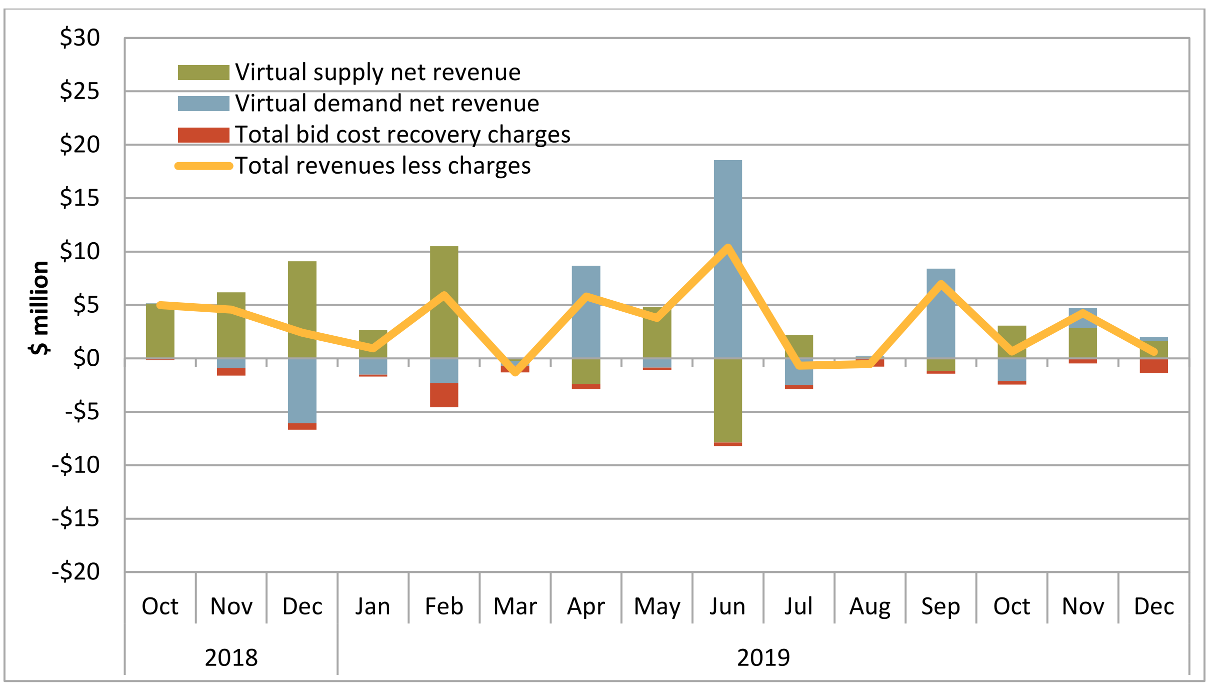
Participants engaged in convergence bidding in the fourth quarter were profitable overall. Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $7.6 million. Net revenues for virtual supply and demand fell to about $5.5 million after including about $2.2 million of virtual bidding bid cost recovery charges.[11] This decline is due primarily to bid cost recovery charges associated with virtual supply.

Figure 1.22 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 fourth quarter totaled about $7.6 million, compared to about $13.4 million during the same quarter in 2018, and about $7.2 million during the previous quarter.
- Virtual demand net revenues were negative in October and positive in November and December. In total, virtual demand generated positive net revenues of about $0.13 million for the quarter. Unlike the previous quarter, there very few large positive net virtual demand hours.
- Virtual supply net revenues were positive in all months of the quarter with $3 million, $2.8 million and $1.6 million for October, November and December, respectively.

Figure 1.22 Convergence bidding revenues and bid cost recovery charges



11 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.

Convergence bidders received about $7.6 million before subtracting bid cost recovery charges of about $2.2 million for the quarter.[12,13] Bid cost recovery charges were about $0.3 million in October, $0.5 million in November and $1.4 million in December.

Net revenues and volumes by participant type

Figure 1.23 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.[14] As with the previous quarter, financial entities represented the largest segment of the virtual bidding market, accounting for about 71 percent of volume and 83 percent of settlement revenue. Marketers represented about 27 percent of the trading volumes and about 15 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 2 percent respectively. Generation owners and load-serving entities accounted for around $0.15 million of net revenues in the market.

Figure 1.23 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	941	1,316	2,257	$0.57	$5.78	$6.35
Marketer	352	502	854	-$0.44	$1.60	$1.15
Physical load	0	22	22	$0.00	$0.08	$0.08
Physical generation	18	33	51	$0.01	$0.06	$0.07
Total	**1,312**	**1,872**	**3,184**	**$0.1**	**$7.5**	**$7.6**

1.8 Ancillary services

1.8.1 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.

12 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.

13 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.

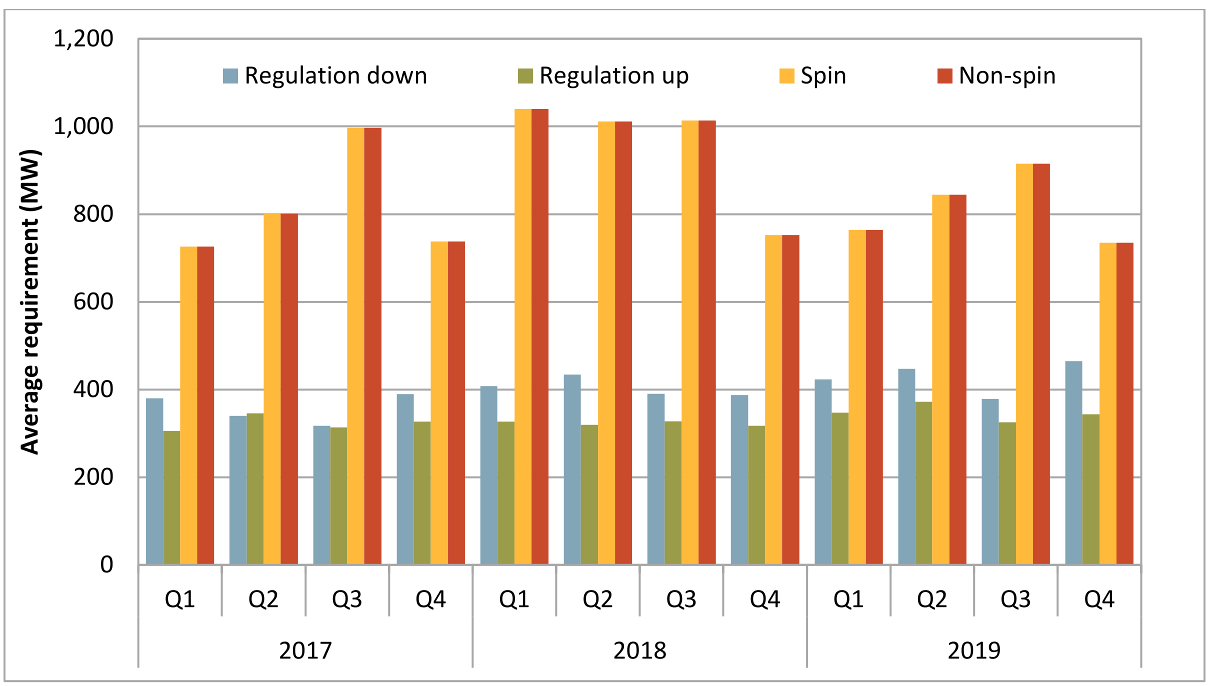
14 DMM has defined financial entities as participants who own no physical power and participate in the convergence bidding and congestion revenue rights markets only. Physical generation and load are represented by participants that primarily participate in the ISO markets as physical generators and 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.

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 nested within the system and corresponding expanded regions. Therefore, ancillary services procured in an inward region also count toward meeting the minimum requirement of the outer region. Both internal resources and imports then meet ancillary service requirements, 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 1.24 shows quarterly average ancillary service requirements for the expanded system region in the day-ahead market. As shown in the figure, regulation down requirements increased during the fourth quarter.

Figure 1.24 Average quarterly day-ahead ancillary service requirements



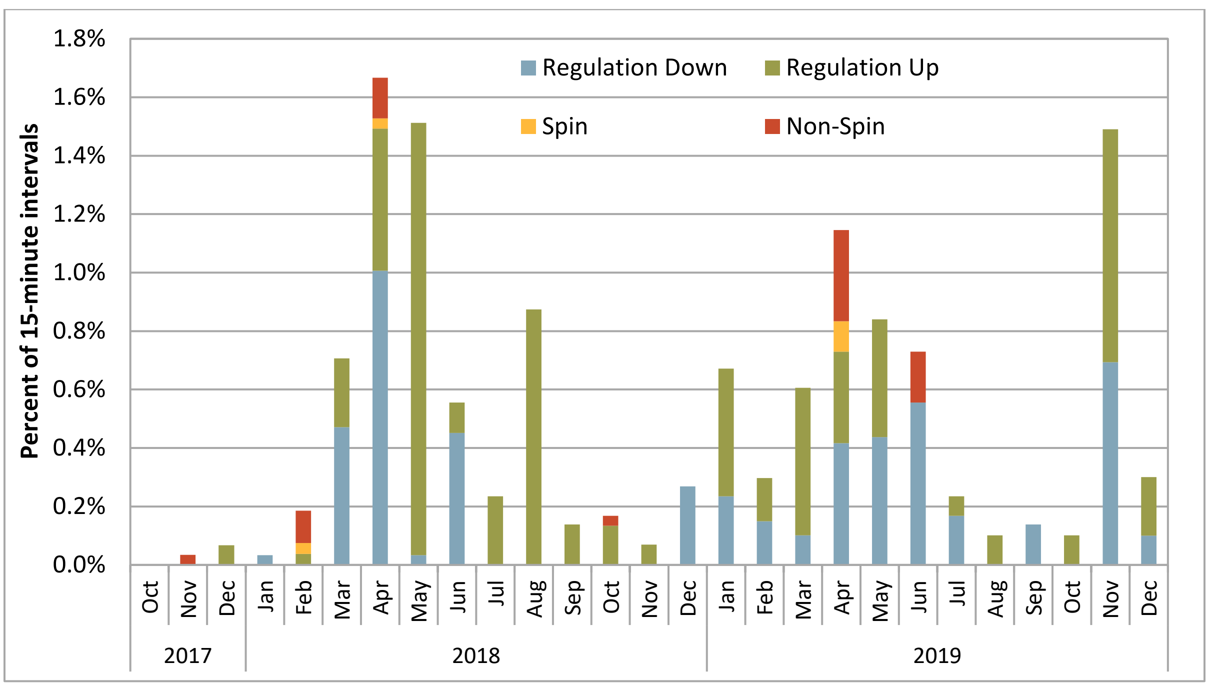
1.8.2 Ancillary service scarcity

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 1.25, there was a spike in the number of intervals with scarcity pricing during November, occurring in 43 intervals. These all occurred because of scarcity in the expanded South of Path 26 sub-region. There were 24 ancillary service scarcities across real-time intervals on November 20.[15] This was the result of manually blocked ancillary service awards, which were blocked in the real-time market but not in the day-ahead market for this day. This led to a shortage of regulation in real-time.

Real-time costs for ancillary services are typically very low, as only the incremental real-time award is settled at the 15-minute market price. As a result, real-time regulation costs on November 20 accounted for around 26 percent of real-time regulation costs during all of the fourth quarter. However, real-time regulation costs on this day were only 2 percent of *total* regulation costs (real-time and day-ahead combined) during the quarter.

Figure 1.25 Frequency of ancillary service scarcities (15-minute market)



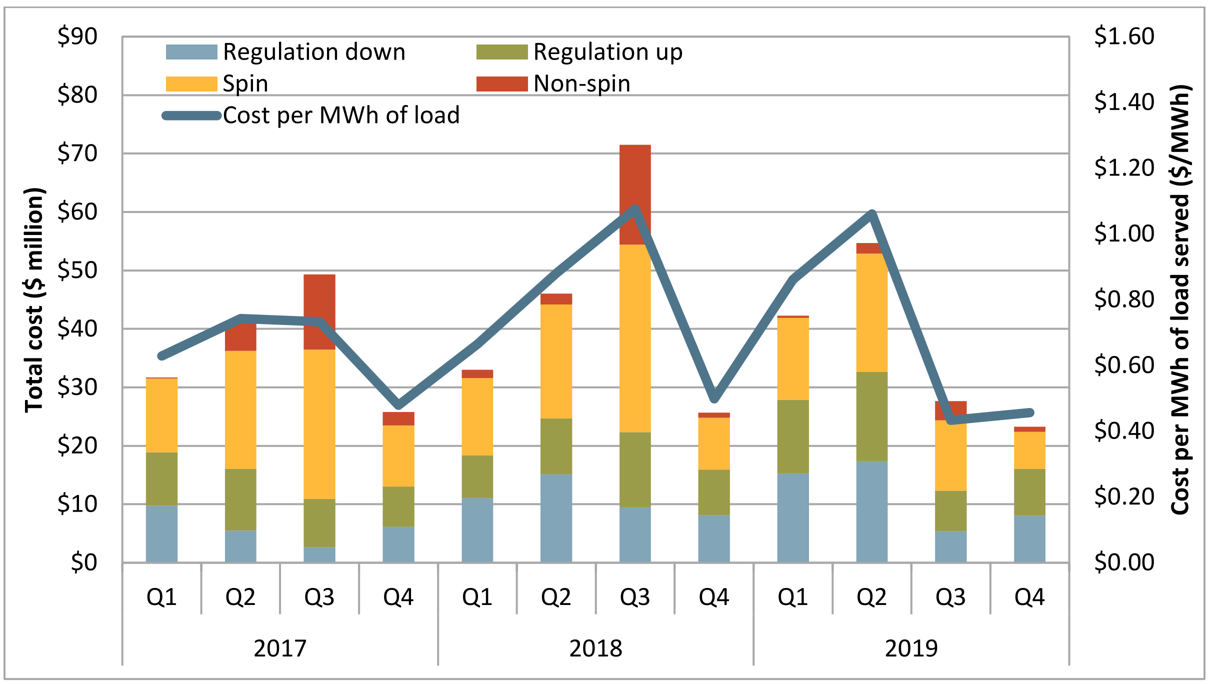
15 Ancillary Services Scarcity Event on 11/20/19, December 4, 2019: http://www.caiso.com/Documents/AncillaryServicesScarcityEvent-112019.html.

1.8.3 Ancillary service costs

Ancillary service payments decreased during the fourth quarter to about $23 million, compared to about $28 million in the previous quarter and $26 million during the same quarter in 2018. Total payments were lower despite more scarcities. In particular, total payments associated with spinning and non-spinning reserves decreased by around $8 million from the previous quarter.

Figure 1.26 shows the total cost of procuring ancillary service products by quarter as well as the total ancillary service cost for each megawatt-hour of load served. The costs reported in this figure have been refined to account for rescinded ancillary service payments. Payments are rescinded when resources providing ancillary services do not fulfill the availability requirements associated with the awards. During 2019, about 6 percent of payments for ancillary service awards were rescinded.

Figure 1.26 Ancillary service cost by product



1.9 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 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 EIM 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 is calculated as the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas.[16]

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

1.9.1 Congestion in the day-ahead market

Day-ahead market congestion frequency tends to be higher than in the 15-minute market, but price impacts to load 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 1.27 shows the overall impact of congestion on day-ahead prices in each load area for each quarter in 2018 and 2019.[17] Figure 1.28 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. Compared to the previous quarter of 2019, the total impact of congestion was low although the frequency of congestion increased in the fourth quarter. Similar to previous quarters, the frequency of congestion was highest in SDG&E.
- In SDG&E congestion increased prices by $0.75/MWh (1.8 percent) but had little net impact on PG&E and SCE (less than $0.10/MWh increase).
- On an average quarterly basis, congestion impact was frequently offsetting, as shown in Figure 1.29. In the fourth quarter, the number of intervals when congestion increased versus decreased prices was about equivalent in each of the load areas.
- The primary constraints impacting price separation in the day-ahead market were the Imperial Valley nomogram, the Doublet Tap-Friars 138 kV line, and the Gates-Midway 230 kV line.

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.

16 This approach does not include price differences that result from transmission losses.

17 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 1.27 Overall impact of congestion on price separation in the day-ahead market

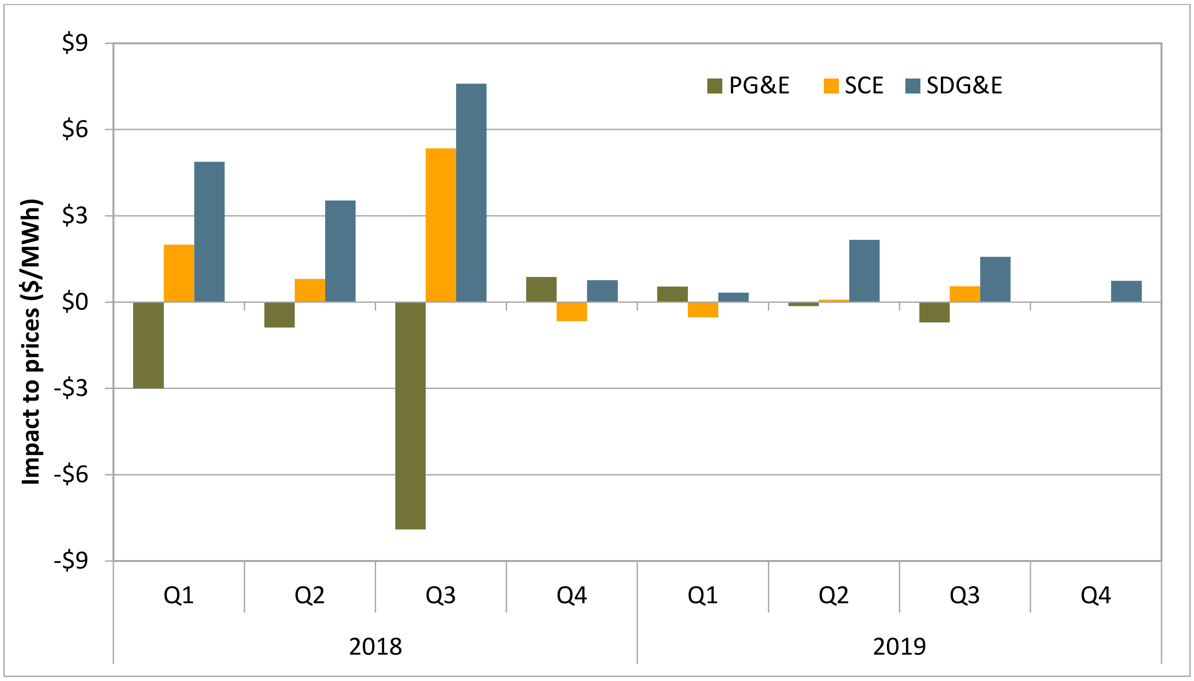


Figure 1.28 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)

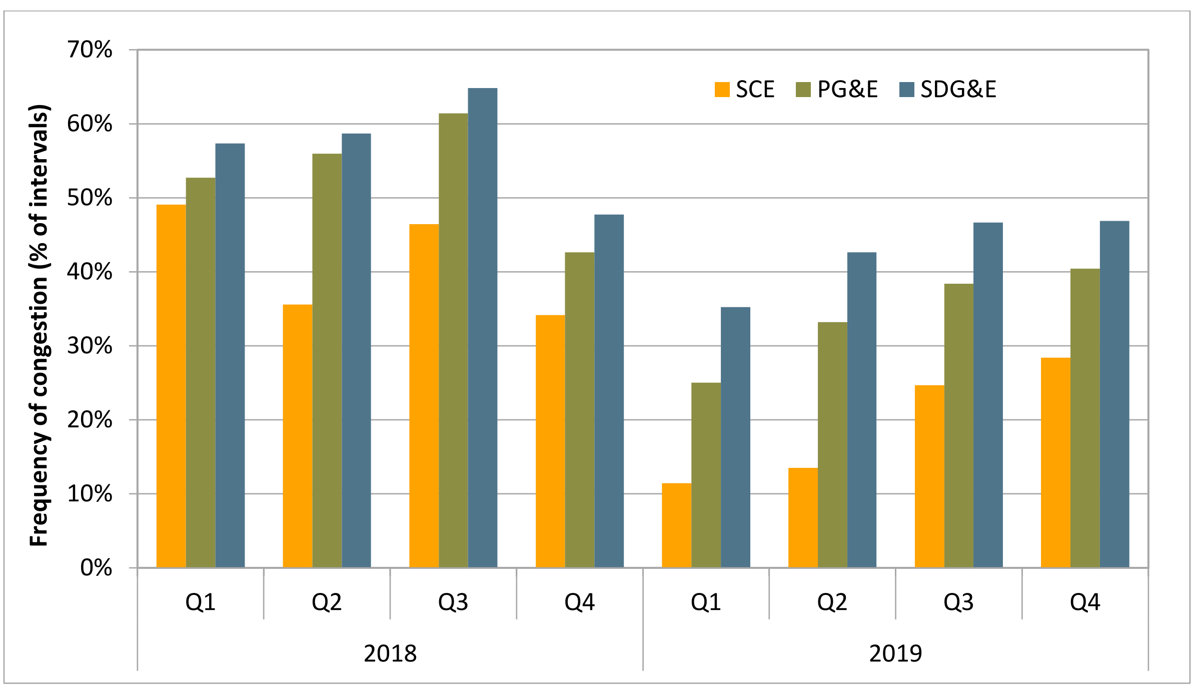
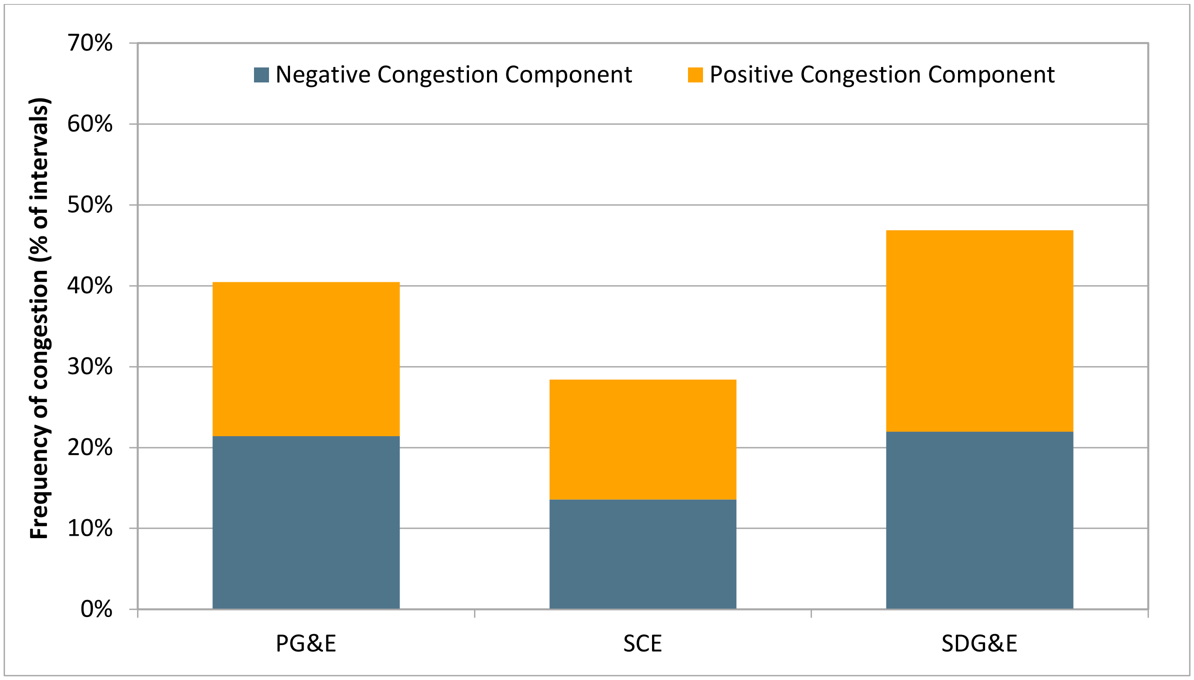


Figure 1.29 Percent of hours with congestion increasing versus decreasing day-ahead prices in the fourth quarter (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.2 breaks down the impact to price separation in the quarter by constraint.[18] Table 1.3 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 with the greatest impact on price separation for the quarter were the Imperial Valley nomogram, the Doublet Tap-Friars 138 kV line, and the Gates-Midway 230 kV line.

Imperial Valley nomogram

The Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) bound frequently in the quarter, during 14 percent of hours. When binding, it increased SDG&E prices by about $5/MWh and decreased PG&E and SCE prices slightly by about $0.50/MWh and $0.21/MWh, respectively. Over the entire quarter, it increased SDG&E prices by about $0.70/MWh (1.6 percent) and decreased PG&E prices $0.07/MWh (0.16 percent). The nomogram is enforced to mitigate for the loss of the Imperial Valley-North Gila 500 kV line. In the 2017-2018 transmission 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.

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

Doublet Tap-Friars 138 kV line

The Doublet Tap-Friars 138 kV line (22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1) bound frequently in about 24 percent of hours. When binding, it decreased prices in SDG&E by about $2/MWh. Overall for the quarter, the constraint decreased prices in SDG&E by about $0.40/MWh (1 percent). This constraint primarily bound due to normal flow conditions and was not a result of outages.

Gates-Midway 230 kV line

In the PG&E area, congestion on the Gates-Midway 230 kV line (30900_GATES _230_30970_MIDWAY _230_BR_1 _1) bound infrequently in about 2.4 percent of hours. When binding, it decreased prices in SDG&E and SCE by about $4.50/MWh and increased prices in PG&E by about $6/MWh. Overall for the quarter, the constraint decreased prices in SCE and SDG&E by about $0.11/MWh (0.3 percent) and increased PG&E prices by about $0.15/MWh (0.4 percent). This constraint bound in part due to outages on a number of Midway breakers in October.

Table 1.2 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	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.15	0.38%	-$0.11	-0.28%	-$0.10	-0.25%
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.04	0.11%	-$0.03	-0.08%	-$0.03	-0.07%
	6310_MWN_NRAS	$0.04	0.10%	-$0.03	-0.07%	-$0.03	-0.06%
	30705_MONTAVIS_230_30720_SARATOGA_230_BR_1 _1	$0.02	0.06%	-$0.02	-0.04%	-$0.02	-0.04%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.02	0.05%	-$0.01	-0.02%	-$0.01	-0.02%
	30440_TULUCAY _230_30460_VACA-DIX_230_BR_1 _1	$0.02	0.05%	$0.00	0.00%	$0.00	0.00%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.11	-0.28%	$0.09	0.21%	$0.08	0.20%
SCE	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.13	-0.32%	$0.16	0.41%	$0.01	0.03%
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	-$0.03	-0.07%	$0.03	0.06%	$0.00	0.00%
	SYLMAR-AC_BG	$0.00	0.00%	$0.02	0.04%	-$0.10	-0.24%
	22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.05	-0.11%
	24085_LUGO _230_24086_LUGO _500_XF_1 _P	$0.00	0.01%	-$0.01	-0.01%	$0.00	0.00%
SDG&E	7820_TL 230S_OVERLOAD_NG	-$0.07	-0.16%	$0.00	0.00%	$0.69	1.66%
	OMS 7921508_TL50003_NG	-$0.03	-0.08%	$0.00	0.00%	$0.33	0.80%
	OMS 7836526 TL50005_NG	-$0.02	-0.04%	$0.00	0.00%	$0.16	0.39%
	MIGUEL_BKs_MXFLW_NG	$0.00	-0.01%	$0.00	0.00%	$0.11	0.25%
	OMS 7994240 MG-BK81_NG	-$0.01	-0.03%	$0.00	0.00%	$0.09	0.21%
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.04	0.09%
	7820_TL23040_IV_SPS_NG	$0.00	-0.01%	$0.00	0.00%	$0.03	0.08%
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.04%
	7820_TL 230S_TL50001OUT_NG	$0.00	0.00%	$0.00	0.00%	$0.02	0.04%
	22476_MIGUELTP_69.0_22456_MIGUEL _69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	OMS 6438774_DV1_DV2_NG	$0.04	0.09%	-$0.04	-0.09%	-$0.01	-0.03%
	7750_D-VISTA1_OOS_CP6_NG	$0.02	0.05%	-$0.02	-0.04%	-$0.02	-0.04%
	7750_D-VISTA1_OOS_N1SV500_NG	$0.03	0.07%	-$0.02	-0.05%	-$0.02	-0.05%
	24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.04	-0.09%
	22596_OLD TOWN_230_22504_MISSION _230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.05	-0.13%
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.06	-0.14%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.40	-0.97%
Other		$0.02	0.04%	$0.02	0.05%	$0.09	0.21%
Total		**$0.01**	**0.01%**	**$0.03**	**0.07%**	**$0.75**	**1.79%**

Table 1.3 Impact of congestion on day-ahead prices during congested hours[19]

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	2.4%	$6.29	-$4.59	-$4.24
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	2.0%	$0.97	-$0.85	-$0.81
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	1.8%	-$6.22	$4.76	$4.57
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	1.6%	$2.72	-$1.99	-$1.83
	6310_MWN_NRAS	0.9%	$4.25	-$3.07	-$2.83
	30705_MONTAVIS_230_30720_SARATOGA_230_BR_1 _1	0.7%	$3.28	-$2.37	-$2.34
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	0.6%	$1.72	-$1.38	-$1.28
	30440_TULUCAY _230_30460_VACA-DIX_230_BR_1 _1	0.2%	$8.57	$0.00	$0.00
SCE	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	7.9%	-$1.62	$2.07	$1.04
	SYLMAR-AC_BG	3.8%	-$0.18	$1.27	-$2.62
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	2.7%	-$1.04	$1.07	$0.00
	22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1	0.9%	$0.00	$0.00	-$5.20
	24085_LUGO _230_24086_LUGO _500_XF_1 _P	0.5%	$0.88	-$1.01	$0.00
SDG&E	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	23.6%	$0.00	$0.00	-$1.71
	7820_TL 230S_OVERLOAD_NG	13.8%	-$0.48	-$0.21	$5.02
	7750_D-VISTA1_OOS_N1SV500_NG	6.3%	$0.44	-$0.40	-$0.59
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1	5.4%	$0.00	$0.00	$0.34
	OMS 6438774_DV1_DV2_NG	5.4%	$0.68	-$0.70	-$0.81
	7750_D-VISTA1_OOS_CP6_NG	4.8%	$0.41	-$0.37	-$0.55
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1	2.1%	$0.00	$0.00	-$2.64
	22596_OLD TOWN_230_22504_MISSION _230_BR_1 _1	1.2%	$0.00	$0.29	-$4.39
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	1.0%	$0.00	$0.00	$3.49
	24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1	0.9%	$0.00	$0.00	-$4.28
	OMS 7921508_TL50003_NG	0.8%	-$4.30	$0.00	$43.10
	OMS 7836526 TL50005_NG	0.5%	-$3.06	$0.00	$29.91
	7820_TL23040_IV_SPS_NG	0.4%	-$0.51	$0.00	$8.89
	MIGUEL_BKs_MXFLW_NG	0.4%	-$1.54	$0.00	$28.95
	OMS 7994240 MG-BK81_NG	0.4%	-$3.60	$0.00	$23.83
	7820_TL 230S_TL50001OUT_NG	0.3%	-$0.56	$0.00	$4.97

1.9.2 Congestion in the 15-minute market

Congestion frequency in the 15-minute market was lower than day-ahead market frequency in 2019, but price impacts to load were higher. The congestion pattern in this quarter reflects this overall trend.

Impact of congestion to overall prices in each load area

Figure 1.30 shows the overall impact of congestion on 15-minute prices in each load area for each quarter of 2018 and 2019. Figure 1.31 shows the frequency of congestion. Highlights for this quarter include:

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

- The frequency and overall net impact to price separation of congestion was lower in the fourth quarter of 2019 compared to the same quarter of 2018. Congestion resulted in a net increase to SCE, SDG&E, and AZPS prices and a net decrease to prices in PG&E, BANC, NEVP, PACE, IPCO, PACW, PGE, PSEI, and PWRX.
- Congestion continued to impact prices in both the positive and negative direction over the quarter in each load area, often offsetting the impact of congestion over the quarter. The frequency of congestion was highest in PacifiCorp East (50 percent of total intervals), where congestion predominantly decreased prices (49 percent of total intervals).
- The primary constraints impacting price separation in the 15-minute market were the Imperial Valley nomogram, the San Bernardino-Devers 230 kV line, and the Sylmar AC branch group.

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

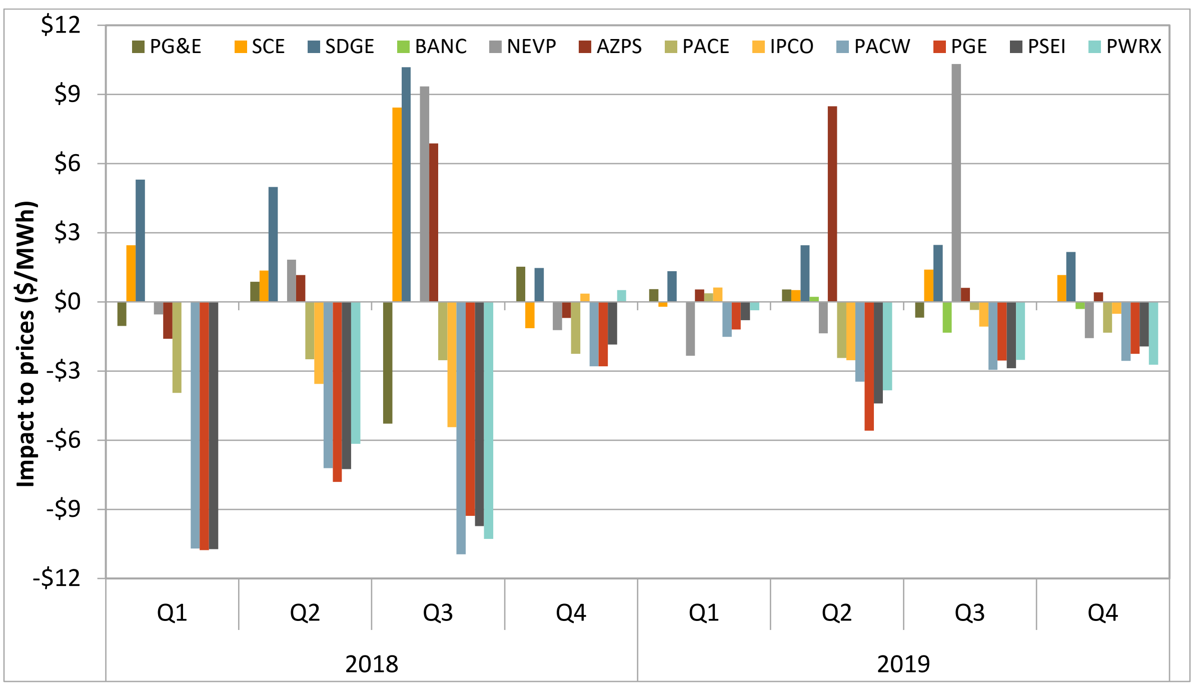


Figure 1.31 Percent of intervals with congestion increasing versus decreasing 15-minute prices in the fourth quarter (>$0.05/MWh)

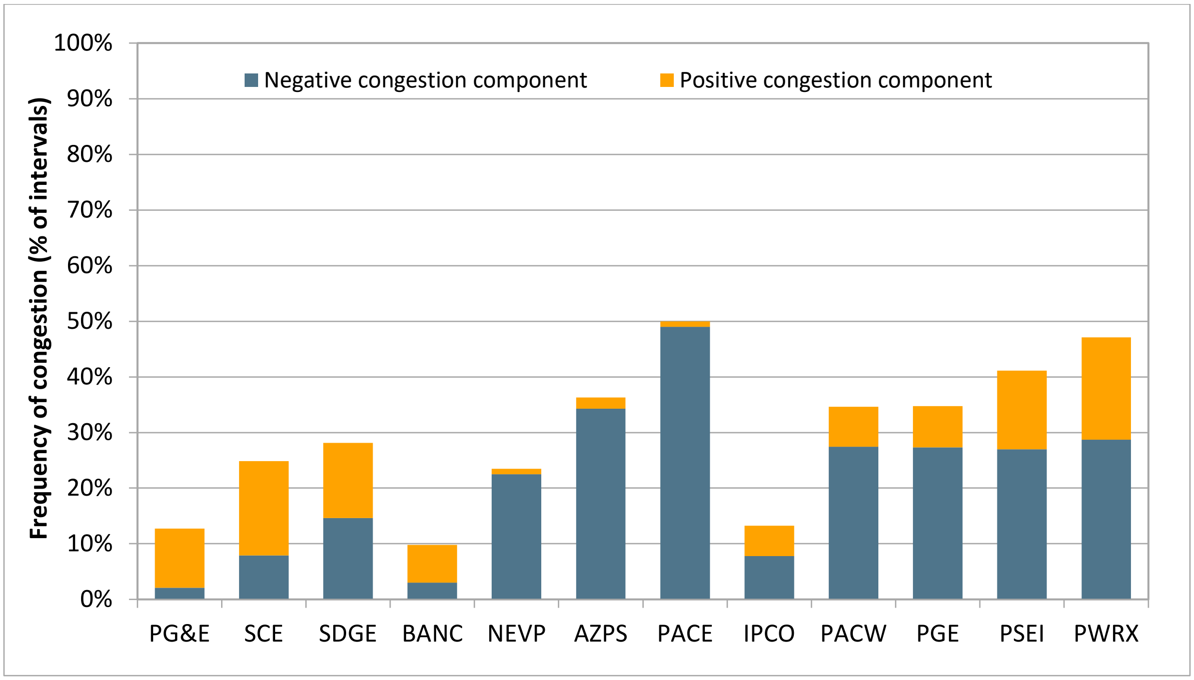
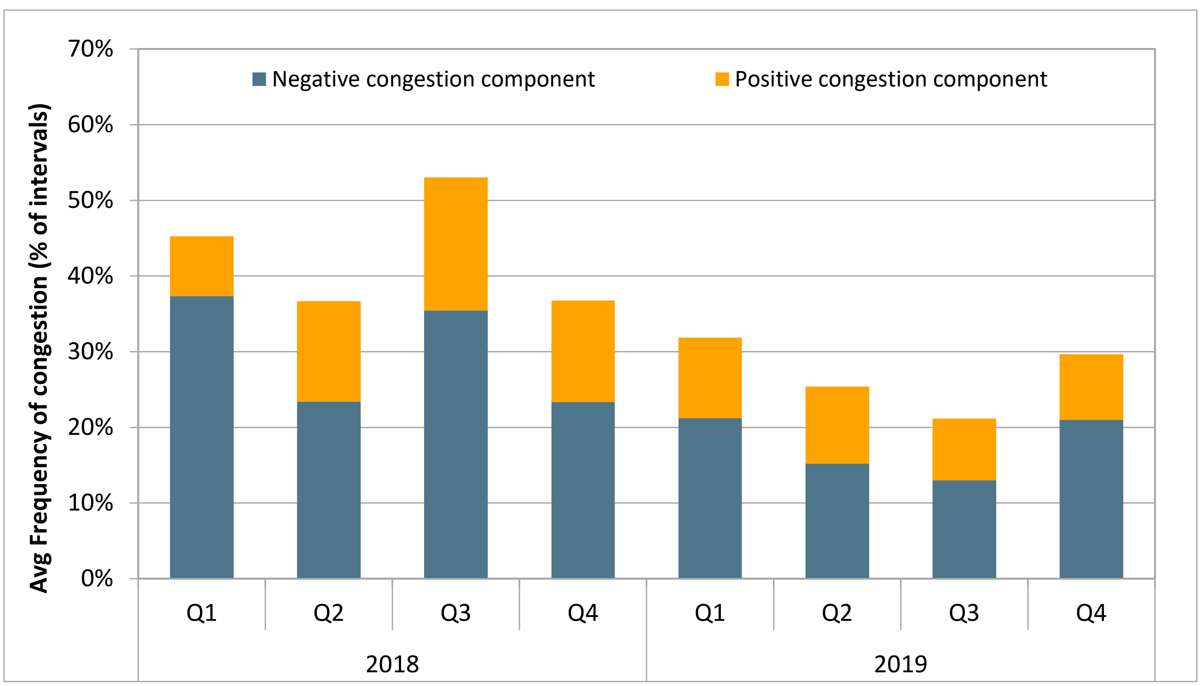


Figure 1.32 Percent of intervals with congestion impacting 15-minute prices (quarterly average of load areas)



Impact of congestion from individual constraints

Table 1.4 shows the overall impact (during all intervals) of congestion on average 15-minute prices in each load area. Table 1.5 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 1.4). The category labeled “other” includes the impact of EIM transfer constraints, greenhouse gas, and power balance constraint (PBC) violations, which often have the greatest impact on price separation for EIM areas. These topics are discussed in greater depth in Chapter 2. This section will focus on individual flow-based constraints.

The constraints that had the greatest impact on price separation in the 15-minute market were the Imperial Valley nomogram, the San Bernardino-Devers 230 kV line, and the Sylmar AC branch group.

Imperial Valley nomogram

The Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) bound frequently in the quarter, during 9 percent of intervals. When binding, it increased prices in SDG&E and SCE by about \$23/MWh and \$2/MWh, respectively, and decreased prices in all EIM areas by about \$2/MWh on average. Over the entire quarter, it increased SDG&E and SCE prices by about \$2/MWh and \$0.14/MWh, respectively, and decreased EIM area prices by about \$0.11/MWh on average. The nomogram is enforced to mitigate for the loss of the Imperial Valley-North Gila 500 kV line. In the 2017-2018 transmission 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.

San Bernardino-Devers 230 kV line

The San Bernardino-Devers 230 kV line (24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1) bound frequently in the quarter during about 12 percent of intervals. When binding, it decreased SDG&E and AZPS prices by about \$11/MWh and \$21/MWh, respectively, and had no impact on the other load areas throughout the west. Overall for the quarter, the constraint increased SDG&E and AZPS prices by about \$0.03/MWh and \$3/MWh, respectively. This constraint is impacted by the planned outages of the Devers-Vista #1 and #2 220 kV lines.

Sylmar AC branch group

The Sylmar AC branch group (SYLMAR-AC_BG) bound infrequently in the quarter, during 4 percent of intervals. When binding, it increased prices in PG&E, SCE and BANC by about \$6/MWh on average and decreased prices throughout the rest of the west by about \$10/MWh on average. Congestion due to the branch group did not impact prices in the Pacific Northwest balancing areas (PGE, PSEI, nor PWRX). Overall for the quarter, the constraint increased prices in PG&E, SCE and BANC by about \$0.2/MWh on average and decreased prices throughout the rest of the west by about \$0.30/MWh on average. This constraint bound as a result of a planned outage on the Sylmar 230 kV bus in late October and early November.

Table 1.4 Impact of congestion on overall 15-minute prices

Constr. Location	Constraint	PG&E	SCE	SDGE	BANC	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX
PACE	WYOMING_EXPORT							-$0.32					
PG&E	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.07	-$0.10	-$0.09	$0.08	-$0.05	-$0.08	-$0.01	$0.02	$0.05	$0.05	$0.05	$0.05
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.04	-$0.07	-$0.07	$0.05	-$0.04	-$0.06		$0.03	$0.04	$0.04	$0.04	$0.04
	6310_MWN_NRAS	$0.02	-$0.03	-$0.03	$0.03	-$0.02	-$0.03	$0.00	$0.01	$0.02	$0.02	$0.02	$0.02
	30055_GATES1 _500_30900_GATES _230_XF_11_S	$0.02	-$0.05	-$0.05	$0.04	-$0.02	-$0.04	$0.00	$0.01	$0.03	$0.03	$0.03	$0.03
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.01	-$0.02	-$0.02	$0.00	$0.00	-$0.01			$0.00	$0.00	$0.00	$0.00
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.01	-$0.02	-$0.02	$0.02	-$0.01	-$0.02	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	$0.01	-$0.01	-$0.01	$0.01	$0.00	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	RM_TM12_NG	$0.01	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01
	30900_GATES _230_30889_CAFLTSSS_230_BR_1 _1	$0.00	-$0.01	-$0.01	$0.00	$0.00	-$0.01		$0.00	$0.00	$0.00	$0.00	$0.00
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-$0.01	$0.01	$0.01	-$0.01	$0.01	$0.01	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.08	$0.08	$0.08	-$0.07	$0.04	$0.07	$0.01	-$0.02	-$0.05	-$0.05	-$0.05	-$0.05
SCE	SYLMAR-AC_BG	$0.06	$0.47	-$0.15	$0.00	-$0.58	-$0.57	-$0.35	-$0.04	$0.00			
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.02	$0.25	$0.11	-$0.02	-$0.08	-$0.16	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	24086_LUGO _500_24238_RANCHVST_500_BR_1 _1	-$0.08	$0.24	$0.24	-$0.08	-$0.20	-$0.12	-$0.14	-$0.10	-$0.10	-$0.10	-$0.10	-$0.10
	6410_CP1_NG	-$0.15	$0.16	$0.16	-$0.14	$0.08	$0.14	$0.02	-$0.03	-$0.09	-$0.09	-$0.09	-$0.09
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.03	$0.10	$0.05	-$0.03	-$0.04	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03
	24156_VINCENT _500_24155_VINCENT _230_XF_4 _P	-$0.01	$0.03	$0.01	-$0.01	-$0.01		-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1		$0.02	$0.02		$0.00	$0.00						
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_1 _1		$0.02										
	OMS 8102092 ELD-LUGO	$0.01	$0.01	$0.00	$0.01	-$0.02	-$0.02	-$0.01	$0.00				
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.00	$0.00	$0.01	$0.00	-$0.01	-$0.01	-$0.01	$0.00				
	24025_CHINO _230_24093_MIRALOM _230_BR_3 _1	$0.00	$0.00	$0.01	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24042_ELDORDO _500_24086_LUGO _500_BR_1 _3	$0.00	$0.00		$0.00	-$0.01	-$0.01	$0.00	$0.00				
	OP-6610_ELD-LUGO	$0.00	$0.00		$0.00	-$0.01	-$0.01	$0.00	$0.00				
	24085_LUGO _230_24086_LUGO _500_XF_1 _P	$0.02	-$0.01		$0.02	-$0.05	-$0.04	-$0.02	-$0.01				
	6410_CP7_NG	$0.01	-$0.01	-$0.01	$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01
	22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1			-$0.08									
	24804_DEVERS _230_24901_VSTA _230_BR_2 _1						-$0.02						
	OMS 7618841 SV_NG						-$0.06						
SDG&E	7820_TL 230S_OVERLOAD_NG		$0.14	$2.04	$0.00	-$0.13	-$0.57	-$0.20	-$0.05	-$0.01	$0.00	$0.00	$0.00
	OMS 7958707_TL50004_OUTAGE_NG		$0.01	$0.23		-$0.01	-$0.04	-$0.01					
	OMS 7994240 MG-BK81_NG			$0.18			-$0.06						
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80			$0.17			-$0.06	$0.00					
	MIGUEL_BKs_MXFLW_NG			$0.16			-$0.05						
	7820_TL 230S_TL50001OUT_NG		$0.01	$0.09		-$0.01	-$0.02	-$0.01					
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P		$0.00	$0.08		-$0.01	-$0.03	-$0.01					
	OMS 7921508_TL50003_NG		$0.00	$0.06		$0.00	-$0.01	$0.00					
	OMS7714583 TL50005_NG			$0.05		$0.00	-$0.01	$0.00					
	OMS 7836526 TL50005_NG		$0.00	$0.03		$0.00	-$0.01	$0.00					
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	$0.00	$0.01	$0.02	$0.00	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22464_MIGUEL _230_22468_MIGUEL _500_XF_81			$0.02			$0.00						
	OMS 6438774_DV1_DV2_NG	$0.04	-$0.04	$0.00	$0.02	-$0.03	-$0.16	-$0.04	$0.00	$0.00	$0.00	$0.00	$0.00
	7750_D-VISTA1_OOS_CP6_NG	$0.01		-$0.01	$0.00	$0.00	-$0.07	-$0.02					
	7750_D-VISTA1_OOS_N1SV500_NG	$0.02		-$0.01	$0.01	-$0.02	-$0.14	-$0.03					
	24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1			-$0.03			-$2.59						
	22710_SNLSRYSC_230_22504_MISSION _230_BR_2 _1		$0.00	-$0.03			-$0.01						
	22596_OLD TOWN_230_22504_MISSION _230_BR_1 _1		$0.00	-$0.09			-$0.05						
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1			-$0.18									
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1			-$0.82			-$0.31						
Other		$0.02	-$0.04	$0.03	-$0.23	-$0.32	$5.69	-$0.06	-$0.28	-$2.42	-$2.11	-$1.79	-$2.59
Total		**-$0.01**	**$1.17**	**$2.16**	**-$0.31**	**-$1.57**	**$0.42**	**-$1.34**	**-$0.52**	**-$2.57**	**-$2.26**	**-$1.93**	**-$2.73**

Table 1.5 Impact of congestion on 15-minute prices in the ISO during congested intervals[20]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDGE	BANC	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX
PACE	WYOMING_EXPORT	35.9%							-$0.90					
PG&E	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	1.1%	$6.05	-$8.82	-$8.32	$7.29	-$4.46	-$7.52	-$1.30	$1.86	$4.79	$4.50	$4.49	$4.49
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	0.9%	$4.87	-$8.47	-$7.95	$5.96	-$4.76	-$7.07		$4.19	$5.15	$5.19	$5.19	$5.19
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	0.7%	$2.57	-$3.35	-$3.24	$1.29	-$1.24	-$2.37			$1.24	$1.29	$1.29	$1.29
	6310_MWN_NRAS	0.6%	$3.75	-$5.42	-$5.12	$4.96	-$3.02	-$4.63	-$0.82	$1.22	$3.21	$3.04	$2.99	$2.99
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	0.3%	$2.95	-$6.06	-$5.67	$6.66	-$2.98	-$5.05	-$0.88	$3.84	$3.80	$3.81	$3.81	$3.81
	30900_GATES _230_30889_CAFLTSSS_230_BR_1 _1	0.3%	$1.55	-$1.87	-$1.75	$2.43	-$1.26	-$1.56		$1.34	$1.71	$1.72	$1.72	$1.72
	30055_GATES1 _500_30900_GATES _230_XF_11_S	0.3%	$6.78	-$16.04	-$15.14	$12.57	-$8.12	-$13.59	-$2.75	$4.50	$10.00	$9.85	$9.85	$9.85
SCE	SYLMAR-AC_BG	3.8%	$2.96	$12.19	-$4.92	$1.63	-$15.07	-$14.81	-$9.21	-$4.86	-$6.18			
	OMS 6438774_DV1_DV2_NG	2.5%	$1.61	-$1.62	-$0.83	$1.23	-$1.59	-$6.36	-$1.80	-$2.06	$0.86	$0.89	$0.89	$0.89
	7750_D-VISTA1_OOS_N1SV500_NG	2.4%	$1.24		-$1.41	$1.66	-$1.41	-$6.02	-$1.45					
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	1.6%	-$3.75	$15.44	$7.63	-$3.75	-$7.72	-$9.89	-$3.75	-$3.75	-$3.75	-$3.75	-$3.75	-$3.75
	24085_LUGO _230_24086_LUGO _500_XF_1 _P	1.4%	$5.53	-$0.49		$4.64	-$13.02	-$11.32	-$7.09	-$2.40				
	6410_CP1_NG	0.5%	-$28.32	$29.47	$29.15	-$26.88	$15.90	$26.23	$4.08	-$8.57	-$16.26	-$16.27	-$16.27	-$16.27
	22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1	0.4%			-$18.28									
	24086_LUGO _500_24238_RANCHVST_500_BR_1 _1	0.4%	-$20.29	$62.97	$63.85	-$21.58	-$53.35	-$32.20	-$37.77	-$27.41	-$25.49	-$25.44	-$25.44	-$25.44
	OMS 7618841 SV_NG	0.4%						-$15.61						
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_1 _1	0.4%		$6.20										
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	0.3%	-$9.51	$29.66	$16.50	-$9.51	-$10.67	-$10.29	-$9.55	-$9.51	-$9.51	-$9.51	-$9.51	-$9.51
SDG&E	24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1	12.5%			-$10.78			-$20.71						
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	10.8%			-$7.55			-$9.51						
	7820_TL 230S_OVERLOAD_NG	9.0%		$1.52	$22.62	-$0.76	-$1.55	-$6.26	-$2.25	-$1.43	-$0.84	-$0.76	-$0.76	-$0.76
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1	1.3%			-$13.72									
	7750_D-VISTA1_OOS_CP6_NG	1.2%	$1.43		-$1.86	$0.23	-$0.96	-$5.55	-$1.46					
	22596_OLD TOWN_230_22504_MISSION _230_BR_1 _1	0.8%		$4.32	-$11.70			-$6.32						
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	0.5%			$32.59			-$11.16	-$7.10					
	MIGUEL_BKs_MXFLW_NG	0.4%			$45.83			-$13.49						

1.9.3 Congestion on interties

Figure 1.33 shows total import congestion charges in the day-ahead market for 2018 and 2019. Figure 1.34 shows the frequency of congestion on five major interties for 2019. Table 1.6 provides a detailed summary of this data over a broader set of interties.

The total import congestion charges reported are the products of the shadow prices times the binding limit for the intertie constraint. For a supplier or load-serving entity trying to import power over a congested intertie, the congestion price represents a decrease in the price for imports into the ISO. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside of the ISO at points corresponding to these interties.

The charts and table highlight the following:

- Total import congestion charges for 2019 were about $91 million compared to $109 million in 2018.

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

- In the fourth quarter of 2019, congestion charges on the major interties decreased in the day-ahead market compared to the same quarter of 2018, and increased slightly compared to the previous quarter of 2019.
- The frequency of congestion in the fourth quarter increased overall compared to both the previous quarter of 2019 and the same quarter of 2018.
- The frequency of congestion and magnitude of congestion charges is typically highest on PACI/Malin 500, NOB, Palo Verde, and the IPP Utah interties. The fourth quarter followed this trend. Congestion on other interties continues to remain relatively low relative to these top constraints.

Figure 1.33 Summary of import congestion in day-ahead market

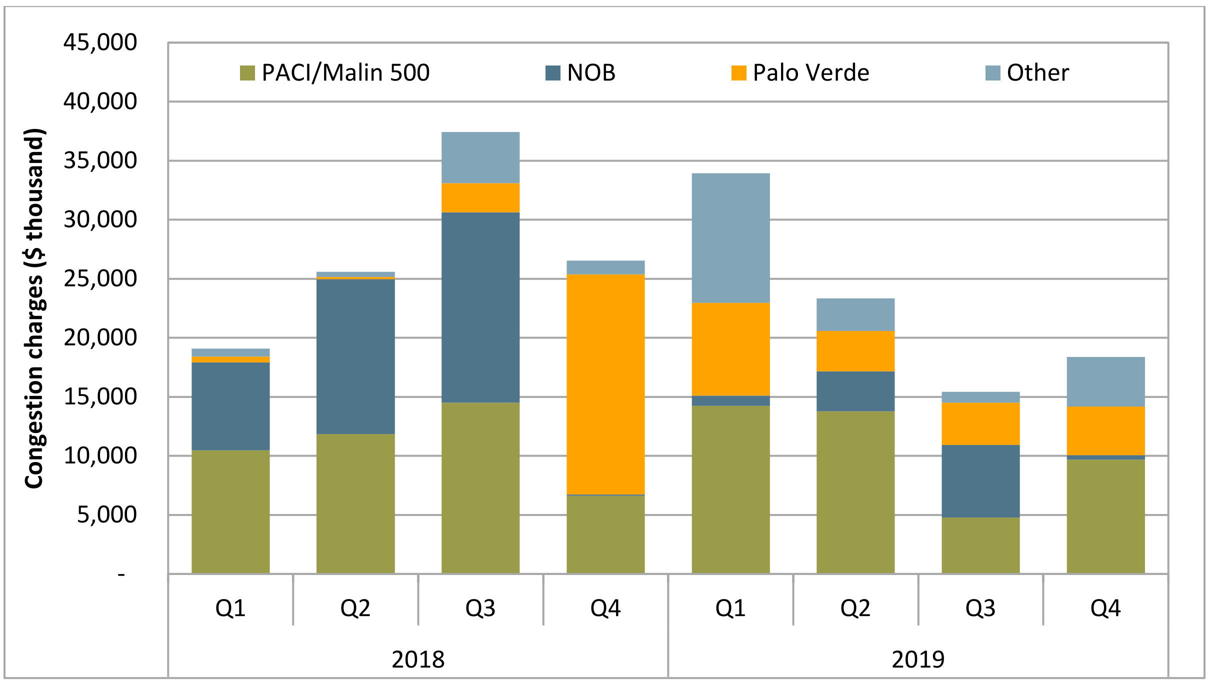


Figure 1.34 Frequency of import congestion on major interties in the day-ahead market (2019)

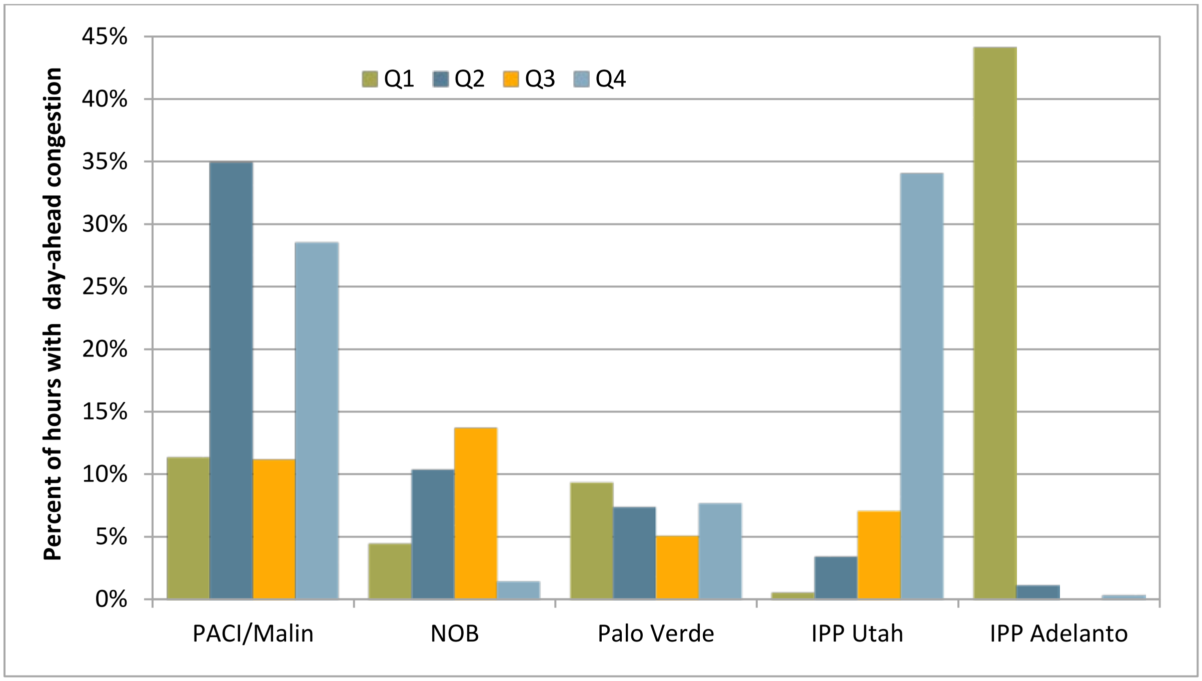


Table 1.6 Summary of import congestion in day-ahead market (2018-2019)

Area	Intertie	Frequency of import congestion								Import congestion charges ($ thousand)							
		2018				2019				2018				2019			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northwest	PACI/Malin 500	24%	20%	21%	13%	11%	35%	11%	29%	10,467	11,860	14,500	6,607	14,246	13,773	4,787	9,681
	NOB	32%	36%	18%	1%	5%	11%	14%	2%	7,445	13,095	16,136	123	858	3,380	6,128	382
	Cascade	0%	1%				1%	2%	0%	3	12	0			30	162	1
	COTPISO	2%	3%	1%	1%	0%	3%		2%	33	51	23	29	4	20		21
Southwest	Palo Verde	1%	1%	2%	20%	9%	8%	5%	8%	487	201	2,463	18,650	7,864	3,409	3,579	4,128
	IPP Adelanto	1%	2%	2%		44%	1%		0%	46	150	394		10,028	120		98
	IPP Utah	17%	10%	26%	15%	1%	4%	7%	34%	385	220	1,018	517	13	99	186	2,528
	Gonder IPP Utah						3%								2,477		
	CFE			0%				0%				1,844				55	
	Mead			0%	1%	1%		0%	2%			18	223	306		238	989
	Marketplace Adelanto	0%				1%			2%	59				477			286
	IID-SDGE			0%								283				197	
	MeadTMead			0%	0%				1%			424	13				37
	Westwing Mead				3%	2%		1%	2%				157	127		21	138
	IID-SCE	1%								158		283					
	Adelanto				1%								223				
Other	Other											33	0		21	63	82

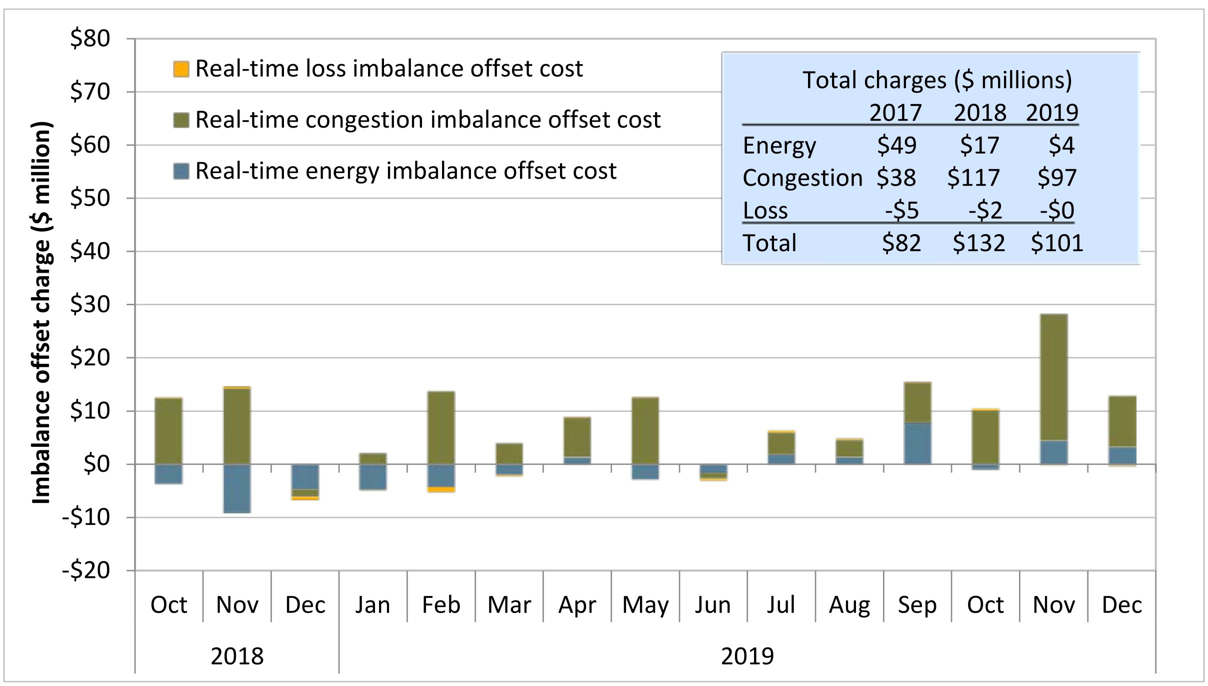
1.10 Real-time imbalance offset costs

Fourth quarter real-time offset costs accounted for almost half of the total 2019 annual cost of $101 million. Real-time congestion imbalance offset charges were $97 million, nearly all of the total $101 million in 2019 real-time offset costs. Fourth quarter imbalance offset charges totaled $50 million, the sum of $43 million congestion offset charges, and $7 million energy offset. Congestion offset charges were associated with network model changes and reductions in constraint limits in the 15-minute market from the day-ahead market as in previous quarters.

The real-time imbalance offset charge consists of three components corresponding to the components of real-time settlement prices: energy, congestion and loss. Any revenue imbalance from the energy components of real-time settlement prices is collected through the real-time imbalance energy offset charge (RTIEO). Revenue imbalance from the congestion component is recovered through the real-time congestion imbalance offset charge (RTCIO), and revenue imbalance from the loss component 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 1.35 Real-time imbalance offset costs



1.11 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).[21] The ISO charges utility distribution companies the transmission access charge 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, revenues from rights sold in the auction have consistently been well below the congestion revenues paid to entities purchasing these rights. Through 2019, transmission ratepayers have lost about $900 million in congestion revenues paid in excess of revenues received from the auction. This represents about 51 cents in auction revenues for every dollar paid to congestion revenue rights holders. Most of these profits to entities purchasing congestion rights in the auction are received by financial entities that do not sell power or serve load in the ISO.[22]

Congestion revenue rights auction modifications

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

- **Track 1A.** The first major change significantly reduces the number and pairs of nodes at which congestion revenue rights are purchased in the auction.[23] This change was designed to limit rights

21 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.

22 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

23 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

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 exceed associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis.[24]

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

Congestion revenue right auction returns

Profits received by buyers of auctioned rights are calculated by summing revenue paid out by the ISO for these congestion revenue rights and then subtracting the auction price paid plus offsets that may be charged to auctioned congestion revenue rights. While this represents a profit to entities purchasing right in the auction, this represents a loss to transmission ratepayers.

Based on this framework, ratepayers lost about $22.1 million during the fourth quarter of 2019 as payments to auctioned congestion revenue rights holders exceeded auction revenues. This compares to average losses of $38 million in the fourth quarter of the prior three years. As shown in Figure 1.36, auction revenues were 46 percent of payments made to non-load-serving entities during the fourth quarter of 2019, slightly down from 48 percent during the same quarter in 2018.

In 2019, ratepayer losses from sales of congestion revenue rights totaled about $34 million, of which $22 million occurred in the fourth quarter. In 2019, transmission ratepayers received about 68 cents in auction revenue per dollar paid out to congestion revenue rights purchased in the auction. Financial entities, which do not serve load or provide supply in the ISO markets, received profits of about $33 million and paid 55 cents in auction revenues per dollar of payments received.

In the fourth quarter, 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 $15.5 million. This was a slight increase from $14.8 million profits during the fourth quarter of 2018. Energy marketers profited about $4.4 million, down from more than $9 million profit during the same quarter in 2018. Generators profited about $2.2 million compared to $4.8 million in profits in the fourth quarter of 2018.

The reduction in fourth quarter losses from the congestion revenue rights in the auction is due to a combination of at least two 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).[25]
- Changes in the settlement of congestion revenue rights implemented in 2019 (Track 1B).

A third factor contributing to lower losses from sales of congestion revenue rights in 2019 was relatively lower congestion than in prior years. Total day-ahead congestion rent for 2019 was about $355 million –

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[24] 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

[25] 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

down from about $628 million in 2018. Thus, while losses dropped from $131 million in 2018 to $34 million in 2019, a significant portion of this decrease can be attributed to the drop in overall congestion.

The impact of Track 1A changes which limits the types of congestion revenue rights that can be 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 these rights by about $24 million in the fourth quarter. A more detailed description of Track 1B changes and the impact of these changes is provided in a later section of this report.

Prior to offset adjustments related to Track 1B of about $24 million, payments to auctioned rights holders totaled $64.6 million in the fourth quarter of 2019. This is about 21 percent higher than the average of $53.4 million in the fourth quarter of each of the prior four years (2015-2018).

Figure 1.36 Auction revenues and payments to non-load-serving entities

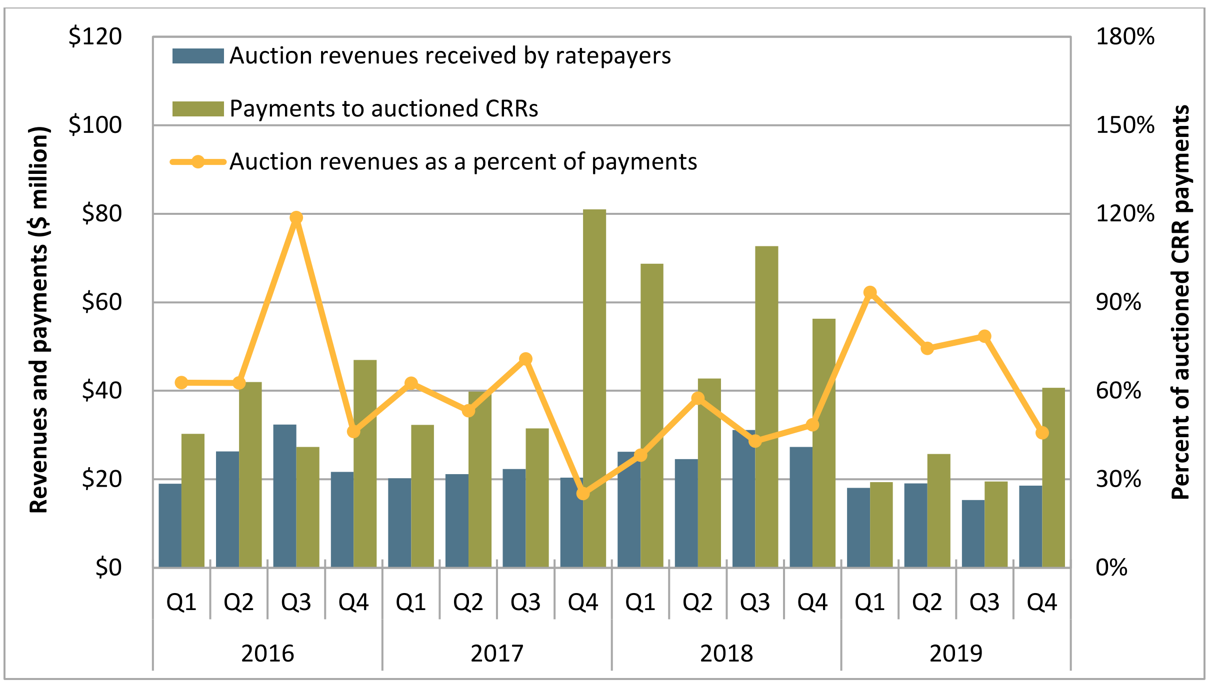
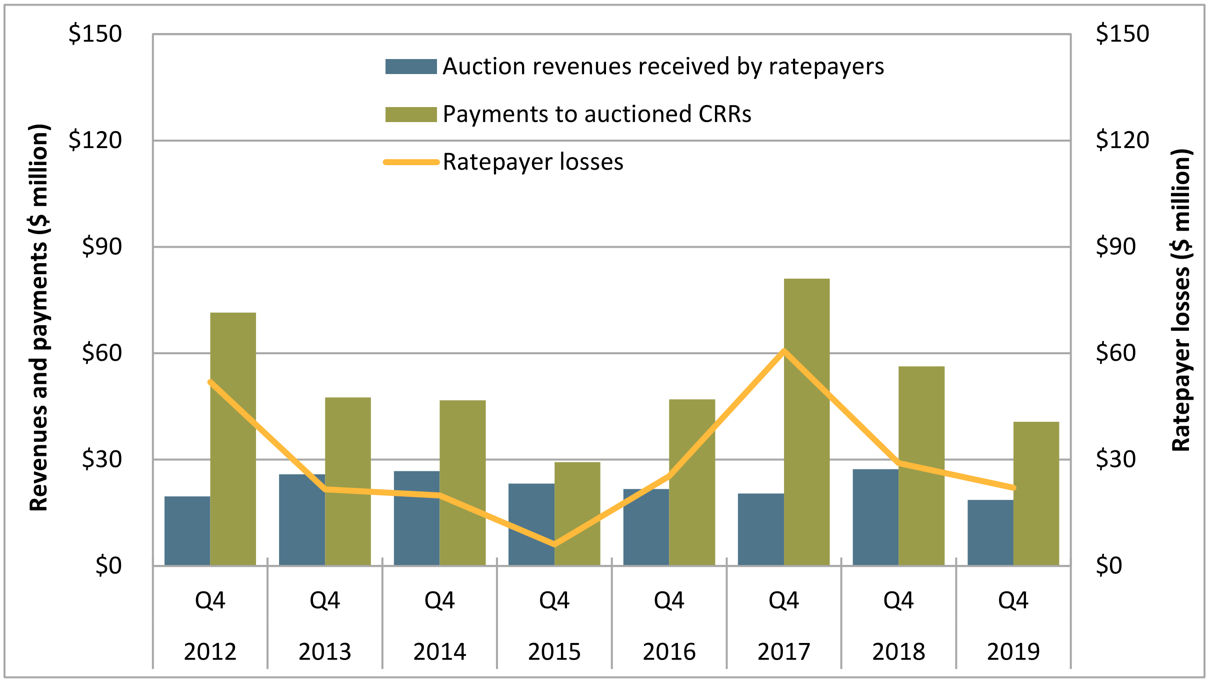


Figure 1.37 Q4 auction revenues and payments to non-load-serving entities (2012-2019)



Impact of Track 1B changes

Beginning on January 1, 2019, changes made under the ISO's Track 1B filing state 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 to scheduling coordinators with net positive flows on the constraint as an offset.

Based on current settlement records for the fourth quarter, DMM estimates that the changes made under Track 1B reduced payments for congestion revenue rights purchased in the auction by about $24 million.

A third factor contributing to lower losses from sales of CRRs in 2019 was relatively lower congestion than in prior years. Total day-ahead congestion rent for 2019 was about $355 million, down from about $628 million in 2018. Ratepayer auction losses in 2019 totaled almost 10 percent of total day-ahead congestion rents in 2019, compared to about 20 percent of congestion rents in 2018. This reduction in CRR losses as a percentage of total day-ahead congestion rents likely reflects the impact of CRR changes made by the ISO beginning in 2019.[26]

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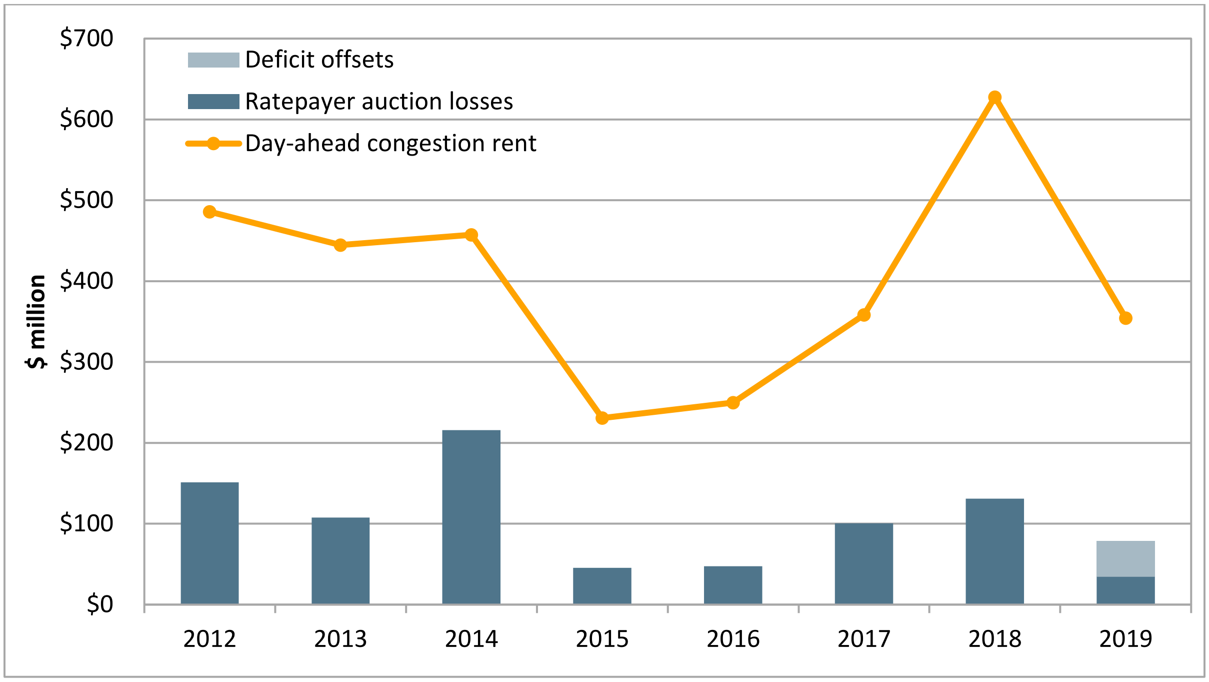
[26] Further analysis of 2019 CRR auction results is available in DMM's *Report on results of 2019 congestion revenue rights auction*, January 27, 2020: http://www.caiso.com/Documents/ReportonResultsof2019CongestionRevenueRightsAuction-Jan272020.pdf

Figure 1.38 shows the annual ratepayer congestion revenue rights auction loss (blue bars), Track 1B revenue deficit offsets (light blue bars), and day-ahead congestion rent (yellow line). These charts provide a comparison of losses from sales of congestion revenue rights and the reduction in auction payments due to Track 1B changes compared to day-ahead congestion rent and each other.

Figure 1.38 Ratepayer auction losses and day-ahead congestion rent (annual)



Rule changes made by the ISO reduced losses from sales of congestion revenue rights significantly in 2019. However, DMM continues to recommend that the ISO take steps to discontinue auctioning congestion revenue rights on behalf of ratepayers. If the ISO believes it is highly beneficial to actively facilitate hedging of congestion costs by suppliers, DMM recommends that the ISO modify the congestion revenue rights auction into a market for financial hedges based on clearing of bids from willing buyers and sellers.

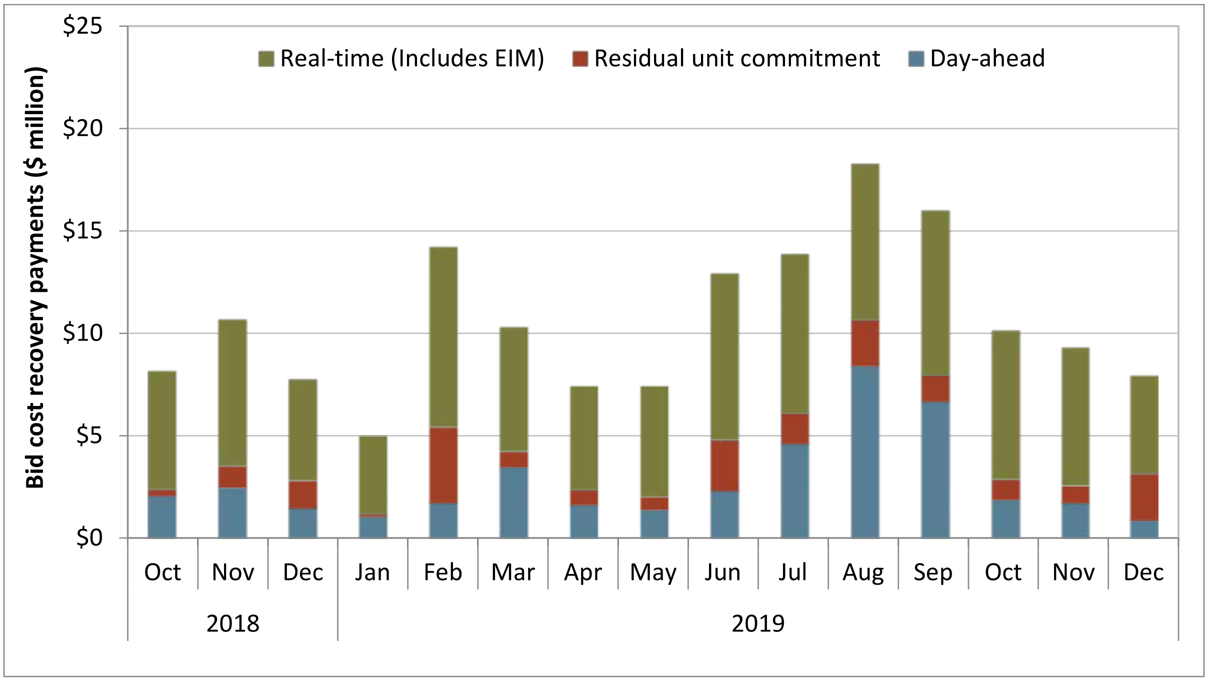
1.12 Bid cost recovery

Estimated bid cost recovery payments for the fourth quarter of 2019 totaled about $27 million. This amount was $21 million lower than the total amount of bid cost recovery in the previous quarter and similar to the amount in the fourth quarter of 2018.

Bid cost recovery attributed to the day-ahead market totaled about $4.5 million, which is about $15 million lower than the prior quarter. Bid cost recovery payments for residual unit commitment during the quarter totaled about $4 million, compared to $5 million in the prior quarter. Bid cost recovery attributed to the real-time market totaled about $19 million, or about $1 million lower than payments in the fourth quarter of 2018 and $4.5 million lower than payments in the third quarter of 2019.

Total bid cost recovery payments in the ISO were $0.47/MWh of load (1.06 percent), compared to $0.48/MWh of load (0.9 percent) in the previous fourth quarter when both fuel costs and wholesale energy costs were higher. Fourth quarter bid cost recovery payments decreased relative to the third quarter ($0.72/MWh of load or 1.87 percent) as system load requirements decreased.

Figure 1.39 Monthly bid cost recovery payments



1.13 Load forecast adjustments

Operators in the ISO and EIM can manually modify load forecasts used in the market through a load adjustment. Load adjustments are 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.[27] 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

Beginning in 2017, there was a large 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. This large increase continues into the current quarter, with average hourly load adjustments in these markets peaking at about 1,100 MW, significantly above the 800 MW peak in the same quarter of the previous year. Figure

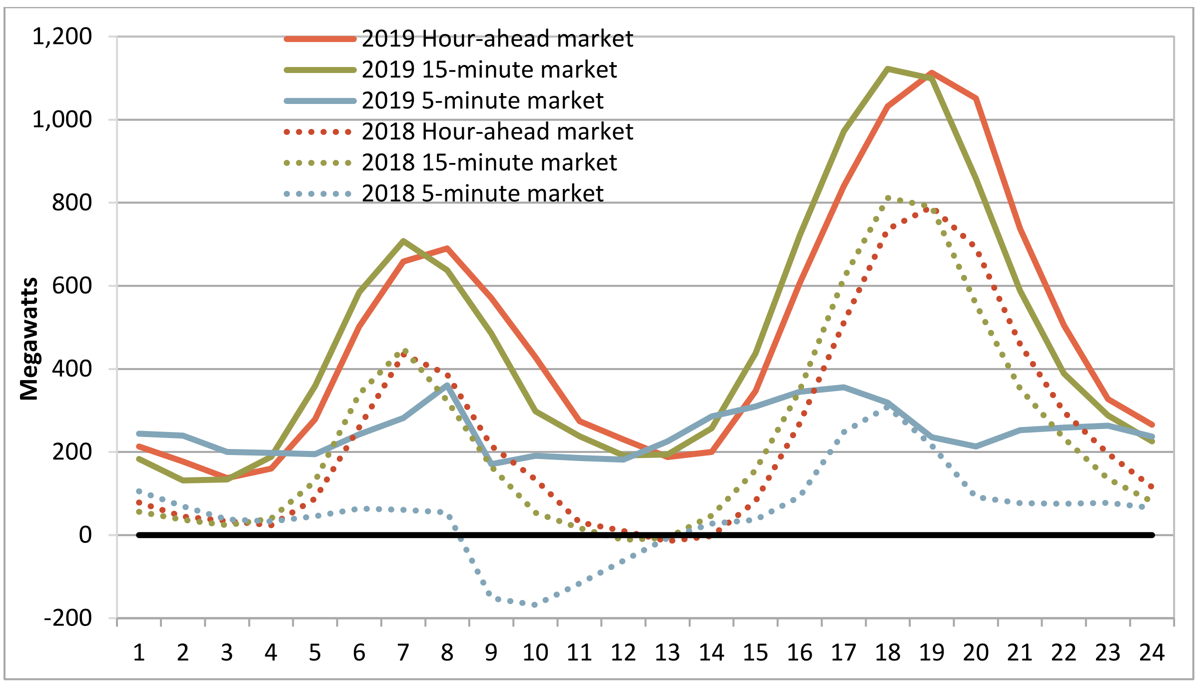
[27] Additional detail can be found in Section 9, Market Adjustments, in the *2016 Annual Report on Market Issues and Performance*, which is available on the ISO website at: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf

1.40 shows that the load adjustments for these markets tends to follow a similar shape, with large increases during the morning and evening net load ramp periods and the lowest adjustments during the early morning, late evening, and mid-day hours. In the fourth quarter, mid-day load adjustments were about 200 MW, compared with neutral or slightly negative adjustments in the same quarter of the previous year.

The 5-minute market load adjustments tend to follow a very different shape throughout the day, and are often well below the hour-ahead and 15-minute adjustments during the steep net load ramp periods. The 5-minute load adjustment in hour ending 18 was about 300 MW, much lower than the nearly 1,100 MW adjustment in the hour-ahead and 15-minute markets. In the fourth quarter of 2019, the average hourly load adjustment in the 5-minute market was about 250 MW compared with an hourly average of about 50 MW in the same quarter in the previous year. There were no negative hourly average load adjustments in the 5-minute market, which can often occur during the mid-day and low load periods.

Load adjustments are often associated with over/under-forecasted load, changes in expected renewable generation, and morning or evening net load ramp periods.

Figure 1.40 Average hourly load adjustment (Q4 2018 – Q4 2019)



1.14 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 runs 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 declined in the fourth quarter of 2019.

As illustrated in Figure 1.41, 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 40 percent lower in the fourth quarter of 2019 than in the same quarter of 2018.

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 increased residual unit commitment requirements in the fourth quarter of 2019, particularly in November and December.

Operator adjustments to residual unit commitment requirements were low during the fourth quarter. The use of this tool averaged about 29 MW per hour compared to about 109 MW per hour in the same quarter of 2018.

Residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of bid in variable energy resources and the forecast output of these renewable resources. This intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market. It is represented by the yellow bar in Figure 1.41.

Figure 1.41 Determinants of residual unit commitment procurement

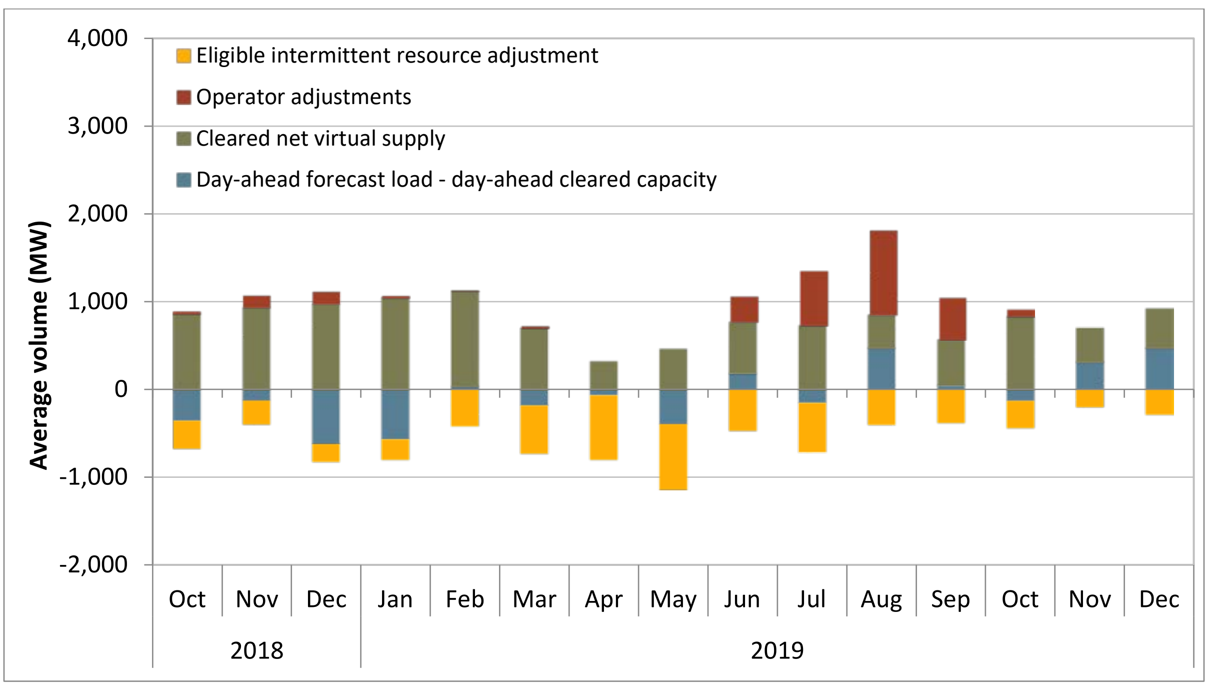
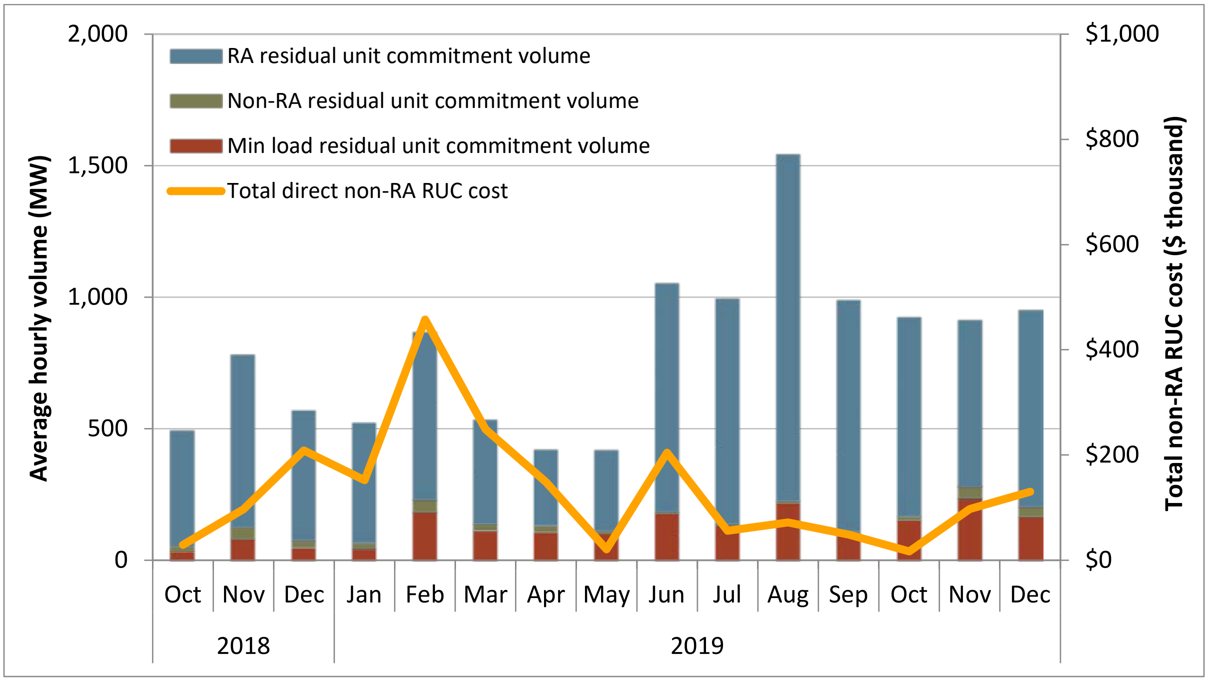


Figure 1.42 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased to about 932 MW per hour in the fourth quarter of 2019 from an average of 619 MW in the same quarter of 2018. Of the 932 MW per hour capacity, the capacity committed to operate at minimum load averaged about 184 MW each hour compared to 56 MW in the fourth 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.[28] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.42. In the fourth quarter of 2019, these costs decreased slightly to $0.24 million when compared to about $0.33 million in the same quarter of 2018.

Figure 1.42 Residual unit commitment costs and volume



1.15 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 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.

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

- **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.

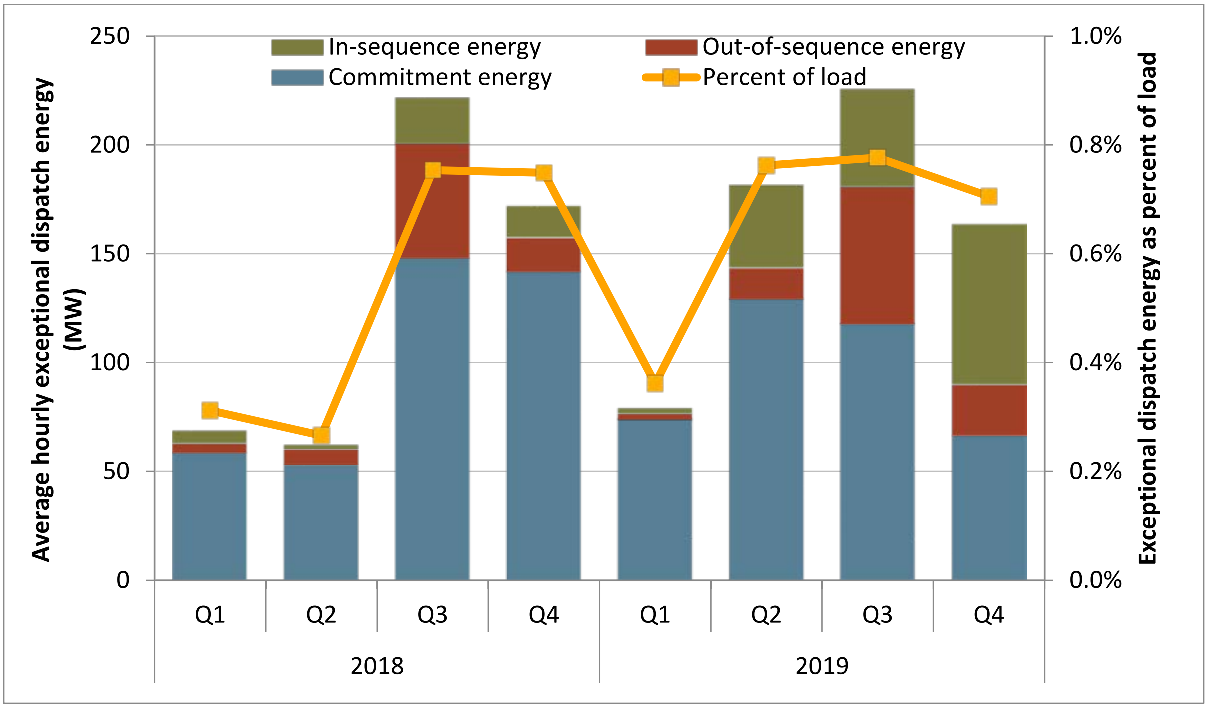
Energy from exceptional dispatch

Energy from exceptional dispatch accounted for almost 1 percent of total load in the ISO balancing area. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 165 MWh in the fourth quarter of 2019 which is about the same amount compared to the fourth quarter in 2018.

As shown in Figure 1.43, exceptional dispatches for unit commitments accounted for about 41 percent of all exceptional dispatch energy in this quarter.[29] About 14 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 45 percent was from in-sequence energy. In-sequence energy was particularly high this quarter due to the increase in commercial unit testing exceptional dispatches issued by the ISO operators.

[29] 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.

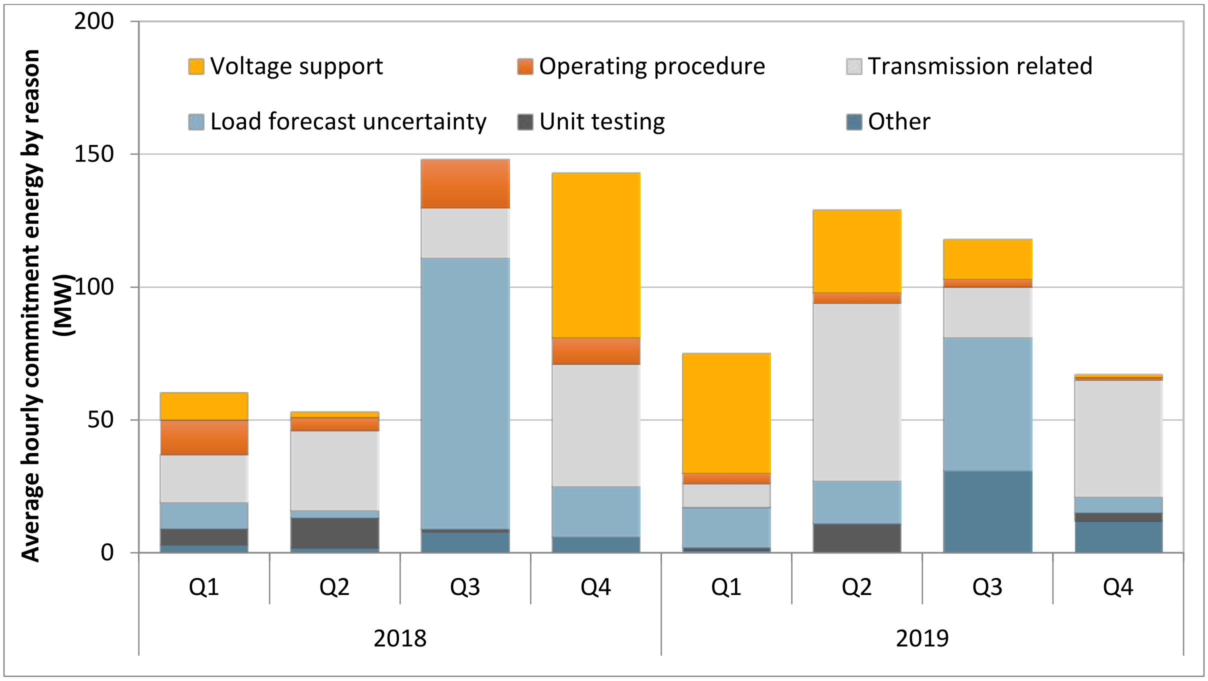
Figure 1.43 Average hourly energy from exceptional dispatch



Exceptional dispatches for unit commitment

Minimum load energy from exceptional dispatch unit commitments in the fourth quarter decreased on average by about half relative to the fourth quarter of the prior year. Lower levels of exceptional dispatch unit commitment were offset by an increase in exceptional dispatch energy above minimum load. The most frequent reason given for transmission related exceptional dispatches was to address planned transmission outages.

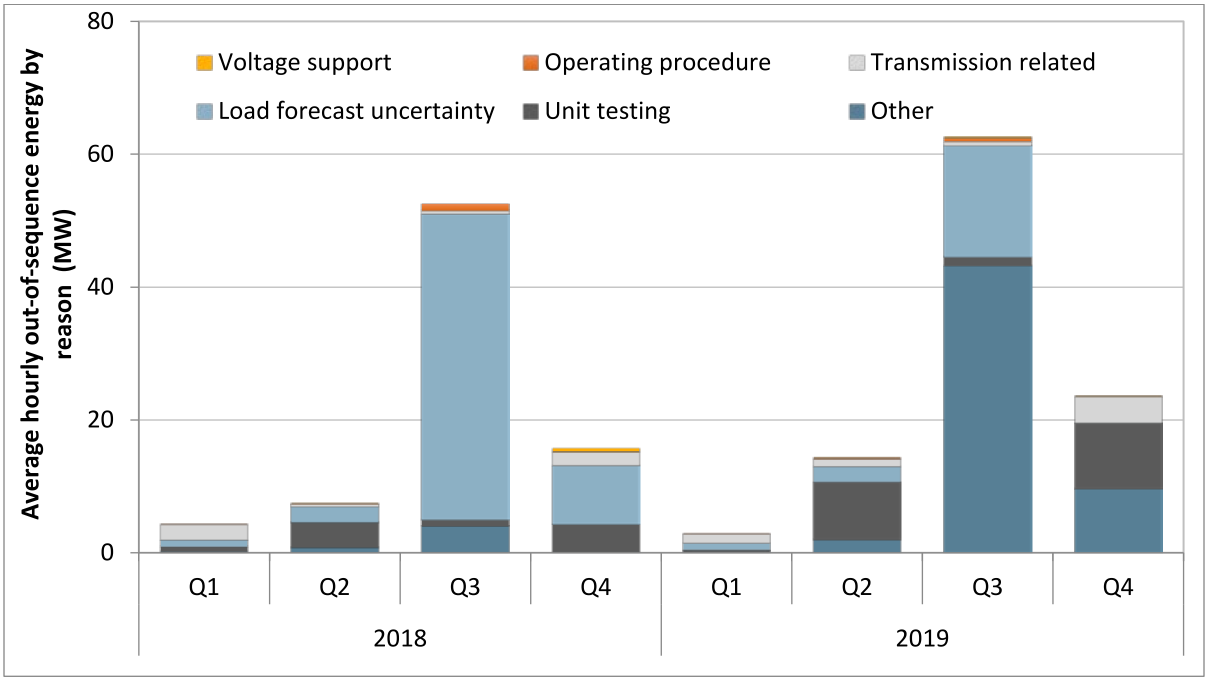
Figure 1.44 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch more than tripled relative to the same quarter in 2018. As previously illustrated in Figure 1.43 about 14 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 1.45 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 fourth quarter was exceptionally dispatched for unit testing and planned transmission outages.

Figure 1.45 Out-of-sequence exceptional dispatch energy by reason



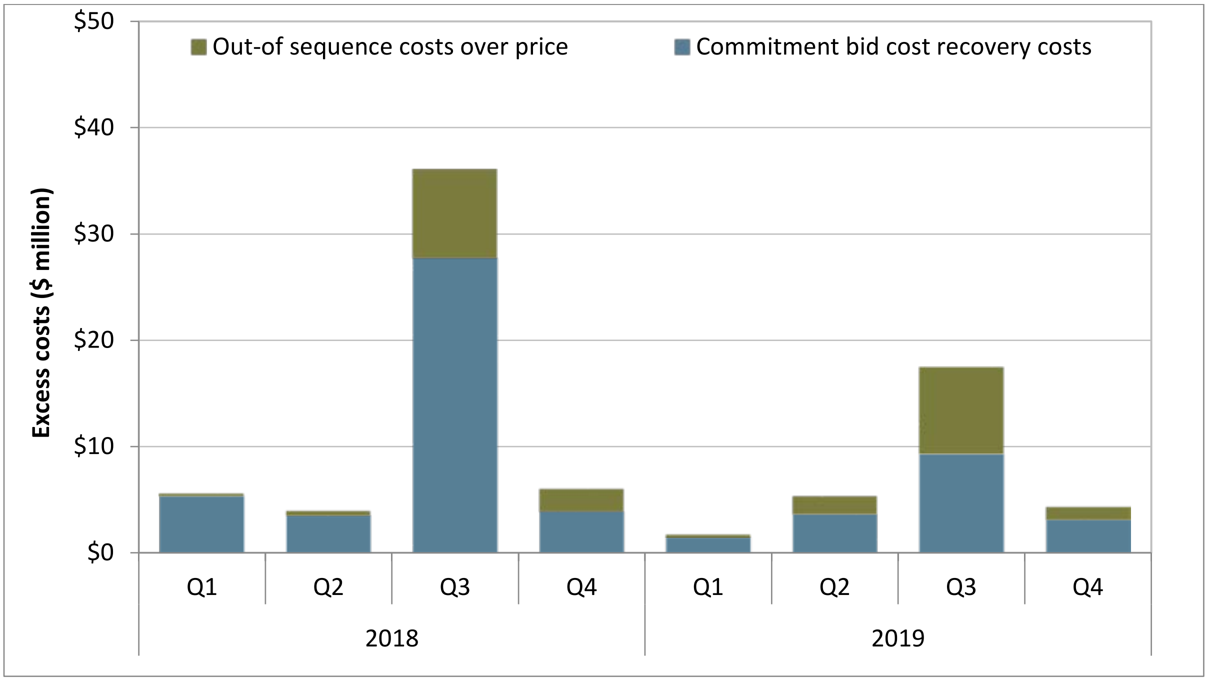
Exceptional dispatch costs

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 1.46 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 fourth quarter, out-of-sequence energy costs were $1.2 million, while commitment costs for exceptional dispatch paid through bid cost recovery were $3.2 million.

Figure 1.46 Excess exceptional dispatch cost by type



2 Western energy imbalance market

This section covers Western EIM performance during the fourth quarter. Key observations and findings include:

- **Prices in the Northwest region**, which includes PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex, were regularly lower than prices in the ISO and other balancing areas due to limited transfer capability out of this region during peak system load hours.
- **Sufficiency test failures and subsequent under-supply power balance constraint relaxations** drove average real-time prices for Arizona Public Service higher. With the modified load conformance limiter implemented in February 2019, almost all intervals with power balance relaxations were priced at the penalty parameter of $1,000/MWh.
- **Congestion imbalance deficits related to base schedules** remained very low in the fourth quarter. Balancing areas may allocate these imbalances to third party customers and others. PacifiCorp East is the only area to have significant base schedule related congestion imbalance deficits which occurred primarily in late 2017 and early 2018.
- **Western EIM greenhouse gas** prices increased as the deemed delivered resources shifted from lower to higher greenhouse gas emissions. In November 2018, the ISO implemented a revised EIM greenhouse gas bid design which limited greenhouse gas bid capacity to the differences between base schedule and available capacity. The weighted average greenhouse gas cost increased as the deemed delivered resources shifted from hydroelectric to natural gas.

2.1 Western EIM performance

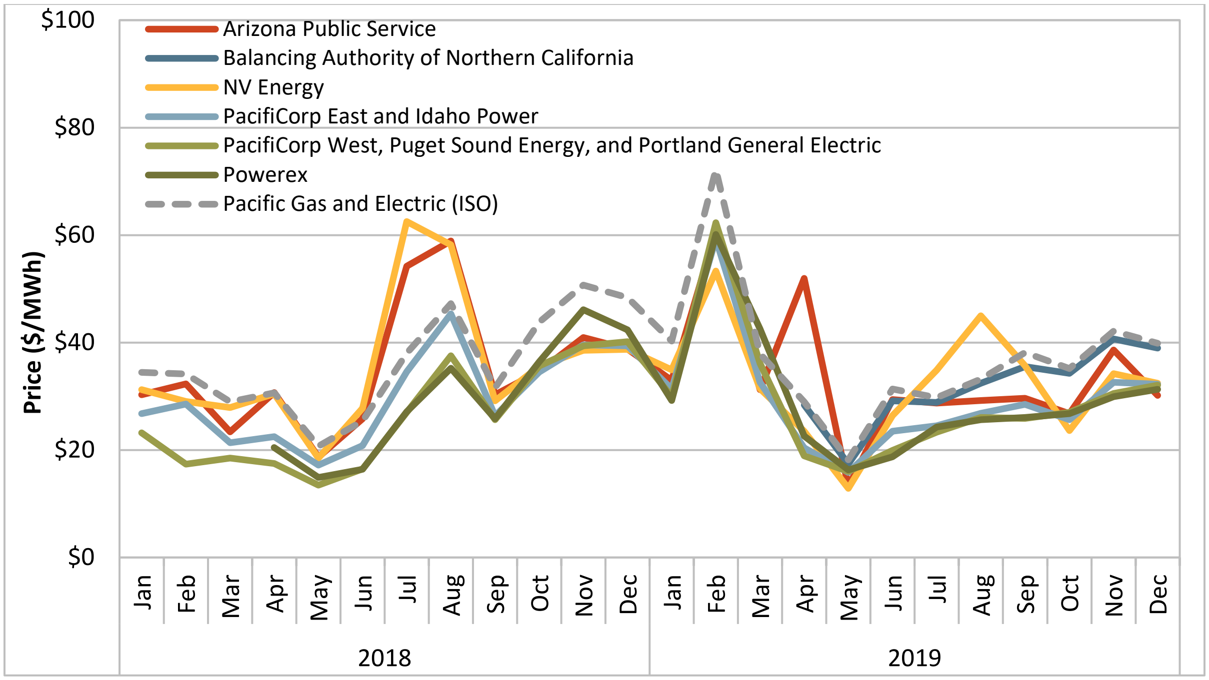
Western EIM prices

This section details the factors that influence changes in Western EIM balancing authority prices in general and what causes price separation between entities. The Western EIM benefits participating balancing authorities by committing lower-cost resources across all areas to balance fluctuations in supply and demand in the real-time energy market. Since dispatch decisions are determined across the whole Western EIM system, prices within each balancing authority diverge from the system price when transfer capability constraints are binding, greenhouse gas compliance costs are enforced for imports into California or power balance constraint violations within a single area are assigned penalty prices.

Figure 2.1 shows average monthly prices from the 15-minute market by balancing authority from January 2018 to December 2019. Several balancing areas are grouped together due to similar average monthly prices. Prices for Powerex (dark green line) and Idaho Power (included in light blue line) begin in April of 2018 while prices for the Balancing Authority of Northern California (dark blue line) begin in

April of 2019 when they joined the Western EIM.[30] Prices for Pacific Gas and Electric (grey dashed line) are included in the figure as a point of comparison for this analysis.

Figure 2.1 Monthly 15-minute market prices



The variability of Western EIM system prices over time is largely explained by natural gas prices. Natural gas price spikes at the SoCal Citygate, PG&E Citygate, and NW Sumas hubs, as shown in Figure 1.1 from the previous chapter, drove the sharp increases in Western EIM system prices between July 2018 and February 2019.

Price separation between Western EIM balancing authorities occurs for several reasons. ISO prices tend to be higher than the rest of the Western EIM due to greenhouse gas compliance cost for energy that is delivered to California.[31] In addition to this, average prices in the Northwest region (including PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex) are regularly lower than the ISO and other balancing areas because of limited transfer capability out of this region. Figure 2.1 also highlights high price spikes in NV Energy and Arizona Public Service in the months when a relatively high number of power balance constraint violations occurred. In many cases, these occurred in intervals in which Western EIM imports into these areas were frozen due to failed resource sufficiency tests.

Figure 2.2 and Figure 2.3 continue this analysis by showing how Western EIM prices vary throughout the day in the fourth quarter of 2019. Average hourly prices are shown for participating balancing authorities between October 1 and December 31, 2019. Prices continue to follow the net load pattern

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30 Prices for Idaho Power are not included in average prices for the PacifiCorp East and Idaho Power grouping from January to March of 2018.

31 See Section 2.5 for more information about California's greenhouse gas compliance cost and its impact on the ISO and EIM.

with the highest energy prices during the morning and evening peak net load hours in some Western EIM balancing areas just as in the ISO. As in the previous analysis, several balancing areas are grouped together because of similar average hourly pricing, and prices at the Pacific Gas and Electric default load aggregation point are shown as a point of comparison.

Figure 2.2 Hourly 15-minute market prices (October – December)

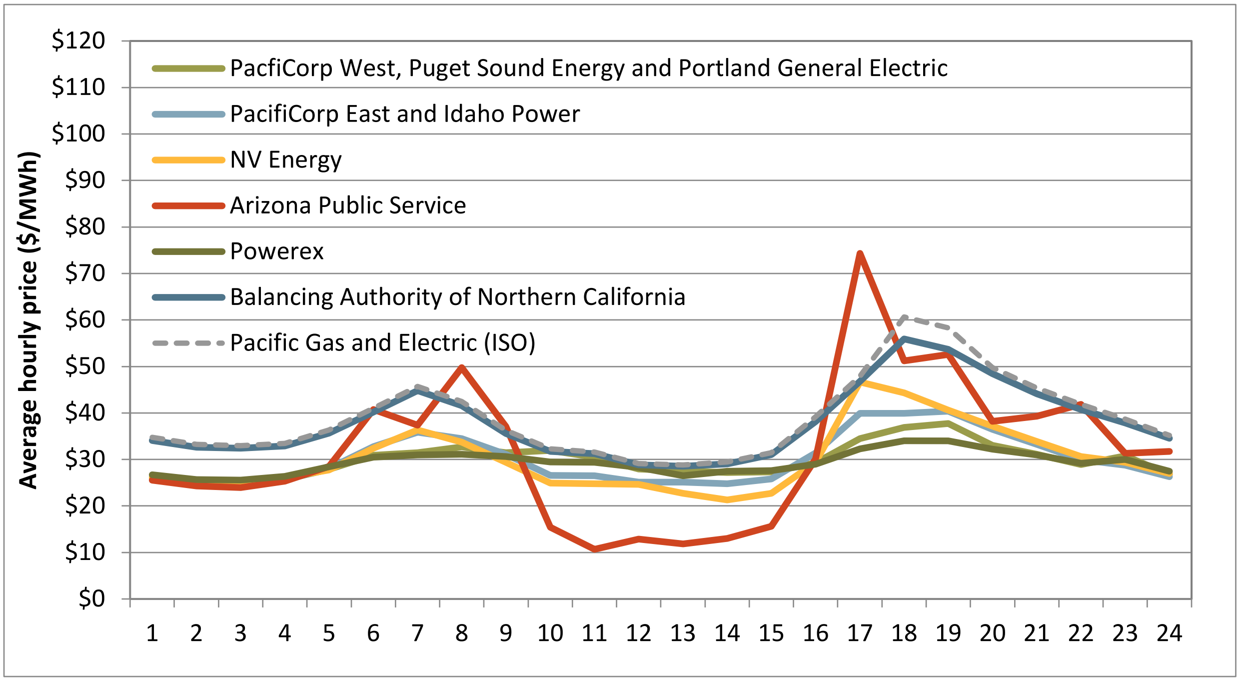

Figure 2.3 Hourly 5-minute market prices (October – December)

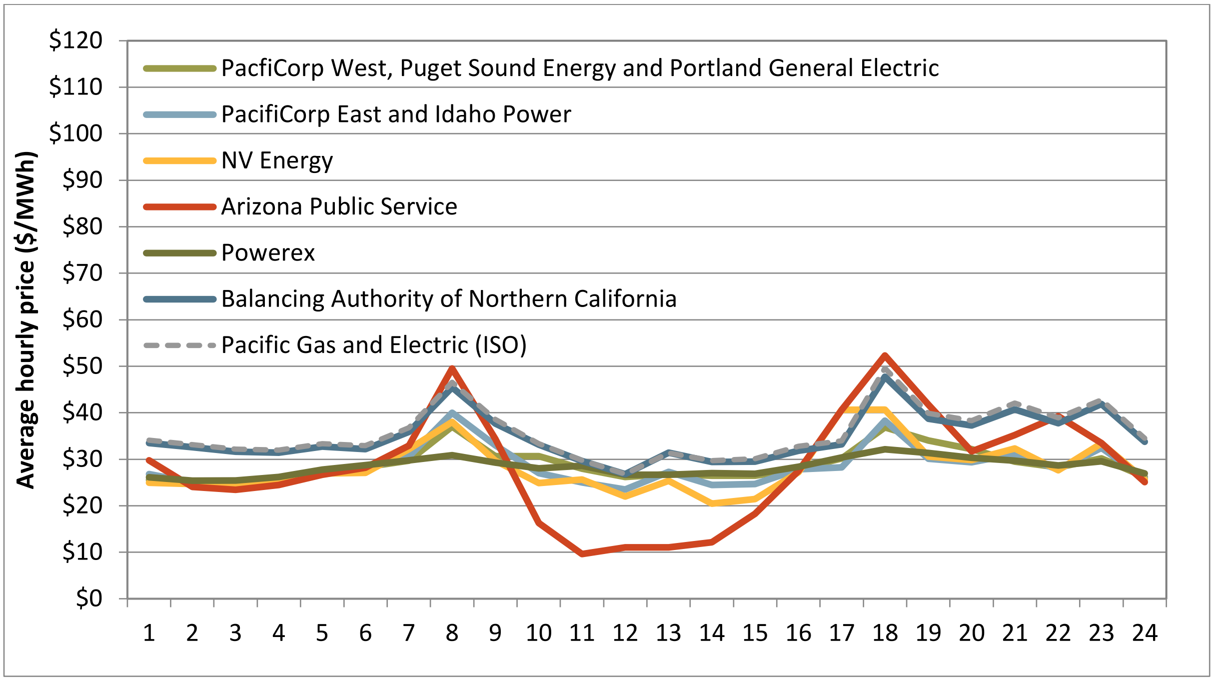

Figure 2.2 and Figure 2.3 show that the relative price differences between Western EIM entities vary throughout the day. Prices in entities outside of California tend to be lower than ISO prices throughout all hours. This price divergence is more pronounced during the morning and evening ramping periods when the ISO is typically importing energy that is subject to greenhouse gas compliance costs. Western EIM entity prices converge with the ISO prices in the middle of the day when the ISO tends to export energy. The Balancing Authority of Northern California (BANC) is the exception to this rule due to their location in California. Prices in the BANC tracked very closely to prices in the ISO in the fourth quarter because of significant transfer capability and little congestion between the areas.

These figures show that average prices in the Northwest region (including PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex) remain very flat throughout the day and do not increase much during ramping hours. This reflects the limited transmission that is available in the Western EIM to support transfers from the Northwest to California and other balancing authorities in the Southwest.

Prices in Arizona Public Service area diverged from the rest of the Western EIM during the morning and afternoon peak load hours as well as throughout the middle of the day. APS experienced a number of flexible ramping sufficiency test failures between hours ending 6 to 8 and 17 to 22. This resulted in under-supply power balance constraint relaxations in the market software. 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.[32] APS also experienced relatively lower prices in the middle of the day due to ISO congestion.[33]

Prices in PacifiCorp East and Idaho Power were often similar to each other and lower than prices in the ISO. As shown in Figure 2.2 and Figure 2.3, price separation between these areas and the ISO was most

32 See Section 2.4 for further details on the load conformance limiter enhancement and its impact.

33 See Section 1.9 for further details on the effect congestion had on ISO and EIM prices.

pronounced during peak load hours when transfers from PacifiCorp East and Idaho Power into the ISO hit export limits.

Average real-time prices for NV Energy were similar to PacifiCorp East and Idaho Power except in hour ending 17, when the area experienced failed flexible ramping sufficiency tests and power balance constraint relaxations.

Western EIM wholesale energy cost

In the energy imbalance market, total estimated wholesale cost to serve load, excluding the ISO, decreased to about $3.8 million or $0.06/MWh of total load in the fourth quarter of 2019 from about $13 million or $0.20/MWh in the same quarter of 2018. Wholesale costs estimated here are costs associated with serving imbalance load in the Western EIM measured per megawatt-hour of total load.

As shown in Figure 2.4 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 decreased by about 37 percent while both real-time congestion imbalance offset and bid cost recovery costs increased compared with the same quarter in 2018. Other costs remained similar to previous quarters. In the EIM, offset costs paid to non-California balancing areas include payments to offset greenhouse gas cap-and-trade obligations incurred due to market dispatch.

Figure 2.4 Total EIM quarterly wholesale costs per MWh of load

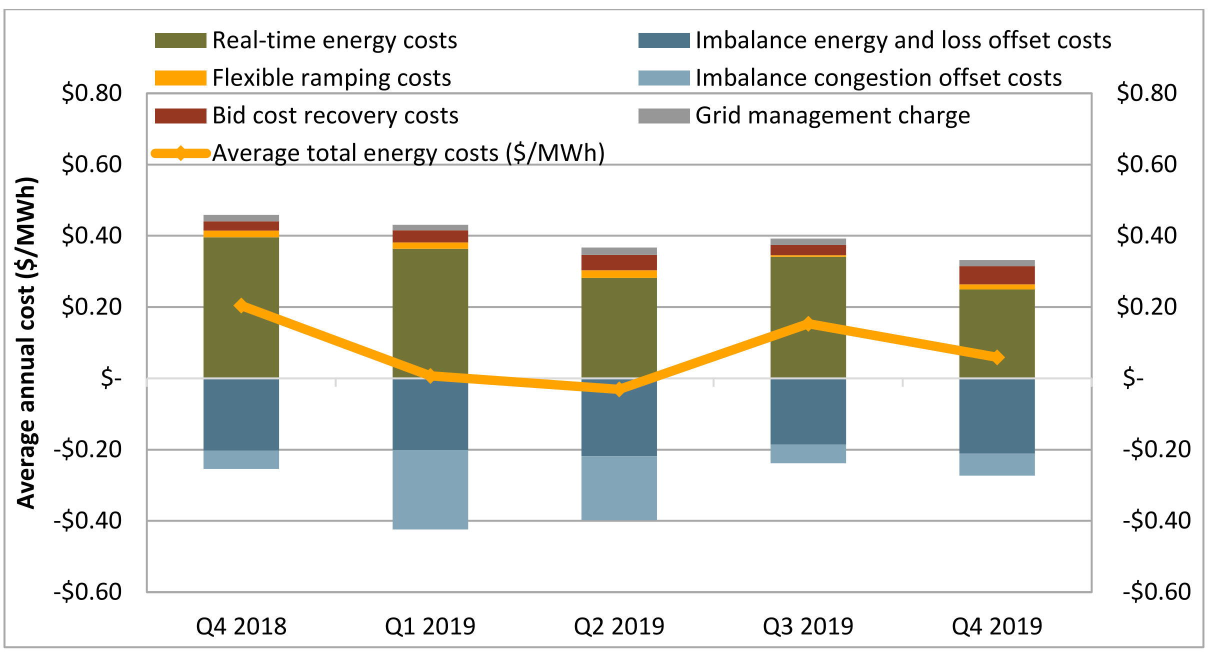

Table 2.1 Estimated average EIM wholesale energy costs per MWh

	Q4 2018	Q1 2019	Q2 2019	Q3 2019	Q4 2019	Change Q4 2018-Q4 2019
Real-time energy costs	$0.40	$0.36	$0.28	$0.34	$0.25	($0.15)
Imbalance congestion offset costs	($0.05)	($0.22)	($0.18)	($0.05)	($0.06)	($0.01)
Imbalance energy and loss offset costs	($0.20)	($0.20)	($0.22)	($0.19)	($0.21)	($0.01)
Flexible ramping costs	$0.02	$0.02	$0.02	$0.00	$0.01	($0.01)
Grid management charge	$0.02	$0.02	$0.02	$0.02	$0.02	($0.00)
Bid cost recovery costs	$0.03	$0.03	$0.04	$0.03	$0.05	$0.03
Average total energy costs ($/MWh)	**$0.20**	**$0.01**	**($0.03)**	**$0.15**	**$0.06**	**($0.15)**

Congestion imbalances from Western EIM internal transmission constraints

Real-time congestion imbalances occur when payments made to schedules reducing flows on binding transmission constraints differ from payments collected from schedules increasing flows on constraints. A deficit is created when payments to flow reductions exceed collections from flow increases. When collections exceed payments there is a congestion surplus.

The ISO allocates real-time congestion imbalance deficits and surpluses to the balancing authority area in which the constraints are located. The balancing authority areas then allocate these imbalances based on their tariffs, which can include allocations to third party customers.

Western EIM base schedules can create flows above limits on constraints internal to a balancing authority area. If base schedule flows exceed internal constraint limits the 15-minute market must adjust schedules to reduce flows. The reduced flows would be paid without corresponding flow increases from which to collect payments, causing a congestion imbalance deficit. This leads to concerns that third party customers, who are not responsible for submitting base schedules or transmission limits to the ISO, will have to pay to offset deficits caused by base schedule flows that exceed internal constraint limits.

Table 2.2 shows estimated real-time congestion imbalance charges from internal transmission constraints in the 15-minute market. These estimates do not include congestion imbalances from the real-time dispatch or inter-balancing authority area transfer constraints. With the exception of the California ISO, which settles deviations from day-ahead market schedules, these data estimate the extent to which congestion imbalance deficits are the result of base schedule flows exceeding 15-minute market transmission limits. Negative values indicate a congestion imbalance deficit and positive values a surplus. Please note that these estimates are calculated from non-settlement quality data.

PacifiCorp East is the only area to have significant base schedule related congestion imbalance deficits which occurred primarily in late 2017 and early 2018. These deficits were in part allocated to third party customers within PacifiCorp East. In 2018 the ISO conducted extensive outreach with Western EIM balancing authority areas and streamlined processes to reduce and prevent base scheduling that creates flows exceeding internal transmission limits. In 2019 PacifiCorp East had a small 15-minute market congestion surplus from internal constraints. There has not been significant congestion imbalance deficits caused by base schedules exceeding transmission limits in other balancing authority areas. The low congestion imbalances from internal constraints in many Western EIM areas results in part from a lack of binding internal constraints.

Table 2.2 Estimated 15-minute market EIM internal constraint congestion imbalances ($ million)

	Annual				2019 Quarterly			
Balancing Authority Area	**2016**	**2017**	**2018**	**2019**	**Q1**	**Q2**	**Q3**	**Q4**
Arizona Public Service	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
BANC				$0.0	$0.0	$0.0	$0.0	$0.0
Powerex	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
California ISO	-$51.1	-$26.2	-$70.4	-$92.3	-$17.9	-$18.4	-$14.0	-$42.0
Idaho Power Company			$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NV Energy	-$0.3	-$0.8	-$0.3	-$0.4	-$0.3	-$0.1	$0.0	$0.0
PacifiCorp - East	-$4.0	-$18.1	-$2.0	$0.7	$0.8	$0.0	$0.1	-$0.3
PacifiCorp - West	$0.0	$0.0	-$0.1	$0.0	$0.0	$0.0	$0.0	$0.0
Portland General Electric		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Puget Sound Energy	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

2.2 Flexible ramping sufficiency test

The flexible ramping sufficiency test is performed every hour and ensures each balancing area has enough ramping resources to meet expected upward and downward ramping needs in the real-time market without relying on transfers from other balancing areas.

If an area fails the upward sufficiency test, EIM transfers into that area cannot be increased.[34] 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 when the capacity test fails for the specific direction. The capacity test ensures that there are sufficient incremental or decremental economic energy bids above or below the base schedules to meet the demand forecast.[35]

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 EIM areas failed the upward or downward sufficiency test.

Figure 2.5 and Figure 2.6 show the percent of *intervals* in which an EIM area failed the sufficiency test in the upward or downward direction.[36] Since May 6, the figures reflect that the flexible ramping

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34 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.

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

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

sufficiency test evaluates sufficient ramping capability in 15-minute increments rather than hourly increments. In particular, Arizona Public Service failed the upward sufficiency test during almost 5 percent of intervals during November, and around 1 percent of intervals in each of October and December. The ISO failed the upward sufficiency test during six intervals during the fourth quarter.

Failures of the sufficiency test are important because these outcomes limit transfer capability. Constraining transfer capability may affect the efficiency of the EIM by limiting transfers into and out of a balancing area that could potentially provide benefits to other balancing areas. Reduced transfer capability also affects 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.

Figure 2.5 Frequency of upward failed sufficiency tests by month

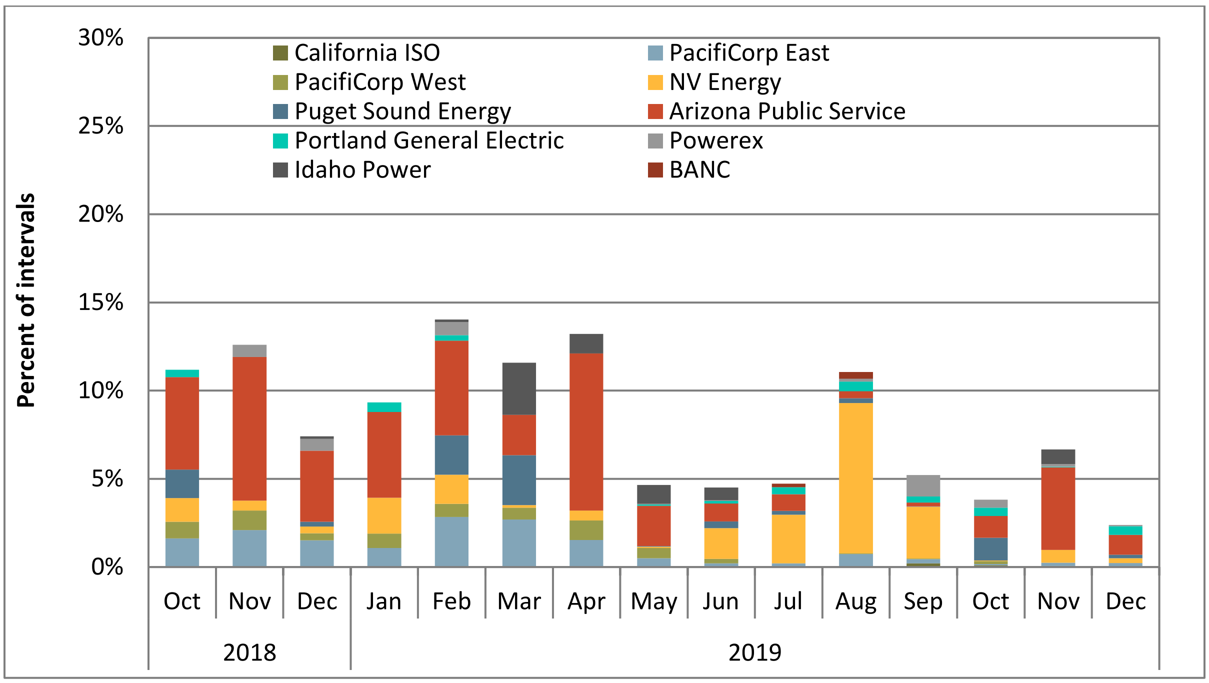
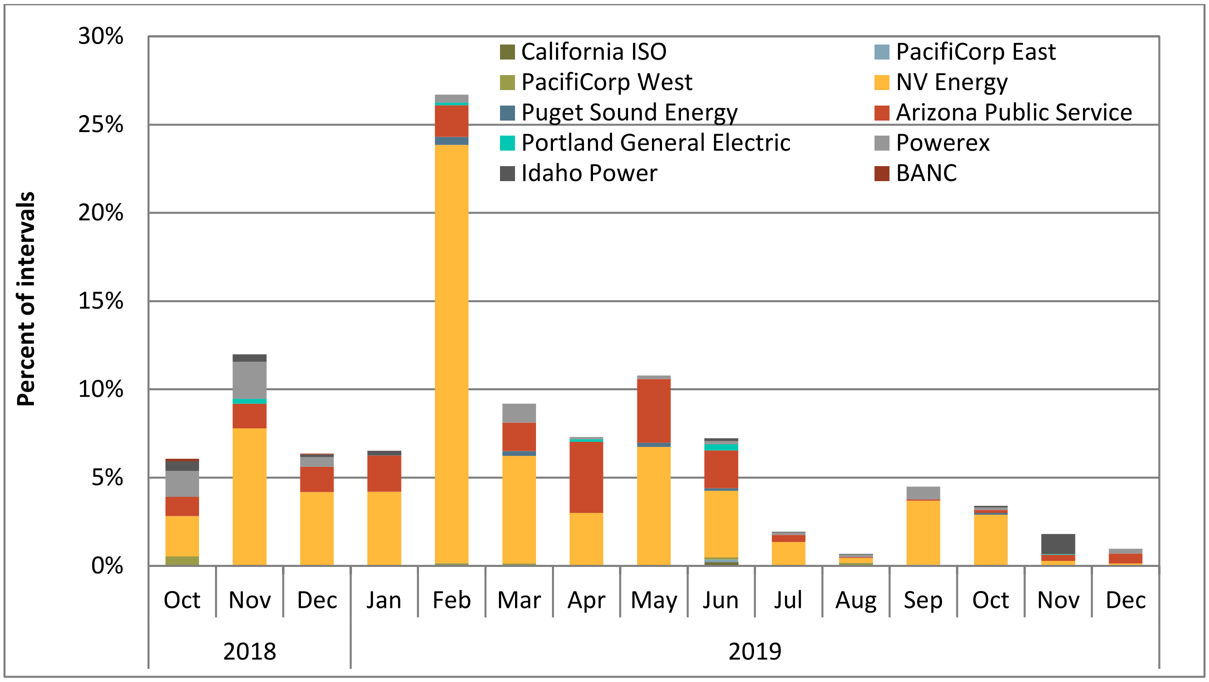


Figure 2.6 Frequency of downward failed sufficiency tests by month

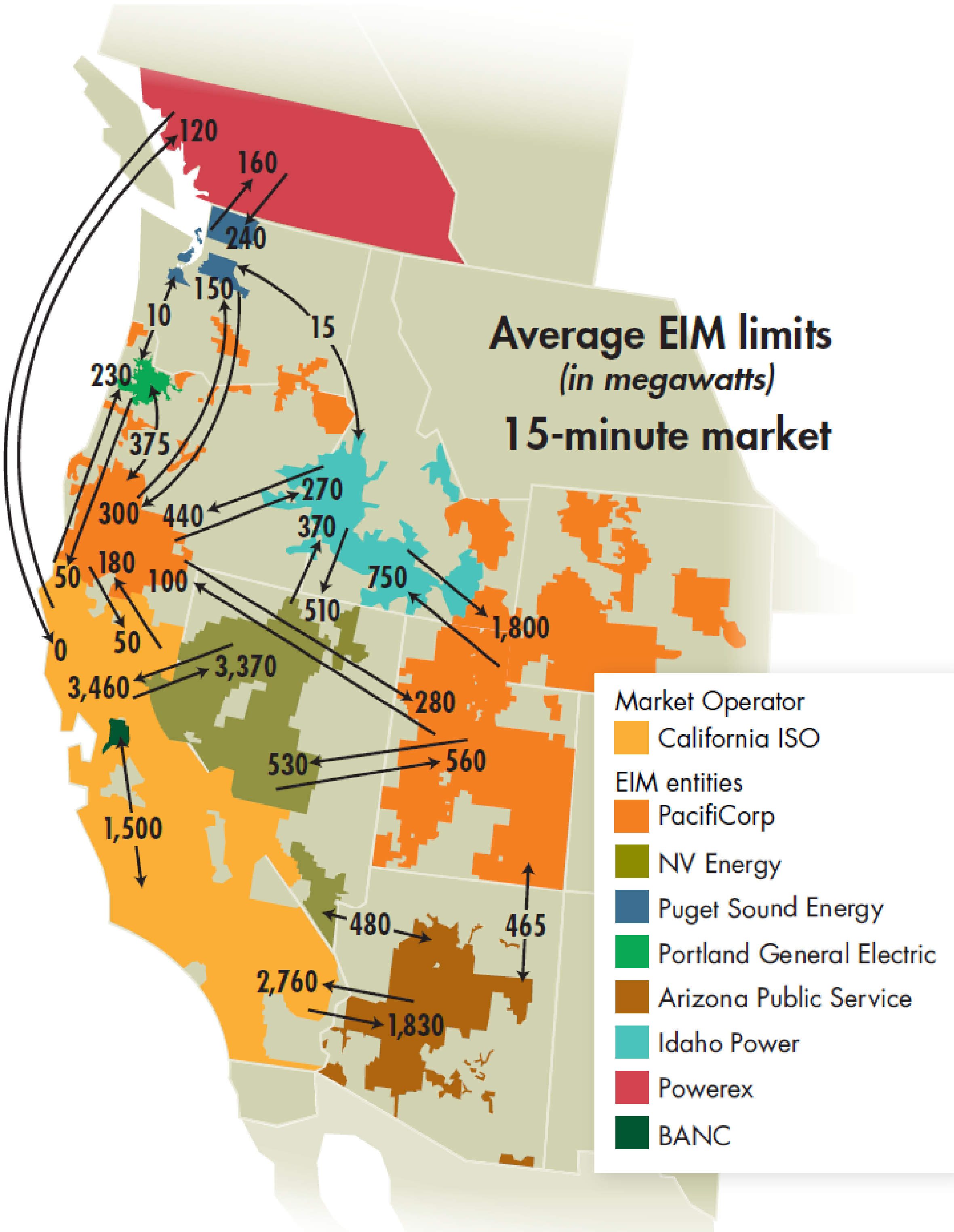


2.3 Western EIM transfers

Western EIM transfer limits

One of the key benefits of the EIM is the ability to transfer energy between areas in the 15-minute and 5-minute markets. Figure 2.7 shows average 15-minute market limits between each of the areas during the fourth quarter. The map shows that there was significant transfer capability between the ISO, NV Energy, Arizona Public Service, and the 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 limited to zero in all intervals in both the 15-minute and 5-minute markets.

Figure 2.7 Average 15-minute market energy imbalance market limits (October – December)



Hourly energy imbalance market transfers

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

Figure 2.8 compares average hourly imports (negative values) and exports (positive values) between the ISO and other EIM areas during the last five quarters in the 15-minute market.[37] The bars show the average hourly transfers with the connecting areas. The gray line shows the average hourly net transfer.

In the fourth quarter of 2019, average exports during the middle of the day from the ISO were similar to the previous quarter, but higher compared to the fourth quarter of the previous year. In particular, exports from the ISO to areas in the Northwest increased significantly from the previous year. In addition, the fourth quarter of 2019 includes exports to the BANC area, which averaged around 170 MW between hours ending 9 and 16.

Figure 2.8 California ISO - average hourly 15-minute market transfer

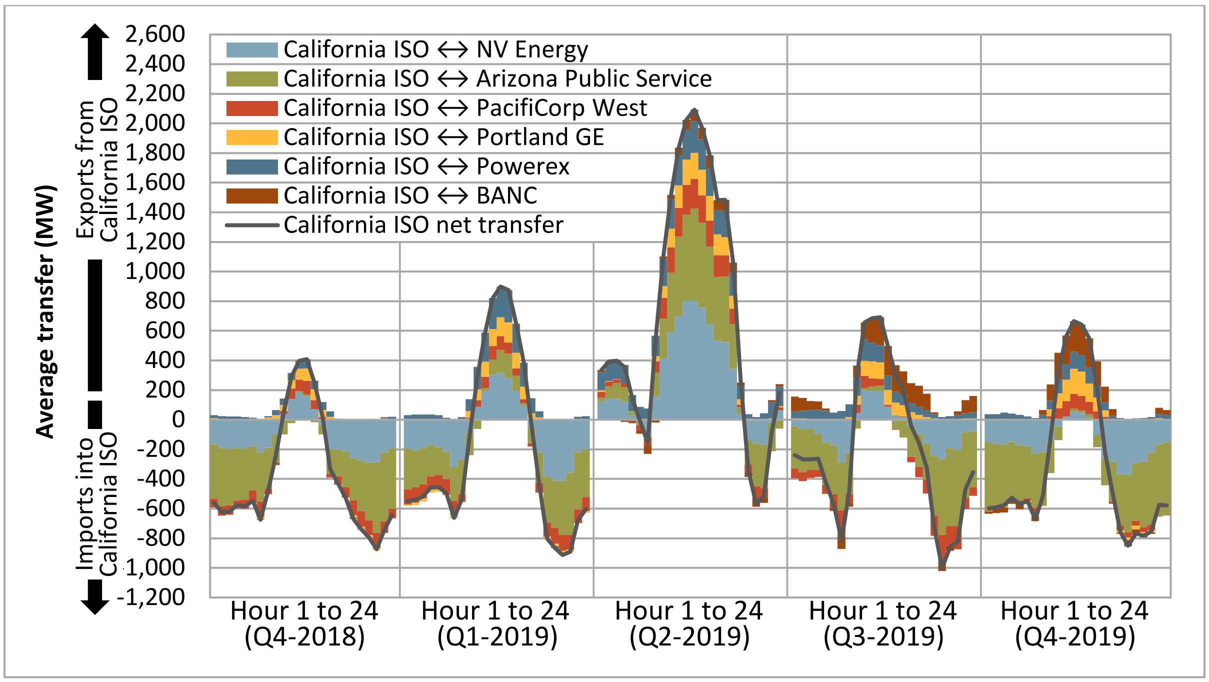


Figure 2.9 through Figure 2.14 show the same information on imports and exports for NV Energy, Arizona Public Service, Idaho Power, PacifiCorp West, Powerex, and Portland General Electric in the 15-minute market.[38] The amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[39]

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[37] 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.

[38] Figures showing transfer information from the perspective of PacifiCorp East, Puget Sound Energy, and BANC are not explicitly included, but are represented in Figure 2.8 through Figure 2.14.

[39] Base schedules on EIM transfer system resources are fixed bilateral transactions between EIM entities.

As shown in Figure 2.8, a large portion of the ISO's transfer capability in the EIM is with NV Energy and Arizona Public Service. Per Figure 2.9 and Figure 2.10, NV Energy and Arizona Public Service were generally net exporters during most hours.

Figure 2.11 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, NV Energy, and — to a limited extent — Puget Sound Energy.

Figure 2.9 NV Energy – average hourly 15-minute market transfer

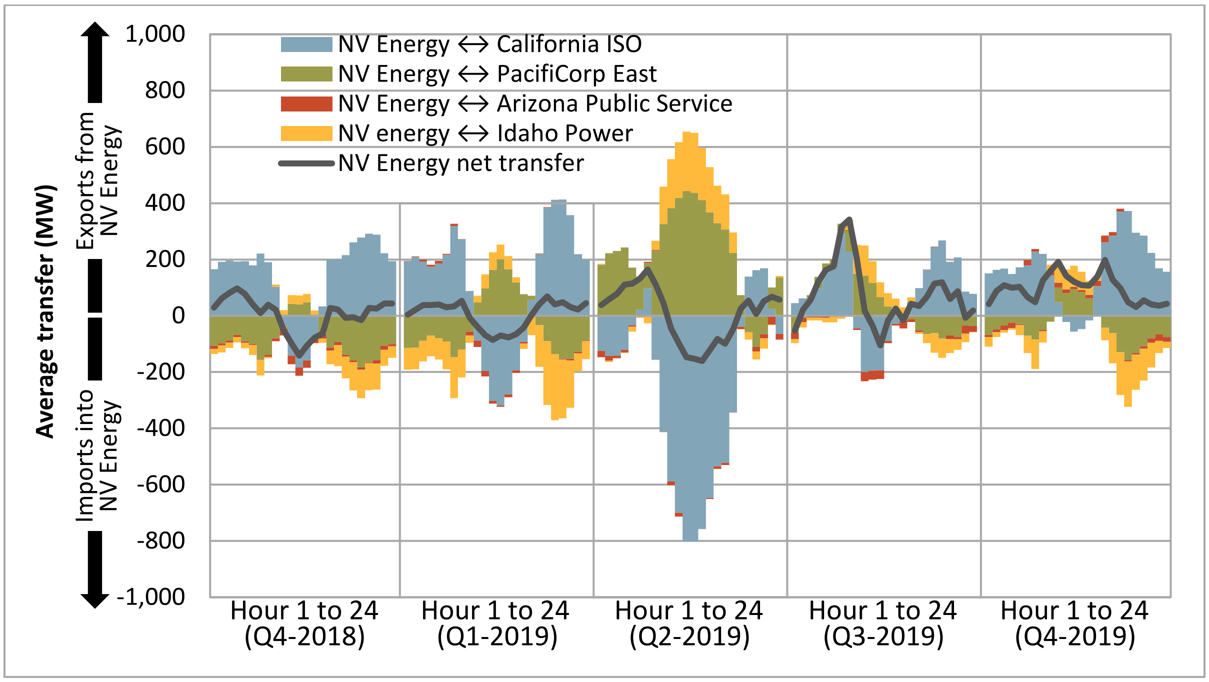


Figure 2.10 Arizona Public Service – average hourly 15-minute market transfer

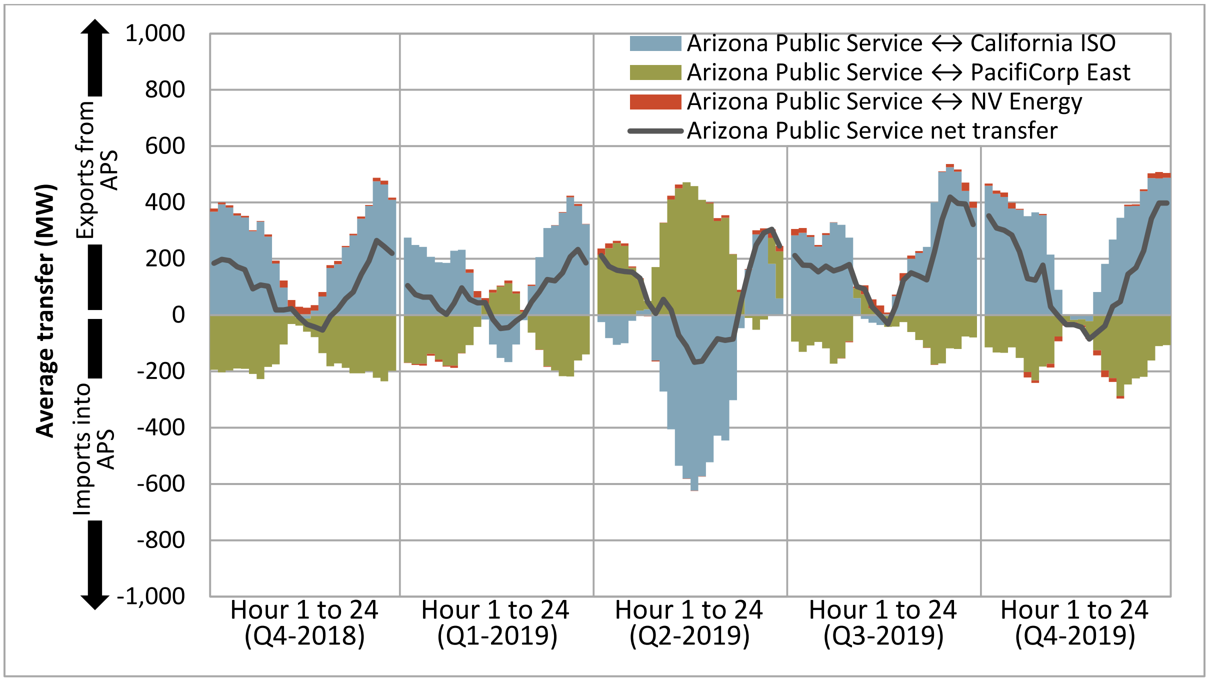


Figure 2.11 Idaho Power – average hourly 15-minute market transfer

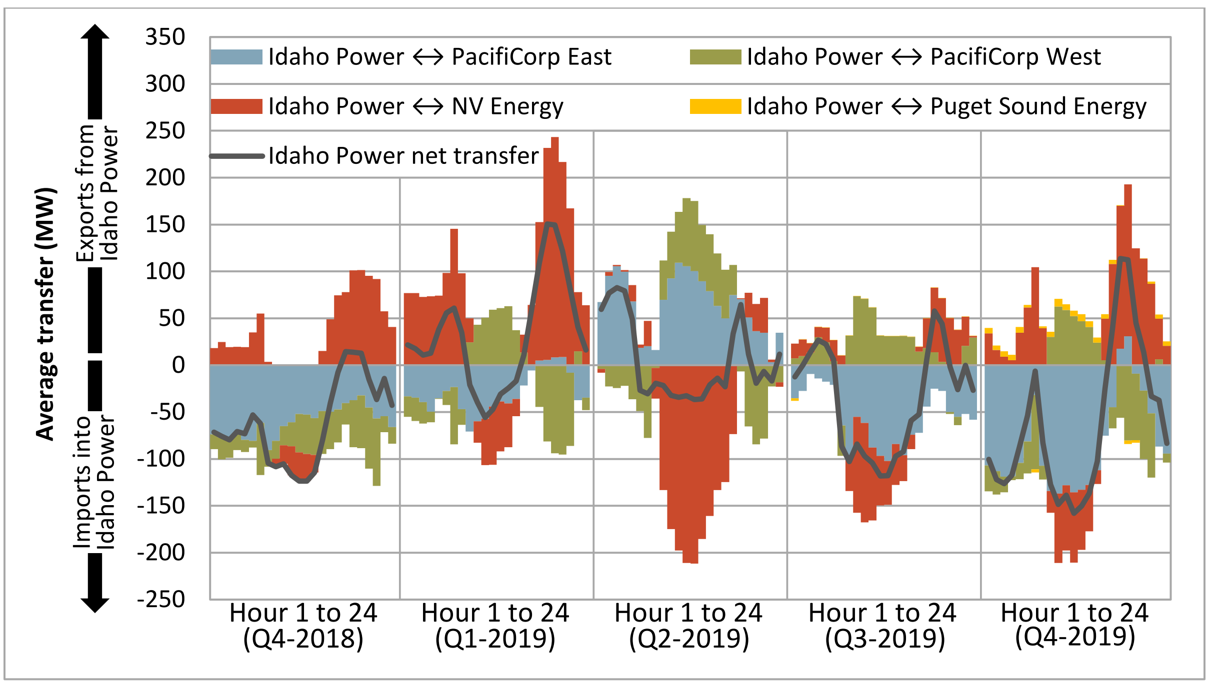


Figure 2.12 shows the hourly 15-minute market transfer pattern between PacifiCorp West and neighboring areas during the last five quarters. PacifiCorp West has transfer capacity between the ISO, PacifiCorp East, Puget Sound Energy, Portland General Electric, and Idaho Power.

Figure 2.13 shows average hourly 15-minute market imports and exports into and out of Powerex. During the fourth quarter of 2019, export transmission capacity from Powerex toward the ISO was limited to zero in all intervals in both the 15-minute and 5-minute markets.

Similarly, Figure 2.14 shows average hourly transfers into and out of the Portland General Electric area. Export limits from Portland General Electric toward the ISO were set to zero during 53 percent of 15-minute intervals and 75 percent of 5-minute intervals during the fourth quarter. Average *import* limits into the Portland General Electric area from the ISO were around 230 MW in the 15-minute market.

Figure 2.12 PacifiCorp West – average hourly 15-minute market transfer

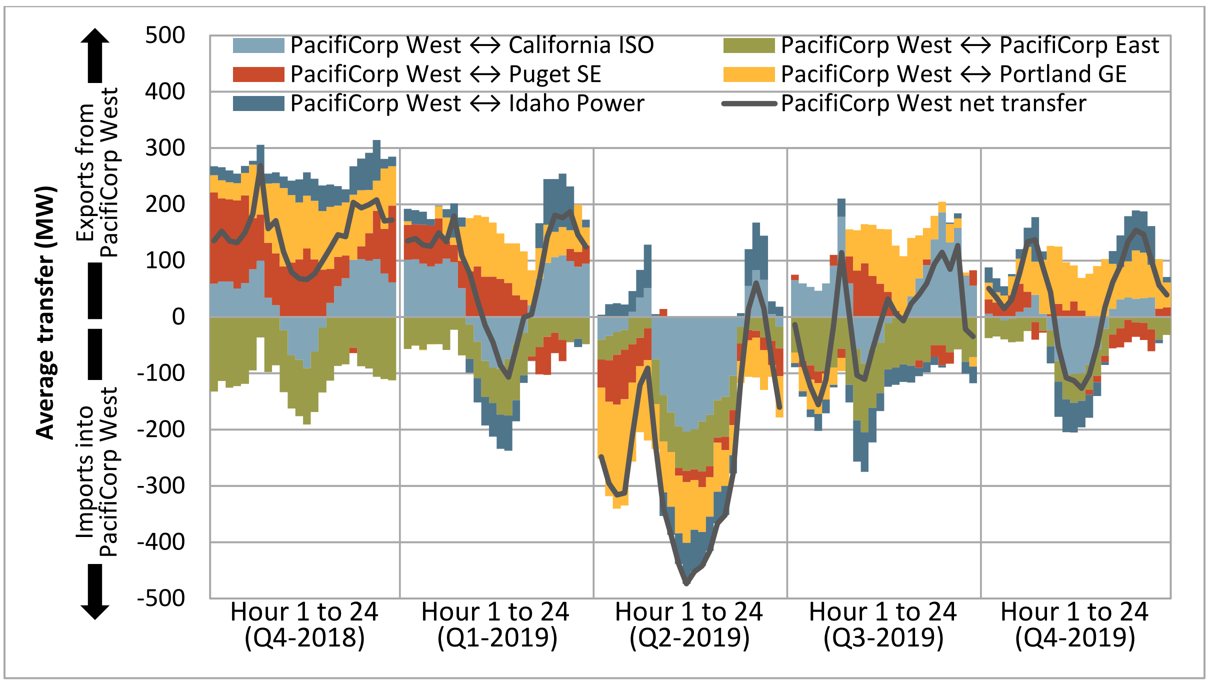


Figure 2.13 Powerex – average hourly 15-minute market transfer

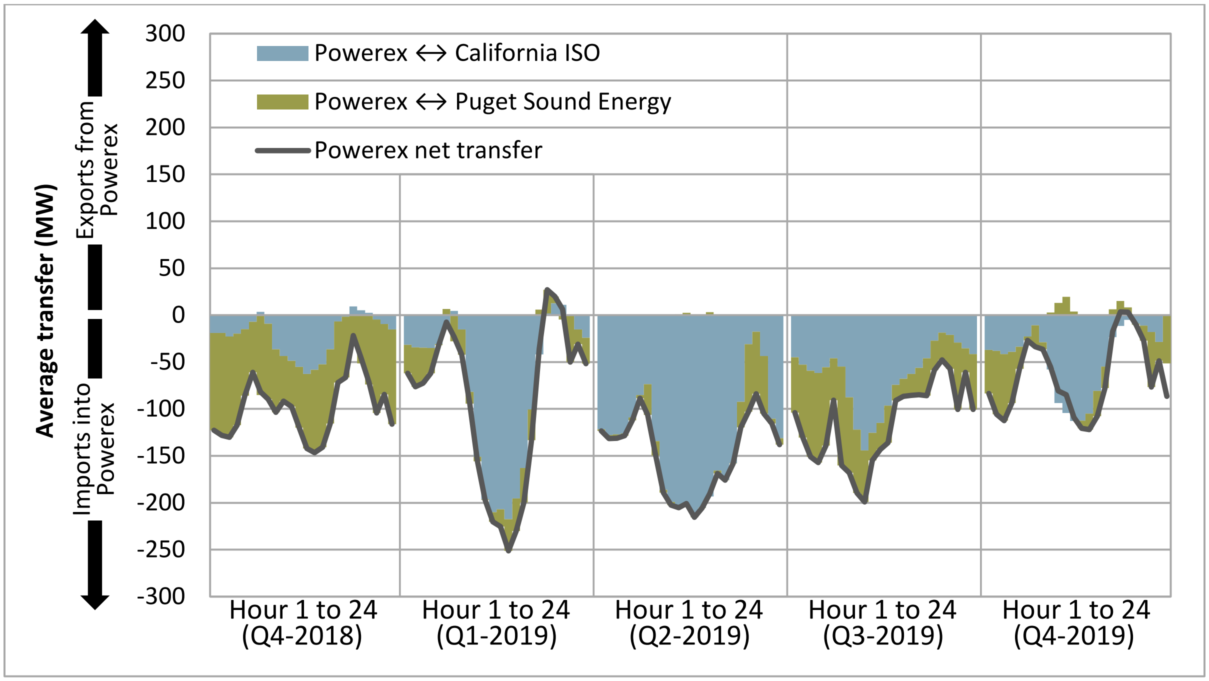
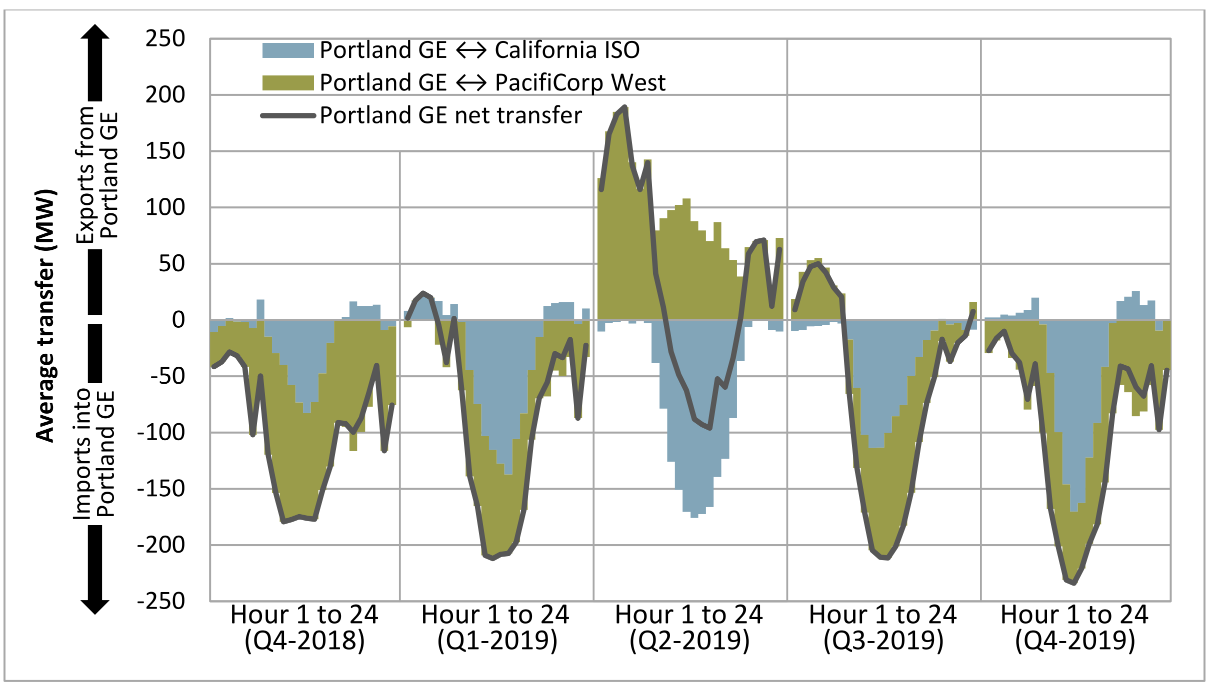


Figure 2.14 Portland General Electric – average hourly 15-minute market transfer



Inter-balancing area congestion

Congestion between an EIM 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 EIM area, relative to prevailing system prices in the ISO.[40]

During intervals when there is net import congestion into an EIM area, the ISO market software triggers local market power mitigation in that area.[41] 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 16 percent of 15-minute market intervals and 27 percent of 5-minute market intervals during the fourth quarter.

Table 2.3 Frequency of congestion in the energy imbalance market (October – December)

	15-minute market		5-minute market	
	Congested toward ISO	Congested from ISO	Congested toward ISO	Congested from ISO
BANC	0%	0%	0%	0%
Arizona Public Service	0%	2%	0%	1%
PacifiCorp East	2%	0%	1%	1%
Idaho Power	2%	3%	1%	4%
NV Energy	1%	0%	1%	0%
PacifiCorp West	26%	4%	13%	5%
Portland General Electric	26%	4%	13%	5%
Puget Sound Energy	26%	12%	13%	15%
Powerex	28%	16%	16%	27%

As shown in the table, the highest frequency of congestion in the EIM 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 27 percent of intervals from PacifiCorp West, Portland General Electric, Puget Sound Energy and Powerex during the fourth quarter. This is roughly twice as frequent relative to the previous quarter.

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

40 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.

41 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.

2.4 Load adjustments in the Western EIM

Frequency and size of load adjustments

Table 2.4 summarizes the average frequency and size of positive and negative load adjustments entered by operators in the EIM for the 15-minute and 5-minute markets during the fourth quarter.[42] The same data for the ISO is provided as a point of reference. In particular, Arizona Public Service entered positive load adjustments in around 58 percent of 15-minute and 5-minute intervals, at an average of around 84 MW. Nearly all EIM entities had a greater frequency of 5-minute market load adjustments than 15-minute market load adjustments during the fourth quarter.

Load conformance limiter enhancement

The load conformance limiter works the same way in the EIM 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.[43]

Figure 2.15 shows the frequency of infeasibilities in the 5-minute market during the fourth quarter in which the current (enhanced) conformance limiter triggered and/or the previous limiter would have triggered.[44] 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.

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

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

[44] 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*.

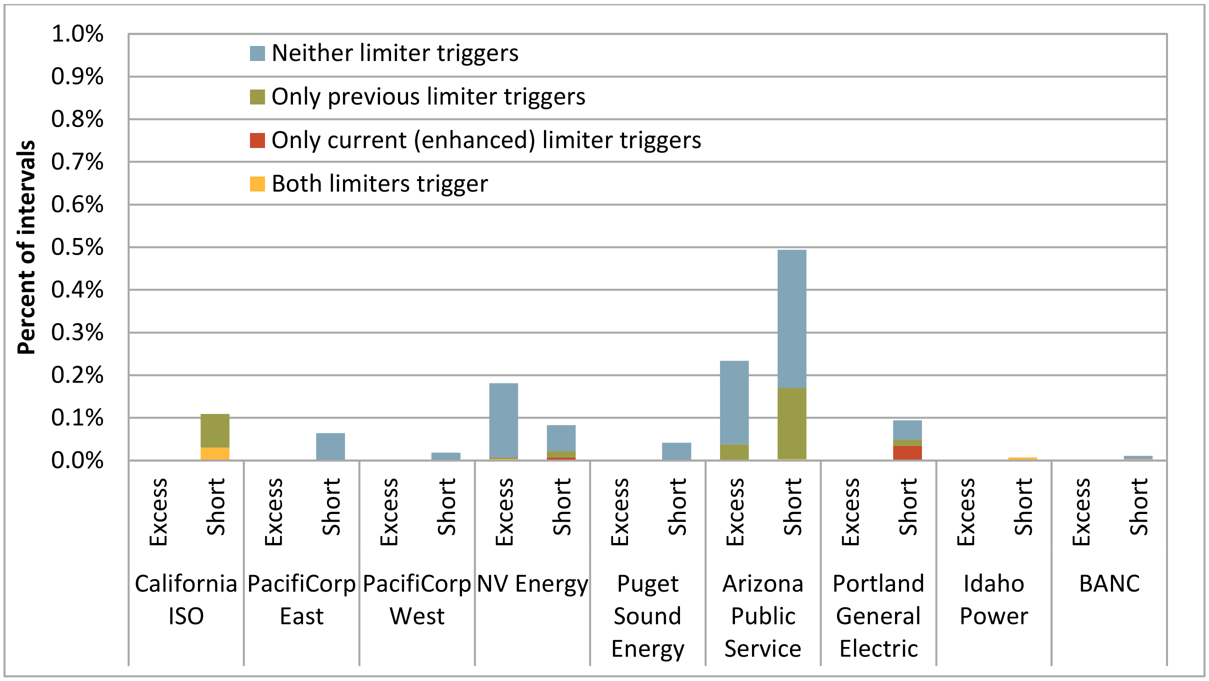
Table 2.4 Average frequency and size of load adjustments (October – December)

	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	70%	671	2.8%	0.2%	-210	1.0%	470
5-minute market	78%	342	1.5%	7%	-261	1.2%	250
PacifiCorp East							
15-minute market	0%	N/A	N/A	0.9%	-135	2.8%	-1
5-minute market	9%	70	1.3%	33%	-77	1.6%	-20
PacifiCorp West							
15-minute market	0%	N/A	N/A	2%	-33	1.3%	-1
5-minute market	0.9%	56	2.3%	20%	-44	1.9%	-8
NV Energy							
15-minute market	3%	96	2.5%	0%	N/A	N/A	3
5-minute market	9%	74	1.9%	5%	-95	2.8%	2
Puget Sound Energy							
15-minute market	0.5%	56	1.7%	8%	-44	1.4%	-3
5-minute market	2%	59	2.0%	48%	-42	1.4%	-19
Arizona Public Service							
15-minute market	59%	87	3.0%	28%	-55	2.0%	36
5-minute market	58%	82	2.9%	28%	-55	2.0%	32
Portland General Electric							
15-minute market	0.2%	29	1.0%	0%	N/A	N/A	0
5-minute market	26%	24	1.0%	0.4%	-58	2.4%	6
Idaho Power							
15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
5-minute market	14%	58	3.1%	2%	-48	2.9%	7
BANC							
15-minute market	0.2%	31	2.5%	0.3%	-44	4.0%	0
5-minute market	1%	26	2.3%	1%	-40	3.7%	0

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 EIM areas. This was not the case during the fourth quarter as the frequency of infeasibilities across energy imbalance market areas was low. Even still, as shown in Figure 2.15, the enhancement reduced the frequency in which the conformance limiter triggered for under-supply conditions for Arizona Public Service during the fourth quarter. Instead, prices for the Arizona Public Service were often set at the $1,000/MWh penalty parameter in these instances.

Figure 2.15 Frequency of load conformance limiter in the 5-minute market (October – December)



2.5 Greenhouse gas in the Western EIM

Under the current design, all energy serving California ISO or BANC load through a non-California EIM transfer is subject to California's cap-and-trade regulation.[45] A participating resource submits a separate bid representing the cost of compliance for its energy attributed to the participating resource as serving the ISO load. The EIM optimization minimizes costs of serving load in both the ISO and EIM taking into account greenhouse gas compliance cost for all energy deemed delivered to the ISO. The EIM 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 the 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.

As of November 2018, the ISO implemented a new policy to address the concerns that the market design was not capturing the full greenhouse gas effect of EIM imports into California to serve the ISO load for compliance with California's cap-and-trade regulation.[46] The amount of capacity that can be

[45] 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.

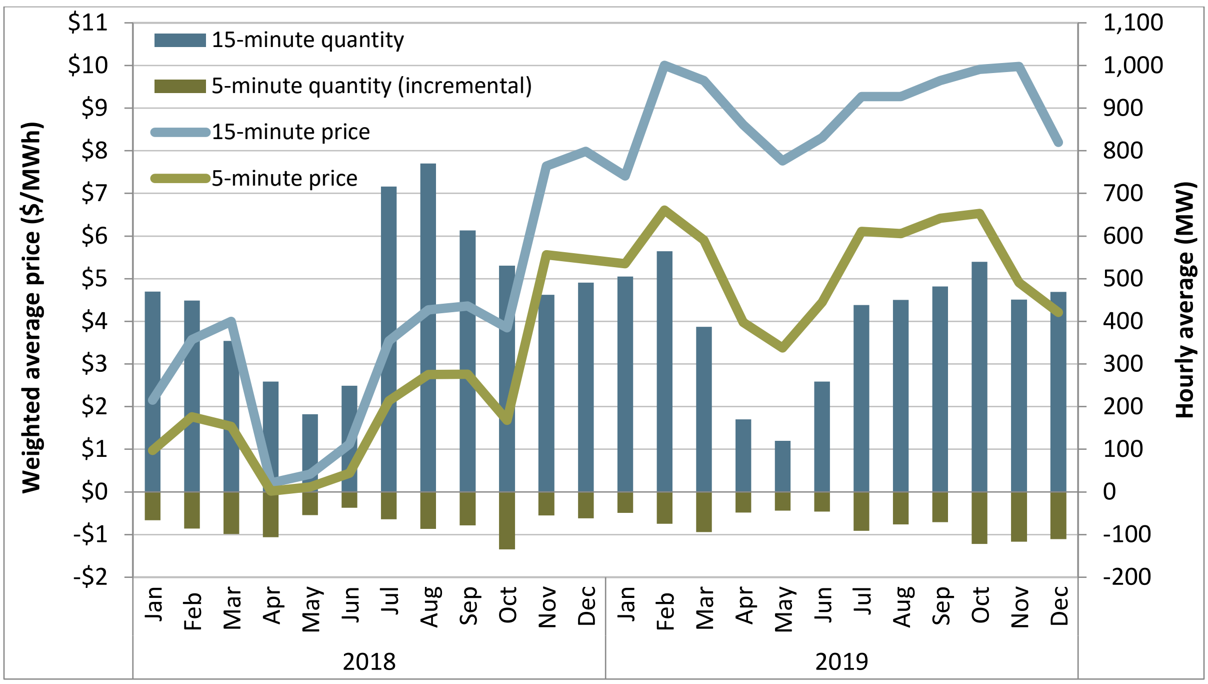
[46] Further information on the energy imbalance market greenhouse gas enhancements proposal can be found here: http://www.caiso.com/Documents/ThirdRevisedDraftFinalProposal-EnergyImbalanceMarketGreenhouseGasEnhancements.pdf

deemed delivered to California is now 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 Western EIM discussed below.

Greenhouse gas prices

Figure 2.16 shows monthly average cleared EIM greenhouse gas prices and hourly average quantities for transfers serving the ISO load settled in the EIM. Weighted average prices are calculated using 15-minute deemed delivered megawatts to weight 15-minute prices and the absolute value of incremental 5-minute greenhouse gas dispatch to weight 5-minute prices. Hourly average 15-minute and 5-minute deemed delivered quantities are represented by the blue and green bars in the chart, respectively.

Figure 2.16 Energy imbalance market greenhouse gas price and cleared quantity



Weighted 15-minute greenhouse gas prices averaged around $9/MWh for the fourth quarter while 5-minute prices averaged about $5/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.

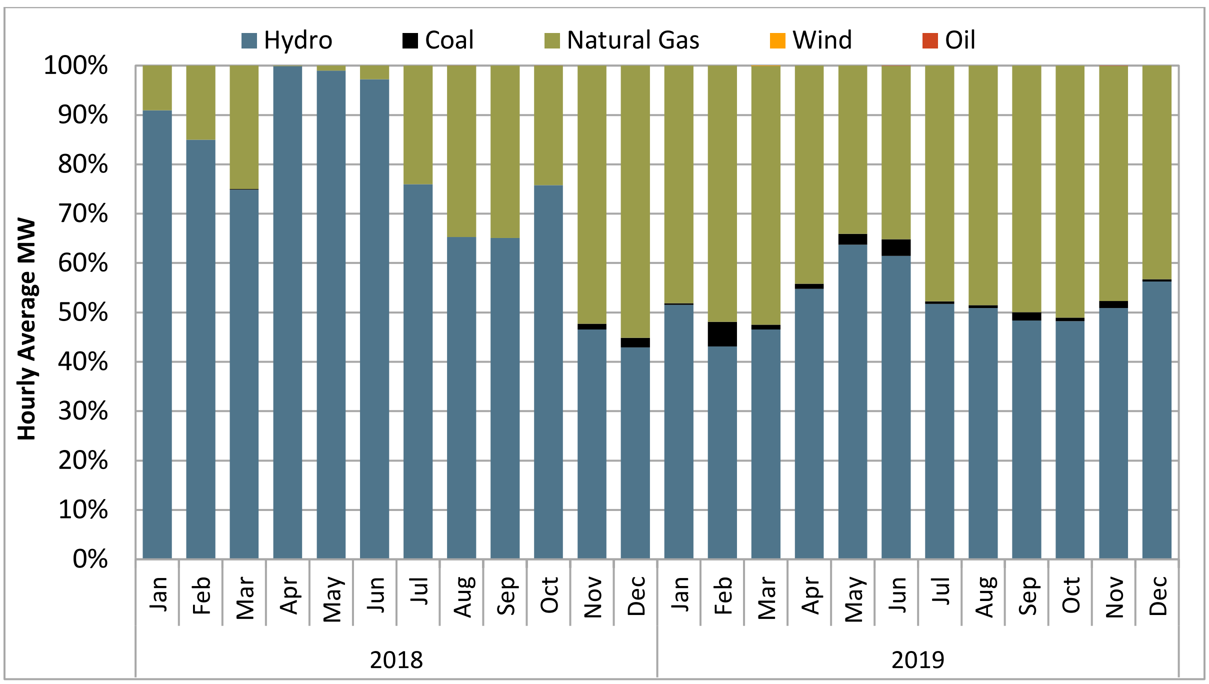
The increase in greenhouse gas prices relative to the previous year appears to be a result of the policy change, which limits the EIM capacity that can be deemed delivered to California and results in higher emitting resources setting the price. Another potential contribution to the increase in the EIM greenhouse gas price compared to 2018 is an increase in the market clearing price of the California Air Resources Board quarterly auction for emission allowances.

DMM estimates the total profit accruing for greenhouse gas bids attributed to EIM participating resources serving the ISO load by subtracting estimated compliance costs from greenhouse gas revenue calculated in each interval. This value totaled around $5.9 million in the fourth quarter, compared to roughly $4.4 million in the same quarter of the previous year.

Energy delivered to California by fuel type

Figure 2.17 shows the hourly average energy deemed delivered to California by fuel type and by month. In the fourth quarter, about 48 percent of EIM greenhouse gas compliance obligations were awarded to gas resources, an increase from 44 percent in the fourth quarter of the previous year. Hydroelectric resources accounted for about 52 percent of total energy delivered to California which decreased from around 55 percent in the same quarter of 2018. Additionally, energy originating from coal resources has increased since the policy change, but only accounted for about 1 percent of energy delivered in the fourth quarter, a slight decrease compared to the first three quarters of 2019.

Figure 2.17 Hourly average EIM greenhouse gas generation by fuel type



3 Special issues

This section provides information about the following special issues:

- **Implementation of the energy storage and distributed energy resources phase 3** initiative had little impact. This initiative created two new demand response dispatch options (hourly and 15-minute) and removed the single load-serving entity aggregation requirement which was expected to decrease the registration of demand response resources sized less than 1 MW. So far, implementation of this initiative on November 13 has had little impact due to both low utilization of new dispatch options and the continued registration of resources sized less than 1 MW.

- **Elimination of carryover mitigation in the ISO** reduced rates of mitigation in the real-time market. One of the local market power mitigation enhancements approved by FERC was the elimination of carryover mitigation, the practice of mitigating a resource in subsequent market intervals only because the resource was mitigated in a prior interval of the same hour which had applied to mitigation in both the 15-minute and 5-minute real-time markets. Rates of real-time mitigation in the ISO were similar to the prior fourth quarter while rates of day-ahead mitigation, which was not affected by carryover mitigation, increased. Rates of mitigation in all markets remained low.

- **Elimination of carryover mitigation in the Western EIM** also reduced rates of mitigation. Rates of mitigation in the Western EIM were lower than the previous fourth quarter and remained very low.

- **A new default energy bid option for hydro resources** became available as part of the local market power mitigation enhancements initiative, implemented on November 13. A small portion of the eligible capacity has selected the new hydro default energy bid. The majority of the capacity that has selected this option is registered with 12 months of storage and located within the California ISO balancing area.

- **Gas usage constraints** were enforced in the SoCalGas region in the fourth quarter but bound infrequently. DMM continues to recommend that gas use limits be set 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.

- **The price-cost markup** averaged $0.71/MWh or just under 2 percent for 2019. This slight positive markup indicates that overall prices have been very competitive for the year.

- **Market power** has had a very limited effect on system market prices even during hours when the ISO system was structurally uncompetitive. However, DMM has expressed concern that market conditions may evolve in a way that will increase the potential for system-level market power. DMM supports the ISO's proposal to continue with an initiative to design system market power mitigation and looks forward to working with the ISO throughout that process.

- **DMM continues to recommend** several other market design changes that may help mitigate system market power beyond the bid mitigation options being examined as part of this initiative. These include consideration of options that would increase the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time. DMM also continues to recommend that the ISO's plan for implementing FERC Order 831 include provisions to (1) ensure that import bids over $1,000/MWh are subject to ex ante cost justification and (2) avoid setting penalty prices at $2,000/MWh except when needed to implement the provisions of Order 831.

3.1 Energy storage and distributed energy resources phase 3

The ISO's energy storage and distributed energy resources stakeholder process focuses on enhancing rules governing the participation of energy storage and distribution-connected resources in the ISO's markets. The ISO proposed the following enhancements in phase 3 of this stakeholder process which were implemented on November 13, 2019:[47]

1. Introduce hourly and 15-minute real-time dispatch options for demand response resources to address concerns that many of these resources cannot respond to 5-minute dispatches.

2. Remove the single load-serving entity aggregation requirement and application of a default load adjustment.

DMM supported both enhancements and expected that these features could improve the performance of demand response resources and facilitate the creation of more reliable resource adequacy demand response aggregations.

Through the end of 2019, less than 1 percent of total demand response capacity registered with the ISO changed to 15-minute or hourly real-time dispatch options. Despite low response rates with respect to real-time dispatch instructions, many demand response resources continued to be modeled as 5-minute dispatchable. While the 15-minute and hourly dispatch features are currently optional, under the ISO's tariff, all resources are required to register their operating characteristics accurately.

DMM expected that the removal of the single load-serving entity requirement could increase the volume of demand response aggregations sized 1 MW or larger, thus increasing the volume of demand response capacity subject to the ISO's resource adequacy availability incentive mechanism. Despite the ISO's removal of the single load-serving entity requirement, about 65 percent of demand response registrations shown on monthly resource adequacy supply plans continued to be sized less than 1 MW.

Thus far, implementation of this initiative has had little impact due to both low utilization of new dispatch options and the continued registration of resources sized less than 1 MW. DMM will continue to monitor the impact of the new demand response dispatch options and removal of the single load-serving entity aggregation requirement. If demand response resources continue to exhibit poor response rates with respect to real-time dispatches and do not modify resource characteristics or change to less flexible bid options, the ISO could consider defaulting demand response resources to the hourly dispatch option and instead allow resources to change to 15- or 5-minute dispatchable. The ISO could also evaluate further what constraints demand response providers face that continue to limit the size of their demand response aggregations.

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[47] Draft final proposal, *Energy storage and distributed energy resources phase 3*, July 11, 2018: http://www.caiso.com/InitiativeDocuments/RevisedDraftFinalProposal-EnergyStorage-DistributedEnergyResourcesPhase3.pdf

In phase 3, the ISO also proposed a load shift product for behind the meter storage resources under the proxy demand response participation model and to recognize behind the meter curtailment of electric vehicle supply equipment load. These two proposals are scheduled to be filed with FERC and implemented in 2020.

3.2 Local market power mitigation enhancements

The ISO's automated local market power mitigation (LMPM) procedures were 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 proposed the following enhancements to the local market power mitigation process for implementation in November 2019:[48]

1. Eliminate carryover mitigation by not mitigating a resource in subsequent market intervals only because the resource was mitigated in a prior interval of the same hour.
2. Allow an EIM entity balancing authority area in the real-time market to limit dispatch of incremental net exports when mitigation is triggered due to import congestion.
3. Introduce a new hydro default energy bid (hydro DEB) option that would apply to all hydroelectric resources with storage capability that participate in the ISO or the EIM.

On September 30, 2019, FERC rejected the proposal to limit net exports by an EIM balancing authority area.[49] Subsequently, the ISO filed on October 30, 2019, a request for rehearing at FERC regarding the net export limit proposal.[50] The rest of the enhancements were implemented on November 13, 2019.

The impact on market prices of bids that were mitigated can only be assessed precisely by re-running the market software without bid mitigation. Currently, DMM does not have the ability to re-run the day-ahead and real-time market software under this scenario. Instead, DMM has developed a variety of metrics to estimate the frequency with which mitigation is 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 estimate the additional energy dispatched from these price changes.[51]

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

3.2.1 Mitigation in the ISO

In the day-ahead market, rates of mitigation increased relative to the fourth quarter of 2018. In the real-time market, there is no significant change to the rates of mitigation that can be attributed to the enhancements implemented in November 2019. In the fourth quarter, the frequency was similar to that of the same quarter in 2018. Incremental energy subject to mitigation has increased relative to prior

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

49 FERC order on LMPM enhancements tariff revisions, September 30, 2019: http://www.caiso.com/Documents/Sep30-2019-Order-TariffRevisions-Accepting-Part-Rejecting-Part-LMPME-ER19-2347.pdf

50 ISO's request for rehearing and alternative motion for clarification, October 30, 2019: http://www.caiso.com/Documents/Oct302019_RequestforRehearingorClarification-LocalMarketPowerMitigationER19-2347.pdf

51 The methodology has been updated to show incremental energy instead of units that have been subject to automated bid mitigation. Prior to the LMPM enhancements in November 2019, 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.

years due, in part, to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers.

As shown in Figure 3.1, in the day-ahead market, an hourly average of about 654 MW was subject to mitigation but corresponding bids were not lowered compared to 247 MW in the same quarter of 2018. About 151 MW of incremental energy had bids lowered due to mitigation compared to 82 MW in 2018. As a result, there was on average about 14 MW increase in dispatch, compared to 6 MW in 2018.

Figure 3.2 and Figure 3.3 show the same metrics but for the ISO's 15-minute and 5-minute markets on a monthly level. As shown in the figures, the average incremental energy that is subject to mitigation and either had bids lowered or not due to mitigation in the ISO is consistently higher in the 5-minute than in the 15-minute market. The frequency of mitigation in both 15-minute and 5-minute markets was very low in the fourth quarter, similar to 2018.

Figure 3.1 Average incremental energy mitigated in day-ahead market

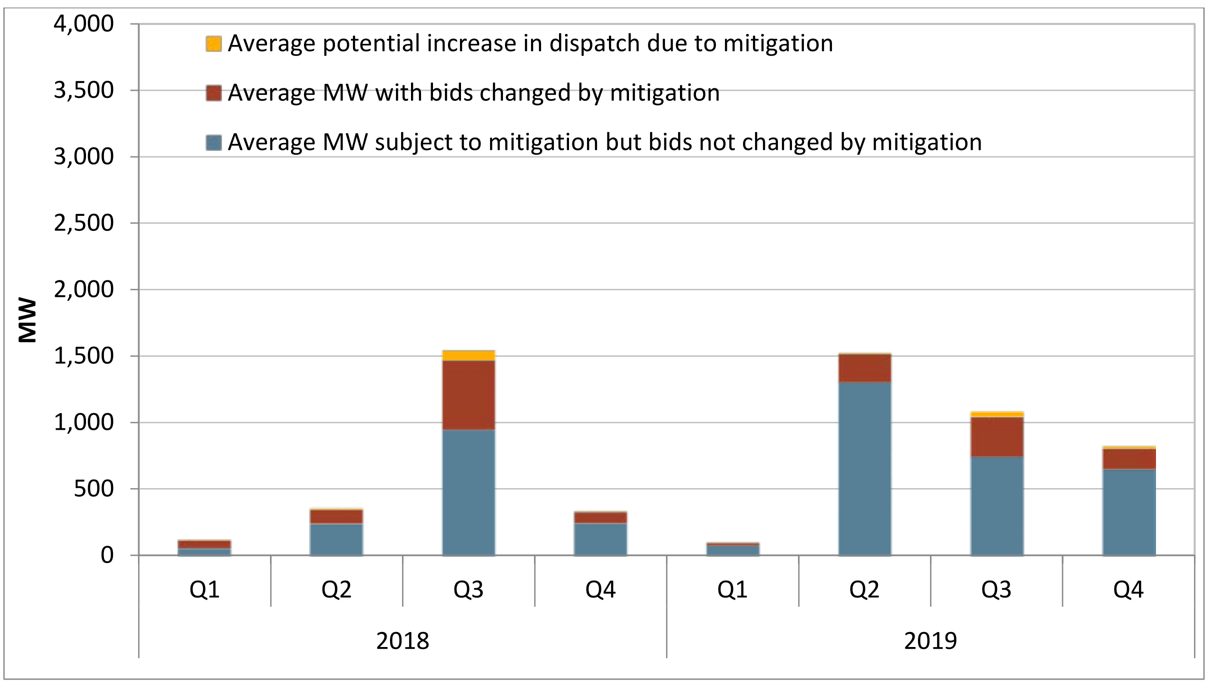


Figure 3.2 Average incremental energy mitigated in 15-minute real-time market (ISO)

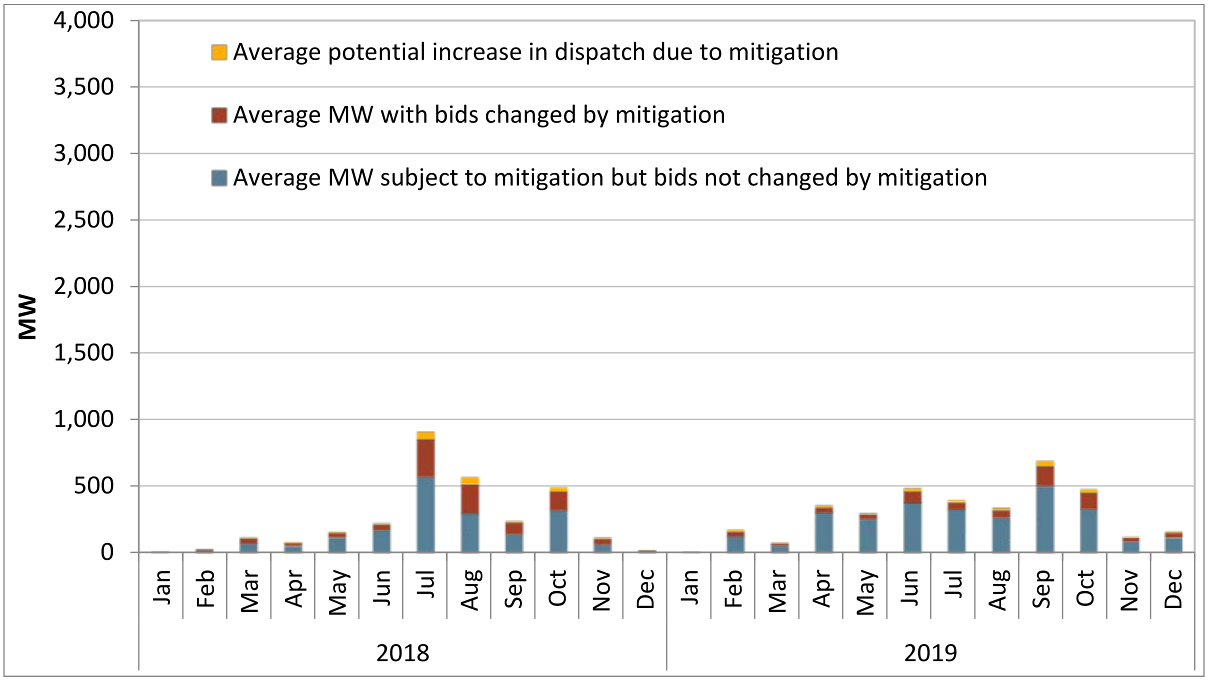
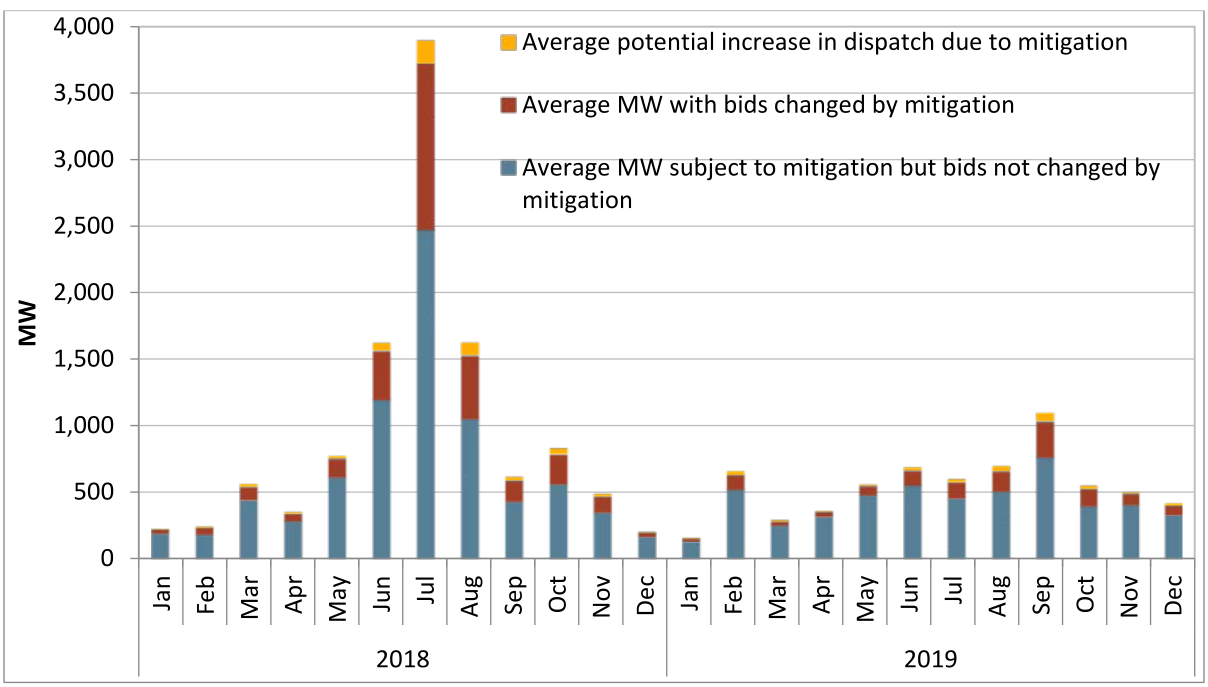


Figure 3.3 Average incremental energy mitigated in 5-minute real-time market (ISO)



3.2.2 Mitigation in the EIM

The elimination of carryover mitigation appears to have reduced mitigation rates in the Western EIM. Figure 3.4 and Figure 3.5 highlight the low frequency and volume of 15-minute and 5-minute market mitigation in all the balancing authority areas in the EIM:

- Average incremental energy subject to mitigation in the EIM in November and December 2019 in the 15-minute and 5-minute markets decreased when compared to the same quarter in 2018.
- An insignificant volume of bids was lowered as result of mitigation in the Western EIM.

Figure 3.4 Average incremental energy mitigated in 15-minute real-time market (EIM)

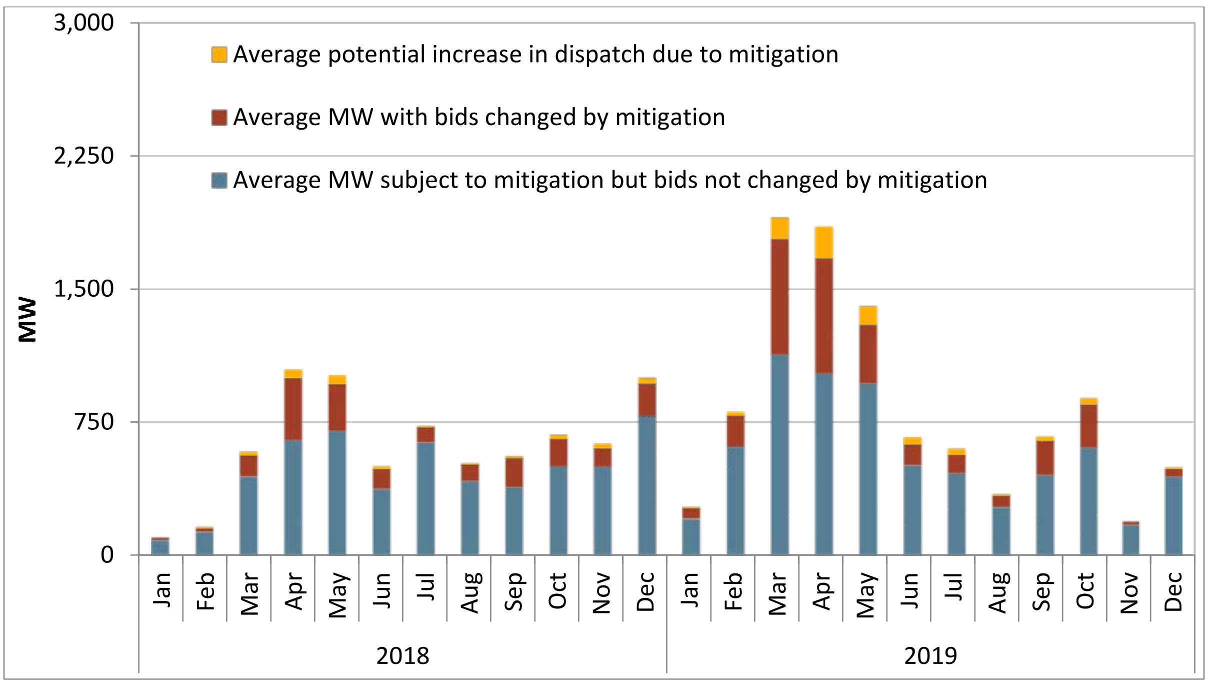
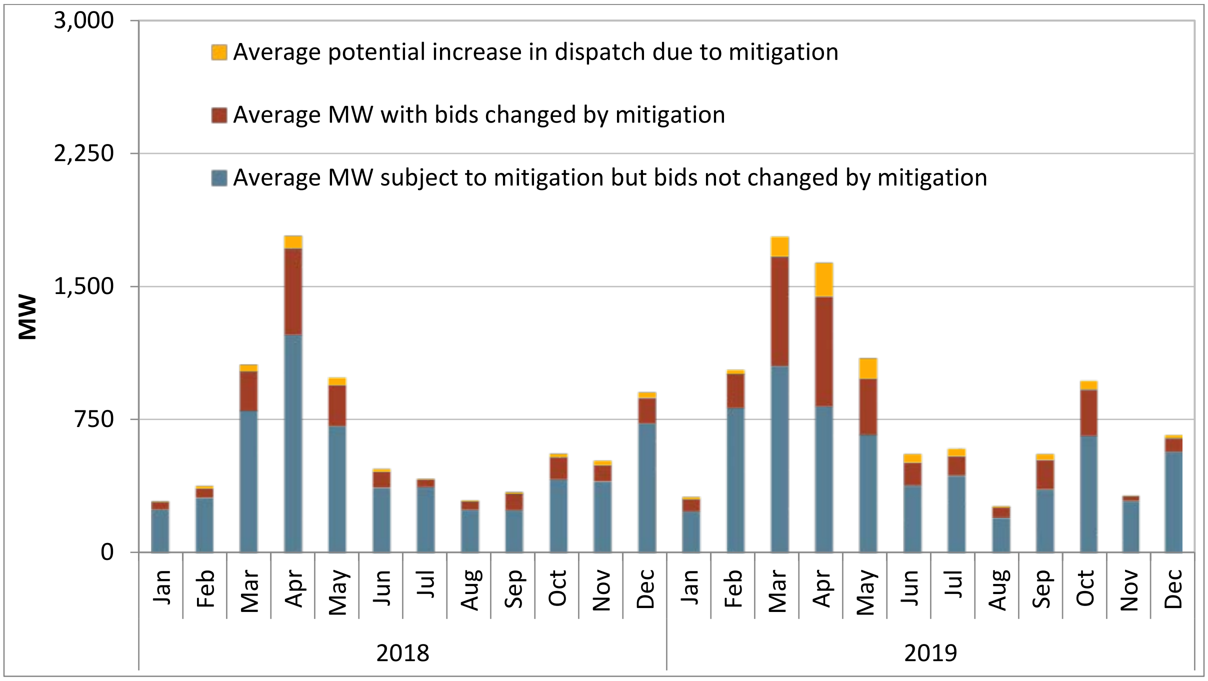


Figure 3.5 Average incremental energy mitigated in 5-minute real-time market (EIM)



3.2.3 New default energy bid option for hydro resources

The hydro default energy bid (DEB) is an option offered to hydroelectric generation resources within the ISO and EIM to promote efficient dispatch solutions when mitigation is triggered. This option incorporates opportunity costs that hydro resources with storage capability may have and is designed to prevent hydro resources from being dispatched too frequently. Establishing a default bid value that is sufficiently high to cover potential opportunity costs ensures that hydro resources can be efficiently dispatched when mitigation occurs. This also encourages increased market participation from hydro resources that have limited operating capability.

The hydro default energy bid value is calculated as the maximum price out of three components. The first component is designed to prevent the resource from being dispatched too frequently when other available energy in the region is more expensive due to gas prices. The other two components are designed to capture the opportunity cost of foregoing future revenues, both locally and in other regions, when a resource is dispatched now. Specifically, these components are:

- **Gas floor**. This component captures the opportunity cost of hydro resources to substitute energy from a gas resource. The calculation is the heat rate of a typical gas generator, multiplied by the local fuel region gas price. This value is then multiplied by a scalar of 1.1.
- **Short term floor**. This component captures the opportunity cost of selling energy locally, now, as opposed to the short-term future. The calculation is the max of the day-ahead power price at a local hub, the balance-of-month price at a local hub, and the month-ahead futures price at a local hub for the next month. This value is then multiplied by a scalar of 1.4.

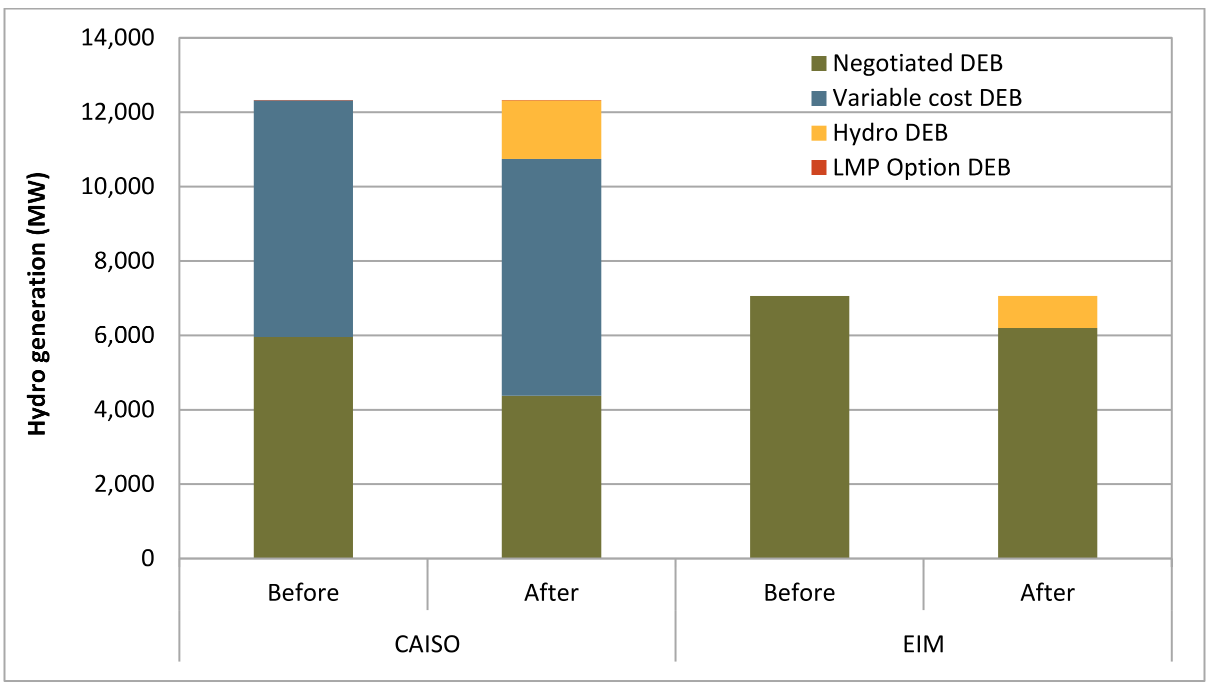
- **Long term / geographic floor**. This component captures the opportunity costs of selling energy now as opposed to the long-term future. It also captures the opportunity cost of selling at more distant hubs, if the resource is capable. The calculation is the maximum of the day-ahead power price at local and additional hubs, the balance-of-month price at local and additional hubs, and the month-ahead futures price at local and additional hubs for the maximum storage horizon of the resource. This value is then multiplied by a scalar of 1.1.

To be eligible for the third component of the default energy bid, resources must verify the capability to store water between 1 and 12 months at a time, or verify the transmission rights that enable delivery to other market regions, or both. Once a resource registers for the hydro option and the calculation inputs are verified by the ISO, the resource is eligible to rank the hydro option as its preferred default energy bid option.

Resources have been slow to adopt the hydro default energy bid

The ISO gained Board approval of the local market power mitigation enhancements initiative in March 2019. Hydro default energy bid values were first incorporated into the market on November 13, 2019. Figure 3.6 shows the rate of adoption of the hydro option among eligible resources within the ISO and EIM. The graph shows the total maximum capacity of resources according to their highest ranked default energy bid option. Total capacity electing each option is presented before and after the hydro default energy bid implementation. As shown in the figure, little eligible capacity has selected the new hydro option.

Figure 3.6 Total capacity by option before and after hydro default energy bid implementation (November 1 and December 31, 2019)

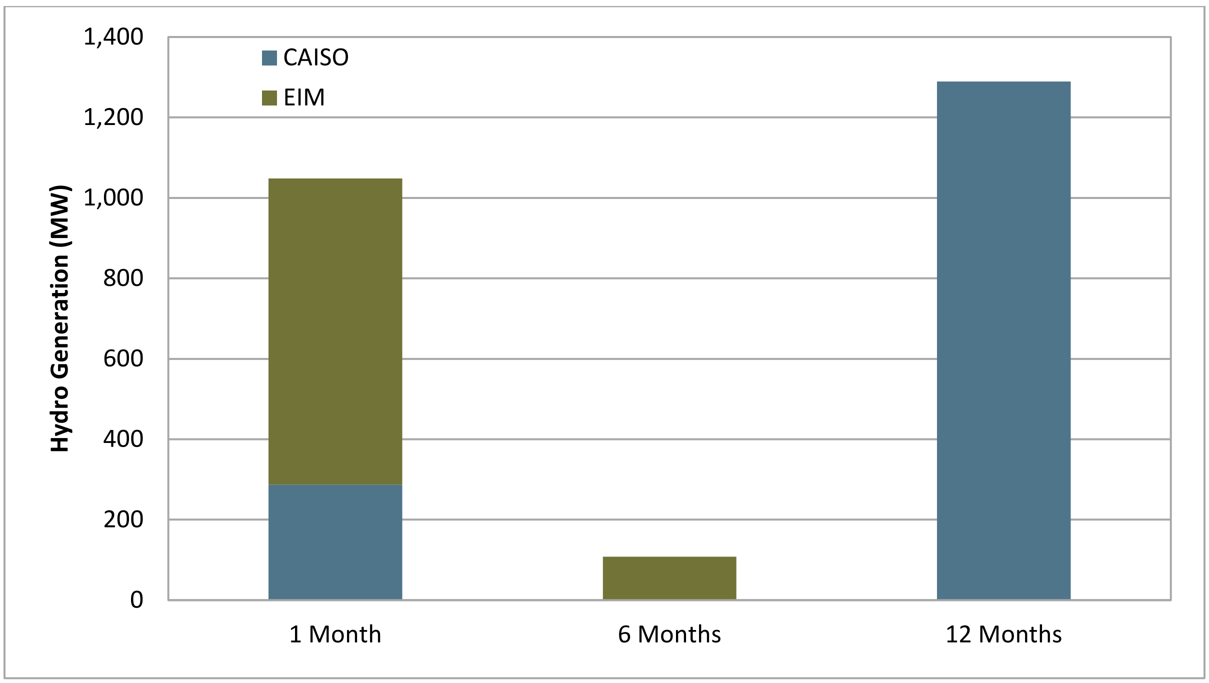


Resources with a combined 2,500 MW of capacity have adopted the hydro default energy bid since implementation. Resources within the ISO account for 65 percent of this capacity. Approximately 13 percent of all hydroelectric resource capacity in the ISO and Western EIM is registered under the hydro option. The remainder is associated with the negotiated default energy bid and other options.

Hydro default energy bid values are based on 12 months of storage for most capacity

Resources submit information to the ISO in order to receive an opportunity cost for their long-term storage capability. Figure 3.7 shows the amount of capacity from resources that have registered 1 month, 6 months, and 12 months of storage capability. The figure also separates capacity located in the ISO from capacity in other balancing areas within the Western EIM.

Figure 3.7 Total capacity by registered storage length (December 31, 2019)



Resources with 12 months of storage capability account for 53 percent (1,300 MW) of generating capacity under the hydro default energy bid option. About 35 percent of total capacity is associated with EIM resources, none of which have registered storage capability greater than 6 months.

The ISO is finalizing how additional hub prices are incorporated into the hydro default energy bid

Resources can have electric prices at distant hubs factored into the long-term geographic floor component if the scheduling coordinator holds transmission rights to other regions. In the event that a resource holds less firm transmission rights than its maximum capacity, the geographic floor component is calculated as a weighted blend of the prices from the default electric hub and the additional hubs. Currently, no resources have registered for additional hubs to be factored into their long-term geographic floor component. The ISO is working with stakeholders to determine the appropriate way to calculate this weighted blend.[52]

DMM supports the overall approach of the hydro default energy bid option

The general approach that the ISO has used for the hydro option is very similar to approaches used in some negotiated default energy bids for hydro resources. DMM is supportive of the overall approach; however, DMM continues to question the appropriateness of using prices from geographically distant hubs as well as using up to 12 months of futures prices in the hydro option formulation. DMM maintains that including futures prices from geographically distant hubs in a default energy bid inappropriately assigns the value of transmission between the two regions to the value of energy in the resource's local lower priced region. Also, unless the methodology for establishing a resource's maximum storage horizon accounts for expected reservoir inflows, allowing default energy bids to be based off of 12-month futures prices will tend to overstate the actual opportunity costs of hydro resources during the fall months. This is when default energy bid values will most likely be driven by high expected futures prices in the summer months of the following year.[53]

3.3 Gas burn constraints

On October 31, 2019, the ISO filed tariff amendments to extend Aliso Canyon provisions permanently.[54] One of these measures gives the ISO the authority to enforce gas burn constraints (or nomograms) in the ISO energy markets which directly limit gas usage by groups of power plants in the SoCalGas system. In its filing, the ISO proposed refining the shaping of the maximum gas burn limit using CAISO's net load rather than gross load. DMM has recommended further refinement of the gas usage constraint to avoid artificially constraining gas burn in peak net load hours. FERC approved these tariff amendments and directed the ISO to file annual informational filings relating to the performance of the enforced nomograms.[55]

DMM believes the net load approach for shaping the gas usage constraint to be a significant improvement. However, DMM 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.[56]

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52 For more information, please refer to PRR 190 "Local power market mitigation enhancements hydro default energy bid option energy imbalance market transfer limit". https://bpmcm.caiso.com/Pages/default.aspx.

53 For a more detailed explanation on DMM's concerns with these Hydro DEB components, please refer to DMM Comments on Revised Straw Proposal, pg. 4-5: http://www.caiso.com/InitiativeDocuments/DMMComments-LocalMarketPowerMitigationEnhancements-RevisedStrawProposal.pdf as well as DMM Comments on Draft Final Proposal, pg. 6-14: http://www.caiso.com/InitiativeDocuments/DMMComments-LocalMarketPowerMitigationEnhancements-DraftFinalProposal.pdf.

54 Tariff Amendment - Aliso Canyon Gas-Electric Coordination Phase 5 (ER20-273), October 31, 2019: http://www.caiso.com/Documents/Oct312019-TariffAmendment-SoCalMaxGasConstraint-AlisoCanyon_ER20-273.pdf

55 FERC Order accepting Aliso Canyon Gas-Electric Coordination Phase 5 tariff revisions (ER20-273), December 31, 2019: http://www.caiso.com/Documents/Dec30-2019-OrderAcceptingTariffRevisions-AlisoCanyonGasElectricCoordination-MaximimGasConstraint-ER20-273.pdf

56 FERC filing - DMM Comments on Aliso Canyon Gas-Electric Coordination Phase 5 (ER20-273), November 21,2019: http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoring-Aliso5-ER20-273-000-Nov212019.pdf

Specifically, DMM suggests that the shape of the gas burn could be estimated based on historical data as well as the two-day-ahead runs of the market software that the ISO performs. This modification could allow the gas limits to be highest during the ramping hours when gas units are needed most.[57]

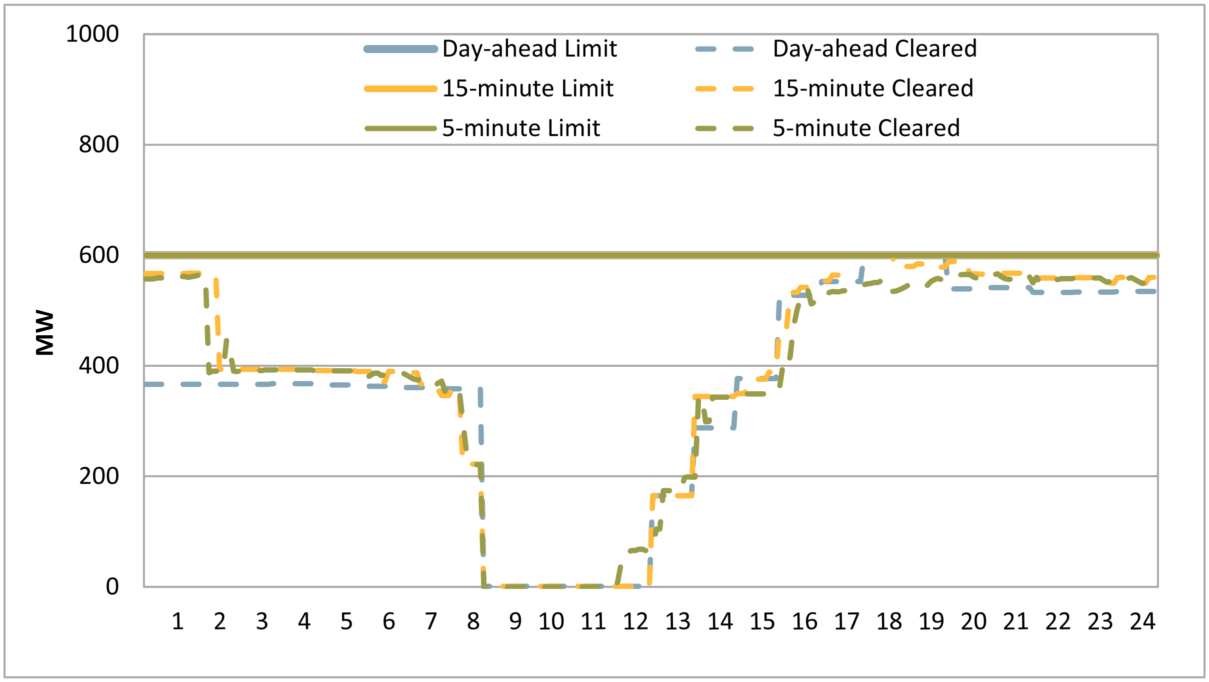
In the fourth quarter of 2019, the ISO enforced the SDG&E area gas burn constraint in either the day-ahead or the real-time markets on two occasions: October 14-18 and November 8-15. This constraint was enforced to facilitate pipeline maintenance work in the SDG&E area.[58] In the day-ahead market, this constraint was binding in about 7 percent of hours when enforced. In the real-time market, this constraint was binding in 8 percent of the 15-minute intervals and 5 percent of the 5-minute intervals when enforced.

The SDG&E maximum gas burn constraint was enforced as a static limit on both occasions when used in the fourth quarter. This is because the gas company requested that gas usage stay below 6 MMcf/hr. Figure 3.8 shows the static limit of 600 MW in the day-ahead and real-time markets on November 9, 2019. As shown in the figure, the nomogram was binding during the evening peak ramping hours ending 17 through 19 in the day-ahead and 15-minute real-time markets.

[57] DMM recommendation on Gas usage nomograms, *2018 Annual Report Market Issues and Performance*, pp 261-262, May 2019: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

[58] Planned System Wide Curtailment for CAISO EG's in SDG&E, Critical Notices on October 16 and November 14, 2019: https://scgenvoy.sempra.com/index.html

Figure 3.8 SDG&E gas nomogram binding status in day-ahead and real-time market (Nov 9, 2019)



Updated natural gas prices for the day-ahead market

On August 30, 2019, the ISO filed tariff amendments at FERC as part of the commitment cost and default energy bid enhancements filing to permanently extend the use of a more up-to-date next-day price in its day-ahead market.[59] This provision was set to expire on 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.[60] FERC's January 21, 2020, order permanently granted ISO authority to use more timely natural gas prices for calculating default energy bids and proxy commitment costs in the day-ahead market.[61] Because the FERC order was received after the provision was expired, a lagged gas price based on the prior day's next-day index was used in the day-ahead market from January 1 through January 27, 2020.[62]

Figure 3.9 and Figure 3.10 illustrate the benefit of using the updated natural gas price index in the fourth quarter of 2019. Figure 3.9 shows next-day trade prices reported on the Intercontinental Exchange (ICE) for the SoCal Citygate during the fourth quarter, compared to the next-day price index previously used

59 Tariff Amendment - Commitment Costs and Default Energy Bid Enhancements (ER19-2727), pp 31-32, Aug 30, 2019: http://www.caiso.com/Documents/Aug30-2019-TariffAmendment-CommitmentCosts-DefaultEnergyBidEnhancements-ER19-2727.pdf

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

61 FERC Order on Tariff Revisions - Commitment Cost and Default Energy Bids Enhancements (ER19-2727), Jan 21, 2020: http://www.caiso.com/Documents/Jan21-2020-OrderOnTariffRevisions-CommitmentCost-DefaultEnergyBidsEnhancements-ER19-2727.pdf

62 Market Notice - Manual Process to Update Gas Price Index, January 24, 2020: http://www.caiso.com/Documents/ManualProcess-UpdateGasPriceIndexWillResume-012820.html

in the day-ahead market which was lagged by one trade day. As shown in Figure 3.9, about 1 percent of the next-day trades were in excess of the 25 percent headroom normally included in commitment cost bid caps. An additional 14 percent of next-day trades were at a price in excess of the 10 percent adder normally included in default energy bids.

Figure 3.10 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 3.10, about 0.5 percent of the 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.

Figure 3.9 Next-day trade prices compared to next-day index from prior day (Oct - Dec)

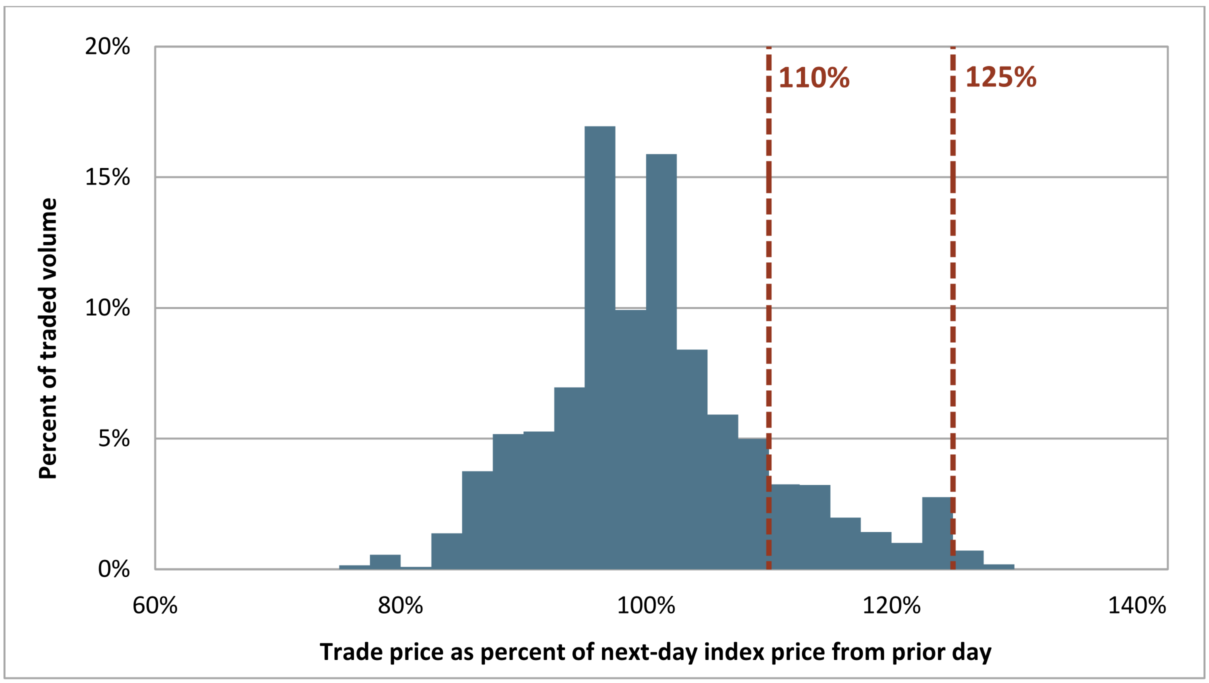
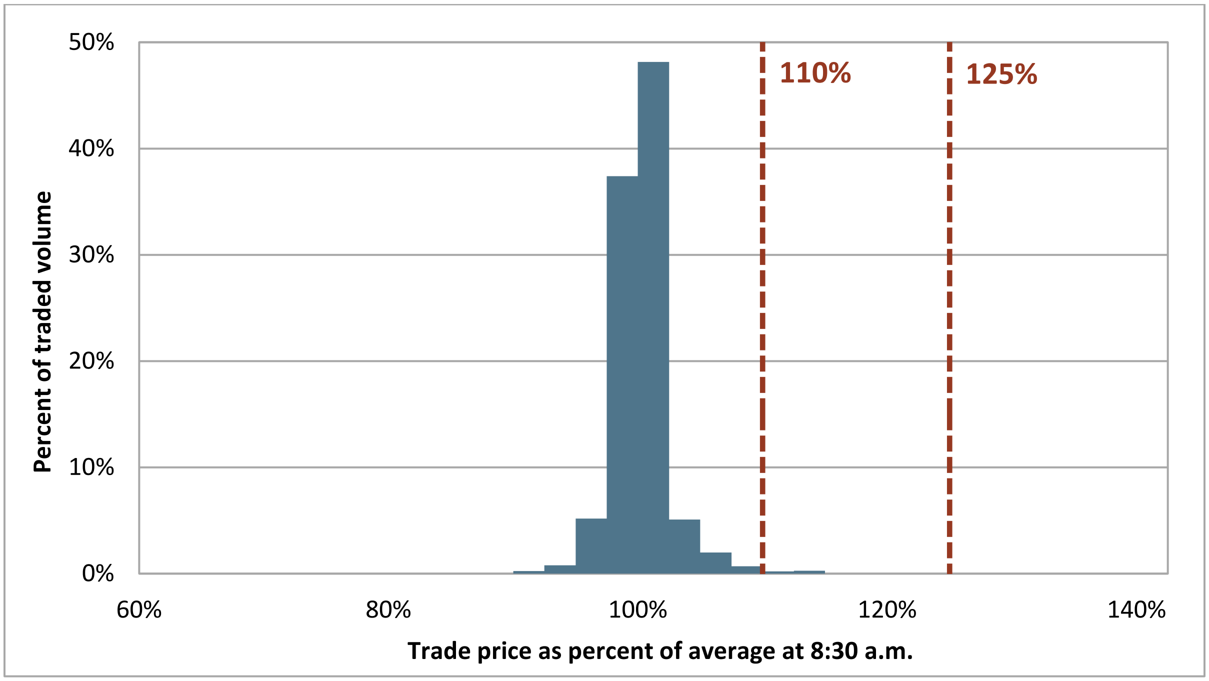


Figure 3.10 Next-day trade prices compared to updated next-day average price (Oct - Dec)



3.4 System market power

This section assesses the competitiveness of the ISO's energy markets in two parts: day-ahead market software simulation and DMM recommendations.

3.4.1 Day-ahead market software simulation

To assess the competitiveness of the ISO energy markets, DMM compares actual market prices to competitive benchmark prices we estimate would result under highly competitive conditions. DMM estimates competitive baseline prices by re-simulating the market after replacing the market bids of all gas-fired units with the lower of their submitted bids or their default energy bids (DEB). This methodology assumes competitive bidding of price-setting resources, and is calculated using DMM's version of the actual market software.[63]

As shown in Figure 3.11, hourly prices in the day-ahead market were very similar to or slightly above the estimated competitive baseline prices on average. DMM calculates the day-ahead price-cost markup by comparing the competitive benchmark to the base case load-weighted average price for all energy transactions in the day-ahead market.

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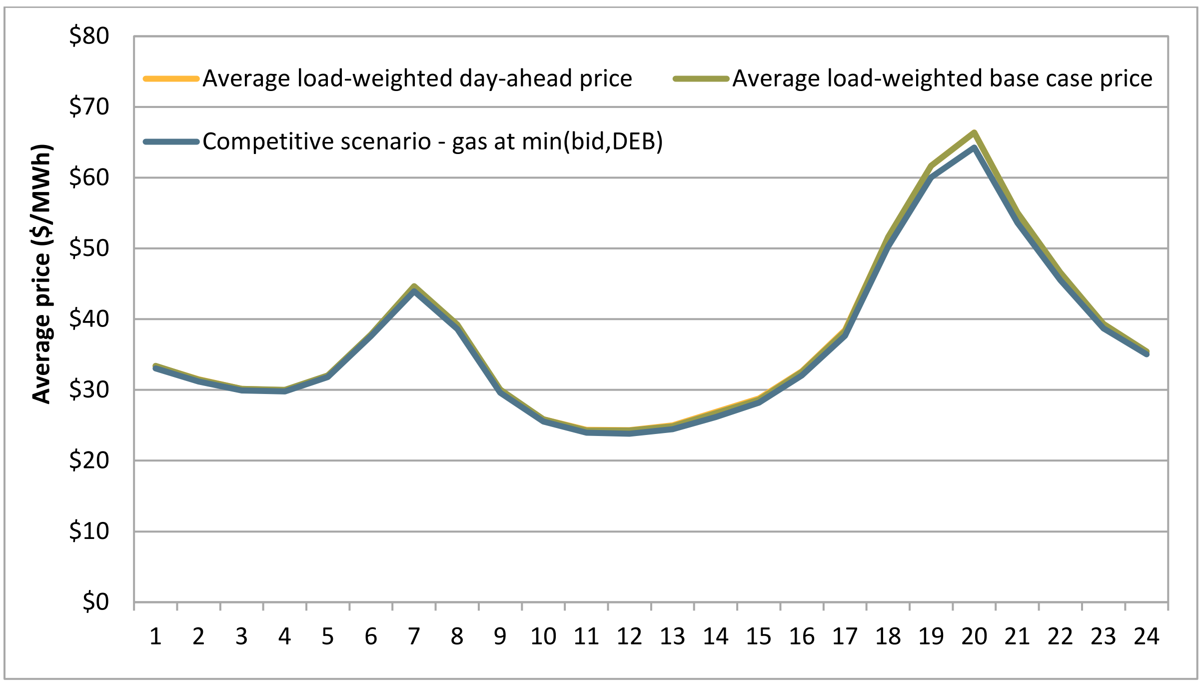
63 In previous years, the competitive baseline was a scenario where bids for gas-fired generation were set to their default energy bids, convergence bids were removed, and system demand was set to actual system load. This tended to overestimate the competitive baseline price, because a significant amount of gas-fired supply is bid at prices lower than their default energy bids (which include a 10 percent adder), and actual system load tended to be greater than day-ahead bid-in load.

Each market simulation is preceded by a base case rerun with all of the same inputs as the original market run before completing the benchmark simulation, to screen for accuracy. For 2019, the base case reruns have replicated original prices with a greater frequency than recent years, allowing a higher percentage of days to be included in this analysis.[64]

As shown in Figure 3.12, in 2019 the average price-cost markup was about $0.71/MWh or just under 2 percent. This slight positive markup indicates that prices have been very competitive, overall, for the year.[65]

This price-cost metric may be a low-end measure of system market power for several reasons. The only change in market inputs made in the competitive scenario is that energy bids of gas-fired resources are capped by each resource's default energy bid – which includes a 10 percent adder above estimated marginal costs. All other bids are assumed to be competitive, including those of non-resource specific imports. Also, this analysis does not change commitment cost bids for non-gas or gas-fired resources which are capped at 125 percent of each resource's estimated start-up and minimum load costs. DMM is working to develop the capability to assess the potential impact of these market bids on overall system prices using the ISO's day-ahead market software.

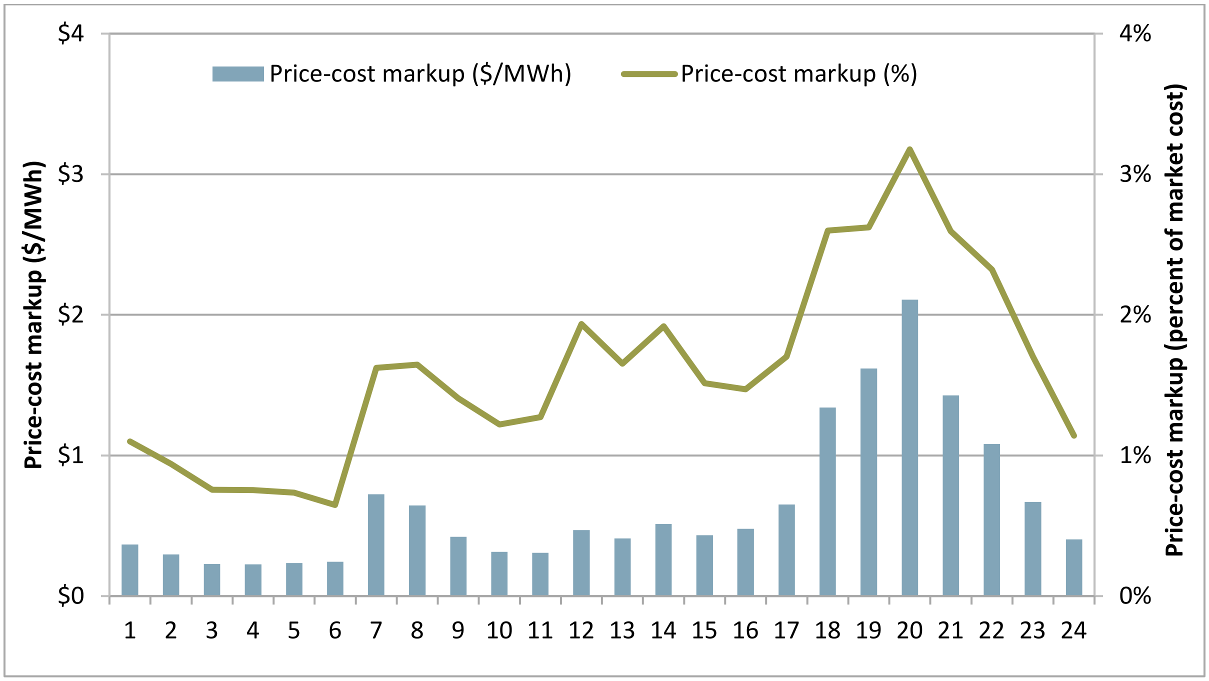
Figure 3.11 Comparison of competitive baseline with hourly day-ahead prices (Jan-Dec)



64 In 2017 and 2018, DMM was unable to include multiple days in the analysis because of issues replicating original prices in the base case rerun. For 2019, the ISO was able to resolve these issues such that a greater percentage of dates was able to be included.

65 DMM calculates the price-cost markup index as the percentage difference between base case market prices and prices resulting under this competitive baseline scenario. For example, if base case prices averaged $55/MWh and the competitive baseline price was $50/MWh, this would represent a price-cost markup of 10 percent.

Figure 3.12 Hourly price-cost markup (Jan-Dec)



3.4.2 Recommendations

Analysis by DMM indicates that in the last few years system market power in the day-ahead market has had a limited effect on market prices, even during the limited number of hours when the ISO system was structurally uncompetitive. In 2019, market prices have continued to be relatively low and stable due to a combination of favorable market and system conditions. However, DMM continues to be concerned that market conditions in the coming years may change in ways that will exacerbate the potential for system-level market power. The ISO recently launched a stakeholder initiative to develop system market power mitigation provisions. DMM supports this initiative and the ISO's efforts to design and implement system market power mitigation.

Potential for increased system market power

In the last few years, system market power in the day-ahead market has had a very limited effect on system market prices, even during hours when the ISO system was structurally uncompetitive based on the three pivotal supplier test used in the ISO's local market power mitigation procedures. Neither DMM nor the ISO have assessed the potential impacts of real-time system market power on market prices. However, DMM has expressed concern that market conditions may evolve in a way that will increase the potential for system-level market power. Changes and trends that may increase the potential for system market power in the coming years include:

- Retirement and mothballing of gas capacity.
- Increasing portion of resource adequacy requirements being met by solar and wind resources, which often provide significantly less energy during the evening ramping hours than the resource adequacy rating of these resources.

- Fewer energy tolling contracts between gas units within the ISO and load-serving entities without an incentive to exercise market power.
- Increasing portion of resource adequacy requirements met by imports not backed by energy contracts or physical resources, which can avoid being called upon by simply bidding at high prices in the day-ahead market.
- Tightening regional supply conditions.

The ISO's comments in the CPUC's Integrated Resource Planning Proceeding indicate that ISO planners also have significant concerns about many of these same issues, and that the supply/demand balance in the ISO system may tighten to the point where system reliability is in jeopardy as soon as summer 2021.

Mitigation of system market power

In December 2019, the ISO launched a market design initiative on system level market power mitigation. This initiative aims to develop market power mitigation provisions for the ISO balancing authority area in the real-time market. A second phase would consider extension of the mitigation mechanism to other areas of the Western EIM and to the day-ahead market.

The approach outlined by the ISO considers mitigating generation resources in the ISO balancing authority area for system market power when the ISO balancing authority area is determined to be import constrained as defined by a set of binding import constraints, and a residual supplier index for the ISO balancing authority area indicates uncompetitive conditions. This approach will be an incremental improvement that will help to mitigate potentially uncompetitive system conditions.

Mitigation of the real-time market can result in indirect mitigation of market power exercised in the day-ahead market, and may also reduce the impacts of real-time market power on day-ahead prices. However, requiring a set of ISO import constraints to bind in order to trigger system market power mitigation may not capture all potentially uncompetitive intervals, particularly in the real-time market.

DMM supports the ISO's efforts to design and implement some level of system market power mitigation in the first phase of the stakeholder initiative. DMM recommends the ISO continue refining the system market power mitigation design in a second phase of the initiative, expanding the design to the entire real-time system (inclusive of EIM), and considering all circumstances which may be potentially uncompetitive. DMM looks forward to working with the ISO throughout each phase of the stakeholder process.

DMM recommends several other market design changes that may help mitigate system market power beyond the bid mitigation options considered in the ISO's system market power initiative.

Given the increasing role that resource adequacy imports may play in ISO system reliability and market competitiveness, DMM recommends consideration of options that would increase the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time. Options might include mechanisms to increase the amount of resource adequacy imports clearing the day-ahead market in tight supply conditions or high load uncertainty.

Such options likely involve a combination of resource adequacy rules for imports established by the CPUC as well as ISO market rules. In the ISO's resource adequacy enhancements third revised straw proposal, the ISO is proposing to require specification of the source balancing area for all resource adequacy imports. However, the ISO is no longer considering extension of the resource adequacy must-offer requirement beyond the day-ahead market.

DMM also recommends that under the ISO's plan for implementing FERC Order No. 831, the ISO should (1) ensure that import bids over $1,000/MWh are subject to ex ante cost justification and (2) avoid setting penalty prices at $2,000/MWh except when needed to implement the provisions of the order. These market design features have important implications in terms of mitigating potential system market power. The ISO has committed to consider these potential design rules in a stakeholder initiative, but has submitted a compliance filing on FERC Order No. 831 that does not include these elements.[66] A supplemental filing by the ISO commits the ISO to implement all changes related to FERC Order No. 831, including the outcome to the ongoing stakeholder initiative considering both import bid cost justification and penalty parameter setting, concurrently.[67]

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66 *Motion to Intervene and Comments of the Department of Market Monitoring*, Docket No. ER19-2757-000, September 26, 2019. http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoringonOrder831Compliance-ER19-2757-Sept262019.pdf.

67 *Motion for Leave to Answer and Supplemental Answer of the California Independent System Operator Corporation to Comments and Limited Protests*, Docket No. ER19-2757-000, January 31, 2020. http://www.caiso.com/Documents/Jan31-2020-SuppAnswer-to-Comments-Order831Compliance-ER19-2757.pdf

Information on the stakeholder initiative is available here: http://www.caiso.com/StakeholderProcesses/FERC-Order-831-Import-bidding-and-market-parameters