California ISO

California Independent System Operator Corporation

California ISO

Q4 2018 Report on Market Issues and Performance

February 13, 2019

Department of Market Monitoring

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Executive summary

This report covers market performance during the fourth quarter of 2018 (October – December). Key highlights during this quarter include the following:

- Energy prices in the ISO increased compared to the same quarter in 2017, driven in part by high gas prices, seasonally high load and lower hydro generation. Average day-ahead prices increased by about $10/MWh (24 percent), while 15-minute prices rose by about $4/MWh (10 percent) and 5-minute prices were up by about $7/MWh (19 percent).

- Average monthly day-ahead prices were higher than 15-minute and 5-minute prices during all months of the quarter, by about $5/MWh and $7/MWh, respectively.

- Average prices of natural gas remained high in the fourth quarter of 2018, particularly at the SoCal Citygate trading hub, where average prices were almost 50 percent higher than in the fourth quarter of 2017. This increase in SoCal Citygate natural gas prices was one of the main drivers of high system marginal energy prices across the ISO system.

- Estimated bid cost recovery payments for the fourth quarter of 2018 declined to about $31 million. This amount was considerably lower than $88 million in the previous quarter and slightly higher than $27 million in the fourth quarter of 2017. Units committed in the real-time market through exceptional dispatches issued by grid operators to meet special reliability issues totaled about $3.6 million, a significant decrease from about $27 million in the third quarter.

- Total energy resulting from all types of exceptional dispatch increased by 80 percent in the fourth quarter compared to the same quarter in 2017. Minimum load energy from unit commitments accounted for over 80 percent of all exceptional dispatch energy in this quarter.

- Fourth quarter real-time imbalance offset charges decreased to about $13 million from $75 million in the third quarter.[1] Real-time congestion imbalances of $27 million drove the total imbalance offset charges while the real-time energy offset had a surplus of $14 million. Reductions in transmission constraint limits reductions below day-ahead limits made in the 15-minute market continued to be a major driver of congestion imbalance charges. A significant portion of the congestion imbalance offset charges appear to be associated with payments to virtual bid schedules.

- Congestion revenue rights auction revenues were $29 million less than payments made in the fourth quarter to non-load-serving entities purchasing these rights. This brings total losses to transmission ratepayers from congestion revenue rights sold in the ISO's auction to over $131 million during 2018. Forty one percent ($54 million) of these losses were associated with "delivery pairs", node pairs that the ISO continues to auction in 2019. Losses in the fourth quarter represent $0.48 in auction revenues collected for every dollar paid out to auctioned rights holders.

[1] The most current settlement imbalance charges are reported. These are subject to change with settlement data updates.

Other key highlights in this report are summarized below.

- Congestion in the fourth quarter primarily occurred in the south-to-north direction, and had less of an impact on overall prices than in the previous quarter, increasing day-ahead prices in PG&E and SDG&E by about $0.9/MWh and $0.8/MWh, respectively, and decreasing prices in SCE by about $0.7/MWh.
- In the energy imbalance market, prices in Northwest areas (PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex) continue to be relatively flat over the hours of the day because of limited transfer capability into and out of the region.
- Real-time prices in the ISO and rest of the energy imbalance market tend to reflect the net load curve, rising in the morning and evening ramping hours and dropping below prices in the Northwest areas during the mid-day hours when solar output is highest.
- The frequency of upward sufficiency test failures decreased across EIM areas overall. In particular, NV Energy failed the upward sufficiency test in less than 1 percent of hours, compared to over 6 percent of hours in the previous quarter.
- Total net payments to generators in the ISO and energy imbalance market areas for providing flexible ramping capacity increased during the fourth quarter of 2018 to around $2.2 million, compared to around $0.6 million during the previous quarter and around $3 million during the fourth quarter of 2017. Power balance constraint relaxations in the 15-minute and 5-minute markets were relatively infrequent during the quarter.
- Convergence bidding was profitable overall for the fourth consecutive quarter. Combined net profit for virtual supply and demand fell to about $12 million after accounting for about $1.5 million of virtual bidding bid cost recovery charges.
- Resource adequacy availability increased to an average 88 percent during the availability assessment hours, relative to 84 percent in the final quarter of 2017. However, less than half of import capacity shown as resource adequacy capacity bid into the real-time on average on non-holiday weekdays during the fourth quarter.
- Intra-monthly capacity procurement mechanism designations were triggered by exceptional dispatches and a significant event during the quarter. Together, estimated costs for these designations totaled about $14.7 million in the fourth quarter of 2018.
- The ISO did not activate any of the special Aliso Canyon gas constraints or gas price scalars during the fourth quarter. Market and system performance was sustained during periods of tight gas and electric supply without these measures in place.

1 Market performance

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

- The frequency of high day-ahead prices decreased significantly during the fourth quarter, at prices at or above $200/MWh relative to the third quarter. System marginal energy prices in the day-ahead market reached record highs on July 24, peaking at almost $980/MWh.

- Average prices increased compared to the same quarter in 2017. Average day-ahead prices increased by about $10/MWh (24 percent), 15-minute by about $4/MWh (10 percent) and 5-minute market prices by about $7/MWh (19 percent).

- Average prices of natural gas remained high in the fourth quarter of 2018, particularly at the SoCal Citygate trading hub where average prices were almost 50 percent higher than average prices in the fourth quarter of 2017. This increase in SoCal Citygate natural gas prices was one of the main drivers of high system marginal energy prices in across the CAISO system.

- Congestion in the fourth quarter primarily occurred in the south-to-north direction, and had less of an impact on overall prices than in the previous quarter. This congestion increased day-ahead prices in PG&E and SDG&E by about $0.9/MWh and $0.8/MWh, respectively, and decreased prices in SCE by about $0.7/MWh. Congestion in the 15-minute market increased PG&E and SDG&E prices by about $1.5/MWh, and decreased SCE prices by about $1/MWh.

- Total bid cost recovery payments for the fourth quarter were about $31 million, significantly lower than the third quarter of 2018. Bid cost recovery attributed to the real-time market totaled about $22 million. DMM estimates that bid cost recovery payments to units committed in the real-time market for exceptional dispatches totaled about $3.6 million.

- Fourth quarter real-time imbalance offset charges decreased to about $13 million from $75 million in the third quarter.[2] Real-time congestion imbalances of $27 million drove the total imbalance offset charges while the real-time energy offset had a surplus of $14 million. Reductions in 15-minute market transmission constraint limits below day-ahead limits appear to be a major contributor to fourth quarter congestion imbalance charges. A significant portion of the congestion imbalance offset charges appear to be associated with payments to virtual bid schedules.

- Costs for ancillary services decreased significantly during the fourth quarter. Costs for ancillary services totaled about $27 million during the fourth quarter, compared to about $77 million in the previous quarter and $28 million during the same quarter in 2017. Further, average spinning and non-spinning operating reserve requirements dropped significantly during the fourth quarter from a combined requirement of around 2,000 MW during the third quarter to around 1,500 during the fourth quarter.

- During the fourth quarter of 2018, congestion revenue rights auction revenues were $29 million less than payments made to non-load-serving entities purchasing these rights. Losses in the fourth quarter represent $0.48 in auction revenues paid to transmission ratepayers for every dollar paid

[2] The most current settlement imbalance charges are reported. These are subject to change with settlement data updates.

out to auctioned rights holders. Total transmission ratepayer losses from the congestion revenue rights auction since the market began in 2009 surpassed $866 million.

- Operator adjustments to procure additional residual unit commitment capacity decreased significantly in the fourth quarter of 2018. During the days of operator adjustments, primary drivers were load forecast error, fire danger and renewable uncertainty concerns.
- Convergence bidding was profitable overall during the fourth quarter. For the fourth consecutive quarter, virtual supply was also profitable. Combined net revenues for virtual supply and demand were about $12 million after accounting for about $1.5 million of virtual bidding bid cost recovery charges.
- Total energy resulting from all types of exceptional dispatch increased by 80 percent in the fourth quarter compared to the same quarter in 2017. Exceptional dispatch energy from commitment energy accounted for over 80 percent of all exceptional dispatch energy in this quarter.

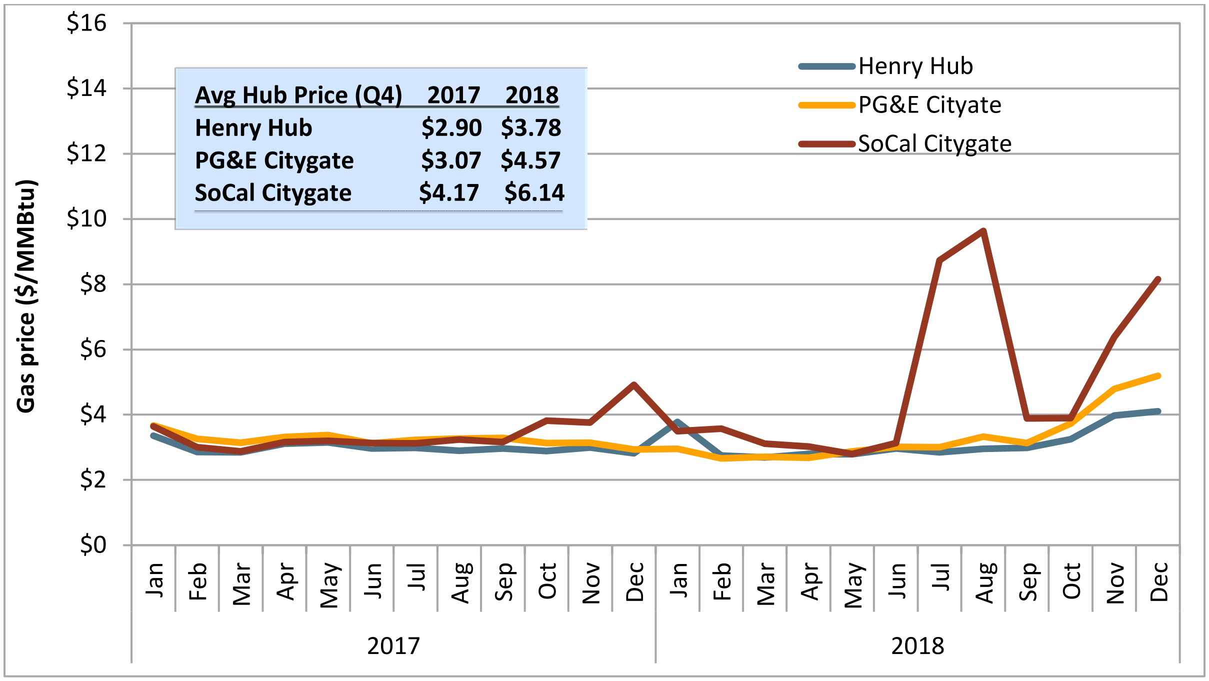
1.1 Supply conditions

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. In the third quarter of 2018, the average price of natural gas more than doubled from 2017 levels at SoCal Citygate trading hub in California. Prices at SoCal Citygate fell 17 percent, relative to the third quarter, remaining high in the fourth quarter, as both national and PG&E Citygate prices increased. The sustained increase in natural gas prices, particularly at SoCal Citygate, was one of the main drivers of high system marginal energy prices across the ISO footprint.

Figure 1.1 shows monthly average natural gas prices at key delivery points in Northern California (PG&E Citygate) and in Southern California (SoCal Citygate) as well as for the Henry Hub trading point, which acts as a point of reference for the national market for natural gas. As reported in the previous quarter, prices at SoCal Citygate were extremely high on some days in July and August of 2018 due to unplanned pipeline maintenance, reduced electricity generation from hydroelectric power, restricted storage activity at Aliso Canyon and anticipation of potential low operational flow order (OFO) non-compliance penalty charges as well as increased natural gas demand amid high temperatures. Prices remained high in the fourth quarter due to ongoing pipeline outages and low OFO penalties. SoCal Citygate prices often impact overall system prices because 1) there are large numbers of natural gas resources in the south, and 2) in the absence of congestion these resources can set system prices.

Figure 1.1 Monthly average natural gas prices



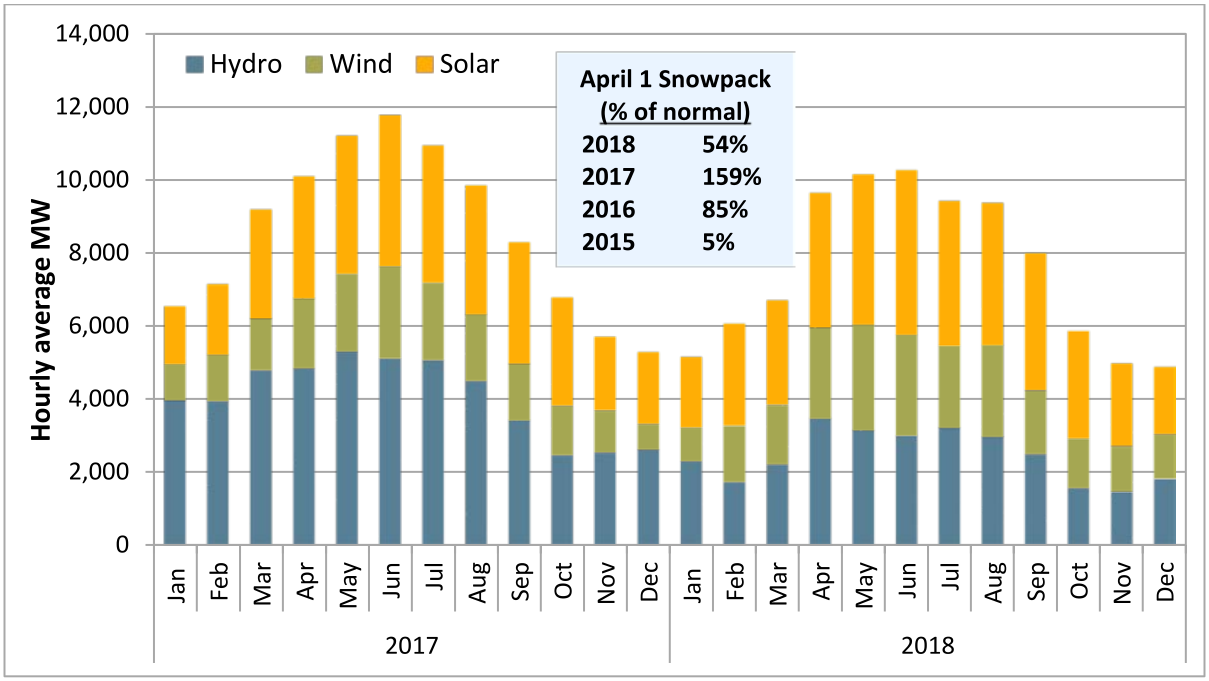
Renewable generation

Overall, total generation from hydroelectric, solar, and wind resources decreased compared to the previous quarter and compared to the fourth quarter of 2017. This was primarily due to reduced snow melt and therefore a lack of availability of hydroelectric production. Compared to 2017, hydroelectric production in the fourth quarter decreased by roughly 36 percent.

Wind and solar production also decreased compared to the third quarter of 2018, following a similar trend between the third and fourth quarters of 2017. This may be due to increased number of storms and cloud cover during this time of the year that reduces solar output. Compared to the fourth quarter of 2017, wind production remained roughly the same. Solar production was roughly 20 percent greater than the same quarter last year, reflecting increased installed capacity.

The availability of renewable resources contributes to patterns in prices both seasonally and hourly. Many factors influence the increase in monthly prices relative to the fourth quarter of 2017 seen in Section 1.2. The decrease in renewable production compared to the same quarter last year contributes to higher prices due to the low marginal cost of renewables relative to other resources. The 36 percent decrease in hydroelectric output is one contributing factor to this trend, as more expensive resources are utilized.

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



1.2 Energy market performance

Average 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 1.3 shows average monthly system marginal energy prices during all hours. During the quarter, average prices decreased in relation to the high prices seen in the previous quarter. Prices in this quarter did, however, increase compared to the fourth quarter of 2017.

- Average day-ahead prices increased by about $10/MWh (24 percent), 15-minute by about $4/MWh (10 percent) and 5-minute market prices by about $7/MWh (19 percent) relative to the same quarter in 2017.
- Average monthly day-ahead prices were higher than 15-minute and 5-minute market prices during all months, by about $5/MWh and $7/MWh respectively during the quarter.

Figure 1.4 shows system marginal energy prices on an hourly basis in the fourth quarter compared to average hourly net load.[3] Hourly prices largely followed the net load pattern with the highest energy prices occurring during the morning and evening peak net load hours. In particular, day-ahead prices

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

were highest during hours ending 18 and 19. Additionally, average prices in the day-ahead market were higher than 15-minute market prices in all hours.

Figure 1.3 Average monthly prices (all hours) – system marginal energy price

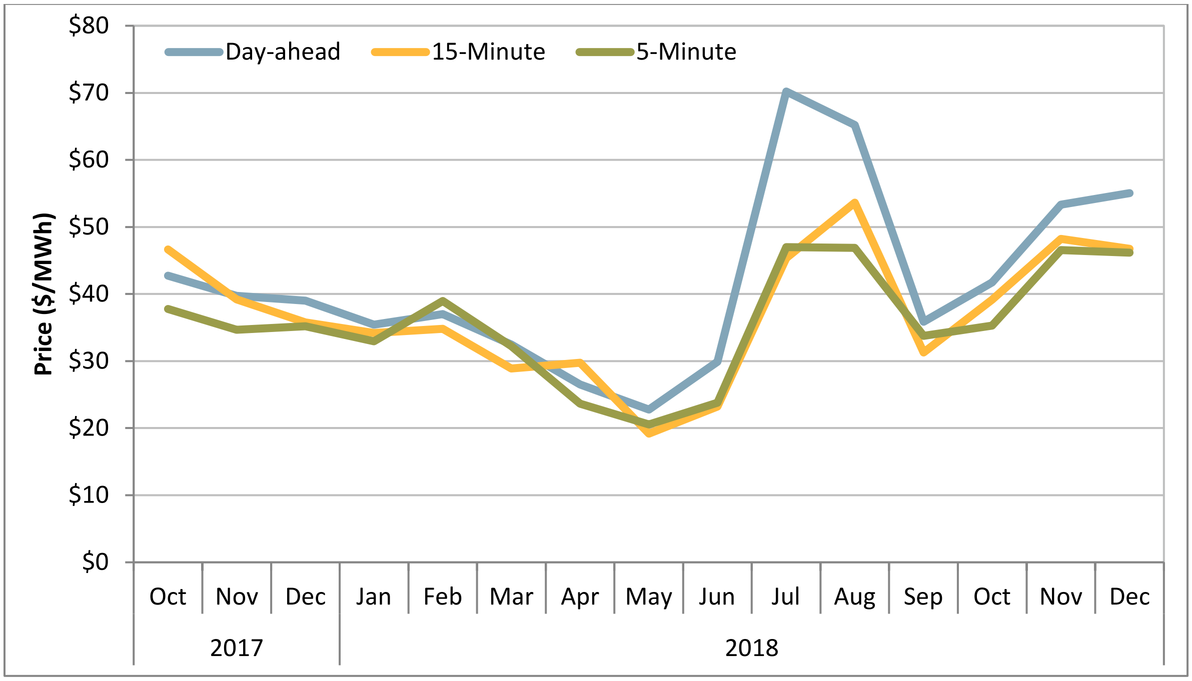
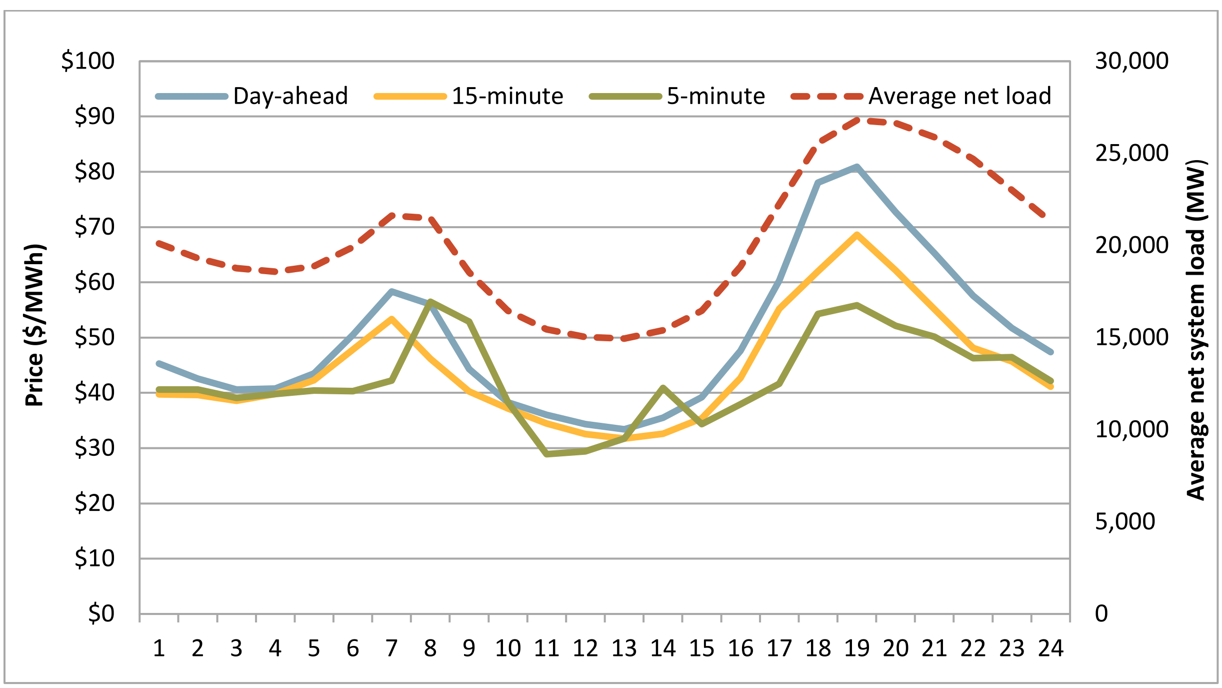


Figure 1.4 Hourly system marginal energy prices

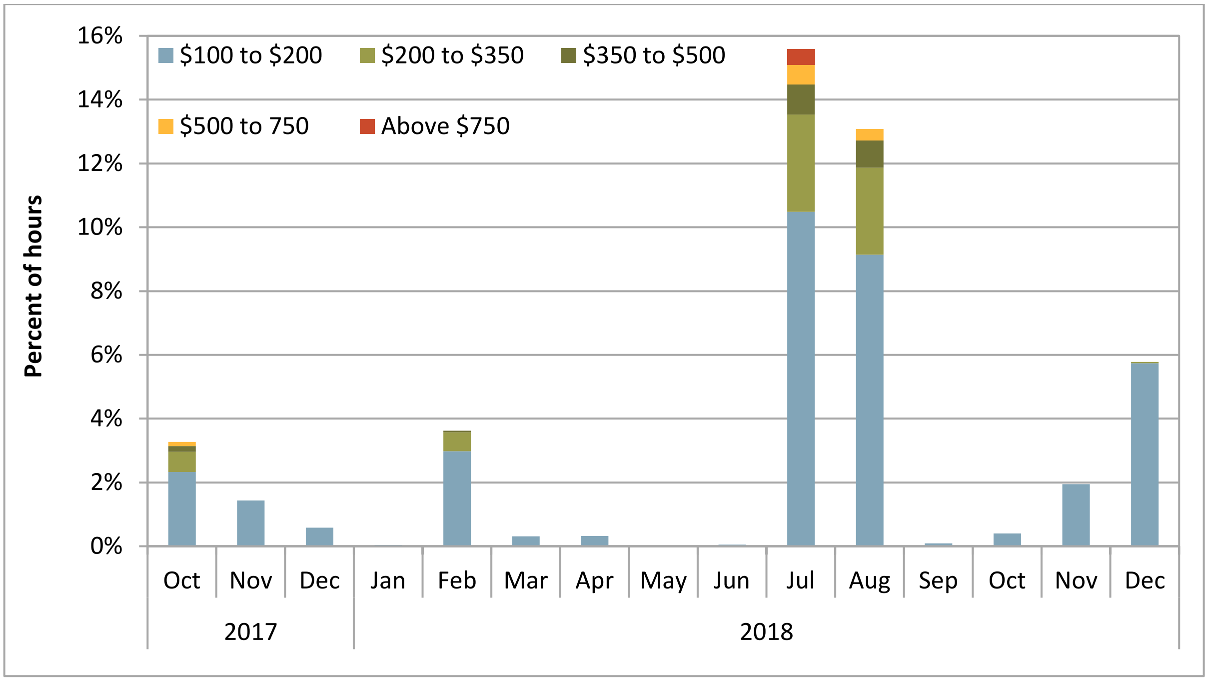


1.3 Day-ahead price variability

High prices

Figure 1.5 shows the frequency of high prices in the day-ahead market. The frequency of high prices in the day-ahead market greater than $100/MWh increased to around 2.7 percent of intervals during the quarter compared to around 1.4 percent of intervals in the fourth quarter of 2017. Furthermore, the frequency of day-ahead prices greater than $100/MWh increased sequentially each month with the highest occurrence of high day-ahead prices in December. However, high prices in the quarter never reached above $200/MWh which did occur during 0.3 percent of intervals in the fourth quarter of 2017.

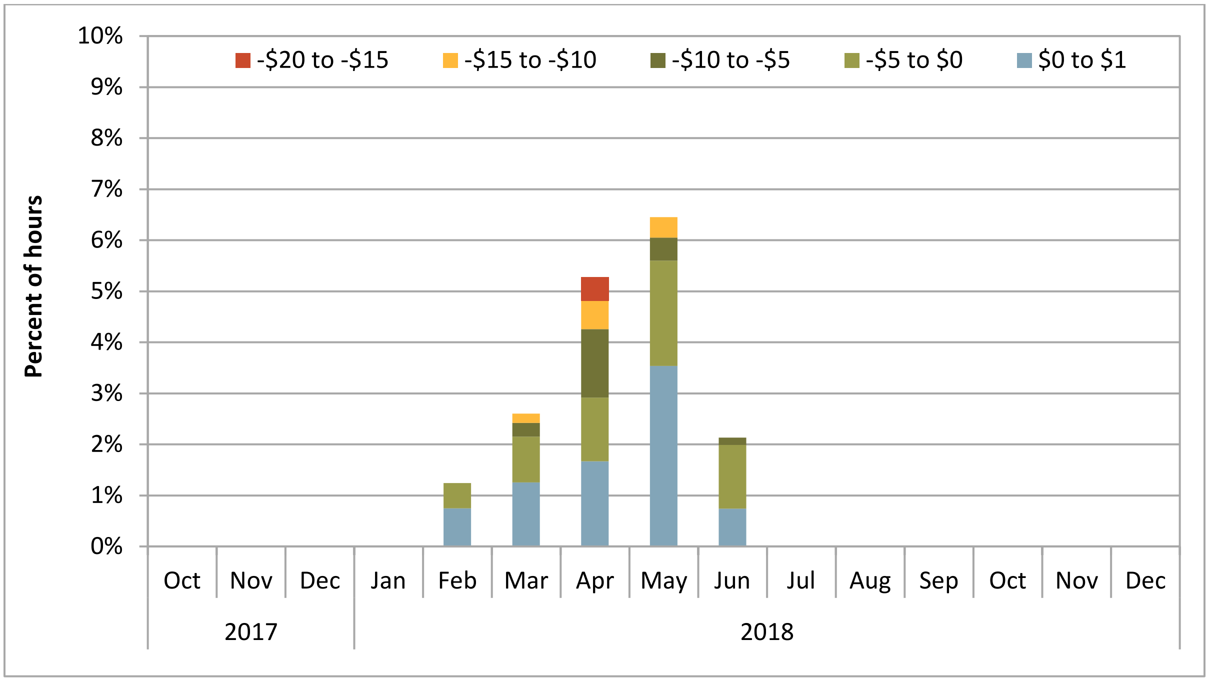
Figure 1.5 Frequency of high day-ahead prices (MWh) by month



Negative prices

As shown in Figure 1.6, there were no occurrences of negative prices in the day-ahead market for the fourth quarter. This result is identical to the fourth quarter of 2017.

Figure 1.6 Frequency of negative day-ahead prices (MWh) by month



1.4 Real-time price variability

Real-time market prices can be volatile with periods of extreme positive and negative prices. Even a short period of extremely high or low prices can significantly impact average prices. During the fourth quarter, the frequency of high prices in the 15-minute and 5-minute markets decreased significantly compared to both the previous quarter and the fourth quarter of 2017. Further, the frequency of under-supply infeasibilities in both markets was lower relative to the fourth quarter of 2017.

In some instances, high bids set the price after the load bias limiter triggered following an under-supply infeasibility.

The frequency of negative prices in the 15-minute and 5-minute markets was significantly higher during the fourth quarter, both relative to the previous quarter and the same quarter in 2017.

High prices

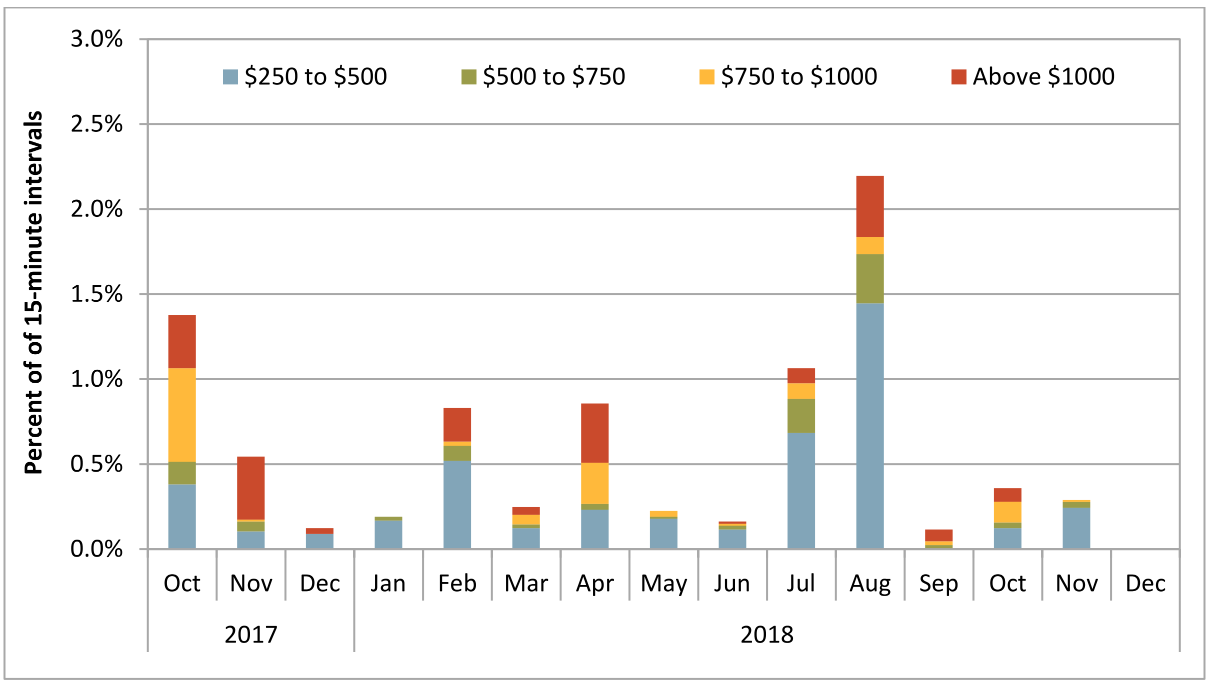
As shown in Figure 1.7, the frequency of high prices in the 15-minute market greater than $250/MWh decreased from over 1 percent of intervals in the previous quarter to 0.2 percent of intervals during the quarter. There were no under-supply infeasibilities in the 15-minute market during the fourth quarter.

Figure 1.8 shows the frequency of high prices in the 5-minute market. The frequency of price spikes greater than $250/MWh in the 5-minute market was about 0.5 percent of intervals in the fourth quarter, down from around 1.4 percent of intervals in the previous quarter and 0.8 percent of intervals in the fourth quarter of 2017. In addition, the frequency of more extreme 5-minute market prices larger than $750/MWh was low, around 0.3 percent of intervals.

Figure 1.9 shows the frequency of under-supply infeasibilities in the 5-minute market. The conditions for the load conformance limiter were met during most of the intervals when there were infeasibilities. Specifically, if the operator load adjustment exceeds the size of the power balance constraint infeasibility and is in the same direction, the size of the load adjustment is automatically reduced and the price is set by the last dispatched economic bid rather than the penalty parameter for the relaxation (for instance, the $1,000/MWh penalty price for shortages). However, during most of the under-supply infeasibilities in the fourth quarter when the limiter triggered, accessible economic bids near the bid cap of $1,000/MWh were dispatched such that the resulting price was near the penalty parameter.

The ISO is expected to change the criteria used to determine when the load conformance limiter is triggered during intervals when the power balance constraint is infeasible and must be relaxed in the real-time market.[4] Under the proposed method, the load conformance limiter would be triggered by a measure based on the change in load adjustment from one interval to the next, rather than the total level of load conformance. This change will significantly reduce the frequency of intervals in which the limiter is triggered and is currently scheduled to be implemented in the first quarter of 2019 if approved by FERC.

Figure 1.7 Frequency of high 15-minute prices (MWh) by month



4 *Tariff Amendment to Enhance Detail on Load Forecast Conformance*, ER19-538-000, December 12, 2018. http://www.caiso.com/Documents/Dec12-2018-TariffAmendment-ImbalanceConformanceEnhancement-ER19-538.pdf

Figure 1.8 Frequency of high 5-minute prices (MWh) by month

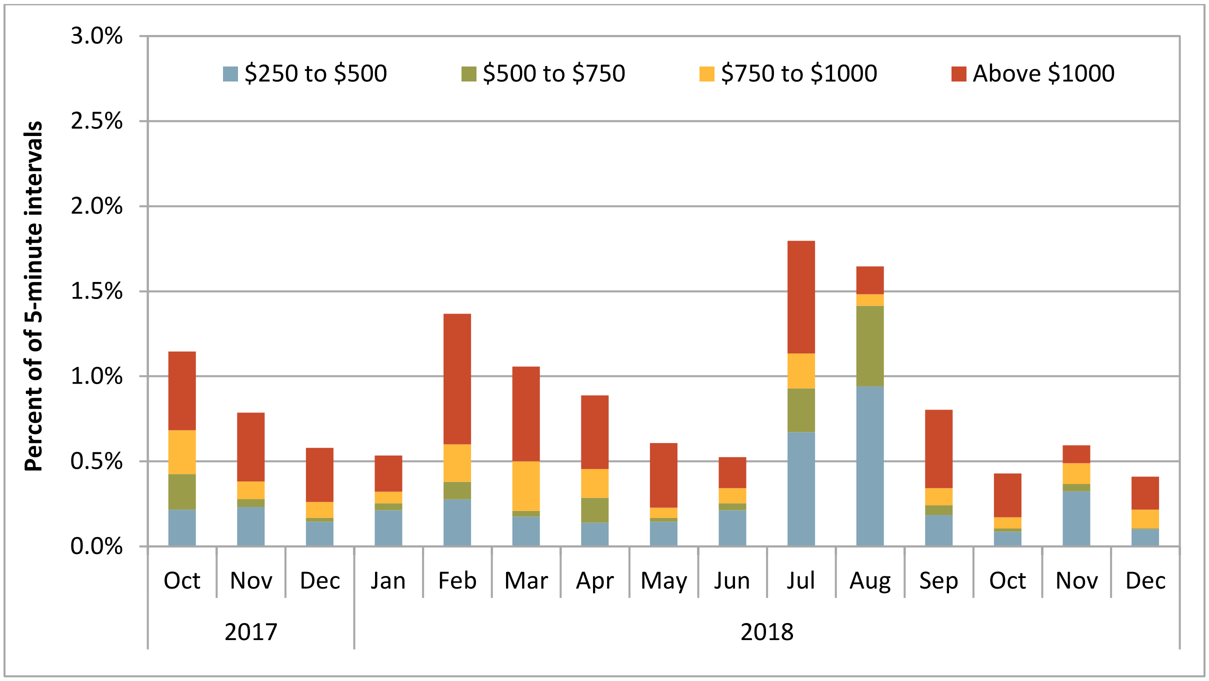
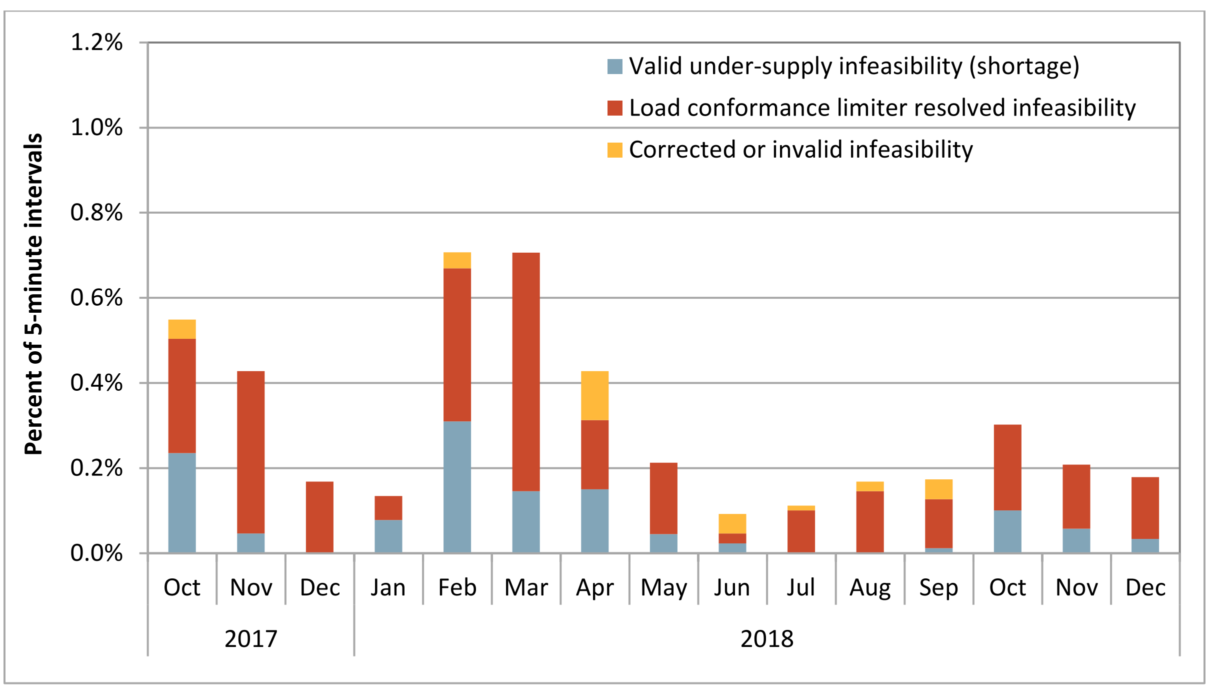


Figure 1.9 Frequency of under-supply power balance constraint infeasibilities (5-minute market)

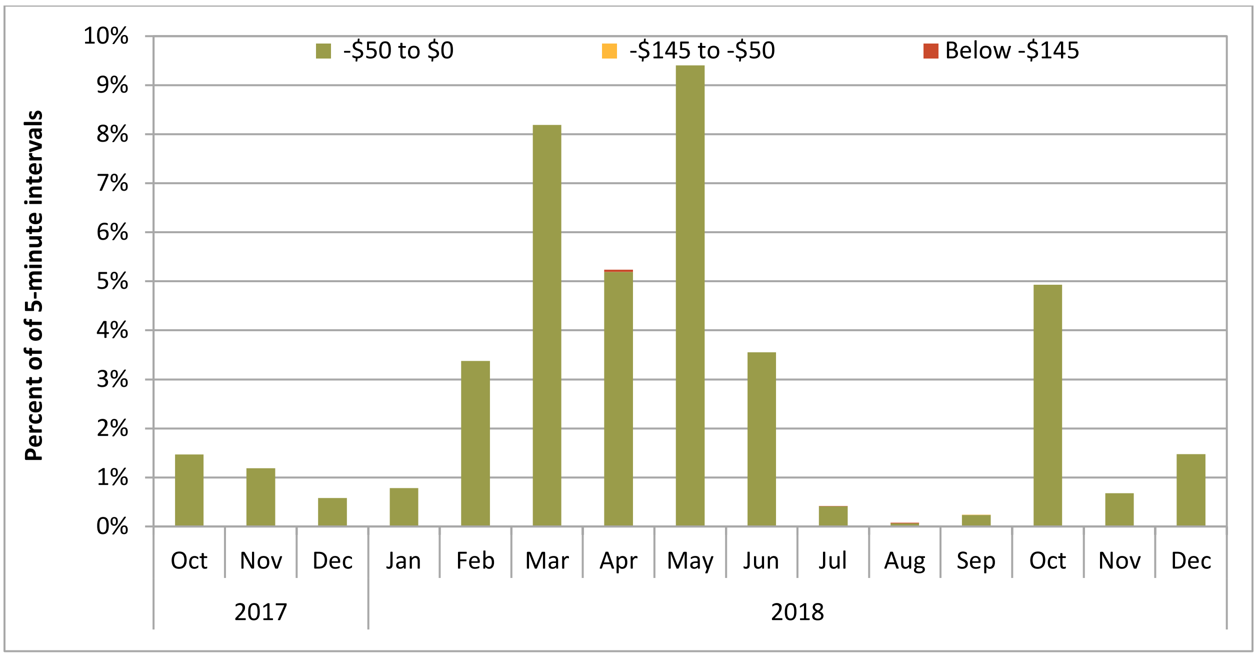


Negative prices

Figure 1.10 shows the frequency of negative prices in the 5-minute market by month inthe three largest load aggregation points in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric).[5] The frequency of both the 15-minute and 5-minute markets increased significantly during the fourth quarter relative to the previous three months. In addition, the frequency of negative prices was higher than in the fourth quarter of 2017. In particular, the month of October had the highest frequency of negative prices during the fourth quarter occurring during about 5 percent of intervals in the 5-minute market.

Negative prices occurred during about 1 percent and 2.4 percent of intervals in the 15-minute and 5-minute markets, respectively. In comparison, negative prices occurred less frequently during about 0.3 percent and 1.1 percent of intervals in the 15-minute and 5-minute markets, respectively in the fourth quarter of 2017.

Figure 1.10 Frequency of negative 5-minute prices by month



1.5 Residual unit commitment

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real time. The residual unit commitment market is run immediately after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of load cleared in the day-ahead market and the day-ahead forecast load. ISO operators are able to increase residual unit commitment requirements. Frequency of these adjustments declined significantly in the fourth quarter of 2018.

As illustrated in Figure 1.11, residual unit commitment procurement appears to be driven primarily the need to replace cleared net virtual supply bids, which can offset physical supply in the day-ahead market

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

run. On average, cleared virtual supply (green bar) was about 145 percent higher in the fourth quarter of 2018 than in the same quarter of 2017.

ISO operators were able to increase the amount of residual unit commitment requirements primarily due to load forecast error, fire danger and renewable variability concerns. This tool noted as operator adjustments (red bar) in the figure, was used less frequently averaging about 109 MW per hour compared to about 983 MW per hour in the previous quarter.

Residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of variable energy resources and the forecast output of these renewable resources. This intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market. It is represented by the yellow bar in Figure 1.11.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar) represents the difference in cleared supply (both physical and virtual) compared to the ISO's load forecast. On average, this factor contributed towards decreased residual unit commitment in the fourth quarter of 2018.

Figure 1.11 Determinants of residual unit commitment procurement

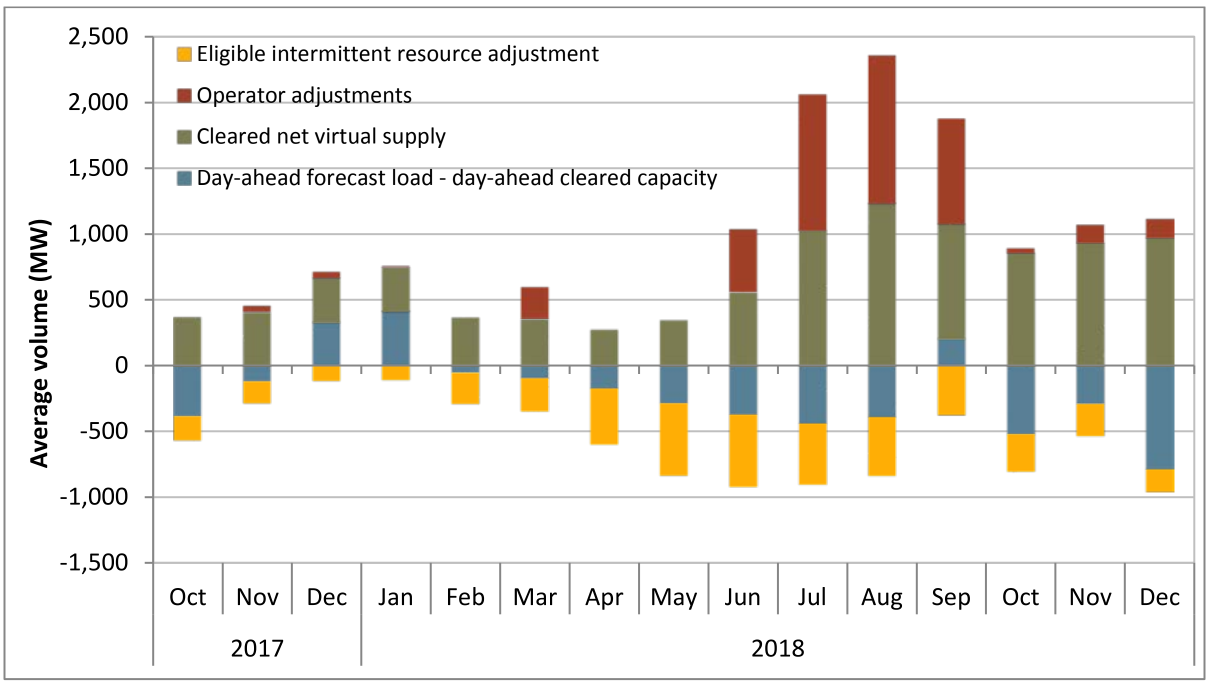
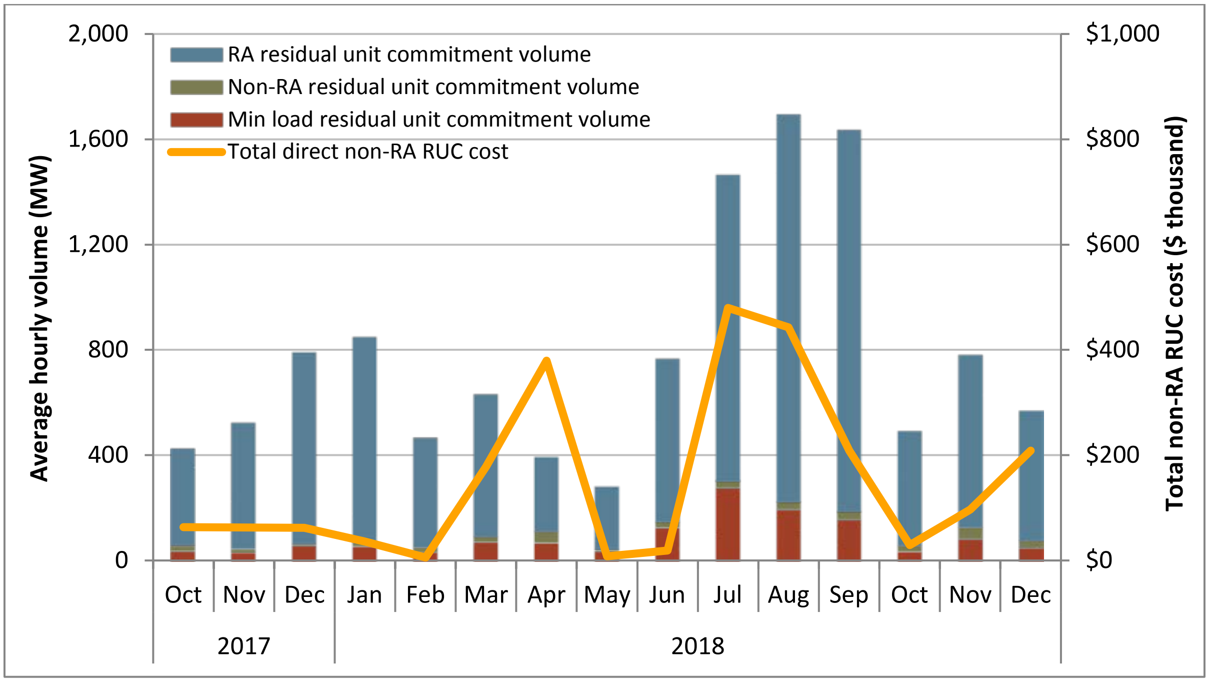


Figure 1.12 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. The figure shows decrease in residual unit commitment volumes and costs due to lower residual unit commitment requirements in the fourth quarter of 2018. Total residual unit commitment procurement increased to about 619MW per hour in the fourth quarter of 2018 from an average of 586 MW in the same quarter of 2017. Out of the 619 MW per hour residual unit commitment capacity, the capacity committed to operate at minimum load averaged about 56 MW each hour compared to 43 MW in the fourth quarter of 2017.

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 the residual unit commitment receive capacity payments.[6] The total direct cost of non-resource adequacy residual unit commitment, represented by the gold line in Figure 1.12, increased slightly by $0.1 million in the fourth quarter of 2018 compared to 2017.

Figure 1.12 Residual unit commitment costs and volume



1.6 Bid cost recovery

Estimated bid cost recovery payments for the fourth quarter of 2018 declined and totaled about $31 million. This amount was considerably lower than the total amount of bid cost recovery in the previous quarter and slightly higher than the fourth quarter of 2017, which were about $88 million and $27 million, respectively.

Bid cost recovery attributed to the day-ahead market totaled about $6 million, significantly lower than the $21 million in the prior quarter. Bid cost recovery payments for residual unit commitment during the quarter totaled about $3 million, compared to $21 million in the prior quarter. As seen in Figure 1.14, after netting against real-time revenues in the fourth quarter of 2018, short-start and long-start resources received about $2.4 million and $0.4 million, respectively, for residual unit commitment bid cost recovery payments. This decrease in residual unit commitment bid cost recovery payments in the quarter can be attributed to lower requirements driven in part by a decline in operator adjustments.[7]

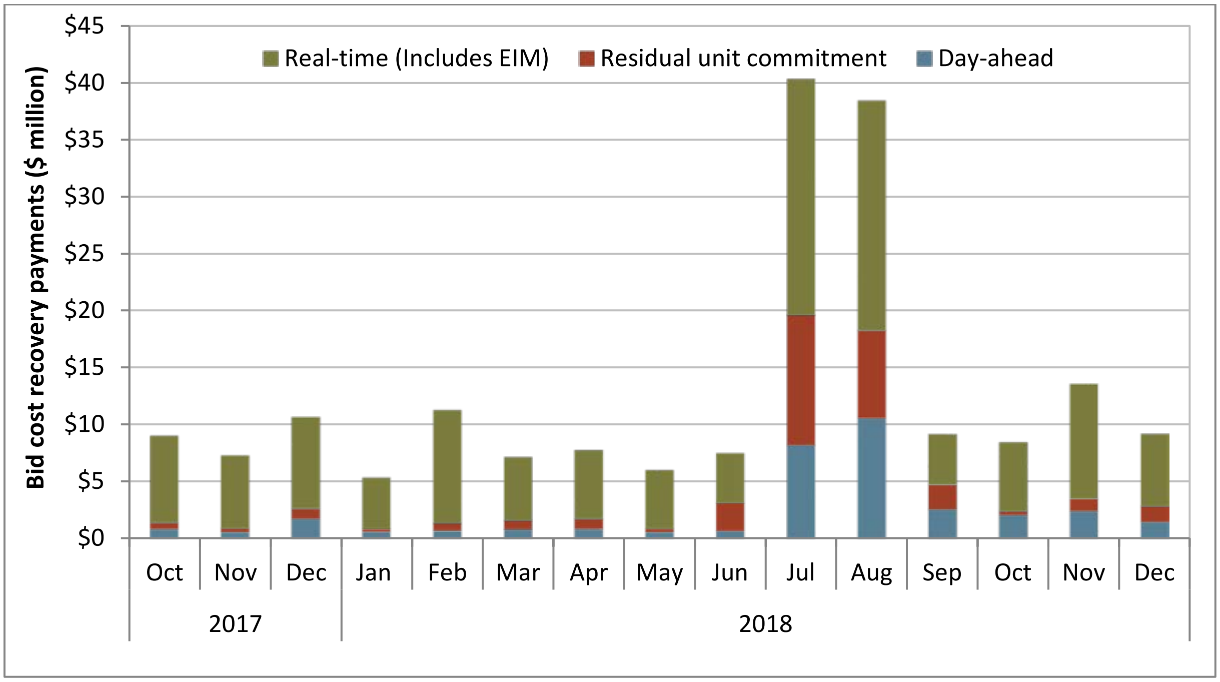
6 If committed, resource adequacy units may receive bid cost recovery payments in addition to resource adequacy payments.

7 Refer to Section 1.5 for more information on residual unit commitment sources.

Bid cost recovery attributed to the real-time market totaled about $22 million, similar to the fourth quarter of 2017 and significantly lower than the $45 million total in the previous quarter.

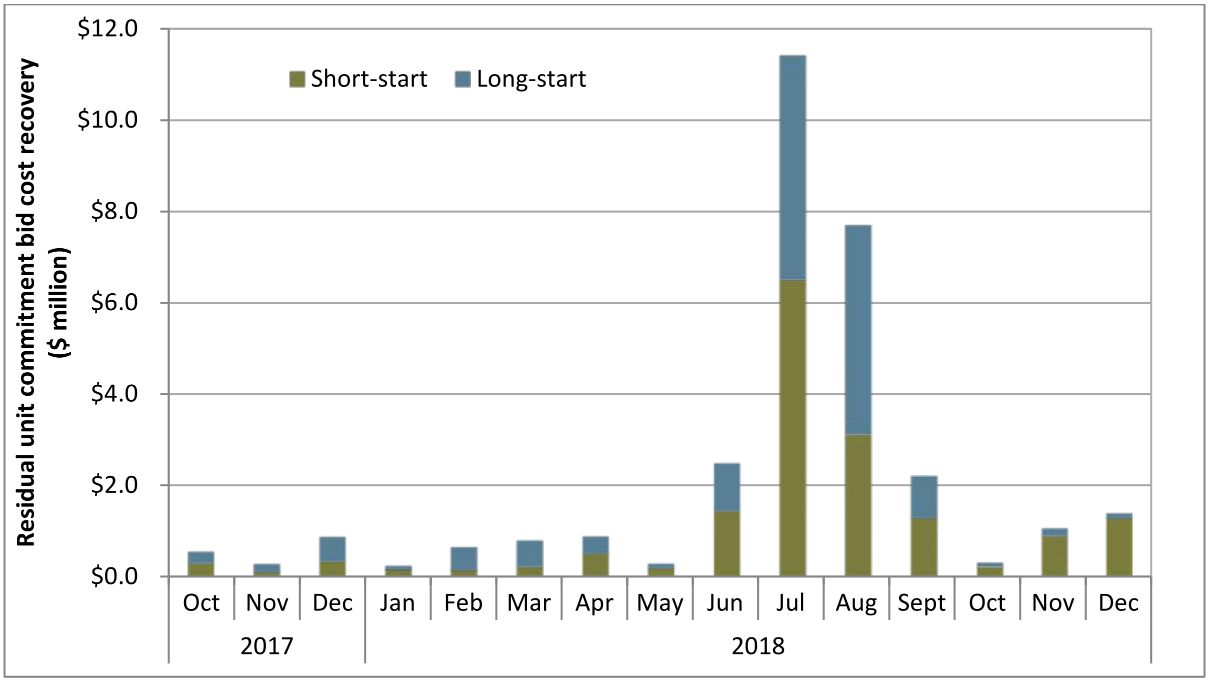
Exceptional dispatch volume in the fourth quarter continued to remain high.[8] However, according to DMM estimates, bid cost recovery payments to units committed in the real-time market for exceptional dispatches totaled only about $3.6 million in the fourth quarter of 2018.

Figure 1.13 Monthly bid cost recovery payments



[8] Refer to Section 1.11.3 for more information on exceptional dispatches.

Figure 1.14 Residual unit commitment bid cost recovery payments by commitment type



1.7 Real-time imbalance offset charges

Fourth quarter real-time imbalance offset charges decreased to about $13 million from $75 million in the third quarter.[9] Real-time congestion imbalances of $27 million drove the total imbalance offset charges while the real-time energy offset had a surplus of $14 million. Fourth quarter real-time loss offsets were about $0.1 million. Reductions in 15-minute market transmission constraint limits below day-ahead limits appear to be a major contributor to fourth quarter congestion imbalance charges. A significant portion of the congestion imbalance offset charges appear to be associated with payments to virtual bid schedules.

Real-time imbalance offset charges are the difference between the total money paid out by the ISO and the total money collected by the ISO for energy schedules settled in the real-time markets. Within the ISO system the charge is allocated to measured demand (metered load plus exports). Offset charges can be an indicator of potential market issues or inefficiency. But it is important to note that offset charges are an accounting construct. Offset charges do not necessarily equal economic costs or financial transfers from measured demand to other entities. Real-time imbalance offset charges can be split into three components:

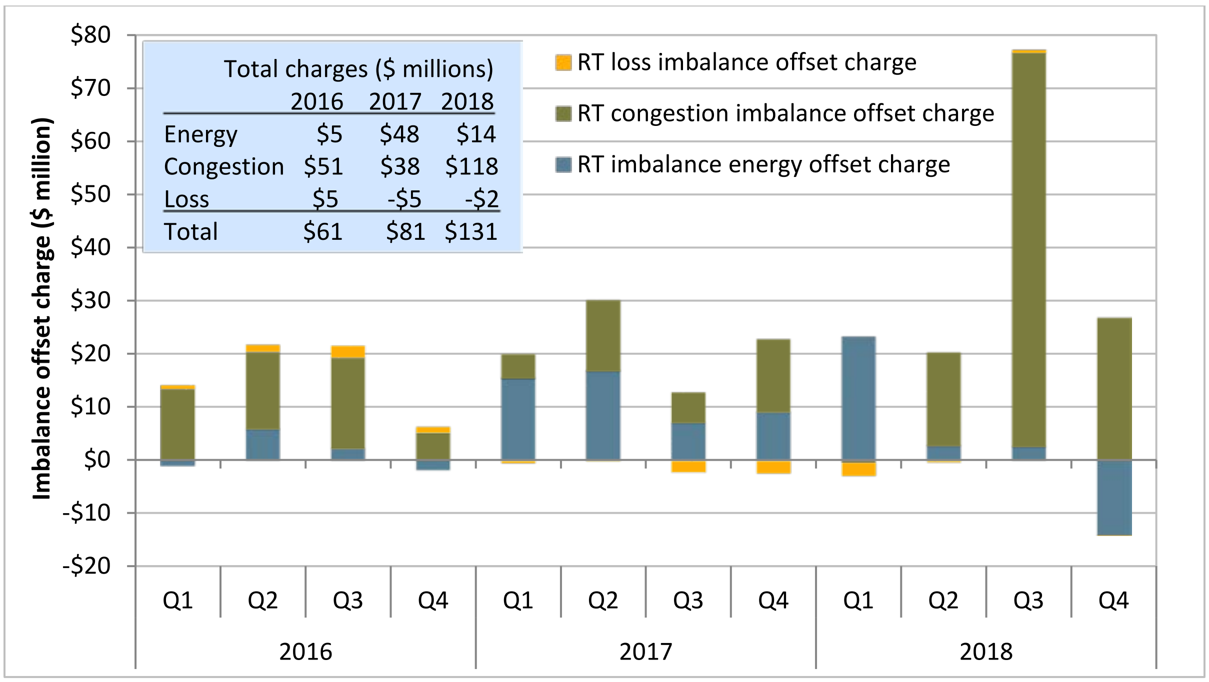
- *Real-time imbalance energy offset charges* (RTIEO) are the sum of real-time energy schedule changes multiplied by the system marginal energy cost component of the real-time price.
- *Real-time congestion imbalance offset charges* (RTCIO) are the sum of real-time energy schedule changes multiplied by the marginal congestion cost component of the real-time price.

9 The most current settlement imbalance charges are reported. These are subject to change with settlement data updates.

- *Real-time loss imbalance offset charges* are the sum of real-time energy schedule changes multiplied by the loss component of the real-time price.

Figure 1.15 shows quarterly imbalance charges. The $27 million in fourth quarter real-time congestion imbalance charges were lower than the $74 million in the third quarter but still significant. Energy imbalance offsets were a surplus of around $14 million, compared to a nearly $2.6 million deficit in the third quarter. Loss imbalance offsets had a surplus of about $0.1 million, versus a $0.6 million deficit in the third quarter.

Figure 1.15 Real-time imbalance offset charges



Overall real-time congestion imbalance is the sum of specific constraint congestion imbalances. When a change to a real-time energy schedule reduces flows on a constraint, that schedule is paid the real-time constraint congestion price for making space available on the constraint. Generally, if the constraint is still binding with a non-zero price, another schedule has increased flows on the constraint. The schedule that increased flows would then pay the ISO enough to cover the ISO's payments to the schedule that reduced flows—and the ISO congestion accounts would remain balanced.

However, there are several reasons the congestion payments will not balance.[10] One reason is that the real-time constraint limits are lower than the day-ahead market limits. With a lower limit, schedules may be forced to reduce flows over the still binding constraint without a corresponding flow increase. The ISO will pay the flow reduction but cannot balance this payment with collections from a flow increase. To maintain revenue balance, the ISO charges an uplift to measured demand to offset the imbalance.[11]

10 One is that flows increase causing a constraint to bind generating additional congestion rent. Others include when some flow changes are settled and others are not.

11 For a more detailed explanation see the DMM paper *Real-Time Revenue Imbalance in CAISO Markets,* April 24, 2013: http://www.caiso.com/Documents/DiscussionPaper-Real-timeRevenueImbalance_CaliforniaISO_Markets.pdf

Table 1.1 shows estimated constraint specific day-ahead to 15-minute market congestion imbalance charges for the ten highest constraints by imbalance. These ten constraints in the fifteen-minute market accounted for about $22 million of the $27 in congestion imbalances. The table also shows the total hours that each constraint 1) was binding in the 15-minute market, 2) had real-time limits lower than day-ahead limits, 3) did not have real-time limits below day-ahead limits, and 4) did not have limits shown in the day-ahead data.[12]

Table 1.1 also shows the average day-ahead limits, and the average limit change from the day-ahead to 15-minute market. Both day-ahead limit and limit changes are averaged over intervals when 15-minute market limits are binding. Table 1.1 indicates fourth quarter congestion imbalance deficits were driven in large part by constraint limit reductions in the 15-minute market.

Table 1.1 Estimated Q4 15-minute market congestion imbalances – top 10 constraints[13]

Constraint	Estimated imbalances (million $)	Total hours in quarter				Avg DA limit (MW)	Avg limit change (MW)
		Binding in FMM	w/ lower FMM limit	w/o lower FMM limit	w/o DA limit		
7750_D-ECASCO_OOS_CP6_NG	($8.7)	236	172	39	25	263	(34)
MALIN500	($3.4)	96	46	50	0	2,096	(485)
MIGUEL_BKs_MXFLW_NG	($3.0)	63	54	2	7	1,340	(187)
OMS_6451207_TRACY-LOSBANOS	($2.8)	228	176	40	12	1,300	(320)
24016_BARRE_230_24154_VILLAPK_230_BR_1_1	($1.5)	28	24	0	4	1,259	(244)
ADLANTO-SP_ITC	($1.0)	53	23	30	0	791	(440)
7750_D-VISTA1_OOS_CP6_NG	($0.5)	12	12	0	0	310	(90)
30515_WARNERVL_230_30800_WILSON_230_BR_1_1	($0.4)	74	17	22	35	347	(10)
OMS6355729TL50003_NG	($0.4)	8	8	0	0	435	(130)
24016_BARRE_230_25201_LEWIS_230_BR_1_1	($0.4)	4	1	0	3	1,410	(354)

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.

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

12 This does not necessarily mean the constraint was not enforced in the day-ahead market. The constraint data may not have been saved in the critical constraint data as the constraint was not close enough to binding to be placed in the market run.

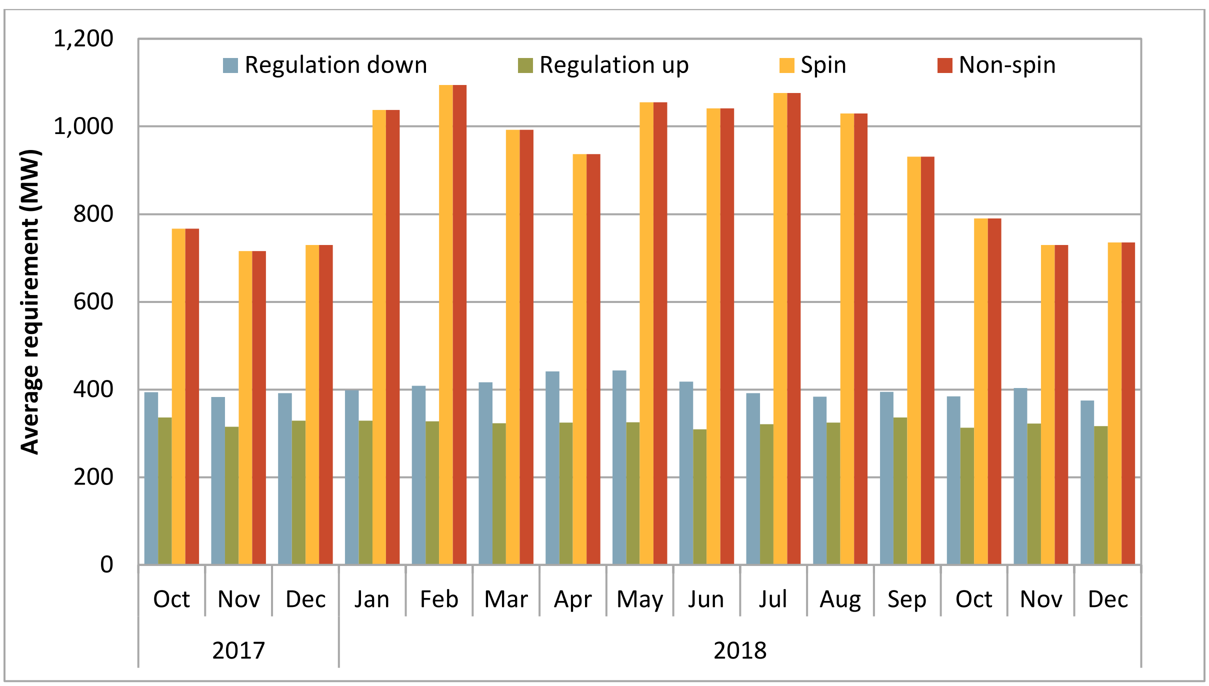
13 Imbalances are estimated as if load settled at the 15-minute market prices. Data are aggregated by constraint element but also matched by contingency case in the underlying data.

regions. Therefore, ancillary services procured in a more inward region also count toward meeting the minimum requirement of the outer region. Ancillary service requirements are then met by both internal resources and imports where imports are indirectly limited by the minimum requirements from the internal regions.

Operating reserve requirements in the day-ahead market are typically set by the maximum of (1) 6.3 percent of the load forecast, (2) the most severe single contingency and (3) 15 percent of forecasted solar production. Operating reserve requirements in real-time are calculated similarly except using 3 percent of the load forecast and 3 percent of generation instead of 6.3 percent of the load forecast. Projected schedules on the Pacific DC intertie that sink in the ISO balancing area (which can include a higher volume than the share that sinks directly in the ISO) often serves as the most severe single contingency.[14]

Figure 1.16 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market during 2018. As shown in the figure, average spinning and non-spinning operating reserve requirements dropped significantly during the fourth quarter from a combined requirement of around 2,000 MW during the third quarter to around 1,500 during the fourth quarter. This was largely due to lower seasonal load forecasts setting the requirement. Further, Pacific DC intertie schedules infrequently set operating reserve requirements as the most severe single contingency during the quarter. As a result, operating reserve requirement during the fourth quarter of 2018 were similar to those in the fourth quarter of the previous year.

Figure 1.16 Average monthly day-ahead ancillary service requirements



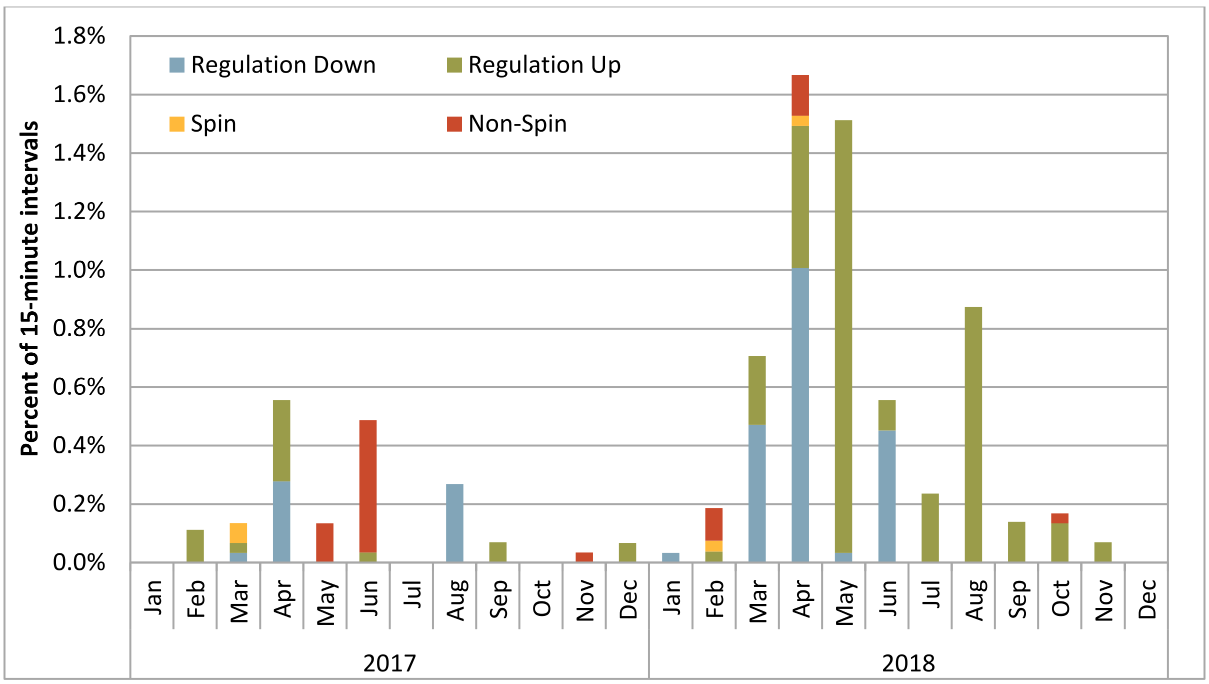
[14] The Federal Energy Regulatory Commission approved a set of newly defined requirements in BAL-002-2, effective January 1, 2018, that required the ISO to reevaluate the most severe single contingency. Both poles of the Pacific DC Intertie were agreed upon as a credible multiple contingency that qualifies as a single event for the purpose of the most severe single contingency.

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 1.17, the number of intervals with scarcity pricing continued to decrease during the fourth quarter. During the quarter, the majority of scarcity intervals were for regulation up and occurred mostly in the expanded South of Path 26 region.

Figure 1.17 Frequency of ancillary service scarcities (15-minute market)



1.8.3 Ancillary service costs

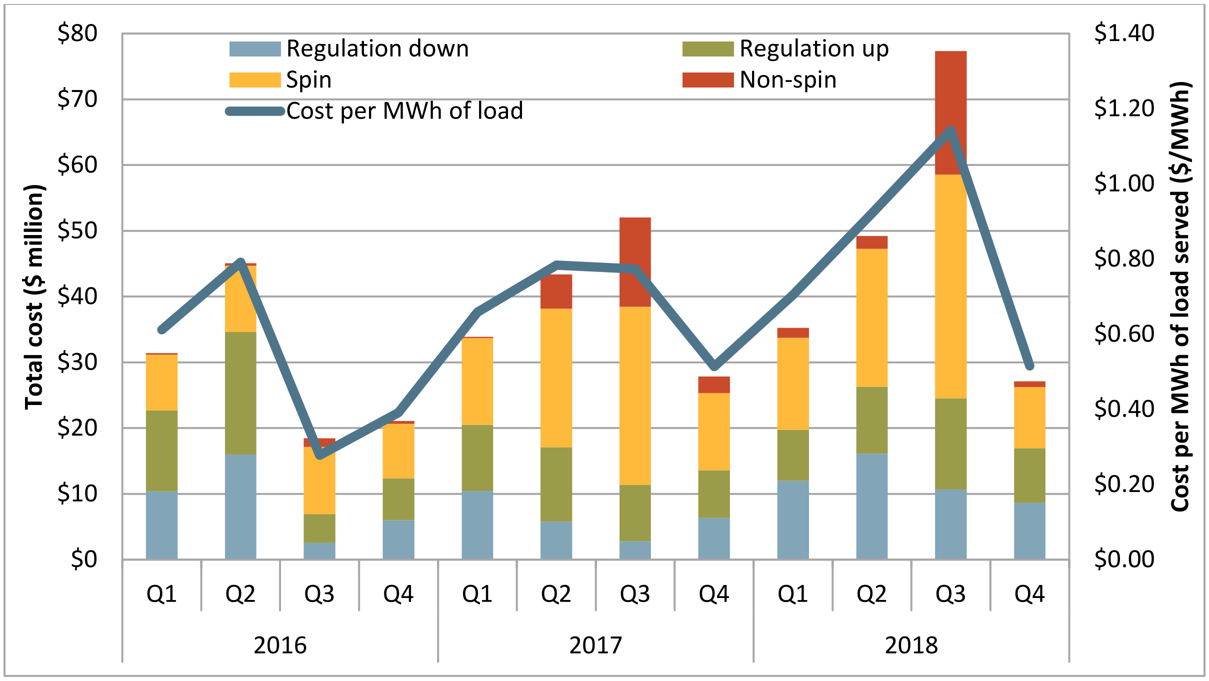
Costs for ancillary services decreased significantly during the fourth quarter. Costs for ancillary services totaled about $27 million during the fourth quarter, compared to about $77 million in the previous quarter and $28 million during the same quarter in 2017.[15]

Figure 1.18 shows the total cost of procuring ancillary service products by quarter and the total ancillary service cost for each megawatt-hour of load served. In particular, total payments associated with spinning and non-spinning reserves decreased from around $53 million during the third quarter to

15 Load-serving entities reduce their ancillary service requirements by self-providing ancillary service. The costs in this section do not account for the economic value of these quantities. By using their own resources to meet ancillary service requirements, load-serving entities are able to hedge against the risk of higher costs in the ISO market.

around $10 million during the fourth quarter. This was largely driven by lower operating reserve requirements and lower day-ahead market prices.

Figure 1.18 Ancillary service cost by product



1.9 Convergence bidding

Overall, convergence bidding was profitable for the fourth quarter. Additionally, virtual supply was profitable for the fourth consecutive quarter highlighting a yearlong trend for 2018. Before accounting for bid cost recovery charges, virtual supply generated net revenues of about $20.4 million while virtual demand net revenues were a loss of about $7 million. Combined net revenues for virtual supply and demand were about $12 million after accounting for about $1.5 million of virtual bidding bid cost recovery charges.

1.9.1 Convergence bidding trends

Average hourly cleared volumes remained around 3,300 MW, about the same as in the previous quarter. Virtual demand averaged around 1,100 MW during each hour of the quarter which, once more, is about the same amount as in the previous quarter. Average hourly virtual supply decreased slightly to about 2,100 MW compared to the previous quarter at about 2,200 MW. On average, about 30 percent of virtual supply and demand bids offered into the market cleared in the fourth quarter, about the same amount as in the previous quarter.[16]

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 990 MW on average, which is a small decrease from about 1,050 MW of net virtual supply in the previous quarter. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply in only one

[16] This was incorrectly reported as 65 percent in Q3 2018 report. The corrected value is 30 percent.

hour – hour ending 19. In the remaining 23 hours, net cleared virtual supply exceeded net cleared virtual demand, with 15 hours in the quarter where net virtual supply exceeded virtual demand by more than 1,000 MW on average.

Convergence bidding is designed to align day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between the two markets. For the quarter, net convergence bidding volumes were consistent with average price differences between the day-ahead and real-time markets during 22 of 24 hours.

Offsetting virtual supply and demand bids

Market participants can hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO system by placing virtual demand and supply bids at different locations during the same hour. These virtual demand and supply bids offset each other in terms of system energy and are not exposed to bid cost recovery settlement charges. When virtual supply and demand bids are paired in this way, one of these bids may be unprofitable independently, but the combined bids may break even or be profitable because of congestion differences between the day-ahead and real-time markets.

Offsetting virtual positions accounted for an average of about 830 MW of virtual demand offset by 830 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 52 percent of all cleared virtual bids in the fourth quarter, about the same as in the previous quarter.[17]

1.9.2 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 $13.4 million. Net revenues for virtual supply and demand fell to about $12 million after including about $1.5 million of virtual bidding bid cost recovery charges.[18]

Figure 1.19 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 three months in the quarter. Net revenues during the fourth quarter totaled about $13.4 million, compared to about $8.9 million during the same quarter in 2017, and about $32 million during the previous quarter.
- Virtual demand net revenues were positive in October and negative for November and December. In total, virtual demand generated negative net revenues of about $7 million for the quarter.

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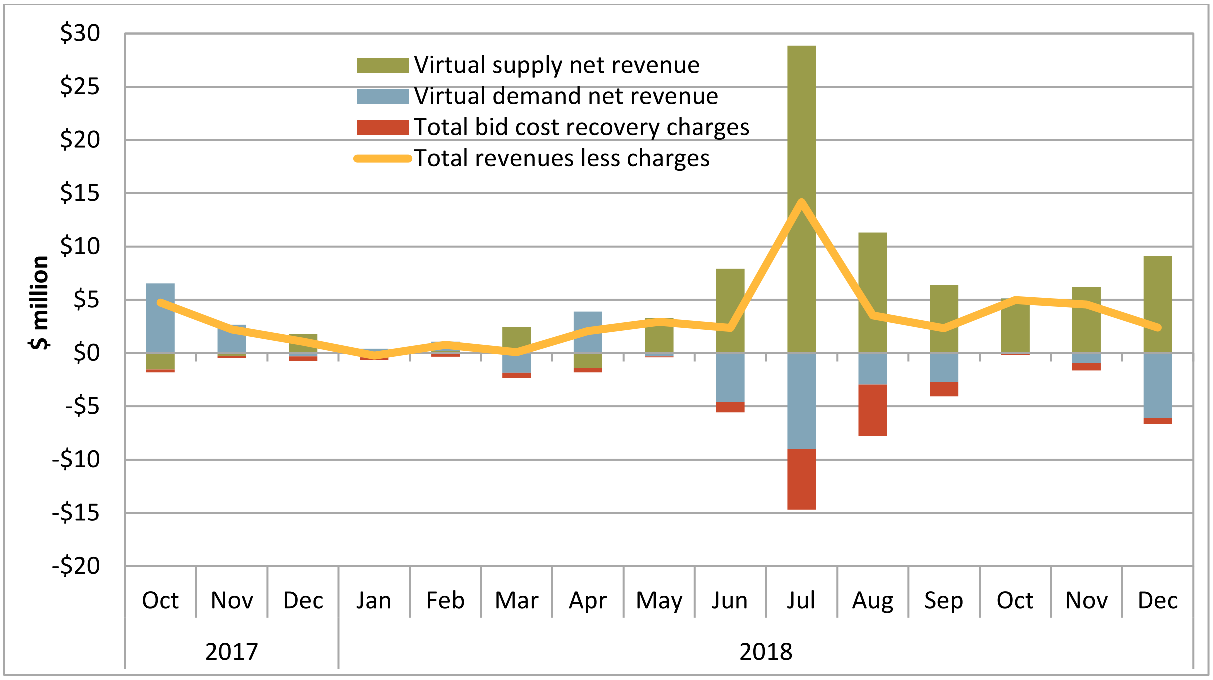
[17] This was incorrectly reported as 47 percent in the Q3 2018 report. The corrected value is 52 percent.

[18] 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.

- Virtual supply net revenues were positive in all months of the quarter, continuing a trend that began in May 2018. In total, virtual supply generated net revenues of about $20.4 million.

Figure 1.19 Convergence bidding revenues and bid cost recovery charges



After accounting for bid cost recovery charges:

- Convergence bidders received about $12 million after subtracting bid cost recovery charges of about $1.5 million for the quarter.[19,20] Bid cost recovery charges were about $0.2 million in October, $0.7 million in November and $0.6 million in December.

Net revenues and volumes by participant type

Table 1.2 compares the distribution of convergence bidding cleared volumes and net revenues, in millions of dollars, among different groups of convergence bidding participants in the fourth quarter.[21] Financial entities represented the largest segment of the virtual bidding market, accounting for about 69 percent of volume and 74 percent of settlement revenue. Marketers represented about 29 percent of the trading volumes and about 23 percent of settlement revenue. Generation owners and load-serving

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

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

21 DMM has defined financial entities as participants who own no physical power and participate in the convergence bidding and congestion revenue rights markets only. Physical generation and load are represented by participants that primarily participate in the ISO markets as physical generators and load-serving entities, respectively. Marketers include participants on the interties and participants whose portfolios are not primarily focused on physical or financial participation in the ISO market.

entities represented a smaller segment of the virtual market in terms of both volumes and settlement revenue, at about 1 percent and 3 percent respectively. In addition, load-serving entities received about $0.2 million in net payments from the market.

Table 1.2 Convergence bidding volumes and revenues by participant type

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	800	1,426	2,226	-$4.34	$14.42	$10.09
Marketer	332	609	941	-$2.59	$5.71	$3.12
Physical load	0	27	27	$0.00	$0.31	$0.31
Physical generation	8	1	9	-$0.05	-$0.03	-$0.08
Total	**1,140**	**2,063**	**3,203**	**-$7.0**	**$20.4**	**$13.4**

1.10 Congestion

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

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

The impact of congestion on each pricing node in the ISO system can be calculated by summing the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation can be done for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas.

Two metrics of congestion impact are presented in each section of this chapter. First, the *overall impact* to average regional prices is presented, which shows the impact of congestion accounting for both the frequency and magnitude of impact. These values are calculated by taking the average congestion component as a percent of the total price during all congested and non-congested intervals.[22] Second, each section provides a more detailed assessment of the impact of congestion from individual constraints that are broken out to separately show the frequency and magnitude of impact *only during the congested intervals*.[23]

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

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

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

1.10.1 Congestion in the day-ahead market

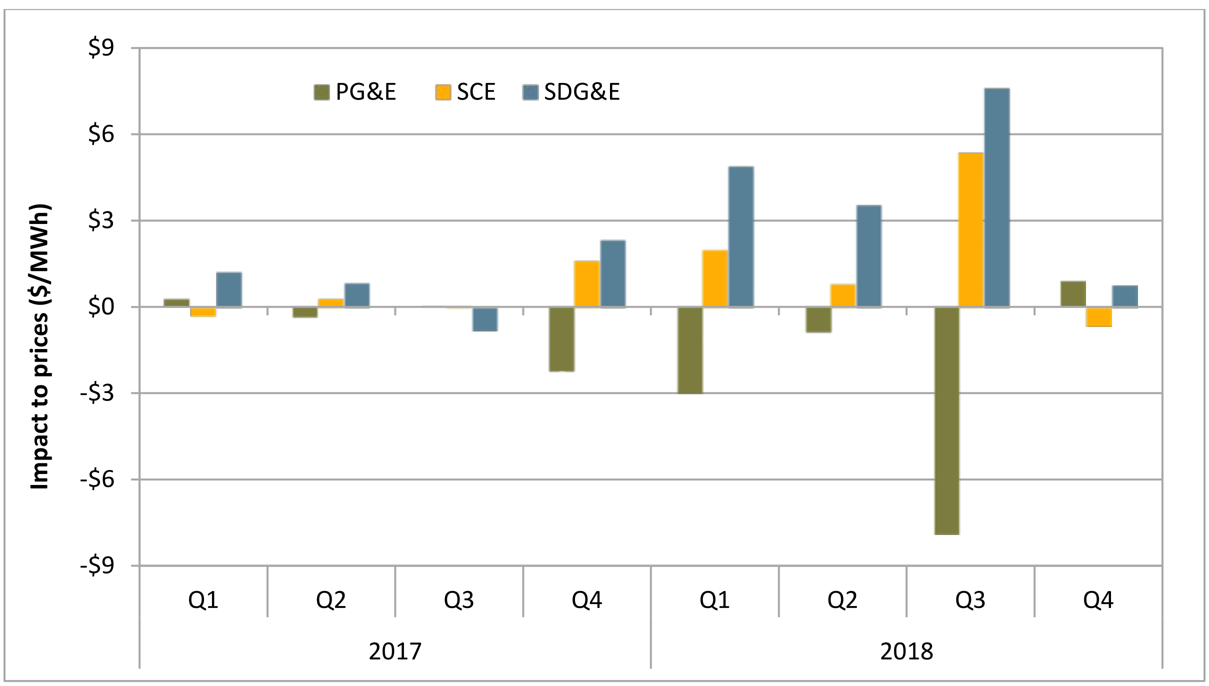
In the day-ahead market, congestion frequency is typically higher than in the 15-minute market, but price impacts tend to be lower. The congestion pattern in this quarter reflects this overall trend.

Impact of congestion to overall prices in each load area

Figure 1.20 shows the overall impact of congestion on day-ahead prices in each load area for each quarter in the last two years. Congestion this quarter had less of a net impact on prices than the previous quarters of 2018 and the fourth quarter of 2017.[24] The direction that congestion increased prices in this quarter also changed. Congestion increased prices in PG&E and SDG&E, and decreased prices in SCE. This was due to an increase in south-to-north congestion.

PG&E area prices increased almost $0.87/MWh (2 percent), compared to a decrease of $7.9/MWh (16 percent) in the previous quarter. In the SCE area, prices decreased $0.67/MWh (1 percent), compared to an increase of $5.34/MWh (8.5 percent) the previous quarter. In the SDG&E area, prices increased by $0.76/MWh (1.5 percent) compared to an increase of almost $8/MWh (11 percent) the previous quarter.

Figure 1.20 Impact of congestion on day-ahead prices



[24] Note that 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.

Table 1.3 breaks down the impact to prices in the fourth quarter by constraint.[25] The primary cause of overall price separation between the ISO areas was congestion on three constraints. The Tracy-Los Banos and Tesla-Tracy outages (OMS_6451207_TRACY-LOSBANOS), located within the PG&E service territory, increased overall prices in PG&E and decreased prices in SCE and SDG&E. Located in the SDG&E area, the Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) and Miguel nomogram (MIGUEL_BKs_MXFLW_NG) increased prices in SDG&E and had little impact to PG&E and SCE. More information regarding individual constraints is discussed below.

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

Table 1.3 Impact of congestion on overall day-ahead prices

Constraint Location	Constraint	PG&E		SCE		SDG&E	
		$ per MWh	Percent	$ per MWh	Percent	$ per MWh	Percent
PG&E	OMS_6451207_TRACY-LOSBANOS	$0.65	1.26%	-$0.47	-0.96%	-$0.43	-0.85%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	$0.06	0.12%	-$0.05	-0.10%	-$0.05	-0.09%
	6310_MWN_NRAS	$0.06	0.12%	-$0.05	-0.10%	-$0.04	-0.09%
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.05	0.10%	-$0.04	-0.07%	-$0.03	-0.07%
	30885_MUSTANGS_230_30900_GATES _230_BR_2 _1	$0.04	0.08%	-$0.03	-0.06%	-$0.03	-0.05%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.03	0.06%	-$0.03	-0.06%	-$0.03	-0.05%
	30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1	$0.03	0.06%	-$0.02	-0.05%	-$0.02	-0.04%
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	$0.02	0.05%	-$0.02	-0.04%	-$0.02	-0.03%
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	$0.01	0.02%	$0.00	-0.01%	$0.00	-0.01%
	OMS_5940391_GATES_MDWY	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.01%
	30875_MC CALL _230_34370_MC CALL _115_XF_3 _P	$0.01	0.01%	$0.00	-0.01%	$0.00	-0.01%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.02	-0.04%	$0.02	0.04%	$0.02	0.03%
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.02	-0.03%	$0.02	0.05%	$0.00	0.01%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	-$0.03	-0.05%	$0.02	0.05%	$0.11	0.21%
	24086_LUGO _500_24092_MIRALOMA_500_BR_2 _1	-$0.01	-0.02%	$0.01	0.02%	$0.01	0.02%
	24025_CHINO _230_24093_MIRALOM _230_BR_3 _1	-$0.01	-0.01%	$0.00	0.01%	$0.01	0.03%
	34150_NEWHALL _115_34154_DAIRYLND_115_BR_1 _1	$0.03	0.06%	$0.00	0.00%	$0.00	0.00%
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	$0.00	0.00%	$0.00	0.00%	-$0.07	-0.13%
	7750_D-SBLR_OOS_N1SV500_NG	$0.00	0.01%	$0.00	-0.01%	-$0.01	-0.03%
	7750_D-ECASCO_OOS_CP6_NG	$0.09	0.18%	-$0.07	-0.15%	-$0.03	-0.06%
SDG&E	7820_TL 230S_OVERLOAD_NG	-$0.07	-0.14%	$0.00	0.00%	$0.78	1.53%
	MIGUEL_BKs_MXFLW_NG	-$0.02	-0.05%	$0.00	0.00%	$0.43	0.84%
	OMS 6355729 TL50003_NG	-$0.01	-0.01%	$0.00	0.00%	$0.07	0.14%
	OMS 6355712 TL50003_NG	-$0.01	-0.01%	$0.00	0.00%	$0.06	0.12%
	OMS 6355725 TL50003_NG	-$0.01	-0.01%	$0.00	0.00%	$0.06	0.12%
	7820_TL23040_IV_SPS_NG	-$0.01	-0.01%	$0.00	0.00%	$0.06	0.12%
	OMS_6540737_50002_OOS_TDM	$0.00	0.00%	$0.00	0.00%	$0.04	0.08%
	OMS_6592932_TL23054_NG	$0.00	0.00%	$0.00	0.00%	$0.03	0.06%
	OMS_6458037_TL23054_NG	$0.00	0.00%	$0.00	0.00%	$0.03	0.06%
	OMS_6585368_TL23055_NG	$0.00	0.00%	$0.00	0.00%	$0.02	0.04%
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.01	-0.02%	$0.01	0.01%	$0.02	0.04%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.03	-0.06%
	IID-SCE_BG	$0.00	0.00%	$0.00	0.00%	-$0.27	-0.53%
Other	Other	$0.00	0.01%	$0.04	0.08%	$0.07	0.15%
Total	**Total**	**$0.87**	**1.70%**	**-$0.67**	**-1.36%**	**$0.76**	**1.50%**

Impact of congestion from individual constraints

Table 1.4 shows the impact of congestion from each constraint *only during congested intervals,* where the number of congested intervals is presented separately as frequency. Located in the PG&E area, the Tracy-Los Banos and Tesla-Tracy outages (OMS_6451207_TRACY-LOSBANOS) bound during about 10.5 percent of intervals. When binding, it increased PG&E prices by about $6/MWh and decreased prices in the SCE and SDG&E areas by about $4/MWh. Congestion from this nomogram occurred due to a planned outage of both the Tracy-Los Banos 500 kV line and Tesla-Tracy 500 kV line for the month of October.

Located in the SCE area, the Devers-El Casco nomogram (7750_D-ECASCO_OOS_CP6_NG) bound frequently, during 16 percent of hours. However, the impact to prices during these intervals was relatively low, and therefore the impact of this constraint on overall prices (shown above) was minor. This nomogram was activated and bound due to a planned outage on the Devers-El Casco 230 kV line that lasted for the majority of October and November.

In the SDG&E area, the Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) bound in 11.6 percent of intervals. When binding, it increased SDG&E prices by $6.75/MWh and had a relatively low impact on SCE and PG&E prices. This nomogram is enforced to protect the San Diego area in the event of a loss of the Imperial Valley – North Gila 500 kV line.

Also in the San Diego area, the Miguel nomogram (MIGUEL_BKs_MXFLW_NG) bound in 2.4 percent of intervals. Because its impact during those intervals was high relative to other constraints (increasing SDG&E prices by roughly $18/MWh), it had a greater overall impact on prices than some constraints that bound more frequently. This nomogram was activated and bound due to a planned outage of the Ocotillo-Suncrest 500 kV line in early November.

Table 1.4 Impact of congestion on day-ahead prices during congested hours[26]

Constraint Location	Constraint	Frequency	Q4		
		Q4	PG&E	SCE	SDG&E
PG&E	OMS_6451207_TRACY-LOSBANOS	10.5%	$6.13	-$4.44	-$4.11
	30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1	5.7%	$0.55	-$0.38	-$0.37
	30885_MUSTANGS_230_30900_GATES _230_BR_2 _1	3.9%	$1.00	-$0.68	-$0.66
	30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1	1.4%	$0.84	$0.00	$0.00
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	1.1%	$5.43	-$4.50	-$4.12
	6310_MWN_NRAS	1.1%	$5.41	-$4.33	-$4.00
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	1.0%	$1.25	-$0.86	-$0.86
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	1.0%	$4.96	-$3.66	-$3.39
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	1.0%	$3.34	-$2.90	-$2.72
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	0.8%	$2.82	-$2.30	-$2.11
	30875_MC CALL _230_34370_MC CALL _115_XF_3 _P	0.6%	$1.05	-$0.73	-$0.72
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	0.4%	-$5.12	$4.21	$3.98
	OMS_5940391_GATES_MDWY	0.4%	$2.29	-$1.82	-$1.68
SCE	7750_D-ECASCO_OOS_CP6_NG	16.2%	$0.56	-$0.53	-$0.89
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	10.6%	-$1.70	$1.60	$1.02
	7750_D-SBLR_OOS_N1SV500_NG	3.3%	$1.04	-$1.03	-$0.38
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	1.8%	$0.00	$0.00	-$3.76
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	1.4%	-$1.45	$1.64	$0.52
	34150_NEWHALL _115_34154_DAIRYLND_115_BR_1 _1	1.0%	$3.01	$0.00	$0.00
	24086_LUGO _500_24092_MIRALOMA_500_BR_2 _1	0.4%	-$2.98	$2.01	$2.54
	24025_CHINO _230_24093_MIRALOM _230_BR_3 _1	0.4%	-$1.92	$1.17	$3.57
SDG&E	7820_TL 230S_OVERLOAD_NG	11.6%	-$0.62	$0.00	$6.75
	IID-SCE_BG	3.1%	$0.00	$0.00	-$8.76
	MIGUEL_BKs_MXFLW_NG	2.4%	-$1.47	$0.00	$17.81
	7820_TL23040_IV_SPS_NG	1.8%	-$0.31	$0.00	$3.42
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	1.7%	$0.00	$0.00	-$1.70
	OMS 6355729 TL50003_NG	0.5%	-$1.28	$0.00	$13.00
	OMS 6355712 TL50003_NG	0.5%	-$1.17	$0.00	$12.46
	OMS 6355725 TL50003_NG	0.4%	-$1.45	$0.00	$14.96
	OMS_6540737_50002_OOS_TDM	0.4%	$0.00	$0.00	$11.89
	OMS_6458037_TL23054_NG	0.3%	-$0.66	$0.00	$9.62
	OMS_6592932_TL23054_NG	0.3%	-$0.70	$0.00	$10.16

1.10.2 Congestion in the 15-minute market

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

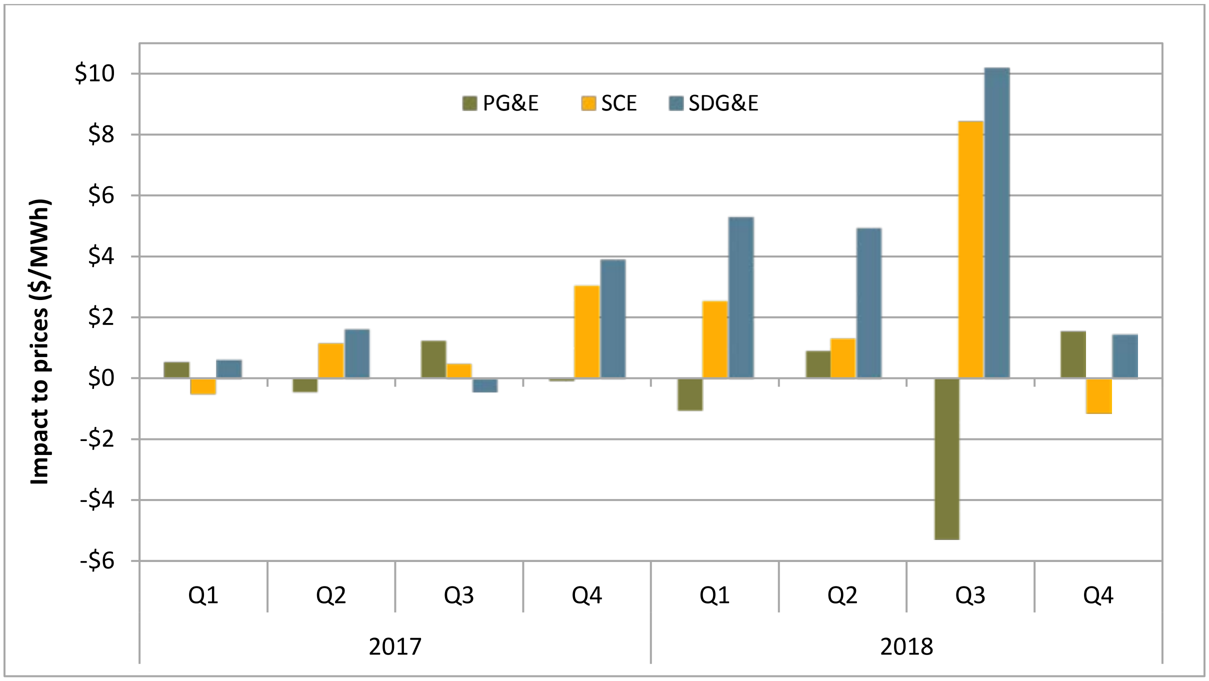
Impact of congestion to overall prices in each load area

Figure 1.21 shows the overall impact of congestion on 15-minute prices in each load area for each quarter in the last two years. Similar to the day-ahead market, congestion impacts on PG&E and SCE

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

changed in the fourth quarter. Congestion in the 15-minute market increased prices in PG&E and SDG&E, and decreased prices in SCE. There was less of a net impact from congestion in the fourth quarter compared to other quarters of 2018.

Figure 1.21 Impact of congestion on 15-minute prices



In the PG&E area, prices increased by about $1.5/MWh (3 percent) compared to a decrease of $5/MWh (13 percent) last quarter. In SCE, prices decreased by about $1/MWh (3 percent) compared to an increase of $8/MWh (16 percent) last quarter. SDG&E prices increased roughly $1.5/MWh (3 percent) compared to $10/MWh (18 percent) last quarter.

Table 1.5 breaks down the impact to prices in the fourth quarter by constraint.[27] Similar to the day-ahead market, the primary cause of overall price separation between the ISO areas was congestion on three constraints. Located within the PG&E service territory, the Tracy-Los Banos and Tesla-Tracy outages (OMS_6451207_TRACY-LOSBANOS) increased overall prices in PG&E and decreased prices in SCE and SDG&E. In the SDG&E area, the Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) and Miguel nomogram (MIGUEL_BKs_MXFLW_NG) increased prices in SDG&E and had little impact to PG&E and SCE.

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

Table 1.5 Impact of congestion on overall 15-minute prices

Constraint Location	Constraint	PG&E		SCE		SDG&E	
		$ per MWh	Percent	$ per MWh	Percent	$ per MWh	Percent
PG&E	OMS_6451207_TRACY-LOSBANOS	$0.62	1.29%	-2.64%	-2.64%	-$1.09	-2.35%
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	$0.14	0.30%	$0.00	0.00%	$0.00	0.00%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	$0.08	0.16%	-$0.10	-0.22%	-$0.09	-0.20%
	30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1	$0.06	0.13%	-$0.04	-0.08%	-$0.04	-0.08%
	30885_MUSTANGS_230_30900_GATES _230_BR_2 _1	$0.05	0.10%	-$0.03	-0.07%	-$0.03	-0.06%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.04	0.09%	-$0.07	-0.16%	-$0.07	-0.14%
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	$0.04	0.08%	-$0.08	-0.18%	-$0.08	-0.16%
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.03	0.07%	-$0.05	-0.12%	-$0.05	-0.10%
	6310_MWN_NRAS	$0.02	0.03%	-$0.02	-0.05%	-$0.02	-0.05%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.02	-0.03%	$0.02	0.04%	$0.02	0.04%
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.01	-0.02%	$0.21	0.47%	$0.17	0.36%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.09	0.19%	$0.12	0.28%	$0.11	0.23%
	OP-6610_ELD-LUGO	$0.04	0.07%	$0.05	0.11%	$0.02	0.04%
	24156_VINCENT _500_24155_VINCENT _230_XF_4 _P	-$0.02	-0.05%	$0.04	0.10%	$0.03	0.06%
	6410_CP5_NG	-$0.03	-0.06%	$0.03	0.07%	$0.03	0.06%
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	$0.00	0.00%	$0.03	0.07%	$0.03	0.06%
	OMS 6414477_OP-6610	$0.03	0.07%	$0.03	0.06%	$0.00	0.00%
	24025_CHINO _230_24093_MIRALOM _230_BR_3 _1	-$0.01	-0.01%	$0.01	0.03%	$0.03	0.06%
	22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.06	-0.12%
	7750_D-ECASCO_OOS_CP6_NG	$0.22	0.46%	-$0.18	-0.40%	$0.00	-0.01%
SDG&E	MIGUEL_BKs_MXFLW_NG	$0.00	0.00%	$0.00	0.00%	$1.34	2.88%
	7820_TL 230S_OVERLOAD_NG	$0.00	0.00%	$0.02	0.05%	$0.32	0.69%
	OMS 6355729 TL50003_NG	$0.00	0.00%	$0.01	0.02%	$0.19	0.40%
	OMS_6458037_TL23054_NG	$0.00	0.00%	$0.00	0.00%	$0.12	0.27%
	OMS 6355725 TL50003_NG	$0.00	0.00%	$0.01	0.01%	$0.11	0.24%
	7820_TL23040_IV_SPS_NG	$0.00	0.00%	$0.00	0.00%	$0.11	0.24%
	OMS 6191454 TL50003_NG	$0.00	0.00%	$0.01	0.01%	$0.11	0.23%
	OMS_6454908_TL23054_NG	$0.00	0.00%	$0.00	0.00%	$0.07	0.15%
	OMS_6441401_TL23054_NG	$0.00	0.00%	$0.00	0.00%	$0.07	0.15%
	OMS 6355712 TL50003_NG	$0.00	0.00%	$0.00	0.01%	$0.06	0.14%
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	$0.00	0.00%	$0.00	0.00%	$0.06	0.13%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.07	-0.15%
	Other	$0.16	0.33%	-$0.01	-0.02%	$0.07	0.14%
	Total	**$1.53**	**3.21%**	**-$1.14**	**-2.61%**	**$1.47**	**3.15%**

Impact of congestion from individual constraints

Table 1.6 shows the impact of congestion from each constraint *only during congested intervals,* where the number of congested intervals is presented separately as frequency. Located in the PG&E area, the constraint used to manage the Tracy-Los Banos and Tesla-Tracy outages (OMS_6451207_TRACY-LOSBANOS) bound during about 8.5 percent of intervals. When binding, it increased PG&E prices by about $7/MWh and decreased prices in the SCE and SDG&E areas by about $13/MWh.

Located in the SCE area, the Devers-El Casco nomogram (7750_D-ECASCO_OOS_CP6_NG) bound frequently, during 8 percent of hours. When binding, it increased PG&E prices by $3/MWh and decreased prices in SCE and SDG&E by roughly $2/MWh. Congestion on this constraint was related to a planned outage on the Devers-El Casco 230 kV line that lasted the majority of October and November.

Also located in the SCE area, congestion on the Barre Villa Park 500 kV line (24016_BARRE _230_24154_VILLA PK_230_BR_1 _1) bound only during 0.8 percent of intervals. However, when binding, it decreased PG&E prices by roughly $23/MWh and increased SCE and SDG&E prices by $27/MWh and $22/MWh, respectively. This constraint likely bound due to the constraint being conformed in order to prevent thermal overloading in the Orange County area.

In the San Diego area, the Miguel nomogram (MIGUEL_BKs_MXFLW_NG) bound in 2.2 percent of intervals. Its impact to SDG&E prices during those intervals was high relative to other constraints (increasing SDG&E prices by roughly $60/MWh), and therefore had a greater overall impact on prices than some constraints that bound more frequently.

Table 1.6 Impact of congestion on 15-minute prices in the ISO during congested intervals[28]

Constraint Location	Constraint	Frequency	Q4		
		Q4	PG&E	SCE	SDG&E
PG&E	OMS_6451207_TRACY-LOSBANOS	8.4%	$7.31	-$13.69	-$12.99
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	1.6%	$9.11	$0.00	$0.00
	30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1	1.4%	$4.57	-$2.64	-$2.56
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	0.9%	$4.73	-$9.30	-$8.89
	30885_MUSTANGS_230_30900_GATES _230_BR_2 _1	0.8%	$5.84	-$3.42	-$3.30
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.5%	$13.87	-$17.83	-$16.72
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	0.5%	$6.28	-$9.34	-$8.90
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	0.5%	$8.66	-$13.76	-$13.04
	6310_MWN_NRAS	0.3%	$4.90	-$7.62	-$7.21
SCE	7750_D-ECASCO_OOS_CP6_NG	8.0%	$2.72	-$2.35	-$1.77
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	1.9%	$4.71	$6.54	$6.21
	OP-6610_ELD-LUGO	0.9%	$3.76	$5.10	$2.09
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.8%	-$22.66	$27.17	$21.80
	OMS 6414477_OP-6610	0.5%	$6.07	$4.95	$0.57
SDG&E	MIGUEL_BKs_MXFLW_NG	2.2%	$0.00	$0.00	$60.45
	7820_TL 230S_OVERLOAD_NG	1.4%	$0.00	$1.62	$23.47
	7820_TL23040_IV_SPS_NG	1.1%	$0.00	$0.00	$9.92
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	0.8%	$0.00	$0.00	-$9.30
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	0.4%	$0.00	$0.00	$14.34

1.10.3 Congestion in the energy imbalance market

Impact of congestion from individual constraints

Table 1.6 shows the impact on prices of congestion from each constraint *only during congested intervals,* where the congested intervals are presented as frequency. Congestion on constraints within

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

the ISO tends to decrease prices in the energy imbalance market, particularly in the north. However, during this quarter, congestion on many constraints within the ISO had the opposite impact, increasing prices in the north.

For most of the year, prices are usually lower in the north when the availability of relatively low-cost hydroelectric resources are unable to reach ISO areas when transmission limits bind. During the fourth quarter, however, hydroelectric resource availability is at its lowest point. Low-cost solar and wind resources from Southern California move north, creating higher flows in the south-to-north direction. Outages, such as those on the Tracy-Los Banos and Tesla-Tracy 500 kV lines (OMS_6451207_TRACY-LOSBANOS), further constrain movement and thus often contribute to price separation.

This quarter, congestion on constraints located between the Pacific Northwest and Southern California (i.e., in the PG&E service territory) increased prices for PacifiCorp West, Puget Sound Energy, Portland General Electric, Powerex, and Idaho Power. For balancing authorities with greater transmission capacity into Southern California, such as NV Energy and Arizona Public Service, congestion from these constraints resulted in lower prices.

Table 1.7 Impact of congestion on 15-minute prices in EIM during congested intervals[29]

Constraint Location	Constraint	Freq.	Q4							
			PACE	PACW	NEVP	PSEI	AZPS	PGE	PWRX	IPCO
NEVP	CAL-WSS__106	0.6%	$0.00	$0.00	-$19.63	$0.00	$0.00	$0.00	$0.00	$0.00
	NTR-CAL__101	0.4%	$0.00	$0.00	-$17.99	$0.00	$0.00	$0.00	$0.00	$0.00
PACE	WYOMING_EXPORT	32.8%	-$1.13	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PG&E	OMS_6451207_TRACY-LOSBANOS	8.4%	-$2.37	$11.95	-$7.49	$11.58	-$11.71	$11.96	$5.35	$5.35
	30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1	1.4%	-$0.85	$0.00	-$1.84	$0.00	-$2.41	$0.00	$0.00	$0.00
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	0.9%	-$0.49	$6.48	-$5.34	$6.24	-$8.05	$6.45	$2.66	$2.66
	30885_MUSTANGS_230_30900_GATES _230_BR_2 _1	0.8%	$0.00	$0.00	-$2.16	$0.00	-$3.07	$0.00	$0.00	$0.00
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.5%	-$4.69	$9.41	-$10.99	$8.82	-$15.34	$9.36	$2.05	$2.05
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	0.5%	$0.00	$7.21	-$5.07	$6.99	-$8.04	$7.21	$3.25	$3.25
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	0.5%	-$2.28	$7.25	-$7.63	$6.83	-$11.75	$7.16	$2.75	$2.75
	6310_MWN_NRAS	0.3%	-$1.07	$4.70	-$3.87	$4.45	-$6.46	$4.63	$1.96	$1.96
SCE	7750_D-ECASCO_OOS_CP6_NG	8.1%	-$2.29	$1.54	-$2.41	$1.48	-$8.35	$1.50	-$0.81	-$0.81
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	1.9%	-$9.20	$1.62	-$16.08	$1.56	-$14.93	$1.56	-$4.47	-$4.47
	OP-6610_ELD-LUGO	0.9%	-$6.50	$0.00	-$12.86	$0.00	-$10.17	$0.00	-$2.46	-$2.46
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.8%	-$9.82	-$9.84	-$11.03	-$9.89	-$10.45	-$10.00	-$9.74	-$9.74
	7750_D-SBLR_OOS_N1SV500_NG	0.7%	-$1.54	$0.00	-$1.38	$0.00	-$6.19	$0.00	$0.00	$0.00
	OMS 6414477_OP-6610	0.5%	-$9.49	$0.00	-$17.30	$0.00	-$14.60	$0.00	-$4.64	-$4.64
SDG&E	MIGUEL_BKs_MXFLW_NG	2.2%	-$10.15	$0.00	-$8.22	$0.00	-$22.80	$0.00	$0.00	$0.00
	7820_TL 230S_OVERLOAD_NG	1.4%	-$2.34	-$0.66	-$2.02	-$0.69	-$5.80	-$0.68	-$1.50	-$1.50
	7820_TL23040_IV_SPS_NG	1.1%	-$0.78	$0.00	-$0.71	$0.00	-$1.87	$0.00	-$0.54	-$0.54
	7750_D-VISTA1_OOS_CP6_NG	0.4%	-$2.49	$1.86	$0.00	$1.58	-$7.96	$1.85	$0.00	$0.00
	22468_MIGUEL _500_22472_MIGUELMP_1.0_XF_80	0.4%	$0.00	$0.00	$0.00	$0.00	-$4.71	$0.00	$0.00	$0.00

Congestion on energy imbalance market internal constraints

Table 1.8 shows the frequency of congestion on internal constraints in the energy imbalance market since 2014. Overall, congestion on internal EIM constraints increased compared to the previous quarter. Internal congestion in PacifiCorp East increased nearly threefold compared to the previous quarter, though decreased compared to the same quarter of 2017. This congestion was primarily a result of a single constraint (WYOMING_EXPORT, also seen in the table above) binding during about 33 percent of

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

intervals in the 15-minute market. In the PacifiCorp West, Arizona Public Service, NV Energy, and Idaho Power areas, the frequency of binding internal constraints also increased compared to the previous quarters in both the 15-minute and 5-minute markets.

Persistent low congestion in some of the balancing authority areas may be a result of the following:

- Each energy imbalance market area may be incorporating some degree of congestion management in their process when making forward unit commitments and developing base schedules.
- Bids may be structured in such a way as to limit or prevent congestion within an energy imbalance market area.
- Within the PacifiCorp areas, physical limits on some local constraints, which are modeled in the full network model, may not be fully reflective of contractual limits that may be enforced through generating base schedules and the amount offered from some resources.

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

Table 1.8 Percent of intervals with congestion on internal EIM constraints

	2014	2015	2016	2017				2018			
				Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
15-minute market (FMM)											
PacifiCorp East	0.1%	0.9%	1.2%	16.1%	4.3%	5.1%	47.6%	14.9%	4.5%	9.1%	33.1%
PacifiCorp West	0.1%	0.1%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.6%
NV Energy		0.0%	0.1%	10.3%	1.8%	7.6%	5.8%	0.5%	0.9%	1.1%	2.6%
Puget Sound Energy				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Arizona Public Service				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	1.9%
Portland General Electric							0.0%	0.0%	0.0%	0.0%	0.0%
Powerex									0.0%	0.0%	0.0%
Idaho Power									0.0%	0.0%	0.2%
5-minute market (RTD)											
PacifiCorp East	0.0%	0.8%	1.2%	17.1%	3.3%	4.5%	46.1%	14.7%	3.9%	8.5%	29.2%
PacifiCorp West	0.1%	0.0%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%
NV Energy		0.0%	0.1%	11.7%	1.6%	7.1%	5.6%	0.4%	0.9%	0.7%	1.9%
Puget Sound Energy				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Arizona Public Service				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%
Portland General Electric							0.0%	0.0%	0.0%	0.0%	0.0%
Powerex									0.0%	0.0%	0.0%
Idaho Power									0.0%	0.0%	0.2%

1.11 Market adjustments

Given the complexity of market models and systems, all ISOs make some adjustments to the inputs and outputs of their standard market models and processes.[30] Market model inputs – such as transmission limits – may sometimes be modified to account for potential differences between modeled power flows and actual real-time power flows. Load forecasts may be adjusted to account for potential differences in modeled versus actual demand and supply conditions, including uninstructed deviations by generation resources.

In this section, DMM reviews the frequency of, and reasons for, a variety of key market adjustments, including exceptional dispatches, modeled load adjustments, blocked dispatch instructions, blocked pricing runs in the real-time market, and residual unit commitment adjustments. Over the last few years, the ISO has placed a priority on reducing various market adjustments and continues to work toward reducing market adjustments going forward. In the fourth quarter, the use of many key market adjustments decreased slightly relative to the third quarter, but remained relatively high.

1.11.1 Load forecast adjustments

Operators in the ISO and energy imbalance market can manually modify load forecasts used in the market through a load adjustment. Load adjustments are also sometimes referred to as *load bias* or *load conformance*. Recently, the ISO has begun using the term *imbalance conformance* to describe these adjustments.

Load forecast adjustments are used to account for potential modeling inconsistencies and inaccuracies. Specifically, operators listed multiple reasons for use of load adjustments including managing load and generation deviations, automatic time error corrections, scheduled interchange variations, reliability events, and software issues.[31] DMM will continue to use the terms load forecast adjustment and load bias limiter for consistency with prior reports.

The dramatic increase in load forecast adjustments in the ISO's hour-ahead and 15-minute markets in 2017 for the steep morning and evening net load ramp periods appears to have slightly decreased in the fourth quarter of 2018. In general, the 5-minute market load forecast adjustments slightly increased throughout the day when comparing the fourth quarter of 2018 with the same period in 2017. Figure 1.22 shows the average hourly load adjustment profile for the hour-ahead, 15-minute and 5-minute markets for the fourth quarter in 2018 and 2017. The general shape and direction of load adjustments were similar for hour-ahead, 15-minute and 5-minute market adjustments.

Load adjustments in the hour-ahead and 15-minute markets are very similar to each other throughout the day. But, like the previous year, the 5-minute market adjustments differ dramatically from other markets for nearly all hours of the day. Load adjustments in the 5-minute market, on average for the quarter, follow a similar pattern compared with the same period in 2017. However, this pattern is

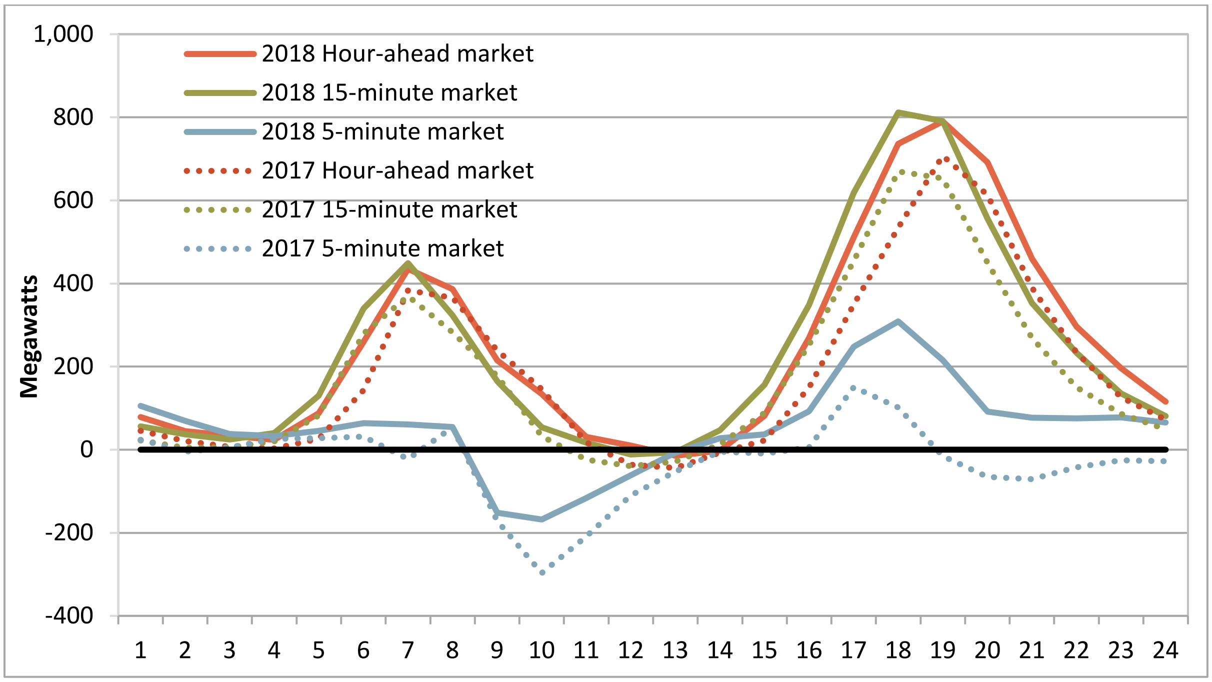
[30] At the California ISO, these adjustments are sometimes made manually based entirely on the judgment of operators. Other adjustments are made in a more automated manner using special tools developed to aid ISO operators.

[31] 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

typically more pronounced in the ramping periods, with more negative bias during the morning ramp and greater positive bias during the afternoon ramp.

The largest negative deviations between the 5-minute and other markets were observed in the evening ramping period, hours ending 18 to 21 when the hour-ahead adjustments exceeded the 5-minute adjustments by around 430 MW, 570 MW, 600 MW and 380 MW, respectively. The morning ramping period also experienced large negative deviations between the 5-minute and other markets in hours ending 7, 8 and 9 with hour-ahead adjustments exceeded the 5-minute adjustments by around 370 MW, 330 MW and 370 MW respectively. Both positive and negative adjustments are often associated with over-forecasted load, changes in expected renewable generation as well as morning or evening net load ramp.

Figure 1.22 Average hourly load adjustment (Q4 2018 – Q4 2017)

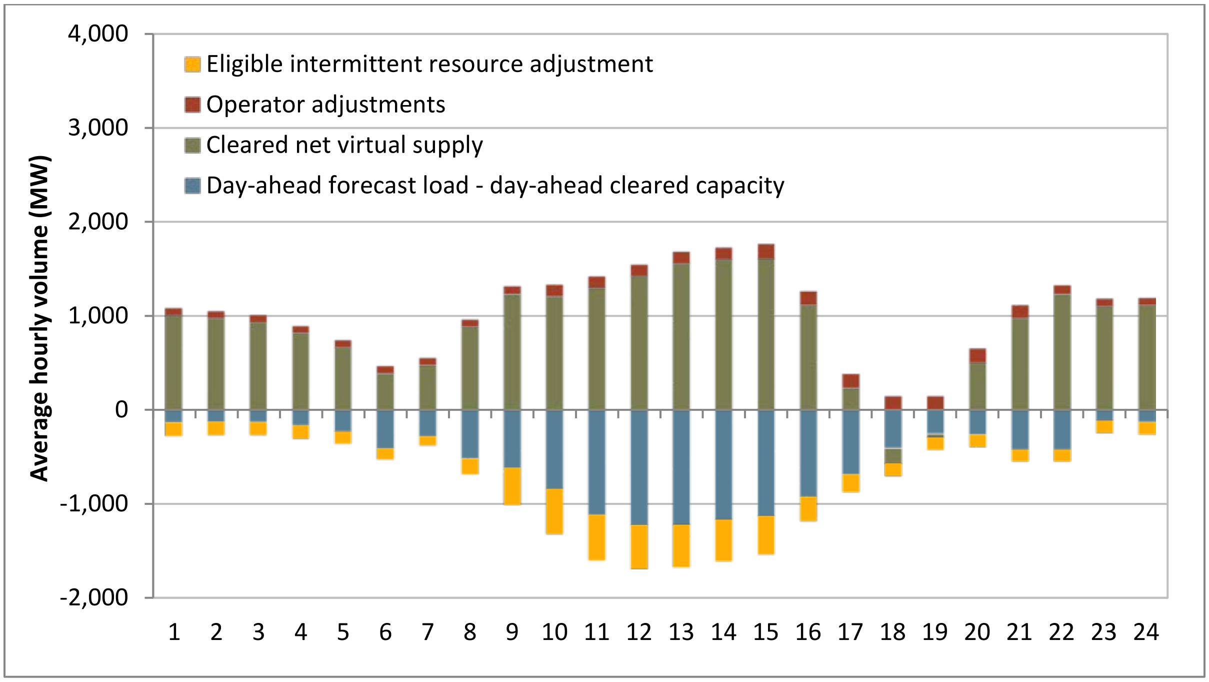


1.11.2 Residual unit commitment adjustments

As noted in Section 1.5, the purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real time. The residual unit commitment market is run immediately after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of load cleared in the day-ahead market and the day-ahead forecast load. ISO operators are able to increase residual unit commitment requirements for reliability purposes. Frequency of these adjustments declined significantly in the fourth quarter of 2018.

Figure 1.23 illustrates the average hourly determinants of residual unit commitment procurement. Operator adjustments were concentrated in the peak load hours of the day, peaking in hours ending 10 through 21. While adjustments were low in the off-peak hours, cleared net virtual supply was the major driver of residual unit commitment procurement in these periods. On average, day-ahead cleared capacity was greater than day-ahead load forecast during all hours in the fourth quarter. Intermittent resource adjustments were greatest during hours ending 9 through 17.

Figure 1.23 Average hourly determinants of residual unit commitment procurement (Oct – Dec)



1.11.3 Exceptional dispatch

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

Exceptional dispatches can be grouped into three distinct categories:

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

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

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

Summary of exceptional dispatch

Energy from exceptional dispatch continued to account for a relatively low portion of total system loads. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 0.10 percent of system load in the fourth quarter.

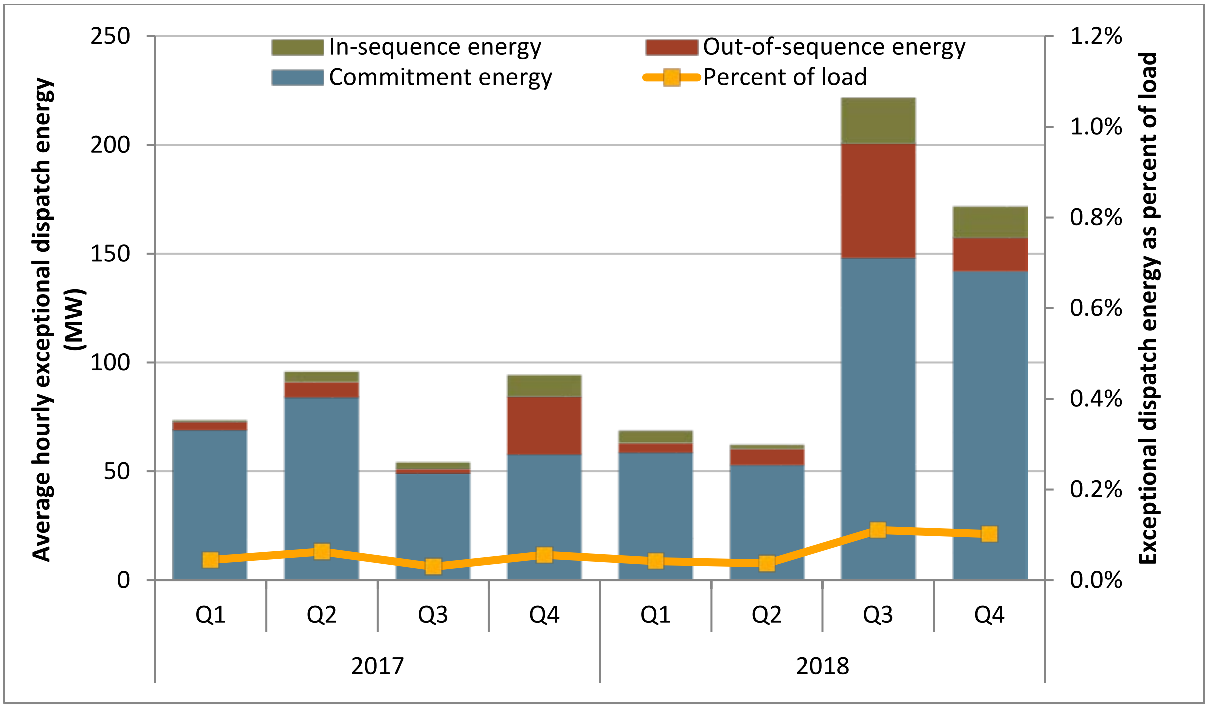
Total energy resulting from all types of exceptional dispatch increased by 80 percent in the fourth quarter of 2018 compared to the same quarter in 2017, as shown in Figure 1.24.[32] Exceptional dispatch energy from commitment energy accounted for over 80 percent of all exceptional dispatch energy this quarter. About 9 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 8 percent was from in-sequence energy. Exceptional dispatches for commitment energy were particularly high in the fourth quarter, largely due to load forecast uncertainty.

Although exceptional dispatches are priced and paid outside of the market, they can affect the market clearing price for energy. Energy resulting from exceptional dispatch effectively reduces the remaining load to be met by other supply. This can reduce market prices relative to a case where no exceptional dispatch was made. However, most exceptional dispatches appear to be made to resolve specific constraints that would make energy from these exceptional dispatches ineligible to set the market price for energy if these constraints were incorporated in the market model.

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

[32] 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 1.24 Average hourly energy from exceptional dispatch

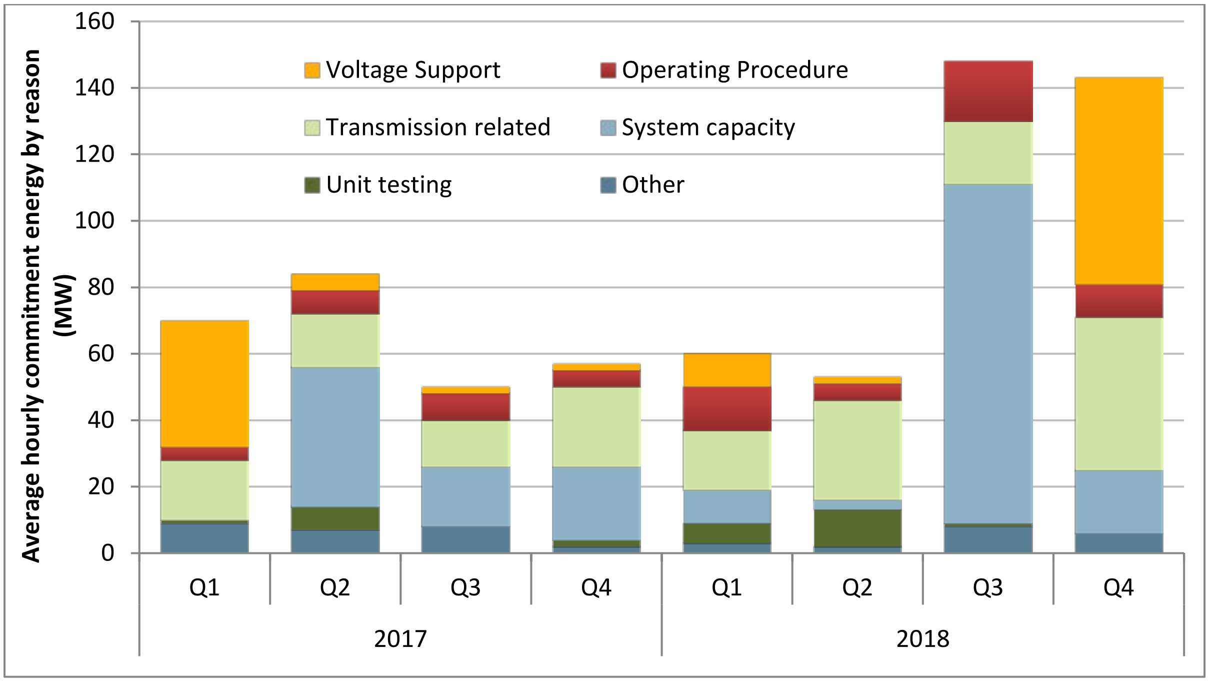


Exceptional dispatches for unit commitment

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

Minimum load energy from exceptional dispatch unit commitments in the fourth quarter was nearly 2.5 times higher than the fourth quarter of 2017. Elevated levels of exceptional dispatch unit commitment were driven by an increase in voltage support exceptional dispatches.

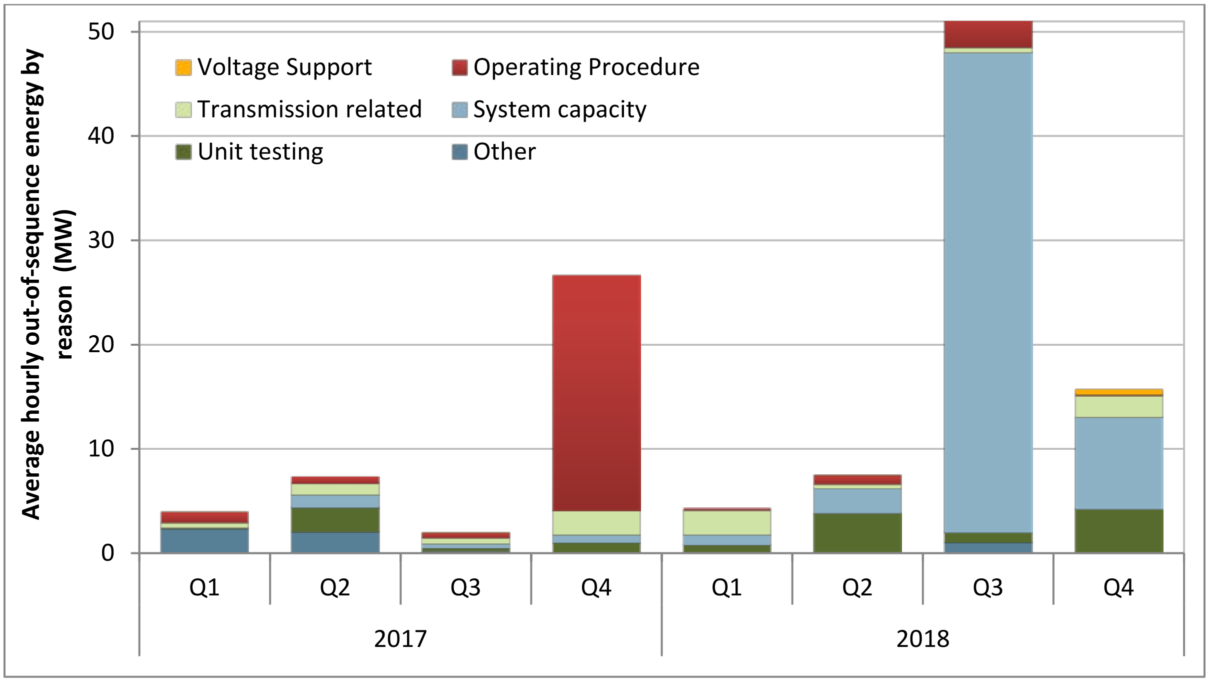
Figure 1.25 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch decreased by nearly half in the fourth quarter 2018 compared to the same quarter in 2017. As previously illustrated in Figure 1.24, about 50 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 1.26 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2017 and 2018. Most of the out-of-sequence energy in the fourth quarter was exceptionally dispatched for system capacity.

Figure 1.26 Out-of-sequence exceptional dispatch energy by reason



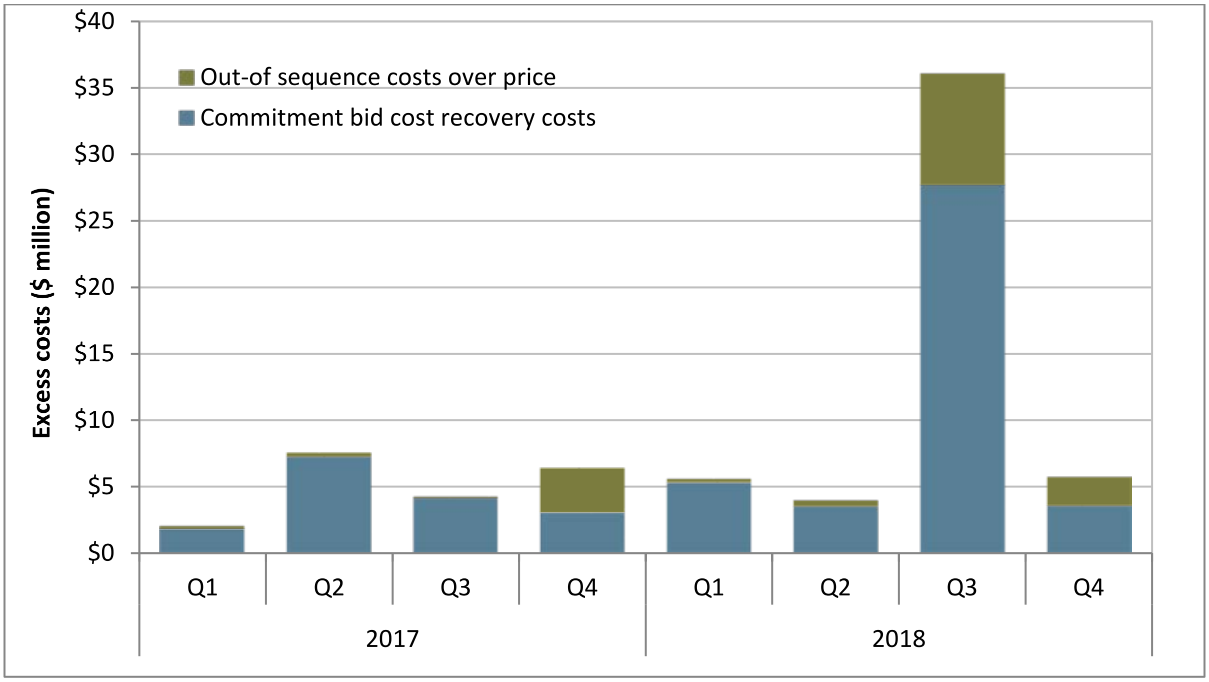
Exceptional dispatch costs

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 1.27 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 $2.1 million, while commitment costs for exceptional dispatch paid through bid cost recovery were $3.6 million.

Figure 1.27 Excess exceptional dispatch cost by type



1.12 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.

The owners of transmission, or entities paying for the cost of building and maintaining transmission, are entitled to congestion revenues associated with transmission capacity in the day-ahead market. In the ISO, most transmission is paid for by ratepayers of the state's investor-owned utilities and other load-serving entities through the transmission access charge (TAC).[33] The ISO charges utility distribution companies the transmission access charge in order to reimburse the entity that builds each transmission line for the costs incurred.

Utility distribution companies then pass that transmission access charge through to ratepayers in their customers' electricity bills. Therefore, these ratepayers are entitled to the revenues from this transmission. When auction revenues are less than payments to other entities purchasing congestion revenue rights at auction, the difference between auction revenues and congestion payments

[33] 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.

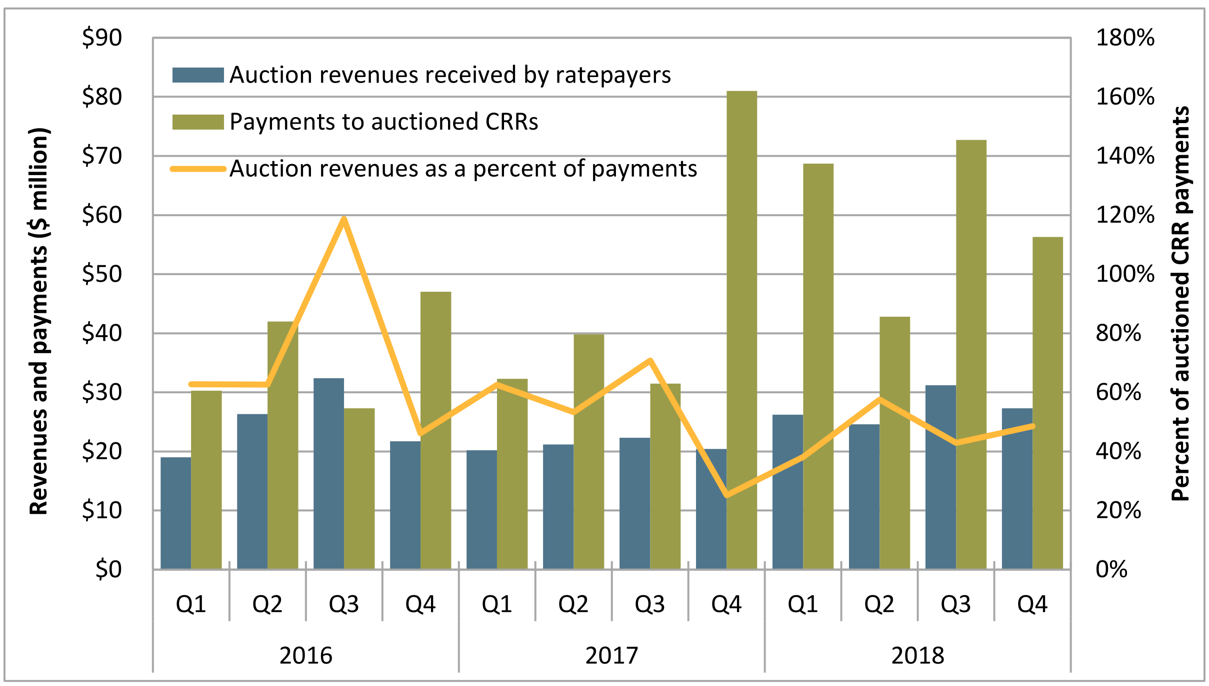
represents a loss to ratepayers. The losses cause ratepayers, who ultimately pay for the transmission, to receive less than the full value of their day-ahead transmission rights.

Analysis of congestion revenue right auction returns

Ratepayers lost about $29 million during the fourth quarter of 2018 as payments to auctioned congestion revenue rights holders exceeded auction revenues. This brings total losses to transmission ratepayers from congestion revenue rights sold in the ISO's auction to over $131 million in 2018. Auction revenues were 48 percent of payments made to non-load-serving entities during the fourth quarter of 2018, up significantly from 25 percent during the same quarter in 2017.

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 million. This was a substantial decrease from $40 million profits during the fourth quarter of 2017. Profits by energy marketers totaled over $9 million, down from the over $12 million during the same quarter in 2017. Generators gained nearly $5 million compared to $8 million in the fourth quarter of 2017.

Figure 1.28 Auction revenues and payments to non-load-serving entities



Congestion revenue rights auction modifications

DMM believes that the trend of revenues being transferred from electric ratepayers to other entities warrants reassessing the standard electricity market design assumption that ISOs should auction off these financial instruments on behalf of ratepayers after the congestion revenue right allocations.[34]

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

DMM believes the current auction is unnecessary and could be eliminated.[35] If the ISO believes it is beneficial to the market to facilitate hedging, DMM believes the current auction format should be changed to a market for congestion revenue rights or locational price swaps based on bids submitted by entities willing to buy or sell congestion revenue rights or price swaps.

On March 22, 2018, the Board of Governors approved policy changes that reduce the number and pairs of nodes at which congestion revenue rights can be purchased in the auction (Track 1A). The changes also require transmission owners to submit planned outages prior to the annual allocation and auction processes. These tariff changes were approved by FERC on June 29, 2018, and were implemented in time for the 2019 annual allocation and auction processes.

A second set of changes (Track 1B) was approved by the Board of Governors on June 22, 2018.[36] FERC issued an order on September 20, 2018, accepting a part of the Track 1B proposal to decrease the percentage of system capacity available in the annual congestion revenue rights allocation and auction processes from 75 percent to 65 percent. FERC issued an order on November 9, 2018, accepting a second part of the Track 1B proposal to reduce the net payment to a congestion revenue right holder if payments to congestion revenue rights exceed associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis. [37] The Track 1A and 1B changes were implemented for the 2019 congestion revenue right auctions.

In combination with the ISO's Track 1A changes, these additional changes will provide a measure of protection against the risks imposed on transmission ratepayers by the current auction design and will likely reduce the current level of ratepayer losses. DMM supported both initiatives as incremental improvements, but continues to recommend that the auction process be replaced by a market for financial hedges based on clearing of bids from willing buyers and sellers.[38]

Of the over $131 million total losses to transmission ratepayers from congestion revenue rights auctioned in 2018, $54 million were associated with pairs of nodes that the ISO continues to auction in 2019. These pairs accounted for 41 percent of total ratepayer losses in 2018, an increase from 39 percent in 2017 and 35 percent in 2016.

1.13 Flexible ramping product

Background

The *flexible ramping product* is designed to enhance reliability and market performance by procuring flexible ramping capacity in the real-time market to help manage volatility and uncertainty of real-time

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

36 DMM presentation on *Potential Market Alternatives to the CRR Auction*, April 10, 2018: http://www.caiso.com/Documents/Presentation-RogerAvalosDMM-Apr102018.pdf

37 *FERC Order on Tariff Amendment - Congestion Revenue Rights Auction Efficiency Track 1B,* September 20, 2018*:* https://www.ferc.gov/CalendarFiles/20180920172657-ER18-2034-000.pdf?csrt=1015546819097727752
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

38 *DMM comments on congestion revenue rights auction efficiency track 1 B*, June 21, 2018: http://www.caiso.com/Documents/DecisiononCongestionRevenueRightsAuctionEfficiencyTrack1BProposal-DMMComments-Jun2018.pdf

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 runs and the three 5-minute market runs with that 15-minute interval. Procurement in the 5-minute market is aimed at ensuring that enough ramping capacity is available to manage differences between consecutive 5-minute market intervals.

Market outcomes for flexible ramping product

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

Figure 1.29 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 a slight increase in binding shadow prices, but these remained infrequent overall in both directions. The 15-minute market system-level demand curves bound in around 6 percent of intervals in the upward direction and never in the downward direction during the quarter.

Figure 1.29 Monthly frequency of positive 15-minute market flexible ramping shadow price

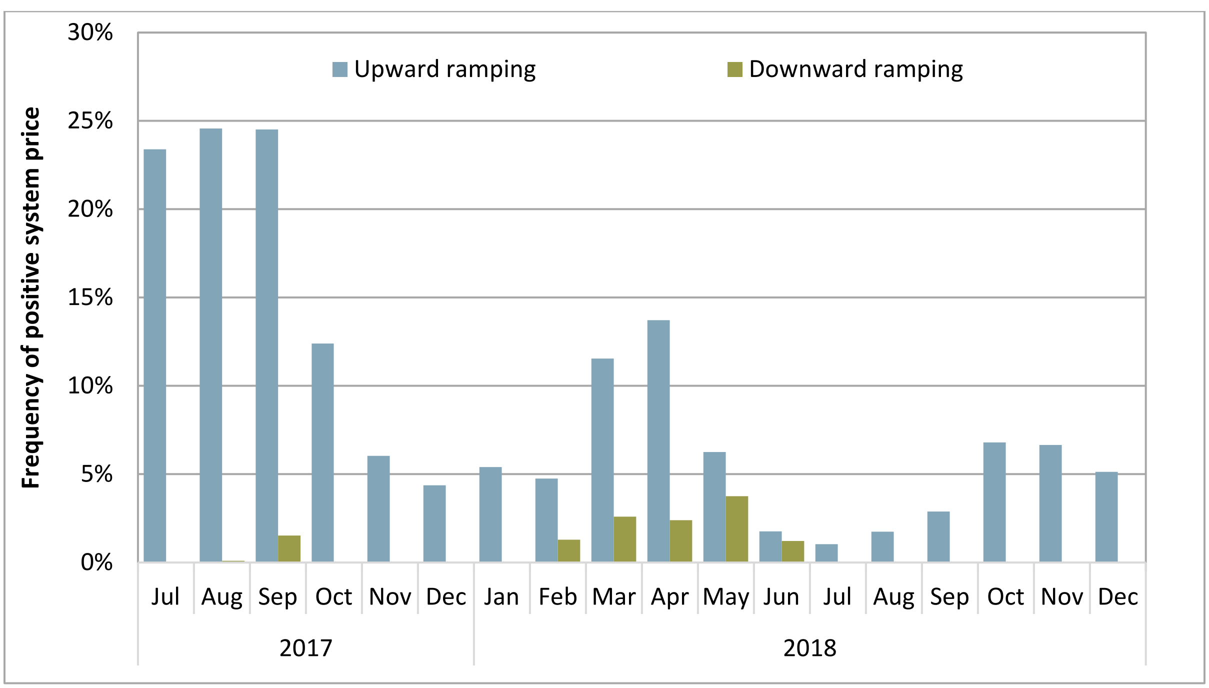
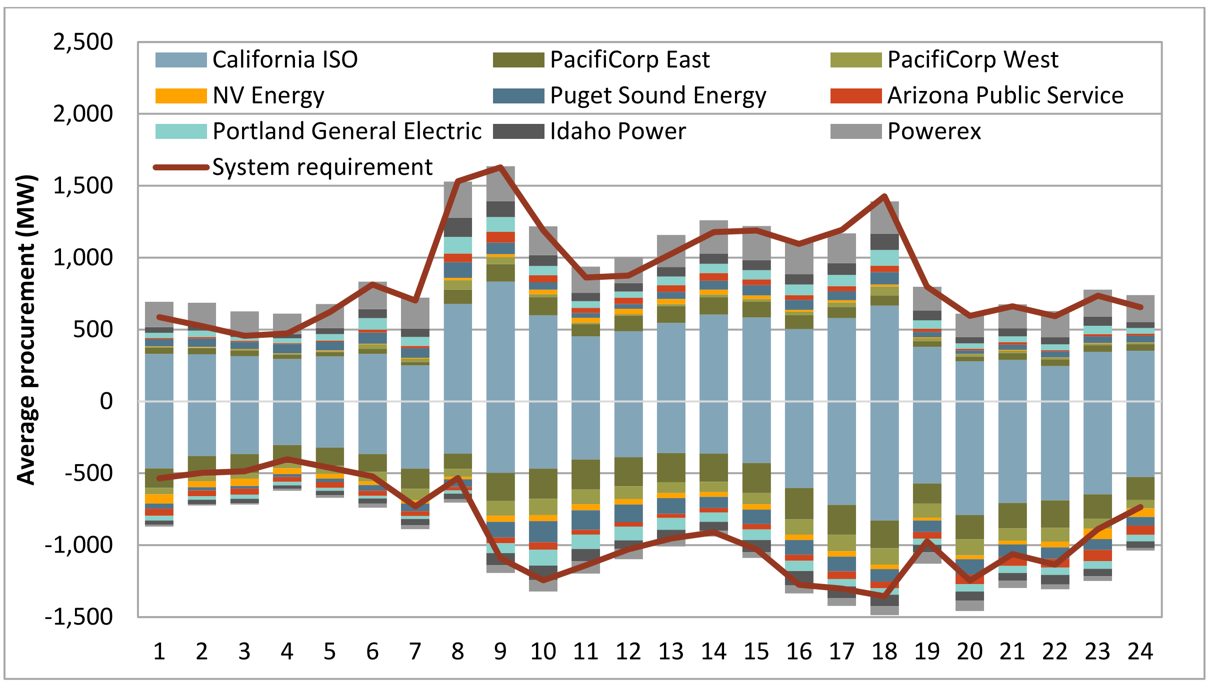


Figure 1.30 shows the hourly average amount of flexible ramping capacity procured in the 15-minute market during the fourth quarter. This capacity may have been procured to satisfy system-level demand, area-specific demand, or both. The positive bars show procurement for upward flexible ramping capacity, and the negative bars show procurement for downward flexible ramping capacity. The hourly procurement profile is very similar to the profile of the system-level demand curves, and reflects that most of the flexible ramping capacity was procured to meet system-level uncertainty needs.

Overall, the market procured an hourly average of about 950 MW of upward capacity and 1,060 MW of downward capacity in the 15-minute market during the fourth quarter. Compared to the fourth quarter of 2017, this represents a slight increase in upward and downward capacity. The total hourly average quantity of flexible ramping capacity procured in the 5-minute market was roughly 300 MW in both the upward and downward directions. Around 50 percent of upward ramping capacity in both markets was procured in the ISO during the fourth quarter. Similarly, roughly 45 percent of downward ramping capacity in both markets was procured in the ISO.

Figure 1.30 Hourly average flexible ramping capacity procurement in 15-minute market (October – December)



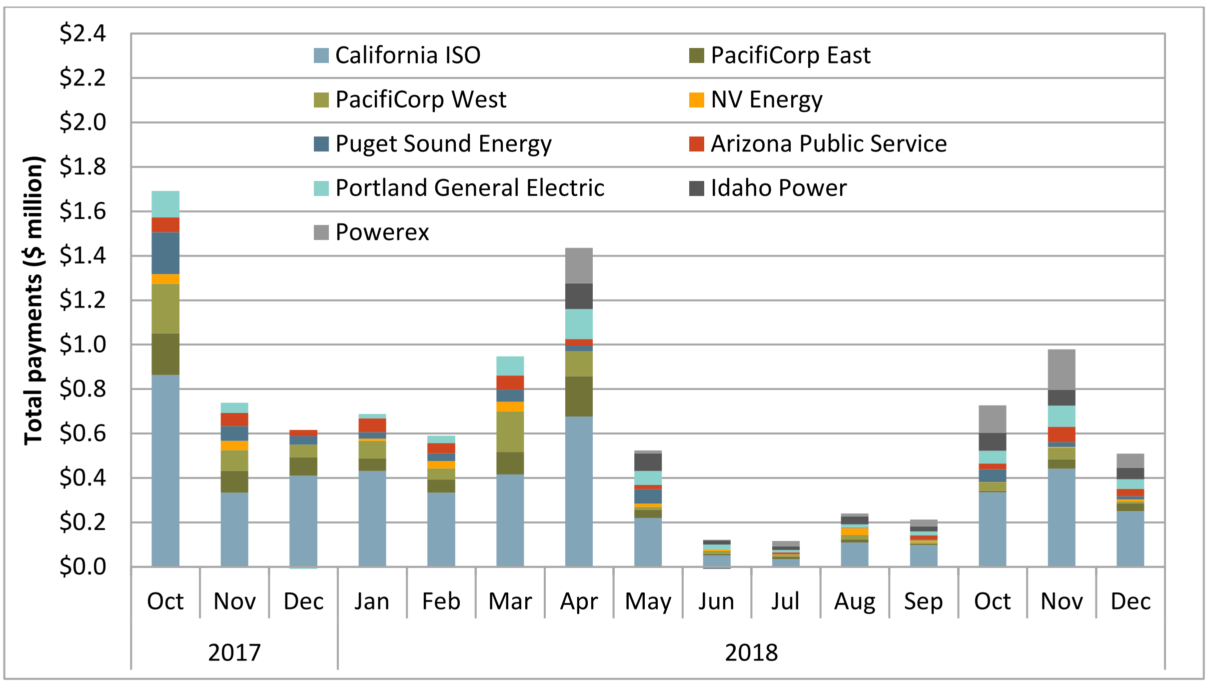
Flexible ramping procurement costs

Generation capacity that satisfied the demand for flexible ramping capacity received payments based on the combined system and area-specific flexible ramping shadow price. In addition, the combined flexible ramping shadow price was also used to pay or charge for forecasted ramping movements. This means that a generator that was given an advisory dispatch by the market to increase output was paid the upward flexible ramping price and charged the downward flexible ramping price. Similarly, a generator that was forecast to decrease output was charged the upward flexible ramping price and paid the downward flexible ramping price.[39]

Figure 1.31 shows the total net payments to generators for flexible ramping capacity from the flexible ramping product by month.[40] This includes the total net amount paid for upward and downward flexible ramping capacity in both the 15-minute and 5-minute markets. Payments for forecast movements are not included.

Total net payments to generators in the ISO and energy imbalance market areas for providing flexible ramping capacity increased during the fourth quarter of 2018 to around $2.2 million, compared to less than $0.6 million during the previous quarter. However, payments were down from the fourth quarter of 2017 when around $3 million were paid in net to generators for flexible ramping capacity.

Figure 1.31 Monthly flexible ramping payments



39 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.

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

2 Energy imbalance market

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

- Prices in Northwest areas (PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex) continue to be relatively flat over the hours of the day because of limited transfer capability into and out of the region.
- Prices in the ISO and the rest of the energy imbalance market tend to reflect the net load curve, rising in the morning and evening ramping hours and dropping below prices in the Northwest areas during the mid-day hours when solar output is highest.
- The frequency of upward sufficiency test failures decreased across EIM areas overall. In particular, NV Energy failed the upward sufficiency test in less than 1 percent of hours, compared to over 6 percent of hours in the previous quarter.
- Powerex was frequently separated by congestion during the quarter, particularly from the ISO during almost 40 percent of 15-minute and 5-minute intervals. In addition, congestion from the other Northwest areas toward the ISO continued to be frequent. Congestion from PacifiCorp West, Portland General Electric and Puget Sound Energy in the direction of the ISO occurred during around 25 percent of 15-minute intervals and 17 percent of 5-minute intervals.
- The frequency and size of the load adjustments from Arizona Public Service continued to be high. Arizona Public Service entered positive load forecast adjustments in over 92 percent of 15-minute and 5-minute intervals at an average of just over 160 MW, or around 5.6 percent of the area's total load.
- Energy imbalance market greenhouse gas attribution changes implemented in November limited the capacity deemed delivered to the difference between maximum resource capacity and base schedule in any interval. Following implementation of these changes, the weighted average 15-minute greenhouse gas price more than doubled to $7.82/MWh from a value between $2.50/MWh and $3.00/MWh in pre-implementation months in 2018 and the fourth quarter of 2017. The deemed delivered quantity from gas resources increased and from hydro-electric resources decreased following implementation.

2.1 Energy imbalance market performance

Energy imbalance market prices

Figure 2.1 and Figure 2.2 show real-time prices for the energy imbalance market balancing areas. Several balancing areas were grouped together because of similar average hourly pricing. The figures also show prices for both Southern California Edison and Pacific Gas and Electric for comparison with prices in the ISO. Congestion within the ISO contributed to price separation between Southern California Edison and Pacific Gas and Electric in hours ending 9 through 14, as shown in Figure 2.1 and Figure 2.2. Average prices for NV Energy and Arizona Public Service tracked closely to system prices during most hours. However, due to the high rate of flexible ramping sufficiency test failures in hours ending 9 through 14, there was price separation between NV Energy and Arizona Public Service for intervals following the failures. Prices for PacifiCorp East and Idaho Power often tracked similarly to system prices on average, except during peak load hours when prices were significantly lower than prices in the ISO.

Prices in the region including PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex were regularly different than those in the ISO and other energy imbalance market balancing areas because of limited transfer capability in and out of this region. This resulted in local resources setting the price in a combined Northwest region during many intervals.

Figure 2.1 Hourly 15-minute market prices (October – December)

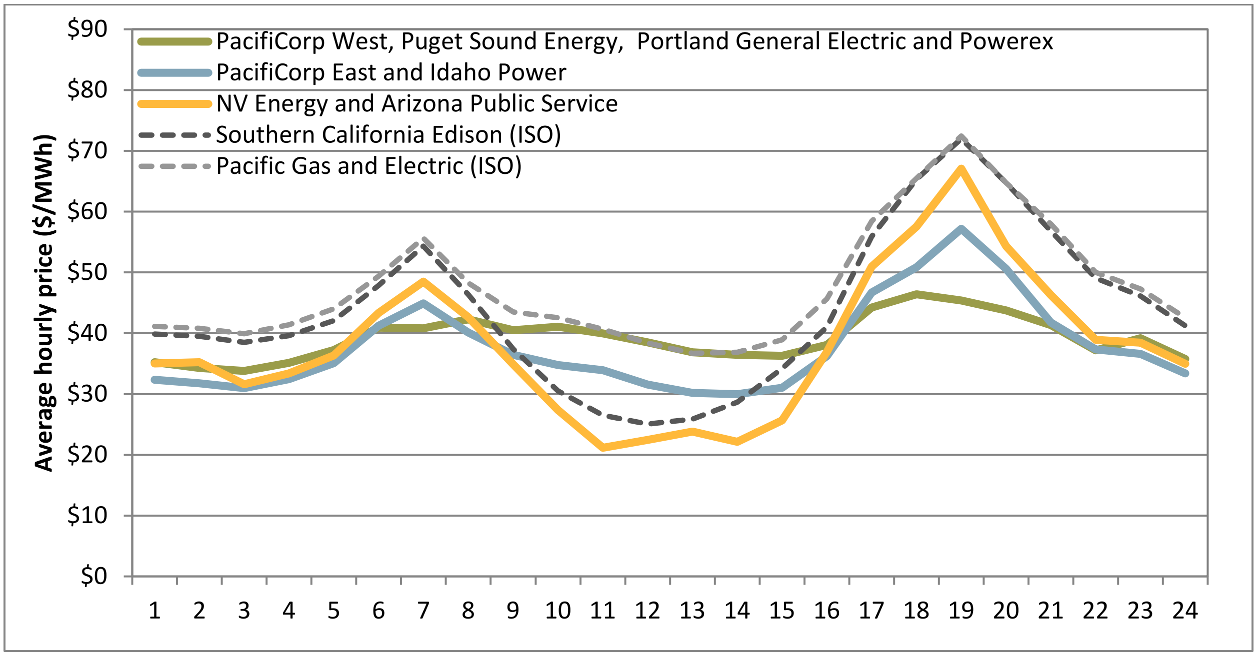
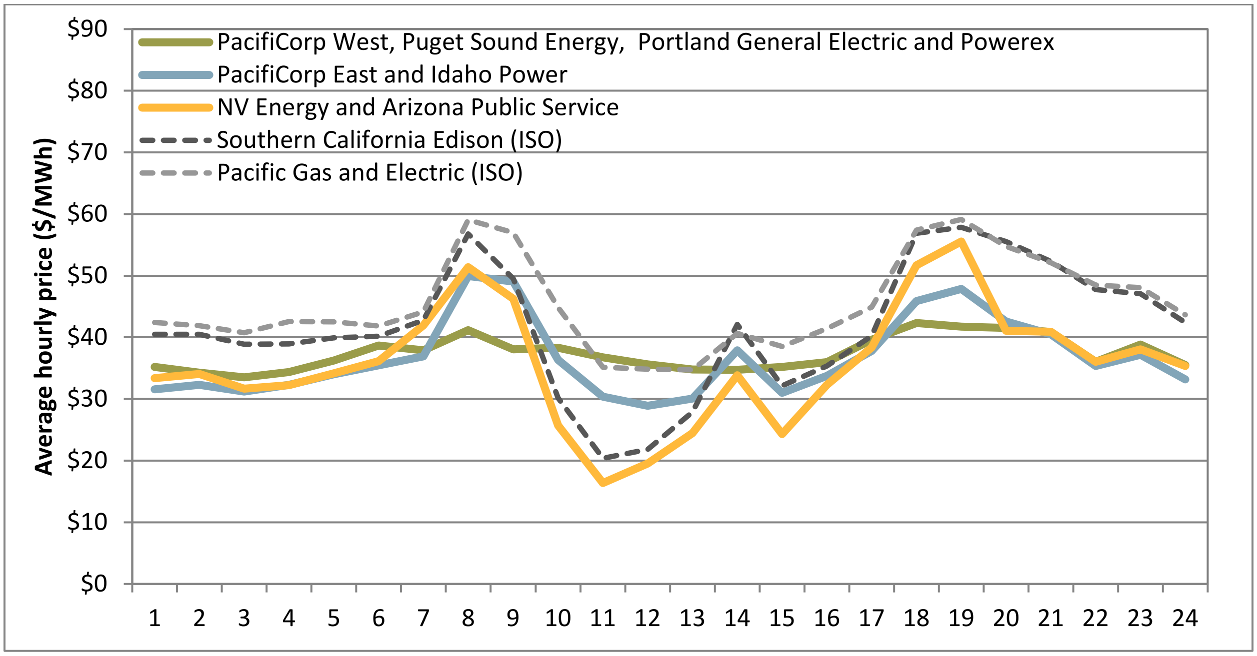


Figure 2.2 Hourly 5-minute market prices (October – December)



2.2 Flexible ramping sufficiency test

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

When the energy imbalance market was initially implemented there was an upward ramping sufficiency test. In November 2016, the ISO implemented an additional downward ramping sufficiency test in the market with the introduction of the flexible ramping product, which replaced the flexible ramping constraint. If an area fails the upward sufficiency test, energy imbalance market imports cannot be increased.[41] Similarly, if an area fails the downward sufficiency test, exports cannot be increased. In addition to the sufficiency test, each area is also subject to a capacity test. If an area fails the capacity test, then the flexible ramping sufficiency test automatically fails as a result.

Sufficiency test results

Limiting transfers can impact the frequency of power balance constraint relaxations and, thus, price separation across balancing areas. The majority of power balance constraint relaxations during the quarter, across all of the energy imbalance market balancing areas, occurred during hours when the area failed the flexible ramping sufficiency test. Constraining transfer capability may also impact the

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

efficiency of the energy imbalance market by limiting transfers into and out of a balancing area that could potentially provide benefits to other balancing areas.

Figure 2.3 and Figure 2.4 show the percent of hours in which an energy imbalance market area failed the sufficiency test in the upward and downward direction, respectively. During the fourth quarter, there was a decrease in the frequency of upward test failures overall. In particular, NV Energy failed the upward sufficiency test in less than 1 percent of hours, compared to over 6 percent of hours in the previous quarter. However, Arizona Public Service failed the upward sufficiency test more frequently during the quarter, in almost 6 percent of hours. Further, NV Energy failed the downward sufficiency test in almost 5 percent of hours, compared to around 4 percent in the previous quarter.

Figure 2.3 Frequency of upward failed sufficiency tests by month

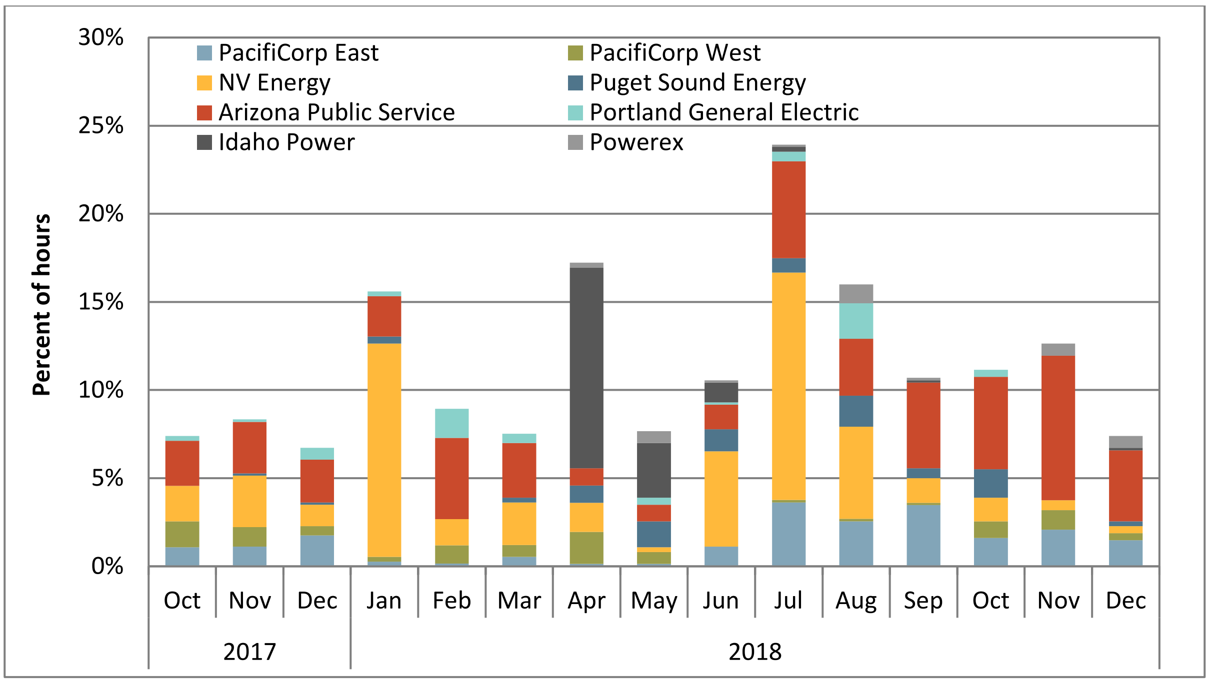
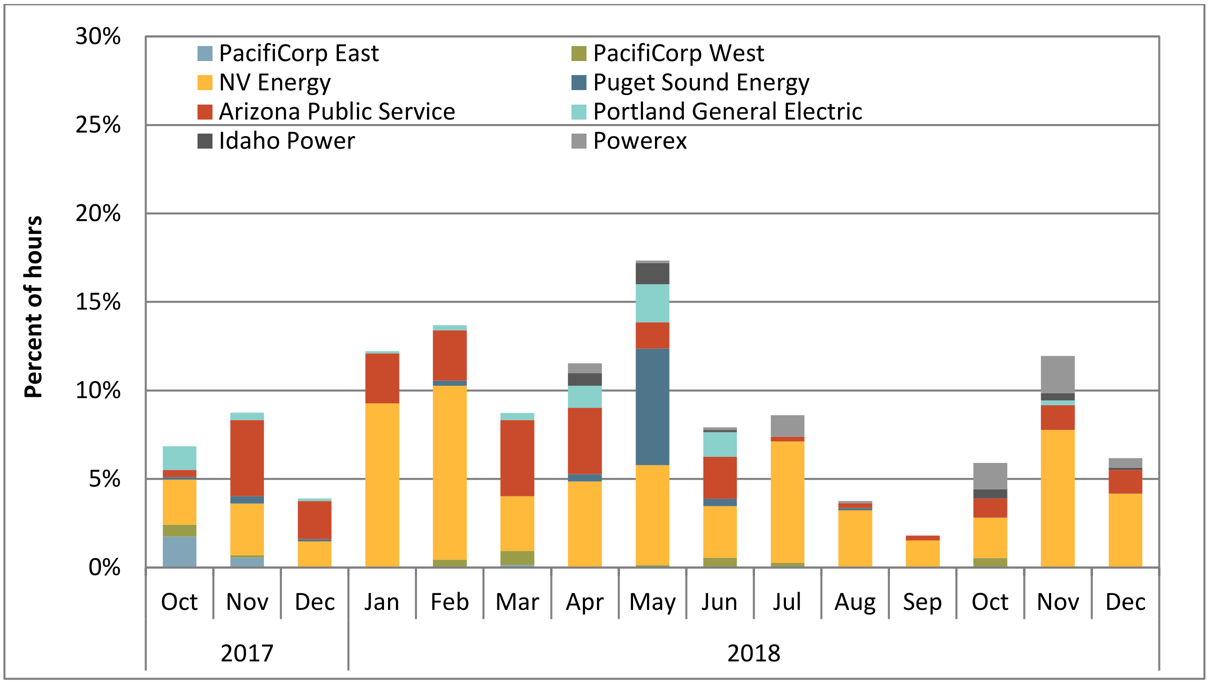


Figure 2.4 Frequency of downward failed sufficiency tests by month



2.3 Energy imbalance market transfers

One of the key benefits of the energy imbalance market is the ability to transfer energy between areas in the 15-minute and 5-minute markets. Initially, when PacifiCorp East and PacifiCorp West were the only energy imbalance market areas, there was little transfer capability between these areas and the ISO. Since then, the amount of transfer capability has increased significantly with the additions of NV Energy, Arizona Public Service, Puget Sound Energy and Portland General Electric. In the second quarter of 2018, Idaho Power and Powerex joined the energy imbalance market, further expanding the transfer capability and associated benefits.

Table 2.1 shows the percent of 15-minute and 5-minute market intervals when there was congestion on the transfer constraints into or out of an energy imbalance market area, relative to prevailing system prices in the ISO.[42]

As shown in the table, Powerex was frequently separated by congestion during the quarter, particularly from the ISO during almost 40 percent of 15-minute and 5-minute intervals. In addition, congestion from the Northwest areas toward the ISO continued to be frequent. Congestion from PacifiCorp West, Portland General Electric and Puget Sound Energy in the direction of the ISO occurred during around 25 percent of 15-minute intervals and 17 percent of 5-minute intervals. Powerex was congested in the direction of the ISO in 22 percent of 15-minute intervals and 8 percent of 5-minute intervals.

Table 2.1 also shows that congestion in either direction between NV Energy, Arizona Public Service, or the ISO area was infrequent during the quarter. Congestion that did occur between these areas was

[42] 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.

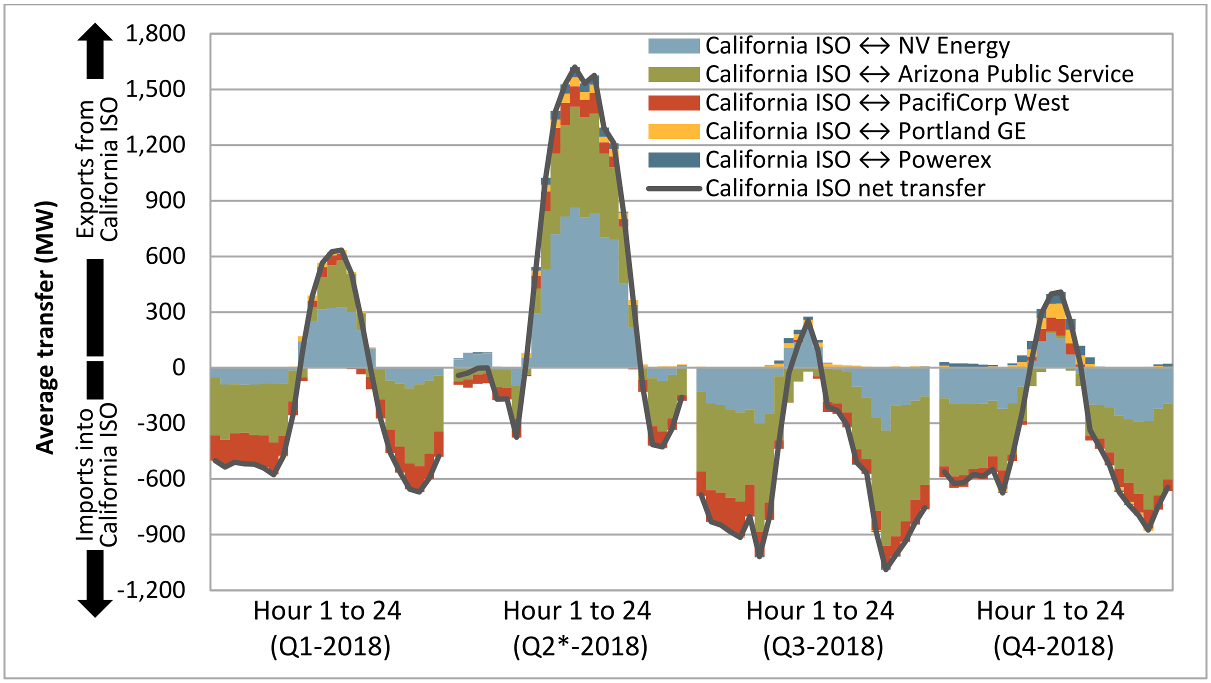
often the result of a failed upward or downward sufficiency test. There was also little congestion to and from the PacifiCorp East and Idaho Power areas.

Table 2.1 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
NV Energy	3%	1%	3%	0%
Arizona Public Service	6%	4%	2%	2%
PacifiCorp East	9%	1%	5%	0%
Idaho Power	3%	6%	1%	6%
PacifiCorp West	25%	3%	17%	3%
Portland General Electric	25%	3%	17%	4%
Puget Sound Energy	25%	11%	17%	8%
Powerex	22%	40%	8%	37%

Different areas in the energy imbalance market exhibited different hourly transfer patterns during the quarter. This pattern is driven by demand and supply conditions and transfer constraints in each area. For instance, Figure 2.5 shows average hourly imports (negative values) and exports (positive values) into and out of the ISO during each quarter in the 15-minute market. The bars show the average hourly transfers with the connecting areas while the gray line shows the average hourly net transfer. On average for the fourth quarter, the ISO was importing during most hours with the exception of midday hours when the ISO was typically exporting. This was similar to the previous quarter but reflects a significant shift from the second quarter of 2018, when the ISO was a net exporter on average as a result of seasonal load and renewable conditions.

Figure 2.5 California ISO – average hourly 15-minute market transfer



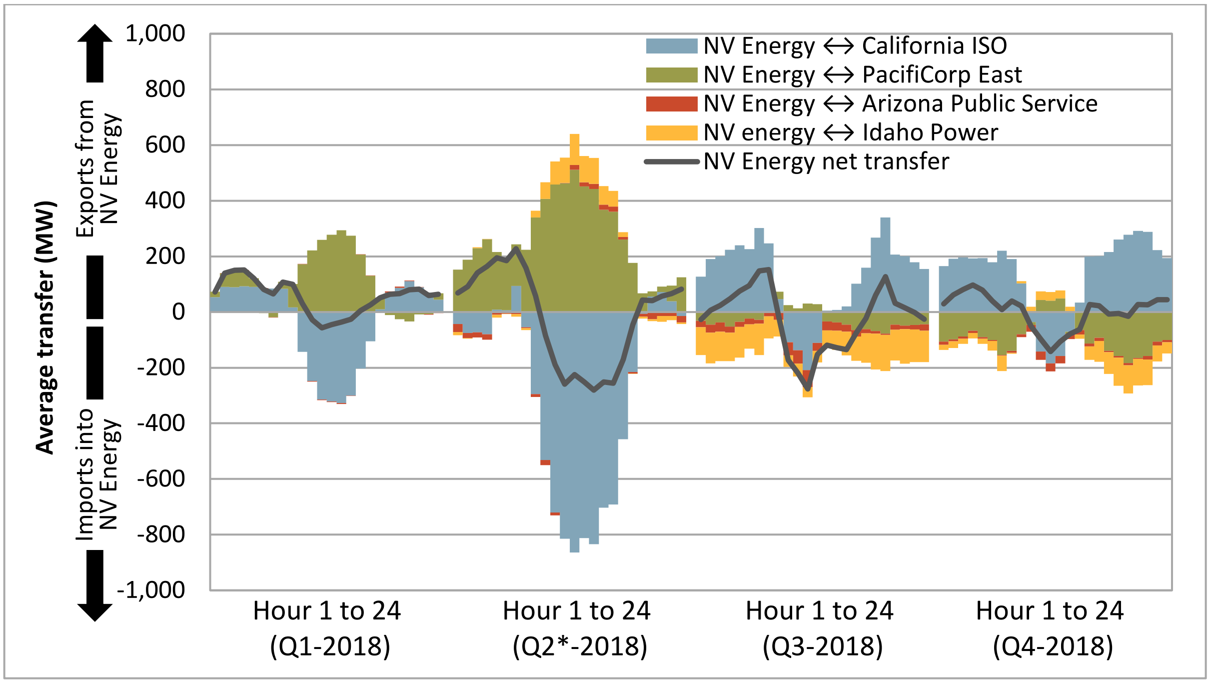
*April 4 to June 30, 2018

Figure 2.6 through Figure 2.10 show the same information on imports and exports for NV Energy, Arizona Public Service, Idaho Power, PacifiCorp West, and Powerex in the 15-minute market.[43] As in prior reports, the amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[44] Similar to the previous quarter, NV Energy in the fourth quarter was a net importer during midday hours and net exporter during many of the other hours. Arizona Public Service, on average for the quarter, was importing from PacifiCorp East and exporting to the ISO in most hours.

[43] Figures showing transfer information from the perspective of PacifiCorp East, Puget Sound Energy and Portland General Electric are not explicitly included, but are represented in Figure 2.6 through Figure 2.10.

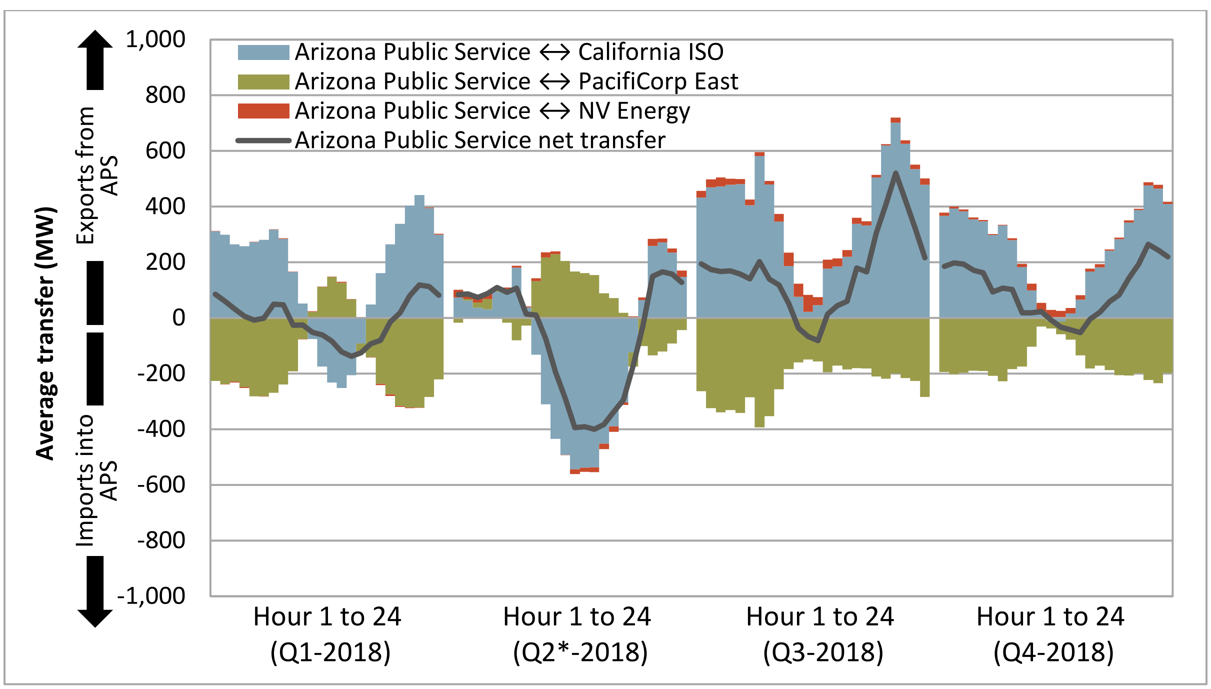
[44] Base schedules on EIM transfer system resources are fixed bilateral transactions between EIM entities. DMM changed the reference data source for dynamic and base-scheduled transfers in this report.

Figure 2.6 NV Energy – average hourly 15-minute market transfer



*April 4 to June 30, 2018

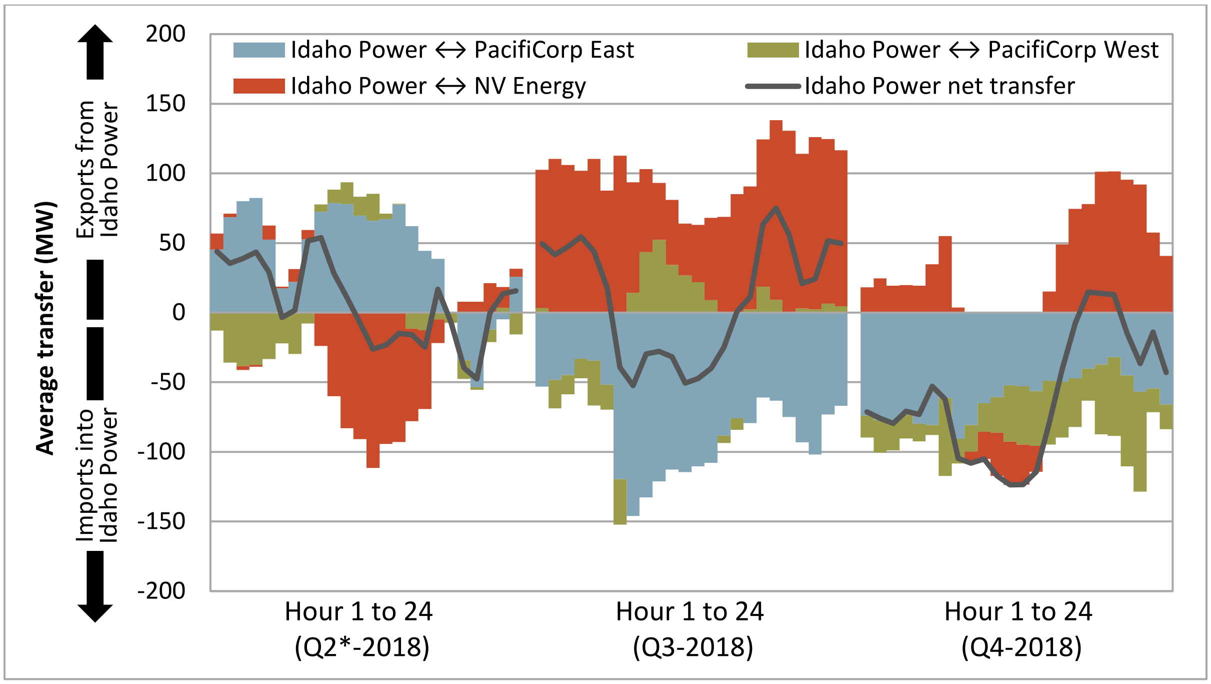
Figure 2.7 Arizona Public Service – average hourly 15-minute market transfer



*April 4 to June 30, 2018

Idaho Power has transfer capacity between PacifiCorp West, PacifiCorp East, and NV Energy. Figure 2.8 shows the hourly 15-minute market transfer pattern between Idaho Power and neighboring areas during the fourth quarter, net of all base schedules. On average for the quarter, Idaho Power base scheduled around 1,100 MW in imports from PacifiCorp East and roughly 700 MW in exports to PacifiCorp West. However, as shown in Figure 2.8, dynamic transfers net of all base schedules were less than 100 MW on average in all hours during the fourth quarter.

Figure 2.8 Idaho Power – average hourly 15-minute market transfer

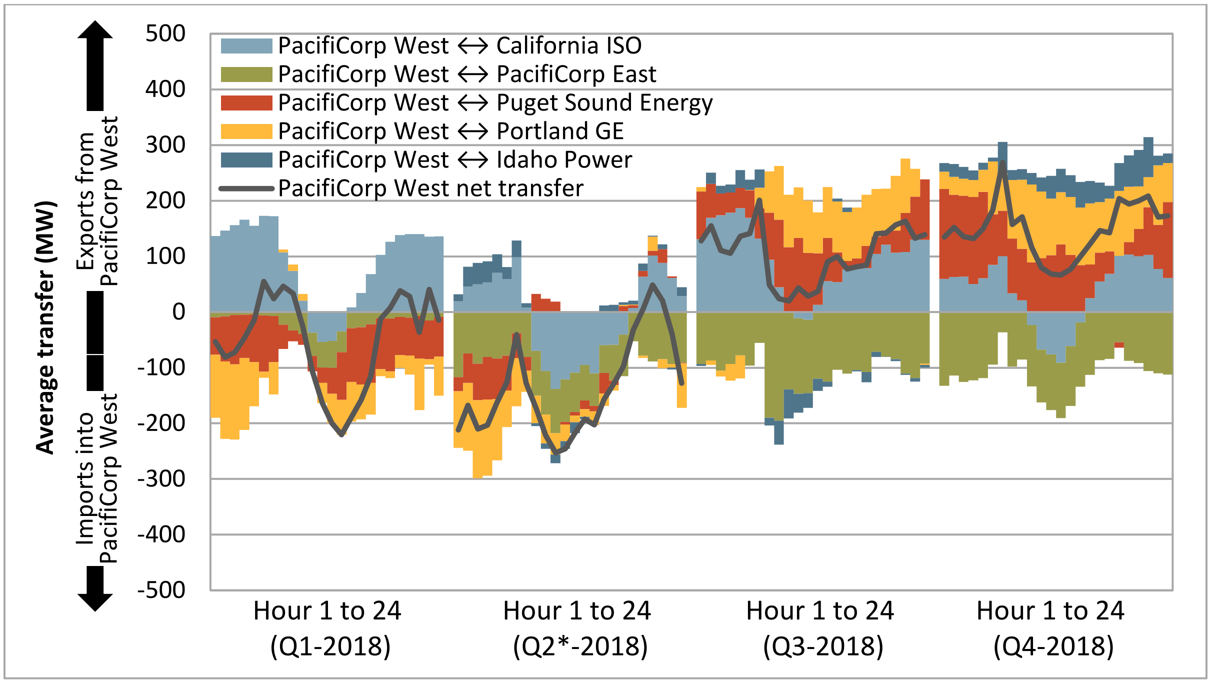


*April 4 to June 30, 2018

PacifiCorp West has transfer capacity between PacifiCorp East, Puget Sound Energy, the ISO, and Portland General Electric. Figure 2.9 shows the hourly 15-minute market transfer pattern between PacifiCorp West and neighboring areas during the fourth quarter. Most of the transfers with Idaho Power and PacifiCorp East continued to be base scheduled in the market, so therefore fixed. PacifiCorp West exported over 1,200 MW to PacifiCorp East on average during the quarter, but net of all base schedules, imported around 100 MW on average.

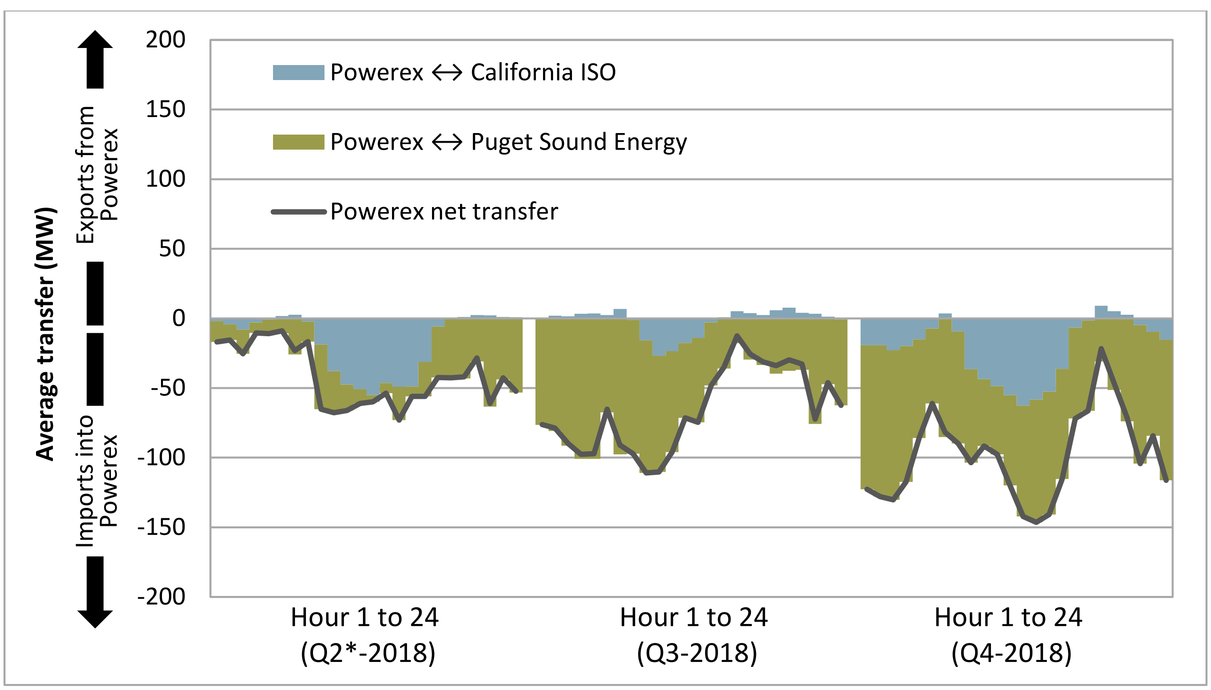
Figure 2.10 shows average hourly 15-minute market imports and exports into and out of Powerex. During the fourth quarter, import and export transmission capacity from Powerex to the ISO were limited to 34 MW or less during almost all 15-minute intervals with the exception of midday hours when import limits were often higher. However, transfer limits between Powerex and the ISO were higher in both import and export directions in the 5-minute market.

Figure 2.9 PacifiCorp West – average hourly 15-minute market transfer



*April 4 to June 30, 2018

Figure 2.10 Powerex – average hourly 15-minute market transfer



*April 4 to June 30, 2018

2.4 Load adjustments

Table 2.2 summarizes the average frequency and size of positive and negative load forecast adjustments for the energy imbalance market areas during the fourth quarter for the 15-minute and 5-minute markets. The same data for the ISO is provided as a point of reference.

Nearly all energy imbalance market entities had a much greater frequency of 5-minute market adjustments than 15-minute market adjustments during the fourth quarter. However, the frequency and size of the adjustments in both markets were relatively low for most of the balancing areas with the exception of Arizona Public Service.

Arizona Public Service entered positive load forecast adjustments in over 92 percent of 15-minute and 5-minute intervals at an average of just over 160 MW, or around 5.6 percent of the area's total load. This is considerably higher than other balancing areas.

Table 2.2 Average frequency and size of load adjustments (October - December)

	Positive load adjustments			Negative load adjustments			Average hourly bias MW
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO							
15-minute market	45%	553	2.2%	4%	-269	1.2%	239
5-minute market	38%	270	1.1%	20%	-260	1.1%	53
PacifiCorp East							
15-minute market	0.1%	246	5.2%	2%	-76	1.5%	-1
5-minute market	7%	71	1.4%	26%	-75	1.5%	-15
PacifiCorp West							
15-minute market	0.4%	33	1.3%	2%	-51	2.1%	-1
5-minute market	2%	49	2.0%	11%	-54	2.3%	-5
NV Energy							
15-minute market	3%	74	1.7%	0%	N/A	N/A	3
5-minute market	11%	57	1.4%	10%	-57	1.6%	0
Puget Sound Energy							
15-minute market	0%	N/A	N/A	0.2%	-94	3.3%	0
5-minute market	1%	59	2.2%	49%	-51	1.8%	-24
Arizona Public Service							
15-minute market	93%	161	5.6%	3%	-85	3.2%	148
5-minute market	92%	162	5.6%	3%	-85	3.3%	148
Portland General Electric							
15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
5-minute market	26%	28	1.2%	4%	-34	1.4%	6
Idaho Power							
15-minute market	2%	37	2.3%	4%	-50	3.1%	-1
5-minute market	7%	47	2.6%	20%	-60	3.7%	-9

3 Special issues

This section covers special issues during the fourth quarter. Key observations and findings include the following.

- Resource adequacy availability increased to an average 88 percent during the availability assessment hours, relative to 84 percent in the final quarter of 2017.
- Less than half of import capacity shown as resource adequacy capacity bid into the real-time on average on non-holiday weekdays during the fourth quarter.
- Intra-monthly capacity procurement mechanism designations were triggered by exceptional dispatches and a significant event during the quarter. Together, estimated costs for these designations totaled about $14.7 million in the fourth quarter of 2018.
- On November 26, 2018, FERC accepted the ISO's proposal to temporarily extend six of its Aliso Canyon-related tariff provisions but rejected the ISO's proposal to temporarily extend the tariff revisions regarding gas price scalars.
- One of the Aliso Canyon-related tariff provisions allows the ISO to update gas prices used in the day-ahead market from an index based on the prior day's trading to a volume-weighted average of next-day trades before 8:30 am. This update allowed gas prices used in the day-ahead market to reflect prevailing next-day gas prices in the fourth quarter.
- DMM continues to recommend that the ISO develop the ability to adjust gas prices used in the real-time market based on observed prices on ICE the morning of each operating day. This approach would closely align the gas price used in the ISO's real-time market with the actual costs for gas purchased in the same-day gas market

3.1 Resource adequacy performance

3.1.1 System resource adequacy availability

Load-serving entities procure resource adequacy capacity to meet system-level requirements. Scheduling coordinators are then incentivized to make resource adequacy capacity available in the market during *availability assessment hours* through the resource adequacy availability incentive mechanism (RAAIM). These are hours ending 17 through 21 on non-holiday weekdays. [45]

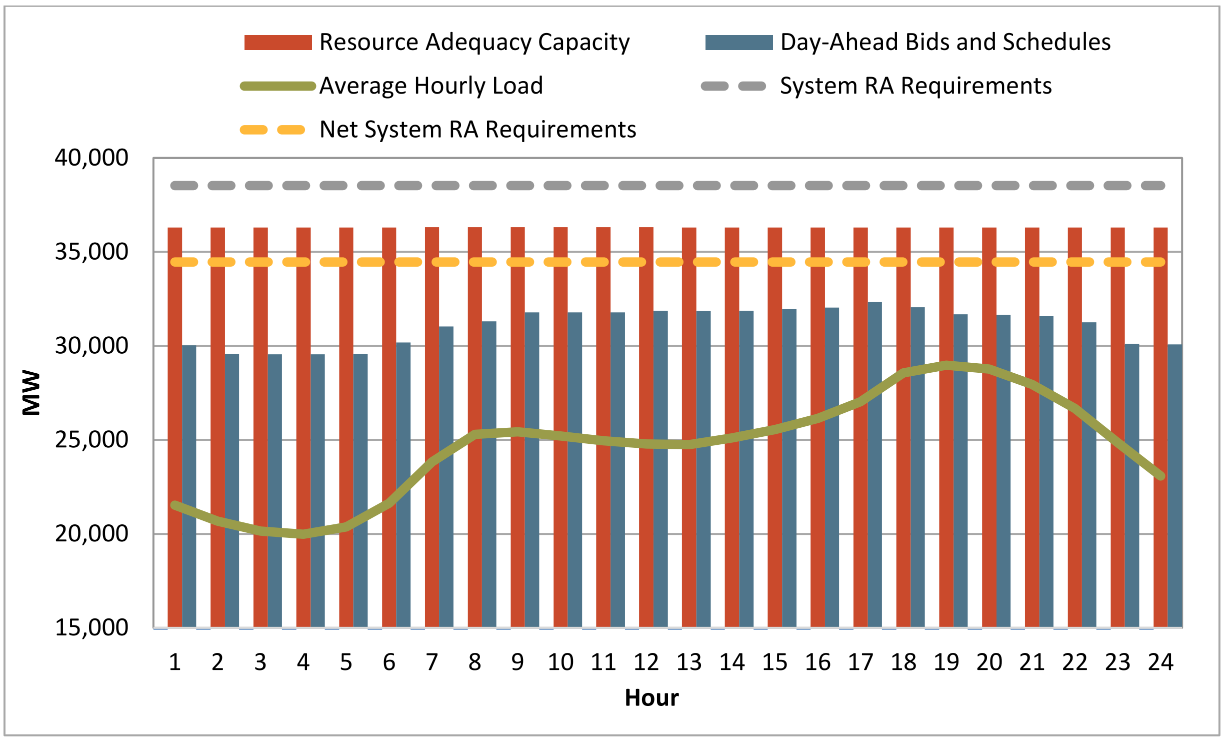
Figure 3.1 shows load, resource adequacy capacity, the capacity that was available in the day-ahead market, and resource adequacy requirements averaged over each hour of the day during the fourth quarter.[46] On average, about 86 percent of resource adequacy capacity was available in the day-ahead

[45] Prior to 2018, the system and local availability assessment hours were hours ending 14 to 18 from April 1 through October 31 and hours ending 17 to 21 from November 1 to March 31. For more information on the change to resource adequacy availability assessment hours, refer to the business practice manual for Reliability Requirements: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Reliability%20Requirements

[46] Federal holidays and weekends are excluded from this analysis to be consistent with the tariff definition of RAAIM assessment hours.

market during each hour of the day throughout the quarter. This availability is measured as the ratio of day-ahead bids and schedules (blue bars) to resource adequacy capacity (red bars). This percentage increases during hours ending 17 through 21, where around 88 percent of capacity procured was available in the day-ahead market. This higher proportion of available capacity in the day-ahead market is incentivized by RAAIM during availability assessment hours. However, capacity available in the day-ahead market drops from a high of 89 percent in hour ending 17 to 87 percent in hour ending 21 when resources such as solar become unavailable but load remains high. Despite this drop in availability during RAAIM assessment hours with highest load, resource adequacy availability during the fourth quarter of 2018 increased over the fourth quarter of 2017 when RA availability averaged about 84 percent during RAAIM assessment hours.[47]

Figure 3.1 Average hourly load and resource adequacy capacity



All available system resource adequacy capacity must be offered in the ISO market through economic bids or self-schedules as follows:

- **Day-ahead energy and ancillary services market** — All available resource adequacy capacity must be either self-scheduled or bid into the day-ahead energy market. Resources certified for ancillary services must offer this capacity in the ancillary services market.
- **Residual unit commitment process** — Market participants are also required to submit bids priced at $0/MWh into the residual unit commitment process for all resource adequacy capacity.

[47] RAAIM availability assessment hours varied seasonally between hours ending 14 and 21 in 2017, but were hours ending 17 to 21 for all months in 2018. To compare RA availability during RAAIM assessment hours between the fourth quarters of 2017 and 2018, RA availability in the fourth quarter of 2017 represents availability during hours ending 14 to 21, regardless of month, while RA availability in the fourth quarter of 2018 represents availability during hours ending 17 to 21.

- **Real-time market** — All resource adequacy resources committed in the day-ahead market or residual unit commitment process must also be made available and offered into the real-time markets. Short-start units providing resource adequacy capacity must also be offered in the real-time energy and ancillary services markets even when they are not committed in the day-ahead market or residual unit commitment process. Long-start units and imports providing resource adequacy capacity that are not scheduled in the day-ahead market or residual unit commitment process are not required to bid into the real-time markets.

Table 3.1 provides a detailed summary of the availability of resource adequacy capacity during non-holiday weekdays for each type of generation for the day-ahead and real-time markets in the fourth quarter. Separate sub-totals are provided for resources that the ISO creates bids for if market participants do not submit a bid or self-schedule, and resources the ISO does not create bids for. As shown in Table 3.1:

- ***Most of the capacity that must bid during all hours continued to be from gas-fired resources.*** About 60 percent of the capacity (21,700 MW) for system resource adequacy must be bid into the market for each hour of the month.[48] Gas-fired generation made up about half of total resource adequacy capacity. Imports continued to represent about 7 percent of total capacity.[49]

- ***Use-limited gas resources made up the largest portion of generation not required to bid in during all hours.*** Use-limited gas units contributed about 5,500 MW of total capacity (15 percent), hydro resources contributed about 4,000 MW of total capacity (11 percent), nuclear resources contributed 5 percent, solar resources contributed 3 percent, and resources with operating restrictions (wind and qualifying facilities) combined contributed an additional 5 percent.

- ***Resource adequacy capacity after reported outages and derates increased over the final quarter of 2017.*** Average resource adequacy capacity was around 36,300 MW during non-holiday weekdays for the fourth quarter of 2018, down from about 39,000 MW in the fourth quarter of 2017. After adjusting for outages and derates, the remaining capacity in the day-ahead market was about 93 percent of the overall resource adequacy capacity, which is up about 5 percent from the fourth quarter of 2017.

- ***Day-ahead market availability was high for all resource types.*** About 93 percent of both must-offer and non must-offer resources were available in the day-ahead market. Must-offer resources bid in about 98 percent of day-ahead availability; the lowest resource type by percent was imports at 79 percent. Non must-offer resources bid in about 84 percent of the day-ahead availability. These are typically variable and non-dispatchable energy resources. Additionally, some of the hours within this analysis of non-holiday weekdays occurred outside of hours when solar resources, non must-offer resources, are not available.

- ***Most resource adequacy capacity was available in the real-time market, after accounting for outages and derates.*** The last four columns of Table 3.1 compare the total resource adequacy

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48 When scheduling coordinators did not submit bids for these resources, they were automatically generated by the ISO. Generation was excluded from bidding requirement when an outage was reported to the ISO.

49 Beginning in January 2012, the ISO began to automatically create energy bids for imports in the day-ahead market when market participants failed to submit bids for this capacity and did not declare the capacity unavailable. If imports were not committed in the day-ahead market, the importer was not required to submit bids for this capacity in the real-time market. If an import cleared the day-ahead market and was not self-scheduled or re-bid in the real-time market, the ISO submitted a self-schedule for this capacity.

capacity potentially available in the real-time market timeframe with the actual amount of capacity scheduled or bid in the real-time market. The resource adequacy capacity available in the real-time market timeframe is calculated as the resource adequacy capacity from resources with a day-ahead or residual unit commitment schedule plus the resource adequacy capacity from uncommitted short-start units. This capacity has been adjusted for outages and derates. About 90 percent of the resource adequacy capacity that was potentially available to the real-time market was scheduled or bid in the real-time market.

- ***Most use-limited gas resource adequacy capacity was bid into the day-ahead market.*** Around 5,500 MW of use-limited gas resources were used to meet resource adequacy requirements. After adjusting for outages, about 96 percent of capacity was bid in the day-ahead market during non-holiday weekdays. In real time, about 4,000 MW of 4,300 MW (91 percent) of net available capacity was scheduled or bid in the real-time market.

Table 3.1 Average system resource adequacy capacity and availability (non-holiday weekdays)

Resource type	Total resource adequacy capacity (MW)	Day-ahead market				Real-time market			
		Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
		MW	% of total RA Cap.	MW	% of adjusted RA Cap	MW	% of total RA Cap.	MW	% of adjusted RA Cap
Must-Offer:									
Gas-fired generators	17,671	16,733	95%	16,729	100%	10,893	62%	10,641	98%
Other generators	1,480	1,389	94%	1,387	100%	1,389	94%	1,362	98%
Imports	2,532	2,381	94%	1,882	79%	1,226	48%	1,019	83%
Subtotal	**21,683**	**20,503**	**95%**	**19,998**	**98%**	**13,508**	**62%**	**13,022**	**96%**
Other:									
Use-limited gas units	5,548	4,836	87%	4,624	96%	4,333	78%	3,938	91%
Hydro generators	3,852	3,307	86%	2,813	85%	3,307	86%	2,877	87%
Nuclear generators	1,910	1,883	99%	1,863	99%	1,883	99%	1,839	98%
Solar generators	1,051	1,021	97%	398	39%	987	94%	419	42%
Wind generators	620	610	99%	327	54%	610	99%	354	58%
Qualifying facilities	1,177	1,095	93%	852	78%	985	84%	795	81%
Other non-dispatchable	460	449	98%	227	51%	438	95%	311	71%
Subtotal	**14,618**	**13,201**	**90%**	**11,104**	**84%**	**12,543**	**86%**	**10,533**	**84%**
Total	**36,301**	**33,704**	**93%**	**31,102**	**92%**	**26,051**	**72%**	**23,555**	**90%**

Imports

Load-serving entities are allowed to use imports to meet system resource adequacy requirements. Imports were used to meet an average of around 2,900 MW (or around 7 percent) of system resource adequacy requirements during the non-holiday weekdays of the fourth quarter in 2017. This decreased to an average of around 2,500 MW in the fourth quarter of 2018, but still composed about 7 percent of system resource adequacy requirements.[50]

[50] For more information and analysis of import resource adequacy in 2017 and 2018 in the context of summer peak loads, see the following report: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf

Resource adequacy imports are not required to be resource specific or to represent supply from a specific balancing area, but only that they be on a specific intertie into the ISO system. Further, scheduling coordinators are only required to submit energy bids for resource adequacy imports in the day-ahead market.[51] Imports can be bid at any price up to the energy bid cap and do not have any further obligation to bid into the real-time market if not scheduled in the day-ahead energy or residual unit commitment process.

DMM has expressed concern that these rules can allow a significant portion of resource adequacy requirements to be met by imports that may have limited availability and value during critical system and market conditions. For example, resource adequacy imports can bid significantly above projected prices in the day-ahead market to ensure they do not clear and would then have no further obligation to be available in the real-time market. Consequently, DMM has recommended the ISO reconsider rules concerning resource adequacy requirements met by imports.[52]

3.1.2 Capacity procurement mechanism

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

In 2015, the ISO proposed the current capacity procurement mechanism which included a competitive bid solicitation process to determine the backstop capacity procurement price for the mechanism. This market allows for competition between different resources that may meet capacity needs.

Scheduling coordinators may submit competitive solicitation process bids for three offer types: yearly, monthly and intra-monthly. In each case, the quantity offered is limited to the difference between the resource's maximum capacity and capacity already procured as either resource adequacy capacity or through the ISO's capacity procurement mechanism. Bids may range up to a soft offer cap set at $6.31/kW-month ($75.68/kW-year).

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

The ISO uses the competitive solicitation process to procure backstop capacity in three distinct processes. First, if insufficient cumulative system, local, or flexible capacity is shown in annual resource adequacy plans, the ISO may procure backstop capacity through an annual competitive solicitation

[51] Day-ahead availability requirements are not applicable to resource adequacy capacity (including imports) for load-following metered subsystems. For more information, see Section 40.6 of ISO's tariff: http://www.caiso.com/Documents/Section40_ResourceAdequacyDemonstration_SCs_CAISOBAA_asof_May1_2018.pdf

[52] For additional information, see DMM's 2017 annual report, p. 259: http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf

process using annual bids. The annual process may also be used to procure backstop capacity to resolve a collective deficiency in any local area.

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

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

Table 3.2 shows intra-monthly capacity procurement mechanism costs for designations that occurred during the fourth quarter of 2018. Intra-monthly designations were triggered by exceptional dispatches and a significant event during the quarter. Together, estimated costs for intra-monthly capacity procurement mechanism designations totaled about $14.7 million in the fourth quarter of 2018.

In all, about 3,300 MW was procured through intra-monthly capacity procurement mechanisms. About 59 MW of capacity was procured for potential thermal overload to address local reliability issues in the PG&E TAC area. In total, these designations cost about $0.75 million, or about $0.55 million for the quarter. The ISO also issued a capacity procurement mechanism significant event, designating about 3,240 MW of backstop capacity for system reliability needs. The designations were made initially for the month of September with extensions and increased procurement through October. The event was issued in light of an alternate load forecast presented by California Energy Commission (CEC) staff which projected higher peak loads than the load forecast used to set resource adequacy requirements. The significant event designations were calculated as the difference between the requirements of the alternate load forecast (including the planning reserve margin of the alternate forecast) and the quantity of resource adequacy capacity shown for the months of September and October. The total cost of these designations was about $14 million in the fourth quarter.

Several intra-monthly designations were declined by one scheduling coordinator. Scheduling coordinators who receive an exceptional dispatch for capacity not designated through the resource adequacy process may choose to decline the designation by contacting the ISO through appropriate channels within 24 hours of the designation. A scheduling coordinator may choose to decline a designation to avoid the associated must-offer obligation, which could reduce capacity costs passed to a single transmission access charge area or to the system as a whole.

Table 3.2 Intra-monthly capacity procurement mechanism costs

Resource	Designated MW	CPM Start Date	CPM End Date	CPM Type	Price ($/kW-mon)	Estimated cost ($ mil)	Estimated cost Q4 ($ mil)	Local capacity area	CPM designation trigger
HUMBPP_1_UNITS3	16	11/12/18	1/10/19	ED	$6.31	$0.20	$0.17	PG&E	Potential thermal overload
HUMBPP_6_UNITS	26	9/10/18	11/8/18	ED	$6.31	$0.32	$0.21	PG&E	Potential thermal overload
HUMBPP_6_UNITS	12	11/14/18	1/12/19	ED	$6.31	$0.16	$0.13	PG&E	Potential thermal overload
STANIS_7_UNIT 1	5	11/28/18	1/26/19	ED	$6.31	$0.07	$0.04	PG&E	Potential thermal overload
ARBWD_6_QF	2	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
BASICE_2_UNITS	89	10/1/18	10/30/18	SIGEVT	$3.79	$0.34	$0.34	SYS	Alternate load forecast
BLACK_7_UNIT 2	2	10/1/18	10/31/18	SIGEVT	$5.50	$0.01	$0.01	SYS	Alternate load forecast
BLACK_7_UNIT 2	84	11/1/18	11/29/18	SIGEVT	$5.50	$0.45	$0.45	SYS	Alternate load forecast
BRODIE_2_WIND	9	10/1/18	10/30/18	SIGEVT	$3.79	$0.03	$0.03	SYS	Alternate load forecast
CARBOU_7_PL4X5	69	10/1/18	10/30/18	SIGEVT	$3.79	$0.26	$0.26	SYS	Alternate load forecast
CARBOU_7_UNIT 1	5	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
CHEVCD_6_UNIT	1	10/1/18	10/30/18	SIGEVT	$3.79	$0.00	$0.00	SYS	Alternate load forecast
CHEVCY_1_UNIT	5	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
COLEMN_2_UNIT	2	10/1/18	11/29/18	SIGEVT	$5.50	$0.02	$0.02	SYS	Alternate load forecast
CONTRL_1_CASAD1	3	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
CONTRL_1_CASAD3	5	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
DIABLO_7_UNIT 1	471	10/1/18	10/30/18	SIGEVT	$3.79	$1.78	$1.78	SYS	Alternate load forecast
DIABLO_7_UNIT 2	977	10/1/18	10/30/18	SIGEVT	$3.79	$3.70	$3.70	SYS	Alternate load forecast
DSABLA_7_UNIT	2	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
ELECTR_7_PL1X3	36	10/1/18	10/30/18	SIGEVT	$3.79	$0.14	$0.14	SYS	Alternate load forecast
ENCINA_7_EA2	104	10/1/18	10/30/18	SIGEVT	$3.47	$0.36	$0.36	SYS	Alternate load forecast
ENCINA_7_EA3	110	10/1/18	10/30/18	SIGEVT	$2.98	$0.33	$0.33	SYS	Alternate load forecast
ENCINA_7_EA4	28	10/1/18	10/30/18	SIGEVT	$3.96	$0.11	$0.11	SYS	Alternate load forecast
ENCINA_7_EA5	57	10/1/18	10/30/18	SIGEVT	$3.96	$0.23	$0.23	SYS	Alternate load forecast
ENCINA_7_GT1	15	10/1/18	10/30/18	SIGEVT	$3.96	$0.06	$0.06	SYS	Alternate load forecast
ETIWND_6_GRPLND	46	10/1/18	11/29/18	SIGEVT	$5.07	$0.47	$0.47	SYS	Alternate load forecast
FELLOW_7_QFUNTS	1	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
FLOWD2_2_FPLWND	2	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
HATCR2_7_UNIT	2	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
HATRDG_2_WIND	9	10/1/18	10/30/18	SIGEVT	$3.79	$0.03	$0.03	SYS	Alternate load forecast
JAWBNE_2_NSRWND	14	10/1/18	10/30/18	SIGEVT	$3.79	$0.05	$0.05	SYS	Alternate load forecast
MNDALY_6_MCGRTH	47	10/1/18	10/30/18	SIGEVT	$3.39	$0.16	$0.16	SYS	Alternate load forecast
MOSSLD_2_PSP2	7	10/1/18	10/30/18	SIGEVT	$6.00	$0.04	$0.04	SYS	Alternate load forecast
MOSSLD_2_PSP2	29	10/1/18	11/29/18	SIGEVT	$4.25	$0.25	$0.25	SYS	Alternate load forecast
PEABDY_2_LNDFL1	5	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
PIT1_7_UNIT 1	7	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
PIT1_7_UNIT 2	8	10/1/18	11/29/18	SIGEVT	$5.50	$0.09	$0.09	SYS	Alternate load forecast
PIT4_7_PL1X2	25	10/1/18	10/30/18	SIGEVT	$3.79	$0.09	$0.09	SYS	Alternate load forecast
PIT5_7_PL3X4	28	10/1/18	11/29/18	SIGEVT	$5.50	$0.31	$0.31	SYS	Alternate load forecast
PIT6_7_UNIT 1	39	10/1/18	11/29/18	SIGEVT	$5.50	$0.43	$0.43	SYS	Alternate load forecast
PIT6_7_UNIT 2	37	10/1/18	10/30/18	SIGEVT	$3.79	$0.14	$0.14	SYS	Alternate load forecast
PIT7_7_UNIT 1	51	10/1/18	10/30/18	SIGEVT	$3.79	$0.19	$0.19	SYS	Alternate load forecast
PIT7_7_UNIT 2	51	10/1/18	10/30/18	SIGEVT	$3.79	$0.19	$0.19	SYS	Alternate load forecast
PWRX_MALIN500_I_F_ CPM01	500	10/1/18	10/30/18	SIGEVT	$5.00	$2.50	$2.50	SYS	Alternate load forecast
PWRX_MALIN500_I_F_ CPM01	210	10/31/18	11/29/18	SIGEVT	$5.00	$1.05	$1.05	SYS	Alternate load forecast
RTREE_2_WIND2	2	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
SALTSP_7_UNITS	6	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
SISQUC_1_SMARIA	1	10/1/18	10/30/18	SIGEVT	$3.79	$0.00	$0.00	SYS	Alternate load forecast

SOUTH_2_UNIT	2	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
SPBURN_2_UNIT 1	5	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
SPIAND_1_ANDSN2	4	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
SPQUIN_6_SRPCQU	5	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
SUNSHN_2_LNDFL	6	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
TIGRCK_7_UNITS	3	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
TXMCKT_6_UNIT	1	10/1/18	10/30/18	SIGEVT	$3.79	$0.00	$0.00	SYS	Alternate load forecast
UNCHEM_1_UNIT	2	10/1/18	10/30/18	SIGEVT	$4.00	$0.01	$0.01	SYS	Alternate load forecast
VOLTA_2_UNIT 1	2	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
WESTPT_2_UNIT	8	10/1/18	10/30/18	SIGEVT	$3.79	$0.03	$0.03	SYS	Alternate load forecast
Total	3,299					$14.89	$14.69		

In addition to the intra-monthly designations, there were four annual CPM designations that remained in place through the fourth quarter. In December 2017, the ISO issued year-ahead CPM designations to address material capacity deficiencies for 2018 in the South Bay-Moss Landing sub-area of the Bay Area Local Capacity Area and the San Diego-Imperial Valley Local Capacity Area. The ISO conducted a Local Capacity Technical Study and found there were both annual RA plan local capacity deficiencies and collective deficiencies in these local capacity areas. The designations were effective January 1, 2018, for a 12-month term. These were the first annual CPM designations made since initial implementation in 2016. Annual designations may vary by month and are determined as the aggregate of the deficiencies in all of the local areas within each transmission access charge area where the resource is located.

Table 3.3 shows the annual capacity procurement mechanism costs for 2018. The price for 490 MW of the Moss Landing resource is $6.19/KW-month, and the price for 20 MW of the resource is $6.31/kW-month, i.e., the soft offer cap price. The price of the capacity for each Encina unit is the applicable monthly soft offer cap of $6.31/kw-month. At these prices and quantities the total estimated cost for annual capacity procurement was about $78 million for 2018.[53]

Table 3.3 Annual capacity procurement mechanism costs

Resource	Designated MW	Price ($/kW-mon)	Estimated cost ($ million)	Local capacity area	Exceptional dispatch CPM trigger
MOSSLD_2_PSP1	20	$6.31	$1.5	PG&E	Material sub-area deficiency
MOSSLD_2_PSP1	490	$6.19	$36.9	PG&E	Material sub-area deficiency
ENCINA_7_EA4	272	$6.31	$19.7	SDG&E	Material sub-area deficiency
ENCINA_7_EA5	273	$6.31	$19.8	SDG&E	Material sub-area deficiency
Total	1,055		$78.0		

There were no monthly capacity procurement designations made in 2018, and there have not been any since the program was implemented in 2016.

53 This estimate takes into account forced outages of the Encina units that happened during December 2018.

3.2 Aliso Canyon gas-electric coordination

On September 28, 2018, the ISO filed tariff amendments to extend Aliso Canyon provisions until December 31, 2019.[54] DMM filed comments, with supporting analysis, opposing the further extension of applying a gas price scalar to increase the gas price used in calculating caps for commitment costs and default energy bids used in real-time market for resources in the SoCalGas area. While DMM supports temporary extension of the ISO's ability to enforce a maximum gas constraint for groups of units in the SoCalGas system, 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.[55] On November 26, 2018, FERC ruled on the ISO's filing, accepting the ISO's proposal to temporarily extend six of its Aliso Canyon-related tariff provisions but rejecting the ISO's proposal to temporarily extend the tariff revisions regarding gas price scalars.[56] Subsequently, the ISO filed a compliance filing at FERC removing the use of the gas price scalars in the real-time market from the tariff.[57]

The ISO did not enforce gas burn constraints in either the day-ahead or real-time markets in the fourth quarter of 2018. Aliso gas price scalars were also not activated during the fourth quarter despite significant increases in same-day gas prices on some days in October and November 2018 at the SoCal Citygate hub. Use of both nomograms and scalars in February of 2018 was associated with additional costs.[58]

Figure 3.2 shows Intercontinental Exchange (ICE) same-day natural gas trade prices for SoCal Citygate compared to the next-day average price from October through December 2018. About 20 percent of traded volume at SoCal Citygate exceeded the normal 25 percent adder and an additional 11 percent of the traded volume exceeded the 10 percent adder. Figure 3.2 also shows the same-day prices relative to next-day averages for days that were the first trading day of the week, which was typically a Monday. These are shown as green bars on the chart. Following the extreme price volatility in the third quarter, prices at SoCal Citygate hub remained high in the fourth quarter due to ongoing pipeline outages and low operational flow order penalties. Refer to Section 1.1 for more detailed information on natural gas prices.

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

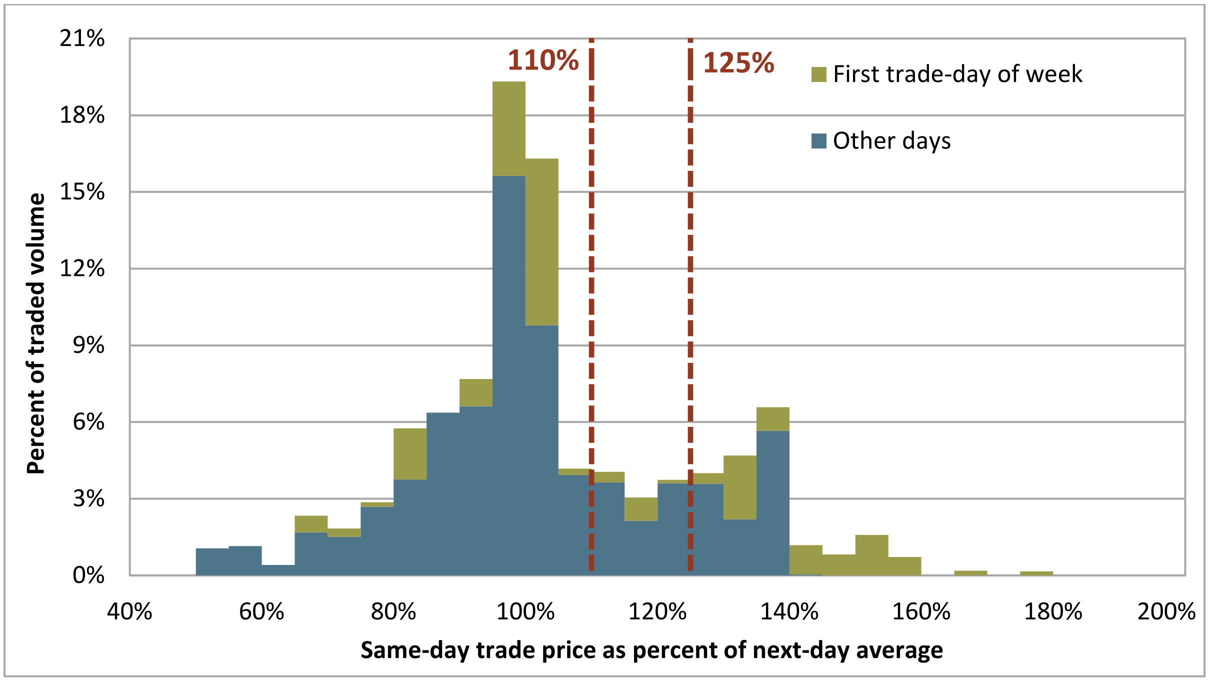
55 FERC filing - Comments on Aliso Canyon Gas-Electric Coordination Phase 4 (ER18-2520), Department of Market Monitoring, October 19,2018: http://www.caiso.com/Documents/CommentsoftheDepartmentofMarketMonitoirng-Aliso4-Oct192018.pdf

56 FERC Order on Tariff Revisions - Aliso Canyon Gas-Electric Coordination Phase 4 (ER18-2520), November 26, 2018: http://www.caiso.com/Documents/Nov26-2018-Order-TariffRevisions-AlisoCanyonGas-ElectricCoordinationPhase4-ER18-2520.pdf

57 Compliance Filing to Remove Gas Price Scalars - Aliso Canyon Phase 4 Gas-Electric Coordination (ER18-2520), December 18, 2018: http://www.caiso.com/Documents/Dec18-2018-ComplianceFiling-Remove-GasPriceScalars-AlisoCanyonPhase4-ER18-2520.pdf

58 See *Q1 2018 Report on Market Issues and Performance*, July 10, 2018, Department of Market Monitoring: http://www.caiso.com/Documents/2018_First_Quarter_Report_on_Market_Issues_and_Performance.pdf

Figure 3.2 Same-day trade prices compared to next-day index (October – December)

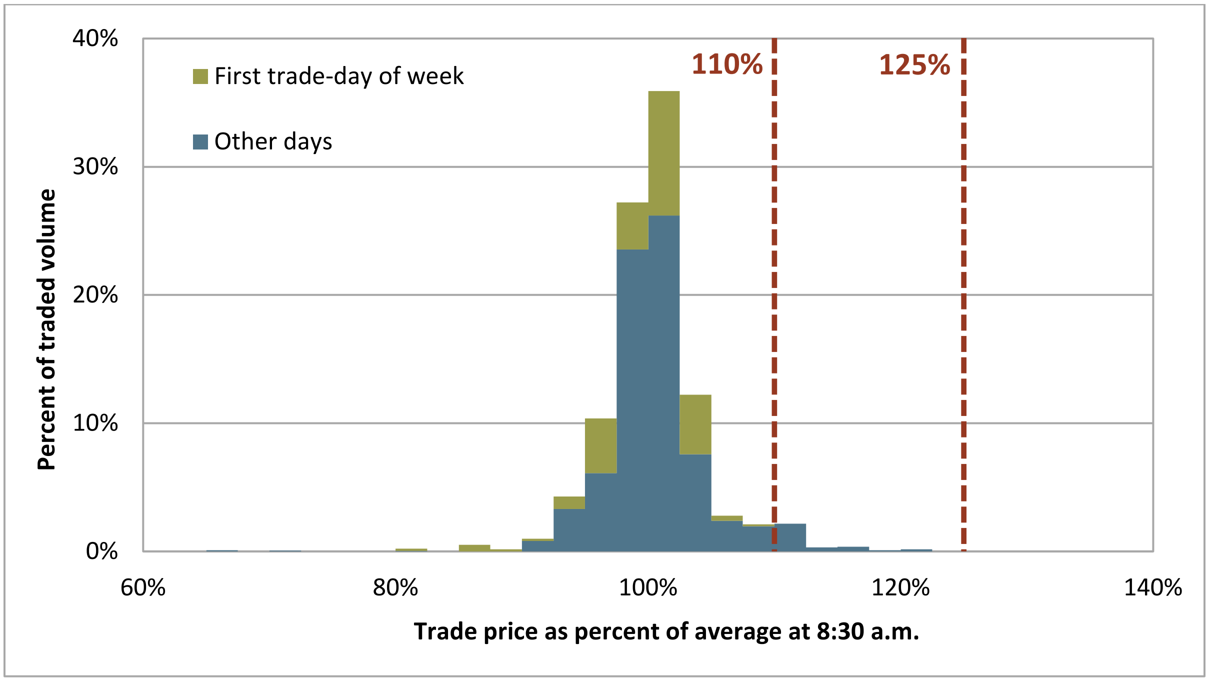


DMM continues to recommend that the ISO develop the ability to adjust gas prices used in the real-time market based on observed prices on ICE the morning of each operating day. This approach would closely align the gas price used in the ISO's real-time market with the actual costs for gas purchased in the same-day gas market.[59]

Figure 3.3 compares the price of each same-day trade at SoCal Citygate to an updated volume-weighted average price of same-day trades reported on ICE before 8:30 am. For the fourth quarter of 2018, this figure shows that if the real-time gas prices were updated using an updated same-day price, then about 97 percent of the same-day trades would have been at or below the 10 percent adder at SoCal Citygate. About 3 percent of the traded volume would have exceeded the 10 percent adder, but still would have been less than the 25 percent adder normally included in commitment cost caps. None of the same-day traded volume exceeded the 25 percent adder. Figure 3.3 also shows the same-day prices relative to updated same-day price for days that were the first trading day of the week, which was typically a Monday. These are shown by the green bars in the chart.

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

Figure 3.3 Same-day prices as a percent of updated same-day averages (October – December)



Updated natural gas prices for the day-ahead market

FERC's November 26, 2018, order extended the ISO's authority to use more timely natural gas prices for calculating default energy bids and proxy commitment costs in the day-ahead market through December 31, 2019. Under this extension, the ISO updates the gas price on next-day trades from the morning of the day-ahead market run instead of using indices from the prior day.[60]

In comments filed in response to the Aliso Canyon phase 4 filing, NRG requested that the ISO consider using ICE's "Monday-only" next-day index for Monday's day-ahead market instead of the next-day index traded as part of weekend package on Friday. Based on the observation that both prices and demand are typically greater on Monday than the preceding weekend, NRG asserts that using the "Monday-only" index reflects the market's expectation of prices specific to the Monday power day.[61] The ISO concurs, and has started a stakeholder process on the temporary use of updated Monday-only gas price index in the day-ahead market for Mondays only and when available.[62] The ISO proposes to include this feature permanently as part of the local market power mitigation enhancements initiative which is currently underway.

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

61 Motion For Leave To File Answer And Answer Of The California Independent System Operator Corporation To Comments And Protests, *NRG comments pp18 -19*: http://www.caiso.com/Documents/Nov5-2018-Motion-Leave-FileAnswer-Answer-Comments-Protests-AlisoCanyonGas-ElectricCoordinationPhase4-ER18-2520.pdf

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

Figure 3.4 and Figure 3.5 illustrate the benefit of using the updated natural gas price index in the fourth quarter of 2018. Figure 3.4 shows next-day trade prices reported on ICE for the SoCal Citygate during the fourth quarter, compared to the next-day price index previously used in the day-ahead market which was lagged by one trade day. As shown in Figure 3.4, about 10 percent of the next-day trades were in excess of the 25 percent headroom normally included in commitment cost bid caps. An additional 11 percent of next-day trades were at a price in excess of the 10 percent adder normally included in default energy bids.

Figure 3.5 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 3.5, about 3 percent of the traded volume exceeded the 10 percent adder included in default energy bids. An insignificant percent 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 3.4 Next-day trade prices compared to next-day index from prior day (Oct – Dec)

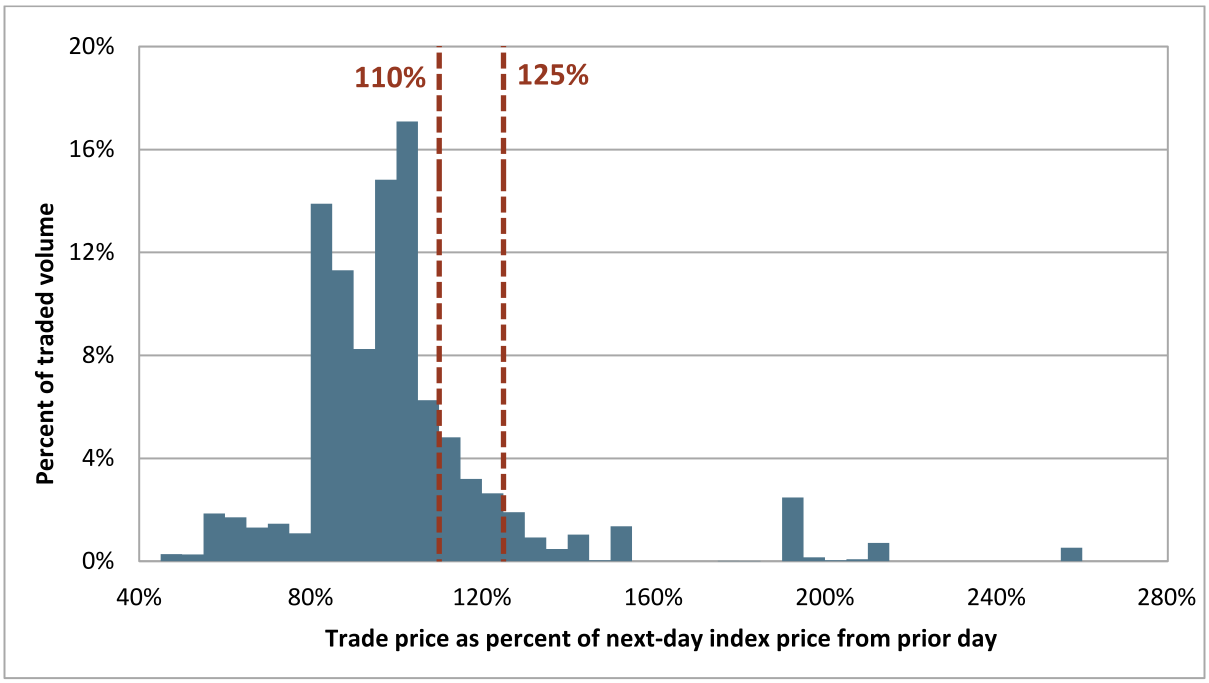


Figure 3.5 Next-day trade prices compared to updated next-day average price (Oct – Dec)