California ISO

California Independent System Operator Corporation

California ISO

Q3 2018 Report on Market Issues and Performance

November 1, 2018

Department of Market Monitoring

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Executive summary

This report covers market performance during the third quarter of 2018 (July – September). Key highlights during this quarter include the following:

- Average prices increased compared to the same quarter in 2017, driven in part by high gas prices, seasonally high load and reduced renewable generation.
- System marginal energy prices in the day-ahead market reached record highs on July 24, peaking at almost $980 in hour ending 20. The frequency of high day-ahead prices increased significantly during the third quarter, largely concentrated in July and August when prices over $250/MWh occurred in over 15 and 12 percent of hours, respectively. The frequency of price spikes greater than $250/MWh in the 5-minute market was about 1.4 percent of intervals in the third quarter.
- Average prices of natural gas increased substantially in the third quarter of 2018, particularly at the SoCal Citygate trading hub where average prices were more than double average prices in 2017. This increase in SoCal Citygate natural gas prices was one of the main drivers of high system marginal energy prices in July and August 2018 across the CAISO system.
- Bid cost recovery payments for the third quarter totaled about $88 million, the highest amount in any quarter since 2011. Bid cost recovery payments in the real-time market totaled about $45 million. Units committed in the real-time market through exceptional dispatches issued by grid operators to meet special reliability issues totaled about $27 million.
- Total energy resulting from all types of exceptional dispatch increased nearly fourfold in the third quarter compared to the same quarter in 2017. Exceptional dispatch energy from commitment energy accounted for about 70 percent of all exceptional dispatch energy in this quarter.
- Third quarter real-time imbalance offset charges increased to about $79 million from about $20 million in each of the first and second quarters.[1] Real-time congestion imbalances accounted for $75 million of the total charges—the highest quarterly congestion imbalances since 2012. High congestion imbalance charges were driven by persistent and significant constraint limit reductions from the day-ahead to real-time markets, combined with high real-time congestion prices. However, the actual net financial transfer from measured demand may be significantly less than the real-time congestion offset amount because, on the constraints associated with the charges, schedules paid day-ahead congestion prices while the offset charge only accounts for the schedules being paid the real-time prices for reducing constraint flows in real-time. Further, a significant portion of the schedules being paid to reduce flows on the constraints in real-time were from entities with measured demand.
- Costs for ancillary services totaled about $77 million during the third quarter, compared to about $52 million during the same quarter in 2017. Costs for ancillary services increased during the third quarter largely due to high fuel costs, tight supply conditions and high day-ahead market prices during the summer.

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

- Congestion revenue rights auction revenues were $41.5 million less than payments made in the third 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 about $100 million during 2018. Losses in the third quarter represent $0.43 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders. The commonly reported revenue inadequacy metric, a $53.4 million surplus this quarter, is not an accurate or appropriate measure of how well the congestion revenue right market is functioning from the perspective of ratepayers.

Other key highlights in this report are summarized below.

- There was significant north-to-south congestion in the day-ahead market. This congestion decreased day-ahead prices in the Pacific Gas and Electric area by about $8/MWh, and increased prices in the Southern California Edison and San Diego Gas and Electric areas by about $5/MWh and $7.5/MWh, respectively. Congestion in the 15-minute market decreased day-ahead prices in the Pacific Gas and Electric area by about $5/MWh, and increased prices in the Southern California Edison and San Diego Gas and Electric areas by about $8.5/MWh and $10/MWh, respectively.
- In the energy imbalance market, prices in the Northwest region (including PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex) continued to be lower than in the ISO and other energy imbalance market balancing areas because of limited transfer capability into and out of the region. The frequency of congestion between EIM balancing areas decreased slightly overall during the quarter, particularly from areas in the Northwest in the 5-minute market. The frequency of congestion between the ISO, PacifiCorp East and Idaho Power decreased significantly from the previous quarter.
- Total net payments to generators in the ISO and energy imbalance market areas for providing flexible ramping capacity continued to decrease overall during the third quarter of 2018 to around $0.6 million, compared to around $2.1 million during the previous quarter and around $5.1 million during the third 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 increased to about $20 million after accounting for about $11.9 million of virtual bidding bid cost recovery charges.
- Operator adjustments to procure additional residual unit commitment capacity increased significantly in the third quarter of 2018. Primary drivers were load forecast uncertainty and fire danger concerns. During most days in the quarter, an adjustment of 2,000 MW was made from hours ending 10 through 22 and an adjustment of 1,000 MW for hours ending 9 and 23.
- The ISO did not activate any of the special Aliso Canyon gas constraints or gas price scalars during the third quarter. Market and system performance was sustained during periods of tight gas and electric supply without these measures in place.
- DMM continues to recommend that rather than continuing use of special gas cost adders for units affected by the Aliso Canyon storage issues, the ISO develop the capability to update gas prices used in real-time market bid limits based on same-day gas market price information available each morning.[2]

[2] Further detail is available in DMM's comments on the ISO's recent tariff filing to extend Aliso provisions: http://www.caiso.com/Documents/CommentsoftheDepartmentofMarketMonitoirng-Aliso4-Oct192018.pdf

1 Market performance

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

- System marginal energy prices in the day-ahead market reached record highs on July 24, peaking at almost $980/MWh in hour ending 20. The frequency of high day-ahead prices increased significantly during the third quarter, largely concentrated between July 23 and August 10, driven by extreme temperatures across the western region and limited natural gas availability.
- Average prices increased compared to the previous quarter and the same quarter in 2017. Compared to the same quarter of 2017, average day-ahead prices increased by about $16/MWh (37 percent), 15-minute by about $3/MWh (7 percent) and 5-minute market prices by about $4/MWh (10 percent).
- Average prices of natural gas increased substantially in the third quarter of 2018, particularly at the SoCal Citygate trading hub where average prices were more than double average prices in 2017. This increase in SoCal Citygate natural gas prices was one of the main drivers of high system marginal energy prices in July and August 2018 across the CAISO system.
- There was significant north-to-south congestion in the day-ahead market. This congestion decreased day-ahead prices in the Pacific Gas and Electric area by about $8/MWh, and increased prices in the Southern California Edison and San Diego Gas and Electric areas by about $5/MWh and $7.5/MWh, respectively. Congestion in the 15-minute market decreased day-ahead prices in the Pacific Gas and Electric area by about $5/MWh, and increased prices in the Southern California Edison and San Diego Gas and Electric areas by about $8.5/MWh and $10/MWh, respectively.
- Total bid cost recovery payments for the third quarter were about $88 million, the highest amount in any quarter since 2011. Bid cost recovery attributed to the real-time market totaled about $45 million. Bid cost recovery payments for units committed through exceptional dispatches also played an important role in real-time bid cost recovery payments. DMM estimates that units committed in the real-time market for exceptional dispatches totaled about $27 million.
- Third quarter real-time imbalance offset charges increased to about $79 million from about $20 million in each of the first and second quarters.[3] Real-time congestion imbalances accounted for $75 million of the total charges—the highest quarterly congestion imbalances since 2012. Persistent and significant constraint limit reductions from the day-ahead to real-time markets, combined with high real-time congestion prices, led to the high congestion imbalance charges. However, the actual net financial transfer from measured demand may be significantly less than the real-time congestion offset amount because, on the constraints associated with the charges, schedules paid day-ahead congestion prices while the offset charge only accounts for the schedules being paid the real-time prices for reducing constraint flows in real-time. Further, a significant portion of the schedules being paid to reduce flows on the constraints in real-time were from entities with measured demand.
- Costs for ancillary services totaled about $77 million during the third quarter, compared to about $49 million in the previous quarter and $52 million during the same quarter in 2017. The number of

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

intervals with ancillary services scarcity pricing decreased from the previous quarter, but remained high, compared to the third quarter of 2017. During the quarter, all of the scarcity intervals were for regulation up and almost all in the expanded South of Path 26 region. Costs for ancillary services increased during the third quarter largely due to tight supply conditions and high day-ahead market prices during the summer.

- During the third quarter of 2018, congestion revenue rights auction revenues were $41.5 million less than payments made to non-load-serving entities purchasing these rights. Losses in the third quarter represent $0.43 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders. Total transmission ratepayer losses from the congestion revenue rights auction since the market began in 2009 surpassed $830 million. The commonly reported revenue inadequacy metric, a $53.4 million surplus this quarter, is not an accurate or appropriate measure of how well the congestion revenue right market is functioning from the perspective of ratepayers.

- Operator adjustments to procure additional residual unit commitment capacity increased significantly in the third quarter of 2018. Primary drivers were load forecast uncertainty and fire danger concerns. During most days in the quarter, an adjustment of 2,000 MW was made from hours ending 10 through 22 and an adjustment of 1,000 MW for hours ending 9 and 23.

- Convergence bidding was profitable overall during the third quarter. For the third consecutive quarter, virtual supply was also profitable. Combined net revenues for virtual supply and demand were about $20 million after accounting for about $11.9 million of virtual bidding bid cost recovery charges.

- Total energy resulting from all types of exceptional dispatch increased nearly fourfold in the third quarter of 2018 compared to the same quarter in 2017. Exceptional dispatch energy from commitment energy accounted for about 70 percent of all exceptional dispatch energy in this quarter.

1.1 Load conditions

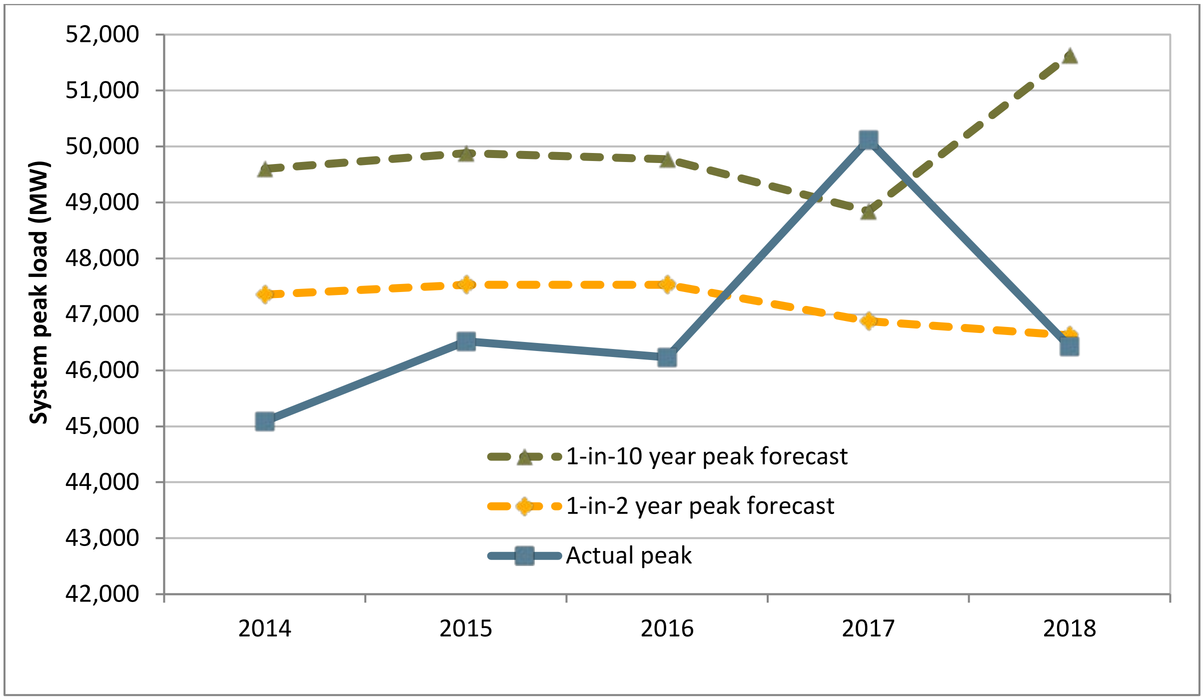
System demand during the single highest load hour often varies substantially year-to-year due to variation in summer heat wave weather conditions which drive peak demand. This variation creates continued challenges for maintaining operational reliability. Because demand in the ISO balancing area is primarily driven by temperature, peak loads usually occur during the third quarter. This summer, the instantaneous peak load was 46,625 MW and occurred on July 25 at 17:33, which was about 7 percent lower than the peak in 2017.[4]

The ISO works with the California Public Utilities Commission (CPUC) and other local regulatory authorities to set reliability planning requirements. System level resource adequacy requirements are based on the *1-in-2 year* (or median year) forecast of peak demand. Resource adequacy requirements for local areas are based on the *1-in-10 year* (or 90th percentile year) peak forecast for each area. As shown in Figure 1.1, the peak load this summer was very close to the ISO's 1-in-2 year load forecast (46,625 MW) and about 10 percent lower than the 1-in-10 year forecast (51,632 MW).

4 This value represents year-to-date peak loads.

Differences in the real-time and day-ahead load forecasts contributed to separation of prices throughout the quarter (see Section 1.3). One reason for over-forecasting of load in the day-ahead market, relative to lower real-time load, was error in weather forecasts used as input to day-ahead load forecasts, particularly on high demand days. The ISO reported that "the National Weather Service (NWS) submitted excessive heat warnings starting July 24, but actual temperatures came in 10 degrees cooler than forecasted in some regions."[5]

Figure 1.1 Actual load compared to planning forecasts



1.2 Supply conditions

Natural gas prices

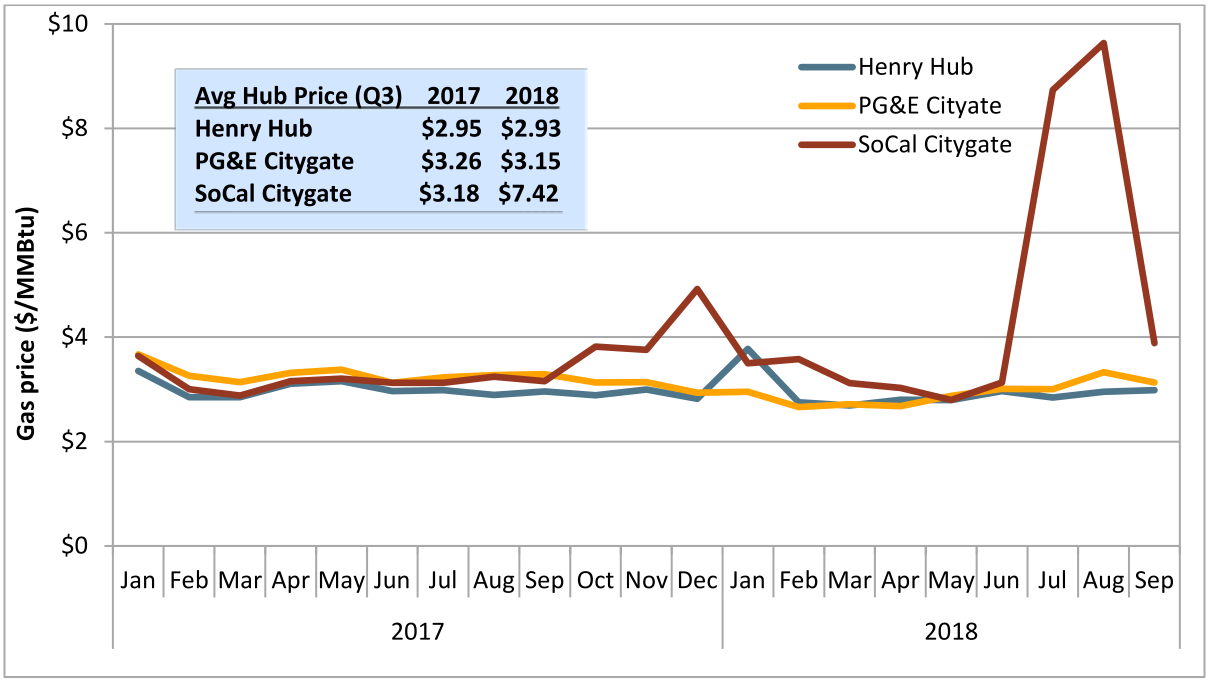
Electricity prices in western states typically follow natural gas price trends because natural gas units are often the marginal source of generation in the ISO and other regional markets. In the third quarter of 2018, the average price of natural gas more than doubled from 2017 levels at SoCal Citygate trading hub in California. This 134 percent increase in SoCal Citygate natural gas prices was one of the main drivers of high system marginal energy prices in July and August 2018 across the ISO footprint.

Figure 1.2 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 shown in Figure 1.2, the 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

5 See Market Performance and Planning Forum presentation, slide 47 at http://www.caiso.com/Documents/Presentation-MarketandPerformancePlanningForum-Aug292018.pdf.

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. SoCal Citygate prices often impact overall system prices because 1) there are large numbers of natural gas resources in the south, and 2) there is often greater congestion in the south that creates load pockets.

Figure 1.2 Monthly average natural gas prices



Impact of recent operational flow orders on Southern California gas prices

Operational flow orders (OFOs) and emergency flow orders (EFOs) are gas system balancing tools to give gas shippers economic incentive to ensure their scheduled deliveries match demand within a prescribed tolerance. SoCalGas issues operational flow orders when the system forecast of gas supply is not in balance with the system forecast of demand, after considering storage withdrawal or injection capacity allocated to the balancing function. The goal is to keep the system in balance, i.e., within acceptable limits, by using the threat of financial penalties known as noncompliance or imbalance charges against shippers who do not take action to either deliver additional supply or limit supply to balance their supply with their usage on a daily basis within a specified tolerance band. The operational flow order structure has five stages, plus a final emergency flow order stage, with noncompliance charges starting at $25/dth for Stage 4 and Stage 5 orders. On August 10, 2018, Southern California Edison and Southern California Generation Coalition submitted a joint petition at CPUC to lower the noncompliance charges associated with Stage 4 and Stage 5 orders.[6] On September 4, 2018, DMM filed a response to this joint motion at

6 *Joint Motion Of Southern California Edison Company (U 338-E) And Southern California Generation Coalition For Expedited Relief*, August 10, 2018: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M221/K852/221852215.PDF

CPUC with supporting analysis on the impact of the relatively high level of potential noncompliance under Stage 4 and Stage 5 orders on gas and electricity prices and costs.[7]

The impact of the $25/dth noncompliance charge triggered during a Stage 4 or Stage 5 low OFO has been clearly reflected in recent next-day gas prices in the SoCalGas system. Figure 1.3 shows the difference between next-day gas prices at SoCal Citygate versus SoCal Border (shown by the yellow line) along with potential noncompliance charges on days when low OFOs were declared (shown as blue dots) for different time periods.

As shown in Figure 1.3, gas prices at SoCal Citygate in the next-day market clearly increased following days when operational flow orders were declared. The magnitude of these gas price increases is correlated with the level of potential noncompliance charges associated with the order. High gas prices often continue to persist for a significant period after OFOs are declared. As shown in Figure 1.3, the magnitude and persistence of high gas prices triggered by the high $25/dth noncompliance charges under Stage 4 orders have become particularly significant in July and August 2018.

Figure 1.3 Impact of potential low OFO noncompliance charges on next-day SoCal Citygate prices

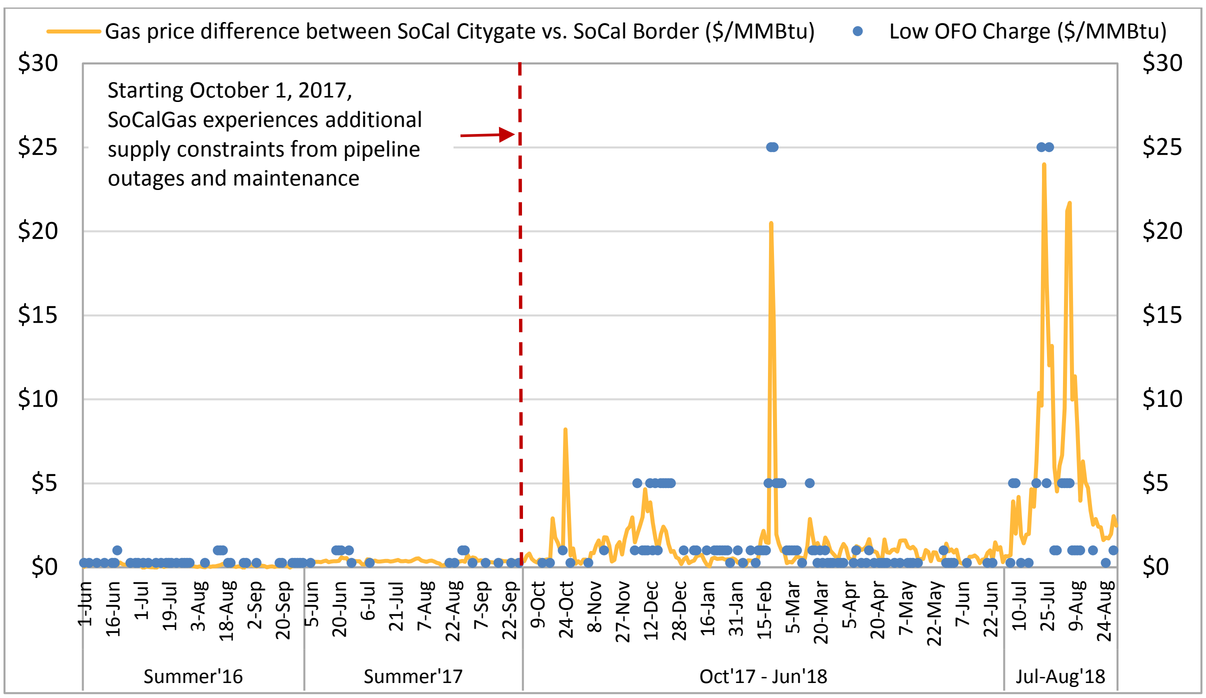


Table 1.1 shows a statistical summary of the difference in next-day gas prices at SoCal Citygate versus SoCal Border for the various periods of time included in Figure 1.3. During summer 2016 (when limitations on the Aliso Canyon gas storage facility were first in effect), average next-day prices at SoCal Citygate were only $0.10/MMBtu (4 percent) higher than prices at SoCal Border. During summer 2017, this price difference increased to $0.36/MMBtu (13 percent). In October 2017, additional limitations on

[7] *DMM response to joint petition for modification of low OFO stage 4 and stage 5 noncompliance charges*, September 4, 2018: http://www.caiso.com/Documents/ResponsetoJointPetitionforModificationofDMMofCAISO-Sept42018.pdf

the SoCalGas system began due to pipeline outages and maintenance. From October 2017 to June 2018, this price difference increased to $1.21/MMBtu (45 percent). During July and August 2018, average next-day prices at SoCal Citygate were $6.17/MMBtu (190 percent) higher than prices at SoCal Border.

Table 1.1 Difference in next-day gas prices at SoCal Citygate vs SoCal Border

Time period	*Difference between gas price at SoCal Citygate versus SoCal Border ($/MMBtu)*		
	Min/Max	Average	Percent
Summer '16 (June - Sept)	-$0.05 - $0.29	$0.10	4%
Summer '17 (June - Sept)	$0.09 - $0.73	$0.36	13%
Oct 2017 - June 2018	$0.05 - $20.50	$1.21	45%
July - August 2018	$0.65 - $24.00	$6.17	190%

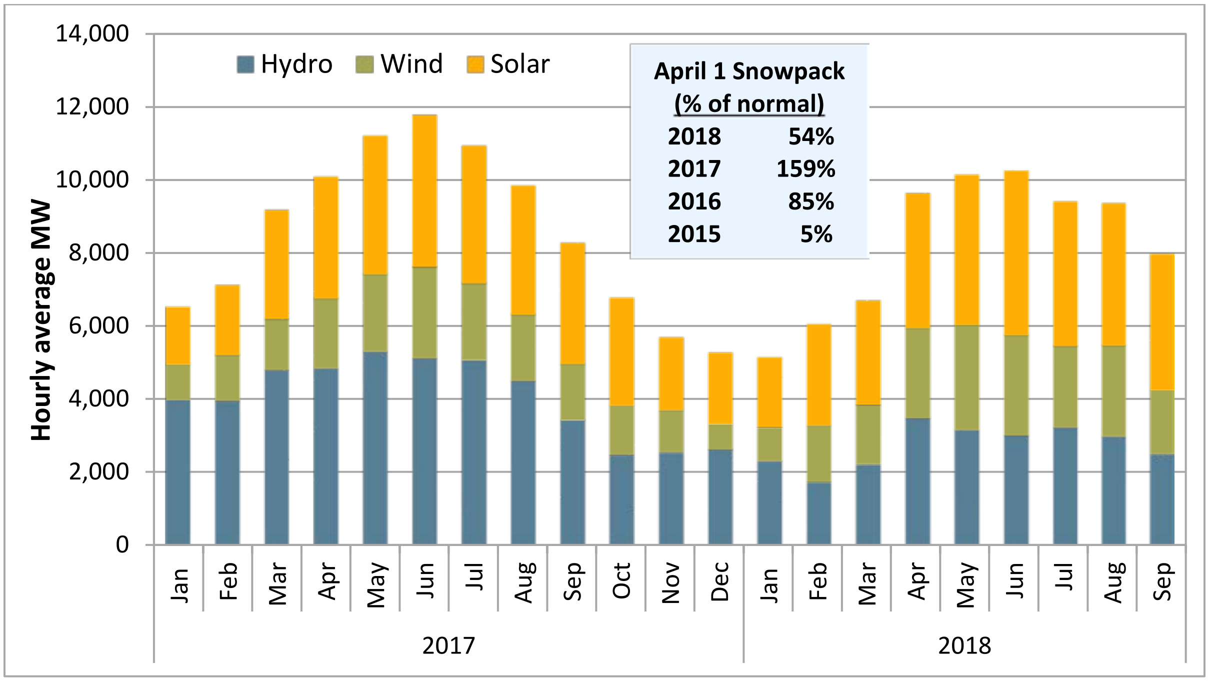
Renewable generation

Overall, total generation from hydroelectric, solar, and wind resources decreased compared to the previous quarter and compared to the third 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 third quarter decreased by roughly 33 percent.

Wind and solar production decreased compared to the second quarter of 2018, following a similar trend between the second and third quarters of 2017. This may be due to the reduced efficiency of solar resources with hotter temperatures. Compared to the third quarter of 2017, wind production was roughly 10 percent greater and solar production roughly 20 percent greater. This is mostly due to an increase in installed capacity.

The availability of renewable resources contributes to patterns in prices seasonally and hourly. Many factors influence the increase in monthly prices seen in Section 1.3. The decrease in renewable production compared to the prior quarter contributes to higher prices due to the low marginal cost of renewables relative to other resources. Midday prices did not fall as low as the previous quarter of 2018 when renewable production was greater (Section 1.3). The 20 percent decrease in solar output is one contributing factor to this trend, as more expensive resources are utilized during the middle of the day.

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



Generation outages

This section provides a summary of generation outages in the first three quarters of 2018. Overall, the total amount of generation outages, and their seasonal variation over the year, was similar to prior quarterly periods.

Under the ISO's current outage management system, known as WebOMS, all outages are categorized as either planned or forced. An outage is considered to be planned if a participant submitted it more than 7 days prior to the beginning of the outage.

Figure 1.5 shows the quarterly averages of maximum daily outages broken out by type during peak hours.[8] Overall, generation outages follow a seasonal pattern with the majority taking place in the non-summer months. This pattern is primarily driven by planned outages for maintenance, as maintenance is performed outside the higher summer load period.

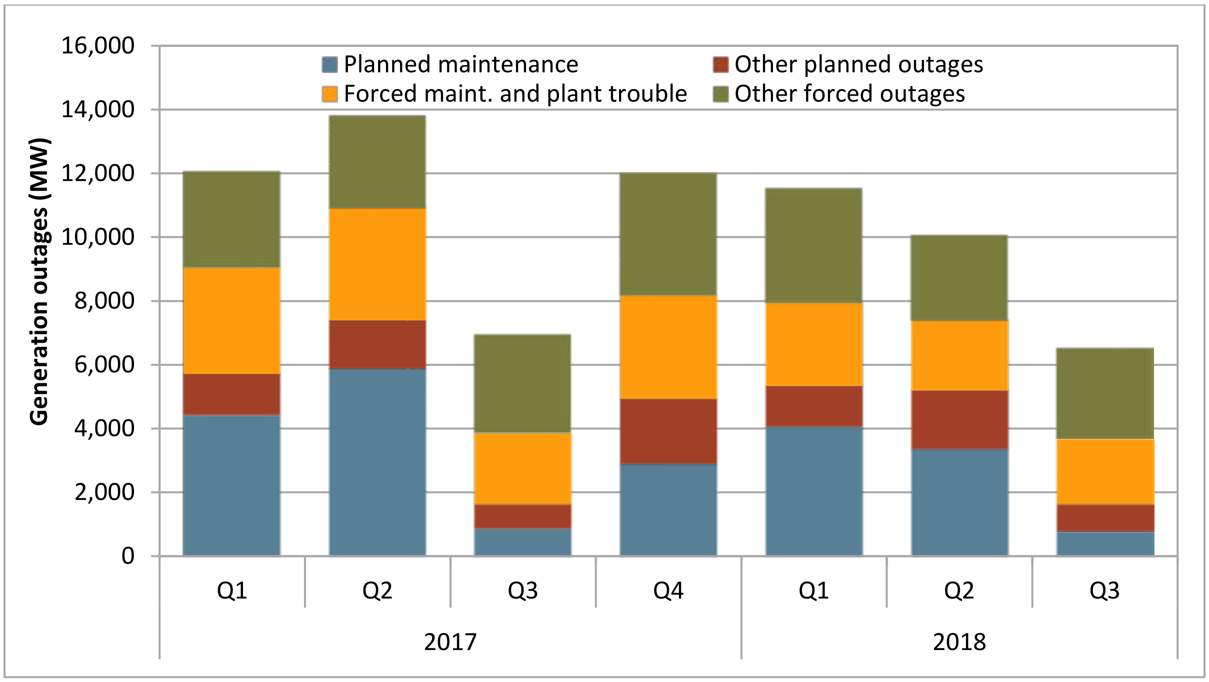
The average total amount of generation outages in the ISO for the third quarter was about 6,500 MW in 2018 compared to 7,000 MW for the same time period in 2017.[9] Outages for planned maintenance decreased by about 100 MW from the previous year and averaged about 800 MW during peak hours. Combined, all other types of planned outages decreased by 50 MW from the same period in 2017 and averaged about 850 MW in the third quarter. Some common types of outages in this category were ambient outages (both due to temperature and not due to temperature) and transmission outages.

[8] WebOMS has a menu of subcategories indicating the reason for the outage. Examples of such categories are: plant maintenance, plant trouble, ambient due to temperature, ambient not due to temperature, unit testing, environmental restrictions, transmission induced, transitional limitations and unit cycling.

[9] This average is calculated as the average of the daily maximum level of outages, excluding off-peak hours. Values reported here only reflect generators in the ISO balancing area and do not include outages from the energy imbalance market.

Forced outages for either plant maintenance or plant trouble totaled about 2,100 MW in the third quarter, about 100 MW decrease from the same time period in the previous year. All other types of forced outages totaled about 2,800 MW for the third quarter of 2018, a decrease of about 300 MW from the same time period in the previous year. This included ambient due to temperature, ambient not due to temperature, environmental restrictions, unit testing and outages for transition limitations. There was less seasonal variation for forced outages compared to planned outages.

Figure 1.5 Average of maximum daily generation outages by type – peak hours



1.3 Energy market performance

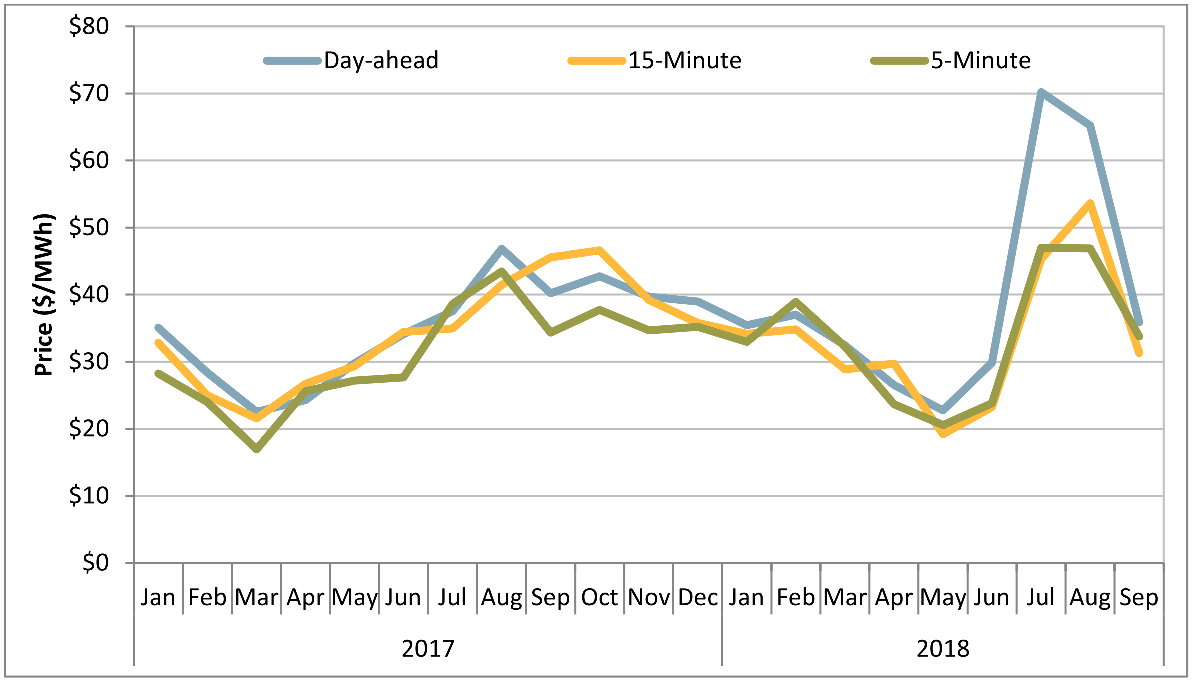
Average monthly energy market prices

This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. Price convergence between these markets may help promote efficient commitment of internal and external generating resources.

Figure 1.6 shows average monthly system marginal energy prices during all hours. During the quarter, average prices increased significantly both from the previous quarter and from the third quarter of 2017. Factors contributing to these trends include increased natural gas prices discussed in Section 1.2.

- Average prices increased compared to the same quarter in 2017. Average day-ahead prices increased by about $16/MWh (37 percent), 15-minute by about $3/MWh (7 percent) and 5-minute market prices by about $4/MWh (10 percent).
- Average monthly day-ahead prices were higher than 15-minute and 5-minute market prices during all months. Average day-ahead prices were around $25/MWh and $12/MWh higher than 15-minute market prices in July and August, respectively.

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

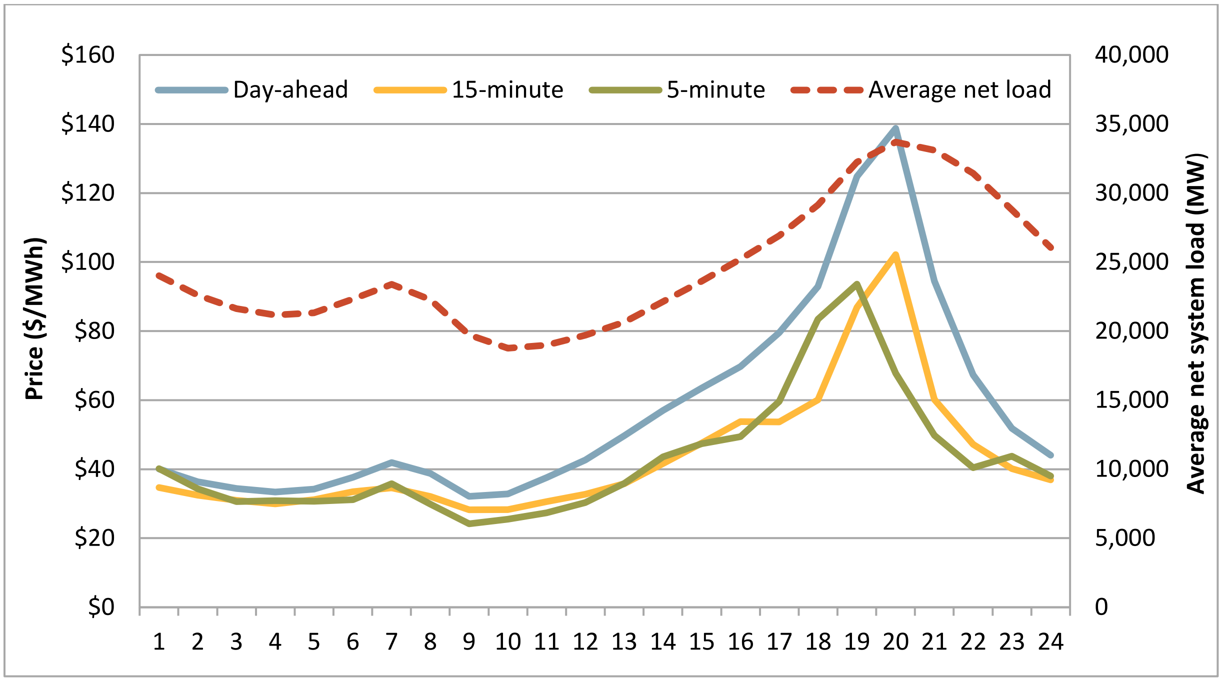


Hourly average energy market prices

Figure 1.7 shows system marginal energy prices on an hourly basis in the third quarter compared to average hourly net load.[10] Hourly prices generally followed the net load pattern with the highest energy prices occurring during the evening peak net load hours. In particular, day-ahead prices were highest during hours ending 19 and 20. Further, average prices in the day-ahead market were higher than 15-minute market prices in all hours.

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

Figure 1.7 Hourly system marginal energy prices



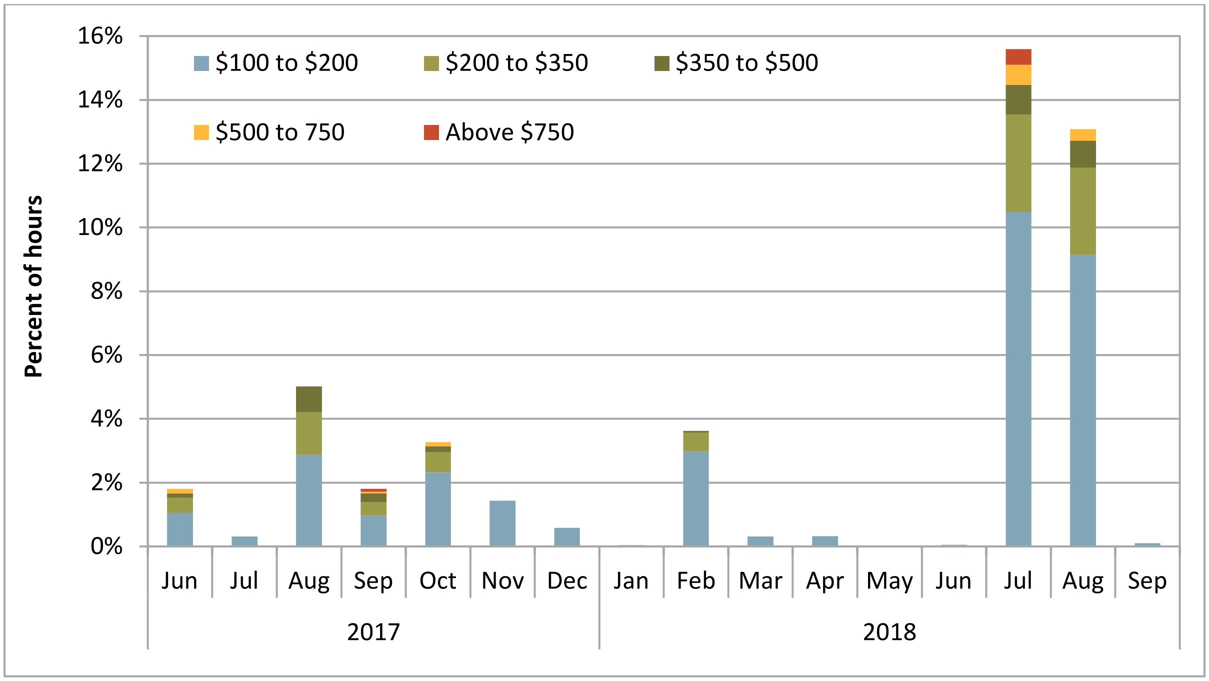
1.4 Day-ahead price variability

Prior to June 2017, system marginal energy prices in the day-ahead market had not reached above $200/MWh since 2009. On June 21, 2017, the day-ahead market experienced record high system marginal energy prices that peaked around $609/MWh related to a system-wide heat wave and associated high loads. Since June 21, 2017, day-ahead market prices greater than $200/MWh have been more frequent, especially during evenings when temperatures and loads are high across the west.

As shown in Figure 1.8, the frequency of high day-ahead prices increased significantly during the third quarter. This was largely driven by extreme temperatures across the western region resulting in high demand and limited natural gas availability. These high prices were concentrated between July 23 and August 10 when loads net of wind and solar were highest.

System marginal day-ahead prices reached record highs on July 24, peaking at almost $980/MWh in hour ending 20. This outcome was driven by tight supply conditions during the hour in combination with very high demand and high gas prices. In particular, there were fewer imports offered and cleared in the day-ahead market on July 23 and July 24 than the previous days. During this period, intertie activity was impacted by extremely high temperatures and loads across the west.

Figure 1.8 Frequency of high day-ahead prices (MWh) by month



1.5 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. Overall during the quarter, the frequency of high prices in the 15-minute and 5-minute markets increased compared to the previous year. However, the frequency of under-supply infeasibilities in both markets was lower relative to the third quarter of 2017.

During the quarter, most high prices occurred as a result of congestion associated with Path 26 (see Section 1.11), which occurred due to high north-to-south flows and multiple outages. 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 lower during the third quarter, both relative to the previous quarter and the same quarter in 2017.

High prices

As shown in Figure 1.9, the frequency of high prices in the 15-minute market increased significantly during the quarter, particularly during August when prices above $250/MWh occurred during over 2 percent of 15-minute intervals. High prices in the 15-minute market were most common during periods when net load was very high, typically between hours ending 18 and 20.

Figure 1.10 shows the monthly frequency of under-supply infeasibilities in the 15-minute market. Under-supply infeasibilities in the 15-minute market during the quarter occurred significantly less frequently than in the third quarter of 2017. All 15-minute market under-supply infeasibilities during the third quarter triggered the load bias limiter. 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 third 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.

Figure 1.11 shows the frequency of high prices in the 5-minute market. The frequency of price spikes greater than $250/MWh in the 5-minute market was about 1.4 percent of intervals in the third quarter, up from around 0.7 percent of intervals in the previous quarter and 1.2 percent of intervals in the third quarter of 2017. However, the frequency of more extreme 5-minute market prices larger than $750/MWh was relatively low compared to the previous year, during around 0.6 percent of intervals.

Figure 1.12 shows the corresponding frequency of under-supply infeasibilities in the 5-minute market. The conditions for the load bias limiter were met during most of the intervals when there were infeasibilities. Similar to the 15-minute market, the frequency of under-supply infeasibilities in the 5-minute market was very low, relative to the previous year. Instead, high prices were largely the result of high gas prices and congestion in the north-to-south direction across Path 26 (see Section 1.11 for more information).

Figure 1.9 Frequency of high 15-minute prices (MWh) by month

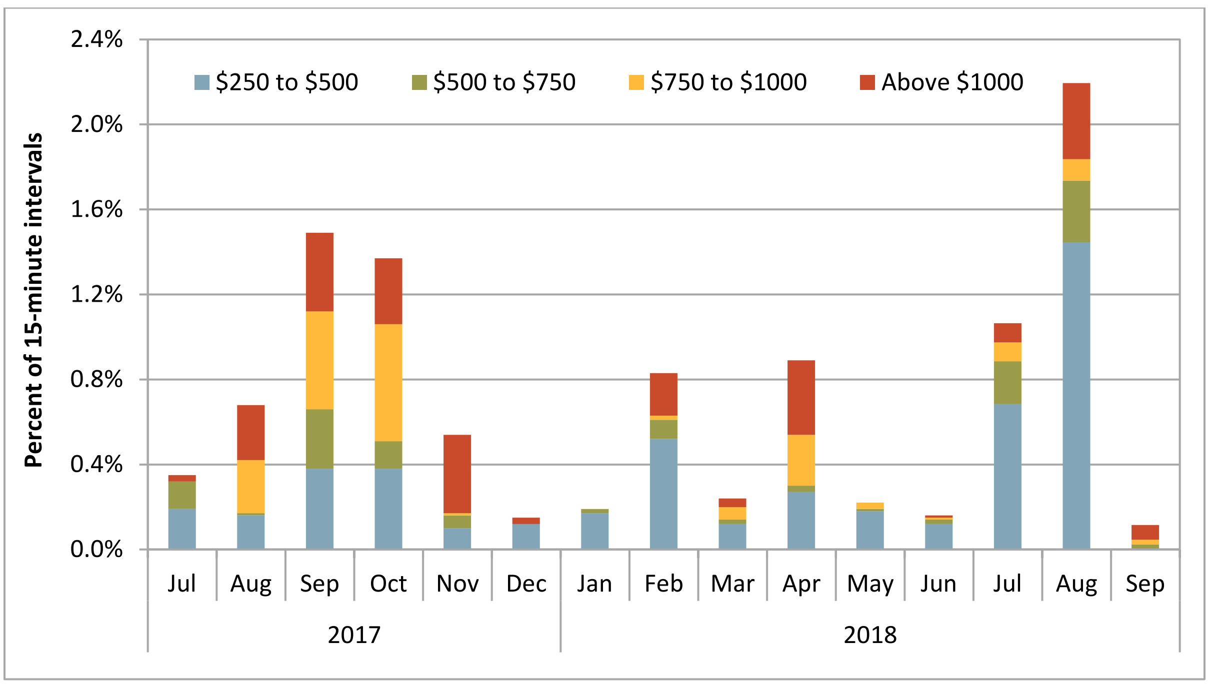


Figure 1.10 Frequency of under-supply power balance constraint infeasibilities (15-minute market)

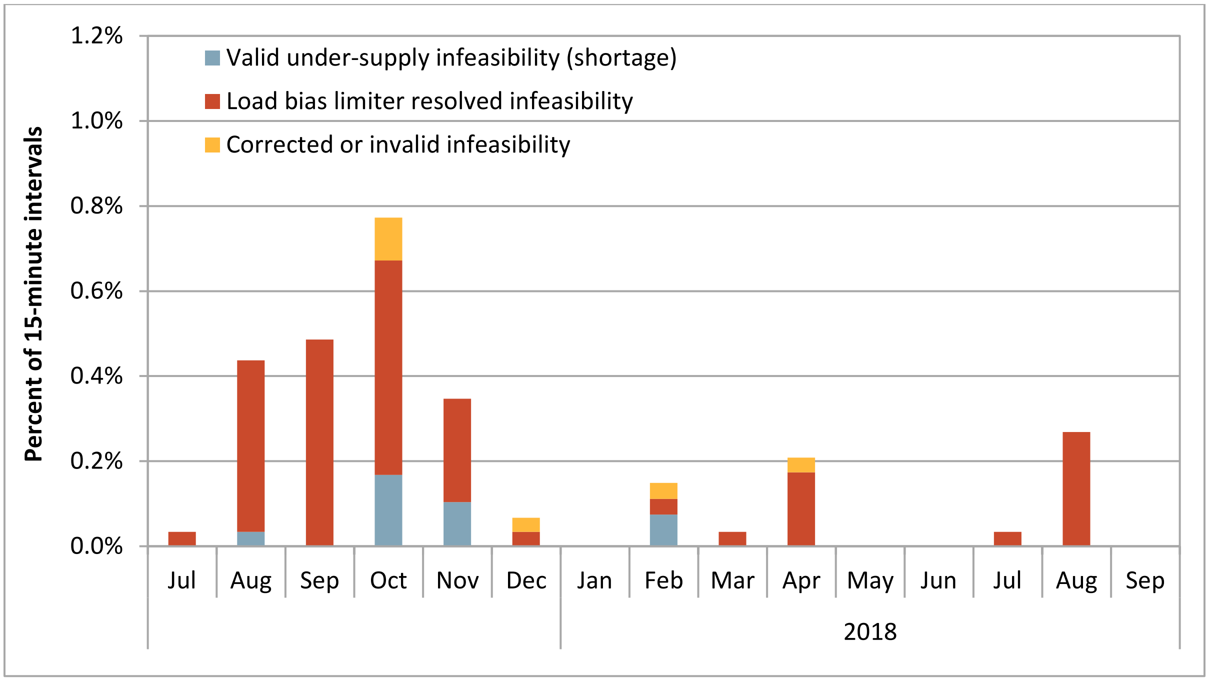


Figure 1.11 Frequency of high 5-minute prices (MWh) by month

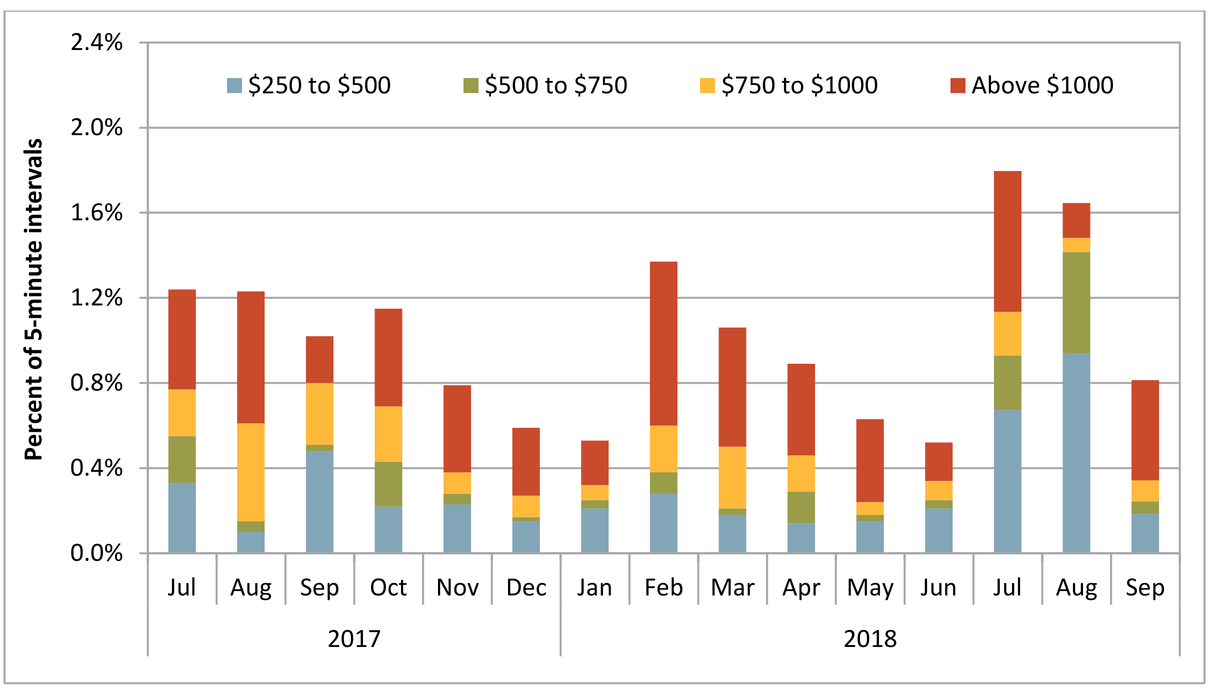
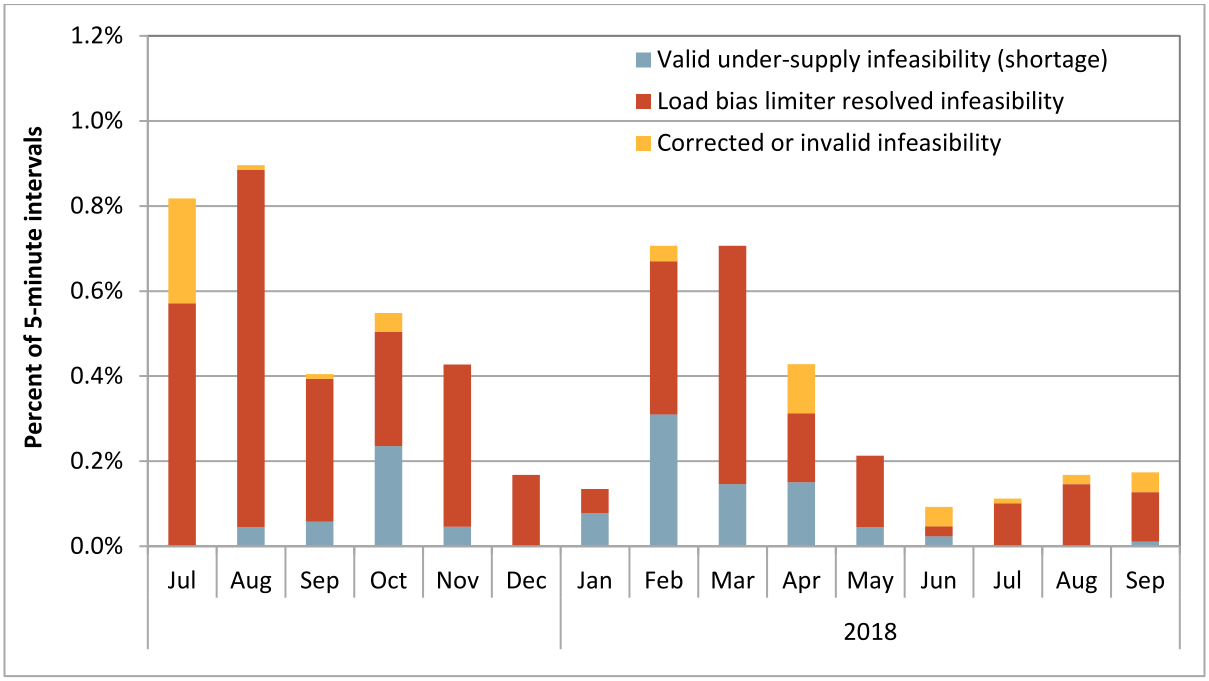


Figure 1.12 Frequency of under-supply power balance constraint infeasibilities (5-minute market)



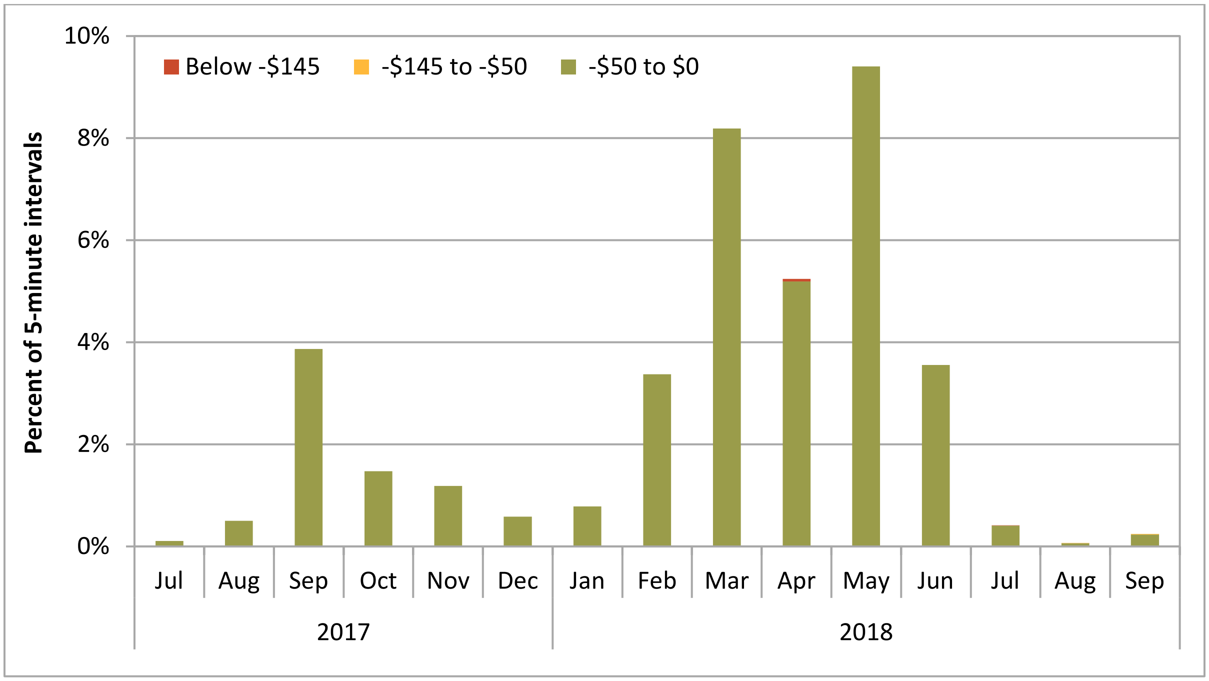
Negative prices

Figure 1.13 shows the frequency of negative prices in the 5-minute market by month.[11] The frequency of negative prices in the 15-minute and 5-minute markets decreased significantly during the third quarter relative to the previous three months. In addition, the frequency of negative prices was lower than in the third quarter of 2017.

Negative prices occurred during less than 0.5 percent of intervals in the 15-minute and 5-minute markets during the third quarter of 2018. In comparison, negative prices occurred during about 4 percent and 6 percent of 15-minute and 5-minute intervals, respectively, during the previous quarter.

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

Figure 1.13 Frequency of negative 5-minute prices by month



1.6 Residual unit commitment

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

As illustrated in Figure 1.14, residual unit commitment procurement appears to be driven in part by the need to replace cleared net virtual supply bids, which can offset physical supply in the day-ahead market run. On average, cleared virtual supply (green bar) was about 35 percent higher in the third 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 uncertainty and fire danger concerns. This tool, noted as operator adjustments (red bar) in the figure, was used frequently in all the months averaging about 982 MW per hour. During most days in the quarter, an adjustment of 2,000 MW was made from hours ending 10 through 22 and an adjustment of 1,000 MW for hours ending 9 and 23.

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 1.14.

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 third quarter of 2018.

Figure 1.14 Determinants of residual unit commitment procurement

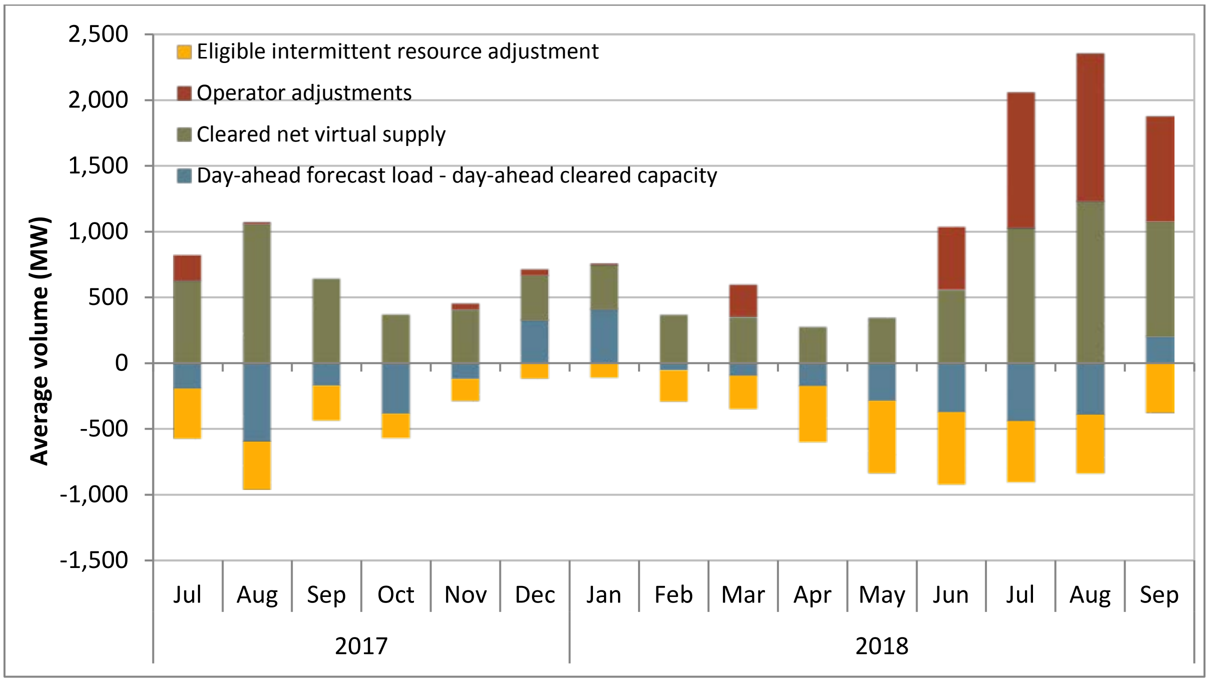
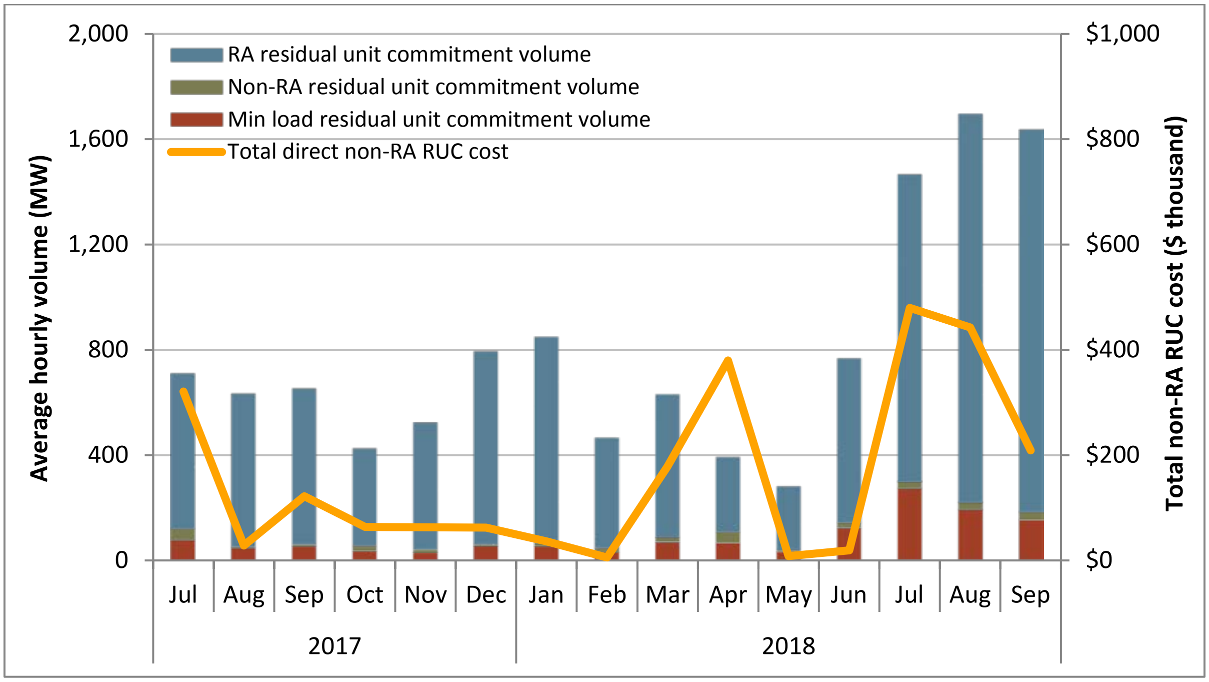


Figure 1.15 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. The figure shows increased residual unit commitment volumes and costs due to high residual unit commitment requirements in the third quarter of 2018. Total residual unit commitment procurement increased to about 1,600 MW per hour in the third quarter of 2018 from an average of 670 MW in the same quarter of 2017. Out of the 1,600 MW per hour residual unit commitment capacity, the capacity committed to operate at minimum load averaged about 207 MW each hour compared to 63 MW in the third 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.[12] The total direct cost of non-resource adequacy residual unit commitment, represented by the gold line in Figure 1.15, more than doubled to $1 million in the third quarter of 2018 compared to 2017.

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

Figure 1.15 Residual unit commitment costs and volume



1.7 Bid cost recovery

Estimated bid cost recovery payments for the third quarter of 2018 totaled about $88 million, the highest cost of any quarter since 2011. This amount was substantially higher than the total amount of bid cost recovery in the previous quarter and in the third quarter of 2017, which were about $21 million and $30 million, respectively.

Bid cost recovery attributed to the day-ahead market totaled about $21 million, significantly up from about $2 million in the prior quarter. Bid cost recovery payments for residual unit commitment during the quarter totaled about $21 million, compared to $3.7 million in the prior quarter. As seen in Figure 1.17, after netting against real-time revenues in the third quarter of 2018, short-start and long-start resources received about $11 million and $10 million, respectively, for residual unit commitment bid cost recovery payments. The significant increase in residual unit commitment bid cost recovery payments in the quarter can be attributed to high volumes of net virtual supply combined with periods of high loads in July and August along with operator adjustments causing the residual unit commitment process to procure more capacity.[13]

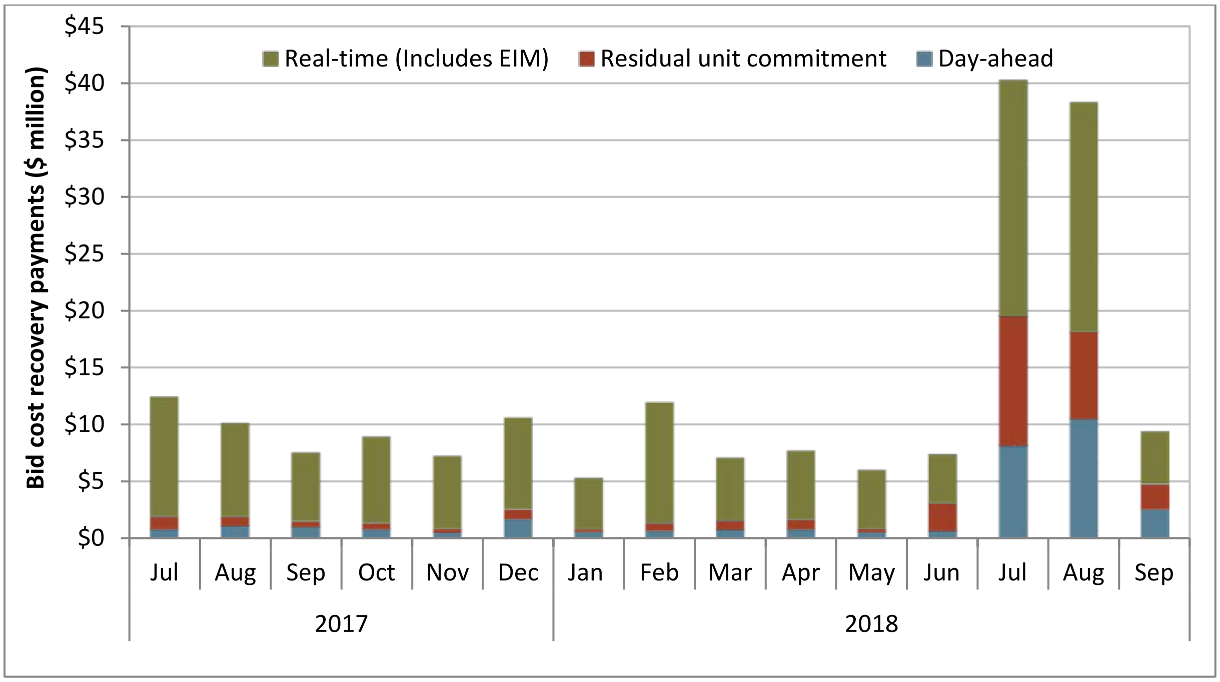
Bid cost recovery attributed to the real-time market totaled about $45 million, compared to $25 million in the third quarter of 2017. Of the $45 million, about $33 million was awarded to gas resources in the SoCalGas service area. More than $25 million of the real-time bid cost recovery payments was awarded to gas resources bidding their start-up and minimum load costs at the 125 percent proxy cost cap.

Bid cost recovery payments for units committed through exceptional dispatches also played an important role in real-time bid cost recovery payments. DMM estimates that units committed in the real-time market for exceptional dispatches totaled about $27 million in the third quarter of 2018.

[13] Refer to Section 1.6 for more information on residual unit commitment sources.

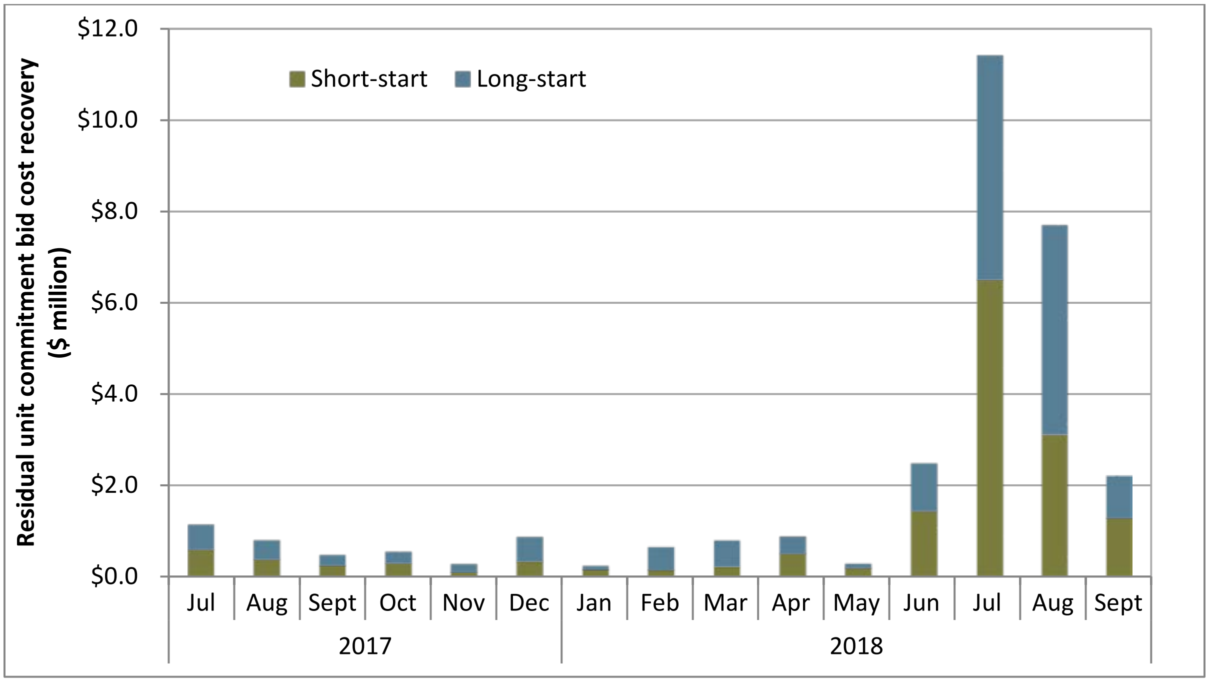
Exceptional dispatches are tools that operators can use to help ensure reliability across the system. In the third quarter, the majority of these exceptional dispatches were due to load forecast uncertainty in July and August.[14]

Figure 1.16 Monthly bid cost recovery payments



[14] Refer to Section 1.12.3 for more information on exceptional dispatches.

Figure 1.17 Residual unit commitment bid cost recovery payments by commitment type



1.8 Real-time imbalance offset charges

Third quarter real-time imbalance offset charges increased to about $79 million from about $20 million in each of the first and second quarters.[15] Real-time congestion imbalances accounted for $75 million of the total charges—the highest quarterly congestion imbalances since 2012. Persistent and significant constraint limit reductions from the day-ahead to real-time markets, combined with high real-time congestion prices, led to the high congestion imbalance charges. However, the actual net financial transfer from measured demand may be significantly less than the real-time congestion offset amount because, on the constraints associated with the charges, schedules paid day-ahead congestion prices while the offset charge only accounts for the schedules being paid the real-time prices for reducing constraint flows in real-time. Further, a significant portion of the schedules being paid to reduce flows on the constraints in real-time were from entities with measured demand.

Third quarter real-time energy and loss offset charges were about $4 million and $0.5 million each.

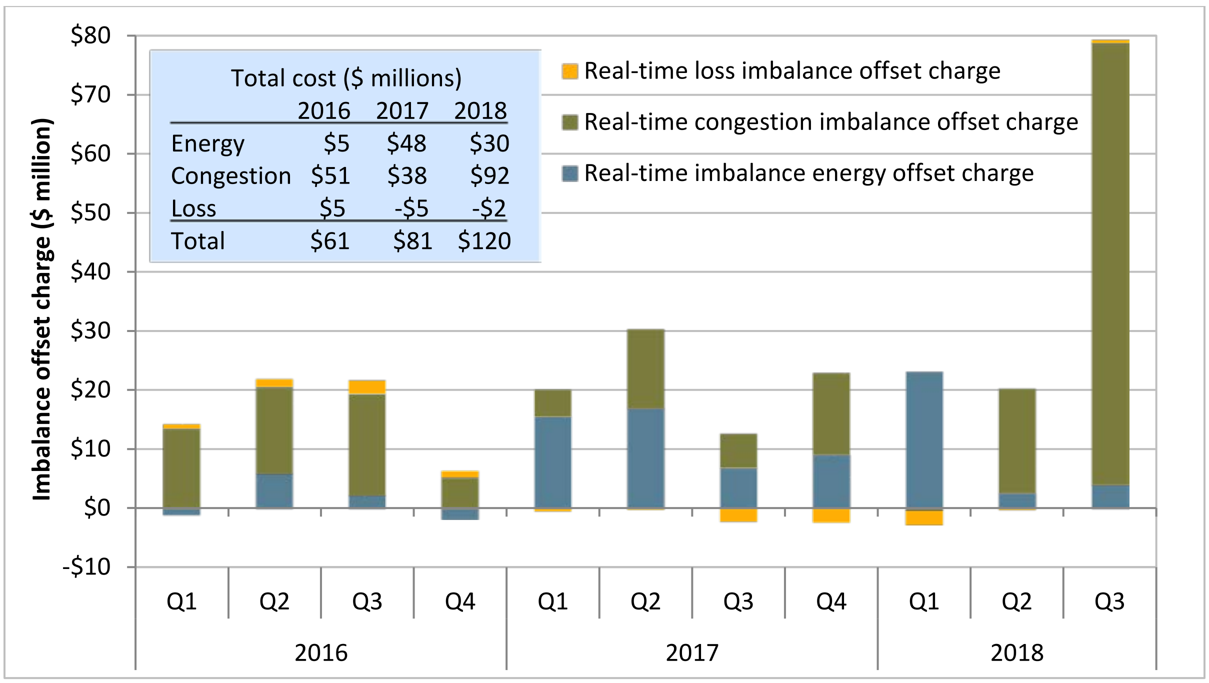
Real-time imbalance offset charges are the difference between the total money paid out by the ISO and the total money collected by the ISO for energy schedules settled in the real-time markets. Within the ISO system, the charge is allocated to measured demand (metered load plus exports). An important note is that, while an indicator of potential market issues, real-time offset charges are an accounting construct. Offset charges do not equal economic costs nor do these charges necessarily equal financial transfers from measured demand to other entities. Real-time imbalance offset charges can be split into three components:

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

- *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.
- *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 1.18 shows quarterly imbalance charges. The $75 million in third quarter real-time congestion imbalance charges were several times higher than any other recent quarter, including the $18 million in the second quarter. Energy imbalance charges were around $4 million, up from nearly $3 million in the second quarter. Loss imbalance charges were about $0.5 million, up from -$0.2 million.

Figure 1.18 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.[16] 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

[16] 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.

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.[17]

Table 1.2 shows estimated constraint specific day-ahead to 15-minute market congestion imbalance charges for the ten highest constraints by imbalance. These ten constraints accounted for about $60 million of the 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.[18] Table 1.2 also shows the average day-ahead limits, the average limit change from the day-ahead to 15-minute market, and estimated congestion revenue right revenue adequacy surpluses. Both day-ahead limit and limit changes are averaged over intervals when 15-minute market limits are binding.

Table 1.2 shows persistent and significant constraint limit reductions in the 15-minute market across most of the binding 15-minute market hours for most of the constraints in the list. It appears that, combined with significant 15-minute market congestion prices, these persistent limit reductions caused the majority of the real-time congestion imbalance charges.

All the constraints in Table 1.2, except for Malin, are in the south or restrict north-to-south power flows. These constraints were the main drivers of real-time price separation between the north and south in the third quarter, as reported in Section 1.11.2. Further, several of these constraints generated large amounts of congestion revenue right revenue adequacy surpluses, driving the overall third quarter surplus (see Section 1.13).

Table 1.2 Estimated Q3 15-minute market congestion imbalances – top 10 constraints[19]

Constraint	Estimated imbalances (million $)	Total hours in quarter				Avg DA limit (MW)	Avg limit change (MW)	Estimated CRR surpluses (million $)
		Binding in FMM	w/ lower FMM limit	w/o lower FMM limit	w/o DA limit			
30060_MIDWAY_500_24156_VINCENT_500_BR_1_1	($14.6)	288	251	2	35	2,094	(506)	$36.6
24016_BARRE_230_24154_VILLAPK_230_BR_1_1	($13.7)	221	206	7	8	1,373	(256)	$2.2
6410_CP5_NG	($8.3)	158	113	15	30	1,288	(681)	$3.3
6510_CP1_NG	($8.0)	60	0	0	60	.	.	$0.0
30055_GATES1_500_30900_GATES_230_XF_11_S	($5.1)	213	132	2	79	1,110	(204)	($1.5)
6410_CP1_NG	($4.5)	67	60	2	5	3,133	(1,309)	$10.4
30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	($2.7)	88	6	49	33	2,172	240	$0.0
MALIN500	($2.3)	89	58	31	0	2,715	(325)	($1.2)
24016_BARRE_230_25201_LEWIS_230_BR_1_1	($1.1)	29	23	4	2	1,528	(291)	$1.7
22192_DOUBLTTP_138_22300_FRIARS_138_BR_1_1	($1.0)	259	214	36	9	162	(15)	($8.6)

17 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

18 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.

19 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.

Figure 1.19 shows the day-ahead market limits, 15-minute market limits, day-ahead market schedule settled flows and day-ahead congestion revenue right settled flows for the Midway-Vincent 1 constraint for hours where the constraint was binding in the 15-minute market. The figure shows all hours between July 27 and August 23.

Settled flows are the flows over the constraint that are paid or charged the constraint congestion price. Flows that are not subject to the ISO prices, or flows from nodes whose impact on a constraint is too small to receive a shift factor, are not settled on the constraint congestion price.[20] The sum of settled and unsettled flows will always be less than or equal to constraint limits. Settled flows are calculated as the sum of the schedule or congestion revenue right megawatts multiplied by their shift factors. Because the total flows on Midway-Vincent 1 do not exceed the limit, and the settled flows are greater than the limit, the total unsettled flows on net provide counterflow to the constraint.

Flows that are not subject to ISO prices include flows from full network model base schedules. These base schedules are designed to allow the ISO markets to account for unscheduled flows from outside the ISO market. The ISO has explained to DMM that full network model base schedules, particularly over high voltage DC lines, created unsettled counterflow that resulted in net settled flows above the constraint limit for Midway-Vincent and other major north-to-south constraints. The ISO also explained that the base schedule counterflow was generally consistent between the day-ahead and 15-minute markets.

Reduced limits between the day-ahead and real-time markets, rather than differences between limits and settled flows or changes in unsettled flows, drove the 15-minute market congestion imbalances on Midway-Vincent 1.

Midway-Vincent 1's 15-minute market limits and congestion revenue right settled flows are generally around 1,500 megawatts. The day-ahead market limits and schedule flows were significantly higher at around 2,100 and 2,800 megawatts on average. The difference between day-ahead schedule and congestion revenue right settled flows resulted in revenue surpluses on the constraint. Midway-Vincent 1 accounted for a very large portion of the overall congestion revenue right revenue adequacy surpluses (see Section 1.13). The average Midway-Vincent 1 limit change between the day-ahead and 15-minute markets was about negative 500 MW. The average settled flow change, measured as the difference between day-ahead settled flow and the 15-minute market settled flows was about negative 680 MW.[21] This suggests reduced 15-minute market limits were a primary cause of negative congestion imbalances on Midway-Vincent 1 and not changes in non-settled flows. The ISO has explained that limits were reduced in real-time to conform to actual conditions.

Persistent and significant constraint differences between the day-ahead and real-time markets can reduce the efficiency of the ISO markets as the day-ahead market attempts to set up schedules to meet conditions that will not occur in real-time. The real-time markets must then meet the actual constraint limits given restrictions and unit commitments that were optimized to meet the different day-ahead constraint limits.

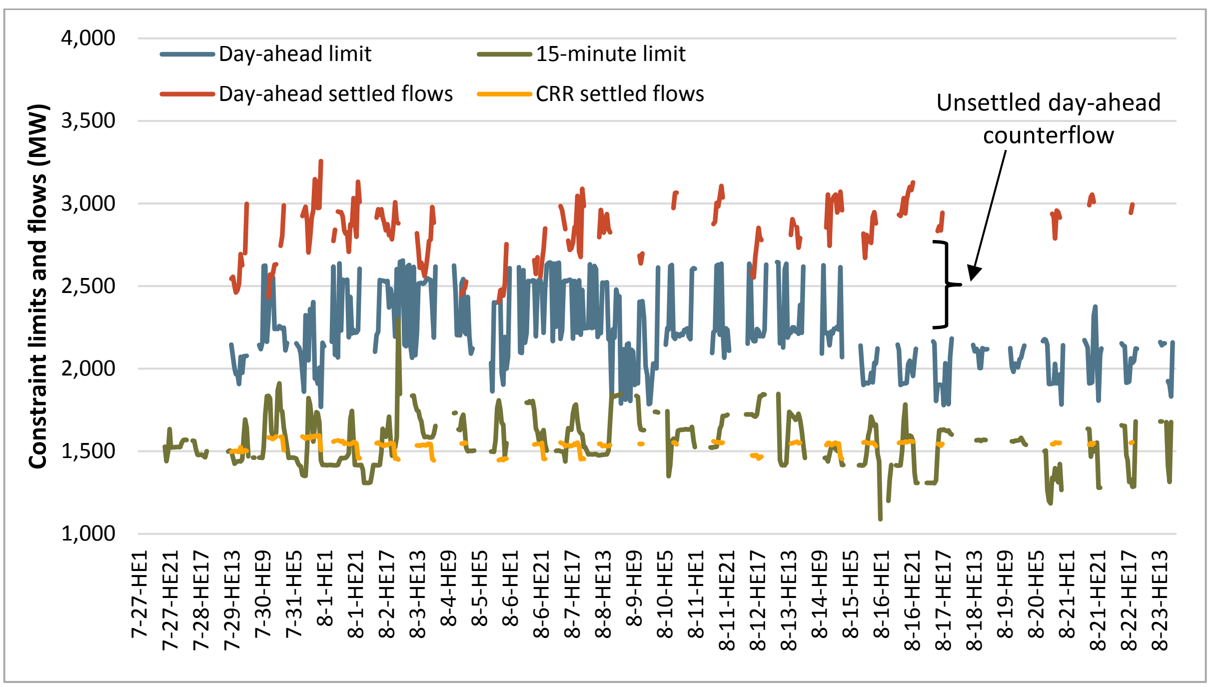
[20] Shift factors are the effect of an injection at a location on the flow over a constraint as modeled in the market run. Shift factors less than 0.02 in absolute value are excluded from the market run. An example of schedules not subject to ISO prices are day-ahead market full network model base schedules.

[21] DMM measures settled flow change as the difference between day-ahead schedule settled flows and the 15-minute market settled flows. The average is calculated over intervals when the limit was binding in the 15-minute market.

Unlike some previous periods with high real-time congestion imbalance charges, such as 2012, the congestion imbalance charges appear to be primarily associated with changes in physical generation, load, and intertie schedules rather than virtual bid schedule changes. To the extent that the payments funded by the real-time congestion imbalance offset charges were paid to entities with measured demand, measured demand would be paying itself. Also, to the extent that the schedules with reduced real-time flows paid day-ahead congestion prices, the real-time congestion imbalances would be higher than the actual financial transfers from entities with measured demand to those without.

As reported in Section 1.1, the day-ahead cleared load was significantly higher than real-time load. Reduced real-time loads led to a portion of the reduced flows on real-time constraints being paid the real-time congestion prices. Further, as shown in Section 1.11.1 and Section 1.11.2, the average effect of Midway-Vincent 1 on SCE prices when congested were $15.72/MWh in the day-ahead and $26.56/MWh in the 15-minute market. For Path 26 CP1 the day-ahead effects were $14.66/MWh and 15-minute effects were $29.97/MWh. Path 26 CP5 effects were $14.27/MWh and 15-minute effects were $20.13/MWh. While not a full accounting, both the day-ahead congestion prices relative to real-time suggest that the actual net financial transfer from measured demand was significantly less than the real-time congestion offset amount. Further, a significant portion of the schedules being paid to reduce flows on the constraints in real-time were from entities with measured demand.

Figure 1.19 Midway-Vincent 1 limits and settled flows[22]



22 30060_MIDWAY_500_24156_VINCENT_500_BR_1_1

1.9 Ancillary services

1.9.1 Ancillary service requirements

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

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

In the past, only four of these regions were typically utilized: expanded system (or expanded ISO), internal system, expanded South of Path 26, and internal South of Path 26. Since December 14, 2017, operators began setting expanded and internal North of Path 26 region minimum requirements to match the expanded and internal South of Path 26 region requirements. The new requirements were initially entered as a result of outages but were maintained to help with the distribution of ancillary service procurement across the ISO, particularly in preparation for the implementation of the NERC reliability standard, BAL-002-2.[23]

During the third quarter, operating reserve requirements in the day-ahead market have typically been set to 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.[24] Operating reserve requirements in real-time were calculated similarly except using 3 percent of the load forecast and 3 percent of generation instead of 6.3 percent of the load forecast.

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. Beginning January 1, 2018, 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) were accounted for in the calculation of

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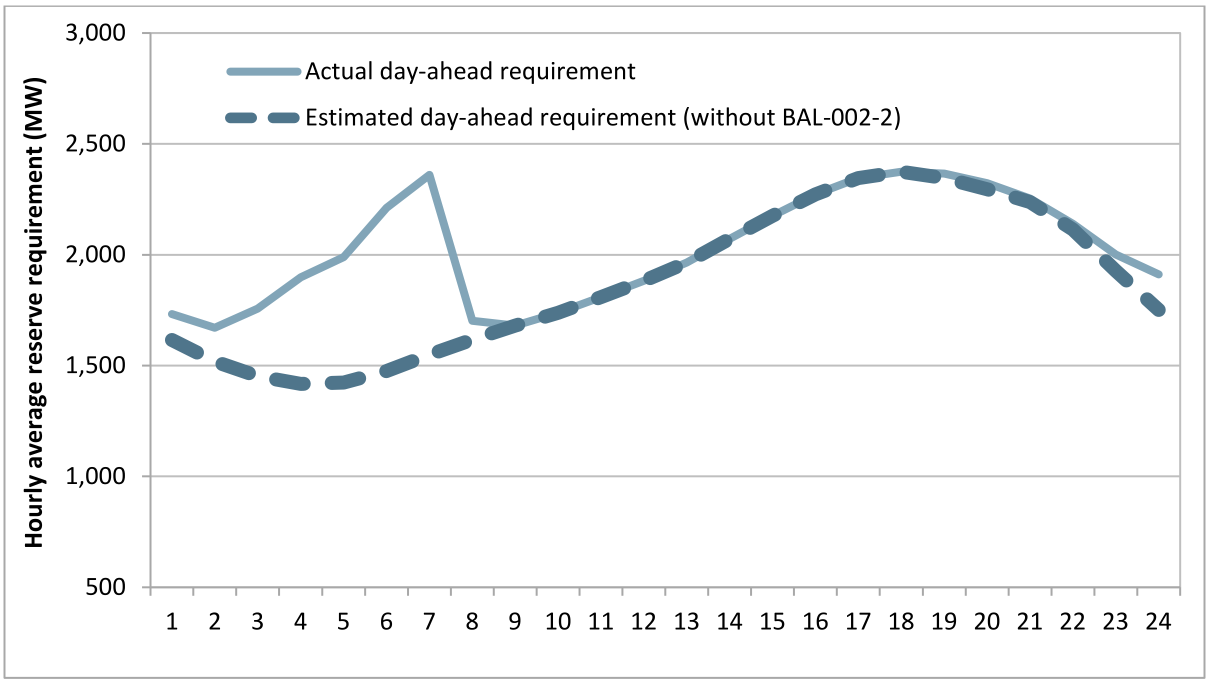
[23] Further information on BAL-002-2 and operating reserve requirement changes implemented by the ISO is available here: http://www.caiso.com/Documents/Presentation-BAL-002-2DisturbanceControlStandard-kContingencyReserveforRecoveryfromaBalancingContingencyEvent.pdf
or in the NERC BAL-002-2 reliability standard here: http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-2.pdf.

[24] The ISO added functionality to explicitly pull solar forecasts when setting ancillary service requirements in early May after the 15 percent threshold began binding in late April. The 15 percent is only of solar units with the potential for the inverter issue. The ISO indicated that the 25 percent solar criteria was reduced to 15 percent effective September 19, 2017.

operating reserve requirements. This change resulted in an increase to the operating reserve requirements overall.

Figure 1.20 shows actual average operating reserve requirements during the third quarter as well as estimated average operating reserve requirements had the changes associated with BAL-002-2 not been implemented.[25] Unlike the previous quarter, the impact of the new definition on operating reserve requirements was largely limited to morning hours during the quarter. Actual day-ahead operating reserve requirements were on average around 580 MW higher during morning hours ending 3 through 7. For comparison, day-ahead operating reserve requirements during the second quarter were on average around 900 MW higher during both morning hours ending 1 through 7 and evening hours ending 19 through 24.

Figure 1.20 Hourly average operating reserve requirement (July – September)



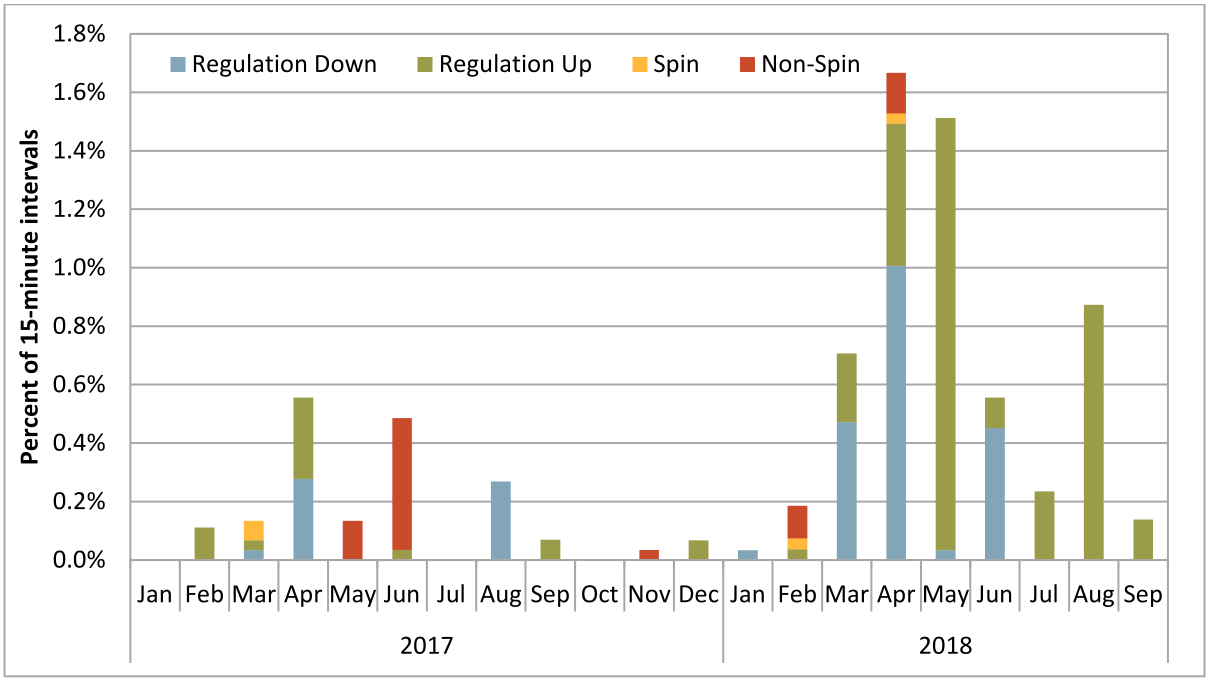
1.9.2 Ancillary service scarcity

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 1.21, the number of intervals with scarcity pricing decreased from the previous quarter, but remained high in comparison to the third quarter of 2017. During the quarter, all of the scarcity intervals were for regulation up and almost all in the expanded South of Path 26 region.

[25] Corresponding values for the real-time requirement are not included, but show a similar pattern.

Figure 1.21 Frequency of ancillary service scarcities (15-minute market)



The increase in scarcity events in real-time from the previous year is associated with both (1) modifications to the ancillary service requirements and (2) observed changes between available capacity between the day-ahead and 15-minute markets. First, higher operating reserve requirements and the enforcement of a North of Path 26 sub-regional requirement in 2018 put increased pressure on the supply stack to meet ancillary service requirements. Next, decreases in available ancillary services in real-time from schedules in the day-ahead market prompted the majority of the scarcity events.

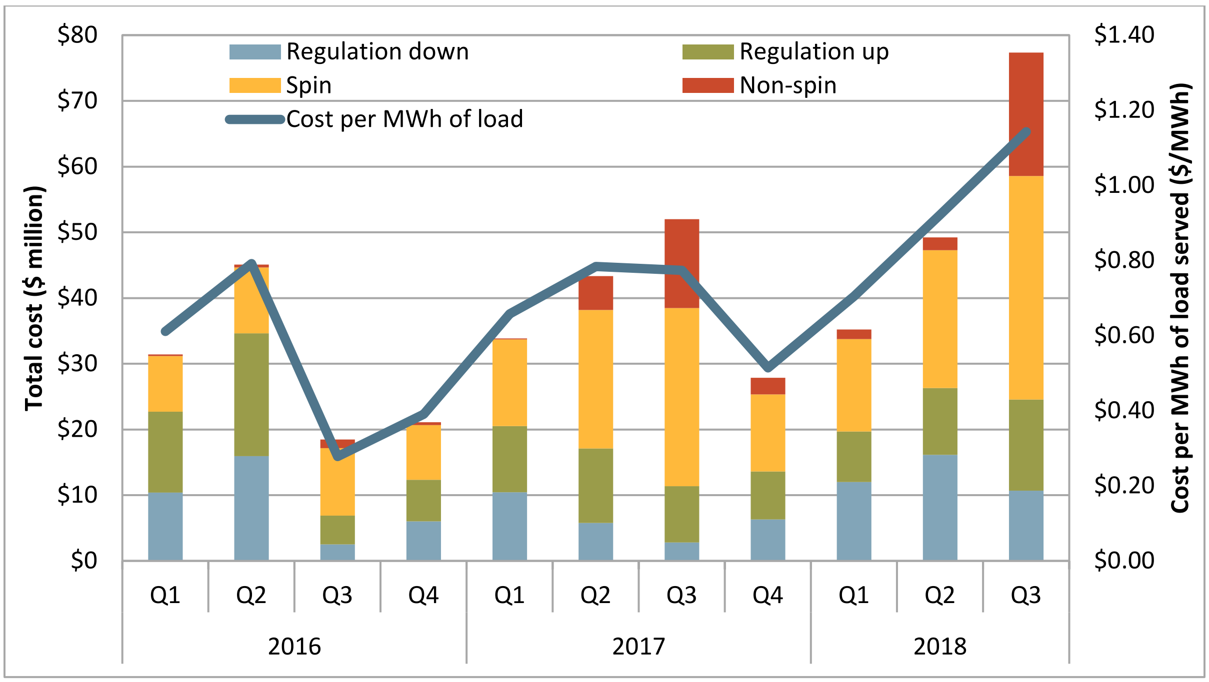
In particular, ancillary services scheduled in the day-ahead market can be capped in real-time at telemetry limits submitted by the plant. This can be a fraction of a megawatt that must then be replaced by other units to meet ancillary service requirements. However, it can often be economic to relax the requirement in this scenario at the scarcity price in lieu of committing a unit or moving a unit to a higher bid segment. This is because the majority of ancillary services are settled at the day-ahead market price with only incremental real-time awards settled at the 15-minute market price. For this reason, over 75 percent of the scarcities in 2018 were for less than 5 MW.

1.9.3 Ancillary service costs

Costs for ancillary services increased during the third quarter largely due to tight supply conditions and high day-ahead market prices during the summer. Costs for ancillary services totaled about $77 million during the third quarter, compared to about $49 million in the previous quarter and $52 million during the same quarter in 2017.[26]

Figure 1.22 shows the total cost of procuring ancillary service products by quarter and the total ancillary service cost for each megawatt-hour of load served. Ancillary service costs during the quarter were largely focused between hours ending 18 and 21 on the highest load days during the summer when day-ahead market energy prices were similarly high. As a result, the increase in operating reserve requirements associated with the BAL-002-2 reliability standard, which was mostly limited to morning hours during the quarter, did not have a significant impact on ancillary service costs during the third quarter.

Figure 1.22 Ancillary service cost by product



1.10 Convergence bidding

Overall, convergence bidding was profitable for the third quarter and virtual supply was profitable for the third consecutive quarter. Before accounting for bid cost recovery charges, virtual supply generated net revenues of about $46.6 million while virtual demand net revenues were a loss of about $14.7 million. Combined net revenues for virtual supply and demand were about $20 million after accounting for about $11.9 million of virtual bidding bid cost recovery charges.

[26] 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.

1.10.1 Convergence bidding trends

Average hourly cleared volumes increased to about 3,300 MW from about 3,000 MW in the previous quarter. Average hourly virtual supply increased to about 2,200 MW compared to the previous quarter at about 1,700 MW. Virtual demand averaged around 1,100 MW during each hour of the quarter, lower than the previous quarter of about 1,300 MW. On average, about 65 percent of virtual supply and demand bids offered into the market cleared in the third quarter, an increase from the previous two quarters of about 38 percent.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 1,050 MW on average, which is a large increase from about 400 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 hour – hour ending 19. In the remaining 23 hours, net cleared virtual supply exceeded net cleared virtual demand, with 16 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 23 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 1,050 MW of virtual demand offset by 1,050 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 65 percent of all cleared virtual bids in the third quarter, up from about 47 percent in the previous quarter.

1.10.2 Convergence bidding revenues

Participants engaged in convergence bidding in the third quarter were profitable overall. Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $32 million. Net revenues for virtual supply and demand fell to about $20 million after including about $12 million of virtual bidding bid cost recovery charges.[27]

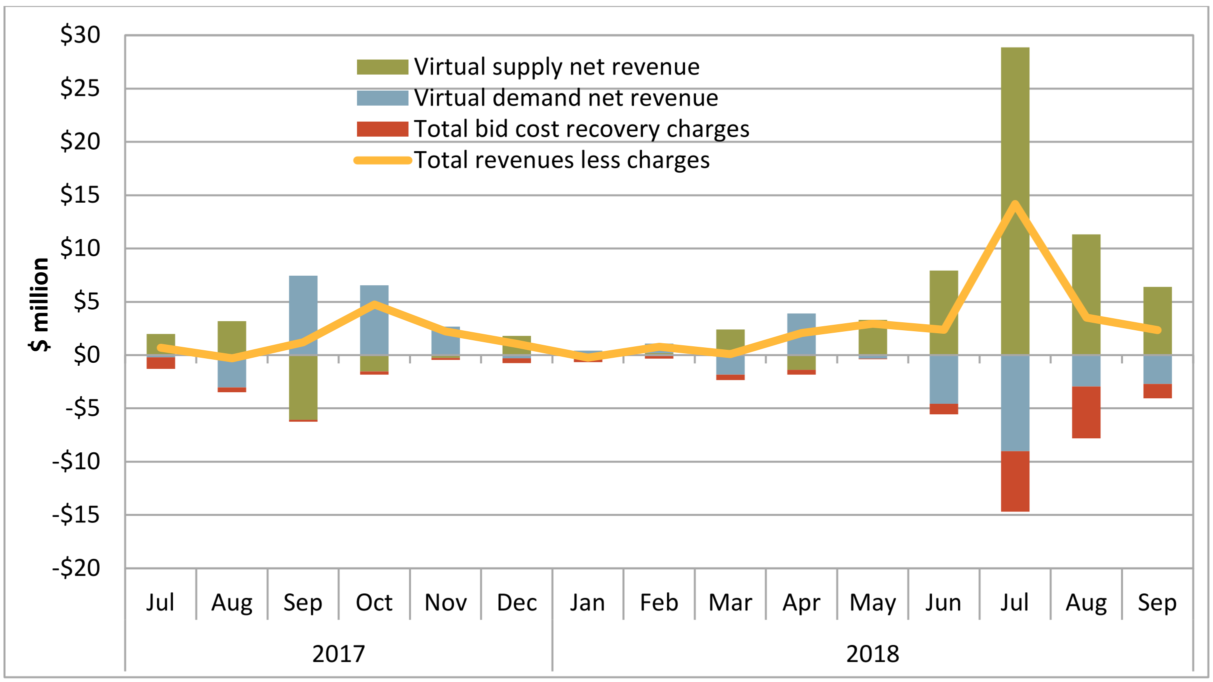
Figure 1.23 shows total monthly net revenues for virtual supply (green bars), total net revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line).

[27] 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.

Before accounting for bid cost recovery charges:

- Total market revenues were positive during all three months in the quarter. Net revenues during the third quarter totaled about $32 million, compared to about $3.2 million during the same quarter in 2017, and about $9 million during the previous quarter.
- Virtual demand net revenues were negative in all months of the quarter. In total, virtual demand generated negative net revenues of about $14.7 million for the quarter.
- 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 $46.6 million.

Figure 1.23 Convergence bidding revenues and bid cost recovery charges



After accounting for bid cost recovery charges:

- Convergence bidders received about $20 million after subtracting bid cost recovery charges of about $12 million for the quarter.[28,29] Bid cost recovery charges were about $5.7 million in July, $4.9 million in August and $2.7 million in September.

[28] 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.

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

Net revenues and volumes by participant type

Table 1.3 compares the distribution of convergence bidding cleared volumes and net revenues, in millions of dollars, among different groups of convergence bidding participants in the third quarter.[30] Financial entities represented the largest segment of the virtual bidding market, accounting for about 67 percent of volume and 75 percent of settlement revenue. Marketers represented about 31 percent of the trading volumes and about 20 percent of settlement revenue. Generation owners and load-serving entities represented a smaller segment of the virtual market in terms of both volumes and settlement revenue, at about 2 percent and 5 percent respectively. Unlike the last two quarters, where load-serving entities accounted for about $0.2 million in net payments to the market, in the third quarter load-serving entities received around $1.2 million in net payments from the market.

Table 1.3 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	750	1,476	2,226	-$8.91	$33.23	$24.33
Marketer	388	661	1,050	-$5.52	$11.95	$6.43
Physical load	0	47	47	$0.00	$1.40	$1.40
Physical generation	7	8	15	-$0.23	$0.02	-$0.21
Total	**1,145**	**2,192**	**3,338**	**-$14.7**	**$46.6**	**$32.0**

1.11 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.

30 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.

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.[31] 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*.[32]

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.

1.11.1 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 1.24 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 a greater impact on prices than any quarter since the beginning of 2017. Similar to the first half of 2018, congestion increased prices in the SCE and SDG&E areas and decreased prices in the PG&E area.

SDG&E area prices increased about $7.6/MWh (11 percent), compared to an increase of almost $3.5/MWh (12 percent) in the previous quarter. In the SCE area, prices increased $5/MWh (8 percent), compared to almost $1/MWh (3 percent) the previous quarter. In the PG&E area, prices decreased by $8/MWh (16 percent) compared to nearly $1/MWh (3 percent) the previous quarter. These impacts were all greater in magnitude than the impact on prices during any prior quarter in 2017 or 2018.

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

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

Figure 1.24 Impact of congestion on day-ahead prices

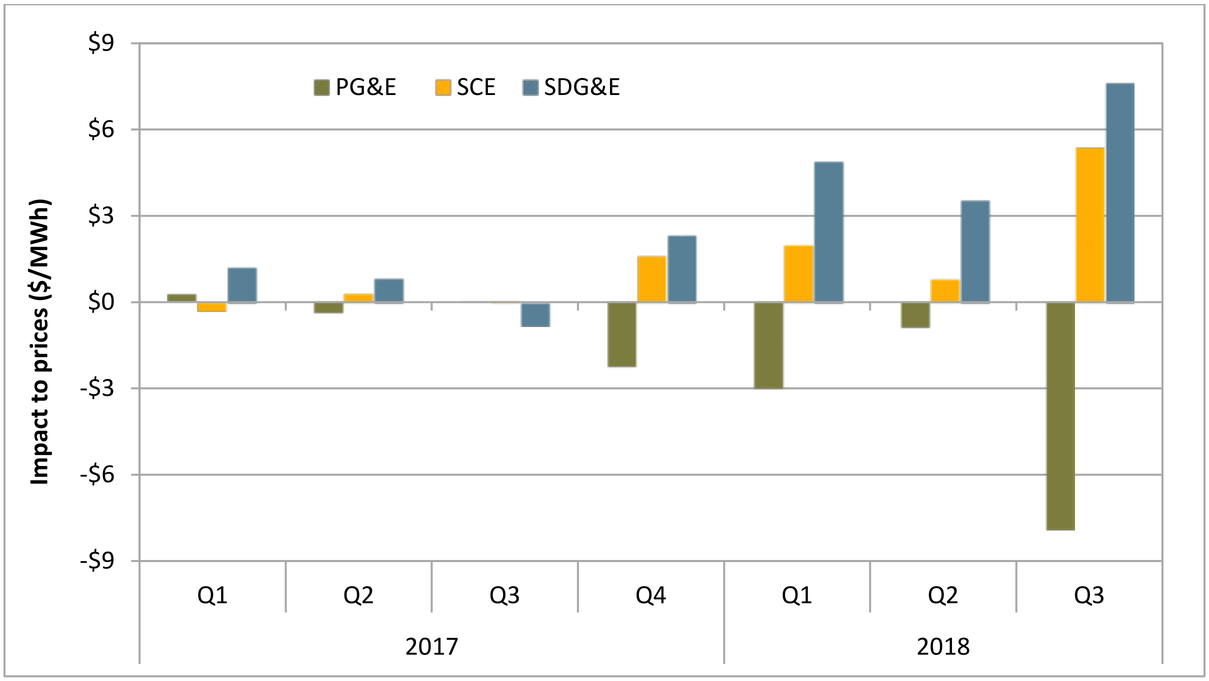


Table 1.4 breaks down the impact to prices in the third quarter by constraint.[33] The primary cause of overall price separation between the ISO areas was congestion on Path 26, which is composed of three lines: the Midway-Vincent 1 500 kV line (30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1), the Midway-Vincent 2 500 kV line, and the Midway-Whirlwind 500 kV line (30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2). In addition, two nomograms that are enforced to manage flows over Path 26, the 6410_CP5_NG and the 6410_CP1_NG also impacted prices during the quarter. Overall, congestion related to Path 26 contributed to roughly 85 percent of the price difference in PG&E and SCE, and roughly 55 percent of the price difference in SDG&E.

In the SDG&E area, the Imperial Valley (7820_TL 230S_OVERLOAD_NG) and the East County-Miguel (7820_TL23040_IV_SPS_NG) nomograms contributed to about 20 percent of the price difference for that area. More information regarding individual constraints is discussed below.

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

Table 1.4 Impact of congestion on overall day-ahead prices

Constraint Location	Constraint	PG&E		SCE		SDG&E	
		$ per MWh	Percent	$ per MWh	Percent	$ per MWh	Percent
PG&E	RM_TM12_NG	$0.04	0.08%	-$0.02	-0.02%	-$0.04	-0.06%
	30055_GATES1 _500_30900_GATES _230_XF_11_S	$0.03	0.07%	-$0.03	-0.04%	-$0.03	-0.04%
	30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1	$0.02	0.04%	-$0.01	-0.01%	-$0.01	-0.01%
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1	$0.01	0.02%	$0.00	0.00%	$0.00	0.00%
	22372_KEARNY _69.0_22140_CLARMTTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.03	0.04%
	30975_MDWAYR11_230_30060_MIDWAY _500_XF_11_P	-$0.01	-0.01%	$0.00	0.01%	$0.00	0.01%
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	-$0.01	-0.02%	$0.01	0.01%	$0.01	0.01%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.02	-0.03%	$0.01	0.02%	$0.01	0.01%
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1	-$3.72	-7.69%	$2.36	3.74%	$2.24	3.34%
SCE	6410_CP5_NG	-$2.06	-4.27%	$1.57	2.48%	$1.48	2.20%
	6410_CP1_NG	-$1.15	-2.38%	$0.69	1.09%	$0.73	1.08%
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.20	-0.42%	$0.21	0.33%	$0.07	0.11%
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.20	-0.42%	$0.19	0.30%	$0.10	0.15%
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_4 _P	-$0.21	-0.42%	$0.13	0.20%	$0.10	0.14%
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_1 _P	-$0.16	-0.33%	$0.10	0.15%	$0.10	0.15%
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	-$0.05	-0.11%	$0.01	0.01%	$0.00	0.00%
	25001_GOODRICH_230_24076_LAGUBELL_230_BR_1 _1	-$0.01	-0.01%	$0.00	0.00%	$0.01	0.01%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.02	-0.03%
	7750_D-ECASCO_OOS_CP5_NG	$0.00	0.00%	$0.00	0.00%	-$0.02	-0.03%
SDG&E	7820_TL23040_IV_SPS_NG	-$0.07	-0.15%	$0.00	0.00%	$0.90	1.35%
	7820_TL 230S_OVERLOAD_NG	-$0.06	-0.13%	$0.00	0.00%	$0.72	1.07%
	22500_MISSION _138_22496_MISSION _69.0_XF_1	$0.00	0.00%	$0.00	0.00%	$0.44	0.65%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.14	0.21%
	OMS 6369451_50001_OOS_NG	-$0.01	-0.02%	$0.00	0.00%	$0.10	0.15%
	MIGUEL_BKs_MXFLW_NG	$0.00	0.00%	$0.00	0.00%	$0.10	0.15%
	OMS6286861 TL50005_NG	-$0.01	-0.01%	$0.00	0.00%	$0.06	0.08%
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.05	0.08%
	OMS_6149794_TL23021_41_NG	$0.00	-0.01%	$0.00	0.00%	$0.04	0.06%
	22357_IV PFC1 _230_22358_IV PFC _230_PS_1	$0.00	0.00%	$0.00	0.00%	$0.04	0.06%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P	-$0.01	-0.01%	$0.00	0.00%	$0.04	0.05%
	OMS 6369454_50001_OOS_NG	$0.00	-0.01%	$0.00	0.00%	$0.03	0.05%
	22596_OLD TOWN_230_22504_MISSION _230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.03	0.05%
	OMS_6107673_SUNCREST BK81_NG	$0.00	0.00%	$0.00	0.00%	$0.03	0.04%
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.04%
	22597_OLDTWNTP_230_22504_MISSION _230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.03%
	22592_OLD TOWN_69.0_22873_VINE SUB_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.03%
	OMS6277840 TL50005_NG	$0.00	0.00%	$0.00	0.00%	$0.02	0.03%
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.02%
	IID-SCE_BG	$0.00	0.00%	$0.00	0.00%	-$0.07	-0.11%
Other	Other	-$0.06	-0.12%	$0.12	0.19%	$0.12	0.19%
Total	**Total**	**-$7.90**	**-16.36%**	**$5.34**	**8.45%**	**$7.59**	**11.34%**

Impact of congestion from individual constraints

Table 1.5 shows the impact of congestion from each constraint *only during congested intervals,* where the number of congested intervals is presented separately as frequency. As mentioned above, congestion associated with Path 26 contributed to the majority of overall price impacts in the third quarter. The Midway-Vincent 1 500 kV constraint (30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1) bound during about 15 percent of intervals. When binding, it decreased prices in the PG&E area by about $25/MWh and increased prices in the SCE and SDG&E areas by about $16/MWh and $15/MWh, respectively. The Path 26 CP5 nomogram (6410_CP5_NG) bound in 11 percent of intervals. The constraint increased SCE and SDG&E area prices by about $14/MWh and decreased PG&E area prices by about $19/MWh. The Path 26 CP1 nomogram (6410_CP1_NG) also bound during the quarter and had a similar price impact as the CP5 nomogram.

Congestion across Path 26 was driven primarily by high north-to-south flows. High gas prices at the SoCal Citygate trading hub (see Section 1.2) and high loads in the south contributed to a pull for energy from cheaper generation in the north. Additionally, there were a number of days with planned and forced outages of the Midway-Whirlwind 500 kV line and of equipment at the Midway and Vincent substations.

In the SDG&E area, the East County-Miguel nomogram (7820_TL23040_IV_SPS_NG), the Imperial Valley (7820_TL 230S_OVERLOAD_NG) nomogram, and the Doublet Tap-Friars 138 kV constraint (22192_DOUBLTTP_138_22300_FRIARS 138_BR_1 _1) each bound in about 13 percent of intervals. Congestion from these constraints increased prices by about $13/MWh in the SDG&E area. The nomograms are enforced to mitigate for the loss of the Imperial Valley-North Gila 500 kV and East County-Miguel 500 kV lines. One reason for congestion on the Doublet Tap-Friars constraint was a daily outage on the Penasquitos-Old Town 230 kV line.

Table 1.5 Impact of congestion on day-ahead prices during congested hours[34]

Constraint Location	Constraint	Frequency	Q3		
		Q3	PG&E	SCE	SDG&E
PG&E	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1	15.0%	-$24.71	$15.72	$14.87
	RM_TM12_NG	2.4%	$1.63	-$1.57	-$1.67
	30055_GATES1 _500_30900_GATES _230_XF_11_S	2.3%	$1.46	-$1.17	-$1.15
	30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1	1.4%	$1.37	-$1.21	-$1.12
	22372_KEARNY _69.0_22140_CLARMTTP_69.0_BR_1 _1	1.3%	$0.00	$0.00	$2.30
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1	0.9%	$1.01	-$1.38	-$1.28
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	0.6%	-$1.85	$1.38	$1.23
	30975_MDWAYR11_230_30060_MIDWAY _500_XF_11_P	0.4%	-$1.82	$1.24	$1.18
SCE	6410_CP5_NG	11.0%	-$18.75	$14.27	$13.40
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	9.0%	-$2.22	$2.09	$1.31
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	8.8%	-$2.30	$2.36	$1.22
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	4.8%	-$2.44	$1.39	-$0.36
	6410_CP1_NG	4.7%	-$24.38	$14.66	$15.39
	7750_D-ECASCO_OOS_CP5_NG	3.9%	$0.00	$0.00	-$0.57
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	2.8%	-$1.85	$0.67	$0.00
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_4 _P	2.4%	-$8.38	$5.25	$3.88
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_1 _P	1.1%	-$14.56	$8.93	$9.27
	25001_GOODRICH_230_24076_LAGUBELL_230_BR_1 _1	0.7%	-$0.86	$0.70	$0.67
SDG&E	7820_TL23040_IV_SPS_NG	14.4%	-$0.50	$0.00	$6.24
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	13.0%	$0.00	$0.00	$1.07
	7820_TL 230S_OVERLOAD_NG	12.0%	-$0.53	$0.00	$5.96
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	1.4%	$0.00	$0.00	$3.78
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1	1.1%	$0.00	$0.00	$2.13
	MIGUEL_BKs_MXFLW_NG	0.6%	-$0.11	$0.00	$15.39
	22500_MISSION _138_22496_MISSION _69.0_XF_1	0.6%	$0.00	$0.00	$68.86
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P	0.5%	-$1.11	$0.00	$7.21
	OMS 6369451_50001_OOS_NG	0.5%	-$1.45	$0.00	$20.40
	OMS 6369454_50001_OOS_NG	0.5%	-$0.48	$0.00	$6.44
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1	0.5%	$0.00	$0.00	$3.21
	OMS6286861 TL50005_NG	0.4%	-$1.25	$0.00	$13.86
	22357_IV PFC1 _230_22358_IV PFC _230_PS_1	0.3%	$0.00	$0.00	$12.30

1.11.2 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.

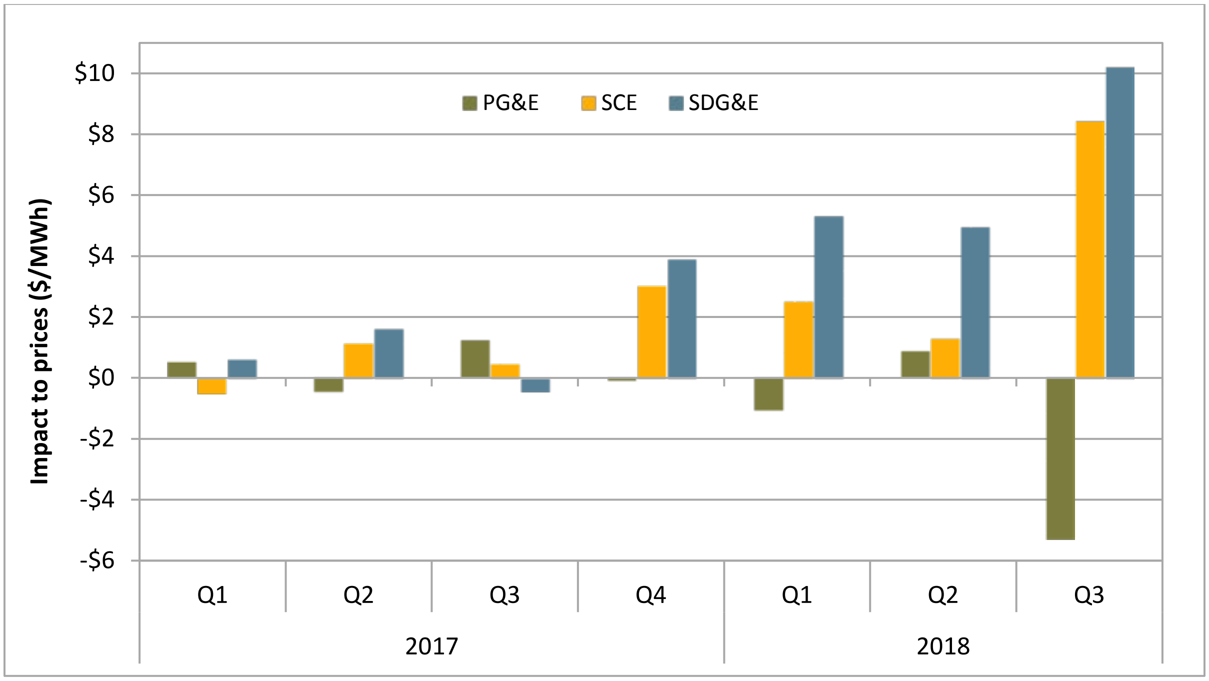
Impact of congestion to overall prices in each load area

Figure 1.25 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 past two quarters and to the day-ahead market, congestion increased prices in the SCE and SDG&E areas. Congestion in the 15-minute market decreased prices in

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

the PG&E area, similar to the day-ahead market. There was significantly more congestion in the third quarter of 2018 compared to any prior quarter in this time period.

Figure 1.25 Impact of congestion on 15-minute prices



In the PG&E area, prices decreased by about $5/MWh (13 percent) compared to an increase of nearly $1/MWh (3 percent) last quarter. In SCE, prices increased by about $8/MWh (16 percent) compared to $1.30/MWh (5 percent) last quarter. SDG&E prices were most impacted by congestion in the 15-minute market, increasing roughly $10/MWh (18 percent) compared to $5/MWh (17 percent) last quarter.

Table 1.6 breaks down the impact to prices in the third quarter by constraint.[35] Similar to the day-ahead market, the primary cause of overall price separation between the ISO areas in the 15-minute market was congestion due to Path 26, including the lines and nomograms associated with the path. In the day-ahead market, the constraints that had the greatest impact on prices were the Midway-Vincent 1 500 kV line, the Path 26 CP5 nomogram, and the Path 26 CP1 nomogram. In the 15-minute market, the Southern California Import Transmission (SCIT) nomogram (6510_CP1_NG) was also used to manage flows over Path 26. Congestion on the Midway-Vincent 2 500 kV line also impacted overall 15-minute market prices, though it did not impact day-ahead market prices.

San Diego area prices were also impacted by congestion on the Imperial Valley nomogram, similar to the day-ahead market. Congestion from this constraint increased SDG&E prices by about $1/MWh (2 percent), and had relatively little impact on PG&E and SCE prices. More information regarding individual constraints is discussed below.

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

Table 1.6 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	RM_TM12_NG	$0.55	1.41%	$0.28	0.53%	$0.25	0.44%
	30055_GATES1 _500_30900_GATES _230_XF_11_S	$0.43	1.10%	-$0.17	-0.32%	-$0.17	-0.30%
	30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1	$0.04	0.11%	-$0.03	-0.06%	-$0.03	-0.05%
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1	$0.03	0.09%	-$0.01	-0.02%	-$0.01	-0.02%
	OMS_6246684_Tracy-LosBanos	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	-$0.04	-0.10%	$0.07	0.13%	$0.07	0.12%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.09	-0.23%	$0.08	0.16%	$0.08	0.14%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.45	-1.16%	$0.41	0.78%	$0.39	0.69%
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1	-$2.97	-7.62%	$2.67	5.04%	$2.54	4.56%
SCE	6410_CP5_NG	-$1.25	-3.20%	$1.21	2.27%	$1.14	2.04%
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	$0.00	0.00%	$1.17	2.20%	$0.78	1.39%
	6510_CP1_NG	-$0.40	-1.03%	$1.11	2.10%	$1.18	2.11%
	6410_CP1_NG	-$0.84	-2.14%	$0.73	1.37%	$0.74	1.32%
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_4 _P	-$0.15	-0.39%	$0.26	0.49%	$0.23	0.41%
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.02%	$0.10	0.19%	$0.08	0.14%
	24156_VINCENT _500_24155_VINCENT _230_XF_3	-$0.07	-0.17%	$0.09	0.18%	$0.06	0.10%
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	$0.00	0.00%	$0.07	0.13%	$0.02	0.03%
	7750_D-ECASCO_OOS_CP5_NG	$0.00	0.00%	$0.05	0.10%	$0.00	0.00%
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_1 _P	-$0.02	-0.06%	$0.04	0.08%	$0.04	0.08%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.03	0.07%	$0.03	0.06%	$0.01	0.02%
	99010_VELAS-LB_230_24076_LAGUBELL_230_BR_1 _1	$0.00	0.00%	$0.03	0.05%	$0.02	0.03%
	24126_RIOHONDO_230_24155_VINCENT _230_BR_2 _1	-$0.01	-0.03%	$0.02	0.03%	$0.01	0.02%
	25654_VIEJOSC _230_24025_CHINO _230_BR_1 _1	-$0.01	-0.02%	$0.00	-0.01%	$0.02	0.04%
	25654_VIEJOSC _230_24131_S.ONOFRE_230_BR_1 _1	-$0.01	-0.01%	-$0.01	-0.01%	$0.02	0.04%
	24072_JOHANNA _230_24134_SANTIAGO_230_BR_1 _1	-$0.01	-0.02%	-$0.01	-0.02%	$0.02	0.04%
	6410_CP10_NG	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
SDG&E	7820_TL 230S_OVERLOAD_NG	$0.00	0.00%	$0.06	0.12%	$1.06	1.90%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.52	0.92%
	MIGUEL_BKs_MXFLW_NG	$0.00	0.00%	$0.00	0.00%	$0.38	0.69%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P	$0.00	0.00%	$0.01	0.03%	$0.19	0.34%
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	$0.00	0.00%	$0.00	0.00%	$0.10	0.17%
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	-$0.01	-0.03%	-$0.02	-0.03%	$0.08	0.14%
	7820_TL23040_IV_SPS_NG	$0.00	0.00%	$0.00	0.00%	$0.06	0.10%
	OMS_6107673_SUNCREST BK81_NG	$0.00	0.00%	$0.00	0.00%	$0.05	0.10%
	OMS6277840 TL50005_NG	$0.00	0.00%	$0.00	0.00%	$0.04	0.08%
	RBS-HA_525KV	$0.00	0.00%	$0.04	0.07%	$0.04	0.07%
	22357_IV PFC1 _230_22358_IV PFC _230_PS_1	$0.00	0.00%	$0.00	0.00%	$0.04	0.07%
	22500_MISSION _138_22496_MISSION _69.0_XF_1	$0.00	0.00%	$0.00	0.00%	$0.03	0.06%
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	$0.00	0.00%	$0.01	0.02%	$0.02	0.04%
Other	Other	-$0.05	-0.13%	$0.16	0.29%	$0.12	0.22%
Total	**Total**	**-$5.28**	**-13.52%**	**$8.43**	**15.87%**	**$10.18**	**18.25%**

Impact of congestion from individual constraints

Table 1.7 shows the impact of congestion from each constraint *only during congested intervals,* where the congested intervals are presented as frequency. In the 15-minute market, the Midway-Vincent 1 (30060_MIDWAY_500_24156_VINCENT _500_BR_1 _1) constraint bound during about 10 percent of intervals. When binding, it decreased prices in the PG&E area by about $30/MWh and increased prices in the SCE and SDG&E areas by about $26/MWh. The Path 26 CP5 nomogram (6410_CP5_NG) bound during 6 percent of intervals, decreasing PG&E prices by about $21/MWh and increasing SCE and SDG&E prices by about $20/MWh. Additionally, the Midway-Vincent 2 constraint (30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3), Path 26 CP1 nomogram (6410_CP1_NG), and SCIT nomogram (6510_CP1_NG) bound in about 3 percent of intervals. When binding, these constraints decreased PG&E prices by about $14/MWh, $34/MWh, and $16/MWh, respectively. The constraints increased SCE and SDG&E prices by about $13/MWh, $30/MWh, and $48/MWh, respectively.

In addition to Path 26, in the PG&E area, the Gates transformer (30055_GATES1 _500_30900_GATES _230_XF_11_S) and Round Mountain-Table Mountain nomogram (RM_TM12_NG) bound in about 6 percent of intervals. When binding, these constraints increased PG&E area prices by about $7/MWh and $9/MWh, respectively. Congestion over the Gates transformer decreased SCE and SDG&E prices by about $3.5/MWh. The Round Mountain-Table Mountain nomogram increased SCE and SDG&E prices by about $4/MWh. These constraints likely bound due to high loads and high gas prices throughout the quarter.

In the SDG&E area, the Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) and the Doublet Tap-Friars 138 kV (22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1) constraint bound most frequently, each in about 7 percent of hours. When binding, they increased SDG&E prices by about $14/MWh and $8/MWh, respectively.

Table 1.7 Impact of congestion on 15-minute prices in the ISO during congested intervals[36]

Constraint Location	Constraint	Frequency	Q3		
		Q3	PG&E	SCE	SDG&E
PG&E	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1	10.1%	-$29.54	$26.56	$25.24
	30055_GATES1 _500_30900_GATES _230_XF_11_S	6.5%	$6.64	-$3.53	-$3.42
	RM_TM12_NG	6.2%	$8.90	$4.52	$4.00
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	3.1%	-$14.43	$13.13	$12.34
	30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1	1.1%	$3.58	-$3.34	-$3.15
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	1.1%	-$4.61	$6.51	$6.04
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1	0.9%	$4.03	-$4.75	-$4.50
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.5%	-$18.05	$17.14	$15.85
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	7.2%	-$1.06	$16.26	$11.22
	6410_CP5_NG	6.0%	-$20.87	$20.13	$19.02
	6410_CP1_NG	2.4%	-$34.33	$29.97	$30.33
	6510_CP1_NG	2.4%	-$16.62	$46.18	$48.72
	7750_D-ECASCO_OOS_CP5_NG	1.4%	$0.00	$3.66	$0.00
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	1.0%	$2.82	$3.50	$1.31
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	0.9%	$0.00	$7.69	$4.76
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	0.9%	-$3.60	$11.58	$9.18
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_4 _P	0.8%	-$19.18	$32.83	$28.91
	6410_CP10_NG	0.4%	$3.26	-$3.57	-$3.40
SDG&E	7820_TL 230S_OVERLOAD_NG	7.4%	$0.00	$0.83	$14.38
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	6.5%	$0.00	$0.00	$7.98
	MIGUEL_BKs_MXFLW_NG	1.1%	$0.00	$0.00	$35.69
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P	0.7%	$0.00	$2.93	$28.91

1.11.3 Congestion in the energy imbalance market

Impact of congestion from individual constraints

Table 1.7 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 the ISO tends to decrease prices in the energy imbalance market, particularly in the north. For example, the Path 26 flowgates and nomograms that impacted ISO prices during the quarter (discussed above) decreased prices in energy imbalance market areas north of the constraint by about $10/MWh on average, due to availability of low-cost hydroelectric resources in the north which are unable to reach ISO areas when transmission limits bind. In the southern part of the state, constraints that are congested tend to have the greatest impact on prices in energy imbalance market areas east of the ISO.

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

Table 1.8 Impact of congestion on 15-minute prices in EIM during congested intervals[37]

Constraint Location	Constraint	Freq.	Q3							
			PACE	PACW	NEVP	PSEI	AZPS	PGE	PWRX	IPCO
NEVP	GON-IPP 230	0.3%	-$58.08	$0.00	$30.13	$0.00	$0.00	$0.00	-$24.33	-$24.33
PACE	WYOMING_EXPORT	9.0%	-$1.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PG&E	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1	10.1%	-$5.83	-$21.66	$15.06	-$20.84	$22.27	-$21.52	-$12.58	-$12.58
	RM_TM12_NG	6.2%	-$5.39	-$13.17	$1.66	-$13.03	$3.02	-$13.26	-$9.71	-$9.71
	30055_GATES1 _500_30900_GATES _230_XF_11_S	4.5%	-$1.57	-$8.61	-$2.85	-$8.57	-$3.52	-$8.57	-$6.97	-$6.97
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	3.1%	-$1.48	-$10.57	$7.26	-$10.19	$10.86	-$10.51	-$6.07	-$6.07
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	1.1%	-$2.01	-$7.62	$3.43	-$7.34	$5.19	-$7.55	-$4.97	-$4.97
	30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1	0.9%	$0.00	$2.57	$0.00	$2.46	-$2.80	$2.52	$0.00	$0.00
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.5%	$0.00	-$13.09	$9.76	-$12.58	$14.01	-$12.99	-$7.50	-$7.50
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	7.2%	-$6.33	-$3.72	-$7.88	-$3.73	-$8.45	-$3.73	-$5.90	-$5.90
	6410_CP5_NG	6.0%	$1.12	-$15.24	$11.49	-$14.64	$16.92	-$15.13	-$8.20	-$8.20
	6410_CP1_NG	2.4%	$0.00	-$25.33	$17.98	-$24.37	$27.12	-$25.18	-$15.05	-$15.05
	6510_CP1_NG	2.4%	-$16.55	-$16.58	-$16.48	-$16.58	-$16.68	-$16.58	-$16.54	-$16.54
	7750_D-ECASCO_OOS_CP5_NG	1.4%	$0.00	$0.00	$0.00	$0.00	-$8.04	$0.00	$0.00	$0.00
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	1.0%	-$4.40	$0.83	-$8.72	$0.48	-$8.15	$1.15	-$1.76	-$1.76
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	0.9%	-$4.89	-$6.26	-$6.06	-$6.08	-$6.30	-$6.27	-$4.82	-$4.82
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_4 _P	0.8%	-$13.51	-$17.65	-$13.72	-$17.38	$0.00	-$17.65	-$15.84	-$15.84
	7750_D-VISTA1_OOS_N2DV500_NG	0.4%	$0.00	$0.00	-$0.53	$0.00	-$11.59	$0.00	$0.00	$0.00
	6410_CP10_NG	0.4%	-$0.39	$2.33	-$2.07	$2.25	-$3.07	$2.32	$1.01	$1.01
SDG&E	7820_TL 230S_OVERLOAD_NG	7.4%	-$1.28	-$1.24	-$1.23	-$1.28	-$3.13	-$1.28	-$0.80	-$0.80
	MIGUEL_BKs_MXFLW_NG	1.1%	-$2.05	$0.00	$0.00	$0.00	-$11.62	$0.00	$0.00	$0.00
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P	0.7%	-$4.17	$0.00	-$3.90	$0.00	-$10.02	$0.00	-$2.96	-$2.96

Congestion on energy imbalance market internal constraints

Table 1.9 shows the frequency of congestion on internal constraints in the energy imbalance market since 2014. Compared to the previous quarter, internal congestion in PacifiCorp East increased by about 5 percent and exceeded levels of congestion compared to the same quarter in 2017. Congestion in PacifiCorp East was primarily a result of a single constraint (WYOMING_EXPORT, also seen in the table above) binding during about 9 percent of intervals in both the 15-minute and 5-minute markets. In the NV Energy area, frequency of binding internal constraints increased compared to the previous quarters in both the 15-minute and 5-minute markets. Similarly there was greater, though minimal congestion, on internal constraints in the PacifiCorp West and in Arizona Public Service areas than in the prior quarter.

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.

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

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

Table 1.9 Percent of intervals with congestion on internal EIM constraints

	2014	2015	2016	2017				2018		
				Q1	Q2	Q3	Q4	Q1	Q2	Q3
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%
PacifiCorp West	0.1%	0.1%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%
NV Energy		0.0%	0.1%	10.3%	1.8%	7.6%	5.8%	0.5%	0.9%	1.1%
Puget Sound Energy				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%
Portland General Electric							0.0%	0.0%	0.0%	0.0%
Powerex									0.0%	0.0%
Idaho Power									0.0%	0.0%
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%
PacifiCorp West	0.1%	0.0%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
NV Energy		0.0%	0.1%	11.7%	1.6%	7.1%	5.6%	0.4%	0.9%	0.7%
Puget Sound Energy				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%
Portland General Electric							0.0%	0.0%	0.0%	0.0%
Powerex									0.0%	0.0%
Idaho Power									0.0%	0.0%

1.12 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.[38] 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 third quarter, the use of many key market adjustments remained relatively high or increased rather than decreased.

[38] 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.

1.12.1 Load forecast adjustments

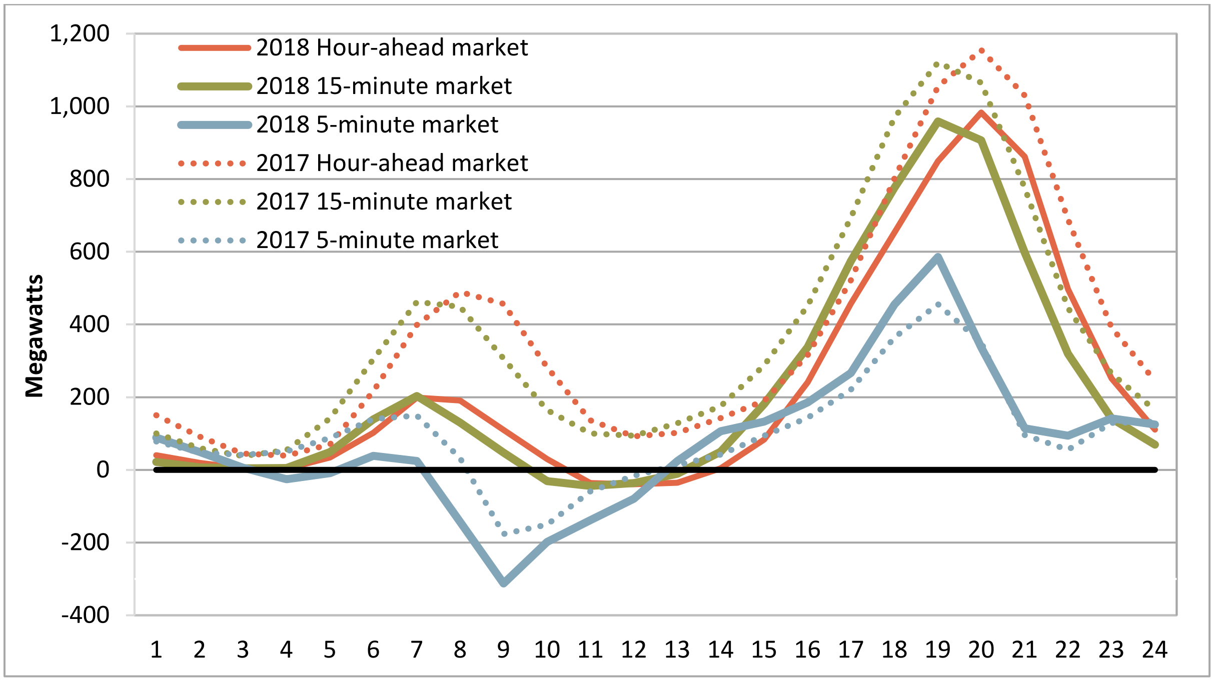
Operators in the ISO and energy imbalance market can manually modify load forecasts used in the market through a load adjustment. Load adjustments are also sometimes referred to as *load bias* or *load conformance*. Recently, the ISO has begun using the term *imbalance conformance* to describe these 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.[39] 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 third quarter of 2018. In general, the 5-minute market load forecast adjustments slightly increased throughout the day when comparing the third quarter of 2018 with the same period in 2017. Figure 1.26 shows the average hourly load adjustment profile for the hour-ahead, 15-minute and 5-minute markets for the third 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 more pronounced in the ramping periods; i.e., 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 hours ending 8, 9, 20, and 21 when the hour-ahead adjustments exceeded the 5-minute adjustments by around 330 MW, 420 MW, 650 MW and 750 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.

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

Figure 1.26 Average hourly load adjustment (Q3 2018 – Q3 2017)

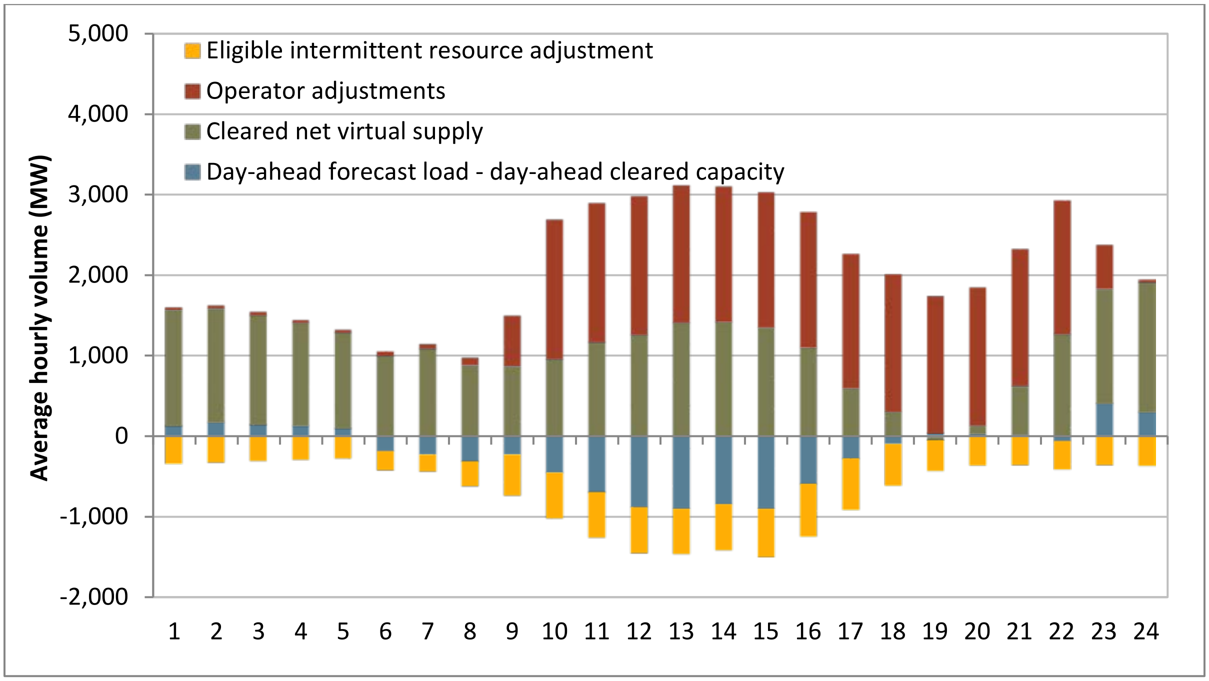


1.12.2 Residual unit commitment adjustments

As noted in Section 1.6, 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. These operator adjustments have increased significantly in the third quarter of 2018.

Figure 1.27 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 22. During most days in the quarter, an adjustment of 2,000 MW was made from hours ending 10 through 22 and an adjustment of 1,000 MW was made for hours ending 9 and 23. 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 hours ending 6 through 18 in the third quarter. Intermittent resource adjustments were greatest during hours ending 8 through 18.

Figure 1.27 Average hourly determinants of residual unit commitment procurement (July - September)



1.12.3 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 0.11 percent of system load in the third quarter.

Total energy resulting from all types of exceptional dispatch increased nearly fourfold in the third quarter of 2018 compared to the same quarter in 2017, as shown in Figure 1.28.[40] Exceptional dispatch energy from commitment energy accounted for about 70 percent of all exceptional dispatch energy in this quarter. About 23 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 9 percent was from in-sequence energy.

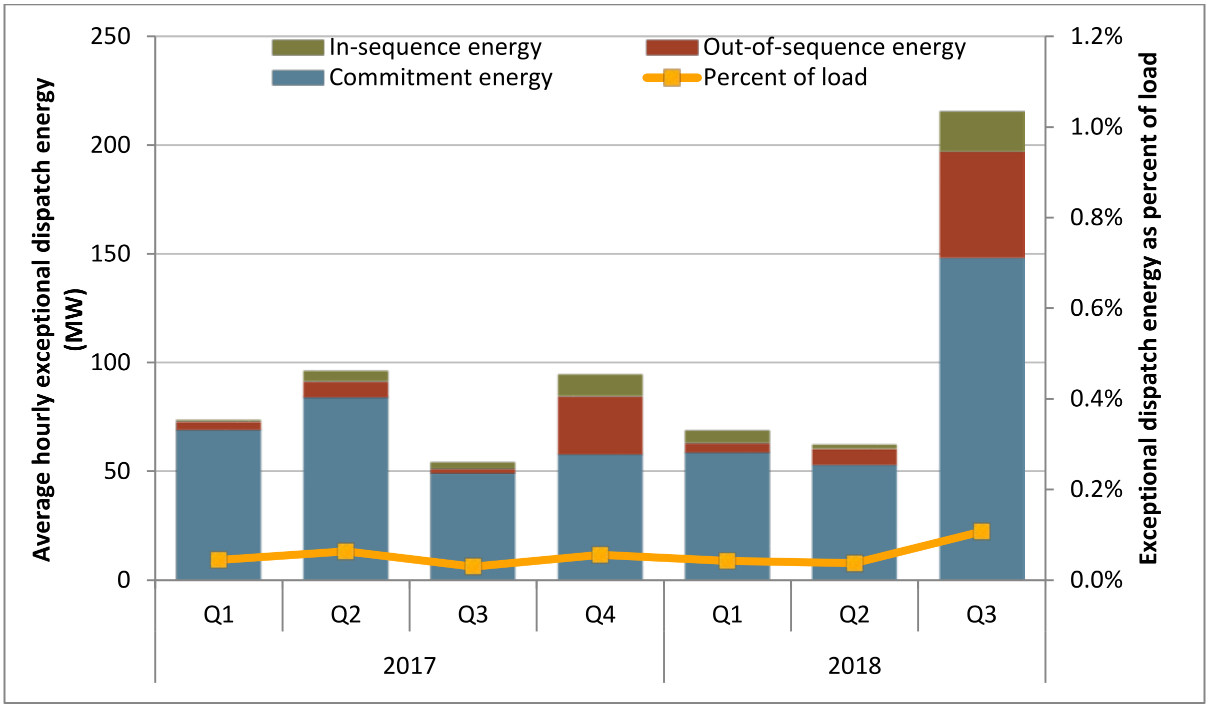
In the third quarter exceptional dispatches for minimum load were particularly high. These were largely due to load forecast uncertainty.

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.

[40] 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 1.28 Average hourly energy from exceptional dispatch

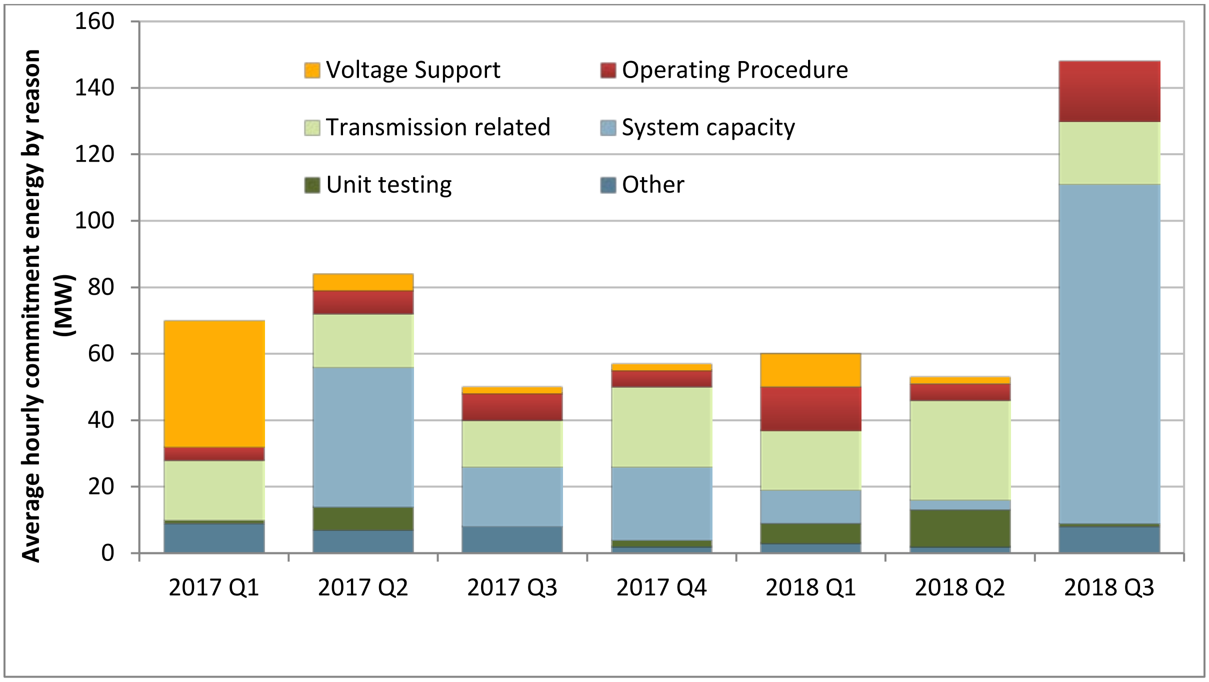


Exceptional dispatches for unit commitment

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 third quarter was nearly three times higher than the third quarter of the prior year. Elevated levels of exceptional dispatch unit commitment were driven by an increase in system capacity exceptional dispatches. The most frequent reason given for system capacity exceptional dispatches was load forecasting uncertainty. When ISO operators believe the load forecast is too low, exceptional dispatches may be issued for load forecast uncertainty. This is the primary reason for exceptional dispatches reported in the category of system capacity.

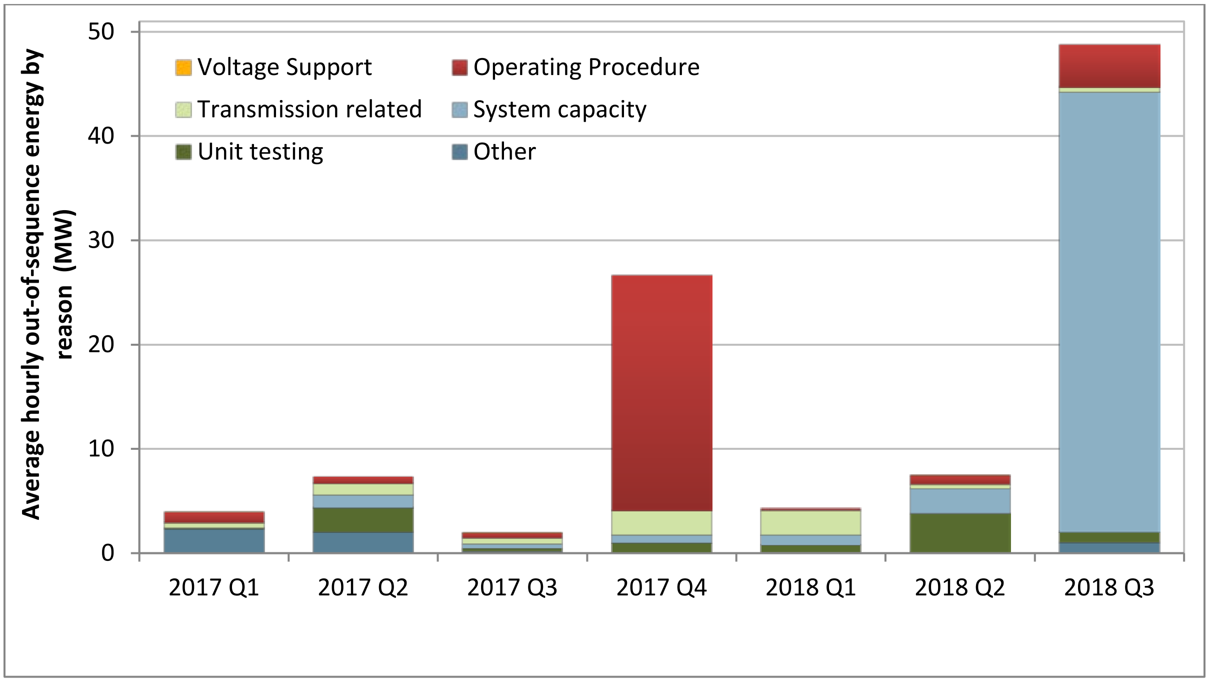
Figure 1.29 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch increased thirteen fold in this quarter compared to the same quarter in 2017. As previously illustrated in Figure 1.28, much of this exceptional dispatch energy (about 72 percent) 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. While the overall level of exceptional dispatch energy increased, the portion of exceptional dispatch for out-of-sequence energy was comparable to previous quarters. Figure 1.30 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 third quarter was exceptionally dispatched for load forecast uncertainty.

Figure 1.30 Out-of-sequence exceptional dispatch energy by reason



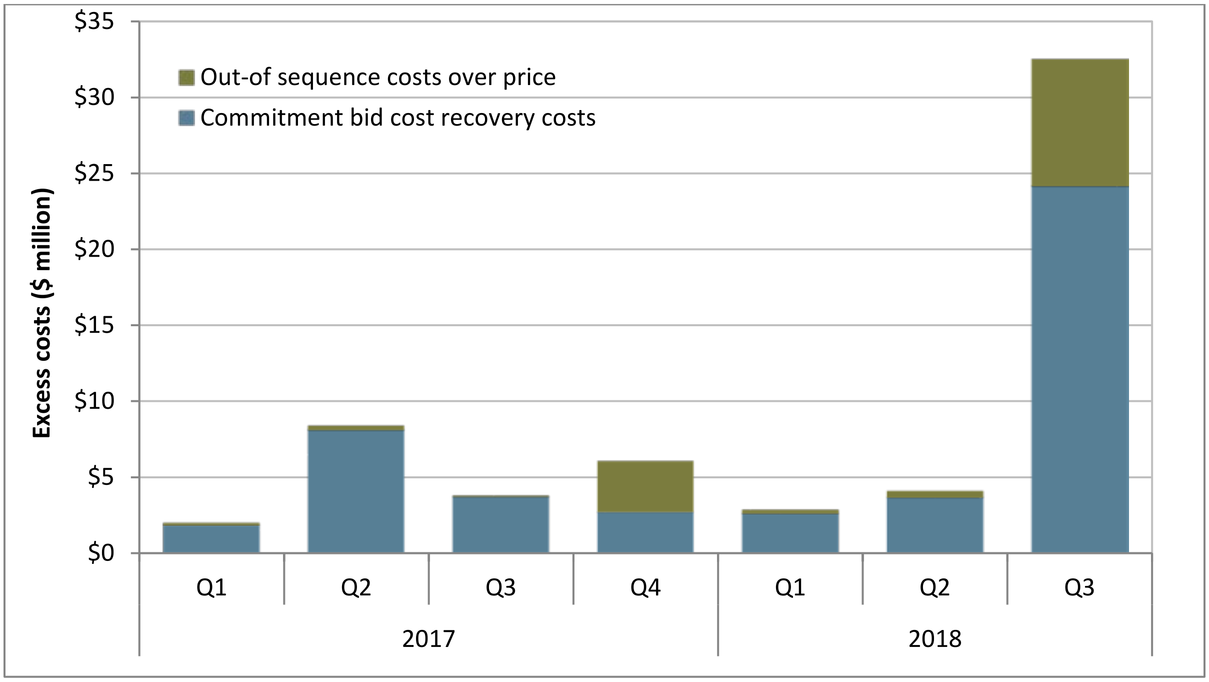
Exceptional dispatch costs

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 1.31 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 third quarter, out-of-sequence energy costs were $8.3 million, while commitment costs for exceptional dispatch paid through bid cost recovery were $24.2 million.

Figure 1.31 Excess exceptional dispatch cost by type



1.12.4 Manual dispatch on the interties

Exceptional dispatches on the interties are often referred to by the ISO operators as *manual dispatches*.[41] There was a decrease in the number and quantity of out-of-market dispatches in the third quarter of 2018 compared to the same quarter in 2017. The use of manual dispatch appears to be related to a number of factors, including generation and transmission outages, day-ahead forecast accuracy coupled with solar ramping down period.

For the first three quarters of 2018 there were 20 manual dispatches on the interties over a span of four days totaling about 1,130 MW. The largest daily quantity occurred on April 10 with about 380 MWh followed by August 9, August 12 and September 8 with 290 MWh, 260 MWh and 200 MWh, respectively. These dispatches occurred between hours ending 17 and 20, with the greatest concentration in hours ending 19 and 20. The single largest hour of manual dispatch occurred in hour ending 20 on August 9 totaling 265 MW. Loads did not reach higher than 45,000 MW in the hours the manual dispatches occurred; however, actual loads in these hours were higher than the day-ahead forecasts, up to 2,000 MW on August 12 in hour ending 18. The prices paid for manual dispatches in 2018 were associated with "bid or better." This refers to either the bid price or the 5-minute market clearing price at the tie point pricing node, whichever is higher.

When the ISO procures imports out-of-market at prices higher than the 15-minute price paid for other imports, this can encourage economic and physical withholding of available imports. In 2017, DMM

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

recommended the ISO closely track and monitor trends in manual dispatches, and seek to limit the use of such out-of-market dispatches.

1.12.5 Blocked instructions and dispatches

Blocked instructions

The ISO's real-time market functions use a series of processes in real time including the 15-minute and 5-minute markets. During each of these processes, the market model occasionally issues commitment or dispatch instructions that are inconsistent with actual system or market conditions. In such cases, operators may cancel or *block* commitment or dispatch instructions generated by the market software.[42] This can occur for a variety of reasons, including the following:

- **Data inaccuracies.** Results of the market model may be inconsistent with actual system or market conditions as a result of a data systems problem. For example, the ISO takes telemetry data and feeds the telemetry into the real-time system. If the telemetry is incorrect, the market model may try to commit or de-commit units based on the bad telemetry data. Operators may act accordingly to stop the instruction from being incorrectly sent to market participants.
- **Software limitations of unit operating characteristics.** Software limitations can also cause inappropriate commitment or dispatch decisions. For example, some unit operating characteristics of certain units are also not completely incorporated in the real-time market models. For instance, the ISO software has problems with dispatching pumped storage units as the model does not reflect all of its operational characteristics.
- **Information systems and processes.** In some cases, problems occur in the complex combination of information systems and processes needed to operate the real-time market on a timely and accurate basis. In such cases, operators may need to block commitment or dispatch instructions generated by the real-time market model.

Figure 1.32 shows the frequency of blocked real-time commitment start-up, shut-down, and multi-stage generator transition instructions. The overall number of blocked instructions for internal ISO units increased dramatically in July and August and then tapered off to closer to historical averages by September. Blocked shut-down instructions continued to be the most common reason for blocked instructions at about 73 percent in the third quarter, higher than the 65 percent in the second quarter.

Blocked start-up instructions accounted for almost 20 percent of blocked instructions within the ISO in the third quarter, a decrease from about 24 percent from the previous quarter. Blocked transition instructions to multi-stage generating units accounted for just 7 percent, a decrease from about 11 percent from the previous quarter. Some reasons for blocked instructions in the ISO include multi-stage generating unit transition issues, a limited number of start-ups for peaking units, and inconsistent instructions for pumping and generation for some units.

Figure 1.32 also includes blocked commitment instructions from energy imbalance market operators (red bars). During the third quarter of 2018 many of these actions were to block start-up and/or

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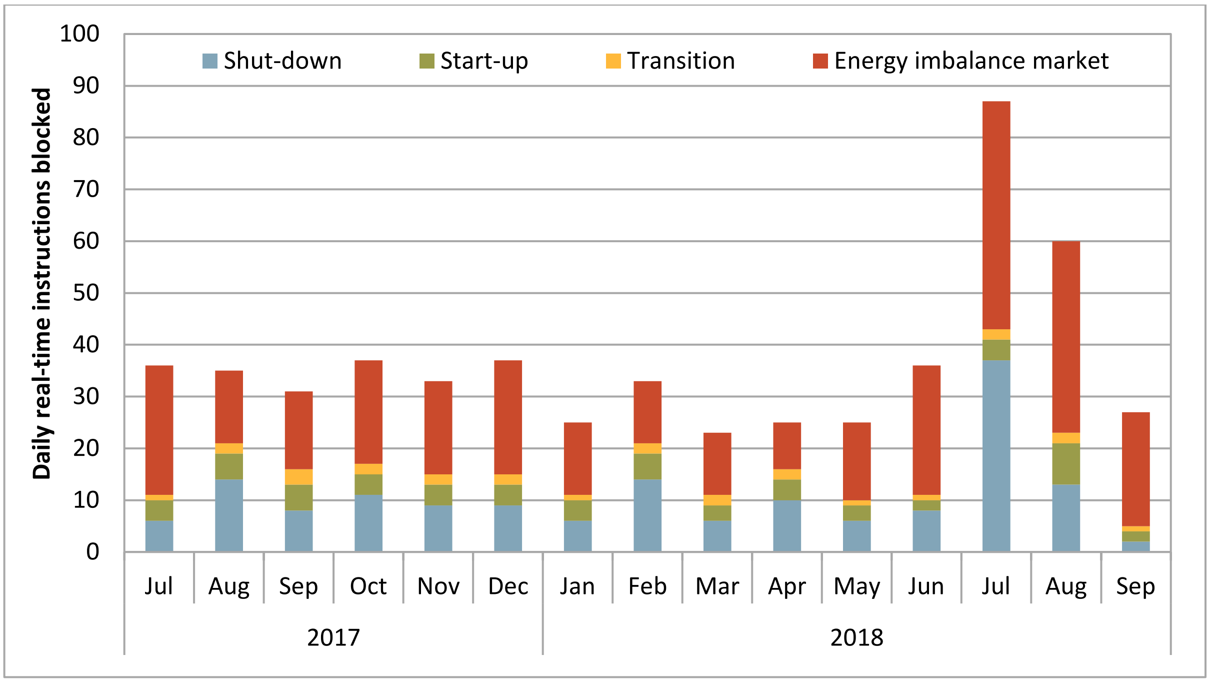
[42] The ISO reports on blocked instructions in its monthly performance metric catalog. Blocked instruction information can be found in the later sections of the monthly performance metric catalog report: https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=AF1E04BD-C7CE-4DCB-90D2-F2ED2EE8F6E9.

transition instructions between unit configurations. In some cases, this was to prevent a drop in reserves as a result of transitioning to a resource with a slower ramp rate. Although a solution was implemented in 2018 to better manage reserves during unit transitions, the number of blocked dispatches for the energy imbalance market dramatically increased from the second quarter onward, due to a single energy imbalance area's selection of this tool to limit transitions of a multi-stage generating resource.

Figure 1.32 Frequency of blocked real-time commitment instructions



Blocked dispatches

Operators review dispatches issued in the real-time market before these dispatch and price signals are sent to the market. If the ISO operators determine that the 5-minute dispatch results are inappropriate, they are able to block the entire real-time dispatch instructions and prices from reaching the market.

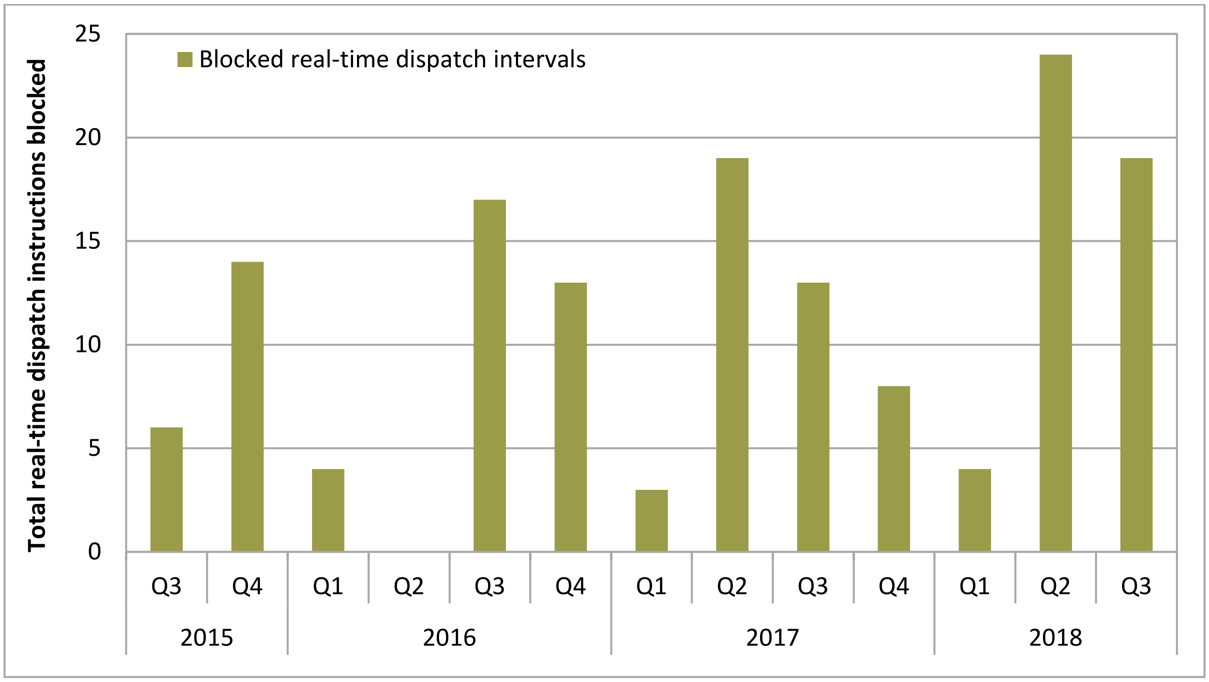
The ISO began blocking dispatches in 2011 as both market participants and ISO staff were concerned that inappropriate price signals were being sent to the market even when they were known to be problematic. These inappropriate dispatches would often cause participants to exacerbate issues with system conditions that were not modeled. Frequently, many of the blocked intervals eliminated the need for a subsequent price correction.

Operators can choose to block the entire market results to stop dispatches and prices resulting from a variety of factors including incorrect telemetry, intertie scheduling information or load forecasting data. Furthermore, the market software is also capable of automatically blocking a solution when market results exceed threshold values.[43]

[43] For example, if the load were to drop by 50 percent in one interval, the software can automatically block results.

Figure 1.33 shows the frequency that operators blocked price results in the real-time dispatch from the third quarter in 2015 through the third quarter in 2018. The total number of blocked intervals in the third quarter slightly decreased to 19 from a high of 24 in the previous quarter. In the third quarter five blocked intervals occurred on a single day: August 22.

Figure 1.33 Frequency of blocked real-time dispatch intervals



1.13 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).[44] The ISO charges load-serving entities the transmission access charge in order to reimburse the entity that builds each transmission line for the costs incurred.

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

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

Revenue inadequacy

This section explains why the revenue inadequacy metric which is commonly reported is not an accurate or appropriate measure of how well the congestion revenue right market is functioning from the perspective of ratepayers.

Consider the following example:

- There is 100 MW of transmission, which is paid for by ratepayers of a load-serving entity through the transmission access charge.

- The load-serving entity is allocated 75 MW of this transmission in the allocation process. These congestion revenue rights exactly match the transmission needed to meet the load-serving entity's actual load.

- The remaining 25 MW is sold to a financial entity in the auction for a price of $5/MWh, resulting in a $125 credit in the balancing account.

- The day-ahead transmission price is $10/MWh.

- The load-serving entity's ratepayers pay $750 into the balancing account as part of the day-ahead congestion charges to meet their load and receive $750 from the balancing account for their 75 MW of congestion revenue rights.

- Other entities utilizing the remaining 25 MW of transmission in the day-ahead market pay $250 into the balancing account.

- The financial entity receives $250 from the balancing account for their 25 MW of congestion revenue rights.

In this example, the balancing account has a net balance of $0 without auction revenues, and a +$125 balance with auction revenues. However, the $125 in the balancing account that is paid to the load-serving entity represents only 50 percent of the $250 value of the 25 MW of transmission paid for by ratepayers that is sold in the congestion revenue rights auction. The remaining $125 of this value is paid to the financial entity purchasing these 25 MW of congestion revenue rights.

As illustrated by this example, revenue inadequacy represents only a portion of the overall performance of the congestion revenue rights auction from the perspective of ratepayers. A positive congestion revenue right account balance with auction revenues does not reflect the actual market value of additional congestion revenue rights sold in the auction. More information on CRR revenue inadequacy can be found in DMM's 2016 annual report.[45]

The third quarter of 2018 was revenue "adequate" by about $53.4 million, meaning net day-ahead congestion rents collected by the ISO exceeded the CRR payments to the holders of the rights. Table 1.10 shows the top 10 constraints that contributed to the revenue surplus. Most of these constraints were also causing high real-time congestion imbalance offset charges as well.[46]

Even though the third quarter of 2018 was revenue adequate, there was still a significant amount of ratepayer losses. Hence, the performance of the congestion revenue rights auction from the perspective of ratepayers should instead be assessed by directly comparing the revenues from auctioning off additional transmission rights to the payments made to these rights at day-ahead prices. DMM believes that the ratepayer gains or losses from the auction is the appropriate metric for assessing the congestion revenue right auction.

Table 1.10 Top 10 constraints contributing to congestion revenue right surplus (Jul – Sep)

Constraint	Net day-ahead congestion rents ($ million)	CRR entitlements ($ million)	Estimated CRR surpluses ($ million)
30060_MIDWAY_500_24156_VINCENT_500_BR_1_1	$83.5	$46.9	$36.6
6410_CP1_NG	$22.7	$12.3	$10.4
6410_CP5_NG	$28.0	$24.6	$3.3
24016_BARRE_230_24154_VILLAPK_230_BR_1_1	$15.5	$13.3	$2.2
24092_MIRALOMA_500_24093_MIRALOM_230_XF_4_P	$11.4	$9.4	$2.0
CFE_ITC	$1.8	$0.0	$1.9
NOB_ITC	$16.1	$14.4	$1.8
24092_MIRALOMA_500_24093_MIRALOM_230_XF_1_P	$9.6	$7.8	$1.7
24016_BARRE_230_25201_LEWIS_230_BR_1_1	$15.5	$13.8	$1.7
NdGrp:24036_EAGLROCK_230_B2	$2.6	$1.8	$0.8

Analysis of congestion revenue right auction returns

Ratepayers lost a total of $41.5 million during the third quarter of 2018 as payments to auctioned congestion revenue rights holders exceeded auction revenues by this amount. This brings total losses to transmission ratepayers from congestion revenue rights sold in the ISO's auction to over $102 million in 2018. Auction revenues were 43 percent of payments made to non-load-serving entities during the third quarter of 2018, significantly down from 71 percent during the same quarter in 2017.

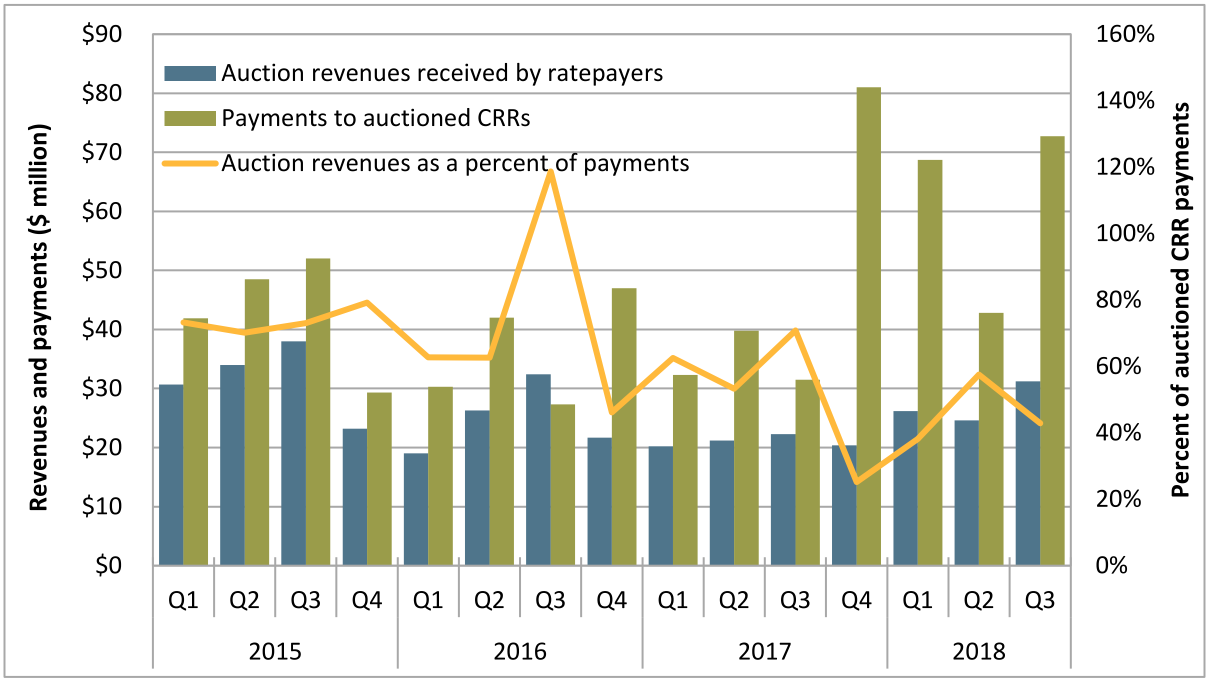
Financial entities (which do not schedule or trade physical power or serve load) continued to have the highest profits among the entity types, at approximately $27 million. This was a substantial increase from $11 million profits during the third quarter of 2017. Profits by energy marketers totaled about $6

[45] *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2017, pp. 243-245: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

[46] Refer to Section 1.8 for more information on real-time imbalance offset charges.

million, up from $0.8 million loss during the same quarter in 2017. Generators gained about $8 million compared to $0.7 million loss in the third quarter of 2017.

Figure 1.34 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.[47] DMM believes the current auction is unnecessary and could be eliminated.[48] 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.

On March 22, 2018, the Board of Governors approved policy changes that will 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. These changes are intended to be implemented in time for the 2019 annual allocation and auction processes.

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

48 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

A second set of changes (Track 1B) was approved by the Board of Governors on June 22, 2018.[49] This proposal would 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.

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.[50] On September 20, 2018, FERC issued an order accepting a part of 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. However, FERC rejected the ISO's proposal to fund congestion revenue right payments using the day-ahead market congestion revenue and revenue from counterflow rights without first allowing a rights holder to net its prevailing flow and counterflow position on individual constraints.[51]

On October 1, 2018, pursuant to FERC's order, the ISO refiled the tariff with a modification that now allows congestion revenue rights holders to consistently net prevailing and counterflow rights against each other as in other ISO and RTO markets.[52]

1.14 Flexible ramping product

Background

The *flexible ramping product* is designed to enhance reliability and market performance by procuring flexible ramping capacity in the real-time market to help manage volatility and uncertainty of real-time imbalance demand. The amount of flexible capacity the product procures is derived from a demand curve which reflects a calculation of the optimal willingness-to-pay for that flexible capacity. The demand curves allow the market optimization to consider the trade-off between the cost of procuring additional flexible ramping capacity and the expected reduction in power balance violation costs.

The flexible ramping product procures both upward and downward flexible capacity, in both the 15-minute and 5-minute markets. Procurement in the 15-minute market is intended to ensure that enough ramping capacity is available to meet the needs of both the upcoming 15-minute market 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.

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

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

51 *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

52 *Tariff Amendment - Congestion Revenue Rights Auction Efficiency Track 1B Modification (ER19-26),* October 1, 2018: http://www.caiso.com/Documents/Oct1-2018-TariffAmendment-CRRAuctionEfficiencyTrack1BModification-ER19-26.pdf

Market outcomes for flexible ramping product

This section describes the amount of flexible ramping capacity that was procured in the third quarter, and the corresponding flexible ramping shadow prices. The flexible ramping product procurement and shadow prices are determined from 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 1.35 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 third quarter, the system-level demand curves bound very infrequently in both directions. The 15-minute market system-level demand curves bound in less than 2 percent of intervals in the upward direction and never in the downward direction during the quarter.

Figure 1.35 Monthly frequency of positive 15-minute market flexible ramping shadow price

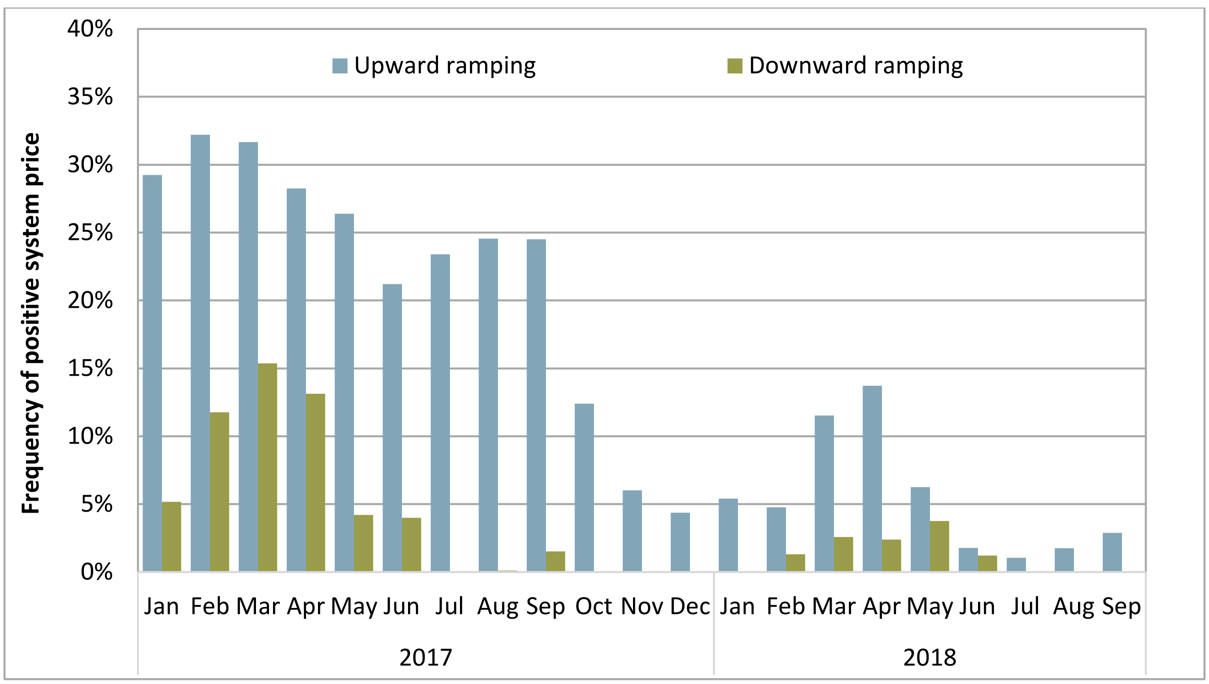
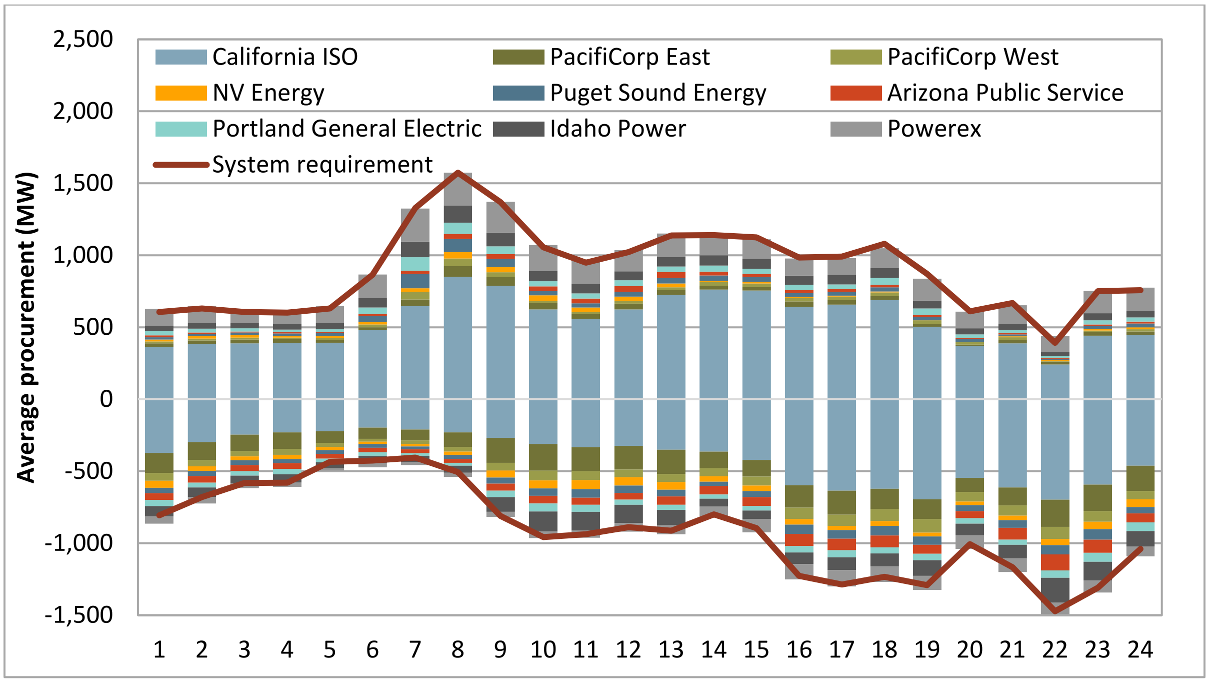


Figure 1.36 shows the hourly average amount of flexible ramping capacity procured in the 15-minute market during the third quarter. This capacity may have been procured to satisfy system-level demand, area-specific demand, or both. The positive bars show procurement for upward flexible ramping capacity, 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 910 MW of upward capacity and 930 MW of downward capacity in the 15-minute market during the third quarter. Compared to the third 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 around 200 MW in both the upward and downward directions, similar to the previous quarter. Of note, the proportion of 5-minute market flexible ramping capacity procured in the ISO relative to the surrounding energy imbalance market areas decreased significantly from the quarter, particularly in the downward direction. Around 42 percent of downward 5-minute market flexible ramping capacity was procured In the ISO during the third quarter, compared to around 60 percent in the previous quarter.

Figure 1.36 Hourly average flexible ramping capacity procurement in 15-minute market (July – September)



Flexible ramping procurement costs

Generation capacity that satisfied the demand for flexible ramping capacity received payments based on the combined system and area-specific flexible ramping shadow price. In addition, the combined flexible ramping shadow price 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.[53]

Figure 1.37 shows the total net payments to generators for flexible ramping capacity from the flexible ramping product by month.[54] This includes the total net amount paid for upward and downward flexible

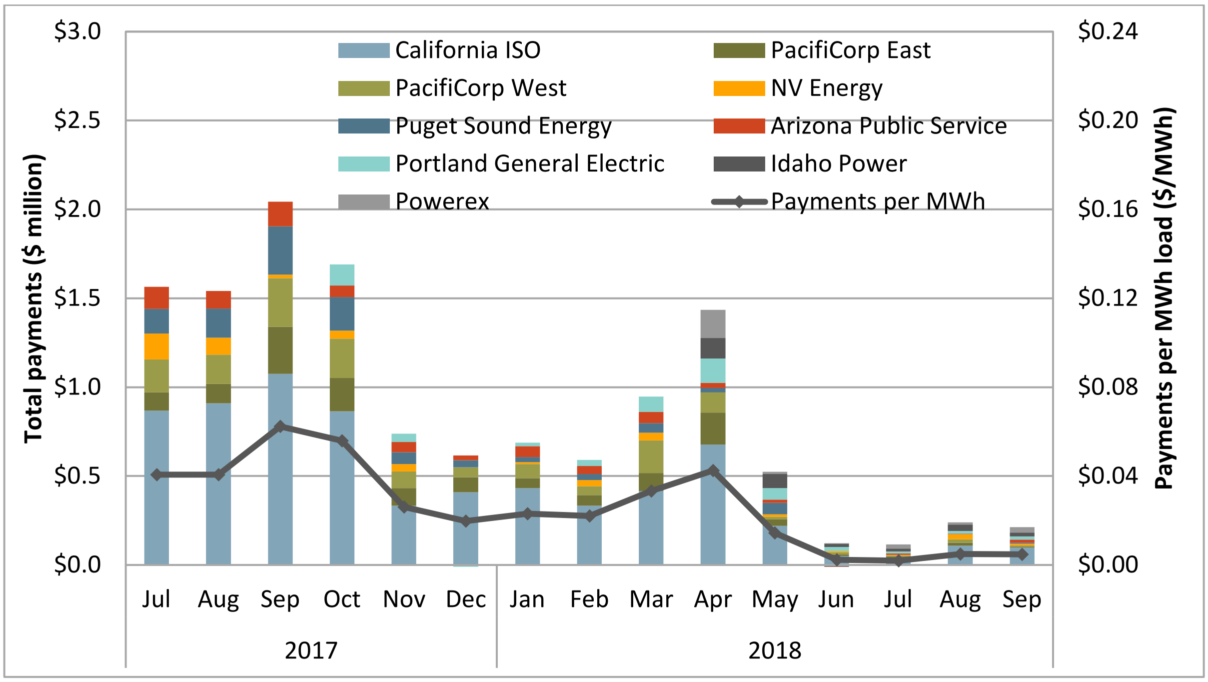
[53] More information about the settlement principles can be found in the ISO's *Revised Draft Final Proposal for the Flexible Ramping Product*, December 2015: http://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

[54] 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.

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 continued to decrease overall during the third quarter of 2018 to less than $0.6 million, compared to around $2.1 million during the previous quarter and around $5.1 million during the third quarter of 2017. However, power balance constraint relaxations in the 15-minute and 5-minute markets were relatively infrequent during the quarter.

Figure 1.37 Monthly flexible ramping payments



2 Energy imbalance market

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

- Prices in the Idaho Power area tracked closely to prices in PacifiCorp East. Price separation between these areas and the ISO was most pronounced during peak load hours when high system prices caused transfers from these areas to reach export limits.
- Prices in the Northwest 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 into and out of the region.
- The frequency of congestion across the energy imbalance market decreased slightly overall during the quarter, particularly from areas in the Northwest in the 5-minute market. In addition, the frequency of congestion to PacifiCorp East or Idaho Power from the ISO decreased significantly from the previous quarter.

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 Southern California Edison for comparison with prices in the ISO. Average prices for NV Energy and Arizona Public Service tracked closely to system prices during most hours. Prices for PacifiCorp East and Idaho Power often tracked similarly to system price. However, on average, prices for PacifiCorp East and Idaho Power were significantly lower than prices in the ISO during peak load hours. This is primarily due to several days with high system prices when energy imbalance market transfers out of PacifiCorp East and Idaho Power reached their upper scheduling limits.

Prices in the region including PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex were often lower 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 (July – September)

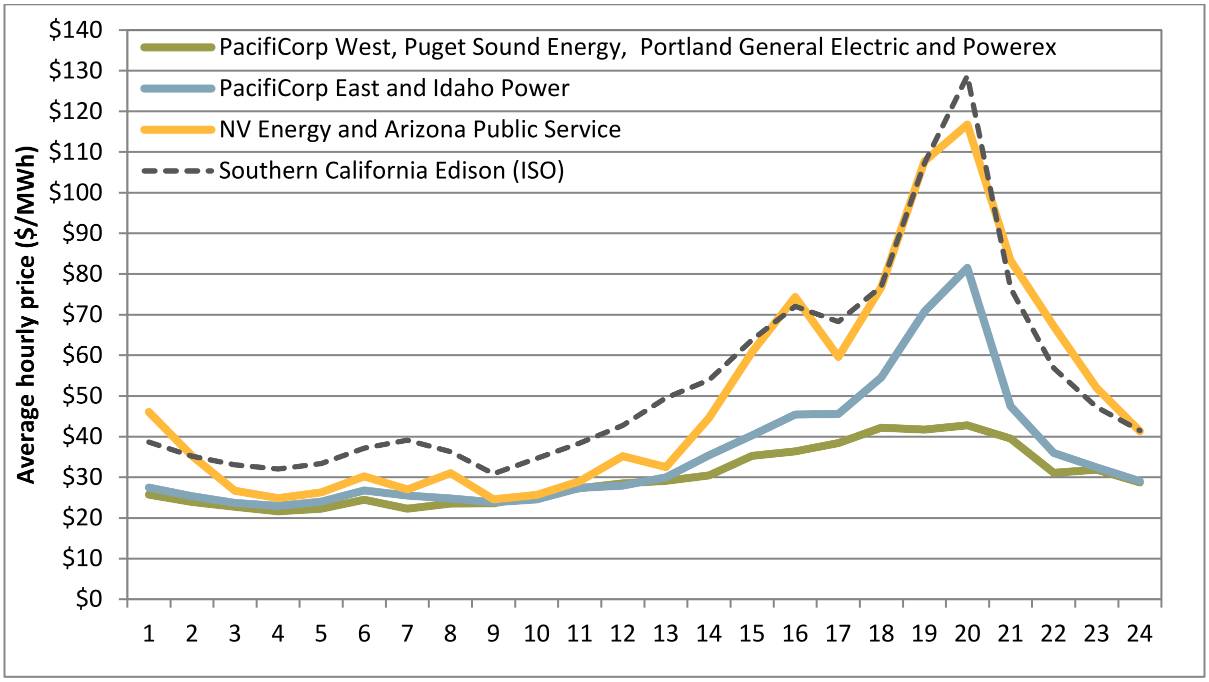
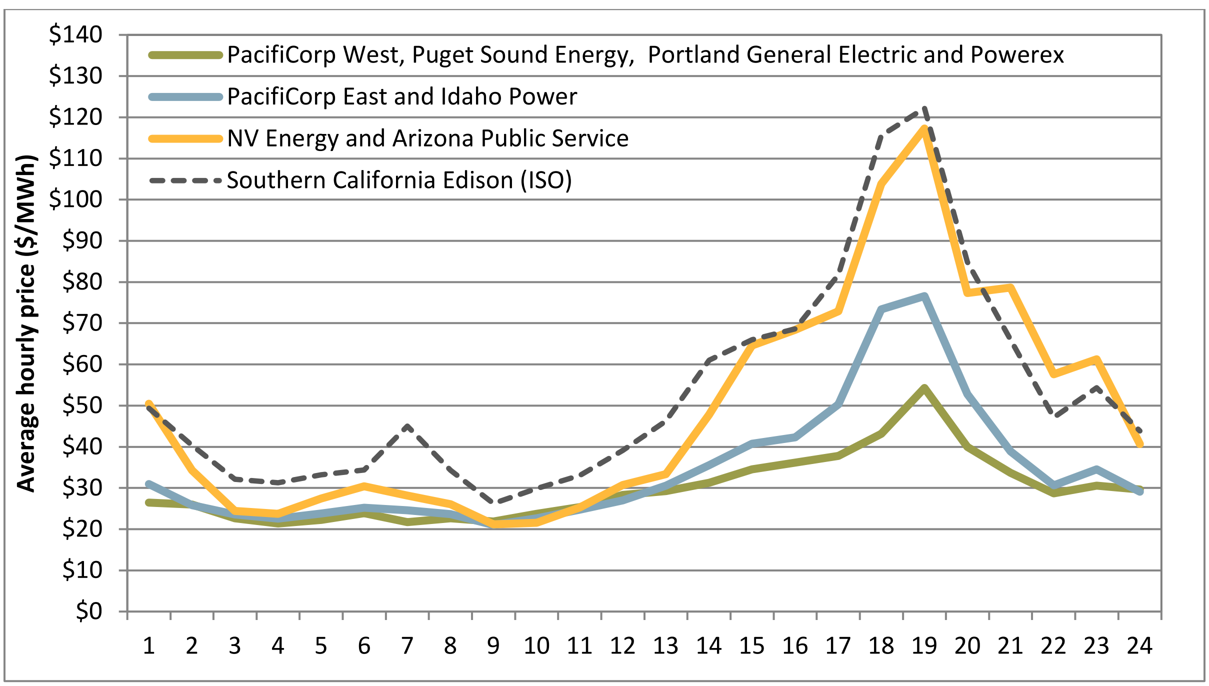


Figure 2.2 Hourly 5-minute market prices (July – September)



2.2 Flexible ramping sufficiency test

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

When the energy imbalance market was initially implemented there was an upward ramping sufficiency test. 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.[55] 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.[56]

Sufficiency test results

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

Figure 2.3 and Figure 2.4 show the percent of hours in which an energy imbalance market area failed the sufficiency test in the upward and downward direction, respectively. During the third quarter, there was an increase in the frequency of upward test failures overall, mostly from PacifiCorp East, NV Energy, and Arizona Public Service. In the downward direction, there were fewer failed sufficiency tests than the previous quarter.

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

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

Figure 2.3 Frequency of upward failed sufficiency tests by month

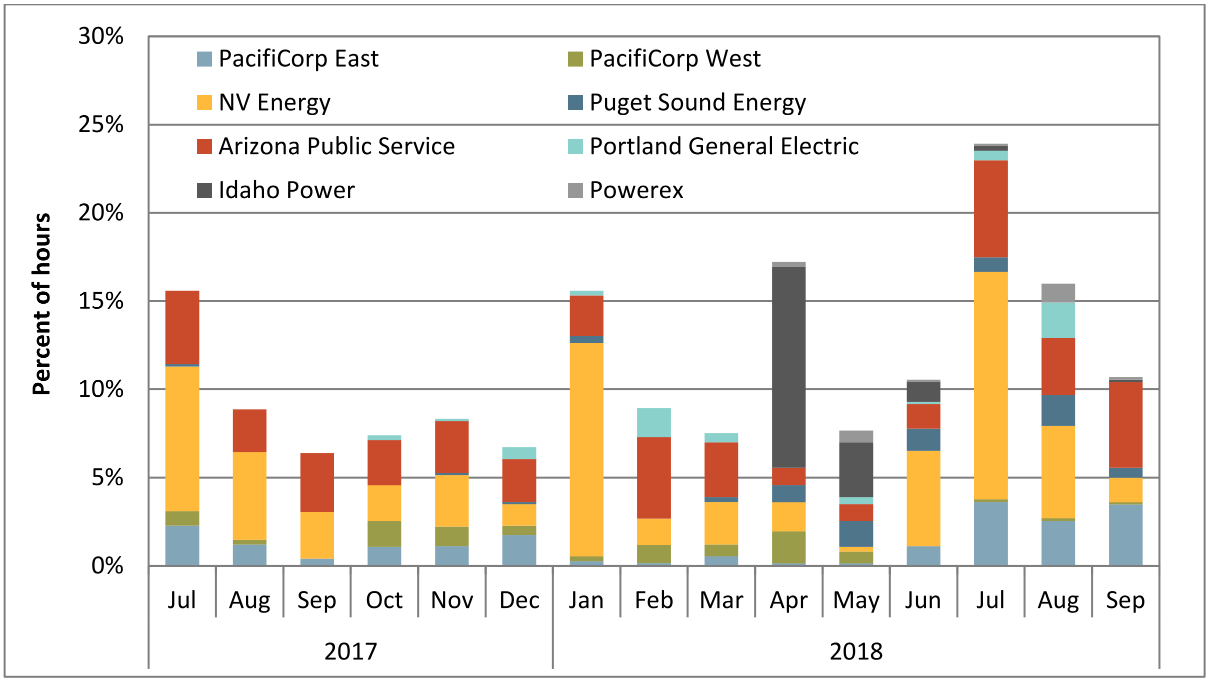
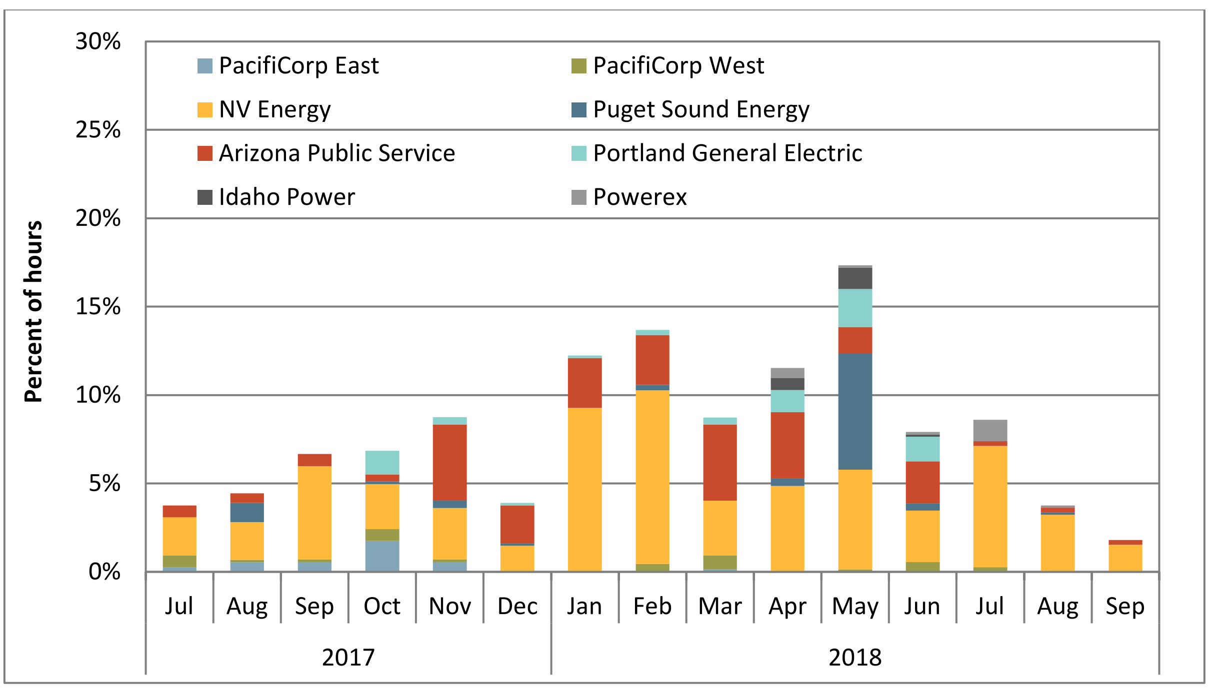


Figure 2.4 Frequency of downward failed sufficiency tests by month

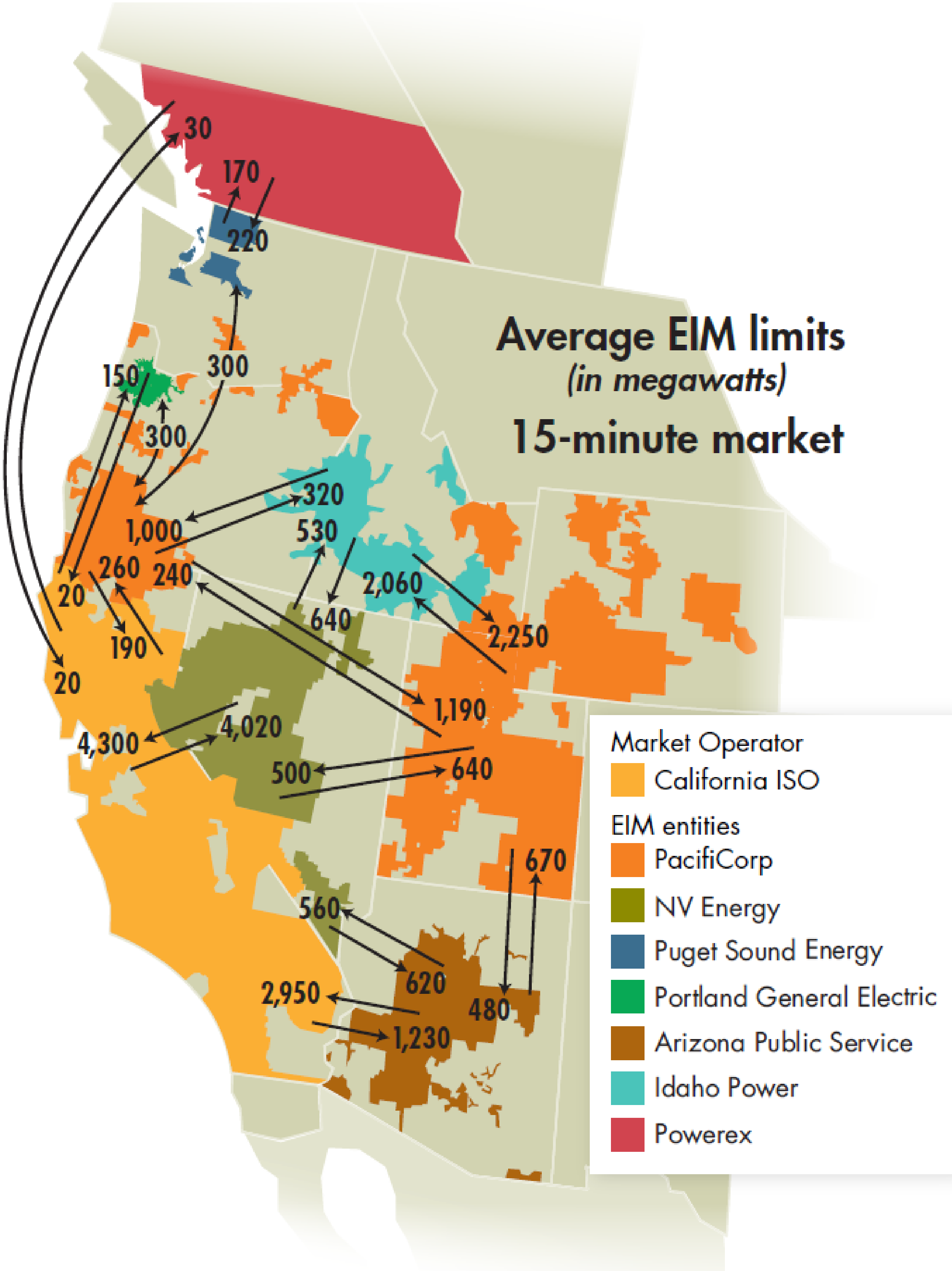


2.3 Energy imbalance market transfers

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 previous quarter, Idaho Power and Powerex joined the energy imbalance market, further expanding the transfer capability and benefits within the market.

Figure 2.5 shows average 15-minute market limits between each of the energy imbalance market areas during the third quarter. The map shows that there was significant transfer capability between the ISO, NV Energy, and Arizona Public Service. Transfer capability between these areas, PacifiCorp East and Idaho Power was also large to an extent. These limits allowed energy to flow between these areas with relatively little congestion. Transfer capability was more limited between the ISO and the Northwest areas which includes PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex. In particular, average 15-minute market limits from each of Portland General Electric and Powerex toward the ISO were less than 25 MW during the third quarter.

Figure 2.5 Average 15-minute market energy imbalance market limits (July - September)



The frequency of congestion across the energy imbalance market decreased slightly overall during the quarter, particularly from areas in the Northwest in the 5-minute market. 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.[57]

As shown in the table, the highest frequency of congestion in the energy imbalance market continued to be from the Northwest areas in the direction toward the ISO. Congestion from PacifiCorp West, Portland General Electric and Puget Sound Energy in the direction of the ISO occurred during around 33 percent of 15-minute intervals and 21 percent of 5-minute intervals. Similarly, Powerex was congested in the direction of the ISO in 31 percent of 15-minute intervals and 14 percent of 5-minute intervals. Combined, this led to lower prices during the quarter in these areas relative to the rest of the energy imbalance market and the ISO. However, the Northwest region was less frequently congested in comparison to the second quarter when congestion toward the ISO from these areas occurred in around 35 percent of 15-minute intervals and 28 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 often the result of a failed upward or downward sufficiency test. There was also relatively little congestion to and from the PacifiCorp East and Idaho Power areas. The frequency of congestion to these areas from the ISO decreased significantly from the previous quarter.

Table 2.1 Frequency of congestion in the energy imbalance market (July – September)

	15-minute market		5-minute market	
	Congested toward ISO	Congested from ISO	Congested toward ISO	Congested from ISO
NV Energy	3%	5%	3%	3%
Arizona Public Service	1%	4%	0%	2%
PacifiCorp East	7%	2%	4%	1%
Idaho Power	6%	0%	4%	1%
PacifiCorp West	34%	1%	21%	1%
Portland General Electric	33%	4%	21%	5%
Puget Sound Energy	33%	8%	21%	4%
Powerex	31%	21%	14%	11%

Different areas in the energy imbalance market exhibited different hourly transfer patterns during the quarter. This pattern is driven by the resource mix and relative prices in these areas during these periods. For instance, Figure 2.6 shows average hourly imports (negative values) and exports (positive values) into and out of the ISO during the quarter in the 15-minute market.[58] The bars show the average hourly transfers with the connecting areas while the gold line shows the average hourly net transfer. On

57 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.

58 Transfer figures in this section show real-time energy market flows net of all base schedules in the 15-minute market. Transfer amounts in previous reports were in the 5-minute market.

average for the quarter, the ISO was importing during most hours. This reflects a significant shift from the previous quarter, when the ISO was a net exporter on average as a result of lower seasonal load conditions.

Figure 2.6 California ISO – average hourly 15-minute market transfer (July – September)

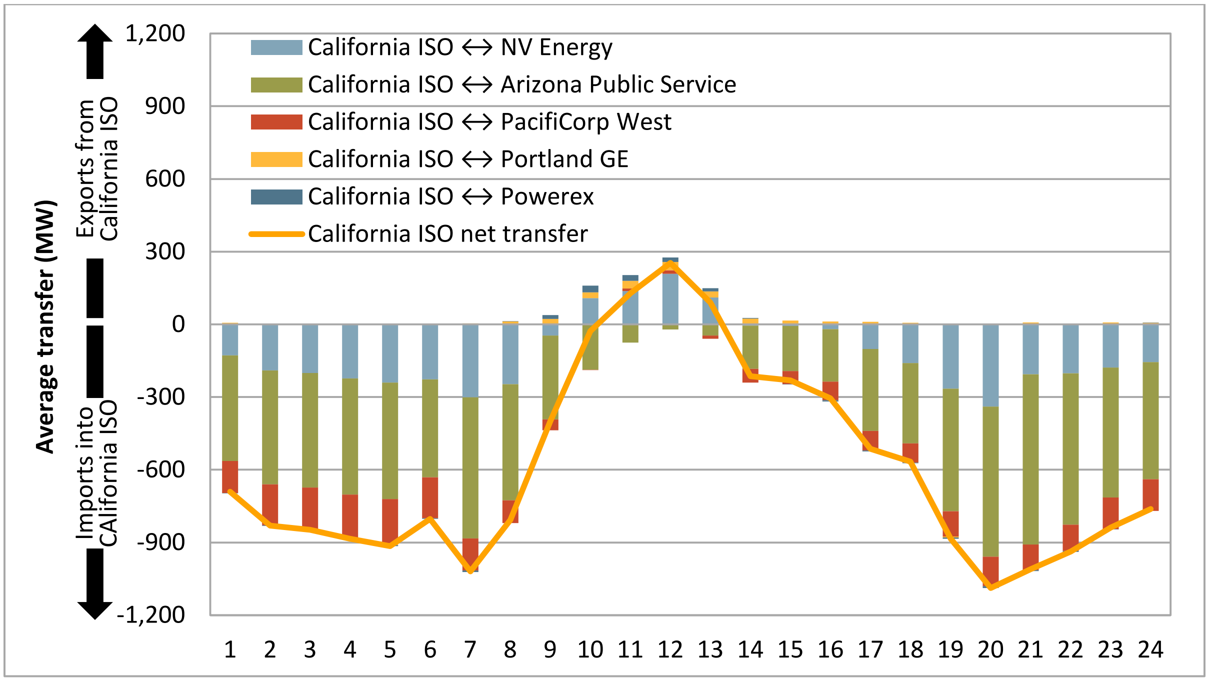


Figure 2.7 through Figure 2.11 show the same information on imports and exports for NV Energy, Arizona Public Service, Idaho Power, PacifiCorp West, and Powerex, net of all base schedules. NV Energy was a net importer during midday hours, and net exporter during most other hours of the day. Arizona Public Service, on average for the quarter, was importing from PacifiCorp East and exporting to the ISO in all hours.

Figure 2.7 NV Energy – average hourly 15-minute market transfer (July – September)

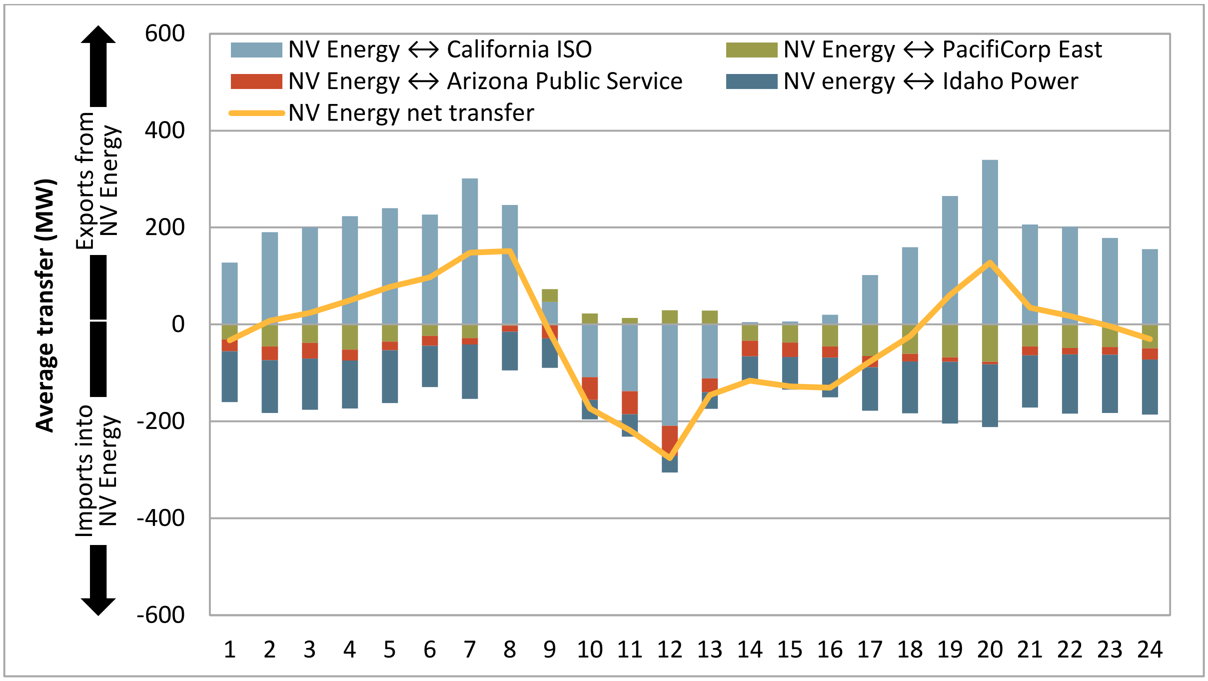
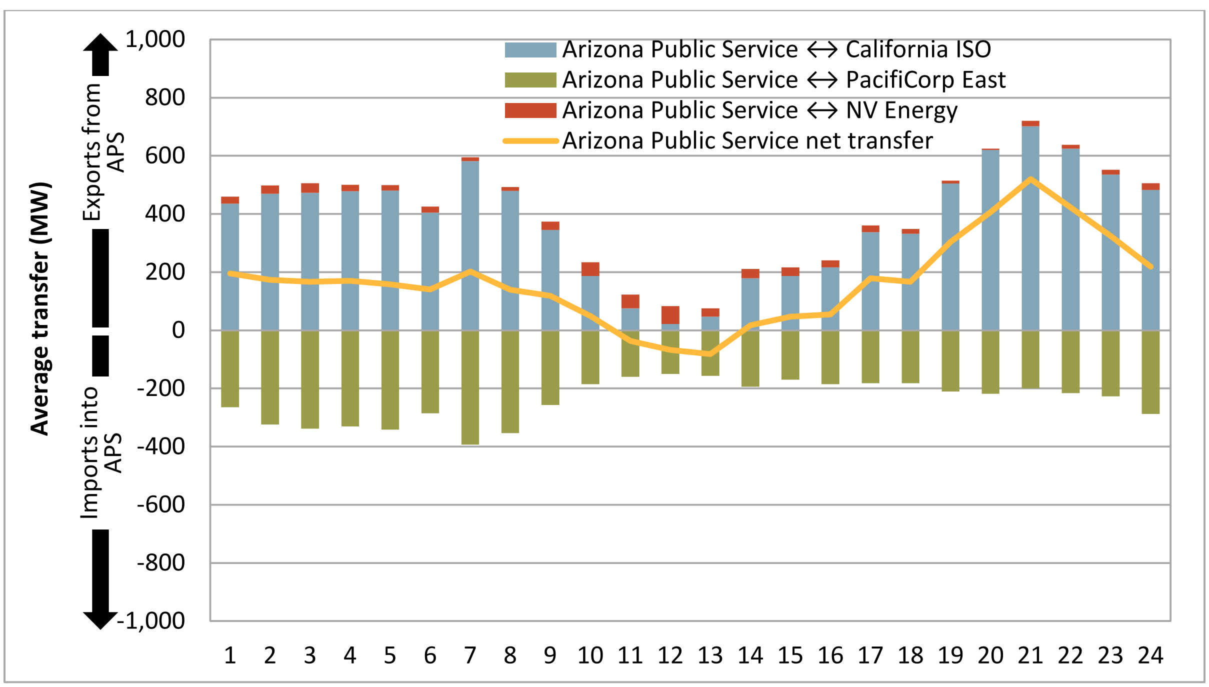
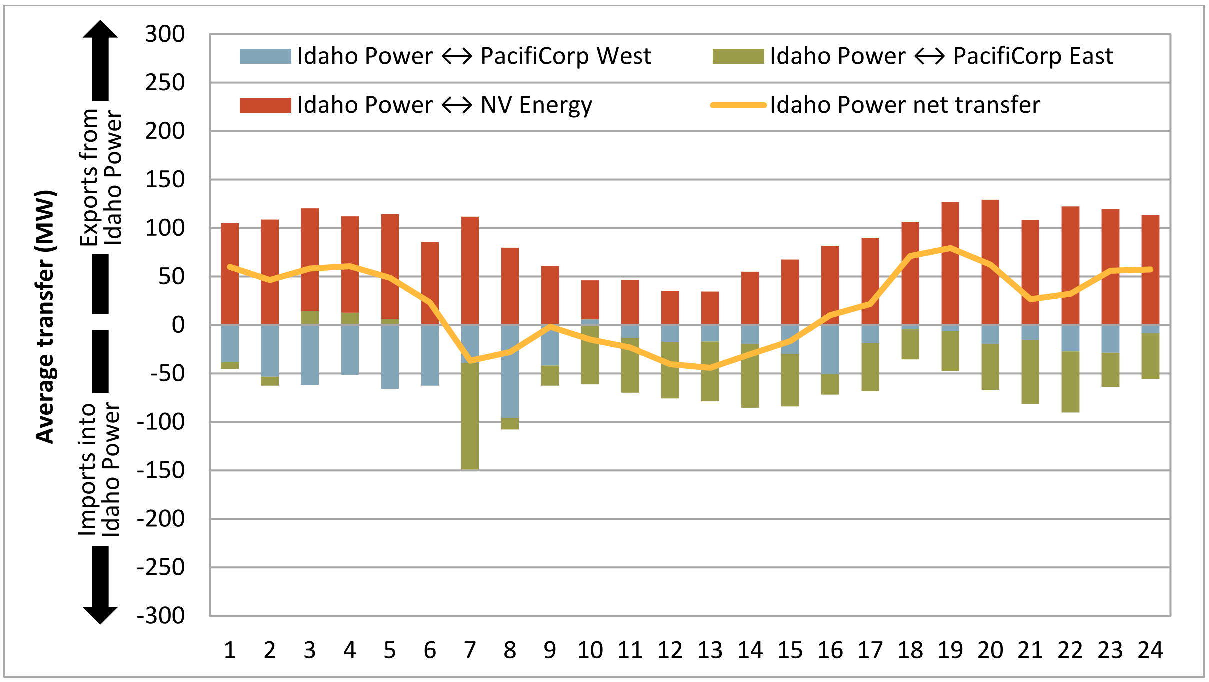


Figure 2.8 Arizona Public Service – average hourly 15-minute market transfer (July – September)



Idaho Power has transfer capacity between PacifiCorp West, PacifiCorp East, and NV Energy. Figure 2.9 shows the hourly 15-minute market transfer pattern between Idaho Power and neighboring areas during the third quarter. This figures shows that, like NV Energy, Idaho Power was a net importer during midday hours, and net exporter during most other hours of the day. Idaho Power, on average for the quarter, was importing from PacifiCorp East and PacifiCorp West and exporting to NV Energy in all hours.

Figure 2.9 Idaho Power – average hourly 15-minute market transfer (July – September)



PacifiCorp West has transfer capacity between PacifiCorp East, Puget Sound Energy, the ISO, and Portland General Electric. Figure 2.10 shows the hourly 15-minute market transfer pattern between PacifiCorp West and neighboring areas during the third quarter. This figure shows that PacifiCorp West was a net exporter in all hours on average during the quarter. PacifiCorp West exported over 1,100 MW to PacifiCorp East on average during the quarter, but net of all base schedules, imported around 110 MW on average.

Figure 2.11 shows average hourly 15-minute market imports and exports into and out of Powerex. The figure also includes average hourly transfer limits with the ISO and Puget Sound Energy. During the third quarter, import and export transmission capacity from Powerex to the ISO were limited to 32 MW or less during the large majority of 15-minute intervals. Transfer limits between Powerex and the ISO were higher in both import and export directions in the 5-minute market. Powerex import and export transfer limits averaged about 135 MW in the 5-minute market during the quarter, compared to about 25 MW in the 15-minute market.

Figure 2.10 PacifiCorp West – average hourly 15-minute market transfer (July – September)

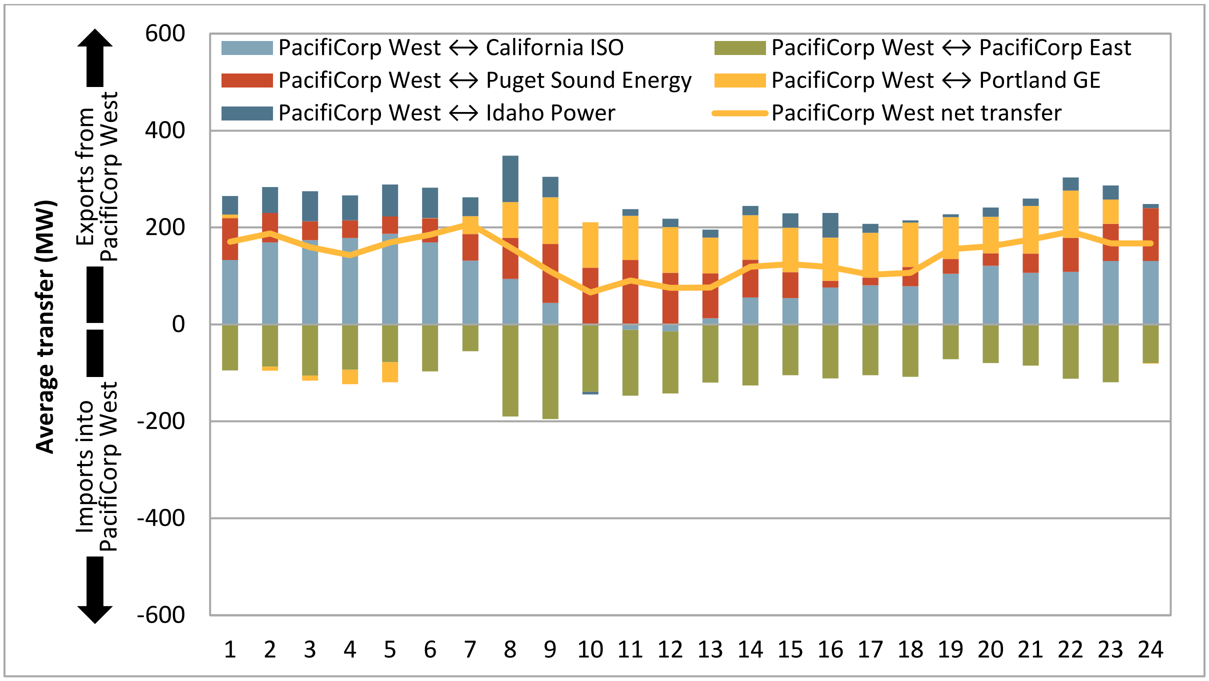
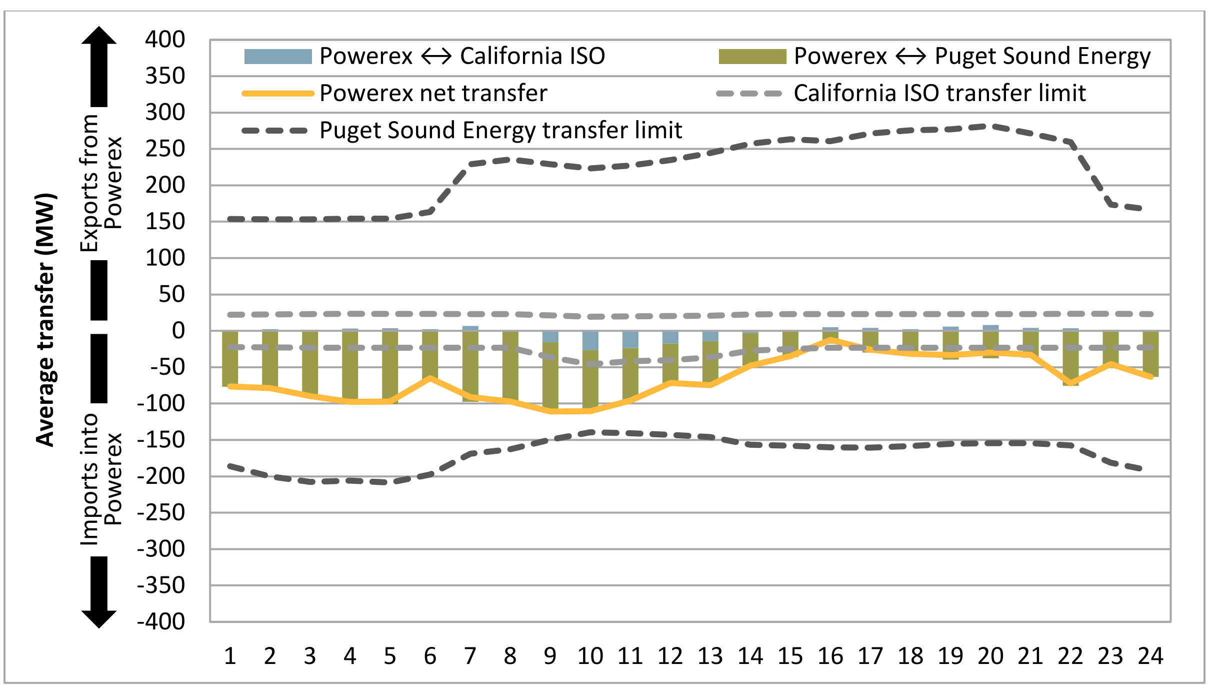


Figure 2.11 Powerex – average hourly 15-minute market transfer (July – September)



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 third quarter for the 15-minute and 5-minute markets. The same data for the ISO is provided as a point of reference. Overall, load adjustments were typically positive in PacifiCorp East, PacifiCorp West, Arizona Public Service, NV Energy and Portland General Electric, while load adjustments were more frequently negative in Puget Sound Energy. Similar to the ISO, nearly all energy imbalance market entities had a much greater frequency of positive 5-minute market adjustments than 15-minute market adjustments during the third quarter.

Table 2.2 also includes the average absolute positive and negative load adjustment as a percent of area load. Average load adjustments as a percent of total area load were similar between areas during the quarter. In previous quarters, average load adjustments as a percent of total area load were considerably higher in some areas than others.

Table 2.2 Average frequency and size of load adjustments (July - September)

	Positive load adjustments			Negative load adjustments			Average hourly bias MW
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO							
15-minute market	40%	593	1.7%	5%	-283	1.0%	225
5-minute market	42%	342	1.0%	25%	-265	1.0%	78
PacifiCorp East							
15-minute market	30%	125	1.9%	2%	-84	1.4%	37
5-minute market	43%	120	1.9%	16%	-88	1.6%	38
PacifiCorp West							
15-minute market	1%	37	1.4%	0%	-119	4.2%	0
5-minute market	10%	39	1.5%	5%	-54	2.4%	1
NV Energy							
15-minute market	13%	90	1.4%	1%	-59	1.0%	11
5-minute market	22%	70	1.1%	9%	-76	1.5%	9
Puget Sound Energy							
15-minute market	0%	56	2.2%	2%	-60	2.5%	-1
5-minute market	6%	50	1.9%	36%	-51	2.1%	-16
Arizona Public Service							
15-minute market	89%	135	2.9%	3%	-70	1.7%	118
5-minute market	88%	135	2.9%	3%	-71	1.7%	118
Portland General Electric							
15-minute market	0%	40	1.2%	0%	-56	3.1%	0
5-minute market	13%	32	1.2%	3%	-44	1.9%	3
Idaho Power Company							
15-minute market	9%	45	1.6%	10%	-39	2.0%	0
5-minute market	13%	48	1.7%	13%	-44	2.2%	1

3 Special issues

3.1 Overall market competitiveness

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

- Overall competitiveness in the day-ahead market remains strong. Higher gas prices resulted in larger overall costs to deliver energy in 2018 and explained much of the increase from 2017 and 2016. Total wholesale energy costs for year-to-date 2018, normalized for gas prices, remain very close to totals from 2017.
- Throughout the quarter, prices in the day-ahead market were higher than prices in the bilateral markets. An exception to this occurred in early August when prices spiked in the ISO and in bilateral markets, though bilateral markets exceeded ISO prices.
- Implied heat rates, a measure of electricity prices with respect to gas prices, show that SoCal Citygate gas prices largely explain electricity prices in Southern California. PG&E Citygate gas prices remained low though PG&E electricity prices reflected high system level prices, resulting in extremely high implied heat rates.

Wholesale energy cost

Total wholesale cost to serve load in the market provides one measure of market competitiveness.[59] Total costs during the first three quarters of 2018 were about $8.3 billion, compared to about $9.3 billion in 2017. Extending the total costs during the first three quarters of 2018 through the end of the year would result in an estimated total cost to serve market load in 2018 of about $11 billion. The average cost per megawatt-hour of load increased 20 percent to about $50/MWh for the first three quarters of 2018 from just under $42/MWh in 2017 (nominal costs shown in blue bars in Figure 3.1). Higher gas prices continue to explain most of the differences in costs, particularly in the south, with volume-weighted average gas prices increasing from about $3.33/MMBtu in 2017 to about $4.11/MMBtu during the first three quarters of 2018.[60] When normalizing for changes in natural gas and greenhouse gas costs, the gold bar in Figure 3.1 shows that wholesale energy costs to serve load increased by about 4 percent, a slight increase from 2017 but comparable to 2014 when average gas prices were about $4.50/MMBtu.

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

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

Figure 3.1 Total annual wholesale costs per MWh of load (2014-2018 *Jan-Sep)

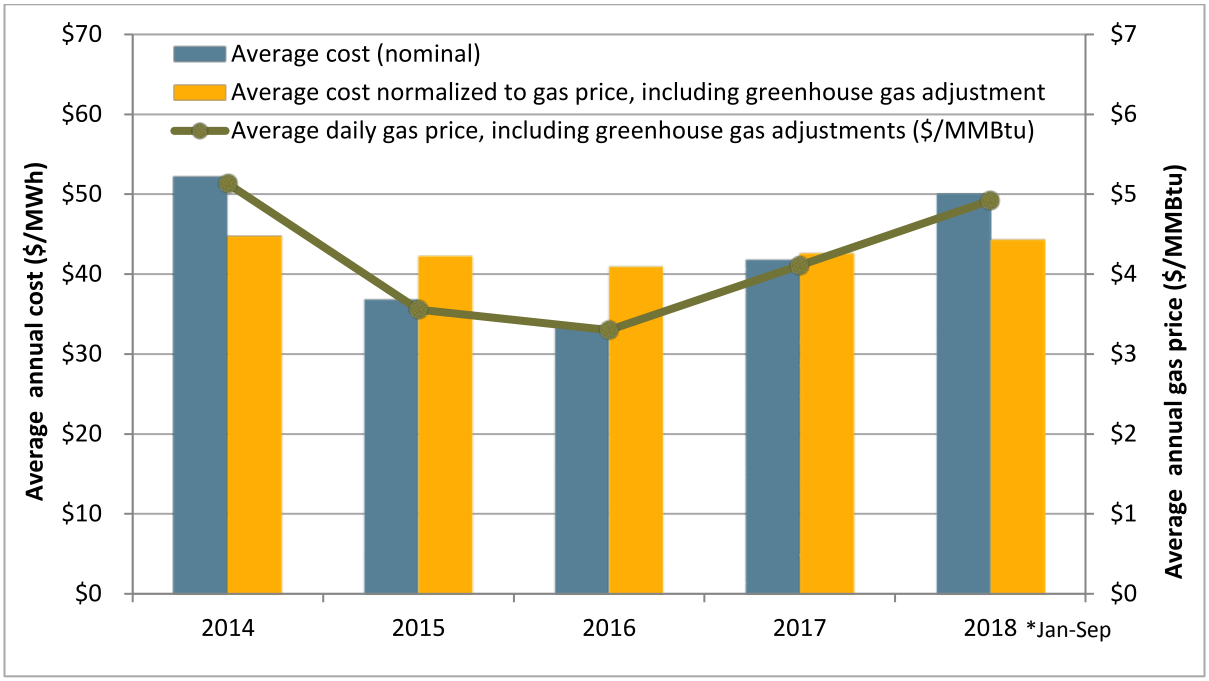


Table 3.1 provides annual summaries of nominal total wholesale costs by category from 2014 through the third quarter of 2018. Costs for energy procured in the day-ahead market continued to make up a majority (89 percent) of the total cost to deliver energy to the market, followed by costs from the real-time market (5 percent). Despite higher prices, particularly in the day-ahead market, the proportion of costs for energy procured in the day-ahead market fell from 90 percent in 2017 and 91 percent in 2016.

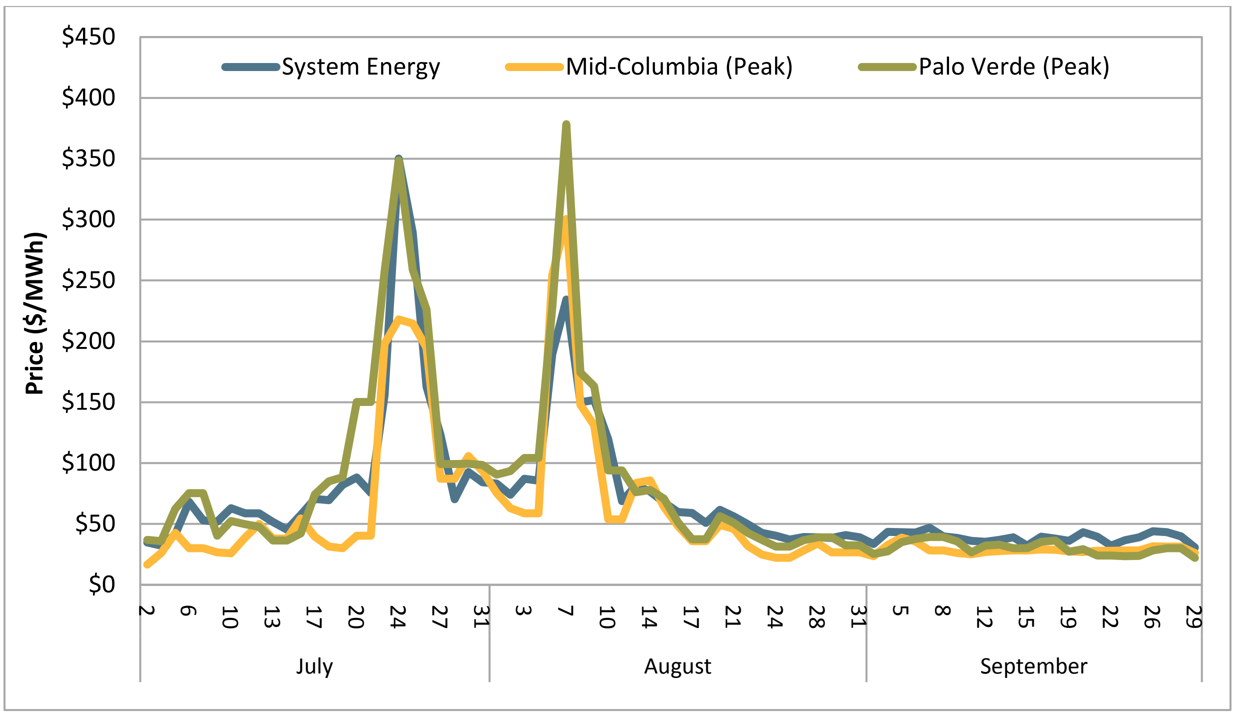
Table 3.1 Estimated average wholesale energy costs per MWh (2014-2018 *Jan-Sep)

	2014	2015	2016	2017	2018	Change '17-'18
Day-ahead energy costs	$ 48.57	$ 34.54	$ 30.70	$ 37.59	$ 44.36	$ 6.77
Real-time energy costs (incl. flex ramp)	$ 1.98	$ 0.69	$ 1.03	$ 2.01	$ 2.49	$ 0.48
Grid management charge	$ 0.80	$ 0.80	$ 0.81	$ 0.81	$ 0.82	$ 0.01
Bid cost recovery costs	$ 0.40	$ 0.39	$ 0.33	$ 0.47	$ 0.78	$ 0.31
Reliability costs (RMR and CPM)	$ 0.14	$ 0.12	$ 0.11	$ 0.10	$ 0.64	$ 0.53
Average total energy costs	**$ 51.89**	**$ 36.54**	**$ 32.98**	**$ 40.99**	**$ 49.09**	**$ 8.10**
Reserve costs (AS and RUC)	$ 0.30	$ 0.27	$ 0.54	$ 0.77	$ 0.96	$ 0.18
Average total costs of energy and reserve	**$ 52.19**	**$ 36.81**	**$ 33.52**	**$ 41.77**	**$ 50.05**	**$ 8.28**

Comparison to bilateral prices

Figure 3.2 shows day-ahead system marginal energy costs (SMEC) for energy in the ISO, as well as average peak energy prices traded at the Palo Verde and Mid-Columbia hubs outside of the California ISO market, for the quarter.[61] Prices at Mid-Columbia and Palo Verde were lower than prices in the ISO, during about 85 percent and 65 percent of the time, respectively. Relatively higher prices in California reflect both the greenhouse gas compliance cost associated with delivering energy into the state and the cost of congestion across limited intertie capacity. One exception to this trend occurred on August 7 when prices peaked and hub prices outside of the ISO exceeded ISO prices. Prices at Palo Verde exceeded Mid-Columbia prices throughout the majority of the quarter, about 75 percent of the time, due to the availability of low-cost hydroelectric resources and limited transfer capacity.

Figure 3.2 Daily system and bilateral market prices (July – September 2018)



Implied heat rates

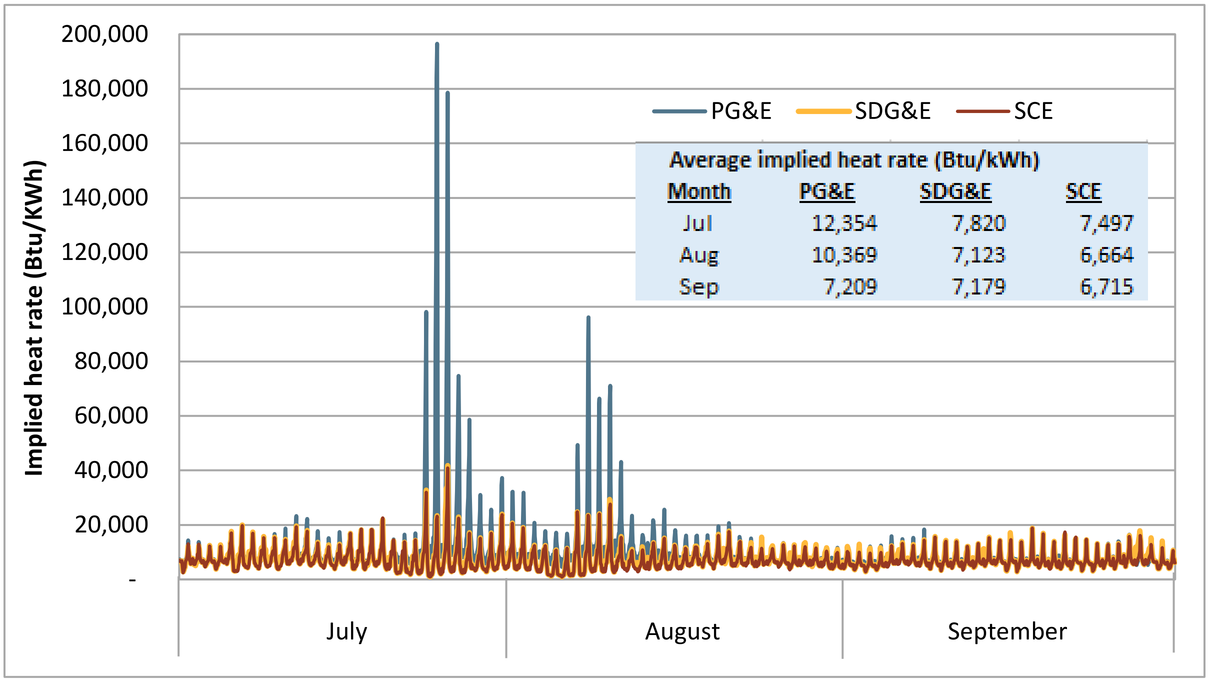
Average prices increased compared to the same quarter in 2017, driven, in part, by high gas prices, particularly at the SoCal Citygate trading hub. The chart below shows the implied heat rates for PG&E, SCE, and SDG&E for the quarter. The rates are calculated by dividing the day-ahead price at each default load aggregation point (DLAP) by the gas price at SoCal Citygate (for SCE and SDG&E) and at PG&E Citygate (for PG&E).

The results show that the electricity prices in Southern California are highly correlated with gas prices. In the PG&E area, gas prices were lower than in Southern California, though electricity prices closely

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

matched those of Southern California in hours without north-to-south congestion. This contributed to significantly higher heat rates in late July and early August when electricity prices peaked.

Figure 3.3 Implied heat rates (July – September 2018)



3.2 Structural measures of market competitiveness

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

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

- **Residual supply index**. The residual supply index is the ratio of supply from non-pivotal suppliers to demand.[62]

In the electric industry, measures based on the two or three pivotal suppliers are often used as measures of competitiveness because of the potential for oligopolistic bidding behavior. This potential is high in the electric industry because the demand for electricity is highly inelastic, and competition

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

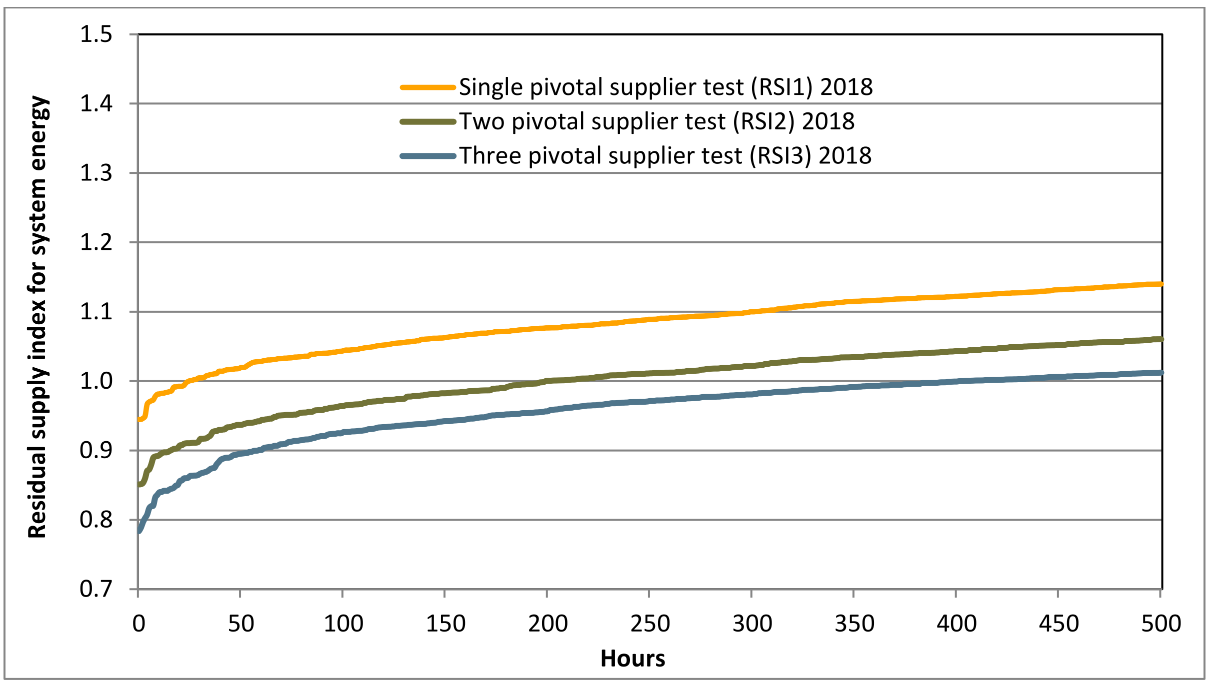
from new sources of supply is limited by long lead times and regulatory barriers for building new generation.

In this report the measure RSI_1 refers to the residual supply index calculated by excluding the largest supplier. The RSI_2 measure refers to the same calculation with the two largest suppliers excluded, and for RSI_3 with the three largest supplier excluded.[63]

The frequency of hours with residual supply less than demand in the day-ahead market increased relative to 2017 by the RSI_2 and RSI_3 measures. As shown in Figure 3.4, the residual supply index with the three largest suppliers removed (RSI_3) was less than 1 during about 374 hours in the first three quarters of 2018, an increase over 336 hours in 2017. The index was less than 1 during about 187 hours with the two largest suppliers removed (RSI_2), compared to 136 hours in 2017. The RSI_1 value was less than 1 during 23 hours, compared to 36 hours in 2017.

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

Figure 3.4 Residual supply index for day-ahead energy (January - September)



[63] A detailed description of the residual supply index was provided in DMM's 2017 annual report. http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf, p 153.

3.3 Resource adequacy performance

3.3.1 Peak load and resource adequacy requirements and performance

Net system resource adequacy requirement (the monthly system resource adequacy requirement adjusted for qualifying discounts) was sufficient to meet actual peak load on most but not all days in the third quarter. Figure 3.5 shows daily peak loads and forecasts as solid green and blue lines from July 20 to August 13. Peak loads on July 23, July 24, and July 25 were above 45,500 MW with loads reaching over 46,000 MW on July 24 and July 25. These loads were higher than net system resource adequacy requirement, shown by the dashed yellow line, which was about 45,000 MW for the month of July. Actual resource adequacy procurement was just above 47,000 MW, with nearly 44,000 MW (93 percent) available in the day-ahead market during the peak load hours on all three days.

The ISO works with the California Public Utilities Commission and other local regulatory authorities to set system level resource adequacy requirements. System resource adequacy provisions require load-serving entities to procure generation capacity to meet forecasted peak load in each month plus a planning reserve margin, which is generally 15 percent of peak load.[64] Load-serving entities meet this requirement by providing resource adequacy showings to the ISO on a year-ahead basis due in October and provide 12 month-ahead showings during the compliance year. Resource adequacy capacity must then be bid into the ISO markets through a must-offer requirement.

Net system resource adequacy requirements for July were substantially less than 115 percent of the ISO's 2018 1-in-2 year forecast of peak load, 53,619 MW.[65] During high load days in July, the sum of monthly 1-in-2 peak load estimates for resource adequacy requirements provided by the California Energy Commission was 43,329 MW. This was less than both day-ahead forecast and loads from July 23 to July 25. Some load-serving entities have resource adequacy requirements calculated with a planning reserve margin of less than 15 percent. Even with this consideration, the addition of the planning reserve margin without discounts, the grey line in Figure 3.5, would have been sufficient to cover both daily peak loads and forecasts during the highest load days in July at about 49,800 MW.

The red bars in Figure 3.5 show the total amount of resource adequacy capacity used to meet resource adequacy requirements from July 20 to August 13. Scheduling coordinators are incentivized to make resource adequacy capacity available in the market during only *availability assessment hours* through the resource adequacy availability incentive mechanism.[66] The system and local resource adequacy availability assessment hours are for hours ending 17 through 21 on non-holiday weekdays.

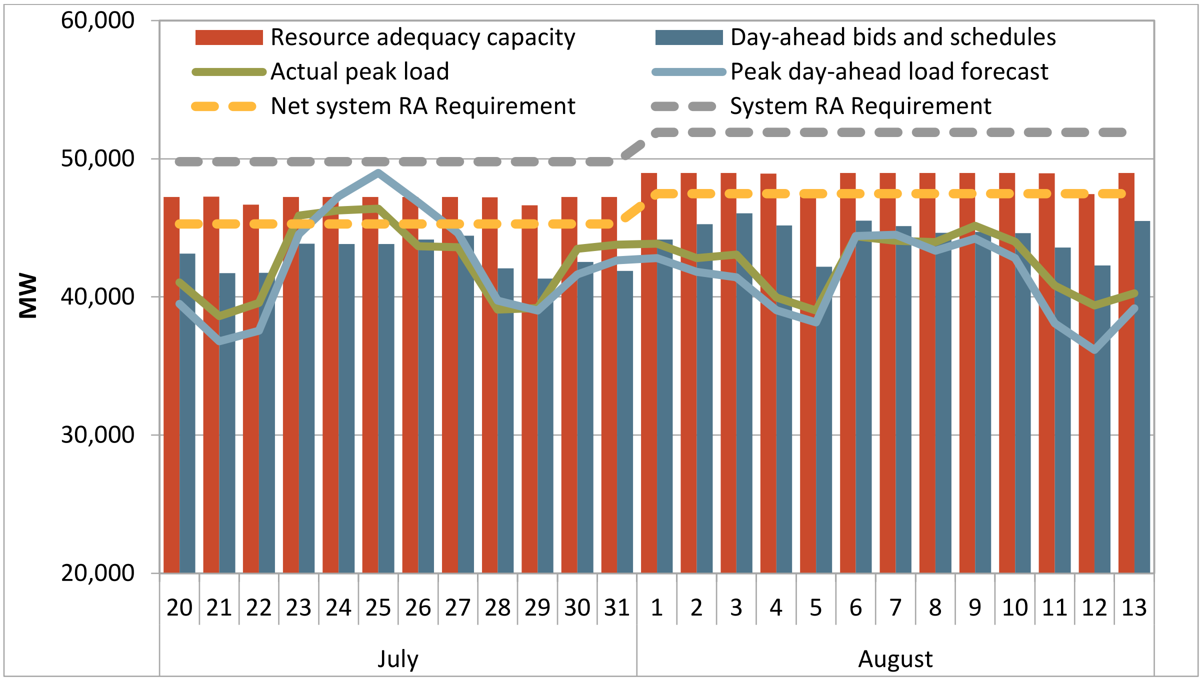
The blue bars in Figure 3.5 show the amount of resource adequacy capacity that was available in the day-ahead market through either a self-schedule or an economic bid during the peak load hour of the day. Differences between the resource adequacy capacity (red bars) and the available resource adequacy capacity in the day-ahead market (blue bars) were mostly driven by solar, wind, hydro, and nuclear resources, which have unique operating limitations.

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

[65] A similar note was made in the 2017 Q3 report regarding resource adequacy requirements for September: http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf.

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

Figure 3.5 Daily peak load, resource adequacy capacity, and planning forecast



3.3.2 System resource adequacy availability

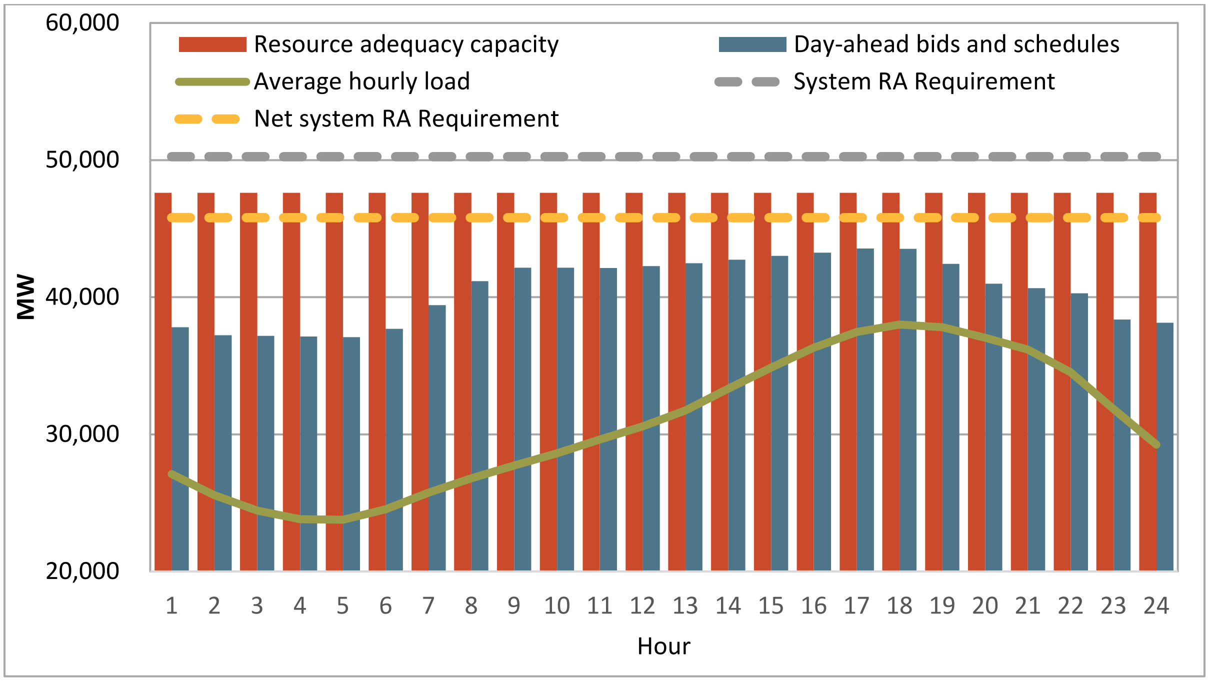
Load-serving entities procure resource adequacy capacity to meet system-level requirements. Scheduling coordinators are then incentivized to make resource adequacy capacity available in the market during *availability assessment hours* through the resource adequacy availability incentive mechanism (RAAIM). These are hours ending 17 through 21 on non-holiday weekdays. [67]

Figure 3.6 shows load, resource adequacy capacity, the capacity that was available in the market, and resource adequacy requirements averaged over each hour of the day during the third quarter.[68] On average, about 85 percent of resource adequacy capacity was available in the day-ahead market during each hour of the day throughout the quarter. Availability is measured as the ratio of day-ahead bids and schedules (blue bar) to resource adequacy capacity (red bars). This percentage increases during hours ending 17 through 21 where around 89 percent of capacity procured was available in the day-ahead market. This high 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 to 85 percent of procured capacity in hour ending 21 when resources such as solar become unavailable but load is still high.

[67] Prior to 2018, the 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

[68] Holidays and weekends are included.

Figure 3.6 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.
- **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 3.2 provides a detailed summary of the availability of resource adequacy capacity during hours with load at or above 40,000 MW for each type of generation for the day-ahead and real-time markets. 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 3.2:

- ***Most of the capacity that must bid during all hours continued to be from gas-fired resources.*** About half of the capacity (26,300 MW) for system resource adequacy must be bid into the market for each hour of the month.[69] Gas-fired generation made up about 21,000 MW (43 percent) of total resource adequacy capacity. Imports continued to represent about 8 percent of total capacity.[70]

- ***Hydro generation made up the largest portion of generation not required to bid in during all hours.*** Hydro resources contributed about 6,100 MW of total capacity (13 percent), use-limited gas resources contributed 11 percent, solar resources contributed 8 percent, nuclear resources contributed 6 percent and resources with operating restrictions (wind and qualifying facilities) combined contributed an additional 6 percent.

- ***Resource adequacy capacity after reported outages and derates continued to be significant.*** Average resource adequacy capacity was around 47,900 MW during the hours with at least 40,000 MW of load in the third quarter of 2018, down from nearly 48,500 MW in the third quarter of 2017. After adjusting for outages and derates, the remaining capacity was about 96 percent of the overall resource adequacy capacity, which is down 1 percent from the third quarter of 2017.

- ***Day-ahead market availability was high for all resource types.*** About 96 percent of both must-offer and non must-offer resources were available in the day-ahead market. Must-offer resources bid in about 99 percent of day-ahead availability; the lowest resource type by percent was imports at 96 percent. Non must-offer resources bid in about 86 percent of the day-ahead availability. These are typically variable and non-dispatchable energy resources. Additionally, some of the hours with at least 40,000 MW of load occurred outside of peak 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 3.2 compare the total resource adequacy 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 88 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 5,000 MW of use-limited gas resources were used to meet resource adequacy requirements. After adjusting for outages, about 98 percent of capacity was bid in the day-ahead market during hours with at least a 40,000 MW load. In real time, about 4,400 MW of 4,800 MW (92 percent) of net available capacity was scheduled or bid in the real-time market.

[69] 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.

[70] 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.

- ***Nuclear capacity contributed to resource adequacy.*** In the third quarter of 2018, around 2,900 MW of nuclear resources were used to meet resource adequacy requirements. This is an increase of about 500 MW from the same quarter of the previous year.

Table 3.2 Average system resource adequacy capacity and availability (load hours >40,000 MW)

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	20,799	19,762	95%	19,762	100%	17,390	84%	16,185	93%
Other generators	1,672	1,541	92%	1,541	100%	1,541	92%	1,374	89%
Imports	3,873	3,865	100%	3,701	96%	3,320	86%	2,491	75%
Subtotal	**26,344**	**25,168**	**96%**	**25,004**	**99%**	**22,251**	**84%**	**20,050**	**90%**
Other:									
Use-limited gas units	5,044	4,901	97%	4,781	98%	4,814	95%	4,435	92%
Hydro generators	6,143	5,663	92%	5,233	92%	5,663	92%	5,086	90%
Nuclear generators	2,894	2,878	99%	2,875	100%	2,878	99%	2,615	91%
Solar generators	3,975	3,957	100%	2,631	67%	3,932	99%	2,758	70%
Wind generators	1,573	1,569	100%	1,004	64%	1,569	100%	1,148	73%
Qualifying facilities	1,404	1,377	98%	1,159	84%	1,297	92%	1,054	81%
Other non-dispatchable	493	487	99%	307	63%	466	94%	380	82%
Subtotal	**21,526**	**20,832**	**97%**	**17,990**	**86%**	**20,619**	**96%**	**17,476**	**85%**
Total	**47,870**	**46,000**	**96%**	**42,994**	**93%**	**42,870**	**90%**	**37,526**	**88%**

Imports

Load-serving entities are allowed to use imports to meet system resource adequacy requirements. Imports were used to meet an average of around 3,600 MW (or around 7 percent) of system resource adequacy requirements during the peak summer hours of 2017. In the summer of 2018, this has increased to an average of around 4,000 MW (or around 8 percent) of system resource adequacy requirements.[71]

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.[72] Imports can be bid at any price 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.

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71 For more information and analysis of import resource adequacy in 2017 and 2018, see the following report: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf

72 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

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 re-consider rules concerning resource adequacy requirements met by imports.[73]

3.3.3 Capacity procurement mechanism

The capacity procurement mechanism within the ISO tariff provides backstop procurement authority to ensure that the ISO will have sufficient capacity available to maintain reliable grid operations. This mechanism establishes a price at which the ISO can procure backstop capacity to meet local resource adequacy 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 receiving notice by electronic mail.

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

Second, the ISO may procure backstop capacity through a monthly competitive solicitation process in the event 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.

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

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 3.3 shows intra-monthly capacity procurement mechanism costs for designations that occurred during the third 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 $2.9 million in the third quarter 2018.

About 46 MW of capacity was procured for potential thermal overload to address local reliability issues in the SDG&E and PG&E areas. In total, these designations cost about $0.56 million, or about $0.14 million for the quarter. The ISO also issued a capacity procurement mechanism significant event, designating 624 MW of backstop capacity for system reliability needs. The designations were made initially for the month of September with potential for extensions. The event was issued in light of an alternate load forecast presented by California Energy Commission (CEC) staff. The initial load forecast was used as the basis of 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 on the alternate forecast) and the quantity of resource adequacy capacity shown for the month of September. In total, they cost the system about $2.8 million.

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 3.3 Intra-monthly capacity procurement mechanism costs[74]

Resource	Designated MW	CPM Start Date	CPM End Date	CPM Type	Price ($/kW-mon)	Estimated cost ($ mil)	Estimated cost Q3 ($ mil)	Local capacity area	CPM designation trigger
ENCINA UNIT 3	20	5/9/18	7/8/18	ED	$6.31	$0.25	$0.03	SDG&E	Potential thermal overload
Humboldt Bay Generating Station 1	26	9/10/18	11/8/18	ED	$6.31	$0.31	$0.11	PG&E	Potential thermal overload
BIG CREEK HYDRO PROJECT PSP	64	9/1/18	9/30/18	SIGEVT	$5.07	$0.31	$0.31	SYS	Alternate load forecast
JAMES B. BLACK 2	84	9/1/18	9/30/18	SIGEVT	$5.50	$0.38	$0.38	SYS	Alternate load forecast
Coleman	2	9/1/18	9/30/18	SIGEVT	$5.50	$0.01	$0.01	SYS	Alternate load forecast
ELK HILLS COMBINED CYCLE (AGGREGATE)	12	9/1/18	9/30/18	SIGEVT	$3.25	$0.04	$0.04	SYS	Alternate load forecast
Grapeland Peaker	46	9/1/18	9/30/18	SIGEVT	$5.07	$0.22	$0.22	SYS	Alternate load forecast
HYATT-THERMALITO PUMP-GEN (AGGREGATE)	60	9/1/18	9/30/18	SIGEVT	$2.00	$0.11	$0.11	SYS	Alternate load forecast
MOSS LANDING POWER BLOCK 2	29	9/1/18	9/30/18	SIGEVT	$4.25	$0.12	$0.12	SYS	Alternate load forecast
PIT PH 1 UNIT 2	8	9/1/18	9/30/18	SIGEVT	$5.50	$0.04	$0.04	SYS	Alternate load forecast
PIT PH 5 UNITS 3 & 4 AGGREGATE	28	9/1/18	9/30/18	SIGEVT	$5.50	$0.15	$0.15	SYS	Alternate load forecast
PIT PH 6 UNIT 1	39	9/1/18	9/30/18	SIGEVT	$5.50	$0.18	$0.18	SYS	Alternate load forecast
PWRX_MALIN500_I_F_CPM01	210	9/1/18	9/30/18	SIGEVT	$5.00	$1.00	$1.00	SYS	Alternate load forecast
Sycamore Cogeneration Unit 1	10	9/1/18	9/30/18	SIGEVT	$5.07	$0.05	$0.05	SYS	Alternate load forecast
Sycamore Cogeneration Unit 2	11	9/1/18	9/30/18	SIGEVT	$5.07	$0.05	$0.05	SYS	Alternate load forecast
Sycamore Cogeneration Unit 3	10	9/1/18	9/30/18	SIGEVT	$5.07	$0.05	$0.05	SYS	Alternate load forecast
Sycamore Cogeneration Unit 4	11	9/1/18	9/30/18	SIGEVT	$5.07	$0.05	$0.05	SYS	Alternate load forecast
Total	**670**					**$3.33**	**$2.90**		

In addition to the intra-monthly designations, there were also four annual designations made for capacity via the capacity procurement mechanism in December 2017 for 2018 that are still in place for the third quarter. These were the first annual designations made by the capacity procurement mechanism 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 3.4 shows the annual capacity procurement mechanism costs for 2018. The annual designation for the Moss Landing resource was made through the competitive solicitation process. 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 Encina units will be compensated at the soft offer

[74] Some resources had variability in their designated megawatts between their capacity procurement mechanism start and end dates. JAMES B. BLACK 2 was not available for two days between September 1 and September 30, while designated megawatts for PIT PH 6 UNIT 1 were reduced from 39 MW to 5.16 MW for two days between September 1 and September 30. These changes are represented in estimated costs in the table.

cap of $6.31/kW-month, as a result of bids generated by the ISO. At these prices and quantities the total estimated cost for this capacity procured is about $80 million for 2018.

Table 3.4 Annual capacity procurement mechanism costs

Resource	Designated MW	Price ($/kW-mon)	Estimated cost ($ million)	Local capacity area	Exceptional dispatch CPM trigger
MOSS LANDING POWER BLOCK 1	490	$6.19	$36.4	PG&E	Material sub-area deficiency
MOSS LANDING POWER BLOCK 1	20	$6.31	$1.5	PG&E	Material sub-area deficiency
ENCINA UNIT 4	272	$6.31	$20.6	SDG&E	Material sub-area deficiency
ENCINA UNIT 5	273	$6.31	$20.7	SDG&E	Material sub-area deficiency

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

3.4 Aliso Canyon gas-electric coordination

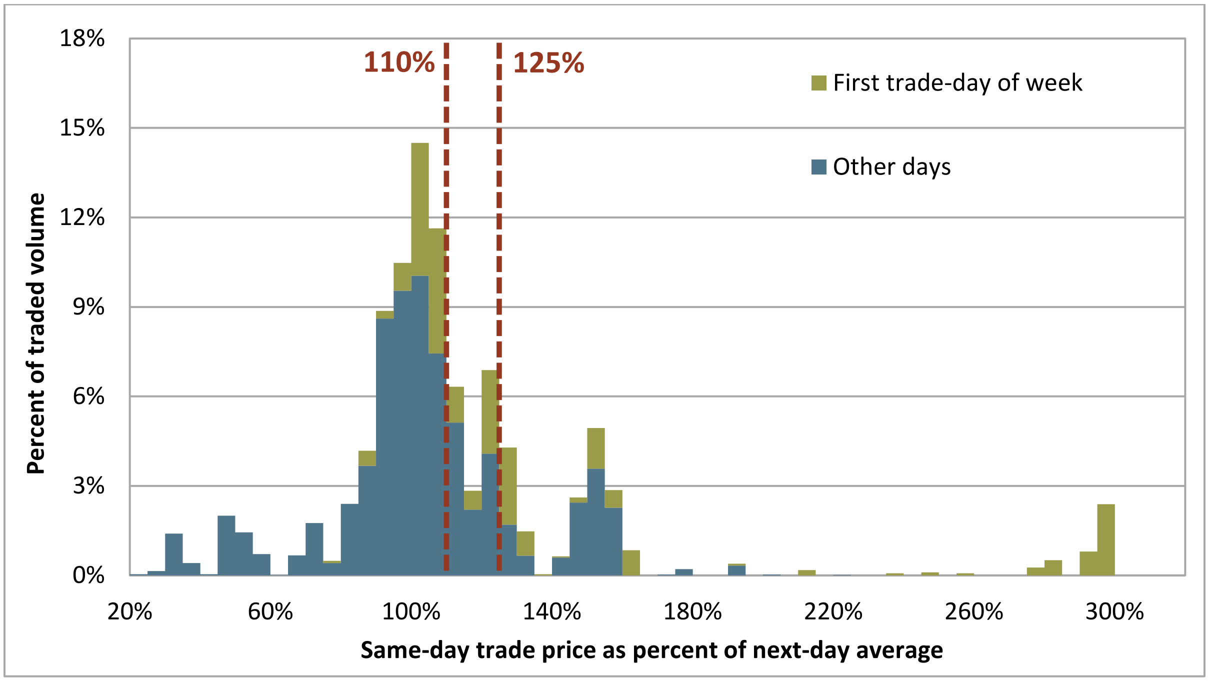
The ISO did not enforce gas burn constraints in either the day-ahead or real-time markets in the third quarter of 2018. Aliso gas price scalars were also not activated during the third quarter despite significant increases in same-day gas prices on some days in July and August 2018 at SoCal Citygate hub. Use of both nomograms and scalars in February of 2018 was associated with additional costs.[75]

Figure 3.7 shows Intercontinental Exchange (ICE) same-day natural gas trade prices for SoCal Citygate compared to the next-day average price from July through September 2018. About 16 percent of traded volume at SoCal Citygate exceeded the normal 10 percent adder and 23 percent of the traded volume exceeded the 25 percent adder. Figure 3.7 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.

Prices at SoCal Citygate were extremely volatile on some days in July and August of 2018. Main drivers include increased natural gas demand amid hot temperatures combined with supply constraints, 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. Refer to Section 1.2 for more detailed information on natural gas prices.

[75] 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 3.7 Same-day trade prices compared to next-day index (July – September)



DMM is not supportive of a further extension of the gas cost scalars beyond the December 2018 date that was approved by FERC in 2017. Instead, 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, rather than relying on much less effective and accurate tools such as the gas cost scalars. 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.[76,77]

Figure 3.8 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 third quarter of 2018, this figure shows that if the real-time gas prices were updated using an updated same-day price, then about 96 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. Only 0.5 percent of the same-day traded volume exceeded the 25 percent adder. Figure 3.8 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.

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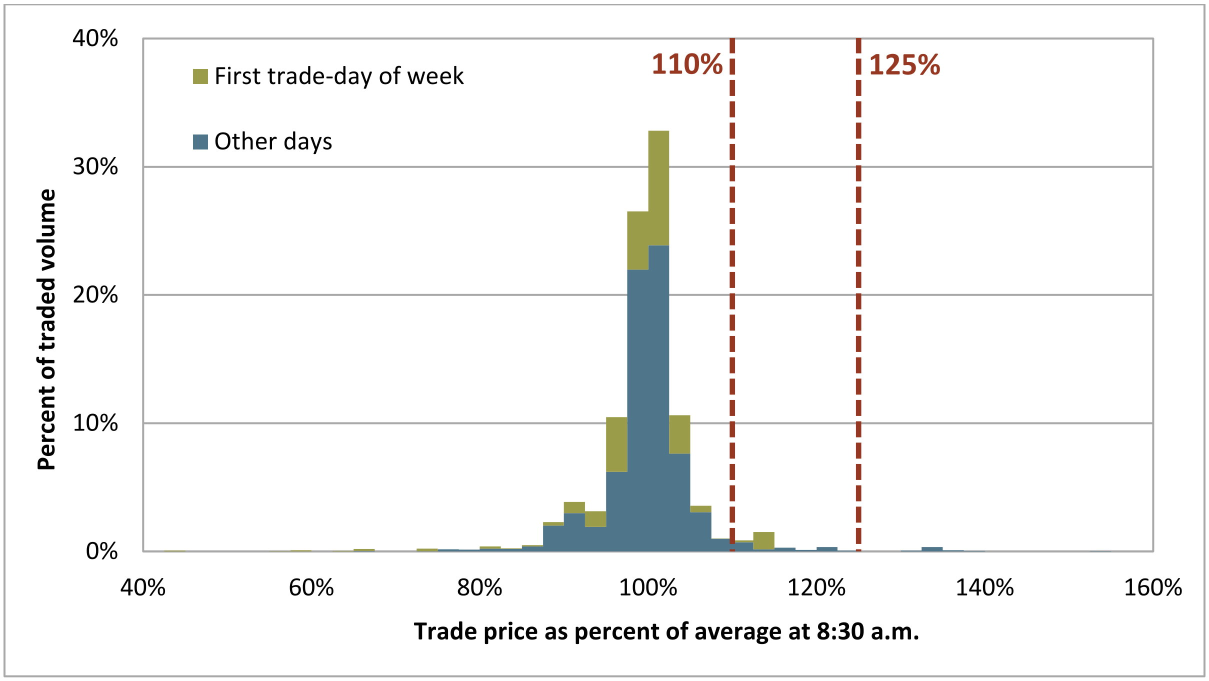
[76] *FERC filing - Comments on Aliso Canyon Gas-Electric Coordination Phase 4 (ER18-2520),* Department of Market Monitoring, October 19,2018: http://www.caiso.com/Documents/CommentsoftheDepartmentofMarketMonitoirng-Aliso4-Oct192018.pdf

[77] *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 3.8 Same-day prices as a percent of updated same-day averages (July – September)



Updated natural gas prices for the day-ahead market

The November 28, 2017, FERC 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 for one additional year, through November 30, 2018. With this modification, the ISO is basing the updated gas price on next-day trades from the morning of the day-ahead market run instead of indices from the prior day.[78]

Figure 3.9 and Figure 3.10 illustrate the benefit of using the updated natural gas price index in the third quarter of 2018. Figure 3.9 shows next-day trade prices reported on ICE for the SoCal Citygate during the third quarter, compared to the next-day price index previously used in the day-ahead market which was lagged by one trade day. As shown in Figure 3.9, about 12 percent of next-day trades were at a price in excess of the 10 percent adder normally included in default energy bids. About 21 percent of the next-day trades were in excess of the 25 percent headroom normally included in commitment cost bid caps.

Figure 3.10 shows the same data but compares the price of each next-day trade to a weighted average price of next-day trades reported on ICE before 8:30 am, just before the ISO runs the day-ahead market. This represents the updated method that the ISO is currently using. As shown in Figure 3.10, about 3 percent of the traded volume exceeded the 10 percent adder included in default energy bids. About 0.4 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.

78 This market modification uses weighted average price of next-day trades at SoCalGas 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.

Figure 3.9 Next-day trade prices compared to next-day index from prior day (July – September)

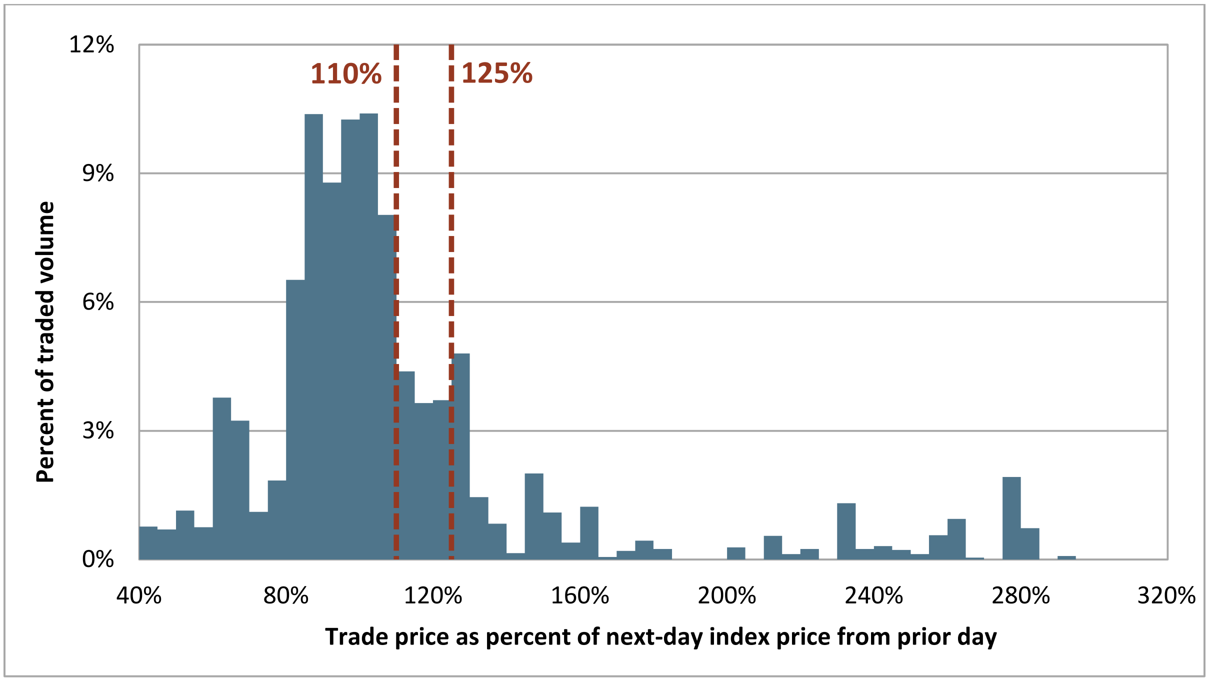


Figure 3.10 Next-day trade prices compared to updated next-day average price (July – September)