

2017

ANNUAL REPORT ON MARKET ISSUES & PERFORMANCE



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Executive summary

This report presents the annual report on market issues and performance by the Department of Market Monitoring (DMM). The report finds that the ISO and energy imbalance markets continued to perform efficiently and competitively overall in 2017. Other key highlights include the following:

- Total wholesale electric costs increased by about 25 percent, driven primarily by a 27 percent increase in natural gas prices in 2017. After adjusting for higher natural gas costs and changes in greenhouse gas prices, wholesale electric costs increased by about 4 percent from 2016. Overall wholesale prices have remained stable since 2013.
- Average hourly prices in both the day-ahead and real-time markets now mirror the net load pattern throughout the year – with the highest prices during the morning and evening ramping hours and some of the lowest prices during midday hours when solar output is highest.
- For the first time, negative system marginal prices were relatively frequent in the day-ahead market. Prices fell below zero in over 110 hours in 2017, all during midday hours in the first two quarters with high levels of solar generation and high hydro conditions. In comparison, day-ahead system marginal energy prices were negative during only three hours during all of 2016.
- Day-ahead prices reached historic highs during some hours. On September 1, day-ahead market prices reached over \$770/MWh and were greater than \$200/MWh during a four-hour period. These high day-ahead prices reflect a tightening of supply conditions during peak ramping hours that DMM expects will continue in 2018 and the coming years.
- Prices in the 5-minute market were lower than prices in both the 15-minute and day-ahead markets, on average in each quarter of the year. This persistent pattern appears to be driven in part by systematic differences between load adjustment made by ISO grid operators in the 5-minute market compared to higher adjustments made in the 15-minute market and hour-ahead scheduling process.
- Expansion of the energy imbalance market (EIM) helped improve the overall structure and performance of the real-time market in the ISO and other participating balancing areas. Portland General Electric became a participant in the energy imbalance market on October 1, 2017. This added transfer capability to the ISO from the Northwest region (that also includes PacifiCorp West and Puget Sound Energy).
- Payouts to holders of auctioned congestion revenue rights (CRRs) exceeded the auction revenues by over \$100 million in 2017 and by about \$42 million in the first quarter of 2018. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge (TAC). These losses now total over \$750 million since the start of the ISO's CRR auction in 2009. Most of these losses stem from congestion revenue rights bought in the auction by purely financial entities, rather than generators that may be purchasing these as hedges.
- DMM seeks to assess the competitiveness of the ISO energy markets by comparing actual market prices to competitive benchmark prices estimated to result under highly competitive conditions. DMM could not perform this analysis for 2017 due to problems with the automated data inputs needed for the day-ahead market software provided by the ISO for this analysis.

- Based on other analyses, DMM concludes that overall wholesale prices in 2017 reflect the efficient and competitive conditions that exist during most hours of the year. However, DMM notes that the tightening of supply and demand conditions observed in 2017 has created the increased potential for uncompetitive market outcomes in 2018 and beyond.

Several other factors contributed to increased wholesale energy costs in 2017:

- Ancillary service costs increased to \$172 million, up from \$119 million in 2016 and \$62 million in 2015. The increase in operating reserve costs was primarily driven by tight supply conditions and higher operating reserve requirements during the summer.
- Bid cost recovery payments increased to the highest value since 2011, totaling \$108 million, or about 1 percent of total energy costs, during 2017. Total bid cost recovery payments during 2016 were about \$76 million, and had been decreasing since 2013. Most of the increase in bid cost recovery payments was driven by an increase of \$29 million in real-time costs. DMM estimates that over \$5.5 million in real-time costs was due to higher start-up and minimum load bid caps implemented due to concern about Aliso Canyon gas issues.
- Exceptional dispatches are *out-of-market* unit commitments and energy dispatches issued by ISO grid operators to meet constraints not incorporated in the market software. Total energy resulting from all types of exceptional dispatch more than doubled between 2017 and 2016, but continued to account for a relatively low portion of total system load (0.5%). Total above-market costs due to exceptional dispatch increased 92 percent to \$20.6 million in 2017 from \$10.7 million in 2016.
- Congestion on transmission constraints within the ISO system was relatively frequent in the third and fourth quarters, primarily impacting San Diego Gas and Electric load area prices in both day-ahead and 15-minute markets. Average annual day-ahead prices in this area increased above the system average by about \$0.90/MWh (2.5 percent) and real-time congestion increased prices by about \$1.50/MWh (4 percent).

This report also highlights key aspects of market performance and issues relating to longer-term resource investment, planning and market design.

- About 3,000 MW of summer peak gas-fired capacity retired in 2017, which is the largest number of generation retirements in one year in the ISO system's history. An additional 600 MW of gas generation has submitted an intent to retire in 2018.
- About 770 MW of summer peak generating capacity was added in 2017. All of this capacity was renewable, primarily new solar generation.
- Solar energy is expected to continue to increase at a high rate during the next few years as a result of projects under construction to meet California's renewable portfolio standards. This continues to increase the need for flexible and fast ramping capacity that can be dispatched by the ISO to integrate increased amounts of variable energy efficiently and reliably.

Total wholesale market costs

The total estimated wholesale cost of serving load in 2017 was about \$9.3 billion or about \$42/MWh. This represents an increase of about 25 percent from wholesale costs of about \$34/MWh in 2016. The increase in electricity prices was driven mainly by an increase in spot market natural gas prices of about 27 percent.¹ After normalizing for natural gas prices and greenhouse gas compliance costs, DMM estimates that total wholesale energy costs increased by about 4 percent.²

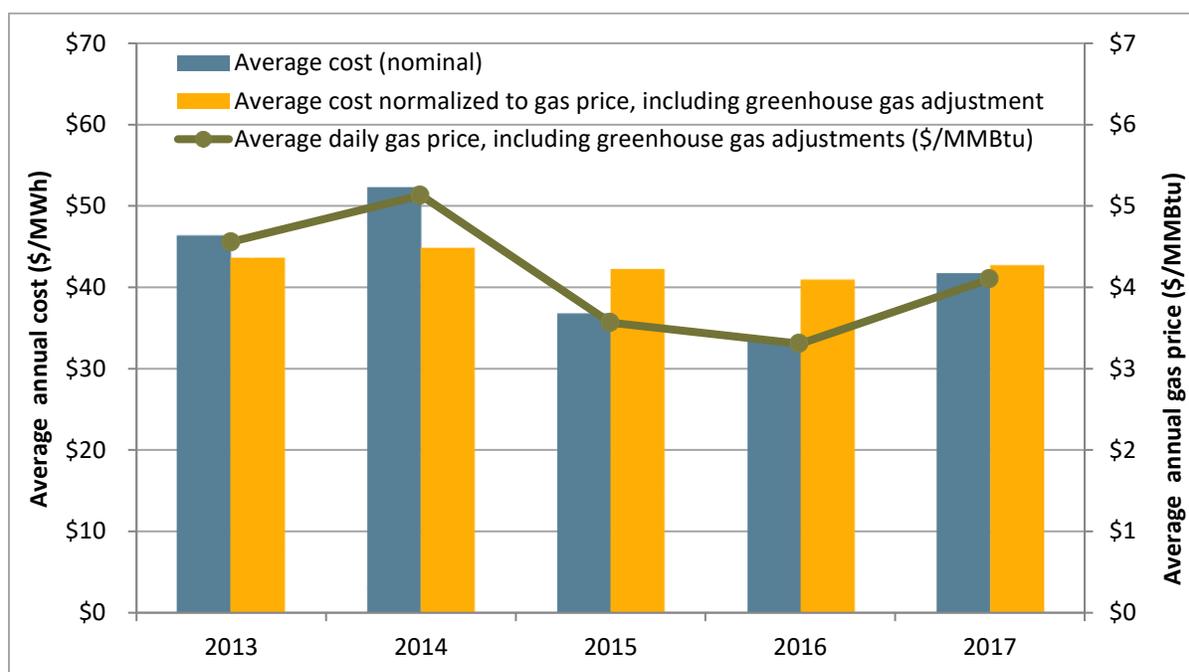
A variety of factors contributed to the increase in total wholesale costs. As highlighted elsewhere in this report, conditions that contributed to higher prices include the following:

- Increased prices for natural gas, especially in Southern California;
- High temperatures and associated loads during the summer;
- Reduced supply offered into the day-ahead market;
- Increased ancillary service requirements; and
- Increased congestion during some intervals.

Figure E.1 shows total estimated wholesale costs per megawatt-hour of system load from 2013 to 2017. Wholesale costs are provided in nominal terms (blue bar), and after being normalized for changes in natural gas prices and greenhouse gas compliance costs (gold bar). The greenhouse gas compliance cost is added to natural gas prices to account for the estimated cost of compliance with California's greenhouse gas cap-and-trade program. The green line represents the annual average daily natural gas price including greenhouse gas compliance and is included to illustrate the correlation between natural gas prices and the total wholesale cost estimate.

¹ For the wholesale energy cost calculation, an average of annual gas prices was used from the SoCal Citygate and PG&E Citygate hubs.

² Greenhouse gas compliance costs are calculated by multiplying a load-weighted annual average greenhouse gas allowance price by an emission factor that is a measure of the greenhouse gas content of natural gas. Derivation of the emission factor used here, 0.531148, is discussed in further detail in Section 1.2.4. Gas prices are normalized to 2010 prices.

Figure E.1 Total annual wholesale costs per MWh of load (2013-2017)

Market competitiveness

The day-ahead energy market – which accounts for most of the total wholesale market – remained structurally competitive on a system-wide level during most but not all hours in 2017. During 36 hours (0.4 percent), there was a single pivotal supplier without whom there would have been insufficient supply to meet demand. During 128 hours (1.6 percent), the two largest suppliers were jointly pivotal. During 336 hours (3.8 percent), the three largest suppliers were jointly pivotal.

DMM seeks to assess the competitiveness of the ISO energy markets each year by comparing actual market prices to competitive benchmark prices we estimate would result under highly competitive conditions. DMM estimates competitive baseline prices by re-simulating the market using a version of the ISO day-ahead market software with bids reflecting the estimated marginal cost of gas-fired units, no convergence bids, and actual load.³ DMM could not perform this analysis for 2017 due to problems with the automated inputs for the competitive scenario needed to run this software. DMM continues to work with the ISO and its software vendor to address these issues.

Based on other analyses of market structure, behavior, and performance, DMM concludes that overall wholesale prices in 2017 reflect the efficient and competitive conditions that exist during most hours of the year. However, DMM notes that the tightening of supply and demand conditions observed in 2017 has created the increased potential for uncompetitive market outcomes in 2018 and beyond.

³ The competitive baseline is a scenario where bids for gas-fired generation are set to default energy bids (DEBs), convergence bids are removed and system demand is set to actual system load. This methodology assumes perfect load forecast, physical generation only, and competitive bidding of price-setting resources. The analysis is performed using DMM's version of the ISO's actual market software.

Energy market prices

Day-ahead and real-time market prices increased in 2017. This was attributed primarily to an increase in natural gas prices and tight system conditions, especially in the third and fourth quarters of the year. Figure E.2 and Figure E.3 highlight the following:

- Average energy market prices were relatively high during the second half of 2017, primarily because of high demand and increased gas prices.
- Prices in the 5-minute market were lower than prices in both the 15-minute and day-ahead markets on average in each quarter of the year.
- Average hourly prices move in tandem with the average net load. Average hourly prices in the 15-minute market were lower than the day-ahead prices for all hours except the peak net load hours when 15-minute prices exceeded day-ahead. Average 5-minute market prices were lower than day-ahead and 15-minute prices in all hours except the afternoon net load ramping hours.
- Hourly prices in the day-ahead and real-time markets followed the shape of the net load curve, which subtracts wind and solar from load.

Figure E.2 Comparison of quarterly prices – system energy (all hours)

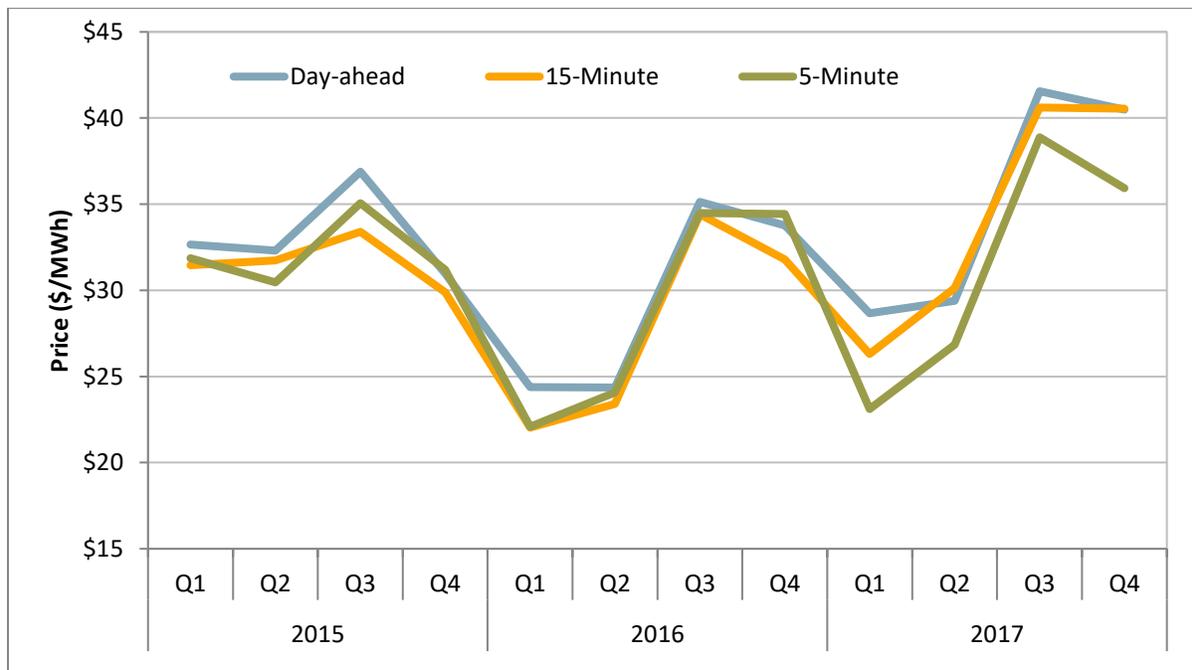
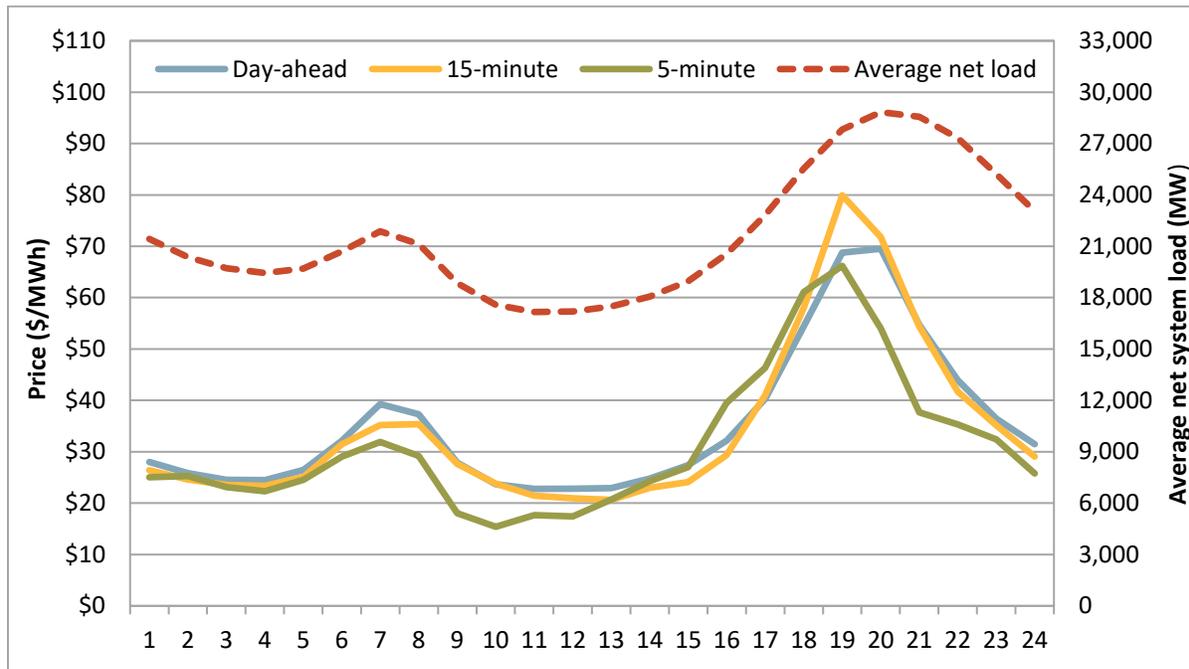


Figure E.3 Hourly system energy prices (2017)

Local market power mitigation

The ISO day-ahead and real-time markets incorporate a transmission competitiveness evaluation and mitigation mechanism to address local market power. This local market power mitigation procedure requires that each constraint be designated as either *competitive* or *non-competitive* prior to the actual market run. This is determined through a test, known as *dynamic path assessment*, which determines the competitiveness of transmission constraints based on actual system and market conditions for each interval. Generation bids are subject to mitigation if mitigation procedures indicate generators can effectively relieve congestion on constraints that are structurally uncompetitive.

For these provisions to be effective, it is important that constraints designated as competitive are in fact competitive under actual market conditions. This dynamic path assessment approach uses actual market conditions and produces a more accurate and less conservative assessment of transmission competitiveness than previous methods.

Most resources subject to mitigation submitted competitive offer prices, so few bids were lowered as a result of the mitigation process. The number of units in the day-ahead market that had bids changed by mitigation remained very low at an average of about 1.4 units per hour in 2017, the same rate observed in 2016. The estimated impact of bid mitigation on the amount of additional energy clearing in the day-ahead market from units with mitigated bids was about 7 MW per hour in 2017 compared to about 4 MW per hour in 2016. Most of the mitigated bids occurred during the evening ramp and peak load hours.

The frequency of bid mitigation in the real-time market was similar to 2016, with an average of 1 unit with bids mitigated per hour in the fifteen-minute market. The estimated impact of bid mitigation on the amount of additional real-time energy dispatched as a result of bid mitigation increased slightly to

about 6 MW per hour in 2017 from about 5 MW per hour in 2016. Units with bids changed by 5-minute market mitigation in 2017 averaged about 3 units. As a result of this mitigation, an average of 2 units were dispatched at higher output in the 5-minute market.

The ISO has determined that a software error resolved in July caused pre-mitigation day-ahead prices to be low on some days. The software error resulted in an erroneous increase in supply available in the market power mitigation run, causing prices in that run to be lower than they would have been had all awarded schedules been feasible.⁴ The ISO has published an initial estimate of the market impact of this error, \$19 million.⁵

Ancillary services

Ancillary service costs increased to \$172 million, up from \$119 million in 2016 and \$62 million in 2015. The increase in operating reserve costs was primarily driven by tight supply conditions and higher operating reserve requirements during the summer.

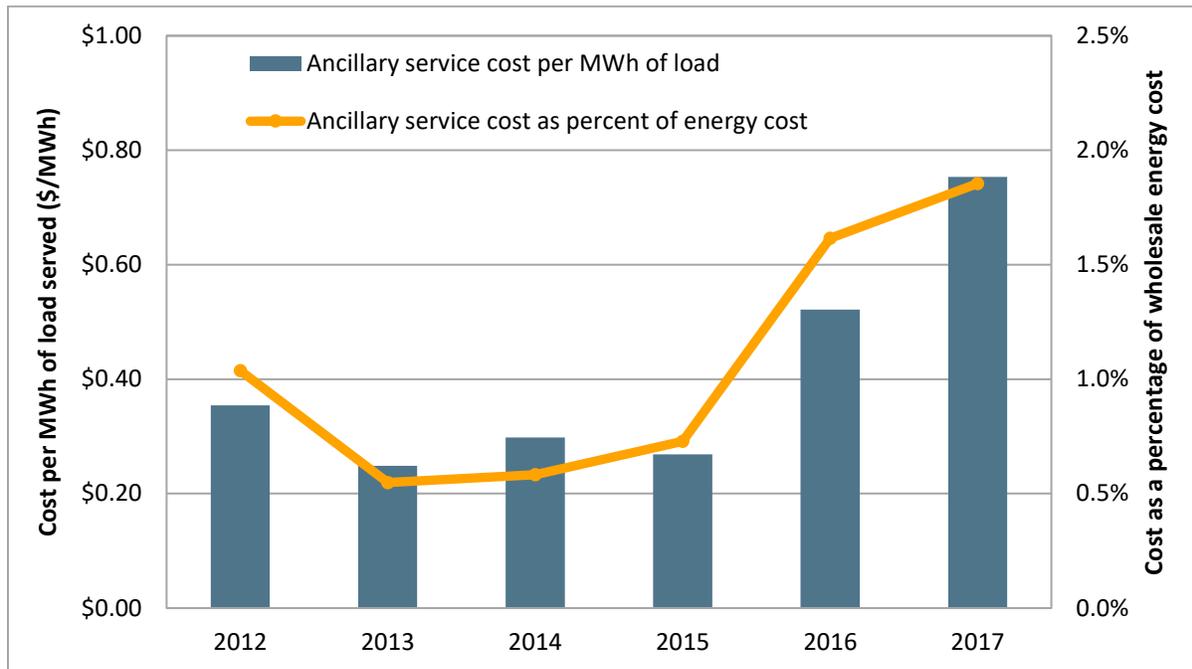
On June 14, the ISO began increasing operating reserve requirements during midday hours to account for solar generation in the system by using an existing functionality within the software that allows operators to increase the requirement by a specified percent of the load forecast. Starting on September 19, the upward adjustments were removed.

Average day-ahead requirements for regulation up and down decreased by about 22 percent and 14 percent from 2016, respectively. This is primarily the result of manually increased regulation requirements during the spring months of 2016 before implementation of a new regulation requirement methodology in October 2016. This new methodology was in place for all of 2017.

As shown in Figure E.4, ancillary service costs increased to \$0.75/MWh of load served in 2017 from \$0.52/MWh in 2016 and \$0.27/MWh in 2015. Ancillary service costs as a percent of total wholesale energy costs also increased from 1.6 percent in 2016 to 1.85 percent in 2017. This increase was directly related to increased requirements as well as to the increasing opportunity cost of meeting those requirements.

⁴ The error allowed resources to receive combined ancillary service and energy schedules in excess of derated capacity in the pre-mitigation run. This error was in place from August 17, 2016 through July 21, 2017.

⁵ The ISO's analysis estimates the increase in congestion rents but does not appear to take changes in the system energy cost into consideration. Market performance and planning forum presentation, June 11, 2018.
http://www.caiso.com/Documents/AgendaPresentation-MarketPerformancePlanningForum-Jun11_2018.pdf, pp. 14-19.

Figure E.4 Ancillary service cost as a percentage of wholesale energy cost

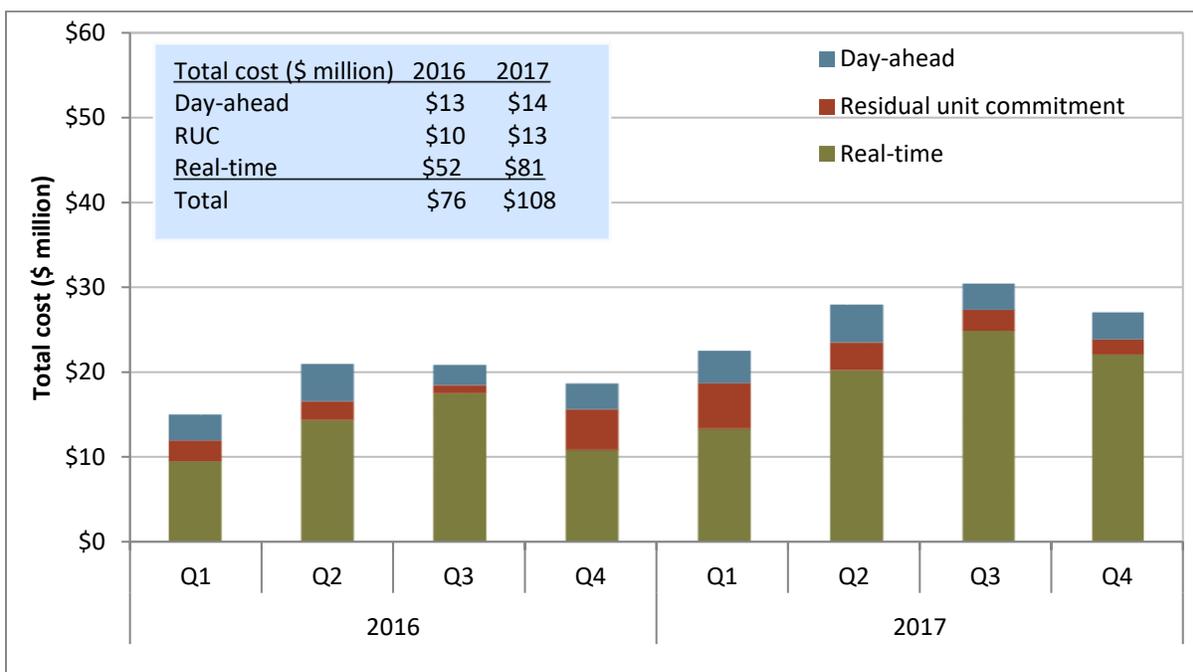
Bid cost recovery payments

Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch.

Figure E.5 provides a summary of total estimated bid cost recovery payments in 2017. Bid cost recovery payments rose to \$108 million in 2017 from \$76 million in 2016, increasing to about 1 percent of total energy costs in 2017. The 42 percent increase in bid cost recovery payment was driven in large part by the 27 percent increase in natural gas prices. Real-time bid cost recovery payments were \$81 million in 2017, a significant increase from about \$52 million in 2016.

DMM estimates that over \$5.5 million in real-time costs is due to higher startup and minimum load bid caps provided under special measures adopted due to Aliso Canyon gas storage issues. About \$7 million was awarded to a single resource which had a single daily start limitation. Bid cost recovery payments are made when the resource buys back its day-ahead schedule at high real-time prices due to the limitation preventing the unit from starting more than once per day. An additional \$5 million increase in real-time bid cost recovery payments was due to the expansion of the energy imbalance market with the addition of Arizona Public Service and Puget Sound Energy in October 2016 and Portland General Electric in October 2017.

Figure E.5 Bid cost recovery payments



Exceptional dispatches

Exceptional dispatches are instructions issued by grid operators when the automated market optimization is not able to address particular reliability requirements or constraints. These dispatches are sometimes referred to as *manual* or *out-of-market* dispatches. Over the past several years, the ISO has made an effort to reduce exceptional dispatches by refining operational procedures and incorporating additional constraints into the market model that reflect reliability requirements.

Total energy from all exceptional dispatches increased in 2017, growing to 0.5 percent of system load in 2017 from 0.3 percent in 2016.⁶ The following is shown in Figure E.6:

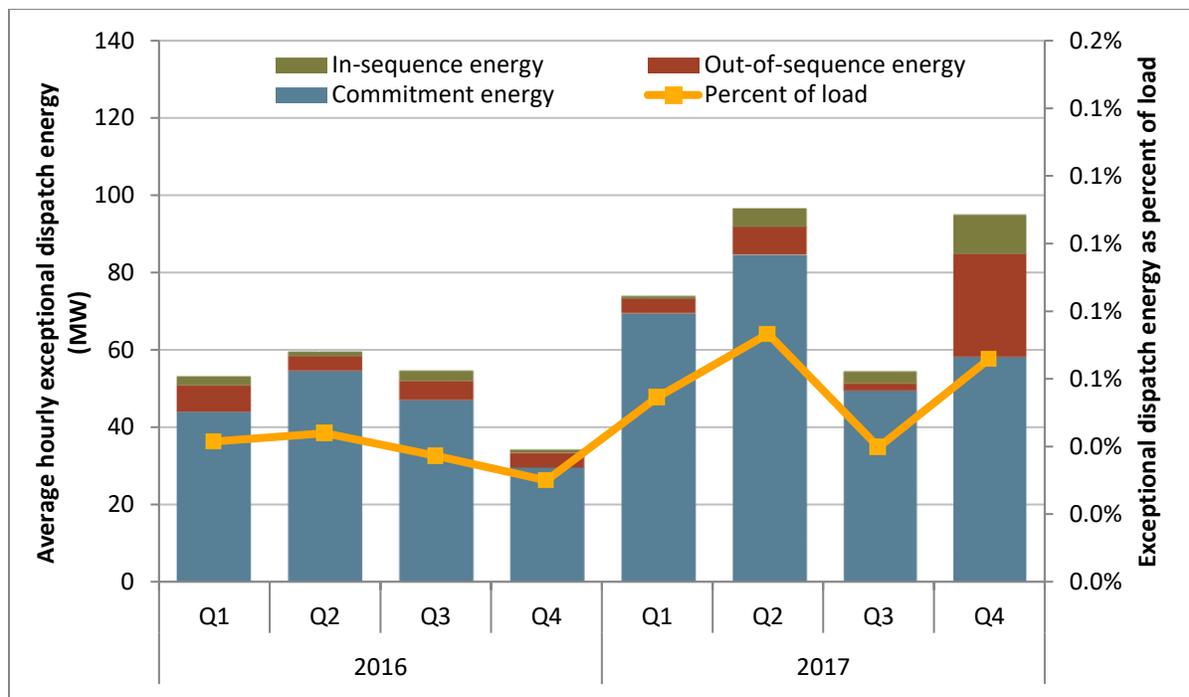
- Overall, above-market costs due to exceptional dispatch increased 92 percent to \$20.6 million in 2017 from \$10.7 million in 2016.
- Energy from exceptional dispatch continued to account for a relatively low portion of total system loads. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 0.5 percent of system loads in 2017, compared to 0.3 percent in 2016.⁶

⁶ DMM reported this number as 0.2 percent of load for 2016 in the 2016 annual report. The change is due to a change in the reference data source.

- Total energy resulting from all types of exceptional dispatch increased by approximately 58 percent in 2017 from 2016, as shown in Figure E.6.⁷ The percentage of total exceptional dispatch energy from minimum load energy accounted for about 82 percent of all exceptional dispatch energy in 2017. About 12 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 6 percent was from in-sequence energy.

Commitment costs for exceptional dispatch paid through bid cost recovery increased from \$10.1 million to \$16.6 million, while out-of-sequence energy costs increased from \$633,000 to \$4.0 million.⁸

Figure E.6 Average hourly energy from exceptional dispatches



Manual out-of-market dispatches on the interties increased significantly in 2017. Procurement of imports out-of-market at prices higher than the 15-minute price paid for other imports can encourage economic and physical withholding of available imports. DMM recommends that the ISO closely track and monitor trends in out-of-market dispatches and seek to limit the use of such out-of-market dispatches. DMM is also recommending that the ISO improve its logging of manual dispatches to ensure proper settlement and allow tracking and monitoring.

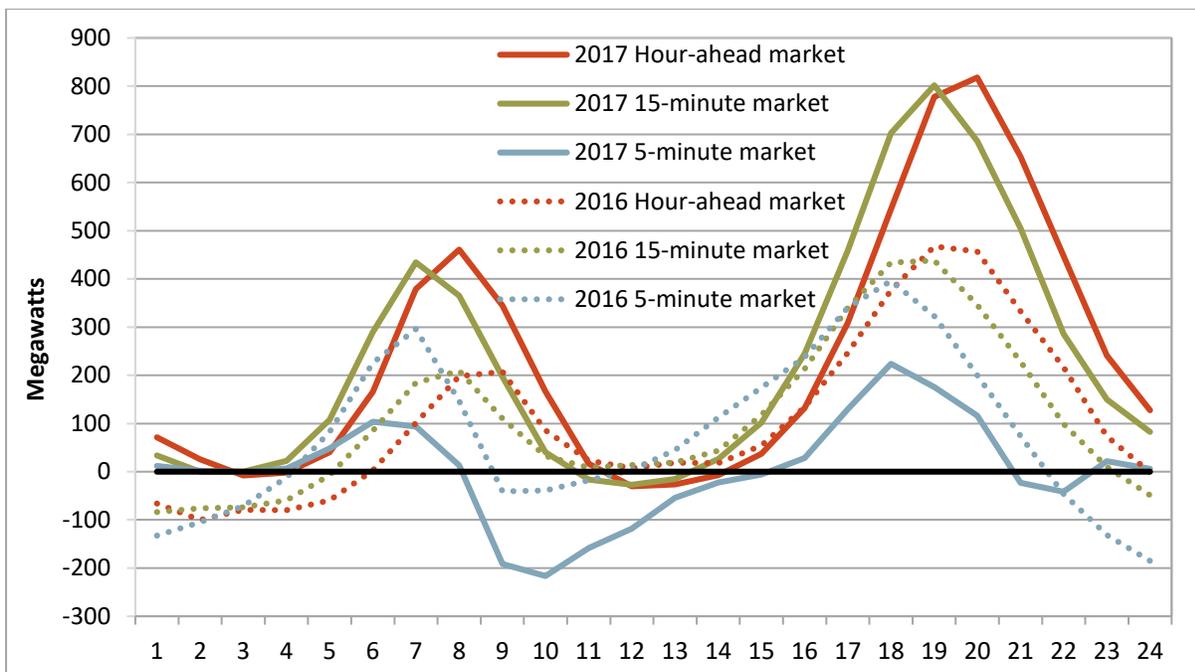
⁷ All exceptional dispatch data are estimates derived from Market Quality System (MQS) data, market prices, dispatch data, bid submissions, and default energy bid data. DMM’s methodology for calculating exceptional dispatch energy and costs has been revised and refined since previous reports. Exceptional dispatch data reflected in this report may differ from previous annual and quarterly reports as a result of these enhancements.

⁸ The out-of-sequence costs are estimated by multiplying the out-of-sequence energy by the bid price (or the default energy bid if the exceptional dispatch was mitigated or the resource had not submitted a bid) minus the locational price for each relevant bid segment. Commitment costs are estimated from the real-time bid cost recovery associated with exceptional dispatch unit commitments.

Load Forecast Adjustments

Load forecast adjustment in the ISO’s hour-ahead and 15-minute markets increased dramatically in 2017. The 5-minute market load forecast adjustment decreased, relative to the same time periods in 2016. Real-time incremental dispatch of imports into the ISO appears consistent with both pricing and load adjustments, with most incremental commitment of imports occurring in the hour-ahead market. Energy imbalance market areas also utilize load forecast adjustments.

Figure E.7 Average hourly load adjustment (2017 - 2016)



Flexible Ramping Product

Flexible ramping product procurement and prices are determined through demand curves, expected to be calculated from historical net load forecast errors, or the *uncertainty* surrounding ramping needs. In February 2018, DMM identified specific errors in how the flexible ramping product was implemented related to the calculation of uncertainty. Overall, these errors had a significant impact on flexible ramping procurement, prices, and payments, though the direction and magnitude of the impact depends on the hour. In particular, this has resulted in under-procurement of upward flexible ramping capacity during key net load ramping intervals.

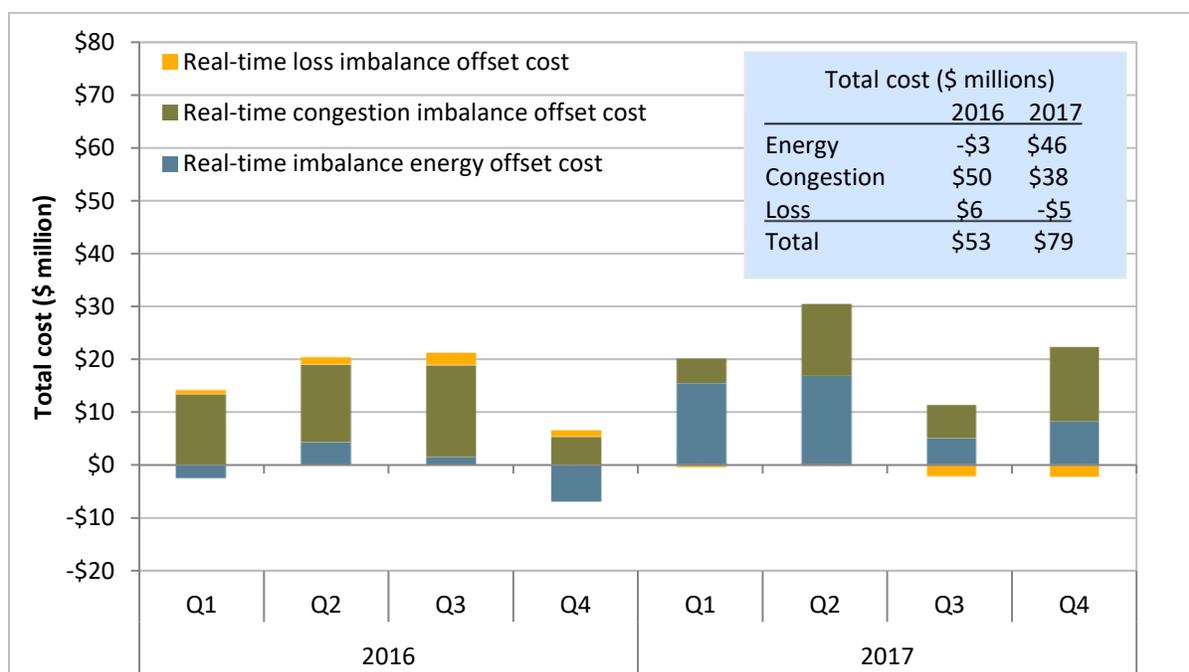
Real-time imbalance offset costs

The real-time imbalance offset charge is the difference between the total money paid by the ISO and the total money collected by the ISO for energy settled at real-time prices. The charge is allocated as an uplift to load-serving entities and exporters based on measured system demand.

The real-time imbalance offset charge consists of three components. Any revenue imbalance from the energy component of real-time energy settlement prices is collected through the *real-time imbalance energy offset charge*. Any revenue imbalance from the congestion component of real-time energy settlement prices is recovered through the *real-time congestion imbalance offset charge*. Since October 2014, any revenue imbalance from the loss component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge*.

Total real-time imbalance offset costs increased by about 50 percent in 2017 to \$79 million. Much of this increase is attributable to a \$49 million increase in real-time imbalance energy offset costs. As shown in Figure E.8, congestion imbalance offset costs and real time loss imbalance costs both fell in 2017.

Figure E.8 Real-time imbalance offset costs



Congestion

Key congestion trends during the year include the following:

- Congestion on transmission constraints within the ISO system was relatively low in the first and second quarters and increased in the third and fourth quarters, but had little impact on average overall prices across the system.

- Prices in the San Diego Gas and Electric area were the most impacted by internal congestion. Average day-ahead prices in this area increased above the system average by about \$0.90/MWh (2.5 percent) and real-time congestion increased prices by about \$1.50/MWh (4 percent).
- Congestion increased average day-ahead and real-time prices in the Southern California Edison area above the system average by about \$0.40/MWh (1.2 percent) and \$1.10/MWh (3 percent), respectively.
- Pacific Gas and Electric area prices were the least impacted by congestion in 2017. Congestion decreased day-ahead prices below the system average by about \$0.60/MWh (2 percent) and increased 15-minute real-time price by \$0.30/MWh (0.8 percent).
- Although the frequency of congestion on interties decreased slightly in the day-ahead market, the impact of congestion was higher in 2017 than in 2016 on most major interties connecting the ISO with other balancing authority areas, particularly for interties connecting the ISO to the Pacific Northwest.

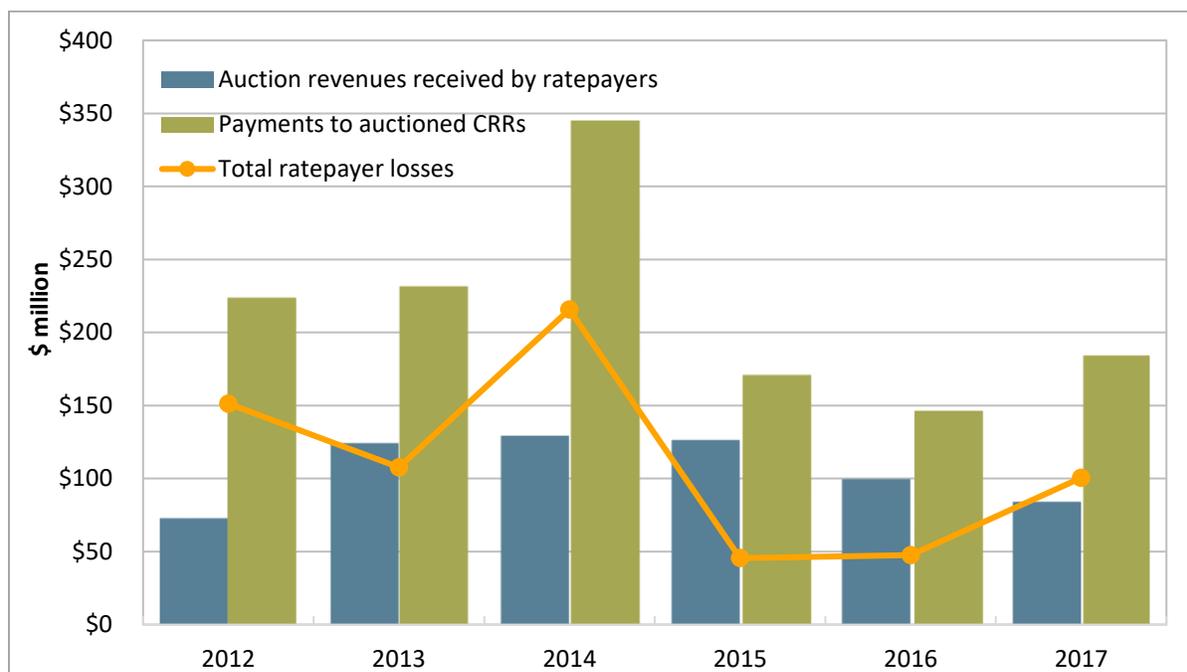
Congestion revenue rights

This report includes an analysis of the performance of the congestion revenue rights auction from the perspective of the ratepayers of load-serving entities. Key findings from this analysis include the following:

- As shown in Figure E.9, congestion revenue rights not allocated to load-serving entities that are sold in the auction consistently generate significantly less revenue than is paid to the entities purchasing these rights in the auction.
- From 2009 through 2017, ratepayers received about 50 percent of the value of their congestion revenue rights that the ISO auctioned. This represents a shortfall of about \$101 million in 2017 and more than a \$750 million shortfall since 2009.
- Entities purchasing congestion revenue rights are primarily financial entities that do not purchase these rights as a hedge for any physical load or generation.

In 2017, DMM completed a whitepaper providing a review and critique of the general congestion revenue rights auction design.⁹ DMM continues to recommend that the ISO continue the process of allocating congestion revenue rights to load-serving entities who pay for the transmission system through the transmission access charge (TAC), but that the ISO stop auctioning off additional congestion revenue rights that are backed financially by transmission ratepayers through the congestion revenue balancing account. DMM also continues to recommend that the ISO move swiftly to replace the current congestion revenue rights auction with a voluntary market for financial contracts based on bids from willing buyers and sellers.

⁹ *Problems in the Performance and Design of the Congestion Revenue Rights Auction*, Department of Market Monitoring, November 27, 2017. http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

Figure E.9 Ratepayer auction revenues compared with congestion payments for auctioned CRRs

Resource adequacy

California's wholesale market relies heavily on a long-term procurement planning process and resource adequacy program adopted by the California Public Utilities Commission (CPUC) to provide sufficient capacity to ensure reliability. The resource adequacy program includes ISO tariff requirements that work in conjunction with regulatory requirements and processes adopted by the CPUC and other local regulatory authorities. Analysis in this report shows that:

- During peak load hours of the year, system resource adequacy requirements fell short of both forecast and peak load. Resource adequacy procurement in September was just below 47,000 MW. On September 1 just over 43,000 MW (96 percent) of procured resource adequacy was available in the day-ahead market during the peak load hour, when load exceeded 50,000 MW. On September 2, about 42,000 MW (92 percent) was available when system load exceeded 47,000 MW. Resource adequacy requirements also fell short of day-ahead load forecasts on June 19, 20, 21, and 22.
- On average, during the 210 hours with the highest loads in 2017, about 96 percent of system resource adequacy capacity procured was available to the day-ahead energy market, about equal to availability in 2016.
- The total amount of local resource adequacy capacity available to bid into the day-ahead and real-time markets exceeded the total local capacity requirement; some individual areas did not meet the requirement, relying on resources from within the greater transmission access charge area.

This year was the third year that new flexible resource adequacy requirements and procurement were in place. These requirements are set based on projections of the maximum three-hour net load ramp during each month. Analysis of these new requirements in this report highlight the following:

- Flexible resource adequacy requirements fell short of the maximum three-hour net load ramp in three months in 2017. Due to varying must-offer hours for different flexible capacity the *effective* resource adequacy requirement fell short of the actual net load ramp in six months, from May to October.
- Despite requirements, load-serving entities collectively procured more flexible capacity than required. This procurement exceeded the actual maximum three-hour net load ramp in all months except June, September, and October. Procurement consisted mostly of gas-fired generation that qualified as Category 1 (base flexibility) capacity.

In 2017, two forms of backstop capacity procurement were utilized:

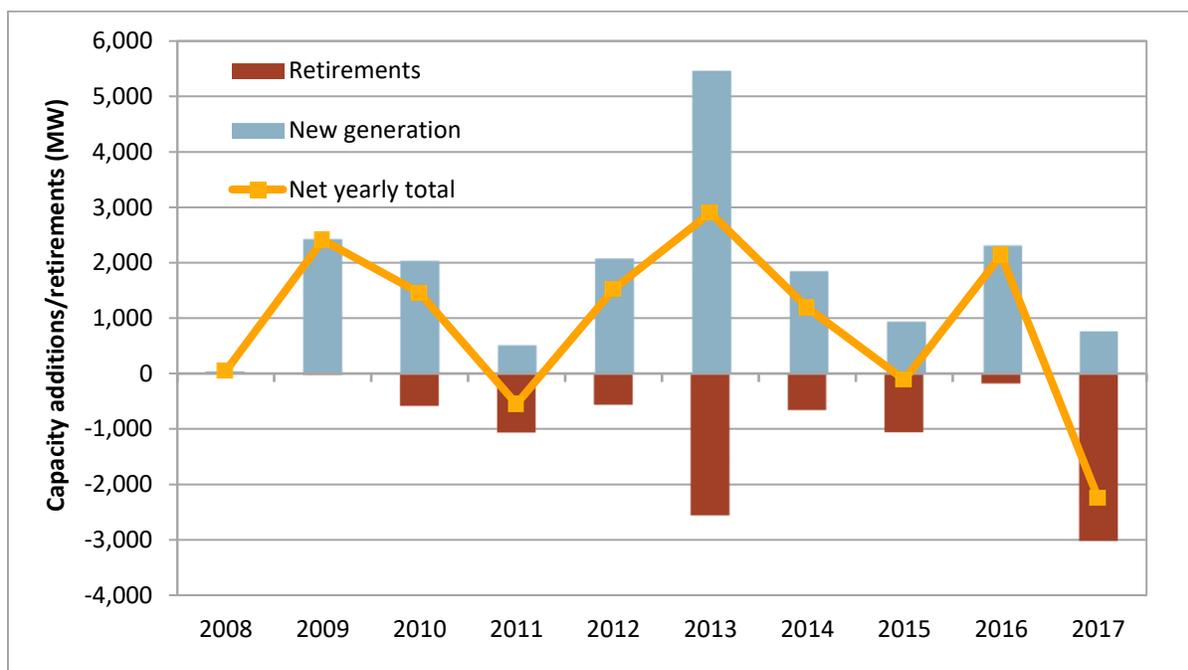
- The capacity procurement mechanism, implemented in November of 2016, was used throughout the year to dispatch non-resource adequacy capacity in the event of higher temperatures and wildfires. The total estimated cost of the designations settled during the year was about \$7 million, compared to \$4.3 million in 2016.
- During 2017, capacity designated as being subject to reliability must-run contracts beginning in 2018 increased sharply. Three newer more efficient gas units representing almost 700 MW were designated by the ISO for reliability must-run service beginning in 2018.

The designation of a significant amount of newer and more efficient units as reliability must-run units highlighted gaps in the state's resource adequacy process, as well as problems with the ISO's two backstop procurement mechanisms: the capacity procurement mechanism and reliability must-run contracts. The CPUC and the ISO continue to work and refine and enhance the resource adequacy framework. Currently, the CPUC and ISO are developing protocols for determining requirements for flexible capacity, counting flexible resource adequacy showings, expanding replacement and substitution provisions, and resolving any shortfalls through backstop procurement.

Generation addition and retirement

California currently relies on long-term procurement planning and resource adequacy requirements placed on load-serving entities by the CPUC to ensure that sufficient capacity is available to meet system and local reliability requirements. Trends in the amount of generation capacity being added and retired each year provide an indication of the effectiveness of the California market and regulatory structure in incenting new generation investment.

Figure E.10 summarizes the annual trends in summer capacity additions and retirements from 2008 - 2017. About 3,000 MW of summer peak gas-fired capacity retired in 2017, which is the largest number of generation retirements in one year in the ISO's history. An additional 600 MW of generation has submitted an intent to retire in 2018. About 770 MW of summer peak generating capacity was added in 2017. All of this capacity was renewable, primarily new solar generation.

Figure E.10 Generation additions and retirements (2008-2017)

The ISO anticipates a continued increase in new nameplate renewable generation in the coming years to meet the state's goal to have 33 percent renewable generation by 2020 and 50 percent by 2030. Going forward, significant reductions in total gas-fired capacity may continue beyond 2017 because of the state's restrictions on once-through cooling technology as well as other retirement risks. The ISO has highlighted the need to maintain adequate flexibility from both conventional and renewable generation resources to maintain reliability as more renewable resources come on-line.

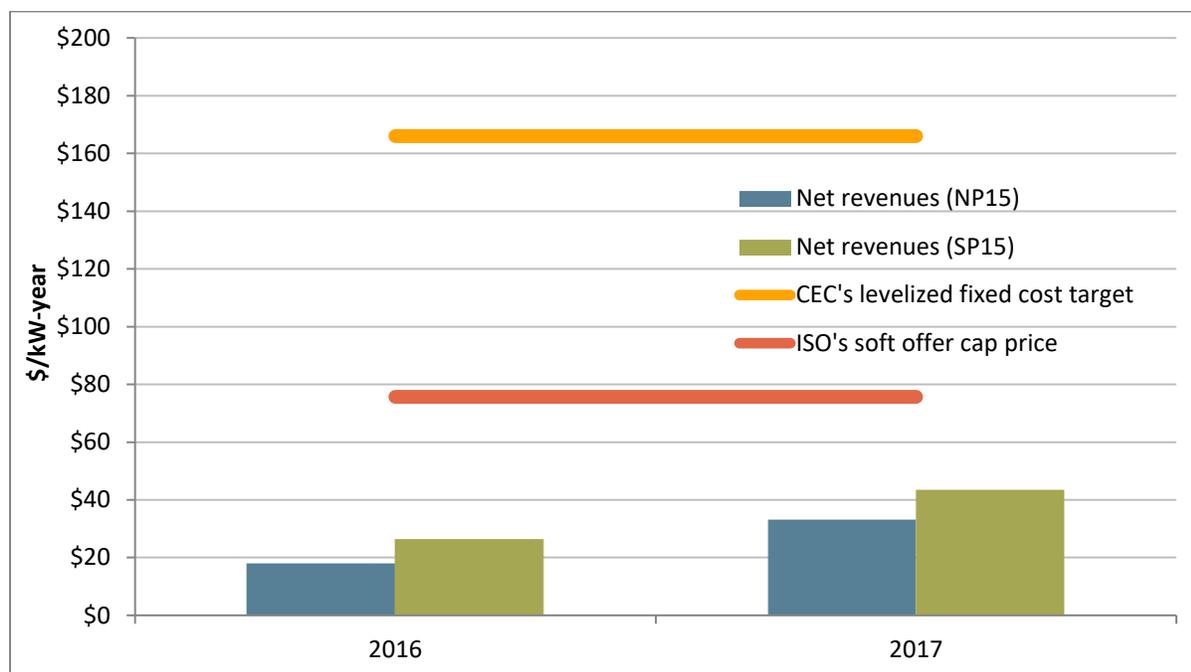
Under the ISO market design, fixed costs for existing and new units critical for meeting reliability needs can be recovered through a combination of long-term bilateral contracts and spot market revenues. Each year DMM analyzes the extent to which revenues from the spot markets would contribute to the annualized fixed cost of typical new gas-fired generating resources. This market metric is tracked by all ISOs and the Federal Energy Regulatory Commission.

DMM revised its approach to estimating net revenues for new gas-fired generating resources in 2016. Results of this new analysis using 2017 prices for gas and electricity show an increase in net operating revenues for hypothetical new combined cycle and combustion turbine gas units compared to the previous methodology. In each case analyzed, the 2017 net revenue estimates for hypothetical combined cycle and combustion turbine units fell substantially below estimates of the annualized fixed costs for these technologies.

DMM's new analysis tests net revenues using multiple scenarios which provide a range of potential results. For a new combined cycle unit, DMM estimates net operating revenues earned from the energy markets in 2017 ranged from \$29/kW-yr to \$50/kW-yr. This compares to potential annualized fixed costs of approximately \$166/kW-year. As shown in the figure below, the 2017 net revenue estimates were also about \$38/kW-yr less than the ISO's capacity procurement mechanism soft offer cap price (\$75.68/kW-yr) for a hypothetical combined cycle unit in either the NP15 or the SP15 region. For a new

combustion turbine unit, our estimates ranged from \$38/kW-yr to \$47/kW-yr compared to potential annualized fixed costs of about \$177/kW-yr.

Figure E.11 Estimated net revenue of hypothetical combined cycle unit



Under current market conditions, net operating revenues for many older existing gas-fired generators may be lower than their going-forward costs. A substantial portion of California’s older gas-fired capacity is located in transmission constrained load pockets and is needed to meet local reliability requirements. Much of this existing capacity is also needed to provide the operational flexibility required to integrate the large volume of variable renewable resources coming on-line. However, this capacity must be retrofitted or replaced over the next decade to eliminate use of once-through cooling technology. This investment is likely to require some form of longer-term capacity payment or contracting.

Recommendations

DMM provides recommendations to the ISO and its Board of Governors on current market issues and new market design initiatives on an ongoing basis. A detailed discussion of DMM’s comments and recommendations is provided in Chapter 11 of this report. This section summarizes DMM recommendations on key current market design initiatives and issues.

Auctioning congestion revenue rights

Since the start of the ISO’s congestion revenue rights (CRR) auction in 2009, payouts to holders of auctioned congestion revenue rights have exceeded the auction revenues by over \$750 million. These losses are borne by transmission ratepayers because congestion revenue rights payments are funded by

the congestion revenue rights balancing account and transmission ratepayers ultimately receive any credits or fund any shortfalls in this balancing account. Most of this \$750 million has gone to purely financial entities. These losses have not declined over time, and actually increased to over \$100 million in 2017 and about \$42 million in the first quarter of 2018.

Beginning in 2016, DMM has been recommending that ISO establish a stakeholder initiative to examine the option of eliminating the congestion revenue rights auction and instead allowing transmission ratepayers to collect congestion revenues. In 2017, DMM completed a whitepaper providing a review and critique of that general congestion revenue rights auction design.¹⁰ In early 2018, the ISO developed a proposal and filed at FERC to limit the pairs of nodes for which congestion revenue rights could be purchased in the auction.

The ISO's proposed auction changes are not sufficient for resolving the fundamental underlying flaws with CAISO's congestion revenue rights auction design.¹¹ DMM continues to recommend that the ISO continue the process of allocating congestion revenue rights to load-serving entities who pay for the transmission system through the transmission access charge (TAC), but that the ISO stop auctioning off additional congestion revenue rights that are backed financially by transmission ratepayers through the congestion revenue balancing account.

DMM also continues to recommend that the ISO move swiftly to replace the current congestion revenue rights auction with a voluntary market for financial contracts based on bids from willing buyers and sellers. Pursuant to Appendix P of the ISO tariff, DMM has also referred the ISO's congestion revenue rights action rules to FERC's Office of Energy Market Regulation as a significant market design flaw that could be effectively addressed by tariff changes.¹²

Aliso Canyon gas measures

In 2017 the ISO filed to extend a variety of provisions initially enacted in 2016 to help address the limited operability of the Aliso Canyon gas storage facility. Although DMM supported these measures on a temporary basis in 2016, DMM believes the use of some of these provisions has become problematic and needs to be limited or significantly improved, as noted below.¹³

Gas usage nomograms

In 2017, the ISO sought approval from FERC to make permanent and expand the use of its temporary tariff authority to implement a gas constraint (or gas nomogram) that limits the maximum amount of natural gas that can be burned by natural gas-fired resources. The ISO contends that the maximum gas

¹⁰ *Problems in the Performance and Design of the Congestion Revenue Rights Auction*, Department of Market Monitoring, November 27, 2017. http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

¹¹ *Motion to Intervene and Comments of the Department of Market Monitoring of the California Independent System Operator*, ER-1344-000, May 2, 2018. http://www.caiso.com/Documents/May2_2018_DMMMotion_Intervene_Comments-CRR AuctionEfficiencyTrack1A_ER18-1344.pdf

¹² See Appendix P, Section 12. DMM formally notified FERC's Office of Energy Market Regulation of that DMMs believes the ISO's current congestion revenues right auction constitutes a significant market design flaw that can be effectively remedied by tariff changes on December 4, 2017 following DMM's review of the ISO's November 21, 2017 *CRR Auction Analysis Report*.

¹³ http://www.caiso.com/Documents/Oct26_2017_DMMComments-AlisoCanyonElectric-GasCoordinationPhase3_ER17-2568.pdf

constraint “has proven to be a useful and discrete tool that balancing authority areas can use to reflect the interactions of gas limitations in the electric market optimization.”¹⁴ DMM’s review of the ISO’s limited experience with maximum gas usage constraints suggests that while such constraints may be a useful tool in the future, additional refinement of the software and operational processes through which the constraints are implemented is necessary before expanding usage of the constraint to other parts of the ISO or EIM.

For example, while gas usage constraints are modeled as 15-minute constraints in the ISO’s real-time market, these gas constraints are actually applicable only over a much longer multi-hour time period. The ISO does not adjust these constraints in real time based on actual gas usage in prior hours. Therefore, when these gas constraints bind in the ISO’s real-time market during the peak ramping hours, there appears to be surplus gas from hours prior in the day when actual usage was well below the constraint as modeled by the ISO.¹⁵ This represents a significant design flaw that remains in the gas nomograms. Thus, DMM continues to recommend that the ISO improve how gas usage constraint limits are set and adjusted in real-time based on actual gas usage in prior hours.

Gas cost scalars

In fall 2017 the ISO also gained approval from FERC to extend interim tariff provisions that allow the ISO to increase the gas price index used to calculate real-time market commitment cost bid caps and default energy bids for gas-fired resources in the SoCalGas area using special *gas cost scalars*. When in effect, these scalars have been set so that the gas costs used to calculate real-time market commitment cost bid caps for units in the SoCalGas area are increased to 175 percent above the gas price index for the next-day gas market. Gas costs used to calculate default energy bids have been increased to 125 percent of the gas price index using the scalar.

DMM has closely monitored gas market trends and performed analysis of the need for these gas cost scalars. DMM believes that these gas cost scalars are a very crude and ineffective tool for seeking to manage potential reliability issues associated with gas limitations in the real-time market while protecting against market power. Under current ISO processes, if gas limitations become apparent during any point of an operating day, the ISO cannot apply the gas cost scalars in the real-time market until the following operating day. Thus, the scalars have not been in place on the very limited number of days when they could have the intended.¹⁶ Once the scalars were applied, the ISO has also left the scalars in place for extended periods even when this does not appear justified by same-day gas market prices.

Rule changes being proposed by the ISO as part of the Commitment Cost and Default Energy Bid Enhancements (CCDEBE) initiative for implementation in fall 2019 do not include the ability for the ISO

¹⁴ *Filing to Extend Temporary Measures to Address Limited Operability of Aliso Canyon Facility and to Make Permanent and Modify Other Measures to Address Potential Gas Limitations*, California Independent System Operator Corporation, ER17-3-000, September 29, 2017, p.3. http://www.caiso.com/Documents/Sep29_2017_TariffAmendment-AlisoCanyonElectric-GasCoordinationEnhancementsPhase3_ER17-2568.pdf

¹⁵ See example and discussion in *Comments of the Department of Market Monitoring of the California Independent System Operator*, ER17-2568, October 26, 2017, pp 15-17. http://www.caiso.com/Documents/Oct26_2017_DMMComments-AlisoCanyonElectric-GasCoordinationPhase3_ER17-2568.pdf

¹⁶ See examples from Q4 2017 in pp. 51-53 of *Q4 2017 Report on Market Issues and Performance*, Department of Market Monitoring, February 14, 2018. <http://www.caiso.com/Documents/2017FourthQuarterReport-MarketIssues-PerformanceFebruary2018.pdf>

to update gas prices used in the real-time market. Therefore, the potential changes proposed in the CCDEBE initiative will not avoid the problems associated with the current gas cost scalars.

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 implement the ability to update gas prices used in the real-time market based on same-day gas market data available each morning, rather than relying on much less effective and accurate tools such as the gas cost scalars.

Commitment cost and default energy bid enhancements

In early 2018, the ISO completed the Commitment Cost and Default Energy Bid Enhancements (CCDEBE) initiative that was started in 2016. DMM opposes the final CCDEBE proposal that will be filed at FERC for reasons summarized in DMM's stakeholder comments and memo to the ISO Board on this initiative.¹⁷

DMM supports the overall goal of providing greater bidding flexibility while ensuring that bid caps used in mitigation are sufficient to cover each resource's actual marginal costs. DMM also supports development of a more dynamic approach to mitigation of commitment costs as a way of achieving these goals. While the ISO's final CCDEBE proposal includes the basic framework for addressing these issues, the proposal still has several significant gaps, implementation uncertainties, and risks. These remaining gaps should be addressed before this major market design change is approved and implemented.

Dynamic mitigation of commitment costs

While the ISO's final CCDEBE proposal includes the basic framework for dynamic mitigation of commitment costs, the proposal still has several significant gaps, implementation uncertainties, and risks. These gaps include the following:

- **Economic withholding.** Under the revised final proposal, units that are not committed will often not be subject to mitigation of commitment costs – even if the resource owner has been determined to have structural market power. This means that dynamic mitigation will fail to mitigate economic withholding (e.g., bidding lower cost units at a higher price, so that a higher cost unit must be dispatched).
- **Inter-temporal constraints and gaming.** The ISO's proposal does not ensure mitigation will be triggered when units are committed or de-committed due to inter-temporal modeling and resource constraints. A specific example of this gap is provided in DMM's comments on the ISO's final proposal.¹⁸
- **Manual dispatches and intervention by grid operators.** The ISO proposal fails to ensure mitigation for exceptional dispatches and/or any commitments (or blocking of de-commitments) that occurs as a result of various forms of manual intervention in the market dispatch by grid operators. DMM's experience indicates that in many or most cases when operators cause units to be committed or transitioned, operators have very little choice between different resources to meet reliability or market needs. If such alternatives exist, operators have limited ability to identify and choose the

¹⁷ Department of Market Monitoring Comments on CCDEBE Proposal, Memo to ISO Board of Governors, Eric Hildebrandt, March 14, 2018. http://www.caiso.com/Documents/Decision_CCDEBEProposal-Department_MarketMonitoringMemo-Mar2018.pdf

¹⁸ Comments on Revised Draft Final Proposal for Commitment Cost and Default Energy Bid Enhancements, pp. 18-19.

lowest cost option. Thus, the ISO needs to develop additional rules for mitigating commitments (or blocked de-commitments) resulting from exceptional dispatch and other forms of manual intervention by grid operators.

DMM also notes that relatively complicated software changes, such as the ISO's dynamic mitigation proposal, are subject to significant implementation errors and unexpected performance issues.¹⁹ The complexity of dynamic mitigation of commitment costs warrants a more cautious approach to raising the commitment cost bid caps. Thus, DMM also recommends that commitment cost bid caps be raised on a more gradual basis only after the effectiveness of dynamic mitigation is confirmed based on actual operational experience.

Reasonableness thresholds for bid costs used in mitigation

The ISO's proposal also includes rule changes that will allow suppliers to request increases in cost-based bid caps used to mitigate potential market power, gaming and manipulation of bid cost recovery (BCR) payments. Under the proposal, the ISO will screen requests for bid cap increases using *reasonableness thresholds* that add to the headroom already included in bid caps used when mitigation is triggered. Bids under this new reasonableness threshold will be automatically approved and used when mitigation is triggered to determine dispatches and prices.

Currently, bid caps for start-up and minimum load commitment costs include a 25 percent *headroom scalar* above estimated costs. Default energy bids (DEBs) used when energy price mitigation is triggered includes a 10 percent headroom scalar that is applied above marginal costs. The ISO proposal will increase the headroom above the current 25 percent and 10 percent scalars already applied to cost-based bids.

Under the proposed changes, the ISO will allow bids used in mitigation to be increased above the current caps by an amount that reflects a gas price that is 10 percent higher than the next-day gas price index currently used in calculating bid caps. The ISO refers to this increase in the gas price used in calculating bid caps as a *fuel volatility scalar*. On Mondays (or the first trade day after a holiday) the ISO will set this fuel volatility scalar to 25 percent.

Thus, the reasonableness threshold caps for gas-fired units will continue to be based on gas prices in the next-day market that occurs the day prior to each operating day. This very static approach is contrary to the key objective the ISO set for this initiative – i.e., to make bids used in real-time mitigation more reflective of actual marginal costs. Analysis of gas prices by DMM shows that during almost all days the additional 10 to 25 percent headroom provided under the ISO proposal is not justified by actual gas market prices. Meanwhile, on the very few days each year that same-day gas prices rise above the headroom already incorporated in bid caps, the extra headroom incorporated in the new reasonableness thresholds will be well below levels that may be justified.²⁰

DMM continues to recommend a more dynamic approach for adjusting reasonableness thresholds based on gas market trade data available at the start of each operating day. DMM's analysis shows that when the price of gas in the same-day market increases significantly above next-day gas prices used by the ISO, the same-day market at major gas trading hubs is sufficiently liquid and provides a very

¹⁹ Recent examples of such errors and unintended performance issues in the real-time market include (1) the flexible ramping product implemented in 2016, (2) the new dynamic energy bid mitigation implemented in 2016 and 2017, and (3) the Aliso Canyon gas constraint implemented in 2016 and 2017.

²⁰ *Department of Market Monitoring Comments on CCDEBE*, pp. 5-6.

accurate basis for adjusting the reasonableness thresholds. The more dynamic approach for determining reasonableness thresholds proposed by DMM will ensure greater market efficiency, reliability and more accurate mitigation than the very static approach being proposed by the ISO.

System market power

DMM has recommended that the ISO begin to consider various actions that might be taken to reduce the likelihood of conditions in which system market power may exist and to mitigate the impacts of any system market power on market costs and reliability.

As noted in this report, DMM's analysis indicates that the ISO system showed signs of becoming less competitive. In the real-time market, there were numerous periods of very tight system conditions in which many suppliers were pivotal and bidding reflected non-competitive conditions. In 2017, the day-ahead market was not structurally competitive in a growing number of hours and prices reached record highs in some hours. Tighter supply conditions in 2018 are likely to create additional potential for the exercise of system market power not subject to mitigation. In 2019, these conditions will be further exacerbated by generation retirement, increasing energy bid caps under FERC Order 831, and ISO proposals to increase bid caps used in mitigation.

DMM recognizes that this recommendation involves major market design and policy issues, including the possible development of new market design options to mitigate potential system market power. DMM also recognizes that the competitiveness of the ISO's markets is heavily affected by the procurement decisions of the state's load-serving entities and policies of their local regulatory authorities. Because of the potential severity of the impact of market power, DMM is making this recommendation at this time so that the ISO, stakeholders and regulatory entities can give this issue and potential options to address it thorough consideration.²¹

DMM has provided some initial suggestions for actions for reducing and mitigating the potential for system market power that might be considered. These include the following:

- Begin discussion and development of options for system market power mitigation.
- Set local and system resource adequacy requirements sufficiently high to ensure both reliability and reduced likelihood of non-competitive market outcomes.
- Re-examine resource adequacy provisions relating to imports, which are only required to be bid into the day-ahead market (at any price) and do not have any further obligation if not scheduled in the day-ahead energy or residual unit commitment process.
- Eliminate or reduce exemptions to must-offer obligations for resources procured to satisfy resource adequacy requirements or through ISO backstop capacity procurement (RMR and CPM).
- Carefully track and seek to limit out-of-market purchases of imports at above-market prices, which can encourage economic and physical withholding of available imports (see Section 11.5).

²¹ Under recently established ISO policies, all recommendations by DMM must be formally submitted in writing to the ISO in order to be considered.

- Closely monitor for potential errors or software issues affecting market power mitigation.²²

Manual dispatches of imports

Exceptional dispatches on the interties are often referred to by the ISO operators as *manual dispatches*. In 2017, these out-of-market dispatches increased significantly. 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. Thus, DMM recommends the ISO closely track and monitor trends in manual dispatches, and seek to limit the use of such out-of-market dispatches. DMM is also recommending that the ISO improve its logging of manual dispatches to ensure proper settlement and allow tracking and monitoring.

Opportunity cost adders for start-up and minimum load bids

In early 2016 the ISO gained Board approval of several changes to the way that commitment costs for natural gas units are calculated as part of its Commitment Cost Enhancements Phase 3 (CCE3) initiative.²³ DMM provided detailed comments on this initiative.²⁴

DMM has been supportive of developing an approach for incorporating any opportunity costs associated with environmental or physical limits on start-ups or run hours into commitment cost bids. However, DMM is not supportive of provisions included in the ISO's proposal that would allow opportunity costs to be calculated based on start-up or run hour limits included in commercial contracts. DMM believes this aspect of the ISO proposal could have the effect of reducing overall market efficiency.

In April 2018, the ISO submitted its CCE3 proposal for allowing opportunity cost bid adders for start-up and minimum load bid costs to FERC for approval. DMM filed comments opposing the exemption included in the ISO's CCE3 proposal to allow opportunity cost adders based on contractual use limits that reflect economic rather than actual environmental or physical limitations.²⁵

²² Specifically, DMM recommends the ISO routinely compare prices and the objective function values in the market power mitigation run compared to market runs. Prices and the objective function value should usually be lower in the market run than in the market power mitigation run. Significantly higher values in the market run indicate potential errors or issues such as software timing limitations that can undermine effectiveness of market power.

²³ *Commitment Cost Enhancements Phase 3 Draft Final Proposal*, February 17, 2016: <http://www.caiso.com/Documents/DraftFinalProposal-CommitmentCostEnhancementsPhase3.pdf>.

²⁴ *Comments on Commitment Cost Enhancements Phase 3 Draft Final Proposal*, Department of Market Monitoring, March 4, 2016: <http://www.caiso.com/Documents/DMMComments-CommitmentCostEnhancementsPhase3-DraftFinalProposal.pdf>.

²⁵ http://www.caiso.com/Documents/Apr13_2018_DMMIntervention_Protest-CCEPhase3TariffAmendment_ER18-1169.pdf

Flexible ramping product

During 2017, DMM raised concerns to the ISO about the level and pattern of requirements being calculated for use in setting the demand curves used to procure flexible capacity.²⁶ In February 2018, DMM identified numerous specific errors in how the demand curves used to procure flexible capacity have been calculated. DMM has completed a report indicating that these errors caused flexible ramping requirements and procurement to be significantly lower than intended in many hours with relatively high ramping needs, and significantly higher than intended in other hours which tend to have lower ramping needs.²⁷ The ISO resolved many of these errors in March of 2018.

DMM recommends that the ISO more closely monitor the requirements used in the flexible ramping product. Once corrections are fully implemented, DMM expects that there should be a decreased need for the systematic manual load adjustments made by grid operators in 2017. The ISO may need to consider increasing flexible ramping requirements if grid operators continue to feel additional ramping capacity is needed for reliable operation of the grid and real-time energy market.

DMM has also recommended that the ISO pursue a variety of enhancements to the current flexible ramping capacity product as it has been designed and implemented. These include a recommendation that the ISO develop an enhancement to avoid cases in which the current implementation inappropriately lowers system-level flexible ramping product prices and procured quantities.²⁸

Reliability must-run units

In late 2017, the additional 700 MW of capacity designated as reliability must-run units by the ISO for 2018 filed to provide service under Condition 2 of the ISO's *pro forma* reliability must-run contract. DMM and numerous other entities filed protests at FERC on the grounds that provisions of Condition 2 of the contract are "economically inefficient, distort overall market prices, undermine the CAISO's automated market power mitigation procedures, and are unjust and unreasonable for consumers."²⁹ Pursuant to Appendix P of the ISO tariff, DMM has also referred the provisions of the ISO's *pro forma* reliability must run contract to FERC's Office of Energy Market Regulation as a significant market design flaw that could be effectively addressed by tariff changes.³⁰

²⁶ For example, DMM's *2016 Annual Report* specifically noted that "the hourly profile of the flexible ramping demand curves suggests that there are systematic net load forecast errors for some hours of the day. A better understanding of the underlying causes for these errors would be valuable." See *Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2017, p.120, <http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf>

²⁷ *Flexible Ramping Product Uncertainty Calculation and Implementation Issues*, Kyle Westendorf, Department of Market Monitoring, April 18, 2018 <http://www.caiso.com/Documents/FlexibleRampingProductUncertaintyCalculationImplementationIssues.pdf>

²⁸ For example, see *Q2 2017 Report on Market Issues and Performance*, Department of Market Monitoring, September 2, 2017, pp. 6, <http://www.caiso.com/Documents/2017SecondQuarterReport-MarketIssuesandPerformance-September2017.pdf>

²⁹ *Motion to Intervene and Protest of the Department of Market Monitoring*, ER18-240-000, November 22, 2017. http://www.caiso.com/Documents/Nov22_2017_DMMMotion_Intervene_Protest-MetcalfEnergyCenterRMRAgreement_ER18-240.pdf

³⁰ See Appendix P, Section 12. DMM notified FERC's Office of Energy Market Regulation of these design flaws on November 22, 2017 concurrent with DMM's November 22, 2017 protest of the Metcalf Energy Center reliability must run agreement.

Specifically, DMM has recommended that the following two basic flaws in the reliability must-run provisions of the ISO tariff for both Condition 1 and Condition 2 must be addressed on an expedited basis.

- The prohibition on RMR capacity under Condition 2 from being offered in the CAISO’s energy market under most conditions must be removed.
- RMR resources on Condition 1 and Condition 2 must be subject to the same must-offer requirement that units are subject to under the resource adequacy program and capacity procurement mechanism.

DMM also believes that compensation under the contracts needs to be modified. The current *pro forma* reliability must-run contract allows for recovery of full fixed (sunk) costs plus a 12 percent return on equity. DMM believes that compensating a resource based on its full sunk capital costs (after depreciation) is unjust and unreasonable. DMM has recommended the ISO address the key flaws in the current contracts on an expedited basis before any more capacity is designated as reliability-must-run by the ISO.

More generally, DMM supports a more comprehensive effort to replace or combine the ISO’s reliability must run provisions with the capacity procurement mechanism (CPM) in the ISO tariff as part of a more comprehensive change to the ISO’s backstop capacity procurement authority. DMM has also recommended that reform of these provisions should be based on the principle that units needed for local or system reliability which have market power should be compensated based on going forward fixed costs (GFFC) plus a reasonable contribution to sunk fixed costs.³¹

Reliability must-run and capacity procurement mechanism initiative

The ISO has initiated a stakeholder process in 2018 to consider changes to the reliability must-run and capacity procurement mechanism provisions of the ISO tariff.³² DMM continues to recommend that the ISO move expeditiously to address the fundamental flaws of the RMR contracts by including a must-offer provision for both Condition 1 and Condition 2 units. In addition, DMM supports also pursuing the general approach suggested by FERC in its order rejecting the ISO’s risk-of-retirement capacity procurement mechanism proposal, under which the ISO’s reliability must-run provisions would be replaced or combined with the capacity procurement mechanism in the ISO tariff as part of a more comprehensive change to the ISO’s backstop capacity procurement authority.

DMM has noted that the ISO’s first option for procuring additional capacity needed to meet reliability requirements – the capacity procurement mechanism – is voluntary and can be declined by suppliers with local market power. This could undermine the capacity procurement mechanism if suppliers view reliability must-run compensation to be more favorable than capacity procurement mechanism compensation.

Thus, DMM recommends that it is imperative that the ISO redesign RMR and CPM compensation that is currently based on Schedule F of the *pro forma* RMR contract in an expeditious manner. Schedule F is

³¹ *Review of Reliability Must-Run and Capacity Procurement Mechanism Issue Paper & Straw Proposal*, Comments by Department of Market Monitoring, March 7, 2018. <http://www.caiso.com/Documents/DMMComments-ReviewofReliabilityMust-RunandCapacityProcurementMechanism-IssuePaperandStrawProposal.pdf>

³² <http://www.caiso.com/Documents/IssuePaperandStrawProposal-ReviewReliabilityMustRunandCapacityProcurementMechanism.pdf>

used in determining compensation for some units under these contracts, and provides for recovery of full fixed (sunk) costs plus a 12 percent return on equity. Under the capacity procurement mechanism, units can receive this full fixed cost payment and still keep all net market revenues earned from operating in the market.

DMM has recommended that the ISO not base its reliability must-run (or other backstop procurement) compensation policy on the incorrect assertion that FERC is requiring ISOs to compensate these units based on the units' full sunk capital costs (minus depreciation).³³ Instead, the ISO should work with DMM and other stakeholders to establish the appropriate theory for determining the fixed cost compensation for reliability must-run and other backstop procurement resources. DMM has recommended that reform of these provisions should be based on the principle that units needed for local or system reliability that have market power should be compensated based on going forward fixed costs (GFFC) plus a reasonable contribution to sunk fixed costs.³⁴

Resource adequacy

California has now maintained adequate supply capacity reserves under the state's resource adequacy program and bilateral long-term procurement process for more than a decade. However, a number of structural changes are creating the need for significant changes in this resource adequacy framework. As summarized in a recent report by CPUC, these changes include the following:³⁵

- Reliance on a growing amount of capacity from intermittent renewable resources, which has limited availability during many hours and increases the need for overall system flexibility during most hours.
- The need to repower or retire gas-fired power plants that rely on once-through cooling (OTC) technology, and an increasing number of resources that approach their design life in the coming years.
- The rapid expansion of community choice aggregators (CCAs), which appear to be reducing long-term contracting and complicating the process for procurement by LSE's of capacity needed to meet local resource adequacy requirements.

The CPUC has identified a number of options for addressing these issues, including increased coordination of resource adequacy procurement with integrated resource planning (IRP) efforts and through a multi-year resource adequacy framework. Under one of the options distribution utilities would serve as the central buyer for residual local resource adequacy requirements. DMM strongly supports these efforts and views the options outlined by the CPUC as potentially effective steps in addressing the current gaps and problems with the state's resource adequacy framework. At the same time, resource adequacy requirements must be aligned with the ISO's operational needs in order to mitigate the need for ISO backstop procurement.

³³ *Review of Reliability Must-Run and Capacity Procurement Mechanism Issue Paper & Straw Proposal*, Comments by Department of Market Monitoring, pp.2-3.

³⁴ *Review of Reliability Must-Run and Capacity Procurement Mechanism Issue Paper & Straw Proposal*, Comments by Department of Market Monitoring, March 7, 2018. <http://www.caiso.com/Documents/DMMComments-ReviewofReliabilityMust-RunandCapacityProcurementMechanism-IssuePaperandStrawProposal.pdf>

³⁵ *Current Trends in California's Resource Adequacy Program*, Energy Division Working Draft Staff Proposal, California Public Utilities Commission, 2/16/2018. <http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457193>

The capacity procurement mechanism and reliability must-run provisions of the ISO tariff play a critical role in mitigating locational market power in the state’s resource adequacy framework by providing the ISO with backstop procurement mechanisms for capacity needed to meet reliability needs. However, to effectively mitigate market power, compensation under these provisions must be just and reasonable for consumers. If total compensation under these provisions exceed levels that would be earned in competitive markets, then units with market power will demand higher compensation or withhold capacity in the resource adequacy market. Thus, compensation for these provisions must be carefully designed to avoid undermining the resource adequacy framework. DMM supports the general approach suggested by FERC in its order rejecting the ISO’s ROR CPM proposal, under which the ISO’s reliability must-run provisions would be replaced or combined with the capacity procurement mechanism in the ISO tariff as part of a more comprehensive change to the ISO’s backstop capacity procurement authority. DMM has recommended that reform of these provisions should be based on the principle that units needed for local or system reliability that have market power should receive compensation based on going forward fixed costs (GFFC) plus a reasonable contribution to sunk fixed costs.

System and local resource adequacy requirements

As noted in this report, DMM’s analysis indicates that the ISO system is showing signs of becoming less competitive. DMM has recommended that the ISO begin to consider various actions that might be taken to reduce the likelihood of conditions in which system market power may exist and to mitigate the impacts of any system market power on market costs and reliability. Options that may be considered suggested by DMM include setting local and system resource adequacy requirements sufficiently high to ensure both reliability and reduced likelihood of non-competitive market outcomes. DMM also suggests the ISO consider strengthening and enforce existing enforcement and penalties for must-offer obligations.

Currently, resource adequacy requirements do not directly mitigate market power, since suppliers can meet must-offer requirements by bidding capacity in at very high prices up to the \$1,000 bid cap. However, units bid into the market are subject to mitigation when local market power mitigation procedures are triggered by congestion on uncompetitive constraints. Thus, the combination of a must-offer requirement stemming from a resource adequacy obligation combined with bid mitigation when uncompetitive conditions exist in the ISO system could be utilized as a mechanism for system level market power mitigation.

Resource adequacy imports

DMM recommends the ISO reconsider rules concerning resource adequacy requirements met by imports. Resource adequacy imports are only required to be bid into the day-ahead market. Imports can be bid at any price and do not have any further obligation if not scheduled in the day-ahead energy or residual unit commitment process. In our last three annual reports, DMM has expressed concern that these rules could 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.³⁶ For example, as noted in prior reports, resource adequacy imports could be routinely bid significantly above projected

³⁶ 2016 Annual Report on Market Issues and Performance, pp.251-252.
2015 Annual Report on Market Issues and Performance, p.239.
2014 Annual Report on Market Issues and Performance, pp.187-188.

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.

Flexible resource adequacy and new day-ahead reserve product

DMM has noted that the ISO's continued efforts to improve flexible resource adequacy criteria and must-offer obligation (FRAC-MOO) requirements include some improvements over the initial design. However, DMM notes the ISO should carefully consider the design of the real-time must-offer obligation for flexible resource adequacy capacity together with the design of the day-ahead imbalance reserve product being developed by the ISO.³⁷ The day-ahead imbalance reserve product being developed will procure additional flexible capacity for the real-time markets. The ISO has not fully specified the design of the imbalance reserve product, but it will also give resources the obligation to economically bid into the real-time market. The ISO should carefully consider the design of the real-time must-offer obligation for flexible resource adequacy resources together with the design of the day-ahead imbalance reserve product, and ensure that the incentives and requirements for these two market design features are clear and are complementary.

³⁷ *Flexible Resource Adequacy Criteria and Must Offer Obligation Phase 2 Revised Draft Framework Proposal*, Comments by Department of Market Monitoring, March 13, 2018 <http://www.caiso.com/Documents/DMMComments-RevisedDraftFlexibleCapacityFrameworkProposal.pdf>

Organization of report

The remainder of this report is organized as follows:

- **Loads and resources.** Chapter 1 summarizes load and supply conditions impacting market performance. This chapter includes an updated analysis of net operating revenues earned by hypothetical new gas-fired generation from the ISO markets.
- **Overall market performance.** Chapter 2 summarizes overall market performance.
- **Real-time market performance.** Chapter 3 provides an analysis of real-time market performance and prices including the energy imbalance market. This chapter also includes a discussion of the real-time market impacts of the Aliso Canyon natural gas storage facility limitations.
- **Energy imbalance market.** Chapter 4 highlights the growth and performance of the energy imbalance market.
- **Convergence bidding.** Chapter 5 analyzes the convergence bidding feature and its effects on the market.
- **Ancillary services.** Chapter 6 reviews performance of the ancillary service markets.
- **Market competitiveness and mitigation.** Chapter 7 assesses the competitiveness of the energy market, along with impact and effectiveness of market power and exceptional dispatch mitigation provisions.
- **Congestion.** Chapter 8 reviews congestion and the market for congestion revenue rights.
- **Market adjustments.** Chapter 9 reviews the various types of market adjustments made by the ISO to the inputs and results of standard market models and processes.
- **Resource adequacy.** Chapter 10 assesses the short-term performance of California's system and flexible resource adequacy programs.
- **Recommendations.** Chapter 11 highlights DMM recommendations on current market issues and new market design initiatives on an ongoing basis.

1 Load and resources

This chapter reviews key aspects of demand and supply conditions that affected overall market prices and performance. In 2017, wholesale electricity prices were driven by a 27 percent increase in gas prices, combined with an increase in supply from new solar generation and an increase in hydro-electric generation. More specific trends highlighted in this chapter include the following:

- The average price of natural gas in the daily spot markets in California increased by about 27 percent from 2016. This was the main driver in the 25 percent increase in the annual wholesale energy cost per MWh of load served in 2017.
- Summer loads peaked at 50,116 MW, about 3 percent above the 1-in-10 year peak forecast, almost reaching the all-time system high: 50,270 MW on July 24, 2006.
- Hydro-electric generation increased in 2017 to around 15 percent of supply, compared to 11 percent in 2016.
- Imports from the Southwest decreased by about 2 percent and imports from the Northwest decreased by about 4 percent. In total, net imports decreased about 3 percent compared to 2016.
- Energy from wind and solar resources directly connected to the ISO grid provided about 17 percent of system energy, compared to about 15 percent in 2016. Solar energy production increased by about 22 percent compared to 2016 and remained the largest source of renewable power.
- About 770 MW of summer peak generating capacity was added in 2017, all of which came from renewable sources with more than 90 percent coming from solar generation.
- About 3,000 MW of summer peak gas-fired capacity retired in 2017, which is the largest number of generation retirements in one year in the ISO's history. An additional 600 MW of generation has submitted an intent to retire in 2018.
- Demand response programs operated by the major utilities met about 4 percent of the ISO's overall system resource adequacy capacity requirements. The amount of proxy demand capacity bid economically in the real-time market increased significantly, 6 times higher than the amount bid in 2016. Similar to previous years, only a fraction of this capacity was dispatched.
- The estimated net operating revenues for typical new gas-fired generation in 2017 were substantially below the annualized fixed cost of new generation. This analysis does not include revenues earned from resource adequacy contracts or other bilateral contracts. These findings highlight the critical importance of long-term contracting as the primary means for investment in any new generation or retrofit of existing generation needed under the ISO's current market design.

1.1 Load conditions

1.1.1 System loads

Although instantaneous peak load in 2017 was significantly higher than in 2016, annual total energy within the ISO was very similar to the prior year. Table 1.1 summarizes annual system peak loads and energy use over the last five years.

Table 1.1 Annual system load in the ISO: 2013 to 2017

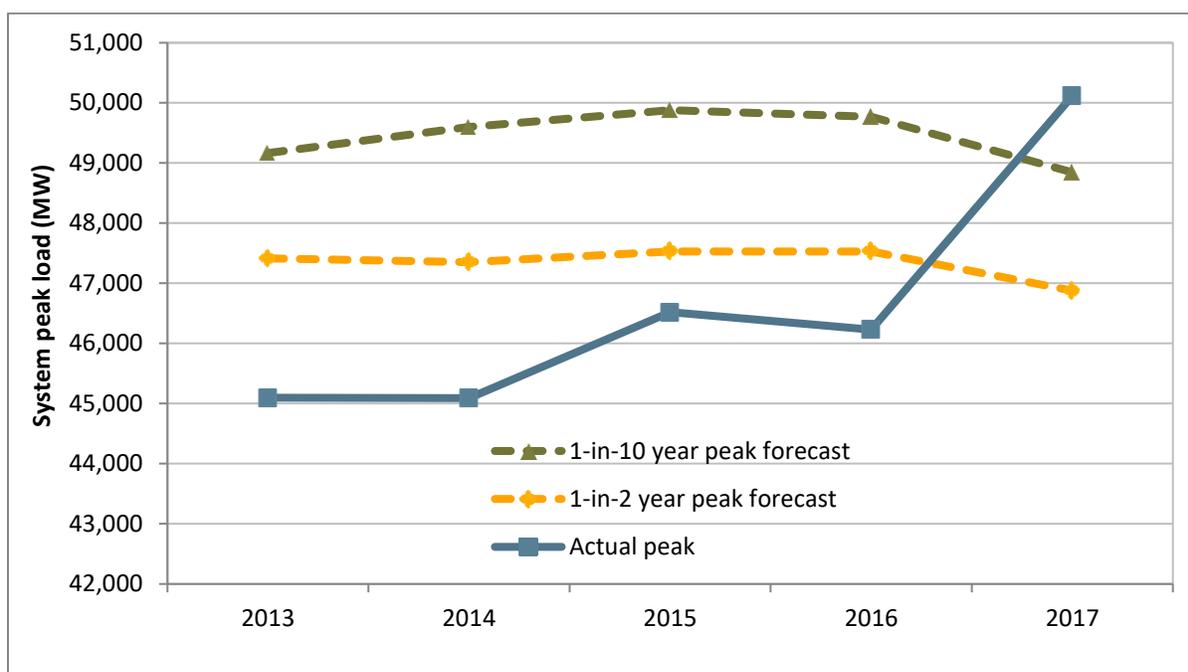
Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2013	231,800	26,461	-1.0%	45,097	-3.7%
2014	231,610	26,440	-0.1%	45,090	0.0%
2015	231,495	26,426	0.0%	46,519	3.2%
2016	228,794	26,047	-1.4%	46,232	-0.6%
2017	228,191	26,049	0.0%	50,116	8.4%

Load remained constant in 2017 compared to 2016, and continued an overall trend of decreasing loads since 2011. The instantaneous peak load increased by about 8 percent from 2016, and was significantly higher than the 1-in-10 year average hourly peak forecast used by the California Public Utilities Commission.

- Annual system energy totaled 228,191 GWh, nearly the lowest load in the last 5 years.
- Summer loads peaked at 50,116 MW on September 1 at 15:58 pm, which was significantly greater than peak loads during recent years and greater than the 1-in-10 year peak load forecast.

System demand during the single highest load hour often varies substantially year-to-year because of summer heat waves. The potential for heat-related peak loads creates a continued threat to operational reliability and drives many of the ISO's reliability planning requirements.

The peak load in 2017 was about 7 percent greater than the ISO's 1-in-2 year load forecast (46,877 MW) and about 3 percent greater than the 1-in-10 year forecast (48,845 MW) as shown in Figure 1.1. The ISO works with the California Public Utilities Commission and other local regulatory authorities to set system level resource adequacy requirements. These 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.

Figure 1.1 Actual load compared to planning forecasts

1.1.2 Local transmission constrained areas

The ISO has defined ten local capacity areas for use in establishing local reliability requirements for the state's resource adequacy program (see Figure 1.2). Table 1.2 summarizes the total amount of load used to set local reliability requirements within each of these local areas under the 1-in-10 year forecast. Most of the total peak system demand is located within two areas: the Los Angeles Basin (40 percent) and the Greater Bay Area (22 percent).

The three investor-owned utility (IOU) areas may be characterized as follows:

- The Southern California Edison area accounts for 50 percent of total local capacity area loads under the 1-in-10 year forecast. Loads in the Los Angeles Basin account for 80 percent of the potential peak load in this area.
- The Pacific Gas and Electric area accounts for about 40 percent of total local capacity area loads under the 1-in-10 year forecast. Loads in the Greater Bay Area account for 55 percent of the potential peak load in the PG&E area.
- The San Diego Gas and Electric area is composed of a single local capacity area, which accounts for about 10 percent of the total local capacity area load forecast.

In the following chapters of this report, we summarize a variety of market results for each of these three main load areas – also known as *load aggregation points* (LAPs). The proportion of load and generation located within the areas is shown in Table 1.2 and is an indication of the relative importance of results for different aggregate load and local capacity areas on overall market results.

Table 1.2 also shows the total amount of generation in each local capacity area and the proportion of that capacity required to meet local reliability requirements established in the state resource adequacy

program. In most areas, a very high proportion of the available capacity is needed to meet peak reliability planning requirements.³⁸ One or two entities own the bulk of generation in each of these areas. As a result, the potential for locational market power in these load pockets is significant. This issue is examined in Chapter 7 of this report.

Table 1.2 Load and supply within local capacity areas in 2017³⁹

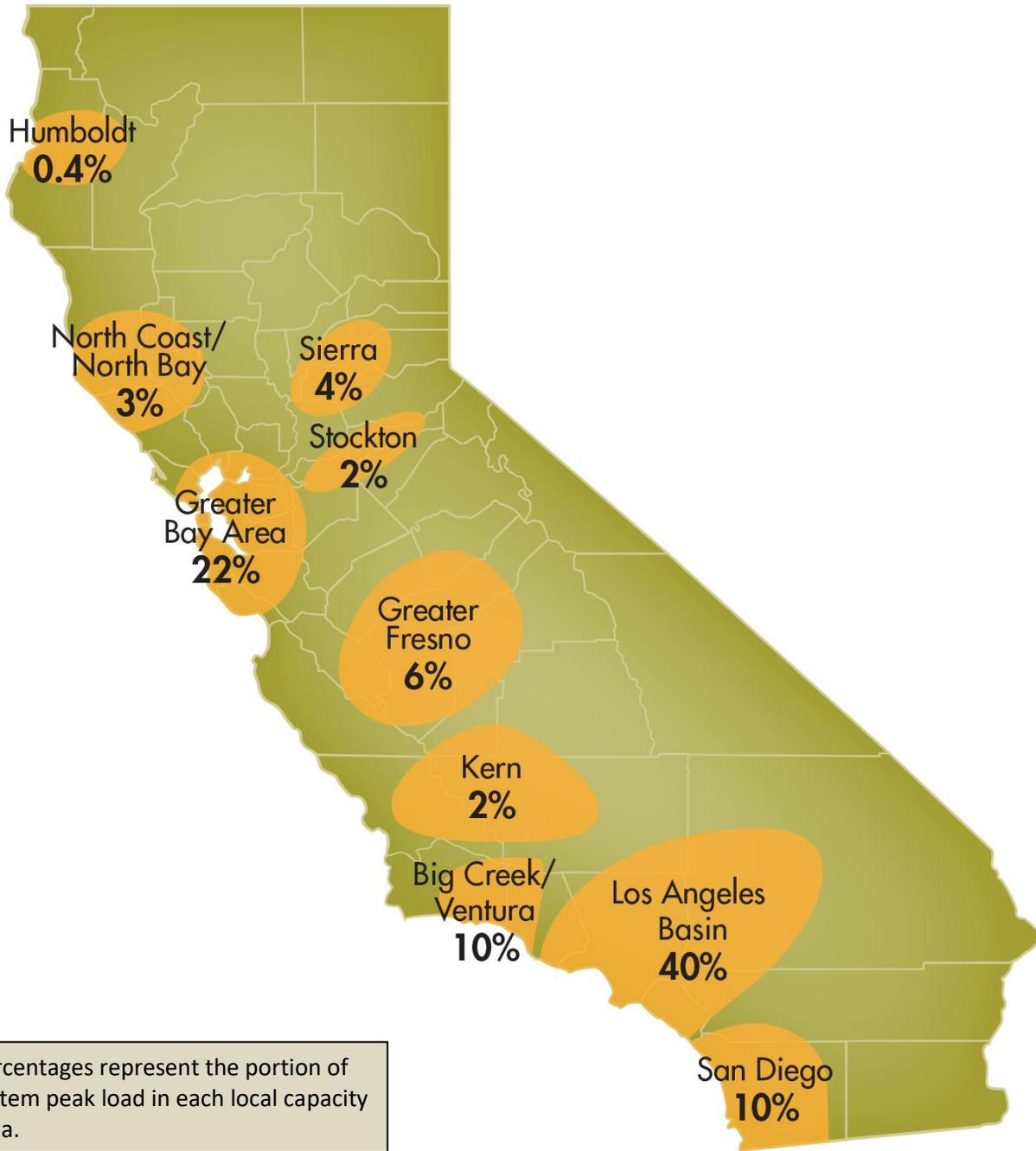
Local Capacity Area	LAP	Peak Load (1-in-10 year)		Dependable Generation (MW)	Local Capacity Requirement (MW)	Requirement as Percent of Generation
		MW	%			
Greater Bay Area	PG&E	10,477	22%	9,862	5,617	57%*
Greater Fresno	PG&E	2,964	6%	3,303	1,779	54%*
Sierra	PG&E	1,757	4%	2,066	2,043	99%*
North Coast/North Bay	PG&E	1,311	3%	850	721	85%
Stockton	PG&E	1,157	2%	598	745	125%*
Kern	PG&E	1,139	2%	551	492	89%
Humboldt	PG&E	188	0.4%	218	157	72%
LA Basin	SCE	18,890	40%	10,575	7,368	70%
Big Creek/Ventura	SCE	4,719	10%	5,463	2,057	38%
San Diego	SDG&E	4,840	10%	5,310	3,570	67%
Total		47,442		38,796	24,594	

* Resource deficient LCA (or with sub-area that is deficient) – deficiency included in LCR. Resource deficient area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

³⁸ California's once-through cooling (OTC) regulations affect a significant proportion of capacity needed to meet requirements in four areas: Greater Bay Area, Los Angeles Basin, Big Creek/Ventura and San Diego.

³⁹ Obtained from the *2018 Local Capacity Technical Analysis*, May 1, 2017, p. 23, table 6:
<http://www.caiso.com/Documents/Final2018LocalCapacityTechnicalReport.pdf>.

Figure 1.2 Local capacity areas



1.1.3 Demand response

Demand response continues to play a role in meeting California’s capacity planning requirements for peak summer demand. These programs are operated by the state’s three investor-owned utilities as well as third party providers, and met about 4 percent of total ISO system resource adequacy capacity requirements in 2017.

Demand response is a resource that allows consumers to adjust electricity use in response to forecast or actual market conditions, including high prices and reliability signals. By providing capacity to help meet demand on extremely high load days, demand response could decrease demand in high use periods enough to lower market prices for energy and ancillary services and increase transmission reliability.

Many demand response programs are currently dispatched and administered by the utilities that sponsor these programs, rather than by the ISO. These programs are overseen by the CPUC. Independent demand response providers offer this resource through utility-sponsored programs, as do other non-utility entities. However, beginning in 2015, more utility and independent demand response programs have been offered directly into the ISO markets. Moreover, pumping load not associated with the utility programs also provides a significant amount of demand response directly to the ISO.⁴⁰

In 2010, the ISO implemented a proxy demand resource product. This allows aggregators of end-use loads to bid directly into the energy and ancillary service markets. This product was implemented to increase direct participation in the energy and ancillary service markets by utility demand response programs, as well as aggregated end-use or independent demand response providers.

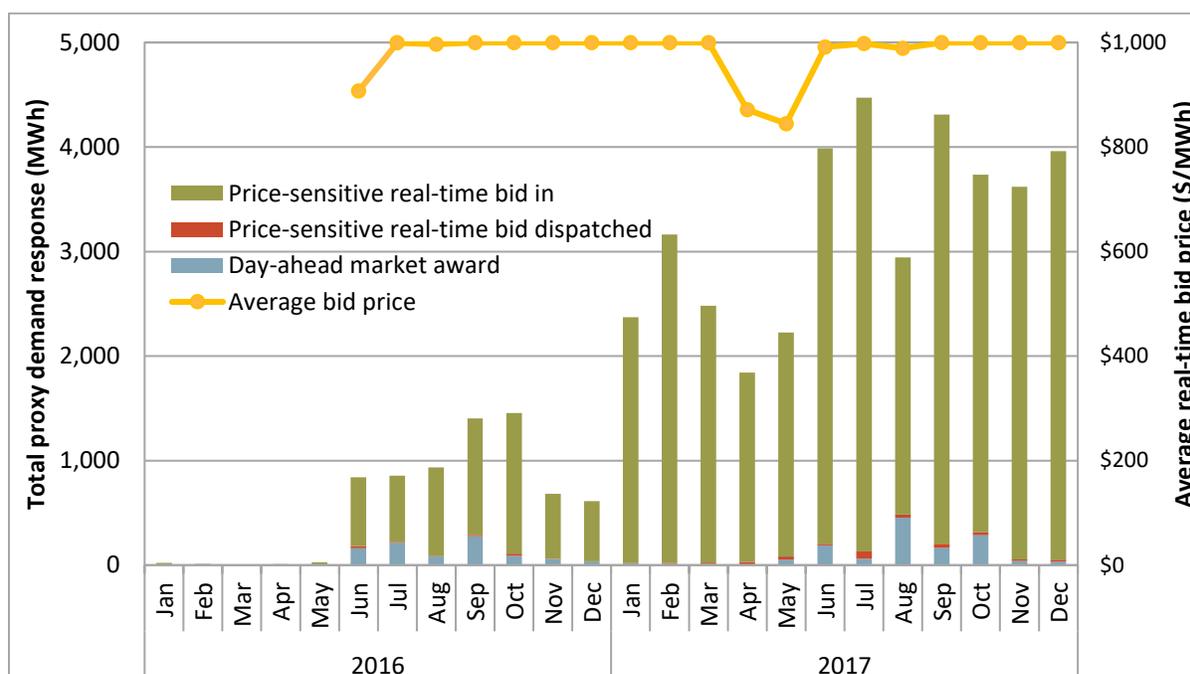
Proxy demand response (PDR) resources can be bid economically in the day-ahead and real-time markets as supply. Figure 1.3 shows the total monthly volume of price sensitive bids from proxy demand response resources offered and dispatched in real-time as well as day-ahead market awards for these resources. Beginning in June of 2016, there was a significant increase in the amount of proxy demand response capacity bid economically in the real-time market. This amount continued to increase significantly in 2017. The amount of proxy demand response capacity bid economically in the real-time market was 6 times higher than in 2016. Only a fraction of this was dispatched in the market as almost all of this capacity was bid at the cap of \$1,000/MWh. Proxy demand response resources can be the marginal resource and set the market clearing price, particularly when the system is ramp constrained or nearly ramp constrained.

The total amount of proxy demand response that was awarded in the day-ahead market increased by more than 40 percent from the previous year. Day-ahead market awards for proxy demand response were most significant in August and October on several days with particularly high day-ahead forecasts and peak system loads.

The total amount of proxy demand response capacity registered in 2017 increased to about 270 MW from about 160 MW during 2016. Only a fraction of this capacity was bid into the market, though the amount and frequency of bids increased significantly from the prior year. In 2017, scheduling coordinators bid in a combined average of about 17 MWh of proxy demand response capacity primarily in about 9 hours of weekdays and 11 hours of weekend periods, compared to an average of about 10 MWh bid during 4 hours of weekday periods in 2016.

⁴⁰ The ISO does not release information on the amount of participating loads since virtually all this capacity is operated by one market participant – the California Department of Water Resources.

Figure 1.3 Proxy demand response awards and bids



The ISO also implemented reliability demand response resources to be dispatched by the ISO during system emergencies beginning in May 2014. Reliability demand response resources can also participate economically in the day-ahead market. In the real-time market, uncommitted reliability demand response resource capacity must be offered as energy for reliability-only purposes at 95 to 100 percent of the bid cap. When an emergency condition is declared, reliability demand response resources can enter the bid stack at prices between \$950/MWh to \$1,000/MWh.

While no reliability demand response resources were registered or available for dispatch in the ISO market in 2014, many of these resources were integrated into the ISO market in 2015 and 2016. The total capacity available in 2017 decreased slightly from the previous year, with total measured capacity of about 1,023 MW. During 2017, reliability demand response resources were regularly scheduled in real time after being awarded in the day-ahead market. These resources were dispatched during 4 intervals during the year.

In addition to these demand response programs, the ISO issues Flex Alerts when system conditions are expected to be particularly stressed. Flex Alerts urge consumers to voluntarily reduce demand and are communicated through press releases, text messages and other means. During 2017, the ISO declared a Flex Alert on June 19, August 29, August 31, and September 1 in response to reliability concerns related to high temperatures and high demand.⁴¹

⁴¹ See: <http://www.caiso.com/Documents/CaliforniaISOIssuesStatewideFlexAlertDuetoHeatWave061917.pdf> (June 19), <https://www.caiso.com/Documents/FlexAlert-CaliforniaISOIssuesStatewideFlexAlertDuetoHeatWave082917.pdf> (August 29), <http://www.caiso.com/Documents/CaliforniaISOIssuesStatewideFlexAlertDuetoHeatWave083117.pdf> (August 31), and <http://www.caiso.com/Documents/FlexAlert-aCallForEnergyConservation-InEffectToday.pdf> (September 1)

Utility operated demand response programs

California’s utility operated demand response consists of load management programs operated by the state’s three investor-owned utilities. Historically, these programs were triggered by criteria set by the utilities and were not necessarily tied to wholesale market prices. Notification times required by the retail programs were historically not well coordinated with ISO market operators, which limited the programs’ use and usefulness in the ISO markets. However, with the integration of a substantial portion of this capacity into the ISO’s proxy demand response and reliability demand response resource programs, there is now a much stronger connection.

Utility-managed demand response programs can be grouped into three categories:

- **Reliability-based programs.** These programs consist primarily of large retail customers under interruptible tariffs and air conditioning cycling programs. These demand resources have been primarily triggered only when the ISO declares a system reliability threat or for a local transmission emergency. However, as these programs have become reliability demand resources, they can also be committed economically in the day-ahead market.
- **Day-ahead price-responsive programs.** These programs are triggered on a day-ahead basis in response to market or system conditions that indicate relatively high market prices. For programs not yet integrated in the ISO’s proxy demand response or reliability demand response programs, utilities trigger these programs using specific indicators, including forecasts of temperatures or unit heat rates that may be scheduled given projected real-time prices. This category also includes *critical peak pricing* programs under which participating customers are alerted that they will pay a significantly higher rate for energy during peak hours of the following operating day.
- **Day-of price-responsive programs.** These programs are referred to as *day-of* demand response programs because they can be dispatched during the same operating day for which the load reduction is needed. These resources include capacity from air conditioning cycling programs dispatched directly by the utilities and much of the load reduction capacity procured through curtailment service providers. These programs can also be triggered on a day-ahead basis in response to market or system conditions. Day-of demand response programs that are also proxy demand response resources can be dispatched through the ISO market systems.

Table 1.3 summarizes total demand response capacity for each of the three major utilities during the peak summer month of August, as reported to the CPUC.⁴²

Each investor-owned utility uses demand response capacity to meet resource adequacy requirements. As shown in the bottom three rows of Table 1.3, demand response capacity used to meet resource adequacy requirements has tracked relatively closely with estimates of actual demand response capacity reported during these years under the more advanced reporting protocols.

⁴² The monthly reports are available here: <http://www.cpuc.ca.gov/General.aspx?id=3914>. Protocols in effect since 2010 require utilities to report two measures of demand response capacity: *ex ante* and *ex post*. *Ex post* values are calculated by multiplying total program enrollment by the average customer impact for customers enrolled in the previous year. *Ex ante* values are calculated by multiplying total program enrollment by the estimated average load impact that would occur under expected weather and load conditions on the peak day of the month between 1:00 pm and 6:00 pm. The *ex ante* values form the basis for the remaining discussion in this section because they are most representative of actual available demand response capacity during 2016.

Estimated total demand response capacity available in August was about equal to the resource adequacy requirements that the CPUC allowed these resources to meet. The CPUC allows a 15 percent adder to be applied to demand response capacity used to meet resource adequacy requirements. This accounts for the fact that demand response reduces the amount of load used to calculate the 15 percent supply margin used in setting resource adequacy requirements.

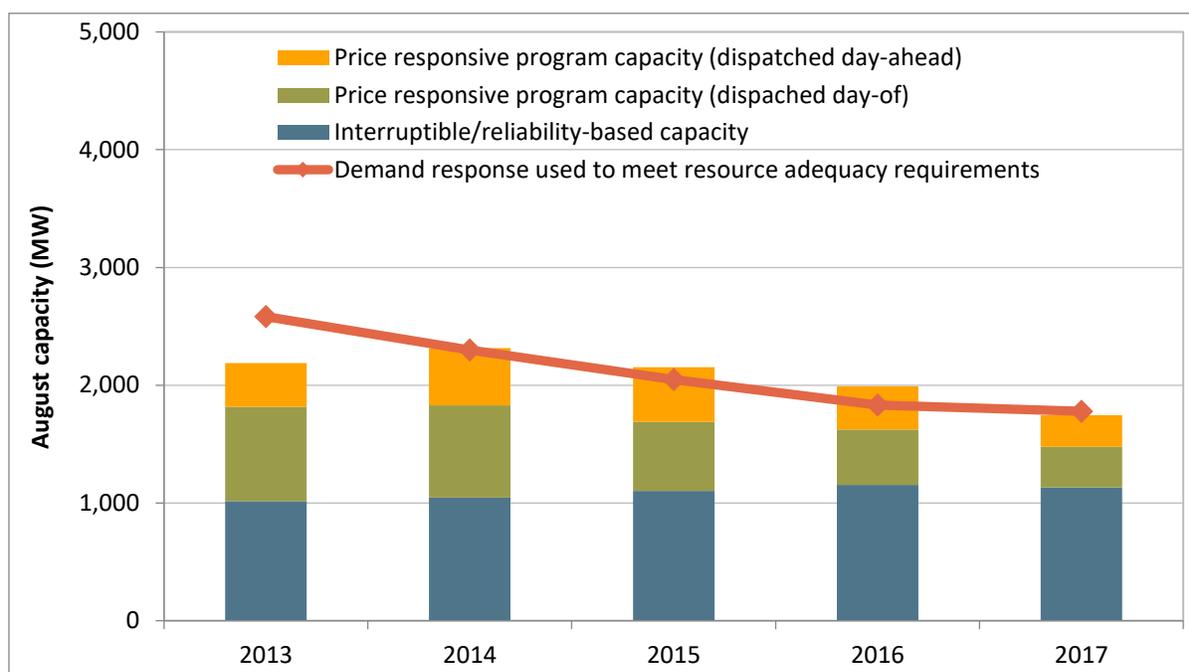
Table 1.3 Utility operated demand response programs (2013-2017)

Utility/type	2013 Estimated MW	2014 Estimated MW	2015 Estimated MW	2016 Estimated MW	2017 Estimated MW
Price-responsive					
SCE	706	790	690	595	456
PG&E	404	418	285	193	125
SDG&E	61	61	83	54	46
Sub-total	1,171	1,269	1,058	842	626
Reliability-based					
SCE	684	733	767	770	731
PG&E	332	313	334	383	401
SDG&E	1	0	1	1	1
Sub-total	1,017	1,046	1,102	1,155	1,132
Total	2,187	2,315	2,160	1,997	1,759
Resource adequacy allocation	2,582	2,299	2,047	1,831	1,778
With 15 percent adder	2,970	2,644	2,354	2,105	2,045

* Capacity based on *ex ante* assessment of program enrollment and impacts.

Figure 1.4 summarizes data in Table 1.3, and provides a further breakdown of the portion of price-responsive capacity that can be dispatched on a day-ahead and day-of basis. As shown in Figure 1.4:

- The total enrollment in price-responsive programs has declined in the last few years as resources register and begin participating in the ISO's markets as proxy demand response resources. This decline has driven down the total volume of overall demand response levels. Price-responsive programs accounted for about 36 percent of total demand response capacity in 2017, down from more than 50 percent three years ago.
- Reliability-based programs accounted for the remaining 64 percent of capacity from utility-managed demand response resources in 2017. Unlike the past few years, capacity from reliability-based programs decreased slightly in 2017.
- In 2017, price-responsive programs that could be dispatched on a day-of basis fell to about 20 percent of all demand response capacity, down from about 23 percent in 2016 and 27 percent in 2015. The amount of price-responsive programs that can be dispatched on a day-ahead basis also fell to 24 percent of total demand response capacity in 2017, from about 32 percent in 2016.

Figure 1.4 Utility operated demand response programs (2013-2017)

Dispatch of demand response in 5-minute real-time market

Resources committed in real time can be dispatched for incremental energy on a 5-minute basis. In some situations, these dispatches may occur for a single 5-minute interval in the real-time market. There are multiple software parameters to constrain unit commitments to ensure feasibility for start-up and minimum load operation. However, no such parameters exist to prevent isolated 5-minute dispatch of committed resources that cannot respond to dispatch instructions during a single 5-minute interval. When resources that cannot respond to dispatch instructions are dispatched in the 5-minute market, it can result in market inefficiency. This occurs when these units set or contribute to system marginal prices.

In 2016, DMM observed that proxy demand response resources may be particularly prone to this outcome during periods of power balance constraint relaxation when system prices go to \$1,000/MWh. In this section, we provide an update on the magnified effects of this outcome for proxy demand response resources in 2017.

As currently modeled, proxy demand response resources are very inexpensive to commit and many can be started in the real-time market. However, these resources typically have expensive incremental energy costs. In situations where the power balance constraint was relaxed in 2017, these resources frequently had the highest priced bids dispatched, and thus set system prices when the load bias limiter was triggered. While proxy demand response resources were sometimes dispatched by the software in these circumstances, the underlying demand response programs were often not able to respond to a single isolated 5-minute dispatch.

In 2017, there were 525 intervals in the 5-minute market in which the power balance constraint was relaxed for a capacity shortage and the load bias limiter was active. In 46 percent of these intervals, proxy demand response resources were dispatched on \$1,000/MWh energy bids to an output level

exceeding their 15-minute schedule, an increase from 13 percent of intervals in 2016. This percentage was considerably higher in some months.

In September 2017, proxy demand response resources were dispatched on \$1,000/MWh energy bids in the 5-minute market in 76 percent of intervals when the load bias limiter was active, compared to 37 percent of intervals in 2016. In May and August, proxy demand response resources were dispatched in the 5-minute market in more than 60 percent of intervals when the load bias limiter was active.

During each of these intervals, the quantity dispatched from each resource was very small, averaging about 0.5 MW, similar to 2016. An average of 10 proxy demand response resources were dispatched in these 5-minute intervals. Measured response from these resources appeared to be minimal. In total, of 2,167 resource-interval dispatches of proxy demand response resources in the 5-minute market in 2017, about 18 percent of these dispatches had corresponding meter data that indicated at least partial response to the dispatch.⁴³

Intervals when the power balance constraint is relaxed and the load bias limiter is triggered are not the only instances where an isolated 5-minute dispatch of a resource unable to respond to such a dispatch could occur and set price. To address this issue in the context of proxy demand response resources, the ISO has proposed to expand bidding options for demand response in the energy storage and distributed energy resources phase 3 stakeholder process.⁴⁴ Given observed market impacts, addressing this issue is important to ensure efficient market outcomes and feasible market awards.

1.2 Supply conditions

1.2.1 Generation mix

Summary

Natural gas, non-hydro renewables, and net imports were the largest sources of energy to meet ISO load in 2017, comprising about 28, 24, and 21 percent of energy respectively.⁴⁵ The share of energy from natural gas generators decreased by about 5 percentage points compared to 2016. Hydro-electric generation continued to increase in 2017 relative to the low levels observed in years prior to 2016. Non-hydro renewable generation also increased, about 2 percent, primarily driven by new solar generation coming on-line. Solar generation increased to about 11 percent of total generation, up from about 9 percent in 2016.

For the 2017 report, DMM is reporting generation mix including tie generators by respective fuel type. Tie generators are located outside the ISO balancing area but are under the direct control of ISO operators and are dispatched in a similar way to internal generators. In prior years, tie generators were aggregated within the imports fuel type. The figures below now include tie generation in the totals for nuclear, hydroelectric, non-hydro renewable, natural gas, and other.

⁴³ The analysis is based on the most recent available settlements meter data. Errors in this data or future changes may impact our estimates.

⁴⁴ *Energy storage and distributed energy resources phase 3 stakeholder process:*
http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResources.aspx

⁴⁵ Including all tie-generation in net imports (as was done in prior years), these percentages were 28, 22, and 27 percent respectively.

Monthly generation by fuel type

Figure 1.5 provides a profile of average hourly generation by month and fuel type. Figure 1.6 illustrates the same data on a percentage basis. These figures show the following:

- Natural gas, non-hydro renewables, and net imports were the largest sources of energy to meet ISO load in 2017, with 28, 24, and 21 percent respectively. Compared to 2016, the share of energy from natural gas decreased around 4 percent, renewables increased 2 percent, and net imports stayed roughly the same.
- Hydro-electric generation increased in 2017 to around 15 percent of supply, compared to 11 percent in 2016.
- Non-hydro renewable generation directly connected to the ISO system and in tie-generation accounted for about 24 percent of total supply in 2017.⁴⁶ This represents an increase from about 22 percent in 2016, driven primarily by growth in generation from solar resources.
- Nuclear generation provided about 10 percent of supply in 2017, slightly less than its contribution in 2016 due in part to an outage at one facility from late April to June.

⁴⁶ In this analysis, non-hydro renewables do not include imports or behind the meter generation such as rooftop solar. DMM has very limited access to this information. Thus, this analysis may differ from other reports of total renewable generation.

Figure 1.5 Average hourly generation by month and fuel type in 2017

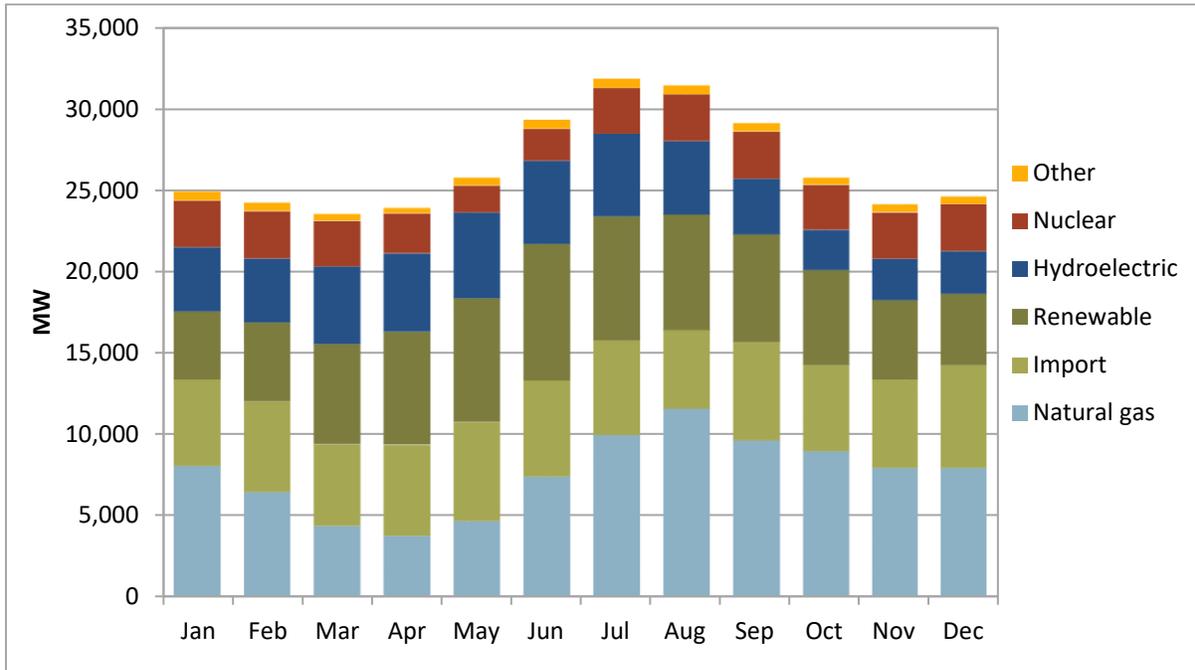
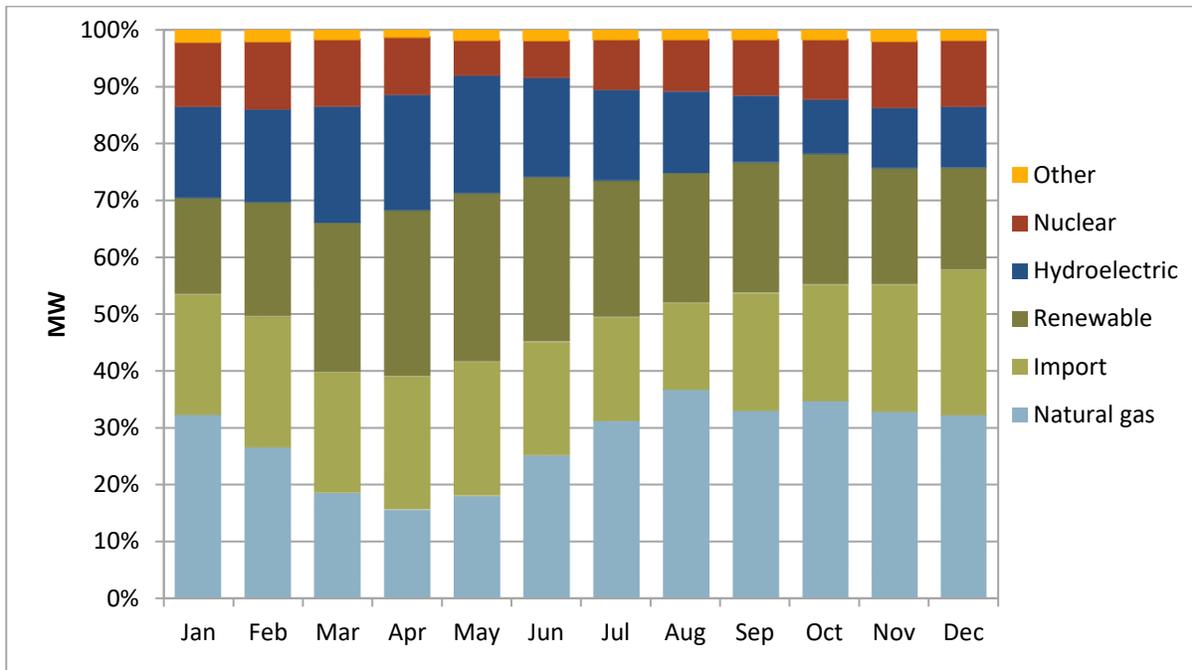


Figure 1.6 Average hourly generation by month and fuel type in 2017 (percentage)



Renewable generation

As noted above, about 24 percent of ISO load was met by non-hydro renewable and about 15 percent from hydroelectric generation directly connected to the grid. In addition, renewable and hydro resource generators also provide energy through net imports and behind the meter generation, though DMM has limited access to this information.

Figure 1.7 provides a detailed breakdown of non-hydro renewable generation including tie generators.⁴⁷ The following is shown in Figure 1.7:

- In 2015, solar power became the largest source of renewable energy within the ISO. In 2017, overall output from solar generation increased by about 22 percent compared to 2016 and accounted for around 11 percent of total supply. The increase was primarily driven by the addition of new solar resources.
- Generation from wind resources increased by almost 3 percent and contributed about 6 percent of total system energy.
- The overall output from geothermal generation remained about the same as 2016, and provided about 4 percent of system energy.
- Biogas, biomass, and waste generation accounted for about 2 percent of system energy, a slight increase compared to 2016.

Figure 1.8 compares average monthly generation from hydro, wind, and solar resources. With increased precipitation, the amount of energy produced by hydro-electric exceeded solar and wind generation for most months of 2017. Average monthly generation from solar exceeded wind for all months. In 2017, average hourly solar generation peaked at 10,085 MW on June 14 hour 13. Generation from wind resources peaked in June, while generation from hydro resources peaked in May. Renewables made up the greatest portion of system generation during May, when they accounted for nearly 30 percent of total generation.

⁴⁷ For the 2017 Annual Report, all generation metrics were updated to include all tie generators. As part of this change, a new dataset was used which is only fully available starting in 2015. For this reason, the year 2014 was removed from Figure 1.7 for this annual report.

Figure 1.7 Total renewable generation by type (2015-2017)

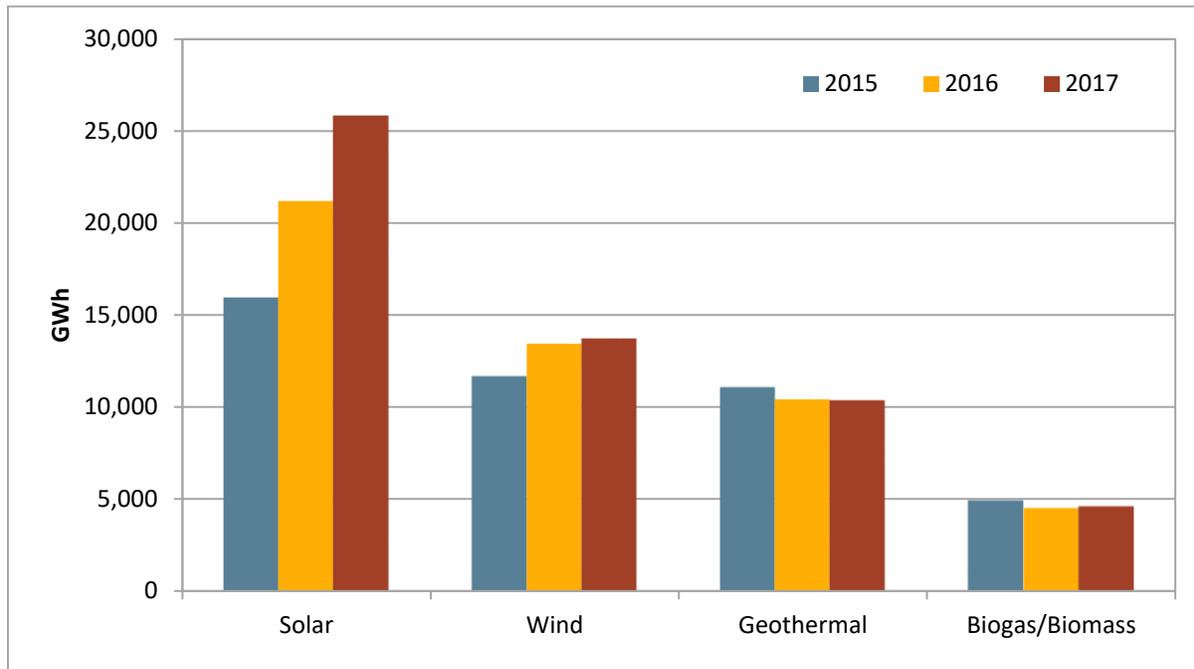
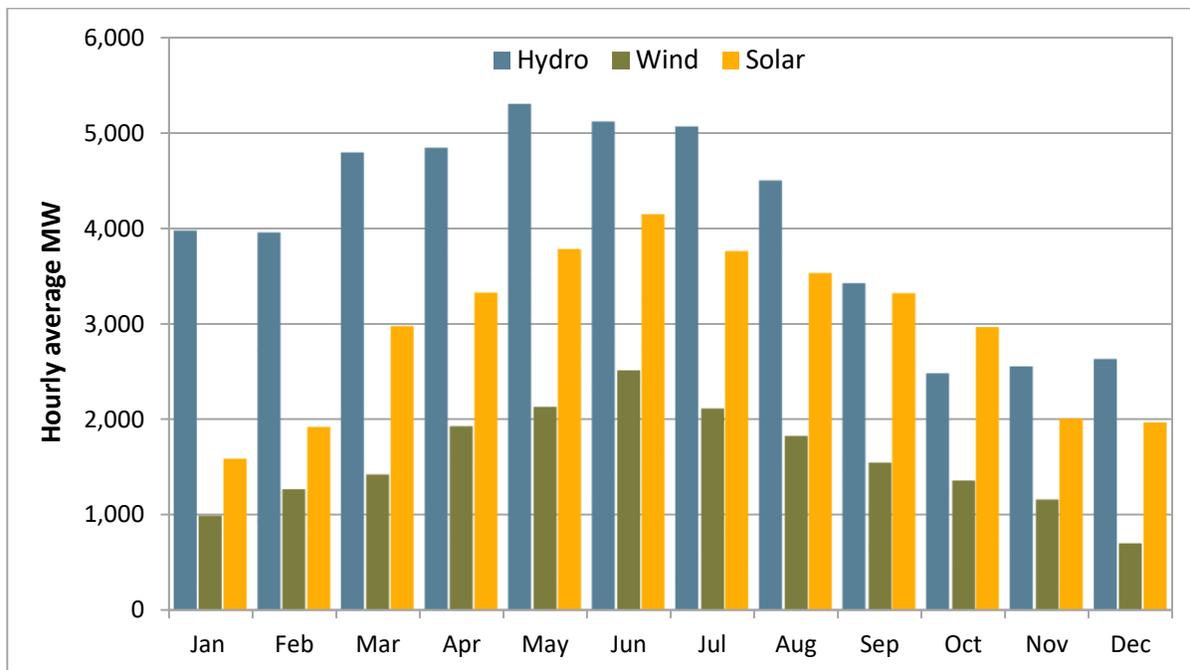


Figure 1.8 Monthly comparison of hydro, wind, and solar generation (2017)



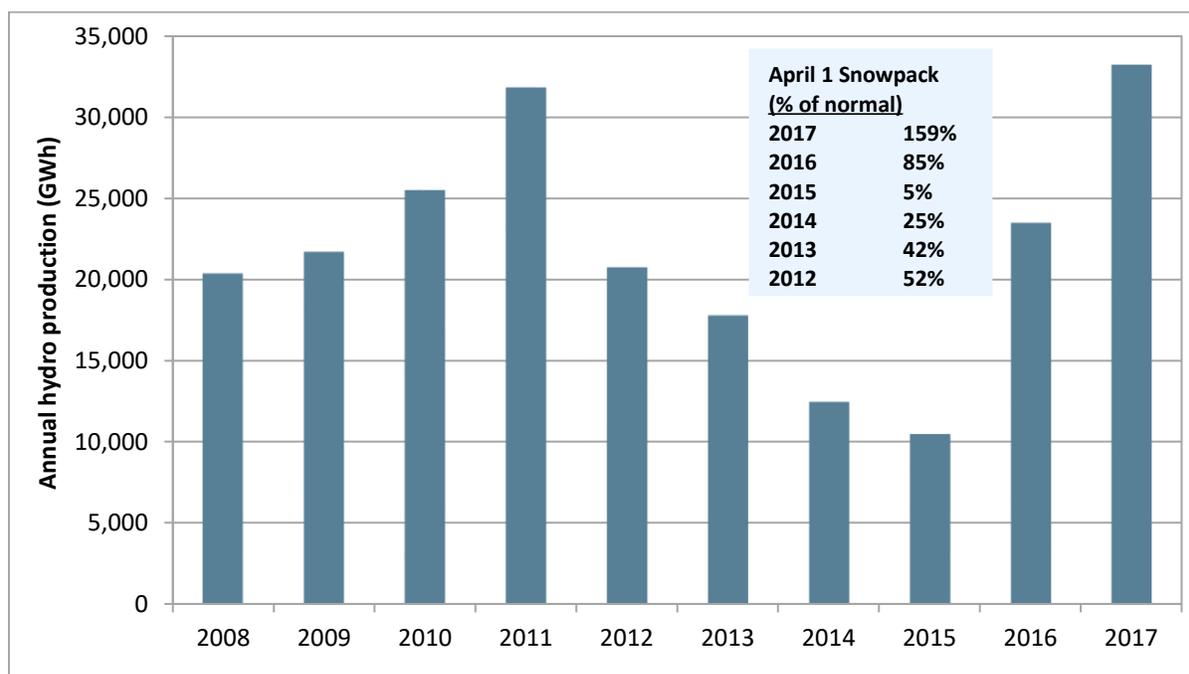
Hydro-electric supplies

Year-to-year variation in hydro-electric power supply in California has a significant impact on prices and the performance of the wholesale energy market. More supply of run-of-river hydro-electric power generally reduces the need for baseload generation and imports. Hydro conditions also impact the amount of hydro-electric power and ancillary services available during peak hours from units with reservoir storage. Almost all hydro-electric resources in the ISO are owned by load-serving entities that are net buyers of electricity.

Total hydro-electric production in 2017 increased 36 percent from the prior year and surpassed average levels from the past decade⁴⁸. Statewide snowpack, as measured on April 1, 2017, was 159 percent of the long-term average – the highest level since 2011.⁴⁹

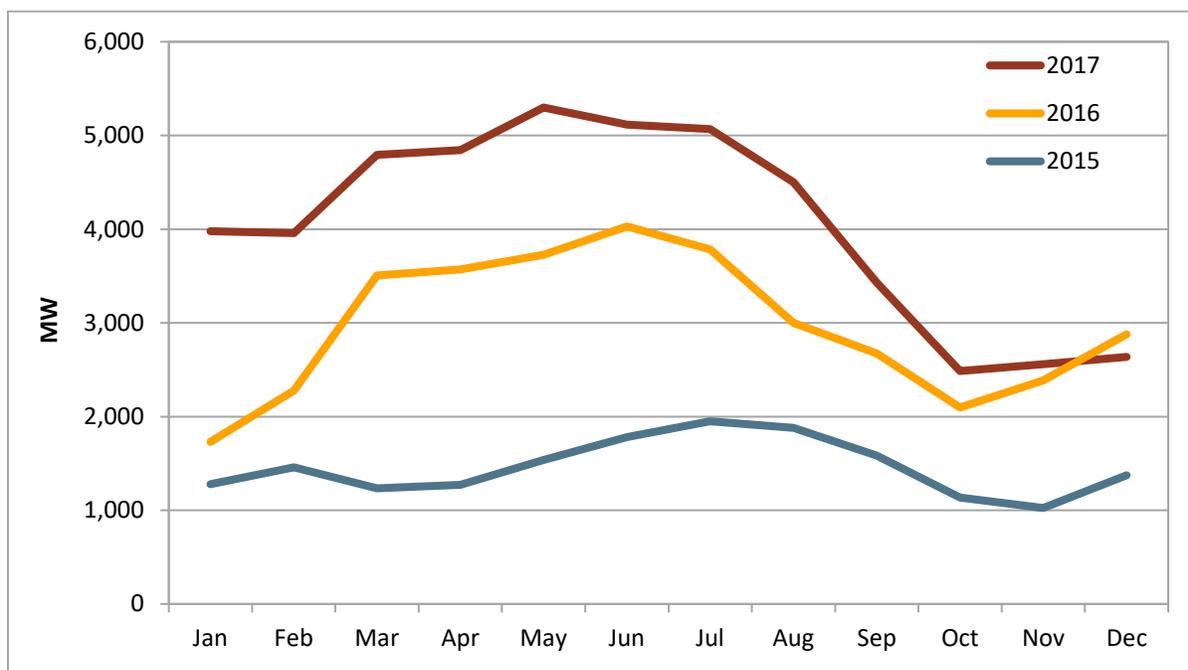
Figure 1.10 compares monthly hydro-electric output from resources within the ISO system for each month during the last three years. As in previous years, hydro generation in 2017 followed a seasonal pattern, with the highest generation in the late spring and early summer months. However, generation in 2017 exceeded generation from the previous two years during every month except December. In fact, generation during the 2017 spring months was almost four times as high as spring generation in 2015. Monthly generation in 2017 was on average about 40 percent higher than in 2016.

Figure 1.9 Annual hydro-electric production (2008-2017)



⁴⁸ Starting in 2016, annual hydro-electric production includes all tie generators. Due to data limitations in years prior to 2015, historical values do not include all tie generators. Due to this change, hydro-electric production in 2016 increased by about 10 percent compared to the value previously reported.

⁴⁹ For snowpack information, please see: California Cooperative Snow Surveys' Snow Water Equivalent (inches), California Department of Water Resources: https://cdec.water.ca.gov/cgi-progs/products/April_1_SWC.pdf.

Figure 1.10 Average hourly hydro-electric production by month (2015-2017)

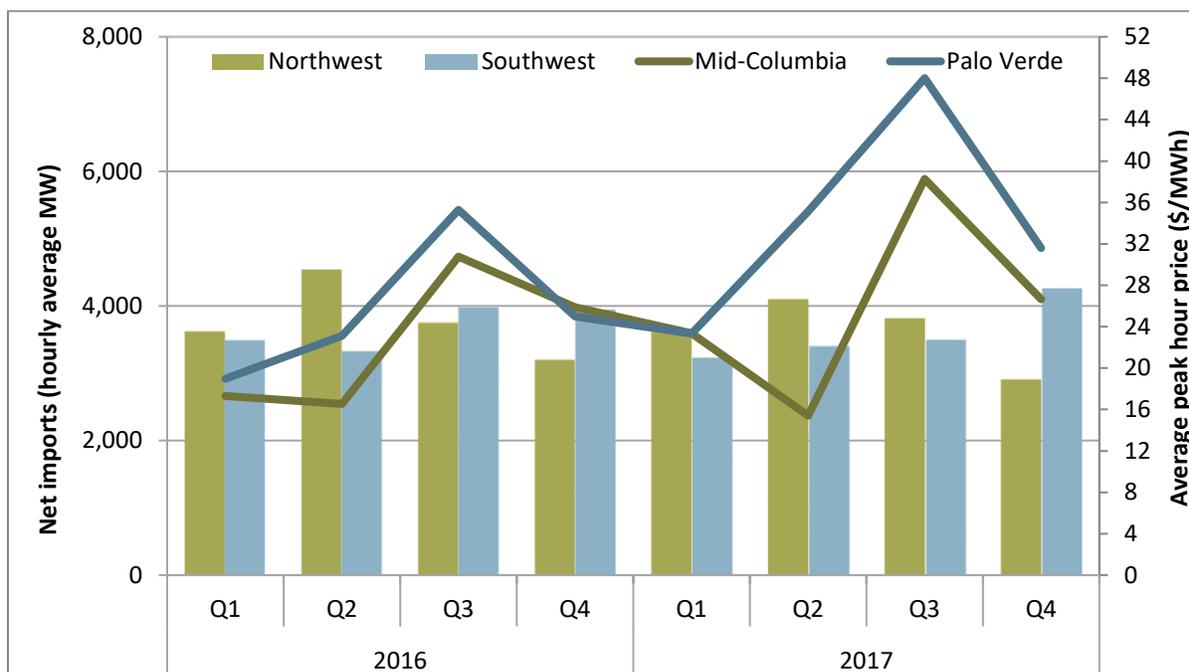
Net imports

Net imports decreased by about 3 percent in 2017 compared to 2016.⁵⁰ Total net imports from sources in the Northwest decreased by around 4 percent while net imports from the Southwest decreased by about 2 percent. Figure 1.11 compares net imports by region for each quarter during 2016 and 2017. Net imports from the Northwest were lower than the previous year in all but the third quarter of 2017, while net imports from the Southwest were lower during the first and third quarters, but higher in the second and fourth quarters. These changes were likely driven by demand and supply conditions in the Pacific Northwest and the Southwest.

Figure 1.11 also shows the quarterly average bilateral prices at Mid-Columbia (Mid-C) and Palo Verde. During 2017, Mid-C prices exceeded prices in the same quarters of 2016, except for the second quarter where prices were about the same. Lower Mid-C prices in the second quarter may have contributed to greater net imports from the northwest during the second quarters of 2016 and 2015. Palo Verde prices in 2017 exceeded prices in all of the same quarters of 2016, peaking at \$48/MWh in the third quarter. In the fourth quarter, despite decreasing Mid-C prices, net imports decreased. There was an outage on the Pacific DC intertie during this time which may have contributed to this trend.

⁵⁰ Net imports are equal to scheduled imports minus scheduled exports in any period. These net imports exclude any transfers associated with the energy imbalance market.

Figure 1.11 Net imports and average day-ahead price difference (peak hours) by region (2016-2017)



1.2.2 Generation outages

This section provides a summary of generation outages in 2017. Overall, the total amount of generation outages, and their seasonal variation over the year, was similar to prior years.

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.

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.

Figure 1.12 shows the quarterly averages of maximum daily outages broken out by type during peak hours. 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.

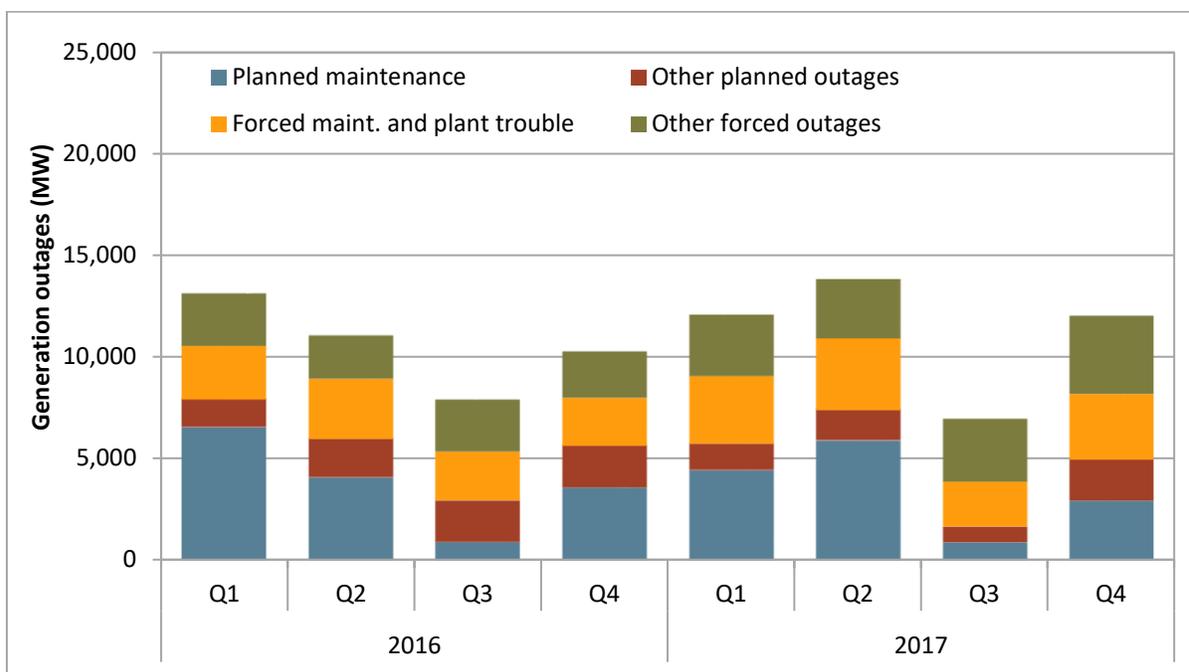
At an aggregated level, the average total amount of generation outages in the ISO was similar in 2017 compared to 2016, at about 11,000 MW.⁵¹ Outages for planned maintenance averaged about 3,500 MW during peak hours in 2017, and ranged from about 900 MW in the third quarter to about 5,900 MW in the second quarter. Combined, all other types of planned outages averaged about 1,400 MW in 2017.

⁵¹ 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.

Some common types of outages in this category were ambient outages (both due to temperature and not due to temperature) and transmission outages.

Forced outages for either plant maintenance or plant trouble totaled about 3,100 MW in 2017. All other types of forced outages totaled about 3,200 MW for 2017. 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 1.12 Average of maximum daily generation outages by type – peak hours



1.2.3 Natural gas prices

Electricity prices in western states typically follow natural gas price trends because natural gas units are usually the marginal source of generation in the ISO and other regional markets. The average price of natural gas in the daily spot markets increased significantly in 2017 from 2016 levels at the main trading hubs in California. At PG&E and SoCal Citygate hubs, the average price increase was about 20 percent and 34 percent in 2017 compared to that of 2016, respectively. The increase in natural gas prices was one of the main drivers causing the annual wholesale energy cost to increase relative to 2016.

Figure 1.13 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 1.13, the prices at SoCal Citygate were extremely volatile during the fourth quarter of 2017. This was due to planned and unplanned natural gas pipeline outages, local natural gas storage use restrictions, and December Southern California wildfires.

Figure 1.13 Monthly average natural gas prices (2014-2017)

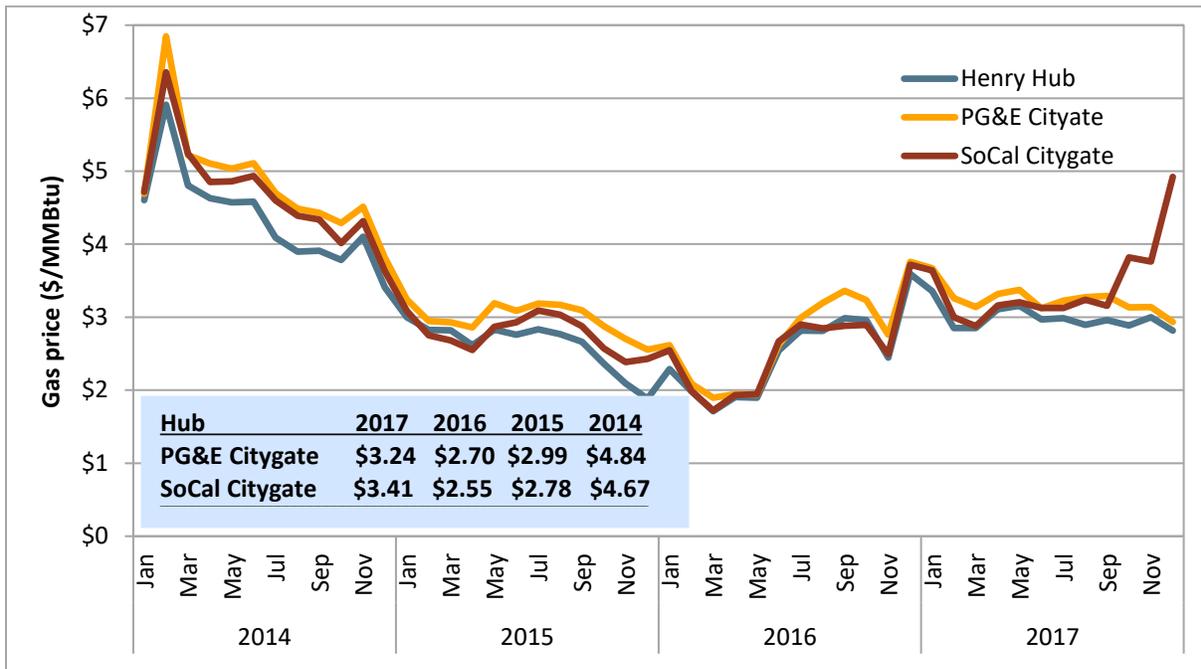


Figure 1.14 Yearly average natural gas prices compared to the Henry Hub

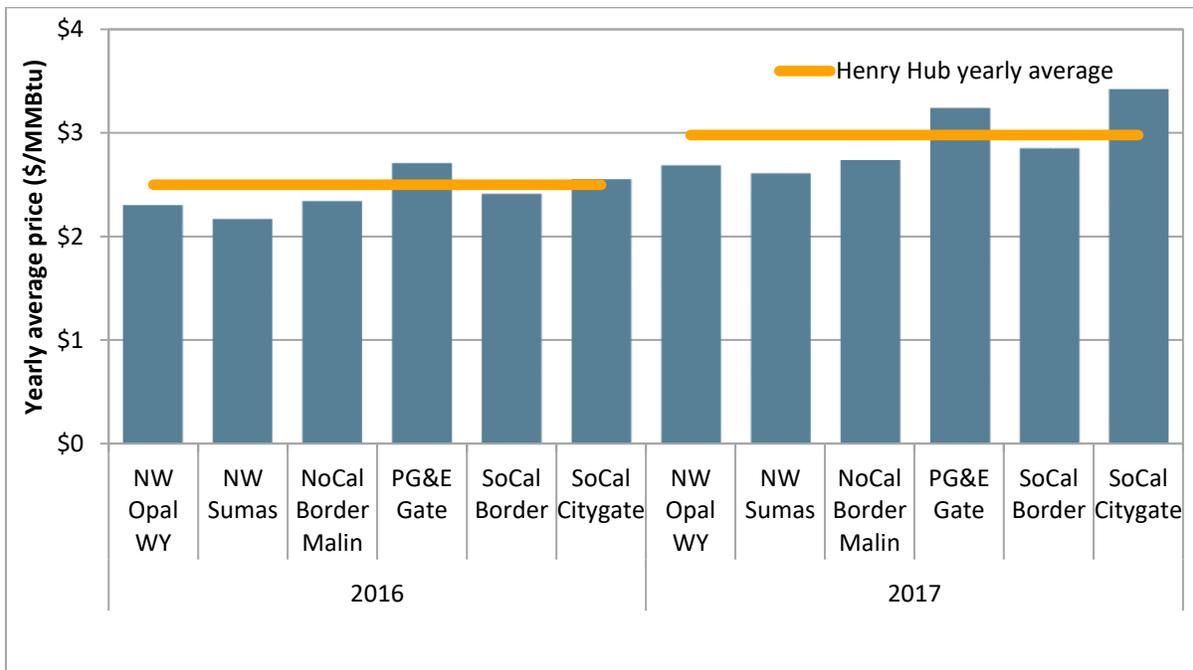


Figure 1.14 compares the yearly average natural gas prices at six major western trading points to the Henry Hub reference average for 2016 and 2017. In addition to PG&E Citygate and SoCal Citygate, Figure 1.14 includes Opal in Wyoming, Sumas in Washington, NorCal Border Malin in Oregon and the SoCal Border which represents deliveries at the California-Arizona border. The yearly average prices in

2017 remained close to the Henry Hub reference price at all six trading points. On average, the yearly price at the PG&E Citygate and SoCal Citygate exceeded the Henry Hub average by 9 percent and 15 percent, respectively. The lowest average price was at Sumas, which on average was 12 percent below the Henry Hub.

1.2.4 California's greenhouse gas allowance market

This section provides background on California's greenhouse gas allowance market under the state's cap-and-trade program, which was applied to the wholesale electric market in 2013. A more detailed description of the cap-and-trade program and its impact on wholesale electric prices in 2013 was provided in DMM's prior annual reports.⁵²

Greenhouse gas compliance costs are included in the calculation of each of the following:

- resource commitment costs (start-up, transition and minimum load costs);
- default energy bids (bids used in the automated local market power mitigation process); and
- generated bids (bids generated on behalf of resource adequacy resources and as otherwise specified in the ISO tariff).⁵³

In addition, all energy imbalance market transfers serving ISO load are attributed to energy imbalance market participating resources to facilitate compliance with California's cap-and-trade program and mandatory reporting regulations. Resource specific compliance obligations are determined by the ISO's optimization based on energy bids and greenhouse gas bid adders and are reported to participating resource scheduling coordinators for compliance. Further detail on greenhouse gas compliance in the energy imbalance market is provided in 4.5.

Greenhouse gas allowance prices

When calculating various cost-based bids used in the ISO market software, the ISO uses a calculated greenhouse gas allowance index price as a daily measure for greenhouse gas allowance costs. The index price is calculated as the average of two market based indices.⁵⁴ Daily values of the ISO greenhouse gas allowance index are plotted in Figure 1.15.

⁵² 2015 Annual Report on Market Issues and Performance, Department of Market Monitoring, April 2016, pp. 45-48:

<http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf>.

⁵³ Details on each of the calculations may be found in the ISO Business Practice Manual for Market Instruments, Appendix K: http://bpmcm.caiso.com/BPM%20Document%20Library/Market%20Instruments/BPM_for_Market%20Instruments_V39-clean.doc.

⁵⁴ The indices are ICE and ARGUS Air Daily. As the ISO noted in a market notice issued on May 8, 2013, the ICE index is a settlement price but the ARGUS price was updated from a settlement price to a volume-weighted price in mid-April of 2013. For more information, see the ISO notice:

http://www.caiso.com/Documents/GreenhouseGasAllowancePriceSourcesRevisedMay8_2013.htm.

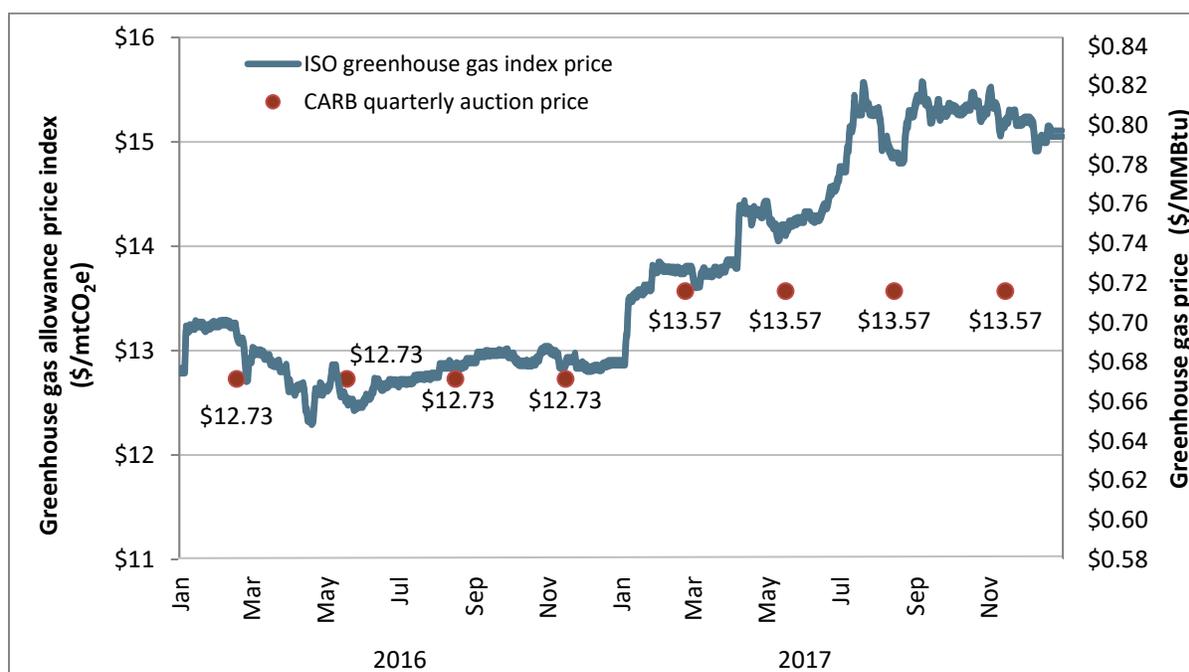
Figure 1.15 ISO's greenhouse gas allowance price index

Figure 1.15 also shows market clearing prices in the California Air Resources Board's quarterly auctions of emission allowances that can be used for the 2016 or 2017 compliance years. The values displayed on the right axis convert the greenhouse gas allowance price into an incremental gas price adder, dollars per MMBtu, by multiplying the greenhouse gas allowance price by an emissions factor that is a measure of the greenhouse gas content of natural gas.⁵⁵ Thus, the blue line can be read from both the left and right hand axes.

As shown in Figure 1.15, the average cost of greenhouse gas allowances in bilateral markets increased from a load-weighted average of \$12.83/mtCO₂e in 2016 to \$14.57/mtCO₂e in 2017. In 2017, each of the California Air Resources Board's quarterly allowance auctions sold a fraction of allowances offered and thus cleared at the annual auction reserve price of \$13.57/mtCO₂e. On July 17, 2017, the California legislature passed AB 398 bill to extend the state's cap-and-trade program to 2030. During August's auction, every emission permit offered by the state was sold, and prices reached their highest level since the program launched five years ago.

The greenhouse gas compliance cost expressed in dollars per MMBtu in 2017 ranged from about \$0.68/MMBtu to \$0.82/MMBtu. This represents about one quarter of the average cost of gas during this period.

⁵⁵ The emissions factor, 0.0531148 mtCO₂e/MMBtu, is the sum of the product of the global warming potential and emission factor for CO₂, CH₄ and N₂O for natural gas. Values are reported in tables A-1, C-1 and C-2 of *Title 40 – Protection of Environment, Chapter 1 – Environmental Protection Agency, Subchapter C – Air Programs (Continued), Part 98-Mandatory Greenhouse Gas Reporting*, available here: http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl.

Impact of greenhouse gas program

A detailed analysis of the impact of the state's cap-and-trade program on wholesale electric prices in 2013 was provided in DMM's 2013 annual report.⁵⁶ The \$14.57/mtCO₂e average in 2017 would represent an additional cost of about \$6.20/MWh for a relatively efficient gas unit.⁵⁷ The average price in 2016, \$12.83/mtCO₂e, would represent an additional cost of about \$5.45/MWh for the same relatively efficient gas resource.

1.2.5 Generation addition and retirement

California currently relies on long-term procurement planning and resource adequacy requirements placed on load-serving entities to ensure that sufficient capacity is available to meet reliability planning requirements on a system-wide basis and within local areas. Trends in the amount of generation capacity being added and retired in the ISO system each year provide important insight into the effectiveness of the California market and regulatory structure in new generation development.

Figure 1.16 summarizes trends in the addition and retirement of generation from 2008 through 2017.⁵⁸ Table 1.4 also shows generation additions and retirements since 2008, including totals across the 10 year period (2008 through 2017). About 3,000 MW of summer peak capacity was retired in 2017, which is the largest number of generation retirements in one year in the ISO system's history. Roughly 82 percent of retirements were located in the Pacific Gas and Electric area, 15 percent in the Southern California Edison area, and roughly 3 percent in the San Diego Gas and Electric area. Additionally, more than 600 MW of generation have submitted intent to retire in 2018. These retirements are not included in the figures in this report.

About 770 MW of new summer peak capacity began commercial operation within the ISO system in 2017. Roughly 280 MW of this capacity was installed in the Southern California Edison and San Diego Gas and Electric areas, and almost 500 MW came on-line in the Pacific Gas and Electric area. All of the generation capacity added in 2017 came from renewable sources, with the majority from solar.

⁵⁶ *2013 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2014, pp. 123-136: <http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf>.

⁵⁷ DMM calculates this cost by multiplying the average index price by the heat rate of a relatively efficient gas unit (8,000 Btu/kWh) and an emissions factor for natural gas: 0.0531148 mtCO₂e/MMBtu derived in footnote 55.

⁵⁸ Starting in 2011, capacity values are calculated summer peak values. The values in 2010 and before are nominal capacity values. For 2012 through 2016, DMM used capacity factors calculated by the ISO for generation of each fuel type on the basis of actual performance over the prior three year period. These factors may change year-to-year.

Figure 1.16 Generation additions and retirements (2008-2017)

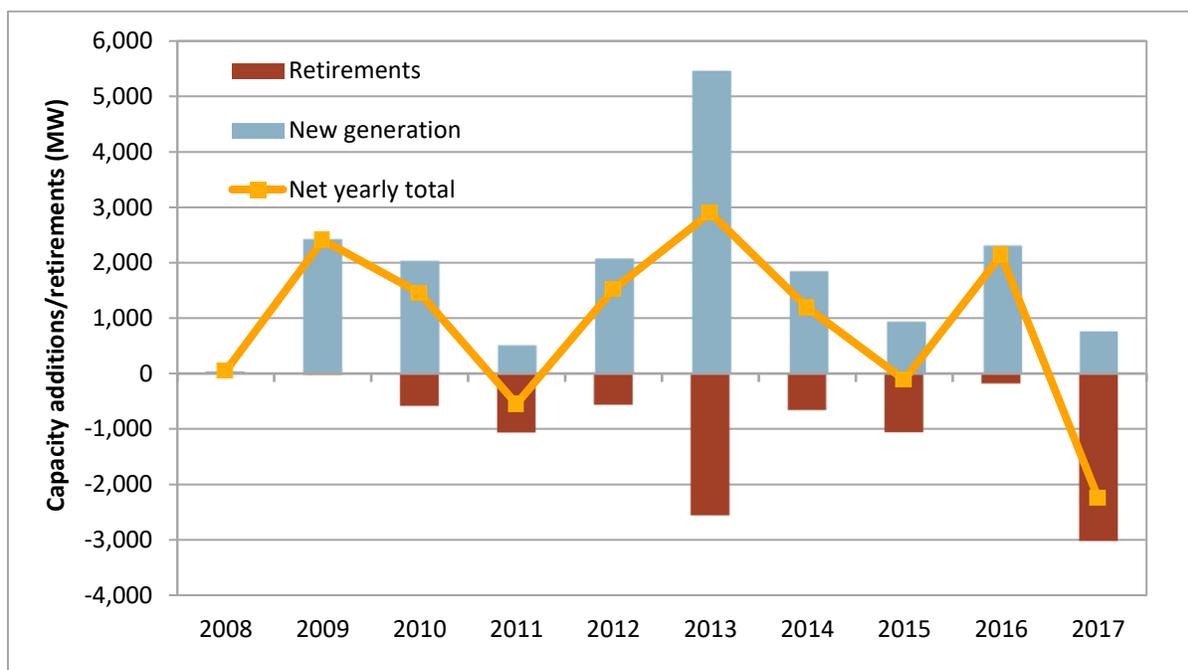


Table 1.4 Changes in generation capacity since 2008

	2008-2012	2013	2014	2015	2016	2017	Total through 2017
SCE and SDG&E							
New Generation	3,649	3,045	1,431	547	1,819	282	10,774
Retirements	(1,568)	(1,883)	(16)	(1,062)	(69)	(548)	(5,144)
Net Change	2,081	1,163	1,415	(515)	1,750	(265)	5,630
PG&E							
New Generation	3,479	2,411	426	401	503	491	7,711
Retirements	(677)	(674)	(650)	0	(113)	(2,468)	(4,582)
Net Change	2,802	1,737	(224)	401	390	(1,977)	3,129
ISO System							
New Generation	7,128	5,456	1,858	948	2,322	773	18,485
Retirements	(2,245)	(2,557)	(666)	(1,062)	(182)	(3,016)	(9,727)
Net Change	4,883	2,899	1,192	(114)	2,140	(2,243)	8,758

Table 1.5 provides detailed information about generation retirements in 2017. All of the 3,000 MW of retiring capacity came from natural gas generators, the largest of which were Moss Landing Units 6 and 7. Together these units comprised just over 1,500 MW of summer peak capacity. Roughly 1,000 MW of summer capacity was retired at the start of the year at Pittsburg Units 5, 6, and 7.

While this generation capacity was not available to the ISO system beginning in 2017, some of these retirements may not be permanent. Generators withdrawing their resource from the market may do so with the intention of repowering or re-entering the interconnection queue in the future. The ISO

provides the possibility for retiring generators to retain full or partial deliverability status as elements of Resource Adequacy and Net Qualifying Capacity for a period of time after the unit has been decommissioned.⁵⁹

In 2017, less than 100 MW of retired generation was designated with a status of permanently retired. At the end of 2017, a significant portion of the remaining capacity was undecided as to whether they would permanently retire, apply for repowering, or enter the generation interconnection queue. Under this undecided status, the resource may be withdrawn from the market for a maximum of 2 application windows.⁶⁰ During this time, the generating unit and interconnection facilities must remain intact and maintain a state of readiness to return to service until the next steps decision is made and the ISO has been notified. Two resources had decided that they would like to maintain deliverability and have or will enter the process to apply for repowering.⁶¹

Table 1.5 Generation retirements in 2017

Generating unit	Unit type	Resource capacity (MW)	Summer capacity (MW)	Date of Retirement	Area
Pittsburg Unit 5	Natural Gas	312	271	21-Jan-17	PG&E
Pittsburg Unit 6	Natural Gas	317	276	21-Jan-17	PG&E
Pittsburg Unit 7	Natural Gas	530	461	21-Jan-17	PG&E
Moss Landing Unit 6	Natural Gas	754	656	8-Feb-17	PG&E
Moss Landing Unit 7	Natural Gas	756	657	8-Feb-17	PG&E
Encina Unit 1	Natural Gas	106	92	28-Feb-17	SDG&E
Inland Empire Energy Center, Unit 2	Natural Gas	366	319	2-Mar-17	SCE
Harbor Cogen Combined Cycle	Natural Gas	109	95	23-May-17	SCE
Carson Cogeneration	Natural Gas	48	42	22-Jun-17	SCE
San Joaquin Cogen	Natural Gas	49	43	19-Jul-17	PG&E
Graphic Packaging Cogen	Natural Gas	28	24	30-Dec-17	PG&E
King City Energy Center, Unit #1	Natural Gas	45	39	31-Dec-17	PG&E
Wolfskill Energy Center, Unit #1	Natural Gas	47	41	31-Dec-17	PG&E
Generation Retirements in 2017		3,467	3,016		

Figure 1.17 and Figure 1.18 show new generation additions by generator type and quarter. Figure 1.17 includes the full nameplate capacity of the new generators, while the values in Figure 1.18 reflect summer peak capacity. As seen in the figures, most of the additional generation capacity in 2017 came from solar generators. In terms of summer peak capacity, about 700 MW of new solar capacity was added. Additionally, 40 MW of energy storage capacity was added in the first quarter and roughly 45 MW of wind capacity was added in the fourth quarter. This reflects the Escondido and Eastern batteries in the San Diego Gas and Electric area and the Golden Hills C wind plant in the Southern California

⁵⁹ More information on Resource Adequacy and Net Qualifying Capacity is available in Section 5 of the BPM for Reliability Requirements, <https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Reliability%20Requirements>

⁶⁰ The Business Practice Manual for Generator Management defines retirement scenarios and procedures for resources that wish to retire their unit either temporarily or permanently. <https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Generator%20Management>

⁶¹ The ISO keeps a list of generating units retaining deliverability for the purpose of repowering on the CAISO website. See the Net Qualifying Capacity List as applicable at <http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx>.

Edison area. Small hydro and landfill gas units accounted for the remaining 15 MW of new capacity. A more detailed listing of units added in 2017 is provided in Table 1.6.

Figure 1.17 Generation additions in 2017 by resource type (nameplate capacity)

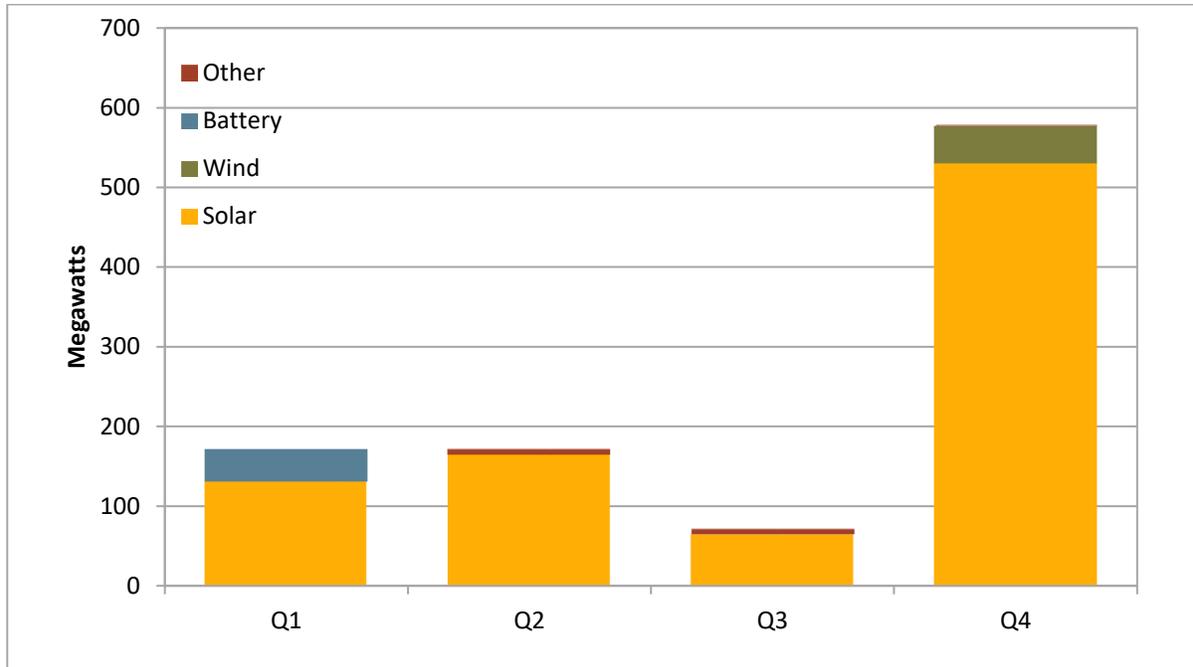


Figure 1.18 Generation additions in 2017 by resource type (summer peak capacity)

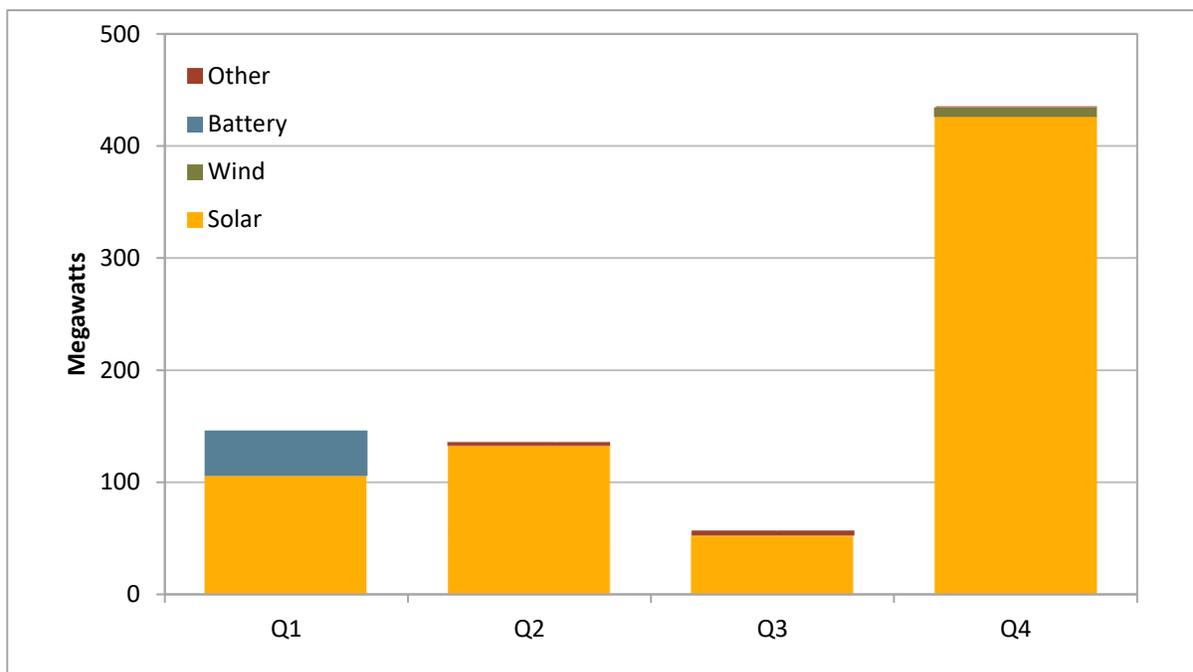


Table 1.6 New generation facilities in 2017

Generating unit	Unit type	Resource capacity (MW)	Summer capacity (MW)	Commercial operation date	Area
SKIC Solar	Solar	10	8	5-Jan-17	PG&E
Wildwood Solar 2	Solar	15	12	11-Jan-17	PG&E
Oro Loma Solar 2	Solar	10	8	28-Jan-17	PG&E
Avenal Solar 2	Solar	8	6	28-Jan-17	PG&E
Oro Loma Solar 1	Solar	10	8	28-Jan-17	PG&E
Avenal Solar 1	Solar	8	6	28-Jan-17	PG&E
Paige Solar	Solar	20	16	9-Mar-17	PG&E
Whitney Point Solar	Solar	20	16	15-Apr-17	PG&E
Quinten Luallen	Hydro	7	4	14-Jun-17	PG&E
Burford Giffen	Solar	20	16	16-Jun-17	PG&E
Montgomery Creek Hydro	Hydro	3	1	1-Aug-17	PG&E
Redwood Renewable Energy	Land Fill Gas	4	3	16-Sep-17	PG&E
Golden Hills C	Wind	46	8	9-Nov-17	PG&E
California Flats North	Solar	130	104	29-Nov-17	PG&E
Cuyama Solar	Solar	40	32	30-Nov-17	PG&E
Richmond Chevron 85	Solar	9	7	21-Dec-17	PG&E
Chevron 2	Solar	2	2	21-Dec-17	PG&E
Tranquillity 8 Azul	Solar	20	16	26-Dec-17	PG&E
Tranquillity 8 Amarillo	Solar	20	16	26-Dec-17	PG&E
Bakersfield Solar 1	Solar	5	4	26-Dec-17	PG&E
Bakersfield Industrial 1	Solar	1	1	27-Dec-17	PG&E
Manteca Land 1	Solar	1	1	28-Dec-17	PG&E
Delano Land 1	Solar	1	1	28-Dec-17	PG&E
Panoche Valley Solar	Solar	240	193	29-Dec-17	PG&E
Madera 1	Solar	2	1	29-Dec-17	PG&E
PG&E Actual New Generation in 2017		651	491		
Generating unit	Unit type	Resource capacity (MW)	Summer capacity (MW)	Commercial operation date	Area
Eastern BESS 1	Battery	8	8	18-Feb-17	SDG&E
Escondido BESS 1	Battery	10	10	6-Mar-17	SDG&E
Escondido BESS 3	Battery	10	10	6-Mar-17	SDG&E
Escondido BESS 2	Battery	10	10	6-Mar-17	SDG&E
Jacumba Solar Farm	Solar	20	16	25-Jul-17	SDG&E
SDG&E Actual New Generation in 2017		58	54		

Table continues on next page.

Generating unit	Unit type	Resource capacity (MW)	Summer capacity (MW)	Commercial operation date	Area
Springerville Aggregate Solar	Solar	14	11	5-Jan-17	SCE
Millikan Avenue BESS	Battery	2	2	14-Jan-17	SCE
Freeway Springs	Solar	2	2	25-Jan-17	SCE
Portal Ridge C	Solar	11	9	14-Feb-17	SCE
Portal Ridge B	Solar	20	16	15-Feb-17	SCE
Golden Springs Building F	Solar	1	1	24-Feb-17	SCE
Golden Springs Building G	Solar	1	1	24-Feb-17	SCE
Golden Springs Building L	Solar	1	1	24-Feb-17	SCE
Blythe Green 1	Solar	20	16	5-Apr-17	SCE
Kramer Junction 3	Solar	30	24	11-Apr-17	SCE
Kramer Junction 4	Solar	30	24	11-Apr-17	SCE
Lancaster B	Solar	3	2	22-Apr-17	SCE
Sunray 2	Solar	20	16	2-Jun-17	SCE
Milliken Landfill Solar	Solar	3	2	23-Jun-17	SCE
Lancaster Aggregate Solar Resources	Solar	6	4	23-Jun-17	SCE
Sunray 3	Solar	14	11	29-Jun-17	SCE
Soccer Center	Solar	3	2	11-Aug-17	SCE
Lancaster East Avenue F	Solar	4	3	25-Aug-17	SCE
Victor Aggregate Solar Resources	Solar	24	20	13-Sep-17	SCE
Aspiration Solar G	Solar	9	7	15-Sep-17	SCE
Central Antelope Dry Ranch B	Solar	3	2	29-Sep-17	SCE
One Ten Partners	Solar	2	2	30-Sep-17	SCE
East Portal Hydro	Hydro	1	0	11-Oct-17	SCE
Big Sky Solar 7	Solar	20	16	8-Dec-17	SCE
Big Sky Solar 8	Solar	20	16	8-Dec-17	SCE
Big Sky Solar 6	Solar	20	16	8-Dec-17	SCE
SCE Actual New Generation in 2017		284	229		
Total Actual New Generation in 2017		993	773		

Source: California ISO Interconnection Resources Department

1.3 Net market revenues of new gas-fired generation

Every wholesale electric market must have an adequate market and regulatory framework for facilitating investment in needed levels of new capacity. The California Public Utilities Commission's long-term procurement process and resource adequacy program are currently the primary mechanisms to ensure investment in new capacity when and where it is needed. Given this regulatory framework, annual fixed costs for existing and new units critical for meeting reliability needs should be recoverable through a combination of long-term bilateral contracts and spot market revenues.

Each year, DMM examines the extent to which revenues from the spot markets contribute to the annualized fixed cost of typical new gas-fired generating resources. This represents an important market metric tracked by all ISOs.

In 2016, DMM revised the methodology used to perform this analysis to more accurately model total production costs and energy market revenues using a SAS/OR optimization tool.⁶² We calculated incremental energy costs using default energy bids.⁶³ Commitment costs were calculated using the proxy start-up and minimum load cost methodology.⁶⁴ For a combined cycle unit, our analysis estimated energy market revenues based on day-ahead and 5-minute real-time market prices. For a combustion turbine unit, our analysis estimated energy market revenues on a generator's commitment and dispatch in the 15-minute real-time market. Our analysis evaluated hypothetical combined cycle and combustion turbine units against both NP15 and SP15 prices, independently. In 2017, the optimization horizon was changed from daily to annual. The objective of the optimization problem was revised to maximize annual net revenues subject to resource operational constraints listed in Table 1.8 and Table 1.10.

The California Energy Commission estimated that the annualized fixed costs for a hypothetical combined cycle unit were \$166/kW-yr. The analysis in this section shows that net revenues for the same combined cycle unit in the ISO may have ranged between \$30/kW-yr and \$50/kW-yr given day-ahead and real-time market conditions that existed in the ISO in 2017. Similarly, the California Energy Commission estimated that the annualized fixed costs for a combustion turbine were \$177/kW-yr. This analysis shows that net revenues for a similar combustion turbine in the ISO may have ranged between \$37/kW-yr and \$47/kW-yr for real-time market conditions that existed in the ISO in 2017.

In both cases, net revenues earned through the market fell significantly below expected fixed costs. This underscores the need for new resources necessary for reliability to recover additional costs from long-term bilateral contracts.

Hypothetical combined cycle unit

Key assumptions used in this analysis for a typical new combined cycle unit are shown in Table 1.8. Results for a hypothetical new combined cycle unit with these characteristics are shown in Table 1.7. This table also shows results from three different scenarios for a unit located in Northern California (NP15) or Southern California (SP15), separately. These scenarios show how different assumptions would change net revenues.

The hypothetical combined cycle unit was modeled as a multi-stage generating resource. A constraint was enforced in the optimization model to ensure that only one configuration could be committed, which is optimized based on the most profitable configuration during each hour of the optimization horizon.

⁶² Net revenues due to ancillary services and flexible ramping capacity have not been modeled in the optimization model. For a combined cycle unit in the ISO, average net revenues for regulation and spinning reserves were approximately \$0.9/kW-yr and payments for flexible ramping capacity were around \$0.3/kW-yr. Similarly, for a combustion turbine unit in the ISO, average net revenues for non-spinning reserve were \$2/kW-yr, while average flexible ramping payments were \$0.3/kW-yr. Therefore, ancillary service and flexible ramping revenues would have had a very small impact on the overall net revenues for both combined cycle and combustion turbine units.

⁶³ Default energy bids are calculated using the variable cost option as described in the Market Instruments Business Practice Manual version 43, pp. 203 – 207: <https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments>.

⁶⁴ Start-up and minimum load costs are calculated using the proxy cost option as described in the Market Instruments Business Practice Manual version 43, pp. 234 – 239: <https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments>. The energy price index used in the proxy start-up costs is calculated using the retail rate option, Market Instruments Business Practice Manual version 43, pp. 281 – 282: <https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments>.

The first scenario evaluated the combined cycle unit commitment and dispatch to day-ahead prices using the default energy bids. In 2017, for a unit located in NP15 with the above assumptions, net revenues were \$30/kW-yr with a 21 percent capacity factor.⁶⁵ Using the same assumptions for a hypothetical unit located in SP15, net revenues were \$39/kW-yr with a 28 percent capacity factor.

The next scenario optimized the units' commitment and dispatch instructions with day-ahead prices using default energy bids without the 10 percent adder. The adder was removed because we understand that, in practice, many resources do not include the full adder as part of their regular bidding approach. This reflects the fact that the default energy bid with the 10 percent adder may overstate the true marginal cost of a resource.⁶⁶ With the assumptions in place for 2017, net revenues for a hypothetical unit in the NP15 area were \$32/kW-yr with a 23 percent capacity factor. In the SP15 area, net revenues were \$41/kW-yr with a 31 percent capacity factor.

The third scenario used day-ahead prices and default energy bids (with the 10 percent scalar adder) to commit and start the combined cycle resource, but the dispatch in this scenario was also based on the higher of the day-ahead and 5-minute real-time prices rather than only day-ahead prices. Using this scenario for 2017, net revenues for the hypothetical unit located in the NP15 area were about \$38/kW-yr with a 27 percent capacity factor. In the SP15 area, net revenues were about \$50/kW-yr with a 34 percent capacity factor.

For 2016, the corresponding capacity factors and net revenues for each of these scenarios are shown in Table 1.7.⁶⁷ As shown in Figure 1.19, net revenues in 2017 have increased significantly in both NP15 and SP15 areas. This is because of historically high day-ahead prices on some days during 2017 which led to increased energy market revenues with only a slight increase in operating costs of the hypothetical combined cycle unit.

The California Energy Commission reports annualized fixed costs of \$166/kW-yr for a new build combined cycle resource.⁶⁸ As shown in Figure 1.19, the 2017 net revenue estimates for a hypothetical combined cycle unit in either the NP15 or the SP15 region falls substantially below these annualized fixed costs. The figure also shows that in 2017, the average net energy market revenues were about \$38/kW-yr less than the ISO's soft offer cap price (\$75.68/kW-yr) for capacity procurement mechanism (CPM).⁶⁹

⁶⁵ The capacity factor was derived using the following equation:

$$\text{Net generation (MWh)} / (\text{facility generation capacity (MW)} * \text{hours/year}).$$

⁶⁶ See Section 2.2 for further discussion on price-cost mark-up and default energy bids.

⁶⁷ For 2016, capacity factor and net revenue numbers differ from 2016 annual report because the optimization horizon has been extended to annual and now the objective function maximizes annual net revenues.

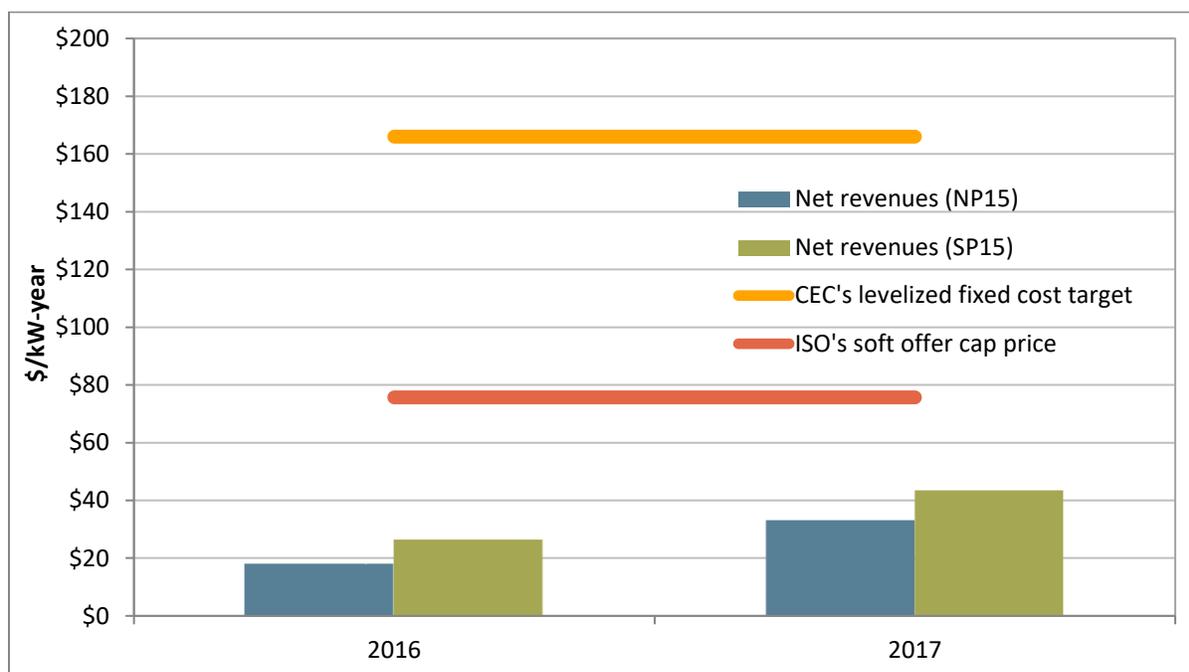
⁶⁸ Annual fixed costs are derived from California Energy Commission's *Estimated Cost of New Renewable and Fossil Generation in California* report which is published once every couple years. The annual fixed costs in this report are the average between IOU, POU and Merchant fixed costs reported in the March 2015 final staff report, Appendix E: <http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf>.

⁶⁹ More information on CPM can be found in section 43A of ISO's tariff: http://www.caiso.com/Documents/Section43A_CapacityProcurementMechanism_asof_Mar16_2018.pdf

Table 1.7 Financial analysis of new combined cycle unit (2016 – 2017)

Zone	Scenario	Capacity factor		Total energy revenues (\$/kW-yr)		Operating costs (\$/kW-yr)		Net revenue (\$/kW-yr)	
		2016	2017	2016	2017	2016	2017	2016	2017
NP15	Day-ahead prices and default energy bids	21%	21%	\$74.68	\$110.44	\$63.72	\$80.90	\$10.96	\$29.54
	Day-ahead prices and default energy bids without adder	23%	23%	\$82.61	\$115.96	\$69.98	\$84.35	\$12.64	\$31.61
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	31%	27%	\$125.17	\$140.34	\$94.62	\$102.60	\$30.55	\$37.74
SP15	Day-ahead prices and default energy bids	29%	28%	\$102.98	\$137.73	\$82.85	\$99.01	\$20.13	\$38.73
	Day-ahead prices and default energy bids without adder	32%	31%	\$111.42	\$146.14	\$89.10	\$104.83	\$22.32	\$41.31
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	36%	34%	\$139.71	\$167.09	\$102.77	\$117.19	\$36.94	\$49.90

Figure 1.19 Estimated net revenue of hypothetical combined cycle unit



We compared the hypothetical combined cycle capacity factors with existing combined cycle resources in NP15 and SP15 as a benchmark. In the NP15 area, actual capacity factors in 2017 ranged between 30 and 70 percent. In the SP15 area, actual capacity factors ranged between 11 and 50 percent. Our estimates ranged from 21 to 34 percent and were relatively low compared to actual results.

These differences in hypothetical capacity factors compared to existing resource capacity factors stem from several factors. First, the model optimally shuts the unit down if it's not economic during any hour. We noted that the hypothetical dispatch would frequently cycle resources during the midday hours when solar generation was highest and prices were lowest. This can differ from actual unit performance

as many units have a limited number of starts per day.⁷⁰ Additionally, software limitations make shut down instructions less frequent for these resources during the middle of the day because of the limited dispatch horizon used.⁷¹ This can result in a resource staying on in the midday hours even when it is uneconomic to do so. This is turn might lead to out-of-market uplift payments. Some combined cycle units may also operate at minimum load during off-peak hours instead of completely shutting down because participants may be concerned about wear and tear on units and increased maintenance costs from frequent shutting down and starting up.⁷²

⁷⁰ DMM has observed many resources with contract limitations that limit the number of starts to one per day even though there may be no technical or environmental reason for limiting the number of starts per day to this level.

⁷¹ The real-time market only sees a couple hours ahead of the current dispatch interval. This can be an issue for resources that have to honor minimum downtime constraints. DMM has observed cases where resources could turn off and honor their minimum downtime if they received the signal to shut down early enough. However, the market does not always look out far enough to give enough time for a resource to shut down and honor its minimum downtime. Our optimization model does not have this limitation.

⁷² While we have observed this in practice, we note that major maintenance adders exist to cover the costs of start-up and run hour major maintenance. Not all participants have availed themselves of these adders.

Table 1.8 Assumptions for typical new combined cycle unit⁷³

Technical Parameters	Configuration 1	Configuration 2
Maximum capacity	350 MW	500 MW
Minimum operating level	150 MW	351 MW
Heat rates (Btu/kWh)		
Maximum capacity	7,500 Btu/kWh	7,100 Btu/kWh
Minimum operating level	7,700 Btu/kWh	7,300 Btu/kWh
Variable O&M costs	\$2.40/MWh	\$2.40/MWh
GHG emission rate	0.053165 mtCO ₂ e/MMBtu	0.053165 mtCO ₂ e/MMBtu
Start-up gas consumption	1,400 MMBtu	1,400 MMBtu
Start-up time	35 minutes	35 minutes
Start-up auxiliary energy	2 MWh	1 MWh
Start-up major maintenance cost adder	\$200	\$200
Minimum load major maintenance cost adder	\$300	\$400
Minimum up time	60 minutes	60 minutes
Minimum down time	60 minutes	60 minutes
Ramp rate	13 MW/minute	13 MW/minute
Financial Parameters		
Financing costs		\$89 /kW-yr
Insurance		\$7 /kW-yr
Ad Valorem		\$9 /kW-yr
Fixed annual O&M		\$44 /kW-yr
Taxes		\$17 /kW-yr
Total Fixed Cost Revenue Requirement		\$166 /kW-yr

Hypothetical combustion turbine unit

Key assumptions used in this analysis for a typical new combustion turbine unit are shown in Table 1.10. Table 1.9 shows estimated net revenues that a hypothetical combustion turbine unit with these characteristics would have earned if it participated in the real-time energy market. This table outlines results for three scenarios that were simulated for a generator located in Northern California (NP15) and in Southern California (SP15), separately.

⁷³ Some technical parameters, such as maximum capacity, minimum operating level and heat rates, and all the financial parameters for a typical unit in this table were derived directly from the data presented in the March 2015 *Estimated Cost of New Renewable and Fossil Generation in California*, CEC Final Staff Report: <http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf>. The cost of actual new generators varies significantly due to factors such as ownership, location and environmental constraints. More detailed information can be found in the CEC report.

The remaining technical characteristics such as variable O&M, start-up parameters, minimum load parameters and ramp rate are assumed based on the technology type (GE F-class turbines) and resource operational characteristics of a typical combined cycle unit within the ISO.

Maximum number of start-up and run-hours constraint has been relaxed in the annual optimization problem.

In the first scenario, we simulated commitment and dispatch instructions the combustion turbine would receive given 15-minute prices, using default energy bids as costs. In this scenario, for a hypothetical unit located in the NP15 area and using 2017 prices, net revenues were approximately \$38/kW-yr with a 6 percent capacity factor. Similarly, in the SP15 area, net revenues were approximately \$37/kW-yr with an 8 percent capacity factor.

The second scenario assumes that 15-minute prices are used for commitment and dispatch instructions, but default energy bids less the 10 percent scalar as a measure of incremental energy costs.⁷⁴ Using this scenario the hypothetical unit in NP15 earned net revenues in 2017 that were approximately \$40/kW-yr with a 7 percent capacity factor. The hypothetical unit in SP15 earned net revenues about \$39/kW-yr with a 10 percent capacity factor.

The third scenario includes all of the unit assumptions made in the first scenario, but also includes 5-minute prices for calculating unit revenues in addition to 15-minute prices. Specifically, this methodology commits the resource based on 15-minute market prices and then re-optimizes the dispatch based on 15-minute and 5-minute market prices. As in the first scenario, default energy bids were used for incremental energy costs. Simulating this scenario in the NP15 area, net revenues were about \$44/kW-yr with a 9 percent capacity factor. In the SP15 area, net revenues were about \$47/kW-yr with a 14 percent capacity factor.

Differences in capacity factors and net revenues between NP15 and SP15 arose because of different daily gas price indices used in the calculation of default energy bids and because of local congestion in the SP15 area in 2017.

Capacity factor and net revenues for 2016 are also shown in Table 1.9.⁷⁵ As shown in Figure 1.20, net revenues for a hypothetical combustion turbine rose in 2017 when compared to 2016 because of significantly high real-time prices in both NP15 and SP15 areas.

The estimated capacity factor from the optimization model is benchmarked with actual capacity factors calculated using actual schedules from existing combustion turbine resources. In the NP15 area, actual capacity factors ranged between 2 and 7 percent, while in the SP15 area, actual capacity factors ranged between 3 and 20 percent. Our estimated capacity factors range between 6 to 14 percent and track closely with the actual numbers.

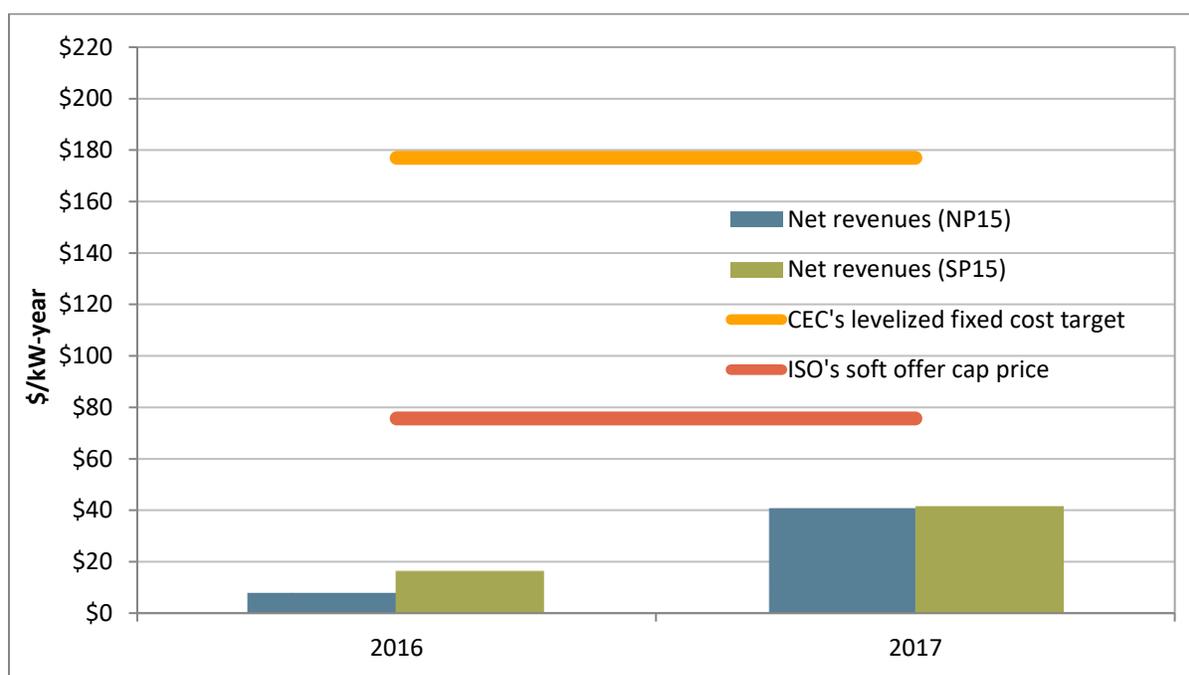
⁷⁴ As noted above, we frequently find resources that bid in excluding the full 10 percent adder in their incremental energy bids.

⁷⁵ See footnote 67.

Table 1.9 Financial analysis of new combustion turbine (2016 – 2017)

Zone	Scenario	Capacity factor		Real-time energy revenues (\$/kW-yr)		Operating costs (\$/kW-yr)		Net revenue (\$/kW-yr)	
		2016	2017	2016	2017	2016	2017	2016	2017
NP15	15-minute prices and default energy bids	4.2%	5.5%	\$22.55	\$66.53	\$17.89	\$28.41	\$4.66	\$38.12
	15-minute prices and default energy bids without adder	6%	7%	\$27.91	\$73.91	\$22.23	\$34.17	\$5.68	\$39.74
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	8%	9%	\$48.62	\$90.52	\$34.86	\$46.41	\$13.76	\$44.12
SP15	15-minute prices and default energy bids	7%	7.5%	\$40.20	\$73.15	\$27.91	\$35.79	\$12.28	\$37.36
	15-minute prices and default energy bids without adder	9%	10%	\$48.25	\$83.43	\$34.39	\$44.03	\$13.87	\$39.40
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	13%	14%	\$74.51	\$110.86	\$51.39	\$63.89	\$23.12	\$46.97

Figure 1.20 Estimated net revenues of new combustion turbine



The California Energy Commission’s estimate of annualized fixed costs for a hypothetical combustion turbine is \$177/kW-yr.⁷⁶ Figure 1.20 shows that in 2017, the estimated net revenues in both NP15 and SP15 areas fell significantly below this amount. The figure also shows that in 2017, the average net energy market revenues were about \$35/kW-yr less than the ISO’s soft offer cap price (\$75.68/kW-yr) for capacity procurement mechanism (CPM).

Findings in this section underscore the critical importance of long-term contracting as the primary means for facilitating new generation investment. Local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC resource adequacy and

⁷⁶ See Footnote 68.

long-term procurement framework. Under California’s current market design, these programs can provide additional revenue for new generation and cover the gap between annualized capital cost and the simulated net spot market revenues provided in this section.

A more detailed discussion of issues relating to capacity procurement, investment in new and existing generating capacity, and longer-term resource adequacy is provided in Chapter 10 of this report.

Table 1.10 Assumptions for typical new combustion turbine⁷⁷

Technical Parameters	
Maximum capacity	100 MW
Minimum operating level	40 MW
Heat rates (Btu/kWh)	
Maximum capacity	9300 Btu/kWh
Minimum operating level	9700 Btu/kWh
Variable O&M costs	\$4.80 /MWh
GHG emission rate	0.053165 mtCO ₂ e/MMBtu
Start-up gas consumption	50 MMBtu
Start-up time	5 minutes
Start-up auxillary energy	1.5 MWh
Start-up major maintenance cost adder	\$400
Minimum load major maintenance cost adder	\$115
Minimum up time	60 minutes
Minimum down time	60 minutes
Ramp rate	50 MW/minute
Financial Parameters	
Financing costs	\$106 /kW-yr
Insurance	\$8 /kW-yr
Ad Valorem	\$11 /kW-yr
Fixed annual O&M	\$35/kW-yr
Taxes	\$17 /kW-yr
Total Fixed Cost Revenue Requirement	\$177 /kW-yr

⁷⁷ See footnote 73 for information about technical and financial parameters. The remaining technical characteristics such as variable O&M, start-up parameters, minimum load parameters and ramp rate are assumed based on the technology type (GE LM6000 turbines) and resource operational characteristics of a typical peaking unit within the ISO.

2 Overview of market performance

The ISO markets continued to perform efficiently and competitively overall in 2017.

- Total wholesale electric costs increased by about 25 percent, driven primarily by a 27 percent increase in natural gas prices in 2017 compared to 2016. After controlling for the higher natural gas costs and changes in greenhouse gas prices, wholesale electric costs increased by about 4 percent from 2016 and have remained stable since 2013.
- Energy market prices were particularly low during the first and second quarters of 2017. Lower prices between February and May resulted in part from increased output from hydro and renewable resources in combination with relatively low loads.
- Day-ahead prices reached historic highs on a few days. On September 1, system marginal energy prices in the day-ahead market reached were greater than \$200/MWh during a four-hour period and over \$770/MWh in one hour. These high day-ahead prices reflect a tightening of supply conditions during peak ramping hours that DMM expects will continue in 2018 and the coming years.
- Prices in the 5-minute market were lower than prices in both the 15-minute and day-ahead markets, on average in each quarter of the year. This persistent pattern appears to be driven in part by systematic differences between load adjustment made by ISO grid operators in the 5-minute market compared to higher adjustments made in the 15-minute market and hour-ahead scheduling process.

Other aspects of the ISO markets contributed to increased wholesale energy costs in 2017.

- Bid cost recovery payments increased to the highest value since 2011, totaling \$108 million, or about 1 percent of total energy costs, during 2017. Total bid cost recovery payments during 2016 were about \$76 million, and had been decreasing since 2013. DMM estimates that over \$5.5 million in real-time costs is due to higher startup and minimum load bid caps provided under special measures adopted due Aliso Canyon gas storage issues. About \$7 million was awarded to a single resource which had a single daily start limitation. Bid cost recovery payments are made when the resource buying back its day-ahead schedule at high real-time prices due to the limitation preventing the unit from starting more than once per day.
- Exceptional dispatches are *out-of-market* unit commitments and energy dispatches issued by ISO grid operators to meet constraints not incorporated in the market software. Total energy resulting from all types of exceptional dispatch more than doubled between 2017 and 2016, but continued to account for a relatively low portion of total system load (0.5%). Total above-market costs due to exceptional dispatch increased 92 percent to \$20.6 million in 2017 from \$10.7 million in 2016.
- Ancillary service costs increased to \$172 million, up from \$119 million in 2016 and \$62 million in 2015. The increase in operating reserve costs was primarily driven by tight supply conditions and higher operating reserve requirements during the summer.

2.1 Total wholesale market costs

The total estimated wholesale cost of serving load in 2017 was about \$9.3 billion or about \$42/MWh. This represents an increase of about 25 percent from wholesale costs of about \$34/MWh in 2016. The increase in electricity prices was driven mainly by an increase in spot market natural gas prices of about 27 percent.⁷⁸ After normalizing for natural gas prices and greenhouse gas compliance costs, DMM estimates that total wholesale energy costs increased by about 4 percent.

A variety of factors contributed to the increase in total wholesale costs. As highlighted elsewhere in this report, conditions that contributed to higher prices include the following:

- Increased prices for natural gas, especially in Southern California;
- High temperatures and associated loads during the summer;
- Reduced supply offered into the day-ahead market;
- Increased ancillary service requirements; and
- Increased congestion during some intervals.

Figure 2.1 shows total estimated wholesale costs per megawatt-hour of system load from 2013 to 2017. Wholesale costs are provided in nominal terms (blue bar), and normalized for changes in natural gas prices and greenhouse gas compliance costs (gold bar). The greenhouse gas compliance cost is included to account for the estimated cost of compliance with California's greenhouse gas cap-and-trade program. The green line represents the annual average daily natural gas price including greenhouse gas compliance.

⁷⁸ For the wholesale energy cost calculation, an average of annual gas prices was used from the SoCal Citygate and PG&E Citygate hubs.

Figure 2.1 Total annual wholesale costs per MWh of load (2013-2017)

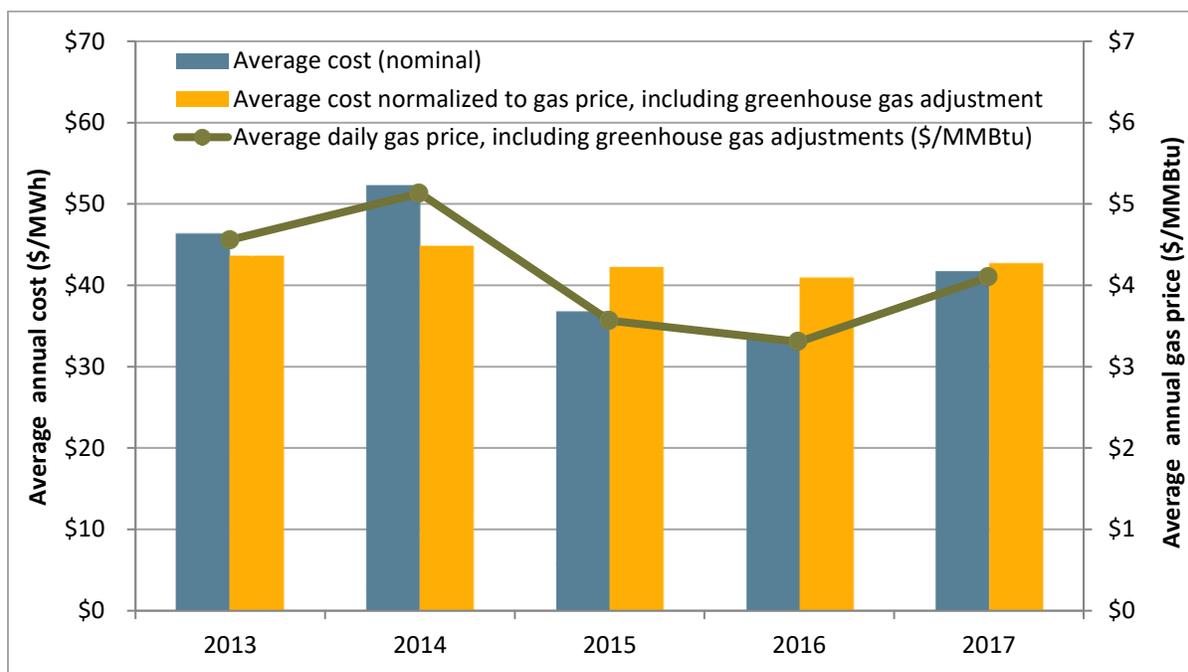


Table 2.1 provides annual summaries of nominal total wholesale costs by category from 2013 through 2017. Beginning in 2015, all total wholesale costs include costs incurred from energy imbalance market operation, in addition to totals from the ISO. The total wholesale energy cost also includes costs associated with ancillary services, convergence bidding, residual unit commitment, bid cost recovery, reliability must-run contracts, the capacity procurement mechanism, the flexible ramping constraint and product, and grid management charges.⁷⁹

As seen in Table 2.1, the increase in total cost in 2017 was primarily due to increases in day-ahead energy costs, which changed by about \$7/MWh, or roughly 22 percent from 2016. The remaining components of the wholesale energy cost, which represent a relatively small portion of total cost, changed modestly from 2016, including an increase of about \$1/MWh for real-time energy costs.

⁷⁹ A description of the basic methodology used to calculate the wholesale costs is provided in Appendix A of DMM’s 2009 Annual Report on Market Issues and Performance, April 2010, <http://www.caiso.com/2777/27778a322d0f0.pdf>. This methodology was modified to include costs associated with the flexible ramping constraint and convergence bidding. Flexible ramping costs are added to the real-time energy costs. This calculation was also updated to reflect the substantial market changes implemented on May 1, 2014. Following this period, both 15-minute and 5-minute real-time prices are used to calculate real-time energy costs. In addition, energy imbalance market costs were added to real-time energy costs beginning in 2015. Energy imbalance market costs are calculated as incremental revenue to generation in the energy imbalance market, per megawatt-hour, relative to base schedules.

Table 2.1 Estimated average wholesale energy costs per MWh (2013-2017)

	2013	2014	2015	2016	2017	Change '16-'17
Day-ahead energy costs	\$ 44.14	\$ 48.57	\$ 34.54	\$ 30.70	\$ 37.59	\$ 6.89
Real-time energy costs (incl. flex ramp)	\$ 0.57	\$ 1.98	\$ 0.69	\$ 1.03	\$ 2.01	\$ 0.98
Grid management charge	\$ 0.80	\$ 0.80	\$ 0.80	\$ 0.81	\$ 0.81	\$ 0.01
Bid cost recovery costs	\$ 0.47	\$ 0.40	\$ 0.39	\$ 0.33	\$ 0.47	\$ 0.14
Reliability costs (RMR and CPM)	\$ 0.10	\$ 0.14	\$ 0.12	\$ 0.11	\$ 0.10	\$ (0.01)
Average total energy costs	\$ 46.08	\$ 51.89	\$ 36.54	\$ 32.98	\$ 40.99	\$ 8.01
Reserve costs (AS and RUC)	\$ 0.26	\$ 0.30	\$ 0.27	\$ 0.54	\$ 0.77	\$ 0.24
Average total costs of energy and reserve	\$ 46.34	\$ 52.19	\$ 36.81	\$ 33.52	\$ 41.77	\$ 8.25

2.2 Overall market competitiveness

DMM seeks to assess the competitiveness of the ISO energy markets each year by comparing actual market prices to competitive benchmark prices we estimated would result under highly competitive conditions. DMM estimates competitive baseline prices by re-simulating the market using the day-ahead market software with bids reflecting the estimated marginal cost of gas-fired units, no convergence bids, and actual load.⁸⁰

DMM could not perform this analysis for 2017 with the software provided by the ISO due to problems with the automated inputs for the competitive scenario.⁸¹ DMM continues to work with the ISO and its software vendor to address these issues. DMM may report limited results for 2017 at a later date.

2.3 Energy market prices

This section reviews energy market prices in the ISO market area by focusing on price levels and convergence. Key points highlighted in this section include the following:

- Average energy market prices were relatively high during the second half of 2017, primarily because of high demand and increased gas prices.
- Prices in the 5-minute market were lower than prices in both the 15-minute and day-ahead markets, on average in each quarter of the year.
- Average hourly prices move in tandem with the average net load. Average hourly prices in the 15-minute market were lower than the day-ahead prices for all hours except the peak net load hours

⁸⁰ The competitive baseline is a scenario where bids for gas-fired generation are set to default energy bids (DEBs), convergence bids are removed and system demand is set to actual system load. This methodology assumes perfect load forecast, physical generation only, and competitive bidding of price-setting resources, and is calculated using DMM's version of the actual market software.

⁸¹ Beginning in late 2014, a new version of the competitive scenario was provided to DMM by the market software vendor as a standalone component in the market software. Two errors in the competitive scenario definition built into this software bias the results to such a degree that they are not reliable as a basis for assessing competitiveness.

when 15-minute prices exceed day-ahead. 5-minute market prices were lower than day-ahead and 15-minute prices in all hours except the afternoon net ramping hours.

Figure 2.2 shows average quarterly system marginal energy prices during all hours. Overall, price convergence between the day-ahead and 15-minute market increased slightly from the previous year while price convergence between the 5-minute market and other markets decreased. Other key trends include the following:

- Energy market prices were lower during the first and second quarters of 2017. Lower prices between February and May resulted from increased output from hydro and renewable resources, combined with relatively low loads. Prices increased during the summer with seasonally higher loads and higher natural gas prices which persisted through the fourth quarter.
- Average prices in the 15-minute market were lower than day-prices during the first quarter of 2017 by around \$2.40/MWh. In the remaining quarters, convergence between day-ahead and 15-minute market prices increased, particularly in comparison to previous years.
- Average prices in the 5-minute market were lower than average day-ahead and 15-minute market prices during all quarters. 5-minute market prices in the first quarter were notably low at about \$23/MWh.
- For the first time, negative system marginal prices were relatively frequent in the day-ahead market. Prices fell below zero in over 110 hours in 2017, all during midday hours in the first two quarters when solar generation was on-line. In comparison, day-ahead system marginal energy prices were negative during only three hours during all of 2016.
- Day-ahead prices reached historic highs. On September 1, system marginal energy prices in the day-ahead market reached were greater than \$200/MWh during a four-hour period and over \$770/MWh in one hour.

Figure 2.3 illustrates hourly system marginal energy prices in the day-ahead and real-time markets and average hourly net load.⁸² The prices in this figure follow the net load pattern as energy prices were lowest during the early morning, midday, and late evening hours, and were highest during the evening peak load hours. Lower prices during the middle of the day corresponded to periods when low-priced solar generation was greatest, and net demand was lowest. As additional solar generation is installed and interconnected with the system, net loads and average system prices during the middle of the day are likely to continue decreasing. This is a result of less expensive units setting prices during periods where net demand is lower, driven by more solar and other renewable generation.

⁸² Net load is calculated as actual load less generation produced by wind and solar directly connected to the ISO grid.

Figure 2.2 Average quarterly prices (all hours) – system marginal energy price

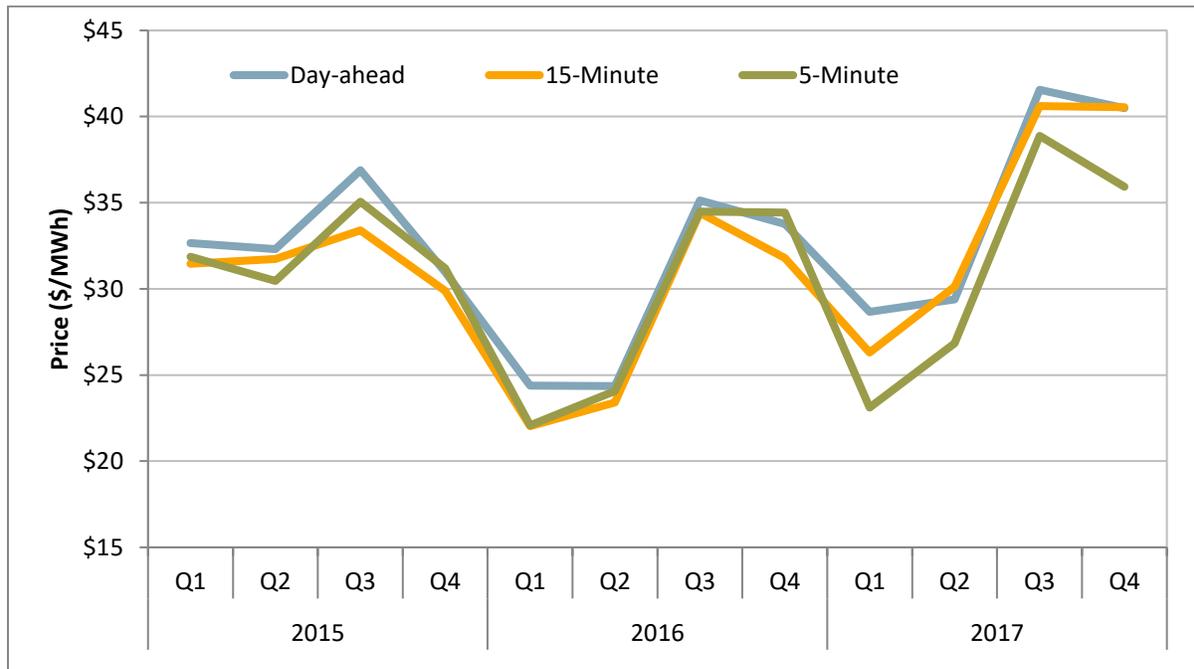


Figure 2.3 Hourly system marginal energy prices (2017)

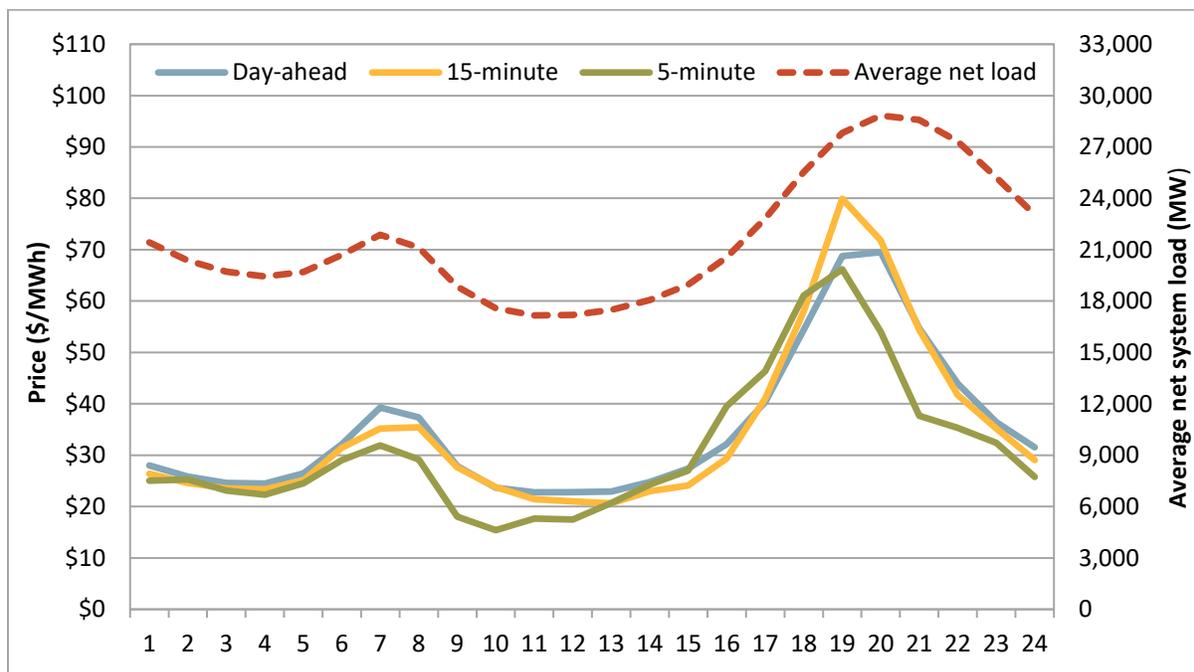


Figure 2.3 also shows that average prices in the 15-minute market were higher than day-ahead and 5-minute market prices during hours ending 19 and 20 when load net of wind and solar was typically at its highest. Under-supply infeasibilities in the 15-minute market during some of the highest load periods of the year increased prices in the 15-minute market.

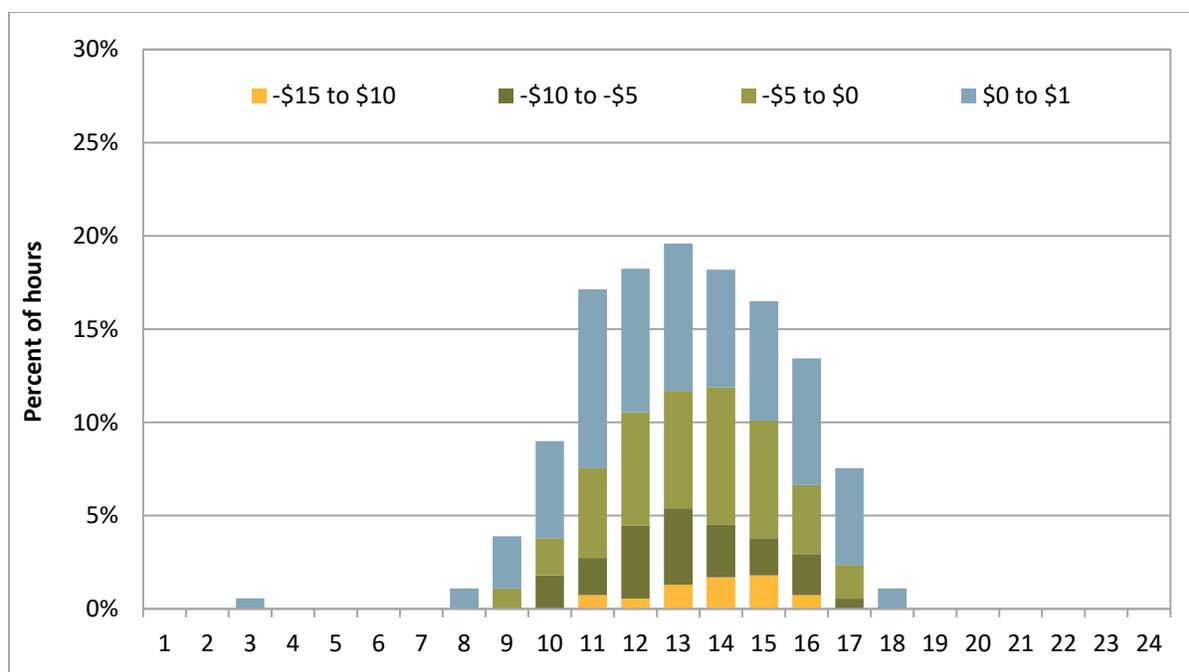
Negative day-ahead market prices

Negative prices were relatively frequent in the day-ahead market in the first two quarters of 2017. There were 114 hours when day-ahead prices were negative, about 2.5 percent of all hours in the first six months of 2017. In comparison, day-ahead market system marginal energy prices were negative during only three hours during all of 2016. More frequent negative prices in the day-ahead market were the result of additional installed renewable capacity and additional generation from hydro resources.

Figure 2.4 shows the frequency of negative prices near or below \$0/MWh in the day-ahead market by hour during the first six months of 2016. Negative prices in the day-ahead market occurred during midday hours beginning in late February through mid-June, when solar generation was greatest and loads were seasonally mild. During the first six months, day-ahead prices were negative during around 10 percent of hours between hours 11 through 15. Negative prices occurred more frequently on weekends when loads were lower.

During the majority of hours that day-ahead prices were negative, prices in the real-time market continued to be more negative. Negative prices in the day-ahead market during the first two quarters reflected real-time prices.

Figure 2.4 Hourly frequency of day-ahead prices near or below \$0/MWh (January – June)



High load and price days during the summer

The ISO market experienced system-wide heat waves and associated high loads towards the end of June, the beginning of August and at the end of August continuing into early September. Within these periods, the day-ahead market experienced record high system marginal energy prices greater than \$250/MWh when loads net of wind and solar were highest. On June 21, day-ahead market prices peaked at around \$609/MWh for hour ending 20. Then on September 1, day-ahead market prices reached \$770/MWh for hour ending 19.

On June 21, there was a downward shift in supply bids in the day-ahead market during these peak hours due to a number of factors, compared to prior days. These factors include changes in variable energy resource forecasts, outages, imports and virtual supply. The combination of these factors resulted in a thinner bid stack during a period with already stressed conditions due to the heat. For hour ending 20, there were around 2,500 MW fewer incremental bids from these sources at or below \$100/MWh than on the previous day.

On August 1, there was a similar downward shift in the quantity of supply bids in the day-ahead market in the peak net load hours from the previous day. In particular, there was a significant downward shift in the quantity of imports offered in the day-ahead market. Between July 30 and August 1, imports offered in the day-ahead market decreased by over 5,500 MW. During these days, temperatures and loads across the west were extremely high leading to increased demand in western market outside of the ISO and reduction of intertie bids into the ISO. In addition, wind and solar forecasts were lower going into August 1 along with a significant downward shift in virtual supply bids.

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

2.4 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 directly after the day-ahead market and procures sufficient capacity to bridge the gap between the amount of physical supply cleared in the day-ahead market and the day-ahead forecast load. Capacity procured through residual unit commitment must be bid into the real-time market.

In 2014, the ISO introduced an automatic adjustment to residual unit commitment schedules to account for differences between the day-ahead schedules of participating intermittent resource program (PIRP) resources and the forecast output of these renewable resources. This adjustment reduced residual unit commitment procurement targets by estimating under-scheduling of bid-in renewable resources in the day-ahead market.

ISO operators are able to increase the amount of residual unit commitment requirements for reliability purposes. These operator adjustments increased in 2017 compared to 2016, with adjustments starting to occur from the second quarter of the year.⁸³

Total residual unit commitment volume decreased in 2017, compared to the volumes in 2016. Figure 2.5 shows quarterly average hourly residual unit commitment procurement, categorized as non-

⁸³ See Section 9.6 for further discussion on operator adjustments in the residual unit commitment process.

resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement decreased to 620 MW per hour in 2017 from an average of 762 MW in 2016.

While residual unit commitment capacity must be bid into the real-time market, only a fraction of this capacity is committed to be on-line by the residual unit commitment process.⁸⁴ Most of the capacity procured in the residual unit commitment process is from units which are already scheduled to be on-line through the day-ahead market or from short-start units that do not need to be started up unless they are actually needed in real time.

The total average hourly volume of residual unit commitment capacity was over 500 MW in each quarter of 2017 and the capacity committed to operate at minimum load averaged 97 MW each hour. This was about 14 percent increase from the capacity that was procured and committed to operate at minimum load in 2016. The primary reason for decrease in the amount of residual unit commitment volumes in 2017 can be attributed to the relatively lower amounts of cleared net virtual supply. When the market clears with net virtual supply, residual unit commitment capacity is needed to replace net virtual supply with physical supply. Only a small fraction (9 percent) of this capacity was from long-start units, which are committed to be on-line by the residual unit commitment process.⁸⁵

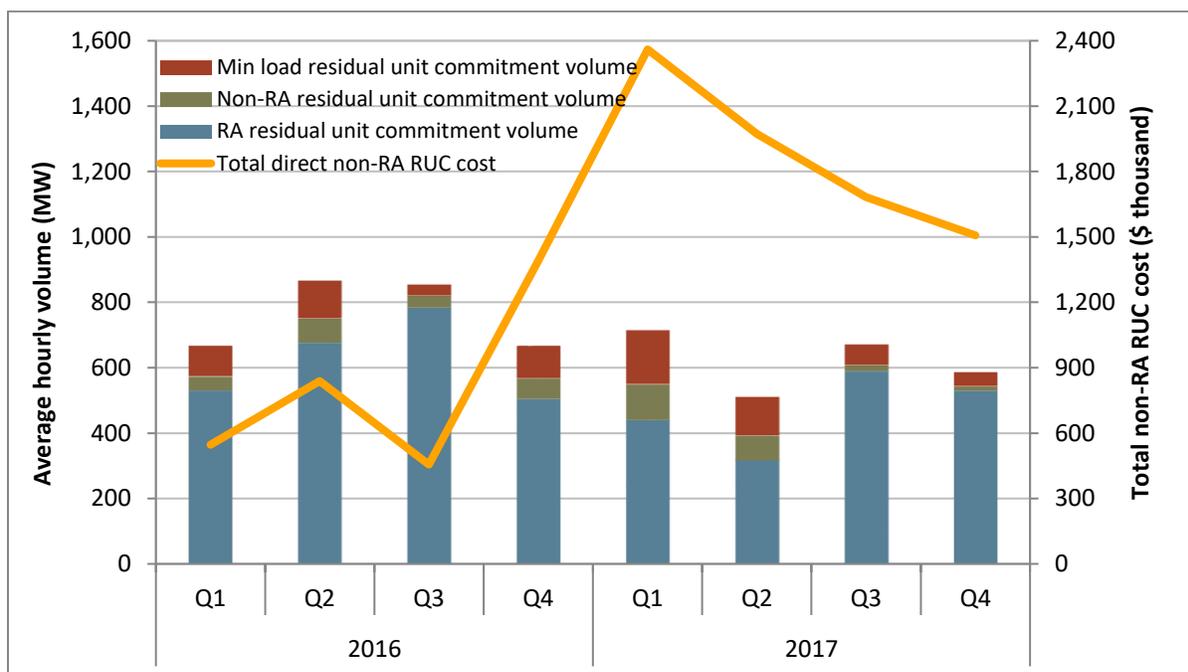
Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units committed in the residual unit commitment receive capacity payments.⁸⁶ As shown by the small green segment of each bar in Figure 2.5, the non-resource adequacy residual unit commitment averaged about 54 MW per hour in 2017, which is about the same as the volume procured in 2016. However, the total direct cost of non-resource adequacy residual unit commitment, represented by the gold line in Figure 2.5, increased to about \$7.5 million in 2017, up from a direct cost of about \$3 million in 2016.

⁸⁴ Only the small portion of minimum load capacity from *long-start units*, units with start-up times greater than or equal to five hours, is committed to be on-line in real-time by the residual unit commitment process.

⁸⁵ Long-start commitments are resources that require 300 or more minutes to start up. These resources receive binding commitment instructions from the residual unit commitment process. Short-start units receive an advisory commitment instruction in the residual unit commitment process, but the actual unit commitment decision for these units occurs in real-time.

⁸⁶ If committed, resource adequacy units may receive bid cost recovery payments in addition to resource adequacy payments.

Figure 2.5 Residual unit commitment costs and volume



2.5 Bid cost recovery payments

Generating units in both the ISO and the energy imbalance market are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit’s accepted bids. This calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment availability, day-ahead energy, and real-time energy. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch.

Figure 2.6 provides a summary of total estimated bid cost recovery payments in 2017 and 2016 by quarter and market. Estimated bid cost recovery payments for units in the ISO and energy imbalance market totaled around \$108 million, or about 1 percent of total energy costs, which was a significant increase from 2016, when bid cost recovery totaled \$76 million and highest ever since 2011.⁸⁷

The significant increase in total bid cost recovery payments in 2017 from 2016 resulted largely from a \$29 million increase in real-time market payments during the same period. Payments for residual unit commitment also increased by \$3 million in 2017 from 2016.

⁸⁷ All values reported in this section refer to DMM estimates for bid cost recovery totals.

Day-ahead bid cost recovery payments totaled \$14 million in 2017, a slight increase from \$13 million in 2016. Bid cost recovery associated with minimum on-line constraints accounted about \$4 million, a small portion of overall bid cost recovery payments in 2017, similar to the payments in 2016.⁸⁸

Real-time bid cost recovery payments were \$81 million in 2017, which was a significant increase from about \$52 million in 2016. Payments for real-time bid cost recovery for units in the energy imbalance market were included in this figure and totaled about \$12 million in 2017 compared to about \$7 million in 2016.⁸⁹ This increase can be attributed to the addition of Arizona Public Service and Puget Sound Energy in October 2016 and Portland General Electric in October 2017.

As shown in Figure 2.6, real-time bid cost recovery payments started to increase from the second quarter of 2017. In May 2017, real-time payments were over \$9 million with payments totaling more than \$1 million on May 3 and May 23. Additionally, there were several other days during the month when payments were unusually high. On May 3, the day the ISO declared a system emergency, many units committed received payments greater than \$50,000. In July 2017, these payments were over \$10 million with real-time payments totaling more than \$7 million between July 6 and July 20. Real-time bid cost recovery payments during July were higher than any other month since 2011. More than \$2 million of these real-time payments were accrued in December because of exceptional dispatches from conditions created by the wildfires in Southern California.

Out of \$81 million in real-time bid cost recovery payments, about \$7 million was awarded to a single resource which had a single daily start limitation. Bid cost recovery payments are made when the resource buying back its day-ahead schedule at high real-time prices due to the limitation preventing the unit from starting more than once per day. DMM continues to recommend the ISO review and enforce the ISO tariff requirement that unit operating limits submitted by resource owners reflect the actual physical limits of each unit.

DMM estimates that activation of gas price scalars associated with Aliso gas-electric coordination resulted in over \$5.5 million in excess uplift payments to resources using the scalar in 2017. These excess payments were estimated by calculating a counterfactual of resulting bid cost recovery payments if the resources using the scalars only bid up to their proxy cost cap calculated without any scalars.⁹⁰

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 \$16 million in 2017, compared to \$10 million in payments in 2016. Exceptional dispatches are tools that real-time operators can use to help ensure reliability across the system.⁹¹

Bid cost recovery payments for units committed through the residual unit commitment process totaled about \$13 million in 2017. This is about 12 percent of total bid cost recovery payments, up from about

⁸⁸ Minimum on-line constraints are used to meet special reliability issues that require having units on-line to meet voltage requirements and for contingencies. These constraints are based on existing operating procedures that require a minimum quantity of on-line capacity from a specific group of resources in a defined area. These constraints ensure that the system has enough longer-start capacity on-line to meet locational voltage requirements and respond to contingencies that cannot be directly modeled in the market.

⁸⁹ 2016 values differ from the \$1 million reported in the 2016 Annual Report on Market issues and performance. This value has been revised to include all participating energy imbalance market balancing areas.

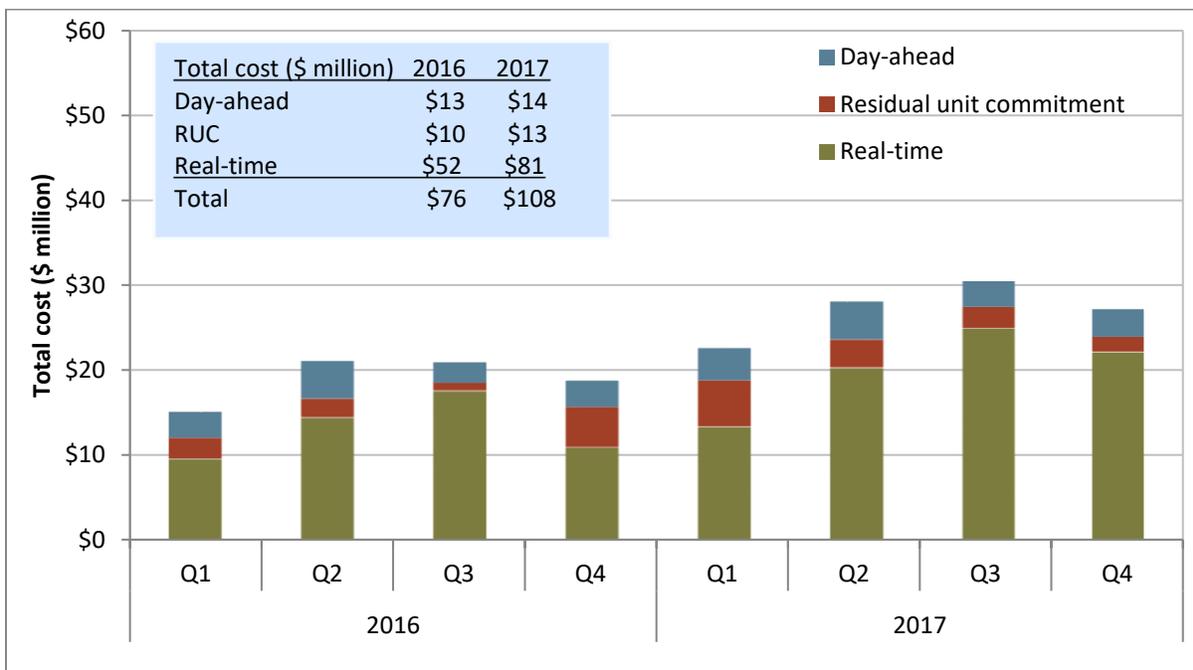
⁹⁰ Additional details on Aliso gas electric coordination provided in section 3.4 of this report.

⁹¹ Additional details regarding exceptional dispatches are covered in section 9.1 of this report.

\$10 million in 2016. About 9 million of these bid cost recovery payments were accrued during the first half of 2017.

Units committed by the residual unit commitment can be either long- or short-start units. Short-start units accounted for about \$9 million in bid cost recovery payments, while long-start unit commitment accounted for \$4 million. These totals represent all bid cost recovery payments to units committed in the residual unit commitment process and are calculated by netting residual unit commitment shortfalls with real-time surpluses in revenue.

Figure 2.6 Bid cost recovery payments



2.6 Real-time imbalance offset costs

Total real-time imbalance offset costs increased by about 50 percent in 2017 to \$79 million. Much of this increase is attributable to a \$49 million increase in real-time imbalance energy offset costs. Congestion imbalance offset costs and real time loss imbalance costs both fell in 2017.

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

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

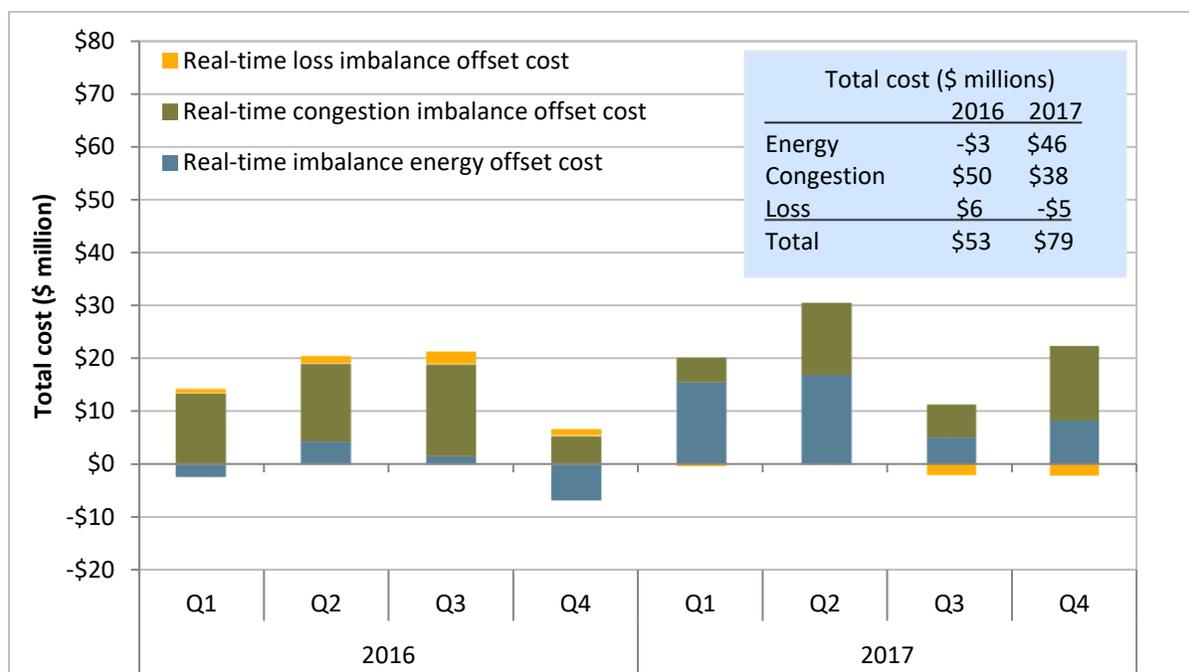
charge. Any remaining revenue imbalance is recovered through the *real-time imbalance energy offset charge* (RTIEO).

Real-time imbalance costs for energy, congestion, and losses totaled \$79 million in 2017, compared to \$53 million in 2016.⁹² As seen in Figure 2.7, the increase in total imbalance offset costs was attributable to an increase in the real-time imbalance energy offset costs, which increased to \$46 million in 2017 from -\$3 million in 2016. Real-time loss imbalance offset costs decreased in 2017.

Real-time energy imbalance offset cost can occur when 15-minute prices exceed 5-minute prices. This is because metered load imbalance is settled on a load-weighted average of 15-minute and 5-minute prices, but metered generation imbalance is settled at the 15-minute price based on instructed dispatch in the 15-minute market and at the 5-minute price for the difference between metered and 15 minute schedules. Settlement of these intervals can result in real-time imbalance energy offset costs allocated to measured demand. There were 10 days in 2017 where the real-time energy imbalance offset costs exceeded \$1 million dollars, typically on days with very high load.

Real-time congestion imbalance offset costs fell to \$38 million in 2017 from \$50 million in 2016. Real-time loss imbalance offset costs declined in 2017 to -\$5 million from \$6 million in 2016.

Figure 2.7 Real-time imbalance offset costs



⁹² Values reported here are the most current reported settlement imbalance charges, and are subject to change.

3 Real-time market volatility and flexibility

Real-time prices tend to experience periods of volatility. This price volatility is often driven by brief periods when the market software has exhausted upward and downward flexibility, and the system power balance constraint needs to be relaxed. Flexibility of resources to manage real-time market conditions is increasingly important as more variable renewable generation is integrated into the ISO system to meet state renewable generation requirements.

This chapter provides key trends relating to the performance of the real-time markets including price volatility and resource flexibility. Highlights in this chapter include the following:

- High prices in the 15-minute market were significantly more frequent in 2017 compared to the previous year. The most extreme prices in the 15-minute market were concentrated between hours ending 18 and 20 during September and October when load net of wind and solar was high. During many of these intervals, the power balance constraint was relaxed due to insufficient incremental energy (shortages). In comparison, valid shortages did not occur in the 15-minute market during 2016.
- Negative prices occurred more frequently in the 15-minute and 5-minute markets compared to the previous year as a result of a growth in installed renewable capacity and increased hydro-electric generation. Negative prices during 2017 were most frequent in midday hours between February and April when loads were modest and hydro and solar generation were greatest.
- Flexible ramping product procurement and prices are determined through demand curves, expected to be calculated from historical net load forecast errors, or the *uncertainty* surrounding ramping needs. In February 2018, DMM identified specific errors in how the flexible ramping product was implemented related to the calculation of uncertainty. Overall, these errors had a significant impact on flexible ramping procurement, prices and payments, though the direction and magnitude of the impact depends on the hour. In particular, this has resulted in under-procurement of upward flexible ramping capacity during key net load ramping intervals.
- The limited operability of the Aliso Canyon natural gas storage facility in Southern California posed a significant reliability concern in 2017. The ISO, along with several other entities including the pipeline operator, took a range of steps to mitigate these risks. The ISO modified rules by improving the accuracy of the natural gas price index used for the ISO's cost estimate used in the day-ahead market and increased bid caps in the real-time market for gas resources on the SoCalGas system.

3.1 Real-time price variability

Prices in 2017 in the 15-minute and 5-minute markets were more volatile than in 2016, particularly in the 15-minute minute market where high prices as well as negative prices were much more frequent than in the previous year.

High prices in the ISO area

The overall frequency real-time price spikes above \$250/MWh as well as the frequency of more extreme price spikes above \$750/MWh were higher in 2017 than in the previous year. During the year, most of the high prices occurred as a result of high bids in the market. In many instances, extremely high bids

cleared the market after the load bias limiter resolved an infeasibility. In other instances, power balance constraint relaxations or congestion in the system played a role in the high prices during 2017.

As shown in Figure 3.1, high prices above \$250/MWh in the 15-minute market were significantly more frequent in 2017 compared to the previous year. Prices in the 15-minute market rose above \$250/MWh in around 0.6 percent of intervals, compared to around 0.3 percent of intervals in 2016. Similarly, the frequency of more extreme 15-minute market prices larger than \$750/MWh increased to almost 0.4 percent of intervals from less than 0.1 percent of intervals in the previous year. The more extreme prices in the 15-minute market were concentrated between hours ending 18 and 20 during September and October when load net of wind and solar was high. During many of these intervals, the power balance constraint was relaxed due to insufficient incremental energy (shortages).

Figure 3.2 shows the frequency of positive price spikes above \$250/MWh in the 5-minute market. The frequency of high prices greater than \$750/MWh were also more frequent in 2017, during about 0.6 percent of intervals compared to around 0.4 percent of intervals in 2016.

When there is no congestion between balancing areas, prices in the energy imbalance market tend to reflect overall system conditions. As the market optimization dispatches higher cost generation to meet system needs or relaxes the system power balance constraint because of insufficient upward ramping capacity, prices in the energy imbalance market can similarly be set near the high system price if transfer limits do not bind. As a result, many of the price spikes illustrated in Figure 3.1 and Figure 3.2 are also in the energy imbalance market, particularly with balancing areas with large transfer capacity.

Figure 3.1 Frequency of positive 15-minute price spikes (ISO LAP areas)

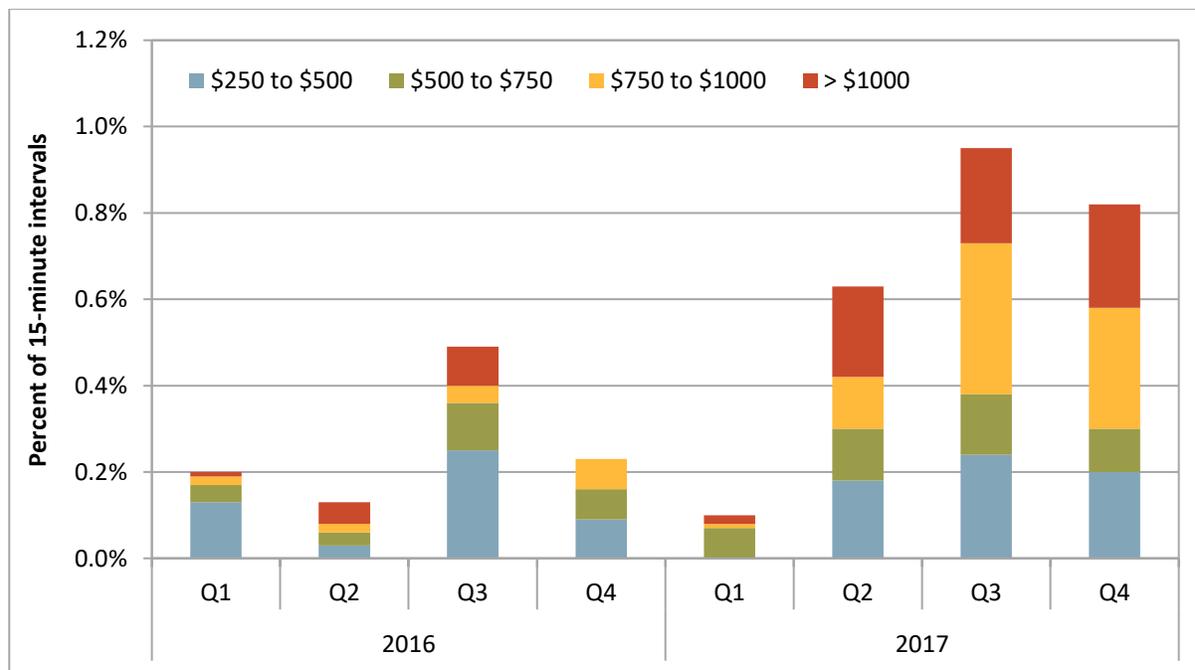
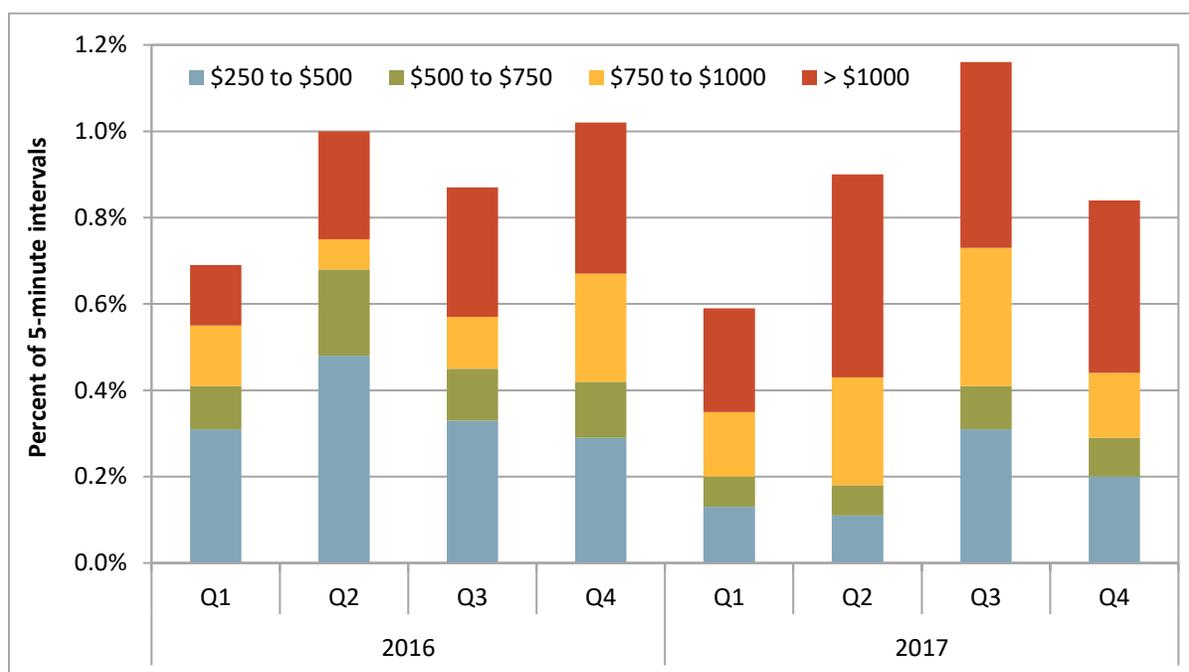


Figure 3.2 Frequency of positive 5-minute price spikes (ISO LAP areas)

Negative prices in the ISO area

When a generator is dispatched down economically the market arrives at a solution by matching supply and demand. Units with negative bids can be dispatched down accordingly. During these intervals the market continues to function efficiently and the least expensive generation serves load, while more expensive generation is dispatched down.

Figure 3.3 and Figure 3.4 shows the frequency of negative prices in the 15-minute market and 5-minute market by quarter. Negative prices occurred more frequently in the 15-minute and 5-minute markets during 2017 compared to the previous year as a result of a growth in installed renewable capacity and increased hydro-electric generation. Negative prices during 2017 were most frequent in midday hours between February and April when loads were modest and hydro and solar generation were greatest. Most of the negative prices in the 15-minute and 5-minute markets were between $-\$50/\text{MWh}$ and $\$0/\text{MWh}$ and were the result of economic bids from renewable generation (mostly market participating solar resources) setting market prices.

When the supply of economic bids to decrease energy are exhausted the power balance constraint can be relaxed up to the regulation requirement to reflect the role regulation plays in balancing the system. Effective April 11, 2017, the extent to which the constraint could be relaxed for over-supply conditions was reduced to 30 MW, down from 300 MW. Past this, self-scheduled generation can be curtailed including self-scheduled wind and solar generation. However, during nearly all of the intervals in 2017 when prices were negative, the market dispatched generation down and did not have to relax the power balance constraint or curtail self-scheduled generation. During 2017, the frequency of prices near or below the $-\$150/\text{MWh}$ floor remained infrequent during around 0.1 percent of intervals, similar to the

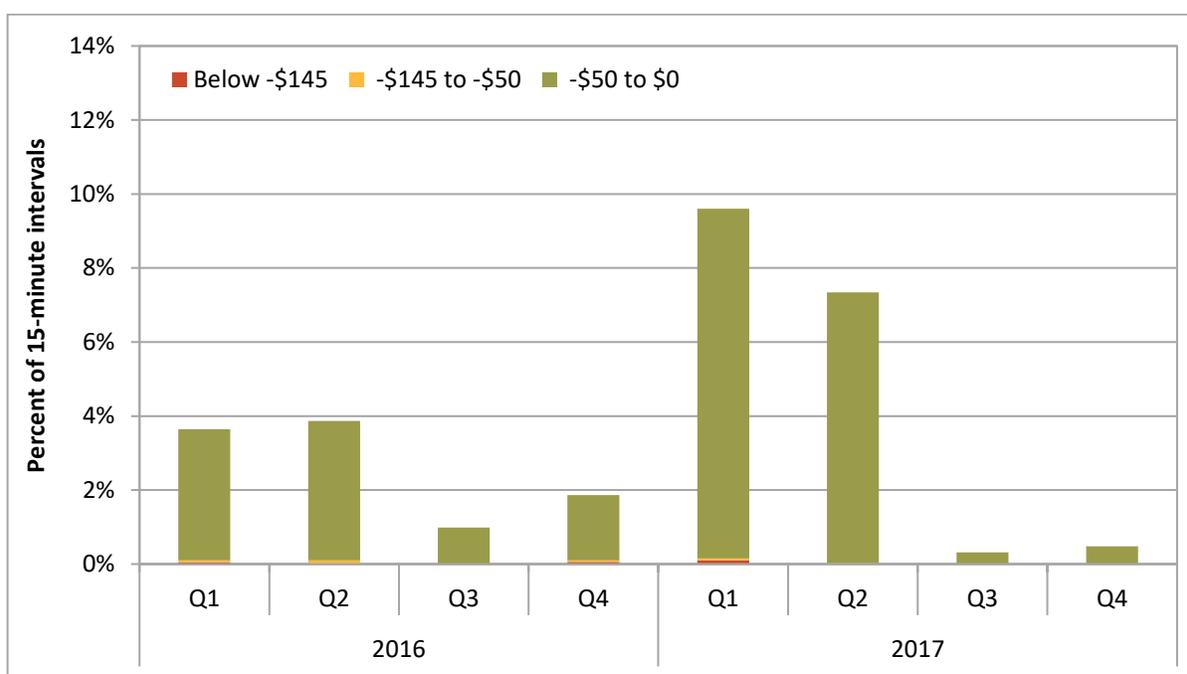
previous year. This is in part the result of bidding flexibility of renewable resources and increased transfer capability in the real-time market from the energy imbalance market.⁹³

Figure 3.5 shows the annual frequency of negative prices in the 5-minute market since 2012.⁹⁴ The overall frequency has been increasing every year since 2013 from about 2 percent of intervals in 2013 to almost 7 percent of intervals in 2017. The increase in negative prices largely reflects a growth in installed renewable generation, particularly from solar resources, and increased hydro generation.

As noted above, prices in the energy imbalance market and in the ISO area largely converged when there was no congestion between the balancing areas. Similarly, negative 15-minute and 5-minute prices illustrated in Figure 3.3 and Figure 3.4 often encompassed energy imbalance market areas to the extent that transfer limits did not bind. See Section 3.1 for further information on transfers and congestion in the energy imbalance market.

Figure 3.6 shows the hourly frequency of negative 5-minute prices in 2013, 2015, and 2017. It shows that the majority of negative prices during 2017 occurred during midday hours when solar generation was highest and net demand was low. This is similar to 2016 and reflects a significant shift over the last five years when negatives prices were most frequent during the early morning hours and were infrequent during midday hours.

Figure 3.3 Frequency of negative 15-minute prices (ISO LAP areas)



⁹³ See Section 3.5 for further discussion on renewable bidding flexibility.

⁹⁴ The bid floor was lowered to a hard bid floor of -\$150/MWh from a soft bid floor of -\$30/MWh in May 2014.

Figure 3.4 Frequency of negative 5-minute prices (ISO LAP areas)

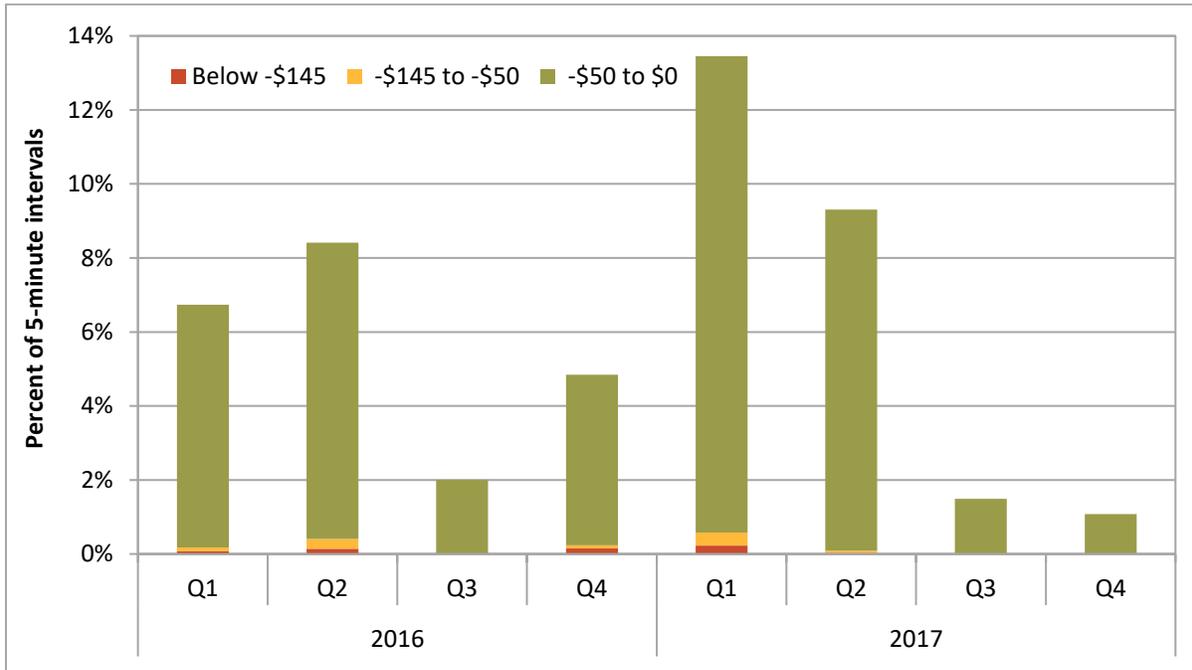


Figure 3.5 Frequency of negative 5-minute prices (ISO LAP areas)

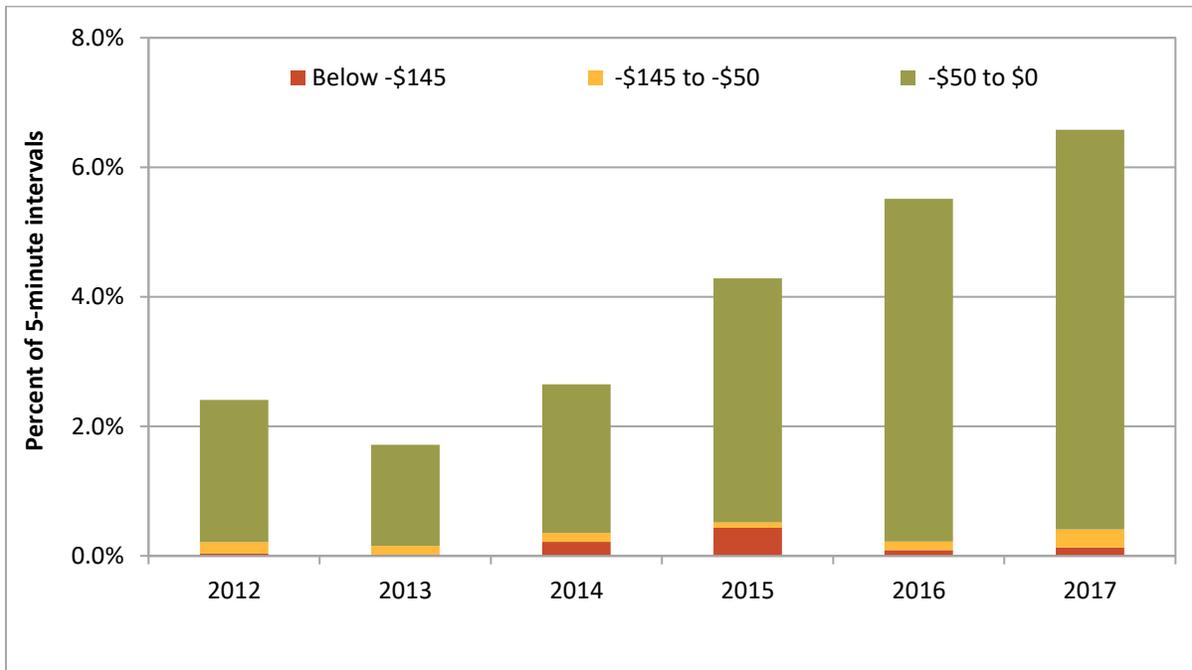
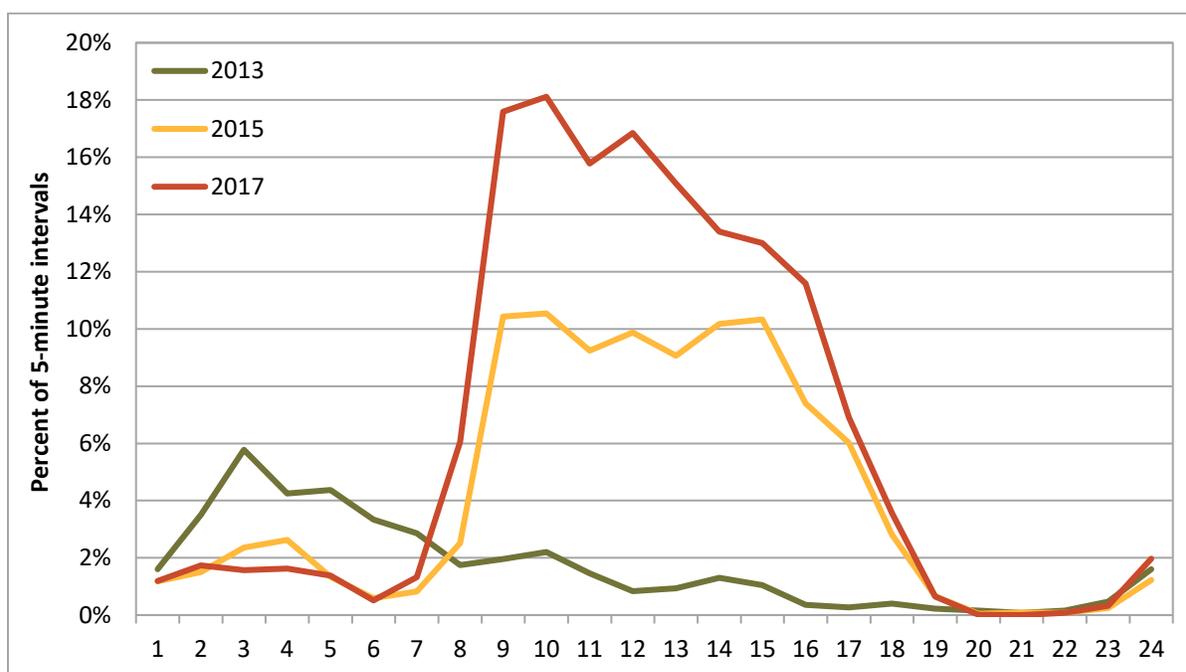


Figure 3.6 Hourly frequency of negative 5-minute prices by year (ISO LAP areas)

3.2 Power balance constraint

The ISO and energy imbalance market areas can run out of ramping capability in either the upward or downward direction to solve the real-time market solution. When this happens, it is known as a power balance constraint relaxation.⁹⁵ When this occurs, prices can be set at the \$1,000/MWh penalty parameter while relaxing the constraint for shortages (under-supply infeasibility), or the -\$155/MWh penalty parameter while relaxing the constraint for excess energy (over-supply infeasibility).

If the operator load adjustment exceeds the size of the power balance constraint relaxation and in the same direction, the size of the load adjustment is automatically reduced and the price is set by the last dispatched economic bid rather than the penalty parameter for the relaxation.

In prior quarterly and annual reports, DMM recommended that the ISO consider modifying the load bias limiter to focus on instances where power balance relaxations occur as the result of a *change* in load adjustments, rather than solely the *magnitude* of the adjustment. The ISO is currently engaged in a stakeholder process to address this change.⁹⁶

⁹⁵ A more detailed description of the power balance constraint and load bias limiter was provided in DMM's 2016 Annual Report on Market Issues and Performance, pp.101-103:
<http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf>.

⁹⁶ The Revised Draft Final Proposal on the Load Conformance Limiter Enhancement (March 14, 2018) can be found here:
<http://www.caiso.com/Documents/RevisedDraftFinalProposal-ImbalanceConformanceEnhancements.pdf>.

System power balance constraint relaxations

The conditions for the load bias limiter were met during most of the intervals when there were infeasibilities. However, during many of the under-supply infeasibilities when the load bias 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 3.7 shows the quarterly frequency of under-supply infeasibilities in the 15-minute market.⁹⁷ In concurrence with the increased frequency of higher 15-minute market price spikes, under-supply infeasibilities in the 15-minute market were relatively frequent in 2017, during about 0.2 percent of intervals before accounting for the load bias limiter. In comparison, valid under-supply infeasibilities did not occur in the 15-minute market during 2016.

Figure 3.8 and Figure 3.9 show quarterly frequency of under-supply and over-supply power balance constraint relaxations in the ISO area in the 5-minute market. While the total number of under-supply infeasibilities decreased overall before considering the load bias limiter, Figure 3.8 shows that the majority of these infeasibilities continued to be resolved by the load bias limiter. Valid under-supply and over-supply infeasibilities when the load bias limiter was not triggered occurred very infrequently during 2017 – during less than 0.1 percent of 5-minute and 15-minute intervals.

Excluding intervals that were corrected due to an underlying issue, the load bias limiter resolved around 90 percent of the undersupply infeasibilities in 2017. However, the resulting price from the unit entering the highest economic bid was often near the penalty parameter. When the load bias limiter resolved under-supply infeasibilities during 2017, system prices were greater than \$900/MWh during about 71 percent of these intervals. This outcome has often been related to economic bids by proxy demand response resources near the bid cap of \$1,000/MWh.

Relaxations because of insufficient downward supply in the 5-minute market occurred more frequently than in 2016, but remained infrequent overall. As shown in Figure 3.9, oversupply infeasibilities occurred most frequently during the first quarter, during around 0.5 percent of intervals, before accounting for the load bias limiter. In many of these intervals, significant south-to-north congestion limited the amount of available generation with downward flexibility and resulted in power balance constraint relaxations. Bidding flexibility from renewable resources and increased transfer capability from the energy imbalance market continued to contribute to reduced oversupply conditions.

⁹⁷ The power balance constraint was not relaxed due to insufficient downward capability in the 15-minute market in the ISO system during 2017.

Figure 3.7 Frequency of under-supply power balance constraint infeasibilities (15-minute market)

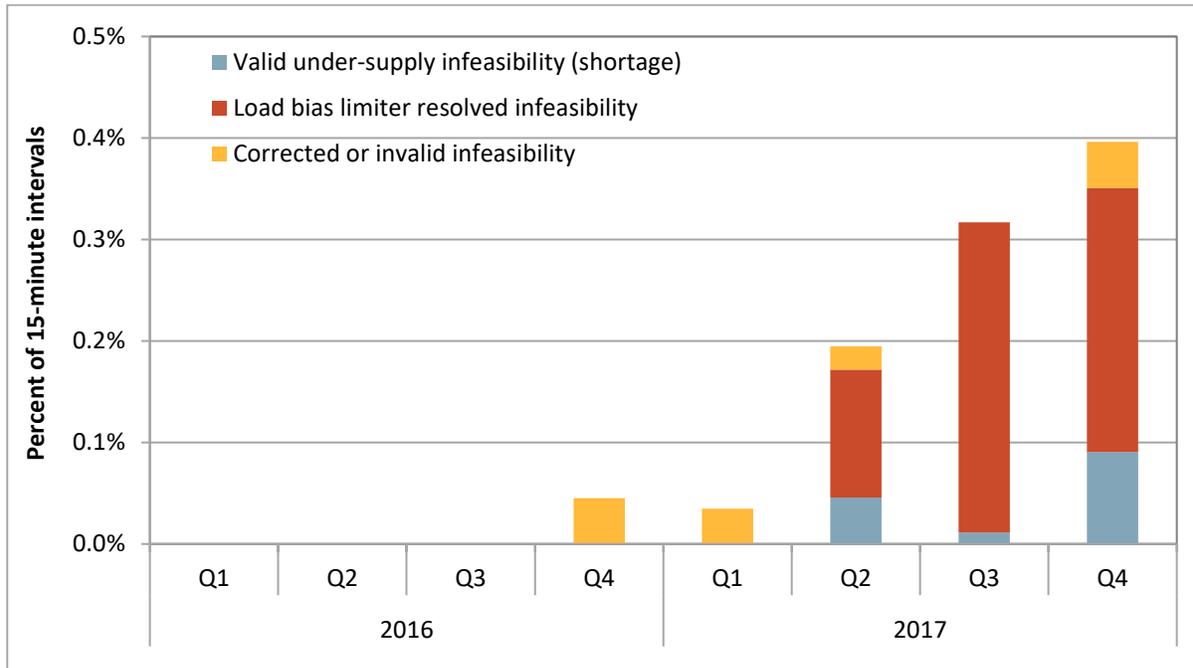


Figure 3.8 Frequency of under-supply power balance constraint infeasibilities (5-minute market)

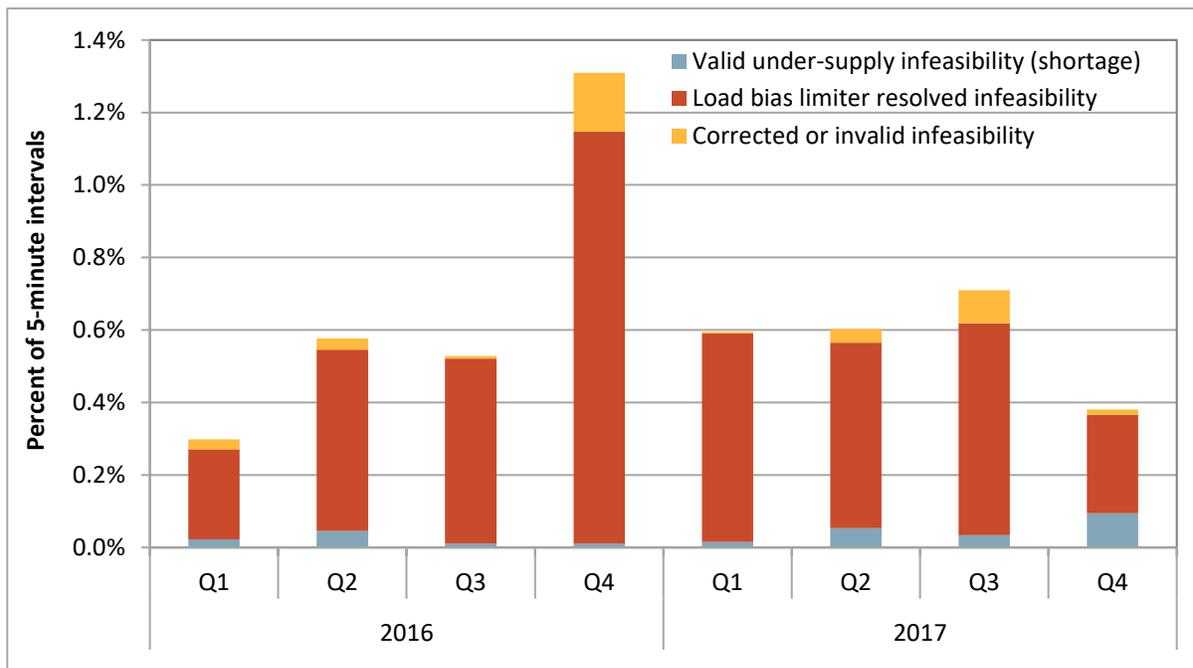
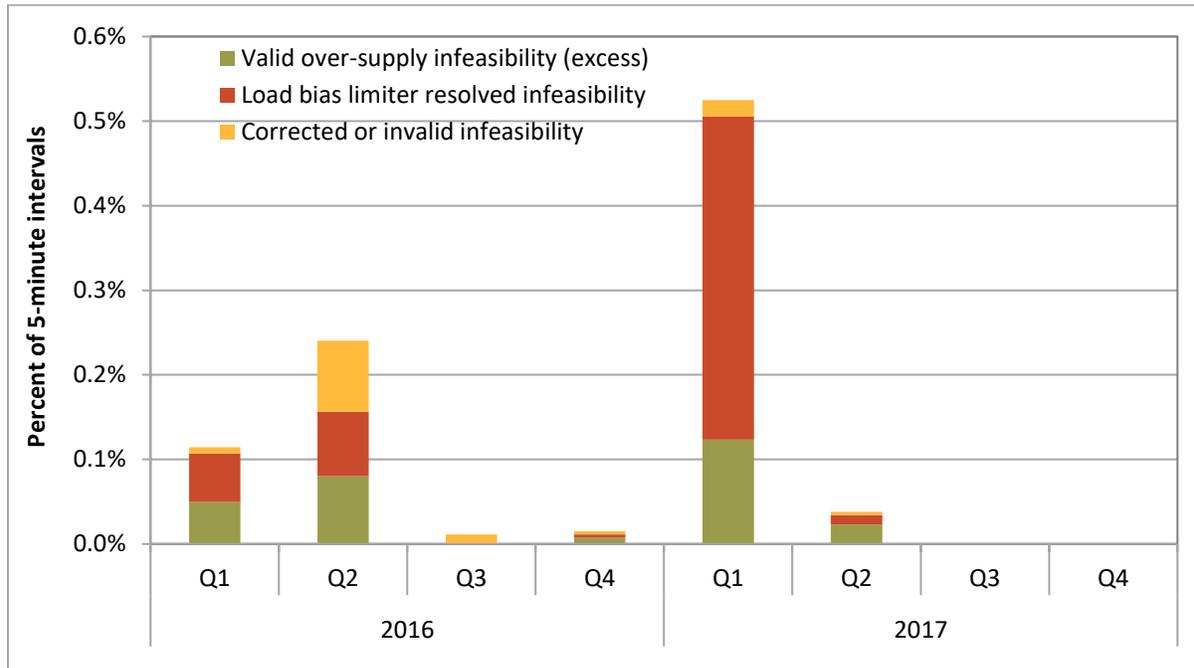


Figure 3.9 Frequency of over-supply power balance constraint infeasibilities (5-minute market)



As in prior years, most of the upward ramping shortages were very short in duration. Similar to 2016, about 83 percent of upward ramping capacity shortages in the 5-minute market during 2017 persisted for one to three 5-minute intervals (or 5 to 15 minutes). Though less infrequent overall, the duration of over-supply infeasibilities in the 5-minute market persisted for one to three 5-minute intervals in about 71 percent of instances. In the 15-minute market, about 79 percent of under-supply infeasibilities persisted for one to three 15-minute intervals (or 15 to 45 minutes).

3.3 Flexible Ramping Product

Background

The ISO implemented a new market feature in November 2016 for procuring real-time flexible ramping capacity known as *the flexible ramping product*. The product replaced the previous procurement mechanism called the *flexible ramping constraint*.

This new 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.

Further, 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.

Uncertainty calculation implementation issues

Flexible ramping product procurement and prices are determined through demand curves, expected to be calculated from historical net load forecast errors, or the *uncertainty* surrounding ramping needs. In February 2018, DMM identified specific errors in how the flexible ramping product was implemented related to the calculation of uncertainty.⁹⁸ The most significant of these errors is described below.

- The net load errors in the hourly historical distributions were intended to be calculated as the difference between (1) the binding net load forecast for the next interval and (2) the first advisory net load forecast for the same corresponding time interval from the prior market run.
- However, when the flexible ramping product was implemented, the net load error calculation was instead based on the difference between the binding and advisory interval in the same market run between two sequential time intervals, or the negative of the expected change in net load.

By calculating uncertainty in this manner (between sequential time intervals), the result systematically biased flexible ramping capacity procurement and prices in the direction opposite of the net load ramp (down when net load is ramping up and vice versa). Overall, this error had a significant impact on flexible ramping procurement, prices, and payments, though the direction and magnitude of the impact depends on the hour. In particular, this has resulted in under-procurement of upward flexible ramping capacity during key net load ramping intervals.

DMM recalculated the uncertainty requirements using the correct methodology and data. DMM believe that these corrected uncertainty requirements are highly consistent with what the uncertainty requirements would have been had the flexible ramping product been implemented as designed.

Figure 3.10 and Figure 3.11 show corrected average hourly uncertainty requirements for the 5-minute market and 15-minute market, respectively. The blue lines show the corrected upward and downward system-level uncertainty requirements between March and December 2017, pulled from recalculated hourly distributions of net load errors during 2017. For comparison, the green lines show average hourly uncertainty requirements used in the market by the ISO during the same period. The upward uncertainty requirements are depicted by the upper lines while the downward uncertainty requirements are depicted by the lower lines. The uncertainty requirements used in the market are capped at zero megawatts at one end and at the uncertainty thresholds at the other.⁹⁹

During hours when the corrected uncertainty requirements were larger in magnitude than the implemented uncertainty requirements, flexible ramping capacity procurement was typically expected

⁹⁸ For more detailed information on the individual implementation issues and the impact of these errors, see DMM's special report: Flexible Ramping Product Uncertainty Calculation and Implementation Issues, April 18, 2018: <http://www.caiso.com/Documents/FlexibleRampingProductUncertaintyCalculationImplementationIssues.pdf>.

⁹⁹ Uncertainty requirements are capped by uncertainty thresholds, designed to prevent extreme outlier or erroneous net load errors from impacting the uncertainty requirement and associated market outcomes. During 2017, these values were unchanged from values used since the implementation of the flexible ramping product and were binding more frequently than expected. The ISO updated the thresholds in April, 2018 and has submitted language for the BPM to evaluate the thresholds periodically.

to be higher. As shown in Figure 3.10, upward uncertainty requirements in the 5-minute market were expected to be around 270 MW higher on average between hours ending 15 and 18, hours in which power balance shortages have occurred more often. Downward uncertainty requirements were expected to be larger by around 120 MW on average during morning hours ending 8 through 12 when solar generation is ramping up. In other hours, the incorrect uncertainty calculation resulted in higher than expected uncertainty requirements – which would tend to cause inefficiently higher ramping capacity procurement and prices.

As illustrated in Figure 3.11, the implementation issues had a similar impact on the uncertainty requirement in the 15-minute market. In particular, 15-minute market upward uncertainty requirements would have been around 460 MW higher on average between hours ending 15 and 19 had the flexible ramping product been implemented as designed.

Systematic under-procurement of flexible ramping capacity during key upward and downward net load ramping hours may have increased the frequency of power balance constraint violations. However it is not possible to determine whether any particular power balance violation would have been resolved had the flexible ramping product been implemented as designed.

In February 2018, the ISO corrected the net load error distributions so that uncertainty was based on an advisory and binding net load in the same time-interval. These distributions were used in the market to calculate the uncertainty requirements and demand curves beginning February 22, 2018.

Figure 3.10 Average hourly 5-minute market system-level uncertainty requirements (March – December, 2017)

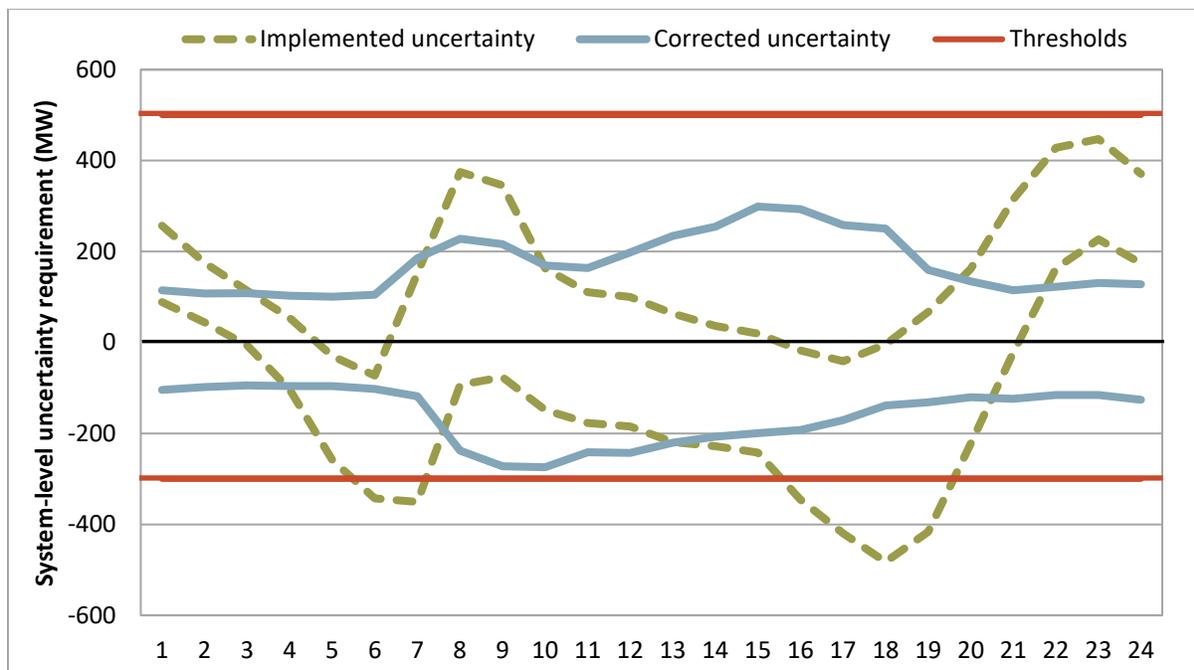
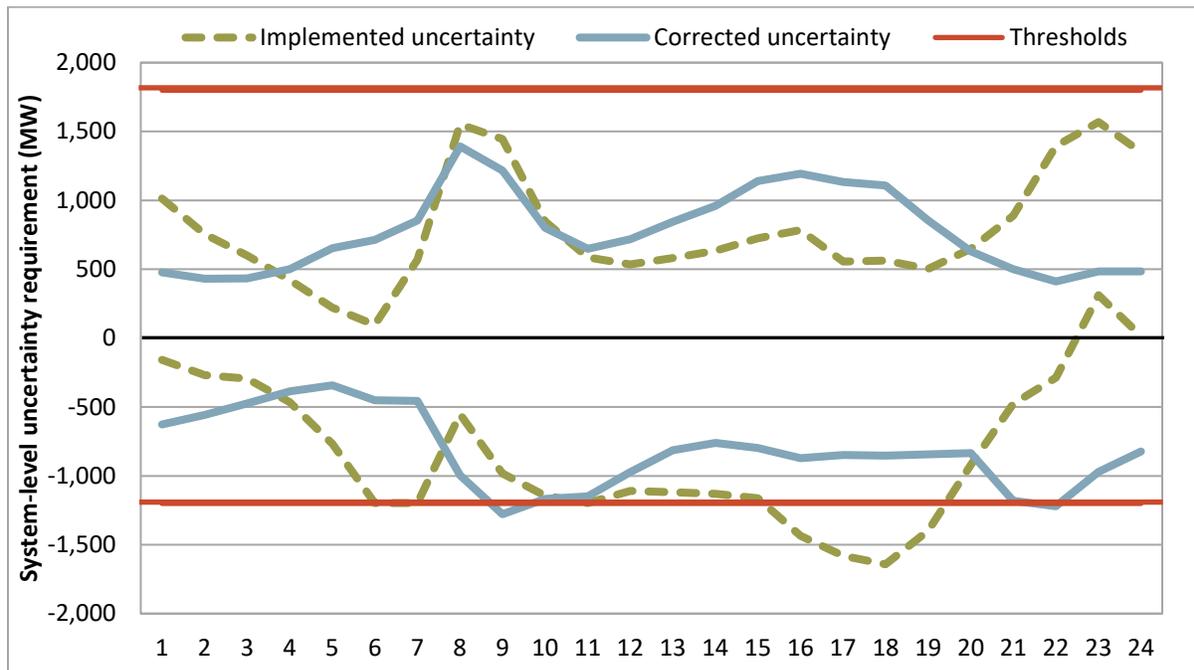


Figure 3.11 Average hourly 15-minute market system level uncertainty requirements (March – December, 2017)



Other implementation issues

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

On July 13, 2017, an adjustment was made to limit the use of flexible ramping product demand curves from individual balancing areas when sufficient transfer capability connected the area with system conditions. However, since this adjustment was made, resources providing flexible ramping capacity to meet system-level flexibility needs have often received lower payments based on the area-specific demand curve rather than the system-level demand curve though sufficient transfer capacity was present.¹⁰⁰ A fix for the issue went into production effective April 4, 2018.

The ISO has also identified an issue related to the deliverability of flexible ramping product procurement. The concern being the potential for system-level flexible ramping capacity procurement external to the ISO to be stranded behind energy imbalance market transfer constraints when prices in the ISO and surrounding areas are extremely high and in need of flexible ramping capacity. The ISO

¹⁰⁰ For additional information on this pricing issue, see *DMM’s Q3 2017 Report on Market Issues and Performance*, December 2017, pp. 49-52: <http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf>.

discussed a proposed enhancement to resolve the issue at the Market Surveillance Committee meeting on February 2, 2018.¹⁰¹

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.¹⁰²

Figure 3.12 shows the total net payments to generators for flexible ramping capacity from the flexible ramping product by month and balancing area.¹⁰³ This includes the total net amount paid for upward and downward flexible ramping capacity in both the 15-minute and 5-minute markets. Payments for forecast movements are not included.

Total net payments to generators in the ISO and energy imbalance market areas for providing flexible ramping capacity in 2017 were about \$25 million. However, monthly total payments decreased during the year from around \$3 million per month between January and May to around \$1.4 million between June and December.

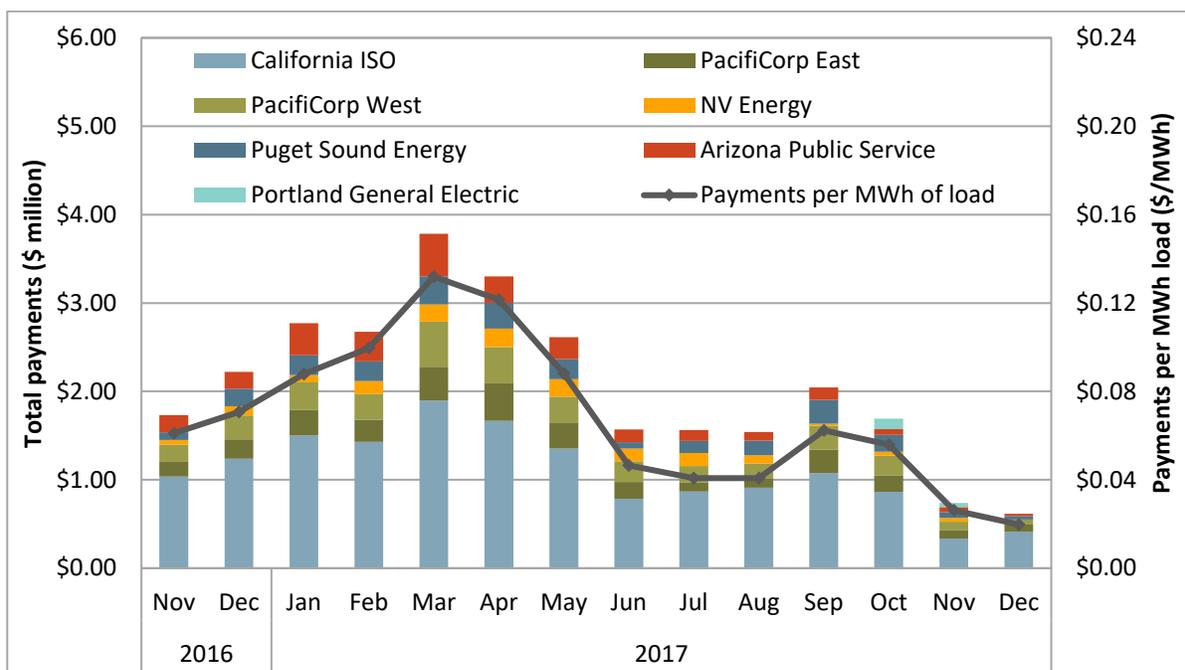
Although flexible ramping payments increased with the implementation of the flexible ramping product, payments per megawatt-hour of load remained low. Average net payments per megawatt-hour of load were about \$0.07/MWh during 2017. For comparison, payments for ancillary services in the ISO were about \$0.75/MWh of load during the same time period.

¹⁰¹ Market Surveillance Committee Flexible Ramping Product Performance Discussion, February 2, 2018, slides 5-7: <http://www.caiso.com/Documents/Presentation-FlexibleRampingProductPerformanceDiscussionFeb22018.pdf>.

¹⁰² 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>.

¹⁰³ 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.

Figure 3.12 Monthly flexible ramping payments by balancing area



3.4 Aliso Canyon gas-electric coordination

Following a significant natural gas leak in late 2015, the injection and withdrawal capabilities of the Aliso Canyon natural gas storage facility in Southern California were severely restricted. These restrictions impacted the ability of pipeline operators to manage real-time natural gas supply and demand deviations, which in turn could have had impacts on the real-time flexibility of natural gas-fired electric generators in Southern California. This primarily impacted resources operated in the Southern California Gas Company (SoCalGas) and San Diego Gas and Electric (SDG&E) service areas, collectively referred to as the SoCalGas system.

The ISO, Los Angeles Department of Water and Power, California Energy Commission and California Public Utilities Commission published a risk assessment and technical report in April 2016. The report indicated that the limited operability of the Aliso Canyon storage facility posed a significant risk to electric reliability during the summer months of 2016.¹⁰⁴ To address these reliability concerns, these agencies took many steps to manage system conditions, including the ISO, which filed for FERC approval

¹⁰⁴ *Aliso Canyon Risk Assessment Technical Report*, April 5, 2016: http://www.energy.ca.gov/2016_energy_policy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf.

for several temporary tariff amendments in May 2016.¹⁰⁵ These tariff amendments were approved by FERC on June 1, 2016, and remained in effect until November 30, 2016.¹⁰⁶

A follow-up risk assessment study, focusing on the 2016-2017 winter months, was published in August.¹⁰⁷ In September, FERC organized a technical conference where both the ISO and DMM discussed the effectiveness of the temporary Aliso Canyon measures.¹⁰⁸ Following these studies and discussions, the ISO in October 2016 filed for FERC approval to allow most of the tariff amendments to remain in effect through November 30, 2017.¹⁰⁹ FERC approved the extension required by the ISO on November 28, 2016.¹¹⁰

During the summer of 2017, the ISO has initiated a stakeholder process, Aliso Canyon gas-electric coordination phase 3, which proposed to extend some of the Aliso Canyon measures in perpetuity and allowing these measures to be applied both across the ISO and energy imbalance market footprint.¹¹¹ The November 28, 2017, FERC Order rejected permanent tariff provisions granting the ISO authority to implement and enforce, throughout the ISO and energy imbalance market balancing areas, maximum gas burn constraints limiting the dispatch of gas-fired generators.¹¹² However, the December 15, 2017, FERC Order extended the ISO's previously held authority to utilize the gas constraints for one additional year.¹¹³

DMM filed comments that were supportive of the ISO's filing overall, but recommended additional enhancements, which included making the update of natural gas prices for the day-ahead market permanent and the ability to update gas prices used in the real-time market based on same-day gas

¹⁰⁵ *Tariff Amendment to Enhance Gas-Electric Coordination to Address Risks Posed by Limited Operability of Aliso Canyon Natural Gas Storage Facility*, May 9, 2016:

http://www.caiso.com/Documents/May9_2016_TariffAmendment_EnhanceGas-ElectricCoordination_LimitedOperation_AlisoCanyonNaturalGasStorageFacility_ER16-1649.pdf.

¹⁰⁶ FERC order accepting tariff revisions, subject to condition, and establishing a technical conference:

http://www.caiso.com/Documents/Jun1_2016_OrderAcceptingTariffRevisions_Establishing_TechnicalConference_AlisoCanyon_ER16-1649.pdf.

¹⁰⁷ *Aliso Canyon Winter Risk Assessment Technical Report*, August 23, 2016:

http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-02/TN212913_20160823T090035_Aliso_Canyon_Winter_Risk_Assessment_Technical_Report.pdf.

¹⁰⁸ The technical conference agenda and presentations can be found here:

<https://www.ferc.gov/eventcalendar/EventDetails.aspx?ID=8413&CalType=>.

¹⁰⁹ *Filing to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility*, October 14, 2016:

http://www.caiso.com/Documents/Oct14_2016_TariffAmendment_AlisoCanyonGasElectricCoordination_Phase2_ER17-110.pdf.

¹¹⁰ FERC order accepting tariff revisions, subject to condition:

http://www.caiso.com/Documents/Nov28_2016_OrderAcceptingTariffAmendment_AlisoCanyonElectricGasCoordinationPhase2_ER17-110.pdf.

¹¹¹ Aliso Canyon gas-electric coordination phase 3 draft final proposal, July 2017:

<http://www.caiso.com/Documents/DraftFinalProposal-AlisoCanyonGas-ElectricCoordinationPhase3.pdf>

¹¹² FERC Order on Tariff Revisions - Aliso Canyon Gas-Electric Coordination Enhancements Phase 3, November 28, 2017:

http://www.caiso.com/Documents/Nov28_2017_Order_TariffRevisions-AlisoCanyonGas-ElectricCoordinationEnhancementsPhase3_ER17-2568.pdf

¹¹³ Order accepting tariff amendment to re-implement expired provisions - Aliso Canyon Gas-Electric Coordination Enhancements, December 15, 2017:

http://www.caiso.com/Documents/Dec15_2017_OrderAccepting_Re-ImplementExpiredProvisions_AlisoCanyonGas-ElectricCoordination_ER18-375.pdf

market data available each morning, rather than relying on much less effective and inaccurate tools such as the gas price scalars.¹¹⁴

Operational tools and corresponding mitigation measures

The ISO has developed a set of operational tools to manage potential gas-system limitations that allow operators to restrict the gas burn of ISO natural gas-fired generating units. The tools were implemented as a set of nomogram constraints that can be used to limit either the total gas burn or deviations in gas burn compared to day-ahead schedules. These tools were available to operators beginning June 2, 2016.¹¹⁵

In 2017, the ISO enforced these constraints on three occasions: January 23- January 26, some hours on August 3, and a few intervals on August 4. On most occasions, these constraints do not appear to have been sufficient, on their own, to limit gas burn from participating gas resources. In each case, measured gas burn was far in excess of the limit for the day due to the units used to define the nomogram limit and the effectiveness with which each gas resource could resolve the constraint. This issue was resolved in February 2018.

Additional bidding flexibility for SoCalGas resources

On July 6, 2016, the ISO implemented a mechanism to adjust the gas price indices used to calculate commitment cost caps and default energy bids in the real-time market for natural gas-fired generators on the SoCalGas system. This mechanism was implemented to allow these resources to reflect higher same-day natural gas prices and to avoid dispatch of these resources for system needs, instead of local needs, during potential constrained gas conditions in Southern California.

These changes included a 75 percent adder (or 175 percent scalar) on the fuel cost component used for calculating proxy commitment costs, and a 25 percent adder (or 125 percent scalar) on the fuel cost component of default energy bids in the real-time market.¹¹⁶ The November 28, 2017, FERC Order extended the ISO's authority to use these adders for an additional year, through November 30, 2018. The 75 percent and 25 percent adders implemented by the ISO were based on analysis presented by DMM in comments on the final Aliso Canyon gas-electric coordination proposal.¹¹⁷

Following DMM's analysis and recommendations, the ISO has decided to reduce to zero the special Aliso Canyon gas price scalars that are being applied to commitment cost and default energy bids used in the

¹¹⁴ FERC filing - Comments on Aliso Canyon Gas-Electric Coordination Phase 3 (ER17-2568), Department of Market Monitoring, October 26, 2017:

http://www.caiso.com/Documents/Oct26_2017_DMMComments-AlisoCanyonElectric-GasCoordinationPhase3_ER17-2568.pdf

¹¹⁵ Refer to *Operating Procedure 4120C SoCalGas Service Area Limitations or Outages*:

<http://www.caiso.com/Documents/4120C.pdf>.

¹¹⁶ These gas price adders are in addition to the 10 percent adder that is included in cost-based default energy bids, and the 25 percent adder that is included in the calculation for commitment cost caps.

¹¹⁷ *Comments on Final Aliso Canyon Gas-Electric Coordination Proposal*, Department of Market Monitoring, May 6, 2016:

http://www.caiso.com/Documents/DMMComments_AlisoCanyonGas_ElectricCoordinationRevisedDraftFinalProposal.pdf.

real-time market.¹¹⁸ This change went into effect in the market starting August 1, 2017. Due to constrained gas system conditions in Southern California¹¹⁹, the ISO reinstated these scalars in the real-time market on four occasions: August 4 – 8, 2017, October 23 – 25, 2017, December 7 – January 31, 2018, and February 20 – March 7, 2018.

Figure 3.13 shows same-day trade prices reported on the Intercontinental Exchange (ICE) for the SoCal Citygate during 2017 compared to the next-day average price. About 17 percent of traded volume at SoCal Citygate exceeded the normal 10 percent adder and 8 percent of the traded volume exceeded the 25 percent adder.

Figure 3.13 further shows that most of the same-day traded volume that was more than 10 percent higher than the next-day average occurred on the first trade day of the week. These trades are represented by the green bars. Same-day trades for the first trade day of the week (which is typically a Monday, unless the Monday is a holiday) are more likely to exceed the next-day average because, in the next-day market, the first day of the week is traded as a package together with the weekend. The next-day prices for these weekend packages are typically somewhat lower than for weekdays.

During the first three quarters of 2017, there was a very limited need for the increased bidding flexibility created by raising the commitment cost and default energy bid caps through these gas price scalars.¹²⁰ In the fourth quarter, high temperatures, supply disruptions caused by pipeline outages, and wildfires in Southern California caused high next-day prices, as well as significant same-day price volatility on some days, thus showing a need for increased flexibility in real-time market. However, under the ISO's current processes, gas limitations occurring during any point of an operating day cannot be reflected in scalars applied to the real-time market until the following operating day. This drawback resulted in real-time gas prices with the scalar either too low or on most days significantly higher than the prevailing same-day natural gas prices.¹²¹

As mentioned earlier, the gas price scalars were also implemented to change the merit order of gas resources on SoCalGas system. This is achieved by using a 175 percent scalar in the gas price used in calculating the commitment cost caps for these resources. The resulting commitment costs are intended to be high enough to allow Southern California resources to be committed for local reliability needs and not for system needs. However, on the days with high temperatures and wildfires in Southern California, the differential between the next-day gas price indices at SoCal Citygate and PG&E

¹¹⁸ *Comments on Aliso Canyon Gas-Electric Coordination Phase 3 Draft Final Proposal*, Department of Market Monitoring, May 30, 2017:

http://www.caiso.com/Documents/DMMComments_AlisoCanyonGas_ElectricCoordinationPhase3DraftFinalProposal.pdf

¹¹⁹ Aliso Canyon Winter Risk Assessment Technical Report 2017-18 Supplement, November 28, 2017:

http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN221863_20171128T103411_Aliso_Canyon_Winter_Risk_Assesment_Technical_Report_201718_Supp.pdf

¹²⁰ Quarterly market issues and performance reports, Department of Market Monitoring:

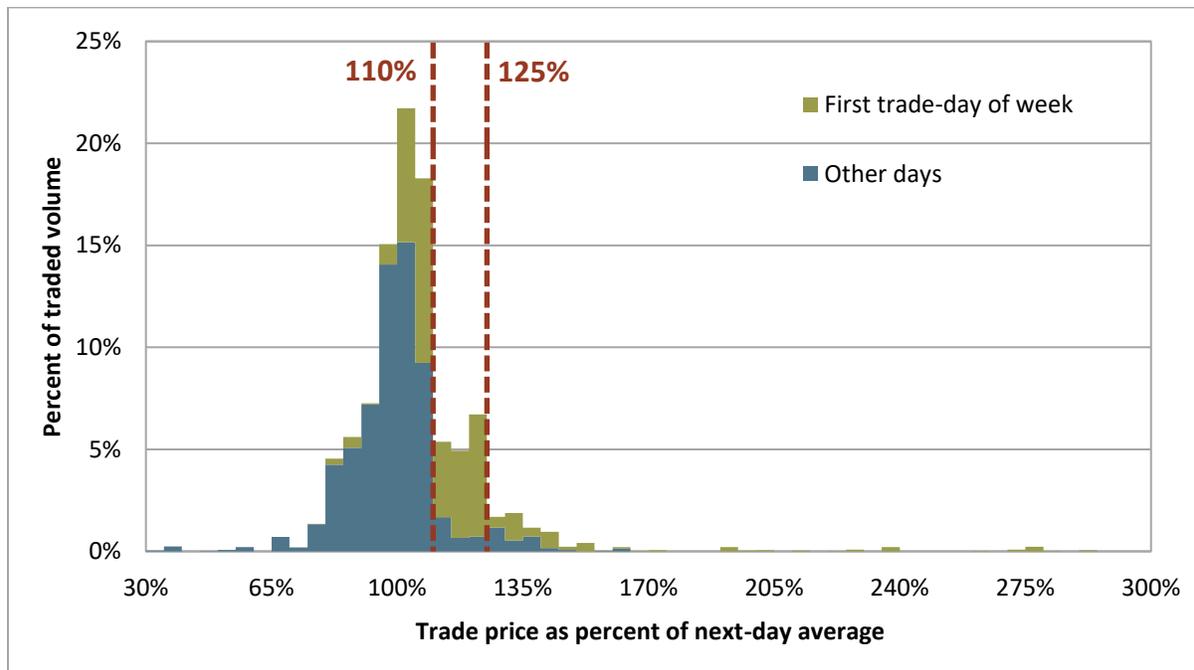
<http://www.caiso.com/Documents/2017FirstQuarterReport-MarketIssuesandPerformance.pdf>
<http://www.caiso.com/Documents/2017SecondQuarterReport-MarketIssuesandPerformance-September2017.pdf>
<http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf>

¹²¹ Evaluating the effectiveness of Aliso gas price scalars in fourth quarter of 2017, pp. 51:

<http://www.caiso.com/Documents/2017FourthQuarterReport-MarketIssues-PerformanceFebruary2018.pdf>

Citygate was sufficiently high to push SoCalGas system resources to the high end of the merit order without the need for additional scalar.¹²²

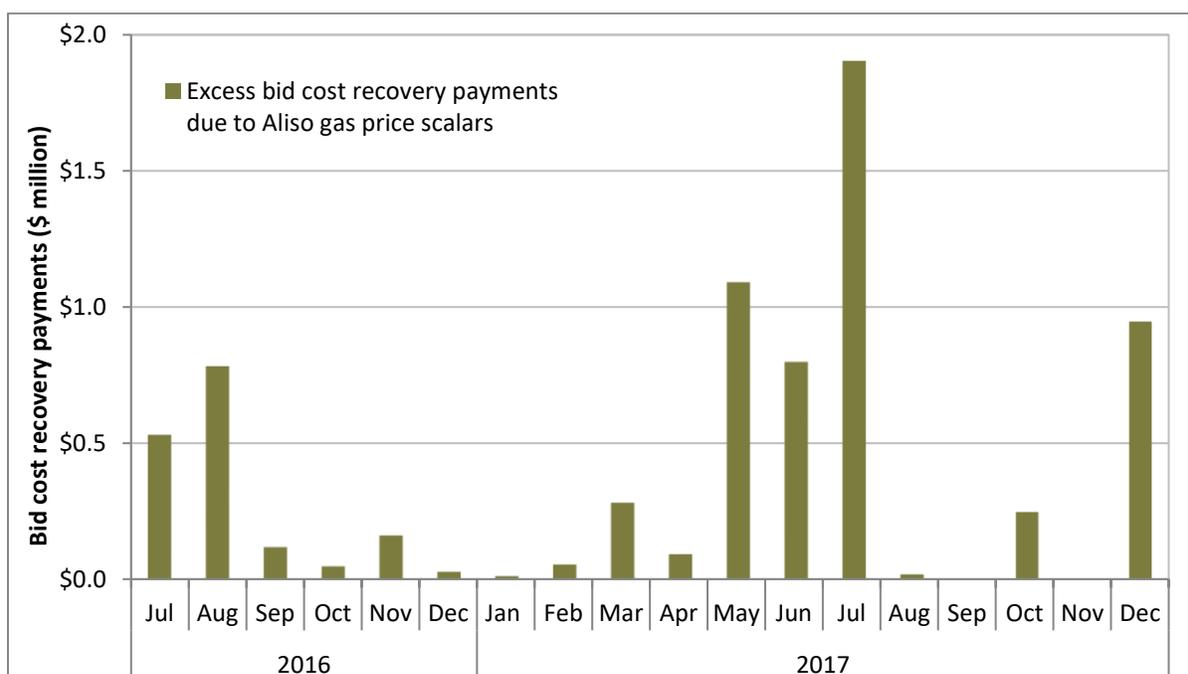
Figure 3.13 Same-day trade prices compared to next-day index (January – December)



DMM estimates that activation of the gas price scalars resulted in over \$7 million in excess uplift payments to resources using the scalar. These excess payments were estimated by calculating a counterfactual of resulting bid cost recovery payments if the resources using the scalars only bid up to their proxy cost cap calculated without any scalars. Figure 3.14 shows an estimate of monthly excess bid cost recovery payments made in the real-time market since the scalars were first activated on July 6, 2016. Total estimated payments in 2017 were about \$5.5 million. In the fourth quarter of 2017, approximately \$1 million of these payments were accrued in December, most of it during Southern California wildfires. This analysis clearly shows that having a fixed 175 percent gas price scalar in place during these days not only inflated the commitment costs that were bid into the market, without a significant impact on merit order of commitment, but also resulted in extra bid cost recovery payments to the resources utilizing the scalar.

¹²² Department of Market Monitoring update on effectiveness of Aliso gas price scalars, Market performance and planning forum, February 20, 2018 pp. 82: <http://www.caiso.com/Documents/AgendaandPresentation-MarketPerformanceandPlanningForum-Feb202018.pdf>

Figure 3.14 Monthly excess bid cost recovery payments due to gas price scalars (2016 – 2017)



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.¹²³ DMM is very supportive of this change and recommends that this be permanently extended. As part of commitment costs and default energy bid enhancements initiative, the ISO has proposed to make this a permanent measure.¹²⁴

Figure 3.15 and Figure 3.16 illustrate the benefit of using the updated natural gas price index. Figure 3.15 shows next-day trade prices reported on ICE for SoCal Citygate during 2017 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 3.15, about 9 percent of next-day trades were at a price in excess of the 10 percent adder normally included in default energy bids and 4 percent were in excess of the 25 percent headroom normally included in commitment cost bid caps.

Figure 3.16 shows the same data but compares the price of each trade to a weighted average of trades reported on ICE before 8:30 am, just before the ISO runs the day-ahead market. This represents the updated method that the ISO is currently using. As shown in Figure 3.16, about 1 percent of the traded volume exceeded the 10 percent adder included in default energy bids. An insignificant amount of

¹²³ This market modification uses weighted average price of next-day trades at SoCal Citygate before 8:30 am from Intercontinental Exchange (ICE). These are next-day trades that occur prior to the ISO beginning the day-ahead market run.

¹²⁴ Second Revised Draft Final Proposal - Commitment Costs and Default Energy Bid Enhancements, March 2018: <http://www.caiso.com/Documents/SecondRevisedDraftFinalProposal-CommitmentCosts-DefaultEnergyBidEnhancements.pdf>

volume exceeded the 25 percent adder included in the commitment cost caps. This shows that the methodology currently in place is significantly more reflective of next-day trading prices than the methodology that was in place prior to the Aliso measure.

Figure 3.15 Next-day trade prices compared to next-day index from prior day (Jan – Dec)

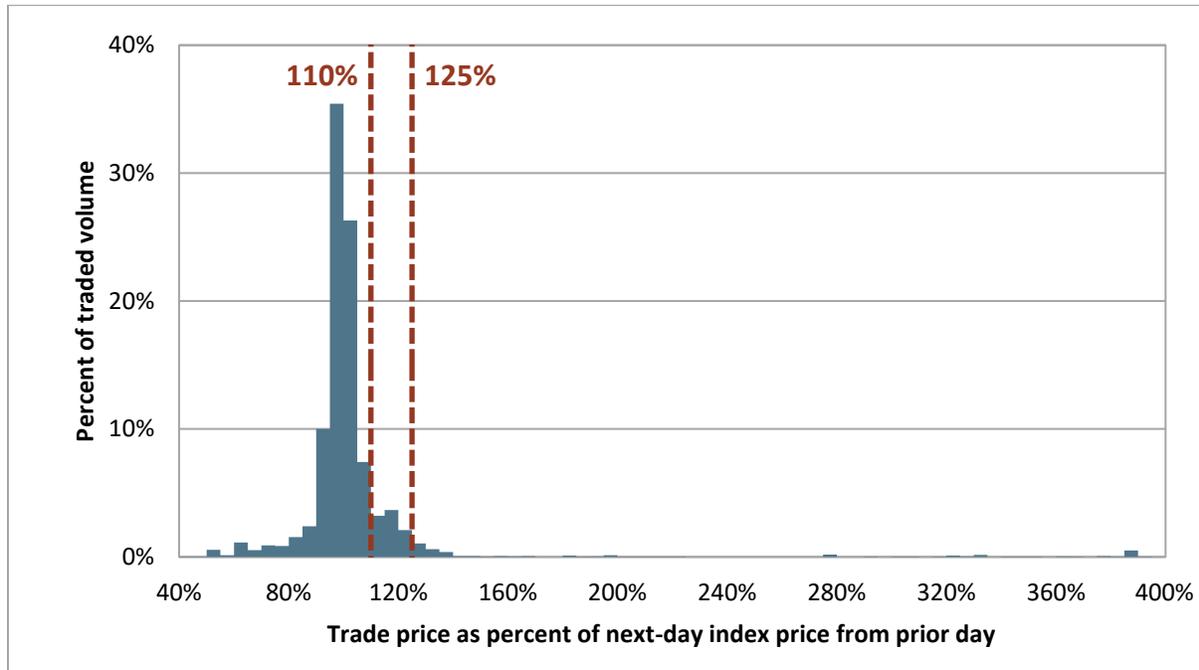
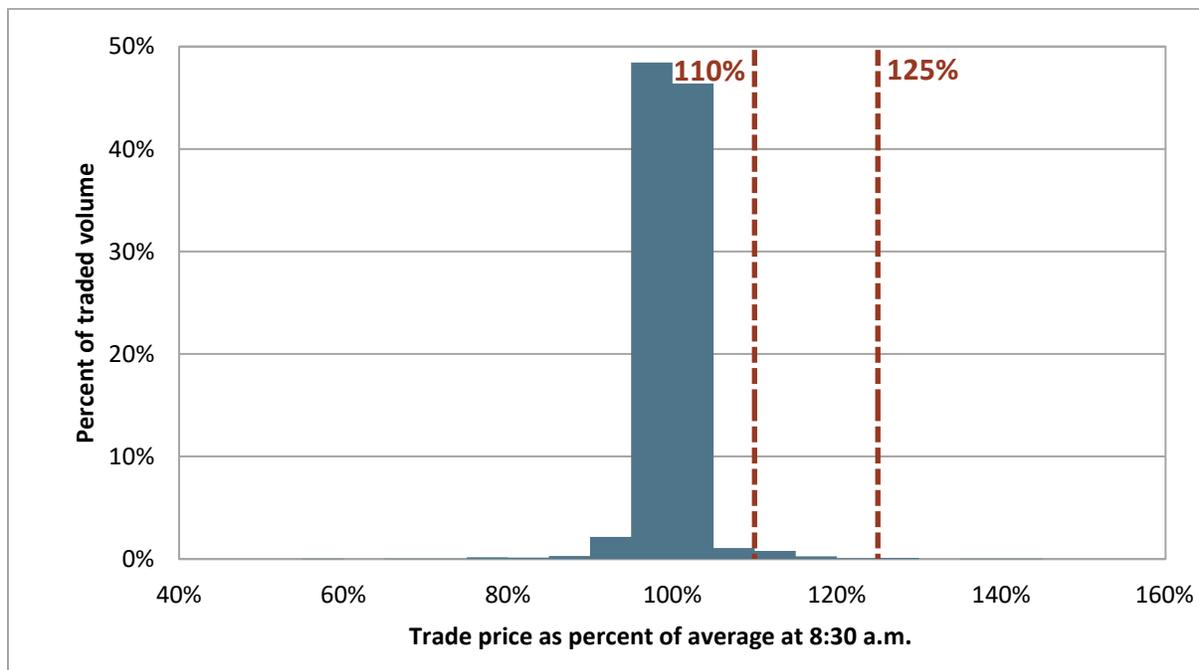


Figure 3.16 Next-day trade prices compared to updated next-day average price (Jan – Dec)



Exceptional dispatch mitigation

While the ISO made very limited use of the operational tools to manage gas limitations in 2017, it did use exceptional dispatches to help manage a broader set of conditions affecting gas supply in Southern California, from December 7 through December 12, due to wildfires. The ISO has the authority to mitigate prices paid for exceptional dispatches made for noncompetitive transmission constraints, but does not have authority to mitigate exceptional dispatches for gas constraints.

As part of DMM's October 20, 2016 FERC filing, we recommended that upward and downward exceptional dispatches issued to manage Aliso Canyon gas constraints be considered non-competitive and subject to market power mitigation because of the potential for high market concentration of resources that could be exceptionally dispatched to address the gas constraints.¹²⁵ Initially, the ISO included the mitigation of exceptional dispatches as one of the topics in to be addressed in the issue paper of commitment costs and default energy bid enhancements stakeholder process.¹²⁶ Subsequently, this issue has been dropped from the draft final proposal.¹²⁷

Impact of Aliso Canyon on natural gas prices

Analysis of gas price data suggests that the limited operability of Aliso Canyon and other supply limitations had a significant impact on natural gas prices in Southern California. Next-day prices were more volatile at the SoCal Citygate in 2017 compared to 2016. As seen in Figure 1.13 in Section 1.2.3, the average next-day price at SoCal Citygate started to deviate from the Henry Hub price in the second half of 2017. The price difference between SoCal Citygate and Henry Hub increased significantly from \$0.05/MMBtu in 2016 to \$0.40/MMBtu in 2017. The average next-day price at the SoCal Citygate increased from \$2.55/MMBtu in 2016 to \$3.42/MMBtu in 2017. The increase in natural gas prices at SoCal Citygate can be attributed to high temperatures, planned and unplanned natural gas pipeline outages, local natural gas storage use restrictions, and December Southern California wildfires.

3.5 Bidding flexibility in real time

This section highlights the availability of economic bids, as opposed to self-schedules, in the real-time market. As more renewable generation is added to meet California state goals, economic bids provide flexibility that helps the market resolve surplus supply conditions without resorting to curtailment of self-schedules by the market software. Having sufficient economic bids also avoids prices set by penalty parameters, or manual intervention by operators to address over-generation conditions.

Similar to 2016, our analysis shows that participants submitted economic bids for only about one-third of generation resources into the ISO real-time market in 2017.¹²⁸ The remaining two-thirds of real-time

¹²⁵ *Comments of the Department of Market Monitoring of the California Independent System Operator on the Tariff Amendment Filed to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility*, Department of Market Monitoring, October 19, 2016, FERC Docket No. ER17-110-000, pp. 12-17.

¹²⁶ *Commitment Costs and Default Energy Bid Enhancements Issue Paper*, November 18, 2016: http://www.caiso.com/Documents/IssuePaper_CommitmentCost_DefaultEnergyBidEnhancements.pdf.

¹²⁷ *Commitment Costs and Default Energy Bid Enhancements Draft Final Proposal*, pp. 80-81, August 23, 2017: http://www.caiso.com/Documents/DraftFinalProposal_CommitmentCosts_DefaultEnergyBidEnhancements.pdf

¹²⁸ This analysis focuses on the real-time energy bids that market participants submit to the ISO balancing area, and does not include bids in the energy imbalance market.

generation was submitted as self-schedules, or, in the case of wind and solar generation, was treated as self-schedules based on generation forecasts.

Figure 3.17 shows the breakdown of economic bids in the real-time market compared with self-scheduled bids by resource type for 2017. This figure compares solar and wind generation to real-time forecasts, while all other generation sources are compared to day-ahead schedules.¹²⁹

Natural gas had the largest volume of economic generation bid into the real-time market and also had a high percentage of bid-in generation (84 percent) compared to self-scheduled generation (16 percent). The high percentage of bid-in generation in 2017 is an increase from 75 percent in 2016. It is also important to note that the analysis does not account for other operational parameters, such as minimum run times, limitations on starts or transitions, or ancillary service awards. These parameters may affect the ability of a natural gas resource to be effectively dispatched down over the time horizon needed to balance the real-time market.

While imports accounted for the highest share of real-time energy capacity, only 9 percent of imports were bid into the real-time market economically.¹³⁰ This is up slightly from 5 percent in 2016. Solar generation had more economic bids (34 percent) than wind (25 percent), both increased from the prior year of 24 percent, and 15 percent respectively. Imports, nuclear, wind and solar represented about 70 percent of real-time self-scheduled generation in 2017, a slight decrease from 2016. The remaining 30 percent was primarily natural gas, geothermal, and hydro-electric generation, as well as other fuel sources including biogas, biomass, and coal.

Figure 3.18 compares the average hourly ISO load curve to the average quantity of self-scheduled generation by type. As shown in this figure, self-scheduled generation averaged about 16,700 MW in 2017, a slight decrease from 2016, with about 64 percent of load. Figure 3.19 shows the average hourly percentage of each type of self-scheduled generation relative to all self-scheduled generation.

Similar to the previous year, both figures show that imports represent the largest share (36 percent) of self-scheduled generation in the real-time market. Most real-time self-scheduled imports come from schedules carried over from the day-ahead market. Switching ranking from last year, hydro-electric and nuclear generation were the second and third largest sources of self-scheduled generation, accounting for an average of almost 17 and 16 percent, respectively. Wind generation averaged about 6 percent of self-schedules, and solar generation represented about 11 percent for the day and about 26 percent during hours ending 10 through 17, very similar to the previous year. Natural gas and geothermal generation only accounted for about 4 and 3 percent of real-time self-schedules, respectively.

¹²⁹ This is a departure from the methodology used in DMM's 2015 annual report, where solar and wind generation were compared to day-ahead schedules, and therefore total generation was limited by the day-ahead market bids. This was done to remain consistent with ISO analysis at the time. As a result, the 2015 analysis likely overstated real-time bidding flexibility, particularly for wind generation and to a lesser extent for solar generation. This is because some wind and solar resources only participated in the real-time market.

¹³⁰ This analysis does not include new import bids in the real-time market as they would be incremental schedules compared to the day-ahead market. Imports also include wheel-through generation, which is consistent with ISO analysis on bid flexibility. Exports are also not included in this analysis at this time.

Figure 3.17 Average hourly real-time economic bids by generation type (2017)

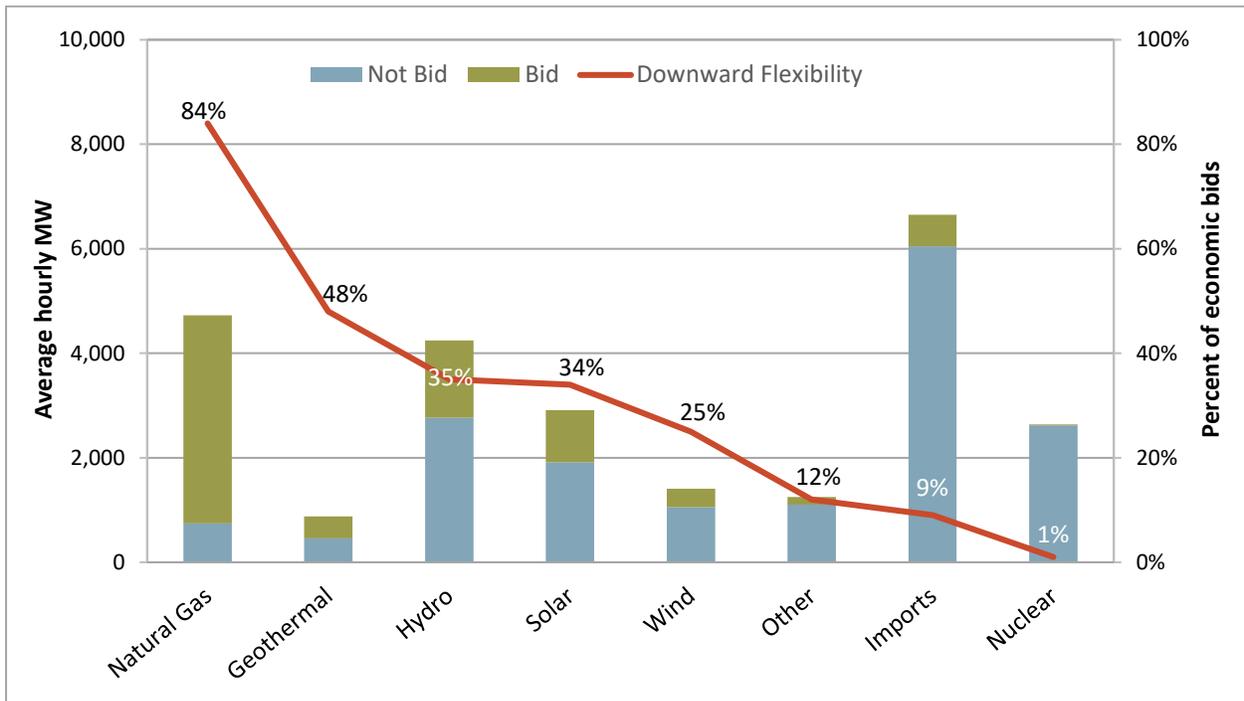


Figure 3.18 Average hourly self-scheduled generation compared to load (2017)

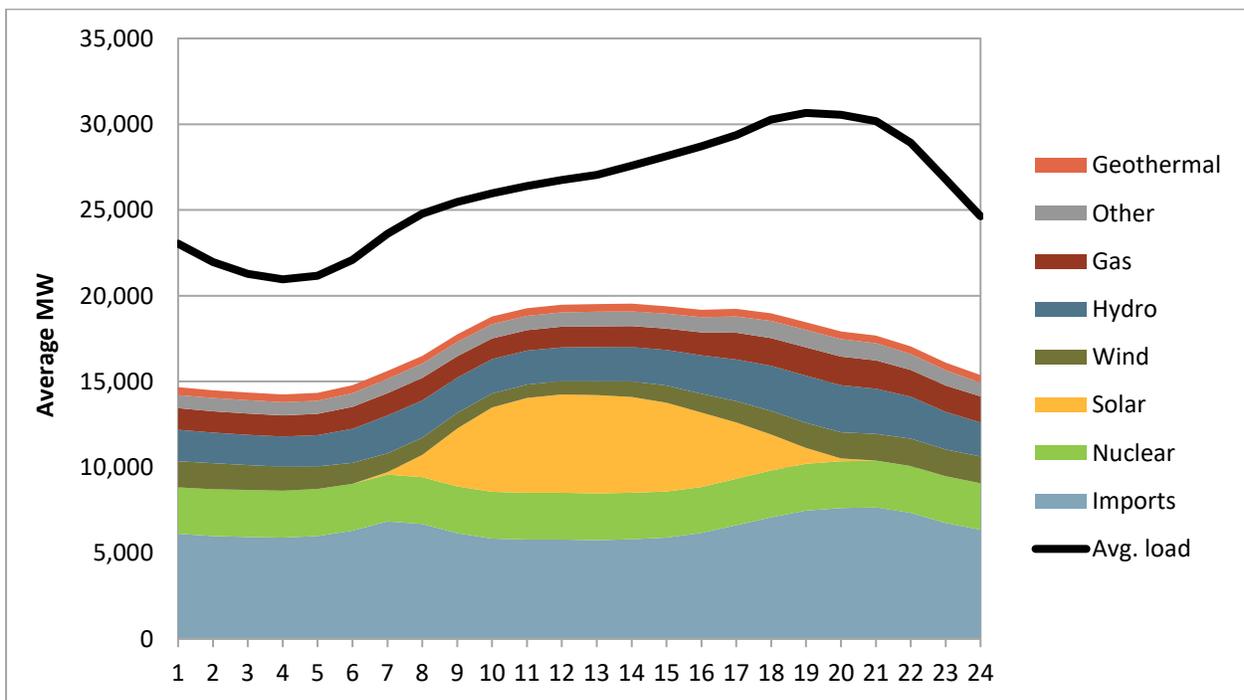
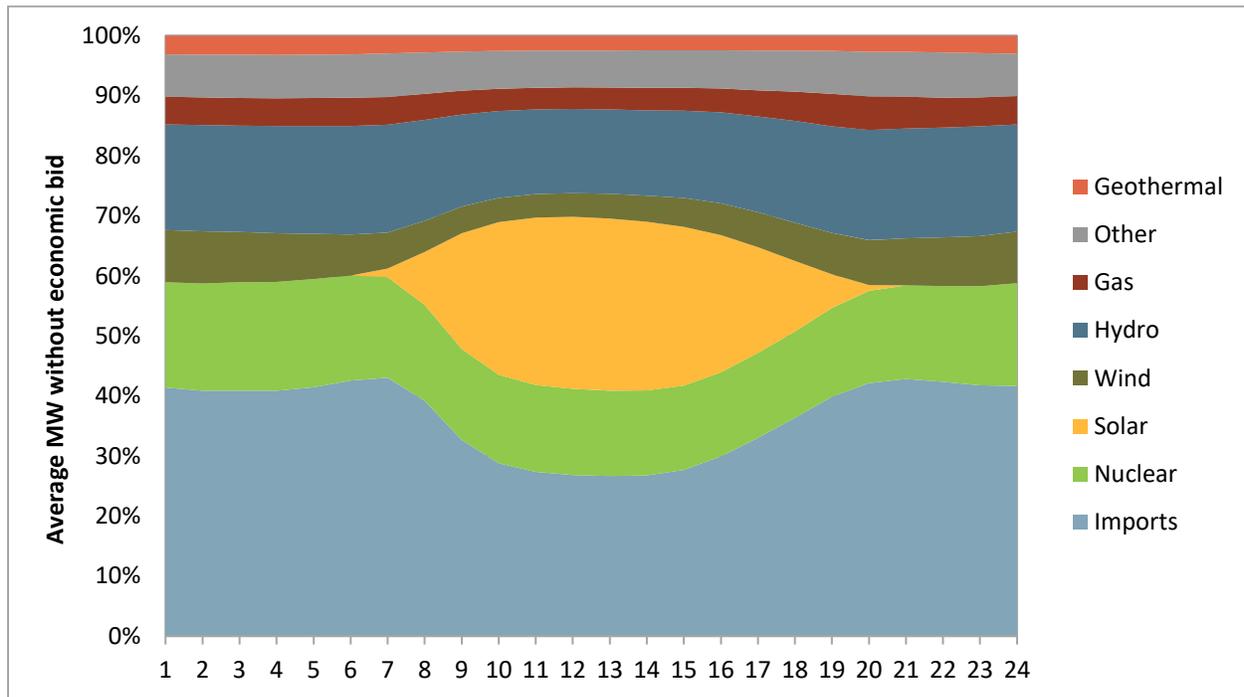


Figure 3.19 Hourly percentage of self-scheduled generation by type (2017)



Economic bids in the real-time markets can have either positive or negative offer prices. When negative bids clear the market, these prices signal oversupply conditions and the ISO makes payments to generators to decrease output. Almost all negative bids were submitted by renewable resources including solar, wind, and geothermal in 2017, a trend similar to the last two previous years.¹³¹

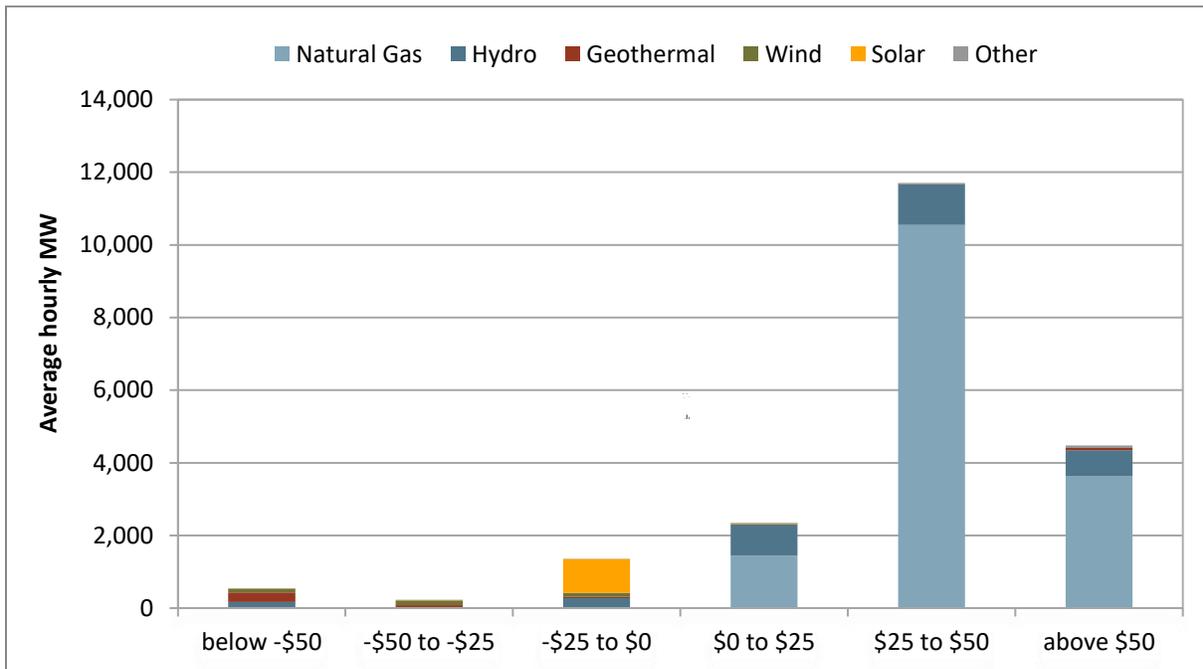
Figure 3.20 shows the range of bids submitted to the 15-minute market by resource type in 2017.¹³² Nearly 100 percent of natural gas-fired generation bid in between \$0/MWh and \$50/MWh, which is consistent with prevailing natural gas and greenhouse gas prices, resource heat rates, and emissions factors. About 86 percent of bids for hydro-electric generation were about between \$0/MWh and \$50/MWh during most hours.¹³³ Geothermal, solar, and wind generation, on the other hand, primarily bid less than \$0/MWh, 83 percent, 99 percent, and 100 percent respectively.

¹³¹ These resources receive tax incentives and renewable energy credits that may be foregone when output is curtailed. Thus these credits and tax incentives can create negative marginal costs for renewable resources.

¹³² This figure only reflects the incremental amounts for each bid and therefore does not account for the generation associated with the minimum operating levels of resources. Prior year results were based on the 5-minute market and only contained incremental bids for the active configuration thus reducing the total incremental economic bid range.

¹³³ Hydro resources may have variable bids because of prevailing conditions at specific facilities, such as spring run-off when bids are low or negative and summer months when water is scarce and bids can tend to be higher to conserve water.

Figure 3.20 15-minute market economic bids by bid range and resource type (2017)



Almost all negative bids submitted were for renewable resources. These bids were generally between -\$50/MWh and -\$10/MWh, which corresponds to the range of tax credits that these resources receive for each megawatt-hour of output. When output from these resources is decreased due to real-time market dispatch, these tax credits represent the opportunity cost of this lost production.

As noted in Section 3.1 above, the frequency of negative prices increased in 2017 as renewable generators were the marginal resource more frequently. The highest frequency of negative prices occurred in the first and second quarters in both real-time markets with a dramatic drop in the third and fourth quarters. This seasonal pattern is a result of higher loads absorbing low-cost renewable generation during the summer months.

When the amount of supply on-line exceeds demand, the market dispatches generation down. Generally, generators are dispatched down in merit order from highest bid to lowest. As with typical incremental dispatch, the last unit dispatched sets the system price and dispatch instructions are subject to constraints including transmission, ramping, and minimum generation. During some intervals, wind and solar resources, which generally have very low or negative bids, are dispatched down. The condition in which these resources are dispatched down is referred to as *oversupply*. If the supply of bids to decrease energy is completely exhausted in the real-time market, the software relaxes the power balance constraint for excess energy up to a point. Past this point, self-scheduled generation can be curtailed including self-scheduled wind and solar generation.

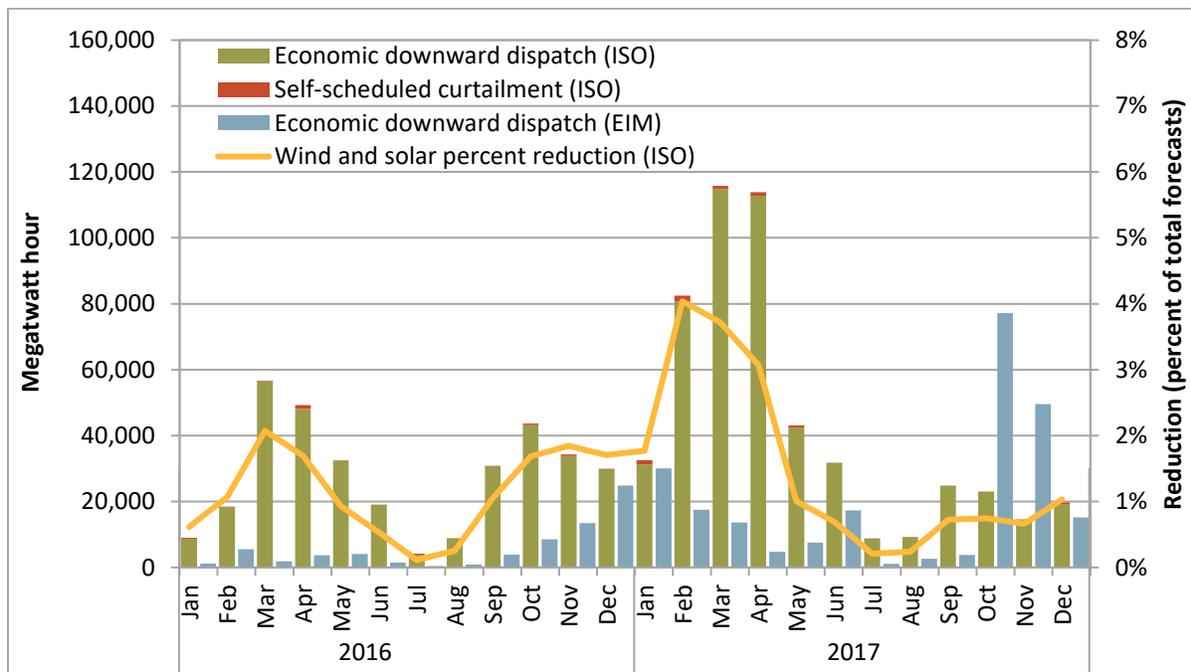
Renewable output can be reduced by economically dispatching renewable generation down or by curtailing self-scheduled renewable generation. Figure 3.21 shows the total quantity of wind and solar in the ISO that was dispatched down economically (green bars) as well as curtailment of self-scheduled wind and solar generation (red bars). The figure also includes the total reduction of wind and solar as a percent of total 5-minute market wind and solar forecasts (yellow line on right axis).

Figure 3.21 shows that nearly all of the reduction in wind and solar output during 2017 was the result of economic downward dispatches rather than self-scheduled curtailments. The majority of renewable generation in the ISO dispatched down were solar resources, rather than wind resources, primarily because market participants bid more economic downward capacity for these resources. Because of increased frequency of negative real-time prices during the spring of 2017, the total quantity of wind and solar generation dispatched down increased significantly from the previous year. This was particularly true between February and April where wind and solar output was reduced by around 3 to 4 percent in each month from the total forecasted output.

Figure 3.21 also shows the amount of economic downward dispatch to energy imbalance market wind and solar resources. As shown in the figure, the quantity of energy from wind and solar resources dispatched down increased significantly during the fourth quarter in the energy imbalance market. Nearly all renewable energy dispatched down here was from PacifiCorp East wind resources. Specifically transmission limits between Wyoming wind generation and the surrounding areas were lower in October and November resulting in increased congestion and downward dispatch during these months.

During the first quarter, the frequency of prices near or below the -\$150/MWh floor continued to occur infrequently at about 0.2 percent of 5-minute intervals. This indicates a low frequency of intervals when the supply of bids to decrease energy were exhausted and the potential need for self-scheduled generation to be curtailed. In many of these intervals, significant south-to-north congestion limited the amount of available generation with downward flexibility and resulted in power balance constraint relaxations up to the MW amount of the regulation requirement. This congestion was driven by adjustments to transmission transfer limits to account for outages.

Figure 3.21 Reduction of wind and solar generation by month



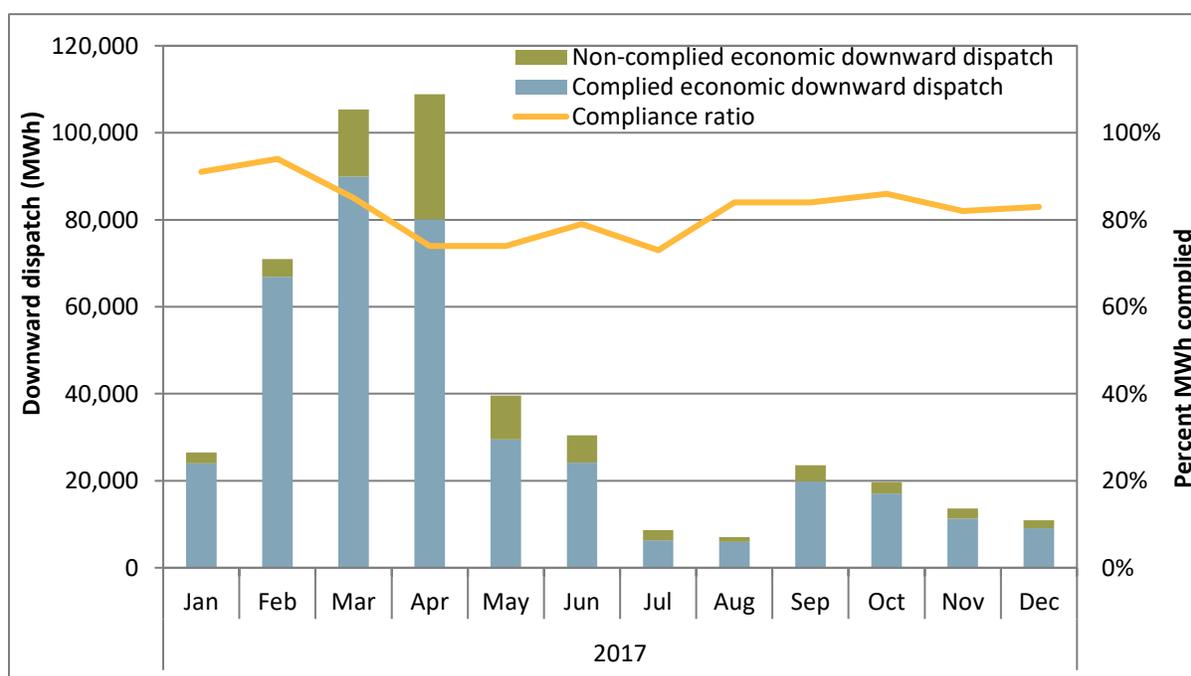
When the market dispatches a wind or solar resource below its forecasted value, scheduling coordinators receive a downward dispatch instruction indicating a need to adjust the resource’s output. Figure 3.22 and 3.23 show monthly solar and wind compliance with economic downward dispatch

instructions during 2017.¹³⁴ The blue bars represent the quantity of renewable generation that complied with economic downward dispatch. The green bars represent the quantity that did not comply with these dispatch instructions. The gold line represents the rate of compliance.

The quantity of economic downward dispatch for solar resources increased significantly during 2017 from the previous year. However, solar performance dipped between March and July. This was largely because of a specific situation that resulted in economic bids being generated in real time for resources that the participant did not intend to bid economically into the real-time market. Excluding this issue, solar performed well overall, at around 90 percent of megawatt hour instructions during the year.

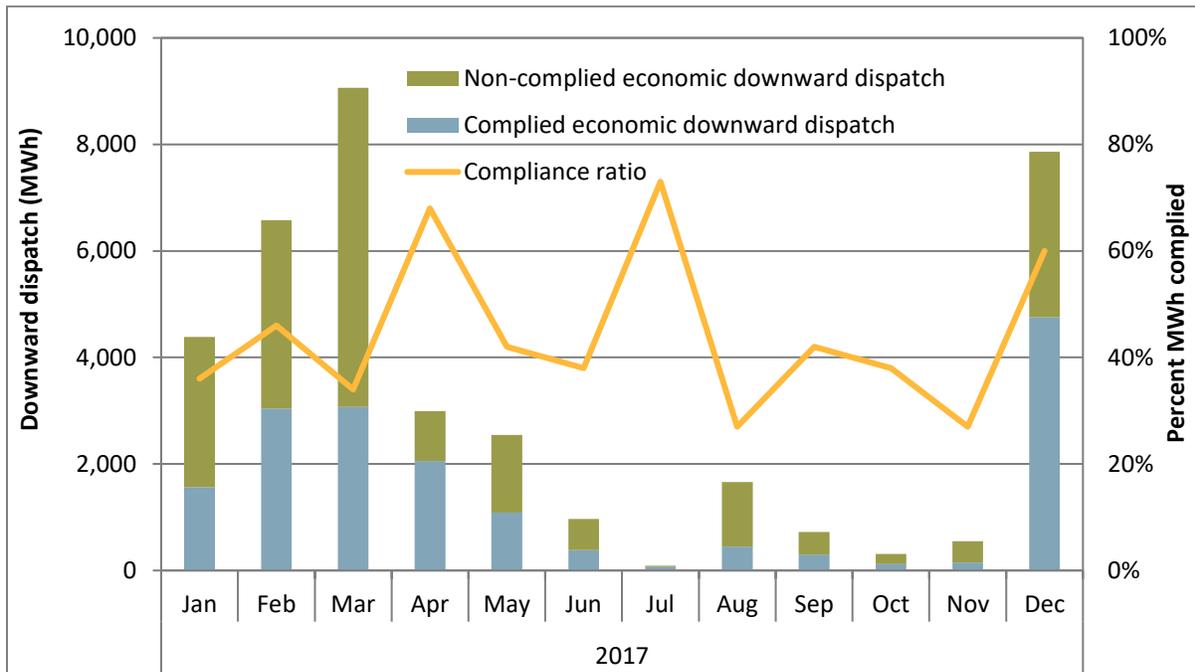
Wind performance was less consistent, at around 45 percent of megawatt hours of downward dispatch instructions complied during 2017. Poor wind performance during the year was largely driven by two participants with wind resources that do not have the ability to follow 5-minute downward dispatch instructions as a result of physical limitations. Both the ISO and DMM expect that all market participants and resources follow ISO dispatch instructions.

Figure 3.22 Compliance with ISO dispatch instructions – solar generation



¹³⁴ This analysis includes variable energy resources in the ISO balancing area only.

Figure 3.23 Compliance with ISO dispatch instructions – wind generation



4 Energy imbalance market

The energy imbalance market allows balancing authority areas outside of the ISO balancing area to voluntarily take part in the ISO real-time market. The energy imbalance market was designed to provide benefits from increased regional integration by enhancing the efficiency of dispatch instructions, reduced renewable curtailment, and reduced total requirements for flexible reserves.

This chapter provides a summary of energy imbalance market performance during 2017. Key elements highlighted in this chapter include the following:

- Portland General Electric became a participant in the energy imbalance market on October 1, 2017. This added transfer capability from the Northwest region (that also includes PacifiCorp West and Puget Sound Energy) to the ISO. However, prices in this region were still often lower than prices in the ISO and the other balancing areas because of limited transmission from PacifiCorp West and Portland General Electric to the ISO.
- Prices in PacifiCorp East, NV Energy, and Arizona Public Service were often similar to each other and the ISO because of large transfer capacities and little congestion. However, there was some price separation between these areas. This was most pronounced during peak load hours when high system prices caused transfers from PacifiCorp East to hit export limits.
- Overall, valid infeasibilities in the energy imbalance market were relatively infrequent in both the 15-minute and 5-minute markets. The exception to this was oversupply infeasibilities in Arizona Public Service in the first quarter. Power balance relaxations were common in this area because of limited export capability as a result of failing the downward sufficiency test. Arizona Public Service failed the downward sufficiency test significantly less frequently beginning in the second quarter of 2017.
- Congestion either towards or from the ISO was infrequent in the 5-minute market for NV Energy and Arizona Public Service. Limited transfer capability resulted in a high frequency of congested intervals in the region including PacifiCorp West, Puget Sound Energy, and Portland General Electric relative to the ISO.
- Overall, NV Energy, Arizona Public Service, and PacifiCorp East were net importers during midday hours (primarily from the ISO) and net exporters during other hours. PacifiCorp West was a net exporter during most hours of the day, except during midday hours when net average transfers were near zero.
- Weighted average greenhouse gas prices appear to be at or below estimated costs for an efficient gas resource in all months, and averaged less than \$5/MWh for each month of the year for both the 15-minute and 5-minute markets. The ISO is currently engaged in a stakeholder process to address concerns that the current energy imbalance market design for greenhouse gas does not capture the full impact of energy imbalance market imports into California on global greenhouse gas emissions for compliance with California's cap-and-trade regulation.
- The number of hours where an area failed the sufficiency test trended downward overall during 2017, particularly in comparison to November and December 2016.

4.1 Background

The energy imbalance market allows balancing authority areas outside of the ISO balancing area to voluntarily take part in the ISO real-time market. The energy imbalance market was designed to provide benefits from increased regional integration by enhancing the efficiency of dispatch instructions, reduced renewable curtailment and reduced total requirements for flexible reserves. The energy imbalance market became financially binding with PacifiCorp becoming the first participant on November 1, 2014.

In 2015, with just PacifiCorp in the energy imbalance market, there was little transfer capability between the two areas and the ISO. This limited the benefits of this market. However, when NV Energy was integrated into the energy imbalance market in December 2015, this added a significant amount of transfer capability with the ISO and PacifiCorp East. As a result, energy transferred in the real-time markets increased between the ISO and the energy imbalance market areas.

Puget Sound Energy and Arizona Public Service joined the energy imbalance market in October 2016, further increasing the total amount of transfer capability available between different balancing areas. In October 2017, Portland General Electric joined the energy imbalance market, with additional transfer capability in the northwest.

During the initial few months after energy imbalance market implementation in the PacifiCorp East and PacifiCorp West balancing areas, results were not reflective of actual economic and operational conditions. This caused the need to relax ramping and power balance constraints in the market software resulting in prices set using the \$1,000/MWh penalty price. The ISO determined that many of these outcomes were inconsistent with actual conditions, and in November 2014 filed with FERC for special *price discovery* measures to set prices based on the last dispatched bid price rather than penalty prices for various constraints.¹³⁵ These measures were approved by FERC on December 1, 2014, and were extended through subsequent orders.

On October 29, 2015, FERC approved the California ISO's proposed tariff amendments to allow a transition period for new energy imbalance market entities during the first six months of market participation, effective November 1, 2015. The transition period allows for the same price discovery mechanism, also referred to as *transition period pricing*, to govern prices when power balance constraint relaxations occur in the market. These measures expired for Puget Sound energy and Arizona Public Service at the end of March 2017 and expired for Portland General Electric at the end of March 2018.

FERC also ordered that the ISO and the Department of Market Monitoring provide reports every 30 days during the period of the waiver that outline the issues driving the need for the energy imbalance market tariff waiver.¹³⁶

4.2 Energy imbalance market prices

Real-time market prices reported in this section include prices within the ISO balancing area as well as the energy imbalance market. The energy imbalance market included PacifiCorp, NV Energy, Puget

¹³⁵ For further details, see: https://www.caiso.com/Documents/Oct29_2015_OrderAcceptingTariffRevisions_EnergyImbalanceMarket_TransitionPeriodPricing_ER15-2565.pdf.

¹³⁶ The DMM filings can be found here: <http://www.caiso.com/rules/Pages/Regulatory/RegulatoryFilingsAndOrders.aspx>.

Sound Energy, and Arizona Public Service for the entire year in 2017. Portland General Electric joined the energy imbalance market in October 2017.

Prices in PacifiCorp East, NV Energy and Arizona Public Service were often similar to each other and the ISO because of large transfer capacities and little congestion. However, there was some price separation between these areas. This was most pronounced during peak load hours when high system prices caused transfers from PacifiCorp East to hit export limits. In other hours one or more of these areas failed the sufficiency test which limited transfers and created price separation between the balancing areas.

Further market interruptions in March contributed to price separation between the balancing areas. Between the evenings of March 6 and March 10, the ISO declared an interruption of NV Energy participation in the real-time market. This occurred as a result of a planned outage on a major transmission line that connects the Northern and Southern NV Energy systems. During this period energy imbalance market transfers were locked to and from NV Energy. During this period, energy imbalance market prices in NV Energy were set by applicable administrative pricing rules.¹³⁷ Additionally, on March 17 a market interruption was declared for Arizona Public Service for 13 hours, during which transfers were locked and administrative pricing rules were also applied.

Portland General Electric added transfer capability from the Northwest region (that also includes PacifiCorp West and Puget Sound Energy) to the ISO. However, prices in this region were still often lower than prices in the ISO and the other balancing areas because of limited transmission from this region to the ISO. This resulted in local resources setting the price in many intervals in a combined PacifiCorp West, Puget Sound Energy, and Portland General Electric region, particularly during peak load hours when prices were highest in the surrounding areas and export limits were reached.

Figure 4.1 and Figure 4.2 show real-time prices for the energy imbalance market balancing areas during 2017. 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. Portland General Electric prices are not included in these figures because participation only since October, but tracked closely to Puget Sound Energy and PacifiCorp West prices during the fourth quarter. Lower average hourly prices than ISO prices for the EIM balancing areas were in part driven by greenhouse gas prices, but otherwise were most impacted by transfer limitations.¹³⁸

¹³⁷ At the time of the market interruption a new methodology for administrative pricing had been approved, but not yet implemented in the ISO tariff. During an extended interruption of participation by an Energy Imbalance Market entity in the real-time market when both 15-minute market and 5-minute market results are unavailable, the ISO now uses the price specified in the entity's open access transmission tariff as the locational marginal price. For further information see January 30, 2017, Order Accepting Tariff Revisions – Administrative Pricing Enhancements: https://www.caiso.com/Documents/Jan30_2017_OrderAcceptingTariffAmendment-AdministrativePricingEnhancements_ER17-415.pdf.

¹³⁸ See Section 3.4 for further information on greenhouse gas in the energy imbalance market.

Figure 4.1 Hourly 15-minute market prices (January – December)

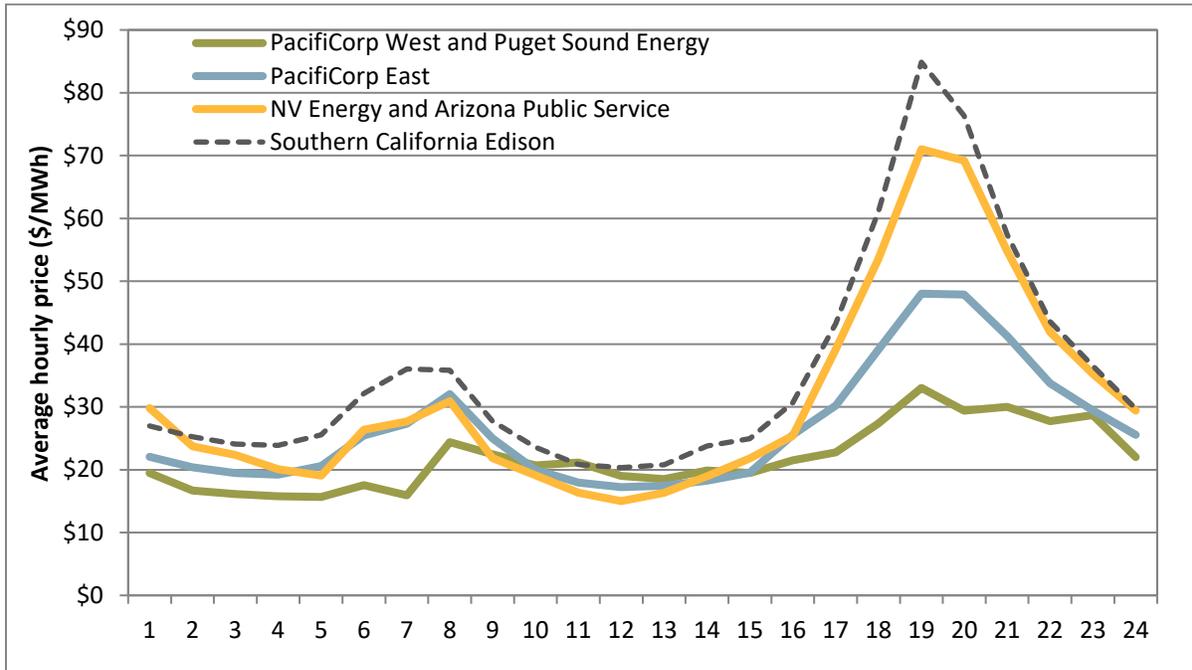
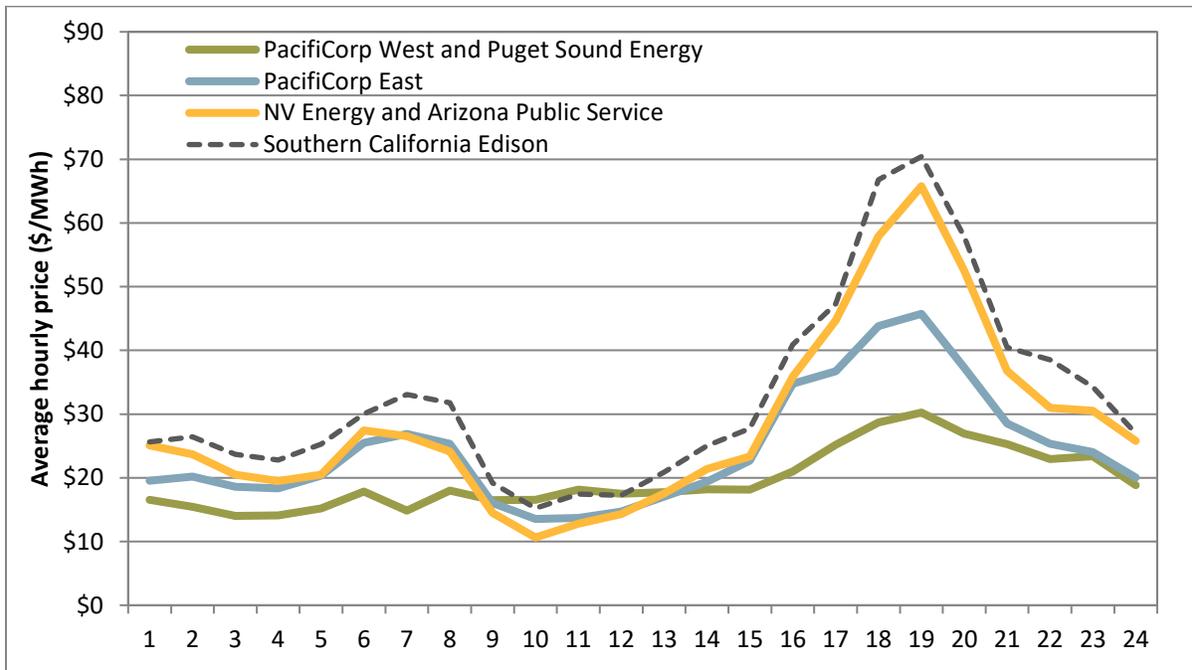


Figure 4.2 Hourly 5-minute market prices (January – December)



4.3 Energy imbalance market power balance constraint relaxations

Energy imbalance market power balance constraints have several unique features. First, because the energy imbalance market does not include ancillary services and therefore excludes co-optimization of regulation, the power balance is not relaxed up to the seasonal regulation requirement. Second, the penalty parameter for shortages in the scheduling run are set at \$1,450/MWh rather than \$1,100/MWh. Third, during the first six months after joining the energy imbalance market, prices in new balancing areas are not set by the price cap or floor when the power balance constraint is relaxed. Instead, prices are set by the last dispatched economic bid. This is known as transition period pricing, or price discovery.

Energy imbalance market performance has been largely connected to the frequency with which the power balance constraint is relaxed. When the power balance constraint was relaxed for undersupply conditions in an energy imbalance market area, prices were set using the \$1,000/MWh penalty price for this constraint in the pricing run of the market model if transition period prices were not in place. Transition period pricing, when active, sets the market price based on the last price bid into the market by a unit when the power balance constraint is relaxed.¹³⁹ Transition period pricing for Puget Sound Energy and Arizona Public Service expired at the end of March 2017 following the end of their six-month transition period. Similarly, transition period pricing for Portland General Electric (PGE) was in effect through March 2018.

The load bias limiter was implemented in the energy imbalance market in March 2015, and works the same way as the load bias limiter in the ISO. As noted above, when the magnitude of an operator load adjustment exceeds the magnitude of a power balance relaxation, the load bias limiter creates a feasible market solution by reducing the magnitude of the adjustment. This market solution is then created in a similar manner to transition period pricing in that the price is set by the last economic bid instead of the penalty price. The load bias limiter feature is more important during periods when transition period pricing is not in effect for an area.

Figure 4.3 and Figure 4.4 show the frequency of power balance constraint relaxations in the 5-minute market by quarter for undersupply (shortage) and oversupply (excess) conditions.¹⁴⁰ The red bars in these figures show infeasibilities that were resolved by the load bias limiter (or would have been without transition period pricing), and the yellow bars show the infeasibilities that required a price correction, would have triggered price correction if transition period pricing was not active, or were otherwise invalid.¹⁴¹

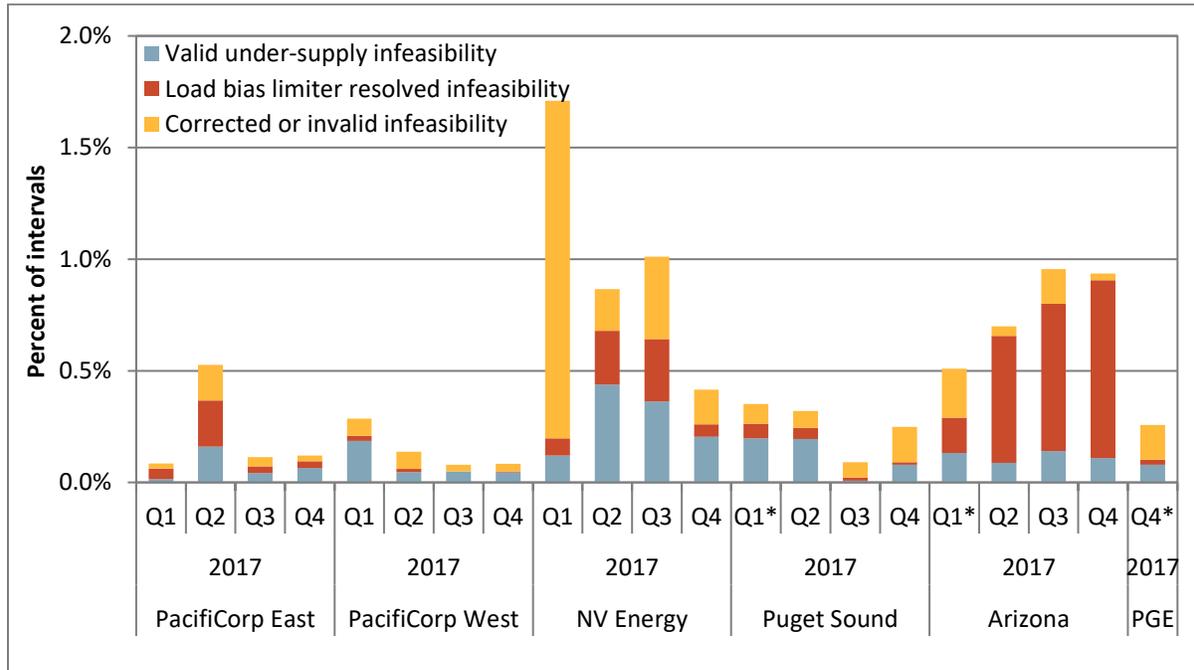
¹³⁹ When transition period pricing triggers, any shadow price associated with the flexible ramping product is set to \$0/MWh to allow the market software to use the last economic bid.

¹⁴⁰ The frequency of power balance constraint relaxations in the 15-minute market had similar patterns to those observed in the 5-minute market.

¹⁴¹ Section 35 of the ISO tariff provides the ISO authority to correct prices if it detects an invalid market solution or issues due to a data input failure, occurrence of hardware or software failure, or a result that is inconsistent with the ISO tariff. During erroneous intervals, the ISO determined that prices resulting under transitional pricing were equivalent to prices that would result from price correction, so no further price adjustment was appropriate.

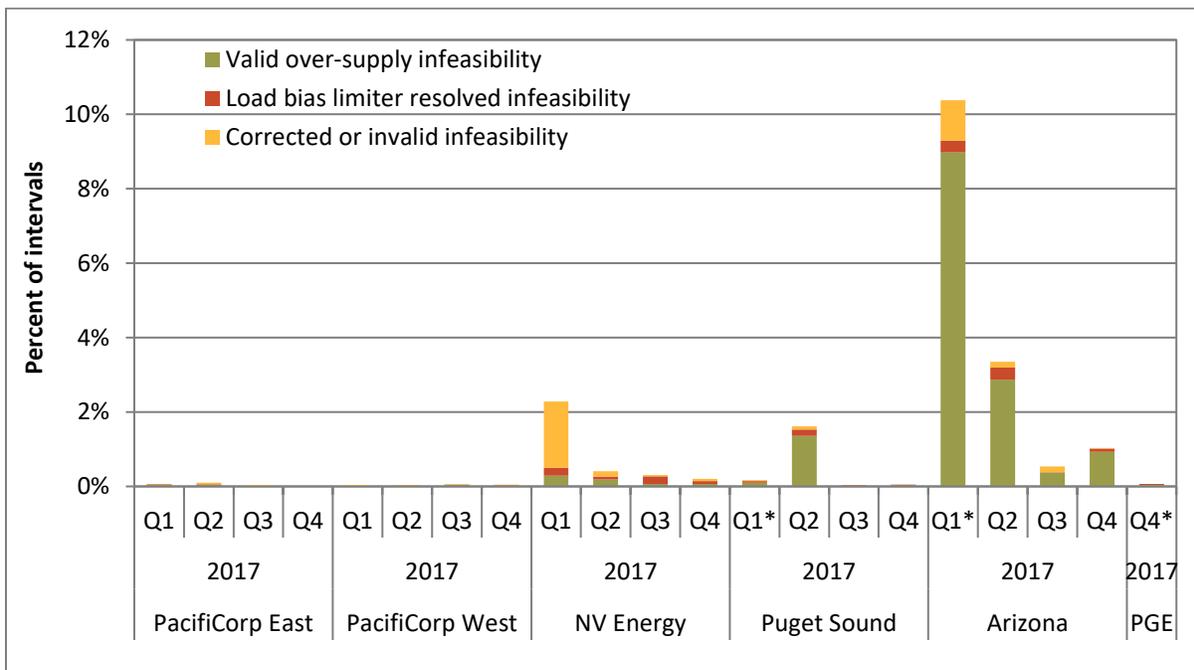
http://www.caiso.com/Documents/Section35_MarketValidationAndPriceCorrection_May1_2014.pdf.

Figure 4.3 Frequency of power balance constraint undersupply (5-minute market)



*Area under transition period pricing for the quarter

Figure 4.4 Power balance constraint oversupply (5-minute market)



*Area under transition period pricing for the quarter

Overall, valid undersupply or oversupply infeasibilities in the energy imbalance market were relatively infrequent in both the 15-minute and 5-minute markets. The majority of power balance constraint relaxations occurred during hours when the balancing area failed the sufficiency test which constrained transfer capability.¹⁴² However overall, transfer limits were reached infrequently, allowing large amounts of generation in the ISO or other energy imbalance market balancing areas to resolve what could have been local power balance infeasibilities.

The exception to this was oversupply infeasibilities in Arizona Public Service in the first quarter. Power balance relaxations were common in this area because of limited transmission capability as a result of failing the downward sufficiency test. However, because of special transition period pricing in effect in this area during the quarter, prices during the power balance constraint relaxations were not set at the -\$155/MWh penalty parameter for over-supply infeasibilities. Arizona Public Service failed the downward sufficiency test significantly less frequently beginning in the second quarter of 2017.

4.4 Energy imbalance market transfers

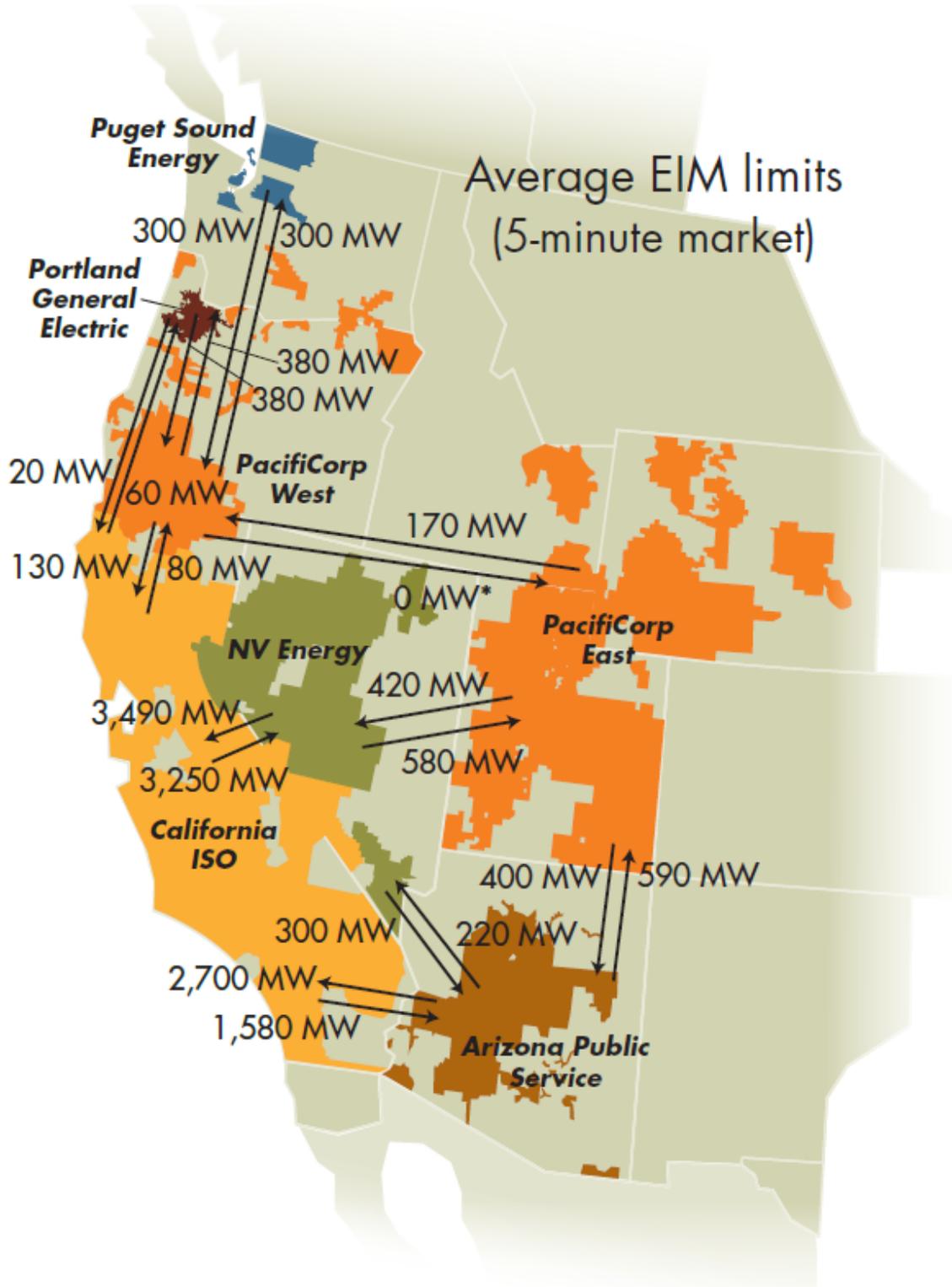
One of the key sources of value from the energy imbalance market is the ability to transfer energy between areas in the 15-minute and 5-minute markets. Since NV Energy joined the energy imbalance market in December 2015, there has been a significant amount of transfer capability between the energy imbalance areas and the ISO. As additional participants join the ISO and transfers grow, the benefits grow as well.

Figure 4.5 shows average real-time limits in the 5-minute market between each of the energy imbalance market areas and the ISO during 2016. It shows that there was significant transfer capacity between the ISO, NV Energy, PacifiCorp East and Arizona Public Service. These large limits allowed energy to flow between these areas with little congestion in the energy imbalance market.

Figure 4.5 also shows that transfer capability was more limited from PacifiCorp West, Puget Sound Energy and Portland General Electric toward the ISO. This resulted in more transmission congestion between these areas and the ISO.

¹⁴² See Section 4.6 for further details on the flexible ramping sufficiency test.

Figure 4.5 Average limits in the 5-minute energy imbalance market - 2017



*0 MW represents that transfer capability is available from PacifiCorp East to PacifiCorp West only.

Inter-balancing area congestion

Congestion between an energy imbalance market area and the ISO causes price separation. Table 4.1 shows the percent of 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.¹⁴³

During intervals when there is net import congestion into an energy imbalance market area, the ISO market software triggers local market power mitigation in that area.¹⁴⁴ Table 4.1 includes the frequency in which transfer limits bound from the ISO into the other balancing areas. For example, the highest frequency of such congestion was from the ISO into the region that includes PacifiCorp West, Puget Sound Energy and Portland General Electric, at around 14 percent of 5-minute intervals during 2017.

Table 4.1 Frequency of 5-minute market congestion in the energy imbalance markets (2017)

	Congested toward ISO	Congested from ISO
NV Energy	2%	2%
Arizona Public Service	5%	2%
PacifiCorp East	10%	1%
PacifiCorp West	45%	13%
Puget Sound Energy	46%	15%
Portland General Electric*	59%	16%

*Portland General Electric joined the energy imbalance market in October. These values reflect October to December only.

Table 4.1 also shows that congestion in either direction between NV Energy, Arizona Public Service, or the ISO area was infrequent during 2017 in the 5-minute market. There was also very little congestion in the direction of the ISO toward PacifiCorp East. Congestion from PacifiCorp East in the direction of the ISO was more frequent, during about 10 percent of intervals. This primarily occurred when less expensive generation in PacifiCorp East was constrained going into NV Energy and Arizona Public Service.

Finally, Table 4.1 also shows that there were a significant number of congested intervals (around 45 percent) from PacifiCorp West and Puget Sound Energy in the direction of the ISO. Limited transfer capability, particularly from PacifiCorp West to the ISO, resulted in a high frequency of congested intervals. This congestion led to lower prices during 2017 in the region including PacifiCorp West and Puget Sound Energy relative to the rest of the energy imbalance market and the ISO. Congestion persisted after Portland General Electric joined the energy imbalance market in October, with similar

¹⁴³ Greenhouse gas prices can contribute to lower energy imbalance market prices relative to those inside the ISO. The previous methodology for congestion toward the ISO accounted for price separation as a result of greenhouse gas prices by removing instances of congestion toward the ISO of smaller magnitude than $-\$6/\text{MWh}$. The new methodology uses prevailing greenhouse gas prices in each interval to account for price separation that is the result of greenhouse gas prices only.

¹⁴⁴ Structural market power may exist if the demand for imbalance energy within a balancing area exceeds the transfer capacity into that balancing area from the ISO or other competitive markets.

prices between PacifiCorp West, Puget Sound Energy and Portland General Electric but separated from the ISO and the rest of the energy imbalance market.

Hourly energy imbalance market transfers

Real-time market software solves a large cost minimization problem for dispatch instructions to generation considering all of the resources available to the market, including those in the energy imbalance market areas and the ISO. This software also considers a number of constraints including transmission availability between balancing areas within the energy imbalance market. Because of real-time differences in system conditions, real-time schedules for generation are frequently different than day-ahead schedules for resources in the ISO and base schedules for resources in the energy imbalance market. When aggregated, these differences can cause large changes in scheduled flows between balancing areas in the real-time market, or *energy transfers* between areas. These transfers may represent the market software electing to use lower cost generation in one area in lieu of higher cost generation in another area, thus reducing the overall cost to meet load for the energy imbalance market. This section includes results for transfers between energy imbalance market areas.¹⁴⁵

Different areas in the energy imbalance market exhibited different hourly transfer patterns during 2017. For example, NV Energy imported, on average, from the ISO during the middle of the day, when solar generation was greatest, and exported to the ISO during the late evening hours. NV Energy primarily exported energy to PacifiCorp East during the morning and afternoon hours. This pattern is driven by the resource mix and relative prices in these areas during these times of the day.

Figure 4.6 shows average hourly imports (negative values) and exports (positive values) into and out of NV Energy for the year in the 5-minute market. Transfers between NV Energy and the ISO are shown by the blue bars, transfers with PacifiCorp East are shown by the green bars, and net transfers are shown by the gold line. As seen in the chart, NV Energy was a net importer during the midday hours, and a net exporter during other hours of the day.

Arizona Public Service was generally a net importer of energy during midday hours and a net exporter during the evening hours. On average, Arizona Public service received imports from the ISO during the midday hours, when solar generation was greatest, and exported to the ISO during other hours of the day. Arizona Public Service also imported energy from PacifiCorp East during the morning and evening, on average. Average hourly imports from PacifiCorp East were similar to exports to the ISO in the morning, but exports were larger to the ISO in the evening when average prices were highest.

Figure 4.7 highlights these trends in the Arizona Public Service area during 2017 in the 5-minute market. Transfers between Arizona Public Service and the ISO are shown by the blue bars, transfers with PacifiCorp East are shown by the green bars. The figure also includes transfers with NV Energy, which were frequently zero MW during 2017, during about 79 percent of 5-minute intervals. The average hourly net transfer is shown by the gold line. Positive numbers represent exports from Arizona Public Service, whereas negative numbers represent imports.

¹⁴⁵ In prior reports, DMM has shown real-time energy flows within the energy imbalance market. These figures show real-time energy market flows net of all base schedules.

Figure 4.6 NV Energy – average hourly 5-minute market transfer (2017)

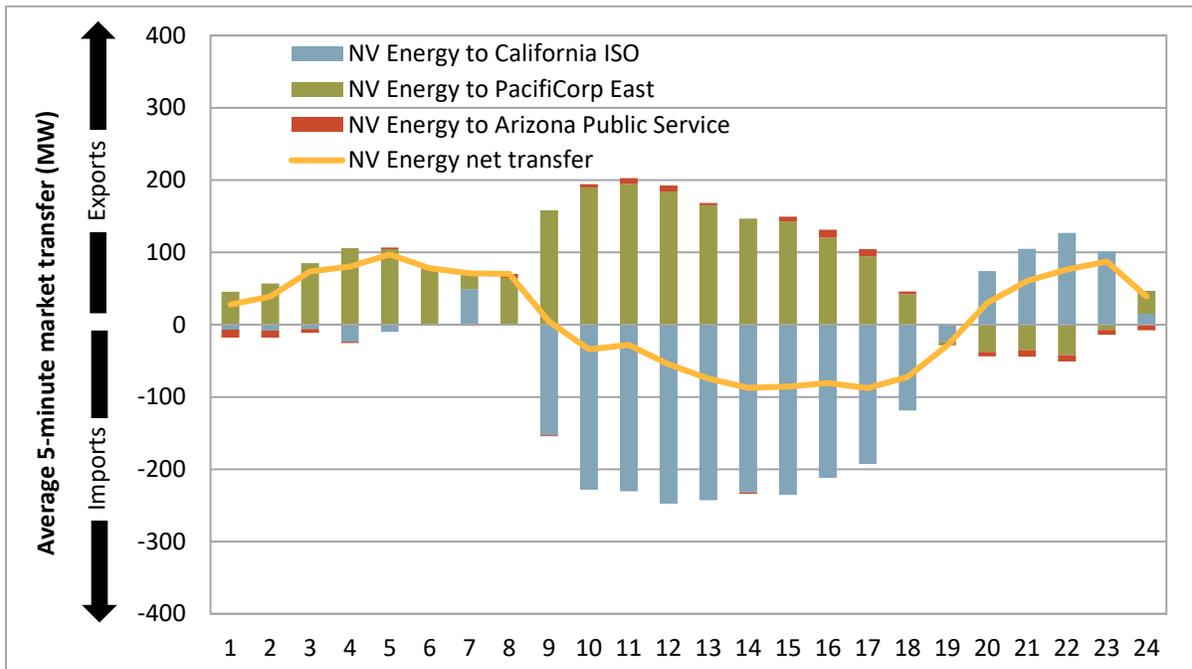
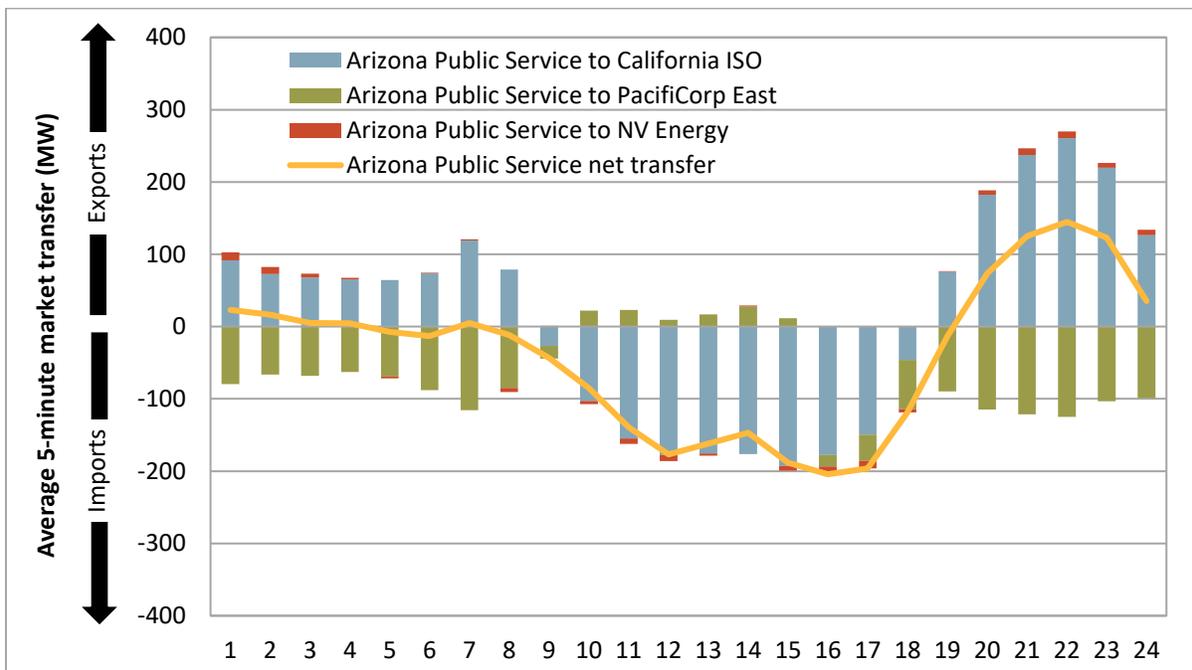


Figure 4.7 Arizona Public Service – average hourly 5-minute market transfer (2017)



PacifiCorp West has transfer capacity between PacifiCorp East, Puget Sound Energy, the ISO, and – beginning October 1 – Portland General Electric. Figure 4.8 shows the hourly 5-minute market transfer pattern between PacifiCorp West and neighboring areas averaged for all of 2017. This figure shows that average flows were somewhat smaller to and from PacifiCorp West than transfers observed in NV Energy or Arizona Public Service. This reflects the lower transfer capability between PacifiCorp West and neighboring areas. This figure also shows that PacifiCorp West was a net exporter during most hours of the day, except during the midday hours when net average transfers were near zero.

For most hours of the day, including the early evening through morning, PacifiCorp West typically exported energy to the ISO except for the midday hours, when solar was greatest, when they imported slightly from the ISO. Figure 4.8 shows that PacifiCorp West always received imports from PacifiCorp East. This is a byproduct of the transfer limits imposed between the two areas, which require that transfers only occur in the east-to-west direction between these two areas.

Figure 4.9 shows average hourly 5-minute market imports and exports into and out of Portland General Electric between October and December, 2017. As shown in the figure, Portland General Electric were net importers during most hours of the day, specifically from the ISO and PacifiCorp West.

Figure 4.8 PacifiCorp West – average hourly 5-minute market transfer (2017)

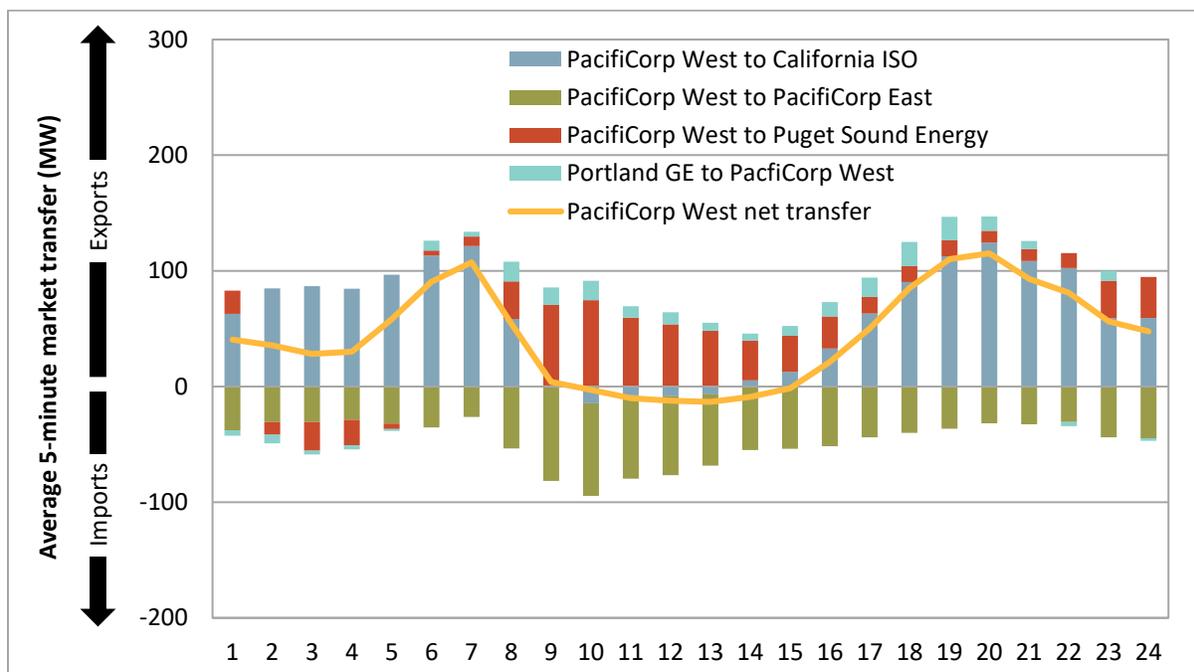
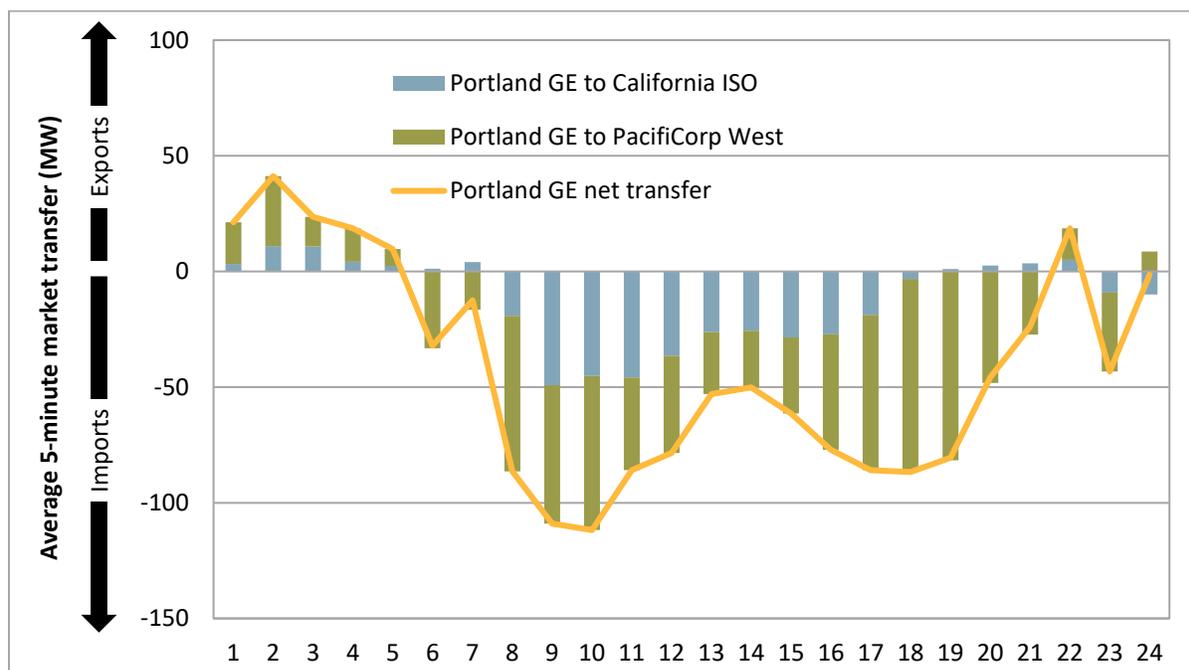


Figure 4.9 Portland General Electric – average hourly 5-minute market transfer (October - December)



4.5 Greenhouse gas in the energy imbalance market

Background

Under the current energy imbalance market design, all energy transferred into the ISO to serve ISO load through an energy imbalance market transfer is subject to California’s cap-and-trade regulation.¹⁴⁶ Under the energy imbalance market design, a participating resource submits a separate bid representing the cost of compliance for its energy attributed to the participating resource as serving ISO load. These bids are included in the optimization for energy imbalance market resource dispatch. Resource specific market results determined within the energy imbalance market optimization are reported to participating resource scheduling coordinators. This information serves as the basis for greenhouse gas compliance obligations under California’s cap-and-trade program.

The energy imbalance market optimization minimizes costs of serving load in both the ISO and energy imbalance market taking into account greenhouse gas compliance cost for all energy deemed delivered to California. The energy imbalance market greenhouse gas price in each 15-minute or 5-minute interval is set at the greenhouse gas bid of the marginal megawatt attributed as serving ISO load. The greenhouse gas price determined within the optimization is included in the price difference between

¹⁴⁶ Further information on energy imbalance market entity obligations under the California Air Resources Board cap-and-trade regulation is available in a posted FAQ on ARB’s website here: <http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/eim-faqs.pdf>.

servicing the ISO and energy imbalance market load, which can contribute to lower energy imbalance market prices relative to those inside the ISO by at least the greenhouse gas price during any interval.¹⁴⁷

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

Scheduling coordinators can guarantee that greenhouse gas compliance costs are covered by bidding in marginal compliance costs for greenhouse gas. The settlement price is set by the highest cleared greenhouse gas bid for the interval and will equal or exceed all cleared bids. The greenhouse gas price may thus be set above the greenhouse gas bid of a marginal resource, which provides energy imbalance market participating resources with low emissions an incentive to export energy to the ISO.

Figure 4.10 shows monthly average cleared energy imbalance market greenhouse gas prices and hourly average quantities for transfers serving ISO load settled in the energy imbalance market in 2017. Weighted average prices are calculated using 15-minute deemed delivered megawatts as weights in the 15-minute market and the absolute value of incremental 5-minute greenhouse gas dispatch in the 5-minute market. Hourly average 15-minute and 5-minute deemed delivered quantities are represented by the blue and green bars in the chart, respectively.

Weighted average greenhouse gas prices in the 5-minute market were lower than 15-minute prices for each month of the year, averaging about \$1.52/MWh less. Weighted 15-minute prices averaged less than \$6/MWh for each month of the year while 5-min prices averages less than \$5/MWh. Price differences may occur if large emitting resources are procured in the 15-minute market and subsequently decrementally dispatched in the 5-minute market. In the 15-minute market, the gas resource with positive greenhouse gas costs may be the marginal resource, but if emitting resources are decremented in the 5-minute market, the new marginal resource may be a hydro or solar resource that will set greenhouse gas prices less than or equal to zero.

Both 15-minute and 5-minute price levels are at or below estimated greenhouse gas compliance costs for an efficient gas resource. Greenhouse gas prices increase with the percentage of gas resources attributed as servicing ISO load through the energy imbalance market. This result is consistent with greenhouse gas bidding requirements adopted under phase 1 of the energy imbalance market year 1 enhancements which required greenhouse gas bids to be cost based.¹⁴⁸

DMM estimates the total profit accruing for greenhouse gas bids attributed to energy imbalance market participating resources serving ISO load by subtracting estimated compliance costs from greenhouse gas

¹⁴⁷ Further detail on the determination of deemed delivered greenhouse gas megawatts within the energy imbalance market optimization is available in Section 11.3.3, Locational Marginal Prices, of the Energy Imbalance Market Business Practice Manual located here: <https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy%20Imbalance%20Market>.

¹⁴⁸ FERC's acceptance of tariff revisions required for the energy imbalance market are available here: http://www.caiso.com/Documents/Jun19_2014_OrderConditionallyAcceptingEIMTariffRevisions_ER14-1386.pdf. These required "CAISO to make a compliance filing within one year after the date on which the energy imbalance market commences operation, with a proposal to implement the flag mechanism. Additionally, as the flag mechanism will obviate the need to use the GHG bid adder to signify that an energy imbalance market participating resource does not wish to be dispatched into California, such compliance filing should include revisions implementing a cost-based GHG bidder concurrent with implementation of the flag mechanism. A flag and cost-based GHG bid adder would support further expansion of the EIM." Paragraph 240.

revenue calculated in each interval. This value totaled almost \$6 million in 2017, compared to roughly \$3 million in 2016. This increase in profits is likely due to a greater portion of energy transfers scheduled into the ISO from non-emitting resources in 2017, described below.

Figure 4.10 Energy imbalance market greenhouse gas price and cleared quantity

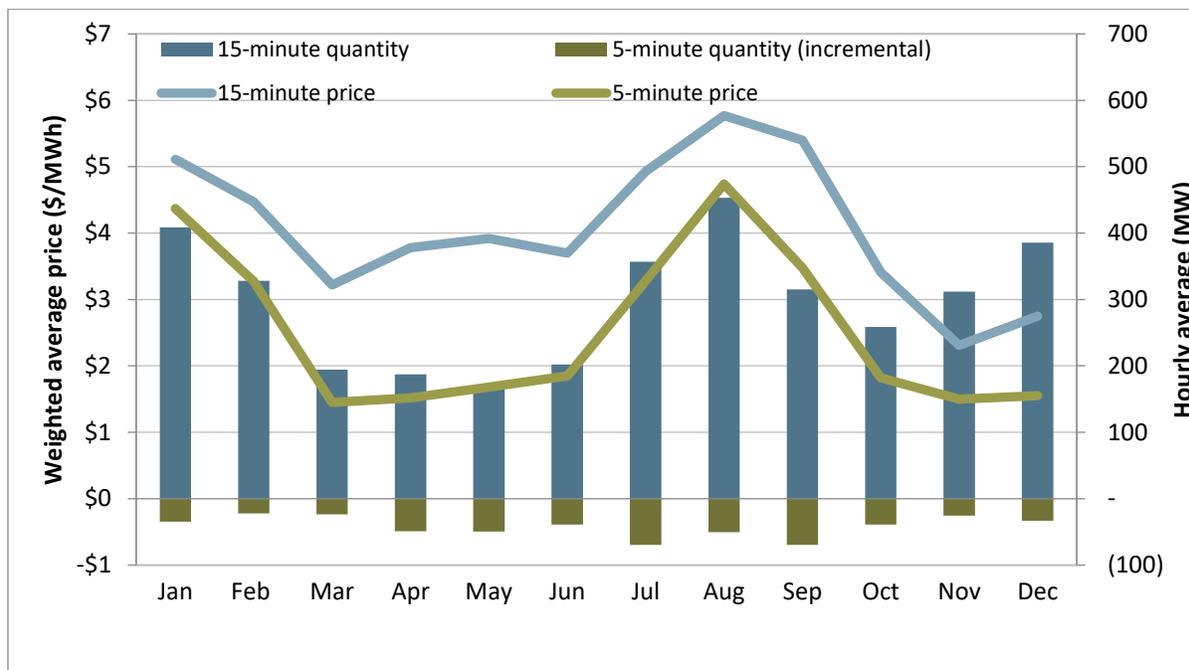


Figure 4.11 shows the hourly average energy deemed delivered to California by fuel type and balancing area.¹⁴⁹ In 2017, almost 65 percent of energy imbalance market greenhouse gas compliance obligations were assigned to hydro resources, compared to almost 48 percent in the previous year. The portion of energy transfers scheduled into the ISO assigned to gas was roughly 35 percent, down from over 52 percent in 2016. Non-gas and non-hydro accounted for less than 0.03 percent for the year.

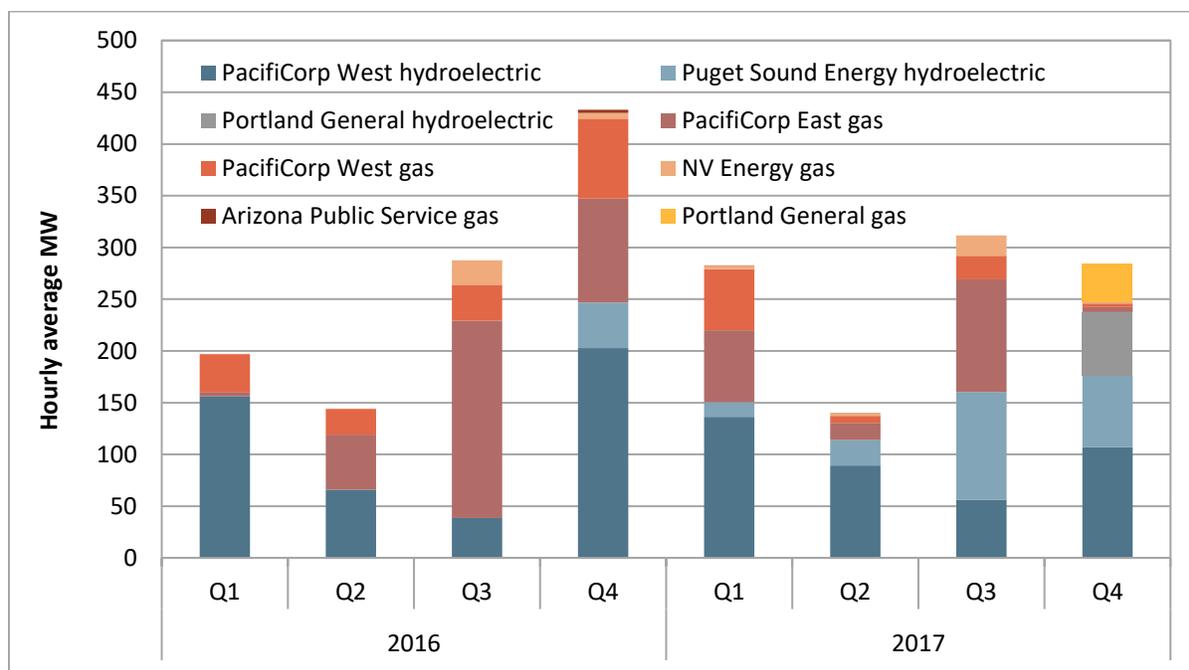
In November 2015, a rule change was implemented requiring non-emitting resources (such as hydro and wind) to bid greenhouse gas compliance costs at \$0/MWh or not bid in at all. The increase in hydro resources used to serve ISO load in 2017 likely also resulted from the addition of Portland General Electric in October as well as from greater rainfall and snowpack in 2017.

The ISO is currently engaged in a stakeholder process to address concerns that the current market design does not capture the full greenhouse gas effect of energy imbalance market imports into California on emissions for compliance with California’s cap-and-trade regulation. The California Air

¹⁴⁹ Minimal quantities were deemed delivered from two additional fuel type balancing area combinations not shown on the graph. An hourly average of 5.95 MW of PacifiCorp East coal was deemed delivered in September. Puget Sound Energy gas was deemed delivered in October (1.67 MW on average) and December (0.39 MW on average).

Resources Board has characterized this issue as leakage.¹⁵⁰ Energy imbalance market design changes are being proposed as part of the ongoing stakeholder process.¹⁵¹

Figure 4.11 Hourly average EIM greenhouse gas megawatts by area and fuel



4.6 Flexible ramping sufficiency test

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

Since the beginning of the energy imbalance market in November 2014 there has been an upward ramping sufficiency test. Beginning in November 2016, the ISO implemented a downward ramping sufficiency test. If an area fails the upward sufficiency test, energy imbalance market transfers into that area cannot be increased.¹⁵² Similarly, if an area fails the downward sufficiency test, transfers out of that area cannot be increased. This effect on transfers can impact the feasibility of the market solution as well as price separation across balancing areas.

¹⁵⁰ Leakage is defined as a decrease in emissions in California that is offset by an increase in emissions outside of California.

¹⁵¹ Further information on the ISO's proposed changes is available here: <http://www.caiso.com/informed/Pages/StakeholderProcesses/RegionalIntegrationEIMGreenhouseGasCompliance.aspx>.

¹⁵² *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.

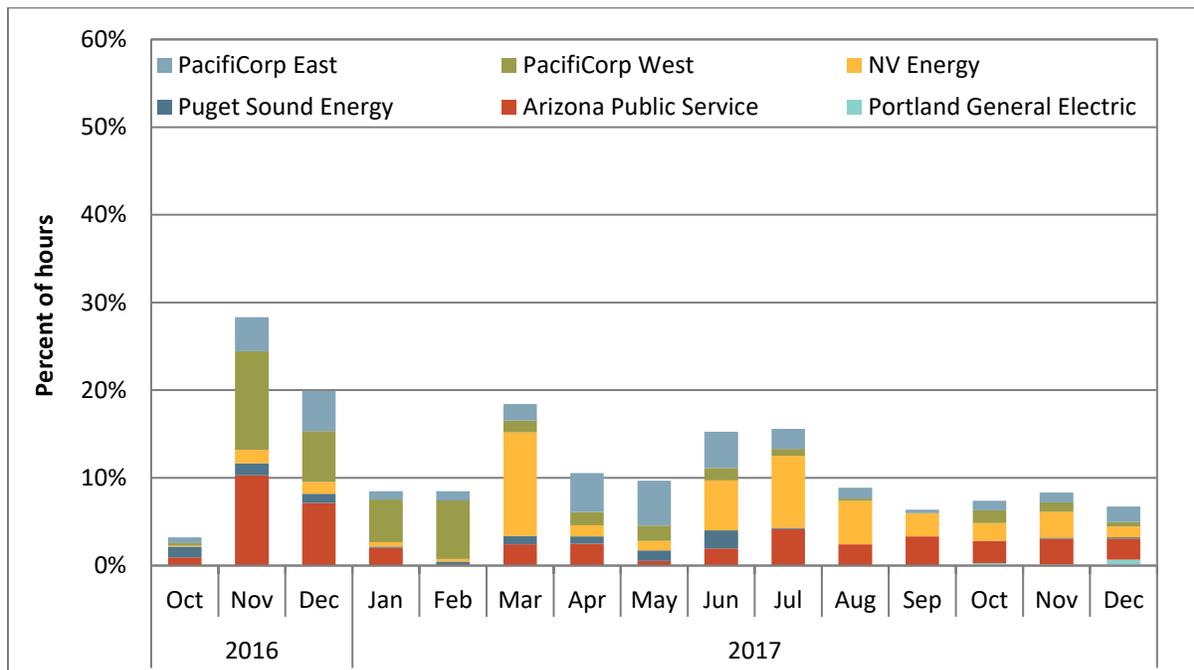
An area will also fail the flexible ramping sufficiency test for any hour when the capacity test fails. The capacity test is a test designed to ensure that there is sufficient resource capacity available to meet load forecasts and scheduled net exports for any given hour.¹⁵³

In November 2016, the ISO implemented the flexible ramping product, which replaced the flexible ramping constraint, as a new mechanism to ensure sufficient upward and downward ramping capability is available to account for forecast net load changes and ramping uncertainty. The ramping requirement also changed with the implementation of the flexible ramping product, set to the hourly 15-minute market uncertainty requirement.

Figure 4.12 shows the monthly frequency with which an energy imbalance market area failed the sufficiency test in the upward direction. As shown in Figure 4.12, the number of hours where an area failed the sufficiency test trended downward overall, compared to November and December 2016 following the implementation of the flexible ramping product. This is in part due to increased understanding and transparency of the flexible ramping sufficiency test since the requirements changed in November 2016.

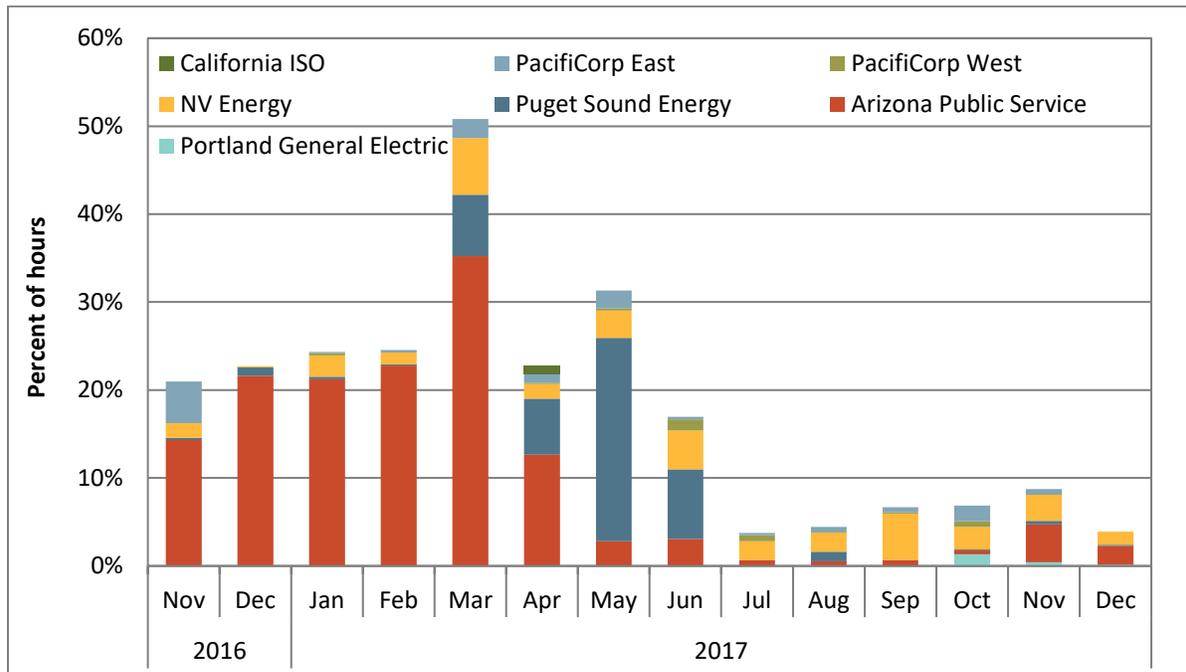
Figure 4.13 provides the same information on failed sufficiency tests for the downward direction. Notably, Arizona Public Service failed the downward sufficiency test significantly less frequently beginning in the second quarter, from around 23 percent of hours prior to April to less than 2 percent of hours between May and December.

Figure 4.12 Frequency of upward failed sufficiency tests by month



¹⁵³ *Business Practice Manual for the Energy Imbalance Market*, August 30, 2016, p. 45.

Figure 4.13 Frequency of downward failed sufficiency tests by month



Failures of the sufficiency tests are important because these outcomes limit transfer capability. Constraining transfer capability may impact the efficiency of the energy imbalance market by limiting transfers into and out of a balance area that could potentially provide benefits to other balancing areas. Reduced transfer capability also impacts the ability for an area to balance load, as there is less availability to import from or export to neighboring areas. This can result in local prices being set at power balance constraint penalty parameters. Although sufficiency test failures have resulted in frequent power balance constraint relaxations in Arizona Public Service, this did not have a large impact on prices because of the transition period pricing mechanism that was in place until April 2017 for the balancing area.¹⁵⁴

DMM has noted in previous reports that the use of net import capability and net export capability in the sufficiency test, as a function of the sufficiency test result in the previous hour, can block balancing areas from the benefit of a lower uncertainty requirement.¹⁵⁵ Failure of a test in one hour can increase the likelihood of failure in the next hour. DMM recommends that the ISO reevaluate this interaction to create a sufficiency test that preserves the independence of consecutive hourly sufficiency test results.

¹⁵⁴ For additional information on local power balance constraint results refer to Section 4.2.

¹⁵⁵ For a more detailed discussion of the issue, see *Q4 2017 Report on Market Issues and Performance*, February 2018, pp.61: <http://www.caiso.com/Documents/2017FourthQuarterReport-MarketIssues-PerformanceFebruary2018.pdf>.

4.7 Available balancing capacity

The ISO implemented the available balancing capacity (ABC) mechanism in the energy imbalance market in late March 2016. This enhancement allows for market recognition and accounting of capacity that entities in the energy imbalance market areas have available for reliable system operations, but is not bid into the market. Available balancing capacity is identified as upward capacity (to increase generation) or downward capacity (to decrease generation) by each energy imbalance market entity in their hourly resource plans. The available balancing capacity mechanism enables the ISO system software to deploy such capacity through the energy imbalance market, and prevents market infeasibilities that may arise without the availability of this capacity.¹⁵⁶

Figure 4.14 and Figure 4.15 summarize the frequency of upward and downward available balancing capacity offered in each energy imbalance market area during 2017. In the NV Energy area, there was some capacity in the upward and downward direction offered during almost all hours during 2017. Available balancing capacity in the downward direction in the PacifiCorp East area increased over the year. The frequency of offered available capacity by PacifiCorp West was low except for in the second quarter in the downward direction, when downward available balancing capacity was offered in around 63 percent of hours.

Arizona Public Service and Puget Sound Energy joined the energy imbalance market in the fourth quarter of 2016. The frequency of available balancing capacity offered by Arizona Public Service decreased during 2017, during less than 10 percent of hours between the second and fourth quarters in each direction. Puget Sound Energy offered available balancing capacity during around 93 percent of hours in the upward direction and 79 percent of hours in the downward direction. Portland General Electric joined the energy imbalance market in the fourth quarter of 2017 and offered available balancing capacity very infrequently during the quarter, during less than 1 percent of hours in each direction.

During hours when available balancing capacity was offered in an energy imbalance market area in 2017, the amount offered in the downward direction averaged 51 MW per balancing authority area for a given hour. The amount offered in the upward direction averaged 96 MW.

ISO data indicates that the dispatch of available balancing capacity was very infrequent in 2017, occurring in less than 1 percent of 5-minute market intervals.

¹⁵⁶ See December 17, 2015, Order Accepting Compliance Filing – Available Balancing Capacity (ER15-861-006): http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf.

Figure 4.14 Frequency of upward available balancing capacity offered

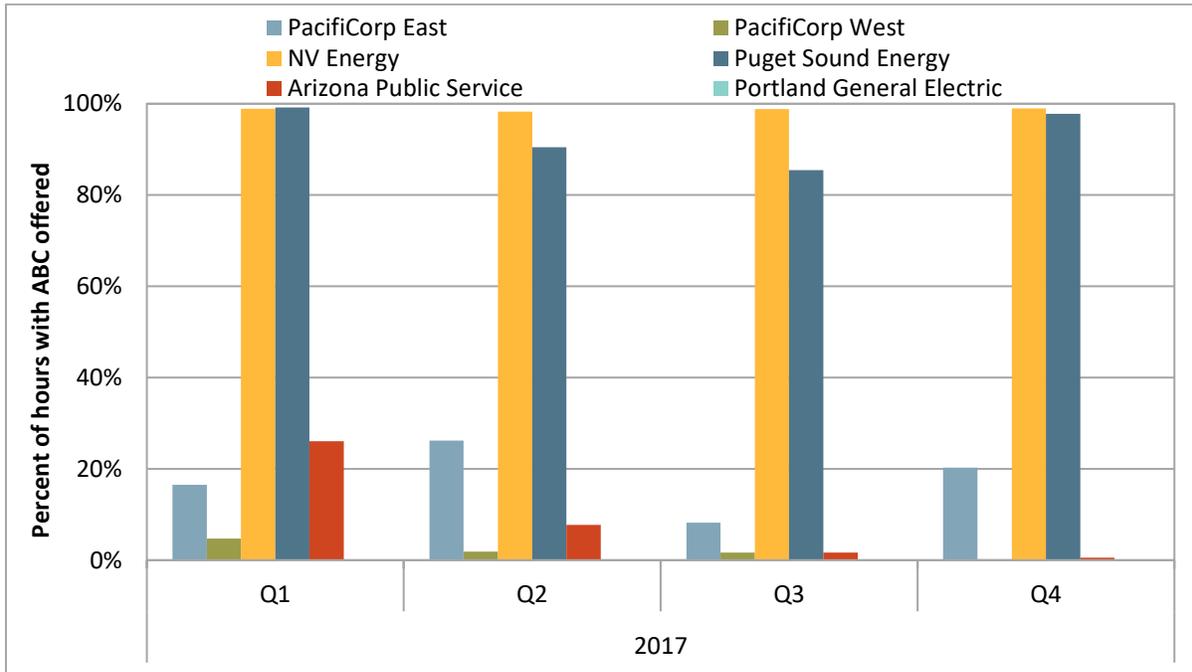
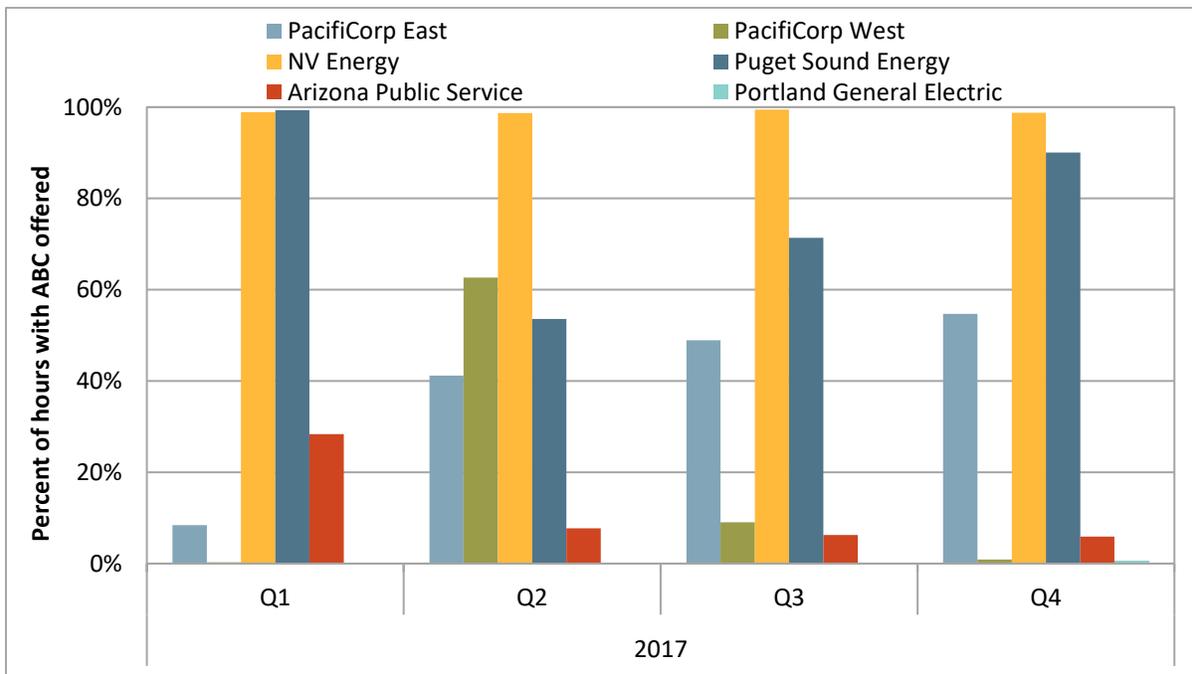


Figure 4.15 Frequency of downward available balancing capacity offered



5 Convergence bidding

2017 experienced decreased volumes of both cleared virtual supply and virtual demand. The decrease in cleared virtual supply halted a yearly trend towards increasing virtual supply that began in the latter half of 2013. Although the virtual supply trend was broken it still exceeded virtual demand by an average of about 640 MW per hour, compared to 780 MW in 2016. The percent of cleared virtual supply and demand decreased as well in 2017, 36 percent and 32 percent in 2017 respectively compared to about 45 percent each in 2016. This change may reflect convergence bidding entities adjusting for periods of increased average real-time prices during the evening net load ramping periods with occasional individual interval price spikes associated with high load periods.

Financial participants decrease in cleared net virtual MWs was the main driver of the overall decrease in net virtual supply and demand in 2017. Similar to financial participants, the virtual bidding activity from marketers decreased from 2016 while physical generation was mixed with increased virtual supply and decreased virtual demand. Compared to the previous year, physical load-serving entities dramatically decreased virtual supply while virtual demand dropped to zero from a very low 2 MWs.

Net revenues paid to entities engaging in convergence bidding totaled around \$12 million in 2017, compared to about \$14 million in 2016. This includes about \$9 million in bid cost recovery charges allocated to virtual bids. Most of these net revenues resulted from virtual supply bids. Despite generally higher net revenues on virtual supply, virtual bidders continued to place significant volumes of offsetting virtual demand and supply bids at different locations during the same hour. These offsetting bids, which are designed to hedge or profit from congestion, represented about 38 percent of all accepted virtual bids in 2016.

Residual unit commitment bid cost recovery costs paid by virtual supply continued to significantly reduce overall payments to virtual bidders. The portion of these costs allocated to virtual supply increased from about \$8 million in 2016 to about \$9 million in 2017. This increase was driven in part by high residual unit commitment levels in the first and second quarters of 2017 related to high volumes of net virtual supply combined with periods of low to moderate loads.

About 66 percent of net virtual bidding revenues were paid to financial entities that only participate in virtual bidding and congestion revenue rights in the ISO markets. About 27 percent of net revenues were received by marketers who also engaged in scheduling of imports and exports. Physical generators and load-serving entities received slightly over 4 percent of net virtual bidding revenues.

Background

Virtual bidding is a part of the Federal Energy Regulatory Commission's standard market design and is in place at all other ISOs with day-ahead energy markets. In the California ISO markets, virtual bidding is formally referred to as *convergence bidding*. The ISO implemented convergence bidding in February 2011.

Convergence bidding allows participants to place purely financial bids for supply or demand in the day-ahead energy market. These virtual supply and demand bids are treated similarly to physical supply and demand in the day-ahead market. However, all virtual bids clearing the day-ahead market are removed from the real-time markets, which are dispatched based only on physical supply and demand. Virtual bids accepted in the day-ahead market are liquidated financially in the real-time market as follows:

- Participants with virtual demand bids accepted in the day-ahead market pay the day-ahead price for this virtual demand. These virtual demand bids are then liquidated in the 15-minute real-time market and participants are paid the real-time price.
- Participants with accepted virtual supply bids are paid the day-ahead price for this virtual supply. These virtual supply bids are then liquidated in the 15-minute real-time market and participants are charged the real-time price.

Virtual bidding allows participants to profit from any difference between day-ahead and real-time prices. In theory, as participants take advantage of opportunities to profit through convergence bids, this activity should tend to converge prices in markets, as illustrated by the following:

- If prices in the real-time market tend to be higher than day-ahead market prices, convergence bidders will seek to arbitrage this price difference by placing virtual demand bids. Virtual demand will raise load in the day-ahead market and thereby increase prices. This increase in load and prices could also lead to the commitment of additional physical generating units in the day-ahead market, which in turn could tend to reduce average real-time prices. In this scenario, virtual demand could help improve price convergence by increasing day-ahead prices and reducing real-time prices.
- If real-time market prices tend to be lower than day-ahead market prices, convergence bidders will seek to profit by placing virtual supply bids. Virtual supply will tend to lower day-ahead prices by increasing supply in the day-ahead market. This increase in virtual supply and decrease in day-ahead prices could also reduce the amount of physical supply committed and scheduled in the day-ahead market.¹⁵⁷ This would tend to increase average real-time prices. In this scenario, virtual supply could help improve price convergence by reducing day-ahead prices and increasing real-time prices.

Convergence bidding also provides a mechanism for participants to hedge or speculate against price differences in the two following circumstances:

- price differences between the day-ahead and real-time markets; and
- congestion at different locations.

However, the degree to which convergence bidding has actually increased market efficiency by improving unit commitment and dispatches has not been assessed. In some cases, virtual bidding may be profitable for some market participants without increasing market efficiency significantly or may even decrease market efficiency.¹⁵⁸

¹⁵⁷ This will not create a reliability issue as the residual unit commitment process occurs after the integrated forward market run. The residual unit commitment process removes convergence bids and re-solves the market using the ISO forecasted load. If additional units are needed, the residual unit commitment process will commit more resources.

¹⁵⁸ A report reviewing the effectiveness of virtual bidding indicates that under certain conditions, virtual bidding may be parasitic to the market rather than adding value and improving efficiency. The report focused on issues that had been identified and noted in the California ISO markets. For more information see:

Parsons, John E., Cathleen Colbert, Jeremy Larriau, Taylor Martin and Erin Mastrangelo. 2015. *Financial Arbitrage and Efficient Dispatch in Wholesale Electricity Markets*. MIT Center for Energy and Environmental Policy Research, Working Paper, February.

Retrieved from http://www.mit.edu/~jparsons/publications/20150300_Financial_Arbitrage_and_Efficient_Dispatch.pdf.

Virtual bids at internal ISO locations accepted in the day-ahead market are settled against prices in the 15-minute market. Prior to implementation of the 15-minute market in May 2014, these bids were settled against 5-minute market prices. All results reported in this chapter reflect the prevailing settlement rules at the time the market ran.

Virtual bidding on interties was temporarily suspended in November 2011 due to issues with settlement of these bids that tended to lead to high revenue imbalance costs and reduced the potential benefits of virtual bids at nodes within the ISO system.¹⁵⁹ Virtual bidding on interties was scheduled to be re-implemented in May 2015. However, in April 2015, the ISO requested a waiver for the requirement to re-implement virtual bidding on interties for up to an additional 12-month period because of lack of liquidity in economic bidding in the 15-minute market.¹⁶⁰ FERC granted a temporary waiver delaying implementation of convergence bidding on the interties pending further review.¹⁶¹ In late September 2015, FERC issued an order requiring the ISO to remove tariff provisions that provided for reinstatement of convergence bids at interties.¹⁶² During 2017, DMM did not find any indication that reinstating virtual bidding on interties would be beneficial.

5.1 Convergence bidding trends

Convergence bidding volumes were relatively stable throughout the year, but net virtual supply began a decreasing trend beginning in the first quarter. This ended the increasing net virtual supply trend that began in the latter half of 2013. Figure 5.1 shows the quantities of both virtual demand and supply offered and cleared in the market. Figure 5.2 shows the average net cleared virtual positions for each operating hour.

Key convergence bidding trends include the following:

- On average, 35 percent of virtual supply and demand bids offered into the market cleared in 2017, compared to 45 percent in 2016.
- The average hourly cleared volume of virtual supply exceeded virtual demand during every quarter by about 640 MW per hour. This represents a break in the trend of increased net virtual supply, which grew from 450 MW in 2014, 580 MW in 2015, 780 MW in 2016 and now 640 MW. This change may be an indication of market participants adjusting to a less consistent predictable pattern of a systematically higher prices in the day-ahead market than the 15-minute market in 2017.
- Average hourly cleared virtual supply was about 1,410 MW in 2017, compared to about 1,850 MW in 2016. This decrease was mainly driven by a decrease in cleared virtual supply by both financial and physical load, 260 MW and 190 MW respectively. Marketers also slightly decreased cleared virtual supply in 2017, about 79 MW, while physical generation was an outlier and increased virtual supply

¹⁵⁹ As described in DMM's 2011 annual report, this problem was created by the fact that virtual bids at interties were settled on hour-ahead prices, while virtual bids at internal locations were settled at 5-minute prices. For further detail see the *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, pp. 77-79: <http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf>.

¹⁶⁰ *Potential market inefficiencies from convergence bidding at interties with insufficient liquidity of fifteen-minute bids*, Department of Market Monitoring, April 3, 2015: <http://www.caiso.com/Documents/DMMReport-ConvergenceBiddingonInterties.pdf>.

¹⁶¹ See: http://www.caiso.com/Documents/Apr29_2015_OrderGrantingWaiverRequest_IntertieVirtualBidding_ER15-1451_ER14-480.pdf.

¹⁶² For further details see: <http://www.ferc.gov/CalendarFiles/20150925164451-ER15-1451-000.pdf>.

by 80 MW in 2017. Average hourly cleared virtual demand decreased to 770 MW in 2017 from about 1,100 MW in 2016. This was mostly driven by a decrease in cleared virtual demand by financial participants.

Figure 5.1 Quarterly average virtual bids offered and cleared

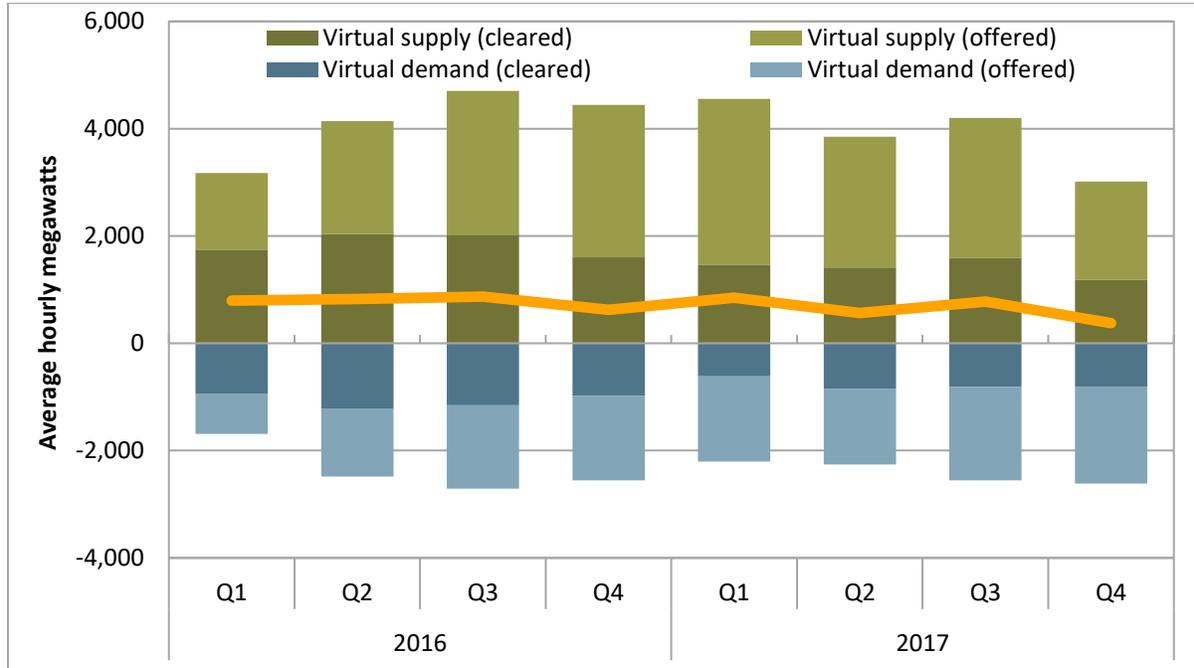
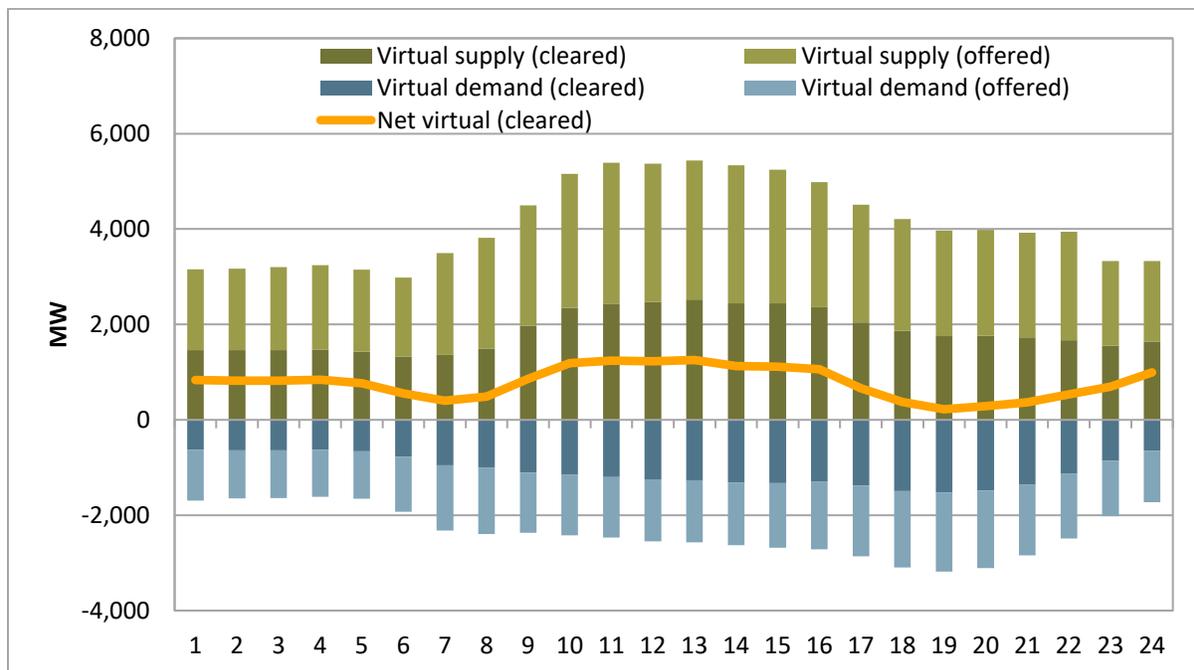


Figure 5.2 Average net cleared virtual bids in 2017



- Net virtual supply was most prevalent from March to October, where cleared virtual supply exceeded virtual demand by around 670 MW per hour on average, a decrease from about 900 MW for the same period in 2016. This coincides with the spring, summer, and fall months, when solar generation is at its highest.
- About 57 percent of cleared virtual positions in 2017 were held by financial participants, essentially same percent as 2016. Financial participants bid less virtual supply than demand in 2016, which contributed to the decline in net virtual supply. However, the major contributor to the decline in average hourly net virtual supply in 2017 was physical generation and load with a dramatic drop from 283 MW to 24 MW in 2017.
- Net virtual supply was lowest during ramping and peak hours. During the morning ramping hours (hours 6 through 8) average hourly net virtual supply was only 350 MW, and during evening peak hours (hours 17 through 21) average hourly net virtual supply was only 240 MW. Virtual supply outweighed virtual demand on average for every hour of the day.
- The need to rapidly increase output from generation in the evening hours for increasing load and declining solar generation resulted in tighter supply conditions and higher real-time prices relative to day-ahead prices. This made virtual demand more attractive to bidders during these hours versus other hours of the day.

Offsetting virtual supply and demand bids

Market participants can also hedge congestion costs or seek to profit from differences in congestion between different locations within the ISO system by placing equal quantities of 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. However, the combination of these offsetting bids can be profitable if there are differences in congestion in the day-ahead and real-time markets between these two locations.

Offsetting virtual positions accounted for an average of about 400 MW of virtual demand offset by 400 MW of virtual supply during each hour in 2017, a decrease from about 700 MW in 2016. The share of these offsetting bids decreased to about 38 percent of all cleared virtual bids in 2017 from about 49 percent in 2016. Offsetting bids made up 29 percent of cleared virtual supply and 54 percent of cleared virtual demand during 2017.

The decrease in offsetting virtual positions suggests that while virtual bidding continues to be used to hedge or profit from congestion, it was used to a lesser extent than in prior years. This is likely because of low levels of congestion during the last couple years.

Consistency of price differences and volumes

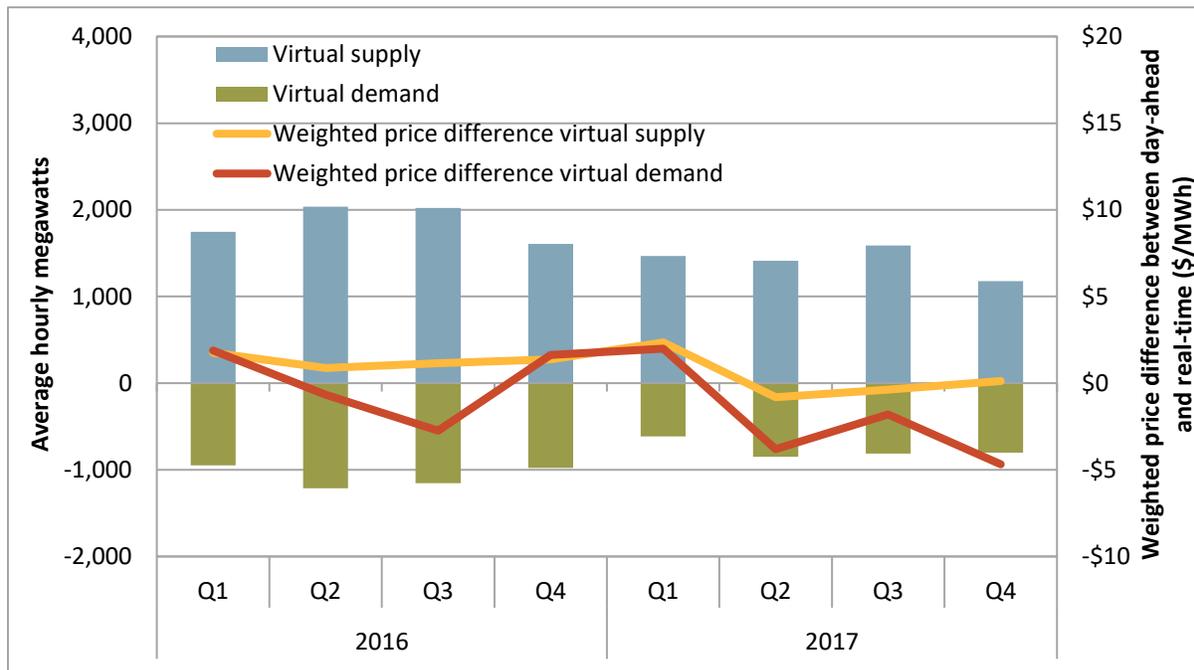
Convergence bidding is designed to help make day-ahead and real-time prices more consistent. Virtual bids are profitable when the net market virtual position is directionally consistent with the price difference between the two markets. Net convergence bidding volumes were generally consistent with price differences in most hours during 2017. Compared to the previous year, net convergence bidding volumes, on average, were slightly less consistent with price differences between the day-ahead and real-time markets. This is primarily due to a select number of days where real-time prices were considerably higher than day-ahead prices in the evening net ramping hours.

Figure 5.3 compares cleared convergence bidding volumes with the volume-weighted average price differences at which these virtual bids were settled. The difference between day-ahead and real-time prices shown in this figure represents the average price difference weighted by the amount of virtual bids cleared at different locations.

Periods when the red line is negative indicate that the weighted average price charged for virtual demand in the day-ahead market was lower than the weighted average real-time price paid for this virtual demand and, thus, was a profitable period. In 2017, virtual demand positions were profitable in all but the first quarter. The profitable quarters were largely due single day events associated with very high loads.

Quarters that the yellow line is positive indicate a higher weighted average price paid for virtual supply in the day-ahead market than the weighted average real-time price charged when this virtual supply was liquidated in the real-time market. Unlike 2016, virtual supply was not consistently profitable in all quarters in 2017 but largely only profitable in the first quarter with nearly a break-even in the fourth quarter.

Figure 5.3 Convergence bidding volumes and weighted price differences

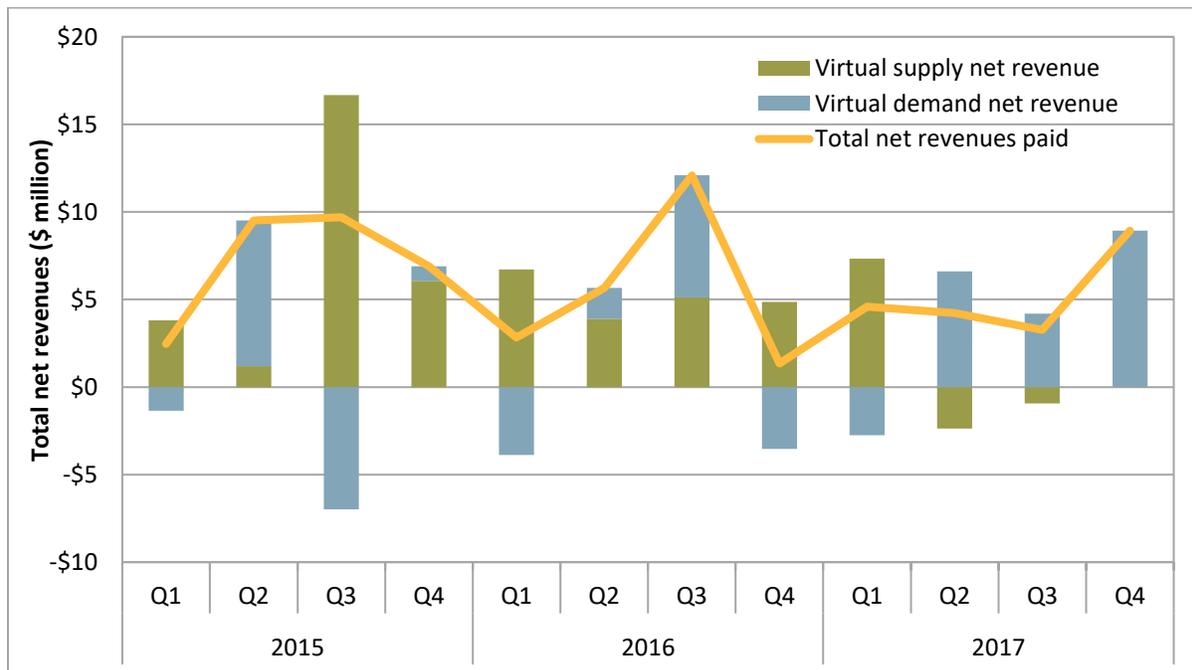


As noted earlier, a large portion of the virtual supply clearing the market was paired with demand bids at different locations by the same market participant. Such offsetting virtual supply and demand bids are likely used as a way of hedging or speculating from congestion within the ISO. When virtual 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 due to congestion.

5.2 Convergence bidding payments

Net revenues paid to convergence bidders (prior to any allocation of bid cost recovery payments) totaled about \$21 million in 2017, down less than \$1 million or about 4 percent from 2016. Unlike 2016, the large majority of these profits were associated with virtual demand. Figure 5.4 shows total quarterly net profits paid for accepted virtual supply and demand bids.

Figure 5.4 Total quarterly net revenues from convergence bidding



As shown in Figure 5.4:

- Most net revenue (\$17 million) was generated from cleared virtual demand. The remaining \$4 million of net revenue was generated from cleared virtual supply.
- Virtual demand positions were profitable in all but the first quarter of 2017. This trend reflects that revenues on virtual demand bids placed in net load ramp down hours were more volatile and positive 15-minute market price spikes were more frequent. Virtual demand profitability occurred even as the average day-ahead prices increased between 2016 and 2017.
- In the first quarter, virtual supply positions were profitable with revenues totaling nearly \$5 million. The remaining quarters of the year virtual demand revenues totaled over \$19 million. Generally, 15-minute market prices were lower than day-ahead prices non-net load ramping hours for most of the year, this is consistent with prior years. The net load ramping hours, particularly hour-end 19 to hour-end 21, experienced a number of significantly higher prices in the real-time market thus increasing virtual demand revenue and decreasing virtual supply revenue.
- Total net revenues for virtual bidders peaked in the fourth quarter at almost \$9 million, more than double net revenues from any other quarter during 2017. Prices in the 15-minute market in

October made virtual demand more profitable during the quarter and reduced the profitability for virtual supply. Total net revenues were lowest in the third quarter at \$3.3 million.

Net revenues and volumes by participant type

Just over 80 percent of total revenues were derived from virtual demand in 2017. This is in contrast to 2016 where about 94 percent of total revenues were from virtual supply. Additionally, average virtual demand hourly megawatts decreased year-over-year, 750 megawatts in 2017 and 943 megawatts in 2016.

Most convergence bidding activity is typically conducted by entities engaging in purely financial trading that do not serve load or transact physical supply. These entities accounted for about \$14 million, or 66 percent, of the total convergence bidding revenues in 2017. This was similar to 2016. In contrast to 2016 most of the revenues in 2017 were associated with virtual demand, \$17 million in 2017 compared to \$1.3 million the previous year. Marketers, the second largest trading entity in terms of revenue and trading volume, also received increased revenue from virtual demand to \$4.8 million in 2017 compared to \$2.3 million in 2016.

Table 5.1 compares the distribution of convergence bidding volumes and revenues among different groups of convergence bidding participants. The trading volumes show cleared virtual positions along with the corresponding revenues in millions of dollars.

Table 5.1 Convergence bidding volumes and revenues by participant type (2017)

Trading entities	Average hourly megawatts			Revenues\Losses (\$ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	484	750	1,233	\$11.3	\$2.9	\$14.2
Marketer	267	415	682	\$4.8	\$1.0	\$5.9
Physical generation	0	223	223	\$0.0	-\$0.2	-\$0.2
Physical load	19	24	43	\$0.9	\$0.2	\$1.1
Total	770	1,411	2,181	\$17.0	\$4.0	\$21.0

DMM categorizes participants who own no physical energy and participate in only the convergence bidding and congestion revenue rights markets as financial entities. Physical generation and load are categories of participants that primarily participate in the ISO 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 markets.

As shown in Table 5.1, financial participants represent the largest segment of the virtual market, accounting for about 57 percent of cleared volume and about 66 percent of revenue. Volumes were similar to 2016 while revenue increased about 6 percent. Marketers represent about 31 and 27 percent of volume and revenue, respectively. Generation owners and load-serving entities represent over 12 percent of the volume, but only about 4 percent of revenue.

Although Table 5.1 also shows that all participant types held significantly more virtual supply than virtual demand the lion's share of the revenues were from virtual demand. The 'flip' in revenue source from virtual supply in the previous year to virtual demand in 2017 can be attributed to a few days with sustained high real-time prices.

5.3 Bid cost recovery charges to virtual bids

As previously noted, virtual supply and demand bids are treated similarly to physical supply and demand in the day-ahead market. However, virtual bids are excluded from the day-ahead market processes for price mitigation and grid reliability (local market power mitigation and residual unit commitment). This impacts how physical supply is committed in both the integrated forward market and in the residual unit commitment process.¹⁶³ When the ISO commits units, it may pay market participants through the bid cost recovery mechanism to ensure that market participants are able to recover start-up costs, minimum load costs, transition costs, and incremental energy bid costs.¹⁶⁴

Because virtual bids can influence unit commitment, they share in the associated costs. Specifically, virtual bids can be charged for bid cost recovery payments under two charge codes.¹⁶⁵

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.¹⁶⁶ In this case, virtual demand leads to increased unit commitment in the day-ahead market, which may not be economic.
- Day-ahead residual unit commitment tier 1 allocation relates to situations where the day-ahead market clears with positive net virtual supply.¹⁶⁷ In this case, virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in the residual unit commitment, which may not be economic.

The day-ahead residual unit commitment tier 1 allocation charge associated with virtual supply increased from the previous year, particularly during the first quarter where bid cost recovery charges were just under \$4.7 million as a result of higher overall residual unit commitment costs, this equated to about 50 percent of the total bid cost recovery charges for the year. As a result, virtual bidders paid more during the first quarter than they received after accounting for these charges. This quarterly situation has only occurred three times since implementation of virtual bidding in the market in 2011, with two of these quarters were back-to-back, Q4 2016 and Q1 2017. About 9 percent of bid cost recovery charges during 2017 were attributed to the day-ahead residual unit commitment tier 1 allocation charge, a decrease from about 11 percent in the previous year. Overall positive revenues returned to the virtual markets again beginning in the second quarter of 2017.

Figure 5.5 shows estimated total convergence bidding revenues, total revenues less bid cost recovery charges, and costs associated with the two charge codes. The total convergence bidding bid cost recovery costs for the year were about \$9.4 million, an increase from around \$8 million in 2016. As noted earlier, the total 2017 estimated net revenue for convergence bidding was around \$21 million.

¹⁶³ If physical generation resources clearing the day-ahead energy market are less than the ISO's forecasted demand, the residual unit commitment process ensures that enough additional physical capacity is available to meet the forecasted demand. Convergence bidding increases unit commitment requirements to ensure sufficient generation in real time when the net position is virtual supply. The opposite is true when virtual demand exceeds virtual supply.

¹⁶⁴ Generating units, pumped-storage units, or resource-specific system resources are eligible to receive bid cost recovery payments.

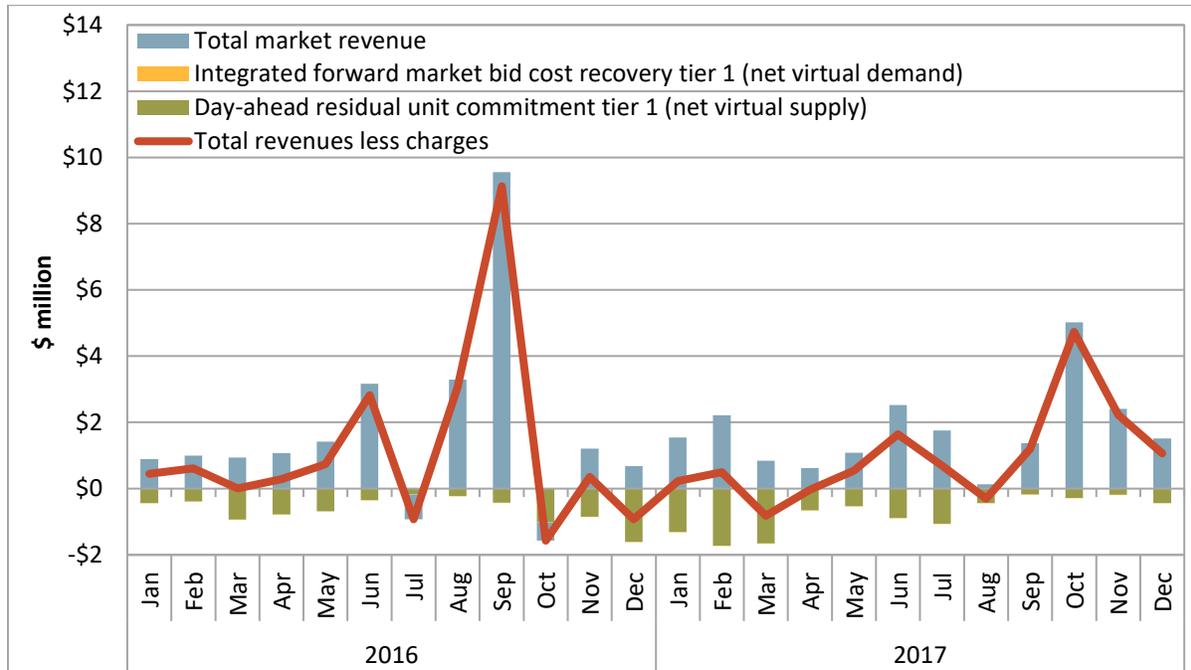
¹⁶⁵ Both charge codes are calculated by hour and charged on a daily basis.

¹⁶⁶ For further detail, see Business Practice Manual configuration guides for charge code (CC) 6636, IFM Bid Cost Recovery Tier1 Allocation_5.1a: <http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing>.

¹⁶⁷ For further detail, see Business Practice Manual configuration guides for charge code (CC) 6806, Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocation_5.5: <http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing>.

Adjusting this total by the bid cost recovery costs allocated to virtual bids results in total convergence bidding revenue of about \$11.7 million.

Figure 5.5 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and RUC tier 1



6 Ancillary services

This chapter provides a summary of the ancillary service market in 2017. Key trends highlighted in this chapter include the following:

- Ancillary service costs increased to \$172 million, up from \$119 million in 2016 and \$62 million in 2015. The increase in operating reserve costs was primarily driven by tight supply conditions and higher operating reserve requirements during the summer.
- On June 14, the ISO began increasing operating reserve requirements during midday hours to account for solar generation in the system by using an existing functionality within the software that allows operators to increase the requirement by a specified percent of the load forecast. Starting on September 19, the upward adjustments were removed.
- Average day-ahead requirements for regulation up and down decreased by about 22 percent and 14 percent from 2016, respectively. This is primarily the result of manually increased regulation requirements during the spring months of 2016 whereas the new regulation requirement methodology was in place for all of 2017.
- There were a total of 54 intervals in the 15-minute market with ancillary service scarcity events in 2017.

A detailed description of the ancillary service market design, implemented in 2009, is provided in DMM's 2010 annual report.¹⁶⁸ This market design includes co-optimizing energy and ancillary service bids provided by each resource. With co-optimization, units are able to bid all of their capacity into the energy and ancillary service markets without risking the loss of revenue in one market when their capacity is sold in the other. Co-optimization allows the market software to determine the most efficient use of each unit's capacity for energy and ancillary services.

6.1 Ancillary service costs

Ancillary service costs increased to \$0.75/MWh of load served in 2017 from \$0.52/MWh in 2016. This represents an increase from about 1.6 percent of total wholesale energy costs in 2016 to 1.9 percent in 2017. These are the highest yearly values since 2011, both as a percentage of wholesale energy costs and per megawatt-hour of load. The cost increase was primarily related to an increase in operating reserve costs. More information about this increase is provided in the next section.

Figure 6.1 illustrates ancillary service costs both as a percentage of wholesale energy costs and per megawatt-hour of load from 2012 through 2017. Figure 6.2 shows the same costs broken out by quarter for 2016 and 2017. In 2017 costs were highest in the second and third quarters, when the operating reserve requirements were also highest. For the third quarter, ancillary service cost reached \$0.92/MWh of load.

¹⁶⁸ 2010 Annual Report on Market Issues and Performance, Department of Market Monitoring, April 2011, pp. 139-142: <http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf>.

Figure 6.1 Ancillary service cost as a percentage of wholesale energy costs (2012-2017)

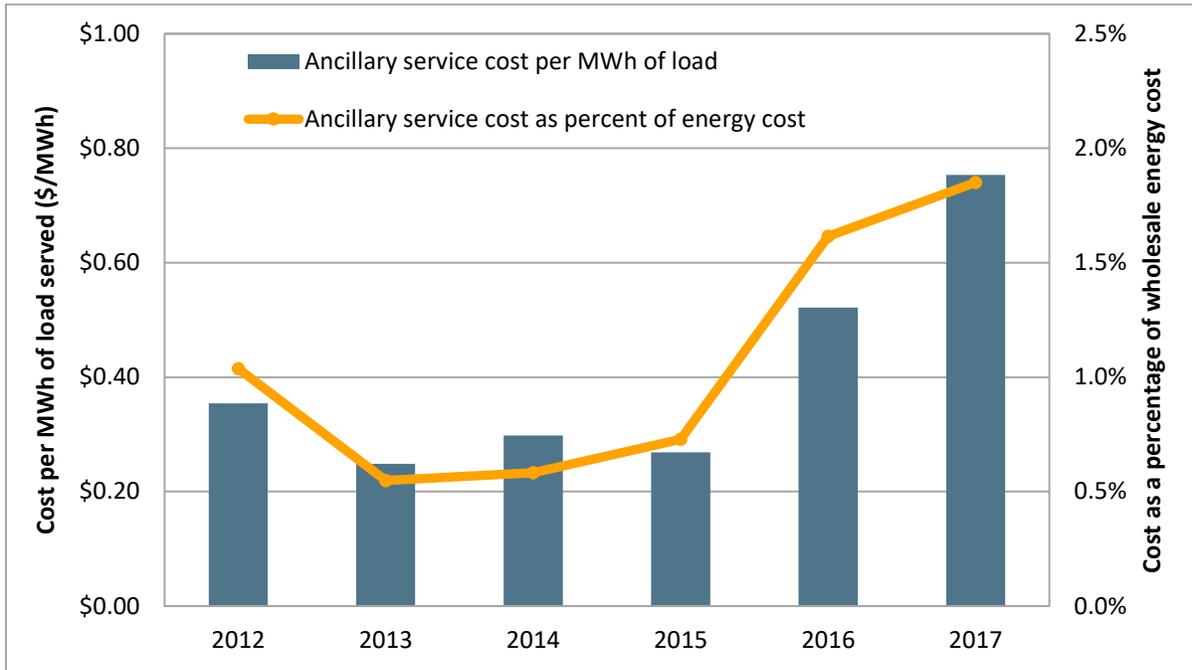
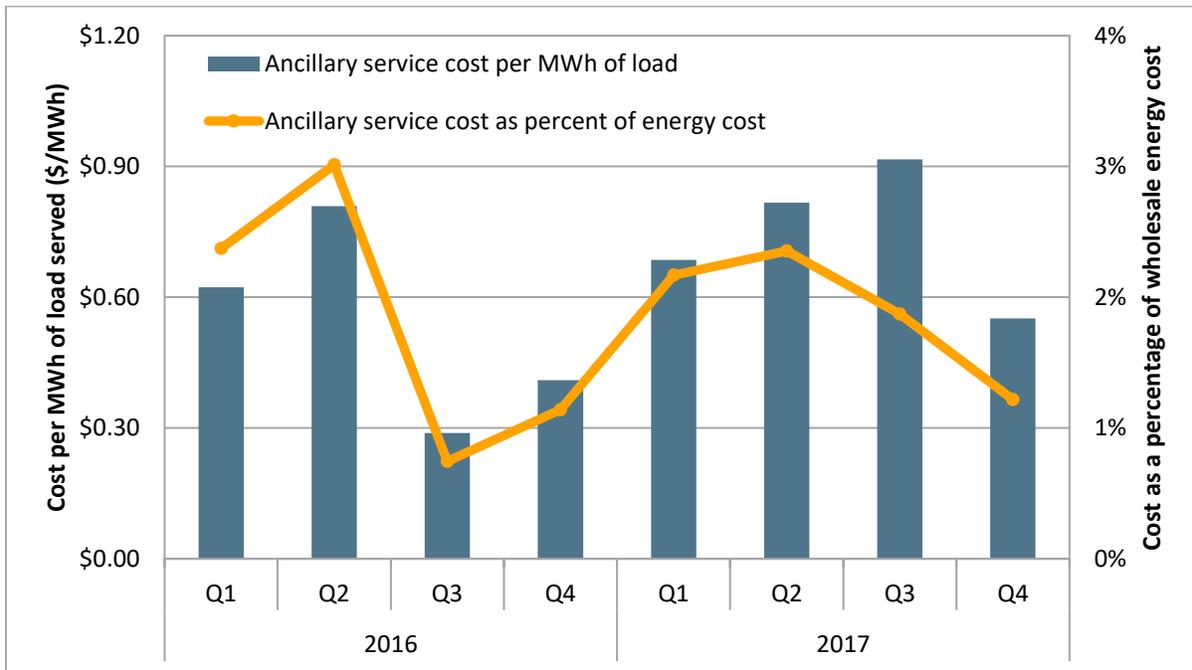


Figure 6.2 Ancillary service cost by quarter



6.2 Ancillary service requirements and procurement

The ISO procures four ancillary services in the day-ahead and real-time markets: regulation up, regulation down, spinning reserves, and non-spinning reserves.¹⁶⁹ Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's minimum operating reliability criteria and North American Electric Reliability Corporation's control performance standards. To the extent possible, the ISO attempts to procure all ancillary services in the day-ahead market. Additional ancillary services are procured in the real-time market, for example, to replace unavailable capacity.

The ISO can procure ancillary services from 10 predefined regions. This includes an internal system region, an 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 inertias. 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 an internal 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-002-2.¹⁷⁰

Operating reserve requirements

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

On June 8, 2017, the North American Electric Reliability Corporation published a report that found a previously unknown reliability risk related to a frequency measurement error that can potentially cause

¹⁶⁹ In addition, in June 2013 the ISO added a performance payment referred to as mileage to the regulation up and down markets, in addition to the existing capacity payment system.

¹⁷⁰ 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-ContingencyReserveforRecoveryfromaBalancingContingencyEvent.pdf> or in the NERC BAL-002-2 reliability standard here: <http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-2.pdf>.

a large loss of solar generation. Although the WECC and NERC requirements did not change, the ISO made an upward adjustment to the operating reserve requirements starting with trade date June 14 to account for a potential loss of solar generation in the system. The ISO has indicated that the new total operating reserve requirements were set to the maximum of (1) the NERC or WECC required operating reserves and (2) up to 25 percent of total solar production.¹⁷¹

However, this functionality does not currently exist in the software. Instead, beginning on June 14, operators increased the percent specified for the load forecast component of the calculation during midday hours to very roughly meet the new solar criteria using the existing tools available within the software. Between June 14 and June 20, a 2 percent load forecast adder was used. Between June 21 and June 24, this was reduced to 1 percent. Between June 25 and September 18, day-ahead and real-time operating reserve requirements have been frequently increased upward by 1.5 percent of the load forecast during midday hours.¹⁷² Starting on September 19, the upward adjustments were removed after the ISO indicated issue remediation had occurred such that the 25 percent solar criteria was reduced to 15 percent.¹⁷³

Figure 6.3 shows *actual* hourly average operating reserve requirements between June 14 and September 18 with the application of the load forecast adders as well as *estimated* hourly average operating reserve requirements during the same period without any adjustment to the requirement.¹⁷⁴ The figure also includes 25 percent of average real-time solar forecasts as a point of comparison. Between July 1 and September 18, the application of these load-based adjustments has often resulted in requirements that are higher than what would be expected using 25 percent of solar.

The Federal Energy Regulatory Commission approved new definitions along with BAL-002-2, effective January 1, 2018, that required the ISO to reevaluate the most severe single contingency. This change resulted in a significant increase to the operating reserve requirements after January 1, 2018, to cover the potential sudden loss of scheduling on the Pacific DC Intertie.

¹⁷¹ *Market Notice – California ISO Temporary Increase Procurement of Operating Reserves*, July 12, 2017:

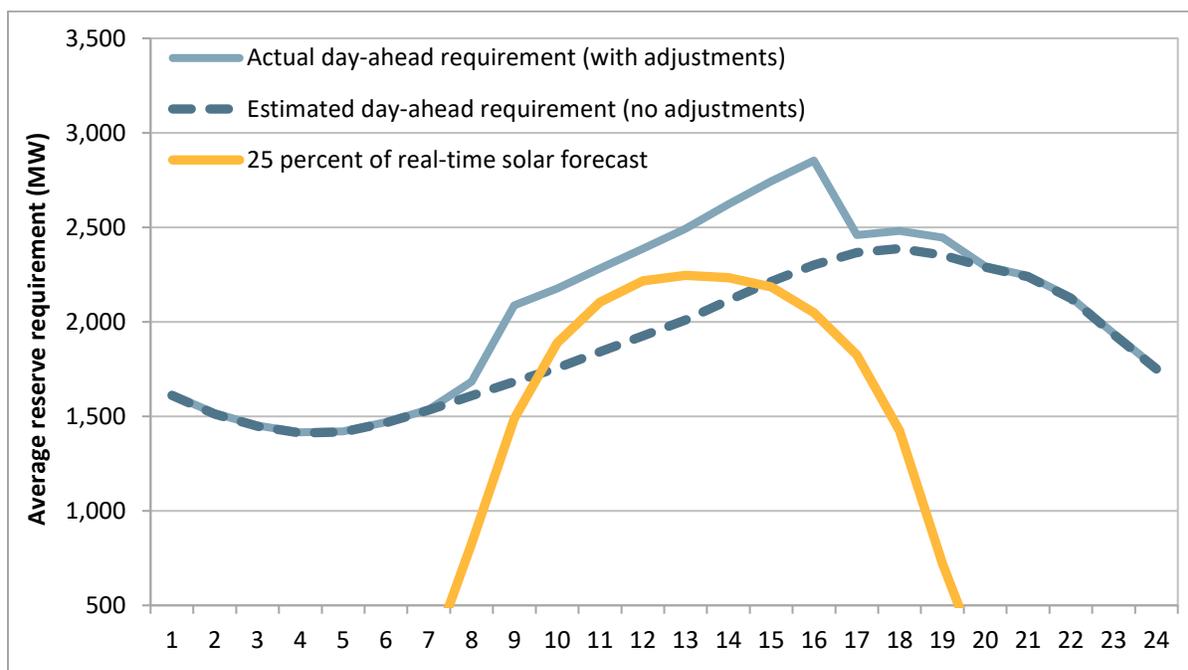
<http://www.caiso.com/Documents/CaliforniaISOTemporaryIncreaseProcurement-OperatingReserves.html>

¹⁷² The upward adjustments to the operating reserve requirements were manually reduced to 0.5 percent of the load forecast between August 30 and September 3 when loads were very high.

¹⁷³ *Adjustment to Temporary Increase of Daily Operating Reserves Procurement*, September 14, 2017:

http://www.caiso.com/Documents/Adjustment_TemporaryIncrease_DailyOperatingReservesProcurement.html

¹⁷⁴ The load forecast adders applied in day-ahead have also been typically applied in real-time for the same hours. In Figure 6.3, corresponding values for the real-time requirement are not included, but show a similar pattern, though at slightly lower values.

Figure 6.3 Hourly average operating reserve requirements (June 14 – September 18)

Regulation requirements

Prior to 2016, the ISO determined day-ahead regulation requirements using a regulation forecasting tool based on changes in the load forecast and changes in self-scheduled generation.¹⁷⁵ The regulation requirements from this tool were bound to remain between 300 MW and 400 MW. Because of this narrow range, the requirements did not vary much over time. Further, real-time requirements were consistently set to 300 MW for all intervals.

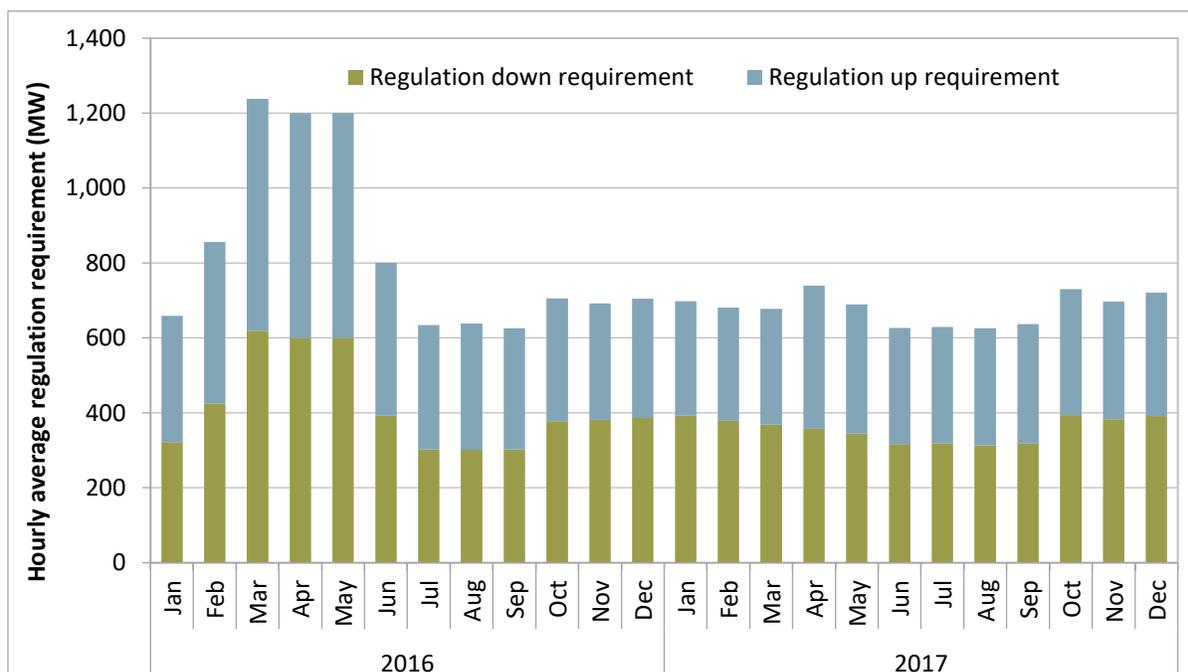
In early 2016 the ISO observed an increased need for regulation to balance variable renewable generation. Therefore, during the period between February 20 and June 9, the ISO increased regulation requirements in the day-ahead and real-time markets to 600 MW for both regulation up and regulation down across all hours of the day. On some days in late February and early March 2016, when weather forecasts indicated high renewable generation volatility, ISO operators further increased the procurement targets to 800 MW. During the summer months of 2016, when renewable generation was less variable, the ISO again used the previous forecasting tool to set regulation requirements between 300 MW and 400 MW.

The ISO began using a new method for determining day-ahead regulation procurement requirements on October 10, 2016. The new method calculates regulation requirements based on observed regulation needs during the same time period in the prior year. Requirements are calculated for each hour of the day, and the values are updated regularly. Furthermore, the ISO can adjust requirements manually for periods when conditions indicate higher net load variability. Compared to the previous tool, requirements are allowed to vary within a wider range.

¹⁷⁵ More information about the tool can be found in this Technical Bulletin: <https://www.caiso.com/Documents/TechnicalBulletin-ASProcurement-Regulation.pdf>.

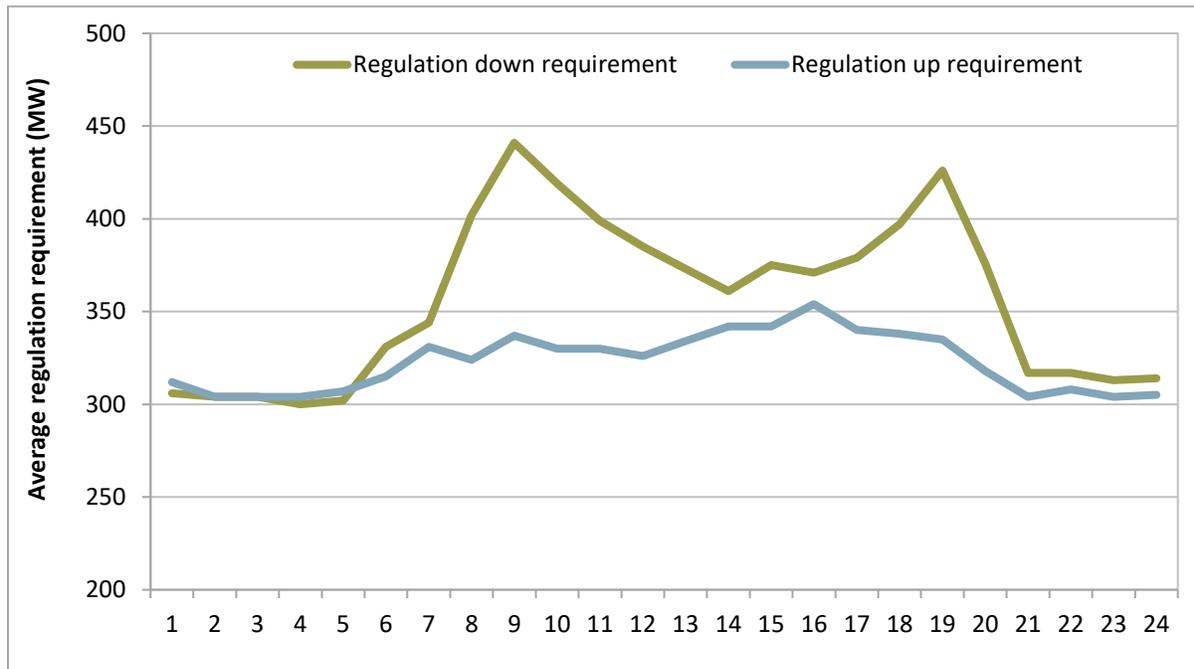
Figure 6.4 shows average day-ahead regulation requirements by month since the methodology update on October 10, 2016. During 2017, day-ahead requirements averaged around 320 MW for regulation up and 360 MW for regulation down. Compared to 2016, this represents a decrease of about 22 percent for regulation up and 14 percent for regulation down. In the real-time market, average requirements were very similar to requirements in the day-ahead market during 2017.

Figure 6.4 Monthly average day-ahead regulation requirements



During 2017, regulation requirements were typically set at increments of 50 MW between 300 MW and 500 MW. Figure 6.5 summarizes the average hourly profile of the day-ahead regulation requirements in this period. Regulation up requirements were highest during afternoon hours when solar is ramping off. Requirements for regulation down were typically higher in the late morning hours when solar is ramping on and evening hours when load is ramping off. Requirements for regulation down were typically higher than requirements for regulation up, particular doing midday hours. This reflects a larger need for regulation down during the historical period used for calculating regulation requirements.

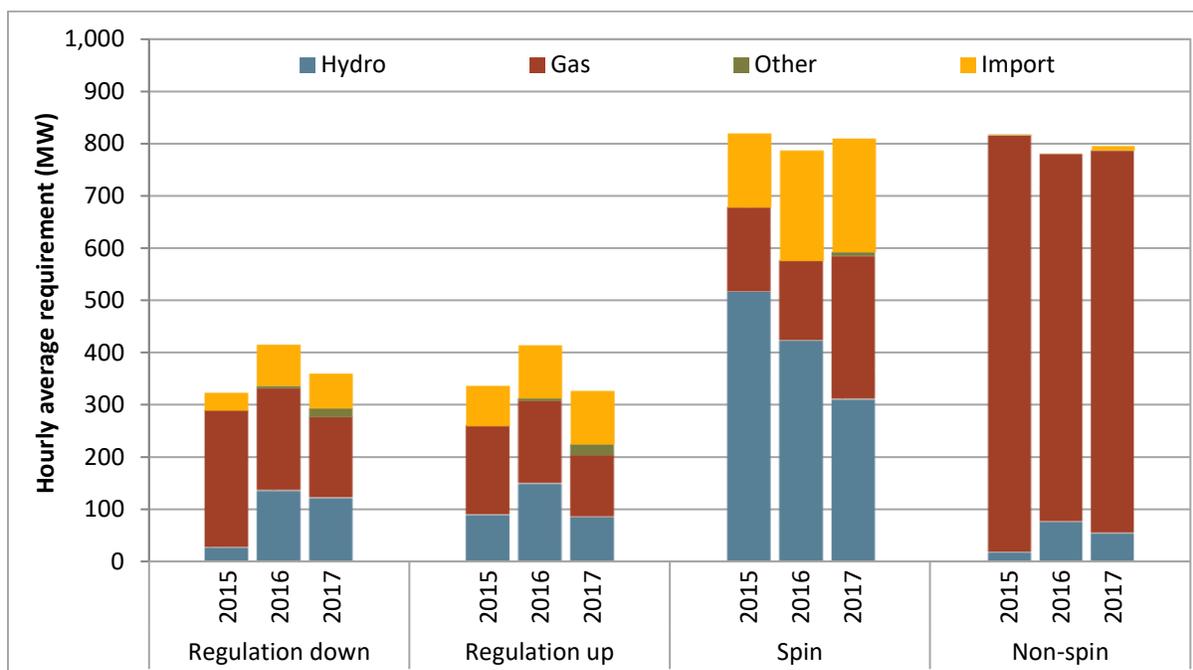
Figure 6.5 Hourly average day-ahead regulation requirements (2017)



Ancillary service procurement by fuel

Figure 6.6 shows the portion of ancillary services procured by fuel type from 2015 through 2017. Ancillary service requirements are met by both internal resources and imports. Ancillary service imports are indirectly limited by minimum requirements set for procurement of ancillary services from within the ISO system. In addition, ancillary services that bid across interties have to compete for transmission capacity with energy. Most ancillary service requirements continue to be met by ISO resources, partly because scheduling coordinators awarded ancillary services are charged applicable intertie congestion rates.

Figure 6.6 Procurement by internal resources and imports



Total procurement of regulation in 2017 decreased compared to 2016. This is primarily the result of manually increased regulation requirements during the spring months of 2016 whereas the new regulation requirement methodology was in place for all of 2017. Total procurement of spinning and non-spinning reserves increased from the previous year because of increased operating reserve requirements during midday hours between June 14 and September 18. The composition of ancillary service resources is characterized as follows:

- Compared to 2016, hydro-electric resources in 2017 provided a smaller proportion of ancillary services overall although there were improved hydro-electric generation conditions. This reflects a shift towards hydro-electric production in lieu of ancillary services. Average hourly provision of ancillary services from hydro-electric resources decreased in 2017 to 574 MW. This is a 27 percent decrease from around 786 MW in 2016.
- Average hourly procurement of ancillary service imports was about the same from the previous year at around 390 MW. Imports provided 18 percent of regulation down capacity, 31 percent of regulation up capacity, 27 percent of spinning reserves and 1 percent of non-spinning reserves.
- Gas-fired resources provided 1,276 MW on average in 2017, up 6 percent from 1,208 MW in 2016. These resources provided the vast majority of non-spinning reserves, as in previous years. Further, gas-fired resources increased their share of spinning reserves to 34 percent, up from 19 percent in the previous year.
- Average hourly provision of ancillary services from limited energy storage resources which includes batteries and other limited devices increased significantly during 2017, but remained low overall. Average hourly procurement from these resources increased from around 11 MW in 2016 to 48 MW in 2017, or about 2 percent of ancillary service procurement.

6.3 Ancillary service pricing

Resources providing ancillary services receive a capacity payment at market clearing prices in both the day-ahead and real-time markets. Capacity payments in the real-time market are only for incremental capacity above the day-ahead award. Figure 6.7 and Figure 6.8 show the weighted average market clearing prices for each ancillary service product by quarter in the day-ahead and real-time markets during 2016 and 2017.

As seen in Figure 6.7, weighted average day-ahead prices increased from 2016 to 2017 for all ancillary services except regulation down. The increase was largest for spin and non-spin operating reserves, primarily because of increased operating reserve requirements and tight supply conditions in the summer months. During the second and third quarter of 2017, when operating reserve requirements were the highest on average, weighted average day-ahead operating reserve prices reached more than double than the average operating reserve prices during 2016.

Weighted average ancillary service prices were higher in the real-time market than in the day-ahead market. In particular, weighted average spinning and non-spinning reserves were about \$20/MWh and \$17/MWh, respectively, in 2017. Real-time ancillary services were highest in the second and third quarter. This was mostly due to a higher number of intervals when prices in the 15-minute market were high which resulted in higher real-time average ancillary service prices. Further, operating reserve requirements were higher.

The weighted average market clearing prices for mileage up and mileage down remained low throughout 2017 in both the day-ahead and real-time markets. The day-ahead weighted average price for mileage up and mileage down was about the same from the previous year at about \$0.02 per unit in 2017. In the real-time market, weighted average mileage prices were slightly lower, averaging \$0.01 per unit for mileage up and mileage down in 2017. One reason for the low average prices of mileage is that the least-cost regulation resources often supplied enough mileage, resulting in frequent non-binding mileage requirements and \$0/MWh market clearing prices.

Figure 6.7 Day-ahead ancillary service market clearing prices

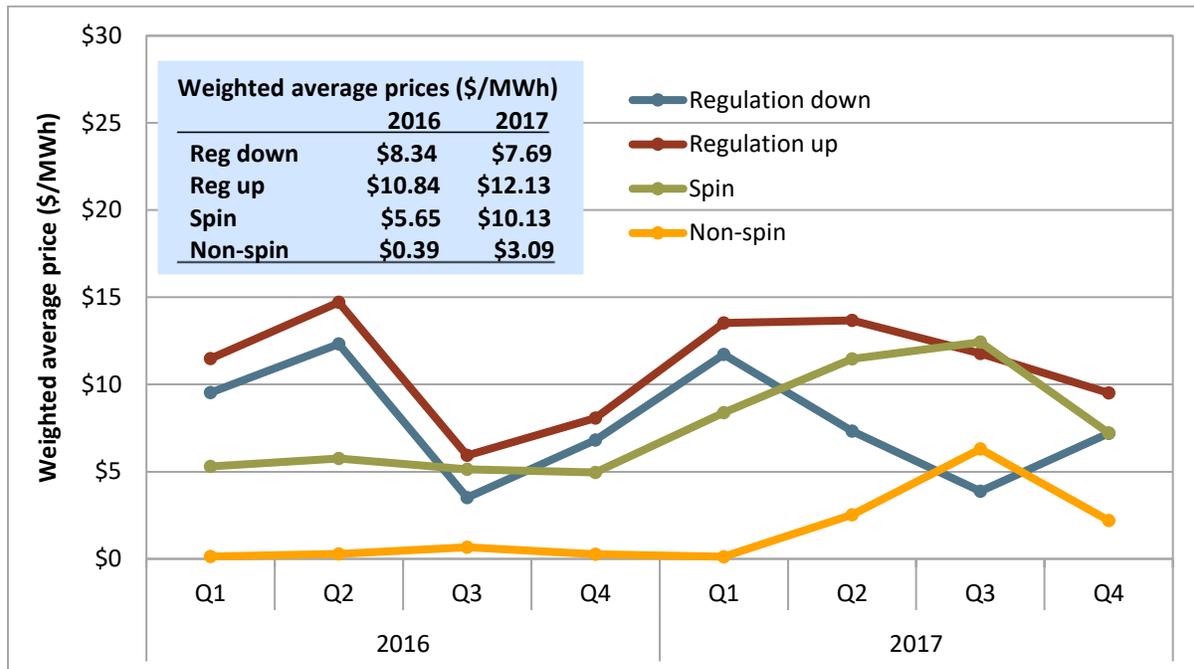
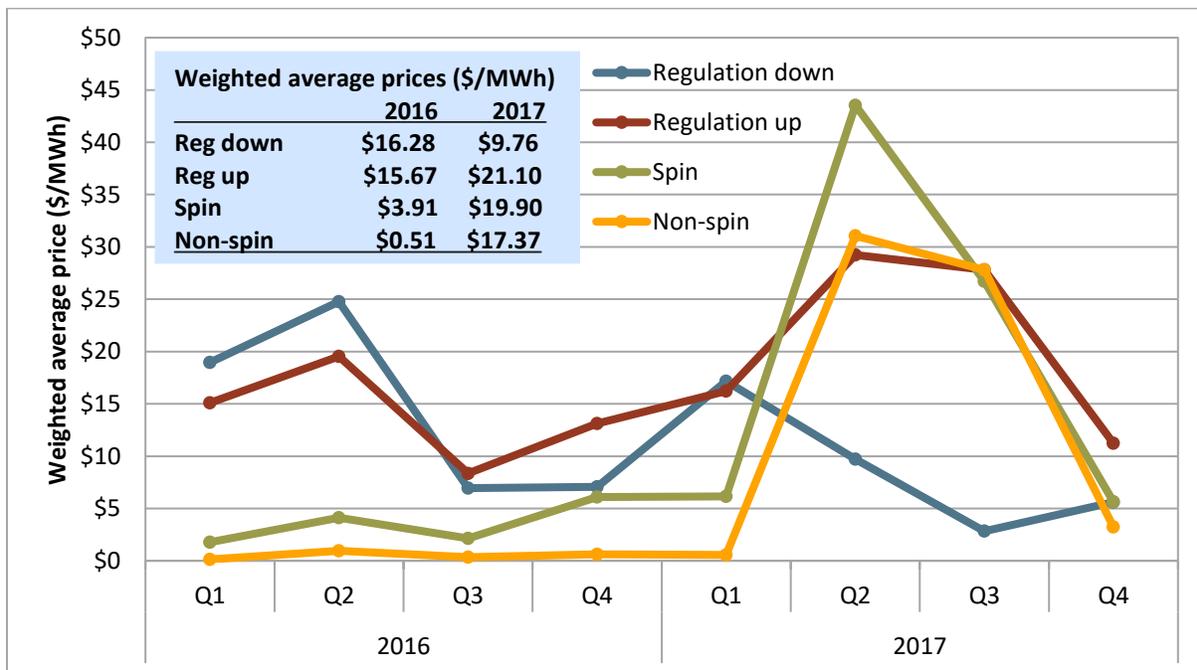


Figure 6.8 Real-time ancillary service market clearing prices

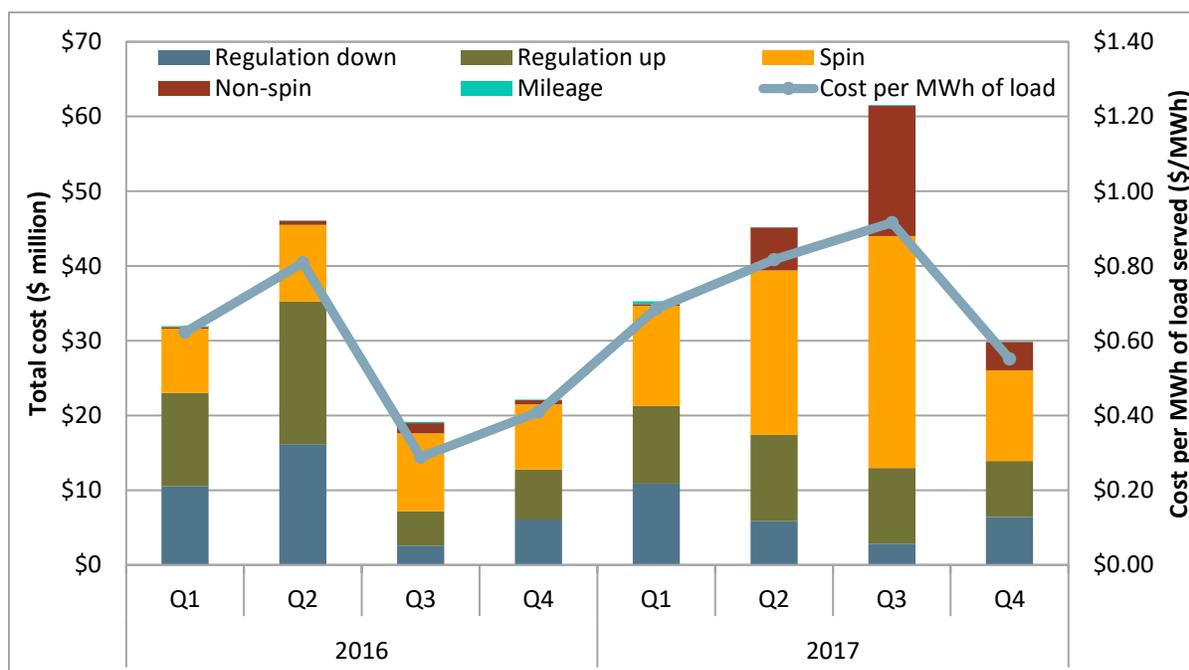


6.4 Ancillary service costs

Overall costs for ancillary services were higher in 2017 from the previous year. Costs for ancillary services totaled about \$172 million in 2017, compared to about \$119 million in 2016 and about \$62 million in 2015.

Figure 6.9 shows the total cost of procuring ancillary service products by quarter and the total ancillary service cost for each megawatt-hour of load served. As shown in the figure, total costs for operating reserves increased significantly during 2017. The increase in operating reserve costs was primarily driven by tight supply conditions and higher operating reserve requirements during the summer.

Figure 6.9 Ancillary service cost by product



6.5 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.

The number of hours with scarcity pricing in the day-ahead market continued to decrease from nine hours in 2015 to only one hour in 2016 to none in 2017. In the real-time market, the number of 15-minute intervals with scarcity pricing increased significantly from 26 intervals in 2016 to 54 intervals in 2017. The 2017 scarcity events are listed in Table 6.1.

Between June 19 and June 21, 13 scarcity intervals occurred when there were shortages for procurement of non-spinning reserves in the expanded ISO region. In the same period, operators blocked a large number of ancillary service awards consisting of mostly day-ahead non-spinning reserves. In real-time, the market attempted to replace this capacity by procuring an equivalent amount of mostly spinning reserves from other resources instead.

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

Table 6.1 Real-time ancillary service scarcity events (2017)

Date	Product	Region	Number of intervals	Shortfall (MW)
February 12	Regulation up	ISO expanded	1	0.7
February 25	Regulation up	ISO expanded	2	3
March 24	Regulation up	ISO expanded	1	2
March 30	Regulation down	ISO expanded	1	0.6
March 31	Spinning reserve	SP26	2	15
April 2	Regulation down	SP26 expanded	4	3
April 3	Regulation up	ISO expanded	3	1 - 5
April 4	Regulation up	ISO expanded	2	0.6
April 4	Regulation up	SP26 expanded	2	14 - 55
April 5	Regulation up	ISO expanded	1	0.3
April 9	Regulation down	SP26	4	3
May 3	Non-spinning reserve	ISO expanded	4	0.8 - 110
June 19	Regulation up	ISO expanded	1	6
June 19	Non-spinning reserve	ISO expanded	5	309 - 609
June 20	Non-spinning reserve	ISO expanded	7	223 - 655
June 21	Non-spinning reserve	ISO expanded	1	25
August 21	Regulation down	ISO expanded	8	102 - 273
September 11	Regulation up	ISO expanded	1	39
September 12	Regulation up	ISO expanded	1	3
November 7	Non-spinning reserve	ISO expanded	1	64
December 14	Regulation up	SP26 expanded	2	5 - 10

7 Market competitiveness and mitigation

Overall prices in the ISO energy markets in 2017 were competitive, averaging close to what DMM estimates would result under highly efficient and competitive conditions, with most supply being offered at or near marginal operating costs (see Chapter 2). This chapter assesses the structural competitiveness of the energy market, along with the impact and effectiveness of specific market power mitigation provisions. Key findings include the following:

- The day-ahead energy market, which accounts for most of the total wholesale market, remained structurally competitive on a system-wide level during most, but not all hours in 2017. In 0.4 percent of hours, there was a single pivotal supplier without whom there would have been insufficient supply to meet demand. In 1.6 percent of hours, there was a pair of pivotal suppliers, and in 3.8 percent of hours three suppliers, without whom there would have been insufficient supply to meet demand.
- The supply of capacity owned by non-load-serving entities meets or exceeds the additional capacity that load-serving entities need to procure to meet local resource adequacy requirements in the major local capacity areas. The San Diego/Imperial Valley, LA Basin, and the North Coast/North Bay areas are not structurally competitive because there is one supplier that is pivotal and controls a significant portion of capacity needed to meet local requirements.
- The dynamic path assessment effectively identified non-competitive constraints in the day-ahead and real-time markets in 2017. This automated test is part of the local market power mitigation procedures incorporated in the market software to determine transmission constraint competitiveness based on actual system and market conditions in each interval.
- The accuracy of the dynamic path assessment in the 15-minute market was improved by enhancements to the process implemented in August 2016. Additional enhancements were implemented in the 5-minute market in May 2017.
- Most resources subject to mitigation submitted competitive offer prices, so few bids were lowered as a result of the mitigation process. The number of units in the day-ahead market that had bids changed by mitigation remained very low at an average of about 1.4 units per hour in 2017, the same rate observed in 2016.
- The ISO has determined that a software error resolved in July caused pre-mitigation day-ahead prices to be low on some days. The software error resulted in an erroneous increase in supply available in the market power mitigation run, causing prices in that run to be lower than they would have been had all awarded schedules been feasible.¹⁷⁶ The ISO has published an initial estimate of the market impact of this error, \$19 million.¹⁷⁷

¹⁷⁶ The error allowed resources to receive combined ancillary service and energy schedules in excess of derated capacity in the pre-mitigation run. This error was in place from August 17, 2016 through July 21, 2017.

¹⁷⁷ The ISO's analysis estimates the increase in congestion rents but does not appear to take changes in the system energy cost into consideration. Market performance and planning forum presentation, June 11, 2018. http://www.caiso.com/Documents/AgendaPresentation-MarketPerformancePlanningForum-Jun11_2018.pdf, pp. 14-19.

- The number of units subject to mitigation and the estimated increase in dispatch increased in 2017 compared to 2016 in both the day-ahead and 15-minute markets. In 2017, the frequency and impact of mitigation in the 5-minute market exceeded those in the 15-minute market.
- Exceptional dispatches are instructions issued by grid operators when the automated market optimization is not able to address a particular reliability requirement or constraint. The above-market costs associated with these exceptional dispatches increased in 2017, totaling \$20.6 million in 2017 compared to \$10.7 million in 2016. A majority of this cost was associated with exceptional dispatch commitments to minimum load rather than out-of-market costs for exceptional dispatch incremental energy. As in 2016, local market power mitigation of exceptional dispatches played a small role in limiting above-market costs, reducing costs by \$33,000 in 2017.
- Majority of the gas-fired capacity on the SoCalGas system did not use the additional headroom in their proxy start-up and minimum load bids. This additional flexibility was provided to them as part of Aliso Canyon mitigation measures put in place on July 6, 2016.

7.1 Structural measures of competitiveness

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

- **Pivotal supplier test.** If supply is insufficient to meet demand with the supply of any individual supplier removed, then this supplier is pivotal. This is referred to as a single pivotal supplier test. The two-pivotal supplier test is performed by removing supply owned or controlled by the two largest suppliers. For the three-pivotal test, supply of the three largest suppliers is removed.
- **Residual supply index.** The residual supply index is the ratio of supply from non-pivotal suppliers to demand.¹⁷⁸ A residual supply index less than 1.0 indicates an uncompetitive level of supply.

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

In this report, when the residual supply index is calculated by excluding the largest supplier, we refer to this measure as RSI_1 . With the two or three largest suppliers excluded, we refer to these results as RSI_2 and RSI_3 , respectively.¹⁷⁹

¹⁷⁸ For instance, assume demand equals 100 MW and the total available supply equals 120 MW. If one supplier owns 30 MW of this supply, the residual supply index equals 0.90, or $(120 - 30)/100$.

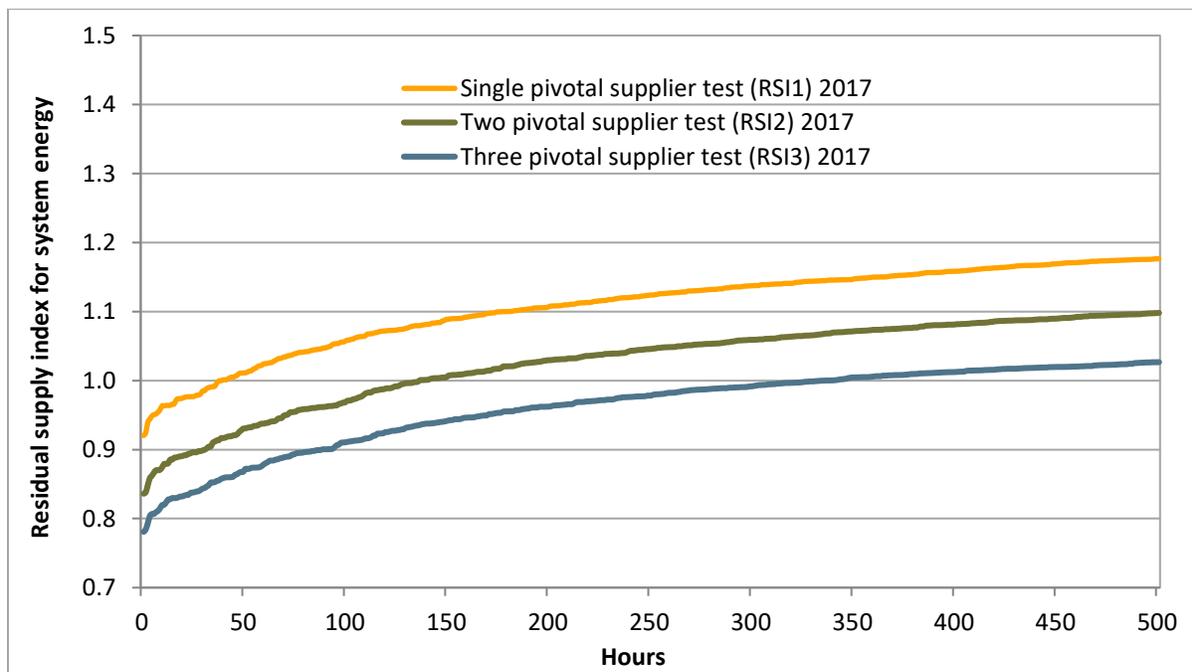
¹⁷⁹ A detailed description of the residual supply index was provided in Appendix A of DMM's 2009 annual report.

7.1.1 Day-ahead system energy

Figure 7.1 shows the hourly residual supply index for the day-ahead energy market in the ISO in 2017. This analysis is based on system energy only and ignores potential transmission limitations.¹⁸⁰ Results are only shown for the 500 hours when the residual supply index was lowest. As shown in Figure 7.1, the residual supply index with the three largest suppliers removed (RSI₃) was less than 1 in 336 hours, and the index was less than 1 during 136 hours with the two largest suppliers removed (RSI₂). The hourly RSI₁ value reached as low as 0.92 in 2017, compared to about 1.06 reported in 2016. Values are not directly comparable due to changes in the analysis discussed below. In 2017, RSI₁ value was less than one in 36 hours.

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. However, as discussed in the following sections, because ownership of resources within different areas of the ISO grid is highly concentrated, local reliability requirements and transmission limitations gave rise to local market power in many areas of the system during 2017.

Figure 7.1 Residual supply index for day-ahead energy



¹⁸⁰ All internal supply bid into the day-ahead market is used in this calculation. Imports are included as bid and aggregated with internal capacity by affiliate. The analysis reported in 2016 assumed 12,000 MWh of competitive import supply in all hours. Virtual bids are excluded. Measures assuming lower levels of internal supply result in greater frequency of residual supply index values below one. Demand includes actual system load plus ancillary services.

7.1.2 Local capacity requirements

The ISO defined 10 separate local capacity areas for which local reliability requirements are established under the state’s resource adequacy program. In most of these areas, a high portion of the available capacity is needed to meet peak reliability planning requirements. One or two entities own most of the generation needed to meet local capacity requirements in each of these areas.

Table 7.1 provides a summary of the residual supply index for major local capacity areas. The demand in this analysis represents the local capacity requirements set by the ISO. Load-serving entities meet these requirements through a combination of self-owned generation and capacity procured through bilateral contracts. For this analysis, we assume that all capacity owned by load-serving entities will be used to meet these requirements, with any remainder procured from non-load-serving entities that own generation in the local area.

Table 7.1 shows that the total amount of supply owned by non-load-serving entities meets or exceeds the additional capacity needed by load-serving entities to meet these requirements in the major local capacity areas. However, in some areas, one supplier is individually pivotal for meeting the remainder of the capacity requirement. In other words, some portion of these suppliers’ capacity is needed to meet local requirements. The San Diego/Imperial Valley, LA Basin, and the North Coast/North Bay areas are not structurally competitive because there is one supplier that is pivotal and controls a significant portion of capacity needed to meet local requirements.

In addition to the capacity requirements for each local area used in this analysis, additional reliability requirements exist for numerous sub-areas within each local capacity area. Some of these require that capacity be procured from specific individual generating plants. Others involve complex combinations of units that have different levels of effectiveness at meeting the reliability requirements.

Table 7.1 Residual supply index for major local capacity areas based on net qualifying capacity

Local capacity area	Net non-LSE capacity requirement (MW)	Total non-LSE capacity (MW)	Total residual supply ratio	RSI ₁	RSI ₂	RSI ₃	Number of individually pivotal suppliers
PG&E area							
Greater Bay	3,422	7,553	2.21	1.42	0.64	0.06	0
North Coast/North Bay	579	737	1.27	0.06	0.02	0.00	1
SCE area							
LA Basin	3,555	6,800	1.91	0.84	0.44	0.30	1
Big Creek/Ventura	0	3,133					0
San Diego/Imperial Valley	1,894	2,393	1.26	0.72	0.41	0.24	2

These sub-area requirements are not formally included in local capacity requirements incorporated in the state’s resource adequacy program. However, these additional sub-area requirements represent additional sources of local market power. If a unit needed for a sub-area requirement is not procured in the resource adequacy program and that resource does not make itself available to the ISO in the spot

market, the ISO may need to procure capacity from the unit using the backstop procurement authority under the capacity procurement mechanism of the ISO tariff.¹⁸¹

In the day-ahead and real-time energy markets, the potential for local market power is mitigated through bid mitigation procedures. These procedures require that each congested transmission constraint be designated as either competitive or non-competitive. This designation is based on established procedures for applying a pivotal supplier test in assessing the competitiveness of constraints. Section 7.2 examines the actual structural competitiveness of transmission constraints when congestion occurred in the day-ahead and real-time markets.

7.2 Competitiveness of transmission constraints and accuracy of congestion predictions

Local market power is created by insufficient or concentrated control of supply within a local area. In addition to load and generation, the availability of transmission to move supply into the local area from outside plays an important role in determining where local market power exists.

The ISO local market power mitigation provisions require that each transmission constraint be designated as either *competitive* or *non-competitive* prior to the binding market run using the *dynamic competitive path assessment*, or DCPA. This assessment uses results of a pre-market mitigation run that clears supply and demand with un-mitigated bids. If any internal transmission constraints are binding in the pre-market run they are assessed for competitiveness of supply of counter-flow.

Competitiveness of each constraint is measured using a residual supply index based on supply and demand of counter-flow from internal resources for each binding constraint. If there is sufficient supply of counter-flow for the binding constraint after removing the three largest net suppliers, then the residual supply index is greater than or equal to one, and the constraint is deemed competitive. Otherwise, it is deemed non-competitive. A non-competitive constraint is considered indicative of local market power and resources that can supply counter-flow to a non-competitive constraint may subsequently be subject to bid mitigation.

Accuracy of transmission congestion assessment on flow based constraints

Evaluating the performance of the current mitigation procedures involves examining both the accuracy that the mitigation run predicts congestion that also occurs during the same interval in the market run as well as the portion of constraints congested in the mitigation or market run which are non-competitive. The framework DMM uses to quantify overall accuracy of mitigation procedures is shown in Table 7.2.

All constraint-intervals defined by the *consistent* group in Table 7.2 would have been treated appropriately. When congestion is *over-identified*, or is projected to occur in the mitigation run but is resolved in the market run, the congestion may have been resolved due to mitigation. In the real-time market, it is also possible that congestion was resolved because of different inputs in the market run. Otherwise, it is possible that mitigation did not play a role in resolving congestion. Mitigation is only applied when the congested constraint is deemed non-competitive, so this is a relatively rare circumstance. As described later in this section, the frequency of such mitigation has been extremely

¹⁸¹ For further information on the capacity procurement mechanism, see Section 10.8.

low in both the day-ahead and real-time markets under the current mitigation procedures. Changes made during 2016 reduced this occurrence to an extremely low frequency.

When congestion is *under-identified*, or is not predicted in the mitigation run but then occurs in the market run, mitigation is not applied even if the congested constraint would have been deemed non-competitive. This is referred to as *under-mitigation*. Because the dynamic competitive path assessment procedure does not evaluate uncongested constraints, we do not know exactly how many under-identified constraints would have been deemed competitive or non-competitive. However, as discussed in the following sections, other analysis by DMM indicates that constraints on which congestion occurs are competitive a high portion of the time.

Table 7.2 Framework for analysis of overall accuracy of transmission competitiveness

Congestion prediction (mitigation run vs. market run)	Competitive status	
	Competitive	Non-competitive
Consistent (congested in both runs)	No mitigation	Mitigation applied, congestion present in market run
Over-identified (congested in mitigation run, not in market run)	No mitigation	Mitigation applied, congestion resolved in market run
Under-identified (not congested in mitigation run, congested in market run)	No mitigation	Mitigation not applied, needed in market run

The analysis below is performed at the constraint-interval level. Each time a constraint is congested for a given interval it is counted as one constraint-interval. A total of 100 constraint-intervals, then, could include 100 constraints each congested for 1 interval, or 1 constraint congested for 100 intervals, or 50 constraints each congested for 2 intervals. For day-ahead results, we refer to the constraint-intervals as constraint-hours, as the intervals in the day-ahead market each represent one hour.

Day-ahead market

In the day-ahead market, the mitigation run is performed immediately before the actual market run and uses the same initial input data – except for bids that are mitigated as a result of the market power mitigation run. DMM has found that the congestion predicted in the day-ahead mitigation run is highly consistent with actual congestion that occurs in the subsequent day-ahead market.

The first panel of Table 7.3 shows that 89 percent of congested constraint-hours were consistent in the mitigation and market runs in 2017, which is up from 79 percent in 2016. Congestion was over-identified during 5 percent of constraint-hours, and under-identified during 6 percent of constraint-hours. If the proportion of competitive to non-competitive constraint-hours was the same for under-identified as for constraints with predicted congestion, then about 1.3 percent of congested constraint-hours may represent missed mitigation in 2017. This is less than half the share of congested constraint intervals with potential missed mitigation in the previous year.

Table 7.3 Consistency of congestion and competitiveness of constraints in the day-ahead and real-time local market power mitigation processes¹⁸²

Market	Congestion prediction	Competitive		Non-competitive		Total	
		# constraint intervals	%	# constraint intervals	%	# constraint intervals	%
DA	Consistent	21,276	71%	5,456	18%	26,732	89%
	Over-identified	1,021	3%	482	2%	1,503	5%
	Under-identified	---	---	---	---	1,900	6%
Total						30,135	100%
15-minute	Consistent	35,478	60%	18,471	31%	53,949	92%
	Over-identified	2,115	4%	808	1%	2,923	5%
	Under-identified	---	---	---	---	1,966	3%
Total						58,838	100%
5-minute Jan 1 thru May 1	Consistent	21,954	58%	6,822	18%	28,776	76%
	Over-identified	3,010	8%	1,181	3%	4,191	11%
	Under-identified	---	---	---	---	5,029	13%
						37,996	100%
5-minute May 2 thru Dec 31	Consistent	67,948	59%	27,598	24%	95,546	83%
	Over-identified	12,075	11%	4,981	4%	17,056	15%
	Under-identified	---	---	---	---	2,057	2%
Total						114,659	100%

***Congestion prediction:**

Consistent = Congestion in mitigation and market runs.

Over-identified = Congestion in mitigation run, but no congestion in market.

Under-identified = No congestion in mitigation run, but congestion in market.

Real-time market

In the spring of 2017, the ISO instituted a new local power market mitigation procedure that allows for mitigation in the 5-minute market. This innovation builds on the previous improvements made to the 15-minute market in 2016 in order to ensure a minimal possibility for missed mitigation to distort outcomes in the CAISO real-time markets. These new procedures have been very successful in predicting congestion on flow based constraints.

15-minute market

The results in the second panel of Table 7.3 show the accuracy of the 15-minute dynamic competitive path assessment process in predicting congestion in the binding run of the 15-minute market. The assessment run predicted congestion consistently with the binding 15-minute market run during about 92 percent of constraint-intervals, compared to 85 percent in the second half of 2016 when the same assessment protocol was in place. Under-identified congestion occurred during 3 percent of congested constraint intervals, a decrease from 6 percent in the relevant period of 2016.

About 66 percent of constraint-intervals congested in the assessment run were competitive. If the same ratio of competitive to non-competitive intervals held for the under-identified constraint-intervals, it

¹⁸² The mitigation run consistently predicts no congestion in the market run in a very large number of instances.

would suggest that under-mitigation occurred in just over 1 percent of the total number of congested constraint-intervals in 2017, which is down from 3 percent in 2016.

5-minute market

Starting on May 2, the ISO modified the mitigation procedure for the real-time market to include a competitive path assessment and a mitigation protocol within the 5-minute market. Prior to this change, all mitigation in the real-time market was done in the 15-minute market. When mitigation was run only in the 15-minute market, this left a large window for changes to load, generation, and other parameters that could impact congestion and competitiveness of transmission constraints. The new protocol significantly decreased the chances of unpredicted congestion showing up in the 5-minute market, as is shown comparing the third and fourth panels in Table 7.3. Under the old system, about 13 percent of congested constraint intervals on flow based constraints were under-predicted in the 5-minute market. Under the new system, that figure dropped to about 2 percent.

The improvement to 5-minute market mitigation is possible because the new mitigation run happens much closer in time to the market run in the 5-minute market. Mitigation that occurs in the 15-minute market is also passed to the 5-minute market, so the new system cannot decrease the overestimated congestion.

Accuracy of transmission congestion assessment on EIM transfer scheduling limit constraints

Transfer constraints between balancing areas in the EIM work differently than flow based constraints. However, the same kind of logic can be applied to measuring the accuracy of congestion predictions made by local market power mitigation systems. One important difference is that there is no need to include measures of competitiveness in these assessments. Because there is only one entity operating in each current EIM balancing area, no transfer constraint can pass a three pivotal supplier test, so all results would be considered non-competitive.

15-minute market

Congestion on EIM transfers in the 15-minute market is accurately predicted in around 90 percent of congested constraint intervals. The least accurately predicted area was Portland General (PGE), which went live in EIM in the fall of 2017, and has the smallest sample size. As shown in the first panel of Table 7.4, about 84 percent of congested constraint intervals were accurately predicted for the PGE transfer constraint in the 15-minute market. The most accurately predicted area was Nevada Energy (NEVP), which saw about 95 percent of congested constraint intervals accurately predicted. Overall, in all EIM areas, 4 percent or fewer congested constraint intervals were under-predicted, meaning that possible instances of unmitigated market power were very rare.

5-minute market

The updates that were made to the mitigation procedures in the 5-minute market had a significant impact on accuracy of prediction for the EIM transfer constraints as well as for flow-based constraints. Comparing the second and third panels of Table 7.4 shows that the share of congested EIM area constraint intervals that were under-identified was drastically reduced.

Despite the significant reduction, under prediction of congestion on EIM transfer constraints in the Pacific Northwest is still high, compared to all other examples under the current procedures. DMM and the ISO are currently investigating this issue.

Table 7.4 Accuracy of congestion prediction on EIM transfer constraints

Market	Region	Consistent	Over identified	Under identified
FMM	PACE	87%	9%	4%
	PACW	92%	5%	3%
	PGE	84%	14%	3%
	PSEI	91%	5%	3%
	NEVP	95%	2%	2%
	AZPS	92%	4%	4%
RTD Jan 1 thru May 1	PACE	47%	44%	9%
	PACW	46%	28%	25%
	PGE	n/a	n/a	n/a
	PSEI	49%	26%	25%
	NEVP	54%	31%	16%
	AZPS	49%	43%	9%
RTD May 2 thru Dec 31	PACE	40%	56%	4%
	PACW	67%	18%	15%
	PGE	66%	16%	18%
	PSEI	67%	21%	13%
	NEVP	33%	66%	2%
	AZPS	55%	41%	4%

The ISO has determined that a software error caused pre-mitigation prices to be low on some days.

As discussed in DMM's Q2 2017 report, on June 21, system marginal prices in the binding integrated forward market run, following mitigation, were significantly higher than in the market power mitigation run.¹⁸³ Similar discrepancies have occurred on other days in both the day-ahead and real-time markets. The ISO has determined that a software error introduced in 2016 resulted in infeasible ancillary service awards with respect to total derated resource capacity for resources with both energy and ancillary service awards in the market power mitigation run but not the binding market run in the day-ahead market on some days between August 17, 2016 and July, 21 2017. This caused prices in the pre-mitigation run to be lower than they would have been had all awarded schedules been feasible. The ISO has published an initial estimate of the market impact of this error, \$19 million.¹⁸⁴

¹⁸³ Q2 2017 Report on Market Issues and Performance, September 25, 2017, pp 68-70:

<http://www.caiso.com/Documents/2017SecondQuarterReport-MarketIssuesandPerformance-September2017.pdf>

¹⁸⁴ The ISO's analysis estimates the increase in congestion rents but does not appear to take changes in the system energy cost into consideration. Market performance and planning forum presentation, June 11, 2018.

http://www.caiso.com/Documents/AgendaPresentation-MarketPerformancePlanningForum-Jun11_2018.pdf, pp. 14-19.

7.3 Local market power mitigation

This section provides an assessment of the frequency and impact of the automated local market power mitigation procedures described earlier. The section also provides a summary of the volume and impact of non-automated mitigation procedures that are applied for exceptional dispatches, or additional dispatches issued by grid operators to meet reliability requirement issues not met by results of the market software.

7.3.1 Frequency and impact of automated bid mitigation

The automated local market power mitigation procedures were enhanced in April 2012 to more accurately identify and mitigate resources with the ability to exercise local market power in the day-ahead and hour-ahead markets. The real-time mitigation procedures were first enhanced in May 2013. As part of these changes, the ISO adopted a new, in-line dynamic approach to the competitive path assessment. This approach uses actual market conditions and produces a more accurate and less conservative assessment of transmission competitiveness. As mentioned in Section 7.2, beginning in mid-August 2016, the real-time mitigation process was implemented in the binding interval of the 15-minute market run, instead of the 15-minute market advisory interval.¹⁸⁵ Starting May 2, 2017, local market power mitigation enhancements incorporated a predictive mitigation procedure in the advisory run for the 5-minute market. More information on 5-minute market mitigation can be found in Section 7.2.

In the day-ahead and 15-minute market, the number of units subject to mitigation and the estimated additional dispatch increased in 2017 compared to 2016. In 2017, the frequency and impact of mitigation in the 5-minute market increased relative to the 15-minute market.

The impact on market prices of bids that were actually mitigated can only be assessed precisely by re-running the market software without bid mitigation. This is not a practical approach because it would take DMM an extreme amount of time to re-run the day-ahead and real-time market software for every run. Alternatively, DMM has developed a variety of metrics to estimate the frequency with which mitigation was triggered and the effect of this mitigation on each unit's energy bids and dispatch levels. These metrics identify bids lowered from mitigation each hour and also estimate the additional energy dispatched from these price changes.¹⁸⁶

Both the frequency of mitigation (as shown in Figure 7.2) and the average estimated change in schedules (as shown in Figure 7.3) increased in the day-ahead market in 2017 compared to 2016:

- An average of 19 units in each hour were subject to day-ahead mitigation in 2017, an increase from 15 units in 2016.
- An average of 1.4 units had day-ahead bids changed in 2017 similar to that of 2016.

¹⁸⁵ More information can be found in the local market power mitigation enhancements 2015 draft final proposal: http://www.caiso.com/Documents/DraftFinalProposal_LocalMarketPowerMitigationEnhancements2015.pdf.

¹⁸⁶ The methodology used to calculate these metrics is illustrated in Section A.4 of Appendix A of DMM's *2009 Annual Report on Market Issues and Performance*, April 2010, <http://www.caiso.com/2777/27778a322d0f0.pdf>. This methodology has been updated beginning in 2014 so the numbers will not be directly comparable to previous years' reports.

- Day-ahead dispatch instructions from bid mitigation increased by about 7 MW per hour in 2017, compared to 4 MW per hour in 2016. This potential increase in dispatch due to mitigation is concentrated mostly during peak hours in 2017, similar to 2016.

Figure 7.4 and Figure 7.5 highlight the frequency and volume of 15-minute market mitigation:

- An average 13 units in each hour were subject to 15-minute market mitigation in 2017, compared to 12 in 2016.
- Bids for an average of 1 unit per hour were lowered as a result of the mitigation process in 2017, similar to 2016.
- On average, the number of units per hour that were dispatched at a higher output in the 15-minute market as a result of bid mitigation increased slightly to 0.5 units in 2017 compared to 0.4 units in 2016.
- 15-minute schedules from bid mitigation increased by about 6 MW per hour in 2017, compared to 5 MW per hour in 2016.

Figure 7.6 and Figure 7.7 highlight the frequency and volume of 5-minute market mitigation since it was implemented on May 2, 2017:

- An average of 68 units in each hour were subject to 5-minute market mitigation in 2017.
- Units with bids changed by 5-minute market mitigation in 2017 averaged about 3 units. As a result of this mitigation, an average of 2 units were dispatched at higher output in the 5-minute market.
- 5-minute real-time dispatch instructions increased by about 22 MW per hour as a result of bid mitigation in 2017.

Figure 7.2 Average number of units mitigated in day-ahead market

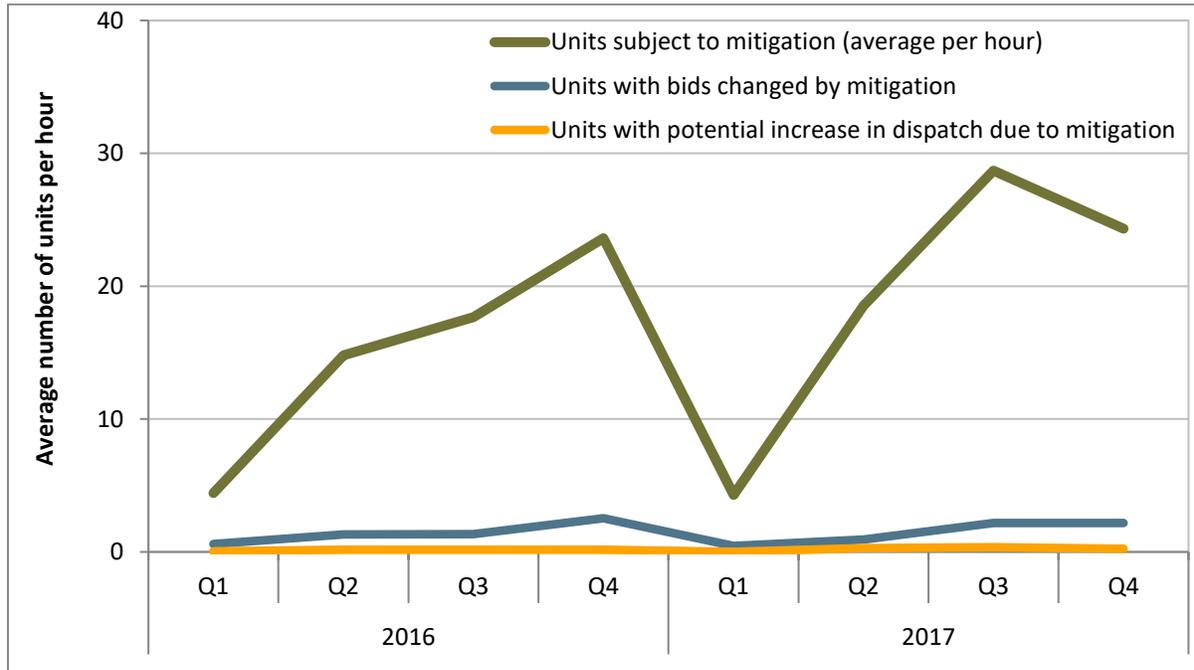


Figure 7.3 Potential increase in day-ahead dispatch due to mitigation (hourly averages)

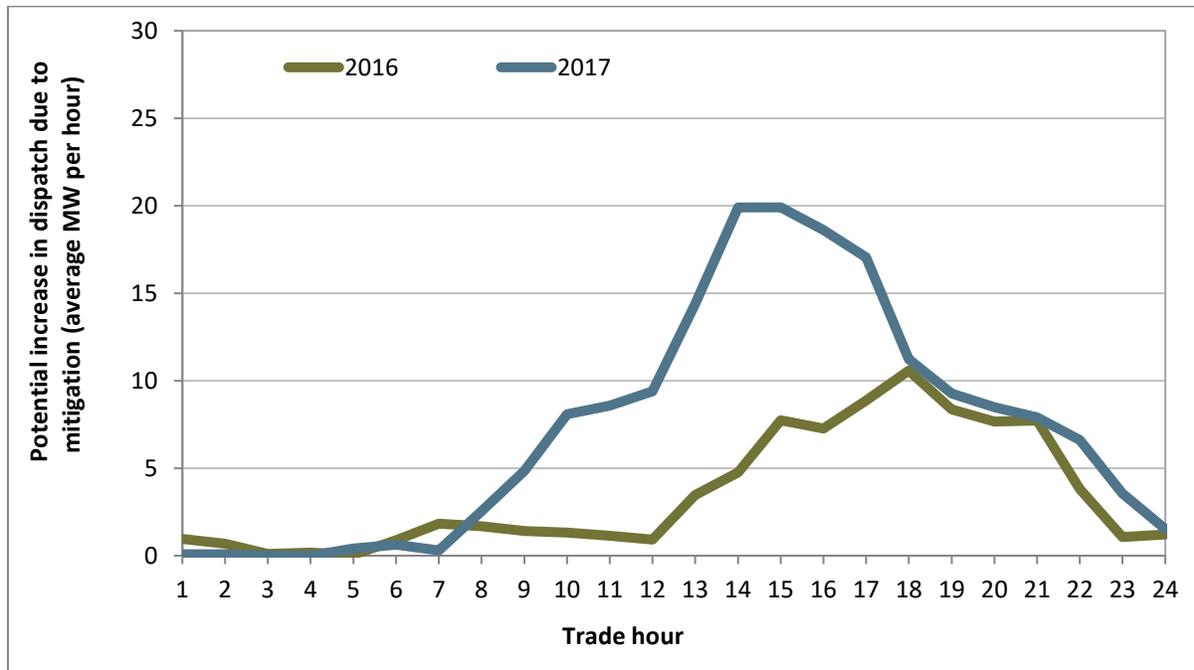


Figure 7.4 Average number of units mitigated in 15-minute market

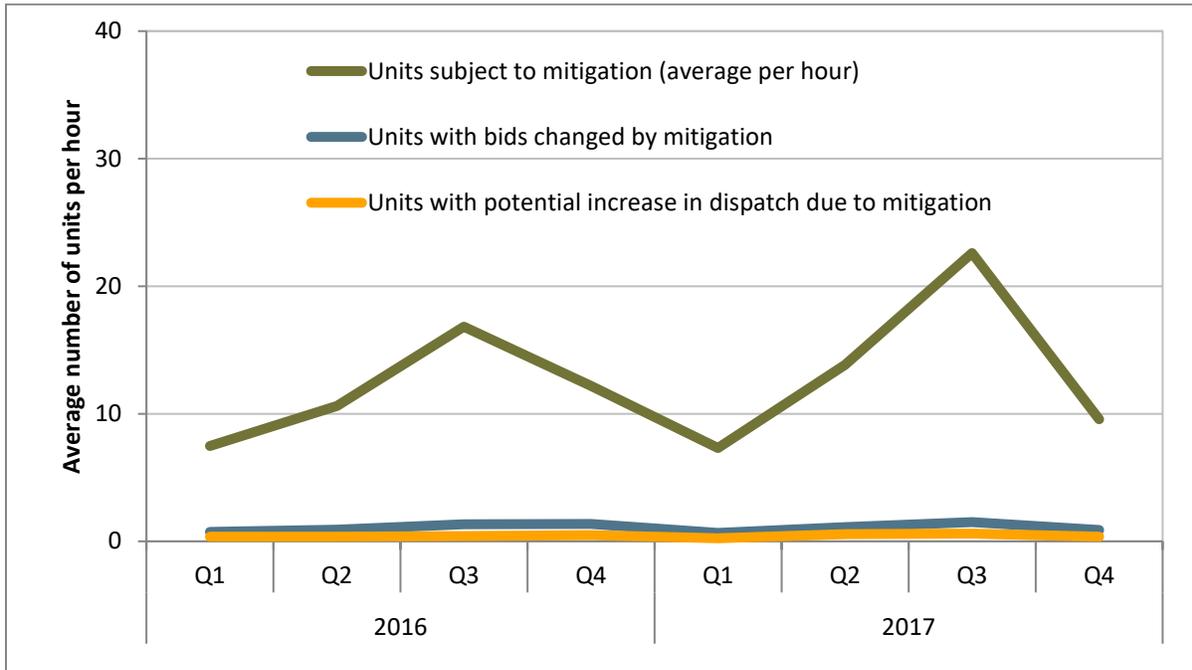


Figure 7.5 Potential increase in 15-minute dispatch due to mitigation (hourly averages)

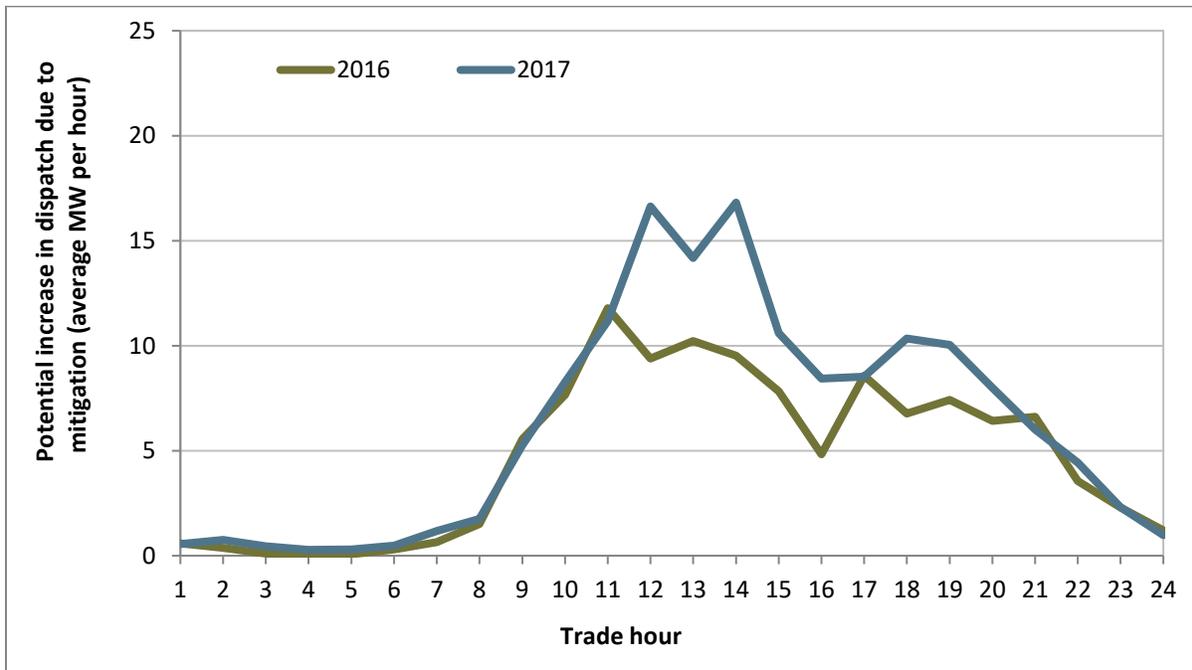


Figure 7.6 Average number of units mitigated in 5-minute market

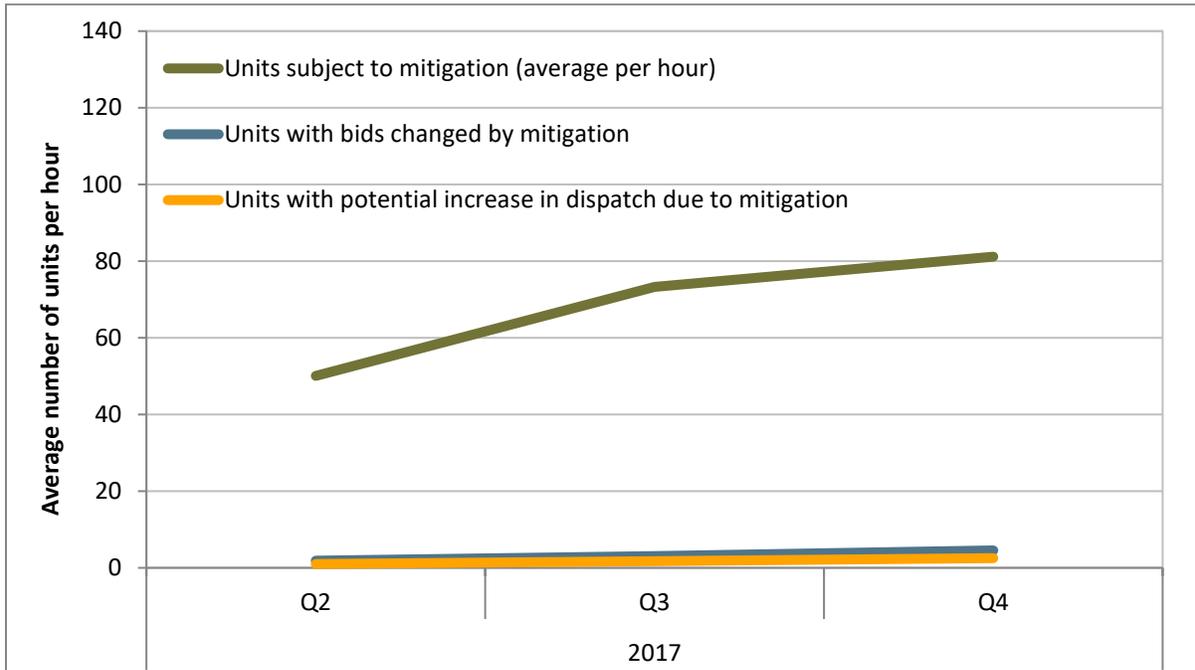
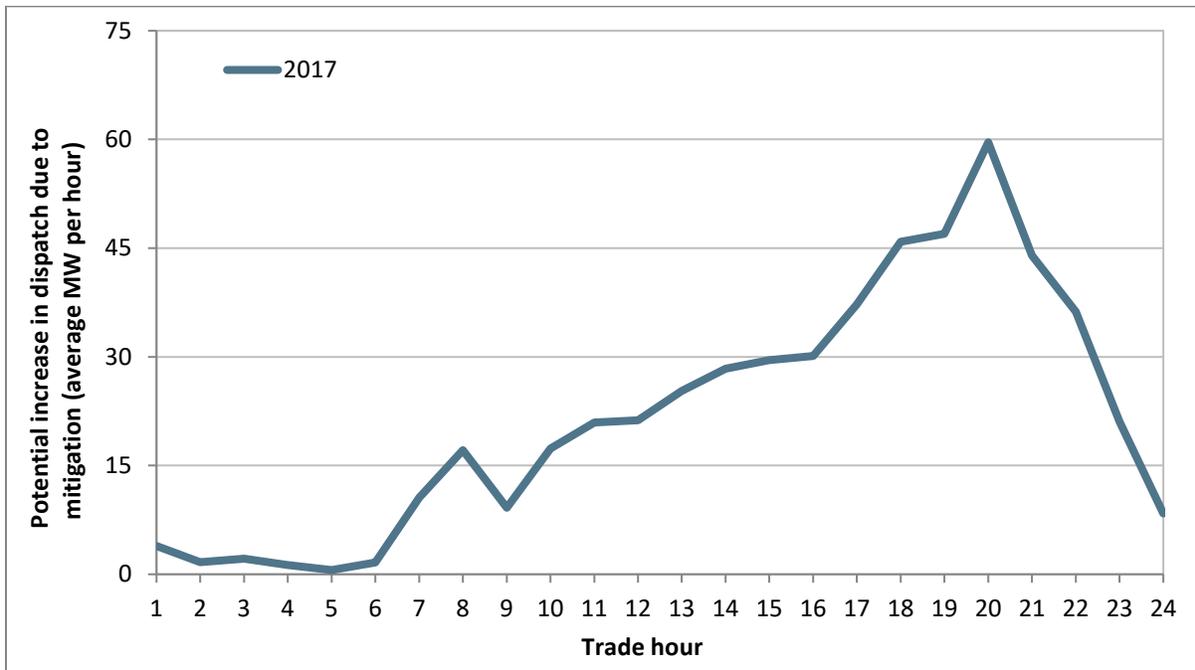


Figure 7.7 Potential increase in 5-minute dispatch due to mitigation (hourly averages)



7.3.2 Mitigation of exceptional dispatches

Overview

Exceptional dispatches are instructions issued by grid operators when the automated market optimization is not able to address a particular reliability requirement or constraint.¹⁸⁷ Total energy from exceptional dispatches increased in 2017. The above-market costs associated with these exceptional dispatches increased as well, totaling \$20.6 million in 2017 compared to \$10.7 million in 2016. A majority of this cost was associated with exceptional dispatch commitments to minimum load rather than out-of-market costs for exceptional dispatch incremental energy. As in 2016, local market power mitigation of exceptional dispatches played a small role in limiting above-market costs, reducing costs by \$33,000 in 2017.

Exceptional dispatches are subject to mitigation if the commitment or dispatch is made for any of the following reasons:

- Address reliability requirements related to non-competitive transmission constraints;
- Ramp resources with ancillary services awards or residual unit commitment capacity to a dispatch level that ensures their availability in real time;
- Ramp resources to their minimum dispatch level in real time, allowing the resource to be more quickly ramped up if needed to manage congestion or meet another reliability requirement; or
- Address unit-specific environmental constraints not incorporated into the model or the ISO's market software that affect the dispatch of units in the Sacramento Delta, commonly known as *Delta Dispatch*.

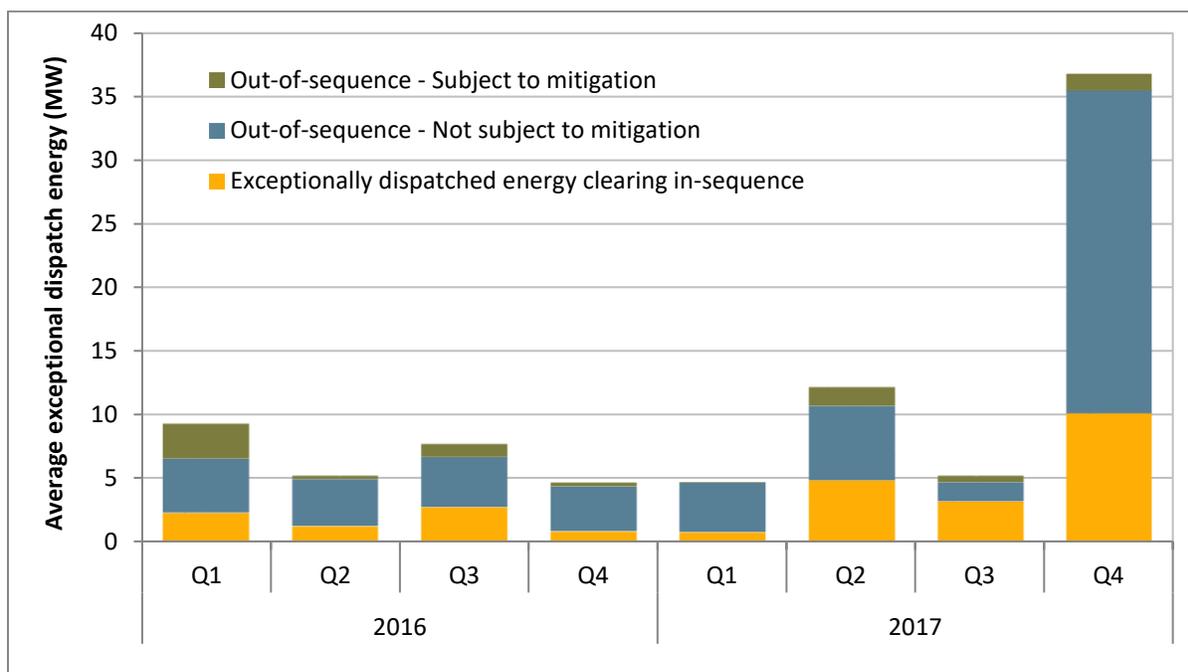
Although the ISO expanded exceptional dispatch market power mitigation provisions in 2012 and 2013, exceptional dispatch of incremental energy above minimum load accounted for only a small portion of overall exceptional dispatch energy in 2017. Further, within that portion of exceptional dispatch energy above minimum load, exceptional dispatch for reasons subject to mitigation accounted for a relatively low portion. This represents a continued trend which began in 2014. Thus, the role of local market power mitigation in limiting exceptional dispatch above-market costs has been minimal in recent years.

Volume and percent of exceptional dispatches subject to mitigation

As shown in Figure 7.8, the overall volume of exceptional dispatch energy above minimum load rose in 2017 when compared to 2016. Out-of-sequence exceptional dispatch energy rose sharply overall. Out-of-sequence energy is energy with bid prices above the market clearing price. Although out-of-sequence exceptional dispatch not subject to mitigation rose by 137 percent, out-of-sequence exceptional dispatch subject to mitigation fell by 24 percent. Out-of-sequence energy not subject to mitigation represented 92 percent of total out-of-sequence energy in 2017 compared to 78 percent in 2016. Declines in exceptional dispatch energy clearing in-sequence occurred primarily in the first quarter.

¹⁸⁷ A more detailed discussion of exceptional dispatches is provided in Section 9.1.

Figure 7.8 Exceptional dispatches subject to bid mitigation



Impact of exceptional dispatch energy mitigation

Out-of-sequence costs for exceptional dispatch energy are out-of-market costs paid for exceptional dispatch energy with bids that exceed the market clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to local market power mitigation provisions of 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. Using the value of out-of-sequence costs with the corresponding megawatt quantities of out-of-sequence exceptional dispatch energy, one can calculate the average price of out-of-sequence exceptional dispatch energy. This price is the amount per megawatt-hour by which out-of-sequence exceptional dispatch energy exceeds the locational marginal price.

Figure 7.9 shows the difference in the average price for out-of-sequence exceptional dispatch energy under three scenarios. The distance between the green and blue lines in Figure 7.9 illustrates the impacts of exceptional dispatch mitigation. The distance between these lines is the difference between the settled average price of out-of-sequence exceptional dispatch energy (blue line) and the average price of out-of-sequence exceptional dispatch energy in the absence of mitigation (green line). Greater distance between these two lines implies a larger overall impact of mitigation. As Figure 7.9 shows, this impact was low in 2016 and remained low in 2017.

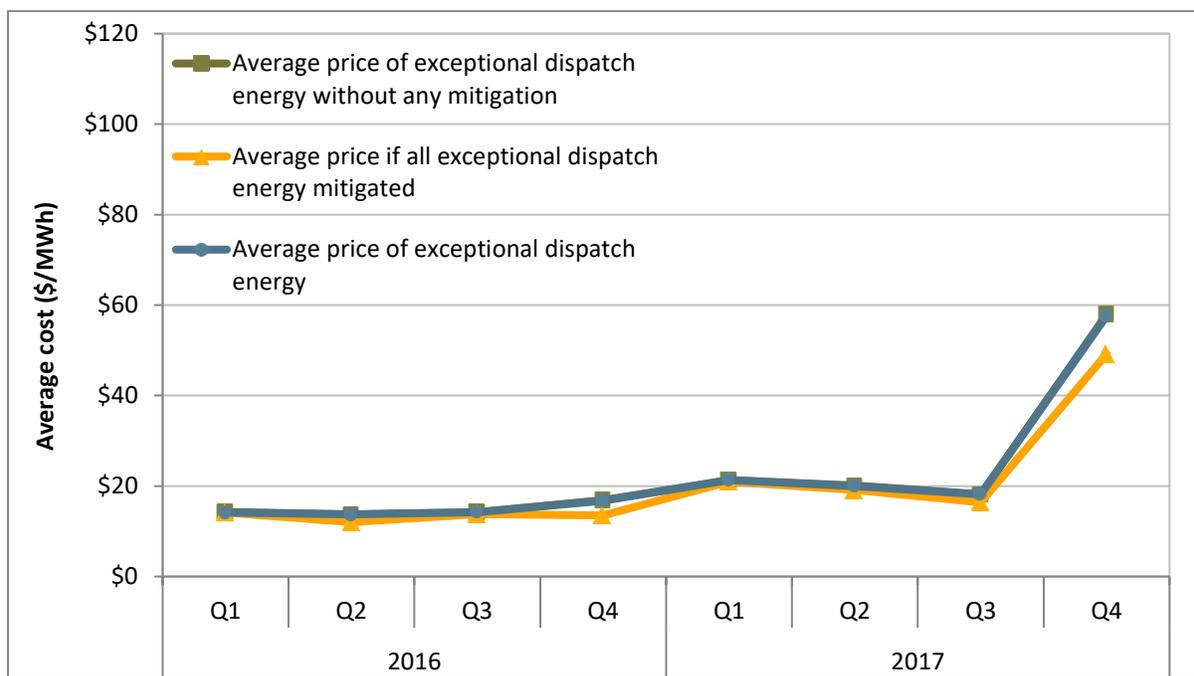
The yellow line in Figure 7.9 shows the average price of out-of-sequence exceptional dispatch energy if all exceptional dispatch energy had been subject to mitigation. A greater distance between the green line and the yellow line is indicative of lower quantities of exceptional dispatch energy subject to mitigation. The distance between these lines was largest in the fourth quarter of 2017, this was more than the distance between the lines in the fourth quarter of 2016.

The average price of out-of-sequence exceptional dispatch energy increased in 2017 to \$29/MWh from \$15/MWh in 2016. This increase is due in large part to a year-over-year increase in the fourth quarter.

In 2017, the fourth quarter average price for exceptional dispatch energy was \$58/MWh. This value was heavily influenced by exceptional dispatch to mitigate problems related to wildfires in Southern California. Bid prices for exceptional dispatch energy in the first through third quarters were competitive, and in 2017 these quarters saw the lowest levels of exceptional dispatch energy subject to mitigation.

Mitigation of exceptional dispatches decreased costs by a negligible \$33,000 in 2017. The amount that was ultimately paid for exceptional dispatch incremental energy in excess of the market price totaled \$4.0 million in 2017, up from \$633,000 in 2016.¹⁸⁸ The primary driver was in the fourth quarter, where as previously discussed there were wildfires in Southern California which led to an increase in exceptional dispatches to handle emergency conditions.

Figure 7.9 Average prices for out-of-sequence exceptional dispatch energy



¹⁸⁸ Exceptional dispatch is discussed in more detail in Section 9.1 of this report.

7.4 Start-up and minimum load bids

Additional start-up and minimum load bidding flexibility was implemented at the end of 2014. Depending on the limitations of a resource, owners could choose from two options for their start-up and minimum load bid costs: proxy costs (variable cost) and registered costs (fixed cost). The proxy cost bid cap was increased from 100 percent to 125 percent and remained available to all resources.¹⁸⁹ The ISO modified this option to capture the fluctuations of daily fuel prices for natural gas-fired resources and combined it with the flexibility to bid above 100 percent of proxy costs to incorporate additional costs that may not be captured under the proxy cost option. The ISO retained the registered cost option, but restricted it to use-limited resources. Participants with resources on the registered cost option continued to have the ability to bid up to 150 percent of the cap.¹⁹⁰ However, the registered costs continued to remain fixed for a period of 30 days.¹⁹¹ The ISO implemented these changes partly in response to the high and volatile natural gas prices on certain days in December 2013 and February 2014. Under commitment costs enhancement phase 3 initiative, the ISO is implementing opportunity cost adders to proxy start-up and proxy minimum load costs for use-limited resources which have limitations on numbers of starts and run hours.¹⁹² This initiative will phase out the registered cost option and will limit the use of that option to resources which do not have sufficient data to calculate an opportunity cost adder.

Capacity under the proxy cost option

Most natural gas-fired resources prior to 2015 elected the registered cost option as the proxy cost option was capped at 100 percent of calculated costs. Resources electing the proxy cost option increased in 2014 after significant natural gas market events resulted in issues as volatile natural gas prices were not reflected in commitment costs. As a result of these events, the ISO and its stakeholders modified the commitment cost rules, which FERC accepted in late 2014.¹⁹³ Specifically, the proxy cost bid cap was increased from 100 percent to 125 percent. Furthermore, the registered cost option was retained only for use-limited resources. Coincident with these changes, the majority of capacity shifted from the registered cost to the proxy cost option. Currently, commitment costs and default energy bid

¹⁸⁹ For more information, see the following FERC order accepting the tariff revisions:
https://www.caiso.com/Documents/Dec302014_OrderAcceptingCommitmentCostEnhancementsTariffRevision_ER15-15-001.pdf.

¹⁹⁰ Registered cost bids were at 150 percent of projected costs as calculated under the proxy cost option beginning in November 2013, whereas registered costs were capped at 200 percent before. One of the reasons for providing this bid-based registered cost option was to provide an alternative for generation unit owners who believed they had significant non-fuel start-up or minimum load costs not covered under the proxy cost option. See the following filing:
<http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/CommitmentCostsRefinement2012.aspx>.

¹⁹¹ A Use-Limited Resource is defined as a resource that, due to design considerations, environmental restrictions on operations, cyclical requirements such as the need to recharge or refill, or other non-economic reasons, is unable to operate continuously on a daily basis, but is able to operate for a minimum set of consecutive Trading Hours each Trading Day. (ISO tariff Section 40.6.4) Examples may include a hydro-electric resource or gas turbine with emissions limitations.

¹⁹² Commitment costs enhancements stakeholder process:
<http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostEnhancements.aspx>

¹⁹³ See footnote 189.

enhancements stakeholder process is underway, to support market-based commitment cost bids subject to caps and mitigation under uncompetitive supply conditions.¹⁹⁴

Figure 7.10 and Figure 7.11 highlight how proxy costs were bid into the day-ahead market in 2017 compared to 2016.¹⁹⁵

In the day-ahead market, more than 50 percent of both start-up and minimum load proxy bids in 2017 were near or below the calculated (100 percent) costs. Figure 7.10 shows that in 2017 about 60 percent of start-up capacity bid at or below the proxy cost cap compared to 50 percent in 2016. Figure 7.11 shows that about 60 percent of minimum load capacity bid at or below the proxy cost cap in 2017 compared to about 70 percent in 2016. Conversely, about 20 percent of the capacity associated with minimum load bids was at or near the cap in 2017 which is more than twice the percent in 2016. About 20 percent of start-up capacity bids were at or near the cap in 2017, close to that of 2016.

As part of the Aliso Canyon mitigation measures starting July 6, 2016, the ISO adjusted the gas price indices used to calculate the commitment cost caps in the real-time market for natural gas-fired generators on the SoCalGas systems. A 175 percent scalar was included in the fuel cost component used for calculating proxy commitment costs for resources on the SoCalGas systems in real time. This was done to ensure that resources on the SoCalGas systems would be committed for local rather than for system needs.

In addition to this, participants were also granted the ability to rebid their commitment costs in the real-time market, except for hours with day-ahead schedules or hours spanning minimum run times if committed in the real-time market. This was activated on June 2, 2016.

Figure 7.12 and Figure 7.13 show the bidding pattern of start-up and minimum load bids for all gas capacity on the SoCalGas system when the gas price scalars were active in 2017.¹⁹⁶ These figures break down the start-up and minimum load bids from these gas resources into three sub-categories. Bids which did not incorporate any scalar are shown by blue bars. Bids which utilized a portion of the scalar and bid up to 119 percent of proxy costs are shown in green. And finally, start-up and minimum load bids that utilized the scalar and bid at or near the 125 percent of proxy cost cap are shown in red.

On average, about 83 percent of capacity on the SoCalGas system did not use the additional headroom provided by the scalar for start-up costs. About 7 percent of the start-up capacity bid their costs at or near the bid cap. The remaining 10 percent of the capacity submitted bids that took advantage of the additional flexibility but did not do so near the cap. Similarly for minimum load costs, about 75 percent of the SoCalGas system minimum load capacity did not incorporate scalar in their bids. About 18 percent of the capacity utilized the additional headroom but not at the proxy cost cap. The remaining 7 percent of the minimum load capacity bid their costs at or near the cap.

¹⁹⁴ Second Revised Draft Final Proposal - Commitment Costs and Default Energy Bid Enhancements, March 2018: <http://www.caiso.com/Documents/SecondRevisedDraftFinalProposal-CommitmentCosts-DefaultEnergyBidEnhancements.pdf>

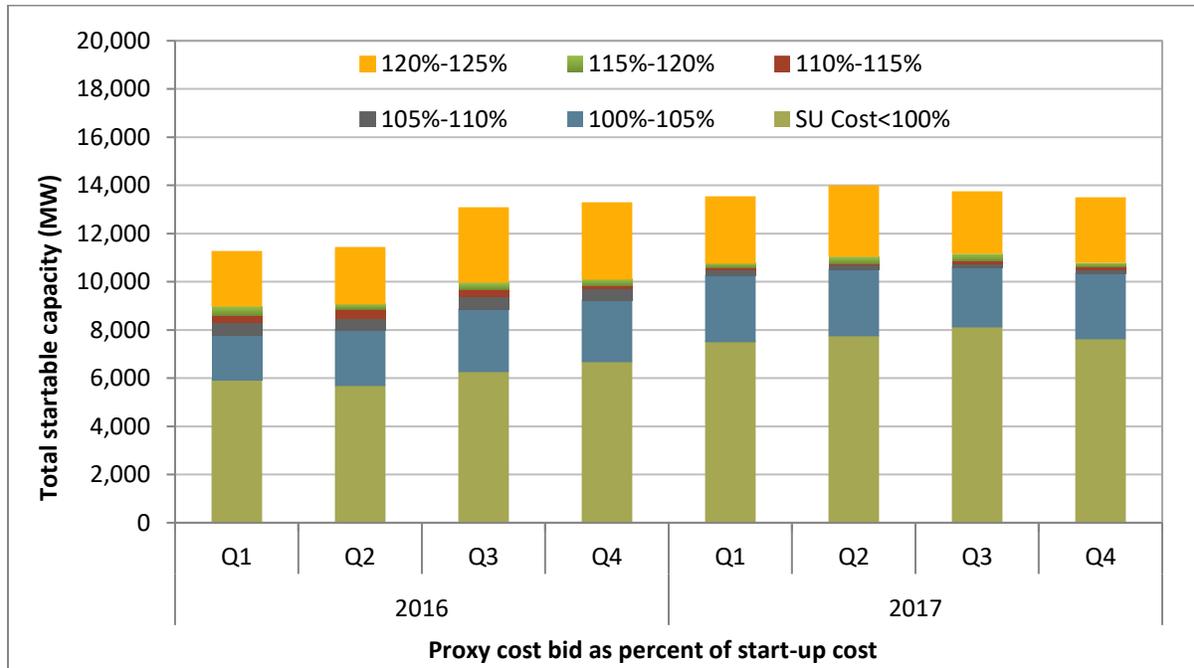
¹⁹⁵ Methodology to calculate the average capacity for both start-up and minimum load has been revised. For start-up capacity, resource Pmin (ONLY startable configurations Pmin for multi-stage generating units) is used to calculate total start-up capacity. For minimum load capacity, Pmin of resources (or configurations) is used to calculate total minimum load capacity.

¹⁹⁶ In 2017, Aliso gas price scalars were active from January 1 – July 31, August 4 – 7, October 23 – 25 and December 7 – 31.

DMM’s analysis showed that having a fixed 175 percent gas price scalar in place not only inflated the commitment costs that were bid into the market, without a significant impact on merit order of commitment, but also resulted in extra bid cost recovery payments to the resources utilizing the scalar. Section 3.4 has more information on these out of market payments.

As part of commitment costs and default energy bid enhancements initiative, DMM has recommended that the ISO adopt a more dynamic approach which would allow real-time commitment cost bid caps to be adjusted based on gas market trade data available at the start of each operating day.¹⁹⁷

Figure 7.10 Day-ahead gas-fired capacity under the proxy cost option for start-up cost bids



¹⁹⁷ DMM Comments - Commitment Costs and Default Energy Bid Enhancements Revised Draft Final Proposal, February 2018: <http://www.caiso.com/Documents/DMMComments-CommitmentCostsandDefaultEnergyBidEnhancementsRevisedDraftFinalProposal.pdf>

Figure 7.11 Day-ahead gas-fired capacity under the proxy cost option for minimum load cost bids

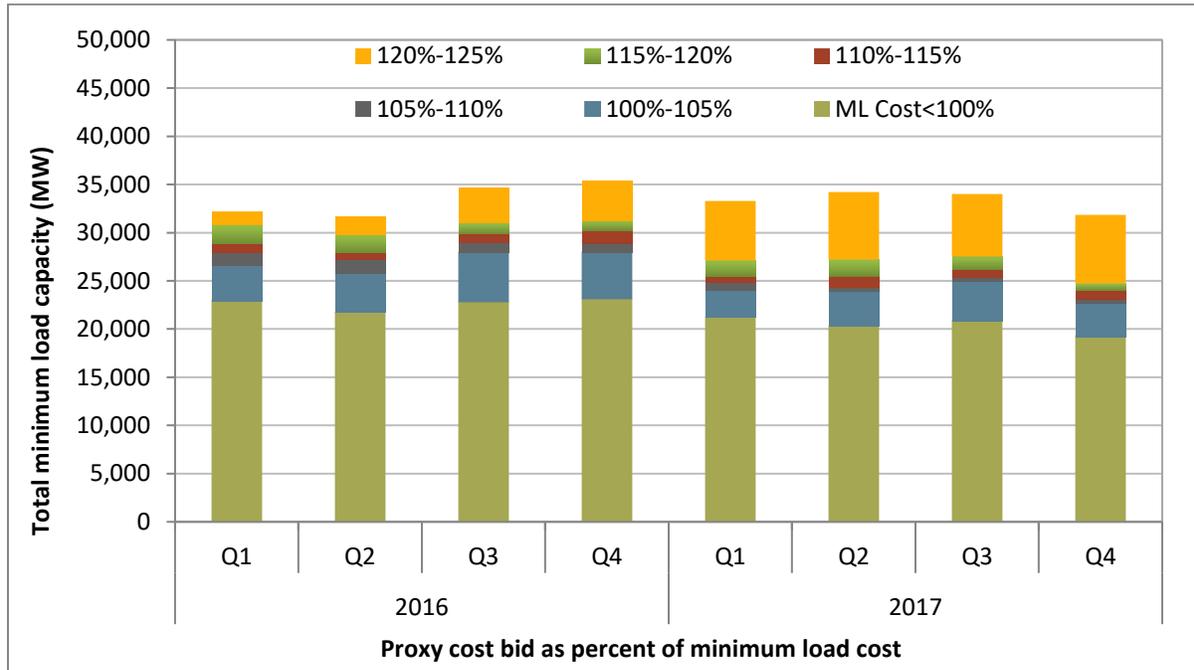


Figure 7.12 Real-time SoCalGas system resources start-up capacity bid level

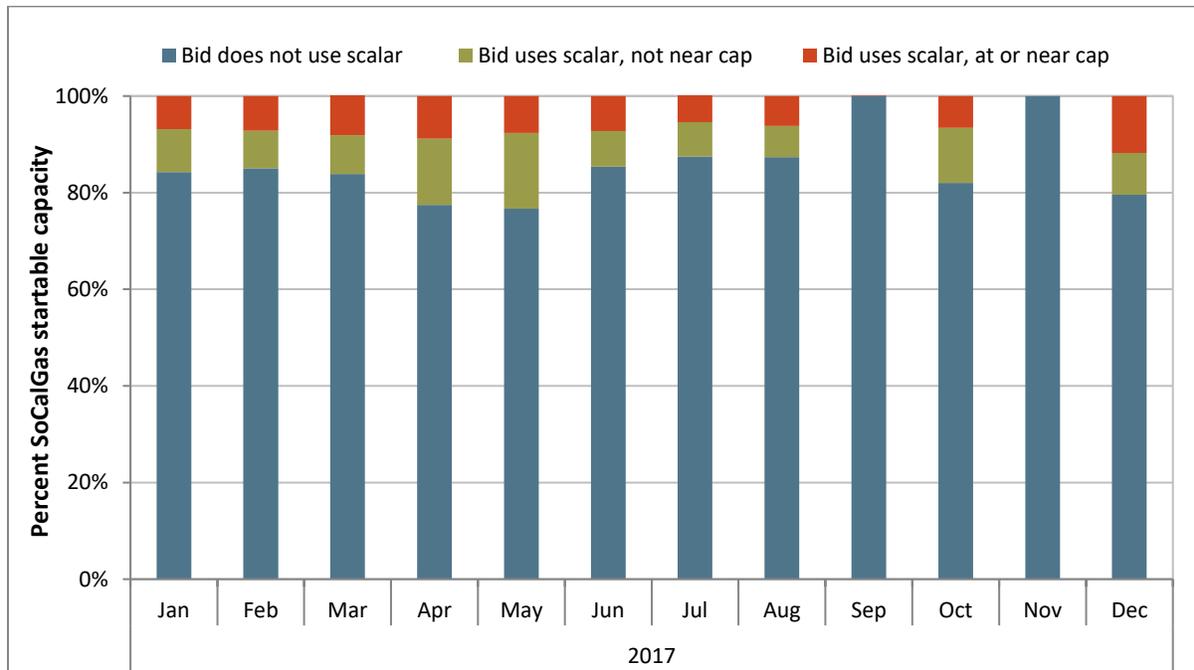
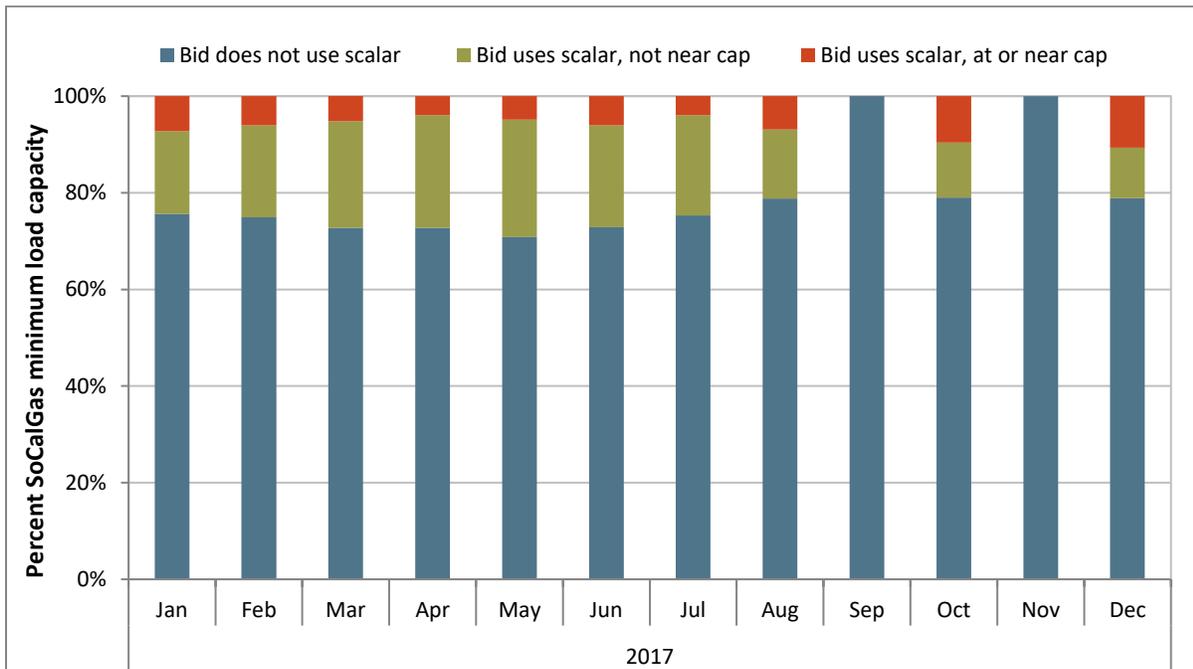


Figure 7.13 Real-time SoCalGas system resources minimum load capacity bid level



8 Congestion

This chapter provides a review of congestion and the market for congestion revenue rights in 2017. The findings from this chapter include the following:

- In 2017, prices in the San Diego Gas and Electric area were the most impacted by internal congestion. Average day-ahead prices in this area increased above the system average by about \$0.90/MWh (2.5 percent) and real-time congestion increased prices by about \$1.50/MWh (4 percent).
- Congestion increased average day-ahead and real-time prices in the Southern California Edison area above the system average by about \$0.40/MWh (1.2 percent) and \$1.10/MWh (3 percent), respectively.
- Pacific Gas and Electric area prices were the least impacted by congestion in 2017. Congestion decreased day-ahead prices below the system average by about \$0.60/MWh (2 percent) and increased 15-minute real-time price by \$0.30/MWh (0.8 percent).
- Though the frequency decreased slightly in the day-ahead market, the impact of congestion was higher in 2017 than in 2016 on most major interties connecting the ISO with other balancing authority areas, particularly for interties connecting the ISO to the Pacific Northwest.

This chapter includes an analysis of the performance of the congestion revenue rights auction from the perspective of the ratepayers of load-serving entities. Key findings of this analysis include the following:

- Congestion revenue rights not allocated to load-serving entities that were sold in the auction consistently generate significantly less revenue than is paid to the entities purchasing these rights at auction. From 2009 through 2017, ratepayers received about 50 percent of the value of their congestion revenue rights that the ISO auctioned. This represents a shortfall of about \$101 million in 2017 and more than a \$730 million shortfall since 2009.
- Entities purchasing congestion revenue rights are primarily financial entities that do not purchase these rights as a hedge for any physical load or generation. 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 “excess transmission capacity” remaining after the congestion revenue right allocations.

8.1 Background

Locational marginal pricing enables the ISO to efficiently manage congestion and provide price signals to market participants to self-manage congestion. Over the longer term, nodal prices are intended to provide efficient signals that encourage development of new supply and demand-side resources within more constrained areas. Nodal pricing also helps identify transmission upgrades that would be most cost-effective for reducing congestion.

Congestion in a nodal energy market occurs when the market model estimates flows on the transmission network have reached or exceeded the limit of a transmission constraint. As congestion appears on the network, locational marginal prices at each node reflect marginal congestion costs or

benefits from supply or demand at that particular location. 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.

When a constraint binds the market software produces a shadow price on that constraint. This generally represents the cost savings that would occur if that constraint had one additional megawatt of transmission capacity available in the congested direction. This shadow price is not directly charged to participants; it only indicates a decremental cost on the objective function of the market software for the limited transmission on the binding constraint.

There are three major types of transmission constraints that are enforced in the market model and may impact prices when they bind:

- Flowgates represent a single transmission line or path with a single maximum limit.
- Branch groups represent multiple transmission lines with a limit on the total combined flow on these lines.
- Nomograms are more complex constraints that represent interdependencies and interactions between multiple transmission system limitations that must be met simultaneously.

Congestion on interties between the ISO and other balancing areas impacts the price of imports and affects payments for congestion revenue rights. However, intertie congestion has generally had a minimal impact on prices for load and generation within the ISO system. This is because when congestion limits additional imports on one or more interties, there is usually additional supply available from other interties or from within the ISO at a relatively small increase in price.

8.2 Congestion on interties

Though the frequency decreased slightly, the financial impacts of congestion on most interties connecting the ISO with other balancing authority areas increased in 2017 from 2016, particularly for interties connecting the ISO to the Pacific Northwest.

Table 8.1 provides a detailed summary of congestion frequency on interties with average and total congestion charges in the day-ahead market. The congestion price reported in Table 8.1 is the megawatt weighted average shadow price for the binding intertie constraint. For a supplier or load-serving entity trying to import power over a congested intertie, assuming a radial line, the congestion price represents the difference between the higher price of the import on the ISO side of the intertie and the lower price outside of the ISO. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside of the ISO at points corresponding to these interties.

Figure 8.1 compares the percentage of hours that major interties were congested in the day-ahead market during the last three years. Figure 8.2 provides a graphical comparison of total congestion charges on major interties in each of the last three years.

The table and figures highlight the following:

- Overall congestion on interties increased to about \$114 million, compared with \$92 million in 2016, but was still lower than \$192 million in 2014. This is largely driven by increased congestion on the

two major interties linking the ISO with the Pacific Northwest: the Nevada/Oregon Border (NOB) and MALIN 500 (PACI/Malin 500).¹⁹⁸

- Total congestion on the Nevada/Oregon Border and MALIN 500 increased to about \$101 million from about \$76 million in 2016. This was likely driven by increased hydro-electric generation in the Northwest imported into the ISO from the Northwest and Northern California in 2017.
- Congestion decreased on Palo Verde, which was the largest intertie linking the ISO with the Southwest in 2017. Congestion on Palo Verde decreased to \$8 million from about \$13 million in 2016.

Table 8.1 Summary of import congestion (2015-2017)

Import region	Intertie	Frequency of import congestion			Average congestion charge (\$/MW)			Import congestion charges (thousands)		
		2015	2016	2017	2015	2016	2017	2015	2016	2017
Northwest	PACI/Malin 500	26%	32%	28%	\$6.2	\$7.4	\$12.2	\$37,687	\$51,139	\$60,716
	NOB	22%	27%	26%	\$6.4	\$6.7	\$11.6	\$12,375	\$24,346	\$40,503
	Tracy 500	0.1%		0.1%	\$6.2		\$19.8	\$20		\$125
	COTPISO	1%	6%	2%	\$36.2	\$12.7	\$25.8	\$97	\$158	\$117
	Cascade	2%	2%	1%	\$7.5	\$19.5	\$21.4	\$101	\$244	\$67
	Summit	0.2%		0.3%	\$2.8		\$9.4	\$3		\$8
Southwest	Palo Verde	3%	5%	2%	\$13.2	\$19.5	\$22.3	\$9,261	\$12,942	\$8,234
	IPP Utah	22%	13%	18%	\$2.9	\$3.6	\$7.9	\$1,079	\$803	\$2,362
	IPP DC Adelanto	1%		3%	\$3.7		\$9.2	\$77		\$950
	Mead	1%	1%	0%	\$14.4	\$12.2	\$21.5	\$1,278	\$1,023	\$808
	Market Place Adelanto	0.3%		0.2%	\$18.9		\$16	\$330		\$139
	West Wing Mead	1%	3%		\$34.3	\$34.4		\$330	\$865	
	CFE_ITC		0%			\$138			\$56	
	Sylmar AC		0.2%			\$4.8			\$70	
	El Dorado	0.1%			\$3.0			\$14		
	Other							\$3	\$92	\$308
	Total								\$66,381	\$91,939

¹⁹⁸ The California ISO Technical Bulletin 'Pricing Logic for Scheduling Point – Tie Combination,' revised on February 24, 2016, describes that MALIN 500 kV intertie scheduling limit replaced the Pacific A/C Intertie constraint with the implementation of the full network model on October 15, 2014:

http://www.caiso.com/Documents/RevisedTechnicalBulletin_PricingLogicforSchedulingPoint-TieCombination.pdf

Figure 8.1 Percent of hours with congestion on major interties (2015-2017)

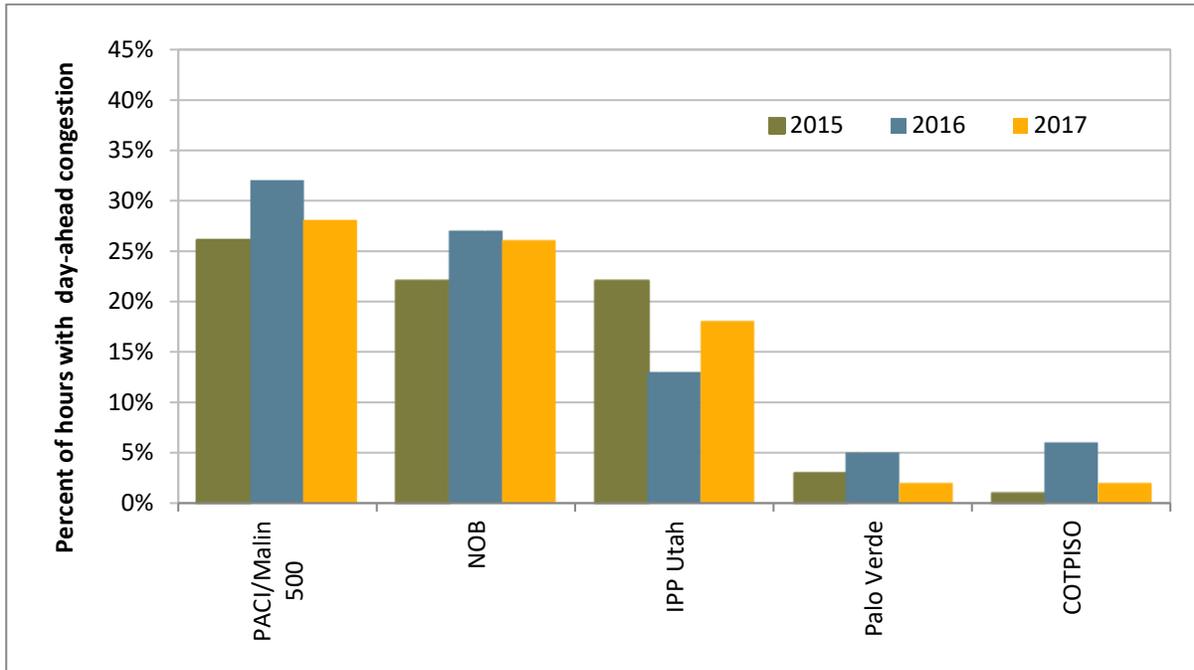
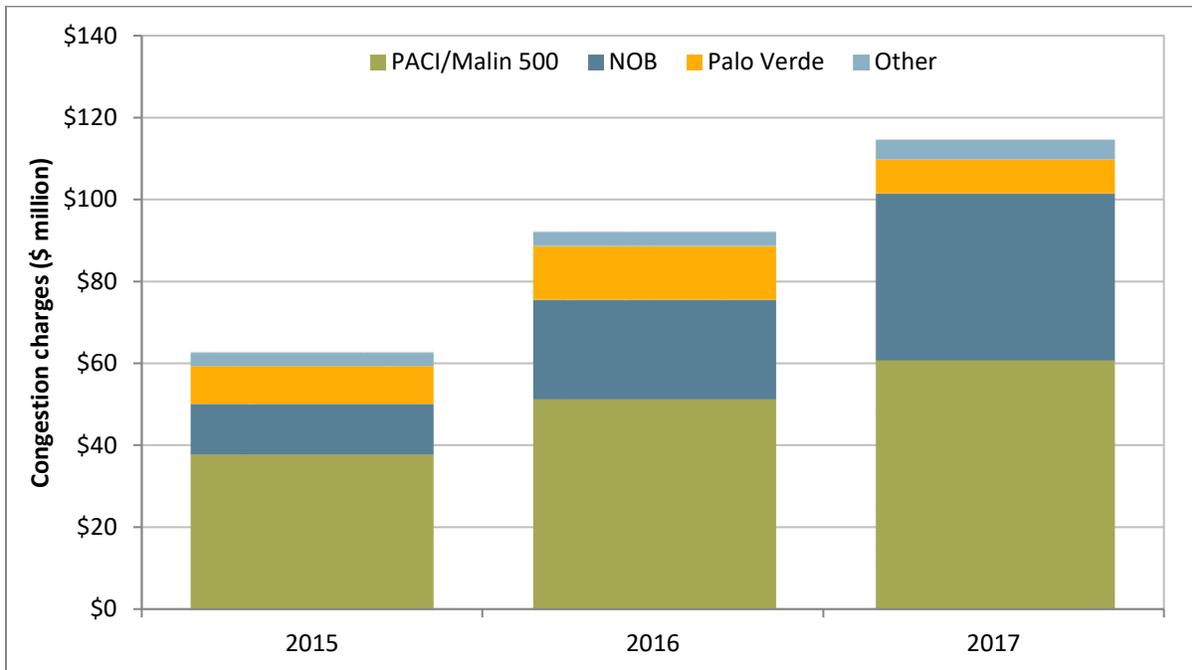


Figure 8.2 Import congestion charges on major interties (2015-2017)



8.3 Congestion impacts of internal constraints

When flow on a constraint within the ISO system is at or near the constraint's limit a shadow price is established. Resources on both sides of the constraint receive economic signals to respect the established limit on the constraint through the congestion component of locational prices. For internal constraints, congestion has a clear and direct impact on prices within the ISO.

The impact of congestion from any constraint on each pricing node in the ISO can be calculated as the product of the shadow price for the constraint and the shift factor of the constraint for that node. This calculation can be done for individual nodes, as well as groups of nodes that represent different load aggregation points or local capacity areas.¹⁹⁹

Congestion on constraints within Southern California generally increases prices within the Southern California Edison and San Diego Gas and Electric areas, but decreases prices in the Pacific Gas and Electric area. Similarly, congestion within Northern California increases prices in the Pacific Gas and Electric area, and decreases prices in Southern California. Constraints are grouped by price impact within each utility area in the tables below, which, depending on system topography, may not always correspond to the physical location of the constraint.

Highlights of congestion in 2017 include the following:

- Much of the congestion during the first quarter, in both day-ahead and 15-minute markets, was a result of binding Crosstrip nomogram.²⁰⁰ This constraint primarily affected the San Diego Gas and Electric load area price.
- The frequency of congestion was relatively low in the first half of the year, falling between the first and second quarters. Much of the congestion occurred on constraints which were enforced in the market to mitigate for line contingencies.
- Third and fourth quarters had relatively high levels of congestion primarily impacting San Diego Gas and Electric load area prices in both day-ahead and 15-minute markets. Main drivers of congestion were Doublet Tap-Friars 138 kV constraint, Serrano 500/230 kV transformer, Southern California Import Transmission (SCIT), OMS 4646112_OP-6610 and the Imperial Valley nomograms.

8.3.1 Day-ahead congestion

Table 8.2 shows the impact of congestion on specific internal constraints during congested hours on average day-ahead prices at the system's three aggregate load areas. This table depicts the magnitude of congestion on load areas when constraints were binding.

In the first quarter of 2017, most of the congestion was due to the Crosstrip (23040_CROSSTRIP) and Imperial valley (7820_TL23040_IV_SPS_NG) constraints which were modeled to mitigate for the contingency of TL50001 (Imperial Valley – Miguel 500 kV line). An outage on this line could cause an overload on the underlying parallel 230kV lines which would then cause remedial action schemes (RAS) to crosstrip and open up another 230kV line. These constraints were binding during approximately 28

¹⁹⁹ Appendix A of DMM's 2009 annual report provides a detailed description of this calculation for both load aggregation points and prices within local capacity areas.

²⁰⁰ The Crosstrip nomogram was discussed in a Market Performance and Planning Forum, March 2017, slides 4-6: http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum-Mar14_2017.pdf

percent of hours, having a combined price impact of \$8/MWh in the San Diego Gas and Electric area and no impact on Southern California Edison area.

The overall frequency of congestion declined in the day-ahead market during the second quarter of 2017. In the Southern California Edison area, Path 26 (6410_CP5_NG) and Path 15 (6310_CP3_NG) constraints were the most frequently binding constraints in the north-to-south direction.²⁰¹ Congestion on Path 26 was primarily a result of an outage on Midway – Whirlwind 500 kV line which returned to service at the end of April 2017. The Path 15 nomogram was enforced to mitigate for the loss of Los Banos – Tesla 500 kV and Los Banos – Tracy 500 kV lines. Path 26 was binding in 7 percent of the intervals and increased Southern California Edison and San Diego Gas and Electric area prices by \$5/MWh and decreased Pacific Gas and Electric area prices by about \$7 MWh. When Path 15 bound in 5 percent of the intervals, it had a relatively smaller impact on all the load area prices.

In the San Diego Gas and Electric area, most of the congestion in the second quarter was due to the Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) which was modeled to mitigate for the contingency of Imperial Valley – North Gila 500 kV line. This constraint was binding during approximately 8 percent of hours, having a price impact of \$4/MWh in the San Diego Gas and Electric area and no impact on the Southern California Edison area.

In the third quarter, the overall frequency of congestion increased in the day-ahead market compared to the previous quarter. In the San Diego Gas and Electric area, Doublet Tap-Friars 138 kV constraint bound most frequently during approximately 35 percent of hours with a negative price impact of \$3.7/MWh. A major reason for congestion on this constraint was the loss of Penasquitos-Old Town 230 line.

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

Congestion in the day-ahead market continued to increase during the fourth quarter. Several outages caused higher frequency of congestion in the San Diego Gas and Electric area. For the loss of Penasquitos-Old Town 230 kV line, Doublet Tap-Friars 138 kV constraint bound most frequently in about 24 percent of hours with a negative price impact of \$3.3/MWh. The second most binding constraint is the nomogram (OMS 4646112_OP-6610) that was modelled to mitigate for the loss of El Dorado-Mohave 500 kV line which was congested in approximately 19 percent of the hours.

In addition to these constraints, congestion on the Serrano 500/230 kV transformer, Southern California Import Transmission (SCIT) nomogram, and the Imperial Valley nomogram significantly impacted prices in the San Diego Gas and Electric area during the fourth quarter. These constraints all bound between 10 and 20 percent of the hours. This congestion increased prices by about \$19/MWh in the San Diego Gas and Electric area and \$9/MWh in the Southern California Edison area, and decreased prices by about \$12/MWh in Pacific Gas and Electric area. An outage on a portion of the Serrano transformer

²⁰¹ Peak RC process update – New naming convention for nomograms, Market Performance and Planning forum, March 2017, slide 7:

http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum-Mar14_2017.pdf

bank caused congestion on the modeled constraint. This outage returned to service at the end of March 2018. The SCIT nomogram was binding for the loss of El Dorado-Moenkopi 500 kV line which returned to service mid-January 2018. Imperial Valley nomogram was enforced to protect for the loss of the Imperial Valley-North Gila 500 kV line.

Table 8.2 Impact of congestion on day-ahead prices during congested hours

Area	Constraint	Frequency				Q1			Q2			Q3			Q4		
		Q1	Q2	Q3	Q4	PG&E	SCE	SDG&E									
PG&E	30735_METCALF_230_30042_METCALF_500_XF_13			0.8%	2.3%							\$1.27	-\$0.85	-\$0.84	\$1.00	-\$0.70	-\$0.70
	6310_CP6_NG			2.0%	2.3%							\$1.90	-\$1.38	-\$1.18	\$1.52	-\$1.06	-\$0.90
	30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_2				0.8%										-\$3.04	\$2.34	\$2.20
	30735_METCALF_230_30042_METCALF_500_XF_12			2.7%	0.5%							\$1.71	-\$1.30	-\$1.29	\$1.64	-\$1.12	-\$1.11
	30060_MIDWAY_500_24156_VINCENT_500_BR_2_3				0.4%										-\$3.30	\$2.09	\$1.93
	RM_TM12_NG			2.2%								\$10.91		-\$2.28			
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1_2		2.3%						\$2.08	-\$2.11	-\$2.64						
	33020_MORAGA_115_30550_MORAGA_230_XF_3_P		0.7%						\$3.82	-\$3.77	-\$3.77						
	40687_MALIN_500_30005_ROUND MT_500_BR_1_3		0.6%						\$2.04	-\$1.88	-\$2.56						
	PATH15_S-N	7.1%				\$5.07	-\$4.09	-\$3.79									
	OMS_4654659_LBN_S_N	0.6%				\$1.25	-\$0.97	-\$0.91									
	OMS_4621181_LBN_S-N	0.4%				\$10.32	-\$8.60	-\$7.90									
	SCE	24016_BARRE_230_24154_VILLA PK_230_BR_1_1		0.4%	7.6%	5.4%				-\$1.14	\$1.28	\$0.00	-\$1.27	\$1.03	\$3.55	-\$2.43	\$1.72
24036_EAGLROCK_230_24059_GOULD_230_BR_1_1					2.8%										-\$1.30	\$1.18	
24086_LUGO_500_26105_VICTORVL_500_BR_1_1		1.5%		6.4%	1.9%			-\$0.63				-\$5.27	\$0.55	-\$1.01		\$0.68	-\$1.12
6310_CP3_NG			5.1%	1.4%					-\$0.44	\$0.38	\$0.34	-\$0.39	\$0.31	\$0.28			
24016_BARRE_230_25201_LEWIS_230_BR_1_1				1.0%								-\$0.86	\$0.99	\$0.37			
6410_CP5_NG			7.1%						-\$6.65	\$5.37	\$5.08						
SDG&E	22192_DOUBLTTP_138_22300_FRIARS_138_BR_1_1	1.1%	1.5%	34.6%	24.1%			-\$3.23			-\$6.50			-\$3.67			-\$3.29
	OMS_4646112_OP-6610				19.0%										\$0.46		-\$1.53
	24138_SERRANO_500_24137_SERRANO_230_XF_1_P				18.8%										-\$3.76	\$2.35	\$6.18
	OMS_4646120_ELD_MKP_SCIT_NG				15.8%										-\$8.23	\$6.33	\$7.77
	7820_TL_230S_OVERLOAD_NG	2.1%	8.3%	8.0%	12.8%	-\$0.17		\$2.07	-\$0.28		\$3.58	-\$0.32	\$0.11	\$3.96	-\$0.48		\$5.39
	IID-SCE_BG	1.8%			0.9%			-\$1.24									-\$4.73
	22260_ESCNDIDO_230_22844_TALEGA_230_BR_1_1				0.9%											\$0.93	-\$6.10
	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1_1				0.7%												\$2.01
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2_1			0.5%	0.5%							\$0.27	\$0.56	-\$5.02		\$0.89	-\$5.78
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1		0.7%	1.2%	0.5%						\$8.76			\$5.53			\$10.07
	OMS_5349592_SCIT				0.4%										-\$5.15	\$3.59	\$4.30
	24801_DEVERS_500_24804_DEVERS_230_XF_1_P				0.4%												-\$2.66
	OMS_5459385_VIC-RNL_SCIT				0.4%										-\$9.27	\$7.34	\$8.38
	22692_ROSCYNTP_69.0_22696_ROSE_CYN_69.0_BR_1_1				0.3%												\$2.82
	22604_OTAY_69.0_22616_OTAYLKP_69.0_BR_1_1		1.5%	2.4%								\$1.18		\$0.99			
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	1.3%		1.0%					\$2.60					\$2.50			
	7820_TL23040_IV_SPS_NG	12.0%	1.3%			-\$0.31		\$4.65	-\$0.52		\$8.24						
	OMS_4602677_50002_OOS_TDM		0.8%								\$3.78						
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1_1		0.7%								\$8.69						
	7820_TL_230S_TL50001OUT_NG		0.7%						-\$0.48		\$5.59						
	22886_SUNCREST_230_92860_SUNC TP1_230_BR_1_1		0.5%						-\$1.00		\$7.35						
	24138_SERRANO_500_24137_SERRANO_230_XF_2_P		0.4%						-\$5.12	\$3.24	\$8.53						
	23040_CROSSTRIP	15.9%					-\$0.22		\$3.10								
22596_OLD TOWN_230_22504_MISSION_230_BR_1_1		2.4%						\$3.47									
92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1_1		1.6%				-\$1.03		\$7.27									
22865_GRNT HLL_138_22852_TELECYN_138_BR_1_1		0.9%						\$1.90									
OMS_4622069_TL50003		0.6%						-\$2.22		\$26.39							
OMS_4585329_TL50001_NG		0.5%						-\$0.56		\$8.30							
OMS_4608811_MG_BK80_NG		0.4%						-\$0.10		\$2.76							

Overall day-ahead price impacts

This section provides an assessment of differences on overall average prices caused by congestion between different areas of the ISO system. Unlike the analysis provided in the previous section, this assessment is based on the average congestion component of the locational marginal prices as a percent of the total average system energy price during all hours – including both congested and non-

congested hours. This approach shows the impact of congestion taking into account the frequency that congestion occurs as well as the magnitude of the impact of congestion during hours when it occurs.²⁰²

Table 8.3 shows the overall impact of congestion on different constraints on average prices in each load aggregation area in 2017. These results show that:

- In 2017, the overall impact of congestion in the day-ahead market was highest in the San Diego Gas and Electric area. Congestion increased average prices in the San Diego area above the system average by about \$0.90/MWh or about 2.5 percent. Congestion on the Serrano 500/230 kV transformer, Southern California Import Transmission (SCIT) nomogram and the Imperial Valley nomogram were the main drivers in overall increase of prices in the San Diego Gas and Electric area.
- Congestion drove prices up in the Southern California Edison area by about \$0.40/MWh or 1.2 percent. The combined impact of congestion on Serrano 500/230 kV transformer, Southern California Import Transmission (SCIT) nomogram and Path 26 (6410_CP5_NG) drove the overall increase in Southern California Edison load area price.
- The overall impact of congestion decreased prices in the Pacific Gas and Electric area below the system average by about \$0.60/MWh, a decrease of about 2 percent. The SCIT nomogram and the Serrano 500/230 kV transformer had the most congestion impact in the overall decrease in the load area price.

²⁰² In addition, this approach identifies price differences caused by congestion without including price differences that result from transmission losses at different locations.

Table 8.3 Impact of constraint congestion on overall day-ahead prices during all hours

Constraint	PG&E		SCE		SDG&E	
	\$/MWh	Percent	\$/MWh	Percent	\$/MWh	Percent
OMS 4646120 ELD_MKP_SCIT_NG	-\$0.33	-0.94%	\$0.25	0.72%	\$0.31	0.86%
24138_SERRANO_500_24137_SERRANO_230_XF_1_P	-\$0.18	-0.51%	\$0.11	0.32%	\$0.29	0.81%
22192_DOUBLTTP_138_22300_FRIARS_138_BR_1_1					-\$0.55	-1.53%
7820_TL 230S_OVERLOAD_NG	-\$0.03	-0.08%	\$0.00	0.00%	\$0.34	0.94%
6410_CP5_NG	-\$0.12	-0.34%	\$0.10	0.27%	\$0.09	0.25%
24016_BARRE_230_24154_VILLA PK_230_BR_1_1	-\$0.06	-0.17%	\$0.05	0.13%	\$0.11	0.30%
7820_TL23040_IV_SPS_NG	-\$0.01	-0.03%			\$0.17	0.46%
PATH15_S-N	\$0.06	0.17%	-\$0.05	-0.14%	-\$0.05	-0.13%
23040_CROSSSTRIP	-\$0.01	-0.02%			\$0.12	0.34%
OMS 4646112_OP-6610	\$0.01	0.02%			-\$0.07	-0.20%
22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1					\$0.05	0.12%
6310_CP6_NG	\$0.02	0.06%	-\$0.01	-0.04%	-\$0.01	-0.03%
OMS 4622069_TL50003	\$0.00	-0.01%			\$0.04	0.10%
30005_ROUND MT_500_30015_TABLE MT_500_BR_1_2	\$0.01	0.03%	-\$0.01	-0.03%	-\$0.02	-0.04%
92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1_1	\$0.00	-0.01%			\$0.03	0.09%
24086_LUGO_500_26105_VICTORVL_500_BR_1_1	\$0.00	-0.01%	\$0.01	0.02%	-\$0.02	-0.07%
30735_METCALF_230_30042_METCALF_500_XF_12	\$0.01	0.04%	-\$0.01	-0.03%	-\$0.01	-0.03%
OMS 4621181_LBN_S-N	\$0.01	0.03%	-\$0.01	-0.03%	-\$0.01	-0.02%
OMS 5459385_VIC-RNL_SCIT	-\$0.01	-0.02%	\$0.01	0.02%	\$0.01	0.02%
RM_TM12_NG	\$0.01	0.03%			-\$0.01	-0.04%
22596_OLD TOWN_230_22504_MISSION_230_BR_1_1					\$0.02	0.06%
30735_METCALF_230_30042_METCALF_500_XF_13	\$0.01	0.02%	-\$0.01	-0.02%	-\$0.01	-0.02%
6310_CP3_NG	-\$0.01	-0.02%	\$0.01	0.02%	\$0.01	0.02%
OMS 4583153_PATH15_S-N	\$0.01	0.02%	-\$0.01	-0.02%	-\$0.01	-0.01%
24138_SERRANO_500_24137_SERRANO_230_XF_2_P	-\$0.01	-0.02%	\$0.00	0.01%	\$0.01	0.02%
22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1					\$0.02	0.05%
30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_2	-\$0.01	-0.02%	\$0.01	0.02%	\$0.01	0.01%
22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1_1					\$0.02	0.05%
22500_MISSION_138_22496_MISSION_69.0_XF_1					\$0.02	0.05%
IID-SCE_BG					-\$0.02	-0.05%
22260_ESCNDIDO_230_22844_TALEGA_230_BR_1_1			\$0.00	0.01%	-\$0.01	-0.04%
24036_EAGLROCK_230_24059_GOULD_230_BR_1_1	-\$0.01	-0.02%	\$0.01	0.02%		
22227_ENCINATP_230_22716_SANLUSRY_230_BR_2_1	\$0.00	0.00%	\$0.00	0.01%	-\$0.01	-0.03%
OMS_5349592_SCIT	-\$0.01	-0.02%	\$0.00	0.01%	\$0.00	0.01%
22886_SUNCREST_230_92860_SUNC TP1_230_BR_1_1	\$0.00	0.00%			\$0.01	0.03%
7820_TL 230S_TL50001OUT_NG	\$0.00	0.00%			\$0.01	0.03%
40687_MALIN_500_30005_ROUND MT_500_BR_1_3	\$0.00	0.01%	\$0.00	-0.01%	\$0.00	-0.01%
22604_OTAY_69.0_22616_OTAYLKTP_69.0_BR_1_1					\$0.01	0.03%
OMS 4585329_TL50001_NG	\$0.00	0.00%			\$0.01	0.03%
24016_BARRE_230_25201_LEWIS_230_BR_1_1	\$0.00	-0.01%	\$0.00	0.01%	\$0.00	0.01%
Other	\$0.05	0.15%	-\$0.02	-0.07%	\$0.03	0.08%
Total	-\$0.59	-1.68%	\$0.42	1.19%	\$0.90	2.49%

8.3.2 Real-time congestion

Congestion in the 15-minute real-time market differs from congestion in the day-ahead market. Real-time congestion typically occurs less frequently overall, but with a bigger impact on prices.²⁰³ This section provides highlights of congestion in the 15-minute market.²⁰⁴

15-minute market congestion

The congestion effect on prices was larger in the 15-minute market, but overall congestion occurred less frequently than in the day-ahead market. Table 8.4 shows the frequency and magnitude of congestion by quarter in 2017.

During the first quarter, similar to the day-ahead market, the Crosstrip constraint bound most frequently at about 5 percent of all intervals. When binding, it increased San Diego Gas and Electric area prices by about \$11/MWh and had no effect on Pacific Gas and Electric and Southern California Edison load area prices. In the Pacific Gas and Electric area, Path 15 constraints (PATH15_S-N, OMS 4687953_P15_S-N) bound most frequently in the south-to-north direction in about 3 percent of intervals. When Path 15 bound, it increased Pacific Gas and Electric area prices on an average by about \$13/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by an average \$14/MWh. These constraints bound primarily because of adjustments to transfer limits to account for nearby outages.

The Path 26 (6410_CP5_NG) and the Round Mountain-Table Mountain 500 kV constraints bound most frequently during the second quarter, with congestion occurring during 5 percent and 4 percent of all intervals, respectively. When Path 26 bound, it increased Southern California Edison and San Diego Gas and Electric area prices by about \$16/MWh while decreasing Pacific Gas and Electric area price by \$20/MWh. It was binding because the Path 26 limit was conformed to account for an outage on the Midway – Whirlwind 500 kV line. When the Round Mountain-Table Mountain 500 kV constraint bound it increased Pacific Gas and Electric area prices by about \$9/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by \$4/MWh.

In the third quarter, the frequency of congestion in the 15-minute market increased especially in the San Diego Gas and Electric area. The Doublet Tap - Friars constraint bound most frequently at about 11 percent of all intervals. This constraint was binding due to an overload in the real-time contingency analysis (RTCA) run for the loss of Penasquitos-Old Town 230 line. When binding, the constraint created a generation pocket and decreased San Diego Gas and Electric area prices by about \$8/MWh.

The frequency of congestion continued to increase in the San Diego Gas and Electric area during the fourth quarter. The Doublet Tap - Friars constraint was most binding constraint at about 9 percent of the hours. In addition to this constraint, the Southern California Import Transmission (SCIT) nomogram, Serrano 500/230 kV constraint, OMS 4646112_OP-6610 nomogram and Imperial Valley nomogram frequently bound and caused prices to increase in the Southern California Edison and San Diego Gas and Electric areas.

²⁰³ For example, in the fourth quarter, the SCIT nomogram was binding during roughly 16 percent of hours in the day-ahead market compared to around 8 percent of intervals in the 15-minute market. Prices were increased by \$16/MWh in the 15-minute market in the SDG&E area when the constraint bound, but only by \$8/MWh in the day-ahead market.

²⁰⁴ Historically, we have provided 5-minute market congestion in addition to 15-minute and day-ahead market congestion. Given that most of the imbalance in real time occurs in the 15-minute market we are only reporting on this congestion at this time. In 2017, overall frequency of congestion is similar between the 15-minute and 5-minute markets, however the price impact was higher in the 5-minute market compared to the 15-minute market.

Table 8.4 Impact of congestion on 15-minute prices by load aggregation point in congested intervals

Area	Constraint	Frequency				Q1			Q2			Q3			Q4				
		Q1	Q2	Q3	Q4	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E		
PG&E	6310_CP6_NG			1.1%	1.7%							\$4.23	-\$5.81	-\$5.36	\$4.10	-\$6.38	-\$5.88		
	30735_METCALF_230_30042_METCALF_500_XF_12			1.2%	0.6%							\$20.01	-\$8.76	-\$8.66	\$12.13	-\$4.91	-\$4.89		
	RM_TM12_NG			3.0%								\$16.96	\$6.39	\$3.23					
	30060_MIDWAY_500_24156_VINCENT_500_BR_2_2		0.7%	1.2%					-\$22.27	\$14.47	\$13.85	-\$12.12	\$8.53	\$8.17					
	30735_METCALF_230_30042_METCALF_500_XF_13			0.8%								\$26.32	-\$10.49	-\$10.44					
	OMS_4864567_CP1			0.4%								\$5.35	-\$3.72	-\$3.52					
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1_2		3.6%						\$8.53	\$4.32	\$3.69								
	OMS_3831815_TMS_DLO		1.4%						\$2.03	\$1.92	\$1.11								
	40687_MALIN_500_30005_ROUND MT_500_BR_1_3		0.8%						\$6.66	\$2.63	\$2.13								
	30797_LASAGUIL_230_30790_PANOACHE_230_BR_2_1		0.3%						\$9.81										
	RM_TM21_NG		0.3%						\$7.05	\$3.49	\$2.81								
	PATH15_S-N	2.4%				\$15.25	-\$16.22	-\$15.28											
	6110_TMS_DLO	0.8%				\$2.54	\$3.39	\$3.08											
	OMS_4621181_LBN_S-N	0.4%				\$25.62	-\$33.28	-\$31.51											
	OMS_4687953_P15_S-N	0.3%				\$10.58	-\$12.56	-\$11.99											
	SCE	24016_BARRE_230_24154_VILLA PK_230_BR_1_1			4.0%	2.9%							-\$3.88	\$5.45	\$10.81	-\$5.08	\$7.32	\$19.76	
		24086_LUGO_500_26105_VICTORVL_500_BR_1_1			1.6%	2.2%							\$12.58	\$16.97	\$29.09	\$6.83	\$6.85	\$10.50	
		6510_CP1_NG			0.4%								-\$3.92	\$8.79	\$9.74				
		6410_CP1_NG			0.4%								-\$11.01	\$6.74	\$6.72				
6410_CP5_NG			4.7%						-\$20.28	\$16.60	\$15.77								
6310_CP3_NG			1.6%						-\$2.59	\$2.77	\$2.55								
PATH26_N-S		0.5%				-\$14.03	\$11.82	\$11.19											
SDG&E	22192_DOUBLTTP_138_22300_FRIARS_138_BR_1_1		1.0%	10.6%	8.7%												-\$11.10		
	OMS_4646120_ELD_MKP_SCIT_NG				8.0%												-\$4.31	\$14.28	\$15.78
	24138_SERRANO_500_24137_SERRANO_230_XF_1_P				7.5%												-\$6.52	\$11.13	\$23.58
	OMS_4646112_OP-6610				5.9%												\$10.22	\$9.23	\$1.62
	7820_TL2305_OVERLOAD_NG	1.5%	1.3%	2.4%	2.3%	\$0.65	\$12.64		\$1.40	\$28.23		\$0.48	\$10.27	-\$0.28	\$0.42	\$9.60			
	7820_TL23040_IV_SPS_NG				1.4%													\$40.28	
	22260_ESCNDIDO_230_22844_TALEGA_230_BR_1_1				0.8%													\$6.91	-\$36.63
	92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1_1	0.8%			0.6%			\$18.81											\$34.40
	OMS_5364247_MIGUEL				0.4%														\$28.23
	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1_1				0.4%														\$23.22
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1				0.3%														\$59.80
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2_1			0.8%								\$1.56	\$2.82	-\$18.88					
	7820_TL2305_TL50001OUT_NG		0.4%							\$0.97	\$17.34								
23040_CROSSTRIP		5.0%						\$11.11											
OMS_4622069_TL50003		0.3%						\$1.05	\$42.46										

Overall 15-minute price impacts

Table 8.5 shows the overall impact of 15-minute congestion in 2017 on average prices in each load area by constraint.²⁰⁵ The overall impact of congestion increased San Diego Gas and Electric, Southern California Edison and Pacific Gas and Electric load area prices by about \$1.50/MWh (4 percent), \$1.10/MWh (3 percent) and \$0.30/MWh (0.8 percent) , respectively.

In the Southern California areas, Serrano 500/230 kV, Southern California Import Transmission (SCIT) and Path 26 constraints had the largest combined overall price impact in the 15-minute market. The impact of congestion by these constraints increased Southern California Edison area price above system average by about \$0.70/MWh and San Diego area prices by almost \$1/MWh.

²⁰⁵ As a result of data issues, details on specific constraints with very low price impacts could not be calculated and were included in the *other* category.

Table 8.5 Impact of constraint congestion on overall 15-minute prices during all hours

Constraint	PG&E		SCE		SDG&E	
	\$/MWh	Percent	\$/MWh	Percent	\$/MWh	Percent
24138_SERRANO_500_24137_SERRANO_230_XF_1_P	-\$0.12	-0.35%	\$0.21	0.59%	\$0.45	1.23%
OMS 4646120_ELD_MKP_SCIT_NG	-\$0.09	-0.24%	\$0.29	0.81%	\$0.32	0.88%
6410_CP5_NG	-\$0.24	-0.67%	\$0.19	0.54%	\$0.18	0.51%
22192_DOUBLTTP_138_22300_FRIARS_138_BR_1_1					-\$0.50	-1.36%
24016_BARRE_230_24154_VILLA PK_230_BR_1_1	-\$0.06	-0.16%	\$0.11	0.30%	\$0.25	0.68%
OMS 4646112_OP-6610	\$0.15	0.43%	\$0.14	0.38%	\$0.01	0.03%
PATH15_S-N	\$0.09	0.25%	-\$0.10	-0.27%	-\$0.09	-0.25%
7820_TL 230S_OVERLOAD_NG	\$0.00	0.00%	\$0.01	0.03%	\$0.25	0.69%
24086_LUGO_500_26105_VICTORVL_500_BR_1_1	\$0.09	0.25%	\$0.11	0.29%	\$0.03	0.08%
RM_TM12_NG	\$0.13	0.37%	\$0.05	0.14%	\$0.02	0.05%
30060_MIDWAY_500_24156_VINCENT_500_BR_2_2	-\$0.07	-0.20%	\$0.05	0.14%	\$0.05	0.13%
7820_TL23040_IV_SPS_NG					\$0.15	0.42%
30735_METCALF_230_30042_METCALF_500_XF_12	\$0.08	0.23%	-\$0.04	-0.10%	-\$0.03	-0.09%
30005_ROUND MT_500_30015_TABLE MT_500_BR_1_2	\$0.08	0.22%	\$0.04	0.11%	\$0.03	0.09%
23040_CROSSSTRIP					\$0.14	0.38%
6310_CP6_NG	\$0.03	0.08%	-\$0.05	-0.13%	-\$0.04	-0.11%
92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1_1					\$0.11	0.30%
30735_METCALF_230_30042_METCALF_500_XF_13	\$0.05	0.15%	-\$0.02	-0.06%	-\$0.02	-0.06%
22260_ESCNDIDO_230_22844_TALEGA_230_BR_1_1			\$0.01	0.04%	-\$0.08	-0.21%
OMS 4621181_LBN_S-N	\$0.02	0.06%	-\$0.03	-0.08%	-\$0.03	-0.07%
30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	-\$0.03	-0.08%	\$0.02	0.06%	\$0.02	0.05%
22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1					\$0.06	0.16%
37585_TRCY PMP_230_30625_TESLA D_230_BR_2_1	\$0.03	0.08%	-\$0.01	-0.03%	-\$0.01	-0.03%
22227_ENCINATP_230_22716_SANLUSRY_230_BR_2_1	\$0.00	0.01%	\$0.01	0.02%	-\$0.04	-0.11%
PATH26_N-S	-\$0.02	-0.05%	\$0.02	0.04%	\$0.01	0.04%
Other	\$0.16	0.45%	\$0.05	0.13%	\$0.20	0.54%
Total	\$0.29	0.81%	\$1.06	2.97%	\$1.45	3.98%

Internal congestion in the energy imbalance market

Table 8.6 shows the frequency of congestion on internal constraints in the energy imbalance market since 2014. In the first quarter of 2017, the frequency of binding constraints in the NV Energy area increased significantly to about 10 percent and 12 percent in the 15-minute and 5-minute markets, respectively. This is because NV Energy was actively adjusting transmission elements for accuracy of line ratings and outages. In the PacifiCorp East area, internal congestion increased significantly in the fourth quarter of 2017. Congestion was mainly a result of a single constraint binding during more than 45 percent of intervals in both the 15-minute and 5-minute markets. This frequency was specifically higher in October 2017 because the limits on this constraint were reduced by almost 50 percent on some days.

In the remaining energy imbalance market areas internal congestion was low, even after more constraints were enforced following FERC’s November 2015 Order requesting this.²⁰⁶

Persistent low congestion may be a result of the following:

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

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

Table 8.6 Percent of intervals with congestion on internal EIM constraints

	2014	2015				2016				2017			
	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
15-minute market (FMM)													
PacifiCorp East	0.1%	0.2%	0.2%	0.5%	2.6%	2.2%	0.2%	1.3%	14.9%	16.1%	4.3%	5.1%	47.6%
PacifiCorp West	0.1%	0.0%	0.0%	0.2%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%	0.0%	0.0%
NV Energy					0.0%	0.0%	0.1%	0.3%	3.2%	10.3%	1.8%	7.6%	5.8%
Puget Sound Energy									0.0%	0.0%	0.0%	0.0%	0.0%
Arizona Public Service									0.0%	0.0%	0.0%	0.0%	0.0%
Portland General Electric													0.0%
5-minute market (RTD)													
PacifiCorp East	0.0%	0.3%	0.2%	0.4%	2.3%	2.2%	0.2%	1.3%	15.2%	17.1%	3.3%	4.5%	46.1%
PacifiCorp West	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.0%	0.1%	0.0%	0.0%
NV Energy					0.0%	0.0%	0.2%	0.3%	3.2%	11.7%	1.6%	7.1%	5.6%
Puget Sound Energy									0.0%	0.0%	0.0%	0.0%	0.0%
Arizona Public Service									0.0%	0.0%	0.0%	0.0%	0.0%
Portland General Electric													0.0%

8.4 Congestion revenue rights

Congestion revenue rights not allocated to load-serving entities that are sold in the auction consistently generate significantly less revenue than is paid to the entities purchasing these rights at auction. From 2012 through 2017, ratepayers received about 49 percent of the value of their congestion revenue rights that the ISO auctioned. This represents a shortfall of about \$101 million in 2017 and more than a \$730 million shortfall since 2009.

Section 8.4.1 provides an overview of both allocated and auctioned congestion revenue right holdings. Section 8.4.2 provides more details on the performance of the congestion revenue right auction.

²⁰⁶ Order on Proposed Market-Based Tariff Changes, November 19, 2015, ER15-2281-000: <https://www.ferc.gov/whats-new/comm-meet/2015/111915/E-5.pdf>.

8.4.1 Allocated and auctioned 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 either allocated or auctioned to market participants. Participants serving load are allocated rights monthly, annually (with seasonal terms), or for 10 years (for the same seasonal term each year). All participants can procure congestion revenue rights in the auctions. Annual auctions are held prior to the year in which the rights will settle. Rights sold in the annual auctions have seasonal terms. Monthly auctions are held the month prior to the settlement month. Rights sold in the monthly auction have monthly terms.²⁰⁷

Ratepayers own the day-ahead transmission rights not held by merchant transmission or long-term rights holders. In this report rights owned by ratepayers are referred to as non-merchant day-ahead transmission rights.

Allocated congestion revenue rights are a means of distributing the revenue from the sale of these non-merchant day-ahead rights, also known as congestion rent, to entities serving load to then be passed to ratepayers. Any revenues remaining after the distribution to allocated congestion revenue rights are allocated based on load share, or are used to pay congestion revenue rights procured at auction.

In exchange for backing the auctioned rights, ratepayers receive the net auction revenue which is allocated by load share. If there is insufficient transmission sales revenue to pay all the congestion revenue rights, a condition known as revenue inadequacy, ratepayers are charged based on load share to cover the difference.

Congestion revenue right holdings

Figure 8.3 and Figure 8.4 show the quarterly peak and off-peak hour average megawatt holdings of congestion revenue rights awarded by type since 2012.

- The total megawatt volume of congestion revenue rights held increased slightly by 3 percent in 2017 compared to 2016.
- Allocated and auctioned megawatt holdings in 2017 increased slightly by 7 percent and 2 percent, respectively, compared to 2016.

Interpreting congestion revenue right megawatt holding changes can be difficult as it is not clear what the megawatt volume represents. Consider a participant holding 10 megawatts from node A to node B, and 10 megawatts from node B to node A. The participant's net holding of transmission rights is zero megawatts but the total megawatts of congestion revenue rights held is 20 megawatts. Total congestion revenue right megawatts does not give a complete view of the transmission rights held.

One alternative is measuring the implied value of transmission rights held by congestion revenue rights. Congestion revenue rights are allocated and auctioned across different time frames. A valuation of the

²⁰⁷ A more detailed explanation of the congestion revenue right processes is provided in the ISO's *2015 Annual CRR Market Results Report*. See: <http://www.caiso.com/Documents/2015AnnualCRRMarketResultsReport.pdf>.

rights held can be computed using the seasonal auction, monthly auction, or day-ahead transmission prices. Figure 8.5 shows the percentage congestion revenue right megawatts held by allocated, seasonally auctioned, and monthly auctioned rights. Figure 8.6 shows the percentage of rights held when valued at the monthly auction prices. Both figures include all peak and off-peak rights. In 2017, allocated congestion revenue rights made up less than a third of total megawatts, but were worth about two-thirds of the implied value of rights at monthly auction prices, a continued trend since 2013.

Figure 8.7 shows payments to congestion revenue rights with auction prices at or below \$0/MWh.²⁰⁸ Figure 8.8 shows payments to rights with auction prices greater than \$0/MWh, which indicate positions in the prevailing flow of congestion, typically from a generation area to a load area. Both figures include peak and off-peak rights. The majority of payments were to rights with positive auction prices which were in the prevailing flow of congestion.

Although there continued to be a significant number of megawatts held priced at \$0/MWh, net payments to these rights were insignificant when compared to total payments to auctioned rights in 2017.²⁰⁹ Net payments to zero priced rights totaled \$0.1 million in 2017, down from \$2 million in 2016. Total payments to auctioned rights were about \$175 million in 2017 and \$139 million in 2016. Congestion revenue rights priced below zero dollars but greater than negative 25 cents were paid \$7 million in 2017 and \$2 million in 2016 versus being charged over \$1 million in 2015.

²⁰⁸ This includes congestion revenue right positions that are counter to the prevailing flow of generation and are known as counter-flow positions. For example, a counter-flow congestion revenue right may go from a load area to a generation area. These positions are paid to take the congestion revenue right in the auction and then make payments based on day-ahead congestion. This grouping also includes positions that have a \$0/MWh price in the auction and cannot be classified as counter-flow or prevailing flow because it is possible that they may be prevailing flow or counter-flow in the day-ahead market, which differs from the results in the auction.

²⁰⁹ In 2013 and 2014 the total amount of rights held priced at \$0/MWh increased sharply. See Section 7.4 of the *2014 Annual Report on Market Issues and Performance*, Department of Market Monitoring: http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

Figure 8.3 Congestion revenue right megawatts held by procurement type (peak)

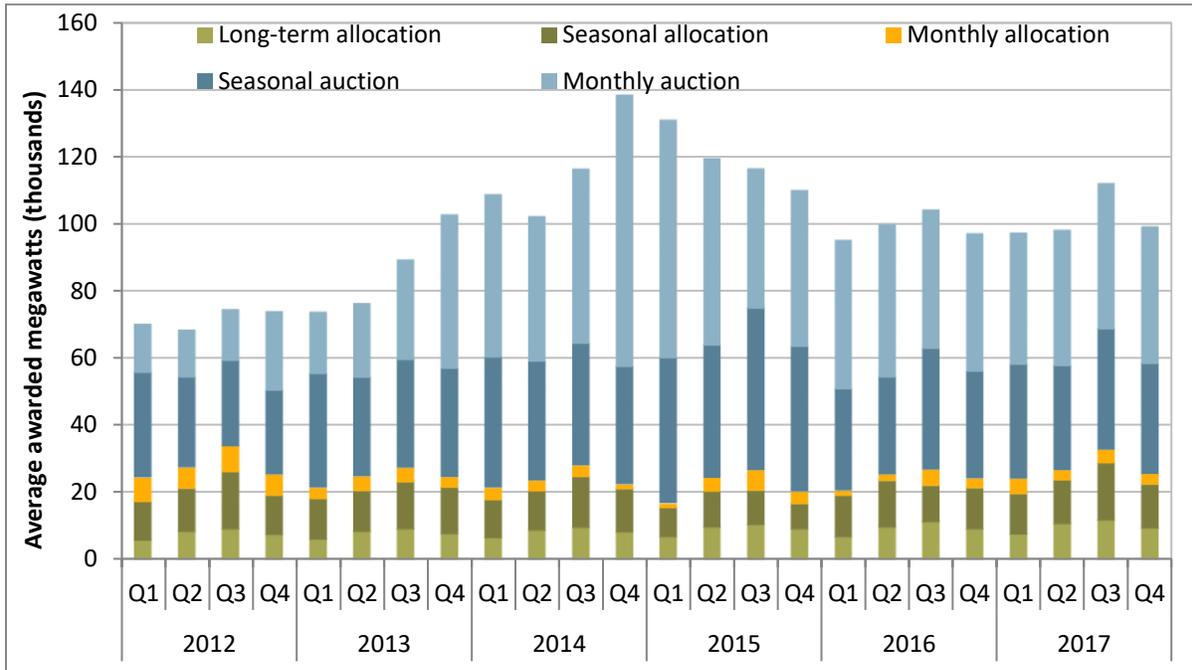


Figure 8.4 Congestion revenue right megawatts held by procurement type (off-peak)

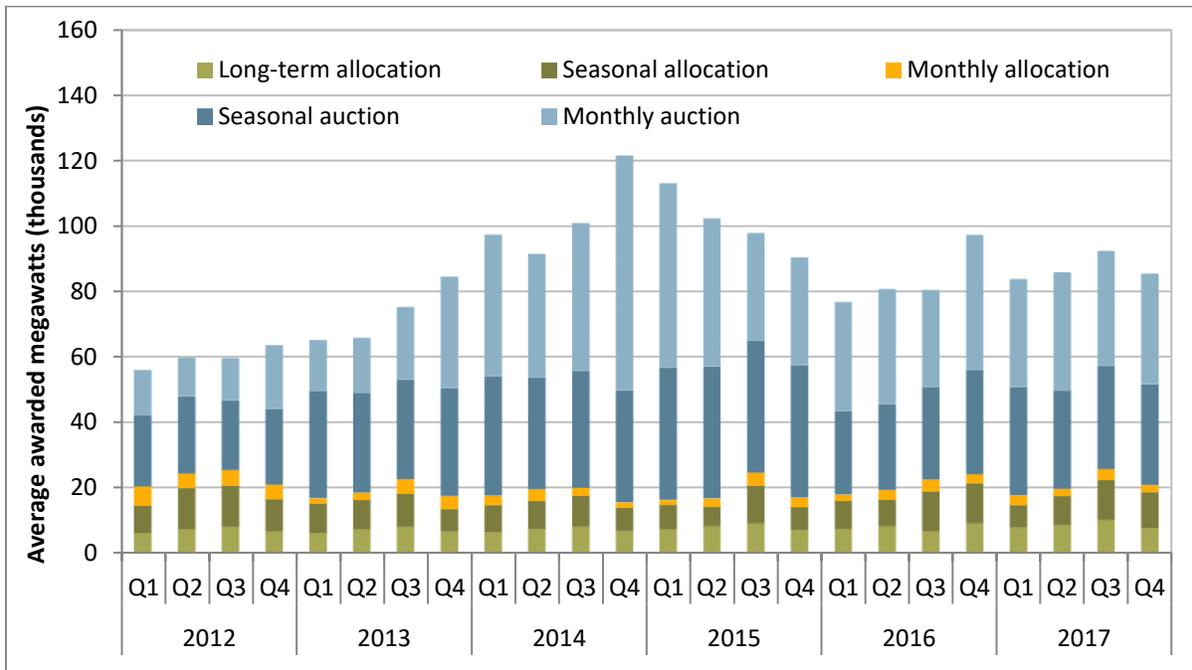


Figure 8.5 Percent of congestion revenue right megawatts held by procurement type

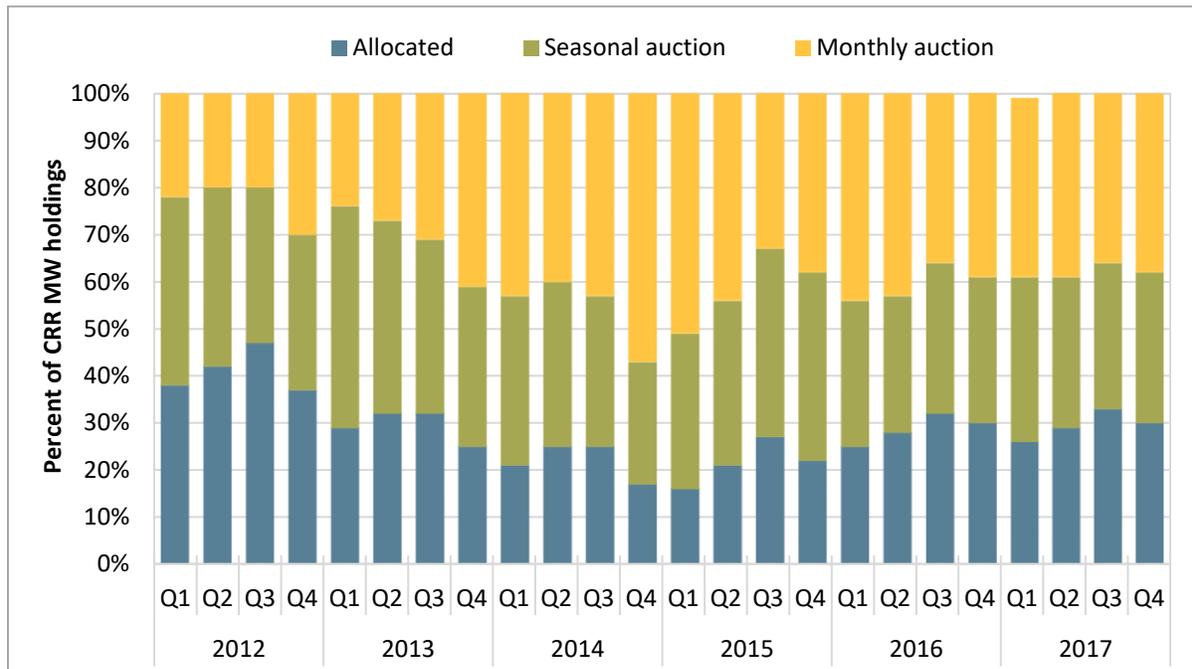


Figure 8.6 Percent of congestion revenue right monthly auction value by procurement type

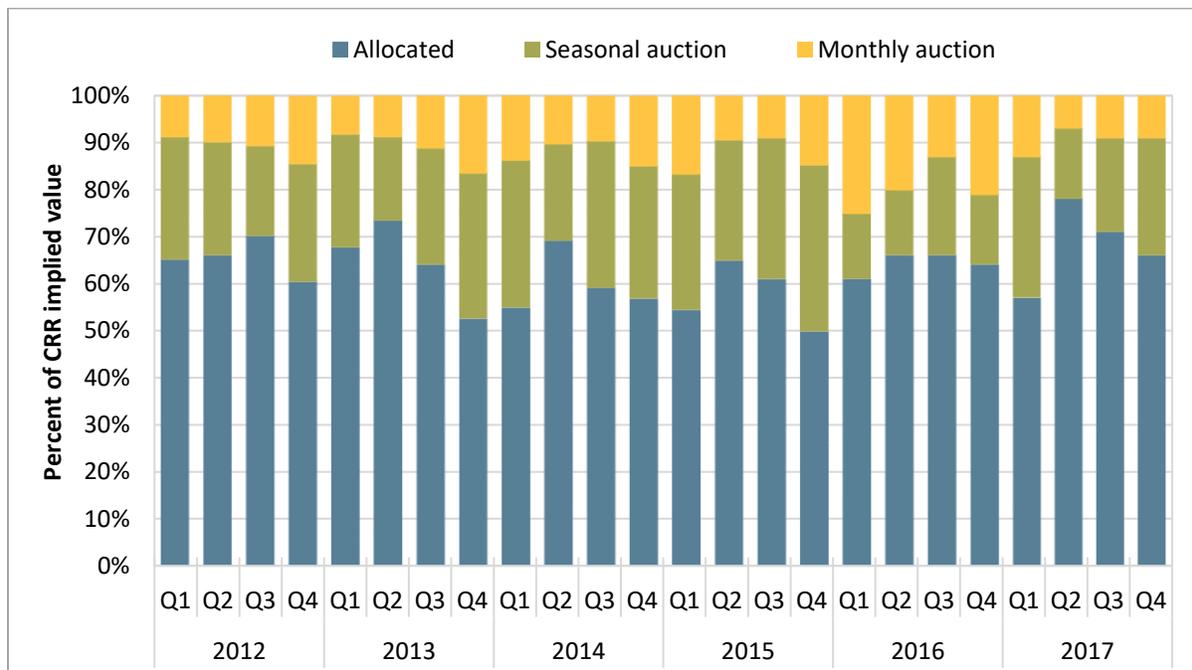


Figure 8.7 Payments to non-positively priced auctioned congestion revenue rights

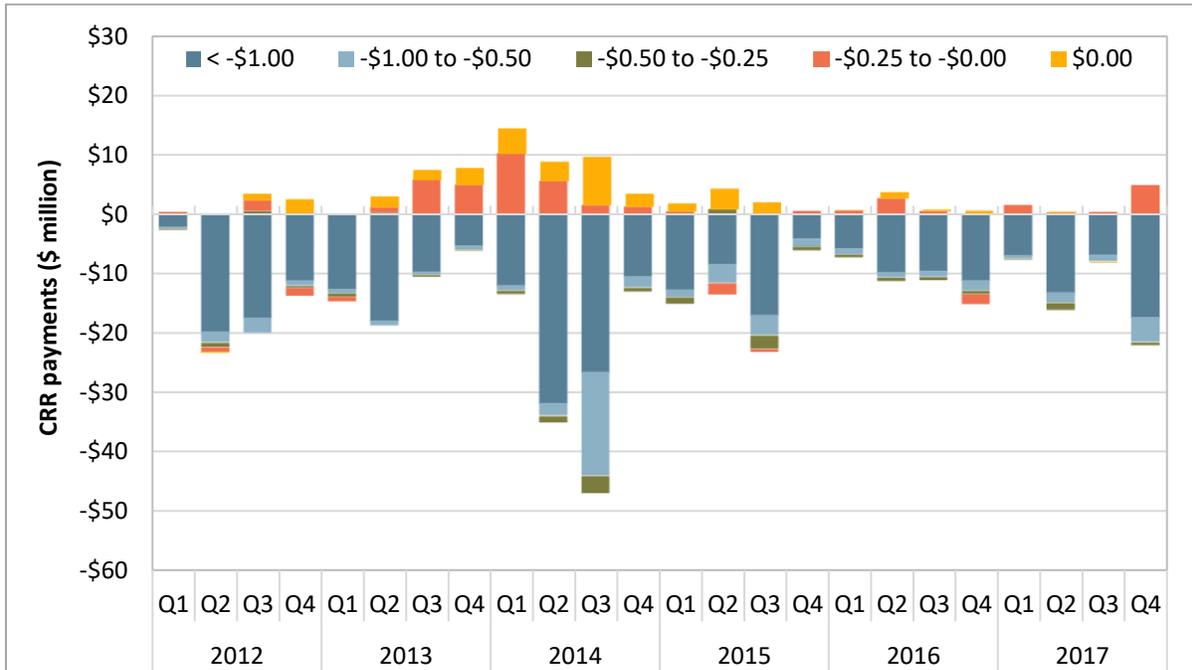
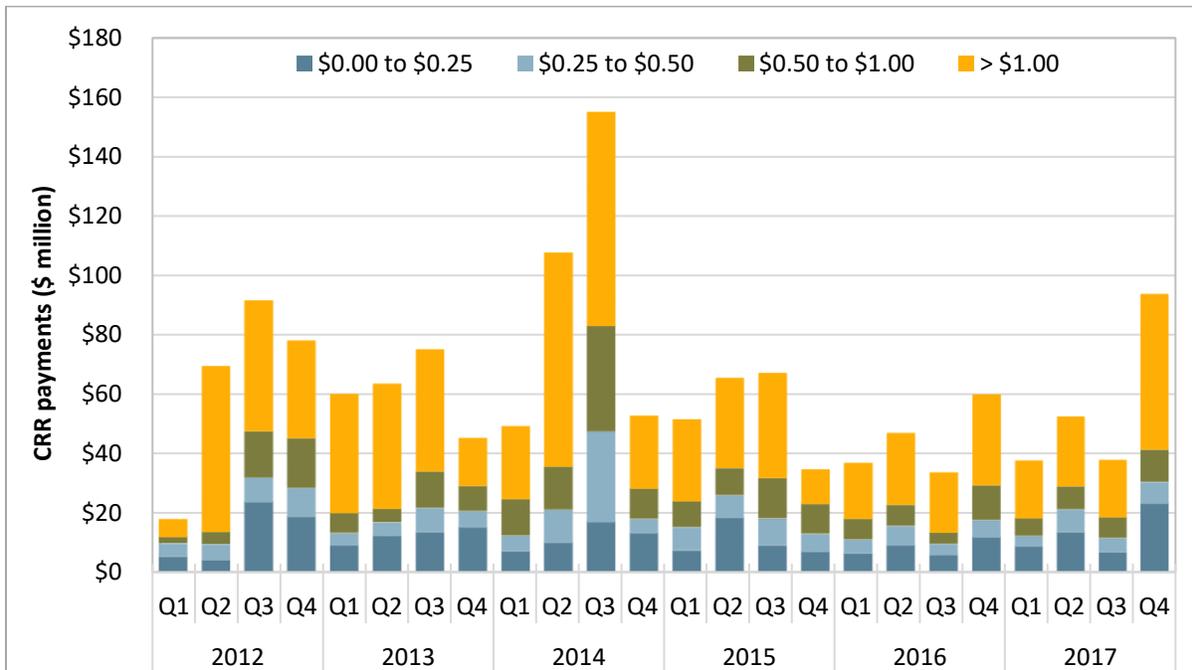


Figure 8.8 Payments to positively priced auctioned congestion revenue rights



8.4.2 Congestion revenue right auction returns

The ISO and DMM have traditionally tracked and reported on congestion revenue right revenue inadequacy as a primary metric to evaluate how well the congestion revenue right market is functioning. This section presents an alternative metric that DMM believes is more appropriate for assessing the congestion revenue right market.²¹⁰ This metric compares the auction revenues that ratepayers receive for rights sold in the ISO's auction to the payments made to these auctioned rights at day-ahead market prices.

Results presented in this report show that auction revenues received by ratepayers have persistently been far below day-ahead market congestion revenues that ratepayers would have received if the ISO had not auctioned any congestion revenue rights.²¹¹ DMM believes this discrepancy warrants reassessing the standard electricity market design assumption that ISOs should auction off transmission capacity in excess of the capacity allocated to load-serving entities.^{212,213}

Background

When a transmission constraint is binding in the day-ahead market, this creates congestion revenue. This is because load that is within the congested area of a constraint is charged a higher price than the price paid to generation on the uncongested side of the constraint. When congestion occurs, each megawatt of the constraint's transmission capacity produces market revenue equal to the constraint's day-ahead market congestion price (or shadow price). For instance, when a 1,000 MW constraint is binding at a \$10/MWh congestion price, this generates \$10,000 in congestion revenues.

The owners of transmission – or entities paying for the cost of building and maintaining transmission – are entitled to the 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).²¹⁴ 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. Load-serving entities then pass that transmission access charge through to

²¹⁰ The ISO reports on a similar metric in its market performance metric catalogue in its congestion revenue right section: <http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx>.

²¹¹ For further information, see DMM's whitepaper: *Shortcomings in the Congestion Revenue Right Auction Design*, November 28, 2016: <http://www.caiso.com/Documents/DMM-WhitePaper-Shortcomings-CongestionRevenueRightAuctionDesign.pdf>.

²¹² It is a convenient analogy to describe the auction as selling excess transmission rights. However, an alternative analogy is that the auction makes ratepayers the counterparty to financial cash settled forward contracts. The difference between the auction revenues and payments to the rights are the gains or losses to ratepayers on these forward contracts.

²¹³ DMM whitepaper on *"Problems in the performance and design of the congestion revenue rights auction"*, November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

²¹⁴ 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.

ratepayers in their customers' electricity bills. Therefore, these ratepayers are entitled to the revenues from this transmission.

These ratepayers currently receive the day-ahead market revenues from a large part of their transmission directly through the congestion revenue right allocation process. This process allocates a portion of congestion rights to load-serving entities which pay the transmission access charge based on these entities' historical load. These entities receive the day-ahead market congestion revenues associated with these congestion revenue rights. These entities then pass on these congestion revenues — along with transmission access charges — to their ratepayers. The analysis in this section does not apply to this portion of ratepayers' transmission. Instead, this analysis only includes the portion of transmission that is paid for by ratepayers, but is not directly allocated to their load-serving entities. Therefore, the congestion revenues from this transmission are not given directly to ratepayers through this congestion revenue right allocation process.

Not all transmission is allocated through the congestion revenue right allocation process. Ratepayers are still entitled to the day-ahead market congestion revenues generated by the transmission capacity that is not allocated to ratepayers through the congestion revenue right allocation process. However, a current principle incorporated in standard electricity market design is that day-ahead market congestion revenues from this additional transmission capacity is not provided directly to ratepayers. Instead, the ISO auctions off congestion revenue rights, which are intended to represent the rights to the day-ahead market congestion revenues of this excess transmission capacity.

For each megawatt of ratepayer transmission capacity auctioned off by the ISO, ratepayers are effectively giving up their right to the day-ahead market congestion revenue for that capacity. In exchange for the right to this congestion revenue, ratepayers receive the auction revenues generated from auctioning off this excess capacity. Ratepayers directly receive the day-ahead market congestion revenues for any of the excess transmission that is available in the day-ahead market that was not auctioned off through the congestion revenue right balancing account.

As long as the auction revenue that ratepayers receive for a megawatt auctioned off is greater than or equal to the day-ahead market congestion payments made for that megawatt, ratepayers benefit from having the ISO auction off that megawatt. However, if the auction revenue from that megawatt is expected to be less than the day-ahead market congestion revenue of that megawatt, then ratepayers should not want the ISO to auction off this extra transmission. Ratepayers would be better off directly receiving revenues from this transmission when congestion occurs in the day-ahead market, rather than receiving a lower price through the congestion revenue right auction process. For this reason, DMM believes it is appropriate to assess the performance of the congestion revenue right auction from the perspective of ratepayers by comparing the auction revenues that ratepayers receive for rights sold in the ISO's auction to the day-ahead market congestion revenues that ratepayers would have received if these congestion revenue rights were not sold in the auction.²¹⁵

²¹⁵ For example, consider a case where there is expected to be 1,000 MW of transmission capacity available in the day-ahead market which has not already been allocated to load-serving entities through the congestion revenue right allocation process. If the ISO auctions off the rights to the day-ahead market congestion revenues for 50 percent of this 1,000 MW capacity, ratepayers receive the auction revenues for this 500 MW of capacity. Ratepayers also receive day-ahead congestion revenues from the other 500 MW of capacity that was not auctioned off through the congestion revenue right balancing account. From the perspective of ratepayers, it is appropriate to compare the auction revenues received for 500 MW of congestion revenue rights sold in the ISO's auction to the day-ahead market congestion revenues that ratepayers would have received for the 500 MW of transmission if these rights were not sold in the auction.

Revenue inadequacy

The ISO and DMM have traditionally tracked and reported on congestion revenue right revenue inadequacy as a primary metric to evaluate how well the congestion revenue right market is functioning. This section explains why the revenue inadequacy 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. As described in this section, 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.

Sources of revenue inadequacy

Revenue inadequacy is, under some conditions, reflective of the additional financial consequences to ratepayers that occur if more transmission capacity is auctioned off than is actually available in the day-ahead market. This situation can occur for a variety of reasons, including outages, modeling

discrepancies, and errors, as described in DMM’s 2014 annual report.²¹⁶ In practice, these factors tend to create a systematic tendency for transmission capacity sold in the congestion revenue right auction to exceed the amount of transmission actually available in the day-ahead market. In this situation, the congestion revenues paid for rights in excess of transmission actually available in the day-ahead market are ultimately allocated to the ratepayers of load-serving entities through the congestion revenue right balancing account.

Given the same example in the prior section, with a \$5/MWh auction price and \$10/MWh day-ahead price, assume now that only 90 MW of transmission service is available in the day-ahead market. In this 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 revenue adequacy account.
- The day-ahead transmission congestion 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 using the remaining 15 MW of transmission in the day-ahead market pay \$150 into the balancing account.
- The financial entity receives \$250 from the balancing account for their 25 MW of congestion revenue rights.
- In total financial entities are making positive revenue of \$125 ($\$250 - \125), and this amount is paid for by load.

In this example the congestion revenue right balancing account has a net balance of $-\$100$ without auction revenues and $+\$25$ with auction revenues.²¹⁷ However, if the 25 MW of congestion revenue rights had not been auctioned off, the balancing account value would have been \$150 (with or without

²¹⁶ *2014 Annual Report on Market Issues and Performance*, Department of Market Monitoring, June 2015, pp. 159-162. http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

²¹⁷ The amount collected in day-ahead congestion is equal to $90 \text{ MW} * \$10/\text{MWh}$ for a total of \$900. From this number we subtract what is owed to the congestion revenue rights holders which is $\$750 (75 \text{ MW} * \$10/\text{MWh})$ for the load-serving entities plus $\$250 (25 \text{ MW} * \$10/\text{MWh})$ for the financial entities, or a total of \$1,000. Thus $\$900 - \$1,000$ results in $-\$100$ without auction revenues. The balance with auction revenues can be calculated as $\$25 (\$125 - \$100)$, or the total auction revenues ($\$125$) less the total without auction revenues.

including the \$0 auction revenues).²¹⁸ The \$125 difference equals the auction revenues less the payments to the auctioned congestion revenue rights.²¹⁹

As illustrated by this example, revenue inadequacy reflects the shortfall between the total payments to congestion revenue rights and day-ahead congestion rents collected from the available transmission capacity. However, this revenue inadequacy represents only a portion of the overall performance of the congestion revenue rights auction from the perspective of ratepayers. If auction revenues are less than the congestion payments to the non-load-serving entities purchasing congestion revenue rights in the auction, then each additional megawatt of transmission capacity auctioned was not financially beneficial for ratepayers.

Analysis of congestion revenue right auction returns

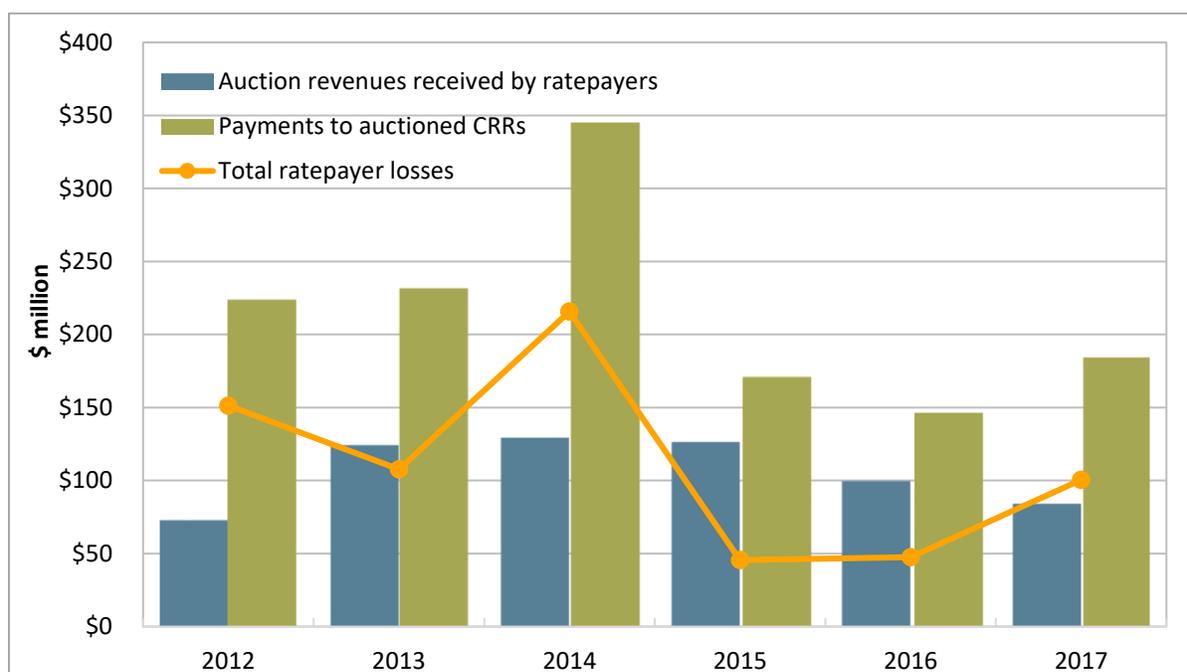
As described above, the performance of the congestion revenue rights auction from the perspective of ratepayers can be assessed by comparing the auction revenues received for auctioning transmission rights to the day-ahead congestion payments to these rights. Figure 8.9 compares the following for each of the last six years:

- Auction revenues received by ratepayers from congestion revenue rights sold in auction (blue bars on left axis).²²⁰
- Net payments made to the non-load-serving entities purchasing congestion revenue rights in auction (green bars on left axis).
- Auction revenues received by ratepayers as a percentage of the net payments made to the entities purchasing congestion revenue rights in auction (yellow line on right axis)

²¹⁸ In this case congestion revenue right holdings are 75 MW, whereas the day-ahead flows exceed this by 15 MW. Thus, the congestion revenue rights holders are owed \$750 (75 MW * \$10/MWh) for the load-serving entities and day-ahead congestion collections were \$900. This results in a surplus collection of congestion of \$150 (\$900 - \$750).

²¹⁹ This is the difference between the account balance in the allocation only scenario (\$150) and the account balance (\$25) in the auction scenario.

²²⁰ The auction revenues received by ratepayers are the auction revenues from congestion revenue rights paying into the auction less the revenues paid to “counter-flow” CRRs. Similarly day-ahead payments made by ratepayers are net of payments by “counter-flow” CRRs.

Figure 8.9 Ratepayer auction revenues compared with congestion payments for auctioned CRRs

Between 2012 and 2017, ratepayers received, on average, about \$111 million less per year from auction revenues than entities purchasing these rights in the auction received from day-ahead congestion revenues. Over this six year period, ratepayers received an average of only about 49 cents in auction revenues for every dollar paid to congestion revenue rights holders, summing to a total shortfall of \$668 million, including \$101 million in 2017.

These findings are not unique to the California ISO market design. The PJM Independent Market Monitor reports similar underpricing of congestion revenue rights in auctions.²²¹ Potential factors contributing to this trend include the following:

- Auctioning a product for which the seller cannot set a reservation price;
- Technical, economic, and regulatory barriers that restrict the participation of ratepayers or their representatives in the auctions; and
- Inconsistencies between the products as auctioned and as settled at day-ahead prices.

This analysis illustrates that auction revenues ratepayers received were consistently below the day-ahead market congestion revenues that ratepayers would have received if these congestion revenue rights were not auctioned off. DMM believes these results warrant reassessing the standard electricity market design assumption that ISOs should auction off transmission capacity that remains in excess of the capacity allocated to load-serving entities. Instead, it would be much more beneficial to allow ratepayers to collect these congestion revenues directly.

²²¹ For a description of this issue in PJM, see the PJM Independent Market Monitor's *2016 State of the Market Report for PJM*, Section 13: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016.shtml.

Figure 8.10 through Figure 8.13 compare the auction revenues received by ratepayers with ratepayer payments to auctioned congestion revenue rights by market participant type.²²² The difference between auction revenues and the payments to congestion revenue rights are the profits for the entities holding the auctioned rights. These profits are losses to ratepayers.

- Financial entities continued to have the highest net revenue among auctioned rights holders in 2017 at \$76 million, more than doubled from \$33 million in 2016.
- Marketers received net revenues of \$16 million from auctioned rights in 2017, an increase from \$10 million in 2016.
- Physical generation entities received \$9 million in net revenue from auctioned rights in 2017, up from nearly \$5 million in 2016. Physical generators continued to receive the lowest overall payments from auctioned congestion revenue rights, among non-load-serving entities.
- Load-serving entities received negative \$2 million in net revenue from auction rights in 2017, down from about \$3 million in 2016. Auction revenues received by load-serving entities were less than their auctioned congestion revenue rights day-ahead payments in 2017. Because the auction revenues and congestion revenue right payments are made simultaneously to and from load-serving entities as a group, they are not the direct effect on ratepayers.

However, these losses are opportunity costs for ratepayers from making the congestion revenue rights available in the auction that show up in the net payments made to other entities.

One of the benefits of auctioning congestion revenue rights is to allow day-ahead market participants to hedge congestion costs. However, in 2017, physical generators as a group accounted for a relatively small portion of congestion revenue rights held. As a group, generators received the lowest overall payments from congestion revenue rights, even after including allocated rights. Generators received congestion revenue rights payments, for both auctioned and allocated CRRs, of \$55 million, while incurring day-ahead congestion costs of \$72 million. Except for balancing authority areas,²²³ the other categories of entities had congestion revenue right payments in excess of their day-ahead congestion costs.

The losses to ratepayers from the congestion revenue rights auction could in theory be avoided if load-serving entities purchased the congestion revenue rights at the auction from themselves. However, there are significant technical and regulatory hurdles making it difficult for load-serving entities to purchase these rights. Moreover, DMM does not believe it is appropriate to design an auction so that load-serving entities would have to purchase rights in order to avoid obligations to pay other congestion revenue rights holders. DMM believes it would be more appropriate to design the auction so that load-serving entities will only enter obligations to pay other participants if they are actively willing to enter

²²² DMM has defined financial entities as participants who own no physical energy and participate in only the convergence bidding and congestion revenue rights markets. Physical generation and load are represented by participants that primarily participate in the ISO 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 markets. Balancing authority areas are participants that are balancing authority areas outside the ISO. With the exception of financial entities, the classification of the other groups is based on the primary function but could include instances where a particular entity performs a different function. For example, a generating entity that has load-serving obligations may be classified as a generator and not a load-serving entity.

²²³ Balancing authority areas held only allocated rights and did not participate in the auctions. Because balancing authority areas did not participate in the auction they do not affect the auction performance metric.

these obligations at the prices offered by the other participants. With this approach, any entity placing a value on purchasing a hedge against congestion costs could seek to purchase it directly from the load-serving, financial, or other entities.

Figure 8.10 Auction revenues and payments (financial entities)

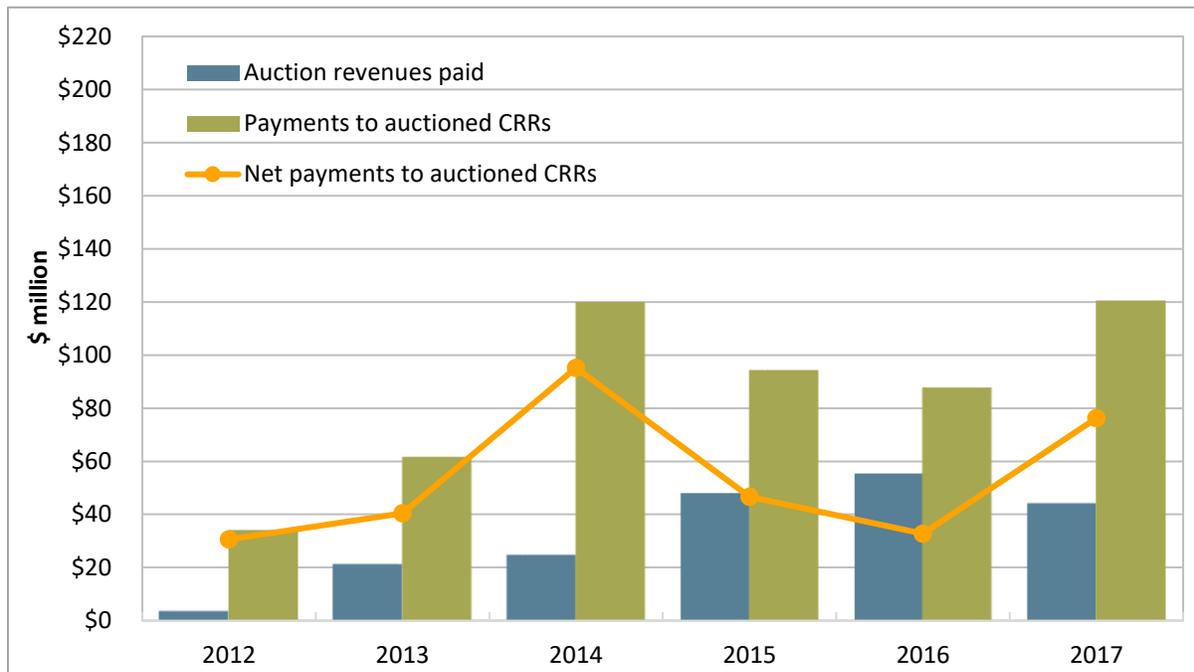


Figure 8.11 Auction revenues and payments (marketers)

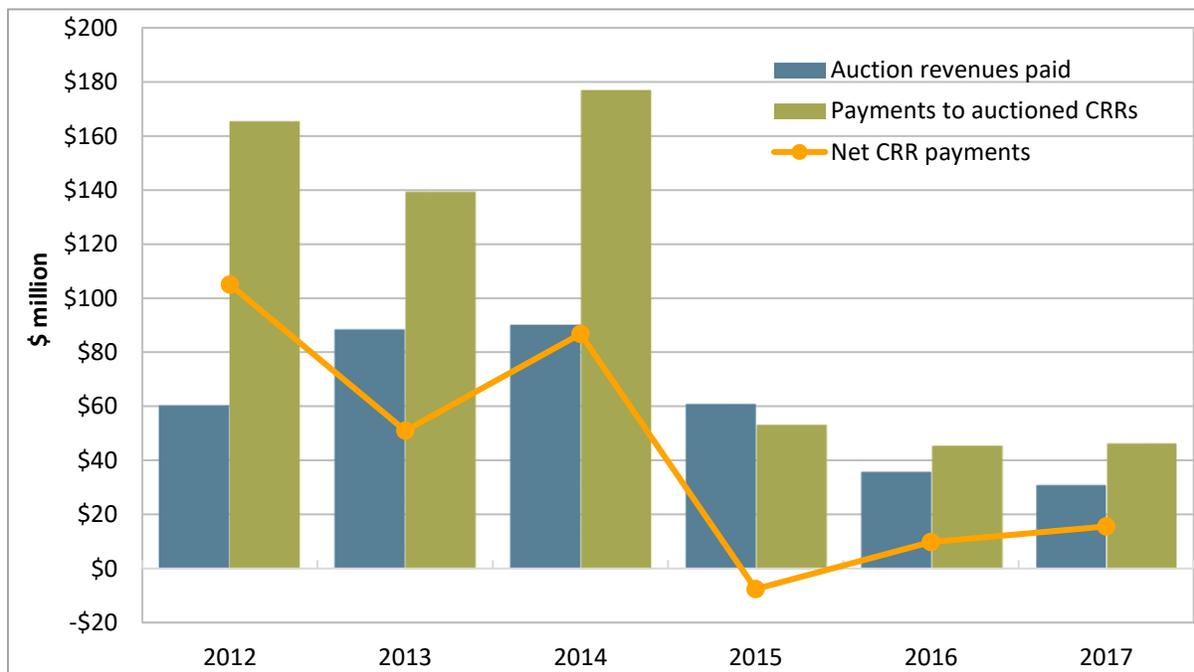


Figure 8.12 Auction revenues and payments (generators)

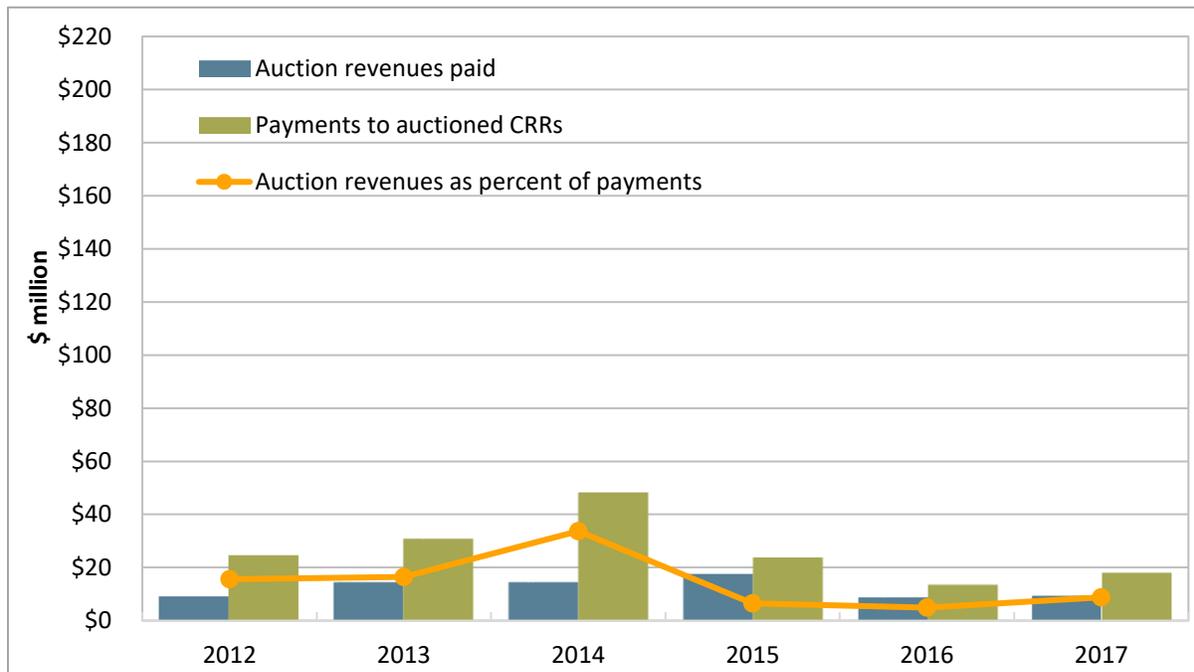
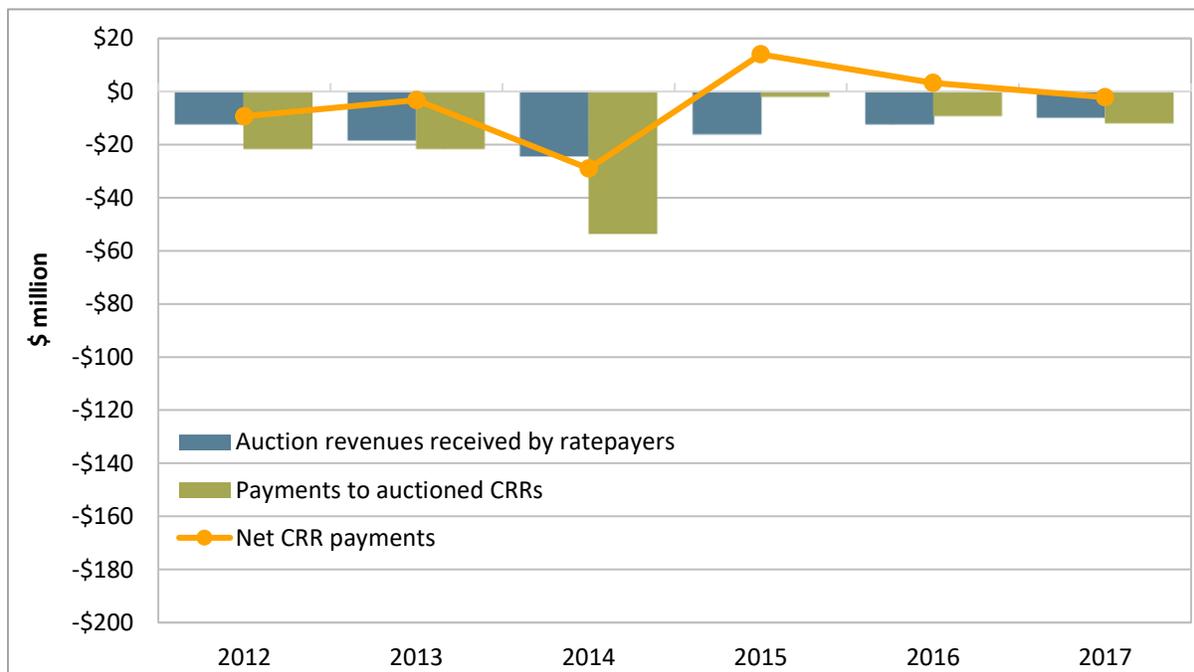


Figure 8.13 Auction revenues and payments (load-serving entities)



9 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.²²⁴ 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 chapter, 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 2017, the use of many key market adjustments increased rather than decreased. The findings from this chapter include the following:

- Total energy resulting from all types of exceptional dispatch more than doubled between 2017 and 2016, but continued to account for a relatively low portion of total system load, 0.5%. Overall, above-market costs due to exceptional dispatch increased 92 percent to \$20.6 million in 2017 from \$10.7 million in 2016.
- Exceptional dispatches on the interties increased significantly in 2017. Procurement of imports at out-of-market at prices higher than the 15-minute price paid for other imports can encourage economic and physical withholding of available imports. DMM recommends that the ISO closely track and monitor trends in out-of-market dispatches and seek to limit the use of such out-of-market dispatches. DMM is also recommending that the ISO improve its logging of manual dispatches to ensure proper settlement and allow tracking and monitoring.
- Load forecast adjustment in the ISO's hour-ahead and 15-minute markets increased dramatically in 2017. The 5-minute market load forecast adjustment decreased, relative to the same time periods in 2016. Real-time incremental dispatch of imports into the ISO appears consistent with both pricing and load adjustments, with most incremental commitment of imports occurring in the hour-ahead market. EIM areas also utilize load forecast adjustments.

9.1 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.

²²⁴ 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.

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 0.5 percent of system loads in 2017, compared to 0.3 percent in 2016.²²⁵

Total energy resulting from all types of exceptional dispatch increased by approximately 58 percent in 2017 from 2016, as shown in Figure 9.1.²²⁶ The percentage of total exceptional dispatch energy from minimum load energy accounted for about 82 percent of all exceptional dispatch energy in 2017. About 12 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 6 percent was from in-sequence energy.

The year on year growth in total energy from exceptional dispatches was driven by increases in the second and fourth quarters. In the second quarter exceptional dispatches for minimum load were particularly high. These were largely due to load forecast uncertainty. The fourth quarter saw high volumes of minimum load as well as out-of-sequence energy exceptional dispatches. Wildfires in Southern California were the primary reason for those exceptional dispatches.²²⁷

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

²²⁵ DMM reported this number as 0.2 percent of load for 2016 in the 2016 Annual Report. The change is due to a change in the reference data source.

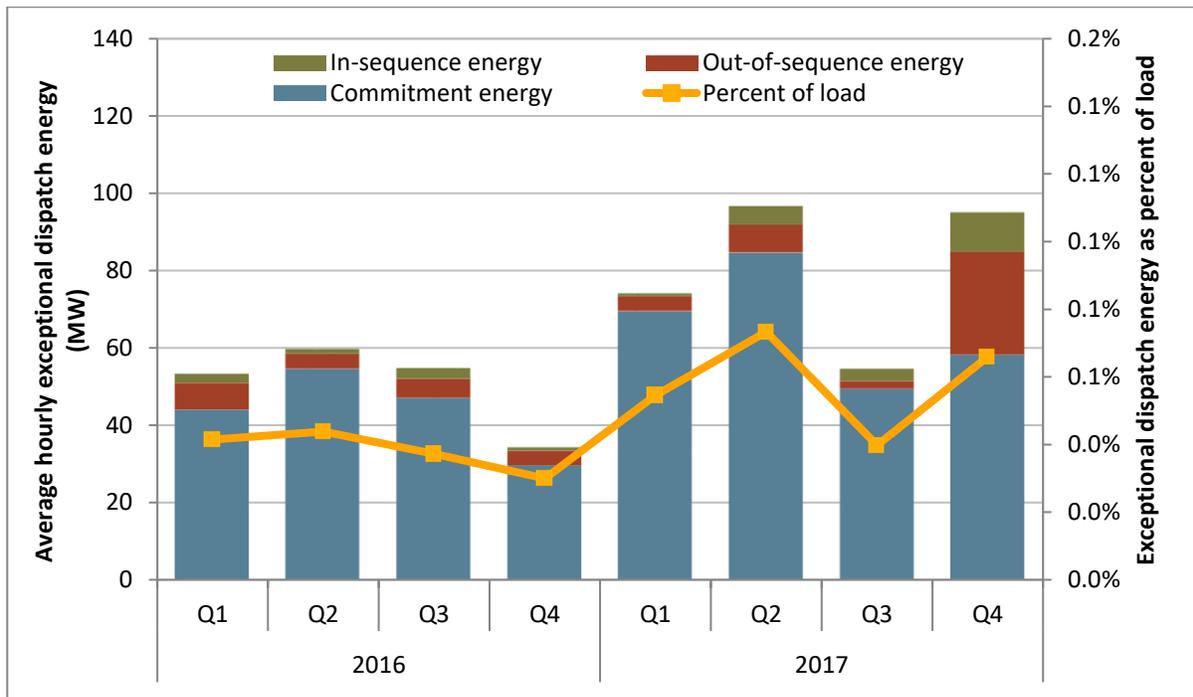
²²⁶ All exceptional dispatch data are estimates derived from Market Quality System (MQS) data, market prices, dispatch data, bid submissions, and default energy bid data. DMM's methodology for calculating exceptional dispatch energy and costs has been revised and refined since previous reports. Exceptional dispatch data reflected in this report may differ from previous annual and quarterly reports as a result of these enhancements.

²²⁷ For more detail on the Southern California wildfires, see DMM's *Q4 2017 Report on Market Issues and Performance*, February 2018: <http://www.caiso.com/Documents/2017FourthQuarterReport-MarketIssues-PerformanceFebruary2018.pdf>.

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.

Figure 9.1 Average hourly energy from exceptional dispatch



Exceptional dispatches for unit commitment

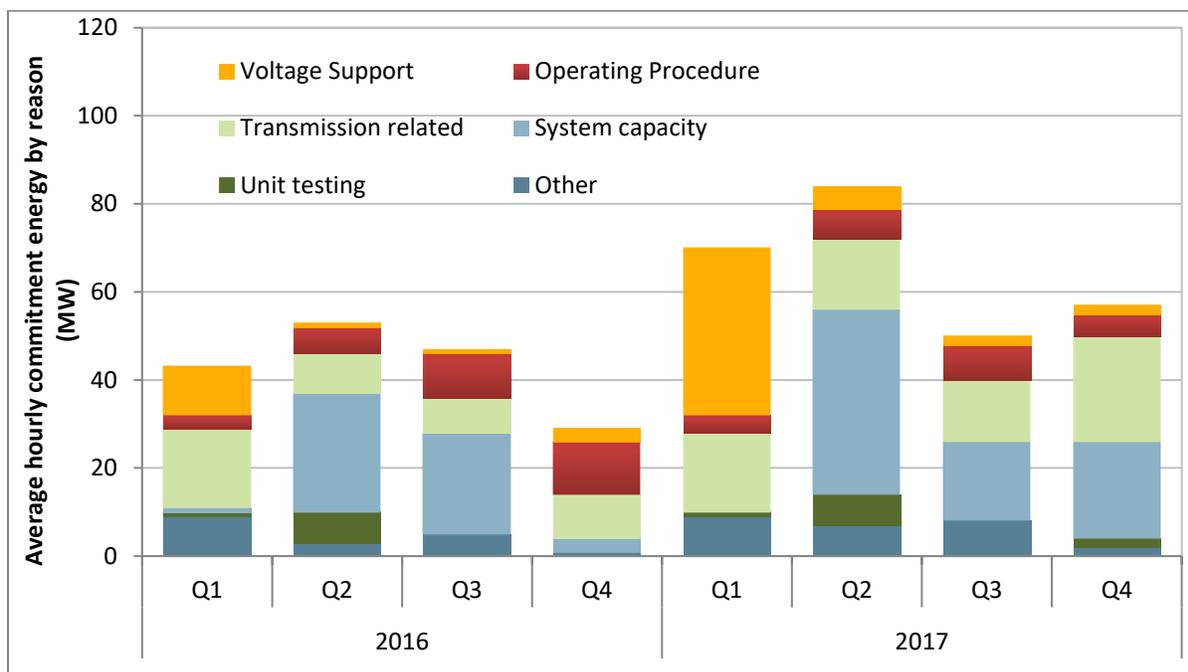
The ISO sometimes finds instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements not directly incorporated in the day-ahead market model. Alternatively, a scheduling coordinator may wish to operate a resource out-of-market for purposes of 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 increased by 49 percent in 2017 compared to 2016. As shown in Figure 9.2, minimum load energy from exceptional dispatch unit commitments was higher in every quarter of 2017 versus the same quarter in 2016.

Exceptional dispatch unit commitment rose the most in the fourth quarter, where 2017 volume was nearly double that of 2016. Elevated levels of exceptional dispatch unit commitment in the fourth quarter of 2017 were driven by an increase in transmission related and system capacity exceptional dispatches. The transmission related exceptional dispatches were the result of an increase in planned

transmission outages over the same quarter in 2016. 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. Load forecast uncertainty was also responsible for the large increase in exceptional dispatches for system capacity in the second quarter of 2017 versus the second quarter in 2016.

Figure 9.2 Average minimum load energy from exceptional dispatch unit commitments

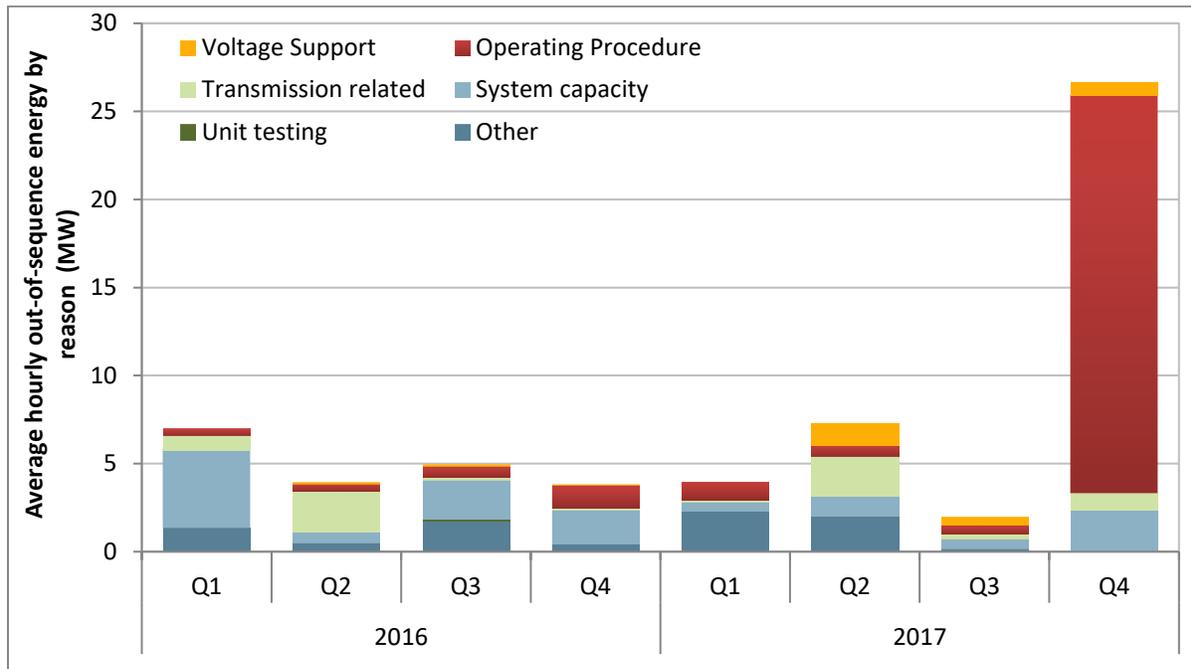


Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch increased by 120% in 2017. As previously illustrated in Figure 9.1, much of this exceptional dispatch energy (about 68 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 in 2017, the portion of exceptional dispatch for out-of-sequence energy was comparable to previous years.

Figure 9.3 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2017 and 2016. Out-of-sequence exceptional dispatch energy was lower in the first and third quarters of 2017 compared to 2016, and higher in the second and fourth. Most of the annual out-of-sequence energy in 2017 was exceptionally dispatched in the fourth quarter related to the December wildfires in Southern California.

Figure 9.3 Out-of-sequence exceptional dispatch energy by reason



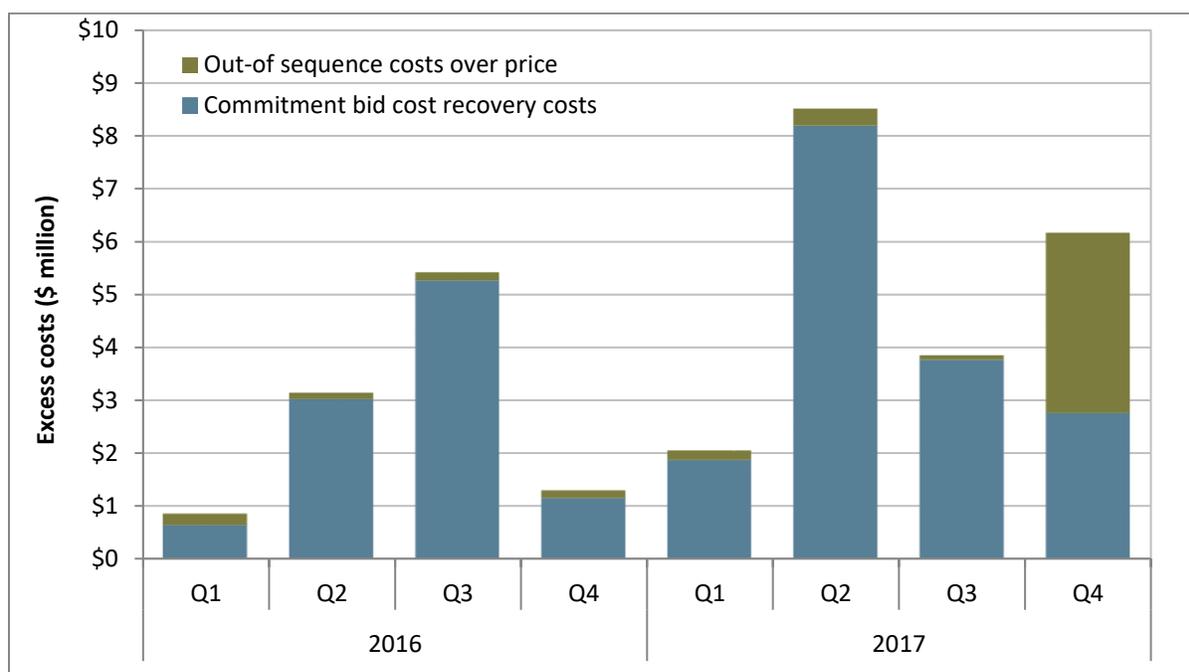
Exceptional dispatch costs

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 9.4 shows the estimated costs for unit commitment and additional energy resulting from exceptional dispatches in excess of the market price for this energy. Commitment costs for exceptional dispatch paid through bid cost recovery increased from \$10.1 million to \$16.6 million, while out-of-sequence energy costs increased from \$633,000 to \$4.0 million.²²⁸ Overall, these above-market costs increased 92 percent to \$20.6 million in 2017 from \$10.7 million in 2016.

²²⁸ The out-of-sequence costs are estimated by multiplying the out-of-sequence energy by the bid price (or the default energy bid if the exceptional dispatch was mitigated or the resource had not submitted a bid) minus the locational price for each relevant bid segment. Commitment costs are estimated from the real-time bid cost recovery associated with exceptional dispatch unit commitments.

Figure 9.4 Excess exceptional dispatch cost by type

9.2 Manual dispatch

Manual dispatch on the interties

Exceptional dispatches on the interties are often referred to by the ISO operators as *manual dispatches*. In 2017, these out-of-market dispatches increased significantly. Between May and September there were over 100 manual dispatches on the interties over a span of 12 days totaling about 15,300 MWh. The largest daily quantities occurred on September 1, 2017, and September 2, 2017, about 6,100 and 5,900 MWh, respectively. These dispatches occurred between hours ending 16 and 22, but were concentrated in hours ending 18, 19 and 20. The single largest hour of manual dispatch occurred on hour-ending 19 on September 1, totaling 1,700 MW. This day experienced loads reaching over 50,000 MW, which was significantly greater than peak loads during recent years and greater than the 1-in-10 year peak load forecast. The ISO has developed specific operating procedures documenting the determination of need and acquisition process.²²⁹

Like exceptional dispatches for generators within the ISO, manual dispatches on the interties are used to maintain or re-establish operating reserves, meet energy over/under-generation events and procure additional energy or reduce excess energy not awarded by the market. Prior to 2017, manual dispatches on the interties were primarily issued in the event of an hour-ahead scheduling process (HASP) or real-time market failure, transmission outage, market software limitation/anomaly, or system emergency (or prevention thereof). The use of manual dispatch appears to have become more common in 2017 to

²²⁹ *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>).

address system reliability on high load days, often associated with the evening net load peak ramp down hours.

The price paid for manual dispatches typically falls into one of three categories:

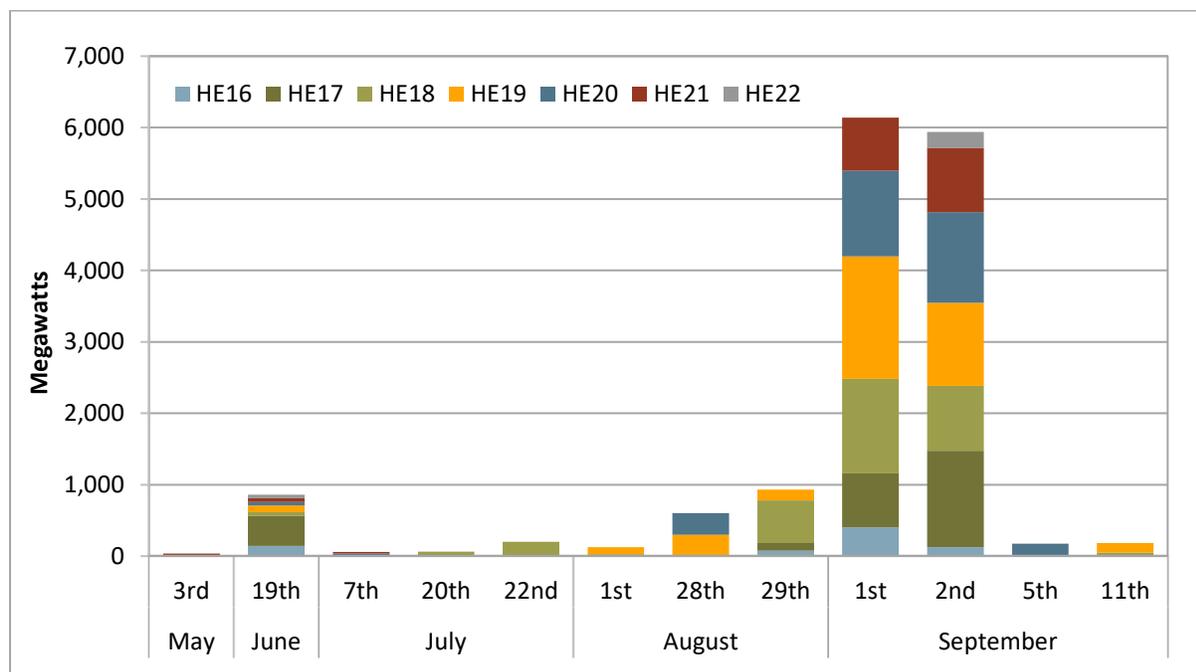
- **Bid or better** – Bid price or 5-minute market clearing price at the tie point pricing node, whichever is higher.
- **5-minute priced with fixed floor** – The highest of the fixed price or the 5-minute market clearing price at the tie point pricing node.
- **Fixed price** – Fixed price agreed upon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

Of the approximate 15,300 MWh in the May to September time period, about 54 percent appear to have been made using the *bid or better* framework. About 31 percent were made based on the 5-minute price with a fixed floor.

DMM estimates the direct revenues paid to market participants to be approximately \$5 million for the May to September time period. This represents about \$1.5 million (42 percent) more than the \$3.5 million that would be paid if these imports were settled at the 15-minute price paid for other imports. Almost three-fourths of these payments occurred around or on the peak load hours for the year on September 1-2, and nearly 70 percent of all manual dispatch costs were in hours ending 18-20.

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. Thus, DMM recommends the ISO closely track and monitor trends in manual dispatches, and seek to limit the use of such out-of-market dispatches. DMM is also recommending that the ISO improve its logging of manual dispatches to ensure proper settlement and allow tracking and monitoring.

Figure 9.5 Hourly manual dispatch volume on select days (May – September)



Energy imbalance market

The energy imbalance market areas sometimes need to dispatch resources out-of-market for reliability, to manage transmission constraints, or for other reasons. These out-of-market dispatches are referred to as *manual dispatches*. Energy imbalance market manual dispatches are similar to exceptional dispatches in the ISO.

Like ISO exceptional dispatches, energy imbalance market manual dispatches do not set prices, and the reasons are similar to those given for ISO exceptional dispatches. Manual dispatches are not issued by the ISO and can only be issued by an energy imbalance market entity for their respective balancing authority area. Manual dispatches may be issued for both participating and non-participating resources.

Manual dispatches in the energy imbalance market do not have the same settlement implications as ISO exceptional dispatches. Energy from these manual dispatches is settled on the market clearing price, which eliminates the possibility of exercising market power by either setting prices or by being paid at above-market prices.

Figure 9.6 through Figure 9.9 summarize monthly manual dispatch activity of participating and non-participating resources across the energy imbalance market areas. Historically, manual dispatch volume in the energy imbalance market areas has tended to peak in the first few months that new market participants were active in the market. However, this does not appear to be the case for the Arizona Public Service area, which remains relatively high, and the Puget Sound Energy area which did not experience the initial high levels of manual dispatch volumes after participation began in November 2017

Figure 9.6 EIM manual dispatches – PacifiCorp areas

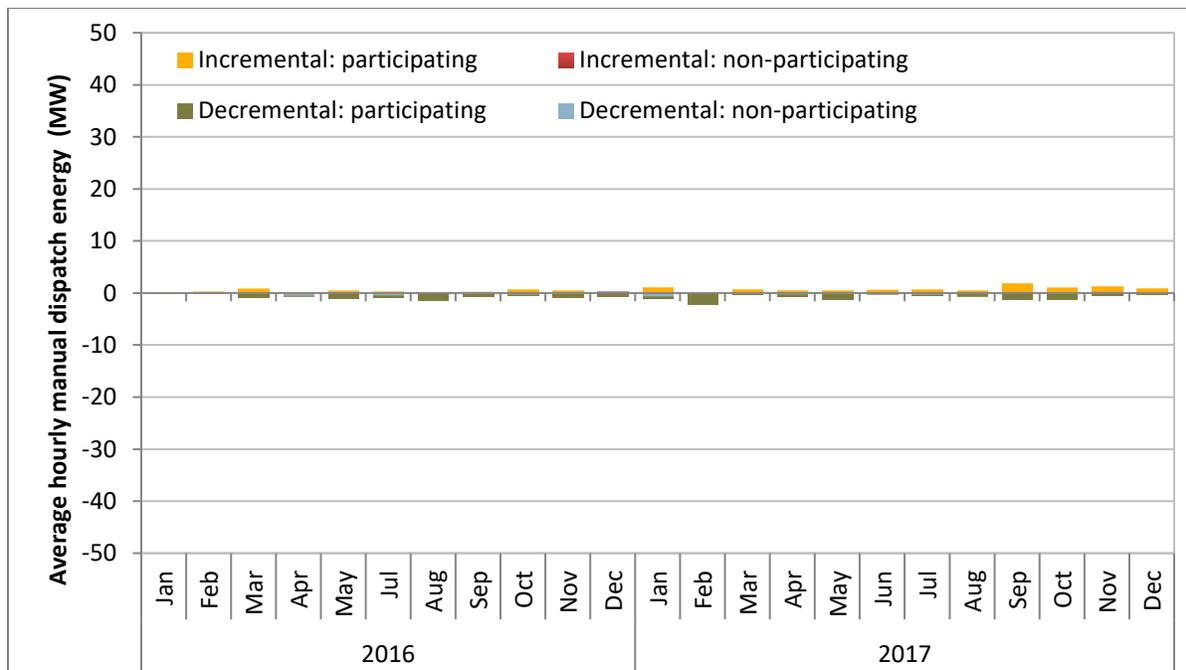


Figure 9.7 EIM manual dispatches – NV Energy area

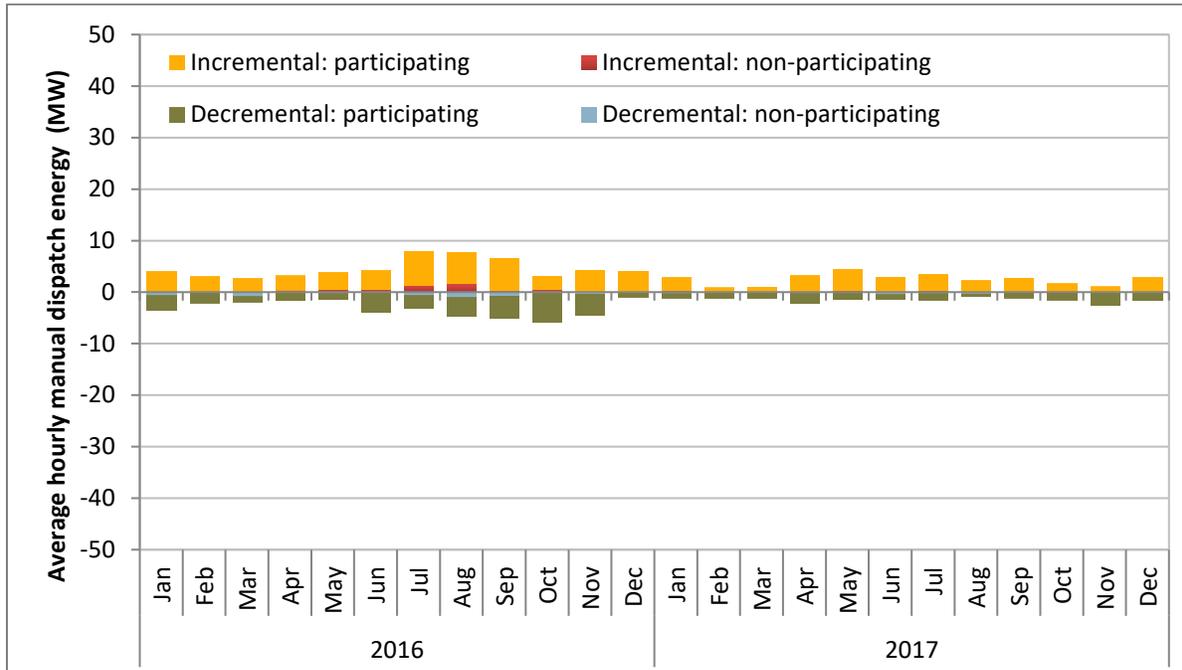


Figure 9.8 EIM manual dispatches – Arizona Public Service area

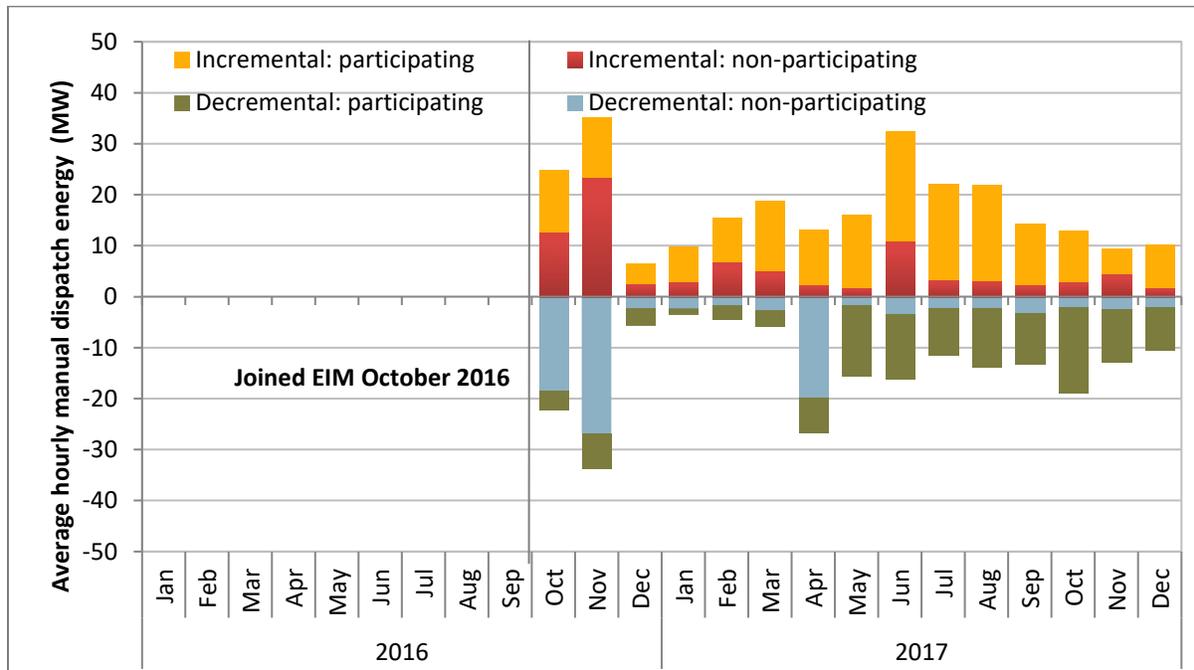


Figure 9.9 EIM manual dispatches – Puget Sound Energy area

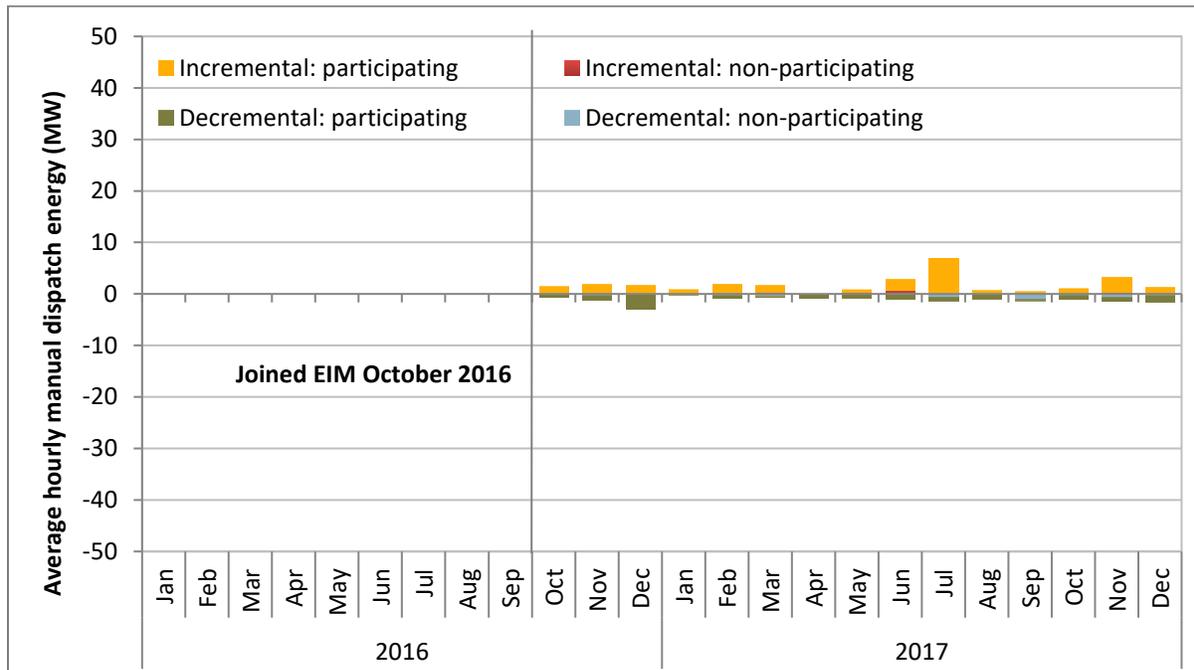
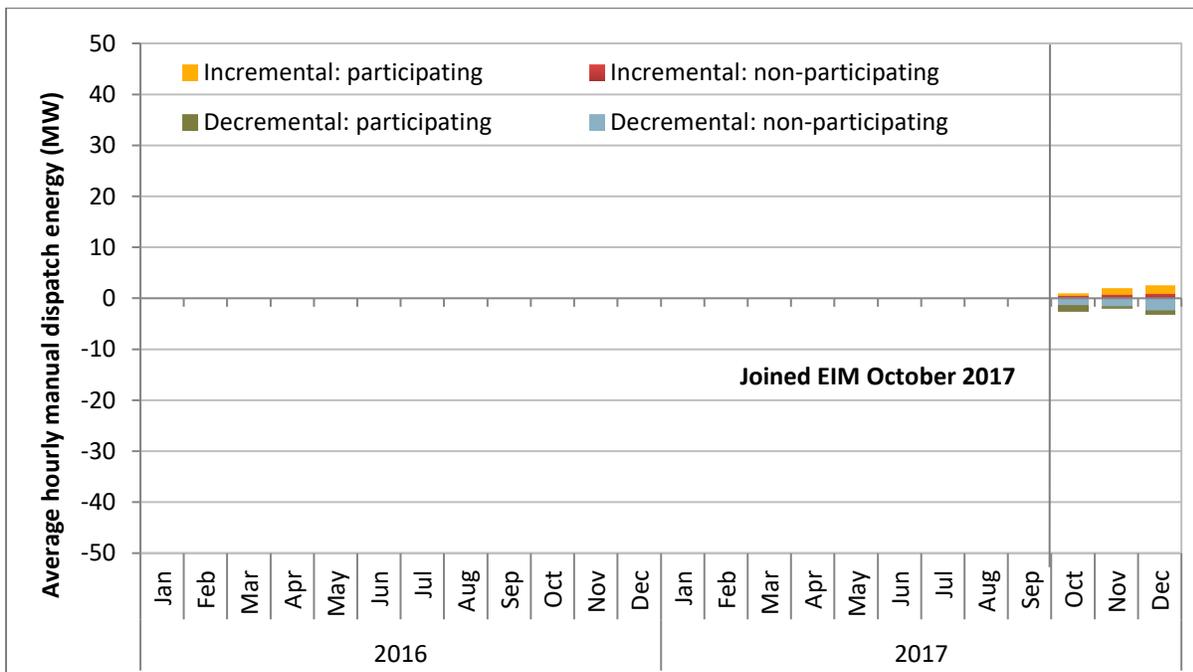


Figure 9.10 EIM manual dispatches – Portland General Electric area



9.3 Load adjustments

Load forecast adjustments

Operators in the ISO and energy imbalance market can manually modify load forecasts used in the market through a load adjustment. Load adjustments are also sometimes referred to as *load bias* or *load conformance*. 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.²³⁰ DMM will continue to use the terms load forecast adjustment and load bias limiter for consistency with prior reports.

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

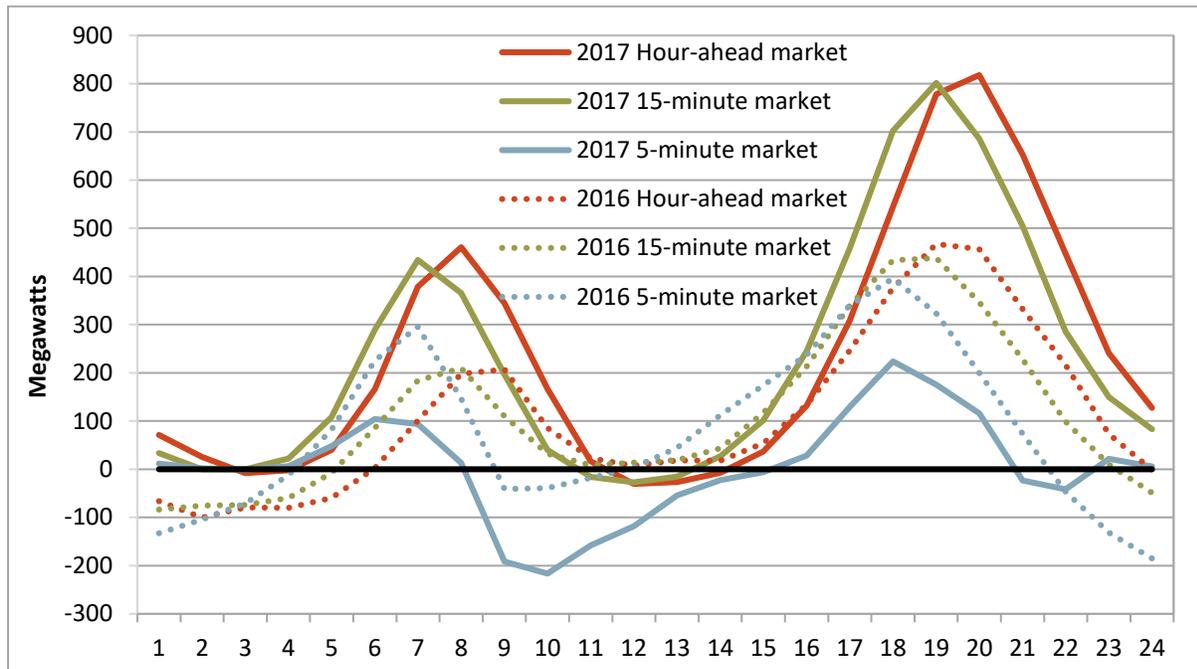
Compared to the prior year, load forecast adjustment in the ISO's hour-ahead and 15-minute markets increased dramatically in 2017. The 5-minute market load forecast adjustment decreased, relative to the same time periods in 2016. Figure 9.11 shows the average hourly load adjustment profile for the hour-ahead, 15-minute and 5-minute markets for 2017 and 2016. The general shape and direction of load adjustments were similar for hour-ahead and 15-minute adjustments, but there was a nearly two fold increase in quantity relative to 2016.

Load adjustments in the hour-ahead and 15-minute markets are very similar to each other throughout the day. But, unlike the previous year, the 2017 5-minute market adjustments differ dramatically from other markets for nearly all hours of the day. The largest positive deviations between the 5-minute and other markets were observed in hours ending 19, 20 and when the hour-ahead and 15-minute adjustments exceeded the 5-minute adjustments by around 625 MW, 570 MW and 528 MW, respectively. The largest deviation in negative adjustments occurred in hours ending 9, 10 and 21, 22 with 390 MW, 255 MW, 530 MW and 330 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.

²³⁰ 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:

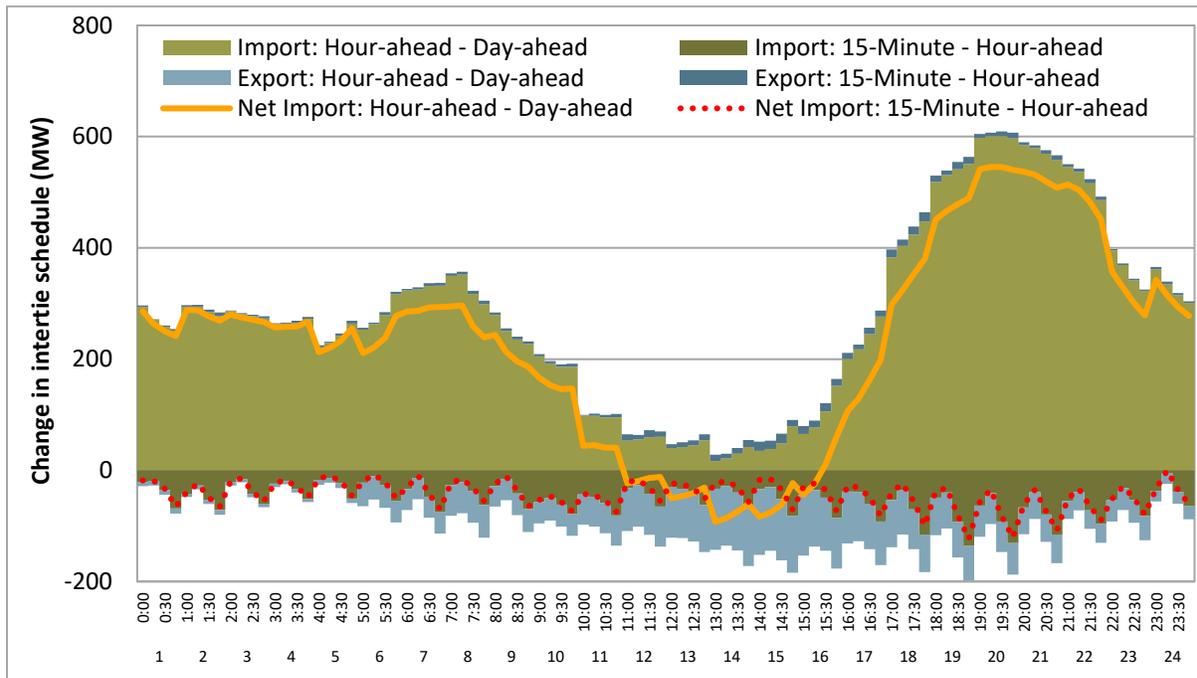
<http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf>

Figure 9.11 Average hourly load adjustment (2017 - 2016)



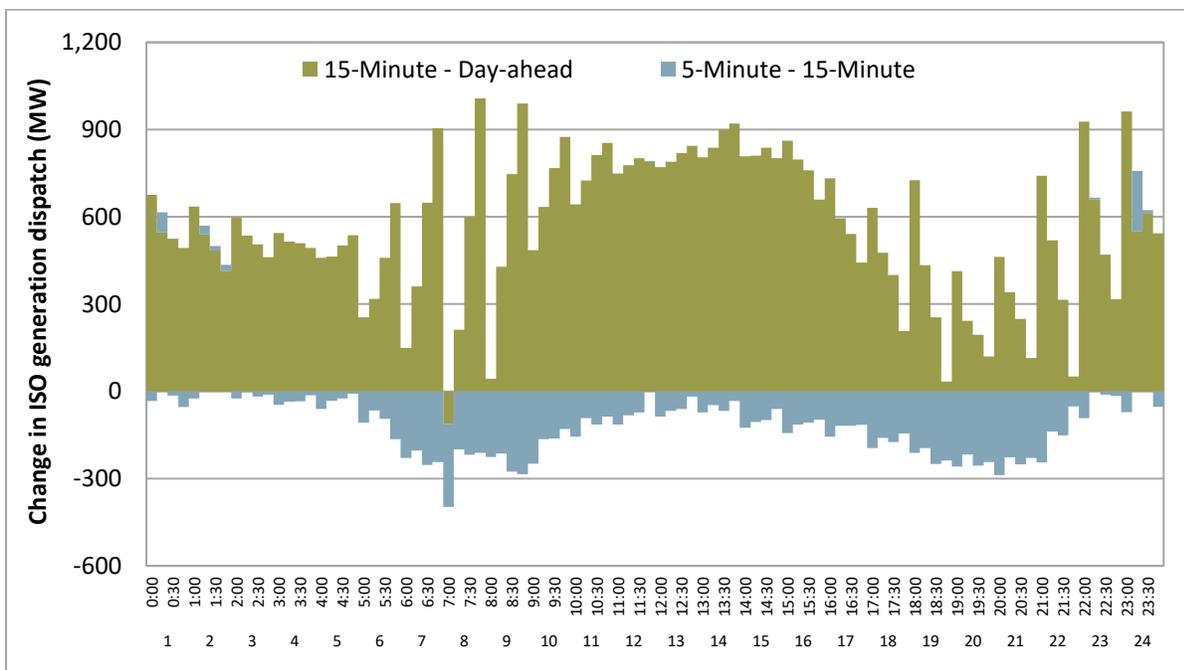
Real-time incremental dispatch of imports appears consistent with both pricing and load adjustments, with most incremental commitment of imports occurring in the hour-ahead market. On average for 2017, over 500 MW of net interchange is committed across the peak load adjustment hours of the day. The light green area in Figure 9.12 shows the average incremental increase in imports between the day-ahead and hour-ahead markets. The light blue area shows the incremental change in exports between the day-ahead and hour-ahead markets where an increased export is displayed as a negative value. The yellow line shows the change in net interchange, summing the effects of increased imports and increased exports. The red dotted line represents the change in net interchange between the 15-minute and hour-ahead markets and is the sum of incremental decreases in imports (dark green) and exports (dark blue). These are lower values relative to the changes observed between the day-ahead and the hour ahead.

Figure 9.12 Net interchange dispatch volume



Incremental dispatch of internal generation decreases between the day-ahead and 15-minute real-time market on average in most intervals across the peak. Figure 9.13 displays the average incremental change for internal generators between the day-ahead and the 15-minute market in green and between the 15-minute market and the 5-minute market in blue. Decreased physical generation appears to be offset by increases in imported energy on the interties, as shown in Figure 9.12.

Figure 9.13 Imbalance generation dispatch volume



The ISO frequently adjusts loads in the 15-minute and 5-minute real-time markets to account for potential modeling inconsistencies. Some of these inconsistencies are because of changing system and market conditions, such as changes in load and supply, between the executions of different real-time markets.²³¹ Specifically, operators have listed multiple reasons for use of load adjustments including managing load and generation deviations, automatic time error correction, scheduled interchange variation, reliability events, and software issues.

Operators can manually adjust load forecasts used in the software through a load adjustment. These adjustments are sometimes made manually based entirely on the judgment of the operator informed by actual operating conditions. Other times, these adjustments are made in a more automated manner using special tools developed to aid operators in determining what adjustments should be made and into which software systems.

In December 2012, the ISO enhanced the real-time market software to limit load forecast adjustments made by operators to only the available amount of system ramp. Beyond this level of load adjustment, a shortage of ramping energy occurs that triggers a penalty price through the relaxation of the power balance constraint without achieving any increase in actual system energy. With this software enhancement, known as the *load bias limiter*, load adjustments made by operators are less likely to have an extreme effect on market prices. This tool was extended to the energy imbalance market balancing areas in March 2015. DMM will continue to monitor and analyze load adjustments in the ISO and energy imbalance market regions.²³²

Figure 9.14 and Figure 9.15 show the frequency of positive and negative load forecast adjustments for the ISO, PacifiCorp East, PacifiCorp West, NV Energy, Puget Sound Energy, Arizona Public Service and Portland General Electric (PGE) during 2017 for the 15-minute and 5-minute markets, respectively. For much of 2017, positive load adjustments were most frequent in Arizona Public Service, ISO and NV Energy areas, while negative load adjustments were most frequent in the PacifiCorp West area throughout the year and Puget Sound Energy in the last quarter. In general, load adjustments in the 5-minute market were more frequent than load adjustments in the 15-minute market for all balancing areas and quarters during the year. This was particularly notable with adjustments by NV Energy and the PacifiCorp areas however the ISO, Arizona Public Service and Portland General were rather consistent between markets.

The increased use and high levels of positive load adjustments in the ISO that began in May 2016 continued in both the 15-minute and 5-minute markets. As with the previous year during this period, positive load adjustments occurred during about 50 percent of 15-minute and a slight reduction to about 36 percent of the 5-minute intervals at an average of about 450 MW. However, as a percent of area load, load adjustments in the ISO were generally smaller than adjustments in the energy imbalance market.

Compared to the previous year, PacifiCorp East significantly decreased the frequency of negative load adjustments in both the 15-minute and 5-minute markets 2017 while PacifiCorp West experienced a

²³¹ See 153 FERC ¶ 61,305, order on compliance filing, issued December 17, 2015: http://www.aiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf.

²³² More details on load adjustments not covered in this annual report including hourly profiles and reasons for load adjustments are provided in the DMM quarterly reports. For instance, see *Q4 2016 Report on Market Issues and Performance*, pp. 47-58: <http://www.aiso.com/Documents/2016FourthQuarterReport-MarketIssuesandPerformanceMarch2017.pdf>.

gradual decline throughout 2017. During this period, PacifiCorp East operators adjusted loads downward during about 4 percent of 15-minute intervals and 18 percent of 5-minute intervals, a significant reduction from the prior year. PacifiCorp West significantly decreased negative load adjustments beginning in the third quarter of 2017. With the drop in negative load adjustments the average for the year was around 86 MW for PacifiCorp East and around 50 MW for PacifiCorp West. During the year, PacifiCorp operators used load adjustments primarily to manage generation deviation (generally from renewable resources), schedule interchange variation and automatic time error correction.²³³

In the NV Energy area, load adjustments were primarily in the positive direction in the 15-minute market with about 25 percent of intervals while the 5-minute market was more balanced with 30 positive and 25 percent negative intervals at an average of about 75 MW. Operators in NV Energy used load adjustments most frequently for reliability based control, managing the area control error and frequency to comply with the balancing authority area limit standard.

Since joining the energy imbalance market in the fourth quarter of 2016, Puget Sound Energy adjusted the load forecast sparingly until the fourth quarter of 2017 where the positive load adjustments increased to about 30 percent of intervals in both the 15-minute and 5-minute markets. Arizona Public Service also joined in the fourth quarter of 2016 and has since increasingly adjusted load in an upward direction throughout 2017 averaging about 90 percent in the third and fourth quarters. Portland General Electric entered joined the energy imbalance market in the fourth quarter and primarily adjusted load in the positive direction in both the 15-minute and the 5-minute markets, about 25 percent and 30 percent of intervals respectively.

²³³ Automatic time error correction is used to maintain interconnection frequency. Load adjustments can be used to inform the market of area control error (ACE) deviation because of automatic time error correction. For more information refer to: <http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-004-WECC-02.pdf>.

Figure 9.14 Average frequency of positive and negative load adjustments (15-minute market)

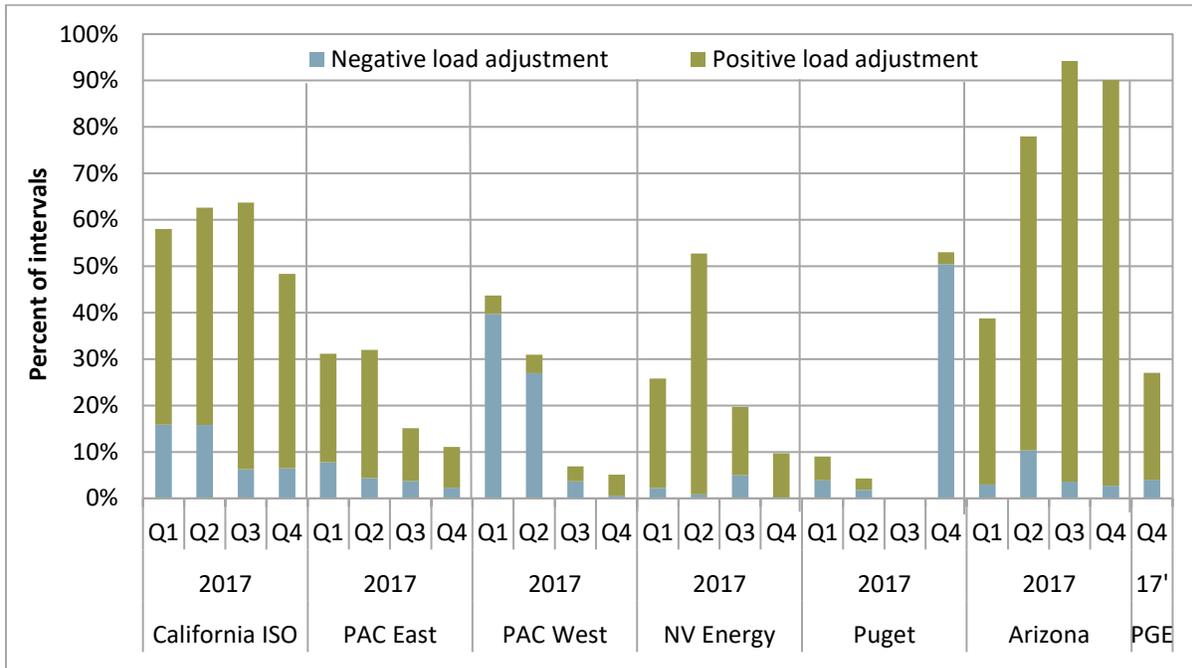
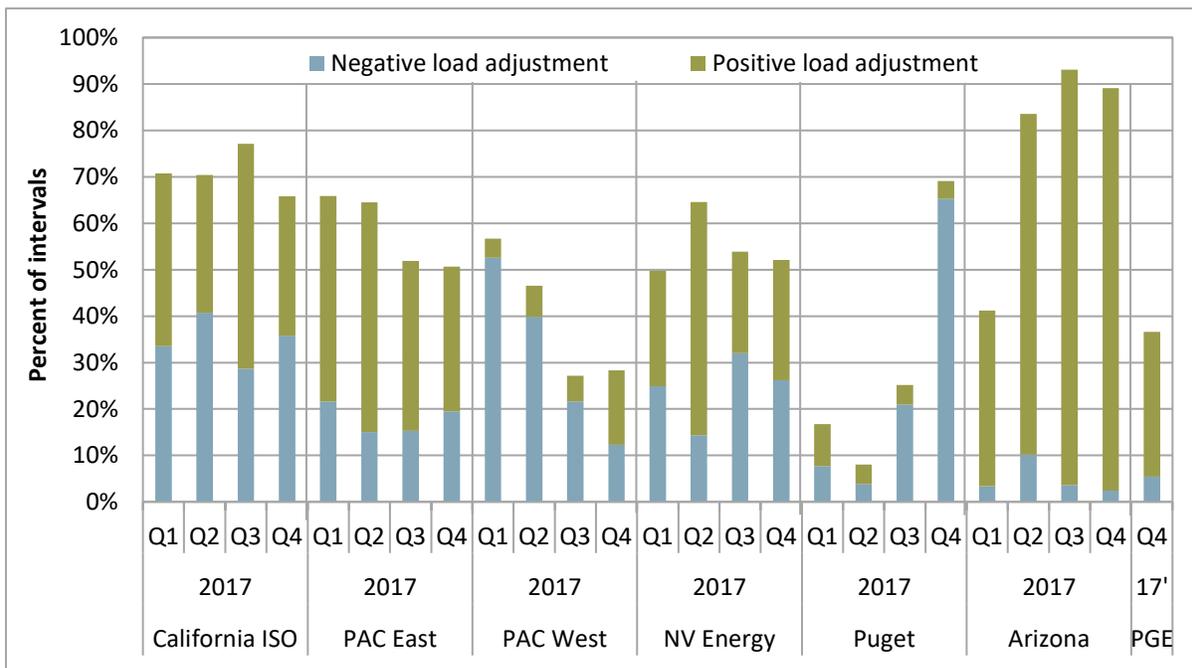


Figure 9.15 Average frequency of positive and negative load adjustments (5-minute market)



9.4 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.²³⁴ This can occur for a variety of reasons, including the following:

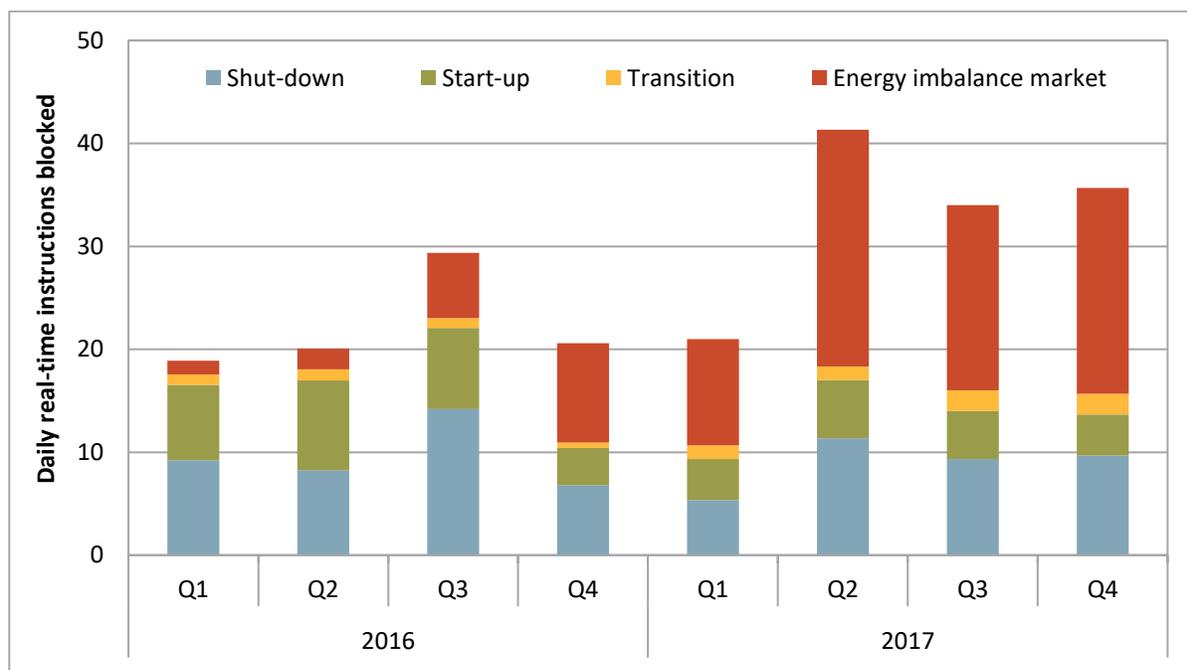
- **Data inaccuracies.** Results of the market model may be inconsistent with actual system or market conditions as a result of a data systems problem. For example, the ISO takes telemetry data and feeds the telemetry into the real-time system. If the telemetry is incorrect, the market model may try 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 9.16 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 during 2017 from the previous year. Blocked shut-down instructions continued to be the most common reason for blocked instructions at about 59 percent in 2017, slightly higher than the 55 percent in 2016. The frequency of these instructions decreased slightly, by about 7 percent in 2017 compared to 2016. Blocked start-up instructions accounted for almost 30 percent of blocked instructions within the ISO in 2017, while blocked transition instructions to multi-stage generating units accounted for just 11 percent. From the previous year the frequency of blocked start-up instructions decreased to about 30 percent from 40 percent, while blocked transition instructions just about doubled for the same period. 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 9.16 also includes blocked commitment instructions from energy imbalance market operators (red bars). During 2017, many of these actions were to block start-up and/or 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 market solution was implemented in 2017 to better manage reserves during unit transitions, the number of block 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.

²³⁴ 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>.

Figure 9.16 Frequency of blocked real-time commitment instructions

9.5 Blocked dispatches

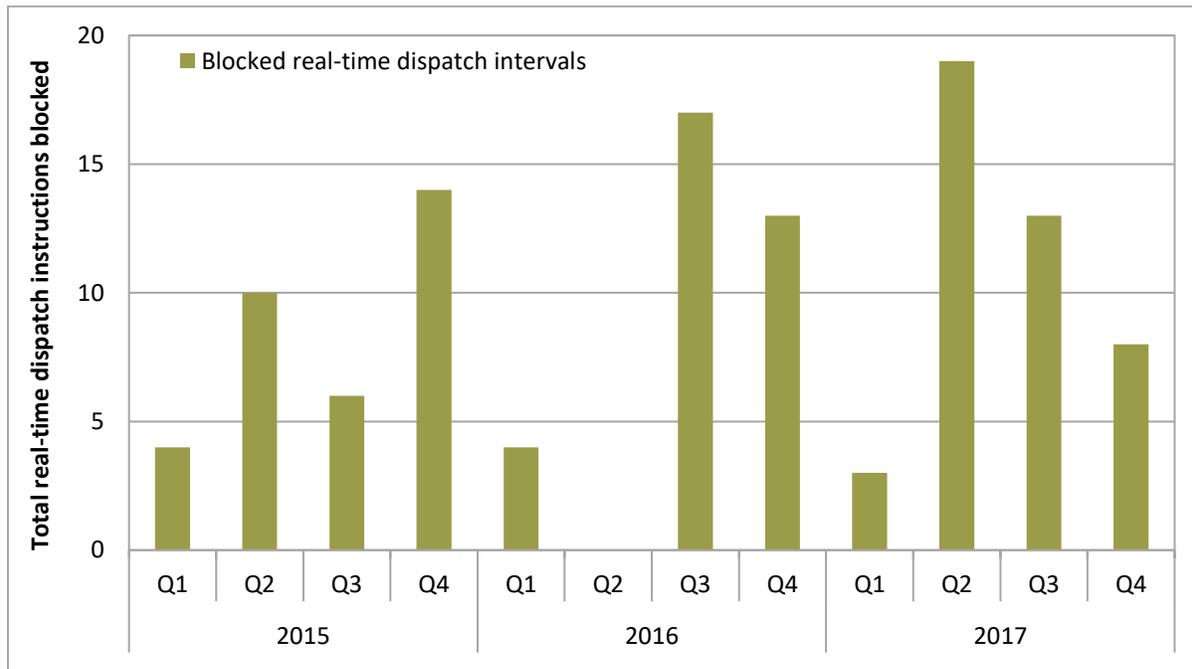
Operators review dispatches issued in the real-time market before these dispatch and price signals are sent to the market. If the ISO operators determine that the 5-minute dispatch results are inappropriate, they are able to block the entire real-time dispatch instructions and prices from reaching the 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.²³⁵

Figure 9.17 shows the frequency that operators blocked price results in the real-time dispatch from 2015 through 2017. The total number of blocked intervals in 2017 increased about 27 percent from 2016. Unlike 2016, when many of the blocked dispatched intervals occurred on one day, September 30, the blocked dispatches in 2017 were more evenly spread out throughout the year with the highest months between April and July. Although there was a year-over-year increase, the frequency of blocked dispatches in 2017 was significantly lower than during 2011 and 2012 due to improvements in market software functionality.

²³⁵ For example, if the load were to drop by 50 percent in one interval, the software can automatically block results.

Figure 9.17 Frequency of blocked real-time dispatch intervals

9.6 Residual unit commitment adjustments

As noted in Section 2.4, 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 in 2017.

As illustrated in Figure 9.18, residual unit commitment procurement appears to be driven in large part by the need to replace cleared net virtual supply, which can offset physical supply in the day-ahead market. On average, cleared virtual supply (green bar) was more prevalent in 2016 than in 2017 (see Chapter 5 for further detail).

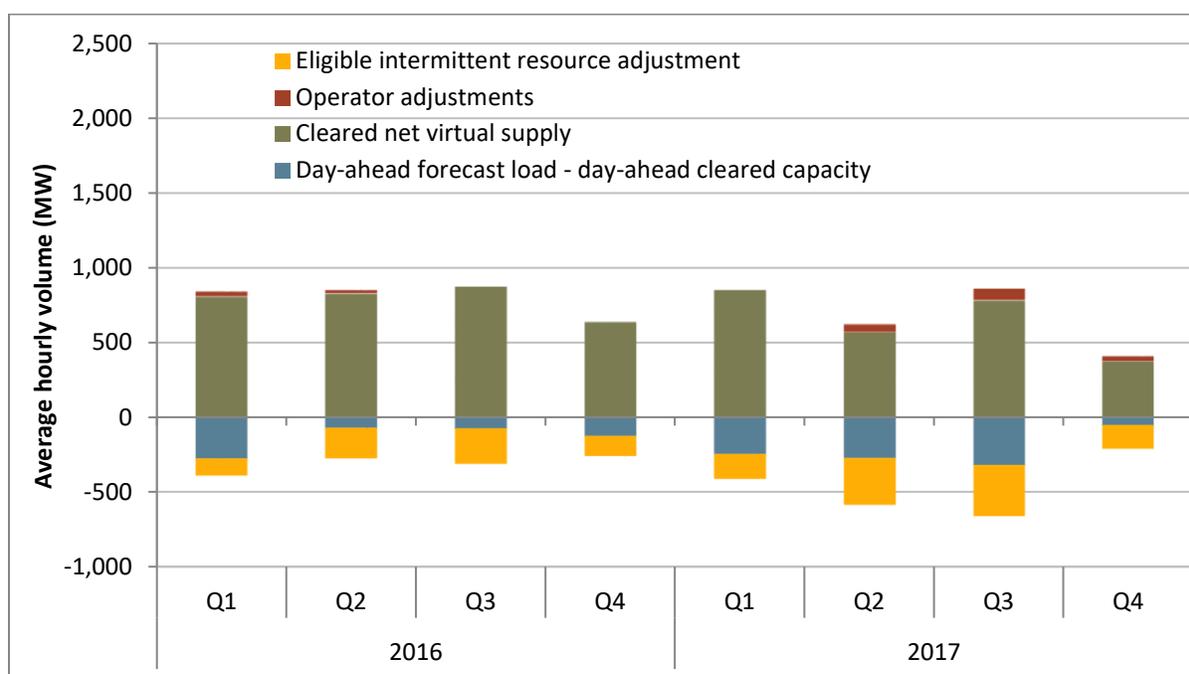
The ISO introduced an automatic adjustment to residual unit commitment schedules to account for differences between the day-ahead schedules of participating intermittent resource program (PIRP) resources and the forecast output of these renewable resources.²³⁶ This adjustment, called the eligible intermittent resource adjustment, went into effect in February 2014 and is represented by the yellow bar in Figure 9.18. In the future, this adjustment may be expanded to include adjustments for forecasts of participating intermittent resource program renewables without day-ahead schedules, though the ISO does not have any current plans to pursue this change. DMM, however, would support this change as it would better align the residual unit commitment with anticipated generation in real time.

²³⁶ Specifically, the adjustment is only made for PIRP resources that have positive schedules in the day-ahead market. PIRP resources that are not scheduled in the day-ahead market are not adjusted at this time.

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.²³⁷ On average, this difference was not a significant factor in increasing residual unit commitment requirements in 2017. Operator adjustments to the residual unit commitment process (red bar) increased residual unit commitment procurement in 2017, averaging about 39 MW per hour, up from 13 MW per hour in 2016.

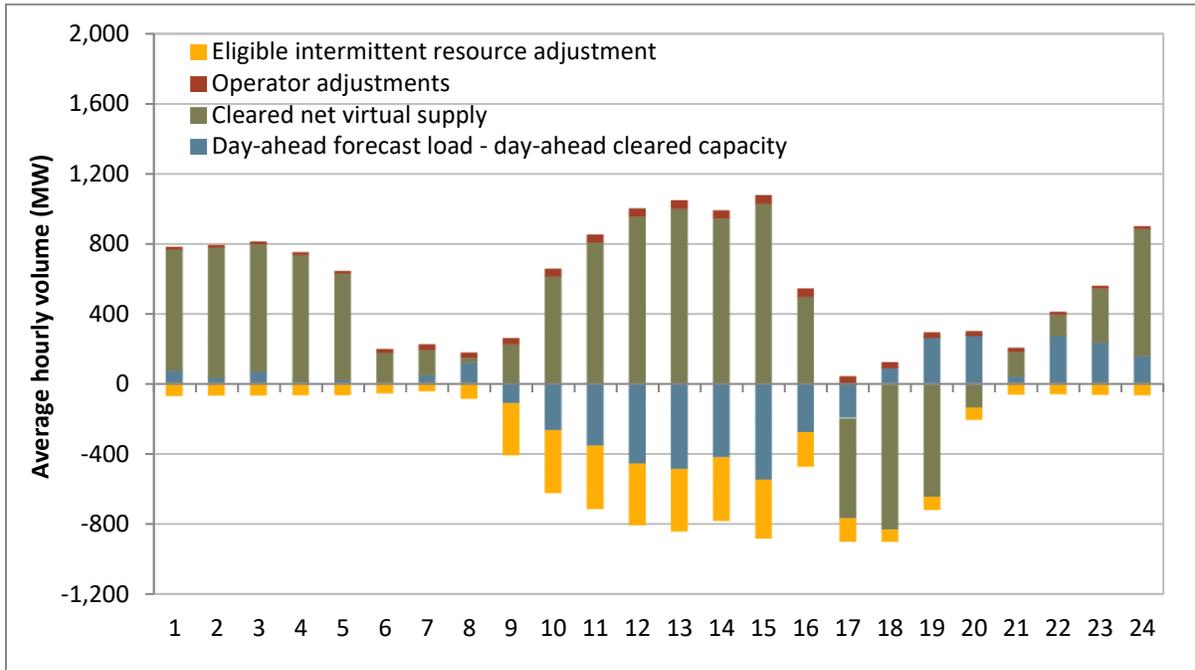
Figure 9.19 illustrates the average hourly determinants of residual unit commitment procurement. Operator adjustments, illustrated by the red bars tended to occur frequently in the peak load hours. While ISO operator adjustments were low in the off-peak hours, net virtual supply was a major driver of residual unit commitment procurement in these periods. On average, day-ahead cleared capacity was greater than day-ahead load forecast during mid-day peak hours in 2017. Intermittent resource adjustments were greatest in hours ending 9 to 17.

Figure 9.18 Determinants of residual unit commitment procurement



²³⁷ Because of the loss of source data, DMM estimated the values reported in the blue bar by subtracting price sensitive load including losses from the sum of forecast load, day-ahead exports and pumped storage load.

Figure 9.19 Average hourly determinants of residual unit commitment procurement (2017)



10 Resource adequacy

California's wholesale market relies heavily on a long-term procurement planning process and resource adequacy program adopted by the CPUC to provide sufficient capacity to ensure reliability. The resource adequacy program includes ISO tariff requirements that work in conjunction with regulatory requirements and processes adopted by the CPUC and other local regulatory authorities.

This chapter analyzes the effectiveness of the resource adequacy program in terms of availability of resources used to meet system and local level requirements during the 210 hours with the highest system loads. This chapter also analyzes the effectiveness of flexible resource adequacy requirements and procurement and the use of the capacity procurement mechanism. This analysis provides an indication of how well the program requirements are meeting actual peak loads. Key findings of this analysis include the following:

- During peak load hours of the year, system resource adequacy requirements fell short of both forecast and peak load. Resource adequacy procurement on September 1 and 2 was just below 47,000 MW, with over 43,000 MW (96 percent) available in the day-ahead market during the peak load hour on September 1, when load exceeded 50,000 MW, and about 42,000 MW (92 percent) available on September 2 when system load exceeded 47,000 MW. Resource adequacy requirements also fell short of day-ahead load forecasts on June 19, 20, 21 and 22.
- On average, during the 210 hours with the highest loads in 2017, about 96 percent of system resource adequacy capacity procured was available to the day-ahead energy market, about equal to availability in 2016.
- The total amount of local resource capacity available to bid into the day-ahead and real-time markets exceeded the total local capacity requirement, though some individual areas did not meet the requirement, relying on resources from within the greater transmission access charge area.
- Flexible resource adequacy requirements fell short of the maximum three-hour net load ramp in three months in 2017. Due to varying must-hour offers for different flexible capacity the *effective* resource adequacy requirement fell short of the actual net load ramp in six months, from May to October.
- Despite requirements, load-serving entities collectively procured more flexible capacity than required. This procurement exceeded the actual maximum three-hour net load ramp in all months except June, September and October. Procurement consisted mostly of gas-fired generation that qualified as Category 1 (base flexibility) capacity.
- The capacity procurement mechanism, implemented in November of 2016, was used throughout the year to dispatch non-resource adequacy capacity in the event of higher temperatures and wild fires. The total estimated cost of the designations settled during the year was about \$7 million, compared to \$4.3 million in 2016.
- During 2017, capacity designated as being subject to reliability must-run contracts beginning in 2018 increased sharply. Three newer more efficient gas units representing almost 700 MW were designated by the ISO for reliability must-run service beginning in 2018. The designation of these

newer and more efficient resources units as reliability must run units has highlighted problems issues with the current resource adequacy framework, and with the ISO's two mechanism for backstop procurement: the capacity procurement mechanism and reliability must-run contracts.

The CPUC and the ISO continue to refine and enhance the resource adequacy framework. Currently, the CPUC and ISO are developing protocols for determining requirements for flexible capacity, counting flexible resource adequacy showings, expanding replacement and substitution provisions, and resolving any shortfalls through backstop procurement.

10.1 System resource adequacy

System resource adequacy capacity is important to meet peak loads during the summer months. It is also important that sufficient resource adequacy capacity be made available to the market throughout the year. For example, significant amounts of generation can be out for maintenance during the non-summer months, making the remaining available resources offering resource adequacy capacity instrumental in meeting even moderate loads during these months.

The ISO works with the California Public Utilities Commission and other local regulatory authorities to set system-level resource adequacy requirements. This requirement is specific to individual load-serving entities based on their forecasted peak load in each month (based on a 1-in-2 year peak forecast) plus a planning reserve margin, which is typically 15 percent of peak load.²³⁸ Load serving entities then procure generation capacity to meet these requirements and demonstrate this procurement through resource adequacy showings to the ISO in year-ahead and month-ahead filings during the compliance year.

Roughly half of the capacity counted toward resource adequacy requirements must be bid into the market for each hour of the month, except when reported to the ISO as unavailable due to outages. This includes most gas-fired generation and imports. If the market participant does not submit bids, the ISO automatically creates bids for these resources.

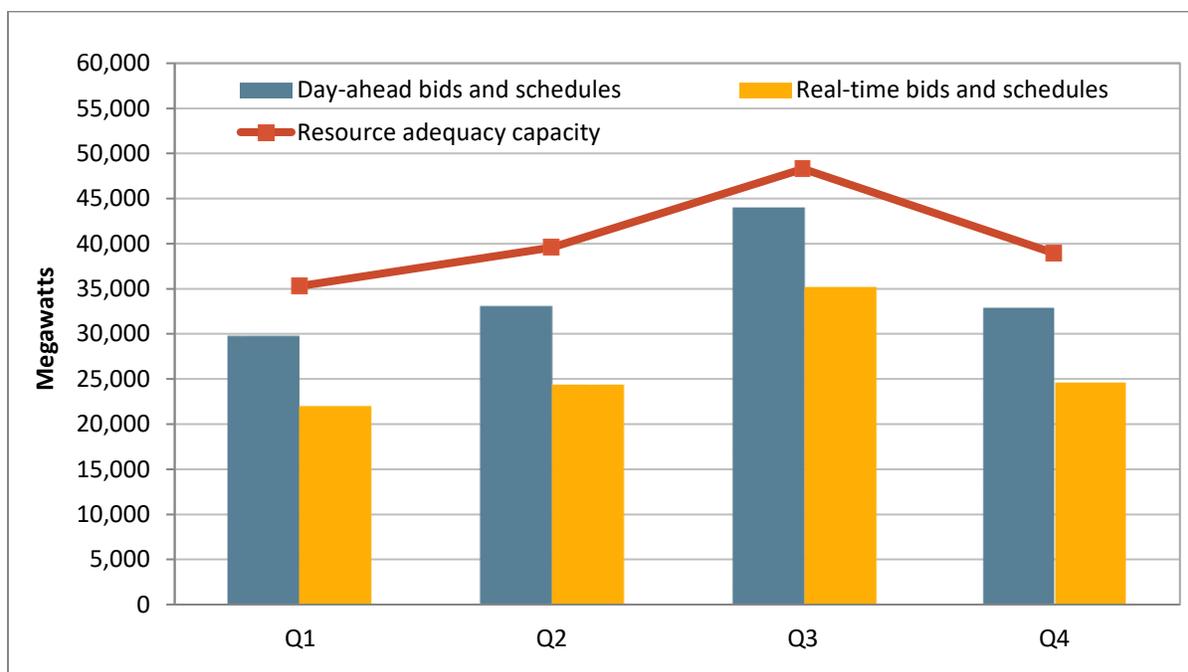
The remaining capacity counted toward system resource adequacy requirements does not have to offer the full resource adequacy capacity in all hours of the month. These resources are required to be available to the market consistent with their operating limitations. These include hydro, use-limited thermal, qualifying facilities, nuclear, wind, solar, demand response and other resources.

The red line in Figure 10.1 shows average quarterly resource adequacy capacity procured to meet system-level resource adequacy requirements. 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. These are hours ending 14 through 18 during April through October, and hours ending 17 through 21 during the remainder of the year. These hours do not necessarily align with hours when loads are highest. The bars in Figure 10.1 summarize the

²³⁸ The planning reserve margin is designed to include additional operating reserve needed above peak load as well as an allowance for outages and other resource limitations. The requirement is then adjusted for several factors including a credit for demand response programs.

average amount of available resource adequacy capacity bid in or scheduled in the day-ahead and real-time markets during the *availability assessment hours*.²³⁹

Figure 10.1 Quarterly resource adequacy capacity scheduled and bid into ISO markets (2017)



Key findings of this analysis include the following:

- The highest percentage of procurements were available during the third quarter. During these months, out of about 48,300 MW of resource adequacy capacity procured, an average of around 44,000 MW (or about 91 percent) was available in the day-ahead market. This coincided with the quarter with the highest amount of resource adequacy procurement.
- Performance for the remaining quarters was close to each other at about 85 percent of resource adequacy capacity available in the day-ahead market.
- Figure 10.1 also shows that a smaller portion of resource adequacy capacity was available in the real-time market. This is primarily because many long-start gas-fired units are not available in the real-time market if they are not committed in the day-ahead energy market or residual unit commitment process.

²³⁹ Real-time bid in or scheduled resource adequacy capacity in the figure does not include capacity from long-start units and imports that were not scheduled in the day-ahead market or residual commitment process. Uncommitted resource adequacy capacity from long-start units and imports do not have a real-time must offer obligation in the real-time market. This figure does not account for resource adequacy capacity that may not be available in real-time due to ramping limitations.

Summer peak hours

California’s resource adequacy program recognizes that a portion of the state’s generation is only available during limited hours. To accommodate this, load-serving entities are allowed to meet a portion of their resource adequacy requirements with generation that is available only a portion of the time. This element of the resource adequacy program reflects assumptions that generation will generally be available and used during hours when peak loads are highest.

Resource adequacy program rules are designed to ensure that the highest peak loads are met by requiring that all resource adequacy capacity be available at least 210 hours over the summer months. The rules do not specify that these hours must include the hours when load is highest or system conditions are most critical because participants do not have perfect foresight for when these will actually occur. However, the program assumes these use-limited generators are managed so that they are available during the peak load hours. In 2017, this included all hours with peak load equal to or above 40,100 MW.

Figure 10.2 provides an overview of resource adequacy capacity and load during the highest 210 hours of load. The red and green lines compare average resource adequacy capacity and load, respectively, during these hours. The yellow line adjusts the resource adequacy capacity so that it includes demand response capacity. In addition, the figure shows the number of hours in each month that belong to the highest 210 hours of load during the year (blue bars). During 2017, these hours had loads greater than 40,100 MW. Many of the highest load hours were concentrated in high temperature days during July, August, and September. As shown in Figure 10.2, average resource adequacy capacity exceeded average load during the highest load hours.

Figure 10.2 Average hourly resource adequacy capacity and load (210 highest load hours)

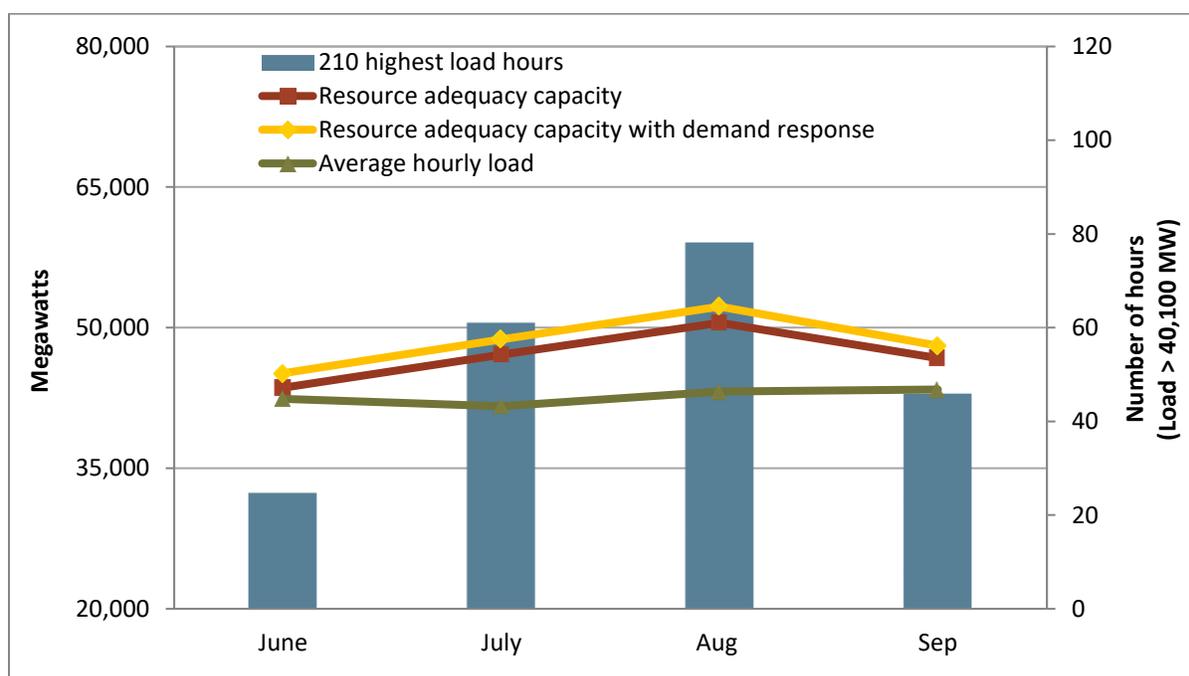
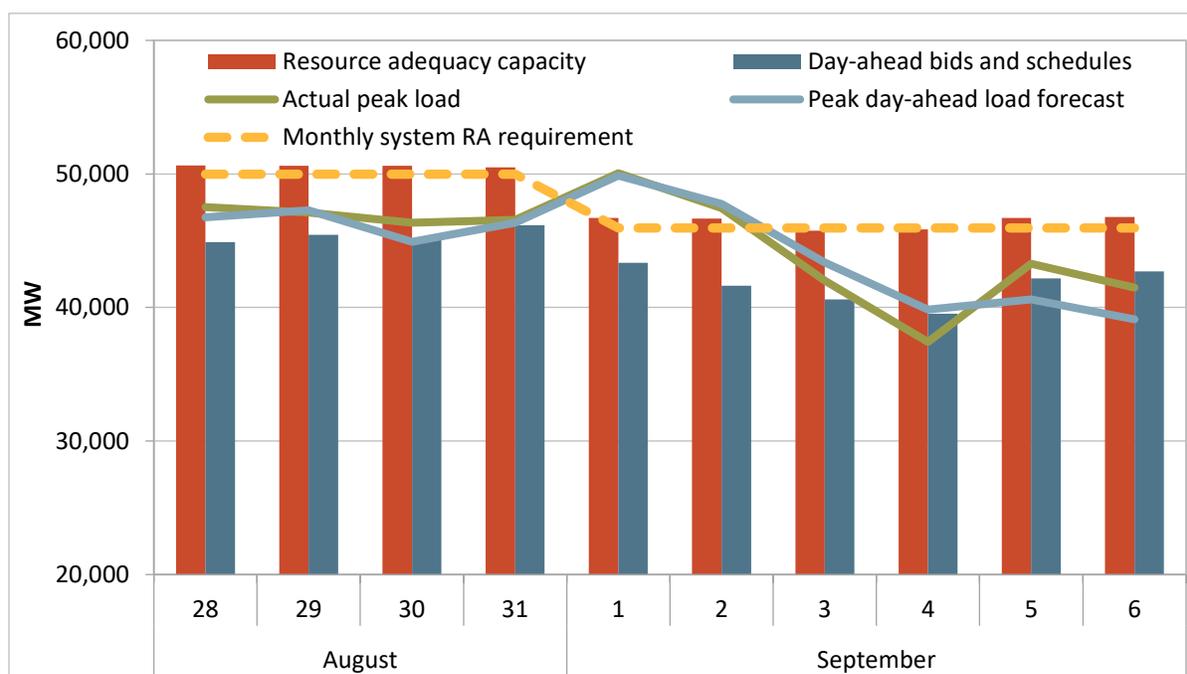


Figure 10.3 Daily peak load, resource adequacy capacity, and planning forecast

In 2017, annual load reached its instantaneous peak on September 1 at 50,116 MW. On this day and the following, peak loads exceeded the monthly system resource adequacy requirement and procured resource adequacy capacity. While the August requirement of 50,000 MW would have been nearly sufficient to meet these peaks, the September requirement was much lower because average loads in September are generally lower than in August.

Figure 10.3 shows daily peak loads and forecasts, as the solid blue and green lines, from August 28 through September 6. Peak loads on September 1 and September 2 were above 47,000 MW, reaching over 50,000 MW on September 1. These loads were significantly larger than the September system resource adequacy requirement of around 46,000 MW, shown by the dashed yellow line. Resource adequacy procurement on both days was just below 47,000 MW, with over 43,000 MW (93 percent) available in the day-ahead market during the peak load hour on September 1 and about 42,000 MW (89 percent) available on September 2. Resource adequacy requirements also fell short of day-ahead load forecasts on June 19, 20, 21 and 22.²⁴⁰

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 markets.

²⁴⁰ Q2 2017 Report on Market Issues and Performance, Department of Market Monitoring, September 2, 2017, pp. 18-20. <http://www.caiso.com/Documents/2017SecondQuarterReport-MarketIssuesandPerformance-September2017.pdf>

- **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 10.1 provides a detailed summary of the availability of resource adequacy capacity during the highest 210 hours of load 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 10.1:

- **Most of the capacity that must bid during all hours continued to be from gas-fired resources.** About half of the capacity (26,200 MW) for system resource adequacy must be bid into the market for each hour of the month.²⁴¹ Gas-fired generation made up about 21,000 MW (44 percent) of total resource adequacy capacity. Imports continued to represent about 7 percent of total capacity.²⁴²
- **Solar generation made up the largest portion of generation not required to bid in during all hours.** Solar resources contributed about 6,200 MW of total capacity (13 percent), hydro resources contributed 12 percent, use-limited gas resources contributed 10 percent, and resources with operating restrictions (wind and qualifying facilities) combined contributed an additional 5 percent.
- **Resource adequacy capacity after reported outages and derates continued to be significant.** Average resource adequacy capacity was around 47,900 MW during the 210 highest load hours in 2017, down from over 49,000 MW in 2016. However, after adjusting for outages and derates, the remaining capacity was about 96 percent of the overall resource adequacy capacity, which was unchanged from 2016.
- **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 93 percent. Non must-offer resources bid in about 91 percent of the day-ahead availability. These are typically variable and non-dispatchable energy resources. Additionally, some of the 210 highest load hours 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 10.1 compare the total resource adequacy capacity potentially available in the real-time market timeframe with the actual amount of capacity

²⁴¹ 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.

²⁴² 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.

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

- **Most use-limited gas resource adequacy capacity was bid into the day-ahead market.** Around 4,400 MW of use-limited gas resources were used to meet resource adequacy requirements. About 98 percent of this capacity was bid in the day-ahead market during the highest 210 load hours. In real time, about 4,200 MW of 4,400 MW (96 percent) of net available capacity was scheduled or bid in the real-time market.
- **Nuclear capacity contributed to resource adequacy.** In 2017 around 2,400 MW of nuclear resources were used to meet resource adequacy requirements. This is a reduction of about 400 MW from the previous year.

Table 10.1 Average system resource adequacy capacity and availability (210 highest load hours)

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
<i>Must-Offer:</i>									
Gas-fired generators	21,129	20,229	96%	20,229	100%	18,086	86%	17,840	99%
Other generators	1,601	1,524	95%	1,524	100%	1,524	95%	1,480	97%
Imports	3,433	3,397	99%	3,172	93%	2,288	67%	2,036	89%
Subtotal	26,163	25,150	96%	24,925	99%	21,898	84%	21,356	98%
<i>Other:</i>									
Use-limited gas units	4,673	4,434	95%	4,362	98%	4,386	94%	4,213	96%
Hydro generators	5,736	5,408	94%	5,085	94%	5,408	94%	5,143	95%
Nuclear generators	2,404	2,301	96%	2,227	97%	2,301	96%	2,175	95%
Solar generators	6,188	6,164	100%	3,526	57%	6,115	99%	3,556	58%
Wind generators	810	804	99%	506	63%	804	99%	625	78%
Qualifying facilities	1,409	1,367	97%	1,188	87%	1,339	95%	1,160	87%
Other non-dispatchable	501	488	97%	295	60%	445	89%	383	86%
Subtotal	21,721	20,966	97%	17,189	82%	20,798	96%	17,255	83%
Total	47,884	46,116	96%	42,114	91%	42,696	89%	38,611	90%

Imports

Load-serving entities are allowed to use imports to meet system resource adequacy requirements. While total import capability into the ISO system is about 11,000 MW, overall net imports averaged about 5,500 MW during the peak summer months. Load-serving entities used imports to meet around

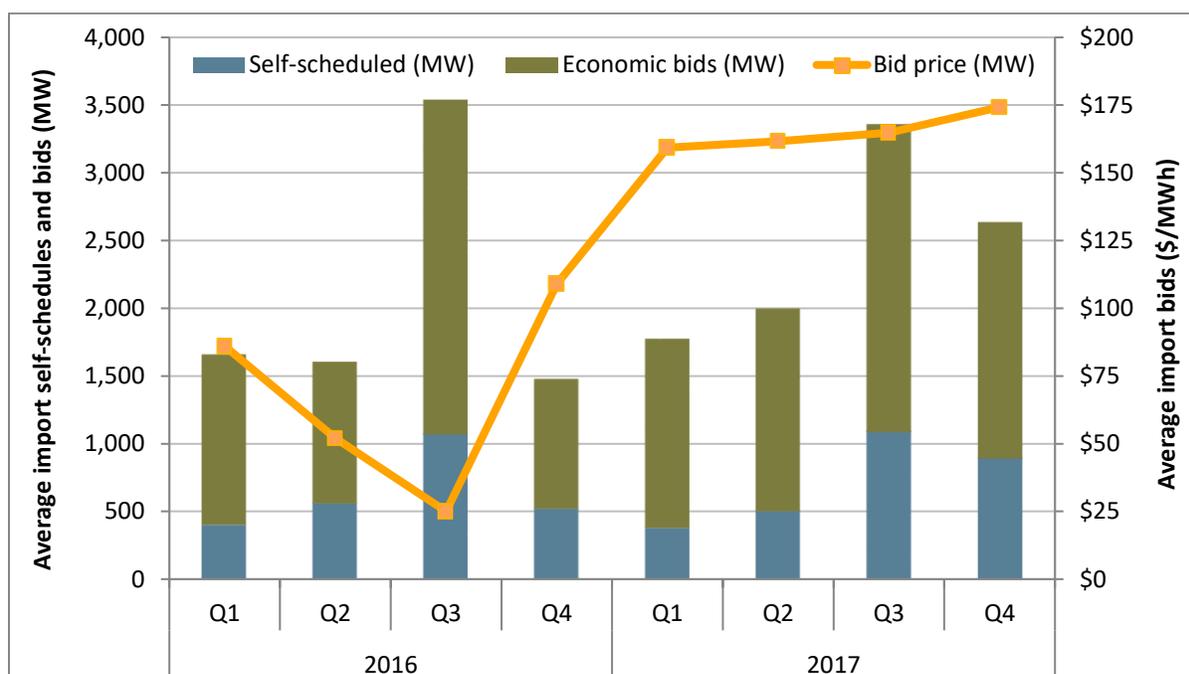
3,400 MW, or about 7 percent, of the system resource adequacy requirements during the 210 highest load hours.

Resource adequacy imports are only required to be bid into the day-ahead market. Imports can be bid at any price and do not have any further obligation if not scheduled in the day-ahead energy or residual unit commitment process. DMM has expressed concern that these rules could 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 could be routinely 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.

Figure 10.4 summarizes the bid prices and volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours, throughout the year. The blue and green bars (plotted against the left axis) show the respective average amounts of resource adequacy import capacity that market participants either self-scheduled (blue bar) or economically bid (green bar) in the day-ahead market. The gold line (plotted against the right axis) shows the weighted average bid prices for resource adequacy import resources for which market participants submitted economic bids to the day-ahead market.

This figure shows that the overall volume of resource adequacy import bids increased in 2017 compared to 2016, with significantly higher volume weighted prices in 2017. The third quarter continued to be the highest quarter for total bid and self-scheduled imports. During every quarter there were more economic bids for imports than self-schedules, and self-scheduled imports constituted only around 29 percent of total bids in the day-ahead market in 2017 compared to 31 percent the previous year.

Prices for weighted average bids began to climb in the fourth quarter of 2016, and remained very high 2017. Prices averaged above \$150/MWh for the entire year, and peaked in fourth quarter, at just about \$175/MWh. These were the highest quarterly average prices since 2013 and are primarily the result of a change in bidding behavior by a few market participants.

Figure 10.4 Resource adequacy import self-schedules and bids (peak hours)

10.2 Local resource adequacy

In addition to a system-wide requirement, load-serving entities are also required to procure capacity to meet resource adequacy requirements for local capacity areas. Table 10.2 shows an analysis similar to the analysis for system resource adequacy outlined above. This table compares the local area capacity requirements established by the CPUC to the amount of capacity that was procured (adjusted for availability) and actually bid into both the day-ahead and real-time markets during the highest 210 load hours in 2017.²⁴³

The key results from this table are:

- Overall the total amount of available resource adequacy capacity exceeded local resource capacity requirements, however significant shortfalls appear in Humboldt, Stockton and Sierra with 25 percent, 64 percent and 75 percent respectively.
- Within the local areas that comprise Pacific Gas and Electric's area, the percentage of total resource adequacy available compared to the local capacity requirement was 103 percent. The apparent shortfall in availability in the Sierra, Stockton, Kern and Humboldt areas were offset by an excess of availability in the Greater Fresno, North Coast/North Bay and Bay areas.²⁴⁴
- Significant amounts of surplus energy, beyond requirements, were bid into several local capacity areas in the day-ahead market. This includes capacity bid into the LA Basin, and Big Creek/Ventura

²⁴³ Obtained from the *2018 Local Capacity Technical Analysis*, May 1, 2017, p. 23, table 6: <http://www.caiso.com/Documents/Final2018LocalCapacityTechnicalReport.pdf>.

²⁴⁴ According to the local resource adequacy reallocation process adopted in the CPUC's Decision (D.) 10-12-038, incremental local resource adequacy requirements may be aggregated by transmission access charge area.

areas, which had a total requirement of 9,425 MW. Roughly 12,650 MW were available to be bid in the day-ahead market (134 percent of the requirement) and 12,234 MW actually bid into the day-ahead market (a surplus of 130 percent of the requirement).

- Bids in the day-ahead market almost exactly matched requirements in the San Diego areas, with roughly 3,500 MW.
- Similar to the system resource adequacy, most of the capacity available to bid into the day-ahead market did bid into the day-ahead market (95 percent). Unlike system resource adequacy where the percentage of bid capacity decreases, the capacity available to bid into the real-time market remains consistent with the day-ahead market (95 percent).

In instances where available capacity does not meet the needs of a local area, the ISO has the ability to designate additional capacity through the capacity procurement mechanism (CPM) within the ISO tariff. Scheduling coordinators who receive exceptional dispatches for capacity through a CPM designation may choose to decline the designation. CPM designations in 2017 are described in depth in 10.4.

Table 10.2 Average local resource adequacy capacity and availability (210 highest load hours)

Local capacity area	Area	Local requirement	Day-ahead				Real-time			
			Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
			MW	% of local RA Req.	MW	% of total RA Net Adj	MW	% of local RA Req.	MW	% of total RA Net Adj
Greater Bay Area	PG&E	5,617	5,911	105%	5,699	96%	5,772	103%	5,529	96%
Greater Fresno	PG&E	1,779	2,825	159%	2,637	93%	2,808	158%	2,604	93%
Sierra	PG&E	2,043	1,525	75%	1,486	97%	1,497	73%	1,439	96%
North Coast/North Bay	PG&E	721	733	102%	651	89%	733	102%	722	98%
Stockton	PG&E	745	474	64%	457	96%	474	64%	457	96%
Kern	PG&E	492	406	83%	337	83%	406	83%	321	79%
Humboldt	PG&E	157	40	25%	39	98%	40	25%	38	95%
LA Basin	SCE	7,368	8,666	118%	8,540	99%	7,535	102%	7,323	97%
Big Creek/Ventura	SCE	2,057	3,988	194%	3,694	93%	3,426	167%	3,170	93%
San Diego	SDG&E	3,570	3,839	108%	3,488	91%	3,545	99%	3,199	90%
Total		24,549	28,407	116%	27,028	95%	26,236	107%	24,802	95%

10.3 Flexible resource adequacy

The resource adequacy program is currently evolving from a program focused solely on peak demand needs to one focused on the grid's operational needs more broadly. As more renewable generation has integrated into the ISO during the last few years, operating conditions have changed and increased the need for ramping capability. This ramping capability is generally needed in the downward direction in morning when solar generation ramps-up and replaces gas generation. In the evening, upward ramping capability is needed as solar generation rapidly decreases while system loads are increasing. For the past few years, the greatest need for 3-hour ramping capability occurred during evening hours. In response to these changing conditions, the CPUC and ISO proposed the flexible resource adequacy program, which requires procurement of capacity with specific resource attributes. This program, which

was approved by FERC in 2014 and became effective in January 2015, now serves as an additional tool to help maintain grid reliability.²⁴⁵

The flexible resource adequacy framework is specifically designed to provide capacity with the attributes required to manage the grid during extended periods of ramping needs. Under this framework, the monthly flexible requirement is set at the forecast maximum contiguous three-hour net load ramp plus a capacity factor.^{246,247} Because the grid commonly faces two pronounced upward net load ramps per day, flexible resource adequacy categories were designed to address both the maximum primary and secondary net load ramp.²⁴⁸

All resources providing flexible capacity are required to submit economic energy and ancillary service bids in both the day-ahead and real-time markets and to participate in the residual unit commitment process. However, the must-offer obligations for these resources differ by category. A brief description of each category, its purpose, requirements, and must-offer obligations are presented below.

- **Category 1 (base flexibility):** Category 1 resources must have the ability to address both the primary and secondary net load ramps each day. These resources must submit economic bids for 17 hours a day and be available 7 days a week. The Category 1 requirement is designed to cover 100 percent of the secondary net load ramp and a portion of the primary net load ramp. The requirement is therefore based on the forecasted maximum three-hour secondary ramp. There is no limit to the amount of resources that meet the Category 1 criteria that can be used to meet the total system flexible capacity requirement.
- **Category 2 (peak flexibility):** Category 2 resources must be able to address the primary net load ramp each day. These resources must submit economic bids for 5 hours a day (which vary seasonally) and be available 7 days a week. The Category 2 operational need is based on the difference between the forecasted maximum three-hour secondary net load ramp (the Category 1 requirement) and 95 percent of the forecasted maximum three-hour net load ramp. The calculated Category 2 operational need serves as the *maximum* amount of flexible capacity in this category that can be used to meet the total system flexible capacity requirement.
- **Category 3 (super-peak flexibility):** Category 3 resources must be able to address the primary net load ramp. These resources must submit economic bids for 5 hours (which vary seasonally) on non-holiday weekdays. The Category 3 operational need is set at 5 percent of the forecasted three-hour net load ramp. The calculated Category 3 operational need serves as the *maximum* amount of flexible capacity in this category that can be used to meet the total system flexible capacity requirement.

²⁴⁵ For more information, see the following FERC order:

http://www.caiso.com/Documents/Oct16_2014_OrderConditionallyAcceptingTariffRevisions-FRAC-MOO_ER14-2574.pdf.

²⁴⁶ The capacity factor is the greater of the loss of the most severe single contingency or 3.5 percent of expected peak load for the month.

²⁴⁷ Net load is defined as total load less wind and solar production.

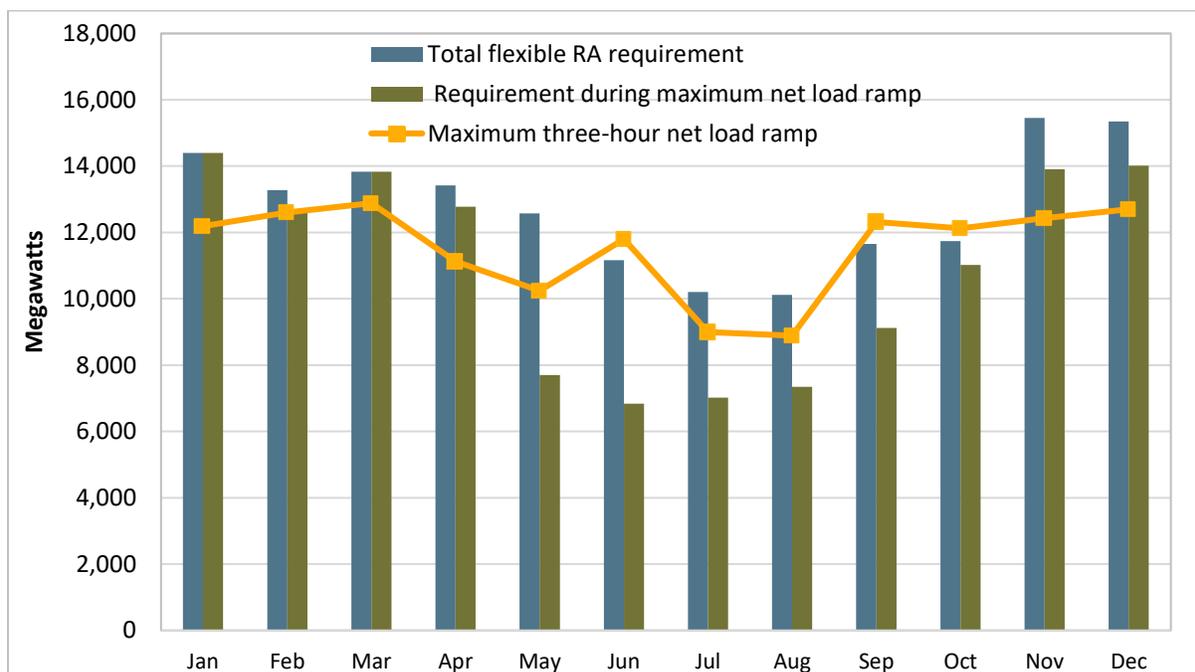
²⁴⁸ The ISO system typically experiences two extended periods of net load ramps, one in the morning and one in the evening. The magnitude and timing of these ramps change throughout the year. The larger of the two three-hour net load ramps (the primary ramp) generally occurs in the evening for non-summer months and in the morning during the summer. The must-offer obligation hours vary seasonally based on this pattern for Category 2 and 3 flexible resource adequacy.

Flexible resource adequacy requirements compared to actual maximum net load ramps

Figure 10.5 compares the monthly flexible resource adequacy requirements and the actual maximum three-hour net load ramp.²⁴⁹ In this figure the blue bars represent total three-hour requirements for the month and the gold line represents the maximum three-hour net load ramp. The green bars in the figure represent the requirement *during* the period of the maximum three-hour net load ramp. Because each category of flexible resource capacity has different must-offer hours, the requirement will effectively differ from day-to-day and hour-to-hour.²⁵⁰ This figure was calculated by first identifying the day and hours the maximum net load ramp occurred, then averaging the flexible capacity requirements for the categories with must-offer obligations during those hours.

Figure 10.5 shows that the maximum three-hour net load ramp exceeded the total flexible resource adequacy requirement during three months in 2017. This is shown where the blue bars are lower than the gold line. This figure also shows that the actual requirements set at the time of the peak ramp were less than the maximum ramp during half of the months of the year. This is shown when the green bars are lower than the gold line.

Figure 10.5 Flexible resource adequacy requirements during the actual maximum net load ramp



The flexible resource adequacy requirements and must-offer rules are very dependent on the ability to predict the size of the maximum net load ramp as well as the time of day the ramp occurs. This analysis

²⁴⁹ Our estimates of the net load ramp may vary slightly from the ISO’s calculations because we used 5-minute interval data and the ISO uses one-minute interval data.

²⁵⁰ For example, because Category 3 resources do not have must-offer obligations on weekends and holidays, the effective requirement during the net load ramps on those days will be less than the total flexible requirement set for the month.

suggests that the 2017 requirements and must-offer hours were insufficient in reflecting actual ramping needs.

Table 10.3 further compares actual net load ramping times to flexible resource adequacy capacity requirements and must-offer hours. The average requirement during the maximum net load ramp is calculated by summing Category 1, 2, and 3 requirements for each of the three hours in the max net load ramp (as applicable) and finding the average. For all of the months from May through September, the maximum net load ramps occurred at least partially outside of Category 2 and 3 must-offer hours. During these months, the Category 2 requirements were in place from 12:00-17:00. As shown in the table, the July max net load ramp did not even begin until 17:15, placing Category 2 requirements outside of the hours where ramping capacity was needed.²⁵¹ Additionally, requirements for Category 3 were not in place during any of the actual maximum ramping periods in 9 months of the year, as they all occurred on Sunday.

If load-serving entities had procured just the minimum Category 1 and maximum Category 2 and 3 requirements, the ISO may have been short the necessary flexibility to meet ramping needs. However, as discussed below, the load-serving entities procured significantly more flexible capacity than required. DMM recommends that the ISO and local regulatory authorities further evaluate the must-offer rules for Category 2 and 3 flexible capacity to better address weekend and holiday availability and, especially, to address months in the middle of the year.

Table 10.3 Maximum three-hour net load ramp and flexible resource adequacy requirements

Month	Maximum 3-hour net load ramp (MW)	Total flexible RA requirement (MW)	Average requirement during maximum net load ramp (MW)	Date of maximum net load ramp	Ramp start time	Average requirement met ramp? (Y/N)	Why average requirement during max net load ramp was less than the maximum 3-hour net load ramp
Jan	12,187	14,400	14,400	1/27/2017	14:55	Y	
Feb	12,601	13,274	12,642	2/12/2017	15:15	Y	
Mar	12,883	13,835	13,835	3/6/2017	15:25	Y	
Apr	11,127	13,415	12,776	4/2/2017	16:45	Y	
May	10,247	12,578	7,706	5/14/2017	16:55	N	Max ramp occurred on Sunday; Category 2 requirement ended at 17:00
Jun	11,796	11,165	6,841	6/11/2017	17:15	N	Max ramp occurred on Sunday; Category 2 requirement ended at 17:00
Jul	8,998	10,204	7,022	7/2/2017	16:15	N	Max ramp occurred on Sunday; Category 2 requirement ended at 17:00
Aug	8,889	10,120	7,346	8/13/2017	15:55	N	Max ramp occurred on Sunday; Category 2 requirement ended at 17:00
Sep	12,319	11,650	9,117	9/24/2017	15:25	N	Max ramp occurred on Sunday; Category 2 requirement ended at 17:00
Oct	12,124	11,737	11,024	10/22/2017	14:50	N	Max ramp occurred on Sunday; Total flex was less than actual 3-hour ramp
Nov	12,434	15,457	13,909	11/5/2017	14:35	Y	
Dec	12,704	15,348	14,017	12/21/2017	14:25	Y	

²⁵¹ Category 2 requirements were in place from 15:00-20:00 from January through April and from October through December, which generally covered the times when the actual 3-hour ramp was the greatest.

Flexible procurement and availability

Table 10.4 presents the average monthly flexible capacity procurement in 2017 by resource type. The flexible resource adequacy categories and must-offer rules were designed to be technology neutral allowing for a variety of resources to provide flexibility to the ISO. While the CPUC and ISO created counting criteria for a variety of resource types, similar to the previous year, almost all flexible ramping procurement in 2017 was composed of natural gas-fired generation.

In 2017, hydro-electric generators made up the next largest volume at about 9 percent of Category 1 flexible capacity, on average, which was down from about 12 percent during the prior year. Load-serving entities procured an average of only 85 MW of Category 3 capacity, significantly less than the maximum allowed – 5 percent of the total flexible requirement during each month. Instead, the load-serving entities procured greater amounts of Category 1 capacity. While energy storage resources comprised a relatively small amount of total capacity (33 MW), they made up a significant portion (18 percent) of the category 3 flexible capacity procured in 2017. In 2016 there was almost no energy storage procured for flexible resource adequacy.

Table 10.4 Average monthly flexible resource adequacy procurement by resource type

Resource type	Category 1		Category 2		Category 3	
	Average MW	Total %	Average MW	Total %	Average MW	Total %
Gas-fired generators	8,890	76%	293	25%	3	3%
Use-limited gas units	1,665	14%	819	71%	61	72%
Hydro generators	1,099	9%	47	4%	6	7%
Geothermal	28	0.2%	0	-	0	-
Energy Storage	17	0.1%	1	0.1%	15	17.6%
Total	11,700	100%	1,160	100%	85	100%

Due in part to greater amounts of Category 1 capacity, total flexible resource adequacy procurement exceeded requirements for most months in 2017. Figure 10.6 displays total monthly flexible resource adequacy requirements and procured capacity, which are determined *year-ahead*. It also presents the total capacity which must be offered *during the actual maximum three-hour net load ramp*.²⁵² Must-offer obligations differ from the total flexible capacity procured because the actual net load ramps often occur outside of Category 2 and 3 must-offer hours. The following results can be derived from Figure 10.6:

- Total flexible resource adequacy procurement (gold bars) exceeded the total requirement (blue bars) in 8 months of the year.
- The must-offer obligation for procured resources during the maximum three-hour net load ramp (green bars) is lower than the total procurement (blue bars) in most months. This suggests that some of the capacity that was procured year-ahead was not obligated to offer during the actual maximum net load ramp hours.
- The must-offer obligation during the actual maximum net load ramp (green bars) exceeded the actual maximum net load ramp (red line) in nearly all months with the exception of June,

²⁵² The must-offer obligation estimate used in this chart is calculated including long-start and extra-long-start resources regardless of whether or not they were committed in the necessary time frame to actually have an obligation in real time.

September and October. This suggests that the obligations for procured capacity was sufficient to meet the maximum net load ramps for some but not all months.

Figure 10.6 Flexible resource adequacy procurement during the maximum net load ramp

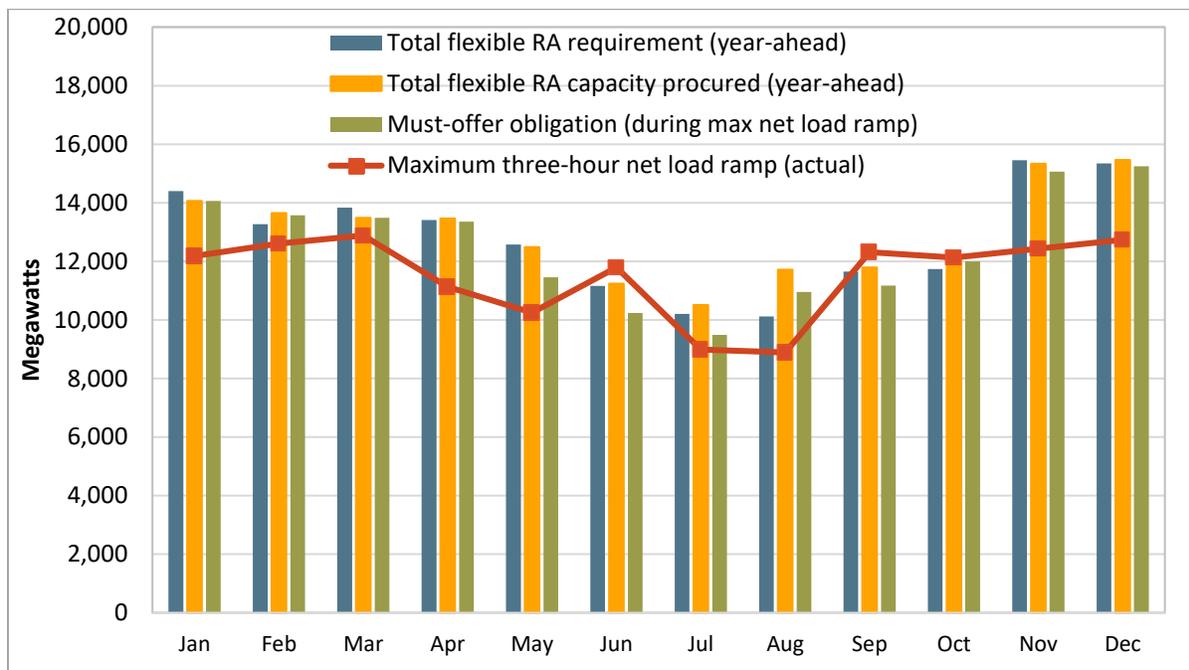


Table 10.5 presents an assessment of the availability of flexible resource adequacy capacity in both the day-ahead and real-time markets. For purposes of this analysis, average capacity represents the must-offer obligation of flexible resource adequacy capacity. Availability is measured by assessing economic bids and outages in the day-ahead and real-time markets. For the resources where minimum output qualified as flexible capacity, the minimum output was only assessed as available if no part of the resource was self-scheduled.

Extra-long-start resources are required to participate in the extra-long-start commitment process and economically bid into the day-ahead and real-time markets when committed by this process. For purposes of this analysis, extra-long-start resources were assessed as available in the day-ahead market to the extent that the resource did not have outages limiting its ability to provide its full obligation. Long-start and extra-long-start resources were only assessed in the real-time market analysis if they received schedules in the day-ahead market or the residual unit commitment process. Day-ahead energy schedules are excluded from real time economic bidding requirements in this analysis, as in the resource adequacy availability incentive mechanism (RAAIM) calculation.

This is a high level assessment of the availability of flexible resource adequacy capacity to the day-ahead and real-time markets in 2017. This analysis is not intended to replicate how availability will be

measured under the incentive mechanism, which was implemented by the ISO in November 2016.²⁵³ The incentive penalties became financially binding on April 1, 2017.

Table 10.5 Average flexible resource adequacy capacity and availability

Month	Average DA flexible capacity (MW)	Average DA Availability		Average RT flexible capacity (MW)	Average RT Availability	
		MW	% of Capacity		MW	% of Capacity
January	13,165	11,923	91%	9,451	7,988	85%
February	12,722	10,511	83%	9,083	7,545	83%
March	12,733	10,529	83%	8,415	7,358	87%
April	12,814	10,091	79%	8,340	6,836	82%
May	11,740	9,984	85%	7,799	6,855	88%
June	10,550	9,733	92%	7,641	6,343	83%
July	9,591	9,001	94%	7,323	5,954	81%
August	10,933	10,220	93%	9,146	7,248	79%
September	11,004	10,071	92%	8,751	7,126	81%
October	11,128	9,712	87%	8,440	6,788	80%
November	14,050	11,559	82%	9,557	8,023	84%
December	14,544	13,184	91%	9,853	8,217	83%

Results presented in Table 10.5 suggest that flexible resource adequacy had fairly high levels of availability in 2017. Availability increased compared to 2016, partially due to the implementation of a financially binding incentive mechanism in April of 2017. This mechanism also provided tools for managing outages and use-limitations. For example, resources can provide substitute capacity when an outage occurs or when a use-limitation is reached.²⁵⁴ Average availability ranged from 79 percent to 94 percent in the day-ahead market, an increase in almost every month compared to 2016. In the real-time market, availability ranged from 79 percent to 88 percent, a significant increase from 67 percent to 80 percent availability in the 2016.

Results presented in Table 10.5 also show that the real-time average must-offer obligation is much lower than the day-ahead obligation. This reflects several factors. First, resources may receive ancillary service awards in the day-ahead market covering all or part of their resource adequacy obligation. Second, long-start and extra-long-start resources do not have an obligation in the real-time market if they are not committed in the day-ahead market, residual unit commitment process or the extra-long-start commitment process. In addition, day-ahead energy awards are excluded from the real-time availability requirement for the incentive mechanism calculation.

²⁵³ The RAAIM calculation allows exemptions that are not included in DMM's calculations in Table 10.5. Specifically, the RAAIM calculation exempts resources with pmax less than 1 MW, non-resource specific imports, some load following meter sub system resources, qualifying facility resources, participating pumping load, reliability must-run resources, use-limited resources approaching or exceeding a registered use limitation and flexible resources that are shown in combination with another resource. In addition, the RAAIM adjusts the obligation of a variable energy resource based on the resource forecast and the portion of effective flexible capacity shown on a monthly flexible resource adequacy showing.

²⁵⁴ Flexible resource adequacy resources were not subject to the standard capacity product in 2015 or 2016. Beginning April 2017, flexible resource adequacy resources were subject to the resource adequacy availability incentive mechanism.

10.4 Capacity procurement mechanism and reliability must-run

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 which the ISO can procure backstop capacity to meet local resource adequacy requirements that are not met through bilateral purchases (see 10.2). 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.

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.

Intra-monthly capacity procurement mechanism designations in 2017 were triggered by exceptional dispatch and local reliability issues during the year. The total estimated cost of the designations settled during the year was about \$7 million, compared to \$4.3 million in 2016.²⁵⁵ More than \$3 million of the

²⁵⁵ DMM updated the calculation of this figure from the 2016 Annual Report to include only the cost of capacity procurement designations *settled* in 2017. Previously the figure was provided for designations *issued* during the year. This change was made to eliminate overlap when reporting the change in cost from year to year.

total cost was charged to the Southern California Edison transmission access charge area in December, coinciding with the procurement of Mandalay Units 1, 2, and 3 for local needs while wildfires were burning nearby. About \$2 million of the total cost was designated for the entire system, usually for system capacity needs after a resource was exceptionally dispatched.

Several intra-monthly designations were declined by one scheduling coordinator. Scheduling coordinators who received 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 10.6 Intra-monthly capacity procurement mechanism costs

Resource	Designated MW	CPM Start Date	CPM End Date	Price (\$/kW-mon)	Estimated cost (\$ mil)	Estimated cost 2017 (\$ mil)	Local capacity area	Exceptional dispatch CPM trigger
MANDALAY GEN STA. UNIT 2	20	11/8/16	1/6/17	\$6.31	\$0.25	\$0.03	SCE	Transmission outage in Santa Clara sub-area
DELTA ENERGY CENTER AGGREGATE	114	12/14/16	2/11/17	\$6.31	\$1.43	\$1.01	PG&E	Transmission outage
Los Medanos Energy Center AGGREGATE	90	12/14/16	2/11/17	\$6.31	\$1.12	\$0.79	PG&E	Transmission outage
MOSS LANDING POWER BLOCK 1	141	12/18/16	1/17/17	\$6.31	\$0.91	\$0.50	System	Cold temperatures, potential gas supply issues and loss of imports
Mountainview Gen Sta. Unit 3	36	12/19/16	2/16/17	\$1.90	\$0.14	\$0.11	SCE	Outages in West of Devers sub-area
Pio Pico Unit 2	50	2/6/17	3/7/17	\$6.31	\$0.31	\$0.31	System	Forced line outage
OTAY MESA ENERGY CENTER	155	5/22/17	5/31/17	\$4.16	\$0.20	\$0.20	System	Higher loads in real-time
MANDALAY GEN STA. UNIT 1	20	6/18/17	6/30/17	\$7.31	\$0.06	\$0.06	System	Higher temperatures and loads
MANDALAY GEN STA. UNIT 2	20	6/18/17	7/17/17	\$7.31	\$0.14	\$0.14	System	Higher temperatures and loads
El Cajon Energy Center	25	7/27/17	8/31/17	\$6.31	\$0.18	\$0.18	SDG&E	Physical overload on local line
MANDALAY GEN STA. UNIT 3	119	10/24/17	11/22/17	\$6.31	\$0.73	\$0.73	System	Higher loads in real-time
MANDALAY GEN STA. UNIT 2	215	12/5/17	2/2/18	\$6.31	\$2.68	\$1.19	SCE	Local availability for wildfire
MANDALAY GEN STA. UNIT 1	215	12/5/17	2/2/18	\$6.31	\$2.68	\$1.19	SCE	Local availability for wildfire
MANDALAY GEN STA. UNIT 3	130	12/5/17	2/2/18	\$6.31	\$1.63	\$0.72	SCE	Local availability for wildfire
Total	1,351				\$12.46	\$7.17		

In addition to the intra-monthly designations, there were also three annual designations made for capacity via the capacity procurement mechanism in December 2017 for 2018. These are 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. The ISO believes that the capacities procured will be reduced for the Encina units.²⁵⁶

The annual designation for the Moss Landing resource was made through the competitive solicitation process at \$6.19/kW-month, as bid by the scheduling coordinator, just below the soft offer cap. The Encina units will be compensated at the soft offer 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 10.7 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	510	\$6.19	\$38.4	PG&E	Material sub-area deficiency
ENCINA UNIT 4	272	\$6.31	\$20.9	SDG&E	Material sub-area deficiency
ENCINA UNIT 5	273	\$6.31	\$21.0	SDG&E	Material sub-area deficiency

There were no monthly capacity procurement designations made in 2017, and there have not been any since the program was implemented in 2016.

Reliability must-run

From 1998 through 2007, reliability must-run contracting played a significant role in the ISO, ensuring the reliable operation of the grid. In 2007, the CPUC's resource adequacy program became effective and provided a cost-effective alternative to reliability must-run contracting by the ISO. By 2011, there were only a handful of units contracted as reliability must-run. Capacity under reliability must-run contracts was very low from 2011 to 2017, and was limited to a very small amount of the oldest and least efficient capacity within the ISO system.

Because load-serving entities procure most of the needed local capacity requirements through the resource adequacy program, the amount of capacity and costs associated with reliability must-run contracts have been relatively low during the past few years. These costs continued to decrease and were about \$17 million in 2017, falling from \$21 million in 2016 which in turn was less than the prior year of \$26 million in 2015.

Just under two-thirds of these costs resulted from the reliability must-run agreement that placed synchronous condensers at Huntington Beach units 3 and 4 into service, which began in late June 2013. This agreement was put into place due to the outage and subsequent retirement of the San Onofre Nuclear Generating Station (SONGS) units in June 2013. The other costs are associated with the Oakland Station Units 1, 2 and 3.

During 2017, however, capacity designated as being subject to reliability must-run contracts beginning in 2018 increased sharply. Three new, efficient gas units that represent almost 700 MW were designated by the ISO to provide reliability must-run service beginning in 2018.²⁵⁷ The designation of

²⁵⁶ *Year Ahead Local CPM Designation Report*, December 22, 2019:

<http://www.caiso.com/Documents/December222017YearAheadLocalCPMDesignationReport.pdf>.

²⁵⁷ These including 593 MW of capacity from the combined cycle Metcalf Energy Center, and 94 MW of peaking capacity owned by Calpine.

these newer and more efficient resources units as reliability must run units has highlighted problems with the current resource adequacy framework, and with the ISO's two mechanism for backstop procurement: the capacity procurement mechanism and reliability must-run contracts.

The ISO will undertake a stakeholder process in 2018 aimed at reforming the current reliability must-run policy. DMM has provided several recommendations to improve the ISO's reliability must-run policy and ensure it functions well in conjunction with the resource adequacy capacity market (see Chapter 11).

10.5 Resource adequacy developments

In addition to the capacity procurement mechanism process changes described above, the ISO is engaged in several multi-phase resource adequacy stakeholder processes.

Proposed changes to the risk-of-retirement capacity procurement mechanism

On January 12, 2018, the ISO filed a tariff amendment with FERC to change the provisions for the risk-of-retirement (ROR) capacity procurement mechanism, to be effective April 13 and apply to the request window opening on May 1, 2018.²⁵⁸ The risk-of-retirement capacity procurement mechanism is a tool that allows the ISO to procure resources needed for reliability that did not receive a resource adequacy award in the current or successive compliance year. The changes outlined by the ISO were designed to accomplish three goals:

1. Allow for designations earlier in the year so that resource owners have sufficient time to plan for potential changes related to a designation. The proposal allows for one window early in the year, where resource owners may receive designations for the current year and the following year, and one window prior to the end of the year where resource owners may receive designations for the following year.
2. Change the payments for designations from the \$6.31/kW-month soft offer cap to payments inclusive of fixed cost recovery, similar to the payments made for the reliability must-run mechanism.
3. Require the resource to retire if it is not sold to another entity, does not receive a resource adequacy contract, or is not procured through an ISO backstop process.

On February 2, 2018, DMM filed a protest to the ISO's filing citing that the change in payments would be unjust and unreasonable.²⁵⁹ The proposed payments for the risk-of-retirement capacity procurement mechanism would allow for resources to recover all sunk fixed costs, including a 12.5 percent return on investment, and would allow resources to retain all profits from operating in the ISO or bilateral markets. This level of compensation would create market inefficiencies, and undermine the resource adequacy mechanism program and capacity procurement mechanism competitive solicitation process.

²⁵⁸ *Tariff Amendment to Improve the Risk of Retirement Capacity Procurement Mechanism*, January 12, 2018: <https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14796643>.

²⁵⁹ *Motion to intervene and protest of the Department of Market Monitoring of the California Independent System Operator Corporation*, February 2, 2018: <https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14814722>.

Resource adequacy availability incentive mechanism

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

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

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

During the interval when advisory results were being published, the ISO identified a number of issues with the current implementation of the availability incentive mechanism, some of which have already been addressed, and some of which will be addressed with software updates in the fall release. The ISO will continue to produce advisory settlement totals using the current mechanism. These calculations will become financially binding, retroactively, beginning on April 1, with regular settlements restatements after the software changes are implemented in November 2017. Due to the timing of resettlements the total advisory payments for 2017 were not provided.

Further enhancements

In addition to the changes that the ISO is implementing in November, there is an additional defect in the way that this mechanism calculates payments for resources that impacts awards for both flexible and system resource adequacy. The ISO released a white paper outlining the details of this defect and the solution they wish to pursue.²⁶⁰ The ISO plans to implement changes to the mechanism in the spring of 2018. All changes implemented at that time will be effective going forward, and will not be retroactively applied to any settlements totals.

²⁶⁰ *Resource Adequacy Availability Incentive Mechanism Modification White Paper*, August 31, 2017.
<http://www.caiso.com/Documents/WhitePaper-RAAIMCalculationModifications.pdf>.

11 Recommendations

DMM provides recommendations to the ISO and its Board of Governors on current market issues and new market design initiatives on an ongoing basis. This chapter summarizes DMM recommendations on key current market design initiatives and issues.

11.1 Auctioning congestion revenue rights

Since the start of the ISO's congestion revenue rights (CRR) auction in 2009, payouts to holders of auctioned congestion revenue rights have exceeded the auction revenues by over \$750 million. These losses are borne by transmission ratepayers because congestion revenue rights payments are funded by the congestion revenue rights balancing account and transmission ratepayers ultimately receive any credits or fund any shortfalls in this balancing account. Most of this \$750 million has gone to purely financial entities. These losses have not declined over time, and actually increased to over \$100 million in 2017 and about \$42 million in the first quarter of 2018.

Beginning in 2016, DMM has been recommending that the ISO establish a stakeholder initiative to examine the option of eliminating the congestion revenue rights auction and instead allowing transmission ratepayers to collect congestion revenues. In fall 2016, DMM completed a whitepaper providing a review and critique of the general congestion revenue rights auction design.²⁶¹

DMM has recommended that the ISO continue the process of allocating congestion revenue rights to load-serving entities who pay for the transmission system through the transmission access charge (TAC), but that the ISO stop auctioning off additional congestion revenue rights that are backed financially by transmission ratepayers through the congestion revenue balancing account. If the ISO believes that it is beneficial for the ISO to play a central role in facilitating hedging by generation owners, then DMM recommends the ISO replace the congestion revenue rights auction with a market for financial contracts between willing buyers and sellers.

ISOs across the United States have implemented the same general design for auctioning congestion revenue rights. At least a decade of data now exists to help policy makers assess how that general congestion revenue rights auction design is functioning. The long term trends of transmission ratepayer losses have continued in California and other large ISOs across the country. Years of persistent attempts of ISOs to reduce revenue inadequacy through actions such as improving outage modeling have failed to resolve the large auction revenue shortfalls at the nation's largest ISOs. This indicates that changes to the general congestion revenue rights auction design are needed.

In response to DMM's recommendations, the ISO initiated a process in 2017 to begin to perform analysis of "Congestion Revenue Rights Auction Efficiency" to assess what issues should be included in

²⁶¹ *Shortcomings in the congestion revenue right auction design*, Department of Market Monitoring, November 28, 2016. <http://www.caiso.com/Documents/DMM-WhitePaper-Shortcomings-CongestionRevenueRightAuctionDesign.pdf>

See also the updated version: *Problems in the Performance and Design of the Congestion Revenue Rights Auction*, Department of Market Monitoring, November 27, 2017 <http://www.caiso.com/Documents/DMMWhitePaper-Problems Performance Design CongestionRevenueRightAuction-Nov27 2017.pdf>

the scope of a stakeholder initiative.²⁶² The ISO completed a report on its analysis in November 2017.²⁶³ Following completion of the ISO’s report on its analysis, DMM referred the ISO’s congestion revenue rights action rules to FERC’s Office of Energy Market Regulation as a significant market design flaw that could be effectively addressed by tariff changes pursuant to Appendix P of the ISO tariff.²⁶⁴

In early 2018, the ISO developed a proposal and filed at FERC to limit the pairs of nodes for which congestion revenue rights could be purchased in the auction. The ISO’s proposed changes are aimed at reducing losses resulting from congestion revenue rights with “non-delivery” sources/sinks, while allowing auctioning of congestion revenue rights with “delivery” sources/sinks which could be used for hedging of energy sales or purchases.²⁶⁵

As explained in DMM’s comments to FERC, the ISO’s proposed auction changes are not sufficient for resolving the fundamental underlying flaws with the congestion revenue rights auction design.²⁶⁶ However, ISO management has made a commitment to its governing board and to the Commission to continue to explore proposals for more extensive changes to the congestion revenue rights framework. Given this commitment by the ISO, DMM supports the measures proposed as incremental improvements that are likely to help partially address the very large losses being imposed on transmission ratepayers from the congestion revenue rights auction.

DMM also continues to recommend that the ISO move swiftly to replace the current congestion revenue rights auction with a voluntary market for financial contracts based on bids from willing buyers and sellers.

11.2 Aliso Canyon gas measures

In 2017 the ISO filed to extend a variety of provisions initially enacted in 2016 to help address the limited operability of the Aliso Canyon gas storage facility. Although DMM supported these measures on a temporary basis in 2016, DMM believes the use of some of these provisions have become problematic and needs to be limited or significantly improved.²⁶⁷ These provisions include the *gas usage nomograms* and the *gas cost scalars*.

²⁶² *2017 Stakeholder Initiatives Catalog*, Market and Infrastructure Policy, March 3, 2017, p. 18: http://www.caiso.com/Documents/Final_2017StakeholderInitiativesCatalog.pdf.

2017 Policy Initiatives Roadmap, Market and Infrastructure Policy, March 3, 2017, pp. 6-7: http://www.caiso.com/Documents/Final_2017PolicyInitiativesRoadmap.pdf.

²⁶³ *CRR Auction Analysis Report*, California Independent System Operator MQRI, November 21, 2017. <http://www.caiso.com/Documents/CRR Auction Analysis Report.pdf>

²⁶⁴ See Appendix P, Section 12. DMM formally notified FERC’s Office of Energy Market Regulation of that DMMs believes the ISO’s current congestion revenues right auction constitutes a significant market design flaw that can be effectively remedied by tariff changes on December 4, 2017 following DMM’s review of the ISO’s November 21, 2017 *CRR Auction Analysis Report*.

²⁶⁵ The ISO’s CRR filing also includes some measures to improve outage reporting in an effort to try to reduce discrepancies between the network models used in the congestion revenue rights auction versus the day-ahead market.

²⁶⁶ *Motion to Intervene and Comments of the Department of Market Monitoring of the California Independent System Operator*, ER-1344-000, May 2, 2018. http://www.caiso.com/Documents/May2_2018_DMMMotion_Intervene_Comments-CRR Auction Efficiency Track 1A ER18-1344.pdf

²⁶⁷ *Comments of the Department of Market Monitoring for the California Independent System Operator*, ER17-2568, October 26, 2017, http://www.caiso.com/Documents/Oct26_2017_DMMComments-AlisoCanyonElectric-GasCoordinationPhase3 ER17-2568.pdf

Gas usage nomograms

In 2017, the ISO sought approval for FERC to make permanent and expand the use of its temporary tariff authority to implement a gas constraint (or gas nomogram) that limits the maximum amount of natural gas that can be burned by natural gas-fired resources. The ISO contends that the maximum gas constraint “has proven to be a useful and discrete tool that balancing authority areas can use to reflect the interactions of gas limitations in the electric market optimization.”²⁶⁸

DMM is not supportive of the ISO extending the use of maximum gas usage constraints to the entire ISO balancing area or EIM areas. DMM’s review of the ISO’s limited experience with maximum gas usage constraints suggests that while such constraints may be a useful tool in the future, additional refinement of the software and operational processes through which the constraints are implemented is necessary before expanding usage of the constraint to other parts of the ISO or EIM. Needed enhancements include:

- Improving how gas usage constraint limits are set and adjusted in real-time; and
- Incorporating gas usage limits in the ISO’s automated market power mitigation and resource sufficiency tests.

FERC rejected the ISO’s request to make its authority for gas usage constraints permanent and to expand use of the gas nomogram beyond the SoCalGas area to the rest of the ISO footprint and EIM areas.²⁶⁹ FERC approved a subsequent filing by the ISO to extend the gas usage provisions in the SoCalGas area on a temporary basis through fall 2018.²⁷⁰ Based on performance of the gas usage constraint in late 2017 and early 2018, DMM continues to believe the gas usage constraints or nomograms need to be refined and improved in the ways previously recommended by DMM.

For example, while gas usage constraints are modeled as 15-minute constraints in the ISO’s real-time market, these gas constraints are actually applicable only over a much longer multi-hour time period. Although operators are able to adjust constraints in real-time in response to changing conditions, the ISO does not appear to adjust these constraints in real time based on actual gas usage in prior hours. Therefore, when these gas constraints bind in the real-time market during the peak ramping hours, there appears to be surplus gas from hours prior in the day when actual usage was well below the constraint as modeled by the ISO.²⁷¹ This represents a significant flaw that remains in the gas nomograms. Thus, DMM continues to recommend that the ISO improve how gas usage constraint limits are set and adjusted in real-time based on actual gas usage in prior hours.

²⁶⁸ Filing to Extend Temporary Measures to Address Limited Operability of Aliso Canyon Facility and to Make Permanent and Modify Other Measures to Address Potential Gas Limitations, California Independent System Operator Corporation, ER17-3-000, September 29, 2017, p.3. http://www.caiso.com/Documents/Sep29_2017_TariffAmendment-AlisoCanyonElectric-GasCoordinationEnhancementsPhase3_ER17-2568.pdf

²⁶⁹ *Order on Tariff Revisions Aliso Canyon Gas-Electric Coordination*, ER17-2568. November 28, 2017. http://www.caiso.com/Documents/Nov28_2017_Order_TariffRevisions-AlisoCanyonGas-ElectricCoordinationEnhancementsPhase3_ER17-2568.pdf

²⁷⁰ *Order Accepting Reimplementation of Expired Provisions*, ER18-375, December 15, 2017. http://www.caiso.com/Documents/Dec15_2017_OrderAccepting_Re-ImplementExpiredProvisions_AlisoCanyonGas-ElectricCoordination_ER18-375.pdf

²⁷¹ See example and discussion in *Comments of the Department of Market Monitoring of the California Independent System Operator*, ER17-2568, October 26, 2017, pp 15-17. http://www.caiso.com/Documents/Oct26_2017_DMMComments-AlisoCanyonElectric-GasCoordinationPhase3_ER17-2568.pdf

Gas cost scalars

In fall 2017 the ISO also gained approval from FERC to extend interim tariff provisions that allow the ISO to increase the gas price index used to calculate real-time market commitment cost bid caps and default energy bids for gas-fired resources in the SoCalGas area using special *gas cost scalars*. When in effect, these scalars have been set so that the gas costs used to calculate real-time market commitment cost bid caps for units in the SoCalGas area are increased to 175 percent of the gas price index for the next-day gas market. Gas costs used to calculate default energy bids have been increased to 125 percent of the gas price index using the scalar.

The initial values of the gas cost scalars were developed by DMM in spring 2016 for use on a temporary basis to allow the ISO to protect against the substantial uncertainties that existed at that time about the impact that Aliso Canyon limitations may have on gas markets. Since then, DMM has closely monitored gas market trends and performed analysis of the need for these gas cost scalars. Based on this analysis, DMM concluded that there was a very limited need for the increased bidding flexibility created by the gas cost scalars and recommended that the ISO review and reduce the gas cost scalars used in the real-time market.²⁷²

DMM believes that these gas cost scalars are a very crude and ineffective tool for seeking to manage potential reliability issues associated with gas limitations in the real-time market while protecting against market power. Under current ISO processes, if gas limitations become apparent during any point of an operating day, the ISO cannot apply the gas cost scalars in the real-time market until the following operating day. Thus, the scalars have not been in place on the very limited number of days when they could have the intended effect, but have been left in place on many more days when DMM believes they were not justified by gas market prices.²⁷³ Once the scalars were applied, the ISO has also left the scalars in place for extended periods when DMM believes they were not justified by gas market prices.

Rule changes being proposed by the ISO as part of the Commitment Cost and Default Energy Bid Enhancements (CCDEBE) initiative for implementation in fall 2019 do not include the ability for the ISO to update gas prices used in the real-time market. Therefore, the potential changes proposed in the CCDEBE initiative will not avoid the problems associated with the current gas cost scalars.

DMM is not supportive of 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 begin to develop the ability to update gas prices used in the real-time market based on same-day gas market data available each morning, rather than relying on much less effective and less accurate tools such as the gas cost scalars.

11.3 Commitment cost and default energy bid enhancements

In early 2018, the ISO completed the Commitment Cost and Default Energy Bid Enhancements (CCDEBE) initiative that was started in 2016. The CCDEBE proposal was approved by the Board in March 2018 and

²⁷² *Q1 2017 Report on Market Issues and Performance*, Department of Market Monitoring, July 10, 2017, pp.6-7. <http://www.caiso.com/Documents/2017FirstQuarterReport-MarketIssuesandPerformance.pdf>.

²⁷³ See examples from Q4 2017 in pp. 51-53 of *Q4 2017 Report on Market Issues and Performance*, Department of Market Monitoring, February 14, 2018. <http://www.caiso.com/Documents/2017FourthQuarterReport-MarketIssues-PerformanceFebruary2018.pdf>

is scheduled to be filed at FERC in mid-2018. DMM opposes the final CCDEBE proposal that will be filed at FERC for reasons summarized in DMM’s stakeholder comments and memo to the ISO Board on this initiative.²⁷⁴

DMM supports the overall goal of providing greater bidding flexibility while ensuring that bid caps used in mitigation are sufficient to cover each resource’s actual marginal costs. DMM also supports development of a more dynamic approach to mitigation of commitment costs as a way of achieving these goals. While the ISO’s final CCDEBE proposal includes the basic framework for addressing these issues, the proposal still has several significant gaps, implementation uncertainties and risks. These remaining gaps should be addressed before this major market design change is approved and implemented.

Dynamic mitigation of commitment costs

While the ISO’s final CCDEBE proposal includes the basic framework for dynamic mitigation of commitment costs, the proposal still has several significant gaps, implementation uncertainties and risks. These gaps include the following:

- **Economic withholding.** Under the revised final proposal, units that are not committed will often not be subject to mitigation of commitment costs – even if the resource owner has been determined to have structural market power. This means that dynamic mitigation will fail to mitigate economic withholding (e.g., bidding lower cost units at a higher price, so that a higher cost unit must be dispatched).
- **Inter-temporal constraints and gaming.** The ISO’s proposal does not ensure mitigation will be triggered when units are committed or prevented from getting de-committed due to inter-temporal modeling and resource constraints. A specific example of this gap is provided in DMM’s comments on the ISO’s final proposal.²⁷⁵
- **Manual dispatches and intervention by grid operators.** The ISO proposal fails to ensure mitigation for exceptional dispatches or any commitments (or blocking of de-commitments) that occur as a result of various forms of manual intervention in the market dispatch by grid operators. DMM’s experience indicates that in many or most cases when operators cause units to be committed or transitioned, operators have very little choice between different resources to meet reliability or market needs. If such alternatives exist, operators have limited ability to identify and choose the lowest cost option. Thus, the ISO needs to develop additional rules for mitigating commitments (or blocked de-commitments) resulting from exceptional dispatch and other forms of manual intervention by grid operators.

²⁷⁴ Department of Market Monitoring Comments on CCDEBE Proposal, Memo to ISO Board of Governors, Eric Hildebrandt, March 14, 2018. http://www.caiso.com/Documents/Decision_CCDEBEProposal-Department_MarketMonitoringMemo-Mar2018.pdf

Comments on Revised Draft Final Proposal for Commitment Cost and Default Energy Bid Enhancements, Department of Market Monitoring, February 28, 2018. <http://www.caiso.com/Documents/DMMComments-CommitmentCostsandDefaultEnergyBidEnhancementsRevisedDraftFinalProposal.pdf>

²⁷⁵ Comments on Revised Draft Final Proposal for Commitment Cost and Default Energy Bid Enhancements, pp. 18-19.

DMM also notes that relatively complicated software changes, such as the ISO's dynamic mitigation proposal, are subject to significant implementation errors and unexpected performance issues.²⁷⁶ The complexity of dynamic mitigation of commitment costs warrants a more cautious approach to raising the commitment cost bid caps. Thus, DMM also recommends that commitment cost bid caps be raised on a more gradual basis only after the effectiveness of dynamic mitigation is confirmed based on actual operational experience.

Reasonableness thresholds for bid costs used in mitigation

The ISO's proposal also includes rule changes that will allow suppliers to request increases in cost-based bid caps used to mitigate potential market power, gaming and manipulation of bid cost recovery (BCR) payments. Under the proposal, the ISO will screen requests for bid cap increases using *reasonableness thresholds* that add to the headroom already included in bid caps used when mitigation is triggered. Bids under this new reasonableness threshold will be automatically approved and used when mitigation is triggered to determine dispatches and prices.

Currently, bid caps for start-up and minimum load commitment costs include a 25 percent *headroom scalar* above estimated costs. Default energy bids (DEBs) used when energy price mitigation is triggered include a 10 percent headroom scalar that is applied above marginal costs. The ISO proposal will increase the headroom above the current 25 percent and 10 percent scalars already applied to cost-based bids.

Under the proposed changes, the ISO will allow bids used in mitigation to be increased above the current caps by an amount that reflects a gas price that is 10 percent higher than the next-day gas price index currently used in calculating bid caps. The ISO refers to this increase in the gas price used in calculating bid caps as a *fuel volatility scalar*. On Mondays (or the first trade day after a holiday) the ISO will set this fuel volatility scalar to 25 percent.

Thus, the reasonableness thresholds caps for gas-fired units will continue to be based on gas prices in the next-day market that occurs the day prior to each operating day. This very static approach is contrary to the key objective the ISO set for this initiative – i.e., to make bids used in real-time mitigation more reflective of actual marginal costs. Analysis of gas prices by DMM shows that during almost all days the additional 10 to 25 percent headroom provided under the ISO proposal is not justified by actual gas market prices. Meanwhile, on the very few days each year that same-day gas prices rise above the headroom already incorporated in bid caps, the extra headroom incorporated in the new reasonableness thresholds will be well below levels that may be justified.²⁷⁷

DMM continues to recommend a more dynamic approach for adjusting reasonableness thresholds based on gas market trade data available at the start of each operating day. DMM's analysis shows that when the price of gas in the same-day market increases significantly above next-day gas prices used by the ISO, the same-day market at major gas trading hubs is sufficiently liquid and provides a very accurate basis for adjusting the reasonableness thresholds. The more dynamic approach for

²⁷⁶ Recent examples of such errors and unintended performance issues in the real-time market include (1) the flexible ramping product implemented in 2016, (2) the new dynamic energy bid mitigation implemented in 2016 and 2017, and (3) the Aliso Canyon gas constraint implemented in 2016 and 2017.

²⁷⁷ Memo to ISO Board of Governors, Eric Hildebrandt, March 14, 2018. pp. 5-6.
http://www.caiso.com/Documents/Decision_CCDEBEProposal-Department_MarketMonitoringMemo-Mar2018.pdf

determining reasonableness thresholds proposed by DMM will ensure greater market efficiency, reliability and more accurate mitigation than the very static approach being proposed by the ISO.

11.4 System market power

DMM has recommended that the ISO begin to consider various actions that might be taken to reduce the likelihood of conditions in which system market power may exist and to mitigate the impacts of system market power on market costs and reliability.

As noted in this report, DMM's analysis indicates that the ISO system showed signs of becoming less competitive. In 2017, the day-ahead market was not structurally competitive in a growing number of hours and prices reached record highs in some hours. In the real-time market, there were numerous periods of very tight system conditions in which many suppliers were pivotal and bidding reflected non-competitive conditions. Conditions in 2018 are likely to allow additional potential for the exercise of system market power not subject to mitigation. In 2019, these conditions will be further exacerbated by generation retirement, increasing energy bid caps under FERC Order 831, and ISO proposals to increase bid caps used in mitigation.

DMM recognizes that this recommendation involves major market design and policy issues, including the possible development of new market design options to mitigate potential system market power. DMM also recognizes that the competitiveness of the ISO's markets is heavily affected by the procurement decisions of the state's load-serving entities and policies of their local regulatory authorities. Because of the potential severity of the impact of market power, DMM is making this recommendation at this time so that the ISO, stakeholders and regulatory entities can give thorough consideration to this issue and potential options to address it.²⁷⁸

DMM has provided some initial suggestions for actions for reducing and mitigating the potential for system market power that might be considered. These include the following:

- Begin discussion and development of options for system market power mitigation.
- Set local and system resource adequacy requirements sufficiently high to ensure both reliability and reduced likelihood of non-competitive market outcomes.
- Reexamine resource adequacy provisions relating to imports, which are only required to be bid into the day-ahead market (at any price) and do not have any further obligation if not scheduled in the day-ahead energy or residual unit commitment process.
- Eliminate or reduce exemptions to must-offer obligations for resources procured to satisfy resource adequacy requirements or through ISO backstop capacity procurement (RMR and CPM).
- Strengthen the penalties and the enforcement of the penalties for must-offer obligations.
- Carefully track and seek to limit out-of-market purchases of imports at above-market prices, which can encourage economic and physical withholding of available imports (see Section 11.5).

²⁷⁸ Under recently established ISO policies, all recommendations by DMM must be formally submitted in writing to the ISO in order to be considered.

- Closely monitor for potential errors or software issues affecting market power mitigation.²⁷⁹

11.5 Manual dispatches of imports

Exceptional dispatches on the interties are often referred to by the ISO operators as *manual dispatches*. In 2017, these out-of-market dispatches increased significantly. 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. Thus, DMM recommends the ISO closely track and monitor trends in manual dispatches, and seek to limit the use of such out-of-market dispatches. DMM is also recommending that the ISO improve its logging of manual dispatches to ensure proper settlement and allow tracking and monitoring.

11.6 Opportunity cost adders for start-up and minimum load bids

In early 2016 the ISO gained Board approval of several changes to the way that commitment costs for natural gas units are calculated as part of its Commitment Cost Enhancements Phase 3 (CCE3) initiative.²⁸⁰ DMM provided detailed comments on this initiative.²⁸¹

DMM has been very supportive of developing an approach for incorporating any opportunity costs associated with environmental or physical limits on start-ups or run hours into commitment cost bids. However, DMM is not supportive of provisions included in the ISO's proposal that would allow opportunity costs to be calculated based on start-up or run hour limits included in commercial contracts. DMM believes this aspect of the ISO proposal could have the effect of reducing overall market efficiency.

In April 2018, the ISO submitted its CCE3 proposal for allowing opportunity cost bid adders for start-up and minimum load bid costs to FERC for approval. DMM filed comments opposing the exemption included in the ISO's CCE3 proposal to allow opportunity cost adders based on contractual use limits which reflect economic rather than actual environmental or physical limitations.²⁸²

11.7 Flexible ramping product

The flexible ramping product is designed to procure additional ramping capacity to address uncertainty in imbalance demand through the market software. If properly implemented, this product should help increase reliability and efficiency, while reducing the need for manual load adjustments by grid operators. Since implementation of this new feature in November 2016, DMM has raised numerous

²⁷⁹ Specifically, DMM recommends the ISO routinely compare prices and the objective function values in the market power mitigation run compared to market runs. Prices and the objective function value should be lower in the market run than in the market power mitigation run. Higher values in the market run indicate potential errors or issues such as software timing limitations that can undermine the effectiveness of market power mitigation.

²⁸⁰ *Commitment Cost Enhancements Phase 3 Draft Final Proposal*, February 17, 2016: <http://www.caiso.com/Documents/DraftFinalProposal-CommitmentCostEnhancementsPhase3.pdf>.

²⁸¹ *Comments on Commitment Cost Enhancements Phase 3 Draft Final Proposal*, Department of Market Monitoring, March 4, 2016: <http://www.caiso.com/Documents/DMMComments-CommitmentCostEnhancementsPhase3-DraftFinalProposal.pdf>.

²⁸² *Motion to intervene and protest of the Department of Market Monitoring*, ER18-1169. April 13, 2018. http://www.caiso.com/Documents/Apr13_2018_DMMIntervention_Protest-CCEPhase3TariffAmendment_ER18-1169.pdf

concerns and questions about the implementation and performance of the flexible ramping product. DMM has also made numerous recommendations involving corrections and enhancements to this market feature.

Flexible ramping requirements

During 2017, DMM raised concerns to the ISO about the level and pattern of requirements for the flexible capacity being calculated for use in setting the demand curves used to procure flexible capacity. In February 2018, DMM identified numerous specific errors in how the demand curves used to procure flexible capacity have been calculated. DMM has completed a report indicating that these errors caused flexible ramping requirements and procurement to be significantly lower than intended in many hours with relatively high ramping needs, and significantly higher than intended in other hours which tend to have lower ramping needs.²⁸³ The ISO resolved many of these errors in March of 2018.

DMM's analysis shows that the overall impact of these errors on flexible ramping market results was significant. DMM estimates that prices and purchased quantities of upward ramping capacity were lower than intended in up to about half of all 15-minute intervals. During these intervals, the correct requirements averaged almost 400 MW greater than historical procurement on average (i.e., 949 MW compared to 564 MW procured).

In addition to affecting prices, quantities and overall payments for flexible ramping capacity, these errors may have contributed to the pattern of systematic manual load adjustments by grid operators. The systematic under-procurement of flexible ramping capacity during key hours may have increased the frequency of power balance violations.

DMM recommends that the ISO more closely monitor the requirements used in the flexible ramping product. Once corrections are fully implemented, DMM expects that there should be a decreased need for the systematic manual load adjustments made by grid operators in 2017. The ISO may need to consider increasing flexible ramping requirements if grid operators continue to feel additional ramping capacity is needed for reliable operation of the grid and real-time energy market. DMM has provided recommendations concerning the use of manual adjustments to the load used in the imbalance market software in its comments on the ISO's imbalance conformance enhancements proposal.²⁸⁴

Flexible ramping product enhancements

DMM has also recommended that the ISO pursue a variety of enhancements to the current flexible ramping capacity product as it has been designed and implemented.

DMM has recommended that the ISO develop an enhancement to avoid cases in which the current implementation inappropriately lowers system-level flexible ramping product prices and procured

²⁸³ *Flexible Ramping Product Uncertainty Calculation and Implementation Issues*, Kyle Westendorf, Department of Market Monitoring, April 18, 2018

<http://www.caiso.com/Documents/FlexibleRampingProductUncertaintyCalculationImplementationIssues.pdf>

²⁸⁴ *Department of Market Monitoring Comments on Imbalance Conformance Enhancements Proposal*, Memo to ISO Board of Governors, Eric Hildebrandt, May 9, 2018.

http://www.caiso.com/Documents/Decision_ImbalanceConformanceEnhancementsProposal-DMMComments-May2018.pdf

quantities.²⁸⁵ In the initial implementation of the flexible ramping product, demand curves for individual balancing areas were included in the constraint for system-level procurement. DMM believes that this implementation approach leads to system-level procurement of flexible ramping capacity, and associated flexible ramping shadow prices, that are lower than what would be consistent with the system-level flexible ramping demand curves.

This aspect of the flexible ramping product was active throughout the second quarter.²⁸⁶ The ISO implemented a software change on July 13, 2017, to limit the use of demand curves from individual balancing areas to zero when sufficient transfer capability connected the area with system conditions. However, as explained in DMM’s quarterly reports for Q2, Q3 and Q4 2017, the implementation of this enhancement has resulted in market outcomes in which resources providing flexible ramping capacity received lower payments based on the balancing area specific demand curve rather than the system level demand curve. The issue and recommendation were included in DMM’s quarterly reports for Q2, Q3 and Q4 2017.²⁸⁷

11.8 Reliability must-run units

In late 2017, the additional 700 MW of capacity designated as reliability must-run units by the ISO for 2018 filed to provide service under Condition 2 of the ISO’s *pro forma* reliability must-run contract. DMM and numerous other entities filed protests at FERC on the grounds that provisions of Condition 2 of the contract are “economically inefficient, distort overall market prices, undermine the CAISO’s automated market power mitigation procedures, and are unjust and unreasonable for consumers.”²⁸⁸

DMM recommended that the following two basic flaws in the reliability must-run provisions of the ISO tariff for both Condition 1 and Condition 2 must be addressed on an expedited basis.

- The prohibition on RMR capacity under Condition 2 from being offered in the CAISO’s energy market under most conditions must be removed.
- RMR resources on Condition 1 and Condition 2 must be subject to the same must-offer requirement that units are subject to under the resource adequacy program and capacity procurement mechanism.

A related issue in need of change is compensation for reliability must-run units. Schedule F of the current *pro forma* reliability must-run contract allows for recovery of full fixed (sunk) costs plus a 12 percent return on equity. As a result, RMR compensation is inflated above a just and reasonable level.

²⁸⁵ For example, see *Q2 2017 Report on Market Issues and Performance*, Department of Market Monitoring, September 2, 2017, pp. 6, <http://www.caiso.com/Documents/2017SecondQuarterReport-MarketIssuesandPerformance-September2017.pdf>

²⁸⁶ For example, see *Q2 2017 Report on Market Issues and Performance*, Department of Market Monitoring, September 2, 2017, pp. 6, <http://www.caiso.com/Documents/2017SecondQuarterReport-MarketIssuesandPerformance-September2017.pdf>

²⁸⁷ For example, see *Q2 2017 Report on Market Issues and Performance*, Department of Market Monitoring, September 2, 2017, pp. 6, <http://www.caiso.com/Documents/2017SecondQuarterReport-MarketIssuesandPerformance-September2017.pdf>

²⁸⁸ *Motion to Intervene and Protest of the Department of Market Monitoring*, ER18-240-000, November 22, 2017. http://www.caiso.com/Documents/Nov22_2017_DMMMotion_Intervene_Protest-MetcalfEnergyCenterRMRAgreement_ER18-240.pdf

DMM believes that compensating a resource based on its full sunk capital costs (after depreciation) is unjust and unreasonable.

In early 2018, a settlement agreement was reached between Calpine and parties which protested Calpine's filing to operate under Condition 2 of the contract, which included DMM, PG&E and the CPUC. Under the settlement agreement, the almost 700 MW of additional capacity designated as reliability must-run units for 2018 will be bid into the market during all hours. The annual fixed cost recovery provided to the units was also reduced by about \$30 million from over \$76 million to about \$26 million. Under the agreement, Calpine will retain all net market revenues received from operating the unit. DMM actively participated in the settlement negotiations and supported the final agreement.

As noted above, DMM has recommended the ISO address the key flaws in the current contracts on an expedited basis before any more capacity is designated as reliability must-run by the ISO. More generally, DMM also supports a more comprehensive effort to replace or combine the ISO's reliability must-run provisions with the capacity procurement mechanism in the ISO tariff as part of more comprehensive changes to the ISO's backstop capacity procurement authority. DMM has also recommended that reform of the ISO's RMR and CPM provisions should be based on the principle that units needed for local or system reliability which have market power should be compensated based on going forward fixed costs (GFFC) plus a reasonable contribution to sunk fixed costs.²⁸⁹

11.9 Risk-of-retirement capacity procurement mechanism

In late 2017, the ISO filed at FERC to revise its existing risk-of-retirement (ROR) capacity procurement mechanism (CPM) process to allow the ISO to issue CPM designations on the earlier timeline. DMM was supportive of expanding the ISO's authority under the process that would be established in its filing. However, DMM filed comments at FERC opposing the compensation provided to these resources.²⁹⁰

Resources receiving a risk-of-retirement capacity procurement mechanism designation would receive a fixed payment covering all fixed costs (including sunk investment costs) plus a return on equity. In addition, these resources would receive all market revenues that result from participation in the ISO and bilateral energy markets. As explained in DMM's comments at FERC protesting the ISO's filing, this compensation is unjust and reasonable, can create market inefficiencies, and may undermine California's resource adequacy program and the CPM competitive solicitation processes.

In April 2018, FERC rejected the ISO's ROR CPM filing, noting that compensation offered by the ISO under the proposed process is likely to exceed what a resource could earn under a bilateral resource adequacy contract. FERC indicated that this created the potential for "the spring request window to distort prices or otherwise interfere with the bilateral resource adequacy process."²⁹¹

FERC's April 2018 order also included a recommendation by the Commission that the ISO adopt a "holistic, rather than piecemeal, approach" to addressing issues relating to capacity procurement issues.

²⁸⁹ *Review of Reliability Must-Run and Capacity Procurement Mechanism Issue Paper & Straw Proposal*, Comments by Department of Market Monitoring, March 7, 2018. <http://www.caiso.com/Documents/DMMComments-ReviewofReliabilityMust-RunandCapacityProcurementMechanism-IssuePaperandStrawProposal.pdf>

²⁹⁰ *Motion to Intervene and Protest of the Department of Market Monitoring, CPM ROR Enhancements*, ER18-641, February 2, 2018. http://www.caiso.com/Documents/Feb2_2018_DMMIntervention_Protest-RORCPM_ER18-641.pdf

²⁹¹ *Order rejecting tariff revisions CPM ROR Enhancements ER18-641*, April 12, 2018. http://www.caiso.com/Documents/Apr12_2018_OrderRejectingTariffRevisions-CPMROREnhancements_ER18-641.pdf

These “include (1) revisiting the issue of the adequacy of CPM and RMR compensation; (2) evaluating whether both risk of retirement CPM and RMR need to be retained as separate backstop mechanisms; (3) examining the timeline and eligibility requirements for issuing risk of retirement CPM.”²⁹²

DMM supports the general approach suggested by FERC. However, as noted above, DMM has recommended the ISO address the key flaws in the current reliability must-run contracts on an expedited basis before any more capacity is designated as RMR by the ISO.

11.10 Reliability must-run and capacity procurement mechanism initiative

The ISO initiated a stakeholder process in 2018 to consider changes to the reliability must-run and capacity procurement mechanism provisions of the ISO tariff.²⁹³ The ISO’s current plan for this stakeholder process appears to be limited in the near term to reviewing whether RMR contracts should have must-offer obligations, and does not appear to include proposed changes in RMR or CPM compensation until at least 2019.²⁹⁴

DMM supports the general approach suggested by FERC in its order rejecting the ISO’s ROR CPM proposal, under which the ISO’s RMR provisions would be replaced or combined with the capacity procurement mechanism in the ISO tariff as part of more comprehensive changes to the ISO’s backstop capacity procurement authority.

DMM has noted that the ISO’s first option for procuring additional capacity needed to meet reliability requirements – the capacity procurement mechanism – is voluntary and can be declined by suppliers with local market power. This could undermine the capacity procurement mechanism if suppliers view reliability must-run compensation to be more favorable than capacity procurement mechanism compensation.

Thus, DMM recommends that it is imperative that the ISO redesigns compensation that is currently based on Schedule F of the *pro forma* reliability must-run contract in an expeditious manner. Schedule F is used in determining compensation for some units under RMR and CPM contracts, and provides for recovery of full fixed (sunk) costs plus a 12 percent return on equity. Under the capacity procurement mechanism, units can receive this full fixed cost payment and still keep all net market revenues earned from operating in the market.

DMM has recommended that the ISO not base its reliability must-run (or other backstop procurement) compensation policy on the incorrect assertion that FERC is requiring ISOs to compensate these units based on the units’ full sunk capital costs (minus depreciation).²⁹⁵ Instead, the ISO should work with DMM and other stakeholders to establish the appropriate theory for determining the fixed cost

²⁹² *Order rejecting tariff revisions CPM ROR Enhancements ER18-641*, April 12, 2018.

http://www.caiso.com/Documents/Apr12_2018_OrderRejectingTariffRevisions-CPMROREnhancements_ER18-641.pdf

²⁹³ *Review of Reliability Must Run and Capacity Procurement Mechanism, Issue Paper and Straw Proposal for Phase 1 Items*, California ISO, January 23, 2018. <http://www.caiso.com/Documents/IssuePaperandStrawProposal-ReviewReliabilityMustRunandCapacityProcurementMechanism.pdf>

²⁹⁴ *Review of Reliability Must Run and Capacity Procurement Mechanism, Issue Paper and Straw Proposal for Phase 1 Items*, California ISO, January 23, 2018. <http://www.caiso.com/Documents/IssuePaperandStrawProposal-ReviewReliabilityMustRunandCapacityProcurementMechanism.pdf>

²⁹⁵ *Review of Reliability Must-Run and Capacity Procurement Mechanism Issue Paper & Straw Proposal*, Comments by Department of Market Monitoring, pp.2-3.

compensation for these and other backstop procurement resources. DMM has recommended that reform of the ISO's RMR and CPM provisions should be based on the principle that units needed for local or system reliability which have market power should be compensated based on going forward fixed costs (GFFC) plus a reasonable contribution to sunk fixed costs.²⁹⁶

11.11 Resource adequacy

California has now maintained adequate supply capacity reserves under the state's resource adequacy program and bilateral long-term procurement process for more than a decade. However, a number of structural changes are creating the need for significant changes in this resource adequacy framework. As summarized in a recent report by CPUC, these changes include the following:²⁹⁷

- Reliance on a growing amount of capacity from intermittent renewable resources, which has limited availability during many hours and increases the need for overall system flexibility during most hours.
- The need to repower or retire gas-fired power plants that rely on once-through cooling (OTC) technology, and an increasing number of resources that approach their design life in the coming years.
- The rapid expansion of community choice aggregators (CCAs), which appear to be reducing long-term contracting and complicates the process for procurement by load-serving entities of capacity needed to meet local resource adequacy requirements.

The CPUC has identified a number of options for addressing these issues, including increased coordination of resource adequacy procurement with integrated resource planning (IRP) efforts and through a multi-year resource adequacy framework. Under one of the options, distribution utilities would serve as the central buyer for residual local resource adequacy requirements.

DMM strongly supports these efforts and views the options outlined by the CPUC as potentially effective steps in addressing the current gaps and problems with the state's resource adequacy framework. The following sections provide a discussion and recommendations regarding elements of the overall resource adequacy framework affected by ISO market rules and mechanisms.

Local capacity area requirements

The ISO has defined 10 separate local capacity areas for which local reliability requirements are established under the state's resource adequacy program. In most of these areas, a high portion of the available capacity is needed to meet peak reliability planning requirements. One or two entities own most of the generation needed to meet local capacity requirements in each of these areas. As a result, the potential for locational market power in these load pockets is significant. The capacity procurement mechanism and reliability must-run provisions of the ISO tariff play a critical role in mitigating locational market power in the state's resource adequacy framework by providing the ISO with backstop

²⁹⁶ *Review of Reliability Must-Run and Capacity Procurement Mechanism Issue Paper & Straw Proposal*, Comments by Department of Market Monitoring, March 7, 2018. <http://www.caiso.com/Documents/DMMComments-ReviewofReliabilityMust-RunandCapacityProcurementMechanism-IssuePaperandStrawProposal.pdf>

²⁹⁷ *Current Trends in California's Resource Adequacy Program*, Energy Division Working Draft Staff Proposal, California Public Utilities Commission, February 16, 2018. <http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457193>

procurement mechanisms for capacity needed to meet reliability needs, as discussed in the following section.

In addition to the capacity requirements set by the ISO for each local area, additional reliability requirements exist for numerous sub-areas within each local capacity area. Some of these require that capacity be procured from specific individual generating plants. Others involve complex combinations of units that have different levels of effectiveness at meeting the reliability requirements. These sub-area requirements create a gap in the local resource adequacy process, since load-serving entities can procure enough capacity in a local area to meet their individual and collective requirements, but the ISO may need to procure additional capacity to meet the actual capacity requirements in the sub-area under the CPM or RMR provisions of the ISO tariff. Additional gaps are due to enforcement of local reliability requirements by transmission access charge area which has created significant shortfalls in several local capacity areas.

One option being considered by the CPUC is a multi-year resource adequacy framework under which distribution utilities would serve as the central buyer for residual local resource adequacy requirements. This option appears to provide a means for addressing the gap currently caused by the sub-area requirements which may not be met by local area requirements set by the ISO for each area. However, this would require the ISO to identify these sub-area and area requirements over a multi-year period.

Backstop procurement mechanisms

The capacity procurement mechanism and reliability must-run provisions of the ISO tariff play a critical role in mitigating locational market power in the state's resource adequacy framework by providing the ISO with backstop procurement mechanisms for capacity needed to meet reliability needs. However, to effectively mitigate market power, compensation under these provisions must be just and reasonable for consumers. Also, if total compensation under these provisions exceed levels that would be earned in competitive markets, then units with market power will demand higher compensation or withhold capacity in the resource adequacy market. Thus, compensation and other provisions must be carefully designed to avoid undermining the resource adequacy framework.

In 2017, the gaps and market power in the current local resource adequacy process became more evident. As noted in Section 11.8, three newer more efficient gas units representing almost 700 MW were designated by the ISO for reliability must-run service beginning in 2018.²⁹⁸ DMM and numerous other entities filed protests at FERC on the grounds that provisions of Condition 2 of the contract are economically inefficient, distort overall market prices, undermine the ISO's automated market power mitigation procedures, and are unjust and unreasonable for consumers. DMM also protested the ISO's proposed expansion of CPM provisions on the grounds that the proposed compensation would be unjust and unreasonable, and would undermine the resource adequacy framework.

DMM supports the general approach suggested by FERC in its order rejecting the ISO's risk-of-retirement capacity procurement mechanism proposal, under which the ISO's reliability must-run provisions would be replaced or combined with the capacity procurement mechanism in the ISO tariff as part of more comprehensive changes to the ISO's backstop capacity procurement authority. DMM has recommended that reform of the ISO's RMR and CPM provisions should be based on the principle that

²⁹⁸ These included 593 MW of capacity from the combined cycle Metcalf Energy Center, and 94 MW of peaking capacity owned by Calpine.

units needed for local or system reliability which have market power should be compensated based on going forward fixed costs (GFFC) plus a reasonable contribution to sunk fixed costs.

Resource adequacy requirements

As noted in this report, DMM's analysis indicates that the ISO system showed signs of becoming less competitive. DMM has recommended that the ISO begin to consider various actions that might be taken to reduce the likelihood of conditions in which system market power may exist and to mitigate the impacts of system market power on market costs and reliability. Options suggested by DMM include setting local and system resource adequacy requirements sufficiently high to ensure both reliability and reduced likelihood of non-competitive market outcomes. DMM also suggests the ISO consider strengthening the penalties and the enforcement of the penalties for must-offer obligations.

Currently, resource adequacy requirements do not directly mitigate market power, since suppliers can meet must-offer requirements by bidding capacity in at very high prices up to the \$1,000 bid cap. However, units bid into the market are subject to mitigation when local market power mitigation procedures are triggered by congestion on uncompetitive constraints. Thus, the combination of a must-offer requirement stemming from a resource adequacy obligation combined with bid mitigation when uncompetitive conditions exist in the ISO system could be utilized as a mechanism for system level market power mitigation.

Resource adequacy imports

DMM recommends the ISO re-consider rules concerning resource adequacy requirements met by imports. Resource adequacy imports are only required to be bid into the day-ahead market. Imports can be bid at any price and do not have any further obligation if not scheduled in the day-ahead energy or residual unit commitment process. In our last three annual reports, DMM has expressed concern that these rules could 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.²⁹⁹ For example, as noted in prior reports, resource adequacy imports could be routinely 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.

Flexible resource adequacy and new day-ahead reserve product

DMM has noted that the ISO's continued efforts to improve flexible resource adequacy criteria and must-offer obligation requirements include some improvements over the initial FRAC-MOO design. However, DMM has also noted that the ISO should carefully consider the design of the real-time must-offer obligation for flexible RA resources together with the design of the day-ahead imbalance reserve product being developed by the ISO.³⁰⁰ The day-ahead imbalance reserve product being developed will procure additional flexible capacity for the real-time markets. The ISO has not fully specified the design of the imbalance reserve product, but the imbalance reserve product will also give resources the

²⁹⁹ 2016 Annual Report on Market Issues and Performance, pp.251-252.
2015 Annual Report on Market Issues and Performance, p.239.
2014 Annual Report on Market Issues and Performance, pp.187-188.

³⁰⁰ Flexible Resource Adequacy Criteria and Must Offer Obligation Phase 2 Revised Draft Framework Proposal, Comments by Department of Market Monitoring, March 13, 2018 <http://www.caiso.com/Documents/DMMComments-RevisedDraftFlexibleCapacityFrameworkProposal.pdf>

obligation to economically bid into the real-time market. The ISO should carefully consider the design of the real-time must-offer obligation for flexible RA resources together with the design of the day-ahead imbalance reserve product, and ensure that the incentives and requirements for these two market design features are clear and are complementary.

11.12 Infeasible demand response dispatches in real-time market

DMM's 2016 annual report highlighted how proxy demand response resources have begun to get dispatched and set prices in the 5-minute real-time market even though most of these resources are not capable of responding to these dispatches.³⁰¹ As explained in DMM's last annual report, proxy demand response resources used to meet resource adequacy requirements have a must-offer requirement, and often get scheduled in the residual unit commitment process. In the real-time market, these resources can be committed because of their \$0/MWh cost at minimum load, even if these resources have a very high energy bid price.

Such dispatches can and do set real-time energy prices in local areas or at the system level. This outcome is inefficient when a resource is unable to respond to such dispatches because of the physical nature of the resource or the structure of the underlying demand response program. For intervals of system power balance constraint relaxation where the load bias limiter is active, the incremental dispatch of a non-responsive resource, with an energy bid at or near the bid cap, may also undermine the intent of the ISO's imbalance conformance limiter (formerly called the *load bias limiter*).

DMM's 2016 annual report recommended that the ISO consider market modeling enhancements which appropriately reflect physical limitations of resources when determining dispatch and market pricing, rather than revising market rules to exempt selected resources from obligations faced by similarly positioned resources. In 2017, proxy demand response resources bid at or near the \$1,000/MW bid cap that cannot respond to 5-minute dispatches continued to be dispatched and be eligible to set prices in the real-time market with a relatively high degree of frequency.³⁰² To address this issue, the ISO has proposed to expand bidding options for demand response resources in the energy storage and distributed energy resources phase 3 stakeholder process.³⁰³ DMM supports the ISO's efforts to address this issue in that initiative to ensure reliability and the integrity of real-time market pricing.

11.13 Fast-start pricing

FERC issued a Notice of Proposed Rulemaking (NOPR) on Fast-Start Pricing in December 2016.³⁰⁴ The NOPR would require that ISOs add start-up and minimum load bid costs to energy bids for fast-start resources and allow these costs to set market energy prices. DMM and the ISO submitted detailed

³⁰¹ *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2017, pp. 259-262. <http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf>

³⁰² *Comments on the Imbalance Conformance Enhancement Straw Proposal*, Department of Market Monitoring December 20, 2017 <http://www.caiso.com/Documents/DMMComments-ImbalanceConformanceEnhancements-IssuePaper-StrawProposal.pdf>

³⁰³ *Energy storage and distributed energy resources phase 3 stakeholder process*: http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResources.aspx

³⁰⁴ 157 FERC ¶ 61,213, *Notice of Proposed Rulemaking: Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. RM17-3-000, December 15, 2016.

comments to the Commission opposing any requirement that the ISO adopt the proposed fast-start pricing modifications.³⁰⁵

The central issue addressed in the NOPR is not a new issue. The question of the optimal pricing system to use when discrete or lumpy costs result in decreasing average costs has been discussed in economic literature for over 70 years. When discrete costs result in average costs that decrease with output, the type of two-part pricing system used by the ISO is just, reasonable and efficient. The ISO sets locational marginal prices based on marginal production costs. The ISO provides bid cost recovery payments made to compensate resources for any discrete commitment costs that are not recovered through marginal cost pricing. DMM strongly recommended that the Commission should not undermine marginal cost pricing by requiring the ISO to allow prices to be set by the average cost of fast-start resources.

FERC withdrew its NOPR in late 2017 based on comments received that “question whether the proposed reforms would bring sufficient value in all RTOs/ISOs and argued for regional flexibility.”³⁰⁶ However, the Commission indicates it “continue[s] to believe that improved fast-start pricing practices have the potential to achieve the goals outlined in the NOPR,” and “will pursue the goals of the NOPR through section 206 actions involving NYISO, PJM, and SPP.”

As the Commission continues to consider the general issue of whether commitment costs should be allowed to set prices, DMM believes that these fundamental principles of locational marginal pricing should be maintained as a core aspect of electricity market design nationwide.³⁰⁷

³⁰⁵ *Comments of the Department of Market Monitoring for the California Independent System Operator*, Docket No. RM17-3-000, February 28, 2017: http://www.caiso.com/Documents/Feb28_2017_DMMComments-Fast-StartPricingNOPR_RM17-3.pdf.

³⁰⁶ *Withdrawal of Notice of Proposed Rulemaking and Termination of Rulemaking Proceeding*, RM17-3-000, December 21, 2017.

³⁰⁷ *Comments of the Department of Market Monitoring for the California Independent System Operator*, Docket No. RM18-34-000, February 9, 2018, <http://www.caiso.com/Documents/DMMcommentsonFERC206proceedingsonPJMFast-StartPricingEL18-34.pdf>