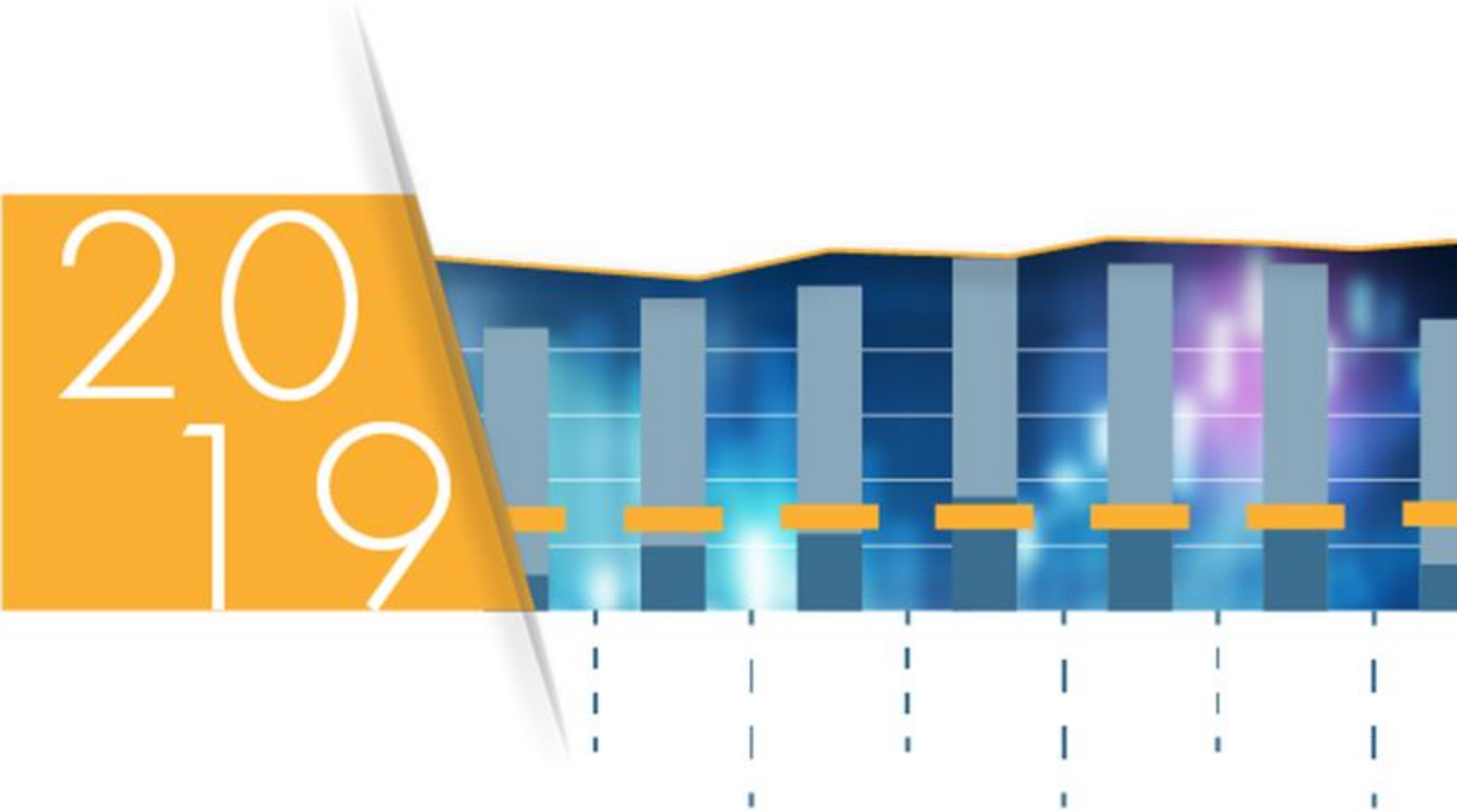
2019

ANNUAL REPORT ON MARKET ISSUES & PERFORMANCE



California ISO

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Executive Summary

This annual report provides analysis and recommendations by the Department of Market Monitoring (DMM) on market issues and performance of California's wholesale energy markets and the Western Energy Imbalance Market (EIM). The report finds that the ISO and energy imbalance markets continued to perform efficiently and competitively in 2019. Other key highlights include the following:

- **The total estimated wholesale cost of serving California ISO load in 2019 dropped by 17 percent, driven by 10 percent decrease in natural gas.** Total wholesale costs for the ISO footprint were about $8.8 billion or about $41/MWh. After adjusting for lower natural gas costs and changes in greenhouse gas prices, wholesale electric costs per MWh decreased by about 10 percent.

- **System loads were low, continuing a trend of decreasing loads since 2011**. Summer load in the ISO system peaked at 44,301 MW, well below the 1-in-2 year load forecast and the lowest peak load since 2003. Total ISO system energy was 2.5 percent less than 2018 due in part to increases in behind-the-meter solar generation, continued initiatives to improve energy efficiency, and lower statewide temperatures.

- **The ISO's energy markets were competitive in 2019**. The combination of low load and low gas prices with the growth in low marginal cost generation supported competitive market outcomes. Overall, wholesale energy prices were about equal to competitive baseline prices DMM estimates would result under competitive conditions.

- **Prices in the day-ahead market were higher than real-time prices**, but the difference was less than in recent years. Lower prices in the real-time market were driven in part by additional supply from renewable generation and other balancing areas available in real time. Real-time prices were also lower in many hours due to manual adjustments made to the hour-ahead load forecast and additional energy from out-of-market unit commitments and energy dispatches issued after the day-ahead market.

- **Expansion of the western energy imbalance market (EIM) helped improve the overall structure and performance of the real-time market** in the ISO and other participating balancing areas. In April 2019, one new market participant (the Sacramento Municipal Utility District in the Balancing Area of Northern California) joined the energy imbalance market. The combined ISO and EIM footprint peaked at over 79 GW, accounting for over half of load in the Western Energy Coordinating Council.

- **Payouts to congestion revenue rights sold in the ISO's auction exceeded auction revenues by over $22 million in 2019**. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge (TAC). Losses from congestion revenue rights sold in the auction totaled about $100 million in 2017 and $131 million in 2018.

- **In response to systematic losses from congestion revenue right auction sales since 2009, the ISO instituted significant changes to the auction starting in 2019.** The reduction in losses from the auction in 2019 resulted from a combination of the changes implemented by the ISO, along with a significant drop in day-ahead market congestion. In 2019 day-ahead congestion revenues totaled about $354 million, compared to about $628 million in 2018. Losses from auctioned congestion revenue rights totaled about 6 percent of total day-ahead congestion revenue in 2019 compared to about 21 percent of congestion revenue in 2018.

Several other factors contributed to decreased wholesale energy costs in 2019:

- **Ancillary service costs decreased** to $148 million, down from $177 million in 2018. Decreased costs were driven by lower load and a 10 percent decrease in natural gas prices compared to 2018.
- **Bid cost recovery payments in the ISO decreased by about 20 percent but remained high by longer term historical standards.** These uplift payments totaled $123 million, or about 1.4 percent of total energy costs, compared to $150 million in 2018. This represents the second highest level since 2011. Uplift payments for units in the energy imbalance market totaled about $10 million in 2019, about $1.5 million lower than in 2018.
- **Total above-market costs due to exceptional dispatches issued by ISO grid operators decreased** to about $29 million from $52 million in 2018, despite higher volumes. About $18 million of these payments were for units committed via exceptional dispatch. Bid mitigation, which was applied to some exceptional dispatches for energy, avoided about $8.3 million in additional out-of-market costs in 2019.
- **Total real-time imbalance offset costs decreased by 23 percent to $103 million.** About $97 million of these costs were from congestion offset costs. As in 2018, these congestion offset costs were caused largely by persistent and significant reductions in constraint limits made by grid operators in the 15-minute market relative to higher limits used in the day-ahead market.
- **Locational price differences due to congestion decreased** in 2019, particularly on constraints associated with major transmission line limits separating northern and southern California. In the real-time markets, EIM transfer constraint congestion had a far greater impact on prices than internal constraint congestion in all areas outside of the ISO.
- **Net profits paid to convergence bidders totaled around $37 million**. Virtual supply bids were profitable with day-ahead prices higher than real-time prices over much of the year.

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

- Gas capacity retiring from the market was largely replaced with renewable resources. The ISO anticipates a continued increase in renewable generation in the coming years to meet state goals.
- No new batteries were added to the ISO's fleet in 2019, with total installed capacity remaining about 136 MW. Most battery capacity participating in ISO markets is located in locally constrained areas.
- Costs for capacity procured under the ISO's two backstop capacity procurement mechanisms (reliability must-run contracts and the capacity procurement mechanism) decreased from $161 in 2018 to $13 million in 2019, or from $0.73/MWh to $0.06/MWh of system load.
- The market for capacity needed to meet local resource adequacy requirements continues to be structurally uncompetitive in most local areas.
- For more than a decade, California has relied 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. However, a number of structural changes, such as the increase in load served by community choice aggregators (CCAs), are driving the need for significant changes in this resource adequacy framework.

Total wholesale market costs

The total estimated wholesale cost of serving load in 2019 was about $8.8 billion or about $41/MWh. This represents a decrease of about 17 percent from wholesale costs of about $49/MWh in 2018. The decrease in electricity prices was driven mainly by a decrease in spot market natural gas prices of about 10 percent.[1] After normalizing for changes in natural gas prices and greenhouse gas compliance costs, DMM estimates that total wholesale energy costs decreased by about 10 percent.[2]

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

- Decreased prices for natural gas, especially in Southern California;
- Reduced load;
- Increased production from both hydroelectric and solar resources; and
- Reduced costs for capacity procured under reliability must-run contracts and the capacity procurement mechanism.

Figure E.1 Total annual wholesale costs per MWh of load (2015-2019)

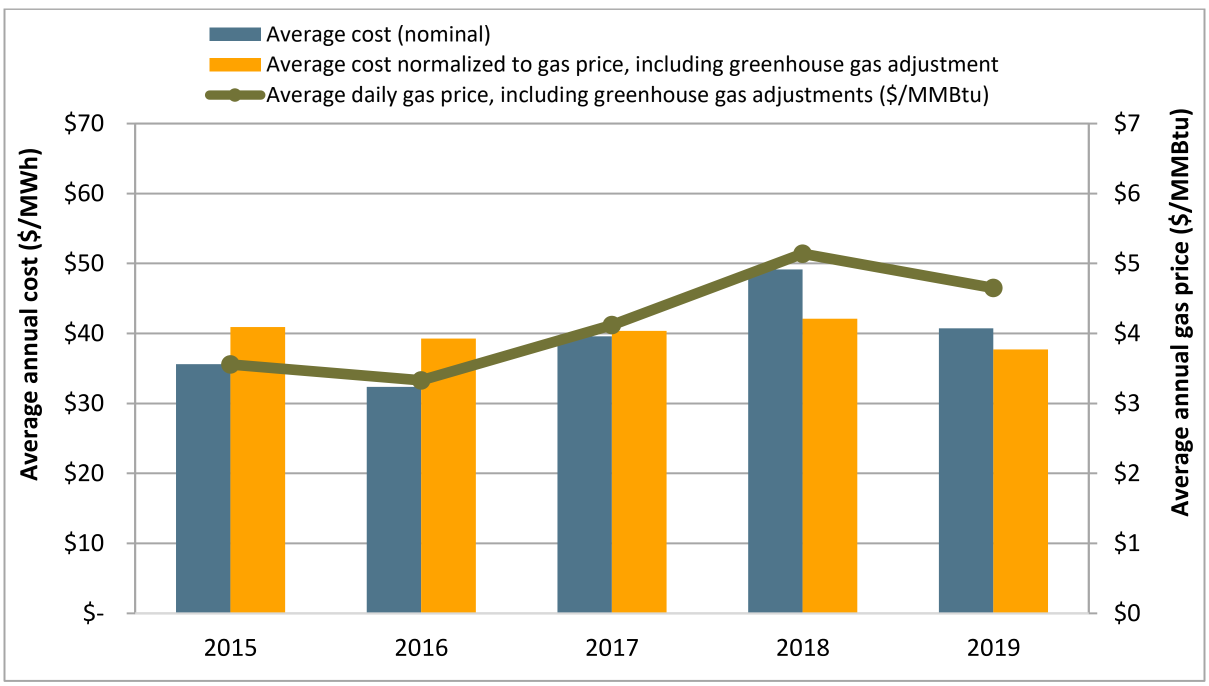


Figure E.1 shows total estimated wholesale costs per megawatt-hour of system load from 2015 to 2019. Wholesale costs are provided in nominal terms (blue bar), and after being normalized for changes in natural gas prices and greenhouse gas compliance costs (gold bar). The green line represents the annual

[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 1.2.8. Gas prices are normalized to 2010 prices.

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.

Energy market prices

Day-ahead and real-time market prices decreased in 2019, driven primarily by a decrease in natural gas prices and moderate system conditions, especially in the third and fourth quarters of the year. Figure E.2 and Figure E.3 highlight the following:

- Energy market prices remained high in the first quarter of 2019, continuing the trend from the second half of 2018. This was primarily caused by high gas prices at SoCal Citygate, PG&E Citygate and Northwest Sumas gas hubs during February. Gas prices dropped in the second quarter but increased at some hubs in the third and fourth quarter, which contributed to steadily increasing average energy market prices.
- Prices in the day-ahead were slightly higher than 15-minute real-time prices, on average, but the day-ahead premium was lower than in recent years. Day-ahead energy prices averaged about $38/MWh, 15-minute prices were about $37.5/MWh, and 5-minute prices were about $37/MWh.
- 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)

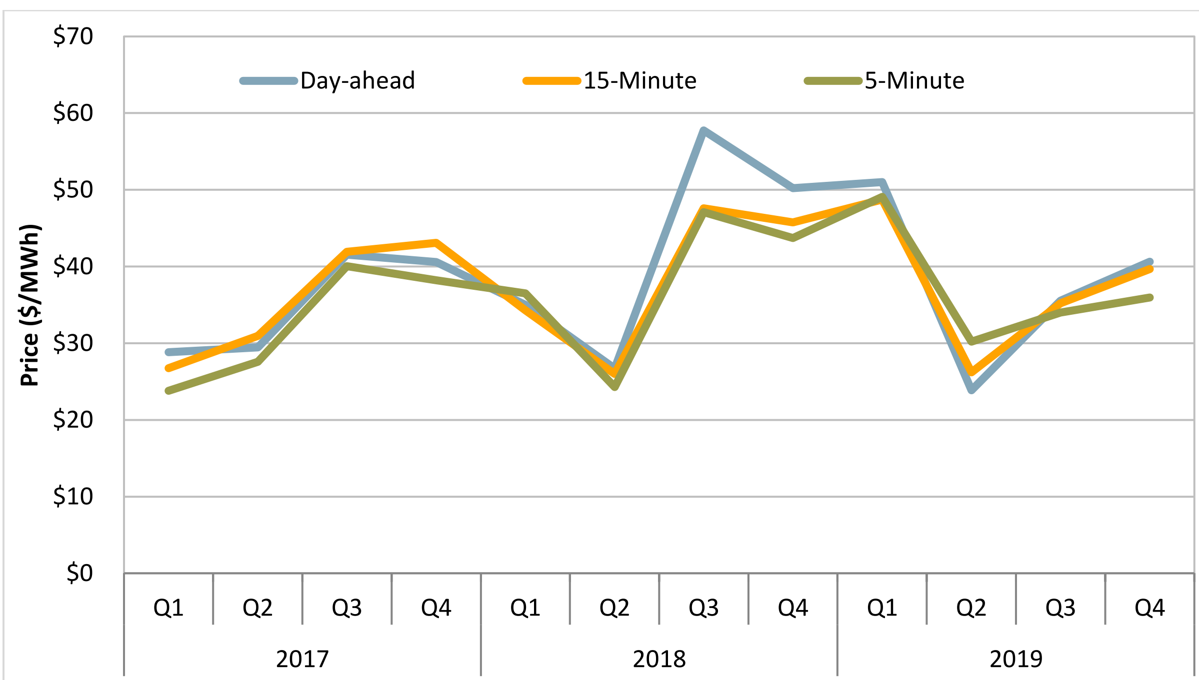
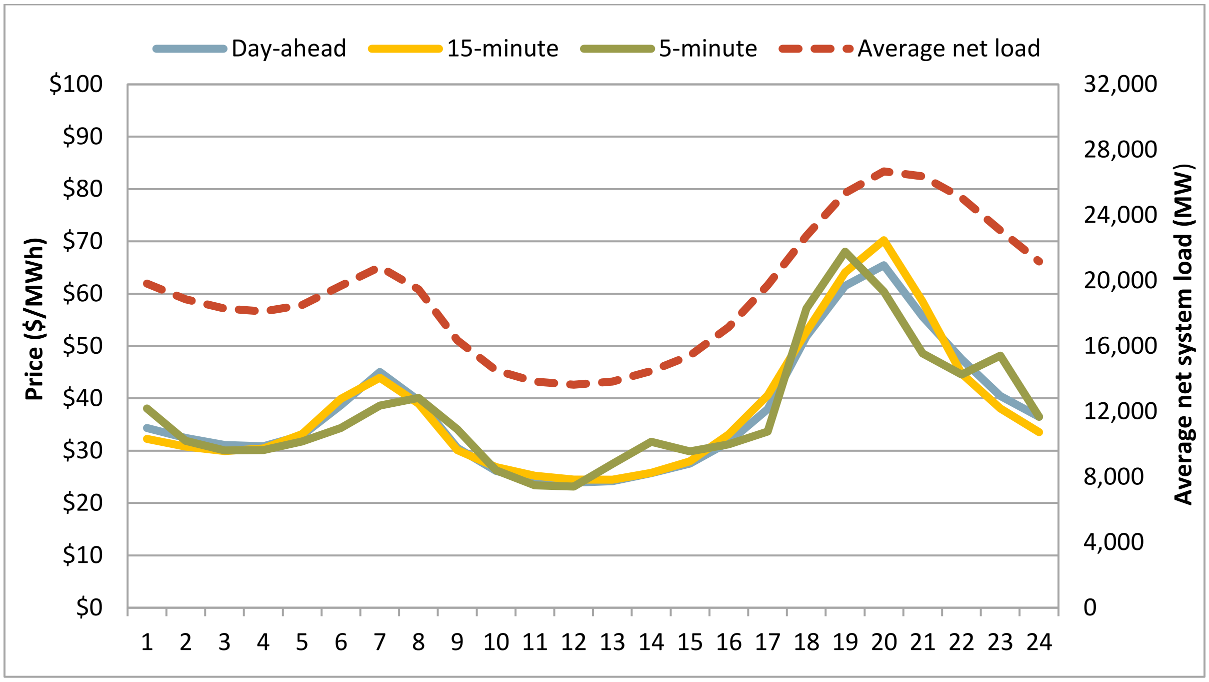


Figure E.3 Hourly system energy prices (2019)



Market competitiveness

Prices in the ISO's energy markets were competitive in 2019. The combination of low load and low gas prices with the growth in low marginal cost generation supported a competitive outcome. Overall, wholesale energy prices were about equal to competitive baseline prices DMM estimates would result under perfectly competitive conditions.

The competitiveness of overall market prices can be assessed based on the *price-cost markup*, which represents a comparison of actual market prices to an estimate of prices that would result in a highly competitive market in which all suppliers bid at or near their marginal costs. DMM estimates competitive baseline prices by re-simulating the market after replacing the market bids of all gas-fired units with the lower of their submitted bids or their default energy bids (DEB). This methodology assumes competitive bidding of price-setting resources, and is calculated using DMM's version of the actual market software.[3]

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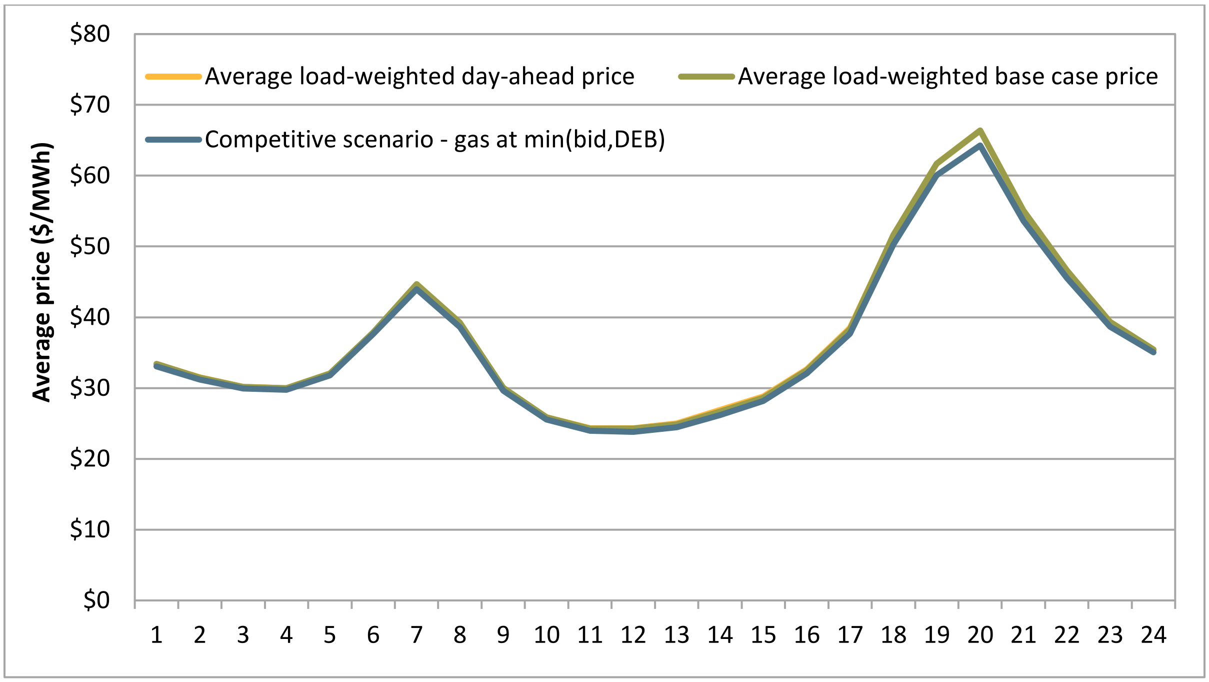
[3] In previous years, the competitive baseline was a scenario where bids for gas-fired generation were set to their default energy bids, convergence bids were removed, and system demand was set to actual system load. This tended to overestimate the competitive baseline price, because a significant amount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

DMM estimates an average price-cost markup of $0.71/MWh or just under 2 percent, as shown in Figure E.4. This slight positive markup indicates that prices have been very competitive, overall, for the year.[4]

Figure E.4 Comparison of competitive baseline with hourly day-ahead prices (Jan-Dec)



Ancillary services

Ancillary service costs decreased to $0.69/MWh from $0.80/MWh in 2018, but increased from 1.62 to 1.68 as a percent of total wholesale energy cost. Total ancillary service costs decreased to $148 million down from $177 million in 2018. Decreased costs were driven primarily by lower load and a 10 percent decrease in natural gas prices compared to 2018.

Regulation requirements increased while operating reserve requirements decreased. Regulation down requirements increased 6 percent to 430 MW and regulation up requirement increased 8 percent to 350 MW, relative to 2018. Both regulation requirements increased in 2018 as well. Requirements for regulation down exceeded regulation up in all hours. Average combined requirements for spinning and non-spinning operating reserves decreased by 15 percent from the previous year to about 1,600 MW.

The frequency of ancillary service scarcity intervals increased, but remained low. There were 194 intervals in the 15-minute market with ancillary service scarcity, with most of them for regulation up or regulation down. In comparison, there were 189 scarcity instances in 2018 and 54 in 2017. Resources failed about 20 percent of ancillary service performance audits and unannounced compliance tests in 2019, a rate of failure comparable to 2018.

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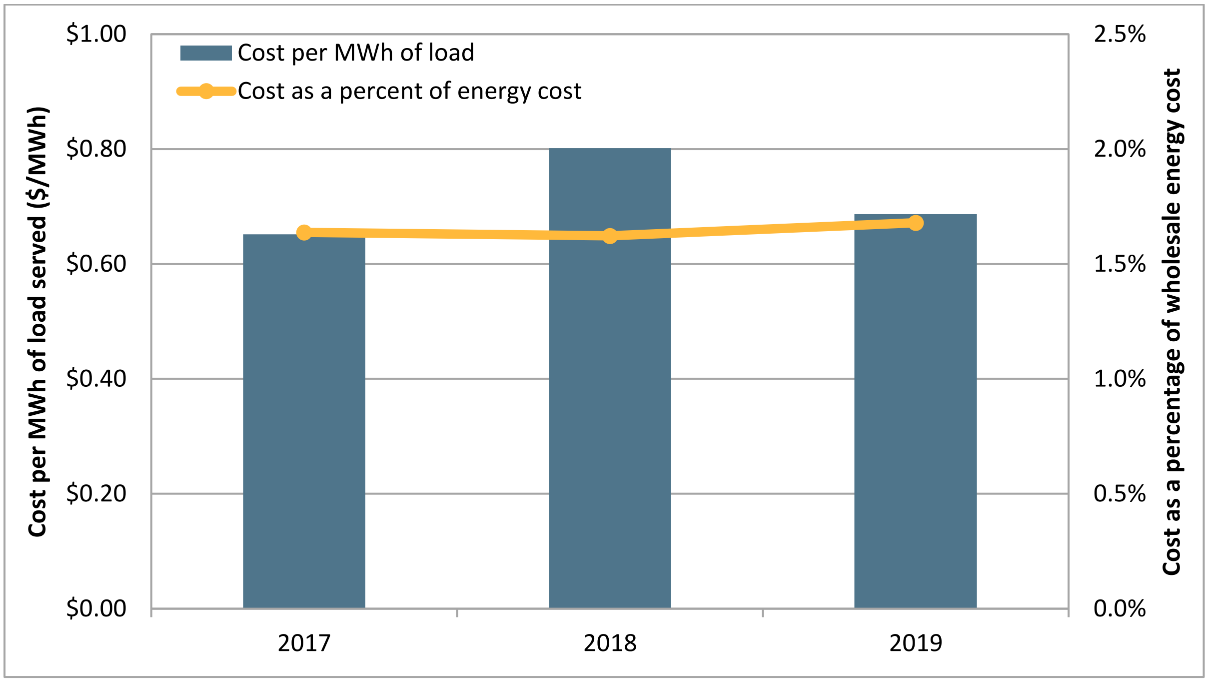
4 DMM calculates the price-cost markup index as the percentage difference between base case market prices and prices resulting under this competitive baseline scenario. For example, if base case prices averaged $55/MWh and the competitive baseline price was $50/MWh, this would represent a price-cost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

Provision of ancillary services from limited energy storage resources continued to increase. Limited energy storage resources include batteries and other limited devices. Average hourly procurement from these resources for regulation increased from around 101 MW in 2018 to 166 MW in 2019, or around 21 percent of regulation requirements.

Figure E.5 Ancillary service cost as a percentage of wholesale energy cost



Bid cost recovery payments

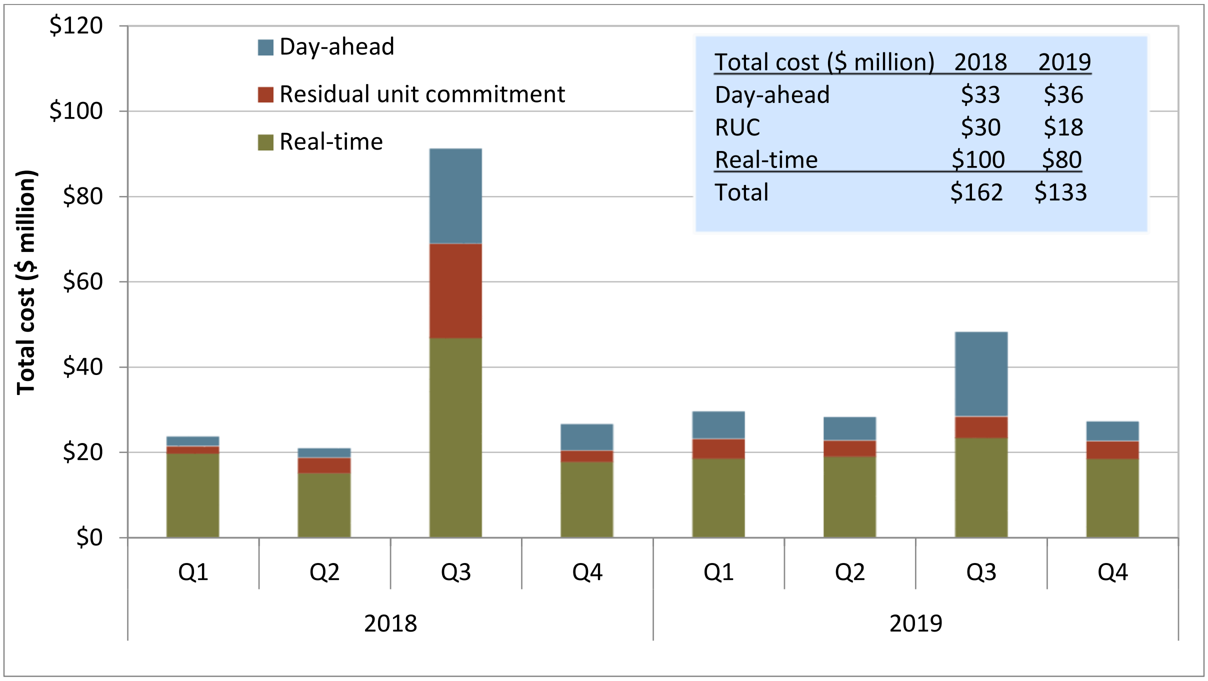
Generating units are eligible to receive bid cost recovery payments if total market revenues received over the course of a day do not cover the sum of all the unit's accepted bids. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch.

Figure E.6 provides a summary of total estimated bid cost recovery payments in 2018 and 2019. Bid cost recovery payments for units in the ISO and energy imbalance market totaled around $123 million and $10 million, respectively. Although lower than 2018, this represents the second highest level of bid cost recovery payments since 2011, and a significant increase from 2017, when bid cost recovery totaled $108 million.

Bid cost recovery payments represented about 1.4 percent of total ISO wholesale energy costs in 2019. As shown in the figure, the decrease in total bid cost recovery payments in 2019 from 2018 resulted largely from decline in payments in the third quarter of 2019 which can be attributed to low loads and lower gas prices in the third quarter.

Two thirds of the ISO's total bid cost recovery payments, approximately $82 million, were allocated to resources that bid their commitment costs above 110 percent of their reference commitment costs. About 93 percent of these payments are for resources bidding at or near the 125 percent bid cap for proxy commitment costs.

Figure E.6 Bid cost recovery payments



Exceptional dispatches

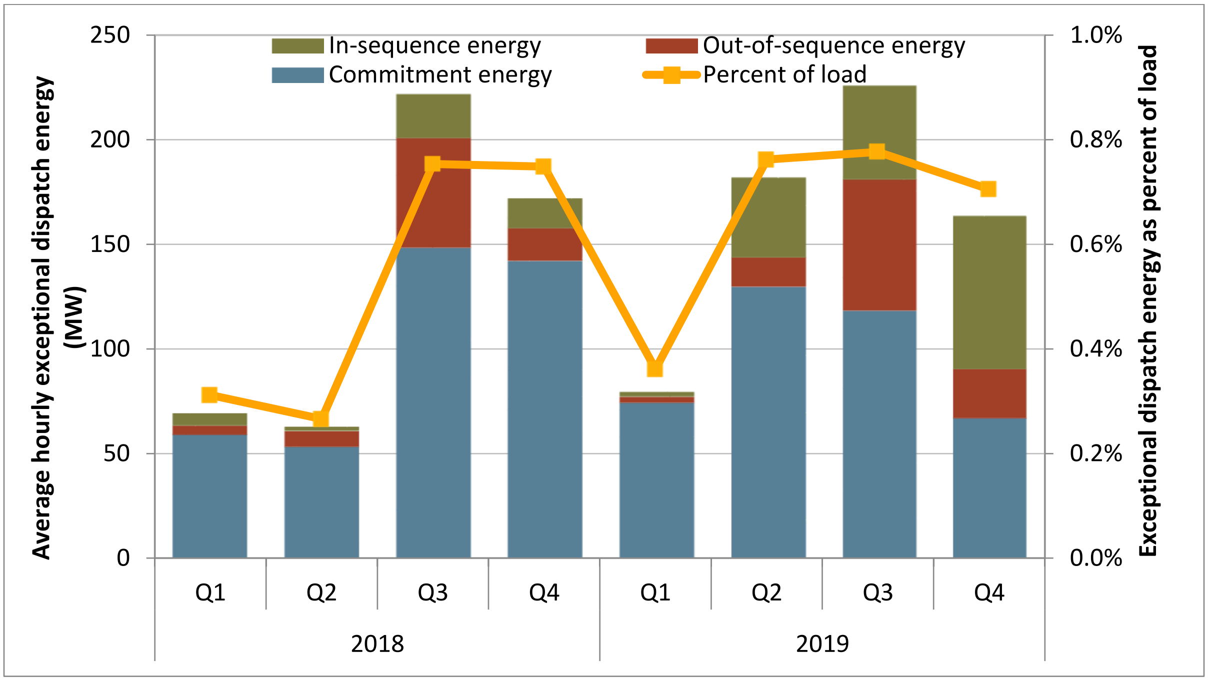
Exceptional dispatches are instructions issued by grid operators when the automated market optimization is not able to address particular reliability requirements or constraints. These dispatches are sometimes referred to as *manual* or *out-of-market* dispatches. Over the past several years, the ISO 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 resulting from all types of exceptional dispatch grew in 2019, but continued to account for a relatively low portion of total system load, as shown in Figure E.7. The growth in total energy from exceptional dispatches in 2019 was driven by increases of in-sequence energy exceptional dispatch at prices below the market clearing price, largely issued for unit testing.

- Total above-market costs due to exceptional dispatch decreased to about $29 million in 2019 from $52 million in 2018. Although exceptional dispatches to commit units to operate at minimum load fell by only 4 percent, the cost of this category fell from $40.6 million in 2018 to $17.7 million in 2019.

- In 2019, ISO operators issued a new category of exceptional dispatch, the “RA Max” exceptional dispatch, up to the maximum of resource adequacy contracts. These exceptional dispatches are issued to increase the amount of ramping capacity available to meet the evening net load ramp and respond to other uncertainties in real-time, the same issues that the flexible ramping product is designed to address.

Figure E.7 Average hourly energy from exceptional dispatches



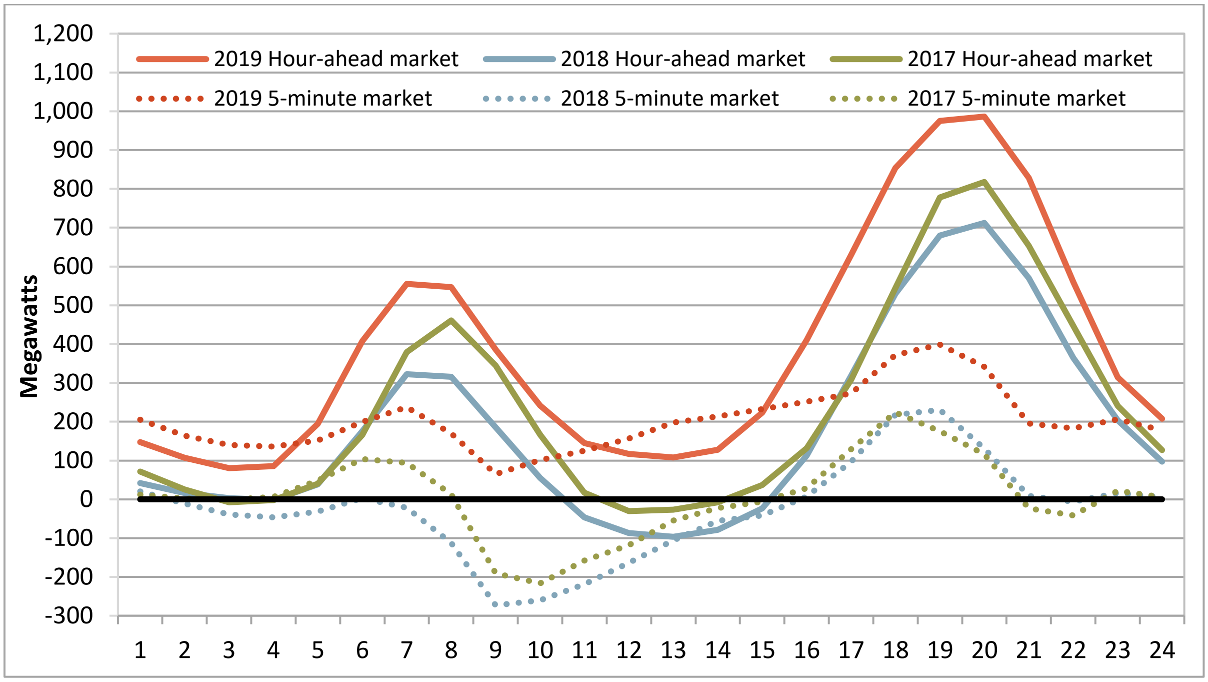
Load forecast adjustments

Operators in the ISO and energy imbalance market can manually modify load forecasts used in the market through load adjustments, sometimes referred to as load bias or load conformance. 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.

In the ISO, load adjustments are routinely used in the hour-ahead and 15-minute scheduling processes to increase the supply of ramping capacity within the ISO during morning and evening hours when net loads increase sharply. Increasing the hour-ahead and 15-minute forecast can increase ramping capacity within the ISO by increasing hourly imports and committing additional units within the ISO.

As shown in Figure E.8, load forecast adjustments in the hour-ahead and 15-minute scheduling processes routinely mirror the pattern of net loads over the course of the day, averaging 550 MW to nearly 1,000 MW during the morning and evening ramping hours respectively. During these hours, imports made in the hour-ahead process often increase significantly, which allows additional generation within the ISO to be available for dispatch in the 15-minute and 5-minute markets. These adjustments increased compared to 2018 and remain high compared to prior years.

Figure E.8 Average hourly load adjustment (2017 - 2019)



Flexible ramping product

The flexible ramping product is designed to enhance reliability and market performance by procuring flexible ramping capacity in the real-time market to help manage the variability and uncertainty of real-time imbalance demand. Flexible ramping product procurement and prices are determined through demand curves calculated from historical net load forecast errors, or the *uncertainty* surrounding ramping needs.

Total net uncertainty payments for flexible ramping capacity decreased to $6.3 million in 2019 from $7.1 million in 2018 and almost $25 million in 2017. Flexible ramping prices were frequently zero in both the 15-minute and 5-minute markets in both the upward and downward directions. In these intervals, flexible ramping capacity was readily available relative to the need for it so that no cost was associated with the level of procurement.

Flexible ramping is often procured from resources that are not able to meet system uncertainty either because of resource characteristics or congestion. This can reduce the effectiveness of the flexible ramping product to manage net load volatility and prevent power balance violations. The ISO published a report in September 2019 that included a discussion of these issues with the flexible ramping product.[5] Further, the ISO initiated a stakeholder process to review refinements to the flexible ramping product and address these inefficiencies.[6]

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5 *CAISO Energy Markets Price Performance Report*, California ISO, September 23, 2019: http://www.caiso.com/Documents/FinalReport-PricePerformanceAnalysis.pdf

6 Stakeholder process information is available here: http://www.caiso.com/StakeholderProcesses/Flexible-ramping-product-refinements

The ISO could extend this initiative to both reduce the need for manual load adjustments and more efficiently integrate distributed and variable energy resources by designing a real-time flexible ramping product that could procure and price the appropriate amount of ramping capability to account for uncertainty over longer time horizons than the current design considers. Uncertainty over load and the future availability of resources to meet that load contributes to operators needing to enter systematic and large imbalance conformance adjustments, as described above.

Power balance constraint relaxation

The ISO and energy imbalance market areas can run out of ramping capability in either the upward or downward direction to meet the real-time market requirement. This condition is known as a power balance constraint relaxation.[7] 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).

The ISO implemented an enhancement to the load conformance limiter, effective February 27, 2019, which decreased the frequency of prices set at the highest priced bid rather than the $1,000/MWh penalty parameter. This enhancement had little impact in the ISO because the highest priced bids dispatched are often at or near the $1,000/MWh bid cap such that the resulting price is often similar with or without the limiter.

For the period between March and December, DMM estimates that the enhancement to the conformance limiter increased average prices for Arizona Public Service by around $3.50/MWh in the 15-minute market and $3/MWh in the 5-minute market.[8] For NV Energy, the enhancement increased average prices by around $0.30/MWh in the 15-minute market and $1/MWh in the 5-minute market. These prices under the enhanced conformance limiter may better reflect actual scarcity conditions.

Within the ISO, the percent of intervals priced at the $1,000/MWh penalty parameter increased from 0.01 in 2018 to 0.08 in 2019 in the 15-minute market and from 0.08 to 0.20 in the 5-minute market. There were no over-supply infeasibilities in the ISO in 2019.

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

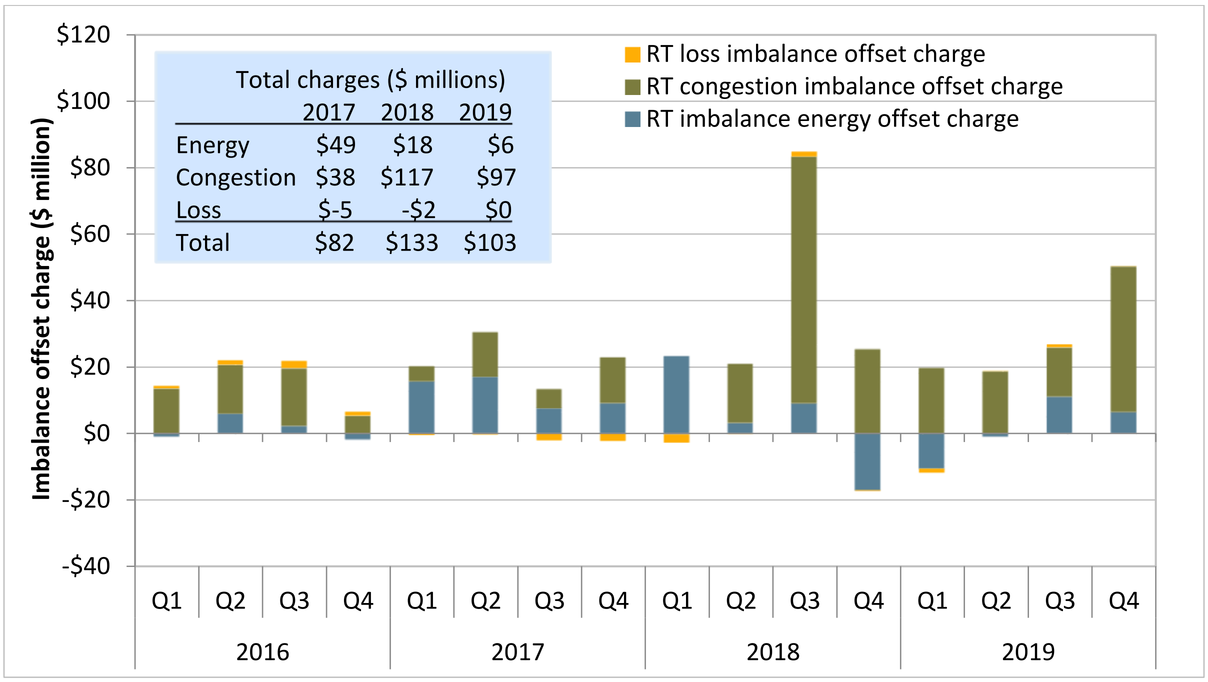
[7] A more detailed description of the power balance constraint was provided in DMM's *2016 Annual Report on Market Issues and Performance,* pp.101-103: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

[8] The impact was calculated by estimating average prices had the previous iteration of the conformance limiter been active instead. For intervals with power balance constraint relaxations, scarcity or estimated non-scarcity prices were inserted depending on whether the current limiter triggered and/or the previous limiter would have triggered.

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 in 2019 were $103 million, a decrease by about 23 percent compared to $133 million in 2018. Congestion offset costs were $97 million of the total $103 million real-time imbalance offset costs in 2019. As in 2018, much of the congestion offset charges appear to have been caused by differences in the network model used in the day-ahead and real-time markets. Much of these differences are caused by persistent and significant reductions in constraint limits by grid operators in the 15-minute market relative to limits used in the day-ahead market.

Figure E.9 Real-time imbalance offset costs



Congestion

Locational price differences due to congestion in both the day-ahead and 15-minute markets decreased in 2019, particularly on constraints associated with major transmission line limits separating Northern and Southern California. Key congestion trends during the year include the following:

- For the year, congestion increased day-ahead prices in the Southern California Edison area by $0.04/MWh and in the San Diego Gas and Electric area by about $1.20/MWh. Congestion decreased day-ahead prices in the Pacific Gas and Electric area by $0.08/MWh.
- In the real-time market, EIM transfer constraint congestion had a far greater impact than internal constraint congestion, decreasing prices in the Pacific Northwest and increasing prices in the Arizona Public Service and NV Energy areas.
- Within the ISO, patterns of real-time congestion followed a similar pattern to the day-ahead market. The constraints that had the greatest impact on price separation were the constraints associated

with the Imperial Valley nomogram, the San Bernardino-Devers 230 kV line, the Midway-Vincent 500 kV lines, the Eldorado-Lugo nomogram, and the Sylmar AC branch group.

- The frequency and impact of congestion in the day-ahead market on most major interties was lower in 2019 compared to both 2018 and 2017. This was primarily driven by lower congestion on interties connecting the ISO to the Pacific Northwest (Malin and NOB).

Congestion revenue rights

From 2009 through 2018, transmission ratepayers received about 48 percent of the value of congestion revenue rights sold in the ISO's auction, with total losses of more than $860 million over this ten year period. In response to these systematic losses from congestion revenue right auction sales, the ISO instituted significant changes to the auction starting in the 2019 settlement year.

As shown in Figure E.10, congestion revenue rights sold in the auction consistently generate significantly less revenue than is paid to the entities purchasing these rights in the auction. In 2019, ratepayer losses from the auctions totaled over $22 million. About $16 million of the $22 million in ratepayer losses occurred in the fourth quarter. Transmission ratepayers received about 80 cents in auction revenue per dollar paid out to these rights purchased in the auction in 2019. Track 1B revenue deficiency offsets reduced payments to auctioned CRRs by about $44 million.

The reduction in losses from the auction in 2019 resulted from a combination of the changes implemented by the ISO, along with a significant drop in day-ahead market congestion. In 2019 day-ahead congestion revenues totaled about $354 million, compared to about $628 million in 2018. Losses from auctioned congestion revenue rights totaled about 6 percent of total day-ahead congestion revenue in 2019 compared to about 21 percent of congestion revenue in 2018.

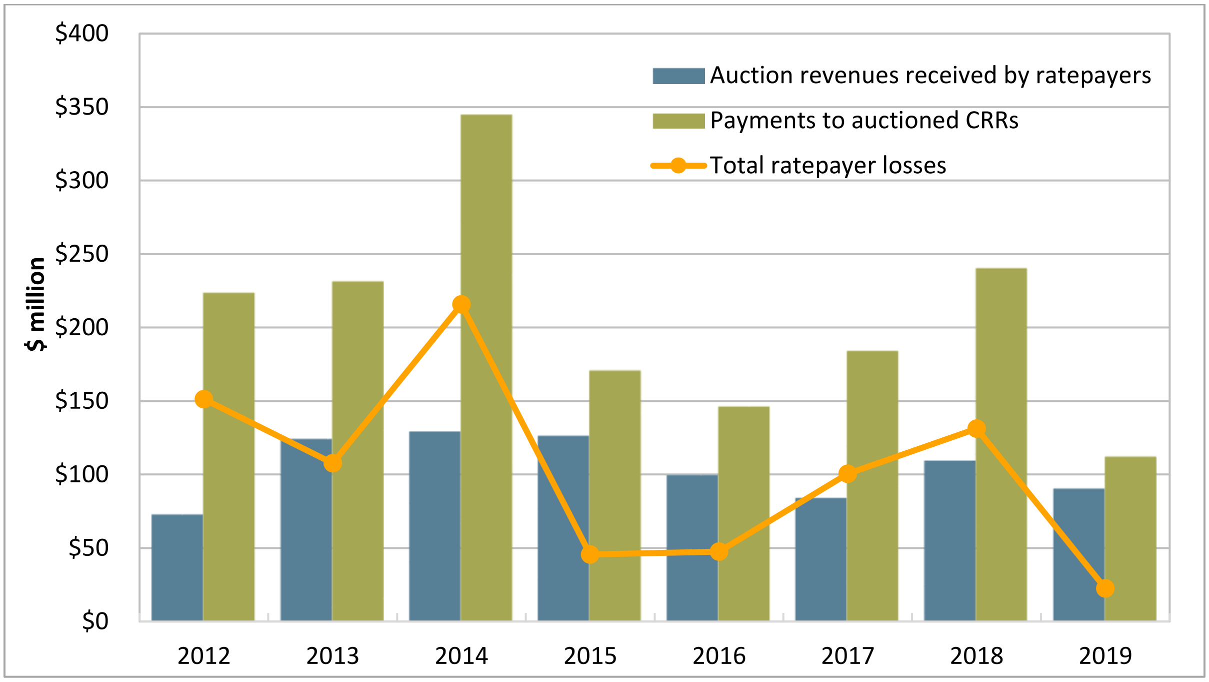
One of the benefits of auctioning congestion revenue rights is to allow day-ahead market participants to hedge congestion costs. However, in 2019, physical generators as a group continued to account for a relatively small portion of congestion revenue rights held. As a group, generators received the lowest overall payments from congestion revenue rights purchased in the auction. Financial entities continued to have the highest net revenue among auctioned rights holders in 2019 at $23 million, down from $91 million in 2018.

DMM believes the current auction is unnecessary and could be eliminated.[9,10] If the ISO believes it is beneficial to the market to facilitate hedging, DMM believes the current auction format should be changed to a market for congestion revenue rights or locational price swaps based on bids submitted by entities willing to buy or sell congestion revenue rights.

9 DMM whitepaper *"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

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

Figure E.10 Ratepayer auction revenues compared with congestion payments for auctioned CRRs



Local market power mitigation

The ISO's day-ahead and real-time markets incorporate a dynamic structural test for transmission competitiveness and a bid mitigation mechanism to address local market power. The portion of constraints found to be structurally uncompetitive and level of bid mitigation in the ISO's day-ahead market increased significantly in 2019 relative to 2018, but remained low. The increase in mitigation was due to an increase in concentration of generation in the portfolios of net sellers, which is a major determinant of the three pivotal supplier test used to trigger bid mitigation.

The ISO implemented an enhancement to increase the accuracy of the structural test for competitiveness used in the real-time market in November 2019. Following this change, rates of mitigation fell in the Western EIM balancing authority and were similar to 2018 levels in the ISO.

Despite increased rates of mitigation, fewer day-ahead bids were lowered due to mitigation than in 2018. Most resources subject to mitigation submitted competitive offer prices, so that a very low portion of bids were lowered as a result of the bid mitigation process.

Local market power mitigation of exceptional dispatches for energy played a significant role in limiting above-market costs in 2019, reducing these costs by about $8.3 million. The above-market costs associated with exceptional dispatches decreased to $29 million although the volume of exceptional dispatch increased. The majority of this cost was associated with exceptional dispatch commitments to run at minimum operating level, rather than for exceptional dispatches for additional energy above minimum levels.

ISO operators started to issue "RA Max" exceptional dispatches to the maximum of resource adequacy contracts in the third quarter. These exceptional dispatches are issued to increase the amount of ramping capacity available to meet the evening net load ramp and respond to other uncertainties in real time, the same issues that the flexible ramping product is designed to address. DMM has recommended that the ISO should take steps to change market rules so that RA Max exceptional dispatches are subject to bid mitigation, because there is a strong potential for suppliers to exercise market power and raise bids substantially over marginal cost.

A new default energy bid option, the hydro default energy bid, became available in November. This option, offered to eligible hydroelectric generation resources within the ISO and EIM, incorporates opportunity costs for hydro resources with storage capability. Only a small amount of eligible capacity selected the new hydro option in 2019.

Opportunity cost adders increased default energy bid and commitment cost bid caps with the implementation of Commitment Cost Enhancements Phase 3 in April 2019. Qualifying resources provided a significant amount of resource adequacy capacity in 2019. Despite additional headroom provided by opportunity costs, the percent of capacity bidding at or near commitment cost bid caps increased in 2019.

The market for capacity needed to meet local resource adequacy requirements was structurally uncompetitive in all local areas. Analysis in this report shows that one pivotal supplier controls a significant portion of capacity needed to meet local requirements in the LA Basin, Stockton, Sierra, and the North Coast/North Bay areas.

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 were sufficient to meet peak day-ahead load forecasts and actual peak loads for all days in 2019. In the real-time market, less than 80 percent of system resource adequacy capacity was bid or self-scheduled during high load hours. During the top 210 load hours of the year, 97 percent of system resource adequacy capacity was available in the day-ahead market after outages; 90 percent of total system resource adequacy capacity was bid or self-scheduled in the day-ahead market; 88 percent of total capacity was available after outages in the real-time market; and 78 percent of total capacity was bid or self-scheduled in the real-time market.

- Most system resource adequacy capacity was procured by investor-owned utilities (IOU). Investor-owned utilities accounted for about 66 percent of procurement, community choice aggregators (CCA) procured 18 percent, municipal entities contributed 9 percent, and direct access (DA) providers accounted for 7 percent.

- 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 fourth year that 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 requirements in this report highlight the following:

- Flexible resource adequacy requirements fell short of the maximum three-hour net load ramp in seven months in 2019. Due to varying must-offer hours for different flexible capacity the *effective* resource adequacy requirement fell short of the actual net load ramp in eight months.

- Despite requirements, load serving entities collectively procured more flexible capacity than required. This procurement exceeded the actual maximum three-hour net load ramp in only five months. Procurement consisted mostly of gas-fired generation that qualified as Category 1 (base flexibility) capacity.

In 2019, two forms of backstop capacity procurement were utilized:

- The capacity procurement mechanism (CPM) was used throughout the year to dispatch non-resource adequacy capacity for conditions requiring exceptional dispatch. The total estimated cost of these intra-monthly designations was about $1.5 million, a substantial decrease from prior years of $21.9 million in 2018, $7 million in 2017 and $4.3 million in 2016. In 2019, intra-monthly designations were triggered by local reliability issues to address potential thermal overloads for the next contingency event in the Pacific Gas and Electric area.

- During 2017, capacity designated as being subject to reliability must-run (RMR) contracts beginning in 2018 increased sharply. Three newer, efficient gas units representing almost 700 MW were designated by the ISO for reliability must-run service beginning in 2018.

- About 600 MW of the 700 MW of gas-fired generation designated by the ISO as being needed under reliability must-run contracts during 2018 was not re-designated for service in 2019. The need to designate these resources was eliminated by transmission upgrades completed in December 2018 and January 2019 and these resources received resource adequacy contracts. The remaining 100 MW under two reliability must-run units were not re-designated for year 2020, and both units returned back to the market as participating generators.

- About 120 MW of gas-fired generation was designated by the ISO as being needed under reliability must-run contracts for year 2020, with FERC filings of the contracts made in the May-June timeframe.

DMM provided recommendations, initiated in 2018, on the stakeholder process aimed at reforming the reliability must-run policy. The two basic flaws in the contract and tariff provisions for reliability must-run units under Condition 2 were:

- Remove the prohibition on reliability must-run capacity under Condition 2 being offered in the ISO's energy market except when needed for local area reliability; and

- Require reliability must-run resources to be subject to a must-offer requirement with cost-based bids.

These recommendations were addressed by the ISO with an amendment to the tariff approved by the Federal Energy Regulatory Commission on April 22, 2019.[11] The prohibition on reliability must-run capacity under Condition 2 was amended[12] and Condition 2 units are now required to be offered in the ISO markets at cost-based bids.[13]

The procurement of a significant amount of newer and more efficient units under reliability must-run contracts in 2017 highlighted gaps in the state's resource adequacy process, as well as problems with the ISO's capacity procurement and reliability must-run backstop procurement mechanisms. The CPUC and the ISO continue to work to refine and enhance the resource adequacy framework through ongoing stakeholder initiatives and proceedings.

Total settlement for reliability must-run capacity was about $11 million in 2019, down from $63 million in 2018. Total settlement for capacity procurement mechanism was about $1.8 million, a substantial decrease from $11.1 million in 2018.

Capacity additions and withdrawals

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. CPUC policies also have a major impact on the type of different generating resources retained and added to the ISO system.

Figure E.11 summarizes the trends in available nameplate capacity from June of 2012 through 2019. During this time gas capacity internal to the ISO fell from about 35 GW to 30 GW as nuclear capacity fell from about 4.5 GW to 2.3 GW. This capacity was replaced by solar, which grew from about 1.0 GW to 11.6 GW; by wind, which grew from 3.9 GW to 6.0 GW; and by demand response which grew from 0 GW to 3.8 GW. Most of the retired natural gas capacity was located in local capacity areas. While solar, wind, and demand response nameplate capacity additions have exceeded reductions in gas and nuclear capacity, variable energy and demand response resources generally have limited energy and availability compared to gas and nuclear capacity.[14]

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11 FERC Tariff Amendment to Improve the Reliability of Must-Run Framework ER19-1641, pages 539 and 540.

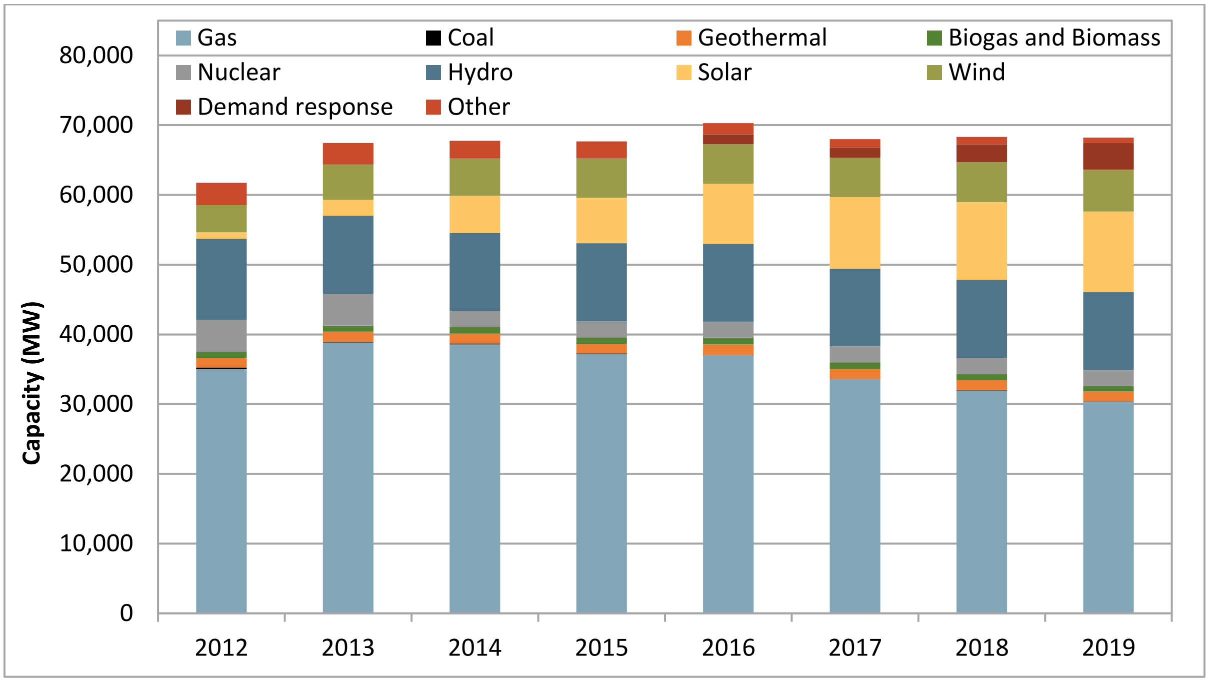
http://www.caiso.com/Documents/Apr22-2019-TariffAmendment-RMR-CPMEnhancements-ER19-1641.pdf

12 Ibid, page 408. R*esource must-run pro forma* and CAISO Tariff Appendix G Article 4.

13 CAISO Tariff Appendix G Section 6.1 http://www.caiso.com/Documents/AppendixG-ProFormaReliabilityMustRunContract-asof-Sep28-2019.pdf

14 In contrast to gas and nuclear capacity the resource adequacy contributions, or qualifying capacity (QC), of wind and solar resources in the ISO is discounted compared to nameplate capacity to reflect that these resource types have limited availability across peak net load hours. Additionally, compared to nuclear and most gas resources demand response resources generally are limited to operating only a subset of hours each month.

Figure E.11 Total ISO participating capacity by fuel type and year (as of June 1)



The ISO anticipates a continued increase in renewable generation in the coming years to meet the state's goal to have 50 percent renewable generation by 2025 and 60 percent by 2030. Going forward, significant reductions in total gas-fired capacity may continue beyond 2019 because of the state's restrictions on once-through cooling technology as well as other retirement risks. The ISO has emphasized 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 estimates net revenues for new gas-fired generating resources using market prices for gas and electricity. In 2019, estimated net revenues for both combined cycles and combustion turbines were less than estimated going forward fixed costs and substantially below annualized fixed costs. These findings highlight the critical importance of capacity payments including resource adequacy contracts and other bilateral contracts, and the 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.

DMM's analysis tests net revenues using multiple scenarios which provide a range of potential results. For a new combined cycle unit, DMM estimates that net operating revenues earned from the energy markets in 2019 ranged from $5/kW-yr to $17/kW-yr. This compares to estimated going forward fixed costs ranging from $26/kW-yr to $34/kW-yr and potential annualized fixed costs of approximately $114/kW-year. Net revenues summed with a generous capacity payment ($76/kW-yr, the ISO's backstop capacity soft offer cap) are well in excess of going forward fixed costs in all years but fall short of annualized fixed costs in every year, with the exception of SP15 in 2017.

For a new combustion turbine unit, our estimates ranged from \$16/kW-yr to \$20/kW-yr compared to going forward fixed costs of \$26/kW-yr to \$27/kW-yr and potential annualized fixed costs of about \$140/kW-yr.

Figure E.12 Estimated net revenue of hypothetical combined cycle unit

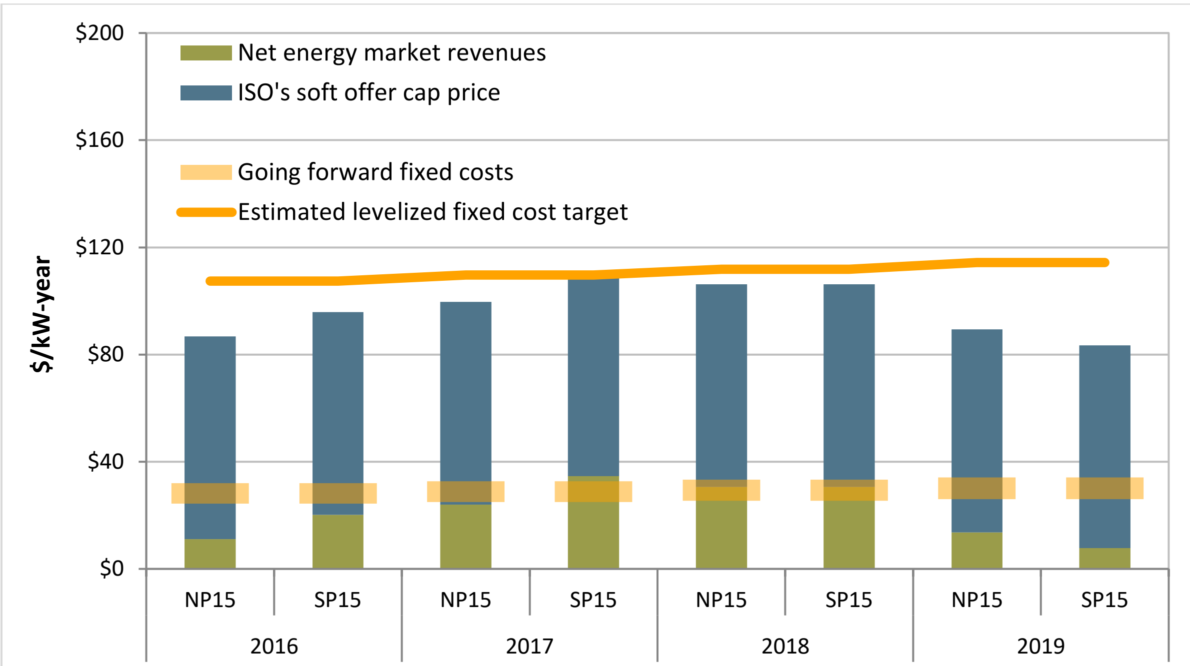
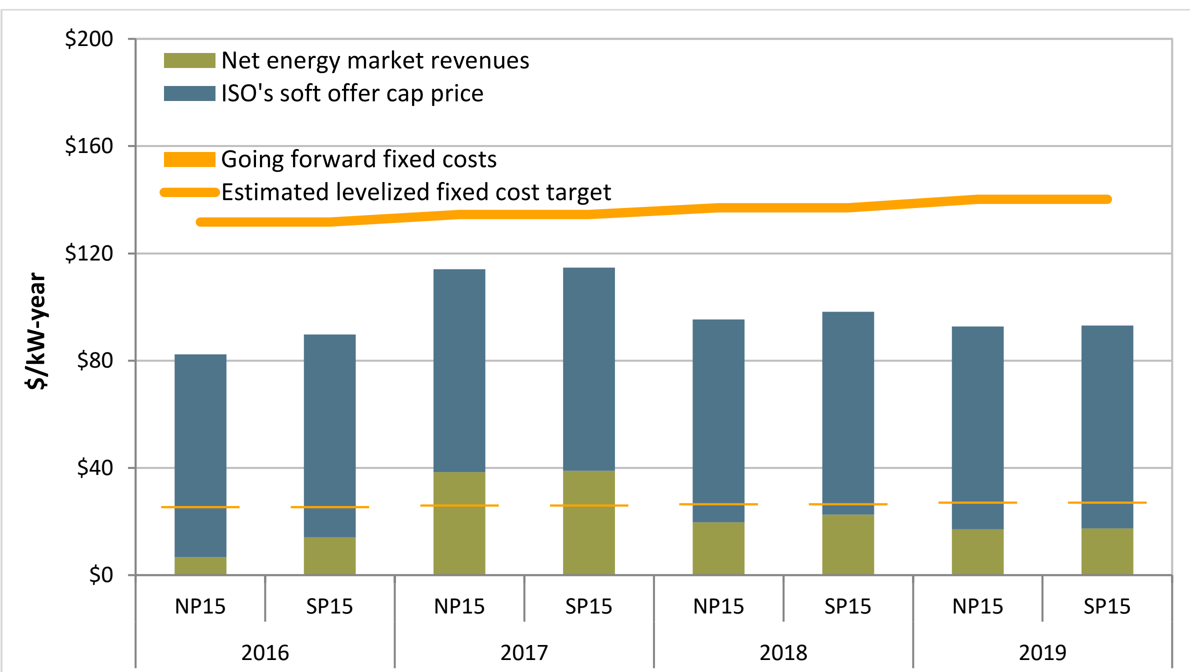


Figure E.13 Estimated net revenues of hypothetical combustion turbine



Recommendations

As the ISO's independent market monitor, one of DMM's key duties is to provide recommendations on current market issues and new market design initiatives to the ISO, the ISO Governing Board, FERC, the CPUC, market participants, and other interested entities.[15] DMM provides written comments and recommendations in the ISO's stakeholder process and in quarterly, annual and other special reports.[16] DMM's current recommendations on key market design initiatives are summarized below and in Chapter 11.

Flexible ramping product enhancements

The flexible ramping product is designed to procure additional ramping capacity to address uncertainty in imbalance demand through the market software. DMM supports the ISO's efforts in the ongoing day-ahead market enhancements initiative to design a product that procures flexible ramping capability in the day-ahead market. DMM also recommends that the ISO seek to enhance the current flexible ramping capacity market design to address two key issues.

Locational procurement

Analyses by DMM and the ISO have shown that the current real-time flexible ramping product may not be deliverable because of transmission constraints.[17] DMM continues to support market design changes to allow locational procurement for both day-ahead and real-time flexible ramping products. Locational procurement, accounting for transmission constraints, would result in deliverable reserves which could significantly increase the efficiency of the ISO's market awards and dispatches. This change could also help to resolve the very low prices for flexible reserves that result from undeliverable reserves being counted towards meeting a reliability need that they cannot actually help to meet.

As part of a new initiative on flexible ramping product refinements started in 2019, the ISO is considering ways to address the issue of undeliverable or stranded flexible ramping capacity through more locational procurement requirements.[18] Options for ensuring deliverability of flexible ramping capacity being considered by the ISO include zonal procurement and nodal procurement.

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15 Tariff Appendix P, ISO Department of Market Monitoring, Section 5.1. http://www.caiso.com/Documents/AppendixP_CAISODepartmentOfMarketMonitoring_asof_Apr1_2017.pdf

16 See Market Monitoring Reports and Presentations at: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx#CommentsRegulatory

17 *Discussion on flexible ramping product*, California ISO, September 8, 2017 pg. 16-17: http://www.caiso.com/Documents/Discussion_FlexibleRampingProduct.pdf

Q3 Report on Market Issues and Performance, December 5, 2019, pp. 84-86. http://www.caiso.com/Documents/2019ThirdQuarterReportonMarketIssuesandPerformance.pdf

18 *Flexible Ramping Product Refinements Issue Paper and Straw Proposal*, November 14, 2019, pp. 6-8. http://www.caiso.com/InitiativeDocuments/IssuePaper-StrawProposal-FlexibleRampingProductRefinements.pdf

Extending the time horizon of the real-time flexible ramping product

DMM continues to recommend that the ISO begin to develop an approach for extending the time horizon of the flexible ramping product to account for uncertainty over longer time horizons. The range of likely outcomes narrows as the time between the uncertain outcome and the evaluation of that uncertain outcome narrows; there is less uncertainty between the 15- and 5-minute markets than over a longer interval.[19] The current flexible ramping product is designed to address uncertainty between the 15- and 5-minute markets. In real time, grid operators face significant uncertainty about loads and resources over a longer timeframe (e.g., 30, 60, and 120 minutes from the current market interval).

This uncertainty is the primary reason why operators need to systematically enter large positive load adjustments during the morning and evening ramping hours, as described in Section 9.3 of this report. Operators also take other out-of-market actions to ensure sufficient ramping capacity is available in the peak ramping hours, including exceptional dispatches to commit additional gas-fired units and to begin ramping these resources up in the peak ramping hours. Extending the time horizon of the flexible ramping product should significantly reduce the need for manual load adjustments and out-of-market dispatches of gas resources.

The ISO's current proposal stemming from the initiative on flexible ramping product refinements begun in 2019 does not include extending the time horizon of the flexible ramping product. DMM does not think that the ISO's other proposed improvements should be delayed to work on an extended horizon product design.[20] However, DMM continues to recommend that the ISO should begin efforts to extend the real-time flexible ramping product to longer time horizons. As the ISO develops day-ahead flexible reserve products it will become even more important to have real-time products to ensure that reserves procured in the day-ahead market are used effectively in real-time, as discussed in DMM's recommendations on day-ahead market enhancements.

Day-ahead market enhancements

In 2018, the ISO initiated a process to develop a proposal for day-ahead market enhancements. The ISO released an initial straw proposal in February 2020.[21]

Day-ahead imbalance reserve product

A key element of the ISO's initial straw proposal is the introduction of a day-ahead imbalance reserve product that is intended to ensure sufficient ramping capacity is available in the real-time market. DMM supports development of a day-ahead imbalance reserve product. The new reserve product will increase day-ahead market costs through the direct payments for this new product as well as through increases to day-ahead market energy prices resulting from procurement of this product.

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19 Illustrations of this concept as applied to the flexible ramping product are available here: *Real-time Flex Ramp Product Enhancements – Western EIM Body of State Regulators*, June 12, 2020. http://www.caiso.com/Documents/Presentation-Real-TimeFlexRampProductEnhancements-WesternEIMBodyofStateRegulators-June122020.pdf

20 *Comments on Flexible Ramping Product Refinements: Issue Paper and Straw Proposal*, Department of Market Monitoring, December 5, 2019, pp. 2.

21 *Day-Ahead Market Enhancements Straw Proposal*, February 3, 2020, http://www.caiso.com/InitiativeDocuments/StrawProposal-Day-AheadMarketEnhancements.pdf

However, if the ISO does not extend the uncertainty horizon of the real-time flexible ramping product, DMM is concerned that the imbalance reserves that are procured in the day-ahead market will provide limited benefit in terms of increased ramping capacity in real-time or reduced real-time market costs. Thus, DMM continues to recommend that the ISO take steps to extend the time horizon of the real-time flexible ramping product to enable the market software to commit and position resources to address uncertainty in net load forecasts further out in the future.

Reliability energy product

Two other key elements of the ISO's initial straw proposal included (1) a new *reliability energy* (REN) product, and (2) combining the day-ahead energy market and residual unit commitment process into a single optimization process. These two elements are related in that the new reliability energy product would be procured through a single optimization process in place of the current residual unit commitment process.

Most stakeholders, including DMM, agree that day-ahead procurement of flexible reserves is desirable and needed as the western grid continues to increasingly rely on renewable generation. However, there was considerable controversy regarding the proposed reliability energy product which has been dropped from the proposal. This new product would have been procured based on the ISO's load forecast and could have had a significant impact on overall market clearing prices. This product would also significantly increase the role that the ISO plays in determining day-ahead market energy awards and prices.

As noted in DMM's comments on the straw proposal, this controversy has consumed much of the DAME initiative process for several years.[22] To expedite the completion of the complicated design work that still needs to be done for imbalance reserve products, DMM has recommended that the ISO separate this design from any potential future development of reliability energy products or combining the day-ahead energy market and residual unit commitment process into a single optimization process. The ISO has pivoted away from the reliability energy product to focus on development of imbalance reserves.[23]

Extended day-ahead market

In 2019, the ISO also initiated a process to develop a proposal for extending the day-ahead market to include other entities in the Western EIM.[24] This initiative is designed to build on market design changes made as part of the ISO's initiative on day-ahead market enhancements.

DMM strongly supports extending participation in the day-ahead market to more entities across the west. An extended day-ahead market would increase trading opportunities across the west and allow entities throughout the Western EIM to more efficiently meet their needs as the western electric grid continues to evolve and reliance on renewable energy increases.

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22 *Comments on Day-Ahead Market Enhancements Straw Proposal*, Department of Market Monitoring March 30, 2020. http://www.caiso.com/InitiativeDocuments/DMMComments-Day-AheadMarketEnhancements-StrawProposal.pdf

23 *Day-Ahead Market Enhancements Revised Straw Proposal,* ISO Stakeholder presentation, June 15-17, 2020. http://www.caiso.com/InitiativeDocuments/Presentation-Day-AheadMarketEnhancements-Jun15-17-2020.pdf

24 *Extending the Day-Ahead Market to EIM Entities Issue Paper*, California ISO, October 10, 2019: http://www.caiso.com/Documents/IssuePaper-ExtendedDayAheadMarket.pdf

In the first phase of this stakeholder process, the ISO is addressing the following three areas: (1) resource sufficiency, (2) provision of transmission, and (3) allocation of congestion rents. Several key issues and concerns highlighted in DMM's initial comments on these issues are briefly summarized below.[25]

Resource sufficiency

The extended day-ahead market design clearly needs to allow entities to meet resource sufficiency obligations with power from resources that must schedule over another balancing authority area's transmission. Western EIM entities have proposed requiring a resource to have firm (or equivalent quality) transmission service to a BAA before the day-ahead market closes in order for the resource to count towards meeting a BAA's resource sufficiency requirement for the extended day-ahead market.

DMM has expressed concern that in the absence of changes to existing timelines and protocols for releasing firm transmission, the proposed firm transmission requirement for resource sufficiency qualification could significantly restrict the amount of transmission that load serving entities can rely on for utilizing the most efficient resources to meet resource sufficiency requirements for the extended day-ahead market. This is because third party entities can purchase long-term firm transmission rights at regulated rates on critical paths between generation and load centers when transmission operators first offer the firm rights far in advance of the day-ahead market timeframe. DMM's understanding is that current open access protocols for transmission in WECC only require long-term firm rights holders to release unused transmission capacity after the ISO's day-ahead market closes.

Provision of transmission

The Western EIM has been designed as a voluntary market. EIM entities have proposed that transmission operators could offer additional unreserved transmission to the extended day-ahead market in the form of unsold, unreserved firm (or equivalent quality) capacity at the time the extended day-ahead market is initiated. On one hand, this approach may increase transmission that is made available in the extended day-ahead market. However, some participants have raised concerns that reservation of transmission capacity could have the effect of reducing competitive access to transmission (and energy) in the extended day-ahead market. DMM believes that mechanisms to ensure competitive access to transmission in the extended day-ahead market warrant further consideration.

Congestion revenues

How congestion rents are allocated will have a major impact on incentives for entities to provide transmission rights to the extended day-ahead market. To create incentives to make transmission available, congestion rents would be allocated to transmission owners. However, if the allocation of congestion rents creates incentives for entities to reduce the available transmission for the purpose of receiving increased congestion rents, this would adversely affect the extended day-ahead market as well as bilateral markets.

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25 *Comments on Extended Day-Ahead Market: February 11-12, 2020 Stakeholder Workshop Bundle 1 Topics: Resource Sufficiency, Transmission, and Congestion Revenue*, Department of Market Monitoring, February 26, 2020: http://www.caiso.com/InitiativeDocuments/DMMComments-ExtendedDay-AheadMarketTechnicalWorkshop-Feb11-12-2020.pdf

Congestion revenue rights

Since the start of the ISO's congestion revenue rights (CRR) auction in 2009, payouts to non-load serving entities purchasing congestion revenue rights have exceeded the auction revenues by about $900 million. If the ISO did not auction these congestion revenue rights, these congestion revenues would be credited back to transmission ratepayers who pay for the cost of the transmission system through the transmission access charge (TAC). Thus, this $900 million represents profits to the entities purchasing these financial rights in the auction, but represents revenue losses to transmission ratepayers. Most of these losses have resulted from profits received by purely financial entities which purchase congestion revenue rights but do not schedule power or load in the ISO.

Losses from congestion revenue rights increased to about $100 million in 2017 and $131 million in 2018. In response to these large and systematic losses from sales of congestion revenue rights, the ISO instituted significant changes to the auction starting in the 2019 settlement year. While changes implemented by the ISO in 2019 reduced losses from the congestion revenue rights auction, losses to ratepayers from the auction were still significant. In 2019, losses from auctioned congestion revenue rights totaled about $22 million. The reduction in losses from the auction resulted from a combination of the changes implemented by the ISO, along with a significant drop in day-ahead market congestion.

DMM believes that under current rules it remains likely that the congestion revenue rights auction will continue to result in significant losses to transmission ratepayers. DMM continues to recommend that the ISO take steps to discontinue auctioning congestion revenue rights and instead reallocate all congestion revenues back to ratepayers who pay for the cost of the transmission system through the Transmission Access Charge. If the ISO believes it is highly beneficial for the ISO to actively facilitate hedging of congestion costs by suppliers, DMM recommends that the ISO replace the auction with a market for financial hedges based on clearing of bids from willing buyers and sellers.

Capacity procurement mechanism

The 2018 and 2019 stakeholder processes to consider changes to the capacity procurement mechanism resulted in very limited changes in the capacity procurement mechanism. DMM supports these limited changes as an incremental improvement to current market rules, but believes that the ISO's proposal does not address the key concerns with the ISO's current backstop procurement mechanisms that are needed as part of a comprehensive reform.

In the second half of 2019, the ISO continued to consider additional changes in the capacity procurement mechanism. Changes included application of a structural market power test to capacity procured under these tariff provisions and lowering the $76/kW-year soft cap applied to capacity procured by the ISO under the capacity procurement mechanism. However, in early 2020 the ISO announced that no further changes would be proposed to the capacity procurement mechanism beyond the limited changes approved by the Board in March 2019.[26]

DMM has submitted an extensive review of different cost studies showing that the current $76/kW-year soft cap is based on an inaccurately high estimate of the annual going forward fixed costs (GFFC) of gas-

[26] *Capacity Procurement Mechanism Draft Final Proposal*, California ISO, January 6, 2020: http://www.caiso.com/InitiativeDocuments/DraftFinalProposal-CapacityProcurementMechanismSoftOfferCap.pdf

fired units.[27] Based on this review, DMM has recommended the ISO perform its own review of cost estimates used by the ISO to set the soft cap. DMM has also recommended that the ISO continue to consider establishing a structural market power test to any capacity procured on an annual basis under the capacity procurement mechanism.

Resource adequacy issues

Resource adequacy imports

DMM has longstanding concerns that existing rules 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.[28] If resource adequacy import capacity is not scheduled in the day-ahead market or residual unit commitment process, these resources have no further obligation to bid into the real-time market. Thus, by simply bidding at or near the $1,000/MWh bid cap in the day-ahead market, resource adequacy imports can receive capacity payments while providing no real benefits in terms of either system reliability or market competitiveness.

For the last few years, DMM has recommended that the ISO and stakeholders come to an explicit policy decision on whether or not resource adequacy capacity must be backed by specific generation resources and how any such requirements should be enforced in practice. DMM has also recommended that resource adequacy imports be subject to some type of real-time must offer requirement when these resources may be needed to ensure system reliability and increase market competitiveness.

DMM has also suggested that resource adequacy imports could be subject to some type of lower bidding limits when potential system market power exists. Unlike other imports, resource adequacy imports receive capacity payments and can be subject to must-offer obligations. DMM has also recommended that the ISO consider options for increasing the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time.

The ISO's recent proposals in its initiative on resource adequacy enhancements would require specification of a physical source backing resource adequacy import showings. This specification could include a specific resource, aggregation of resources, or balancing area. The ISO is also proposing to require that import resource adequacy be backed by firm transmission, at a minimum, in the day-ahead timeframe. In its most recent proposal, the ISO also has also proposed to extend the real-time must-offer obligation to resource adequacy imports.[29] However, the ISO's proposal may still not ensure that

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[27] *DMM Comments on CPM Tariff Filing ER20-1075*, April 3, 2020: http://www.caiso.com/Documents/AnswerandMotionforLeavetoAnswer-DMMCommentsonCPMTariffFilingER20-1075-Apr32020.pdf

[28] *2018 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2019, p. 269: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

Import Resource Adequacy, Department of Market Monitoring, September 10, 2018: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept1020

[29] *Resource Adequacy Enhancements Fourth Revised Straw Proposal*, CAISO, March 17, 2020: http://www.caiso.com/InitiativeDocuments/FourthRevisedStrawProposal-ResourceAdequacyEnhancements.pdf

the energy supporting import resource adequacy will not be recalled by other balancing areas, particularly when energy is scarce throughout the west.[30]

In 2019, the CPUC also took numerous steps to address longstanding concerns expressed by DMM in prior reports about resource adequacy imports. DMM supports the efforts taken in 2019 and 2020 by the ISO and CPUC to address the issue of resource adequacy imports. In May 2020, the CPUC issued a proposed decision specifying that non-resource specific import resource adequacy resources must be self-scheduled or bid into ISO markets at or below $0/MWh, at minimum in the availability assessment hours.[31] DMM has supported the proposed decision as an interim measure while rules governing a source-specific framework are developed further under ISO stakeholder processes. A source-specific framework for resource adequacy imports which ensures that import energy cannot be recalled to other balancing areas, particularly when other balancing areas also face supply shortages, could better ensure that import capacity is truly dedicated to the CAISO.

Energy and availability limited resources

Beginning in 2019, DMM has provided analysis and expressed concern about the cumulative impacts of various energy-limited or availability-limited resources which are being relied upon to meet an increasing portion of resource adequacy requirements. As noted in recent comments by DMM in the CPUC long-term integrated resource planning proceedings:

> These energy-limited or availability-limited resources include renewables, import capacity, demand-side resources and energy storage. Unlike gas and nuclear capacity, these resource types may have limited availability to meet both peak demand and demand across all multiple hours in an operating day. When available, these resources could also be very expensive to dispatch. If increased reliance is placed on these resources to meet RA requirements, DMM is concerned that the RA fleet could have limited output during hours when net loads – and the potential for uncompetitive supply conditions – are highest.[32]

DMM has noted that the costs and actual operation of these types of energy and availability limited resources in ISO markets to meet both peak demand and energy needs will be important to consider in procurement directives by the CPUC and other local regulatory entities, particularly if these resources will comprise an increasing share of the resource adequacy fleet going forward.

DMM has suggested potential changes to CPUC and ISO rules that could help mitigate availability concerns related to import and battery resources. These recommendations include considering a form

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30 *Comments on Resource Adequacy Enhancements Fourth Revised Straw Proposal*, Department of Market Monitoring, April 21, 2020. http://www.caiso.com/InitiativeDocuments/DMMComments-ResourceAdequacyEnhancements-FourthRevisedStrawProposal.pdf

31 *Proposed Decision Adopting Resource Adequacy Import Requirements*, R.17-09-020, CPUC, May 18, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M337/K861/337861765.PDF

32 *Reply Comments of the Department of Market Monitoring*, 16-02-007, August 12, 2019: http://www.caiso.com/Documents/CPUC-DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf

of real-time must-offer for resource adequacy import capacity[33], and developing default energy bids and subjecting battery resources participating under the CAISO's non-generator resource (NGR) model to local market power mitigation.[34]

Centralized procurement of resource adequacy capacity

California has 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 – including the growth of load served by community choice aggregators (CCAs) – are creating the need for significant changes in this resource adequacy framework, as summarized in a recent report by the California Public Utilities Commission.[35]

In June 2020, the CPUC adopted a decision which establishes central procurement of multi-year local resource adequacy capacity beginning with the 2023 compliance year.[36] Under the decision, the state's two major investor-owned utilities (Pacific Gas and Electric and Southern California Edison) will serve as the central procurement entities for local capacity in their respective distribution service areas.

DMM has supported the CPUC's efforts to adopt a multi-year framework for local resource adequacy through a central procurement framework. The adopted framework should help avoid unnecessary reliance on the ISO's two backstop procurement mechanisms: the capacity procurement mechanism and reliability must-run contracts.

System market power

In 2018, DMM 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. 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.

In 2019, the ISO launched an initiative to begin to design a system-level market power mitigation process. In proposals put forth to date, the ISO has outlined potential market power mitigation measures for the real-time market only. The proposed measures would be triggered when the ISO, or the ISO with a larger subarea of the western interconnection, may be import constrained.

DMM supports the ISO's efforts to design and implement system market power mitigation and is generally supportive of the proposal being developed. Despite some limitations of the ISO's current proposal, DMM believes that it may mitigate real-time market power in some situations. Mitigation of market power in the real-time market may also help mitigate market power in the day-ahead market to

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33 *Comments on Resource Adequacy Enhancements Revised Straw Proposal*, DMM, July 24, 2019, p. 5. http://www.caiso.com/Documents/DMMComments-ResourceAdequacyEnhancements-RevisedStrawProposal.pdf

34 *2018 Annual Report on Market Issues and Performance*, p. 24: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

35 *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

36 *Decision on Central Procurement of the Resource Adequacy Program*, R.17-09-020, June 11, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M340/K671/340671902.PDF

some degree. DMM supports the ISO's continued development of system-level market power mitigation measures for the day-ahead and real-time markets in the second phase of the initiative.

DMM has also suggested that resource adequacy imports could be subject to some type of lower bidding limits when potential system market power exists. Unlike other imports, resource adequacy imports receive capacity payments and can be subject to must-offer obligations. DMM has also recommended that the ISO consider options for increasing the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time.

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.
- **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 2019, wholesale electricity prices were driven by a 10 percent decrease in gas prices, combined with lower load and an increase in supply from both hydroelectric and new solar generation. More specific trends highlighted in this chapter include the following:

- **ISO load continued to decrease in 2019**, measured as both instantaneous peak load and total energy, due in part to increases in behind-the-meter solar generation, continued initiatives to improve energy efficiency, and lower statewide temperatures in 2019.
- **The average price of natural gas in the California spot market decreased by about 10 percent** from 2018, particularly at SoCal Citygate. Lower gas prices reflect the return to service of gas pipeline capacity, revised Aliso Canyon storage protocols, and lower gas penalty prices.
- **Hydroelectric generation increased to 14 percent of supply** in 2019, compared to 10 percent of supply in 2018, 15 percent in 2017, and 11 percent in 2016.
- **Net imports decreased about 15 percent** in 2019 compared to 2018, almost entirely due to the decline of imports from the Northwest.
- **Non-hydro renewable generation accounted for about 27 percent of total supply in 2019**, up from 26 percent in 2018 and 24 percent in 2017.[37] Solar generation increased by about 4 percent and accounted for around 13 percent of total supply. The increase was primarily driven by the addition of new solar generation capacity.
- **The majority of capacity retiring or withdrawing from the market was from gas resources in local areas,** while the majority of additions came from repowered gas capacity, solar, and other renewable resources.
- **Demand response resource capacity that was registered and bid into the market increased significantly** between 2018 and 2019, but most of this incremental capacity was offered into the day-ahead market at bid prices over $750/MWh and into the real-time market near the $1,000/MWh bid cap.
- **Capacity from battery storage resources remained unchanged at 136 MW** and continued to be dispatched primarily for ancillary services rather than energy.
- **The estimated net operating revenues for typical new gas-fired generation in 2019 fell below DMM's estimate of the going forward fixed costs** of gas capacity and remained substantially below the annualized fixed cost of new generation.

[37] In this analysis, non-hydro renewables include tie generators but do not include other imports or behind-the-meter generation such as rooftop solar. Thus, this analysis may differ from other reports of total renewable generation.

1.1 Load conditions

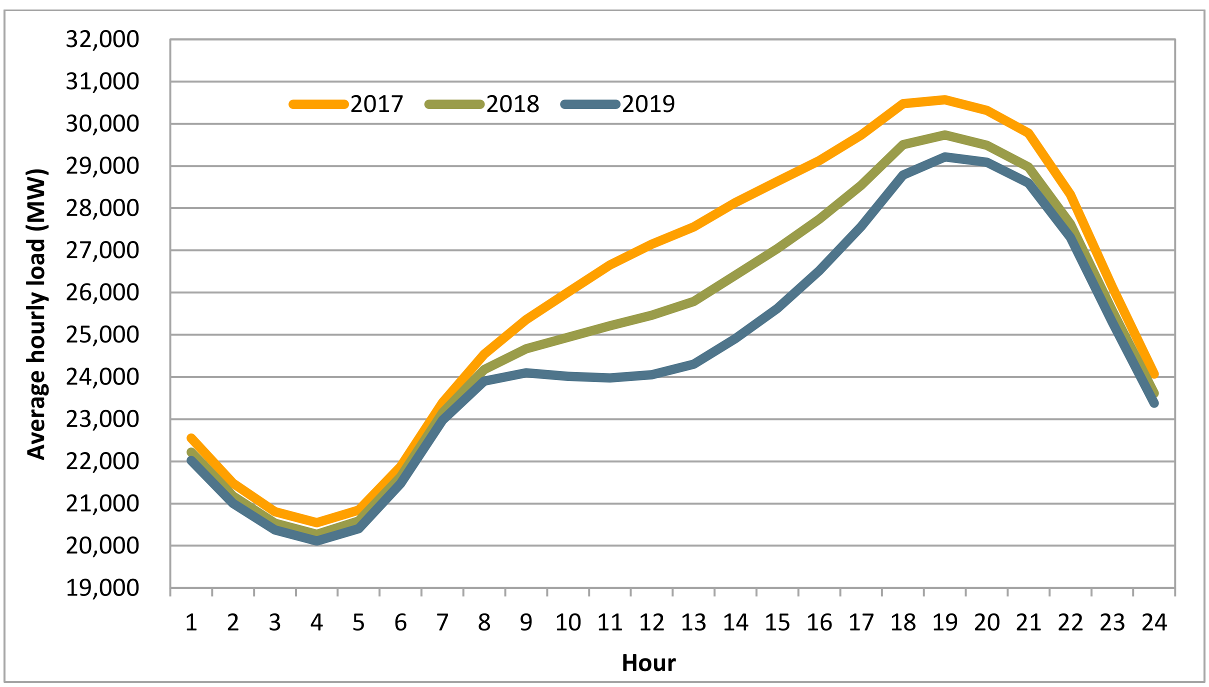
1.1.1 System loads

ISO load decreased in 2019, measured as both instantaneous peak load and total energy. Table 1.1 summarizes annual system peak loads and energy use over the last three years. The drop in total annual load in 2019 continued a trend of decreasing loads since 2011. In 2019, annual system load totaled 214,955 GWh, and averaged about 24,500 MW on an hourly basis. This was about a 2.5 percent decrease from 2018 and 5.6 percent from 2017. Figure 1.1 shows average hourly loads by year. Lower loads are due, in part, to increases in behind-the-meter solar generation, continued initiatives to improve energy efficiency, and lower statewide temperatures in 2019. The variations in the annual peak load are primarily a function of the weather conditions in the days leading up to and the day of the annual peak.

Table 1.1 Annual system load in the ISO: 2017 to 2019

Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2017	227,749	26,002	0.0%	50,116	8.4%
2018	220,458	25,169	-3.2%	46,427	-7.4%
2019	214,955	24,541	-2.5%	44,301	-4.6%

Figure 1.1 Average hourly load (2017-2019)

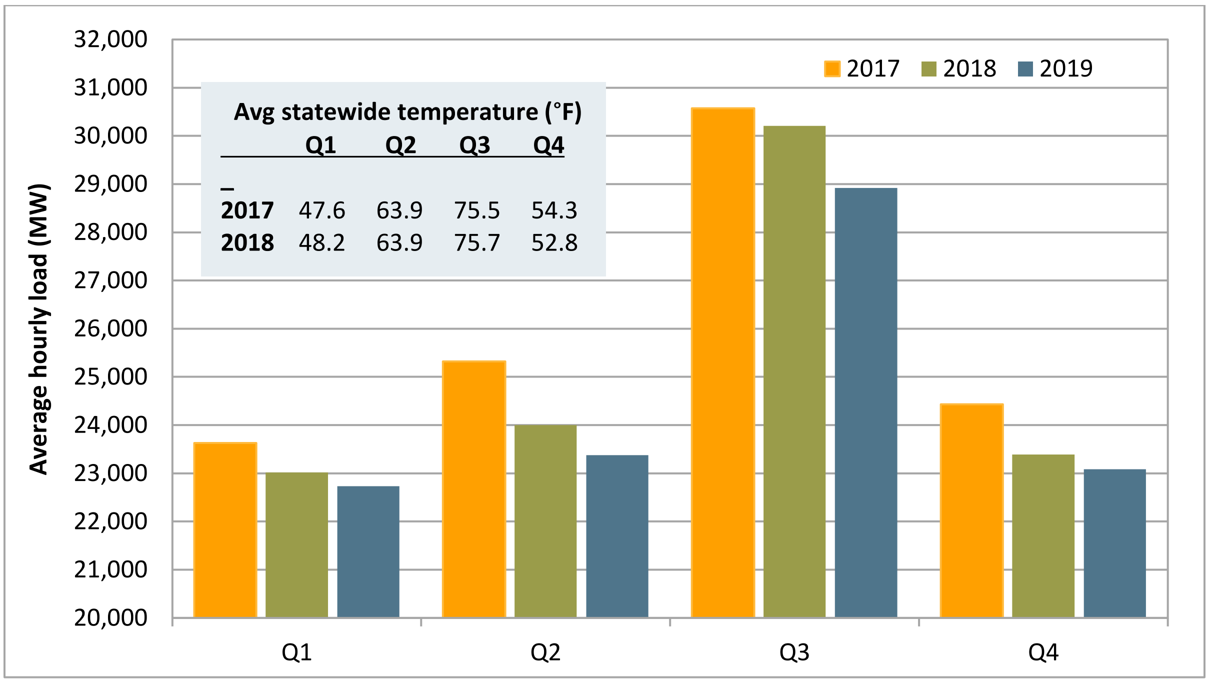


Seasonal load trends

Figure 1.2 shows the average hourly load by quarter as observed in 2019 and the prior two years. Figure 1.3 shows the average hourly load by month for these same years to show more detail. These figures work to paint a clearer picture of the trends and fluctuations of load over the years.

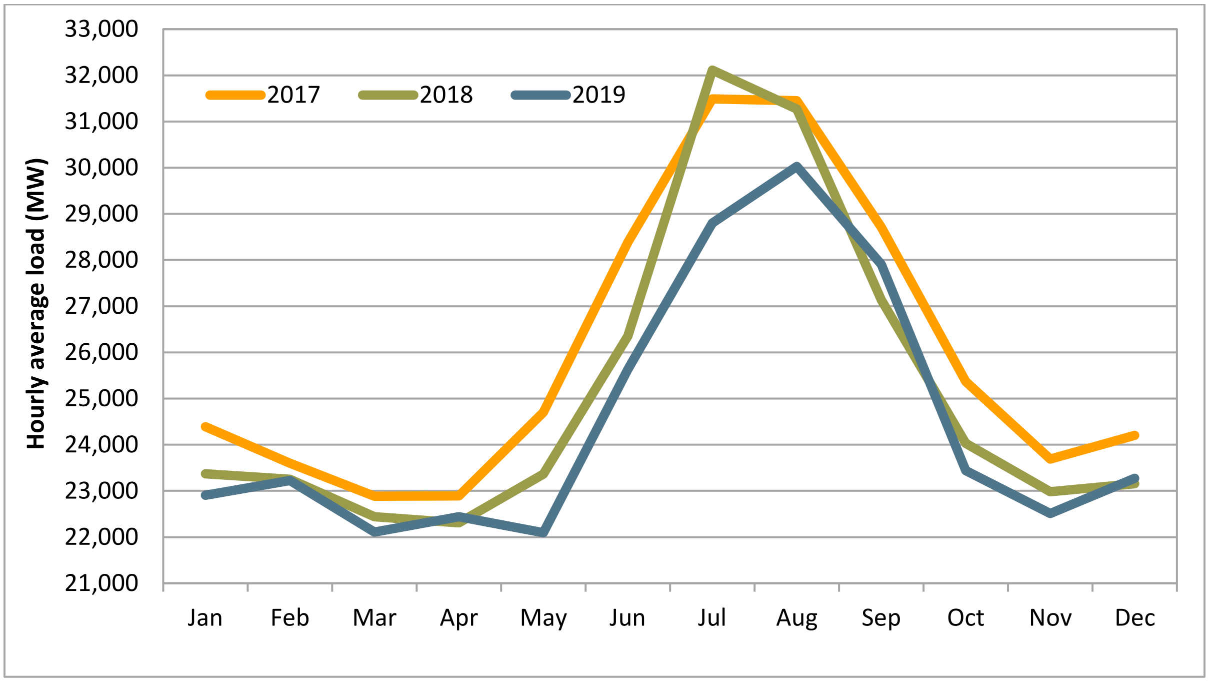
Average load was lower in each quarter of 2019 compared to all quarters of 2017 and 2018. Load trends are influenced by a number of factors, but do follow statewide temperatures on average.[38] The average statewide temperature was lower in 2019 for every respective quarter, which correlates with the lower average hourly load.

Figure 1.2 Average hourly load by quarter (2017-2019)



[38] For statewide temperature data, please see: Climate at a Glance: Statewide Mapping, National Oceanic and Atmospheric Administration (NOAA): https://www.ncdc.noaa.gov/cag/.

Figure 1.3 Average hourly load by month (2017-2019)

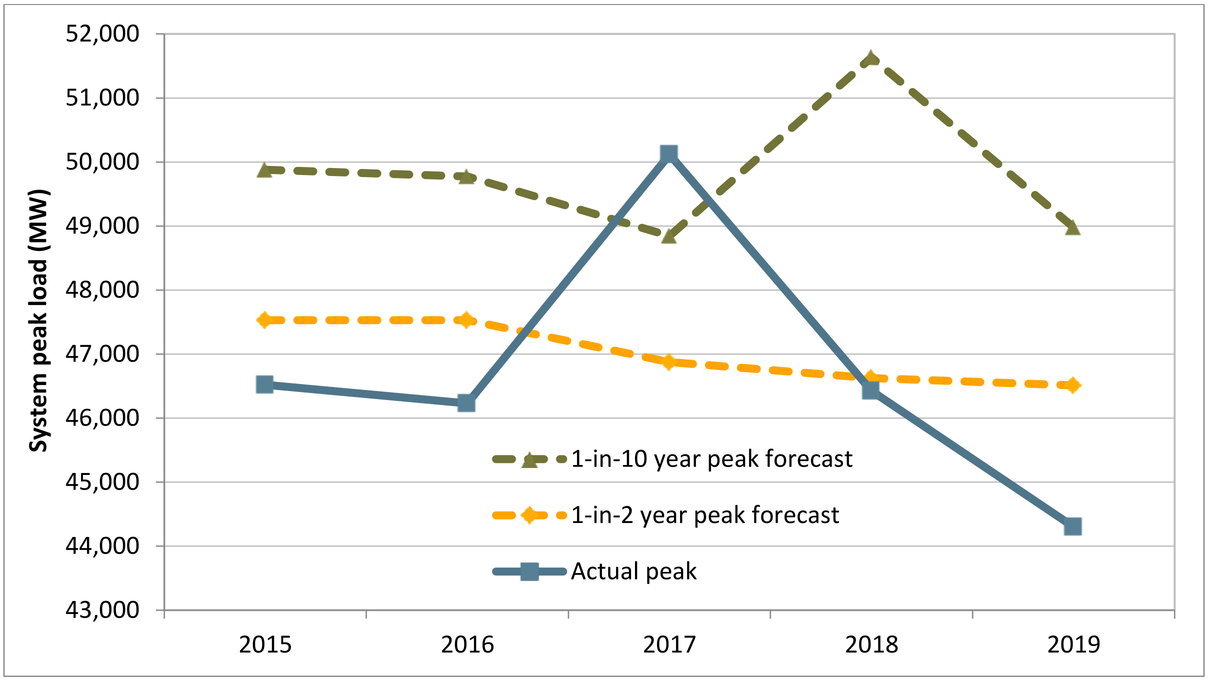


Peak load

Summer loads peaked at 44,301 MW on August 15th, significantly lower than peak load in 2017 or 2018 and the lowest load peak since 2003. System demand during the single highest load hour often varies substantially year-to-year based on the weather conditions that drive each year's peak load. The potential for extreme 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 2019 was about 5 percent lower than the ISO's 1-in-2 year load forecast (46,511 MW) and about 10 percent lower than the 1-in-10 year forecast (48,979 MW) as shown in Figure 1.4. Weather conditions during the 2019 ISO peak were mild, ranked as a 1-in-1.2 weather condition, lower than the 1-in-2 forecast. 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 1.4 Actual load compared to planning forecasts



Public Safety Power Shutoff (PSPS)

Under the PSPS program, begun in 2019, California's three largest investor-owned utilities de-energized both distribution and transmission lines, dropping load, when weather and other environmental factors indicated a high fire risk. In 2019, PSPS events occurred in October and November in targeted areas for all three utilities.[39]

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. Local capacity areas are by definition transmission constrained, and are therefore an important point of focus for reliability reasons as well as for the potential for market power. Chapter 7 of this report assesses the structural competitiveness of the market for capacity in local areas, along with the frequency and impact of local energy market power mitigation procedures. This section provides a high level perspective of supply and demand conditions in each local area.

Table 1.2 presents forecasted peak load, current dependable generation, and capacity requirements for these local capacity areas. Figure 1.5 shows the location of each local capacity area and the proportion of each area's load relative to the total peak load defined for all local areas.[40] The local capacity requirement is defined as the resource capacity needed to reliably serve load within a local capacity

39 Further information on PSPS events is available from the CPUC here: https://www.cpuc.ca.gov/Oct2019PSPS/

40 Note that the total local area peak load figure, as well as proportion of each local capacity area's load of the total, is illustrative. Each local area's load will peak at a different time from one another and from the system-coincident peak load.

area. Dependable generation is the net qualifying capacity of available resources within the locally constrained area.

Local capacity requirements increased to a total of 25,244 MW for 2019 compared to 25,207 in 2018. However, dependable generation decreased overall in these areas. This was largely due to recent gas generation retirements, described in greater detail in Section 1.2. Table 1.2 also shows the proportion of dependable generation capacity required to meet local reliability requirements established in the state resource adequacy program. In most areas, a high proportion of the available capacity is needed to meet peak reliability planning requirements.[41] 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.

Table 1.2 Load and supply within local capacity areas in 2019[42]

Local Capacity Area	LAP	Peak Load (1-in-10 year) MW	%	Dependable Generation (MW)	Local Capacity Requirement (MW)	Requirement as Percent of Generation
Greater Bay Area	PG&E	10,230	21%	7,054	4,461	63%
Greater Fresno	PG&E	3,070	6%	3,438	1,671	49%*
Sierra	PG&E	1,758	4%	2,150	2,247	105%*
North Coast/North Bay	PG&E	1,465	3%	890	689	77%
Stockton	PG&E	1,174	2%	633	777	123%*
Kern	PG&E	1,088	2%	475	478	101%*
Humboldt	PG&E	187	0.4%	202	165	82%
LA Basin	SCE	19,266	40%	10,225	8,116	79%
Big Creek/Ventura	SCE	5,162	11%	5,073	2,614	52%
San Diego	SDG&E	4,412	9%	4,358	4,026	92%
Total		**47,812**		**34,498**	**25,244**	

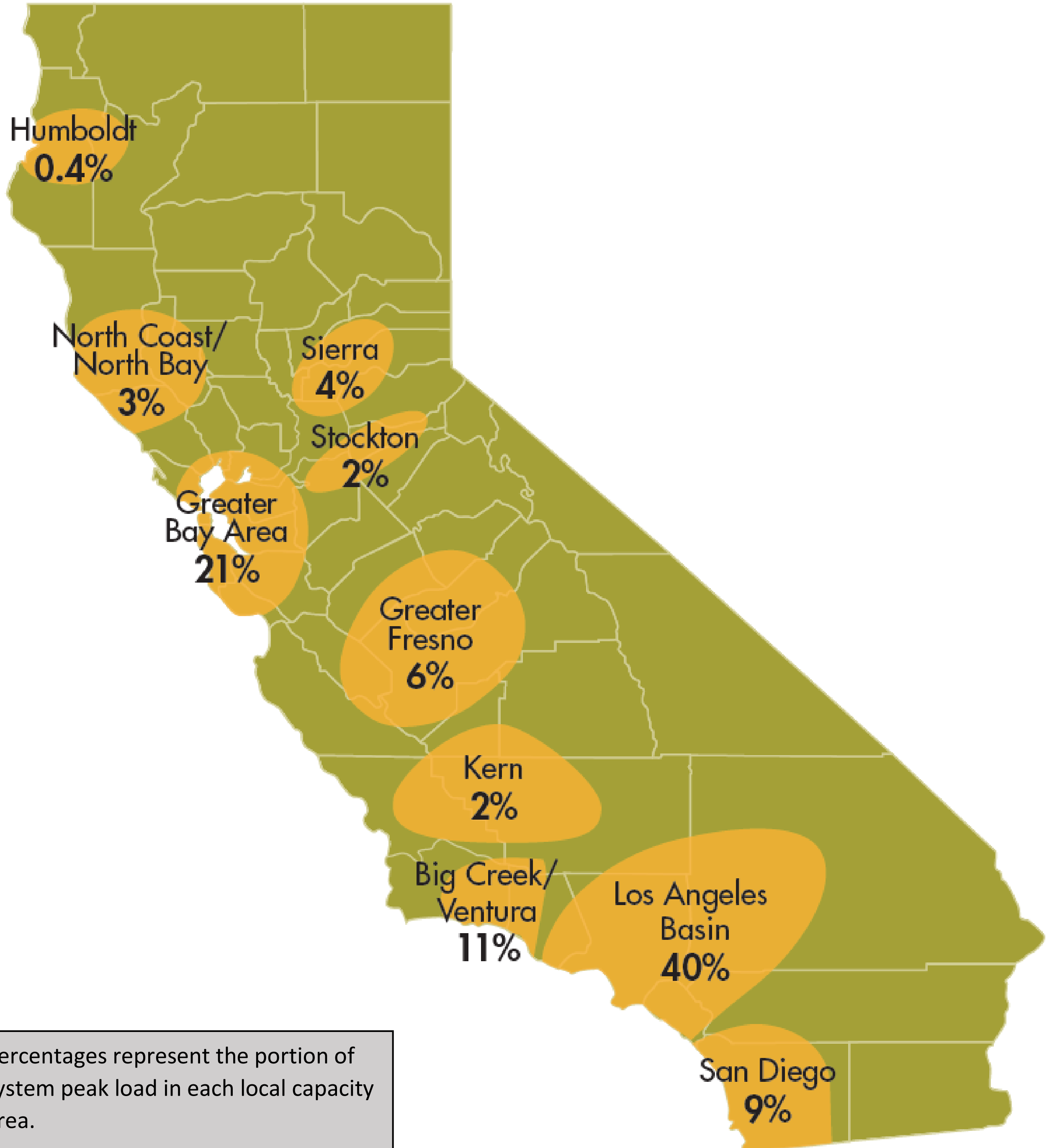
* Resource deficient LCA (or with sub-area that is deficient) – deficiency included in LCR. Resource deficient area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

Of the local capacity areas, the Los Angeles Basin and the Greater Bay Area have the highest local capacity requirements, in part due to high peak load based on 1-in-10 year forecasts. Between 2018 and 2019, the Greater Bay Area experienced a decrease in peak load projection (17 MW) and the amount of dependable generation (49 MW). As a result, the requirement for the Greater Bay Area as a percent of generation decreased from 73 percent in 2018 to 63 percent in 2019. The LA Basin local capacity area also experienced a decrease in dependable generation by over 500 MW. Unlike the Greater Bay area, forecasted peak load projections increased by about 360 MW. As a result, the requirement for the LA Basin as a percent of generation increased from 70 percent to 79 percent in 2019, indicating a greater reliance on fewer resources to meet local reliability needs.

41 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.

42 Obtained from the *2019 Local Capacity Technical Analysis*, May 15, 2018, p. 22, Table 5: http://www.caiso.com/Documents/Final2019LocalCapacityTechnicalReport.pdf

Figure 1.5 Local capacity areas



Percentages represent the portion of system peak load in each local capacity area.

1.2 Supply conditions

1.2.1 Generation mix

Natural gas, non-hydro renewables, and net imports were the largest sources of energy in the ISO's energy mix in 2019, together comprising over 75 percent of total system energy. The share of energy from natural gas generators decreased by about 1 percent compared to 2018. The share of hydroelectric generation of total generation increased by about 4 percent in 2019 relative to the levels observed in 2018. The share of non-hydro renewable generation increased less than 1 percent, driven by new solar generation capacity. Solar generation increased to about 13 percent of total generation, up from about 12 percent in 2018.

Monthly generation by fuel type

Figure 1.6 provides a profile of average hourly generation by month and fuel type. Figure 1.7 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 generation in 2019, with 30, 27, and 19 percent, respectively.[43] Compared to 2018, the share of energy from renewables increased less than 1 percent, natural gas decreased around 1 percent, and net imports decreased about 3 percent.
- Hydroelectric generation increased to 14 percent of supply, compared to 10 percent in 2018.
- Non-hydro renewable generation accounted for about 27 percent of total supply, an increase from about 26 percent in 2018, driven primarily by growth in generation from solar resources.[44]
- Nuclear generation provided 10 percent of supply, roughly the same as its contribution in 2018.

[43] Including all tie generation in net imports (as was done in 2016 and years prior), these percentages were 29, 25, and 25 percent respectively.

[44] In this analysis, non-hydro renewables do not include imports or behind-the-meter generation such as rooftop solar, but do include tie generation. Thus, this analysis may differ from other reports of total renewable generation.

Figure 1.6 Average hourly generation by month and fuel type in 2019

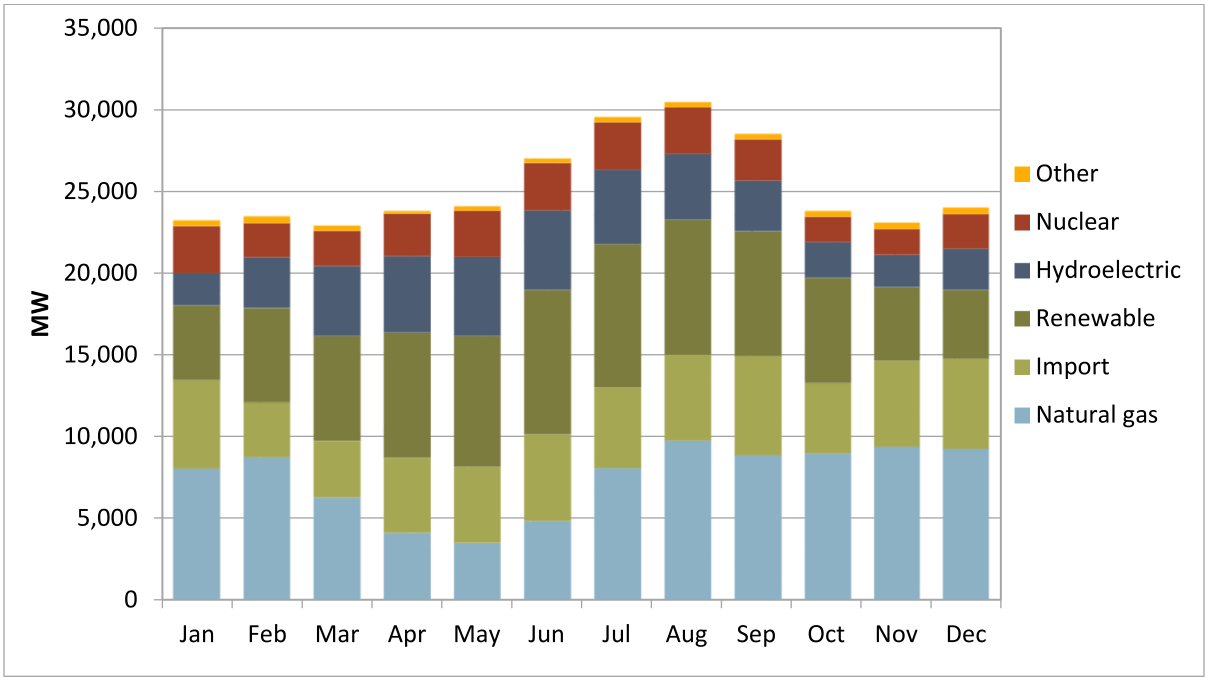
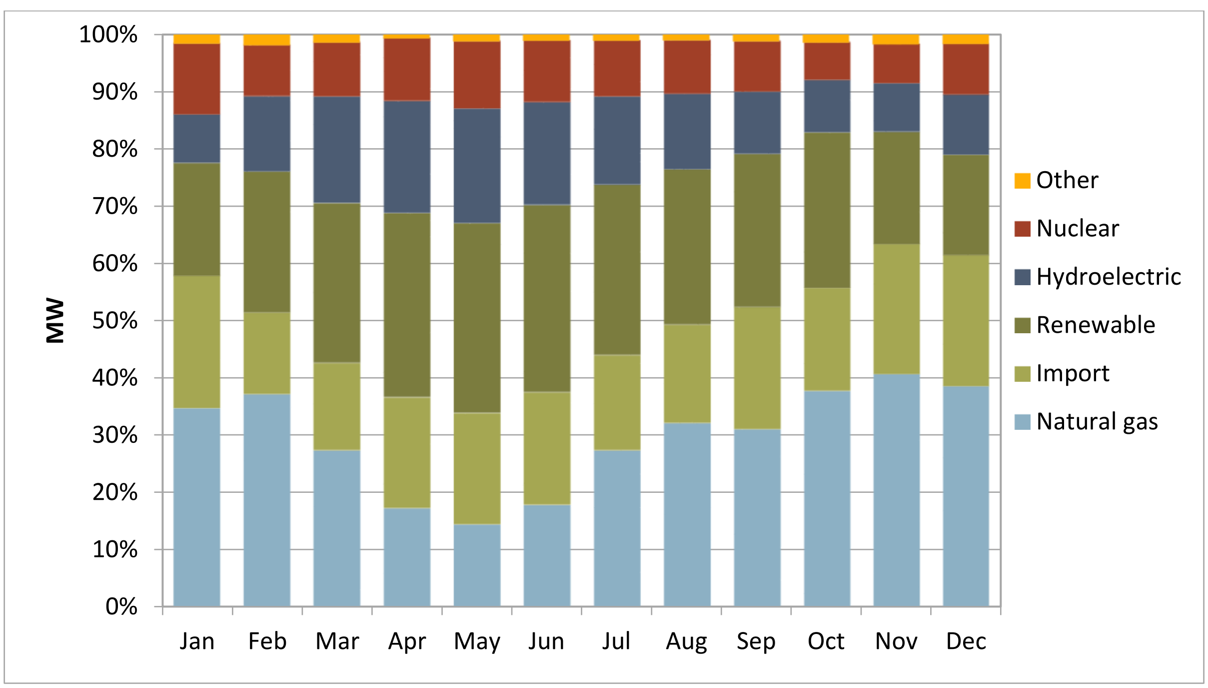


Figure 1.7 Average hourly generation by month and fuel type in 2019 (percentage)



Generation by fuel type

Figure 1.8 shows average hourly generation for the year by fuel type. During the first and second quarters in hours ending 18 through 21, as solar ramped down the resources being used to meet the evening peak included hydro, natural gas, and imports. In the third quarter, higher loads and lower wind and hydroelectric generation resulted in significantly more production from natural gas relative to the prior quarter, particularly in the evening hours. During the fourth quarter, lower loads coincided with lower solar and hydroelectric generation, which resulted in significantly more production from natural gas relative to other resource types compared to the third quarter.

Over the course of 2019, hour ending 19 averaged the highest amount of generation at about 29,700 MW, while hour ending 4 averaged the lowest at about 20,600 MW. Generation from nuclear, bio-based resources, and geothermal resources comprised on average about 3,900 MW of inflexible base generation. Generation from "other" resources, including coal, battery storage, demand response, and additional technologies, was a small share of generation, averaging about 320 MW.

Figure 1.8 Average hourly generation by fuel type (2019)

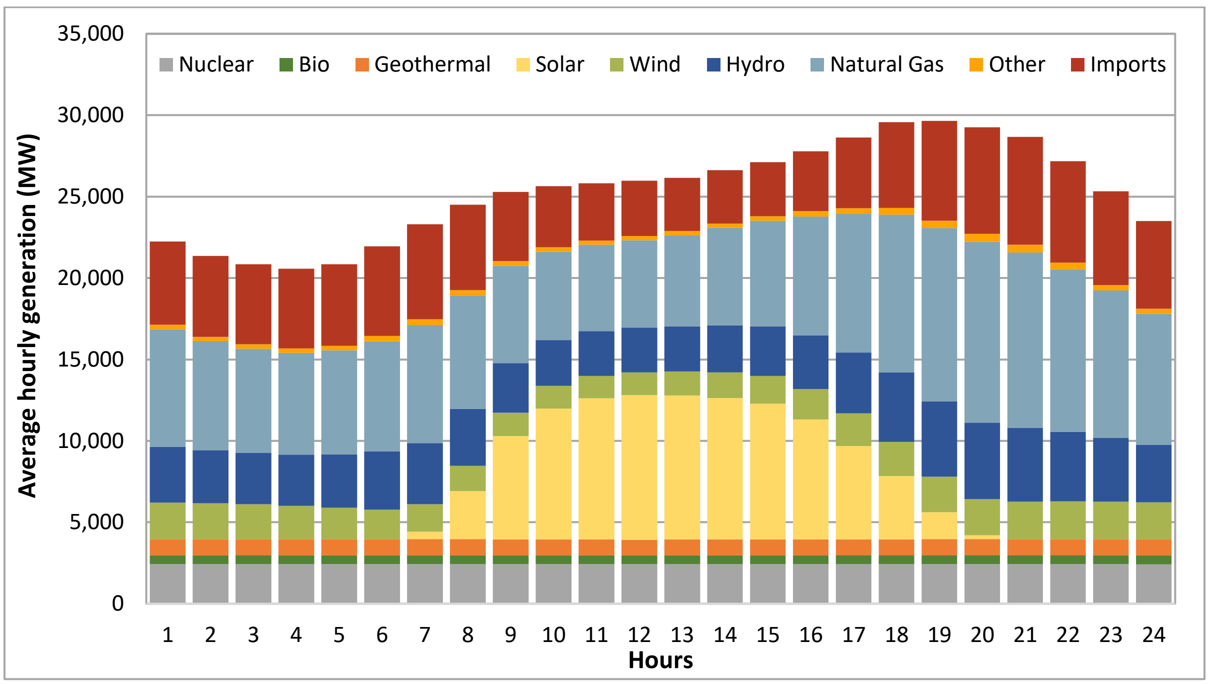
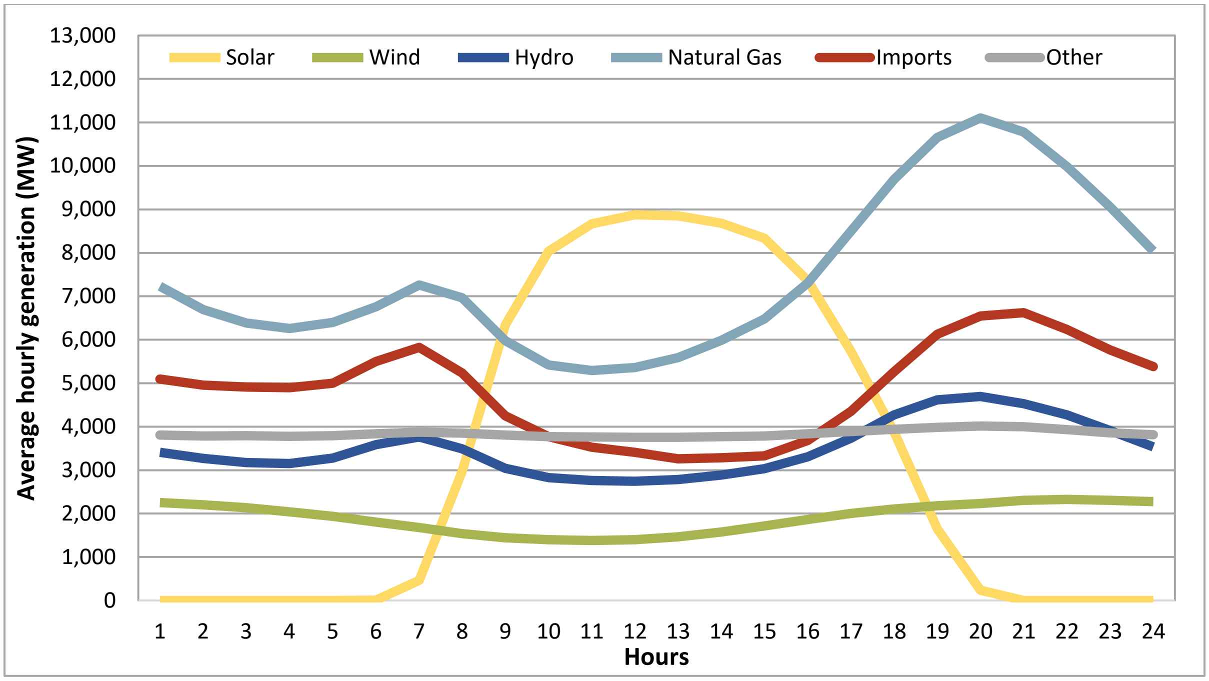


Figure 1.9 shows hourly variation of generation by fuel group, driven by hourly variation of solar production. Throughout the year, natural gas varied most over the day and produced significantly more than other resource types during the peak net load hours. Net imports and hydroelectric generation also varied significantly over the day, ramping up for the morning and evening net load peaks, and backing down when solar was producing.

During the year, imports consistently had higher levels of production than hydroelectric resources throughout the day. Wind generation typically complements solar production by generating more in the early morning and late evening, and less in the middle of the day. There was little variability from resources in the "other" category on an hourly basis.[45]

Figure 1.9 Hourly variation in generation by fuel type (2019)



1.2.2 Renewable generation

As noted above, about 27 percent of ISO load was met by non-hydro renewable and about 14 percent from hydroelectric generation. This section provides additional detail about trends in renewable generation, factors influencing renewable resource availability, and the impact of renewable generation on prices.

Figure 1.10 provides a detailed breakdown of non-hydro renewable generation including imports which are specifically identified as wind and solar resources.[46] As shown in Figure 1.10:

- In 2015, solar power became the largest source of renewable energy within the ISO. In 2019, overall output from solar generation increased by about 4 percent compared to 2018 and accounted for around 13 percent of total supply. The increase was primarily driven by the addition of new solar resources. The rate of increase in generation from solar has slowed over recent years.

45 In this figure, the "other" category contains nuclear, geothermal, bio-based resources, coal, battery storage, demand response, and additional resources of unique technologies.

46 In addition to values reported here, renewable and hydro resource generators provide energy through imports and behind-the-meter generation. These values are excluded due to lack of input data.

- Generation from wind resources increased by about 1 percent and contributed about 8 percent of total system energy.
- The overall output from geothermal generation decreased about 16 percent compared to 2018, and provided about 4 percent of system energy. This decrease was due in part to an extended outage for a set of geothermal resources located within a Public Safety Power Shutoff (PSPS) event area and fire zone.
- Biogas, biomass, and waste generation accounted for about 2 percent of system energy, remaining relatively unchanged compared to 2018.
-

Figure 1.10 Total renewable generation by type (2016-2019)

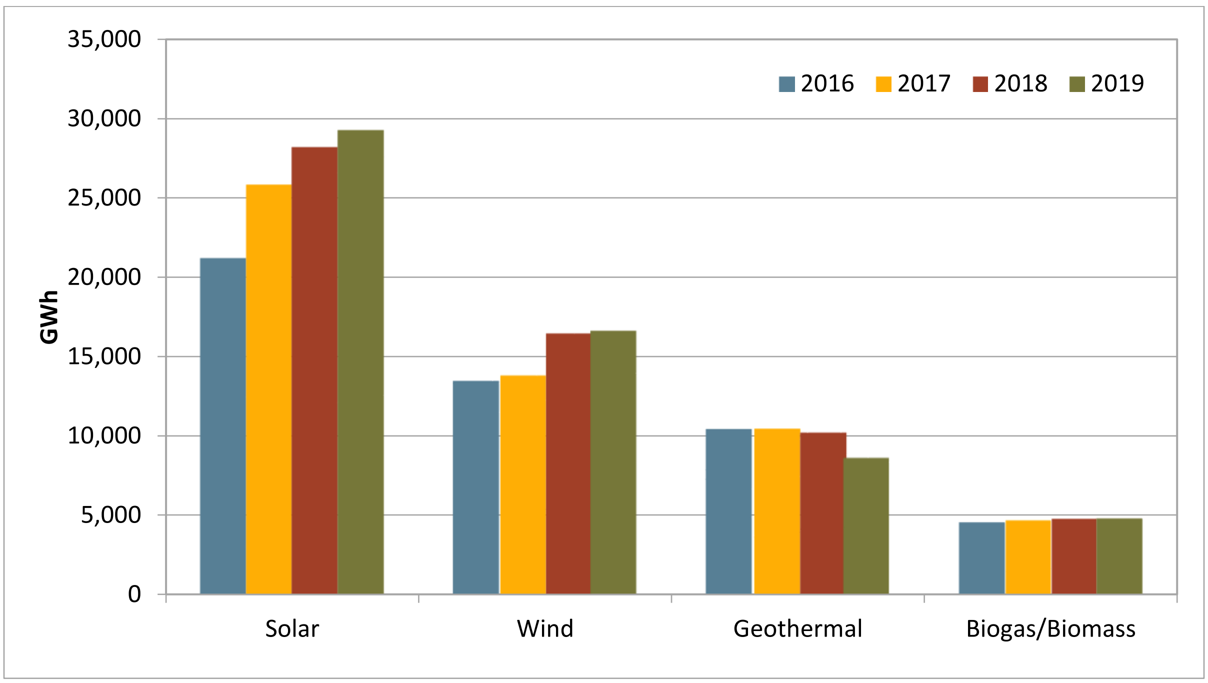
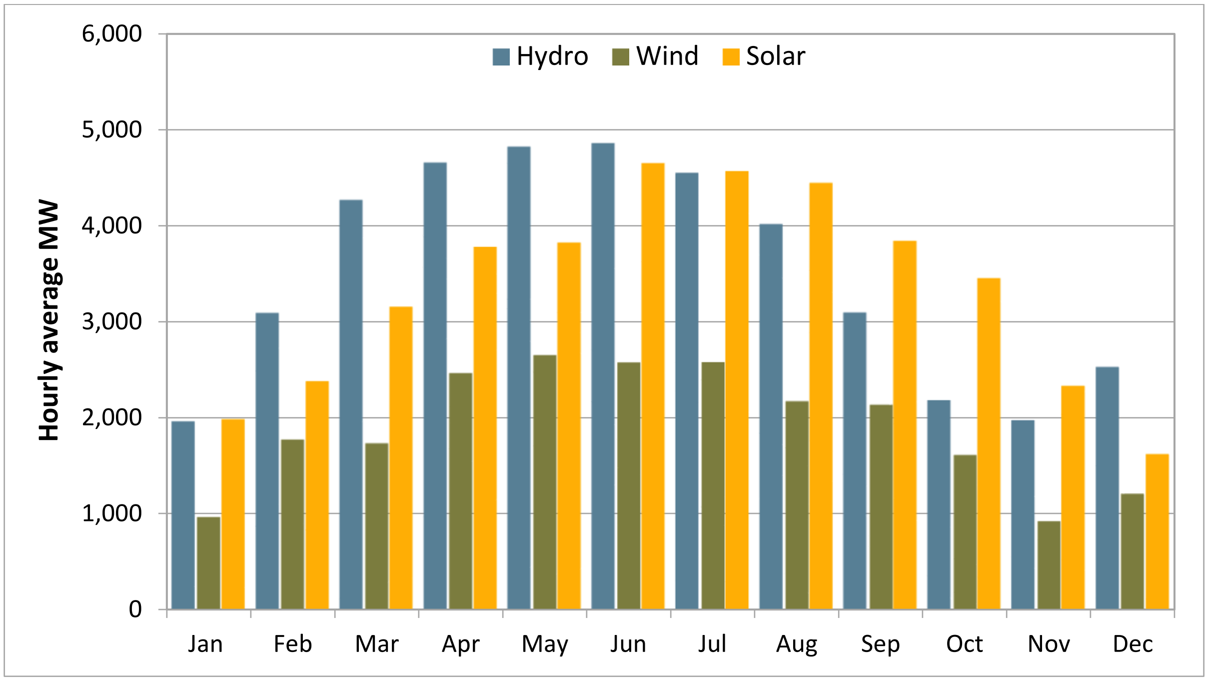


Figure 1.11 compares average monthly generation from hydro, wind and solar resources. With dramatically increased snowpack, the amount of energy produced by hydroelectric was higher than solar generation and wind generation for most months of 2019.

In 2019, average hourly solar generation peaked at 11,540 MW on July 2 during hour ending 13. Generation from wind resources peaked in May, while generation from hydro resources peaked in June. Non-hydro renewable generation made up the greatest portion of system generation during May, when it accounted for 33 percent of total generation.

Figure 1.11 Monthly comparison of hydro, wind and solar generation (2019)



Downward dispatch and curtailment of variable energy resources

When the amount of supply online 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 economically.

If the supply of bids to decrease energy is completely exhausted in the real-time market, the software may curtail self-scheduled generation including self-scheduled wind and solar generation.

Figure 1.12 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).

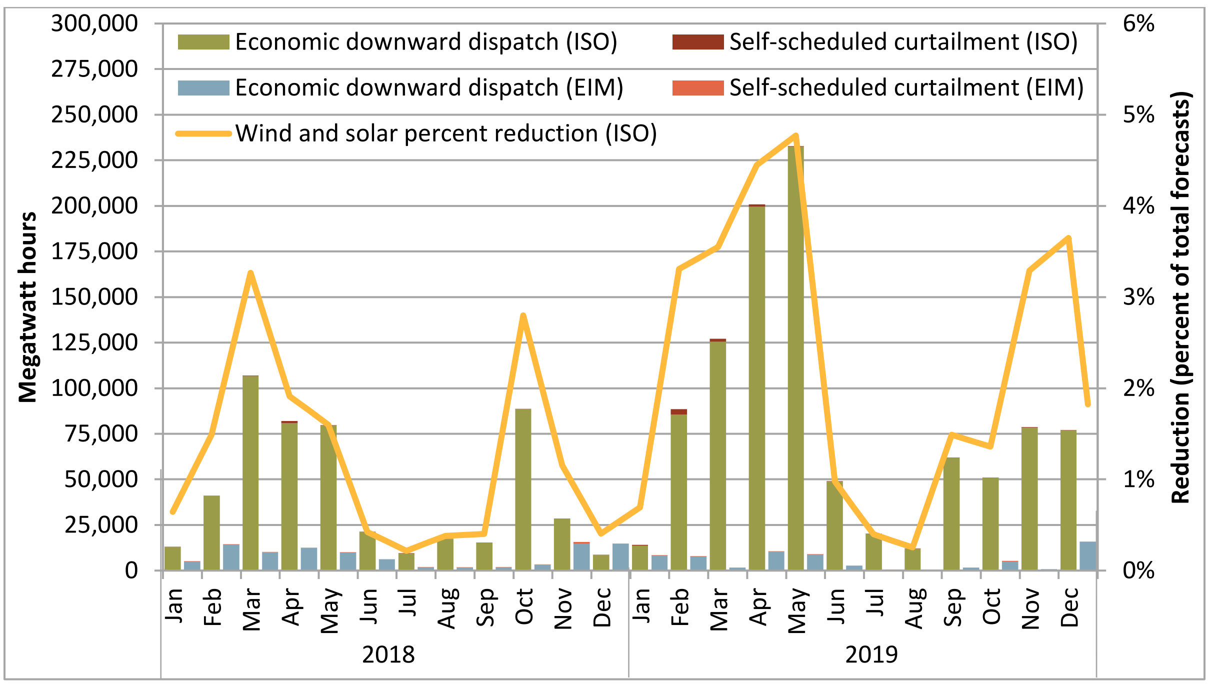
Figure 1.12 shows that nearly all of the reduction in wind and solar output during 2019 was the result of economic downward dispatch rather than self-schedule curtailment. The majority of renewable generation in the ISO dispatched down were solar resources, rather than wind resources. This is due in part to the greater solar capacity, the fact that a large portion of solar resources bid economically, and bidding patterns.

In 2019, ISO economic downward dispatch was higher in every month compared to the previous year, with the exceptions of August and October. The relatively high level of economic downward dispatch over the year was due in part to both higher levels of renewable capacity available and lower loads, among other contributing factors. The total reduction as a percent of total forecasted capability increased from 1.19 percent in 2018 to 2.24 percent in 2019.

Figure 1.12 also shows the amount of economic downward dispatch of non-ISO wind and solar resources in the energy imbalance market. Compared to 2018, downward dispatch of wind and solar resources in the energy imbalance market decreased in 2019.

Prices near or below the -$150/MWh floor continued to occur infrequently at about 0.1 percent of 5-minute intervals. This indicates a very low frequency of intervals when the supply of bids to decrease energy were exhausted leading to potential self-scheduled generation curtailment.

Figure 1.12 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 1.13 and Figure 1.14 show monthly solar and wind compliance with economic downward dispatch instructions during 2019.[47] 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.

For solar resources, the quantity and performance of complied economic downward dispatch increased in 2019 compared to the previous year. Solar resource performance was roughly 92 percent compliant, compared to 89 percent compliant in 2018. Performance dipped slightly in January and August, when the quantity of downward dispatch instruction was lower.

Wind performance improved in 2019 compared to the previous year. Wind resources complied with roughly 83 percent of downward dispatch instructions, compared to roughly 78 percent complied during

[47] This analysis includes variable energy resources in the ISO balancing area only.

2018. Under ISO market rules, all market participants and resources are expected to follow ISO dispatch instructions.

Figure 1.13 Compliance with ISO dispatch instructions – solar generation

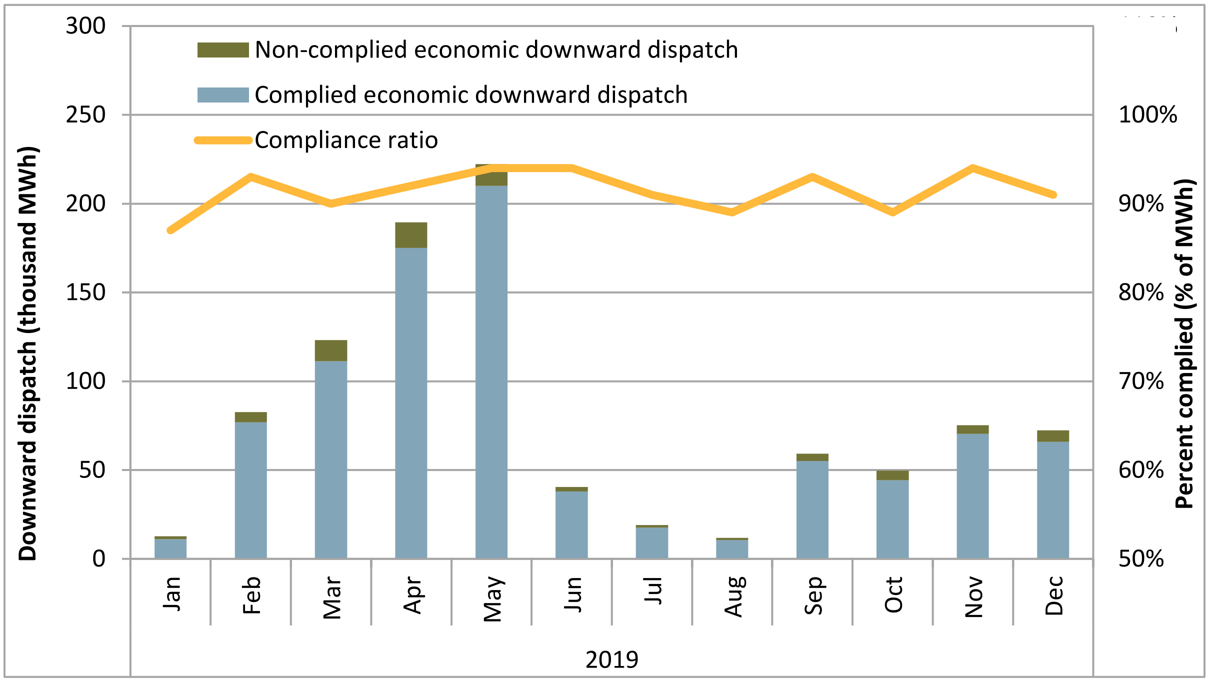
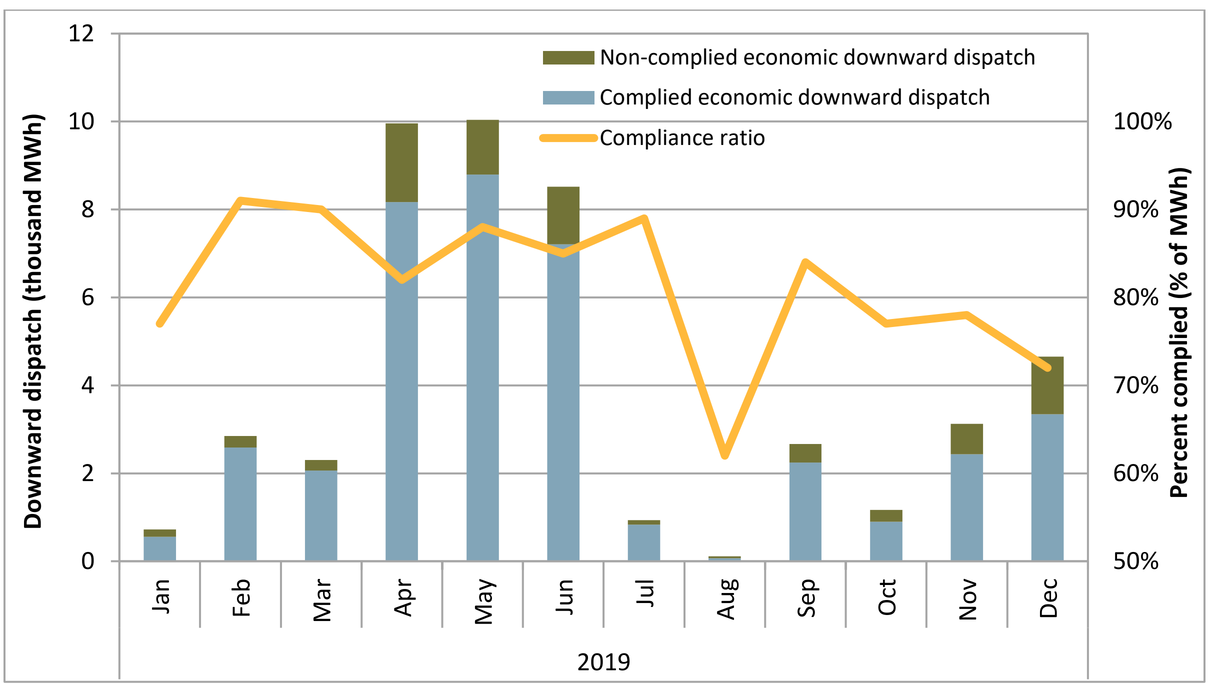


Figure 1.14 Compliance with ISO dispatch instructions – wind generation



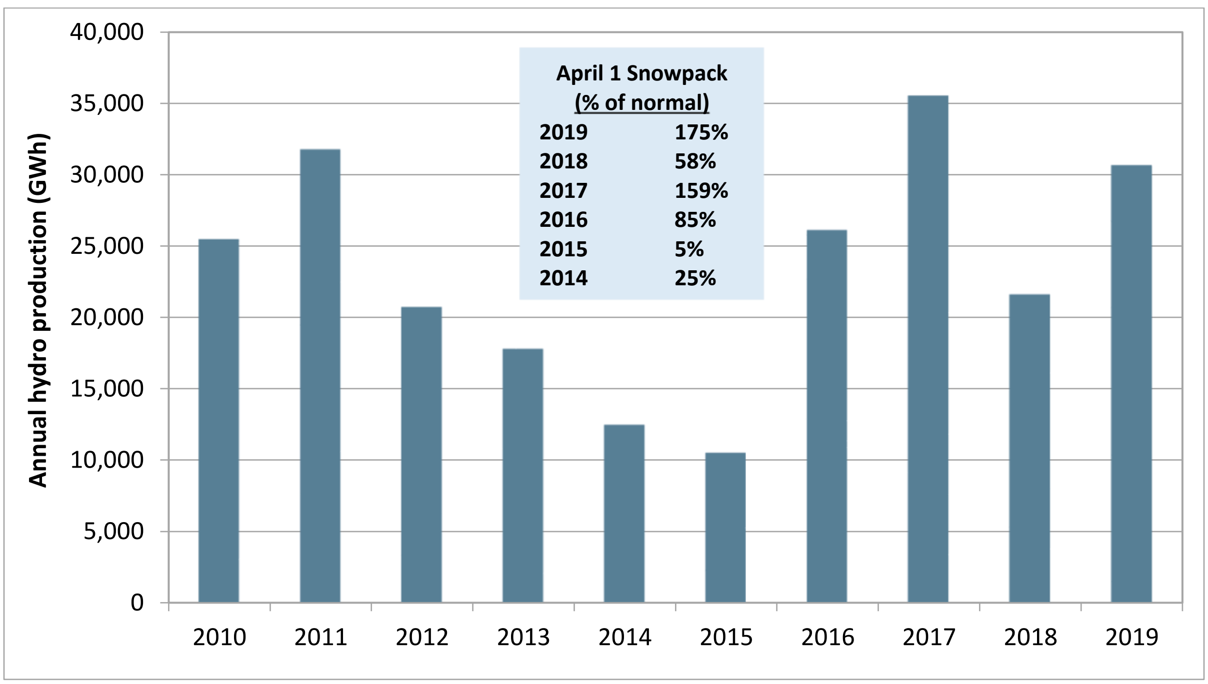
Hydroelectric supplies

Year-to-year variation in hydroelectric power supply in California can have a significant impact on prices and the performance of the wholesale energy market because run-of-river hydroelectric power generally reduces the need for baseload generation and imports. Hydro conditions also impact the amount of hydroelectric power and ancillary services available during peak hours from units with reservoir storage. In 2019, almost all hydroelectric resources in the ISO were owned by CPUC jurisdictional investor-owned utilities.

Total hydroelectric production in 2019 increased 42 percent from the prior year.[48] Statewide snowpack, as measured on April 1, 2019, was 175 percent of the long-term average – the highest since 1995.[49]

Figure 1.16 compares monthly hydroelectric output from resources within the ISO system for each month during the last three years. As in previous years, hydro generation in 2019 followed a seasonal pattern, with the highest generation in the late spring and early summer months. Generation in 2019 was lower than in 2017, but higher than 2018 during every month except January. Monthly generation in 2019 was about 42 percent higher, on average, than in 2018.

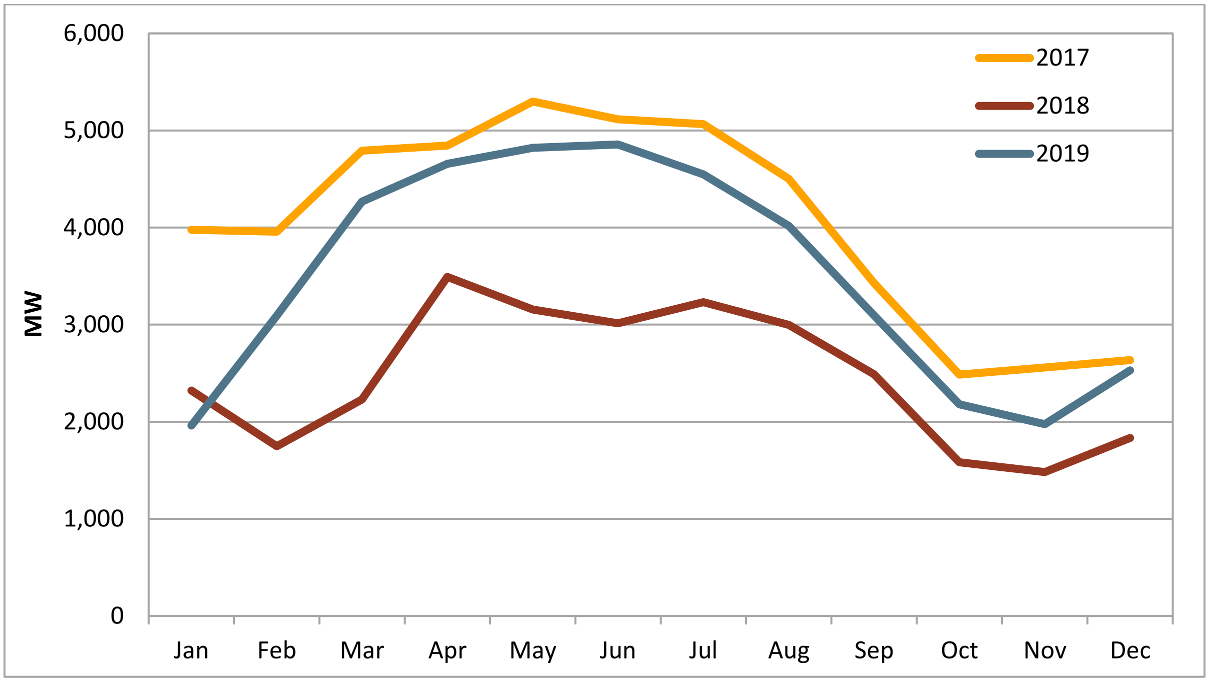
Figure 1.15 Annual hydroelectric production (2010-2019)



48 Starting in 2016, annual hydroelectric 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, hydroelectric 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 Course Measurements, California Department of Water Resources: https://cdec.water.ca.gov/cgi-progs/prevsnow/COURSES

Figure 1.16 Average hourly hydroelectric production by month (2017-2019)



1.2.3 Energy storage and distributed energy resources

Batteries

The number of batteries participating in ISO markets has increased over the past four years. Battery resources can currently participate in ISO markets through the non-generator resource (NGR) model or as demand response resources. The majority of batteries participating in ISO markets are located in locally constrained areas. DMM has made recommendations in Chapter 11 related to battery modeling and the potential need to apply market power mitigation to battery resources given the increasing volume of these types of resources.

Figure 1.17 shows the total capacity of batteries participating as non-generator resources represented both in terms of maximum output (megawatt) and maximum duration (megawatt-hour). Since 2015, the total capacity of batteries increased and totaled about 136 MW by the end of 2018. There were no new resources participating under the non-generator resource model in 2019.

Figure 1.17 Battery capacity (2015-2019)

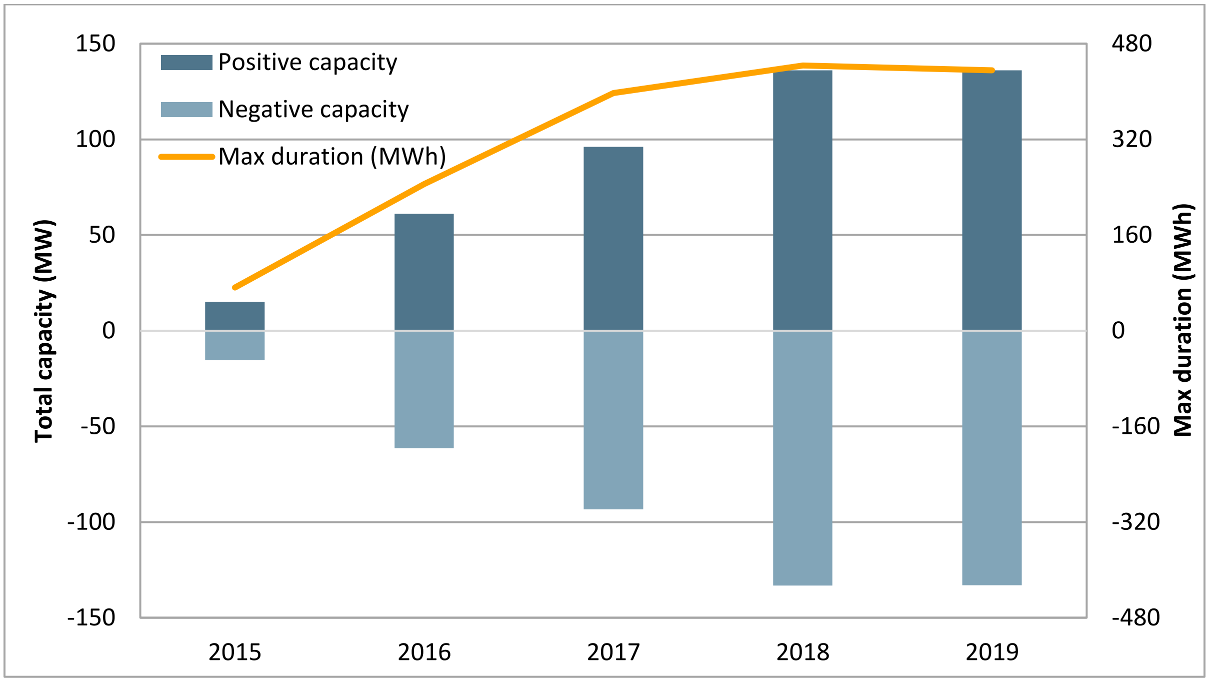


Figure 1.18 shows total capacity and duration for front-of-the-meter battery resources participating in the ISO market, based on resources' registered Pmax and maximum state of charge values. The duration of each battery is rounded to the nearest integer. Although duration ranges from one to seven hours, the greatest number of resources participating have a duration of four hours when operating at maximum capacity.

Figure 1.19 shows average hourly real-time schedules in 2019. Batteries continue to primarily receive awards for ancillary services, including regulation up, regulation down, and spin reserves. When providing energy, schedules are highest during the morning and evening ramping hours. Batteries often recharged overnight and during mid-day hours when renewable energy production was highest.

Non-generator resources remain effective for meeting both regulation capacity and mileage requirements. These resources have very fast ramp rates which allows them to provide a significant amount of mileage per megawatt of regulation capacity. Non-generator resources also bid relatively low prices to provide both regulation capacity and mileage. Thus, non-generator resources can contribute towards meeting both regulation and mileage requirements at relatively low cost compared to other resource types. Additionally, real-time ancillary service schedules shown in Figure 1.19 generally reflect day-ahead ancillary service awards, which are considered binding commitments in real-time.

Figure 1.18 Total battery capacity and duration (2019)

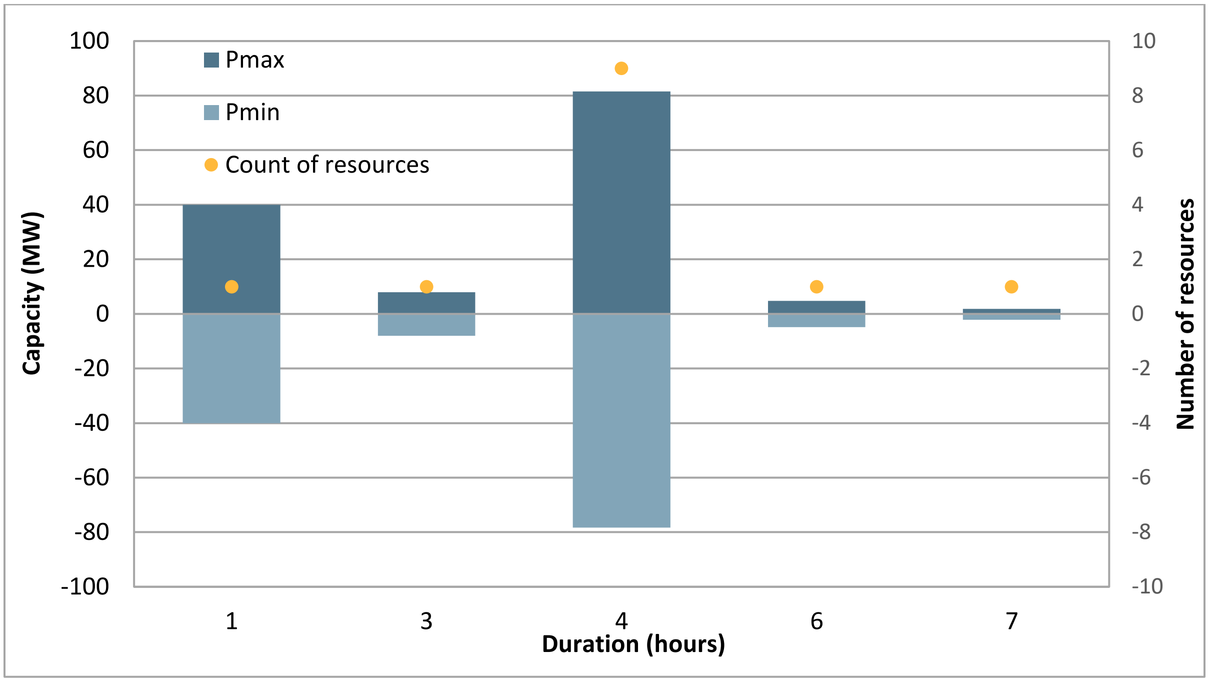


Figure 1.19 Average hourly battery schedules (2019)

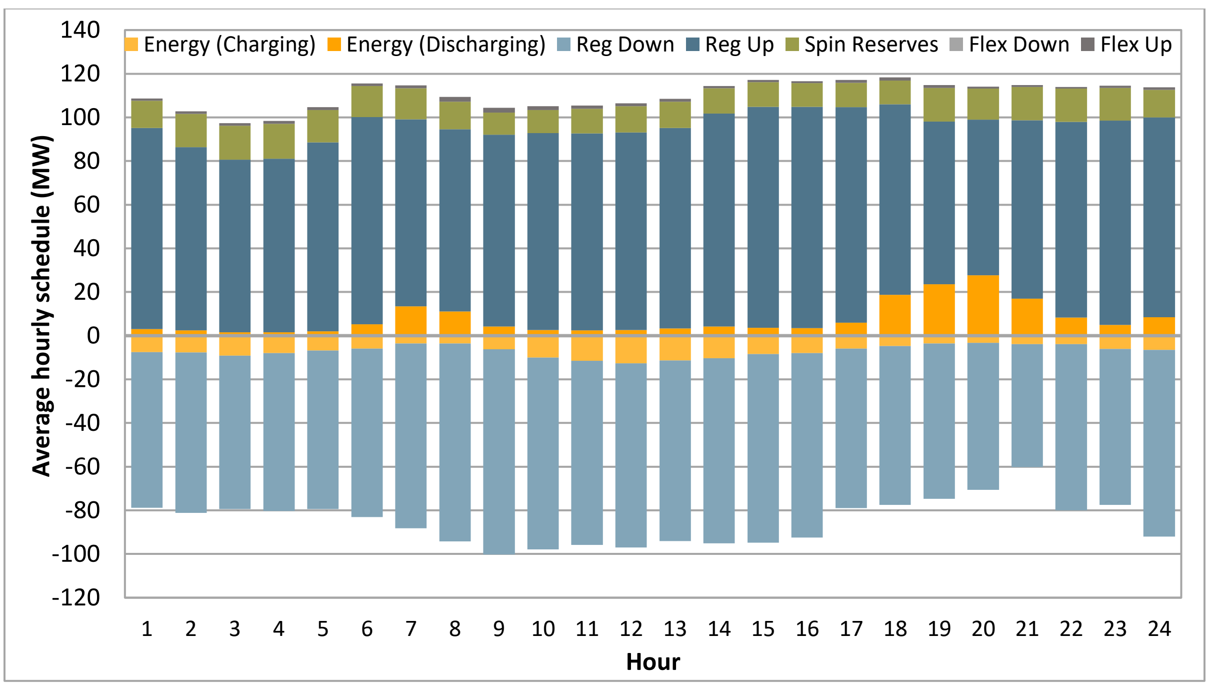


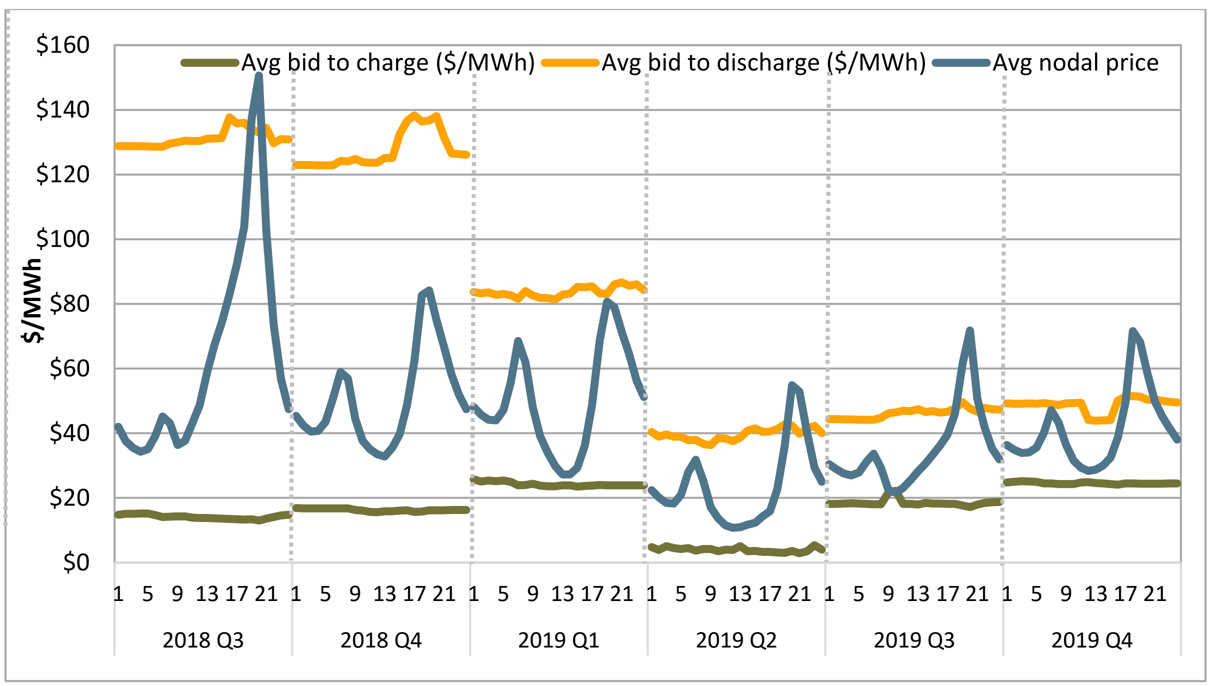
Figure 1.20 shows the average day-ahead energy bids of non-generator resources compared to average nodal prices by quarter beginning in the third quarter of 2018. Under the non-generator resource model, resources submit a single energy bid curve which reflects both willingness to charge and discharge. Compared to 2018, average discharge bid prices decreased while average charge bids increased, implying the average price spread between willingness to charge and discharge decreased in 2019.

As shown in Figure 1.20, discharge bids were generally economic between hours ending 19 and 21 starting in the second quarter of 2019. However, average charge bids continued to trend below corresponding nodal prices. Energy schedules on non-generator resources appear to be more limited by the economics of charge bids, particularly in real-time where the market may not be able to look out far enough to capture potential energy arbitrage opportunities between the lowest and highest net load hours.

Though non-generator resource energy bids appeared to be more economic in 2019 than in 2018, non-generator resource schedule compositions have not changed significantly compared to 2018, as shown in Figure 1.19. In particular, there has not been a significant increase in energy schedules compared to regulation capacity schedules in 2019. Regulation capacity scheduled in the day-ahead market continues to comprise the majority of battery resource schedules.

Battery resources have high ramp rates and generally bid lower than other resource types to provide regulation and mileage, making these resources very effective towards meeting both regulation and mileage requirements. In general, regulation and ancillary service awards carried over from the day-ahead market leave little room for batteries to provide additional movement in real-time, and any additional charging in real-time is generally limited by the economics of real-time charging bids.

Figure 1.20 Average day-ahead hourly battery bids and nodal prices (Q3 2018 – 2019)



Demand response

Demand response continues to play a role in meeting California's capacity planning requirements for peak summer demand. 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.

Demand response programs are operated by load serving entities throughout the state as well as third party providers. Demand response resources shown on monthly resource adequacy supply plans are scheduled by third-party (non-load serving entity) demand response providers. Utility-operated demand response programs are not shown on monthly resource adequacy supply plans and instead may be credited toward load serving entity resource adequacy requirements under local regulatory authority provisions.

Historically, many demand response programs were dispatched and administered by utilities, rather than by the ISO. However, since 2015, utility and third-party demand response programs have increasingly participated directly in ISO markets. The increase in ISO-participating demand response and third-party ownership can be attributed in part to the CPUC's demand response auction mechanism pilots, which seek to integrate demand response into the resource adequacy framework and allow for direct participation of demand response in the ISO market. Utilities also continue to integrate their demand response programs into the wholesale market.

Proxy demand response (PDR) resources can be bid economically in the day-ahead and real-time markets as supply. Reliability demand response resources (RDRR) can also participate economically in the day-ahead market. In the real-time market, reliability demand response resource capacity is offered as energy for reliability-only purposes at 95 to 100 percent of the bid cap.

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. In 2019, the ISO declared a Flex Alert on June 11 in response to reliability concerns related to high temperatures in California.[50]

Figure 1.21 shows the total demand response resource adequacy capacity (proxy demand response and reliability demand response resources) from 2017 to 2019 that was reflected on monthly load serving entity resource adequacy supply plans. This chart does not include utility-operated demand response credited against resource adequacy requirements under local regulatory authority provisions. Since 2016, demand response capacity shown on monthly supply plans has increased significantly, and continued to increase in 2019. This capacity was solely scheduled by third-party providers.

The number of individual resources comprising this capacity also continued to increase. In 2019, 65 percent of demand response resources shown on resource adequacy supply plans were sized with a maximum capacity less than 1 megawatt, exempting these resources from the ISO's resource adequacy availability incentive mechanism.

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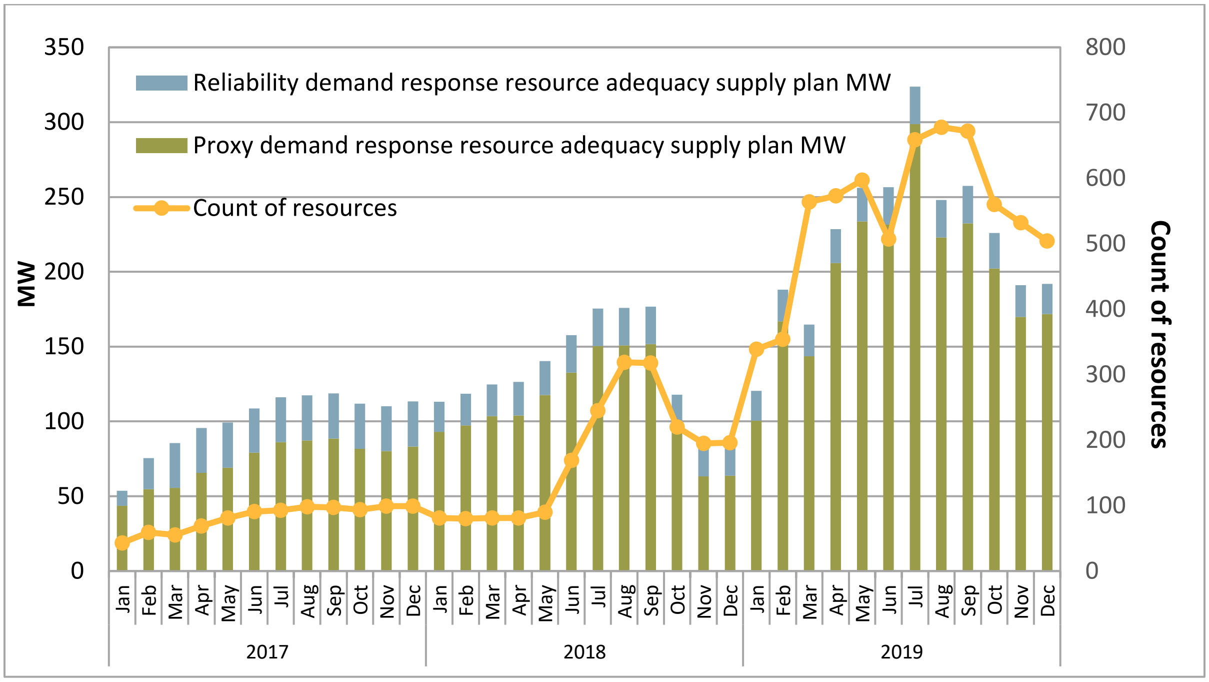
50 See: http://www.caiso.com/Documents/FlexAlertACallForEnergyConservation-InEffectToday-20190611.pdf

Figure 1.21 Demand response capacity reflected on monthly LSE RA supply plans



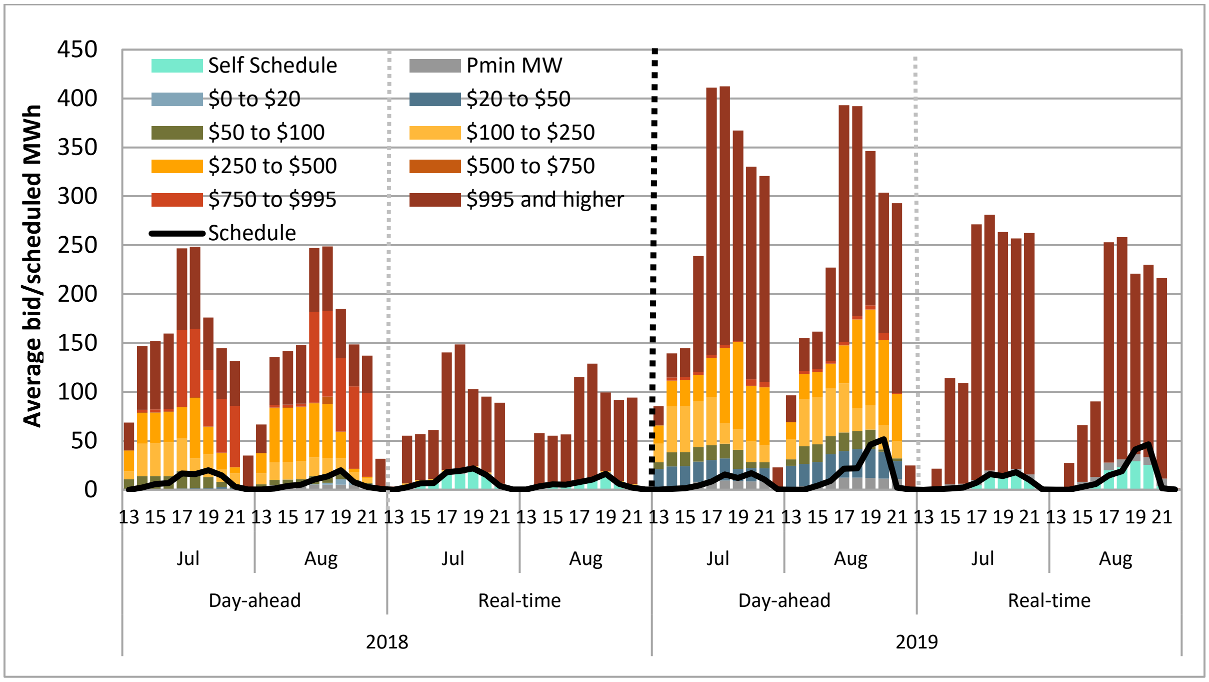
In addition to the increase in demand response reflected on monthly resource adequacy supply plans, proxy demand response capacity increased overall in the ISO market in 2019. Between 2018 and 2019, total registered proxy demand response capacity increased from 700 MW to about 1,700 MW. The majority of the increase in proxy demand response capacity can be attributed to utility-owned demand response registrations. Between 2018 and 2019, total registered reliability demand response resource capacity decreased from 1,700 MW to about 1,500 MW.

While the total amount of registered capacity and bids from demand response increased between 2018 and 2019, the incremental proxy demand response capacity bid into day-ahead and real-time markets was primarily bid at prices near the $1,000/MWh bid cap. However, there was also an increase in proxy demand response supply bid at prices below $100/MWh primarily associated with non-supply plan resources.

Figure 1.22 shows average energy bids by price range from all proxy demand response resources and average energy schedules in the day-ahead and real-time market in July and August of 2018 and 2019, in hours where demand response is most frequently bid and dispatched (hours ending 14 to 21).[51] In 2019 there was an increase in the volume of proxy demand response capacity bid in the day-ahead and real-time markets. Proxy demand response dispatched in the day-ahead and real-time markets also increased in 2019, particularly in August on days with high system loads.

[51] Hours ending 13 and 22 are also shown to capture the change in bid and scheduled capacity outside of the hours ending 14-21 window. In contrast to the 2018 annual report, this analysis includes only non-holiday weekdays.

Figure 1.22 Proxy demand response bid prices and average schedules July and August (HE 13-22)



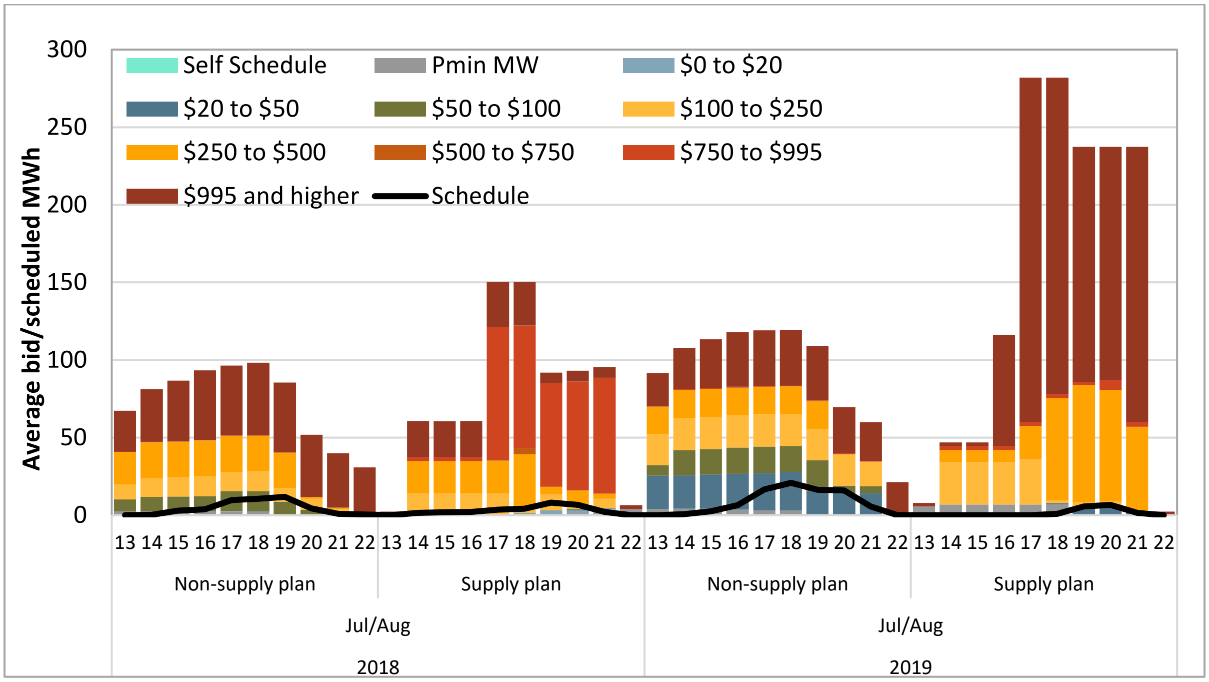
Reliability demand response resources were scheduled less frequently in both the day-ahead and real-time markets in 2019 versus 2018. In 2018 in the day-ahead market, reliability demand response schedules in hours 19 and 20 of July and August averaged 30 MWh compared to 5 MWh in 2019.

Figure 1.23 shows the change in proxy demand response capacity bid in the day-ahead market between July and August of 2018 and 2019, separating supply plan and non-supply plan resources.[52] Non-supply plan resource availability tended to be shaped and concentrated around hours 14-20 while supply plan resource availability was more aligned with availability assessment hours. The volume of non-supply plan proxy demand response bid into ISO markets increased modestly in 2019, despite a significant increase in registered non-supply plan capacity in 2019. While utility demand response programs continued to be integrated into the ISO market in 2019, total utility demand response capacity bid into the ISO markets consistently fell short of utility demand response credits to resource adequacy requirements in peak load hours.

Additionally, comparable levels of supply plan and non-supply plan capacity were bid more economically in 2019 than in 2018. While total supply plan proxy demand response capacity increased in 2019, the majority of incremental capacity was offered near the $1,000/MWh bid cap.

52 Like Figure 1.22, in contrast to the 2018 annual report, Figure 1.23 includes only non-holiday weekdays.

Figure 1.23 Supply plan and non-supply plan day-ahead PDR bid prices July and August



While supply plan proxy demand response bid capacity increased in 2019, DMM has also raised concerns that bid capacity was frequently in excess of actual load reduction capability from underlying resources.[53] DMM found that actual load associated with underlying resources was often insufficient to support load reduction up to resource adequacy values and capacity bid into the market in several months in 2019. While demand began to trend above bid capacity in July and August in aggregate, this was not the case for each individual demand response provider. Therefore, DMM has concerns about the validity of a portion of the supply plan proxy demand bid capacity reflected in Figure 1.23.

Dispatch and performance of demand response

Since 2016, DMM has raised concerns that proxy demand response resources may be dispatched for incremental energy on a 5-minute basis, even though these resources may not have the capability to respond to isolated 5-minute dispatches. Resources dispatched in the 5-minute market contribute to setting system marginal prices even when they cannot respond to such dispatches.

In situations when the power balance constraint was relaxed in 2019, demand response resources frequently had the highest priced bids dispatched and thus set system prices when the load bias limiter was triggered. However, the underlying demand response programs were often not able to respond to 5-minute dispatches.

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53 *Q3 Report on Market Issues and Performance*, December 10, 2019, pp. 90-92: http://www.caiso.com/Documents/2019ThirdQuarterReportonMarketIssuesandPerformance.pdf

In November 2019, FERC approved the ISO's Energy Storage and Distributed Energy Resources phase 3 (ESDER 3) policy which introduced hourly and 15-minute real-time dispatch options for demand response resources.[54] DMM supported this enhancement and expected that this feature could help improve the performance of demand response resources and address concerns that many of these resources cannot respond to 5-minute dispatches. The ISO implemented ESDER 3A enhancements in November 2019.[55] DMM reported that there had been very limited use of the new dispatch options through the end of 2019 and will continue to monitor the use of the new features.[56]

Figure 1.24 below shows average hourly 5-minute market dispatch of supply plan and non-supply plan proxy demand response resources compared to performance in July and August of 2018 and 2019, in hours ending 15 to 21 on non-holiday weekdays.[57] Proxy demand response dispatches increased in 2019 for non-supply plan resources while performance rates dropped. Conversely, dispatches of supply plan resources decreased in 2019 while performance rates appeared to increase.[58]

Despite an overall increase in proxy demand response performance as submitted by demand response providers, performance remained poor for several individual resources which demonstrated an inability to respond to isolated 5-minute dispatches. In addition to these resources not utilizing less flexible dispatch options, DMM also observed that many demand response resources continued to be modeled as fast responding by registering high ramp rates and short start-up times, despite low response rates with respect to real-time dispatches.

54 *Order accepting tariff amendment to implement demand response enhancements*, ER19-2733, FERC, November 6, 2019: http://www.caiso.com/Documents/Nov6-2019-LetterOrderAcceptingTariffAmendment-EnergyStorage-DistributedEnergyResourcePhase3-ER19-2733.pdf

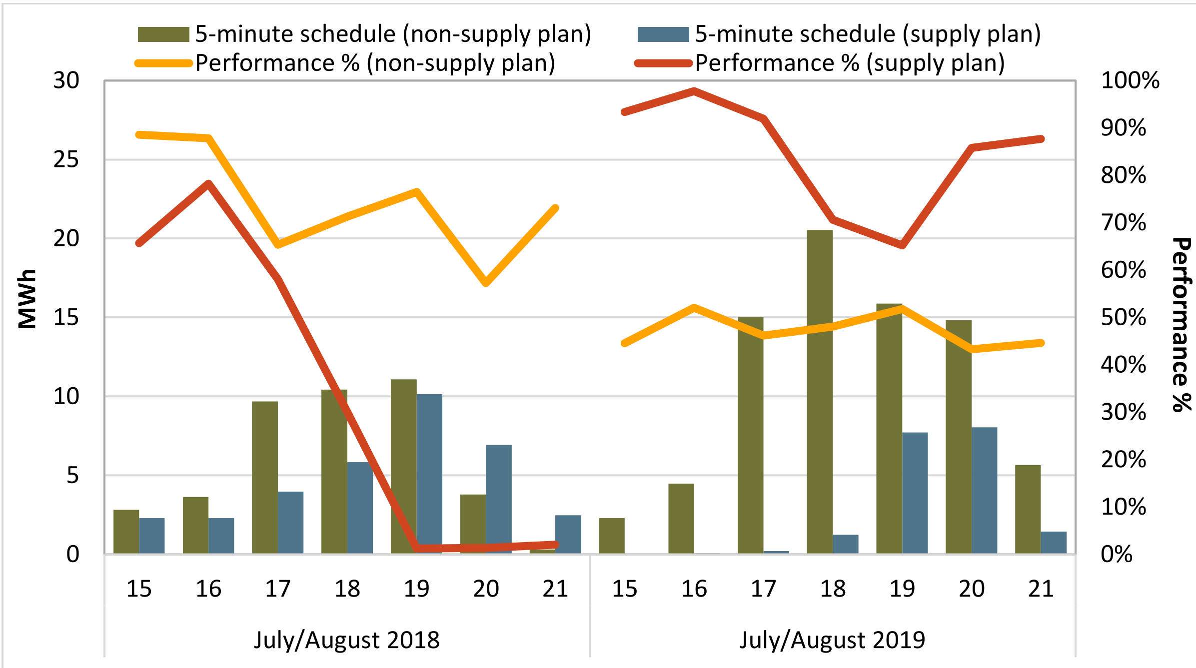
55 In ESDER phase 3, the ISO also proposed a load shift product for behind-the-meter storage resources under the proxy demand response participation model and to recognize behind-the meter-curtailment of electric vehicle supply equipment load. These two proposals (ESDER 3B) are scheduled to be filed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

56 *Q4 Report on Market Issues and Performance*, February 28, 2020, p. 82: http://www.caiso.com/Documents/2019FourthQuarterReportonMarketIssuesandPerformance.pdf

57 Performance rate is bound between 0 and 100 percent. For example, if a resource curtailed more load relative to its baseline than its dispatch instruction, performance would be capped at 100 percent. If a resource's load exceeded its load baseline, its performance would be 0 percent.

58 In November 2018, the ISO implemented policy changes associated with the energy storage and distributed energy resources 2 (ESDER2) policy initiative. Starting November 2018, demand response providers began to calculate resource baselines and performance values instead of the ISO. Performance metrics for 2019 are based on the assumption that performance values are calculated accurately by demand response providers. Ongoing review of demand response resource performance suggests that some resources' performance values may be inconsistent with underlying metered load and load baselines. Thus, the actual performance of proxy demand response resources may be lower than what has been reported to the ISO.

Figure 1.24 Proxy demand response schedules and performance July and August



1.2.4 Net imports

Peak hours and average prices

Total generation from net imports decreased about 15 percent in 2019 compared to 2018.[59] As shown in Figure 1.25, net imports from sources in the Northwest decreased by 25 percent, while net imports from the Southwest decreased by about 1 percent.

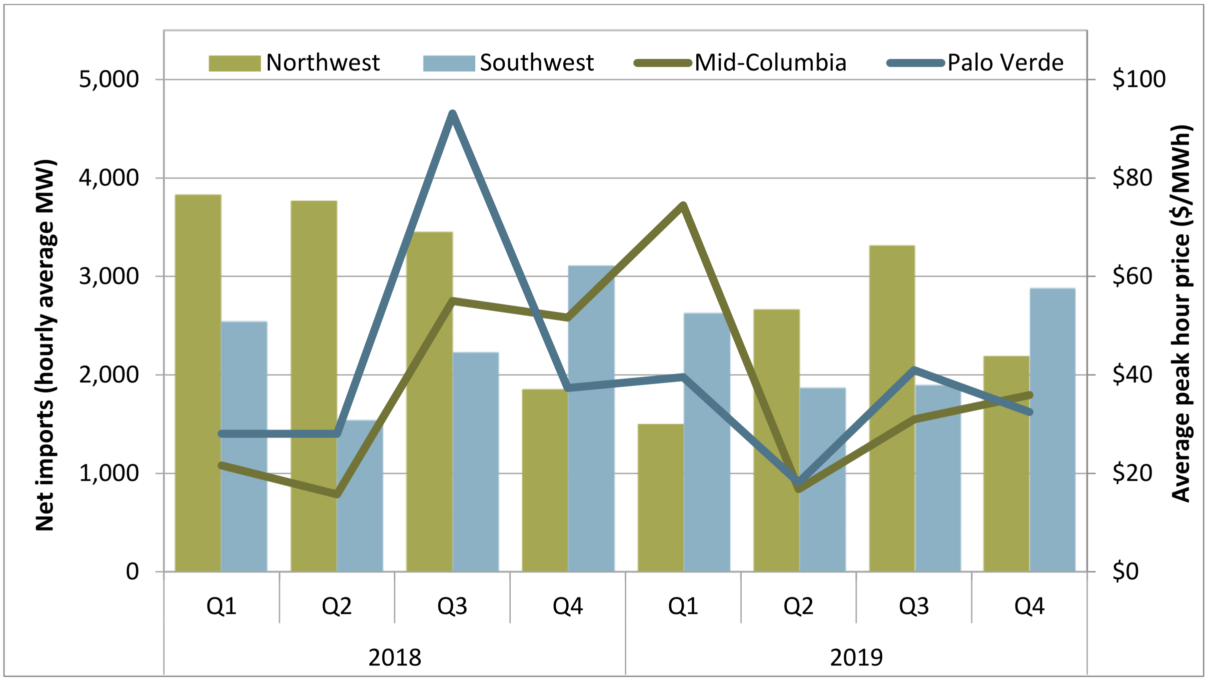
Figure 1.25[60] also shows the quarterly average bilateral prices at Mid-Columbia (Mid-C) and Palo Verde. Prices at Mid-Columbia were substantially higher than Palo Verde in the first quarter of 2019, but similar in the remaining quarters.

Net imports from the Southwest increased in most quarters over the previous year, while net imports from the Northwest were lower in most quarters. In the first and fourth quarters net imports from the Southwest exceeded those from the Northwest while in the second and third quarters the opposite occurred.

59 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.

60 In 2019 this figure removes pseudo tie generators and incorporates the same peak hours for the bilateral prices as for net imports. This is a change from the prior year and results in a decrease in net import megawatts from both the Northwest and Southwest; representation of bilateral prices were not impacted by the change.

Figure 1.25 Net imports and average day-ahead price difference (peak hours, 2018-2019)



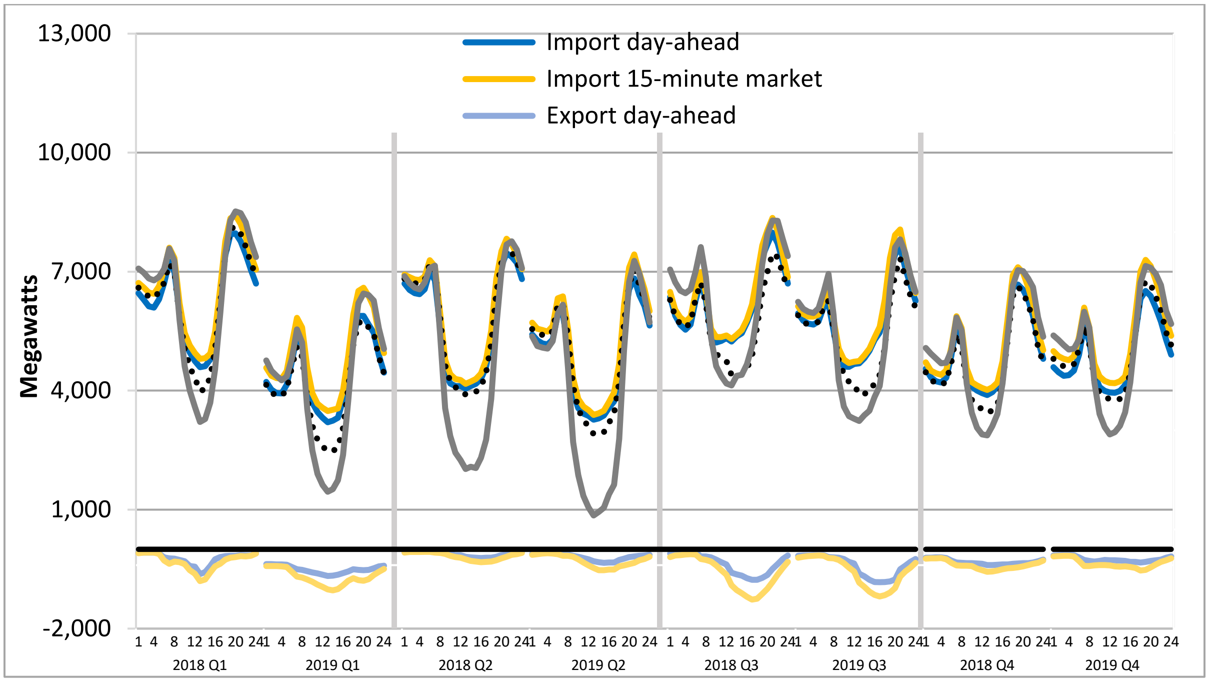
Net interchange – ISO imports and exports with EIM transfers

The energy imbalance market provides additional interchange between the ISO and other balancing authority areas, both in the import and export directions. The net quantity of imports to and exports from the ISO as well as EIM transfers is the ISO system net interchange.

As shown in Figure 1.26 average hourly cleared imports (shown in dark blue and dark yellow) peaked at a similar hour, volume, and quarter as in 2018. First quarter net interchange was about 2,000 MW lower than 2018 in all hours. Fourth quarter net interchange was similar to 2018 and both second and third quarter interchange were similar to 2018 in peak hours.

The greatest import transfer into the ISO from the EIM occurred in the first quarter of 2019 in hour ending 22 at about 830 MW. Exports (shown as negative numbers below the horizontal axis in pale blue and yellow), were the highest in the third quarter, peaking at about 820 MW in hour ending 16 through 19. The average net interchange, excluding EIM transfers (shown in dashes), is based on meter data and averaged by hour and quarter. The solid grey line adds incremental EIM interchange; the lowest point for 2019 occurred in the second quarter in hour ending 12 with a low point of about 940 MW.

Figure 1.26 Average hourly net interchange by quarter



1.2.5 Generation outages

This section provides a summary of generation outages in 2019. Overall, the total amount of generation outages and the 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.

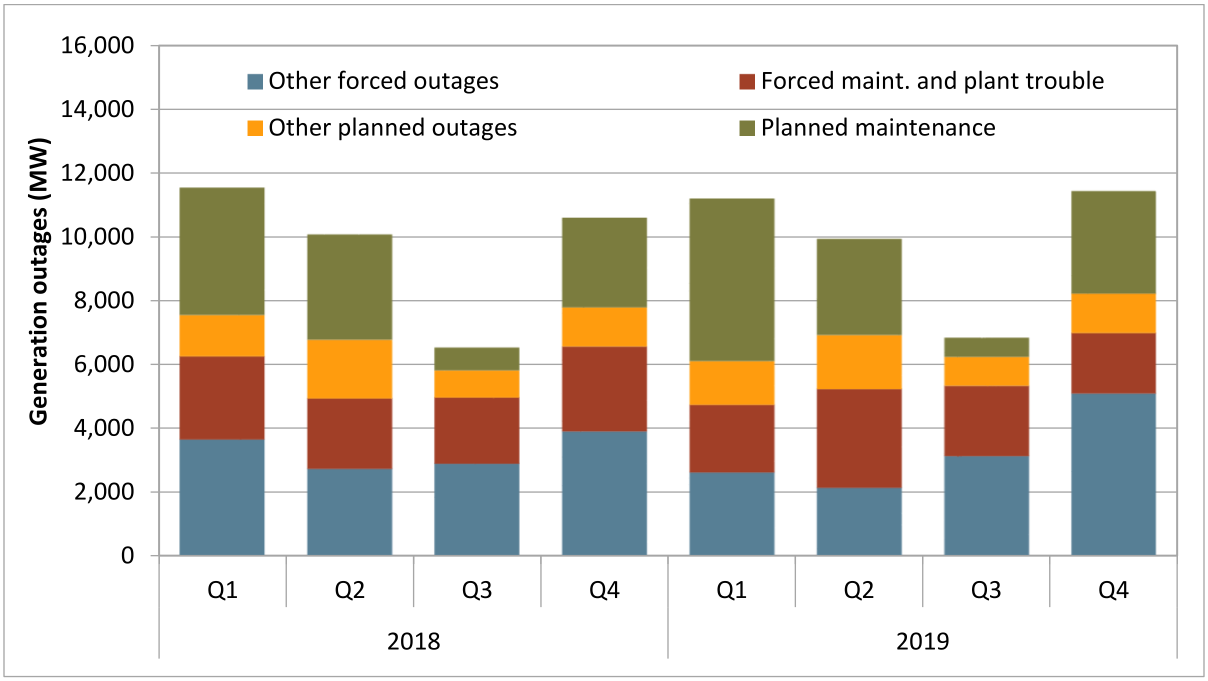
Figure 1.27 shows the quarterly averages of maximum daily outages broken out by type during peak hours. Overall, generation outages follow a seasonal pattern with the majority taking place in the non-summer months. This pattern is primarily driven by planned outages for maintenance, as maintenance is performed outside the higher summer load period.

At an aggregated level, the average total amount of generation outages in the ISO was roughly the same as the previous year at about 10,000 MW.[61] Outages for planned maintenance averaged about 2,900 MW during peak hours in 2019, and ranged from about 600 MW in the third quarter to about 5,000 MW in the first quarter. Combined, all other types of planned outages averaged about 1,300 MW in 2019. Some common types of outages in this category were ambient outages (both due to temperature and not due to temperature) and transmission outages.

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

Forced outages for either plant maintenance or plant trouble totaled about 2,300 MW in 2019. All other types of forced outages totaled about 3,200 MW for 2019. 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 1.27 Average of maximum daily generation outages by type – peak hours



1.2.6 Natural gas prices

Electricity prices in western states typically follow natural gas price trends because natural gas units are often the marginal source of generation in the ISO and other regional markets. Across key delivery points in the west, the average price of natural gas in the daily spot markets increased significantly beginning in the last quarter of 2018 and continued into the first quarter of 2019. The decrease in natural gas prices was one of the main drivers causing the annual wholesale energy cost to decrease relative to 2018.

Figure 1.28 shows monthly average natural gas prices at PG&E Citygate, SoCal Citygate, Northwest Sumas, and El Paso Permian, as well as for the Henry Hub trading point which acts as a point of reference for the national market for natural gas.

SoCal Citygate prices often impact overall system prices because 1) there are large numbers of natural gas resources in the south, and 2) these resources can set system prices in the absence of congestion. As shown in Figure 1.28, the prices at SoCal Citygate spiked in February 2019. High heating demand and limited availability of gas due to supply constraints led to high prices at SoCal Citygate during February 2019. These factors also led to SoCalGas issuing electric power generation curtailment orders and withdrawing gas from the Aliso Canyon storage facility throughout February. On most days in February, a low operational flow order was in effect, which may also have increased prices. Prices remained low after the first quarter but started to trend higher in November 2019. High SoCal Citygate prices during late November and December 2019 were a result of colder-than-normal temperatures and maintenance at SoCalGas storage facilities. During the maintenance, SoCalGas withdrew natural gas from the Aliso Canyon facility under the new withdrawal protocol.[62]

Key factors contributing to lower SoCal Citygate mid-winter prices in 2019 include:

- On September 17, the California Public Utilities Commission (CPUC) urged Southern California Gas Company (SoCalGas) to increase injections of natural gas at its underground storage fields to prepare for winter.[63]
- On October 14, SoCalGas announced the completion of maintenance and return to service at reduced pressure of Line 235-2. This line had been out of service since October 2, 2017, causing significant supply constraints, which increased the SoCal Citygate gas prices during the outage.
- Gas pipeline capacity of 270 million cubic feet per day of at Topock and Needles returned to service. These lines support access to lower cost natural gas supplies in the San Juan and Permian Basins.
- The CPUC granted SoCalGas more flexibility in winter to withdraw from the Aliso Canyon natural gas storage facility. During the past few winters, Aliso Canyon was only available for withdrawals as a last resort.

PG&E Citygate gas prices also increased in February 2019. This was primarily due to increased regional demand reflecting colder weather and regional supply limitations. PG&E also issued high stage low

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

63 Southern California Daily Energy Report, September 26, 2019: https://www.eia.gov/special/disruptions/socal/summer/#commentary

operational flow orders on some days in February, which may have contributed to high PG&E Citygate spot prices. For the rest of 2019, prices at PG&E Citygate remained low.

The Northwest Sumas gas hub in the Pacific Northwest saw record high gas prices during the winter of 2018 and volatility continued into 2019. Prices at the Sumas gas hub have been volatile since the October 9, 2018, Canadian gas pipeline explosion reducing imports into hubs in the Northwest. The February 2019 price spike occurred amid limited supply deliverability and unseasonably cold temperatures, which drove up demand in the Northwest. Similar to other gas hubs across the west, prices at Sumas trended lower after the first quarter of 2019. On November 28, 2019, the Canada Energy Regulator approved the Enbridge Westcoast line to return to full operating pressure, following the October 2018 explosion.

In contrast to the other gas hubs across the west, prices at Permian basin declined sharply during the first quarter of 2019. This price drop was due to a force majeure on El Paso Natural Gas's pipeline because of a potential leak. This outage led to a constraint on takeaway capacity out of the Permian basin thus putting downward pressure on gas prices. After occasionally trending negative in the second quarter, Permian prices started to rise in June because a new pipeline entered into service. It provided additional takeaway capacity and relieved the shortage caused by the force majeure on El Paso Natural Gas's pipeline. However, natural gas production in the region has increased, exhausting the newly available capacity and resulting in ongoing export constraints that placed downward pressure on prices.

Figure 1.28 Monthly average natural gas prices (2018-2019)

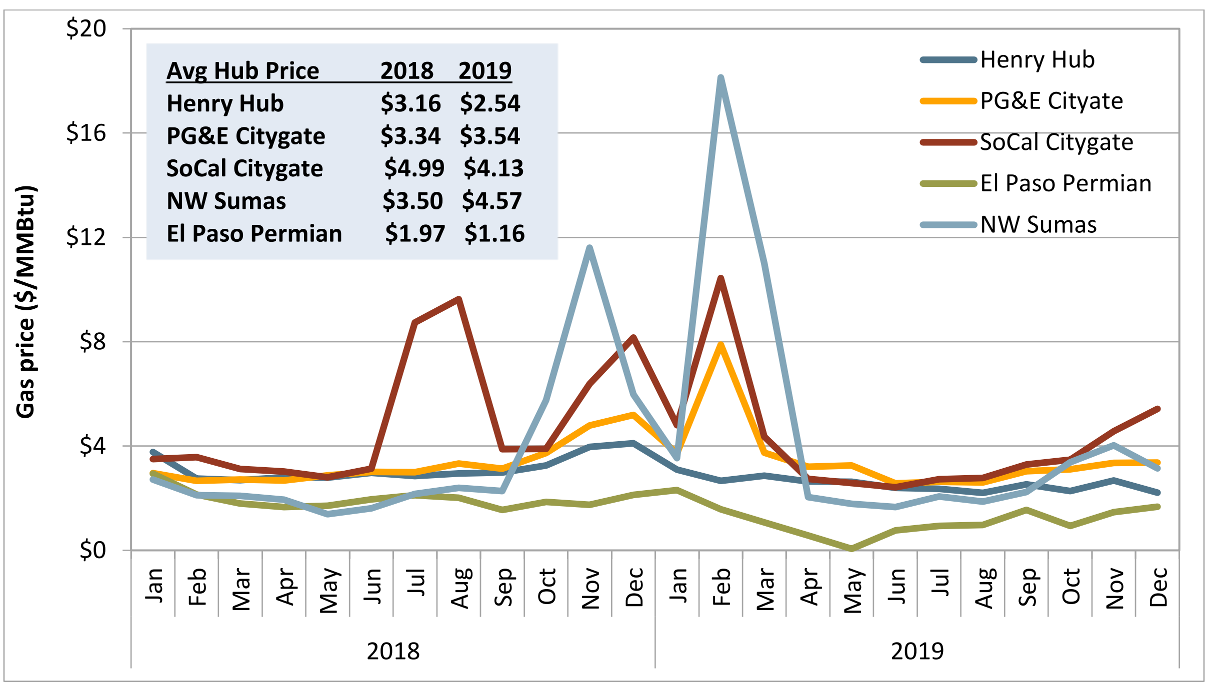
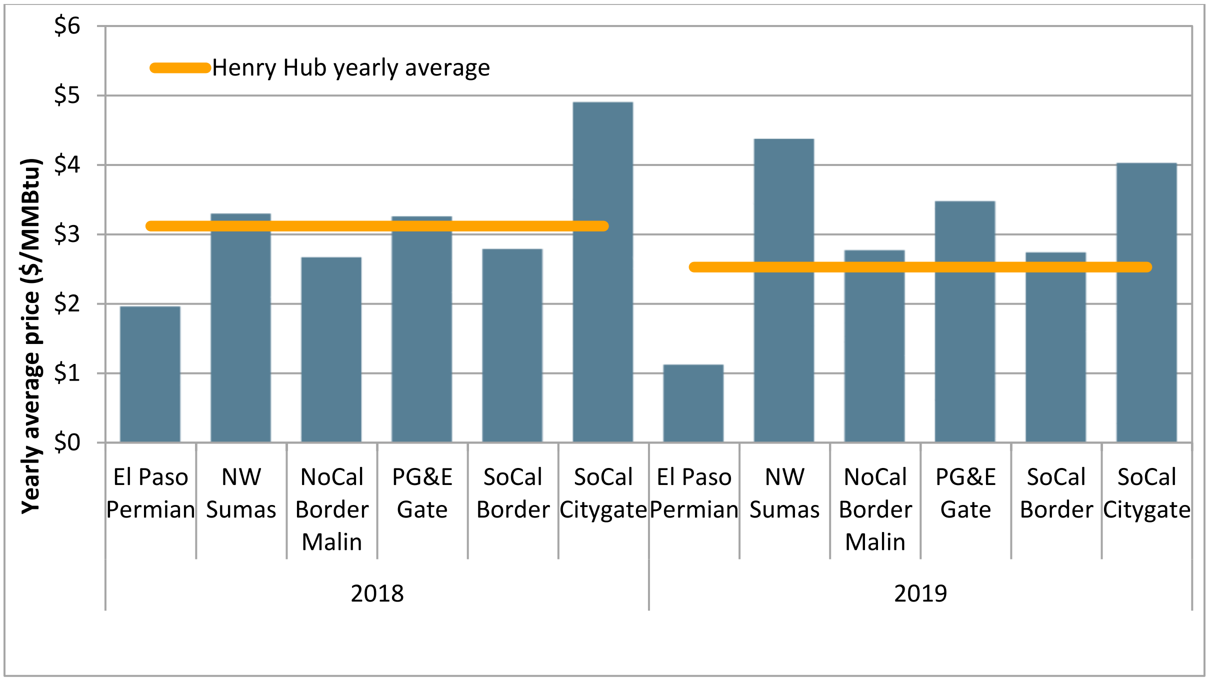


Figure 1.29 compares the yearly average natural gas prices at six major western trading points to the Henry Hub reference average for 2019 and 2018. The yearly average prices in 2019 exceeded the Henry Hub reference price at all but El Paso Permian trading point. On average, the yearly price at SoCal Citygate exceeded the Henry Hub average by 60 percent. Similarly, PG&E Citygate and Northwest Sumas

exceeded Henry Hub average by 38 percent and 73 percent, respectively. The average Permian price was 44 percent of the Henry Hub average.

Figure 1.29 Yearly average natural gas prices compared to the Henry Hub



Impact of operational flow orders on Southern California gas prices

Operational flow orders (OFOs) and emergency flow orders (EFOs) are gas system balancing tools. They give gas shippers economic incentive to ensure their scheduled deliveries match demand within a prescribed tolerance. SoCalGas issues operational flow orders when the system forecast of gas supply is not in balance with the system forecast of demand, after considering storage withdrawal or injection capacity allocated to the balancing function. Traditionally, the operational flow order structure has had five stages, plus a final emergency flow order stage. Noncompliance charges start at $25/dth for Stage 4 and Stage 5 orders.

In August 2018, Southern California Edison and Southern California Generation Coalition submitted a joint petition to the CPUC to lower the noncompliance charges associated with Stage 4 and Stage 5 orders.[64] DMM filed a response to this joint motion at the CPUC with supporting analysis on the impact of the relatively high level of potential noncompliance under Stage 4 and Stage 5 orders on gas and electricity prices and costs.[65] In January 2019, SoCalGas issued comments on the CEC/CPUC joint workshop on Southern California Natural Gas Prices held on January 11, 2019. These comments included

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

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

clarifying explanations on the cause of recent reliability and gas price volatility challenges, SoCalGas's proposed solutions to these challenges, and additional information on pipeline capacity reductions and outages. On April 29, 2019, the CPUC approved capping the Stage 4 and Stage 5 operational flow order (OFO) non-compliance penalties from $25/dth to $5/dth. This penalty structure was in place from June 1 through September 30, 2019. During this period, the SoCalGas Company did not declare any low OFOs exceeding Stage 1. Beginning October 1, 2019 through May 31, 2020, an alternate tiered structure will be in place, which expands the stages from 5 to 8.[66] In the fourth quarter of 2019, SoCalGas Company did not declare any low OFOs exceeding Stage 3 (maximum penalty of $5/dth).

Figure 1.30 shows the difference between next-day gas prices at SoCal Citygate versus SoCal Border (shown by the yellow line) along with potential noncompliance charges on days when low operational flow orders were declared (shown as blue dots) for different time periods. As shown in Figure 1.30, the $25/dth noncompliance charge triggered during a Stage 4 or Stage 5 low OFO has been reflected in next-day gas price spikes in the SoCalGas system.

Figure 1.30 Impact of potential low OFO noncompliance charges on next-day SoCal Citygate prices

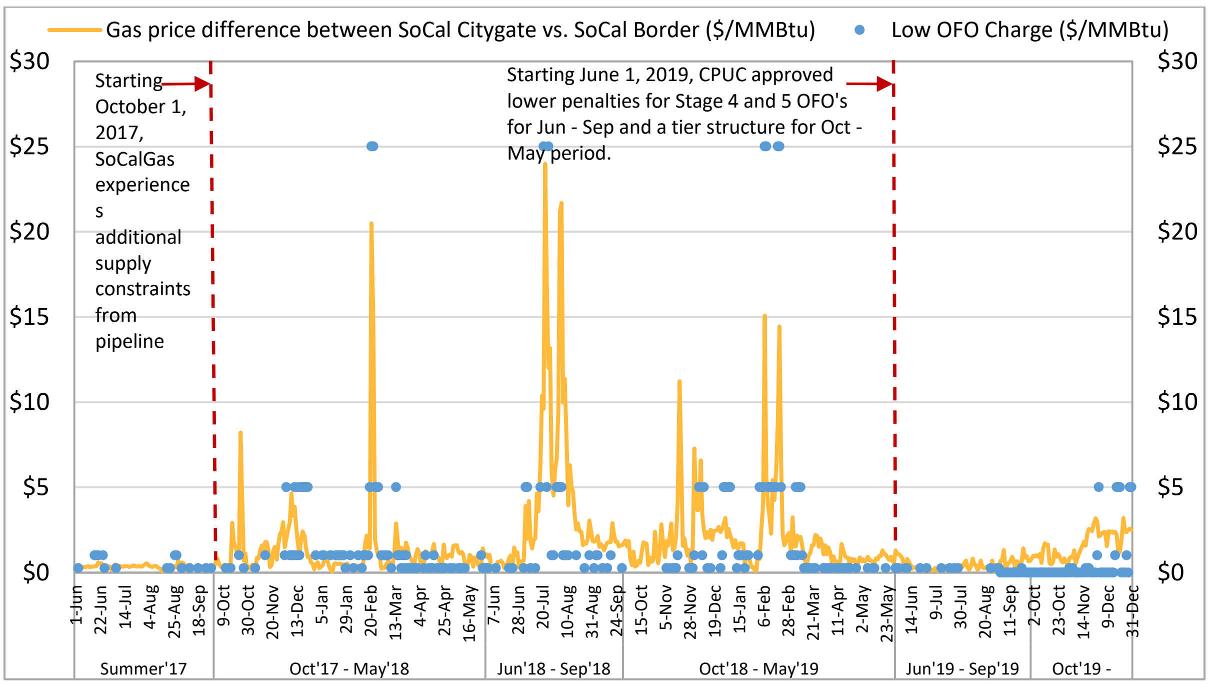


Figure 1.30 illustrates how next-day market gas prices at SoCal Citygate tend to increase following days when operational flow orders were declared. The magnitude of these gas price increases is correlated with the level of potential noncompliance charges associated with the order. High gas prices often persist for a significant period after operational flow orders are declared. As shown in Figure 1.30, the magnitude and persistence of high gas prices, potentially triggered by market expectations of high $25/dth noncompliance charges under Stage 4 orders, became particularly significant during the months of February, July, August and December 2018. The impact of the new noncompliance penalty structure

66 CPUC's Proposed Decision Granting In Part and Denying In Part for Modification Filed by Southern California Edison & Southern CA Generation Coalition of Commission, pp 31-32, April 29,2019: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M285/K085/285085989.PDF

beginning June 1, 2019, cannot be directly quantified because SoCalGas Company did not declare any Stage 4 or higher low OFOs during this period.

Table 1.3 shows a statistical summary of the difference between next-day gas prices at SoCal Citygate and SoCal Border for various time periods included in Figure 1.30. As shown in Table 1.3:

- During the summer of 2017, this price difference increased to $0.36/MMBtu (13 percent).
- In October 2017, additional limitations on the SoCalGas system began due to pipeline outages and maintenance. From October 2017 to May 2018, this price difference further increased to $1.28/MMBtu (50 percent).
- During summer of 2018, average next-day prices at SoCal Citygate were $3.81/MMBtu higher than prices at SoCal Border (137 percent).
- From October 2018 through May 2019, average next-day prices at SoCal Citygate were $1.98/MMBtu higher than prices at SoCal Border (58 percent).
- During the fourth quarter of 2019, average next-day prices at SoCal Citygate were $1.62/MMBtu higher than prices at SoCal Border (56 percent).

Table 1.3 Difference in next-day gas prices at SoCal Citygate vs SoCal Border

Time period	*Difference between gas price at SoCal Citygate versus SoCal Border ($/MMBtu)*		
	Min/Max	Average	Percent
Summer '17 (June - Sept)	$0.09 - $0.73	$0.36	13%
Oct 2017 - May 2018	$0.05 - $20.50	$1.28	50%
Summer '18 (June - Sept)	$0.18 - $24.00	$3.81	137%
Oct 2018 - May 2019	$0.10 - $15.09	$1.98	58%
Summer '19 (June - Sept)	$0.07 - $1.42	$0.46	19%
Oct - Dec 2019	$0.44 - $3.20	$1.62	56%

1.2.7 Aliso Canyon gas-electric coordination

Background

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.

In response to the gas supply restrictions stemming from the Aliso Canyon natural gas leak, the ISO received temporary authority to implement numerous measures to improve gas-electric coordination and the ISO's ability to maintain reliability while limiting gas usage by generators in the SoCalGas system. Beginning in 2020, FERC granted ISO permanent authority to extend the use of gas burn constraints and updated gas prices in the day-ahead market. The following section discusses DMM's review and recommendations on one of these key measures.

Gas usage nomogram constraints

One of the tools the ISO has developed to manage potential gas-system limitations is a set of constraints (or nomograms) that allow operators to restrict, through the market dispatches, the gas burn of groups of natural gas-fired generating units. These gas usage nomograms 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.[67]

In 2019, the ISO enforced these constraints in both day-ahead and real-time markets in selected sub-regions of SoCalGas service area during only four periods: February 6-8, February 20, October 14-18 and November 8-15. In February, in the day-ahead market, these constraints were binding in about 10 percent of hours during which they were enforced and were not binding when enforced in the real-time market. In October and November, the gas burn constraint was enforced to facilitate pipeline maintenance work in the SDG&E area.[68] In the day-ahead market, this constraint was binding in about 7 percent of hours when enforced. In the real-time market, this constraint was binding in 8 percent of the 15-minute intervals and 5 percent of the 5-minute intervals when enforced.

On October 31, 2019, the ISO filed tariff amendments to extend Aliso Canyon provisions permanently.[69] As mentioned earlier, one of these measures gives the ISO the authority to enforce gas burn constraints (or nomograms) in the ISO energy markets which directly limit gas usage by groups of power plants in the SoCalGas system. In its filing, the ISO proposed refining the shaping of the maximum gas burn limit using net load rather than gross load. DMM has recommended further refinement of the gas usage constraint to avoid artificially constraining gas burn during peak net load hours. FERC approved these tariff amendments and directed the ISO to file annual informational filings relating to the performance of the enforced nomograms.[70]

DMM believes the net load approach for shaping the gas usage constraint to be a significant improvement. However, DMM continues to recommend that the ISO refine how it utilizes the maximum gas constraint and improve how gas usage constraint limits are set and adjusted in real-time.[71]

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67 Refer to *Operating Procedure 4120C SoCalGas Service Area Limitations or Outages:* http://www.caiso.com/Documents/4120C.pdf

68 Planned System Wide Curtailment for CAISO EGs in San Diego Gas & Electric, Critical Notices on October 16 and November 14, 2019: https://scgenvoy.sempra.com/index.html

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

70 FERC Order accepting Aliso Canyon Gas-Electric Coordination Phase 5 tariff revisions (ER20-273), December 30, 2019: http://www.caiso.com/Documents/Dec30-2019-OrderAcceptingTariffRevisions-AlisoCanyonGasElectricCoordination-MaximimGasConstraint-ER20-273.pdf

71 FERC filing - DMM Comments on Aliso Canyon Gas-Electric Coordination Phase 5 (ER20-273), November 21,2019:

Specifically, DMM suggests that the shape of the gas burn could be estimated based on historical data as well as the two-day-ahead runs of the market software that the ISO performs. This modification could allow the gas limits to be highest during the ramping hours when gas units are needed most. DMM has also expressed concern about the potential impacts of the gas usage constraints on real-time energy offset costs.[72]

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 spanning all or part of each operating day. Although operators are able to adjust constraints in real time in response to changing conditions, 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 may be surplus gas from hours prior in the day when actual usage was well below the constraint as modeled by the ISO. 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.[73]

1.2.8 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.[74] Greenhouse gas compliance costs are included in the calculation of cost-based bids used in commitment cost bid caps and local market power mitigation of energy.

In addition, greenhouse gas compliance costs are attributed to resources who participate in the energy imbalance market and serve ISO load. This facilitates 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 Section 4.7 of this report.

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http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoring-Aliso5-ER20-273-000-Nov212019.pdf

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

73 See example and discussion in DMM's *Q4 Report on Market Issues and Performance*, February 2020, pp 91-92: http://www.caiso.com/Documents/2019FourthQuarterReportonMarketIssuesandPerformance.pdf

74 *2015 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2016, pp. 45-48:

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

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.[75] Daily values of the ISO greenhouse gas allowance index are plotted in Figure 1.31.

Figure 1.31 ISO's greenhouse gas allowance price index

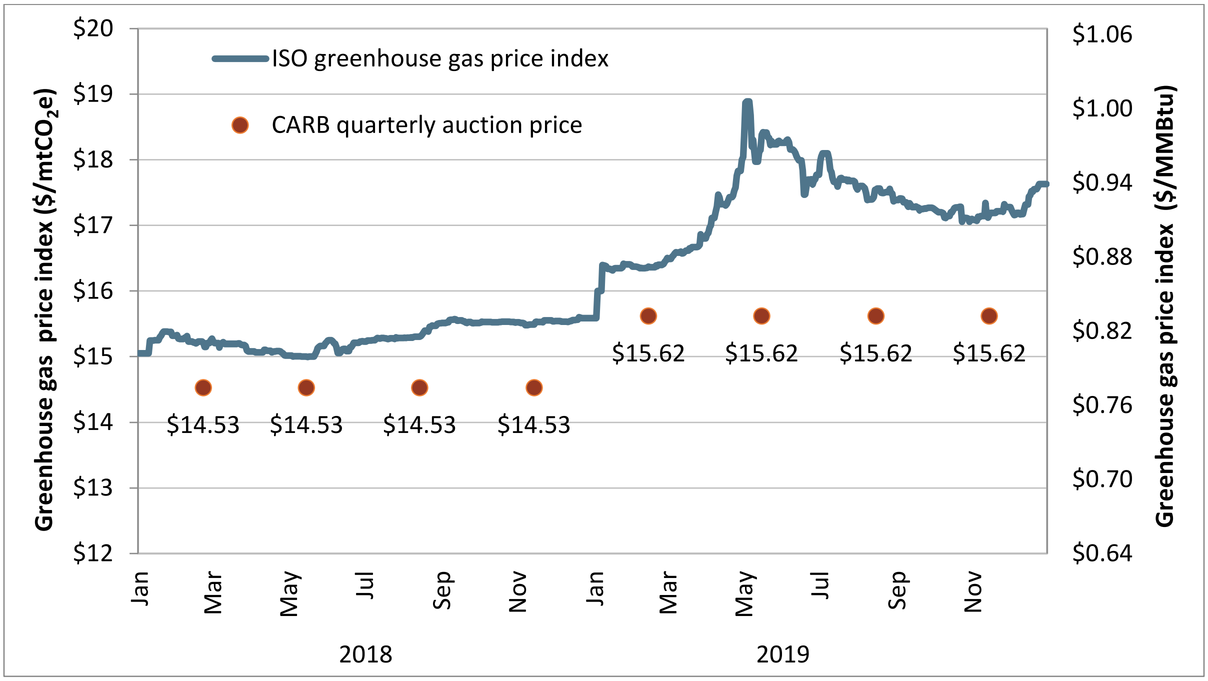

Figure 1.31 also shows market clearing prices in the California Air Resources Board's quarterly auctions of emission allowances that can be used for the 2018 or 2019 compliance years. The values displayed on the right axis convert the greenhouse gas allowance price into an incremental gas price adder, 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.[76] Thus, the blue line can be read from both the left and right hand axes.

As shown in Figure 1.31, the average cost of greenhouse gas allowances in bilateral markets increased from a load-weighted average of $15.31/mtCO_2e$ in 2018 to $17.28/mtCO_2e$ in 2019. In 2019, each of the

[75] 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

[76] The emissions factor, 0.0531148 $mtCO_2e/MMBtu$, is the sum of the product of the global warming potential and emission factor for CO_2, CH_4 and N_2O 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 (Updated 2019)

California Air Resources Board's quarterly allowance auctions sold a fraction of allowances offered and thus cleared at the annual auction reserve price of \$15.62/mtCO_2e.

The greenhouse gas compliance cost expressed in dollars per MMBtu in 2019 ranged from about \$1.00/MMBtu to \$0.83/MMBtu. This represents about one quarter of the average cost of gas during this period.

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.[77] The \$17.28/mtCO_2e average in 2019 would represent an additional cost of about \$7.34/MWh for a relatively efficient gas unit.[78] The average price in 2018, \$15.31/mtCO_2e, would represent an additional cost of about \$6.60/MWh for the same relatively efficient gas resource.

1.2.9 Capacity changes

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 each year provide important insight into the effectiveness of the California market and regulatory structure in incenting new generation development.

Values reported here differ from those reported elsewhere. First, these figures evaluate changes to the *market*, rather than exclusively the decommissioning or new interconnection of a unit. A generation withdrawal represents a resource that was once participating in ISO markets and no longer participates. In addition to decommissioned units, withdrawals may include resources that exit the market for a short period of time before returning (also known as mothballing), resources that withdraw to upgrade the unit and then repower, and resources whose contracts have expired with the ISO regardless of the units' capability to provide power.

A generation addition is reported whenever a market participant enters the market, which includes resources that re-enter after a period of mothballing.[79] Graphs reflect nameplate capacity and changes between June of one year to the next to reflect changes to peak summer capacity.[80] In addition, because resources can and do change registered capacity while participating in the market, a resource joining the market in one year and choosing to withdraw in another may not net to zero.

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77 *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.

78 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 mtCO_2e/MMBtu derived in footnote 76.

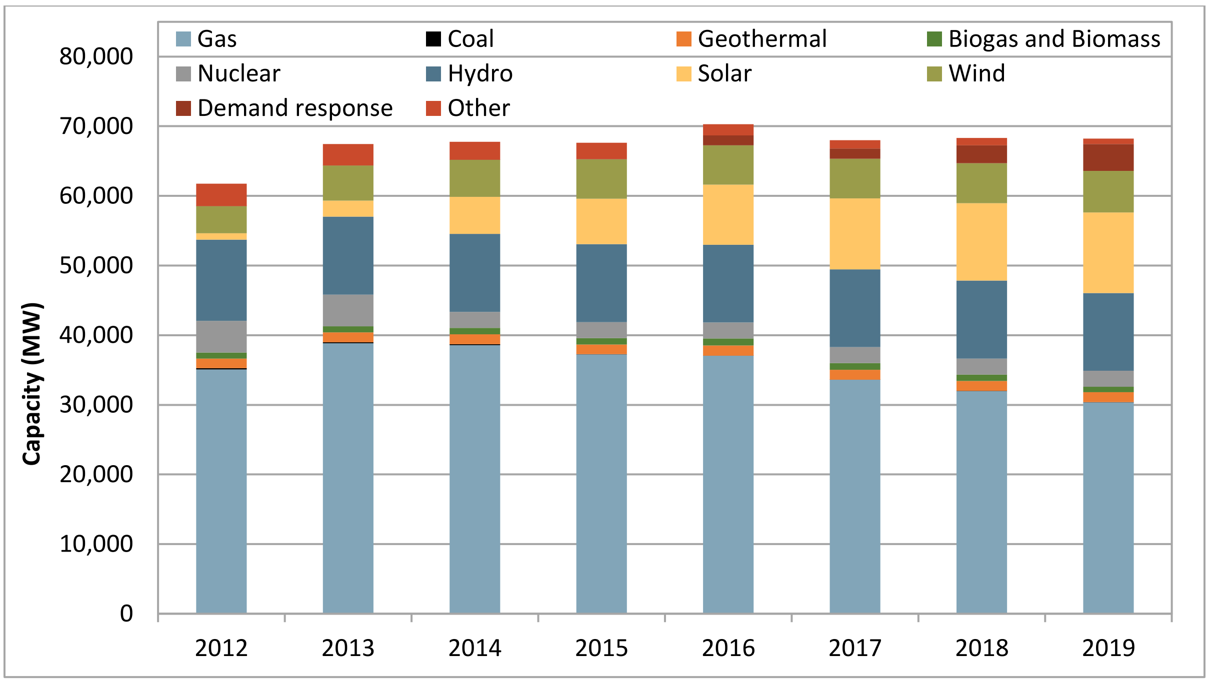
79 These figures do not account for generation outages, despite being similar in nature.

80 A resource's start, withdraw, or return date can vary by source due to different milestones associated with generation interconnection procedures. The figures below represent a rough estimate of the timeline when resources were added, withdrawn, or returned to the market and may differ from other reports.

Total ISO registered and participating capacity

Figure 1.32 summarizes the trends in available nameplate capacity from June of 2012 through 2019. Between 2012 and 2019, gas capacity internal to the ISO fell from about 35 GW in 2012 to 30 GW in 2019, and nuclear capacity fell from about 4.5 GW to 2.3 GW. This capacity was replaced by solar, which grew from about 1.0 GW to 11.6 GW; by wind, which grew from 3.9 GW to 6.0 GW; and by demand response which grew from 0 GW to 3.8 GW. While solar, wind, and demand response nameplate capacity additions have exceeded reductions in gas and nuclear capacity, variable energy and demand response resources generally have limited energy and availability compared to gas and nuclear capacity.81

Figure 1.32 Total ISO participating capacity by fuel type and year (as of June 1)



Withdrawal and retirement of ISO participating capacity

Figure 1.33 and Figure 1.34 summarizes the trends in withdrawal and retirement of capacity from June of 2015 through 2020. Over the entire time period, roughly 9,800 MW of capacity withdrew from market participation. The vast majority of this capacity, 98 percent, was from natural gas generators. Prior to the summer of 2019, roughly 1,800 MW withdrew, compared to roughly 2,100 MW prior to the summer of 2018.

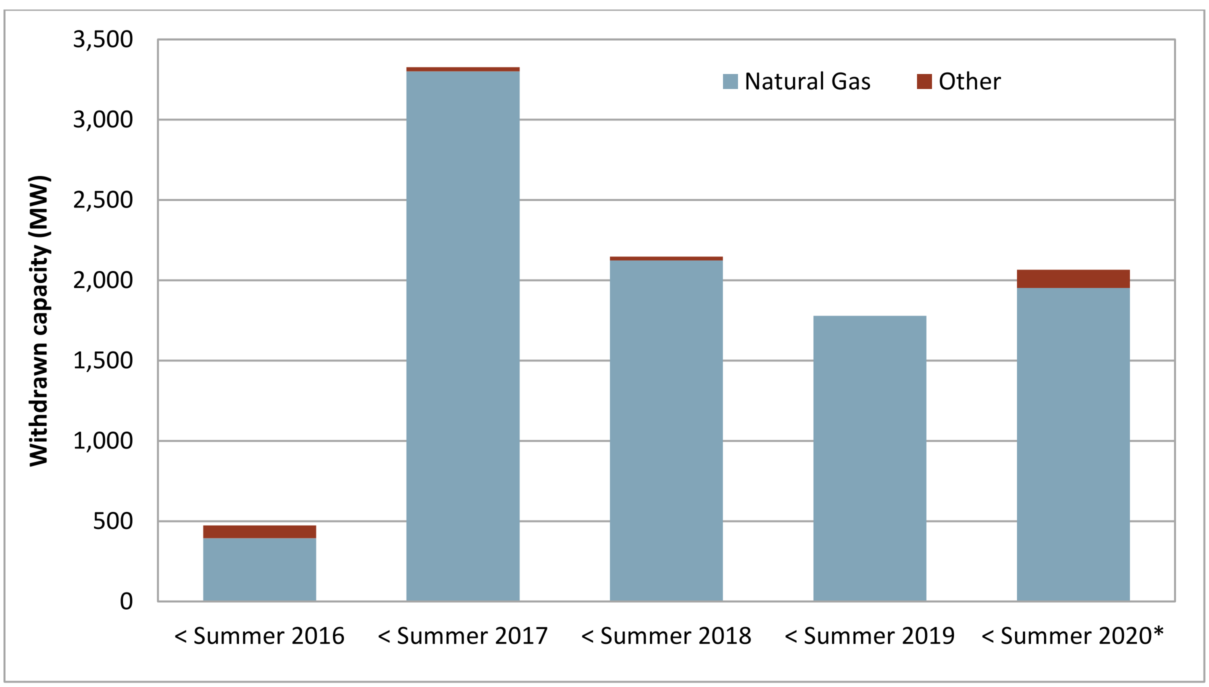
81 In contrast to gas and nuclear capacity the resource adequacy contributions, or qualifying capacity (QC), of wind and solar resources in the ISO is discounted compared to nameplate capacity to reflect that these resource types have limited availability across peak net load hours. Additionally, compared to nuclear and most gas resources demand response resources generally are limited to operating only a subset of hours each month.

Over the time period, roughly 6,000 MW of gas-fired capacity withdrew in accordance with once-through cooling provisions. This represents about 60 percent of the total retirements for this period (June 2015-June 2020). Some of this capacity was or will be replaced with natural gas, solar, and/or battery storage capacity. Examples include the Encina Power Station, which repowered with a new 530 MW combined cycle gas-fired power plant (the Carlsbad Energy Center), and the Alamitos and Huntington power plants, which have also been replaced on site with new gas-fired combined cycle power plants totaling roughly 1,350 MW. Battery storage is also under construction as part of the replacement of the Alamitos Energy Center.

Other resources included in these figures return to service after a temporary period of withdrawing from the market. The time period that each resource is unavailable varies significantly, ranging from less than one year to indefinitely (i.e., a permanent retirement with no planned replacement). Roughly 1,100 MW of withdrawn capacity was from resources that have since returned to the market in their current state (not repowered), and are currently fully participating.

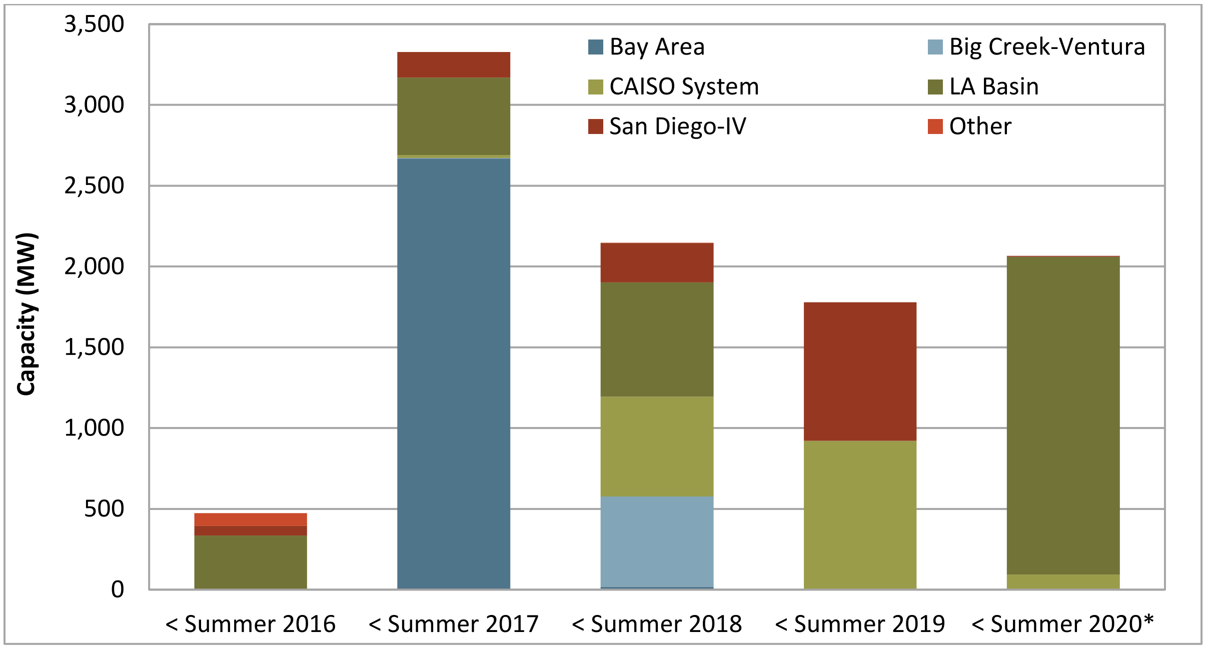
Figure 1.34 shows withdrawals by local area. The chart shows that withdrawals from participation have largely come from the state's four largest local areas: the Bay Area, LA Basin, San Diego-Imperial Valley, and Big Creek-Ventura. Over the past few years, the greatest withdrawals or retirement of capacity occurred in the LA Basin (about 3,500 MW). About 2,700 MW of generation withdrew in the Bay Area, about 1,300 MW in the San Diego-Imperial Valley area, and about 600 MW from the Big Creek-Ventura area. About 1,700 MW came from resources located outside of a local area in the ISO system.

Figure 1.33 Withdrawals from ISO market participation by fuel type[82]



82 Please note that this is not a complete picture of capacity changes and resource availability in the ISO system. Other changes in available capacity that are not included in this metric include 1) generation outages, 2) increases and decreases to capacity without changes in participation status, 3) changes associated with qualifying facilities, demand response, tie-generators, or any other non-typical participating generator type. *Preliminary estimate of withdrawals as of May 1, 2020.

Figure 1.34 Withdrawals from ISO market participation by local area



Additions to participating capacity

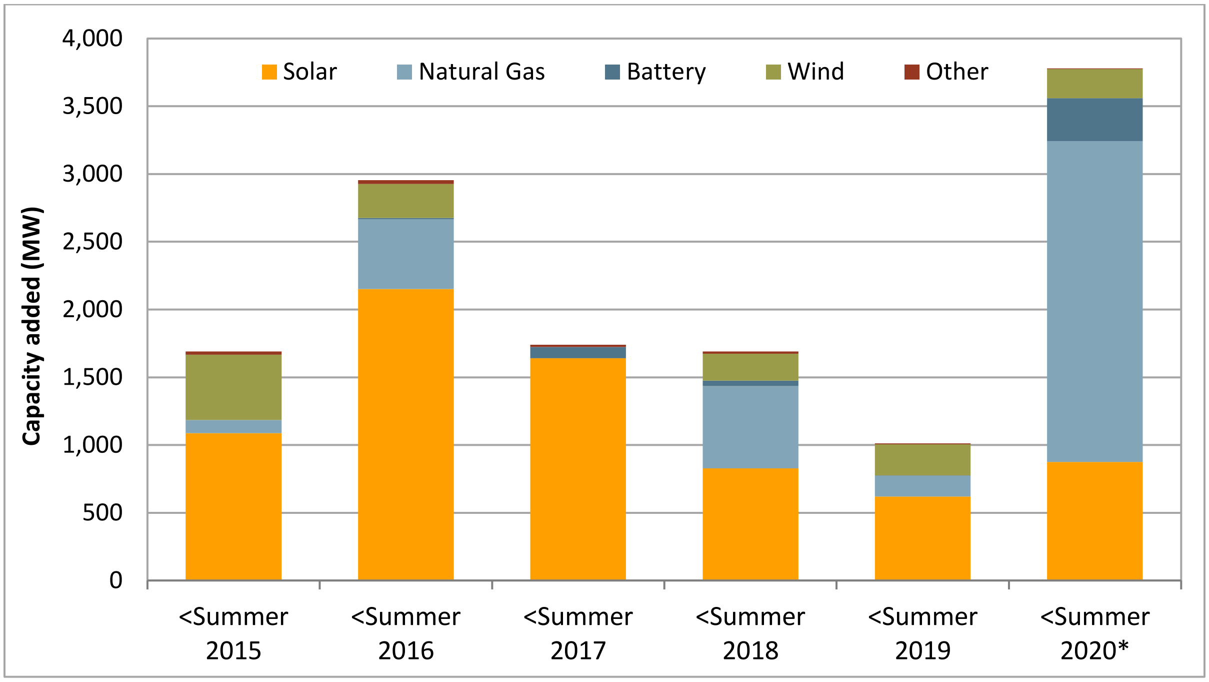
Figure 1.35 shows additions to market participation. Over the June 2015 to June 2020 time period, roughly 3,800 MW of gas capacity, 7,200 MW of solar, 1,400 MW of wind, and 450 MW of battery capacity was added or returned to the market.[83] Prior to the summer of 2019, the ISO market saw the lowest levels of new entry compared to the prior 5 years. This was primarily driven by relatively low new entry of solar resources. Prior to the summer 2019, roughly 620 MW of new solar capacity was added, compared to an average of 1,400 MW annually in years prior.

Preliminary estimates for the time period from June 2019 to June 2020 (shown as *< summer 2020* in the chart) show a large increase in capacity additions. This is largely driven by new natural gas resources, which have come online as part of the repowering plans of once-through cooling facilities mentioned above. There was also a significant increase in battery capacity (320 MW), relative to lower levels in previous years. As mentioned in Section 1.2.3 above, at the end of 2019, there was roughly 136 MW of battery capacity in the ISO market.

As mentioned earlier, these figures include about 1,100 MW of capacity which returned to service after a temporary period of withdrawing from the market. Sometimes this occurs when a resource is not able to obtain a capacity contract as part of California's resource adequacy processes.

83 Resource additions transition into the market often with phases of testing, so the exact date of market entry reported can vary.

Figure 1.35 Additions to ISO market participation by fuel type[84]



*Preliminary estimate of capacity additions as of May 1, 2020.

[84] Please note that this is not a complete picture of capacity changes and resource availability in the ISO system. Other changes in available capacity that are not included in this metric include 1) generation outages, 2) increases and decreases to capacity without changes in participation status, 3) changes associated with qualifying facilities, demand response, tie-generators, or any other non-typical participating generator type.

1.3 Net market revenues of new gas-fired generation

Overview

Every wholesale electric market must have an adequate market and regulatory framework for facilitating investment in needed levels of new capacity. In California, the CPUC'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 other energy market revenues.

Each year, DMM examines the extent to which revenues from the ISO's day-ahead and real-time markets contribute to the annualized fixed cost of typical new gas-fired generating resources. This represents a market metric tracked by FERC and all other ISOs.

In 2019, net revenues earned through the ISO's energy market continued to be significantly lower than DMM's estimate of levelized fixed costs for typical new gas-fired units. For 2019, DMM estimates that net energy market revenues for a typical gas combined cycle unit ranged from $5 to $17/kW-yr compared to total annualized fixed costs of about $114/kW-yr. For a typical combustion turbine unit, DMM estimates net energy market revenues of about $16 to $20/kW-yr compared to total annualized fixed costs of about $140/kW-yr.

The estimated net energy market revenues of gas units in 2019 also dropped below DMM's estimate of the annual going forward fixed costs of gas generation. DMM estimates that the annual going forward fixed costs of a typical combined cycle unit are about $26 to $34/kW-yr, compared to net energy market revenues of $5 to $17/kW-yr. In 2017 and 2018, DMM estimated net energy market revenues for combined cycle units of about $24 to $35/kW-yr, which was in the same range as estimated annual going forward fixed costs. For a typical combustion turbine unit, DMM estimates net energy market revenues of about $16 to $20/kW-yr in 2019 compared to estimated annualized going forward fixed costs of about $26 to $27/kW-yr.

These results continue to underscore the need for any new gas resources needed for local or system reliability to recover additional costs from long-term bilateral contracts. In addition, results indicate that at 2019 price levels, the net energy market revenues for many or most gas units would not cover their annual going forward fixed costs.

Existing units that cannot recover their going forward fixed costs from their energy market revenues would be expected to mothball or retire if they did not receive additional revenues from a resource adequacy contract, the ISO's capacity procurement mechanism, or a reliability must-run contract. The ISO's soft cap for the capacity procurement mechanism is currently set at $76/kW-yr, which DMM estimates is more than twice the annual going forward fixed costs of gas units. Under the capacity procurement mechanism, units also retain all net market revenues from market operations.

Methodology

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.[85] Incremental energy costs are calculated using default energy bids used in local market power mitigation.[86] Commitment costs are calculated using the ISO's proxy start-up and minimum load cost methodology.[87]

For a combined cycle unit, energy market revenues are estimated based on day-ahead and 5-minute real-time market prices. For a combustion turbine unit, estimated energy market revenues are based on a generator's commitment and dispatch in the 15-minute real-time market and any incremental dispatch using the 5-minute prices. The analysis includes estimated net revenues for hypothetical combined cycle and combustion turbine units based on prices for 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. The characteristics and constraints for a combined cycle unit and combustion turbine unit are listed in Table 1.4 and Table 1.6, respectively.

For 2019, DMM updated several resource characteristic assumptions and financial parameters and re-ran analysis for prior years. The most significant change made in this year's report was to revise estimates of the fixed annual going forward costs of gas units. DMM continued to use estimates from a report by the California Energy Commission (CEC) for most components of a unit's going forward fixed costs (insurance and *ad valorum*).[88] However, instead of fixed annual O&M costs from the CEC report, DMM now uses estimates derived from DMM's review of California-specific and nationwide sources.[89]

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85 Net revenues due to ancillary services and flexible ramping capacity are not modeled in the optimization model. For a combined cycle unit in the ISO, total average annual net revenues for regulation (up & down), and spinning reserves were approximately $1.23/kW and payments for flexible ramping capacity were around $0.06/kW. Similarly, for a combustion turbine unit in the ISO, total average net revenues for spin and non-spinning reserve were $1.6/kW while average flexible ramping payments were $0.14/kW. 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.

86 Default energy bids are calculated using the variable cost option as described in the Market Instruments Business Practice Manual Appendix F, https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

87 Start-up and minimum load costs are calculated using the proxy cost option as described in the Market Instruments Business Practice Manual, Appendix G.2. The energy price index used in the proxy start-up costs is calculated using the retail rate option, Market Instruments Business Practice Manual, Appendix M.2, https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

88 The annual fixed costs used by DMM represent the average between IOU, POU, and Merchant fixed costs reported by the CEC. See *Estimated Cost of New Renewable and Fossil Generation in California,* California Energy Commission, May 2019. Appendix D: https://www.energy.ca.gov/2019publications/CEC-200-2019-005/CEC-200-2019-005.pdf

89 DMM Comments on CPM Tariff Filing ER20-1075 - Apr 3, 2020: http://www.caiso.com/Documents/AnswerandMotionforLeavetoAnswer-DMMCommentsonCPMTariffFilingER20-1075-Apr32020.pdf

Metcalf RMR Agreement Filing, ER18-240, Schedule F, Article II Part B, pp 140-142, November 2, 2017: https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=14741407

Gilroy RMR Agreement Filing, ER18-230, Schedule F, Article II Part B, pp 140-147, November 2, 2017: https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=14739579

S&P Global Average. (2019). Data downloaded from S&P Global's online screener tool. S&P Global Market Intelligence (subscription required): https://platform.mi.spglobal.com

DMM's analysis indicates that the annual fixed O&M from the CEC report, which is used by the ISO to set the capacity procurement mechanism soft offer cap, significantly overstates the actual fixed annual O&M costs of combined cycle gas units. In this report, DMM estimates that annual going forward fixed costs range from $26 to $34/kW-yr for a typical combined cycle resource and $26 to $27/kW-yr for a typical combustion turbine.[90]

Combined cycle units

Table 1.4 shows the key assumptions used in this analysis for a typical new combined cycle unit. This includes the technical parameters for two configurations of a hypothetical new combined cycle unit that were used in the optimization model. The table also provides a breakdown of financial parameters that contribute to the estimate of total annualized fixed costs for a new 2x1 combined cycle unit.

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

Table 1.5 shows the optimization model results using the parameters specified in Table 1.4. Results were calculated using three different price scenarios for a unit located in Northern California (NP15) or Southern California (SP15), separately. These scenarios show how different assumptions would change net revenues for 2019.

The first scenario in Table 1.5 modeled unit commitment and dispatch based on day-ahead energy prices and the unit's default energy bids. In 2019, for a unit located in NP15 with the above assumptions, net revenues were $10.60/kW-yr with a 13 percent capacity factor.[91] Using the same assumptions for a hypothetical unit located in SP15, net revenues were $5.10/kW-yr with a 4 percent capacity factor.

The second scenario in Table 1.5 optimized the unit's commitment and dispatch instructions with day-ahead market prices combined with default energy bids excluding the 10 percent adder which is included under the tariff. The 10 percent adder was removed in this scenario because the default energy bid with the 10 percent adder may overstate the true marginal cost of some resources.[92] Many resources do not include the full adder as part of their typical energy bid. Under this scenario, net revenues in 2019 for a hypothetical unit in the NP15 area were $13.40/kW with a 17 percent capacity factor. In the SP15 area, net annual revenues were $6.30/kW with a 6 percent capacity factor.

The third scenario in Table 1.5 is based on the same assumptions as the first scenario to commit and start the combined cycle resource, but bases the dispatch of energy above minimum operating level on the higher of the day-ahead and 5-minute real-time prices (rather than day-ahead prices alone). This reflects how after the day-ahead market gas units can rebid and get re-dispatched in the real-time

90 The upper end of DMM's estimate of going forward fixed costs for each technology type is based on the average of reported annual fixed O&M ($19.8/kW for CC and $8.7/kW for CT) for all gas-fired units in California listed in S&P Global data (which includes 71 combined cycle units and 160 combustion turbines). The lower end of DMM's estimate of going forward fixed costs is based on the average reported annual fixed O&M ($11.7/kW for CC and $7.8/kW for CT) values for a subset of all units in California which are most similar to the size of the hypothetical units used in this analysis. This subset includes 20 combined cycle units and 60 combustion turbines in California listed in the S&P Global data.

91 The capacity factor was derived using the following equation:
Net generation (MWh) / (facility generation capacity (MW) * hours/year).

92 See Section 2.2 for further discussion on price-cost markup.

market. Under this scenario, net revenues for a hypothetical unit located in the NP15 area were $17/kW with a 24 percent capacity factor. In the SP15 area, net annual revenues were $11.90/kW with an 11 percent capacity factor.

Table 1.4 Assumptions for typical new 2x1 combined cycle unit[93]

Technical Parameters	Configuration 1	Configuration 2
Maximum capacity	360 MW	720 MW
Minimum operating level	150 MW	361 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 $mtCO_2e$/MMBtu	0.053165 $mtCO_2e$/MMBtu
Start-up gas consumption	1,400 MMBtu	2,800 MMBtu
Start-up time	35 minutes	50 minutes
Start-up auxillary energy	5 MWh	5 MWh
Start-up major maintenance cost adder (2019)	$5,890	$11,780
Minimum load major maintenance cost adder (2019)	$295	$589
Minimum up time	60 minutes	60 minutes
Minimum down time	60 minutes	60 minutes
Ramp rate	40 MW/minute	40 MW/minute
Financial Parameters (2019)		
Financing costs		$79 /kW-yr
Insurance		$6 /kW-yr
Ad Valorem		$8 /kW-yr
Fixed annual O&M		$11.70 /kW-yr
Taxes		$9 /kW-yr
Total Fixed Cost Revenue Requirement		**$114/kW-yr**

93 Start-up and minimum load major maintenance adders are derived based on Siemens SGT6-5000F5 gas turbine technology and costs reported in a NYISO study and adjusted each year for inflation: https://www.nyiso.com/documents/20142/1391705/Analysis Group NYISO DCR Final Report - 9 13 2016 - Clean.pdf/55a04f80-0a62-9006-78a0-9fdaa282cfc2
The cost of actual new generators varies significantly due to factors such as ownership, location, and environmental constraints.
The remaining technical characteristics were assumed based on the manufacturer spec sheet and resource operational characteristics of a typical combined cycle unit within the ISO. https://assets.new.siemens.com/siemens/assets/api/uuid:d91426bf-3555-4677-9ad9-db9d2de0cb28/version:1572432184/sgt6-5000f-pac-highres.pdf

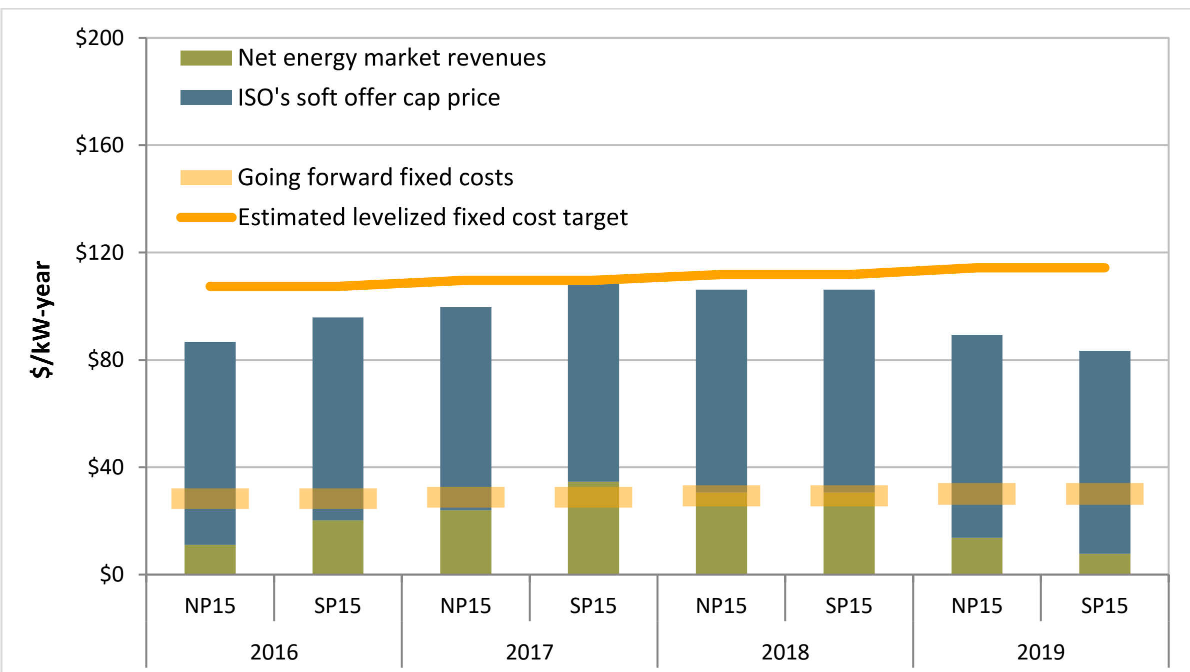
Maximum number of start-up and run-hours constraint has been relaxed in the annual optimization problem.

Table 1.5 Financial analysis of new combined cycle unit (2019)

Zone	Scenario	Capacity factor	Total energy revenues ($/kW-yr)	Operating costs ($/kW-yr)	Net revenue ($/kW-yr)
NP15	Day-ahead prices and default energy bids	13%	$76.25	$65.63	$10.62
	Day-ahead prices and default energy bids without adder	17%	$94.16	$80.79	$13.37
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	24%	$126.84	$109.80	$17.04
SP15	Day-ahead prices and default energy bids	4%	$30.56	$25.44	$5.12
	Day-ahead prices and default energy bids without adder	6%	$41.14	$34.82	$6.32
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	11%	$68.73	$56.81	$11.93

Figure 1.36 shows how net revenue results from the optimization model compare to the estimated annual fixed costs of a hypothetical combined cycle unit over the last four years. The green bars in this chart show the average net revenue estimates over all the scenarios listed in Table 1.5. The blue bars in the chart show the potential capacity payment a unit would receive based on the ISO's soft offer cap price for the capacity procurement mechanism ($75.68/kW-yr).

Figure 1.36 Estimated net revenue of hypothetical combined cycle unit



As shown in Figure 1.36, net revenues in 2019 decreased significantly from 2017-18 levels in both NP15 and SP15 areas. This is because of low day-ahead prices, which persisted from the second through fourth quarters of 2019, which in turn led to a decline in commitment and hence decreased net energy market revenues.

Figure 1.36 also shows that net revenue estimates for a combined cycle unit continued to fall substantially below the annualized fixed cost estimate, shown by the solid yellow line. As noted above, fixed costs for existing and new units should be recoverable through a combination of long-term bilateral contracts and spot market revenues. The blue bars, equal to the ISO's soft offer cap price for the capacity procurement mechanism ($75.68/kW-yr), represent the potential additional contribution of a capacity payment up to the capacity procurement mechanism soft cap.

For 2019, the net revenues fall well short of the going forward fixed cost estimate range, shown by transparent yellow bars in Figure 1.36. As shown in this chart, DMM estimates that annual going forward fixed costs range from $26/kW-yr to $34/kW-yr for combined cycle resources.

The net revenues of a combined cycle resource can be sensitive to the unit's realized capacity factor. We compared the hypothetical combined cycle capacity factors from Table 1.5 with existing combined cycle resources in NP15 and SP15 as a benchmark. In the NP15 area, actual capacity factors in 2019 ranged between 4 and 84 percent with an average of 40 percent capacity factor. In the SP15 area, actual capacity factors ranged between 1 and 70 percent, with an average capacity factor of 32 percent. Our estimates ranged from 4 to 24 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 is 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.

Additionally, software limitations make shutdown instructions less frequent for these resources during the middle of the day because of the limited dispatch horizon used.[94] This can result in a resource staying on in the midday hours even when it is uneconomic to do so. This in 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.[95]

94 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.

95 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.

Hypothetical combustion turbine unit

Table 1.6 shows the key assumptions used in this analysis for a typical new combustion turbine unit. Also included in the table is the breakdown of financial parameters that contribute to the estimated annualized fixed costs for a hypothetical combustion turbine unit.

Table 1.7 shows the optimization model results using the parameters specified in Table 1.6. Results were calculated using three different price scenarios for a unit located in Northern California (NP15) or Southern California (SP15), separately. These scenarios show how different assumptions would change net revenues for 2019.

Table 1.6 Assumptions for typical new combustion turbine [96]

Technical Parameters	
Maximum capacity	48.6 MW
Minimum operating level	24.3 MW
Heat rates (Btu/kWh)	
Maximum capacity	9,300 Btu/kWh
Minimum operating level	9,700 Btu/kWh
Variable O&M costs	$4.80 /MWh
GHG emission rate	0.053165 $mtCO_2e$/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 (2019)	$0
Minimum load major maintenance cost adder (2019)	$189
Minimum up time	60 minutes
Minimum down time	60 minutes
Ramp rate	50 MW/minute
Financial Parameters (2019)	
Financing costs	$103 /kW-yr
Insurance	$8 /kW-yr
Ad Valorem	$11 /kW-yr
Fixed annual O&M	$7.80 /kW-yr
Taxes	$10 /kW-yr
Total Fixed Cost Revenue Requirement	**$140/kW-yr**

96 Start-up and minimum load major maintenance adders are derived based on an aeroderivative GE LM6000 PH Sprint technology and costs reported in a NYISO study and adjusted each year for inflation: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B25745D07-C958-42EA-AC1A-A1BB0D80FF52%7D
The cost of actual new generators varies significantly due to factors such as ownership, location, and environmental constraints.

Table 1.7 Financial analysis of new combustion turbine (2019)

Zone	Scenario	Capacity factor	Real-time energy revenues ($/kW-yr)	Operating costs ($/kW-yr)	Net revenue ($/kW-yr)
NP15	15-minute prices and default energy bids	2.3%	$31.87	$16.21	$15.66
	15-minute prices and default energy bids without adder	3.2%	$37.61	$21.17	$16.44
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	3.3%	$41.38	$22.44	$18.94
SP15	15-minute prices and default energy bids	1.4%	$26.13	$9.99	$16.14
	15-minute prices and default energy bids without adder	1.7%	$28.71	$12.12	$16.59
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	2.2%	$35.04	$15.51	$19.53

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 2019 prices, net annual revenues were approximately $16/kW-yr with a 2 percent capacity factor. Similarly, in the SP15 area, net revenues were approximately $16/kW-yr with a 1 percent capacity factor.

The second scenario assumes that 15-minute prices are used for commitment and dispatch instructions, but does not factor the 10 percent scalar into the default energy bids as a measure of incremental energy costs.[97] Using this scenario, the hypothetical unit in NP15 earned net revenues of about $16/kW-yr with a 3 percent capacity factor. The hypothetical unit in SP15 earned net revenues of about $17/kW-yr with a capacity factor of 1.7 percent.

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 $19/kW-yr with a 3 percent capacity factor. In the SP15 area, net revenues were about $20/kW-yr with a 2.2 percent capacity factor.

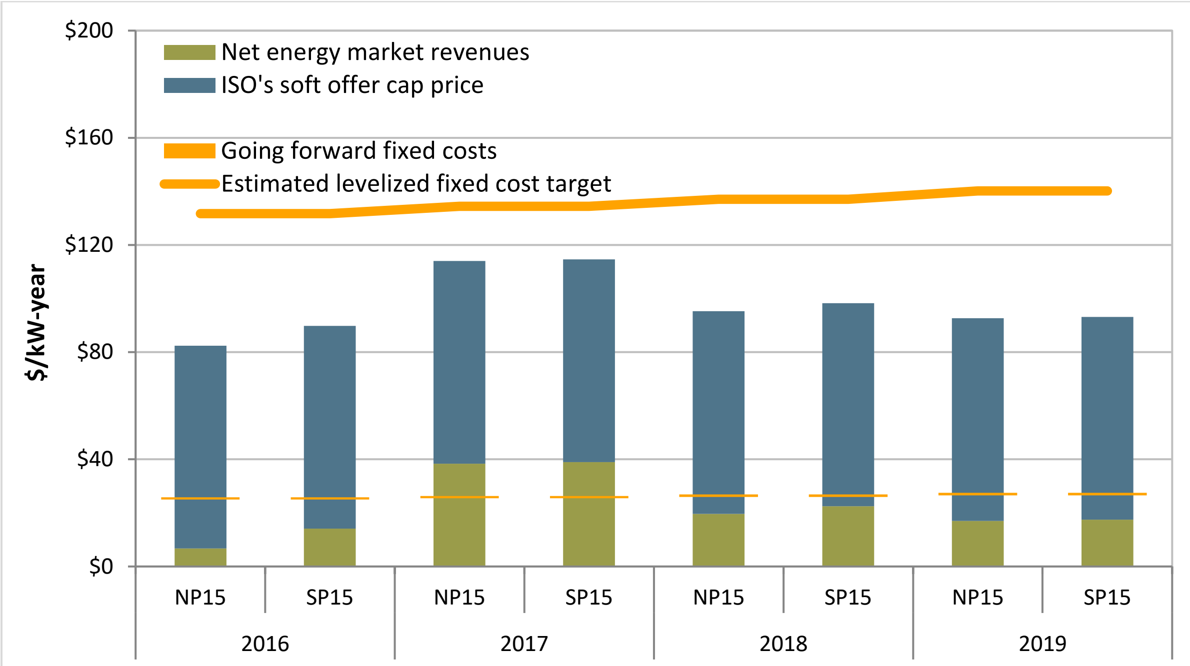
Figure 1.37 shows how net revenue results from the optimization model compare to an estimated annualized fixed cost of a hypothetical combustion turbine unit.[98] The green bars in this chart show estimated net revenues over the past four years.

The remaining technical characteristics were assumed based on the manufacturer spec sheet based on the technology type and resource operational characteristics of a typical peaking unit within the ISO. https://www.ge.com/content/dam/gepower/global/en_US/documents/gas/gas-turbines/aero-products-specs/lm6000-fact-sheet-product-specifications.pdf

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

98 More information on the capacity procurement mechanism can be found in Section 43A of ISO's tariff: http://www.caiso.com/Documents/Section43A-CapacityProcurementMechanism-asof-Sep28-2019.pdf

Figure 1.37 Estimated net revenues of new combustion turbine



As shown in Figure 1.37, net revenues for a hypothetical combustion turbine rose significantly in 2017 when compared to 2016. This is because of significantly high real-time prices in both NP15 and SP15 areas. Net revenues then decreased in 2018 and 2019, but remained higher than 2016 levels. Both regions experienced a drop in capacity factor and hence operating costs with an average decrease of about $8/kW-year between 2018 and 2019. Real-time energy revenues dropped even more with an average decrease of $12/kW-year. This is in part due to relatively lower gas prices in 2019 compared to 2018, which led to overall lower real-time energy market prices in both NP15 and SP15 areas.

Figure 1.37 shows that, from 2016 through 2019, net revenue estimates for a hypothetical combustion turbine unit in both the NP15 and the SP15 regions fall substantially below the annualized fixed cost estimate, shown by the solid yellow line. As noted above, fixed costs for existing and new units should be recoverable through a combination of long-term bilateral contracts and spot market revenues.

In practice, the net revenues of a combustion turbine resource can be sensitive to the unit’s realized capacity factor. Therefore, DMM compared the capacity factors for the hypothetical combustion turbine from Table 1.6 with existing combustion turbines in NP15 and SP15 as a benchmark. In the NP15 area, actual capacity factors in 2019 ranged between 0.5 and 2.7 percent, with an average capacity factor of 2 percent. In the SP15 area, actual capacity factors ranged between 0.1 and 8 percent, with an average capacity factor of 4 percent. DMM’s estimates ranged from 1.4 to 3.3 percent and were relatively close to these actual capacity factors.

2 Overview of market performance

The ISO markets continued to perform efficiently and competitively in 2019.

- **Total wholesale electric costs decreased by about 17 percent,** driven primarily by a 10 percent decrease in natural gas prices compared to 2018. Controlling for both natural gas costs and greenhouse gas prices, wholesale electric costs decreased by about 10 percent.
- **Energy market prices were competitive, with prices usually reflecting resources' marginal costs**. DMM estimates that the impact of gas resources bidding above reference levels, a conservative measure of the average price-cost markup, was about $0.71/MWh or just under 2 percent.
- **Lower prices in the real-time market were driven in part by additional supply** from renewables and other balancing areas available in real time. Real-time prices were also lower in many hours due to manual adjustments made to the hour-ahead load forecast and additional energy from out-of-market commitments and dispatches issued after the day-ahead market.[99]
- **Bid cost recovery payments in the ISO decreased by about 20 percent to the second highest value since 2011**, totaling $123 million, or about 1.4 percent of total energy costs, from $153 million in 2018. The largest portion of the $30 million decrease was for payments for resources committed to operate through exceptional dispatches which totaled about $19 million, decreasing by $21 million compared to $40 million in 2018.
- **Bid cost recovery payments for units in the energy imbalance market totaled about $10 million** in 2019; about $1.5 million lower than in 2018. About $0.2 million of these payments are for units in Balancing Authority of Northern California Phase 1 balancing authority. The cost of these payments is allocated back to the energy imbalance market balancing area in which the units receiving these payments is located.
- **Total ISO real-time imbalance offset costs decreased by 22 percent to $103 million** compared to $133 million in 2018. Congestion offsets make up the bulk of the total at $97 million and were again attributable to persistent and significant reductions in constraint limits made by grid operators in the 15-minute market relative to limits used in the day-ahead market and network model changes.
- **Costs for capacity procured under reliability must-run contracts and the capacity procurement mechanism decreased about 92 percent**. The higher cost in 2018 was from $78 million paid to four resources that were procured on an annual basis under the capacity procurement mechanism at prices close to or at the $76/kW-year soft offer cap.[100]
- **Total residual unit commitment procurement increased slightly** to 845 MW per hour in 2019 from an average of 839 MW in 2018. Direct costs remained low, falling to $1.6 million.

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99 The ISO is investigating factors contributing to a day-ahead price premium in an on-going stakeholder process. The ISO's initial findings are available here: http://www.caiso.com/Documents/WhitePaper-PricePerformanceAnalysis-Apr3-2019.pdf

100 Additional discussion of these costs is available in this report in Sections 10.5 and 10.6.

2.1 Total wholesale market costs

The total estimated wholesale cost of serving load in 2019 was about $8.8 billion or about $41/MWh. This represents a decrease of about 17 percent from wholesale costs of about $49/MWh in 2018. The decrease in electricity prices was partly driven by a decrease in natural gas prices of about 10 percent.[101] After normalizing for natural gas prices and greenhouse gas compliance costs, using 2010 as a reference year, DMM estimates that total wholesale energy costs decreased by about 10 percent.

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

- Decreased prices for natural gas, especially in Southern California;
- Reduced load;
- Increased production from both hydroelectric and solar resources; and
- Reduced costs for capacity procured under reliability must-run contracts and the capacity procurement mechanism.

Figure 2.1 shows total estimated wholesale costs per megawatt-hour of system load from 2015 to 2019. 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. Historically, electricity costs tend to move with changes in gas costs, which is illustrated by the ratio between the blue bar and the green line for 2015 through 2017. A gas cost factor of 80 percent has therefore been incorporated into the normalization calculations to account for this relation between the electricity costs and gas prices. In recent years, the relation between the two costs has diverged somewhat, and this factor of 80 percent may need to be revised to more precisely estimate the contribution of gas costs on the changes in electricity costs from year to year going forward.

[101] 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 (2015-2019)

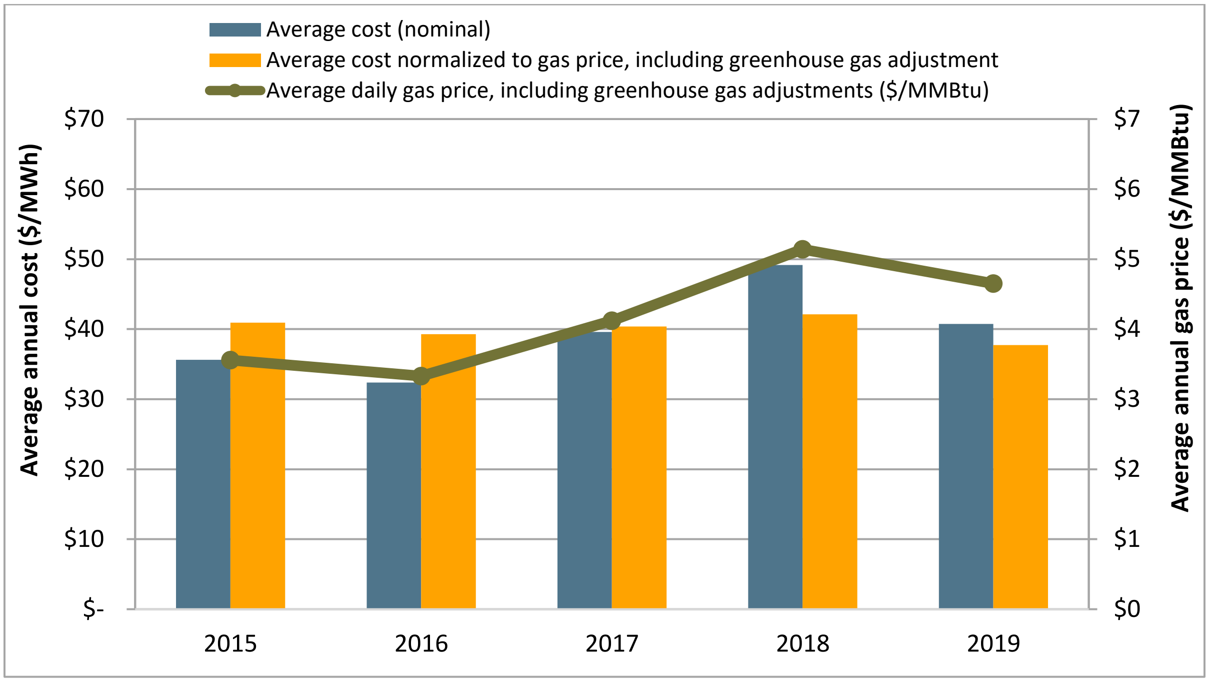


Table 2.1 provides annual summaries of nominal total wholesale costs by category from 2015 through 2019. In previous reports, costs incurred from the energy imbalance market were included in this table. The total wholesale energy cost also includes costs associated with ancillary services, convergence 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.[102]

As seen in Table 2.1, the 17 percent decrease in total cost in 2019 was primarily due to decreases in day-ahead energy costs, which changed by about $8/MWh or roughly 17 percent from 2018. The remaining components of the wholesale energy costs continue to represent a relatively small portion of total cost, with real-time costs increasing from 2018 and bid cost recovery, reliability, and reserve costs decreasing.

[102] 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 then the flexible ramping product when introduced in November of 2016. 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. Prior year reported values have been adjusted to account for an inconsistency in treatment of convergence bids and load aggregation by market, resulting in slightly lower costs per megawatt-hour than previously reported. These changes were made to conform this calculation to settlement values.

Table 2.1 Estimated average wholesale energy costs per MWh (2015-2019)

	2015	2016	2017	2018	2019	Change '18-'19
Day-ahead energy costs	$ 34.23	$ 30.49	$ 37.40	$ 46.05	$ 38.12	$ (7.94)
Real-time energy costs (incl. flex ramp)	$ 0.18	$ 0.54	$ 0.73	$ 0.60	$ 1.01	$ 0.42
Grid management charge	$ 0.42	$ 0.42	$ 0.44	$ 0.46	$ 0.46	$ (0.00)
Bid cost recovery costs	$ 0.38	$ 0.30	$ 0.41	$ 0.69	$ 0.57	$ (0.11)
Reliability costs (RMR and CPM)	$ 0.12	$ 0.11	$ 0.10	$ 0.73	$ 0.06	$ (0.67)
Average total energy costs	**$ 35.33**	**$ 31.86**	**$ 39.09**	**$ 48.52**	**$ 40.22**	**$ (8.31)**
Reserve costs (AS and RUC)	$ 0.27	$ 0.53	$ 0.71	$ 0.87	$ 0.74	$ (0.13)
Average total costs of energy and reserve	**$ 35.60**	**$ 32.39**	**$ 39.80**	**$ 49.40**	**$ 40.96**	**$ (8.44)**

2.2 Overall market competitiveness

To assess the competitiveness of the ISO energy markets, DMM compares actual market prices to competitive benchmark prices we estimate would result under highly competitive conditions. DMM estimates competitive baseline prices by re-simulating the market after replacing the market bids of all gas-fired units with the lower of their submitted bids or their default energy bids (DEB). This methodology assumes competitive bidding of price-setting resources, and is calculated using DMM's version of the actual market software.[103]

As shown in Figure 2.2, hourly prices in the day-ahead market were very similar to or slightly above the estimated competitive baseline prices on average. DMM calculates the day-ahead price-cost markup by comparing the competitive benchmark to the base case load-weighted average price for all energy transactions in the day-ahead market.

Each market simulation is preceded by a base case rerun with all of the same inputs as the original market run before completing the benchmark simulation, to screen for accuracy. For 2019, the base case reruns have replicated original prices with a greater frequency than recent years, allowing a higher percentage of days to be included in this analysis.[104]

As shown in Figure 2.3, in 2019 the average price-cost markup was about $0.71/MWh or just under 2 percent. This slight positive markup indicates that prices have been very competitive, overall, for the year.[105]

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

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

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

Figure 2.2 Comparison of competitive baseline with hourly day-ahead prices (Jan-Dec)

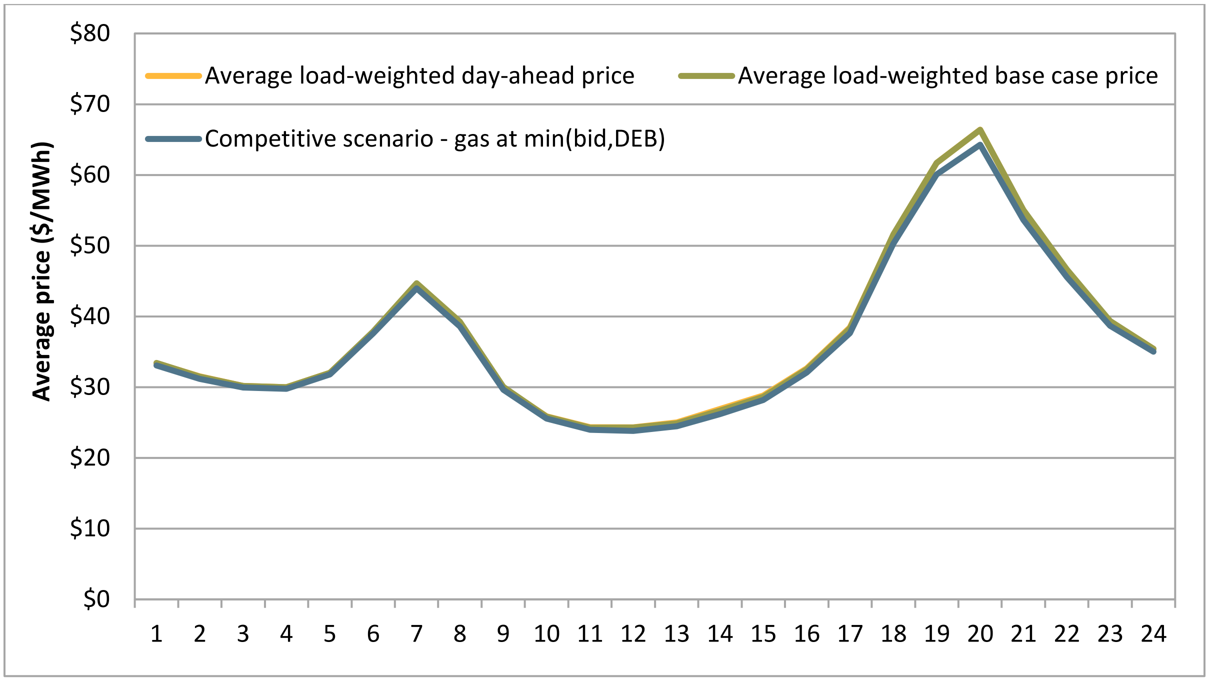
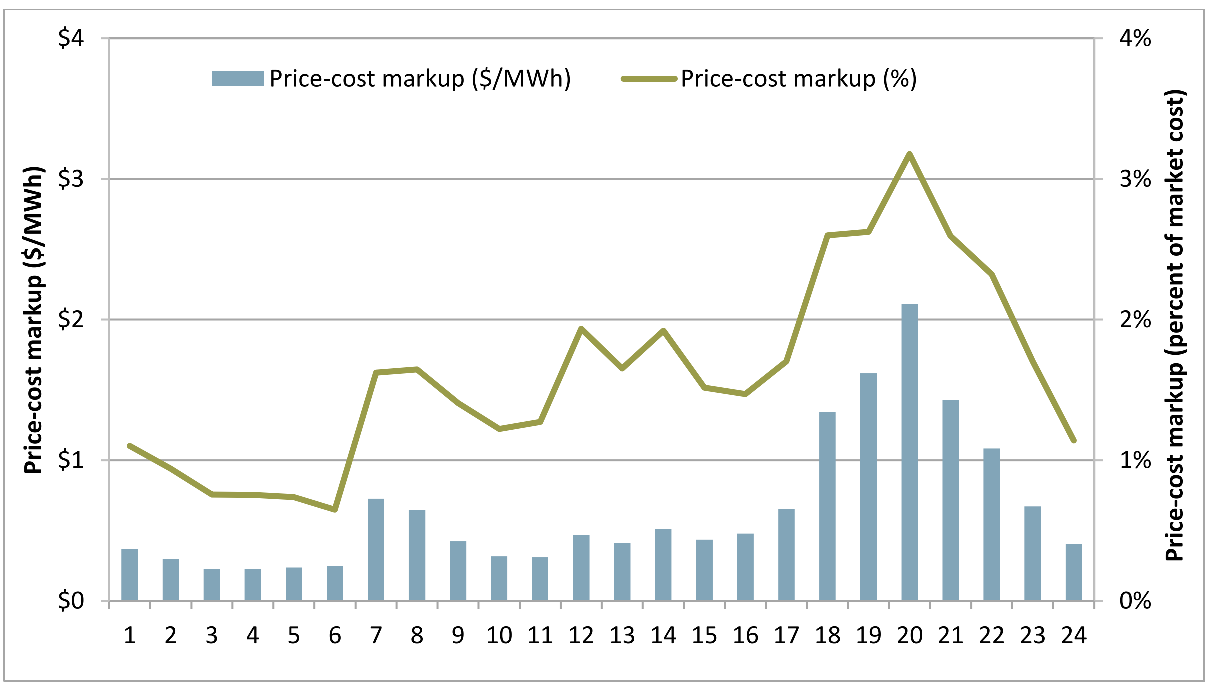


Figure 2.3 Hourly price-cost markup (Jan-Dec)



This price-cost metric is a conservative estimate of system market power for several reasons. The only change in market inputs in the competitive scenario is that energy bids of gas-fired resources are capped by each resource's default energy bid, which includes a 10 percent adder above estimated marginal costs. All other bids are assumed to be competitive, including those of non-resource specific imports. Also, this analysis does not change commitment cost bids for non-gas or gas-fired resources which are capped at 125 percent of each resource's estimated start-up and minimum load costs. DMM is working to develop the capability to assess the potential impact of these market bids on overall system prices using the ISO's day-ahead market software in 2020.

2.3 Energy market prices

This section reviews energy market prices in the ISO balancing area by focusing on price trends and comparison of prices in the day-ahead and real-time market. Key points highlighted in this section include the following:

- Average energy market prices were relatively high during the first quarter of 2019, primarily due to relatively high gas prices at the Northwest Sumas, PG&E Citygate, and SoCal Citygate gas hubs.
- Prices in the day-ahead market were higher than prices in both the 15-minute and 5-minute markets on average during the year. Day-ahead energy prices averaged about $38/MWh, 15-minute prices were about $37.5/MWh, and 5-minute prices were about $37/MWh.
- Average hourly prices generally moved in tandem with the average net load. Average hourly prices in the day-ahead, 15-minute, and 5-minute markets were generally similar on an hourly basis with day-ahead prices being slightly below real-time prices about half of the hours of the day.

Figure 2.4 shows load-weighted average energy prices across the three largest load aggregation points in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric) during all hours. Overall, price convergence between the day-ahead and real-time markets increased from the previous year. On average, price convergence between the 15-minute and 5-minute markets also increased compared to the previous year; however, this masks the changes in relative prices between quarters. Other key trends include the following:

- Energy market prices remained high in the first quarter of 2019, continuing the trend from the second half of 2018. This was primarily caused by high gas prices at SoCal Citygate, PG&E Citygate and Northwest Sumas gas hubs during February. After dropping in the second quarter, gas prices in some hubs increased slightly in the third and fourth quarters which contributed to steadily increasing average energy market prices.
- Day-ahead prices have typically been higher than real-time prices in the ISO, but this changed in the second quarter when average day-ahead prices were about $2/MWh lower than 15-minute prices and about $6/MWh lower than 5-minute prices. Lower second quarter prices were due to low gas prices and increased production from renewable resources.
- Average 15-minute prices were about the same as 5-minute prices for the year. The yearly average masks quarterly variability, however, where 15-minute prices were about $4/MWh lower than 5-minute prices in the second quarter and nearly $4/MWh higher in the fourth quarter.
- Similar to the previous year, negative average energy prices were relatively frequent in the day-ahead market. Prices fell below zero in nearly 100 hours in 2019, an increase from about 80 hours in 2018. Negative prices in the day-ahead market occurred during midday hours when solar generation was highest.

Figure 2.4 Average quarterly prices (all hours) – load-weighted average energy prices

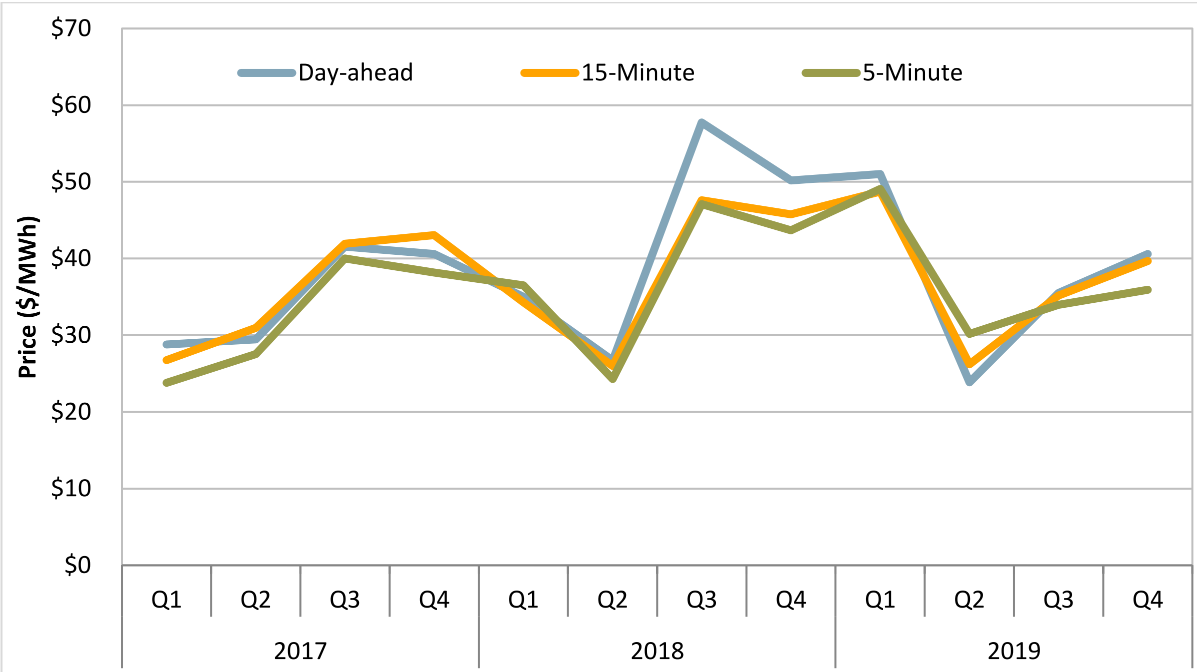
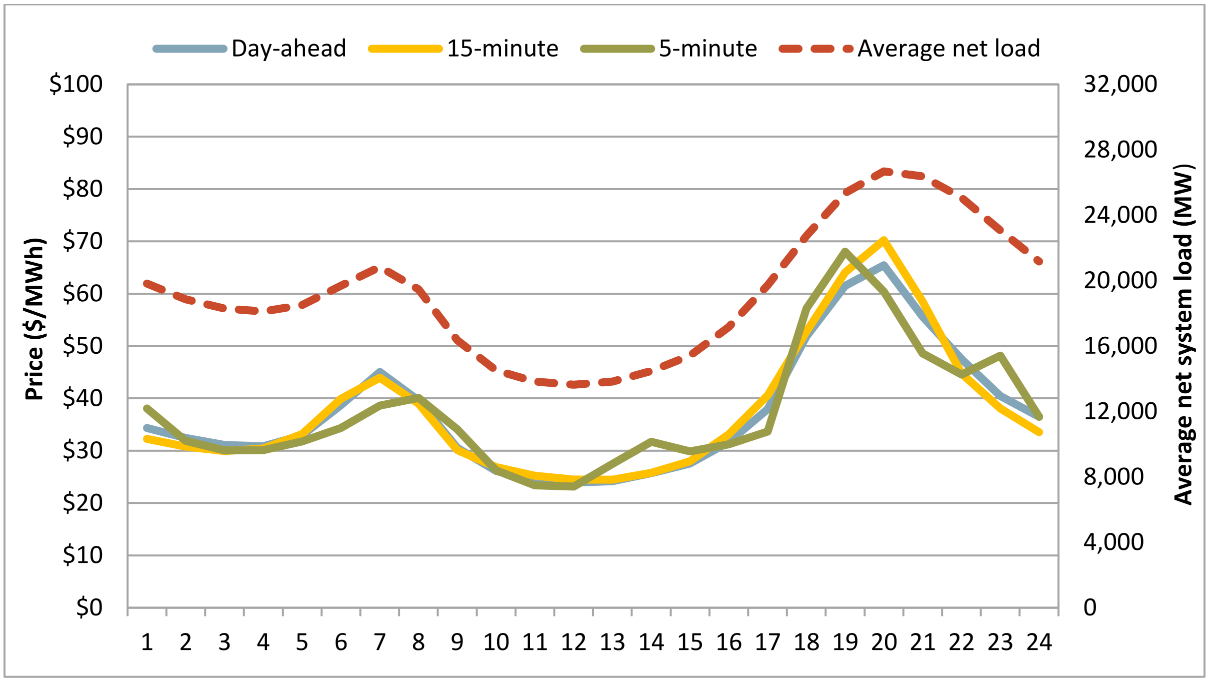


Figure 2.4 illustrates hourly load-weighted average energy prices in the ISO in the day-ahead and real-time markets as well as average hourly net load.[106] Average hourly prices in this figure follow the net load pattern as energy prices were lowest during the early morning, midday, and late evening 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, both utility scale and behind the meter, is installed or 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.

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

Figure 2.5 Hourly load-weighted average energy prices (2019)

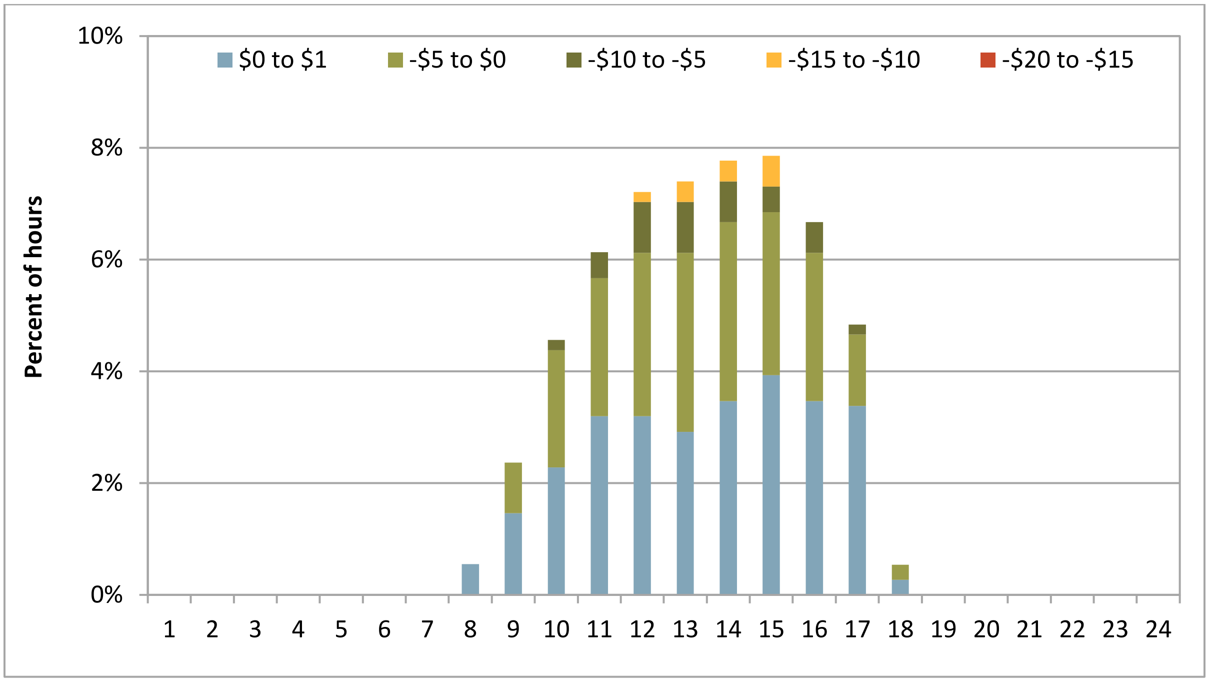


Negative day-ahead market prices

Negative prices were relatively frequent in the day-ahead market in 2019. There were about 130 hours when day-ahead prices were negative, or about one percent of total hours. This is an increase from 2018 when there were less than 90 hours with negative day-ahead prices. Prior to 2017, day-ahead market system marginal energy prices had been negative during only three hours. More frequent negative prices in the day-ahead market were the result of additional installed renewable capacity and additional generation from hydro resources.

Figure 2.6 shows the frequency of negative prices near or below $0/MWh in the day-ahead market by hour in 2019. Negative prices in the day-ahead market occurred during midday hours, primarily in the second quarter when hydroelectric and solar generation were greatest and loads were seasonally mild. Day-ahead prices were negative during around 3.5 percent of hours between hours 11 through 15. Negative prices occurred more frequently on weekends when loads were lower.

Figure 2.6 Hourly frequency of day-ahead prices near or below $0/MWh



Comparison to bilateral prices

High prices in California, relative to bilateral prices at trading hubs elsewhere in the West, reflect both the greenhouse gas compliance cost associated with delivering energy into the state and the cost of congestion associated with limited transfer capacity with other balancing authority areas. Figure 2.7 shows monthly average day-ahead prices in the ISO compared to monthly average peak energy prices traded at the Palo Verde and Mid-Columbia hubs published by the Intercontinental Exchange.[107]

Prices in the ISO are represented in Figure 2.7 by prices at the Southern California Edison and Pacific Gas and Electric load aggregation points. Average monthly prices at the Mid-Columbia and Palo Verde hubs were lower than ISO prices in Pacific Gas and Electric and Southern California Edison for all but two months in 2019.

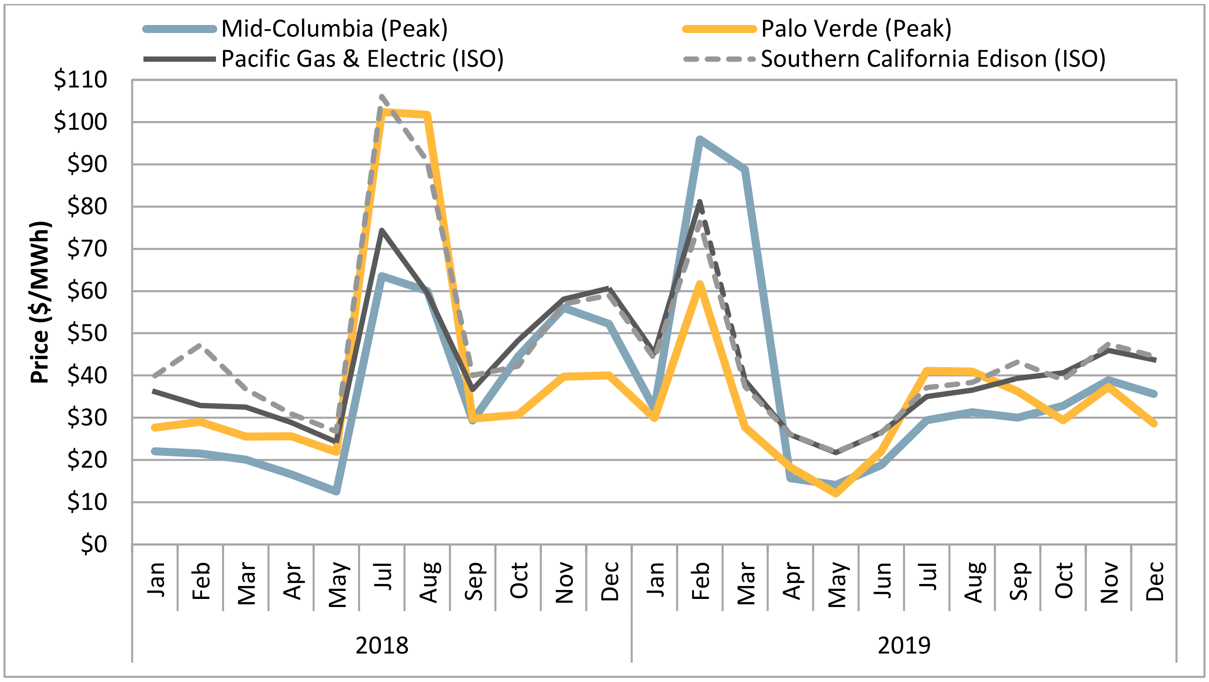
Day-ahead prices in the ISO were also compared to hourly energy prices traded at Mid-Columbia and Palo Verde hubs published by Powerdex. Prices in the Pacific Gas and Electric and Southern California Edison areas across all hours in 2019 were greater on average than prices in Mid-Columbia and Palo Verde by about $7/MWh and $6/MWh, respectively. Higher prices at Mid-Columbia in February and March were associated with record high gas prices at the Northwest Sumas gas hub following a pipeline outage.

Relatively higher prices in California reflect both the greenhouse gas compliance cost associated with delivering energy into the state and the cost of congestion associated with limited transfer capacity with other balancing authority areas. Natural gas prices and availability in the ISO and other locations also play a large role in energy price differences across the west. Prices between Pacific Gas and Electric and

[107] Day-ahead prices from the ISO include only the peak hours for comparison to peak bilateral prices from the Intercontinental Exchange (ICE).

Southern California Edison tracked very closely in 2019 and did not display the large levels of price separation that occurred in 2018 due to the divergence in gas prices between SoCal Citygate and PG&E Citygate during the summer months.

Figure 2.7 Monthly average day-ahead and bilateral market prices



2.4 Residual unit commitment

The purpose of the residual unit commitment process is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real time. The residual unit commitment process 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.

The total volume of capacity procured through the residual unit commitment process in 2019 was similar to 2018. ISO operators are able to increase the amount of residual unit commitment requirements for reliability purposes. In 2019, these operator adjustments increased significantly beginning in June and continued until September.[108]

Residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of bid-in variable energy resources and the forecast output of these renewable

108 See Section 9.4 for further discussion on operator adjustments in the residual unit commitment process.

resources. This intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market.

Figure 2.8 Residual unit commitment (RUC) costs and volume (2018 – 2019)

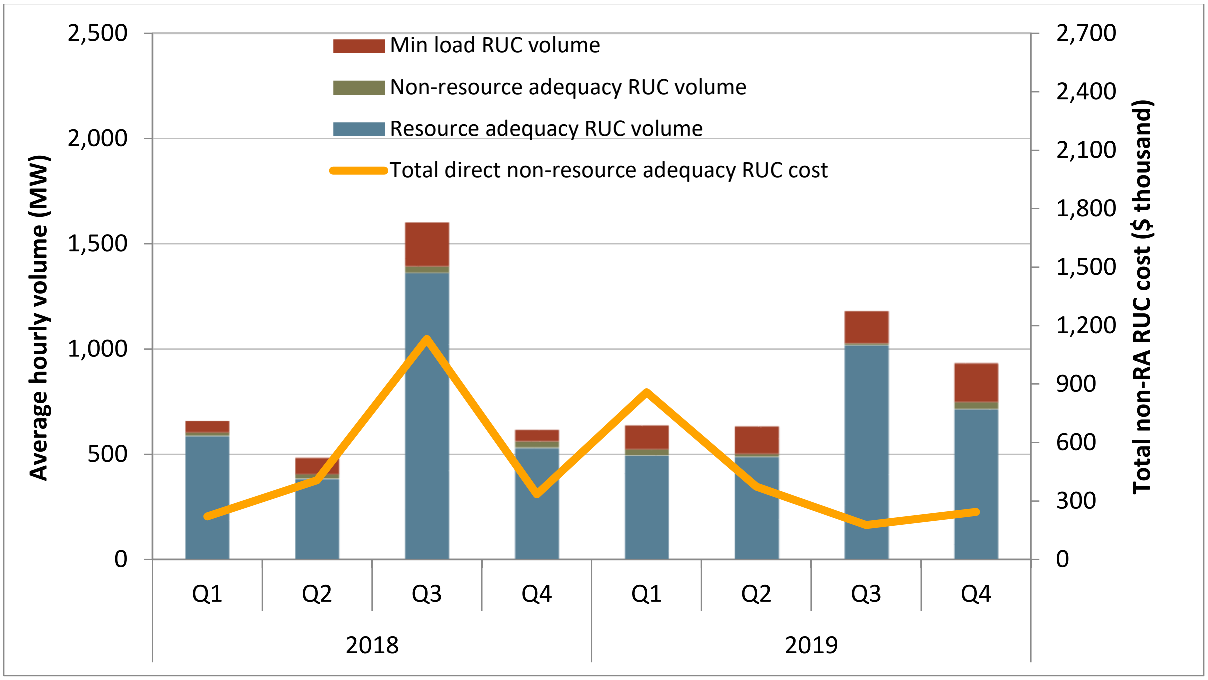


Figure 2.8 shows quarterly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased slightly to 845 MW per hour in 2019 from an average of 839 MW in 2018. Specifically, the figure shows increased volumes due to high residual unit commitment requirements in the third and fourth quarters of 2019. The increased volumes in the third and fourth quarters can be attributed to a combination of factors including relatively high operator adjustments, increase in amounts of cleared net virtual supply, and energy net short adjustments. When the market clears with net virtual supply, residual unit commitment capacity is needed to replace net virtual supply with physical supply.

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.[109] Most of the capacity procured 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 at or above 600 MW in each quarter of 2019 and the capacity committed to operate at minimum load averaged 144 MW each hour. This was an increase of about 46 percent from the capacity that was procured and committed to

109 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.

operate at minimum load in 2018. In 2019, about 9 percent of this capacity was from long-start units compared to 19 percent in 2018.[110]

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 process receive capacity payments.[111] As shown by the small green segment of each bar in Figure 2.8, the non-resource adequacy commitment averaged about 22 MW per hour in 2019, slightly down from about 25 MW procured in 2018. The total direct cost of non-resource adequacy residual unit commitment, represented by the gold line in Figure 2.8, decreased to about $1.6 million in 2019, down from a direct cost of about $2 million in 2018.

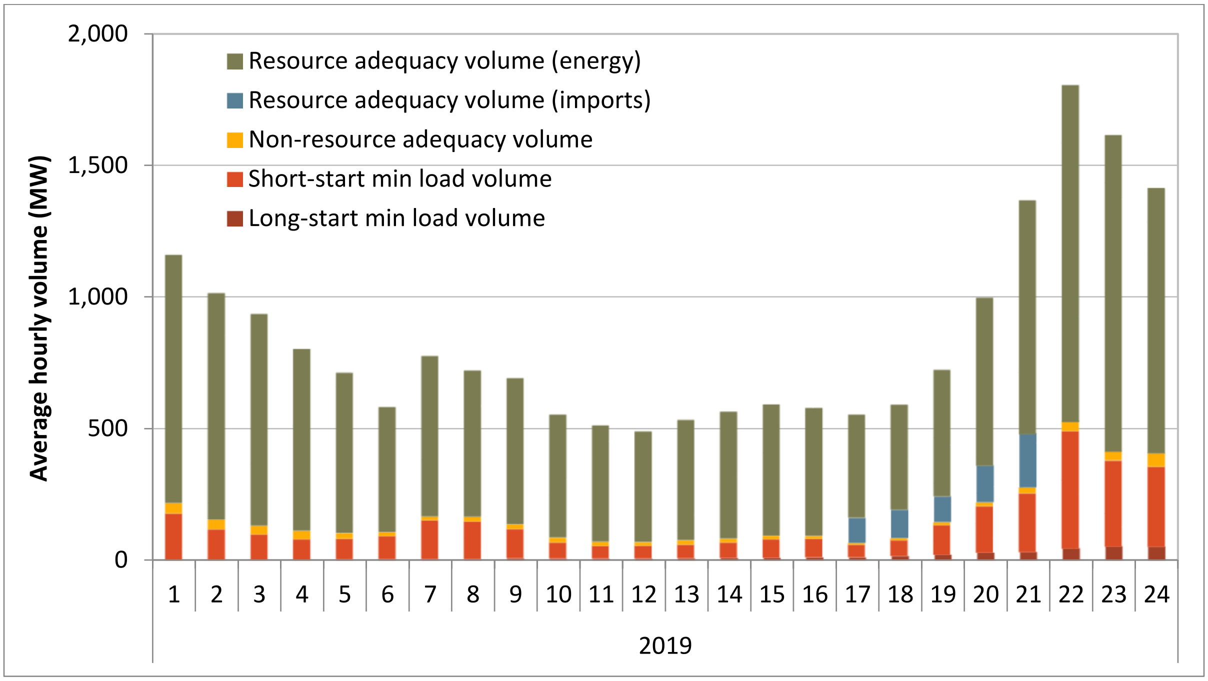
Figure 2.9 shows the same data presented in Figure 2.8 by energy type on an average hourly basis for 2019. As shown by the green bars in the figure, resource adequacy capacity scheduled in the residual unit commitment process was greatest during the off-peak hours of the day. The capacity procured from resource adequacy imports, shown by blue bars, was concentrated during hours ending 17 through 21. Overall, less than five percent of this import capacity cleared the real time hour-ahead market because about 95 percent was rebid at or above $50/MWh.

Capacity procured from short-start and long-start resources tended to be greatest during the end of the day, as shown in the red bars in Figure 2.9. Long-start resources receiving residual unit commitment awards are committed to run at their minimum operating level and must bid this capacity into the real-time market. Fast-start resources providing residual unit commitment capacity are not committed to run in real time, but have an obligation to bid into the real-time market.

[110] 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.

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

Figure 2.9 Average hourly residual unit commitment (RUC) volume (2019)



2.5 Bid cost recovery payments

Bid cost recovery payments for units in the ISO and energy imbalance market totaled around $123 million and $10 million, respectively, the second highest total since 2011. Bid cost recovery payments decreased in 2019 compared to 2018, when payments were highest and totaled $162 million.[112] The ISO's portion of these payments in 2019 represents about 1.4 percent of total ISO wholesale energy costs.

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.

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

Figure 2.10 Bid cost recovery payments

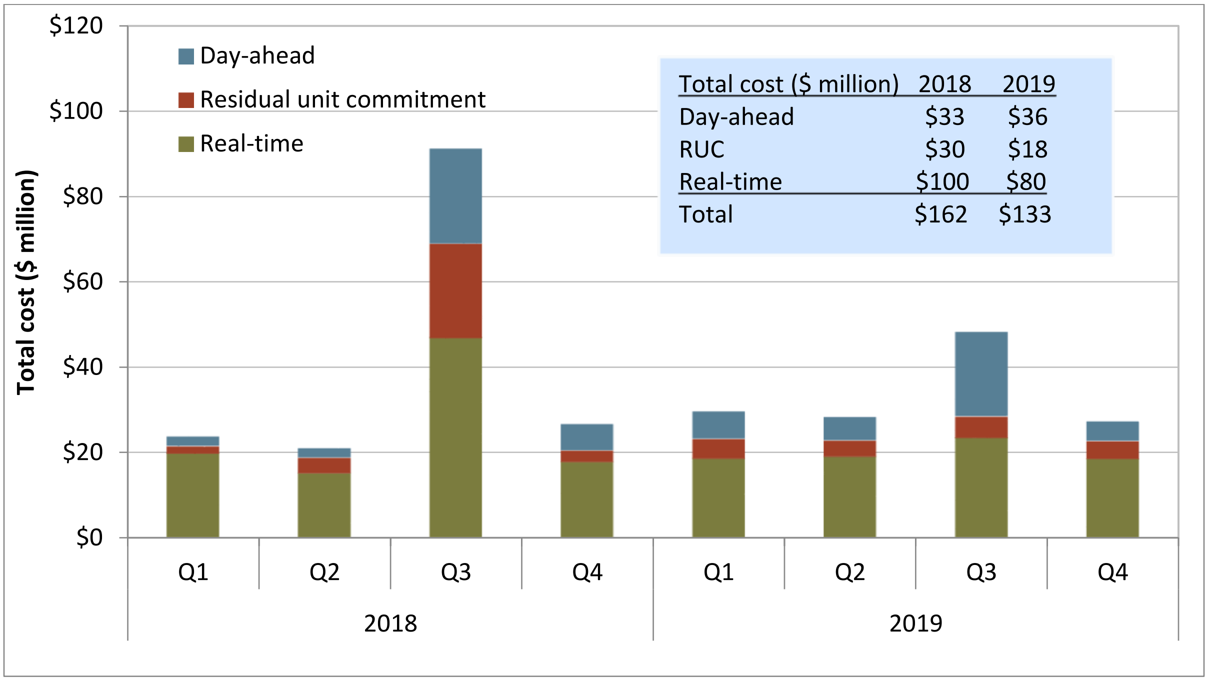


Figure 2.10 provides a summary of total estimated bid cost recovery payments in 2019 and 2018 by quarter and market. As shown in the figure, the decrease in total bid cost recovery payments in 2019 from 2018 resulted largely from decline in payments in the third quarter of 2019. This decline can be attributed to low loads and lower gas prices in the third quarter.

Day-ahead bid cost recovery payments totaled $36 million in 2019, a slight increase from $33 million in 2018. An estimated 68 percent of these payments can be attributed to resources effective at meeting the minimum online constraints enforced in the day-ahead market, compared to 75 percent in 2018.[113]

Real-time bid cost recovery payments were $80 million in 2019, down from about $100 million in 2018. Payments in February alone totaled about $9 million, because of relatively high natural gas prices at both SoCal Citygate and PG&E Citygate gas hubs. In addition, about $5 million of these payments were accrued between June 10 through 12 due to relatively high loads and high system energy prices on those days. The real-time bid cost recovery amount also included payments for units in the energy imbalance market (EIM) which totaled about $10 million in 2019; about $1.5 million lower than in 2018. About $0.2 million of these payments were to units in the BANC Phase 1 balancing authority, which joined the EIM on April 3, 2019.

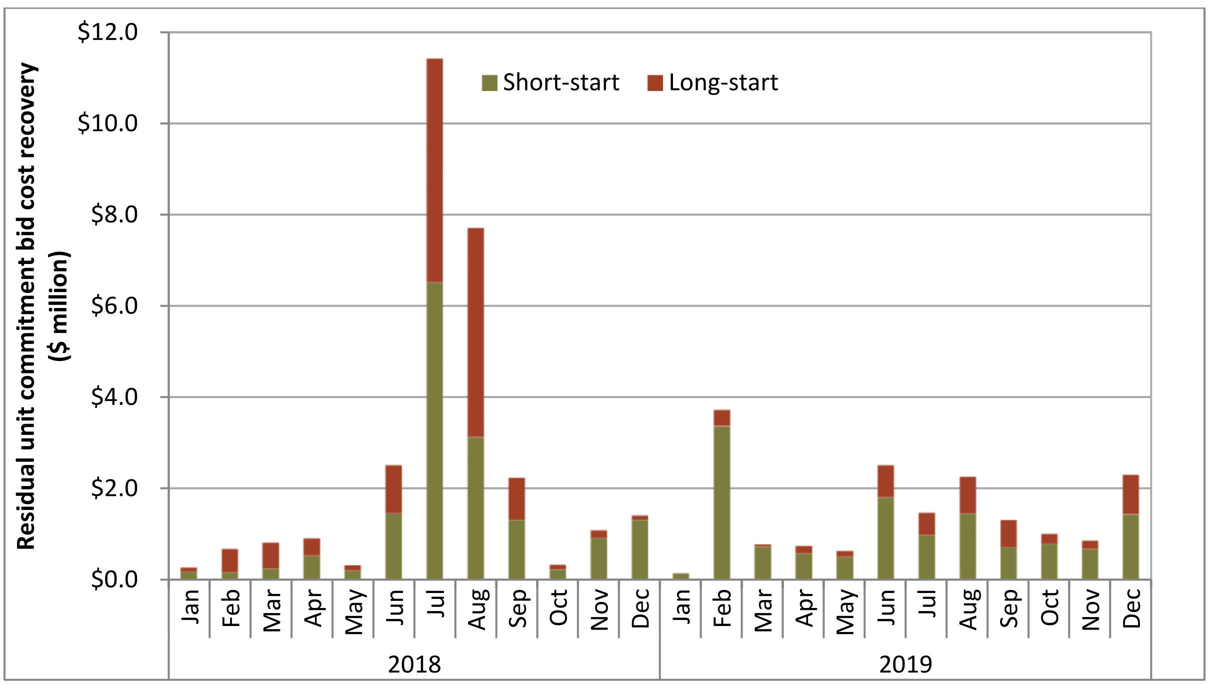
[113] Minimum on-line constraints (MOCs) are used to meet special reliability issues that require having units on-line to meet voltage requirements and for contingencies. These constraints are based on existing operating procedures that require a minimum quantity of on-line capacity from a specific group 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.
Bid cost recovery payments attributed to resources committed to meet minimum online constraints in 2018 has been re-calculated based on an updated methodology.

Bid cost recovery payments for units committed through the residual unit commitment process totaled about $18 million in 2019. This is about 14 percent of total bid cost recovery payments, down from about $30 million in 2018.

Units committed by the residual unit commitment can be either long- or short-start units. As shown in Figure 2.11, short-start units accounted for about $13 million in bid cost recovery payments, while long-start unit commitment accounted for $5 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.

DMM estimates that about 67 percent of the ISO's total bid cost recovery payments, approximately $82 million, were allocated to resources that bid their commitment costs above 110 percent of their reference commitment costs. Commitment cost bids are capped at 125 percent of a reference proxy costs.[114] About 93 percent of these payments are for resources bidding at or near the 125 percent bid cap for proxy commitment costs.

Figure 2.11 Residual unit commitment bid cost recovery payments by commitment type



Bid cost recovery payments for units committed through exceptional dispatches also played an important role in real-time bid cost recovery payments. Exceptional dispatches are made by real-time operators to help ensure reliability across the system. DMM estimates these payments for resources committed to operate through exceptional dispatches totaled about $19 million in 2019, compared to $40 million in payments in 2018. The majority of this decline was in the third quarter when payments fell to $10 million compared to $29 million in the same quarter of 2018. Additional details regarding exceptional dispatches are covered in Section 9.1 of this report.

114 See Section 7.5 for additional information on commitment cost bid caps and bidding behavior.

In 2019, the ISO resolved several real-time bid cost recovery payment issues. In one case, multi-stage generating resources with day-ahead self-schedules and real-time economic bids were over-compensated. The ISO's impact analysis found about $15 million in over-payments to resources between May 2016 and February 2019. The ISO has resolved this issue and resettled the correct amount consistent with the settlement timeline. In the second case, multi-stage generating resources with real-time outages received over-payments. In this situation, current settlement rules provide generators with payments to offset any loss from real-time energy charges incurred because of the outage. DMM estimated about $3.3 million of real-time bid cost recovery was paid to resources with outages on June 10 and June 11, 2019. The ISO has implemented a fix to this issue as well.[115]

2.6 Real-time imbalance offset costs

Total real-time imbalance offset costs decreased in 2019 to $103 million from $133 million in 2018 within the ISO. The bulk of the offset costs were $97 million in real-time congestion imbalance offset costs, down from $117 million in 2018. Real-time imbalance energy offset costs decreased and loss offsets increased modestly in 2019.

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. The real-time offsets include imbalances from both the 15-minute market and 5-minute dispatch. 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 energy offset charges fell from $18 million in 2018 to $6 million in 2019. Real-time loss imbalance offsets went from $2 million surplus in 2018 to about $0.2 million deficit in 2019. Real-time congestion imbalance offset charges decreased from $117 million in 2018 to $97 million in 2019. In 2018 and 2019, most congestion offset charges were associated with network model differences and reductions in constraint limits in the 15-minute market from the day-ahead market.

Overall real-time congestion imbalance is the sum of specific constraint congestion imbalances. When a change to a real-time energy schedule reduces flows on a constraint, that schedule is paid the real-time constraint congestion price for making space available on the constraint. Generally, if the constraint is still binding with a non-zero price, another schedule has increased flows on the constraint. The schedule that increased flows would then pay the ISO enough to cover the ISO's payments to the schedule that reduced flows—and the ISO congestion accounts would remain balanced. However, there are several reasons the congestion payments will not balance.[116]

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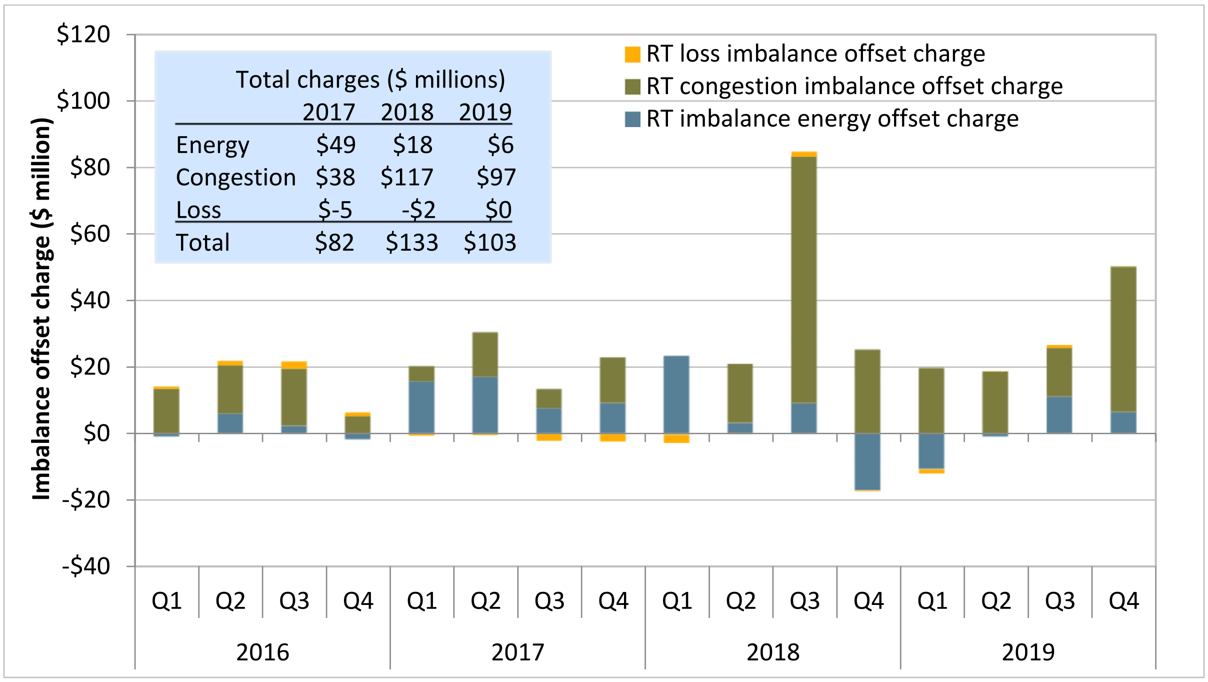
115 How should partial configuration outages be treated, BPM Change Management, PRR1220: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1220&IsDlg=0

116 One is that flows increase causing a constraint to bind generating additional congestion rent.

One reason is that the real-time constraint limits are lower than the day-ahead market limits. With a lower limit, schedules may be forced to reduce flows over the still binding constraint without a corresponding flow increase. The ISO will pay the flow reduction but cannot balance this payment with collections from a flow increase. To maintain revenue balance, the ISO charges an uplift to measured demand to offset the imbalance.[117] Congestion imbalances can also occur from differences in transmission modeling and the modeling of non-settled flows.

Figure 2.12 Real-time imbalance offset costs



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

3 Real-time market

Real-time prices in the ISO and energy imbalance market can experience periods of market volatility. This volatility is often driven by brief periods when the market software has exhausted upward and downward flexibility, requiring relaxation of the system power balance constraint. As more variable renewable generation is integrated into the ISO system to meet state renewable generation goals, the importance of real-time resource flexibility increases, for all resource types.

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 were less frequent in both the 15-minute and 5-minute markets**. Extreme price spikes greater than $750/MWh in the 15-minute market were concentrated in the evening ramping period while spikes in the 5-minute market occurred in nearly all hours.
- **Negative prices occurred more frequently** in the 15-minute and 5-minute markets compared to the previous year.
- **The ISO implemented an enhancement to the load conformance limiter**, effective February 27, 2019, which decreased the frequency of prices set at the highest priced bid rather than the $1,000/MWh penalty parameter. This enhancement had little impact in the ISO because the highest priced bids dispatched are often at or near the $1,000/MWh bid cap such that the resulting price is often similar with or without the limiter.
- **Flexible ramping prices were frequently zero in both the 15-minute and 5-minute markets** in both the upward and downward directions. In these intervals, flexible ramping capacity was readily available relative to the need for it so that no cost was associated with the level of procurement.
- **Flexible ramping is often procured from resources that are not able to meet system uncertainty** either because of resource characteristics or congestion. This can reduce the effectiveness of the flexible ramping product to manage net load volatility and prevent power balance violations.
- **The ISO could reduce the need for manual load adjustments** and more efficiently integrate distributed and variable energy resources by designing a real-time flexible ramping product that could procure and price the appropriate amount of ramping capability to account for uncertainty over longer time horizons than the current design considers. Uncertainty over load and the future availability of resources to meet that load contributes to operators needing to enter systematic and large imbalance conformance adjustments, as described in Chapter 9 of this report.
- **The ISO enforced gas burn constraints** in both day-ahead and real-time markets in selected sub-regions of the SoCalGas service area during only 17 days. These constraints did not bind frequently and were not associated with substantial uplift costs. DMM continues to recommend that the ISO refine how it utilizes the maximum gas constraint and improve how gas usage constraint limits are set and adjusted in real-time.

3.1 Real-time price variability

Prices in the 15-minute and 5-minute markets were slightly more variable in 2019 than in 2018, particularly in the second quarter. Compared to the previous year, negative prices occurred more frequently in the ISO area, while high prices occurred less frequently in both the 15-minute and 5-minute real-time markets.

High prices in the ISO area

Similar to the previous year, most high prices in 2019 occurred as a result of high bids in the market and congestion within the ISO. Real-time market price spikes occurred most frequently in the second quarter rather than the third quarter when there was higher demand. Most high real-time prices also continued to occur in the morning and evening ramping hours.

Figure 3.1 shows the frequency of prices above $250/MWh at load aggregation points (LAPs) within the ISO in the 15-minute market. The overall frequency of 15-minute prices above $250/MWh was 0.3 percent of intervals, slightly lower than 2017 and 2018 when the frequency was about 0.5 percent of intervals. The greatest portion of 15-minute price spikes in 2019 was less than $500/MWh followed closely by the above $1,000/MWh category. The higher percentage of $1,000/MWh prices was due in part to the load conformance limiter enhancement implemented in February 2019.

Prices greater than $750/MWh occurred during 0.02 percent of intervals in 2019. This remained unchanged from 2018. High prices in the 15-minute market occurred mainly in the second quarter, particularly in the month of June when prices above $250/MWh occurred in over 1.1 percent of intervals.

Figure 3.2 shows the frequency of prices above $250/MWh in the 5-minute market. The frequency of these prices declined slightly from 0.9 percent of intervals in 2018 to 0.8 percent in 2019. Similarly, the frequency of extreme prices above $750/MWh declined from 0.5 percent of intervals in 2018 to 0.4 percent of intervals in 2019. High price spikes in the 5-minute market are often associated with congestion. In other instances, extreme price spikes were the result of power balance constraint infeasibilities resolved at a penalty price or set by an extremely high bid when resolved by the load bias limiter.

High prices in both the 5-minute and 15-minute markets were most common between hours ending 18 and 20 during the peak evening net load ramp period. Price spikes in the 5-minute market also occurred throughout the day, with the exception of hours ending 3 and 4, mostly because of variability of generation from renewable energy resources.

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

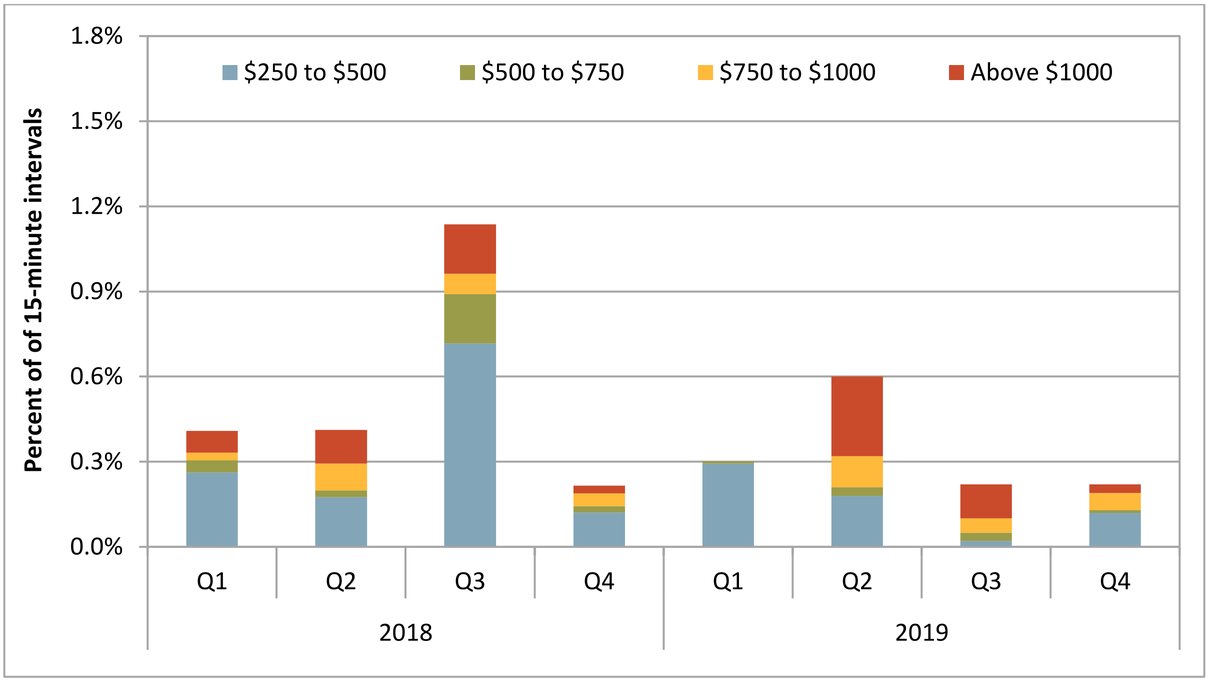
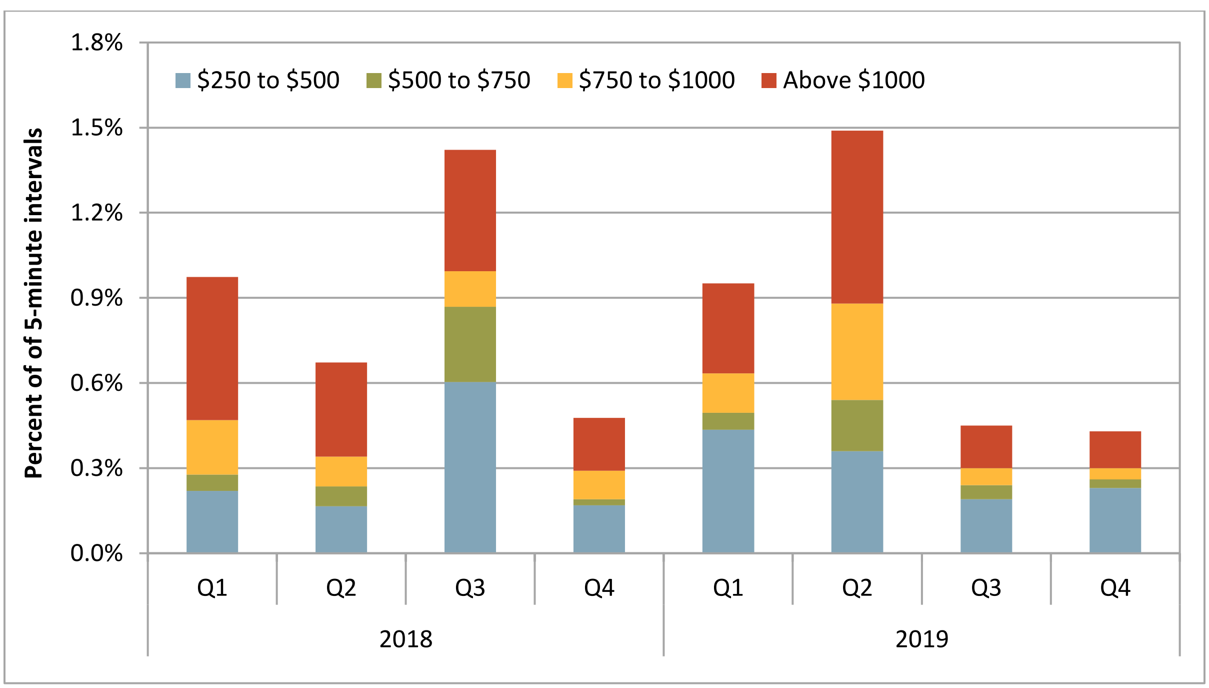


Figure 3.2 Frequency of positive 5-minute price spikes (ISO LAP areas)



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.

Negative prices occurred more frequently in both the 15-minute and 5-minute markets during 2019 compared to the previous year, particularly in the second quarter, with almost all negative prices falling between negative $50/MWh and $0/MWh. Figure 3.3 and Figure 3.4 show the frequency of negative prices in the 15-minute and 5-minute markets by quarter.

The higher frequency of negative prices this year in both the day-ahead and real-time markets is due in part to increased hydroelectric generation and lower load. Negative prices during 2019 were most frequent in the midday hours when renewable generation was highest with many renewable resources (primarily participating solar resources) bidding negative. Most negative prices occurred between February and June when hydroelectric generation was greatest.

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 if the over-supply is less than 30 MW. Beyond this threshold, self-scheduled generation can be curtailed including self-scheduled wind and solar generation. Similar to 2018, there was sufficient downward flexibility during all negatively priced intervals in 2019 such that the market software did not have to relax the power balance constraint for excess energy. Any curtailment of self-scheduled generation was the result of local congestion rather than system over-supply.

Similar to the previous year, the frequency of prices near or below the -$150/MWh floor remained almost nonexistent in 2019. This result reflects the bidding flexibility of renewable resources and increased transfer capability in the real-time market from the energy imbalance market.

Figure 3.5 shows the annual frequency of negative prices in the 5-minute market since 2014.[118] The overall frequency of negative prices increased every year between 2013 until 2017, with a drop in 2018 followed by an increase in 2019. The decline of negative prices in 2018 reflects decreased generation from hydroelectric resources relative to prior years. The 2019 increase over the prior year reflects both lower load and an increase in hydroelectric generation.

Figure 3.6 shows the hourly frequency of negative 5-minute prices in the last four years. The figure illustrates that the majority of negative prices during 2019 generally occurred during midday hours when solar generation was highest and net demand was low. This has been a trend since 2015, although in 2018 and 2019 the frequency of negative prices during the midday hours was higher than the previous years.

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[118] In the *2018 Annual Report on Market Issues and Performance* this figure presented 15-minute price data and not 5-minute price data. This has been corrected in the 2019 report. Note that the trends between the 15-minute and 5-minute were very similar; however, 5-minute data is about one percent greater than the previously published 15-minute data.

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

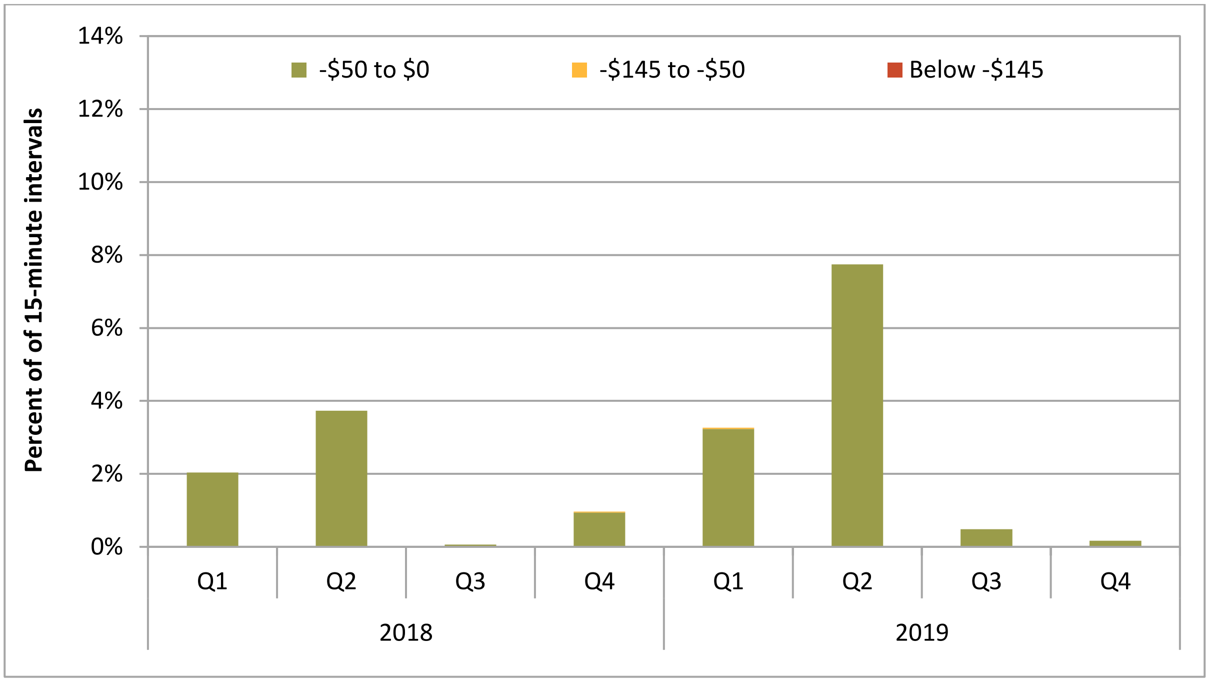


Figure 3.4 Frequency of negative 5-minute prices (ISO LAP areas)

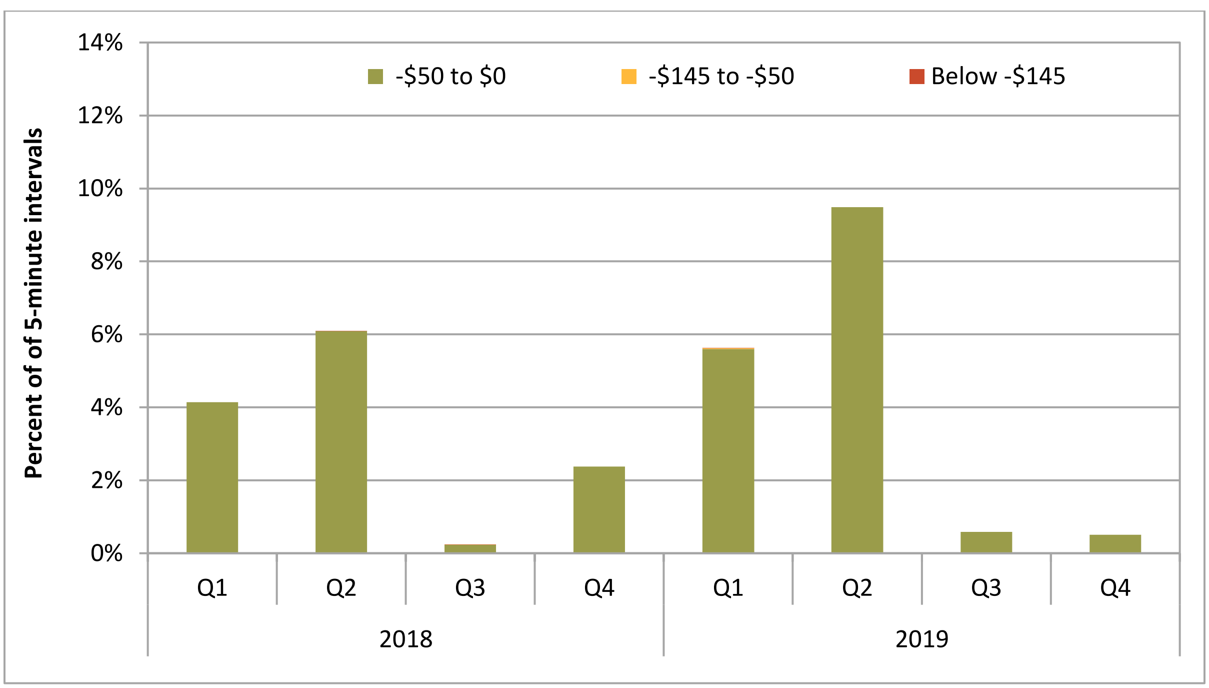


Figure 3.5 Frequency of negative 5-minute prices (ISO LAP areas)

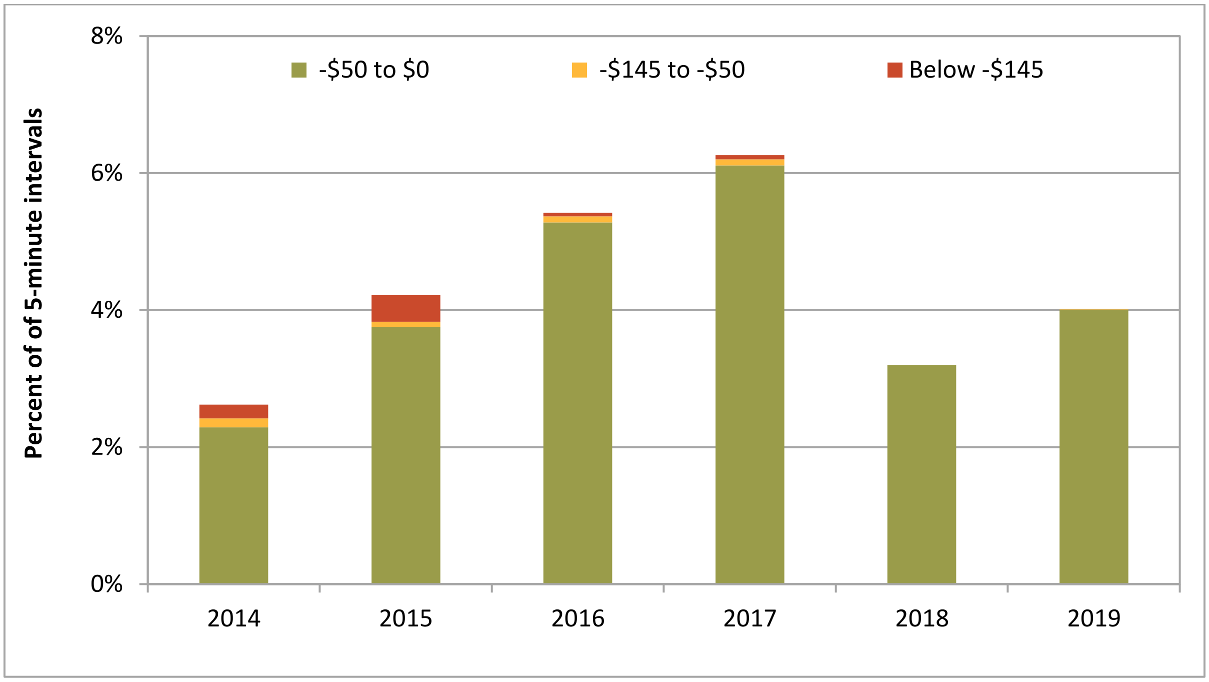
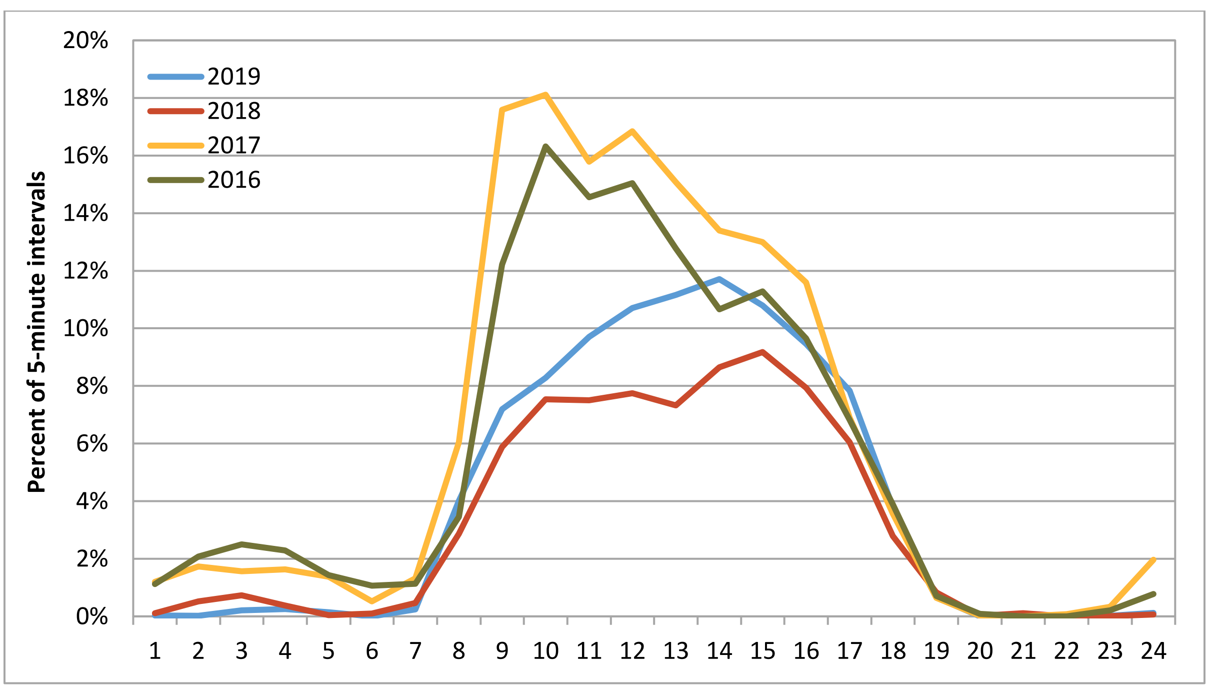


Figure 3.6 Hourly frequency of negative 5-minute prices by year (ISO LAP areas)



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. This condition is known as a power balance constraint relaxation.[119] 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).

The load conformance limiter reduces the impact of an excessive load adjustment on market prices when it is considered to have caused a power balance constraint relaxation. If the limiter triggers, 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.

The ISO implemented an enhancement to the load conformance limiter, effective February 27, 2019. With the enhancement, the load conformance limiter triggers by a measure based on the change in load adjustment from one interval to the next, rather than solely the magnitude of the load adjustment. This change significantly reduced the frequency in which the limiter triggers. However, under current market conditions, the enhancement to the conformance limiter does not have a significant impact on average prices in the ISO. This is because in most intervals when the limiter triggers in the ISO, the highest priced bids dispatched are often at or near the $1,000/MWh bid cap such that the resulting price is often similar with or without the limiter.

System power balance constraint relaxations

The frequency of system power balance constraint relaxations in 2019, either valid or resolved by the load conformance limiter, were relatively low and similar to the previous year.

Figure 3.7 and Figure 3.8 show the quarterly frequency of under-supply infeasibilities in the 15-minute market and 5-minute market, respectively. Between March and December, since the enhancement to the load conformance limiter, the limiter triggered in only 4 percent of 15-minute market infeasibilities and 17 percent of 5-minute market infeasibilities. In comparison, the limiter triggered during 89 and 70 percent of 15-minute and 5-minute market infeasibilities, respectively, during 2018. The percent of intervals priced at the $1,000/MWh penalty parameter increased from 0.01 in 2018 to 0.08 in 2019 in the 15-minute market and from 0.08 to 0.20 in the 5-minute market.

When the load bias limiter was triggered in 2019, the resulting price from the highest bid dispatched was often near the penalty parameter. In these instances, system prices were greater than $800/MWh during about 86 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.

There were no intervals during 2019 in either the 15-minute or the 5-minute markets in which the power balance constraint was relaxed because of insufficient downward flexibility. Bidding flexibility from renewable resources and increased transfer capability from the energy imbalance market continued to contribute to reduced oversupply conditions.

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119 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.

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

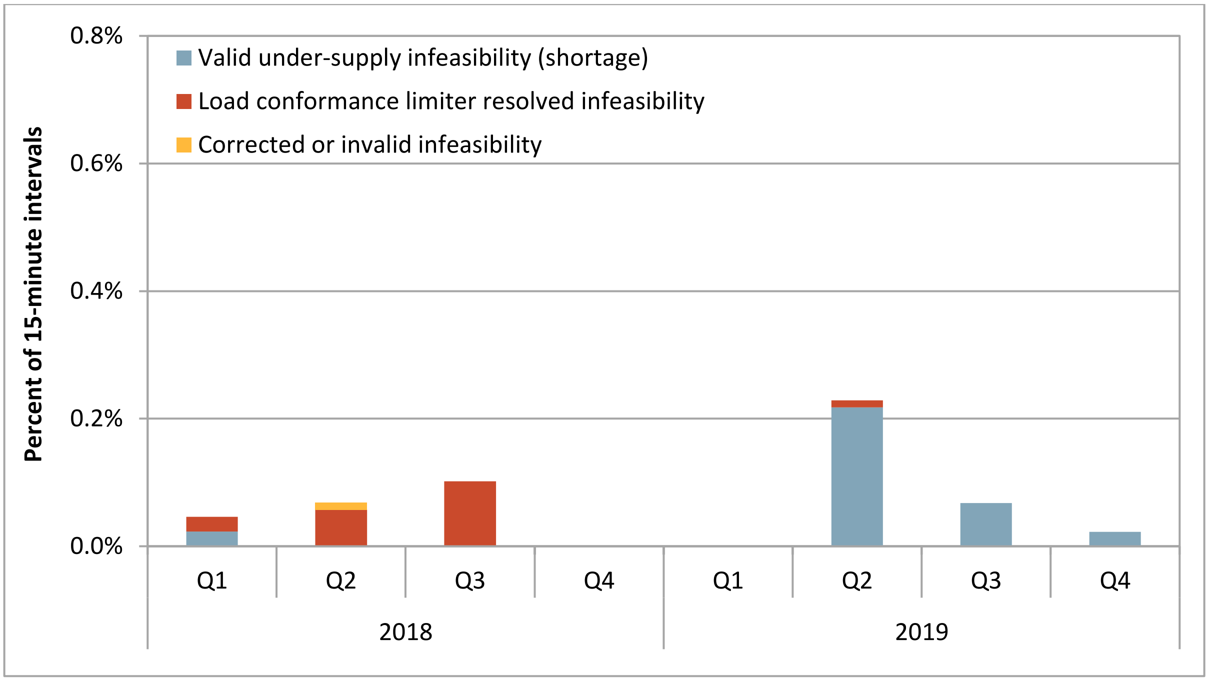
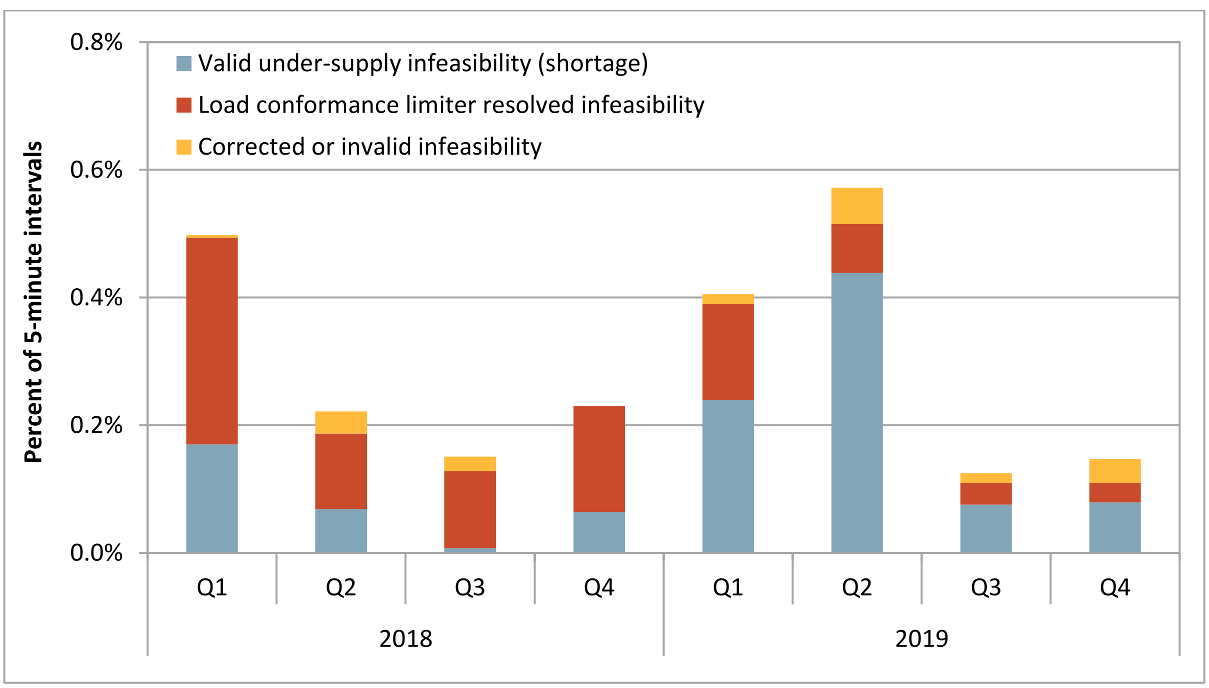


Figure 3.8 Frequency of under-supply power balance constraint infeasibilities (5-minute market)



As in prior years, most of the upward ramping shortages were very short in duration. Similar to 2018, about 83 percent of upward ramping capacity shortages in the 5-minute market during 2019 persisted for one to three 5-minute intervals (or 5 to 15 minutes). In the 15-minute market, about 87 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 flexible ramping product is designed to enhance reliability and market performance by procuring flexible ramping capacity in the real-time market to help manage volatility and uncertainty of real-time imbalance demand. The amount of flexible capacity the product procures is derived from a demand curve which reflects a calculation of the optimal willingness-to-pay for that flexible capacity. The demand curves allow the market optimization to consider the trade-off between the cost of procuring additional flexible ramping capacity and the expected reduction in power balance violation costs.

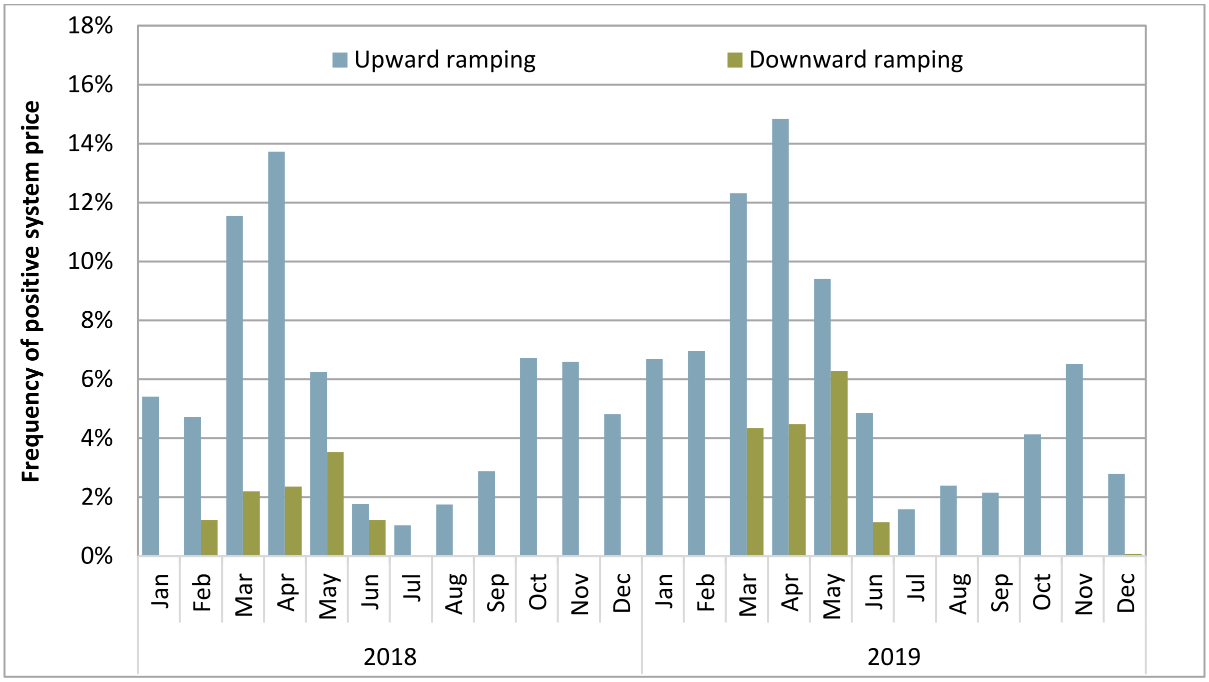
The flexible ramping product procures both upward and downward flexible capacity, in both the 15-minute and 5-minute markets. Procurement in the 15-minute market is intended to ensure that enough ramping capacity is available to meet the needs of both the upcoming 15-minute market runs and the three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

Flexible ramping product prices

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

Figure 3.9 shows the percent of intervals that the system-level flexible ramping demand curve bound and had a positive shadow price in the 15-minute market. The low frequency of binding system-level shadow prices in both directions in 2019 was similar to 2018. The 15-minute market system-level demand curves bound in around 6 percent of intervals in the upward direction and 1 percent of intervals in the downward direction. In the 5-minute market, the system-level demand curves bound very infrequently during 2019, in around 0.1 percent of intervals in the upward direction and almost never in the downward direction. Similar to the previous year, positive system-level flexible ramping product prices were most frequent during the spring months.

Figure 3.9 Monthly frequency of positive 15-minute market flexible ramping shadow price



Flexible ramping product costs

Flexible ramping capacity that satisfies the demand for upward or downward uncertainty receives payments based on the combined system and area-specific flexible ramping shadow price. In addition, the combined flexible ramping shadow price is used to pay or charge for forecasted ramping movements. This means a generator that was given an advisory dispatch by the market to increase output was paid the upward flexible ramping price and charged the downward flexible ramping price. Similarly, a generator that was forecast to decrease output was charged the upward flexible ramping price and paid the downward flexible ramping price.[120] The following section looks at flexible ramping product payments from three different perspectives: (1) by payment type, (2) by area, and (3) by fuel type.

Figure 3.10 shows the total monthly net payments to resources from the flexible ramping product, including both payments for flexible ramping capacity to meet upward and downward uncertainty as well as payments for forecasted movements. All payments associated with the flexible ramping product were $8.7 million during 2019, compared to around $7.5 million in 2018. Payments for only upward and downward uncertainty awards were $6.3 million during 2019, compared to around $7.1 million in the previous year.

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

Figure 3.10 Monthly flexible ramping product payments by type

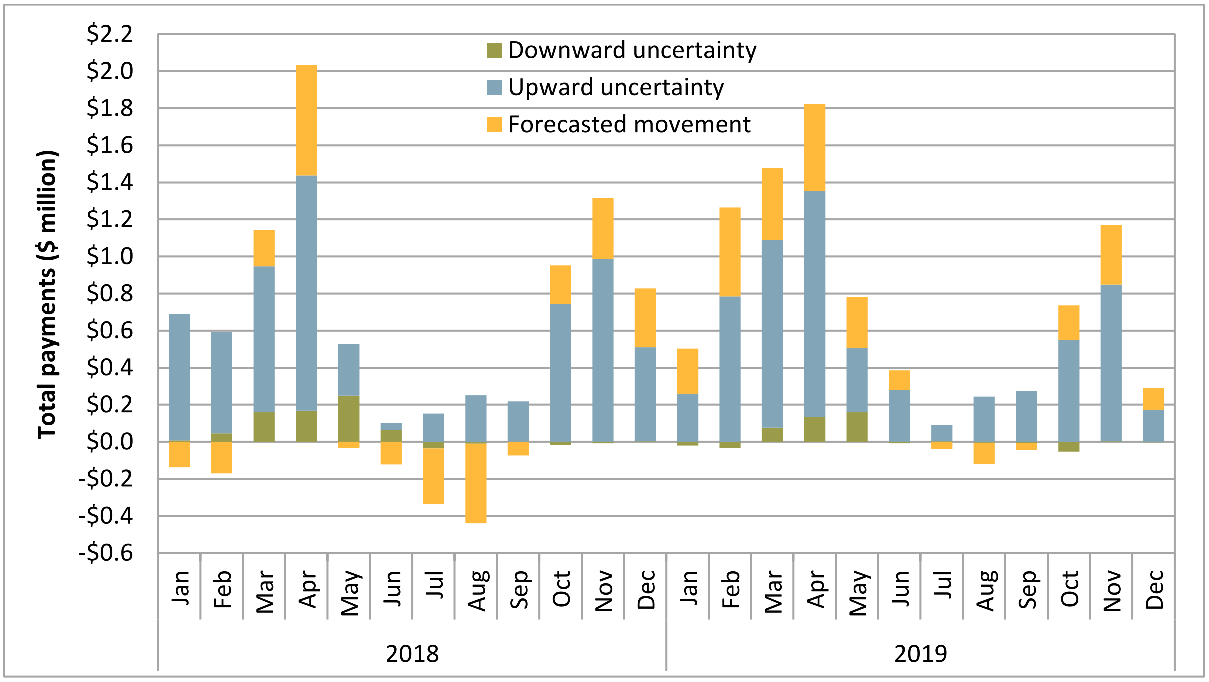


Figure 3.11 and Figure 3.12 do not include payments for forecasted movements and therefore only reflect payments to generators for upward and downward ramping capacity to meet uncertainty needs.

Figure 3.11 shows these payments by area, arranged generally by geographic location. Payments for this capacity may have been procured to satisfy system-level demand, area-specific demand, or both. During 2019, 42 percent of payments for flexible ramping capacity have been to resources internal to the ISO while 45 percent of payments have been to areas in the Northwest region that includes PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex. In both cases, the large majority of payments have been for system uncertainty needs rather than area-specific uncertainty needs.

Figure 3.12 shows the same information by fuel type. In 2019, around 57 percent of flexible capacity payments for upward and downward uncertainty have been to hydroelectric generators. Similarly, 29 percent of payments have been to gas resources while roughly 6 percent of payments have been to each of coal and proxy demand response units.

Figure 3.11 Monthly flexible ramping product uncertainty payments by area

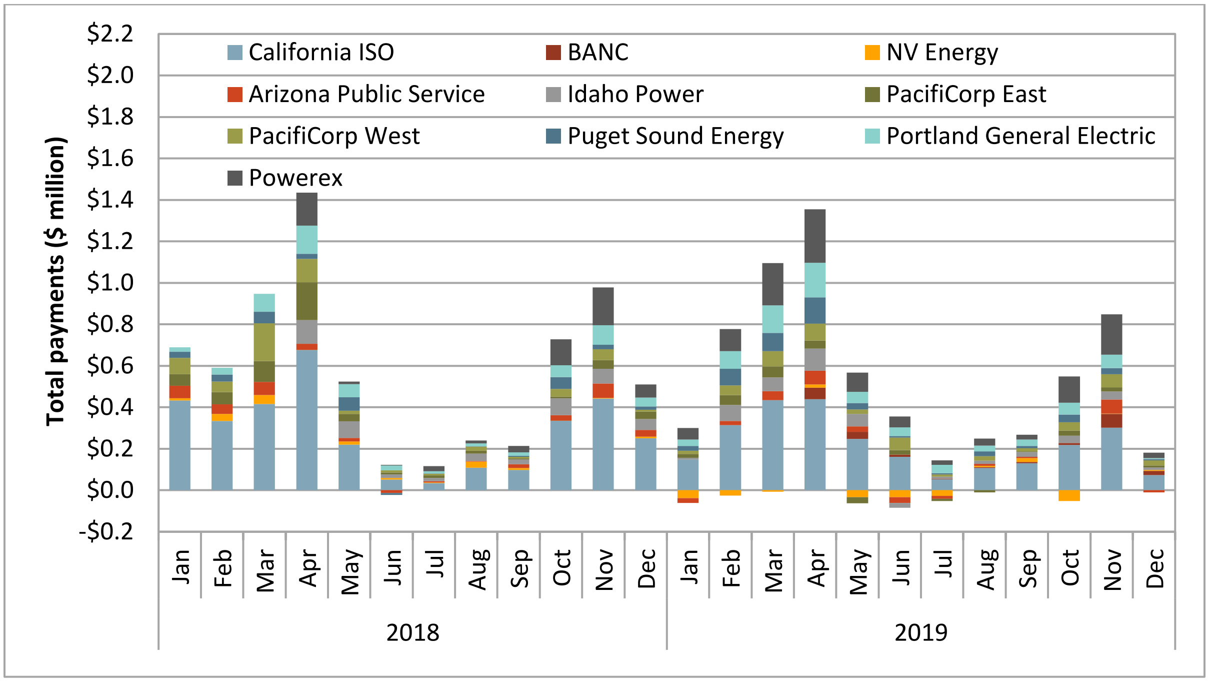
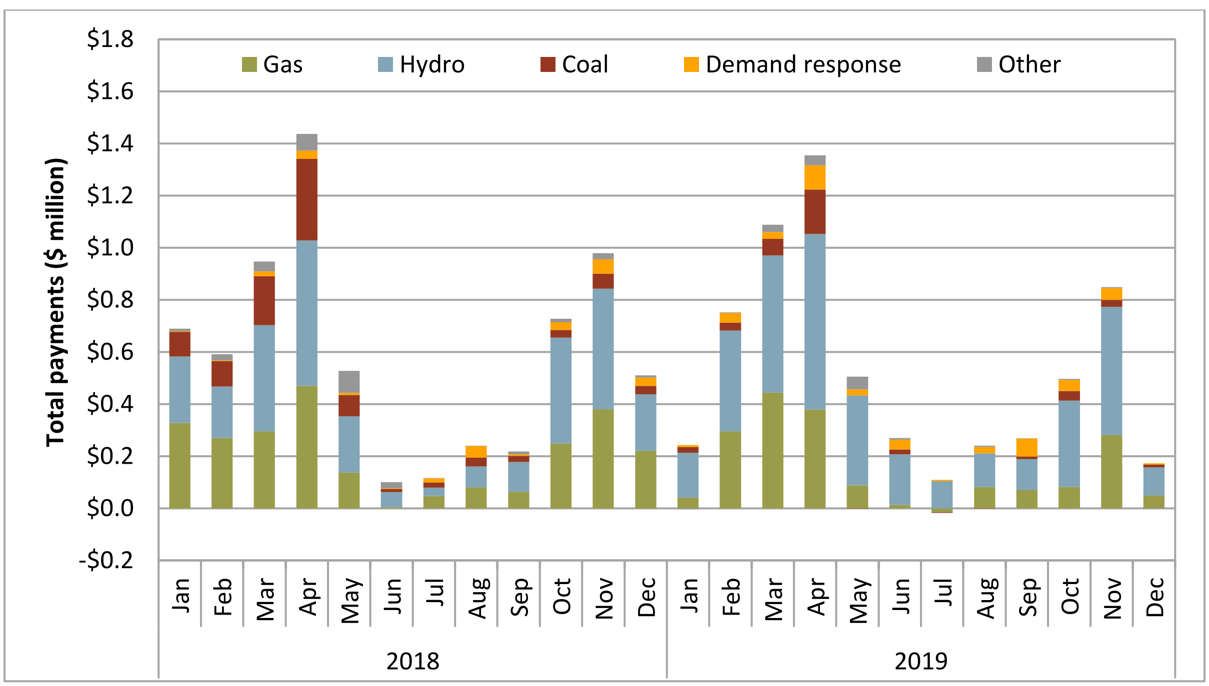


Figure 3.12 Monthly flexible ramping product uncertainty payments by fuel type



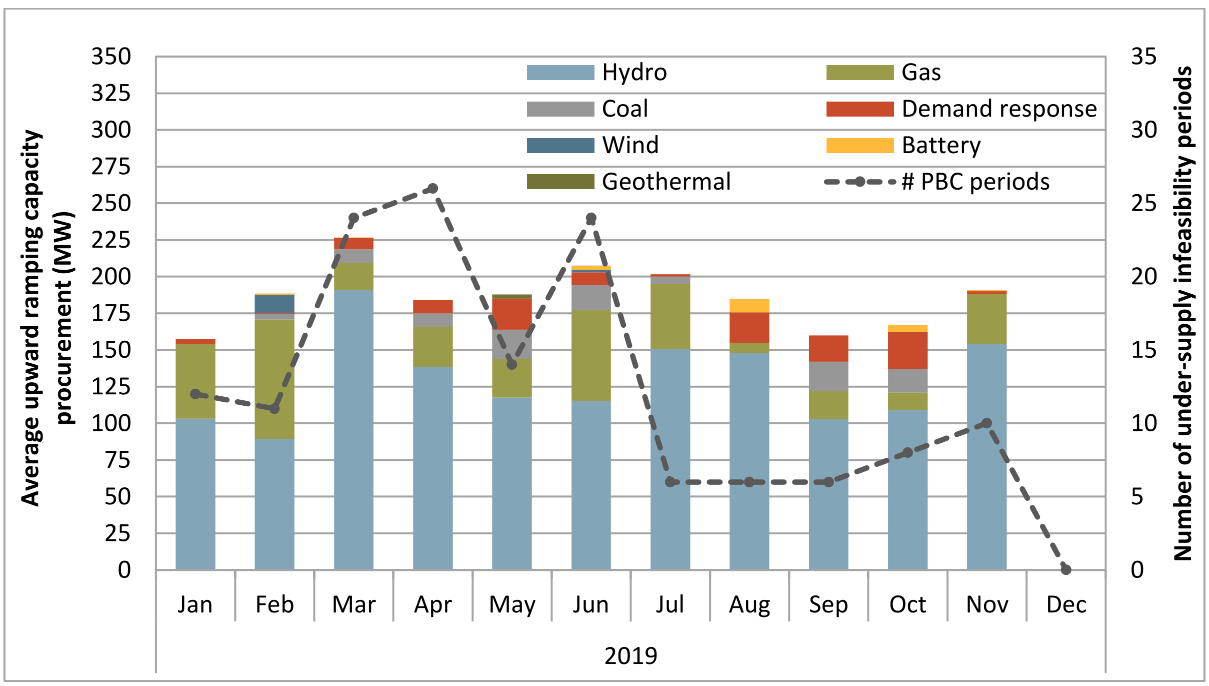
Flexible ramping product procurement

Figure 3.13 shows the average upward ramping capacity procured in the 5-minute market by fuel type in the interval prior to any system under-supply infeasibility (or period of consecutive infeasibilities).[121] The dotted line shows the underlying number of under-supply infeasibility periods in each month. The bars show the average procurement of upward ramping capacity by fuel type in the interval prior to these periods. During May, August, September and October, upward flexible ramping capacity awards to demand response resources made up roughly 12 percent of procurement in the intervals prior to infeasibility periods.

Figure 3.14 shows the same procurement information as Figure 3.13, except by area instead of fuel type. During 2019, flexible ramping capacity awards to resources in the Northwest region made up 57 percent of procurement in the interval prior to under-supply infeasibility periods.

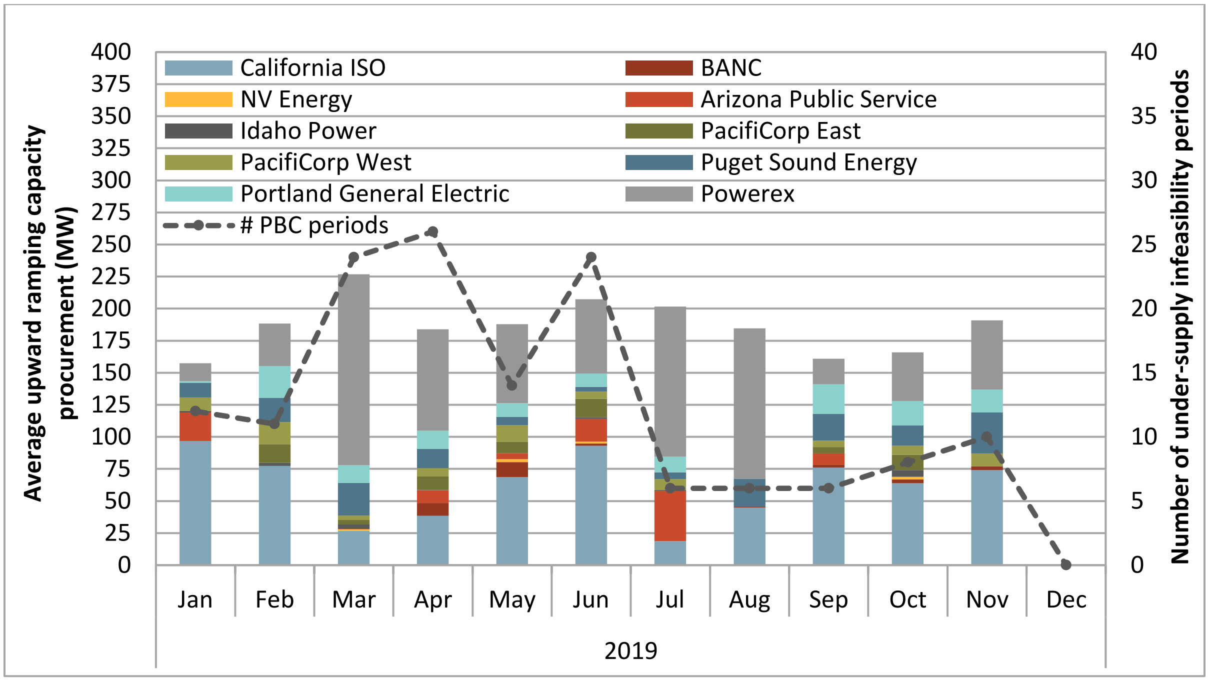
Procurement from proxy demand resources and from resources stranded behind transfer constraints (particularly in the Northwest) can contribute to lower deliverability of flexible capacity at the system level and suppress the true opportunity cost of providing such capacity instead of energy. More details on these issues are described in the following section.

Figure 3.13 Average 5-minute market upward ramping capacity procurement prior to under-supply infeasibility periods - by fuel type



121 For under-supply infeasibility periods lasting longer in duration than one 5-minute interval, only procurement in the interval prior to these periods is summarized in these figures. There were no under-supply infeasibilities in December.

Figure 3.14 Average 5-minute market upward ramping capacity procurement prior to under-supply infeasibility periods - by area



Flexible ramping product issues

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

The ISO published a report in September 2019 that included a discussion of several issues with the flexible ramping product.[122] Further, the ISO initiated a stakeholder process to review refinements to the flexible ramping product and address these inefficiencies.[123] Some of the items addressed in this initiative are discussed below.

Procurement from proxy demand response resources

The ISO's September report highlighted the issue of procuring flexible ramping capacity from proxy demand response units. In particular, the market frequently procured flexible capacity from demand response units since there was typically no opportunity cost of providing such capacity in lieu of energy, as these units generally bid at or near the price cap of $1,000/MWh. However, these units are often not

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122 *CAISO Energy Markets Price Performance Report*, California ISO, September 23, 2019: http://www.caiso.com/Documents/FinalReport-PricePerformanceAnalysis.pdf

123 Stakeholder process information is available here: http://www.caiso.com/StakeholderProcesses/Flexible-ramping-product-refinements

able to respond to isolated 5-minute dispatches and therefore can contribute to lower deliverability of flexible ramping capacity and suppress the true opportunity cost of providing such capacity instead of energy. As part of the energy storage and distributed energy resources phase 3A initiative, effective November 13, 2019, additional bidding options were made available to proxy demand response units including 60-minute and 15-minute dispatchability. A fix was implemented at the start of April 2020 to ensure that proxy demand response resources flagged as 60-minute or 15-minute dispatchable do not receive flexible ramping product uncertainty awards.

Stranded flexible ramping capacity

The system-level demand curve for the entire ISO and EIM footprint is always enforced in the market. However, the uncertainty requirement for the individual areas is reduced in every interval by balancing area transfer capability.[124] Therefore, when the uncertainty requirement for all of the individual areas is zero, then only the system-level uncertainty requirement is active. Due to the potential for system-level flexible ramping capacity procurement external to one area to be stranded behind EIM transfer constraints, the ISO implemented an enhancement in the spring of 2018 to cap procurement in each area by the sum of the area-specific uncertainty requirement and net export capability (for upward direction).[125] Upward ramping capacity in excess of the area-specific uncertainty requirement is capped by net export capability.

However, even with the enhancement, there is still the potential for stranded flexible ramping capacity, particularly in the Northwest region that includes PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex. For instance, in cases when supply conditions are tight in the ISO and surrounding system but export capability out of the Northwest region is zero, these areas may still have export capability to each other within the Northwest region. As a result, the export capability cap on upward flexible ramping capacity will often do little to prevent procurement that is stranded in this region. Further, when supply conditions are tight, it can often be economic to procure more flexible ramping capacity from the Northwest region than from the ISO and surrounding system as the opportunity cost of providing that ramping capacity in lieu of energy is lower in the Northwest.

Figure 3.15 illustrates an example of this interaction from an actual interval in the 15-minute market. In the figure, the arrows show net export capability out of each area, and the red arrows further indicate zero net export capability. In this particular interval, there was 822 MW of upward ramping capacity awarded to resources in the Northwest region (or 69 percent of the system requirement), but 0 MW of actual export capability to the surrounding system through any of Idaho Power, PacifiCorp East, or the ISO. Here, export capability to each other within the Northwest region allowed for higher system-level procurement than was actually accessible for the ISO and surrounding system.

The ISO's revised straw proposal includes an initiative to design nodal procurement for the flexible ramping product.[126] DMM supports the ISO's initiative to design locational procurement for both day-ahead and real-time flexible ramping products. Locational procurement that accounts for transmission

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[124] In each interval, the upward uncertainty requirement is reduced by net import capability while the downward uncertainty requirement is reduced by net export capability. If the balancing authority area fails the flexible ramping sufficiency test in the corresponding direction, the uncertainty requirement will not include this reduction.

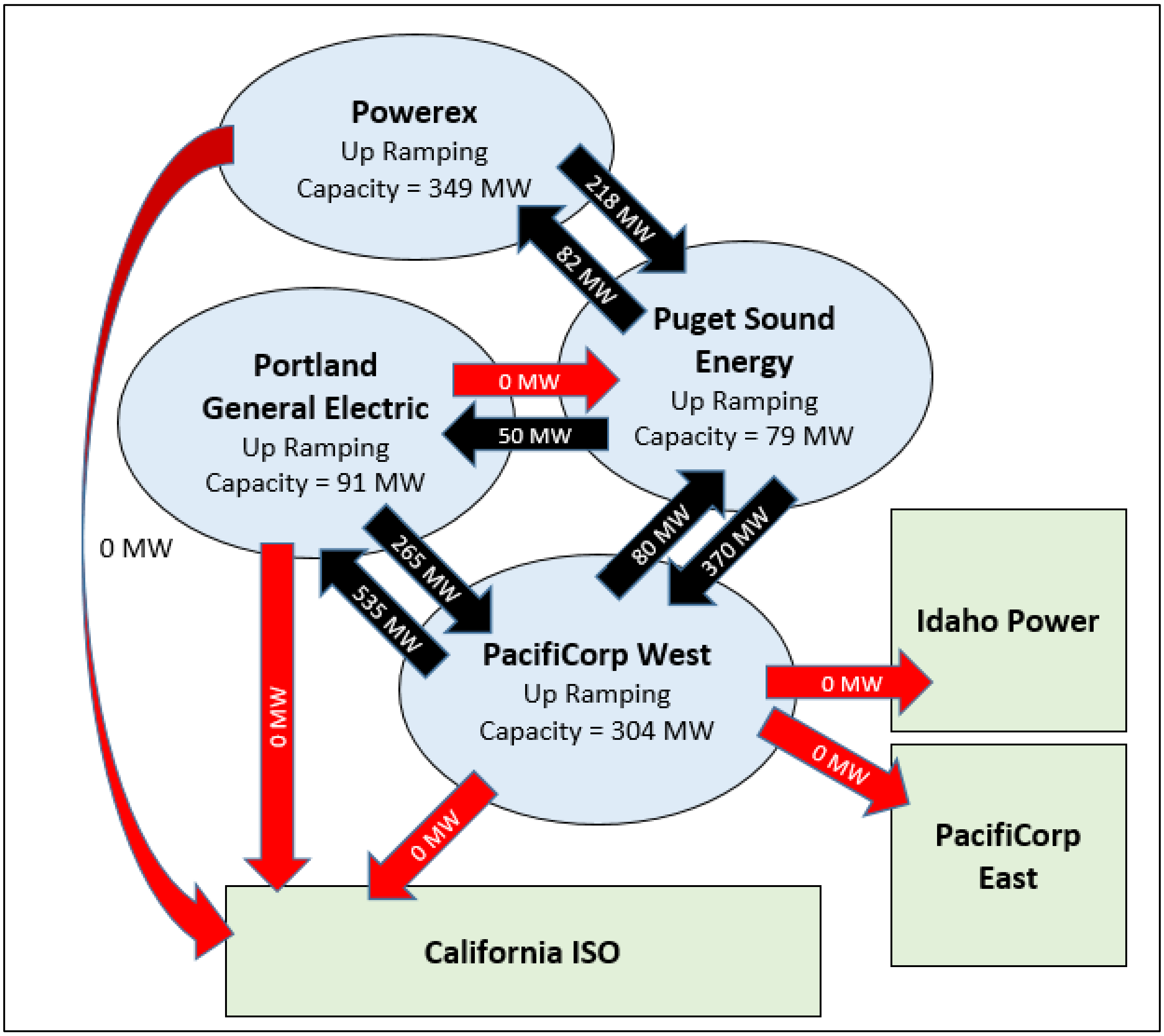
[125] Net export capability is the sum of export energy imbalance market transfer limits in excess of the net energy imbalance market transfer. Downward ramping capacity is instead capped by the sum of the area-specific uncertainty requirement and net *import* capability.

[126] *Flexible Ramping Product Refinements Revised Straw Proposal*, California ISO, March 16, 2020: http://www.caiso.com/Documents/IssuePaper-StrawProposal-FlexibleRampingProductRefinements.pdf

constraints would result in more deliverable reserves and could significantly increase the efficiency of the ISO's market awards and dispatches. It could also help to resolve the very low prices for flexible reserves associated with undeliverable reserves being counted towards meeting a flexibility need that they cannot actually help to address.

The ISO is further proposing interim minimum flexible ramping requirements for some balancing authority areas because of the significant complexity and computational requirements of nodal procurement implementation. The minimum requirements, which would end after the ISO implements the nodal flexible ramping product procurement, may help to address some of the issues surrounding stranded flexible ramping capacity.

Figure 3.15 Example – Stranded upward ramping capacity in the Northwest



Uncertainty over a longer time horizon

The current flexible ramping product design procures and prices ramping capability in the 15-minute market to account for uncertainty between the 15-minute and 5-minute markets. In the 5-minute market, the market software then procures and prices the appropriate amount of ramping capability to account for the uncertainty in only 5-minute net load forecasts. As the ISO incorporates growing quantities of distributed and variable energy resources, there will be increasingly greater uncertainty in the net load forecasts for intervals 30, 60, or 120 minutes out from a given real-time market run.

Grid operators face significant uncertainty over load and the future availability of resources to meet that load. As highlighted in this report, the ISO operators regularly take significant out-of-market actions to address the net load uncertainty over a longer multi-hour time horizon (e.g., 2 or 3 hours). These actions include routine upward biasing of the hour-ahead and 15-minute load forecast, and exceptional dispatches to commit and begin to ramp up additional gas-fired units in advance of the evening ramping hours. Thus, rather than rely on the flexible ramping product, operators take significant manual actions to address ramping needs and net load uncertainty. This uncertainty contributes to operators needing to enter systematic and large imbalance conformance adjustments, as described in Chapter 9 of this report. The ISO could reduce the need for manual load adjustments and more efficiently integrate distributed and variable energy resources by designing a real-time flexible ramping product that could procure and price the appropriate amount of ramping capability to account for uncertainty over longer time horizons than the current design considers.

The ISO launched a new initiative to address the deliverability of the real-time flexible ramping product and proposed adding a new day-ahead market imbalance reserve product to address net load uncertainty. However, the ISO has indicated that it does not intend to extend the flexible ramping product uncertainty horizon beyond five minutes to address uncertainty in what the actual net load will be further out in time from the current interval.

DMM continues to recommend that the ISO work on designing an extension of the uncertainty horizon of the real-time flexible ramping product in the real-time market.[127] DMM recognizes that this enhancement could be a complicated and time-consuming endeavor. However, DMM believes it is prudent to start work on this enhancement prior to implementation of a new day-ahead market imbalance reserve product. Without the enhancement, the real-time market software may not commit or position resources to be able to provide the flexibility purchased as imbalance reserves in the extended day-ahead market.[128]

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127 *DMM Comments on Day-Ahead Market Enhancements June 20, 2018 Technical Workshop*, July 24, 2019, p. 1: http://www.caiso.com/InitiativeDocuments/DMMComments-Day-AheadMarketEnhancementsWorkshop-June20-2019.pdf

DMM Comments on Day-Ahead Market Enhancements August 13, 2019 Working Group, September 6, 2019, pp. 1-3: http://www.caiso.com/InitiativeDocuments/DMMCommentsDay-AheadMarketEnhancements-Aug13-Aug19Meetings.pdf

128 *DMM Comments on Issue Paper on Extending the Day-Ahead Market to EIM Entities, November 26*, 2019: http://www.caiso.com/InitiativeDocuments/DMMComments-ExtendedDay-AheadMarket-IssuePaper.pdf

3.4 Real-time gas price variability

DMM has recommended that the ISO develop the ability to adjust gas prices used in the real-time market based on observed prices on the Intercontinental Exchange (ICE) the morning of each operating day. This approach would closely align the gas price used in the ISO's real-time market with the actual costs for gas purchased in the same-day gas market.[129]

The ISO did not include DMM's recommendation to update gas prices used in calculating bid caps for the real-time market in the commitment cost and default energy bid enhancement (CCDEBE) proposal that was approved by the ISO Board in May 2018. However, in 2019 the ISO subsequently included provisions to update bid caps using same-day gas prices as part of the local market power mitigation enhancements initiative. Under this revised proposal*, reasonableness thresholds* used to automatically approve generators' requests to increase bid caps will be updated if the same-day gas price for a fuel region exceeds 10 percent of the next-day index for the same gas flow day.[130]

On August 30, 2019, the ISO filed tariff amendments to enhance its market rules to allow suppliers to request adjustments to their commitment cost and default energy bid reference levels to more accurately reflect their costs.[131] In comments on this tariff filing, DMM questioned the need to continue including a 25 percent headroom scalar in commitment cost bid caps calculated by the ISO and in reference level requests by suppliers to increase these bid caps if they are based on the suppliers' own determination of their resources' actual costs.[132] FERC's January 21, 2020, order rejected part of the ISO's CCDEBE proposal citing that the "ISO has not demonstrated that its proposal to apply the 125 percent multiplier to supplier submitted costs is just and reasonable."[133]

Figure 3.16 and Figure 3.17 illustrate the benefits that would result from using updated same-day gas prices in the real-time market at SoCal Citygate.

- Figure 3.16 shows same-day natural gas trade prices reported on ICE at SoCal Citygate compared to the next-day average price used by the ISO to calculate bid caps for commitment costs and default energy bids used in the real-time market in 2019. This chart shows this comparison in terms of the

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

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

[131] Tariff Amendment to enhance Commitment Cost and Default Energy Bid Provisions, August 30, 2019: http://www.caiso.com/Documents/Aug30-2019-TariffAmendment-CommitmentCosts-DefaultEnergyBidEnhancements-ER19-2727.pdf

[132] Motion To Intervene And Comments Of The Department Of Market Monitoring Of The California Independent System Operator Corporation, September 20, 2019: http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoring-CCDEBE-ER19-2727-Sept202019.pdf

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

percentage difference between same-day gas trade prices and the next-day gas index used by the ISO.

Figure 3.17 compares the same-day natural gas trade prices at SoCal Citygate to the volume-weighted average price of same-day trades reported on ICE before 8:30 am. This reflects the difference between same-day gas trade prices and the same-day gas index price that would be used for the real-time market under DMM's recommendation.

Figure 3.18 and Figure 3.19 show the same comparisons of next-day and same-day gas prices for PG&E Citygate prices in 2019.

As shown in Figure 3.16, about 25 percent of same-day trade volume at SoCal Citygate exceeded the next-day gas index used by the ISO by 10 percent or more. About 12 percent of this volume exceeded the next-day index price by 25 percent or more.[134] Similarly, as shown in Figure 3.18, at PG&E Citygate, about 13 percent of same-day trade volume exceeded the next-day gas index used by the ISO by 10 percent or more, out of which 4 percent exceeded the next-day index price by 25 percent or more.

As shown in Figure 3.17 and Figure 3.19, if the real-time gas prices were updated using an updated same-day price, about 98 to 99 percent of the same-day trades at SoCal and PG&E Citygate would have been at or below the 10 percent adder included in default energy bids used in mitigation. About 1 to 2 percent of the traded volume would have exceeded the 10 percent adder, but still would have been less than the 25 percent adder normally included in commitment cost caps. An insignificant amount of the same-day traded volume would have exceeded the 25 percent adder.

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

Figure 3.16 SoCal Citygate same-day trade prices compared to next-day index (2019)

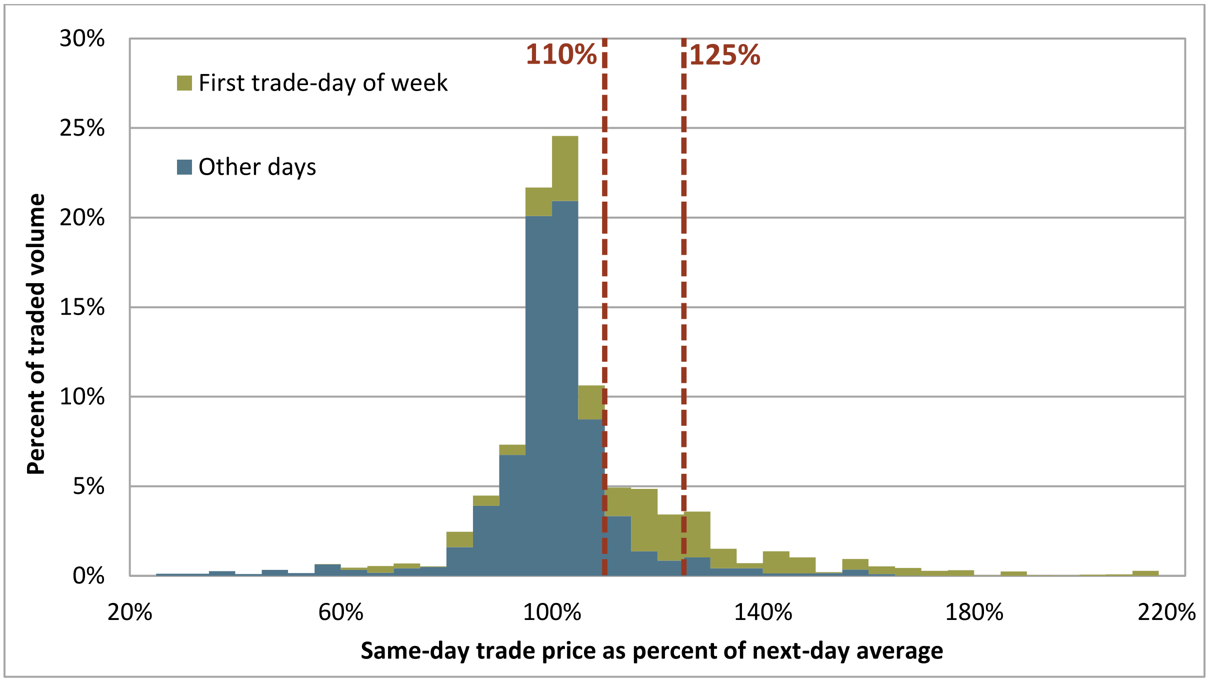


Figure 3.17 SoCal Citygate same-day prices as a percent of updated same-day averages (2019)

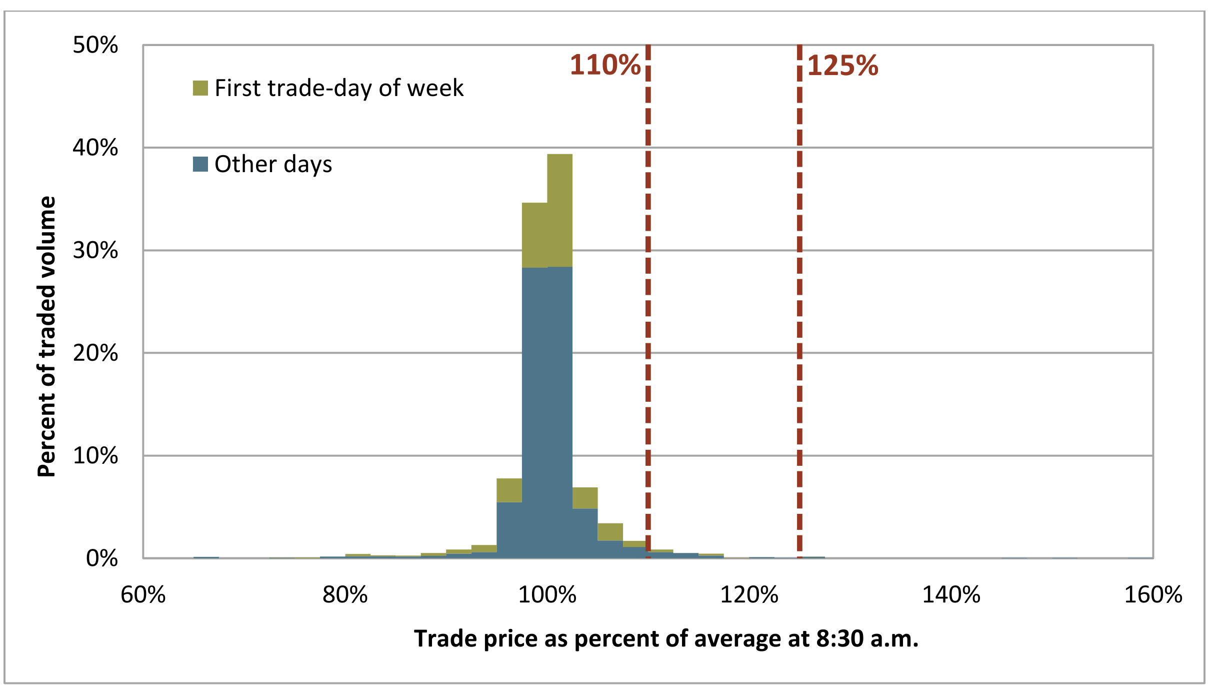


Figure 3.18 PG&E Citygate same-day trade prices compared to next-day index (2019)

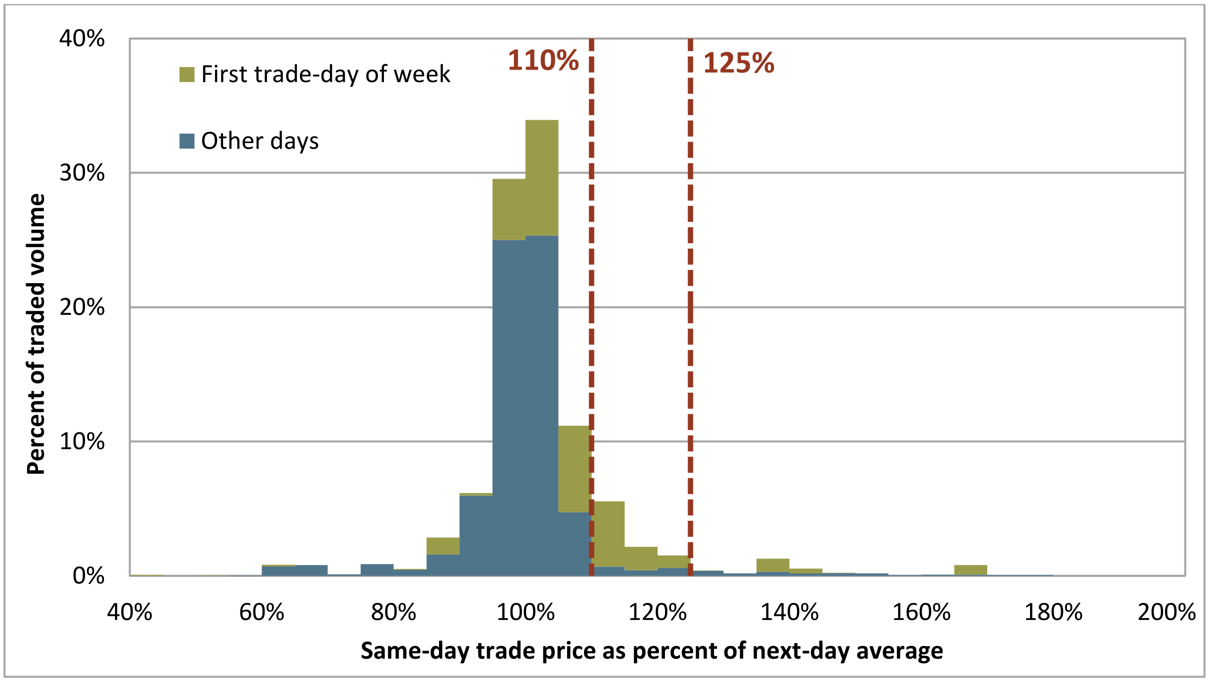
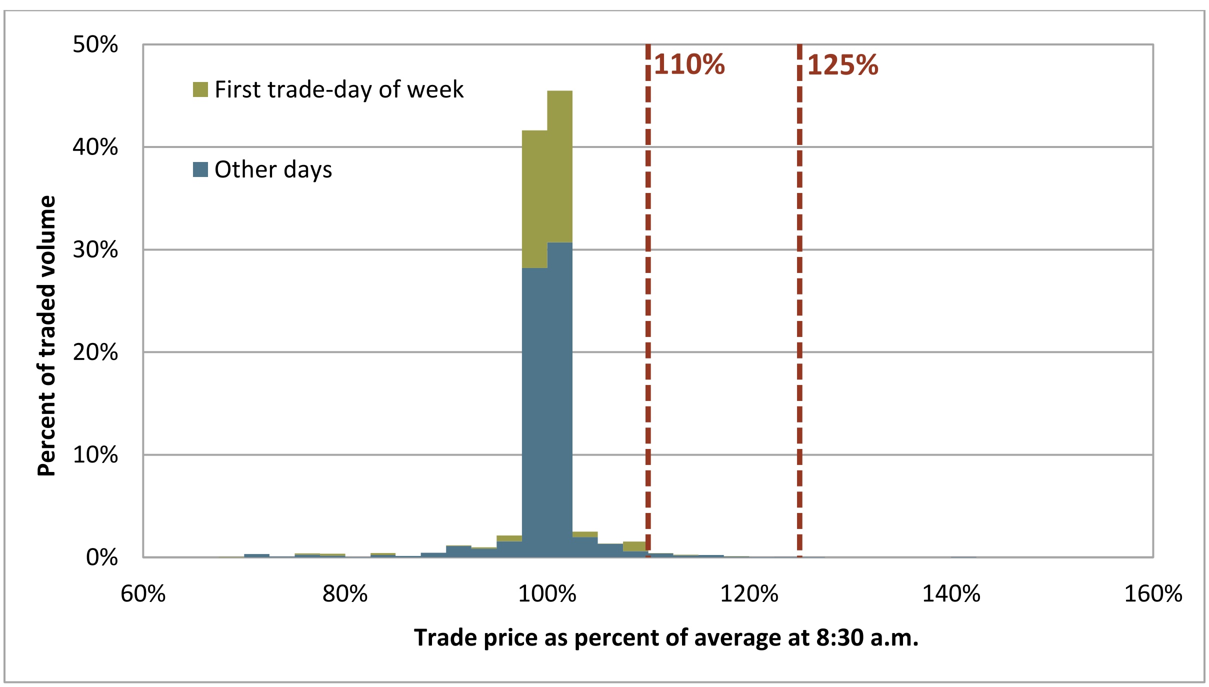


Figure 3.19 PG&E Citygate same-day prices as a percent of updated same-day averages (–2019)



4 Energy imbalance market

The energy imbalance market allows balancing authority areas outside of the ISO balancing area to participate in the ISO real-time market. This chapter provides a summary of energy imbalance market performance during 2019. Key elements highlighted in this chapter include the following:

- **The energy imbalance market continued to perform well and grow** by the addition of a new participant in 2019. The growth of the energy imbalance market since 2015 and increase in available transmission has increased the economic transfers between balancing areas. Prices and transfers of energy are now marked by distinct daily and seasonal patterns which reflect differences in regional supply conditions and transfer limitations.
- **The Balancing Authority of Northern California joined the energy imbalance market** on April 3. The Balancing Authority of Northern California participates in the market with the Sacramento Municipal Utility District as a member within the balancing area. The combined ISO and EIM footprint now accounts for more than 79 GW, over half of load in the Western Energy Coordinating Council.
- **On average, prices in the ISO are higher than other energy imbalance market balancing areas**. These price differences are driven by a combination of transmission transfer limitations and greenhouse gas emissions costs in California. Prices also reflect a distinct geographic pattern, with higher average prices in the southern areas and lower prices in the northern areas.
- **The ISO exports energy out to other balancing areas in the energy imbalance market** during periods of relatively low net loads and high solar production. By allowing the ISO to transfer energy out during these periods, the energy imbalance market has helped to reduce the need to curtail solar production.
- **During the morning and evening ramping hours, the ISO tends to import** from other balancing areas. Similarly, prices and transfers between other areas in the energy imbalance market reflect how the market allows entities in the other areas to “buy low and sell high” during different hours and seasons based on supply conditions in each area relative to the rest of the market.
- **The ISO implemented a sufficiency test enhancement** on May 6, 2019, which evaluates results and potentially limits transfers on a 15-minute interval basis rather than for the entire hour. This decreased the frequency of failures of both the upward and downward sufficiency tests.
- **The ISO implemented a load conformance limiter enhancement**, effective February 27, 2019. The enhancement significantly reduced the frequency in which the limiter triggered for the Arizona Public Service and NV Energy areas, which increased average prices in these areas.
- **Congestion imbalance deficits related to base schedules remained very low in 2019**. Balancing areas may allocate these imbalances to third party customers and others.
- **The decrease in supply that can be deemed delivered into California has been significant**. Beginning in 2019, there were intervals in which all eligible supply was imported, limiting energy imbalance market imports to California. In November 2018, the ISO implemented a revised energy imbalance market greenhouse gas bid design which limited greenhouse gas bid capacity. Following that change, the weighted average greenhouse gas cost increased as the delivered resources shifted from lower to higher greenhouse gas emissions.

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.

The ISO's 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 can allow the energy imbalance market to increase market efficiency in two ways. First, the market software can re-optimize dispatches and manage congestion within each energy imbalance market area. Second, the market software can allow economic transfers in real-time from lower cost balancing areas to higher cost balancing areas participating in the market.

These changes in scheduled flows between balancing areas in the real-time market are referred to as *energy transfers* between energy imbalance market balancing areas. The ability to transfer energy between balancing areas in real time also helps to reduce the degree to which low cost renewables or hydro energy may need to be curtailed in one balancing area during times of excess generation.

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 market in December 2015, this added a significant amount of transfer capability with the ISO and PacifiCorp East. Since then, transfer capacity between the ISO and the energy imbalance market areas has continued to increase. Puget Sound Energy and Arizona Public Service joined the market in October 2016. In 2017 and 2018, Portland General Electric, Powerex, and Idaho Power joined the market.

The Balancing Authority of Northern California joined the energy imbalance market on April 3, 2019. The Balancing Authority of Northern California participates in the market with the Sacramento Municipal Utility District as a member within the balancing area. The combined ISO and EIM footprint now accounts for more than half of load in the Western Energy Coordinating Council.[135]

As highlighted in this chapter, the growth of the energy imbalance market since 2015 and increase in available transmission has increased the economic transfers between balancing areas. Prices and transfers are now marked by distinct daily and seasonl patterns which reflect differences in regional supply conditions and transfer limitations.

4.2 Energy imbalance market prices

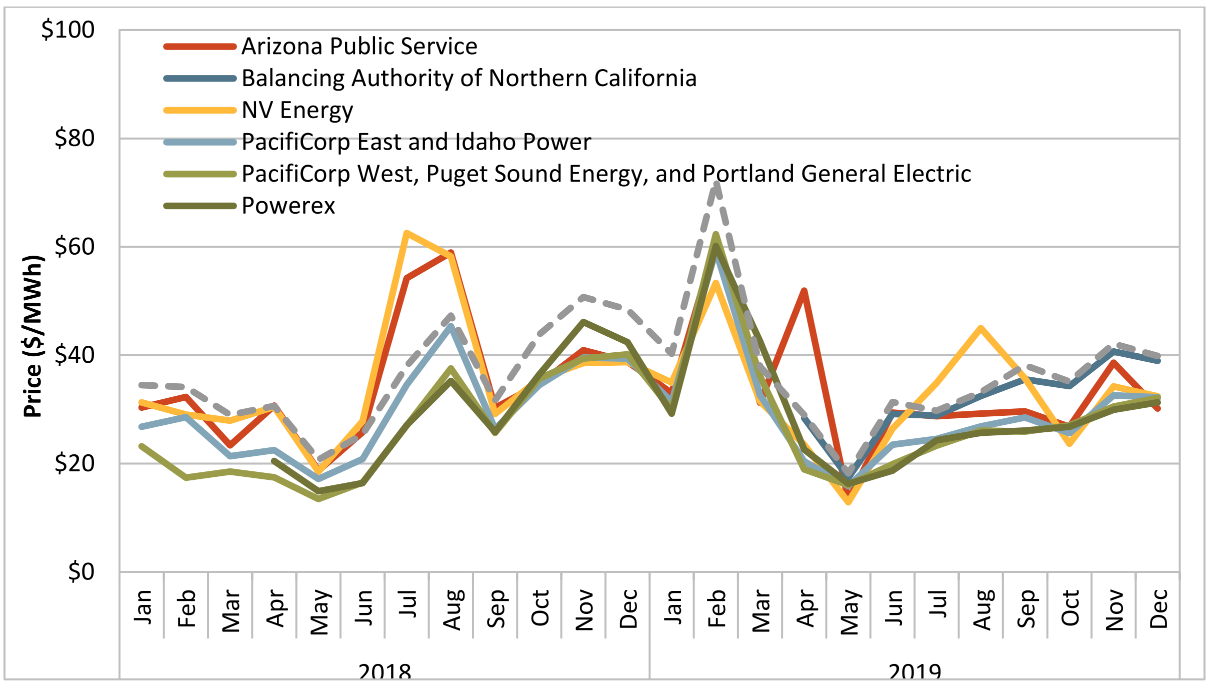
This section details the factors that influence changes in Western EIM balancing authority prices in general and what causes price separation between entities. The Western EIM benefits participating balancing authorities by committing lower-cost resources across all areas to balance fluctuations in supply and demand in the real-time energy market. Since dispatch decisions are determined across the

[135] Concurrent peak load in the energy imbalance market was 79,974 in 2019, excluding load in BC Hydro. This is 51 percent of total peak WECC load (156,142 MW). North American Electric Reliability Corporation, 2020 Summer Reliability Assessment, June 2020. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2020.pdf

whole Western EIM system, prices within each balancing authority will be similar but can diverge from the system price when transfer capability constraints are binding, greenhouse gas compliance costs are enforced for imports into California, or power balance constraint violations within a single area are assigned penalty prices.

Figure 4.1 shows average monthly prices from the 15-minute market by balancing authority from January 2018 to December 2019. Several balancing areas are grouped together due to similar average monthly prices. Prices for Powerex (dark green line) and Idaho Power (included in light blue line) begin in April 2018 while prices for the Balancing Authority of Northern California (dark blue line) begin in April 2019 when they joined the Western EIM.[136] Prices for Pacific Gas and Electric (grey dashed line) are included in the figure as a point of comparison for this analysis.

Figure 4.1 Monthly 15-minute market prices



The variability of Western EIM system prices over time is largely explained by natural gas prices. Natural gas price spikes at the SoCal Citygate, PG&E Citygate, and NW Sumas hubs, as shown in Figure 1.28 from Chapter 1, drove the sharp increases in Western EIM system prices between July 2018 and February 2019.

Price separation between Western EIM balancing authorities occurs for several reasons. ISO prices tend to be higher than the rest of the Western EIM due to greenhouse gas compliance cost for energy that is delivered to California.[137] In addition to this, average prices in the Northwest region (including PacifiCorp

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

137 See Section 4.7 for more information about California's greenhouse gas compliance cost and its impact on the ISO and energy imbalance market.

West, Puget Sound Energy, Portland General Electric, and Powerex) are regularly lower than the ISO and other balancing areas because of limited transfer capability out of this region.

Figure 4.1 also highlights high price spikes in NV Energy and Arizona Public Service in the months when a relatively high number of power balance constraint violations occurred. In many cases, these occurred in intervals in which Western EIM imports into these areas were frozen due to failed resource sufficiency tests.

Figure 4.2 and Figure 4.3 continue this analysis by showing the hourly variability between Western EIM area prices throughout the day in 2019. Prices continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours in some Western EIM balancing areas just as in the ISO. As in the previous analysis, several balancing areas are grouped together because of similar average hourly pricing, and prices at the Pacific Gas and Electric default load aggregation point are shown as a point of comparison.

Figure 4.2 Hourly 15-minute market prices

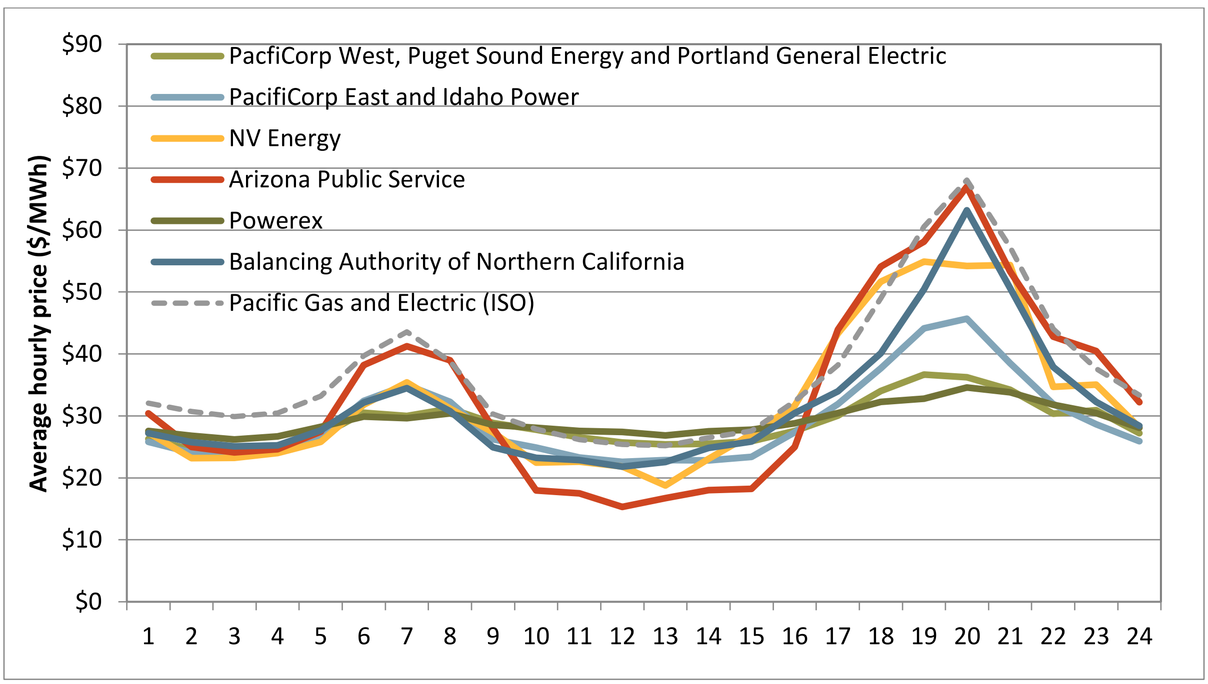


Figure 4.3 Hourly 5-minute market prices

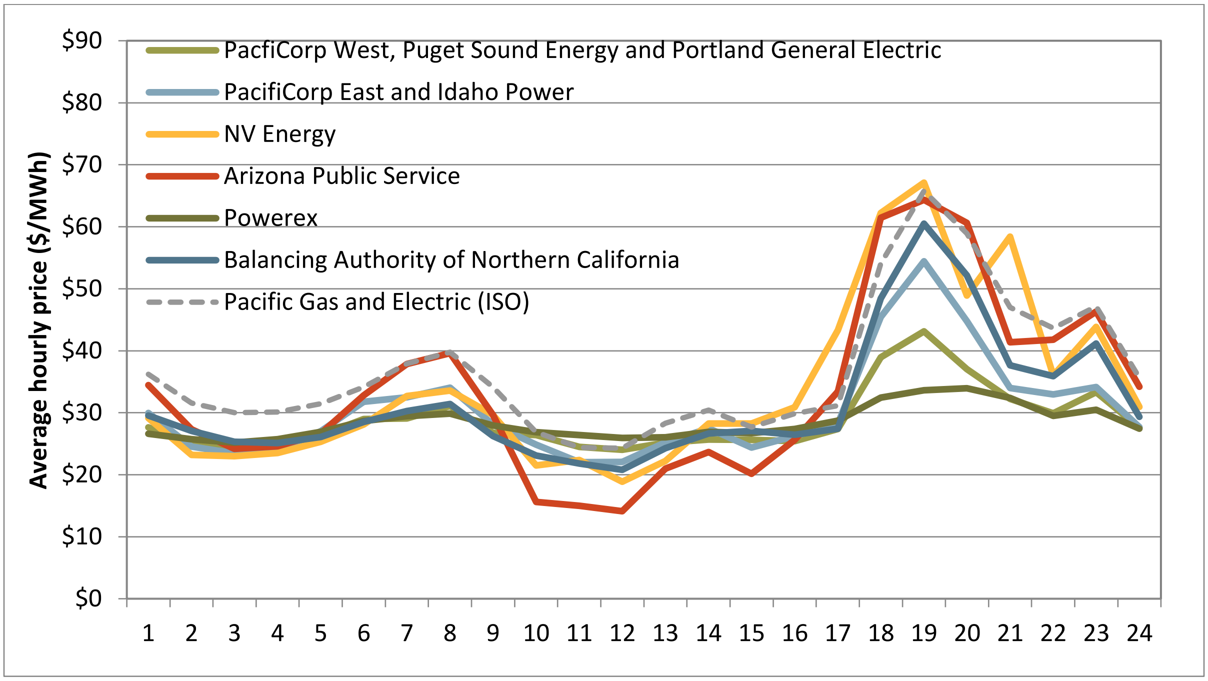


Figure 4.2 and Figure 4.3 show that the relative price differences between Western EIM entities vary throughout the day. Prices in entities outside of California tend to be lower than ISO prices throughout most hours. This price divergence is more pronounced during the morning and evening ramping periods when the ISO is typically importing energy that is subject to greenhouse gas compliance costs. Western EIM entity prices converge with ISO prices in the middle of the day when the ISO tends to export energy. The Balancing Authority of Northern California (BANC) is the exception to this rule due to its location in California. After joining the Western EIM in the second quarter, prices in the BANC area tracked very closely to prices in the ISO because of significant transfer capability and little congestion between the areas.[138]

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

Prices in Arizona Public Service area diverged from the rest of the Western EIM during the morning and afternoon peak load hours as well as throughout the middle of the day. APS experienced a number of flexible ramping sufficiency test failures that resulted in under-supply power balance constraint relaxations in the market software. The majority of these infeasibilities were not resolved by the

[138] Separation in prices between BANC and the ISO in the hourly price figures is primarily due to the general seasonality of prices and the fact that average prices for the ISO are based on all quarters while prices for BANC are based on the second through fourth quarters.

enhanced load conformance limiter and were therefore priced at the penalty parameter of $1,000/MWh.[139]

Prices in PacifiCorp East and Idaho Power were often similar to each other and lower than prices in the ISO. As shown in Figure 4.2 and Figure 4.3, price separation between these areas and the ISO was most pronounced during peak load hours when transfers from PacifiCorp East and Idaho Power into the ISO tended to hit export limits.

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

4.3 Energy imbalance market transfers

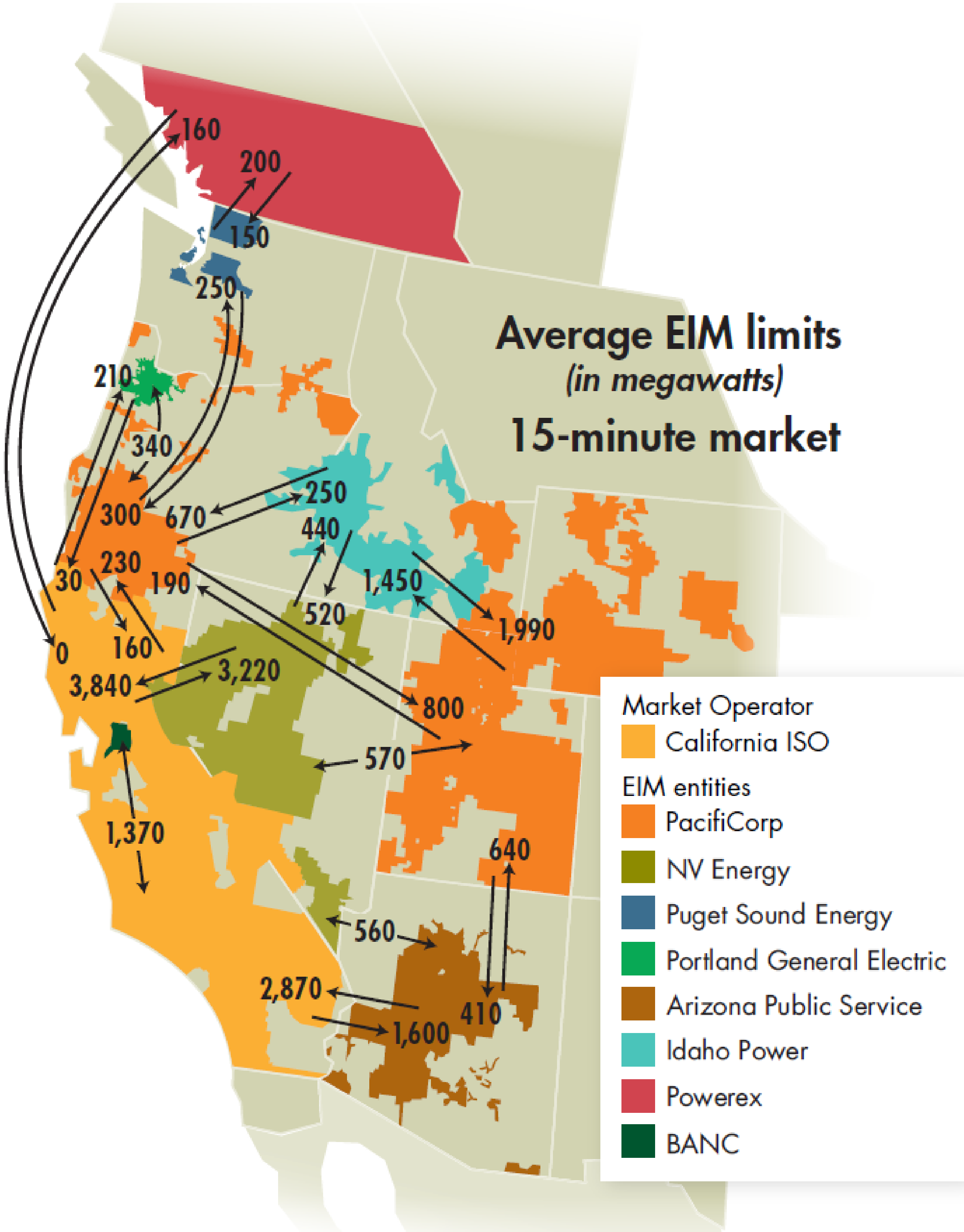
4.3.1 Energy imbalance market transfer limits

Figure 4.4 shows average 15-minute market limits between each of the energy imbalance market areas in 2019 after the addition of the Balancing Authority of Northern California (April 3 to December 31, 2019). The map shows that there was significant transfer capability between most of the energy imbalance market system, including the ISO, the Balancing Authority of Northern California, NV Energy, Arizona Public Service, Idaho Power, and PacifiCorp East. The availability of this transmission capacity allowed energy to flow between these areas with relatively little congestion.

Transfer capability was more limited between the ISO and Northwest areas which include PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex. This resulted in more transmission congestion between these areas and the ISO. The 15-minute market export limits from each of Portland General Electric and Powerex toward the ISO were particularly limited during 2019. Export transmission capacity from Powerex toward the ISO was limited to zero megawatts in 98 percent of intervals since the second quarter of 2019 in both the 15-minute and 5-minute markets. Similarly, export limits from Portland General Electric toward the ISO were set to zero during 65 percent of 15-minute intervals and 83 percent of 5-minute intervals during the year.

139 See Section 4.6 for further details on the load conformance limiter enhancement and its impact.

Figure 4.4 Average 15-minute market energy imbalance market limits (April 3 – December 31, 2019)



4.3.2 Hourly energy imbalance market transfers

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

Figure 4.5 shows average hourly imports (negative values) and exports (positive values) between the ISO and other energy imbalance market areas during each quarter in the 15-minute market.[140] The bars show the average hourly transfers with the connecting areas. The gray line shows the average hourly net transfer.

As in 2018, net exports were highest during the second quarter, particularly during midday hours as a result of high solar and mild load conditions. During the third and fourth quarters of 2019, the average hourly transfer pattern was similar, with the ISO exporting most to the BANC area and areas in the Northwest during midday hours, and importing from Arizona Public Service and NV Energy in the remaining hours.

Figure 4.5 California ISO - average hourly 15-minute market transfer

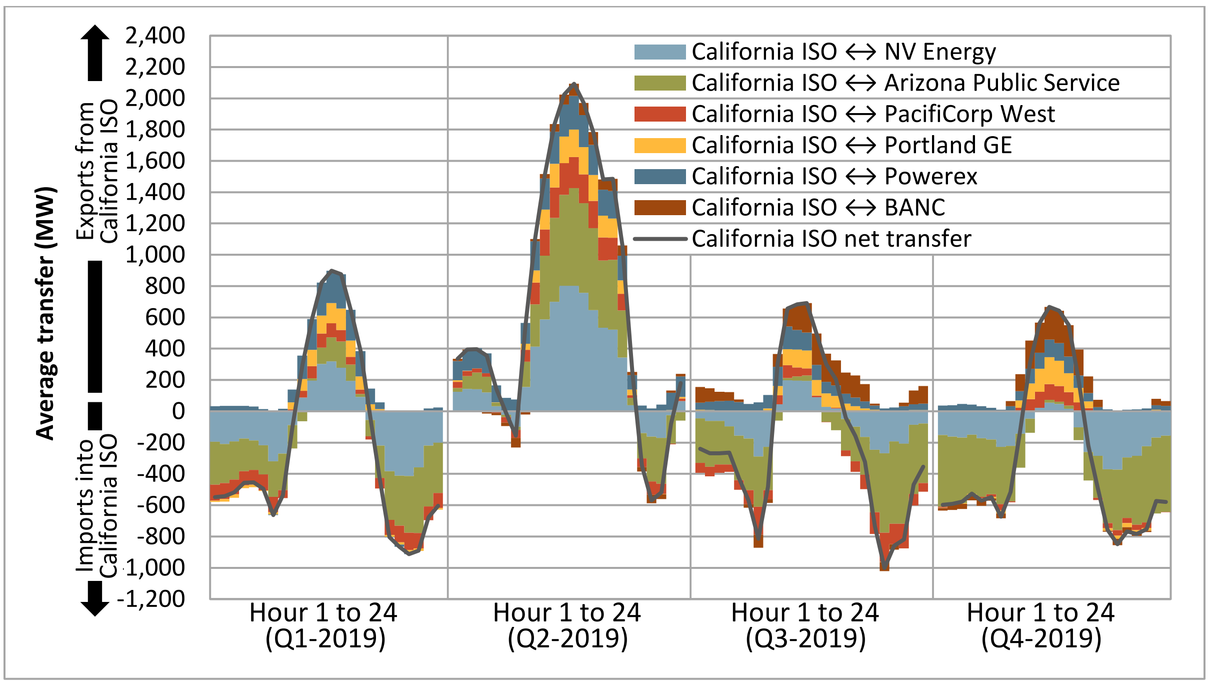


Figure 4.6 through Figure 4.14 show the same information on imports and exports for all energy imbalance market areas in the 15-minute market. The amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[141]

Average hourly transfers for NV Energy and Arizona Public Service were similar to the previous year. Per Figure 4.6 and Figure 4.7, these areas were typically net importers during midday hours in the first and

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

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

second quarters, with most imports coming from the ISO and most exports out to the eastward areas including PacifiCorp East and Idaho Power. In other periods, including off-solar hours in the first and second quarters as well as most hours in the third and fourth, NV Energy and Arizona Public Service were generally net exporters with most transfers out to the ISO.

Figure 4.8 shows the hourly 15-minute market transfer pattern between Idaho Power and neighboring areas, net of all base schedules. Idaho Power has transfer capacity between PacifiCorp West, PacifiCorp East, NV Energy, and — to a limited extent — Puget Sound Energy. During the first, third, and fourth quarters, Idaho Power typically imported from PacifiCorp East. During midday hours for all quarters, Idaho Power typically exported out to PacifiCorp West.

Figure 4.9 through Figure 4.11 show average hourly 15-minute market imports and exports out of PacifiCorp East, PacifiCorp West, and Puget Sound Energy. PacifiCorp East has transfer capacity between PacifiCorp West, NV Energy, Arizona Public Service, and Idaho Power. PacifiCorp West has transfer capacity between the ISO, PacifiCorp East, Puget Sound Energy, Portland General Electric, and Idaho Power. The majority of Puget Sound Energy's transfer capacity is with PacifiCorp West and Powerex.

Figure 4.12 and Figure 4.13 show the average hourly 15-minute market transfer patterns for Powerex, Portland General Electric, and their neighboring areas. Export transmission capacity from Powerex toward the ISO was limited to zero megawatts in 98 percent of intervals since the second quarter of 2019 in both the 15-minute and 5-minute markets. Similarly, export limits from Portland General Electric toward the ISO were set to zero during 65 percent of 15-minute intervals and 83 percent of 5-minute intervals during the year.

Figure 4.14 shows average hourly transfers between the Balancing Authority of Northern California and the ISO since joining the energy imbalance market on April 3, 2019. The BANC area typically imported from the ISO during midday hours and exported to the ISO during morning and evening load ramping hours.

Figure 4.6 NV Energy – average hourly 15-minute market transfer

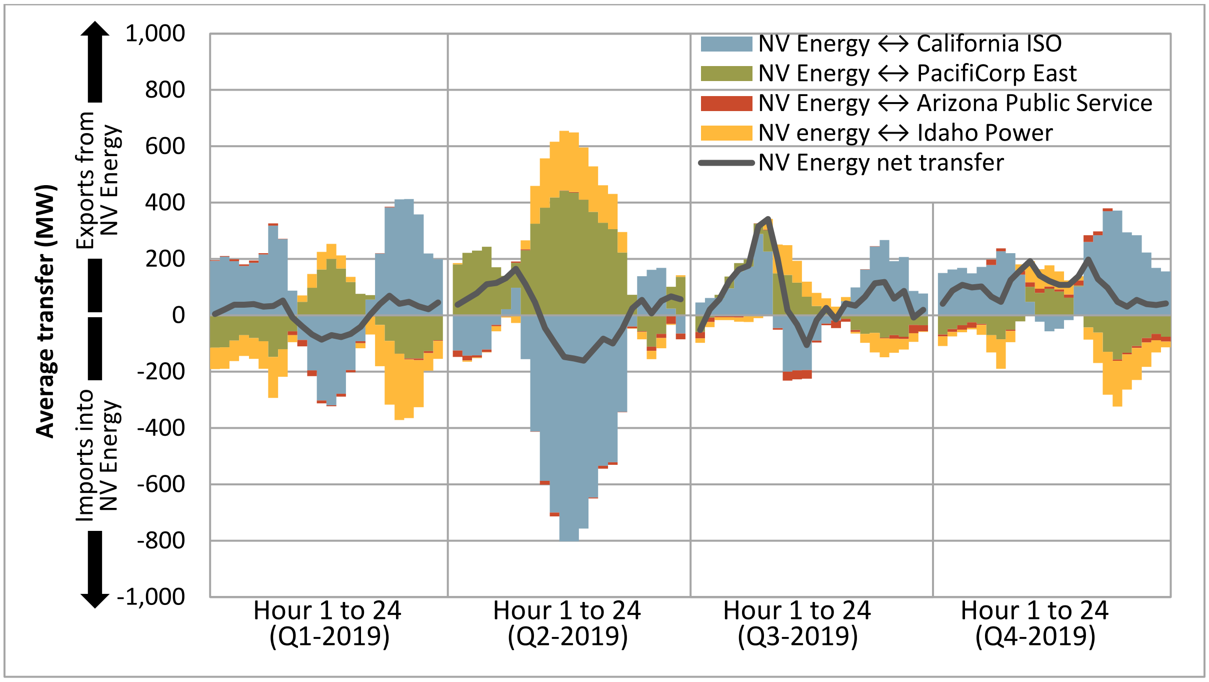


Figure 4.7 Arizona Public Service – average hourly 15-minute market transfer

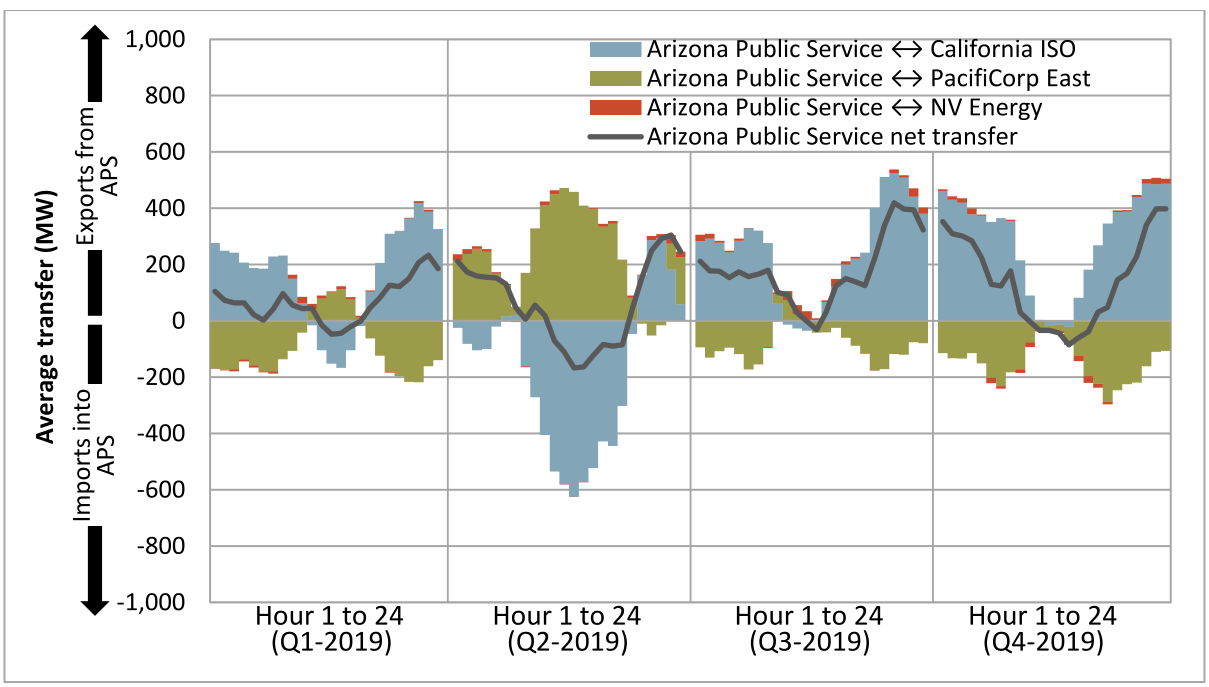


Figure 4.8 Idaho Power – average hourly 15-minute market transfer

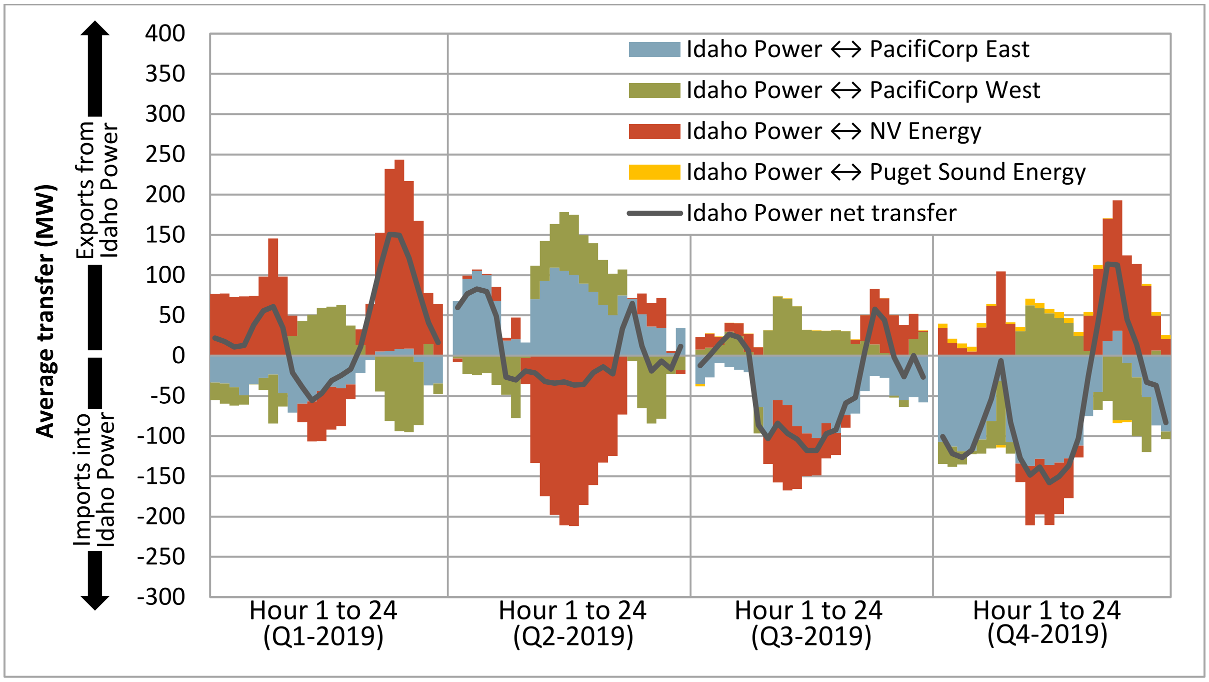


Figure 4.9 PacifiCorp East – average hourly 15-minute market transfer

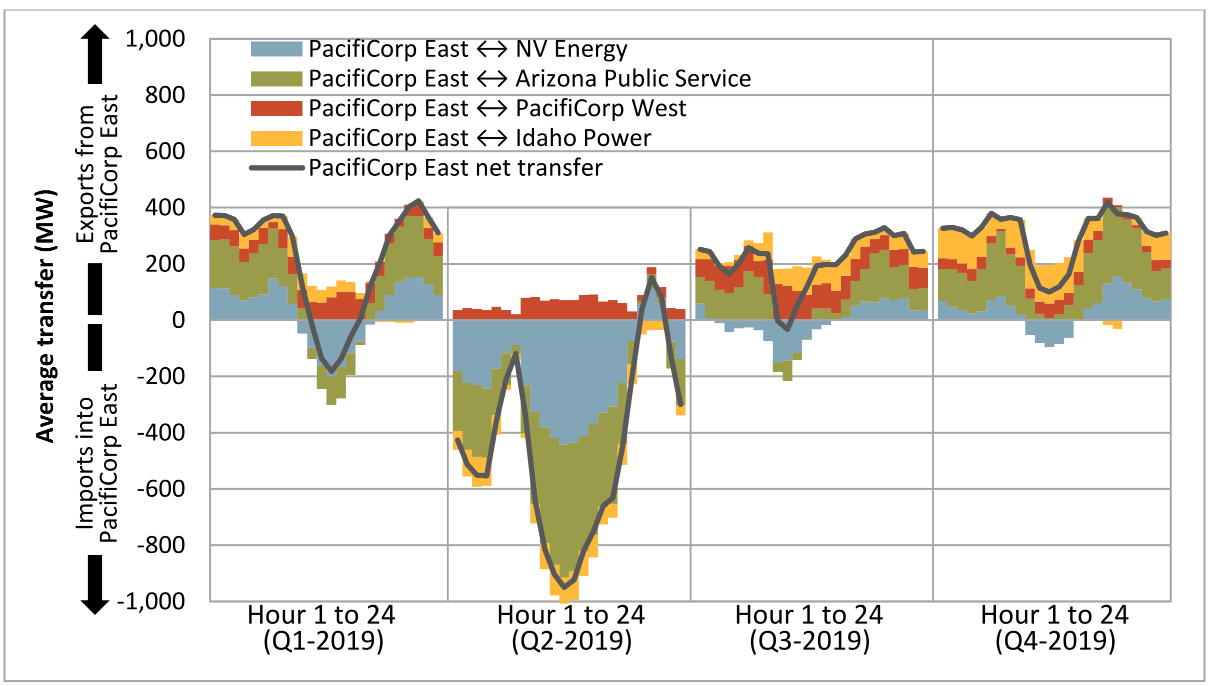


Figure 4.10 PacifiCorp West – average hourly 15-minute market transfer

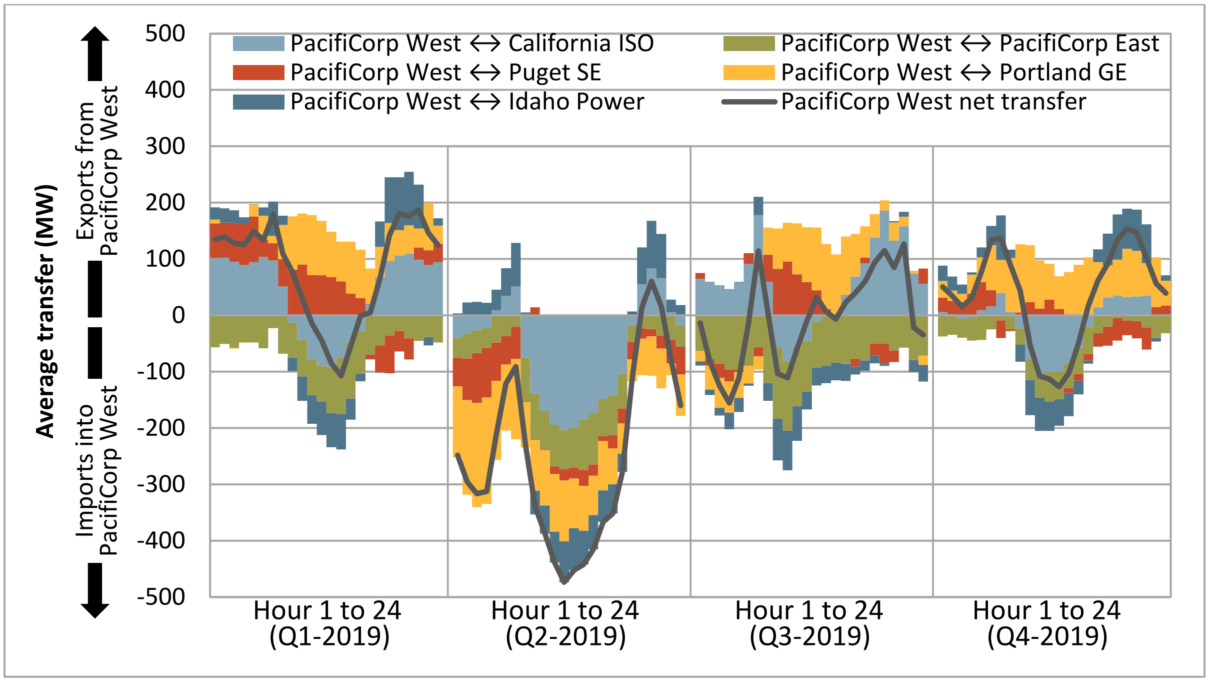


Figure 4.11 Puget Sound Energy – average hourly 15-minute market transfer

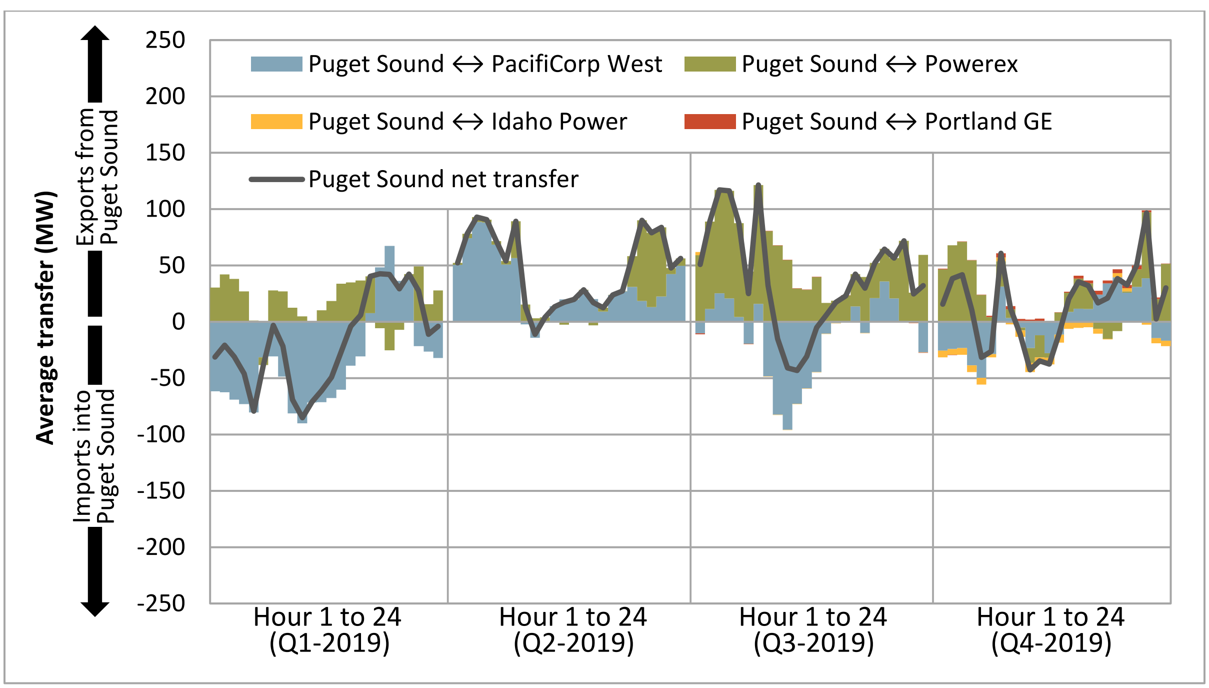


Figure 4.12 Powerex – average hourly 15-minute market transfer

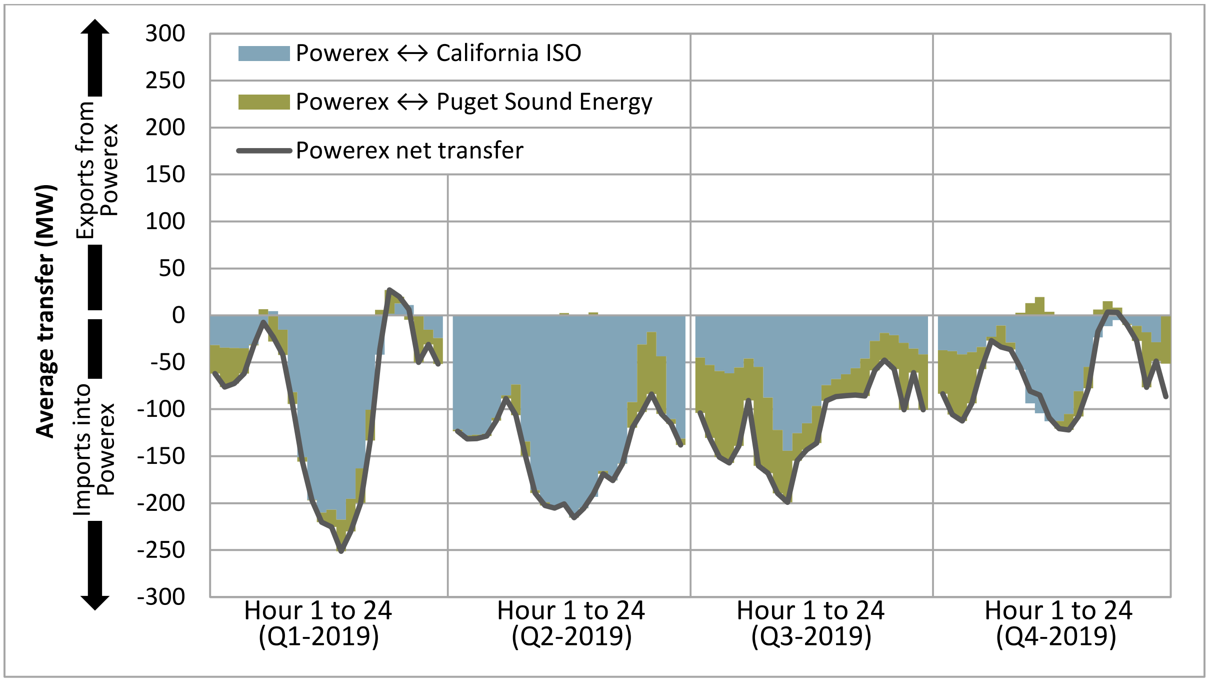


Figure 4.13 Portland General Electric – average hourly 15-minute market transfer

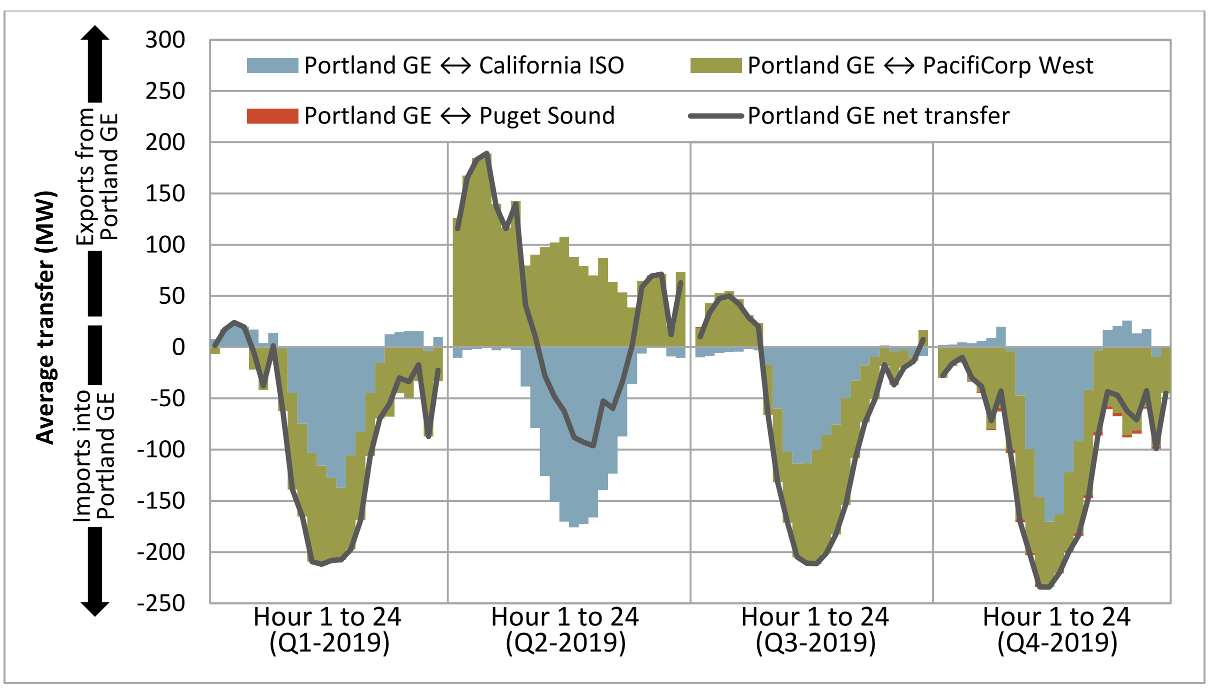
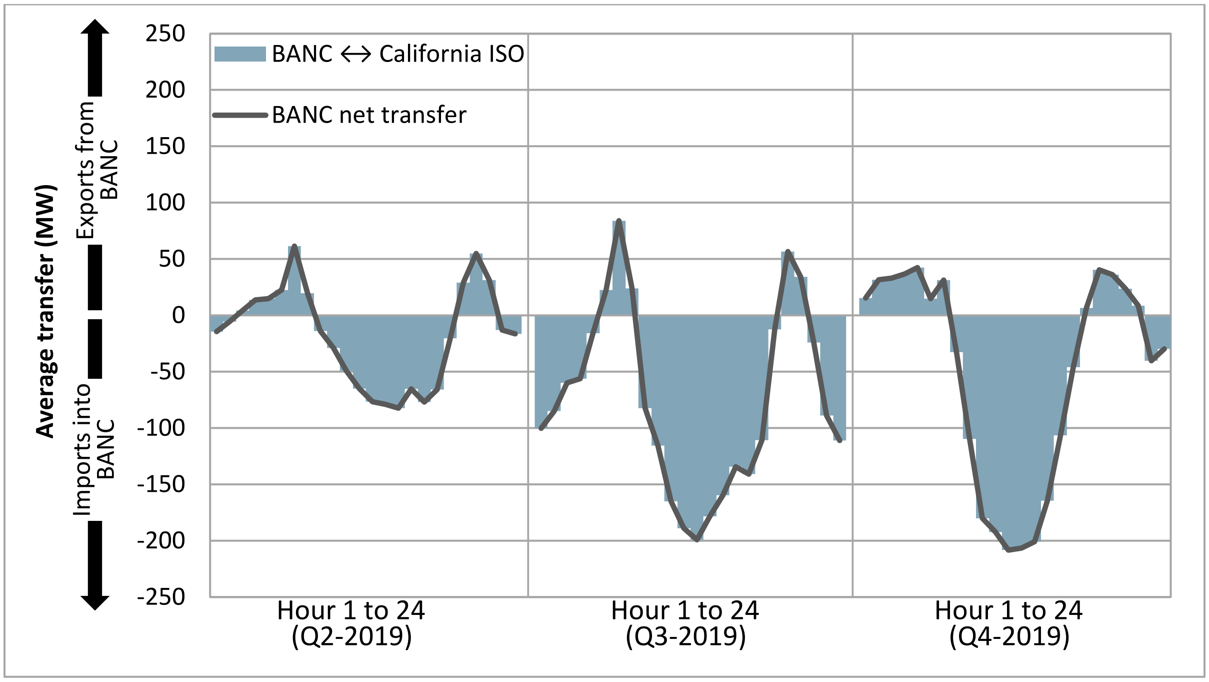


Figure 4.14 Balancing Authority of Northern California - average hourly 15-minute market transfer



4.3.3 Impact of congestion between balancing areas on transfer capability

Congestion between an energy imbalance market area and the rest of the system limits an area's import and export capability. In addition, during intervals when there is net import congestion into an energy imbalance market area, the market software triggers local market power mitigation for resources in that area.[142]

Table 4.1 shows the percent of 15-minute and 5-minute market intervals when there was congestion on the transfer constraints into or out of an energy imbalance market area. This is calculated as the frequency of intervals where the shadow price on an area's transfer constraint was positive or negative, indicating higher or lower prices in an area relative to prevailing system prices.[143] When prices are lower relative to the system, this indicates congestion out of an area and limited export capability. Conversely, when prices are higher within an area, this indicates that congestion is limiting the ability for energy outside of an area to serve that area's load. The results of this section are the same as those found in Section 8.2.3 of this report on EIM transfers. Section 8.2.3 focused on the impact of congestion to EIM prices, whereas this section describes the same information in terms of the impact to import or export capability and the potential for market power mitigation.

[142] 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. The ISO area is not subject to market power mitigation under these conditions.

[143] Greenhouse gas prices can contribute to lower energy imbalance market prices relative to those inside the ISO. The current methodology uses the energy imbalance market greenhouse gas prices in each interval to account for and omit price separation that is the result of greenhouse gas prices only.

In 2019, congestion out of the Northwest areas decreased significantly compared to the previous year. The highest frequency congestion into an area occurred in the Powerex area, where 25 percent of 15-minute market intervals and 32 percent of 5-minute market intervals were congested in 2019.

The highest frequency of congestion in the energy imbalance market continued to be from the Northwest areas toward the larger energy imbalance market system. Congestion in the 15-minute market from PacifiCorp West, Portland General Electric, Puget Sound Energy, and Powerex occurred during roughly 21 percent of intervals during the year. This is significantly lower than the previous year when congestion occurred during 31 percent of intervals from Powerex and 39 percent of intervals from PacifiCorp West, Portland General Electric, and Puget Sound Energy.

Table 4.1 also shows that congestion in either direction for BANC, NV Energy, Arizona Public Service, PacifiCorp East and Idaho Power was relatively infrequent during the year. Congestion that did occur between these areas and the larger energy imbalance market system was often the result of a failed upward or downward sufficiency test, which limited transfer capability.

Table 4.1 Frequency of congestion on the energy imbalance market transfer constraints (2019)

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC*	1%	1%	1%	1%
Arizona Public Service	1%	2%	1%	3%
NV Energy	3%	1%	2%	3%
PacifiCorp East	2%	3%	1%	4%
Idaho Power	2%	4%	1%	5%
PacifiCorp West	19%	6%	12%	8%
Portland General Electric	21%	7%	14%	8%
Puget Sound Energy	21%	11%	14%	12%
Powerex	23%	25%	19%	33%

*April 3 to December 31, 2019 only

4.4 Energy imbalance market congestion imbalance offset costs

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

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

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

Table 4.2 shows estimated real-time congestion imbalance charges from internal transmission constraints in the 15-minute market. These estimates do not include congestion imbalances from the real-time dispatch or inter-balancing authority area transfer constraints. With the exception of the California ISO, which settles deviations from day-ahead market schedules, these data estimate the extent to which congestion imbalance deficits are the result of base schedule flows exceeding 15-minute market transmission limits. Negative values indicate a congestion imbalance deficit and positive values a surplus. Please note that these estimates are calculated from non-settlement quality data.

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

Table 4.2 Estimated 15-minute market EIM internal constraint congestion imbalances (million $)

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

4.5 Flexible ramping sufficiency test

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

If an area fails the upward sufficiency test, energy imbalance market transfers into that area cannot be increased.[144] Similarly, if an area fails the downward sufficiency test, transfers out of that area cannot be increased.

The ISO implemented multiple enhancements to the flexible ramping sufficiency test during 2019. First, a tolerance threshold was implemented effective February 15, 2019, that allows an energy imbalance market entity to pass the test if the insufficiency is less than either 1 MW or 1 percent of the requirement.[145]

A second enhancement, implemented on May 6, 2019, evaluates sufficiency test results and limits transfers on a 15-minute interval basis rather than for the entire hour. The flexible ramping sufficiency test requires balancing areas to show sufficient ramping capability from the start of the hour to each of the four 15-minute intervals within the hour. Previously, a failure of any of these four 15-minute interval sub-tests would result in a failure of the sufficiency test and limit transfers for the entire hour. With the enhancement, however, the four 15-minute interval evaluations are executed separately with the potential consequences applied only to the applicable interval. As a result, this decreased the frequency in which energy imbalance market areas failed the upward or downward sufficiency tests.

Figure 4.15 and Figure 4.16 show the percent of intervals in which the energy imbalance market area failed the sufficiency test in the upward or downward direction.[146] Since May 6, the figures reflect that the flexible ramping sufficiency test evaluates sufficient ramping capability in 15-minute increments rather than hourly increments. As a result, energy imbalance market areas generally failed the sufficiency tests less frequently relative to the previous year. For the upward direction, NV Energy and Arizona Public Service failed the sufficiency test most frequently in 2019, during around 2 percent and 3 percent of intervals, respectively. For the downward direction, NV Energy failed the test most frequently, during around 4.5 percent of intervals.

The flexible ramping sufficiency test is also applicable to the California ISO area. During 2019, the ISO failed the upward sufficiency test during 13 intervals in the upward direction and 6 intervals in the downward direction.

Failures of the sufficiency test are important because these outcomes limit transfer capability. Constraining transfer capability may impact the efficiency of the energy imbalance market by limiting transfers into and out of a balancing area that could potentially provide benefits to other balancing areas. Reduced transfer capability also impacts the ability for an area to balance load, as there is less availability to import from or export to neighboring areas. This can result in local prices being set at power balance constraint penalty parameters.

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

[145] Market Notice - EIM Resource Sufficiency Enhancements 1% Threshold Implementation, February 8, 2019: http://www.caiso.com/Documents/EIMResourceSufficiencyEnhancements-1-ThresholdImplementation-021519-Active-MAPStage.html

[146] Intervals in which an energy imbalance market area is entirely disconnected from the market (market interruption) are removed.

Figure 4.15 Frequency of upward failed sufficiency tests by month

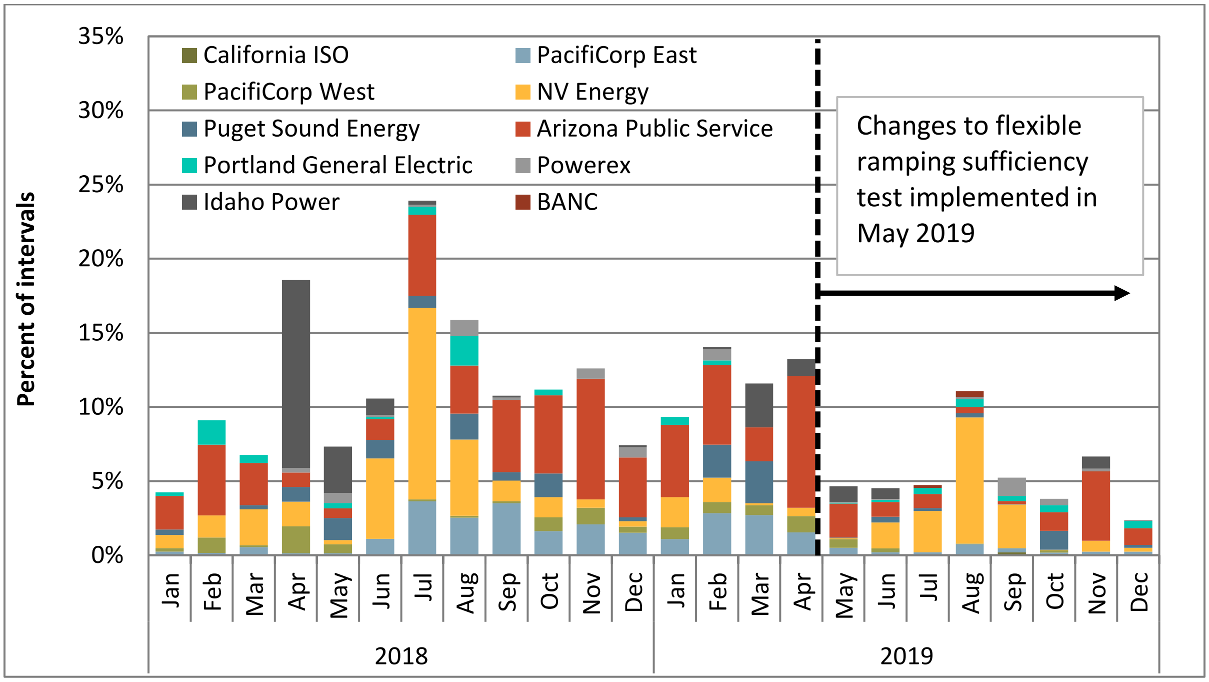
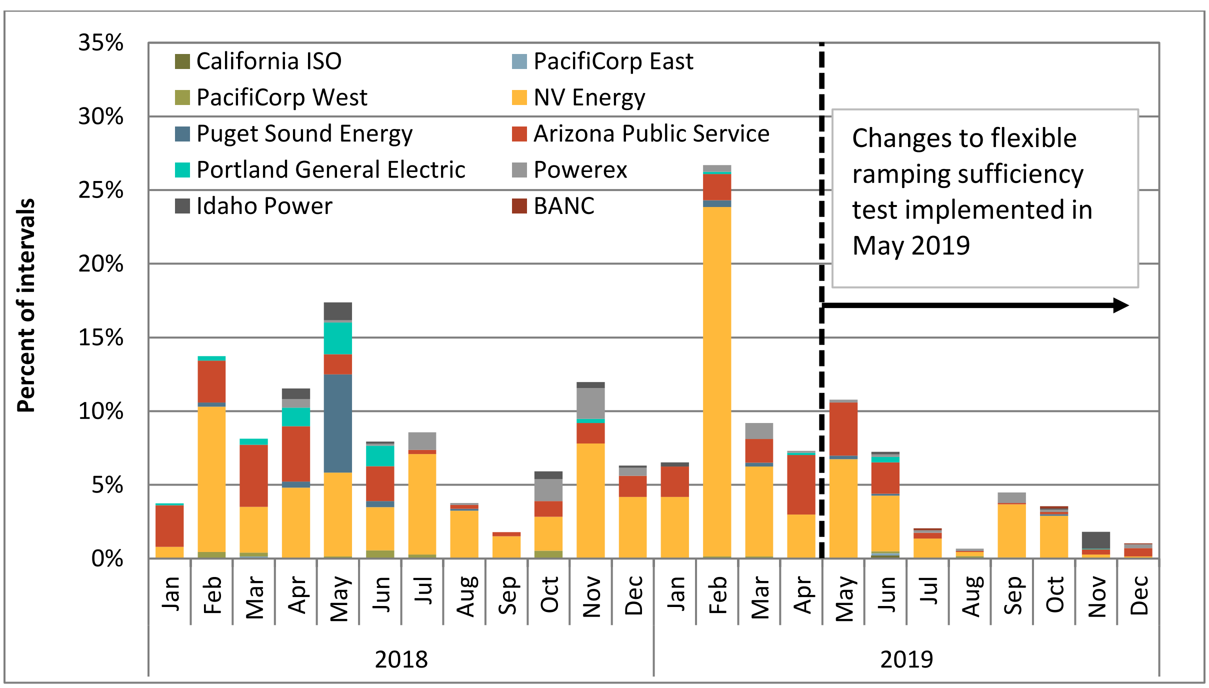


Figure 4.16 Frequency of downward failed sufficiency tests by month



4.6 Power balance constraint and load conformance limiter

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 is 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*.

Prices in different energy imbalance market areas are often driven by the frequency with which the power balance constraint is relaxed. When the power balance constraint is relaxed for undersupply conditions in an energy imbalance market area, prices are set using the $1,000/MWh penalty price for this constraint in the pricing run of the market model if transition period pricing is not in place. When transition period pricing is active and the power balance constraint is relaxed, market prices are based on the last price bid into the market by a unit.[147] Transition period pricing for the Balancing Authority of Northern California expired on September 30 following the end of their six month transition period.

The load conformance limiter works the same way as it does in the ISO.[148] It reduces the impact of an excessive load adjustment on market prices when it is considered to have caused a power balance constraint relaxation. The 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 ISO implemented an enhancement to the load conformance limiter, effective February 27, 2019. With the enhancement, the load conformance limiter triggers by a measure based on the change in load adjustment from one interval to the next, rather than solely the magnitude of the load adjustment. This change significantly reduced the frequency in which the limiter triggers.

Figure 4.17 and Figure 4.18 show the frequency of power balance constraint relaxations in the 5-minute market by quarter for undersupply (shortage) and oversupply (excess) conditions.[149] The red bars in these figures show infeasibilities that were resolved by the load conformance limiter (or would have been without transition period pricing).

The load conformance limiter has been triggered much less frequently since the changes implemented at the end of the first quarter, resulting in more prices set by penalty parameters. During 2019, most of the power balance constraint relaxations occurred in either the NV Energy or Arizona Public Service areas. Most of these occurred after failing the flexible ramping sufficiency test.

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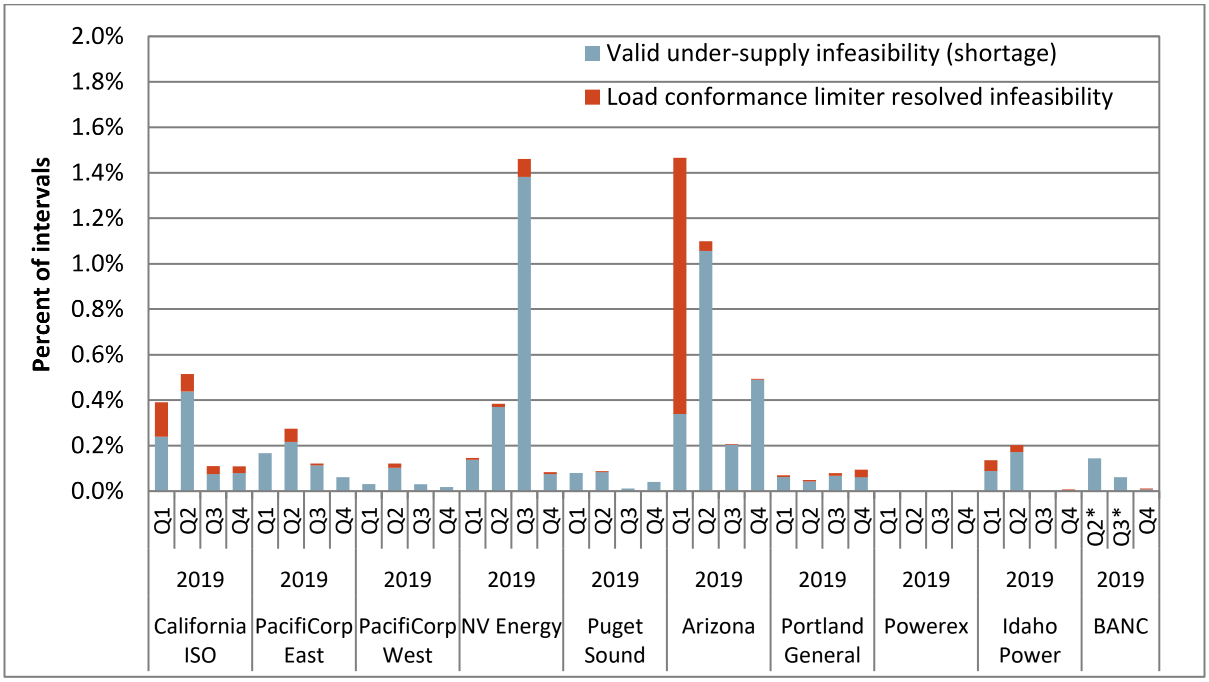
147 When transition period pricing triggers, any shadow price associated with the flexible ramping product is set to $0/MWh to allow the market software to use the last economic bid.

148 For further detail on load conformance limiter (load bias limiter), see Attachment M.2 in the Market Operations Business Practice Manual, https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market Operations

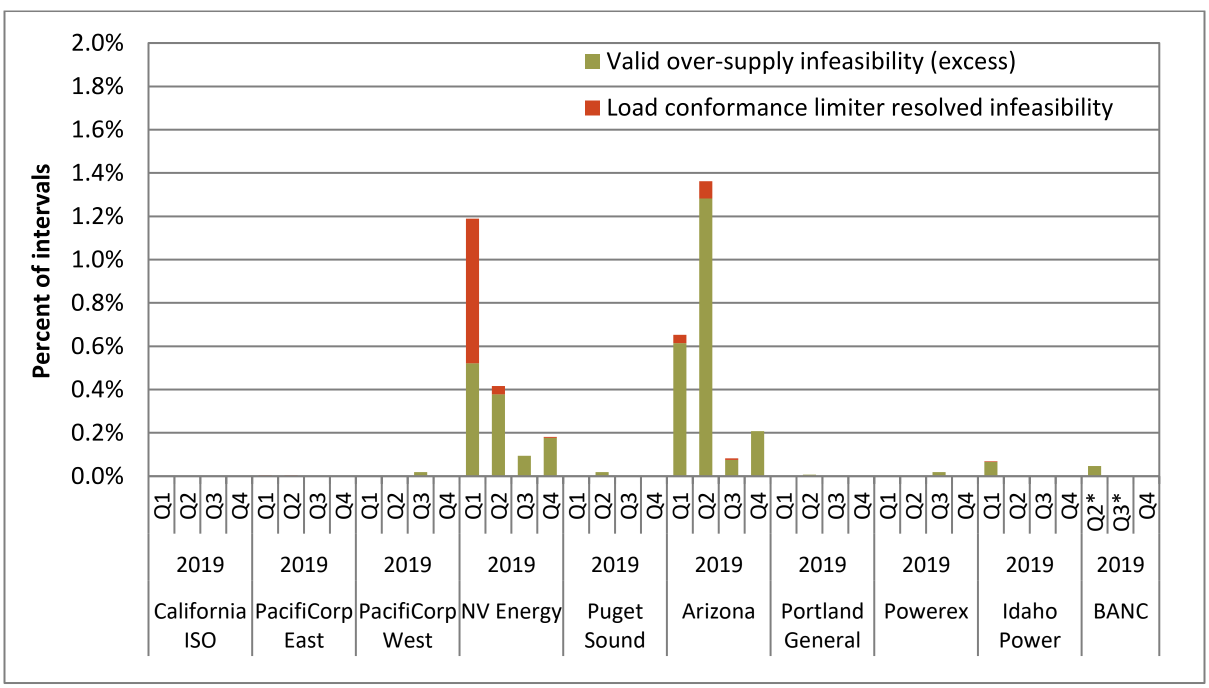
149 The frequency of power balance constraint relaxations in the 15-minute market had similar patterns to those observed in the 5-minute market.

Figure 4.17 Frequency of power balance constraint undersupply (5-minute market)



*Area under transition period pricing for the quarter

Figure 4.18 Frequency of power balance constraint oversupply (5-minute market)



*Area under transition period pricing for the quarter

Load conformance limiter enhancement

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

With the enhancement implemented on February 27, 2019, the load conformance limiter instead triggers by a measure based on the change in load adjustment from one interval to the next, rather than solely the magnitude of the load adjustment. DMM’s monitoring and review of real-time market performance suggests that the enhanced logic better captures the cause-and-effect relationship between an excessive operator adjustment and an infeasibility.

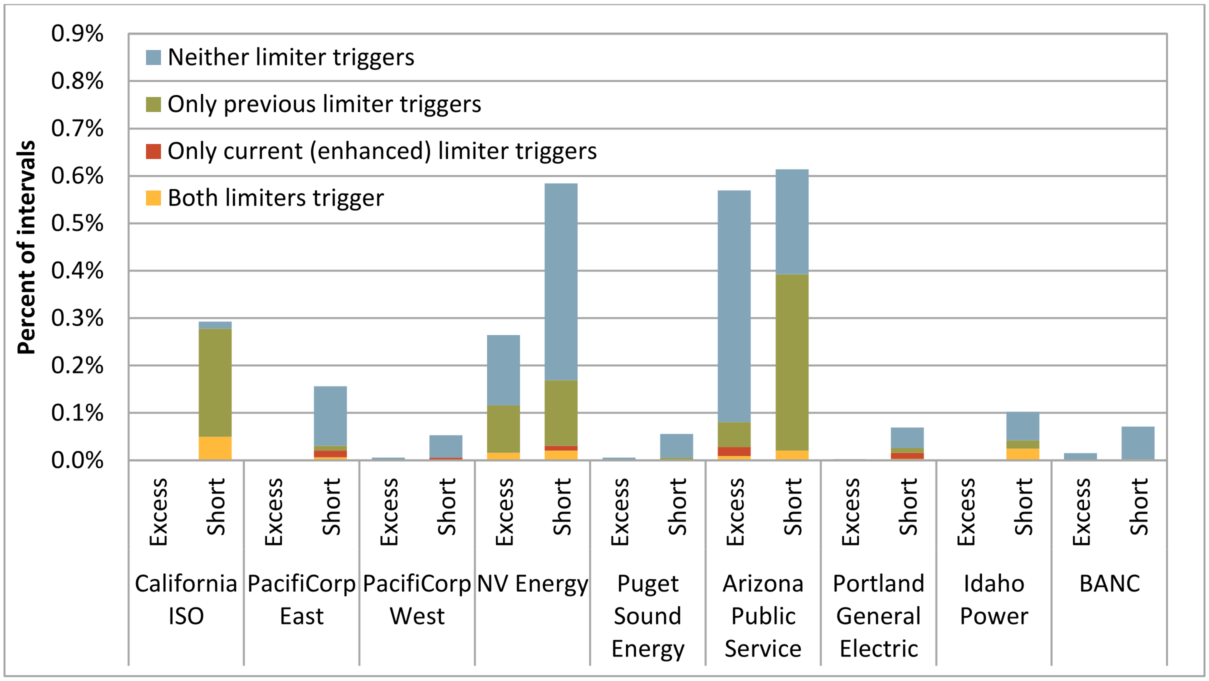
Figure 4.19 shows the frequency of infeasibilities in the 5-minute market between March and December in which the current (enhanced) conformance limiter triggered and/or the previous limiter would have triggered. The green bars represent intervals when the current limiter did not trigger, but would have under the previous approach. For intervals with ramping shortages in this category, the current approach increases prices relative to the previous method since prices would have been set by an economic bid under the previous approach but were instead set by the $1,000/MWh penalty parameter. Instances when the current limiter triggered but would not have under the previous approach (red bars) were rare.

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

However, the changes to the conformance limiter can have a significant impact on prices for some of the energy imbalance market areas. As shown in Figure 4.19, the enhancement reduced the frequency in which the conformance limiter triggered for under-supply conditions for Arizona Public Service and NV Energy, resulting in more prices set at the $1,000/MWh penalty parameter. For the period between March and December, DMM estimates that the enhancement to the conformance limiter increased average prices for Arizona Public Service by around $3.50/MWh in the 15-minute market and $3/MWh in the 5-minute market.[150] For NV Energy, the enhancement increased average prices by around $0.30/MWh in the 15-minute market and $1/MWh in the 5-minute market. These prices under the enhanced conformance limiter tend to better reflect actual scarcity conditions.

[150] The impact was calculated by estimating average prices had the previous iteration of the conformance limiter been active instead. For intervals with power balance constraint relaxations, scarcity or estimated non-scarcity prices were inserted depending on whether the current limiter triggered and/or the previous limiter would have triggered.

Figure 4.19 Frequency of load conformance limiter in the 5-minute market (March – December 2019)



4.7 Greenhouse gas compliance costs

Background

Under the current energy imbalance market design, all energy delivered to serve California load is subject to California's cap-and-trade regulation.[151] A participating resource must submit a separate bid representing the cost of compliance for energy attributed to the participating resource as serving California load. These bids are included in the optimization for energy imbalance market dispatch. Resource specific market results determined within the 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 optimization minimizes the cost of serving system load taking into account greenhouse gas compliance cost for all energy 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 deemed to serve California load. This price determined within the optimization is also included in the price difference between serving California and non-California energy imbalance market load, which can

[151] 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

contribute to higher prices for energy imbalance market areas in California.[152] If all bids have been exhausted, the price may be set higher than the greenhouse gas bid of a marginal resource.

Scheduling coordinators who deliver energy receive revenue as compensation for compliance obligations. The revenue is equal to the cleared 15-minute market greenhouse gas 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 their resource. Because prices are set at or equal to the highest cleared bid, participating resources with low emissions are incentivized to export energy to California.

In November 2018, the ISO implemented a policy change to address concerns that the market design was not capturing the full greenhouse gas effect of energy imbalance market imports into California. The California Air Resources Board (ARB) and other stakeholders raised concern that the market optimization's least cost dispatch was structured such that the decrease in emissions within California was being offset by an increase in emissions outside of California. This resulted from instances where low-emitting resources were scheduled as imports in to California due to the lower cost of compliance with the ARB's cap-and-trade regulations. In such cases, higher-emitting resources were dispatched to make up the difference in demand in the energy imbalance areas, an outcome the ISO has defined as "secondary dispatch".

To address the concern over "secondary dispatch", the ISO implemented changes that restrict capacity that can be deemed delivered to California from energy imbalance areas. Beginning in November 2018, the amount of capacity that can be deemed delivered to California is now limited to the difference between the upper economic bid limit of a resource and the resource's base schedule. Since the change, prices have increased, and both the resource mix of deliveries in to California and the energy imbalance entities being scheduled to deliver energy to California have changed, as discussed below. The decrease in supply that can be deemed as being imported into California has been significant. Beginning in 2019, there have been intervals in which all eligible supply was imported, limiting energy imbalance market imports into California.

Greenhouse gas prices

Figure 4.20 shows monthly average cleared energy imbalance market greenhouse gas prices and hourly average quantities for energy delivered to California in 2018 and 2019. Weighted average prices are calculated using 15-minute 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 delivered quantities are represented by the blue and green bars in the chart, respectively.

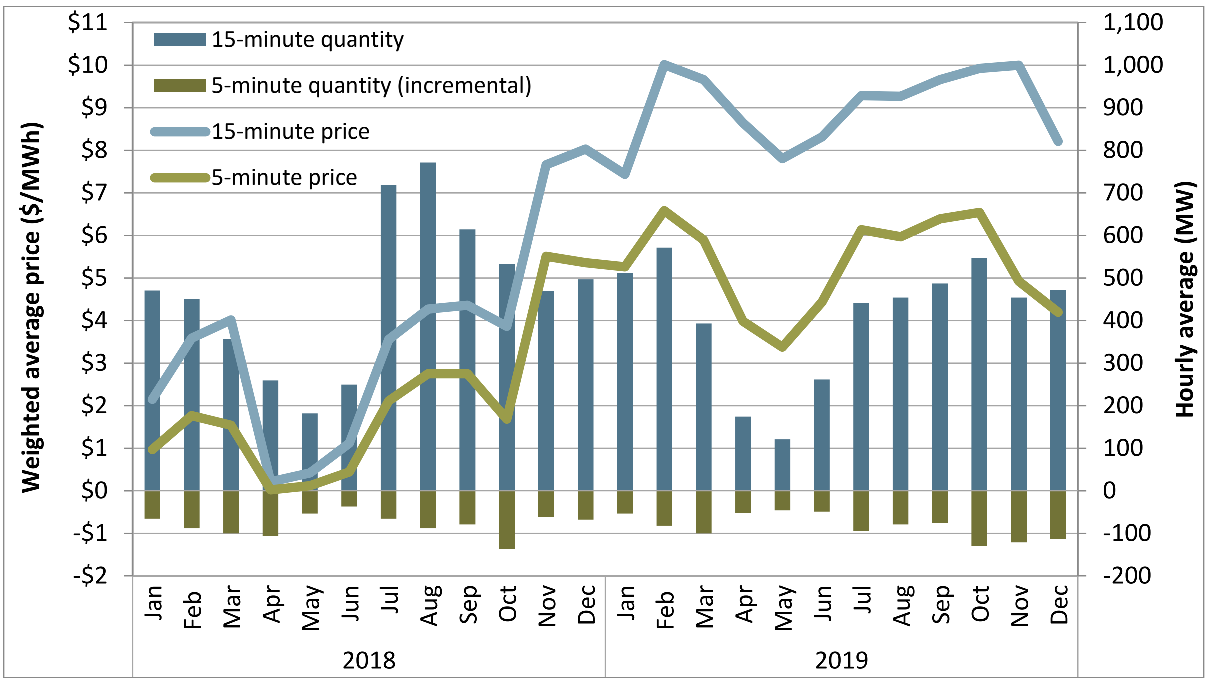
In 2019, weighted 15-minute prices averaged around $9.00/MWh for each month of the year while 5-minute prices averaged around $5.30/MWh. This was a significant increase compared to 2018, where weighted prices averaged $3.06/MWh in the 15-minute market and $2.08/MWh in the 5-minute market. In 2019, weighted average 15-minute prices were above the estimated greenhouse gas compliance costs for an efficient gas resource ($7.34/MWh) for every month of the year. This result

[152] 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

occurred for the first time in November 2018 when the greenhouse gas policy change was implemented. Conversely, weighted average 5-minute prices were lower than the estimated greenhouse gas compliance cost for an efficient resource in every month.

Price differences between markets may occur if high emitting resources are procured in the 15-minute market and subsequently decrementally dispatched in the 5-minute market. Separation between 15-minute prices and 5-minute prices has increased over time. Weighted average greenhouse gas prices in the 5-minute market were lower than 15-minute prices for each month of 2019, averaging about $3.71 less. In 2018, 15-minute prices were $1.49/MWh higher than 5-minute prices on average. This price separation is often correlated with operator load adjustments (described in Section 9.3), which are consistently higher in the 15-minute market than the 5-minute market. Operator load adjustments have been used for a number of years, but more recently contribute to accentuated differences in greenhouse gas prices due to the compressed bid stack.

Figure 4.20 Energy imbalance market greenhouse gas price and cleared quantity



Trends in these average prices can be further explained by the frequency of high and $0 prices. Figure 4.21 and Figure 4.22 illustrate the frequency of high prices for each market and quarter of the last two years. The charts also show the maximum price by quarter.

Historically, EIM greenhouse gas prices have not exceeded $7/MWh in either the 15-minute or 5-minute market. After November 2018, prices above $7/MWh occur frequently. In the 15-minute market, prices exceeded $10/MWh in 12 percent of intervals in 2019. In the 5-minute market, prices exceeded $10/MWh in 8 percent of intervals in 2019. The majority of these intervals were set by bids from emitting generators with compliance cost that bid a non-zero price to delivered energy to California. Some prices, however, were not set by bids.

As mentioned above, EIM greenhouse gas supply can be exhausted, limiting the total transfer of energy imported to California through the energy imbalance market, and setting greenhouse gas prices that exceed the highest cleared bid. In 2019, nearly 70 15-minute intervals and roughly 170 5-minute intervals exceeded $18/MWh. Overall in 2019, DMM estimates that there were nearly 150 intervals in the 5-minute market and 50 intervals in the 15-minute market where prices were set above the maximum cleared bid.

Prior to the fourth quarter of 2018, the highest 15-minute greenhouse gas price was $6.60/MWh and the highest 5-minute price was $6.69/MWh. In 2019, the highest 15-minute price was $889.17/MWh and the highest 5-minute price was $973.09/MWh.

Overall, there was also a decrease in the frequency of $0/MWh prices. In 2018, there were roughly 30 percent of intervals with $0/MWh prices in the 15-minute market, compared to roughly 9 percent in 2019. In the 5-minute market, there were 30 percent in 2018 versus 12 percent in 2019. This likely occurred due to the restriction of bids from non-emitting resources.

Figure 4.21 High 15-minute EIM greenhouse gas prices

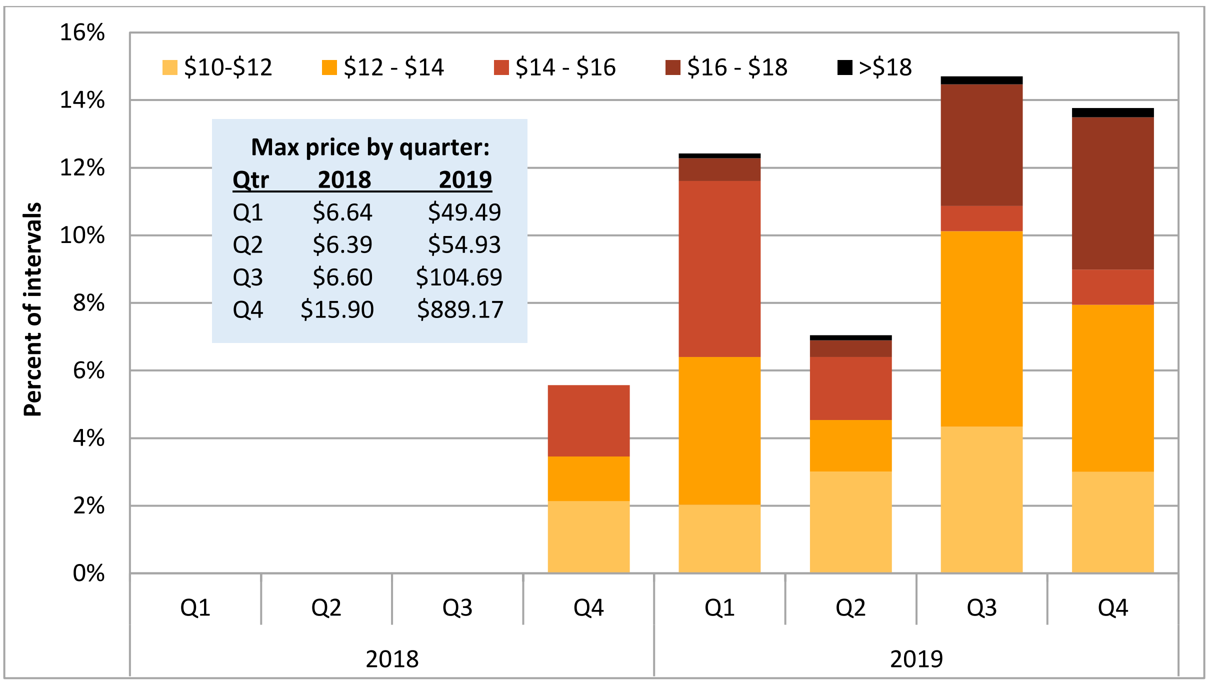
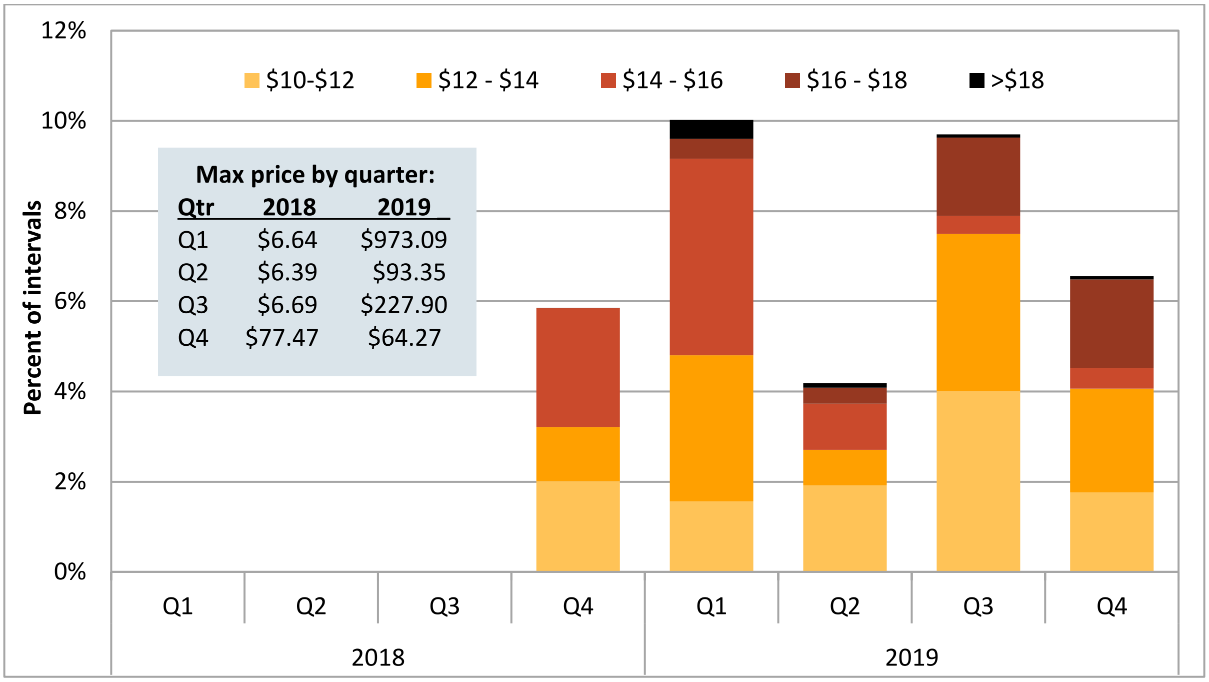


Figure 4.22 High 5-minute EIM greenhouse gas prices



Energy delivered to California by fuel type and balancing area

Figure 4.23 shows hourly average greenhouse gas energy by fuel type. In 2019, about 51 percent of EIM greenhouse gas compliance obligations were assigned to hydro resources, compared to about 72 percent in the previous year. The decrease in hydroelectric resources used to serve ISO load likely resulted from the policy change, which limited the capacity available to be delivered to California to exclude base-scheduled capacity. The portion of energy delivered to California from natural gas resources was roughly 48 percent, up from around 27 percent in 2018. Delivery from coal resources accounted for 2 percent for the year, an increase compared to less than 0.3 percent in 2018.

Figure 4.24 shows the percentage of total greenhouse gas energy cleared by area. In 2019, nearly all EIM entities submitted greenhouse gas bids and generated energy that was delivered to California. Prior to November 2018, most greenhouse gas energy came from entities in the northwest with large fleets of hydroelectric resources.

After the change, greenhouse gas energy was procured more evenly across areas. In 2019, northwestern areas produced about 63 percent of energy delivered to California, while 34 percent came from PacifiCorp East, NV Energy, and Arizona Public Service. After entering the market in April 2018, Powerex produced a small amount of energy delivered to California (2 percent) in 2018. Starting in June 2019, no energy was delivered to California from Powerex.

Figure 4.23 Percentage of energy delivered to California by fuel type (MW)

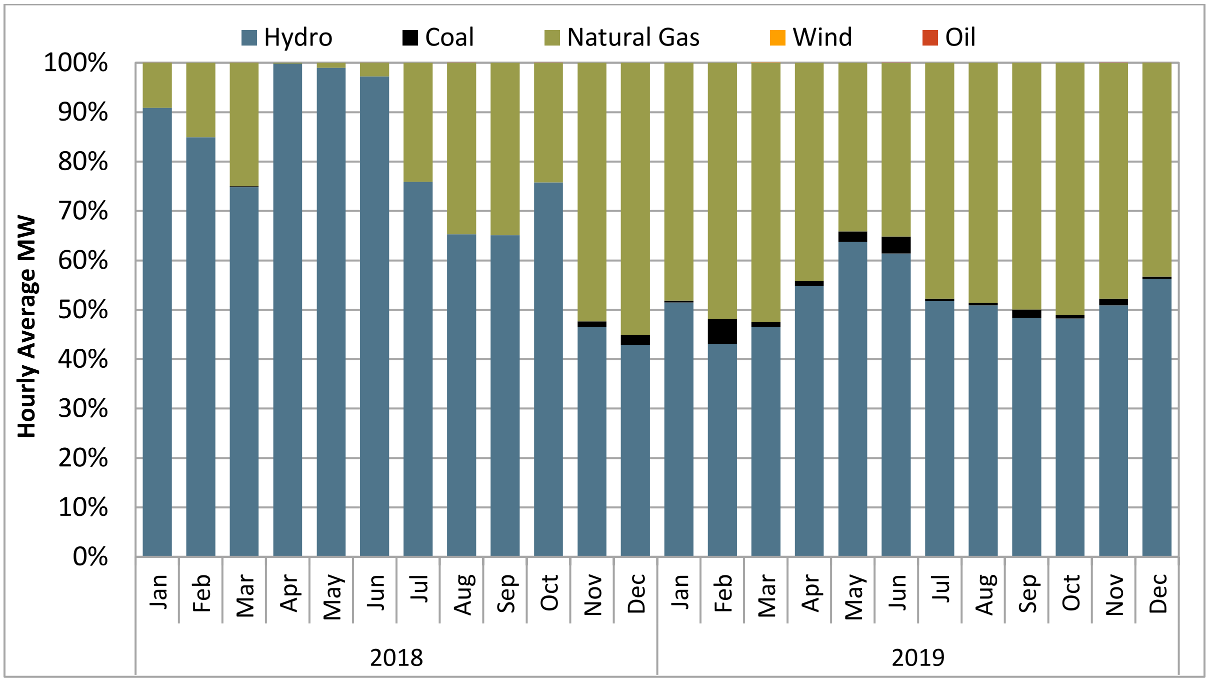
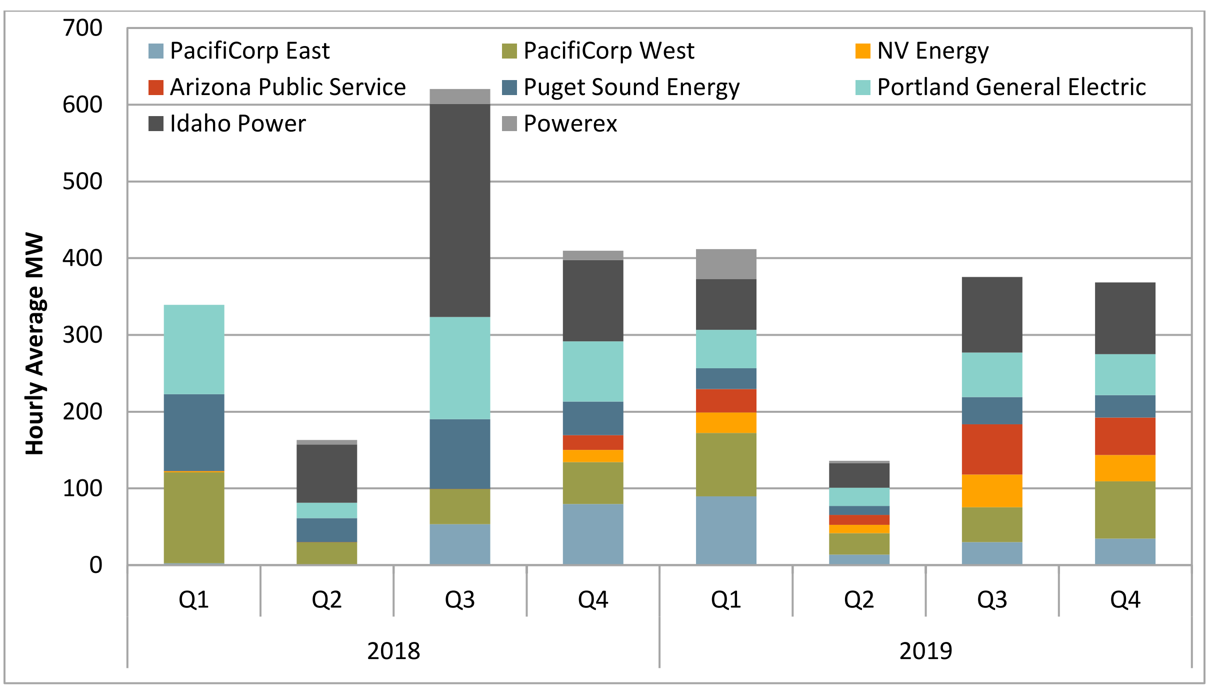


Figure 4.24 Energy delivered to California by area (MW)



EIM greenhouse gas revenues

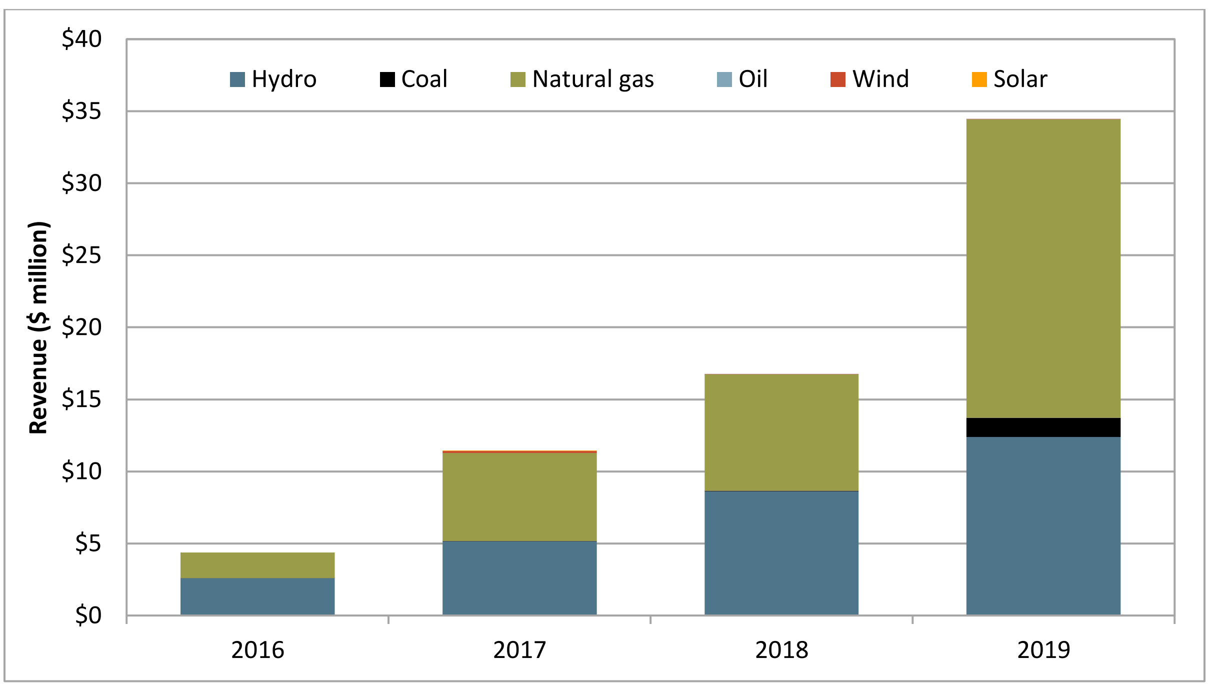
Figure 4.25 shows revenues accruing to EIM resources for energy delivered to California by fuel type. In 2019, revenues totaled roughly $34.5 million, more than double revenues in 2018 ($16.7 million). This occurred despite lower total energy delivered.

In 2019, the increase in revenues was not related to new entities joining the energy imbalance market as it has been historically. BANC joined in April 2019, but because they are located within California, does not bid a greenhouse gas component in the energy imbalance market.

Between 2016 and 2018, revenues for hydroelectric generators ranged from 50 to 60 percent of annual revenues, while natural gas ranged from 40 to 55 percent. In 2019, hydroelectric revenues comprised 36 percent of revenues, while natural gas revenues comprised 60 percent, and coal revenues comprised about 4 percent.

From 2018 to 2019, revenues for hydroelectric generators increased from $8.6 million to $12.4 million, despite less actual energy delivered. Revenues for natural gas generators increased from $8.1 million to $20.7 million, while revenues for coal resources increased from $0.04 million to $1.3 million. This occurred in part due to higher overall prices resulting from a shorter bid stack.

Figure 4.25 Annual greenhouse gas revenues



4.8 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 market, and prevents market infeasibilities that may arise without the availability of this capacity.[153]

Table 4.3 summarizes the quarterly frequency of upward and downward available balancing capacity offered and scheduled in each area during 2019.[154] Powerex, NV Energy, Puget Sound Energy, and BANC offered upward and downward balancing capacity during almost all hours. Table 4.3 also shows the average magnitude of the available balancing capacity when offered in their hourly resource plan. In particular, Powerex on average offered roughly 1,150 MW and 600 MW of upward and downward available balancing capacity during 2019.

The frequency of upward available balancing capacity offered by Arizona Public Service increased significantly to around 50 percent of hours, up from 11 percent of hours from the previous year. Upward available balancing capacity offered by Portland General Electric also increased significantly during the year, to around 99 percent of hours since the end of July, compared to around zero prior to then.

PacifiCorp West offered available balancing capacity in either direction infrequently, during less than 5 percent of hours for during 2019. Idaho Power did not offer upward or downward available balancing capacity for any hour during the year.

Overall, available balancing capacity was dispatched for scarcity conditions infrequently during 2019. However, upward and downward available balancing capacity offered by NV Energy was dispatched most frequently during the year compared to other balancing areas due to a relatively high frequency of infeasibilities and offered available balancing capacity.

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153 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

154 The ISO has identified instances when a resource is required to cross the operational range where available balancing capacity is defined, therefore “scheduling” it in the real-time market without scarcity conditions. Therefore, dispatched available balancing capacity without scarcity pricing in the scheduling run is omitted from this table.

Table 4.3 Frequency of available balancing capacity offered and scheduled (2019)

	Offered		Scheduled	
	Percent of hours	Average MW	Percent of intervals (15-minute market)	Percent of intervals (5-minute market)
Upward ABC				
Powerex	100%	1,156	0.1%	0.0%
NV Energy	100%	65	1.4%	2.0%
Puget Sound Energy	99%	35	0.1%	0.1%
BANC*	98%	41	0.1%	0.1%
Arizona Public Service	50%	125	0.2%	0.1%
Portland General Electric	44%	30	0.0%	0.1%
PacifiCorp East	25%	72	0.0%	0.0%
PacifiCorp West	5%	64	0.0%	0.0%
Idaho Power	0%	N/A	0.0%	0.0%
Downward ABC				
Powerex	100%	-598	0.1%	0.2%
NV Energy	100%	-65	1.0%	1.5%
Puget Sound Energy	99%	-40	0.0%	0.0%
BANC*	98%	-29	0.0%	0.1%
Arizona Public Service	33%	-109	0.1%	0.0%
Portland General Electric	0%	-24	0.0%	0.0%
PacifiCorp East	10%	-89	0.0%	0.0%
PacifiCorp West	4%	-66	0.0%	0.0%
Idaho Power	0%	N/A	0.0%	0.0%

*April 3 to December 31, 2019, only

5 Convergence bidding

Virtual bidding is a part of the Federal Energy Regulatory Commission's standard market design and has been part of the ISO's market since February 2011. Virtual bidding allows participants to profit from any difference between day-ahead and real-time prices. Findings from this chapter include the following:

- **Net profits paid to convergence bidders totaled around $37 million**, a decrease from about $40 million in 2018, after accounting for about $8 million in bid cost recovery charges allocated to virtual bids. Net profits before accounting for these charges rose to $44 million, the second highest amount since 2012. This increase reflects both the profitability of virtual demand, particularly in the second quarter, and overall virtual supply bids with sustained day-ahead prices greater than real-time prices over much of the year.
- **Virtual supply exceeded virtual demand by an average of about 660 MW per hour**, compared to 680 MW in 2018. The percent of cleared virtual supply and demand was around 29 percent, a decrease from about 36 percent in 2018.
- **Most profits from virtual bidding continue to be received by financial entities and marketers,** who received 67 percent and 29 percent of net revenues, respectively. 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* since it is intended to help decrease differences in day-ahead and real-time prices. 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.[155] 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.[156]

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.[157] In late September 2015, FERC issued an order requiring the ISO to remove tariff provisions that provided for reinstatement of convergence bids at interties.[158]

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155 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.

156 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 Larrieu, 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

157 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

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

5.1 Convergence bidding trends

In 2019 convergence bidding volumes increased over 2018, with net cleared volumes of virtual supply outweighing virtual demand for all quarters. This continues a trend of cleared virtual supply outweighing cleared virtual demand for all quarters since 2014. Figure 5.1 shows the quantities of both virtual supply and demand 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, 29 percent of virtual supply and demand bids offered into the market cleared in 2019, compared to 36 percent in 2018.
- The average hourly cleared volume of virtual supply exceeded virtual demand for all quarters by about 660 MW per hour, a decrease from about 680 MW per hour in 2018.
- Average hourly cleared virtual supply was about 2,160 MW in 2019, compared to 1,790 MW in 2018. This increase was mainly driven by an increase in cleared virtual supply by financial participants by 260 MW. Average hourly cleared virtual demand increased to 1,500 MW in 2019 from about 1,100 MW in 2018. This was largely the result of increased bidding activity by both financial participants and marketers.

Figure 5.1 Quarterly average virtual bids offered and cleared

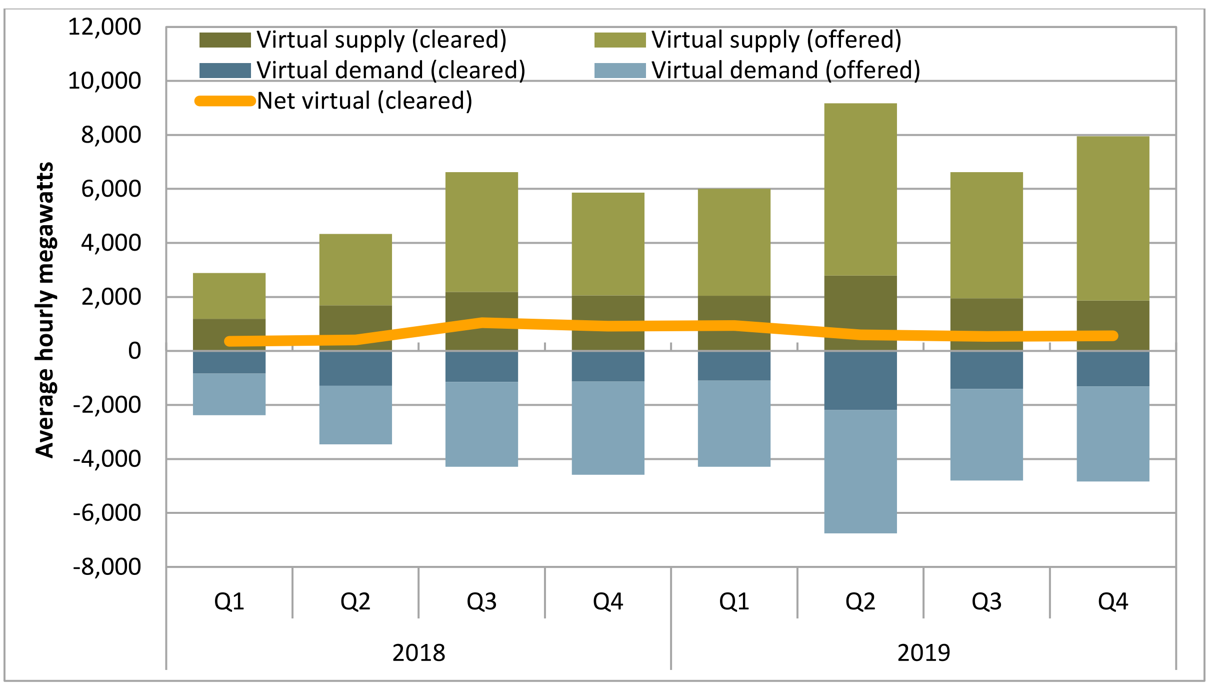
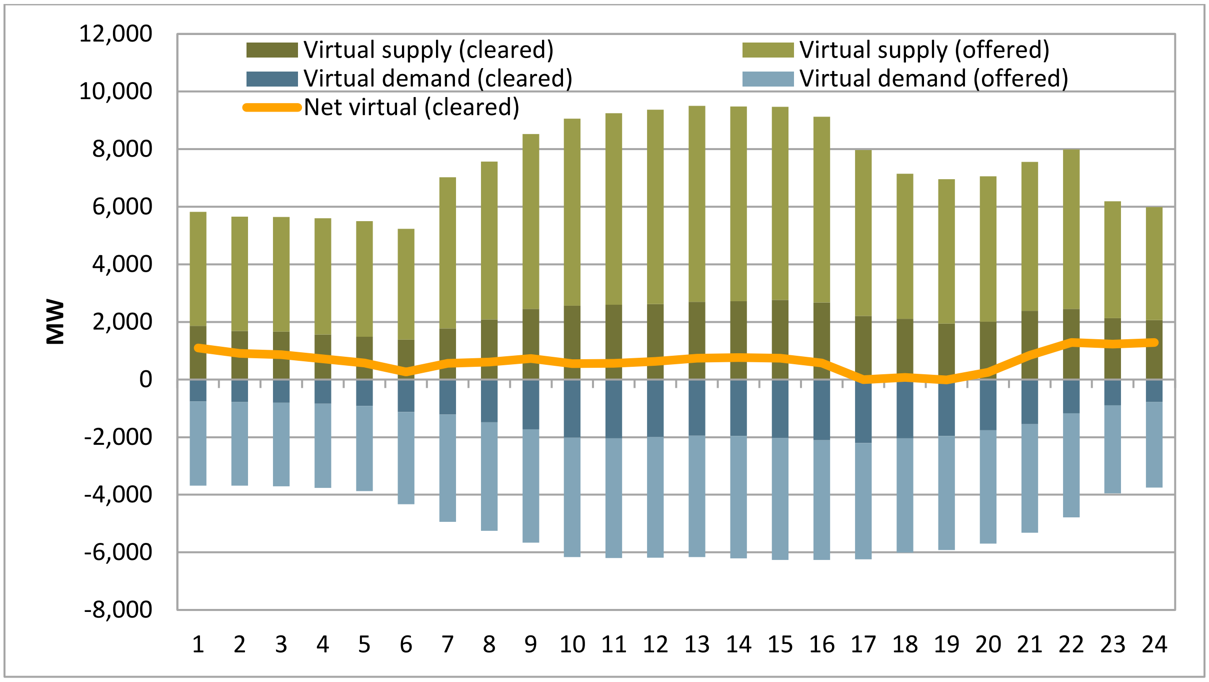


Figure 5.2 Average net cleared virtual bids in 2019



- Net virtual supply volumes were highest during the second quarter of the year when virtual supply exceeded virtual demand by around 460 MW per hour on average, an increase from about 400 MW for the same period in 2018.
- About 70 percent of cleared virtual positions in 2019 were held by financial participants, an increase from 63 percent in 2018. Financial participants bid more virtual supply than demand in 2019, which contributed to the increase in net virtual supply.
- Net virtual supply was lowest during the morning ramp hour ending 6 and the evening peak hours 17 through 20. Virtual supply was nearly balanced with virtual demand or slightly negative on average during hours 17, 18, and 19. For all other hours, virtual supply outweighed virtual demand.
- Historically, virtual demand has been most profitable during the evening peak hours (hours 17 through 21) when tighter supply conditions can lead to higher real-time prices relative to day-ahead prices. However, in 2019, day-ahead prices were higher on average during all evening peak hours in 2019 making virtual demand less profitable overall during these hours than prior years.

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 790 MW of virtual demand offset by 790 MW of virtual supply during each hour in 2019, an increase from about 730 MW in 2018. The share of these offsetting bids totaled about 48 percent of all cleared virtual bids in 2019, slightly down from about 51 percent in 2018. Offsetting bids made up 41 percent of cleared virtual supply and 60 percent of cleared virtual demand during 2019.

Consistency of price differences and volumes

Convergence bidding was 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. Similar to 2018, net convergence bidding volumes were generally less consistent with price differences between the day-ahead and real-time markets on average. Particularly, this can be seen, on average, with consistent virtual supply profitability punctuated by a relatively few instances of highly unprofitable days and hours which were inversely highly profitable for virtual demand. This trend was particularly evident in the second quarter.

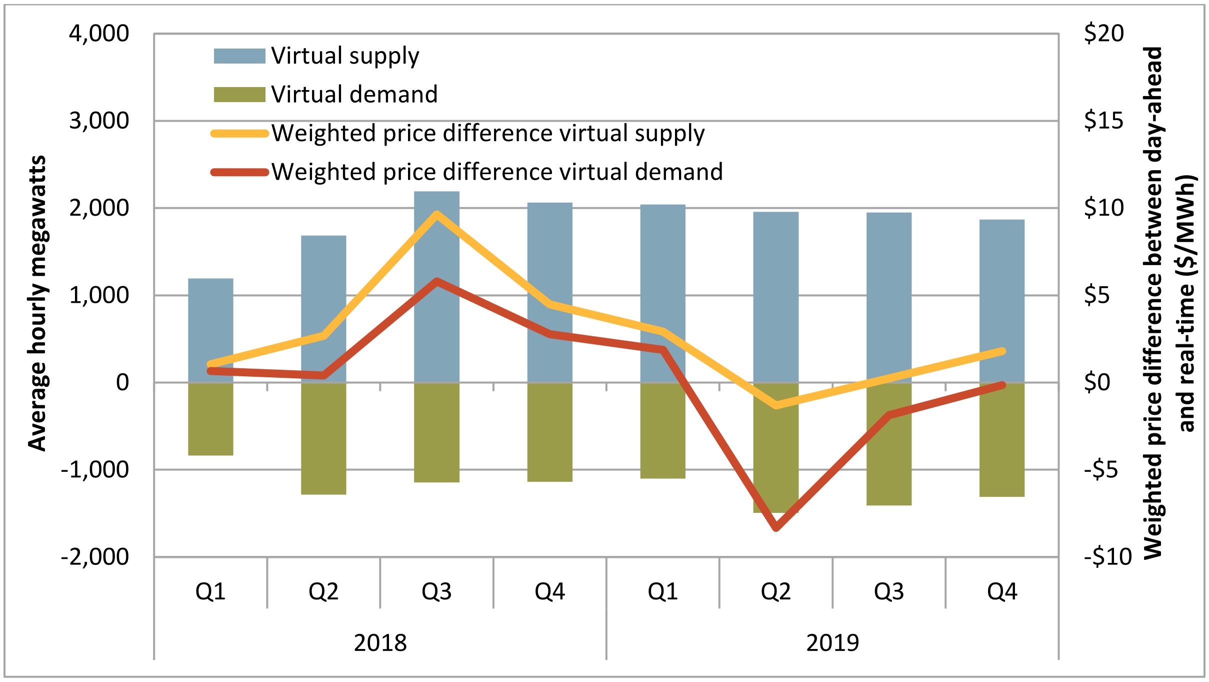
Figure 5.3 compares cleared convergence bidding volumes with the volume-weighted average price differences at which these virtual bids were settled. The difference between day-ahead and real-time prices shown in this figure represents the average price difference weighted by the amount of virtual bids 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 2019, virtual demand positions were mainly profitable in the second and third quarters.

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. This might help explain the surge of virtual demand bids during ostensibly unprofitable periods which could be earning revenue by speculating on congestion.

Quarters where 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. Virtual supply was profitable in all but the second quarter of 2019. As shown in Figure 5.3, virtual supply and virtual demand bid volumes were very consistent throughout the year.

Figure 5.3 Convergence bidding volumes and weighted price differences



5.2 Convergence bidding payments

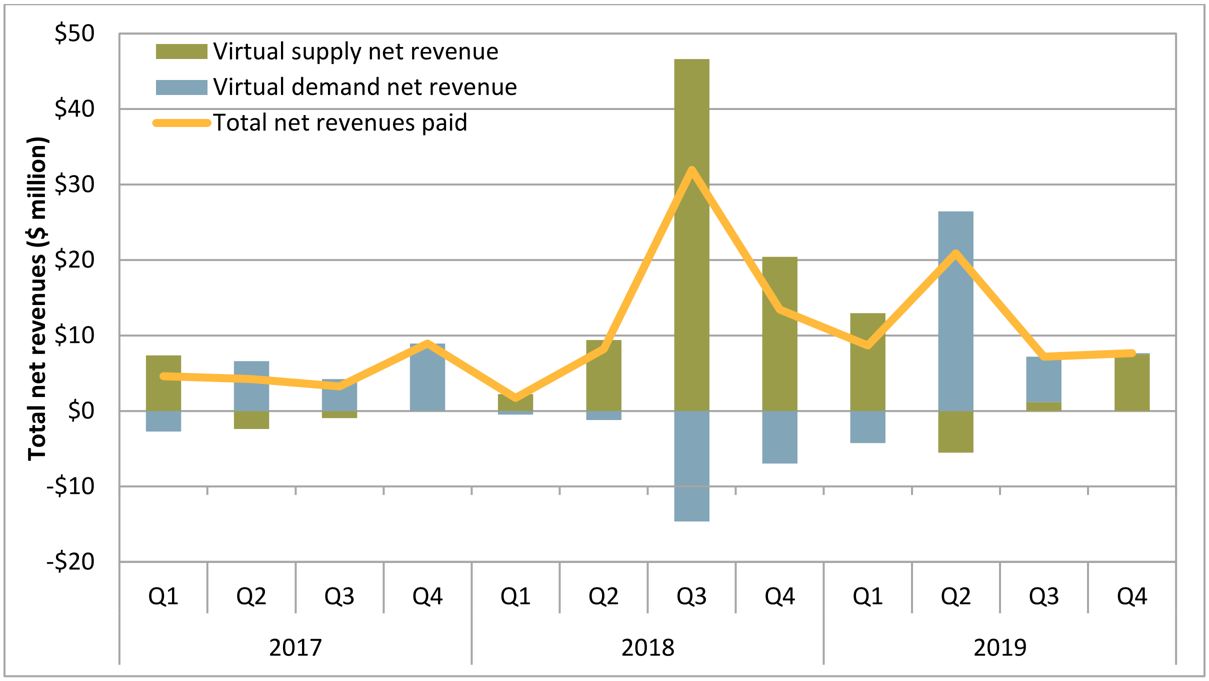
Net profits paid to virtual bidders (prior to any allocation of bid cost recovery payments) totaled about $44 million in 2019, a decrease of about $11 million from 2018 or about 20 percent. Similar to 2018, day-ahead energy prices were more consistently higher than in the real-time market, but there were a number of large real-time price spikes, particularly in the second quarter, when virtual demand bids were highly profitable.

Figure 5.4 shows total quarterly net profits paid for accepted virtual supply and demand bids. As shown in Figure 5.4:

- Total net profits ($44 million) were paid to both cleared virtual supply and virtual demand, with about 36 percent of profits from virtual supply and 64 percent from virtual demand. In the previous year all total net profits were attributed to cleared virtual supply.
- Virtual supply positions were profitable in all but the second quarter of 2019, totaling about $16 million for the year. This was primarily driven by sustained average day-ahead market prices greater than real-time market prices.
- Virtual demand positions were profitable in only the second and third quarters in 2019, with most of the $28 million in net revenues occurring in the second quarter. This is primarily the result of a few large positive price differences between the real-time and day-ahead markets.
- Total net revenues for virtual bidders peaked in the second quarter at almost $21 million, more than double any other quarter in 2019. Net revenues in the third and fourth quarters were around $7

million each, primarily from virtual demand in the third quarter and virtual supply in the fourth quarter.

Figure 5.4 Total quarterly net revenues from convergence bidding



Net revenues and volumes by participant type

Most convergence bidding is typically conducted by entities engaging in purely financial trading that do not serve load or transact physical supply. These entities accounted for almost $43 million of the total convergence bidding revenues in 2019.

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

Table 5.1 Convergence bidding volumes and revenues by participant type (2019)

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	931	1,338	2,269	$17.6	$12.3	$30.0
Marketer	378	553	931	$9.1	$3.7	$12.9
Physical generation	20	33	53	$1.6	-$0.2	$1.4
Physical load	0	30	30	$0.0	$0.2	$0.2
Total	**1,330**	**1,954**	**3,283**	**$28.3**	**$16.1**	**$44.4**

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 bidders, accounting for about 69 percent of cleared volume and about 68 percent of profits. Marketers represent about 28 and 29 percent of volume and profit, respectively. Load serving entities and generation owners account for the smallest share of both total revenues and volume at 2 and 3.5 percent, respectively.

Table 5.1 shows that all participant types held significantly more virtual supply than virtual demand, similar to the prior year. However, unlike the previous year virtual demand revenues reversed from negative to a positive $28 million while virtual supply remained positive but decreased from about $80 million to $16 million.

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 residual unit commitment process, which ensures sufficient capacity bids into the real-time market.[159] When the ISO commits units in the residual unit commitment process, 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.[160]

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.[161]

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.[162] 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.[163] In this case, virtual supply leads to decreased unit

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159 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.

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

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

162 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

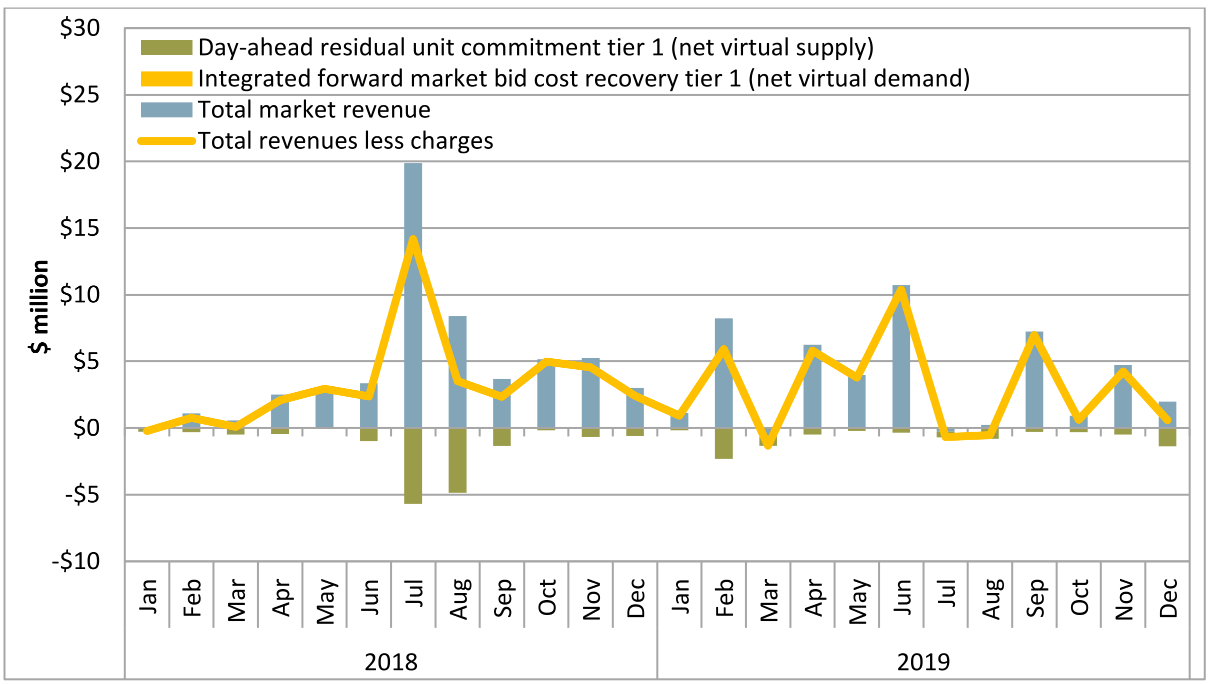
163 For further detail, see Business Practice Manual configuration guides for charge code (CC) 6806, Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocation_5.5: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

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 decreased from the previous year. In particular, the third quarter accounted for the largest decrease in bid cost recovery charges resulting from lower residual unit commitment costs which were about $1 million compared to just under $12 million for the same period in the previous year.

Figure 5.5 shows estimated total virtual bidding profit before and after bid cost recovery charges. Total convergence bidding bid cost recovery costs for the year were about $7.8 million, a decrease from around $16 million in 2018. As noted earlier, the total estimated profits for convergence bidding in 2019 were around $44.4 million before accounting for these charges. After subtracting bid cost recovery costs allocated to virtual bids, net virtual bidding profits totaled about $36.7 million. This is a slight decrease compared to about $40 million in net virtual bidding profits in 2018.

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 2019. Key trends highlighted in this chapter include the following:

- **Ancillary service costs decreased to $148 million**, down from $177 million in 2018.
- **Regulation requirements increased while operating reserve requirements decreased**. Regulation down requirements increased 6 percent to 430 MW and regulation up requirement increased 8 percent to 350 MW, relative to 2018. Average combined requirements for spinning and non-spinning operating reserves decreased by 15 percent from the previous year to about 1,600 MW.
- **Provision of ancillary services from limited energy storage resources continued to increase**. Limited energy storage resources include batteries and other limited devices. Average hourly procurement from these resources for regulation increased from around 101 MW in 2018 to 166 MW in 2019, or around 21 percent of regulation requirements.
- **The frequency of ancillary service scarcity intervals increased, but remained low**. There were 194 intervals in the 15-minute market with ancillary service scarcity, with most of them for regulation up or regulation down. In comparison, there were 189 scarcity instances in 2018 and 54 in 2017.
- **Twenty percent of resources failed** ancillary service performance audits and unannounced compliance tests in 2019, a rate of failure comparable to 2018.

The ISO's ancillary service 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. A detailed description of the ancillary service market design is provided in DMM's 2010 annual report.[164]

6.1 Ancillary service costs

Costs for ancillary services totaled about $148 million in 2019. In comparison, total ancillary service costs were higher in 2018 at about $177 million and around the same in 2017 at about $148 million.

The costs reported in this section have been refined from the previous year to account for rescinded ancillary service payments. Payments are rescinded when resources providing ancillary services do not fulfill the availability requirement associated with the awards. During 2019, about 6 percent of payments for ancillary service awards were rescinded.

Figure 6.1 shows ancillary service costs both as a percentage of wholesale energy costs and per megawatt-hour of load from 2017 through 2019. Ancillary service costs decreased to $0.69/MWh of load served in 2019 from $0.80/MWh in 2018. Ancillary service costs as a percent of total wholesale energy costs were just under 1.7 percent in 2019, similar to the previous two years.

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164 *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 6.2 shows the total cost of procuring ancillary service products by quarter and the total ancillary service cost for each megawatt-hour of load served. Unlike the previous two years, ancillary service costs were highest during the second quarter while costs in the third quarter were relatively low.

Payments for regulation increased relative to payments for operating reserves. In total for the year, payments associated with non-spinning reserves were around $6 million, compared to over $20 million in each of the previous two years. Payments for spinning reserves were also lower for the year at around $53 million compared to over $68 million in 2017 and 2018. Conversely, payments for regulation up and regulation down, at $43 million and $46 million respectively, were each higher compared to the previous two years.

Figure 6.1 Ancillary service cost as a percentage of wholesale energy costs (2017-2019)

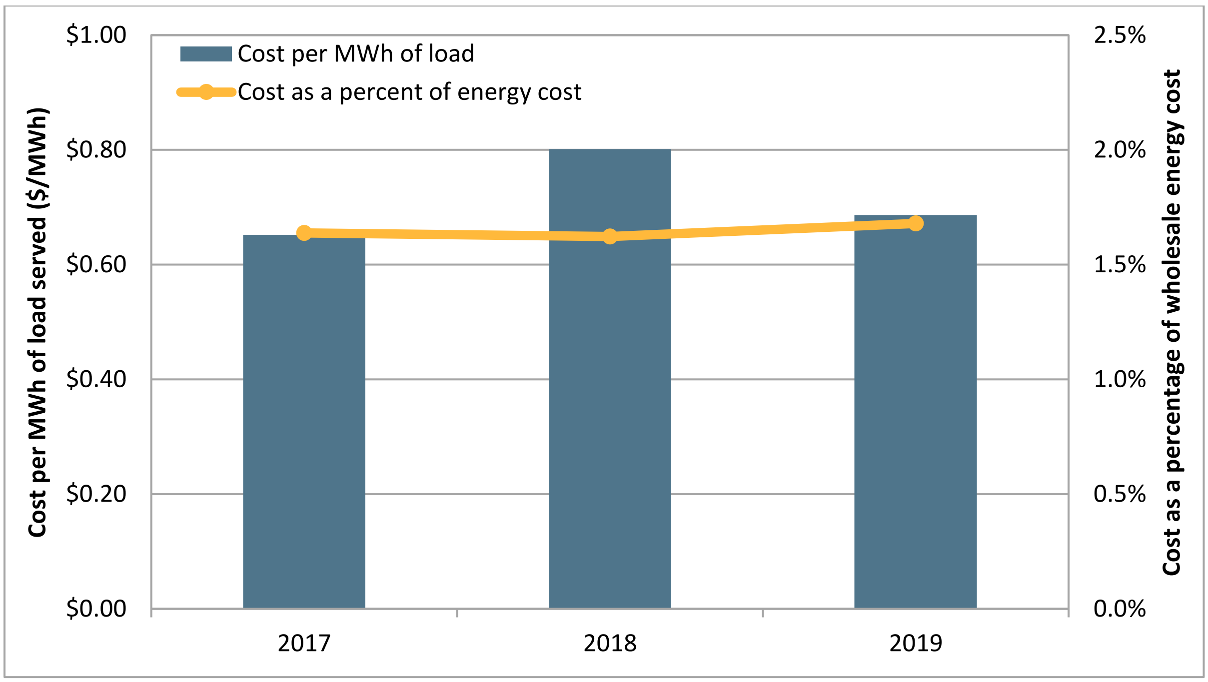
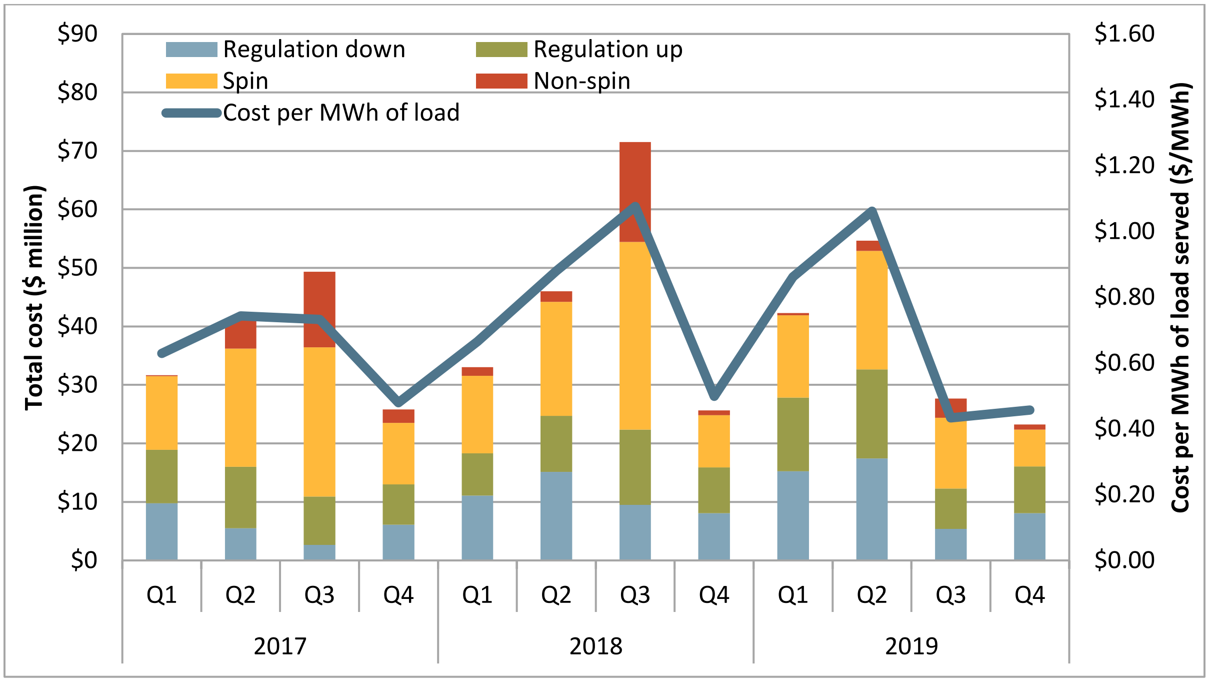


Figure 6.2 Total ancillary service cost by quarter and type



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.[165] 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. The ISO attempts to procure all ancillary services in the day-ahead market to the extent possible.

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

Six of these regions are typically utilized: expanded system (or expanded ISO), internal system, expanded South of Path 26, internal South of Path 26, expanded North of Path 26, and internal North of Path 26.

165 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.

Operating reserve requirements

Operating reserve requirements in the day-ahead market are typically set by the maximum of three factors: (1) 6.3 percent of the load forecast, (2) the most severe single contingency and (3) 15 percent of forecasted solar production.[166] Operating reserve requirements in real-time are calculated similarly except using 3 percent of the load forecast and 3 percent of generation instead of 6.3 percent of the load forecast. The total operating reserve requirements are then typically split equally between spinning and non-spinning reserves.

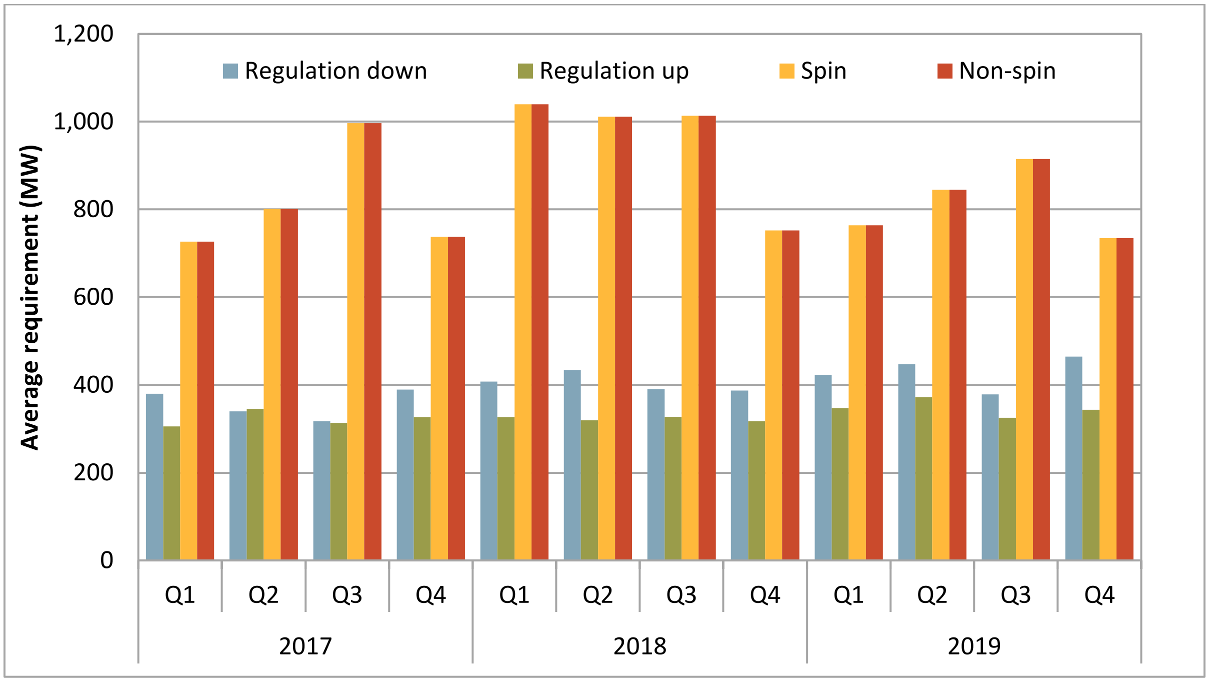
The Federal Energy Regulatory Commission approved a set of requirements in BAL-002-2, effective January 1, 2018, that required the ISO to reevaluate the most severe single contingency.[167] Both poles of the Pacific DC Intertie were agreed upon as a credible multiple contingency that qualifies as a single event for the purpose of the most severe single contingency. Beginning January 1, 2018, operating reserve requirements account for the contingency of the loss of projected schedules on the Pacific DC Intertie sinking in the ISO balancing area. This can include a higher volume than the share that sinks directly in the ISO and resulted in an increase to the operating reserve requirements overall.

Figure 6.3 includes quarterly average day-ahead operating reserve requirements since 2017. During 2019, average combined requirements for spinning and non-spinning operating reserves decreased by 15 percent from the previous year due in part to lower loads. Operating reserve requirements in the day-ahead market averaged around 1,600 MW in 2019, compared to around 1,900 MW in 2018.

[166] 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 a large loss of solar generation. Only solar forecasts from resources that have the potential for the inverter issue are considered.

[167] Further information on the NERC BAL-002-2 reliability standard is available here: http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-2.pdf

Figure 6.3 Quarterly average day-ahead ancillary service requirements



Regulation requirements

The ISO 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.

Figure 6.3 also shows average regulation requirements by quarter. During 2019, day-ahead requirements averaged around 430 MW for regulation down and 350 MW for regulation up. Compared to 2018, this represents an increase of about 6 percent for regulation down and an increase of about 8 percent for regulation up.

Figure 6.4 summarizes the average hourly profile of the day-ahead regulation requirements in 2018. Regulation up requirements were highest during midday hours. Requirements for regulation down were typically highest in morning hours when solar is ramping on and evening hours when solar is ramping off. Requirements for regulation down were typically higher than requirements for regulation up.

Figure 6.4 Hourly average day-ahead regulation requirements (2019)

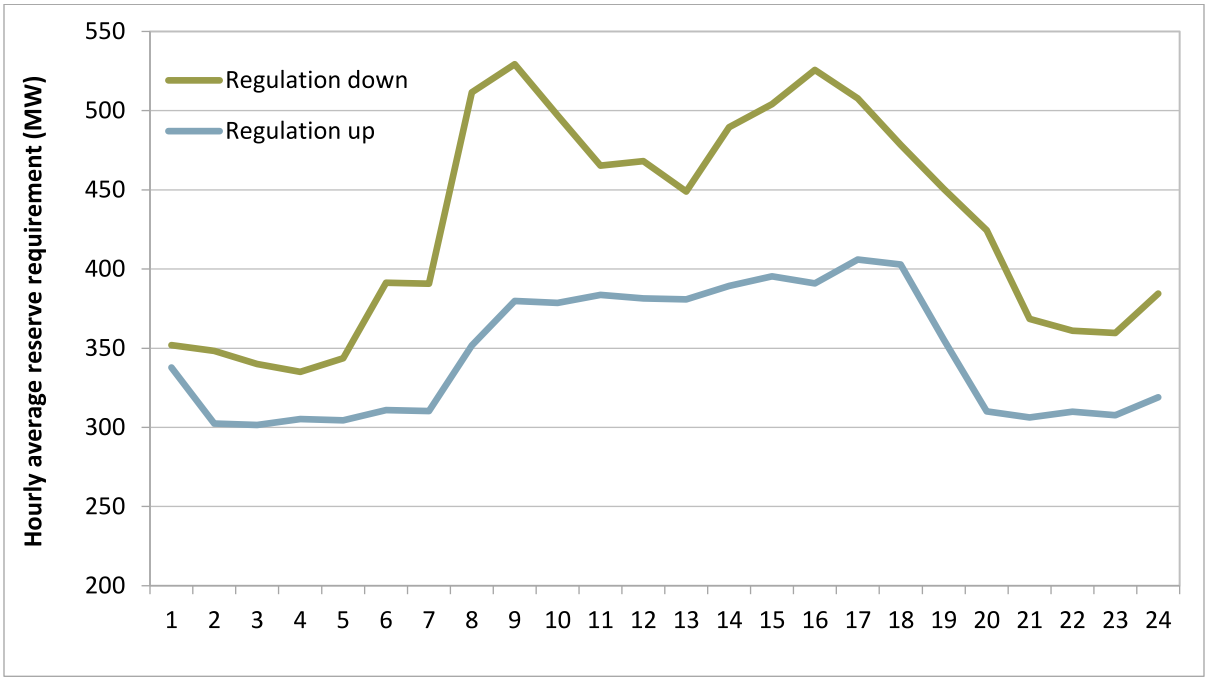
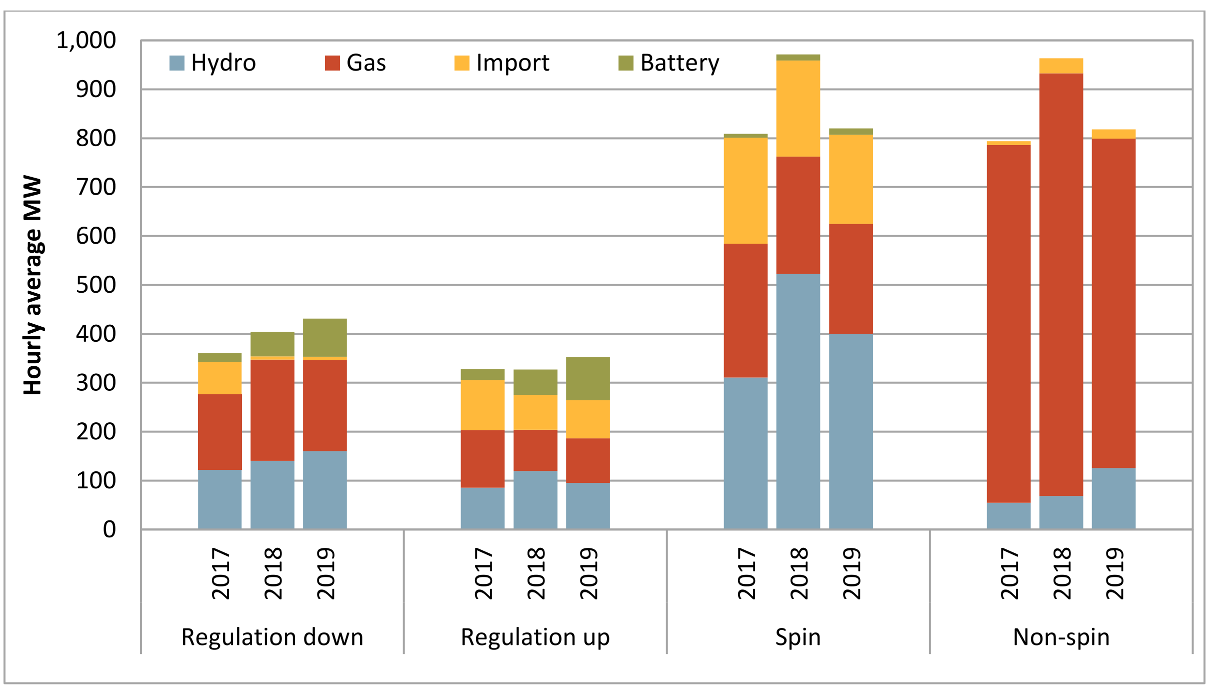


Figure 6.5 Procurement by internal resources and imports



Ancillary service procurement by fuel

Figure 6.5 shows the portion of ancillary services procured by fuel type from 2017 through 2019. Ancillary service requirements are met by both internal resources and imports (tie generation). 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.

Total procurement of regulation in 2019 increased slightly compared to 2018. Total procurement of spinning and non-spinning reserves decreased significantly from the previous year. The composition of ancillary service resources is characterized as follows:

- Compared to 2018, hydroelectric resources in 2019 provided a smaller quantity of ancillary services, but a similar portion of total ancillary services (32 percent). Average hourly procurement of ancillary services from hydroelectric resources decreased in 2019 to 780 MW. This is an 8 percent decrease from around 850 MW in 2018.
- Average hourly procurement of ancillary services from imports continued to decrease, from around 306 MW in the previous year to around 285 MW, or around 12 percent of total procurement.
- Gas-fired resources continued to provide the largest portion of ancillary services (49 percent). These resources provided 1,177 MW on average in 2019, down 16 percent from 1,395 MW in 2018. These resources provided the large majority of non-spinning reserves, as in previous years.
- Average hourly provision of ancillary services from limited energy storage resources, which includes batteries and other limited devices, continued to increase during 2019. Average hourly procurement from these resources for regulation increased from around 101 MW in 2018 to 166 MW in 2019, or around 21 percent of regulation requirements.
- In June 2019, the first solar resource was certified and began receiving awards for ancillary services for spinning reserve. Overall for the year, the procurement of ancillary services from solar resources was extremely small and is therefore not depicted in Figure 6.5.

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 6.6 and Figure 6.7 show the weighted average market clearing prices for each ancillary service product by quarter in the day-ahead and real-time markets during 2018 and 2019, weighted by the quantity settled.[168]

As shown in Figure 6.6, weighted average day-ahead prices for spinning and non-spinning reserves decreased from 2018 to 2019, consistent with lower requirements.

As shown in Figure 6.7, weighted average real-time prices for ancillary services increased in the second quarter. However, overall real-time costs for ancillary services continued to be very low relative to day-

[168] Values reported here differ slightly from the previous year due to an update in the data source.

ahead costs as only incremental real-time awards are settled at the 15-minute market price. As a result, real-time ancillary service costs accounted for only 12 percent of total costs during the year.

Figure 6.6 Day-ahead ancillary service market clearing prices

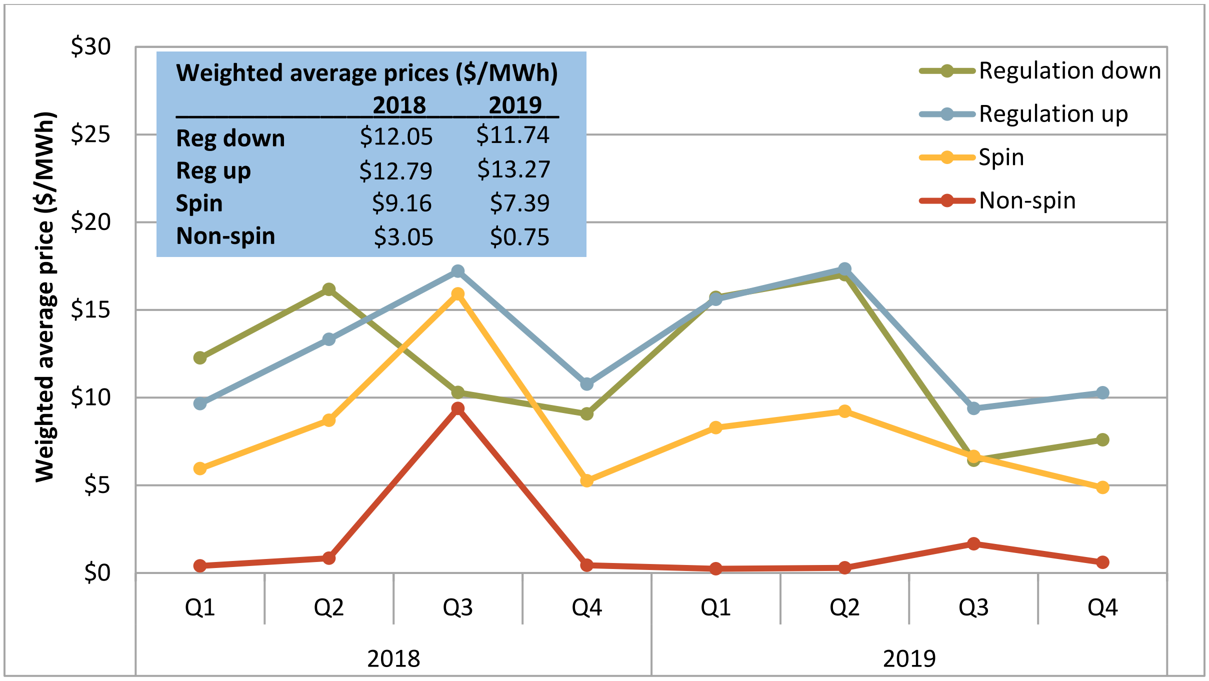
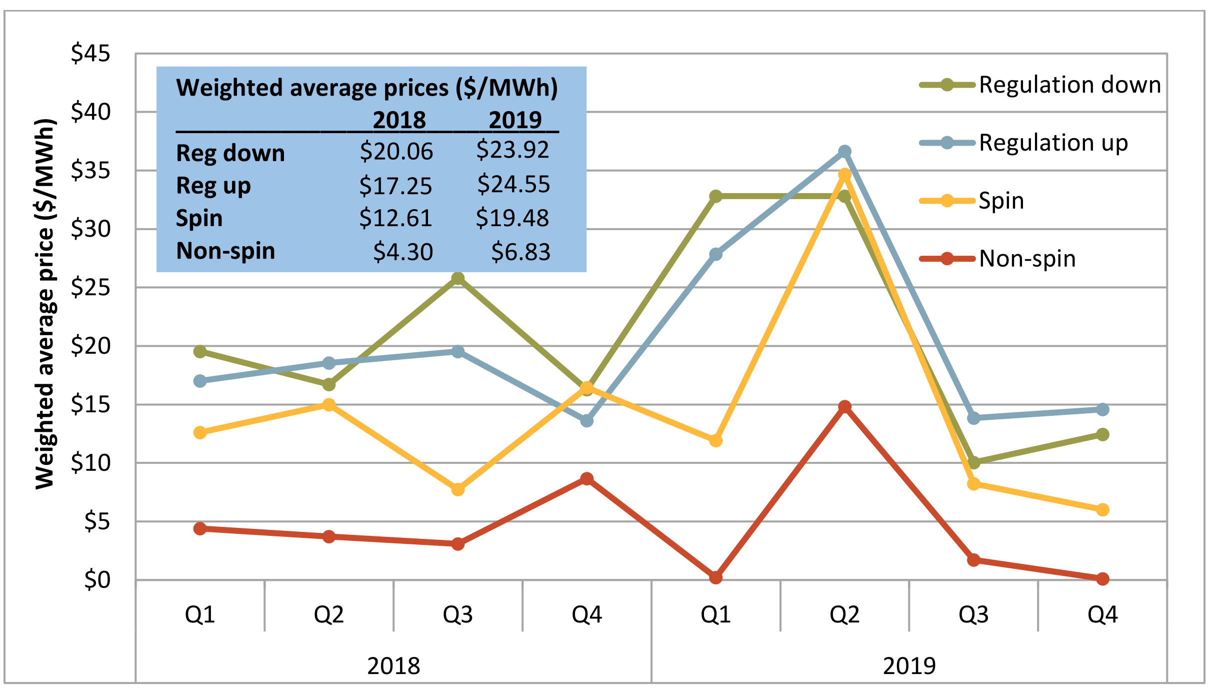


Figure 6.7 Real-time ancillary service market clearing prices



6.4 Ancillary service scarcity

Ancillary service scarcity pricing occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, 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.

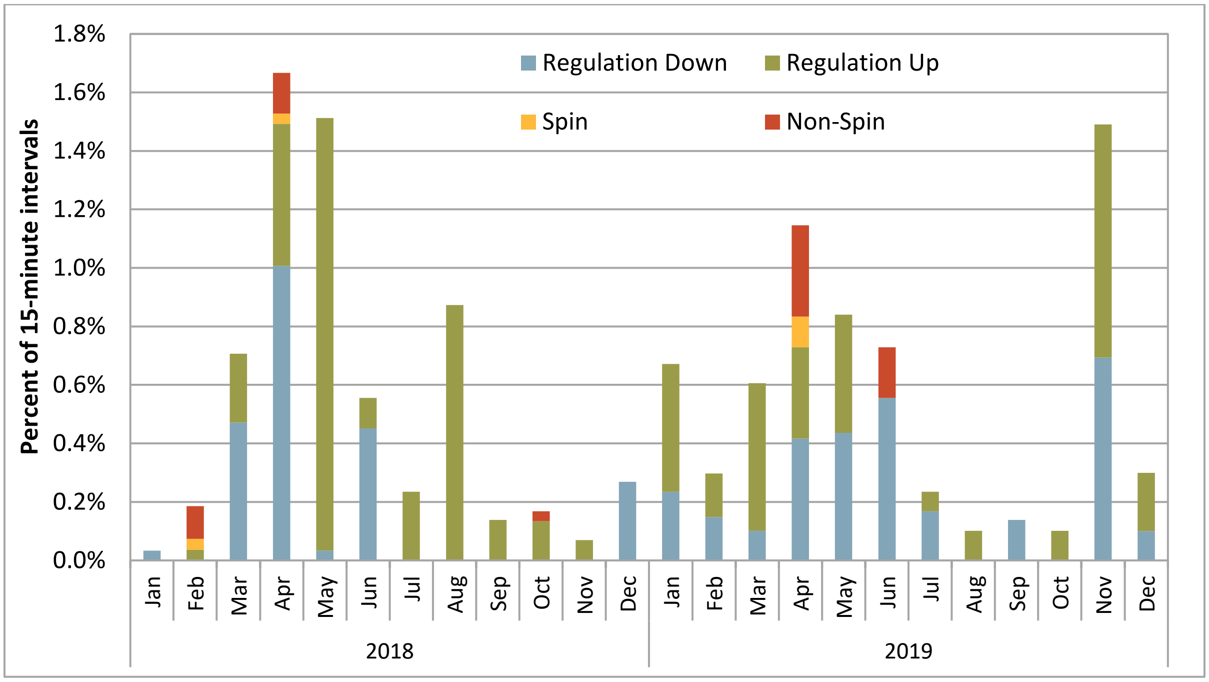
Figure 6.8 shows the monthly frequency of ancillary service scarcities in the 15-minute market by type. Similar to the previous year, there were no day-ahead market ancillary service scarcities during 2019. However, there were over 194 valid scarcity intervals in the 15-minute market with the most occurring in November.[169] In comparison, there were 189 instances during 2018 and 54 instances in 2017. During 2019, 46 percent of the scarcity intervals were for regulation up and 45 percent were for regulation down. By region, around 56 percent of scarcity events occurred in the expanded South of Path 26 region, 34 percent in the expanded system region, and 10 percent in the North of Path 26 region.

Ancillary services scheduled in the day-ahead market can be capped in real-time at telemetry limits submitted by the plant, which can be as little as a fraction of a megawatt less than the day-ahead schedule. That shortfall must then be replaced by other units to meet ancillary service requirements in the real-time market. However, it can often be economic to relax the requirement in this scenario at the scarcity price in lieu of committing a unit or moving a unit to a higher bid segment. This is because the majority of ancillary services are settled at the day-ahead market price with only incremental real-time awards settled at the 15-minute market price. As a result, most of the ancillary service scarcities in 2019 were small, with around 53 percent of these under 1 MW and 76 percent under 5 MW.

The slight increase in scarcity events in 2019 over 2018 is the continuation of a dramatic increase in real-time scarcity events from 2017 associated with a combination of two factors: (1) modifications to the ancillary service requirements and (2) observed changes of available capacity between the day-ahead and 15-minute markets. Higher operating reserve requirements and the enforcement of a North of Path 26 sub-regional requirement in 2018 increased demand for regionally limited supply to meet ancillary service requirements. The majority of scarcity events were triggered by decreases in available ancillary services in real-time from schedules in the day-ahead market.

[169] There were 24 ancillary service scarcities across real-time intervals on November 20. This was the result of manually blocked ancillary service awards, which were blocked in the real-time market but not in the day-ahead market for this day. This led to a shortage of regulation in real-time.

Figure 6.8 Frequency of ancillary service scarcities (15-minute market)



6.5 Ancillary service compliance testing

Resources may be subject to two types of testing: performance audits and compliance tests. A performance audit occurs when a resource is flagged for failing to meet dispatch during a contingency run. The compliance test is an unannounced test when a resource is called upon to produce energy at a time when it is scheduled to hold reserves. Failing either of these tests results in a warning notice. Failing a second test while a warning is in effect will immediately disqualify the resource from providing the concerned ancillary service. In addition, payments that were made to the resource for the impacted ancillary service will be rescinded.[170]

During 2019, the ISO performed a total of 163 performance audits and unannounced compliance tests for resources with spinning or non-spinning reserves, an increase from the 145 tests performed in 2018. Resources failed about 20 percent of these tests, a failure rate comparable to 2018. Four failures occurred during a period when a warning notice for the resource was in effect, resulting in disqualification of these units for the concerned ancillary service.

The ISO adopted a new monthly process for performance audits of regulation, starting in February 2020. A resource providing regulation must pass at least 90 percent of qualifying tests in a month to pass, where each individual test requires the unit to reach an output threshold within the test period. Failing the monthly performance audit results in a warning. Failing a second test while a warning is in effect will immediately decertify the resource from providing the ancillary service.

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170 For more information about the ISO's ancillary service testing procedures including updates to regulation performance audits, see Operating Procedure 5370: http://www.caiso.com/Documents/5370.pdf

7 Market competitiveness and mitigation

This chapter assesses the competitiveness of the ISO's energy markets, local capacity areas, and the impact and effectiveness of various market power mitigation provisions. Key findings include the following:

- **Overall prices in the ISO energy markets in 2019 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 cost.[171]
- **The day-ahead energy market, which accounts for most of the total wholesale market, remained competitive during most hours in 2019** and was structurally competitive relative to 2017 and 2018. Lower loads and high rates of low cost renewable production were factors that contributed to competitive conditions and a reduction in potentially non-competitive hours in 2019 relative to the previous two years.
- **The market for capacity needed to meet local resource adequacy requirements was structurally uncompetitive in all local areas**. In the day-ahead and real-time energy markets, the potential for local market power is mitigated through bid mitigation procedures.
- **The dynamic path assessment used to trigger local market power mitigation accurately identified non-competitive constraints** in the day-ahead and real-time markets in 2019. This automated test is incorporated in the market software to determine the structural competitiveness of transmission constraints based on actual system and market conditions in each interval.
- **In the ISO, rates of day-ahead mitigation increased significantly** beginning in the second quarter of 2019 relative to 2018. The percent of constraints identified as non-competitive also increased relative to 2018 due to an increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers.
- **The ISO implemented an enhancement eliminating carryover mitigation in the real-time market in November 2019.** Following this, rates of mitigation fell in the Western EIM and were similar to 2018 levels in the ISO.
- **Despite increased rates of mitigation, fewer day-ahead bids were lowered due to mitigation** than in 2018. Most resources subject to mitigation submitted competitive offer prices, so that a very low portion of bids were lowered as a result of the bid mitigation process; bids for an average of about 170 MW were changed in 2019 compared to 193 MW in 2018. Day-ahead dispatch instructions from bid mitigation increased by about 16 MW per hour on average in 2019, compared to 22 MW per hour in 2018.
- **Capacity with bids lowered by mitigation in the 15-minute market also remained low**, averaging 56 MW per hour in the ISO and 221 MW per hour in the EIM. In the 5-minute market, capacity with bids lowered by mitigation averaged 103 MW per hour in the ISO and 220 MW in the EIM.
- **The above-market costs associated with exceptional dispatches decreased to $29 million** although the volume of exceptional dispatch increased. Although less than the $52 million cost in 2018,

171 Further information on DMM's estimation of overall market competitiveness is available in Section 2.2.

above-market costs exceeded both $20.6 million in 2017 and $10.7 million in 2016. The majority of the above-market cost for these exceptional dispatches was associated with commitments to run at minimum operating level, rather than for additional energy above minimum levels.

- **Local market power mitigation of exceptional dispatches for energy played a significant role** in limiting above-market costs in 2019, reducing above-market costs by about $8.3 million.
- **ISO operators started to issue "RA Max" exceptional dispatches** to the maximum of resource adequacy contracts in the third quarter. These exceptional dispatches are issued to increase ramping capacity available to meet the evening net load ramp and respond to other uncertainties in real-time, the same issues that the flexible ramping product is designed to address. DMM has recommended that the ISO take steps to change market rules so that RA Max exceptional dispatches are subject to bid mitigation, because there is a strong potential for suppliers to exercise market power and raise bids substantially over marginal cost.
- **A new default energy bid option, the hydro default energy bid, became available in November.** This option, offered to eligible hydroelectric generation resources within the ISO and EIM, incorporates opportunity costs for hydro resources with storage capability. Only a small amount of eligible capacity selected the new hydro option in 2019.
- **Opportunity cost adders increased default energy bid and commitment cost bid caps** with implementation of the commitment cost enhancements phase 3 initiative in April. Qualifying resources provided a significant amount of resource adequacy capacity in 2019. Between May and December, these resources accounted for 25 percent of local capacity and 27 percent of flexible capacity on average.
- **Despite additional headroom provided by opportunity costs, the percent of capacity bidding at or near commitment cost bid caps increased in 2019**. In the day-ahead market, about 38 percent of capacity submitted start-up bids at or near the proxy cost cap in 2019 compared to 33 percent in 2018. About 35 percent of the minimum load capacity now bids at or near the cap compared to 20 percent prior to the third quarter of 2018.

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.[172] 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.

7.1.1 Day-ahead system energy

The values presented below include several refinements with how the RSI was calculated relative to previous annual reports. These include:

- Use of day-ahead input bids for physical generating resources (adjusted for outages and de-rates) instead of post-processed bids used in the final market software optimization (or output bids);
- Accounting for losses (typically increasing demand by 2 to 3 percent);
- Including self-scheduled exports as demand (combined with the day-ahead load forecast plus upward ancillary service requirements and transmission losses);
- Including ancillary services bids in excess of energy bids to account for this additional supply available to meet ancillary service requirements in the day-ahead market;
- Exclusion of CPUC jurisdictional investor-owned utilities as potentially pivotal suppliers;
- Accounting for the maximum availability of non-pivotal imports offered relative to import transmission constraint limits (the end of this section provides additional details on this); and
- As in prior DMM analyses, virtual bids are excluded.

During 2019, DMM has observed fewer hours with an RSI less than one relative to the previous two years. Table 7.1 shows the annual number of hours with a residual supply index ratio less than one since 2016, based on the assumptions listed above. Figure 7.1 shows the same information graphically by quarter. For 2019, the residual supply index with the three largest suppliers removed (RSI_3) was less than one during 145 hours, and the index was less than one during 38 hours with the two largest suppliers removed (RSI_2). There were no hours in 2019 with the index less than one and the largest single supplier removed. Lower loads and high rates of low cost renewable production were factors that contributed to competitive conditions and a reduction in potentially non-competitive hours in 2019 relative to the previous two years.

2019 was structurally competitive relative to 2017 and 2018. Figure 7.2 shows the lowest 500 RSI_3 values for each year. Overall, the figure shows greater structural competitiveness during 2019 relative to the

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172 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.

previous two years. At the bottom end of the curve, during the hours with the lowest residual supply index ratios, 2019 was higher than in 2018 and 2017, and similar to that of 2016. This indicates greater structural competitiveness from the previous two years in the least competitive hours. The hourly RSI_3 value was around 0.87 at its lowest in 2019, compared to around 0.75 in 2018, 0.79 in 2017, and 0.86 in 2016. Between the bottom 500th and 250th RSI hours, 2019 was similar to 2017.

Table 7.1 Hours with residual supply index less than one by year

Year	RSI_1	RSI_2	RSI_3
2016	9	54	96
2017	64	136	197
2018	35	114	336
2019	0	38	145

Figure 7.1 Hours with residual supply index less than one by quarter

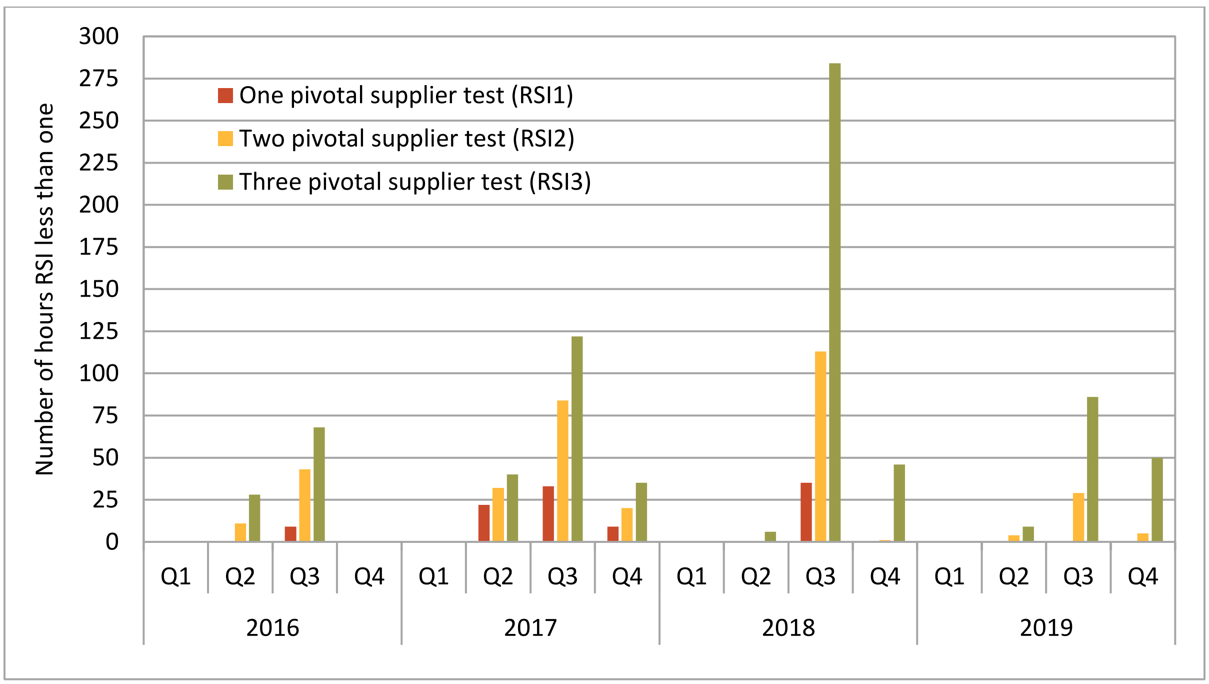
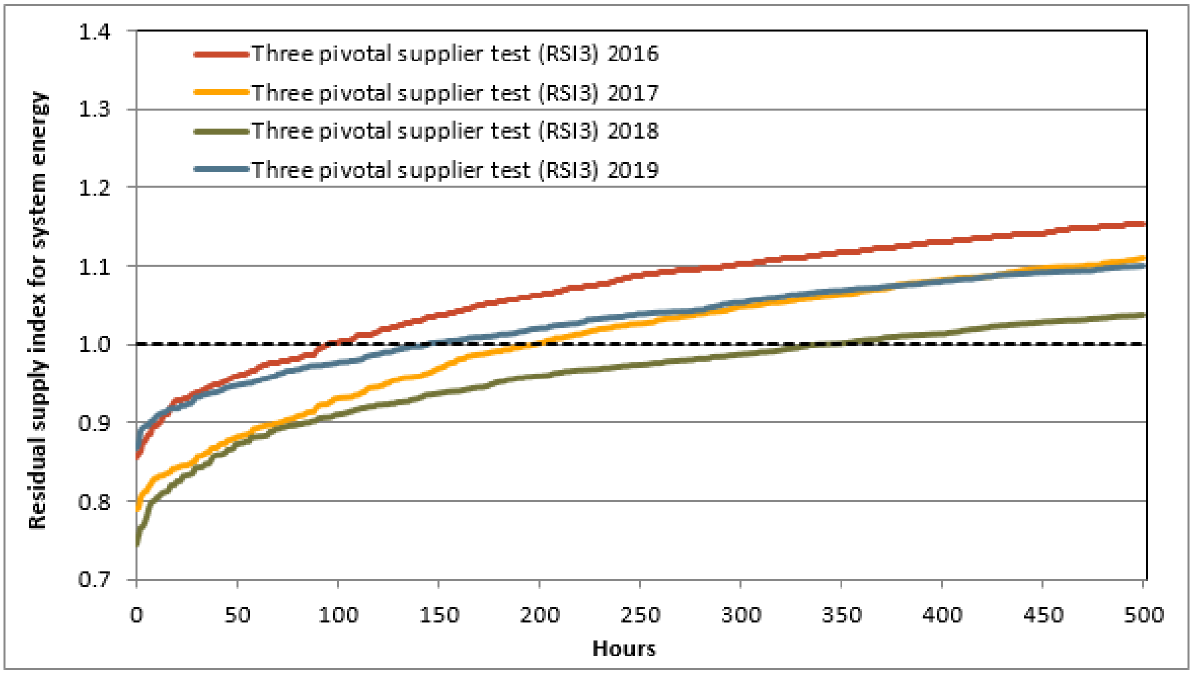


Figure 7.2 Residual supply index with largest three suppliers excluded (RSI_3) – lowest 500 hours

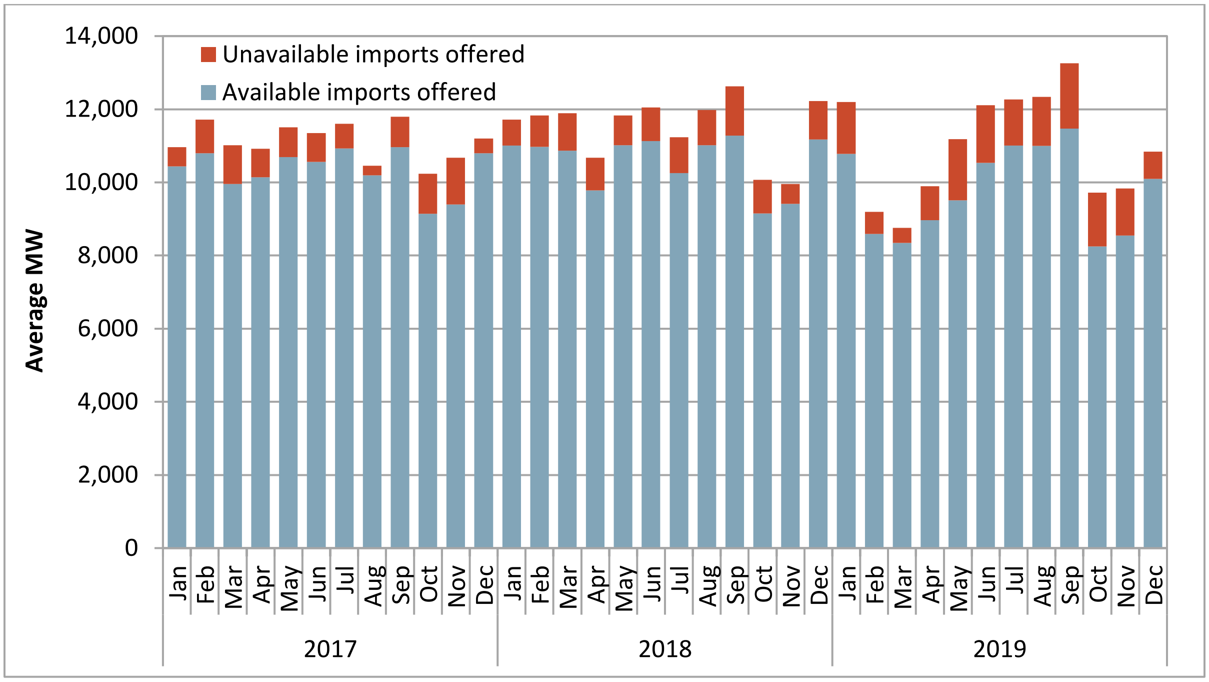


In June 2019, DMM presented residual supply index results showing 272 hours during 2018 with a residual supply index less than one with the three largest suppliers removed.[173] The only change since that analysis is a refinement to account for the maximum availability of non-pivotal imports offered relative to import transmission constraint limits. To illustrate this distinction, Figure 7.3 shows the average hourly megawatts of all imports offered in the day-ahead market, and the maximum portion that is feasible relative to the applicable intertie scheduling limits.[174] After accounting for this factor, DMM calculated 336 hours during 2018 with a residual supply index less than one.

173 DMM presentation on Analysis on System Market Power, June 7, 2019: http://www.caiso.com/Documents/Presentation-AnalysisOfSystemLevelMarketPowerDMM-June7_2019.pdf

174 The highest amounts of imports offered is derived using only self-scheduled exports as counter-flow and maximizing imports relative to corresponding intertie constraint or scheduling limits.

Figure 7.3 Day-ahead market imports offered and transmission availability



7.1.2 Local capacity requirements

The ISO has defined 10 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 most local capacity areas.

Table 7.2 provides a summary of the residual supply index for major local capacity areas in which the total local resource adequacy requirement exceeds capacity held by load serving entities. These areas have a net non-load serving entity capacity requirement. 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 though bilateral contracts. For this analysis, we assume that all capacity scheduled 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.[175]

Table 7.2 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 all local capacity areas with a net non-load serving entity local capacity requirement. In some areas, at least one supplier

175 This analysis assumes load serving entities show resources at their net qualifying capacity on resource adequacy supply plans. However, based on actual resource availability, entities may show resources at less than net qualifying capacity values in any given month. Therefore, this analysis is likely a conservative assessment of competitiveness in local areas.

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.

Key finding of this analysis include the following:

- The North Coast/North Bay, Sierra, Stockton, LA Basin, and San Diego/Imperial Valley local areas are not structurally competitive because there is at least one supplier that is pivotal and controls a significant portion of capacity needed to meet local requirements.
- The Greater Bay local area is not structurally competitive under a two pivotal supplier test.
- Local capacity requirements for the Big Creek/Ventura local area increased from 2018 such that supply controlled by load serving entities no longer covered the local area requirement. The Big Creek/Ventura local area is not structurally competitive under a three pivotal supplier test.

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.

These sub-area requirements are not reflected 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, the ISO may need to procure capacity from the unit using the backstop procurement authority under the capacity procurement mechanism of the ISO tariff.[176]

Table 7.2 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 TAC area							
Big Creek/Ventura	37	2,364	63.92	22.13	1.44	0.50	0
Greater Bay	1,010	3,631	3.59	1.55	0.38	0.17	0
North Coast/North Bay	560	713	1.27	0.02	0.01	0.00	1
Sierra	477	336	0.70	0.22	0.02	0.02	All*
Stockton	162	36	0.22	0.11	0.00	0.00	All*
SCE TAC area							
LA Basin	3,346	4,948	1.48	0.34	0.24	0.16	1
San Diego/Imperial Valley	782	1,063	1.36	0.60	0.19	0.06	2

*Available capacity is insufficient to meet the LCA requirement; All supply is needed to contribute toward the LCA requirement

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

176 For further information on the capacity procurement mechanism, see Section 10.5.

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 make additional supply available to meet load in the local area plays an important role in determining where local market power exists.

The ISO's 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 indicates local market power and resources that can supply counter-flow to a non-competitive constraint may be subject to bid mitigation.

7.2.1 Accuracy of transmission congestion assessment in ISO

Evaluating the performance of the current mitigation procedures involves examining both the accuracy with which 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. Table 7.3 shows the framework DMM uses to quantify overall accuracy of mitigation procedures.

All constraint-intervals defined by the *consistent* group in Table 7.4 were congested in both the mitigation run and the market run. When congestion is *resolved in market run* this means that congestion occurs in the mitigation run but is resolved in the market run. In these cases, 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. As described later in this section, the frequency of such mitigation has been low in both the day-ahead and real-time markets under the current mitigation procedures.

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*. The dynamic competitive path assessment procedure does not evaluate uncongested constraints, and therefore does not establish the number of under-identified constraints that 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 7.3 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
Resolved in Market Run (congestion present in mitigation run, but resolved 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 following analysis 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 7.4 shows that 91 percent of congested constraint-hours were consistent in the mitigation and market runs in 2019, a 2 percent increase from 2018. Congestion was present in the mitigation run but resolved in the market run during 4 percent of constraint-hours, and under-identified during 5 percent of constraint-hours.

The percent of consistent and competitive intervals fell in both day-ahead and real-time markets as the percent of consistent and non-competitive constraints increased relative to 2018. The day-ahead percent of non-competitive constraints increased from 17 percent in 2018 to 32 percent in 2019. Non-competitive constraints increased relative to prior years due in part to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers.

If the proportion of competitive to non-competitive constraint-hours was the same for under-identified as for constraints with predicted congestion, then about 1.7 percent of congested constraint-hours may represent missed mitigation in 2019. This is a modest increase over the 1.2 percent share of congested constraint-hours with potential missed mitigation in the previous year.

Real-time market

On November 13, 2019, the ISO implemented changes to real-time market power mitigation procedures. These changes resulted from the local market power mitigation enhancements (LMPME) stakeholder process, and modified the way mitigation in one interval impacts mitigation of future intervals. While the 2019 data includes a limited number of days following implementation of these changes, the real-time local market power mitigation results presented in Table 7.4 are very similar to results from 2018.

Results in the second panel of Table 7.4 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 90 percent of constraint-intervals, unchanged from 2018.

Under-identified congestion and congestion that was resolved in the market run were also the same in 2019 as in 2018. Under-identified congestion occurred in 3 percent of congested constraint-intervals and congestion that was resolved in the market run occurred in 6 percent of congested constraint-intervals.

Table 7.4 Consistency of congestion and competitiveness in local market power mitigation

Market	Congestion prediction	Competitive # constraint intervals	Competitive %	Non-competitive # constraint intervals	Non-competitive %	Total # constraint intervals	Total %
Day-ahead	Consistent	22,643	61%	11,150	30%	33,793	91%
	Resolved in Market Run	843	2%	662	2%	1,505	4%
	Under-identified	---	---	---	---	1,893	5%
	Total					**37,191**	**100%**
15-minute	Consistent	43,716	69%	13,330	21%	57,046	90%
	Resolved in Market Run	2,702	4%	1,336	2%	4,038	6%
	Under-identified	---	---	---	---	2,185	3%
	Total					**63,269**	**100%**
5-minute	Consistent	110,354	58%	48,346	25%	158,700	83%
	Resolved in Market Run	19,137	10%	9,875	5%	29,012	15%
	Under-identified	---	---	---	---	3,578	2%
	Total					**191,290**	**100%**

About 73 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, this would suggest that under-mitigation occurred in about 0.8 percent of the total number of congested constraint-intervals in 2019, up from 0.5 percent in 2018.

Results for the 5-minute market were largely similar in 2019 to 2018. The third panel in Table 7.4 shows that the assessment run predicted congestion consistently with the binding 5-minute market run in about 83 percent of constraint-intervals, up from 81 percent in 2018. Constraints that were congested in the mitigation run but resolved in the market run fell to 15 percent in 2019 from 17 percent in 2018. Under predicted constraint-intervals were the same as 2018 levels at about 2 percent of the total in the 5-minute market.

7.2.2 Accuracy of transmission congestion assessment for EIM transfer limits

Transfer constraints between balancing areas in the energy imbalance market work differently than flow-based constraints. However, the same 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, since there is currently a single pivotal suppler in each balancing area in the energy imbalance market. Results of this analysis for transfer constraints are shown in Table 7.5.

Table 7.5 Accuracy of congestion prediction on EIM transfer constraints

Market	Region	Consistent	Resolved in Market Run	Under identified
15-minute	PacifiCorp East	94%	4%	2%
	PacifiCorp West	93%	4%	3%
	Portland General Electric	91%	5%	4%
	Powerex	90%	6%	4%
	Puget Sound Energy	91%	5%	5%
	Idaho Power	92%	5%	4%
	NV Energy	93%	4%	3%
	Arizona Public Service	96%	3%	1%
	BANC	88%	7%	5%
5-minute	PacifiCorp East	58%	38%	4%
	PacifiCorp West	61%	32%	7%
	Portland General Electric	55%	37%	7%
	Powerex	72%	20%	8%
	Puget Sound Energy	63%	29%	8%
	Idaho Power	61%	32%	7%
	NV Energy	60%	34%	6%
	Arizona Public Service	50%	47%	3%
	BANC	63%	30%	7%

In the 15-minute market, congestion on transfer constraints across all areas was accurately predicted in 91 percent of congested constraint-intervals. As shown in Table 7.5, congestion on transfer constraints for each energy imbalance market area was predicted with a similar degree of accuracy, with 88 percent to 94 percent of congested constraint-intervals being congested in both runs. Overall, across all areas, 4 percent or fewer congested constraint-intervals were under-predicted, meaning that possible instances of unmitigated market power were very rare.

In the 5-minute market, the accuracy of predicting congestion on transfer constraints was generally consistent with 2018 levels.[177] As shown in the bottom half of Table 7.5, under prediction of congestion ranged from only 3 to 8 percent of congested constraint-intervals for different transfer constraints.

[177] Year-over-year comparison is to revised 2018 data reflecting an enhanced calculation approach for congestion prediction on transfer constraints. The same enhanced approach was used to calculate 2019 data presented in Table 7.5. The revised 2018 data do not differ significantly from that presented in DMM's 2018 annual report.

7.3 Local market power mitigation

This section provides an assessment of the frequency and impact of the automated local market power mitigation procedures in the ISO and Western EIM balancing authority areas. 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

In the day-ahead market, rates of mitigation increased significantly beginning in the second quarter of 2019 relative to 2018. This is due, in part, to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers. In the real-time market, for the ISO's balancing authority area, there was no significant change to the rates of mitigation that could be attributed to the enhancements implemented in November 2019. However, in the Western EIM balancing authority areas, the elimination of carryover mitigation appears to have reduced mitigation rates beginning November 2019.

Background

The ISO's automated local market power mitigation (LMPM) procedures have been enhanced in numerous ways since 2012 to more accurately identify and mitigate resources with the ability to exercise local market power in the day-ahead and real-time markets. The ISO proposed the following enhancements to the local market power mitigation process for implementation in November 2019:[178]

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

On September 30, 2019, FERC rejected the proposal to limit net exports by a Western EIM balancing authority area.[179] Subsequently, the ISO filed on October 30, 2019, a request for rehearing at FERC regarding the net export limit proposal.[180] The rest of the enhancements were implemented on

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

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

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

November 13, 2019. On June 18, 2020, FERC denied the request for rehearing but granted the motion for clarification.[181]

The impact on market prices of bids that were mitigated can only be assessed precisely by re-running the market software without bid mitigation. Currently, DMM does not have the ability to re-run the day-ahead and real-time market software under this scenario. Instead, DMM has developed a variety of metrics to estimate the frequency with which mitigation is triggered and the effect of this mitigation on each unit's energy bids and dispatch levels. These metrics identify bids lowered from mitigation each hour and estimate the additional energy dispatched from these price changes.[182]

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

Day-ahead market

As shown in Figure 7.4, beginning in the second quarter of 2019, the average incremental energy subject to mitigation increased significantly relative to 2018. This is due, in part, to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers.

- Bids for an average of 694 MW were subject to mitigation but not lowered in 2019, an increase from 373 MW in 2018.
- Bids for an average of about 170 MW were changed in 2019 compared to 193 MW in 2018.
- Figure 7.5 shows day-ahead dispatch instructions from bid mitigation increased by about 16 MW per hour in 2019, compared to 22 MW per hour in 2018. This potential increase in dispatch due to mitigation is concentrated mostly during peak hours in 2019, similar to 2018.

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181 FERC order denying rehearing and granting clarification, ER19-2347-001, June 18, 2020: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14869989

182 The methodology has been updated to show incremental energy instead of units that have been subject to automated bid mitigation. Prior to the local market power mitigation enhancements in November 2019, this metric also captures carryover mitigation (balance of hour mitigation) in 15-minute and 5-minute markets by comparing the market participant submitted bid at the top of each hour (in the 15-minute market) to the bid used in each interval of 15-minute and 5-minute market runs.

Figure 7.4 Average incremental energy mitigated in day-ahead market

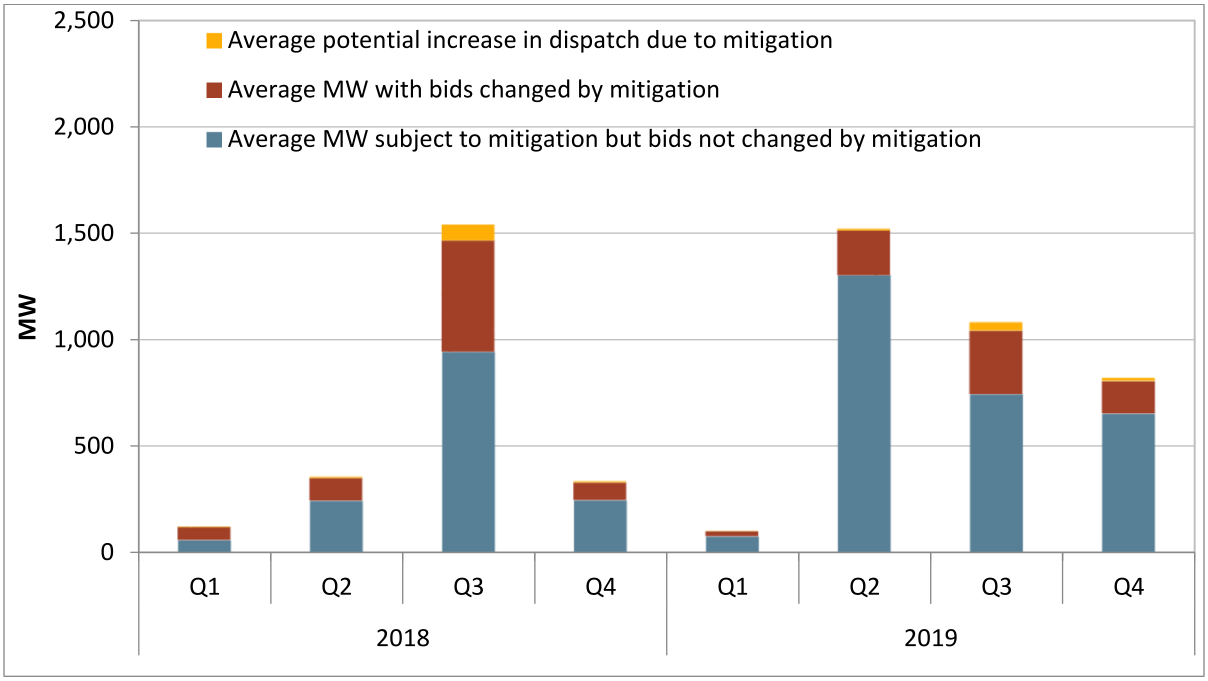
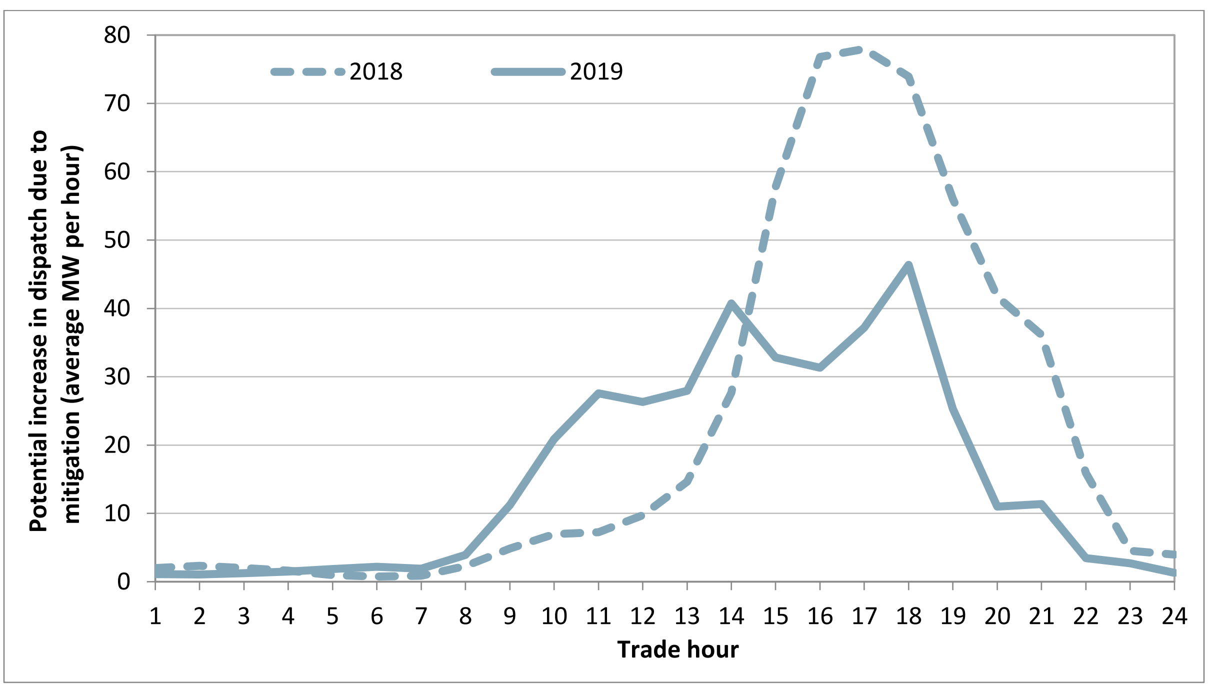


Figure 7.5 Potential increase in day-ahead dispatch due to mitigation (hourly averages)



Real-time market

Figure 7.6 through Figure 7.8 highlight the frequency and volume of 15-minute and 5-minute market mitigation in the ISO.

- As shown in these figures, average incremental energy subject to mitigation in the ISO is consistently higher in the 5-minute than in the 15-minute market.
- In the 15-minute market, bids for about 284 MW of incremental energy were subject to mitigation in 2019. Of this energy, bids for about 228 MW were not lowered compared to 56 MW which were lowered due to mitigation. Similarly, in the 5-minute market, bids for about 525 MW were unchanged due to mitigation compared to 103 MW which were lowered.
- On average, the number of 15-minute dispatch instructions potentially increased from bid mitigation was similar in 2019 compared to 2018. On the other hand, 5-minute dispatch instructions potentially increased from bid mitigation decreased to 22 MW per hour in 2019 compared to 40 MW per hour in 2018.

Figure 7.6 Average incremental energy mitigated in 15-minute real-time market (ISO)

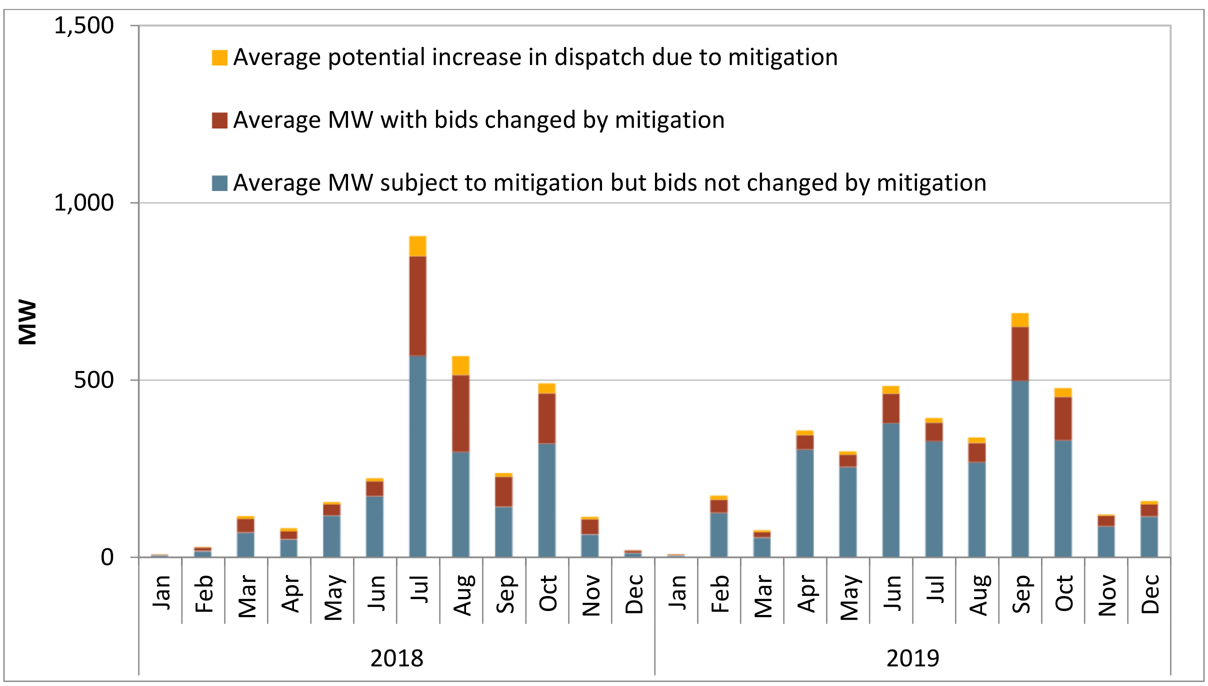


Figure 7.7 Average incremental energy mitigated in 5-minute real-time market (ISO)

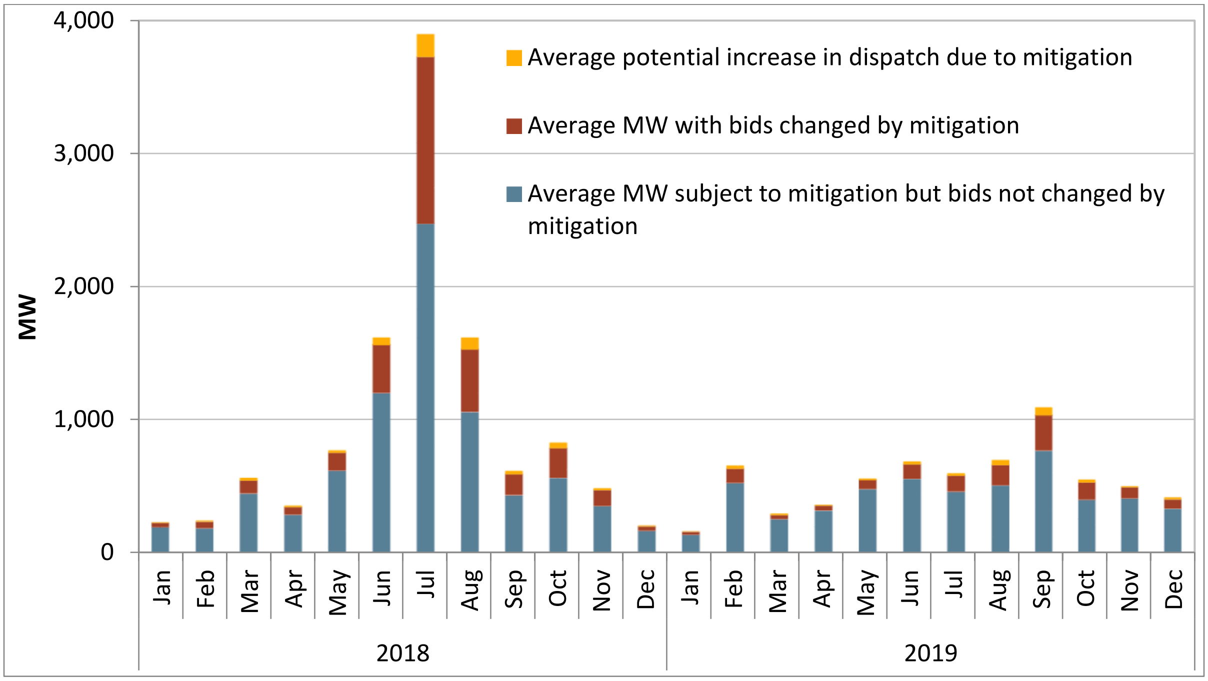


Figure 7.8 Potential increase in 15-minute and 5-minute dispatch due to mitigation (ISO)

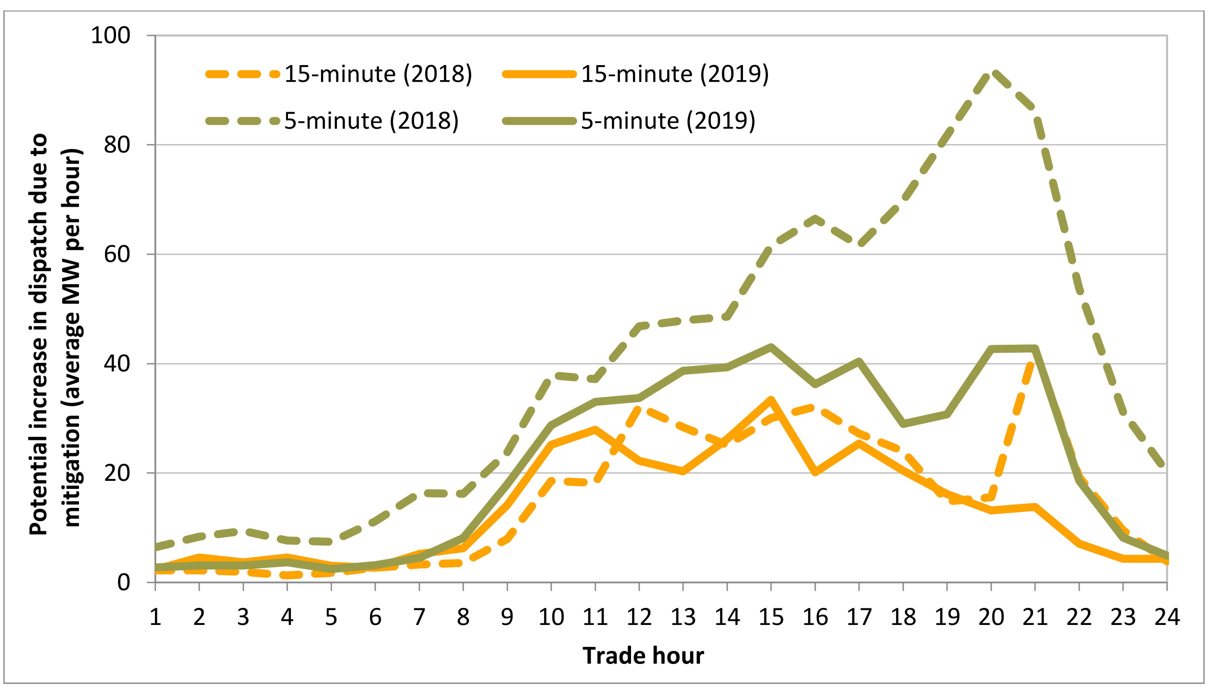


Figure 7.9 through Figure 7.11 highlight the frequency and volume of 15-minute and 5-minute market mitigation in all the balancing authority areas in the Western EIM:

- As shown in the figures, in the 15-minute market, bids for an average of 796 MW were subject to mitigation in 2019 compared to 611 MW in 2018. In the 5-minute market, bids for about 761 MW were subject to mitigation in 2019 compared to 645 MW in 2018.
- Of the energy that was subject to mitigation, in the 15-minute market, bids for about 575 MW were not changed due to mitigation compared to 221 MW which were lowered in 2019. Similarly, in the 5-minute market, bids for an average of 541 MW were not impacted by bid mitigation compared to 220 MW which were lowered in 2019.
- As shown in Figure 7.11, as a result of increased bid mitigation in 2019, the average megawatts potentially increased in both 15-minute and 5-minute markets also rose in the energy imbalance market areas.

Figure 7.9 Average incremental energy mitigated in 15-minute real-time market (Western EIM)

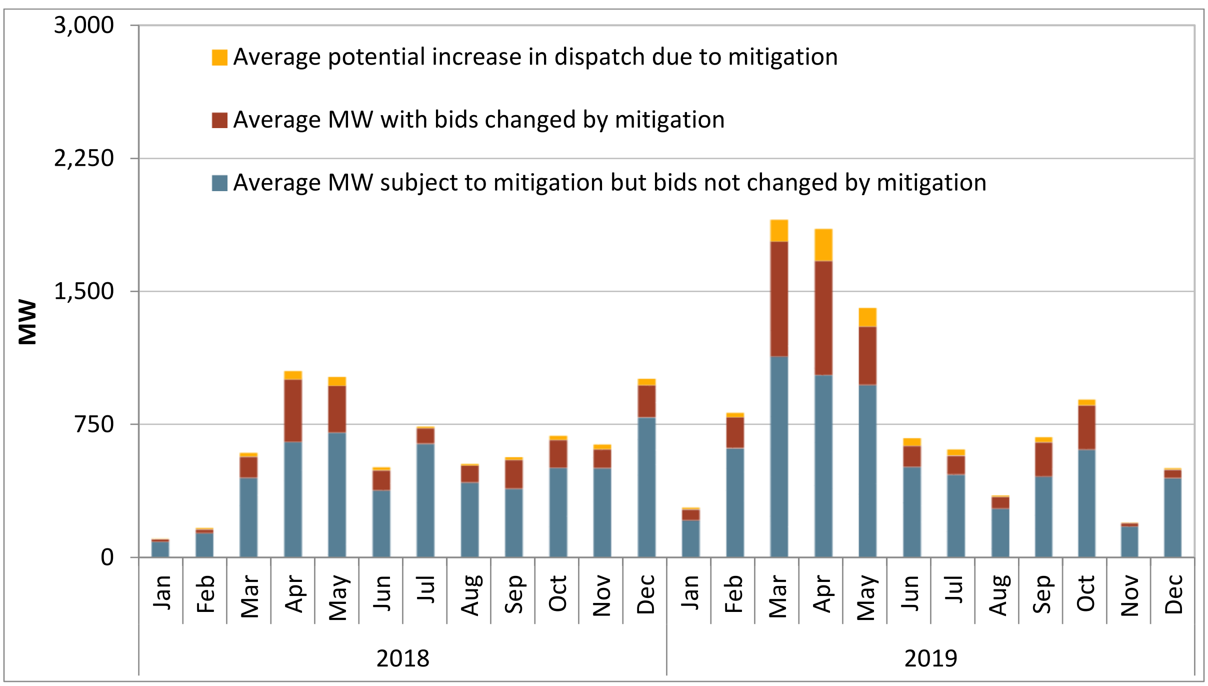


Figure 7.10 Average incremental energy mitigated in 5-minute real-time market (Western EIM)

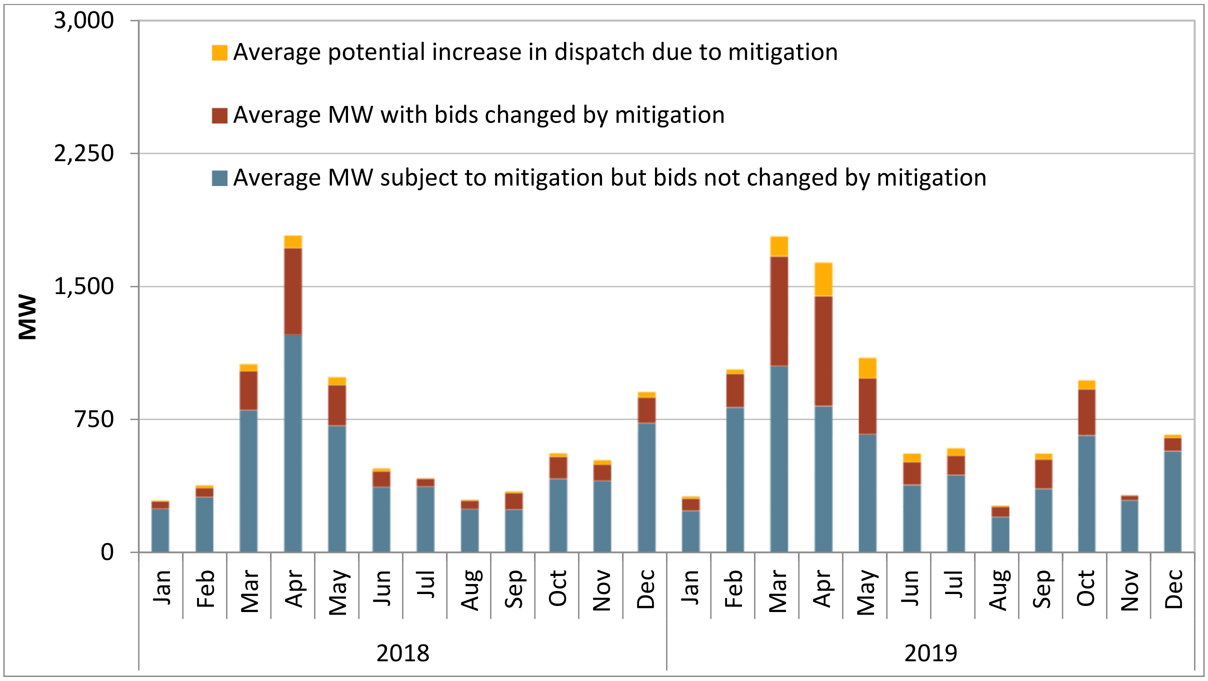
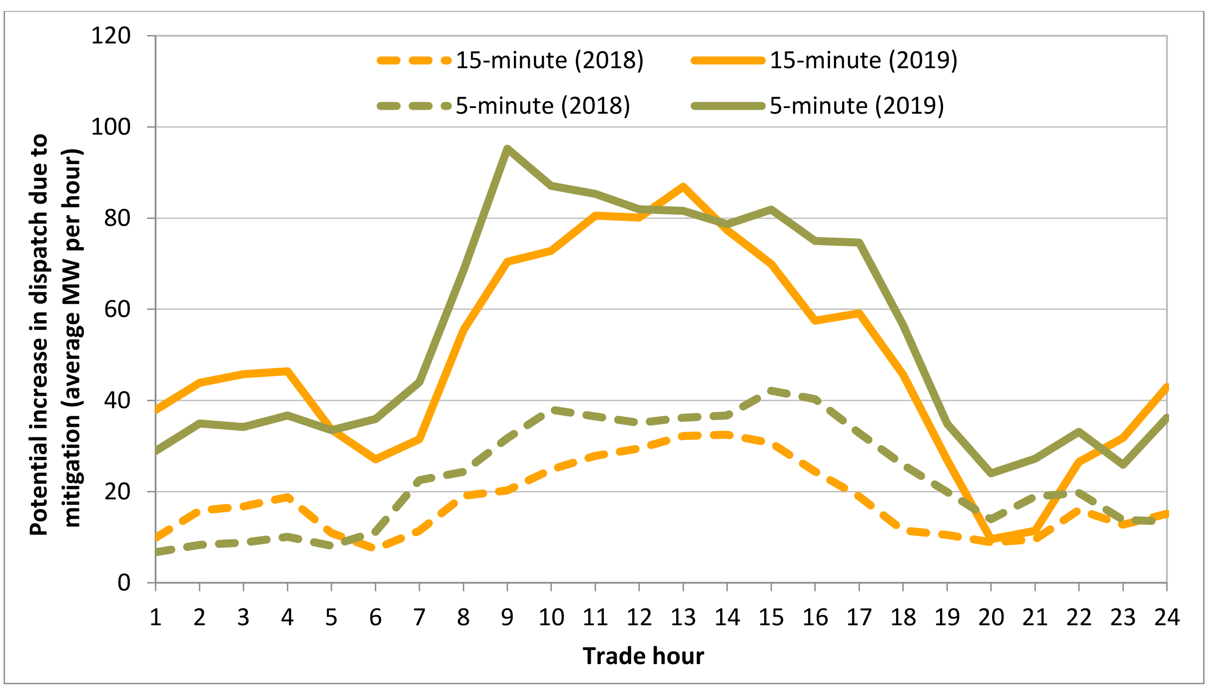


Figure 7.11 Potential increase in 15-minute and 5-minute dispatch due to mitigation (Western EIM)



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.[183] Total energy from exceptional dispatches increased in 2019 from an average of about 131 MW per hour to about 163 MW per hour. The above-market costs associated with these exceptional dispatches decreased, totaling $29 million in 2019 compared to $52 million in 2018. 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.

Commitment cost bids for units that are committed via exceptional dispatch are not subject to any additional mitigation beyond the commitment cost bid caps, which include 25 percent headroom above estimated start-up and minimum load costs. Exceptional dispatches for energy above minimum load are subject to mitigation if a grid operator indicates the 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*.

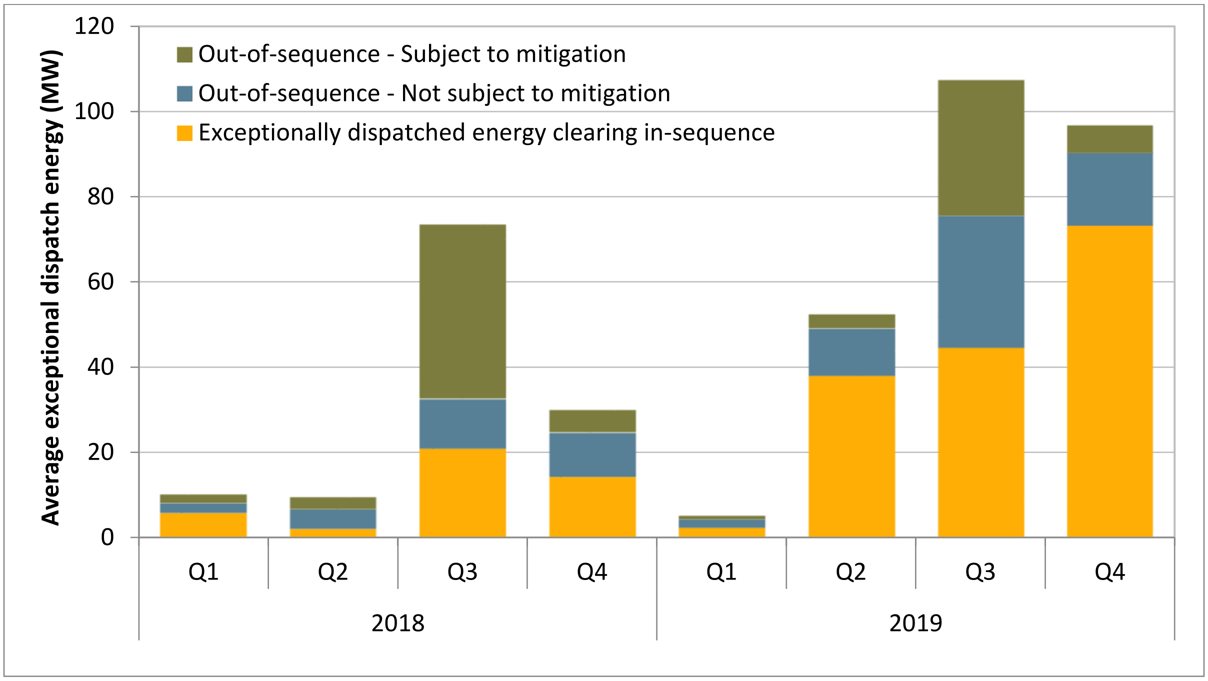
In 2019, local market power mitigation played a substantial role in limiting above-market costs for exceptional dispatches for energy, reducing these costs by $8.3 million.

Volume and percent of exceptional dispatches subject to mitigation

As shown in Figure 7.12, the overall volume of exceptional dispatch energy above minimum load rose in 2019 when compared to 2018. This increase was largely attributed to in-sequence exceptional dispatch energy as a result of unit testing exceptional dispatches, discussed in Chapter 9. Out-of-sequence energy is energy with bid prices or default energy bids above the market clearing price. Out-of-sequence exceptional dispatches not subject to mitigation doubled in 2019 compared to 2018. Out-of-sequence exceptional dispatches subject to mitigation decreased by about 17 percent in 2019 compared to 2018.

[183] A more detailed discussion of exceptional dispatches is provided in Section 9.1.

Figure 7.12 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.

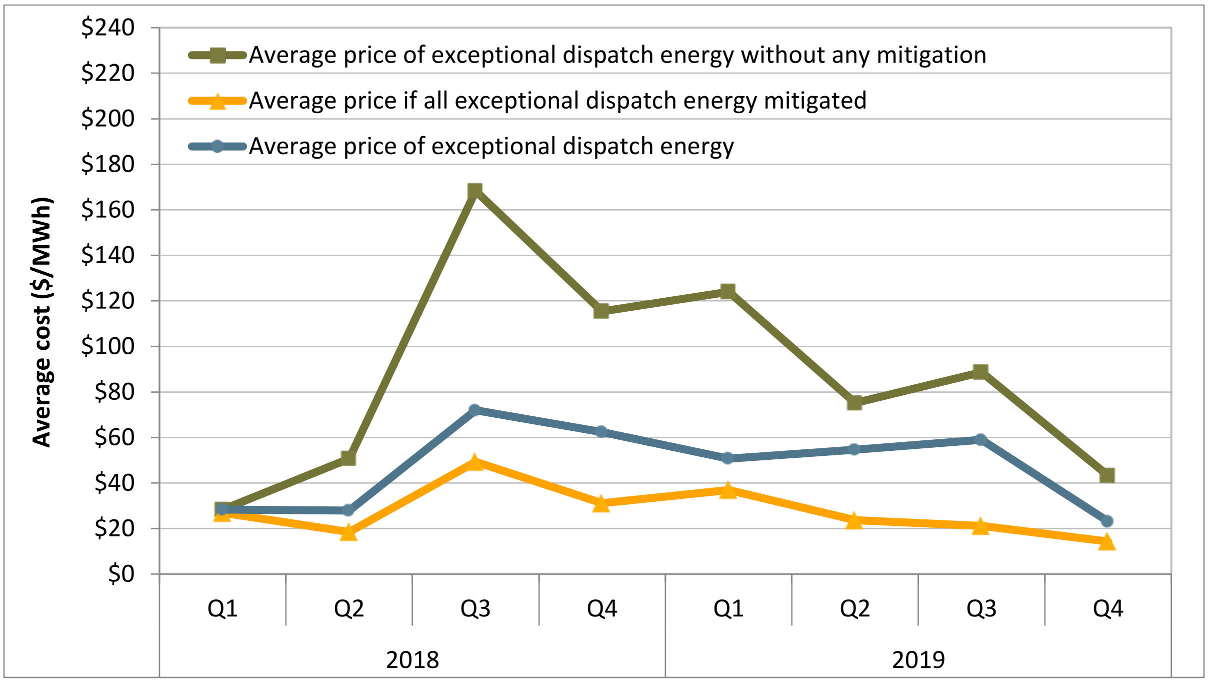
Using the value of out-of-sequence costs with the corresponding megawatt quantities of out-of-sequence exceptional dispatch energy, one can calculate the average price of out-of-sequence exceptional dispatch energy. This price is the amount per megawatt-hour by which out-of-sequence exceptional dispatch energy exceeds the locational marginal price.

Figure 7.13 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 7.13 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 7.13 shows, this price difference decreased in 2019 compared to 2018.

The yellow line in Figure 7.13 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 first quarter of 2019; however, average out-of-sequence energy was very small in that period. The impact from mitigation was likely more meaningful in the third quarter, although this amount decreased in 2019 compared to the same quarter in 2018.

The average price of out-of-sequence exceptional dispatch energy remained about the same in 2019 as in 2018 at $47/MWh. Out-of-sequence exceptional dispatch energy was highest during the second and third quarters in 2019, at $54/MWh and $59/MWh, respectively. The exceptional dispatches driving these values were largely due to software limitations of unit operating characteristics which cannot be factored completely in to the real-time market model.

Figure 7.13 Average prices for out-of-sequence exceptional dispatch energy



RA Max exceptional dispatches

Beginning in the third quarter of 2019, ISO operators started to issue exceptional dispatches to manually commit and dispatch resources to the maximum of their resource adequacy contracts. These are referred to as "RA Max" exceptional dispatches and are typically issued to a number of slow-ramping, gas generator resources located in the Los Angeles basin. The intention of RA Max exceptional dispatches is to increase the amount of ramping capacity available to meet the evening net load ramp and respond to other uncertainties in real-time. Thus, many of these exceptional dispatches are used to address the same issues that the flexible ramping product is designed to address.

RA Max exceptional dispatches totaled around 38,000 MWh in the third quarter, roughly 16 percent of all exceptional dispatch energy above minimum load. Exceptional dispatches to RA Max are not subject to energy bid mitigation, and are paid the higher of the unit's energy bid or the market price.[184] The total unmitigated RA Max exceptional dispatch energy costs were around $5.2 million, about $3.3 million

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[184] More information on exceptional dispatch mitigation can be found in Section 39.10 of ISO's tariff: http://www.caiso.com/Documents/Section39-MarketPowerMitigationProcedures-asof-Sep28-2019.pdf

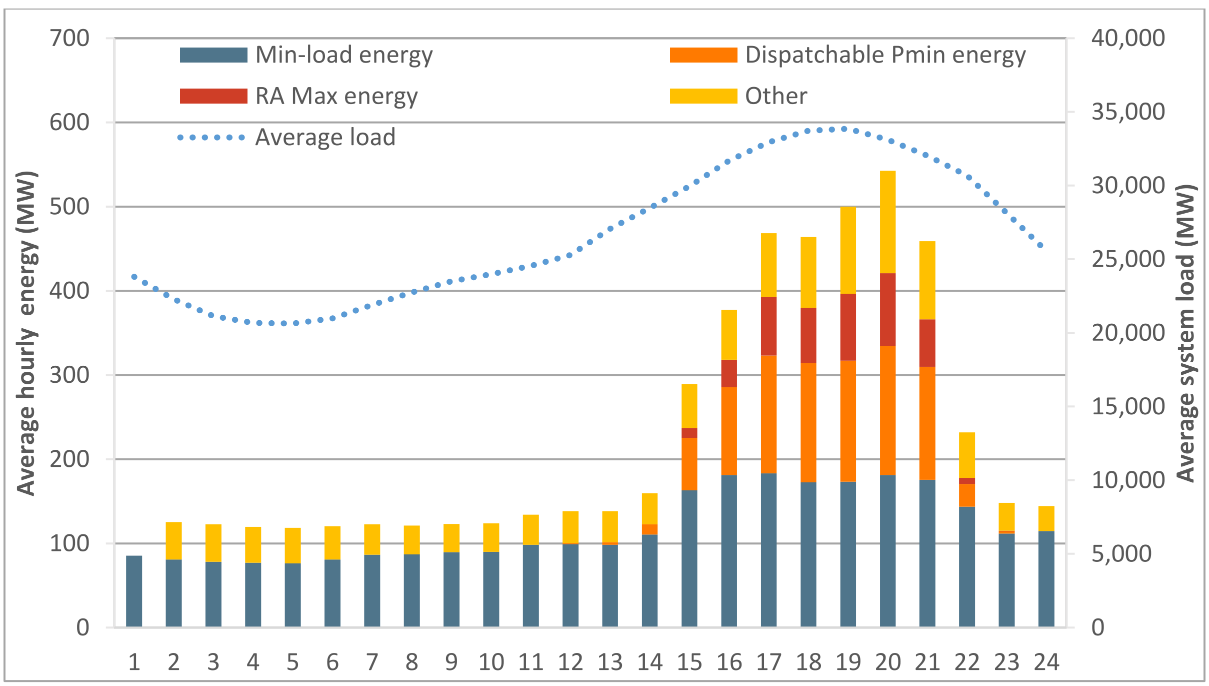
above market prices in the third quarter of 2019.[185] The average unmitigated price paid for these exceptional dispatches was about $150/MWh, compared to an average market price of about $55/MWh. If these exceptional dispatches were subject to bid mitigation, the average price paid for this energy would have been about $70/MWh. Moreover, about 98 percent of RA Max exceptional dispatches were issued to units controlled by a single supplier.

Exceptional dispatches for ramping energy

Figure 7.14 shows the average volume of energy from exceptional dispatches to gas-fired resources by hour in the third quarter of 2019. As shown in Figure 7.14:

- The average hourly minimum load energy from gas units committed via exceptional dispatch ranged from 100 MW during off-peak hours up to almost 200 MW in the peak ramping hours (blue bars).
- During the evening ramping hours, the ISO often starts some slower ramping gas units to their minimum dispatchable levels or dispatchable minimum load. Energy from these exceptional dispatches averaged about 120 MW per hour over the peak load hours of 17-22 (orange bars).
- RA Max exceptional dispatch hourly energy averaged about 70 MW over the peak load hours of 17-22 (red bars). As previously noted, these dispatches are exceptional dispatches to the maximum of a unit's resource adequacy contract, which is often set at a unit's maximum capacity.
- In the third quarter, energy from other exceptional dispatches averaged about 40 MW during off-peak hours and about 90 MW in the peak ramping hours (yellow bars).

Figure 7.14 Average hourly exceptional dispatch energy by type (July – September)



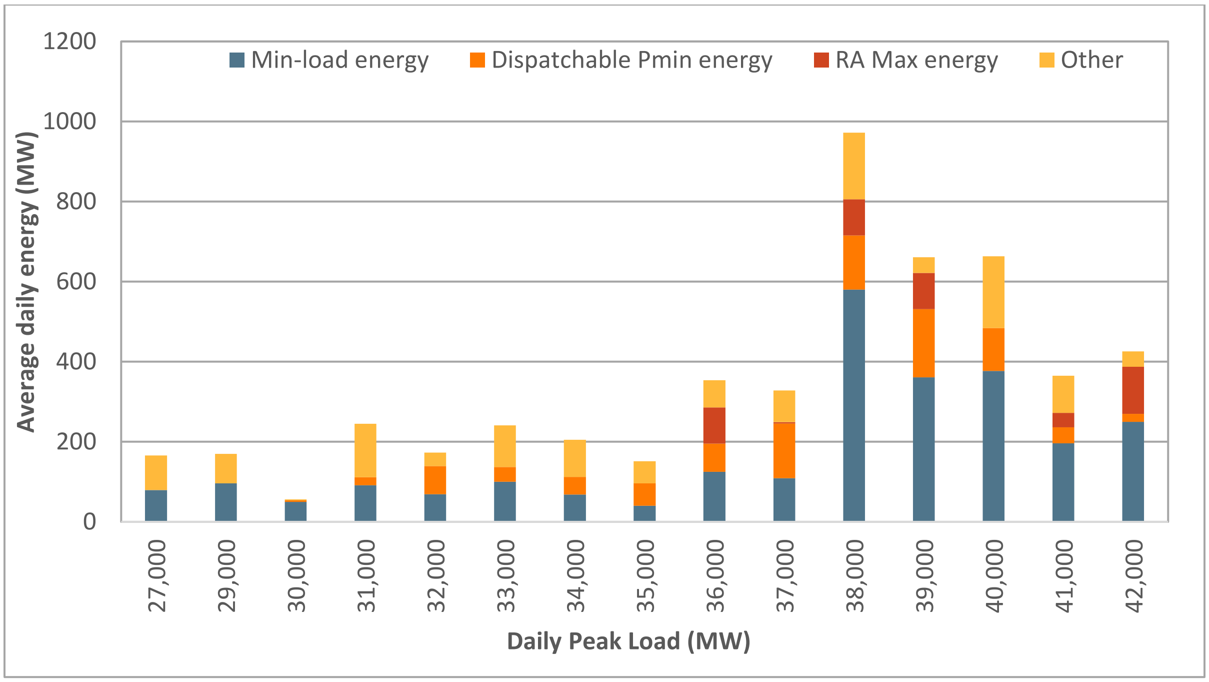
185 RA Max exceptional dispatches are reported for the third quarter of 2019 when they were most frequently issued. These exceptional dispatches continued in the fourth quarter to a lesser degree.

Exceptional dispatches by load level

Total energy from exceptional dispatches averaged nearly 100 MW during off-peak hours and about 450 MW in the peak ramping hours. However, the amount of exceptionally dispatched energy from gas units was much higher on days with higher peak loads.

As shown in Figure 7.15, on days with peak loads over 37,000 MW, total energy from exceptional dispatches often ranged from over 600 MW to almost 1,000 MW on some days. Additionally, RA Max exceptional dispatches were only issued on days with peak loads greater than 36,000 MW in the third quarter of 2019.

Figure 7.15 Average exceptional dispatch energy by peak load amount (July-September, hours ending 17-21)



DMM recommends mitigation for RA Max exceptional dispatches

DMM has recommended that the ISO should take steps to change market rules so that RA Max exceptional dispatches are subject to bid mitigation, since there is a strong potential for suppliers to exercise market power and raise bids substantially over marginal cost. Indicators of the need for mitigation of these exceptional dispatches include the following:

- First, about 98 percent of RA Max exceptional dispatches were issued to units controlled by a single supplier.
- Second, as illustrated in the prior section, the conditions under which the ISO is likely to issue RA Max exceptional dispatches should be highly predictable, with such exceptional dispatches occurring as loads reach 36,000 MW and above.

- Finally, the bid prices of units receiving RA Max exceptional dispatches have been uncompetitive, with an average price paid for these exceptional dispatches of about $150/MWh, compared to an average market price of about $55/MWh. If these exceptional dispatches were subject to bid mitigation and were paid the higher of the market price or their default energy bid, the average price paid for this energy would have been about $70/MWh.

The ISO has indicated it will monitor the frequency of RA Max exceptional dispatches and take actions if costs become excessive. The ISO has also indicated it will develop procedures to help ensure that RA Max exceptional dispatches are only issued when needed to ensure reliability.

7.4 Mitigated reference level changes

7.4.1 Opportunity costs

Overview

In early 2016, the ISO gained Board approval of commitment cost enhancements phase 3 (CCE3), an initiative to implement an opportunity cost methodology for use-limited resources that reflects eligible limitations to be used in commitment cost bids and variable cost default energy bids.[186] CCE3 was implemented in the second quarter of 2019 with the use of opportunity cost adders beginning in May. Resource use limits were based on registered exogenous limits (i.e., limits imposed on resources from outside parties, such as air quality regulation) as well as contractual limits.

Both DMM and the ISO believe that economic limits that originate from commercial power contracts are not appropriate for calculating opportunity cost adders. However, FERC approved the ISO's proposal to allow a three-year exemption that allows contractual limitations that were agreed upon before January 1, 2015, to contribute to opportunity cost adders.[187] DMM maintains that it is inefficient and inequitable to treat contractual limitations as actual physical or environmental limitations when calculating market optimization inputs.

About 35 percent of resources with start limitations reached or exceeded 90 percent of their limit at some point during the year. This included mostly gas units with contractual limitations as well as demand response resources. About 12 percent of resources with run-hour limitations reached or exceeded 90 percent of their limit during the year. This was almost entirely demand response resources. Finally, about 42 percent of resources with energy limitations reached or exceeded 90 percent of their limit during the year. These were all hydro units which were potentially capable of generating more energy than projected.

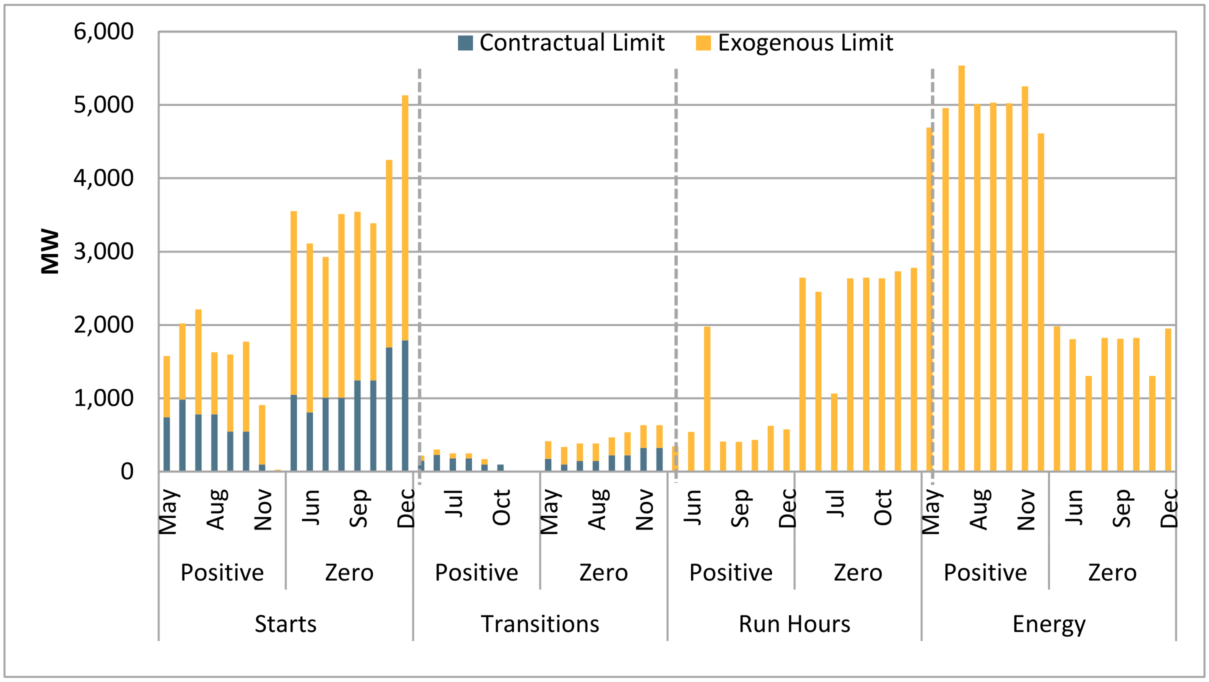
[186] *Commitment Cost Enhancements Phase 3 Draft Final Proposal*, February 17, 2016: http://www.caiso.com/Documents/DraftFinalProposal-CommitmentCostEnhancementsPhase3.pdf

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

Capacity associated with opportunity costs

Figure 7.16 shows the megawatt capacity associated with use-limited resources' start, run hour, and energy limit opportunity costs between May and December.[188] This capacity is categorized by whether the limit resulted in a non-zero opportunity cost (Positive OC) or an opportunity cost value of zero (Zero OC) as well as by whether the limit was contractual or exogenous.

Figure 7.16 Capacity from resources with use-limit opportunity costs



Positive opportunity costs associated with start limits included both contractual and exogenous limits in 2019. The capacity associated with start limits with positive opportunity costs averaged about 1,400 MW per month. About 38 percent of this capacity is restricted due to contractual limits. The capacity associated with multi-stage generating resources' positive start opportunity costs associated with transitions averaged about 160 MW. About 72 percent of this capacity is restricted due to contractual limits. Resources with positive start and transition opportunity costs over this period were almost entirely gas units.

Positive opportunity costs related to run hour and energy limits were not contractual limits. This capacity averaged about 670 MW per month for run hours.[189] The average monthly capacity associated

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

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

with energy limits with positive opportunity costs was about 5,000 MW per month.[190] Resources with positive run hour opportunity costs were mostly gas units with some demand response units, while resources with positive energy opportunity costs were mostly hydro units with some gas units.

There was also a significant amount of capacity that had zero opportunity costs in 2019. This capacity comes from resources that qualified for opportunity cost calculations, but their start, run hour, or energy limits were not reached. There was an average of about 2,000 MW of capacity with zero opportunity costs during these months. Most of this capacity was from start and run hour limits.

Resource adequacy

Use-limited resources are eligible to provide resource adequacy capacity if they are shown on a load serving entity's annual or monthly supply plan. These resources are subject to must-offer obligations as well as resource adequacy availability incentive mechanism (RAAIM) charges associated with bid activity during the availability assessment hours. Use-limited resources can be exempt from RAAIM for the remainder of the month that the resource has reached its limitation by submitting use-limited related outage cards.[191] This allows for a greater diversity of capacity for reliability needs by allowing use-limited resources to meet reliability requirements although these resources may not be available in critical times if the calculated opportunity costs and outage card usage do not manage resources' limits efficiently.

Use-limited resources provided a significant amount of resource adequacy capacity in 2019. Between May and December, these resources accounted for an average of about 6,200 MW of local capacity and 3,500 MW of flexible capacity. This translates to about 25 percent of the local capacity requirements for the year and about 27 percent of monthly flexible capacity requirements. Use-limited resources accounted for a slightly lower proportion of monthly (local and system) resource adequacy requirements at about 19 percent.

Outages

To complement the addition of opportunity costs to commitment cost bids to help manage resource usage, the ISO designated use-limited related outage cards. These are used for several reasons:

- To help prevent resources from reaching their limit prematurely in the event the calculated opportunity costs are ineffective in managing their limit;
- To indicate a use-limited resource has reached its limit and is exempt from RAAIM if they are a resource adequacy resource; and
- To allow demand response programs to take "fatigue" breaks.

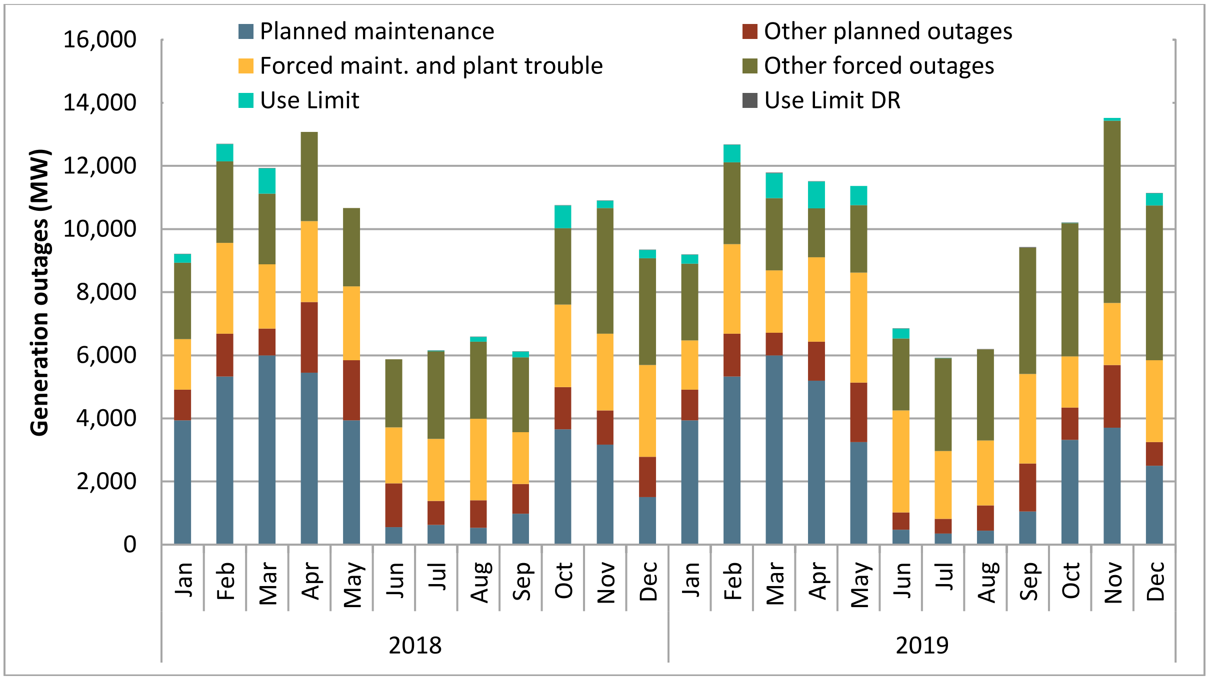
Figure 7.17 shows the monthly averages of maximum daily outages broken out by type during peak hours. This figure shows the megawatt capacity from resources that took outages specifically related to

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

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

use limits as well as for other outage types such as planned maintenance, other planned outages, forced maintenance and plant trouble, and other forced outages.

Figure 7.17 Average of maximum daily generation outages by type - peak hours



Scheduling coordinators started using outage cards related to use limits in January 2018. The proportion of total capacity on outage from use-limited resources ranges from 0.1 percent to 7.5 percent per month in 2019. Average daily maximum capacity on use limit outage peaked at about 860 MW in April. Similar to planned outages, outages related to use limits appear to be less prevalent during summer months when loads are high and system capacity is tight. Conversely, outages related to use limits are more prevalent during months when system capacity is well above load.

7.4.2 Hydro default energy bid option

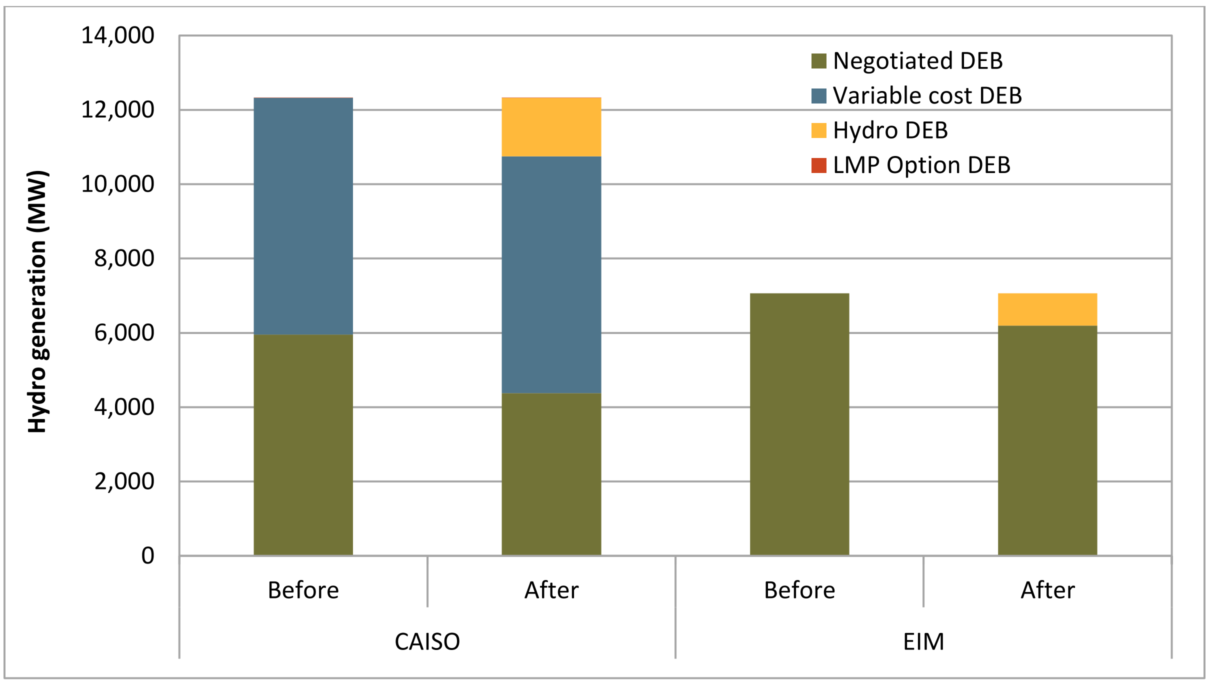
Overview

The hydro default energy bid (DEB) is an option offered to hydroelectric generation resources within the ISO and EIM to promote efficient dispatch solutions when mitigation is triggered. This option incorporates opportunity costs that hydro resources with storage capability may have and is designed to prevent hydro resources from being dispatched too frequently. Establishing a default bid value that is sufficiently high to cover potential opportunity costs ensures that hydro resources can be efficiently dispatched when mitigation occurs. This also encourages increased market participation from hydro resources that have limited operating capability.[192]

Resources have been slow to adopt the hydro default energy bid

The ISO gained Board approval of the local market power mitigation enhancements initiative in March 2019. Hydro default energy bid values were first incorporated into the market on November 13, 2019. Figure 7.18 shows the rate of adoption of the hydro option among eligible resources within the ISO and EIM. The graph shows the total maximum capacity of resources according to their highest ranked default energy bid option. Total capacity electing each option is presented before and after the hydro default energy bid implementation. As shown in the figure, only a small amount of eligible capacity has selected the new hydro option.

Figure 7.18 Total capacity by option before and after hydro default energy bid implementation (November 1 and December 31, 2019)



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

[192] For a more detailed overview of the hydro default energy bid, refer to DMM's *Fourth Quarter Report on Market Issues and Performance*, February, 2020: http://www.caiso.com/Documents/2019FourthQuarterReportonMarketIssuesandPerformance.pdf

The ISO updated the formula to incorporate additional hub prices into the hydro DEB in May 2020

Resources can have electric prices at distant hubs factored into the long-term geographic floor component if the scheduling coordinator holds transmission rights to other regions. In the event that a resource holds less firm transmission rights than its maximum capacity, the geographic floor component is calculated as a weighted blend of the prices from the default electric hub and the additional hubs. The ISO worked with stakeholders to determine the appropriate way to calculate this weighted blend.[193] Resources were able to incorporate additional hubs into their default energy bids beginning in June 2020.

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

The general approach that the ISO has used for the hydro option is very similar to approaches used in some negotiated default energy bids for hydro resources. DMM is supportive of the overall approach; however, DMM continues to question the appropriateness of using prices from geographically distant hubs as well as using up to 12 months of futures prices in the hydro option formulation. DMM maintains that including futures prices from geographically distant hubs in a default energy bid inappropriately assigns the value of transmission between the two regions to the value of energy in the resource's local lower priced region. Also, unless the methodology for establishing a resource's maximum storage horizon accounts for expected reservoir inflows, allowing default energy bids to be based off of 12-month futures prices will tend to overstate the actual opportunity costs of hydro resources during the fall months. This is when default energy bid values will most likely be driven by high expected futures prices in the summer months of the following year.[194]

7.5 Start-up and minimum load bids

This section provides analysis on the amount of day-ahead and real-time capacity – excluding use-limited resources – under the proxy cost option for commitment cost bids. Beginning in the third quarter of 2018 and into 2019, gas resources bidding their minimum load costs at the proxy cost cap has significantly increased. Section 7.4.1 provides more information on use-limited resources' capacity associated with opportunity costs.

Background

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

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193 For more information, please refer to PRR 1190 "Local power market mitigation enhancements hydro default energy bid option energy imbalance market transfer limit" and PRR 1242 "Changes to hydro default energy bid formulation": https://bpmcm.caiso.com/Pages/default.aspx

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

cap was increased from 100 percent to 125 percent and remained available to all resources.[195] 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.[196] However, the registered costs continued to remain fixed for a period of 30 days.[197] 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 the commitment cost enhancement phase 3 (CCE3) initiative, the ISO implemented opportunity cost adders to proxy start-up and proxy minimum load costs for use-limited resources which have limitations on numbers of starts, run hours and energy output.[198] This initiative phased out the registered cost option and limited the use of that option to resources which do not have sufficient data to calculate an opportunity cost adder.

The ISO is planning to file a revised proposal for the commitment costs and default energy bid enhancements (CCDEBE) initiative at FERC in 2020. Under this revision, the ISO is retaining the 125 percent bid cap on proxy commitment cost reference levels. However, suppliers requesting reference level adjustments are not allowed to incorporate any multiplier above their actual or expected costs.[199] For 2019, DMM estimates that about 67 percent of the ISO's total bid cost recovery payments were allocated to resources bidding their commitment costs above 110 percent of their proxy costs. About 93 percent of these payments were for resources bidding at or near the 125 percent bid cap for proxy commitment costs.

195 For more information, see the following FERC order accepting the tariff revisions: https://www.caiso.com/Documents/Dec302014_OrderAcceptingCommitmentCostEnhancementsTariffRevision_ER15-15-001.pdf

196 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.

197 Updated use-limited resource definition, CAISO tariff, pp 10-11: http://www.caiso.com/Documents/Section30-Bid-Self-ScheduleSubmission-CAISOMarkets-asof_Apr1-2019.pdf

198 Commitment costs enhancements stakeholder process: http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostEnhancements.aspx

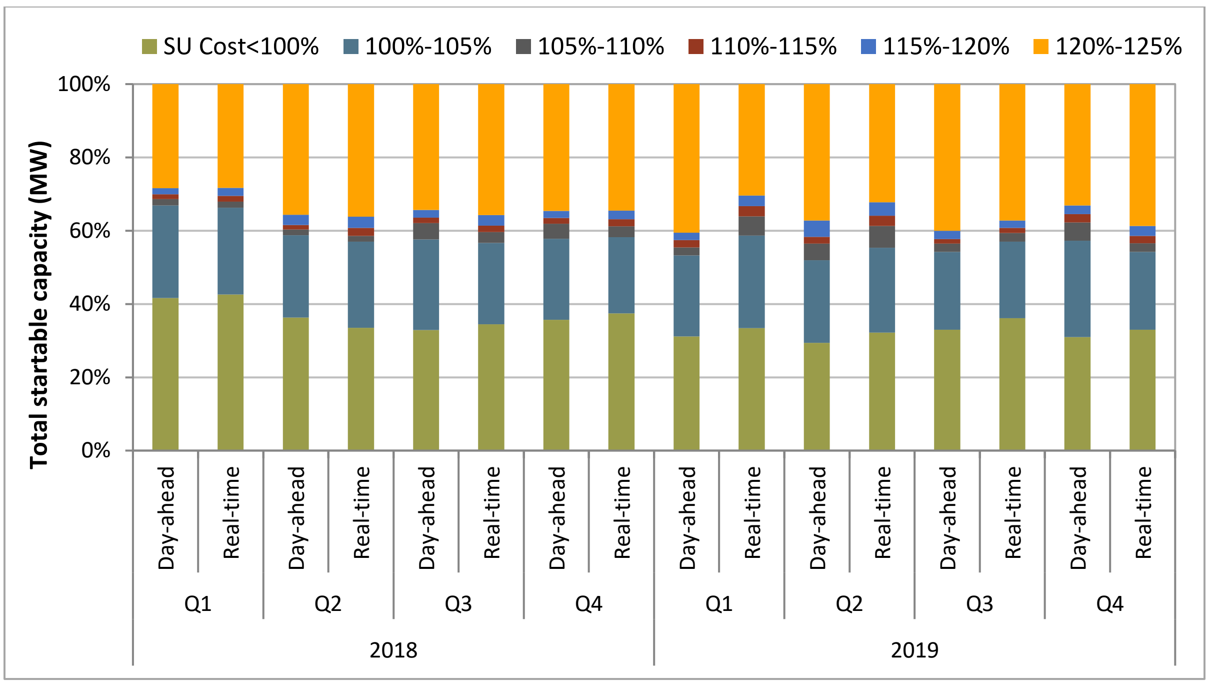
199 Commitment costs and default energy bid enhancements stakeholder call, May 20, 2020: http://www.caiso.com/InitiativeDocuments/Presentation-CommitmentCosts-DefaultEnergyBidEnhancements-May20-2020.pdf

Day-ahead and real-time capacity under the proxy cost option

Figure 7.19 and Figure 7.20 highlight how proxy commitment costs were bid into the day-ahead and real-time markets in 2019 compared to 2018.[200] As shown in Figure 7.19, in the day-ahead market about 31 percent of capacity submitted start-up bids at or below the proxy cost compared to 37 percent in 2018. About 38 percent of the capacity submitted start-up bids at or near the proxy cost cap in 2019 compared to 33 percent in 2018. In the real-time market, in 2019, about 35 percent of the startable capacity submitted bids at or near the proxy cost cap similar to that of 2018.

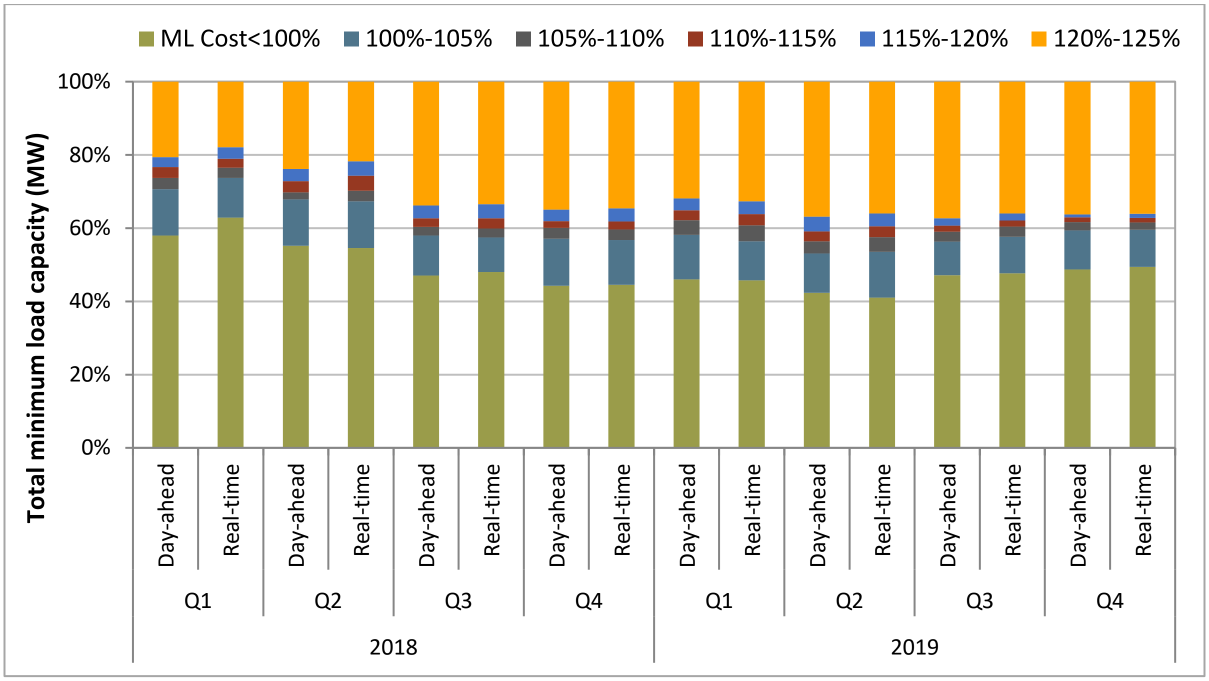
As shown in Figure 7.20, in both the day-ahead and real-time markets, the percent of minimum load capacity bidding at or near the proxy cost cap increased from the third quarter of 2018 and continued into 2019. About 35 percent of the minimum load capacity now bids at or near the cap compared to 20 percent prior to the third quarter of 2018.

Figure 7.19 Day-ahead and real-time gas-fired capacity under the proxy cost option for start-up cost bids (percentage)



[200] 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.

Figure 7.20 Day-ahead and real-time gas-fired capacity under the proxy cost option for minimum load cost bids (percentage)



7.6 Market based rate authority in the energy imbalance market

Energy imbalance market participants that are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) must seek authority from FERC to sell at market based rates in the energy imbalance market. Once granted, each entity's authority to continue selling at market based rates in the energy imbalance market and other markets is reviewed by FERC on a triennial basis. Currently, all FERC jurisdictional energy imbalance market participants have authority to sell in the energy imbalance market at market based rates. This includes participants that were granted market based rate authority at the beginning of their participation in the energy imbalance market, as well as participants that have since undergone triennial review by FERC and retained this authority.

8 Congestion

This chapter provides a review of congestion and the congestion revenue rights auction in 2019. Findings from this chapter include the following:

- **Day-ahead market congestion declined significantly**, measured as both frequency and magnitude of congestion impacting load area prices. The primary constraints impacting price separation in the day-ahead market were the constraints associated with the Imperial Valley nomogram, the Ocotillo-Suncrest outage nomogram, and the Barre-Lewis 500 kV line. In 2019 day-ahead congestion revenues totaled about 4.3 percent of total day-ahead market energy costs, compared to about 6.8 percent in 2018.
- **Real-time market congestion declined significantly**. In the 15-minute market, patterns of congestion were similar to the day-ahead market. The primary constraints impacting price separation in the real-time market were the constraints associated with the Imperial Valley nomogram, the San Bernardino-Devers 230 kV line, and the Midway-Vincent 500 kV lines.
- **The frequency of transfer constraint congestion declined in 2019**. Similar to 2018, the frequency of congestion was highest among the load areas located in the Pacific Northwest. Since entering the market in the second quarter of 2018, transfer constraints into and from Powerex bound with consistently higher frequency than the rest of the load areas within the EIM.
- **Intertie congestion declined**. Overall import congestion on interties totaled about $152 million, compared with $205 million in 2018 and $259 million in 2017[201]. The decrease from previous years was largely driven by decreased congestion on the two major interties linking the ISO with the Pacific Northwest: the Nevada/Oregon Border (NOB) and MALIN 500 (PACI/Malin 500).

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:

- In 2018, FERC approved a set of changes to the congestion revenue rights auction process which reduced the number and pairs of nodes at which congestion revenue rights can be purchased in the auction (Track 1A). FERC also approved a second set of changes which reduced the net payment to a congestion revenue right holder if payments to congestion revenue rights exceed associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis (Track 1B).
- Both of these sets of changes have been implemented for the 2019 allocation and auction. DMM supported both initiatives as incremental improvements that should help reduce the losses incurred by transmission ratepayers due to the ISO’s auction of congestion revenue rights.
- In 2019, the share of allocated congestion revenue rights increased to about 53 percent of the total megawatts held. Auctioned rights held declined significantly to about 47 percent of the total.
- 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

201 Overall import congestion was revised to include import congestion charges from the day-ahead, 15-minute, and 5-minute markets. Therefore, values in this report are not comparable with previous reports.

auction. From 2012 through 2018, ratepayers received about 48 percent of the value of their congestion revenue rights that the ISO auctioned. This represents a shortfall of about $131 million in 2018 and more than an $860 million shortfall since 2009. In 2019, ratepayer losses from congestion revenue right auctions totaled over $22 million. About $16 million of the $22 million in ratepayer losses occurred in the fourth quarter. Transmission ratepayers received about 80 cents in auction revenue per dollar paid out to rights purchased in the auction in 2019.

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 more 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 shadow price associated with that constraint represents the cost savings that would occur if that constraint had one additional megawatt of transmission capacity available in the congested direction.

There are three major types of transmission constraints that are enforced in the market model:

- 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.

The impact of congestion from any constraint on each pricing node can be calculated as the product of the constraint shadow price 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.[202]

The overall impact to average regional prices shows the impact of congestion accounting for both the frequency and magnitude of impact. These values are calculated by taking the average congestion component as a percent of the total price during all congested and non-congested intervals.[203]

202 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.

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

8.2 Congestion impacts on locational prices

This section provides an assessment of the frequency and impact of congestion on locational price differences in the day-ahead and real-time markets. The section assesses the impact of congestion to the major load serving areas in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric), as well as prices for each balancing area in the energy imbalance market.

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.

Highlights of congestion in 2019 include the following:

- In the day-ahead market, both the frequency and magnitude of congestion impacting load area prices in 2019 declined significantly when compared to 2018. The constraints that had the greatest impact on price separation throughout the year were the Imperial Valley nomogram, the Ocotillo-Suncrest outage nomograms, and the Barre-Lewis 230 kV line.
- In the real-time market, EIM transfer constraint congestion decreased prices in the Pacific Northwest and increased prices in the Arizona Public Service and NV Energy areas. Transfer constraint congestion had a far greater impact on prices than internal constraint congestion in all areas outside of the ISO.
- In the 15-minute market, patterns of congestion followed a similar pattern to the day-ahead market. The constraints that had the greatest impact on price separation in the 15-minute market were the constraints associated with the Imperial Valley nomogram, the San Bernardino-Devers 230 kV line, the Midway-Vincent 500 kV lines, the Eldorado-Lugo nomogram, and the Sylmar AC branch group.

8.2.1 Day-ahead congestion

Congestion rent and loss surplus

In the day-ahead market, hourly congestion rent collected on a constraint is equal to the product of the shadow price and the megawatt flow on that constraint. The daily congestion rent is the sum of hourly congestion rents collected on all constraints for all trading hours of the day. The daily marginal loss surplus is computed as the difference between daily net energy charge and daily congestion rent. The loss surplus is allocated to measured demand.[204]

Congestion rents and loss surplus were lower overall in 2019 compared to 2018. Day-ahead congestion revenues totaled about 4.3 percent of total day-ahead market energy costs, compared to about 6.8 percent in 2018. The variation between quarters was also lower than 2018. The peak congestion rents occurred in the fourth quarter while peak loss surplus occurred in the third quarter. There was a pronounced increase in both congestion rent and loss surplus in the third quarter of 2018; however, this was not the case in 2019.

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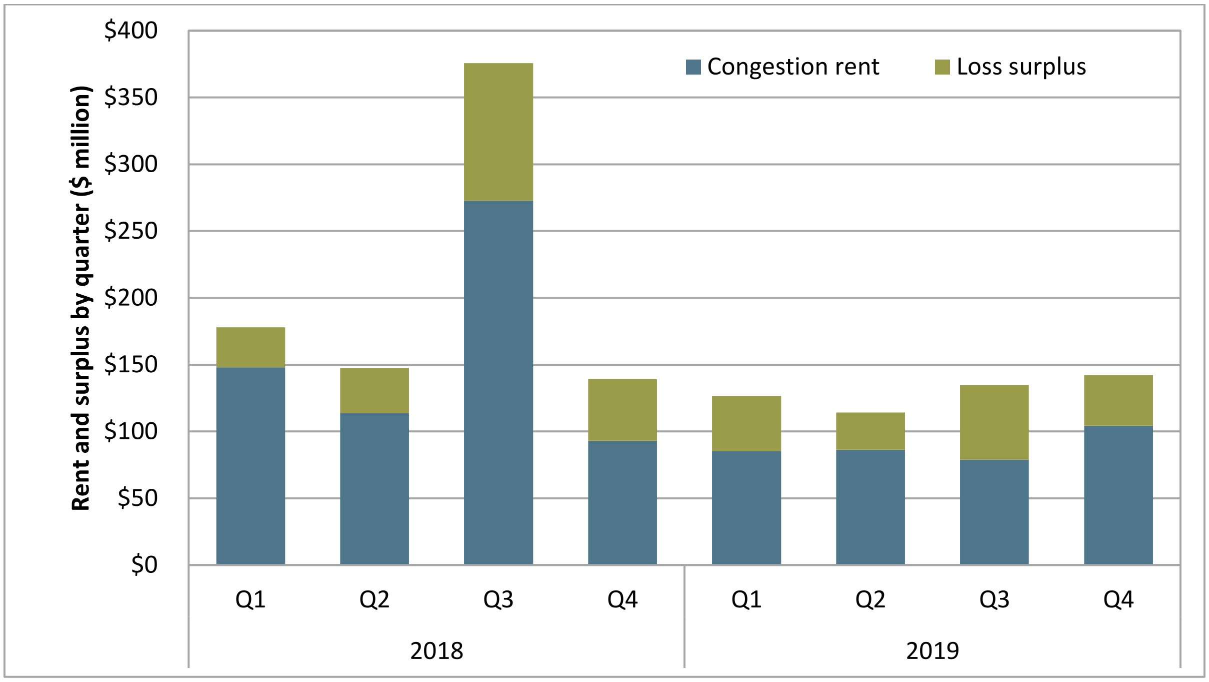
[204] For more information on marginal loss surplus allocation refer to ISO's business practice manual for Settlements and Billing, CG CC6947 IFM Marginal Losses Surplus Credit Allocation: https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

In the day-ahead market, congestion frequency is typically higher than in the 15-minute market, but impacts on price differences between load areas tend to be lower. The congestion patterns over 2019 reflect this overall trend. Figure 8.2 shows price separation resulting from congestion by quarter for the current and previous year. Figure 8.3 shows the frequency of congestion.

Figure 8.1 Congestion rent and loss surplus by quarter (2018 – 2019)



Congestion impact in the day-ahead market from internal, flow-based constraints

The overall impact of day-ahead congestion on price separation decreased in 2019 relative to 2018. In both years, congestion increased average prices in the San Diego Gas & Electric and Southern California Edison areas and decreased average prices in the Pacific Gas and Electric area. The following summary values can be seen in Table 8.1:

- For San Diego Gas and Electric, congestion increased average prices above the system average by about $1.20/MWh or about 3 percent, compared to about $4.19/MWh or roughly 9 percent in 2018.
- For Southern California Edison, congestion drove prices up by about $0.04/MWh or 0.10 percent, compared to $1.87/MWh or about 4 percent in 2018.
- For Pacific Gas and Electric, congestion reduced prices below the system average by about $0.08/MWh or 0.20 percent, compared to a decrease of $2.73/MWh or 7 percent in 2018.
- In 2019, the San Diego Gas and Electric load area had the highest impact of congestion on its price in all but the first quarter.

Figure 8.2 Overall impact of congestion on price separation in the day-ahead market

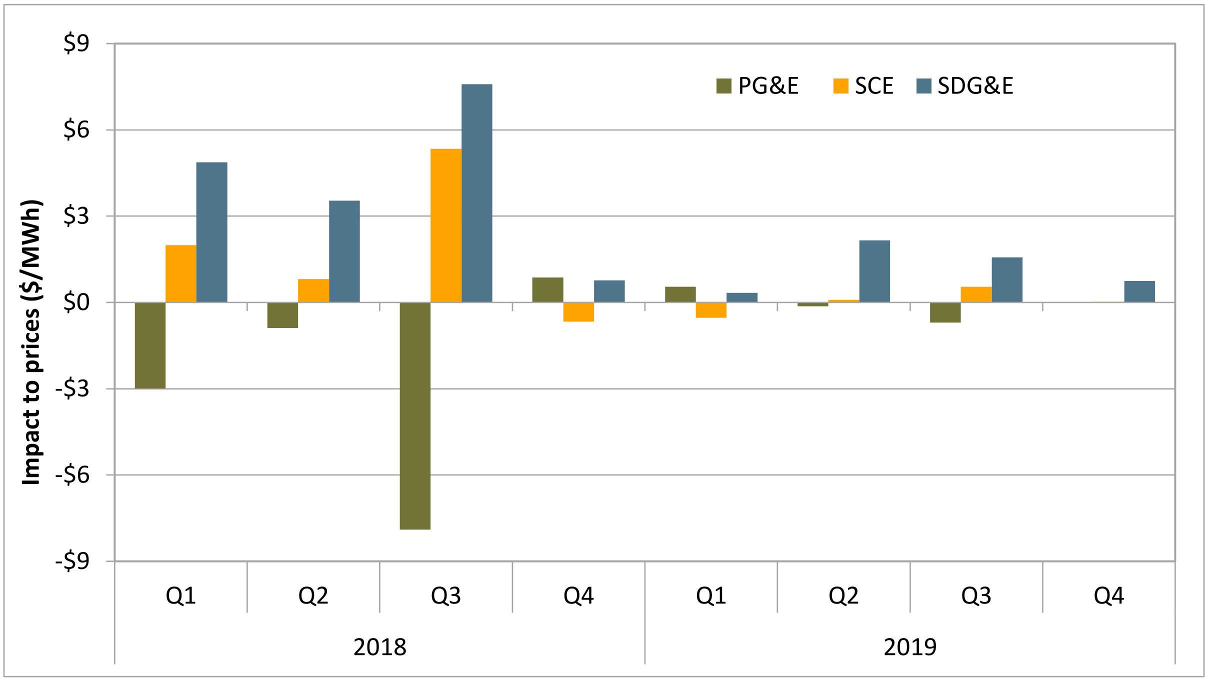
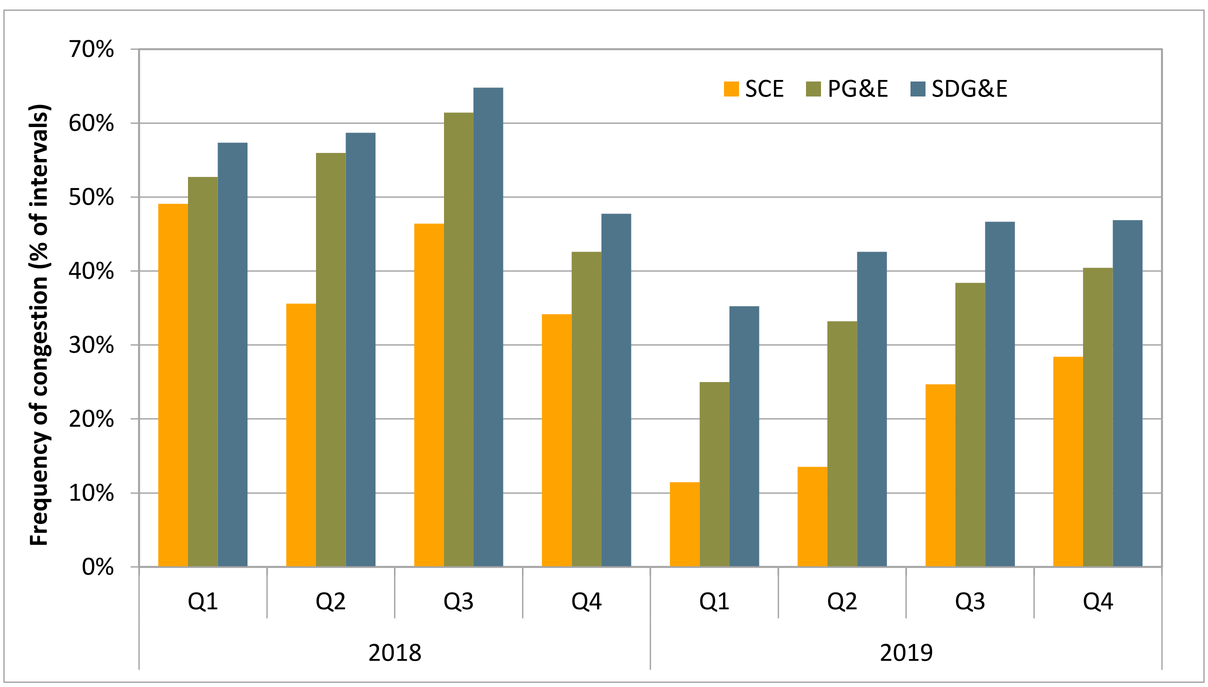


Figure 8.3 Percent of hours with congestion impacting prices by load area



The frequency with which congestion impacts prices at aggregated load areas provides additional insight into trends in congestion. Compared to 2018, the frequency of congestion declined in 2019; however, it trended upwards quarter over quarter in all load areas. The frequency of congestion impacting prices peaked for all areas in the fourth quarter of 2019. This was mostly a result of congestion from the Imperial Valley nomogram, Devers-Vista nomogram, the Doublet Tap-Friars 138 kV line, and the Barre-Lewis 230 kV line.

Measuring the net impact of congestion on price separation reduces the full impact of constraints that offset each other within a given time period. Similar to 2018, for example, the total impact of congestion in the fourth quarter of 2019 was very low, despite having the highest frequency of congestion for the year. In this period, some congestion increased prices in the south and decreased prices in the north, while at other times congestion decreased prices in the south and increased prices in the north. This offsetting congestion can be observed, to some extent, in all quarters of 2019.

Information regarding the impact of congestion from individual constraints appears below, with additional detail on the cause of congestion for constraints with the largest impact on prices.

Table 8.1 shows the overall impact of congestion from different constraints on average prices in each load aggregation area in 2019. The table also shows the frequency with which the constraint was binding in each quarter.[205] The constraints that had the greatest impact on price separation throughout the year were the Imperial Valley nomogram, the Ocotillo-Suncrest outage nomograms, and the Barre-Lewis 230 kV line.

Imperial Valley nomogram
The Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) primarily impacted the San Diego Gas and Electric area, increasing prices by $0.54/MWh (1.38 percent) compared to the average system energy price for the year. The nomogram is enforced to mitigate for the loss of the Imperial Valley-North Gila 500 kV line. There were no significant outages directly impacting this constraint in 2019, though it is frequently used to manage flows in the San Diego area.

Ocotillo-Suncrest outage nomograms
The Ocotillo-Suncrest 500 kV line (OMS 6840921_TL50003_NG and OMS 7921508_TL50003_NG) increased prices in San Diego Gas and Electric by about $0.24/MWh (0.62 percent) and decreased prices in Pacific Gas and Electric by about $0.03/MWh (0.06 percent). This nomogram was enforced due to planned outages in the second and fourth quarters, which significantly impacted average prices for the year.

Barre-Lewis 230 kV line
The Barre-Lewis 500 kV line (24016_BARRE _230_25201_LEWIS _230_BR_1 _1) increased prices in both Southern California Edison and San Diego Gas and Electric by about $0.10/MWh (0.28 percent) and $0.03/MWh (0.07 percent), respectively, and decreased Pacific Gas and Electric prices by about $0.08/MWh (0.23 percent).

[205] To see the breakdown of each individual constraint's impact on prices during the respective quarter, please see DMM's quarterly reports. A comprehensive set of DMM's quarterly reports is located at: http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx

Table 8.1 Impact of constraint congestion on overall day-ahead prices during all hours (2019)

Constraint Location	Constraint	Frequency				PG&E		SCE		SDG&E	
		Q1	Q2	Q3	Q4	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
PG&E	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	3.7%			0.6%	$0.06	0.17%	-$0.05	-0.14%	-$0.05	-0.13%
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1				2.4%	$0.04	0.10%	-$0.03	-0.08%	-$0.03	-0.07%
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	1.4%		0.4%		$0.04	0.10%	-$0.03	-0.09%	-$0.03	-0.08%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1		1.9%	0.9%	2.0%	$0.02	0.04%	$0.00	-0.01%	$0.00	-0.01%
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1				1.6%	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
	6310_MWN_NRAS		0.1%		0.9%	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
	30705_MONTAVIS_230_30720_SARATOGA_230_BR_1 _1				0.7%	$0.01	0.02%	$0.00	-0.01%	$0.00	-0.01%
	OMS_5413443_LOSBNS_MDWY2	0.7%				$0.01	0.02%	$0.00	-0.01%	$0.00	-0.01%
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	0.1%				$0.01	0.01%	$0.00	-0.01%	$0.00	-0.01%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1			0.5%	0.0%	-$0.01	-0.02%	$0.01	0.02%	$0.01	0.01%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	1.8%	0.5%	2.9%	1.8%	-$0.03	-0.09%	$0.02	0.06%	$0.02	0.06%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2			2.6%	0.1%	-$0.05	-0.13%	$0.03	0.09%	$0.03	0.08%
SCE	24016_BARRE _230_25201_LEWIS _230_BR_1 _1		0.5%	15.1%	7.9%	-$0.08	-0.23%	$0.10	0.28%	$0.03	0.07%
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	0.1%	2.1%	3.4%	2.7%	-$0.02	-0.06%	$0.01	0.04%	$0.00	0.00%
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1		2.3%	0.5%	0.1%	-$0.01	-0.02%	$0.01	0.03%	$0.00	0.00%
	25201_LEWIS _230_24137_SERRANO _230_BR_2 _1			1.0%		-$0.01	-0.03%	$0.01	0.02%	$0.00	0.00%
	24156_VINCENT _500_24155_VINCENT _230_XF_3			1.1%		-$0.01	-0.04%	$0.01	0.03%	$0.00	0.01%
	SYLMAR-AC_BG			0.0%	3.8%	$0.00	0.00%	$0.00	0.01%	-$0.03	-0.07%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	6.6%	1.2%	0.0%	0.2%	$0.00	-0.01%	$0.00	0.00%	$0.01	0.03%
	7750_D-ECASCO_OOS_CP6_NG	13.3%	4.5%	0.0%		$0.01	0.01%	-$0.01	-0.02%	-$0.02	-0.06%
	6410_CP7_NG	0.4%				$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
	22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1	0.1%		0.0%	0.9%	$0.00	0.00%	$0.00	0.00%	-$0.01	-0.03%
	7750_D-ECASCO_OOS_N1SV500_NG	3.8%				$0.00	0.00%	$0.00	0.00%	-$0.01	-0.03%
SDG&E	7820_TL 230S_OVERLOAD_NG	16.9%	12.4%	15.2%	13.8%	-$0.05	-0.13%	$0.00	0.00%	$0.54	1.38%
	OMS 6840921_TL50003_NG		2.2%			-$0.02	-0.04%	$0.00	0.00%	$0.16	0.41%
	OMS 7921508_TL50003_NG				0.8%	-$0.01	-0.02%	$0.00	0.00%	$0.08	0.22%
	MIGUEL_BKs_MXFLW_NG	0.3%	1.5%		0.4%	$0.00	-0.01%	$0.00	0.00%	$0.08	0.21%
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	0.6%	0.7%	5.1%		$0.00	0.00%	$0.00	0.00%	$0.08	0.20%
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1		3.0%			$0.00	-0.01%	$0.00	0.00%	$0.06	0.15%
	22592_OLD TOWN_69.0_22873_VINE SUB_69.0_BR_1 _1	0.1%	4.5%	3.6%		$0.00	0.00%	$0.00	0.00%	$0.05	0.14%
	22873_VINE SUB_69.0_22380_KETTNER _69.0_BR_1 _1		5.3%	3.6%		$0.00	0.00%	$0.00	0.00%	$0.05	0.12%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P		1.8%			-$0.01	-0.02%	$0.00	0.00%	$0.04	0.10%
	OMS 7836526 TL50005_NG				0.5%	$0.00	-0.01%	$0.00	0.00%	$0.04	0.11%
	7820_TL23040_IV_SPS_NG	0.9%	0.4%	1.7%	0.4%	$0.00	-0.01%	$0.00	0.00%	$0.04	0.11%
	OMS 7994240 MG-BK81_NG				0.4%	$0.00	-0.01%	$0.00	0.00%	$0.02	0.06%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P			0.4%		$0.00	-0.01%	$0.00	0.00%	$0.02	0.05%
	OMS 7020096_50001_OOS_NG		0.6%			$0.00	0.00%	$0.00	0.00%	$0.02	0.05%
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1		0.6%	0.8%	1.0%	$0.00	0.00%	$0.00	0.00%	$0.02	0.05%
	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_81		2.4%			$0.00	0.00%	$0.00	0.00%	$0.02	0.04%
	22592_OLD TOWN_69.0_22596_OLD TOWN_230_XF_1		0.3%	0.3%		$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	OMS 7333672 ML_BK80_NG			0.7%		$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	22592_OLD TOWN_69.0_22660_POINTLMA_69.0_BR_2 _1		0.2%	1.9%		$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	OMS 6438774_DV1_DV2_NG				5.4%	$0.01	0.03%	-$0.01	-0.03%	$0.00	-0.01%
	7750_D-VISTA1_OOS_N1SV500_NG		0.2%	0.4%	6.3%	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
	7750_D-VISTA1_OOS_CP6_NG			1.2%	4.8%	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1	0.3%		1.0%	2.1%	$0.00	0.00%	$0.00	0.00%	-$0.04	-0.10%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	1.3%	0.4%	3.6%	23.6%	$0.00	0.00%	$0.00	0.00%	-$0.08	-0.22%
Other	Other					$0.02	0.06%	$0.01	0.03%	$0.10	0.26%
Total	**Total**					**-$0.08**	**-0.20%**	**$0.04**	**0.10%**	**$1.20**	**3.08%**

8.2.2 Real-time congestion

Congestion in the 15-minute real-time market was similar to the 5-minute market, but had a lower impact on locational price differences.[206] Below is an analysis of the frequency and effects of congestion on each of these real-time markets.

Congestion in the 15-minute market from internal, flow-based constraints

Figure 8.4 shows price separation resulting from internal congestion on load areas in the ISO and energy imbalance market by quarter. Figure 8.5 shows the percent of hours with internal congestion increasing versus decreasing 15-minute prices by more than $0.05/MWh in 2019.

DMM updated the congestion frequency metric by removing the energy imbalance market greenhouse gas (GHG) component, removing energy imbalance market transfer constraint congestion, correcting for market interruptions, and adjusting for price corrections. These changes focus this metric on the impact of internal transmission constraint congestion alone.[207]

Over the entire year, congestion resulted in a net increase to prices for Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric; while resulting in a net decrease to prices in energy imbalance market areas. The greatest net increase to prices occurred in the San Diego Gas and Electric area, while the greatest net decrease occurred in the Arizona Public Service area.

On a quarterly basis, net price separation due to internal congestion was greatest in the second quarter. During the second quarter, San Diego Gas and Electric experienced the largest price impact, with prices increasing by $2.46/MWh. Price impacts in PacifiCorp West, Portland General Electric, Puget Sound Energy, and Powerex were very similar for every quarter. Arizona Public Service had the largest average quarterly price impact of 2019 during the fourth quarter, where prices decreased by $5.28/MWh.

The frequency with which congestion impacts prices at aggregated load areas provides additional insight into trends in congestion that are not apparent in the net impact. The greatest frequency of congestion occurred in the fourth quarter, followed very closely by the first quarter. In each quarter, congestion decreased prices more than it increased prices. For 2019, PacifiCorp East had the largest average frequency of congestion. This congestion in PacifiCorp East primarily decreased prices (32 percent of intervals) rather than increasing prices (less than 1 percent of intervals).

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

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206 In 2019, as in previous years, 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.

207 These factors were included in previous reports and mainly manifested themselves in the "Other" category. The data for 2018 has been retroactively updated to reflect the revised methodology for this report. These revisions mean that the figures presented in this section are no longer directly comparable to previous reports; the congestion frequency in energy imbalance market areas is higher than previously reported.

Figure 8.4 Overall impact of internal congestion on price separation in the 15-minute market

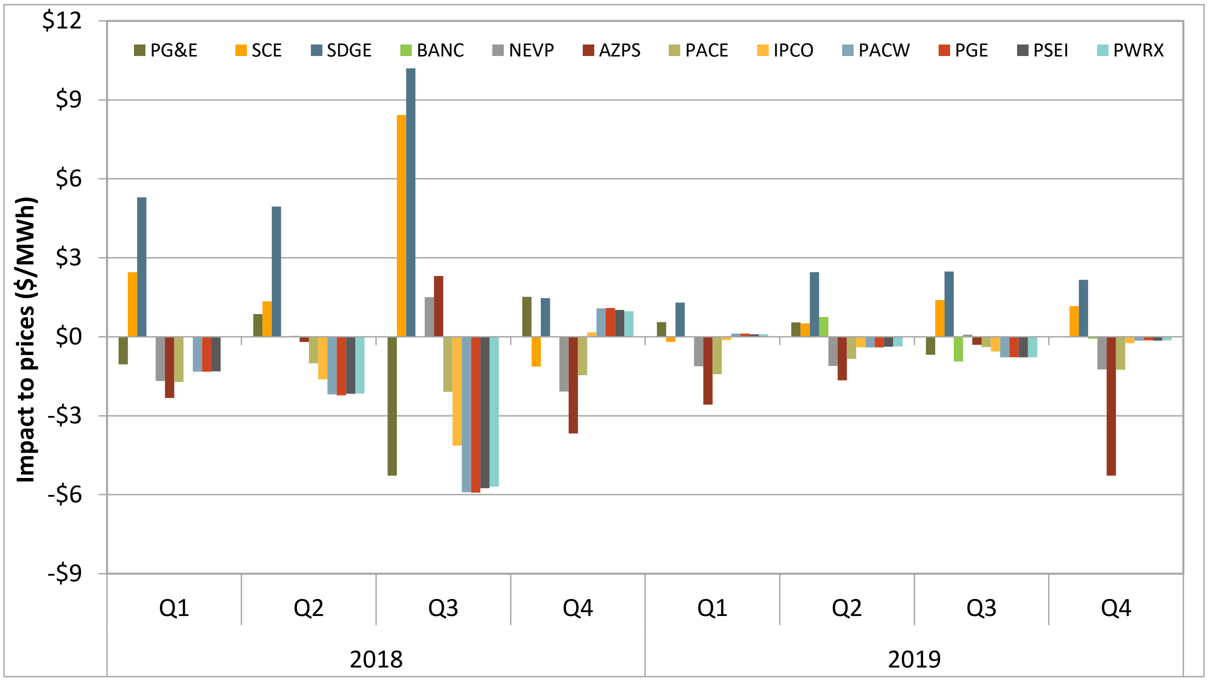


Figure 8.5 Average percent of hours with internal congestion increasing versus decreasing 15-minute prices in 2019 (>$0.05/MWh)

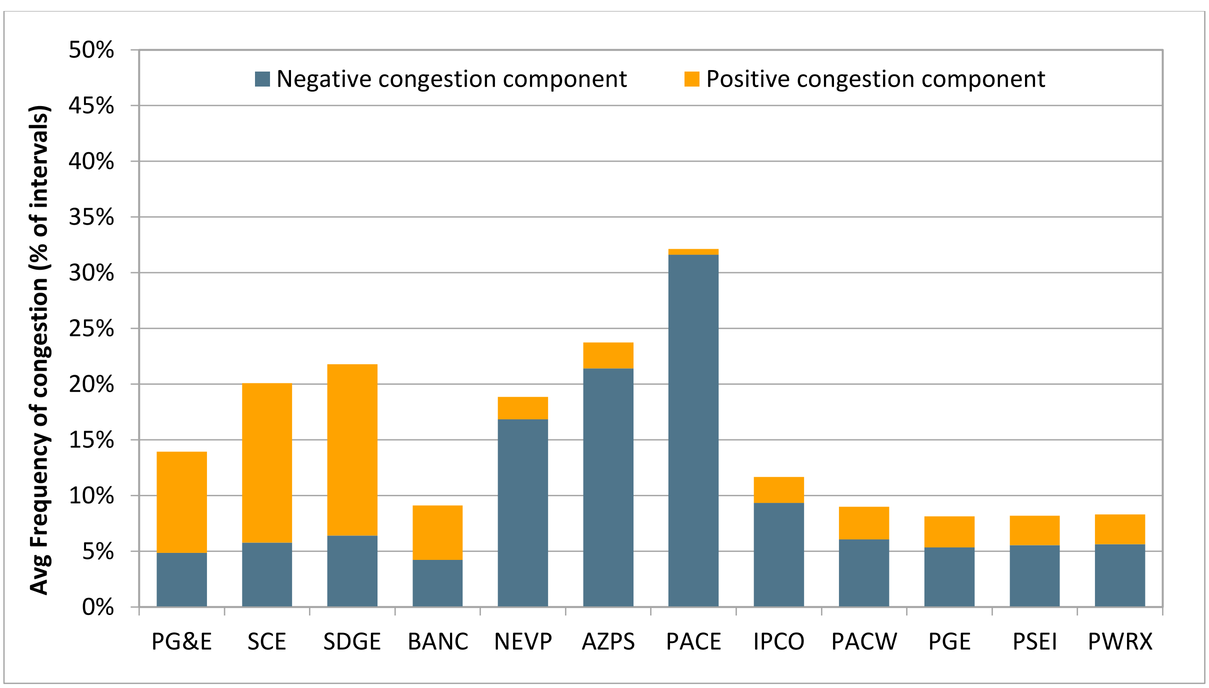


Table 8.2 shows the overall impact of 15-minute congestion from individual constraints on prices in each load area in 2019. The color scales in the table below help to highlight congestion that was particularly impactful. The category labeled ”Other” has been revised and no longer includes the impact of energy imbalance market transfer constraints, which have the greatest impact on price separation for Western EIM areas. These transfer constraints are found at the bottom of the table and are discussed in greater depth in Section 8.2.3. This section will focus on the individual flow-based constraints that are internal to balancing authority areas, rather than schedule-based constraints between areas.

The constraints that had the greatest impact on price separation in the 15-minute market were the constraints associated with the Imperial Valley nomogram, the San Bernardino-Devers 230 kV line, the Midway-Vincent 500 kV lines, the Eldorado-Lugo nomogram, and the Sylmar AC branch group.

Imperial Valley nomogram

The Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) bound frequently in 2019. Over the entire year, it increased San Diego Gas and Electric prices by about $1.29/MWh, and decreased prices by about $0.31/MWh in Arizona Public Service. The nomogram is enforced to mitigate for the loss of the Imperial Valley-North Gila 500 kV line. In the 2017-2018 transmission planning cycle, an upgrade to the Imperial Valley-El Centro 230 kV S-Line was approved. The project, which is planned to be complete in 2021, will help to alleviate congestion in this area.

San Bernardino-Devers 230 kV line

The San Bernardino-Devers 230 kV line (24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1) also had a large impact on price separation in 2019, particularly decreasing prices in the Arizona Public Service area. It bound most frequently during the fourth quarter; binding in about 12 percent of intervals. The constraint decreased Arizona Public Service prices by about $0.69/MWh. This constraint was impacted by the planned outages of the Devers-Vista #1 and #2 220 kV lines.

Midway-Vincent 500 kV lines

The Midway-Vincent 500 kV lines (30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 and 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _1) bound infrequently in 2019. Overall for the year, the nomogram increased prices in Southern California Edison, San Diego Gas and Electric, NV Energy, and Arizona Public Service by about $0.05/MWh on average and decreased prices throughout the rest of the west by about $0.04/MWh on average. This constraint was binding in part due to a planned outage of the Whirlwind 500 kV line series capacitor.

Eldorado-Lugo nomogram

The Eldorado-Lugo nomogram (OP-6610_ELD-LUGO) bound infrequently over the course of 2019, but had a high impact when binding. Overall, the nomogram increased prices in California by $0.03/MWh on average and decreased prices in the southwest and east of California by $0.05/MWh on average. The largest impact occurred in NV Energy with a decrease of about $0.17/MWh over the year. This nomogram bound in particular on two days in June when loads in California were at their peak and flows into California were constrained.

Sylmar AC branch group

The Sylmar AC branch group (SYLMAR-AC_BG) created price separation between the western and eastern balancing areas in the 15-minute market. The constraint increased prices in Pacific Gas and Electric and Southern California Edison by $0.07/MWh on average, and decreased prices south and east of the constraint (in NV Energy, Arizona Public Service, PacifiCorp East, and San Diego Gas and Electric) by about $0.08/MWh on average. Congestion due to the branch group did not impact prices in the Pacific Northwest balancing areas (Portland General Electric, Puget Sound Energy, or Powerex). This constraint bound as a result of a planned outage on the Sylmar 230 kV bus in late October and early November.

Table 8.2 Impact of internal constraint congestion on overall 15-minute prices during all hours

Constraint Location	Constraint	PGAE	SCE	SDGE	BANC	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX
NEVP	HBT-COY_3423	$0.00	-$0.01	-$0.01	$0.00	-$0.03	-$0.01	$0.01	$0.02	$0.01	$0.01	$0.01	$0.01
PACE	WYOMING_EXPORT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.17	$0.00	$0.00	$0.00	$0.00	$0.00
PG&E	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.05	-$0.07	-$0.07	$0.02	-$0.03	-$0.06	-$0.01	$0.01	$0.04	$0.04	$0.04	$0.04
	RM_TM12_NG	$0.03	$0.02	$0.01	$0.02	$0.00	$0.01	-$0.02	-$0.03	-$0.04	-$0.04	-$0.04	-$0.04
	30010_INDSPRNG_500_30005_ROUND MT_500_BR_2 _1	$0.02	$0.01	$0.01	$0.02	$0.00	$0.01	-$0.01	-$0.02	-$0.03	-$0.03	-$0.03	-$0.03
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	$0.01	-$0.02	-$0.02	$0.00	-$0.01	-$0.02	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	$0.01	$0.00	$0.00	$0.02	$0.00	$0.00	$0.00	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.01	-$0.02	-$0.02	$0.01	-$0.01	-$0.02	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	6310_MWN_NRAS	$0.01	-$0.01	-$0.01	$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01
	6310_LBS_NRAS	$0.01	-$0.01	-$0.01	$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01
	30105_COTTNWD _230_30245_ROUND MT_230_BR_2 _1	$0.01	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	$0.01	-$0.02	-$0.01	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01
	30055_GATES1 _500_30900_GATES _230_XF_11_S	$0.01	-$0.01	-$0.01	$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.00	-$0.01	-$0.01	$0.01	$0.00	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01
	30523_CC SUB _230_30525_C.COSTA _230_BR_1 _1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30335_ATLANTC _230_30337_GOLDHILL_230_BR_1 _1	$0.00	$0.00	$0.00	$0.05	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.03	$0.02	$0.02	-$0.02	$0.01	$0.02	$0.00	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-$0.03	$0.03	$0.03	-$0.03	$0.01	$0.02	$0.00	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _1	-$0.05	$0.05	$0.04	-$0.05	$0.02	$0.04	$0.00	-$0.02	-$0.03	-$0.03	-$0.03	-$0.03
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.08	$0.07	$0.07	-$0.08	$0.04	$0.06	$0.00	-$0.03	-$0.05	-$0.05	-$0.05	-$0.05
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.01	$0.12	$0.07	-$0.01	-$0.04	-$0.05	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	SYLMAR-AC_BG	$0.02	$0.12	-$0.04	$0.00	-$0.14	-$0.14	-$0.09	-$0.01	$0.00	$0.00	$0.00	$0.00
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.02	$0.06	$0.04	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	24086_LUGO _500_24238_RANCHVST_500_BR_1 _1	-$0.02	$0.06	$0.06	-$0.02	-$0.05	-$0.03	-$0.04	-$0.03	-$0.02	-$0.02	-$0.02	-$0.02
	24156_VINCENT _500_24155_VINCENT _230_XF_3	-$0.03	$0.06	$0.03	-$0.03	$0.00	$0.00	-$0.02	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03
	6410_CP1_NG	-$0.05	$0.05	$0.05	-$0.05	$0.03	$0.04	$0.01	-$0.01	-$0.03	-$0.03	-$0.03	-$0.03
	OP-6610_ELD-LUGO	$0.06	$0.04	$0.00	$0.05	-$0.17	-$0.13	-$0.08	-$0.03	$0.00	$0.00	$0.00	$0.00
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	$0.00	$0.04	$0.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_2 _P	-$0.02	$0.03	$0.06	$0.00	-$0.01	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	OMS 7228298_OP-6610	$0.02	$0.03	$0.01	$0.02	-$0.05	-$0.05	-$0.03	-$0.01	$0.00	$0.00	$0.00	$0.00
	7750_DV2_N2DV500_NG	$0.00	$0.01	$0.00	$0.00	-$0.01	-$0.04	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00
	24042_ELDORDO _500_24086_LUGO _500_BR_1 _3	$0.01	$0.01	$0.00	$0.00	-$0.02	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00
	7750_D-ECASCO_OOS_N1SV500_NG	$0.01	$0.00	$0.00	$0.00	-$0.01	-$0.08	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00
	7750_D-ECASCO_OOS_CP6_NG	$0.05	-$0.05	$0.01	$0.01	-$0.03	-$0.22	-$0.05	$0.00	$0.00	$0.00	$0.00	$0.00
SDG&E	7820_TL 230S_OVERLOAD_NG	$0.00	$0.09	$1.29	$0.00	-$0.09	-$0.31	-$0.12	-$0.04	-$0.01	-$0.01	-$0.01	-$0.01
	MIGUEL_BKs_MXFLW_NG	$0.00	$0.00	$0.15	$0.00	$0.00	-$0.06	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00
	7820_TL23040_IV_SPS_NG	$0.00	$0.00	$0.11	$0.00	$0.00	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 6840921_TL50003_NG	$0.00	$0.00	$0.06	$0.00	$0.00	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	$0.00	$0.00	$0.06	$0.00	$0.00	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	$0.00	$0.00	$0.06	$0.00	$0.00	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 7958707_TL50004_OUTAGE_NG	$0.00	$0.00	$0.06	$0.00	$0.00	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24138_SERRANO _500_24137_SERRANO _230_XF_3	$0.00	$0.02	$0.05	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	25201_LEWIS _230_24137_SERRANO _230_BR_2 _1	$0.00	$0.01	$0.00	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 6438774_DV1_DV2_NG	$0.01	-$0.01	$0.00	$0.00	-$0.01	-$0.04	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00
	24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1	$0.00	$0.00	-$0.01	$0.00	$0.00	-$0.69	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	$0.01	$0.02	-$0.15	$0.00	$0.00	-$0.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	$0.00	-$0.25	$0.00	$0.00	-$0.09	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Other	$0.08	$0.00	$0.36	-$0.04	-$0.17	-$0.41	-$0.22	-$0.03	-$0.02	-$0.02	-$0.02	-$0.02
	Internal Total	**$0.10**	**$0.73**	**$2.10**	**-$0.07**	**-$0.85**	**-$2.46**	**-$0.98**	**-$0.34**	**-$0.30**	**-$0.30**	**-$0.30**	**-$0.30**
	Transfers	$0.00	$0.00	$0.00	-$0.39	$2.25	$4.84	-$0.08	-$0.55	-$2.33	-$2.59	-$2.21	-$2.06
	Grand Total	**$0.10**	**$0.73**	**$2.10**	**-$0.46**	**$1.40**	**$2.38**	**-$1.06**	**-$0.89**	**-$2.63**	**-$2.89**	**-$2.51**	**-$2.36**

Congestion in the 5-minute market from internal, flow-based constraints

Figure 8.6 shows the average price separation resulting from congestion between ISO area and energy imbalance market area prices in the 5-minute market by quarter. Figure 8.7 shows the average percent of hours with congestion increasing versus decreasing 5-minute prices by more than $0.05/MWh in 2019.[208]

Congestion frequency in the 5-minute market was very similar to that of the 15-minute market. The most notable difference between the two markets is that price impacts were higher in the 5-minute market. As in the 15-minute market, internal congestion resulted in a net increase to prices in Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric; while resulting in a net decrease to prices in the rest of the Western EIM. The greatest net increase to prices occurred in San Diego Gas and Electric, while the greatest net decrease occurred in the Arizona Public Service balancing area.

On a quarterly basis, net price separation due to congestion was greatest in the second quarter. During the second quarter, San Diego Gas and Electric experienced the largest price impact, with prices increasing by $3.18/MWh. Price impacts in PacifiCorp West, Portland General Electric, Puget Sound Energy, and Powerex were very similar for each quarter. Arizona Public Service had the largest average quarterly price impact of 2019 during the fourth quarter, where its prices decreased by $5.47/MWh.

The frequency with which congestion impacts prices at aggregated load areas provides additional insight into trends in congestion that are not apparent in the net impact. The greatest frequency of congestion occurred in the fourth quarter, followed closely by the first quarter. In each quarter, congestion more frequently increased prices than decreased prices across energy imbalance market areas. For 2019, PacifiCorp East was most frequently impacted by congestion from internal constraints in the 5-minute market. Most of this congestion in the PacifiCorp East area drove prices down (29 percent of intervals) rather than increasing prices (1 percent of intervals).

208 As with the 15-minute market, DMM refined the 5-minute market congestion frequency analysis through the removal of the greenhouse gas (GHG) component and transfer constraint congestion, correcting for market interruptions, and adjusting for price corrections. These changes allow the frequency of congestion to more accurately reflect what is occurring in the market. Therefore, the congestion frequency in EIM areas is higher than previously reported.

Figure 8.6 Overall impact of internal congestion on price separation in the 5-minute market

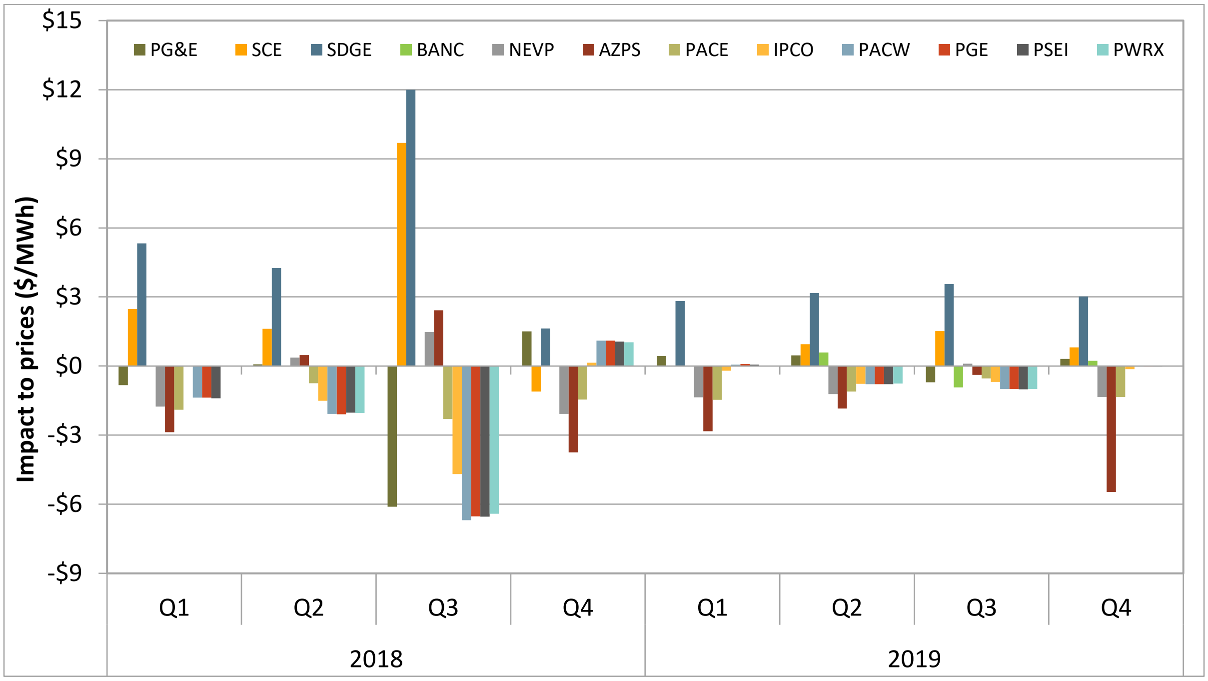
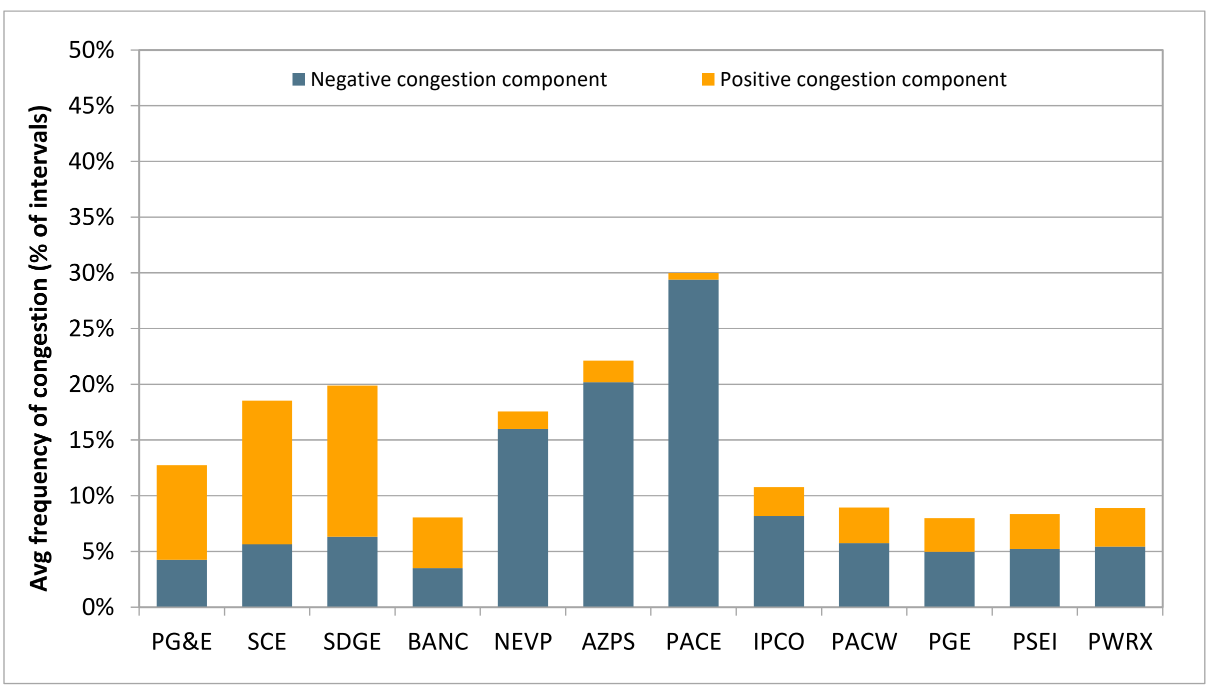


Figure 8.7 Average percent of hours with internal congestion increasing versus decreasing 5-minute prices in 2019 (>$0.05/MWh)



8.2.3 Congestion on EIM transfer constraints

This section focuses on price impact due to congestion on schedule-based transfer constraints. In the 15-minute market, the total impact of congestion on a specific energy imbalance market (EIM) area is equal to the sum of price impact of flow-based (listed in Table 8.2) and schedule-based constraints (listed in Table 8.3).[209]

The results of this section are the same as those found in Section 4.3.3 of this report. Both sections analyze transfer constraint congestion in the EIM; however, each focuses on different aspects. Section 4.3.3 focus on the impact of transfer constraint congestion to transfer capability. Thus, Section 4.3.3 discusses congestion frequency split by the direction of congestion into (import congestion) or out of (export congestion) an energy imbalance market area. Conversely, this section discusses the same data as an increase or decrease to prices. When congestion decreases prices in an energy imbalance market area relative to the system, this indicates congestion out of an area and limited export capability. Conversely, when prices are higher within an area relative to the system, this indicates that congestion is limiting the ability for energy outside of an area to serve that area's load (i.e., import capability is limited).

Table 8.3 shows the frequency of transfer constraint congestion and average price impact in the 15-minute and 5-minute markets for 2019. As shown in the figure, the highest frequency occurred either into or away from the EIM load areas located in the Pacific Northwest. On average, this congestion typically reduced prices in those areas.

Table 8.3 Average price impact and congestion frequency on EIM transfer constraints (2019)

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC*	1%	-$0.39	1%	-$0.23
Arizona Public Service	3%	$4.84	4%	$4.32
NV Energy	5%	$2.25	5%	$3.45
PacifiCorp East	5%	-$0.08	5%	$0.75
Idaho Power	6%	-$0.55	6%	$0.33
PacifiCorp West	26%	-$2.33	20%	-$2.60
Portland General Electric	28%	-$2.59	22%	-$2.84
Puget Sound Energy	31%	-$2.21	26%	-$2.53
Powerex	47%	-$2.06	52%	-$3.15

*April 3 to December 31, 2019 only

[209] The marginal congestion component at each energy imbalance market load area is adjusted to remove the impact due to greenhouse gas price.

Transfer congestion in the 15-minute market

Figure 8.8 shows the frequency of congestion on transfer constraints by quarter for 2018 and 2019. Figure 8.9 shows the average impact to prices in the 15-minute market by quarter for 2018 and 2019.

As shown in Figure 8.8, the frequency of transfer congestion affecting EIM load areas declined in 2019 when compared to 2018. Similar to 2018, the frequency of congestion was highest among the load areas located in the Pacific Northwest. Since entering the market in the second quarter of 2018, transfer constraint into and from Powerex bound with consistently higher frequency than the rest of the load areas within the EIM.

As shown in Figure 8.9, transfer congestion had a significant impact by raising prices by about $5/MWh and $2/MWh in Arizona Public Service and NV Energy load areas, respectively. Similar to 2018, this congestion tended to decrease prices for balancing areas located in the Northwest. However, on average, the impact was lower in magnitude in 2019.

Figure 8.8 EIM transfer constraint congestion frequency in the 15-minute market (>$0.01/MWh)

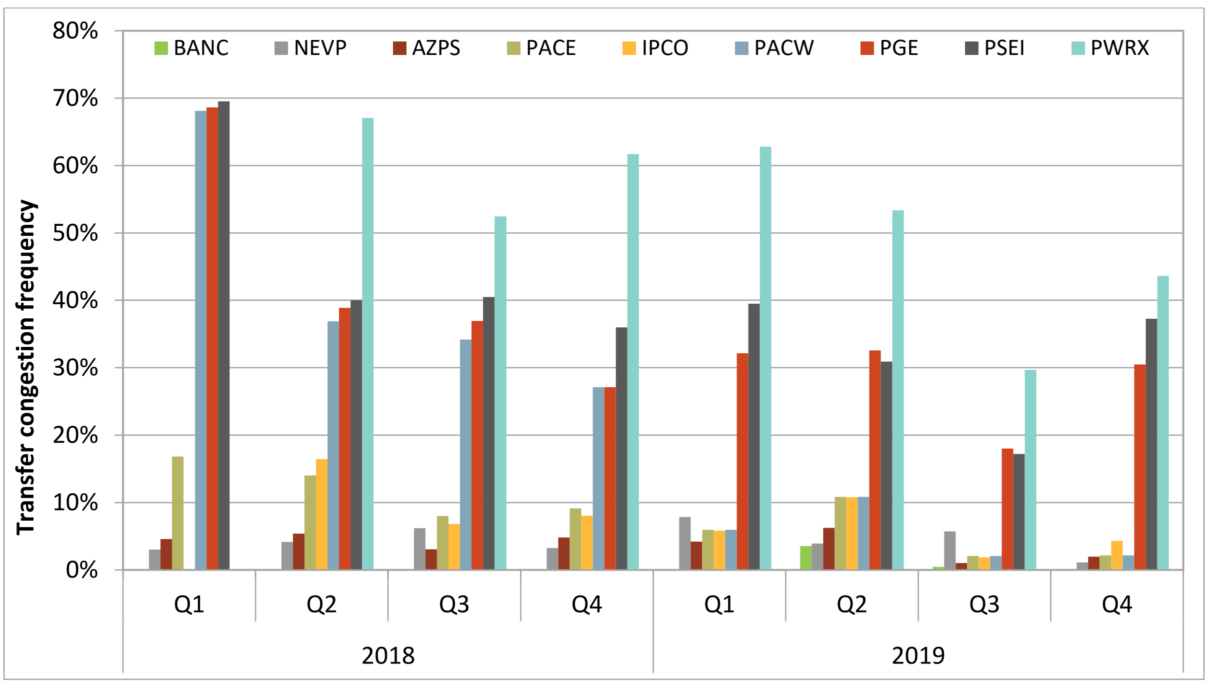
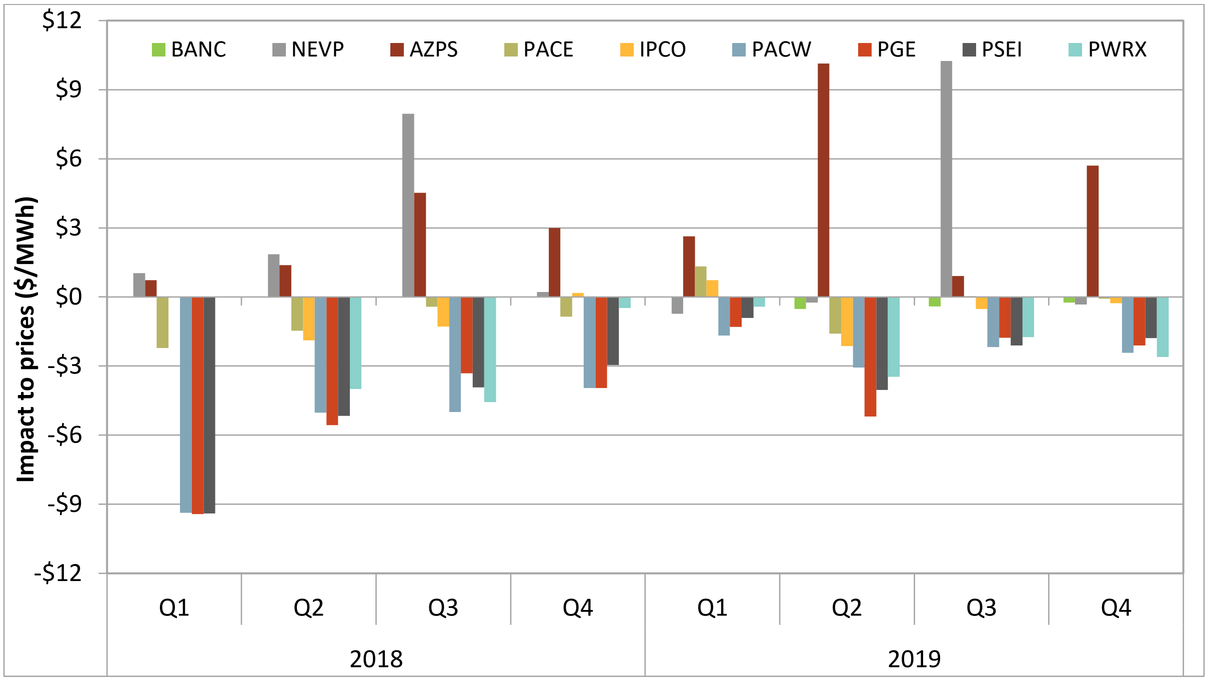


Figure 8.9 EIM transfer constraint congestion average impact on prices in the 15-minute market



Transfer congestion in the 5-minute market

Figure 8.10 shows the frequency of congestion on transfer constraints in the 5-minute market by quarter for 2018 and 2019. Figure 8.11 shows the average impact on price in the 5-minute market by quarter for 2018 and 2019.

Overall, the frequency of transfer constraint congestion is lower in 2019 compared to 2018, except for Powerex. Similar to 2018, the frequency of congestion was highest among the load areas located in the Northwest. The net impact of congestion reduced prices in those areas indicating, on average, that congestion was either towards the ISO or other EIM load areas. Similar to the 15-minute market, the frequency was lower for Arizona Public Service and NV Energy load areas but the impact was larger, raising prices on average by $4/MWh and $3/MWh, respectively.

Figure 8.10 EIM transfer constraint congestion frequency in the 5-minute market

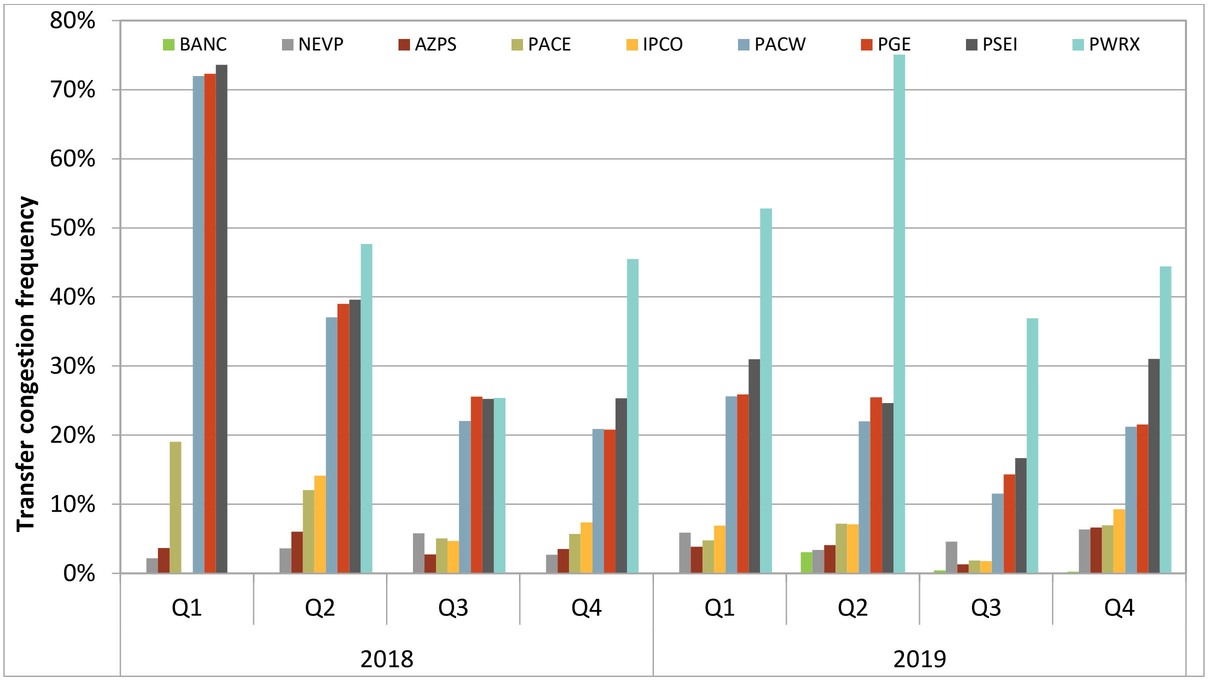
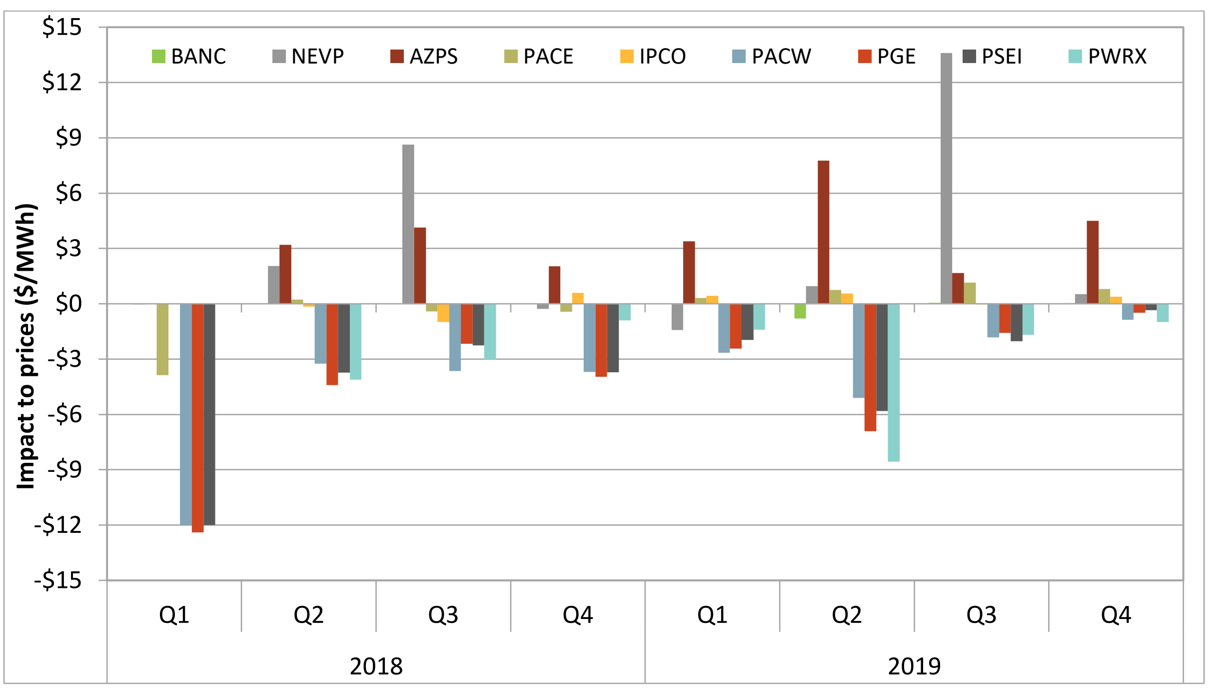


Figure 8.11 EIM transfer constraint congestion average impact on prices in the 5-minute market



8.3 Congestion on interties

The frequency and financial impact of congestion on most interties connecting the ISO with other balancing authority areas decreased in 2019 compared to 2018, particularly for interties connecting the ISO to the Pacific Northwest.

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.

Table 8.4 provides a summary of congestion frequency on interties including average day-ahead congestion charges and the total congestion charges from the day-ahead, 15-minute, and 5-minute market. The congestion price reported in Table 8.4 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 8.12 compares the percentage of hours that major interties were congested in the day-ahead market during the last three years. Figure 8.13 provides a graphical comparison of total congestion charges on major interties in each of the last three years.

Trends in impact of congestion on interties

Overall, congestion on interties across all markets (day-ahead, 15-minute, and 5-minute) reached about $152 million, compared with $205 million in 2018 and $259 million in 2017. The decrease from 2018 was largely driven by decreased congestion on the two major interties linking the ISO with the Pacific Northwest: the Nevada/Oregon Border (NOB) and MALIN 500 (PACI/Malin 500).[210] On these interties, total congestion decreased to about $79 million in 2019 from about $165 million in 2018. This was mostly driven by decreased frequency of import congestion on the Nevada/Oregon Border, falling to 8 percent from 22 percent in 2018. On the IPP DC Adelanto intertie, total congestion charges increased significantly, increasing to $40 million from about $3 million in 2018. This increase was due in large part to repairs and maintenance that limited the transfer capabilities of IPP DC Adelanto for over two months.

In the 15-minute and 5-minute markets, import congestion charges on interties have been declining since 2017. The 15-minute market fell from roughly $90 million in 2017 to $29 million in 2019, while the 5-minute market fell from roughly $55 million in 2017 to $32 million in 2019. Total import congestion charges were higher in the 15-minute than the 5-minute market until 2019. This change is mainly due to three specific interties: MALIN 500, COTPISO, and IPP DC Adelanto. These interties each had notably higher import congestion charges in the 5-minute market than in the 15-minute market, with a

[210] 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

combined total in 2019 of about $30 million in the 5-minute market compared to $22 million in the 15-minute market.

Table 8.4 Summary of import congestion (2017-2019)

Import region	Intertie	Day-ahead frequency of import congestion			Day-ahead average congestion charge ($/MW)			Total import congestion charges* (thousands)		
		2017	2018	2019	2017	2018	2019	2017	2018	2019
Northwest	PACI/Malin 500	28%	19%	22%	$12.16	$10.67	$12.76	$158,735	$119,814	$65,103
	NOB	26%	22%	8%	$11.59	$12.24	$8.40	$75,406	$44,844	$14,051
	Cascade	1%	0%	1%	$21.38	$7.98	$16.90	$98	$24	$197
	COTPISO	2%	2%	1%	$25.82	$33.94	$25.60	$192	$215	$90
	Summit	0%		0%	$9.40		$59.81	$31	$7	$33
Southwest	IPP DC Adelanto	3%	1%	11%	$9.20	$11.15	$17.85	$6,108	$2,637	$39,645
	Palo Verde	2%	6%	7%	$22.29	$13.82	$11.69	$13,020	$24,473	$21,716
	IPP Utah	18%	17%	11%	$7.88	$7.61	$7.92	$3,089	$3,370	$3,436
	Mead	0%	0%	1%	$21.52	$5.39	$24.25	$808	$323	$1,673
	Market Place Adelanto	0%	0%	1%	$15.96	$22.45	$26.14	$290	$59	$878
	West Wing Mead		1%	1%		$13.99	$25.04	$67	$171	$779
	CFE_ITC		0%	0%		$645.79	$19.35		$1,997	$75
	Other							$1,290	$25,589	$3,869
Total								***$259,135***	***$205,281***	***$151,544***

* Total import congestion charges is the combined total from the day ahead, 15-minute, and 5-minute markets.

Figure 8.12 Percent of hours with day-ahead congestion on major interties (2017-2019)

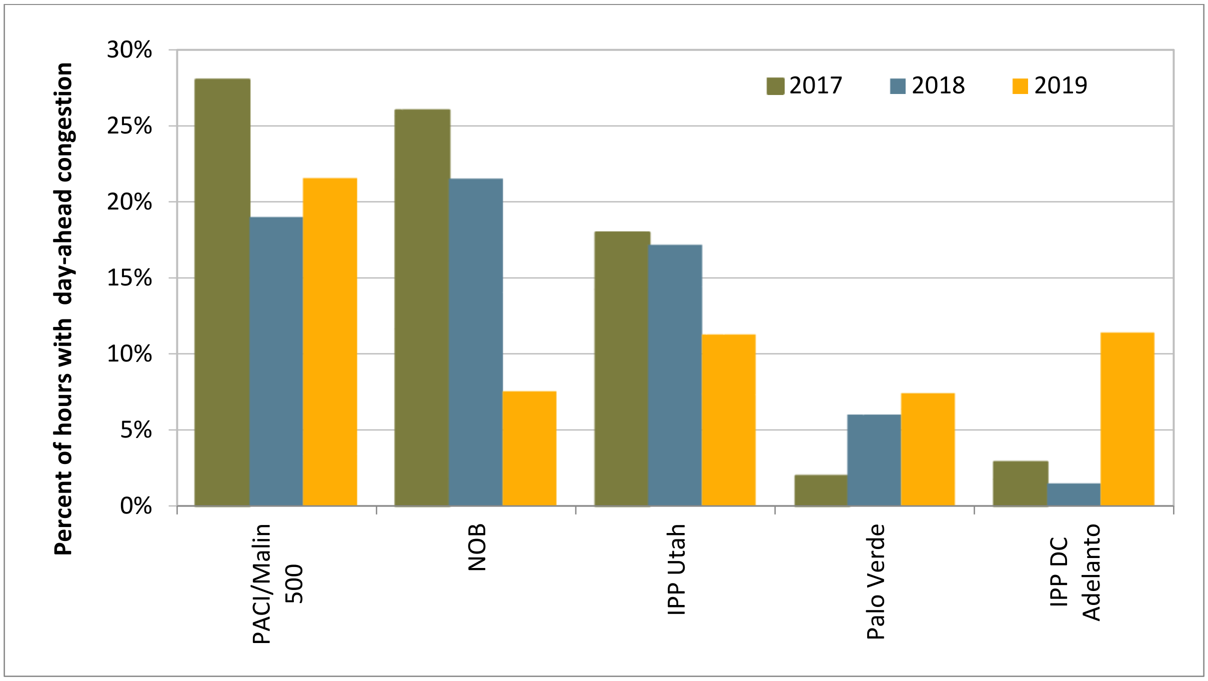
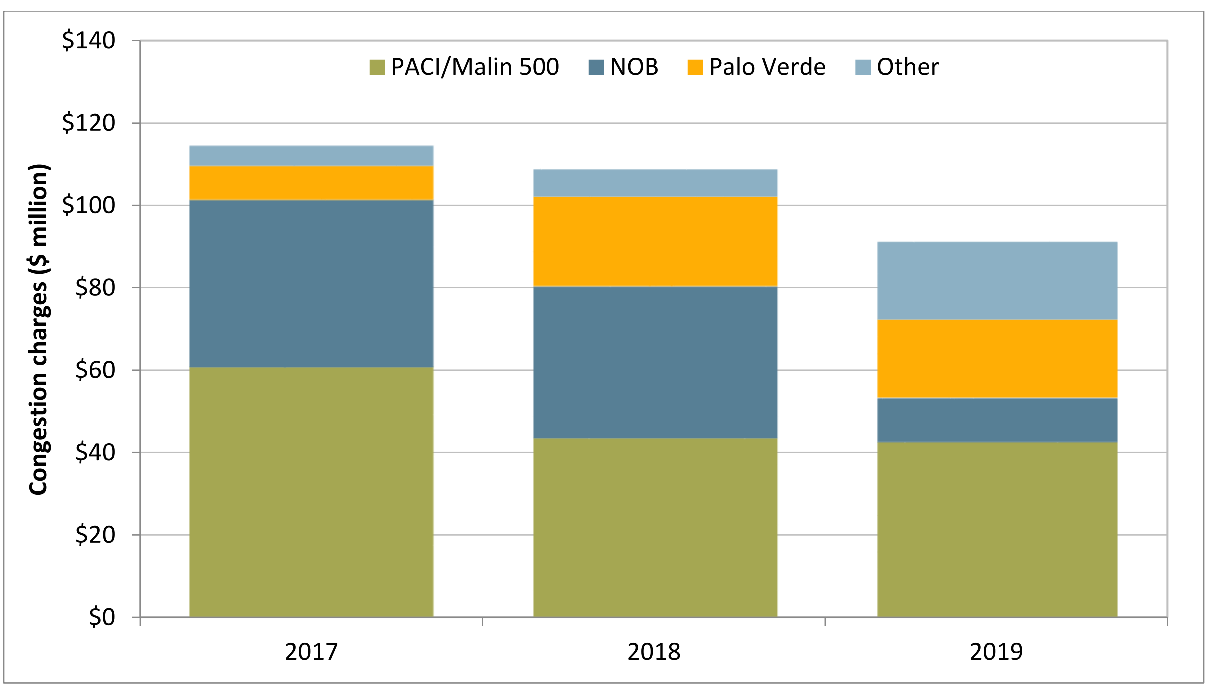


Figure 8.13 Day-ahead import congestion charges on major interties (2017-2019)



8.4 Congestion revenue rights

Congestion revenue rights sold in the auction consistently pay more to purchasers than they cost at auction. If these congestion revenue rights were not sold in the auction, all of these congestion revenues would be allocated back to load serving entities based on their share of total load. From 2009 through 2018, transmission ratepayers received about 48 percent of the value of their congestion revenue rights sold at auction, with a total shortfall of more than $860 million.

In response to these systematic losses from congestion revenue right auction sales, the ISO instituted significant changes to the congestion revenue right auction starting in the 2019 settlement year. These changes include the following:

- Track 0 – Increasing the number of constraints enforced by default in the congestion revenue right models, identifying potential enforcement of "nomogram" constraints in the day-ahead market to include in the congestion revenue right models, and other process improvements.[211]
- Track 1A – Limiting allowable source and sink pairs to "delivery path" combinations.[212]
- Track 1B – Limiting congestion revenue right payments to not exceed congestion rents actually collected from the underlying transmission constraints.[213]

In 2019, transmission ratepayer losses from congestion revenue right auctions totaled over $22 million. About $16 million of the $22 million in losses occurred in the fourth quarter. Transmission ratepayers received about 80 cents in auction revenue per dollar paid out to these rights purchased in the auction in 2019.

Section 8.4.1 provides an overview of allocated and auctioned congestion revenue rights holdings. Section 8.4.2 provides more details on the performance of the congestion revenue rights auction.

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

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211 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal*, April 19, 2018: http://www.caiso.com/InitiativeDocuments/StrawProposal-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

212 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1A Draft Final Proposal Addendum*, March 8, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalAddendum-CongestionRevenueRightsAuctionEfficiency-Track1.pdf

213 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum*, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

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.[214]

Ratepayers own the day-ahead transmission rights not held by merchant transmission or long-term rights holders. Allocating congestion revenue rights is a means of distributing the revenue from the sale of these rights, also known as congestion rent, to entities serving load to then be passed on 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 auctions. In exchange for backing the auctioned rights, ratepayers receive the net auction revenue which is allocated by load share.

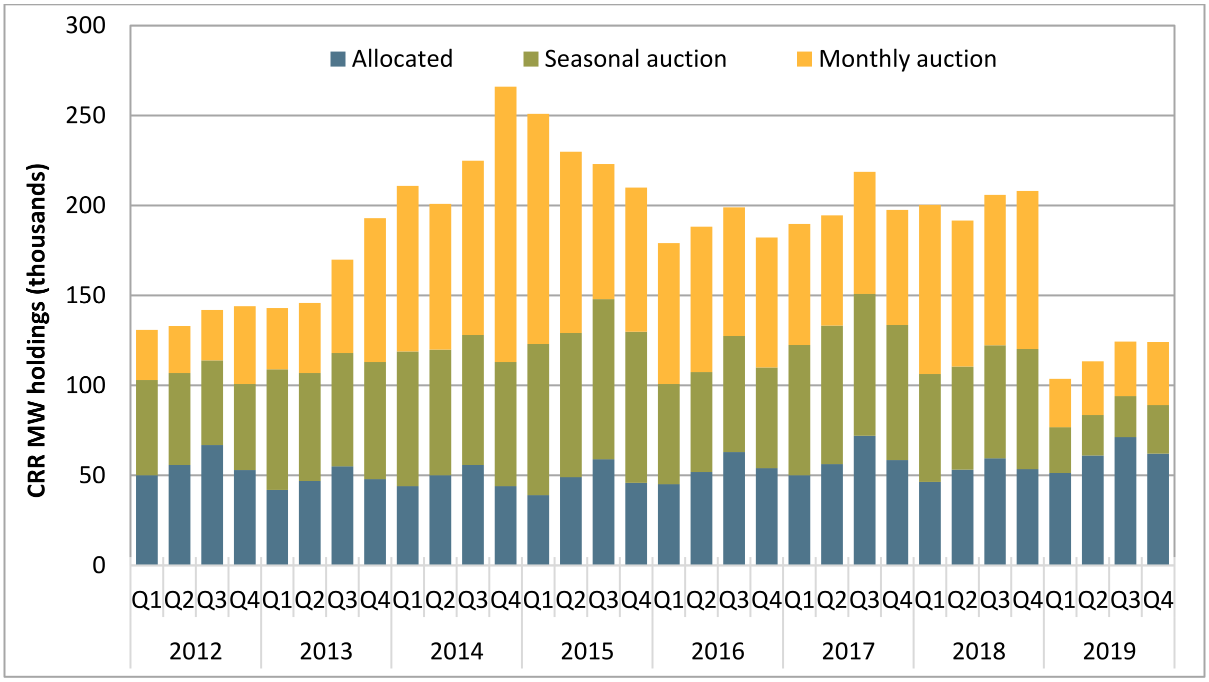
Congestion revenue right holdings

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.

Figure 8.14 shows the congestion revenue right megawatts held by allocated, seasonally auctioned, and monthly auctioned rights. This figure includes all peak and off-peak rights. In 2019, the share of allocated congestion revenue rights increased to about 53 percent of the total megawatts held. Auctioned rights held declined significantly to about 47 percent of the total. This is because of the Track 1A changes implemented for the 2019 auction which limited allowable source and sink pairs to "delivery path" combinations.

[214] 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.

Figure 8.14 Congestion revenue rights held by procurement type (2012 – 2019)[215]



8.4.2 Congestion revenue right auction returns

The ISO has historically reported on congestion revenue right revenue inadequacy as a primary metric to evaluate how well the market is functioning. This section presents an alternative metric that DMM believes is more appropriate for assessing the congestion revenue right auction.[216] 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.

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.[217] In response to these persistent losses, the ISO instituted significant changes to the auction starting in the 2019 settlement year. These changes include the following:

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215 Allocated CRR holdings also include existing transmission rights (ETCs) and transmission ownership rights (TORs)

216 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. The ISO presented an alternative metric at the May 15 market surveillance committee meeting: http://www.caiso.com/Documents/CRRDiscussion-Presentation-May15_2020.pdf and in a recent paper: http://www.caiso.com/InitiativeDocuments/CongestionRevenueRightsMarketAnalysisReport-May12-2020.pdf. The ISO's original metric summed returns to CRRs sold by the ISO at auction. The alternative metric sums returns to these CRRs with returns to allocated CRRs sold at the auction. DMM's metric, described below, sums returns to CRRs sold by either the ISO or any CRR bought or sold by load serving entities at auction. This is a measure of the CRR losses caused by agents acting on behalf of transmission ratepayers.

217 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.

- Track 0 – Increasing the number of constraints enforced by default in the congestion revenue right models, identifying potential enforcement of "nomogram" constraints in the day-ahead market to include in the congestion revenue right models, and other process improvements.[218]
- Track 1A – Limiting allowable source and sink pairs to "delivery path" combinations.[219]
- Track 1B – Limiting congestion revenue right payments to not exceed congestion rents actually collected from the underlying transmission constraints.[220]

DMM believes the current auction is unnecessary and could be eliminated.[221] If the ISO believes it is beneficial to the market to facilitate hedging, DMM believes the current auction format should be changed to a market for congestion revenue rights or locational price swaps based on bids submitted by entities willing to buy or sell congestion revenue rights.

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).[222] 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. Transmission owners then pass that transmission access charge through to ratepayers in their customers' electricity bills. Therefore, these ratepayers are entitled to the revenues from this transmission.

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

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218 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal*, April 19, 2018: http://www.caiso.com/InitiativeDocuments/StrawProposal-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

219 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1A Draft Final Proposal Addendum*, March 8, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalAddendum-CongestionRevenueRightsAuctionEfficiency-Track1.pdf

220 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum*, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

221 DMM whitepaper *"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

222 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.

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 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.[223]

[223] 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.

Congestion revenue rights auction modifications

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

A second set of changes (Track 1B) was approved by the Board of Governors in June 2018.[224] The Track 1B changes reduce the net payment to a congestion revenue right holder if payments to congestion revenue rights exceed associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis. On November 9, 2018, FERC accepted the ISO's proposal to fund congestion revenue right payments using only the day-ahead market congestion revenue and revenue from counterflow rights.[225]

Both of these sets of changes have been implemented for the 2019 auction. DMM supported both initiatives as incremental improvements that should help reduce the losses incurred by transmission ratepayers due to the ISO's auction of congestion revenue rights. However, DMM believes the current auction is unnecessary and could be eliminated.[226] If the ISO and stakeholders believe it is beneficial to facilitate hedging by selling financial contracts after the allocation of rights to load serving entities, DMM believes the current auction format should be changed to a market for congestion revenue rights or locational price swaps based on bids submitted by entities willing to buy or sell financial contracts.[227]

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 revenues received for auctioning transmission rights to the day-ahead congestion payments to these rights. Figure 8.15 compares the following for each of the last several years:

- Auction revenues received by ratepayers from congestion revenue rights sold in auction (blue bars on left axis).[228]

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

225 *FERC Order on Tariff Amendment - Congestion Revenue Rights Auction Efficiency Track 1B,* September 20, 2018*:* https://www.ferc.gov/CalendarFiles/20180920172657-ER18-2034-000.pdf?csrt=1015546819097727752
FERC Order on Tariff Amendment - Congestion Revenue Rights Auction Efficiency Track 1B, November 9, 2018*:* http://www.caiso.com/Documents/Nov9-2018-OrderAcceptingTariffRevisions-CRRTrack1BModification-ER19-26.pdf

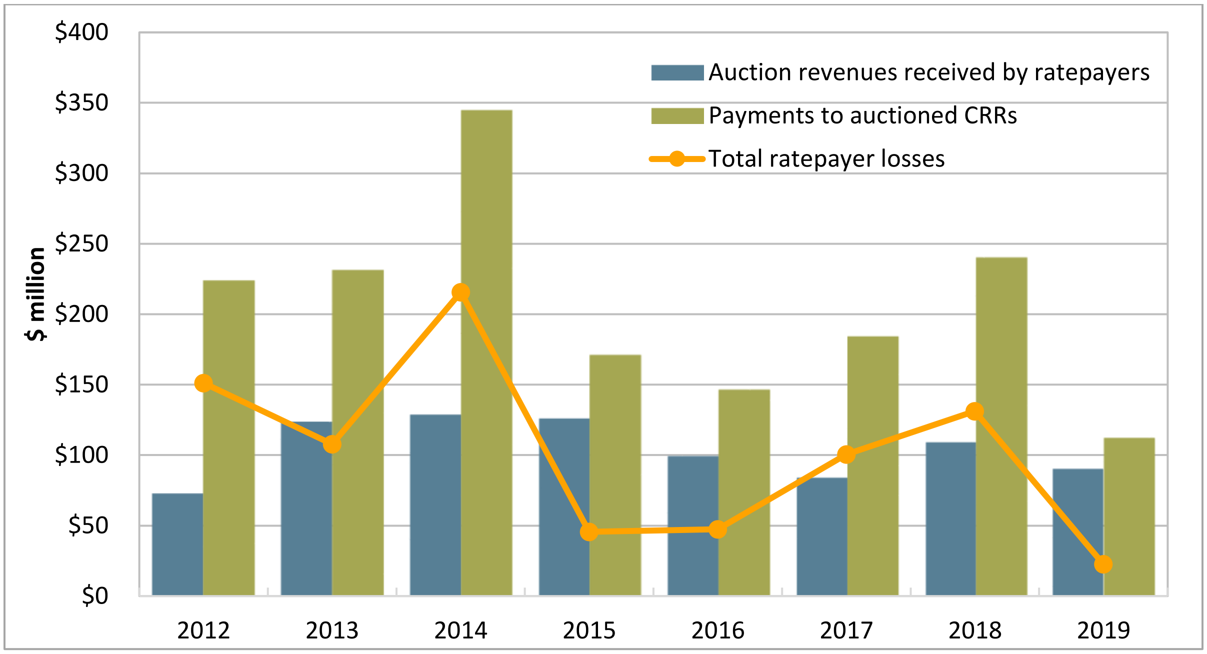
226 DMM whitepaper on market alternatives to the congestion revenue rights auction, November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Market_Alternatives_CongestionRevenueRightsAuction-Nov27_2017.pdf

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

228 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" rights. Similarly day-ahead payments made by ratepayers are net of payments by "counter-flow" rights.

- Net payments made to the non-load serving entities purchasing congestion revenue rights in auction (green bars on left axis).

Figure 8.15 Ratepayer auction revenues compared with congestion payments for auctioned CRRs



Between 2012 and 2018, ratepayers received on average about $114 million less per year from auction revenues than entities purchasing these rights in the auction received from day-ahead congestion revenues. Over this seven year period, ratepayers received an average of only about 48 cents in auction revenues for every dollar paid to congestion revenue rights holders, summing to a total shortfall of $800 million.

In 2019, the first settlement year with the restrictions on allowable source and sink “paths” and constraint specific allocations of revenue deficiency, losses were about $22 million. Ratepayers received an average of 80 cents in auction revenue per dollar paid to auctioned congestion revenue rights holders. Track 1B revenue deficiency offsets reduced payments to auctioned rights by about $44 million.

The reduction in losses from the auction in 2019 resulted from a combination of the changes implemented by the ISO, along with a significant drop in day-ahead market congestion. In 2019 day-ahead congestion revenues totaled about $354 million, compared to about $628 million in 2018. Losses from auctioned congestion revenue rights totaled about 6 percent of total day-ahead congestion revenue in 2019 compared to about 21 percent of congestion revenue in 2018.

Figure 8.16 through Figure 8.18 compare the auction revenues paid for and payments received from congestion revenue rights traded in the auction by market participant type.[229] 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 2019 at $23 million, down from $91 million in 2018. Total revenue deficit offsets were about $23 million.
- Marketers received net revenues of nearly $3 million from auctioned rights in 2019, a significant decline from $24 million in 2018. Total revenue deficit offsets were nearly $14 million.
- Physical generation entities received negative $3 million in net revenue from auctioned rights in 2019, down from over $16 million in 2018. Physical generators continued to receive the lowest overall payments from auctioned congestion revenue rights, among non-load serving entities. Total revenue deficit offsets were over $7 million.
- With the implementation of the Track 1B changes the value of congestion revenue rights sold by load serving entities cannot be known precisely because the deficit offsets charged to entities who purchased the rights made available from the sale of allocated congestion revenue rights are not known. Therefore losses caused by the load serving entity sales will be overestimated.[230] For 2019 this estimate, excluding estimates of 1B offsets, is a loss of about $1 million.

One of the benefits of auctioning congestion revenue rights is to allow day-ahead market participants to hedge congestion costs. However, in 2019, physical generators as a group continued to account for a relatively small portion of congestion revenue rights held. As a group, generators received the lowest overall payments from congestion revenue rights.

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, load serving entities face significant technical and regulatory hurdles to purchasing 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 these obligations at the prices offered by the other participants. With this approach, any entity placing a value on purchasing a

[229] 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.

[230] With the implementation of the Track 1B policy, the value of rights sold by load serving entities (LSEs) cannot be known because one cannot know precisely who the counterparty is that bought a particular right from an LSE. As a result, the additional 1B offsets that the counterparty must pay because the counterparty bought the right from the LSE cannot be calculated. The final day-ahead market payout on the right is the congestion payout minus the 1B offset. If the 1B offset owed on the CRR cannot be known then the value of the CRR cannot be accurately calculated. Excluding estimates of the 1B offsets from the CRRs that were allocated to LSEs and subsequently sold by the LSEs would cause estimates of the LSE losses from load serving entity sales to be over (under) estimated.

hedge against congestion costs could seek to purchase it directly from the load serving, financial, or other entities.

Figure 8.16 Auction revenues and payments (financial entities)

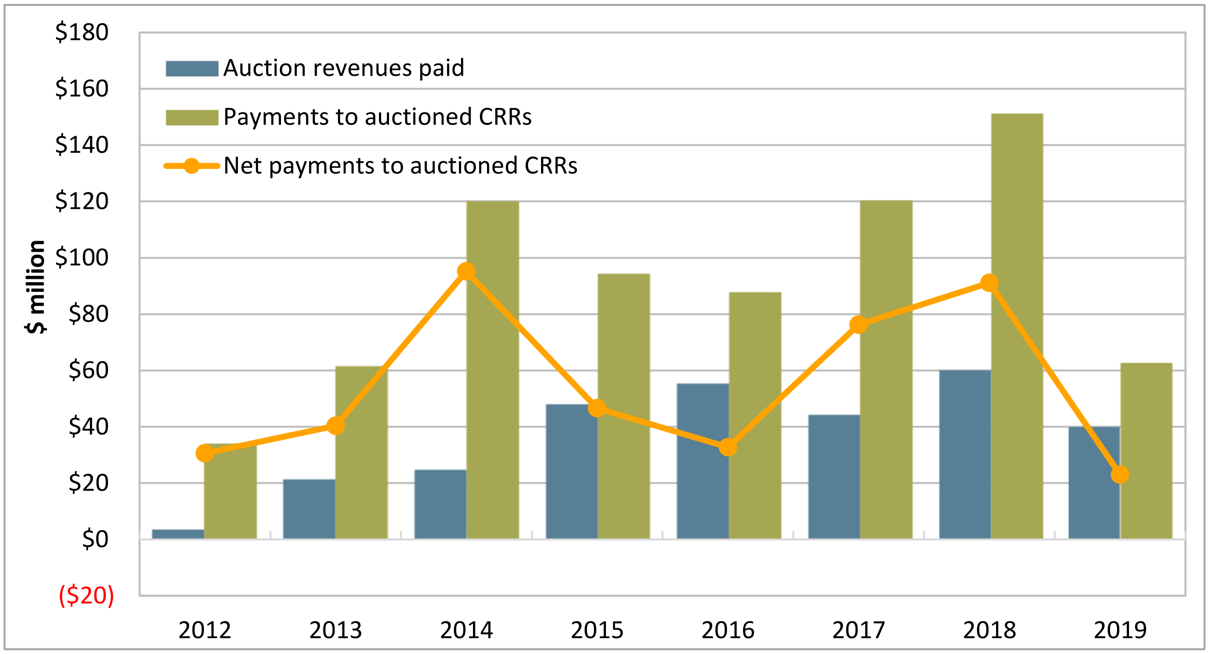


Figure 8.17 Auction revenues and payments (marketers)

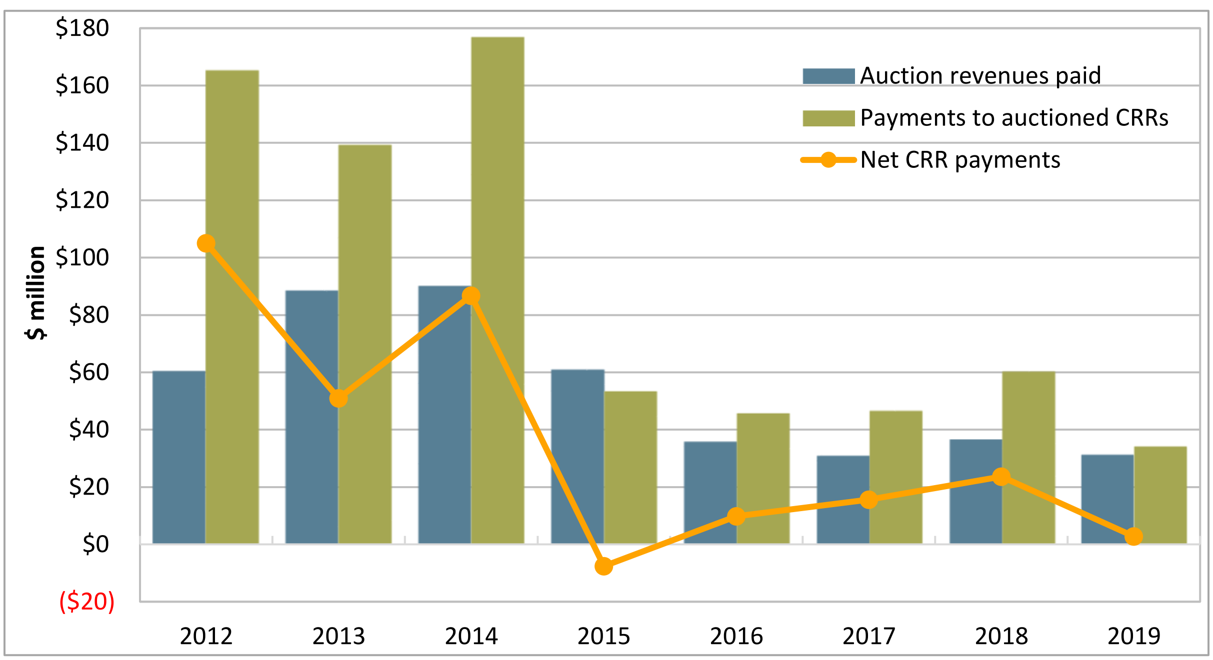
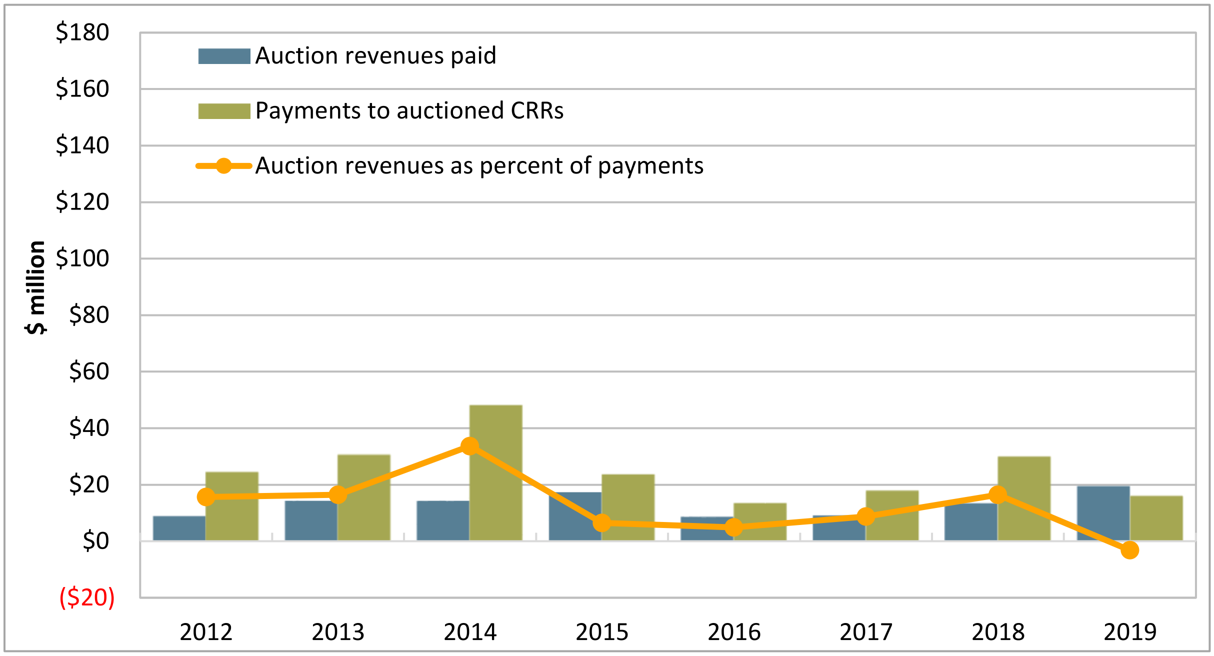


Figure 8.18 Auction revenues and payments (generators)



9 Market adjustments

Given the complexity of market models and systems, all ISO operators make some adjustments to the inputs and outputs of their standard market models and processes. For example, transmission limits may 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.

This chapter reviews the frequency of and reasons for key market adjustments made by grid operators, including exceptional dispatches, adjustments to modeled loads and residual unit commitment requirements, and blocked dispatch instructions and pricing runs in the real-time market. 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.

Findings from this chapter include the following:

- **Total energy resulting from all types of exceptional dispatch grew in 2019,** but continued to account for a relatively low portion of total system load, or 0.7 percent compared to 0.5 percent in 2018. The growth in total energy from exceptional dispatches in 2019 was driven by increases of in-sequence energy exceptional dispatch at prices below the market clearing price, largely issued for unit testing.
- **Total above-market costs due to exceptional dispatch decreased** to about $29 million in 2019 from $52 million in 2018. Although exceptional dispatches to commit units to operate at minimum load fell by only 4 percent, the cost of this category fell from $40.6 million in 2018 to $17.7 million in 2019.
- **Manual adjustments to ISO system loads increased to almost 1,000 MW in peak net load ramp hours** in the hour-ahead and 15-minute markets, continuing a dramatic increase over 2018 and 2017, which were both substantially above previous years. High hour-ahead load adjustments tend to increase imports in the ISO's hour-ahead market.
- **ISO operator adjustments added an average of 210 MW per hour to residual unit commitment requirements**, a decrease from 335 MW in 2018. In the third quarter, the average adjustment was about 690 MW per hour. In 2019 these manual adjustments were primarily attributed to load forecast uncertainty, fire danger and renewable variability concerns.
- **Within the ISO, blocked instructions fell to a daily average of 13** from a daily average of 18 in 2018. Half of the blocked instructions were blocked shut downs. In the rest of the western energy imbalance market, blocked instructions averaged 22 in both 2018 and 2019.

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* or *manual* dispatch. While exceptional dispatches are necessary for reliability, they may create uplift costs not fully recovered through market prices, affect market prices, and create opportunities for the exercise of temporal market power by suppliers.

Exceptional dispatches can be grouped into three distinct categories:

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

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

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

Summary of exceptional dispatch

Energy from exceptional dispatch continued to account for a relatively low portion of total system loads. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 0.7 percent of system loads in 2019, compared to 0.5 percent in 2018.

Total energy resulting from all types of exceptional dispatch increased by approximately 24 percent in 2019 from 2018, as shown in Figure 9.1.[231] Minimum load energy from units committed via exceptional dispatch accounted for 60 percent of all exceptional dispatch energy in 2019. About 16 percent of energy from exceptional dispatches was from out-of-sequence energy (to operate above minimum load), and the remaining 24 percent was from in-sequence energy.

The growth in total energy from exceptional dispatches in 2019 was driven by increases from in-sequence energy. Average in-sequence energy increased nearly threefold from 2018 to 2019. The increase of in-sequence energy is largely due to exceptional dispatches issued for unit testing. These exceptional dispatches are typically requested by plant operators to validate the operational characteristics of a resource.

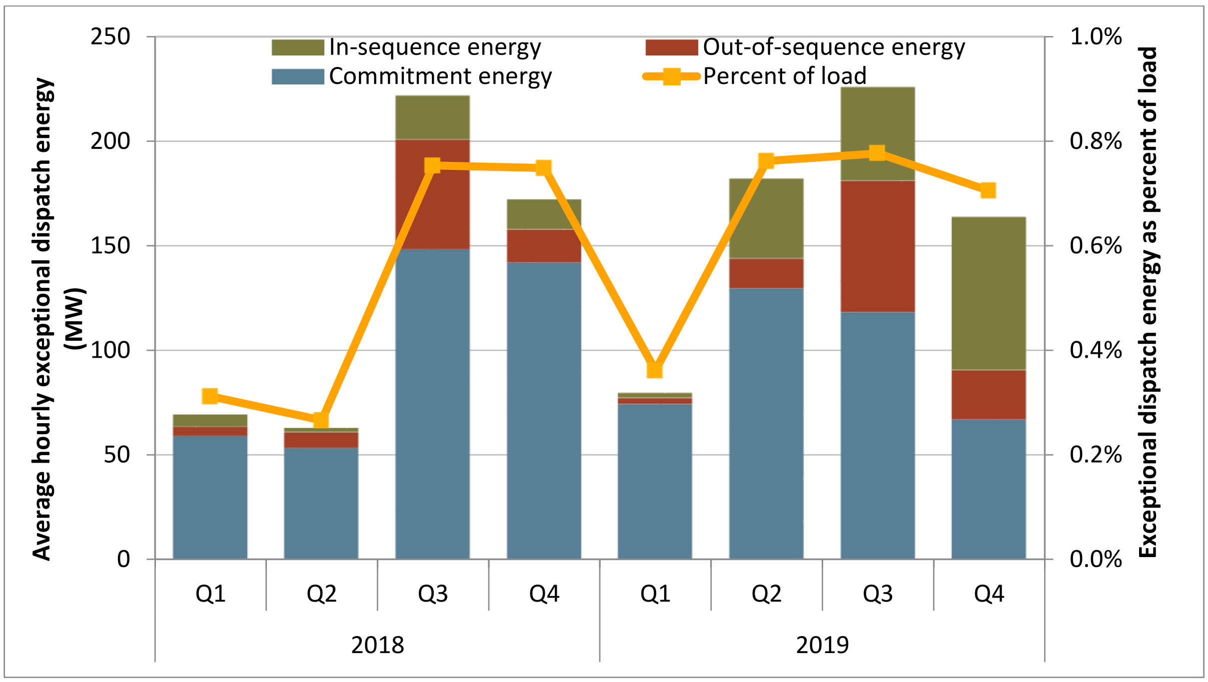
Although most exceptional dispatches are not priced and paid based on market clearing energy prices, they can affect the market clearing price for energy. Energy resulting from exceptional dispatch effectively reduces the remaining load to be met by other supply. This can reduce market prices relative

[231] 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.

to a case where no exceptional dispatch was made. However, most exceptional dispatches appear to be made to resolve specific constraints that would make energy from these exceptional dispatches ineligible to set the market price for energy if these constraints were incorporated in the market model.

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

Figure 9.1 Average hourly energy from exceptional dispatch

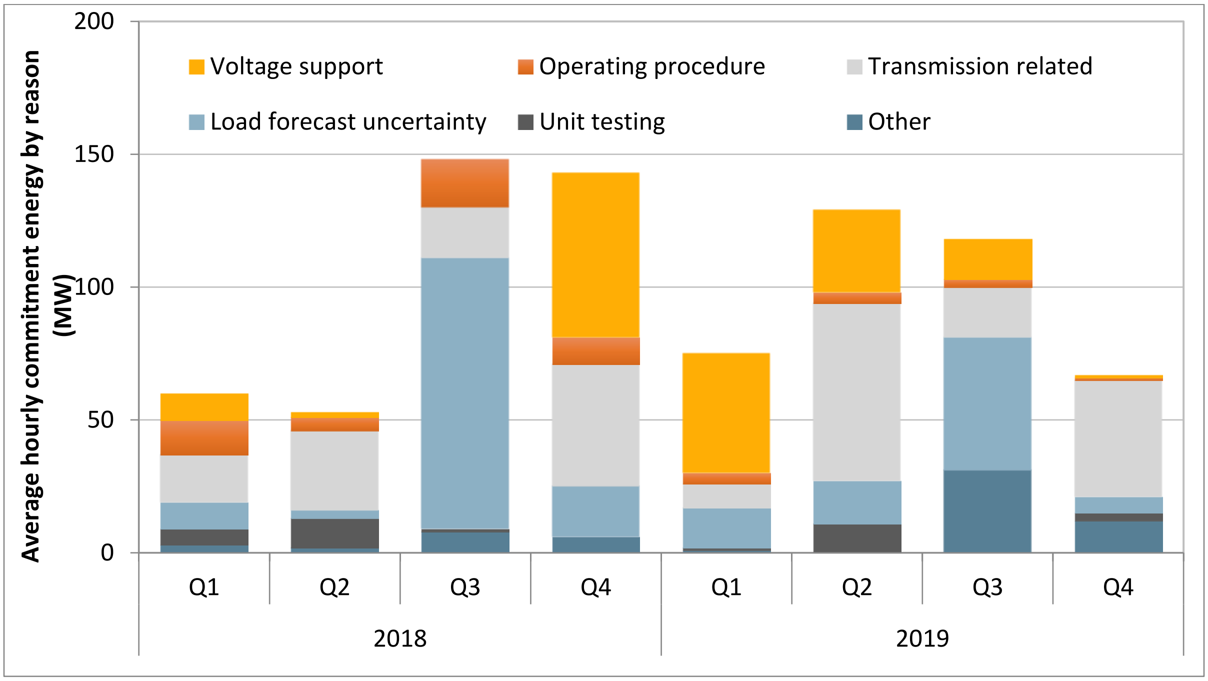


Exceptional dispatches for unit commitment

ISO operators sometimes find 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. In some cases, a scheduling coordinator may request 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. Multi-stage generating units may be committed to operate at the minimum output of a specific multi-stage generator configuration, e.g., one by one or duct firing.

Minimum load energy from exceptional dispatch unit commitments decreased by just 4 percent in 2019 compared to 2018, with most occurring in the second and third quarters of 2019. Exceptional dispatch unit commitments in the second quarter of 2019 were predominately issued for transmission-related modeling limitations. Most of these exceptional dispatches were issued to address congestion related to planned transmission outages which generally occur outside of the summer months. Unit commitment exceptional dispatches in the third quarter were primarily issued for load forecast uncertainty. When ISO operators believe the load forecast is too low, exceptional dispatches may be issued for load forecast uncertainty.

Figure 9.2 Average minimum load energy from exceptional dispatch unit commitments



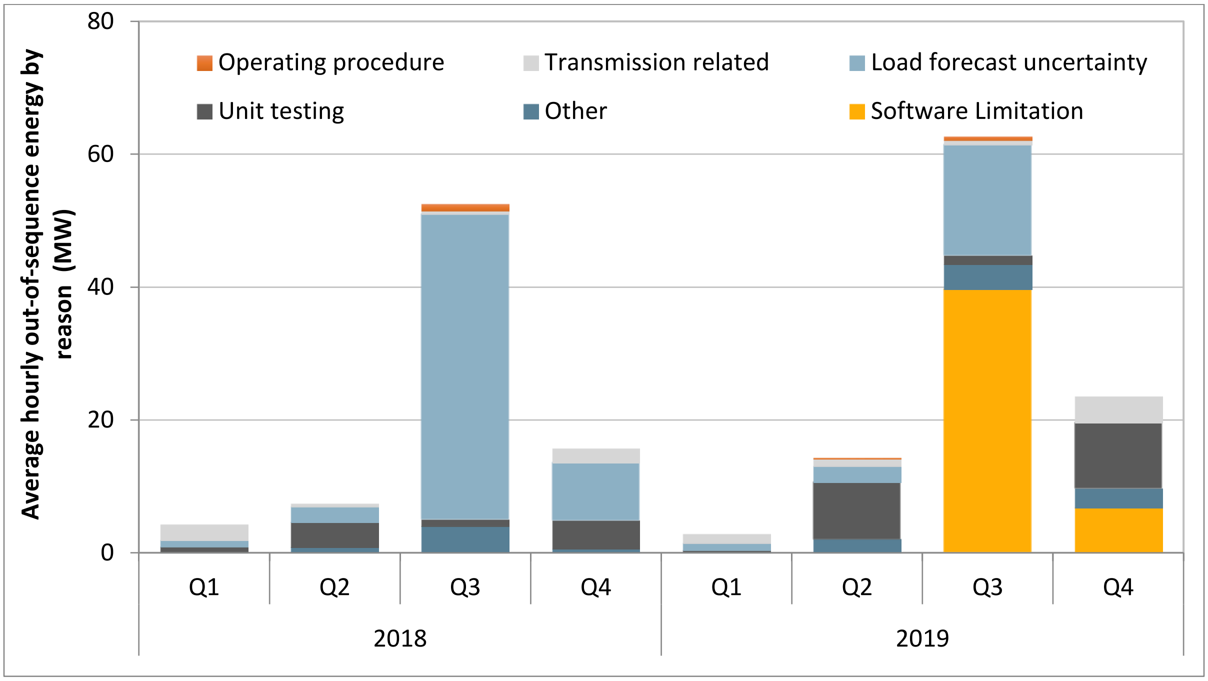
Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units above minimum load or to ensure they do not operate below their regular market dispatch increased by 29 percent in 2019. As illustrated in Figure 9.1, about 40 percent of this type of exceptional dispatch was out-of-sequence, meaning the bid price was greater than the locational market clearing price.[232] While the overall level of exceptional dispatch energy increased in 2019, the portion of exceptional dispatch for out-of-sequence energy decreased compared to previous years.

Figure 9.3 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2018 and 2019. Out-of-sequence exceptional dispatch energy was similar to the previous year, with most occurring in the third quarter. The primary reason logged for out-of-sequence energy exceptional dispatches was a software limitation. Many of these exceptional dispatches were used to ramp thermal resources to their minimum dispatchable level – a higher operating level with a faster ramp rate which allows these units to be more available to meet reliability requirements.

232 The unit's bid price can equal the resource's default energy bid if subject to energy bid mitigation or if the resource did not submit a bid.

Figure 9.3 Out-of-sequence exceptional dispatch energy by reason



Exceptional dispatch costs

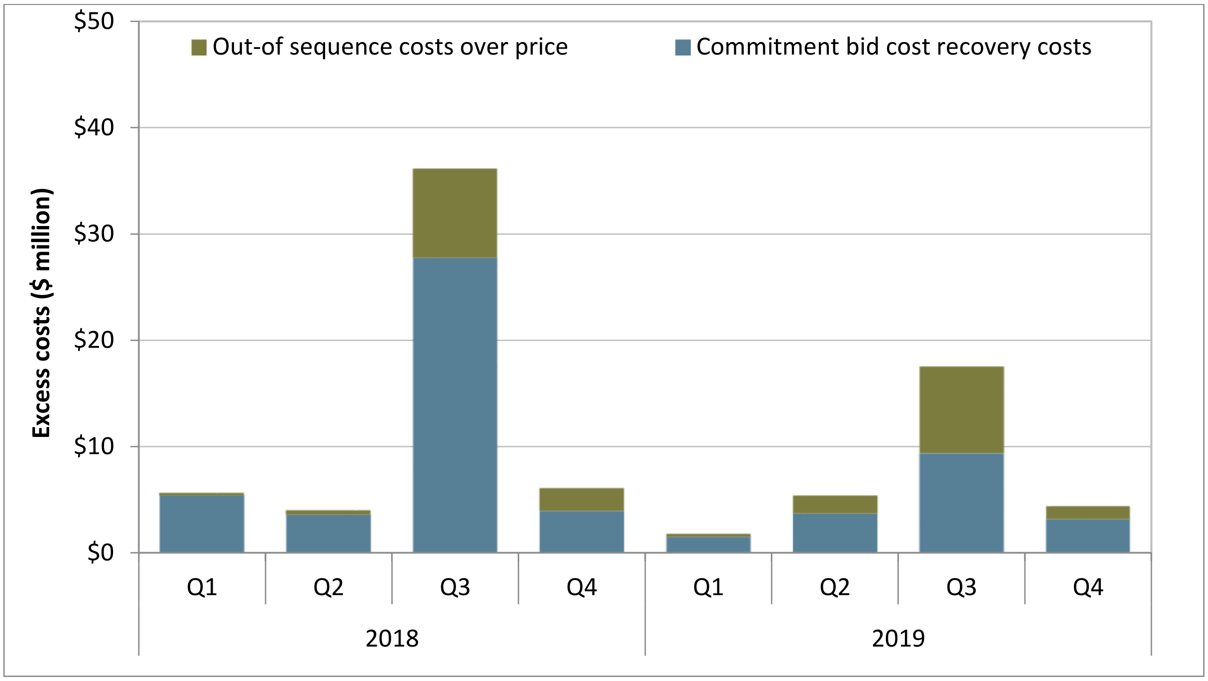
Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

- 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 clearing price for this energy. Commitment costs for exceptional dispatch paid through bid cost recovery decreased from $40.6 million to $17.7 million, while out-of-sequence energy costs remained roughly the same around $11.2 million.[233] Total above-market costs decreased by 44 percent to about $29 million in 2019 from $52 million in 2018.

233 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 dispatches

Manual dispatch on the interties

Exceptional dispatches on the interties are referred to by the ISO operators as *manual dispatches*. In 2017, imports procured through manual dispatches increased significantly. DMM's 2017 annual report cautioned 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.[234] DMM also recommended that the ISO improve its logging of manual dispatches to ensure proper settlement and allow tracking and monitoring.

In 2018, the ISO implemented improved procedures, training and logging which appear to have been effective at ensuring proper settlement and allowing better tracking and monitoring of manual dispatches of imports.

Out-of-market dispatches of imports decreased significantly in 2018 and 2019 compared to 2017. There were about 50 hours of non-emergency assistance out-of-market dispatches on the ties in 2019, accounting for less than 6,000 MWh. About 60 percent of the total non-emergency out-of-market dispatches for the year were met by one market participant.

234 *2017 Annual Report on Market Issues and Performance*, pp.206-207: http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf

Nearly 10,400 MWh of export dispatches for emergency assistance occurred in 2019 with about 80 percent attributed to one balancing authority. Export emergency assistance occurred in all months, with the maximum occurring in July with about 2,300 MWh.

Energy imbalance market

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*. In the energy imbalance market, manual dispatches are similar to exceptional dispatches in the ISO. Manual dispatches within the energy imbalance market 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.

Like exceptional dispatches in the ISO system, manual dispatches in the energy imbalance market do not set prices, and the reasons for these manual dispatches are similar to those given for ISO exceptional dispatches. However, manual dispatches in the energy imbalance market are not settled in the same manner as exceptional dispatches within the ISO. Energy from these manual dispatches is settled on the market clearing price, similar to uninstructed energy. This eliminates the possibility of exercising market power by either setting prices or by being paid "as-bid" at above-market prices.

Figure 9.5 through Figure 9.8 summarize monthly manual dispatch activity of participating and non-participating resources for energy imbalance market areas with incremental or decremental volume above 10 MW in any month. The volume of manual dispatches in energy imbalance market areas can peak in the first few months that a new market participant is active in the market, such as the Balancing Authority of Northern California in 2019.

However, as with the previous year, manual dispatches in the Arizona Public Service area remained relatively high in 2019. In September 2018, Portland General Electric experienced a period of high decremental manual dispatches on participating resources. This was related to software limitations associated with a multi-stage generator which were resolved.

Figure 9.5 EIM manual dispatches – Arizona Public Service area

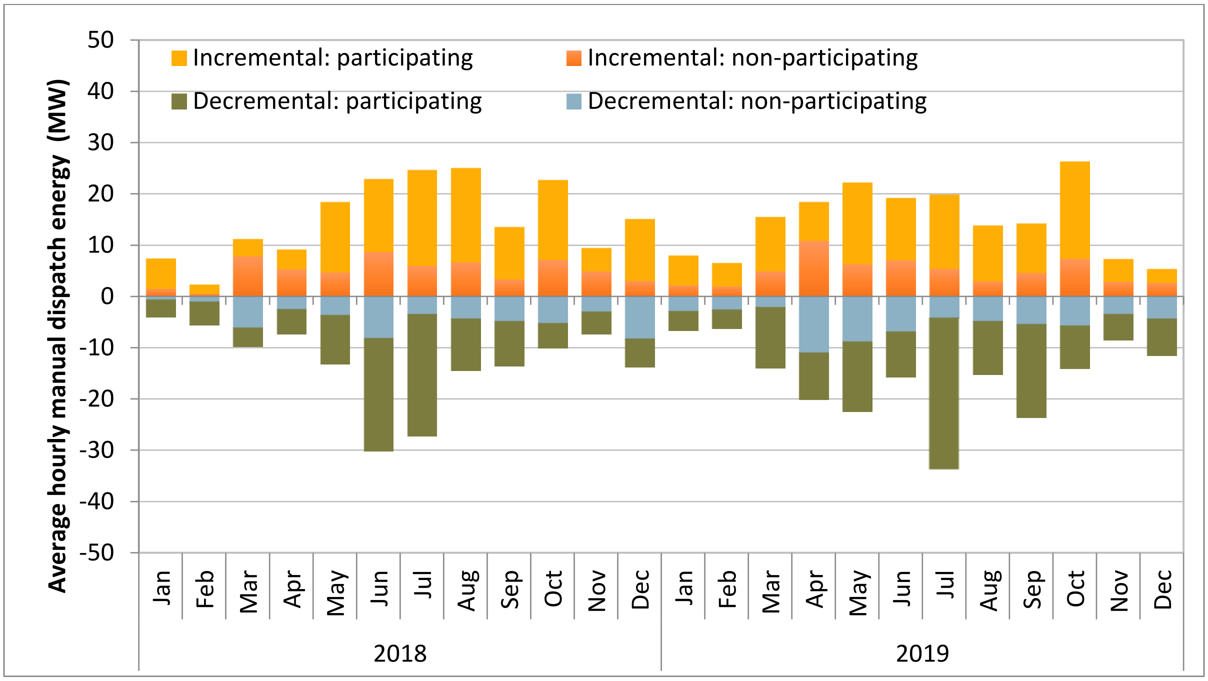


Figure 9.6 EIM manual dispatches – Portland General Electric area

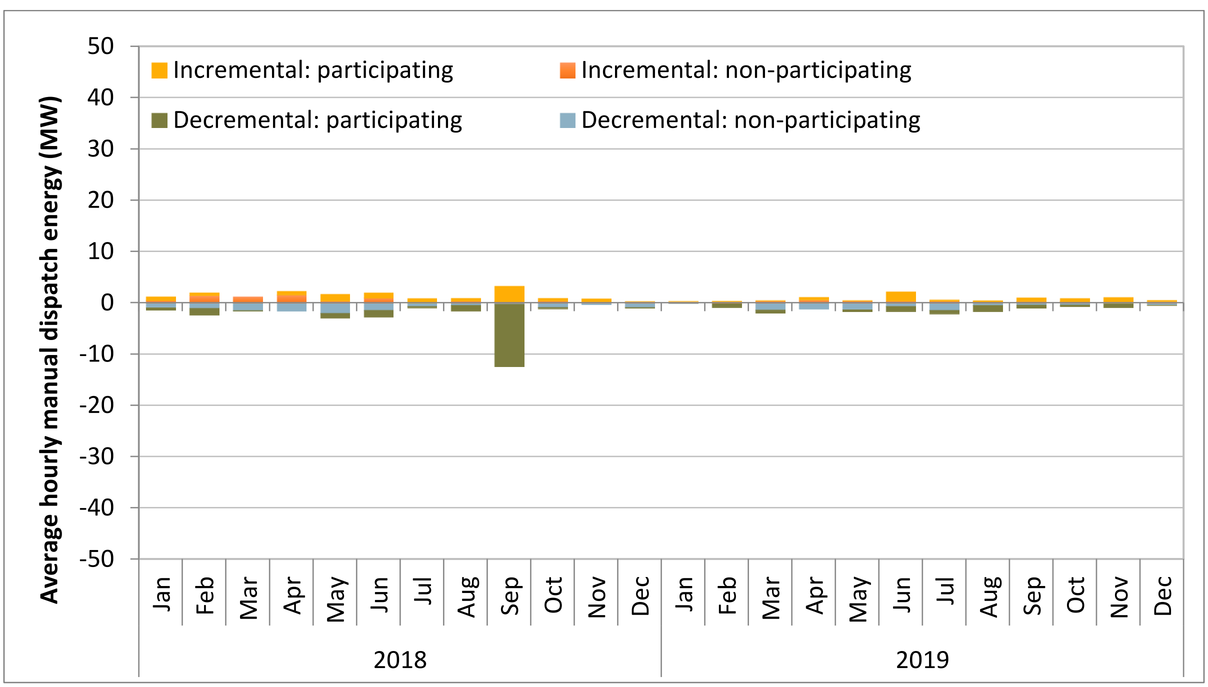


Figure 9.7 EIM manual dispatches – Idaho Power Company area

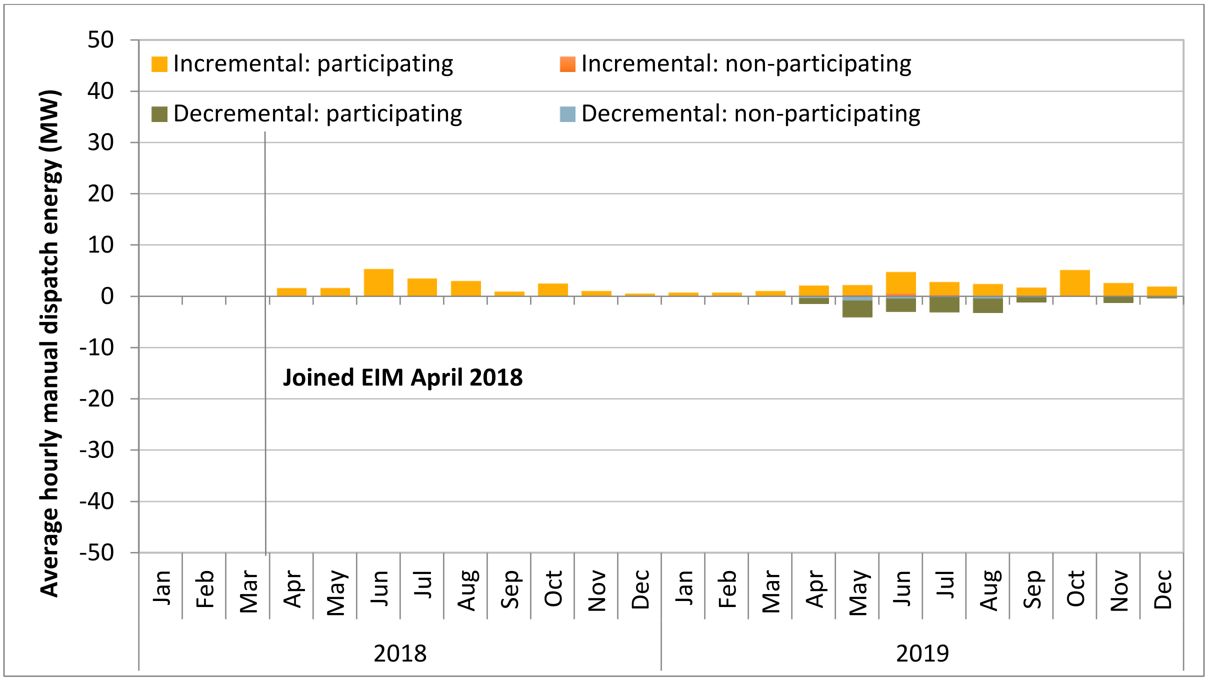
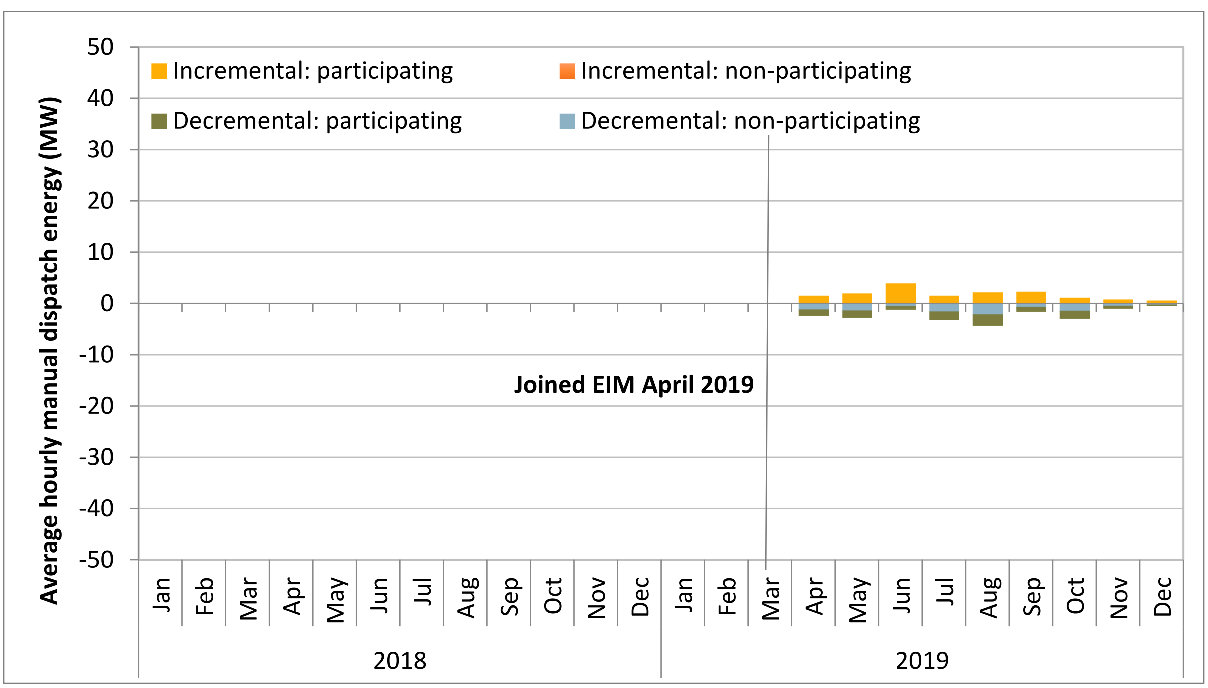


Figure 9.8 EIM manual dispatches – Balancing Authority of Northern California area



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*. The ISO has begun using the term *imbalance conformance* to describe these adjustments. Load forecast adjustments can be used to account for potential modeling inconsistencies and inaccuracies.

In the ISO, load adjustments are also routinely used in the hour-ahead and 15-minute scheduling processes in a manner which helps to increase the supply of ramping capacity within the ISO during morning and evening hours when net loads increase sharply. Increasing the hour-ahead and 15-minute forecast can increase ramping capacity within the ISO by increasing hourly imports and committing additional units within the ISO.

Real-time market load adjustments by the ISO

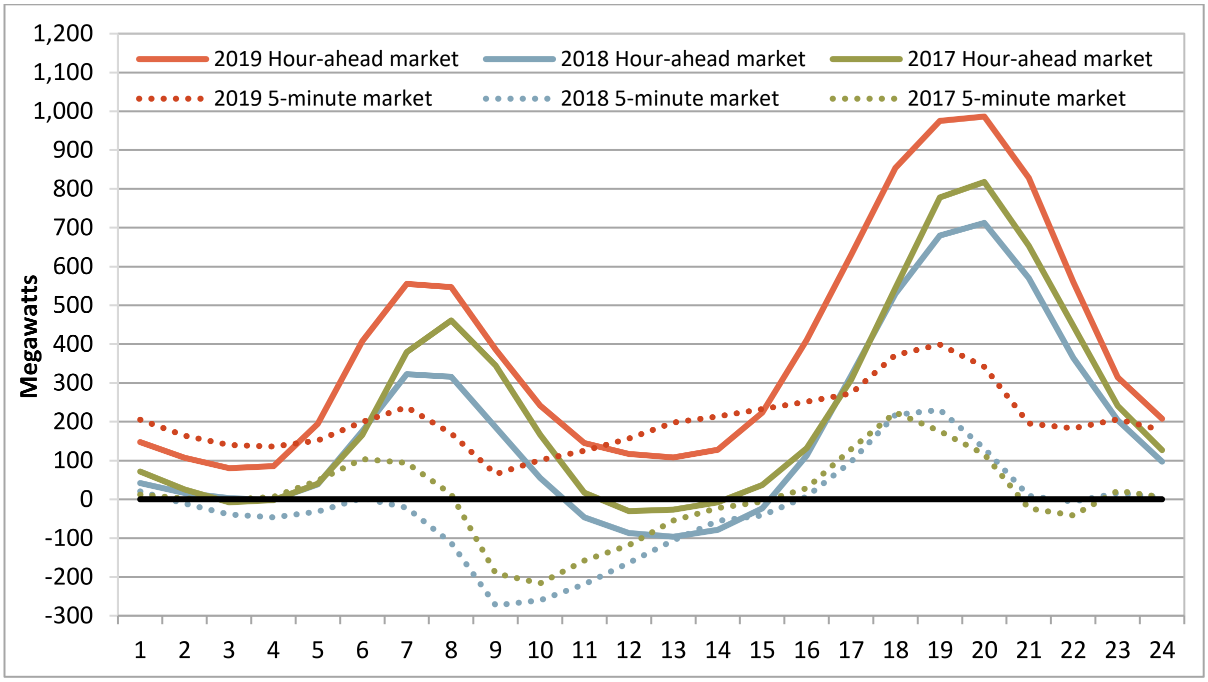
Beginning in 2017, there was a large increase in load forecast adjustments in the steep morning and evening net load ramp periods in the ISO's hour-ahead and 15-minute markets. This large increase continued in 2019, with average hourly load adjustments in the hour-ahead and 15-minute markets peaking at almost 1,000 MW, almost a two-fold increase from the peak in 2016 (460 MW).

Figure 9.9 shows the average hourly load adjustment profile for the hour-ahead and 5-minute markets for 2017 to 2019.[235] As in prior years, the general shape and direction of load adjustments were similar for hour-ahead and 15-minute adjustments. As shown in Figure 9.9 average hour-ahead load forecast adjustments in 2019 mirror the pattern of net loads over the course of the day, averaging 380 MW over the entire day with a maximum of about 550 MW in the morning ramp hours and nearly 1,000 MW during the evening ramping hours.

The load adjustments in the 5-minute market have a similar shape as the hour-ahead market, but less pronounced. The early morning and mid-day hours differ the most, with the 5-minute market slightly exceeding the hour-ahead market. The largest positive deviations between the 5-minute and other markets were observed in hours ending 19 to 21, when the hour-ahead adjustments exceeded the 5-minute adjustments by around 600 MW.

[235] Load adjustments in the hour-ahead and 15-minute markets are very similar to each other throughout the day. The 15-minute market data has been removed from the figure for clarity.

Figure 9.9 Average hourly load adjustment (2017 - 2019)



Adjustments are often associated with over- or under-forecasted load, changes in expected renewable generation, and morning or evening net load ramp periods. The ISO also adjusts loads in the 15-minute and 5-minute real-time markets to account for potential modeling inconsistencies. Some of these inconsistencies are due to changing system and market conditions, such as changes in load and supply (e.g., exceptional dispatches), between the executions of different real-time markets.[236] 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.

High real-time market load adjustments in peak net load hours are associated with increasing hourly import bids in morning and evening ramping hours. Increasing imports in these hours increases the supply of internal generation that could be ramped up or down in the real-time market.

Similarly, since unit commitments and transitions for resources within the ISO are made in the 15-minute market, maintaining a relatively high positive load bias in the 15-minute market can make additional generation available within the ISO during the morning and evening ramping hours.

The impact of the hour-ahead load bias on real-time imports is reflected in Figure 9.10, which shows the incremental change in gross and net imports in the real-time market. The light green area in Figure 9.10 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 in Figure 9.10 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

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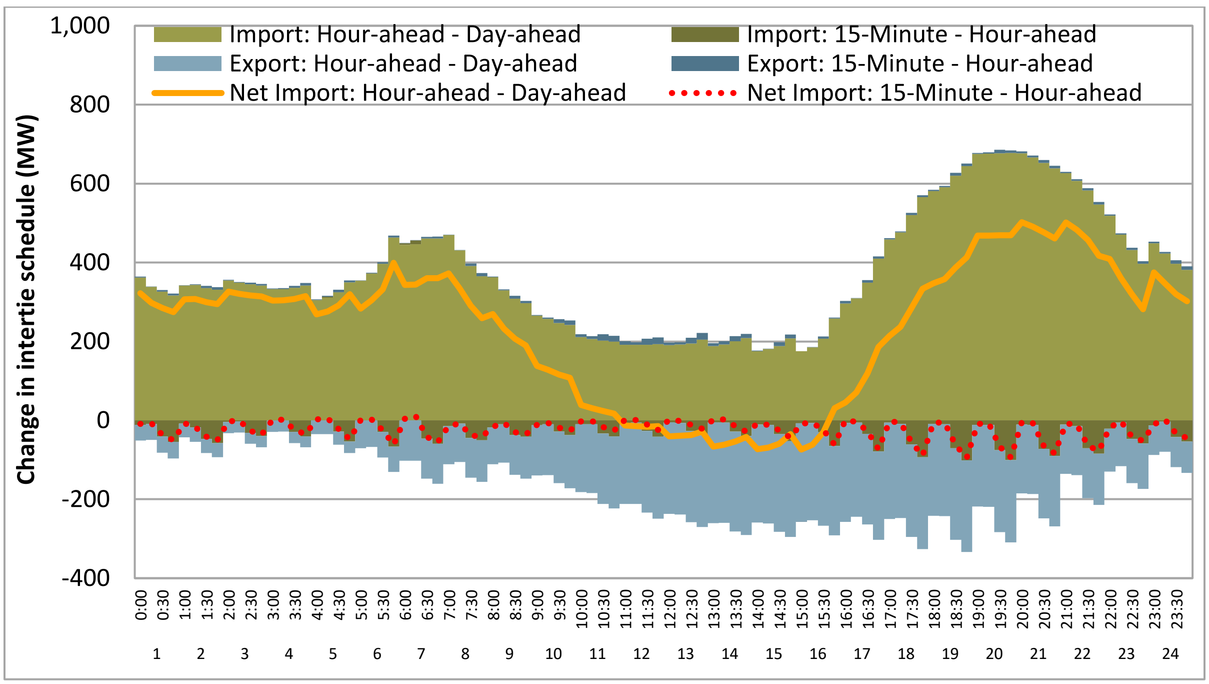
236 See 153 FERC ¶ 61,305, order on compliance filing, issued December 17, 2015: http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf

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.

As shown in Figure 9.10, most incremental commitment of imports occurs in the hour-ahead market outside the mid-day hours in two periods, hours ending 1 to 10 and hours ending 17 to 24. During these hours in 2019, net interchange averaged about 320 MW, an increase from an average of 230 MW during these hours in 2018 but similar to 2017. As in 2018, the highest average net interchange was in hours ending 19 to 22, reaching a peak in hour ending 21 at 480 MW.

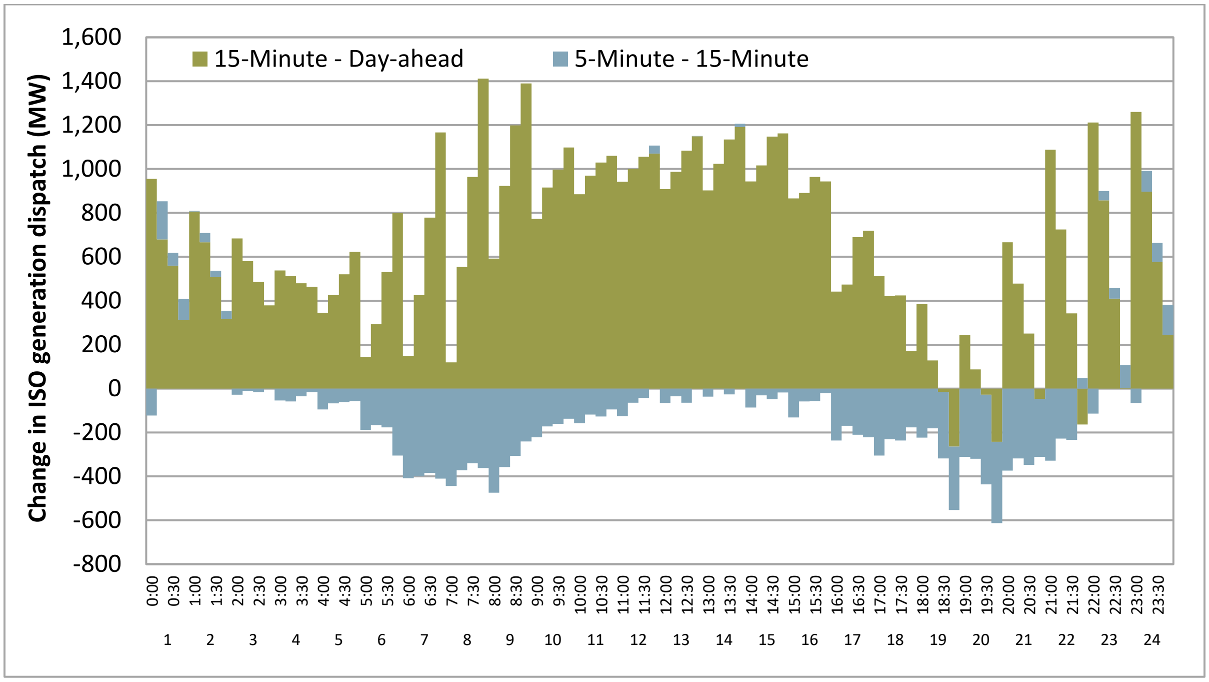
There was also a noticeable increase in both imports and exports in 2019 between the hour-ahead and day-ahead markets during mid-day solar peak periods, compared to both 2018 and 2017. Net imports fell between the day-ahead and hour-ahead markets in these hours, similar to prior years. This appears to be associated with rebidding of energy that did not clear the day-ahead market that then often cleared at price-taker bid floor levels associated with self-schedules in the real-time markets.

Figure 9.10 Net interchange dispatch volume



Meanwhile, the incremental dispatch of internal generation between the day-ahead and 15-minute real-time markets tended to decrease during the morning and evening ramping hours, similar to the previous year. Figure 9.11 shows the average incremental change for internal generators between the day-ahead and the 15-minute market (green bars) and between the 15-minute market and the 5-minute market (blue bars). This decrease in generation within the ISO tends to offset the increases in energy imports in the hour-ahead market as shown in Figure 9.10.

Figure 9.11 Imbalance generation dispatch volume



Load adjustments in the energy imbalance market

Energy imbalance market operators can also make load adjustments in their respective balancing areas. Figure 9.12 and Figure 9.13 show the frequency of positive and negative load forecast adjustments for the ISO and different energy imbalance market areas during 2019 for the 15-minute and 5-minute markets, respectively.

For much of 2019, positive load adjustments in the 15-minute market were most frequent in Arizona Public Service. Negative load adjustments also occurred in Arizona Public Service as well as PacifiCorp and Puget.

Load adjustments in the 5-minute market were more frequent than load adjustments in the 15-minute market for most balancing areas and quarters during the year. This trend was particularly notable in the NV Energy, Puget Sound Energy, Portland General Electric, Idaho Power, and PacifiCorp areas. In Arizona Public Service, the frequency of 5-minute load adjustment was similar to the 15-minute adjustment.

Figure 9.12 Average frequency of positive and negative load adjustments (15-minute market)

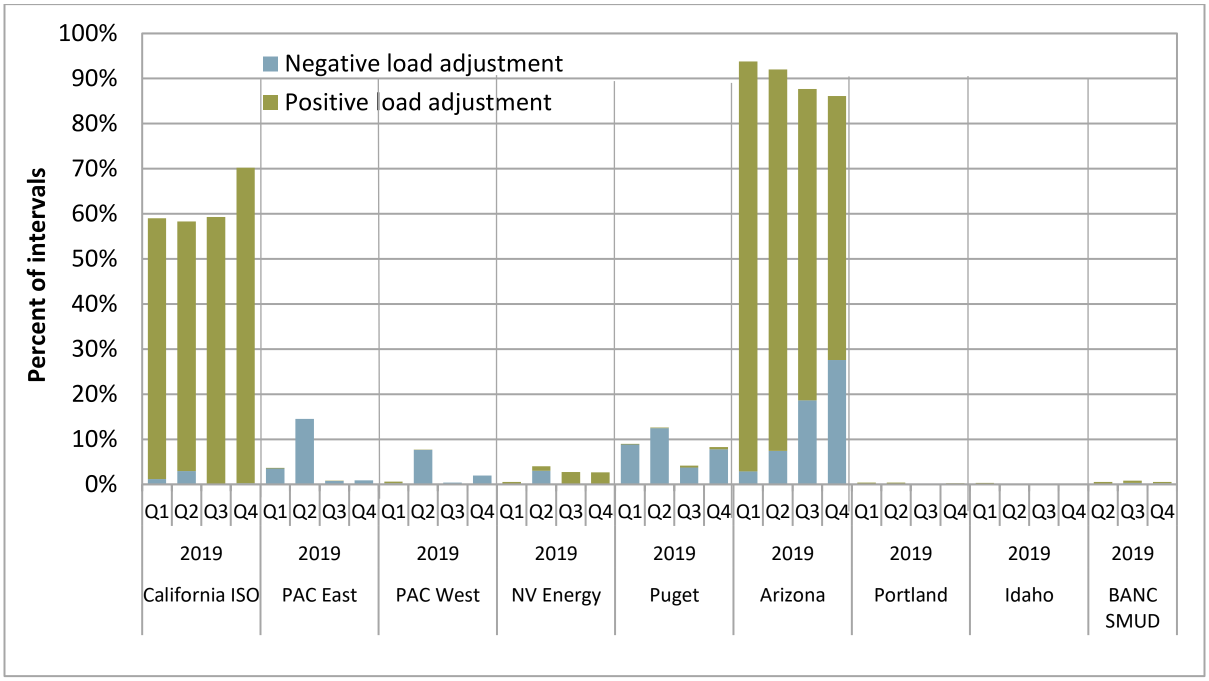
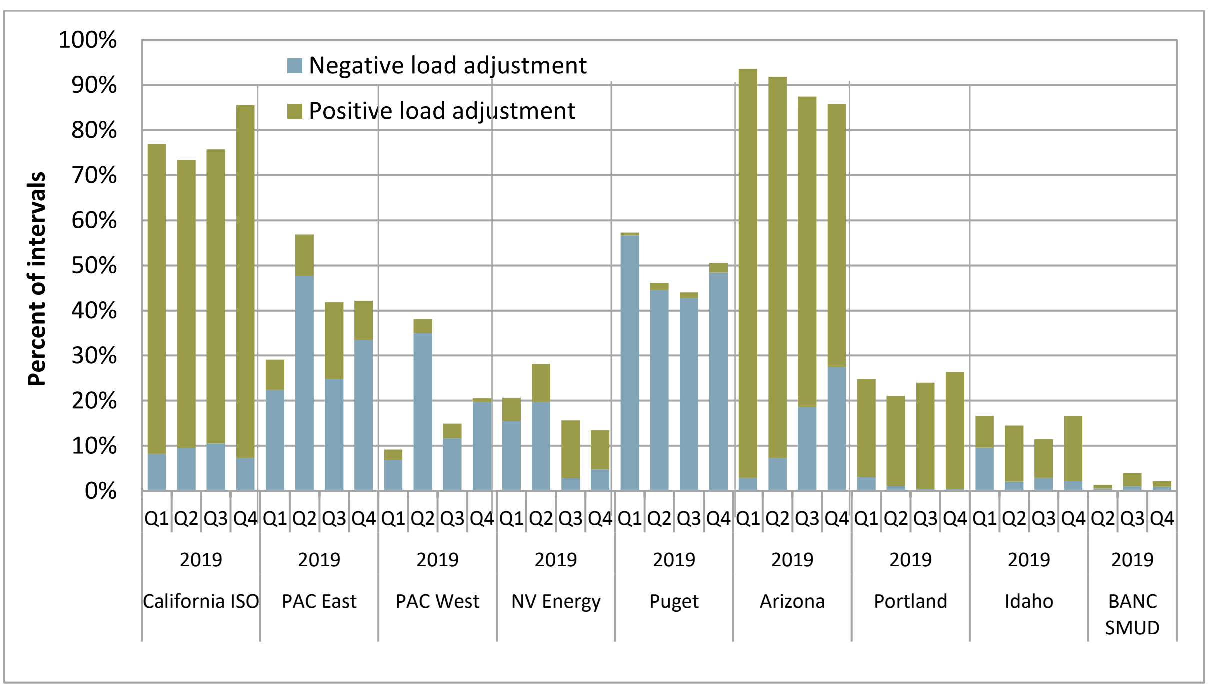


Figure 9.13 Average frequency of positive and negative load adjustments (5-minute market)



9.4 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 to bridge the gap between the amount of load cleared in the day-ahead market and the day-ahead forecast load.

The quantity of residual unit commitment procured is determined by several components which are automatically calculated, as well as any manual adjustment that ISO operators make to increase residual unit commitment requirements for reliability purposes. These operator adjustments to residual unit commitment requirements have increased significantly starting in June 2018.

Figure 9.14 shows the average hourly determinants of capacity requirements used in residual unit commitment process by quarter in 2018 and 2019.

The blue bars in Figure 9.14 show the portion of the residual unit commitment requirement that is calculated based on the difference between cleared supply (both physical and virtual) in the day-ahead market and the ISO’s day-ahead load forecast. This difference decreased residual unit commitment requirements on a yearly average basis in 2018 and 2019. Average forecast values exceeded cleared supply, however, in all but the peak solar hours of the day as well as during the third and fourth quarters of 2019.

The residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of variable energy resources and the forecast output of these renewable resources. This intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market. This automated adjustment is represented by the yellow bar in Figure 9.14.

The residual unit commitment process also includes an automated adjustment to account for the need to replace net virtual supply clearing in the day-ahead market, which can offset physical supply in the day-ahead market. In 2019, this automated adjustment, shown in the green bars in Figure 9.14, was the primary driver of positive residual unit commitment requirement. The average increase in residual unit commitment requirements due to net virtual supply decreased slightly in 2019, particularly in the third and fourth quarters.

Finally, ISO operators can also make manual adjustments to increase the amount of residual unit commitment requirements. These manual adjustments, shown in the red bar in Figure 9.14, contributed an average of 210 MW per hour to requirements, a decrease from about 335 MW per hour in 2018. As with the previous year, these manual adjustments were primarily attributed to load forecast uncertainty, fire danger, and renewable variability concerns. These operator adjustments were frequent from June through September. In the third quarter, the average adjustment was about 690 MW per hour, a decrease from about 985 MW per hour in 2018.

Figure 9.15 shows these same four determinants of the residual unit commitment requirements for 2019 for each operating hour of the day. As shown by the red bars in Figure 9.15, manual adjustments by grid operators tended to be greatest between the peak load hours ending 9 through 22. During the third quarter of 2019, operators increased the residual unit commitment requirement by about 1,100 MW on average for hours ending 9 through 23.

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 2019. Similar to 2018, the bulk of the intermittent resource adjustments occurred in hours ending 9 to 18.

Figure 9.14 Determinants of residual unit commitment procurement

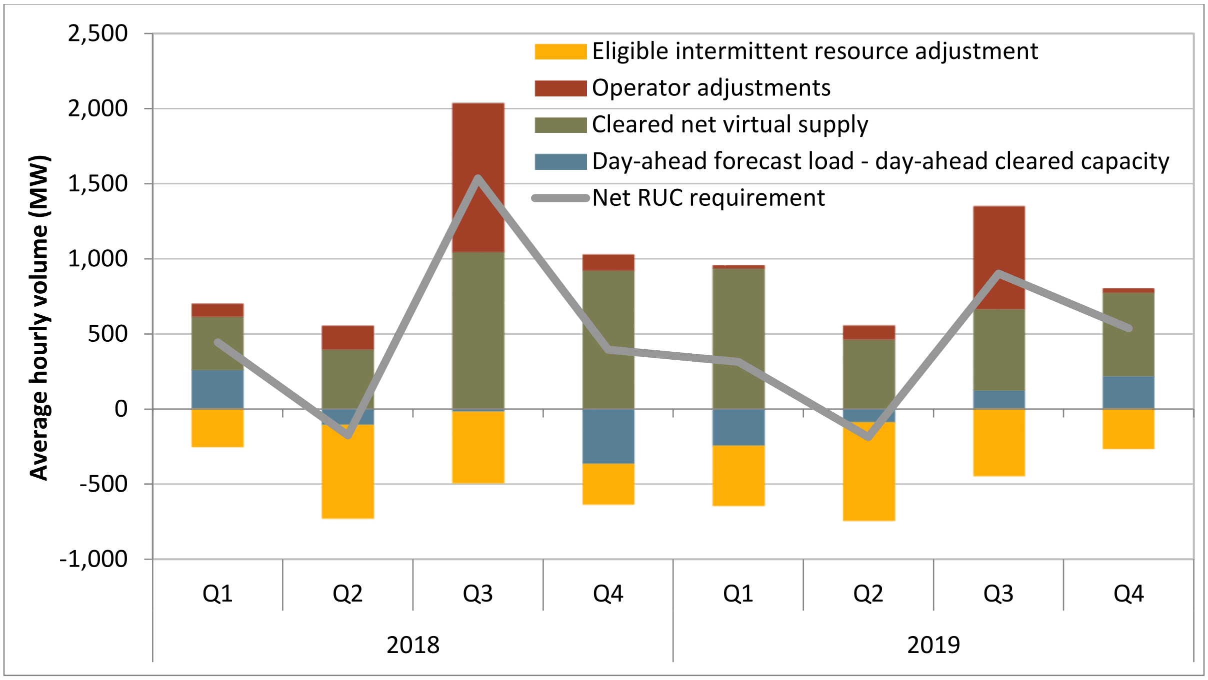
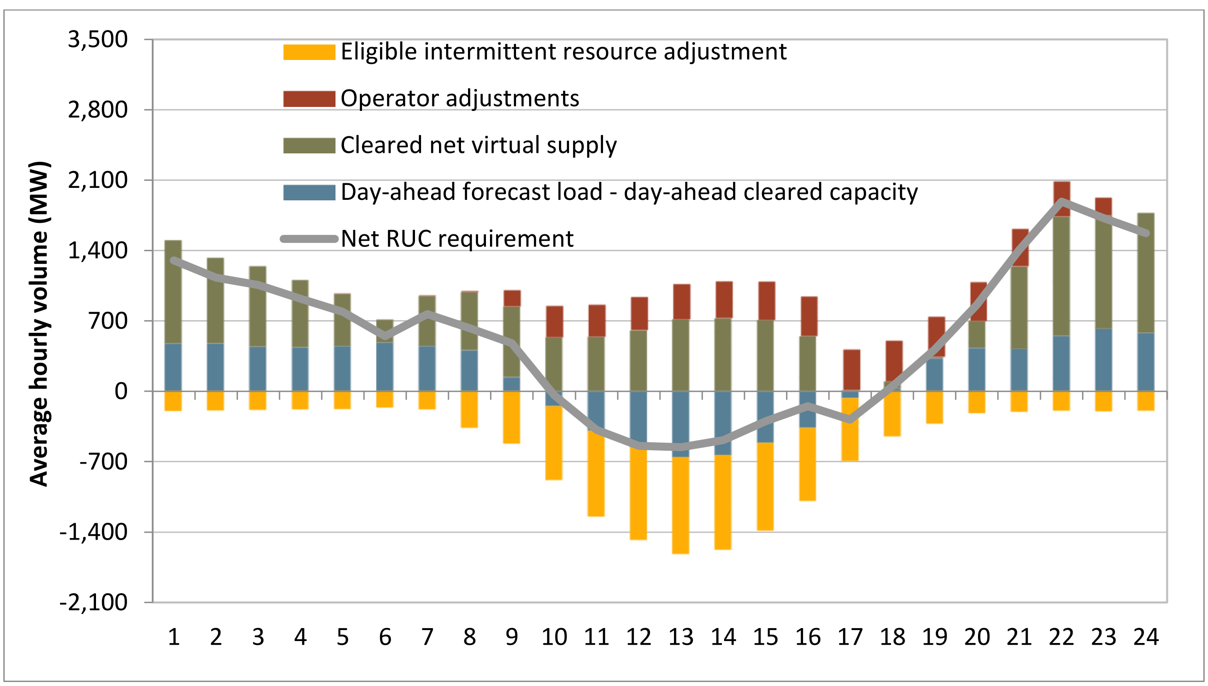


Figure 9.15 Average hourly determinants of residual unit commitment procurement (2019)



9.5 Blocked instructions

The 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.[237] 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, telemetry data is an input to the real-time market system. If that 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.

Within the ISO, blocked instructions fell from a daily average of 18 in 2018 to 13 in 2019 (blue, green, and gold bars in the figure). Figure 9.16 shows the frequency of blocked real-time commitment start-up, shut-down, and multi-stage generator transition instructions. Blocked shut-down instructions continued to be the most common reason for blocked instructions at about 50 percent in 2019, a decrease from about 72 percent the previous year.

Blocked start-up instructions accounted for about 35 percent of blocked instructions within the ISO in 2019, an increase from nearly 20 percent in 2018. Blocked transition instructions to multi-stage generating units also increased to about 15 percent from 8 percent in 2018. 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.

The average number of instructions blocked by western energy imbalance market operators was 22 per day in both 2019 and 2018 (red bars in Figure 9.16). During 2019, 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 blocked dispatches for the energy imbalance market remains high due to two balancing areas' selection of this tool to limit transitions of multi-stage generating resources.

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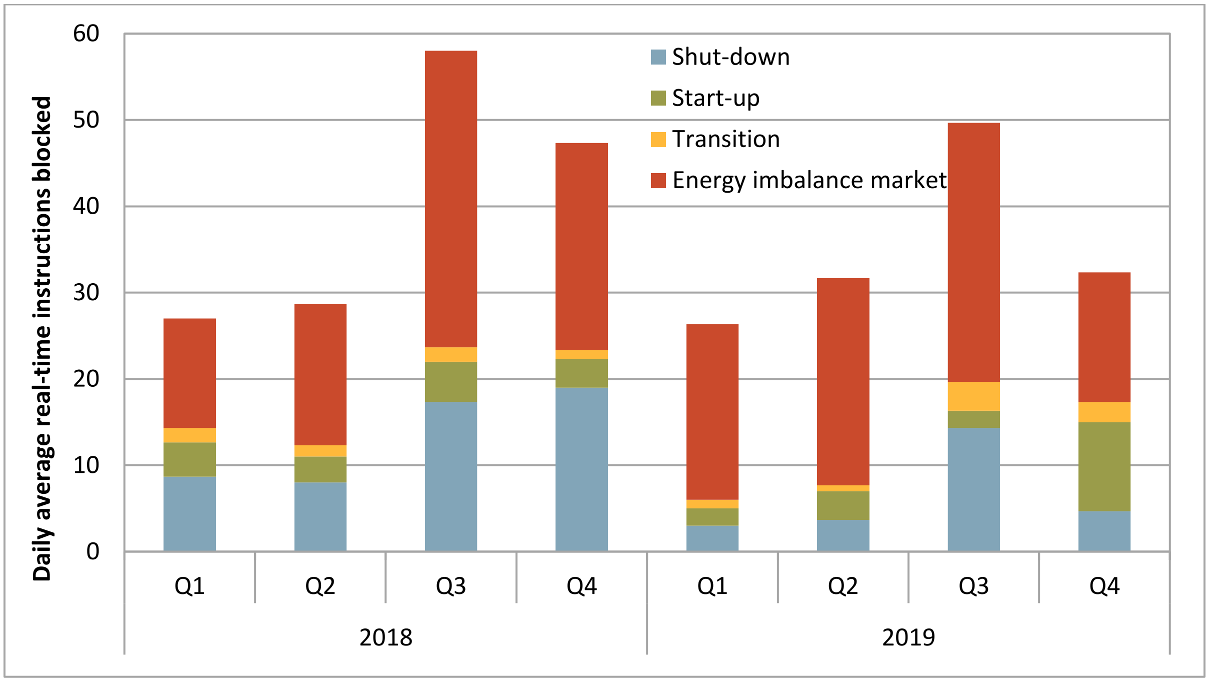
[237] The ISO reports on blocked instructions in its monthly performance metric catalog. Blocked instruction information can be found in the later sections of the monthly performance metric catalog report: https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=AF1E04BD-C7CE-4DCB-90D2-F2ED2EE8F6E9.

Figure 9.16 Frequency of blocked real-time commitment instructions



9.6 Blocked dispatches

Grid 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 have caused 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.

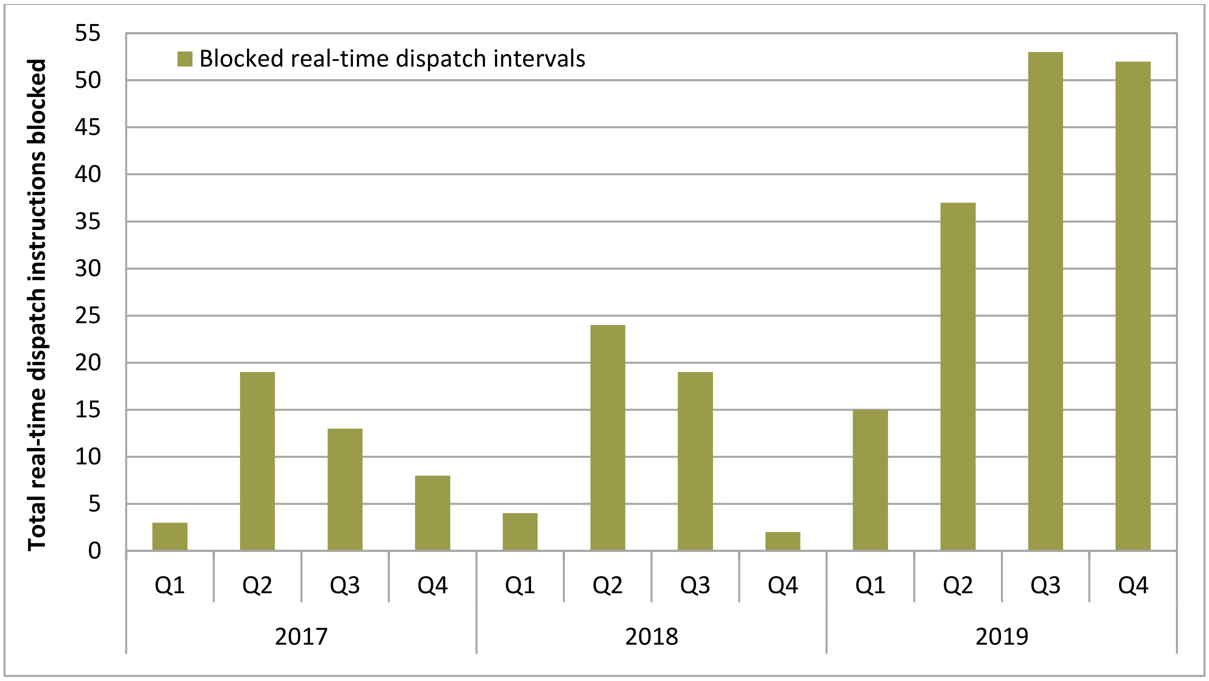
Operators can choose to block the entire market result to stop dispatches and prices resulting from a variety of factors including incorrect telemetry, intertie scheduling information, or load forecasting data. Furthermore, the market software is also capable of automatically blocking a solution when market results exceed threshold values.[238]

Figure 9.17 shows the frequency that operators blocked price results in the real-time dispatch from the first quarter 2017 through 2019. The total number of blocked intervals in 2019 increased about 220 percent from 2018. All quarters in 2019 experienced a higher level of blocked dispatches than the previous year, with the highest months between June and October. Although there was a year-over-year increase, the frequency of blocked dispatches in 2019 was lower than during 2011 and 2012 due to improvements in market software functionality. In the second quarter of 2012 there were nearly 100

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

blocked real-time dispatch intervals while most other quarters in 2011 and 2012 experienced 60, or greater, blocked intervals.

Figure 9.17 Frequency of blocked real-time dispatch intervals



10 Resource adequacy

The purpose of the resource adequacy program is to ensure the ISO system has enough resources to operate the grid safely and reliably in real-time and to provide incentives for the siting and construction of new resources to operate the grid reliably in the future. Key findings in this chapter include:

- **Most system resource adequacy capacity was procured by investor-owned utilities**. Investor-owned utilities accounted for about 66 percent of procurement, community choice aggregators procured 18 percent, municipal entities contributed 9 percent, and direct access providers accounted for 7 percent.
- **On high load days, resource adequacy resources bid in enough capacity to meet average hourly load**. During the evening load ramp, however, changes in bids from RAAIM exempt solar causes increased reliance on RAAIM exempt gas, demand response, and imports to meet system needs. Less than half of resource adequacy capacity was subject to ISO bid insertion in the ISO's market in peak load hours.
- **In the real-time market, less than 80 percent of system resource adequacy capacity was bid or self-scheduled during high load hours**. During the top 210 load hours of the year, 97 percent of system resource adequacy capacity was available in the day-ahead market after outages; 90 percent of total system resource adequacy capacity was bid or self-scheduled in the day-ahead market; 88 percent of total capacity was available after outages in the real-time market; and 78 percent of total capacity was bid or self-scheduled in the real-time market.
- **Energy bid prices for some resource adequacy imports continued to be high** compared to bids from other resource adequacy resources. Energy bid prices for resource adequacy imports averaged above $100/MWh for the entire year. Since a significant portion of these imports do not clear the day-ahead market, only about 70 percent of procured capacity was bid or self-scheduled into the real-time market during peak hours.
- **Overall, total local resource adequacy capacity exceeded requirements in local capacity areas**. After adjusting for outages, total available capacity exceeded aggregate local requirements in the day-ahead and real-time markets by 116 percent and 101 percent, respectively.
- **Procurement in some local capacity areas was significantly lower than the local requirement.** Total resource adequacy capacity was below the local requirements in the Sierra, Stockton, Kern, and Humboldt local areas, which are located in the Pacific Gas and Electric transmission access charge area.
- **Flexible resource adequacy procurement exceeded requirements in all months**. However, year-ahead flexible capacity requirements fell short of the maximum three-hour net load ramp observed in seven months in 2019.
- **Intra-monthly capacity procurement mechanism (CPM) designations cost about $1.5 million in 2019**. Intra-monthly designations were triggered by local reliability issues to address potential thermal overloads for the next contingency event in the Pacific Gas and Electric area.

10.1 Background

The purpose of the resource adequacy program is to ensure the ISO system has enough resources to operate the grid safely and reliably in real time, and to provide incentives for the siting and construction of new resources to operate the grid reliably in the future. In order to achieve this, the California Public Utilities Commission establishes yearly obligations for all load serving entities within their jurisdiction to procure enough resources to ensure capacity is available to the ISO when and where it is needed to operate the power system. Similarly, non-CPUC jurisdictional load serving entities must procure enough capacity to satisfy the requirements of their local regulatory authority (LRA).

The bilateral transactions between load serving entities and electricity suppliers that result from these requirements are meant to provide sufficient revenue to compensate the fixed costs of existing generators and the financing needed for new generator construction. 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.

The resource adequacy program includes obligation requirements for three types of capacity:

1. System resource capacity needed to ensure reliability during system-level peak demand;
2. Local resource capacity needed to ensure reliability in specific areas with limited import capability; and
3. Flexible resource capacity needed to ensure reliability during ramping periods.

Load serving entities are required to make filings to demonstrate that they have procured enough capacity to fulfill their obligations for all three types of resource adequacy. Once established in an entity's supply plan, capacity must be made available to the ISO according to rules that depend on requirement type and resource type.

In 2019, the CPUC concluded that the resource adequacy market was tight despite the appearance of unused capacity on the system. Many load serving entities were unable to procure enough capacity at what they deemed as reasonable prices. The CPUC found that 11 load serving entities had year-ahead local deficiencies, six had year-ahead system deficiencies, and five had year-ahead flexible deficiencies. Many of these deficiencies extended to the month-ahead resource adequacy filings.[239] This chapter extends the CPUC's analysis by reviewing and analyzing the rules, requirements, and availability of resources for each category of resource adequacy in the ISO markets.

10.2 System resource adequacy

Analysis in this section focuses on the availability of system resource adequacy resources throughout the year as well as a special focus on peak loads during the summer months where loads are the highest and energy supply is the tightest in California.

System resource adequacy requirements are set based on system-level peak demand. While system capacity is important to meet peak loads during the summer months, it is also important that sufficient capacity be made available to the market throughout the year. For example, significant amounts of

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[239] For more information, refer to the CPUC's *The State of the Resource Adequacy Market – Revised*, January 2020: https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442463739

generation can be out for maintenance during the non-summer months. This can make the remaining available resources offering resource adequacy capacity instrumental in meeting even moderate loads during non-summer months.

Regulatory requirements

The ISO works with the CPUC and other local regulatory authorities to set system-level requirements. These requirements are 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.[240] Load serving entities then procure capacity to meet these requirements and demonstrate this procurement through the filing of annual and monthly supply plans to the ISO.

For annual showings, CPUC-jurisdictional load serving entities are required to demonstrate they have procured 90 percent of their system resource adequacy obligations for the five summer months in the coming compliance year. For monthly showings, CPUC-jurisdictional entities must demonstrate they have procured 100 percent of their monthly system obligation. Annual supply plans are submitted to the ISO by the last business day of October prior to the coming compliance year. Monthly supply plans are submitted to the ISO at least 45 days prior to the compliance month.

Bidding and scheduling obligations

Scheduling coordinators representing procured resource adequacy capacity must make the capacity listed in a load serving entity's monthly supply plan available to the ISO markets through economic bids or self-schedules as follows:

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

In 2019, about 42 percent of the capacity procured to meet resource adequacy requirements was from resources that are not use-limited and bid into ISO markets 24x7, unless reported to the ISO as unavailable due to outages. This capacity primarily includes most gas-fired resources. If a market participant does not submit bids, the ISO automatically creates and inserts bids for these resources.

240 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.

The remaining capacity counted toward meeting system resource adequacy requirements in 2019 are generally only 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 availability-limited resources.

Availability

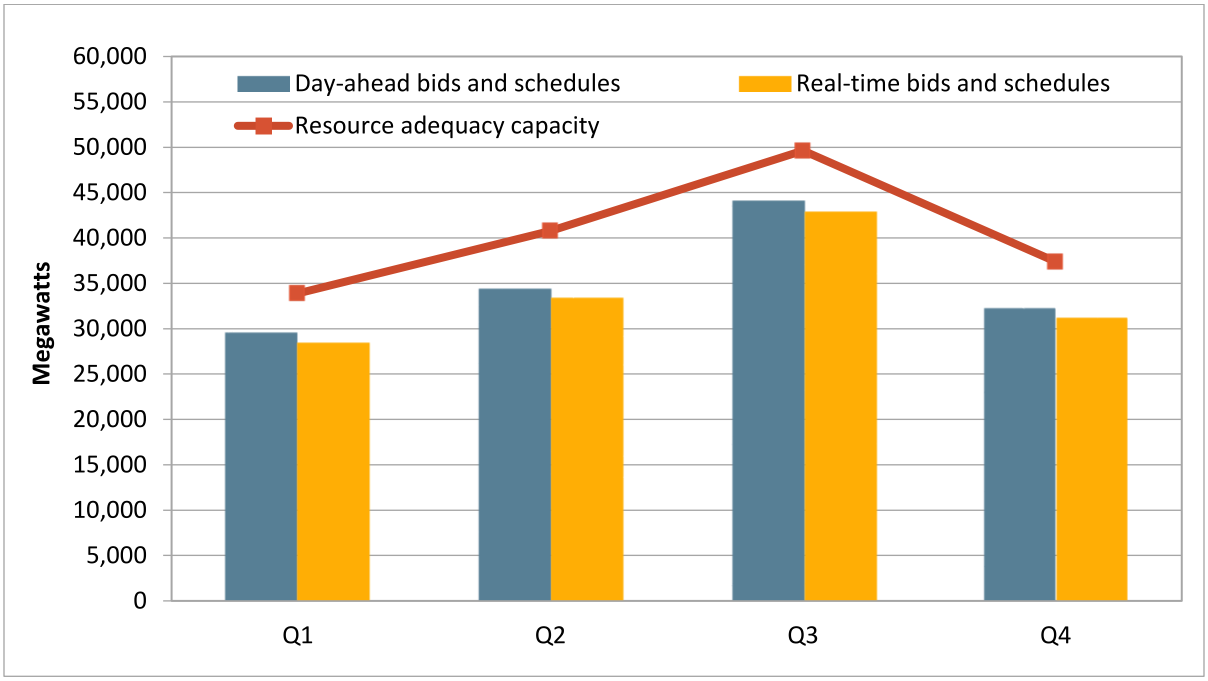
The ISO uses the resource adequacy availability incentive mechanism (RAAIM) to incentivize the availability of resources providing system, local, and flexible resource adequacy capacity during the availability assessment hours each month. This mechanism gives scheduling coordinators the incentive to make resource adequacy capacity available in the market during the availability assessment hours by charging a penalty to resources that are not made available at least 94.5 percent of the time and paying resources that are available at least 98.5 percent of the time during those hours. In 2019, the availability assessment hours were hours ending 17 through 21 of non-holiday weekdays.[241]

Figure 10.1 captures resource adequacy availability at a quarterly level by showing average capacity procurement and market bidding and scheduling activity during the availability assessment hours. The red line shows the average quarterly capacity procured to meet system-level requirements. The bars summarize the average amount of available capacity bid in or scheduled in the day-ahead and real-time markets during the availability assessment hours.[242]

241 Non-holiday weekdays are weekdays that are not a FERC holiday.

242 Real-time bids and schedules in the figure do not include capacity from long-start units and imports that were not scheduled in the day-ahead market or residual unit commitment process. Resource adequacy capacity from long-start units and imports does not have a real-time must-offer obligation if not scheduled in the day-ahead or residual unit commitment processes. This figure also does not account for resource adequacy capacity that may not be available in real-time due to ramping limitations.

Figure 10.1 Quarterly resource adequacy capacity scheduled and bid into ISO markets (2019)



Key findings of this analysis include:

- ***On average, bids and schedules were lower than total capacity in each quarter***. Less than 90 percent resource adequacy capacity on average was available in the day-ahead market during availability assessment hours on a quarterly basis.
- ***The percentage of capacity available during availability assessment hours was highest in the third quarter***. During these months, an average of about 44,000 MW out of almost 50,000 MW of procured resource adequacy capacity (or 89 percent) was available in the day-ahead market. Availability was similar for the remaining quarters at about 86 percent of resource adequacy capacity available in the day-ahead market.
- ***A smaller proportion of capacity was available in the real-time market compared to the day-ahead market for each quarter of 2019.*** This is primarily because many long-start gas-fired units and import capacity are not available in the real-time market if these resources are not committed in the day-ahead energy market or residual unit commitment process.

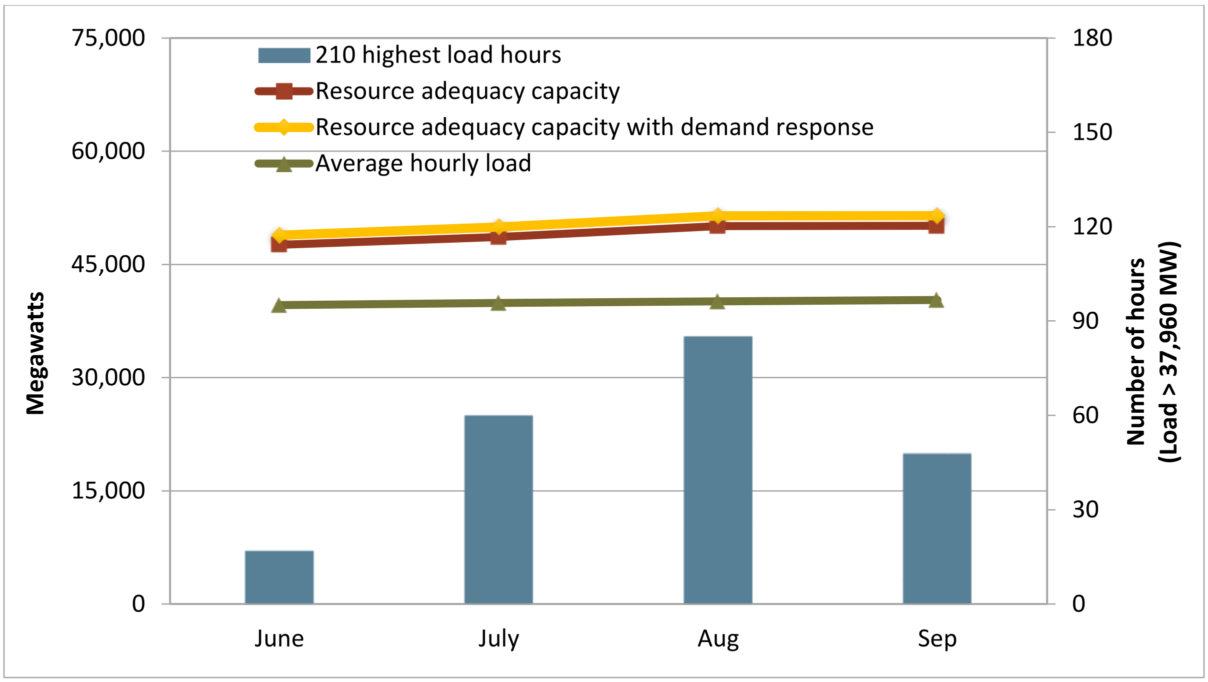
Availability during summer peak hours

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 availability-limited generation. This element of the program reflects assumptions that generation will generally be available and used during hours when peak loads are highest.

The CPUC's resource adequacy program is designed to ensure that the highest load hours are met by requiring that all resource adequacy capacity be available at least 210 hours across summer months.[243] It is assumed that use-limited resources are managed such that they will be available during the peak load hours.

Figure 10.2 provides an overview of resource adequacy capacity during the 210 highest load hours in 2019. 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 utility-operated demand response capacity credited against requirements under CPUC provisions. In addition, the blue bars show the number of hours in each month that belong to the 210 highest load hours during the year.

Figure 10.2 Average hourly resource adequacy capacity and load (210 highest load hours)



Key findings of this analysis include:

- ***Average resource adequacy capacity exceeded average load during the 210 highest load hours in 2019***. Average hourly load was around 40,000 MW for these hours, while average resource adequacy capacity was around 49,000 MW.

[243] 210 hours is derived from the CPUC's maximum cumulative capacity (MCC) bucket construct. Under this construct, all resources counted toward resource adequacy requirements (except for demand response) must be available for at least 210 hours across summer months. While analysis in this section is based on the top 210 highest load hours in a year regardless of month, the MCC bucket construct specifies minimum required availability in each month, May through September.

- ***During 2019, load during the 210 highest load hours was greater than 37,960 MW.*** These hours were typically concentrated in high temperature days during July and August, but also included some days in June and September.

Load serving entities can contract with multiple types of resources to fulfill their resource adequacy obligations. Table 10.1 provides insight into what types of resources were procured for system capacity, what their bidding obligations are, and what their availability was on average during the 210 highest load hours in 2019.[244] Separate sub-totals are provided for resources that the ISO creates bids for if market participants do not submit a bid or self-schedule (must-offer), and resources the ISO does not create bids for (other).

Table 10.1 Average system resource adequacy capacity and availability by fuel type (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 total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.
Must-Offer:									
Gas-fired generators	19,499	18,497	95%	18,497	95%	14,977	77%	14,376	74%
Other generators	1,490	1,402	94%	1,402	94%	1,402	94%	1,342	90%
Subtotal	**20,989**	**19,899**	**95%**	**19,899**	**95%**	**16,379**	**78%**	**15,718**	**75%**
Other:									
Imports	4,704	4,669	99%	4,440	94%	4,078	87%	3,289	70%
Use-limited gas units	6,708	6,479	97%	6,386	95%	6,395	95%	5,961	89%
Hydro generators	6,551	6,278	96%	5,800	89%	6,265	96%	5,711	87%
Nuclear generators	2,872	2,857	99%	2,856	99%	2,857	99%	2,756	96%
Solar generators	4,176	4,164	100%	2,896	69%	4,145	99%	2,799	67%
Wind generators	1,704	1,698	100%	1,082	63%	1,698	100%	1,057	62%
Qualifying facilities	1,078	1,062	98%	880	82%	948	88%	803	75%
Other non-dispatchable	686	664	97%	483	70%	582	85%	509	74%
Subtotal	**28,479**	**27,871**	**98%**	**24,823**	**87%**	**26,968**	**95%**	**22,885**	**80%**
Total	**49,468**	**47,770**	**97%**	**44,722**	**90%**	**43,347**	**88%**	**38,603**	**78%**

244 Bids and self-schedules in the day-ahead and real-time markets are now reported as the proportion of total resource adequacy capacity. This is a change from previous reports which presented bids and self-schedules as the proportion of capacity after adjusting for outages and availability.

Key findings of this analysis include:

- ***About 53 percent of resource adequacy capacity was procured from gas-fired generators***. Gas-fired resources supplied 26,200 MW of resource adequacy capacity during the 210 highest load hours of 2019.
- ***Just 43 percent of resource adequacy capacity was procured from resources that are not availability-limited and are subject to ISO bid insertion***. About 21,000 MW of system resource adequacy capacity was not classified as use-limited and was subject to ISO bid insertion 24x7.[245] Gas-fired generation in this category made up about 19,500 MW (39 percent) of total resource adequacy capacity. Other generators accounted for 3 percent.
- ***Use-limited gas units made up the largest portion of resource adequacy capacity with limited availability not subject to ISO bid insertion***. These resources contributed about 6,700 MW of total capacity (14 percent), hydro generators contributed 13 percent, imports contributed 10 percent, solar resources contributed 8 percent, nuclear resources contributed 6 percent, wind resources contributed 3 percent, qualifying facility resources contributed 2 percent, and other non-dispatchable resources (e.g., demand response) contributed 1 percent of system capacity.
- ***Capacity available after reported outages and de-rates continued to be significant***. Average resource adequacy capacity was around 49,500 MW during the 210 highest load hours in 2019, about 1,500 MW more than in 2018. After adjusting for outages and de-rates, the remaining capacity available in the day-ahead market was about 97 percent of the overall resource adequacy capacity, which was unchanged from 2018.
- ***Day-ahead market availability was high for all resource types***. About 95 percent of must-offer and 98 percent of non must-offer resources were available in the day-ahead market. Must-offer resources bid in about 100 percent of day-ahead availability. Non must-offer resources bid in about 89 percent of the day-ahead availability. These are typically variable and non-dispatchable energy resources. Additionally, some of the 210 highest load hours occurred in evening hours when solar resources and other non must-offer resources have limited availability.
- ***Most capacity was available in the real-time market, after accounting for outages and de-rates***. The last four columns of Table 10.1 show how potentially available resource adequacy capacity and actual bids in the real-time market compare with total resource adequacy capacity. The 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 de-rates. About 78 percent of the total resource adequacy capacity was scheduled or bid in the real-time market.
- ***Most use-limited gas capacity was bid into the day-ahead market***. Around 6,700 MW of use-limited gas resources were used to meet resource adequacy requirements. About 95 percent of this capacity was bid in the day-ahead market during the highest 210 load hours. In real-time, about 6,000 MW (89 percent) of this capacity was scheduled or bid in the real-time market.

[245] 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.

Table 10.2 shows the availability of resources in ISO markets aggregated by the type of load serving entity that the resources were contracted with. In this analysis, supply plans were used to proportionally assign resource bid availability to load serving entities based on corresponding contracted capacity.[246] Bid availability is aggregated by load type, depending on whether the entity is a community choice aggregator (CCA), direct access (DA) service, investor-owned utility (IOU), or a municipal/government (Muni) entity. Substituted capacity represents resources that substituted for a resource that went on outage, but were not originally on a load serving entity's supply plan.

Table 10.2 Average system resource adequacy capacity and availability by load type (210 highest load hours)

Load Type	Total resource adequacy capacity	Day-ahead				Real-time			
		Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
		MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.
CCA	8,725	8,429	97%	8,127	93%	7,896	91%	7,136	82%
DA	3,497	3,417	98%	3,226	92%	3,158	90%	2,691	77%
IOU	32,707	31,502	96%	29,640	91%	28,027	86%	25,071	77%
Muni	4,398	4,284	97%	3,600	82%	4,131	94%	3,590	82%
Substituted capacity	142	136	96%	128	90%	136	96%	115	81%
Total	**49,469**	**47,768**	**97%**	**44,721**	**90%**	**43,348**	**88%**	**38,603**	**78%**

Key findings of this analysis include:

- ***Most system capacity was procured by investor-owned utilities.*** Investor-owned utilities accounted for about 33,000 MW (or 66 percent) of system resource adequacy procurement, community choice aggregators contributed 18 percent, municipal utilities contributed 9 percent, and direct access services contributed 7 percent. This compares to 2018, when investor-owned utilities and community choice aggregators accounted for 71 percent and 11 percent of procurement, respectively.
- ***Day-ahead availability was high for all load types***. About 98 percent of resource adequacy capacity was available from resources contracted with direct access, 97 percent of resource adequacy capacity was available from resources that contracted with community choice aggregators and municipal utilities, and 96 percent was available from investor-owned utilities.
- ***All load serving entity types contracted with a majority of resources with availability limitations and which are not subject to ISO bid insertion.*** Community choice aggregators procured 51 percent of their resource adequacy capacity from these resources, while direct access services procured 58 percent, investor-owned utilities procured 57 percent, and municipal utilities procured 73 percent.

[246] Since a single resource can contract with multiple load serving entities, bidding behavior for individual resources was distributed proportionately among entities according to their contracted share of a resource's capacity. For example, if Generator A has 100 MW of resource adequacy capacity in total and contracted 60 MW of capacity to LSE 1 and 40 MW to LSE 2, then 60 percent of Generator A's bids in the markets are assigned to LSE 1 and 40 percent to LSE 2. Load serving entity assigned bids are then aggregated up to the type of load the entity serves.

- ***All load types continue to procure a significant amount of imports to meet system resource adequacy requirements.*** Municipal utilities procured 22 percent of their resource adequacy capacity from imports, while direct access services procured 16 percent, community choice aggregators procured 8 percent, and investor-owned utilities procured 6 percent.

- ***Most capacity was available in the real-time market for each load type***. Real-time resource adequacy capacity availability ranged from 86 percent to 94 percent for each load type. Availability of resources contracted with investor-owned utilities was slightly lower than for the other load types. This was primarily due to lower availability from must-offer gas generators.

- ***Substitute capacity had high rates of availability and market participation.*** An average of about 142 MW of resource adequacy capacity came from substituted capacity during the 210 highest load hours.

Table 10.3 shows the availability of resource adequacy capacity in the ISO markets based on whether the capacity was exempt from charges under the resource adequacy availability incentive mechanism. For this analysis, settlements data was used to identify resources that were exempt from RAAIM charges if they were unavailable during the availability assessment hours.[247]

Table 10.3 Average system resource adequacy capacity and availability by RAAIM category (210 highest load hours)

RAAIM Category	RA capacity by RAAIM group (MW)	% of total RA capacity	Day-ahead market				Real-time market			
			Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
			MW	% of group capacity	MW	% of group capacity	MW	% of group capacity	MW	% of group capacity
Non-RAAIM Exempt	35,872	73%	34,417	96%	33,737	94%	30,369	85%	28,181	79%
RAAIM Exempt	13,596	27%	13,352	98%	10,984	81%	12,978	95%	10,422	77%
Total	**49,468**	**100%**	**47,769**	**97%**	**44,721**	**90%**	**43,347**	**88%**	**38,603**	**78%**

Key findings of this analysis include:

- ***Capacity exempt from RAAIM charges accounted for over 27 percent of overall resource adequacy capacity*** during the 210 highest load hours of 2019. This was mostly made up of gas, solar, and wind resources.

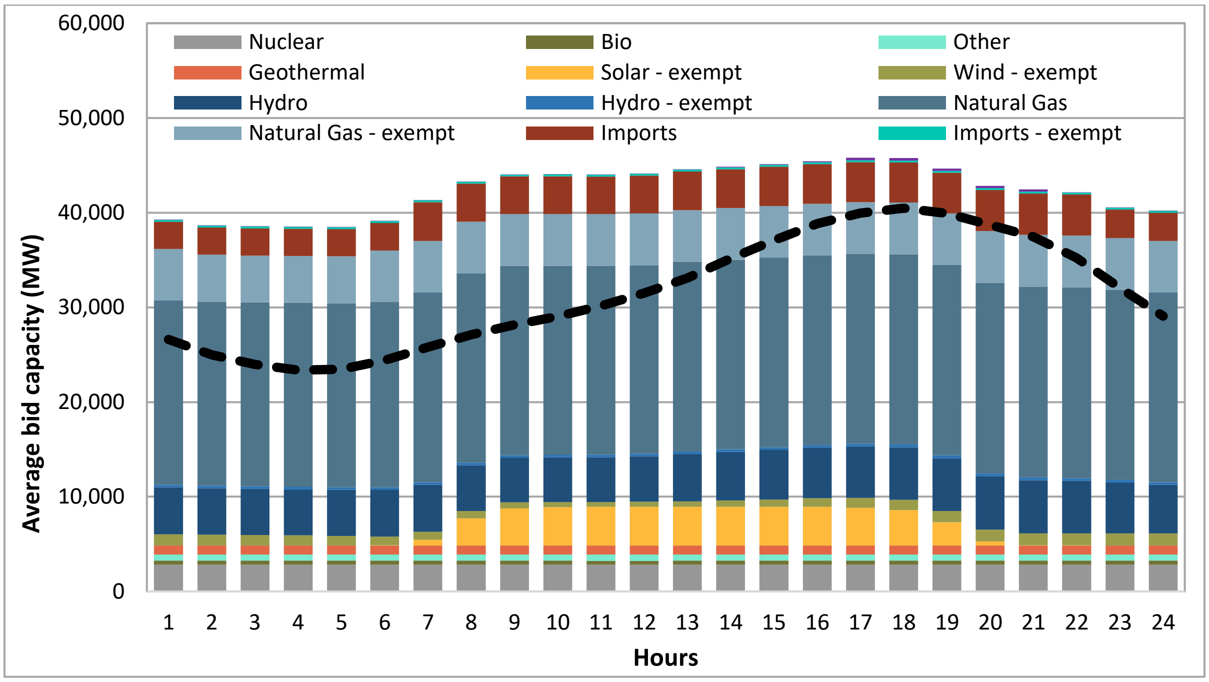
- ***Capacity subject to RAAIM was adjusted more for outages and availability, but bid a higher percentage of available capacity in the markets***. About 85 percent of resource adequacy capacity subject to RAAIM was available in the real-time market on average. Reduced availability was mainly driven by gas units that were adjusted for outages and availability.

[247] There are many reasons why a resource may be exempt from RAAIM charges in general or on any particular day. This includes the resource's maximum generation capacity, generation type, or outage type, among others. For more information on RAAIM exemptions, refer to Section 40.9 of the ISO tariff.

- ***Capacity exempt from RAAIM bid a lower percentage in the markets***. Capacity exempt from RAAIM was adjusted for outages less often, but only 77 to 81 percent of their capacity was bid into the markets during high load hours. Reduced availability was mainly driven by solar and wind resources that are typically not able to generate to resource adequacy values when loads are highest.

Figure 10.3 shows the average hourly resource adequacy capacity that was bid into the day-ahead market during the days that contained the 210 highest load hours in 2019. Capacity is grouped by fuel type and RAAIM exemption status. Average hourly load is also represented on the graph as a point of reference.

Figure 10.3 Average hourly bids by fuel type and RAAIM category (Days with 210 highest load hours)



Key findings of this analysis include:

- ***There was enough bid-in capacity in the day-ahead market from resource adequacy resources to cover average hourly load across the day during high load days***. On average, bids in the day-ahead market exceeded load by a minimum of about 4,000 MW in hour 20 to a maximum of about 16,000 MW in hour 8.

- ***Availability-limited capacity plays a significant role in meeting demand during peak load hours***. After about hour-ending 16, a reduction in the availability of solar capacity causes increased reliance on RAAIM exempt gas resources, demand response, and imports to meet system demand.

Resource adequacy imports

Load serving entities are allowed to use non-resource specific imports to meet system resource adequacy requirements. Imports can be bid at any price up to the $1,000/MWh bid cap as they are not subject to market power mitigation and do not have any further bid obligation in the real-time market 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, 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. Analysis of resource adequacy resources shows that during peak hours of 2019, the availability of imports in the real-time market is relatively low while the energy bid prices for imports are relatively high compared to other resources.

After reviewing concerns from both DMM and the ISO about the availability of import resource adequacy resources in the real-time market and high bid prices in the day-ahead market, the CPUC ordered that non-resource-specific imports would be required to self-schedule into the ISO markets in Decision (D.) 19-10-021 in October 2019.[248] The CPUC subsequently granted a motion for stay by the California Community Choice Association in Decision (D.) 19-12-064 in December 2019. In March 2020, the CPUC granted a limited rehearing of Decision (D.) 19-10-021 in order to clarify the self-scheduling requirement and allow stakeholders to comment. In May 2020, after further record was developed on import resource adequacy issues, the CPUC issued a proposed decision specifying that non-resource-specific import resource adequacy resources must be self-scheduled or bid into ISO markets at or below $0/MWh, at minimum in the availability assessment hours.[249]

Table 10.1 shows that load serving entities used about 4,700 MW of imports (or about 10 percent of total resource adequacy capacity) to meet system requirements during the top 210 load hours of 2019. These resources had a high participation rate in the day-ahead market with about 94 percent of available capacity submitting bids and self-schedules. In the real-time market, however, imports had the lowest participation rate of non-variable energy resources with only 70 percent of capacity available through bids or self-schedules.

In addition, energy bid prices for many resource adequacy imports were relatively high in 2019. Figure 10.4 summarizes the bid prices and volume of self-scheduled and economic bids for import resources in the day-ahead market during peak hours on a quarterly basis.[250] The blue and green bars (plotted against the left axis) show the 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 energy bid prices for import resources for which market participants submitted economic bids to the day-ahead market.

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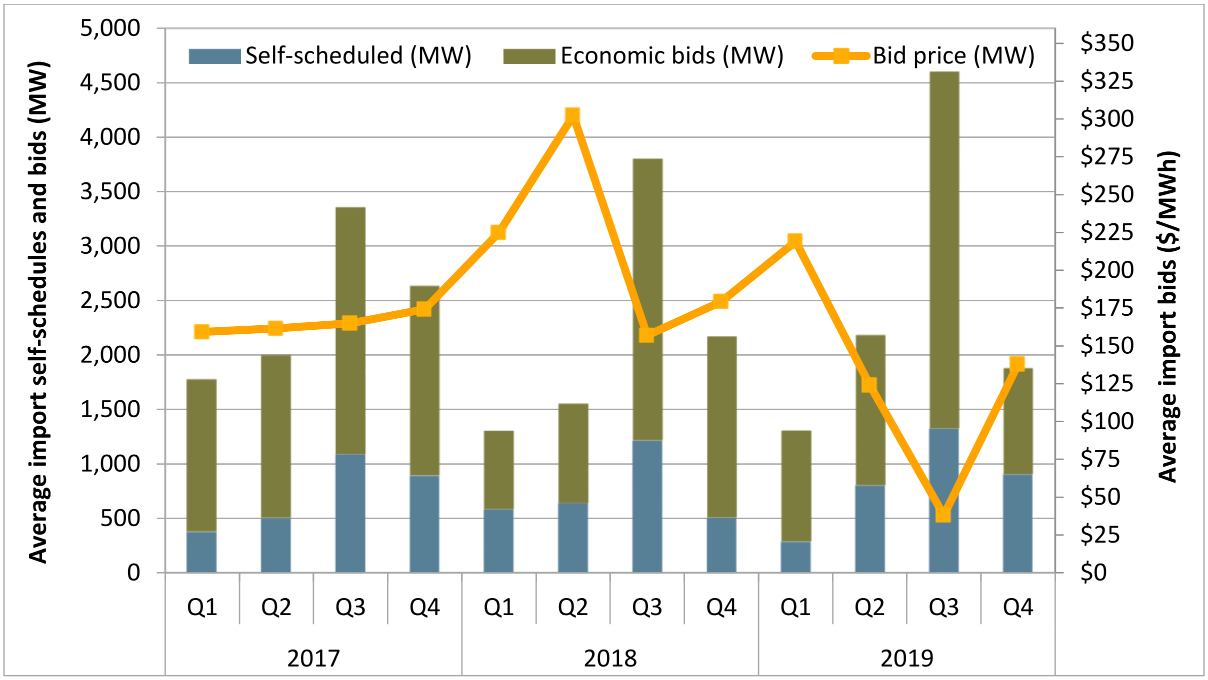
248 The concerns from DMM and the ISO can be found at *DMM Special Report: Import Resource Adequacy*, September 2018: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf and *Resource Adequacy Enhancements Straw Proposal – Part 1*, December 2018: http://www.caiso.com/Documents/StrawProposalPart1-ResourceAdequacyEnhancements.pdf

249 *Proposed Decision Adopting Resource Adequacy Import Requirements*, R.17-09-020, CPUC, May 18, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M337/K861/337861765.PDF

250 Peak hours are defined as Monday through Saturday, excluding North American Electric Reliability Council holidays, from hour-ending 7 to hour-ending 22.

Figure 10.4 Resource adequacy import self-schedules and bids (210 highest load hours)



Key findings of this analysis include:

- ***Overall volume of resource adequacy import bids in high load hours increased in 2019 compared to 2018***. Quarterly averages for import bids and self-schedules ranged from about 1,300 MW to 3,800 MW in 2018 compared to 1,300 MW to 4,600 MW in 2019.
- ***Weighted average prices for energy bids from resource adequacy imports for 2019 were highest in the first quarter***. Energy bid prices averaged over $200/MWh in this quarter before decreasing over successive quarters. Energy bid prices averaged about $100/MWh for 2019. This is the lowest yearly average since 2016.
- ***There were more economic bids for imports than self-schedules in every quarter***. Self-scheduled resource adequacy imports accounted for about 33 percent of total bids from these resources in the day-ahead market, the same as in 2018.

10.3 Local resource adequacy

Analysis in this section focuses on the market availability of resource adequacy resources in local capacity areas during summer month peak load hours where energy supply is the tightest in California. The goal of local resource adequacy requirements is to ensure reliability in specific transmission constrained load pockets. Load serving entities are required to procure resource adequacy capacity within certain local areas that have limited import capability.

Requirements

Local resource adequacy requirements are determined from the local capacity technical study that is performed by the ISO on an annual basis. This study identifies the minimum amount of megawatts that must be available within local capacity areas for reliability using a 1-in-10 weather year and N-1-1 contingencies. The ISO allocates local capacity area obligations to scheduling coordinators for non-CPUC jurisdictional load serving entities based on each entity's proportionate share of transmission access charge (TAC) area load during the coincident forecasted peak for the resource adequacy compliance year as determined by the California Energy Commission. For CPUC-jurisdictional load serving entities, the CPUC must first adopt the results of the ISO's technical study; the CPUC allocates the adopted local requirements to each load serving entity in each transmission access charge area using the ratio of load serving entities' peak load to total peak load in each TAC area in August of the compliance year, as indicated in each entity's peak load forecast.

For annual showings, CPUC-jurisdictional load serving entities are required to demonstrate they have procured 100 percent of their local resource adequacy requirements for each month of the compliance year.[251] Annual supply plans are submitted to the ISO by the last business day of October prior to the compliance year. Load serving entities must also demonstrate they have met their revised local obligation on a monthly basis from May through December due to load migration.

In 2019, DMM analysis of local requirements has found the existence of local market power in most local capacity areas. This is due to lack of competition and insufficient supply to meet requirements, depending on the area.[252]

Bidding and scheduling obligations

Scheduling coordinators representing resource adequacy capacity that satisfies local requirements must make the capacity listed in a load serving entity's monthly supply plan available to the day-ahead, ancillary services, residual unit commitment, and real-time markets through economic bids or self-schedules consistent with the obligations for resources providing system resource adequacy.

Availability during summer peak hours

Table 10.4 shows an analysis similar to the availability analysis for system resource adequacy. This table compares the local area capacity requirements established by the ISO to the amount of capacity that was procured and actually bid into both the day-ahead and real-time markets during the highest 210 load hours in 2019.[253]

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[251] Under the CPUC's Decision (D.) 19-02-022, local resource adequacy requirements will be three-year forward requirements starting in the 2021 compliance year. CPUC-jurisdictional load serving entities will be required to procure capacity to meet 100 percent of local requirements for the upcoming compliance year, 100 percent of requirements for the following year, and 50 percent of local requirements for the third year.

[252] For more information on competitiveness in local capacity areas, refer to Chapter 7.

[253] Local capacity area resource adequacy requirements obtained from the *2019 Local Capacity Technical Analysis*, May 15, 2018, pg. 23, Table 6: http://www.caiso.com/Documents/Final2019LocalCapacityTechnicalReport.pdf.

Table 10.4 Average local resource adequacy capacity and availability (210 highest load hours)

Local capacity area	TAC area	Total resource adequacy capacity	Local requirement	Day-ahead				Real-time			
				Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
				MW	% of local req.	MW	% of local req.	MW	% of local req.	MW	% of local req.
Greater Bay Area	PG&E	6,658	4,461	6,373	143%	6,241	140%	6,159	138%	5,839	131%
Greater Fresno	PG&E	2,857	1,671	2,715	162%	2,572	154%	2,639	158%	2,431	145%
Sierra	PG&E	1,800	2,247	1,731	77%	1,588	71%	1,649	73%	1,473	66%
North Coast/North Bay	PG&E	820	689	753	109%	658	96%	753	109%	723	105%
Stockton	PG&E	643	777	607	78%	574	74%	600	77%	555	71%
Kern	PG&E	463	478	441	92%	410	86%	352	74%	299	63%
Humboldt	PG&E	114	165	113	68%	104	63%	113	68%	99	60%
LA Basin	SCE	8,757	8,116	8,377	103%	8,200	101%	6,730	83%	6,165	76%
Big Creek/Ventura	SCE	4,411	2,614	4,353	167%	4,101	157%	3,076	118%	2,807	107%
San Diego	SDG&E	3,997	4,026	3,749	93%	3,441	85%	3,548	88%	3,122	78%
Total		**30,520**	**25,244**	**29,212**	**116%**	**27,889**	**110%**	**25,619**	**101%**	**23,513**	**93%**

Key findings of this analysis include:

- ***Overall, total resource adequacy capacity exceeded requirements in local capacity areas***. Load serving entities procured almost 31,000 MW of capacity in local areas in 2019, compared to about 25,000 MW of required capacity. Even after controlling for outages, the overall available capacity exceeded local requirements in the day-ahead (116 percent of requirements) and real-time (101 percent of requirements) markets.

- ***Procurement in some disaggregated local capacity areas was significantly lower than the local area requirement***. Total resource adequacy capacity was below the local requirements in the Sierra, Stockton, Kern, and Humboldt local areas. This deficit was offset by capacity procurement that surpassed local requirements in the Greater Bay Area, Greater Fresno, and North Coast/North Bay.[254]

- ***Significant amounts of energy, beyond requirements, were available in the day-ahead market for several local capacity areas***. Capacity in the Greater Bay Area, Greater Fresno, North Coast/North Bay, LA Basin, and Big Creek/Ventura was available between 103 percent and 167 percent of the local area requirement, after accounting for outages and de-rates. This offset lower availability rates from capacity in Sierra, Stockton, Kern, Humboldt, and San Diego. Overall, about 116 percent of local capacity area requirements were available in the day-ahead market.

- ***Available capacity was generally lower in the real-time market compared to the day-ahead market***. About 110 percent of local capacity area requirements was bid into the day-ahead market, while 93 percent of local area requirements was bid into the real-time market.

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254 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. Under the CPUC's Decision (D.) 19-02-022, starting 2020, procurement requirements for each disaggregated local capacity area will be assigned to CPUC-jurisdictional load serving entities in relevant transmission access charge areas. In particular, the "PG&E Other" local area requirements will be disaggregated into individual local area requirements.

In instances where available resource adequacy capacity does not meet the needs of a local area, the ISO has the ability to designate additional capacity through the capacity procurement mechanism. Capacity procurement mechanism designations in 2019 are described in depth in Section 10.5.

Table 10.5 shows availability of local resource adequacy resources in the ISO markets aggregated by transmission access charge area and types of loads that they contracted with. Supply plans were used to proportionally assign resource bid availability to load serving entities based on corresponding contracted capacity. Bid availability was then aggregated by load type, depending on whether the entity is a community choice aggregator, direct access service, investor-owned utility, or a municipal/government entity. Substituted capacity represents bids from resources that substituted for a resource that went on outage, but were not originally on a load serving entity's supply plan.

Table 10.5 Average local resource adequacy capacity and availability by TAC area load type (210 highest load hours)

Area	Load Type	Total resource adequacy capacity	Day-ahead				Real-time			
			Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
			MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.
PG&E	CCA	3,654	3,508	96%	3,410	93%	3,480	95%	3,287	90%
	DA	798	762	95%	735	92%	739	93%	682	85%
	IOU	7,687	7,298	95%	6,995	91%	6,916	90%	6,433	84%
	Muni	1,108	1,060	96%	908	82%	1,026	93%	931	84%
	Substituted Capacity	108	104	96%	98	91%	104	96%	86	80%
	Subtotal	**13,355**	**12,732**	**95%**	**12,146**	**91%**	**12,265**	**92%**	**11,419**	**86%**
SCE	CCA	1,186	1,155	97%	1,130	95%	914	77%	854	72%
	DA	776	759	98%	720	93%	668	86%	595	77%
	IOU	9,974	9,618	96%	9,501	95%	7,070	71%	6,575	66%
	Muni	1,212	1,179	97%	932	77%	1,134	94%	931	77%
	Substituted Capacity	19	19	100%	18	95%	19	100%	18	95%
	Subtotal	**13,167**	**12,730**	**97%**	**12,301**	**93%**	**9,805**	**74%**	**8,973**	**68%**
SDG&E	CCA	34	34	100%	34	100%	34	100%	33	97%
	DA	414	407	98%	405	98%	407	98%	392	95%
	IOU	3,548	3,308	93%	3,001	85%	3,106	88%	2,697	76%
	Muni	-	-	-	-	-	-	-	-	-
	Substituted Capacity	0	0	100%	0	100%	0	100%	0	100%
	Subtotal	**3,996**	**3,749**	**94%**	**3,440**	**86%**	**3,547**	**89%**	**3,122**	**78%**
	Total	**30,518**	**29,211**	**96%**	**27,887**	**91%**	**25,617**	**84%**	**23,514**	**77%**

Key findings of this analysis include:

- ***Most local resource adequacy capacity was procured by investor-owned utilities***. Investor-owned utilities accounted for about 21,000 MW (or about 70 percent) of local resource adequacy procurement, community choice aggregators contributed 16 percent, direct access services contributed 7 percent, and municipal utilities contributed 8 percent.

- ***Most local resource adequacy capacity procurement by community choice aggregators occurred in the Pacific Gas and Electric TAC area***. Community choice aggregators procured about 27 percent of total resource adequacy capacity in the Pacific Gas and Electric area, mostly in the Greater Bay Area, Greater Fresno, and Sierra local capacity areas.

- ***Day-ahead availability was high for all load types in each TAC area***. Availability in the day-ahead market ranged from 94 percent to 97 percent of total resource adequacy capacity for each area and load type.
- ***Most resource adequacy capacity was available in the real-time market for all load types in each TAC area.*** About 84 percent of the total local resource adequacy capacity was available to the real-time market. Resources in the Southern California Edison TAC area had the lowest availability in the real-time market out of the three areas with 74 percent availability. This was mainly due to outages of resources that contracted with the investor-owned utilities and community choice aggregators.

10.4 Flexible resource adequacy

The purpose of flexible resource adequacy capacity is to ensure the system has enough flexible resources available to meet forecasted net load ramps, plus contingency reserves. With increased reliance on renewable generation, the need for flexible capacity has also increased to manage changes in net load. This ramping capability is generally needed in the downward direction in the 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. The greatest need for three-hour ramping capability occurs during evening hours.

To address flexibility needs for changing system conditions, the CPUC and the ISO developed flexible resource adequacy requirements. The flexible resource adequacy framework was approved by FERC in 2014 and became effective in January 2015, and now serves as an additional tool to help maintain grid reliability.[255]

Requirements

Flexible capacity needs are determined from the flexible capacity needs assessment study that is performed by the ISO on an annual basis. This study identifies the minimum amount of flexible capacity that must be available to the ISO to address ramping needs for the upcoming year. The ISO uses the results to allocate shares of the system flexible capacity need to each local regulatory authority that has load serving entities responsible for load in the ISO balancing authority area.

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.[256,257] Because the grid commonly faces two pronounced upward net load ramps per

[255] For more information, see the following FERC order: http://www.caiso.com/Documents/Oct16_2014_OrderConditionallyAcceptingTariffRevisions-FRAC-MOO_ER14-2574.pdf

[256] 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.

[257] Net load is defined as total load less wind and solar production.

day, flexible resource adequacy categories were designed to address both the maximum primary and secondary net load ramp.[258]

For annual showings, load serving entities are required to demonstrate they have procured 90 percent of their flexible resource adequacy requirements for each month of the coming compliance year. Annual supply plans are submitted to the ISO by the last business day of October prior to the coming compliance year. For the monthly showings, load serving entities must demonstrate they have procured 100 percent of their flexible resource adequacy obligation.

Bidding and scheduling obligations

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 is 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.

Requirements compared to actual maximum net load ramps

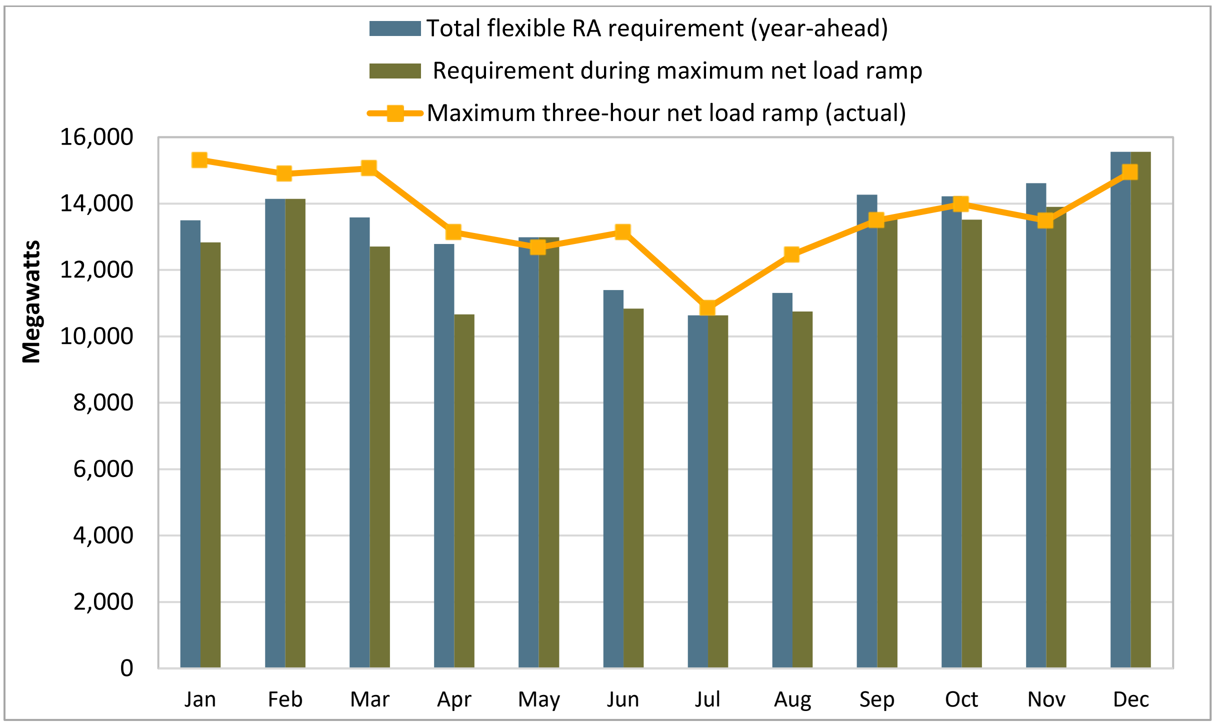
Figure 10.5 investigates how well flexible resource adequacy requirements addressed system load ramping needs in 2019 by comparing the requirements and the actual maximum three-hour net load

[258] 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.

ramp on a monthly basis.[259] 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.[260] Figure 10.5 was therefore 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 Flexible resource adequacy requirements during the actual maximum net load ramp



Key findings of this analysis include:

- ***Year-ahead flexible resource adequacy requirements were insufficient to meet the actual maximum three-hour net load ramp for seven months in 2019.*** This is shown where the blue bars are lower than the gold line. The maximum three-hour net load ramps in January, February, March, April, June, July, and August were all greater than the year-ahead requirements set in those months.
- ***Actual flexible resource adequacy requirements set at the time of the peak ramp were insufficient to meet actual maximum three-hour net load ramps for most months***. This is shown when the green bars are lower than the gold line. The maximum three-hour net load ramps in January,

[259] 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.

[260] 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.

February, March, April, June, July, August, and October were all greater than the actual requirements set at the time of the peak ramp set in those months.

The effectiveness of flexible resource adequacy requirements and must-offer rules in addressing supply during maximum load ramps is 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 suggests that the 2019 requirements and must-offer hours were insufficient in reflecting actual ramping needs.

Table 10.6 provides another comparison of 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.

Table 10.6 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	15,311	13,500	12,829	1/1/2019	14:00	N	Total flexible RA requirement less than max ramp; Max ramp occurred on a holiday
Feb	14,898	14,144	14,144	2/11/2019	15:00	N	Total flexible RA requirement less than max ramp
Mar	15,060	13,583	12,704	3/17/2019	16:00	N	Total flexible RA requirement less than max ramp; Max ramp occurred on a Sunday
Apr	13,129	12,787	10,665	4/20/2019	16:45	N	Total flexible RA requirement less than max ramp; Max ramp ended after Category 2 requirement ended; Max ramp occurred on a Saturday
May	12,677	12,984	12,984	5/4/2019	16:20	Y	
Jun	13,138	11,395	10,833	6/9/2019	15:55	N	Total flexible RA requirement less than max ramp; Max ramp occurred on a Sunday
Jul	10,855	10,630	10,630	7/8/2019	16:45	N	Total flexible RA requirement less than max ramp
Aug	12,462	11,309	10,750	8/18/2019	15:55	N	Total flexible RA requirement less than max ramp; Max ramp occurred on a Sunday
Sep	13,492	14,272	13,560	9/29/2019	15:40	Y	
Oct	13,980	14,217	13,521	10/6/2019	14:55	N	Total flexible RA requirement less than max ramp; Max ramp occurred on a Sunday
Nov	13,487	14,618	13,904	11/3/2019	14:00	Y	
Dec	14,947	15,559	15,559	12/16/2019	14:05	Y	

Key results of this analysis include:

- ***The average requirement during the maximum net load ramp was insufficient to meet the actual maximum three-hour net load ramps in most months***. This occurred during the maximum three-hour net load ramps for January, February, March, April, June, July, August, and October.
- ***For most of the months with insufficient average requirements, the maximum net load ramps occurred at least partially outside of Category 2 and Category 3 must-offer hours***. The maximum net load occurred on either a holiday, Saturday, or Sunday when Category 3 resources do not have must-offer obligations in January, March, April, June, August, and October. In addition, the maximum three-hour net load ramp occurred outside of Category 2 must-offer obligations in April.

Procurement

Table 10.7 shows what types of resources provided flexible resource adequacy and details the average monthly flexible capacity procurement in 2019 by fuel 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 to meet ramping needs. While the CPUC and ISO created counting criteria for a variety of resource types, the majority of flexible ramping procurement continued to be composed of natural gas-fired generation in 2019.

Table 10.7 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	9,619	68%	21	6%	2	6%
Use-limited gas units	2,898	21%	338	90%	6	14%
Use-limited hydro generators	1,257	9%	9	2%	1	3%
Other hydro generators	82	1%	-	-	-	-
Geothermal	235	1.7%	-	-	-	-
Energy Storage	21	0.1%	1	0.3%	24	54.7%
Solar	7	0.0%	-		-	-
Other non-dispatchable	-	-	8	2.0%	10	22.9%
Total	14,119	**100%**	377	**100%**	44	**100%**

Key findings of this analysis include:

- ***Most flexible resource adequacy capacity was procured from non-use-limited gas-fired generators***. Almost 10,000 MW (or 66 percent) of total flexible capacity came from these resources. This is a decrease from 2018 when gas-fired generators accounted for about 77 percent of total flexible capacity. Almost all (99 percent) of the capacity supplied by gas-fired generators served as Category 1 resources in 2019.
- ***Use-limited gas units made up the second largest volume of flexible resource adequacy capacity***. These generators made up about 21 percent of Category 1 capacity and 22 percent of overall flexible capacity.
- ***Use-limited hydroelectric generators made up the third largest volume of Category 1 flexible resource adequacy capacity***. These generators accounted for about 9 percent of Category 1 capacity, up from about 7 percent in 2019.
- ***Load serving entities procured significantly less than the maximum allowed amount of Category 3 flexible capacity in 2019***. Load serving entities procured a monthly average of 44 MW of Category 3 capacity. This is significantly less than the maximum amount that they are allowed to procure, or 5 percent of the total flexible requirement each month.
- ***Energy storage and other non-dispatchable resources (e.g., demand response) comprised a significant proportion of Category 3 flexible resource adequacy capacity***. These resources

accounted for a small amount of total flexible capacity, but together they made up about 78 percent of Category 3 capacity in 2019.

Table 10.8 shows what types of load serving entities procure different categories of flexible resource adequacy and details the average monthly flexible capacity procurement in 2019 by load type. Supply plans were used to proportionally assign resource bidding behavior to load serving entities based on corresponding contracted capacity. Bid availability was then aggregated by load type, depending on whether the entity is a community choice aggregator, direct access, investor-owned utility, or a municipal/government entity.

Table 10.8 Average monthly flexible resource adequacy procurement by resource type and load type

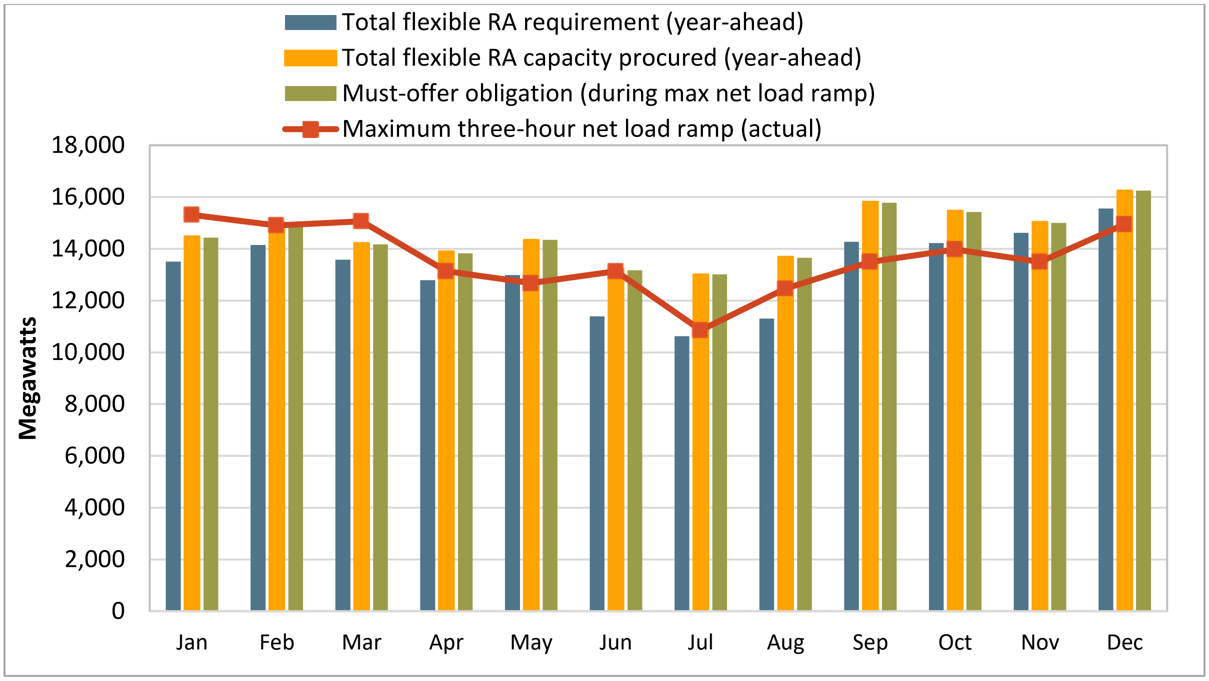
Load Type	Category 1		Category 2		Category 3	
	Average MW	Total %	Average MW	Total %	Average MW	Total %
CCA	2,633	19%	0	0%	2	5%
DA	1,259	9%	1	0%	2	5%
IOU	9,611	68%	293	78%	31	70%
Muni	613	4%	82	22%	9	20%
Total	**14,116**	**100%**	**376**	**100%**	**44**	**100%**

Key findings of this analysis include:

- ***Investor-owned utilities procured the highest proportion of each flexible resource adequacy category***. Investor-owned utilities procured 68 percent of total flexible capacity, community choice aggregators procured 18 percent, direct access services procured 9 percent, and municipal utilities procured 5 percent. Investor-owned utilities procured at least 68 percent of the capacity of each category.
- ***Most load types procured resources for each flexible resource adequacy category***. Investor-owned utilities, direct access services, and municipal utilities procured Category 1, 2, and 3 flexible resource adequacy resources. Community choice aggregators did not procure any Category 2 capacity.
- ***Municipal utilities procured the second highest proportion of Category 2 and Category 3 flexible capacity***. Municipal utilities procured most of their flexible capacity from Category 1 resources, but their procurement also contributed to a portion of total Category 2 (22 percent) and Category 3 (20 percent) capacity.

Due in part to greater amounts of Category 1 capacity, total flexible resource adequacy procurement exceeded requirements for all months in 2019. Figure 10.6 builds upon the information presented in Figure 10.5. Figure 10.6 shows total monthly flexible requirements and procured capacity, which are determined a year ahead. It also shows the total capacity that should be offered during the actual maximum three-hour net load ramp.[261] Must-offer obligations differ from the total flexible capacity procured because the actual net load ramps can occur outside of Category 2 and 3 must-offer hours.

Figure 10.6 Flexible resource adequacy procurement during the maximum net load ramp



Key findings of this analysis include:

- ***Year-ahead total flexible resource adequacy procurement exceeded total requirements***. Total flexible resource adequacy procurement (gold bars) exceeded the total requirement (blue bars) in all months of the year.
- ***The must-offer obligation for procured resources during the maximum three-hour net load ramp is lower than total procurement in most months***. Must-offer obligations during maximum net load ramps (green bars) is the same as total procurement (gold bars) in February, May, July, and December. For every other month, the must-offer obligation is 40 to 70 MW lower than the amount procured.
- ***The must-offer obligation for procured capacity was sufficient to meet the maximum net load ramp in most months***. The must-offer obligation during actual maximum net load ramp (green bars) exceeded the actual three-hour net load ramp (red line) for all months except for January and March in 2019.

261 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.

Availability

Table 10.9 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 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, an extra-long-start resource is considered 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 2019. This analysis is not intended to replicate how availability is measured under the resource adequacy availability incentive mechanism, which was implemented by the ISO in November 2016.[262] Resource adequacy availability incentive mechanism penalties became financially binding on April 1, 2017.

Table 10.9 Average flexible resource adequacy capacity and availability

Month	Average DA flexible	Average DA Availability		Average RT flexible	Average RT Availability	
		MW	% of Capacity		MW	% of Capacity
January	14,411	12,886	89%	10,167	9,153	90%
February	14,887	12,577	84%	10,842	9,450	87%
March	14,111	11,499	81%	10,218	9,084	89%
April	13,741	10,984	80%	9,741	8,067	83%
May	14,261	11,363	80%	9,677	8,558	88%
June	12,958	11,052	85%	8,503	7,593	89%
July	12,730	11,580	91%	9,011	8,092	90%
August	13,365	11,942	89%	9,800	8,772	90%
September	15,451	13,930	90%	11,650	10,282	88%
October	15,002	12,881	86%	11,002	9,827	89%
November	14,567	12,032	83%	10,477	9,023	86%
December	15,797	13,730	87%	10,958	9,833	90%
Total	**14,273**	**12,205**	**86%**	**10,171**	**8,978**	**88%**

262 The RAAIM calculation allows exemptions that are not included in DMM's calculations in the table. Specifically, the RAAIM calculation exempts resources with Pmax less than 1 MW, 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.

Key findings of this analysis include:

- ***Flexible resource adequacy resources had fairly high levels of availability in both the day-ahead and real-time markets in 2019***. Average availability in the day-ahead market was 86 percent and ranged from 80 percent to 91 percent. This is similar to 2018 when average availability in the day-ahead market was about 88 percent with a range from 80 percent to 92 percent. Average availability in the real-time market was 88 percent and ranged from 83 percent to 90 percent. This is similar to 2018 when average real-time availability was 87 percent and ranged from 81 percent to 92 percent.
- ***The real-time average must-offer obligation is much lower than the day-ahead obligation***. Flexible capacity must-offer requirements were about 14,300 MW in the day-ahead market and only about 10,200 MW in the real-time market on average. 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.

Table 10.10 is based on the same data summarized in Table 10.9, but aggregates average flexible resource adequacy availability by the type of load that the resources contracted with. Supply plans were used to proportionally assign resource bidding behavior to load serving entities based on their corresponding contracted flexible capacity. Bid availability was then aggregated by load type, depending on whether the entity is a community choice aggregator, direct access service, investor-owned utility, or a municipal/government entity.

Table 10.10 Average flexible resource adequacy capacity and availability by load type

Load Type	Average DA flexible capacity (MW)	Average DA Availability		Average RT flexible capacity (MW)	Average RT Availability	
		MW	% of Capacity		MW	% of Capacity
CCA	2,633	2,069	79%	2,028	1,753	86%
DA	1,260	1,003	80%	1,143	977	86%
IOU	9,704	8,509	88%	6,380	5,707	89%
Muni	676	624	92%	619	540	87%
Total	**14,273**	**12,205**	**86%**	**10,170**	**8,977**	**88%**

Key findings from this analysis include:

- ***Flexible resource adequacy resources had similar availability in the day-ahead and real-time markets across load types***. Resources that contracted with community choice aggregators and direct access services had about 80 percent availability in the day-ahead market, while those that contracted with investor-owned utilities and municipal utilities had about 90 percent availability. In the real-time market, these resources had availability between 86 and 89 percent of the time, depending on load type.

10.5 Capacity procurement mechanism

Background

The capacity procurement mechanism (CPM) provides backstop procurement authority to ensure that the ISO will have sufficient capacity available to maintain reliable grid operations. This mechanism facilitates pay-as-bid competitive solicitations for backstop capacity and also establishes a price cap at which the ISO can procure backstop capacity to meet resource adequacy requirements that are not met through resource adequacy showings by load serving entities. This backstop authority should also mitigate the potential exercise of locational market power by resources needed to meet local reliability requirements.

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, its clearing price is set at the soft offer cap. Resources can also file at FERC for costs that exceed 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.

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 a year-ahead competitive solicitation process using annual bids. The year-ahead 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 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.

Annual designations

There were no annual capacity procurement designations in 2019. Since the implementation of the current capacity procurement mechanism framework in 2016, the only annual designations were made in 2018.

Intra-monthly and monthly designations

Table 10.11 shows the intra-monthly capacity procurement mechanism designations that occurred in 2019. The table shows which resources were designated, amount of megawatts procured, the date range of the designation, the price, estimated cost of the procurement, the area that had insufficient capacity, and the event that triggered the designation. There were no monthly capacity procurement mechanism designations made in 2019, and there have not been any since the program was implemented in 2016.

Table 10.11 Intra-monthly capacity procurement mechanism costs

Resource	Designated MW	CPM Start Date	CPM End Date	CPM Type	Price ($/kW-mon)	Estimated cost ($ mil)	Estimated cost 2019 ($ mil)	Local capacity area	CPM designation trigger
CSCGNR_1_UNIT 1	7.95	5/23/19	5/31/19	ED	$6.31	$0.02	$0.02	PGE	Potential thermal overload
CSCGNR_1_UNIT 1	0.75	6/1/19	7/21/19	ED	$6.31	$0.01	$0.01	PGE	Potential thermal overload
DUANE_1_PL1X3	130.1	5/23/19	5/31/19	ED	$6.31	$0.25	$0.25	PGE	Potential thermal overload
DUANE_1_PL1X3	53.5	6/1/19	6/30/19	ED	$6.31	$0.34	$0.34	PGE	Potential thermal overload
HUMBPP_1_UNITS3	15.73	11/12/18	1/10/19	ED	$6.31	$0.20	$0.03	PGE	Potential thermal overload
HUMBPP_1_UNITS3	15	7/15/19	9/12/19	ED	$6.31	$0.19	$0.19	PGE	Potential thermal overload
HUMBPP_6_UNITS	12.46	11/14/18	1/12/19	ED	$6.31	$0.16	$0.03	PGE	Potential thermal overload
HUMBPP_6_UNITS	48.73	7/5/19	9/2/19	ED	$6.31	$0.61	$0.61	PGE	Potential thermal overload
STANIS_7_UNIT 1	5.4	11/28/18	1/26/19	ED	$6.31	$0.07	$0.03	PGE	Potential thermal overload
Total	290					$1.84	$1.51		

Key findings of this analysis include:

- ***About 290 MW of capacity was procured with an estimated cost of about $1.5 million in 2019.*** Intra-monthly designations were triggered by local reliability issues to address potential thermal overloads for the next contingency event in the Pacific Gas and Electric area. Total settlement for capacity procurement mechanism in 2019 was about $1.8 million, a substantial decrease from $11.1 million in 2018.
- ***Several intra-monthly designations were declined***. Scheduling coordinators who receive an exceptional dispatch for capacity not designated through the resource adequacy process may choose to decline the designation by contacting the ISO through appropriate channels within 24 hours of the designation. A scheduling coordinator may choose to decline a designation to avoid the associated must-offer obligation, which could reduce capacity costs passed to a single transmission access charge area or to the system as a whole.

10.6 Reliability must-run contracts

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 was implemented and provided a cost-effective alternative to reliability must-run contracting by the ISO. In late 2017, however, capacity designated as being subject to reliability must-run contracts during 2018 increased sharply.

In 2017, three new efficient gas units that represent almost 700 MW were designated by the ISO to provide reliability must-run service beginning in 2018.[263]

About 600 MW of the 700 MW of gas-fired generation designated by the ISO in 2018 to provide reliability must-run service was not re-designated for reliability must-run service in 2019. The need to designate the Metcalf Energy Center as a reliability must-run unit was eliminated by transmission upgrades completed in December 2018 and January 2019, with Metcalf Energy Center returning as a resource adequacy unit in 2019. The remaining 100 MW of gas-fired generation designated by the ISO in 2018 to provide reliability must-run service was not re-designated for reliability must-run service in 2020. The two units, Yuba City Energy Center and Feather River Energy Center, returned as resource adequacy units in 2020.

In 2018, the ISO designated one unit at the Ormond Beach Generating Station and Ellwood Energy Support Facility as reliability must-run units (aggregating 800 MW) extending the life of the units to the retirement dates originally considered in system planning. In 2019, the ISO did not enter into reliability must-run contracts with these units and they were picked up in the resource adequacy program.

In 2020, the ISO designated three new units aggregating 120 MW of capacity, namely E.F. Oxnard, Greenleaf II, and Channel Islands Power, for service as reliability must-run units. The contracts for these three units were filed at FERC in the May-June timeframe.

DMM provided recommendations, initiated in 2018, on the stakeholder process aimed at reforming the reliability must-run policy. The two basic flaws in the contract and tariff provisions for reliability must-run units under Condition 2 were:

- Remove the prohibition on reliability must-run capacity under Condition 2 being offered in the ISO's energy market except when needed for local area reliability; and
- Require reliability must-run resources to be subject to a must-offer requirement with cost-based bids.

These recommendations were addressed by the ISO with an amendment to the tariff approved by the Federal Energy Regulatory Commission on April 22, 2019.[264] The prohibition on reliability must-run capacity under condition 2 was amended[265] and Condition 2 units are now required to be offered in the ISO markets at cost-based bids.[266]

Total settlement for reliability must-run capacity was about $11 million in 2019, down from $63 million in 2018.

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263 These included 593 MW of capacity from the combined cycle Metcalf Energy Center, and 94 MW of peaking capacity owned by Calpine.

264 FERC Tariff Amendment to Improve the Reliability of Must-Run Framework ER19-1641, pages 539 and 540.

http://www.caiso.com/Documents/Apr22-2019-TariffAmendment-RMR-CPMEnhancements-ER19-1641.pdf

265 Ibid, page 408. R*esource must-run pro forma* and CAISO Tariff Appendix G Article 4.

266 CAISO Tariff Appendix G Section 6.1 http://www.caiso.com/Documents/AppendixG-ProFormaReliabilityMustRunContract-asof-Sep28-2019.pdf

11 Recommendations

As the ISO's independent market monitor, one of DMM's key duties is to provide recommendations on current market issues and new market design initiatives to the ISO, the ISO Governing Board, FERC staff, the California Public Utilities Commission, market participants, and other interested entities.[267]

DMM participates in the ISO's stakeholder process and provides recommendations in written comments submitted in this process. DMM also provides written recommendations in quarterly, annual and other special reports, which are also posted on the ISO's website. This chapter summarizes DMM's current recommendations on key market design initiatives and issues. Additional details on many of DMM's recommendations are provided in comments and other reports posted on DMM's page on the ISO website.[268]

11.1 Flexible ramping product

The flexible ramping product is designed to procure additional ramping capacity to address uncertainty in imbalance demand through the market software. This product has the potential to help increase reliability and efficiency, while reducing the need for manual load adjustments by grid operators. However, DMM has viewed the initial design approved by the Board in February 2016 as just the starting point for the more comprehensive set of flexible ramping market products that will be needed to facilitate the integration of distributed and variable energy resources into the western grid.

Even before the initial implementation of the flexible ramping product in 2016, DMM has recommended that the ISO start another stakeholder initiative to work on other important enhancements to the product's basic design.[269] Two key enhancements DMM has recommended since 2016 include the following:

- More locational procurement of flexible ramping capacity to decrease the likelihood that the product is not deliverable (or *stranded*) because of transmission constraints.
- Increasing the time horizon of real-time flexible ramping product beyond the 5-minute and 15-minute timeframe of the current product to address expected ramping needs and net load uncertainty over a longer time frame (e.g., 30, 60, and 120 minutes out from a given real-time internal).

267 Tariff Appendix P, ISO Department of Market Monitoring, Section 5.1. http://www.caiso.com/Documents/AppendixP_CAISODepartmentOfMarketMonitoring_asof_Apr1_2017.pdf

268 DMM reports, presentations, and stakeholder comments can be found on the ISO's website here: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx#CommentsRegulatory

269 *2017 Stakeholder Initiatives Catalog*, Discretionary Initiative 11.6 Flexible Ramping Product Enhancements requested by the Department of Market Monitoring, September 15, 2016, p. 22: http://www.caiso.com/Documents/Draft_2017StakeholderInitiativesCatalog.pdf

DMM also highlighted these two recommendations in DMM's 2018 annual report and in more recent comments in the ISO's stakeholder process.[270] In the ISO's new day-ahead market enhancements initiative, the ISO is proposing a new imbalance reserve product that would be procured in the day-ahead market based on the ISO's net load forecast. However, this new day-ahead load following product is not directly linked in any way to the real-time flexible ramping product. While DMM is generally supportive of the ISO's proposal for an enhanced day-ahead market, DMM recommends that the ISO enhance the real-time flexible ramping product to address uncertainty in net load forecasts over longer time horizons. DMM continues to recommend these enhancements, as described in more detail below.

Locational procurement

Analyses by DMM and the ISO have shown that the current real-time flexible ramping product may not be deliverable because of transmission constraints.[271]

As part of a new initiative on flexible ramping product refinements started in 2019, the ISO is considering ways to address the issue of undeliverable or stranded flexible ramping capacity through more locational procurement requirements.[272] Options for ensuring deliverability of flexible ramping capacity being considered by the ISO include nodal procurement.

A more refined zonal procurement may be an improvement over the current balancing authority area requirements, but will still have the same underlying problem of not accounting for transmission constraints within the zones. Accounting for transmission constraints through nodal procurement would significantly improve the effectiveness of procured flexible ramping reserves. A nodal procurement would provide more benefits than a zonal procurement. However, the effectiveness of either a nodal or zonal procurement would depend on the final constraint and product formulations.[273]

DMM has recommended that the ISO work on designing locational procurement for both day-ahead and real-time flexible ramping products. Locational procurement that accounts for transmission constraints would result in deliverable reserves. This could significantly increase the efficiency of the ISO's market awards and dispatches. This change could also help to resolve the very low prices for flexible reserves that result from undeliverable reserves being counted towards meeting a reliability need that they cannot actually help to meet.

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[270] *2018 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2019, pp. 269-270: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

[271] *Discussion on flexible ramping product*, California ISO, September 8, 2017 pg. 16-17: http://www.caiso.com/Documents/Discussion_FlexibleRampingProduct.pdf

Q3 Report on Market Issues and Performance, December 5, 2019, pp.84-86. http://www.caiso.com/Documents/2019ThirdQuarterReportonMarketIssuesandPerformance.pdf

[272] *Flexible Ramping Product Refinements Issue Paper and Straw Proposal*, November 14, 20019, pp.6-8. http://www.caiso.com/InitiativeDocuments/IssuePaper-StrawProposal-FlexibleRampingProductRefinements.pdf

[273] *Comments on Flexible Ramping Product Refinements: Issue Paper and Straw Proposal*, Department of Market Monitoring, December 5, 2019, pp.2: http://www.caiso.com/InitiativeDocuments/DMMComments-FlexibleRampingProductRefinements-IssuePaper-StrawProposal.pdf

Real-time product for uncertainty over longer time horizons

DMM continues to recommend that the ISO begin to develop an approach for extending the time horizon of the flexible ramping product to account for uncertainty over longer time horizons. The range of likely outcomes narrows as the time between the uncertain outcome and the evaluation of that uncertain outcome narrows; there is less uncertainty between the 15- and 5-minute markets than over a longer interval.[274] The current flexible ramping product is designed to address uncertainty between the 15- and 5-minute markets. In real time, grid operators face significant uncertainty about loads and resources over a longer timeframe (e.g., 30, 60, and 120 minutes from the current market interval).

The initial flexible ramping product design procures and prices ramping capability in the 15-minute market to account for uncertainty between the 15- and 5-minute markets. In the 5-minute market, the market software then procures and prices the appropriate amount of ramping capability to account for the uncertainty in only 5-minute net load forecasts. As the ISO incorporates growing quantities of distributed and variable energy resources, there will be increasingly greater uncertainty in the net load forecasts for intervals 30, 60, and 120 minutes out from a given real-time market run.

Grid operators already face significant uncertainty over load and the future availability of resources to meet that load. This uncertainty is the primary reason why operators need to systematically enter the large positive load adjustments during the morning and evening ramping hours, as described in Section 9.3 of this report. Operators also take other out-of-market actions to ensure sufficient ramping capacity is available in the peak ramping hours, including exceptional dispatches to commit additional gas-fired units and to begin ramping these resources up in the peak ramping hours. Extending the time horizon of the flexible ramping product should significantly reduce the need for manual load adjustments and out-of-market dispatches of gas resources.

The ISO's current proposal stemming from the initiative on flexible ramping product refinements begun in 2019 does not include extending the time horizon of the flexible ramping product. DMM does not think that the ISO's other proposed improvements should be delayed to work on an extended horizon product design.[275] However, DMM continues to recommend that the ISO should begin efforts to extend the real-time flexible ramping product to longer time horizons. As the ISO develops day-ahead flexible reserve products it will become even more important to have real-time products to ensure that reserves procured in the day-ahead market are used effectively in real-time, as discussed in the following section.

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[274] Illustrations of this concept as applied to the flexible ramping product are available here: *Real-time Flex Ramp Product Enhancements – Western EIM Body of State Regulators*, June 12, 2020. http://www.caiso.com/Documents/Presentation-Real-TimeFlexRampProductEnhancements-WesternEIMBodyofStateRegulators-June122020.pdf

[275] Comments on Flexible Ramping Product Refinements: Issue Paper and Straw Proposal, Department of Market Monitoring, December 5, 2019, pp.2.

11.2 Day-ahead market enhancements

In 2018 the ISO initiated a process to develop a proposal for day-ahead market enhancements. The CAISO released an initial straw proposal in February 2020.[276]

Day-ahead imbalance reserve product

A key element of the ISO's initial straw proposal is the introduction of a day-ahead imbalance reserve product that is intended to ensure sufficient ramping capacity is available in the real-time market. DMM supports development of a day-ahead imbalance reserve product. The new day-ahead imbalance reserve product will increase day-ahead market costs through the direct payments for this new product as well as through increases to day-ahead market energy prices resulting from procurement of this product.

However, if the ISO does not extend the uncertainty horizon of the real-time flexible ramping product, DMM is concerned that the imbalance reserves that are procured in the day-ahead market will provide limited benefit in terms of increased ramping capacity in real-time or reduced real-time market costs. Thus, DMM continues to recommend that the ISO take steps to extend the time horizon of the real-time flexible ramping product to enable the market software to commit and position resources to address uncertainty in net load forecasts further out in the future.

Reliability energy product

Two other key elements of the ISO's initial straw proposal included (1) a new *reliability energy* (REN) product, and (2) combining the day-ahead energy market and residual unit commitment process into a single optimization process. These two elements are related in that the new reliability energy product would be procured through a single optimization process in place of the current residual unit commitment process.

Most stakeholders, including DMM, agree that day-ahead procurement of flexible reserves is desirable and needed as the western grid continues to increasingly rely on renewable generation. However, there is considerable controversy regarding the proposed reliability energy product. This new product would be procured based on the ISO's load forecast and could have a significant impact on overall market clearing prices. This product would also significantly increase the role that the ISO plays in determining day-ahead market energy awards and prices.

As noted in DMM's comments on the straw proposal, this controversy has consumed much of the DAME initiative process for the last couple years.[277] To expedite the completion of the complicated design work that still needs to be done for imbalance reserve products, DMM has recommended that the ISO separate any potential future development of reliability energy products or combining the day-ahead

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276 *Day-Ahead Market Enhancements Straw Proposal*, California ISO, February 3, 2020: http://www.caiso.com/InitiativeDocuments/StrawProposal-Day-AheadMarketEnhancements.pdf

277 *Comments on Day-Ahead Market Enhancements Straw Proposal*, Department of Market Monitoring, March 30, 2020. http://www.caiso.com/InitiativeDocuments/DMMComments-Day-AheadMarketEnhancements-StrawProposal.pdf

energy market and residual unit commitment process into a single optimization process. The ISO has pivoted away from the reliability energy product to focus on development of imbalance reserves.[278]

11.3 Extended day-ahead energy market

In 2019 the ISO also initiated a process to develop a proposal for extending the day-ahead market to include other entities in the Western EIM.[279] This initiative is designed to build on market design changes made as part of the ISO's initiative on day-ahead market enhancements.

DMM strongly supports extending participation in the day-ahead market to more entities across the west. An extended day-ahead market would increase trading opportunities across the west and allow entities throughout the Western EIM to more efficiently meet their needs as the western electric grid continues to evolve and reliance on renewable energy increases.

In the first phase of this stakeholder process, the ISO is addressing the following three areas: (1) resource sufficiency, (2) provision of transmission, and (3) allocation of congestion rents. These three areas are being addressed first because they are expected to be the most controversial. Several key issues and concerns highlighted in DMM's initial comments on these issues are briefly summarized below.[280]

Resource sufficiency

The extended day-ahead market design clearly needs to allow entities to meet resource sufficiency obligations with power from resources that must schedule over another balancing authority area's transmission. Western EIM entities proposed requiring a resource to have firm (or equivalent quality) transmission service to a BAA before the day-ahead market closes in order for the resource to count towards meeting a BAA's resource sufficiency requirement for the extended day-ahead market.

DMM has expressed concern that in the absence of changes to existing timelines and protocols for releasing firm transmission, the proposed firm transmission requirement proposed by EIM entities for resource sufficiency qualification could significantly restrict the amount of transmission that load serving entities can rely on for utilizing the most efficient resources to meet resource sufficiency requirements for the extended day-ahead market. This is because third party entities can purchase long-term firm transmission rights at regulated rates on critical paths between generation and load centers when transmission operators first offer the firm rights far in advance of the day-ahead market timeframe. DMM's understanding is that current open access protocols for transmission in WECC only require long-term firm rights holders to release unused transmission capacity after the ISO's day-ahead market closes.

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278 *Day-Ahead Market Enhancements Revised Straw Proposal,* ISO Stakeholder presentation, June 15-17, 2020. http://www.caiso.com/InitiativeDocuments/Presentation-Day-AheadMarketEnhancements-Jun15-17-2020.pdf

279 *Extending the Day-Ahead Market to EIM Entities Issue Paper*, California ISO, October 10, 2019: http://www.caiso.com/Documents/IssuePaper-ExtendedDayAheadMarket.pdf

280 *Comments on Extended Day-Ahead Market: February 11-12, 2020 Stakeholder Workshop Bundle 1 Topics: Resource Sufficiency, Transmission, and Congestion Revenue*, Department of Market Monitoring, February 26, 2020: http://www.caiso.com/InitiativeDocuments/DMMComments-ExtendedDay-AheadMarketTechnicalWorkshop-Feb11-12-2020.pdf

Provision of transmission

The Western EIM has been designed as a voluntary market. Energy imbalance market entities have proposed that transmission operators could offer additional unreserved transmission to the extended day-ahead market in the form of unsold, unreserved firm (or equivalent quality) capacity at the time the extended day-ahead market is initiated. On one hand, this approach may increase transmission that is made available in the extended day-ahead market. However, some participants have raised concerns that reservation of transmission capacity could have the effect of reducing competitive access to transmission (and energy) in the extended day-ahead market. DMM believes that mechanisms to ensure competitive access to transmission in the extended day-ahead market warrant further consideration.

Congestion revenues

How congestion rents are allocated will have a major impact on the incentives for entities to provide transmission rights to the extended day-ahead market. To create incentives to make transmission available, congestion rents would be allocated to transmission owners. However, if the allocation of congestion rents creates incentives for entities to reduce the available transmission for the purpose of receiving increased congestion rents, this would adversely affect the extended day-ahead market as well as bilateral markets.

11.4 Congestion revenue rights

Since the start of the ISO's congestion revenue rights (CRR) auction in 2009, payouts to non-load serving entities purchasing congestion revenue rights have exceeded the auction revenues by about $860 million through 2018. If the ISO did not auction these congestion revenue rights, these congestion revenues would be credited back to transmission ratepayers who pay for the cost of the transmission system through the transmission access charge (TAC). Thus, this $860 million represents profits to the entities purchasing these financial rights in the auction, but represents revenue losses to transmission ratepayers. Most of these losses have resulted from profits received by purely financial entities which purchase congestion revenue rights but do not schedule power or load in the ISO.

Losses from congestion revenue rights increased to about $100 million in 2017 and $131 million in 2018. In response to these large and systematic losses from sales of congestion revenue rights, the ISO instituted significant changes to the auction starting in the 2019 settlement year. These changes include the following:

- Track 0 – Increasing the number of constraints enforced by default in the congestion revenue rights models, identifying potential enforcement of "nomogram" constraints in the day-ahead market to include in the congestion revenue rights models, and other process improvements.[281]

[281] *Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal*, California ISO, April 19, 2018: http://www.caiso.com/InitiativeDocuments/StrawProposal-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

- Track 1A – Limiting congestion revenue rights sold in the auction to pairs of sources and sinks corresponding to potential "delivery paths" for energy to load.[282]
- Track 1B – Limiting congestion revenue rights payments to not exceed congestion rents actually collected from the underlying transmission constraints.[283]

As discussed in Chapter 8 of this report (Section 8.4), while changes implemented by the ISO in 2019 reduced losses from the congestion revenue rights auction, losses to ratepayers from the auction were still significant. In 2019, losses from auctioned congestion revenue rights totaled about $22 million. Financial entities, which do not serve load or provide supply in the ISO markets, received profits of $23 million and paid 63 cents in auction revenues per dollar of congestion rights payments received in 2019. Physical generators incurred losses of $3 million and paid $1.20 into the auction per dollar of payments received.

The reduction in losses from the auction resulted from a combination of the changes implemented by the ISO, along with a significant drop in day-ahead market congestion. Losses from the auction in 2019 totaled about 6 percent of total day-ahead congestion rents in 2019, compared to about 21 percent of congestion rents in 2018.

DMM believes that under current rules it remains likely that the congestion revenue rights auction will continue to result in significant losses to transmission ratepayers. DMM continues to recommend that the ISO take steps to discontinue auctioning congestion revenue rights and instead reallocate all congestion revenues back to ratepayers who pay for the cost of the transmission system through the transmission access charge. If the ISO believes it is highly beneficial for the ISO to actively facilitate hedging of congestion costs by suppliers, DMM recommends that the ISO modify the auction into a market for financial hedges based on clearing of bids from willing buyers and sellers.

11.5 Reliability must-run contracts

In 2018 the ISO initiated a stakeholder process to consider changes to the two backstop capacity procurement mechanisms in the ISO tariff: reliability must-run (RMR) contracts and the capacity procurement mechanism (CPM).[284] This 2018 initiative resulted in numerous proposed changes to reliability must-run contract provisions which were approved by the ISO Board in March 2019 and approved by FERC in September 2019.[285]

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[282] *Congestion Revenue Rights Auction Efficiency Track 1A Draft Final Proposal Addendum*, California ISO, March 8, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalAddendum-CongestionRevenueRightsAuctionEfficiency-Track1.pdf

[283] *Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum*, California ISO, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

[284] *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

[285] Order Accepting Tariff Revisions, ER19-1641-001, September 27, 2019. http://www.caiso.com/Documents/Sep27-2019-OrderAcceptingTariffAmendment-RMR-CPMEnhancements-ER19-1641.pdf

DMM supported the changes in reliability must-run contract rules in 2019, which addressed key market design flaws in the contract provisions identified by DMM in November 2017.[286] These flaws included lack of must-offer requirement for reliability must-run units receiving full cost of service compensation. With these changes, these units will be required to be offered in the ISO markets at cost-based bids, with net revenues earned being credited back to transmission owners who pay the full fixed and variable costs of the units.

The ISO's 2019 proposal indicates that the ISO will seek to limit reliability must-run contracts only to units that would retire or mothball if they did not receive a reliability must-run contract. To help ensure this, the ISO will require the owner of any resource that wants to be considered for a reliability must-run designation to submit a formal affidavit stating that the unit is retiring or mothballing because it is uneconomic for the resource to remain in operation or if the resource is retiring for other reasons (such as loss of license).[287]

FERC's September 2019 order denied requests that the Commission formally direct ISO to engage in active monitoring of retirement and mothball requests, but noted that "CAISO and DMM already review these requests and we expect that, if DMM has reason to suspect that a resource has submitted false, inaccurate, or otherwise misleading information in its affidavit, it should refer such suspected violations to the Commission."[288]

11.6 Capacity procurement mechanism

The 2018 and 2019 stakeholder processes to consider changes to the capacity procurement mechanism resulted in very limited changes. Changes proposed by the ISO have been limited to addressing a key flaw in the potential compensation of any capacity with bids in excess of the capacity procurement mechanism soft cap of $76/kW-year. Rules in place since 2016 allow such capacity to be paid full fixed costs (including recovery of undepreciated sunk costs and a return on investment) and also retain all net revenues from energy market sales. Although no capacity with bids in excess of this soft cap has been procured by the ISO under the capacity procurement mechanism, DMM and other parties have protested that such compensation would be unreasonably high.[289]

In the second half of 2019, the ISO continued to consider additional changes in the capacity procurement mechanism. These included the application of a structural market power test to capacity procured under these tariff provisions and lowering the $76/kW-year soft cap applied to capacity

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286 *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

287 Memorandum to ISO Board of Governors, Re: Decision on reliability must-run and capacity procurement mechanism enhancements proposal, Keith Casey, March 20, 2019, pp.4-5. http://www.caiso.com/Documents/Decision-ReliabilityMust-Run-CapacityProcurementMechanismEnhancementsProposal-Memo-Mar2019.pdf

288 Order Accepting Tariff Revisions (September 27, 2019), ¶58 at p. 23.

289 *Motion to Intervene and Protest of the Department of Market Monitoring*, ER18-641-000, February 2, 2018. http://www.caiso.com/Documents/Feb2_2018_DMMIntervention_Protest-RORCPM_ER18-641.pdf.

procured by the ISO. However, in early 2020 the ISO announced that no further changes would be proposed beyond the limited changes approved by the Board in March 2019.[290]

DMM supports the limited changes to compensation of any capacity procured at prices in excess of the capacity procurement mechanism soft cap filed at FERC in 2020 as an incremental improvement to current market rules. However, DMM believes that the ISO's proposal does not address the key concerns with the current backstop procurement mechanisms that are needed as part of a comprehensive reform.

DMM has submitted an extensive review of different cost studies showing that the current $76/kW-year soft cap is based on an inaccurately high estimate of the annual going forward fixed costs (GFFC) of gas-fired units.[291] Based on this review, DMM has recommended the ISO perform its own review of cost estimates used by the ISO to set the soft cap. DMM has also recommended that the ISO continue to consider establishing a structural market power test to any capacity procured on an annual basis under the capacity procurement mechanism.

11.7 Commitment cost and default energy bid enhancements

In early 2018, the ISO completed a multi-year stakeholder process to propose changes in the bid caps used in mitigation under the commitment cost and default energy bid enhancements (CCDEBE) proposal. The proposal includes numerous provisions that will allow higher bid caps for gas-fired units used in mitigation of start-up, minimum load, and energy bids.

DMM did not support the proposal that was presented for approval by the ISO Board in March 2018 for numerous reasons.[292] However, over the last two years the ISO has addressed most of these issues by changing or deferring elements of the 2018 proposal. In October 2019, the ISO filed a proposal at FERC with several key revisions, as described below.

Dynamic mitigation of commitment costs. The 2018 proposal approved by the ISO Board would replace the ISO's existing static commitment cost cap with a dynamic commitment cost local market power test. With this approach, suppliers could submit higher "market-based" commitment cost bids which would only be mitigated to cost-based reference levels if this test indicated structural market power.[293] DMM opposed the ISO's proposal for dynamic mitigation of commitment costs because the proposal had

290 *Capacity Procurement Mechanism Draft Final Proposal*, California ISO, January 6, 2020: http://www.caiso.com/InitiativeDocuments/DraftFinalProposal-CapacityProcurementMechanismSoftOfferCap.pdf

291 DMM Comments on CPM Tariff Filing ER20-1075, April 3, 2020: http://www.caiso.com/Documents/AnswerandMotionforLeavetoAnswer-DMMCommentsonCPMTariffFilingER20-1075-Apr32020.pdf

292 *Memorandum to ISO Board of Governors, Re: Department of Market Monitoring Comments on CCDEBE Proposal*, March 14, 2018: http://www.caiso.com/Documents/Decision_CCDEBEProposal-Department_MarketMonitoringMemo-Mar2018.pdf

293 Transmittal letter, pp. 21-23: http://www.caiso.com/Documents/Aug30-2019-TariffAmendment-CommitmentCosts-DefaultEnergyBidEnhancements-ER19-2727.pdf

several key gaps in mitigation and numerous unresolved implementation details and uncertainties.[294] In 2019, the ISO deferred this element of the proposal until at least fall 2022.

Updating gas prices used for setting bid caps. Since 2015, DMM has been recommending that the ISO adjust real-time bid caps (or reasonableness thresholds used to screen and mitigate bids) based on same-day gas market data available at the start of each operating day.[295] The proposal approved by the ISO Board in 2018 did not incorporate this recommendation. However, in 2019 the proposal was modified so that the reasonableness threshold used to screen and mitigate bids in the real-time market will be updated based on same-day gas market prices available at the start of each operating day.[296]

Gas imbalance penalties. DMM also objected to provisions in the 2018 proposal allowing suppliers to incorporate the cost of potential gas imbalance penalties into their estimated actual or expected gas costs when requesting increases in bids used in mitigation. DMM provided analysis showing that limitations on gas supply and potential gas imbalance penalties are generally reflected directly in the gas market prices at which suppliers may procure gas and the electricity market prices they receive.[297] In response to a deficiency letter from FERC following the ISO's 2019 tariff filing, the ISO agreed to modify its proposal to explicitly exclude the inclusion of potential gas imbalance penalties in suppliers' estimated gas costs.[298]

Commitment cost and energy bid adders. Bid caps for start-up and minimum load commitment costs currently include a 25 percent bid adder above estimated costs. Default energy bids used when energy price mitigation is triggered include a 10 percent adder above each unit's marginal costs. In the past, these adders have been justified as being needed to cover potential differences in the gas price indices used by the ISO and the supplier's actual gas costs. DMM has questioned the need to continue allowing the 25 percent adder in bid caps that are based on the supplier's own estimate of actual or expected gas costs. The ISO's October 2019 filing was rejected by FERC on the grounds that the ISO had not justified allowing the 25 percent adder in bid caps based on suppliers' estimates of their actual or expected gas costs.[299]

294 These gaps included lack of provisions to effectively mitigate economic withholding, gaming of bid cost recovery payments associated with inter-temporal constraints, or market power associated with most manual commitments made by CAISO operators. *Memorandum to ISO Board of Governors, Re: Department of Market Monitoring Comments on CCDEBE Proposal*, March 14, 2018. pp. 3-4: http://www.caiso.com/Documents/Decision_CCDEBEProposal-Department_MarketMonitoringMemo-Mar2018.pdf.

295 *Memorandum to ISO Board of Governors, Re: Department of Market Monitoring Comments on CCDEBE Proposal*, March 14, 2018, pp.1-2 and pp. 5-7. http://www.caiso.com/Documents/Decision_CCDEBEProposal-Department_MarketMonitoringMemo-Mar2018.pdf.

296 *Local Market Power Mitigation Enhancements Draft Final Proposal*, California ISO, January 31, 2019, pp. 43-46. http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements-UpdatedJan31_2019.pdf

297 Refer to Section 1.2.6 for more information on impact of operational flow orders on Southern California gas prices.

298 Response to deficiency letter, p.9. http://www.caiso.com/Documents/Nov22-2019-ResponseDeficiencyLetter-CCDEBE-ER19-2727.pdf

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

In 2020, the ISO has indicated it plans to refile a revised proposal that will maintain the current 25 percent and 10 percent adders on commitment cost bid caps and default energy bids calculated by the ISO, but will not allow inclusion of any adder in requests by generators for higher bid caps based on the generators' estimate of actual or expected gas costs.

DMM supports the ISO's revised 2020 filing. However, DMM has recommended that the ISO will need to justify the 25 percent adder in commitment cost bid caps calculated by the ISO in large part as a profit margin that provides a reasonable level of protection against market power.[300]

11.8 Gas usage nomograms

In 2016, the ISO gained temporary authority from FERC to help address the limited operability of the Aliso Canyon gas storage facility by enforcing a maximum gas constraint (or nomogram) for groups of units in the SoCalGas system. The ISO renewed its temporary authority to impose gas use constraints several times before receiving permanent tariff authority to impose a gas constraint in the SoCalGas area in fall 2019.

DMM agrees that incorporating maximum gas constraints into the market software can in theory be more effective and efficient at managing gas limitations than alternatives, such as use of manual dispatches made by system operators. However, DMM's review of the limited times that the ISO has utilized maximum gas constraints since 2016 indicates that the design and implementation of gas constraints require significant enhancements to ensure that these constraints are an effective tool for helping to ensure reliability. Thus, DMM continues to recommend that the CAISO enhance how it utilizes the maximum gas constraint and improve how gas usage constraint limits are set and adjusted in real-time.[301]

DMM's main concern with gas usage nomograms is that when the gas company notifies the ISO of a daily or multi-hour gas limitation for a group of generating units, the ISO converts this multi-hour gas limit into a series of limits on individual hourly or 15-minute market intervals. The ISO sets these hourly or 15-minute gas use limits based on the shape of the overall system loads, which is referred to as *gross load*. However, gas usage from the market optimization is actually shaped much more like the *net load* curve, ramping up and peaking in the evening ramping hours.

DMM has provided analysis showing that the ISO's use of gross loads to shape the gas constraint appears to have resulted in unnecessary inefficiencies in both the day-ahead and real-time markets.[302] As illustrated in examples provided by DMM, during most hours actual gas usage is well below the maximum gas limit set by the ISO's gross load approach. However, during the peak evening ramping hours, gas usage often hits or exceeds the limit set by the ISO for these intervals. In these examples,

[300] *Comments on Revised Draft Tariff Language for Commitment Cost and Default Energy Bid Enhancements*, Department of Market Monitoring, March 27, 2020. http://www.caiso.com/InitiativeDocuments/DMMComments-CommitmentCosts-DefaultEnergyBidEnhancements-StakeholderBriefing-Mar19-2020.pdf

[301] *Motion to Intervene and Comments of the Department of Market Monitoring*, ER20-273-000, November 21, 2019: http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoring-Aliso5-ER20-273-000-Nov212019.pdf

[302] *Motion to Intervene and Comments of the Department of Market Monitoring*, ER20-273-000, pp. 3-7, November 21, 2019: http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoring-Aliso5-ER20-273-000-Nov212019.pdf

excess gas should actually have been available during the evening ramping hours when the gas usage constraint was binding and the need for fast ramping capacity from gas-fired units was most critical. This problem is exacerbated since there is no method for allowing operators to raise gas limits in real-time to account for excess gas from prior hours.

The ISO has indicated that it plans to enhance how the gas usage constraint is shaped and adjusted over the course of the operating day. The ISO has indicated it favors shaping daily gas limits based on net loads rather than gross loads. However, DMM has recommended that the ISO consider using projected gas usage from the ISO's two-day ahead run of the day-ahead market software. This two-day ahead modeling process is specifically designed to project and assess gas and generation needs based on the best available information prior to each day.[303] DMM has provided analysis showing that while shaping gas constraints based on net loads would a significant improvement, shaping the gas constraint based on projected gas use from the two-day ahead modeling process may reduce cases in which gas usage is unnecessarily limited in the peak ramping hours.[304] The ISO is considering adopting this shaping.

FERC approved the ISO's request for permanent authority to implement gas usage constraints in the SoCalGas area on December 30, 2019. The Commission's order noted that:

> We acknowledge DMM's comments regarding potential enhancements to the design and implementation of the constraint, as well as CAISO's stated commitment to exploring such enhancements …. We note CAISO's commitment to work with DMM to consider appropriate enhancements, and to vet these enhancements with stakeholders through its business practice manual change management process to address concerns. … We encourage CAISO to engage with DMM and stakeholders to focus on additional refinements to the software and operational processes necessary in the design of the gas burn constraint, and to make the implementation more transparent and efficient.[305]

DMM looks forward to working with the ISO and stakeholders in the process to make the implementation more transparent and efficient.

11.9 System level market power

The ISO has tariff provisions and automated procedures for mitigation of local market power in congested areas within the balancing area, but not for mitigation of potential market power at a system level (or across the entire ISO balancing area). Despite the lack of any bid mitigation for system market power, the ISO's energy markets have been highly competitive at a system level since the early 2000s due to a high level of forward bilateral energy contracting by the ISO's load serving entities, relatively high supply margins, and access to imports from other balancing areas. The long-term procurement framework and resource adequacy requirements developed by the CPUC and other local regulatory

[303] Results of this two-day ahead modeling process are provided to scheduling coordinator for the explicit purpose of helping to enhance their gas purchasing and scheduling decisions. As explained in the CAISO's 2017 filing, this two-day ahead modeling process "involves the CAISO running the commitment process based on available bids and estimates of system conditions at that time."

[304] *Motion to Intervene and Comments of the Department of Market Monitoring*, ER20-273-000, pp. 7-10, November 21, 2019: http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoring-Aliso5-ER20-273-000-Nov212019.pdf

[305] *Order Accepting Tariff Revisions*, ER20-271-000, December 30, 2019, P. 7 ¶18 http://www.caiso.com/Documents/Dec30-2019-OrderAcceptingTariffRevisions-AlisoCanyonGasElectricCoordination-MaximumGasConstraint-ER20-273.pdf

authorities have played a key role in making the ISO's energy market competitive at a system level for more than 15 years.

California's resource adequacy program rules are focused primarily on ensuring sufficient capacity for reliability, rather than for a competitive supply of energy or for hedging of high energy prices by load serving entities. In practice, however, the state's load serving entities have traditionally met most resource adequacy import capacity requirements through some form of firm energy purchases or options. Such "bundling" of energy with capacity used to meet resource adequacy requirements has played an important role in helping to ensure a competitive supply of energy to the CAISO day-ahead and real-time energy markets.

Likewise, the bulk of resource adequacy requirements for capacity within the ISO have been met by generation under some form of energy tolling agreement or forward energy contract with load serving entities, which has also helped mitigate potential market power in the ISO's day-ahead and real-time energy markets. Such energy contracts or tolling agreements reduce the potential for system market power by reducing the amount of energy that must be purchased by load serving entities in the ISO's spot markets and providing load serving entities with hedges against the potential for uncompetitive high energy prices.

However, in recent years a number of regulatory and structural market changes have occurred which have increased the potential for system level market power in the ISO balancing area. These include the following:

- Reliance on a growing amount of capacity from intermittent renewable resources, which has limited the availability of capacity 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 appears to be reducing long-term contracting and complicates the process for procurement of capacity needed to meet local resource adequacy requirements by load serving entities.
- Fewer energy tolling contracts between gas units within the ISO and load serving entities without an incentive to exercise market power.
- Regional supply and demand conditions appear to be tightening as well, so that the supply of imported power to the ISO may be reduced under high load conditions.

In 2018 DMM recommended that the ISO begin to consider actions to reduce the likelihood of uncompetitive system conditions and to mitigate the potential impacts of system market power on energy market costs and reliability. DMM provided the following recommendations for consideration by the ISO and stakeholders:

- Begin to discuss and develop an approach that could be implemented to provide some degree of system level market power mitigation.
- Set local and system resource adequacy requirements sufficiently high to ensure reliability and reduce the potential frequency of non-competitive market outcomes.

- Consider options for increasing the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time. These options include extending a must-offer requirement for all or some resource adequacy imports into the real-time market. Options may also include scheduling and bidding requirements and limitations designed to increase the amount of resource adequacy imports clearing the day-ahead market in tight supply conditions or high load uncertainty.

- When implementing FERC Order No. 831, require that import bids over $1,000/MWh are subject to *ex ante* cost justification and do not raise penalty prices up to $2,000/MWh except when bids over $1,000/MWh which have been cost justified are actually dispatched.

- 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 incentives and sanctions for failing to meet 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.

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

DMM recognizes that many of these recommendations involve major market design challenges and raise numerous controversial policy issues. 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. At least three of these recommendations are being addressed in different ISO stakeholder initiatives and CPUC proceedings, as discussed below.

System market power bid mitigation

In 2019, the ISO launched an initiative to begin designing a system-level market power mitigation process. In proposals put forth to date, the ISO has outlined potential market power mitigation measures for the real-time market only. The proposed measures would be triggered when the ISO, or the ISO with a larger subarea of the western interconnection, may be import constrained.[306,307] The ISO plans to present a final proposal to its Board for approval in 2020 so that the CAISO may implement the proposed changes before summer of 2021.

DMM supports the ISO's efforts to design and implement system market power mitigation and is generally supportive of the proposal being developed. In comments on the ISO's December 2019 straw proposal, DMM has recommended that the ISO develop a system market power mitigation approach that captures all instances in which system conditions may be uncompetitive. This requires assessing system competitiveness even when ISO import constraints may be non-binding, and expanding mitigation procedures to consider the entire real-time system inclusive of the Western EIM.[308]

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306 *System Market Power Mitigation Straw Proposal*, California ISO, December 11, 2019: http://www.caiso.com/InitiativeDocuments/StrawProposal-SystemMarketPowerMitigation.pdf

307 *System Market Power Mitigation Revised Straw Proposal*, California ISO, April 7, 2020: http://www.caiso.com/InitiativeDocuments/RevisedStrawProposal-SystemMarketPowerMitigation.pdf

308 *Comments by Department of Market Monitoring on System Market Power Mitigation Straw Proposal*, January 10, 2020, pop.6-8. http://www.caiso.com/InitiativeDocuments/DMMComments-SystemMarketPowerMitigation-StrawProposal.pdf

Despite some limitations of the ISO's current proposal, DMM believes that the ISO's proposal may mitigate real-time market power in some situations. Mitigation of market power in the real-time market may also help mitigate market power in the day-ahead market to some degree. DMM supports the ISO's continued development of system-level market power mitigation measures for the day-ahead and real-time markets in the second phase of the initiative.

Resource adequacy imports

DMM has longstanding concerns that existing rules 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.[309] If resource adequacy import capacity is not scheduled in the day-ahead market or residual unit commitment process, these resources have no further obligation to bid into the real-time market. Thus, by simply bidding at or near the $1,000/MWh bid cap in the day-ahead market, resource adequacy imports can receive capacity payments while providing no real benefits in terms of either system reliability or market competitiveness.

DMM has suggested that resource adequacy imports could be subject to some type of lower bidding limits when potential system market power exists. Unlike other imports, resource adequacy imports receive capacity payments and can be subject to must-offer obligations. DMM has also recommended that the ISO consider options for increasing the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time.

The ISO contends that subjecting resource adequacy imports to any type of bid mitigation would be "ineffective and inappropriate."[310] Additional discussion of DMM's recommendations on resource adequacy imports is provided under Section 11.10 of this chapter.

Implementing Order No. 831

FERC Order No. 831 requires that all ISOs allow submission of bids of up to $2,000/MWh. If the ISO can verify that bids over the current $1,000/MWh bid cap within the ISO's balancing area are cost justified before the market runs (*ex ante*), cost verified bids over $1,000/MWh may set market clearing prices. If the ISO cannot verify that bids over $1,000/MWh are cost justified *ex ante*, these bids are capped at $1,000/MWh but may apply for *ex post* cost recovery if dispatched.

Order No. 831 found that although cost justification for import bids can be difficult, ISOs may file tariff changes with the Commission which would also require imports to be cost justified *ex ante* in order to set market clearing prices. If the ISO cannot verify that import bids over $1,000/MWh are cost justified *ex ante*, these bids could be capped at $1,000/MWh but may apply for *ex post* cost recovery if dispatched.

In May 2019, DMM recommended that before implementing Order No. 831, the ISO should file tariff changes with FERC to subject import bids over $1,000/MWh to *ex ante* cost justification similar to

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309 *2018 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2019, p. 269: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

Import Resource Adequacy, Department of Market Monitoring, September 10, 2018: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept1020

310 *System Market Power Mitigation Straw Proposal*, California ISO, December 11, 2019, pp.30-32: http://www.caiso.com/InitiativeDocuments/StrawProposal-SystemMarketPowerMitigation.pdf

resources within the ISO system.[311] DMM also recommended that the ISO should develop an approach that would allow any cost-verified bids over $1,000/MWh to set market prices when dispatched without setting the power balance constraint penalty price from $1,000/MWh to $2,000/MWh during all hours, as was proposed by the ISO.

In September 2019, the ISO indicated it would consider these recommendations as part of a future stakeholder process, but proceeded to submit compliance filing for Order No. 831 that did not include these changes. DMM and numerous other parties opposed the ISO's filing and recommended that the ISO defer its tariff filing until it concluded a stakeholder initiative that addressed these changes.[312]

In January 2020, the ISO submitted a supplemental answer to FERC indicating that it will not be prepared to implement the Order No. 831 compliance requirements until the fall of 2021. The ISO indicated that "this will allow the CAISO and stakeholders the time necessary to complete the stakeholder process" and for the ISO to submit the necessary section 205 tariff amendments to address the two issues raised by DMM.[313]

DMM continues to recommend that before filing to implement Order No. 831, the ISO should (1) file tariff changes with the Commission to subject import bids over $1,000/MWh to *ex ante* cost justification similar to resources within the ISO system; and that (2) the ISO should develop an approach that will allow any cost-verified bids over $1,000/MWh to set market prices when dispatched without setting the power balance constraint penalty price from $1,000/MWh to $2,000/MWh during all hours. The ISO is currently engaged in a stakeholder process considering both of these options.[314]

11.10 Resource adequacy and bilateral energy procurement

California has relied upon the state's long-term bilateral procurement process and resource adequacy program to maintain adequate system capacity and help mitigate market power for over 15 years. However, as noted in the discussion of system market power in Section 11.9, numerous regulatory and structural market changes have occurred in recent years which create the need for significant changes in the state's resource adequacy framework.

The CPUC has identified a number of options for addressing these issues and is currently working with the ISO and stakeholders on moving forward with more detailed market design options and decisions. These include:

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311 *Comments on Issue Paper and Straw Proposal Requirements for Import Bids Greater than $1,000 under FERC Order 831*, Department of Market Monitoring, May 30, 2019. http://www.caiso.com/Documents/DMMcomments-ImportBidCostVerification_IssuePaperandStrawProposal.pdf

312 *Motion to Intervene and Comments of the Department of Market Monitoring*, ER19-2757-000, September 26, 2019. http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoringonOrder831Compliance-ER19-2757-Sept262019.pdf http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoringonOrder831Compliance-ER19-2757-Sept262019.pdf

313 *Motion for Leave to Answer and Supplemental of the California Independent System Operator,* ER19-2757-000, January 31, 2020. http://www.caiso.com/Documents/Jan31-2020-SuppAnswer-to-Comments-Order831Compliance-ER19-2757.pdf

314 Initiative: FERC Order 831 - Import bidding and market parameters, http://www.caiso.com/StakeholderProcesses/FERC-Order-831-Import-bidding-and-market-parameters

- Development of resource adequacy requirements for sufficient flexible capacity needed to integrate a high level of renewable resource capacity.
- Adoption of a multi-year framework for local resource adequacy requirements and procurement by load serving entities.
- Development of a central buyer framework for meeting any local resource adequacy requirements not met by resource adequacy capacity procured by CPUC-jurisdictional load serving entities.
- Strengthening requirements for the use of imports to meet system level resource adequacy requirements.

DMM supports these efforts and views the options being considered by the CPUC as potentially effective steps in addressing the current gaps and problems with the state's resource adequacy framework.

Energy and availability limited resources

In 2019, DMM provided analysis and expressed concern about the cumulative impacts of various energy-limited or availability-limited resources which are being relied upon to meet an increasing portion of resource adequacy requirements. As noted in recent comments by DMM in the CPUC long-term integrated resource planning proceedings:

> These energy-limited or availability-limited resources include renewables, import capacity, demand-side resources and energy storage. Unlike gas and nuclear capacity, these resource types may have limited availability to meet both peak demand and demand across all multiple hours in an operating day. When available, these resources could also be very expensive to dispatch. If increased reliance is placed on these resources to meet RA requirements, DMM is concerned that the RA fleet could have limited output during hours when net loads – and the potential for uncompetitive supply conditions – are highest.[315]

DMM's comments to the CPUC in this proceeding provide analyses on the actual availability of energy-limited (or availability-limited) resources such as solar, imports, demand response, and battery capacity in peak net load hours. This analysis shows that each of these resource types have generally had limited availability during peak net load hours when the ISO counts on resource adequacy capacity to be available the most. In addition, when resource adequacy imports, demand response, and battery capacity is available, this capacity is relatively expensive to dispatch during high net load periods.

DMM has noted that the costs and actual operation of these types of energy and availability limited resources in ISO markets to meet both peak demand and energy needs will be important to consider in procurement directives by the CPUC and other local regulatory entities, particularly if these resources will comprise an increasing share of the resource adequacy fleet going forward.

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[315] *Reply Comments of the Department of Market Monitoring*, 16-02-007, August 12, 2019: http://www.caiso.com/Documents/CPUC-DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf

DMM has suggested potential changes to CPUC and ISO rules that could help mitigate availability concerns related to import and battery resources. These recommendations include considering a form of real-time must-offer for resource adequacy import capacity,[316] and developing default energy bids and subjecting battery resources participating under the CAISO's non-generator resource (NGR) model to local market power mitigation.[317]

Resource adequacy imports

In 2019, the CPUC and the ISO took numerous steps to address longstanding concerns expressed by DMM in prior reports about resource adequacy imports. DMM has warned that existing 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 instance, resource adequacy imports can be routinely bid significantly above projected prices in the day-ahead market to help ensure they do not clear, thus relieving the imports of any further offer obligations in the real-time market.[318]

The CPUC sought to address this concern through a decision affirming requirements governing the use of energy imported into California to meet resource adequacy requirements provided in prior CPUC orders. In this decision, the CPUC affirmed that CPUC orders dating back to 2004 and 2005 required that resource adequacy import contracts include an "energy product" that "cannot be curtailed for economic reasons," and that such resource adequacy imports are required to be self-scheduled into the ISO markets, consistent with the timeframe established in the governing contract.[319]

To address concerns about the inflexible nature of self-scheduled resources, the CPUC noted that contracts could be limited to the ISO's availability assessment hours for resource adequacy resources (4 to 9 pm). The availability assessment hours are a set of five consecutive hours that correspond to the operating periods when high demand conditions typically occur and when availability of resource adequacy capacity is most critical to maintaining system reliability.

DMM supported the CPUC's approach of requiring self-schedules of resource adequacy imports during the peak ramping hours of 4 to 9 pm as an interim measure that could be enforced under the CPUC's existing decisions, while the CPUC and stakeholders considered alternative solutions that would allow resource adequacy imports to participate more flexibly in the market.[320] DMM noted that other solutions discussed in this proceeding and in the ISO's stakeholder process including real-time must offer provisions, negotiated bid caps, and an option based on energy or option contracts could be viable

[316] *Comments on Resource Adequacy Enhancements Revised Straw Proposal*, DMM, July 24, 2019, p. 5. http://www.caiso.com/Documents/DMMComments-ResourceAdequacyEnhancements-RevisedStrawProposal.pdf

[317] *2018 Annual Report on Market Issues and Performance*, p. 24: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

[318] *DMM Special Report: Import Resource Adequacy* (September 10, 2018) pp. 1-2.: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf

[319] *Decision Affirming Resource Adequacy Import Rules (D.19-10-021)*, R.17-09-020, October 10, 2019, p. 2 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M317/K931/317931103.PDF

[320] *Comments on Proposed Decision Clarifying Resource Adequacy Import Rules*, R.17-09-020, September 26, 2019. http://www.caiso.com/Documents/CommentsofDepartmentofMarketMonitoringonProposedDecisionClarifyingRAImportRules-R17-09-020-Sept262019.pdf

long term solutions to improve the reliability of import resource adequacy and address system market power concerns.

DMM provided analysis in this proceeding showing that the CPUC's proposed rule clarification was not likely to result in significant displacement of renewable generation or cause a significant increase in low negative prices if limited to the ISO assessment hours.[321] However, DMM also recommended that the CPUC could consider further limitations to the energy delivery requirement such as limiting these requirements to only some months of the year.

In late 2019 and early 2020, the CPUC issued a stay and granted limited rehearing on the decision on resource adequacy imports issued in October 2019.[322] The CPUC has granted limited rehearing in order to allow parties to provide further comments as to the self-scheduling requirement, and as to the distinction between resource-specific and resource-non-specific resource adequacy import contracts. In May 2020, after further record was developed on import resource adequacy issues, the CPUC issued a proposed decision specifying that non-resource specific import resource adequacy resources must be self-scheduled or bid into ISO markets at or below $0/MWh, at minimum in the availability assessment hours.[323] DMM has supported the proposed decision as an interim measure while rules governing a source-specific framework are developed further under ISO stakeholder processes. A source-specific framework for resource adequacy imports which ensures that import energy cannot be recalled to other balancing areas, particularly when other balancing areas also face supply shortages, could better ensure that import capacity is truly dedicated to the CAISO.

ISO initiative on resource adequacy enhancements

The ISO is also considering changes to requirements for resource adequacy imports through an ongoing initiative on resource adequacy enhancements started in October 2018. The ISO acknowledged DMM's concern about resource adequacy imports at the start of this initiative, noting that "current RA import provisions may allow some RA import resources to be shown to meet RA obligations while also representing speculative supply (*i.e.,* no true physical resource or contractual obligation backing the RA showing) or being committed to other regions and double counted."[324]

In its July 2019 straw proposal, the ISO proposed requiring specification of the source balancing area for all resource adequacy imports, but declined DMM's recommendation to extend a must-offer

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[321] *Comments on Proposed Decision Clarifying Resource Adequacy Import Rules*, pp. 9-14.

[322] *Order Granting Stay of Decision (D.) 19-10-021*, December 23, 2019: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M322/K049/322049843.PDF

Order Granting Limited Rehearing of Decision (D.) 19-10-021, March 16, 2020: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M328/K622/328622451.PDF

[323] *Proposed Decision Adopting Resource Adequacy Import Requirements*, R.17-09-020, CPUC, May 18, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M337/K861/337861765.PDF

[324] *Resource Adequacy Enhancements Straw Proposal – Part 1*, December 20, 2018, p. 9: http://www.caiso.com/Documents/StrawProposalPart1-ResourceAdequacyEnhancements.pdf.

requirement for resource adequacy imports beyond the day-ahead market and into the real-time market.[325]

In comments on this straw proposal, DMM submitted results of DMM's benchmarking with other ISOs regarding similar rules that apply to import capacity used to meet system reliability requirements – through either a resource adequacy program or a capacity market.[326] This benchmarking indicates that other ISOs require that imports used to meet capacity requirements be tied to specific generation resources. Other ISOs require, at a minimum, that suppliers demonstrate that the import capacity has not been sold into another balancing area or resource adequacy market, and that the energy delivered by the import resource is both deliverable and not recallable or curtailable by the source balancing area. DMM believes the combination of such rules could also encourage (but not require) that resource adequacy import capacity be "bundled" with some type of energy sales agreement or contract.

The ISO's subsequent proposals in its own initiative on resource adequacy enhancements would require specification of a physical source backing resource adequacy import showings which may include a specific resource, aggregation of resources, or balancing area. The ISO will also require that import resource adequacy be backed by firm transmission, at a minimum, in the day-ahead timeframe. In its most recent proposal, the ISO has also proposed to extend the real-time must-offer obligation to resource adequacy imports.[327]

However, the ISO's proposal may still not ensure that the energy supporting import resource adequacy will not be recalled by other balancing areas, particularly when energy is scarce throughout the west.[328] DMM agrees that a source-specific framework for resource adequacy imports which ensures that import energy cannot be recalled to other balancing areas could better ensure that import capacity is truly dedicated to the CAISO. However, several details regarding a source-specific framework require further discussion and development. Key details that would determine the effectiveness of a source-specific framework include real-time must offer obligations, provision of transmission, and provisions to ensure imported energy from resource adequacy capacity cannot be recalled by other balancing areas, even in the absence of transmission congestion.

Centralized procurement

In 2018, the CPUC initiated a proceeding to develop and consider options for establishing one or more *central procurement entities* authorized to procure capacity needed to meet local area reliability requirements assigned to CPUC-jurisdictional load serving entities. The central procurement entity would be authorized to procure local resource adequacy capacity through multi-year contracts, with costs being allocated to entities serving load within each distribution service area.

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325 *Resource Adequacy Enhancements Revised Straw Proposal*, California ISO, July 1, 2019, pp. 46-47: http://www.caiso.com/Documents/RevisedStrawProposal-ResourceAdequacyEnhancements.pdf

326 *Comments on Resource Adequacy Enhancements Revised Straw Proposal,* Department of Market Monitoring, July 24, 2019. http://www.caiso.com/Documents/DMMComments-ResourceAdequacyEnhancements-RevisedStrawProposal.pdf

327 *Resource Adequacy Enhancements Fourth Revised Straw Proposal*, CAISO, March 17, 2020: http://www.caiso.com/InitiativeDocuments/FourthRevisedStrawProposal-ResourceAdequacyEnhancements.pdf

328 *Comments on Resource Adequacy Enhancements Fourth Revised Straw Proposal,* Department of Market Monitoring, April 21, 2020. http://www.caiso.com/InitiativeDocuments/DMMComments-ResourceAdequacyEnhancements-FourthRevisedStrawProposal.pdf

The concept of centralized procurement of resource adequacy capacity stems primarily from the significant and growing portion of load within local areas served by community choice aggregators. Prior to the growth of community choice aggregators, capacity procured by the state's major investor-owned utilities in local areas was generally sufficient to meet local resource adequacy requirements assigned to CPUC-jurisdictional load.[329]

In June 2020, the CPUC adopted a decision that establishes central procurement of multi-year local resource adequacy capacity beginning with the 2023 compliance year.[330] Under the CPUC decision, the state's two major investor-owned utilities (Pacific Gas and Electric and Southern California Edison) will serve as the central procurement entities for local areas in their respective distribution service areas. The decision does not adopt a central procurement framework for the San Diego Gas and Electric area at this time.

The CPUC decision adopts a hybrid central procurement framework. With this approach, the central procurement entity will secure a portfolio of the most effective local resources to meet local capacity requirements and potentially mitigate the need for CAISO backstop procurement in certain local areas.

The hybrid approach allows individual load serving entities to voluntarily procure local resources to meet their system and flexible resource adequacy requirements and count them towards the collective local resource adequacy requirements, or sell local capacity to the central procurement entity. Costs for centralized procurement will be allocated to bundled service, community choice aggregator, and direct access customers based on load share in the distribution service area, accounting for load migration.

As noted in our 2018 annual report, DMM supports the CPUC decision to adopt a multi-year framework for local resource adequacy through a central buyer framework.[331] The adopted framework should help avoid unnecessary reliance on the ISO's two backstop procurement mechanisms: the capacity procurement mechanism and reliability must-run contracts.

11.11 Demand response resources

Dispatchability

As noted in DMM's 2016 and 2017 annual reports, for the last several years proxy demand response resources have been dispatched and set prices in the 5-minute real-time market with a relatively high degree of frequency even though most of these resources are not capable of responding to these

[329] The emergence of several community choice aggregators over the past few years has led to multiple load serving entities being assigned a small share of local capacity requirements within the distribution service area that the entity serves load. The CPUC already has a cost allocation mechanism (CAM) in place for investor-owned utilities to allocate costs associated with procurement initiated on behalf of several load serving entities to all benefitting customers. Under the CPUC decision, the same cost allocation mechanism will be used to allocate local capacity procurement costs among benefitting customers under different load serving entities.

[330] *Decision on Central Procurement of the Resource Adequacy Program*, R.17-09-020, June 11, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M340/K671/340671902.PDF

[331] *2018 Annual Report on Market Issues and Performance*, Department of Market Monitoring, p. 268.: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

dispatches.[332] Proxy demand response resources are not subject to bid mitigation and most capacity is bid at or near the $1,000/MWh bid cap in real-time.

Additionally, proxy demand response resources which are modeled as 5-minute dispatchable are eligible to receive flexible ramping product awards. If these resources cannot actually respond to 5-minute dispatches, these resources may displace other 5-minute dispatchable capacity from being awarded flexible ramp, and potentially contribute to suppressing flexible ramping product prices when these resources have no opportunity cost of providing energy.

The ISO's 15-minute and hourly dispatch options established under the energy storage and distributed energy resources (ESDER) initiative are designed to help address the problem of demand response resources being unable to respond to 5-minute dispatches. However, through the end of 2019, less than 1 percent of total proxy demand response capacity registered with the ISO changed to 15-minute or hourly real-time dispatch options. Despite low response rates with respect to real-time dispatch instructions, many demand response resources continued to be modeled as 5-minute dispatchable through the end of 2019.

The ISO's 15-minute and hourly dispatch features are currently optional. DMM has suggested that if demand response resources continued to exhibit poor response rates with respect to real-time dispatches and do not modify resource characteristics or change to less flexible bid options, the ISO could change the default status for demand response resources to the hourly dispatch option and instead allow resources to change to 15- or 5-minute dispatchable.[333]

Under the ISO's flexible ramping product refinements proposal, the ISO has proposed to default all proxy demand response resources to the hourly dispatch option and require proxy demand response resources to affirm that a resource can be dispatched in either 15-minute or 5-minute intervals in order to modify the master file dispatch option.[334]

Resource adequacy demand response

Demand response resources are part of a more general category of energy-limited or availability-limited resources which are being relied upon to meet an increasing portion of resource adequacy requirements. As noted in comments by DMM in the CPUC integrated resource planning proceedings, DMM is concerned about the cumulative effect of increased amounts of resources with limited availability.[335] While demand response resources are generally availability-limited by nature, additional

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332 *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2017, pp. 259-262. http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf

2017 Annual Report on Market Issues and Performance, Department of Market Monitoring, May 2017, p. 260. http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf

333 *Q4 2019 Report on Market Issues and Performance*, February 28, 2020, p. 82: http://www.caiso.com/Documents/2019FourthQuarterReportonMarketIssuesandPerformance.pdf

334 *Flexible Ramping Product Refinements Revised Straw Proposal*, CAISO, March 16, 2020, p. 5: http://www.caiso.com/InitiativeDocuments/RevisedStrawProposal-FlexibleRampingProductRefinements.pdf

335 *Reply Comments of the Department of Market Monitoring*, R.16-02-007, August 12, 2019. p. 2. Also see discussion and analysis of demand side resources on pp. 8-11: http://www.caiso.com/Documents/CPUC-DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf

issues may further limit these resources' value in terms of providing reliability and being available during hours when net loads – and the potential for uncompetitive supply conditions – are highest.

DMM has identified several issues regarding the performance and operation of demand response resources which are counted towards meeting resource adequacy requirements. First, as discussed in Section 1.2.3 of this report, proxy demand response performance in response to ISO dispatches remains relatively low, and may be even lower than what has been reported to the ISO based on ongoing monitoring of actual metered load and counterfactual load baselines.

Second, DMM has observed that proxy demand response resources shown on resource adequacy supply plans were often bid into the ISO markets in excess of actual metered load, suggesting that actual load was often insufficient to support load reduction up to resources' resource adequacy values and capacity bid into the market.[336] Third, many demand response resource adequacy resources are sized with a maximum capacity less than 1 megawatt, exempting these resources from the ISO's resource adequacy availability incentive mechanism (RAAIM) and thus limiting incentives for these resources to be available at resource adequacy values.[337]

Lastly, local regulatory authorities may credit demand response capacity (proxy demand response and reliability demand response programs) against resource adequacy requirements from the demand side. However, resources underlying these demand response credits are not shown on resource adequacy supply plans submitted to the ISO and thus are not subject to must-offer obligations like other resource adequacy capacity. DMM has observed that resource adequacy credits associated with demand response consistently exceed non-supply plan demand response capacity bid into ISO markets in peak hours, potentially contributing to capacity shortfalls when the ISO may need capacity the most.[338]

DMM provides the following recommendations on demand response resources to address these issues:

- The ISO should proactively monitor demand response resource master file parameters to ensure these resources can actually provide the capacity and resource attributes that have been reflected to the ISO and local regulatory authorities.
- The ISO should also proactively validate demand response performance values which are self-submitted by scheduling coordinators to ensure resources are able to operate and perform consistent with their resource attributes. These assessments will require a review of both underlying load data and the statistical methodologies used to calculate baseline load values.

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336 *Q3 Report on Market Issues and Performance*, December 5, 2019, pp. 90-92. http://www.caiso.com/Documents/2019ThirdQuarterReportonMarketIssuesandPerformance.pdf

337 In November 2019, the ISO removed the requirement that demand response aggregations must be registered under a single load serving entity. While DMM observed little change in resource aggregation sizes through 2019, DMM expects that the ISO's policy change could result in the consolidation of demand response resources going forward, and thus increase the volume of demand response capacity subject to the ISO's resource adequacy availability incentive mechanism. This issue is highlighted in DMM's Q4 2019 report:

Q4 Report on Market Issues and Performance, December 5, 2019, p. 82. http://www.caiso.com/Documents/2019FourthQuarterReportonMarketIssuesandPerformance.pdf

338 *Reply Comments of the Department of Market Monitoring*, R.16-02-007, August 12, 2019. pp. 8-11: http://www.caiso.com/Documents/CPUC-DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf

- The ISO should continue to work with local regulatory authorities to ensure that demand response capacity credits accurately reflect the reliability value that underlying demand response resources provide to the system.

11.12 Energy storage resources

While the amount of energy storage resources (such as batteries) on the ISO system is currently quite limited, the amount of new energy storage resources is projected to increase rapidly in future years and is being relied upon to play a key role in the integration of renewable resources. Consequently, DMM has played an active role in efforts to develop new market and software enhancements to facilitate use of energy storage resources.

Modeling energy storage costs

Energy storage resources face unique costs and operating parameters that may not align with current market mechanisms designed for traditional generators. DMM has recommended that the ISO and the energy storage community continue working together in the energy storage and distributed energy resources phase 4 (ESDER 4) stakeholder initiative to identify and develop modeling of unique energy storage resource costs in both market optimization and default energy bids used in local market power mitigation.

Accurate modeling of energy storage resource costs will allow the ISO optimization to fully consider all energy storage costs, as well as how those costs are incurred, when determining the efficient dispatch. Accurately modeling the actual causes of these costs will also allow market participants to efficiently limit the kinds of battery operations that cause significant maintenance costs and allow resources to recover these costs through market revenues when incurred.

Stakeholders have explained that battery operators may agree to less expensive tolling contracts with developers when the contract or negotiated warranty includes provisions limiting the operation of the battery. For instance, a battery may be contractually limited to a set number of cycles per day over a determined period of time in order to guarantee a certain capacity level over the period before requiring a designated maintenance activity.

Stakeholders have advocated for such limitations to be considered when participating in ISO markets. However, managing maintenance costs by restricting resource operation to respect contractual limitations or negotiated warranties could result in inefficient utilization of battery resources in wholesale electricity markets. Therefore, DMM does not support the use of contractual limitations to restrict market operation of a resource. The ISO has also taken the general position that it is inappropriate to restrict market operation of a resource based on contractual provisions that are not based on physical resource limitations.

Currently, market participants can rely on energy bids to operate the resource in ways that limit the cycling of batteries and avoid violating contractual limitations. However, because costs of batteries and other energy storage resources may be incurred in ways that are not associated with incremental energy production, this approach can reduce efficiency of market dispatch. As described in Section 1.2.3, battery energy bids have become more economic over time. However, regulation capacity scheduled in the day-ahead market continues to comprise the majority of battery schedules due to batteries' fast ramp rates and the economics of regulation and mileage bids compared to other resource types.

Furthermore, when the ISO begins to mitigate energy bids of batteries, default energy bids based on cost of incremental energy production will sometimes be used in place of the scheduling coordinator submitted energy bids. Therefore, market participants will no longer be able to rely solely on their submitted energy bids to control battery operation. Each of these points highlights the need to identify and accurately model the incurred costs of operating batteries and other energy storage resources.

The ISO and DMM have made significant progress in understanding costs of batteries through the ESDER 4 stakeholder process. This information has helped in developing a proposal for a default energy bid for energy storage resources, as well as proposals to model different operational limitations of energy storage resources. DMM supports these efforts, as well as the ISO's proposal to apply local market power mitigation procedures to energy storage resources.

The ISO's February 2020 proposal indicates that the ISO will model four cost categories for energy storage resources – energy costs, energy losses, cycling costs, and opportunity costs. The ISO would calculate a static default energy bid value over the day for each battery resource.[339] DMM is supportive of the proposal, but has recommended several additional refinements.[340] DMM recommends that the ISO continue to enhance the proposed default energy bid for energy storage resources to:

- Allow the default energy bid value to vary throughout the day to capture costs that may differ based on resource operation over the day;
- More accurately reflect opportunity cost of charging and discharging at different times throughout the day, reflecting the dynamic nature of opportunity costs faced by battery resources; and
- Refine price estimation methods for day-ahead opportunity cost calculations to allow for the possibility of decreasing prices day-over-day.

Resource adequacy battery capacity

Batteries are also part of a more general category of energy-limited or availability-limited resources which are being relied upon to meet an increasing portion of resource adequacy requirements. Like with demand response resources, DMM has observed issues that could contribute further to limiting energy storage availability.

As detailed in comments by DMM in the CPUC integrated resource planning proceedings, battery resources have been unable to provide resource adequacy values for three and four consecutive hours across CAISO availability assessment hours due to limited state of charge values going into peak load

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339 *Energy Storage and Distributed Energy Resources Phase 4 Second Revised Straw Proposal*, California ISO, February 24, 2020: http://www.caiso.com/InitiativeDocuments/SecondRevisedStrawProposal-EnergyStorage-DistributedEnergyResourcesPhase4.pdf

340 *Comments on Energy Storage and Distributed Energy Resources Phase 4 (ESDER 4) Second Revised Straw Proposal*, Department of Market Monitoring, March 27, 2020. http://www.caiso.com/InitiativeDocuments/DMMComments-EnergyStorage-DistributedEnergyResourcesPhase4-SecondRevisedStrawProposal.pdf

hours.[341] A battery resource's ability to delivery energy across peak net load hours depends on the resource's state of charge and thus its market awards in preceding hours.

As described in Section 1.2.3 of this report, ancillary service awards carried over from the day-ahead market generally leave little room for batteries to charge incrementally in real-time in order to increase these resources' state of charge. While lack of charge on the battery fleet across peak hours may not pose an issue to the ISO on most days, it will be important for the ISO to be able to call on or exceptionally dispatch battery resources in peak net load hours as battery capacity increases on the system. The ability to exceptionally dispatch storage resources would require that state of charge values be sufficient for these resources to deliver energy in specific intervals. DMM has recommended that the ISO detail how it will exceptionally dispatch battery resources under its initiative.[342]

DMM has also observed that existing and proposed bid features available to batteries could be used to limit resources' availability while allowing resources to avoid exposure to resource adequacy availability incentive mechanism (RAAIM) penalties. These bid parameters include 1) the existing daily maximum charge limit parameter which allows suppliers to set a maximum state of charge that can be held on a resource at any point in time, and 2) the end-of-hour state of charge bid parameter being proposed in the ISO's initiative which would allow battery resources to set target state of charge values at the end of each hour in the real-time market.

DMM has recommended that the ISO consider whether a battery submitting a maximum end-of-hour state of charge or daily maximum state of charge value less than a resource's four-hour resource adequacy value at the start of the CAISO assessment hour window should constitute a type of outage or de-rate.[343] Alternatively, since a battery resource may still be able to reach its resource adequacy value or maximum capacity for less than four hours, instead of a de-rate reflected in the market, the ISO could consider an ex-post settlement process for batteries that is linked to the resource adequacy availability incentive mechanism. Batteries providing resource adequacy should be exposed to the same availability penalties and incentives as other resource adequacy resources, creating an incentive for these resources to remain available to the CAISO at their resource adequacy values.

11.13 Mitigation of exceptional dispatches

Beginning in the third quarter of 2019, ISO operators started to issue exceptional dispatches to manually commit and dispatch resources to the maximum of their resource adequacy contracts. These are referred to as "RA Max" exceptional dispatches and are typically issued to a number of slow-ramping, gas generator resources located in the Los Angeles basin.[344] The intention of RA Max exceptional

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341 *Reply Comments of the Department of Market Monitoring*, R.16-02-007, August 12, 2019. pp. 12-14: http://www.caiso.com/Documents/CPUC-DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf

342 *Comments on Energy Storage and Distributed Energy Resources Phase 4 (ESDER 4) Second Revised Straw Proposal*, Department of Market Monitoring, March 27, 2020, p. 9: http://www.caiso.com/InitiativeDocuments/DMMComments-EnergyStorage-DistributedEnergyResourcesPhase4-SecondRevisedStrawProposal.pdf

343 *Comments on Energy Storage and Distributed Energy Resources Phase 4 (ESDER 4) Revised Straw Proposal*, Department of Market Monitoring, November 25, 2019, p. 6: http://www.caiso.com/InitiativeDocuments/DMMComments-EnergyStorage-DistributedEnergyResourcesPhase4-RevisedStrawProposal.pdf

344 See Section 7.3.2 of this report.

dispatches is to increase the amount of ramping capacity available to meet the evening net load ramp and respond to other uncertainties in real-time.

Exceptional dispatches to RA Max are not subject to energy bid mitigation, and are paid the higher of the unit's energy bid or the market price. However, there is a strong potential for units being dispatched out-of-market via RA Max exceptional dispatches to exercise market power and raise bids substantially over marginal cost. Indicators of the need for mitigation of these exceptional dispatches include the following:

- About 98 percent of RA Max exceptional dispatches were issued to units controlled by a single supplier.
- The conditions under which the ISO is likely to issue RA Max exceptional dispatches should be highly predictable, with such exceptional dispatches occurring as loads reach 36,000 MW and above.
- The bid prices of units receiving RA Max exceptional dispatches have been uncompetitive, with an average price paid for these exceptional dispatches of about $150/MWh, compared to an average market price of about $55/MWh. If these exceptional dispatches were subject to bid mitigation and were paid the higher of the market price or their default energy bid, the average price paid for this energy would have been about $70/MWh.

The ISO has indicated it will monitor the frequency of RA Max exceptional dispatches and take actions if costs become excessive. The ISO has also indicated it will develop procedures to help ensure that RA Max exceptional dispatches are only issued when needed to ensure reliability.

DMM is recommending that RA Max exceptional dispatch energy should be subject to mitigation as there is a strong potential for suppliers to exercise market power and raise bids substantially over marginal cost.[345]

[345] *Q3 Report on Market Issues and Performance*, December 5, 2019, pp.97-98. http://www.caiso.com/Documents/2019ThirdQuarterReportonMarketIssuesandPerformance.pdf