Q2 2020 Report on Market Issues and Performance

October 6, 2020

Prepared by: Department of Market Monitoring

California Independent System Operator

TABLE OF CONTENTS

Executive Summary

This report covers market performance during the second quarter of 2020 (April - June). Key highlights during this quarter include the following:

- **Market prices** were highly competitive in the second quarter due to a combination of favorable market and system conditions. Lower load and lower gas prices led to a decrease in wholesale electric costs compared to the previous quarter. Electricity prices decreased from the first quarter to the second quarter of 2020, with average day-ahead prices ($21/MWh) slightly lower than both 15-minute ($22/MWh) and 5-minute prices ($23/MWh) (Figure E.1).

- **The total estimated wholesale cost of serving load** in the second quarter of 2020 was about $1.2 billion ($25/MWh), a decrease from $1.4 billion ($28/MWh) in the same quarter of 2019. After adjusting for natural gas costs and changes in greenhouse gas prices, wholesale electric costs increased by 10 percent to $33/MWh from $30/MWh in the same quarter of 2019.

- **Gas prices** were lower in the second quarter compared to Q2 2019 at both SoCal and PG&E Citygates. At SoCal Citygate, the return to service of gas pipeline capacity that had been out of service since 2017, as well as other changes to operational flow order (OFO) penalties and Aliso Canyon storage withdrawal protocols contributed to lower gas prices, which, in turn, contributed to lower wholesale energy costs relative to the same quarter of 2019.

- **Load** fell in the second quarter of 2020 relative to 2018 and 2019, due in part to increases in behind-the-meter solar generation, continued initiatives to improve energy efficiency, as well as the public health order that directed Californians to stay at home in response to COVID-19.

- **Congestion** in the day-ahead market increased PG&E area prices, decreased SCE area prices, and had an insignificant impact on SDG&E area prices. In the 15-minute market, in most areas, internal congestion impact on prices increased relative to the same quarter of 2019.

- **Real-time offset costs** in the second quarter increased to $15 million from $5 million in the first quarter of 2020. Real-time offset costs were driven by congestion offsets at $23 million, less about $7 million in energy surpluses, and $1 million in loss offset surpluses.

- **Congestion revenue rights** auction revenues were $12.8 million less than payments made to non-load-serving entities during the second quarter of 2020. Auction revenues were 70 percent of payments made to non-load-serving entities, a decrease from 84 percent in Q2 2019. The second quarter auction losses were about 14 percent of day-ahead congestion rent, an increase from 5 percent of rent in Q2 2019, 6 percent for all of 2019, and a decrease from 18 percent in Q1 2020.

- **Ancillary services** costs decreased during the second quarter to about $24 million, compared to about $30 million in the Q1 and $55 million during Q2 2019. The frequency of scarcity intervals was low with the majority occurring in the expanded South of Path 26 region.

- **Bid cost recovery payments** for the second quarter of 2020 totaled about $19 million, or about $1 million more than the previous quarter and about $9 million lower than the same quarter of 2019.

- **Flexible ramping product** system level prices were zero for around 99 percent of intervals in the 15-minute market and 99.9 percent of intervals in the 5-minute market for each of upward and downward flexible ramping capacity. Some resources supplying flexible ramping capacity continue to not be able to resolve system level uncertainty because of congestion, reducing the efficacy with which the product can manage net load volatility or prevent power balance violations.

- **Imbalance conformance adjustments** reached 1,000 MW during the peak net load ramp hours, on average, continuing the increase in operator use of imbalance conformance that began in 2017.

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

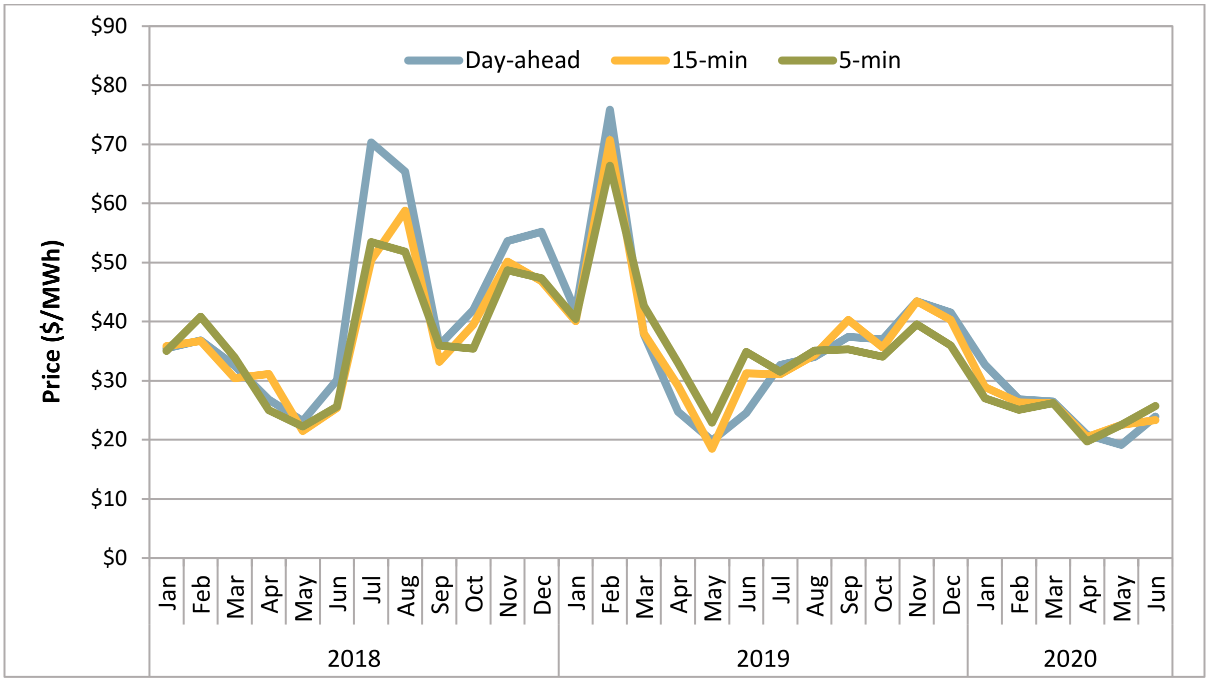
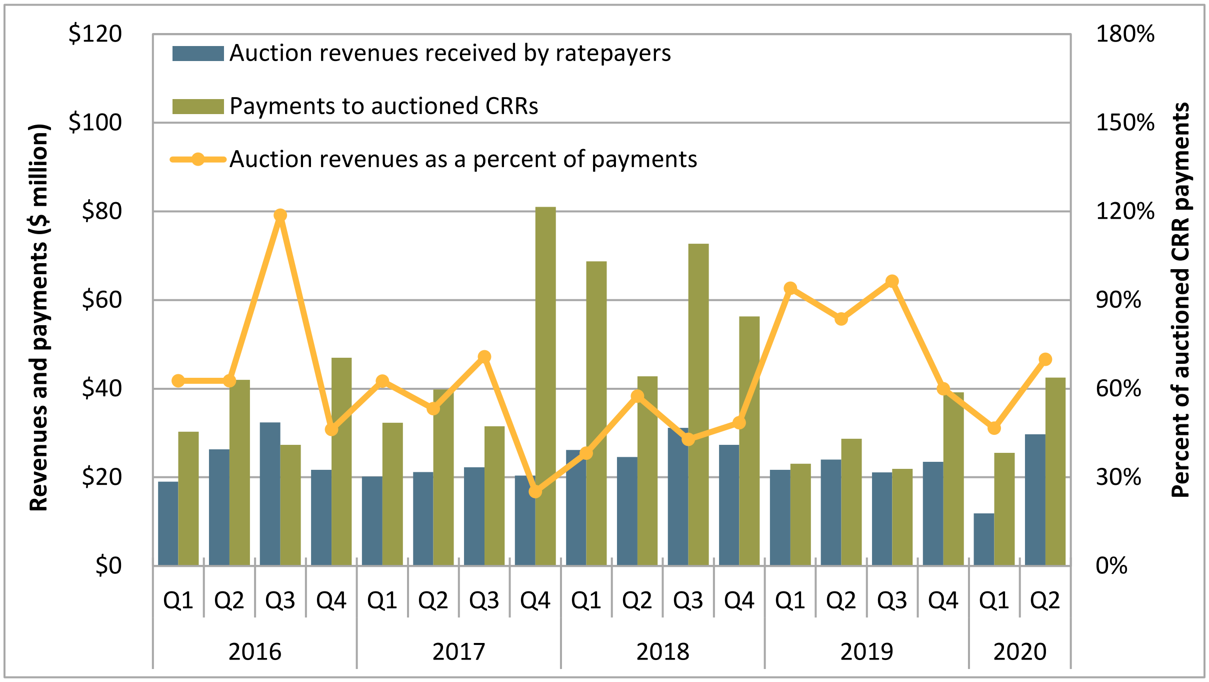


Figure E.2 Auction revenues and payments to non-load-serving entities



Western energy imbalance market

- **On April 1, 2020, Seattle City Light and Salt River Project** joined the Western Energy Imbalance Market. Seattle City Light and Salt River Project have about 1,048 MW and 6,547 MW of participating capacity, respectively. The 15-minute transfer limits for Seattle City Light and Salt River Project to the rest of the system have averaged 417 MW and 6,048 MW for exports, respectively, while imports have averaged 412 MW and 7,687 MW, respectively. Salt River Project's average 15-minute transfer limit for exports to the ISO balancing area averaged 2,209 MW and import limit averaged about 1,458 MW. Seattle City Light has no transfer capacity with ISO balancing area.
- **Prices in the Northwest region,** which includes PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex, were regularly lower than prices in other balancing areas due to limited transfer capability out of this region during peak system load hours.
- **Sufficiency test failures and subsequent under-supply power balance constraint relaxations** drove average real-time prices for Arizona Public Service and NV Energy higher. With the modified load conformance limiter implemented in February 2019, the majority of intervals with power balance relaxations were priced at the penalty parameter of $1,000/MWh.
- **Congestion imbalance deficits related to base schedules** remained low in the second quarter, totaling about $0.1 million in PacifiCorp East and $0.4 million in NV Energy. Balancing areas may allocate these imbalances to third party customers and others. Historically, PacifiCorp East is the only area to have had significant base schedule related congestion imbalance deficits which occurred primarily in late 2017 and early 2018.

- **Western EIM greenhouse gas prices** increased as the deemed delivered resources shifted from lower to higher greenhouse gas emissions, relative to before the policy change in 2018. In November 2018, the ISO implemented a revised EIM greenhouse gas bid design which limited greenhouse gas bid capacity to the differences between base schedule and available capacity. In the second quarter, the weighted average greenhouse gas prices decreased relative to the same quarter the previous year. This is mainly driven by an increase in hydro-electric capacity that is deemed delivered into California and additional available capacity from two new energy imbalance market participants beginning in April 2020.
- **Rates of mitigation** fell in the Western EIM, following the elimination of carryover mitigation in November 2019.

Special issues

COVID-19 impacts

- **Stay-at-home orders to control COVID-19 reduced load** following a California state-wide public health order to preserve public health effective March 19. Reductions in natural gas prices, associated with reduced demand, and lower electricity load have both contributed to lower ISO market prices.
- **DMM estimates that the reductions in load resulted in a reduction of day-ahead market prices** of about $2-$5/MWh during the morning and evening peaks. DMM utilized the ISO's load analysis to estimate this day-ahead market price impact from the reduction in load due to COVID-19 related stay-at-home orders in the second quarter. These results are most appropriate for the general market conditions that were included in the analysis and should not be extrapolated to the high load situations that occurred later in the summer of 2020. The decreases in gas prices, relative to the first quarter, resulted in decreases in day-ahead energy prices between $4-$14/MWh depending on the time of day.

Downward dispatch of renewable resources

- **Downward dispatch of renewable resources was considerably higher** in the ISO for every month of the second quarter compared to the same quarter of 2019. In the energy imbalance market outside of the ISO, this downward dispatch was higher during June 2020. Downward dispatch, often called curtailment, was most often the result of economic downward dispatch rather than self-schedule curtailment (Figure E.3 and Figure E.4).

Figure E.3 Reduction of wind and solar generation by month (ISO)

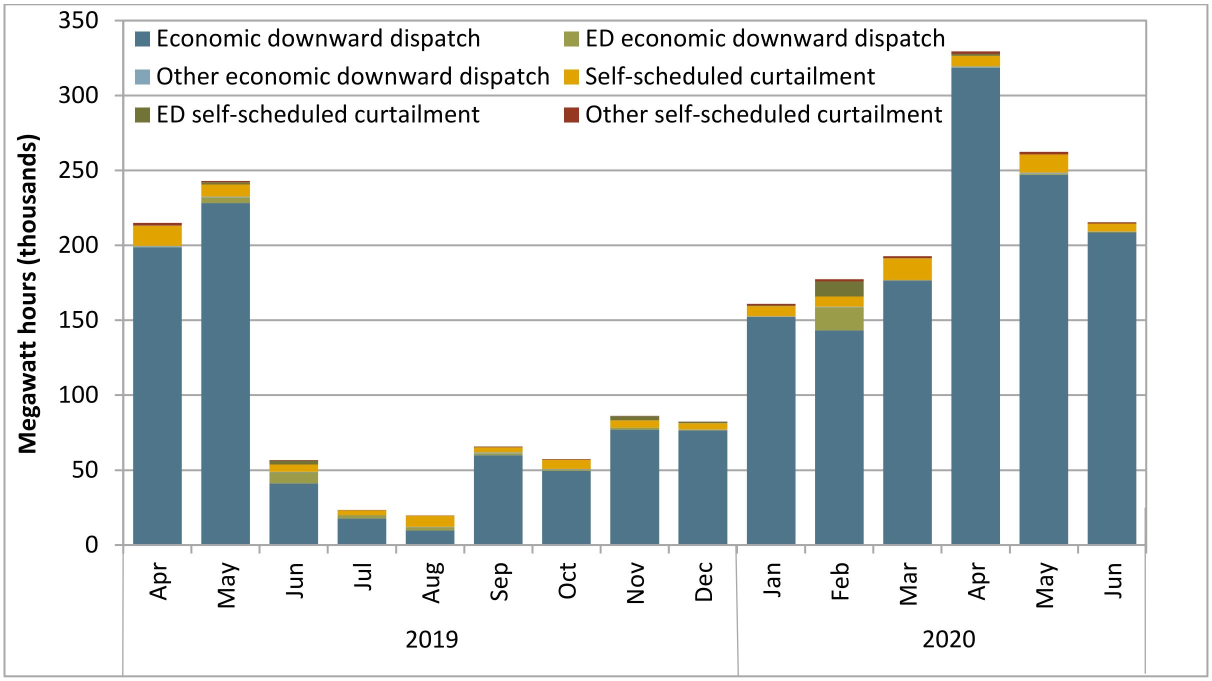
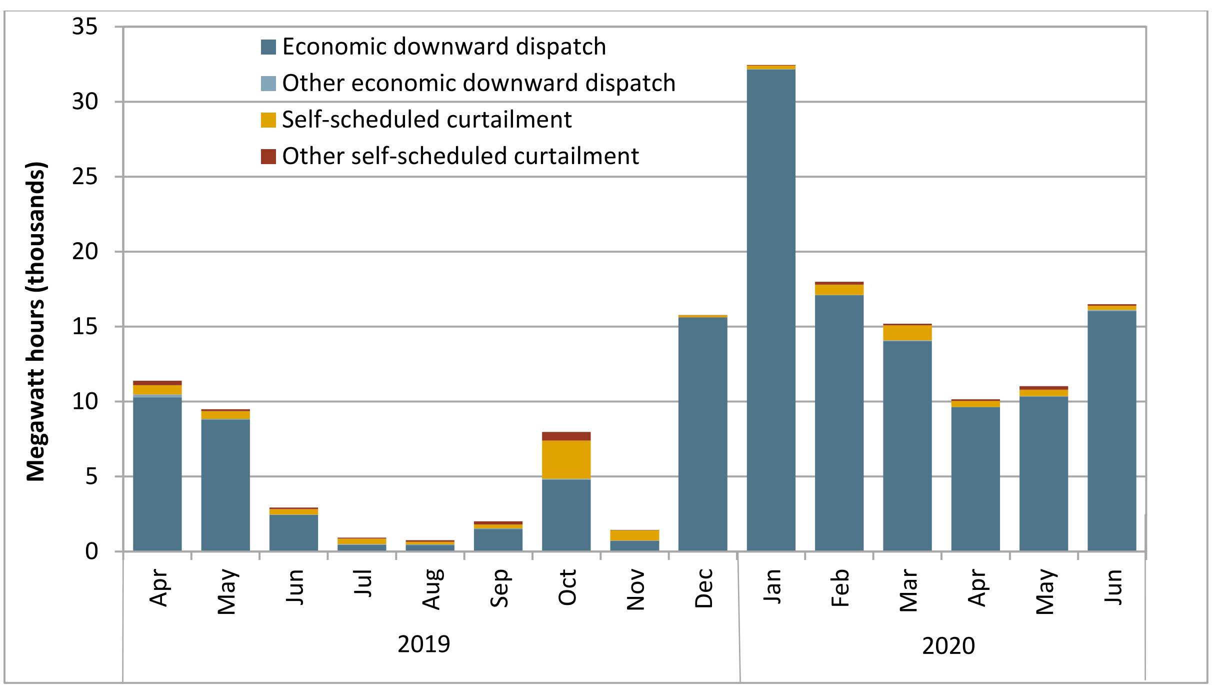


Figure E.4 Reduction of wind and solar generation by month (EIM)



Energy storage and distributed energy resources

- **Through the first half of 2020, the battery fleet participating and bidding** in the ISO market had a total minimum and maximum registered capacity of about -134 MW and 137 MW and continued to be dispatched primarily for ancillary services rather than energy. If all of the energy storage projects seeking 2020 interconnection remain on track, the ISO expects to have roughly 923 MW of battery storage online by the end of 2020.[1]

- **Implementation of the energy storage and distributed energy resources phase 3** initiative has reduced the occurrence of isolated 5-minute dispatches of demand response resources, due to several resources changing to 15-minute and hourly dispatch options. However, resource performance in response to 5-minute dispatches has not appeared to increase commensurately. This initiative created two new demand response dispatch options (hourly and 15-minute) and removed the single load serving entity aggregation requirement which was expected to decrease the registration of demand response resources sized less than 1 MW. So far, implementation of this initiative has resulted in increased utilization of new dispatch options. However, some demand response providers continue to have resources sized less than 1 MW in the same sub-load aggregation points.

System market power

- **Market results were competitive in the second quarter**. DMM estimates that the impact of gas resources bidding above reference levels, a conservative measure of the average price-cost markup, was about $0.48/MWh or just over 2 percent for the default energy bid scenario.

- **DMM introduced several new competitiveness scenarios**. These include a scenario that replaces bid-in demand with actual load and removes virtual bids, a scenario that caps gas commitment costs at 110 percent of estimated reference levels, and a scenario that caps import bids at a conservative measure of opportunity cost based on the recently introduced hydro default energy bid. DMM also runs combinations of scenarios.

- **The price-cost markup** for the gas default energy bid scenario averaged $0.48/MWh or 2 percent for the second quarter. The markup for that scenario combined with capping of import bids and commitment costs was $0.66/MWh or 3 percent. When this scenario is combined with the physical scenario including both actual load and removal of virtual bids, the markup fell slightly to $0.56/MWh or 2.5 percent. The slight positive markup for different scenarios indicates that overall prices have been very competitive for this quarter.

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

- **DMM continues to recommend** several other market design changes that may help mitigate system market power beyond the bid mitigation options being examined as part of this initiative. These

---

1 Most powerful US battery system charges up in California storage surge, June 24 2020: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/most-powerful-us-battery-system-charges-up-in-calif-storage-surge-59164757

include consideration of options that would increase the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time. DMM recommended that the ISO's plan for implementing the Federal Energy Regulatory Commission's Order 831 include provisions to (1) ensure that import bids over $1,000/MWh are subject to ex ante cost justification and (2) avoid setting penalty prices at $2,000/MWh except when needed to implement the provisions of Order 831. Overall, DMM supports the ISO's final proposal as a reasonable approach to allowing bids over the $1,000/MWh soft offer cap in compliance with FERC Order 831.[2] The proposal is a vast improvement from the ISO's 2019 Order 831 compliance filing, and places more reasonable limits on instances in which the ISO will raise the power balance penalty price over $1,000/MWh and allow import bids over $1,000/MWh. However, DMM believes it is prudent to fully analyze and consider how the proposed approach would have worked during system and market conditions that existed during the mid-August heat wave.[3]

---

2 FERC Order 831 – Import Bidding and Market Parameters Final Proposal, California ISO, August 24, 2020: http://www.caiso.com/InitiativeDocuments/FinalProposal-FERCOrder831-ImportBidding-MarketParameters.pdf

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

3 Comments on FERC Order 831 – Import Bidding and Market Parameters Final Proposal, Department of Market Monitoring, September 10, 2020: http://www.caiso.com/Documents/DMMCommentsonFERCOrder831-ImportBiddingandMarketParametersFinalProposal-Sep102020.pdf

1 Market Performance

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

- **Market prices** were highly competitive in the second quarter due to a combination of favorable market and system conditions as both lower load and lower gas prices led to a decrease in wholesale electric costs compared to the previous quarter.

- **The total estimated wholesale cost of serving load** in the second quarter of 2020 was about $1.2 billion ($25/MWh), a decrease from $1.4 billion ($28/MWh) in the same quarter of 2019. After adjusting for natural gas costs and changes in greenhouse gas prices, wholesale electric costs increased by 10 percent to $33/MWh from $30/MWh in the same quarter of 2019.

- **Gas prices** were lower in the second quarter compared to Q2 2019 at both SoCal and PG&E Citygates. At SoCal Citygate, drivers include return to service of gas pipeline capacity that had been out of service since 2017, as well as other changes to operational flow order (OFO) penalties and Aliso Canyon storage withdrawal protocols. The drop in gas prices compared to last year contributed to lower wholesale energy costs relative to the same quarter of 2019.

- **ISO load** fell in the second quarter of 2020 relative to the same quarter in 2018 and 2019, due in part to increases in behind-the-meter solar generation, continued initiatives to improve energy efficiency, as well as the public health order that directed Californians to stay at home except for essential needs or to work at essential jobs in response to COVID-19.

- **Renewable production** increased by about 60 percent compared to the previous quarter. Total renewable generation decreased by 15 percent compared to the same quarter in 2019, primarily due to a 45 percent reduction in hydroelectric production.

- **Electricity prices** decreased from the previous quarter to the second quarter of 2020, with average day-ahead prices ($21/MWh) slightly lower than both 15-minute ($22/MWh) and 5-minute prices ($23/MWh).

- **Flexible ramping product** system level prices were zero for around 99 percent of intervals in the 15-minute market and 99.9 percent of intervals in the 5-minute market for each of upward and downward flexible ramping capacity. Some resources supplying flexible ramping capacity continue to not be able to resolve system level uncertainty because of congestion, reducing the efficacy with which the product can manage net load volatility or prevent power balance violations.

- **Bid cost recovery payments** for the second quarter of 2020 totaled about $19 million, or about $1 million more than the previous quarter and about $9 million lower than the same quarter of 2019.

- **Congestion.** In the day-ahead market, congestion increased PG&E area prices, decreased SCE area prices and had an insignificant impact on SDG&E area prices. In the 15-minute market, in most areas, internal congestion impact on prices increased relative to the same quarter of 2019.

- **Real-time offset costs** in the second quarter increased to $15 million from $5 million in the first quarter of 2020. Real-time offset costs were driven by congestion with deficit of about $23 million, about $7 million in energy surpluses, and $1 million in loss offset surpluses.

- **Congestion revenue rights** auction revenues were $12.8 million less than payments made to non-load-serving entities during the second quarter of 2020. Auction revenues were 70 percent of payments made to non-load-serving entities, a decrease from 84 percent during the same quarter in 2019. The second quarter auction losses were about 14 percent of day-ahead congestion rent, an increase from 5 percent of rent in the second quarter of 2019, 6 percent for all of 2019, and 18 percent in the first quarter of 2020.
- **Ancillary services** costs decreased during the second quarter to about $24 million, compared to about $30 million in the previous quarter and $55 million during the same quarter in 2019. The frequency of scarcity intervals was also relatively low, with the majority occurring in the expanded South of Path 26 region.
- **Imbalance conformance adjustments** made by system operators reached an average of 1,000 MW during the peak net load ramp hour in the second quarter, continuing a dramatic increase in operator use of imbalance conformance that began in 2017.

1.1 Supply conditions

1.1.1 Natural gas prices

Electricity prices in western states typically follow natural gas price trends because natural gas units are often the marginal source of generation in the ISO and other regional markets. During the second quarter of 2020, natural gas prices declined across major gas trading hubs in the west, when compared to the same quarter in 2019. This decrease in natural gas prices also led to lower system marginal energy prices across the ISO footprint during the second quarter.

Figure 1.1 shows monthly average natural gas prices at key delivery points across the west including PG&E Citygate, SoCal Citygate, Northwest Sumas, 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. As shown in the figure, natural gas prices at all the gas trading hubs have been steady and relatively low since the second quarter of 2019.

Prices at the SoCal Citygate gas hub averaged $1.79/MMBtu compared to $2.58/MMBtu in the second quarter of 2019. The Aliso Canyon protocol remains in effect this summer making the facility available for withdrawals for Stage 2 or above low operational flow orders (OFO) to help mitigate price spikes and maintain system reliability.[4] According to SoCalGas Company’s annual report, this protocol proved very effective in mitigating price spikes last winter.[5] In addition, for the period between June 1 through September 30, 2020, SoCalGas will temporarily reduce the number of OFO non-compliance stages from

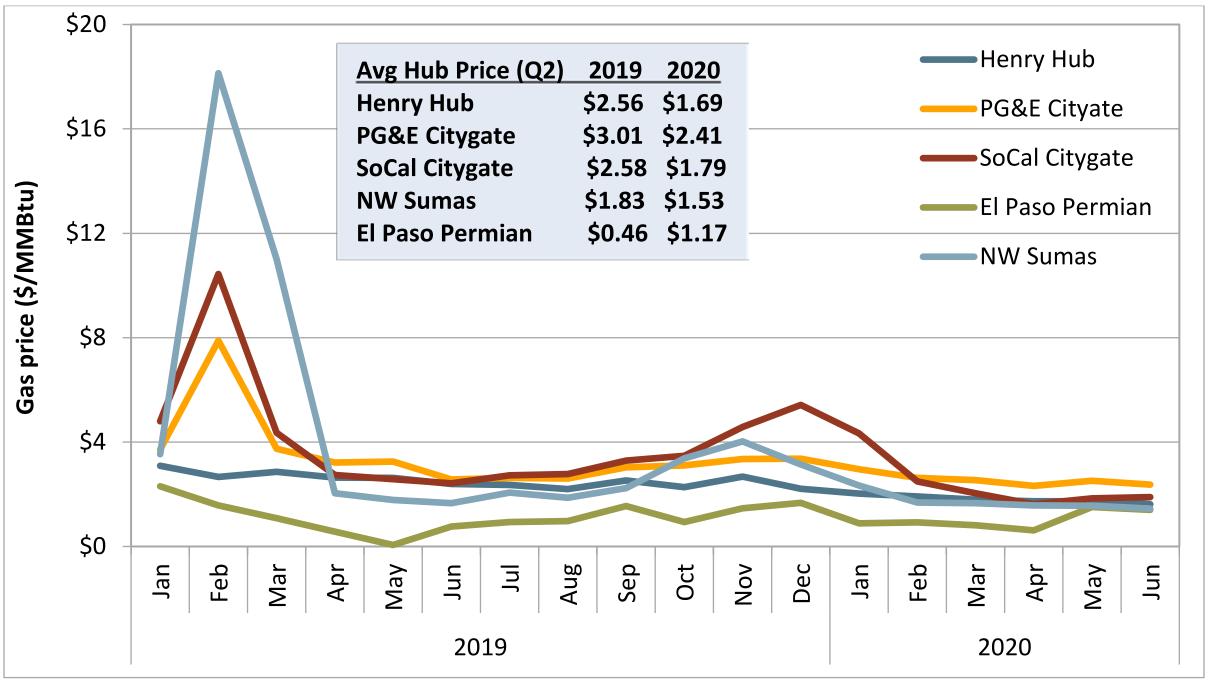
[4] Aliso Canyon Withdrawal Protocol, July 23, 2019: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/UpdatedWithdrawalProtocol_2019-07-23%20-%20v2.pdf

[5] SoCalGas’s Eleventh Annual Report of System Reliability Issues, April 29, 2020: https://scgenvoy.sempra.com/ebb/attachments/1588197649834_Eleventh_Annual_Report_of_System_Reliability_Issues_04-29-2020.pdf

8 to 5. The non-compliance charge will be reduced from $25/Dth and capped at $5/Dth for Stage 4 and Stage 5 OFOs. This is consistent with the California Public Utilities Commission's ruling on April 29, 2019.[6] SoCal Citygate prices often impact overall electric system prices because 1) there are large numbers of natural gas resources in the south, and 2) these resources can set system prices in the absence of congestion.

Permian prices continued to be low and sometimes negative during April 2020. This is because of reduced takeaway capacity resulting from pipeline maintenance. For the rest of the second quarter, there was lower production in the Permian basin and higher demand from warm temperatures in the Southwest. This narrowed the region's price differential to the Henry Hub to the smallest margin.

Figure 1.1 Monthly average natural gas prices



1.1.2 Aliso Canyon gas-electric coordination

In the second quarter of 2020, the ISO enforced maximum gas burn constraints in both day-ahead and real-time markets. These constraints were enforced in selected sub-regions of the SoCalGas service area during three periods: April 7-11, May 11-15 and May 29-June 12. In April, the gas burn constraint was enforced to facilitate pipeline maintenance work in the SDG&E area. In the day-ahead market, this constraint was binding in about 36 percent of hours during which it was enforced. In the real-time market, the constraint was binding in about 21 percent and 13 percent of 15-minute and 5-minute intervals, respectively. In May and June, the gas burn constraint was enforced to facilitate pipeline maintenance work in the southern system of the SoCalGas area. In the day-ahead market, this

[6] 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

constraint was binding in about 9 percent of hours when enforced. In the real-time market, this constraint was binding in 10 percent of the 15-minute intervals and 6.5 percent of the 5-minute intervals when enforced.

On October 31, 2019, the ISO filed tariff amendments to extend Aliso Canyon provisions permanently.[7] One of these measures gives ISO the authority to enforce gas burn constraints (or nomograms) in the ISO market. These constraints limit the gas usage through market dispatches from 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 burn constraint to avoid artificially constraining gas usage during peak net load hours. Beginning in 2020, FERC approved these tariff amendments and directed the ISO to file annual informational filings relating to the performance of the enforced nomograms.[8]

DMM believes the net load approach for shaping the gas burn constraint to be a significant improvement. However, DMM continues to recommend that the ISO refine how it utilizes the maximum gas burn constraint and improve how its limits are set and adjusted in real-time.[9] 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 usage limits to be highest during the ramping hours when gas units are needed the most. DMM has also expressed concern about the potential impacts of the gas burn constraints on real-time energy offset costs.[10]

On June 30, 2020, the ISO filed its first Aliso Canyon informational report in response to the FERC order. The report describes the performance of the constraint during three occasions it was enforced in the market during the second quarter of 2020. In addition, the report also mentions the ISO is considering adopting DMM's recommendations on better shaping the maximum gas burn constraint limit using the net load approach and also based on estimated gas burn from the two-day-ahead runs of the market software that the ISO performs.[11] This additional functionality will be available to operators by the end of 2020.[12,13] In addition, DMM continues to recommend that the ISO improve how gas burn constraint

7 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

8 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

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

10 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

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

12 Informational filing - Use of the Maximum Gas Burn Constraint - Aliso Canyon (ER20-273), June 30, 2020: http://www.caiso.com/Documents/Jun30-2020-AnnualReport-Use-MaximumGasBurnConstraint-AlisoCanyon-ER20-273.pdf

13 PRR 1262 Aliso Canyon gas-electric coordination Phase 5: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1262&IsDlg=0

limits are set and adjusted in real-time based on actual gas usage in prior hours. DMM understands that currently this process is manual and cumbersome for the operators to use in real-time and hence the operators opt for out-of-market actions such as exceptional dispatches. DMM believes that incorporating maximum gas constraints into the market software can in theory be more effective and efficient at managing gas limitations than the use of manual dispatches made by system operators.

1.1.3 Renewable generation

In the second quarter, total generation from hydroelectric, solar, and wind resources increased by about 60 percent compared to the previous quarter. Generation from these resources tends to peak in the second quarter. Total renewable generation decreased by 15 percent compared to the same quarter in 2019, primarily due to a reduction in hydroelectric production.

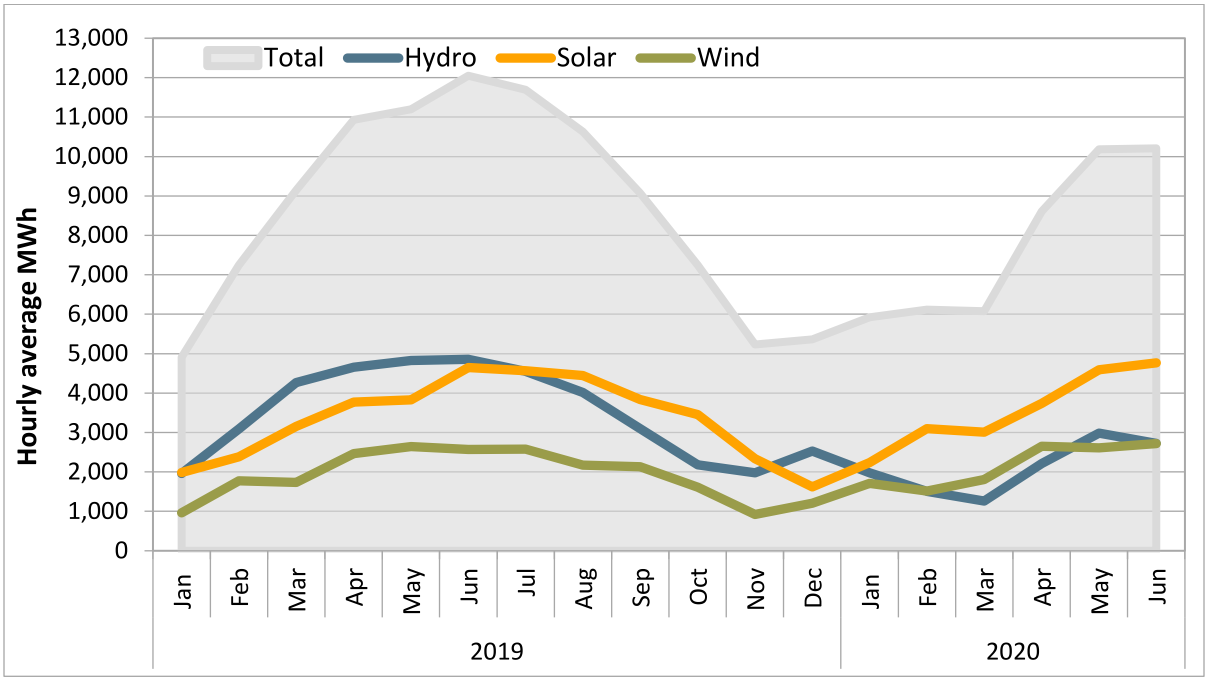
Compared to the same period in 2019, hydroelectric production in the second quarter decreased by roughly 45 percent. As of April 1, the statewide weighted average snowpack in California was 50 percent of normal compared to 175 percent of normal on April 1, 2019.[14] Compared to the previous quarter, hydroelectric generation increased about 67 percent.

Compared to the second quarter of 2019, solar production increased by about 7 percent while wind production increased by about 4 percent. Compared to the first quarter of 2020, solar and wind production increased by about 57 percent and 59 percent, respectively.

The availability of variable resources contributes to patterns in prices both seasonally and hourly due to their low marginal cost relative to other resources. Although hydroelectric generation declined in all hours of the day compared to the same time last year, increased solar and wind generation coupled with lower gas prices might have contributed to relatively lower wholesale electric prices in the second quarter.

14 For snowpack information, please see California Cooperative Snow Survey's Snow Course Measurements on the California Department of Water Resources website: https://cdec.water.ca.gov/snow/current/snow/.

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



1.1.4 Generation by fuel type

In the second quarter, an increase in solar generation in the middle of the day resulted in a mid-day decrease in imports. During ramping periods, there was an increase in natural gas generation, hydroelectric generation, and imports. Generally nuclear generation remained static, while generation from geothermal resources slightly increased and bio-based resources decreased, relative to the previous quarter. As shown in Figure 1.3, on average, these types of resources comprised about 4,300 MW of inflexible base generating capacity, same as the last quarter. Generation from "other" resources, including coal, battery storage, demand response, and additional non-gas technologies, decreased in this quarter, and continued to be a small share of overall generating capacity (about 230 MW on average).

Figure 1.3 Average hourly generation by fuel type (Q2 2020)

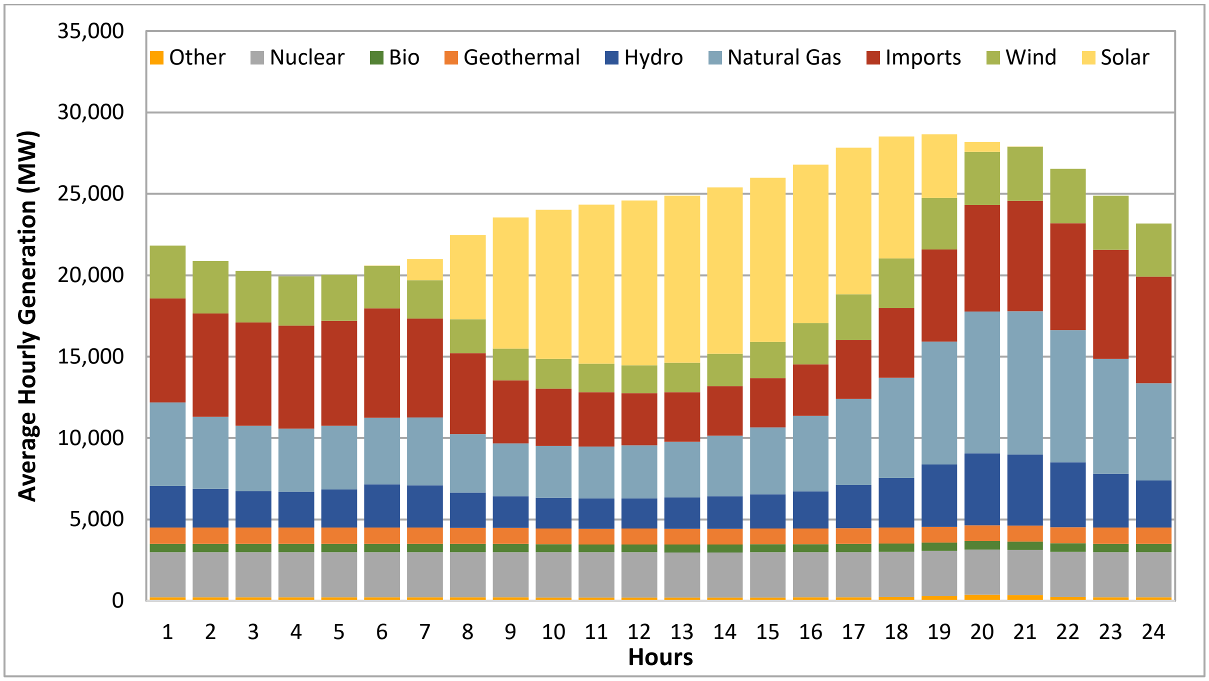
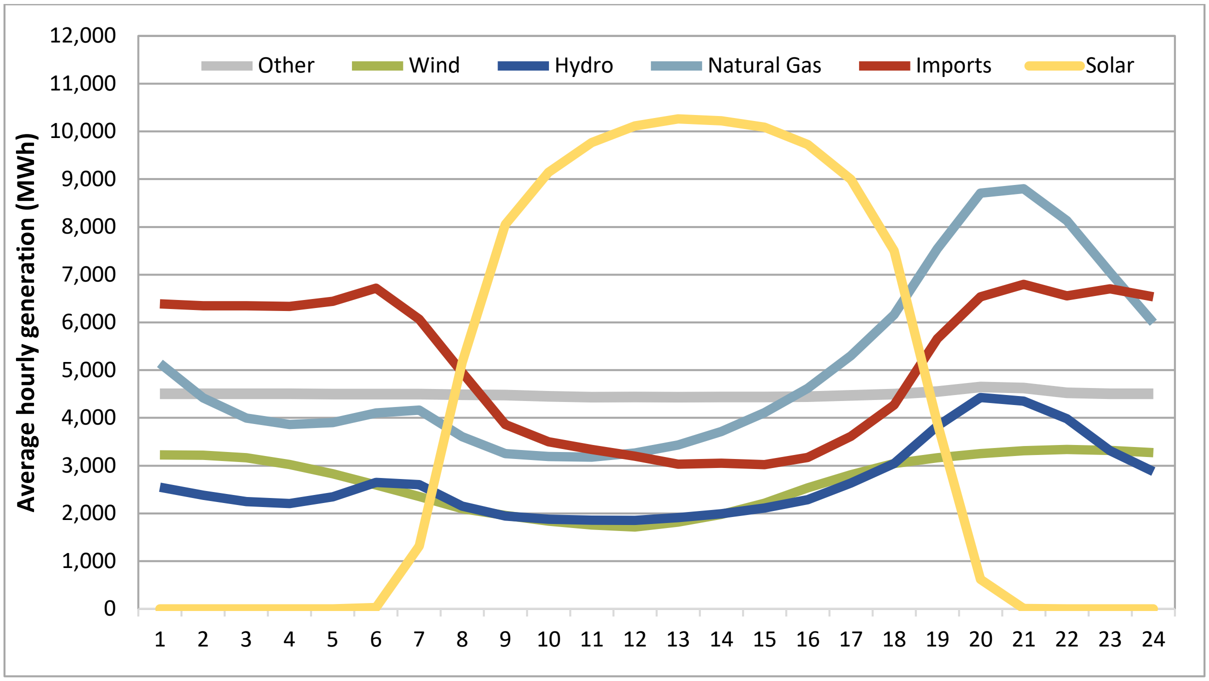


Figure 1.4 shows hourly variation of generation by fuel group, driven primarily by hourly variation of solar production. In the second quarter, after solar production, natural gas varied most over the day and produced significantly more than any resource during the peak net load hours, similar to previous quarters. Compared to the previous quarter, the large increase in wind generation variability was driven by a significant increase in average generation during the morning and evening hours. Wind generation typically complements solar production by generating more in the early morning and late evening hours, and less in the middle of the day. On average, this pattern was prevalent during the second quarter.

Similar to the previous quarter, imports consistently produced more than hydroelectric resources throughout the day. Average hourly generation from "other" category resources had little variability and marginally decreased compared to the previous quarter.[15] This was primarily due to decreases in nuclear and bio-based resource generation.

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

Figure 1.4 Hourly variation in generation by fuel type (Q2 2020)



1.1.5 Generation outages

This section provides a summary of generation outages in the second quarter of 2020. Overall, the total amount of generation outages over the quarter was higher than the same quarter in 2019.

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 include 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 1.5 shows the monthly averages of maximum daily outages broken out by type during peak hours of 2019 and 2020. The typical seasonal outage pattern is primarily driven by planned outages for maintenance, as maintenance is performed outside of the high summer load period. During the first half of 2020, generation outages deviated from this seasonal pattern as shown by an increase in outages between the first and second quarter of 2020. This pattern may potentially be observed in the third quarter of 2020 as well. Figure 1.6 shows the quarterly averages of maximum daily outages by type during peak hours from 2016 to 2020. As shown, 2017 also deviated from the typical seasonal pattern described above.

As shown in Figure 1.5, April and May experienced about the same level of outages, around 14,300 MW. While there were almost equal amounts of planned and forced outages in April, June experienced four times more forced outages than planned outages. A large portion of the increase in generation outage was due to a single resource undergoing maintenance during the quarter.

During the first half of 2020, the average total generation outages in the ISO surpassed the same period in 2019 by about 4,700 MW.[16] Outages for planned maintenance were about 3,900 MW during peak hours in the second quarter of 2020, an increase of about 900 MW compared to the second quarter of 2019. Combined, all other types of planned outages averaged about 1,000 MW over the quarter. Some common types of outages in this category include ambient outages (both due to temperature and not due to temperature) and transmission outages.

Forced outages for either plant maintenance or plant trouble totaled about 4,100 MW, while all other types of forced outages totaled about 4,500 MW, during the quarter. The other types of forced outages included ambient due to temperature, ambient not due to temperature, environmental restrictions, unit testing, and outages for transition limitations.

16 This 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.

Figure 1.5 Monthly average of maximum daily generation outages by type – peak hours (2019 - 2020)

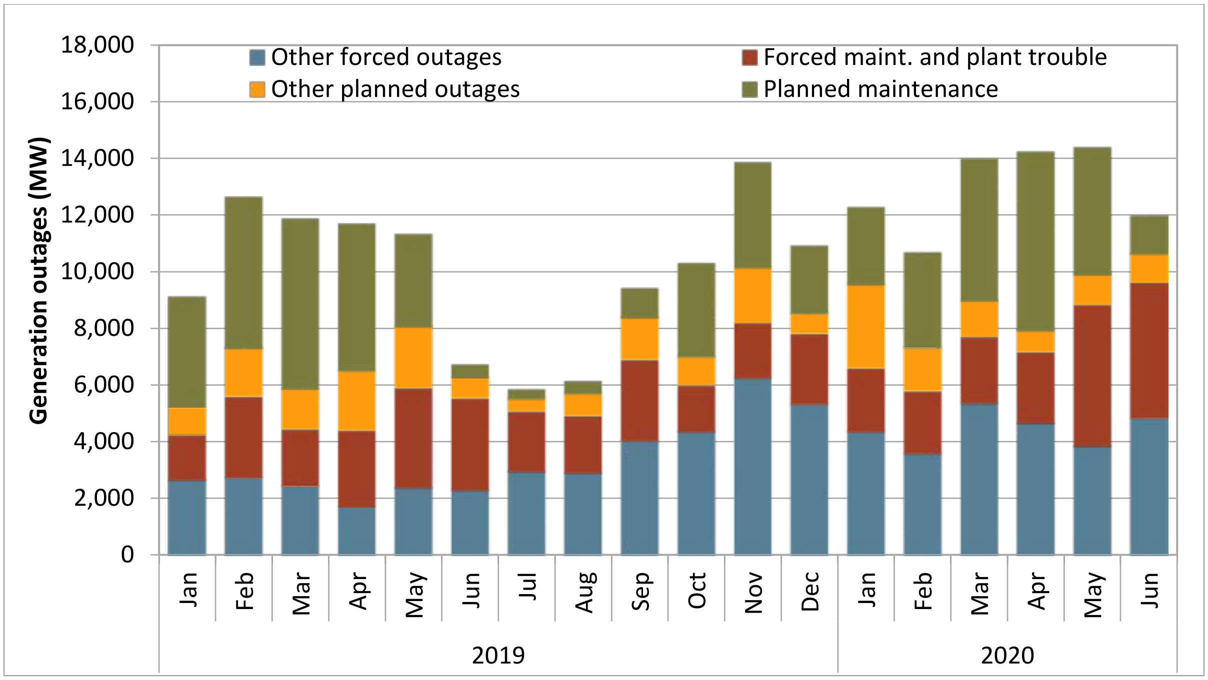
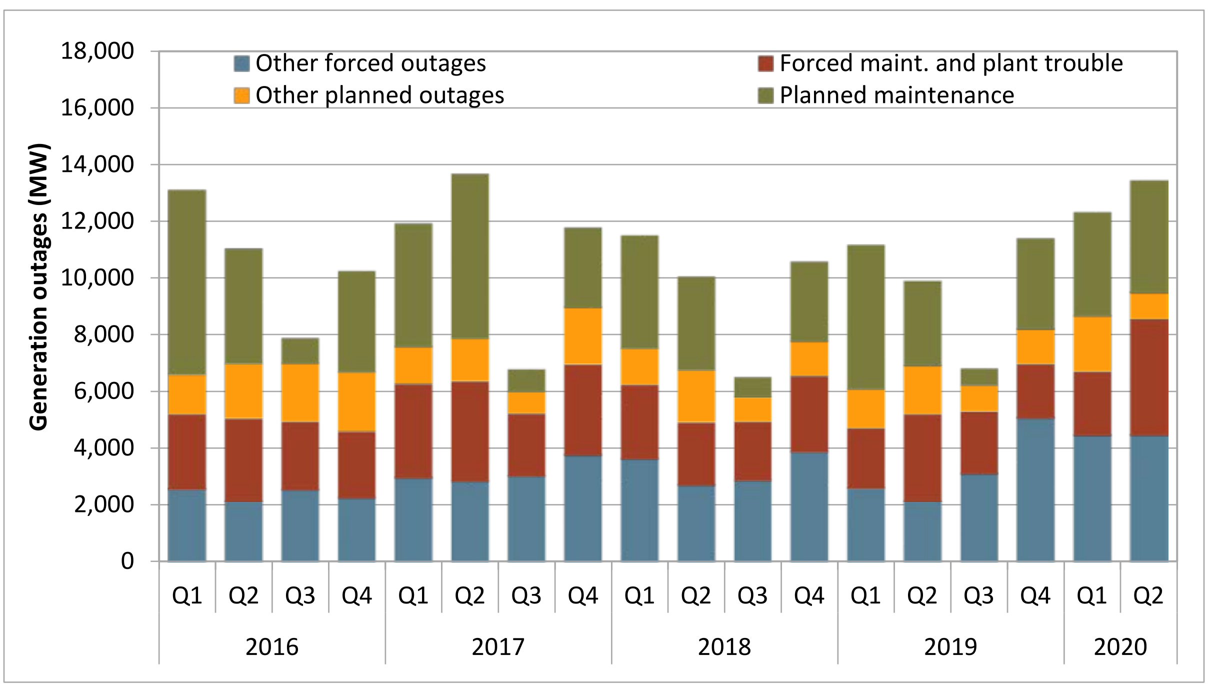


Figure 1.6 Quarterly average of maximum daily generation outages by type – peak hours (2016 – 2020)



1.2 Load conditions

ISO load decreased in the second quarter of 2020 relative to the same quarter in 2018 and 2019. Figure 1.7 shows average hourly load by month from 2018 to 2020. Lower loads are due in part to increases in behind-the-meter solar generation, continued initiatives to improve energy efficiency, as well as the public health order that directed Californians to stay at home except for essential needs or to work at essential jobs in response to COVID-19.[17] The biggest year-over-year change in load happened in April when average load dropped by about 9 percent compared to the previous two years.

Figure 1.7 Average hourly load by second quarter month (2018-2020)

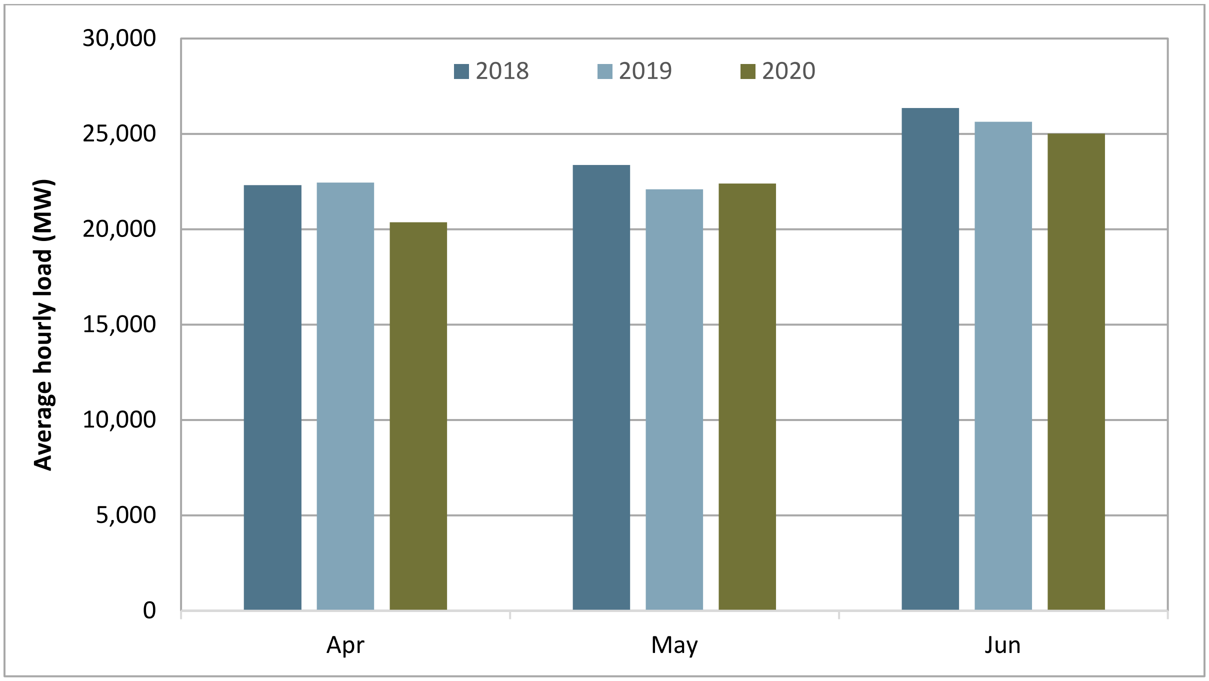


Figure 1.8 shows how the variability of the net load curve has changed over time. It shows the average hourly net load as well as the minimum and maximum hourly average net load from January 2018 to June 2020. Average net load tends to follow seasonal patterns in California by increasing during warmer months and decreasing during cooler months. Apart from this general pattern, average net loads have decreased by about 10 percent since the second quarter of 2018.

The figure also shows that the difference between maximum and minimum hourly average net load per month has increased over time. Net load is a measure of load minus generation from wind and solar resources. Therefore, the monthly maximum net load is influenced by the high net loads in the evenings when the combination of wind and solar resource production is low. The minimum monthly net load is influenced by the low net loads during the middle of the day when the combination of solar and wind production is at its highest. An increase in this difference over time is indicative of increased penetration

[17] For more information on how the stay-at-home orders in response to COVID-19 affected the ISO, please refer to Section 3.1

of solar and wind resources in the ISO market. The net load minimum has decreased over time, and notably reached as low as 5,000 MW multiple times since the second quarter of 2019.

Figure 1.8 Average hourly net load by month (2018-2020)

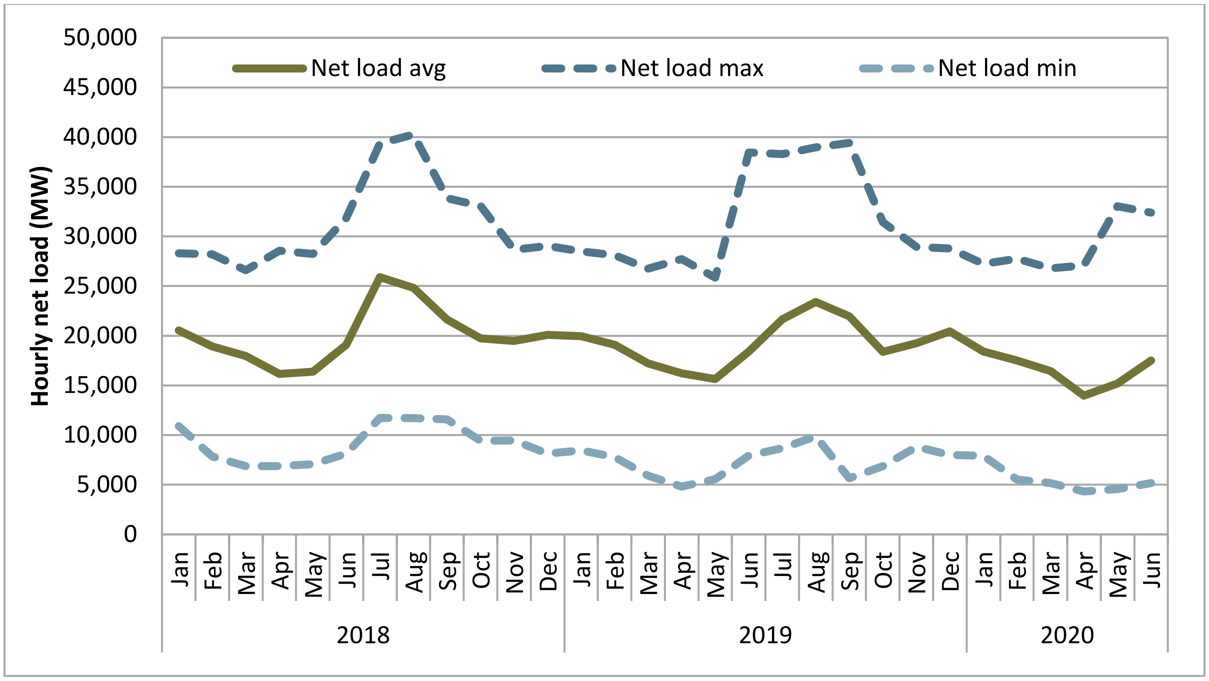
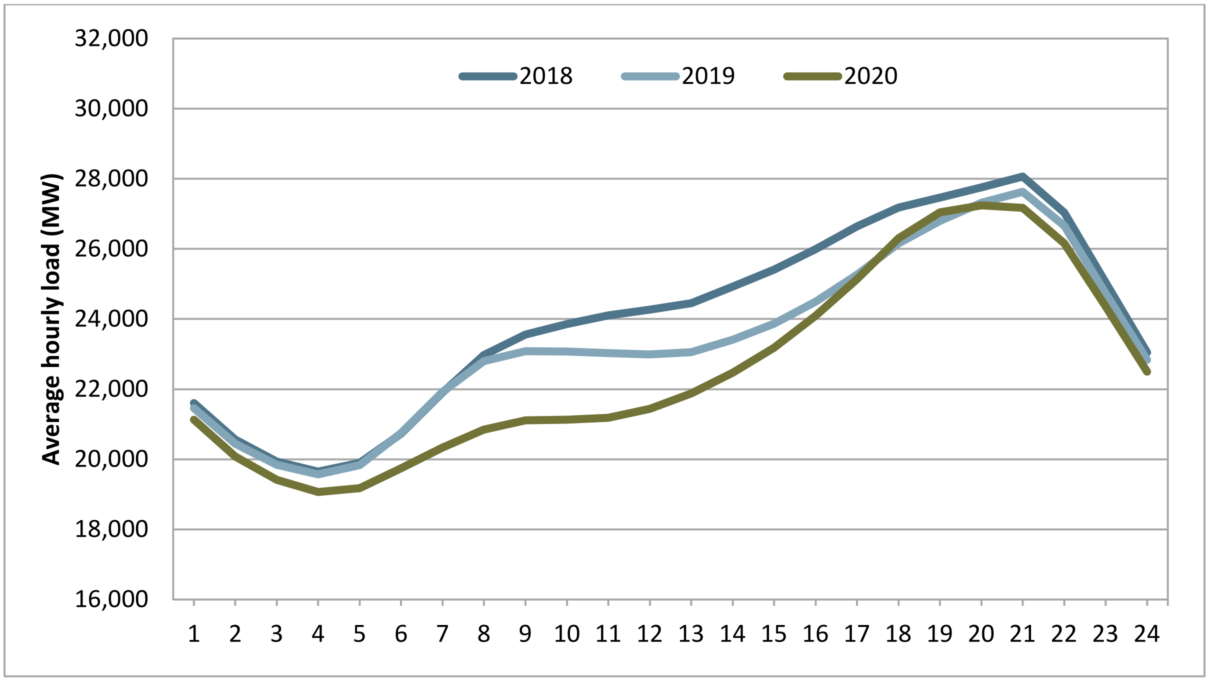


Figure 1.9 offers insight into how behind-the-meter solar resources affect ISO load. Generation from utility scale wind and solar resources indirectly affects load by influencing how other generation sources must meet demand after wind and solar have been factored out, i.e., the net load. Conversely, generation from behind-the-meter solar resources directly reduces the amount of load that must be met by generation from the ISO market, regardless of source.

The figure shows average load by hour in the second quarter of 2018 to 2020. Average hourly load during the morning and evening peaks tracked closely together in the second quarter of 2018 and 2019. Loads in the second quarter of 2020 decreased, as previously shown. This is true for nearly all hours on average. The divergence in load across years through the middle of the day, when solar production is high, shows the effect of increased behind-the-meter solar generation on load in California.

Figure 1.9 also shows how the public health orders related to COVID-19 impacted the typical load pattern in the ISO. The decrease in commercial and industrial load and corresponding increase in residential load due to the orders resulted in a relatively lower morning peak and a slightly earlier evening peak. Average loads in the middle of the day continue to diverge from historic levels primarily due to increases in behind-the-meter solar.

Figure 1.9 Average load by second quarter hour (2018-2020)



1.3 Energy market performance

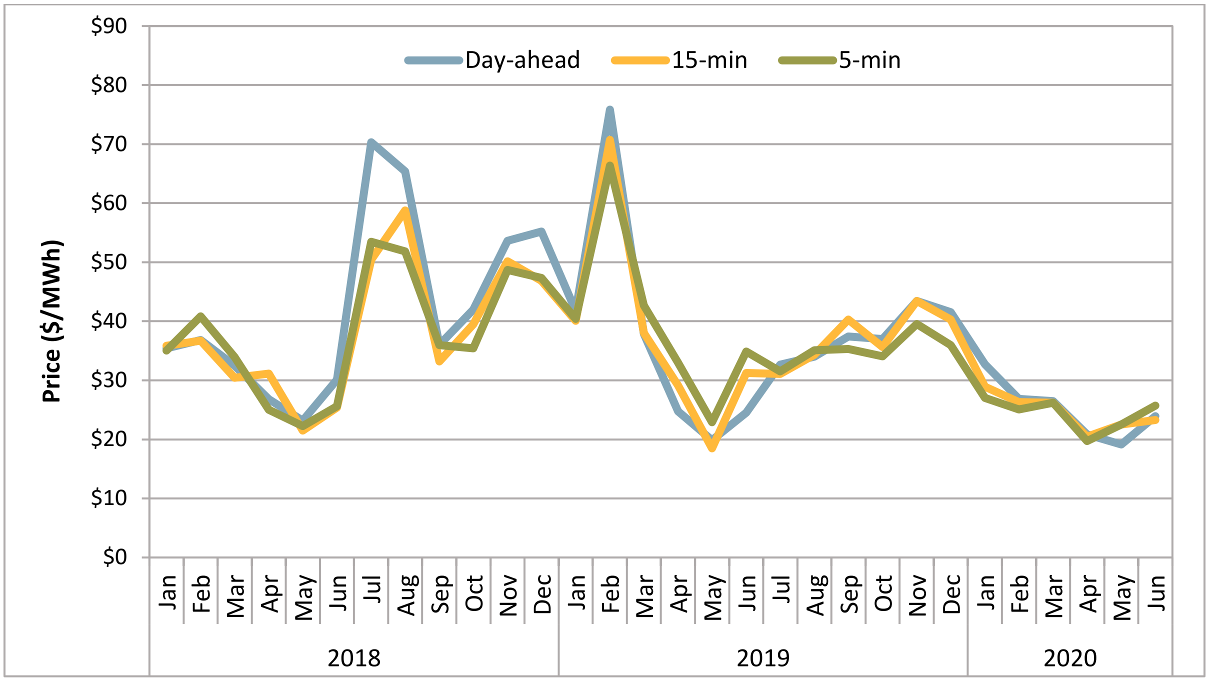
1.3.1 Energy market prices

This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. Price convergence between these markets may help promote efficient commitment of internal and external generating resources. Prices decreased between the first and second quarters of 2020. Average day-ahead prices decreased by 26 percent, 15-minute prices decreased by 19 percent, and 5-minute prices decreased by 13 percent. This decrease was similar to the year-over-year change from the second quarter of 2019 where day-ahead, 15-minute, and 5-minute prices respectively decreased by 12 percent, 16 percent, and 25 percent.

Figure 1.10 shows load-weighted average monthly energy prices during all hours across the four largest load aggregation points in the ISO (Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, and Valley Electric Association). Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) from January 2018 to June 2020.[18]

[18] In this report, the methodology has been updated such that both day-ahead and real-time prices are weighted by real-time load as opposed to individual market schedules.

Figure 1.10 Monthly load-weighted average energy prices (all hours)

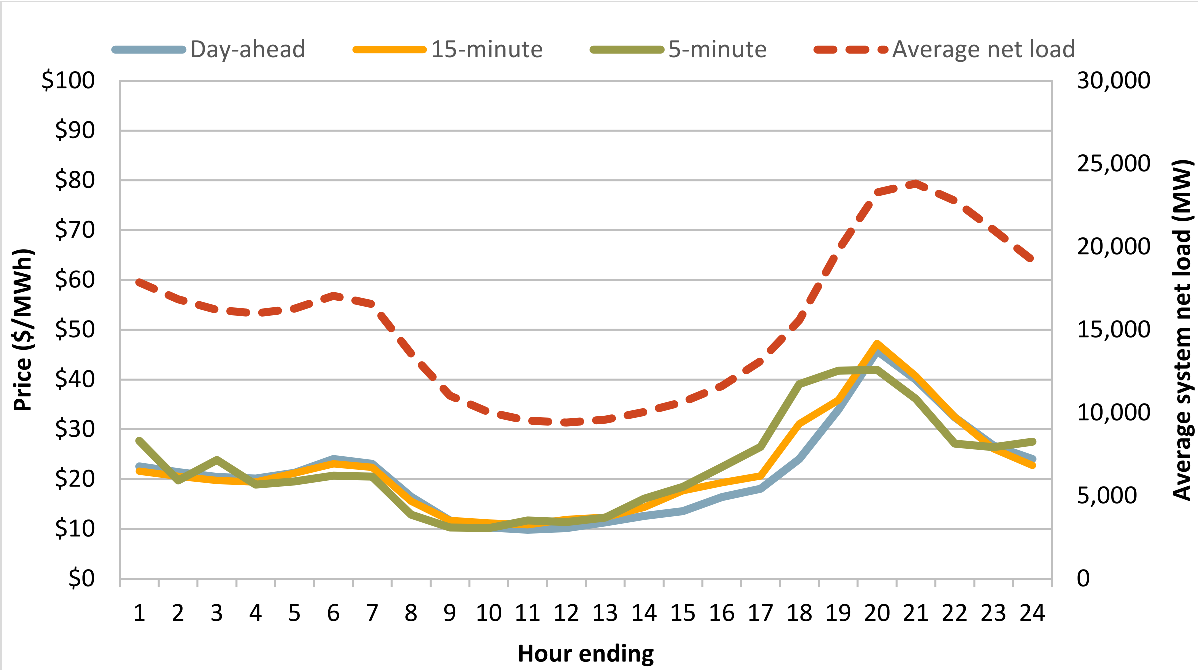


Average prices generally converged across the three markets in the second quarter. Day-ahead prices averaged about $21/MWh, 15-minute prices averaged $22/MWh, and 5-minute prices averaged $23/MWh. Prices in the day-ahead market were slightly lower than the real-time market prices. This conflicts with the general trend since 2014 where day-ahead prices tended to be relatively higher; however, day-ahead prices were relatively lower in the second quarter of 2019 as well.

Figure 1.11 illustrates load-weighted average energy prices on an hourly basis in the second quarter compared to average hourly net load.[19] Average hourly prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) and are measured by the left axis while average hourly net load (red dashed line) is measured by the right axis.

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

Figure 1.11 Hourly load-weighted average energy prices (Apr – Jun)

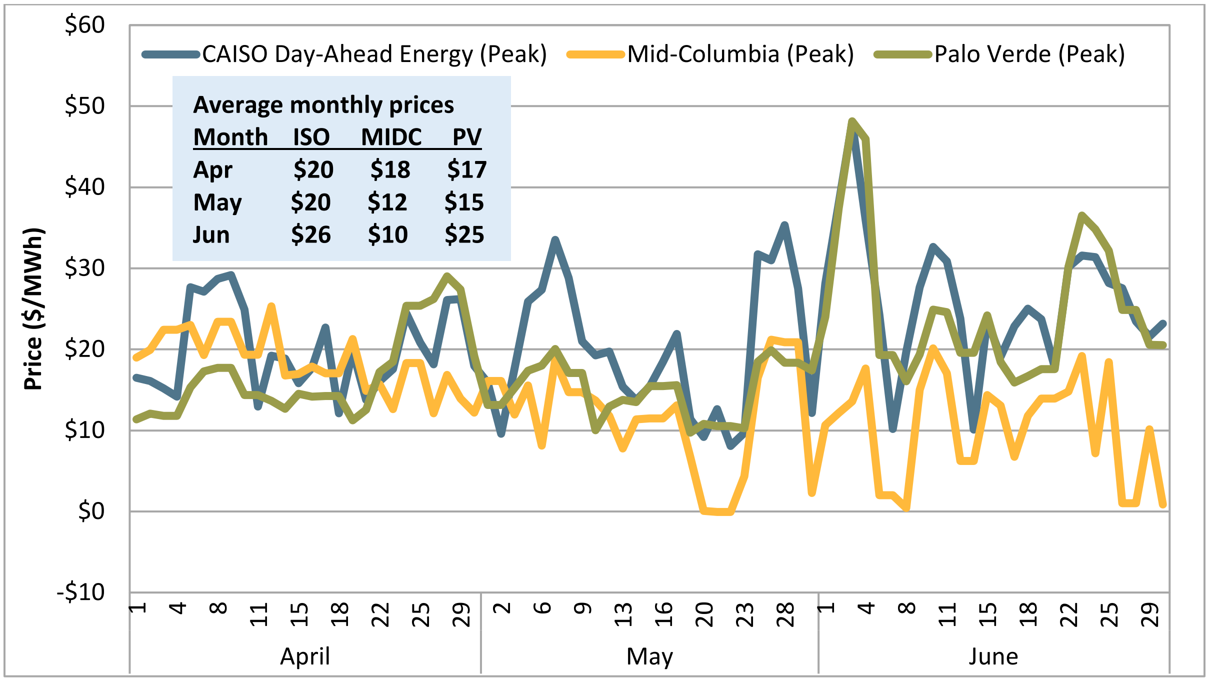


Average hourly prices in the second quarter continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours, particularly between hours ending 18 and 21. The figure shows that the trend of lower day-ahead prices over the quarter was primarily due to the divergence of real-time prices between hours ending 15 and 19 as net load was increasing to the afternoon peak. Real-time prices averaged $6/MWh to $10/MWh above day-ahead prices during these hours, which is primarily an effect of violating the system power balance constraint.

1.3.2 Bilateral price comparison

On average, day-ahead market prices in the ISO across all hours in the second quarter were greater than prices at Mid-Columbia and Palo Verde electricity hubs. The ISO prices reflect transmission constraints as well as greenhouse gas compliance costs. Figure 1.12 shows the ISO's day-ahead weighted average peak prices across the three largest load aggregation points (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric), as well as average day-ahead peak energy prices at the Mid-Columbia and Palo Verde hubs outside of the ISO market.

Figure 1.12 Daily system and bilateral market prices (Apr – Jun)



Average prices in the ISO and bilateral trading hubs were calculated during peak hours (hours ending 7 through 22) for all days excluding Sundays and holidays. Daily ISO system prices were generally higher than both bilateral hub prices during most of the second quarter. Daily energy prices converged periodically which resulted in Mid-Columbia prices exceeding ISO prices for thirteen days (17 percent of total) and for twenty six days (34 percent of total) at Palo Verde.

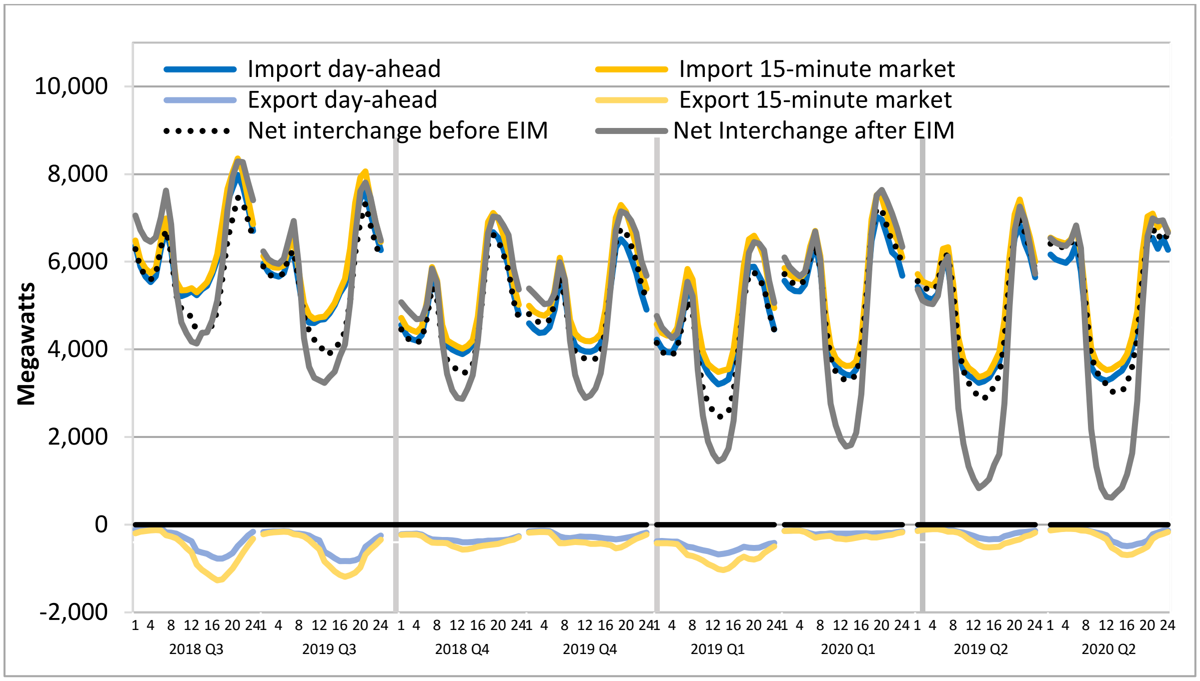
Average day-ahead prices in the ISO were also compared to hourly energy prices traded at Mid-Columbia and Palo Verde hubs for all hours of the quarter using data published by Powerdex. Average hourly prices in the ISO were greater than prices in Mid-Columbia and Palo Verde by $12.02/MWh and $1.75/MWh, respectively.

Imports and exports

In the second quarter of 2020, average hourly cleared imports (day-ahead and real-time) peaked at the same time but at slightly lower volumes when compared to the same quarter in 2019. As shown in Figure 1.13, second quarter peak imports in the day-ahead (dark blue line) decreased slightly to 6,500 MW from about 6,800 MW in the same quarter the previous year. For the same comparable period, the peak 15-minute (dark yellow line) cleared imports also slightly decreased from about 7,400 MW to 7,100 MW. Exports (shown as negative numbers below the horizontal axis in pale blue and yellow), increased by about 170 MW from the same quarter in 2019, peaking at about 690 MW in hour ending 16 and 17.

The average net interchange, excluding EIM transfers (shown in dashes), is based on meter data and averaged by hour and quarter. The solid grey line adds incremental EIM interchange, which reached a low point of about 600 MW in hour ending 13. The greatest import transfer into the ISO from the EIM occurred in hour ending 22 at about 400 MW, compared to 300 MW from the same quarter in the prior year. Also, the greatest export transfer from the ISO to the EIM occurred in hour ending 12 at about 2,500 MW, an increase of about 500 MW from the same quarter in 2019.

Figure 1.13 Average hourly net interchange by quarter



1.4 Wholesale energy cost

Total wholesale cost to serve load in the ISO market during the second quarter of 2020 was about $1.2 billion, down from about $1.4 billion in the same quarter of 2019. The average cost per megawatt-hour of load decreased 10 percent to about $25/MWh for the second quarter from $28/MWh in the same quarter of 2019 (nominal costs shown in blue bars in Figure 1.14).

The decrease in average wholesale electric prices is primarily from a 20 percent decrease in natural gas prices compared to the same quarter in 2019. Load-weighted gas prices decreased to about $2.97/MMBtu, a 20 percent decrease from about $3.73/MMBtu in the same quarter of 2019. When normalizing for changes in natural gas and greenhouse gas costs using the 2010 gas price as a reference year, the gold bar in Figure 1.14 shows the wholesale energy costs to serve load increased by 10 percent to about $33/MWh from about $30/MWh in the same quarter of 2019. In addition to lower natural gas costs, lower loads also contributed to lower wholesale energy costs this quarter.

Figure 1.14 Total quarterly wholesale costs per MWh of load

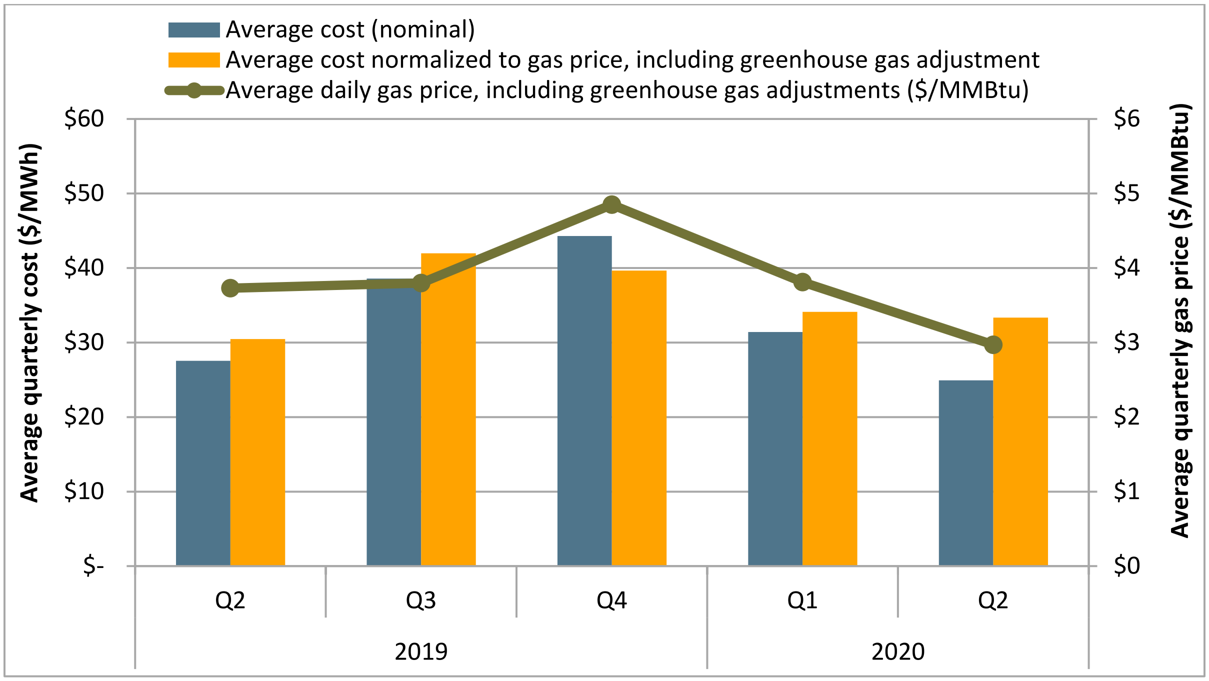


Table 1.1 provides quarterly summaries of nominal total wholesale costs by category. Costs for energy procured in the day-ahead market continued to make up a majority (90 percent) of the total cost to deliver energy to the market, a slight decrease from the previous quarter but similar to the second quarter of 2019. Real-time market costs increased to nearly 5 percent of the total cost from about 1.5 percent in the previous quarter, similar to the same quarter in 2019. Bid cost recovery, reliability, and reserve costs remained low, decreasing slightly compared with the same quarter in 2019.

Table 1.1 Estimated average wholesale energy costs per MWh

	Q2 2019	Q3 2019	Q4 2019	Q1 2020	Q2 2020	Change Q2 2019-Q2 2020
Day-ahead energy costs	$ 24.08	$ 35.94	$ 41.36	$ 29.45	$ 22.36	$ (1.72)
Real-time energy costs (incl. flex ramp)	$ 1.30	$ 0.97	$ 1.45	$ 0.49	$ 1.23	$ (0.07)
Grid management charge	$ 0.47	$ 0.45	$ 0.46	$ 0.45	$ 0.47	$ 0.01
Bid cost recovery costs	$ 0.50	$ 0.72	$ 0.46	$ 0.34	$ 0.36	$ (0.14)
Reliability costs (RMR and CPM)	$ 0.06	$ 0.06	$ 0.06	$ 0.03	$ 0.00	$ (0.06)
Average total energy costs	**$ 26.41**	**$ 38.14**	**$ 43.80**	**$ 30.76**	**$ 24.42**	**$ (1.99)**
Reserve costs (AS and RUC)	$ 1.15	$ 0.46	$ 0.49	$ 0.65	$ 0.50	$ (0.65)
Average total costs of energy and reserve	**$ 27.56**	**$ 38.60**	**$ 44.29**	**$ 31.41**	**$ 24.93**	**$ (2.64)**

1.5 Price variability

Day-ahead market prices range greatly over the course of a year, with periods of high and low prices. These variations tend to follow seasonal patterns, primarily due to the availability of variable energy resources such as wind and solar. One of the fundamental differences between the day-ahead market and the real-time market is the participants who may bid in.

Bids in the day-ahead market are from ISO market participants, while the real-time market includes bids from both ISO and EIM participants.[20] Due in part to this difference, the magnitude of the variation tends to be higher in the real-time market. Real-time market prices can be volatile with periods of extreme positive or negative prices. Even a short period of extremely high or low prices can significantly impact average prices.

1.5.1 Day-ahead price variability

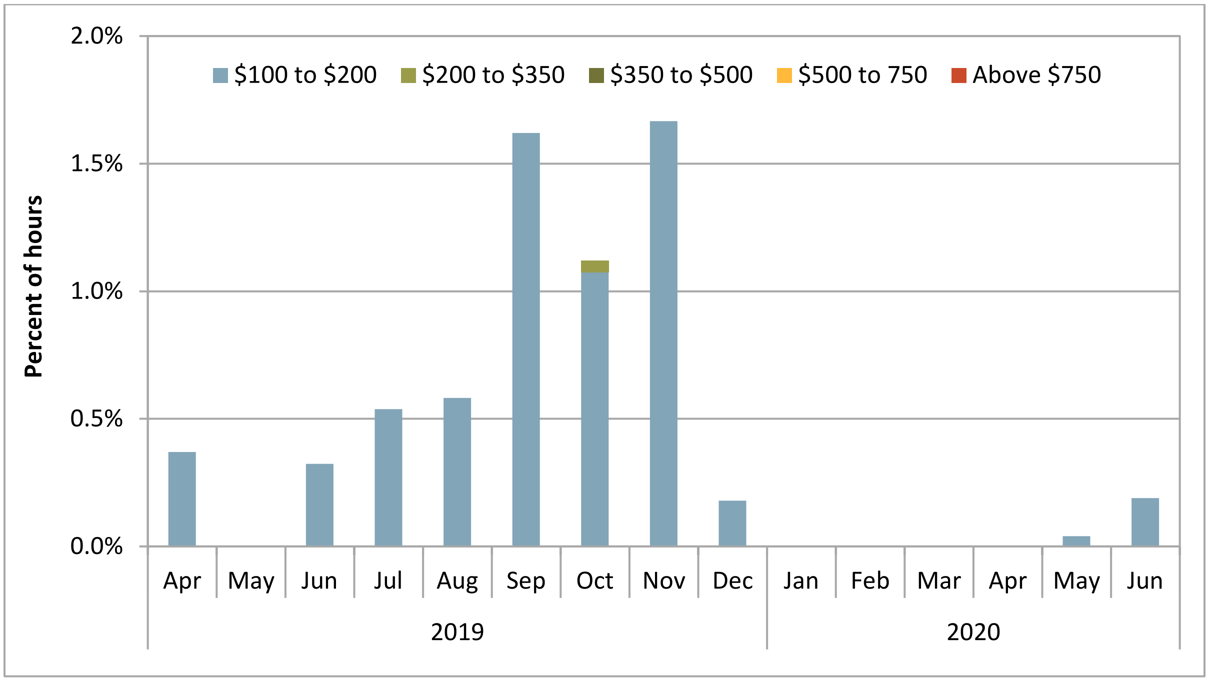
In the second quarter of 2020, the frequency of both high and negative day-ahead prices decreased compared to the same quarter in 2019.

High prices

Figure 1.15 shows the frequency of day-ahead market prices in various high priced ranges from April 2019 to June 2020. There were few high prices over $100/MWh in the day-ahead market during the second quarter of 2020. High prices have occurred less frequently in the second quarter of 2020 compared to the same quarter of 2019.

[20] The day-ahead price variability section accounts for price spikes in PG&E, SDG&E, and SCE independently. This method allows for price spikes that affect only one area not to be overlooked.

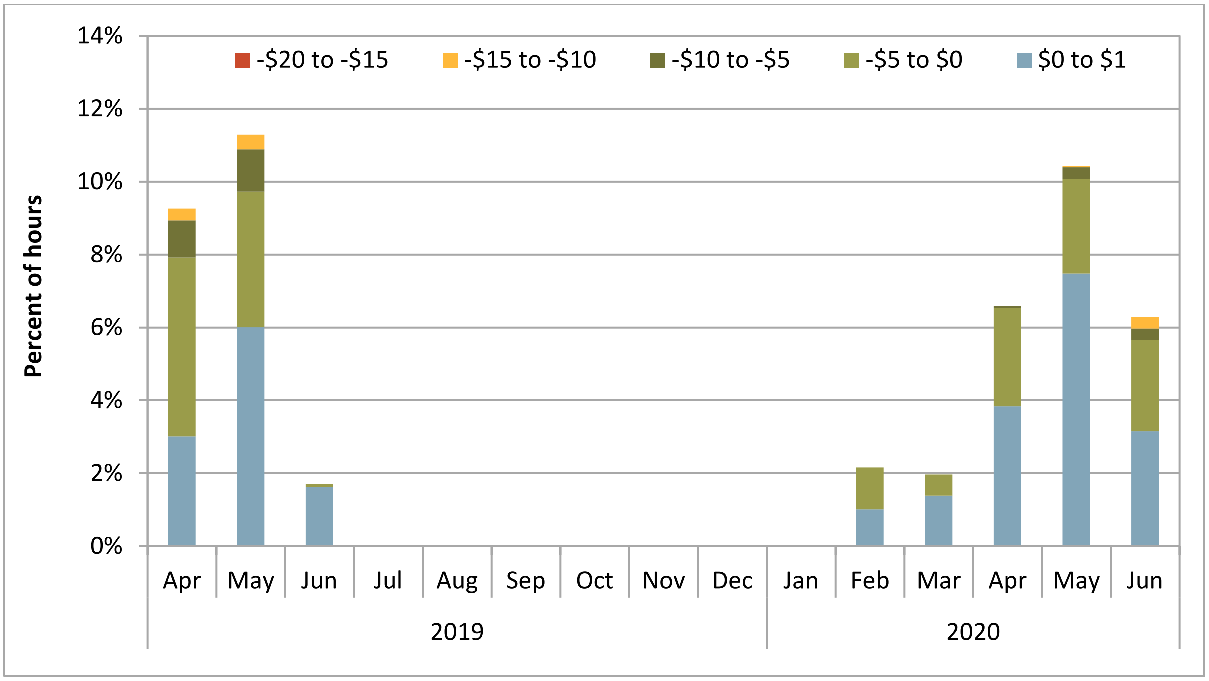
Figure 1.15 Frequency of high day-ahead prices ($/MWh) by month



Negative prices

Figure 1.16 shows the frequency of day-ahead market prices in various low priced ranges from April 2019 to June 2020. The frequency of negative prices was lower in April and May but higher in June compared to the same time period in 2019. Negative day-ahead prices typically occur during the middle of the day when production from generators with low marginal costs, like solar resources, is at its highest.

Figure 1.16 Frequency of negative day-ahead prices ($/MWh) by month



1.5.2 Real-time price variability

During the second quarter of 2020, the frequency of high real-time prices was relatively low. The frequency of negative prices in the real-time markets increased from the previous quarter, and was slightly higher than the second quarter of 2019.

High prices

Figure 1.17 and Figure 1.18 show the frequency of prices above $250/MWh across the three largest load aggregation points (LAP) in the ISO. As shown in Figure 1.17, the occurrence of high prices in the 15-minute market greater than $250/MWh was infrequent during the second quarter, and did not reach the same high levels as the same quarter of 2019. There were no system under-supply infeasibilities for the quarter in the 15-minute market.

Figure 1.18 shows the frequency of high prices in the 5-minute market. During the second quarter, the frequency of price spikes greater than $250/MWh in the 5-minute market increased slightly from the previous quarter, but was much lower than the same quarter of 2019.

Figure 1.19 shows the corresponding frequency of under-supply infeasibilities in the 5-minute market. Valid under-supply infeasibilities were very infrequent in the second quarter, occurring less than 0.1 percent of 5-minute market intervals.

Infeasibilities resolved by the load conformance limiter continued to be infrequent and had an insignificant impact on prices in the ISO. This is because in most intervals when the limiter triggers in the

ISO, the highest priced bids dispatched are often at or near the $1,000/MWh bid cap such that the resulting price is often very similar with or without the limiter.

Figure 1.17 Frequency of high 15-minute prices by month (ISO LAP areas)

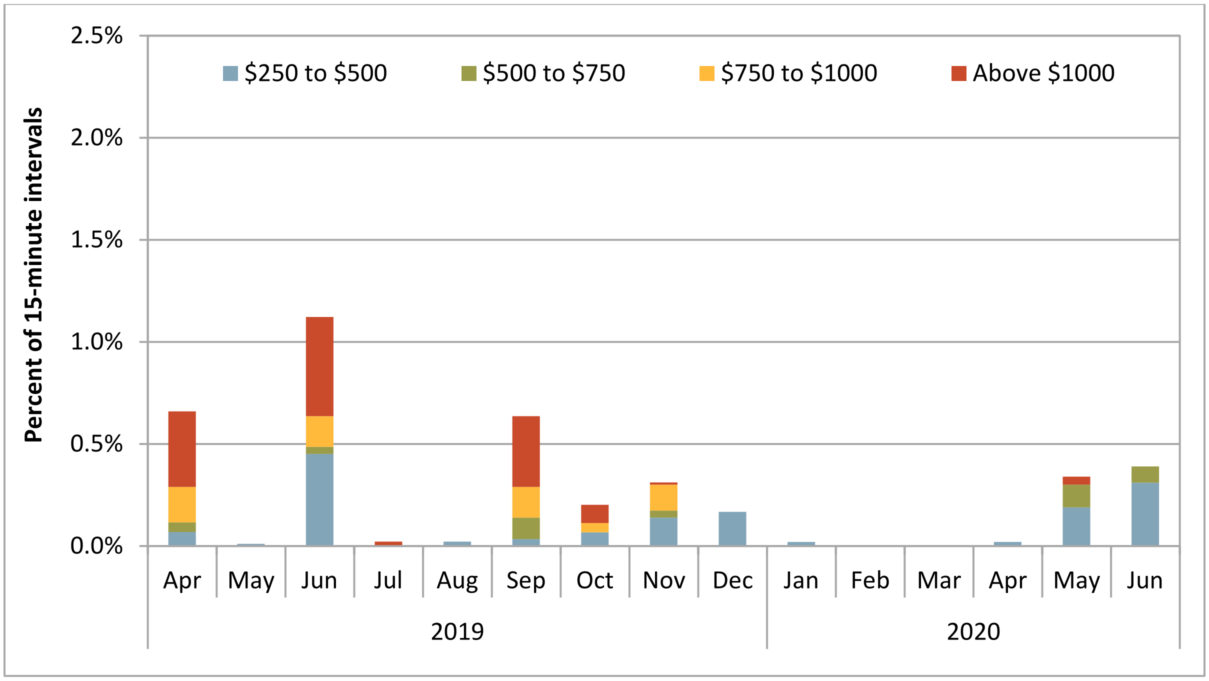


Figure 1.18 Frequency of high 5-minute prices by month (ISO LAP areas)

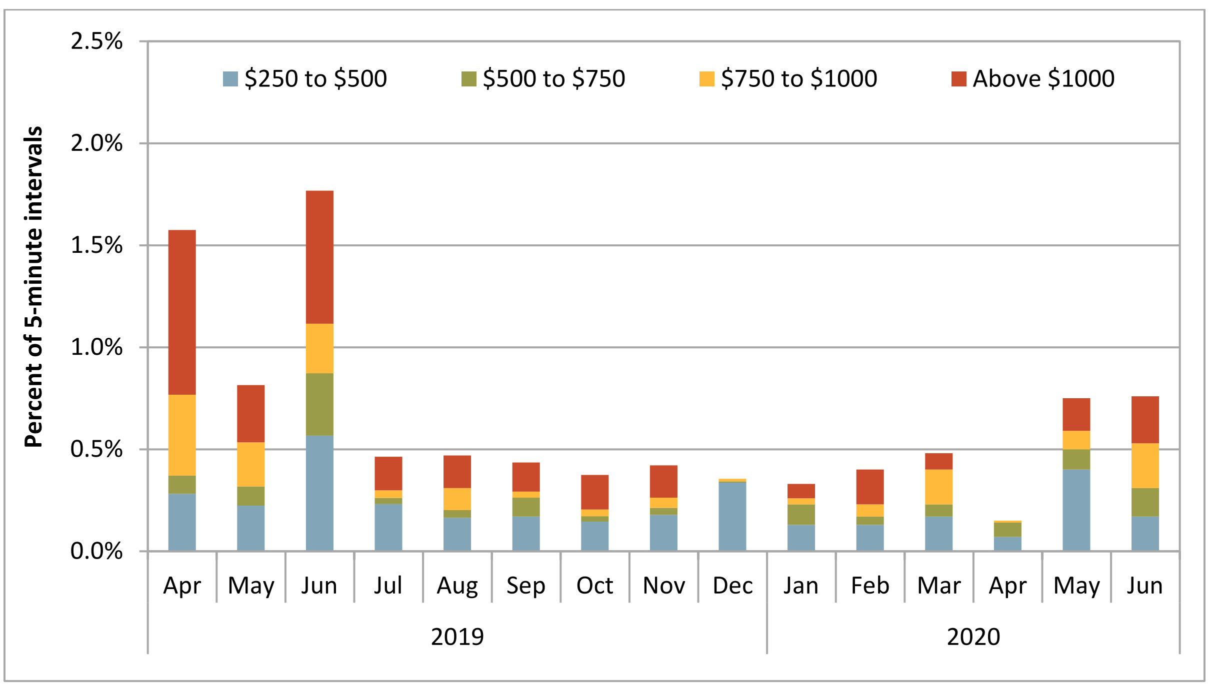
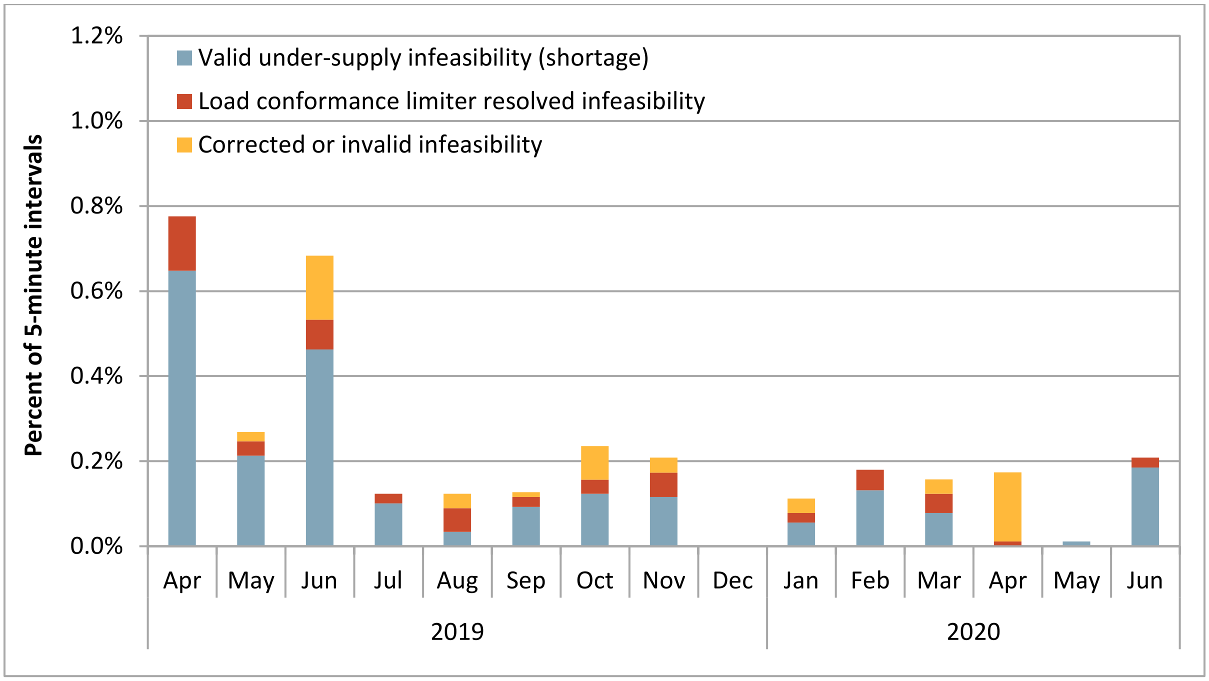


Figure 1.19 Frequency of under-supply power balance constraint infeasibilities (5-minute market)



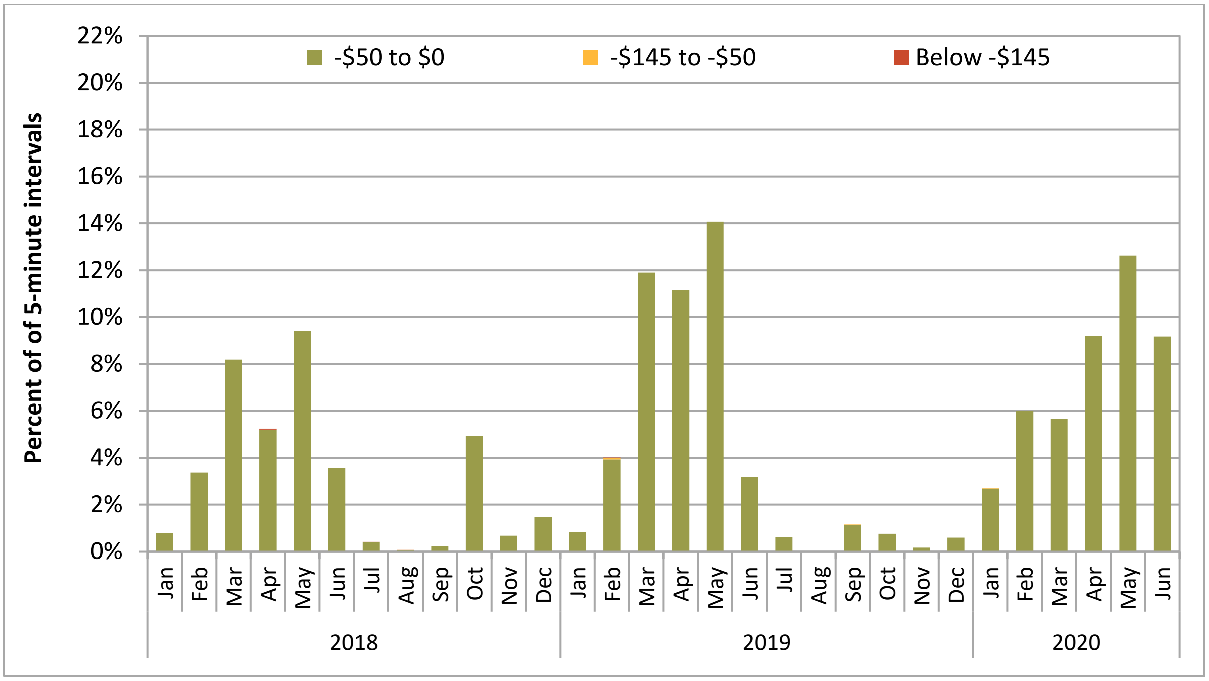
Negative prices

Figure 1.20 shows the frequency of negative prices in the 5-minute market by month across the three largest load aggregation points in the ISO.[21] The frequency of negative prices in the 15-minute and 5-minute markets increased from the previous quarter, and were similar to the second quarter of 2019. Negative prices during the second quarter of 2020 occurred during around 8 percent of 15-minute intervals and 10 percent of 5-minute intervals.

There were no intervals when the power balance constraint was relaxed because of excess supply during the quarter. Instead, negative prices were typically set by economic bids from wind and solar resources reflecting their relatively low marginal costs. During the second quarter, this was most frequent between hours ending 10 and 17 when loads, net of wind and solar, were lowest.

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

Figure 1.20 Frequency of negative 5-minute prices by month (ISO LAP areas)



1.6 Flexible ramping product

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

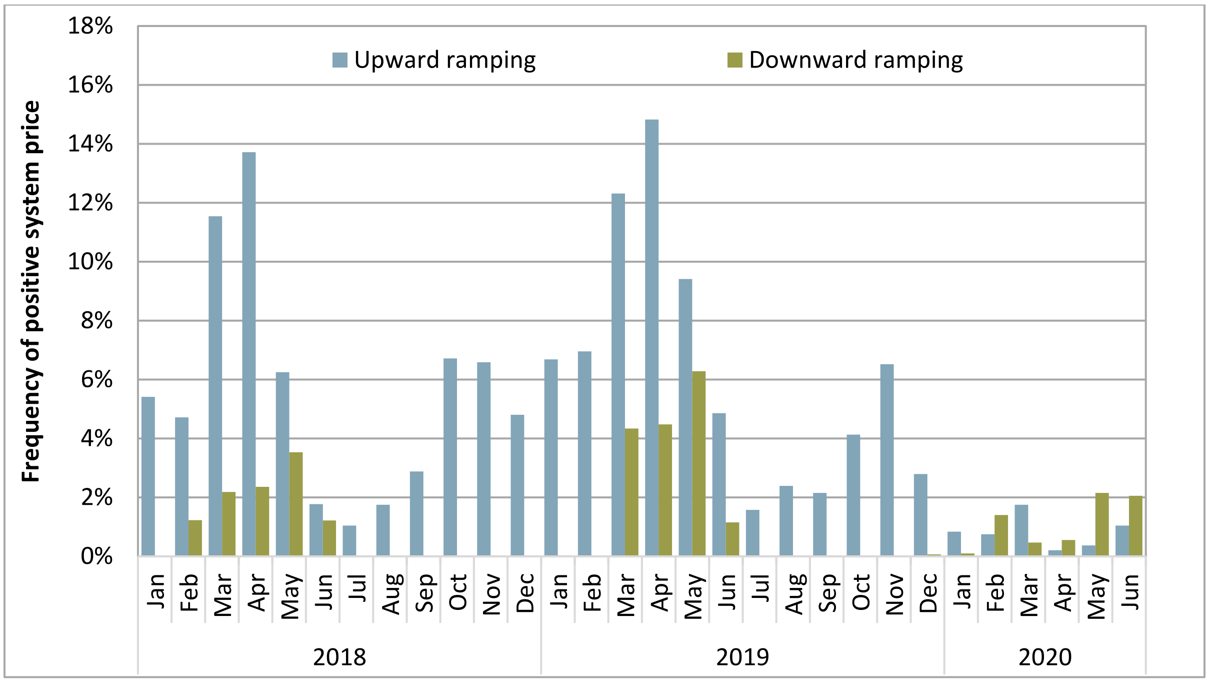
The flexible ramping product procures both upward and downward flexible capacity, in both the 15-minute and 5-minute markets. Procurement in the 15-minute market is intended to ensure that enough ramping capacity is available to meet the needs of both the upcoming 15-minute market run and the three 5-minute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

1.6.1 Flexible ramping product prices

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

Figure 1.21 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 frequency of positive shadow prices continued to be very low, particularly in comparison to 2018 and 2019. The 15-minute market system-level demand curves for both upward ramping and downward ramping bound in around 1 percent of intervals during the quarter. In the 5-minute market, the system-level demand curves bound in less than 0.1 percent of intervals.

Figure 1.21 Monthly frequency of positive 15-minute market flexible ramping shadow price



1.6.2 Flexible ramping product costs

Flexible ramping capacity that satisfies the demand for upward and 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.[22]

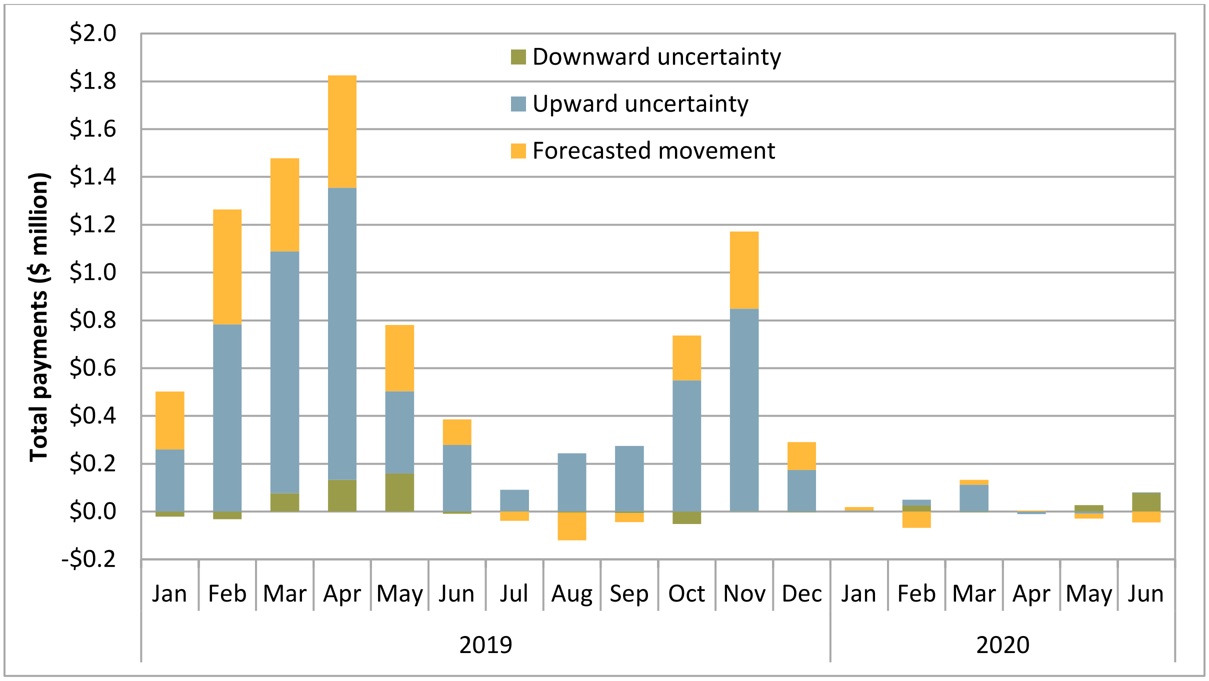
Figure 1.22 shows the total monthly net payments to resources from the flexible ramping product, including payments for flexible ramping capacity to meet upward and downward uncertainty as well as payments for forecasted movements. Payments for flexible ramping capacity continued to be very low during the second quarter, consistent with a low frequency of non-zero prices for flexible ramping capacity. Total uncertainty payments to generators in the ISO and the EIM for providing flexible ramping

---

[22] 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.

capacity during the second quarter were around $0.1 million, compared to around $0.2 million in the previous quarter and $2.1 million in the second quarter of 2019.

Figure 1.22 Monthly flexible ramping product payments by type



1.7 Convergence bidding

Convergence bidding was profitable overall for the second quarter of 2020. Combined net revenue for virtual supply and demand was about $9 million after including about $1.6 million of virtual bidding bid cost recovery charges. Virtual demand generated revenues of about $7.6 million. Before accounting for bid cost recovery charges, virtual supply generated positive net revenues of $3 million.

1.7.1 Convergence bidding trends

Average hourly cleared volumes were about 3,900 MW, an increase of about 800 MW from the previous quarter. Average hourly cleared virtual supply increased by about 200 MW from the previous quarter to about 2,100 MW. Cleared virtual demand averaged around 1,800 MW during each hour of the quarter, a 600 MW increase from the previous quarter. On average, about 28 percent of virtual supply and demand bids offered into the market cleared in the quarter, up from 24 percent in the previous quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 350 MW on average, a decrease from 720 MW of net virtual supply in the previous quarter. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply in 8 hours, between hours ending 13 and 20. In the remaining 16 hours, net cleared virtual supply exceeded net cleared virtual demand. Cleared virtual supply exceeded virtual demand by around 1,000 MW during hours ending 22 through 24, which is a slight shift to later hours from the previous quarter. Additionally, cleared virtual supply exceeded cleared virtual demand between 650 MW and 1,000 MW between hours ending 1 and 8.

Convergence bidding is designed to align day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between the two markets. For the quarter, net convergence bidding volumes were consistent with average price differences between the day-ahead and real-time markets during 18 of 24 hours. Hours where volumes were inconsistent with price differences were the 6 hours ending 9 through 12 and 19 through 20.

Offsetting virtual supply and demand bids

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

Offsetting virtual positions accounted for an average of about 1,000 MW of virtual demand offset by 1,000 MW of virtual supply in each hour of the quarter. This represents an increase of about 220 MW over the previous quarter. These offsetting bids represented about 51 percent of all cleared virtual bids in the second quarter, an increase of about 3 percent from the previous quarter.

1.7.2 Convergence bidding revenues

Participants engaged in convergence bidding in the second quarter were overall profitable. Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $10.6 million. Net revenues for virtual supply and demand fell to about $9 million after the inclusion of about $1.6 million of virtual bidding bid cost recovery charges,[23] primarily associated with virtual supply.

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

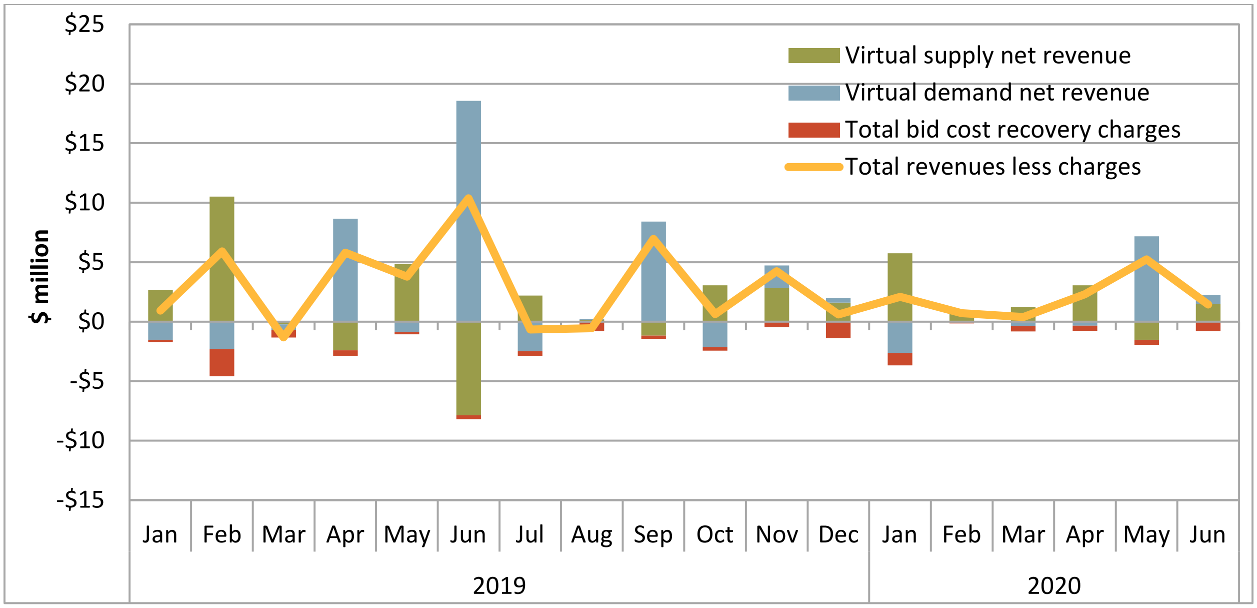
Before accounting for bid cost recovery charges:

- Total market revenues were positive during all months of the quarter. Net revenues during the second quarter totaled about $10.6 million, compared to nearly $21 million during the same quarter in 2019, and about $4.8 million during the previous quarter.
- Virtual demand net revenues were negative $0.3 million in April, and positive $7.2 million and $0.7 million in May and June, respectively.

23 For more information on how bid cost recovery charges are allocated please refer to the *Q3 2017 Report on Market Issues and Performance*, December 2017, pp. 40-41: http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf.

- Virtual supply net revenues were positive in April and June with $3 million and $1.5 million, respectively, while revenues in May were a negative $1.5 million.

Figure 1.23 Convergence bidding revenues and bid cost recovery charges



Convergence bidders received about $9 million after subtracting bid cost recovery charges of about $1.6 million for the quarter.[24,25] Bid cost recovery charges were about $0.4 million in April and May and $0.8 million in June.

Net revenues and volumes by participant type

Table 1.2 compares the distribution of convergence bidding cleared volumes and net revenues, in millions of dollars, among different groups of convergence bidding participants in the quarter.[26] As with the previous quarter, financial entities represented the largest segment of the virtual bidding market, accounting for about 70 percent of volume and 67 percent of settlement revenue. Marketers represented about 27 percent of the trading volumes and about 31 percent of settlement revenue. Generation owners and load serving entities represented a smaller segment of the virtual market in terms of both volumes and settlement revenue, at about 3 percent and 2 percent respectively.

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

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

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

Generation owners and load serving entities accounted for around $0.2 million of net revenues in the market.

Table 1.2 Convergence bidding volumes and revenues by participant type

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	1,264	1,497	2,761	$4.37	$2.79	$7.16
Marketer	484	579	1,063	$3.11	$0.15	$3.25
Physical load	0	64	64	$0.01	$0.08	$0.09
Physical generation	47	4	52	$0.09	$0.02	$0.11
Total	**1,795**	**2,145**	**3,940**	**$7.6**	**$3.0**	**$10.6**

1.8 Residual unit commitment

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real time. The residual unit commitment market runs immediately after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of load cleared in the day-ahead market and the day-ahead forecast load. ISO operators are also able to increase residual unit commitment requirements. Use of this tool increased in the second quarter of 2020 when compared to the same quarter of 2019.

As illustrated in Figure 1.24, residual unit commitment procurement appears to be driven in part by the need to replace cleared net virtual supply bids, which can offset physical supply in the day-ahead market run. On average, cleared virtual supply (green bar) was about 23 percent lower in the second quarter of 2020 than in the same quarter of 2019.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar) represents the difference in cleared supply (both physical and virtual) compared to the ISO's load forecast. On average, this factor contributed towards increased residual unit commitment requirements in the second quarter of 2020, particularly in May and June.

Operator adjustments to residual unit commitment requirements increased in the second quarter. The use of this tool averaged about 160 MW per hour compared to about 99 MW per hour in the same quarter of 2019. Primary reasons for these adjustments include addressing reliability concerns and to account for load forecast errors.

Residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of bid-in variable energy resources and the forecast output of these renewable resources. This intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market. It is represented by the yellow bar in Figure 1.24.

Figure 1.24 Determinants of residual unit commitment procurement

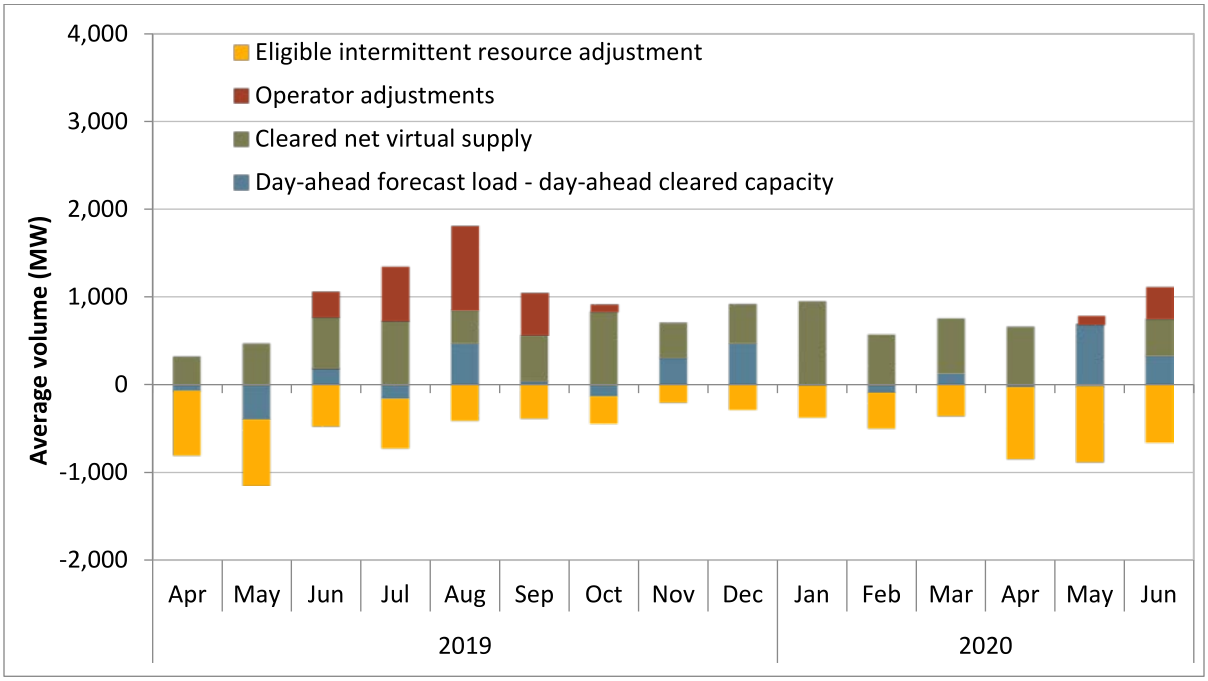
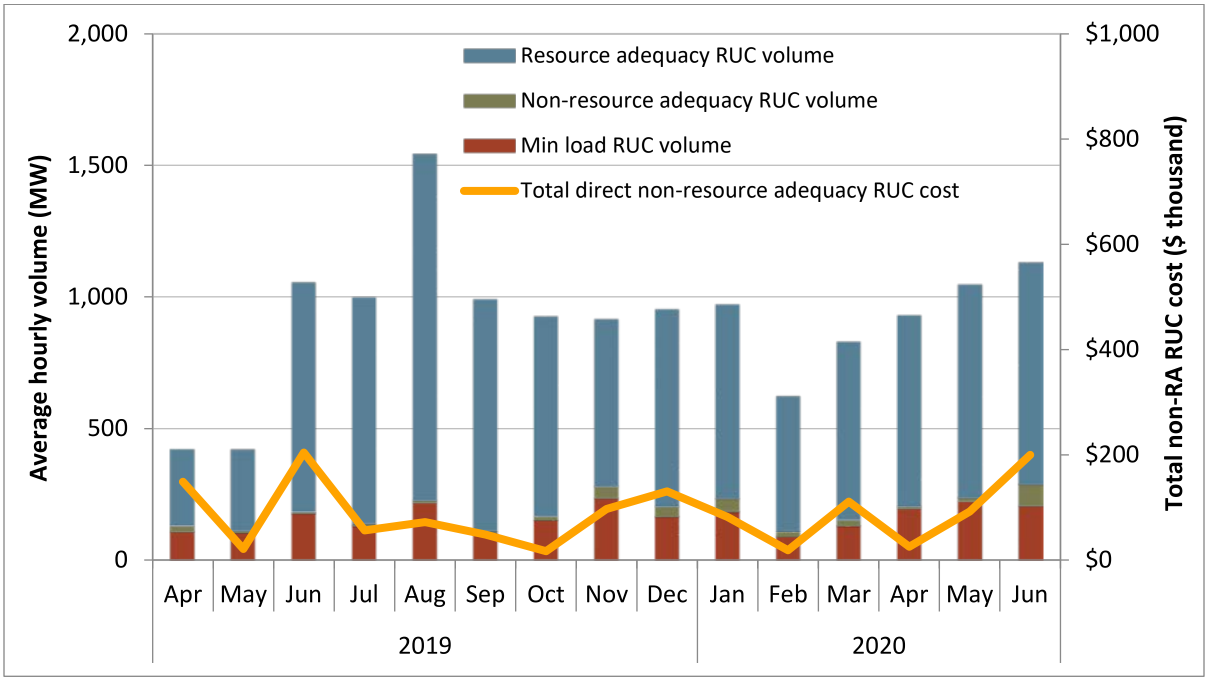


Figure 1.25 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased to about 1,036 MW per hour in the second quarter of 2020 from an average of 635 MW in the same quarter of 2019. Of the 1,036 MW per hour capacity, the capacity committed to operate at minimum load averaged about 207 MW each hour compared to 130 MW in the second quarter of 2019.

Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units committed in this process receive capacity payments.[27] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.25. In the second quarter of 2020, these costs decreased slightly to $0.32 million when compared to about $0.37 million in the same quarter of 2019.

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

Figure 1.25 Residual unit commitment costs and volume



1.9 Ancillary services

1.9.1 Ancillary service requirements

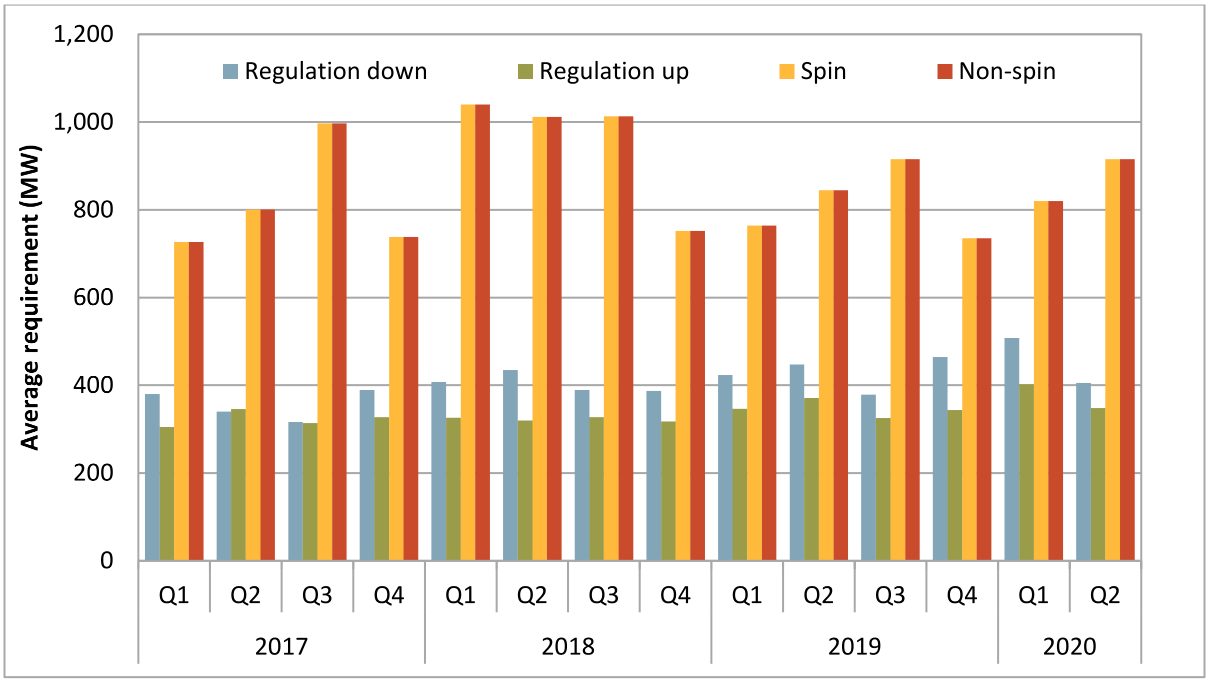
The ISO procures four ancillary services in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (WECC)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

The ISO can procure ancillary services in the day-ahead and real-time markets from the internal system region, expanded system region, four internal sub-regions, and four corresponding expanded sub-regions. The expanded regions are identical to the corresponding internal regions but include interties. Each of these regions can have minimum requirements set for procurement of ancillary services where the internal sub-regions are nested within the system and corresponding expanded regions. Therefore, ancillary services procured in an inward region also count toward meeting the minimum requirement of the outer region. Both internal resources and imports then meet ancillary service requirements, where imports are indirectly limited by the minimum requirements from the internal regions.

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

Figure 1.26 shows quarterly average ancillary service requirements for the expanded system region in the day-ahead market. As shown in the figure, average requirements for spinning and non-spinning operating reserves continued to increase during the quarter. Average requirements for regulation down and regulation up both decreased from the previous quarter.

Figure 1.26 Average quarterly day-ahead ancillary service requirements

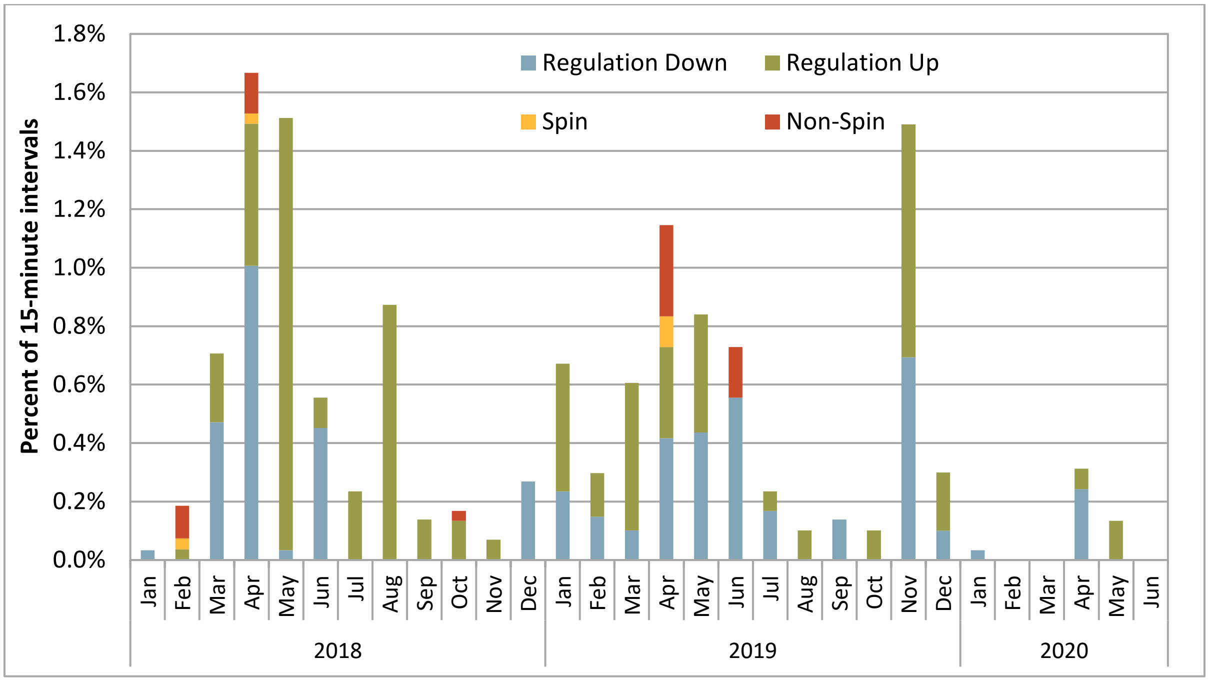


1.9.2 Ancillary service scarcity

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, the ISO pays a pre-determined scarcity price for ancillary services procured during scarcity events. The scarcity prices are determined by a scarcity demand curve, such that the scarcity price is higher when the procurement shortfall is larger.

As shown in Figure 1.27, the frequency of intervals with scarcity pricing was relatively low during the second quarter. During the second quarter, around 85 percent of the scarcity intervals occurred in the expanded South of Path 26 region, and the remaining 15 percent in the expanded North of Path 26 region.

Figure 1.27 Frequency of ancillary service scarcities (15-minute market)

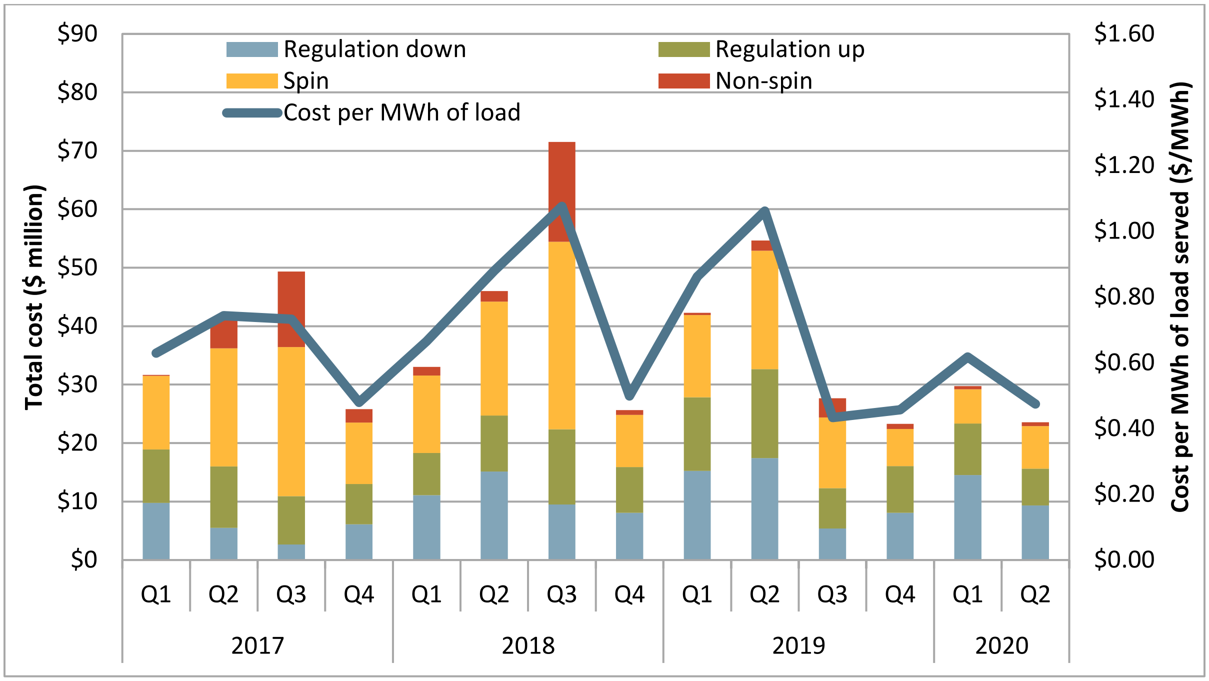


1.9.3 Ancillary service costs

Ancillary service payments decreased during the second quarter to about $24 million, compared to about $30 million in the previous quarter and $55 million during the same quarter in 2019. Total payments associated with regulation down decreased by around $5 million from the previous quarter.

Figure 1.28 shows the total cost of procuring ancillary service products by quarter as well as the total ancillary service cost for each megawatt-hour of load served. The costs reported in this figure account for rescinded ancillary service payments. Payments are rescinded when resources providing ancillary services do not fulfill the availability requirements associated with the awards.

Figure 1.28 Ancillary service cost by product



1.10 Congestion

In the day-ahead market, congestion in the second quarter increased PG&E area prices, decreased SCE area prices, and had an insignificant impact on SDG&E area prices. In the 15-minute market, congestion impact due to internal constraints increased in most areas relative to the same quarter of 2019.

The following sections provide an assessment of the frequency and impact of congestion on prices in the day-ahead, 15-minute, and 5-minute markets. It assesses the impact of congestion on local areas in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric) as well as on EIM entities.

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

The impact of congestion on each pricing node in the ISO system is calculated as the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas.[28]

[28] This approach does not include price differences that result from transmission losses.

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

1.10.1 Congestion in the day-ahead market

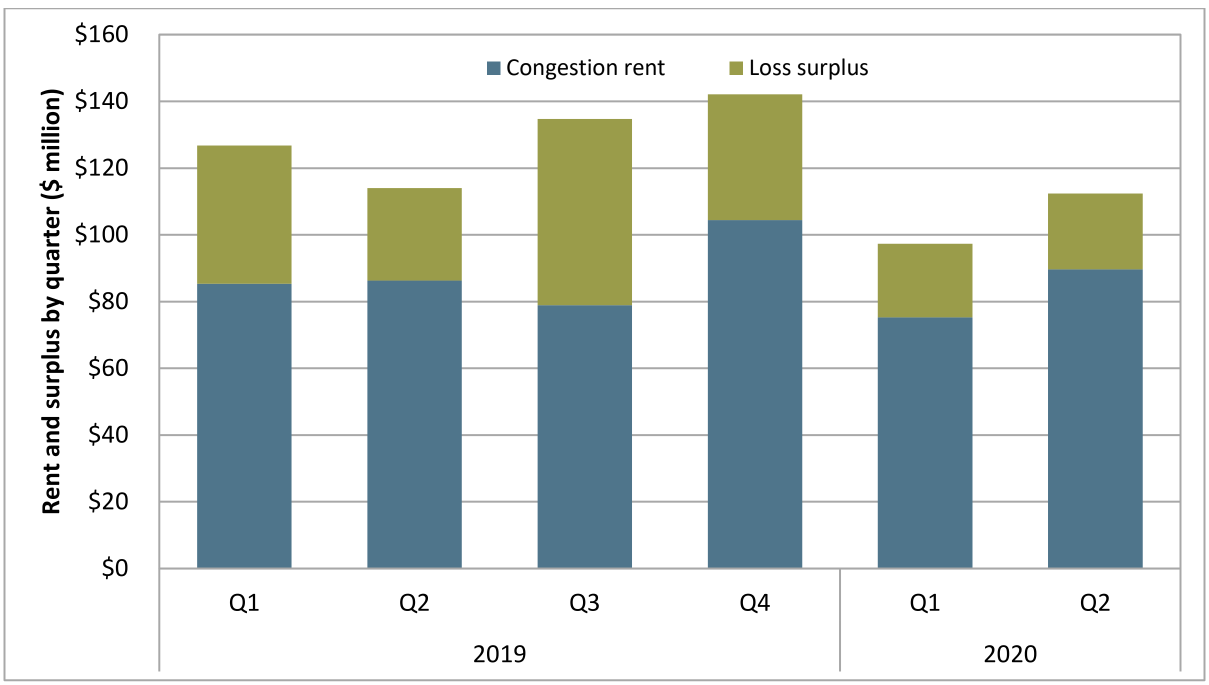
Day-ahead market congestion frequency tends to be higher than in the 15-minute market, but price impacts to load tend to be lower. The congestion pattern in this quarter reflects this overall trend.

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.[29]

Figure 1.29 shows the congestion rent and loss surplus by quarter for 2019 and 2020. Compared to the second quarter of 2019, congestion rents increased by 4 percent while the loss surplus decreased by 18 percent in the second quarter of 2020.

Figure 1.29 Day-ahead congestion rent and loss surplus by quarter (2019-2020)



[29] 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

Impact of congestion on overall prices in each load area

Figure 1.30 shows the overall impact of congestion on day-ahead prices in each load area in 2019 and 2020. Figure 1.31 shows the frequency of congestion. Highlights for this quarter include:

- In the second quarter of 2020, the overall net impact of congestion on price separation increased in PG&E and SCE areas while significantly decreasing in the SDG&E area relative to the same quarter of 2019. Compared to the first quarter of 2020, the impact was higher in this quarter, especially at PG&E and SCE load areas. The frequency of congestion increased in PG&E and SCE, while it decreased in SDG&E during the second quarter.
- Congestion increased prices in PG&E by $0.91/MWh (4.1 percent) and decreased prices in SCE by $0.78/MWh (-3.8 percent), but had little net impact on SDG&E where it raised prices by $0.03/MWh (0.1 percent).
- On an average quarterly basis, the congestion impact was frequently offsetting in SDG&E but not in PG&E or SCE, as shown in Figure 1.32. In the second quarter, PG&E experienced positive congestion more frequently, while SCE experienced negative congestion more frequently.
- The primary constraints impacting day-ahead market prices were the Los Banos-Quinto 230 kV line, Moss Landing-Las Aguilas 230 kV line, and the Serrano 500/230 kV transformer.

Additional information regarding the impact of congestion from individual constraints and the cause of congestion on constraints that had the largest impact on price separation is provided below.

Figure 1.30 Overall impact of congestion on price separation in the day-ahead market

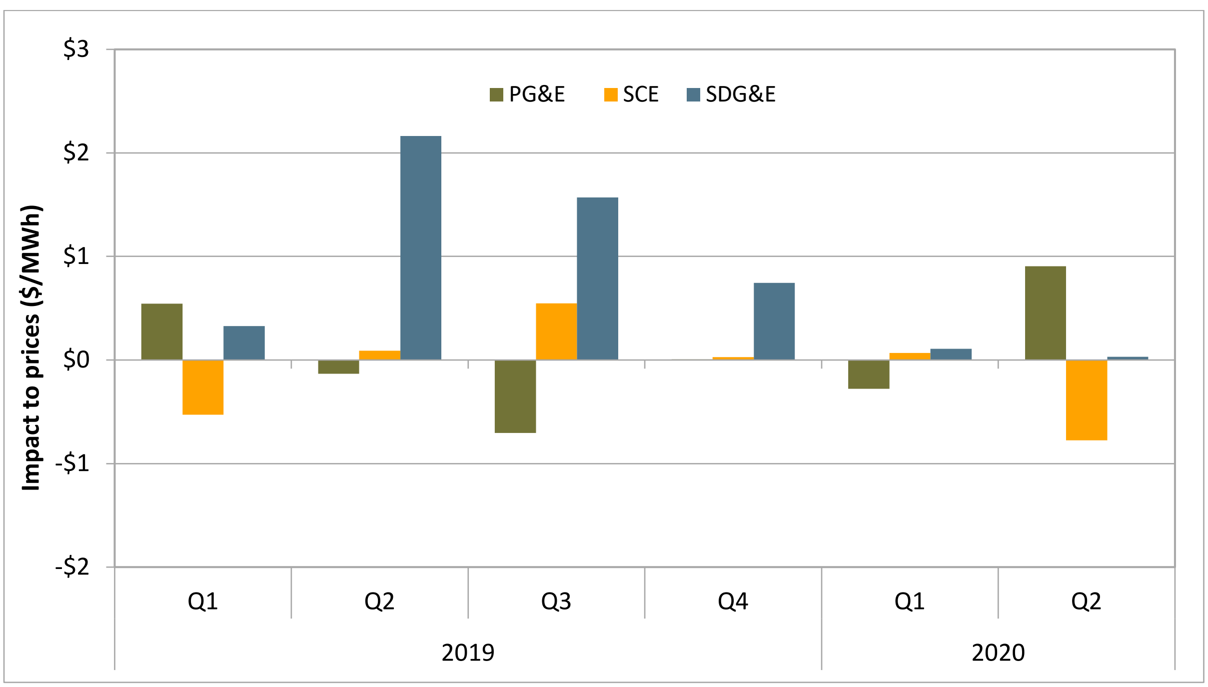


Figure 1.31 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)

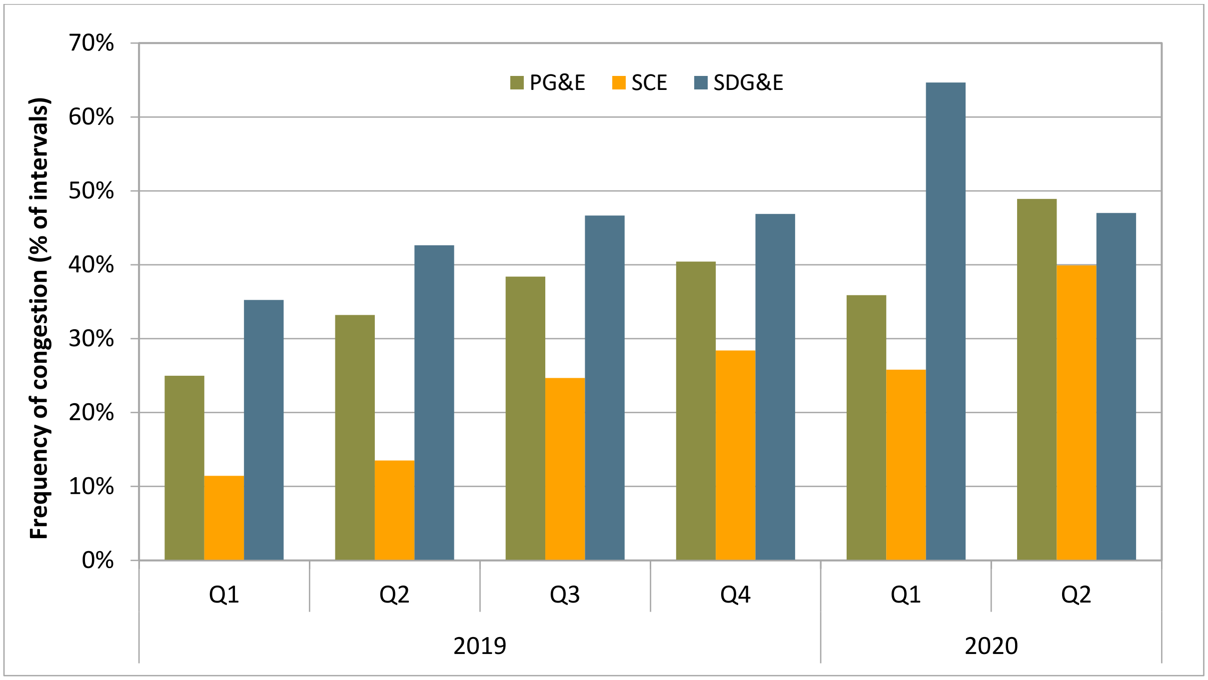
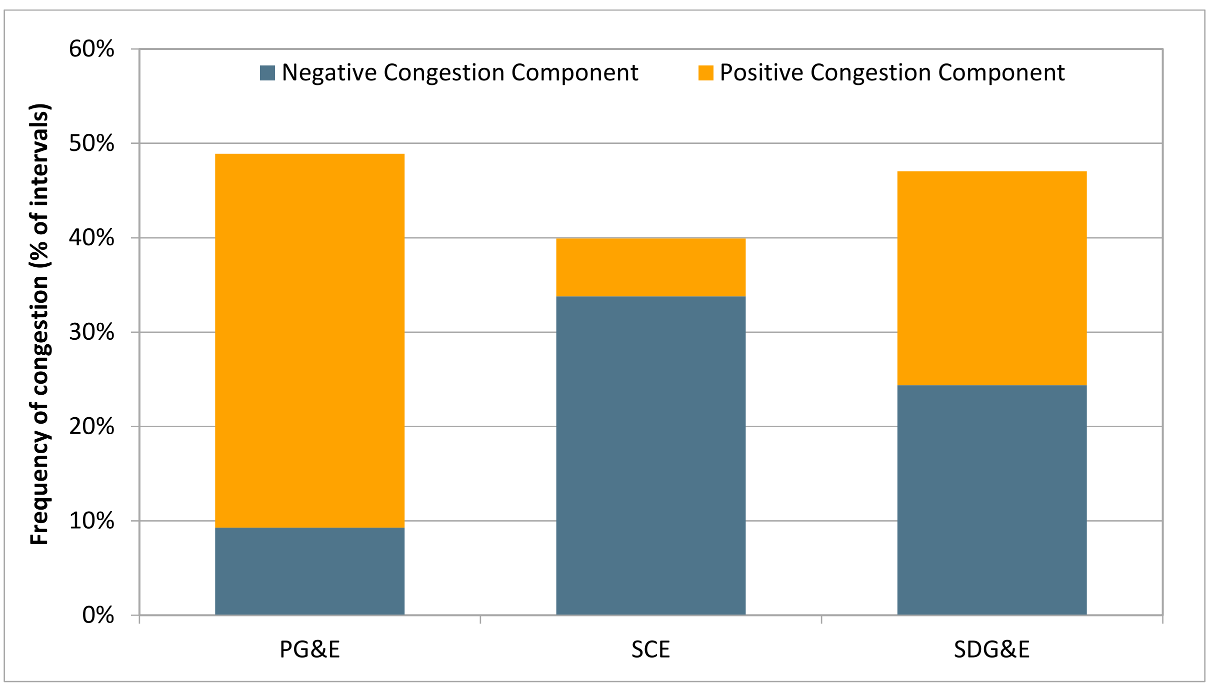


Figure 1.32 Percent of hours with congestion increasing versus decreasing day-ahead prices in the second quarter (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.3 breaks down the congestion impact on price separation in the second quarter by constraint.[30] Table 1.4 shows the impact of congestion from each constraint only during congested intervals, where the number of congested intervals is presented separately as frequency. The constraints with the greatest impact on price separation for the quarter were the Los Banos-Quinto 230 kV line, Moss Landing-Las Aguilas 230 kV line, and the Serrano 500/230 kV transformer.

Los Banos-Quinto 230 kV line

The Los Banos-Quinto 230 kV line (30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1) bound frequently in about 22 percent of hours. When binding, it increased prices in PG&E by about $2.68/MWh and decreased prices in SCE and SDG&E by $2.22/MWh and $2.02/MWh, respectively. Overall for the quarter, the constraint increased prices in PG&E by about $0.59/MWh (2.6 percent), while it decreased prices in SCE and SDG&E by $0.49/MWh (2.4 percent) and $0.44/MWh (2.1 percent), respectively. This constraint primarily bound due to outages on the Moss Landing 500 kV line.

Moss Landing-Las Aguilas 230 kV line

The Moss Landing-Las Aguilas 230 kV line (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1 _1) was the most frequently congested constraint in the quarter, binding in about 29 percent of hours. When binding, it increased PG&E prices by about $1.22/MWh and decreased both SCE and SDG&E prices by $0.99/MWh. Over the entire quarter, it increased PG&E prices by about $0.35/MWh (1.6 percent) and decreased SCE and SDG&E prices by $0.26/MWh (1.3 percent) and $0.24/MWh (1.1 percent), respectively. This line underwent repairs and maintenance during the second quarter and was further impacted by outages on the Tesla-Metcalf 500 kV line.

Serrano transformer 500/230 kV

Congestion on the Serrano 500/230 kV transformer (24138_SERRANO _500_24137_SERRANO _230_XF_2 _P) was relatively less frequent in the quarter, at about 4 percent of hours. When binding, the constraint increased SCE and SDG&E prices by about $1.14/MWh and $4.63/MWh, respectively, while it decreased prices in PG&E by about $2.37/MWh. Overall for the quarter, it decreased PG&E prices by about $0.09/MWh (0.4 percent) and increased prices in SCE and SDG&E by $0.04/MWh (0.2 percent) and $0.17/MWh (0.8 percent), respectively.

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

Table 1.3 Impact of congestion on overall day-ahead prices

Constraint Location	Constraint	PG&E		SCE		SDG&E	
		$ per MWh	Percent	$ per MWh	Percent	$ per MWh	Percent
PG&E	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.59	2.64%	-$0.49	-2.41%	-$0.44	-2.07%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.35	1.57%	-$0.26	-1.29%	-$0.24	-1.10%
	OMS 6196189 Moss Landing PP	$0.07	0.29%	-$0.06	-0.28%	-$0.06	-0.26%
	RM_TM21_NG	$0.02	0.07%	-$0.01	-0.03%	-$0.01	-0.05%
	30735_METCALF _230_30042_METCALF _500_XF_13	$0.02	0.07%	-$0.01	-0.07%	-$0.01	-0.06%
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	$0.01	0.06%	-$0.01	0.00%	-$0.01	0.00%
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$0.01	0.06%	-$0.01	-0.05%	-$0.01	-0.05%
	OMS 8628630 Moss Landing PP	$0.01	0.04%	-$0.01	-0.04%	-$0.01	-0.04%
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	$0.00	-0.02%	$0.00	0.02%	$0.00	0.00%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.01	-0.02%	$0.00	0.02%	$0.00	0.02%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-$0.02	-0.11%	$0.02	0.10%	$0.02	0.00%
	35122_NWARK EF_115_30630_NEWARK _230_XF_11	$0.00	0.00%	-$0.01	-0.02%	-$0.01	-0.02%
SCE	24091_MESA CAL_230_24076_LAGUBELL_230_BR_1 _1	-$0.04	0.00%	$0.02	0.00%	$0.02	0.08%
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.02	-0.09%	$0.02	0.00%	$0.03	0.12%
	OMS 8220439_D-SBLR_OOS_N1SV500	$0.01	0.04%	-$0.01	0.00%	$0.00	0.00%
	OMS 8095129_D-SBLR_OOS_N1SV500	$0.01	0.06%	-$0.01	0.00%	$0.00	-0.01%
	OMS 8220388_N2_DV2_N1SV500	$0.02	0.08%	-$0.02	-0.08%	$0.00	-0.01%
SDG&E	OMS 8447302 ML_BK80_NG	-$0.03	0.00%	$0.00	0.00%	$0.22	1.02%
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.09	-0.40%	$0.04	0.19%	$0.17	0.80%
	7820_TL 230S_OVERLOAD_NG	-$0.01	0.00%	$0.00	0.00%	$0.12	0.56%
	OMS 8573611 SUNCREST BK81_NG	$0.00	0.00%	$0.00	0.00%	$0.07	0.30%
	OMS 8420328_50004_OOS_NG	$0.00	-0.01%	$0.00	0.00%	$0.04	0.20%
	OMS 8523747_TL50003_NG	$0.00	0.00%	$0.00	0.00%	$0.04	0.19%
	OMS 8472480_TL50003_NG	$0.00	0.00%	$0.00	0.00%	$0.02	0.11%
	7820_TL23040_IV_SPS_NG	$0.00	0.00%	$0.00	0.00%	$0.01	0.07%
Other		$0.03	0.12%	$0.01	0.04%	$0.06	0.30%
Total		**$0.91**	**4.06%**	**-$0.78**	**-3.84%**	**$0.03**	**0.14%**

Table 1.4 Impact of congestion on day-ahead prices during congested hours[31]

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	OMS 6196189 Moss Landing PP	2.3%	$2.82	-$2.46	-$2.45
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	21.9%	$2.68	-$2.22	-$2.02
	30735_METCALF _230_30042_METCALF _500_XF_13	1.0%	$1.54	-$1.39	-$1.38
	OMS 8628630 Moss Landing PP	0.5%	$1.45	-$1.46	-$1.44
	RM_TM21_NG	1.3%	$1.26	-$0.87	-$1.00
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	28.8%	$1.22	-$0.99	-$0.99
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	2.4%	$0.55	-$0.44	-$0.41
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	2.4%	$0.55	-$0.44	-$0.41
	35122_NWARK EF_115_30630_NEWARK _230_XF_11	0.1%	$0.00	-$3.47	-$3.47
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	0.2%	-$1.88	$1.62	$1.55
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	0.2%	-$2.15	$1.73	$1.61
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	0.6%	-$3.92	$3.28	$3.06
SCE	24091_MESA CAL_230_24076_LAGUBELL_230_BR_1 _1	1.1%	-$3.23	$2.13	$2.12
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.2%	-$1.66	$1.71	$2.13
	OMS 8220439_D-SBLR_OOS_N1SV500	4.0%	$0.22	-$0.20	$0.05
	OMS 8095129_D-SBLR_OOS_N1SV500	5.5%	$0.23	-$0.23	-$0.34
	OMS 8220388_N2_DV2_N1SV500	5.1%	$0.35	-$0.35	-$0.16
SDG&E	OMS 8420328_50004_OOS_NG	0.4%	-$0.78	$0.00	$10.18
	OMS 8523747_TL50003_NG	0.5%	-$0.64	$0.00	$8.11
	OMS 8447302 ML_BK80_NG	3.7%	-$0.90	$0.00	$5.92
	OMS 8472480_TL50003_NG	0.5%	-$0.42	$0.00	$4.93
	OMS 8573611 SUNCREST BK81_NG	1.3%	-$0.30	$0.00	$4.86
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	3.7%	-$2.37	$1.14	$4.63
	7820_TL23040_IV_SPS_NG	0.4%	-$0.19	$0.00	$3.78
	7820_TL 230S_OVERLOAD_NG	8.1%	-$0.14	$0.00	$1.47

1.10.2 Congestion in the real-time market

Congestion frequency in the 15-minute market is typically lower than in the day-ahead market, but has higher price impacts on load area prices. The congestion pattern in this quarter reflects this overall trend.

Impact of internal congestion to overall 15-minute prices in each load area

Figure 1.33 shows the overall impact of internal flow-based constraint congestion on 15-minute prices in each load area for 2019 and 2020. Figure 1.34 shows the frequency of this congestion. Highlights for this quarter include:

- The overall net impact of internal flow-based constraint congestion on price separation in the second quarter of 2020 increased in most areas compared to the same quarter of 2019. Congestion resulted in a net increase to PG&E, SDG&E, and BANC prices and a net decrease to prices in other ISO and EIM areas.

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

- Congestion continued to impact prices in both the positive and negative direction over the quarter in each load area, often offsetting the impact of congestion over the quarter. The frequency of congestion was highest in PacifiCorp East (37 percent of total intervals in the 15-minute market), where congestion predominantly decreased prices.
- The primary constraints impacting price separation in the 15-minute market were the Los Banos-Quinto 230 kV line, the Round Mountain-Table Mountain nomogram, and the Round Mountain-Table Mountain 500 kV line.

Additional information regarding the impact of congestion from individual constraints and the cause of congestion on constraints that had the largest impact on price separation is provided below.

Figure 1.33 Overall impact of internal congestion on price separation in the 15-minute market

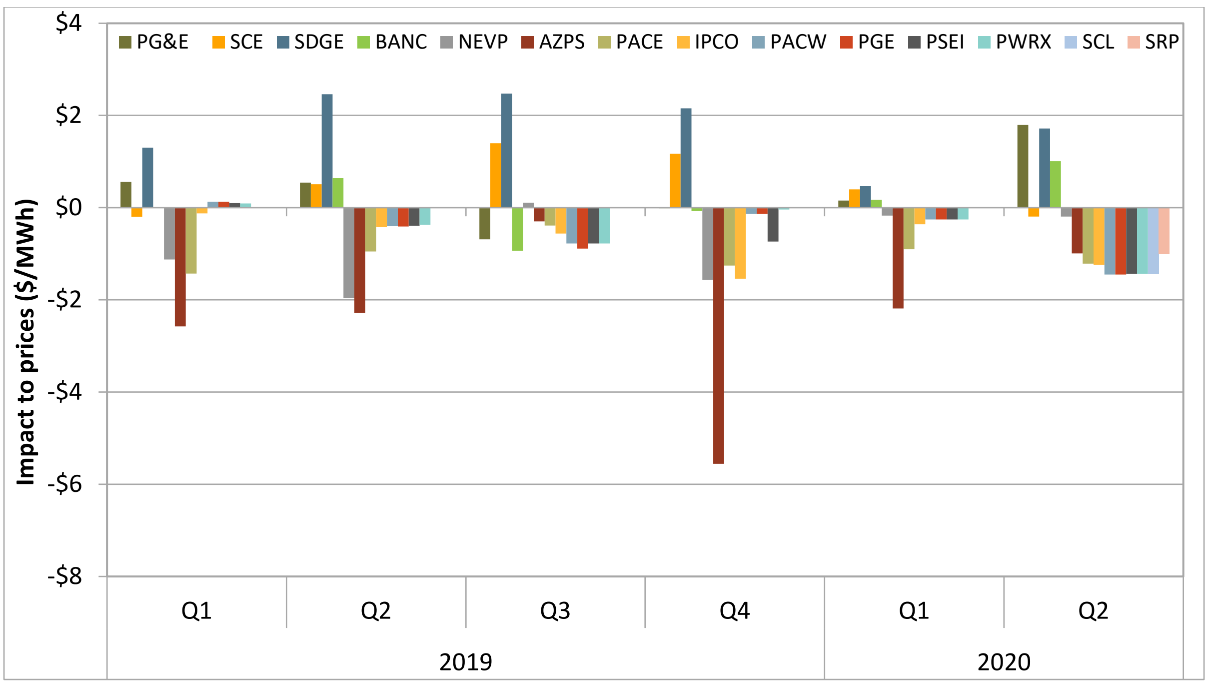
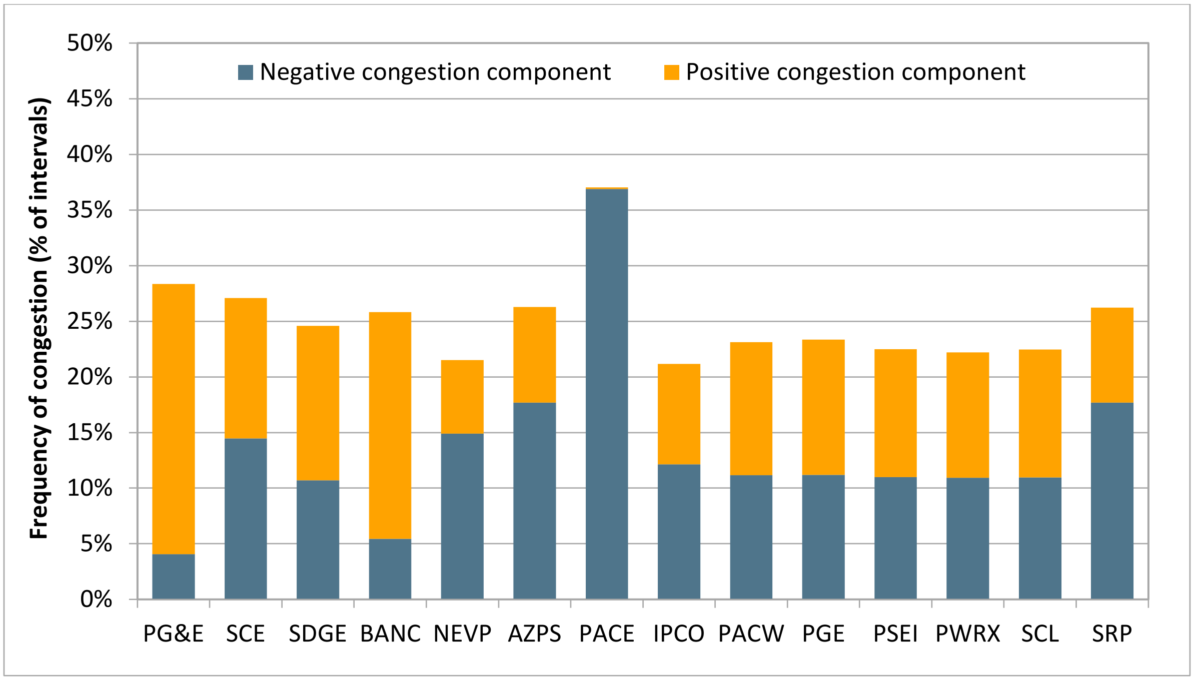


Figure 1.34 Percent of intervals with internal congestion increasing versus decreasing 15-minute prices in the second quarter (>$0.05/MWh)



Impact of internal congestion from individual constraints

Table 1.5 shows the overall impact (during all intervals) of internal congestion on average 15-minute prices in each load area. Table 1.6 shows the impact of internal congestion from each constraint only during congested intervals, where the number of congested intervals is presented separately as frequency. The color scales in the table below apply only to the individual constraints (excludes "other" in Table 1.5). The category labeled "other" includes the impact of power balance constraint (PBC) violations, which often has an impact on price separation. These topics are discussed in greater depth in Chapter 2. This section will focus on individual flow-based constraints.

The constraints that had the greatest impact on price separation in the 15-minute market were the Los Banos-Quinto 230 kV line, the Round Mountain-Table Mountain nomogram, and the Round Mountain-Table Mountain 500 kV line.

Los Banos-Quinto 230 kV line

The Los Banos-Quinto 230 kV line (30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1) bound frequently in the quarter during about 9 percent of intervals. When binding, it affected prices across most of the EIM, with the most increase in the BANC area price by $9.39/MWh and the most decrease in the SCE area price by $8.37/MWh. Overall for the quarter, the constraint increased prices in the BANC area by about $0.88/MWh and decreased prices in the SCE area by $0.79/MWh. This constraint primarily bound due to outages on the Moss Landing 500 kV line.

Round Mountain-Table Mountain nomogram

The Round Mountain-Table Mountain nomogram (RM_TM21_NG) bound infrequently during the quarter, in about 3 percent of intervals. When binding, it increased prices in PG&E by about $16.14/MWh, and decreased prices in PACW, PGE, PSEI, PWRX, and SCL by over $25/MWh. Over the entire quarter, it increased the former area's prices by about $0.55/MWh, and decreased the latter areas' prices by over $0.85/MWh.

Round Mountain-Table Mountain 500 kV line

The Round Mountain-Table Mountain 500 kV line (30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2) bound infrequently during the quarter, in about 3 percent of intervals. When binding, it increased prices in PG&E, BANC, SCE, and SDG&E by an average of $8/MWh and decreased prices in PACW, PGE, PSEI, PWRX, and SCL by over $18/MWh. Overall for the quarter, the constraint increased the former areas' prices by $0.30/MWh on average and decreased the latter areas' prices by over $0.60/MWh.

Table 1.5 Impact of congestion on overall 15-minute prices

Constraint Location	Constraint	PG&E	SCE	SDGE	BANC	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX	SCL	SRP
NEVP	CAL-DRM_2 120	-$0.06			-$0.10	$0.20									
	NTR-DRM_1 120				-$0.02	$0.04									
PACE	WYOMING_EXPORT							-$0.23							
PG&E	RM_TM21_NG	$0.55	$0.27	$0.24	$0.40	$0.00	$0.16	-$0.38	-$0.66	-$0.89	-$0.89	-$0.88	-$0.87	-$0.88	$0.16
	OMS 6196189 Moss Landing PP	$0.40	-$0.17	-$0.16		-$0.15	-$0.15	-$0.13	-$0.11	-$0.10	-$0.10	-$0.10	-$0.10	-$0.10	-$0.15
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.39	$0.24	$0.20	$0.25	$0.05	$0.15	-$0.26	-$0.46	-$0.64	-$0.64	-$0.62	-$0.62	-$0.62	$0.15
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.38	-$0.79	-$0.74	$0.88	-$0.38	-$0.65		$0.33	$0.60	$0.59	$0.57	$0.56	$0.57	-$0.65
	30640_TESLA C _230_30040_TESLA _500_XF_6	$0.21	-$0.07	-$0.07		-$0.07	-$0.06	-$0.06	-$0.07	-$0.07	-$0.07	-$0.07	-$0.07	-$0.07	-$0.06
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.21	-$0.07	-$0.03			$0.00								$0.00
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	$0.18	-$0.18	-$0.16	$0.17	-$0.09	-$0.14		$0.07	$0.12	$0.12	$0.12	$0.12	$0.12	-$0.14
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.03	-$0.04	-$0.03	$0.03	-$0.02	-$0.03		$0.00	$0.02	$0.02	$0.02	$0.02	$0.02	-$0.03
	30050_LOSBANOS_500_30055_GATES1 _500_BR_3 _1	$0.02	-$0.04	-$0.04	$0.04	-$0.02	-$0.04		$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	-$0.04
	30635_NWK DIST_230_30731_LS ESTRS_230_BR_1 _1	$0.02			-$0.01			$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	
	30440_TULUCAY _230_30460_VACA-DIX_230_BR_1 _1	$0.02													
	30630_NEWARK _230_30635_NWK DIST_230_BR_1 _1	$0.02			-$0.01			$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	
	37585_TRCY PMP_230_30625_TESLA D _230_BR_2 _1	$0.01	$0.00	$0.00	-$0.01		$0.00								$0.00
	OMS 8628630 Moss Landing PP	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00						$0.00
	30050_LOSBANOS_500_30055_GATES1 _500_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	$0.01	-$0.01
	30529_BRDSLDNG_230_30525_C.COSTA _230_BR_1 _1	$0.00								$0.00	$0.00	$0.00	$0.00	$0.00	
	30015_TABLE MT_500_30030_VACA-DIX_500_BR_1 _3	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30797_LASAGUIL_230_30790_PANOCHE _230_BR_1 _1	$0.00	-$0.01	-$0.01			$0.00								$0.00
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	$0.00			-$0.02					$0.00	$0.00	$0.00		$0.00	
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-$0.01	$0.01	$0.01	-$0.01	$0.01	$0.01	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.01
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.02	$0.02	$0.02	-$0.02	$0.01	$0.02		-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	$0.02
	SUMMIT2-DRUM	-$0.04			-$0.07	$0.14									
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	-$0.39	$0.36	$0.36	-$0.37	$0.21	$0.30	$0.00	-$0.17	-$0.29	-$0.28	-$0.28	-$0.27	-$0.28	$0.29
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1		$0.00	$0.00	$0.01		$0.00			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1				-$0.03	$0.05									
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1				$0.03	-$0.09									
	SUMMIT1-DRUM				-$0.01	$0.02									
SCE	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1 _1	-$0.24	$0.24	$0.22	-$0.23	$0.12	$0.20		-$0.09	-$0.17	-$0.17	-$0.16	-$0.16	-$0.16	$0.20
	24091_MESA CAL_230_24076_LAGUBELL_230_BR_1 _1	$0.00	$0.01	$0.01	$0.00			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
	OMS 8095129_D-SBLR_OOS_N1SV500	$0.00	$0.00		$0.00	$0.00	-$0.01			$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01
	OMS 8220388_N2_DV2_N1SV500	$0.07	-$0.07	$0.00	$0.07	$0.00	-$0.18			$0.04	$0.04	$0.03	$0.03	$0.03	-$0.18
	22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1			-$0.02											
SDG&E	OMS 8573611 SUNCREST BK81_NG			$1.18		-$0.06	-$0.36	-$0.06							-$0.36
	7820_TL 230S_OVERLOAD_NG		$0.02	$0.26		-$0.02	-$0.05	-$0.02	-$0.01						-$0.06
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.04	$0.06	$0.17	-$0.04	-$0.03	$0.00	-$0.03	-$0.03	-$0.04	-$0.04	-$0.03	-$0.03	-$0.03	$0.00
	OMS 8447302 ML_BK80_NG		$0.01	$0.16		-$0.01	-$0.05	-$0.01							-$0.05
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P		$0.01	$0.07		-$0.01	-$0.02	-$0.01							-$0.02
	22464_MIGUEL _230_22468_MIGUEL _500_XF_81		$0.00	$0.05			-$0.01								-$0.01
	OMS_8357522_TL23055_NG		$0.00	$0.03		$0.00	-$0.01	$0.00							-$0.01
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P			$0.02			-$0.01								-$0.01
	OMS_8573631_SUNCREST BK81_NG		$0.00	$0.02		$0.00	-$0.01	$0.00							-$0.01
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1			-$0.02											
	Other	$0.07	-$0.01	-$0.02	$0.06	-$0.09	-$0.03	-$0.02	-$0.03	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.03
	Total	**$1.79**	**-$0.19**	**$1.71**	**$1.01**	**-$0.19**	**-$0.99**	**-$1.21**	**-$1.24**	**-$1.45**	**-$1.45**	**-$1.44**	**-$1.43**	**-$1.44**	**-$1.00**
	Transfers				-$0.12	$6.88	$1.13	$0.18	$0.23	-$2.42	-$3.08	-$2.53	-$2.83	-$2.79	$1.26
	Grand Total	**$1.79**	**-$0.19**	**$1.71**	**$0.89**	**$6.69**	**$0.14**	**-$1.03**	**-$1.01**	**-$3.87**	**-$4.53**	**-$3.97**	**-$4.26**	**-$4.23**	**$0.26**

Table 1.6 Impact of internal congestion on 15-minute prices during congested intervals[32]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDGE	BANC	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX	SCL	SRP
NEVP	CAL-DRM_2 120	0.4%	-$20.39			-$24.06	$47.17									
	SUMMIT2-DRUM	0.4%	-$20.82			-$17.03	$32.49									
	NTR-DRM_1 120	0.5%				-$8.78	$8.47									
PACE	WYOMING_EXPORT	33.4%														
PG&E	OMS 6196189 Moss Landing PP	0.5%	$83.64	-$34.51	-$34.22		-$30.72	-$32.19	-$26.30	-$23.26	-$21.15	-$21.22	-$21.37	-$21.42	-$21.37	-$32.18
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.6%	$27.85	-$28.74	-$24.79	$26.17	-$13.79	-$21.97		$10.73	$19.44	$19.38	$18.80	$18.52	$18.78	-$21.96
	RM_TM21_NG	3.4%	$16.14	$8.03	$6.88	$11.57	$1.42	$4.73	-$10.98	-$19.25	-$26.01	-$26.08	-$25.65	-$25.43	-$25.63	$4.66
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	3.4%	$11.23	$6.93	$5.97	$7.32	$1.66	$4.45	-$7.59	-$13.52	-$18.59	-$18.51	-$18.18	-$18.02	-$18.16	$4.38
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	0.3%	$7.62	-$10.46	-$9.88	$9.91	-$5.51	-$8.68		$4.80	$6.98	$6.93	$6.66	$6.56	$6.65	-$8.51
	30050_LOSBANOS_500_30055_GATES1 _500_BR_3 _1	0.4%	$6.80	-$12.16	-$11.52	$10.12	-$5.73	-$10.38		$4.95	$8.57	$8.54	$8.32	$8.20	$8.31	-$10.35
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	9.4%	$4.09	-$8.37	-$7.84	$9.39	-$4.02	-$6.88		$3.54	$6.34	$6.28	$6.10	$6.00	$6.09	-$6.86
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	9.3%	$2.21	-$1.89	-$2.42			-$0.69								-$0.69
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	0.4%	$1.26	-$2.12	-$1.99	$1.85	-$1.04	-$1.76	$0.14	$0.90	$1.62	$1.61	$1.56	$1.54	$1.56	-$1.76
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	0.4%	$1.09			-$5.65					-$1.81	-$1.75	-$2.37		-$3.25	
	30797_LASAGUIL_230_30790_PANOCHE _230_BR_1 _1	1.9%	$0.15	-$0.34	-$0.32			-$0.40								-$0.41
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	2.4%	-$16.14	$15.09	$14.74	-$15.20	$8.74	$12.27	-$0.44	-$6.86	-$11.89	-$11.80	-$11.47	-$11.29	-$11.44	$12.19
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	0.7%				-$4.38	$6.72									
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1	1.2%				$4.81	-$8.13									
SCE	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1 _1	0.8%	-$31.65	$30.66	$29.06	-$29.74	$16.01	$25.61		-$12.04	-$22.03	-$21.92	-$21.26	-$20.93	-$21.22	$25.54
	OMS 8095129_D-SBLR_OOS_N1SV500	0.4%	$0.47	-$0.48		$0.44	-$0.33	-$1.26			$0.32	$0.32	$0.29	$0.29	$0.29	-$1.29
	OMS 8220388_N2_DV2_N1SV500	4.4%	$1.67	-$1.47	-$0.56	$1.55	-$1.33	-$4.02			$0.94	$0.93	$0.94	$0.97	$0.94	-$4.12
SDG&E	OMS 8573611 SUNCREST BK81_NG	1.4%			$84.07		-$4.17	-$25.85	-$4.16							-$25.81
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.4%	-$9.64	$15.04	$45.92	-$9.53	-$9.19	-$6.46	-$8.38	-$8.92	-$9.28	-$9.28	-$9.23	-$9.23	-$9.23	-$6.46
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	0.4%		$2.50	$20.15		-$2.29	-$6.53	-$2.29							-$6.16
	OMS 8447302 ML_BK80_NG	1.0%		$1.59	$16.37		-$1.56	-$5.27	-$1.49							-$5.30
	7820_TL 230S_OVERLOAD_NG	1.7%		$1.17	$15.57		-$1.12	-$3.31	-$1.23	-$0.83						-$3.59
	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	0.4%		$1.54	$11.15			-$3.28								-$3.31

Impact of internal congestion to overall 5-minute prices in each load area

Figure 1.35 shows the overall impact of internal flow-based constraint congestion on 5-minute prices in each load area for 2019 and 2020.

Figure 1.36 shows the frequency of intervals with internal congestion increasing versus decreasing prices. Highlights for this quarter include:

- The overall net impact of internal flow-based constraint congestion on price separation was marginally higher in the second quarter of 2020 compared to the same quarter of 2019. Congestion resulted in a net increase to 5-minute prices in PG&E, SCE, SDG&E, BANC, and NEVP and a net decrease to 5-minute prices in other EIM areas.
- Congestion continued to impact prices in both the positive and negative direction over the quarter in each load area, often offsetting the impact of congestion over the quarter. The frequency of congestion was highest in PacifiCorp East (32 percent of total intervals), where congestion predominantly decreased prices.

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

Figure 1.35 Overall impact of internal congestion on price separation in the 5-minute market

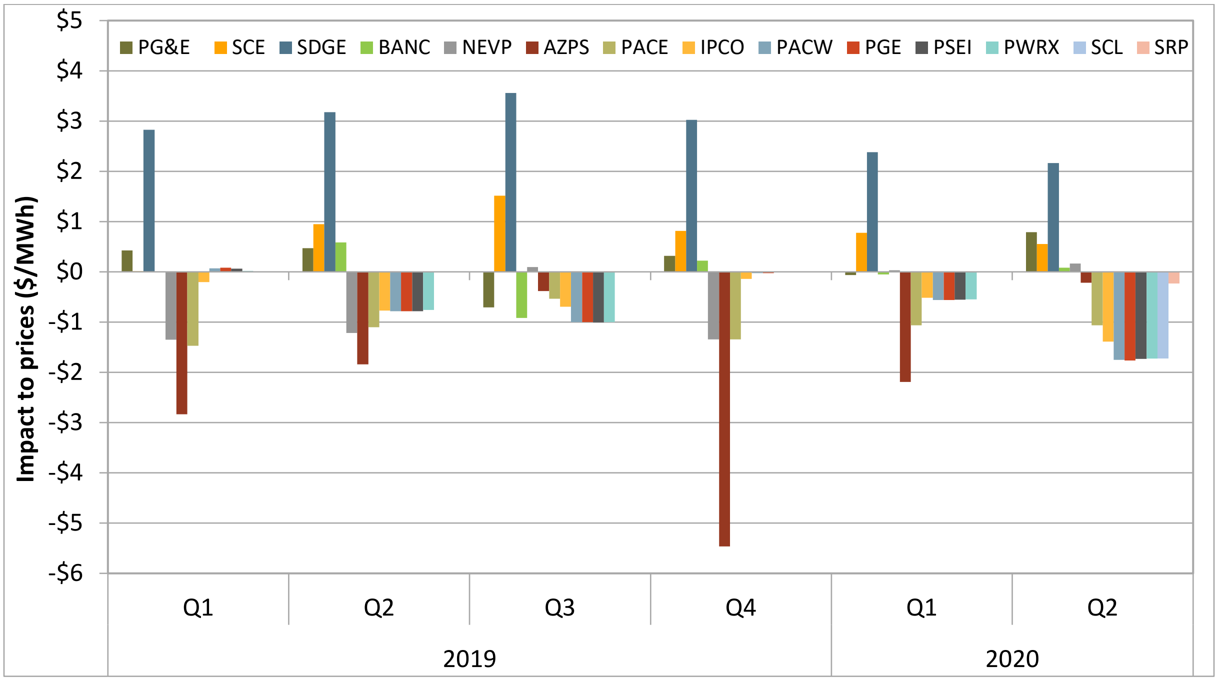
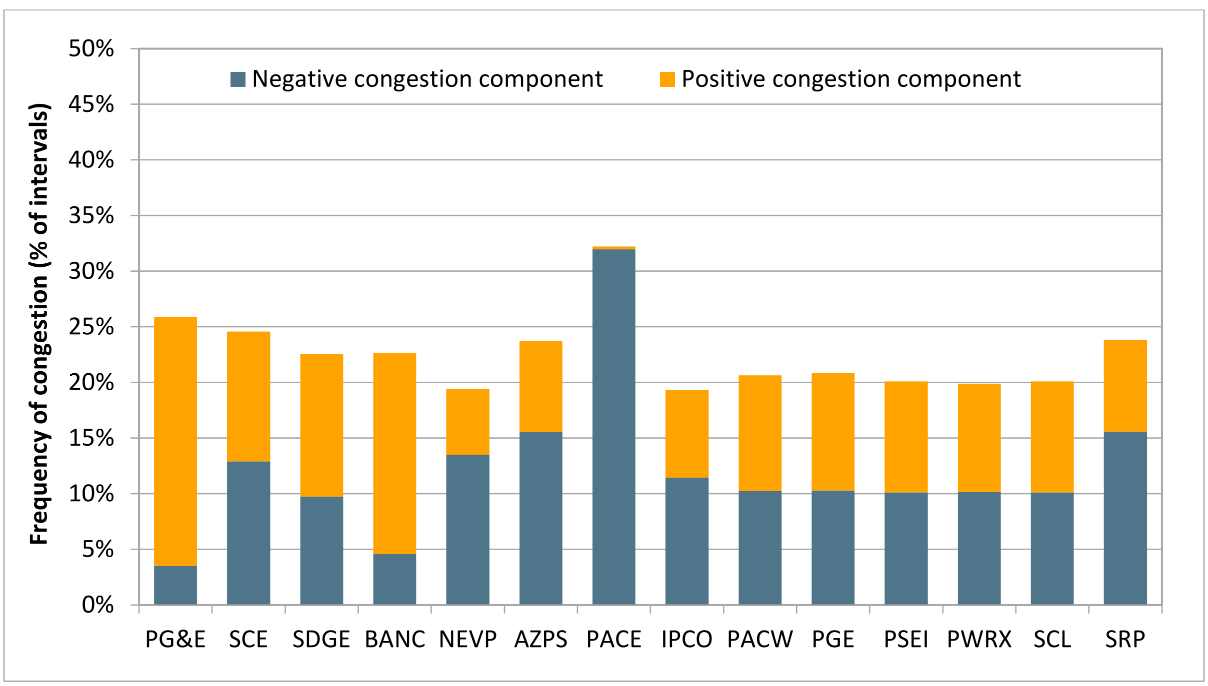


Figure 1.36 Percent of intervals with internal congestion increasing versus decreasing 5-minute prices in the second quarter (>$0.05/MWh)



Impact of congestion from transfer constraints

This section focuses on price impacts from 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 the price impact of flow-based (shown in Figure 1.33 and Table 1.5) and schedule-based constraints (listed in Table 1.7). Transfer constraint congestion typically has the largest impact on prices. Therefore, it is isolated here to better show its effects on EIM load areas. Table 1.7 shows the congestion frequency and average price impact from transfer constraint congestion in the 15-minute and 5-minute markets during the second quarter of 2020. As shown below, 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. The largest price impact was in the NV Energy area, with an average increase of about $7/MWh in both the 15-minute and 5-minute markets.

Table 1.7 Quarterly average price impact and congestion frequency on EIM transfer constraints (Q2 2020)

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	1%	-$0.12	1%	-$0.20
NV Energy	6%	$6.88	5%	$6.69
Arizona Public Service	7%	$1.13	5%	$2.07
PacifiCorp East	11%	$0.18	7%	-$0.01
Idaho Power	11%	$0.23	8%	$0.18
Salt River Project	17%	$1.26	16%	$1.36
PacifiCorp West	41%	-$2.42	32%	-$3.45
Portland General Electric	43%	-$3.08	35%	-$3.82
Seattle City Light	43%	-$2.79	36%	-$4.09
Puget Sound Energy	43%	-$2.53	36%	-$3.58
Powerex	45%	-$2.83	49%	-$4.16

Transfer congestion in the 15-minute market

Transfer constraint congestion in the 15-minute market occurred with similar frequencies and average price impacts across the balancing areas in the Pacific Northwest. Figure 1.37 shows the average impact to prices in the 15-minute market by quarter for 2019 and 2020. Figure 1.38 shows the frequency of congestion on transfer constraints by quarter for 2019 and 2020.

There was an overall decrease in the impact on average prices from transfer constraint congestion in the second quarter of 2020, compared to the same quarter in 2019. NEVP is the outlier in this observation, as the impact to its prices increased sharply compared to the same quarter in 2019. Furthermore, NEVP had the highest average price impact, where transfer constraint congestion increased prices by $6.88/MWh on average.

Transfer constraint congestion frequency in the second quarter of 2020 was similar to that of the same quarter of 2019, but with more similar high frequencies across the Pacific Northwest. PacifiCorp West had an increase in congestion from 11 percent in the second quarter of 2019 to 41 percent in the second quarter of 2020.

Figure 1.37 Transfer constraint congestion average impact on prices in the 15-minute market

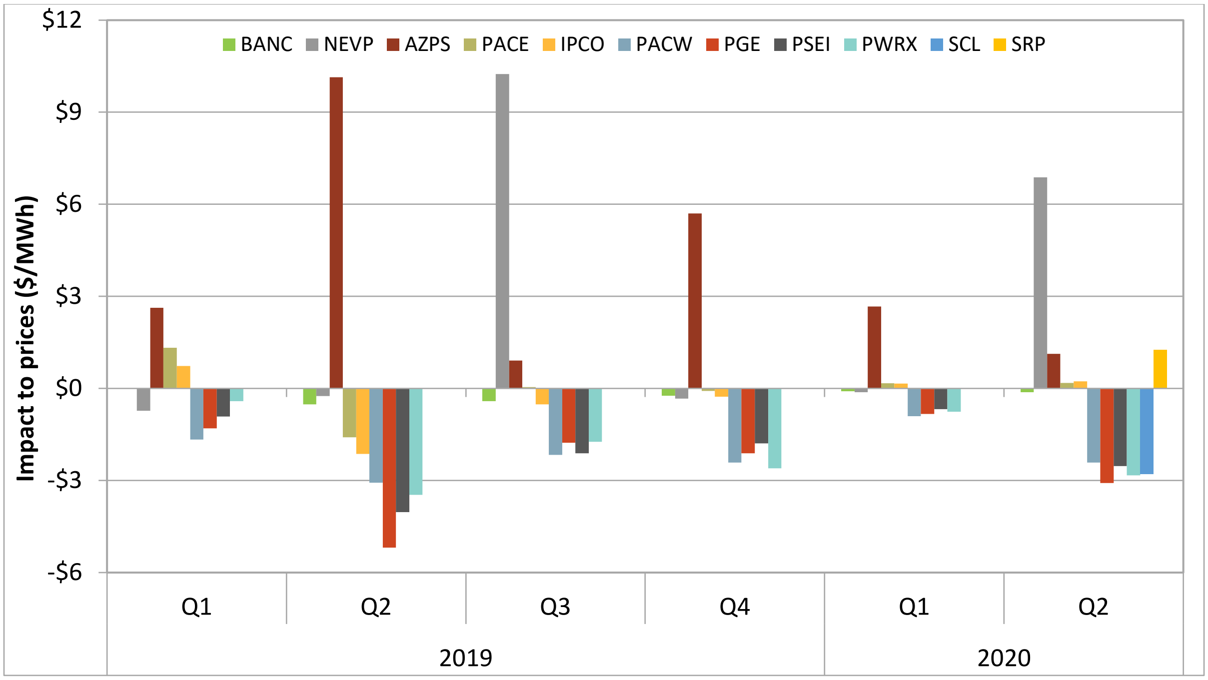
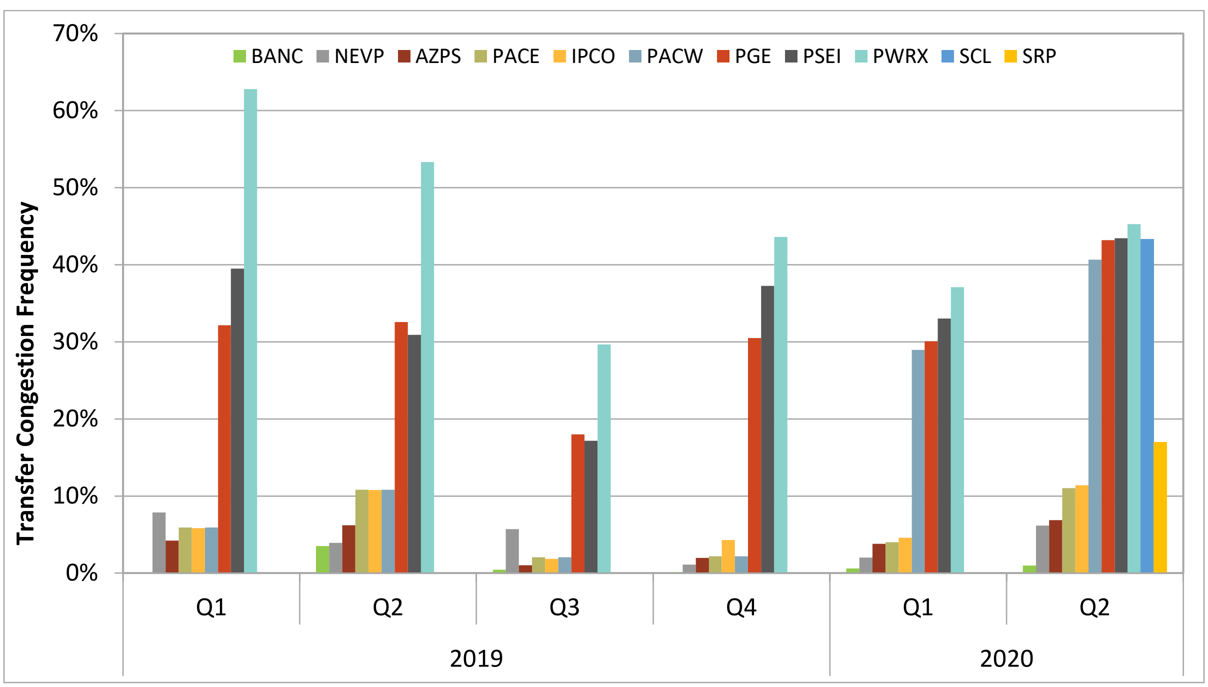


Figure 1.38 Transfer constraint congestion frequency in the 15-minute market



Transfer congestion in the 5-minute market

Similar to the 15-minute market, transfer constraint congestion in the 5-minute market occurred with similar frequencies and average price impacts across the balancing areas in the Pacific Northwest. Figure 1.39 shows the average impact on price in the 5-minute market by quarter for 2019 and 2020. Figure 1.40 shows the frequency of congestion on transfer constraints in the 5-minute market by quarter for 2019 and 2020.

The impact to prices in the second quarter of 2020 was lower than the same quarter of 2019. Powerex consistently has the highest frequency of transfer constraint congestion. NEVP experienced the largest impact on prices in the 5-minute market for the second quarter of 2020, with an average increase by $6.69/MWh.

Overall, the frequency of transfer constraint congestion was higher in the second quarter of 2020 compared to the same quarter in 2019. Areas that had high frequencies of transfer constraint congestion in the second quarter of 2020 include PacifiCorp West, Portland General Electric, Puget Sound Energy, Powerex, and Seattle City Light. In each of these areas, the quarterly congestion frequency was above 30 percent. Other than these five areas, the congestion frequency was comparatively low.

Figure 1.39 Transfer constraint congestion average impact on prices in the 5-minute market

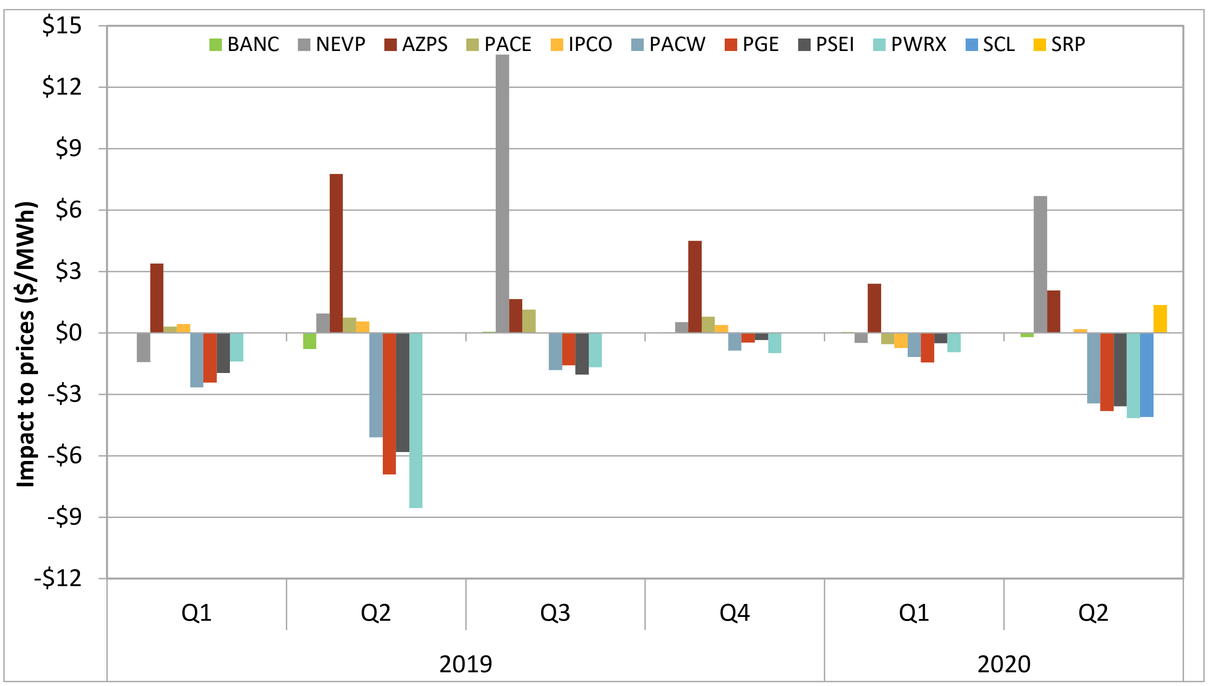
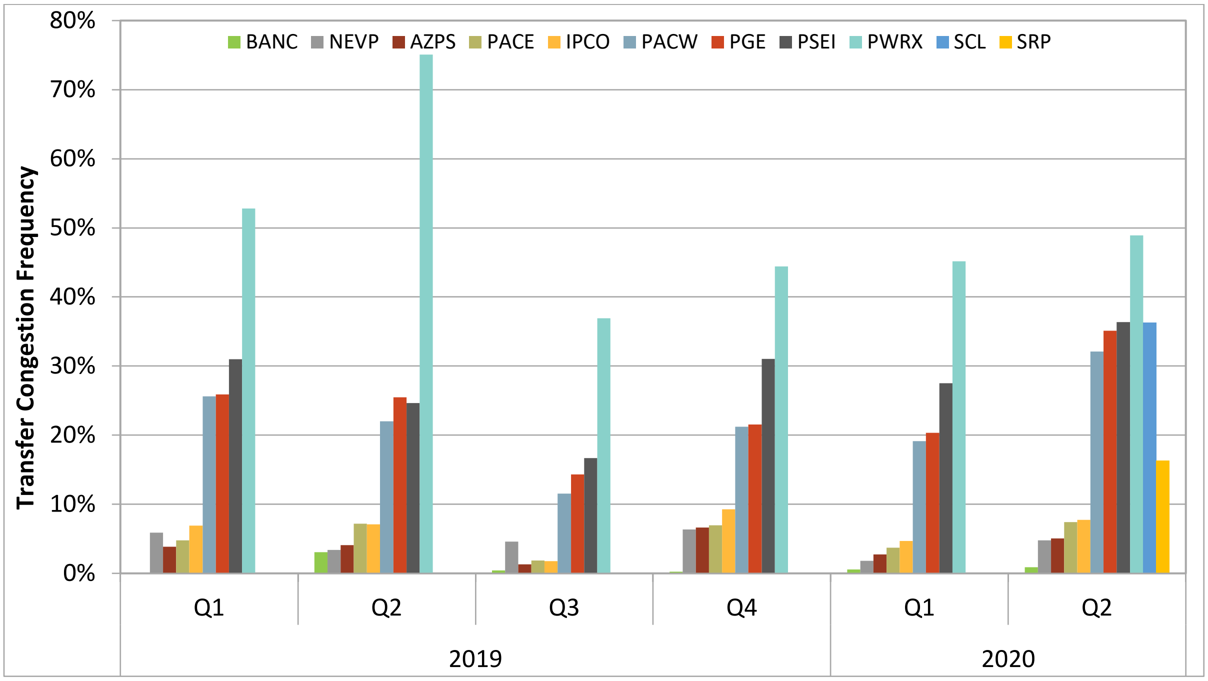


Figure 1.40 Transfer constraint congestion frequency in the 5-minute market



1.10.3 Congestion on interties

In the second quarter of 2020, both frequency and import congestion charges increased significantly on major interties such as PACI/Malin 500 and NOB relative to the same quarter in 2019. Figure 1.41 shows total import congestion charges in the day-ahead market for 2019 and 2020. Figure 1.42 shows the frequency of congestion on five major interties. Table 1.8 provides a detailed summary of this data over a broader set of interties.

The total import congestion charges reported are the products of the shadow prices times the binding limits for the intertie constraints. 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.

The charts and table highlight the following:

- Total import congestion charges for the second quarter of 2020 increased significantly to about $37 million compared to $23 million in the same quarter of 2019. This is mainly driven by an increase in congestion on PACI/Malin 500 and NOB interties.
- The frequency of congestion in the second quarter increased significantly on PACI/Malin 500, NOB, and COTPISO, while remaining infrequent on Palo Verde.
- The frequency of congestion and magnitude of congestion charges is typically highest on PACI/Malin 500, NOB, Palo Verde, and the IPP Utah interties. The second quarter followed this

trend. Congestion on other interties continues to remain relatively low relative to these top constraints.

Figure 1.41 Day-ahead import congestion charges on major interties

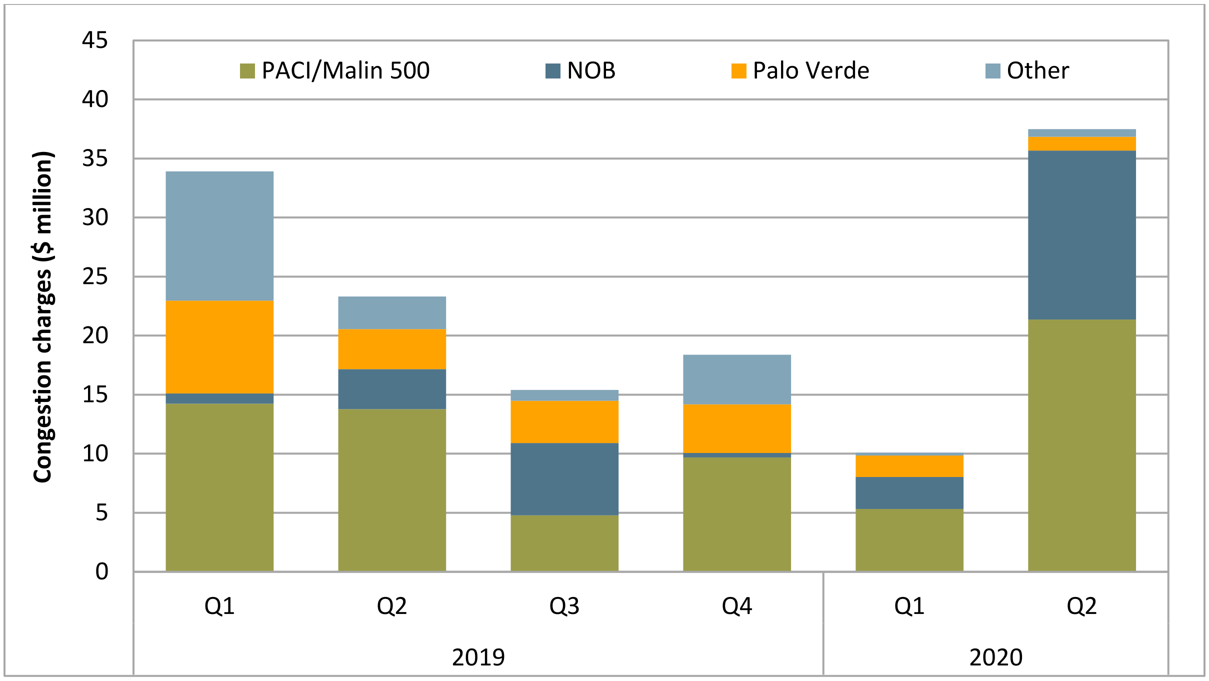


Figure 1.42 Frequency of import congestion on major interties in the day-ahead market

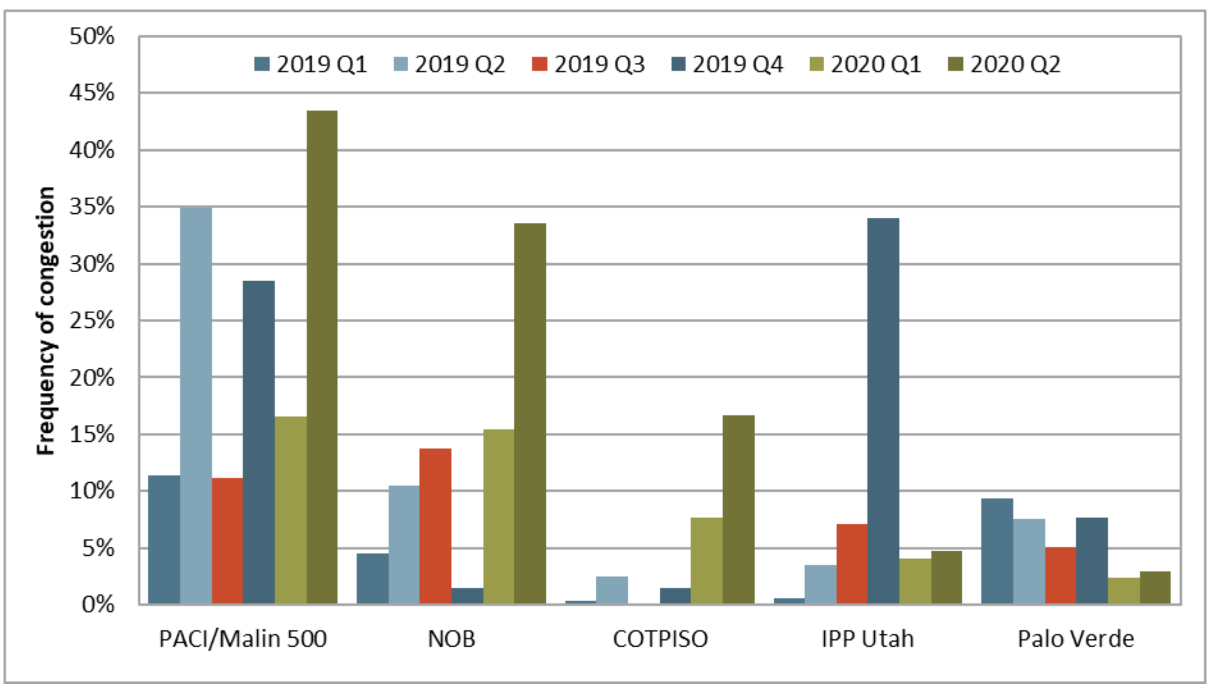


Table 1.8 Summary of import congestion in day-ahead market (2019-2020)

Area	Intertie	Frequency of import congestion						Import congestion charges ($ thousand)					
		2019				2020		2019				2020	
		Q1	Q2	Q3	Q4	Q1	Q2	Q1	Q2	Q3	Q4	Q1	Q2
Northwest	PACI/Malin 500	11%	35%	11%	29%	17%	44%	$14,246	$13,773	$4,787	$9,681	$5,318	$21,358
	NOB	5%	11%	14%	2%	15%	34%	$858	$3,380	$6,128	$382	$2,715	$14,317
	COTPISO	0%	3%		2%	8%	17%	$4	$20		$21	$85	$258
	Summit			1%		1%				$26		$6	
Southwest	Palo Verde	9%	8%	5%	8%	2%	3%	$7,864	$3,409	$3,579	$4,128	$1,827	$1,174
	IPP Utah	1%	4%	7%	34%	4%	5%	$13	$99	$186	$2,528	$136	$136
	Mead	1%		0%	2%		1%	$306		$238	$989		$133
	IPP Adelanto	44%	1%		0%		0%	$10,028	$120		$98		$96
	Marble		1%				1%		$18				$18

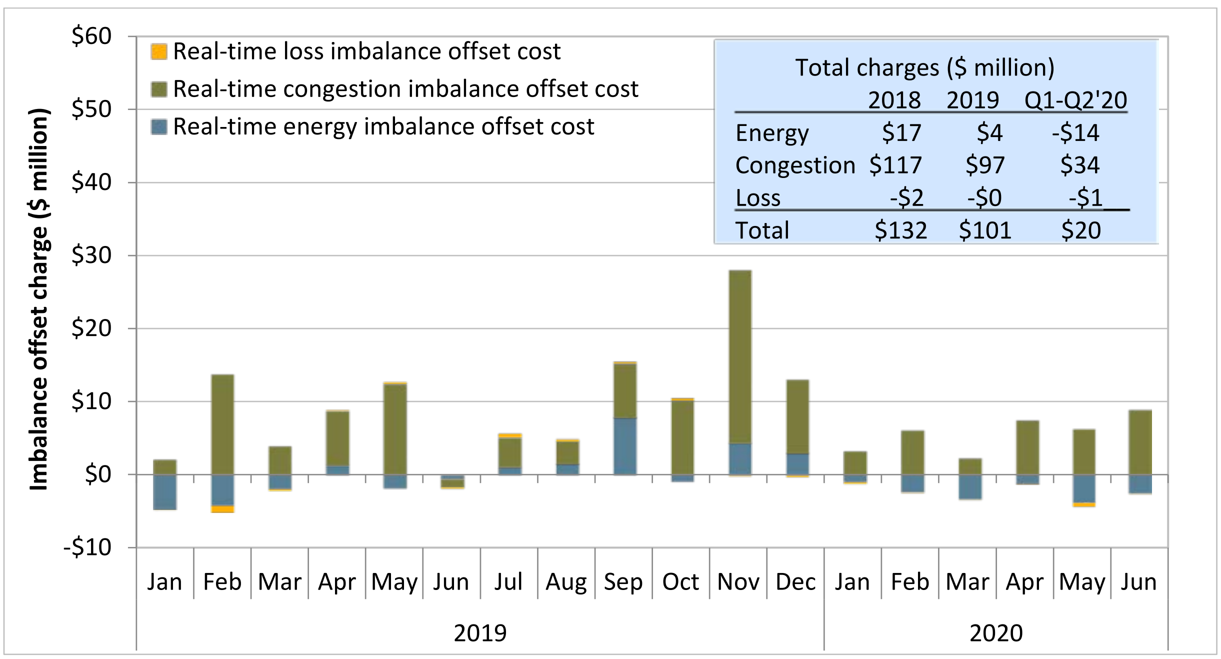
1.11 Real-time imbalance offset costs

Second quarter real-time offset costs were about $15 million, up from $5 million in the first quarter of 2020. Real-time imbalance offset costs were comprised of about $23 million in congestion deficits, about $7 million in energy surpluses, and $1 million in loss offset surpluses.

The real-time imbalance offset charge consists of three components corresponding to the main components of real-time settlement prices: energy, congestion and loss.[33] Any revenue imbalance from the energy components of real-time settlement prices is collected through the real-time imbalance energy offset charge (RTIEO). Revenue imbalance from the congestion component is recovered through the real-time congestion imbalance offset charge (RTCIO), and revenue imbalance from the loss component is collected through the real-time loss imbalance offset charge.

The real-time imbalance offset cost is the difference between the total money paid out by the ISO and the total money collected by the ISO for energy settled in the real-time energy markets—the 15-minute market and the 5-minute market. Within the ISO system, the charge is allocated as an uplift to measured demand (i.e., physical load plus exports).

Figure 1.43 Real-time imbalance offset costs



Total charges ($ million)	2018	2019	Q1-Q2'20
Energy	$17	$4	-$14
Congestion	$117	$97	$34
Loss	-$2	-$0	-$1
Total	$132	$101	$20

33 The greenhouse gas (GHG) price component rent is not settled through the real-time offset accounts but is used to pay schedules backing Western EIM transfers for taking on greenhouse gas compliance obligations.

1.12 Congestion revenue rights

Background

Congestion revenue rights are paid (or charged), for each megawatt held, based on the congestion between the sink and source nodes defining the right. These rights can have monthly or seasonal (quarterly) terms, and can include on-peak or off-peak hourly prices. Congestion revenue rights are allocated to entities serving load. Congestion revenue rights can also be procured in monthly and seasonal auctions.

In the ISO, most transmission is paid for by ratepayers of the state's investor-owned utilities, and other load serving entities, through the transmission access charge (TAC).[34] The ISO charges utility distribution companies the transmission access charge to reimburse the entity that builds each transmission line for the costs incurred. As the owners of transmission or the entities paying for the cost of building and maintaining transmission, the ratepayers of utility distribution companies should collect the congestion revenues associated with transmission capacity in the day-ahead market.

When auction revenues are less than payments to other entities purchasing congestion revenue rights at auction, the difference between auction revenues and congestion payments represents a loss to ratepayers. The losses cause ratepayers, who ultimately pay for the transmission, to receive less than the full value of their day-ahead transmission rights.

In the eleven years since the start of the congestion revenue rights auction, revenues from rights sold in the auction have consistently been well below the congestion revenues paid to entities purchasing these rights. Through 2019, transmission ratepayers have lost about $890 million in congestion revenues paid in excess of revenues received from the auction. This represents about 51 cents in auction revenues for every dollar paid to congestion revenue rights holders. Most of these profits to entities purchasing congestion rights in the auction are received by financial entities that do not sell power or serve load in the ISO.[35]

Congestion revenue rights auction modifications

In 2016, DMM recommended the ISO modify or eliminate the congestion revenue rights auction to reduce the losses to transmission ratepayers from rights sold in the auction. Starting in the 2019 auctions, the ISO implemented several significant changes to the auction design to reduce the systematic losses from rights sold in the auction.[36] [37]

---

34 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.

35 A more detailed discussion of congestion revenue rights is provided in DMM's *2018 Annual Report on Market Issues and Performance* (pp.197-205). http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

36 See *FERC Order on Tariff Amendment - Congestion Revenue Rights Auction Efficiency Track 1A,* April 11, 2018*:* http://www.caiso.com/Documents/Apr11_2018_TariffAmendment-CRRAuctionEfficiencyTrack1A_ER18-1344.pdf

37 See *FERC Order on Tariff Amendment - Congestion Revenue Rights Auction Efficiency Track 1B,* November 9, 2018*:* http://www.caiso.com/Documents/Nov9-2018-OrderAcceptingTariffRevisions-CRRTrack1BModification-ER19-26.pdf

Congestion revenue right auction returns

Non-load-serving entity congestion revenue right auction profits are calculated by summing revenue paid out to these congestion revenue rights and then subtracting the auction price paid. While this represents a profit to entities purchasing rights in the auction, this represents a loss to transmission ratepayers.

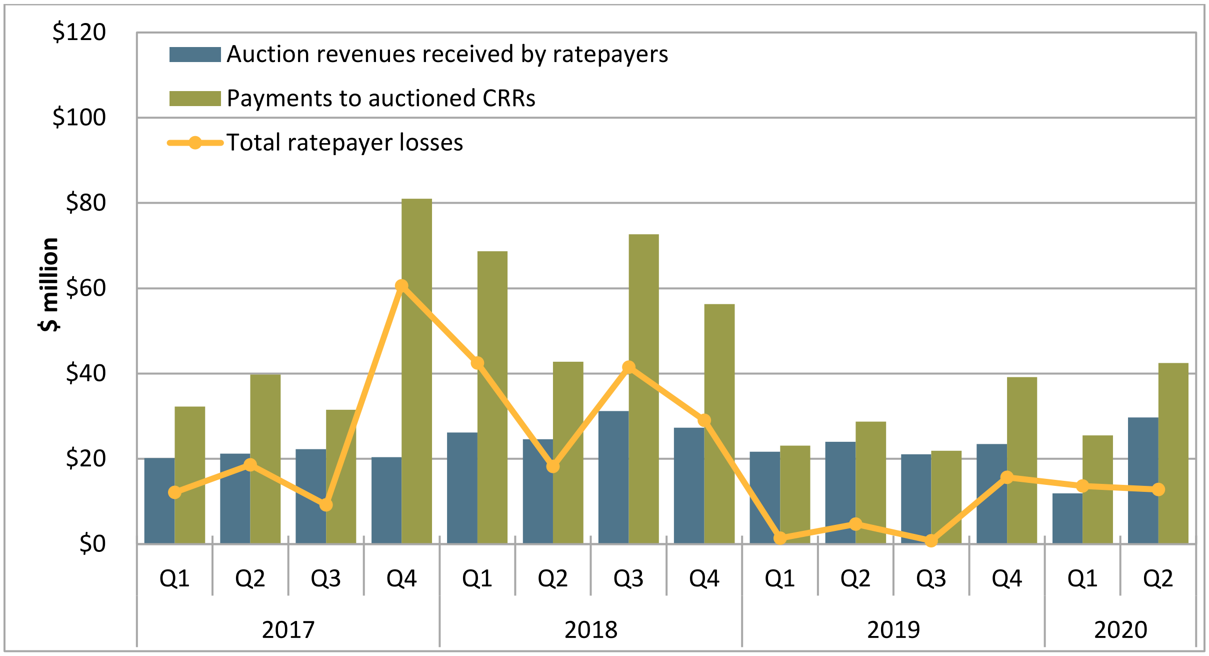
As shown in Figure 1.44, transmission ratepayers lost about $12.8 million during the second quarter of 2020 as payments to auctioned congestion revenue rights holders exceeded auction revenues. This is above the $4.7 million loss in the second quarter of 2019, but below average losses of $17.5 million in the second quarters of the prior three years (2016 through 2018). Auction revenues were 70 percent of payments made to non-load-serving entities during the second quarter of 2020, down from 84 percent during the same quarter in 2019.

In the second quarter, financial entities (which do not schedule or trade physical power or serve load) had profits of approximately $3.2 million. This was a decrease from $4.8 million in profits during the second quarter of 2019. Marketers' profits were about $6.8 million, up from a $0.3 million loss during the second quarter of 2019. Generators profited about $2.9 million compared to a $0.2 million in the second quarter of 2019.

The $12.8 million in second quarter auction losses was about 14 percent of day-ahead congestion rent. This is up from 5 percent of rent in the second quarter of 2019 and 6 percent for all of 2019. However, the losses as a percent of day-ahead congestion rent were significantly below the average of 47 percent during the second quarters of the three years before the Track 1A and 1B changes (2016 through 2018) and below the 28 percent for all quarters from 2009 through 2018.

The impact of Track 1A changes which limit the types of congestion revenue rights that can be sold in the auction cannot be directly quantified. However, based on current settlement records, DMM estimates that changes in the settlement of congestion revenue rights made under Track 1B reduced payments to non-load-serving entities by about $8 million in the second quarter. The Track 1B effects on auction bidding behavior and reduced auction revenues is not known.

Figure 1.44 Auction revenues and payments to non-load-serving entities



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

1.13 Bid cost recovery

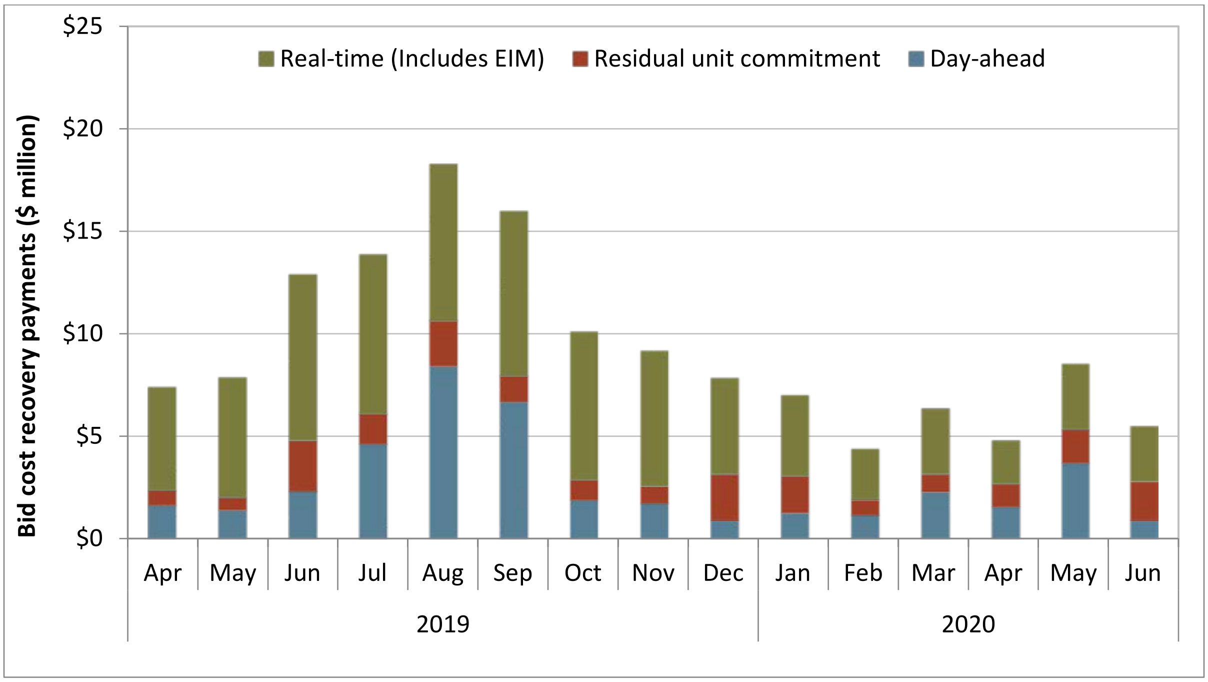
During the second quarter of 2020, estimated bid cost recovery payments for units in the ISO and energy imbalance market totaled about $19 million. This was $1 million higher than total bid cost recovery in the previous quarter and about $9 million lower than in the second quarter of 2019. Lower payments in 2020 can be attributed to lower gas prices at major trading hubs across the west.

Bid cost recovery attributed to the day-ahead market totaled about $6.2 million, about $1.4 million higher than the prior quarter. Bid cost recovery payments for residual unit commitment during the quarter totaled about $4.7 million, compared to $3.4 million in the prior quarter. Bid cost recovery attributed to the real-time market totaled about $8.1 million, or about $1.6 million lower than payments in the first quarter of 2020 and $11 million lower than payments in the second quarter of 2019.

Total bid cost recovery payments in the ISO were $0.36/MWh of load (1.4 percent), slightly increased relative to the previous quarter ($0.34/MWh of load or 1.1 percent) but decreased compared to $0.50/MWh of load (1.8 percent) in the second quarter of 2019.

During the first half of 2020, DMM estimates that about 58 percent of the ISO's total bid cost recovery payments, approximately $19.7 million, was allocated to gas resources that bid their commitment costs above 110 percent of their reference commitment costs. Commitment cost bids are capped at 125 percent of reference proxy costs. About 89 percent of these payments were for resources bidding at or near the 125 percent bid cap for proxy commitment costs.

Figure 1.45 Monthly bid cost recovery payments



1.14 Local market power mitigation enhancements

The ISO's automated local market power mitigation (LMPM) procedures were enhanced in numerous ways since 2012 to more accurately identify and mitigate resources with the ability to exercise local market power in the day-ahead and real-time markets. The ISO proposed the following enhancements to the local market power mitigation process for implementation in November 2019:[38]

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

On September 30, 2019, FERC rejected the proposal to limit net exports by an EIM balancing authority area.[39] Subsequently, the ISO filed on October 30, 2019, a request for rehearing at FERC regarding the net export limit proposal.[40] The rest of the enhancements were implemented on November 13, 2019. On June 18, 2020, FERC denied the request for rehearing but granted the motion for clarification.[41]

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.[42]

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

---

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

39 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

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

41 FERC order denying rehearing and granting clarification, ER19-2347-001, June 18, 2020: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14869989

42 The methodology has been updated to show incremental energy instead of units that have been subject to automated bid mitigation. Prior to the LMPM enhancements in November 2019, this metric also captures carry over mitigation (balance of hour mitigation) in 15-minute and 5-minute markets by comparing the market participant submitted bid at the top of each hour (in the 15-minute market) to the bid used in each interval of 15-minute and 5-minute market runs.

Mitigation in the ISO

In the day-ahead and real-time markets, rates of mitigation increased significantly relative to the second quarter of 2019. Incremental energy subject to mitigation has 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.

As shown in Figure 1.46, in the day-ahead market, an hourly average of about 1,377 MW was subject to mitigation but corresponding bids were not lowered compared to 916 MW in the same quarter of 2019. About 368 MW of incremental energy had bids lowered due to mitigation compared to 210 MW in 2019. As a result, there was on average about 14 MW increase in dispatch, compared to 8 MW in 2019.

Figure 1.47 and Figure 1.48 show the same metrics but for the ISO's 15-minute and 5-minute markets on a monthly level. As shown in the figures, the average incremental energy that is subject to mitigation and either had bids lowered or not due to mitigation in the ISO is consistently higher in the 5-minute than in the 15-minute market. The frequency of mitigation in both 15-minute and 5-minute markets increased significantly in the second quarter relative to the same quarter in 2019.

Figure 1.46 Average incremental energy mitigated in day-ahead market

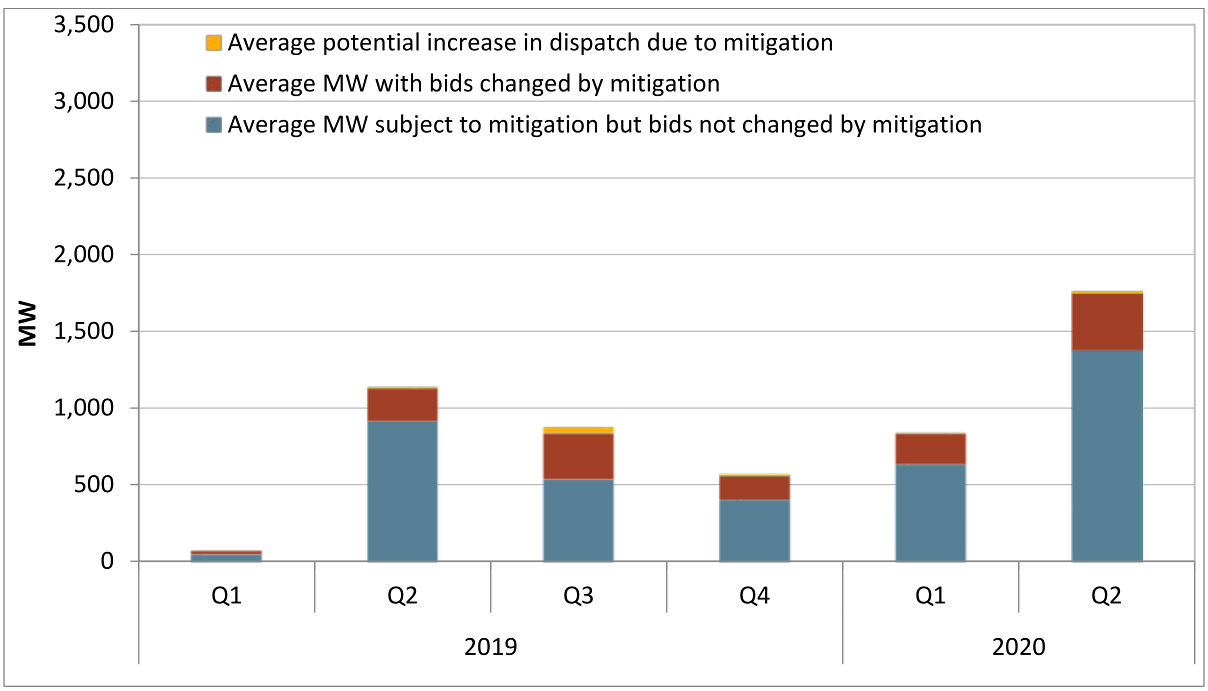


Figure 1.47 Average incremental energy mitigated in 15-minute real-time market (ISO)

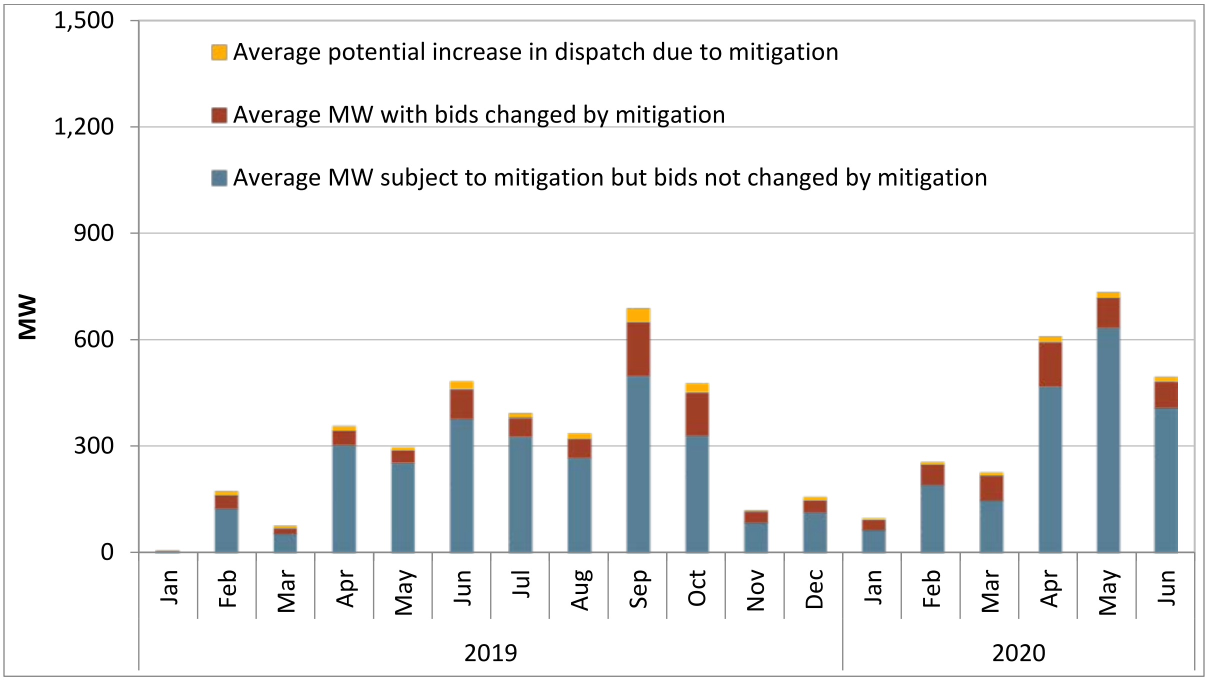
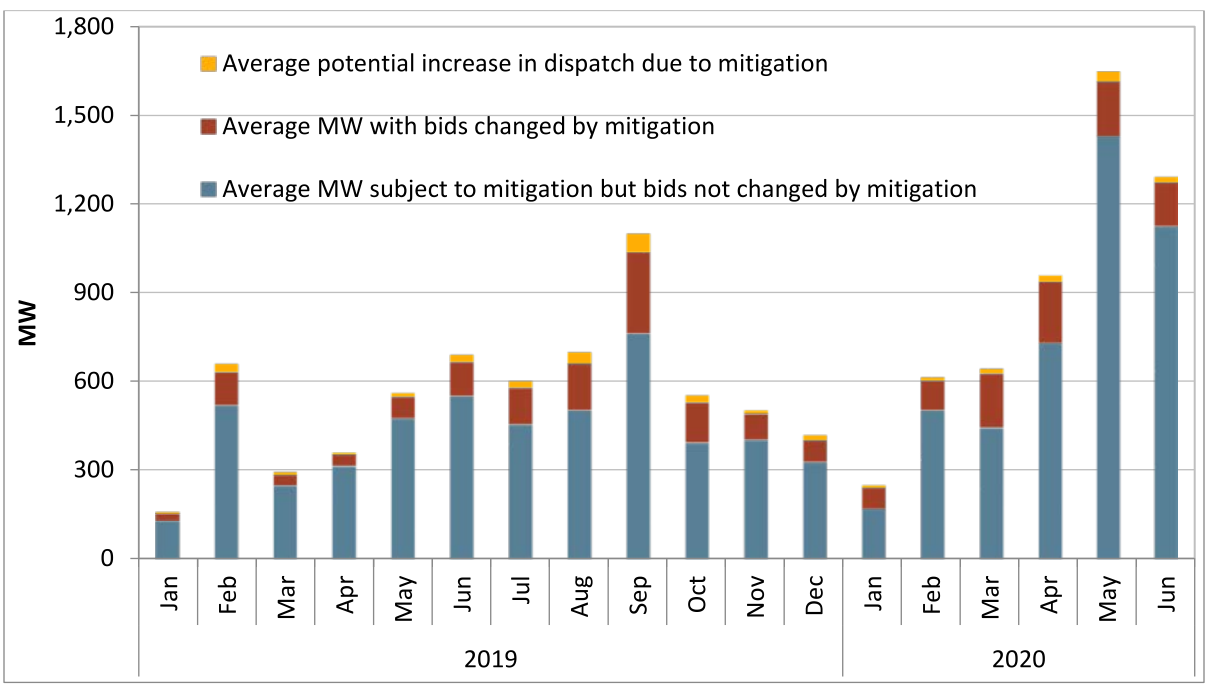


Figure 1.48 Average incremental energy mitigated in 5-minute real-time market (ISO)



Hydro default energy bid option

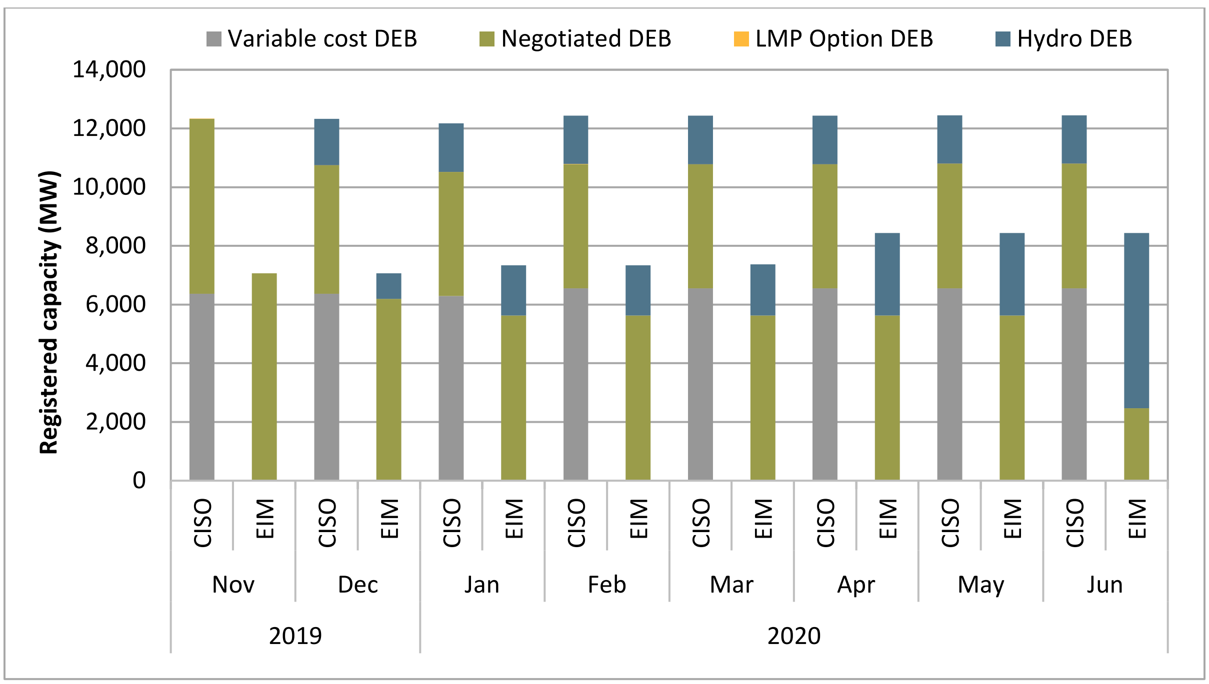
Overview

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 an energy reference level 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.[43]

Resources were 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 1.49 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. As shown in the figure, only a small amount of eligible capacity selected the new hydro option during the first few months.

Figure 1.49 Total capacity by option after hydro default energy bid implementation



43 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.[44] Resources were able to incorporate additional hubs into their default energy bids beginning in June 2020. As shown in Figure 1.49, this caused Western EIM capacity that elected the hydro DEB to more than double from May to June of 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.[45]

1.15 Imbalance conformance

Operators in the ISO and EIM can manually adjust the amount of imbalance conformance used in the market to balance supply and demand conditions to maintain system reliability. Previously imbalance conformance was sometimes referred to as load adjustment, load bias or load conformance; however, these terms did not accurately encapsulate the reasons and actions taken by the operators. Imbalance conformance adjustments are used to account for potential modeling inconsistencies and inaccuracies. Specifically, operators listed multiple reasons for use of imbalance conformance adjustments including managing load and generation deviations, automatic time error corrections, scheduled interchange variations, reliability events, and software issues.[46] From the first quarter of 2020 the term "imbalance conformance" has been used in these reports to describe these operator manual adjustments.

---

44 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

45 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

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

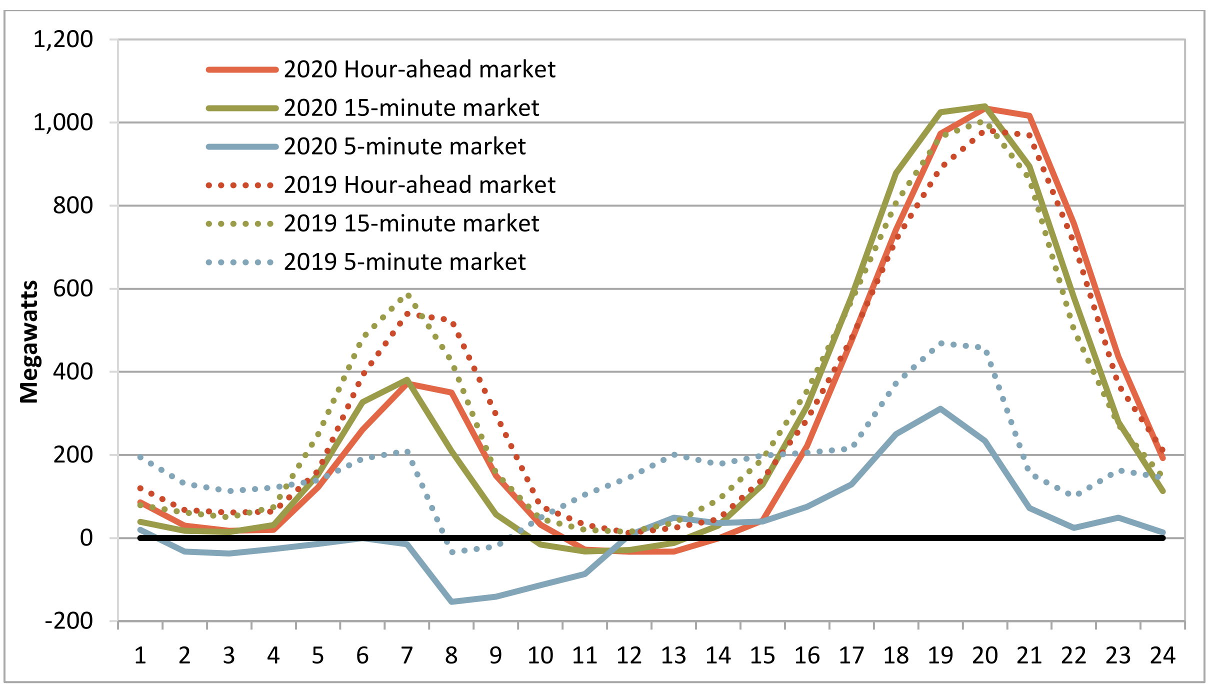
Frequency and size of imbalance conformance adjustments

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the ISO's hour-ahead and 15-minute markets. This large increase continues into the current quarter, with average hourly imbalance conformance adjustments in these markets peaking at just over 1,000 MW, which is similar to the peak in the same quarter of the previous year. Figure 1.50 shows imbalance conformance adjustments in these markets tends to follow a similar shape, with large increases during the morning and evening net load ramp periods and the lowest adjustments during the early morning, late evening, and mid-day hours.

The 5-minute market adjustments tend to follow a much less exaggerated shape throughout the day, and are often well below the hour-ahead and 15-minute adjustments during the steep net load ramp periods. The 5-minute adjustment in hour ending 19 was about 310 MW, much lower than the 1,000 MW adjustment in the hour-ahead and 15-minute markets. In the second quarter, mid-day adjustments were slightly negative in the hour-ahead and the 15-minute markets, while the 5-minute market adjustments were negative throughout the morning until hour ending 12 and then were positive for the remainder of the day. The 5-minute market adjustments in this quarter were also consistently lower than the same quarter from the previous year.

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

Figure 1.50 Average hourly imbalance conformance adjustment (Q2 2019 – Q2 2020)



1.16 Exceptional dispatch

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

Exceptional dispatches can be grouped into three distinct categories:

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

- **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 have likely cleared the market without an exceptional dispatch (i.e., that has an energy bid price below the market clearing price) as in-sequence real-time energy.

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

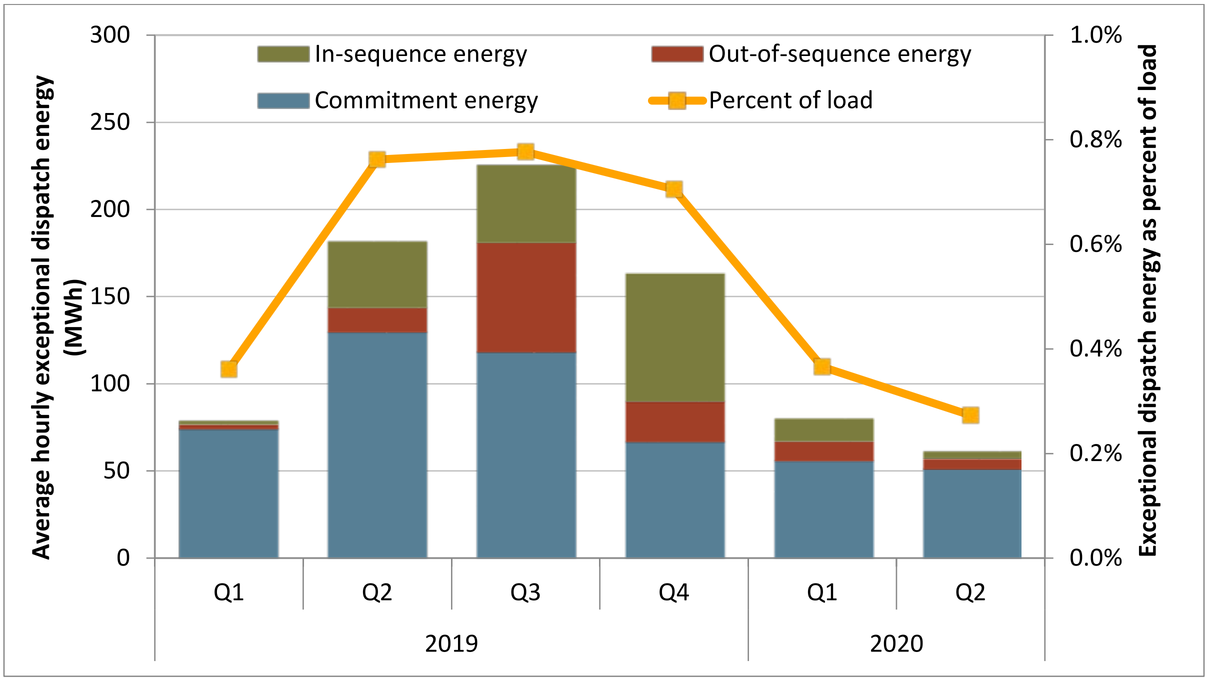
Energy from exceptional dispatch

Energy from exceptional dispatch accounted for under 0.5 percent of total load in the ISO balancing area. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 62 MWh in the second quarter of 2020, which is significantly down from 182 MWh in the same quarter in 2019.

As shown in Figure 1.51, exceptional dispatches for unit commitments accounted for about 83 percent of all exceptional dispatch energy in this quarter.[47] About 10 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 7 percent was from in-sequence energy.

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

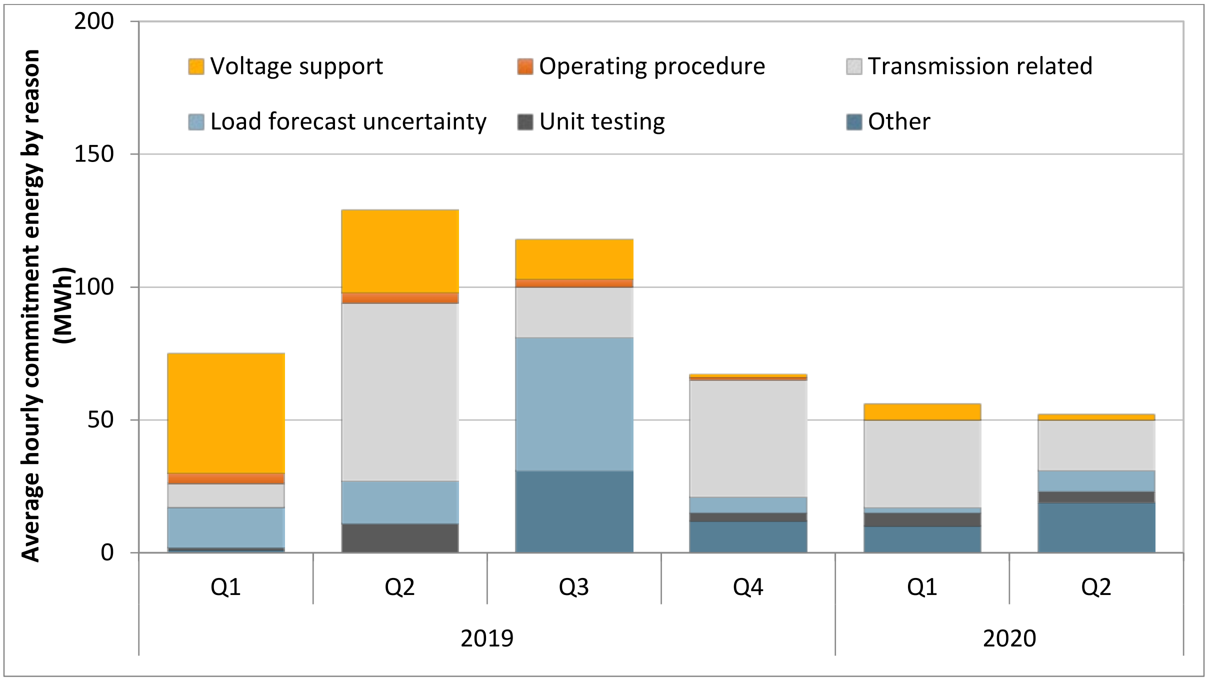
Figure 1.51 Average hourly energy from exceptional dispatch



Exceptional dispatches for unit commitment

Minimum load energy from exceptional dispatch unit commitments in the second quarter decreased on average by about 60 percent relative to the second quarter of the prior year. The most frequent reason given for exceptional dispatch unit commitments was for transmission related exceptional dispatches.

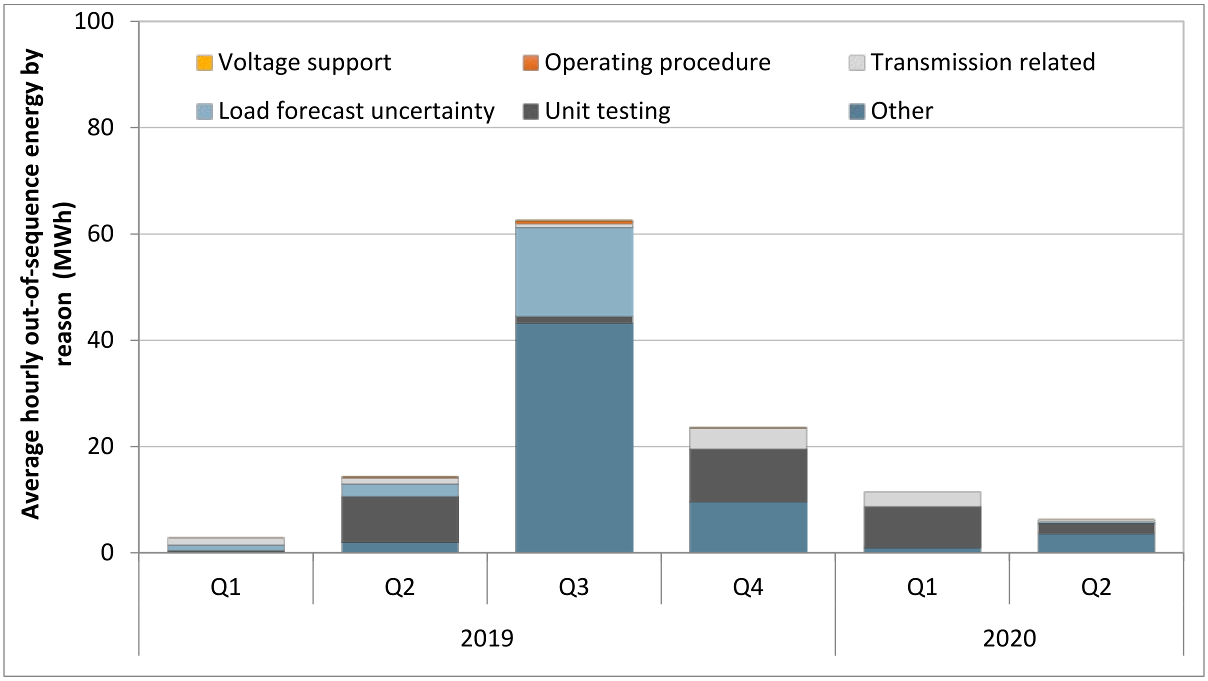
Figure 1.52 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

As shown in Figure 1.51, energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch declined by 80 percent relative to the same quarter in 2019. Compared to the previous quarter, this decline was about 67 percent. Figure 1.51 also shows that about 10 percent of this exceptional dispatch energy was out-of-sequence, meaning the bid price (or default energy bid if mitigated, or if the resource did not submit a bid) was greater than the locational market clearing price. Figure 1.53 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2019 and 2020. Most of the out-of-sequence energy in the second quarter of 2020 was exceptionally dispatched for reliability assessment, shown as “Other” reason in Figure 1.53.

Figure 1.53 Out-of-sequence exceptional dispatch energy by reason



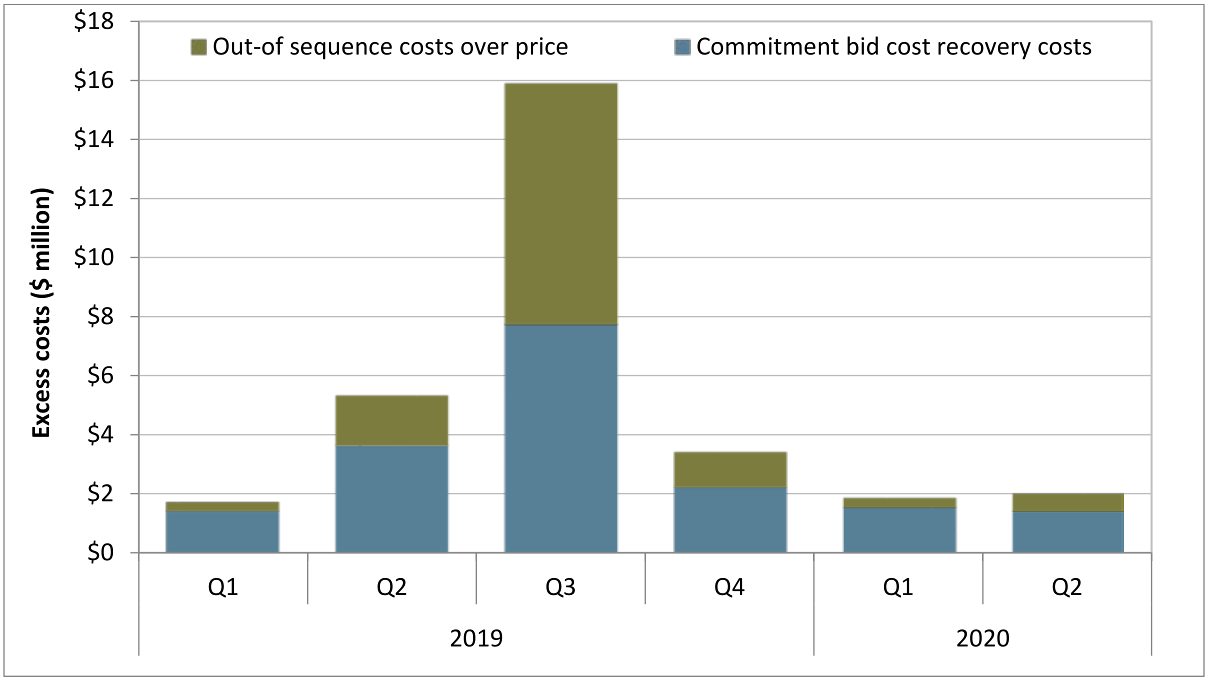
Exceptional dispatch costs

Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

- Units committed through exceptional dispatch that do not recover their start-up and minimum load bid costs through market sales can receive bid cost recovery for these costs.
- Units exceptionally dispatched for real-time energy out-of-sequence may be eligible to receive an additional payment to cover the difference in their market bid price and their locational marginal energy price.

Figure 1.54 shows the estimated costs for unit commitment and additional energy resulting from exceptional dispatches in excess of the market price for this energy. In the second quarter, out-of-sequence energy costs were $0.6 million, while commitment costs for exceptional dispatch paid through bid cost recovery were $1.4 million.

Figure 1.54 Excess exceptional dispatch cost by type



1.17 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.[48]

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. This resource returned 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 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

48 These included 593 MW of capacity from the combined cycle Metcalf Energy Center, and 94 MW of peaking capacity owned by Calpine.

three units were filed at FERC in the May-June timeframe. FERC proceedings for all three units are currently ongoing.[49]

[49] Motion to Intervene and Comments of the Department of Market Monitoring, Greenleaf Energy RMR Agreement, June 22, 2020: http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoring-GreenleafEnergyRMRAgreement-Jun222020.pdf

2 Western energy imbalance market

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

- **Prices in the Northwest region**, which includes PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex, were regularly lower than prices in the ISO and other balancing areas due to limited transfer capability out of this region during peak system load hours.
- **Prices in the ISO and BANC** exceeded the rest of the system in each month, on average, due to binding transfer constraints and greenhouse gas compliance costs enforced for imports into California.
- **Sufficiency test failures and subsequent under-supply power balance constraint relaxations** drove average real-time prices for Arizona Public Service and NV Energy higher. With the modified load conformance limiter implemented in February 2019, the majority of intervals with power balance relaxations were priced at the penalty parameter of $1,000/MWh.
- **Congestion imbalance deficits related to base schedules** remained low in the second quarter, totaling about $0.1 million in PacifiCorp East and $0.4 million in NV Energy. Balancing areas may allocate these imbalances to third party customers and others. PacifiCorp East is the only area to have significant base schedule related congestion imbalance deficits which occurred primarily in late 2017 and early 2018.
- **Western EIM greenhouse gas** prices increased as the deemed delivered resources shifted from lower to higher greenhouse gas emissions. In November 2018, the ISO implemented a revised EIM greenhouse gas bid design which limited greenhouse gas bid capacity to the differences between base schedule and available capacity. In the second quarter, the weighted average greenhouse gas prices decreased relative to the same quarter the previous year. This is mainly driven by an increase in hydro-electric capacity that is deemed delivered into California and additional available capacity from two new energy imbalance market participants beginning in April 2020.
- **Rates of mitigation** fell in the Western EIM, following the elimination of carryover mitigation in November 2019.

2.1 Western EIM performance

New Western EIM balancing authority areas

On April 1, 2020, Seattle City Light and Salt River Project joined the Western Energy Imbalance Market. Seattle City Light and Salt River Project have about 1,048 MW and 6,547 MW of participating capacity, respectively. The 15-minute transfer limits for Seattle City Light and Salt River Project to the rest of the system have averaged 417 MW and 6,048 MW for exports, respectively, while imports have averaged

412 MW and 7,687 MW, respectively.[50] Specifically to the ISO balancing area, Salt River Project's average 15-minute transfer limit for exports averaged 2,209 MW and import limit averaged about 1,458 MW. Seattle City Light has no transfer capacity with the ISO balancing area. For more information on these entities' transition into the Western EIM, please refer to the Department of Market Monitoring's monthly EIM transition reports.[51]

Western EIM prices

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

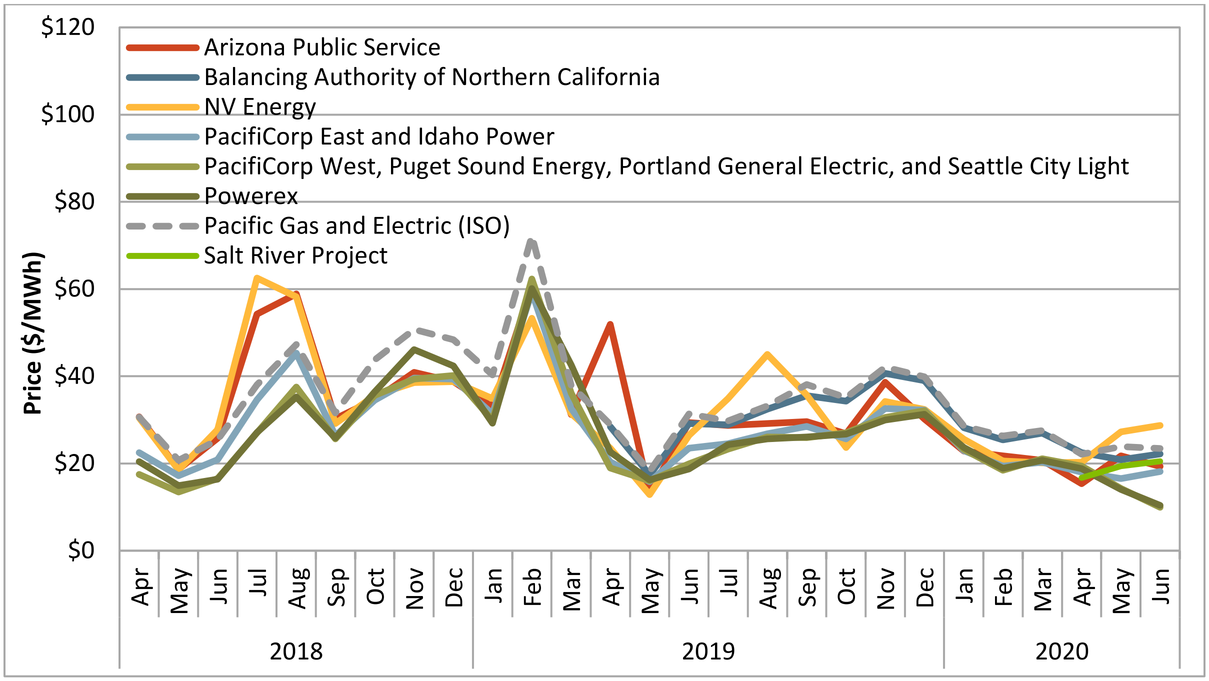
Figure 2.1 shows average monthly prices for the 15-minute market by balancing authority area from April 2018 to June 2020. Several balancing areas are grouped together due to similar average monthly prices. Prices for Powerex (dark green line) and Idaho Power (included in light blue line) begin in April of 2018, prices for the Balancing Authority of Northern California (dark blue line) begin in April of 2019, and prices for Seattle City Light (included in medium green) and Salt River Project (bright green line) begin in April 2020 when they joined the Western EIM.[52] Prices for Pacific Gas and Electric (grey dashed line) are included in the figure as a point of comparison for this analysis.

[50] Average 15-minute transfer limits include all transfer limits between these new entities and all of the Western EIM.

[51] Monthly EIM transition reports, Department of Market Monitoring: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=18E44BAD-3816-448F-A735-3E64FBBBD057

[52] Prices for Seattle City Light are not included with PacifiCorp West, Puget Sound Energy, and Portland General Electric prior to April 2020.

Figure 2.1 Monthly 15-minute market prices



The variability of Western EIM system prices over time is largely explained by natural gas prices. Natural gas price spikes at the SoCal Citygate, PG&E Citygate, and NW Sumas hubs, as shown in Figure 1.1 from the previous chapter, drove the sharp increases in Western EIM system prices between July 2018 and February 2019. In the second quarter of 2020, Western EIM prices outside of California were about $5/MWh and about $6/MWh below Balancing Authority of Northern California and Pacific Gas and Electric prices, respectively, with the exception of NV Energy where average prices exceeded all other areas by about $9/MWh.

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.[53] In addition to this, average prices in the Northwest region (including PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex) are regularly lower than the ISO and other balancing areas because of limited transfer capability out of this region. Figure 2.1 also highlights high price spikes in NV Energy and Arizona Public Service in the months when a relatively high number of power balance constraint violations occurred. In many cases, these occurred in intervals in which Western EIM imports into these areas were frozen due to failed resource sufficiency tests.

Figure 2.2 and Figure 2.3 continue this analysis by showing how Western EIM prices vary throughout the day in the second quarter of 2020. Average hourly prices are shown for participating balancing authorities between April 1 and June 30, 2020. 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

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

together because of similar average hourly pricing, and prices at the Pacific Gas and Electric default load aggregation point are shown as a point of comparison.

Figure 2.2 Hourly 15-minute market prices (April – June)

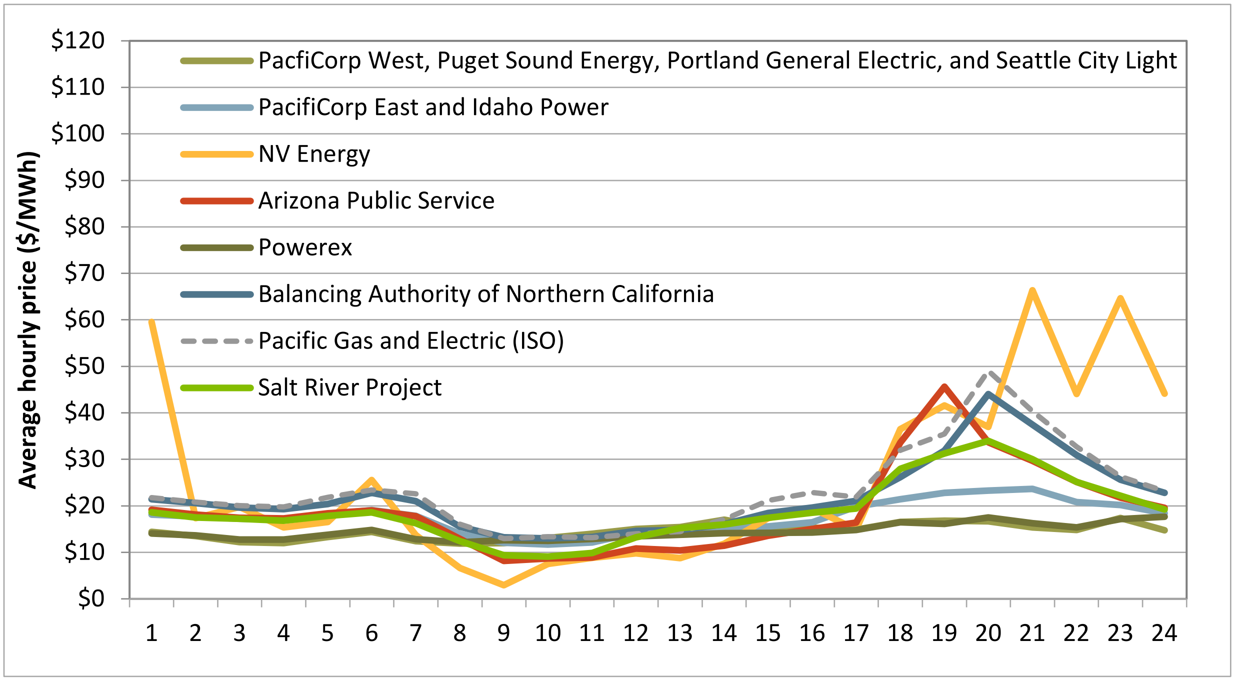
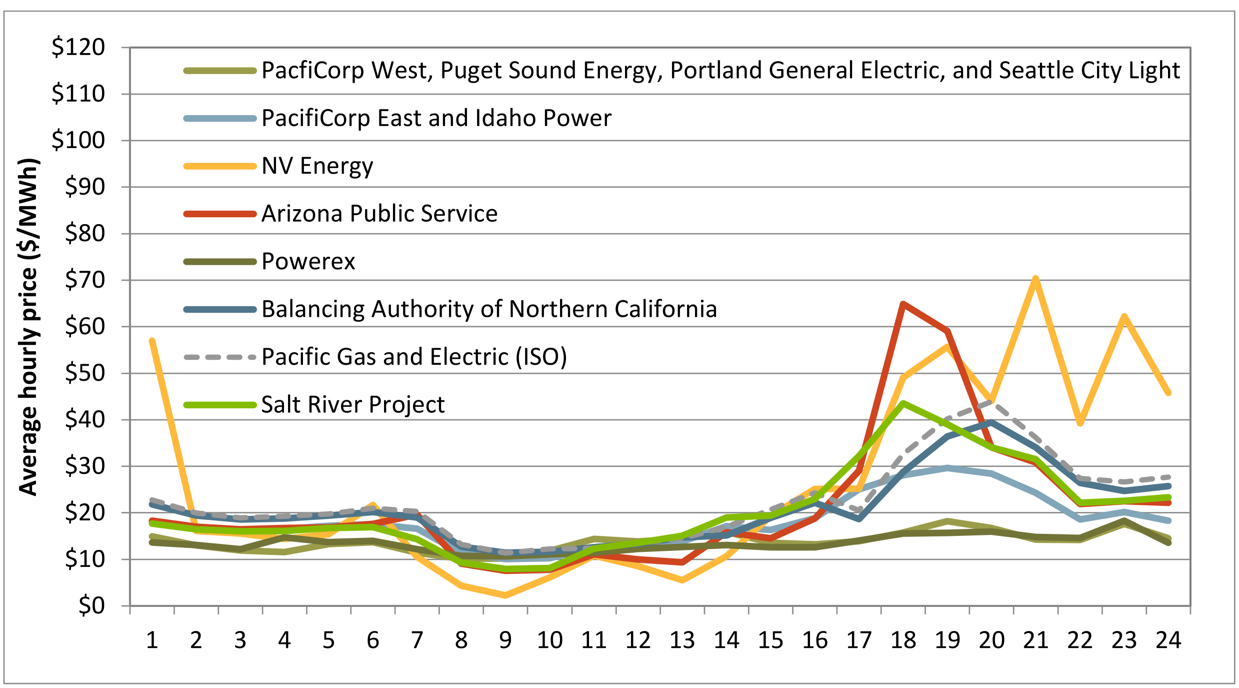


Figure 2.3 Hourly 5-minute market prices (April – June)



These figures also 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 in 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 the ISO prices in the middle of the day when the ISO tends to export energy. The Balancing Authority of Northern California (BANC) is the exception to this rule due to its location in California. Prices in the BANC tracked very closely to prices in the ISO in the second quarter because of significant transfer capability and little congestion between the areas.

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

Prices in Arizona Public Service and NV Energy diverged from the rest of the Western EIM during the afternoon peak load and evening hours. These areas experienced a number of flexible ramping sufficiency test failures in the upward direction in hour ending 1 and between hours ending 18 through 24. This resulted in under-supply power balance constraint relaxations in the market software. The majority of these infeasibilities were not resolved by the enhanced load conformance limiter and were therefore priced at the penalty parameter of $1,000/MWh.[54]

Prices in PacifiCorp East and Idaho Power were often similar to each other and lower than prices in the ISO. As shown in Figure 2.2 and Figure 2.3, price separation between these areas and the ISO was most pronounced during peak load hours when transfers from PacifiCorp East and Idaho Power into the ISO met export limits.

Western EIM wholesale energy cost

In the energy imbalance market, total estimated wholesale cost to serve load, excluding the ISO, was about -$6.3 million or -$0.09/MWh of total load in the second quarter of 2020, a decrease from about -$2.8 million or -$0.05/MWh in the same quarter of 2019.[55] Wholesale costs estimated here are costs associated with serving imbalance load in the Western EIM measured per megawatt-hour of total load.

As shown in Figure 2.4 and Table 2.1, real-time energy costs contributed the largest portion of the costs. Imbalance offset costs typically reduce costs to serve load in the energy imbalance market, such that for the first half of 2020 the overall costs were slightly negative, similar to early 2019.

Real-time energy costs and real-time congestion imbalance offset costs decreased by about 34 percent and 38 percent, respectively, while other costs decreased slightly compared with the same quarter in the previous year. In the Western EIM, offset costs paid to non-California balancing areas include payments to offset greenhouse gas cap-and-trade obligations incurred due to market dispatch.

---

[54] See Section 2.4 for further details on the load conformance in the EIM.

[55] Total wholesale costs for both ISO and EIM areas are calculated from settlements data. Because settlements data may be updated multiple times during a calendar year according to the settlements timeline, the values reported here may be different than previously reported.

Figure 2.4 Total EIM quarterly wholesale costs per MWh of load

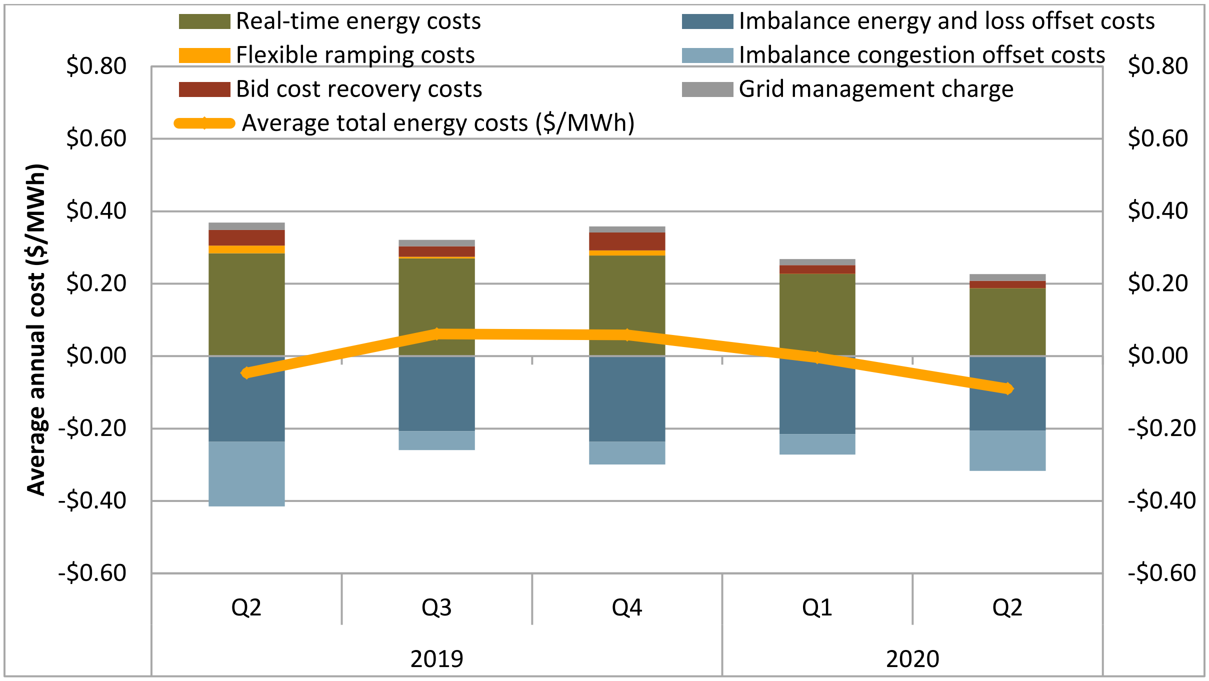


Table 2.1 Estimated average EIM wholesale energy costs per MWh

	Q2 2019	Q3 2019	Q4 2019	Q1 2020	Q2 2020	Change Q2 2019-Q2 2020
Real-time energy costs	$0.28	$0.27	$0.28	$0.23	$0.19	($0.10)
Imbalance congestion offset costs	($0.18)	($0.05)	($0.06)	($0.06)	($0.11)	$0.07
Imbalance energy and loss offset costs	($0.24)	($0.21)	($0.24)	($0.21)	($0.21)	$0.03
Flexible ramping costs	$0.02	$0.00	$0.01	$0.00	$0.00	($0.02)
Grid management charge	$0.02	$0.02	$0.02	$0.02	$0.02	($0.00)
Bid cost recovery costs	$0.04	$0.03	$0.05	$0.02	$0.02	($0.02)
Average total energy costs ($/MWh)	**($0.05)**	**$0.06**	**$0.06**	**($0.00)**	**($0.09)**	**($0.04)**

Fifteen-minute market congestion imbalances from EIM internal transmission constraints

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

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

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 to collect payments from, causing a congestion imbalance deficit. This leads to concerns that third party customers, who are not responsible for submitting base schedules or transmission limits to the ISO, will have to pay to offset deficits caused by base schedule flows that exceed internal constraint limits.

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

PacifiCorp East is the only area to have significant base schedule related congestion imbalance deficits which occurred primarily in late 2017 and early 2018. These deficits were in part allocated to third party customers within PacifiCorp East. In 2018, the ISO conducted extensive outreach with 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. In the second quarter of 2020, congestion imbalance deficits in PacifiCorp East and NV Energy were about $0.1 million and $0.4 million, respectively.

There have not been significant congestion imbalance deficits caused by base schedules exceeding transmission limits in other balancing authority areas. The lack of congestion imbalances from internal constraints in many EIM areas results in part from a lack of binding internal constraints.

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

	Annual				2019				2020	2020
Balancing Authority Area	**2016**	**2017**	**2018**	**2019**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**
Arizona Public Service	$0.0	$0.0	$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	$0.0	$0.0
Powerex	$0.0	$0.0	$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	-$12.7	-$23.2
Idaho Power Company			$0.0	$0.0	$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	$0.0	-$0.4
PacifiCorp - East	-$4.0	-$18.1	-$2.0	$0.7	$0.8	$0.0	$0.1	-$0.3	-$0.7	-$0.1
PacifiCorp - West	$0.0	$0.0	-$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Portland General Electric		$0.0	$0.0	$0.0	$0.0	$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	$0.0	$0.0

2.2 Flexible ramping sufficiency test

In the second quarter of 2020, the frequency of EIM areas failing the upward sufficiency test decreased relative to the same quarter of 2019. NV Energy failed the upward and downward sufficiency test most frequently in this quarter.

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

If an area fails the upward sufficiency test, EIM transfers into that area cannot be increased.[56] Similarly, if an area fails the downward sufficiency test, transfers out of that area cannot be increased. An area will also fail the flexible ramping sufficiency test when the capacity test fails for the specific direction. The capacity test ensures that there are sufficient incremental or decremental economic energy bids above or below the base schedules to meet the demand forecast.[57]

Figure 2.5 and Figure 2.6 show the percent of *intervals* in which an EIM area failed the sufficiency test in the upward or downward direction.[58] During the second quarter of 2020, EIM areas failing the upward sufficiency test increased but remained infrequent. NV Energy failed the upward sufficiency test most frequently in the energy imbalance market, around 2 percent of intervals during the quarter. The frequency of downward sufficiency test failures increased from the previous quarter. NV Energy failed the downward sufficiency test most frequently over the quarter, during roughly 6 percent of intervals.

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

---

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

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

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

Figure 2.5 Frequency of upward failed sufficiency tests by month

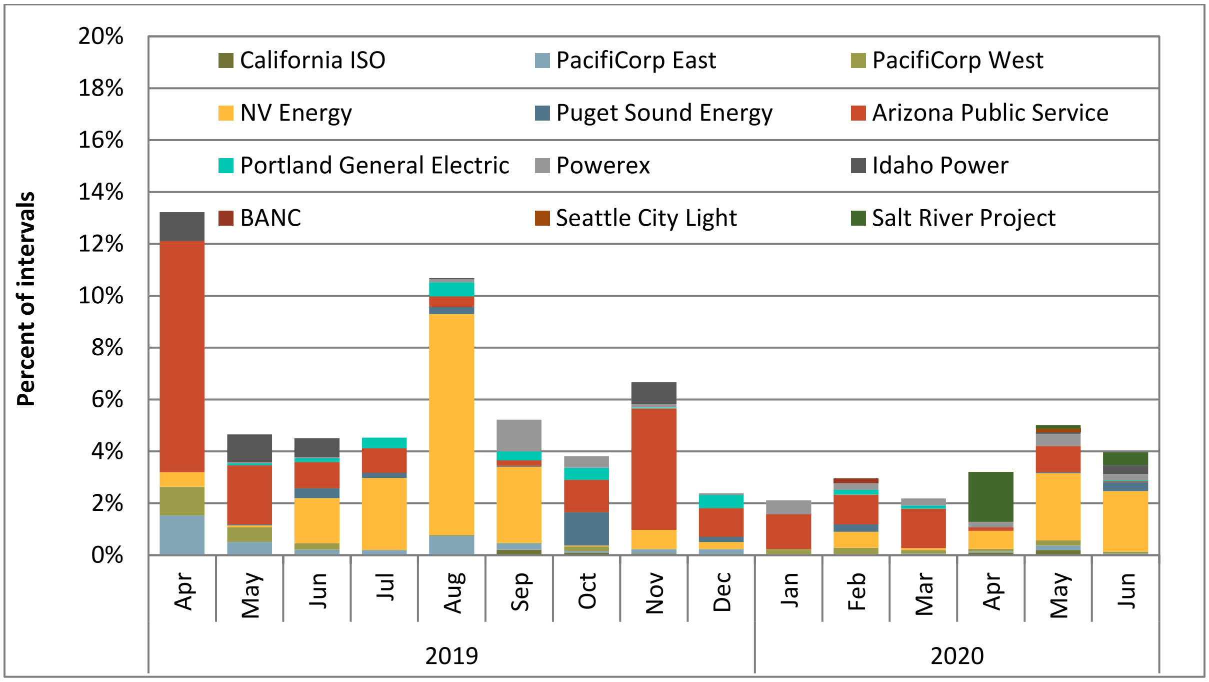
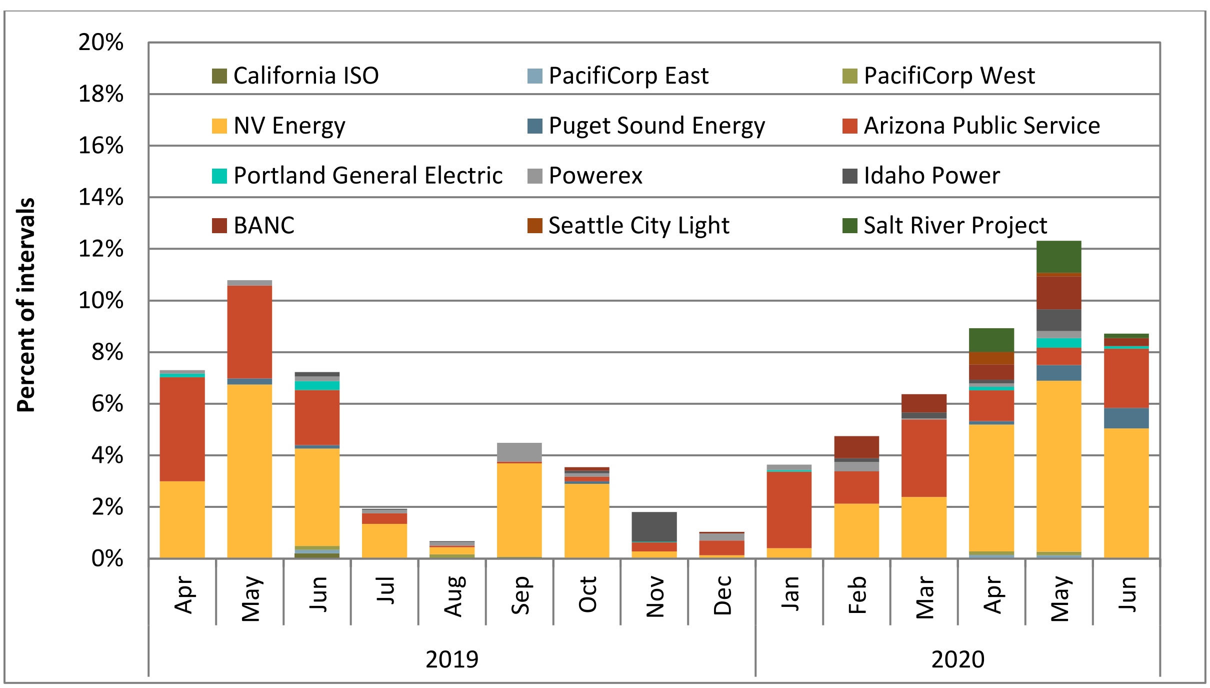


Figure 2.6 Frequency of downward failed sufficiency tests by month

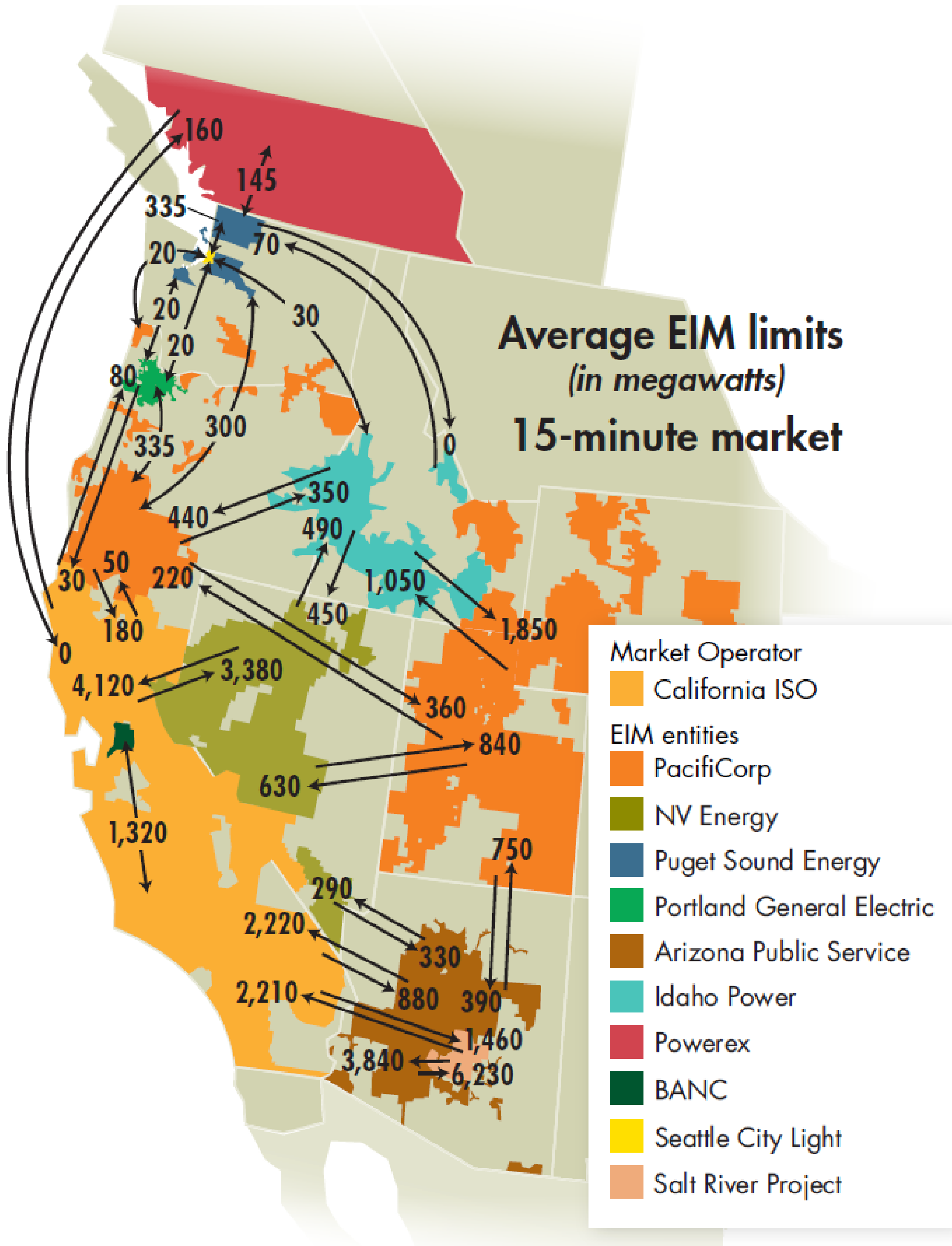


2.3 Western EIM transfers

Western EIM transfer limits

One of the key benefits of the energy imbalance market is the ability to transfer energy between areas in the 15-minute and 5-minute markets. Figure 2.7 shows average 15-minute market limits between each of the areas during the second quarter. The map shows that there was significant transfer capability between the ISO, NV Energy, Arizona Public Service, Salt River Project, and the BANC. Transfer capability between these areas, PacifiCorp East, and Idaho Power was lower but still significant. These limits allowed energy to flow between these areas with relatively little congestion. Transfer capability was more limited between the ISO and the Northwest areas which include PacifiCorp West, Puget Sound Energy, Portland General Electric, Powerex, and Seattle City Light. Average combined export limits from any of these areas to the ISO was around 210 MW during the quarter.

Figure 2.7 Average 15-minute market energy imbalance market limits (April – June)



Hourly energy imbalance market transfers

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

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

In the second quarter of 2020, average exports from the ISO during the middle of the day continued to increase in part due to the addition of Salt River Project in the EIM. Exports from the ISO during the second quarter averaged around 2,300 MW between hours ending 11 and 15.

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

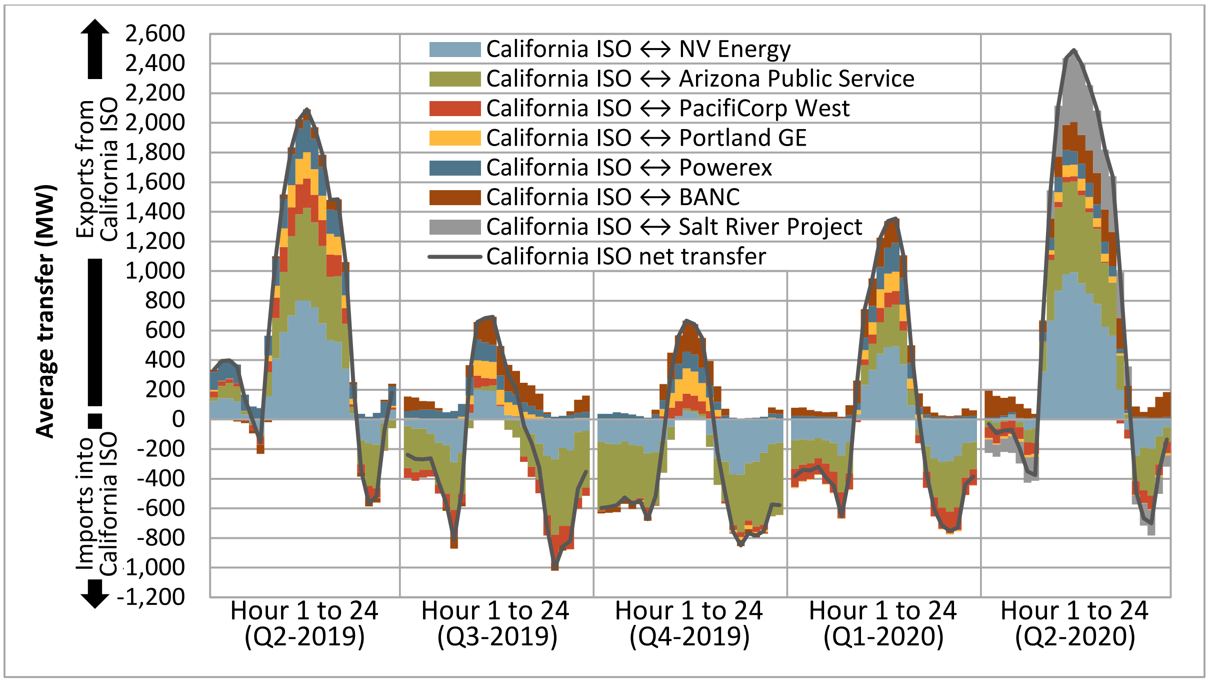


Figure 2.9 through Figure 2.17 show the same quarterly information on imports and exports for the other energy imbalance market areas in the 15-minute market.[59] The amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[60]

Figure 2.9 and Figure 2.10 show average hourly transfers for NV Energy and Arizona Public Service. During midday hours in the second quarter, these areas typically imported from the ISO and exported out to the eastward areas including PacifiCorp East and Idaho Power. During off-solar hours, these areas were generally net exporters with most transfers out to the ISO.

59 Figures showing transfer information from the perspective of Salt River Project and Seattle City Light for the second quarter are not explicitly included, but are represented in Figure 2.8 through Figure 2.16.

60 Base schedules on EIM transfer system resources are fixed bilateral transactions between EIM entities.

Figure 2.11 shows the hourly 15-minute market transfer pattern between Idaho Power and neighboring areas, net of all base schedules. Idaho Power has transfer capacity between PacifiCorp West, PacifiCorp East, NV Energy, and to a limited extent with Puget Sound Energy and Seattle City Light.

Figure 2.12 through Figure 2.14 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, Idaho Power, and Seattle City Light. The majority of Puget Sound Energy's transfer capacity is with PacifiCorp West, Powerex, and Seattle City Light.

Figure 2.15 and Figure 2.16 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 0 MW during all intervals in the second quarter of 2020 in both the 15-minute and 5-minute markets.

Figure 2.17 shows average hourly transfers between the Balancing Authority of Northern California and the ISO. The BANC area imported from the ISO during all hours on average during the second quarter of 2020.

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

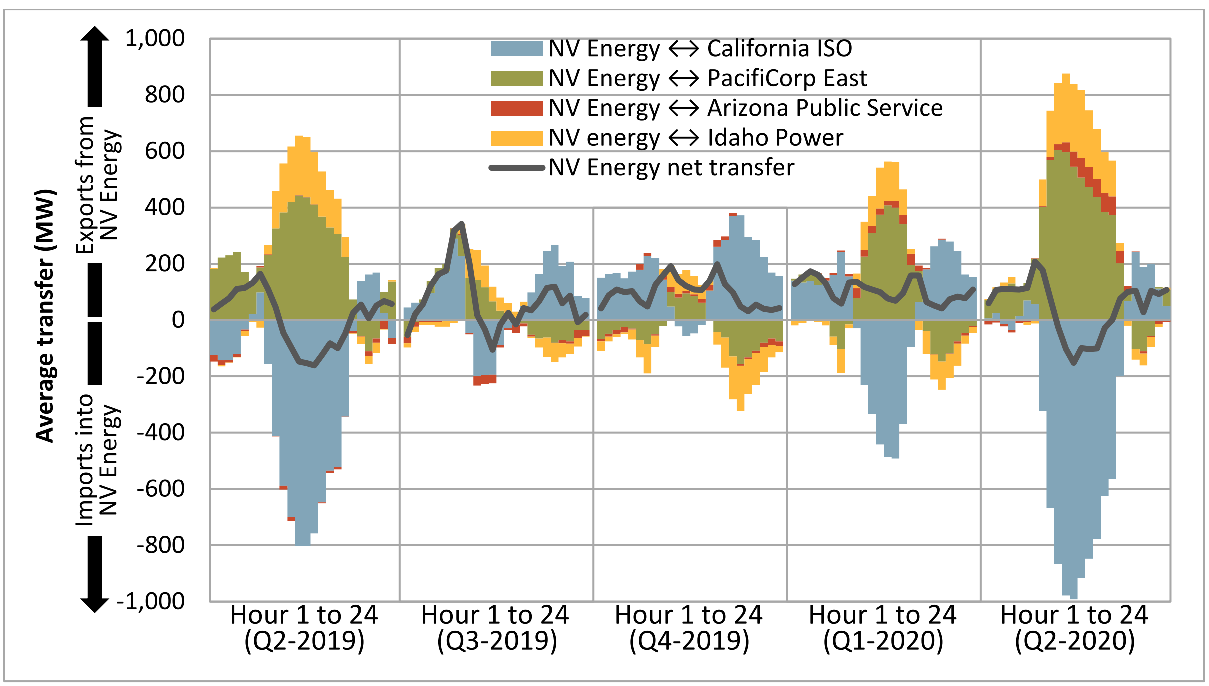


Figure 2.10 Arizona Public Service – average hourly 15-minute market transfer

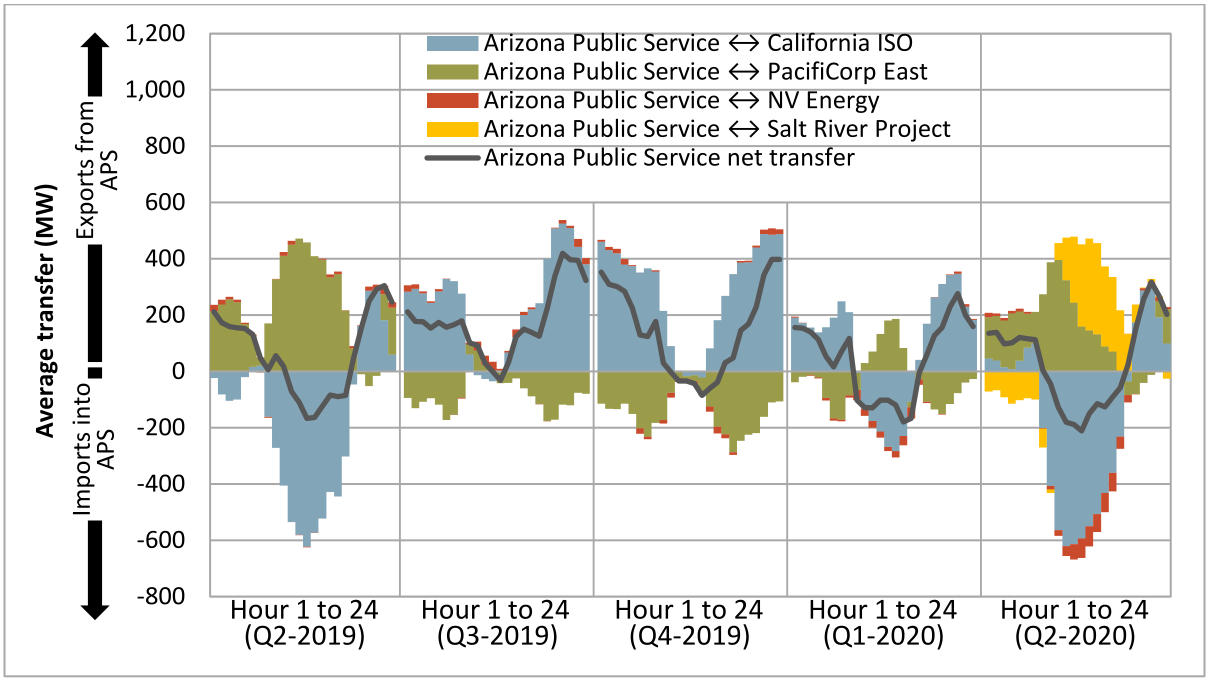


Figure 2.11 Idaho Power – average hourly 15-minute market transfer

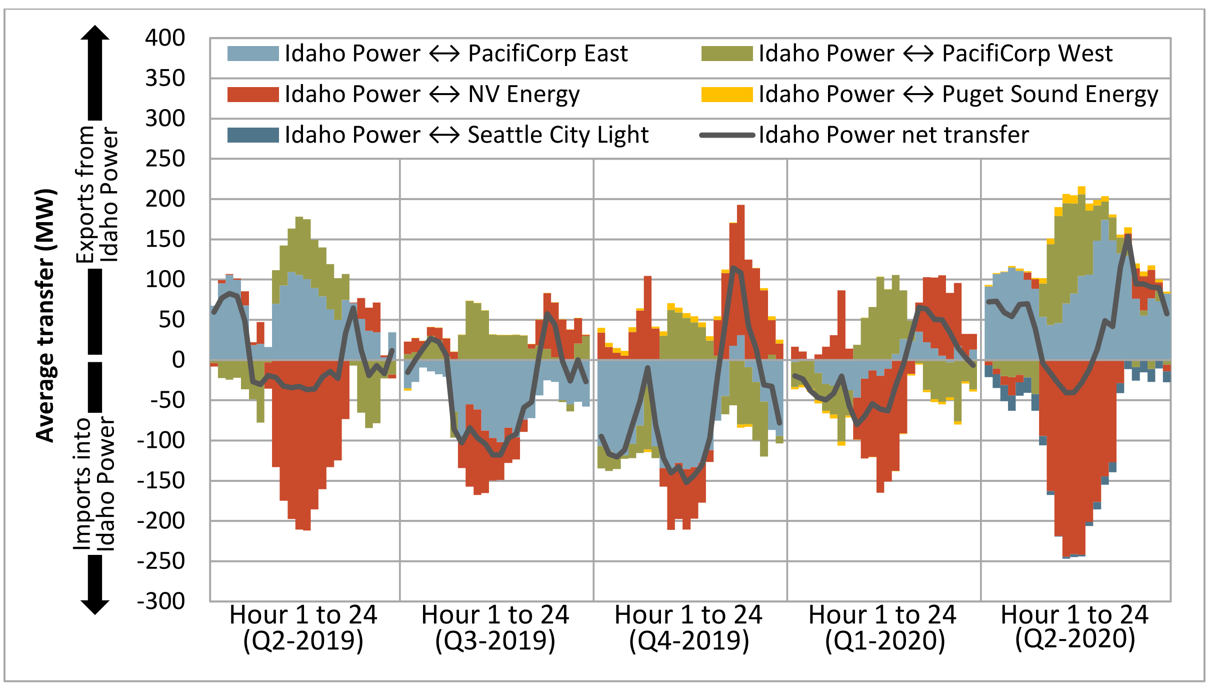


Figure 2.12 PacifiCorp East – average hourly 15-minute market transfer

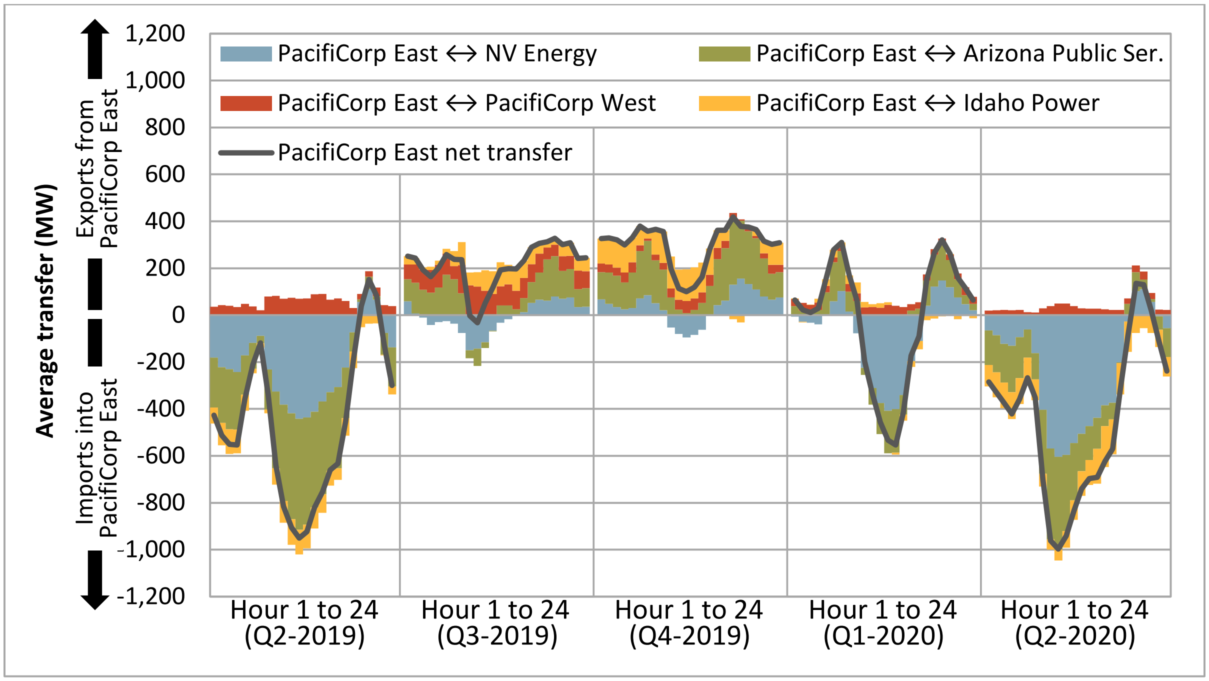


Figure 2.13 PacifiCorp West – average hourly 15-minute market transfer

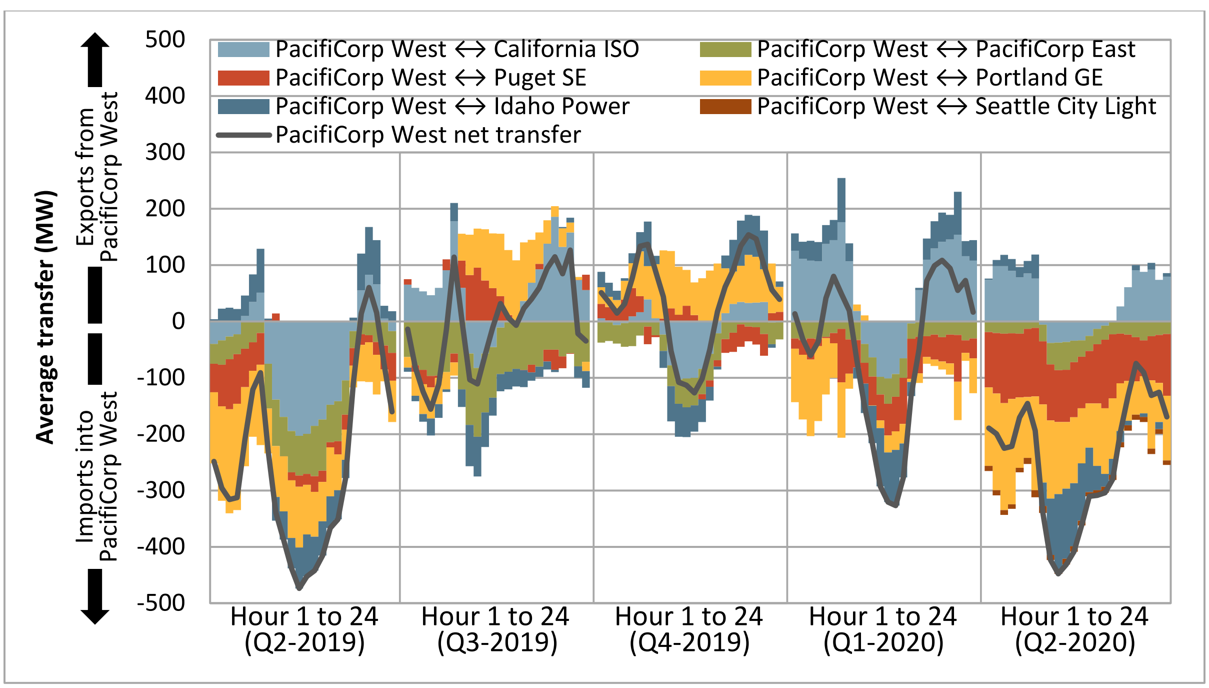


Figure 2.14 Puget Sound Energy – average hourly 15-minute market transfer

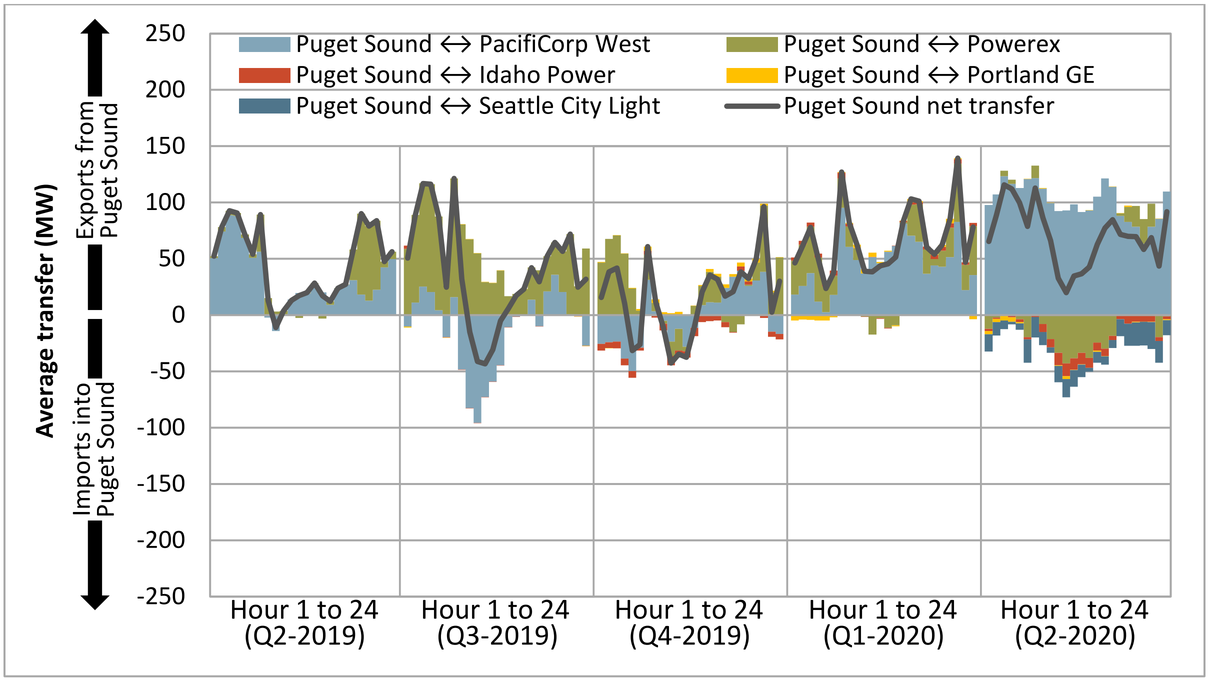


Figure 2.15 Powerex – average hourly 15-minute market transfer

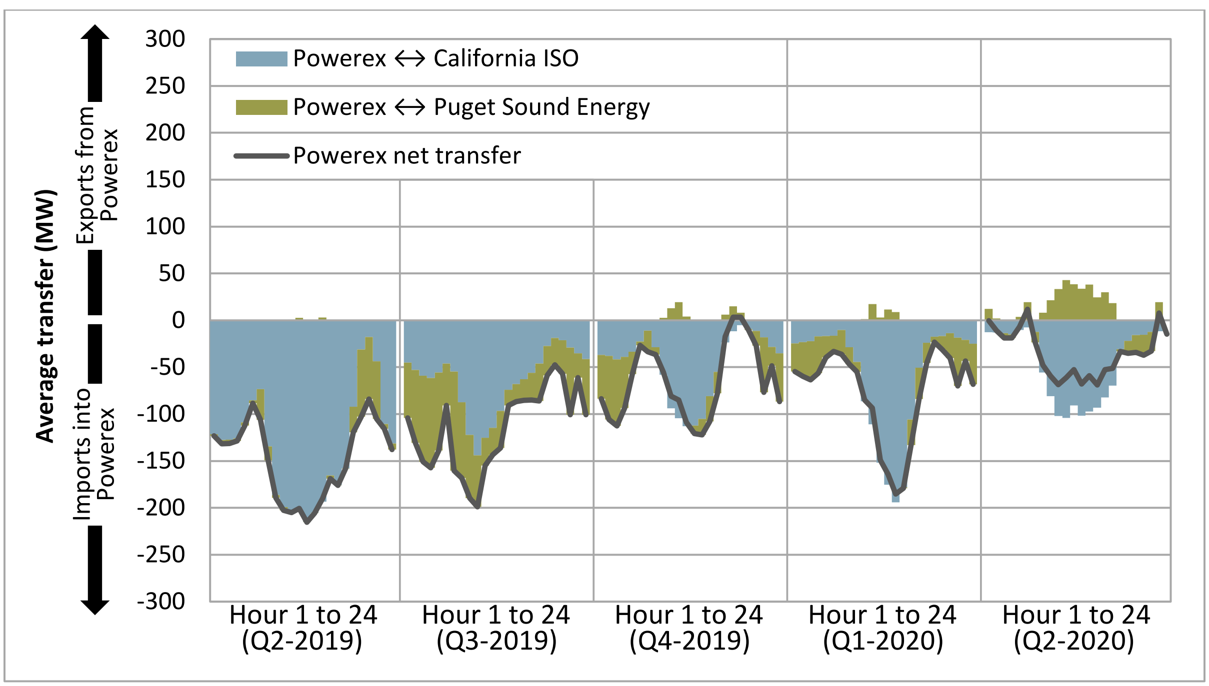


Figure 2.16 Portland General Electric – average hourly 15-minute market transfer

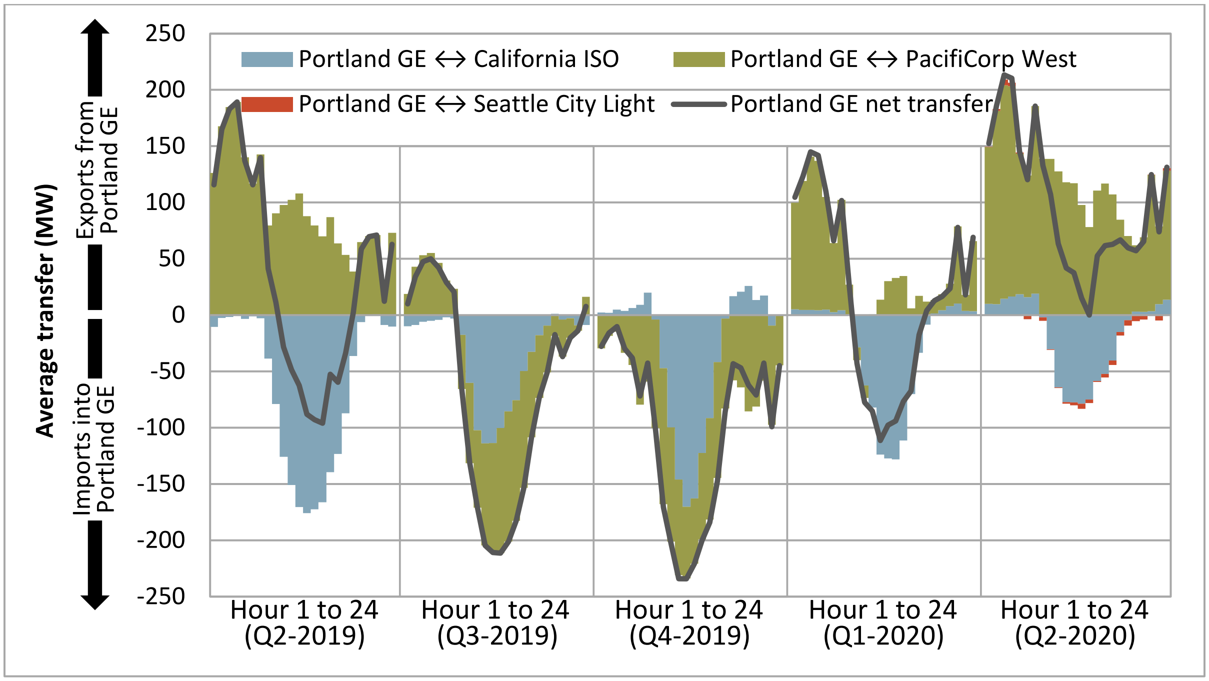
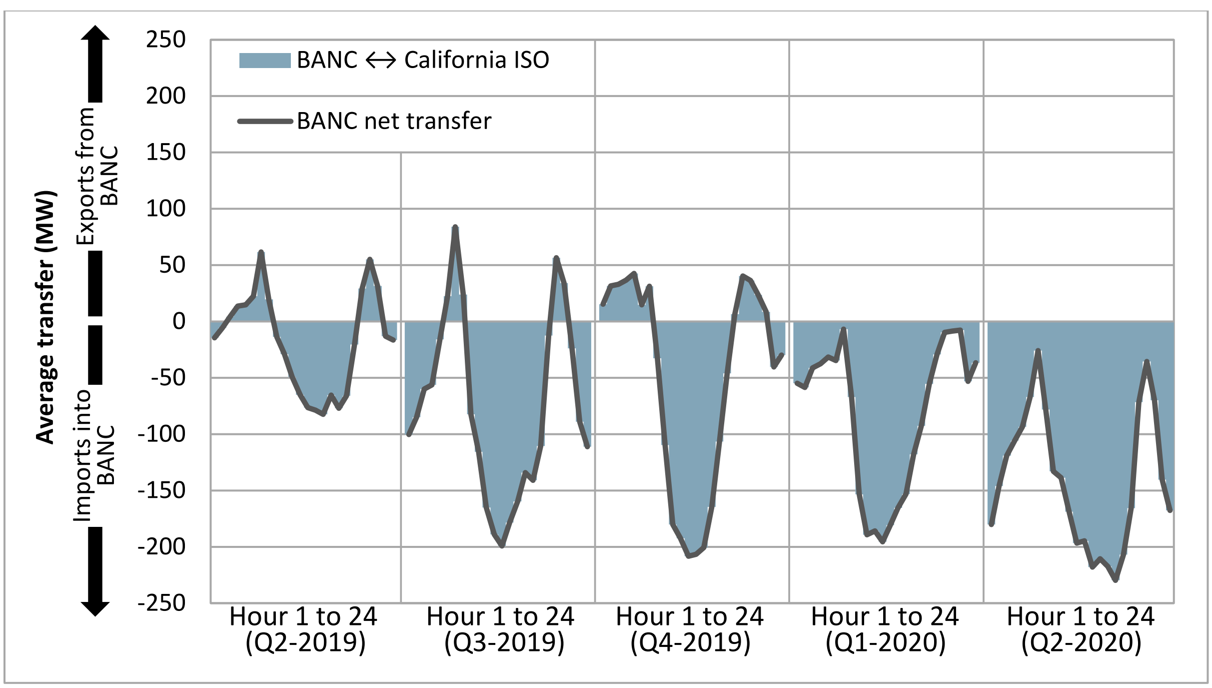


Figure 2.17 Balancing Authority of Northern California - average hourly 15-minute market transfer



Inter-balancing area congestion

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.[61]

Table 2.3 shows the percent of 15-minute and 5-minute market intervals with congestion on 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.[62] 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 1.10.2 of this report on EIM transfers. Chapter 1 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.

Table 2.3 Frequency of congestion in the energy imbalance market (April – June)

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	1%	0%	1%	0%
NV Energy	4%	2%	3%	1%
Arizona Public Service	1%	5%	1%	4%
PacifiCorp East	4%	7%	2%	6%
Idaho Power	4%	8%	2%	6%
Salt River Project	3%	14%	3%	13%
PacifiCorp West	30%	11%	23%	9%
Portland General Electric	32%	11%	26%	9%
Seattle City Light	32%	11%	27%	10%
Puget Sound Energy	32%	12%	27%	10%
Powerex	36%	10%	34%	15%

The highest frequency of congestion in the energy imbalance market continued to be from the Northwest areas toward the larger energy imbalance market system. This congestion in the 15-minute market from PacifiCorp West, Portland General Electric, Seattle City Light, Puget Sound Energy, and

[61] 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.

[62] 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.

Powerex occurred during 32 percent of intervals on average during the quarter. This is higher than the previous quarter when this occurred during 25 percent of intervals on average from these areas, with the exception of Seattle City Light which was not yet participating in the EIM.

The highest frequency of net import congestion (such that the ISO market software triggers local market power mitigation in that area) occurred in the Salt River Project area, during 14 percent of 15-minute market intervals and 13 percent of 5-minute market intervals during the second quarter.

Table 2.3 also shows that congestion in either direction between the BANC, NV Energy, Arizona Public Service, PacifiCorp East, Idaho Power, Salt River Project, or the ISO area was relatively infrequent during the second quarter. Congestion that did occur between these areas was often the result of a failed upward or downward sufficiency test, which limited transfer capability.

2.4 Imbalance conformance in the Western EIM

Frequency and size of imbalance conformance

Table 2.4 summarizes the average frequency and size of positive and negative imbalance conformance entered by operators in the EIM for the 15-minute and 5-minute markets during the second quarter.[63] The same data for the ISO is provided as a point of reference. In particular, Arizona Public Service entered positive imbalance conformance in around 49 percent of 15-minute and 5-minute intervals, at an average of around 96 MW. Puget Sound Energy entered negative imbalance conformance in around 24 and 53 percent of 15-minute and 5-minute intervals, at an average of around 32 and 33 MW, respectively. Nearly all EIM entities had a greater frequency of 5-minute market imbalance conformance than 15-minute market during the second quarter.

[63] Imbalance conformance is sometimes referred to as *load bias* or *load adjustments*. The ISO uses the term *imbalance conformance* to describe this process.

Table 2.4 Average frequency and size of imbalance conformance (April – June)

	Positive imbalance conformance			Negative imbalance conformance			Average hourly adjustment MW
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO							
15-minute market	47%	659	2.6%	5%	-344	1.8%	292
5-minute market	41%	262	1.1%	33%	-241	1.2%	29
PacifiCorp East							
15-minute market	0%	92	2.2%	0%	N/A	N/A	0
5-minute market	17%	81	1.6%	29%	-85	1.8%	-11
PacifiCorp West							
15-minute market	0%	N/A	N/A	0%	-80	4.4%	0
5-minute market	4%	46	2.2%	23%	-47	2.3%	-9
NV Energy							
15-minute market	2%	72	1.5%	1.2%	-193	6.1%	-1
5-minute market	23%	75	1.6%	9%	-150	4.5%	4
Puget Sound Energy							
15-minute market	0.8%	27	1.0%	24%	-32	1.4%	-8
5-minute market	1.1%	33	1.2%	53%	-33	1.4%	-17
Arizona Public Service							
15-minute market	49%	96	2.7%	37%	-108	3.3%	7
5-minute market	49%	96	2.8%	36%	-108	3.3%	7
Portland General Electric							
15-minute market	0%	200	8.2%	0%	N/A	N/A	0
5-minute market	31%	27	1.3%	3.6%	-28	1.4%	7
Idaho Power							
15-minute market	0%	N/A	N/A	1.1%	-39	2.2%	0
5-minute market	2.9%	60	2.5%	28%	-55	3.0%	-14
BANC							
15-minute market	0.2%	32	1.9%	0.2%	-89	7.2%	0
5-minute market	4%	21	1.3%	2%	-34	3.0%	0
Seattle City Light							
15-minute market	1.4%	24	2.6%	20.3%	-23	2.6%	-4
5-minute market	4%	22	2.4%	51%	-22	2.5%	-10
Salt River Project							
15-minute market	10.5%	72	1.5%	0.2%	-46	1.4%	7
5-minute market	13%	72	1.5%	1%	-80	2.5%	9

2.5 Greenhouse gas in the Western EIM

In the second quarter, weighted 15-minute and 5-minute greenhouse gas prices declined compared to the same quarter last year. This is mainly driven by an increase in hydro-electric capacity that is deemed delivered into California and additional available capacity from two new energy imbalance market participants beginning in April 2020.

Under the current design, all energy serving California ISO or BANC load through a non-California EIM transfer is subject to California's cap-and-trade regulation.[64] A participating resource submits a separate bid representing the cost of compliance for its energy attributed to the participating resource as serving the ISO load. The EIM optimization minimizes costs of serving load in both the ISO and EIM taking into account greenhouse gas compliance cost for all energy deemed delivered to the ISO. The EIM greenhouse gas price in each 15-minute or 5-minute interval is set at the greenhouse gas bid of the marginal megawatt attributed as serving the ISO load. This information serves as the basis for greenhouse gas compliance obligations under California's cap-and-trade program.

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

As of November 2018, the ISO implemented a policy change to address the concerns that the market design was not capturing the full greenhouse gas effect of energy imbalance market imports into California to serve the ISO load for compliance with California's cap-and-trade regulation.[65] The amount of capacity that can be deemed delivered to California is now limited to the upper economic bid limit of a resource minus the resource's base schedule.

Greenhouse gas prices

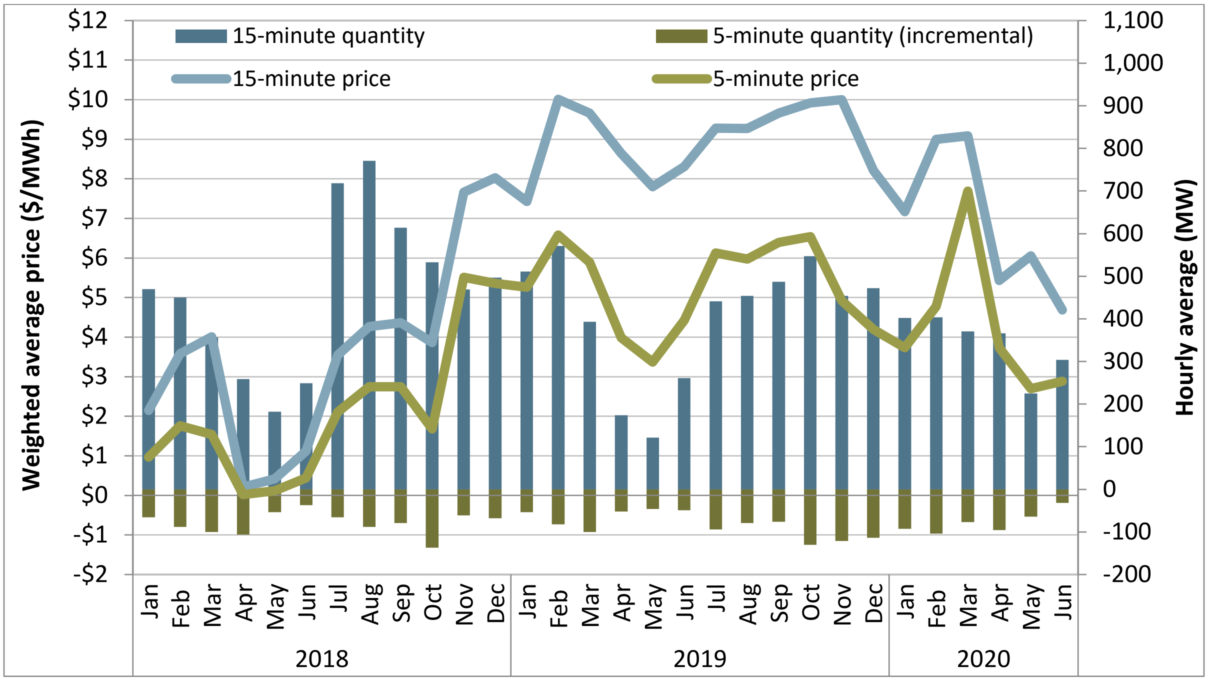
Figure 2.18 shows monthly average cleared EIM greenhouse gas prices and hourly average quantities for transfers serving the ISO load settled in the EIM. Weighted average prices are calculated using 15-minute deemed delivered megawatts to weight 15-minute prices and the absolute value of incremental 5-minute greenhouse gas dispatch to weight 5-minute prices. Hourly average 15-minute and 5-minute deemed delivered quantities are represented by the blue and green bars in the chart, respectively.

---

64 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.

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

Figure 2.18 Energy imbalance market greenhouse gas price and cleared quantity



Weighted 15-minute greenhouse gas prices averaged around $5/MWh for the second quarter while 5-minute prices averaged about $3/MWh. Greenhouse gas prices are the lowest they have been since before the policy change in 2018. This trend is likely driven by an increase in non-emitting, hydroelectric capacity deemed delivered to California and additional available capacity from two new energy imbalance market participants joining in April 2020. Greenhouse gas prices decreased by about $3/MWh in the 15-minute market and by about $1/MWh in the 5-minute market compared to the same quarter of last year.

Price differences between markets can 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 also increased since the policy change in 2018 and continued in the second quarter. In the second quarter, the price difference between the 15-minute and 5-minute markets decreased to about $2/MWh, compared to about $4/MWh in the same quarter of the previous year. This price separation is often correlated with imbalance conformance in California (described in Section 1.15 and 2.4), which is consistently higher in the 15-minute market than the 5-minute market. Imbalance conformance has contributed to accentuated differences in greenhouse gas prices due to the compressed bid stack.

Historically, EIM greenhouse gas prices have not exceeded $7/MWh in either the 15-minute or 5-minute market. After November 2018, prices around $7/MWh occur frequently and some prices are set higher than the highest cleared bid. Figure 2.19 and Figure 2.20 show the frequency of high prices and maximum price by quarter for each market during the last two years. In the second quarter, there were no instances of prices exceeding $18/MWh in either the 15-minute or 5-minute markets, halting a trend that began after the policy change in 2018.

Figure 2.19 High 15-minute EIM greenhouse gas prices

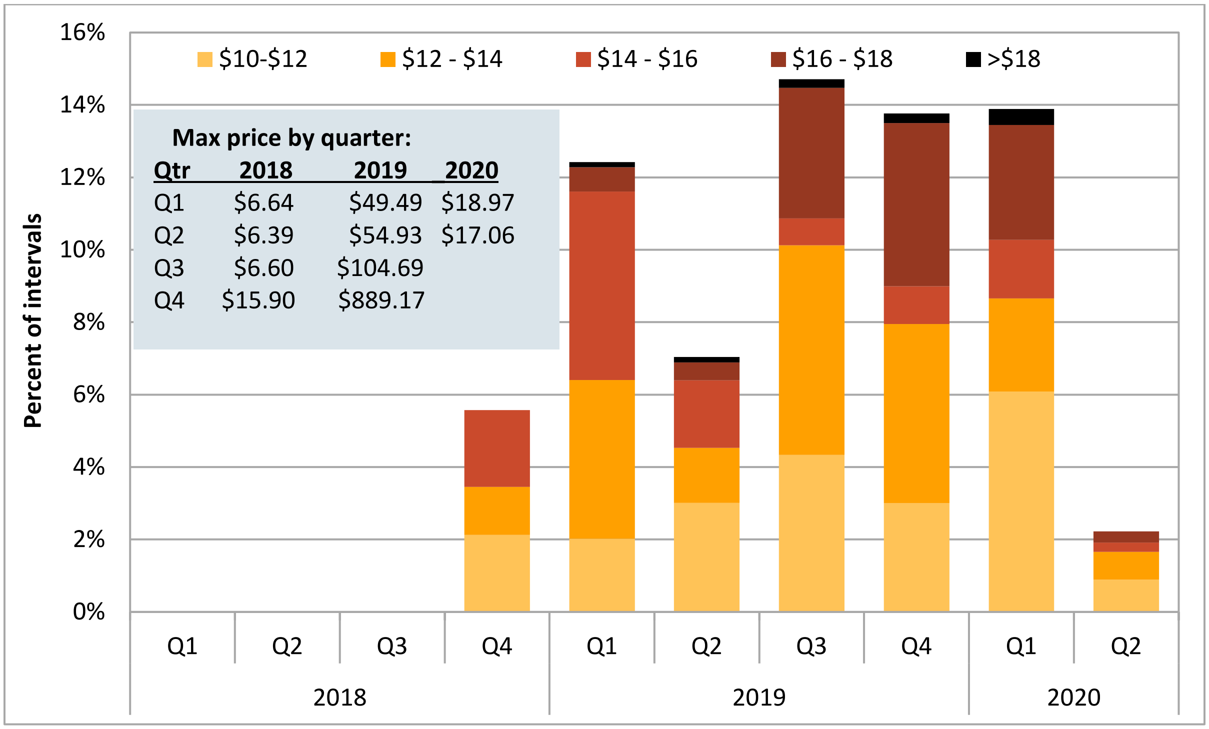
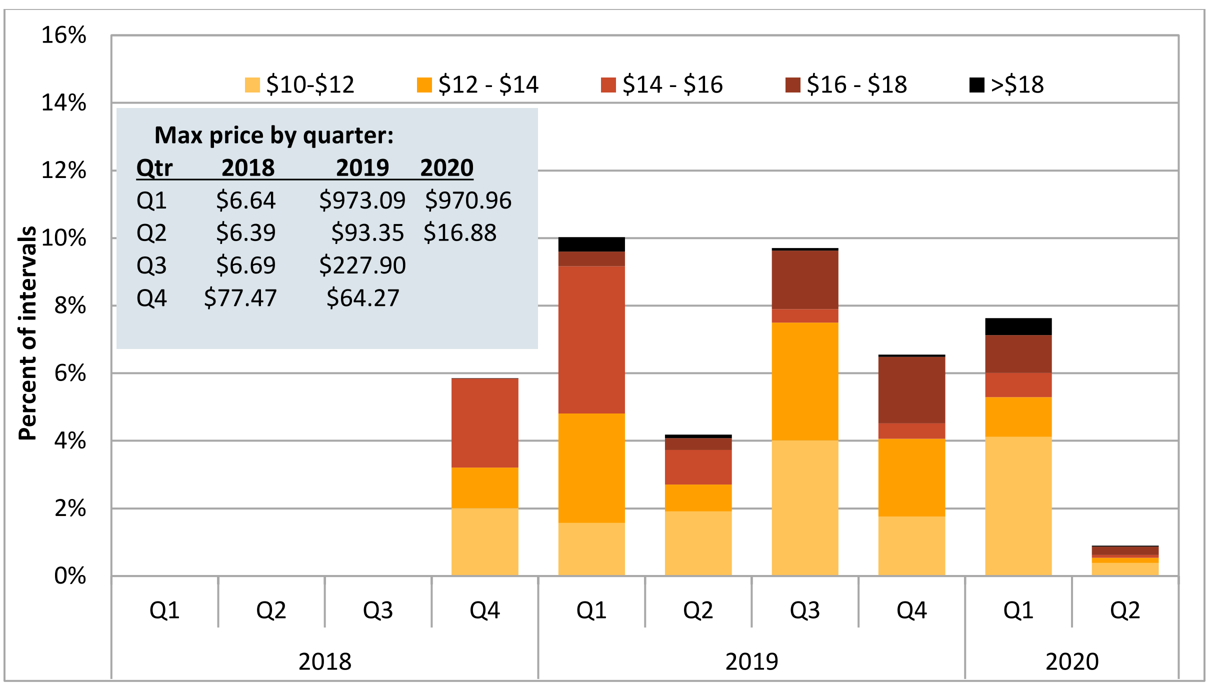


Figure 2.20 High 5-minute EIM greenhouse gas prices

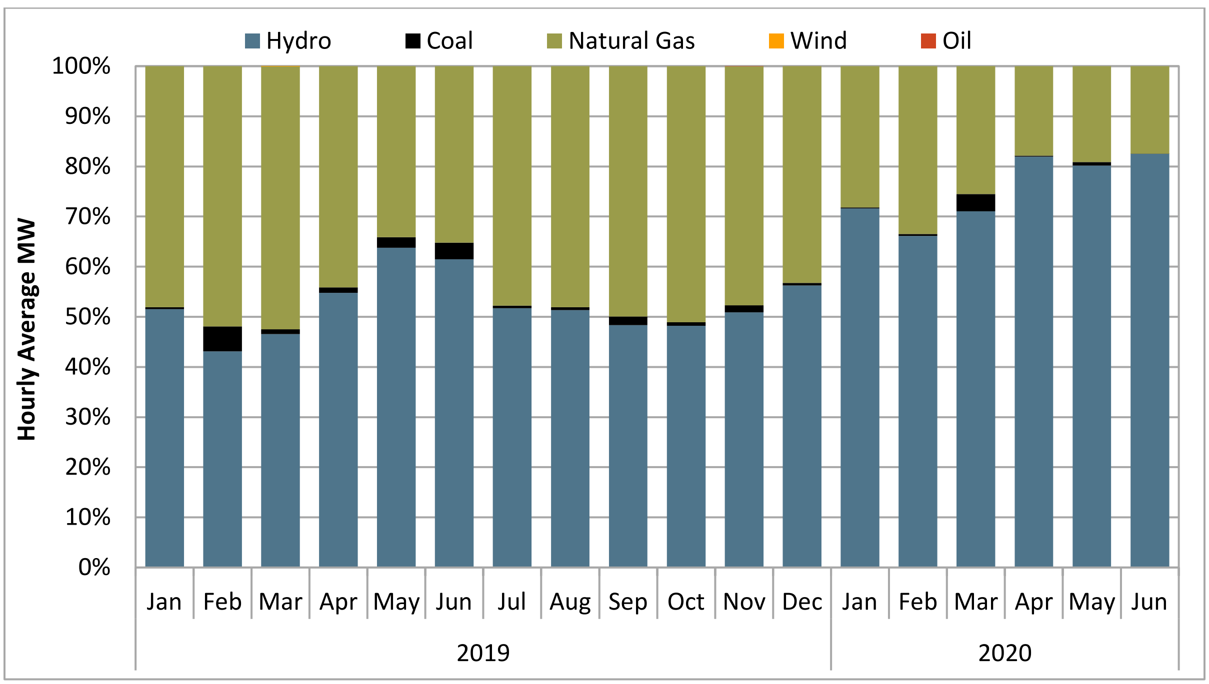


DMM estimates the total revenue accruing for greenhouse gas bids attributed to EIM participating resources serving the ISO load before subtracting estimated compliance costs from greenhouse gas revenue calculated in each interval. This value totaled around $3.8 million in the second quarter, compared to roughly $3.4 million in the same quarter of the previous year.

Energy delivered to California by fuel type

Figure 2.21 shows the hourly average energy deemed delivered to California by fuel type and by month. In the second quarter, about 18 percent of EIM greenhouse gas compliance obligations were awarded to gas resources, a decrease from 38 percent in the second quarter of the previous year. Hydroelectric resources accounted for about 82 percent of total energy delivered to California which increased from around 60 percent in the same quarter of 2019. Additionally, energy originating from coal resources has increased since the policy change, but only accounted for less than 1 percent of energy delivered in the second quarter, compared to around 2 percent in the second quarter of 2019.

Figure 2.21 Hourly average EIM greenhouse gas generation by fuel type



2.6 Mitigation in the EIM

The elimination of carryover mitigation appears to have reduced mitigation rates in the Western EIM. In the second quarter of 2020, average incremental energy with bids lowered due to mitigation declined significantly in the 15-minute and 5-minute markets, compared to the same quarter in 2019. Figure 2.22 and Figure 2.23 highlight the volume of 15-minute and 5-minute market mitigation in all the balancing authority areas in the EIM:

- Blue bars in Figure 2.22 and Figure 2.23 show average incremental energy subject to mitigation but whose bids were not lowered in the 15-minute and 5-minute markets, respectively. In the second quarter of 2020, this portion has increased when compared to the same quarter in 2019. This is in part due to new EIM balancing areas joining the real-time market in April 2020.
- A small volume of bids were lowered as a result of mitigation in the Western EIM.

Figure 2.22 Average incremental energy mitigated in 15-minute real-time market (EIM)

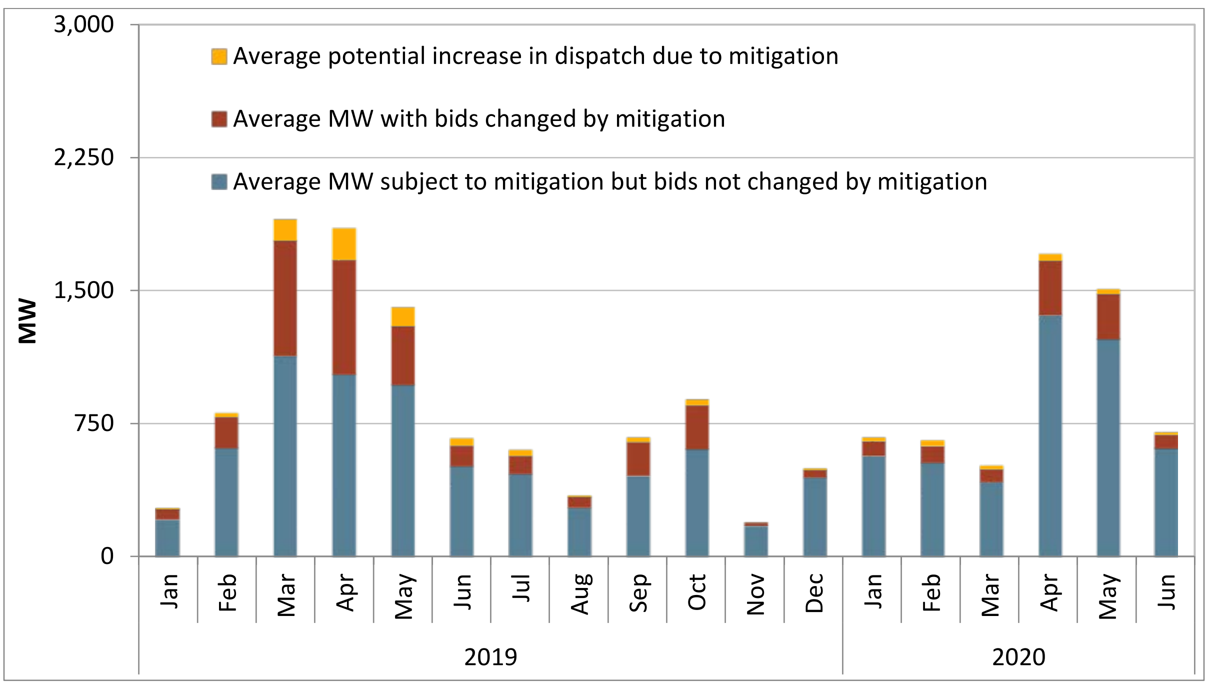
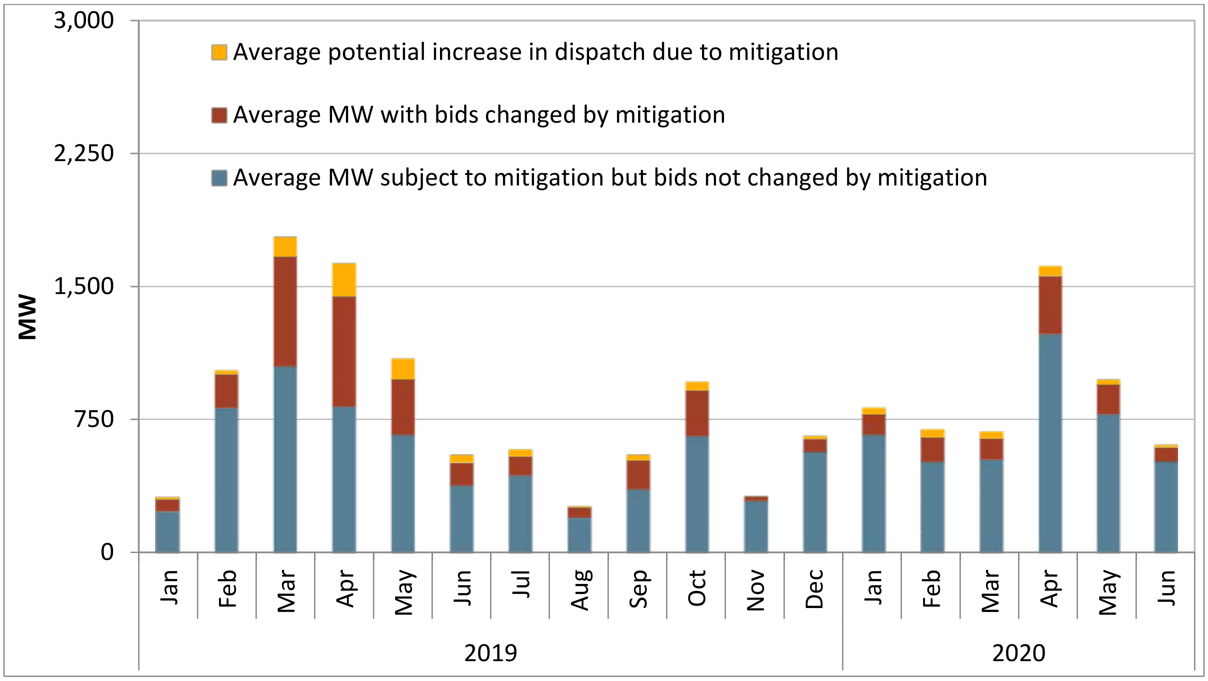


Figure 2.23 Average incremental energy mitigated in 5-minute real-time market (EIM)



3 Special issues

This section provides information about the following special issues:

- **Stay-at-home orders to control COVID-19 reduced load** following a California state-wide public health order to preserve public health effective March 19. Reductions in natural gas prices associated with reduced demand, and lower electricity load have both contributed to lower ISO market prices.
- **DMM estimates that the reductions in load resulted in a reduction of day-ahead market prices** of about $2-$5/MWh during the morning and evening peaks. DMM utilized the ISO's load analysis to estimate this day-ahead market price impact due to the reduction in load due to COVID-19 related stay-at-home orders in the second quarter. These results are most appropriate for the general market conditions that were included in the analysis and should not be extrapolated to the high load situations that occurred later in the summer of 2020. The decreases in gas prices, relative to the first quarter, resulted in decreases in day-ahead energy prices between $4-$14/MWh depending on the time of day.
- **Implementation of the energy storage and distributed energy resources phase 3** initiative has reduced the occurrence of isolated 5-minute dispatches of demand response resources, due to several resources changing to 15-minute and hourly dispatch options. However, resource performance in response to 5-minute dispatches has not appeared to increase commensurately. This initiative created two new demand response dispatch options (hourly and 15-minute) and removed the single load serving entity aggregation requirement which was expected to decrease the registration of demand response resources sized less than 1 MW. So far, implementation of this initiative has resulted in increased utilization of new dispatch options. However, some demand response providers continue to have resources sized less than 1 MW in the same sub-load aggregation points.
- **Downward dispatch of renewable resources was considerably higher** in the ISO for every month of the second quarter compared to the same quarter of 2019. In the energy imbalance market outside of the ISO, this downward dispatch was higher during June 2020. Downward dispatch, often called curtailment, was most often the result of economic downward dispatch rather than self-schedule curtailment.
- **Market results were competitive in the second quarter**. DMM estimates that the impact of gas resources bidding above reference levels, a conservative measure of the average price-cost markup, was about $0.48/MWh or just over 2 percent for the default energy bid scenario.
- **DMM introduced several new competitiveness scenarios**. These include a scenario that replaces bid-in demand with actual load and removes virtual bids, a scenario that caps gas commitment costs at 110 percent of estimated reference levels, and a scenario that caps import bids at a conservative measure of opportunity cost based on the recently introduced hydro default energy bid. DMM also runs combinations of scenarios.
- **The price-cost markup** for the gas default energy bid scenario averaged $0.48/MWh or 2 percent for the second quarter. The markup for that scenario combined with capping of import bids and commitment costs was $0.66/MWh or 3 percent. When this scenario is combined with the physical

scenario including both actual load and removal of virtual bids, the markup fell slightly to $0.56/MWh or 2.5 percent. The slight positive markup for different scenarios indicates that overall prices have been very competitive for this quarter.

- **Market power has had a very limited effect on system market prices** even during hours when the ISO system was structurally uncompetitive. However, DMM has expressed concern that market conditions may evolve in a way that will increase the potential for system-level market power. DMM supports the ISO's proposal to continue with an initiative to design system market power mitigation and looks forward to working with the ISO throughout that process.
- **DMM continues to recommend several other market design changes** that may help mitigate system market power beyond the bid mitigation options being examined as part of this initiative. These include consideration of options that would increase the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time. DMM recommended that the ISO's plan for implementing FERC Order 831 include provisions to (1) ensure that import bids over $1,000/MWh are subject to ex ante cost justification and (2) avoid setting penalty prices at $2,000/MWh except when needed to implement the provisions of Order 831. Overall, DMM supports the ISO's final proposal as a reasonable approach to allowing bids over the $1,000/MWh soft offer cap in compliance with FERC Order 831. However, DMM believes it is prudent to fully analyze and consider how the proposed approach would have worked during system and market conditions that existed during the mid-August heat wave.

3.1 COVID-19

The following analysis details DMM's use of the Market Analysis and Forecasting team's load analysis to estimate the impact the reduction in load due to COVID-19 had on day-ahead market prices during the second quarter. Reductions in natural gas prices, associated with reduced demand, and lower electricity load have both contributed to lower ISO market prices. DMM estimates that the initial reductions in load resulted in a reduction in day-ahead market prices of about $2-$4/MWh during the morning peak and $4-$5/MWh for the evening peak. Lower average load reductions published more recently resulted in a reduction in day-ahead market prices of about $2-$3/MWh during both the morning and evening peaks. Recent decreases in gas prices resulted in decreases in day-ahead energy prices between $4$14/MWh, however these results are impacted by many factors in addition to reduced demand associated with COVID-19. These results are most appropriate for the general market conditions that were included in the analysis and should not be extrapolated to the high load situations that occurred later in the summer of 2020.

Background

In response to the spread of the novel coronavirus causing COVID-19, local governments in California started to declare local health emergencies beginning in February 2020. On March 4, 2020, the governor of California proclaimed a state of emergency to formalize actions needed to prepare the state for the spread of the novel coronavirus. Seven counties around the San Francisco bay area began shelter-in-place orders for residents to not leave their homes except for essential needs. A statewide executive order and a public health order took effect on March 19, 2020, to preserve public health and safety by disrupting the spread of the virus. Californians were directed to stay at their place of residence except to go to an essential job in a critical infrastructure sector or to shop for essential needs.

The economic impacts of the spread of the virus and resulting shelter-in-place orders are numerous and widespread, and therefore difficult to quantify. The same can be said about impacts to the ISO market; however, careful analysis can isolate partial impacts in specific situations. For example, the ISO's Market Analysis and Forecasting team conducted an analysis to calculate how the stay-at-home orders caused a change in the typical load pattern (hereafter referred to as the backcast analysis).[66] Specifically, DMM used two sets of backcast estimates in the current analysis – the initial results that covered March 23 to April 26 as well as the most recent results that covered March 23 to July 26.

DMM took advantage of the backcast analysis to estimate the effect that lower loads due to COVID-19 had on market prices. The basic methodology used was to establish a relationship between load and prices, treat the backcast analysis as a counterfactual of what load would have looked like in the absence of COVID-19, and apply the estimated relationship to counterfactual load to get counterfactual prices. DMM used regression analysis to estimate the relationship that day-ahead load forecast has on day-ahead market prices, while controlling for other market fundamentals. This relationship was then applied to the counterfactual load estimate to determine what day-ahead market prices would have been without the shelter-in-place orders.

Data

The purpose of this analysis is to form a consistent estimate of the relationship between day-ahead load forecast and day-ahead market price that can then be applied to the backcast analysis results. Therefore, it is important to control for other market fundamentals that may affect price, even at similar levels of expected demand. DMM decided to use variables that are determined outside of the ISO system to calculate consistent estimates – as opposed to characteristics and situations that are determined within the ISO system that may affect price.[67]

These other market fundamentals include hourly day-ahead forecast megawatt values of wind and solar resources, daily day-ahead gas prices from SoCal Citygate, as well as self-scheduled megawatt values from hydro resources in the day-ahead market to proxy for hydrological conditions.[68] The sampled data spanned from September 1, 2018, to June 30, 2020. This time period was chosen due to relatively low congestion to aid in the consistency of coefficient estimates.[69]

---

[66] *COVID-19 impacts to California ISO Load & Markets, July 31, 2020*: http://www.caiso.com/Documents/COVID-19-Impacts-ISOLoadForecast-Presentation.pdf

[67] In other words, DMM decided to use exogenous explanatory variables as opposed to endogenous ones.

[68] Models were also run using prices from different gas hubs such as PG&E Citygate and Kern Delivery. Results remained robust to gas hub choice.

[69] The sampled time period includes all of the dates in this quarter, including those where loads were impacted by the shelter-in-place orders. The inclusion of these dates in the regressions should not be an issue because it is assumed that these orders affected load levels and not the fundamental relationship between supply and demand in forming energy prices during this time period.

Model [70]

DMM used regression analysis to establish a relationship between load forecast and day-ahead market prices. After conducting a literature review, DMM followed the general methodology of a group of studies that specifically investigate the determinants of electricity prices in ISOs. Woo et al. (2016, 2017, and 2018) and Zarnikau et al. (2020) use systems of seemingly unrelated regressions to either measure the determinants of electricity prices or measure the impact of different policies while controlling for market fundamentals.[71] In this analysis, DMM used a system of seemingly unrelated regressions to estimate the determinants of hourly day-ahead electricity prices.[72]

In order to reduce the total amount of parameters to be estimated, data is averaged over hourly bins instead of using a system of 24 hourly regressions. These bins are consistent with the cited literature and include hour-ending one to hour-ending six, HE7-10, HE11-14, HE15-18, HE19-22, and HE23-24.

The model takes the following form:

$$Price_{k,t} = \beta_1 * log(Load\ forecast)_{k,t} + \beta_2 * log(VER\ forecast)_{k,t} + \beta_3 * log(Gas\ price)_t + \beta_4 * log(Hydro\ self - schedules)_{k,t} + \alpha_{k,t} + \epsilon_{k,t}$$

where $Price_{k,t}$ is the average day-ahead energy price for each hour bin k (HE1-6, HE7-10, etc.) for each day t in the sample; $Load\ forecast_{k,t}$ is the average day-ahead load forecast MW value for hour bin k on day t; $VER\ forecast_{k,t}$ is the sum of the day-ahead forecast MW value for wind and solar resources averaged over hour bin k on day t; $Gas\ price_t$ is the day-ahead gas price at SoCal Citygate for day t; $Hydro\ self - schedules_{k,t}$ is the average MW value of self-schedules in the day-ahead market from hydro resources for hour bin k on day t; $\alpha_{k,t}$ is a vector of intercepts for the day-ahead market price's hour bin, day-type (week or weekend), and month of the year; and $\epsilon_{k,t}$ is a random error term that is

70 **References**

Woo, Chi-Keung, Jack Moore, Brendan Schneiderman, Tony Ho, Arne Olson, Lakshmi Alagappan, Kiran Chawla, Nate Toyama, and Jay Zarnikau, J. (2016). Merit-order effects of renewable energy and price divergence in California's day-ahead and real-time electricity markets. *Energy Policy*, *92*, 299-312.

Woo, C. K., Chen, Y., Olson, A., Moore, J., Schlag, N., Ong, A., & Ho, T. (2017). Electricity price behavior and carbon trading: new evidence from California. *Applied Energy*, *204*, 531-543.

Woo, C. K., Chen, Y., Zarnikau, J., Olson, A., Moore, J., & Ho, T. (2018). Carbon trading's impact on California's real-time electricity market prices. *Energy*, *159*, 579-587.

Zarnikau, J., Tsai, C. H., & Woo, C. K. (2020). Determinants of the wholesale prices of energy and ancillary services in the Midcontinent electricity market. Energy, 195, 117051.

71 In the context of hourly electricity prices, the system of regressions treats each hour in the day as its own time series where the prices in hour ending one throughout the sample are explained by the control variable values in hour ending one, hour ending two prices are explained by the control variable values in hour ending two, and so on.

72 Though not perfect, this system of seemingly unrelated regressions mimics the way the day-ahead market functions better than a single autoregressive model. An autoregressive model in this context assumes the information set updates between each hour of the day. The day-ahead market does not function this way, however, because bids are submitted before the market run where day-ahead hourly prices are determined jointly. Indeed, the seemingly unrelated regression models performed better than other methodologies that DMM tested such as autoregressive models and panel data regressions.

assumed to be correlated across hour bins k within the same day t.[73] The continuous independent variables are logged, but the dependent price variable is not due to the presence of negative prices in the sample.

β_1 is the coefficient of interest in this model as it signifies the impact that a change in the day-ahead load forecast has on day-ahead price changes.[74] This estimate can then be applied to the backcast analysis results to determine the effect that COVID-19 driven changes in load had on day-ahead market prices.

Model results

Table 3.1 shows the coefficient estimates from the model. The signs of the estimates are in line with expectations – higher forecasted load causes day-ahead energy prices to increase, higher forecasted VER production causes day-ahead energy prices to decrease, higher gas prices cause day-ahead energy prices to increase, and higher hydrological production causes day-ahead energy prices to decrease. These effects vary throughout the day as evidenced by the variation in coefficient estimates across hour bins.

[73] This model explicitly controls for autocorrelation within hour bins, but does not explicitly specify the form of heteroscedasticity in the error terms. Similar to Woo et al. (2017), DMM chose an AR(2) process to control for autocorrelation since AR(n>2) processes have insignificant estimates and inclusion of higher order AR processes does not affect the coefficients of interest. Also consistent with the study, DMM used heteroscedasticity-consistent standard errors to ensure robust coefficient estimates.

[74] In the chosen methodology, β_1 measures the impact of load on market prices independent of other market price determinants, where price is allowed to be correlated with the prices in the other hour bins within the same day as well as be affected by price shocks over the previous two days.

Table 3.1 Seemingly unrelated regression results for determinants of day-ahead energy prices

	HE1-6	HE7-10	HE11-14	HE15-18	HE19-22	HE23-24
log(Load forecast)	29.42	54.37	49.89	64.46	89.05	28.89
	(3.54)	(6.78)	(12.82)	(17.06)	(11.16)	(5.27)
log(VER forecast)	-2.47	-7.41	-18.46	-11.11	-5.13	-2.86
	(-3.25)	(-5.54)	(-10.92)	(-9.91)	(-5.51)	(-4.26)
log(Gas price)	22.31	25.18	13.31	22.19	37.15	26.38
	(8.23)	(8.81)	(7.57)	(9.41)	(10.92)	(10.23)
log(Hydro self-schedules)	-3.30	-2.95	-3.31	-5.89	*-0.89*	-3.05
	(-2.66)	(-2.41)	(-3.55)	(-4.41)	*(-0.51)*	(-2.23)
Observations	669	669	669	669	669	669
Adjusted R-squared	0.869	0.888	0.907	0.922	0.857	0.867
AR(2) error	Yes	Yes	Yes	Yes	Yes	Yes
Hour, day-type, month intercepts	Yes	Yes	Yes	Yes	Yes	Yes
HCCME standard errors	Yes	Yes	Yes	Yes	Yes	Yes

Results from linear-log, iterated seemingly unrelated regressions of hourly day-ahead market price on load forecast, variable energy resource forecast, daily Socal-Citygate gas price, and self-scheduled hydro generation. Models include AR(2) errors as well as hour, day-type, and month intercepts. Standard errors adjusted for heteroscedasticity. Estimated coefficients are presented with t-stats in parentheses. Coefficients that are not statistically significant are italicized.

Due to the linear-log nature of the model specification, the coefficient mean estimate of 54.37 for the HE7-10 bin translates to an increase in day-ahead market prices of $0.54 with a one percent increase in load forecast.[75] Similarly, a one percent *decrease* in load forecast translates to a *decrease* in day-ahead market price between $0.29 and $0.89 depending on the time of day according to the mean estimates of the hour bins.

Important to the later steps of this analysis, these effects can be scaled to larger changes in load. However, estimates are less accurate the further away from the mean these changes are made. It is also important to note that there is uncertainty involved in these estimates. Therefore, final results should be presented as ranges of values to reflect this uncertainty.

75 This effect is approximated by the formula $\left(\frac{\beta_1}{100}\right) * \%\Delta x = \Delta y$. In this case, $\left(\frac{54.37}{100}\right) * 1 = 0.54$.

Analysis results

Figure 3.1 and Figure 3.2 present the estimated impact load reductions had on day-ahead prices using the load forecast coefficient estimates from Table 3.1 and the load reduction estimates from the initial and final backcast analyses.[76]

Figure 3.1 Effect of initial backcast load reduction estimates on price

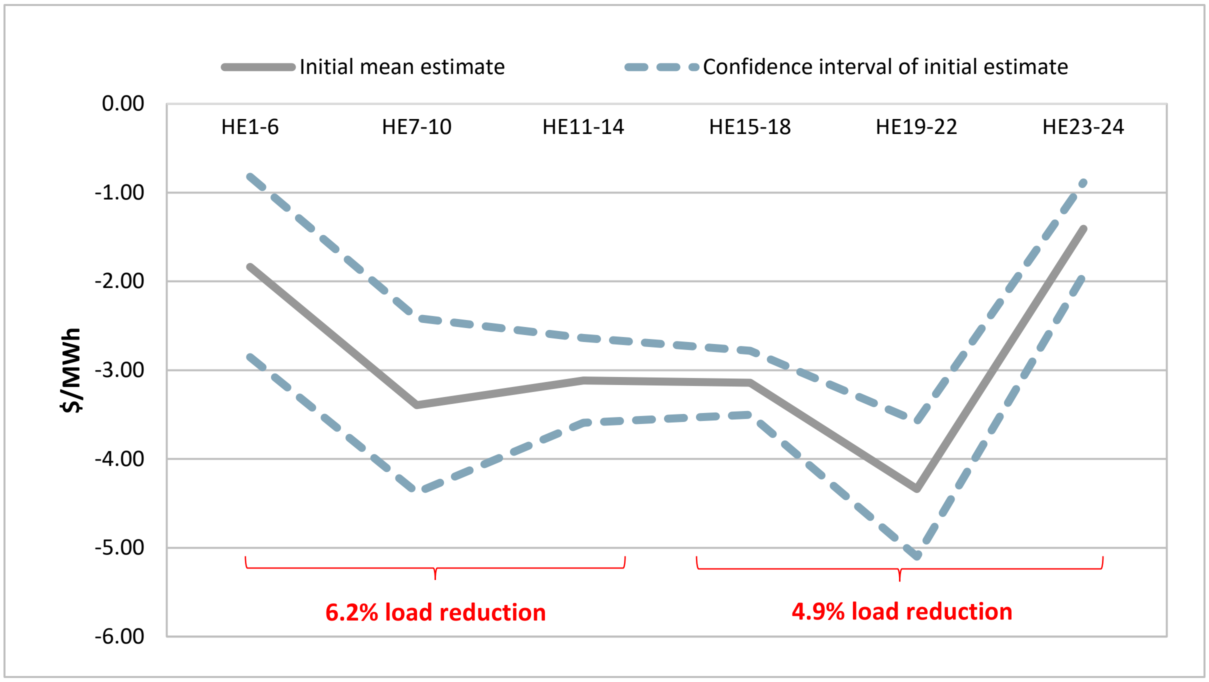


Figure 3.1 illustrates the effect of the estimated load reductions from the first backcast analysis on day-ahead prices while accounting for the uncertainty of coefficient estimates from DMM's econometric model. Mean estimates are presented as a solid line while the 95 percent confidence interval is shown as the dashed lines. According to the backcast analysis for March 23 to April 26, the initial impacts of COVID-19 were a drop in morning peak load of about 6.2 percent and a drop in evening peak load of about 4.9 percent.[77]

Using HE7-10 as the appropriate hour bin for morning peak load, the interpretation of the coefficient estimate of 54.37 translates to a mean estimate of a $3.39/MWh reduction in day-ahead prices with a

[76] Load reductions from the backcast analyses are reported for morning and evening peak loads. For illustrative purposes in these figures, the morning peak load reduction value is applied to the coefficient estimates for HE1-6, HE7-10, and HE11-14, and the evening peak load reduction value is applied to the coefficient estimates for HE15-18, HE19-22, and HE23-24. DMM's final analysis results just applies the morning peak load reduction value to the HE7-10 coefficient estimate and the afternoon peak load reduction value to the HE19-22 coefficient estimate.

[77] Actual reported values were reductions in morning peak load of 7.5 percent for weekdays and 3.1 percent for weekends and reductions in evening peak load of 6.5 percent for weekdays and 0.8 percent for weekends. Since DMM controls for day-type explicitly in the model, the backcast analysis numbers are reported here as weighted averages for the morning and evening peak loads.

reduction range of \$2.41/MWh to \$4.38/MWh from a 6.2 percent reduction in load.[78] Similarly, using HE19-22 as the appropriate hour bin for evening peak load, the interpretation of the coefficient estimate of 89.05 translates to a mean estimate of \$4.34/MWh reduction in day-ahead prices with a reduction range of \$3.58/MWh to \$5.10/MWh from a 4.9 percent reduction in load.[79]

Figure 3.2 Effect of later backcast load reduction estimates on price

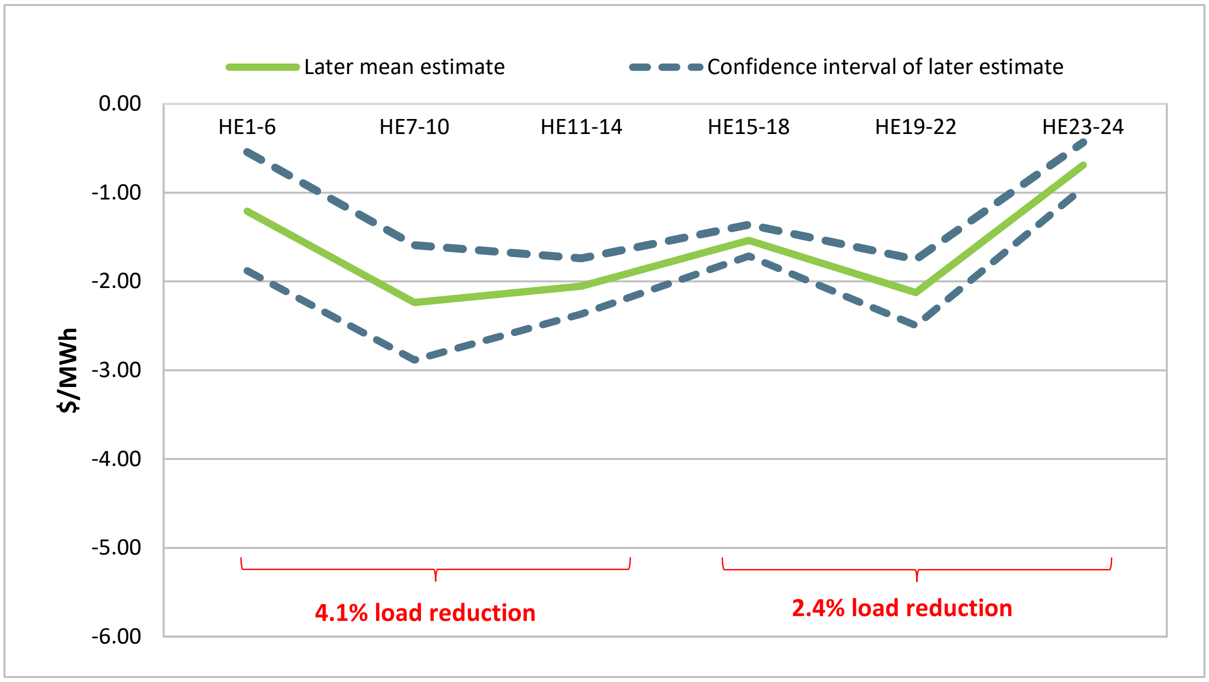


Figure 3.2 illustrates the effect of the estimated load reductions from the most recent backcast analysis on day-ahead prices while accounting for the uncertainty of coefficient estimates from DMM's econometric model. According to the backcast analysis for March 23 to July 26, the longer-term impacts of COVID-19 were a drop in morning peak load of about 4.1 percent and a drop in evening peak load of about 2.4 percent.[80] This longer time period gives a more complete picture of the persistent effect the

78 The mean estimate is calculated by $\left(\frac{54.37}{100}\right) * (-6.24) = -3.39$. With a standard error of 8.03 and a z-score of 1.96, this translates to an estimated range of $\left(\frac{54.37-8.03*1.96}{100}\right) * (-6.24) = -2.41$ to $\left(\frac{54.31+8.03*1.96}{100}\right) * (-6.24) = -4.38$.

79 The mean estimate is calculated by $\left(\frac{89.05}{100}\right) * (-4.87) = -4.34$. With a standard error of 7.98 and a z-score of 1.96, this translates to an estimated range of $\left(\frac{89.05-7.98*1.96}{100}\right) * (-4.87) = -3.58$ to $\left(\frac{89.05+7.98*1.96}{100}\right) * (-4.87) = -5.10$.

80 Actual reported values were reductions in morning peak load of 5 percent for weekdays and 1.9 percent for weekends and reductions in evening peak load of 2.9 percent for weekdays and 1.1 percent for weekends. Since DMM controls for day-type explicitly in the model, the backcast analysis numbers are reported here as weighted averages for the morning and evening peak loads.

shelter-in-place orders had on load reductions, however, the lower reported reductions compared to the initial report could result from forecasting improvements over time.[81]

Using HE7-10 as the appropriate hour bin for morning peak load, the interpretation of the coefficient estimate of 54.37 translates to a mean estimate of a $2.24/MWh reduction in day-ahead prices with a reduction range of $1.59/MWh to $2.88/MWh from a 4.1 percent reduction in load.[82] Similarly, using HE19-22 as the appropriate hour bin for evening peak load, the interpretation of the coefficient estimate of 89.05 translates to a mean estimate of $2.12/MWh reduction in day-ahead prices with a reduction range of $1.75/MWh to $2.50/MWh from a 2.4 percent reduction in load.[83]

The model results in Table 3.1 also show how changes in other market fundamentals affect day-ahead prices. For example, the mean estimate for gas price in the HE19-22 bin shows that a one percent increase in gas price results in a $0.37/MWh increase in day-ahead energy price during the evening peak, on average. Applying this coefficient estimate to recent changes in gas prices is informative, although, without a counterfactual backcast analysis, it does not allow estimation of a causal relationship between COVID-related gas price reductions and energy prices.

As shown in Section 1.1.1, gas prices at SoCal Citygate during this quarter decreased by 31 percent from the second quarter of 2019 and 39 percent from the first quarter of 2020. Depending on the quarter and hour bin used, this decrease in gas price translates to a decrease in energy prices in the range of $4-$12/MWh or $5-$14/MWh. These changes in gas prices were due to a mixture of factors including lower demand because of COVID-19 as well as increased access to gas supply. Therefore, these estimated impacts reflect multiple confounding factors and are not interpreted as causal impacts from COVID-19.

Conclusion

Using regression analysis, DMM established the impact that a marginal change in load has on day-ahead prices while controlling for other market fundamentals that affect price. According to this analysis, a one percent change in load leads to a change in day-ahead prices of about $0.54/MWh during the morning peak and about $0.89/MWh during the evening peak, on average. This relationship was applied to the load backcast analysis done by the ISO's Market Analysis and Forecasting team to estimate the impact that reduced loads caused by COVID-19 had on day-ahead market prices.

The impact that reduced loads caused by COVID-19 had on day-ahead market prices is dependent on the magnitude of reduced load. DMM used a range of load reduction estimates from the initial and most recent backcast analyses to quantify the impact on prices. Accounting for the uncertainty in the regression coefficient estimates, reduced loads of 4.1 to 6.2 percent during the morning peak reduced day-ahead prices by about $1.59/MWh to $4.38/MWh while reduced loads of 2.4 to 4.9 percent during the evening peak reduced day-ahead prices by $1.75/MWh to $5.10/MWh. Recent decreases in gas

---

81 This could reduce the gap between forecasted load and the counterfactual load and bias the price impact estimates lower than the true effect. Regardless, DMM has included the results in the current analysis because it is still informative to include in a range of possible effects.

82 The mean estimate is calculated by $\left(\frac{54.37}{100}\right) * (-4.11) = -2.24$. With a standard error of 8.03 and a z-score of 1.96, this translates to an estimated range of $\left(\frac{54.37-8.03*1.96}{100}\right) * (-4.11) = -1.59$ to $\left(\frac{54.31+8.03*1.96}{100}\right) * (-4.11) = -2.88$.

83 The mean estimate is calculated by $\left(\frac{89.05}{100}\right) * (-4.87) = -2.12$. With a standard error of 7.98 and a z-score of 1.96, this translates to an estimated range of $\left(\frac{89.05-7.98*1.96}{100}\right) * (-2.39) = -1.75$ to $\left(\frac{89.05+7.98*1.96}{100}\right) * (-2.39) = -2.50$.

prices resulted in decreases in day-ahead energy prices between $4-$14/MWh, however these results are impacted by many factors in addition to COVID-19 and are therefore should not be interpreted as causal in nature.

The methodology and results developed in this analysis are most appropriate for relatively small reductions in load during periods of the medium to low loads that were characteristic of the time period analyzed. They should not be extrapolated to periods of high loads such as those experienced during the summer months of 2020.

3.2 Downward dispatch and curtailment of variable energy resources

When the amount of supply on-line exceeds demand, the real-time 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 3.3 shows the curtailment of wind and solar resources by month in the ISO. Curtailments fall into six categories:

- **economic downward dispatch**, in which an economically bid resource is dispatched down and the market price falls within one dollar of a resource bid, below a resource bid, or the resource's upper limit is binding;[84]
- **exceptional economic downward dispatch**, in which a resource receives an exceptional dispatch or out of market instruction to decrease dispatch;
- **other economic downward dispatch**, in which the market price is greater than one dollar above a resource bid and that resource is dispatched down;
- **self-schedule curtailment**, in which a price-taking self-scheduled resource receives an instruction to reduce output while the market price is below a resource bid or the resource's upper limit is binding;
- **exceptional self-schedule curtailment**, in which a self-scheduled resource receives an exceptional dispatch or out of market instruction to reduce output; and
- **other self-schedule curtailment**, in which a self-scheduled resource receives an instruction to reduce output and the market price is above the bid floor.

The majority of the reduction in wind and solar output during the second quarter of 2020 was a result of economic downward dispatch, rather than self-schedule curtailment. Most renewable generation dispatched down in the ISO were solar resources, rather than wind, because solar resources bid more economic downward capacity.

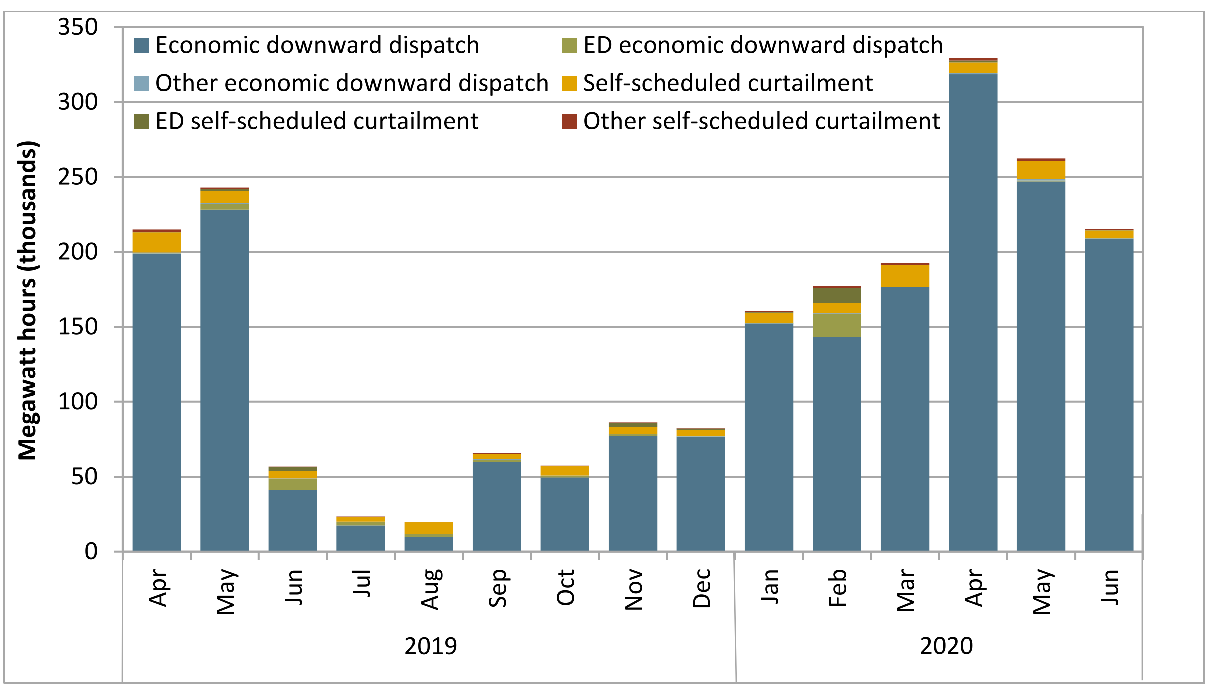
84 A resource's upper limit is determined by a variety of factors and can vary throughout the day.

In the ISO, economic downward dispatch was considerably higher in every month of the second quarter compared to the same quarter of 2019. Economic downward dispatch accounted for about 318,500 MWh of curtailment in April 2020, compared to 199,000 MWh during the same time in 2019. The high level of economic downward dispatch over the quarter was due to higher renewable production, lower load, and congestion from south to north. April also experienced the largest exceptional dispatch curtailments of both self-scheduled and economic bid resources during the quarter, totaling about 1,400 MWh.

Downward dispatch also increased in the energy imbalance market areas outside of the ISO. Figure 3.4 shows the amount of downward dispatch of non ISO wind and solar resources. Curtailments fall into four categories: economic downward dispatch, other economic downward dispatch, self-schedule curtailment, and other self-schedule curtailment, each defined above. Economic downward dispatch in the EIM during June 2020 reached about 16,100 MWh, a large increase compared to the roughly 2,400 MWh in June 2019. This increase was related to the high frequency of congestion on the Wyoming Export constraint, which led to one resource being heavily curtailed.[85]

Figure 3.5 and Figure 3.6 show the quarterly average reduction of wind and solar generation by type for ISO and EIM areas, respectively. In both ISO and EIM areas, economic downward dispatch represents about 96 percent of total curtailments on average for the second quarter. In the ISO, self-scheduled resources being curtailed represented 3 percent, while combined exceptional dispatches were less than half a percent.

Figure 3.3 Reduction of wind and solar generation by month (ISO)



85 The Wyoming_Export constraint was congested during 33.4 percent of intervals during the quarter as shown in Table 1.6. The overall effects of transfer congestion are discussed in detail in Section 1.10.2.

Figure 3.4 Reduction of wind and solar generation by month (EIM)

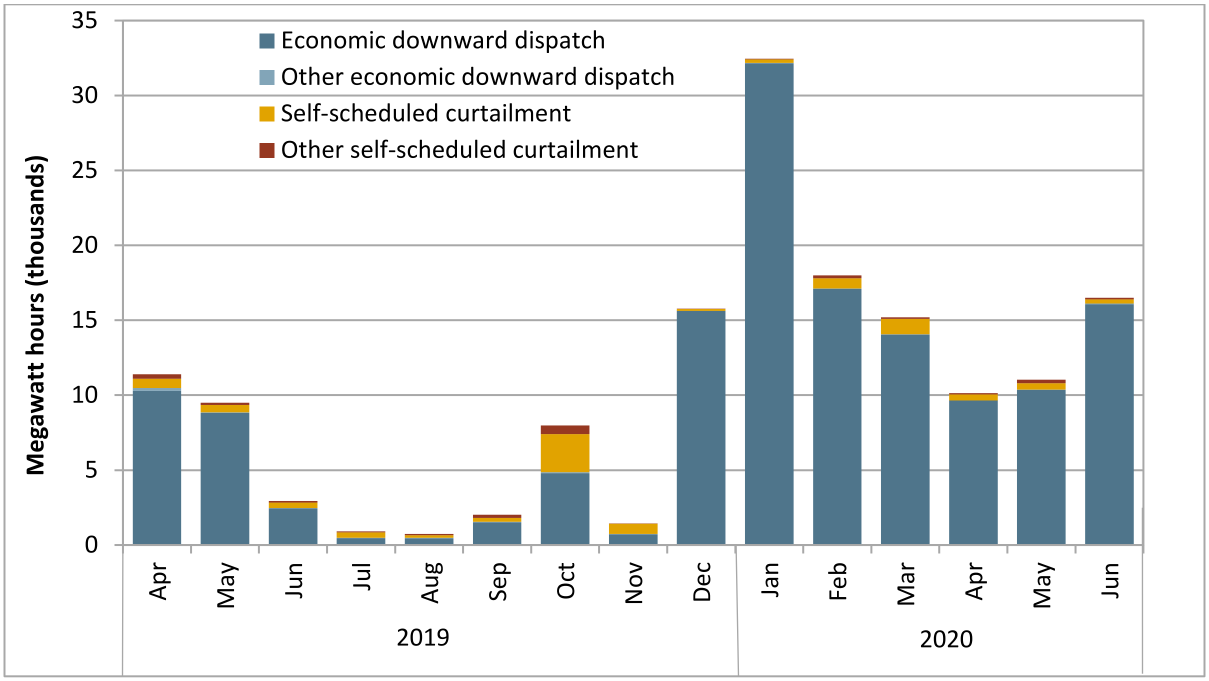


Figure 3.5 Second quarter average reduction of wind and solar generation by type (ISO)

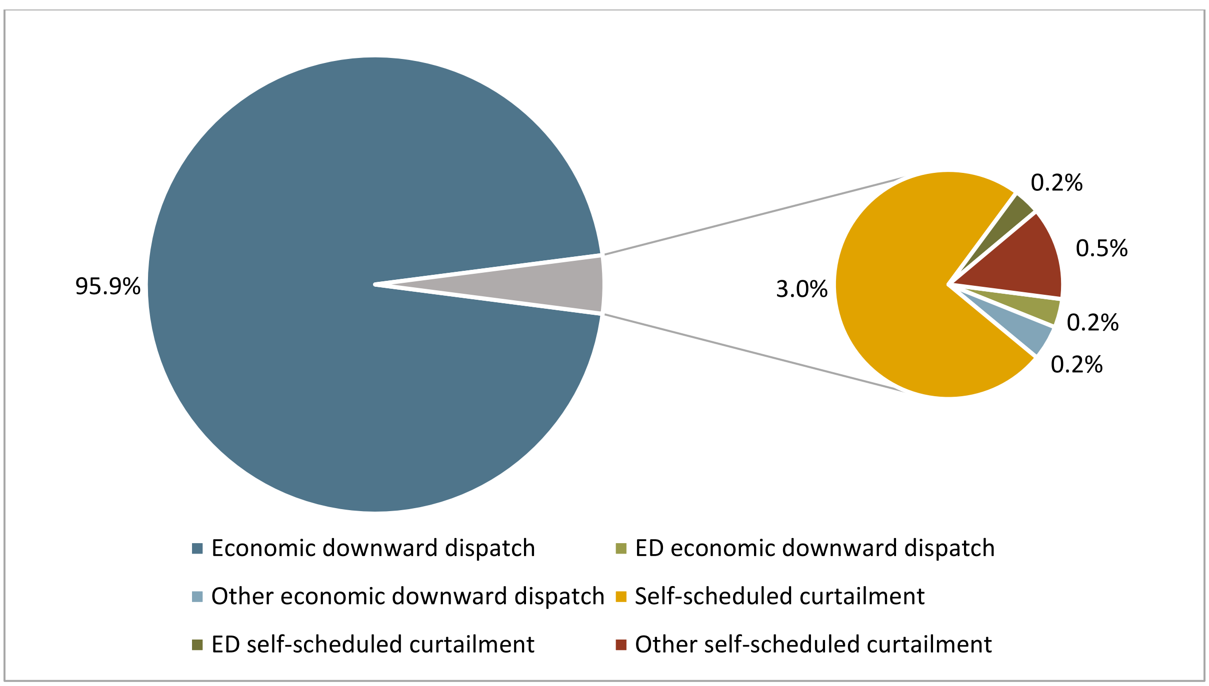
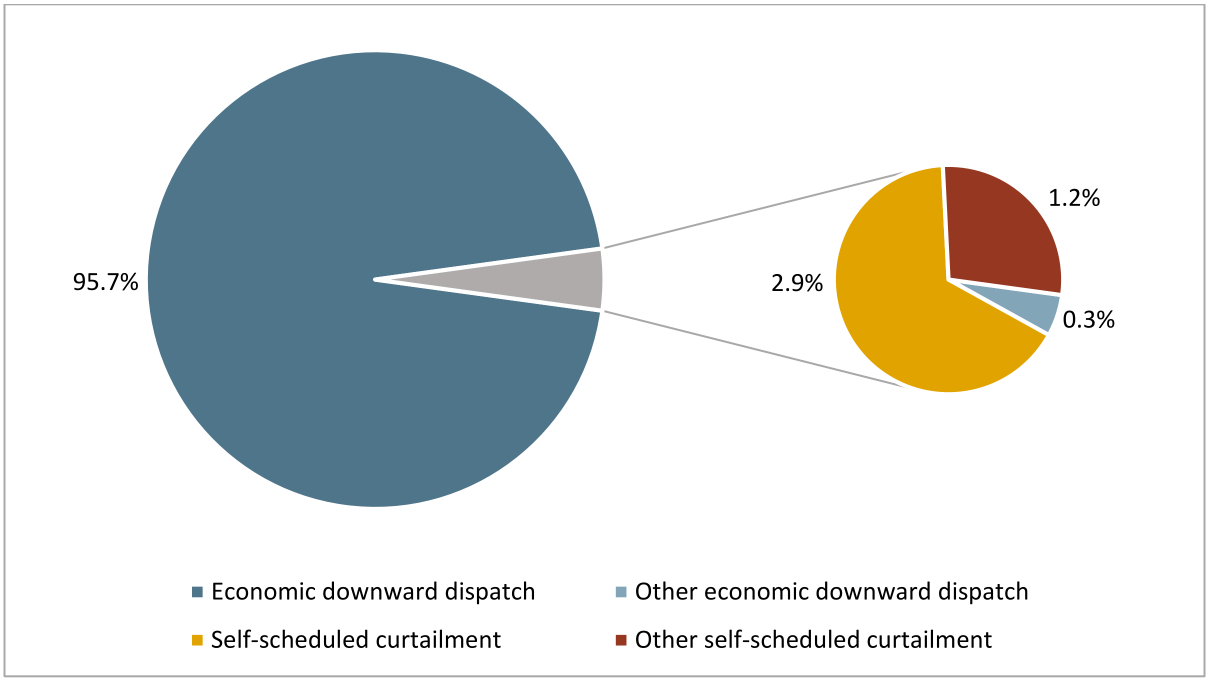


Figure 3.6 Second quarter average reduction of wind and solar generation by type (EIM)



3.3 Energy storage and distributed energy resources

Through the first half of 2020, the battery fleet participating and bidding in the ISO market had a total minimum and maximum registered capacity of about -134 MW and 137 MW and continued to be dispatched primarily for ancillary services rather than energy. If all of the energy storage projects seeking 2020 interconnection remain on track, the ISO expects to have roughly 923 MW of battery storage online by the end of 2020.[86] As of June 2020, 95 percent of all demand response resources have switched to 15-minute or hourly dispatch options. These resources represent 93 percent of total registered demand response capacity.

Batteries

DMM has reported on bidding trends of batteries operating under the ISO's non-generator resource (NGR) model in the day-ahead market.[87] Because the day-ahead market horizon spans 24 hours, the day-ahead market can optimize battery schedules based on price spreads between a resource's bids to charge and discharge in the lowest and highest net load hours in the day. However, the real-time market generally does not look out far enough to be able to capture price spreads between the lowest and highest net load hours in a day. Because of the limited real-time look ahead horizon, the real-time

86 *Most powerful US battery system charges up in California storage surge*, June 24 2020: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/most-powerful-us-battery-system-charges-up-in-calif-storage-surge-59164757

87 *2019 Annual Report on Market Issues and Performance*, Department of Market Monitoring, July 2020, p. 50: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

market has limited ability to schedule batteries to provide energy incremental to day-ahead schedules. Batteries could be scheduled to provide energy incremental to day-ahead schedules in real-time if price spreads between charge and discharge bids are economic in a shorter time horizon, or if charge or discharge bids are independently economic in an interval and a resource's state of charge can support the schedule.

DMM cited the economics of battery resource charge bids and the limited real-time look ahead horizon as two reasons why batteries may have limited ability to provide additional energy in real-time.[88] If a battery resource's charge bids are uneconomic in the lowest net load hours of the day, the battery may not be charged further in real-time and thus cannot increase its state of charge to be able to discharge incrementally later in the day. Batteries may also have little room to move incrementally in real-time because these resources are typically awarded significant ancillary service awards in the day-ahead market, which are subsequently carried into real-time.

Figure 3.7 shows the average dispatch range that is available to the real-time market across the battery fleet. This capacity represents batteries' operating range that is not covered by real-time self-schedules or day-ahead ancillary service awards carried into real-time. In 2019, the battery fleet participating in the ISO market had a total minimum and maximum registered capacity of about -134 MW and 136 MW. Through the first half of 2020, the battery fleet participating and bidding in the ISO market had a total minimum and maximum registered capacity of about -134 MW and 137 MW. As shown in Figure 3.7, only a fraction of the total operating range of the battery fleet is available to be scheduled incrementally in real-time in both charge and discharge directions. This is primarily due to battery resources receiving significant ancillary service awards in the day-ahead market in both upward and downward directions and, in some instances, self-scheduling day-ahead energy awards into real-time.

Figure 3.8 shows the average real-time energy bids of battery resources for the portion of resources' dispatch range that is available to the real-time market (i.e., the dispatch range reflected in Figure 3.7). As shown in Figure 3.8, compared to nodal prices, battery discharge bids were generally economic between hours ending 18 and 21. However, incremental real-time energy schedules on battery resources often appeared to be limited by the economics of charge bids, and the fact that the real-time market does not look out far enough to capture price spreads between the lowest and highest net load hours. For example in the second quarter of 2020, despite discharge bids appearing economic in hours 18-22, on average charge bids were not economic. Because real-time market runs for the lowest price hours would not look out far enough to capture evening hours, the market may not move resources to charge earlier in the day. Despite discharge bids appearing economic in evening hours, lack of additional charge earlier in the day may leave a resource with insufficient state of charge to discharge energy in evening hours.

88 *Ibid.*, p. 50.

Figure 3.7 Average available real-time dispatch range on battery resources (2019 – Q2 2020)

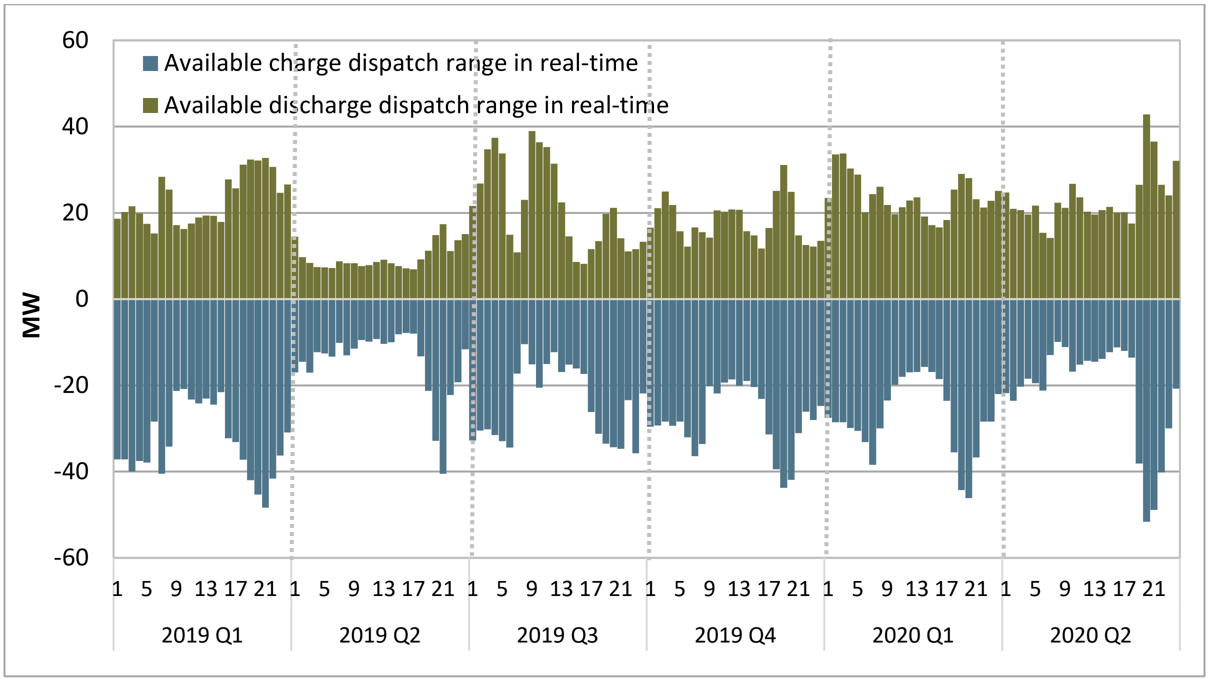
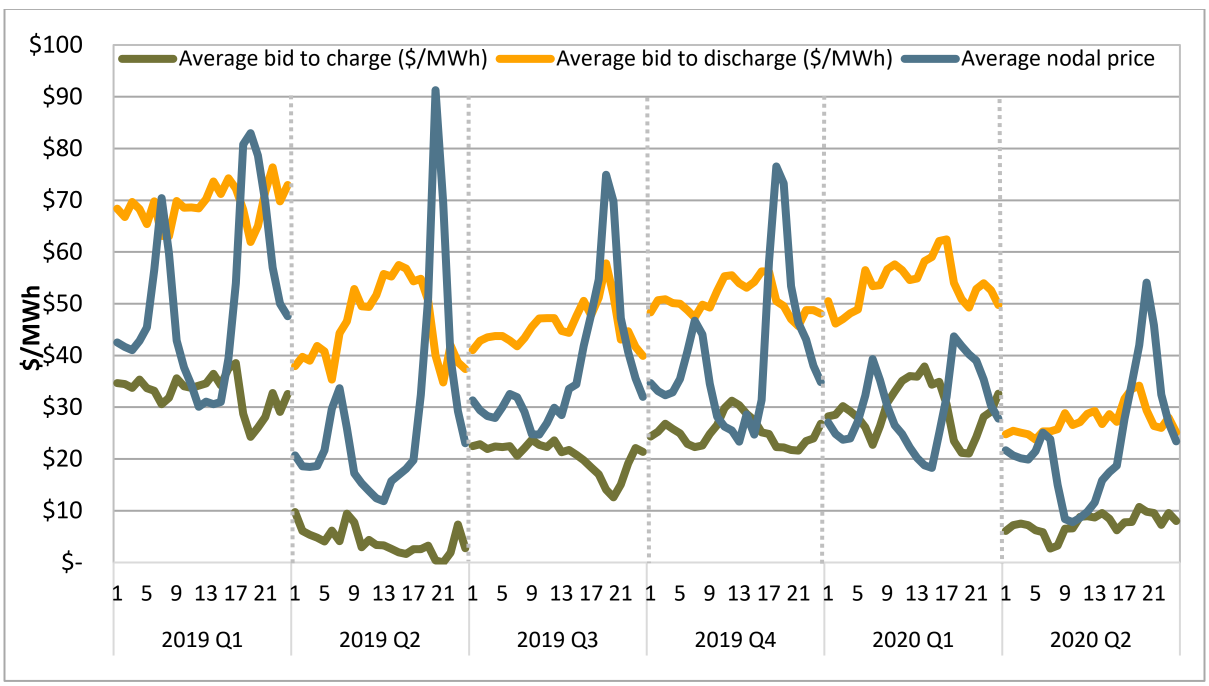


Figure 3.8 Average real-time battery bids and nodal prices (2019 – Q2 2020)



Demand response

Impact of energy storage and distributed energy resources phase 3 initiative

The ISO's energy storage and distributed energy resources stakeholder process focuses on enhancing rules governing the participation of energy storage and distribution-connected resources in the ISO's markets. The ISO proposed the following enhancements in phase 3 of this stakeholder process which were implemented on November 13, 2019:[89]

1. Introduce hourly and 15-minute real-time dispatch options for demand response resources to address concerns that many of these resources cannot respond to 5-minute dispatches.
2. Remove the single load serving entity aggregation requirement and application of a default load adjustment.

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

DMM reported that through the end of 2019, less than 1 percent of total demand response capacity registered with the ISO had changed to 15-minute or hourly real-time dispatch options.[90] Despite low response rates with respect to real-time dispatch instructions, many demand response resources continued to be modeled as 5-minute dispatchable through 2019 and early 2020.

In early 2020, the ISO began to reach out to demand response providers about use of the new dispatch options for resources unable to respond to 5-minute dispatch instructions. As of June 2020, 95 percent of all demand response resources have switched to 15-minute or hourly dispatch options. These resources represent 93 percent of total registered demand response capacity.

The shift of demand response resources to 15-minute and hourly dispatch options has resulted in significantly less flexible ramping product being awarded to these resources, which addresses some of DMM's concern that flexible ramp has been awarded to resources incapable of actually providing flexibility in real-time. Use of 15-minute and hourly dispatch options has also resulted in demand response resources receiving fewer isolated 5-minute dispatch instructions.

Figure 3.9 shows total 5-minute market energy schedules on proxy demand response resources that were not associated with day-ahead awards or schedules carried into the 5-minute market either due to self-schedules or use of 15-minute or hourly dispatch options. Compared to June of last year, these isolated 5-minute dispatches decreased significantly in June 2020. While slightly less proxy demand response capacity has been bid on average into real-time in 2020, this capacity has been bid at lower prices compared to 2019 which has contributed to higher overall proxy demand response real-time schedules this year. However, use of 15-minute and hourly bid options has shifted real-time schedules

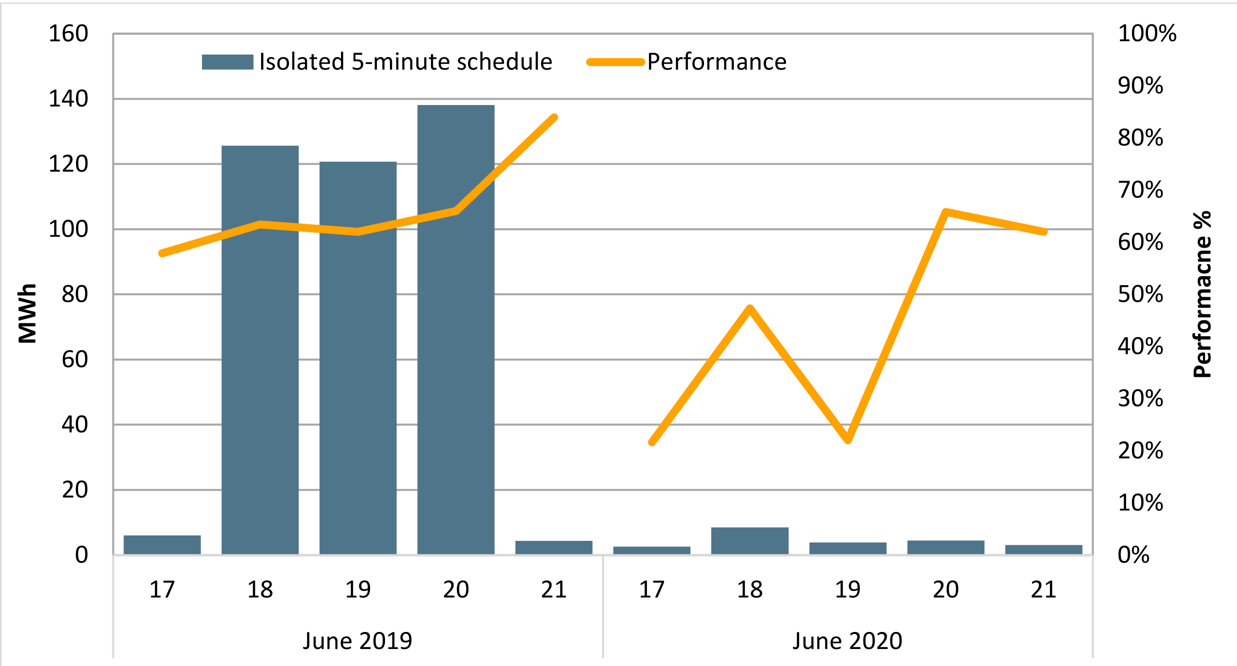
---

89 *Energy storage and distributed energy resources phase 3 draft final proposal*, California ISO, July 11, 2018: http://www.caiso.com/InitiativeDocuments/RevisedDraftFinalProposal-EnergyStorage-DistributedEnergyResourcesPhase3.pdf
In phase 3, the ISO also proposed a load shift product for behind the meter storage resources under the proxy demand response participation model and to recognize behind the meter curtailment of electric vehicle supply equipment load. These two proposals were filed with FERC on July 16, 2020 (ER20-2443) and are scheduled to be implemented in fall 2020.

90 *2019 Annual Report on Market Issues and Performance*, Department of Market Monitoring, July 2020, p. 304. http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

to the hour ahead scheduling process (HASP) and 15-minute markets instead of the 5-minute market. Despite the reduction in isolated 5-minute market dispatches, performance in response to these 5-minute dispatches has not improved.

Figure 3.9 Demand response isolated 5-minute market dispatches and performance

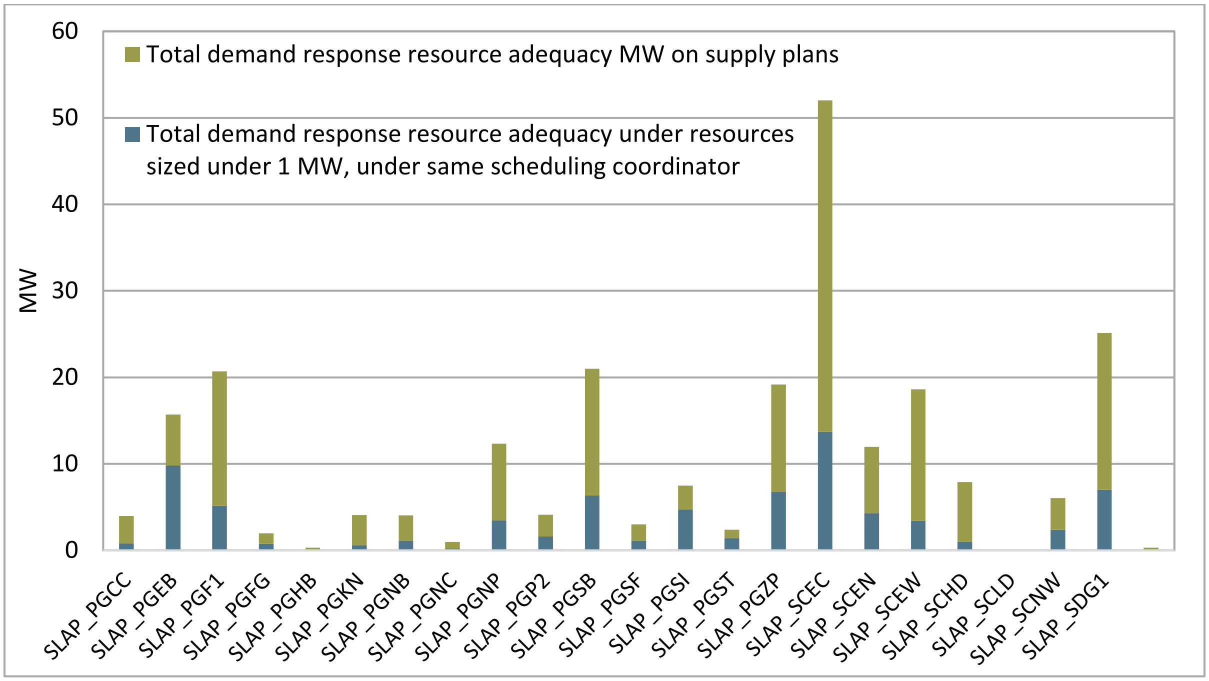


DMM also expected that the removal of the single load serving entity requirement for demand response aggregations could increase the volume of resource adequacy demand response aggregations sized 1 MW or larger, thus increasing the volume of demand response capacity subject to the ISO's resource adequacy availability incentive mechanism. Despite the ISO's removal of the single load serving entity requirement, DMM observed little change in resource aggregation sizes though the end of 2019.

DMM continues to observe that there are several resource adequacy demand response resources sized under 1 MW under a single scheduling coordinator, within the same sub-load aggregation point.[91] Figure 3.10 shows this capacity compared to total demand response resource adequacy capacity in each sub-load aggregation point. Capacity (shown by blue bars) is only included if a scheduling coordinator had more than one resource sized under 1 MW in the sub-load aggregation point. In June 2020, this capacity represented 31 percent, or 76 MW, of total demand response resource adequacy reflected on monthly supply plans. DMM suggests that the ISO further evaluate what constraints that demand response providers face that continue to limit the size of their demand response aggregations within the same sub-load aggregation point.

[91] Sub-load aggregation points, or sub-LAPs, are areas defined within broader default load aggregation points and generally reflect local capacity areas or other transmission-constrained regions. Customer accounts aggregated under a demand response resource must be located within the same sub-load aggregation point.

Figure 3.10 Demand response resource adequacy sized under 1 MW by sub-LAP (June 2020)



3.4 System market power

This section assesses the competitiveness of the ISO's energy markets through day-ahead market software simulation under different scenarios. In the second quarter of 2020, the average price-cost markup was about $0.48/MWh or just over 2 percent for the default energy bid scenario, slightly above the $0.38/MWh or about 1 percent for the previous quarter.

3.4.1 Measuring ISO market competitiveness: day-ahead market software simulation

To assess the competitiveness of the ISO energy markets, DMM compares actual market prices to competitive benchmark prices we estimate would result under highly competitive conditions. DMM estimates competitive benchmark prices by re-simulating the market after replacing bids or other market inputs using DMM's version of the actual market software.

In previous reports, the competitive baseline price was calculated by re-running the day-ahead market after replacing the market bids of all gas-fired units with the lower of their submitted bids or their default energy bids (DEB).[92] This methodology assumes competitive bidding of price-setting resources. Beginning in January 2020, the functionality of DMM's version of the actual market software was

92 Historically, 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. In recent years DMM moved away from this scenario as it 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 tends to be greater than day-ahead bid-in load.

expanded to allow additional day-ahead market simulations to further analyze competitiveness under different scenarios. This section includes preliminary results from the following scenarios:

1. Replace market bids of gas-fired units with the lower of their submitted bids or their default energy bids (DEBs), to capture the effect of competitive bidding of energy by gas resources;
2. Replace bid-in commitment costs (start-up, transition and minimum load) of gas-fired units with the lower of their submitted bids or 110 percent of their proxy cost, to capture the effect of competitive bidding of commitment costs by gas resources;
3. Replace bids for import resources with the lower of their submitted bids or an estimated default energy bid based on a generous opportunity cost default energy bid option offered by the ISO (the hydro DEB), to capture the effect of competitive bidding of imports; and
4. Replace day-ahead bid-in load with actual 5-minute real-time market requirement and remove convergence bids as a proxy for actual system conditions.

In addition, simulations with various combinations of the above scenarios were completed to evaluate market competitiveness under different conditions:

5. (1) Default energy bids, (2) commitment costs, and (3) import bids;
6. (1) Default energy bids, and (4) insert 5-minute real-time market requirement and remove convergence bids; and
7. (1) Default energy bids, (2) commitment costs, (3) import bids, and (4) insert 5-minute real-time market requirement and remove convergence bids.

Each market simulation run 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 2020, 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.[93]

As shown in Figure 3.11, average hourly prices in the day-ahead market were very similar to or slightly above the estimated competitive baseline prices when comparing with the scenario that replaces submitted bids with default energy bids. Prices are shown separately for each default load aggregation point in the ISO balancing area.

Figure 3.12 shows the hourly price-cost markup, calculated as the difference between the default energy bid scenario and base case prices, averaged by hour and load area. In the second quarter of 2020, prices remained very competitive, with average hourly prices in the competitive baseline scenario very close to actual market results.

[93] 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 and 2020, the ISO was able to resolve these issues such that a greater percentage of dates was able to be included.

Figure 3.11 Default energy bid scenario price results (Apr – Jun)

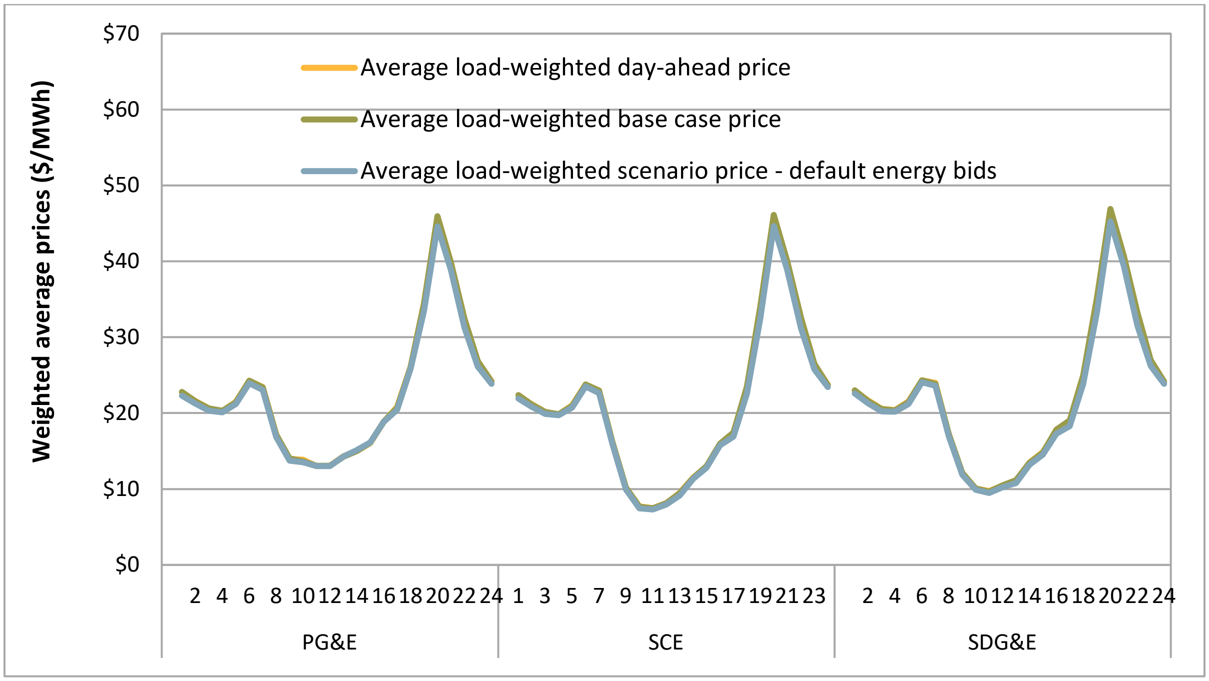
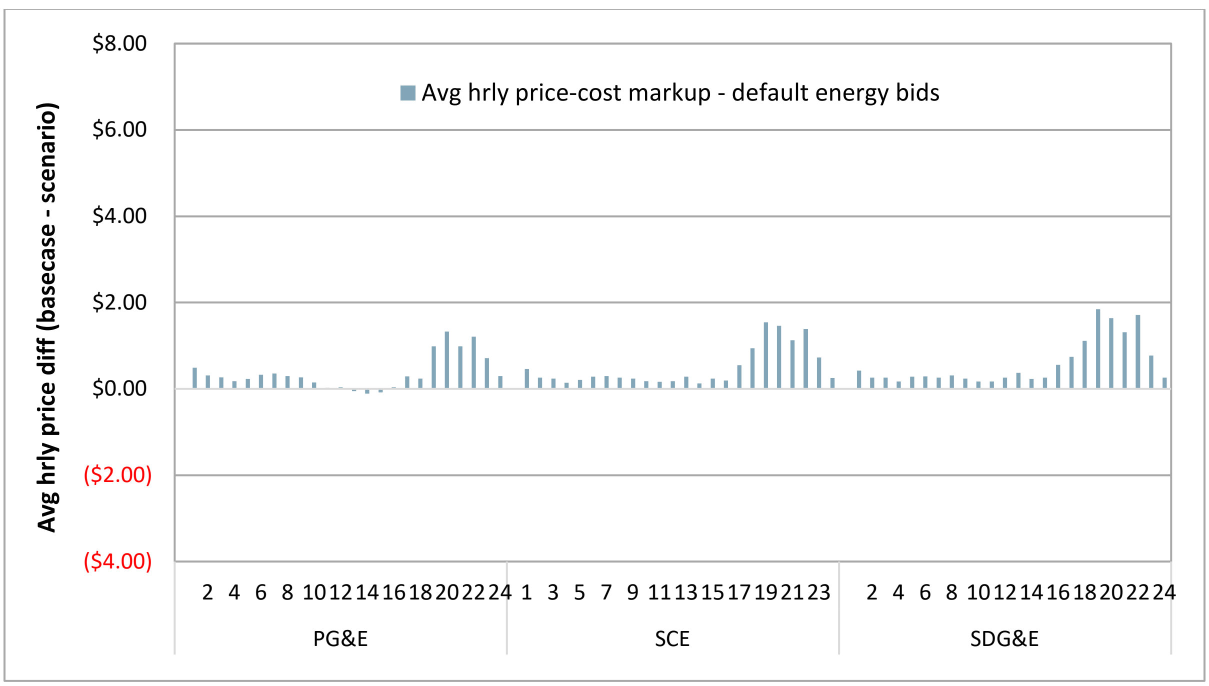


Figure 3.12 Hourly price-cost markup – default energy bid scenario (Apr – Jun)



Subsequent charts show these same values for selected additional scenarios. As expected, the scenarios with the largest hourly differences when compared with the base case reruns are those where system demand is set to the 5-minute market requirement and convergence bids are removed. The real-time market requirement can be higher or lower than the day-ahead demand, and corresponding price differences follow the same pattern. Even with these hourly price differences, however, prices for these scenarios are still very close to actual market results when averaged over the quarter.

Figure 3.13 Default energy, commitment cost, and import bids scenario price results (Apr – Jun)

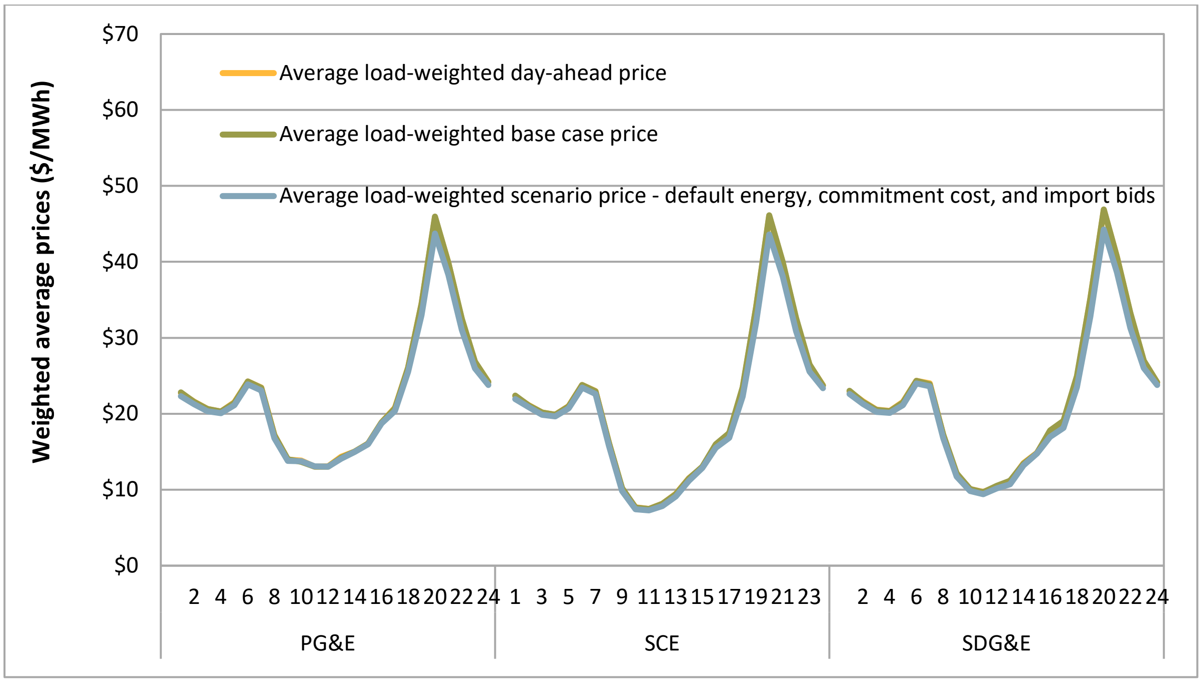


Figure 3.14 Hourly price-cost markup – default energy, commitment cost, and import bids scenario (Apr – Jun)

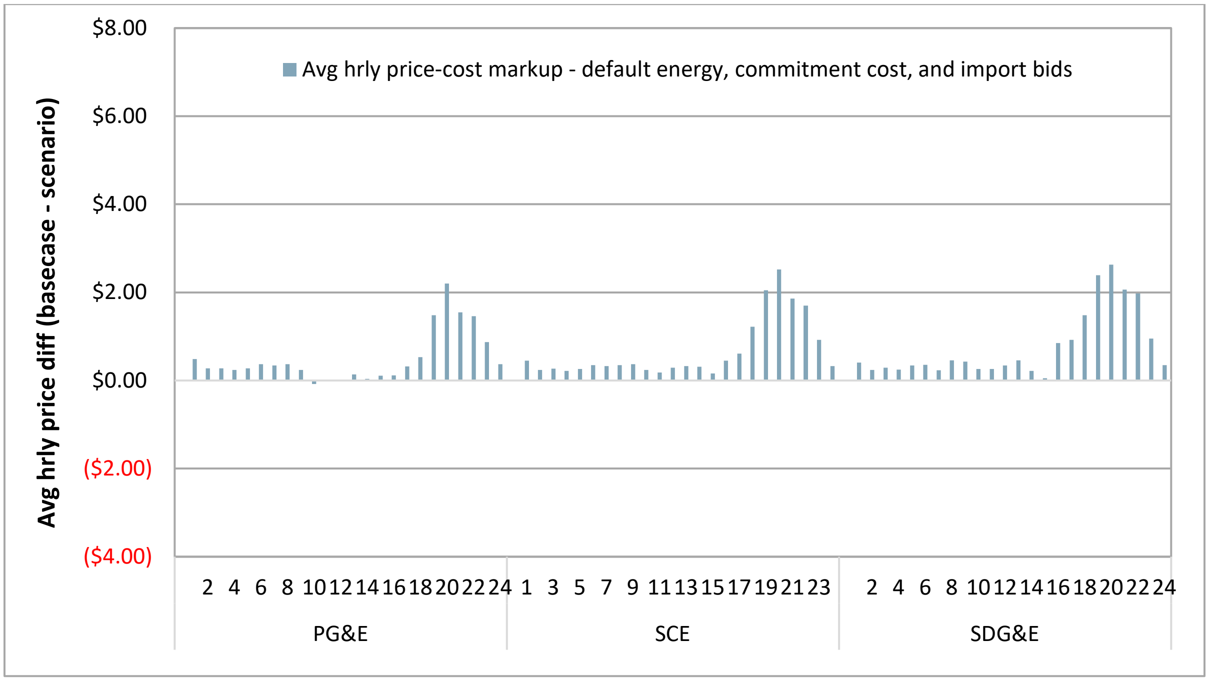


Figure 3.15 Actual load and default energy, commitment cost, and import bids scenario price results (Apr – Jun)

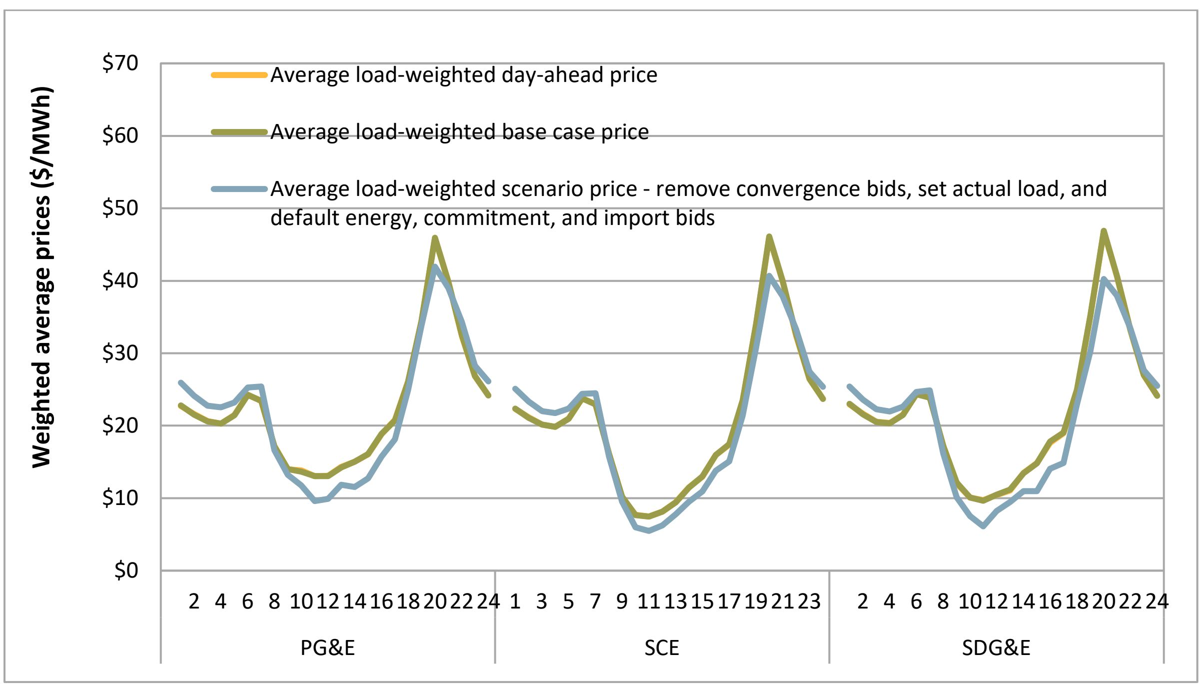
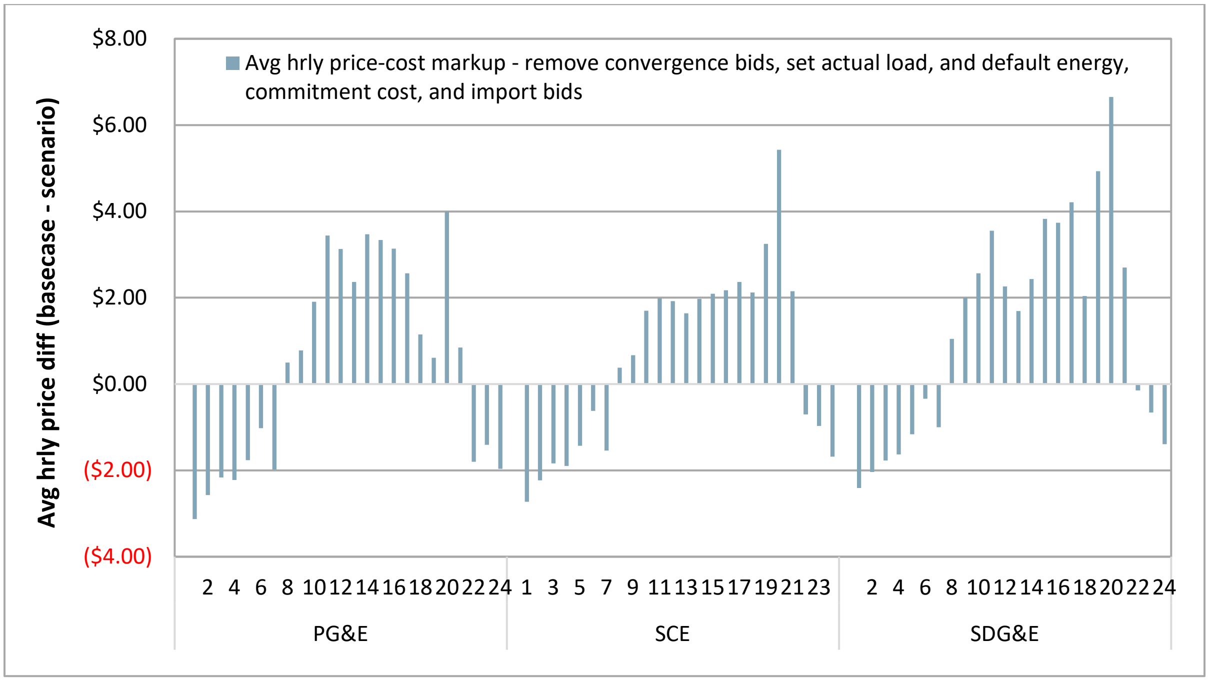


Figure 3.16 Hourly price-cost markup – actual load and default energy, commitment cost, and import bids scenario (Apr – Jun)



DMM calculates the day-ahead price-cost markup by comparing the load-weighted average competitive benchmark prices to the base case load-weighted average price for all energy transactions in the day-ahead market. As shown in Figure 3.17, in the second quarter of 2020 the average price-cost markup was about $0.48/MWh or just over 2 percent for the default energy bid scenario, slightly above the $0.38/MWh or about 1 percent for the previous quarter.

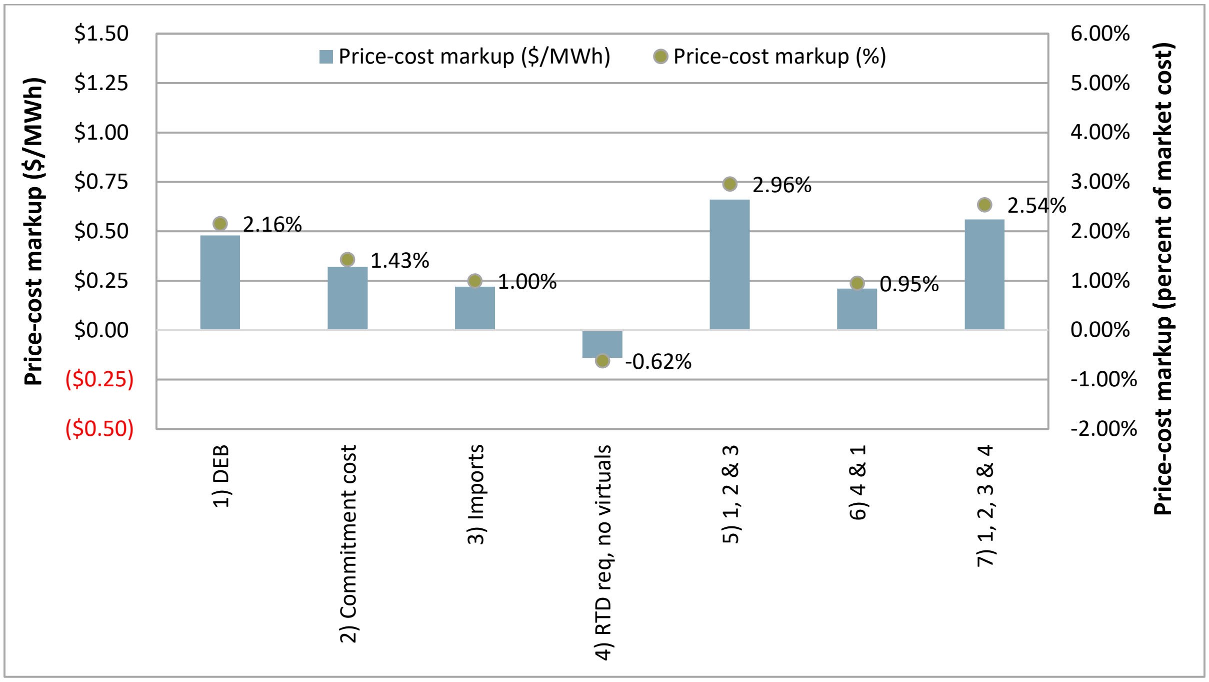
This slight positive markup indicates that prices have been very competitive, overall, for the quarter.[94] However, this price-cost markup metric may be a low-end measure of system market power for several reasons. The only change in market inputs made in this scenario is that energy bids of gas-fired 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 gas-fired resources which are capped at 125 percent of each resource's estimated start-up and minimum load costs. When calculating the price-cost markup for a scenario where bids for gas-fired resources are set to the minimum of the submitted bid or the default energy bid, bids for gas-fired resources' commitment costs are set to the minimum of the bid or 110 percent of proxy cost, and import bids are set to the minimum of the bid or an estimated hydro default energy bid, the price-cost markup is $0.66/MWh or about 3 percent, slightly above the $0.64/MWh or 2 percent for the previous quarter.

Another way to look at price-cost markup is to re-run the market simulation with these same input adjustments, and also set day-ahead load equal to the 5-minute real-time market requirement and

94 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.

remove convergence bids. This assumes competitive bidding of price-setting resources, perfect load forecast, and physical generation only. When comparing these results against the base case load-weighted average price, the average markup for the quarter is about $0.56/MWh or about 2.5 percent, slightly above the $0.16/MWh or less than 1 percent for the previous quarter. The results for this and the remaining scenarios indicate that prices remain very competitive, overall, for the quarter.

Figure 3.17 Quarterly price-cost markup by scenario (Apr – Jun)[95]



Duration curves of the highest and lowest 200 markup hours over the quarter are shown in Figure 3.18 and Figure 3.19. As shown in the figures, for most scenarios the maximum markup value is less than $10, and the minimum markup value is less than -$5. Scenarios where system demand was set to the 5-minute market requirement and convergence bids were removed show larger hourly markup variation, because the 5-minute market requirement can often be higher or lower than the day-ahead demand, with corresponding price differences following the same pattern.

95 The scenarios included on this chart are as follows: 1) Insert lower of bid or default energy bid for gas-fired resources; 2) insert lower of bid or 110 percent of proxy cost for gas-fired resources' commitment costs; 3) insert lower of bid or estimated hydro DEB for imports; 4) insert 5-minute real-time market requirement and remove convergence bids; 5) default energy, commitment cost, and import bids; 6) default energy bids, insert real-time market requirement, and remove convergence bids; and 7) default energy, commitment cost, and import bids; insert real-time market requirement; and remove convergence bids.

Figure 3.18 Duration curve of highest hourly price-cost markups (Apr – Jun)

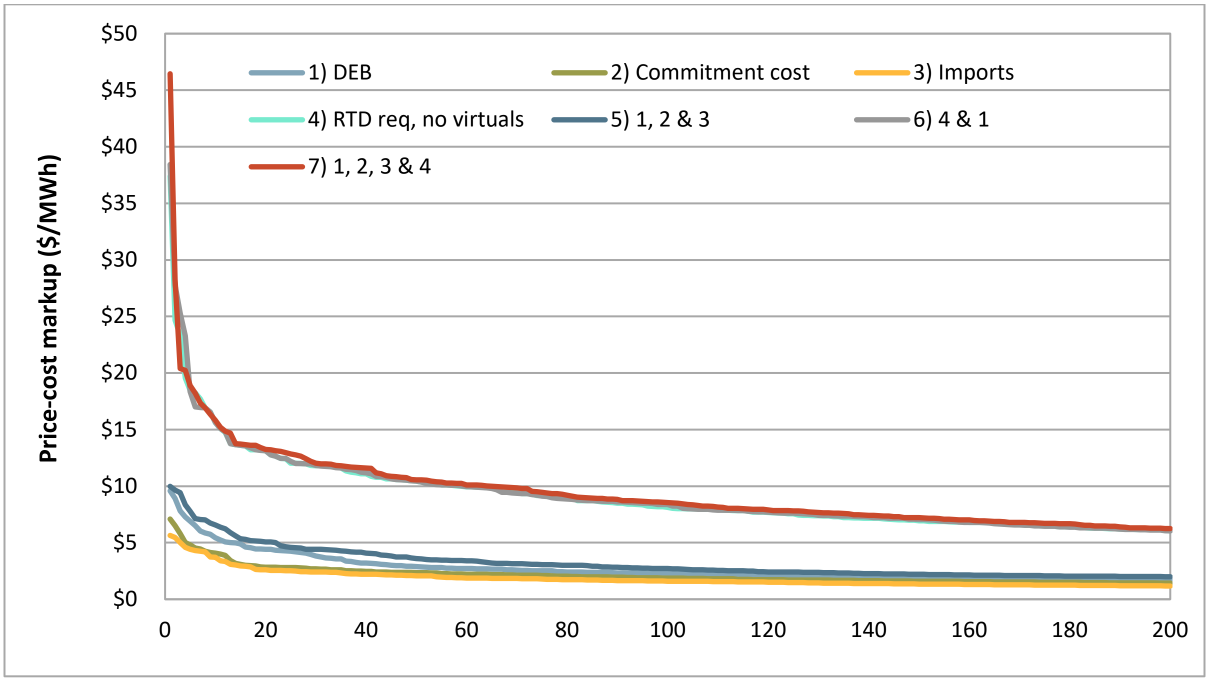
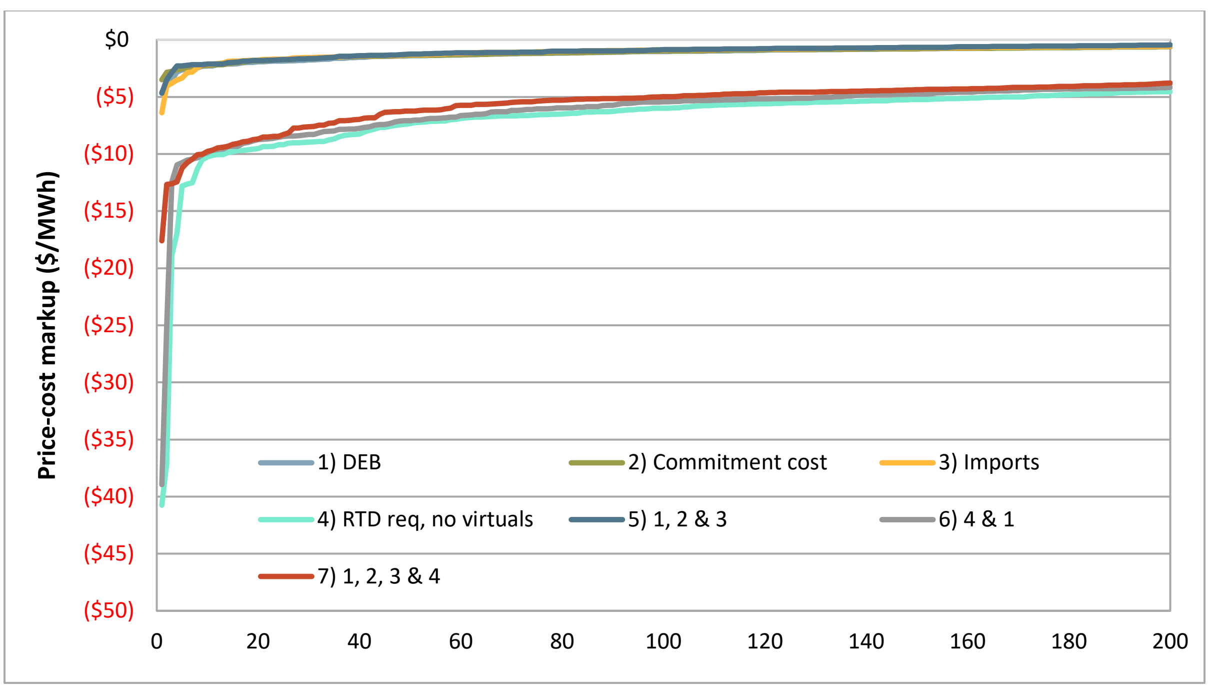


Figure 3.19 Duration curve of lowest hourly price-cost markups (Apr – Jun)



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

3.4.2 Recommendations

Analysis by DMM indicates that in the last few years system market power in the day-ahead market has had a limited effect on market prices, even during the limited number of hours when the ISO system was structurally uncompetitive. Through the first half of 2020, market prices have continued to be relatively low and stable due to a combination of favorable market and system conditions. However, DMM continues to be concerned that market conditions in the coming years may change in ways that will exacerbate the potential for system-level market power. The ISO recently launched a stakeholder initiative to develop system market power mitigation provisions. DMM supports this initiative and the ISO's efforts to design and implement system market power mitigation.

Potential for increased system market power

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

- Retirement and mothballing of gas capacity.
- Increasing portion of resource adequacy requirements being met by solar and wind resources, which often provide significantly less energy during the evening ramping hours than the resource adequacy rating of these resources.
- Fewer energy tolling contracts between gas units within the ISO and load serving entities without an incentive to exercise market power.
- Increasing portion of resource adequacy requirements met by imports not backed by energy contracts or physical resources, which can avoid being called upon by simply bidding at high prices in the day-ahead market.
- Tightening regional supply conditions.

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

Mitigation of system market power

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

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

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

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

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

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

Such options likely involve a combination of resource adequacy rules for imports established by the CPUC as well as ISO market rules. For example, in June 2020, the CPUC adopted a decision to require non-resource specific resource adequacy imports to bid at or below $0/MWh during availability assessment hours starting with the 2021 compliance year.[96]

DMM recommended that under the ISO's plan for implementing FERC Order No. 831, the ISO should (1) ensure that import bids over $1,000/MWh are subject to ex ante cost justification and (2) avoid setting penalty prices at $2,000/MWh except when needed to implement the provisions of the order. These market design features have important implications in terms of mitigating potential system market power. Overall, DMM supports the ISO's final proposal as a reasonable approach to allowing bids over the $1,000/MWh soft offer cap in compliance with FERC Order 831.[97] The proposal is a vast

[96] *Decision Adopting Resource Adequacy Import Requirements*, California Public Utilities Commission, Decision 20-06-028, Rulemaking 17-09-020, June 25, 2020, p. 71: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF

[97] FERC Order 831 – Import Bidding and Market Parameters Final Proposal, California ISO, August 24, 2020: http://www.caiso.com/InitiativeDocuments/FinalProposal-FERCOrder831-ImportBidding-MarketParameters.pdf

Information on the stakeholder initiative is available here: http://www.caiso.com/StakeholderProcesses/FERC-Order-831- Import-bidding-and-market-parameters improvement from the ISO's 2019 Order 831 compliance filing, and places more reasonable limits on instances in which the ISO will raise the power balance penalty price over $1,000/MWh and allow import bids over $1,000/MWh. However, DMM believes it is prudent to fully analyze and consider how the proposed approach would have worked during system and market conditions that existed during the mid-August heat wave.[98]

[98] Comments on FERC Order 831 – Import Bidding and Market Parameters Final Proposal, Department of Market Monitoring, September 10, 2020: http://www.caiso.com/Documents/DMMCommentsonFERCOrder831-ImportBiddingandMarketParametersFinalProposal-Sep102020.pdf