California ISO

Q3 2020 Report on Market Issues and Performance

February 4, 2021

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California Independent System Operator

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Executive summary

This report covers market performance during the third quarter of 2020 (July - September). Key highlights during this quarter include the following:

- **On August 14 and 15, CAISO grid operators called upon participating transmission owners to curtail load** for several hours due to system-wide conditions for the first time since 2001. From mid-August to September 7, 2020, regional high temperatures led to a high demand across the entire western region. This load curtailment event and the combination of factors that contributed to it are covered in more detail in the special issues section of this report and in a separate standalone report.[1]
- **Market prices** were high, relative to both the previous quarter and previous year. Average ISO monthly day-ahead prices were higher than both 15-minute and 5-minute market prices during the third quarter (Figure E.1). Day-ahead prices averaged about \$47/MWh, 15-minute prices averaged \$44/MWh, and 5-minute prices averaged \$36/MWh. Palo Verde prices exceeded the day-ahead ISO prices and the ISO prices exceeded Mid-Columbia prices during most of the third quarter.
- **The total estimated wholesale cost of serving ISO load** in the third quarter of 2020 was about \$3.8 billion (\$61/MWh), a significant increase from \$2.5 billion (\$39/MWh) in the same quarter of 2019. After adjusting for natural gas costs and changes in greenhouse gas prices, wholesale electric costs increased by 53 percent to \$64/MWh from \$42/MWh in the same quarter of 2019.
- **Average loads were lower** in the third 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. This effect was offset during the afternoon peak hours, however, when higher than average temperatures caused large increases in demand.
- **Renewable production decreased** by 16 percent compared to the same quarter in 2019, primarily due to a 38 percent reduction in hydroelectric production.
- **Generation outages were higher** over the quarter compared to the same quarter in any of the previous four years. The increase was driven by outages for forced maintenance which were similar in magnitude to the sum of all outages during the third quarter of each of the prior years.
- **Congestion increased.** The \$220 million in day-ahead congestion rent was more than double the third quarter of 2019 (\$79 million). In the day-ahead market, congestion decreased PG&E area prices and increased SCE and SDG&E area prices.
- **Real-time offset costs increased** in the third quarter to \$104 million, almost as high as the total offset cost in 2019. Real-time imbalance offset costs were comprised of about \$50 million in

[1] An in-depth analysis and report of these factors may be found in the Department of Market Monitoring's *Report on Market Conditions, Issues and Performance – August and September 2020*. http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

congestion offset costs, about $56 million in energy offset costs, and $2 million in loss offset surpluses. Offset costs were concentrated on a small number of high demand days (Figure E.2).

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

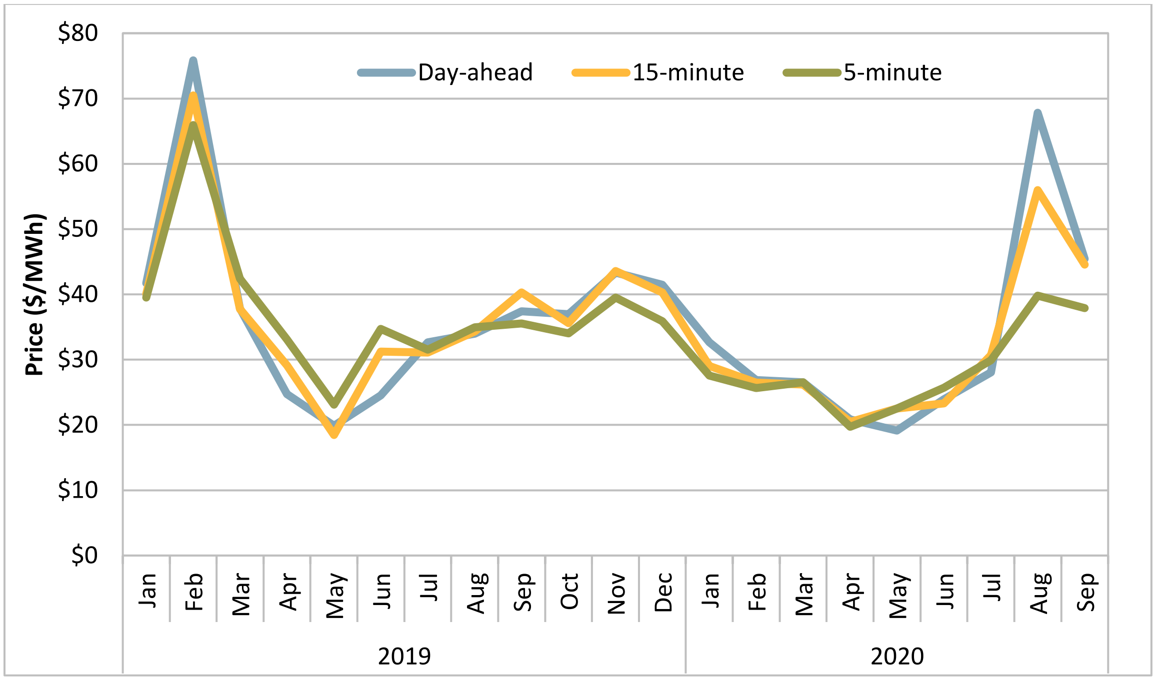
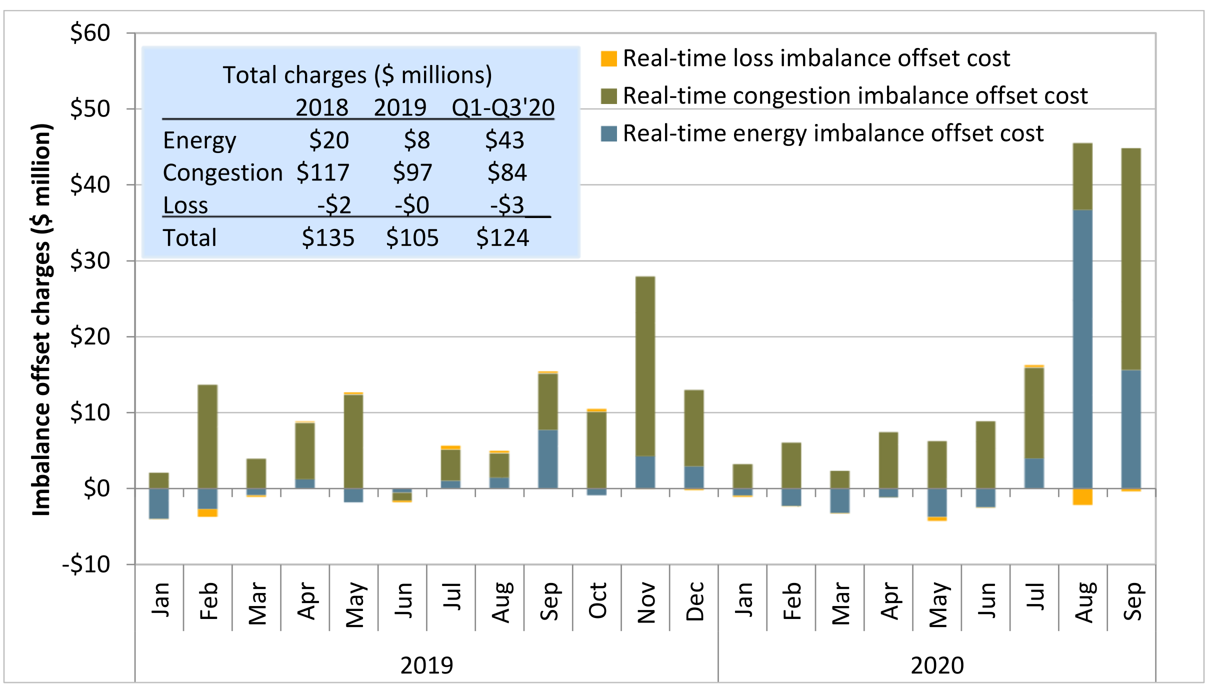


Figure E.2 Real-time imbalance offset costs



- **Ancillary service payments** increased significantly during the third quarter to about $97 million, compared to about $24 million in the previous quarter and $28 million during the same quarter in 2019. The frequency of scarcity intervals for operating reserves was relatively high in August and September, occurring in the expanded South of Path 26 region or on a system level.
- **Bid cost recovery payments** for the third quarter of 2020 totaled about $62 million, or about $43 million more than the previous quarter and about $14 million more than the same quarter of 2019.
- **Congestion revenue rights** auction revenues were $38 million less than payments made to non-load-serving entities during the third quarter of 2020, representing about 17 percent of day-ahead congestion rent. This is up from 1 percent of rent in the third quarter of 2019 and 6 percent for all of 2019. However, the losses as a percent of day-ahead congestion rent were below the average of 28 percent during the three years before the Track 1A and 1B changes (2016 through 2018).

Western energy imbalance market

- **Prices in NV Energy, Arizona Public Service, and Salt River Project** exceeded the rest of the system on average during peak hours in both the 15-minute and 5-minute markets reflecting regional high demand, particularly in the Southwest. As noted in the previous chapter, average bilateral prices at Palo Verde were greater than peak day-ahead prices in the ISO as well.
- **Sufficiency test failures and subsequent under-supply power balance constraint relaxations** drove average real-time NV Energy prices 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.
- **Prices in the Northwest region were consistently lower** than prices in the ISO and other balancing areas due to limited transfer capability out of this region during peak system load hours. This region includes PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex.
- Significant transfer capability between the ISO, NV Energy, Arizona Public Service, Salt River Project, and BANC allowed energy to flow between these areas with relatively little congestion.
- **Rates of energy bid mitigation** fell in the Western EIM, following the elimination of carryover mitigation in November 2019.
- **Western EIM greenhouse gas prices decreased in the third quarter** but remained high relative to the period prior to November 2018 when the ISO implemented a revised EIM greenhouse gas bid design and resources deemed delivered to the ISO area shifted from lower to higher greenhouse gas emissions. In some intervals in the third quarter, all resource bids eligible for delivery into California were imported, so that energy imbalance market imports into California were constrained by greenhouse gas limitations.

Special issues

Load curtailment event

Regional high temperatures led to a high demand heat wave across the entire western region in mid-August and again over the Labor Day weekend. On August 14 and 15, CAISO grid operators called upon participating transmission owners to curtail load due to system-wide conditions for the first time since 2001. In the following days and weeks, CAISO loads remained high but were well below forecasted levels, due largely to voluntary conservation efforts. Prices in the CAISO, the Western EIM, and bilateral markets reached record levels on August 17-19, but no further load curtailments occurred.

There was no single cause of the rotating outages. Instead, a combination of factors led to the extraordinary market events of this period including resource adequacy and forward planning processes that allowed load serving entities to procure less generation than was required to serve load during an atypically high, widespread, and extended heat wave. Conditions were exacerbated by ISO market practices which allowed exports to increase demand to a level not supported by physical generation. Further discussion of these factors is available in a special report published by DMM and in both a preliminary and final root cause analysis issued by the ISO, CPUC, and CEC.[2]

DMM agrees with many of the key recommendations related to resource adequacy in the CAISO/CPUC/CEC reports and supports the coordinated efforts by the CAISO, CPUC, and stakeholders to make the various planning, market design, and operational enhancements identified in these reports. The most significant and actionable of these recommendations involve California's resource adequacy program. To limit the potential for similar resource shortages in future years, a high priority should be placed on the following two recommendations:

- *Increase resource adequacy requirements to more accurately reflect increasing risk of extreme weather events* (e.g., beyond the 1-in-2 year load forecast and 15 percent planning reserve margin currently used to set system resource adequacy targets).
- *Continue to work with stakeholders to clarify and revise the resource adequacy capacity counting rules*, especially as they apply to hydro resources, demand response resources, renewable resources, imports, and other use-limited resources. Counting rules should specifically take into account the availability of different resource types during the net load peak.

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2 DMM report: *Report on Market Conditions, Issues and Performance – August and September 2020*, November 24. 2020. http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

Preliminary root cause analysis: *Preliminary Root Cause Analysis: Mid-August 2020 Heat Storm*, October 6, 2020, prepared by the California Independent system Operator, California Public Utilities Commission and California Energy Commission. http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf. Preliminary CAISO/CPUC/CEC report

Final root cause analysis: *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*, January 13, 2020, prepared by the California Independent system Operator, California Public Utilities Commission and California Energy Commission. http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

In addition, DMM provides the following recommendation regarding the issue of exports.

- *DMM recommends that further changes and clarifications in the rules and processes for limiting or curtailing exports be discussed and pursued by the CAISO in conjunction with other balancing areas.*[3]

Finally, DMM provides the following recommendation regarding demand response.

- *DMM recommends that steps be taken to ensure a higher portion of demand response used to meet resource adequacy requirements is available during critical net load hours.*

Load under-scheduling

The CAISO/CPUC/CEC report and CAISO presentations have emphasized under-scheduling of load in the day-ahead market as a major root cause of the load curtailments and stressed real-time market conditions during the summer 2020 heat waves.

Load serving entities within the CAISO submitted self-schedules or demand bids equal to a relatively high percentage of the energy needed to meet their load forecast in the day-ahead market during the high load hours of mid-August to early September. However, under these high load conditions, under-scheduling of even a small percentage of total load had a significant impact on the volume of demand that needed to be met in the real-time market.

Cleared physical load schedules averaged about 95 percent of actual load during the evening hours of August 13 to August 16, and about 99 percent of actual load during the evening hours of August 17 to 19. Analysis of newly available meter data shows that community choice aggregators were responsible for half of the under-scheduling on days with load curtailment and most under-scheduling on the following days.

Hourly block import compensation

The ISO has proposed a set of measures to be implemented before the summer of 2021 to lessen the probability of recurring outages.[4] One measure would add bid cost recovery provisions for hourly block imports during tight system conditions. Hourly block imports are scheduled in the hour-ahead market, but compensated at the 15-minute market price in each interval, rather than the hour-ahead price at which they are scheduled.

Cleared hourly block imports received higher revenues by being compensated at the 15-minute price than they would have received had they been compensated at the hour-ahead price, on average over the quarter. As noted in DMM's comments on the summer readiness initiative, although provisions to allow recovery of losses may not be warranted during most hours, changes may be warranted for high

[3] These changes and clarifications are being discussed in the ISO's Market enhancements for Summer 2021 readiness Initiative: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-enhancements-for-summer-2021-readiness

[4] *Market Enhancements for Summer 2021 Readiness*, CAISO presentation given January 6, 2021. http://www.caiso.com/InitiativeDocuments/Presentation-MarketEnhancements-Summer2021Readiness-Jan6-2021.pdf

demand hours.[5] Hourly block imports cleared during the high demand period would have had higher revenues if compensated at the hour-ahead price in some hours but not others. Monitoring metrics included here do not account for hourly block imports that were not offered into the market or that failed to clear.

Resource adequacy showings and performance

Resource adequacy showings and performance were similar, although load was higher, in the top 210 load hours in Q3 2020 compared to Q3 2019. In both years, 43 percent of the obligation was met by resources with a 24 hour bid obligation and 92 percent of this capacity bid into the real-time market. A lower percentage of the remaining resource adequacy capacity bid into the real-time market: 86 percent in 2020 and 85 percent in 2019.

Solar and wind resources accounted for a significant portion of resource adequacy capacity that was not available in the real-time market during high load hours. The output from these resources is predictably lower in these evening hours when net loads are highest, compared to the output of these resources in hours with highest gross load which are used to determine their resource adequacy rating.

Gas units accounted for a significant share of resource adequacy capacity unavailable in real-time during high load hours, with 92 percent of shown capacity bid into the real-time market in high load hours in both 2019 and 2020. Ambient derates which occur in very hot weather accounted for about half of the derated gas resource adequacy during the heat wave period. Ambient derates occur when the total output from gas units falls below their normal rated capacity due to ambient temperature. This is an example of one of the types of factors that should be factored in resource adequacy counting rules.

Demand response resources, which counted for 1,847 MW of resource adequacy in August and 1,769 MW in September, self-reported performance of 73 to 77 percent in hours of load curtailment. Based on supplier-submitted baseline and meter data, there is some evidence that baseline adjustments could have been limited in the upward direction by defined baseline adjustment caps on these days, possibly increasing performance.

System market power

- **Market results were competitive in the third quarter**. DMM estimates that the impact of gas and import resources bidding above reference levels, a conservative measure of the average price-cost markup, was about $1.42/MWh or about 2.6 percent, an increase from the $0.66/MWh or 3 percent for the previous quarter.
- **The CAISO market was structurally uncompetitive** during the high load days in August. During the third quarter, the number of hours with an RSI less than one increased significantly. For every hour of potential scarcity, there are many hours of potential system market power.
- **System wide mitigation of imports and gas-fired resources would not have lowered prices**. Although prices were very high during the high load days in August, analysis using the CAISO's day-ahead market software indicates that system wide mitigation of imports and gas-fired resources

[5] *Comments on Market Enhancements for Summer 2021 Readiness January 6, 2021 Stakeholder Call* Department of Market Monitoring, January 14, 2021. http://www.caiso.com/Documents/DMMCommentsonMarketEnhancementsSummer2021ReadinessJanuary6StakeholderCall.pdf

during this period would not have lowered prices. This reflects the fact that gas-fired and other resources that may be subject to mitigation were generally infra-marginal in re-runs of the day-ahead market using cost-based bids, and that high prices were set by demand response and other resources not subject to mitigation.

- **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 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.[6] 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.[7]

6 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

7 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 third quarter:

- **On August 14 and 15, CAISO grid operators called upon participating transmission owners to curtail load** due to system-wide conditions for the first time since 2001. From mid-August to September 7, 2020, regional high temperatures led to a high demand across the entire western region. This load curtailment event and the combination of factors that contributed to it are covered in more detail in Chapter 3 of this report and in a separate standalone report.[8]
- **Market prices** were high, relative to both the previous quarter and previous year. Average monthly day-ahead prices were higher than both 15-minute and 5-minute market prices during the third quarter. Day-ahead prices averaged about $47/MWh, 15-minute prices averaged $44/MWh, and 5-minute prices averaged $36/MWh.
- **Bilateral prices at Mead, Palo Verde, and other locations** exceeded the $1,000/MWh WECC soft offer cap for two days during the quarter. On average, peak day-ahead market prices in the ISO across all hours in the third quarter were greater than prices at Mid-Columbia hub and lower than the prices at Palo Verde electricity hub in the third quarter.
- **The total estimated wholesale cost of serving load** in the third quarter of 2020 was about $3.8 billion ($61/MWh), a significant increase from $2.5 billion ($39/MWh) in the same quarter of 2019. After adjusting for natural gas costs and changes in greenhouse gas prices, wholesale electric costs increased by 53 percent to $64/MWh from $42/MWh in the same quarter of 2019.
- **Gas prices were slightly higher** in the third quarter compared to Q3 2019 at both SoCal and PG&E Citygates. At SoCal Citygate, gas prices remained significantly lower than Q3 2018 due to factors including the return to service of gas pipeline capacity that had been out of service since 2017 as well as changes to operational flow order (OFO) penalties and Aliso Canyon storage withdrawal protocols. The ISO enforced maximum gas burn constraints in both day-ahead and real-time markets in selected sub-regions of the SoCalGas service area in the third quarter.
- **ISO load fell** in the third 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. Although average load has fallen, the maximum monthly net load was higher than either 2018 or 2019.
- **Renewable production decreased** by 16 percent compared to the same quarter in 2019, primarily due to a 38 percent reduction in hydroelectric production.

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[8] An in-depth analysis and report of these factors may be found in the Department of Market Monitoring's *Report on Market Conditions, Issues and Performance – August and September 2020*, November 2020. http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

- **Generation outages were higher** over the quarter compared to the same quarter in any of the previous four years. The increase was driven by outages for forced maintenance which were similar in magnitude to the sum of all outages during the third quarter of each of the prior years.
- **Flexible ramping product** system level prices were zero for around 98 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 rose** in the third quarter to $62 million, or about $43 million more than the second quarter and about $14 million more than the third quarter of 2019.
- **Congestion increased in the third quarter.** The $220 million day-ahead congestion rent was more than double the third quarter of 2019 ($79 million). In the day-ahead market, congestion decreased PG&E area prices and increased SCE and SDG&E area prices.
- **Real-time offset costs** in the third quarter increased to $104 million, almost as high as the total offset cost in 2019. Real-time imbalance offset costs were comprised of about $50 million in congestion offset costs, about $56 million in energy offset costs, and $2 million in loss offset surpluses. Offset costs were concentrated on a small number of high demand days.
- **Congestion revenue rights** auction revenues were $38 million less than payments made to non-load-serving entities during the third quarter of 2020, representing about 17 percent of day-ahead congestion rent. This is up from 1 percent of rent in the third quarter of 2019 and 6 percent for all of 2019. However, the losses as a percent of day-ahead congestion rent were below the average of 28 percent during the three years before the Track 1A and 1B changes (2016 through 2018).
- **Ancillary service payments** increased significantly during the third quarter to about $97 million, compared to about $24 million in the previous quarter and $28 million during the same quarter in 2019. The frequency of scarcity intervals for operating reserves was relatively high in August and September, occurring in the expanded South of Path 26 region and on a system level.
- **Virtual bidding was temporarily suspended** beginning on operating day August 18 because of significant challenges associated with system conditions during the August heat wave. On the morning of Sunday August 16, the ISO announced the suspension of convergence bidding effective in the day-ahead market for operating day August 18.

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 third quarter of 2020, natural gas prices at SoCal Citygate were slightly higher on average than during the same quarter in 2019. The increase in natural gas prices due to high temperatures and gas demand on some days in August and September also led to higher system marginal energy prices across the ISO footprint on those days.

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 gas trading hubs outside of California have been steady and relatively low since the second quarter of 2019.

Prices at the SoCal Citygate gas hub averaged $2.94/MMBtu compared to $2.93/MMBtu in the third quarter of 2019. The Aliso Canyon protocol remains in effect, 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.[9] In addition, for the period between June 1 through September 30, 2020, SoCalGas temporarily reduced the number of OFO non-compliance stages from 8 to 5. The non-compliance charge was reduced from $25/Dth and capped at $5/Dth for Stage 4 and Stage 5 OFOs.

These changes are consistent with the California Public Utilities Commission's ruling on April 29, 2019.[10] With the revisions from the ruling set to expire in October 2021, DMM has submitted comments to a new CPUC ruling to revise the existing OFO penalty structure.[11]

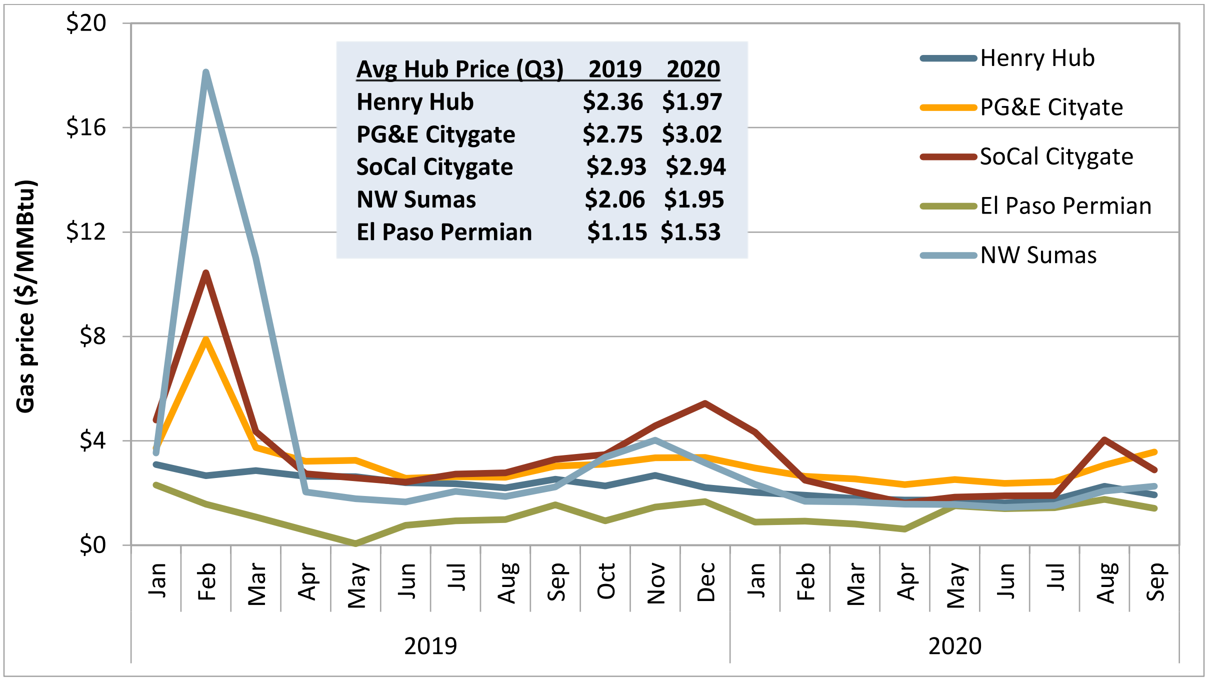
During the days of high gas demand in August, prices at SoCal Citygate reached a high of about $13/MMBtu. SoCalGas withdrew gas from the Aliso Canyon storage facility from August 13-20. No low OFOs were declared during this period. SoCal Citygate prices often impact overall electric system prices because 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.

9 *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

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

11 DMM Response to Judge's Ruling Seeking Comments - Safe and Reliable Gas Systems - R20-01-007, Aug 14, 2020: http://www.caiso.com/Documents/CPUC-ResponsetoJudgesRulingSeekingComments-SafeandReliableGasSystems-R20-01-007-Aug142020.pdf

Figure 1.1 Monthly average natural gas prices



1.1.2 Aliso Canyon gas-electric coordination

In the third 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: July 3, July 17-20, and September 14 through October 24.

In July and September, the gas burn constraint was enforced to facilitate pipeline maintenance work in the southern system of the SoCalGas area. During the July period, this constraint was binding in about 9 percent, 2 percent, and 0.2 percent of day-ahead, 15-minute, and 5-minute intervals, respectively.

During the September and October period, this constraint was binding in about 25 percent of hours when enforced in the day-ahead market. In the real-time market, this constraint was binding in 14 percent of the 15-minute intervals and 11 percent of the 5-minute intervals when enforced.

On October 31, 2019, the ISO filed tariff amendments to extend Aliso Canyon provisions permanently.[12] 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. DMM has also expressed concern about the potential impacts of

12 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

the gas burn constraints on real-time energy offset costs.[13] 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.[14]

Beginning on November 4, 2020, the ISO is implementing functionality 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.[15,16] In addition, DMM continues to recommend that the ISO improve how gas burn constraint 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.

Figure 1.2 shows the nomogram limits being adjusted in real-time in response to changing system conditions on September 19, 2020. 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. The ISO is still working on automating the process of including the maximum gas burn constraint as part of local market power mitigation process (LMPM) to automatically designate a constraint as competitive or not.[17]

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13 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

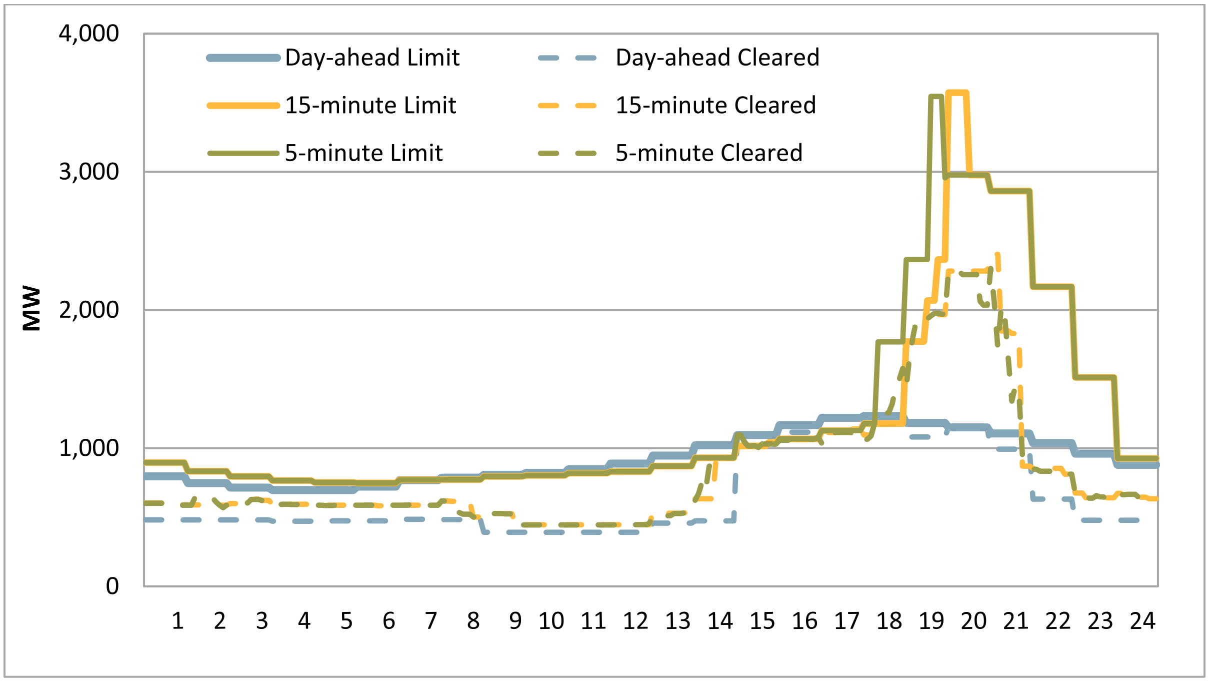
14 FERC Order accepting Aliso Canyon Gas-Electric Coordination Phase 5 tariff revisions (ER20-273), December 30, 2019: http://www.caiso.com/Documents/Dec30-2019-OrderAcceptingTariffRevisions-AlisoCanyonGasElectricCoordination-MaximimGasConstraint-ER20-273.pdf

15 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

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

17 Business requirements specifications for Aliso Canyon Phase 5 functionality: http://www.caiso.com/Documents/BusinessRequirementsSpecification-AlisoCanyonPhase5.pdf

Figure 1.2 Aliso gas nomogram binding status in day-ahead and real-time market (Sep 19, 2020)



1.1.3 Renewable generation

In the third quarter, total generation from hydroelectric, solar, and wind resources decreased by about 9 percent compared to the previous quarter. This decrease is expected as generation from these resources tends to peak in the second quarter. Total renewable generation decreased by 16 percent compared to the same quarter in 2019, primarily due to a reduction in hydroelectric production.

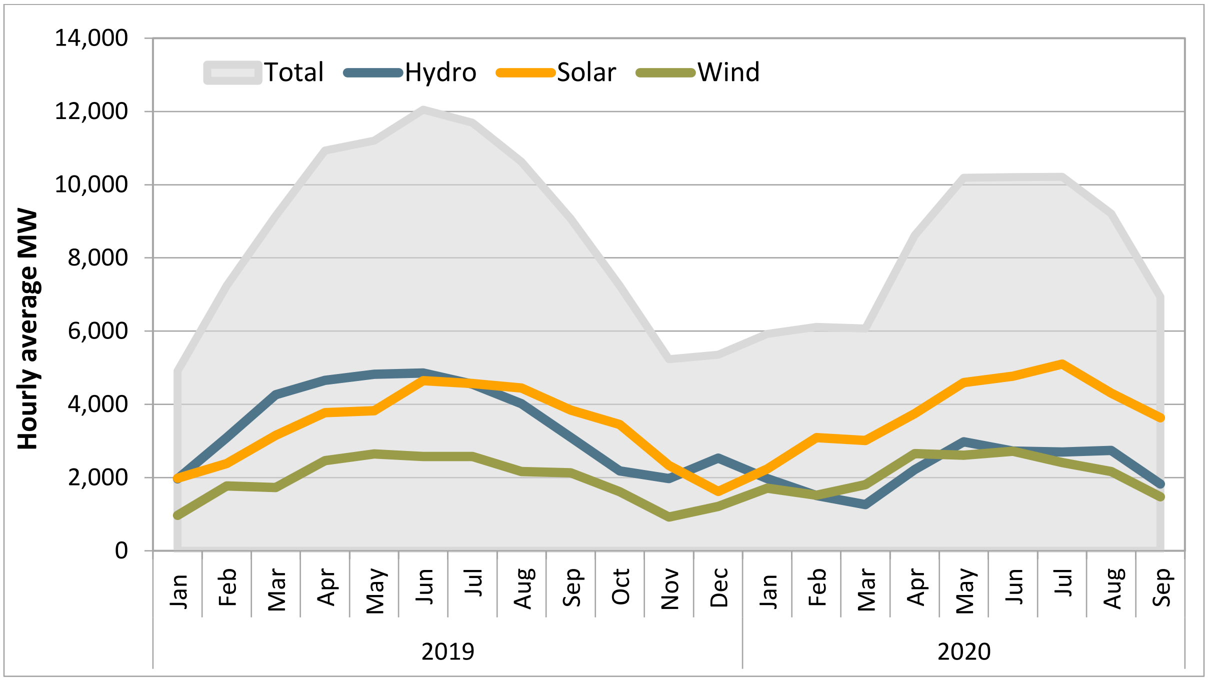
The availability of variable resources contributes to patterns in prices both seasonally and hourly due to low marginal cost relative to other resources. Although solar generation increased slightly, hydroelectric and wind generation declined considerably compared to the same time last year.

Compared to the same period in 2019, hydroelectric production in the third quarter decreased by roughly 38 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.[18] Compared to the previous quarter, hydroelectric generation decreased about 8 percent.

Compared to the third quarter of 2019, solar production increased by about 2 percent while wind production decreased by about 12 percent. Compared to the second quarter of 2020, solar production remained about the same while wind production decreased by 24 percent.

18 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 1.3 Average hourly hydroelectric, wind, and solar generation by month



1.1.4 Generation by fuel type

In the third quarter, a significant increase in natural gas generation met seasonally high demand in the net load peak evening hours. During ramping periods, there was an increase in natural gas generation, hydroelectric generation, and imports.

Nuclear generation decreased slightly, while generation from geothermal and bio-based resources increased, relative to the previous quarter. As shown in Figure 1.4, on average, these types of resources comprised about 4,200 MW of inflexible base generating capacity, similar to the last quarter. Generation from "other" resources, including coal, battery storage, demand response, and additional non-gas technologies, increased in this quarter, but continued to be a small share of overall generating capacity at about 350 MW on average.

Figure 1.4 Average hourly generation by fuel type (Q3 2020)

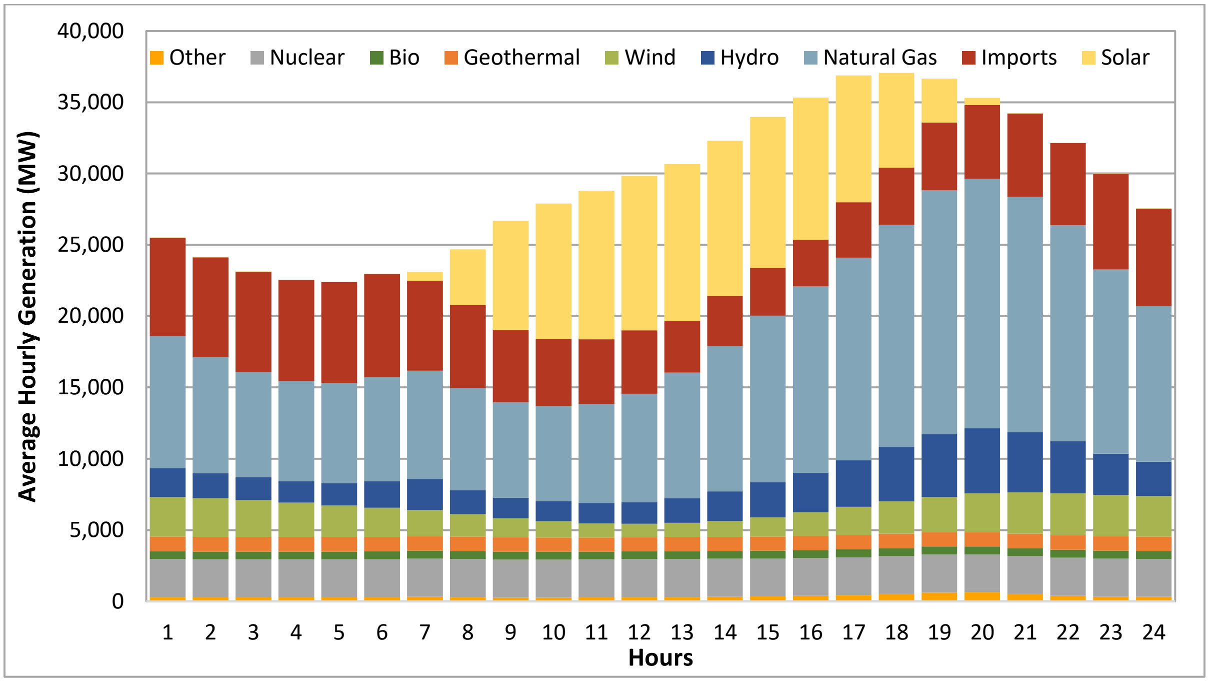
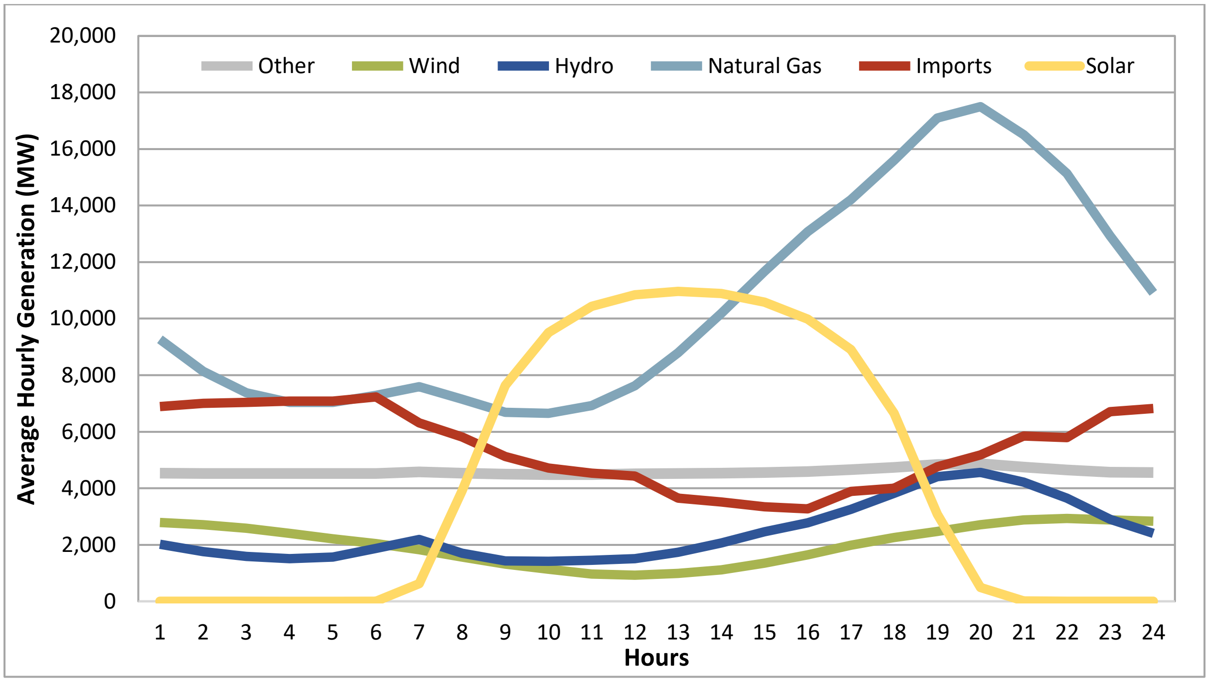


Figure 1.5 shows hourly variation of generation by fuel group, driven primarily by hourly variation of solar production. In the third quarter, differences in hourly average natural gas generation were similar to changes in solar production, as gas generation produced significantly more than any resource during the peak net load hours. Compared to the previous quarter, the large increase in natural gas generation variability was driven by a significant increase in demand during peak net load hours. Wind generation in the third quarter complemented solar production by generating more in the early morning and late evening hours, and less in the middle of the day, as is typical in the ISO.

Similar to the previous quarter, imports consistently produced more than hydroelectric resources throughout the day. Average hourly generation from "other" category resources had more variability throughout the day, about 21 percent more compared to the third quarter of 2019.[19] This was primarily due to increases in battery storage generation as new resources entered the market.

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

Figure 1.5 Hourly generation by fuel type (Q3 2020)



1.1.5 Generation outages

This section provides a summary of generation outages in the third quarter of 2020. Overall, the total amount of generation outages over the quarter was higher than the same quarter in any of the previous four years. The increase was driven by outages for forced maintenance which were similar in magnitude to the sum of all outages during the third quarter of each of the prior years.

Under the ISO's current outage management system, known as WebOMS, all outages are categorized as either planned or forced. An outage is considered to be planned if a participant submitted it more than 7 days prior to the beginning of the outage. WebOMS has a menu of subcategories indicating the reason for the outage. Examples of such categories 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 1.6 shows the monthly averages of maximum daily outages broken out by type during peak hours of 2019 and 2020. Figure 1.7 shows the quarterly averages of maximum daily outages by type during peak hours from 2016 to 2020. The typical seasonal outage pattern is primarily driven by planned outages for maintenance which are typically performed outside of the high summer load period.[20]

[20] Revisions and enhancements made to this analysis have updated some of the results, therefore the historic values reported here have been retroactively updated to reflect the recent revisions. Findings and conclusions published in previous reports may no longer be accurate as they do not include these revisions. In the second quarter report, it was reported that Q2 2020 represented a deviation from the expected seasonal pattern as generation outages had increased between Q1 and Q2; however, updates to the analysis have revealed that was not the case.

As shown in Figure 1.6, within the third quarter, both planned and forced outages peaked in September. The amount of generation on forced outages has remained relatively consistent in 2020, while the aforementioned seasonal trend is clearly present in the monthly variation of planned outages.

Figure 1.6 Monthly average of maximum daily generation outages by type – peak hours

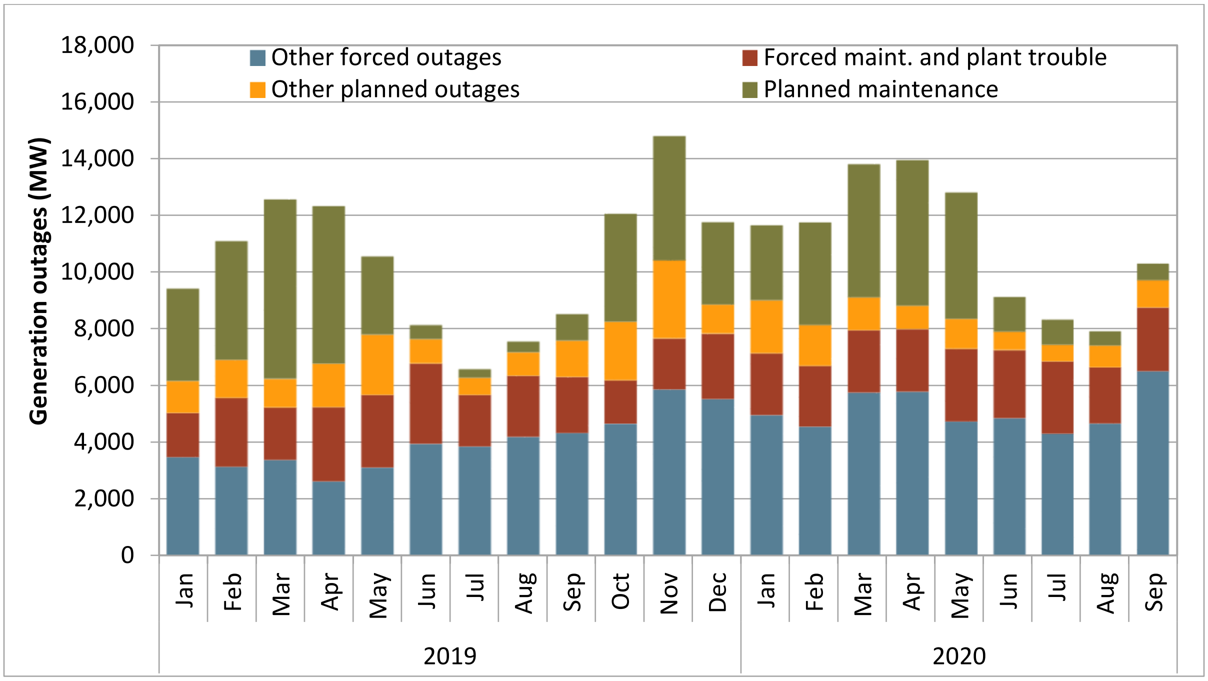
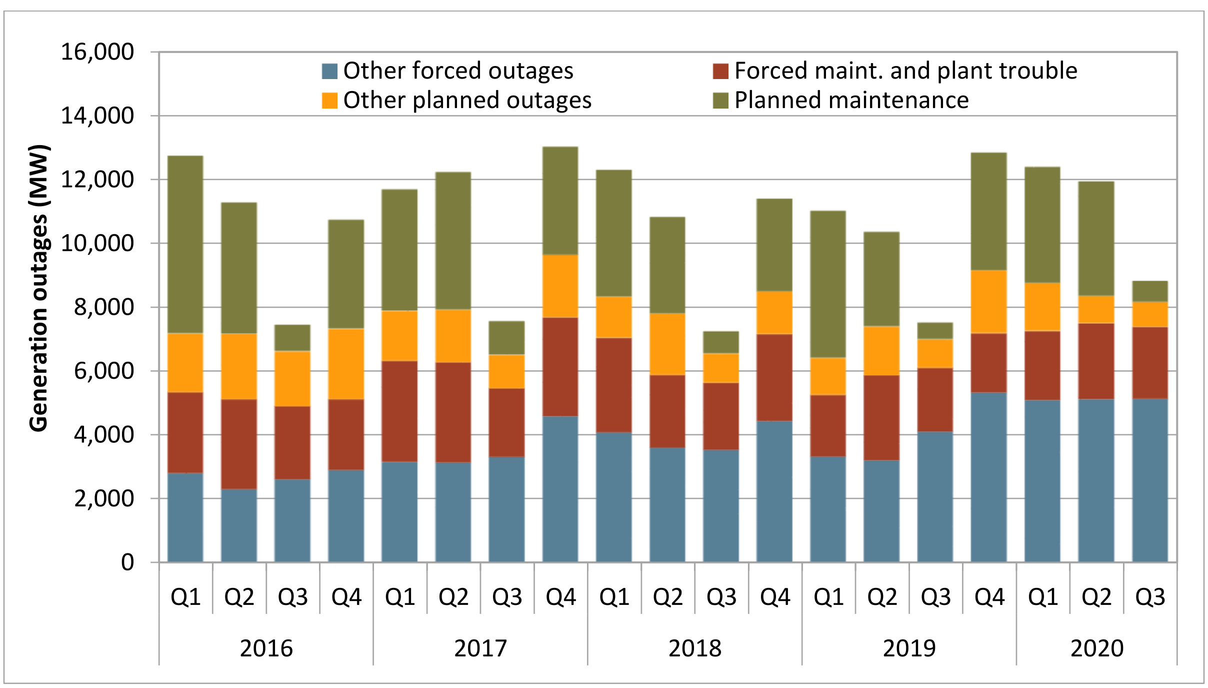


Figure 1.7 Quarterly average of maximum daily generation outages by type – peak hours



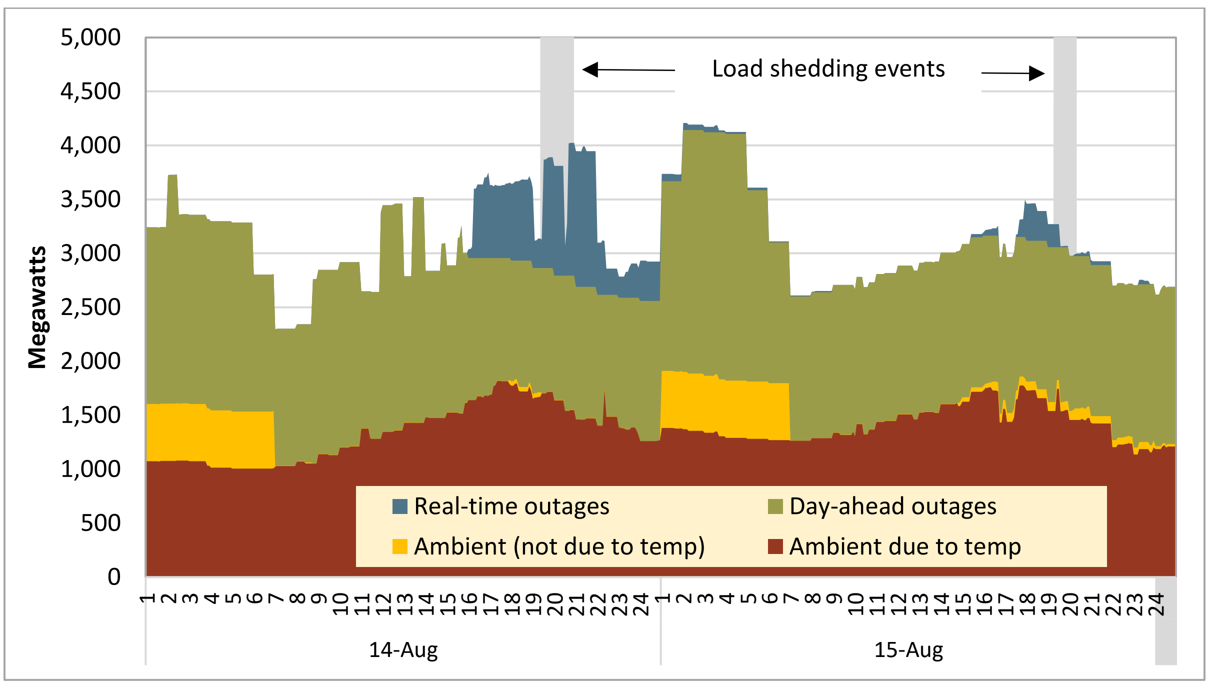
During the third quarter of 2020, the average total generation on outage in the ISO surpassed the same period in 2019 by about 1,300 MW, as shown in Figure 1.7.[21] Forced outages were about 7,400 MW during peak hours in the third quarter of 2020, similar in magnitude to the sum of all outages during the third quarter of 2019. Planned maintenance outages were about 650 MW, while other types of planned outages averaged about 750 MW over the quarter. Some common types of outages that fall into the other planned outages 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 averaged about 2,250 MW, while all other types of forced outages averaged about 5,150 MW during the quarter. The other types of forced outages include ambient due to temperature, ambient not due to temperature, environmental restrictions, unit testing, and outages for transition limitations.

Gas generation outages during the August heat storm

One of the key factors cited for triggering the load curtailment events on August 14 and 15 was sudden forced outages of several large gas-fired units in real-time. Figure 1.8 shows the gas-fired capacity (including resource adequacy and non-resource adequacy capacity) on outage during August 14 and 15.

Figure 1.8 Gas unit outages and load shedding events (August 14-15)



On August 14, there was a large spike in outages in the hours leading up to load curtailment. On August 15, there was also a significant increase in the amount of capacity on outage in the hours leading up to load curtailment. Although the overall level of gas capacity on outage was not unusually high on these

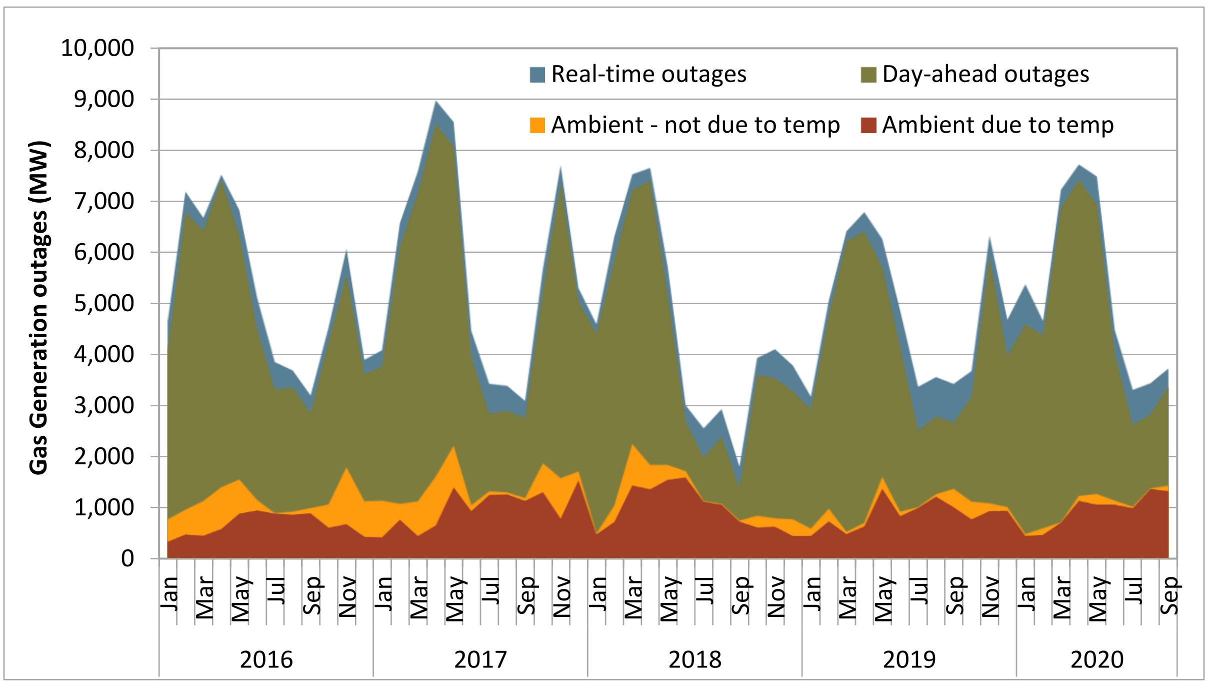
21 This is calculated as the average of the daily maximum level of outages, excluding off-peak hours. Values reported here only reflect generators in the ISO balancing area and do not include outages from the energy imbalance market.

days, this sudden loss of a significant amount of gas capacity came at a time when the amount of available supply was very low due to a combination of other factors.[22]

As shown in Figure 1.8, about half of the gas-fired capacity unavailable was due to ambient derates which occur in very hot weather – when the total output from gas units falls below their normal rated capacity due to ambient temperature. During the hours of load curtailment on August 14, about 12 percent of total gas-fired capacity was on outage, with about 5.3 percent of total gas capacity reporting ambient derates due to high temperatures. On August 15, just over 10 percent of total gas-fired capacity was on outage during hours of load curtailment, with about 5 percent of total gas capacity reporting ambient derates due to high temperatures.

Figure 1.9 expands on Figure 1.8 and shows the monthly average of daily maximum gas generation outages during peak hours from 2016 to 2020.[23] Ambient derates peak in May and seasonal lows for these derates tend to occur around January. Total gas outages in the real-time and day-ahead time frames track together and have a distinctive dual peak trend, with the first peak occurring around May and the second around November.

Figure 1.9 Gas unit outages and ambient derates (Jan. 2016 – Sep. 2020)



[22] An in-depth analysis and report of these factors may be found in the Department of Market Monitoring's *Report on Market Conditions, Issues and Performance – August and September 2020*. http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

[23] Peak hours are defined as Monday through Saturday, excluding North American Electric Reliability Council (NERC) holidays, from 6:00 AM to 10:00 PM.

1.2 Load conditions

ISO load decreased in the third quarter of 2020 relative to the same quarter in 2018 and 2019, on average. Figure 1.10 shows average hourly load by month from 2018 to 2020. Lower loads are due in part to increases in behind-the-meter solar generation, initiatives to improve energy efficiency, as well as the continued shift from industrial to residential demand in response to COVID-19. The biggest year-over-year change in load happened in July when average hourly load dropped by between 4 and 14 percent compared to the previous two years.

Figure 1.10 Average hourly load by third quarter month (2018-2020)

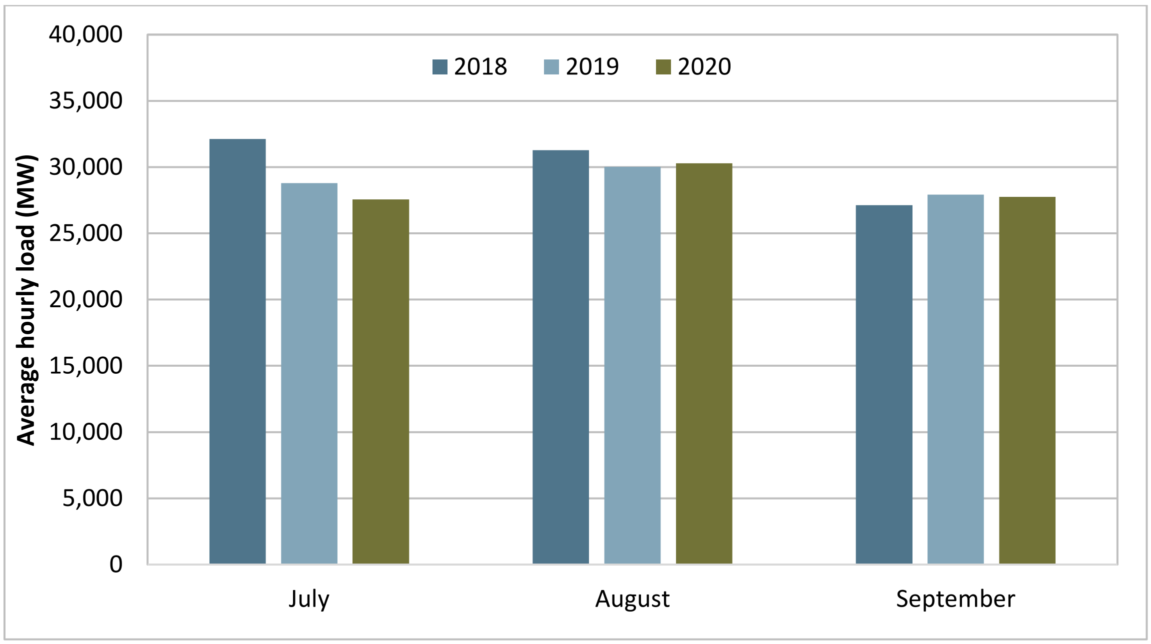


Figure 1.11 shows how the variability of the net load curve has changed over time. It shows the average hourly net load as well as the minimum and maximum hourly average net load from July 2018 to September 2020. Average net load tends to follow seasonal patterns in California by increasing during warmer months and decreasing during cooler months. Apart from this general pattern, average net loads have decreased by about 8 percent since the third quarter of 2018.

Figure 1.11 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 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 1.11 Average hourly net load by month (2018-2020)

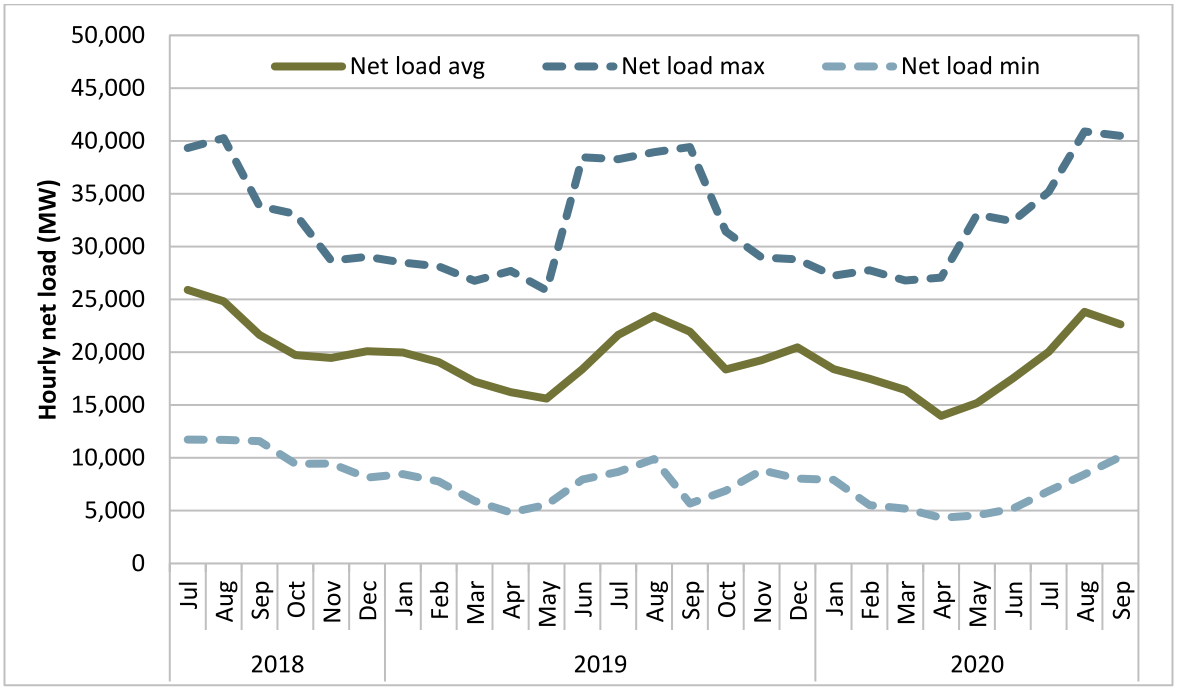
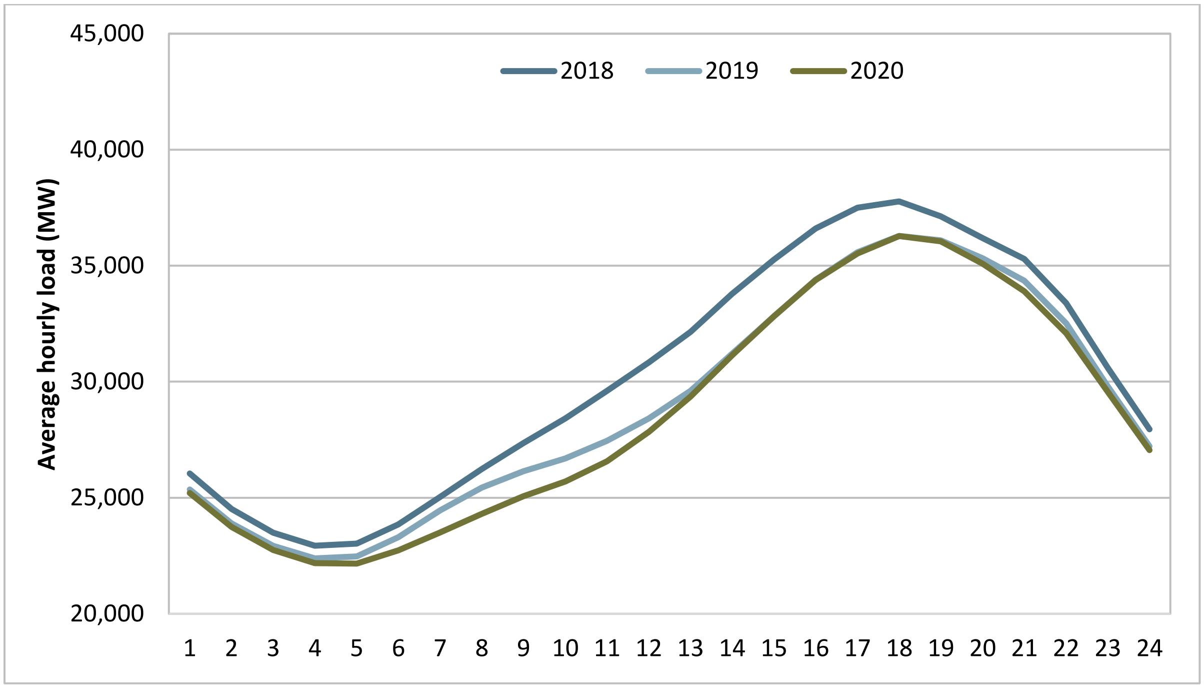


Figure 1.12 offers insight into how behind-the-meter solar resources affect ISO load. Generation from utility scale wind and solar resources indirectly affects load by influencing how other generation sources must meet demand after wind and solar have been factored out, i.e., the net load. Conversely, 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. Though not as pronounced in the third quarter as in other quarters, 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.

The figure shows average load by hour in the third quarter of 2018 to 2020. Average hourly load in the third quarter of 2020 was generally lower than the same quarter in 2019 due to the continued shift in commercial and industrial load to residential load that resulted from the COVID-19 stay-at-home orders. This effect was offset during the afternoon peak hours, however, when higher than average temperatures caused large increases in demand for cooling driven by air conditioning use.[24] These competing effects resulted in similar average afternoon peak loads for this quarter over the past two years.

[24] California Energy Commission. August 19, 2020. *CEC Energy Insights*: https://www.energy.ca.gov/sites/default/files/2020-08/Energy%20Insights_2020-08_ada.pdf

Figure 1.12 Average load by third quarter hour (2018-2020)



1.3 Energy market performance

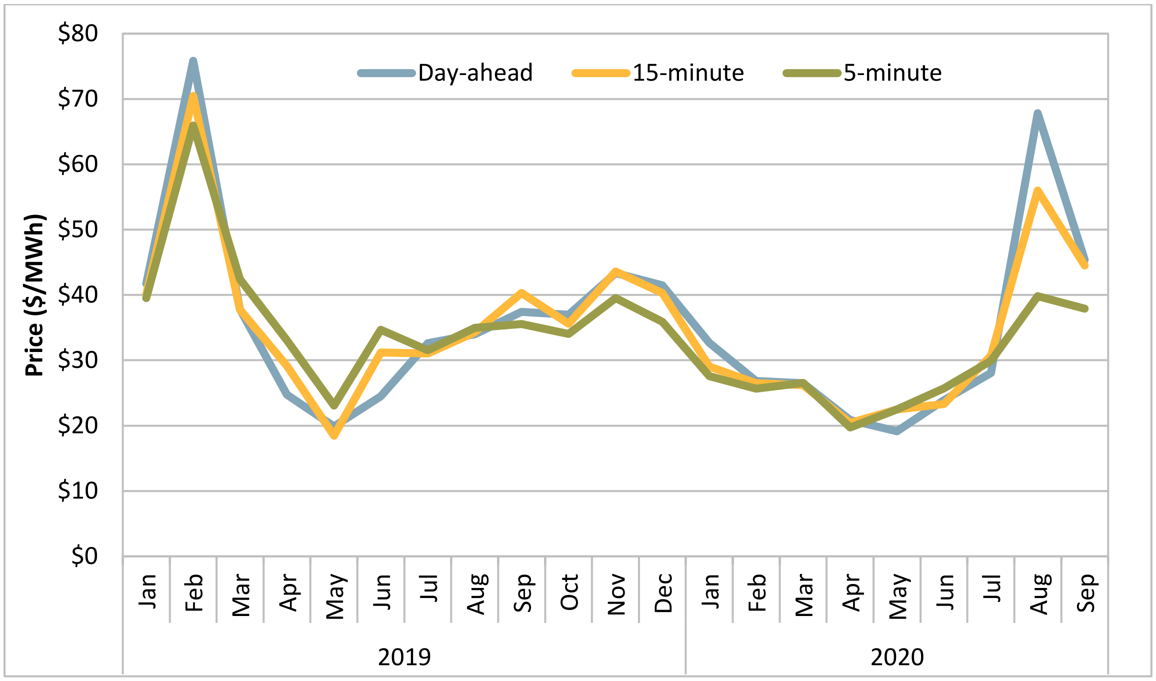
1.3.1 Energy market prices

This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. Third quarter prices were high, relative to both the previous quarter and previous year. Between the second and third quarters of 2020, average day-ahead prices increased by 121 percent, 15-minute prices increased by 98 percent, and 5-minute prices increased by 58 percent.

Average monthly day-ahead prices were higher than both 15-minute and 5-minute market prices during the third quarter. Day-ahead prices averaged about $47/MWh, 15-minute prices averaged $44/MWh, and 5-minute prices averaged $36/MWh, an increase over the same quarter of 2019 of 34 percent, 26 percent and 6 percent, respectively.

Figure 1.13 shows load-weighted average monthly energy prices during all hours across four 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 2019 to September 2020.

Figure 1.13 Monthly load-weighted average energy prices (all hours)



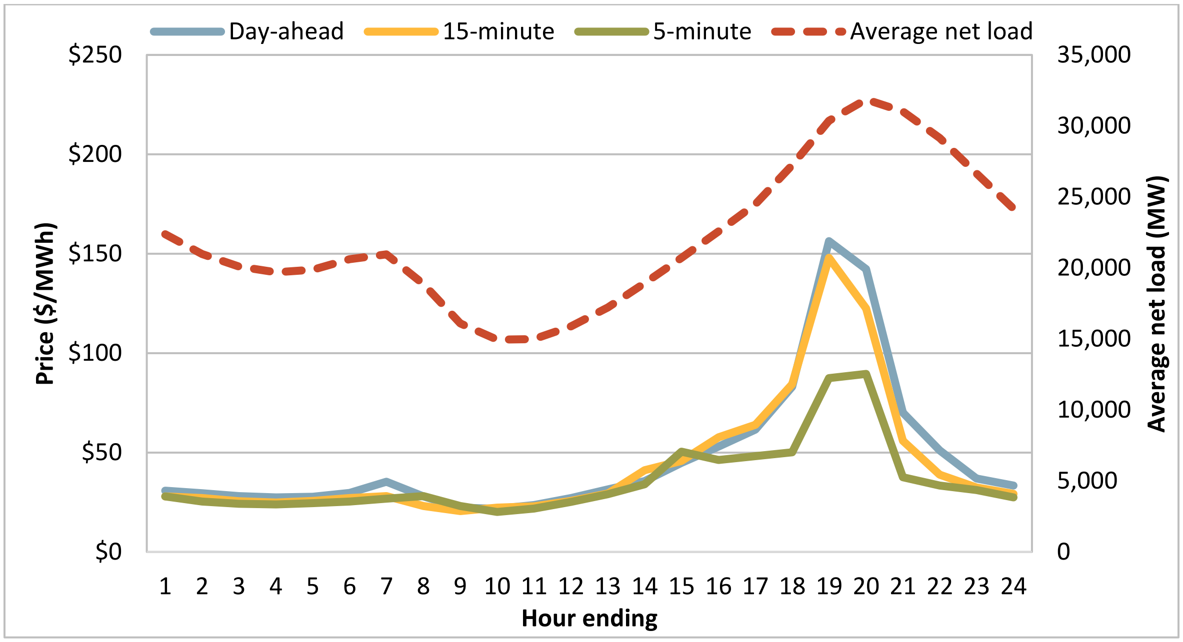
Average prices generally diverged across the three markets in the third quarter, particularly in August and September. Prices in the day-ahead market were higher than the real-time market prices, consistent with the general trend since 2014 of higher day-ahead prices than real-time. However, Figure 1.13 shows that the price divergence in August was more pronounced than normal. As discussed in DMM's heatwave report, the ISO experienced high loads from August 14-21 and September 5-7.[25] Prices spiked during this time period with day-ahead prices hitting the $1,000/MWh bid cap during many hours.

Figure 1.14 illustrates load-weighted average energy prices on an hourly basis in the third quarter compared to average hourly net load.[26] 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.

25 An in-depth analysis and report of these factors may be found in the Department of Market Monitoring's *Report on Market Conditions, Issues and Performance – August and September 2020*. http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

26 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 1.14 Hourly load-weighted average energy prices (July – September)



Average hourly prices in the third 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 5-minute prices over the quarter was primarily due to the divergence of real-time prices between hours ending 16 and 21 as net load was increasing to the afternoon peak.

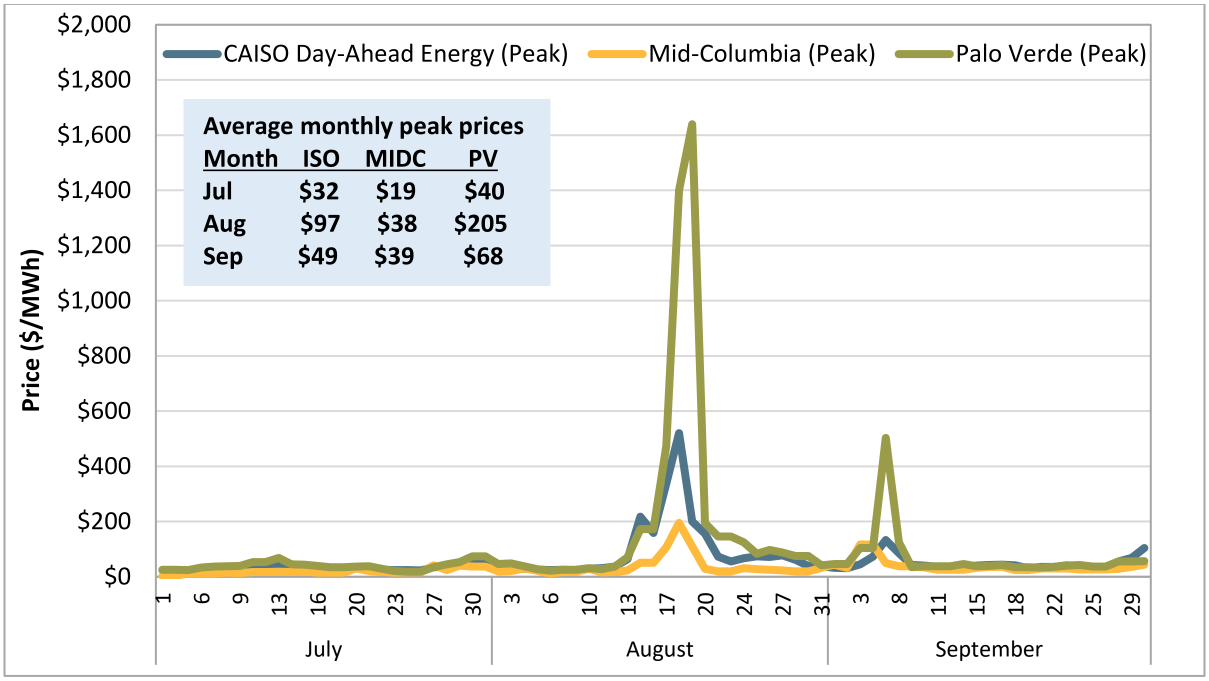
1.3.2 Bilateral price comparison

On average, day-ahead market prices in the ISO across peak hours in the third quarter were greater than prices at Mid-Columbia hub and lower than the prices at Palo Verde electricity hub. Regional differences in prices reflect transmission constraints as well as greenhouse gas compliance costs.

Figure 1.15 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 from Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the ISO market. 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.

As shown in Figure 1.15, Palo Verde prices exceeded the day-ahead ISO prices and the ISO prices exceeded Mid-Columbia prices during most of the third quarter. The figure also shows significant price divergence between the ISO and these bilateral hubs during the heat wave conditions that existed in mid-August and early September. Prices at Mead, Palo Verde, and other locations exceeded the $1,000/MWh WECC soft offer cap, requiring sellers to submit cost justification for sales made above this cap to FERC. DMM has intervened in this cost justification proceeding and submitted comments on most of the company filings.[27,28]

Figure 1.15 Day-ahead ISO and bilateral market prices (Jul – Sep)



Average day-ahead prices in the ISO and bilateral hubs (from ICE) were also compared to real-time hourly energy prices traded at Mid-Columbia and Palo Verde hubs for all hours of the quarter using data published by Powerdex. Average day-ahead hourly prices in the ISO were greater than average real-time prices at Mid-Columbia and Palo Verde by $26/MWh and $11/MWh, respectively. Average day-ahead prices at Mid-Columbia and Palo Verde (from ICE) were greater than the average real-time prices at Mid-Columbia and Palo Verde (from Powerdex) by $5/MWh and $46/MWh, respectively.

Imports and exports

Compared to previous quarters, the net hourly interchange shape is quite different for the third quarter of 2020. This can be attributed to regional high temperatures during this reporting period, specifically from mid-August to September 7, 2020, which led to high demand across the entire western region. The import and export trends for the quarter reflect the extraordinary conditions during this period, particularly atypically high levels of self-scheduled exports. Greater detail on these and other factors can

27 Motion To Intervene And Comments Of The Department Of Market Monitoring Of The California Independent System Operator Corporation, Docket No. EL10-56-000, September 1, 2020: http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoring-WECCSoftOfferCap-Sept12020.pdf

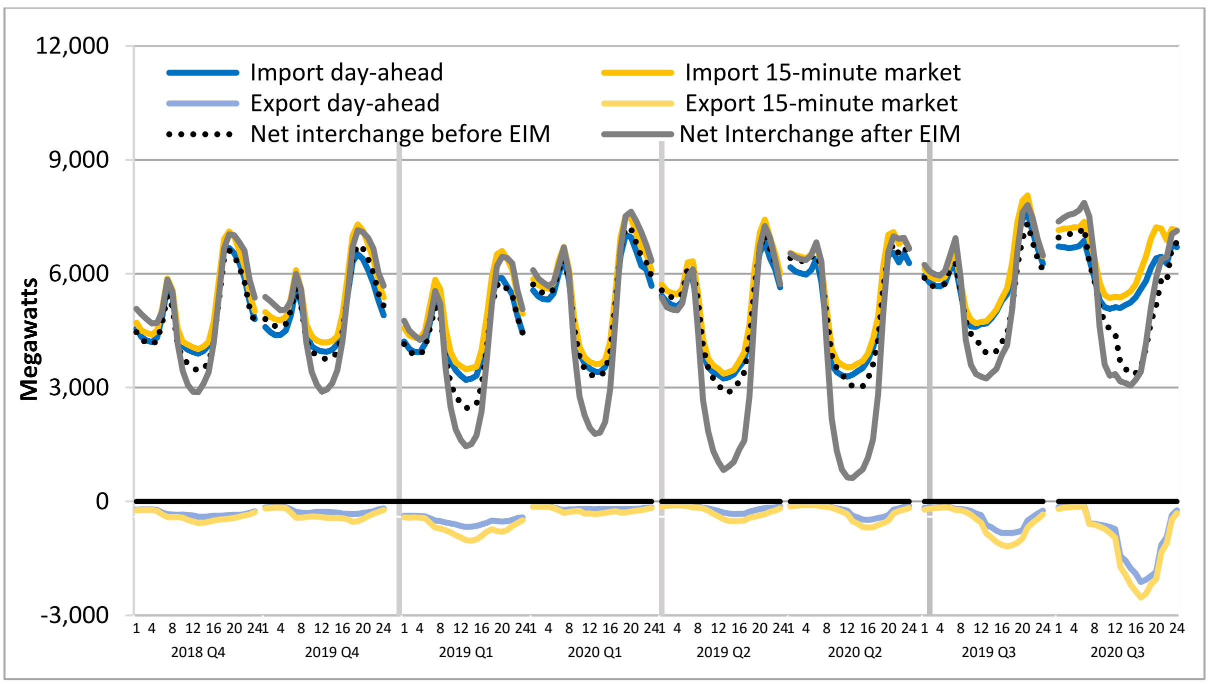
28 DMM comments on WECC soft offer cap cost justification filings, October 28, 2020: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=55CBE632-386E-470C-921E-B2F8C41AECE5

be found in DMM's Report on Market Conditions, Issues and Performance – August and September 2020.[29]

Volumes of imports in both the day-ahead and real-time markets increased in morning and mid-day hours; however, in the critical evening solar ramp down periods volumes decreased compared to the same quarter in 2019. As shown in Figure 1.16, day-ahead (dark blue line) peak imports for this quarter decreased from about 7,600 MW to 6,900 MW in the same quarter the previous year. For the same comparable period, the peak 15-minute (dark yellow line) cleared imports also decreased from about 8,000 MW to 7,400 MW. Exports (shown as negative numbers below the horizontal axis in pale blue and yellow), increased by about 1,300 MW from the same quarter in 2019 and peaked at an average of about 2,500 MW in hour ending 16 and 18.

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 3,000 MW in hour ending 15. The greatest import transfer into the ISO from the EIM occurred in hour ending 7 at about 1,200 MW, compared to 700 MW in hour ending 20 from the same quarter in the prior year. The greatest export transfer from the ISO to the EIM occurred in hour ending 11 at about 1,200 MW, an increase of about 400 MW from the same quarter in 2019.

Figure 1.16 Average hourly net interchange by quarter



29 An in-depth analysis and report of Department of Market Monitoring's *Report on Market Conditions, Issues and Performance – August and September 2020*. http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

1.4 Wholesale energy cost

Total wholesale cost to serve load in the ISO market during the third quarter of 2020 was about $3.8 billion, up significantly from about $2.5 billion in the same quarter of 2019. The average cost per megawatt-hour of load increased nearly 60 percent to about $61/MWh for the third quarter from $39/MWh in the same quarter of 2019 (nominal costs shown in blue bars in Figure 1.17).

The increase in average wholesale electric prices is partially from a 4 percent increase in natural gas prices compared to the same quarter in 2019. Load-weighted gas prices increased to about $3.95/MMBtu, a 4 percent increase from about $3.80/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 1.17 shows the wholesale energy costs to serve load increased by 53 percent to about $64/MWh from about $42/MWh in the same quarter of 2019. In addition to slightly higher natural gas costs, lower renewable generation and periods of high load also contributed to higher wholesale energy costs this quarter.

Figure 1.17 Total quarterly wholesale costs per MWh of load

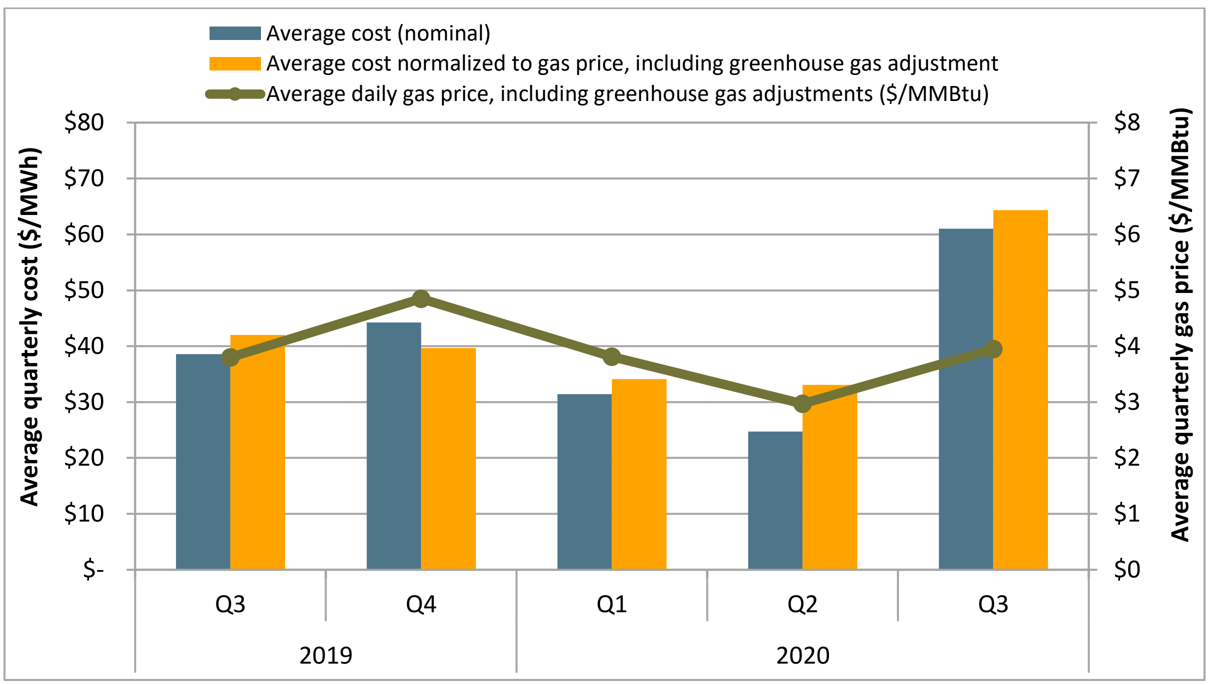


Table 1.1 provides quarterly summaries of nominal total wholesale costs by category. Costs for energy procured in the day-ahead market continued to make up a majority (90 percent) of the total cost to deliver energy to the market, about the same as the previous quarter but a decrease compared to the third quarter of 2019. Real-time market costs decreased to about 4.3 percent of the total cost from about 5 percent in the previous quarter, but increased from 2.5 percent in the same quarter the previous year. Bid cost recovery, reliability, and reserve costs remained low, but increased slightly compared with the same quarter in 2019.

Table 1.1 Estimated average wholesale energy costs per MWh

	Q3 2019	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Change Q3 2019-Q3 2020
Day-ahead energy costs	$ 35.94	$ 41.36	$ 29.45	$ 22.17	$ 55.05	$ 19.11
Real-time energy costs (incl. flex ramp)	$ 0.97	$ 1.45	$ 0.50	$ 1.24	$ 2.61	$ 1.64
Grid management charge	$ 0.45	$ 0.46	$ 0.45	$ 0.47	$ 0.48	$ 0.03
Bid cost recovery costs	$ 0.72	$ 0.45	$ 0.34	$ 0.35	$ 1.05	$ 0.34
Reliability costs (RMR and CPM)	$ 0.06	$ 0.06	$ 0.03	$ 0.00	$ 0.10	$ 0.05
Average total energy costs	**$ 38.14**	**$ 43.79**	**$ 30.77**	**$ 24.24**	**$ 59.30**	**$ 21.16**
Reserve costs (AS and RUC)	$ 0.46	$ 0.49	$ 0.65	$ 0.50	$ 1.73	$ 1.26
Average total costs of energy and reserve	**$ 38.60**	**$ 44.27**	**$ 31.42**	**$ 24.74**	**$ 61.03**	**$ 22.43**

1.5 Price variability

In the third quarter, high day-ahead prices occurred with more than double the frequency of high prices in the fifteen-minute market which themselves occurred with greater frequency than high five-minute market prices.

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.[30] 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

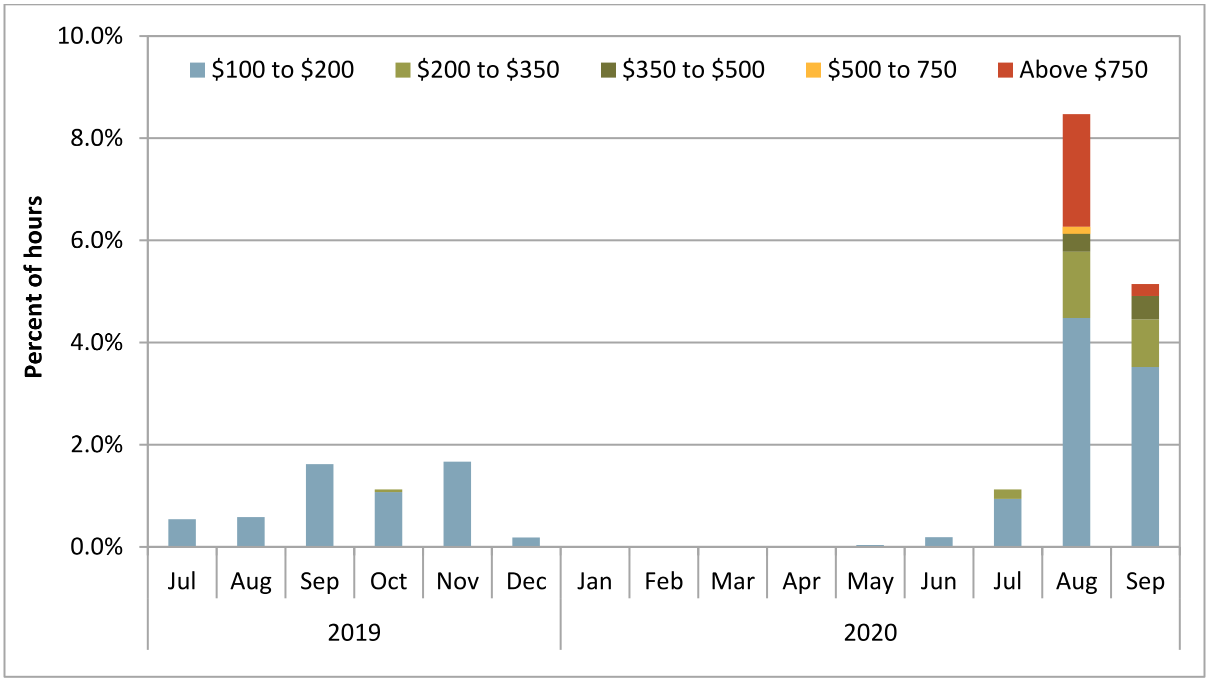
In the third quarter of 2020, the frequency of high day-ahead prices increased, while negative day-ahead prices remained the same, compared to the same quarter in 2019.

High prices

Figure 1.18 shows the frequency of day-ahead market prices in various high priced ranges from July 2019 to September 2020. There were frequent high prices over $100/MWh in the day-ahead market during the third quarter of 2020, occurring in over 8 percent of total intervals in August of 2020. High prices occurred more frequently in the third quarter of 2020 compared to the same quarter of 2019.

[30] 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.

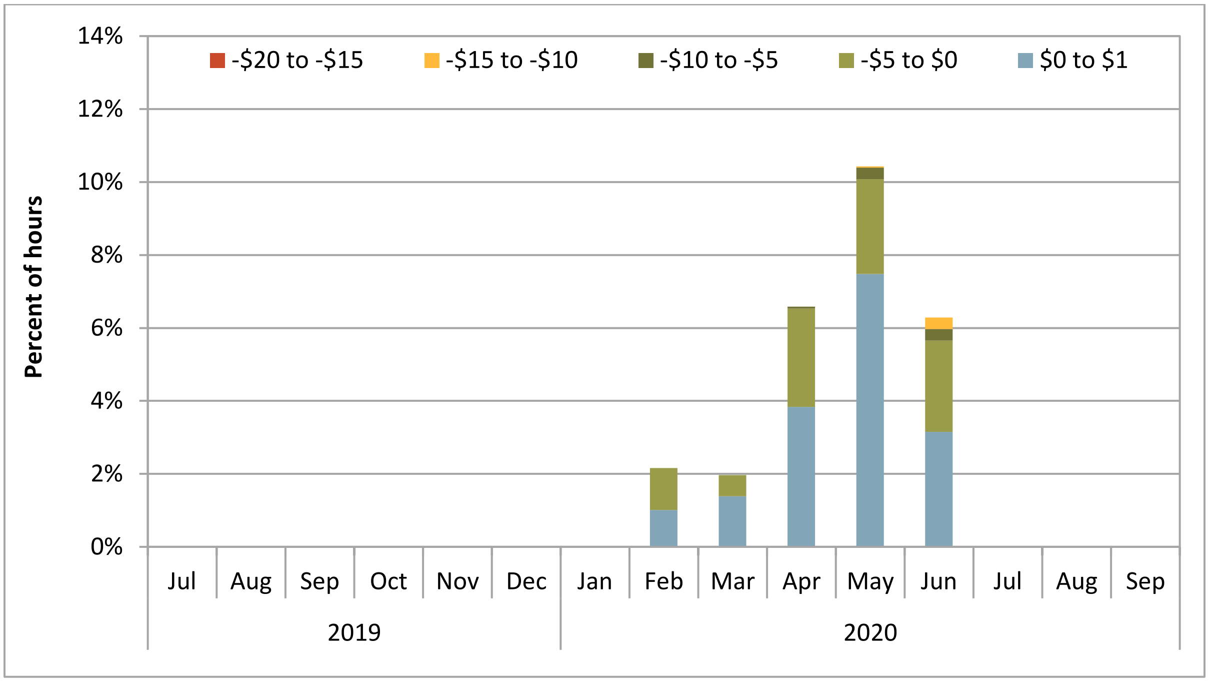
Figure 1.18 Frequency of high day-ahead prices ($/MWh) by month



Negative prices

Figure 1.19 shows the frequency of day-ahead market prices in various low priced ranges from July 2019 to September 2020. The absence of negative prices in the third quarter of 2020 is not unexpected as it is similar to the third quarter of 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. Therefore, the lack of negative prices during the quarter is due to the increased demand during the middle of the day from higher temperatures across the system.

Figure 1.19 Frequency of negative day-ahead prices ($/MWh) by month



1.5.2 Real-time price variability

During the third quarter of 2020, the frequency of high real-time prices was high, but lower than the frequency of high prices in the day-ahead market. The frequency of negative prices in the real-time markets decreased from the previous quarter, and was similar to the third quarter of 2019.

High prices

Figure 1.20 and Figure 1.21 show the frequency of prices above $250/MWh across the three largest load aggregation points (LAP) in the ISO. As shown in Figure 1.20, the occurrence of high prices in the 15-minute market greater than $250/MWh was more frequent during the third quarter, significantly surpassing the levels in the third quarter of 2019.

Figure 1.21 shows the frequency of high prices in the 5-minute market. During the third quarter, the frequency of price spikes greater than $250/MWh increased steadily from the previous quarter, and was higher than the same quarter of 2019.

Figure 1.22 and Figure 1.23 shows the corresponding frequency of under-supply infeasibilities in the 15-minute and 5-minute markets. The frequency of valid 15-minute market under-supply infeasibilities during August was high, during around 1 percent of intervals. Valid under-supply infeasibilities in the 5-minute market were less frequent than in the 15-minute market, but more frequent relative to the previous quarter and the same quarter in the previous year.

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

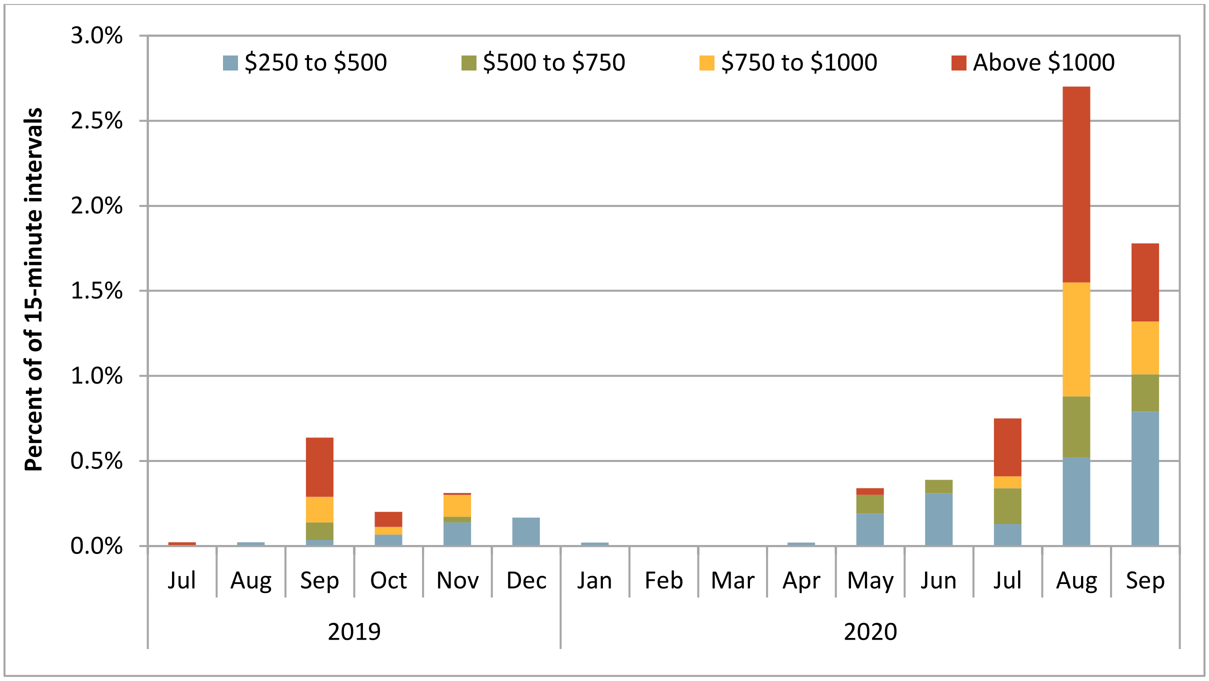


Figure 1.21 Frequency of high 5-minute prices by month (ISO LAP areas)

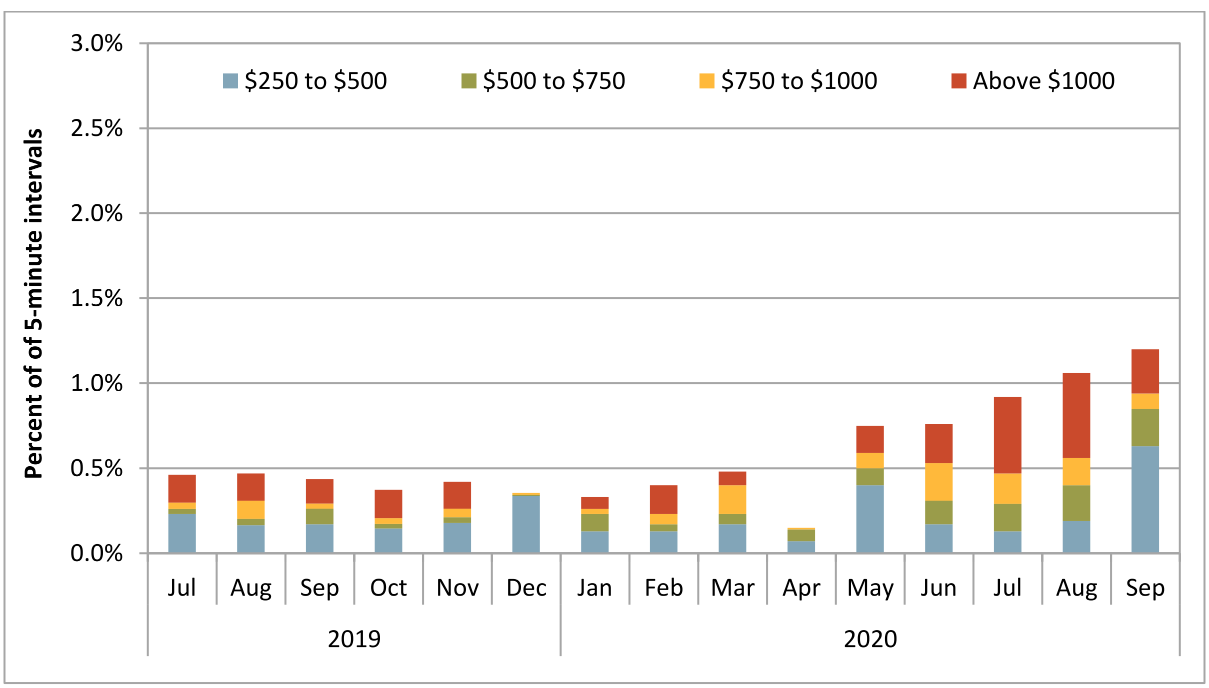


Figure 1.22 Frequency of under-supply power balance constraint infeasibilities (15-minute market)

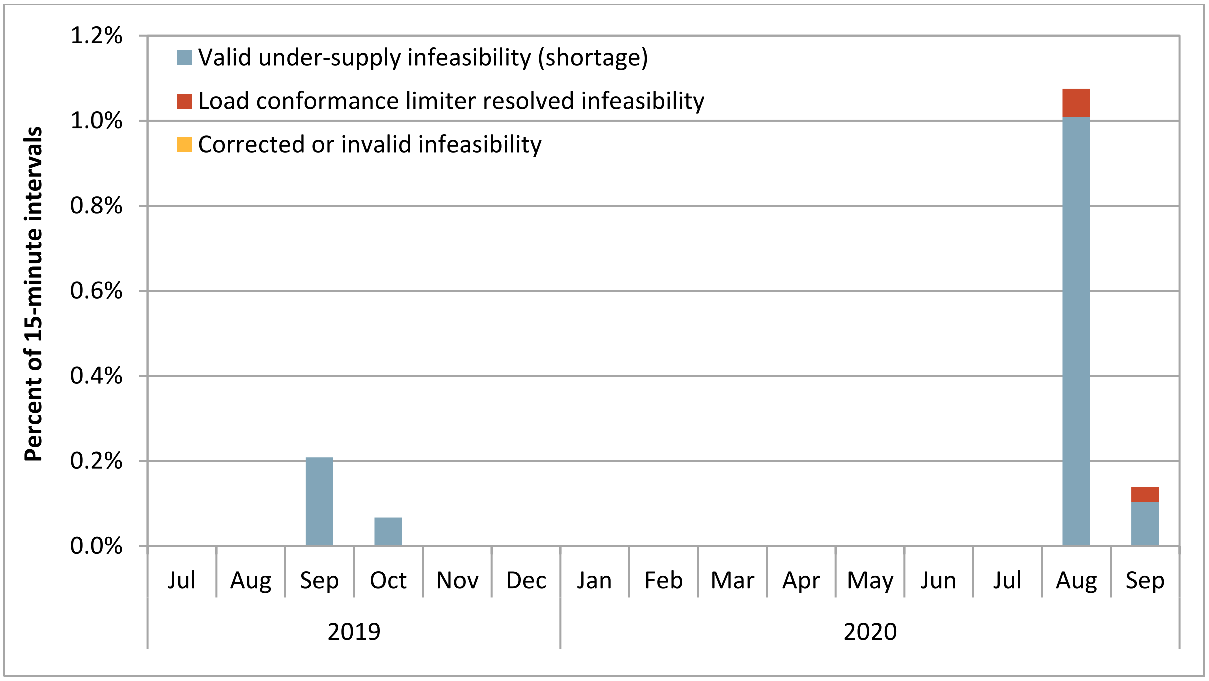
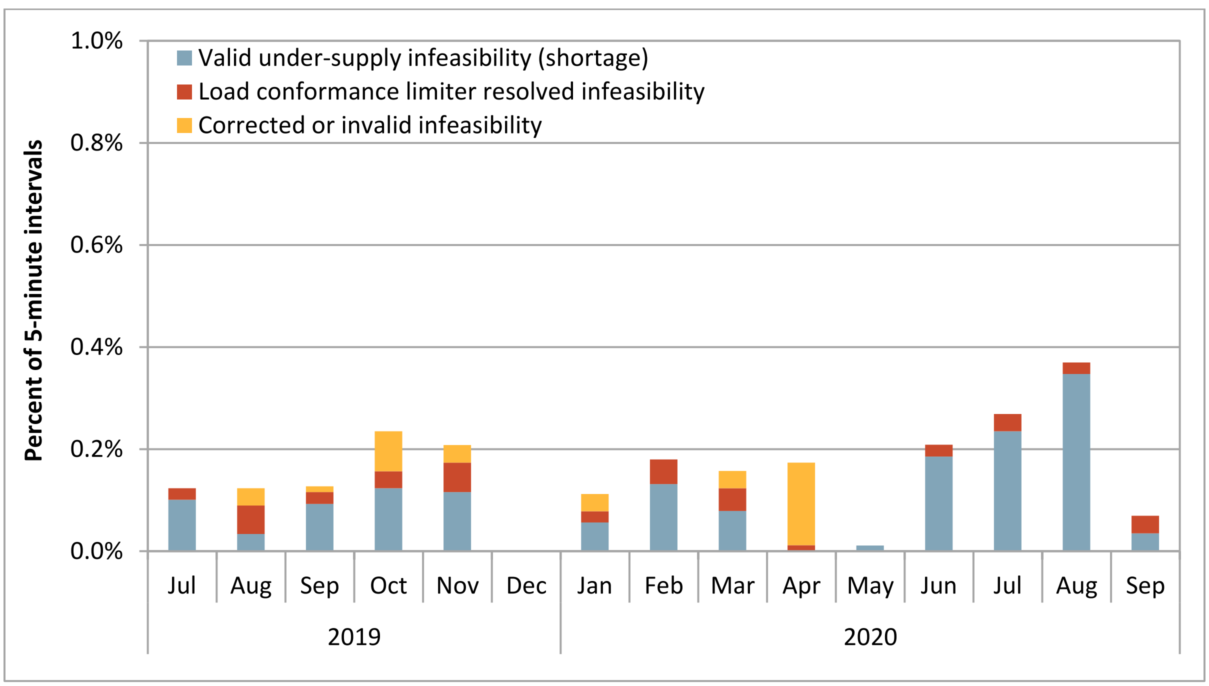


Figure 1.23 Frequency of under-supply power balance constraint infeasibilities (5-minute market)

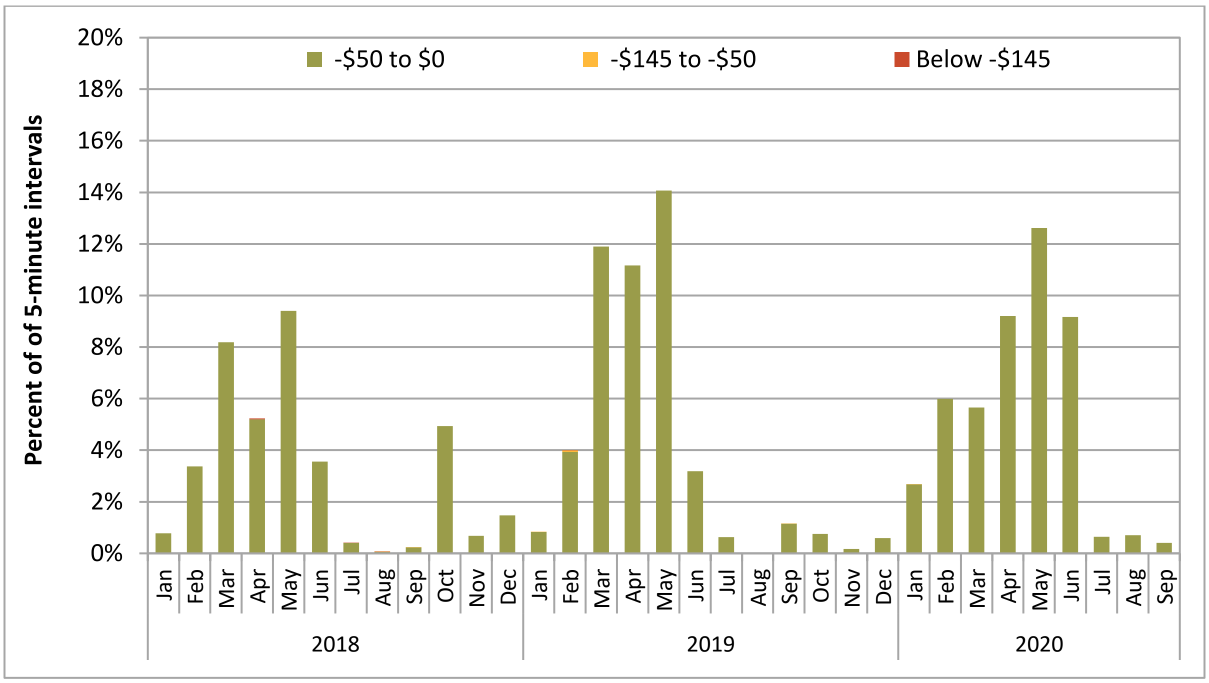


Negative prices

Figure 1.24 shows the frequency of negative prices in the 5-minute market by month across the three largest load aggregation points in the ISO.[31] The frequency of negative prices in the 15-minute and 5-minute markets decreased from the previous quarter, similar to the third quarter of 2019. Negative prices during the third quarter of 2020 occurred during about 1 percent of 15-minute intervals and 2 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 third quarter, this was most frequent between hours ending 8 and 14 when loads, net of wind and solar, were lowest.

Figure 1.24 Frequency of negative 5-minute prices by month (ISO LAP areas)



1.6 Flexible ramping product

Flexible ramping product system level prices were zero for around 98 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.

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

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

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.

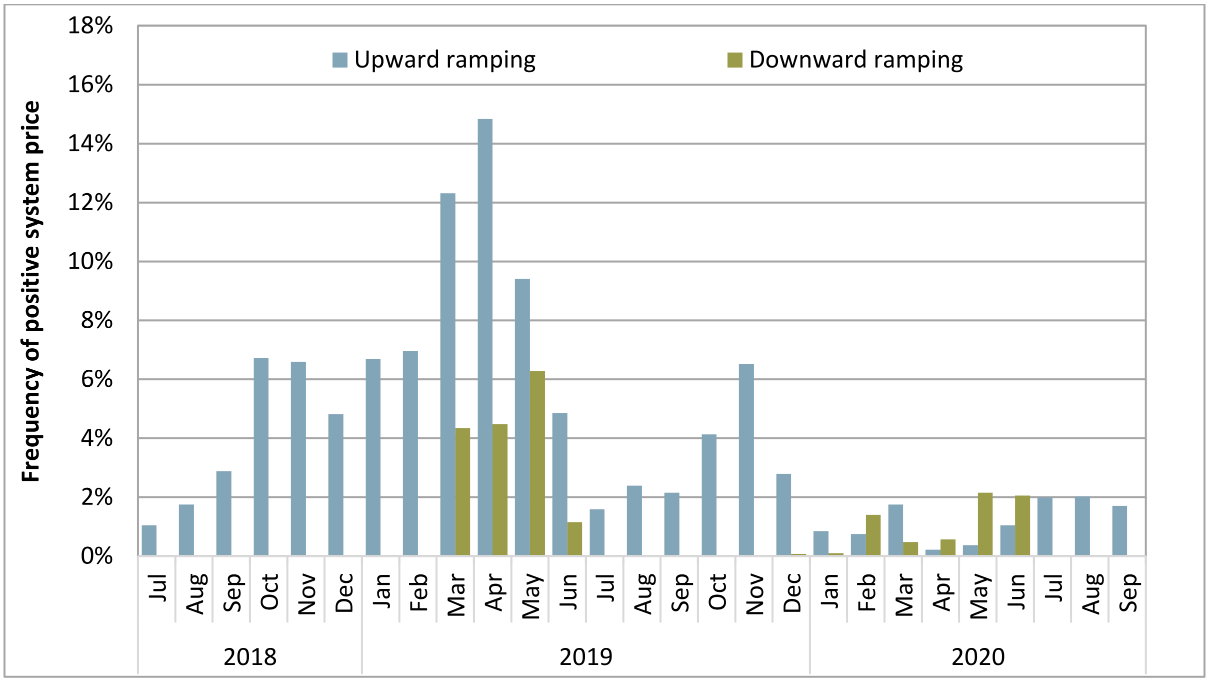
1.6.1 Flexible ramping product prices

This section describes the amount of flexible ramping capacity that was procured in the 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 1.25 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 low overall. The 15-minute market system-level demand curve for upward ramping capacity bound in around 2 percent of intervals during the quarter across all hours. However, during hours 18 and 19 there was a positive shadow price during around 13 percent of 15-minute market intervals.

In the 5-minute market, the system-level demand curves for upward ramping capacity bound in around 0.1 percent of intervals.

Figure 1.25 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.[32] The following section looks at flexible ramping product payments from three different perspectives: (1) by payment type, (2) by area, and (3) by fuel type.

Figure 1.26 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 upward ramping capacity increased during the quarter. Payments for only upward and downward uncertainty awards were around $1.7 million during the quarter. However, net of costs associated with forecasted movement, total payments associated with the flexible ramping product dropped to $0.3 million. The large majority of the costs associated with forecasted movement were to solar resources ramping off during periods with high demand for upward ramping capacity. Total costs to solar resources for downward forecasted movement were partially offset by payments to other resources for upward forecasted movement.

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

Figure 1.26 Monthly flexible ramping product payments by type

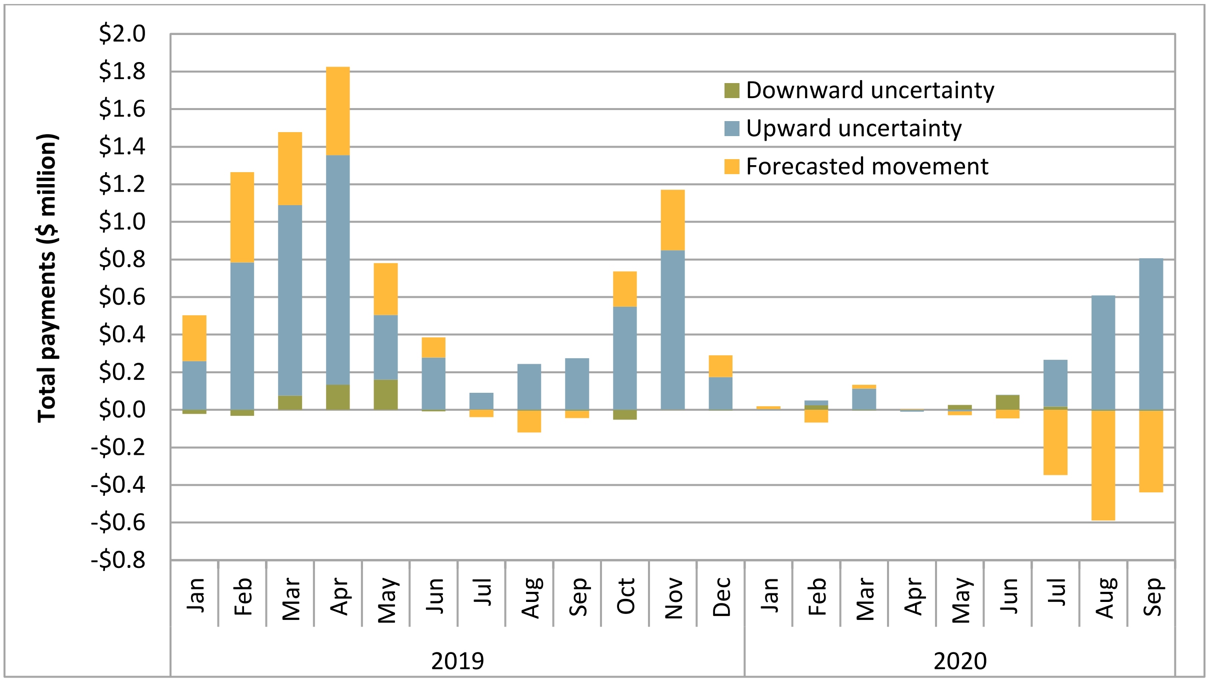


Figure 1.27 and Figure 1.28 do not include payments for forecasted movements and therefore only reflect payments to generators for upward and downward ramping capacity to meet uncertainty needs.

Figure 1.27 shows these payments by area, arranged generally by geographic location. Payments for this capacity may have been procured to satisfy system-level demand, area-specific demand, or both. During the quarter, 48 percent of payments for flexible ramping capacity have been to resources internal to the ISO while 34 percent of payments have been to areas in the Northwest region (which includes PacifiCorp West, Puget Sound Energy, Portland General Electric, Powerex, and Seattle City Light). In both cases, the majority of payments were for system uncertainty needs rather than area-specific uncertainty needs. 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.

Figure 1.28 shows the same information by fuel type. During the quarter, around 53 percent of flexible capacity payments for upward and downward uncertainty were to hydroelectric generators and 38 percent of payments were to gas resources. Payments to limited energy storage resources, which includes batteries and other limited devices, made up roughly 5 percent of payments.

Figure 1.27 Monthly flexible ramping product uncertainty payments by area

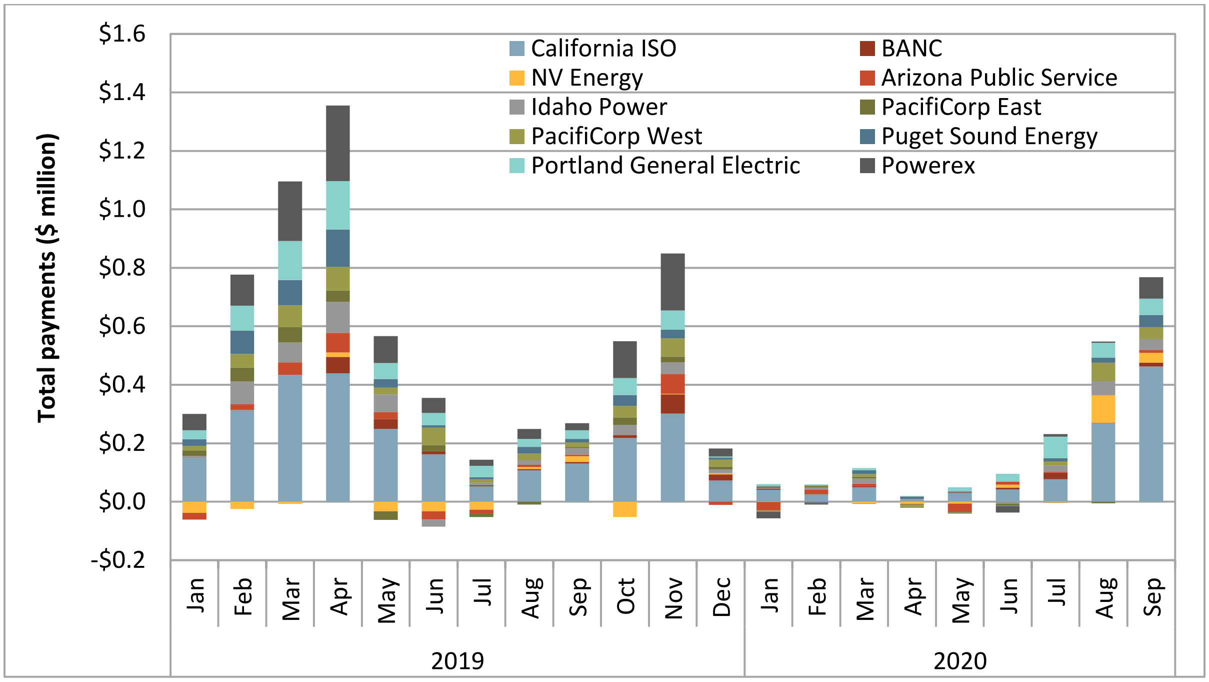
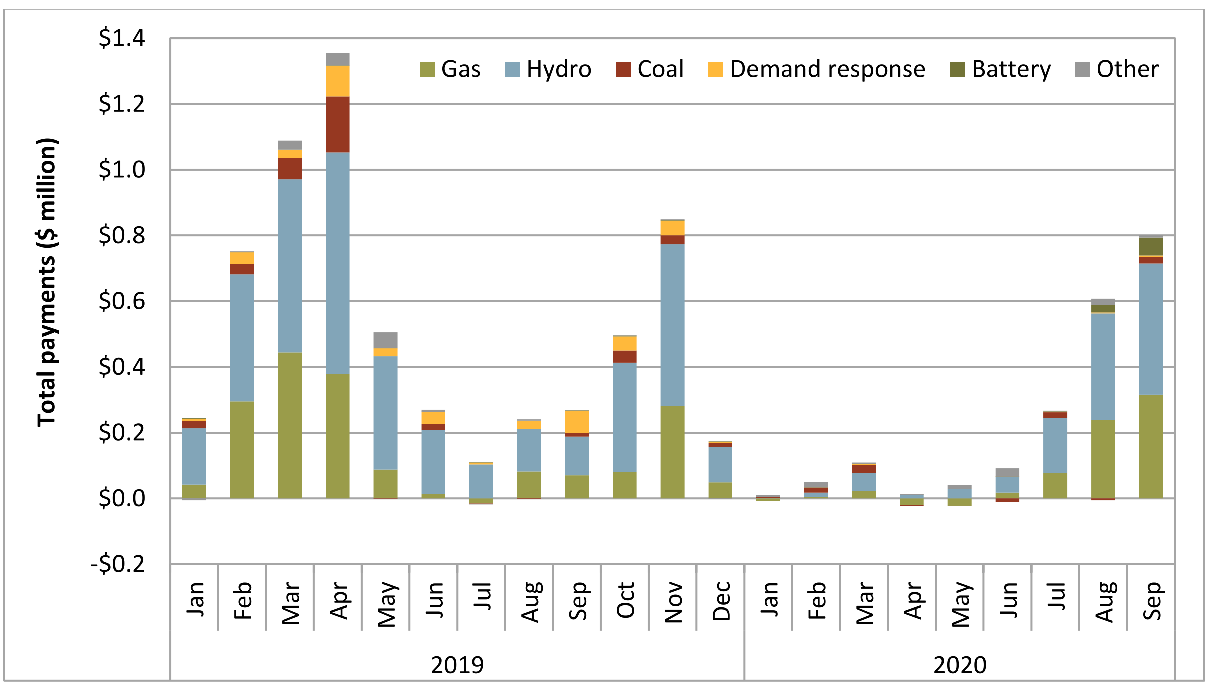


Figure 1.28 Monthly flexible ramping product uncertainty payments by fuel type



1.7 Convergence bidding

Convergence bidding was profitable overall for the third quarter of 2020. Combined net revenue for virtual supply and demand was about $19 million after subtracting about $6.3 million of virtual bidding bid cost recovery charges. Virtual demand generated revenues of about $12.6 million for the quarter while virtual supply generated a similar amount at about $12.7 million before accounting for bid cost recovery charges.

Virtual bidding was temporarily suspended beginning on operating day August 18 because of significant challenges associated with system conditions during the August heat wave. On the morning of Sunday, August 16, the ISO announced the suspension of convergence bidding effective in the day-ahead market for operating day August 18.[33] This suspension was designed to better align physical supply with demand, in part by preventing virtual supply bids from allowing additional exports to be scheduled in the day-ahead market which would ultimately need to be met by physical supply from within the ISO system.

The ISO reinstated virtual bidding in the day-ahead market for August 22. By this time, system and market conditions had changed so that virtual bidding was again viewed as providing market benefits without presenting a risk to the system. Although the ISO continues to have authority to suspend virtual bidding, the ISO anticipates that changes to the management of export schedules and more accurate day-ahead load scheduling will reduce the risk of further suspensions if similar market conditions reoccur.[34] Greater detail and analysis on convergence bidding and market performance during the summer 2020 heat wave can be found in the DMM report on system and market conditions for August and September 2020.[35]

1.7.1 Convergence bidding trends

Average hourly cleared volumes were about 3,500 MW, a decrease of about 400 MW from the previous quarter and a slight increase, 100 MW, over the same quarter from the previous year. Average hourly cleared virtual supply decreased by about 100 MW from the previous quarter to about 2,000 MW. Cleared virtual demand averaged around 1,500 MW during each hour of the quarter, a 300 MW decrease from the previous quarter. On average, about 36 percent of virtual supply and demand bids offered into the market cleared in the quarter, up from 28 percent in the previous quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 550 MW on average, an increase from 350 MW of net virtual supply in the previous quarter. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply in six hours, between hours ending 15 and 20. In the remaining 18 hours, net cleared virtual supply exceeded net cleared virtual demand. Cleared virtual supply exceeded virtual demand by around 1,000 MW between hours ending

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33 California ISO Suspends Convergence Bidding due to Current System Conditions http://www.caiso.com/Documents/CaliforniaISOSuspendsConvergenceBiddingCurrentSystemConditions.html

34 Final *Root Cause Analysis, Mid-August Extreme Heat Wave*, January 13, 2021, p. 62-63. http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

35 *Report on Market Conditions, Issues and Performance – August and September 2020*. http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

1 through 8 and hours ending 23 and 24. The morning hours represented a slight increase, on average, from the previous quarter.

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 six hours ending 15 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 850 MW of virtual demand offset by 850 MW of virtual supply in each hour of the quarter. This represents a decrease of about 150 MW over the previous quarter. These offsetting bids represented about 50 percent of all cleared virtual bids in this quarter, a decrease of about 1 percent from the previous quarter.

1.7.2 Convergence bidding revenues

Participants engaged in convergence bidding in this quarter were overall profitable. Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $25.3 million. Net revenues for virtual supply and demand fell to about $19 million after the inclusion of about $6.3 million of virtual bidding bid cost recovery charges,[36] primarily associated with virtual supply.

Figure 1.29 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:

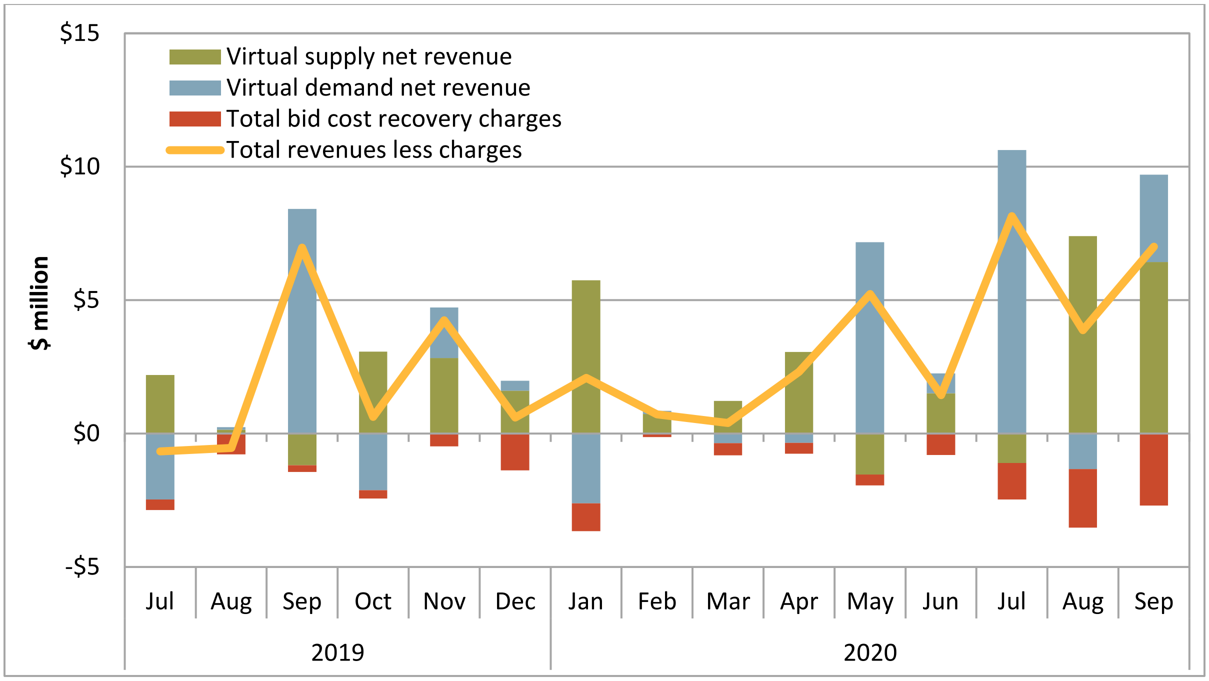
- Total market revenues were positive during all months of the quarter. Net revenues during this quarter totaled about $25.29 million, compared to about $7.2 million during the same quarter from the previous year, and about $10.6 million during the previous quarter.

- Virtual demand net revenues were $10.6 million, negative $1.3 million, and $3.3 million in July, August and September, respectively.

[36] 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 negative $1.1 million in July and positive in August and September with $7.4 million and $6.4 million, respectively.

Figure 1.29 Convergence bidding revenues and bid cost recovery charges



Convergence bidders received about $19 million after subtracting bid cost recovery charges of about $6.3 million for the quarter.[37,38] Bid cost recovery charges were about $1.4 million, $2.2 million and $2.7 million in July, August and September, respectively.

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.[39] As with the previous quarter, financial entities represented the largest segment of the virtual bidding market,

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37 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.

38 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.

39 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.

accounting for about 71 percent of volume and 78 percent of settlement revenue, an increase from about 67 percent. Marketers represented about 27 percent of the trading volumes and about 21 percent of settlement revenue, a revenue decrease from about 31 percent from the previous quarter. Generation owners and load serving entities represented the smallest segment of the virtual market in terms of both volumes and settlement revenue, at about 3 percent and 1 percent, respectively. Generation owners and load serving entities accounted for around $0.24 million of net revenues in the market.

Table 1.2 Convergence bidding volumes and revenues by participant type (Q3 2020)

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	1,010	1,384	2,394	$9.03	$10.75	$19.78
Marketer	386	517	903	$3.42	$1.85	$5.27
Physical load	0	54	54	-$0.02	$0.12	$0.10
Physical generation	32	0	32	$0.14	$0.00	$0.14
Total	**1,429**	**1,955**	**3,383**	**$12.6**	**$12.7**	**$25.3**

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.

During the period between mid-August to September 7, 2020, when regional high temperatures led to high demand across the entire western region, the ISO made two specific changes outlined below which impacted the residual unit commitment process, allowing that process to better align physical supply with demand.

- On August 16, the ISO announced the suspension of virtual bidding effective in the day-ahead market for operating day August 18, in part to prevent virtual supply bids from allowing additional exports to be scheduled in the day-ahead market which would ultimately need to be met by physical supply from within the ISO system.[40] The ISO reinstated virtual bidding in the day-ahead market for August 22.[41] By this time, system and market conditions had changed so that virtual bidding was again viewed as providing market benefits without presenting a risk to the system.

40 Market Notice - California ISO Suspends Convergence Bidding due to Current System Conditions, August 16, 2020: http://www.caiso.com/Documents/CaliforniaISOSuspendsConvergenceBiddingCurrentSystemConditions.html

41 Market Notice - California ISO Reinstates Convergence Bidding for 8/22/20 due to Updated System Conditions, August 20, 2020: http://www.caiso.com/Documents/CaliforniaISOReinstatesConvergenceBiddingfor82220DuetoUpdatedSystemConditions.html

- Effective September 5, the ISO implemented several software modifications in the residual unit commitment process designed to reduce exports from being scheduled in the real-time market at high day-ahead penalty prices which could not be supported by available physical supply in the ISO system.[42]

DMM has recently published a special report which includes detailed analysis of the impacts of these changes and provides recommendations on the residual unit commitment process.[43]

As illustrated in Figure 1.30, residual unit commitment procurement was primarily driven by operator adjustments to residual unit commitment requirements. These manual adjustments increased in the third quarter relative to the same quarter in 2019. The operators used this tool on 64 days (out of 92 days) and the adjustment averaged about 1,156 MW per hour compared to about 685 MW per hour in the same quarter of 2019. Primary reasons for these adjustments included addressing reliability concerns and accounting for load forecast errors.

Figure 1.30 also shows that residual unit commitment capacity is procured 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 3 percent lower in the third 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 third quarter of 2020, particularly in August averaging about 1,160 MW per hour.

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 1.30.

42 PRR 1282 Market Operations BPM, Emergency PRR, Scheduling of export resources in real time market, September 4, 2020: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1282&IsDlg=0

43 *Report on Market Conditions, Issues and Performance – August and September 2020*. http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

Figure 1.30 Determinants of residual unit commitment procurement

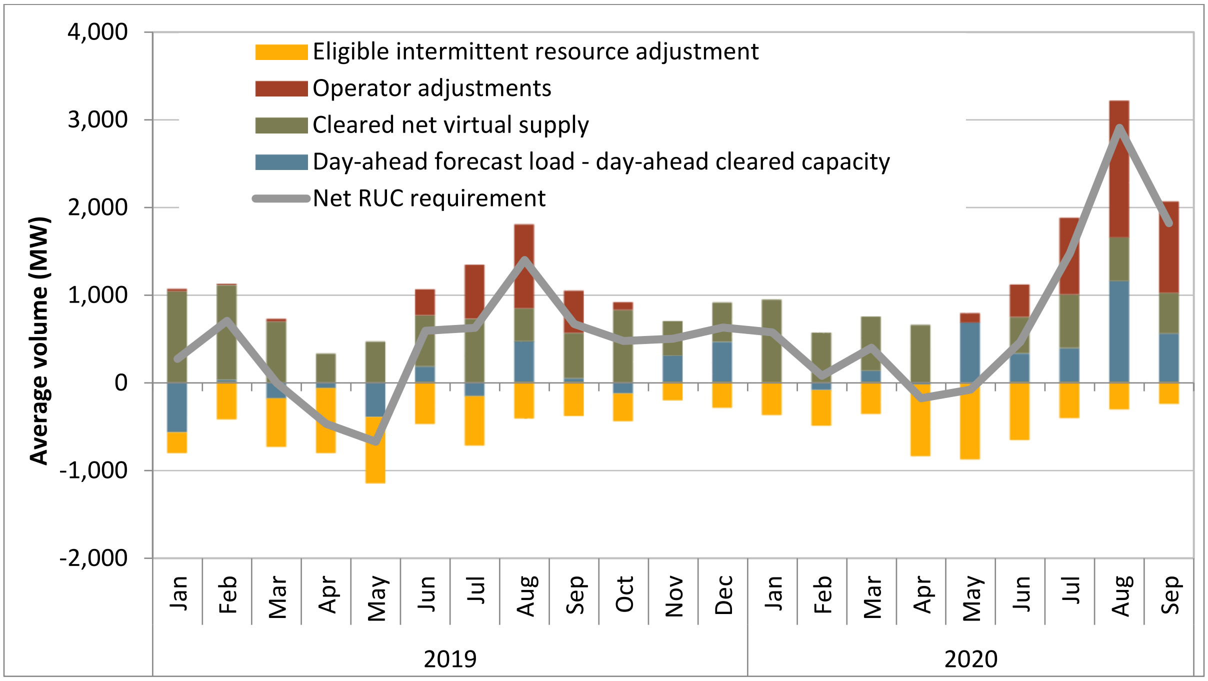


Figure 1.31 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased to about 2,060 MW per hour in the third quarter of 2020 from an average of 1,176 MW in the same quarter of 2019. Of the 2,060 MW per hour capacity, the capacity committed to operate at minimum load averaged about 437 MW each hour compared to 151 MW in the third 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.[44] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.31. In the third quarter of 2020, these costs increased to $1.2 million when compared to about $0.17 million in the same quarter of 2019.

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

Figure 1.31 Residual unit commitment costs and volume

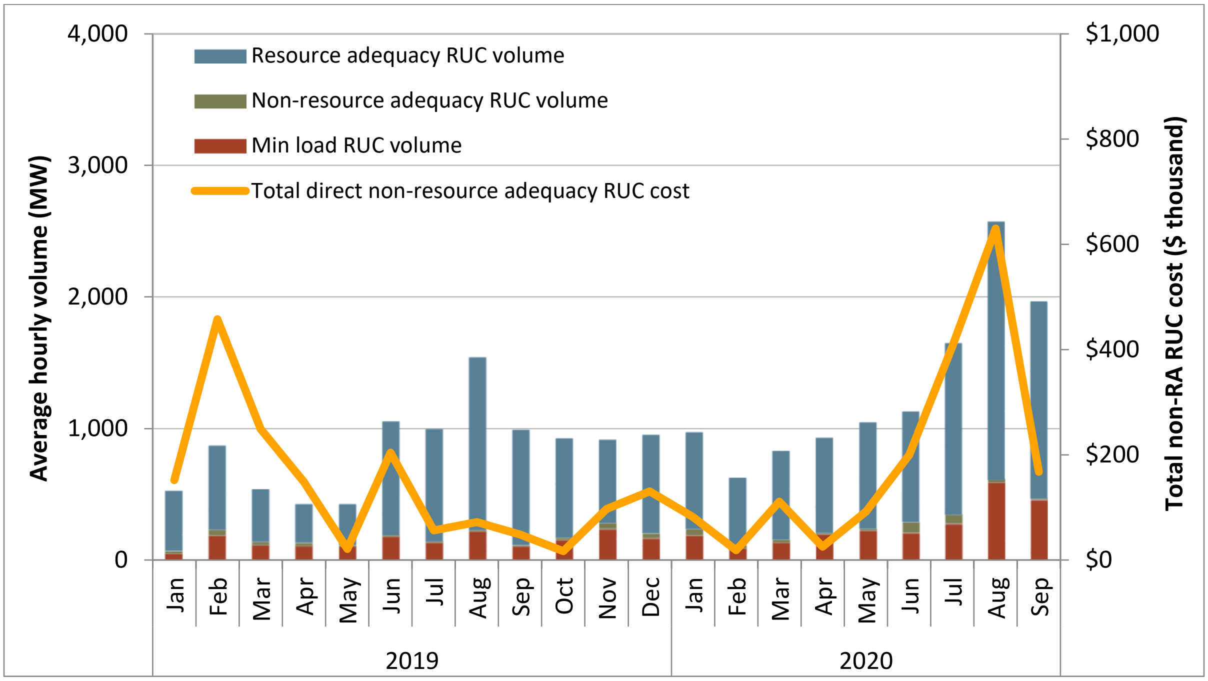
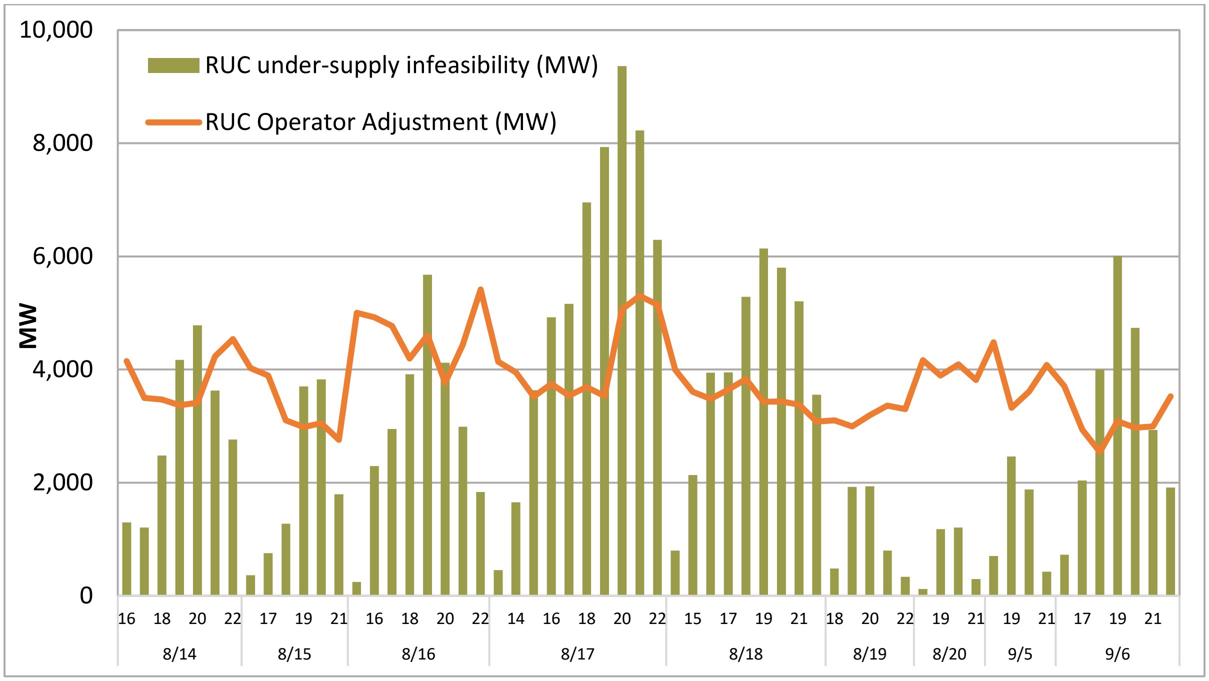


Figure 1.32 shows the residual unit commitment power balance constraint hourly under-supply infeasibility quantities that resulted during the heat wave conditions during mid-August and early September. These infeasibilities resulted in prices being set around $250/MWh during those hours. The market change that went in place on September 5 was designed to address the treatment of economic and self-scheduled exports that cleared the day-ahead integrated forward market (IFM) run. With this change, the residual unit commitment process is able to curtail certain exports before relaxing the power balance constraint. These reduced exports no longer receive a real-time scheduling priority that exceeds real-time ISO load and can choose to re-bid in real-time or resubmit as self-schedules in real-time.[45]

[45] The ISO provided details and examples of this change in the Market Performance and Planning Forum meeting on September 9, 2020: http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Sep9-2020.pdf#search=market%20performance%20and%20planning%20forum

Figure 1.32 Residual unit commitment under-supply infeasibilities (Aug 14 – 20 and Sep 5 – 6)



1.9 Ancillary services

Ancillary service payments increased significantly during the third quarter to about $97 million, compared to about $24 million in the previous quarter and $28 million during the same quarter in 2019. The frequency of scarcity intervals for operating reserves was relatively high in August and September, occurring in the expanded South of Path 26 region or on a system level.

1.9.1 Ancillary service requirements

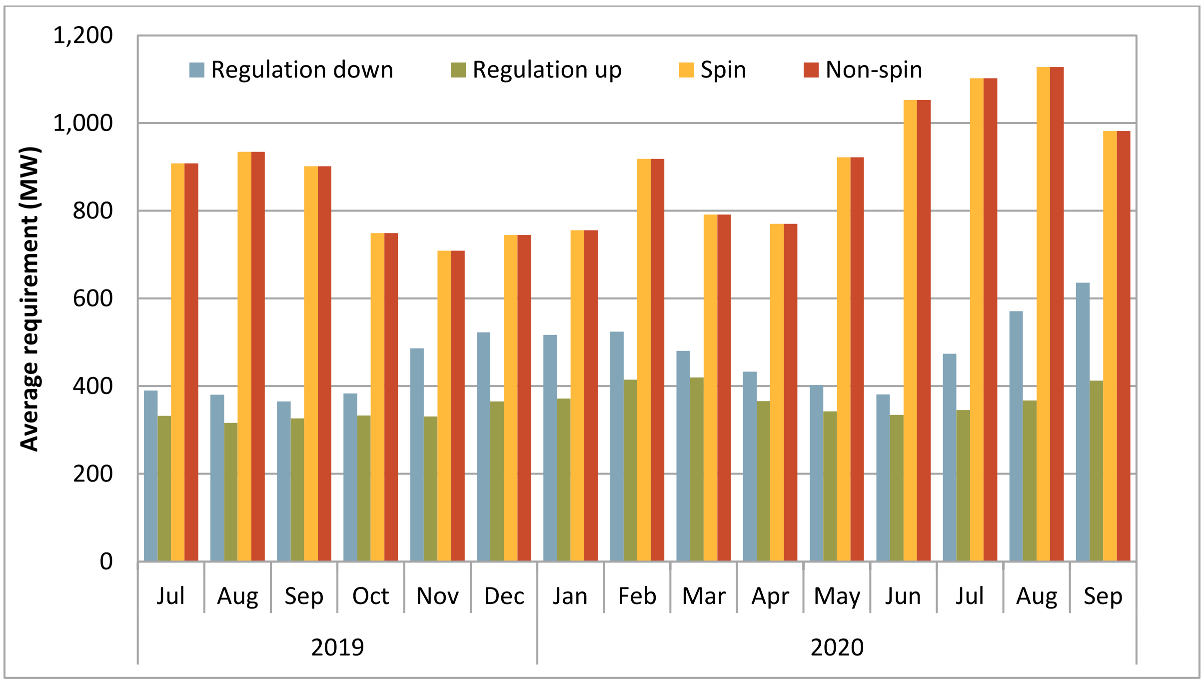
The ISO procures four ancillary services in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (WECC) 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 often serve as the most severe single contingency.

Figure 1.33 shows monthly 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 consistent with higher loads. Average requirements for regulation down and regulation up also increased from the previous quarter.

Figure 1.33 Average monthly day-ahead ancillary service requirements



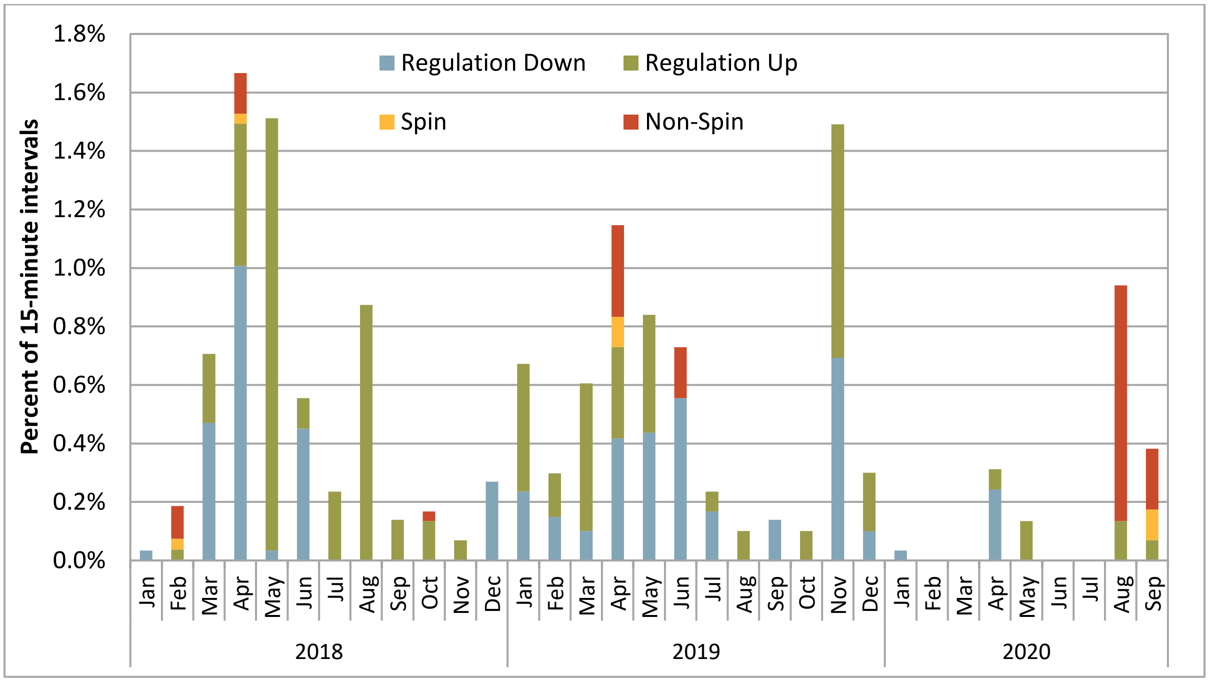
1.9.2 Ancillary service scarcity

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 1.34, the frequency of intervals with scarcity pricing increased during the quarter. Here, around 51 percent of the scarcity intervals occurred in the expanded system region, and the remaining 49 percent in the expanded South of Path 26 region.

Between August 13 and August 18, the 15-minute market had scarcity of non-spinning reserve in 21 intervals and of regulation up in 4 intervals. These occurred during peak load hours and were associated with high demand conditions during the mid-August heatwave. For more information on ancillary service requirements, procurement, and scarcities during this period, see DMM's report on this period.[46]

Figure 1.34 Frequency of ancillary service scarcities (15-minute market)



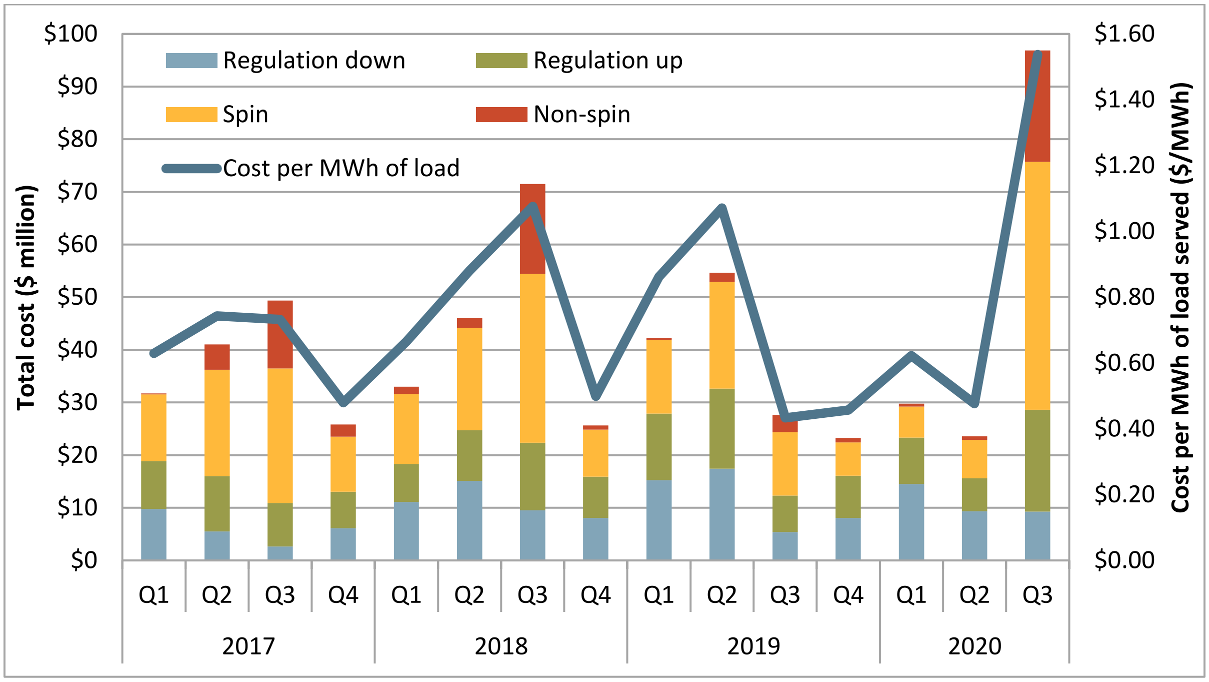
1.9.3 Ancillary service costs

Ancillary service payments increased significantly during the third quarter to about $97 million, compared to about $24 million in the previous quarter and $28 million during the same quarter in 2019. In particular, total payments associated with spinning and non-spinning reserve increased by around $40 million and $21 million, respectively.

Figure 1.35 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.

46 *Report on system and market conditions, issues and performance: August and September 2020*, DMM, November 24, 2020, pp/19-20: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

Figure 1.35 Ancillary service cost by product



1.10 Congestion

In the day-ahead market, congestion in the third quarter decreased PG&E area prices while it increased prices in the SCE and SDG&E areas. 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.[47]

[47] 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

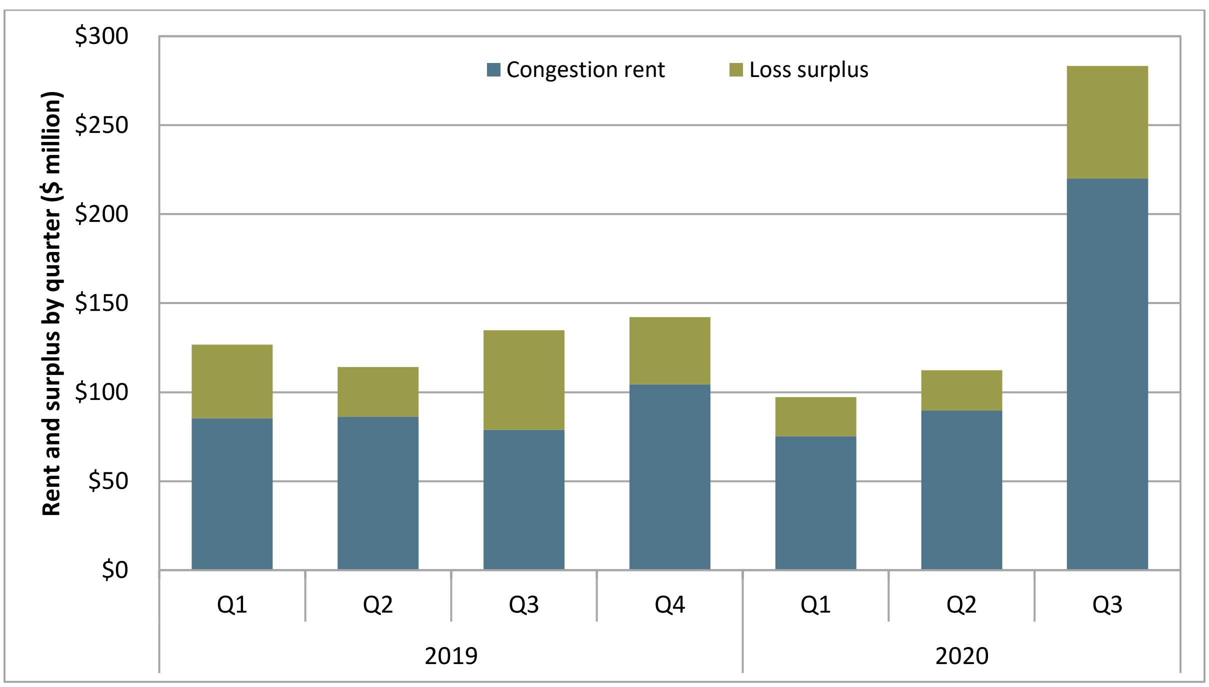
Day-ahead market congestion frequency tends to be higher than in the 15-minute market, but price impacts to load tend to be lower. The congestion pattern in this quarter reflects this overall trend.

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.[48]

Figure 1.36 shows the congestion rent and loss surplus by quarter for 2019 and 2020. The $220 million third quarter congestion rent was a 179 percent increase over the third quarter of 2019 ($79 million), while the loss surplus increased by 13 percent over the third quarter of 2019. This significant increase in congestion rent was due to the high levels of congestion in the system due to fires across the state and the high temperatures seen throughout the quarter.

Figure 1.36 Day-ahead congestion rent and loss surplus by quarter (2019-2020)



[48] 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

Figure 1.37 shows the overall impact of congestion on day-ahead prices in each load area in 2019 and 2020. Figure 1.38 shows the frequency of congestion. Highlights for this quarter include:

- In the third quarter of 2020, the overall net impact of congestion on price separation increased significantly in PG&E, SCE, and SDG&E relative to both the previous quarter and the same quarter of 2019. Congestion frequency decreased in PG&E and SDG&E, while it increased in SCE during the third quarter, relative to the same quarter in 2019.
- Congestion decreased prices in PG&E by $6.47/MWh (16 percent), and increased prices in SCE and SDG&E by $4.53/MWh (9 percent) and $5.30/MWh (10 percent), respectively.
- On an average quarterly basis, the congestion impact was infrequently offsetting in all areas, as shown in Figure 1.39. For the quarter, PG&E experienced negative congestion more frequently, while SCE and SDG&E experienced positive congestion more frequently.
- The primary constraints impacting day-ahead market prices were the Midway Nomogram, Midway – Vincent #2 500 kV line, and the East County nomogram.

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

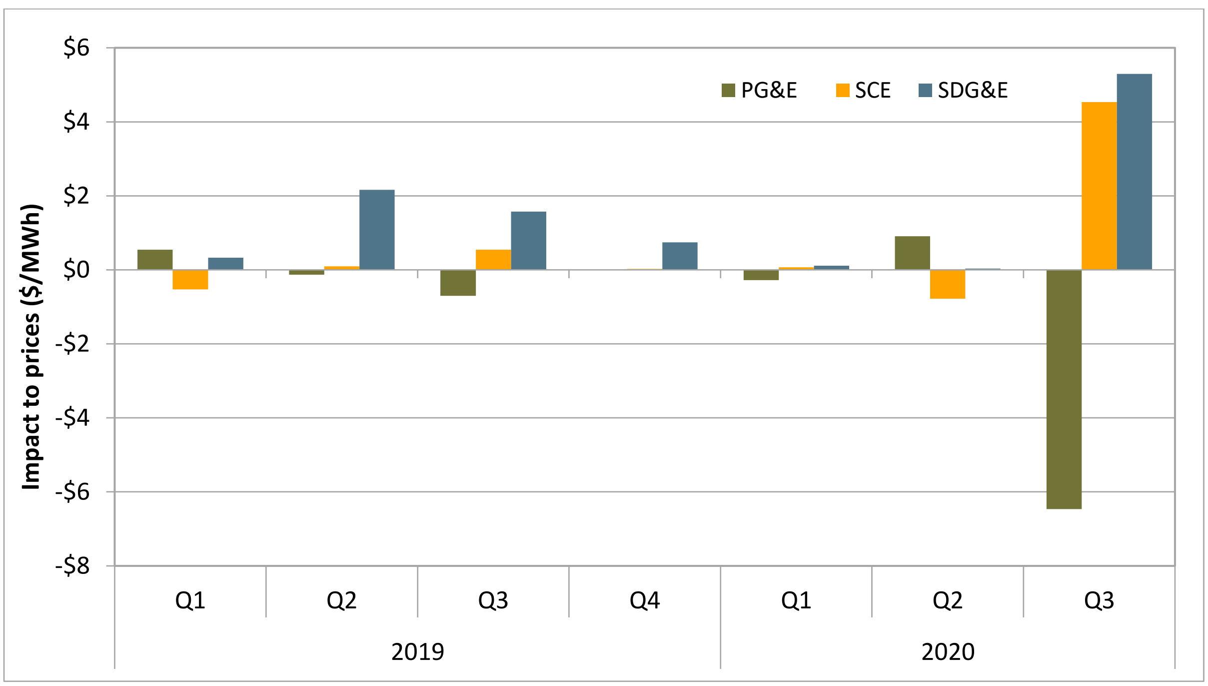


Figure 1.38 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)

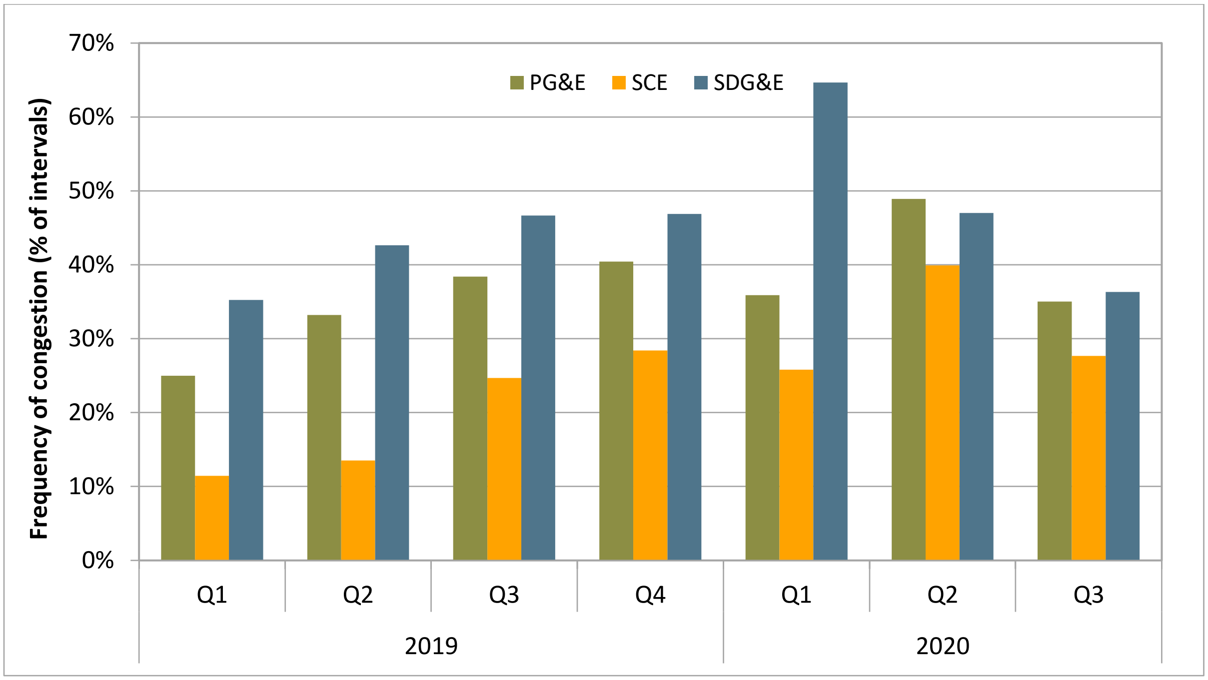
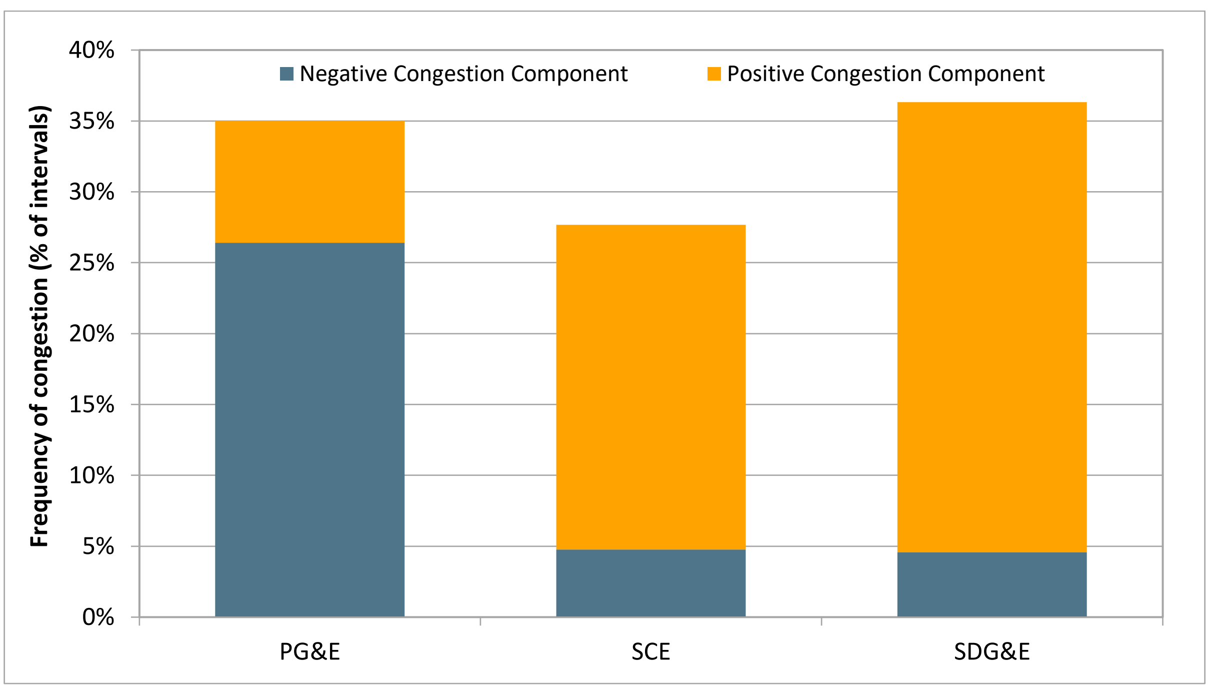


Figure 1.39 Percent of hours with congestion increasing versus decreasing day-ahead prices in the third quarter (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.3 breaks down the congestion impact on price separation in the third quarter by constraint.[49] 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 Midway Nomogram, Midway – Vincent #2 500 kV line, and the East County nomogram.

The Midway Nomogram

The Midway nomogram (6410_CP6_NG) bound infrequently during the quarter, about 2 percent of hours, and had the greatest impact on prices. When binding, it decreased prices in PG&E by about $164.97/MWh and increased prices in SCE and SDG&E by $116.73/MWh and $109.40/MWh, respectively. Overall for the quarter, the nomogram decreased prices in PG&E by about $3.59/MWh (9 percent), while it increased prices in SCE and SDG&E by $2.54/MWh (5 percent) and $2.38/MWh (5 percent), respectively. This nomogram was primarily used due to the Lake Fire threatening the Midway – Vincent #1 and #2 lines during the August heat storm.

Midway – Vincent #2 500 kV line

The Midway – Vincent #2 500 kV line (30060_MIDWAY_500_24156_VINCENT_500_BR_2_3) was the most frequently congested constraint in the quarter, binding in about 17 percent of hours. When binding, it decreased PG&E prices by about $17.13/MWh and increased SCE and SDG&E prices by $11.91/MWh and $11.40/MWh, respectively. Over the entire quarter, it decreased PG&E prices by about $2.96/MWh (7 percent) and increased SCE and SDG&E prices by $2.06/MWh (4 percent) and $1.97/MWh (4 percent), respectively. This congestion seen on this line can be largely attributed to maintenance and repairs that were performed on the Midway – Vincent #1 500 kV line during the quarter.

East County nomogram

The East County nomogram (7820_TL23040_IV_SPS_NG) was congested during about 3 percent of hours during the quarter. When binding, the constraint increased SDG&E prices by about $13.59/MWh, while it decreased prices in PG&E by about $0.98/MWh. Overall for the quarter, it increased SDG&E prices by about $0.36/MWh (1 percent), and decreased prices in PG&E by $0.03/MWh (<1 percent).

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49 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	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$2.96	-7.30%	$2.06	3.96%	$1.97	3.68%
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.06	0.15%	-$0.04	-0.08%	-$0.06	-0.12%
	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.04	0.10%	-$0.03	-0.05%	-$0.04	-0.07%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.04	0.10%	-$0.03	-0.06%	-$0.03	-0.06%
	7440_MetcalfImport_Tes-Metcalf	$0.03	0.08%	-$0.03	-0.05%	-$0.03	-0.05%
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	-$0.03	-0.07%	$0.02	0.00%	$0.02	0.00%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	-$0.02	-0.06%	$0.02	0.03%	$0.02	0.03%
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	$0.02	0.04%	-$0.01	-0.02%	-$0.01	-0.02%
	RM_TM12_NG	$0.01	0.02%	$0.00	0.00%	-$0.01	0.00%
SCE	6410_CP6_NG	-$3.59	-8.85%	$2.54	4.89%	$2.38	4.45%
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.02	-0.04%	$0.02	0.04%	$0.00	0.00%
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.03%	$0.01	0.02%	$0.00	0.00%
SDG&E	7820_TL23040_IV_SPS_NG	-$0.03	0.00%	$0.00	0.00%	$0.36	0.68%
	22886_SUNCREST_230_92861_SUNC TP2_230_BR_2 _1	$0.00	0.00%	$0.00	0.00%	$0.31	0.58%
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	-$0.03	-0.08%	$0.00	0.00%	$0.20	0.37%
	OMS 8618881 MG_BK81_NG	-$0.01	-0.02%	$0.00	0.00%	$0.07	0.13%
	7820_TL 230S_OVERLOAD_NG	-$0.01	-0.01%	$0.00	0.00%	$0.06	0.11%
	22644_PENSQTOS_69.0_22164_DELMARTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.04	0.08%
Other		$0.03	0.06%	$0.00	0.01%	$0.05	0.09%
Total		**-$6.47**	**-15.97%**	**$4.53**	**8.72%**	**$5.30**	**9.90%**

Table 1.4 Impact of congestion on day-ahead prices during congested hours[50]

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	0.3%	$5.43	-$3.17	-$4.40
	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	1.2%	$3.36	-$2.20	-$2.97
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	1.9%	$3.13	-$2.28	-$3.25
	7440_MetcalfImport_Tes-Metcalf	1.4%	$2.24	-$1.84	-$1.77
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	2.6%	$1.56	-$1.32	-$1.29
	RM_TM12_NG	1.0%	$0.87	$0.00	-$0.92
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	0.5%	-$4.14	$2.92	$2.70
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	0.4%	-$8.01	$5.99	$5.69
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	17.3%	-$17.13	$11.91	$11.40
SCE	6410_CP6_NG	2.2%	-$164.97	$116.73	$109.40
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	1.9%	-$0.89	$1.07	-$0.44
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.6%	-$0.67	$0.76	$0.57
SDG&E	7820_TL23040_IV_SPS_NG	2.7%	-$0.98	$0.00	$13.59
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	1.6%	-$1.87	$0.00	$12.26
	22886_SUNCREST_230_92861_SUNC TP2_230_BR_2 _1	3.8%	$0.00	$0.00	$8.06
	OMS 8618881 MG_BK81_NG	1.9%	-$0.37	$0.00	$3.52
	22644_PENSQTOS_69.0_22164_DELMARTP_69.0_BR_1 _1	1.8%	$0.00	$0.00	$2.43
	7820_TL 230S_OVERLOAD_NG	2.4%	-$0.24	$0.00	$2.41

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

1.10.2 Congestion in the real-time market

Congestion frequency in the real-time 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 1.40 shows the overall impact of internal flow-based constraint congestion on 15-minute prices in each load area for 2019 and 2020. Figure 1.41 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 third quarter of 2020 increased in most areas compared to the same quarter of 2019. Congestion resulted in a net increase to SCE, SDG&E, NEVP, SRP, and AZPS prices and a net decrease to prices in other ISO and EIM areas.
- Congestion continued to impact prices in both the positive and negative direction over the quarter in each load area, which worked to offset the impact of congestion over the quarter. The frequency of congestion was highest in AZPS and SRP, where congestion predominantly increased prices.
- The primary constraints impacting price separation in the 15-minute market were the Midway – Vincent #2 500 kV line, the Midway nomogram, and the Round Mountain-Table Mountain nomogram.

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

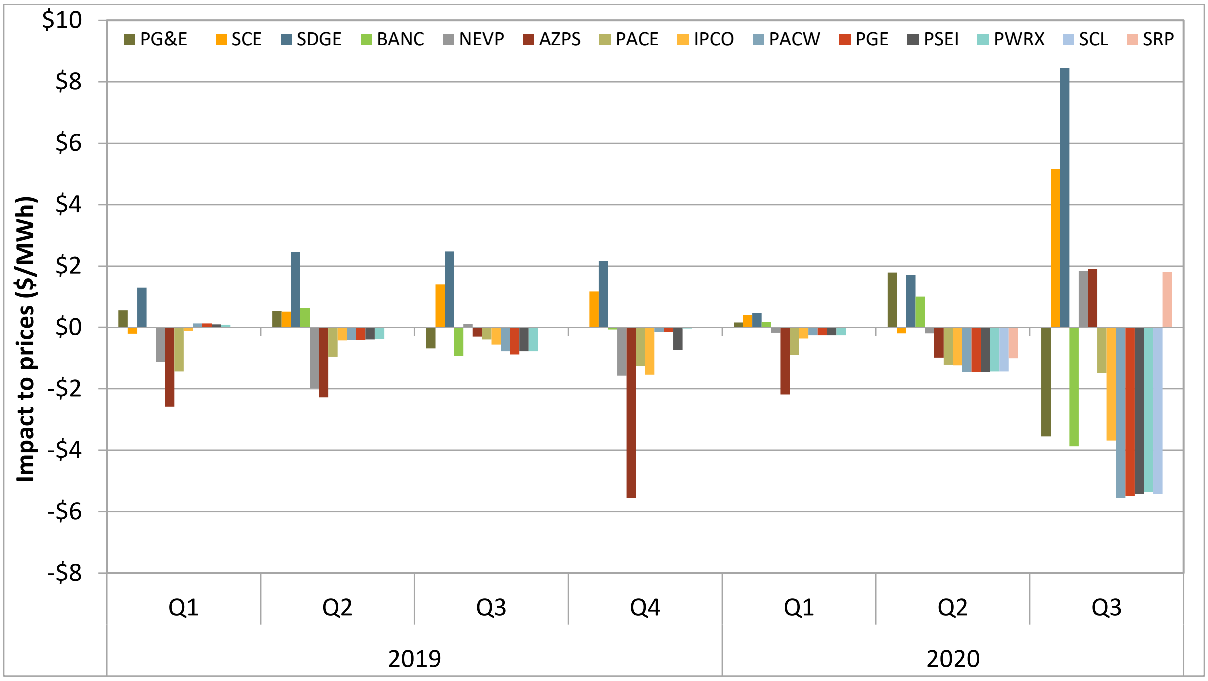
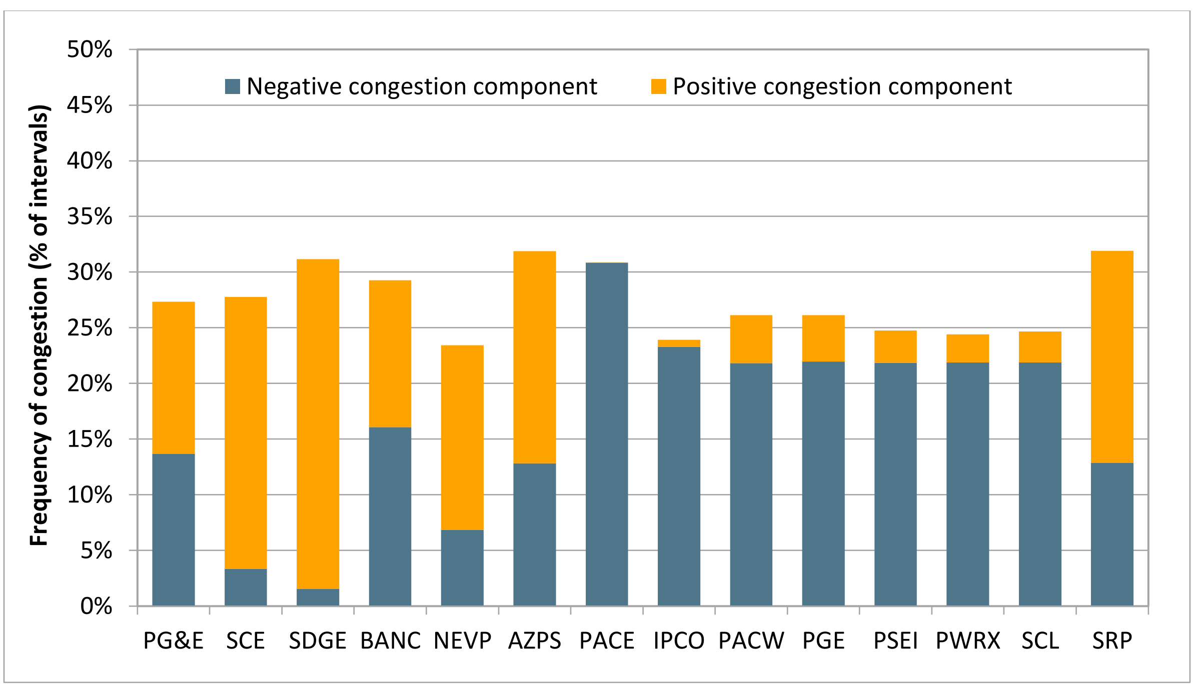


Figure 1.41 Percent of intervals with internal congestion increasing versus decreasing 15-minute prices in the third quarter (>$0.05/MWh)



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, and therefore 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 Midway - Vincent 500 kV line, the Midway nomogram, and the Round Mountain-Table Mountain nomogram.

Midway – Vincent #2 500 kV line

The Midway - Vincent #2 500 kV line (30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3) bound frequently in the quarter during about 9 percent of intervals. When binding, it affected prices across the EIM, increasing prices in SCE, SDG&E, NEVP, AZPS, and SRP by about $23.26/MWh on average, and decreasing prices elsewhere in the ISO and EIM by $22.95/MWh on average. Overall for the quarter, the constraint increased prices in the former areas by about $2.02/MWh and decreased prices in the latter areas by $1.94/MWh. This congestion seen on this line can be largely attributed to maintenance and repairs that were performed on the Midway – Vincent #1 500 kV line during the quarter.

Midway nomogram

The Midway nomogram (6410_CP1_NG) bound infrequently during the quarter, in about 2 percent of intervals. When binding, it affected prices across the EIM, increasing prices in SCE, SDG&E, NEVP, AZPS, and SRP by about $26.92/MWh on average, and decreasing prices elsewhere in the ISO and EIM by $25.54/MWh on average. Overall for the quarter, the constraint increased the former areas’ prices by $0.62/MWh on average and decreased prices elsewhere by $0.58/MWh on average. Similar to the day-ahead, this nomogram was primarily used due to the Lake Fire threatening lines connected to the Midway substation lines during the August heat storm.

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, SCE, SDG&E, BANC, NEVP, AZPS, and SRP by an average of $6.02/MWh, and decreased prices elsewhere by $19.12/MWh on average. Over the entire quarter, it increased the former areas’ prices by about $0.20/MWh on average, and decreased the latter areas’ prices by about $0.63/MWh on average.

Table 1.5 Impact of congestion on overall 15-minute prices

Constraint Location	Constraint	PG&E	SCE	SDGE	BANC	NEVP	AZPS	SRP	PACE	IPCO	PACW	PGE	PSEI	PWRX	SCL
NEVP	CAL-DRM_2 120				-$0.04	$0.15									
	NTR-DRM_1 120	-$0.01			-$0.02	$0.05									
	HBT-COY_3423					$0.02			-$0.01	-$0.02	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
PACE	WYOMING_EXPORT								-$0.17						
PACW	ALBINA_KNOTT_115										$0.02				
PG&E	RM_TM21_NG	$0.40	$0.22	$0.19	$0.29	$0.00	$0.13	$0.13	-$0.30	-$0.53	-$0.72	-$0.73	-$0.71	-$0.71	-$0.71
	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.37	$0.18	$0.16	$0.37	$0.01	$0.12	$0.12	-$0.23	-$0.43	-$0.59	-$0.60	-$0.58	-$0.58	-$0.58
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.26	$0.15	$0.13	$0.19	$0.01	$0.09	$0.09	-$0.20	-$0.34	-$0.47	-$0.47	-$0.47	-$0.46	-$0.46
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.07	-$0.02	$0.00											
	7440_MetcalfImport_Tes-Metcalf	$0.07	-$0.05	-$0.05	$0.04	-$0.03	-$0.04	-$0.04			$0.02	$0.02	$0.02	$0.02	$0.02
	30525_C.COSTA _230_30543_ROSSTAP1_230_BR_1 _1	$0.05													
	30543_ROSSTAP1_230_30550_MORAGA _230_BR_1 _1	$0.04													
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	$0.04	$0.02	$0.02	$0.03		$0.01	$0.01	-$0.03	-$0.05	-$0.06	-$0.06	-$0.06	-$0.06	-$0.06
	COI_600 N-S	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30060_MIDWAY _500_24156_VINCENT _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
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	-$0.04	$0.03	$0.03	-$0.04	$0.02	$0.03	$0.02	$0.00	-$0.02	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-$0.28	$0.24	$0.22	-$0.26	$0.13	$0.19	$0.19	$0.00	-$0.11	-$0.20	-$0.19	-$0.19	-$0.19	-$0.19
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.47	$0.40	$0.37	-$0.45	$0.21	$0.32	$0.32	-$0.02	-$0.20	-$0.35	-$0.34	-$0.33	-$0.33	-$0.33
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$3.04	$2.42	$2.33	-$2.80	$1.37	$1.99	$1.98	-$0.06	-$1.21	-$2.12	-$2.15	-$2.03	-$2.00	-$2.02
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1				$0.01						$0.00	-$0.01	$0.00	$0.00	$0.00
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1				-$0.20						$0.00	$0.00	$0.00	$0.00	$0.00
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1				$0.00	$0.35									
	SUMMIT2-DRUM				-$0.05	$0.09									
	30805_BORDEN _230_30810_GREGG _230_BR_2 _1		$0.00		$0.06										
SCE	6410_CP1_NG	-$0.88	$0.72	$0.71	-$0.85	$0.41	$0.63	$0.62	$0.00	-$0.37	-$0.65	-$0.65	-$0.63	-$0.62	-$0.62
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.12	$0.32	$0.23	$0.11	-$0.51	-$0.43	-$0.43	-$0.26	-$0.10	$0.01	$0.00	-$0.02	-$0.02	-$0.02
	24156_VINCENT _500_24155_VINCENT _230_XF_4 _P	-$0.25	$0.31	$0.20	-$0.24		$0.06	$0.06	-$0.03	-$0.13	-$0.19	-$0.19	-$0.19	-$0.19	-$0.19
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	$0.00	$0.07	$0.03	$0.00	-$0.03	-$0.03	-$0.03	-$0.03	-$0.02	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	6410_CP6_NG	-$0.05	$0.05	$0.04	-$0.05	$0.03	$0.04	$0.04	$0.00	-$0.02	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04
	SYLMAR-AC_BG	$0.01	$0.02	-$0.01	$0.01	-$0.03	-$0.03	-$0.03	-$0.02	$0.00					
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1		$0.01	-$0.01		$0.00	-$0.01	-$0.01	$0.00						
	OMS 8460508_OP-6610	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SDG&E	MIGUEL_BKs_MXFLW_NG			$1.74			-$0.54	-$0.54							
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80			$0.86		-$0.05	-$0.25	-$0.25	-$0.06						
	22886_SUNCREST_230_92861_SUNC TP2_230_BR_2 _1			$0.82			-$0.28	-$0.28							
	7820_TL 230S_OVERLOAD_NG		$0.02	$0.24		-$0.02	-$0.05	-$0.05	-$0.02	-$0.01					
	OMS 8618881 MG_BK81_NG		$0.00	$0.11			-$0.03	-$0.03							
	7820_TL23040_IV_SPS_NG		$0.00	$0.02		$0.00	$0.00	$0.00	$0.00						
	OMS 9083014_D-SBLR_OOS_CP3	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01			$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 8421617_D-VST2_OOS_CP3	$0.01	-$0.01		$0.01	-$0.01	-$0.04	-$0.04	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 9082895_D-SBLR_OOS_CP3	$0.00	$0.00		$0.00		-$0.01	-$0.01			$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 9082909_D-SBLR_OOS_CP3	$0.00	$0.00		$0.00		-$0.01	-$0.01			$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 9082986_D-SBLR_OOS_CP3	$0.00	$0.00		$0.00		$0.00	$0.00			$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 9083026_D-SBLR_OOS_CP3	$0.00	$0.00		$0.00	$0.00	-$0.01	-$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00
	Other	-$0.02	$0.04	$0.05	-$0.02	-$0.33	$0.06	-$0.02	-$0.03	-$0.11	-$0.15	-$0.03	-$0.15	-$0.15	-$0.15
	Total	**-$3.55**	**$5.15**	**$8.44**	**-$3.87**	**$1.84**	**$1.90**	**$1.80**	**-$1.49**	**-$3.68**	**-$5.55**	**-$5.49**	**-$5.43**	**-$5.36**	**-$5.42**
	Transfers				-$2.89	$15.06	-$2.33	-$2.40	-$3.98	-$3.97	-$9.18	-$9.08	-$9.08	-$13.88	-$9.66
	Grand Total	**-$3.55**	**$5.15**	**$8.44**	**-$6.76**	**$16.90**	**-$0.43**	**-$0.60**	**-$5.47**	**-$7.65**	**-$14.73**	**-$14.57**	**-$14.51**	**-$19.24**	**-$15.08**

Table 1.6 Impact of internal congestion on 15-minute prices during congested intervals[51]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDGE	BANC	NEVP	AZPS	SRP	PACE	IPCO	PACW	PGE	PSEI	PWRX	SCL
NEVP	CAL-DRM_2 120	0.6%				-$9.70	$23.00									
	SUMMIT2-DRUM	0.7%				-$6.82	$12.43									
	NTR-DRM_1 120	0.5%	-$4.27			-$4.46	$9.81									
PACE	WYOMING_EXPORT	21.8%								-$0.79						
PG&E	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	1.6%	$16.48	$9.21	$8.09	$12.17	$1.15	$5.86	$5.78	-$12.68	-$21.52	-$29.54	-$29.66	-$29.13	-$28.87	-$29.10
	RM_TM21_NG	3.3%	$12.20	$6.68	$5.78	$8.85	$0.63	$4.05	$3.97	-$9.11	-$15.95	-$21.98	-$22.08	-$21.65	-$21.40	-$21.63
	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	4.3%	$8.62	$4.25	$3.72	$8.64	$0.70	$2.69	$2.66	-$5.37	-$9.89	-$13.50	-$13.77	-$13.48	-$13.37	-$13.46
	7440_MetcalfImport_Tes-Metcalf	1.0%	$6.95	-$4.77	-$4.56	$3.69	-$3.11	-$4.19	-$4.19			$1.88	$1.83	$1.81	$1.84	$1.85
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	1.1%	$6.32	-$6.89	-$0.87											
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	0.5%	-$7.09	$6.02	$5.63	-$8.09	$3.54	$4.93	$4.90	-$0.18	-$3.55	-$6.08	-$5.99	-$5.80	-$5.72	-$5.79
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	1.3%	-$21.51	$18.85	$17.24	-$20.35	$10.26	$15.19	$15.09	-$3.69	-$8.55	-$15.46	-$15.21	-$14.74	-$14.47	-$14.73
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	8.7%	-$34.98	$27.91	$26.81	-$32.28	$15.82	$22.94	$22.82	-$6.46	-$13.94	-$24.39	-$24.79	-$23.38	-$23.02	-$23.31
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	1.1%	-$42.59	$35.87	$33.02	-$40.37	$18.71	$28.94	$28.75	-$4.13	-$18.35	-$31.29	-$30.98	-$30.12	-$29.61	-$30.03
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	3.0%				-$6.74						-$0.65	-$0.65	-$0.72	-$0.49	-$0.72
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	1.8%				-$13.04	$19.91									
	30805_BORDEN _230_30810_GREGG _230_BR_2 _1	0.9%		-$0.44		$7.28										
SCE	24156_VINCENT _500_24155_VINCENT _230_XF_4 _P	0.8%	-$32.40	$39.97	$25.48	-$31.36		$14.71	$14.59	-$17.89	-$17.48	-$25.21	-$25.12	-$24.70	-$24.38	-$24.67
	6410_CP1_NG	2.3%	-$38.10	$31.19	$31.07	-$36.92	$17.97	$27.24	$27.11	-$1.04	-$16.27	-$28.31	-$28.06	-$27.20	-$26.78	-$27.17
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	2.2%	$5.96	$14.76	$11.43	$5.11	-$23.53	-$20.20	-$20.08	-$11.97	-$5.62	$0.38	$0.12	-$2.85	-$4.20	-$3.22
SDG&E	MIGUEL_BKs_MXFLW_NG	2.7%			$64.62			-$19.95	-$20.00							
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	2.0%			$43.34		-$6.07	-$12.43	-$12.41	-$5.60						
	22886_SUNCREST_230_92861_SUNC TP2_230_BR_2 _1	2.8%			$29.80			-$10.24	-$10.16							
	7820_TL 230S_OVERLOAD_NG	1.3%		$1.42	$18.41		-$1.34	-$3.84	-$4.19	-$1.44	-$1.22					
	OMS 8618881 MG_BK81_NG	0.7%		$0.81	$17.06			-$4.90	-$4.94							
	OMS 8421617_D-VST2_OOS_CP3	0.9%	$1.61	-$1.18		$1.50	-$1.52	-$4.66	-$4.78	-$3.66		$0.70	$0.67	$0.56	$0.68	$0.56

Impact of internal congestion from individual constraints during the August heat storm

Internal congestion led to significant price separation in the ISO and the EIM during the August heat storm. Table 1.7 shows the effects of internal congestion on 15-minute prices when binding on each balancing authority area between August 13 and 21. Most clear in the table is the congestion on constraints associated with Path 26, specifically the Midway – Vincent 500 kV line #2, and Midway – Whirlwind 500 kV line #1 and #2. Together, these three constraints increased prices south of Path 26 by an average of $50.25/MWh, and decreased prices north of Path 26 by an average of $49.33/MWh.

Another highly influential constraint was the Round Mountain – Table Mountain 500 kV line. This constraint bound during 6.6 percent of intervals and increased prices south of the constraint by an average of $11.90/MWh. Furthermore, it decreased prices north of the constraint by an average of $37.04/MWh.

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

Table 1.7 Impact of internal congestion on 15-minute prices during congested intervals[52]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDGE	BANC	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX	SCL	SRP
BANC	HUR_PGG	0.6%				$24.31										
NEVP	CAL-DRM_2 120	3.0%				-$5.49	$27.83									
PACE	WYOMING_EXPORT	15.4%							-$1.23							
PG&E	30543_ROSSTAP1_230_30550_MORAGA _230_BR_1 _1	0.9%	$40.06													
	30525_C.COSTA _230_30543_ROSSTAP1_230_BR_1 _1	2.1%	$26.82													
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	6.6%	$23.40	$13.17	$11.51	$17.34	$1.22	$8.41	-$18.38	-$30.85	-$42.43	-$42.58	-$41.84	-$41.45	-$41.78	$8.27
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	3.2%	-$9.50	$8.15	$7.60	-$9.02	$4.72	$6.73	-$3.69	-$3.90	-$6.92	-$6.60	-$6.64	-$6.54	-$6.63	$6.70
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	8.0%	-$23.39	$19.71	$18.57	-$22.25	$11.64	$16.43	-$4.13	-$10.48	-$17.32	-$17.16	-$16.68	-$16.43	-$16.64	$16.34
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	11.5%	-$38.43	$31.56	$30.36	-$36.49	$19.20	$26.86	-$9.28	-$17.40	-$28.45	-$28.18	-$27.41	-$27.04	-$27.33	$26.72
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	10.4%				-$10.11										
	30805_BORDEN _230_30810_GREGG _230_BR_2 _1	1.9%				$11.56										
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	6.1%					$27.55									
	32218_DRUM _115_32220_DTCH FL1_115_BR_1 _1	0.6%					$14.20									
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1	2.7%					$6.73									
	32228_PLACER _115_32238_BELL PGE_115_BR_1 _1	0.6%					$32.94									
	37563_MELONES _230_30800_WILSON _230_BR_1 _1	1.3%				-$5.71										
SCE	6410_CP1_NG	3.8%	-$7.79	$6.61	$6.62	-$7.38	$4.11	$5.90	-$1.12	-$3.48	-$5.75	-$5.69	-$5.54	-$5.47	-$5.53	$5.87
	6410_CP6_NG	1.0%	-$1.66	$1.58	$1.50	-$1.56	$0.83	$1.34		-$0.60	-$1.16	-$1.14	-$1.11	-$1.09	-$1.10	$1.33

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

Figure 1.42 shows the overall impact of internal flow-based constraint congestion on 5-minute prices in each load area for 2019 and 2020.

Figure 1.43 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 higher in the third quarter of 2020 compared to the same quarter of 2019. Congestion resulted in a net increase to 5-minute prices in SCE, SDG&E, NEVP, AZPS, and SRP, and a net decrease to 5-minute prices in other ISO and EIM areas.

- Congestion continued to impact prices in both the positive and negative direction over the quarter in each load area, which worked to offset some of the impact of congestion over the quarter. The frequency of congestion was highest in AZPS and SRP (29 percent of total intervals), where congestion predominantly increased prices.

52 Congestion frequencies and impacts reported only reflect Aug. 13-21. Furthermore, details on constraints binding in less than 0.3 percent of the intervals during that time frame have not been reported.

Figure 1.42 Overall impact of internal congestion on price separation in the 5-minute market

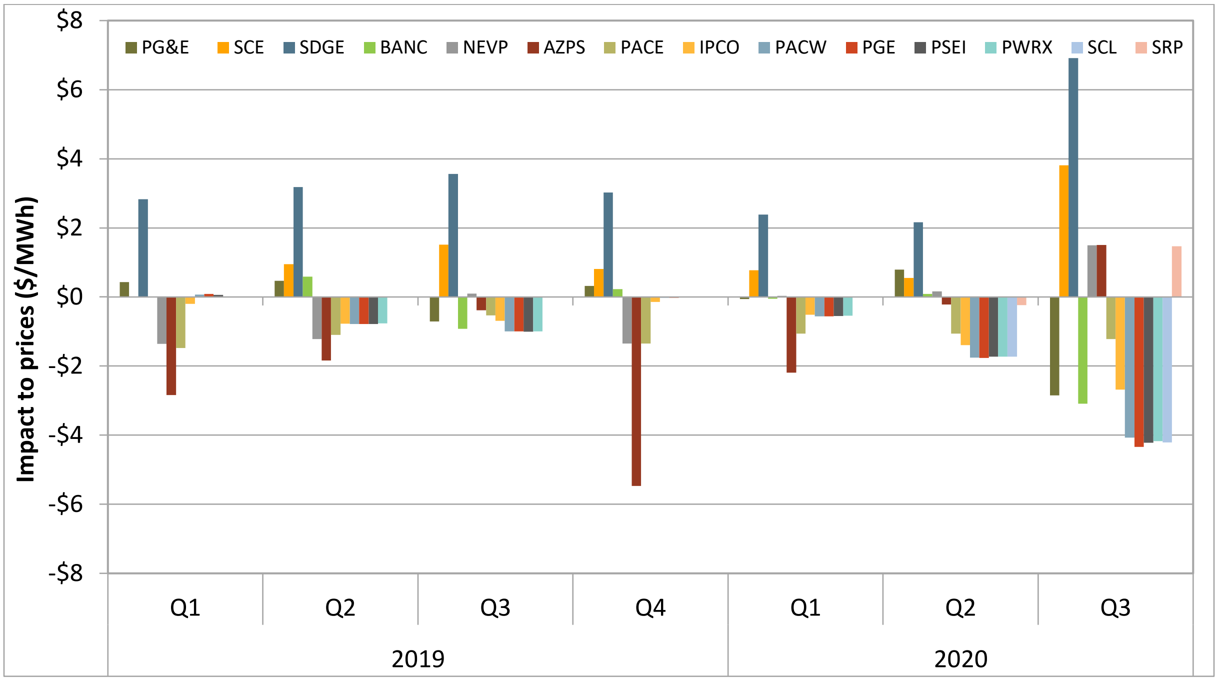
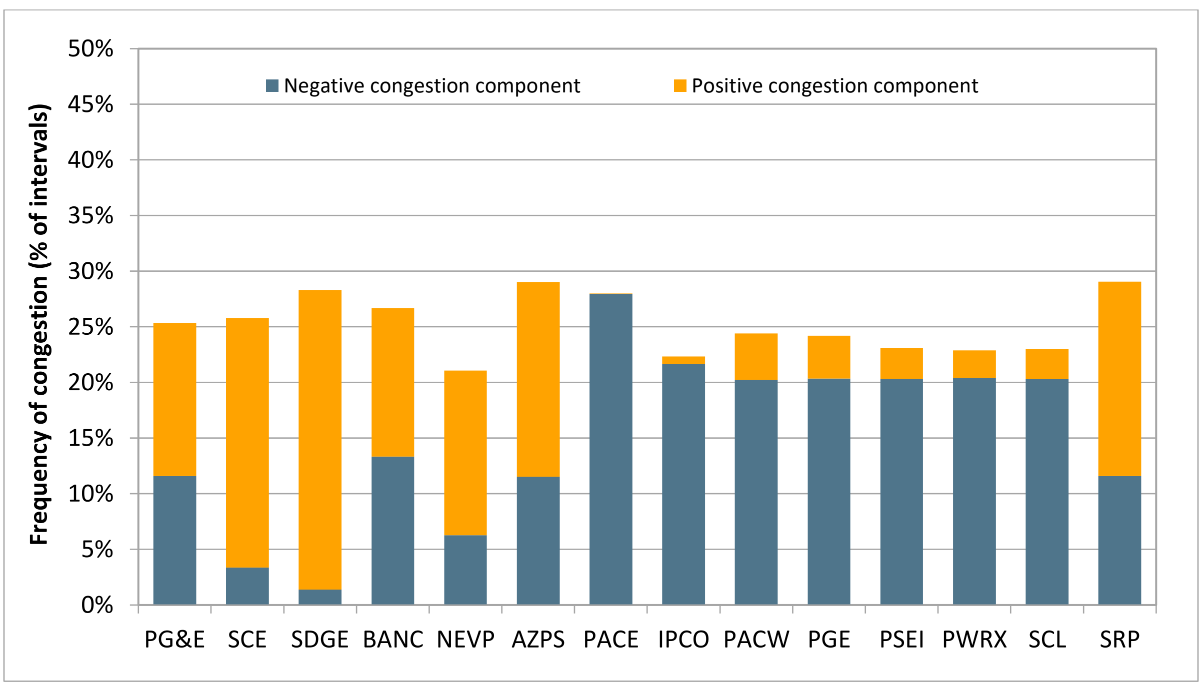


Figure 1.43 Percent of intervals with internal congestion increasing versus decreasing 5-minute prices in the third quarter (>$0.05/MWh)



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 constraints as shown in Figure 1.40 and Table 1.5, and schedule-based constraints as listed in Table 1.8. 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 1.8 shows the congestion frequency and average price impact from transfer constraint congestion in the 15-minute and 5-minute markets during the third 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, transfer congestion typically reduced prices in those areas. The largest price impact was in the NV Energy area, with an average increase of about $15.06/MWh in the 15-minute market and $21.70/MWh 5-minute market.

Table 1.8 Quarterly average price impact and congestion frequency on EIM transfer constraints (Q3 2020)

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	1%	-$2.89	1%	-$0.30
Arizona Public Service	2%	-$2.33	2%	$0.50
NV Energy	6%	$15.06	5%	$21.70
Idaho Power	7%	-$3.97	4%	-$0.73
PacifiCorp East	7%	-$3.98	4%	-$0.19
Salt River Project	10%	-$2.40	9%	-$0.41
PacifiCorp West	38%	-$9.18	25%	-$4.07
Seattle City Light	43%	-$9.66	32%	-$4.82
Puget Sound Energy	43%	-$9.08	32%	-$3.94
Portland General Electric	50%	-$9.08	35%	-$3.58
Powerex	61%	-$13.88	52%	-$8.69

Transfer congestion in the 15-minute market

Transfer constraint congestion in the 15-minute market occurred with very different frequencies and average price impacts across the EIM. Figure 1.44 shows the average impact to prices in the 15-minute market by quarter for 2019 and 2020. Figure 1.45 shows the frequency of congestion on transfer constraints by quarter for 2019 and 2020.

There was an overall increase in the impact on average prices from transfer constraint congestion in the third quarter of 2020, compared to the same quarter in 2019. NEVP had the greatest average price impact, where transfer constraint congestion increased prices by $15.06/MWh on average.

Transfer constraint congestion frequency in the third quarter of 2020 was higher than the same quarter of 2019, with similar high frequencies across the Pacific Northwest. PacifiCorp West had an increase in congestion from 2 percent in the third quarter of 2019 to 38 percent in the third quarter of 2020.

Figure 1.44 Transfer constraint congestion average impact on prices in the 15-minute market

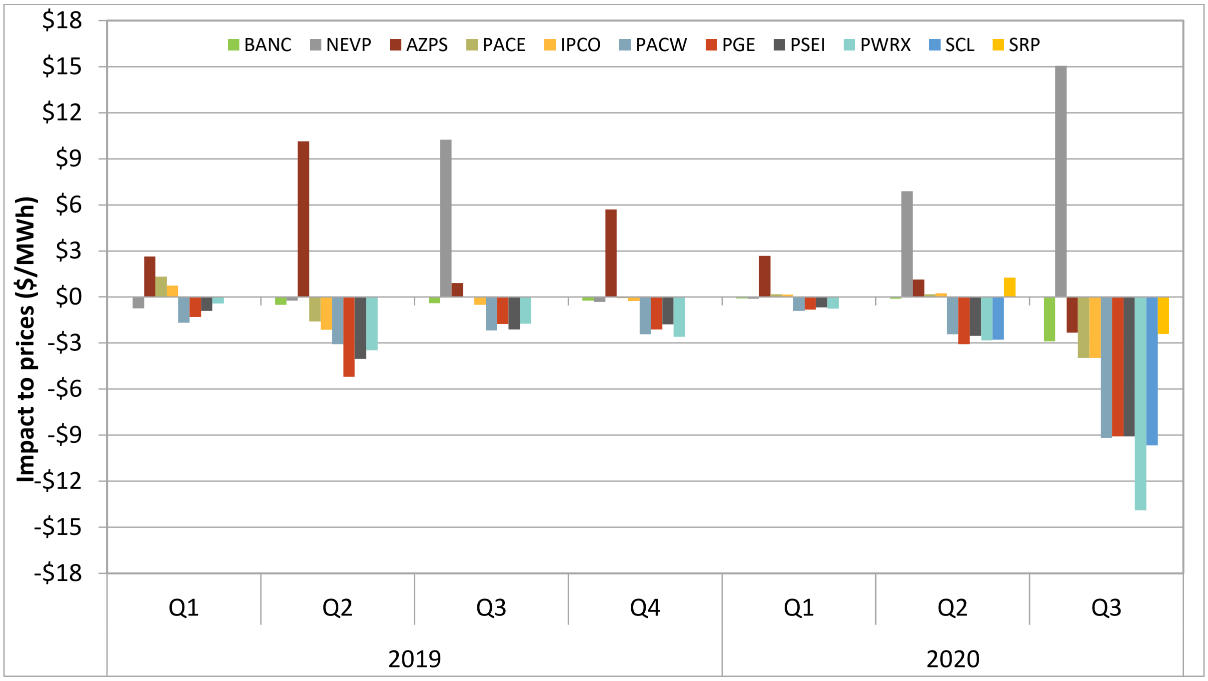
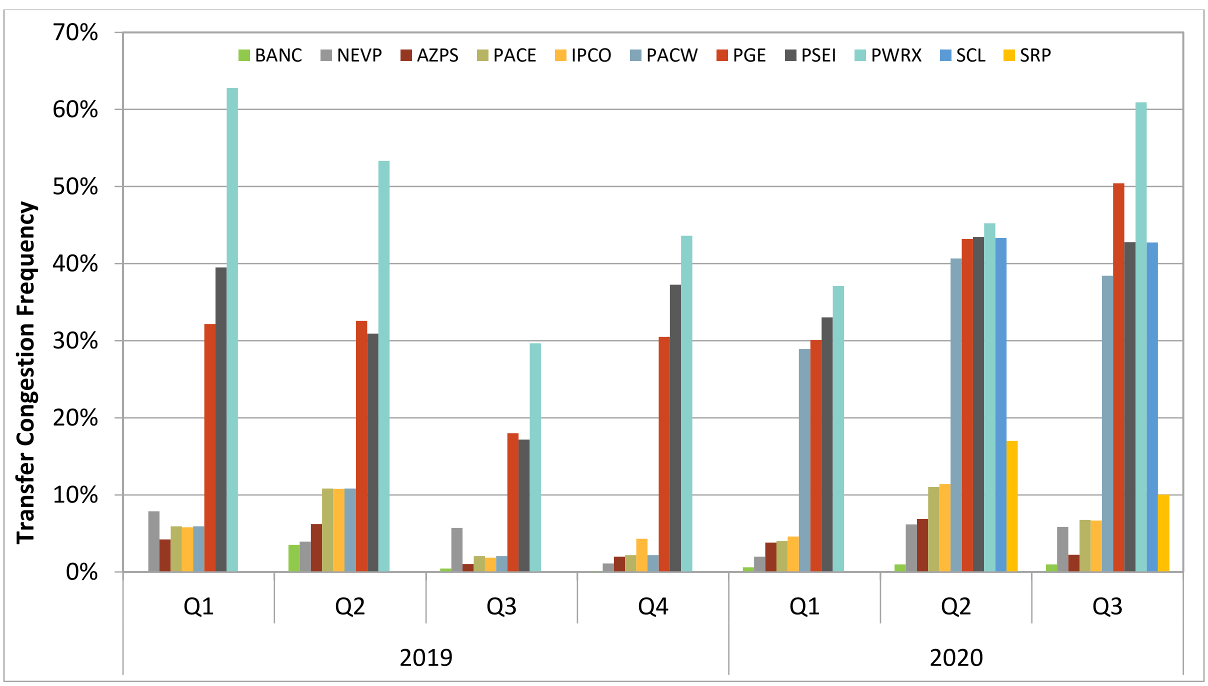


Figure 1.45 Transfer constraint congestion frequency in the 15-minute market



Transfer congestion in the 5-minute market

Similar to the 15-minute market, transfer constraint congestion in the 5-minute market occurred with vastly different frequencies and average price impacts across the EIM. Figure 1.46 shows the average impact on price in the 5-minute market by quarter for 2019 and 2020. Figure 1.47 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 third quarter of 2020 was higher than the same quarter of 2019. Powerex consistently has the highest frequency of transfer constraint congestion, but does not have the most heavily impacted prices. NV Energy experienced the largest impact on prices in the 5-minute market for the third quarter of 2020, where transfer congestion increased average prices by $21.70/MWh.

Overall, the frequency of transfer constraint congestion was higher in the third quarter of 2020 compared to the same quarter in 2019. Areas that had high frequencies of transfer constraint congestion in this quarter include Portland General Electric, Puget Sound Energy, Powerex, and Seattle City Light. In each of these areas, the quarterly transfer congestion frequency was over 30 percent.

Figure 1.46 Transfer constraint congestion average impact on prices in the 5-minute market

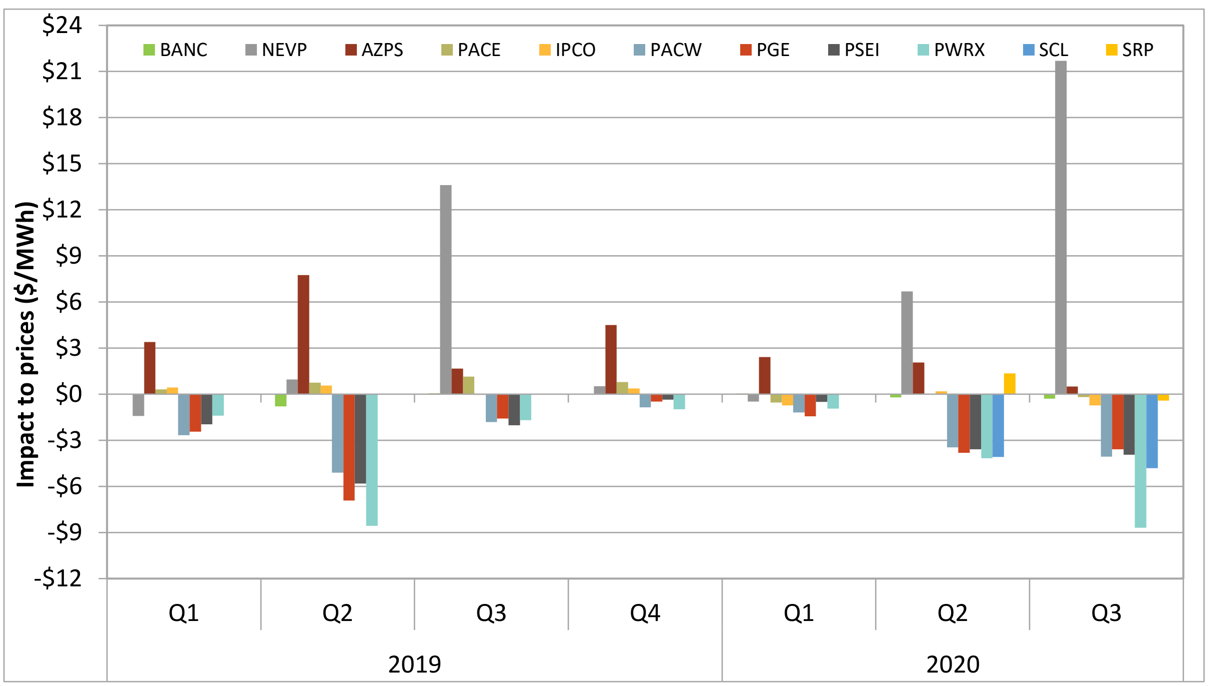
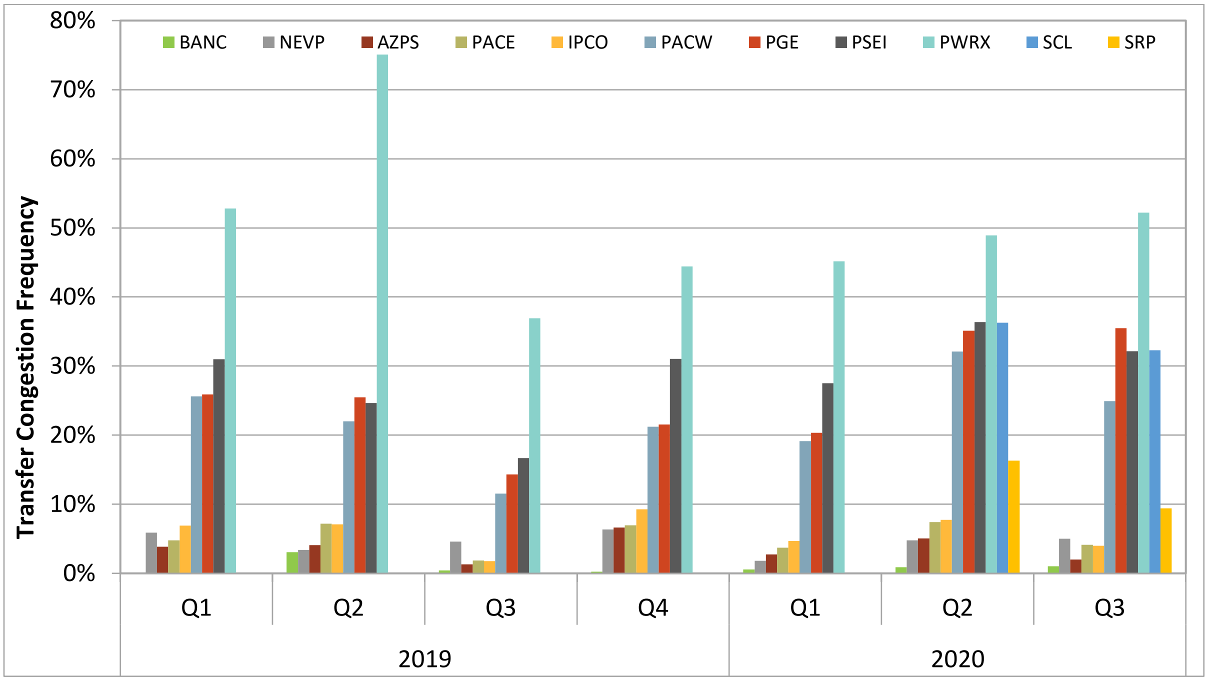


Figure 1.47 Transfer constraint congestion frequency in the 5-minute market



1.10.3 Congestion on interties

In the third 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 1.48 shows total import congestion charges in the day-ahead market for 2019 and 2020. Figure 1.49 shows the frequency of congestion on five major interties. Table 1.9 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 third quarter of 2020 increased significantly to about $115 million compared to $15 million in the same quarter of 2019. This is mainly driven by an increase in congestion on PACI/Malin 500 and NOB interties, which combined account for 97 percent of the total import congestion charges for the quarter.
- The frequency of congestion in the third quarter increased significantly on PACI/Malin 500 and NOB, while it decreased on IPP Utah and 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 third quarter deviated from

this trend. Congestion charges on the Palo Verde and IPP Utah interties were surpassed by the Mead and MeadTMead interties, while congestion on other interties continued to remain relatively low relative to these constraints.

Figure 1.48 Day-ahead import congestion charges on major interties

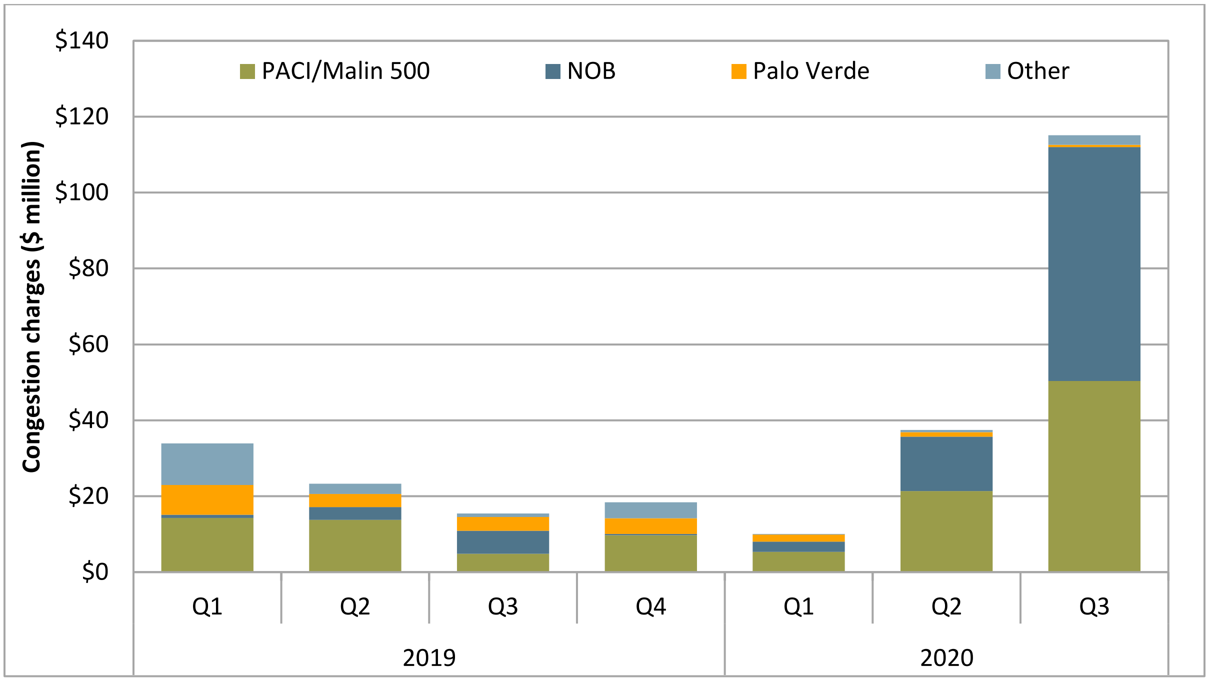


Figure 1.49 Frequency of import congestion on major interties in the day-ahead market

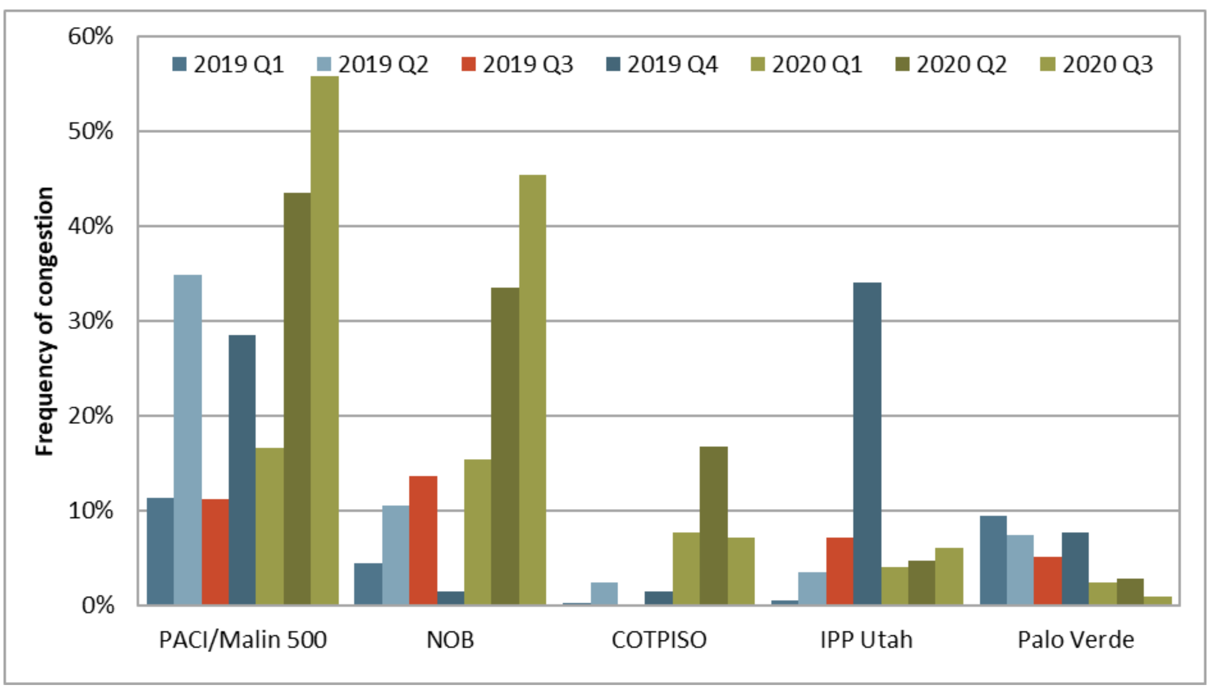


Table 1.9 Summary of import congestion in day-ahead market (2019-2020)

Area	Intertie	Frequency of import congestion							Import congestion charges ($ thousand)						
		2019				2020			2019				2020		
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q1	Q2	Q3	Q4	Q1	Q2	Q3
Northwest	NOB	5%	11%	14%	2%	15%	34%	45%	$858	$3,380	$6,128	$382	$2,715	$14,317	$61,672
	PACI/Malin 500	11%	35%	11%	29%	17%	44%	56%	$14,246	$13,773	$4,787	$9,681	$5,318	$21,358	$50,334
	COTPISO	0%	3%		2%	8%	17%	7%	$4	$20		$21	$85	$258	$66
	Cascade		1%	2%	0%	0%		0%		$30	$162	$1	$2		$52
	Summit			1%		1%					$26		$6		
Southwest	MeadTMead				1%			0%				$37			$985
	Mead	1%		0%	2%		1%	1%	$306		$238	$989		$133	$856
	Palo Verde	9%	8%	5%	8%	2%	3%	1%	$7,864	$3,409	$3,579	$4,128	$1,827	$1,174	$576
	IPP Utah	1%	4%	7%	34%	4%	5%	6%	$13	$99	$186	$2,528	$136	$136	$528
	IPP Adelanto	44%	1%		0%		0%	0%	$10,028	$120		$98		$96	$12
	Marble		1%				1%			$18				$18	

1.11 Real-time imbalance offset costs

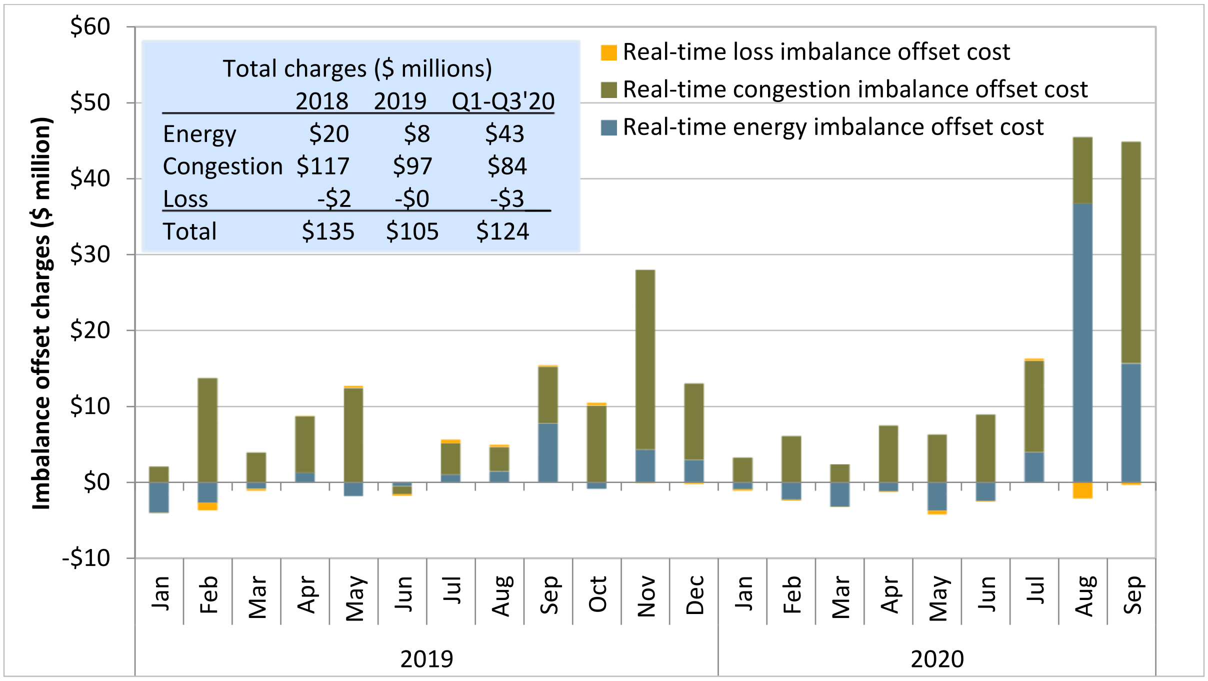
Third quarter real-time offset costs were about $104 million, up from $15 million in the second quarter of 2020, and almost as high as the total offset cost in 2019. Real-time imbalance offset costs were comprised of about $50 million in congestion offset costs, about $56 million in energy offset costs, and $2 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.[53] 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).

53 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.

Figure 1.50 Real-time imbalance offset costs



Energy offset costs exceeded $2 million per day for many of the days during the high demand period.[54] These costs rose to almost $10 million on August 18 alone, more than the sum of energy offset in all of 2019. As on other similar days during this period, the ISO relied on out of market dispatches and other non-market measures to meet high demand. Large offset costs account for the revenue imbalance between real-time payment to the ISO by load and real-time market payments for generation on these days.

Like energy offset costs, congestion offset costs were concentrated on a few days.[55] As has been reported in previous reports, in the presence of significant real-time market congestion, constraint limit reductions between day-ahead and real-time can generate real-time congestion imbalance charges.[56]

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54 Based on current settlement data, days with energy offset costs greater than $2 million in the third quarter are: August 13 ($2.4 million), August 14 ($2.4 million), August 17 ($6.0 million), August 18 ($9.9 million), August 19 ($2.4 million), August 24 ($3.4 million), September 5 ($3.8 million), and September 6 ($4.9 million). Costs on these days account for $35 million of the total $56 million for the quarter.

55 Based on current settlement data, days with congestion offset costs greater than $2 million in the third quarter are: July 31 ($4.7 million), August 13 ($2.1 million), August 28 ($3.1 million), September 5 ($5.4 million), September 6 ($8.7 million), and September 18 ($2.3 million). Costs on these days account for $26 million of the total $50 million for the quarter.

56 *Q3 2018 Report on Market Issues and Performance,* Department of Market Monitoring, November 1, 2018, pp. 23-27. http://www.caiso.com/Documents/2018ThirdQuarterReportonMarketIssuesandPerformance.pdf

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).[57] 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. From 2009 through 2019, transmission ratepayers have received 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.[58]

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.[59] [60]

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57 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.

58 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

59 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

60 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 1.51, transmission ratepayers lost about $38 million during the third quarter of 2020 as payments to auctioned congestion revenue rights holders exceeded auction revenues. This is above the $1 million loss in the third quarter of 2019, and above the average losses of $15 million in the third quarters of the prior three years before the congestion revenue right modifications (2016 through 2018). Auction revenues were 43 percent of payments made to non-load-serving entities during the third quarter of 2020, down from 96 percent during the same quarter in 2019.

Ratepayer auction losses can come from congestion revenue rights sold by the ISO as well as trades by load serving entities in the auction. From the start of 2019 through the second quarter of 2020, DMM estimates that load serving entities on net made a small amount on their auction trades. DMM estimates that the about $49 million in ratepayer losses over this time were from ISO sales of congestion revenue rights in the auction.

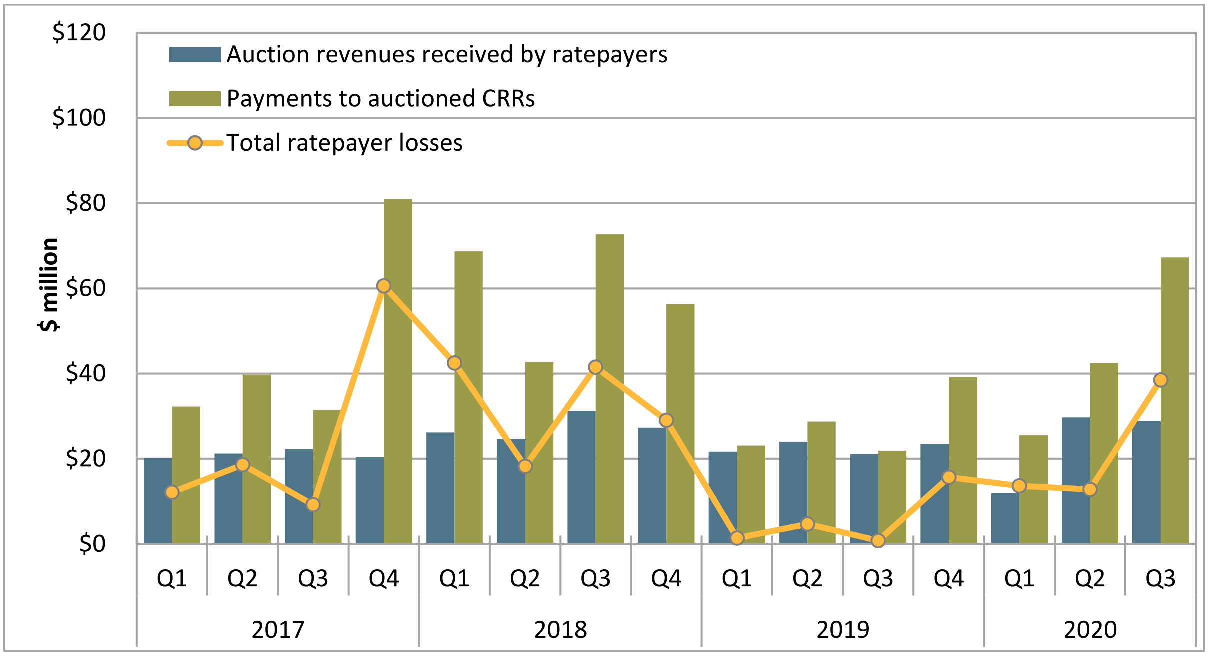
Before the congestion revenue right modifications implemented in 2019, gains and losses from load serving entity trades were not the major contributor to total ratepayer auction losses. However, DMM estimates nearly all of the $38 million losses in the third quarter of 2020 came from trades made by load serving entities and very little, less than $2 million, from ISO sales. The losses appear to come primarily from sales of allocated congestion revenue rights made by a small number of direct access providers and community choice aggregators. Thus, the composition of third quarter 2020 ratepayer losses was very different than previous quarters. DMM will include additional analysis and explanation of this in future reports.

In the third quarter, financial entities (which do not schedule or trade physical power or serve load) had profits of approximately $10 million. This was an increase from $2 million in profits during the third quarter of 2019. Marketers' profits were about $19 million, up from a $1 million in the third quarter of 2019. Generators profited about $9 million compared to over $2 million lost in the third quarter of 2019.

The $38 million in third quarter auction losses was about 17 percent of day-ahead congestion rent. This is up from 1 percent of rent in the third quarter of 2019 and 6 percent for all of 2019. However, the losses as a percent of day-ahead congestion rent were below the average of 28 percent during the three years before the Track 1A and 1B changes (2016 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 $10 million in the third quarter. While Track 1B changes may have had an effect on auction bidding behavior and could have reduced auction revenues, these potential impacts cannot be determined.

Figure 1.51 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 third quarter of 2020, estimated bid cost recovery payments for units in the ISO and energy imbalance market totaled about $62 million. This was $43 million higher than total bid cost recovery in the previous quarter and about $14 million higher than in the third quarter of 2019. These significantly high payments in the third quarter can be attributed to higher loads experienced throughout the west during some days in August and September.

Bid cost recovery attributed to the day-ahead market totaled about $8 million, about $2 million higher than the prior quarter. Bid cost recovery payments for residual unit commitment during the quarter totaled about $21.7 million, compared to $4.7 million in the prior quarter. Units committed by the residual unit commitment can be either long-start or short-start units. In the third quarter, short-start units accounted for about $12 million in bid cost recovery payments, while long-start unit commitment accounted for $9 million.[61] The significant increase in residual unit commitment bid cost recovery

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

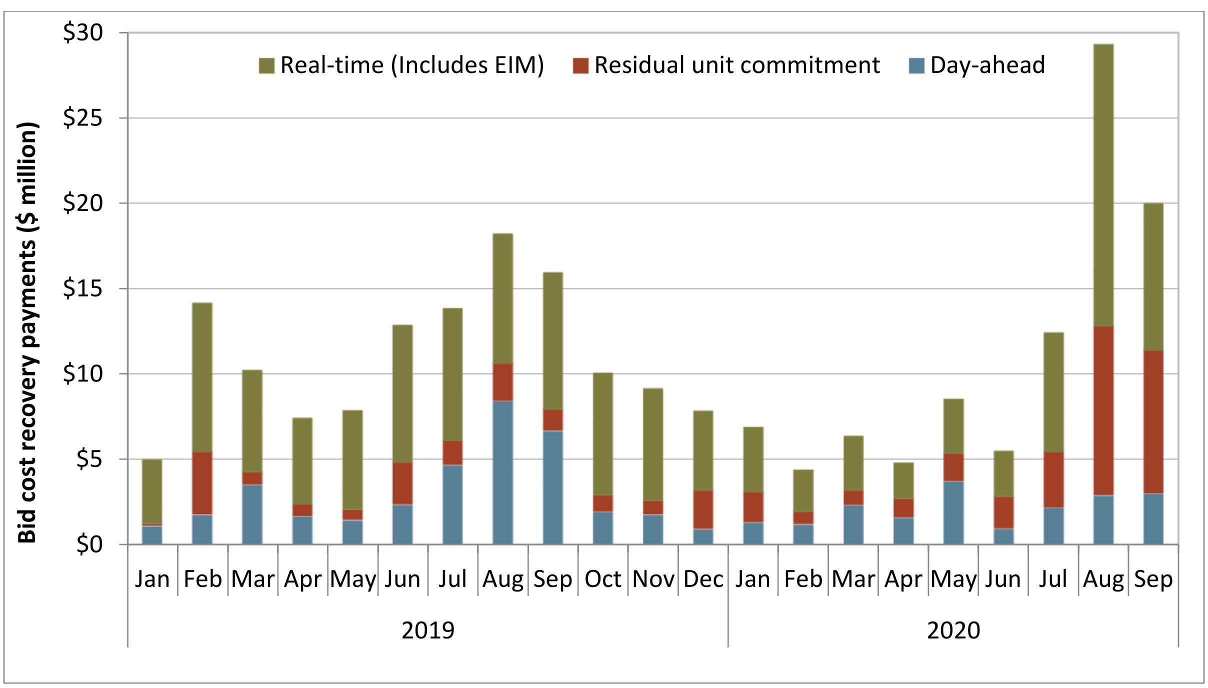
payments in the quarter can be attributed to periods of high loads in August and September along with operator adjustments causing the residual unit commitment process to procure more capacity.

Bid cost recovery attributed to the real-time market totaled about $32 million, or about $24 million higher than payments in the second quarter of 2020 and $9 million higher than payments in the third quarter of 2019. Of the total real-time bid cost recovery, $2.5 million was paid to resources in the western energy imbalance market outside of the ISO and $29.6 million to ISO resources. From August 14 to August 18, the ISO operators activated between 820 and 975 MW of reliability demand response resources (RDRR) during peak net load hours. In several hours, the ISO operators activated available RDRR out-of-market similar to exceptional dispatch instructions. These resources have minimum bids of $950/MWh. Because they were manually dispatched in many hours, they were often dispatched when prices were well below $950 and thus received significant bid cost recovery payments. Of the total $8.6 million in real-time bid cost recovery payments between August 14 and August 18, $4.8 million was paid to these RDRR resources.

Total bid cost recovery payments in the ISO, $59 million, were $1.05/MWh of load (1.7 percent), increased relative to the previous quarter ($0.35/MWh of load or 1.4 percent) and increased in absolute but not as a portion of wholesale energy cost compared to $0.72/MWh of load (1.9 percent) in the third quarter of 2019.

During the third quarter, DMM estimates that about 62 percent of the ISO's total bid cost recovery payments, approximately $36.5 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 95 percent of these payments were for resources bidding at or near the 125 percent bid cap for proxy commitment costs.

Figure 1.52 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:[62]

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.[63] Subsequently, the ISO filed on October 30, 2019, a request for rehearing at FERC regarding the net export limit proposal.[64] 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.[65]

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.[66]

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.

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

63 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

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

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

66 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 third 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. Heat wave conditions that existed across the west during August and September might have also contributed to increased rates of mitigation in the third quarter.

As shown in Figure 1.53, in the day-ahead market, an hourly average of about 1,747 MW was subject to mitigation but corresponding bids were not lowered compared to 538 MW in the same quarter of 2019. About 490 MW of incremental energy had bids lowered due to mitigation compared to 297 MW in 2019. As a result, there was on average about 71 MW increase in dispatch, compared to 39 MW in 2019.

Figure 1.54 and Figure 1.55 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 third quarter relative to the same quarter in 2019.

Figure 1.53 Average incremental energy mitigated in day-ahead market

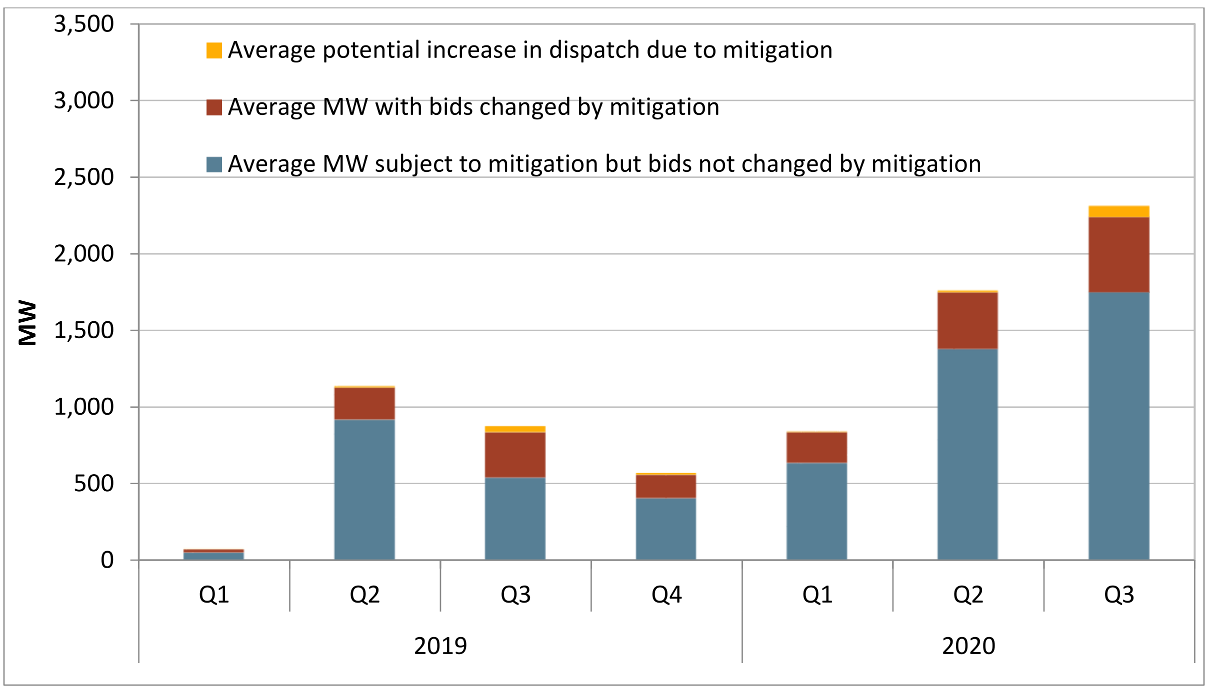


Figure 1.54 Average incremental energy mitigated in 15-minute real-time market (ISO)

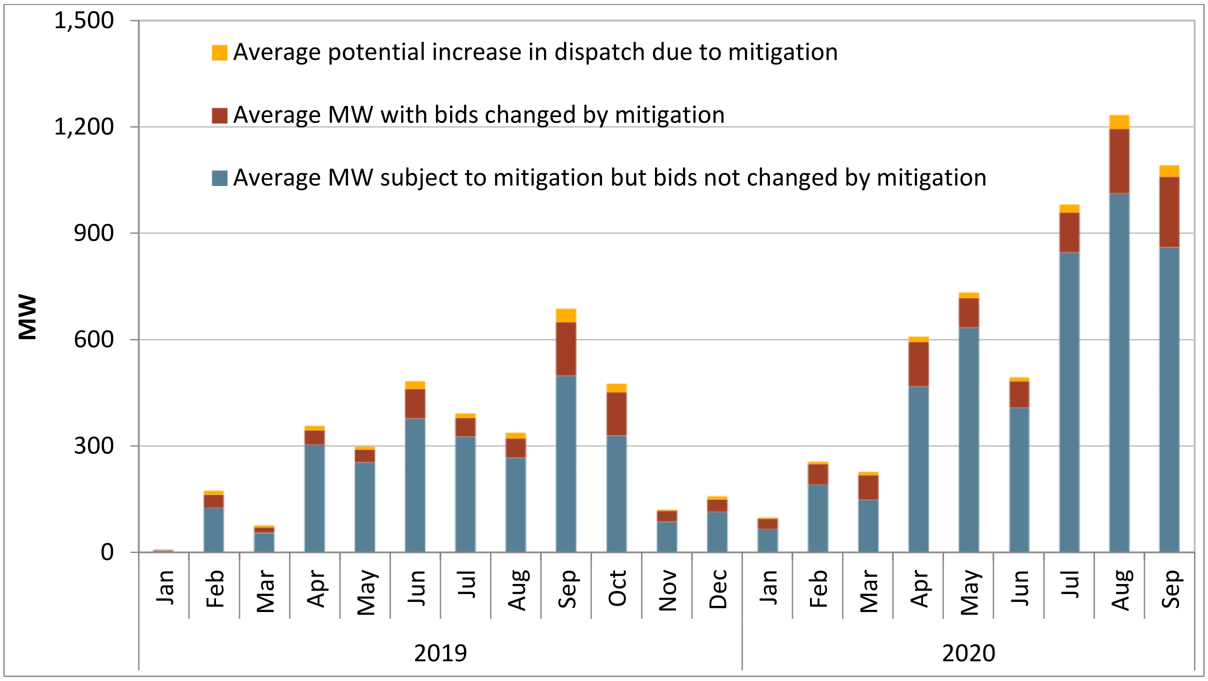
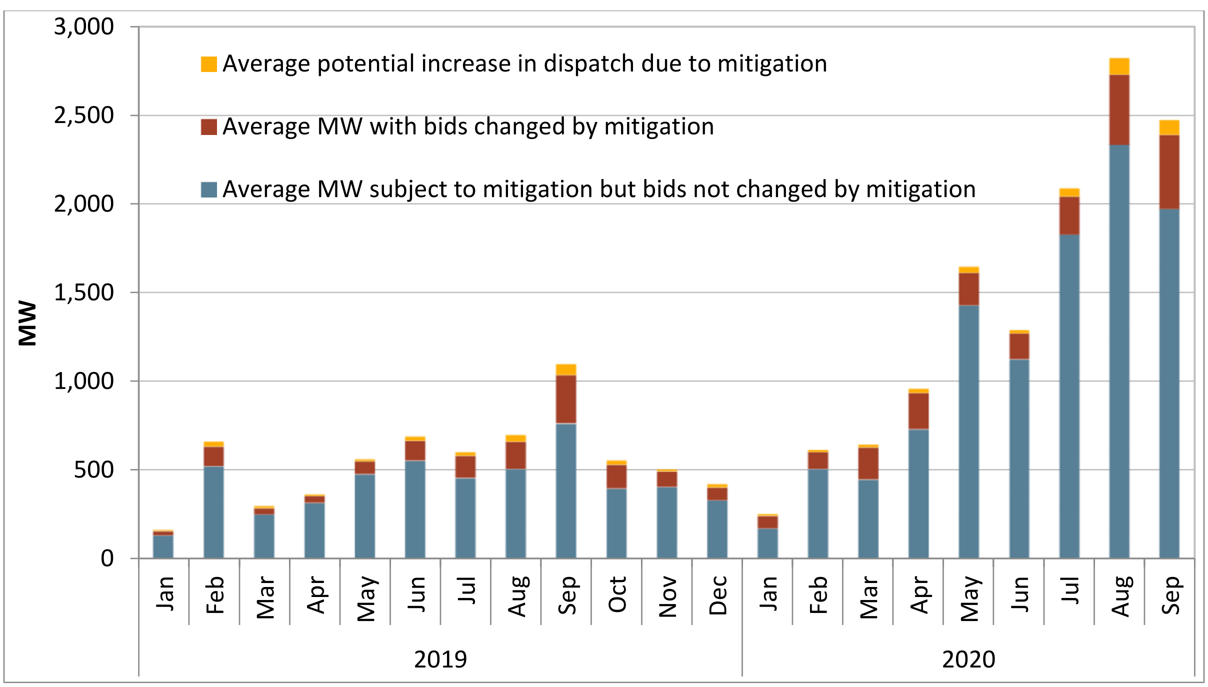


Figure 1.55 Average incremental energy mitigated in 5-minute real-time market (ISO)



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.[67]

Frequency and size of imbalance conformance adjustments, generation/import prices and imports

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 in the afternoon peak solar ramp down period, with average hourly imbalance conformance adjustments in these markets peaking at nearly 1,200 MW, which is similar to the peak in the same quarter of the previous year. Imbalance conformance in the morning ramp up period has decreased this quarter compared to the prior year with averages around 200 MW while last year the averages were nearly 500 MW in hour ending 7.

Figure 1.56 shows imbalance conformance adjustments in all real-time markets tend to follow a similar shape, with 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 340 MW, much lower than the 1,200 MW adjustment in the hour-ahead and 15-minute markets. In this quarter, mid-day adjustments were typically less than 200 MW in the hour-ahead and the 15-minute markets, while the 5-minute market adjustments trended a little lower throughout the morning until hour ending 15 where they diverged substantially 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.

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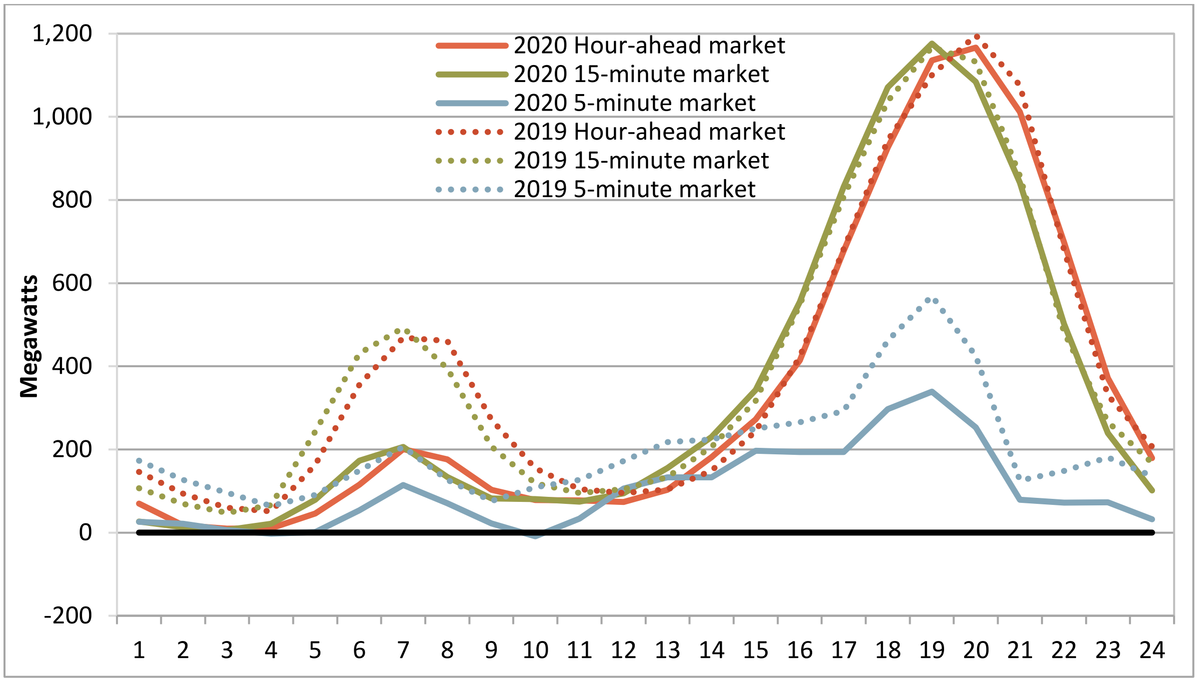
67 Additional detail can be found in Section 9, Market Adjustments, in the *2016 Annual Report on Market Issues and Performance*, which is available on the ISO website at: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf

Figure 1.56 Average hourly imbalance conformance adjustment (Q3 2019 – Q3 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.

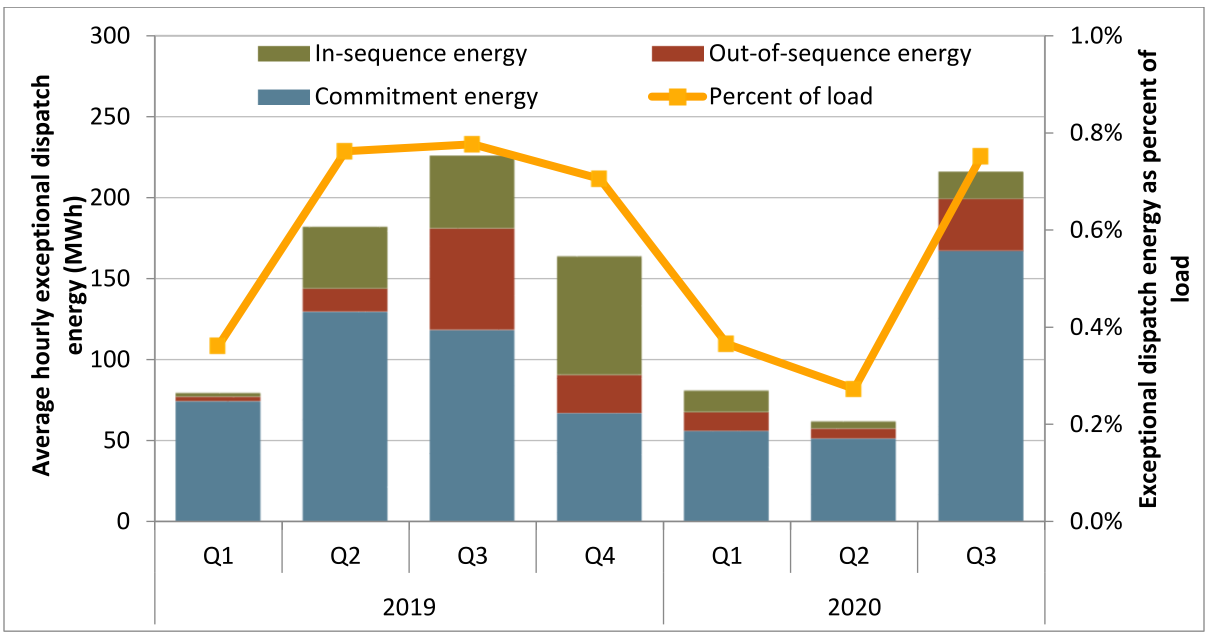
- **Out-of-sequence real-time energy** — Exceptional dispatches may also result in out-of-sequence real-time energy. This occurs when exceptional dispatch energy has an energy bid priced above the market clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to 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 1 percent of total load in the ISO balancing area. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 216 MWh in the third quarter of 2020, which is slightly down from 226 MWh in the same quarter in 2019.

As shown in Figure 1.57, exceptional dispatches for unit commitments accounted for about 77 percent of all exceptional dispatch energy in this quarter.[68] About 15 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 8 percent was from in-sequence energy.

Figure 1.57 Average hourly energy from exceptional dispatch



Exceptional dispatches for unit commitment

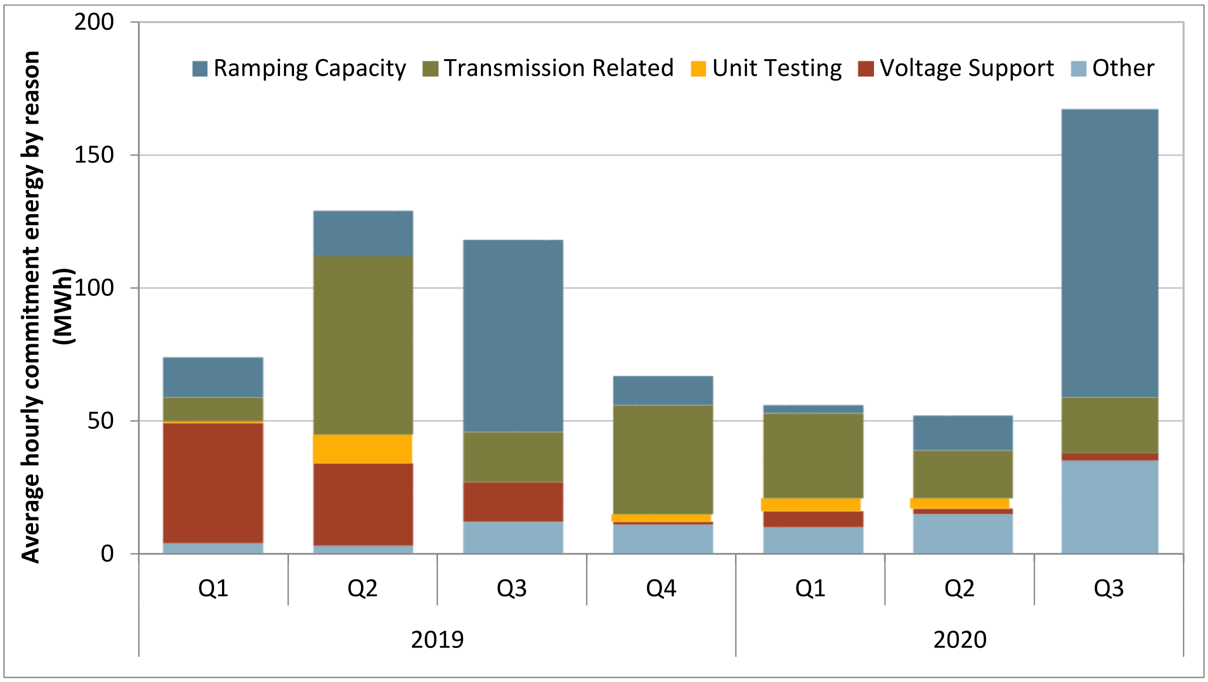
ISO operators sometimes find instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements not directly incorporated in the day-ahead market model. In these instances, the ISO may commit additional capacity by issuing an exceptional dispatch for resources to come on-line and operate at minimum load. Multi-stage generating units may be

68 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.

committed to operate at the minimum output of a specific multi-stage generator configuration, e.g., one by one or duct firing.

Minimum load energy from exceptional dispatch unit commitments in the third quarter increased on average by about 42 percent relative to the third quarter of the prior year. The most frequent reason given for exceptional dispatch unit commitments was for ramping capacity. Exceptional dispatch unit commitments for ramping capacity may be issued to address load forecast uncertainty or to commit a unit to its minimum dispatchable level.

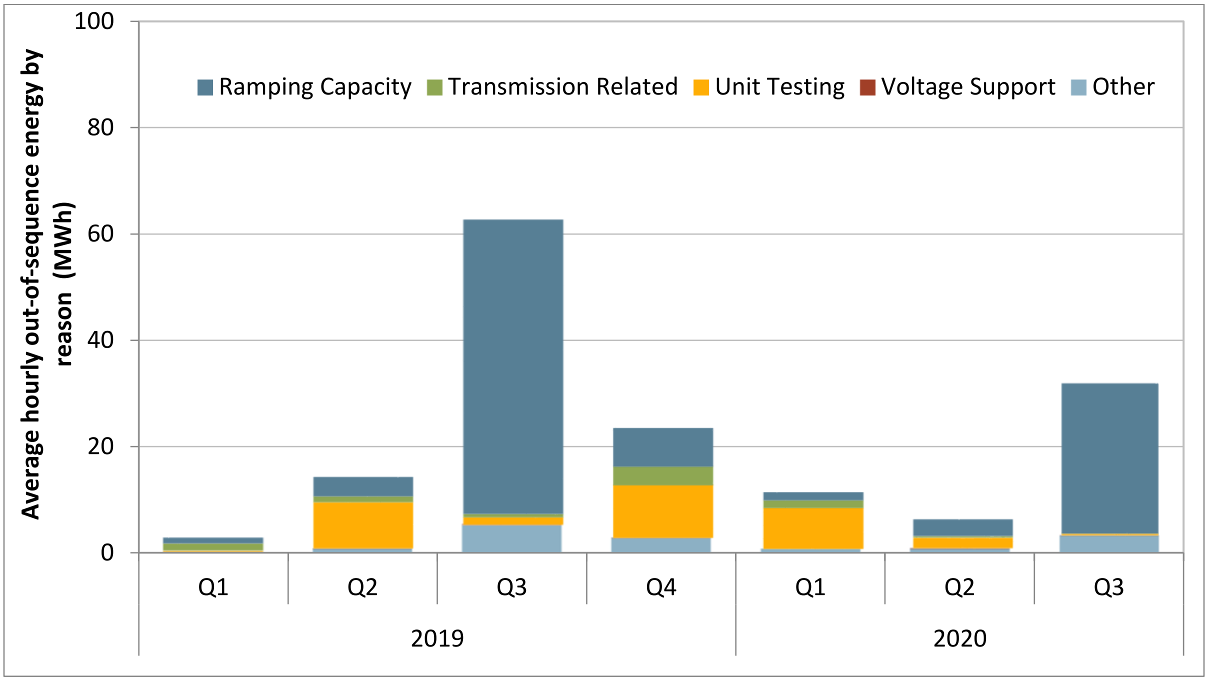
Figure 1.58 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

As shown in Figure 1.57, in the third quarter of 2020, energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch decreased by about 56 percent from the same quarter in 2019. Figure 1.57 also shows that about 15 percent of the total 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 1.59 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2019 and 2020. The primary reason logged for out-of-sequence energy in the third quarter of 2020 was exceptionally dispatched for ramping capacity. Ramping capacity exceptional dispatches are predominately used to ramp thermal resources to their minimum dispatchable level – a higher operating level with a faster ramp rate which allows these units to be more available to meet reliability requirements.

Figure 1.59 Out-of-sequence exceptional dispatch energy by reason



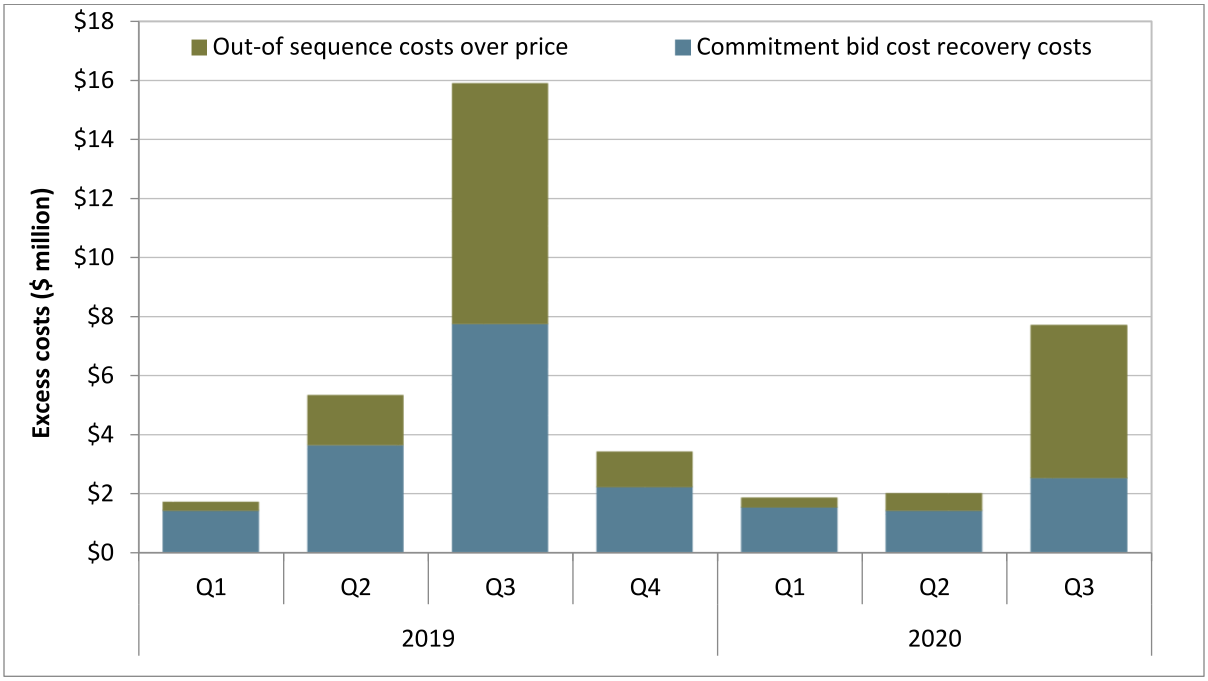
Exceptional dispatch costs

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 1.60 shows the estimated costs for unit commitment and additional energy resulting from exceptional dispatches in excess of the market price for this energy. In the third quarter, out-of-sequence energy costs were $5 million, while commitment costs for exceptional dispatch paid through bid cost recovery were $2.5 million.

Figure 1.60 Excess exceptional dispatch cost by type



Manual dispatches on the interties and export curtailments

Exceptional dispatches on the interties are referred to by the ISO operators as *manual dispatches.* When conditions are tight, the ISO may call upon neighboring balancing authority areas to request imported energy on the interties in the real-time markets. ISO operators also may curtail self-scheduled exports to external balancing authority areas to prevent potential load shed and maintain system reliability.

Figure 1.61 shows the average hourly megawatts from all out-of-market actions taken by the ISO operators during peak net load hours (17-22). These include exceptional dispatches of internal generation within the ISO as well as manually dispatched imports from intertie resources, imports from emergency assistance by other balancing areas, and export curtailments determined by the market.

Imports coming from emergency assistance reflect energy imported from balancing authority areas with whom the ISO has contractual agreements during emergency conditions. All other manual dispatches reflect energy from offers made by ISO operators for imports from entities in neighboring balancing areas for imports in the real-time market. These types of imports are often paid a negotiated price floor, typically for 'bid or better'.[69]

Figure 1.62 shows the volume of out-of-market energy dispatches on the interties and curtailments of self-scheduled exports by the ISO operators in the third quarter during peak net load hours (17-22). In this figure, out-of-market import energy dispatches are shown for different scheduling points into the ISO. Export curtailments show all self-scheduled exports leaving the ISO to outside balancing authority areas that were curtailed in the real-time market.

69 DMM's 2017 annual report (pp. 206-207) provides more detail on manual dispatch types and prices paid for out-of-market imports, http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

Figure 1.61 Average hourly out-of-market energy and export curtailments (hours 17-22)

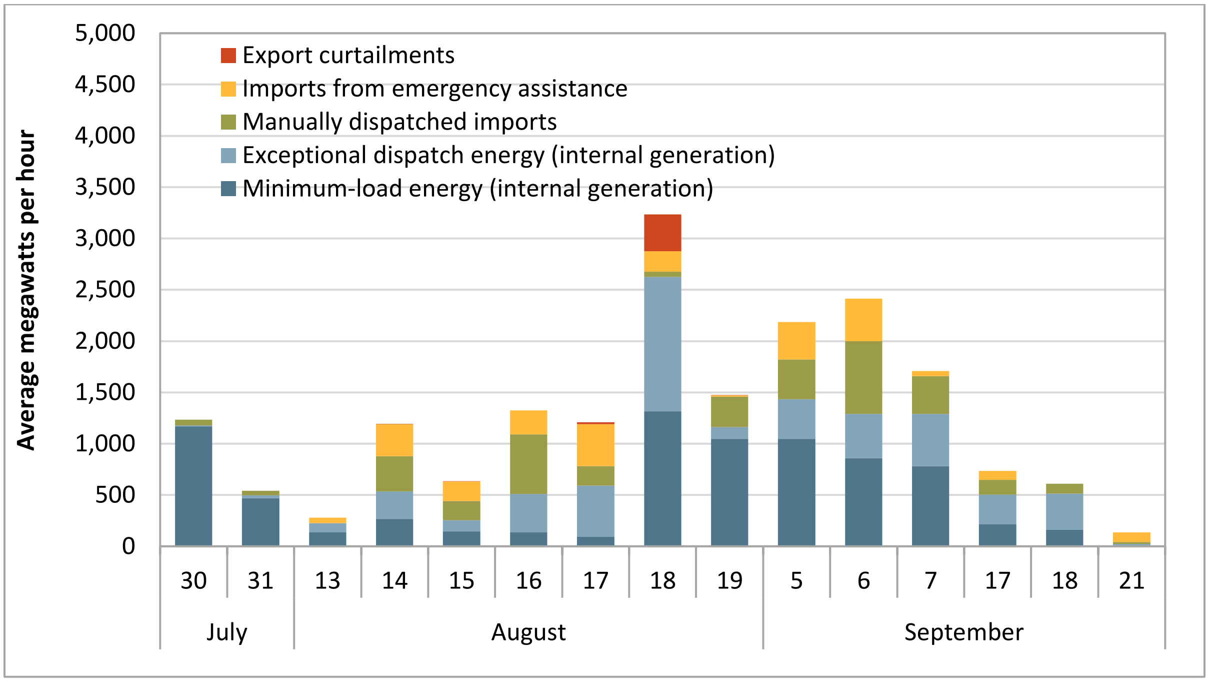
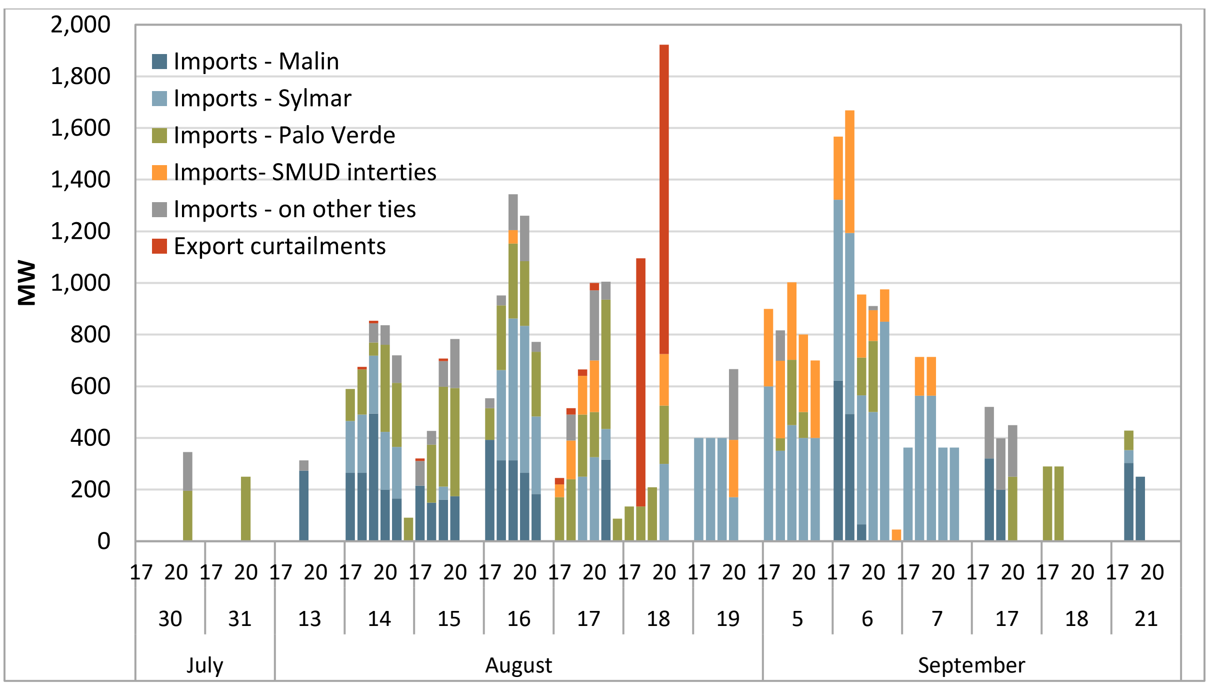


Figure 1.62 Hourly out-of-market imports and market export curtailments (hours 17-22)



1.17 Capacity procurement mechanism

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

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

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

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

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

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

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

Table 1.10 shows intra-monthly capacity procurement mechanism costs for designations that occurred during the third quarter of 2020. Intra-monthly designations were triggered by exceptional dispatches and a significant event during the quarter. Together, estimated costs for intra-monthly capacity procurement mechanism designations totaled about $2.38 million in the third quarter of 2020.

In all, about 700 MW was procured through intra-monthly capacity procurement mechanisms. The ISO issued a capacity procurement mechanism significant event, which designated about 685 MW of backstop capacity for system reliability needs. The designations were made initially for the month of August with extensions and increased procurement through September. The event was issued to meet the need of the August and September heat waves in California and the rest of the West so that the ISO could meet NERC reliability standards for load and reserve obligations. These heat waves created load conditions that were significantly above the projected loads that set the resource adequacy requirements during the planning stage. The total cost of these designations was about $2.38 million in the third quarter.

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

Table 1.10 Intra-monthly capacity procurement mechanism costs

Resource	Designated MW	CPM Start Date	CPM End Date	CPM Type	Price ($/kW-mon)	Estimated cost ($ mil)	Estimated cost Q3 ($ mil)	Local capacity area	CPM designation trigger
DUANE_1_PL1X3	9	8/16/20	8/31/20	ED	$6.31	$0.03	$0.03	SYS	Significant Event CPM Designation
BARRE_6_PEAKER	47	8/17/20	8/31/20	SIGEVT	$6.31	$0.15	$0.15	SYS	Significant Event CPM Designation
GATEWY_2_GESBT1	24	8/17/20	8/31/20	SIGEVT	$6.31	$0.08	$0.08	SYS	Significant Event CPM Designation
MNDALY_6_MCGRTH	47	8/17/20	8/31/20	SIGEVT	$6.31	$0.15	$0.15	SYS	Significant Event CPM Designation
SBERDO_2_PSP4	20	8/17/20	8/31/20	SIGEVT	$6.31	$0.06	$0.06	SYS	Significant Event CPM Designation
SNCLRA_6_PROCGN	27	8/17/20	8/31/20	SIGEVT	$6.31	$0.08	$0.08	SYS	Significant Event CPM Designation
SUTTER_2_CISO	250	8/17/20	8/31/20	SIGEVT	$6.31	$0.79	$0.79	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 1	3	8/17/20	8/31/20	SIGEVT	$6.31	$0.01	$0.01	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 2	2	8/17/20	9/15/20	SIGEVT	$6.31	$0.01	$0.01	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 3	2	8/17/20	9/15/20	SIGEVT	$6.31	$0.01	$0.01	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 4	3	8/17/20	9/15/20	SIGEVT	$6.31	$0.02	$0.02	SYS	Significant Event CPM Designation
GATEWY_2_GESBT1	20	8/17/20	8/31/20	ED	$6.31	$0.06	$0.06	SYS	Significant Event CPM Designation
GATEWY_2_GESBT1	8	8/18/20	9/16/20	SIGEVT	$6.31	$0.05	$0.05	SYS	Significant Event CPM Designation
BIGCRK_2_EXESWD	15	8/19/20	9/17/20	SIGEVT	$6.31	$0.09	$0.09	SYS	Significant Event CPM Designation
GATEWY_2_GESBT1	25	9/1/20	9/15/20	SIGEVT	$6.31	$0.08	$0.08	SYS	Significant Event CPM Designation
SBERDO_2_PSP4	10	9/1/20	9/15/20	SIGEVT	$6.31	$0.03	$0.03	SYS	Significant Event CPM Designation
SNCLRA_6_PROCGN	3	9/1/20	9/15/20	SIGEVT	$6.31	$0.01	$0.01	SYS	Significant Event CPM Designation
SUTTER_2_CISO	155	9/1/20	9/15/20	SIGEVT	$6.31	$0.49	$0.49	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 1	3	9/1/20	9/15/20	SIGEVT	$6.31	$0.01	$0.01	SYS	Significant Event CPM Designation
HUMBPP_1_UNITS3	16	9/1/20	9/30/20	ED	$6.31	$0.10	$0.10	PGE	Potential thermal overload
ARCOGN_2_UNITS	12	9/6/20	10/5/20	SIGEVT	$6.31	$0.08	$0.06	SYS	Significant Event CPM Designation
Total	**700**					**$2.39**	**$2.38**		

2 Western energy imbalance market

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

- **Prices in NV Energy, Arizona Public Service, and Salt River Project** exceeded the rest of the system on average during peak hours in both the 15-minute and 5-minute markets reflecting regional high demand, particularly in the Southwest. As noted in the previous chapter, average bilateral prices at Palo Verde were greater than peak day-ahead prices in the ISO as well.

- **Sufficiency test failures and subsequent under-supply power balance constraint relaxations** drove average real-time NV Energy prices 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.

- **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.

- **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. Significant transfer capability between the ISO, NV Energy, Arizona Public Service, Salt River Project, and BANC allowed energy to flow between these areas with relatively little congestion.

- **Congestion imbalance deficits related to base schedules** remained low in the second quarter, totaling about $0.2 million in PacifiCorp East and $0.4 million in NV Energy. Balancing areas may allocate these imbalances to third party customers and others.

- **Western EIM greenhouse gas** prices decreased but remained high relative to the period prior to November 2018 when the ISO implemented a revised EIM greenhouse gas bid design, as the deemed delivered resources shifted from lower to higher greenhouse gas emissions. In some intervals in the third quarter, all eligible supply was imported, limiting energy imbalance market imports into California.

- **Rates of mitigation** fell in the Western EIM, following the elimination of carryover mitigation in November 2019.

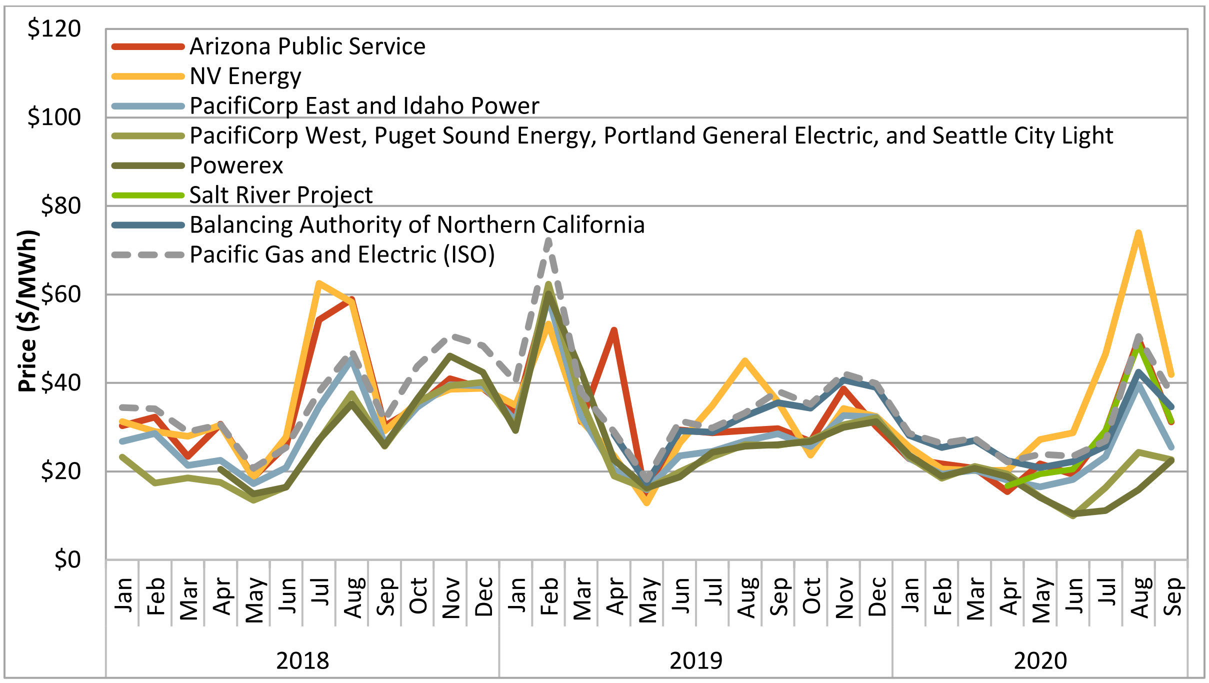
2.1 Western EIM performance

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 January 2018 to September 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.[70] Prices for Pacific Gas and Electric (grey dashed line) are included in the figure as a point of comparison for this analysis.

Figure 2.1 Monthly 15-minute market prices



Tight supply conditions and a west wide heat storm in August led to high prices and increased price separation during the third quarter of 2020. Overall for the quarter, Western EIM prices outside of California averaged about $6/MWh and about $10/MWh below Balancing Authority of Northern California and Pacific Gas and Electric prices, respectively. NV Energy differed from the rest of the EIM as average prices exceeded the average of all other areas by about $25/MWh.

Price separation between Western EIM balancing authorities occurs for several reasons. ISO and other California area 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.[71] In addition to this, average prices in the Northwest region (including PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City

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

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

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 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 third quarter of 2020. Average hourly prices are shown for participating balancing authorities between July 1 and September 30, 2020. Prices continue to follow the net load pattern with the highest energy prices during the evening peak net load hours in most Western EIM balancing areas, just as in the ISO. As in the previous analysis, several balancing areas are grouped together because of similar average hourly pricing, and prices at the Pacific Gas and Electric default load aggregation point are shown as a point of comparison.

Figure 2.2 Hourly 15-minute market prices (July – September)

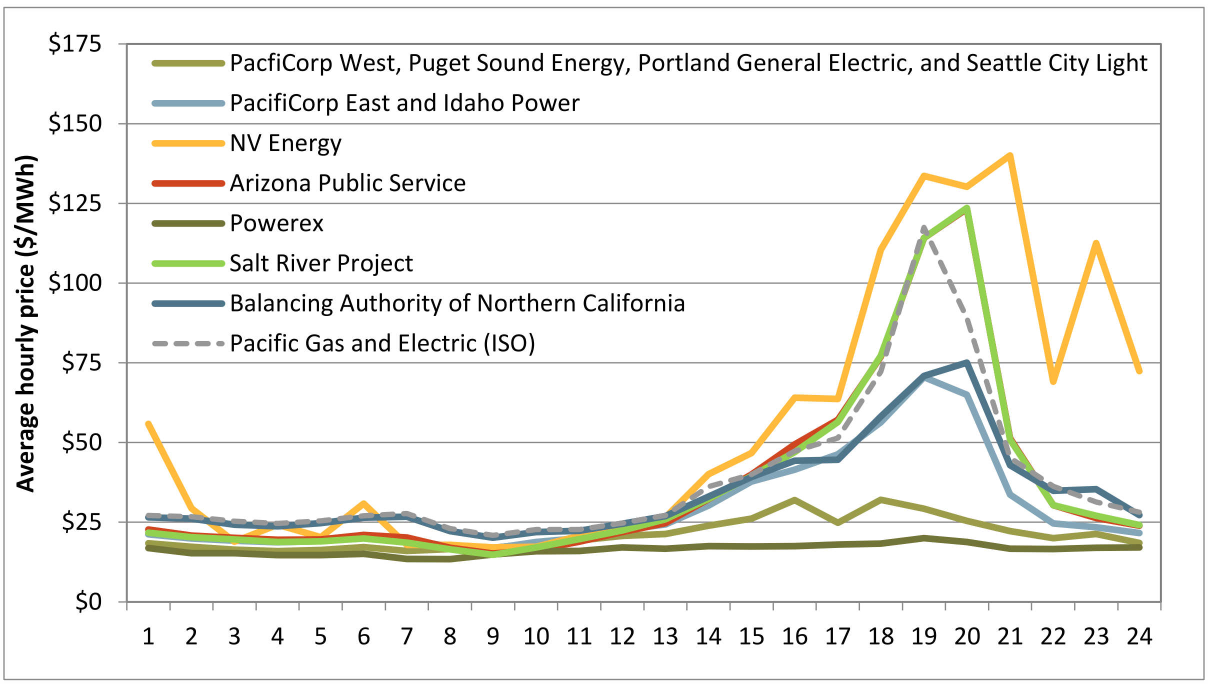
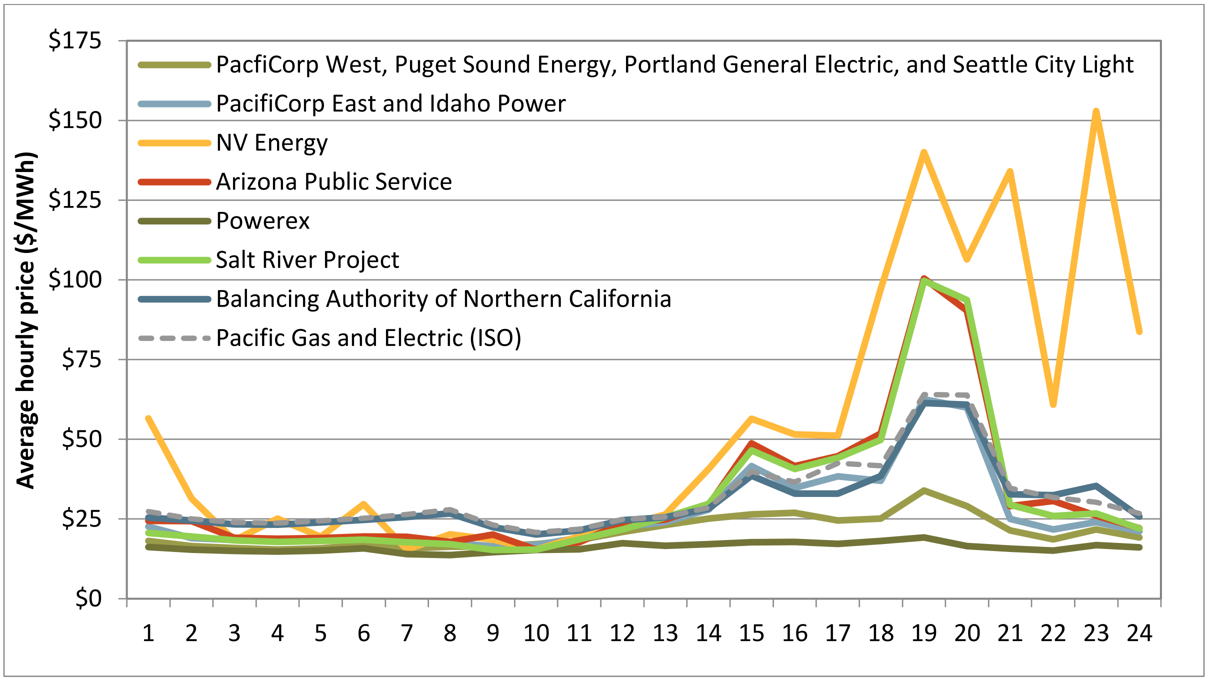


Figure 2.3 Hourly 5-minute market prices (July – September)



These figures also show that the relative price differences between Western EIM entities vary throughout the day. Prices in some entities outside of California tend to be lower than ISO prices in most hours, while others tend to be higher. This price divergence is most pronounced during the evening ramping periods and net load peak hours, 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 third 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, NV Energy, and Salt River Project diverged from the rest of the Western EIM during the afternoon net load peak and evening hours. These areas experienced a number of flexible ramping sufficiency test failures in the upward direction throughout the quarter. 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.[72]

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72 See Section 2.2 for further details on the load conformance in the EIM.

Prices in PacifiCorp East and Idaho Power were often similar to each other and tracked well with prices in the ISO in the 5-minute market. As shown in Figure 2.2 and Figure 2.3, price separation between these areas and the ISO was most pronounced in the 15-minute market during peak load hours when transfers from PacifiCorp East and Idaho Power into the ISO met export limits.

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 2.1 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.

Table 2.1 Estimated 15-minute market EIM internal constraint congestion imbalances ($ million)

	Annual				2019				2020		
Balancing Authority Area	**2016**	**2017**	**2018**	**2019**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**
Arizona Public Service	$0.0	$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	$0.0
Powerex	$0.0	$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	-$49.1
Idaho Power Company			$0.0	$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	-$0.4
PacifiCorp - East	-$4.0	-$18.1	-$2.0	$0.7	$0.8	$0.0	$0.1	-$0.3	-$0.7	-$0.1	-$0.2
PacifiCorp - West	$0.0	$0.0	-$0.1	$0.0	$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	$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	$0.0
Seattle City & Light									$0.0	$0.0	$0.0
Salt River Project									$0.0	$0.0	$0.0

2.2 Flexible ramping sufficiency test

In the third quarter of 2020, the frequency of EIM areas failing the upward sufficiency test decreased relative to the same quarter of 2019.[73] 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.[74] 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 bid range capacity test fails for the specific direction. The bid range capacity test ensures that there are sufficient incremental or decremental economic energy bids above or below the base schedules to meet the demand forecast.

Figure 2.4 and Figure 2.5 show the percent of *intervals* in which an EIM area failed the sufficiency test in the upward or downward direction.[75] During the third quarter of 2020, EIM areas failing the upward sufficiency test decreased but remained near the same levels seen in the same quarter of 2019. NV Energy failed the upward sufficiency test most frequently in the energy imbalance market, during about 14 percent of intervals during the quarter. The frequency of downward sufficiency test failures decreased significantly from the previous quarter. NV Energy failed the downward sufficiency test most frequently over the quarter, during about 4 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.

The CAISO balancing area failed the upward flexible ramping sufficiency test on both days with load curtailment events (August 14 and August 15). DMM analysis found that failing the flexible ramping sufficiency test had little or no impact on net transfers from the energy imbalance market into the ISO on these days. For more information, see DMM's report on this period.[76]

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73 Salt River Project and Seattle City Light were not participating in the EIM during 2019. Therefore, with these two entities removed, the frequency of EIM areas failing the upward sufficiency test in Q3 2020 was lower than that of Q3 2019.

74 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.

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

76 *Report on system and market conditions, issues and performance: August and September 2020*, DMM, November 24, 2020, pp/43-44: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

Figure 2.4 Frequency of upward failed sufficiency tests by month

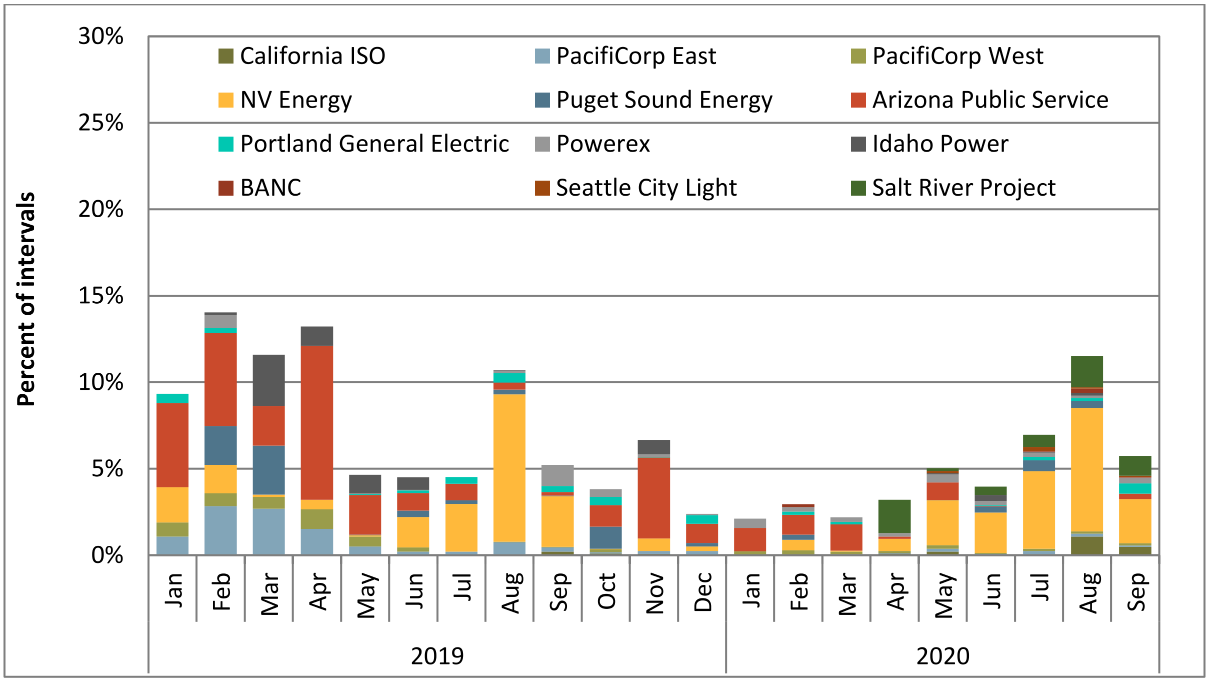
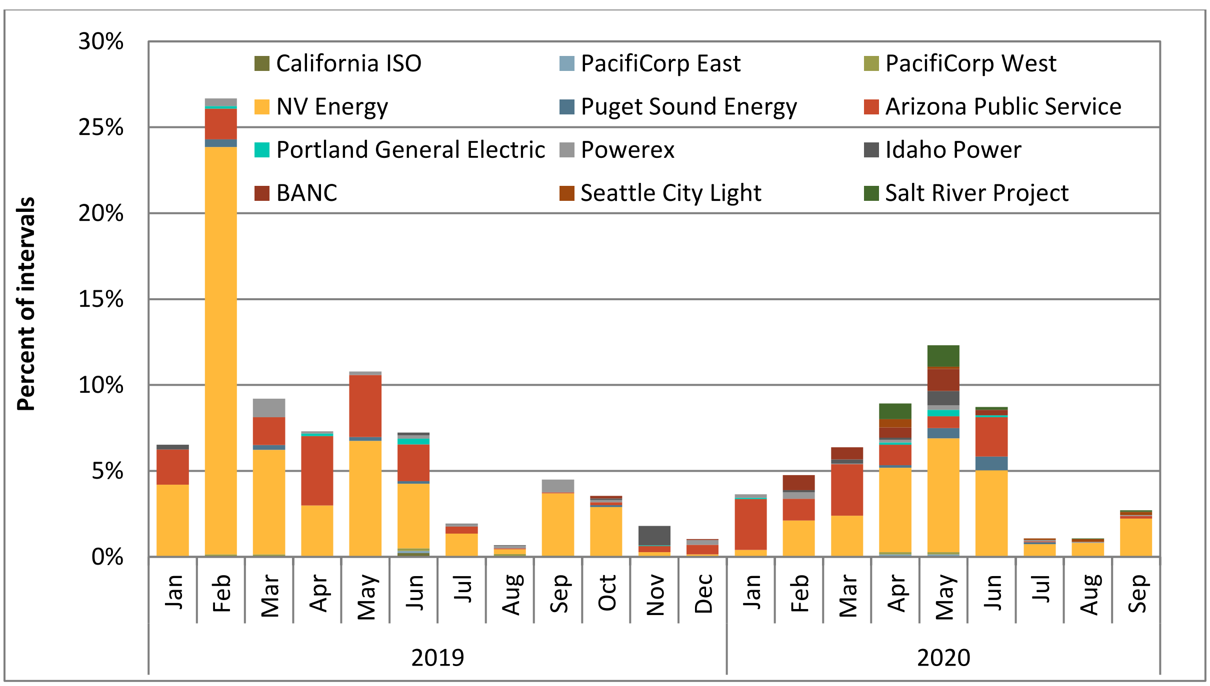


Figure 2.5 Frequency of downward failed sufficiency tests by month



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. Table 2.2 shows average 15-minute market limits between each of the areas during the quarter.[77] In addition, the sum of each column reflects the average total import limit into each balancing area, while the sum of each row reflects the average total export limit from each area.

For example, import transfer capacity into the ISO from areas in the Northwest region including PacifiCorp West, Portland General Electric, Puget Sound Energy, and Powerex was around 160 MW on average during the quarter, or roughly 2 percent of total import capability. However, significant transfer capability between the ISO, NV Energy, Arizona Public Service, Salt River Project, and BANC allowed energy to flow between these areas with relatively little congestion.

Table 2.2 Average 15-minute market energy imbalance market limits (July – September)

From Balancing Authority Area	To Balancing Authority Area												*Total export limit*
	CISO	BANC	NEVP	AZPS	SRP	PACE	IPCO	PACW	PGE	PSEI	SCL	PWRX	
California ISO		1,310	3,370	860	1,480			0	20	0		100	7,140
BANC	1,310												1,310
NV Energy	3,850			330		840	590						5,610
Arizona Public Service	2,230		240		7,880	710							11,060
Salt River Project	2,660			4,900		0							7,560
PacifiCorp East			630	440	0		1,250	220					2,540
Idaho Power			530			2,050		490		40	30		3,140
PacifiCorp West	130					480	450		280	300	20		1,660
Portland GE	30							300		0	20		350
Puget Sound Energy	0						0	300	0		350	150	800
Seattle City Light							30	30	30	360			450
Powerex	0									230			230
Total import limit	10,210	1,310	4,770	6,530	9,360	4,080	2,320	1,340	330	930	420	250	

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 2.6 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 third quarter of 2020, average imports into the ISO during the morning and evening periods were significant, particularly from the Southwest regions including NV Energy, Arizona Public Service, and Salt River Project. Net EIM imports into the ISO during the peak net-load hours averaged around 1,000 MW during the third quarter.

77 The blank cells indicate that the pair of areas have no energy transfer system resource (ETSR) defined between them. A cell with zero MW indicates that there is an ETSR defined between the pair of areas, but the limit was zero on average during the quarter.

Figure 2.6 California ISO - average hourly 15-minute market transfer

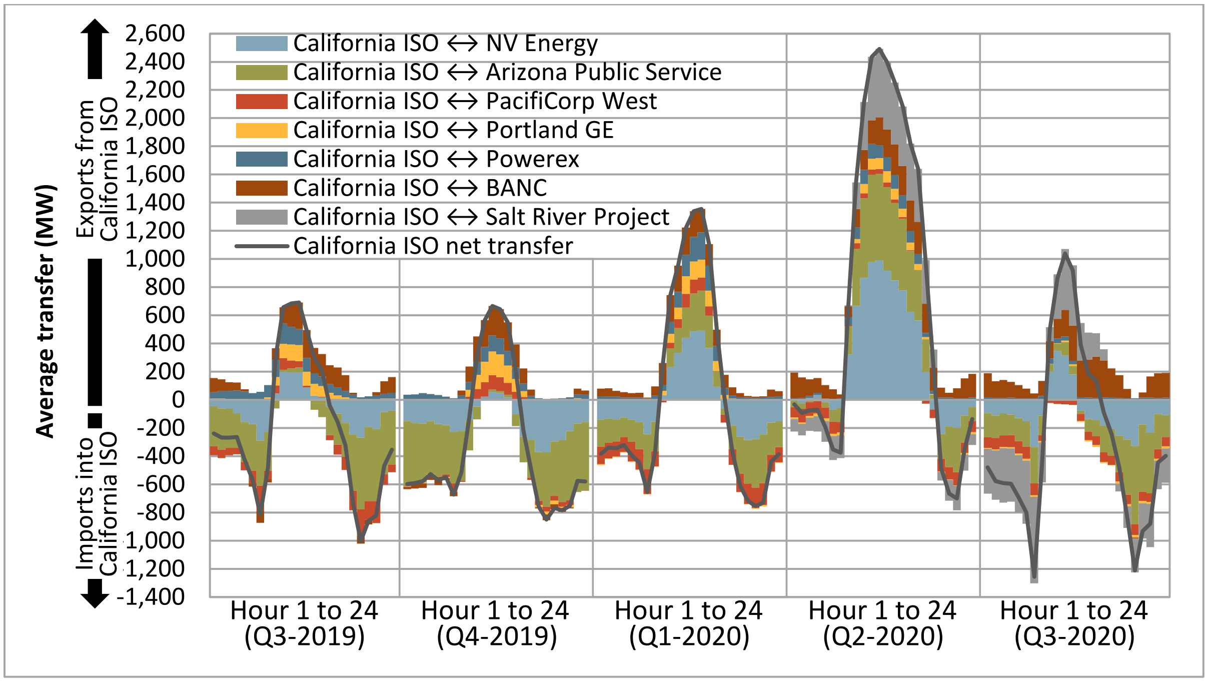


Figure 2.7 through Figure 2.15 show the same quarterly information on imports and exports for the other energy imbalance market areas in the 15-minute market.[78] The amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[79]

Figure 2.7 and Figure 2.8 show average hourly transfers for NV Energy and Arizona Public Service. During evening hours in the third quarter, these areas typically imported from PacifiCorp East and exported out to the ISO.

Figure 2.9 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 2.10 through Figure 2.12 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 2.13 and Figure 2.14 show the average hourly 15-minute market transfer patterns for Powerex, Portland General Electric, and their neighboring areas. Export transmission capacity from Powerex

78 Figures showing transfer information from the perspective of Salt River Project and Seattle City Light are not explicitly included, but are represented in Figure 2.6 through Figure 2.15.

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

toward the ISO was limited to 0 MW during all intervals in the third quarter of 2020 in both the 15-minute and 5-minute markets.

Figure 2.15 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 third quarter with the exception of hour-ending 20.

Figure 2.7 NV Energy – average hourly 15-minute market transfer

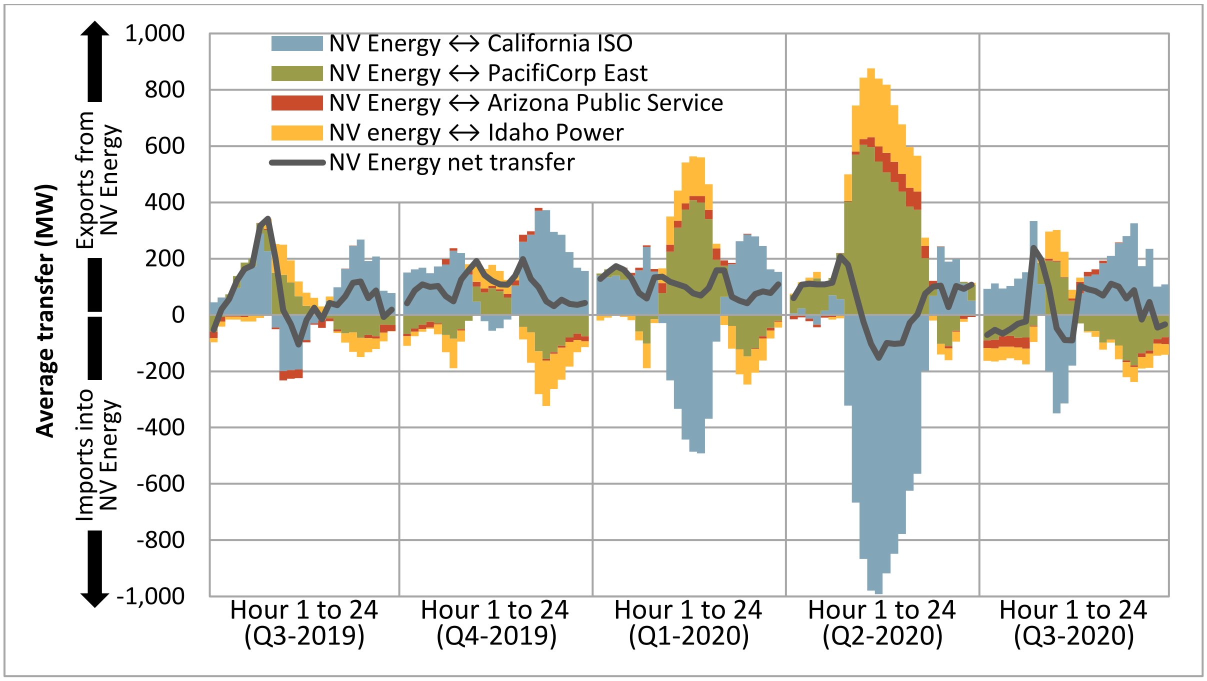


Figure 2.8 Arizona Public Service – average hourly 15-minute market transfer

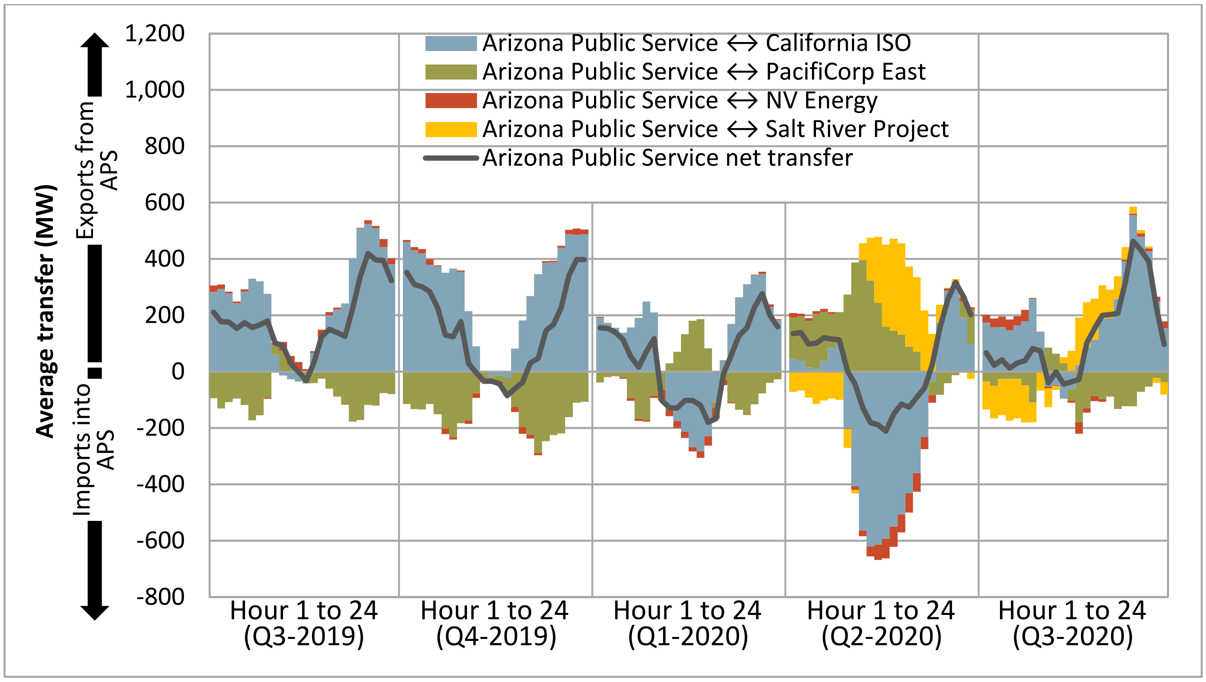


Figure 2.9 Idaho Power – average hourly 15-minute market transfer

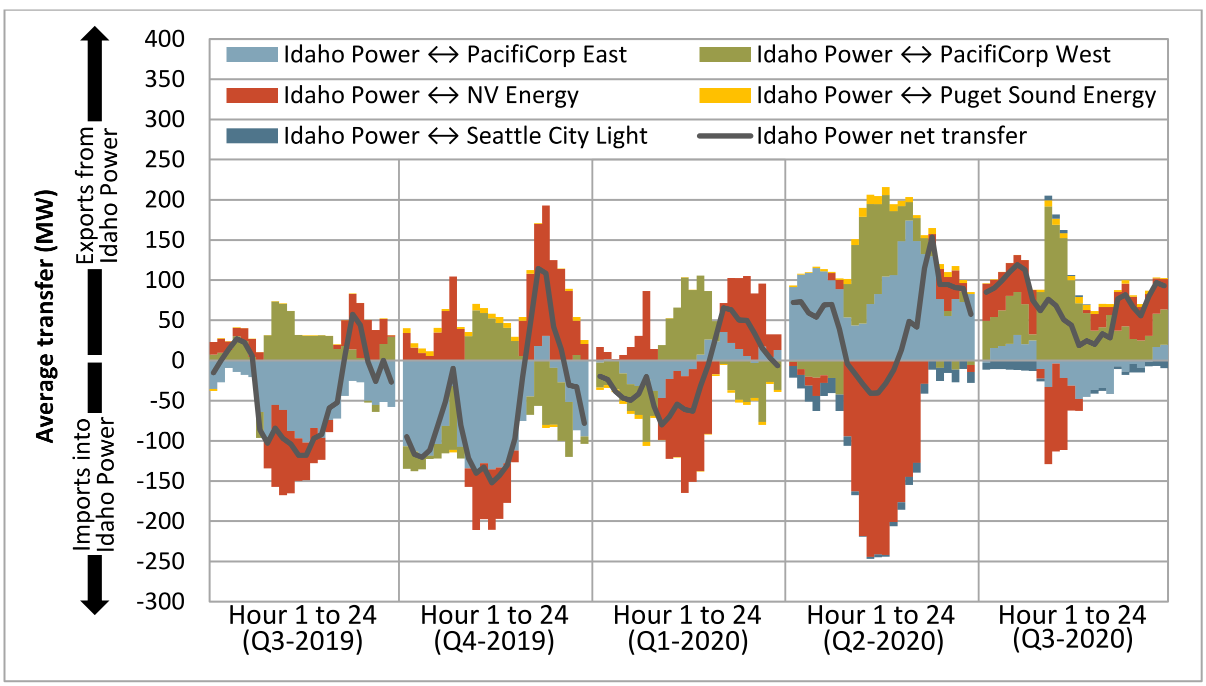


Figure 2.10 PacifiCorp East – average hourly 15-minute market transfer

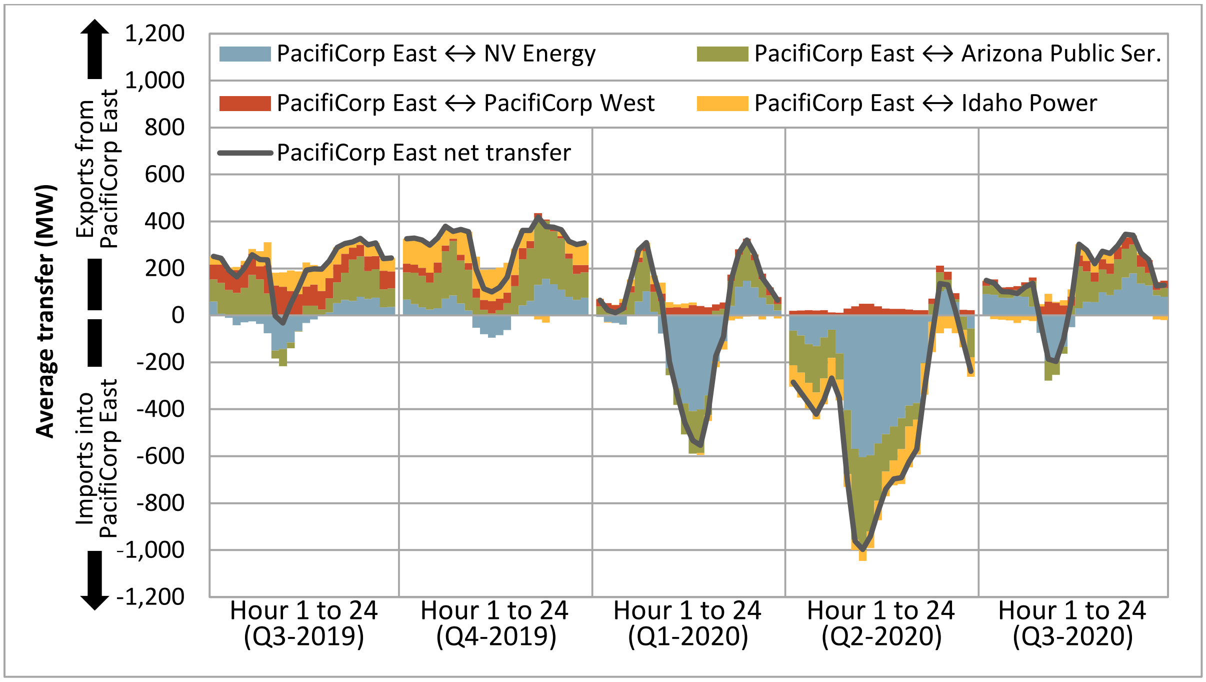


Figure 2.11 PacifiCorp West – average hourly 15-minute market transfer

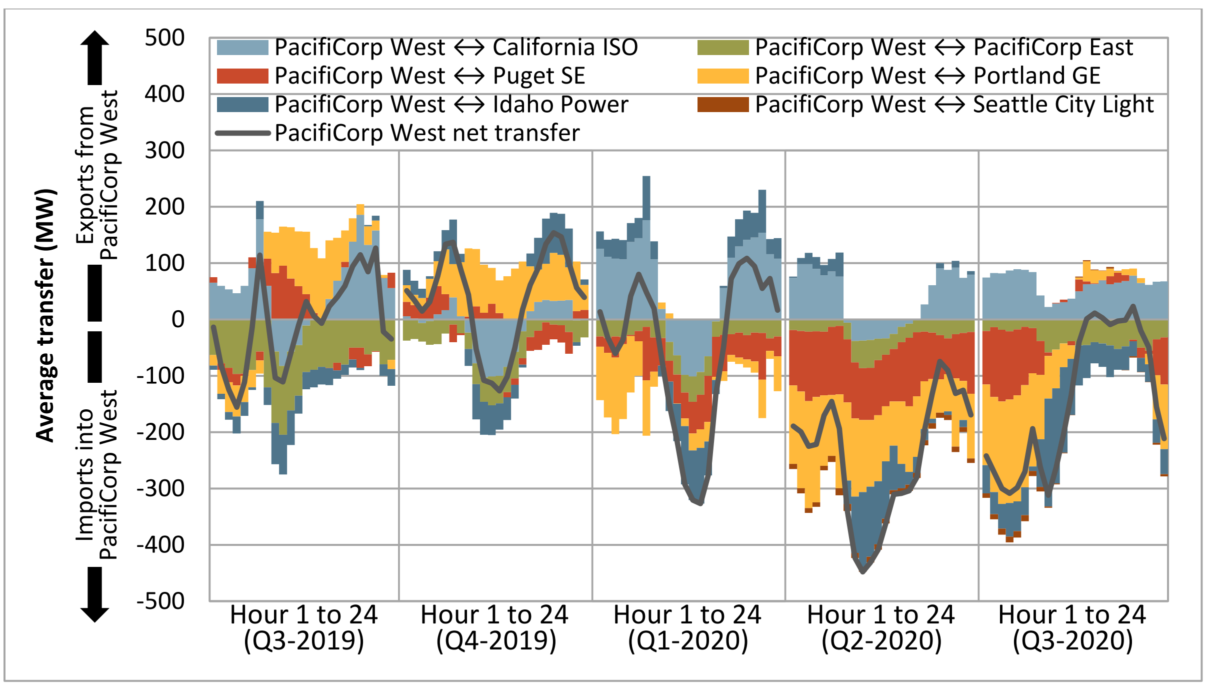


Figure 2.12 Puget Sound Energy – average hourly 15-minute market transfer

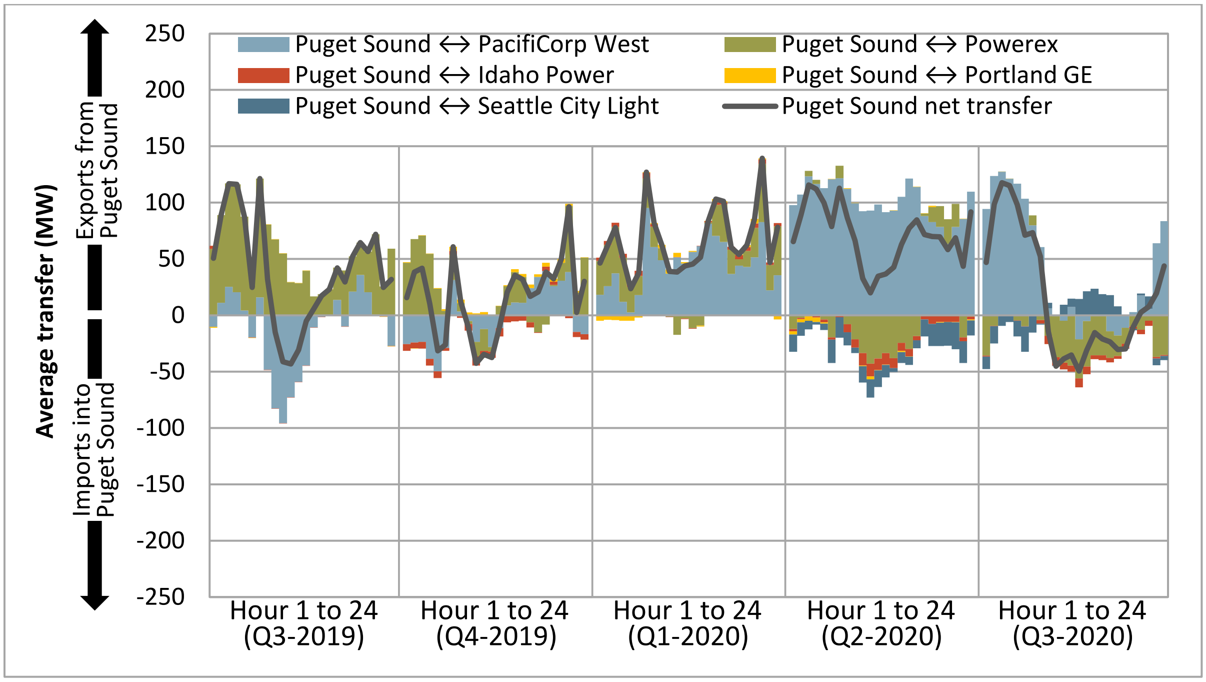


Figure 2.13 Powerex – average hourly 15-minute market transfer

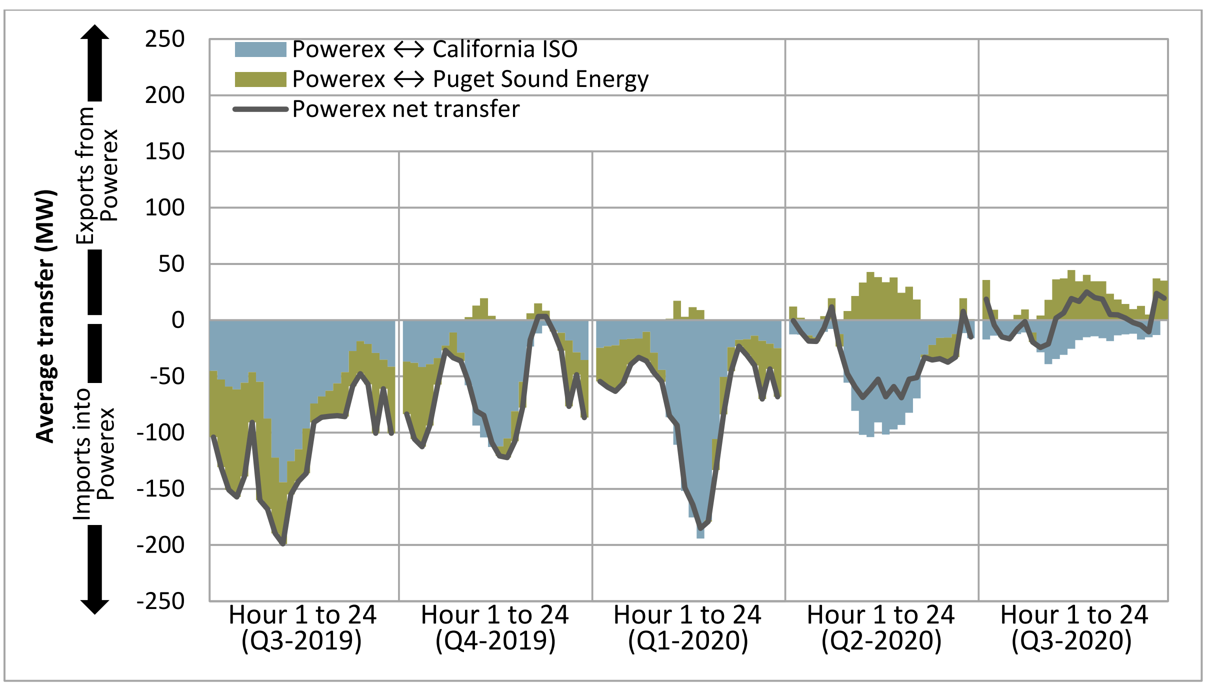


Figure 2.14 Portland General Electric – average hourly 15-minute market transfer

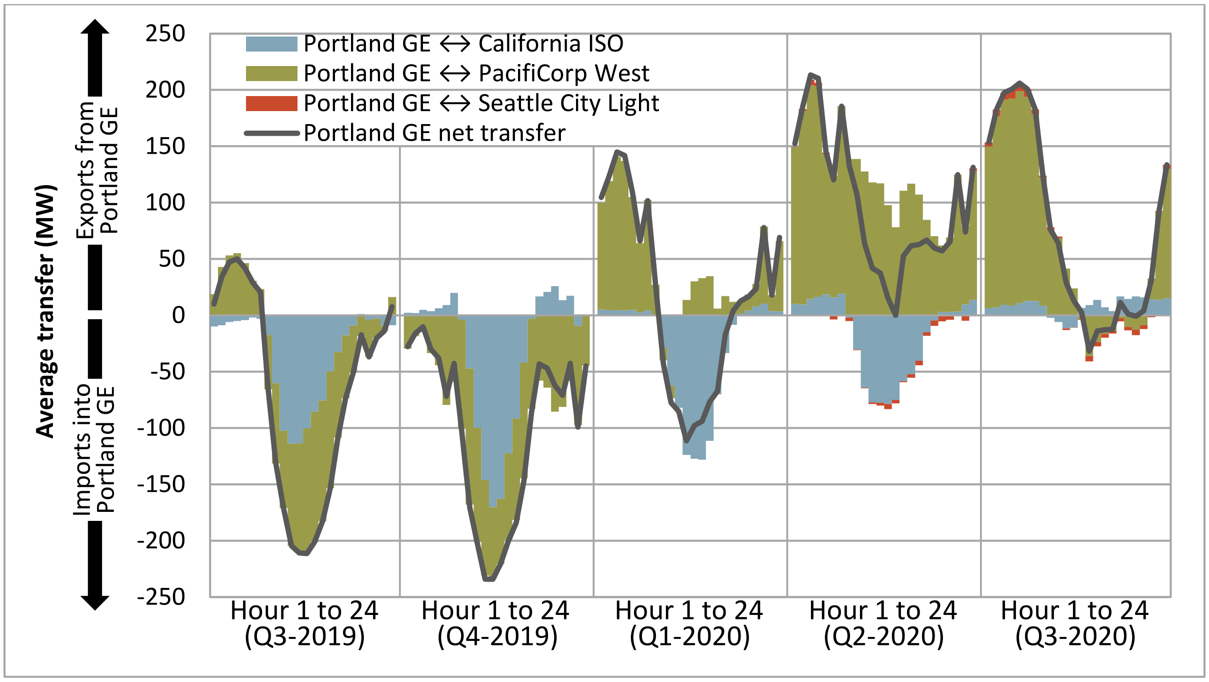
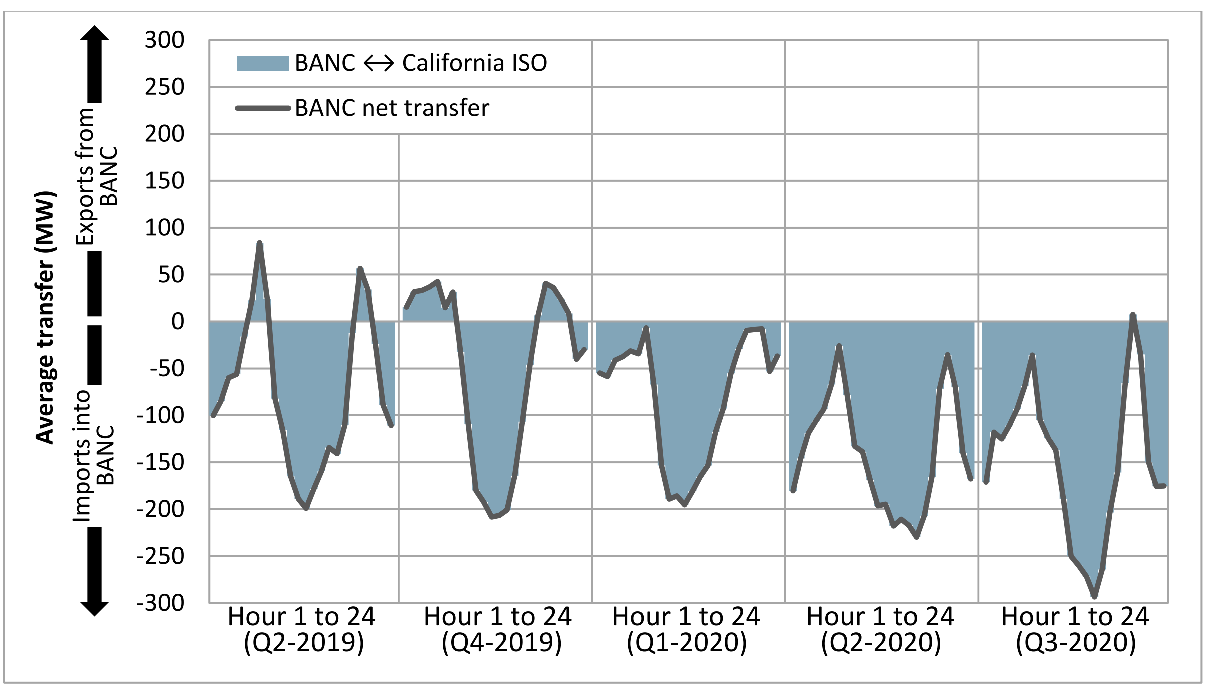


Figure 2.15 Balancing Authority of Northern California - average hourly 15-minute market transfer



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.[80]

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.[81] 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 (July – September)

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	1%	0%	0%	1%
NV Energy	2%	4%	1%	4%
Arizona Public Service	2%	0%	1%	1%
PacifiCorp East	6%	1%	3%	1%
Idaho Power	6%	0%	3%	0%
Salt River Project	6%	4%	6%	4%
PacifiCorp West	34%	4%	22%	3%
Portland General Electric	41%	9%	32%	4%
Seattle City Light	37%	6%	29%	4%
Puget Sound Energy	37%	6%	28%	4%
Powerex	55%	6%	47%	6%

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

80 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.

81 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 41 percent of intervals on average during the quarter. This is higher than the previous quarter when congestion from these areas occurred during 32 percent of intervals on average.

The highest frequency of net import congestion (such that the ISO market software triggers local market power mitigation in that area) occurred in the Portland General Electric area, during 9 percent of 15-minute market intervals and 4 percent of 5-minute market intervals during the third quarter.

Table 2.3 also shows that congestion in either direction for the BANC, NV Energy, Arizona Public Service, PacifiCorp East, Idaho Power, and Salt River Project areas was relatively infrequent during the third quarter. Congestion that did occur for 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 third quarter.[82] The same data for the ISO is provided as a point of reference. In particular, Arizona Public Service entered positive imbalance conformance in around 34 percent of 15-minute and 5-minute intervals, at an average of around 74 MW. Seattle City Light entered negative imbalance conformance in around 17 and 70 percent of 15-minute and 5-minute intervals, respectively, at an average of around 21 MW in each. Nearly all EIM entities had a greater frequency of 5-minute market imbalance conformance than 15-minute market during the quarter.

[82] 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 (July – September)

	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	44%	782	2.4%	2%	-267	1.0%	338
5-minute market	49%	291	1.0%	20%	-207	0.8%	101
PacifiCorp East							
15-minute market	0.0%	50	0.7%	3%	-53	1.0%	-1
5-minute market	12%	80	1.2%	25%	-87	1.5%	-12
PacifiCorp West							
15-minute market	0.1%	25	1.3%	2%	-44	2.2%	-1
5-minute market	5%	42	1.5%	14%	-46	2.1%	-4
NV Energy							
15-minute market	3%	96	1.3%	0.2%	-56	0.9%	3
5-minute market	8%	97	1.4%	4%	-84	1.8%	4
Puget Sound Energy							
15-minute market	0.2%	45	1.5%	14%	-32	1.4%	-4
5-minute market	3.1%	34	1.2%	44%	-40	1.8%	-16
Arizona Public Service							
15-minute market	34%	74	1.4%	50%	-79	1.8%	-14
5-minute market	34%	74	1.5%	50%	-79	1.8%	-15
Portland General Electric							
15-minute market	0.1%	30	0.9%	1%	-31	0.9%	0
5-minute market	20%	26	1.1%	1%	-53	2.1%	4
Idaho Power							
15-minute market	1%	53	1.9%	8%	-51	2.3%	-3
5-minute market	3.7%	50	2.0%	16%	-53	2.4%	-7
BANC							
15-minute market	0.7%	43	2.2%	0.2%	-59	5.2%	0
5-minute market	3%	31	1.7%	2%	-35	2.5%	0
Seattle City Light							
15-minute market	0.1%	27	2.6%	17%	-21	2.5%	-4
5-minute market	2%	24	2.7%	70%	-21	2.4%	-14
Salt River Project							
15-minute market	3%	62	1.0%	0.7%	-55	1.4%	2
5-minute market	8%	69	1.1%	2%	-60	1.4%	4

2.5 Greenhouse gas in the Western EIM

In the third quarter, weighted 15-minute and 5-minute greenhouse gas prices declined compared to the same quarter last year. This is likely 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.[83] 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.[84] The amount of capacity that can be deemed delivered to California has been since limited to the upper economic bid limit of a resource minus the resource's base schedule.

Greenhouse gas prices

Figure 2.16 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.

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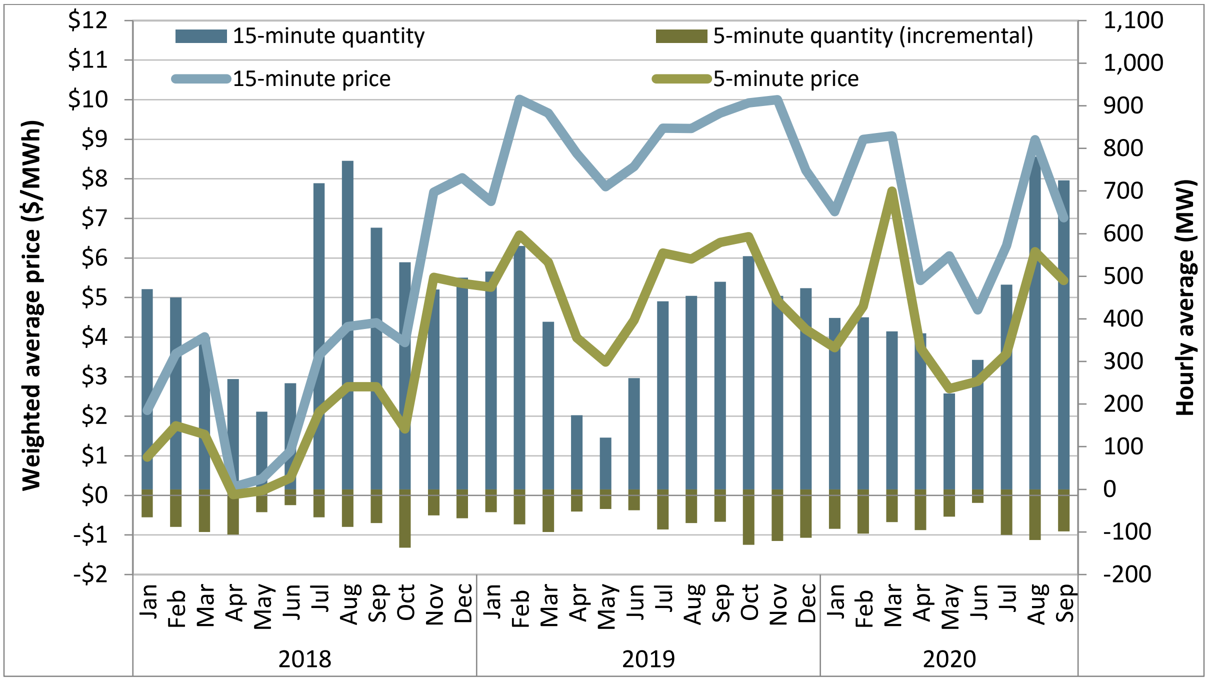
[83] Further information on energy imbalance market entity obligations under the California Air Resources Board cap-and-trade regulation is available in a posted FAQ on ARB's website here: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/eim-faqs.pdf.

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

Figure 2.16 Energy imbalance market greenhouse gas price and cleared quantity



Weighted 15-minute greenhouse gas prices averaged around $7/MWh for the third quarter while 5-minute prices averaged about $5/MWh. Prior to the policy change in November 2018, monthly greenhouse gas prices from January to October of that year averaged around $2.75/MWh in the 15-minute market and $1.40/MWh in the 5-minute market. Since the policy change in 2018, greenhouse gas prices have increased overall. The increase in greenhouse gas prices is due in part to higher emitting resources setting the price which was, in turn, likely the result of policy changes limiting the energy imbalance market capacity that can be deemed delivered to California as the upper economic bid limit of a resource minus their base schedule.

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 third quarter. In the third quarter, the price difference between the 15-minute and 5-minute markets decreased to about $2/MWh, compared to about $3/MWh in the same quarter of the previous year. This price separation is often correlated with imbalance conformance in California (described in Section 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 the 5-minute market. After November 2018, prices around $7/MWh occur frequently and some prices are set higher than the highest cleared bid. Figure 2.17 and Figure 2.18 show the frequency of high prices and maximum price by quarter for each market since 2018. In the third quarter, 26 intervals in the 15-minute market and 40 intervals in the 5-minute market exceeded $18/MWh. In the third quarter the highest 15-minute price was $708.86/MWh and the highest 5-minute price was $37.33/MWh which is significantly higher than the highest bid-in offer.

Figure 2.17 High 15-minute EIM greenhouse gas prices

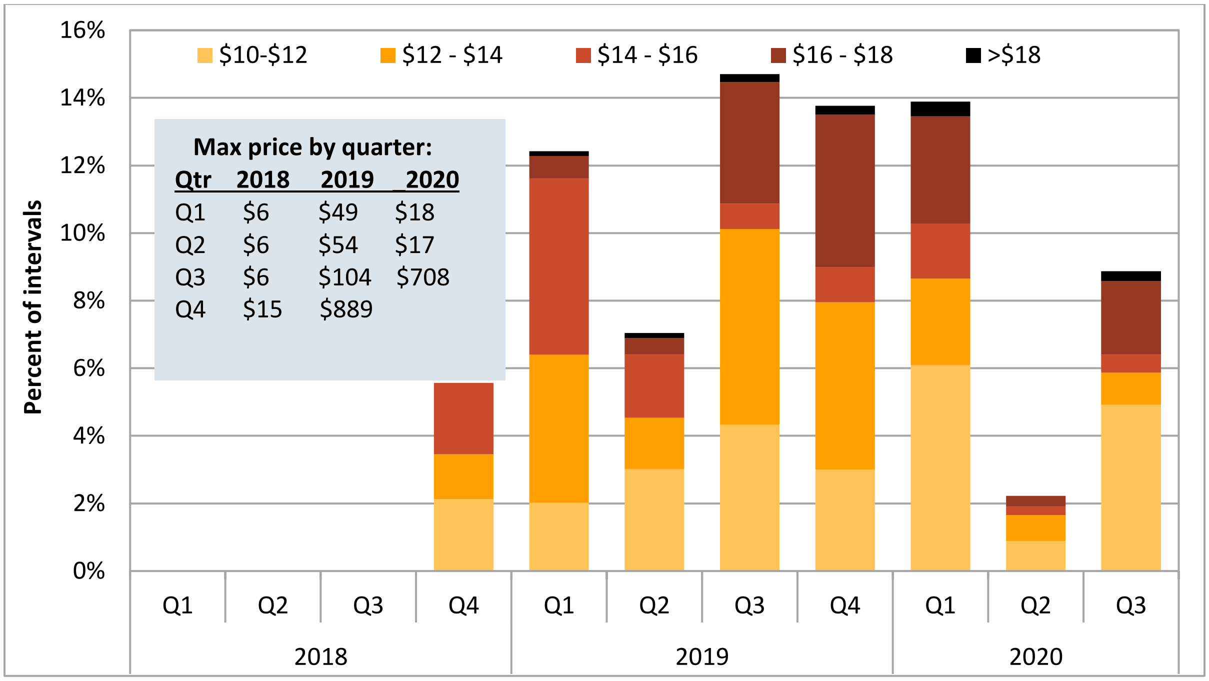
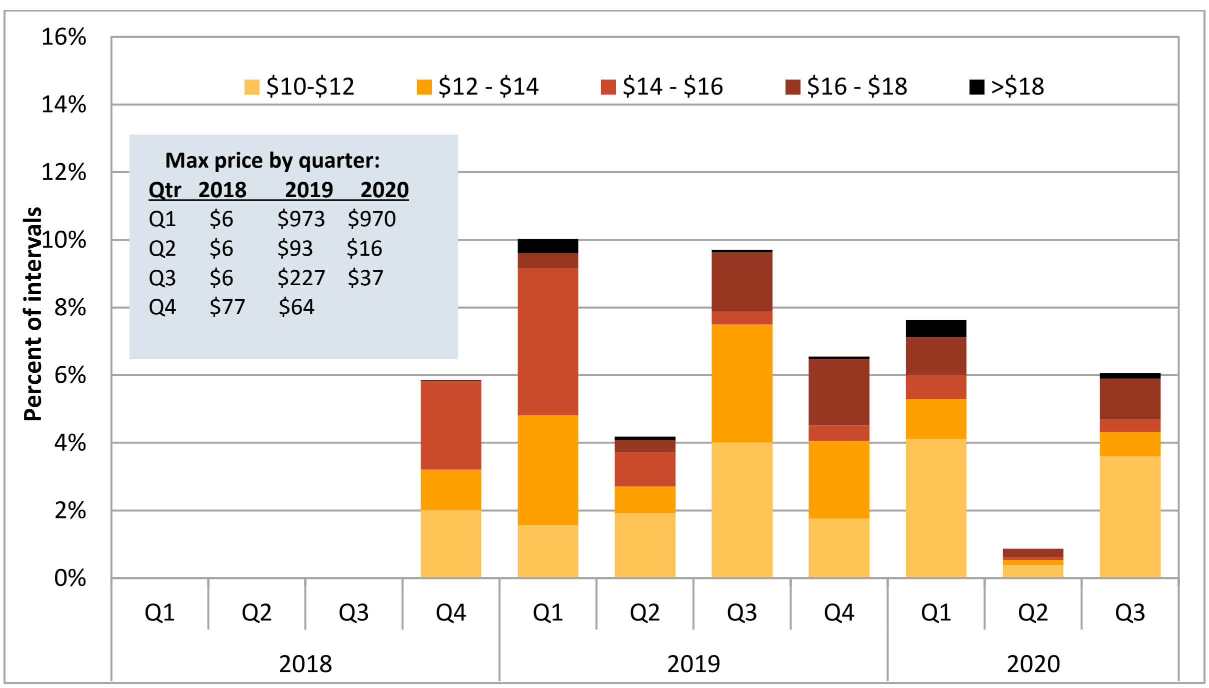


Figure 2.18 High 5-minute EIM greenhouse gas prices

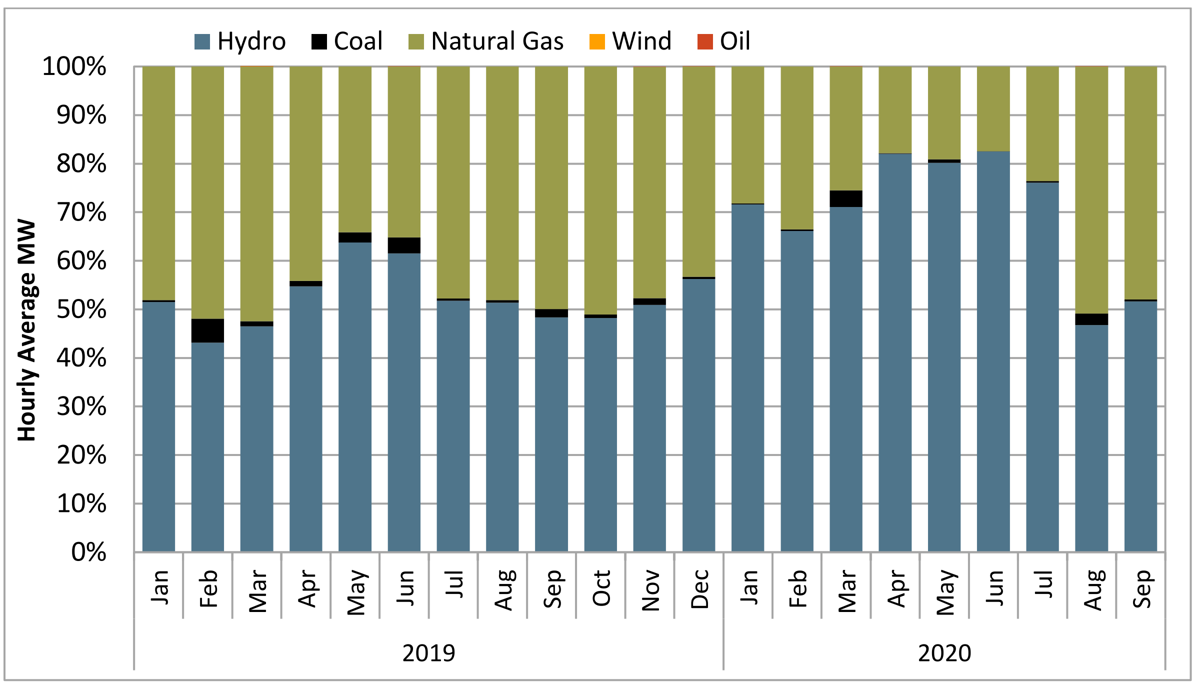


DMM estimates the total revenue accruing for greenhouse gas bids attributed to EIM participating resources serving the ISO load before subtracting estimated compliance costs from greenhouse gas revenue calculated in each interval. This value totaled around $12.1 million in the third quarter, compared to roughly $10.2 million in the same quarter of the previous year.

Energy delivered to California by fuel type

Figure 2.19 shows the hourly average energy deemed delivered to California by fuel type and by month. In the third quarter, about 44 percent of EIM greenhouse gas compliance obligations were awarded to gas resources, roughly about the same amount in the third quarter of the previous year. Hydroelectric resources accounted for about 55 percent of total energy delivered to California which increased slightly from around 50 percent in the same quarter of 2019. Additionally, energy originating from coal resources has increased since the policy change, but only accounted for about 1 percent of energy delivered in the third quarter, about the same amount as in the third quarter of 2019.

Figure 2.19 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 third 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 2.20 and Figure 2.21 highlight the volume of 15-minute and 5-minute market mitigation in all the balancing authority areas in the EIM:

- Blue bars in Figure 2.20 and Figure 2.21 show average incremental energy subject to mitigation but with no change in bids in the 15-minute and 5-minute markets, respectively. In the third quarter of 2020, this portion has slightly increased during August and September when compared to the same months in 2019.

- A small volume of bids were lowered as a result of mitigation in the Western EIM.

Figure 2.20 Average incremental energy mitigated in 15-minute real-time market (EIM)

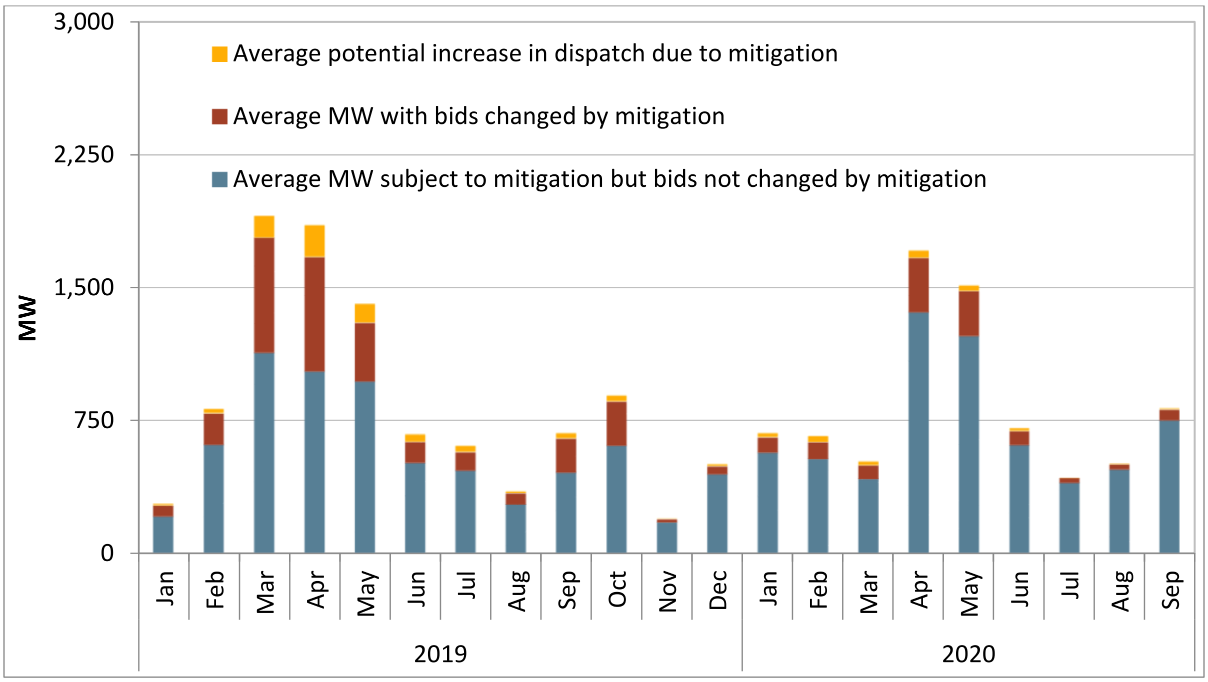
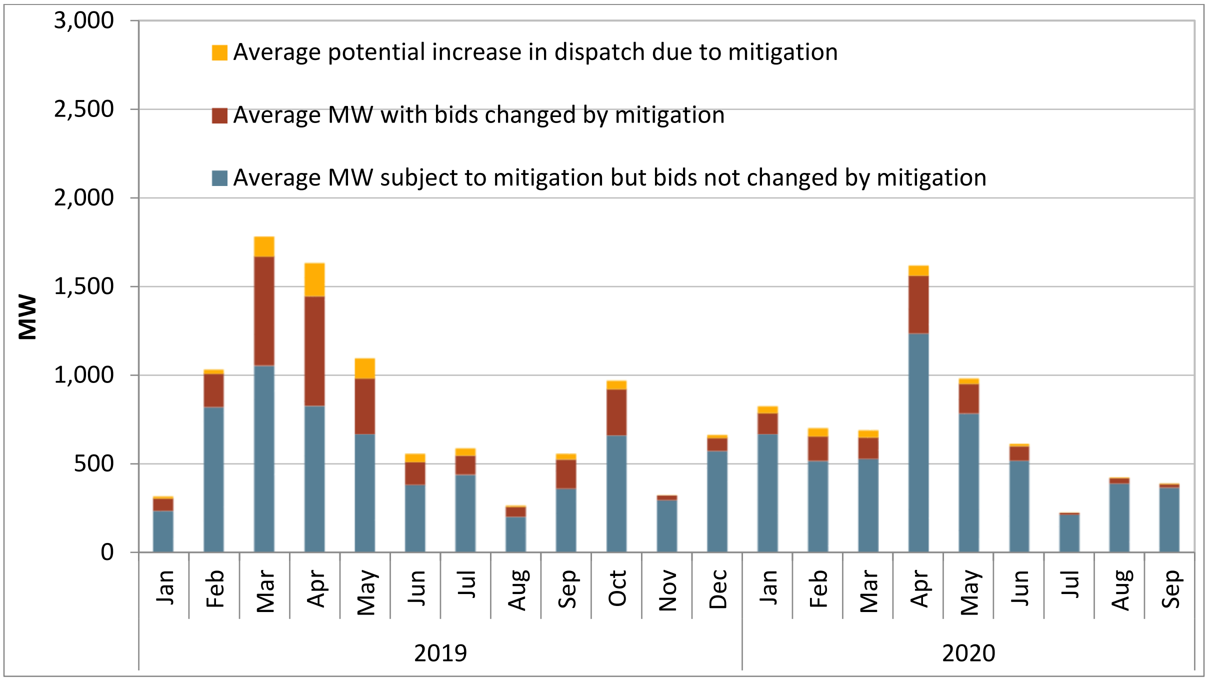


Figure 2.21 Average incremental energy mitigated in 5-minute real-time market (EIM)



3 Special issues

This section provides information about the following special issues:

- **Rotating outages in mid-August** were not the result of any single factor. Instead, a combination of factors led to the extraordinary market events of this period including resource adequacy and forward planning processes which allowed load serving entities to procure less generation than was required to serve load during an atypically high, widespread, and extended heat wave. Conditions were exacerbated by ISO market practices which allowed exports to increase demand to a level not supported by physical generation.
- **Under-scheduled load** was cited by the ISO/CPUC/CEC root cause analysis as one of the factors contributing to load curtailment on August 14 and 15 and tight system conditions on the days following. Analysis of newly available meter data shows that community choice aggregators were responsible for half of the under-scheduling on days with load curtailment and most under-scheduling on the following days.
- **Cleared hourly block imports** received higher revenues by being compensated at the 15-minute price than they would have received had they been compensated at the hour-ahead price, on average over the quarter.
- **Resource adequacy showings and performance were similar, although load was higher**, in the top 210 load hours in Q3 2020 compared to Q3 2019. In both years, 43 percent of the obligation was met by resources with a 24 hour bid obligation and 92 percent of this capacity bid into the real-time market. A lower percentage of the remaining resource adequacy capacity bid into the real-time market: 86 percent in 2020 and 85 percent in 2019.
- **Demand response resources**, which counted for 1,847 MW of resource adequacy in August and 1,769 MW of resource adequacy in September, self-reported performance of 73 to 77 percent in hours of load curtailment. Based on supplier-submitted baseline and meter data, there is some evidence that baseline adjustments could have been limited in the upward direction by defined baseline adjustment caps on these days, possibly increasing performance.
- **The standalone battery fleet** was scheduled primarily for ancillary services and flexible ramping rather than energy, but was scheduled to provide energy more frequently in real-time than in prior quarters, particularly on high load days in August and September in the third quarter.
- **The CAISO market was structurally uncompetitive** during the high load days in August. During the third quarter, the number of hours with an RSI less than one increased significantly. For every hour of potential scarcity, there are many hours of potential system market power.
- **Market results were competitive in the third quarter**. DMM estimates that the impact of gas and import resources bidding above reference levels, a conservative measure of the average price-cost markup, was about $1.42/MWh or about 2.6 percent, an increase from the $0.66/MWh or 3 percent for the previous quarter.
- **System wide mitigation of imports and gas-fired resources would not have lowered prices**. Although prices were very high during the high load days in August, analysis using the CAISO's day-ahead market software indicates that system wide mitigation of imports and gas-fired resources

during this period would not have lowered prices. This reflects the fact that gas-fired and other resources that may be subject to mitigation were generally infra-marginal in re-runs of the day-ahead market using cost-based bids, and that high prices were set by demand response and other resources not subject to mitigation.

- **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.

- **Downward dispatch of renewable resources was higher** in both the ISO and the EIM for the third quarter compared to the same quarter of 2019. Downward dispatch, often called curtailment, was most often the result of economic downward dispatch rather than self-schedule curtailment.

3.1 Load curtailment event

Regional high temperatures led to a high demand heat wave across the entire western region in mid-August and again over the Labor Day weekend. On August 14 and 15, CAISO grid operators called upon participating transmission owners to curtail load due to system-wide conditions for the first time since 2001. In the following days and weeks, CAISO loads remained high but were well below forecasted levels, due largely to voluntary conservation efforts. Prices in the CAISO, the Western EIM, and bilateral markets reached record levels on August 17-19, but no further load curtailments occurred.

There was no single cause of the rotating outages. Instead, a combination of factors led to the extraordinary market events of this period including resource adequacy and forward planning processes which allowed load serving entities to procure less generation than was required to serve load during an atypically high, widespread, and extended heat wave. Conditions were exacerbated by ISO market practices which allowed exports to increase demand to a level not supported by physical generation. Further discussion of these factors is available in a special report published by DMM and in both a preliminary and final root cause analysis issued by the ISO, CPUC, and CEC.[85]

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[85] DMM report: *Report on Market Conditions, Issues and Performance – August and September 2020*, November 24. 2020. http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

DMM agrees with many of the key recommendations related to resource adequacy in the CAISO/CPUC/CEC reports and supports the coordinated efforts by the CAISO, CPUC, and stakeholders to make the various planning, market design, and operational enhancements identified in these reports. The most significant and actionable of these recommendations involve California's resource adequacy program. To limit the potential for similar resource shortages in future years, a high priority should be placed on the following two recommendations:

- ***Increase resource adequacy requirements to more accurately reflect increasing risk of extreme weather events*** (e.g., beyond the 1-in-2 year load forecast and 15 percent planning reserve margin currently used to set system resource adequacy targets). Prior to this summer, CAISO peak load fell under the 1-in-2 years forecast four of the last five years.[86] However, summer 2020 illustrates that higher reliability will require that resource adequacy requirements be based on load forecasts which reflect the high likelihood of much higher load conditions than are reflected in the 1-in-2 year forecast.

- ***Continue to work with stakeholders to clarify and revise the resource adequacy capacity counting rules,*** especially as they apply to hydro resources, demand response resources, renewable resources, imports, and other use-limited resources. Counting rules should specifically take into account the availability of different resource types during the net load peak. Beginning in 2019, DMM has provided analysis and expressed concern in reports and CPUC filings about the cumulative impacts of various energy-limited or availability-limited resources which are being relied upon to meet an increasing portion of resource adequacy requirements.[87] This report includes additional analysis of the availability of different resource types during the peak net load hour in which load was curtailed in August, and highlights a variety of specific factors which could be incorporated into the resource adequacy ratings of these resources to better reflect their actual availability during the most critical net load peak hours.

In addition, DMM provides the following recommendation regarding the issue of exports.

- ***DMM recommends that further changes and clarifications in the rules and processes for limiting or curtailing exports be discussed and pursued by the CAISO in conjunction with other balancing areas.***

Preliminary root cause analysis: *Preliminary Root Cause Analysis: Mid-August 2020 Heat Storm*, October 6, 2020, prepared by the California Independent system Operator, California Public Utilities Commission and California Energy Commission. http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf. Preliminary CAISO/CPUC/CEC report

Final root cause analysis: *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*, January 13, 2020, prepared by the California Independent system Operator, California Public Utilities Commission and California Energy Commission. http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

86 *2019 Annual Report on Market Issues and Performance*, Department of Market Monitoring, June 2020, pp.34-35. http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

87 *2019 Annual Report on Market Issues and Performance,* pp. 26-27, 299-302.

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

The preliminary CAISO/CPUC/CEC report includes the following recommendation regarding curtailment of exports:

> Ensure that market processes appropriately curtail lower priority exports that are not supported by non-resource adequacy resources to minimize the export of capacity that could be related to RA resources during reliability events.[88]

Just prior to the Labor Day weekend heatwave, the ISO made important enhancements to the residual unit commitment process and the real-time scheduling priority of day-ahead energy market export schedules that do not receive RUC awards. DMM supported these changes and believes that these changes played a key role in helping to improve real-time supply conditions on September 5 to 7.

DMM's understanding is that CAISO's current policy is still to prioritize exports that receive RUC awards over native CAISO balancing area load in real-time. DMM appreciates that curtailment of exports should be avoided when possible, given the potentially detrimental direct and indirect impacts of export curtailment on other balancing areas and the CAISO itself, as discussed in the preliminary CAISO/CPUC/CEC report.[89] However, DMM believes that additional changes and clarifications to the residual unit commitment rules and other market processes are needed to address the issue of exports.[90]

The rules and processes for limiting or curtailing exports used by the CAISO and other balancing areas should be reviewed, clarified, and potentially modified -- with a goal of establishing equal treatment and expectations of exports by all balancing areas. CAISO and other WECC balancing areas' ultimate policy on the priority of exports relative to native load will be a critical factor in CPUC resource adequacy reforms and many major CAISO market design initiatives. These include the extended day-ahead market, day-ahead market enhancements, system market power mitigation phase 2, resource adequacy enhancements, scarcity pricing, and refinements to export bidding rules. Further discussion of the need to clarify and potentially refine how CAISO and other balancing areas treat exports is provided in the final section of this report.

Finally, DMM provides the following recommendation regarding the demand response.

- ***DMM recommends that steps be taken to ensure a higher portion of demand response used to meet resource adequacy requirements is available during critical net load hours.***

DMM recommends that steps be taken to ensure the availability of these resources. These steps include (1) re-examining demand response counting methodologies, (2) adopting the ISO's recommendation to remove the planning reserve margin adder applied to demand response capacity counted towards system resource adequacy requirements under the CPUC jurisdiction, and (3) adopting a process to manually dispatch available demand response shown on resource adequacy supply plans before issuing

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88 Preliminary CAISO/CPUC/CEC Report, p. 66.

89 Preliminary CAISO/CPUC/CEC Report, pp. 106-107.

90 Further discussion is available in DMM's comments on two recent stakeholder workshops: *Comments on Market Enhancements for Summer 2021 Readiness Stakeholder Workshops*. January 12-13, 2021, Department of Market Monitoring, January 21, 2021. http://www.caiso.com/Documents/DMMCommentsonMarketEnhancementsSummer2021Readiness-Jan12-13Workshops-Final.pdf

exceptional dispatches to non-resource adequacy capacity and curtailing firm load. DMM recommends that these steps be taken before expanding reliance on demand response capacity.

A more detailed discussion of resource performance and recommendations relating to demand response is provided in Section 3.5 of this report.

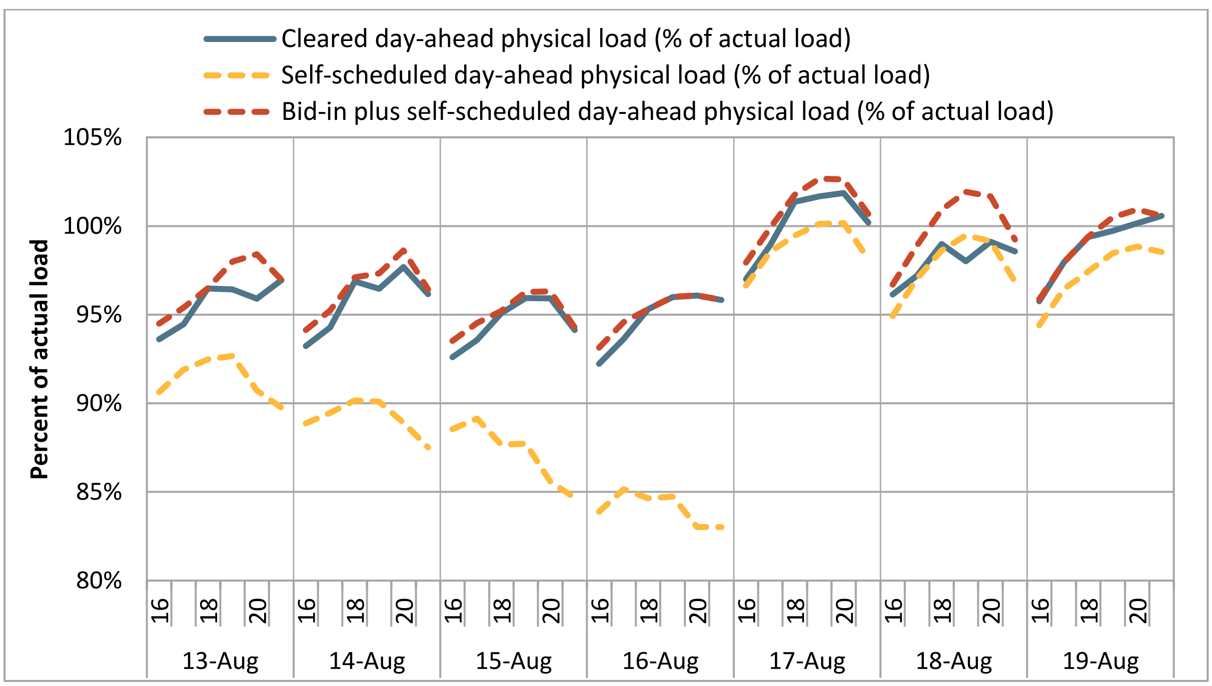
3.2 Under-scheduling of load during the August heatwave

DMM previously reported on the extent of load under-scheduling in the day-ahead market during the August and September heatwaves, comparing physical load schedules in the day-ahead market against the day-ahead load forecast and real-time market requirement. The section below is an extension of that analysis, based on recent availability of final settlement-quality meter data, or “actual” load.

Figure 3.1 shows self-scheduled, bid-in, or cleared day-ahead market load as a percent of actual load during the evening hours of August 13 to 19. Below 100 percent reflects under-scheduling while over 100 percent reflects over-scheduling relative to actual load.

- Cleared physical load schedules averaged about 95 percent of actual load during the evening hours of August 13 to August 16, and about 99 percent of actual load during the evening hours of August 17 to 19.
- Beginning on Monday, August 17, load serving entities significantly increased the portion of actual load that was self-scheduled in the day-ahead market. Self-scheduled load averaged about 88 percent of actual load in the evening hours prior to August 16, compared to 98 percent of hours after.

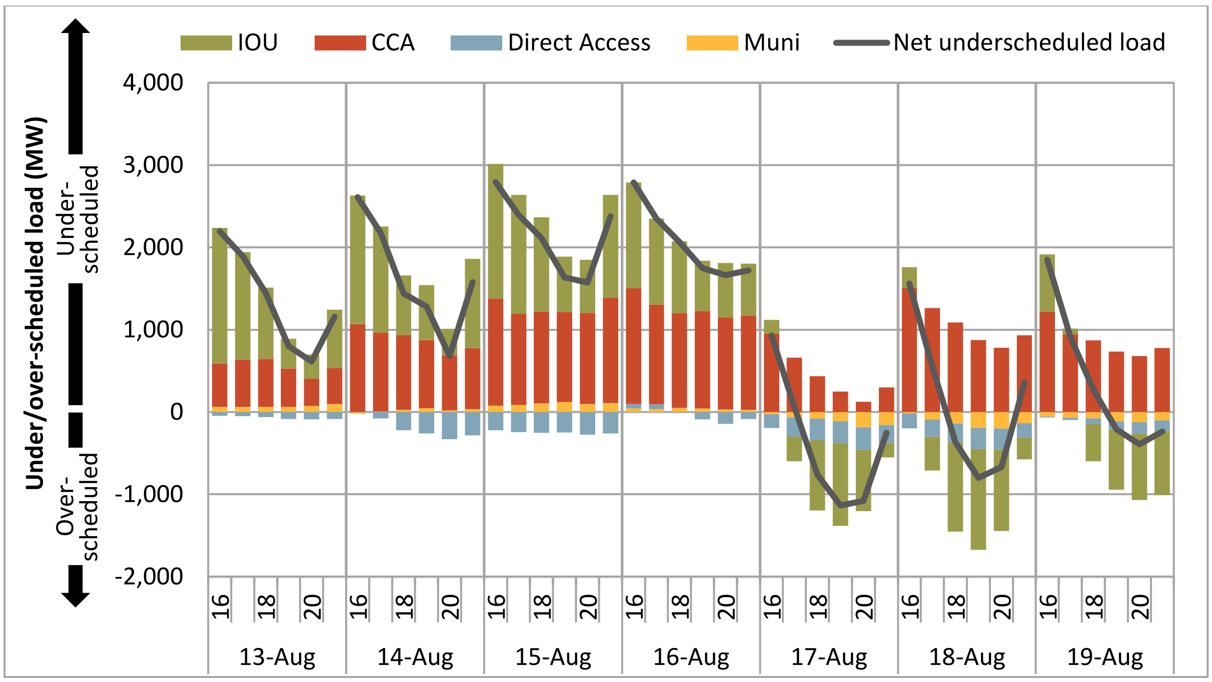
Figure 3.1 Self-scheduled, bid-in, or cleared load as a percent of settled load (August 13 – August 19)



The following section looks at the volume of under-scheduled load during the August heatwave by load serving entity type, either community choice aggregator (CCA), direct access service, investor-owned utility (IOU), or municipal/government (Muni) entity. Figure 3.2 shows net under-scheduled load by entity type during the evening hours of August 13 to August 19.[91] Here, under-scheduled megawatts are calculated as the difference between (1) actual load and (2) day-ahead self-scheduled or bid-in load.

Between August 13 and August 16, community choice aggregators and investor-owned utilities each contributed to roughly half of the under-scheduled load that existed in the evening peak load hours. However, community choice aggregators self-scheduled or bid-in about 91 percent of actual load, compared to 99 percent for investor-owned utilities during this period. For the evening hours between August 17 and August 19, investor-owned utilities largely contributed to over-scheduling on net, while community choice aggregators contributed to the majority of under-scheduling.

Figure 3.2 Net under-scheduled load by entity type



3.3 Hourly block import compensation

The ISO has proposed a set of measures to be implemented before the summer of 2021 to lessen the probability of recurring outages.[92] One measure would add bid cost recovery provisions for hourly block

91 Under-scheduling associated with auxiliary or pump load were omitted from this chart, but was minor.

92 *Market Enhancements for Summer 2021 Readiness*, CAISO presentation given January 6, 2021. http://www.caiso.com/InitiativeDocuments/Presentation-MarketEnhancements-Summer2021Readiness-Jan6-2021.pdf

imports during tight system conditions. Hourly block imports are scheduled in the hour-ahead market, but compensated at the 15-minute market price in each interval, rather than the hour-ahead price at which they are scheduled.

On average in the third quarter, cleared hourly block imports received higher revenues by being compensated at the 15-minute price than they would have received had they been compensated at the hour-ahead price. The red bars in Figure 3.3 represent the lost revenue that would have resulted had cleared hourly block imports been compensated at the hour-ahead price rather than the 15-minute price. The blue bars represent a positive change in revenue and the grey dotted line shows the net value of both positive and negative changes in revenue.

As noted in DMM's comments on the summer readiness initiative, although provisions to allow recovery of losses may not be warranted during most hours, changes may be warranted for high demand hours.[93] As shown in Figure 3.4, hourly block imports cleared during the high demand period would have had higher revenues if compensated at the hour-ahead price in some hours but not others. On net for hours shown,[94] fifteen minute market price revenue exceeds hour-ahead price revenue. Monitoring metrics included here do not account for hourly block imports that were not offered into the market or that failed to clear. A bid cost recovery or pay-as-bid option for hourly block imports could be warranted in the very limited number of hours when the contracted resource adequacy fleet may not be sufficient to meet CAISO load and reserve requirements.

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93 *Comments on Market Enhancements for Summer 2021 Readiness January 6, 2021 Stakeholder Call* Department of Market Monitoring, January 14, 2021. http://www.caiso.com/Documents/DMMCommentsonMarketEnhancementsSummer2021ReadinessJanuary6StakeholderCall.pdf

94 No data available for August 18, 2020 hour-end 19 for the hour-ahead market run (HASP) due to a market disruption. https://www.caiso.com/Documents/2710.pdf

Figure 3.3 2020 Q3 intertie hour-ahead versus 15-minute compensation ($ million)

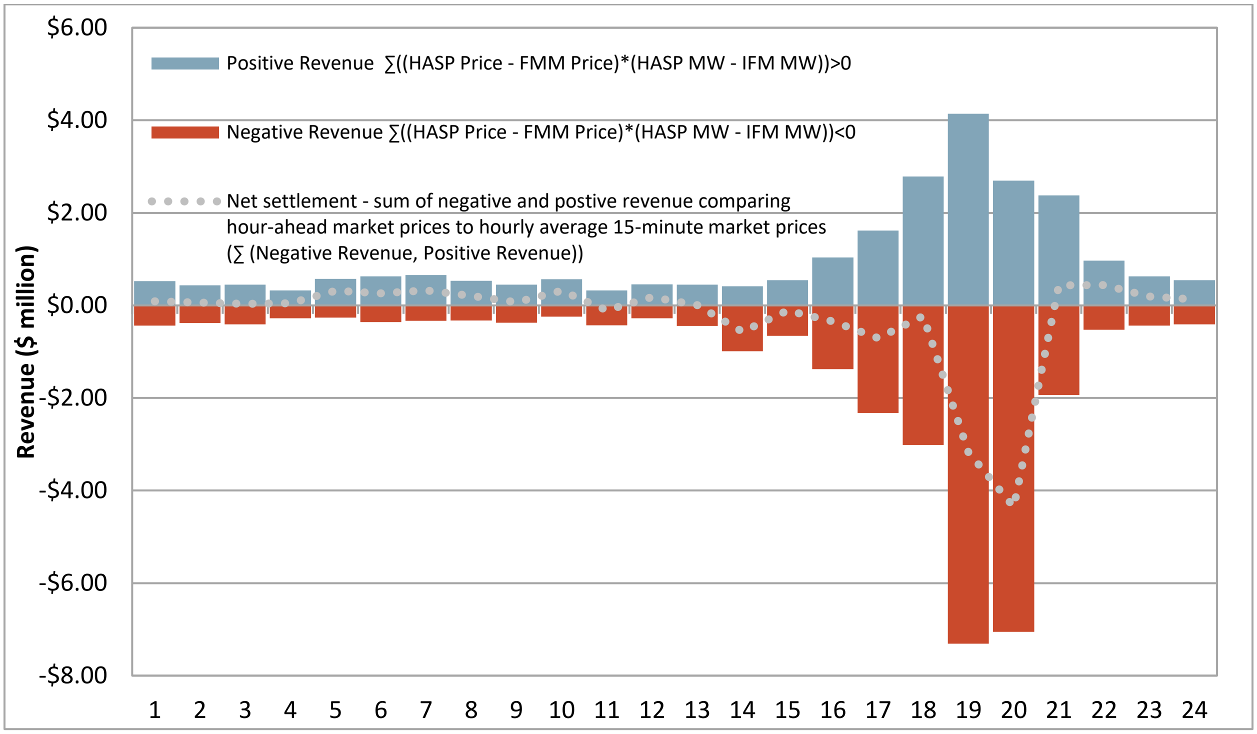
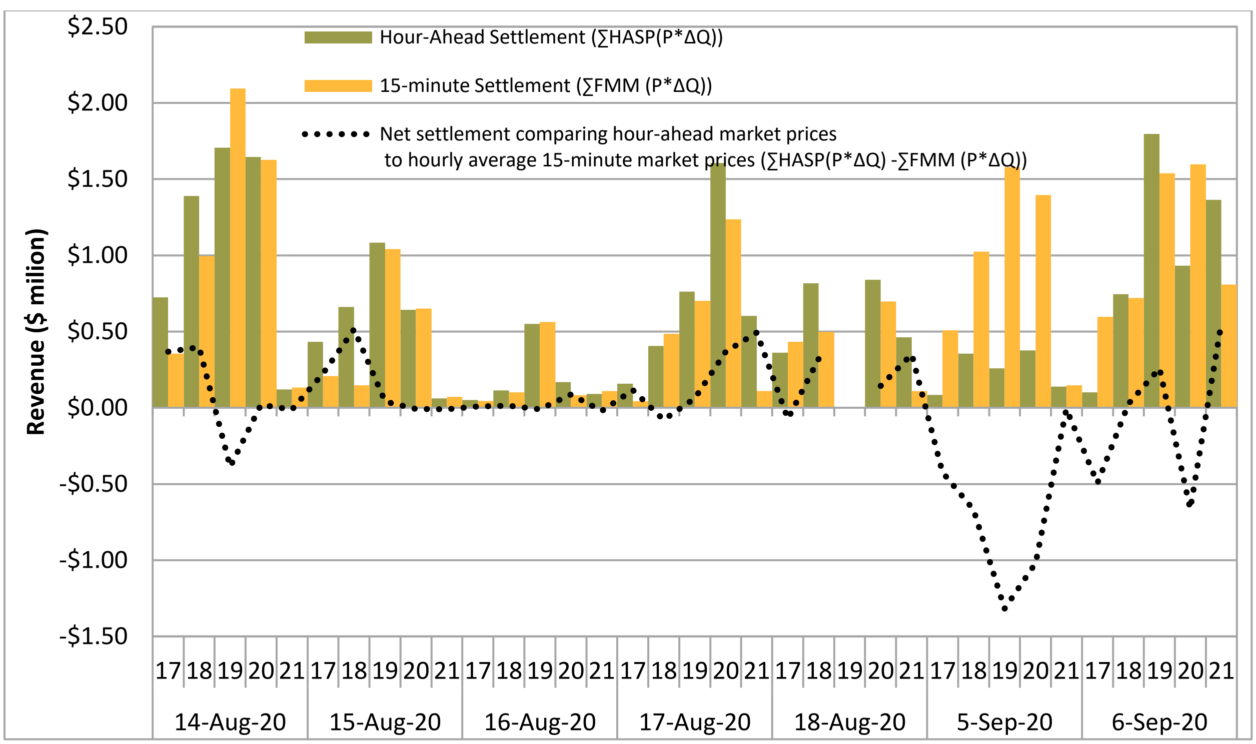


Figure 3.4 Intertie hour-ahead versus 15-minute compensation



3.4 Resource adequacy performance

DMM analyzed the availability of resource adequacy capacity in the market during the peak load hours of the August and September heatwaves, with a focus on hours when load was shed, in a report on system and market conditions, issues, and performance.[95] Analysis in this section is broader and focuses on the availability of resource adequacy capacity during high load hours of the entire third quarter. This analysis does not include bids and transfers from EIM entities. Due to data availability, this analysis includes bid availability from the entire resource adequacy fleet except for legacy reliability must-run and utility demand response resources.[96]

System resource adequacy requirements are set based on system-level peak demand. In California, yearly peak demand typically occurs in the third quarter during the summer months. Due to the increased level of variable energy resources in the California fleet, the CPUC sets rules to ensure each load serving entity's procured capacity portfolio is well balanced in terms of resource availability. For instance, there is a cap on maximum percentage of a load serving entity's resource adequacy portfolio that can come from resources with the most restricted availability – those that can be offered for a minimum of 210 hours from May until September each year.[97] The following analysis shows the availability of capacity that was used to meet system resource adequacy requirements as measured by bids into the day-ahead and real-time markets during the top 210 highest average load hours in the quarter.

Day-ahead market bids include energy bids and non-overlapping ancillary service bids; real-time market bids include energy bids only.[98] Bids are capped at the resource adequacy capacity values shown for individual resources to measure the availability of capacity that was secured in the planning timeframe. Bids are also capped according to individual resource outages and derates. While the analysis below includes available resource adequacy bids at the system level, congestion and operating constraints may prevent the market from actually utilizing all of the bid capacity in this analysis.

Figure 3.5 shows average hourly metered load levels for the 210 hours with the highest load in the third quarter of the past two years. Further, Table 3.1 and Table 3.2 show how much resource adequacy capacity was procured during these hours, on average. Load during the highest load hours of this quarter in 2020 was significantly higher than 2019; the top 80 load hours in 2020 were 500-2,500 MW

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95 For more information, refer to the *Report on system and market conditions, issues and performance: August and September 2020*, DMM, November 24, 2020: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

96 For more information on the availability of legacy reliability must-run and utility demand response resource adequacy capacity during the heatwaves, refer to DMM's report on system and market conditions, issues and performance (see Footnote 95). Demand response resource adequacy performance is further analyzed in Section 3.5 of this report as well.

97 This requirement is based off of the Maximum Cumulative Capacity categories for non-demand response resources. The cumulative total of 210 hours is comprised of minimum monthly requirements of 30, 40, 40, 60, and 40 hours for May through September, respectively. For more information, refer to the *2020 Filing guide for system, local, and flexible resource adequacy (RA) compliance filings*, CPUC, July 21, 2020: https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442462872

98 To calculate hourly real-time bid amounts, bids from variable energy resources were averaged over the hour. Bids from non-variable energy resources reflect the maximum hourly bid in the hour-ahead, 15-minute, and 5-minute markets adjusted for derates, due to data issues.

higher than in 2019. Despite this, average procured resource adequacy capacity in 2020 (49,052 MW) was lower than in 2019 (49,348 MW). As discussed in DMM's heatwave analysis, the actual peak load exceeded the CEC's 1-in-2 year peak forecast used to set resource adequacy requirements and contributed to the capacity shortfalls experienced during the quarter. DMM recommends increasing resource adequacy requirements to more accurately reflect increasing risk of extreme weather events.

Figure 3.5 Average hourly load for the top 210 load hours in the third quarter

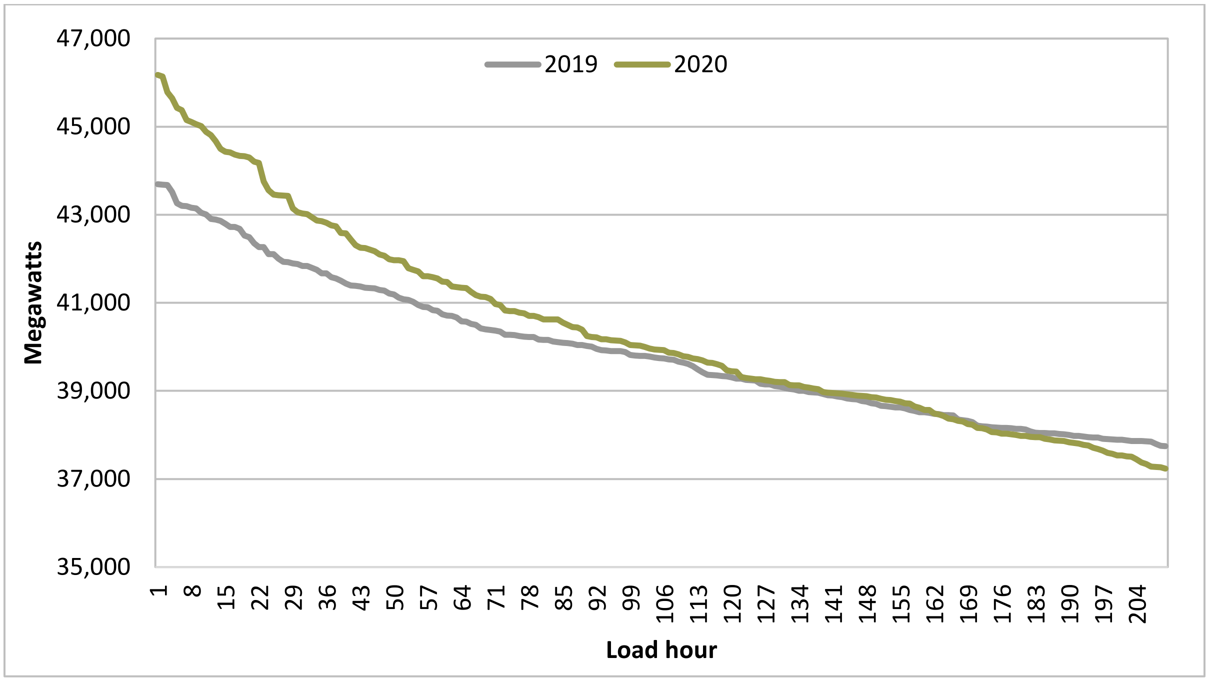


Table 3.1 and Table 3.2 list the average hourly availability of resource adequacy capacity in the day-ahead and real-time markets during the top 210 load hours of the third quarter in 2020 and 2019, respectively. These tables show resource adequacy capacity bids compared to the amount of capacity that was shown or credited towards resource adequacy obligations, by resource type. Bids and self-schedule megawatt totals for the day-ahead and real-time markets are derived by adjusting the bids and self-schedules of individual resources for outages and derates, capping bids by individual resource adequacy capacity values, and aggregating by fuel type.

As shown in the bottom row of the tables, resource adequacy capacity performed similarly in high load hours over the past two years. A small amount of procured capacity (between 3 and 5 percent) was on outage in the day-ahead market. About 91 to 92 percent of this capacity was bid or self-scheduled in the day-ahead market. This dropped slightly in the real-time market where 88 to 89 percent of procured capacity was bid or self-scheduled.

The similar performance of resource adequacy capacity in 2019 and 2020 suggests that the capacity shortfalls that occurred at times during the quarter were not due to atypical behavior from resource adequacy capacity. Instead, inadequate planning requirements, counting rules during the net load peak, as well as other non-resource adequacy related issues outlined in DMM's heatwave report contributed more to the problems.

Table 3.1 Average system resource adequacy capacity and availability by fuel type (210 highest load hours – third quarter 2020)

Resource type	Total resource adequacy capacity (MW)	Day-ahead market				Real-time market			
		Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
		MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.
Must-Offer:									
Gas-fired generators	19,659	18,572	94%	18,571	94%	18,190	93%	18,157	92%
Other generators	1,441	1,361	94%	1,361	94%	1,350	94%	1,350	94%
Subtotal	**21,100**	**19,933**	**94%**	**19,932**	**94%**	**19,540**	**93%**	**19,507**	**92%**
Other:									
Imports	4,475	4,437	99%	4,135	92%	4,463	100%	3,783	85%
Imports - MSS	331	331	100%	109	33%	331	100%	119	36%
Use-limited gas units	8,206	7,923	97%	7,890	96%	7,788	95%	7,729	94%
Hydro generators	6,491	5,836	90%	5,531	85%	5,720	88%	5,422	84%
Nuclear generators	2,818	2,776	99%	2,769	98%	2,776	99%	2,769	98%
Solar generators	2,937	2,923	100%	2,034	69%	2,907	99%	2,043	70%
Wind generators	1,191	1,177	99%	802	67%	1,174	99%	786	66%
Qualifying facilities	984	973	99%	819	83%	964	98%	830	84%
Other non-dispatchable	519	511	98%	471	91%	488	94%	468	90%
Subtotal	**27,952**	**26,887**	**96%**	**24,560**	**88%**	**26,611**	**95%**	**23,949**	**86%**
Total	**49,052**	**46,820**	**95%**	**44,492**	**91%**	**46,151**	**94%**	**43,456**	**89%**

Table 3.2 Average system resource adequacy capacity and availability by fuel type (210 highest load hours – third quarter 2019)

Resource type	Total resource adequacy capacity (MW)	Day-ahead market				Real-time market			
		Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
		MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.
Must-Offer:									
Gas-fired generators	19,646	18,720	95%	18,720	95%	18,251	93%	18,133	92%
Other generators	1,494	1,409	94%	1,409	94%	1,398	94%	1,398	94%
Subtotal	**21,140**	**20,129**	**95%**	**20,129**	**95%**	**19,649**	**93%**	**19,531**	**92%**
Other:									
Imports	4,535	4,507	99%	4,449	98%	4,510	99%	3,945	87%
Imports - MSS	312	312	100%	149	48%	312	100%	161	52%
Use-limited gas units	6,718	6,510	97%	6,422	96%	6,450	96%	6,251	93%
Hydro generators	6,546	6,278	96%	6,010	92%	6,209	95%	5,863	90%
Nuclear generators	2,872	2,852	99%	2,851	99%	2,847	99%	2,846	99%
Solar generators	4,141	4,131	100%	2,873	69%	4,085	99%	2,769	67%
Wind generators	1,618	1,612	100%	1,082	67%	1,610	100%	1,042	64%
Qualifying facilities	1,074	1,057	98%	877	82%	1,031	96%	864	80%
Other non-dispatchable	392	372	95%	358	91%	366	93%	361	92%
Subtotal	**28,208**	**27,631**	**98%**	**25,071**	**89%**	**27,420**	**97%**	**24,102**	**85%**
Total	**49,348**	**47,760**	**97%**	**45,200**	**92%**	**47,069**	**95%**	**43,633**	**88%**

In the highest load hours in the third quarter of 2020, about 43 percent (21,100 MW) of procured capacity was from resources with must-offer obligations such that the ISO inserts generated bids when they are missing. This is mostly composed of capacity from gas fired resources. A combined 19,900 and 19,500 MW, or 92-94 percent, of this capacity was bid or self-scheduled in the day-ahead and real-time markets.

About 28,000 MW (57 percent) of procured capacity during these hours in 2020 was from use-limited and variable energy resources. The biggest contributing fuel-type was use-limited gas resources (8,200 MW). These gas resources had high availability and bid or self-scheduled 94-96 percent of their designated capacity in the day-ahead and real-time markets. Considering the rest of capacity from partially shown resources above the amount that was procured during the planning process, resources in this category bid or self-scheduled 101 percent of resource adequacy capacity in the day-ahead and real-time markets.

Hydro generators accounted for about 6,500 MW of shown resource adequacy capacity in the high load hours of the third quarter. These resources bid or self-scheduled 84-85 percent of procured capacity into the day-ahead and real-time markets. Considering the rest of capacity from partially shown resources above the amount that was procured during the planning process, resources in this category bid or self-scheduled 92-94 percent of resource adequacy capacity in the day-ahead and real-time markets.

Non-resource-specific imports accounted for about 4,800 MW of shown resource adequacy capacity during these hours. This includes about 330 MW of non-resource-specific imports shown by load-following metered sub-system entities. These resources bid or self-scheduled 82-88 percent of procured capacity into the day-ahead and real-time markets. Considering the rest of capacity from partially shown resources above the amount that was procured during the planning process, resources in this category bid or self-scheduled 84-93 percent of resource adequacy capacity in the day-ahead and real-time markets.

Solar generators accounted for about 3,000 MW of shown resource adequacy capacity during these hours. These resources bid or self-scheduled 69-70 percent of procured capacity into the day-ahead and real-time markets. Considering the rest of capacity from partially shown resources above the amount that was procured during the planning process, resources in this category bid or self-scheduled 174 percent of resource adequacy capacity in the day-ahead and real-time markets.

Wind generators accounted for about 1,200 MW of shown resource adequacy capacity during these hours. These resources bid or self-scheduled 66-67 percent of procured capacity into the day-ahead and real-time markets. Considering the rest of capacity from partially shown resources above the amount that was procured during the planning process, resources in this category bid or self-scheduled 120-134 percent of resource adequacy capacity in the day-ahead and real-time markets.

Nuclear generators accounted for about 2,800 MW of shown resource adequacy capacity during these hours. These resources bid or self-scheduled 98 percent of procured capacity into the day-ahead and real-time markets. Considering the rest of capacity from partially shown resources above the amount that was procured during the planning process, resources in this category bid or self-scheduled 100 percent of resource adequacy capacity in the day-ahead and real-time markets.

Qualifying facilities accounted for about 1,000 MW of shown resource adequacy capacity during these hours. These resources bid or self-scheduled 83-84 percent of procured capacity into the day-ahead and real-time markets. Considering the rest of capacity from partially shown resources above the amount that was procured during the planning process, resources in this category bid or self-scheduled 97-104 percent of resource adequacy capacity in the day-ahead and real-time markets.

Other non-dispatchable generators accounted for about 500 MW of shown resource adequacy capacity during these hours. These resources bid or self-scheduled 90-91 percent of procured capacity into the day-ahead and real-time markets. Considering the rest of capacity from partially shown resources above the amount that was procured during the planning process, resources in this category bid or self-scheduled 116-133 percent of resource adequacy capacity in the day-ahead and real-time markets.

3.5 Demand response resource adequacy

Background

In DMM's report on August and September market conditions, DMM reported on the availability and dispatch of demand response resources during the August and September heatwaves.[99] DMM did not report on demand response performance as self-reported performance calculations rely on retail customer meter data. Self-reported performance can change significantly as retail customer meter data is finalized and shared with demand response providers, often months after relevant market days.

Demand response programs counted for 1,847 MW of resource adequacy capacity in August and 1,769 MW in September. This capacity is comprised of both demand response programs across all local regulatory authorities which are credited against resource adequacy requirements, and third-party demand response programs which are contracted with load serving entities and are shown on resource adequacy supply plans.

This section details the self-reported performance of demand response resources counted towards resource adequacy requirements.

Utility demand response performance

Demand response programs counted for 1,604 MW of system resource adequacy credits in August. Of these demand response credits, demand response programs under the CPUC local regulatory authority (LRA) accounted for 1,482 MW.[100] System resource adequacy demand response credits under the CPUC

99 *Report on system and market conditions, issues and performance: August and September 2020*, DMM, November 24, 2020, pp/55-59: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

100 This figure includes transmission and distribution loss factors and a planning reserve margin gross-up. About 10 megawatts of non-utility demand response credits are reflected in this figure, which represents transmission and distribution loss factors and a planning reserve margin gross up for non-utility, non-DRAM, demand response resource adequacy capacity contracted with CPUC-jurisdictional load serving entities.

local regulatory authority also include a 15 percent planning reserve margin adder. In August, the CPUC planning reserve margin adder represented 193 MW.

As shown in DMM's August and September report,[101] on high load days in August and September, available utility demand response capacity (across all jurisdictions) fell short of resource adequacy credits by about 530 to 680 MW in real-time when firm load was shed. While utility demand response availability fell short of credited values, nearly all of the *available* CPUC-jurisdictional utility demand response was dispatched across peak net load hours. The majority of CPUC-jurisdictional utility demand response dispatches were due to the ISO issuing manual dispatches to reliability demand response resources (RDRR) on August 14-18 and September 5-6.

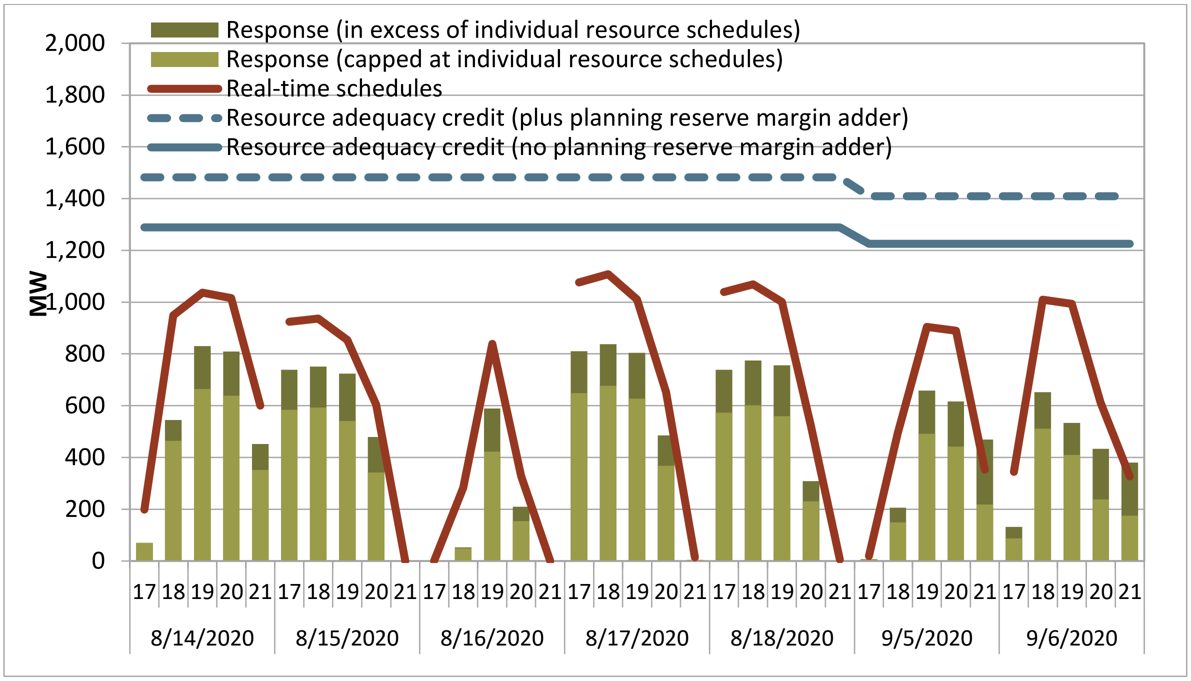
Figure 3.6 shows the real-time dispatches and self-reported response of CPUC-jurisdictional utility demand response capacity on high load days in August and September. Figure 3.6 reflects both proxy demand response (PDR) and reliability demand response (RDRR) capacity scheduled by CPUC-jurisdictional investor-owned utilities. Non-CPUC jurisdictional demand response programs are currently not tied to specific resources in the ISO market and thus are not included in this analysis.

Figure 3.6 shows utility demand response self-reported performance capped at individual resources' dispatch instructions (light green bar), and self-reported performance in excess of individual resource dispatches (dark green bar). These metrics indicate that some individual resources under-performed while other resources curtailed load in excess of dispatch instructions. In aggregate, however, the total CPUC-jurisdictional utility demand response fleet reported to under-perform compared to ISO dispatch instructions in peak net load hours.

On August 14, while just over 1,000 MW of available CPUC-jurisdictional utility demand response was dispatched in hours 19 and 20, resources reported that about 820 MW of load was curtailed each hour, or about 80 percent of total demand response dispatched each hour (including load curtailment in excess of ISO dispatches). Limiting response to individual resources' dispatch instructions, reported response on August 14 in hours 19 and 20 was about 64 percent. On August 15 in hours 19 and 20, CPUC-jurisdictional utility demand response curtailed about 740 MW of load each hour, which was about 82 percent of total demand response dispatched each hour. Limiting response to individual resources' dispatch instructions, reported response on August 15 in hours 19 and 20 was about 63 percent.

101 *Ibid*., pp. 57-59.

Figure 3.6 Self-reported performance of CPUC-jurisdictional utility demand response



Third-party demand response performance

Demand response capacity shown on resource adequacy supply plans currently represents demand response programs scheduled by third party, non-utility providers. This capacity is primarily contracted with load serving entities through the CPUC's Demand Response Auction Mechanism (DRAM), but also includes third-party demand response contracted with load serving entities and vetted through the CPUC's Load Impact Protocol (LIP) process.

In August, supply plan demand response counted for 243 MW of resource adequacy capacity. In September, supply plan demand response counted for 237 MW of resource adequacy capacity.

As detailed in DMM's August and September report, on August 14 in hours 19 and 20, about 45 to 50 percent of total demand response capacity shown on resource adequacy supply plans was dispatched by the ISO.[102] On August 15 in hours 19 and 20, only about 25 percent of supply plan demand response capacity was dispatched. There were no manual dispatches of supply plan demand response resources on high load days in August and September.

Figure 3.7 shows supply plan demand response dispatches capped at individual resources' shown resource adequacy values (red line) *and* dispatches of these resources in excess of shown resource adequacy values (dashed red line). Of note, 99 percent of supply plan demand response dispatches in excess of shown resource adequacy in this timeframe was associated with a single demand response provider.

Figure 3.7 also shows the self-reported performance of demand response resources shown on resource adequacy supply plans. Figure 3.7 shows both response capped at individual resources' resource

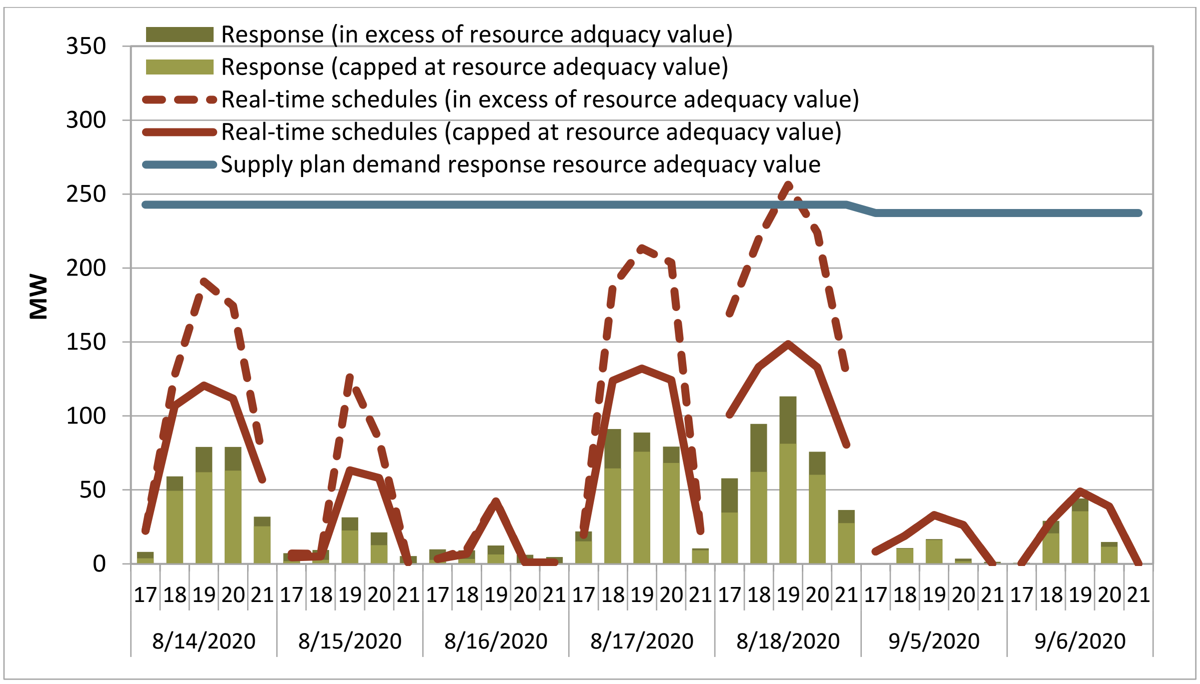
102 *Ibid*., pp. 55-57.

adequacy values (light green bar) and response in excess of resource adequacy values (dark green bar). In aggregate, the total demand response fleet reflected on resource adequacy supply plans reported to under-perform compared to ISO dispatch instructions in peak net load hours in August and September.

In aggregate on August 14 in hours 19 and 20, the supply plan demand response fleet reported to curtail about 79 MW of load in each hour, which was 41 to 45 percent of total MW dispatched in each hour. Limiting dispatches and response to individual resources' resource adequacy values, total reported response was 51 to 57 percent of real-time dispatches on August 14 in hours 19 and 20.

In aggregate on August 15 in hours 19 and 20, the supply plan demand response fleet reported to curtail about 20 to 30 MW of load in each hour, which was 25 percent of total MW dispatched in each hour. Limiting dispatches and response to individual resources' resource adequacy values, total reported response was 22 to 36 percent of real-time dispatches on August 15 in hours 19 and 20.

Figure 3.7 Self-reported performance of third-party demand response



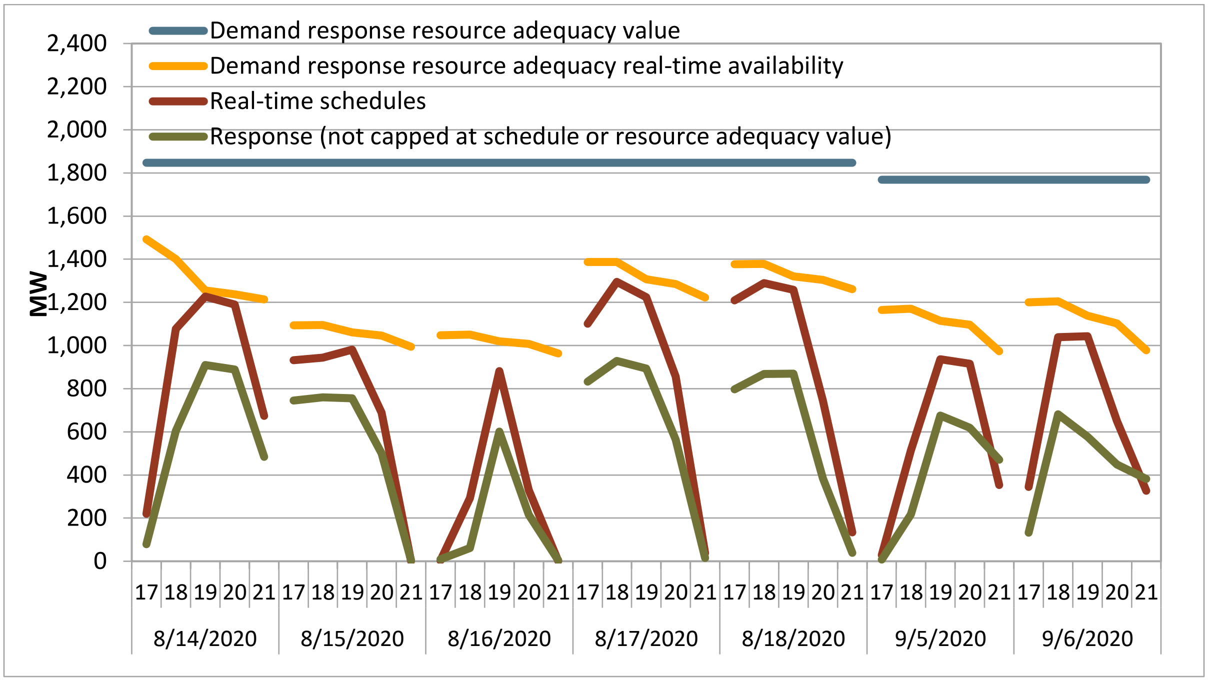
Demand response resource adequacy aggregate summary

Figure 3.8 shows the availability, dispatch, and response of *all* demand response capacity counted towards resource adequacy requirements on high load days in August and September. In aggregate, demand response resources counted for 1,847 MW of resource adequacy in August and 1,769 MW of resource adequacy in September (all local regulatory authority jurisdiction credits and capacity shown on resource adequacy supply plans).

Figure 3.8 shows that total demand response availability, as reflected through utility and third-party provider bids and daily reports sent from investor-owned utilities to the ISO, fell short of resource adequacy values on high load days. Further, some resources were not fully dispatched up to available bid values on these days. Of the demand response capacity dispatched, about 900 MW, or about 74 percent, reported to respond in hours 19 and 20 on August 14 (including load curtailment in excess of

ISO dispatches). On August 15 in hour 19, about 756 MW, or about 77 percent of demand response resource adequacy capacity that was dispatched, reported to respond. On August 15 in hour 20, about 500 MW, or about 73 percent of demand response resource adequacy capacity that was dispatched, reported to respond.

Figure 3.8 Aggregate demand response resource adequacy activity in August and September



Demand response baseline calculations generally rely on historical metered load to establish the day-of counterfactual load baselines from which demand response performance is measured. The ISO also requires certain baseline calculations to be adjusted upward and downward to capture intra-day load deviations from historical levels. However, there are also tariff-defined caps on the amount that baselines can be adjusted, based on different baseline methodologies.[103]

Based on supplier-submitted baseline and meter data, there is some evidence that baseline adjustments could have been limited in the upward direction by defined baseline adjustment caps on these days. That is, there is some evidence based on self-reported meter data, that certain customer loads on high load days may have deviated from historic days' load by factors greater than the ISO's baseline adjustments allowed. This could have resulted in self-reported performance values that were lower than actual load reduction, if baselines could not be adjusted further upward. DMM is continuing to evaluate this issue.

3.6 Batteries

In the third quarter of 2020, the total capacity of standalone battery resources participating in the ISO market under the non-generator resource (NGR) model more than doubled from the prior quarter. As of September 2020, the standalone battery fleet participating and bidding in the ISO market had a total

103 Tariff Section 4.13.4

minimum and maximum registered capacity of about -384 MW and 387 MW with a maximum state of charge of about 673 megawatt-hours.

Battery schedules

In the third quarter of 2020, the ISO standalone battery fleet was scheduled primarily for ancillary services and flexible ramping rather than energy, but was scheduled to provide energy more frequently in real-time than in prior quarters, particularly on high load days in August and September. Figure 3.9 shows the average real-time (15-minute market) schedules of the standalone battery fleet between August 14 and August 18. Figure 3.10 shows the average real-time schedules of the standalone battery fleet on September 5 and 6.

The increase in flexible ramp schedules on battery resources was primarily due to the entry of new battery capacity which is not yet capable of providing regulation. The increased use of battery resources to provide energy on September 5 and 6 was primarily due to high real-time price spreads and the ISO issuing exceptional dispatches to battery resources to both charge and discharge on September 6.

Figure 3.9 and Figure 3.10 also show that on high load days, some battery capacity was scheduled to charge across peak net load hours. Some battery capacity received charging schedules on August 14 and August 15 when the ISO remained in emergency and alert stages. While some charging activity was associated with regulation movement, the majority of charging activity was economic based on resource bids and real-time prices in the tail end of emergency and alert periods. For example, on August 14, real-time prices in hour ending 21 were relatively low while a Stage 3 emergency was still in effect, allowing for some battery capacity to re-charge economically.

The ISO's current capability for manually dispatching battery resources is to issue set fixed megawatt instructions to resources at certain points in time. The ISO does not currently have functionality to issue target state of charge instructions to battery resources, though the ISO is currently developing this type of capability through its Energy Storage and Distributed Energy Resources 4 (ESDER4) policy initiative.[104]

On September 6, the ISO issued exceptional dispatches to most standalone storage resources so that resources would be able to discharge energy across the net load peak. To effectuate this outcome, the ISO issued instructions for these resources to charge during earlier afternoon hours. Additionally, to ensure charge would be available on battery resources in peak net load hours, the ISO issued instructions not to discharge (generally to hold fixed 0 MW schedules) in hours between the charge instructions and peak net load hours.

Figure 3.10 includes the impact of September 6 exceptional dispatch instructions on the real-time battery schedule compositions. Exceptional dispatches resulted in battery resources providing more energy across peak net load hours than average and also resulted in resources being charged more than average, particularly in hour ending 15. Exceptional dispatches also resulted in battery resources being backed off of most operating reserve awards in hours when exceptional dispatches were in place, requiring the market to find spinning reserve and regulation capacity up and down on other resources in real-time.

DMM supports the ISO in continuing to enhance its tools for dispatching and managing storage resources in real-time. For example, issuing minimum state of charge values to battery resources instead

[104] Energy Storage and Distributed Energy Resources Phase 4 Final Proposal, California ISO, August 21, 2020: http://www.caiso.com/InitiativeDocuments/FinalProposal-EnergyStorage-DistributedEnergyResourcesPhase4.pdf

of static megawatt values when resources are needed for reliability could help maintain flexibility on battery resources in real time. This approach could also allow battery resources to maintain operating reserve awards, limiting the amount of reserve capacity that must be procured on short notice from other resources, particularly when the pool of available supply is already limited in real-time.

Figure 3.9 Average real-time battery schedules (August 14-18)

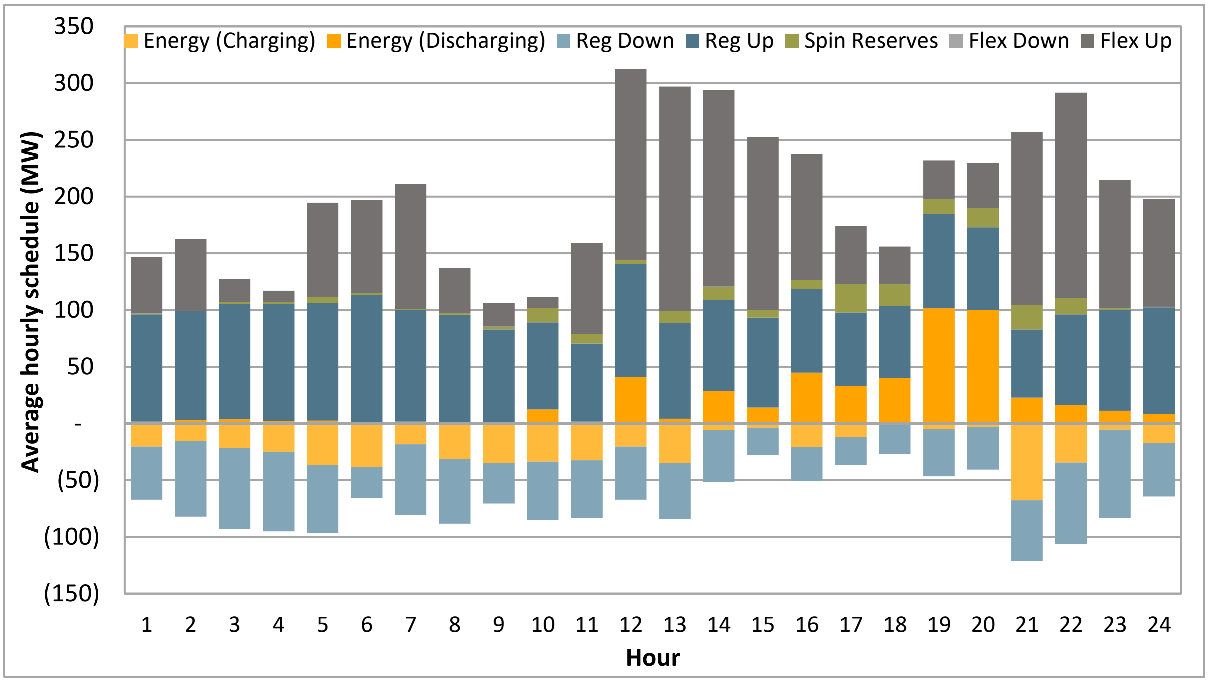
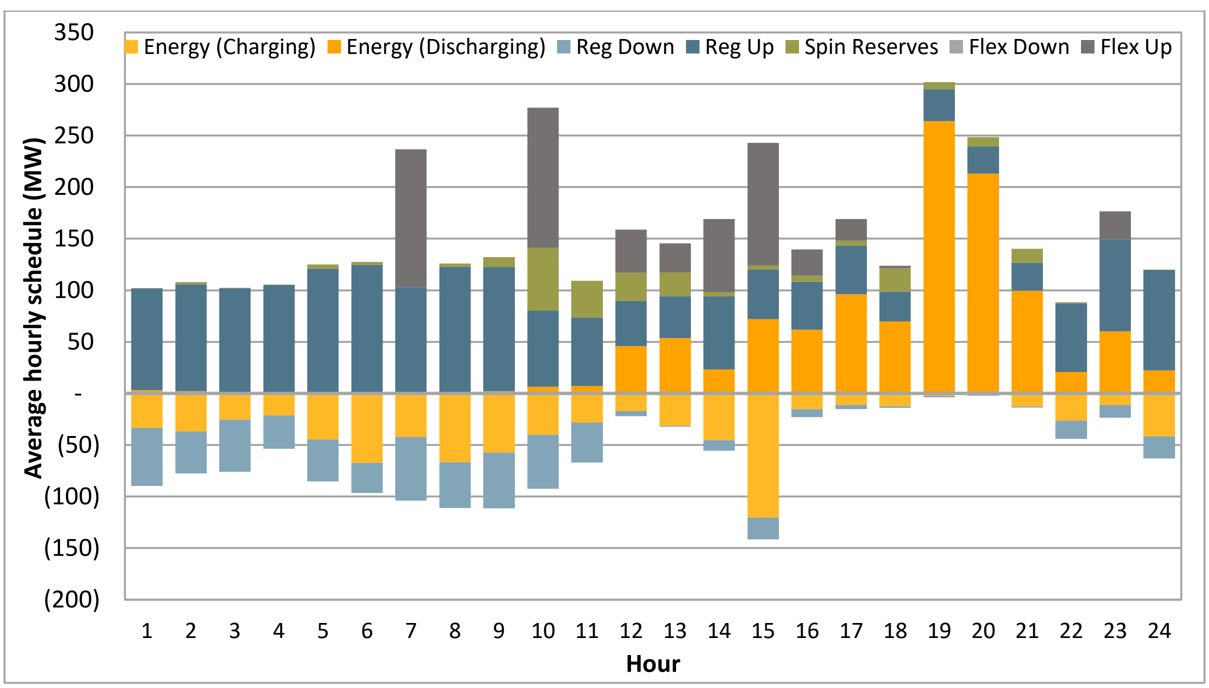


Figure 3.10 Average real-time battery schedules (September 5 and 6)



3.7 System market power

This section assesses the competitiveness of the ISO's energy markets through a review of structural measures of market competitiveness and a day-ahead market software simulation under different scenarios. In the third quarter of 2020, the average price-cost markup was about $0.63/MWh or just over 1 percent for the default energy bid scenario, slightly above the $0.48/MWh or about 2 percent for the previous quarter.

3.7.1 Structural measures of competitiveness

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

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

- **Residual supply index.** The residual supply index is the ratio of supply from non-pivotal suppliers to demand.[105] A residual supply index less than 1.0 indicates an uncompetitive level of supply.

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

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

The residual supply index analysis includes the following elements for accounting for supply and demand:

- Day-ahead market bids were used for physical generating resources (adjusted for outages and derates).

- Transmission losses were not explicitly added to demand. The day-ahead load forecast already factors in losses. This reflects a change from prior DMM analyses.

- Ancillary services bids in excess of energy bids were included to account for this additional supply available to meet ancillary service requirements in the day-ahead market.

- Excluded CPUC jurisdictional investor-owned utilities as potentially pivotal suppliers.

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

- Accounted for the maximum availability of non-pivotal imports offered relative to import transmission constraint limits.
- As in prior DMM analyses, virtual bids were excluded.

Figure 3.11 shows the quarterly number of hours with a residual supply index less than one since 2016, based on the assumptions listed above. During the third quarter, the number of hours with an RSI less than one increased significantly. For the quarter alone, the residual supply index with the three largest suppliers removed (RSI3) was less than one during 305 hours. In comparison, there were 111 hours with RSI3 less than one during all of 2019, and 269 hours with RSI3 less than one during all of 2018.

With the largest two suppliers removed (RSI2), the residual supply index for the third quarter was less than one in 213 hours. With the largest supplier removed (RSI1), it was less than one in 90 hours.

Figure 3.12 illustrates the level of the residual supply index measurements by showing the lowest 500 RSI values during the quarter. With the three largest suppliers removed, the RSI3 was less than 0.9 in 136 hours, and less than 0.8 in 43 hours. Extremely low RSI values (at the bottom of the curve) can indicate scarcity conditions. During the third quarter, there were 22 hours in which calculated supply was less than demand — prior to the removal of the largest supplier(s).

Figure 3.13 illustrates the distinction between hours with scarcity conditions and non-competitive conditions. The figure compares the reserve margin using the same assumptions as the residual supply index analysis (except with no suppliers removed) against the day-ahead market system marginal energy cost. The vertical thresholds show the equivalent reserve margin at which supply is less than demand with the top one-, two-, or three-largest pivotal suppliers removed. Here, the chart shows a significant number of hours where the reserve margin is greater than 100 percent, but would be in a deficit with the largest pivotal supplier(s) removed. For every hour of potential scarcity, there are many hours of potential system market power.

Figure 3.11 Hours with residual supply index less than one

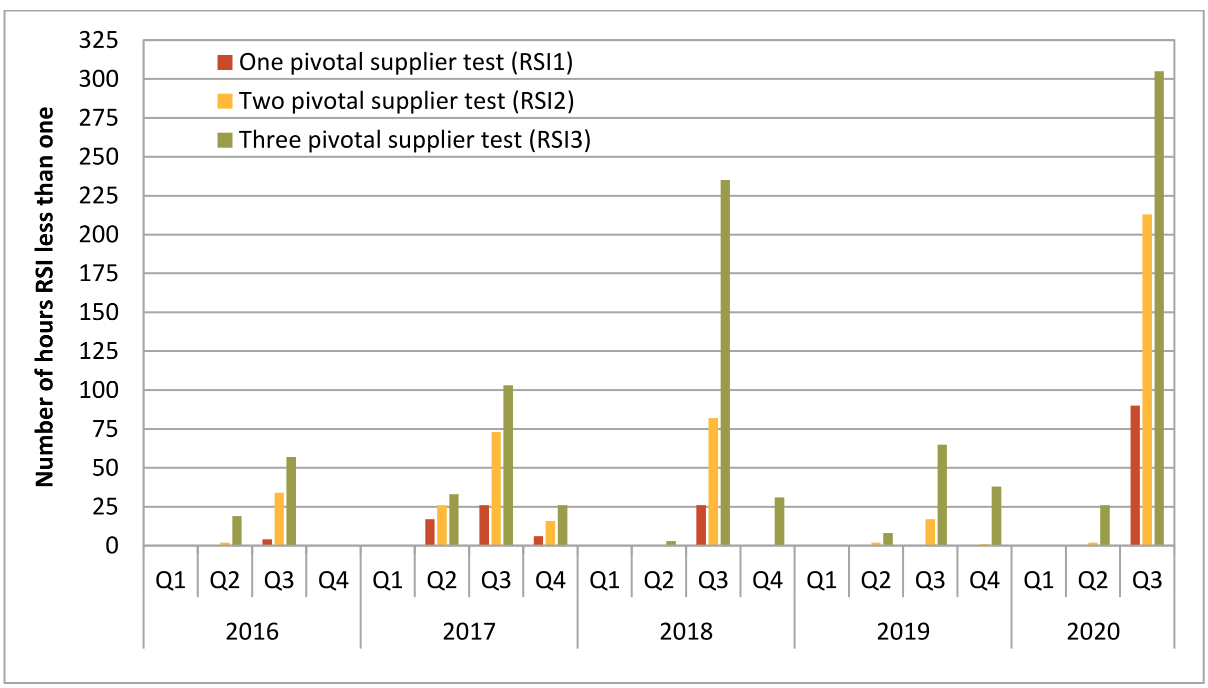


Figure 3.12 Lowest 500 residual supply index with largest one, two, or three suppliers excluded (July – September)

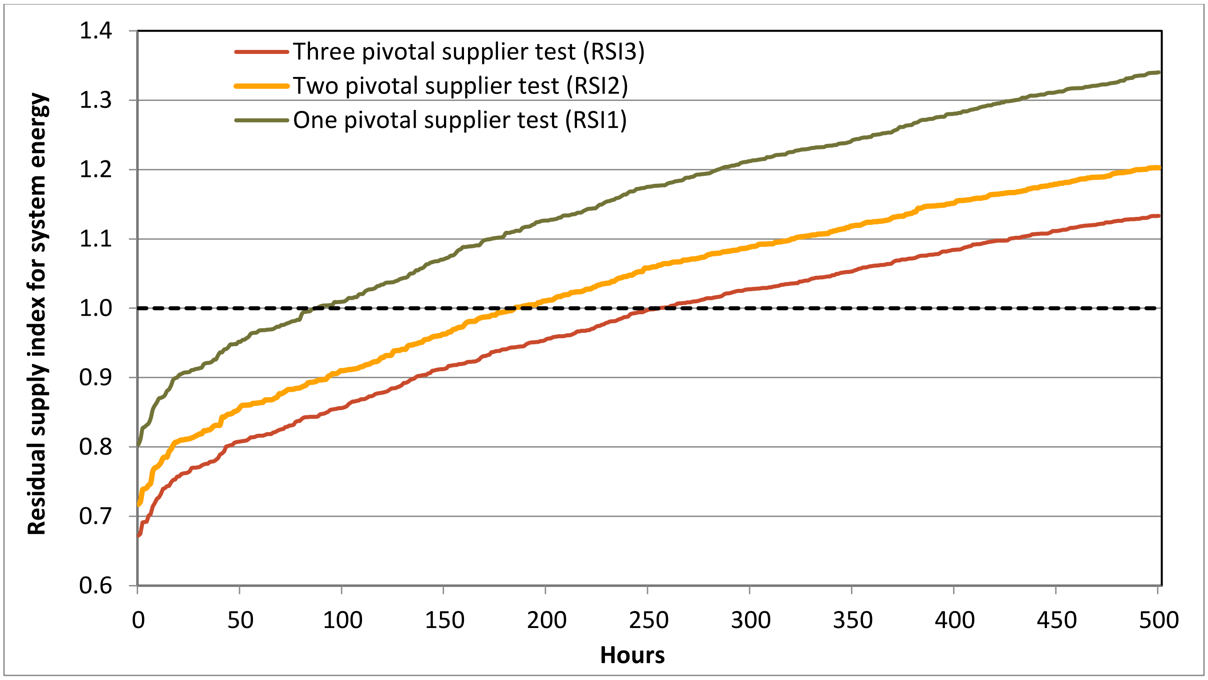
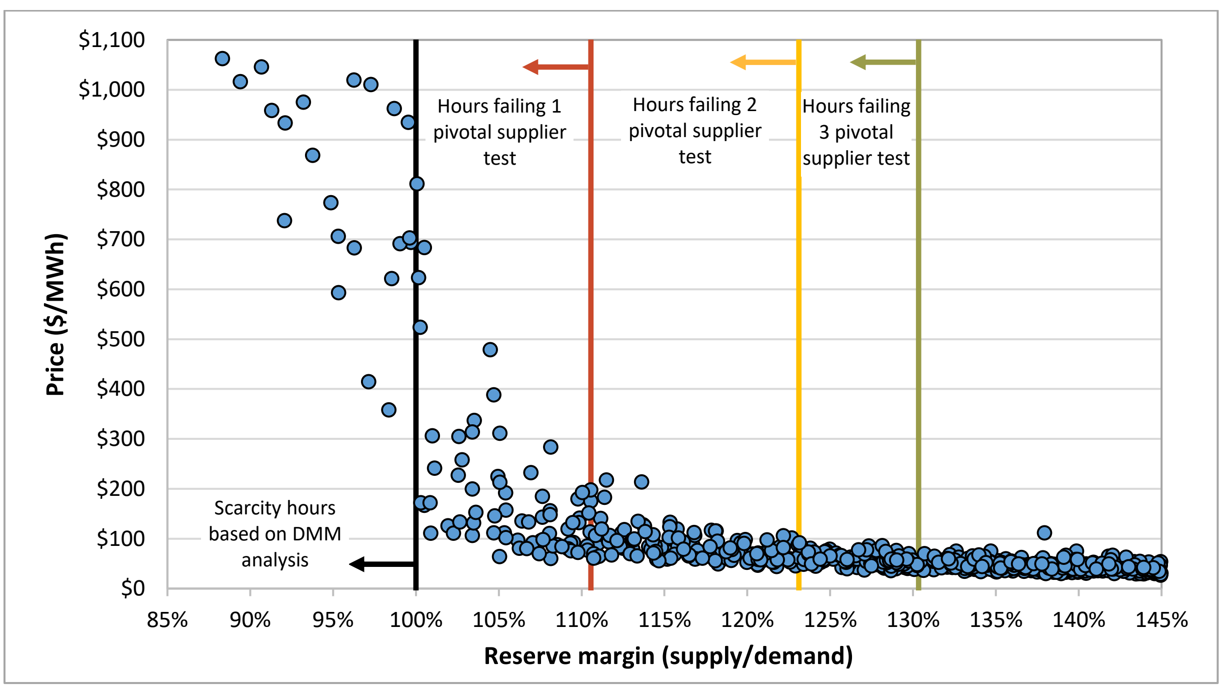


Figure 3.13 Comparison of potential scarcity and non-competitive hours



3.7.2 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 these benchmark prices by re-simulating the day-ahead market after replacing bids or other market inputs using DMM's version of the actual market software.

Day-ahead market simulation results show that market prices were very close to competitive benchmark prices, even during the heat wave period of August 14 to 19. Replacing high-priced energy bids with cost-based bids did not result in lower prices, since these high-priced bids were often infra-marginal in high price hours. This reflects the fact that gas-fired and other resources that may be subject to mitigation were generally infra-marginal in reruns of the day-ahead market using cost-based bids, and that high prices were set by demand response and other resources not subject to mitigation. System-wide mitigation of imports and gas-fired resources during this period would not have lowered prices.

Competitive benchmark prices were calculated by rerunning day-ahead market simulations under the following scenarios:

Scenario 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;

Scenario 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;

Scenario 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

Scenario 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:

Scenario 5: Adjust market inputs as described in Scenarios 1, 2 and 3 above.

Scenario 6: Adjust market inputs as described in Scenarios 1 and 4 above.

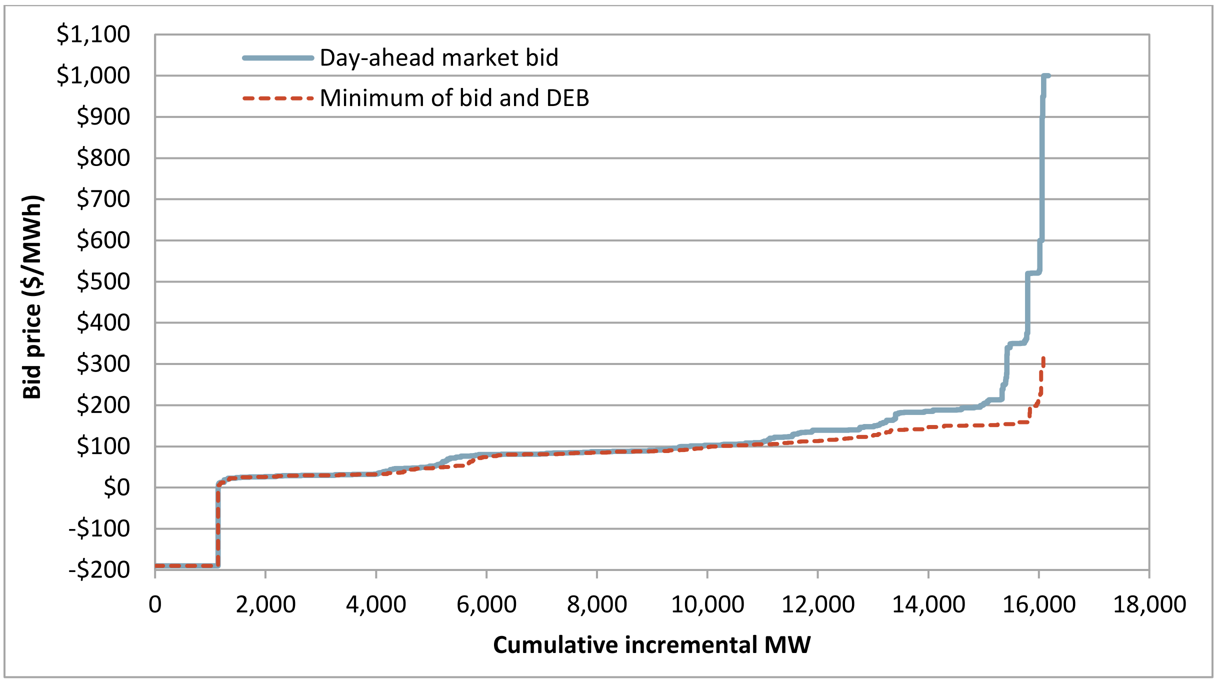
Scenario 7: Adjust market inputs as described in Scenarios 1 through 4 above.

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. The price-cost markup is calculated as the difference between load-weighted average scenario prices compared to load-weighted average prices from this base case rerun.

Figure 3.14 illustrates the gas scenarios by comparing gas bids on a sample day and hour with the lower of themselves or their default energy bid.[106] The default energy bids (or DEBs) are used for local market power mitigation and reflect each unit's estimated marginal cost plus a 10 percent adder. As shown in Figure 3.14, bids are largely near or below default energy bids for the first 11,000 MW segment of the curve, but exceed reference levels for the remaining 5,000 MW of gas supply. This behavior, which has been observed in other hours, largely comes from *net sellers.*[107]

Figure 3.15 illustrates the import scenarios using the same sample hour and a comparison of import bids with the lower of themselves or the *estimated* default energy bid. The estimated default energy bid based on the hydro default energy bid can reflect a conservative estimate of a competitive price for imports. For this sample hour, only around 300 MW of imports was bid higher than the estimated default energy bid.

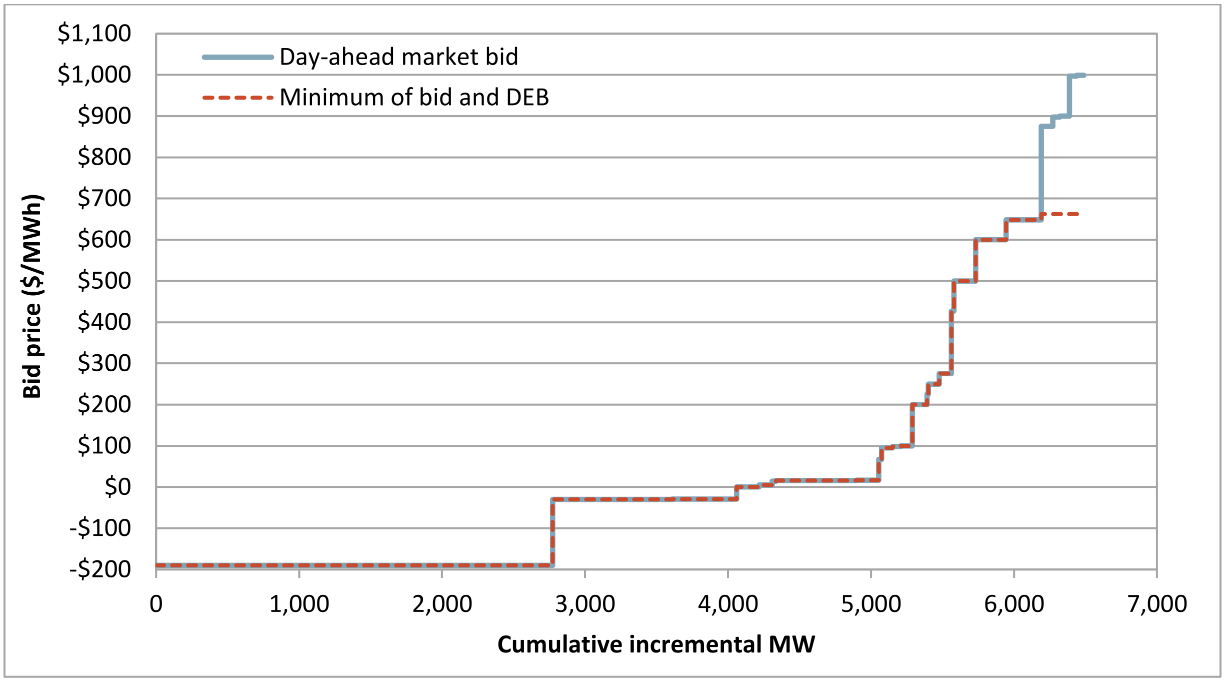
Figure 3.14 Comparison of day-ahead market gas bids (August 18, hour-ending 19)



[106] Gas supply curves show the incremental amount for each bid segment and therefore do not account for the generation associated with the minimum operating levels of the resources. Self-scheduled supply is depicted at -$190/MWh for illustrative purposes.

[107] ISO markets classify each supplier as either a net seller or a net buyer, based on purchases and sales over an extended period.

Figure 3.15 Comparison of day-ahead market import bids (August 18, hour-ending 19)



As shown in Figure 3.16, 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 the lower of the bid or the default energy bid. Prices are shown separately for each default load aggregation point in the ISO balancing area.

Figure 3.17 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 third quarter of 2020, prices remained competitive, with average hourly prices in the competitive baseline scenario very close to actual market results.

Figure 3.16 Default energy bid scenario price results (Jul – Sep)

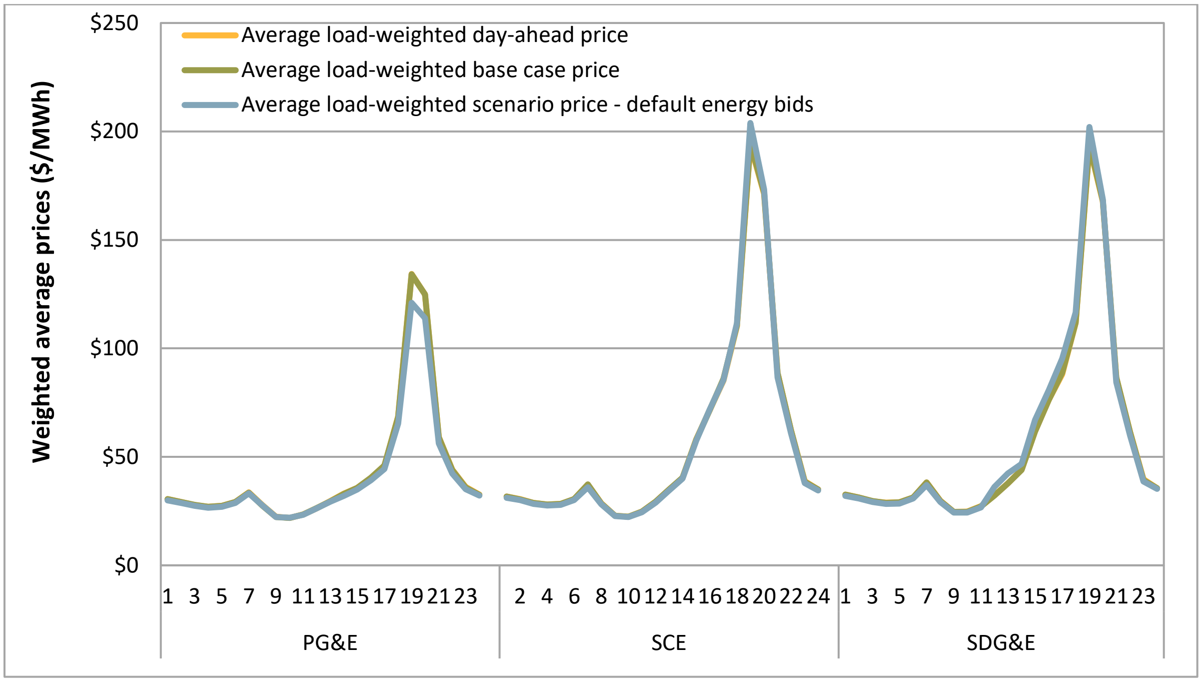
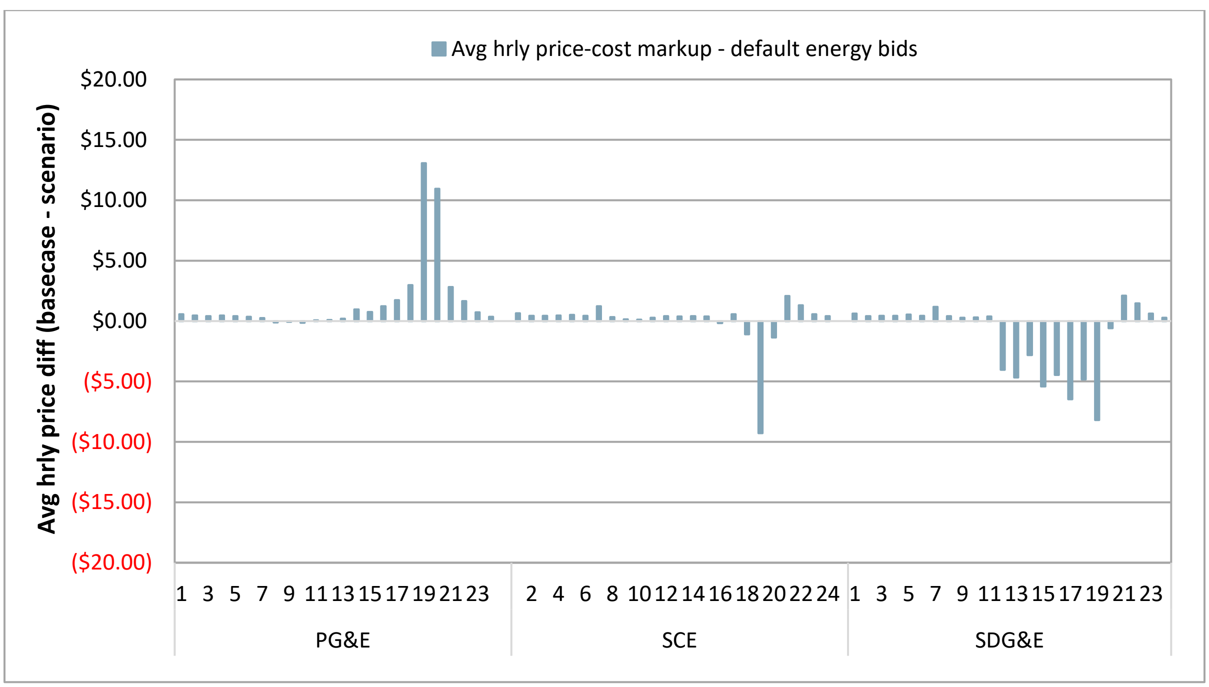


Figure 3.17 Hourly price-cost markup – default energy bid scenario (Jul – Sep)



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 3.18 Default energy, commitment cost, and import bids scenario price results (Jul – Sep)

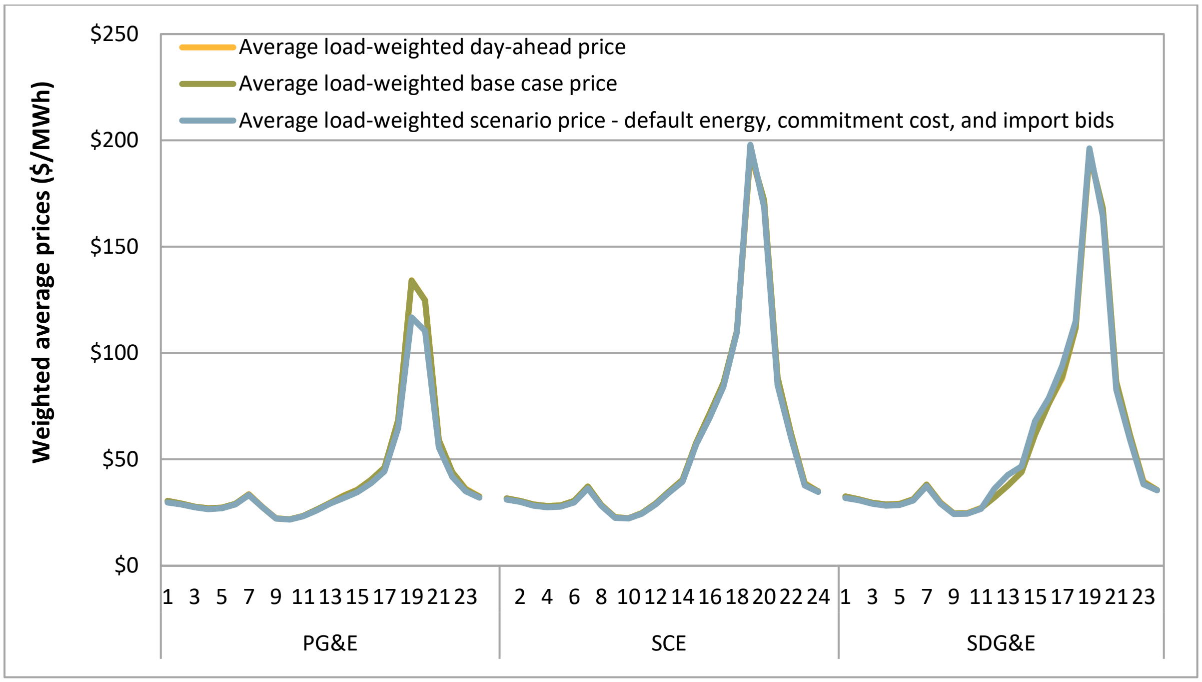


Figure 3.19 Hourly price-cost markup – default energy, commitment cost, and import bids scenario (Jul – Sep)

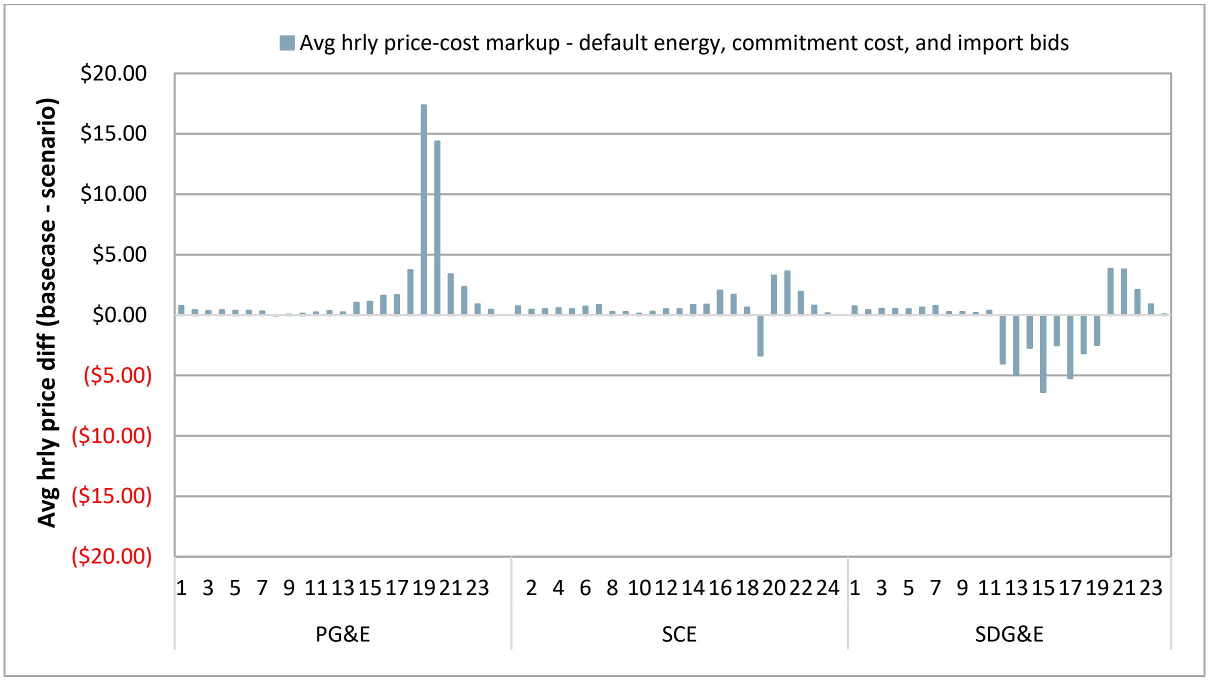


Figure 3.20 Actual load and default energy, commitment cost, and import bids scenario price results (Jul – Sep)

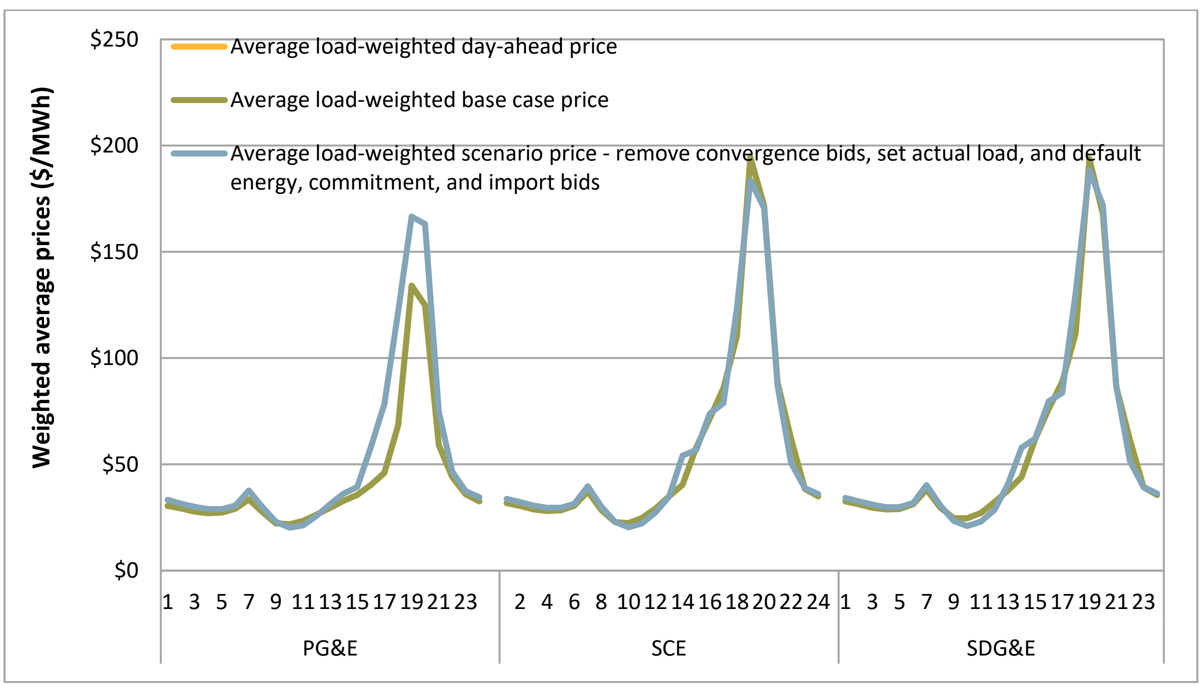
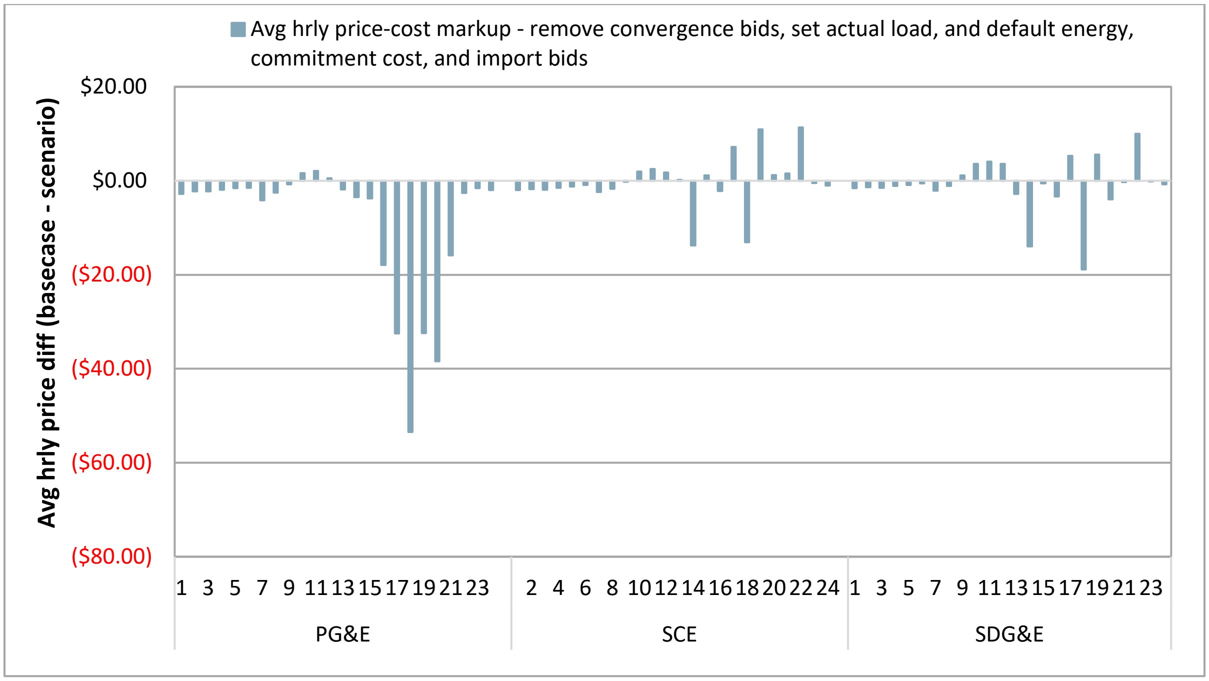


Figure 3.21 Hourly price-cost markup – actual load and default energy, commitment cost, and import bids scenario (Jul – Sep)



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 Table 3.3, in the third quarter of 2020 the average price-cost markup was about $0.63/MWh or just over 1 percent for the default energy bid scenario, slightly above the $0.48/MWh or about 2 percent for the previous quarter.

This slight positive markup indicates that prices have been competitive, overall, for the quarter.[108] 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.

The price-cost markup increases to $1.42/MWh or about 2.6 percent, an increase from the $0.66/MWh or 3 percent for the previous quarter, when calculating 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.

[108] DMM calculates the price-cost markup index as the percentage difference between base case market prices and prices resulting under the 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.

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 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 -$4.56 or -11 percent, below the $0.56/MWh or about 2.5 percent for the previous quarter. The results for this and the remaining scenarios indicate that prices remain very competitive, overall, for the quarter.

Table 3.3 Quarterly price-cost markup by scenario (Jul – Sep)[109]

Scenario	Load-wtd avg day-ahead prices	Load-wtd avg base case prices	Load-wtd avg scenario prices	Price-cost markup ($/MWh)	Price-cost markup (%)
Gas resources at min(bid,DEB)	$55.36	$55.39	$54.75	$0.63	1.1%
Commitment costs for gas resources at min(bid,110% proxy)	$55.36	$55.39	$55.66	-$0.27	-0.5%
Import bids at min(bid,hydro DEB)	$55.36	$55.39	$55.68	-$0.30	-0.5%
Remove convergence bids, set load to 5-min mkt req	$55.36	$55.39	$63.54	-$8.16	-14.7%
Energy and commitment cost bids capped for gas resources, imports capped	$55.36	$55.39	$53.96	$1.42	2.6%
Remove convergence bids, set load to 5-min mkt req, and cap gas resources at default energy bids	$55.36	$55.39	$61.73	-$6.34	-11.5%
Remove convergence bids, set load to 5-min mkt req, cap gas resources' energy and commitment cost bids, and cap import bids	$55.36	$55.39	$59.95	-$4.56	-8.2%

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.

3.7.3 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. 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.

109 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.

The ISO has not included this initiative in the set of fast-tracked changes for implementation prior to summer 2021. DMM continues to support work on this initiative. The CAISO market was structurally uncompetitive during the high load days in August. Although prices were very high on these days, analysis using the CAISO's day-ahead market software indicates that system-wide mitigation of imports and gas-fired resources during this period would not have lowered prices. This reflects the fact that gas-fired and other resources that may be subject to mitigation were generally infra-marginal in re-runs of the day-ahead market using cost-based bids, and that high prices were set by demand response and other resources not subject to mitigation. However, these results do not provide conclusive evidence that there was no exercise of system market power on these days.

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 area is determined to be import constrained as defined by a set of binding import constraints, and a residual supplier index for the ISO 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.[110]

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.[111] 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

110 *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

111 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 the proposed approach would have worked during system and market conditions that existed during the mid-August heat wave.[112]

3.8 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 3.22 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;[113]
- **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 third 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.

In the ISO, economic downward dispatch was higher in the third quarter compared to the same quarter of 2019. Economic downward dispatch accounted for about 112,000 MWh of curtailment over the

112 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

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

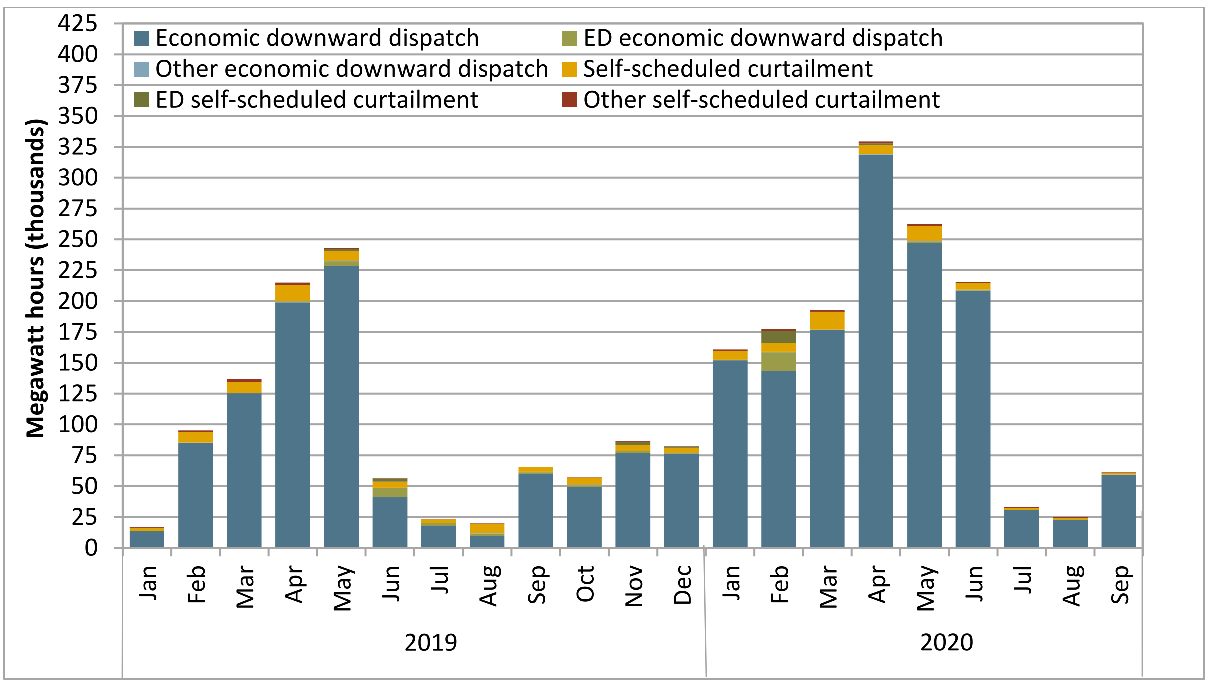
quarter, compared to 87,000 MWh during the same time in 2019. Over the quarter, exceptional dispatch curtailments of both self-scheduled and economic bid resources totaled about 600 MWh.

Downward dispatch increased in the energy imbalance market areas outside of the ISO, relative to the same quarter of 2019.

Figure 3.23 shows 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 the quarter reached about 13,000 MWh, a large increase compared to the 2,400 MWh over the third quarter of 2019. Much of this curtailment was due to the high frequency of congestion on the Wyoming_Export constraint, which led to one resource being heavily curtailed.[114]

Figure 3.24 and Figure 3.25 show the quarterly average reduction of wind and solar generation by type for ISO and EIM areas, respectively. In the ISO and EIM, economic downward dispatch represented about 94 and 89 percent of total curtailments on average for the third quarter, respectively. In the ISO, curtailment of self-scheduled resources represented 3.6 percent, while economic and self-scheduled exceptional dispatches combined were less than one percent.

Figure 3.22 Reduction of wind and solar generation by month (ISO)



114 The Wyoming_Export constraint was congested during 21.8 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 3.23 Reduction of wind and solar generation by month (EIM)

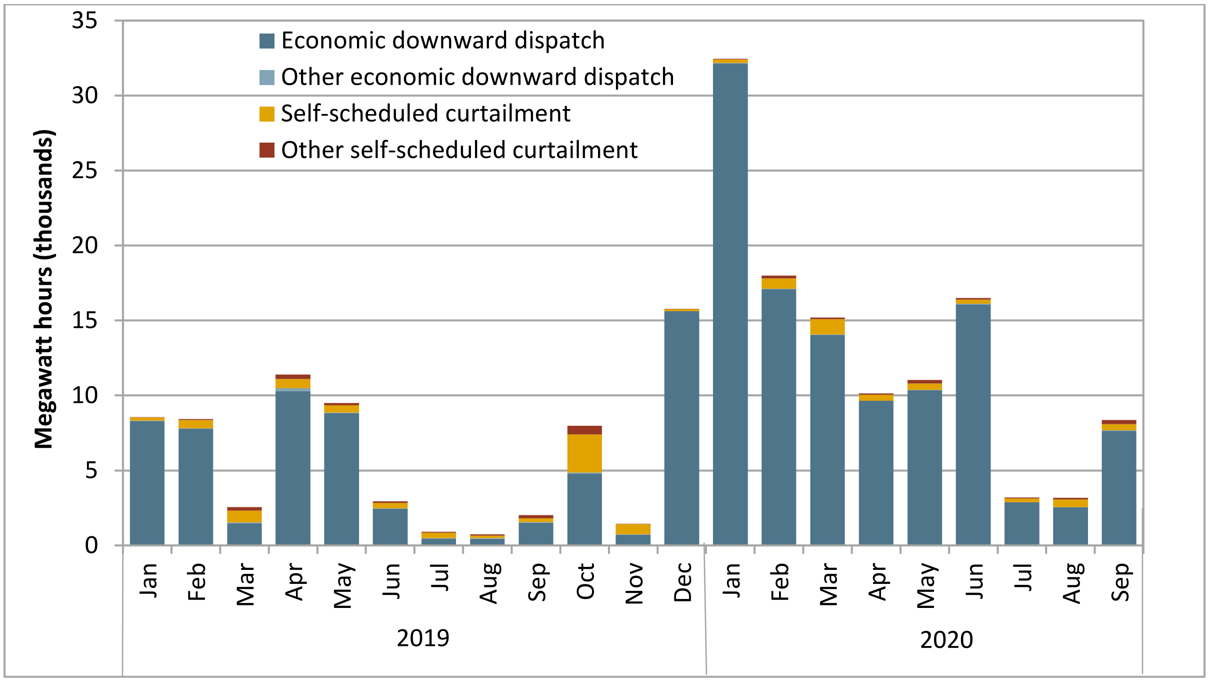


Figure 3.24 Third quarter average reduction of wind and solar generation by type (ISO)

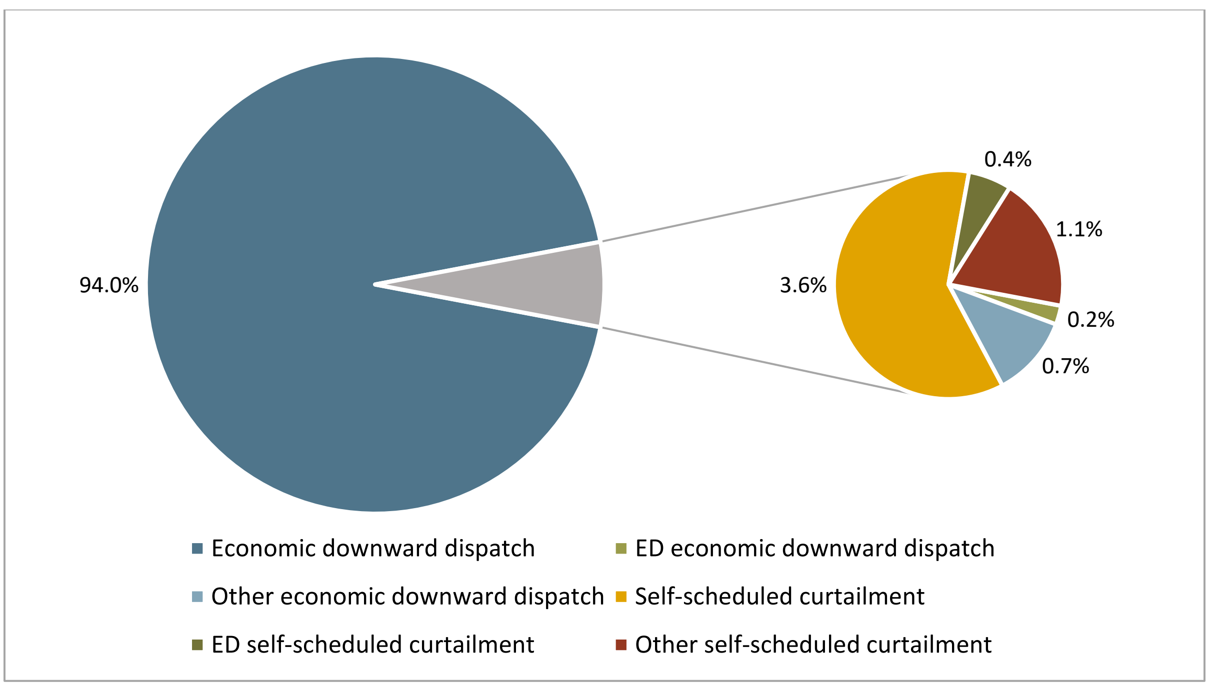
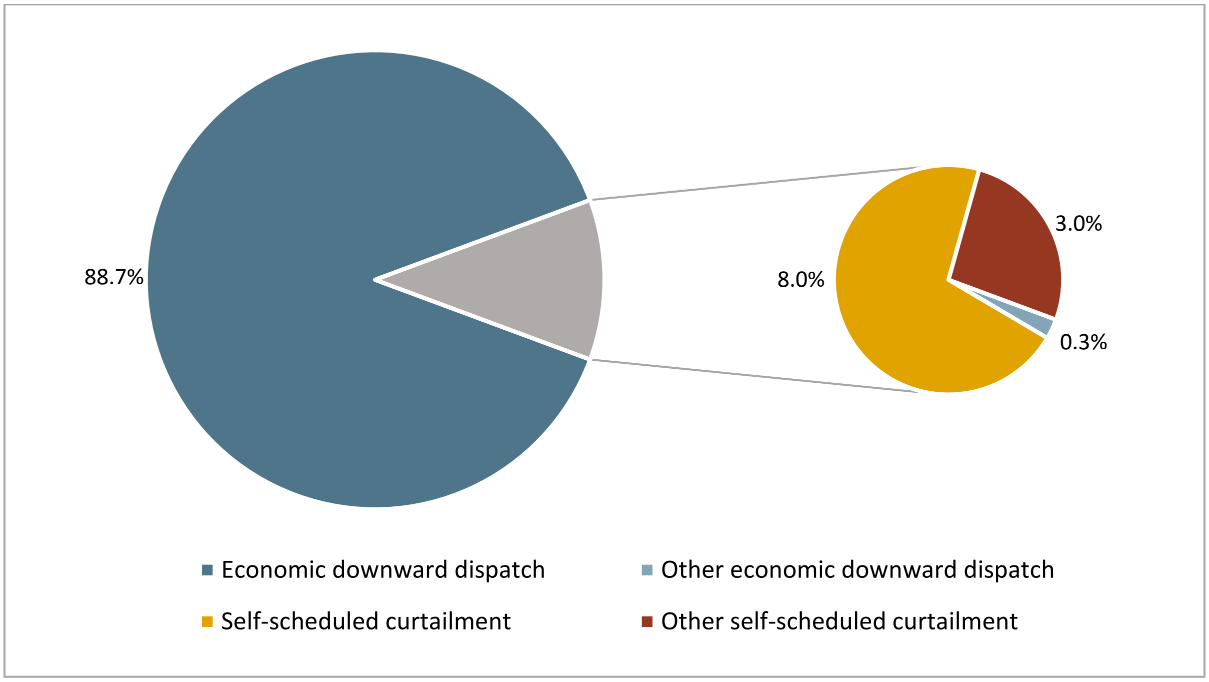


Figure 3.25 Third quarter average reduction of wind and solar generation by type (EIM)



Curtailment during the August heat storm

Despite tight system conditions during the heat storm and the need to shed load on August 14 and 15, wind and solar resources in the ISO were curtailed. Figure 3.26 shows the curtailment of wind and solar resources by day in the ISO between August 13 and 21. Figure 3.27 shows hourly curtailment by type on a 5-minute basis leading up to the time load was shed. Similar to most days, curtailments were primarily considered economic, meaning the market clearing price was below the bid. However, there were economically bid resources that were exceptionally dispatched down on August 14, and self-scheduled resources that were curtailed on August 15.

As shown in Figure 3.26, total curtailment of wind and solar resources peaked during this time on August 19, where total curtailment reached about 1,100 MWh, 94 percent of which was resources that had bid economically into the market. There was about 650 and 550 MWh of curtailment on August 14 and 15, respectively. Looking deeper into these days and the time of load shed, Figure 3.27 shows that while there was curtailment in the hours leading up to the load shed events, there was little to no curtailment while load was shed.

Figure 3.26 Wind and solar resource curtailments by type and day (ISO)

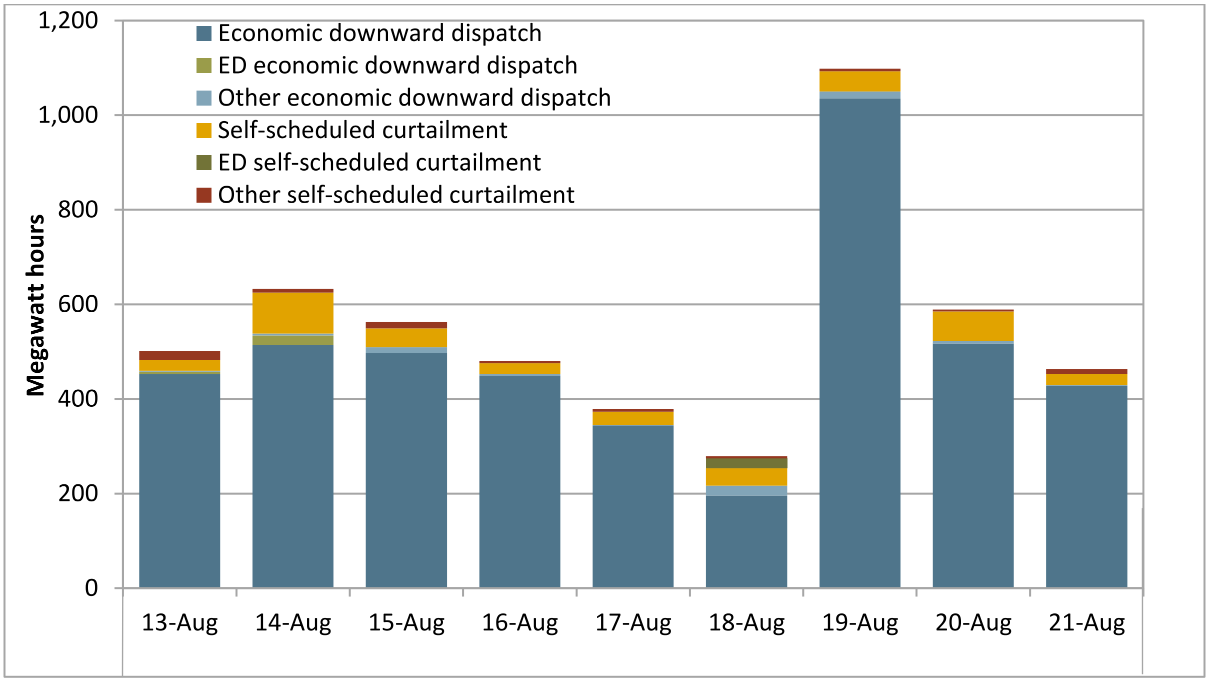


Figure 3.27 Hourly wind and solar resource curtailments by type in the ISO