California ISO

Q4 2020 Report on Market Issues and Performance

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California Independent System Operator

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Executive summary

This report covers market performance during the fourth quarter of 2020 (October - December).

Key highlights during this quarter include the following:

- **Market prices** were slightly higher than the same quarter of 2019. Average ISO monthly 5-minute prices were lower than both 15-minute and day-ahead market prices during the fourth quarter (Figure E.1). Day-ahead prices averaged about $41/MWh, 15-minute prices averaged $42/MWh, and 5-minute prices averaged $34/MWh.
- **The total estimated wholesale cost of serving ISO load** in the fourth quarter of 2020 was about $2.4 billion ($47/MWh), an increase from $2.3 billion ($44/MWh) in the same quarter of 2019.
- **Average loads were higher** in the fourth quarter of 2020 relative to 2018 and 2019, because of higher than normal peak temperatures in October.
- **Renewable production** increased by 11 percent compared to the same quarter in 2019 for non-hydro resources, while hydroelectric production decreased 40 percent.
- **Generation outages were higher** on average over peak hours compared to any quarter in the previous four years. The increase was driven by outages for forced maintenance.
- **Real-time offset costs totaled** $57 million in the fourth quarter, for an annual total of $177 million, the highest annual total since the introduction of the 15-minute market in 2014 (Figure E.2).
- **The ISO introduced a minimum area flexible ramping product procurement requirement** in November. The minimum requirement bound frequently for the ISO, but not other areas and is applied in the 15-minute market, but not the 5-minute market.
- **Ancillary service payments** rose to about $49 million, compared to about $23 million in the same quarter of the previous year. Higher payments were driven, in part, by higher requirements for both regulation and operating reserves.
- **Congestion revenue rights** auction revenues were $6 million less than payments made to non-load-serving entities during the fourth quarter of 2020, representing about 6 percent of day-ahead congestion rent. The losses as a percent of day-ahead congestion rent were well below the average of 28 percent during the three years before the Track 1A and 1B changes (2016 through 2018).

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

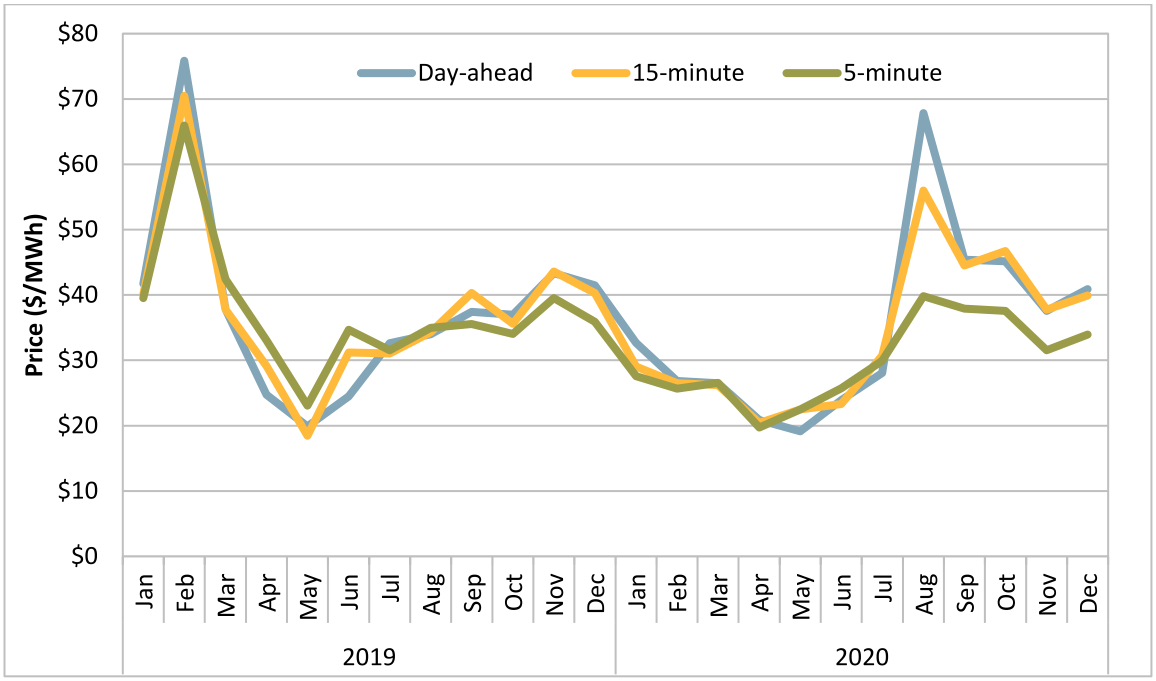
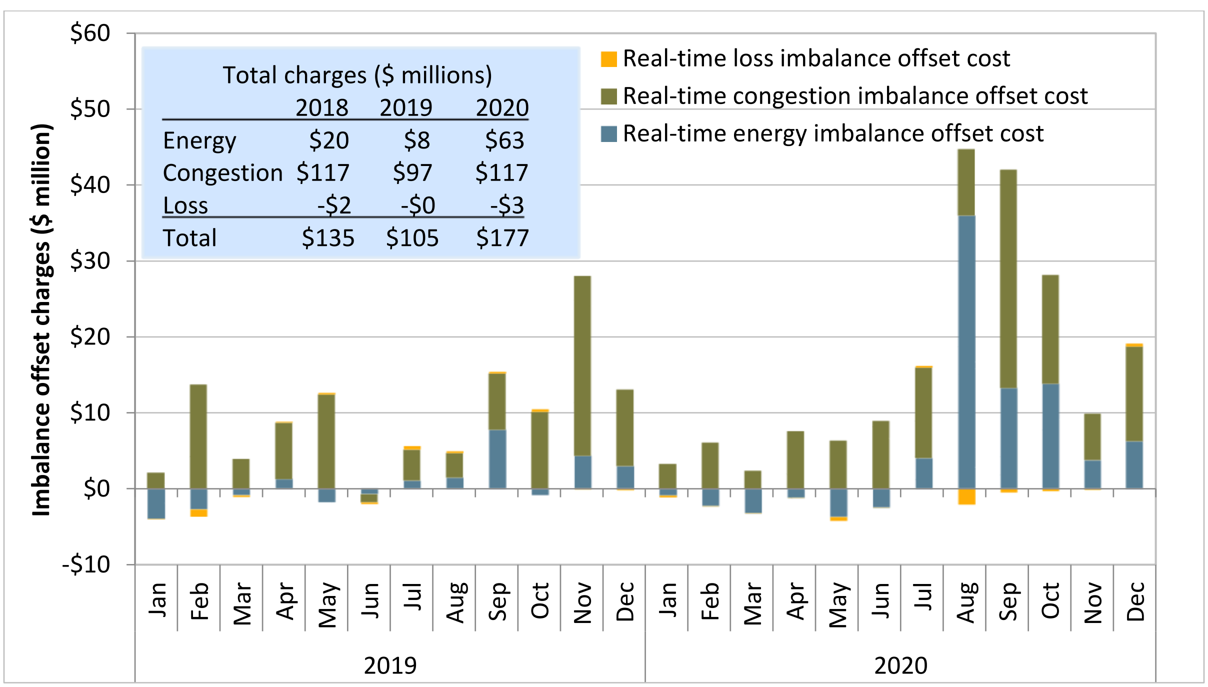


Figure E.2 Real-time imbalance offset costs



Western Energy Imbalance Market

- **Prices in the ISO and the Balancing Authority of Northern California were more than $10/MWh higher than other regions of the EIM on average.** Prices tend to be higher in California than the rest of the Western EIM due to greenhouse gas compliance cost for energy that is delivered to California.
- **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.
- **Sufficiency test failures and subsequent under-supply power balance constraint relaxations** drove average real-time prices higher for Arizona Public Service, NV Energy, and the Salt River Project. 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.
- **Western EIM greenhouse gas** prices decreased as the deemed delivered resources shifted from higher to lower greenhouse gas emissions. In November 2018, the ISO implemented a revised EIM greenhouse gas bid design which limited greenhouse gas bid capacity to the differences between base schedule and available capacity.
- **Rates of mitigation** in the Western EIM have continued to drop following the elimination of carryover mitigation in November 2019.

Special issues and recommendations

Energy imbalance market resource sufficiency tests

High temperatures led to high demand across the entire western region in mid-August. 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.

As part of the energy imbalance market, the ISO and energy imbalance market areas are subject to a resource sufficiency evaluation. The evaluation includes two tests:

- **The bid-range capacity test** requires that each area provide incremental bid-range capacity to meet the imbalance between load, intertie, and generation base schedules.
- **The flexible ramping sufficiency test** requires that each balancing area has enough ramping flexibility over an hour to meet the forecasted change in demand as well as uncertainty.

Both of these tests are performed prior to each hour to help ensure that generation in each energy imbalance market area is sufficient without relying on transfers from other balancing areas. If an area fails the bid capacity test or flexible ramping sufficiency test, energy imbalance market transfers into that area are capped.

The CAISO balancing area passed the bid range capacity test in all hours on August 14 and 15, to include intervals when the area experienced high levels of scarcity in the real-time energy market and curtailed load. The CAISO balancing area failed the flexible ramping sufficiency tests during some high demand intervals on August 14 and 15, but passed in other high demand intervals.

After more detailed review of the tests on these days, the ISO identified two errors which caused the CAISO area to pass the bid capacity test when it should have failed this test:[1]

- Resource de-rates and outages were not accounted for which resulted in higher resource capacity relative to actual availability. This affected both the ISO and energy imbalance market areas.
- Mirror resources were incorrectly included for the ISO, impacting net scheduled interchange and the capacity test requirement.[2] This affected only the ISO.

The ISO resolved both of these issues effective February 4, 2021 and proposed to add net load uncertainty to the requirement of the bid range capacity test as part of a package of market enhancements for Summer 2021 Readiness.[3]

This report includes DMM's analysis of the impact of these errors and the proposed changes on the bid range capacity test during the August heat wave. This analysis shows that the ISO passed the bid range capacity test in all intervals during the August heat wave in part because of the two errors identified by the ISO. The analysis shows that increasing the requirement by accounting for net load uncertainty would have further increased the frequency of failed intervals during this period.

Based on further review of the bid range capacity test, DMM recommends that the ISO consider eliminating additional capacity, which is unavailable because of various operating limitations that are independent of energy imbalance market transfers. Some examples of constrained capacity in this category include the following:

(1) Capacity limited by maximum or fixed operating levels due to exceptional dispatches issued by grid operators.

(2) Capacity with start times beyond the horizon of the real-time market.

(3) Capacity constrained by resource-level ramping constraints immediately following an outage.

DMM's analysis indicates that this category of constrained capacity accounted for most of the constrained resource capacity in the CAISO that was included in the test during hours when load was curtailed on August 14 and 15.

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1 *Resource Sufficiency Evaluation*, January 13, 2021. http://www.caiso.com/InitiativeDocuments/Presentation-MarketEnhancements-Summer2021ReadinessJan13,2021Workshop.pdf

2 Mirror resources are import and export schedules into or out of an EIM area to model power flow from the EIM area perspective at ISO intertie scheduling points. This allows the market to solve for both the California ISO and adjacent EIM areas simultaneously.

3 *Market Enhancements for Summer 2021 Readiness*, March 19, 2021. http://www.caiso.com/InitiativeDocuments/FinalProposal-MarketEnhancements-Summer2021Readiness.pdf .

System market power

- **Market results were competitive in the fourth quarter**. DMM estimates that the impact of gas and import resources bidding above reference levels reflecting marginal costs was about $1.11/MWh or about 2.5 percent, a slight decrease from the $1.42/MWh or 2.6 percent for the previous quarter.
- **The ISO's markets were structurally uncompetitive in more hours** than any other fourth quarter since at least 2015, but were structurally uncompetitive in fewer hours than the third quarter.
- **Market power has had a very limited effect on system market prices** even during hours when the ISO system was structurally uncompetitive. However, DMM continues to caution that if market conditions continue to tighten with increased frequency and become more predictable and sustained, the potential for system-level market power in hours when scarcity does not exist may increase significantly.
- **DMM supports the ISO's proposal to continue with an initiative to design system market power mitigation.** The ISO has not included this initiative in the set of fast-tracked changes for implementation prior to summer 2021 and will resume this initiative later in 2021 or 2022.
- **DMM recommends the ISO consider developing the capability to implement a simpler method to mitigate system market power** should conditions warrant before this initiative is fully completed and implemented. Specifically, DMM has suggested that the process already used for local market power mitigation could be applied system-wide based on a much simpler criteria (e.g., hours when net loads are forecast to be over a certain level).

1 Market performance

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

- **Market prices** were competitive and slightly higher than the same quarter of 2019. Average ISO monthly 5-minute prices were lower than both 15-minute and day-ahead market prices during the fourth quarter. Day-ahead prices averaged about $41/MWh, 15-minute prices averaged $42/MWh, and 5-minute prices averaged $34/MWh.
- **The total estimated wholesale cost of serving ISO load** in the fourth quarter was about $2.4 billion ($47/MWh), a modest increase from $2.3 billion ($44/MWh) in the same quarter of 2019. After adjusting for natural gas costs and changes in greenhouse gas prices, wholesale electric costs increased by 6 percent to $42/MWh from $40/MWh in the same quarter of 2019. In addition to slightly higher load-weighted natural gas costs, lower hydro-electric generation contributed to higher wholesale energy costs this quarter.
- **Gas prices** decreased at SoCal Citygate and increased at PG&E Citygate compared to the same quarter in 2019. The ISO enforced maximum gas burn constraints in both day-ahead and real-time markets in selected sub-regions of the SoCalGas service area between September 14 and October 24. On November 4, the ISO implemented a new gas limitation shaping tool which will offer operators additional flexibility in shaping daily limitations.
- **Average loads were higher** in the fourth quarter of 2020 relative to 2018 and 2019, because of higher than normal peak temperatures in October.
- **Renewable production** increased by 11 percent compared to the same quarter in 2019 for non-hydro resources, while hydroelectric production decreased by 40 percent.
- **Generation outages** over the quarter were higher than any quarter in the previous five years. The increase was driven by outages for forced maintenance.
- **Flexible ramping product** system level prices were zero for around 99 percent of intervals in the 15-minute market and 99.9 percent of intervals in the 5-minute market for each of upward and downward flexible ramping capacity. Some resources supplying flexible ramping capacity continue to be unable 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 ISO introduced a minimum area flexible ramping product procurement requirement** in November. The minimum requirement bound frequently for the ISO but not other areas, and is applied in the 15-minute market but not the 5-minute market. 15-minute prices in the ISO were zero in 93 percent of intervals.
- **Bid cost recovery payments** for the fourth quarter of 2020 totaled about $37 million, or about $25 million less than the previous quarter and about $10 million higher than the same quarter of 2019.
- **Congestion.** In the day-ahead market, congestion increased SDG&E area prices. Total day-ahead congestion rent was $103 million, a reduction from $220 million in the previous quarter and $104 million in the same quarter of the previous year.

- **Congestion revenue rights** auction revenues were $6 million less than payments made to non-load-serving entities during the fourth quarter of 2020, representing about 6 percent of day-ahead congestion rent. The losses as a percent of day-ahead congestion rent were well below the average of 28 percent during the three years before the Track 1A and 1B changes (2016 through 2018).
- **Real-time offset costs totaled** $57 million in the fourth quarter, for an annual total of $177 million, the highest annual total since the introduction of the 15-minute market in 2014.
- **Ancillary service payments** rose to about $49 million, compared to about $23 million in the same quarter of the previous year. Higher payments were driven, in part, by higher requirements for both regulation and operating reserves.
- **Imbalance conformance adjustments** made by system operators reached an average of 1,100 MW during the peak net load ramp hour in the fourth quarter, continuing a dramatic increase in operator use of imbalance conformance that began in 2017.

1.1 Supply conditions

1.1.1 Natural gas prices

Electricity prices in western states typically follow natural gas price trends because natural gas units are often the marginal source of generation in the ISO and other regional markets. During the fourth quarter of 2020, natural gas prices at SoCal Citygate were slightly lower on average than during the same quarter in 2019.

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 the Henry Hub trading point, which acts as a point of reference for the national market for natural gas. SoCal Citygate prices often affect 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. As shown in the figure, natural gas prices at these major gas trading hubs started to rise at the beginning of the fourth quarter of 2020.

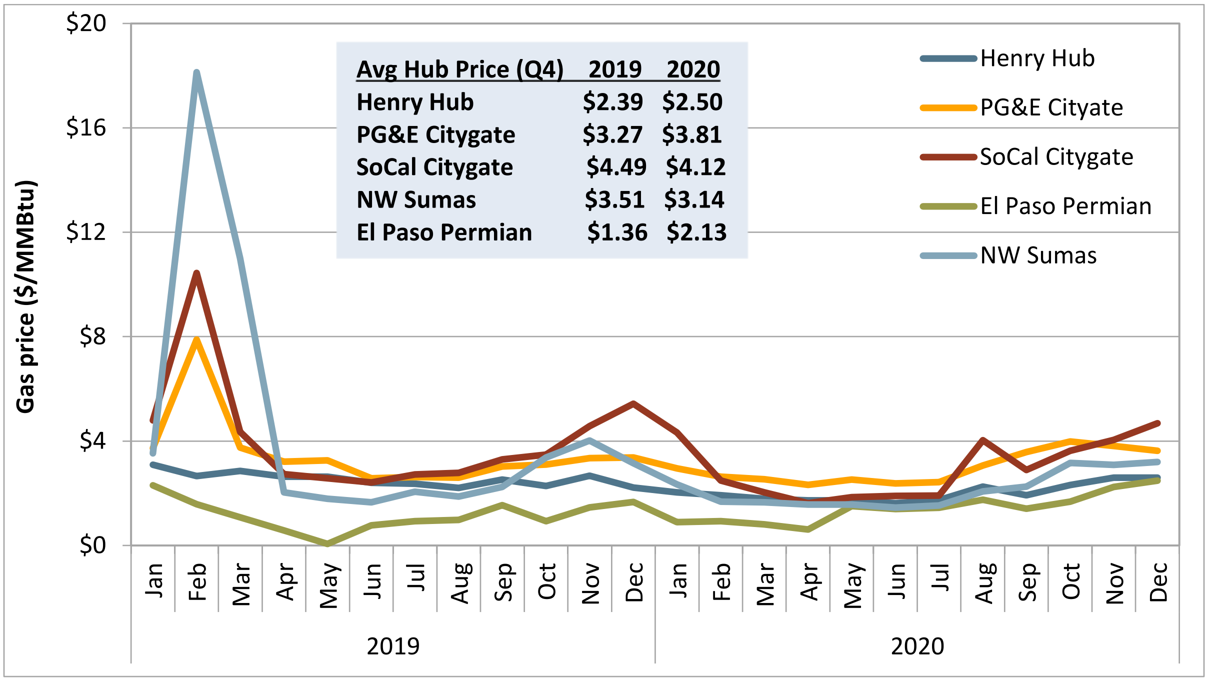
Prices at the SoCal Citygate gas hub averaged $4.12/MMBtu compared to $4.50/MMBtu in the fourth quarter of 2019. The Aliso Canyon protocol remains in effect making the facility available for withdrawals for Stage 2 or above low operational flow orders (OFO) to help mitigate price spikes and maintain system reliability.[4] In the fourth quarter, SoCalGas withdrew gas from Aliso Canyon storage facility on 18 gas days.

In addition, for the period October 1, 2020, through May 31, 2021, SoCalGas temporarily expanded the number of OFO non-compliance stages from 5 to 8. The non-compliance charge for Stage 3 OFO follows a tiered structure ranging from $5/Dth to $20/Dth; Stage 4 and Stage 5 OFOs will be set at $25/Dth. This

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

is consistent with the California Public Utilities Commission's ruling on April 29, 2019.[5] With the revisions from the ruling set to expire in October 2021, DMM submitted comments to a new CPUC ruling to revise the existing OFO penalty structure.[6] During the fourth quarter, SoCalGas Company declared low OFOs on 29 gas days, primarily either Stage 1 or Stage 2.

Figure 1.1 Monthly average natural gas prices



1.1.2 Aliso Canyon gas-electric coordination

In the fourth 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 the period September 14 through October 24. The gas burn constraint was enforced to facilitate pipeline maintenance work in the southern system of the SoCalGas area.

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.

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

6 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

On October 31, 2019, the ISO filed tariff amendments to extend Aliso Canyon provisions permanently.[7] One of these measures gives 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 the gas burn constraints on real-time energy offset costs.[8] 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.[9]

Effective November 4, 2020, the ISO implemented 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.[10,11] 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 October 4, 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.[12]

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

8 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

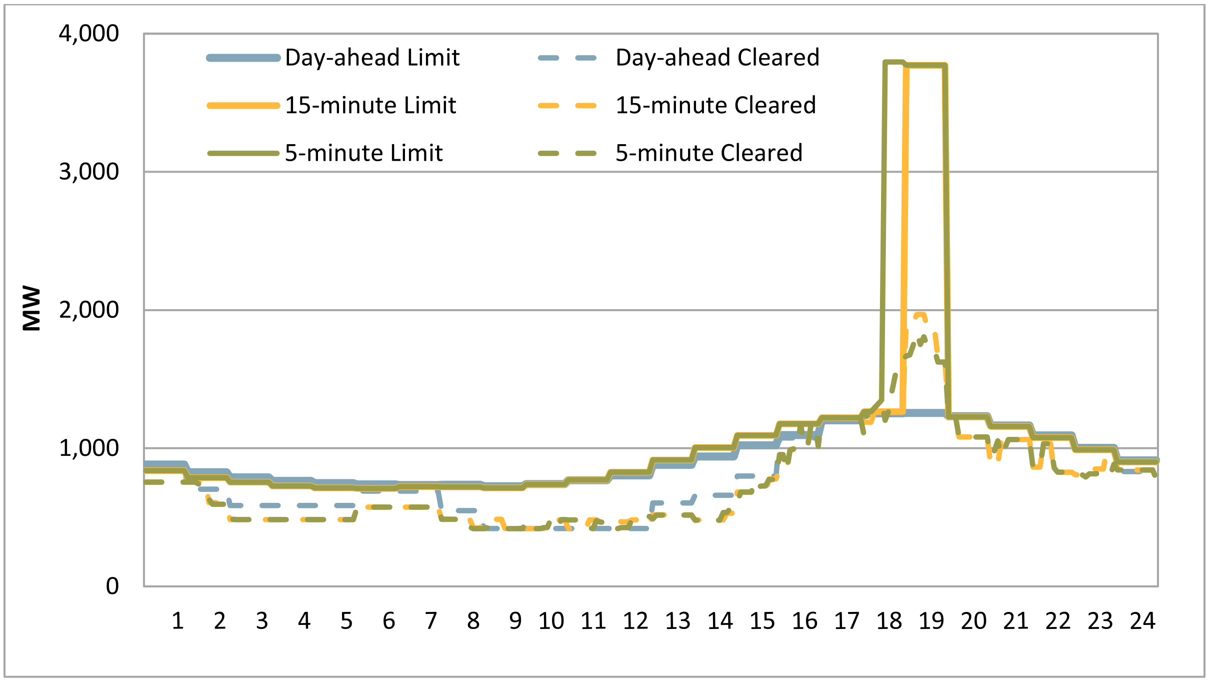
9 FERC Order accepting Aliso Canyon Gas-Electric Coordination Phase 5 tariff revisions (ER20-273), December 30, 2019: http://www.caiso.com/Documents/Dec30-2019-OrderAcceptingTariffRevisions-AlisoCanyonGasElectricCoordination-MaximimGasConstraint-ER20-273.pdf

10 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

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

12 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 (Oct 4, 2020)



1.1.3 Renewable generation

In the fourth quarter, the combined average hourly generation from hydroelectric, solar, wind, geothermal, and biogas-biomass resources decreased by 1,075 MW (5 percent) compared to the same quarter of 2019. This overall decrease is primarily due to a reduction in hydroelectric generation, as generation from non-hydro renewable resources increased 11 percent over the quarter.

Figure 1.3 shows the average hourly hydroelectric, wind, and solar generation by month. Non-hydroelectric renewable generation, which includes wind, solar, geothermal, and biogas-biomass resources, increased by a total of 11 percent compared to the same quarter in 2019, primarily due to increases in geothermal and solar generation. Compared to the fourth quarter of 2019, geothermal generation increased by about 625 MW (26 percent), while biogas-biomass generation decreased by about 185 MW (12 percent).

Compared to the same period in 2019, hourly average hydroelectric production in the fourth quarter decreased by roughly 40 percent. As of April 1, 2020, the statewide weighted average snowpack in California was 50 percent of normal compared to 175 percent of normal on April 1, 2019.[13]

Compared to the fourth quarter of 2019, hourly average wind and solar production increased by about 7 percent and 13 percent, respectively. The availability of variable energy resources contributes to price patterns both seasonally and hourly due to low marginal cost, relative to other resources. Although solar and wind generation increased slightly, hydroelectric generation declined considerably compared to the same time last year.

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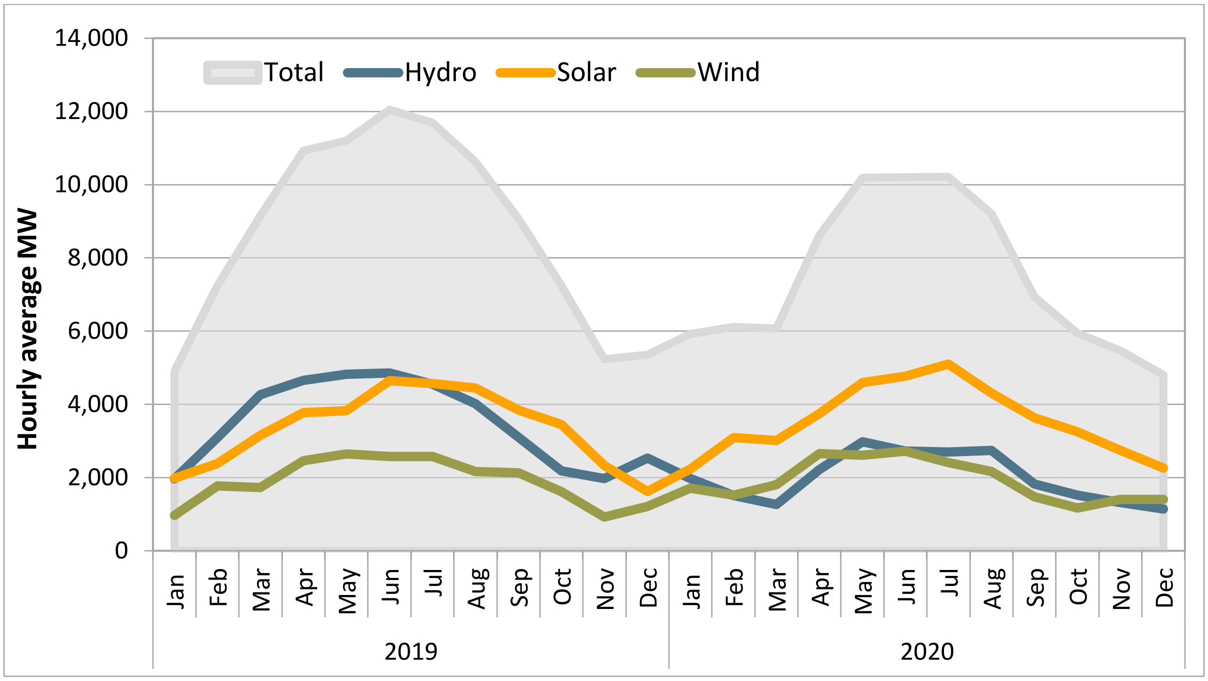
13 For snowpack information, please see California Cooperative Snow Survey's Snow Course Measurements on the California Department of Water Resources website: https://cdec.water.ca.gov/snow/current/snow/.

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



1.1.4 Generation by fuel type

In the fourth quarter, generation increased on average for some fuel types, while decreasing sharply for others. Average hourly generation by solar and geothermal resources increased by 11 percent and 26 percent, respectively, while average hourly generation by nuclear and hydroelectric fell by 18 percent and 41 percent, respectively, compared to the same quarter of 2019.[14] As shown in Figure 1.4, on average, nuclear, geothermal, and bio-based resources comprised about 2,900 MW of inflexible base generating capacity, about 200 MW less than the same quarter of 2019. Generation from "other" resources, including coal, battery storage, demand response, and additional non-gas technologies, decreased slightly this quarter and continued to be a small share of overall generating capacity at about 340 MW on average, which represents a 9 percent decrease from the fourth quarter of 2019.

[14] The primary cause of the decrease in average hourly nuclear generation is attributed to an outage that occurred during the quarter and lasted through the end of the year.

Figure 1.4 Average hourly generation by fuel type (Q4 2020)

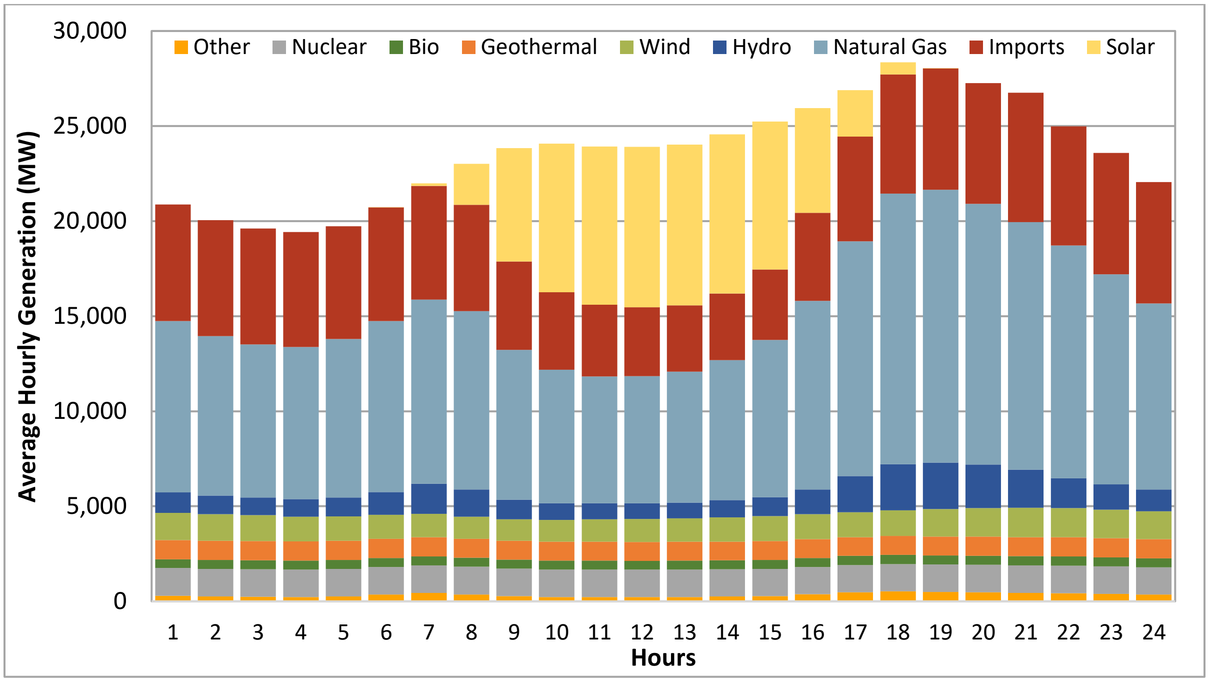
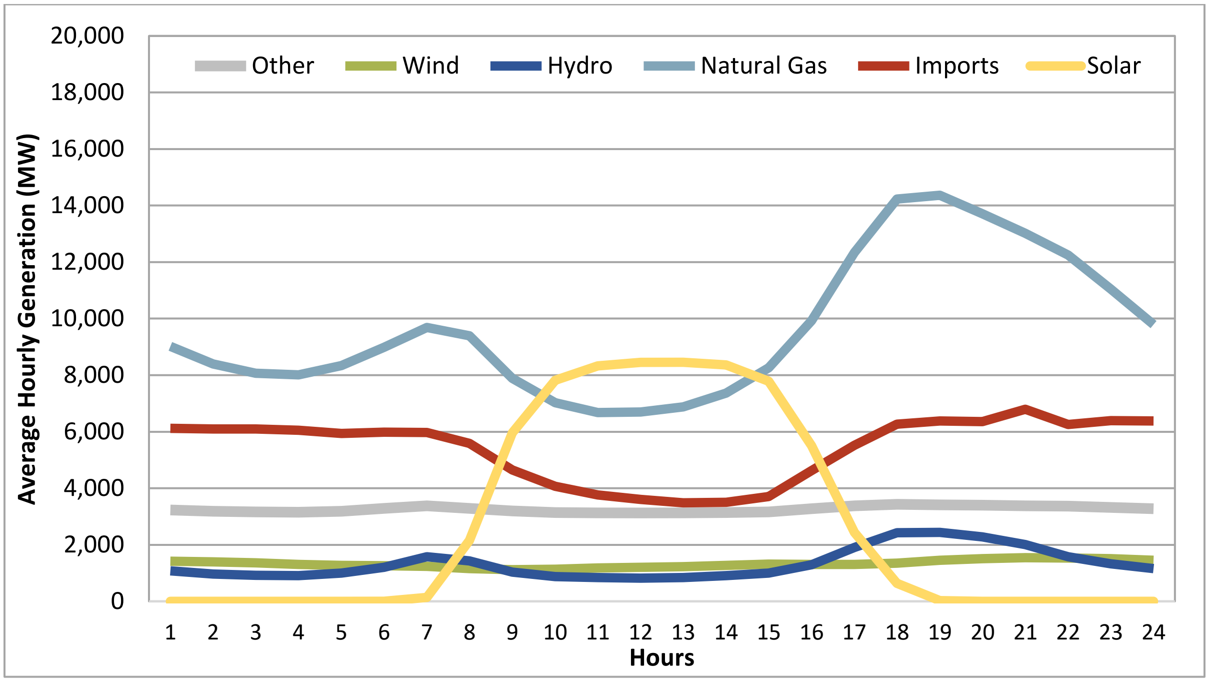


Figure 1.5 shows hourly variation of generation by fuel group, driven primarily by hourly variation of solar production. In the fourth quarter, differences in hourly average natural gas generation were similar to changes in solar production, as gas generation produced significantly more than any resource during the peak net load hours. Compared to the fourth quarter of 2019, natural gas generation variability increased 41 percent, driven by a significant decrease in hydroelectric production. Wind generation in the fourth quarter returned to having low hourly variability on average, though it increased moderately compared to the fourth quarter of 2019.

Import variability trended similarly to natural gas generation over the quarter, with a large dip in the middle of the day when solar generation peaks. Average hourly generation from resources in the "other" category was less variable throughout the day, down 1 percent compared to the same quarter of 2019.[15]

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

Figure 1.5 Hourly variation in generation by fuel type (Q4 2020)



1.1.5 Generation outages

This section provides a summary of generation outages in the fourth 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.

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 is typically performed outside of the high summer load period.

As shown in Figure 1.6, within the fourth quarter, forced outages peaked in October while planned outages peaked in November. The amount of generation on planned outage tripled in the fourth quarter compared to the previous quarter, likely due in part to the aforementioned seasonal trend in the quarterly variation of outages as well as the high frequency of restricted maintenance notices in CAISO during the third quarter. The overall increase in generation outages during the fourth quarter is due in large part to outages and de-rates of nuclear resources.

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

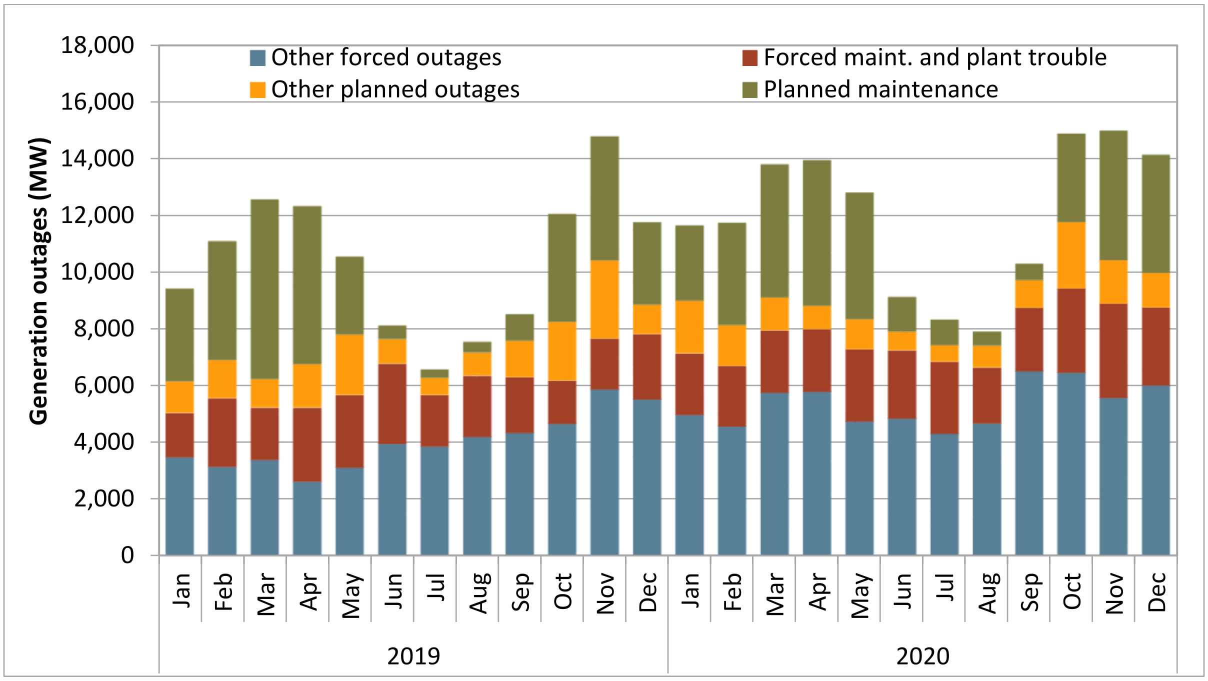
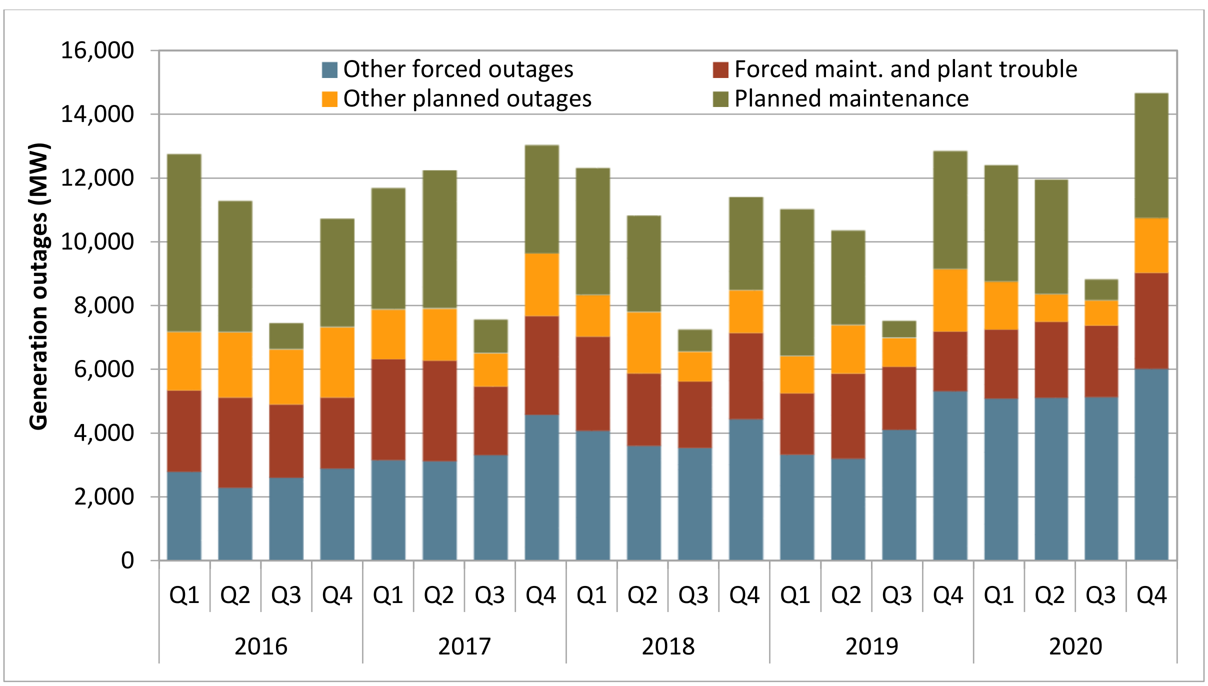


Figure 1.7 Quarterly average of maximum daily generation outages by type – peak hours



During the fourth quarter of 2020, the average total generation on outage in the ISO surpassed the same period in 2019 by about 1,800 MW, as shown in Figure 1.7.[16] Planned maintenance outages averaged about 3,900 MW, while other types of planned outages averaged about 1,700 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 reached about 9,000 MW during peak hours in the fourth quarter of 2020, about 26 percent higher than during the fourth quarter of 2019. Forced outages for either plant maintenance or plant trouble averaged about 3,000 MW, while all other types of forced outages averaged about 6,000 MW during the quarter. These other types of forced outages include ambient due to temperature, ambient not due to temperature, environmental restrictions, unit testing, and outages for transition limitations.

1.2 Load conditions

ISO load increased in the fourth quarter of 2020 relative to the same quarter in 2018 and 2019, on average. Figure 1.8 shows average hourly load by month from 2018 to 2020. This increase was driven by higher loads in October due to higher statewide temperatures relative to the same month in previous years. The statewide maximum temperature for October 2020 (81 degrees Fahrenheit) was about 6-7 degrees higher than the same month of the previous two years.[17] This resulted in an average October load 900-1,500 MW greater than the previous two years. Average loads in November and December were similar to the previous two years.

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

[17] NOAA National Centers for Environmental information, Climate at a Glance: Statewide Mapping, published January 2021, retrieved on January 21, 2021, from https://www.ncdc.noaa.gov/cag/

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

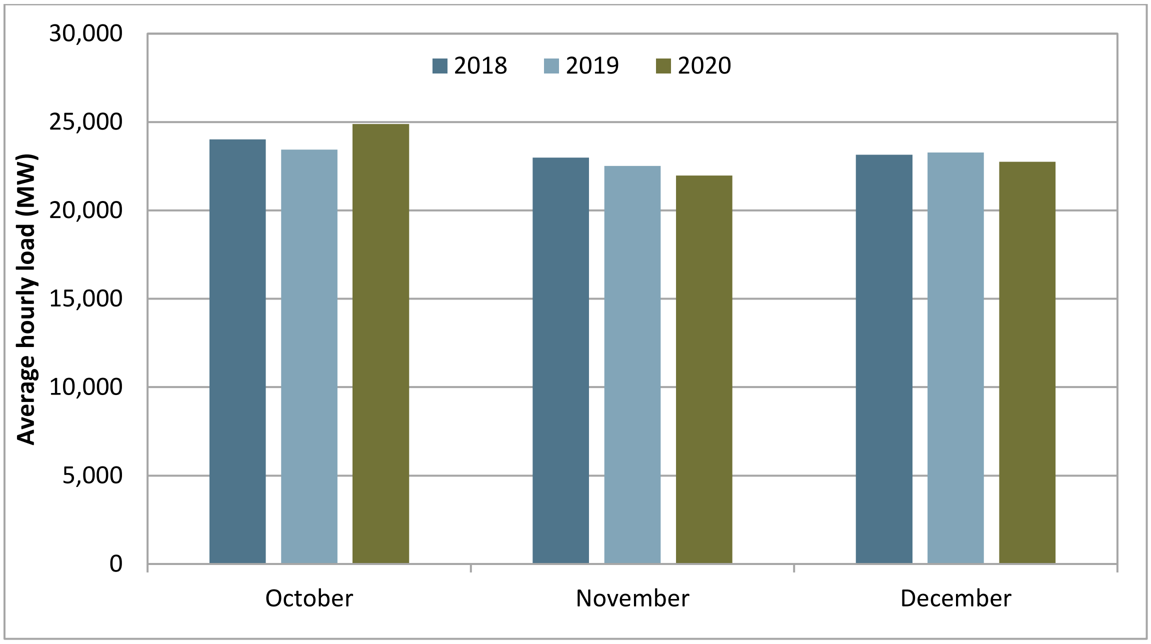


Figure 1.9 shows how the variability of the net load curve has changed over time. It shows the average hourly net load as well as the minimum and maximum hourly average net load from October 2018 to December 2020. Average net load tends to follow seasonal patterns in California by increasing during warmer months and decreasing during cooler months. Apart from this general pattern, average net loads have decreased by about 2 percent since the fourth quarter of 2018.

The figure also shows that the difference between maximum and minimum hourly average net load per month has increased over time. Net load is a measure of load minus generation from wind and solar resources. Therefore, the monthly maximum net load is influenced by the high net loads in the evenings when the combination of wind and solar resource production is low; the minimum monthly net load is influenced by the low net loads during the middle of the day when the combination of solar and wind production is at its highest. An increase in this difference over time is indicative of increased penetration 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 1.9 Average hourly net load by month (2018-2020)

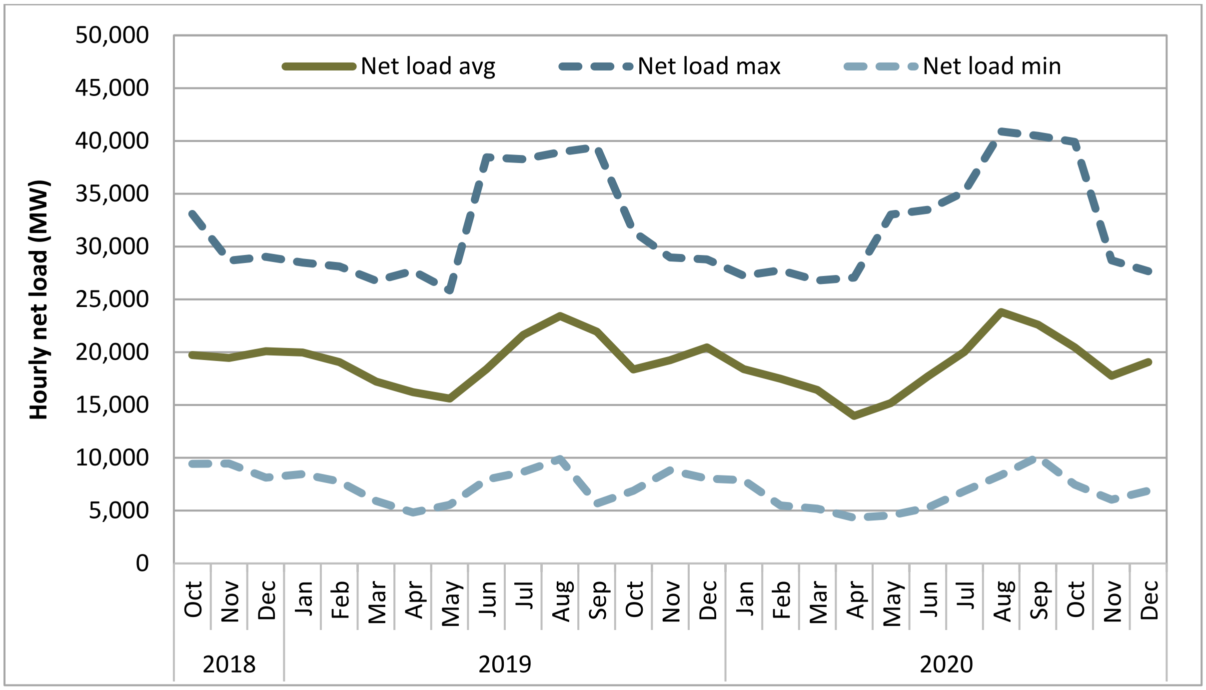
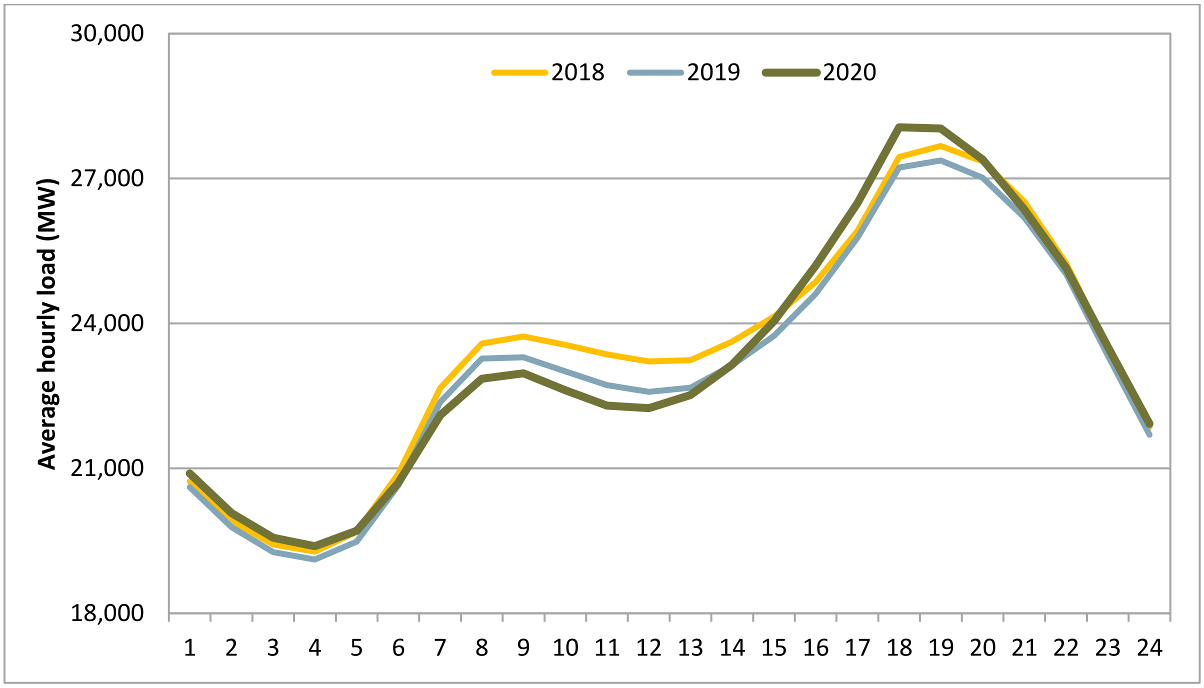


Figure 1.10 offers insight into how behind-the-meter solar resources affect ISO load. Generation from utility scale wind and solar resources indirectly affects load by influencing how other generation sources must meet demand after wind and solar have been factored out, i.e., the net load. Conversely, generation from behind-the-meter solar resources directly reduces the amount of load that must be met by generation from the ISO market, regardless of source.

The figure shows average load by hour in the fourth quarter of 2018 to 2020. Average hourly load tracked closely together in the fourth quarter of 2018 and 2019 except for the morning and afternoon peaks. The slightly lower morning peak load may be due to the continued decrease in commercial and industrial load and corresponding increase in residential load due to COVID-19. The higher afternoon peak loads for this quarter were greater than the previous two years due to higher than normal temperatures in the beginning of October.

Though not as pronounced in the fourth 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.

Figure 1.10 Average load by fourth quarter hour (2018-2020)



1.3 Energy market performance

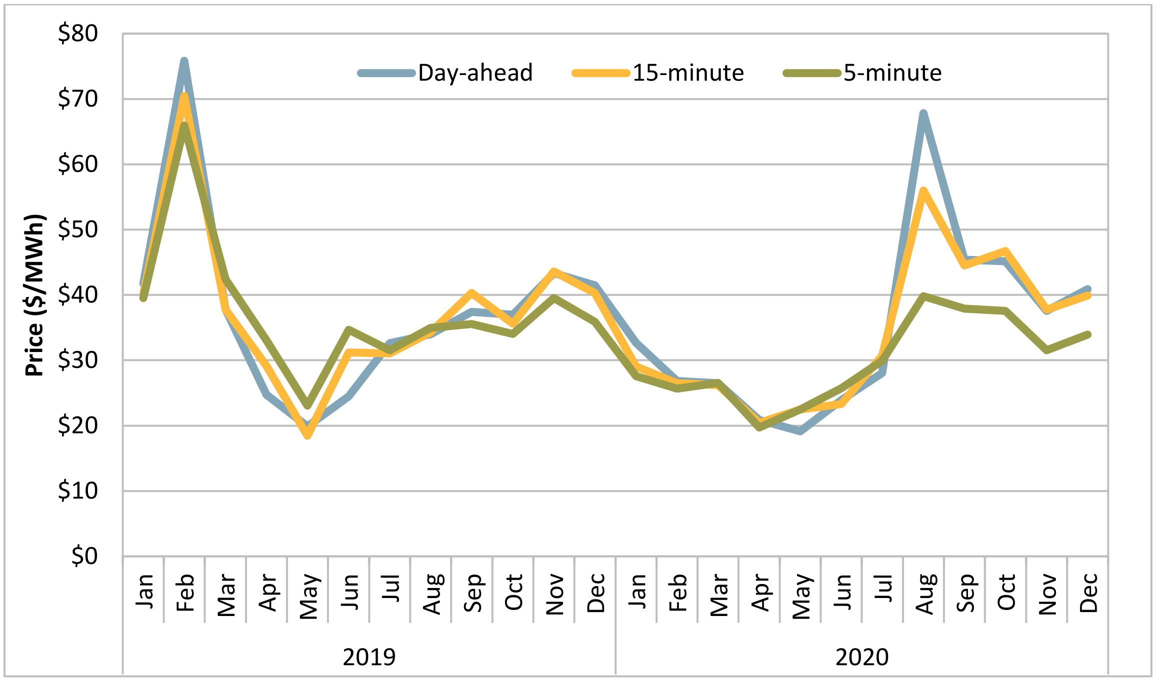
1.3.1 Energy market prices

This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. Price convergence between these markets may help promote efficient commitment of internal and external generating resources. Compared to the fourth quarter of 2019, 5-minute market prices were 6 percent lower while prices in the day-ahead and 15-minute market increased slightly.

Prices in the 5-minute market decreased to an average of $34/MWh. This decline reflects the increasing divergence of 5-minute market prices from the other two markets. Day-ahead and 15-minute market prices increased 1 percent and 4 percent, respectively, to averages of $41.20/MWh and $41.50/MWh. The marginal increase in these prices is driven by substantially higher prices in October compared to last year.

Figure 1.11 shows load-weighted average monthly energy prices during all hours across the four largest 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 December 2020.

Figure 1.11 Monthly load-weighted average energy prices (all hours)



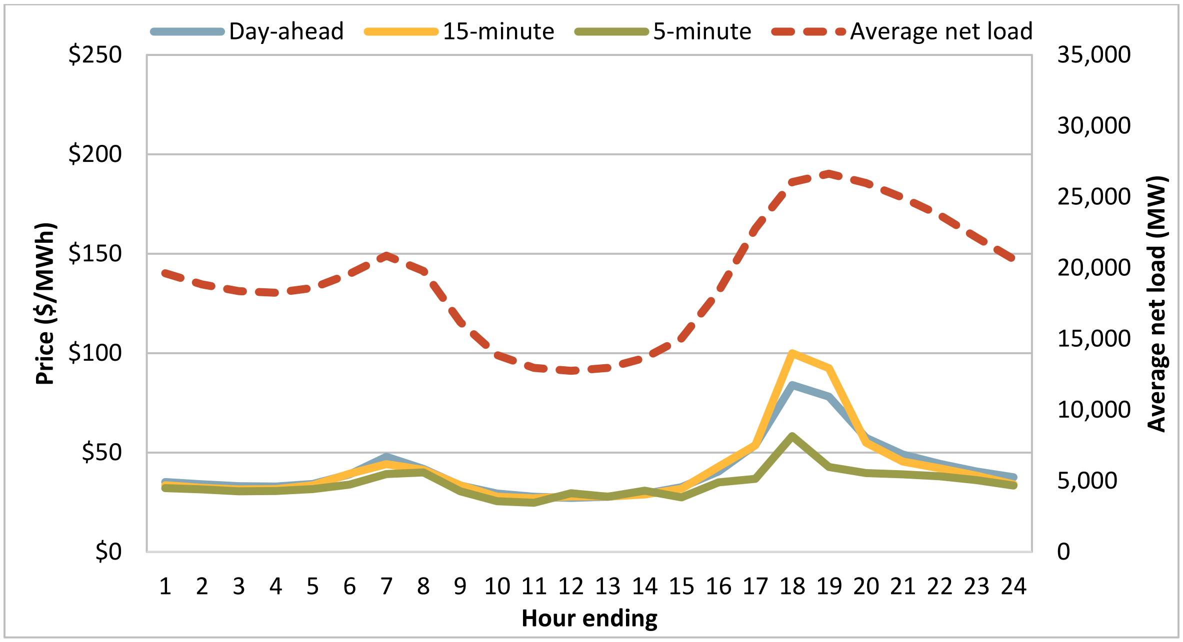
Average prices in this quarter were similar to that of the fourth quarter last year. However, analyzing the trends by month we see that prices in all three markets were substantially higher in October of 2020 compared to October 2019. Day-ahead and 15-minute market prices were 20-30 percent higher. These higher prices are correlated with higher demand in October due to warmer weather along with less renewable generation, compared to October 2019. Average prices in each market were considerably lower (13-20 percent) in November and slightly lower in December compared to the previous year.

The figure shows that the divergence of 5-minute market prices from the day-ahead and 15-minute market was more pronounced in both the fourth quarters of 2019 and 2020 compared to the rest of the year. In this quarter last year, prices in the 5-minute market were 6-8 percent lower than the other two markets, while this year that separation increased to 12-13 percent.

Figure 1.12 illustrates load-weighted average energy prices on an hourly basis in the fourth quarter compared to average hourly net load.[18] 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.

[18] 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 1.12 Hourly load-weighted average energy prices (October - December)



Average hourly prices continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours. The peak prices in hour ending 18 were 10-20 percent higher, depending on the market, in this quarter compared to the fourth quarter last year. The figure shows that the trend of lower 5-minute prices over the quarter was primarily due to the divergence of real-time prices during peak net load hours. Lower real-time prices is a persistent pattern that appears to be driven in part by systemic differences between 5-minute market imbalance conformance and imbalance conformance in other markets.

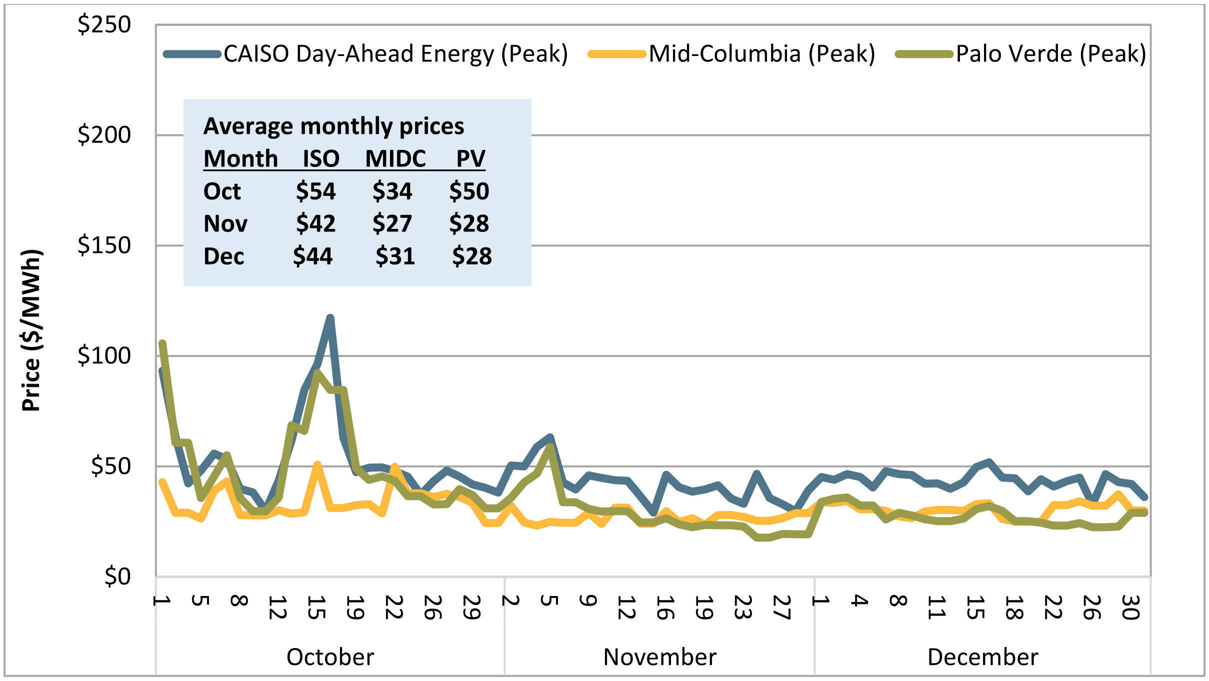
1.3.2 Bilateral price comparison

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

Figure 1.13 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 the 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 the figure, the day-ahead ISO prices exceeded Mid-Columbia and Palo Verde prices during most of the fourth quarter.

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 $15/MWh and $10/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 $2/MWh and $0.25/MWh, respectively.

Figure 1.13 Day-ahead ISO and bilateral market prices (Oct – Dec)



Imports and exports

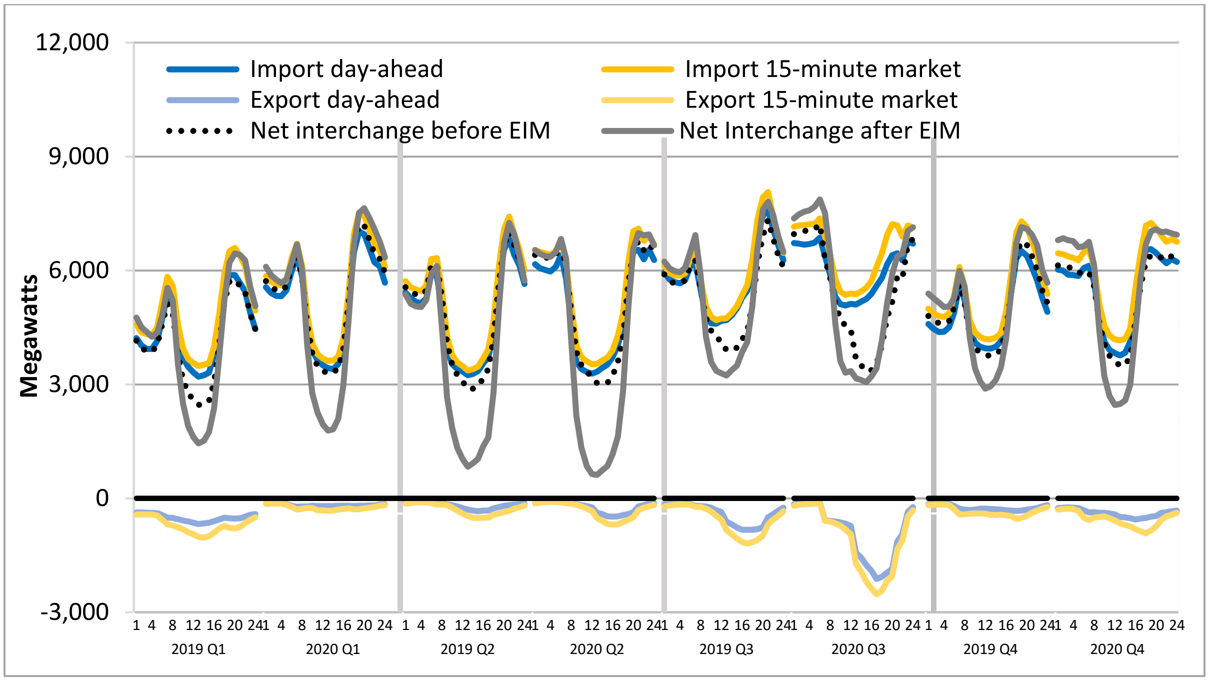
Average net imports increased compared to the same quarter in 2019, in the hour just before the morning and after the evening peak periods. This may be due to low hydroelectric production caused by California's 2020 drought conditions.[19]

As shown in Figure 1.14, peak imports in the day-ahead (dark blue line) increased slightly in hour ending 19, from about 6,510 MW to 6,570 MW compared to the fourth quarter of 2019. Peak 15-minute cleared imports (dark yellow line) decreased slightly from about 7,300 MW to 7,260 MW compared to last year. Peak exports (shown as negative numbers below the horizontal axis in pale blue and yellow), increased compared to the fourth quarter of 2019 by about 230 MW and 380 MW in the day-ahead and 15-minute markets, respectively.

The average net interchange excluding EIM transfers (dashed grey line) 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 2,400 MW in hour ending 12. The greatest import transfer into the ISO from the EIM occurred in hour ending 7 at about 800 MW, compared to about 640 MW in hour ending 22 from the same quarter in the prior year. The greatest export transfer from the ISO to the EIM occurred in hour ending 12 at about 1,150 MW, an increase of about 250 MW from the same quarter in 2019.

[19] U.S. Drought Monitor Conditions for California: https://www.drought.gov/states/california

Figure 1.14 Average hourly net interchange by quarter



1.4 Wholesale energy cost

Total wholesale cost to serve load in the ISO market during the fourth quarter of 2020 was about $2.4 billion, a slight increase from about $2.3 billion in the same quarter of 2019. The average cost per megawatt-hour of load increased about 7 percent to about $47/MWh for the fourth quarter from just over $44/MWh in the same quarter of 2019 (nominal costs shown in blue bars in Figure 1.15).

The increase in average wholesale electric prices is partially from a 1 percent increase in natural gas prices compared to the same quarter in 2019. Load-weighted gas prices increased to about $4.90/MMBtu compared to about $4.85/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 1.15 shows the wholesale energy costs to serve load increased by 6 percent to about $42/MWh from about $40/MWh in the same quarter of 2019. In addition to slightly higher natural gas costs, lower hydro-electric generation contributed to higher wholesale energy costs this quarter.

Figure 1.15 Total quarterly wholesale costs per MWh of load

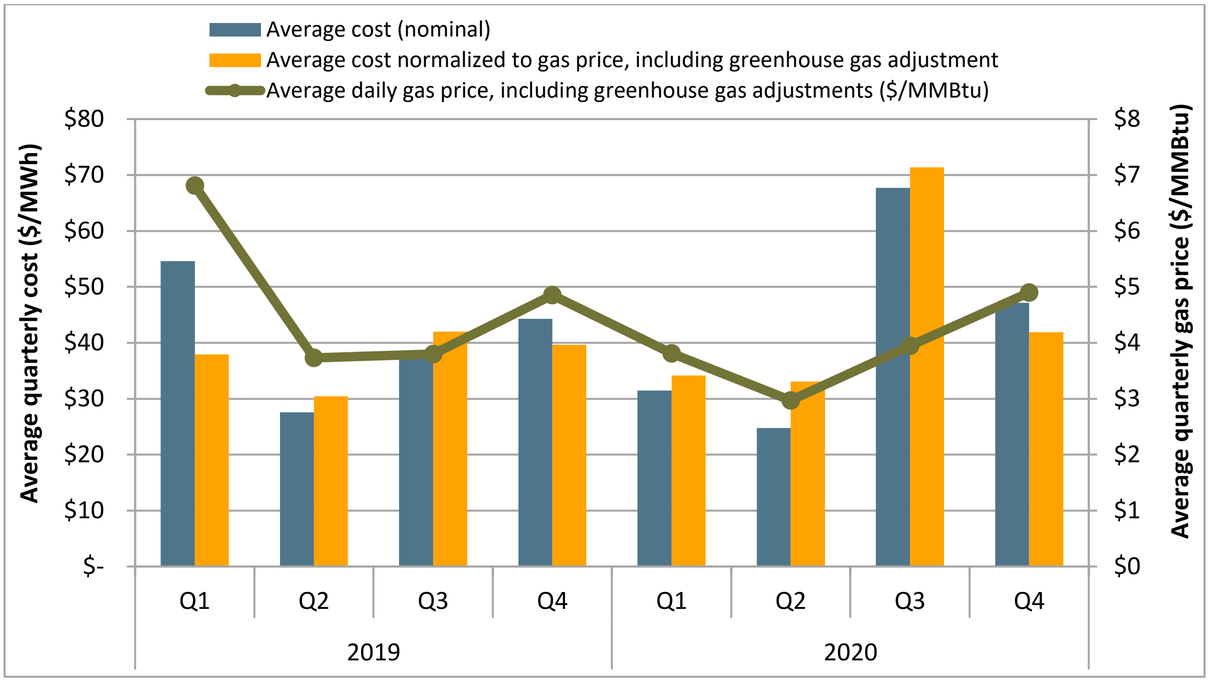


Table 1.1 provides quarterly summaries of nominal total wholesale costs by category. Costs for energy procured in the day-ahead market continued to make up a majority (91 percent) of the total cost to deliver energy to the market, slightly above the previous quarter but a decrease compared to the fourth quarter of 2019. Real-time market costs were about 4 percent of the total cost, similar to both the previous quarter and the same quarter the previous year. Bid cost recovery, reliability, and reserve costs remained low, but increased compared with the same quarter in 2019.

Table 1.1 Estimated average wholesale energy costs per MWh

	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Change Q4 2019-Q4 2020
Day-ahead energy costs	$ 41.36	$ 29.48	$ 22.17	$ 54.68	$ 43.10	$ 1.73
Real-time energy costs (incl. flex ramp)	$ 1.45	$ 0.51	$ 1.24	$ 2.61	$ 1.91	$ 0.46
Grid management charge	$ 0.46	$ 0.45	$ 0.47	$ 0.48	$ 0.45	$ (0.01)
Bid cost recovery costs	$ 0.45	$ 0.34	$ 0.35	$ 0.94	$ 0.64	$ 0.20
Reliability costs (RMR and CPM)	$ 0.06	$ 0.03	$ 0.00	$ 0.13	$ 0.12	$ 0.06
Average total energy costs	**$ 43.78**	**$ 30.82**	**$ 24.24**	**$ 58.83**	**$ 46.22**	**$ 2.44**
Reserve costs (AS and RUC)	$ 0.50	$ 0.65	$ 0.50	$ 1.72	$ 1.01	$ 0.51
Average total costs of energy and reserve	**$ 44.28**	**$ 31.47**	**$ 24.74**	**$ 60.55**	**$ 47.23**	**$ 2.95**

1.5 Price variability

Day-ahead market prices range greatly over the course of a year, with periods of high and low prices. These variations tend to follow seasonal patterns, primarily due to the availability of variable energy resources such as wind and solar. 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.

One of the fundamental differences between the day-ahead market and the real-time market is the participants who may place a bid. Bids in the day-ahead market are from ISO market participants, while the real-time market includes bids from both ISO and EIM participants.[20] Due in part to this difference, the magnitude of the variation tends to be higher in the real-time market.

1.5.1 Day-ahead price variability

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

High prices

Figure 1.16 shows the frequency of day-ahead market prices in various high priced ranges from October 2019 to December 2020. The frequency of hours with prices over $100/MWh increased compared to last year's fourth quarter; this is driven by an increase in high day-ahead prices in October.

Negative prices

Figure 1.17 shows the frequency of day-ahead market prices in various low priced ranges from October 2019 to December 2020. Similar to the previous quarter and the fourth quarter of 2019, there were no negative day-ahead prices in the fourth quarter of 2020, even during the mid-day hours when generation from solar is highest and load is relatively low.

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

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

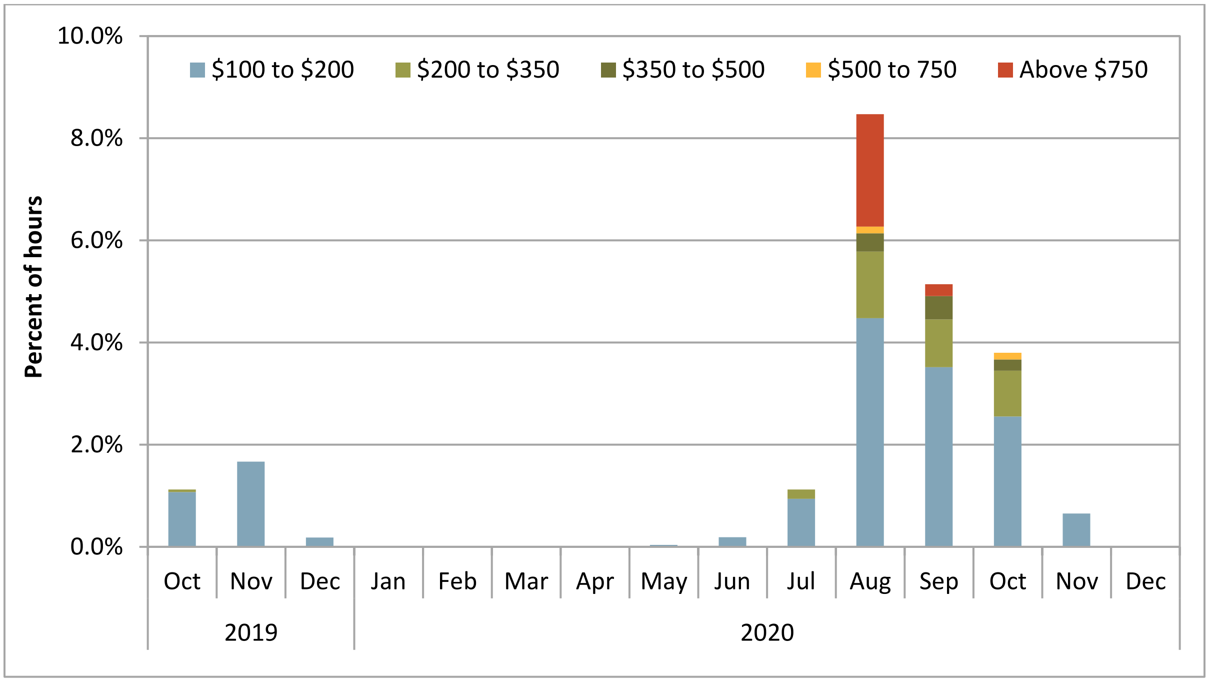
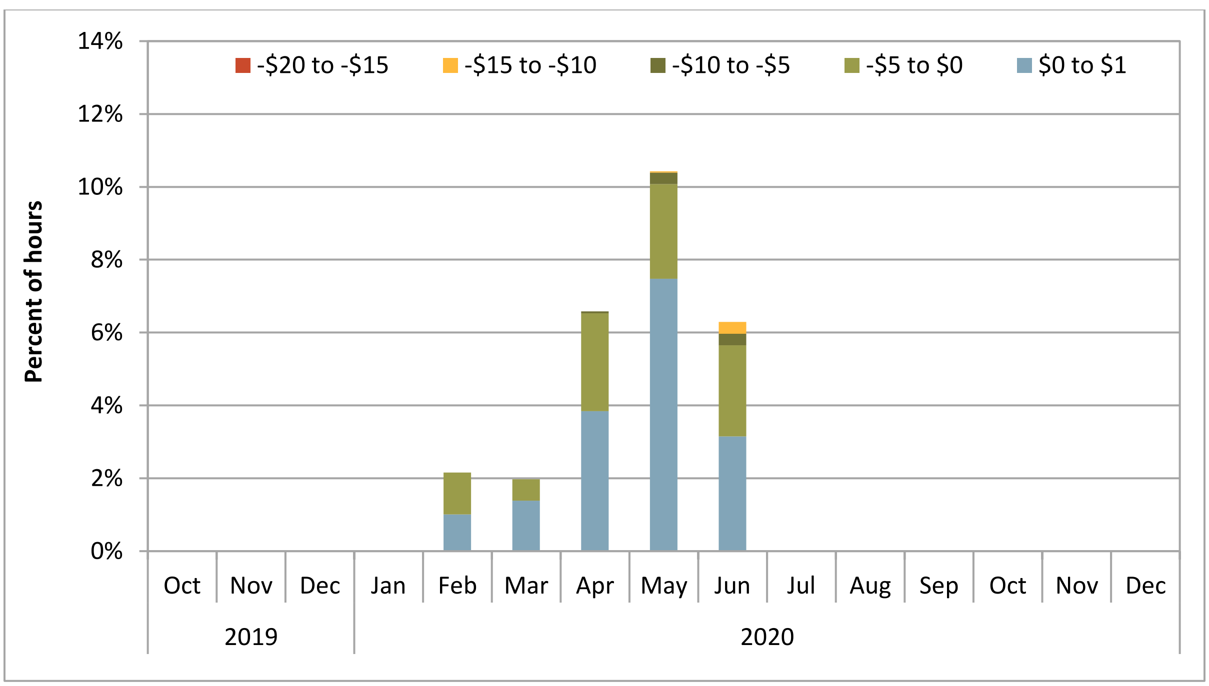


Figure 1.17 Frequency of negative day-ahead prices ($/MWh) by month



1.5.2 Real-time price variability

During the fourth quarter of 2020, the frequency of high real-time prices was low, down significantly from the previous quarter. The frequency of negative prices in the real-time markets also remained low during the quarter.

High prices

Figure 1.18 and Figure 1.19 show the frequency of prices above $250/MWh across the three largest load aggregation points (LAP) in the ISO. As shown in Figure 1.18, the occurrence of high prices in the 15-minute market greater than $250/MWh was much less frequent from the previous quarter but was still higher relative to the fourth quarter of 2019.

Figure 1.19 shows the frequency of high prices in the 5-minute market. During the quarter, the frequency of price spikes greater than $250/MWh also decreased steadily from the previous quarter.

Figure 1.20 and Figure 1.21Figure 1.20 show the corresponding frequency of under-supply infeasibilities in the 15-minute and 5-minute markets. Valid under-supply infeasibilities in the 15-minute market were limited to October, occurring in 0.3 percent of intervals. In the 5-minute market, valid under-supply infeasibilities were infrequent, occurring in less than 0.1 percent of 5-minute market intervals.

Infeasibilities resolved by the load conformance limiter continued to be infrequent and had an insignificant impact on prices in the ISO. This is because in most intervals when the limiter triggers in the ISO, the highest priced bids dispatched are often at or near the $1,000/MWh bid cap such that the resulting price is often very similar with or without the limiter.

Figure 1.18 Frequency of high 15-minute prices by month (ISO LAP areas)

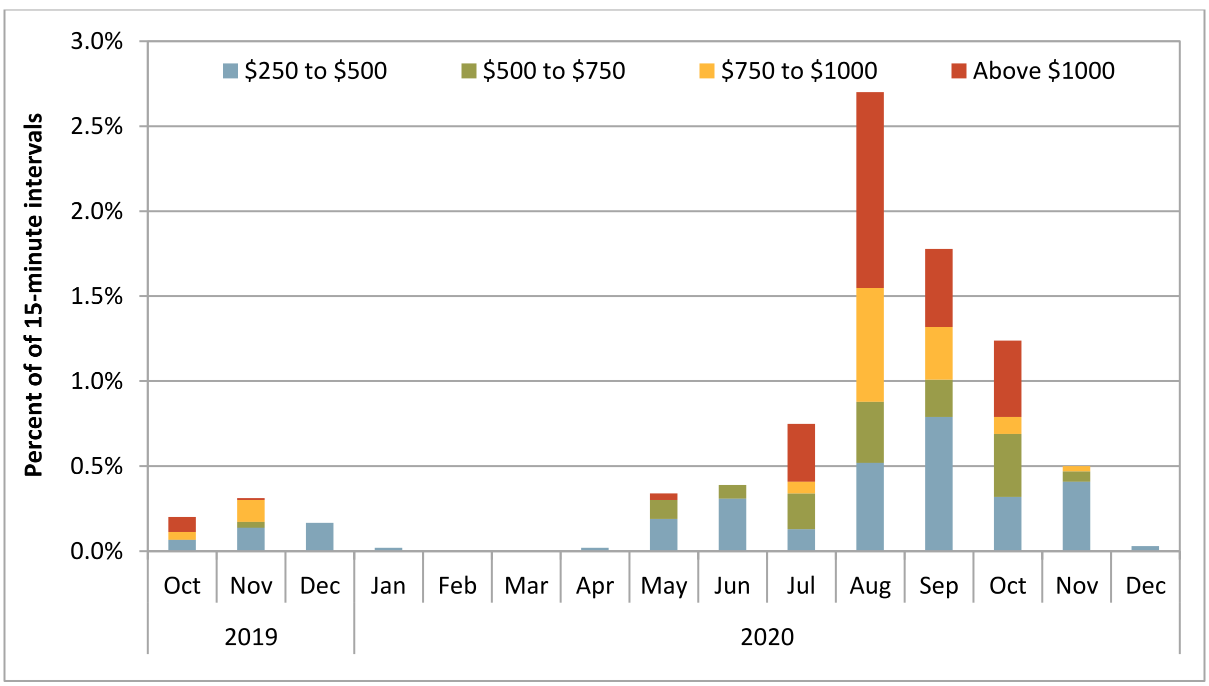


Figure 1.19 Frequency of high 5-minute prices by month (ISO LAP areas)

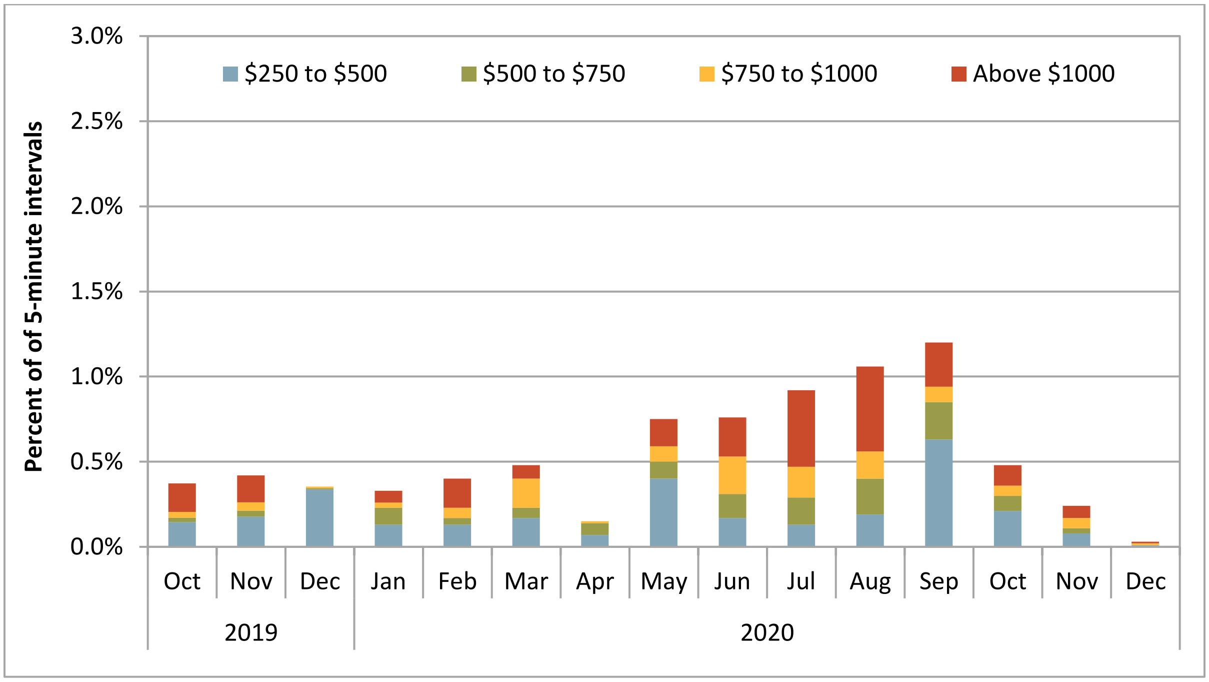


Figure 1.20 Frequency of under-supply power balance constraint infeasibilities (15-minute market)

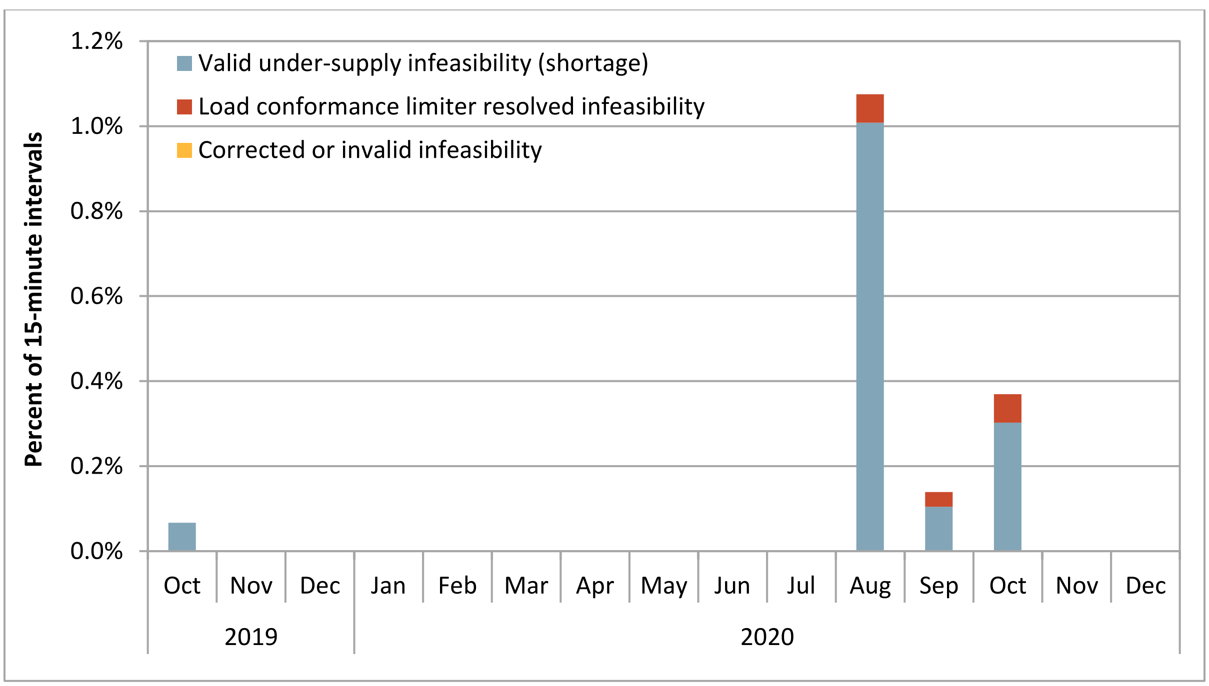
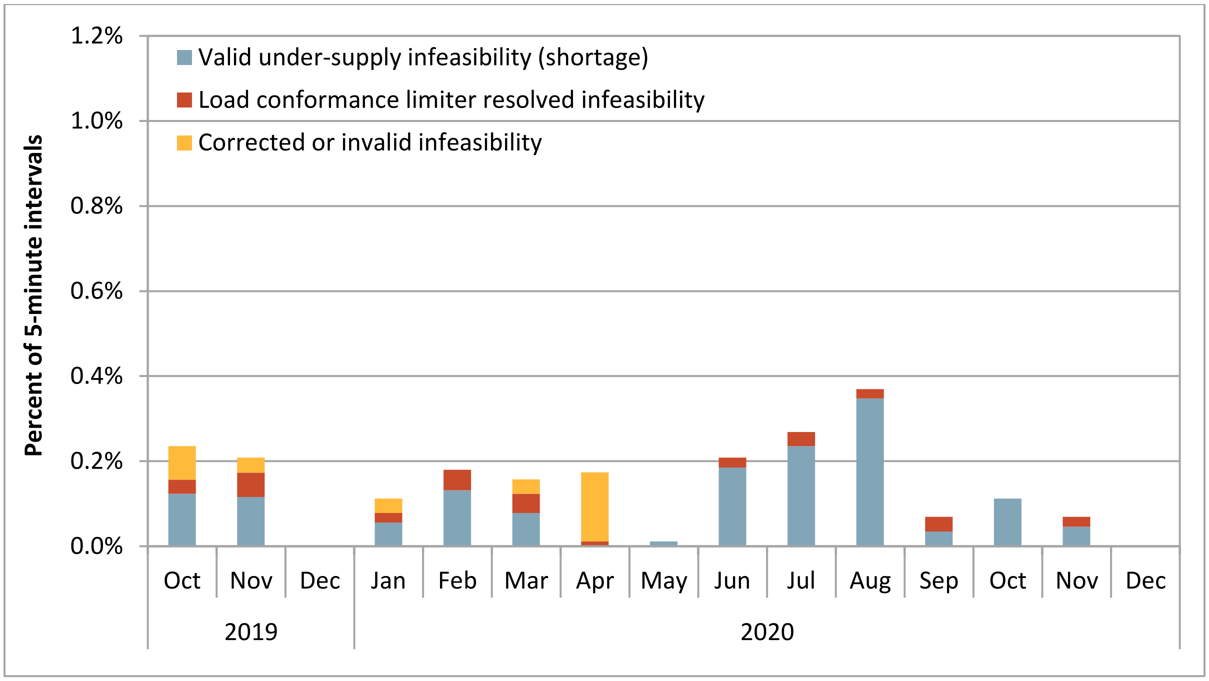


Figure 1.21 Frequency of under-supply power balance constraint infeasibilities (5-minute market)



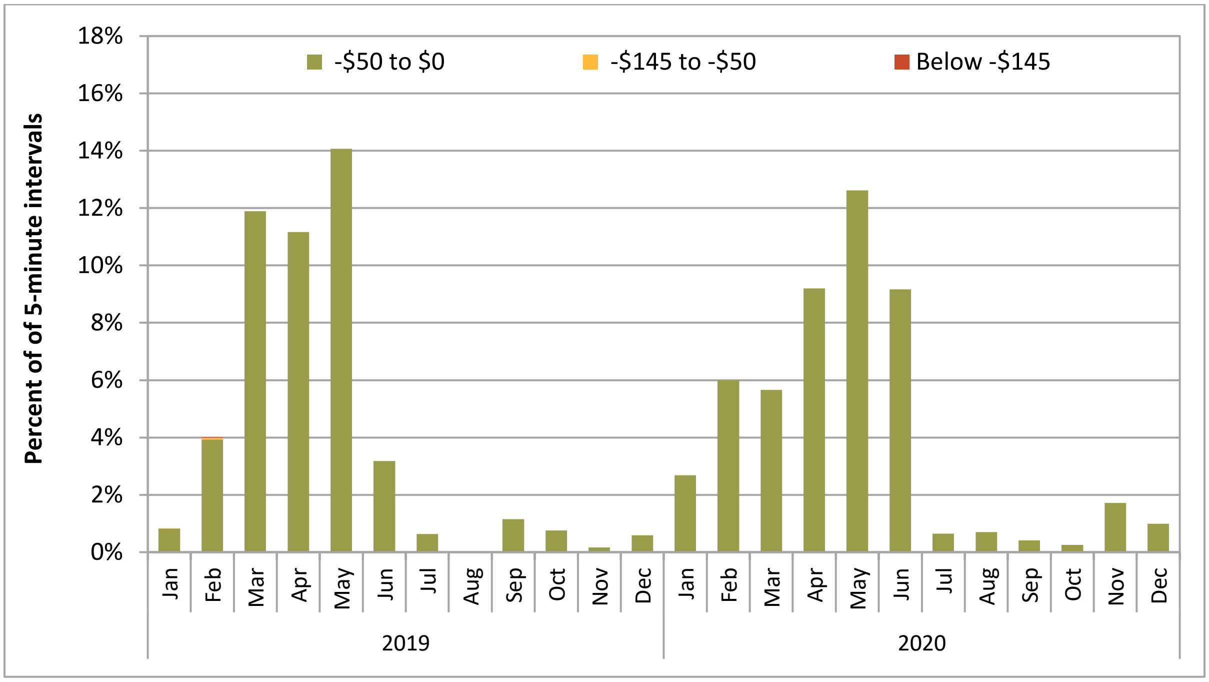
Negative prices

Figure 1.22 shows the frequency of negative prices in the 5-minute market by month across the three largest load aggregation points in the ISO.[21] The frequency of negative prices in the 15-minute and 5-minute markets remained low. Negative prices occurred during about 0.3 percent of 15-minute market intervals and 1 percent of 5-minute market 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 quarter, this was most frequent between hours ending 9 and 16 when loads, net of wind and solar, were lowest.

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

Figure 1.22 Frequency of negative 5-minute prices by month (ISO LAP areas)



1.6 Flexible ramping product

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

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

1.6.1 Minimum flexible ramping product requirement

There are separate demand curves calculated for each energy imbalance market area in addition to a system-level demand curve. The system-level demand curve for the entire footprint is always enforced in the market while the uncertainty requirement for the individual balancing areas is reduced in every interval by their transfer capability.[22] Previously, if the transfer capability for each area was sufficient, then only the system-level uncertainty requirement was active.

The flexible ramping product refinements stakeholder initiative introduced a new minimum flexible ramping product requirement. Effective in early November 2020, if a balancing authority area requirement individually is greater than 60 percent of the system requirement, then a minimum will be enforced equal to the balancing authority area's share of the diversity benefit.[23] The minimum requirement is intended to help mitigate some of the issues surrounding procurement of stranded flexible ramping product prior to the implementation of nodal procurement, expected in fall 2021.

A minimum requirement helps procure flexible ramping capacity within areas that contribute to a large portion of system-wide uncertainty. Figure 1.23 shows the frequency in which a minimum requirement was active for the ISO in the 15-minute market since the implementation of the minimum requirement in early November. Here, the ISO had a minimum upward requirement enforced in around 96 percent of intervals and a minimum downward requirement enforced in around 88 percent of intervals.

The minimum requirement was only implemented in the 15-minute market, and not in the 5-minute market. Procurement in the 5-minute market ensures that enough ramping capacity is available to manage uncertainty that may materialize between consecutive 5-minute market intervals. Without a minimum requirement in the 5-minute market, there can be cases where flexible ramping capacity procured internal to the ISO and settled in the 15-minute market is released in the 5-minute market in favor of undeliverable flexible ramping capacity stranded behind energy imbalance market transfer constraints. While the minimum requirement was intended as a temporary measure prior to implementation of nodal procurement, DMM believes that the minimum requirement should be included in the 5-minute market as an enhancement to improve the effectiveness of the flexible ramping product.

Figure 1.24 shows the frequency in which a minimum requirement was enforced for all other energy imbalance market areas.[24] Non-ISO areas, which exceed the 60 percent threshold in any interval, can similarly have a minimum requirement applied that will procure and price flexible ramping capacity in that area. In particular, PacifiCorp East had a minimum downward flexible ramping requirement during around 3 percent of intervals.

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

[23] For example, if a balancing authority area's upward requirement is greater than 60 percent of the system requirement at 1,000 MW and the diversity benefit factor (ratio of the system requirement to the sum of all area requirements) is 25 percent, then the minimum requirement for this area would be 250 MW. See *Flexible Ramping Product Refinements Final Proposal*, August 31, 2020. http://www.caiso.com/InitiativeDocuments/FinalProposal-FlexibleRampingProductRefinements.pdf

[24] Energy imbalance market areas which never had a minimum requirement applied during this period are not included in this figure.

Figure 1.23 California ISO frequency of enforced minimum requirement (15-minute market)

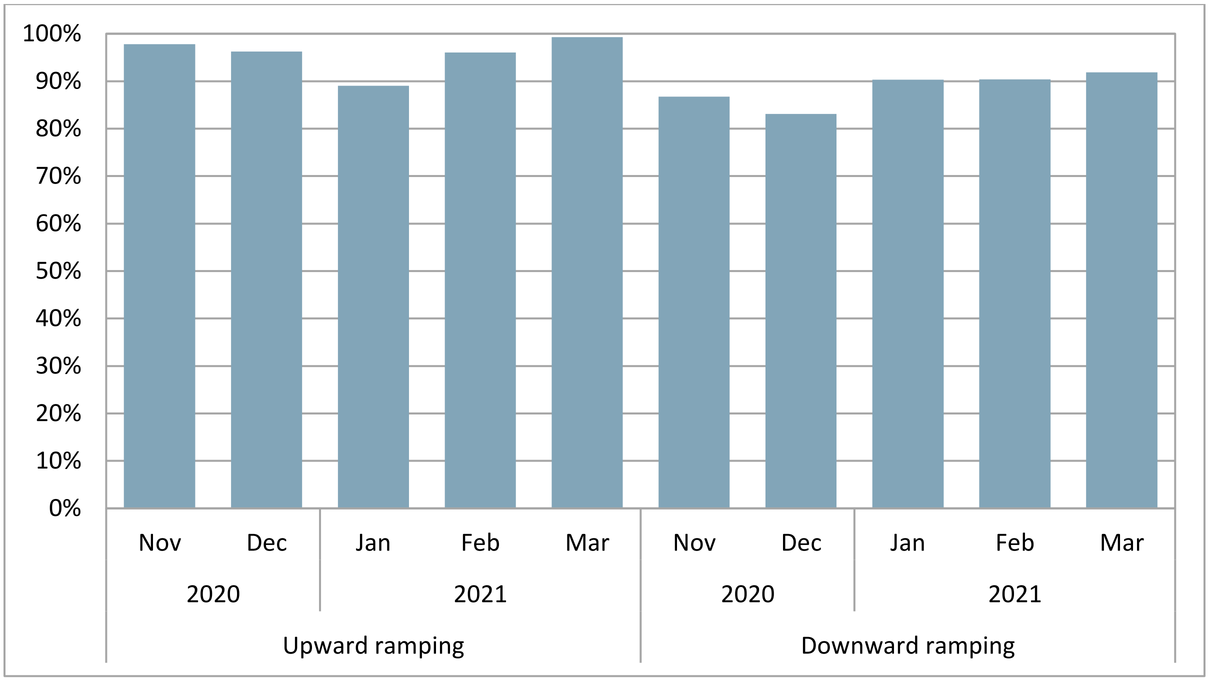
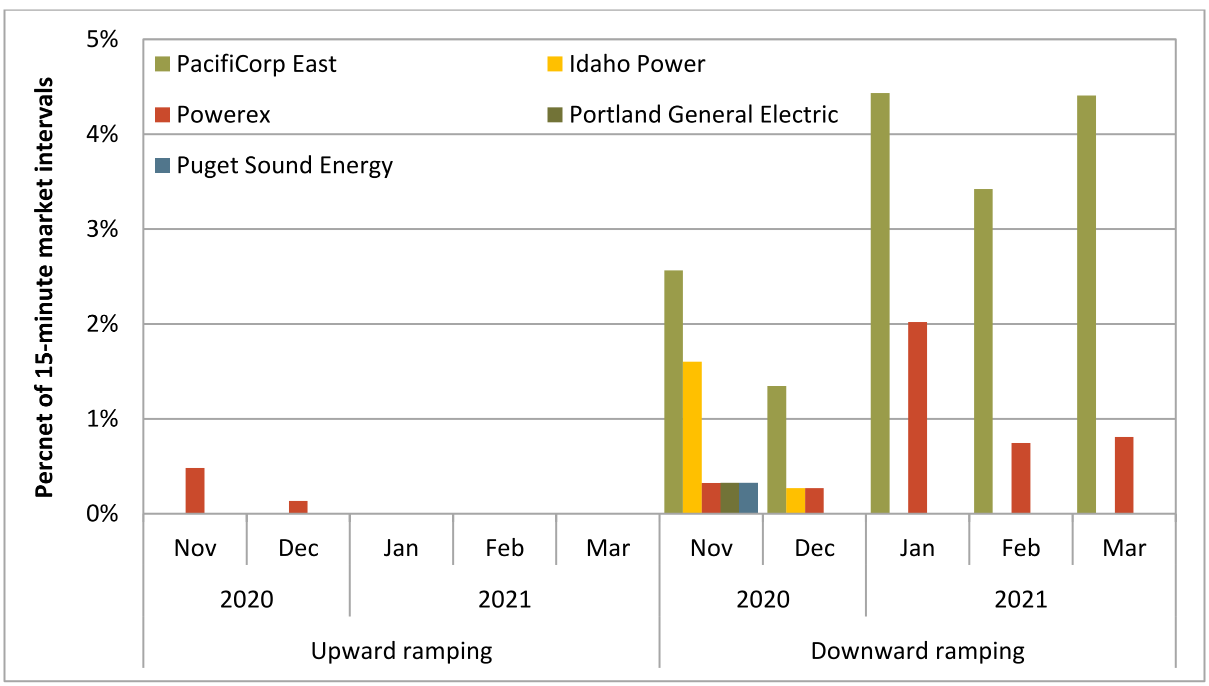


Figure 1.24 Energy Imbalance Market frequency of enforced minimum requirement (15-minute market)



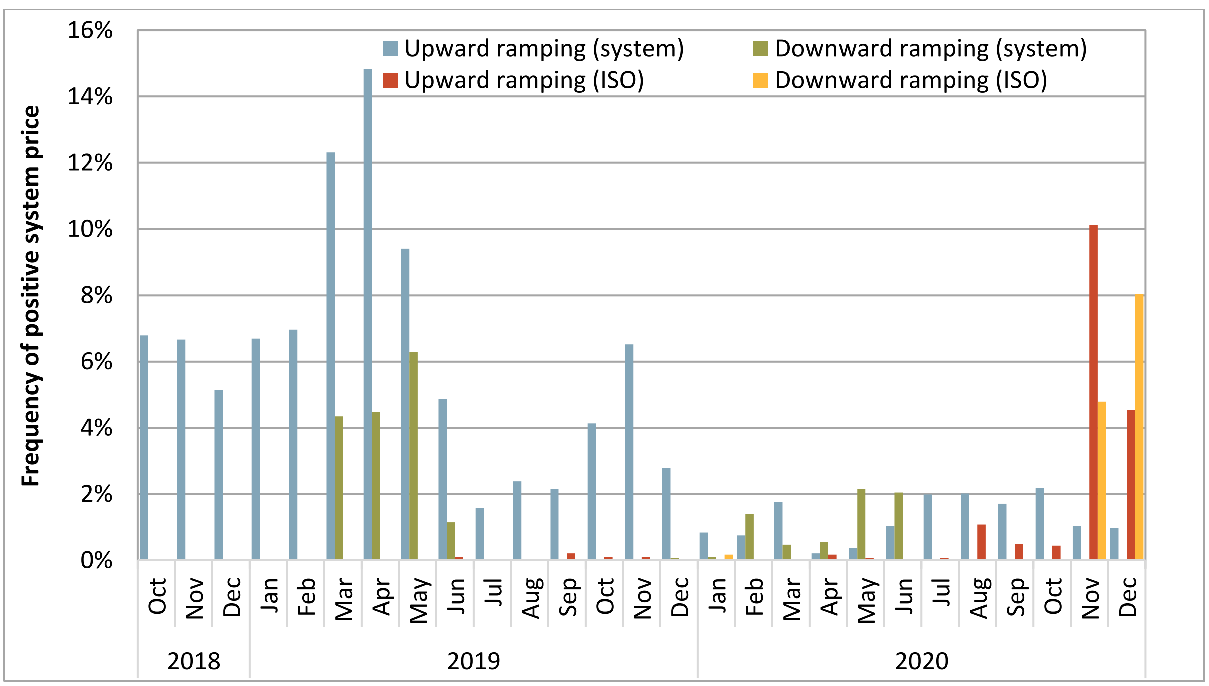
1.6.2 Flexible ramping product prices

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 full 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. Given the high frequency of the minimum requirement for the ISO, the percent of intervals in which the ISO demand curve bound at a positive shadow price is also shown. The frequency of positive shadow prices for the system continued to be low overall. During the quarter, the 15-minute market system-level demand curve bound in around 1 percent of intervals for upward ramping and never for downward ramping. However, the ISO-specific demand curve bound more frequently because of the implementation of the minimum requirement. Between November and December, there was a positive shadow price for ISO flexible ramping capacity during around 7 percent of intervals for both directions.

In the 5-minute market, the system-level and ISO-specific demand curves for upward and downward ramping capacity bound in less than 0.1 percent of intervals.

Figure 1.25 Monthly frequency of positive system or ISO flexible ramping shadow price (15-minute market)



1.6.3 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.[25]

The following figures show the 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 and downward ramping capacity increased during the quarter to around $2.6 million, compared to $1.7 million in the previous quarter. After accounting for costs associated with forecasted movement, total payments during the quarter reached $3.1 million.

Figure 1.26 Monthly flexible ramping product payments by type

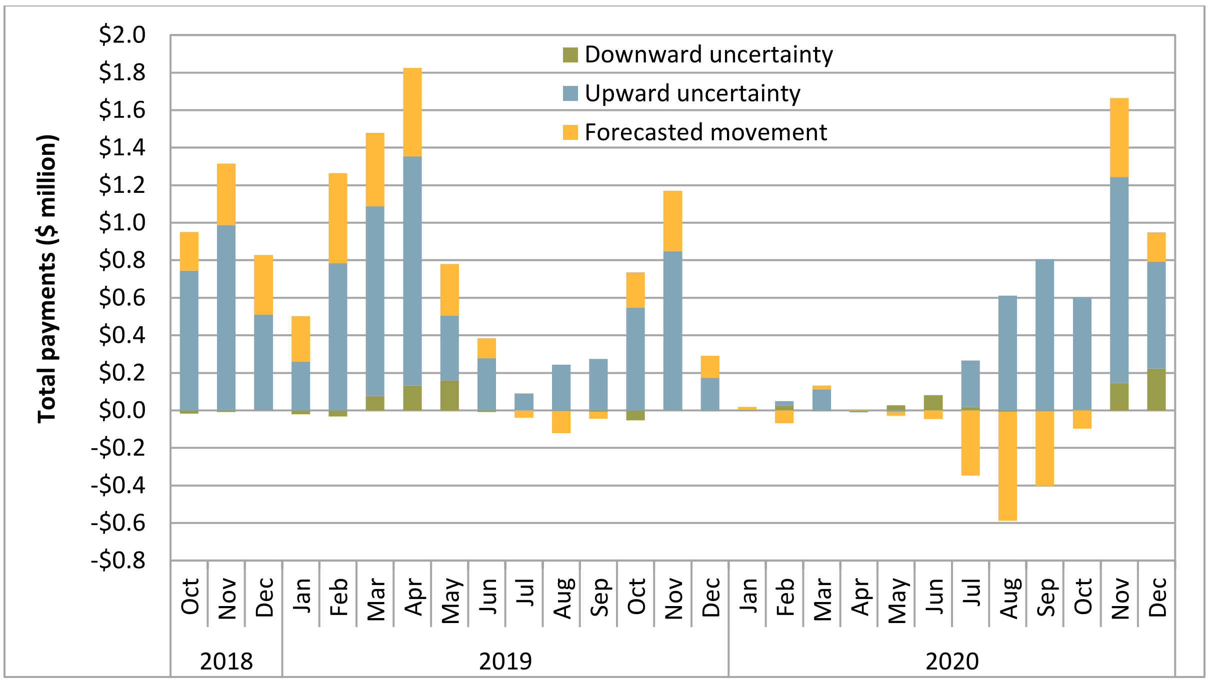


Figure 1.27 and Figure 1.28 do not include payments for forecasted movements and therefore only reflect payments to generators for upward and downward ramping capacity to meet uncertainty needs.

Figure 1.27 shows these payments by three region groups. Payment shown here reflect both capacity procured to satisfy system-level demand as well as area-specific demand. During the fourth quarter, around 72 percent of payments were for capacity procured to meet area-specific demand, compared to 30 percent in the previous quarter. These area-specific payments were primarily to ISO resources

[25] 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.

because of the implementation of the minimum requirement in early November. Around 84 percent of payments for flexible ramping capacity in the fourth quarter were to resources internal to the ISO while 12 percent of payments were to areas in the Northwest region that includes PacifiCorp West, Puget Sound Energy, Portland General Electric, Powerex, and Seattle City Light. In comparison, during the previous quarter, 48 percent of payments were internal to the ISO while 34 percent of payments were to areas in the Northwest region. The Northwest region is highlighted here as this region has historically had less transfer capability. This resulted in less deliverable flexible ramping capacity, which was stranded behind EIM transfer constraints. The ISO's changes associated with the minimum requirement helped shift flexible ramping capacity procurement internal to the ISO that is more likely to be deliverable to manage uncertainty.

Figure 1.28 shows the same information by fuel type. During the quarter, around 27 percent of flexible capacity payments for upward and downward uncertainty were to hydroelectric generators and 50 percent of payments were to gas resources. In comparison, during the previous quarter, 53 percent were to hydro resources while 38 percent were to gas resources. Payments to limited energy storage resources, which includes batteries and other limited devices, increased to 11 percent of payments, compared to 5 percent in the previous quarter.

Figure 1.27 Monthly flexible ramping product uncertainty payments by region

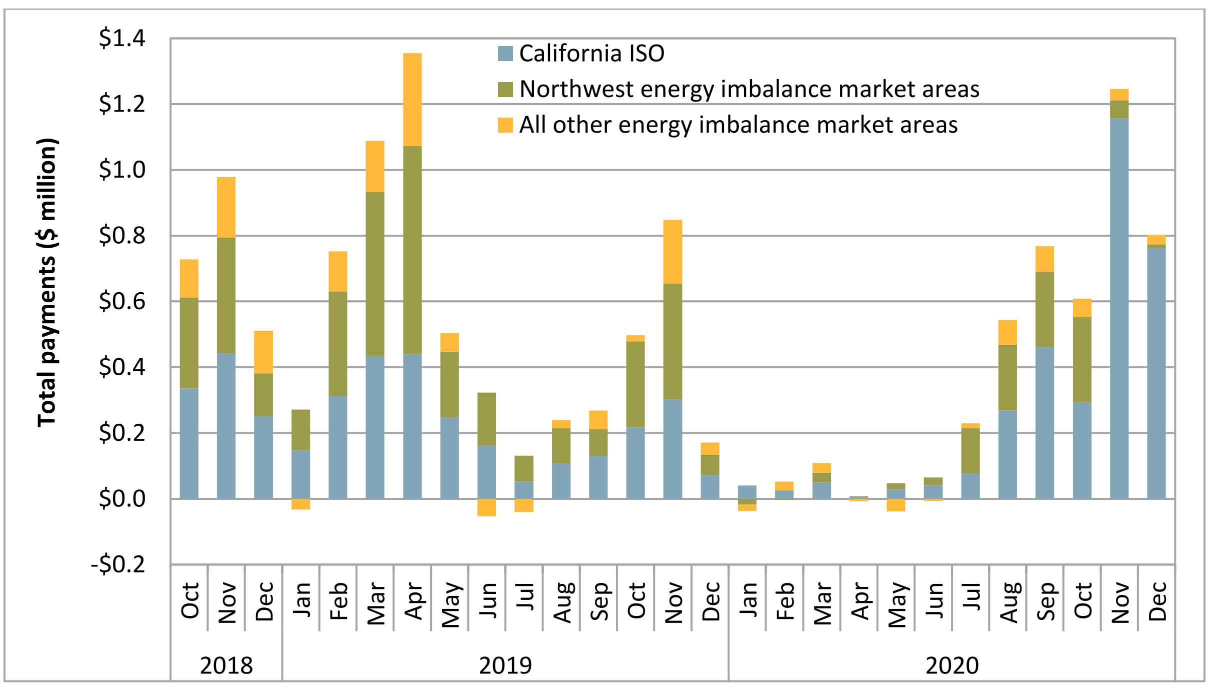
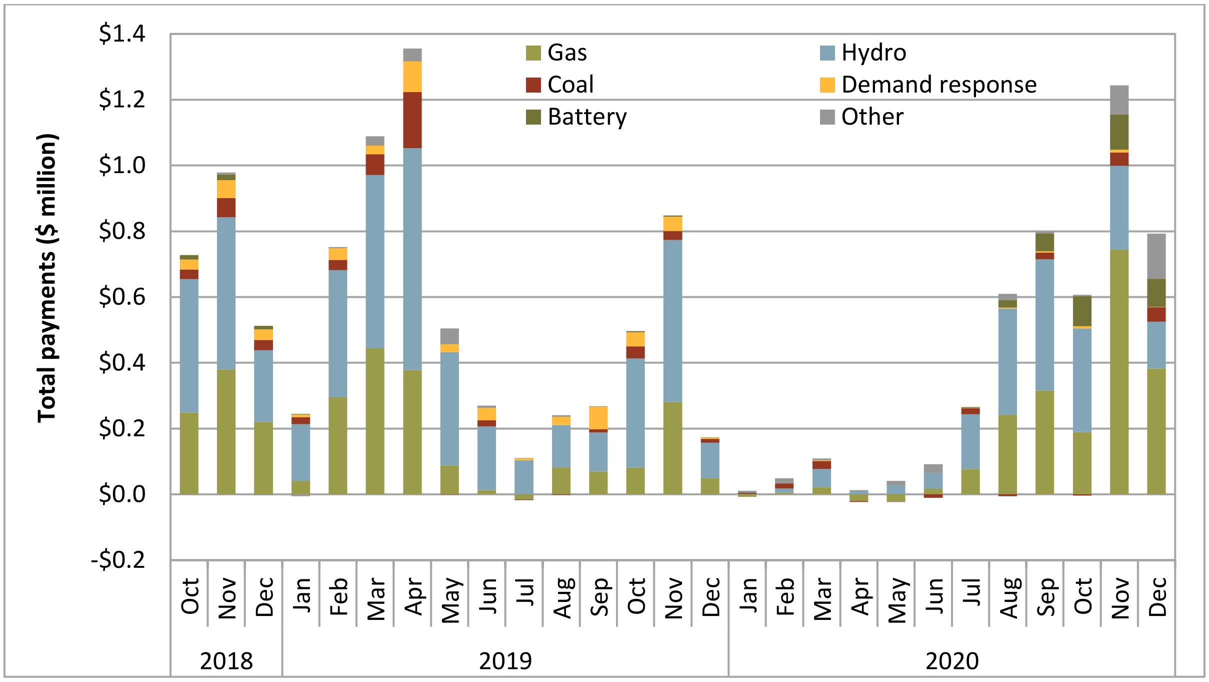


Figure 1.28 Monthly flexible ramping product uncertainty payments by fuel type



1.7 Convergence bidding

Convergence bidding was profitable overall for the fourth quarter of 2020. Combined net revenue for virtual supply and demand was about $13.4 million after including about $3.2 million of virtual bidding bid cost recovery charges. Virtual demand generated revenues of about $10.8 million for the quarter while virtual supply generated less at about $5.8 million, before accounting for bid cost recovery charges.

1.7.1 Convergence bidding trends

Average hourly cleared volumes were about 3,300 MW, a slight increase of 100 MW from the same quarter of 2019. Average hourly cleared virtual supply increased by about 100 MW from the fourth quarter of 2019 to about 2,000 MW. Cleared virtual demand averaged around 1,300 MW during each hour of the quarter, which was about the same as the fourth quarter of 2019. On average, about 37 percent of virtual supply and demand bids offered into the market cleared in the quarter, which was up from 25 percent in the fourth quarter of 2019.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 625 MW on average, an increase from 560 MW of net virtual supply in the same quarter of 2019. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply in 4 hours, between hours ending 16 and 19. In the remaining 20 hours, net cleared virtual supply exceeded net cleared virtual demand. Cleared virtual supply exceeded virtual demand by over 1,000 MW during hours ending 1 through 4 and hours ending 22 through 24. The morning hours represented an increase, on average, from the fourth quarter of 2019.

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 22 of 24 hours. Hours where volumes were inconsistent with price differences were hours ending 16 and 17.

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 860 MW of virtual demand offset by 860 MW of virtual supply in each hour of the quarter. This represents an increase of about 80 MW over the fourth quarter of 2019. These offsetting bids represented about 52 percent of all cleared virtual bids in this quarter, an increase of about 3 percent from the same quarter of 2019.

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 $16.6 million. Net revenues for virtual supply and demand fell to about $13.4 million after the inclusion of about $3.2 million of virtual bidding bid cost recovery charges,[26] 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).

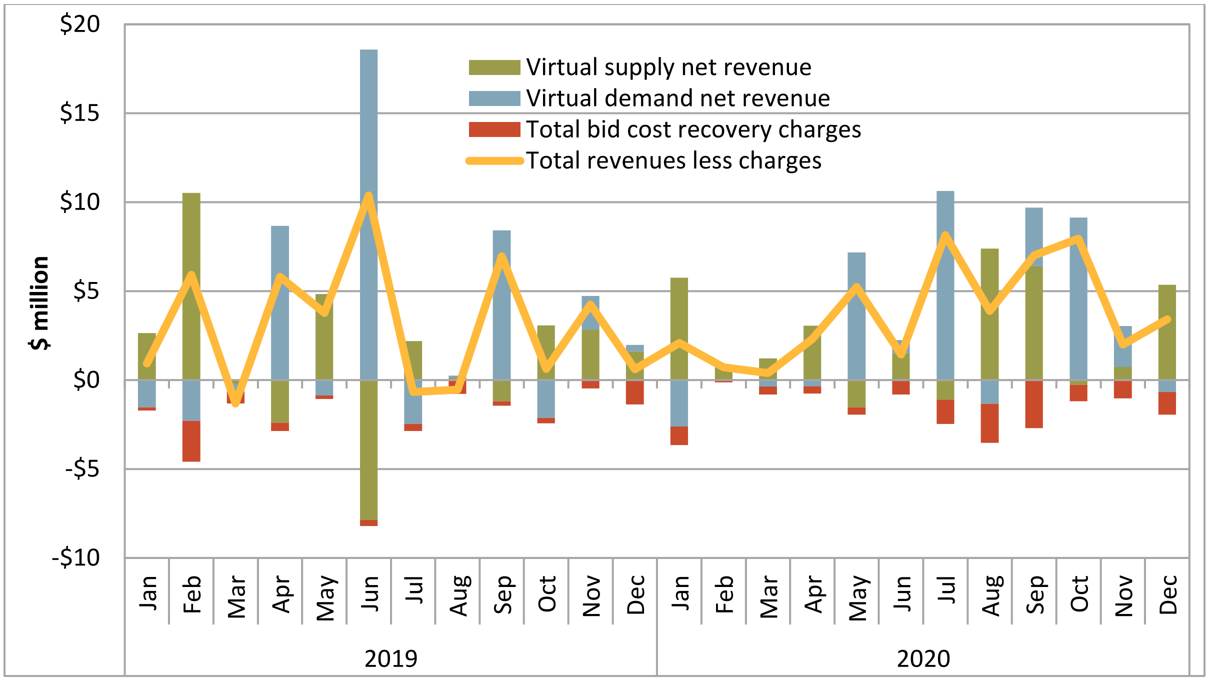
Before accounting for bid cost recovery charges:

- Total market revenues were positive during all months of the quarter. Net revenues during the quarter totaled about $16.59 million, compared to about $7.64 million during the same quarter from the previous year, and about $25.29 million during the previous quarter.
- Virtual demand net revenues were $9.1 million, $2.3 million, and negative $0.7 million in October, November, and December, respectively.

[26] 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 $0.3 million in October and positive in November and December with $0.7 million and $5.4 million, respectively.

Figure 1.29 Convergence bidding revenues and bid cost recovery charges



Convergence bidders received about $13.4 million after subtracting bid cost recovery charges of about $3.2 million for the quarter.[27,28] Bid cost recovery charges were about $0.9 million, $1 million and $1.3 million in October, November, and December, 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.[29] As with the previous quarter, financial entities represented the largest segment of the virtual bidding market,

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27 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.

28 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.

29 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 74 percent of volume and 65 percent of settlement revenue, a decrease from about 83 percent from the same quarter of 2019. Marketers represented about 24 percent of the trading volumes and about 32 percent of settlement revenue, a revenue increase from about 15 percent from the fourth quarter of 2019. Generation owners and load serving entities continued to represent the smallest segment of the virtual market in terms of both volumes and settlement revenue, at about 2 percent and 3 percent respectively. Generation owners and load serving entities accounted for around $0.42 million of net revenues in the market.

Table 1.2 Convergence bidding volumes and revenues by participant type

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	994	1,445	2,439	$6.15	$4.72	$10.87
Marketer	336	471	807	$4.19	$1.12	$5.32
Physical load	0	51	51	-$0.01	-$0.02	-$0.02
Physical generation	11	0	11	$0.44	$0.00	$0.44
Total	**1,340**	**1,967**	**3,307**	**$10.77**	**$5.83**	**$16.60**

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.

As illustrated in Figure 1.30, 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 13 percent higher in the fourth 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 fourth quarter of 2020 averaging about 420 MW per hour.

Operator adjustments to residual unit commitment requirements increased in the fourth quarter compared to the same quarter in 2019. The use of this tool averaged about 172 MW per hour compared to about 29 MW per hour in the same quarter of 2019. The primary reason for these adjustments is to account for load forecast errors.

Residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of bid-in variable energy resources and the forecast output of these renewable resources. This intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market. It is represented by the yellow bar in Figure 1.30.

Figure 1.30 Determinants of residual unit commitment procurement

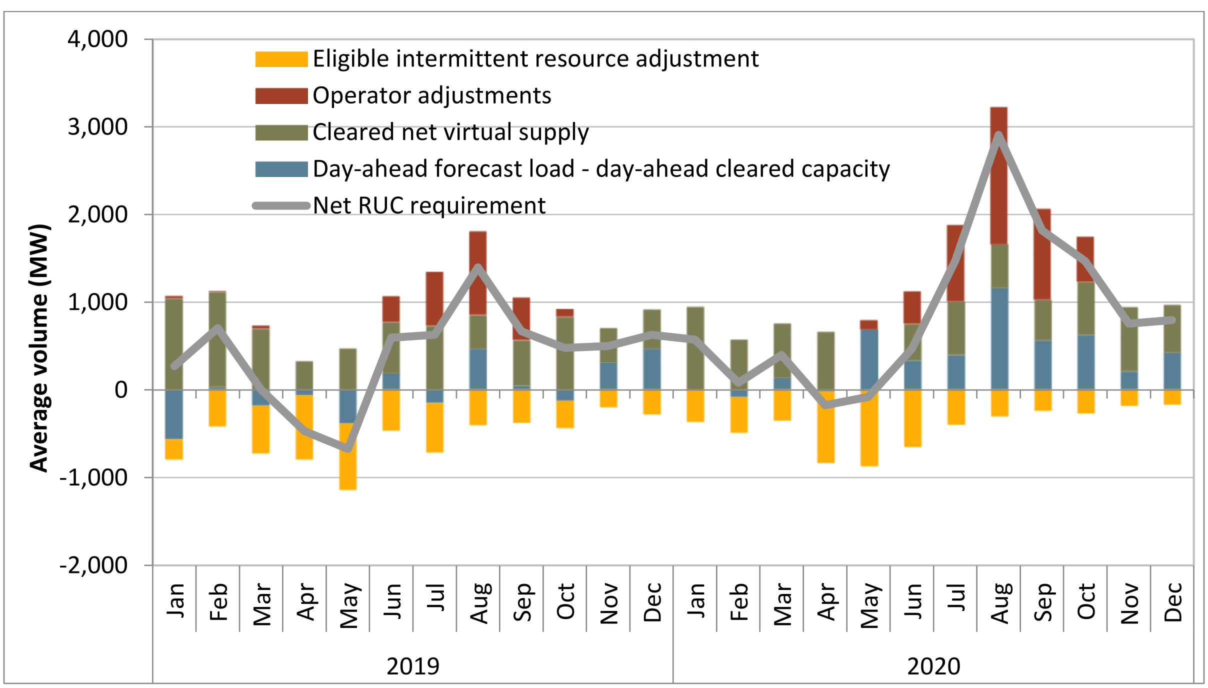
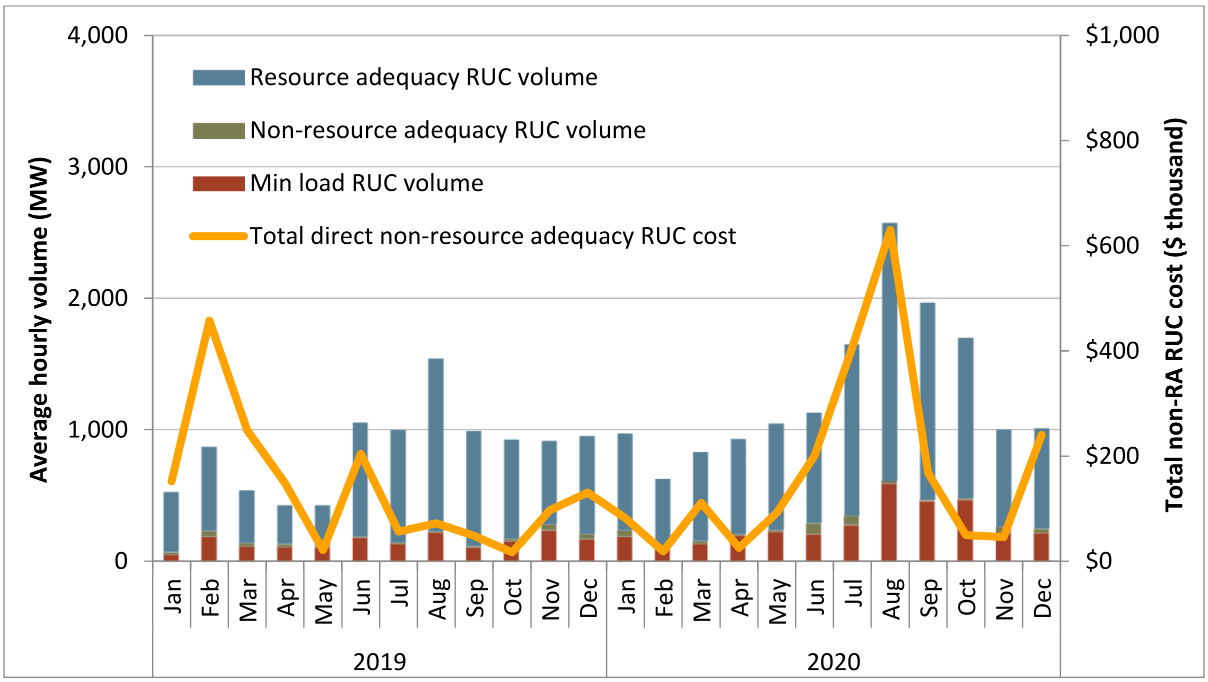


Figure 1.31 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased to about 1,240 MW per hour in the fourth quarter of 2020 from an average of 932 MW in the same quarter of 2019. Of the 1,240 MW per hour capacity, the capacity committed to operate at minimum load averaged about 297 MW each hour compared to 184 MW in the fourth 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.[30] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.31. In the fourth quarter of 2020, these costs increased slightly to $0.3 million when compared to about $0.2 million in the same quarter of 2019.

Figure 1.31 Residual unit commitment costs and volume



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

1.9 Ancillary services

Ancillary service payments decreased during the quarter to about $49 million, compared to about $97 million in the previous quarter and $23 million during the same quarter in 2019. Higher payments from the previous year were driven, in part, by higher requirements for both regulation requirements and operating reserves.

1.9.1 Ancillary service requirements

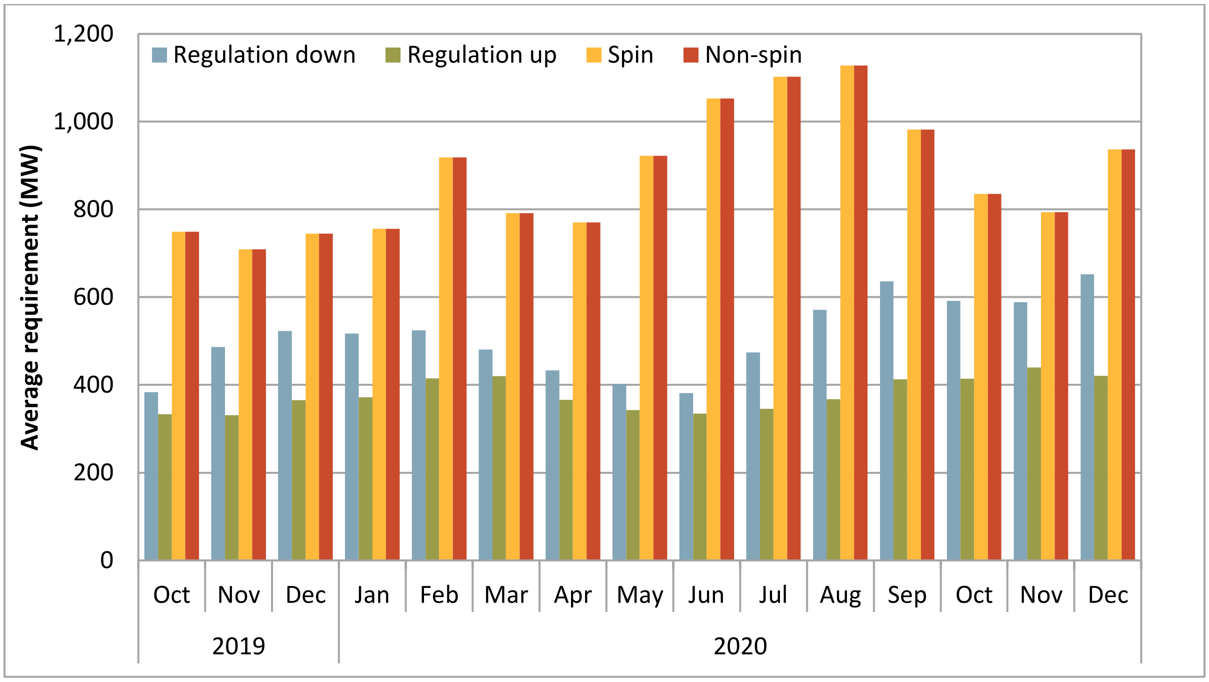
The ISO procures four ancillary services in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (WECC)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

Figure 1.32 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 decreased relative to the previous quarter consistent with lower loads. Average requirements for regulation down and regulation up continued to increase from the previous quarter.

Figure 1.32 Average monthly day-ahead ancillary service requirements



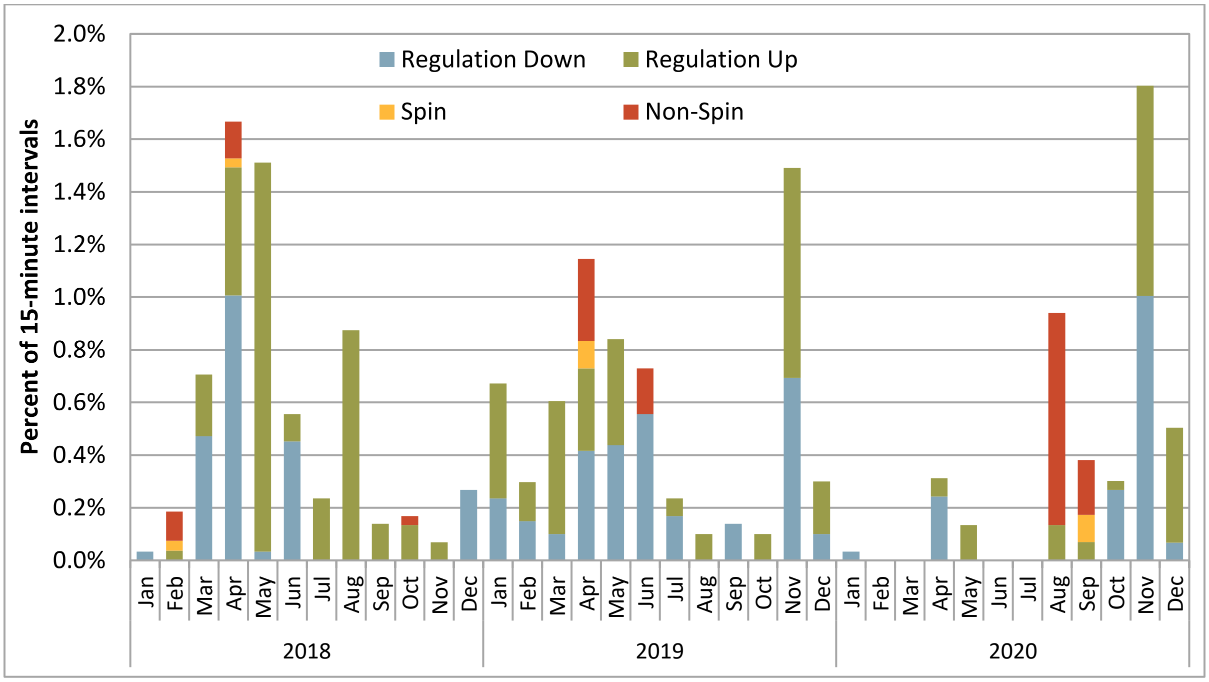
1.9.2 Ancillary service scarcity

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 1.33, the frequency of intervals with scarcity pricing increased significantly during the quarter. In particular, during November, scarcity of regulation down occurred during 1 percent of intervals while scarcity of regulation up occurred during 0.8 percent of intervals. Here, the large majority of the scarcity intervals occurred in the expanded South of Path 26 region.

During November, most of the regulation scarcities were the result of changes in real-time, including (1) real-time telemetry limits which can cap day-ahead market ancillary service awards or (2) higher real-time requirements. Real-time costs for ancillary services are typically low, as only the incremental real-time award is settled at the 15-minute market price. In some cases when there are changes from the day-ahead market, it can be economic to relax the real-time requirement at the scarcity price in lieu of committing a unit or moving a unit to a higher bid segment. In November, 92 percent of ancillary service scarcities were 5 MW or less.

Figure 1.33 Frequency of ancillary service scarcities (15-minute market)

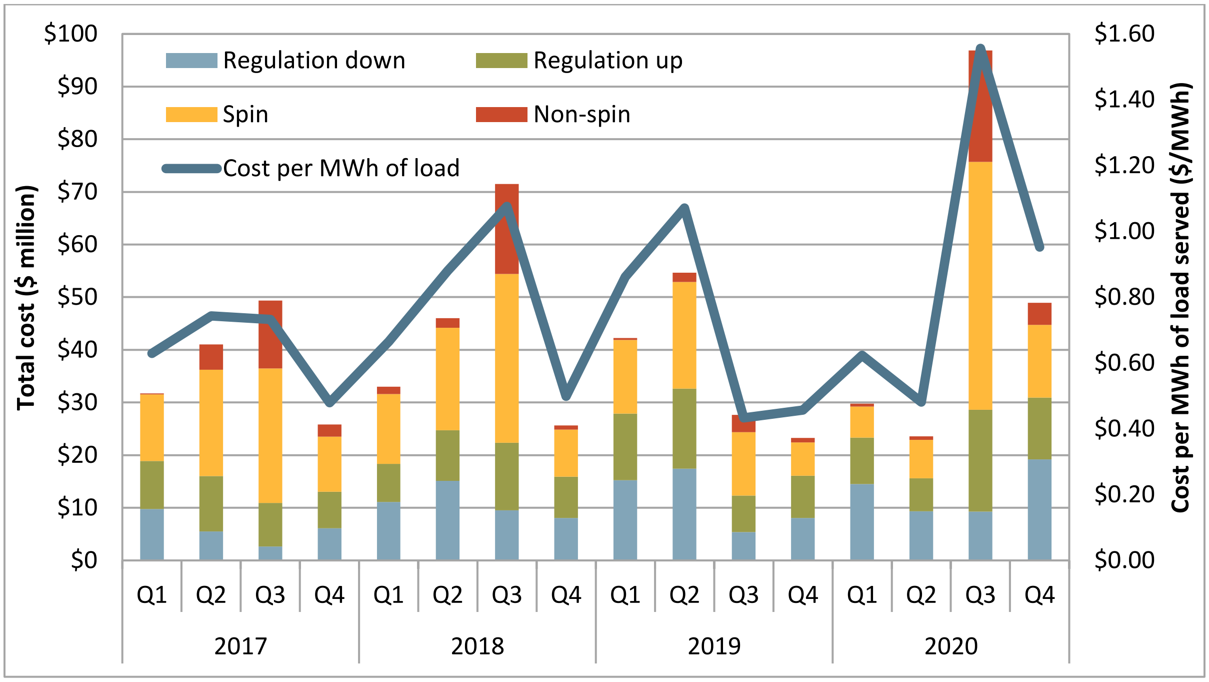


1.9.3 Ancillary service costs

Ancillary service payments decreased during the quarter to about $49 million, compared to about $97 million in the previous quarter and $23 million during the same quarter in 2019. Higher payments from the previous year were driven in part from higher regulation requirements.

Figure 1.34 shows the total cost of procuring ancillary service products by quarter as well as the total ancillary service cost for each megawatt-hour of load served. The costs reported in this figure account for rescinded ancillary service payments. Payments are rescinded when resources providing ancillary services do not fulfill the availability requirements associated with the awards.

Figure 1.34 Ancillary service cost by product



1.10 Congestion

In the day-ahead market, congestion in the fourth quarter decreased prices in the PG&E and SCE areas while it increased prices in the SDG&E area. 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.[31]

[31] 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

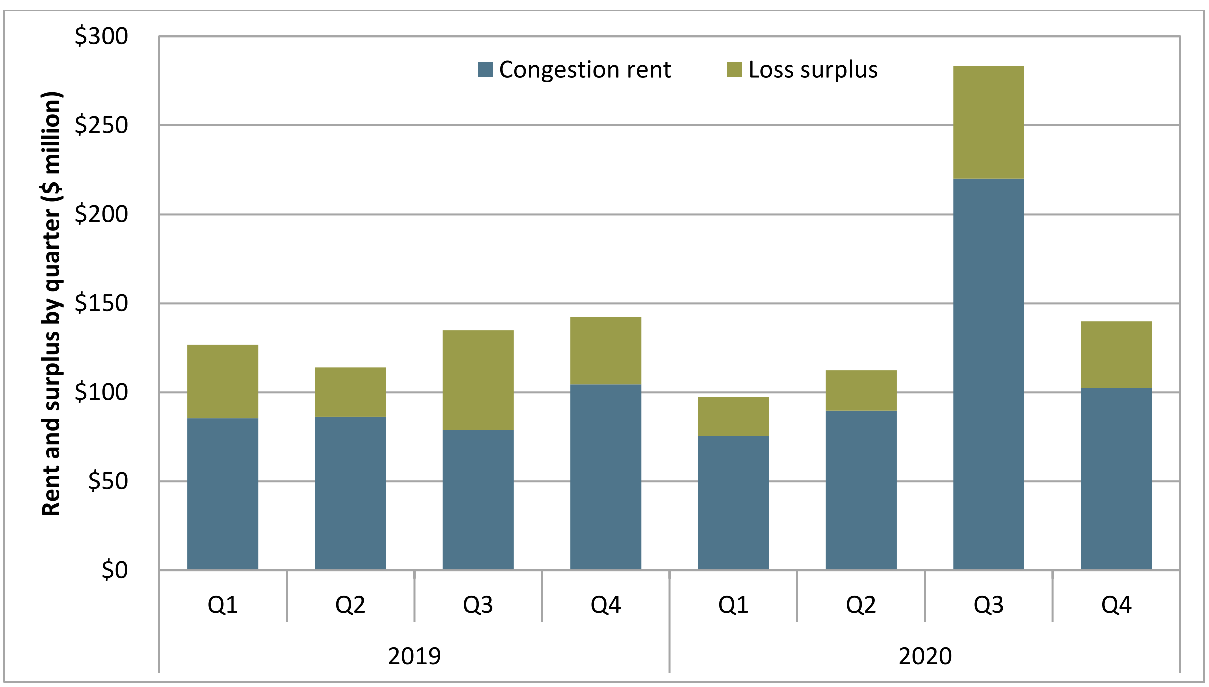
Day-ahead market congestion frequency tends to be higher than in the 15-minute market, but price impacts to load tend to be lower. The congestion pattern in this quarter reflects this overall trend.

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.[32]

Figure 1.35 shows the congestion rent and loss surplus by quarter for 2019 and 2020. Compared to the fourth quarter of 2019, congestion rents decreased by about 2 percent while the loss surplus decreased by about 1 percent in the fourth quarter of 2020.

Figure 1.35 Day-ahead congestion rent and loss surplus by quarter (2019-2020)



32 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 1.36 shows the overall impact of congestion on day-ahead prices in each load area in 2019 and 2020. Figure 1.37 shows the frequency of congestion. Highlights for this quarter include:

- In the fourth quarter of 2020, the overall net impact of congestion on price separation increased PG&E, SCE, and SDG&E relative to the same quarter of 2019. Compared to the third quarter of 2020, the impact was significantly lower during this quarter. The frequency of congestion decreased in PG&E and SCE, while it increased in SDG&E during the fourth quarter, relative to the same quarter in 2019.
- Overall for the quarter, congestion decreased average prices in PG&E and SCE by \$0.01/MWh (0.03 percent) and \$0.07/MWh (0.17 percent), respectively, while it increased prices in SDG&E by \$1.20/MWh (2.78 percent).
- On an average quarterly basis, the congestion impact was frequently offsetting in all areas, as shown in Figure 1.38. For the quarter, PG&E experienced positive congestion more frequently, while SCE and SDG&E experienced negative congestion more frequently.
- The primary constraints impacting day-ahead market prices were the Midway-Vincent #2 500 kV line, the Suncrest substation 230/500 kV transformer, and the Malin-Round Mountain 500 kV line.

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

Figure 1.36 Overall impact of congestion on price separation in the day-ahead market

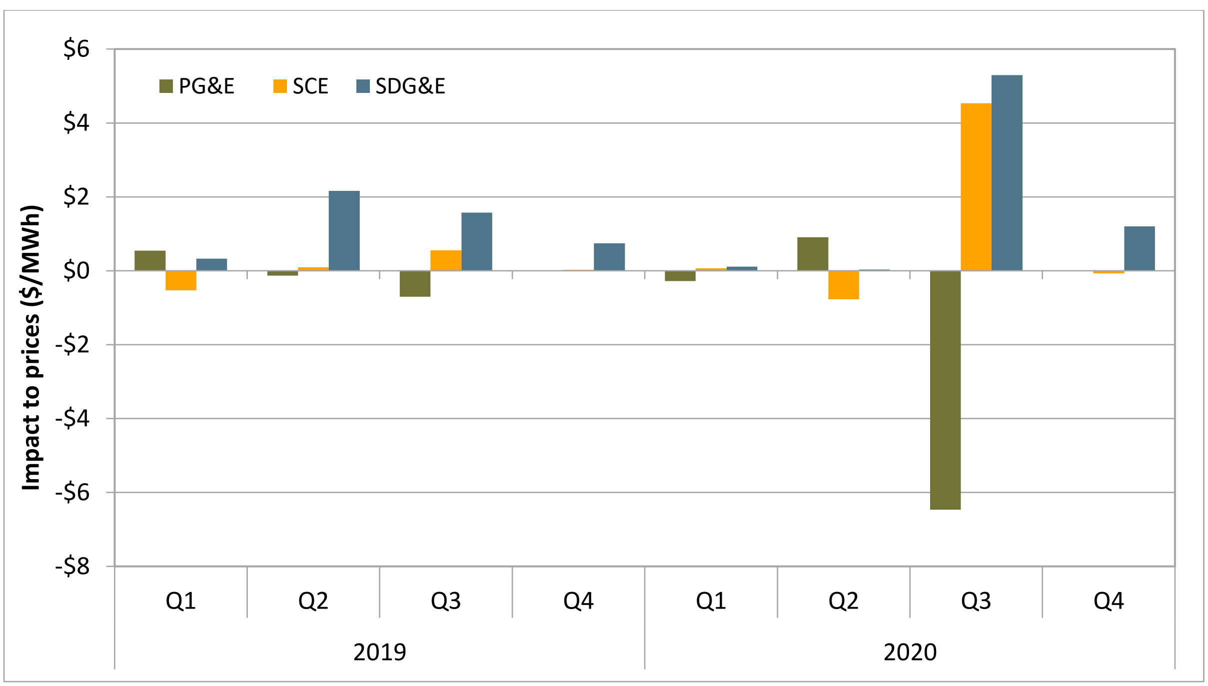


Figure 1.37 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)

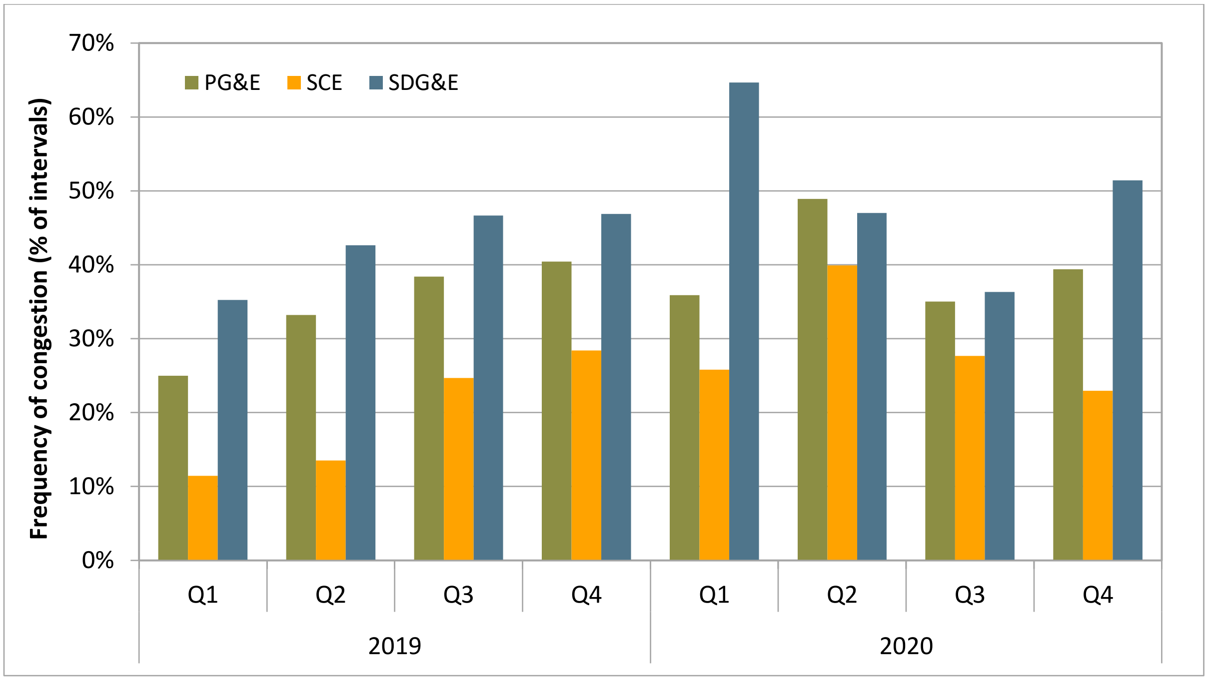
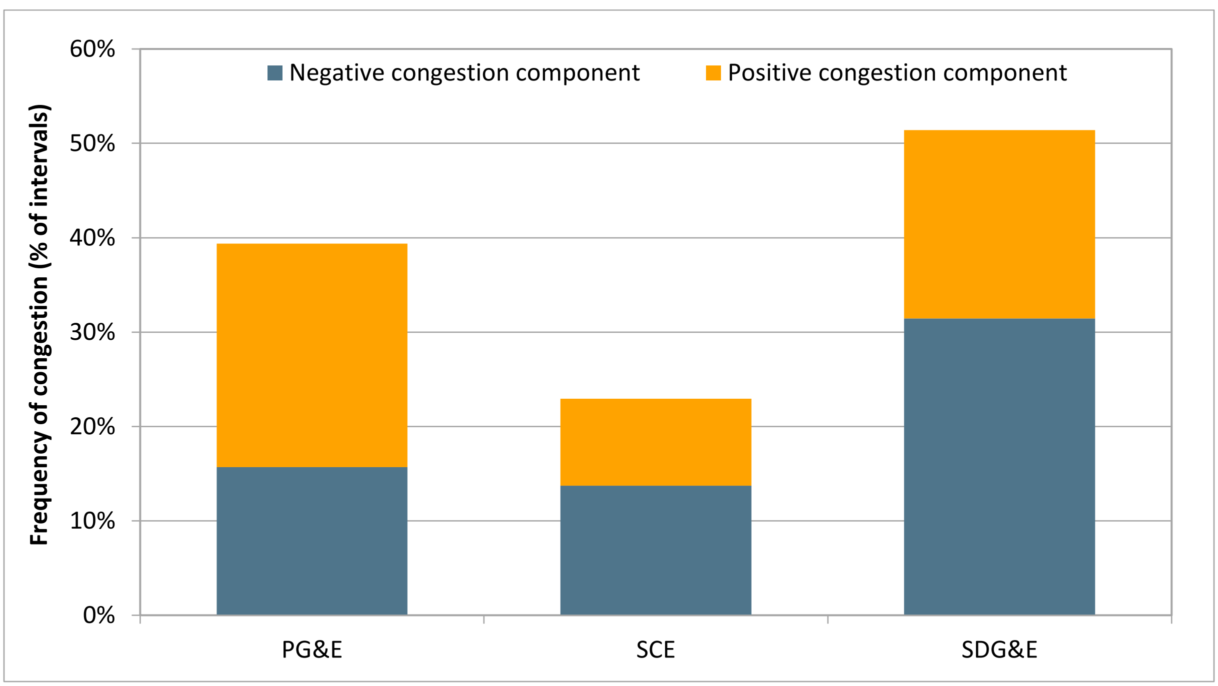


Figure 1.38 Percent of hours with congestion increasing versus decreasing day-ahead prices in the fourth quarter (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.3 breaks down the congestion impact on price separation in the fourth quarter by constraint.[33] 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-Vincent #2 500 kV line, the Suncrest substation 230/500 kV transformer, and the Malin-Round Mountain 500 kV line.

Midway-Vincent 500 kV line

The Midway-Vincent 500 kV line (30060_MIDWAY_500_24156_VINCENT_500_BR_2_3) had the greatest impact on day-ahead prices during the fourth quarter on average. It was not the most frequently congested constraint in the quarter, binding in only 1.5% percent of hours. However, when binding, it decreased PG&E prices by about $18.59/MWh and increased SCE and SDG&E prices by $13.68/MWh and $12.85/MWh, respectively. Over the entire quarter, it decreased PG&E prices by about $0.28/MWh (0.67 percent) and increased SCE and SDG&E prices by $0.20/MWh (0.49 percent) and $0.19/MWh (0.45 percent), respectively. The congestion seen on this line can be largely attributed to maintenance and repairs that were performed on the Midway-Vincent 500 kV lines during the quarter.

Suncrest substation 230/500 kV transformer

The Suncrest substation 230/500 kV transformer (22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P) had a marginal impact on prices in PG&E and SCE, but a significant impact in SDG&E on average for the quarter. When binding, it decreased prices in PG&E by about $2.45/MWh and increased prices in SDG&E by $14.40/MWh, respectively. Overall for the quarter, the nomogram decreased prices in PG&E by about $0.09/MWh (0.23 percent), while it increased prices in SDG&E by $0.55/MWh (1.29 percent).

Malin-Round Mountain 500 kV line

The Malin-Round Mountain 500 kV line (40687_MALIN _500_30005_ROUND MT_500_BR_1 _3) was congested during about 4.2 percent of hours during the quarter. When binding, the constraint increased PG&E prices by about $4.18/MWh, while it decreased prices in SCE and SDG&E by about $2.90/MWh and $3.75/MWh, respectively. Overall for the quarter, it increased PG&E prices by about $0.18/MWh (0.42 percent), and decreased prices in SCE and SDG&E by $0.12/MWh (0.30 percent) and $0.16/MWh (0.37 percent), respectively. The congestion seen on this line can be largely attributed to maintenance and repairs that were performed on the Malin-Round Mountain 500 kV lines during the quarter.

[33] 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	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.18	0.42%	-$0.12	-0.30%	-$0.16	-0.37%
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.14	0.34%	-$0.12	-0.29%	-$0.11	-0.26%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.02	0.06%	-$0.02	-0.04%	-$0.02	-0.04%
	30055_GATES1 _500_30900_GATES _230_XF_11_S	$0.02	0.04%	-$0.01	-0.03%	-$0.01	-0.03%
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.01%
	7440_MetcalfImport_Tes-Metcalf	$0.01	0.01%	$0.00	-0.01%	$0.00	-0.01%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	-$0.01	-0.03%	$0.01	0.02%	$0.01	0.02%
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	-$0.02	-0.05%	$0.02	0.04%	$0.02	0.04%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.28	-0.67%	$0.20	0.49%	$0.19	0.45%
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.05	-0.13%	$0.06	0.14%	$0.05	0.13%
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.02	-0.04%	$0.02	0.06%	-$0.02	-0.05%
	6410_CP5_NG	-$0.02	-0.04%	$0.01	0.03%	$0.01	0.03%
	OMS 8421617_D-VST2_OOS_CP3	$0.01	0.01%	$0.00	0.00%	-$0.01	-0.02%
	OMS 9317653_Devers-ElCasco_NG	$0.01	0.02%	$0.00	0.00%	-$0.01	-0.02%
	6410_CP10_NG	$0.13	0.31%	-$0.11	-0.27%	-$0.10	-0.24%
	OMS 9076082 ELD-MHV_NG	$0.01	0.02%	$0.00	0.00%	-$0.12	-0.27%
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	$0.02	0.04%	$0.00	0.00%	-$0.07	-0.15%
	OMS 9317626_Devers-ElCasco_NG	$0.00	0.01%	$0.00	0.00%	-$0.02	-0.05%
	8705726_Devers VISTA1_NG	$0.00	0.01%	$0.00	0.00%	-$0.02	-0.04%
	OMS 9317668_Devers VISTA1_NG	$0.01	0.02%	$0.00	0.00%	-$0.01	-0.03%
SDG&E	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	-$0.09	-0.23%	$0.00	0.00%	$0.55	1.29%
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	-$0.06	-0.14%	$0.00	0.00%	$0.35	0.80%
	OMS 8701994_50001_OOS_NG	-$0.02	-0.04%	$0.00	0.00%	$0.17	0.40%
	OMS 8701990_50001_OOS_NG	-$0.02	-0.04%	$0.00	0.00%	$0.16	0.36%
	7820_TL 230S_OVERLOAD_NG	-$0.01	-0.03%	$0.00	0.00%	$0.14	0.32%
	OMS 9300871_50001_OOS_NG	-$0.01	-0.02%	$0.00	0.00%	$0.12	0.27%
	OMS 8701965_50001_OOS_NG	-$0.01	-0.02%	$0.00	0.00%	$0.07	0.16%
	MIGUEL_BKs_MXFLW_NG	-$0.01	-0.01%	$0.00	0.00%	$0.06	0.15%
	OMS 8702004_50001_OO_NG	$0.00	-0.01%	$0.00	0.00%	$0.02	0.05%
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.01	-0.03%	$0.01	0.02%	$0.02	0.05%
	OMS 9300860_50001_OOS_NG	$0.00	0.00%	$0.00	0.00%	$0.02	0.03%
	7820_TL 230S_TL50001OUT_NG	$0.00	0.00%	$0.00	0.00%	$0.01	0.02%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.01	-0.03%
	OMS 8929209_D-SBLR_OOS_CP3	$0.06	0.14%	-$0.01	-0.02%	-$0.09	-0.20%
Other		$0.01	0.01%	$0.01	0.02%	$0.01	0.03%
Total		**-$0.01**	**-0.03%**	**-$0.07**	**-0.17%**	**$1.20**	**2.78%**

Table 1.4 Impact of congestion on day-ahead prices during congested hours[34]

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	4.2%	$4.18	-$2.90	-$3.75
	30055_GATES1 _500_30900_GATES _230_XF_11_S	0.5%	$2.72	-$2.16	-$2.08
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	5.7%	$2.47	-$2.12	-$1.92
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	0.5%	$1.61	-$1.20	-$1.11
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	1.9%	$1.25	-$0.94	-$0.94
	7440_MetcalfImport_Tes-Metcalf	0.8%	$0.59	-$0.45	-$0.43
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	0.5%	-$1.96	$1.51	$1.40
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	0.3%	-$8.33	$5.97	$5.59
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	1.5%	-$18.59	$13.68	$12.85
SCE	6410_CP5_NG	0.5%	-$3.34	$2.74	$2.50
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.0%	-$1.55	$2.46	-$2.54
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	4.7%	-$1.17	$1.20	$1.84
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	2.7%	$0.76	$0.00	-$2.45
	8705726_Devers VISTA1_NG	1.5%	$0.47	$0.00	-$0.98
	OMS 9076082 ELD-MHV_NG	9.1%	$0.52	$0.00	-$1.26
	OMS 9317626_Devers-ElCasco_NG	2.3%	$0.72	$0.00	-$0.94
	OMS 9317668_Devers VISTA1_NG	0.8%	$1.02	$0.00	-$1.37
	OMS 8421617_D-VST2_OOS_CP3	1.7%	$0.45	-$0.38	-$0.41
	OMS 9317653_Devers-ElCasco_NG	1.1%	$0.76	-$0.69	-$0.86
	6410_CP10_NG	2.8%	$4.55	-$3.98	-$3.67
SDG&E	OMS 8701990_50001_OOS_NG	0.3%	-$4.85	$0.00	$49.20
	OMS 8701994_50001_OOS_NG	0.4%	-$4.05	$0.00	$42.61
	OMS 9300871_50001_OOS_NG	0.5%	-$1.95	$0.00	$23.67
	OMS 8701965_50001_OOS_NG	0.3%	-$2.01	$0.00	$21.87
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	3.8%	-$2.45	$0.00	$14.40
	MIGUEL_BKs_MXFLW_NG	0.5%	-$1.13	$0.00	$12.59
	OMS 8702004_50001_OO_NG	0.3%	-$0.76	$0.00	$8.15
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	4.3%	-$1.33	$0.00	$8.04
	OMS 9300860_50001_OOS_NG	0.3%	-$0.41	$0.00	$5.39
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	0.5%	-$2.37	$1.40	$4.06
	7820_TL 230S_OVERLOAD_NG	4.8%	-$0.27	-$0.12	$2.90
	7820_TL 230S_TL50001OUT_NG	0.6%	-$0.16	$0.00	$1.46
	OMS 8929209_D-SBLR_OOS_CP3	9.1%	$0.65	-$0.38	-$1.13
	7820_TL 230S_OVERLOAD_NG	0.4%	$0.00	$0.00	-$3.35

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

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 1.39 shows the overall impact of internal flow-based constraint congestion on 15-minute prices in each load area for 2019 and 2020. Figure 1.40 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 fourth quarter of 2020 increased in most areas compared to the same quarter of 2019. Congestion resulted in a net increase to PG&E, SCE, SDG&E, and BANC prices and a net decrease to prices in all other 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 overall frequency of congestion was highest in PACE and SRP, where congestion predominantly decreased prices.
- The primary constraints impacting price separation in the 15-minute market were the Malin-Round Mountain 500 kV line, the Midway-Vincent 500 kV line, and the El Dorado-Mohave 500 kV line.

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

Figure 1.39 Overall impact of internal congestion on price separation in the 15-minute market

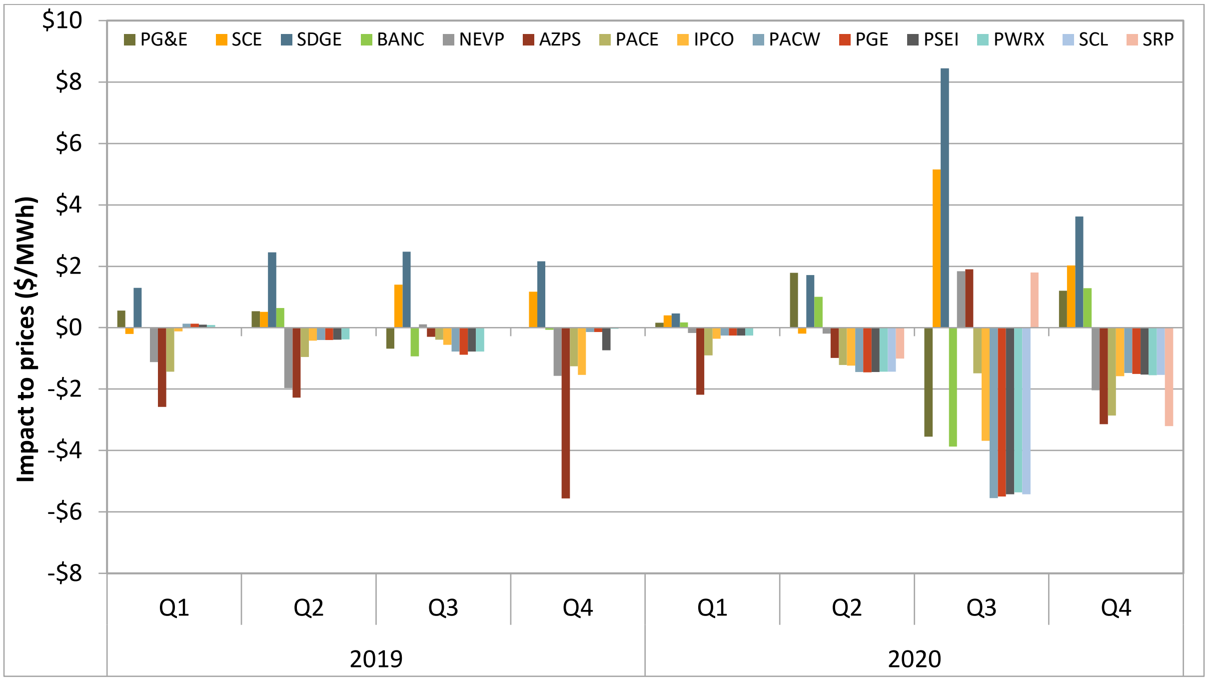
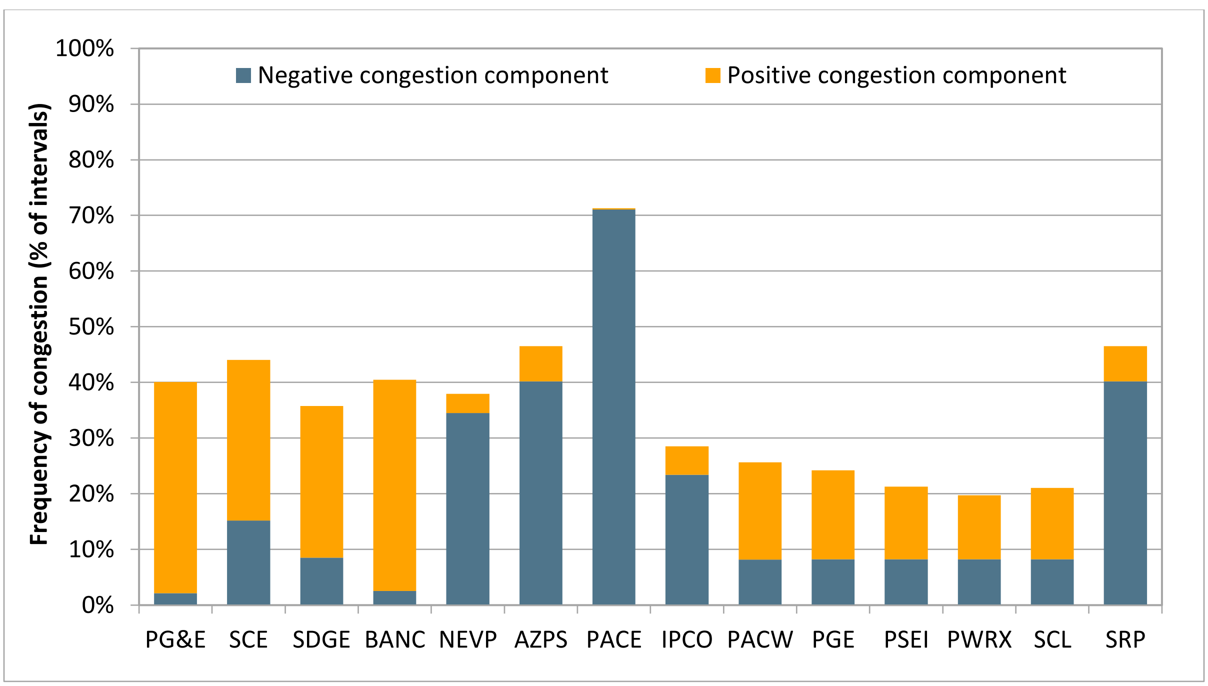


Figure 1.40 Percent of intervals with internal congestion increasing versus decreasing 15-minute prices in the fourth quarter (>$0.05/MWh)



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 Malin-Round Mountain 500 kV line, the Midway-Vincent 500 kV line, and the El Dorado-Mohave 500 kV line.

Malin-Round Mountain 500 kV line

The Malin-Round Mountain 500 kV line (40687_MALIN _500_30005_ROUND MT_500_BR_1 _3) bound frequently in the quarter during about 6 percent of intervals. When binding, it affected prices across the EIM, increasing prices in PG&E, SCE, SDG&E, BANC, NEVP, AZPS, and SRP by about $7.00/MWh on average, and decreasing prices elsewhere in the ISO and EIM by $16.64/MWh on average. Overall for the quarter, the constraint increased prices in the former areas by about $0.41/MWh and decreased prices in the latter areas by $1.00/MWh. The congestion seen on this line can be largely attributed to maintenance and repairs that were performed on the Malin-Round Mountain 500 kV lines during the quarter.

Midway-Vincent 500 kV line

The Midway-Vincent 500 kV line (30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3) bound infrequently during the quarter, during about 2 percent of intervals. When binding, it increased prices in SCE, SDG&E, NEVP, AZPS, SRP, and PACE by about $31.54/MWh on average, and decreased prices elsewhere in the ISO and EIM by $36.87/MWh on average. Overall for the quarter, the constraint increased the former areas’ prices by $0.48/MWh on average and decreased prices elsewhere by $0.56/MWh on average. Similar to the day-ahead, the congestion seen on this line can be largely attributed to maintenance and repairs that were performed on the Midway-Vincent 500 kV lines during the quarter.

El Dorado-Mohave 500 kV line

The El Dorado-Mohave 500 kV line (OMS 9076082 ELD-MHV_NG) bound frequently during the quarter, in about 11 percent of intervals. When binding, it increased prices in PG&E, SCE, SDG&E, BANC, PACW, PGE, PSEI, PWRX, and SCL by an average of $2.47/MWh, and decreased prices elsewhere by $8.74/MWh on average. Over the entire quarter, it increased the former areas’ prices by about $0.22/MWh on average, and decreased the latter areas’ prices by about $0.93/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	GON-IPP 230		$0.02	$0.02		$0.04			-$0.07	-$0.03					
	GON-RBS #3430		$0.01	$0.01		$0.01	$0.01	$0.01	-$0.03	-$0.01					
	HA BK-2		$0.01	$0.01		$0.01	$0.01	$0.01	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00
	GON 230TXF#4		$0.01	$0.01			$0.00	$0.00	-$0.07	$0.00					
	GON 345TXF#4		$0.00	$0.00			$0.00	$0.00	-$0.08	$0.00					
PACE	WYOMING_EXPORT								-$0.07						
	WINDSTAR EXPORT TCOR								-$0.09						
	EAST_WYO_EXP								-$0.14						
	TOTAL_WYOMING_EXPORT								-$0.35						
PG&E	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.83	$0.39	$0.33	$0.82	$0.01	$0.25	$0.25	-$0.45	-$0.84	-$1.14	-$1.15	-$1.13	-$1.13	-$1.13
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.10	-$0.25	-$0.24	$0.31	-$0.12	-$0.21	-$0.21		$0.09	$0.18	$0.18	$0.17	$0.17	$0.17
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2	$0.05	-$0.06	-$0.05	$0.05	-$0.03	-$0.05	-$0.05	-$0.01	$0.01	$0.03	$0.03	$0.02	$0.02	$0.02
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.04	-$0.05	-$0.05	$0.05	-$0.03	-$0.05	-$0.05	$0.00	$0.02	$0.04	$0.04	$0.03	$0.03	$0.03
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.04	-$0.01	$0.00			$0.00								
	RM_TM21_NG	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.01	-$0.01	-$0.01	$0.01	-$0.01	-$0.01	-$0.01		$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	7440_MetcalfImport_Tes-Metcalf	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00			$0.00	$0.00	$0.00	$0.00	$0.00
	6310_CP6_NG	$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	$0.00
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	$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
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _2	-$0.01	$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_2 _3	-$0.78	$0.68	$0.65	-$0.74	$0.39	$0.58	$0.58	$0.01	-$0.29	-$0.55	-$0.55	-$0.53	-$0.53	-$0.53
	32214_RIO OSO _115_30330_RIO OSO _230_XF_1					$0.02									
	32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1					$0.02									
SCE	OMS 9076082 ELD-MHV_NG	$0.59	$0.59	$0.15	$0.52	-$1.34	-$1.21	-$1.19	-$0.68	-$0.24	$0.05	$0.04	$0.03	$0.02	$0.03
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	$0.00	$0.16	-$0.01	$0.00	-$0.05	-$0.07	-$0.07	-$0.05	-$0.04	-$0.01	-$0.01	-$0.02	-$0.02	-$0.02
	6410_CP6_NG	-$0.18	$0.15	$0.15	-$0.18	$0.09	$0.13	$0.13	$0.00	-$0.07	-$0.13	-$0.13	-$0.13	-$0.12	-$0.13
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.03	$0.14	$0.21	-$0.03	-$0.07	-$0.04	-$0.04	-$0.06	-$0.05	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03
	SYLMAR-AC_BG	$0.01	$0.10		$0.00	-$0.09	-$0.07	-$0.07	-$0.05	$0.00					
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.10	$0.10	$0.02	$0.08	-$0.21	-$0.22	-$0.22	-$0.11	-$0.04	$0.02	$0.02	$0.01	$0.01	$0.01
	24025_CHINO _230_24093_MIRALOM _230_BR_3 _1	-$0.02	$0.03	$0.09	-$0.02	-$0.02			-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	7750 CP5_NG	$0.01	$0.03		$0.01	-$0.02	-$0.06	-$0.06	-$0.01						
	6410_CP5_NG	-$0.02	$0.02	$0.02	-$0.02	$0.01	$0.02	$0.02	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	$0.10	$0.01	-$0.11	$0.09	-$0.18	-$0.20	-$0.20	-$0.08		$0.04	$0.04	$0.03	$0.03	$0.03
	OMS 9364948 LUG-VIC_OOS_NG	$0.01	$0.01		$0.01	-$0.02	-$0.02	-$0.02	-$0.01	$0.00	$0.00	$0.00			
	OMS 9488403 LUG-VIC_OOS_NG	$0.01	$0.01		$0.00	-$0.01	-$0.01	-$0.01	-$0.01	$0.00					
	24042_ELDORDO _500_24086_LUGO _500_BR_1 _3	$0.00	$0.01	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00		$0.00
	24801_DEVERS _500_99014_CALCAPS2_500_BR_2 _1	$0.00	$0.00		$0.00	$0.00	-$0.01	-$0.01	$0.00						
	24091_MESA CAL_230_25001_GOODRICH_230_BR_1 _1		$0.00	$0.00		-$0.01	$0.00	$0.00	$0.00						
	9315244_Devers VISTA1_NG	$0.00	$0.00		$0.00	$0.00	-$0.02	-$0.02	$0.00						
	OMS 9317668_Devers VISTA1_NG	$0.01	$0.00		$0.01	$0.00	-$0.02	-$0.02	$0.00						
	OMS 9316717_Devers VISTA1_NG	$0.01	-$0.01		$0.01	-$0.01	-$0.03	-$0.03	$0.00						
	8705726_Devers VISTA1_NG	$0.02	-$0.02		$0.02	-$0.01	-$0.06	-$0.09	-$0.01						
	OMS 9317626_Devers-ElCasco_NG	$0.02	-$0.02	$0.00	$0.02	-$0.02	-$0.07	-$0.07	-$0.01						
	OMS 9317653_Devers-ElCasco_NG	$0.02	-$0.02		$0.02	-$0.01	-$0.07	-$0.07	-$0.01						
	24601_VICTOR _230_24085_LUGO _230_BR_4 _1		-$0.04			-$0.03									
	6410_CP10_NG	$0.05	-$0.06	-$0.06	$0.05	-$0.03	-$0.05	-$0.05	-$0.01	$0.01	$0.03	$0.03	$0.03	$0.03	$0.03
	OMS_9283023_Dervers_Vista1						-$0.07	-$0.07							
	OMS_9536265_Devers_Elcasco						-$0.02	-$0.02							
	OMS_9536265_Devers_Vista1						-$0.06	-$0.06							
	SCE Bond Fire	$0.01	-$0.01	-$0.01	$0.01	$0.00	-$0.02	-$0.02	$0.00						
SDG&E	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P		$0.13	$1.31		-$0.14	-$0.43	-$0.42	-$0.15						
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80		$0.00	$0.57		-$0.03	-$0.18	-$0.18	-$0.05						
	7820_TL 230S_OVERLOAD_NG		$0.04	$0.53		-$0.04	-$0.11	-$0.12	-$0.04	-$0.02					
	OMS 9300860_50001_OOS_NG		$0.00	$0.03		$0.00	-$0.01	-$0.01	$0.00						
	92321_SYCA TP2_230_22832_SYCAMORE_230_BR_2 _1			$0.02			-$0.01	-$0.01							
	7820_TL23040_IV_SPS_NG			$0.02		$0.00	$0.00	$0.00	$0.00						
	22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1			$0.02			-$0.01	-$0.01							
	OMS 8701987_50001_OOS_NG		$0.00	$0.01		$0.00	$0.00	$0.00	$0.00						
	OMS 8421617_D-VST2_OOS_CP3	$0.03	-$0.02	$0.00	$0.02	-$0.02	-$0.07	-$0.08	-$0.01		$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 8929209_D-SBLR_OOS_CP3	$0.16	-$0.12	-$0.05	$0.14	-$0.03	-$0.57	-$0.58	-$0.05		$0.07	$0.06	$0.04	$0.04	$0.04
	7750_DV2_N1SV500_NG	$0.00	$0.00		$0.00	$0.00	-$0.01	-$0.02	$0.00		$0.00	$0.00			
	Other	$0.01	$0.07	$0.02	$0.01	-$0.03	-$0.03	-$0.03	-$0.02	-$0.01	-$0.01	-$0.01	-$0.02	-$0.02	-$0.02
	Internal Total	**$1.20**	**$2.02**	**$3.62**	**$1.29**	**-$2.04**	**-$3.14**	**-$3.20**	**-$2.87**	**-$1.57**	**-$1.47**	**-$1.51**	**-$1.53**	**-$1.55**	**-$1.53**
	Transfers				-$0.96	$0.34	-$0.07	$0.65	-$2.41	-$2.84	-$5.61	-$5.09	-$6.05	-$5.52	-$5.34
	Grand Total	**$1.20**	**$2.02**	**$3.62**	**$0.33**	**-$1.70**	**-$3.21**	**-$2.55**	**-$5.28**	**-$4.41**	**-$7.08**	**-$6.60**	**-$7.58**	**-$7.07**	**-$6.87**

Table 1.6 Impact of internal congestion on 15-minute prices during congested intervals[35]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDGE	BANC	NEVP	AZPS	SRP	PACE	IPCO	PACW	PGE	PSEI	PWRX	SCL
NEVP	GON-IPP 230	0.4%		$5.88	$5.66		$11.59			-$19.09	-$7.27					
	GON 230TXF#4	0.7%		$3.63	$3.64			$2.78	$2.82	-$9.89	-$10.86					
	GON 345TXF#4	0.7%		$0.97	$0.97			$1.29	$1.28	-$11.48	$0.00					
PACE	WINDSTAR EXPORT TCOR	17.2%								-$0.55						
	WYOMING_EXPORT	7.8%								-$0.86						
	TOTAL_WYOMING_EXPORT	32.7%								-$1.08						
	EAST_WYO_EXP	10.6%								-$1.34						
PG&E	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	6.0%	$13.86	$6.45	$5.60	$13.78	$1.07	$4.16	$4.11	-$7.51	-$13.97	-$19.01	-$19.20	-$18.98	-$18.88	-$18.96
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	0.8%	$5.39	-$7.14	-$6.69	$6.40	-$3.75	-$6.00	-$5.99	-$1.11	$2.24	$4.65	$4.59	$4.45	$4.39	$4.44
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	3.4%	$2.97	-$7.42	-$6.98	$9.06	-$3.48	-$6.19	-$6.18		$2.63	$5.26	$5.20	$5.04	$4.96	$5.03
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	0.6%	$1.44	-$1.99	-$1.88	$1.88	-$1.11	-$1.70	-$1.69		$0.73	$1.36	$1.34	$1.31	$1.30	$1.31
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	1.5%	-$51.17	$44.67	$42.31	-$48.49	$25.46	$37.82	$37.67	$1.32	-$19.23	-$36.00	-$35.72	-$34.91	-$34.62	-$34.85
SCE	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	0.3%	-$11.50	$46.07	-$3.81	-$11.50	-$16.09	-$21.29	-$21.50	-$14.63	-$12.39	-$14.13	-$14.22	-$13.41	-$12.69	-$13.41
	SYLMAR-AC_BG	0.7%	$9.41	$15.31		$13.22	-$12.84	-$10.33	-$10.21	-$6.88	-$4.31					
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	1.0%	-$4.14	$13.41	$20.56	-$4.14	-$6.46	-$10.76	-$11.03	-$5.63	-$5.13	-$4.28	-$4.43	-$4.44	-$4.44	-$4.44
	OMS 9076082 ELD-MHV_NG	10.7%	$5.53	$5.52	$1.64	$4.81	-$12.51	-$11.26	-$11.14	-$6.37	-$2.43	$1.04	$1.01	$0.93	$0.84	$0.94
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	2.0%	$4.73	$5.02	$1.11	$4.13	-$10.46	-$10.89	-$10.96	-$5.44	-$1.90	$1.30	$1.21	$1.08	$0.92	$1.08
	7750 CP5_NG	0.7%	$1.97	$3.40		$1.76	-$2.34	-$8.44	-$8.61	-$1.87						
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	0.7%	$15.19	$2.90	-$16.24	$13.73	-$26.59	-$28.44	-$28.26	-$12.15		$9.30	$11.32	$13.20	$12.67	$13.15
	8705726_Devers VISTA1_NG	1.3%	$1.68	-$1.26		$1.52	-$1.01	-$4.81	-$6.82	-$1.11						
	OMS 9317626_Devers-ElCasco_NG	1.4%	$1.75	-$1.35	-$2.84	$1.59	-$1.12	-$4.93	-$5.09	-$1.10						
	OMS 9316717_Devers VISTA1_NG	0.5%	$2.06	-$1.54		$1.88	-$1.45	-$5.76	-$5.96	-$1.37						
	OMS 9317653_Devers-ElCasco_NG	0.7%	$3.08	-$2.71		$2.79	-$2.02	-$9.03	-$9.35	-$1.78						
	6410_CP10_NG	0.5%	$10.40	-$13.12	-$12.32	$9.73	-$6.82	-$11.13	-$11.13	-$1.86	$2.67	$6.53	$6.44	$6.21	$6.09	$6.19
	OMS_9283023_Dervers_Vista1	0.3%						-$21.28	-$21.52							
SDG&E	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	4.1%		$3.44	$31.59		-$3.57	-$10.29	-$10.18	-$3.79						
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	2.7%		$2.09	$21.60		-$4.19	-$6.68	-$6.66	-$2.98						
	7820_TL 230S_OVERLOAD_NG	3.6%		$1.06	$14.59		-$1.15	-$3.14	-$3.40	-$1.20	-$0.69					
	OMS 8421617_D-VST2_OOS_CP3	1.4%	$1.91	-$1.50	-$0.24	$1.75	-$1.34	-$5.36	-$5.52	-$1.30		$0.54	$0.53	$0.59	$0.56	$0.59
	OMS 8929209_D-SBLR_OOS_CP3	9.3%	$1.68	-$1.35	-$1.28	$1.55	-$1.13	-$6.15	-$6.27	-$1.25		$0.92	$0.89	$0.87	$0.87	$0.87

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

Figure 1.41 shows the overall impact of internal flow-based constraint congestion on 5-minute prices in each load area for 2019 and 2020.

Figure 1.42 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 fourth quarter of 2020 compared to the same quarter of 2019. Congestion resulted in a net increase to 5-minute prices in PG&E, SCE, SDG&E, and BANC, while leading to a net decrease to 5-minute prices in other EIM areas.
- Congestion continued to impact prices in both the positive and negative direction over the quarter in each load area, which worked to offset some of the impact of congestion over the quarter. The frequency of congestion was highest in PACE (65 percent of total intervals), where congestion predominantly decreased prices.

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

Figure 1.41 Overall impact of internal congestion on price separation in the 5-minute market

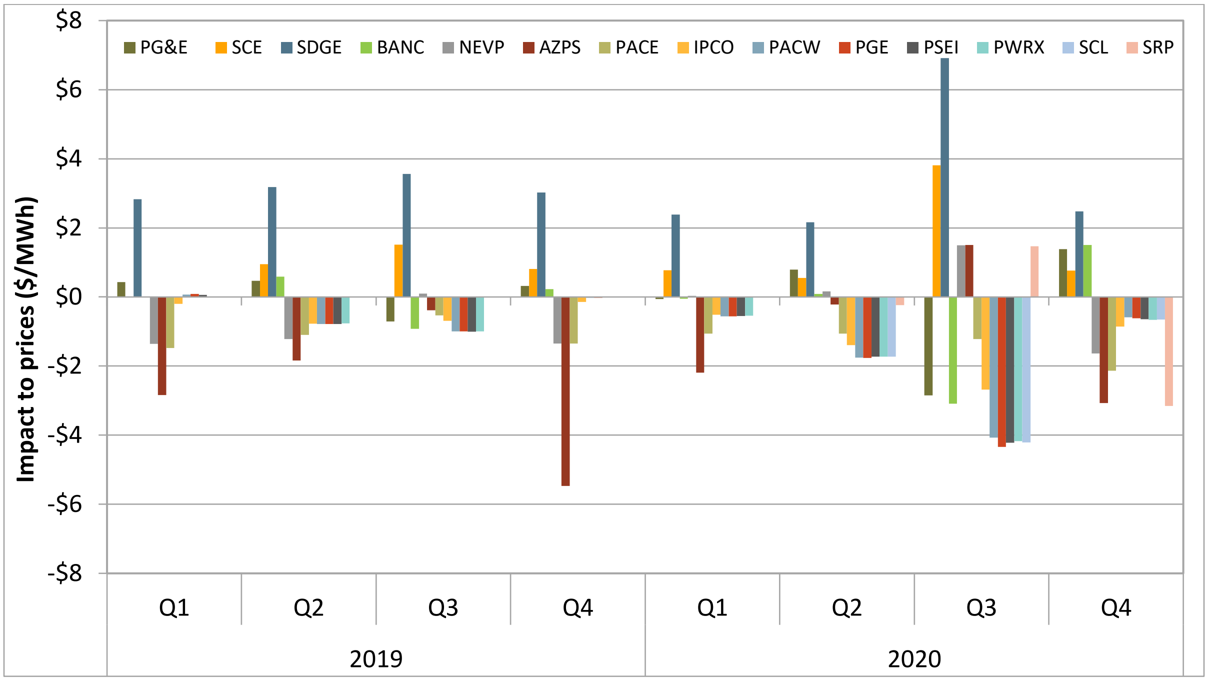
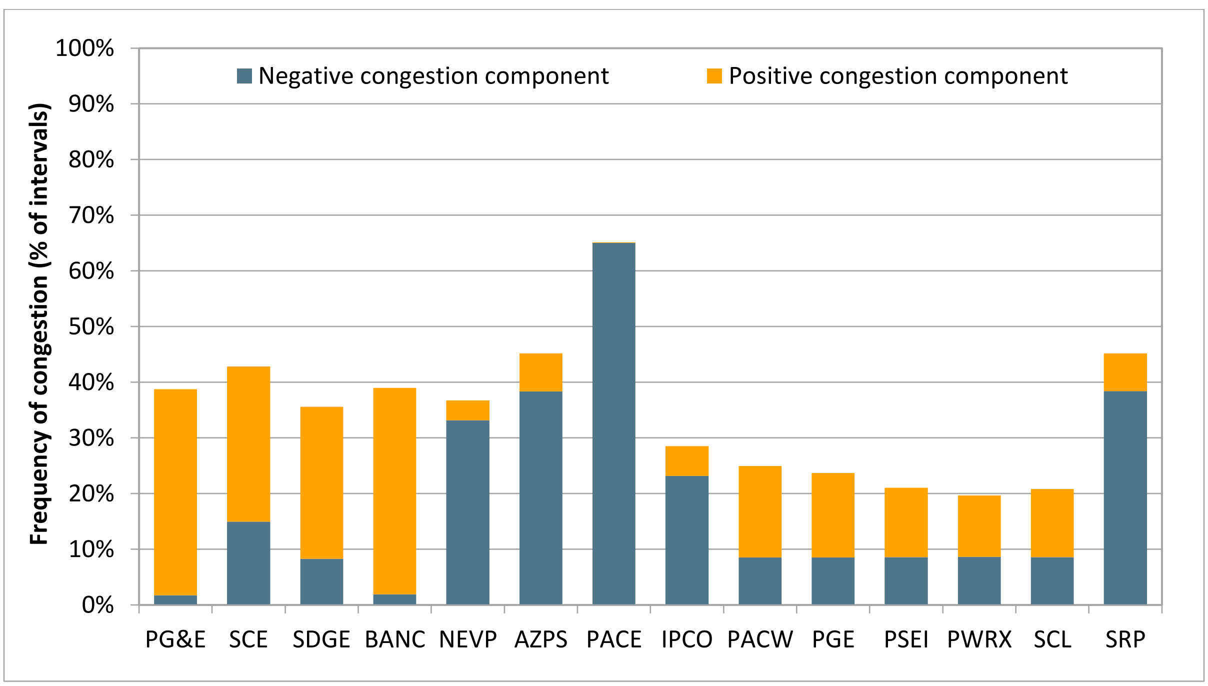


Figure 1.42 Percent of intervals with internal congestion increasing versus decreasing 5-minute prices in the fourth quarter (>$0.05/MWh)



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 1.39 and Table 1.5, and schedule-based constraints as listed in Table 1.7. Transfer constraint congestion typically has the largest impact on prices, therefore, it is isolated here to better show its effects on EIM load areas. Table 1.7 shows the congestion frequency and average price impact from transfer constraint congestion in the 15-minute and 5-minute markets during the quarter. 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 Puget Sound Energy area, with an average decrease of about $6.05/MWh in the 15-minute market and $3.11/MWh in the 5-minute market.

Table 1.7 Quarterly average price impact and congestion frequency on EIM transfer constraints (Q4 2020)

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	1%	-$0.96	1%	-$0.14
NV Energy	2%	$0.34	2%	$0.99
Arizona Public Service	3%	-$0.07	2%	$1.21
Salt River Project	4%	$0.65	3%	$3.07
Idaho Power	9%	-$2.84	5%	-$1.22
PacifiCorp East	9%	-$2.41	6%	-$0.78
PacifiCorp West	39%	-$5.61	23%	-$2.29
Portland General Electric	40%	-$5.09	25%	-$1.52
Puget Sound Energy	45%	-$6.05	37%	-$3.11
Seattle City Light	45%	-$5.34	37%	-$2.67
Powerex	48%	-$5.52	47%	-$2.53

Transfer congestion in the 15-minute market

Transfer constraint congestion in the 15-minute market occurred with vastly different frequencies and average price impacts across the EIM. Figure 1.43 shows the average impact to prices in the 15-minute market by quarter for 2019 and 2020. Figure 1.44 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 fourth quarter of 2020, compared to the same quarter in 2019. Price impacts were greatest in the Puget Sound Energy area, where transfer constraint congestion decreased prices by $6.05/MWh on average.

Transfer constraint congestion frequency in the fourth quarter of 2020 was higher than that of the same quarter of 2019, with similar high frequencies across the Pacific Northwest. Powerex continued to have the highest frequency of transfer congestion, occurring during about 48 percent of intervals.

Figure 1.43 Transfer constraint congestion average impact on prices in the 15-minute market

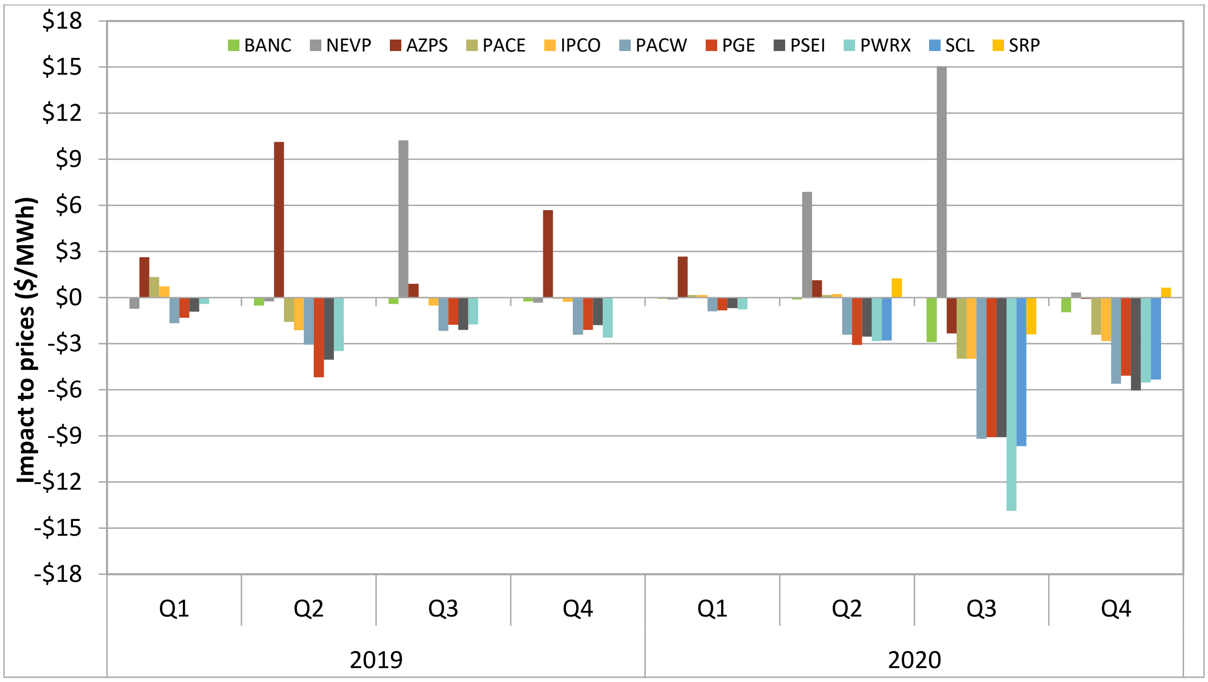
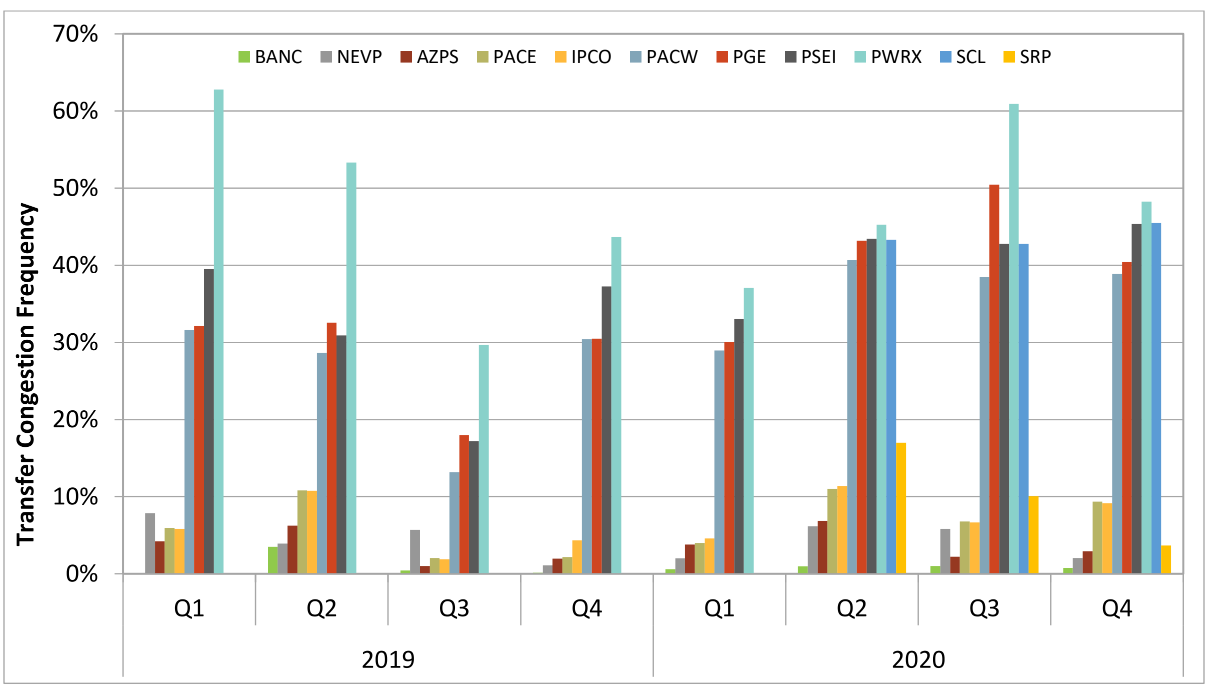


Figure 1.44 Transfer constraint congestion frequency in the 15-minute market



Transfer congestion in the 5-minute market

Similar to the 15-minute market, transfer constraint congestion in the 5-minute market occurred with different frequencies and average price impacts across the EIM. Figure 1.45 shows the average impact on prices in the 5-minute market by quarter for 2019 and 2020. Figure 1.46 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 fourth quarter of 2020 were 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. Puget Sound Energy experienced the largest impact on prices in the 5-minute market for the fourth quarter of 2020, where transfer congestion decreased average prices by $3.11/MWh.

Overall, the frequency of transfer constraint congestion was higher in the fourth quarter of 2020 compared to the same quarter in 2019. Areas that had high frequencies of transfer constraint congestion in this quarter include Puget Sound Energy, Powerex, and Seattle City Light. In each of these areas, the quarterly transfer congestion frequency was over 35 percent.

Figure 1.45 Transfer constraint congestion average impact on prices in the 5-minute market

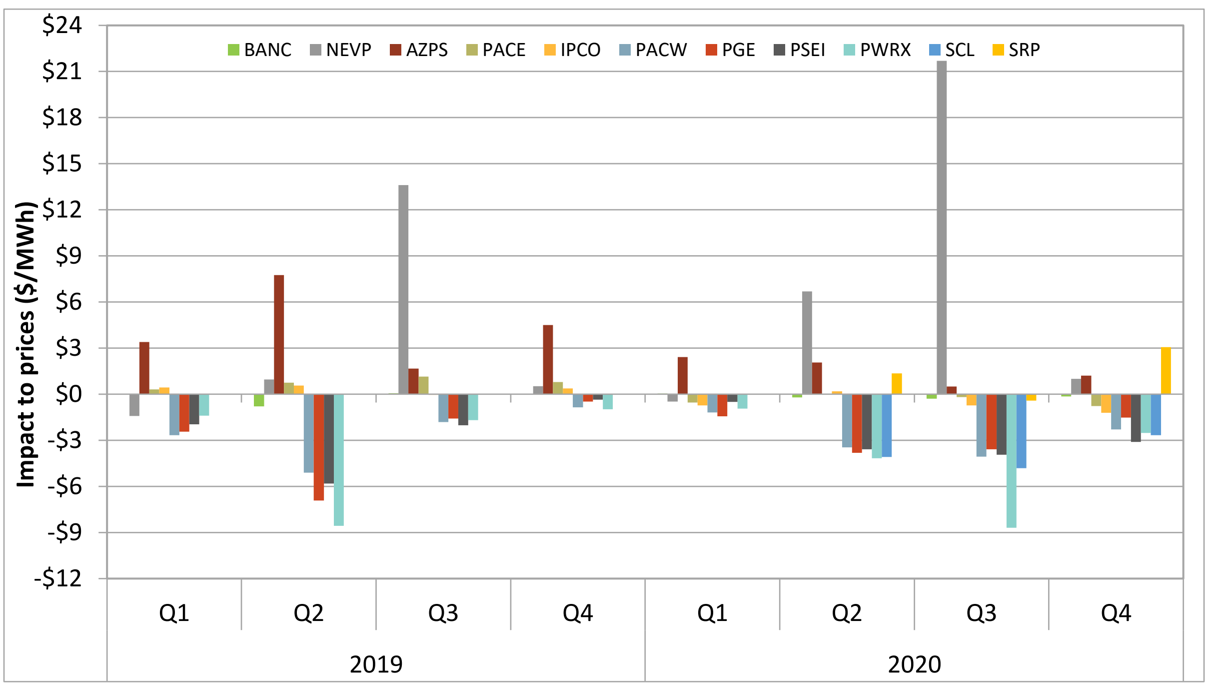
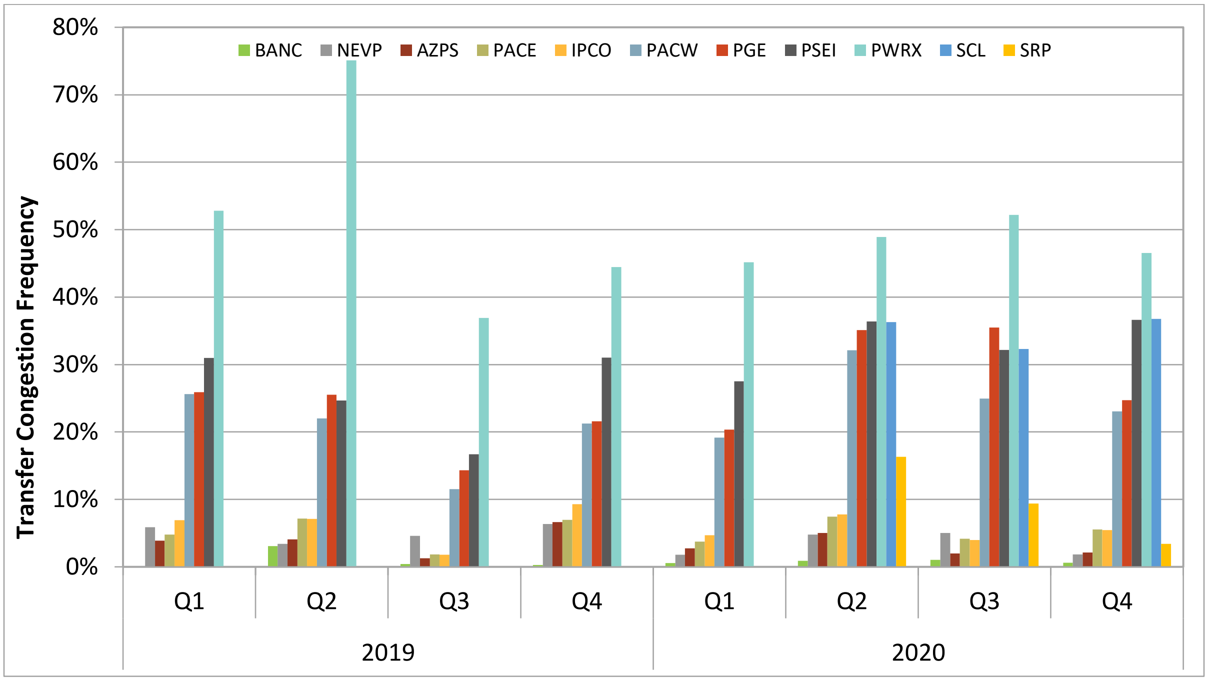


Figure 1.46 Transfer constraint congestion frequency in the 5-minute market



1.10.3 Congestion on interties

In the fourth quarter of 2020, both frequency and import congestion charges decreased on most major interties such as PACI/Malin 500 and IPP Utah relative to the same quarter in 2019. Figure 1.47 shows total import congestion charges in the day-ahead market for 2019 and 2020. Figure 1.48 shows the frequency of congestion on five major interties. Table 1.8 provides a detailed summary of this data over a broader set of interties.

The total import congestion charges reported are the products of the shadow prices multiplied by 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 fourth quarter of 2020 increased to about $19 million compared to about $18 million in the same quarter of 2019. This is mainly driven by an increase in congestion on the NOB intertie, which accounted for 30 percent of the total import congestion charges for the quarter.
- The frequency of congestion in the fourth quarter increased significantly on NOB, while it decreased on the other interties relative to the fourth quarter of 2019.

- 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 fourth quarter followed this trend. Congestion on other interties continued to remain relatively low relative to these constraints.

Figure 1.47 Day-ahead import congestion charges on major interties

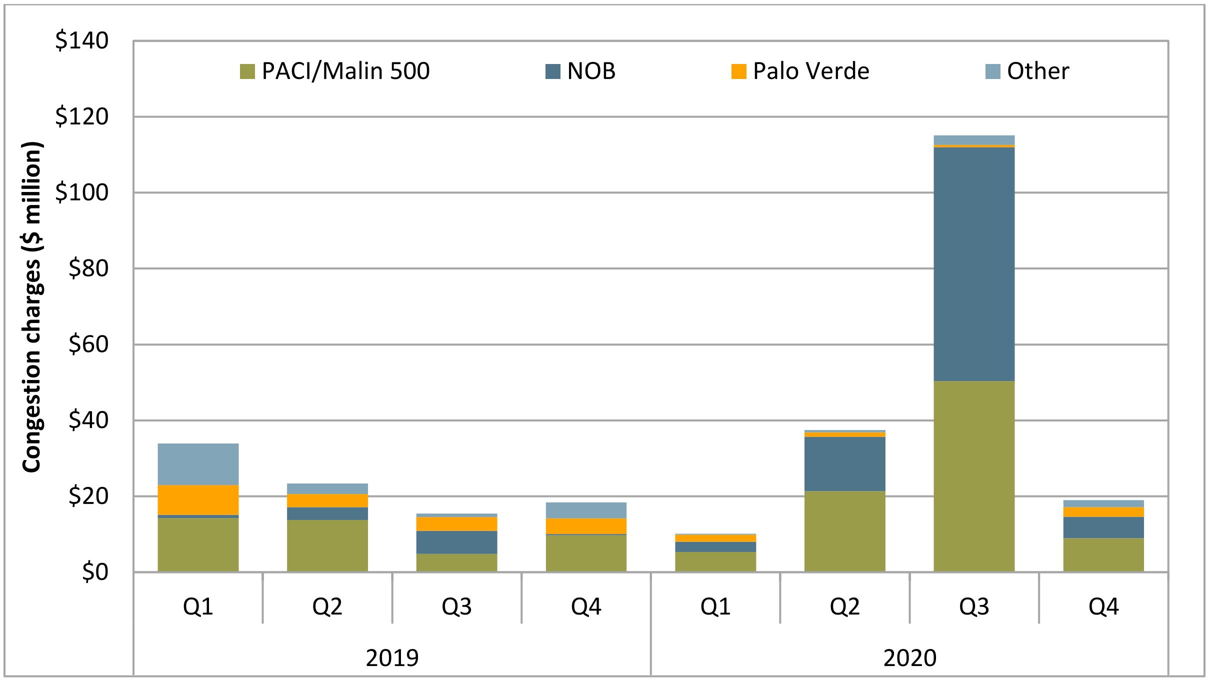


Figure 1.48 Frequency of import congestion on major interties in the day-ahead market

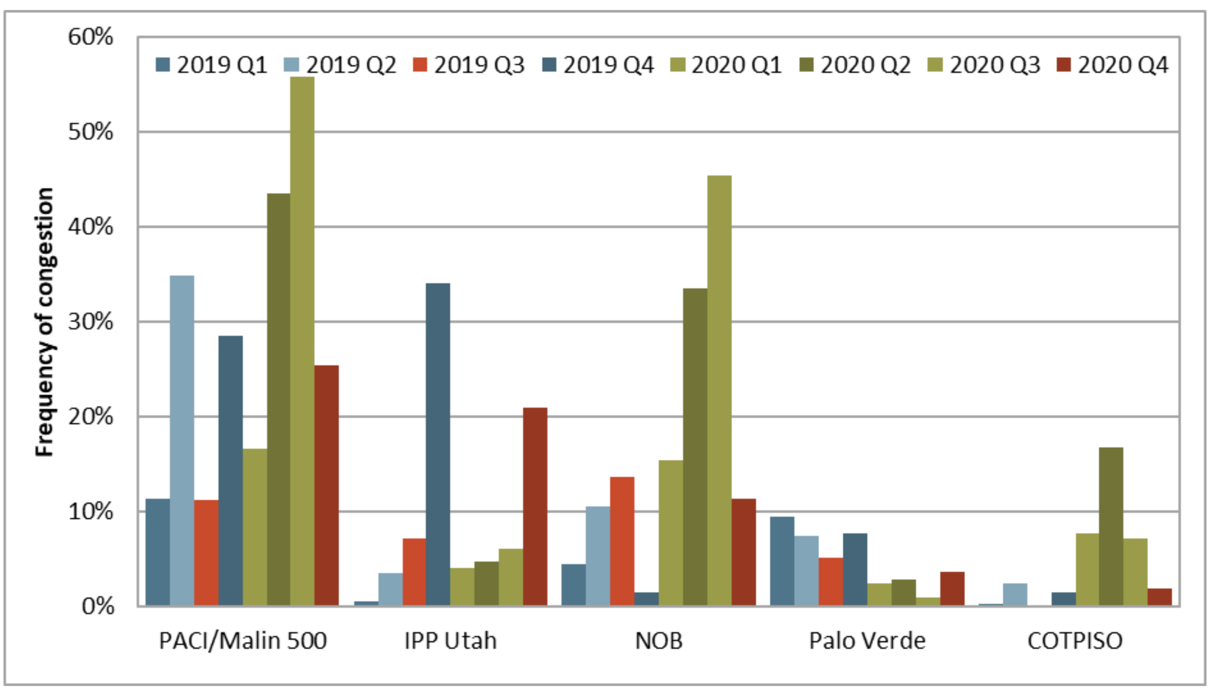


Table 1.8 Summary of import congestion in day-ahead market (2019-2020)

Area	Intertie	Frequency of import congestion								Import congestion charges ($ thousand)							
		2019				2020				2019				2020			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northwest	PACI/Malin 500	11%	35%	11%	29%	17%	44%	56%	25%	14,246	13,773	4,787	9,681	5,318	21,358	50,334	8,919
	NOB	5%	11%	14%	2%	15%	34%	45%	11%	858	3,380	6,128	382	2,715	14,317	61,672	5,670
	COTPISO	0%	3%		2%	8%	17%	7%	2%	4	20		21	85	258	66	14
	Cascade		1%	2%	0%	0%		0%			30	162	1	2		52	
	Summit			1%		1%						26		6			
Southwest	Palo Verde	9%	8%	5%	8%	2%	3%	1%	4%	7,864	3,409	3,579	4,128	1,827	1,174	576	2,516
	IPP Utah	1%	4%	7%	34%	4%	5%	6%	21%	13	99	186	2,528	136	136	528	1,459
	Mead	1%		0%	2%		1%	1%	2%	306		238	989		133	856	357
	Westwing Mead	2%		1%	2%				0%	127		21	138				19
	Sylmar								0%								17
	IPP Adelanto	44%	1%		0%		0%	0%		10,028	120		98		96	12	
	MeadTMead				1%			0%					37			985	
	Marble		1%				1%				18				18		

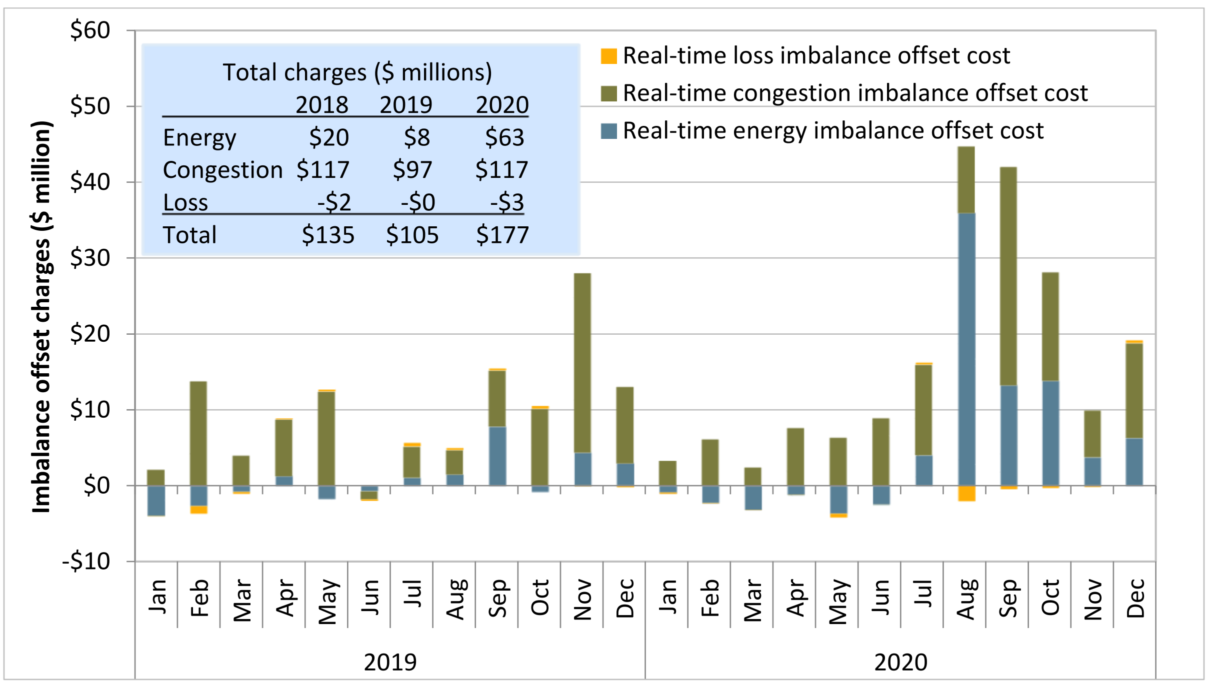
1.11 Real-time imbalance offset costs

Fourth quarter real-time offset costs were about $57 million, down from over $100 million in the third quarter of 2020. Real-time imbalance offset costs were comprised of about $33 million in congestion deficits and about $24 million in energy deficits.

The real-time imbalance offset charge consists of three components corresponding to the main components of real-time settlement prices: energy, congestion and loss.[36] Any revenue imbalance from the energy components of real-time settlement prices is collected through the real-time imbalance energy offset charge (RTIEO). Revenue imbalance from the congestion component is recovered through the real-time congestion imbalance offset charge (RTCIO), and revenue imbalance from the loss component is collected through the real-time loss imbalance offset charge.

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

Figure 1.49 Real-time imbalance offset costs



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

1.12 Congestion revenue rights

Congestion revenue right auction returns

Profits from the congestion revenue right auction by non-load-serving entities are calculated by summing revenue paid out to 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 1.50, transmission ratepayers lost about $6 million during the fourth quarter of 2020 as payments to auctioned congestion revenue rights holders exceeded auction revenues. This is lower than the over $15 million loss in the fourth quarter of 2019. Auction revenues were 77 percent of payments made to non-load-serving entities during the fourth quarter of 2020, up from 63 percent during the same quarter in 2019.

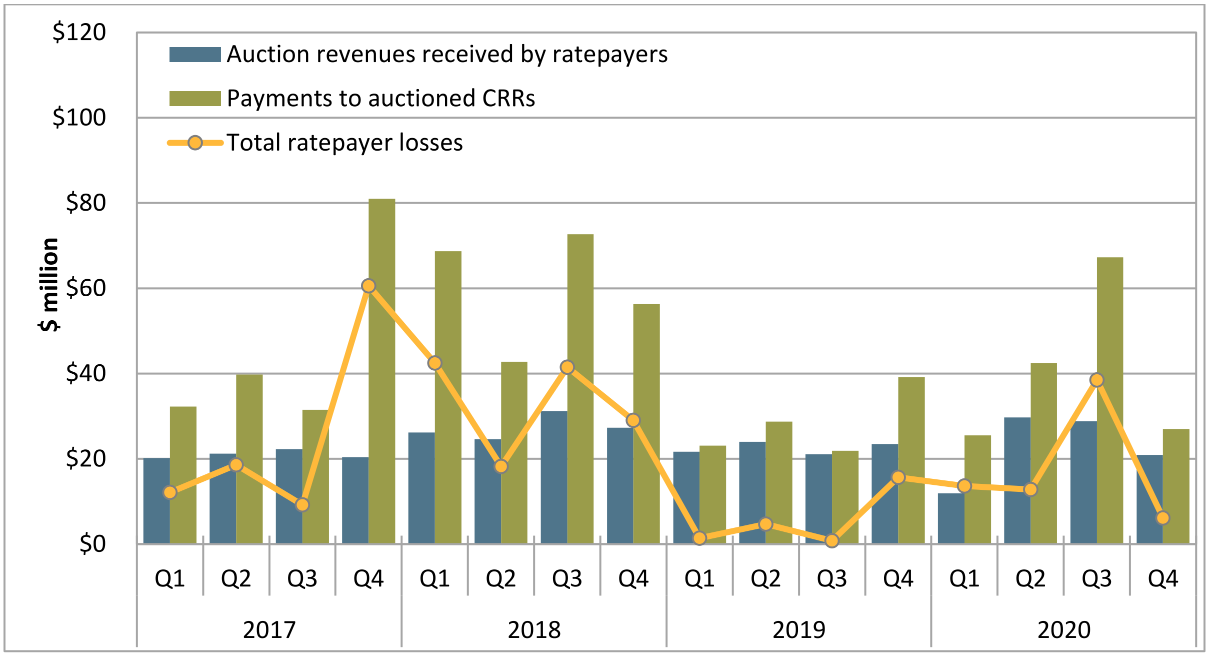
In the third quarter of 2020, a majority of transmission ratepayer losses were from congestion revenue right sales made by load serving entities. This was the first time this has happened. In the fourth quarter, ratepayer losses returned to the normal pattern of being primarily from sales of these rights by the ISO.

In the fourth quarter, financial entities (which do not schedule or trade physical power or serve load) had profits of over $2 million. This was a decrease from the nearly $11 million in profits during the same quarter in 2019. Marketers' profits were a little below $4 million, about the same as the fourth quarter of 2019. Generators broke even with profit near one hundred thousand dollars compared to over $1 million gained in the fourth quarter of 2019.

The $6 million in fourth quarter auction losses was about 6 percent of day-ahead congestion rent. This is down from 15 percent of rent in the fourth quarter of 2019 and the same as the 6 percent for all of 2019. 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 $7 million in the fourth quarter. The Track 1B effects on auction bidding behavior and reduced auction revenues is not known.

Figure 1.50 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, and also into 2020. However, DMM continues to recommend that the ISO take steps to discontinue auctioning congestion revenue rights on behalf of ratepayers. The auction continues to consistently cause millions of dollars of losses to transmission ratepayers each year, while exposing transmission ratepayers to risk of significantly higher losses in the event of unexpected increases in congestion or modeling errors. 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 fourth quarter of 2020, estimated bid cost recovery payments for units in the ISO and energy imbalance market totaled about $37 million. This was $25 million lower than total bid cost recovery in the previous quarter and about $10 million higher than in the fourth quarter of 2019.

Bid cost recovery attributed to the day-ahead market totaled about $8 million, similar to the prior quarter. Bid cost recovery payments for residual unit commitment during the quarter totaled about $8 million, compared to $22 million in the prior quarter. Units committed by the residual unit commitment can be either long-start or short-start units. In the fourth quarter, short-start units accounted for about

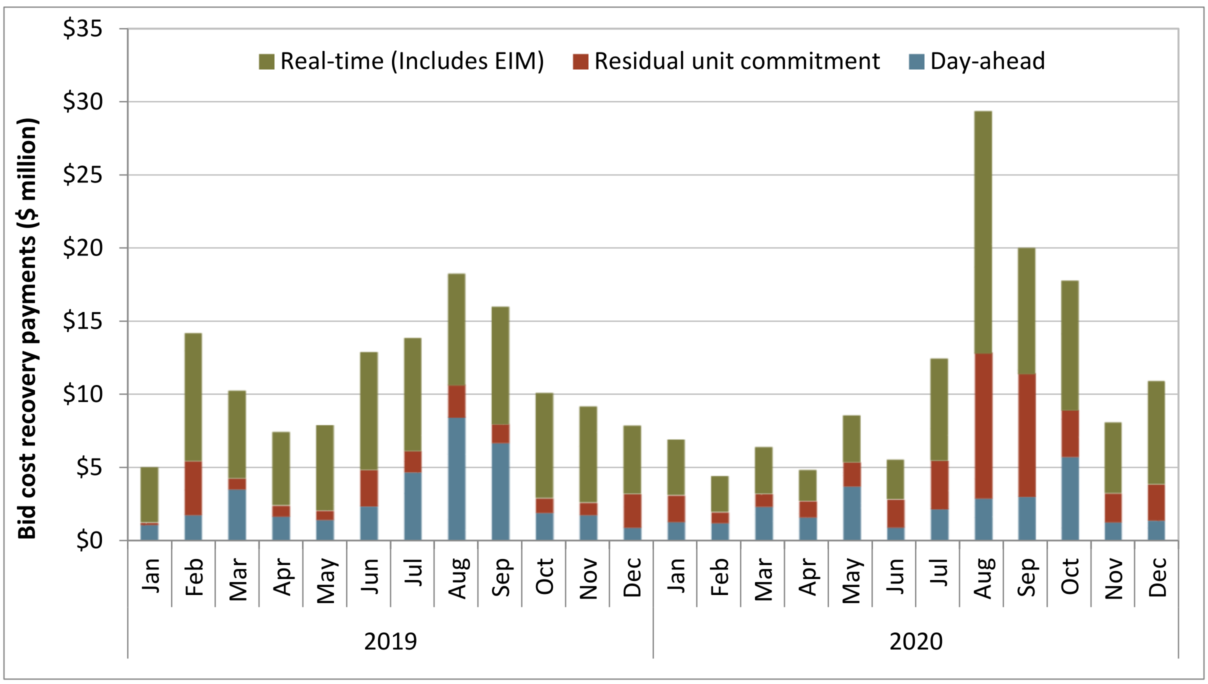
$5.4 million in bid cost recovery payments, while long-start unit commitment accounted for $2.3 million.[37]

Bid cost recovery attributed to the real-time market totaled about $21 million, or about $11 million lower than payments in the third quarter of 2020 and $2 million higher than payments in the fourth quarter of 2019. Of the total real-time bid cost recovery, $4 million was paid to resources in the Western Energy Imbalance Market outside of the ISO and $17 million to ISO resources.

Total bid cost recovery payments in the ISO were $0.64/MWh of load (1.4 percent), a decrease relative to the previous quarter ($0.94/MWh of load or 1.6 percent) but an increase compared to $0.45/MWh of load (1.0 percent) in the fourth quarter of 2019.

During the fourth quarter, DMM estimates that about 58 percent of the ISO's total bid cost recovery payments, approximately $19 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 92 percent of these payments were for resources bidding at or near the 125 percent bid cap for proxy commitment costs.

Figure 1.51 Monthly bid cost recovery payments



37 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.

1.14 Local market power mitigation enhancements

The ISO's automated local market power mitigation (LMPM) procedures are triggered when congestion occurs on a constraint that is determined to be uncompetitive. When this occurs, bids are mitigated to the higher of the system market energy price or a default energy bid designed to reflect a unit's marginal energy cost.

The impact on market prices of bids that were mitigated can only be assessed precisely by rerunning the market software without bid mitigation. Currently, DMM does not have the ability to rerun the day-ahead or 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.[38]

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

Mitigation in the ISO balancing area

In the day-ahead and real-time markets, rates of mitigation increased significantly relative to the fourth quarter of 2019. Incremental energy subject to mitigation has increased relative to prior years due, in part, to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers.

As shown in Figure 1.52, in the day-ahead market, an hourly average of about 974 MW was subject to mitigation but corresponding bids were not lowered compared to 404 MW in the same quarter of 2019. About 267 MW of incremental energy had bids lowered due to mitigation compared to 151 MW in 2019. As a result, there was on average about 14 MW increase in dispatch, similar to that of in 2019.

Figure 1.53 and Figure 1.54 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 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 fourth quarter relative to the same quarter in 2019.

[38] 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.

Figure 1.52 Average incremental energy mitigated in day-ahead market

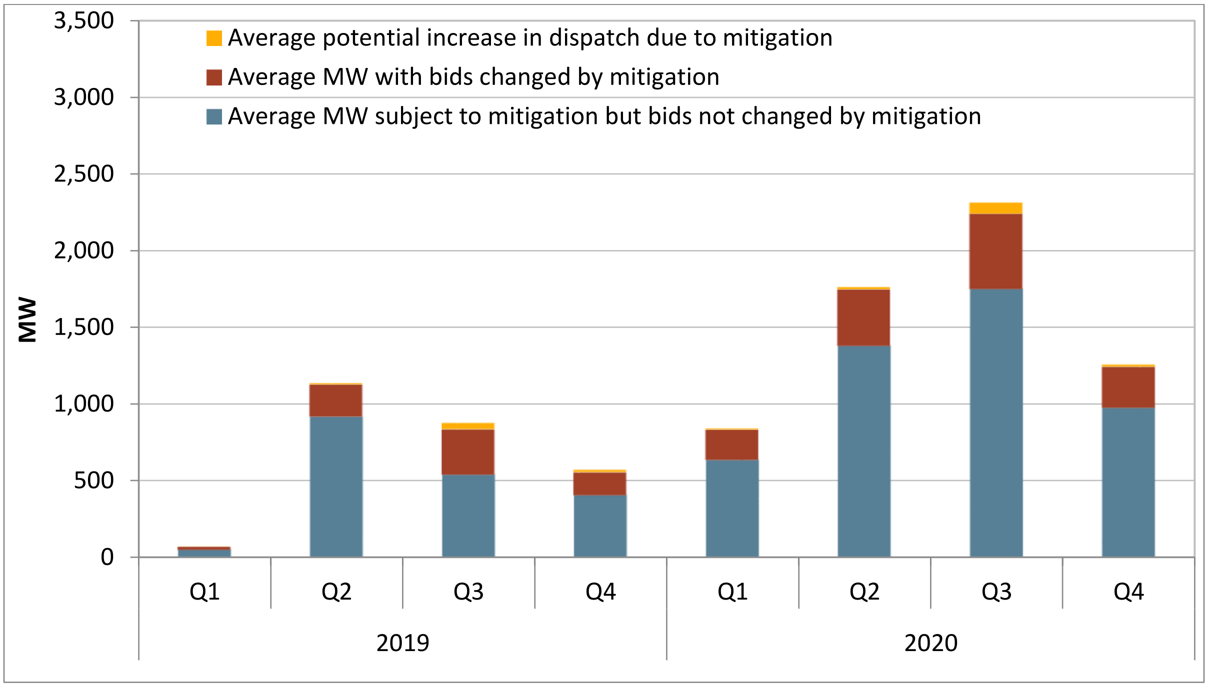


Figure 1.53 Average incremental energy mitigated in 15-minute real-time market (ISO)

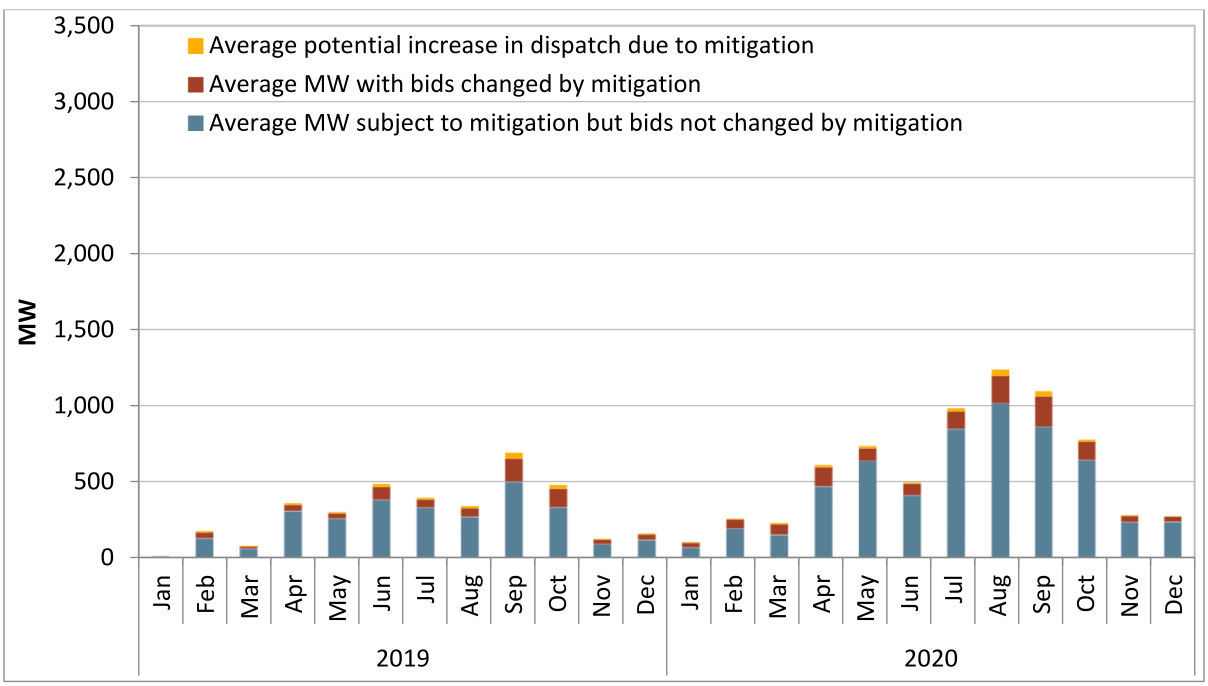
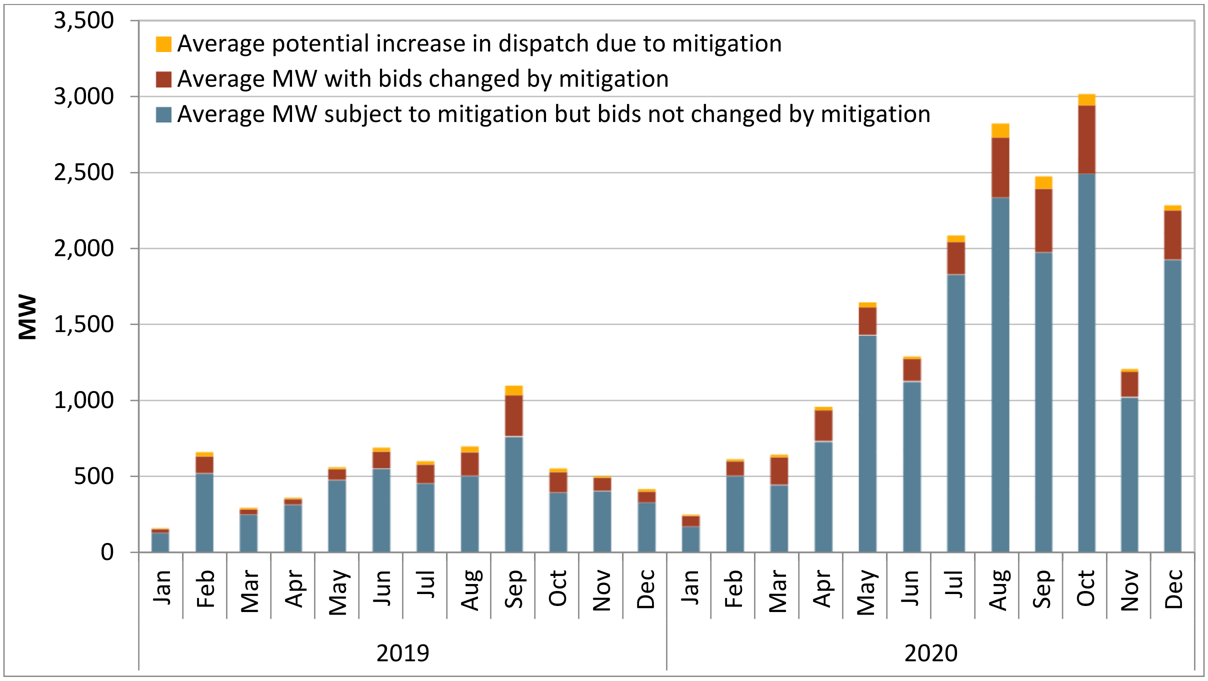


Figure 1.54 Average incremental energy mitigated in 5-minute real-time market (ISO)



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. 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.[39]

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 1,100 MW, which is similar to the peak in the same quarter of the previous year. Imbalance conformance in the morning ramp up period decreased this quarter compared to the prior year, with averages around 450 MW in hour ending 7 compared to about 660 MW the previous year.

Figure 1.55 shows imbalance conformance adjustments in the 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 pre-ramp, mid-day, and post-evening ramp periods.

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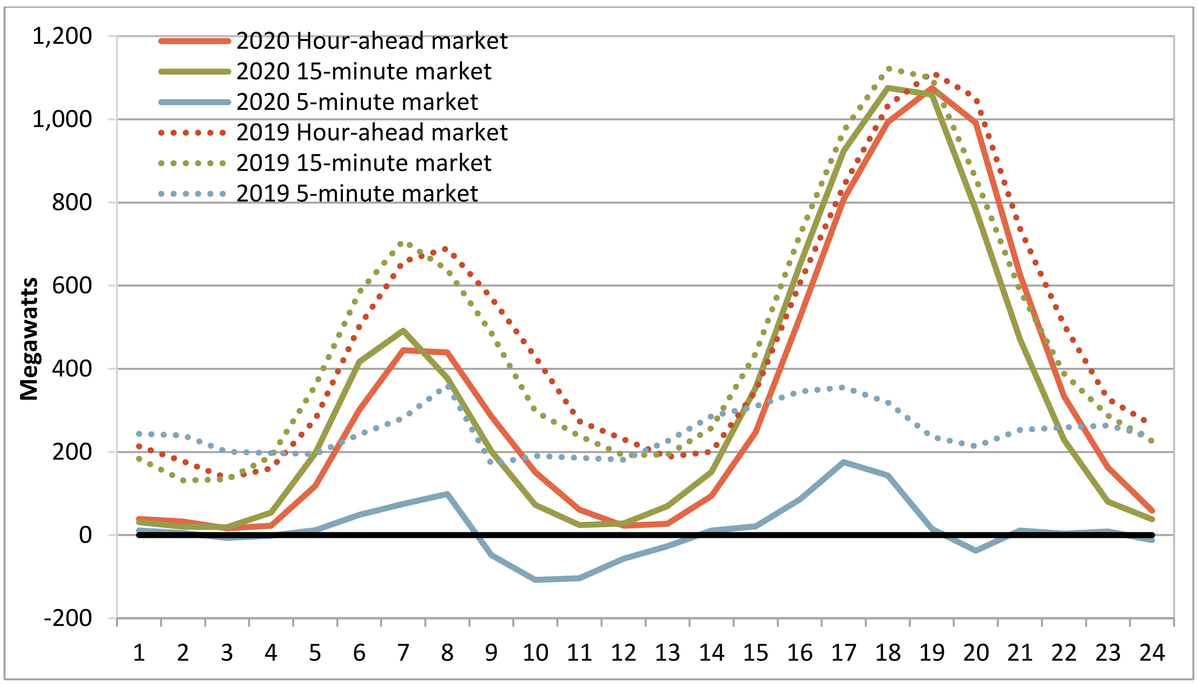
39 Additional detail can be found in Section 9, Market Adjustments, in the *2016 Annual Report on Market Issues and Performance*, which is available on the ISO website at: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf

The 5-minute market adjustments in this quarter were consistently lower than 15-minute market imbalance conformance. The wider gap between 15-minute and 5-minute imbalance conformance contributed to the greater deviation between 15-minute and 5-minute prices this quarter.

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 18 was about 140 MW, much lower than the 1,100 MW adjustment in the hour-ahead and 15-minute markets. In this quarter, mid-day adjustments were typically less than 100 MW in the hour-ahead and the 15-minute markets, while the 5-minute market adjustments trended negative throughout the morning between hour ending 9 and 13. The 5-minute market adjustments in this quarter were also consistently lower than the same quarter from the previous year.

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

Figure 1.55 Average hourly imbalance conformance adjustment (Q4 2019 – Q4 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.

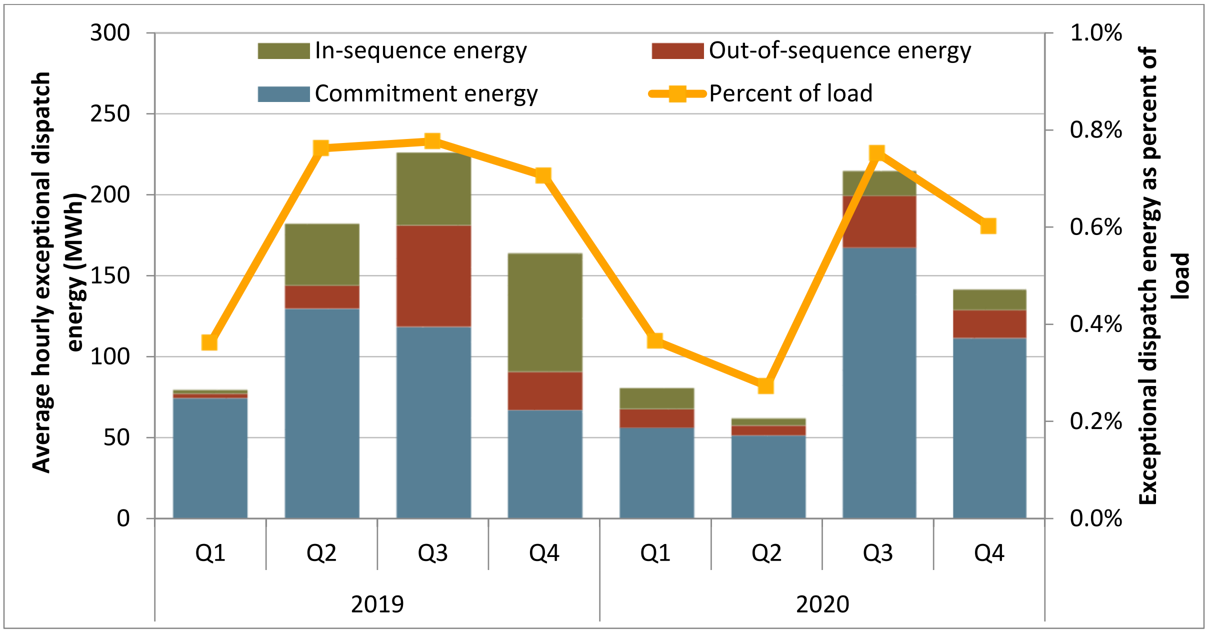
Energy from exceptional dispatch

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 141 MWh in the fourth quarter of 2020, which is down from 163 MWh in the same quarter in 2019.

As shown in Figure 1.56, exceptional dispatches for unit commitments accounted for about 79 percent of all exceptional dispatch energy in this quarter.[40] About 12 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 9 percent was from in-sequence energy.

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

Figure 1.56 Average hourly energy from exceptional dispatch

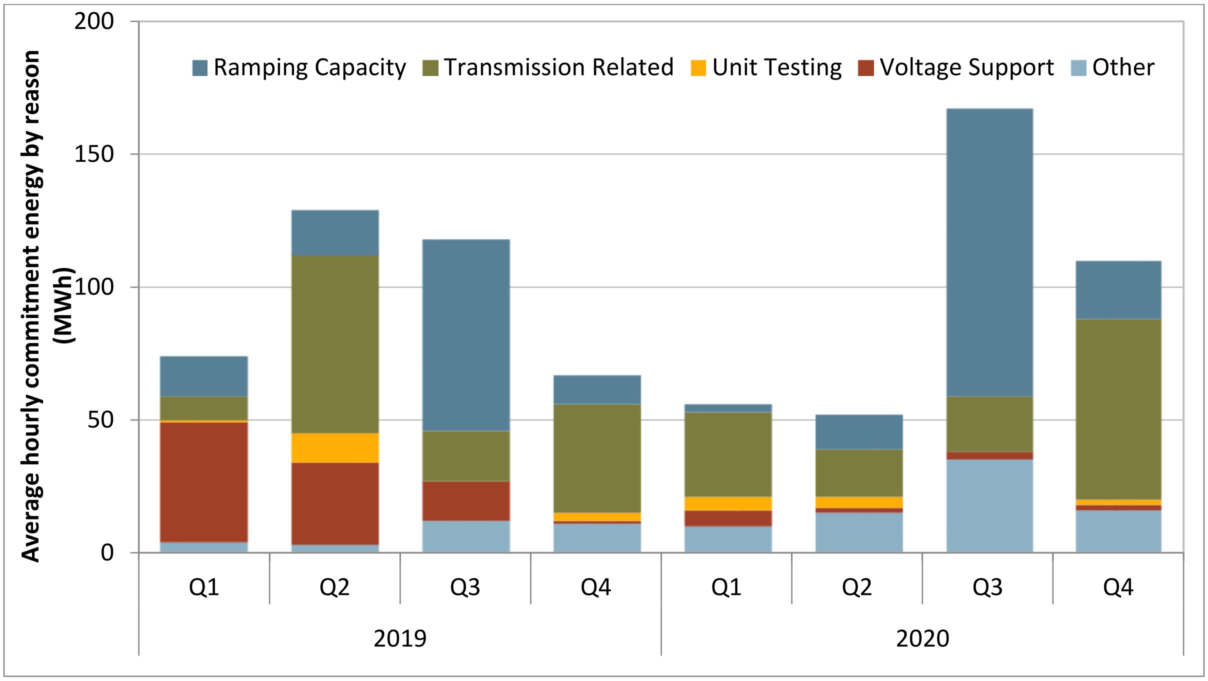


Exceptional dispatches for unit commitment

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 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 fourth quarter increased on average by about 64 percent relative to the same quarter of the prior year. The most frequent reasons given for exceptional dispatch unit commitments were transmission related. Exceptional dispatch unit commitments for transmission related issues are to address any planned transmission outages in participating transmission owner service territory.

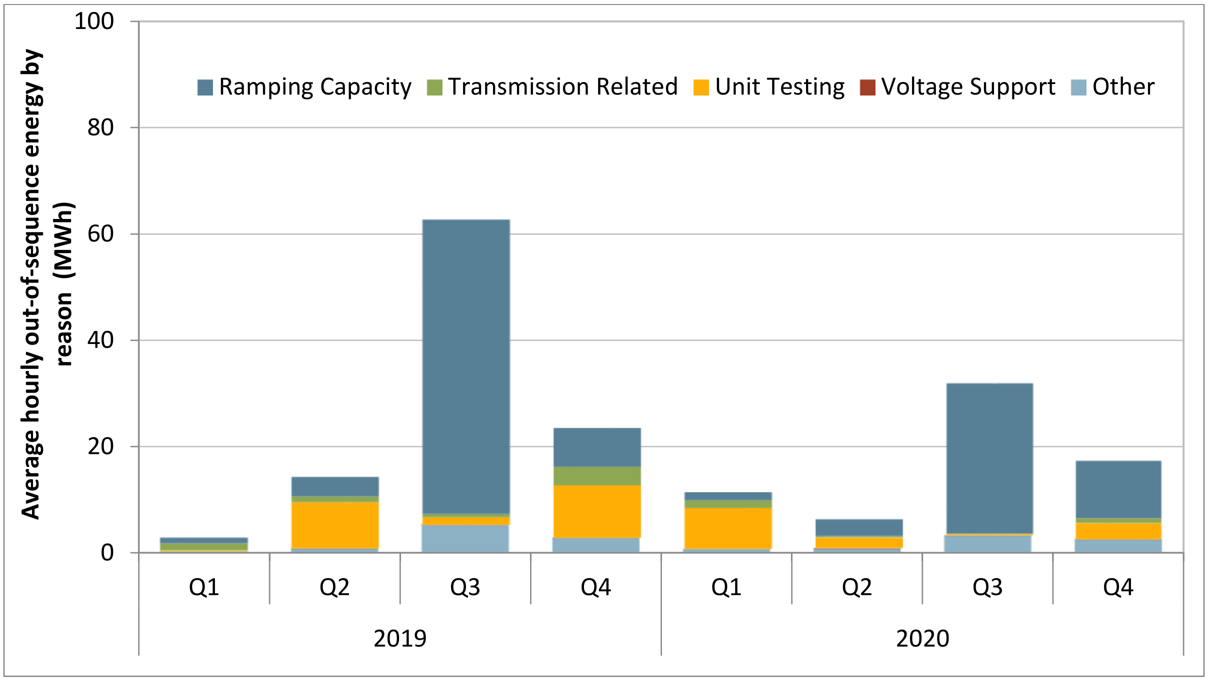
Figure 1.57 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

As shown in Figure 1.56, in the fourth quarter of 2020, energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch decreased by about 69 percent from the same quarter in 2019. Figure 1.56 also shows that about 12 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 1.58 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 fourth quarter of 2020 was exceptional dispatches 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 1.58 Out-of-sequence exceptional dispatch energy by reason



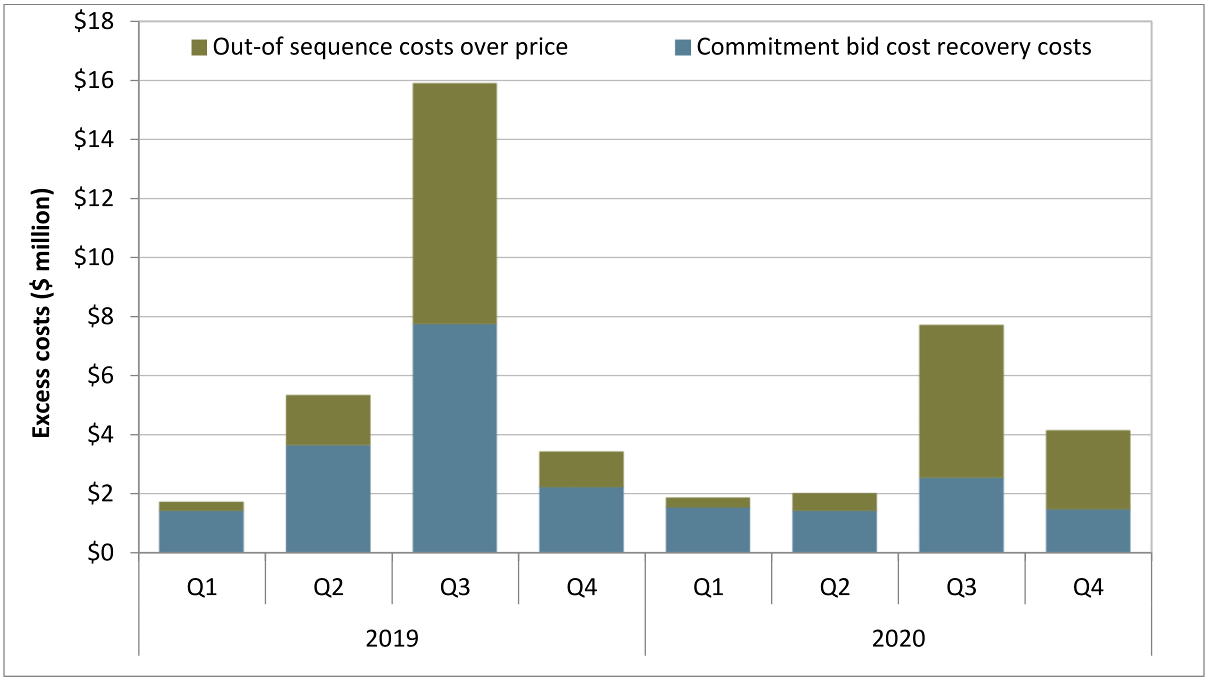
Exceptional dispatch costs

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 1.59 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 fourth quarter, out-of-sequence energy costs were $2.7 million, while commitment costs for exceptional dispatch paid through bid cost recovery were $1.5 million.

Figure 1.59 Excess exceptional dispatch cost by type



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.[41]

Table 1.9 shows intra-monthly capacity procurement mechanism costs for designations that occurred during the fourth quarter of 2020. Intra-monthly designations were triggered by significant events during the quarter. Estimated costs for intra-monthly capacity procurement mechanism designations totaled about $1.59 million in the fourth quarter of 2020.

In all, about 262 MW was procured through intra-monthly capacity procurement mechanisms. The ISO issued capacity procurement mechanism significant events, which designates the backstop capacity for system reliability needs. Twelve MW of this capacity was designated to meet the need of a September heat wave in California and the rest of the West so that the ISO could meet NERC reliability standards for load and reserve obligations. This heat wave created load conditions that were significantly above the projected loads that set the resource adequacy requirements during the planning stage. Similarly, 250 MW of capacity was designated to address the discrepancy between the October demand forecast used to set procurement requirements and the day-ahead demand forecast.

41 For further information on the capacity procurement mechanism, see DMM's 2018 Annual Report on Market Issues & Performance, Section 10.5 Capacity procurement mechanism, pp 251. http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

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 1.9 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 Q4 ($ mil)	Local capacity area	CPM designation trigger
SUTTER_2_CISO	250	10/1/20	10/30/20	SIGEVT	6.31	$1.58	$1.58	SYS	Significant Event CPM Designation
ARCOGN_2_UNITS	12	9/6/20	10/5/20	SIGEVT	6.31	$0.08	$0.01	SYS	Significant Event CPM Designation
Total	**262**					**$1.65**	**$1.59**		

2 Western Energy Imbalance Market

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

- **Prices in the ISO and the Balancing Authority of Northern California were more than $10/MWh higher than other regions of the EIM on average.** Prices tend to be higher in California than the rest of the Western EIM due to greenhouse gas compliance cost for energy that is delivered to California.
- **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.
- **Sufficiency test failures and subsequent under-supply power balance constraint relaxations** drove average real-time prices higher for Arizona Public Service, NV Energy, and the Salt River Project. 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.
- **Western EIM greenhouse gas** prices decreased as the deemed delivered resources shifted from higher to lower greenhouse gas emissions. In November 2018, the ISO implemented a revised EIM greenhouse gas bid design which limited greenhouse gas bid capacity to the differences between base schedule and available capacity.
- **Rates of mitigation** in the Western EIM have continued to drop following the elimination of carryover mitigation in November 2019.

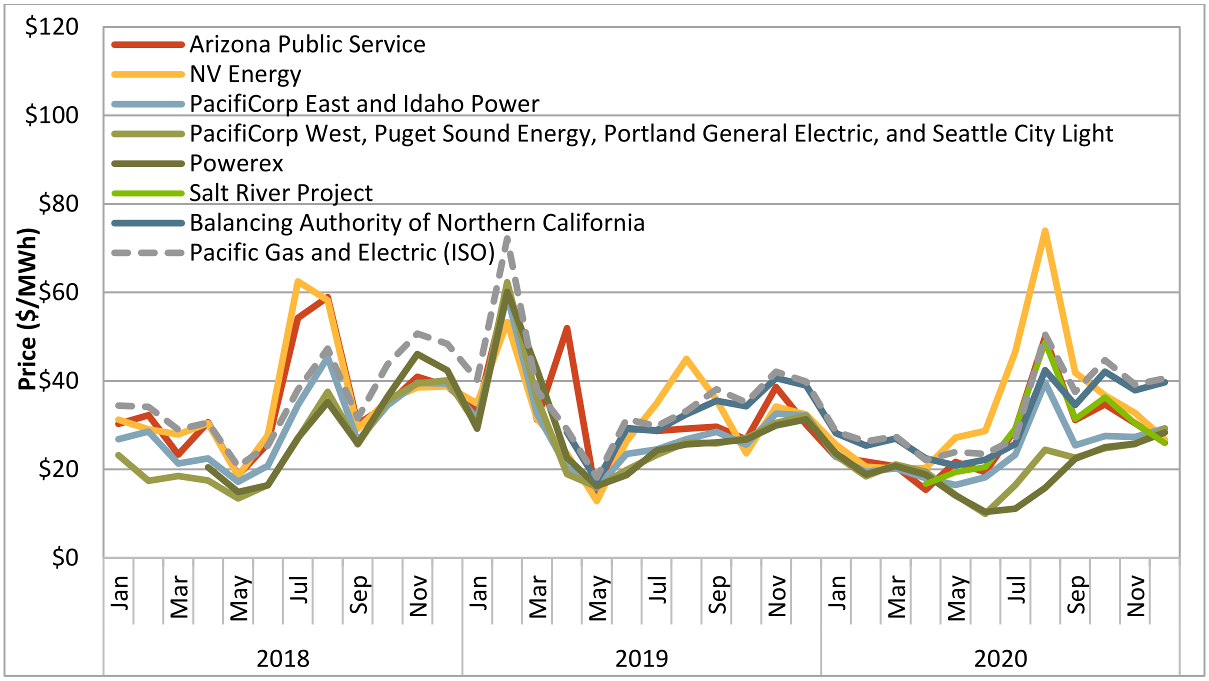
2.1 Western EIM performance

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 December 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.[42] 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



Western EIM prices outside of California were below Balancing Authority of Northern California and Pacific Gas and Electric average prices by $10.81/MWh and $12.42/MWh on average, respectively.

Price separation between Western EIM balancing authorities occurs for several reasons. ISO prices tend to be higher than the rest of the Western EIM due to greenhouse gas compliance cost for energy that is delivered to California.[43] In addition to this, average prices in the Northwest region (including PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex) are regularly lower than the ISO and other balancing areas because of limited transfer capability out of this region.

Figure 2.2 and Figure 2.3 show the variation in Western EIM prices throughout the day in the fourth quarter of 2020. Average hourly prices are shown for participating balancing authorities between October 1 and December 31, 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.

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

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

Figure 2.2 Hourly 15-minute market prices (October – December)

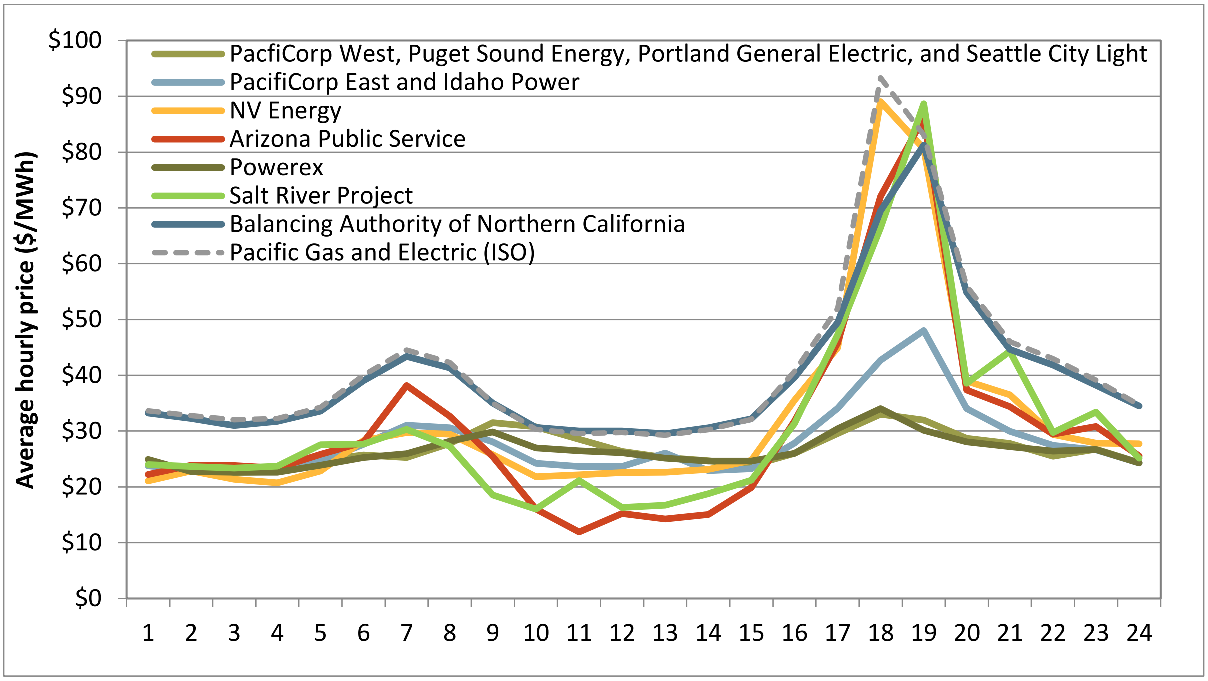
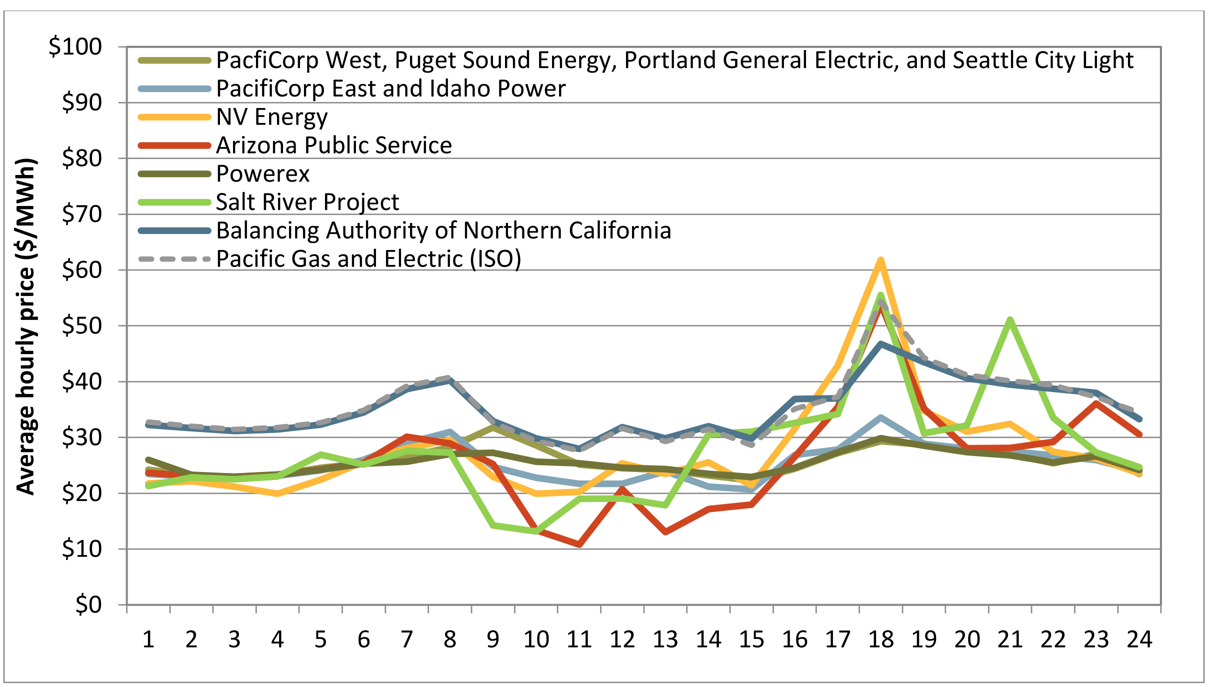


Figure 2.3 Hourly 5-minute market prices (October – December)



These figures also show that the relative price differences between Western EIM entities vary throughout the day. Prices in entities outside of California tend to be lower than ISO prices in most hours, though some may be higher during some hours. 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 continued to track very closely with prices in the ISO in the fourth 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 for 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 bid range capacity and flexible ramping sufficiency test failures in the upward direction throughout the quarter, which 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.[44]

Prices for PacifiCorp East and Idaho Power were often similar to each other and tended to track somewhere between the Northwest and Southwestern EIM entity prices. As shown in Figure 2.2 and Figure 2.3, price separation between these areas and the rest of the EIM 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

44 See Section 2.4 for further details on the load conformance in the EIM.

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				2020			
Balancing Authority Area	**2016**	**2017**	**2018**	**2019**	**Q1**	**Q2**	**Q3**	**Q4**
Arizona Public Service	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
BANC				$0.0	$0.0	$0.0	$0.0	$0.0
Powerex	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
California ISO	-$51.1	-$26.2	-$70.4	-$92.3	-$12.7	-$23.2	-$49.1	-$29.5
Idaho Power Company			$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NV Energy	-$0.3	-$0.8	-$0.3	-$0.4	$0.0	-$0.4	-$0.4	-$1.4
PacifiCorp - East	-$4.0	-$18.1	-$2.0	$0.7	-$0.7	-$0.1	-$0.2	$1.5
PacifiCorp - West	$0.0	$0.0	-$0.1	$0.0	$0.0	$0.0	$0.0	$0.0
Portland General Electric		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Puget Sound Energy	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Seattle City & Light					$0.0	$0.0	$0.0	$0.0
Salt River Project					$0.0	$0.0	$0.0	$0.0

2.2 Flexible ramping sufficiency and bid range capacity tests

This section summarizes flexible ramping sufficiency and bid-range capacity test results during the fourth quarter. For information on the resource sufficiency evaluation for the ISO on August 14, see Section 3.1.

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.[45] Similarly, if an area fails the downward sufficiency test, transfers out of that area cannot be increased.

The capacity test ensures that there are sufficient incremental or decremental economic energy bids to meet the demand forecast. If an area fails the upward or downward capacity test, they will automatically fail the flexible ramping sufficiency test for the same direction.

Failures of the capacity and 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

[45] 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.

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.

Figure 2.4 and Figure 2.5 show the percent of intervals in which each EIM area failed the upward capacity and sufficiency tests, while Figure 2.6 and Figure 2.7 provide the same information for the downward direction.[46] The dash indicates that the area did not fail the test during the month.

During 2020, across all areas:

- Around 4 percent of upward sufficiency test failures and 9 percent of downward sufficiency test failures were caused entirely by failing the capacity test.
- During 46 percent of upward capacity test failures and 27 percent of downward capacity test failures, the sufficiency test would have failed regardless resulting in the same outcome.

During the fourth quarter of 2020, EIM areas failed the sufficiency test infrequently. Salt River Project, NV Energy, and Arizona Public Service each failed the upward sufficiency test in around 1 percent of intervals during the quarter. In the downward direction, Arizona Public Service failed the sufficiency test in around 2 percent of intervals while NV Energy failed in around 1 percent of intervals. Energy imbalance market areas failed the capacity test very infrequently during the quarter.

Figure 2.4 Frequency of upward capacity test failures by month and area (percent of intervals)

	2019			2020											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
California ISO	—	—	0.0	—	—	—	0.1	0.2	—	—	—	—	—	—	—
BANC	—	—	—	—	—	—	—	—	—	0.0	0.0	—	0.1	0.0	—
NV Energy	0.0	—	—	—	—	—	0.0	0.0	—	—	—	—	0.1	0.2	—
Arizona PS	0.0	0.1	0.0	—	—	0.1	—	—	0.0	—	—	—	—	—	0.3
Salt River Project							0.2	—	—	—	—	—	0.1	0.1	—
Idaho Power	—	0.3	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	0.1	—
PacifiCorp West	—	—	—	—	0.1	—	—	—	—	—	—	—	—	0.1	—
Portland GE	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Seattle City Light							—	0.1	—	0.2	0.1	—	—	—	—
Puget Sound En	0.0	—	—	—	0.1	—	—	—	—	—	—	—	—	—	—
Powerex	0.0	0.0	0.0	0.4	0.2	0.3	0.2	0.3	—	—	—	0.1	0.1	0.1	—

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

Figure 2.5 Frequency of upward sufficiency test failures by month and area (percent of intervals)

	2019			2020											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
California ISO	0.1	0.1	0.0	—	—	—	0.1	0.2	—	0.1	1.1	0.5	0.4	0.5	—
BANC	—	—	—	—	0.2	—	—	—	—	0.0	0.2	0.0	0.2	0.0	0.1
NV Energy	0.0	0.7	0.3	—	0.6	0.1	0.7	2.6	2.3	4.5	7.1	2.6	1.5	0.8	—
Arizona PS	1.2	4.7	1.1	1.3	1.1	1.5	0.1	1.0	0.0	—	—	0.3	0.8	0.7	0.6
Salt River Project							1.9	0.1	0.5	0.7	1.8	1.1	1.8	0.9	0.3
Idaho Power	—	0.8	—	—	—	—	—	0.1	0.3	0.1	0.2	—	—	—	—
PacifiCorp East	0.1	0.2	0.2	0.0	0.0	0.1	0.0	0.2	0.1	0.2	0.2	0.1	0.5	0.2	—
PacifiCorp West	0.2	—	—	0.2	0.3	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.1
Portland GE	0.5	0.0	0.5	—	0.2	0.1	—	—	0.0	0.2	0.2	0.6	0.1	0.1	0.2
Seattle City Light							—	0.1	—	0.2	0.1	0.1	0.2	0.2	0.1
Puget Sound En	1.3	—	0.2	—	0.3	—	—	0.0	0.3	0.6	0.4	—	0.2	—	—
Powerex	0.4	0.1	0.1	0.5	0.3	0.3	0.2	0.5	0.2	0.2	0.1	0.3	0.1	0.7	0.2

Figure 2.6 Frequency of downward capacity test failures by month and area (percent of intervals)

	2019			2020											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BANC	0.1	—	—	—	0.0	0.0	0.2	0.2	—	—	—	—	0.1	0.1	—
NV Energy	—	—	—	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—
Arizona PS	—	—	—	—	—	0.3	0.3	0.1	—	—	—	—	0.1	0.1	—
Salt River Project							0.6	0.6	0.0	—	—	—	0.1	0.1	—
Idaho Power	—	0.7	—	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—
PacifiCorp East	—	—	—	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—
PacifiCorp West	—	—	—	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—
Portland GE	—	—	—	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—
Seattle City Light							0.1	0.1	—	—	—	—	0.1	0.1	—
Puget Sound En	—	—	—	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—
Powerex	0.0	—	0.1	—	—	—	0.1	0.3	—	0.0	0.0	—	0.2	0.1	—

Figure 2.7 Frequency of downward sufficiency test failures by month and area (percent of intervals)

	2019			2020											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BANC	0.1	—	0.1	—	0.9	0.7	0.6	1.3	0.3	—	—	—	0.1	0.4	—
NV Energy	2.9	0.2	0.1	0.4	2.1	2.4	4.9	6.7	5.1	0.7	0.8	2.2	0.7	1.5	1.1
Arizona PS	0.2	0.3	0.6	3.0	1.3	3.0	1.2	0.7	2.3	0.1	—	0.1	2.1	1.1	2.5
Salt River Project							1.0	1.2	0.2	—	0.0	0.1	0.2	0.3	0.8
Idaho Power	0.1	1.1	—	—	0.1	0.2	0.1	0.8	—	0.0	—	—	0.2	0.2	—
PacifiCorp East	—	0.0	—	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—
PacifiCorp West	—	—	0.0	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—
Portland GE	—	0.0	—	0.1	—	—	0.1	0.4	0.1	—	—	—	0.1	0.1	—
Seattle City Light							0.6	0.1	—	0.1	0.2	0.2	0.2	0.2	0.1
Puget Sound En	0.1	—	—	—	—	—	0.1	0.6	0.8	0.1	—	—	0.1	0.1	—
Powerex	0.1	—	0.3	0.2	0.4	0.0	0.1	0.3	—	0.1	0.1	0.1	0.2	0.1	—

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.[47] 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 150 MW on average during the quarter, or roughly 1.5 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.

[47] 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.

Table 2.2 Average 15-minute market energy imbalance market limits (October – December)

From Balancing Authority Area	CISO	BANC	NEVP	AZPS	SRP	PACE	IPCO	PACW	PGE	PSEI	SCL	PWRX	*Total export limit*
	To Balancing Authority Area												
California ISO		1,340	3,660	1,230	1,980			30	40	0		110	8,390
BANC	1,330												1,330
NV Energy	3,570			330		790	440						5,130
Arizona Public Service	2,270		270		7,690	760							10,990
Salt River Project	2,380			5,420		0							7,800
PacifiCorp East			610	370	0		820	250					2,050
Idaho Power			490			1,840		500		40	30		2,900
PacifiCorp West	70					340	310		360	150	10		1,240
Portland GE	80							370		40	40		530
Puget Sound Energy	0						0	170	40		340	150	700
Seattle City Light							30	20	10	370			430
Powerex	0									330			330
Total import limit	9,700	1,340	5,030	7,350	9,670	3,730	1,600	1,340	450	930	420	260	

Hourly energy imbalance market transfers

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

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

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

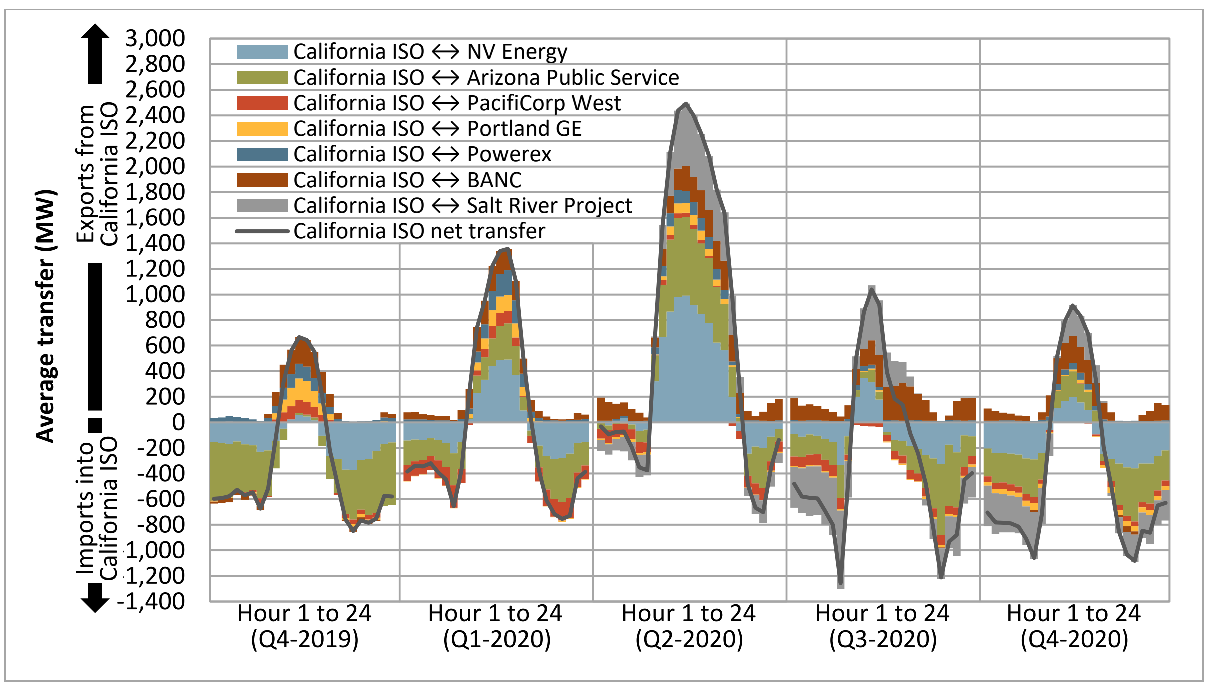
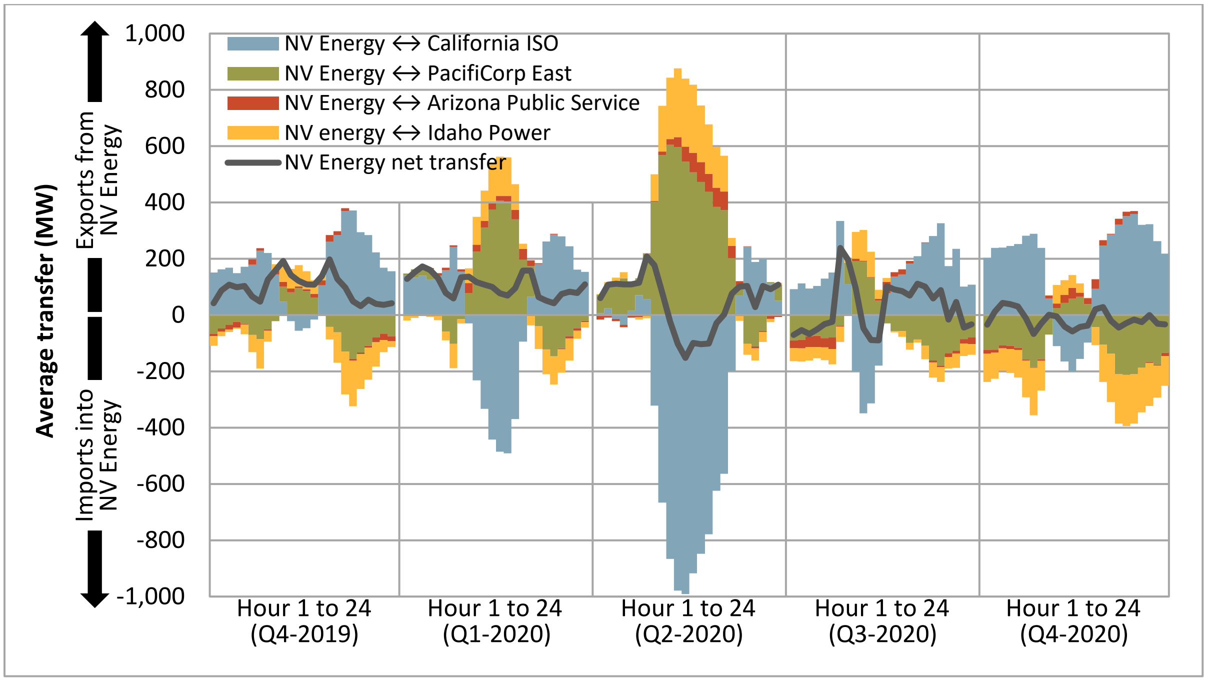


Figure 2.9 through Figure 2.17 show the same quarterly information on imports and exports for the other energy imbalance market areas in the 15-minute market.[48] The amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[49]

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



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

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

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

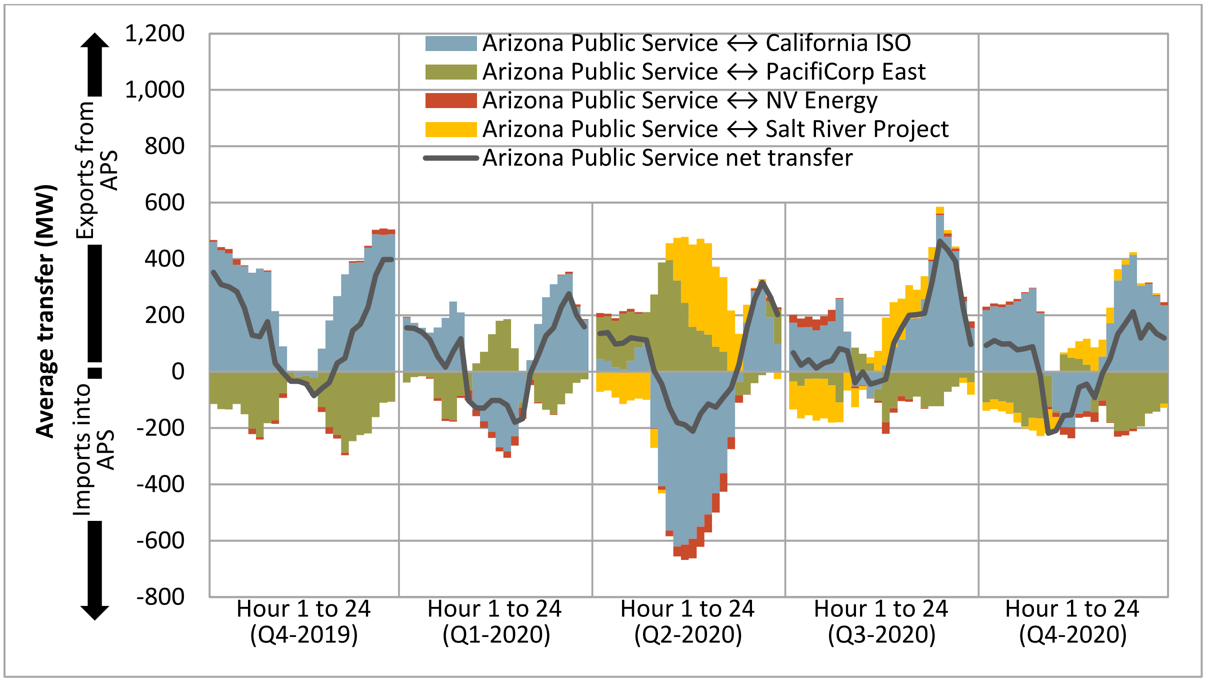


Figure 2.11 Idaho Power – average hourly 15-minute market transfer

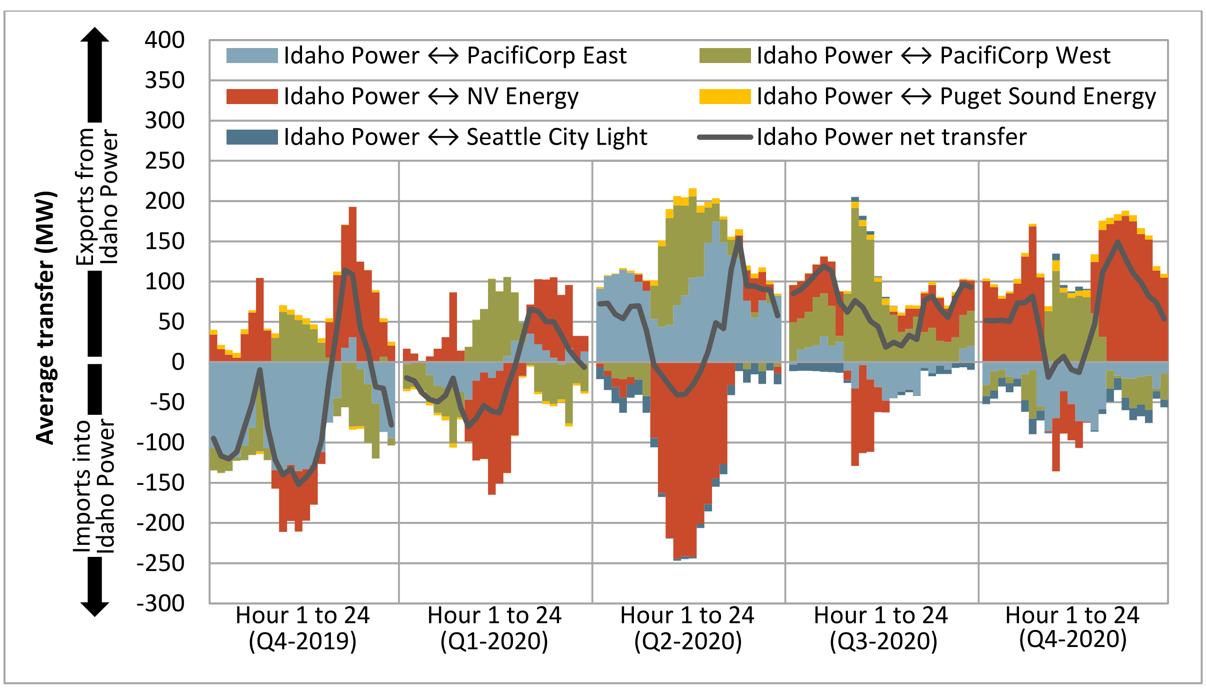


Figure 2.12 PacifiCorp East – average hourly 15-minute market transfer

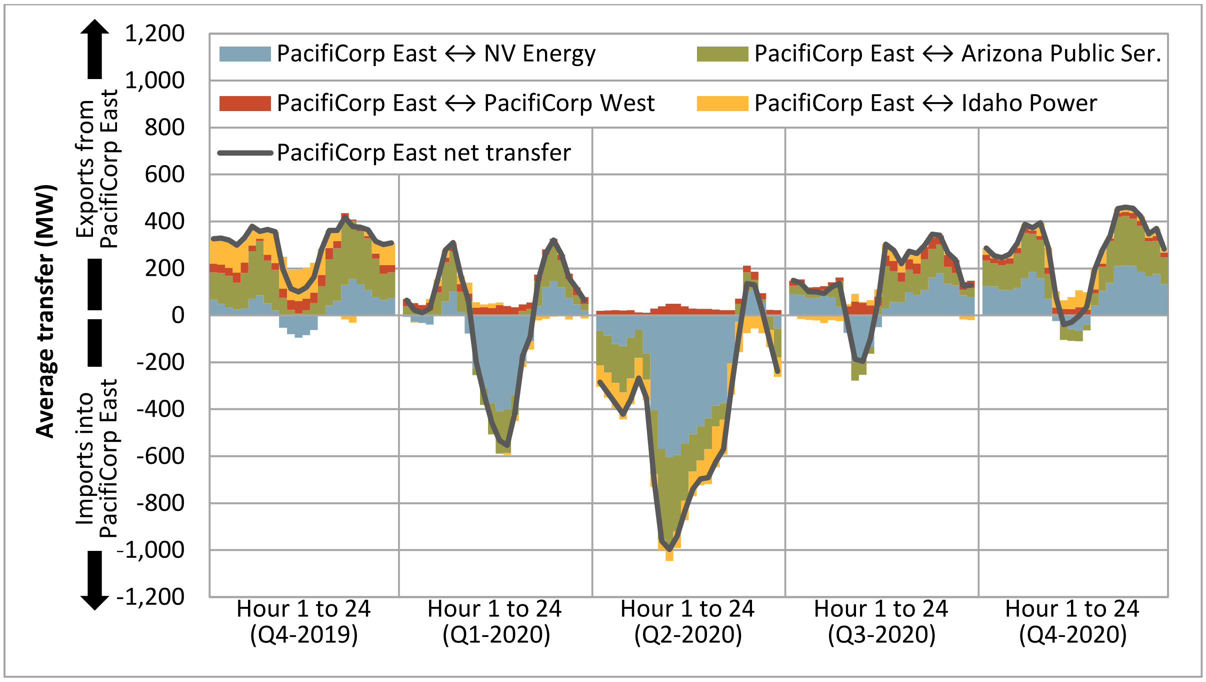


Figure 2.13 PacifiCorp West – average hourly 15-minute market transfer

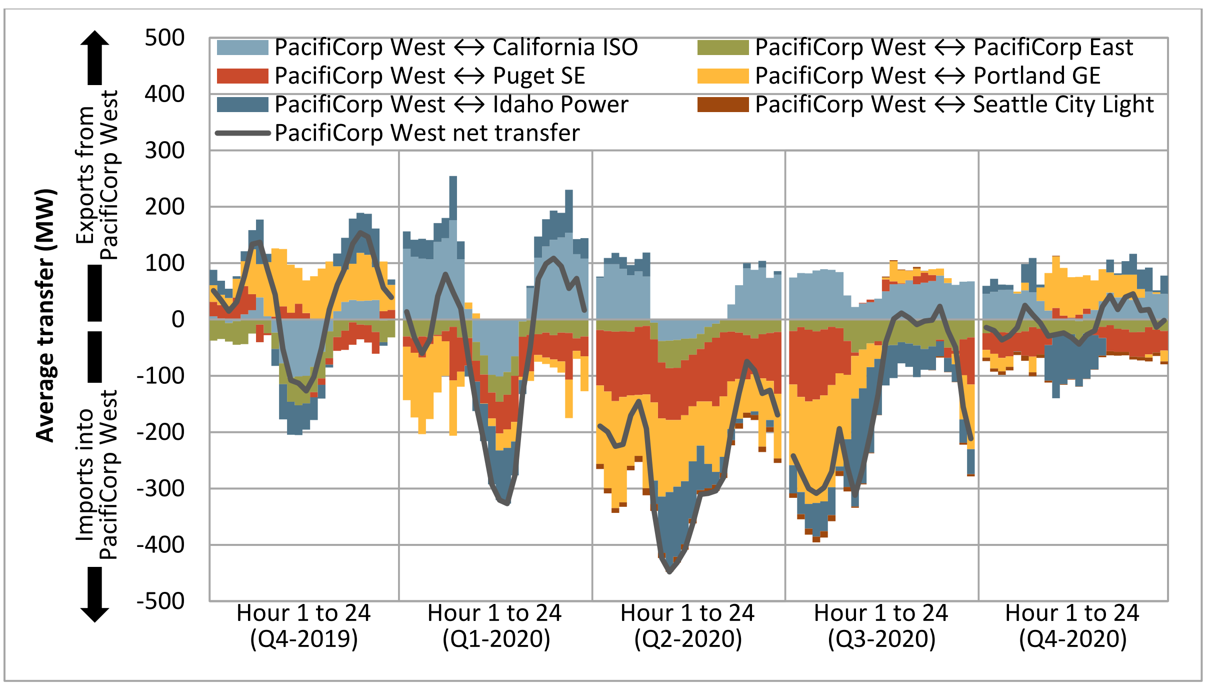


Figure 2.14 Puget Sound Energy – average hourly 15-minute market transfer

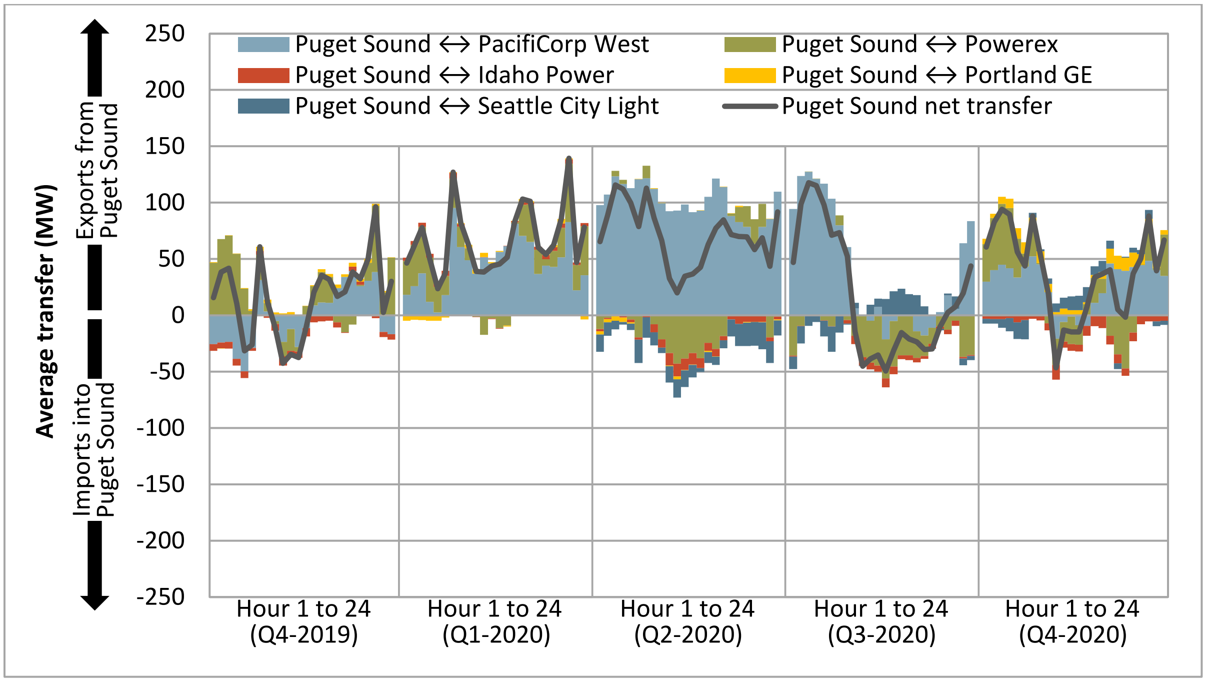


Figure 2.15 Powerex – average hourly 15-minute market transfer

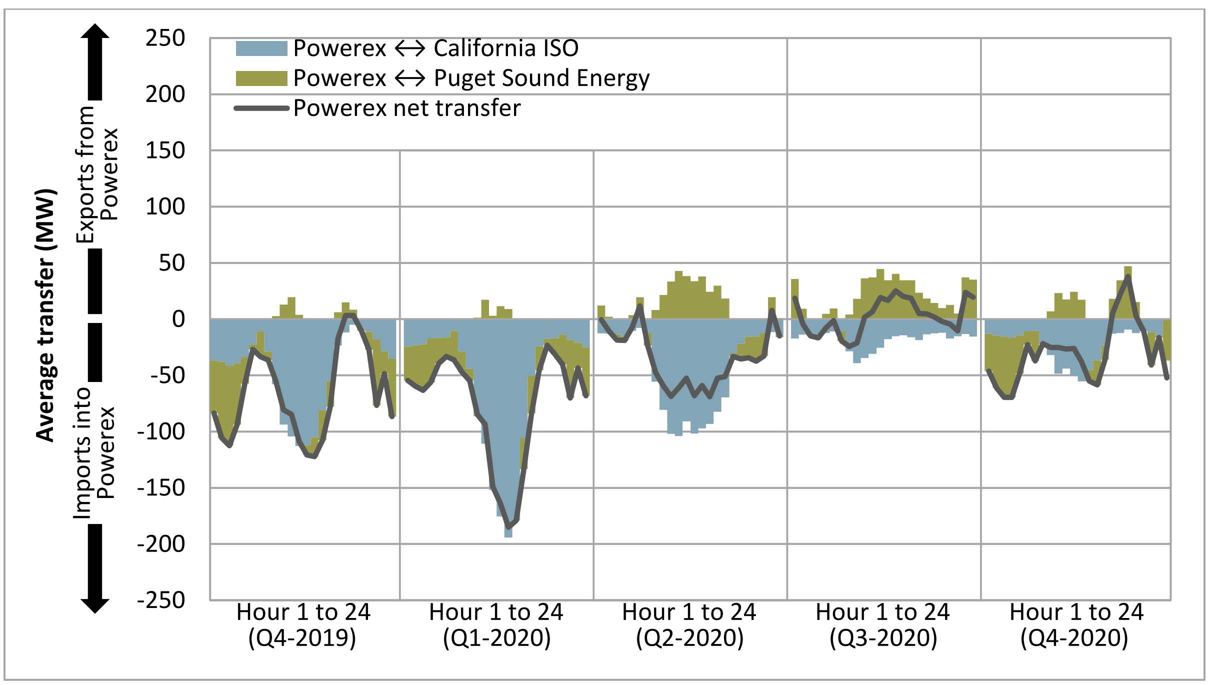


Figure 2.16 Portland General Electric – average hourly 15-minute market transfer

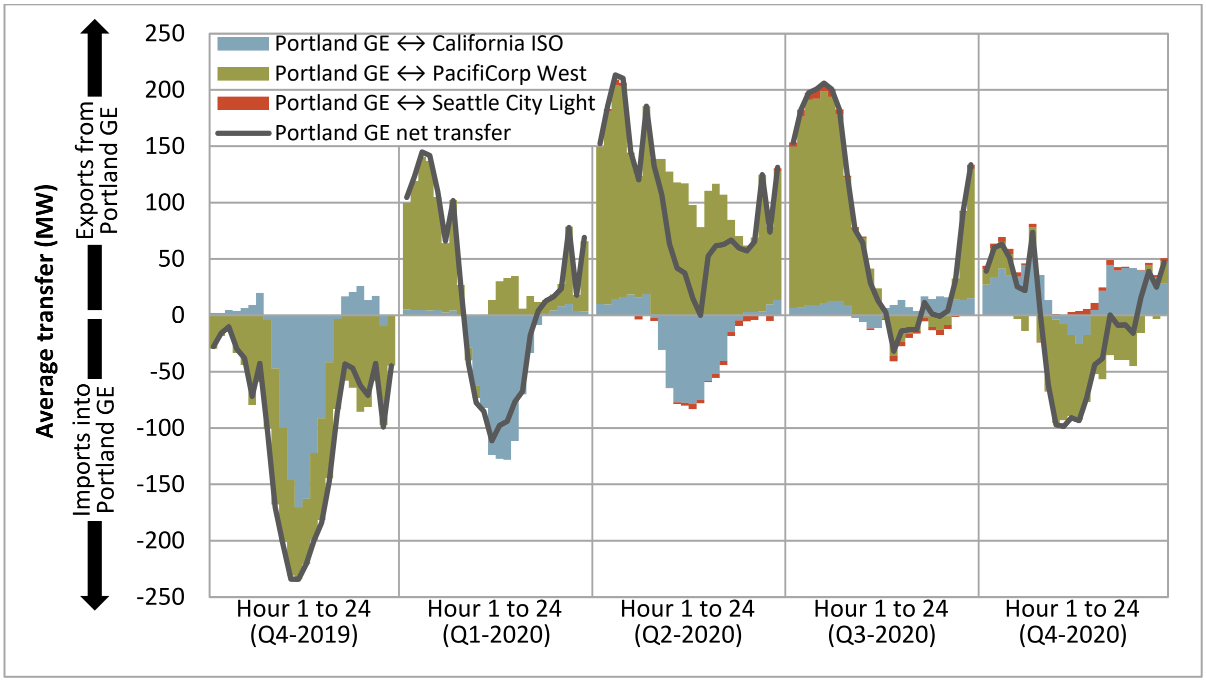
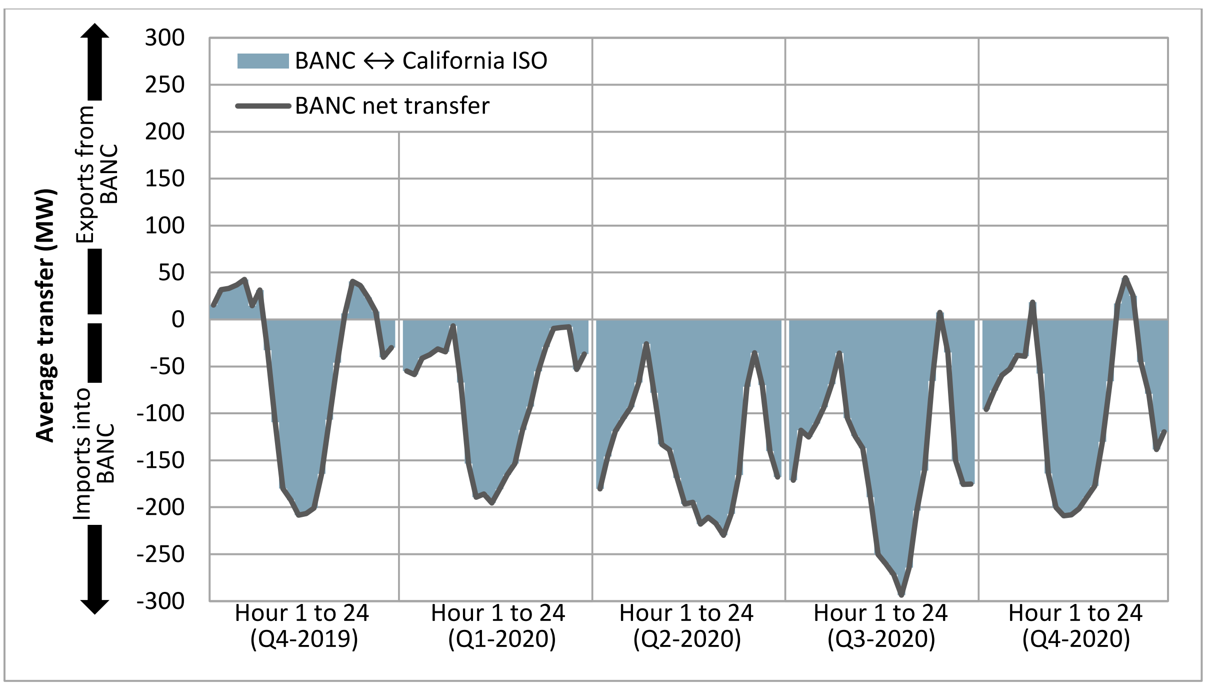


Figure 2.17 Balancing Authority of Northern California - average hourly 15-minute market transfer



Inter-balancing area congestion

Congestion between an energy imbalance market area and the rest of the system limits an area's import and export capability. In addition, during intervals when there is net import congestion into an energy imbalance market area, the market software triggers local market power mitigation for resources in that area.[50]

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.[51] 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 (October – December)

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	0%	0%	0%	0%
NV Energy	1%	1%	1%	1%
Arizona Public Service	2%	1%	1%	1%
Salt River Project	3%	1%	2%	1%
Idaho Power	9%	0%	5%	0%
PacifiCorp East	9%	0%	5%	0%
PacifiCorp West	36%	3%	21%	2%
Portland General Electric	36%	4%	22%	3%
Puget Sound Energy	41%	4%	31%	5%
Seattle City Light	41%	4%	31%	5%
Powerex	40%	8%	33%	14%

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, Puget Sound Energy, Seattle City Light, and

[50] 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.

[51] 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 39 percent of intervals on average during the quarter. This is slightly lower than the previous quarter when congestion from these areas occurred during an average of 41 percent of intervals.

The highest frequency of net import congestion (such that the ISO market software triggers local market power mitigation in that area) occurred in the Powerex area, during 8 percent of 15-minute market intervals and 14 percent of 5-minute market intervals during the fourth quarter.

Table 2.3 also shows that congestion in either direction for the BANC, NV Energy, Arizona Public Service, Salt River Project, Idaho Power, and PacifiCorp East areas was relatively infrequent during the fourth 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

Arizona Public Service had the highest frequency of positive imbalance conformance, while Seattle City Light had the highest frequency of negative imbalance conformance during the fourth quarter. While BANC infrequently used positive or negative imbalance conformance, its average MW biased was the highest average percent of its total load.

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 fourth quarter.[52] The same data for the ISO is provided as a point of reference. In particular, Arizona Public Service entered positive imbalance conformance in around 30 percent of 15-minute and 5-minute intervals, at an average of around 57 MW. Seattle City Light entered negative imbalance conformance in around 16 and 61 percent of 15-minute and 5-minute intervals, respectively, at an average of around 20 MW in each. Nearly all EIM entities had a greater frequency of 5-minute market imbalance conformance than 15-minute market during the quarter.

[52] 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 (October – December)

	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	51%	649	2.6%	1%	-336	1.6%	325
5-minute market	34%	239	1.0%	32%	-212	1.0%	13
PacifiCorp East							
15-minute market	0.2%	67	1.3%	0%	-81	1.6%	0
5-minute market	13%	75	1.4%	24%	-78	1.6%	-9
PacifiCorp West							
15-minute market	1.1%	99	3.8%	0%	-34	1.4%	1
5-minute market	7%	64	2.5%	20%	-51	2.3%	-6
NV Energy							
15-minute market	4%	130	3.4%	0.0%	N/A	N/A	5
5-minute market	17%	92	2.4%	3%	-97	2.7%	13
Puget Sound Energy							
15-minute market	2.7%	25	0.8%	21%	-54	1.9%	-10
5-minute market	2.7%	28	0.9%	50%	-61	2.3%	-30
Arizona Public Service							
15-minute market	30%	56	1.8%	53%	-69	2.4%	-20
5-minute market	29%	57	1.8%	53%	-69	2.4%	-20
Portland General Electric							
15-minute market	0.0%	50	1.8%	0%	-47	1.9%	0
5-minute market	29%	27	1.1%	2%	-37	1.5%	7
Idaho Power							
15-minute market	9%	46	2.3%	4%	-52	3.1%	2
5-minute market	13.6%	46	2.4%	7%	-51	3.0%	3
BANC							
15-minute market	3.3%	40	3.4%	0.4%	-47	4.7%	1
5-minute market	5%	36	2.9%	1%	-31	2.6%	1
Seattle City Light							
15-minute market	0.7%	20	1.7%	16%	-21	2.2%	-3
5-minute market	3%	20	1.7%	61%	-20	1.9%	-11
Salt River Project							
15-minute market	0%	68	2.2%	0.5%	-62	2.0%	0
5-minute market	4%	63	2.1%	3%	-60	2.0%	1

2.5 Greenhouse gas in the Western EIM

In the fourth 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 was deemed delivered into California and additional available capacity from two new energy imbalance market participants who joined 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.[53] 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.[54] The amount of capacity that can be deemed delivered to California has since been limited to the upper economic bid limit of a resource, minus the resource's base schedule.

Greenhouse gas prices

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

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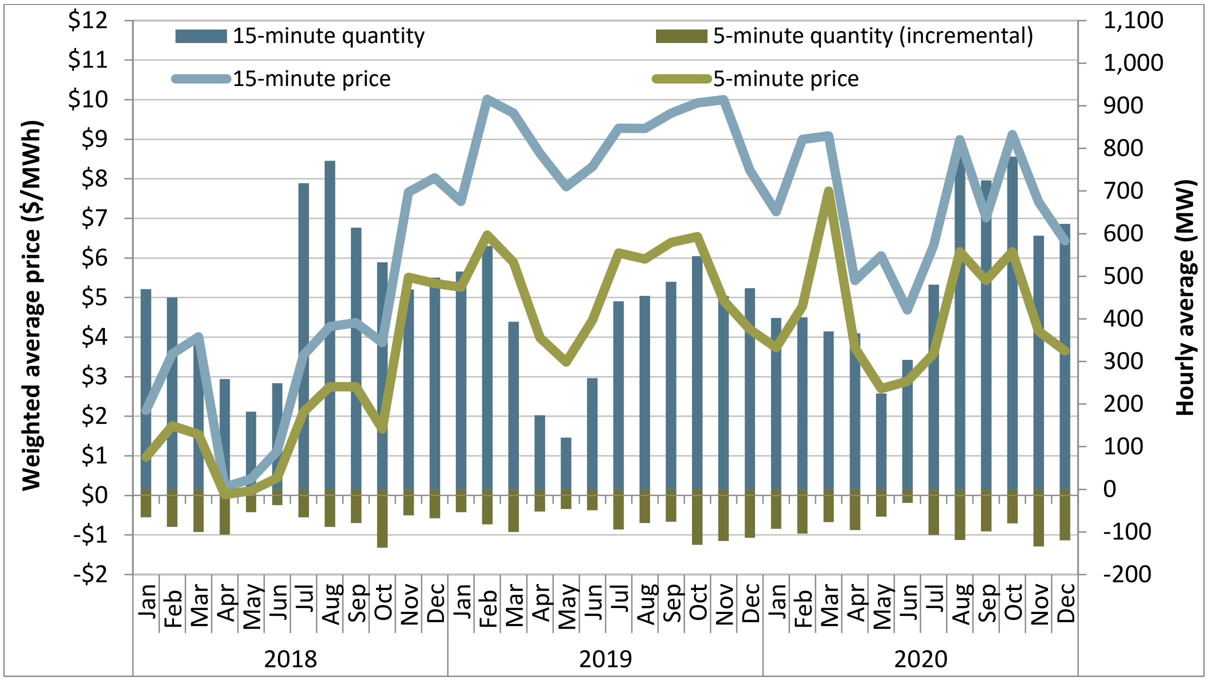
[53] Further information on energy imbalance market entity obligations under the California Air Resources Board cap-and-trade regulation is available in a posted FAQ on ARB's website here: https://ww2.arb.ca.gov/mrr-data.

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

Figure 2.18 Energy imbalance market greenhouse gas price and cleared quantity



Weighted 15-minute greenhouse gas prices averaged around $8/MWh for the fourth 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 into the fourth quarter. In the fourth quarter, the price difference between the 15-minute and 5-minute markets was about $3/MWh. 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 2.19 and Figure 2.20 show the frequency of high prices and maximum price by quarter for each market since 2018. In the fourth quarter, the highest 15-minute price was $174.78/MWh which is significantly higher than the highest bid-in offer.

Figure 2.19 High 15-minute EIM greenhouse gas prices

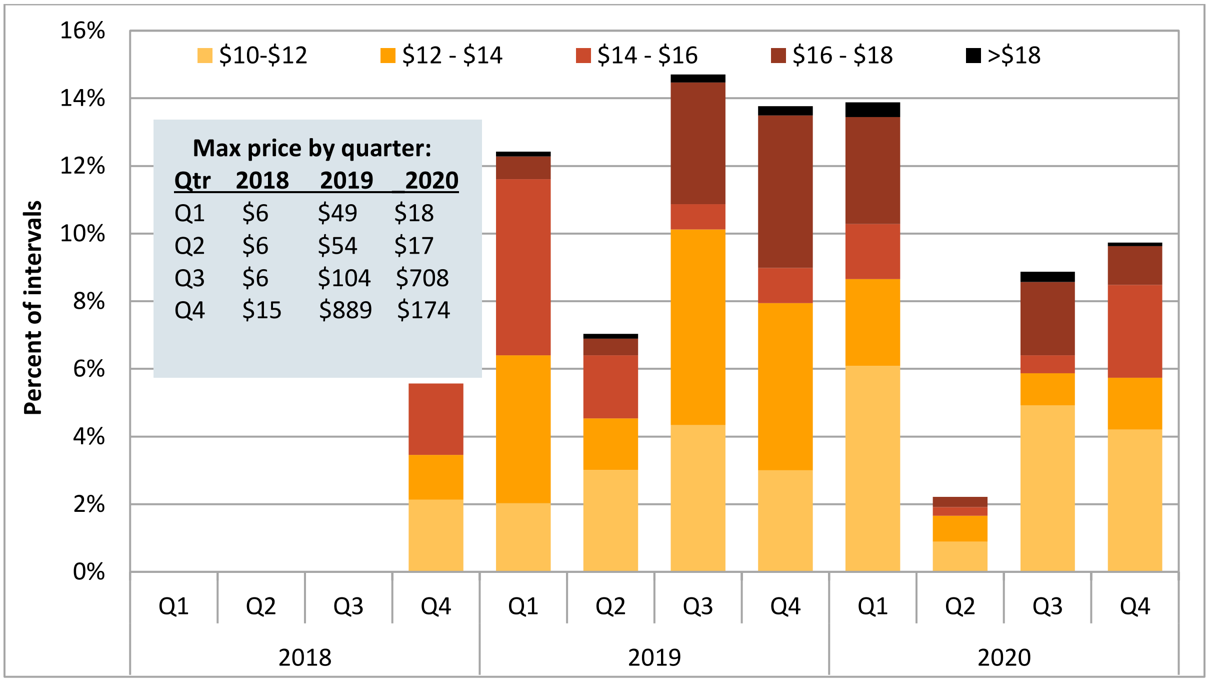
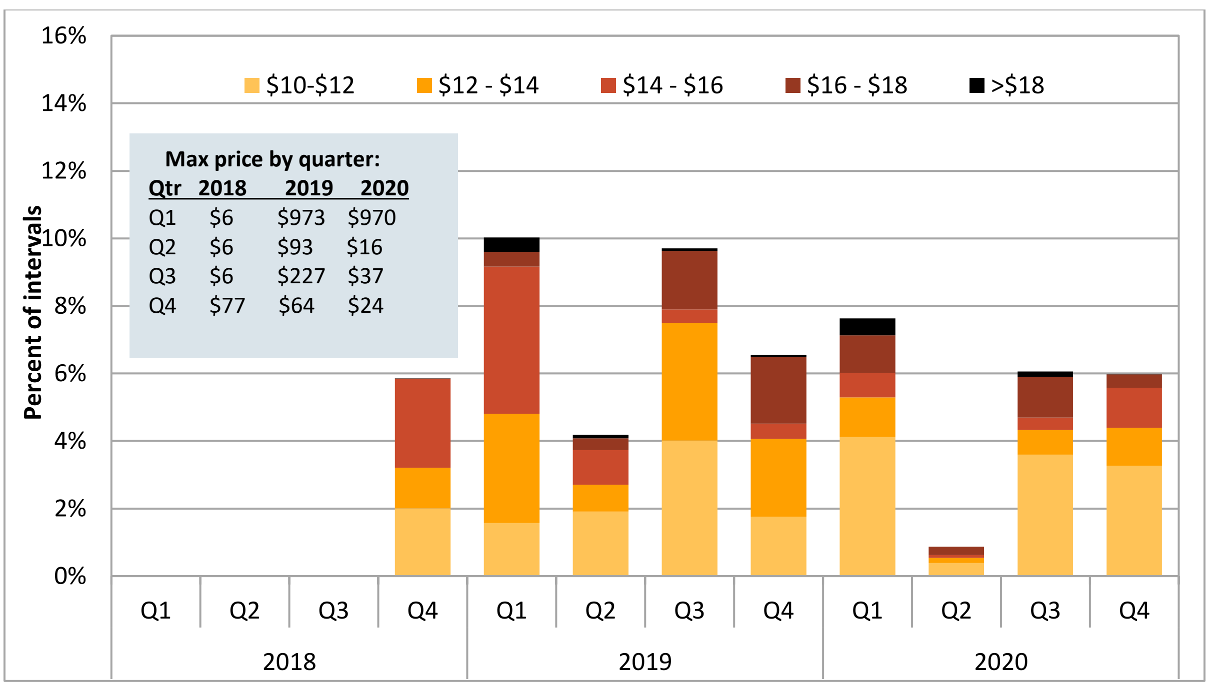


Figure 2.20 High 5-minute EIM greenhouse gas prices

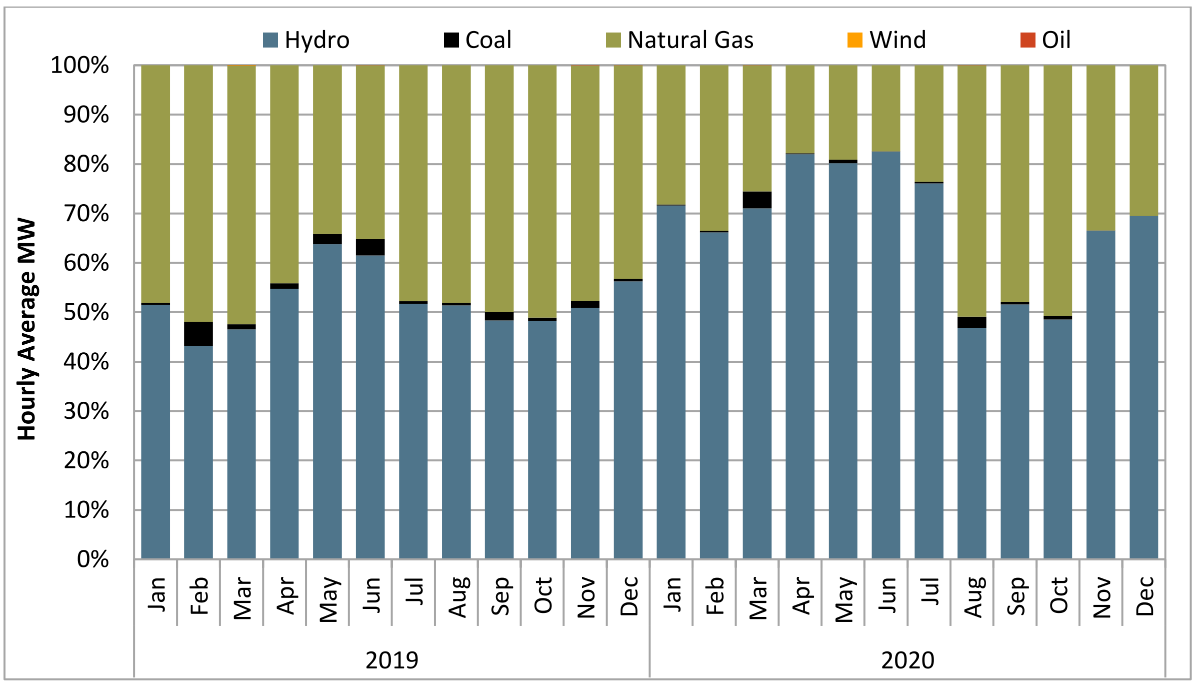


DMM estimates the total revenue accruing for greenhouse gas bids attributed to EIM participating resources serving the ISO load before subtracting estimated compliance costs from greenhouse gas revenue calculated in each interval. This value totaled around $12.1 million in the fourth quarter, compared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

Energy delivered to California by fuel type

Figure 2.21 shows the hourly average energy deemed delivered to California by fuel type and by month. In the fourth quarter, about 40 percent of EIM greenhouse gas compliance obligations were awarded to gas resources; slightly less than the fourth quarter of the previous year. Hydro-electric resources accounted for about 60 percent of total energy delivered to California, which increased slightly from around 52 percent in the same quarter of 2019. Additionally, energy originating from coal resources has increased since the policy change, but accounted for less than 1 percent of energy delivered in the fourth quarter; about the same amount as in the fourth quarter of 2019.

Figure 2.21 Hourly average EIM greenhouse gas generation by fuel type



2.6 Mitigation in the EIM

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

- Blue bars in Figure 2.22 and Figure 2.23 show average incremental energy subject to mitigation but whose bids were not lowered in the 15-minute and 5-minute markets, respectively. In the fourth quarter of 2020, on average, this portion has decreased by about 200 MW when compared to the same quarter in 2019.
- A small volume of bids were lowered as a result of mitigation in the Western EIM.

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

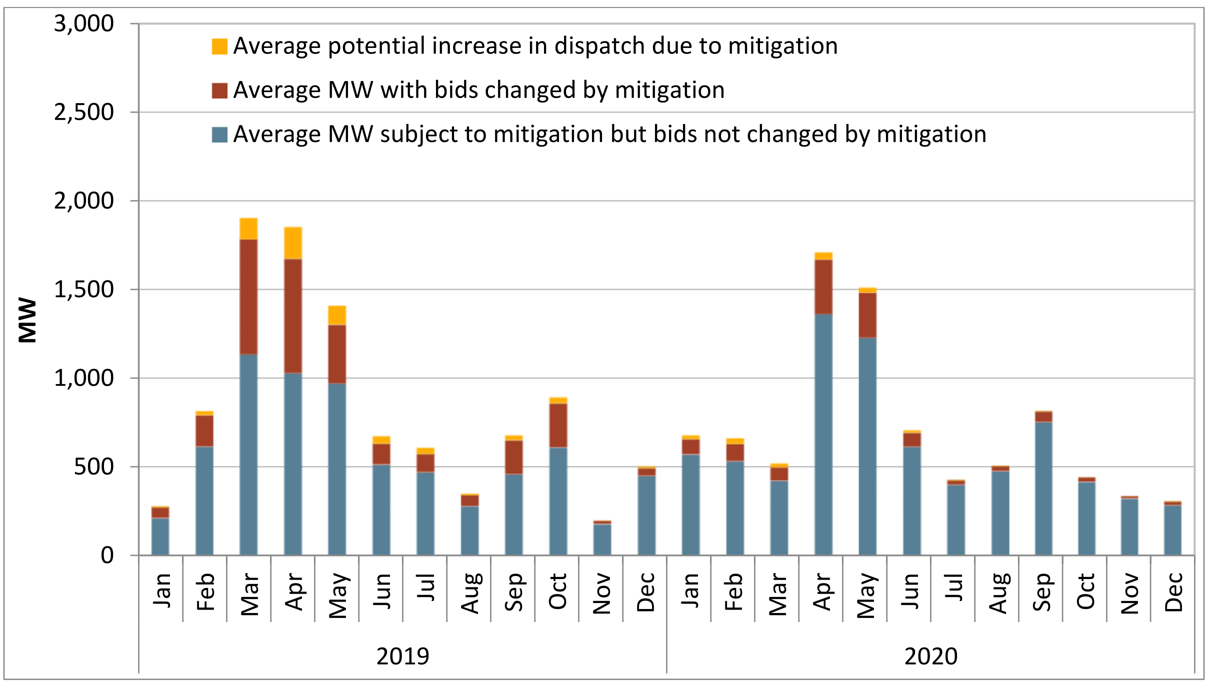
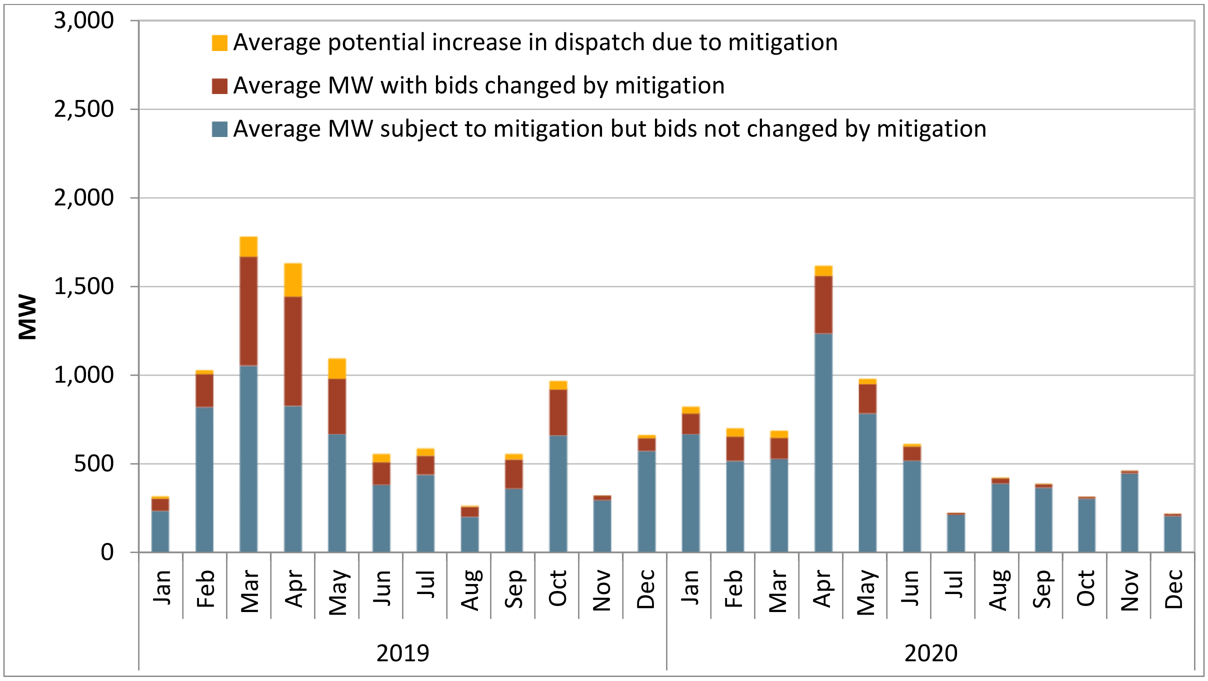


Figure 2.23 Average incremental energy mitigated in 5-minute real-time market (EIM)



3 Special issues

This section provides information about the following special issues:

- **The ISO balancing area passed the bid range capacity and flexible ramping sufficiency tests on August 14 and 15** during intervals when the ISO experienced high levels of real-time market energy scarcity and curtailed load for the first time in two decades.
- **The ISO identified two errors in the bid range capacity test which caused the CAISO area to pass this test during hours when load was being curtailed.** These errors were fixed on February 4, 2021. The ISO is also proposing to add net load uncertainty to the bid range capacity test requirement.
- **DMM recommends that the ISO consider eliminating additional categories of capacity which are constrained by various operating limitations** from the supply that is counted towards meeting bid range capacity requirements.
- **The ISO's markets were structurally uncompetitive in more hours** than any other fourth quarter since at least 2015, but were structurally uncompetitive in fewer hours than the third quarter.
- **Market results were competitive in the fourth quarter**. DMM estimates that the impact of gas and import resources bidding above reference levels reflecting marginal costs was about $1.11/MWh or about 2.5 percent, a slight decrease from the $1.42/MWh or 2.6 percent for the previous quarter.
- **Market power has had a very limited effect on system market prices,** even during hours when the ISO system was structurally uncompetitive. However, DMM continues to caution that if market conditions continue to tighten with increased frequency and become more predictable and sustained, the potential for system-level market power in hours when scarcity does not exist may increase significantly.
- **DMM supports the ISO's proposal to continue with an initiative to design system market power mitigation.** The ISO has not included this initiative in the set of fast-tracked changes for implementation prior to summer 2021 and will resume this initiative later in 2021 or 2022.
- **DMM recommends the ISO consider developing the capability to implement a simpler method to mitigate system market power,** should conditions warrant, before this initiative is completed and implemented. Specifically, DMM has suggested that the process already used for local market power mitigation could be applied system-wide based on a much simpler criteria (e.g., hours when net loads are forecast to be over a certain level).

3.1 CAISO balancing area resource sufficiency evaluation

As part of the energy imbalance market, the ISO is subject to a resource sufficiency evaluation. The evaluation is performed prior to each hour to ensure that generation in each area is sufficient without relying on transfers from other balancing areas. The evaluation includes two tests:

- **The bid range capacity test** requires that each area provide incremental bid-range capacity to meet the imbalance between load, intertie, and generation base schedules.
- **The flexible ramping sufficiency test** requires that each balancing area has enough ramping flexibility over an hour to meet the forecasted change in demand as well as uncertainty.

If an area fails the upward bid range capacity test or upward flexible ramping sufficiency test, energy imbalance market transfers into that area cannot be increased.[55]

Resource sufficiency test failures on August 14-15

The CAISO balancing area passed the bid range capacity test in all hours on August 14 and 15, including during intervals when the area experienced high levels of scarcity in the real-time energy market and curtailed load. The CAISO balancing area failed the flexible ramping sufficiency tests during some high demand intervals on August 14 and 15 including some intervals when load was being curtailed, but passed in other high demand intervals.

The fact that the CAISO system passed during periods of real-time scarcity and load curtailment on August 14 and 15 has led to a closer examination of these results and the underlying methodologies by both the ISO and market participants. This section provides additional context and analysis of the ISO's resource sufficiency evaluation on August 14 and 15.

Figure 3.1 shows 15-minute and 5-minute market energy imbalance market imports coming into the ISO on August 14. The shaded regions illustrate three critical periods on this day. The red line shows the intervals in which the ISO failed the upward sufficiency test, limiting transfers to the transfer level of the last binding 15-minute interval. The ISO did not fail the capacity test during any interval on this day.

Figure 3.2 shows the same information for August 15. For this day, the ISO failed the flexible ramping sufficiency test throughout the twenty-minute period in which the ISO curtailed load. Similar to the previous day, the ISO passed the capacity test during all intervals.

55 If an area fails the test, net EIM imports (negative) during the hour cannot exceed the lower of either the base transfer or optimal transfer from the last 15-minute interval prior to the hour.

Figure 3.1 Limits on EIM imports into CAISO due to resource sufficiency test failure (August 14, 2020)

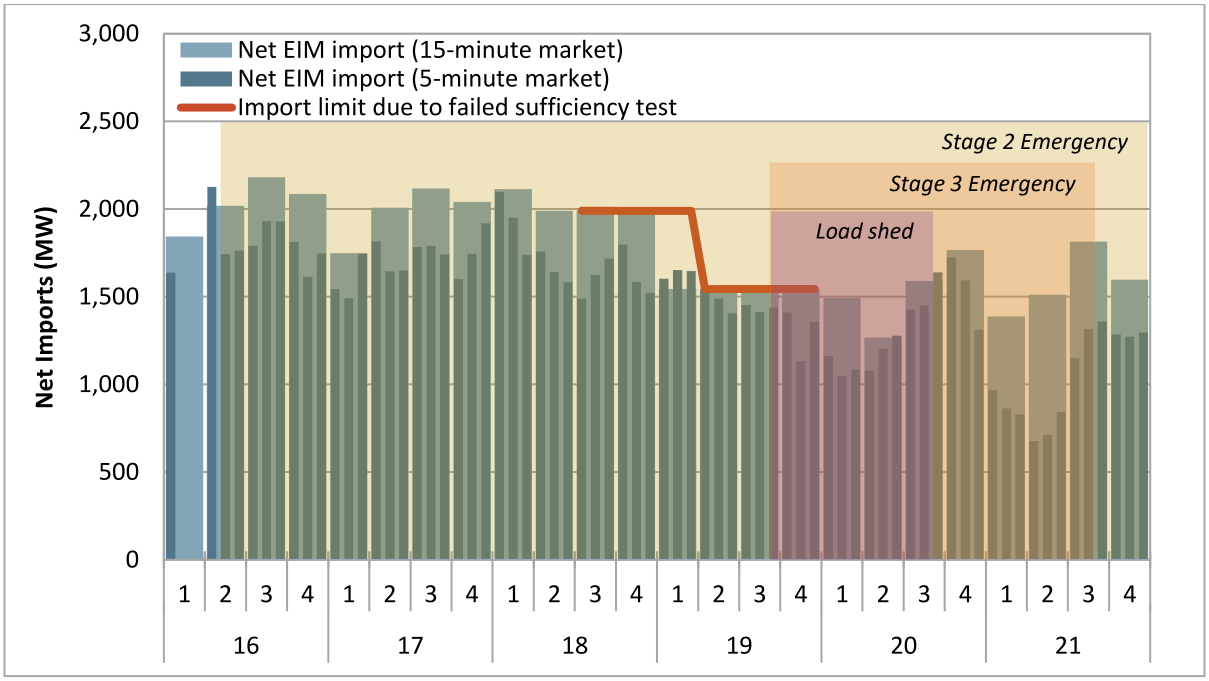
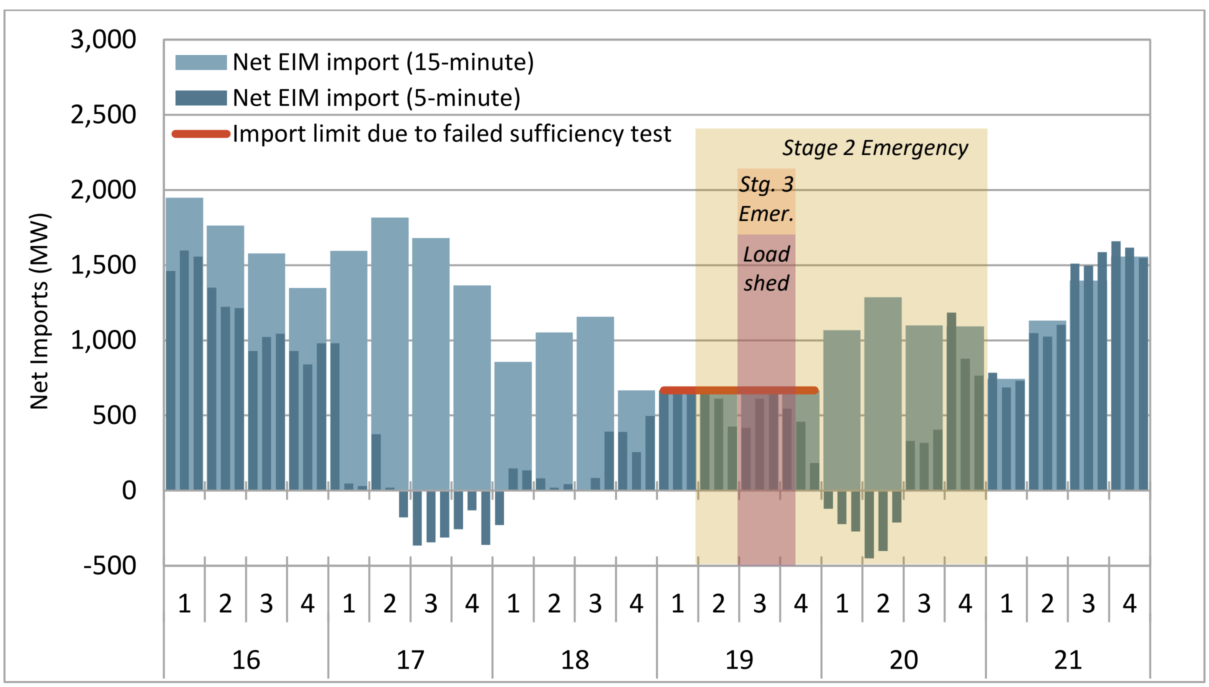


Figure 3.2 Limits on EIM imports into CAISO due to resource sufficiency test failure (August 15, 2020)



Bid range capacity test

In January 2021, the ISO held a workshop to review the design of the resource sufficiency evaluation and its application to the ISO during the August heatwave.[56] The ISO identified two errors in the way the bid capacity test was implemented:

- Resource de-rates and outages were not accounted for resulting in higher resource capacity relative to actual availability. This affected both the ISO and energy imbalance market areas.
- Mirror resources were incorrectly included for the ISO, impacting net scheduled interchange and the capacity test requirement.[57] This affected only the ISO.

The ISO corrected both of these issues effective February 4, 2021. The ISO has also proposed to add net load uncertainty to the requirement of the bid range capacity test as part of a package of market enhancements for Summer 2021 Readiness.[58]

Figure 3.3 summarizes the bid-range capacity test for the ISO on August 14, 2020. The yellow line shows the original capacity test requirement including the issue, described in the second bullet above. The dotted black line shows the recalculated requirement, which correctly accounts for mirror resources, and the dotted gray line adds uncertainty, as proposed by the ISO.[59] Figure 3.4 shows the same information for August 15.

The bars show the bid-range capacity that was used to meet capacity test requirements. The blue and yellow bars are for 15-minute dispatchable incremental imports and decremental exports. The red bars reflect generation capacity which was unavailable after accounting for outages and de-rates. Therefore, comparing the bars net of de-rates and outages against the recalculated requirement plus uncertainty illustrates the ISO's capacity test evaluation, had the changes proposed by the ISO been effective.

The dark green bars reflect capacity that was considered available for the bid-range capacity test but unavailable for the flexible ramping sufficiency test because of all other resource constraints. These constraints include exceptional dispatches, start-up times, transition times, ramp rates, and other intertemporal constraints.

The bid range capacity test should measure capacity that could be feasible without energy imbalance market transfers. In some cases, this constrained capacity may be offline or unrampable in the immediate interval because of energy imbalance market imports and associated commitment decisions in a current *or previous* interval. In that case, this capacity should be considered in the capacity test as it could have been available had the balancing area been required to meet its load on its own.

However, in other cases, this constrained capacity would not have been available regardless of energy imbalance market participation. Examples of this include a maximum or fixed exceptional dispatch

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56 *Resource Sufficiency Evaluation*, January 13, 2021. http://www.caiso.com/InitiativeDocuments/Presentation-MarketEnhancements-Summer2021ReadinessJan13,2021Workshop.pdf

57 Mirror resources are import and export schedules into or out of an EIM area to model power flow from the EIM area perspective at ISO intertie scheduling points. This allows the market to solve for both the California ISO and adjacent EIM areas simultaneously.

58 *Market Enhancements for Summer 2021 Readiness*, March 19, 2021. http://www.caiso.com/InitiativeDocuments/FinalProposal-MarketEnhancements-Summer2021Readiness.pdf .

59 Uncertainty is the same as that used currently in the flexible ramping sufficiency test net of the diversity benefit.

issued by grid operators, a long start time beyond the horizon of the real-time market, or ramp-constrained capacity immediately following an outage. In the case of the ISO in hour-ending 19 and 20 on August 14, most of the constrained resource capacity would have been unavailable regardless of energy imbalance market transfers.

Figure 3.4 shows the same information for August 15. Based on the ISO's proposed changes and comparing the upward capacity accounting for de-rates against the recalculated requirement including uncertainty, the ISO would have still passed the capacity test for hour-ending 19 interval 3, the period in which the ISO curtailed load. However, the ISO did fail the flexible ramping sufficiency test for the entire hour, which resulted in the same effective outcome.

DMM recommends that the ISO consider eliminating constrained capacity that would be unavailable regardless of energy imbalance market transfers from the bid-range capacity test.

Figure 3.3 CAISO upward bid range capacity test requirement and capacity (August 14, 2020)

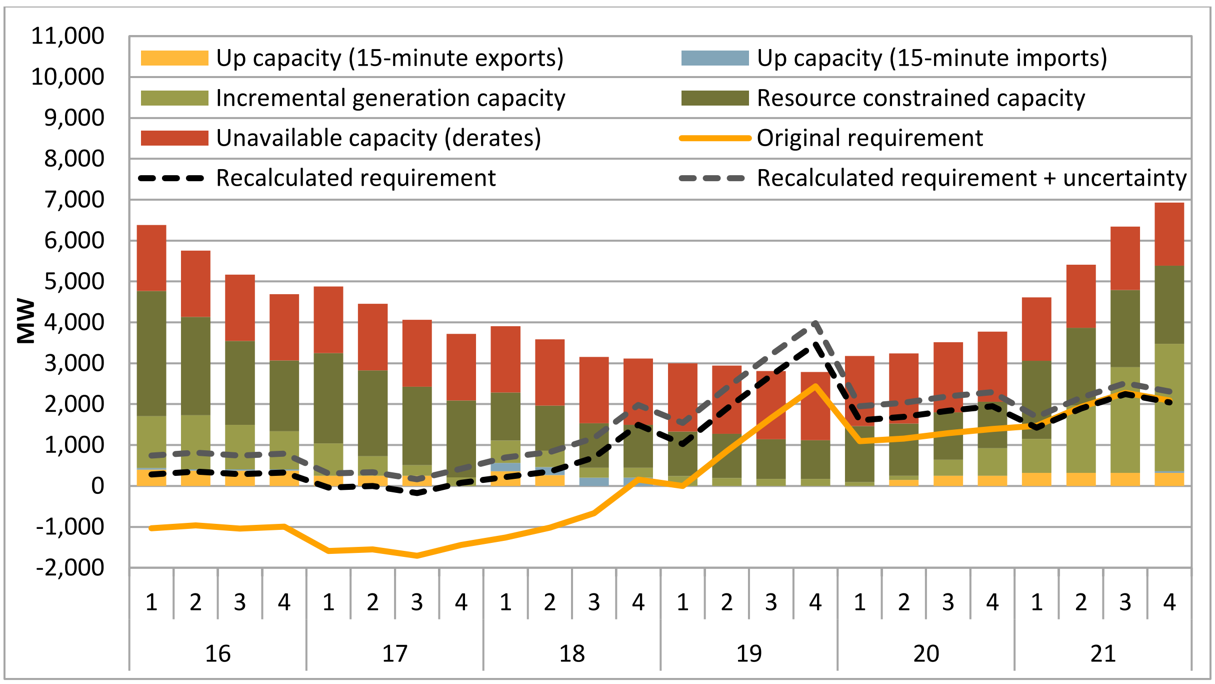
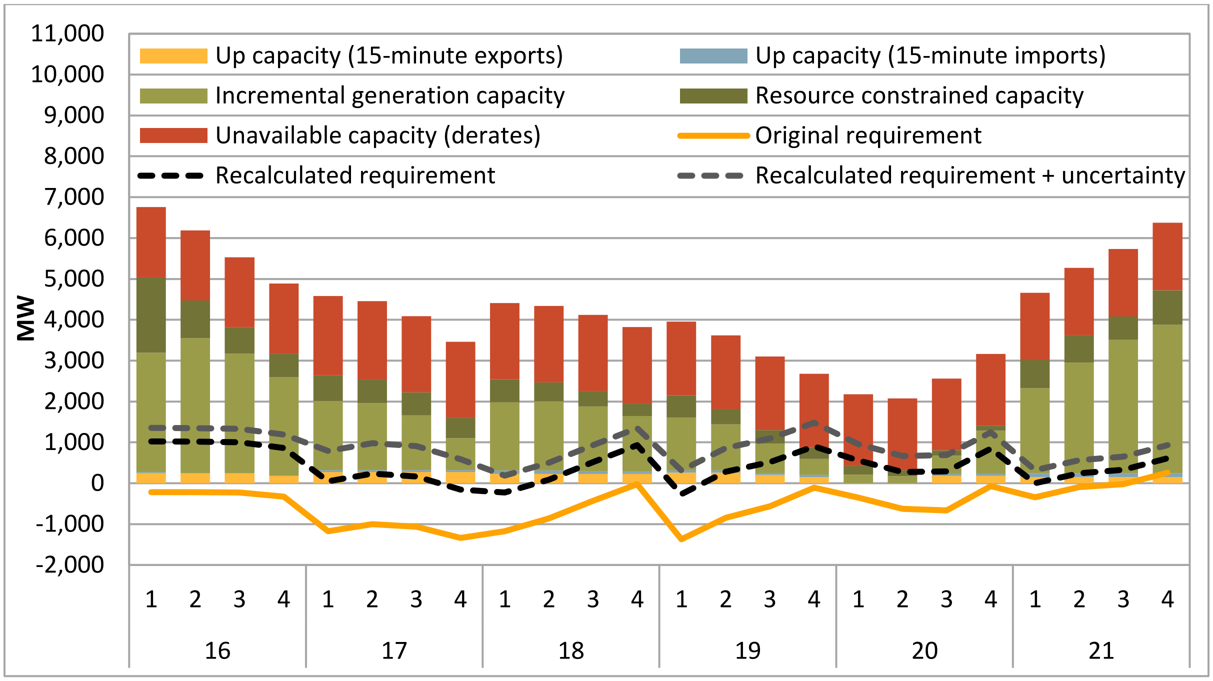


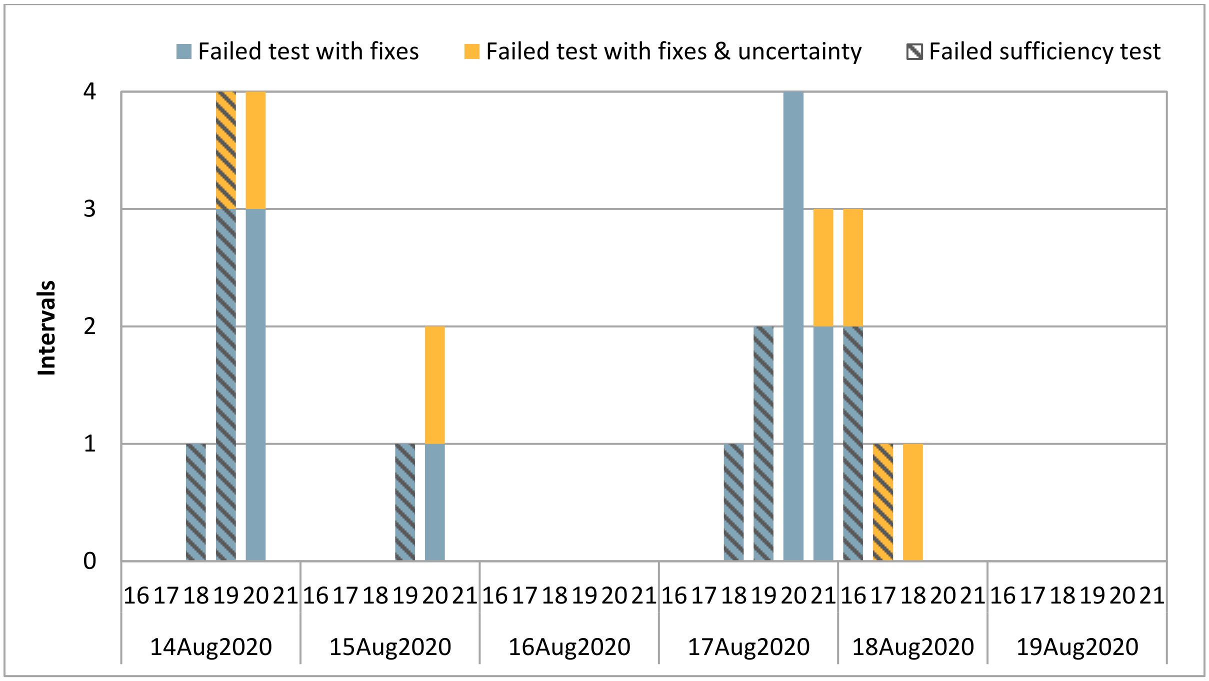
Figure 3.4 CAISO upward bid range capacity test requirement and capacity (August 15, 2020)



The ISO passed the bid-range capacity test in all intervals during the August heat wave in part because of the two errors the ISO identified related to resource de-rates and mirror resources. Figure 3.5 summarizes intervals that would have failed the capacity test with the ISO identified issues corrected as well as intervals that would have failed with uncertainty added on top of that. The dashed bars reflect capacity tests in which the ISO failed the upward flexible ramping sufficiency test, resulting in the same outcome regardless of whether or not the capacity test would have failed.

Results of this analysis show that with the errors corrected and uncertainty added to the requirement, the ISO would have failed the capacity test during 27 intervals across this August heatwave period. If constrained capacity, which is unavailable regardless of energy imbalance market operation, were accounted for, the number of failed capacity test intervals would have been higher.

Figure 3.5 CAISO upward bid range capacity test failures with proposed enhancements (August 14 – August 19, 2020)



Flexible ramping sufficiency test

The ISO passed the flexible ramping sufficiency test during all of hour-ending 20 on August 14, during a period when the ISO shed load. The ISO passed the flexible ramping sufficiency test despite emergency conditions because this test only measures the *change* associated with load and ramping capacity. If the area is starting from a state of deficiency, but is able to meet the changing conditions in the next hour, then the area will pass the test and can simultaneously have emergency or scarcity conditions.

For example, assume that the load-forecast increases significantly in the current hour such that the area fails the flexible ramping sufficiency test during all intervals in the hour and experiences high levels of scarcity in the real-time market. If in the next hour, the load forecast declines slightly, the flexible ramping sufficiency test requirement could be negative reflecting the change in load despite very high loads and a continuation of scarcity conditions.

On August 14, this scenario describes the ISO balancing area between hour-ending 19 and hour-ending 20, except with a significant decline in solar rather than an increase in load. Figure 3.6 and Figure 3.7 show the requirement and calculated supply for the ISO system's upward flexible ramping sufficiency test during the peak hours on this day.

Starting with the requirement components in Figure 3.6, the upward requirement for the flexible ramping sufficiency test is calculated as the forecasted change in load plus uncertainty minus two discounts, diversity benefit and flexible ramping credits. The diversity benefit reflects that system-level flexible ramping needs are typically smaller than the sum of the individual balancing area flexible ramping needs because of reduced uncertainty across a larger footprint.

Upward credits are net EIM exports prior to the hour, reflecting the ability to reduce exports to increase upward ramping capability. For this peak period on August 14, the ISO was importing on net in every interval so no credits were applied to the upward sufficiency test.

Last, the reduction in the upward sufficiency test requirement because of any diversity benefit or flexible ramping credit is capped by the area's net import capability. For hour-ending 19 and 20, the load forecast is declining resulting in a negative upward sufficiency test requirement for most of this period. Changes in wind and solar forecasts are instead accounted for on the opposite side of the equation as positive or negative ramping capacity.

Figure 3.7 shows ramping capacity used to meet the sufficiency test requirement by resource type. The dotted line shows the sufficiency test requirement from the previous chart. Ramping capacity accounts for both economic energy bids (constrained by unit limitations such as ramp rates) as well as fixed changes in schedules or renewable forecasts from the previous hour to the next. So, an increase in imports (or decrease in exports) will contribute to positive ramping capacity.

In hour-ending 19, the ISO failed the sufficiency test in large part because of a significant decline in solar and limited remaining ramping capacity. However, starting from a point of deficiency, the ISO was able to meet the mild decline in solar paired with a decline in load in the next hour. This occurred even though the ISO was short in the real-time market during this hour.

Instead, resource sufficiency needed to meet total load is captured by the capacity test. However, as discussed in the previous section, additional capacity test enhancements are needed to account for constrained resource capacity that is unavailable independent of energy imbalance market transfers.

Figure 3.6 CAISO flexible ramping sufficiency test requirement by component (August 14, 2020)

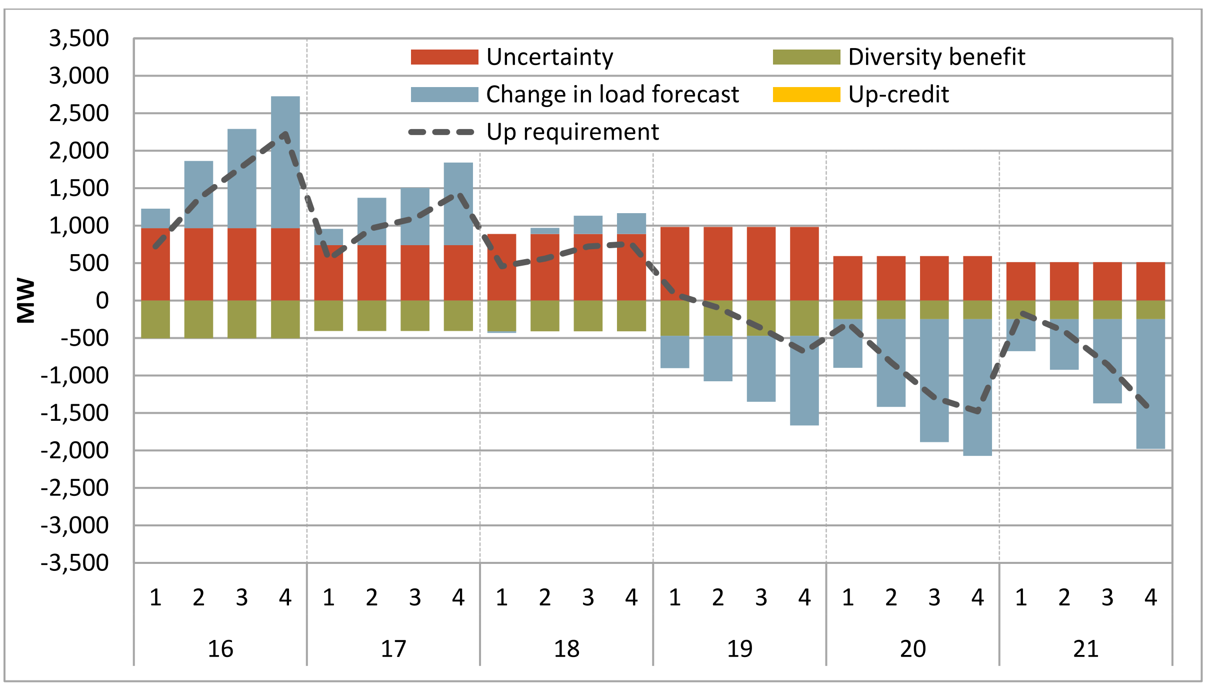
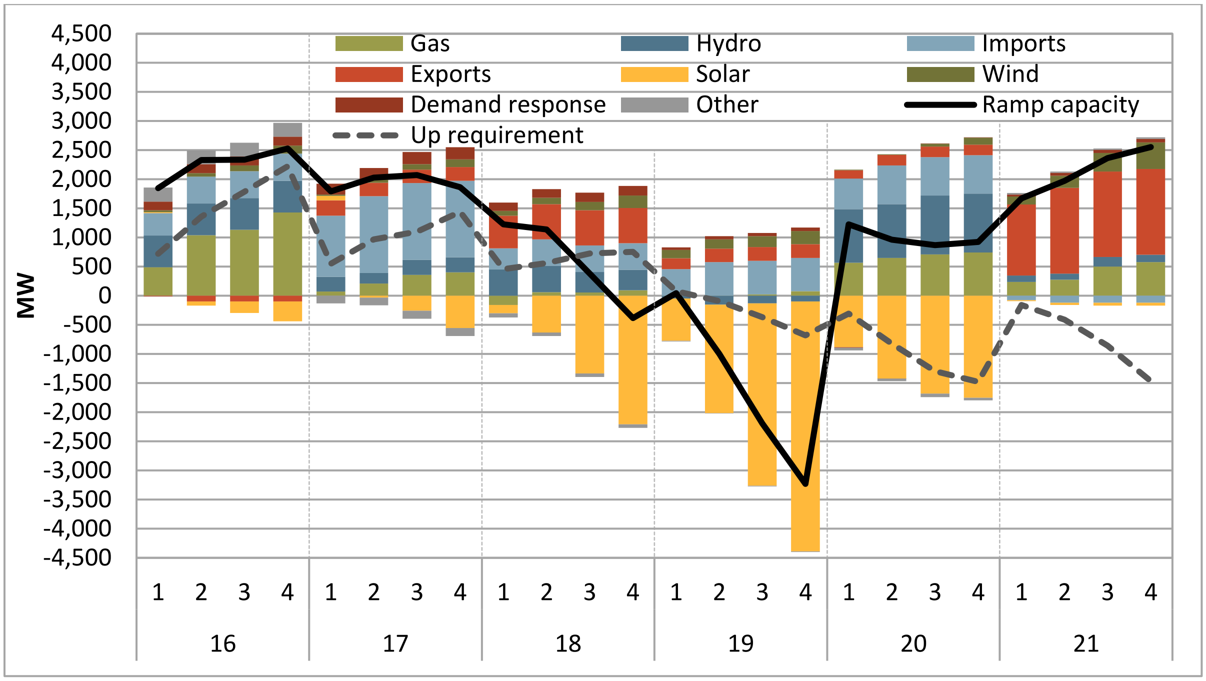


Figure 3.7 CAISO flexible ramping sufficiency test ramping capacity by type (August 14, 2020)



3.2 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 fourth quarter of 2020, 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 $1.11/MWh or about 2.5 percent, a slight decrease from the $1.42/MWh or 2.6 percent for the previous quarter.

3.2.1 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.[60] 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 de-rates).
- Transmission losses were not explicitly added to demand. The day-ahead load forecast already factors in losses.
- 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.
- 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 3.8 shows the quarterly number of hours with a residual supply index less than one since 2016, based on the assumptions listed above. During the fourth quarter, the number of hours with an RSI less than one decreased, but remained higher relative to the fourth quarter of the previous four years. For the quarter alone, the residual supply index with the three largest suppliers removed (RSI_3) was less than one during 144 hours. These occurred primarily in October during peak net load hours.

With the largest two suppliers removed (RSI_2), the residual supply index for the third quarter was less than one in 88 hours. With the largest supplier removed (RSI_1), it was less than one in 21 hours. RSI_2 and RSI_3 were less than one in more hours in the fourth quarter than in the third quarters of 2019, 2017, or 2016.

Figure 3.9 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 RSI_3 was less than 0.9 in 64 hours, and less than 0.8 in 14 hours.

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60 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.

Figure 3.8 Hours with residual supply index less than one

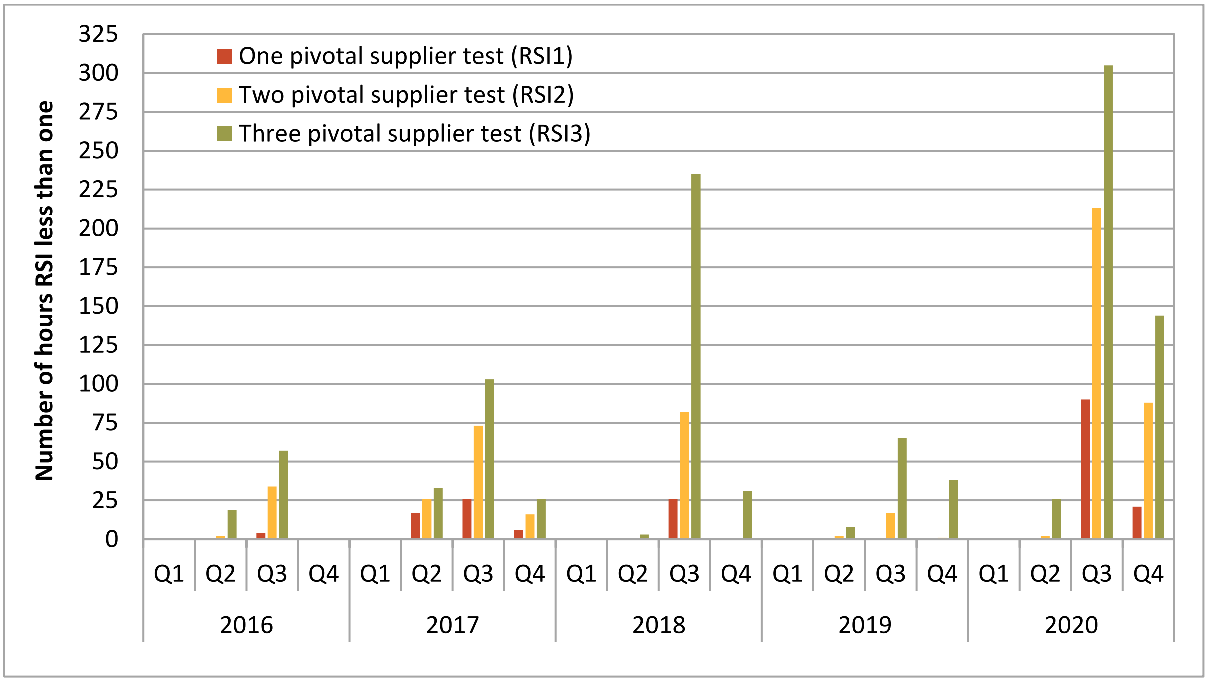
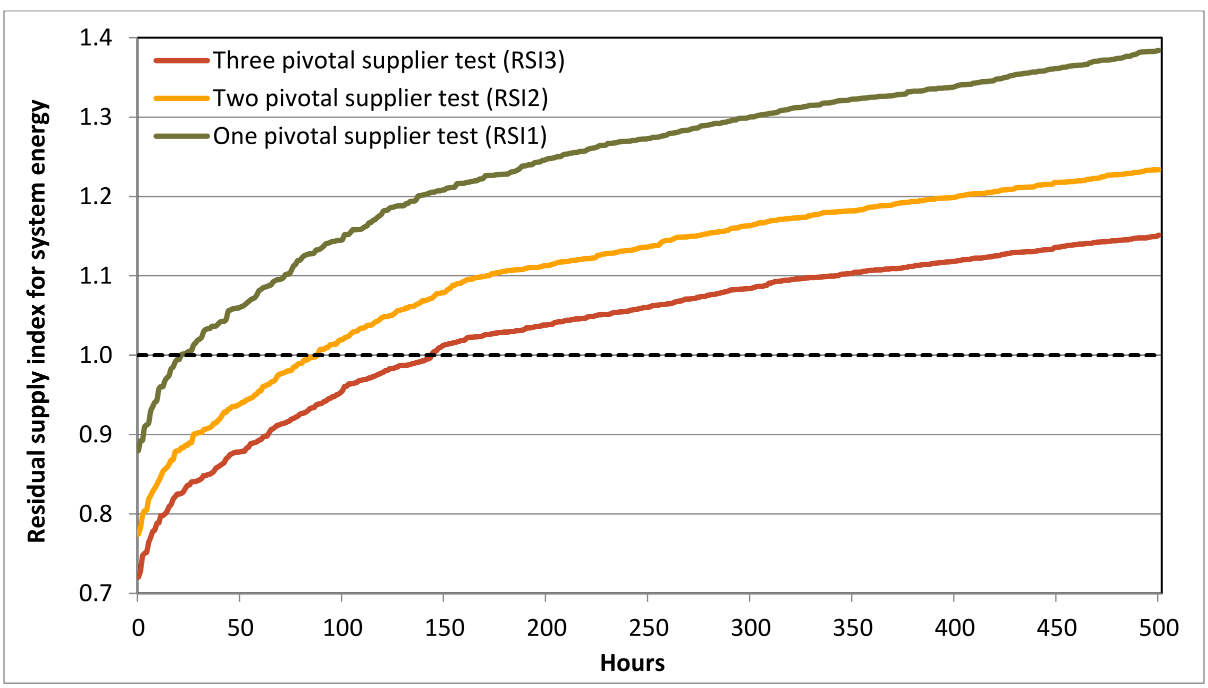


Figure 3.9 Lowest 500 residual supply index with largest one, two, or three suppliers excluded (October – December)



3.2.2 Day-ahead market competitiveness

The performance of California's wholesale energy markets remained competitive, with prices during most hours at or near the marginal cost of generation. DMM assesses the competitiveness of overall market prices based on the *price-cost markup*, which represents a comparison of actual market prices to an estimate of prices that would result in a highly competitive market in which all suppliers bid at or near their marginal costs.

DMM estimates these competitive baseline prices by re-simulating the day-ahead market after replacing bids or other market inputs using DMM's version of the day-ahead market software. Actual market prices were very close to these estimated competitive baseline prices, even during the heat wave period of August 14 to 19, indicating that replacing high-priced energy bids with cost-based bids did not lower prices. Resources that may be subject to mitigation, such as gas-fired and other resources, were generally infra-marginal during high-priced hours. When performing day-ahead market reruns using cost-based bids, 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.

As shown in Figure 3.10, 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. The blue bars in the figure show the load-weighted average scenario price for each load area, while the red bars show the difference between the scenario price and the base case price. This difference is the hourly price-cost markup, calculated as the difference between the default energy bid scenario and base case prices, by hour and load area. In the fourth quarter of 2020, prices remained competitive, with average hourly scenario prices very close to actual market results.

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 3.10 Hourly price-cost markup – default energy bid scenario (Oct – Dec)

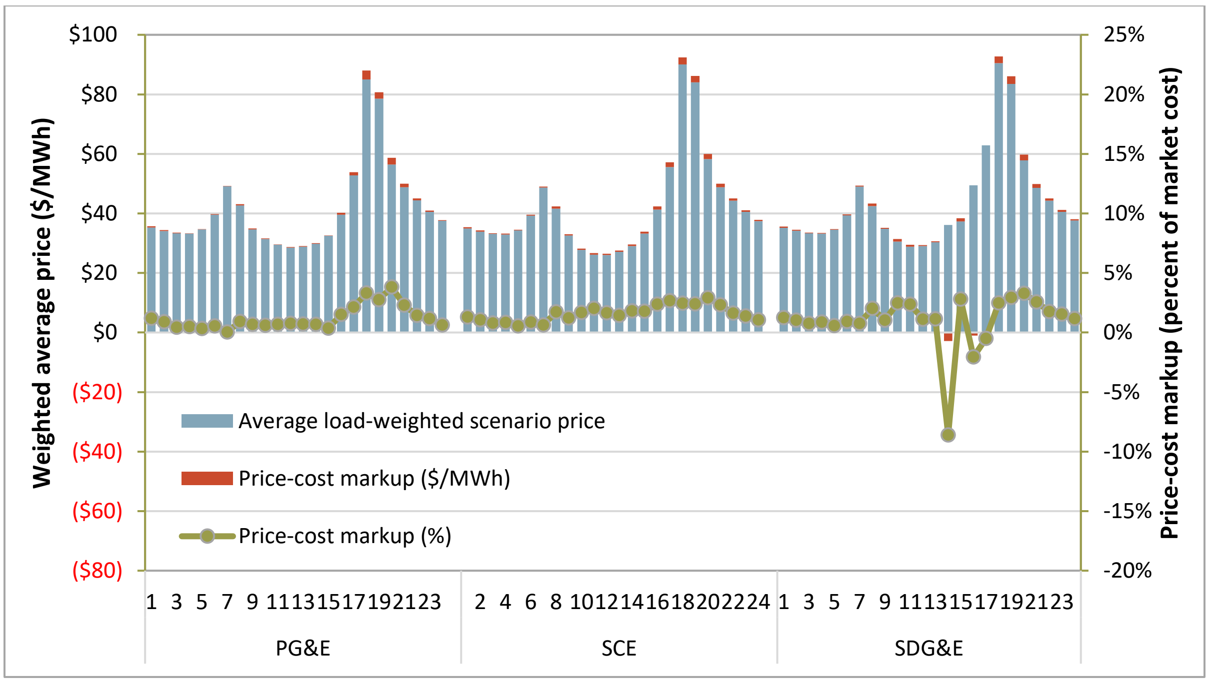


Figure 3.11 Hourly price-cost markup – default energy, commitment cost, and import bids scenario (Oct – Dec)

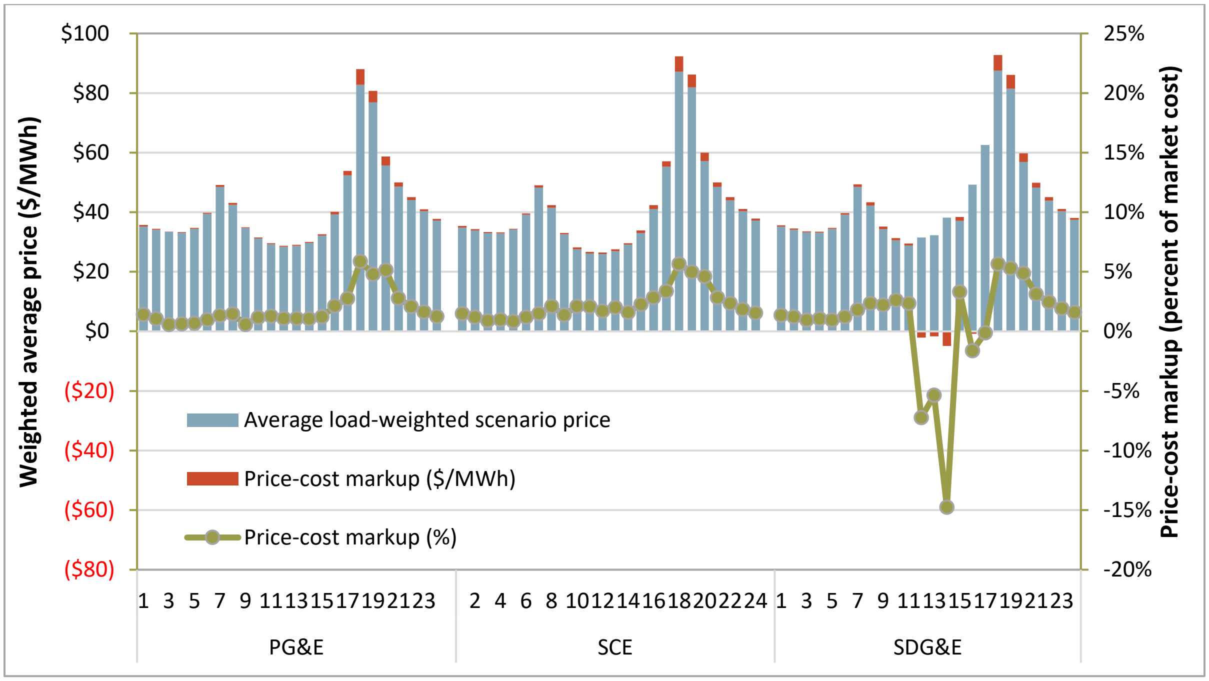
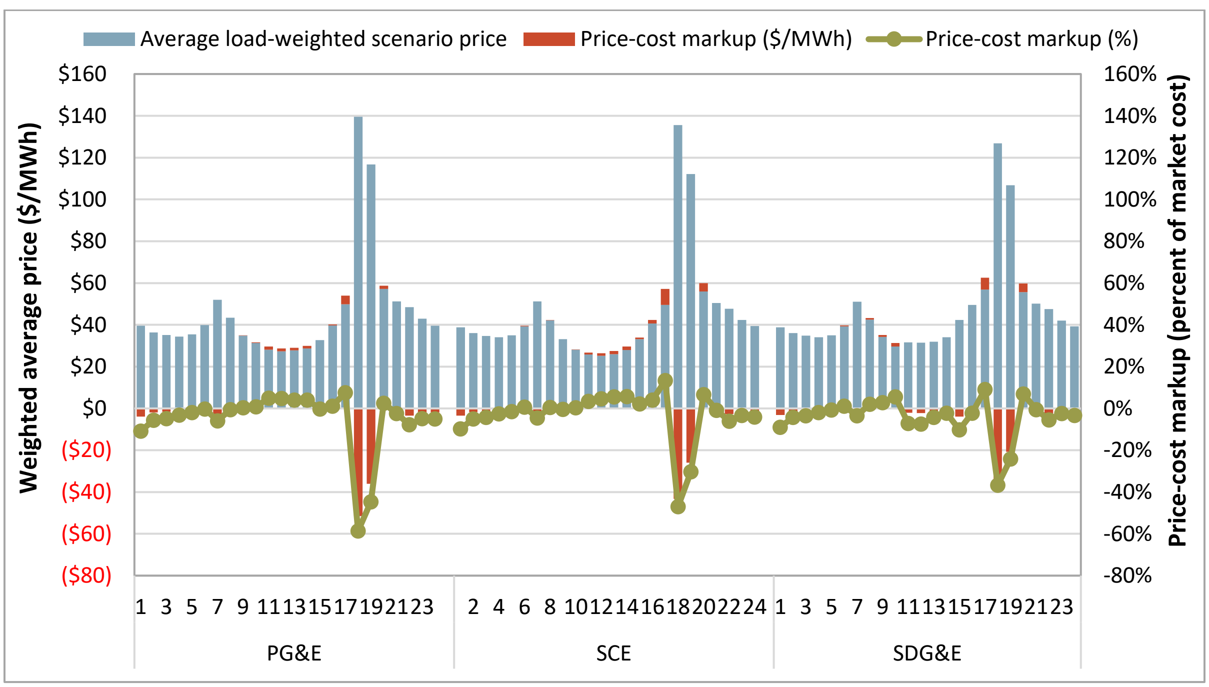


Figure 3.12 Hourly price-cost markup – actual load and default energy, commitment cost, and import bids scenario (Oct – Dec)



As described above, 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 3.1, in the fourth quarter of 2020 the average price-cost markup was about $0.72/MWh or about 1.5 percent for the default energy bid scenario, slightly above the $0.63/MWh or just over 1 percent for the previous quarter.

This slight positive markup indicates that prices have been competitive, overall, for the quarter.[61] 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 $1.11/MWh or about 2.5 percent, a slight decrease from the $1.42/MWh or 2.6 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.

Another way to look at price-cost markup is to rerun 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 -$3.97/MWh or -9 percent, similar to the -$4.56/MWh or -11 percent for the previous quarter. The results for this and the remaining scenarios indicate that prices remain very competitive, overall, for the quarter.

61 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.

Table 3.1 Quarterly price-cost markup by scenario (Oct – Dec)[62]

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)	$44.09	$43.99	$43.27	$0.72	1.64%
Commitment costs for gas resources at min(bid,110% proxy)	$44.09	$43.99	$43.68	$0.31	0.69%
Import bids at min(bid,hydro DEB)	$44.09	$43.99	$43.89	$0.10	0.22%
Remove convergence bids, set load to 5-min mkt req	$44.09	$43.99	$49.90	-$5.91	-13.43%
Energy and commitment cost bids capped for gas resources, imports capped	$44.09	$43.99	$42.88	$1.11	2.53%
Remove convergence bids, set load to 5-min mkt req, and cap gas resources at default energy bids	$44.09	$43.99	$48.57	-$4.58	-10.42%
Remove convergence bids, set load to 5-min mkt req, cap gas resources' energy and commitment cost bids, and cap import bids	$44.09	$43.99	$47.96	-$3.97	-9.03%

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.

3.2.3 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 2021 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.

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 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. However, these results do not provide conclusive evidence that there was no exercise of system market power on these days.

62 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.

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.
- Tightening regional supply conditions.
- 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. This concern has been mitigated by a CPUC ruling imposing requirements on resource adequacy imports to bid in at or below $0/MWh during peak hours.

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.[63]

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 ISO has not included this initiative in the set of fast-tracked changes for implementation prior to summer 2021. DMM supports the consideration of interim feasible measures to mitigate system market power should conditions warrant before this initiative is implemented.

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

63 See for example, recent testimony in CPUC proceeding R20-11-003, pages 11-12. http://www.caiso.com/Documents/Jan11-2021-OpeningTestimony-JeffBillinton-ReliableElectricService-ExtremeWeatherEvent-R20-11-003.pdf

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 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.[64]

64 *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