Q1 2021 Report on Market Issues and Performance

June 9, 2021

Prepared by: Department of Market Monitoring

California Independent System Operator

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Executive Summary

This report covers market performance during the first quarter of 2021 (January - March).

Key highlights during this quarter include the following:

- **Market prices were significantly higher** than the same quarter of 2020, driven by high natural gas prices in February.
- **Natural gas prices at SoCal Citygate were over $100/MMBtu** from February 13 to February 17, a record high for the hub. These high prices were tied to high demand outside of California (Figure E.2).
- **Hydroelectric production decreased** by 25 percent compared to the first quarter of 2020.
- **Non-hydroelectric renewable production increased** by 15 percent compared to the same quarter in 2020, as utility-scale solar continues to be added to the ISO's fleet.
- **Generation outages were higher** on average over peak hours compared to the same quarter in the previous five years. Planned and forced outages increased 20 percent and 6 percent, respectively, relative to the same time last year.
- **The ISO's day-ahead market was structurally competitive** on a system level in all hours of the quarter.
- **The ISO introduced a minimum area flexible ramping product procurement requirement** in November 2020. 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.
- **Average ISO monthly 5-minute prices were lower than both 15-minute and day-ahead market prices** during the quarter (Figure E.1). Day-ahead prices averaged $44/MWh, 15-minute prices averaged $43/MWh, and 5-minute prices averaged $37/MWh.
- **Imbalance conformance adjustments in the 15-minute market** reached 1,100 MW during the peak net load ramp hours, on average, continuing the increase in operator use of imbalance conformance that began in 2017. The widening gap between high conformance in the 15-minute market and lower conformance in the 5-minute market contributes to the price difference between these markets.

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

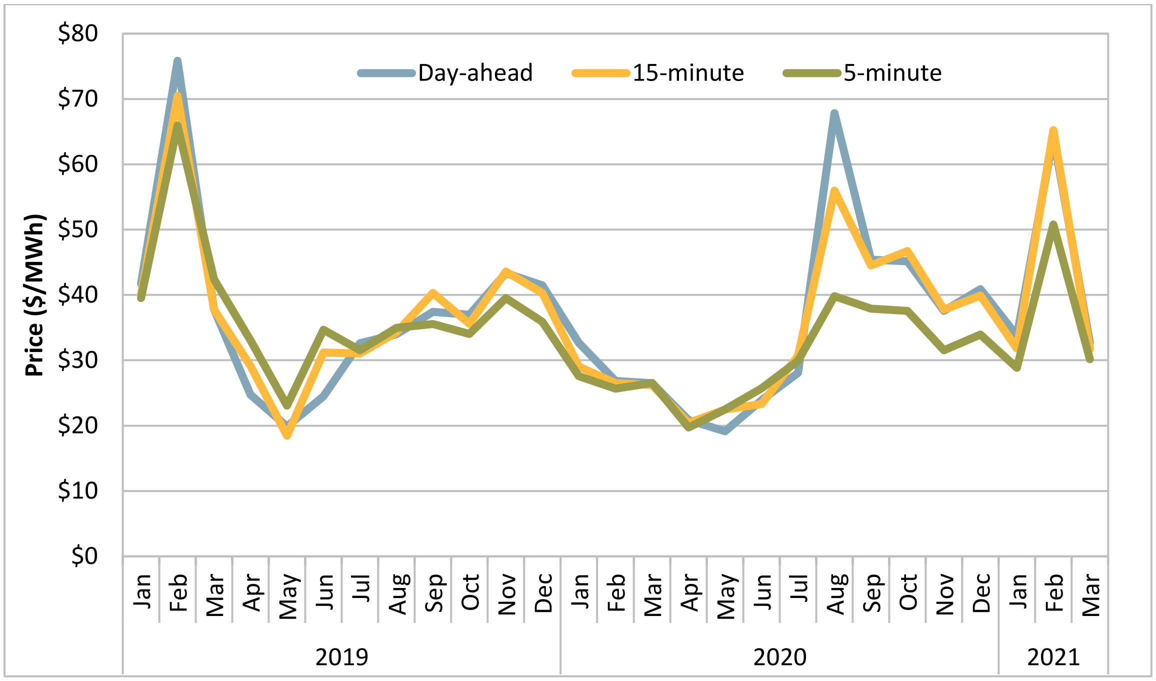
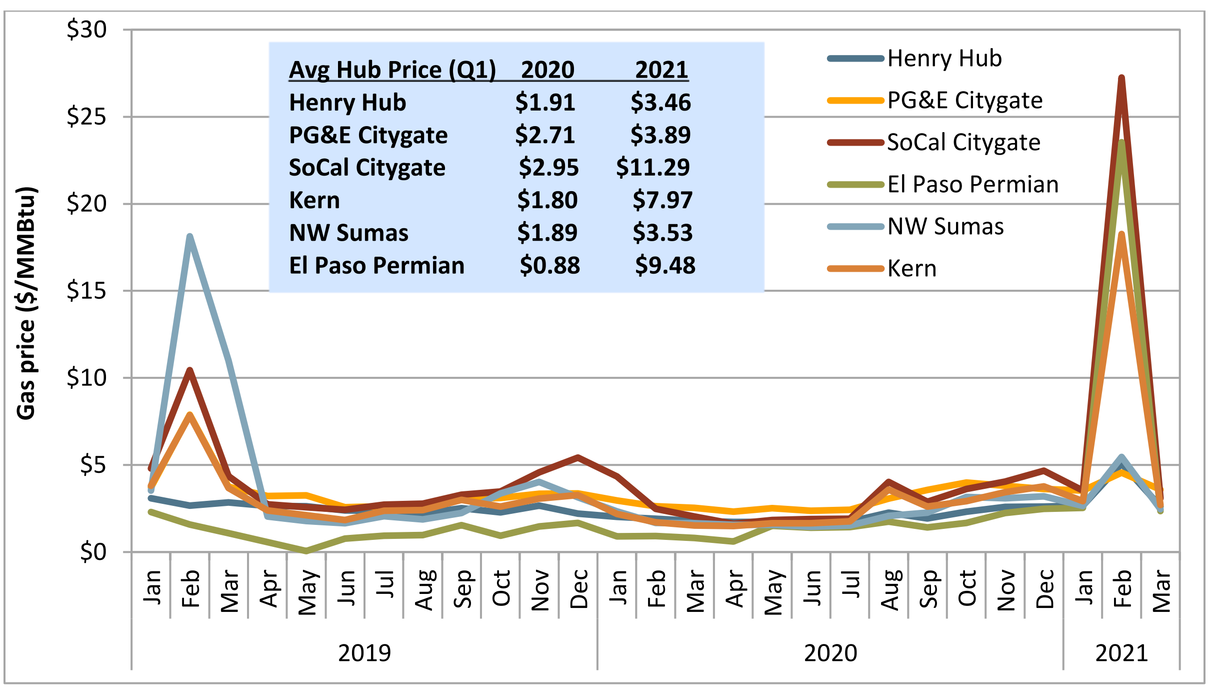


Figure E.2 Natural gas prices



Western Energy Imbalance Market

- **The Turlock Irrigation District and the Balancing Authority of Northern California** joined the Western Energy Imbalance Market on March 25, bringing over 6 GW of additional participating generation capacity and over 3 GW of transfer capacity.
- **Prices in the Southwestern areas averaged over $60/MWh in February**, exceeding the rest of the system, driven by high gas costs associated with a cold weather event in Texas and across the Midwestern United States.
- **Prices in the California ISO and the Balancing Authority of Northern California were on average more than $5/MWh higher than other regions of the energy imbalance market.** Prices tend to be higher in California than the rest of the Western Energy Imbalance Market 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 California 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 in peak net load hours.
- **Following modification of the penalty price with FERC Order 831 implementation in March 2021**, the majority of intervals with power balance relaxations were priced at the penalty parameter of $2,000/MWh. Failures of the downward sufficiency test, also most common in the same areas, increase the likelihood of over-supply infeasibilities priced at the -$150/MWh penalty price.

Special issues

In response to high gas prices in February, the ISO accelerated the implementation of two initiatives.

- The Commitment Costs and Default Energy Bids Enhancements – Phase 1 allows market participants to request adjustments to the marginal cost reference levels used in mitigation and to make after-market requests for cost recovery to the ISO. The ISO also waived conditions to allow resources to seek after-market cost recovery above $1,000/MWh. This initiative was implemented effective February 16.
- FERC Order No. 831 compliance – Phase 1 allows some resources to bid between $1,000/MWh and $2,000/MWh and raises the penalty prices associated with a power balance constraint under-supply violation from $1,000/MWh to $2,000/MWh. This initiative was effective March 20.

Overall these two tariff amendments had little effect on the market during the first quarter. Following the implementation of Commitment Costs and Default Energy Bids Enhancements (CCDEBE), there were about 20 manual reference level requests made during the week of higher gas prices.[1] Most of these

[1] One automated request was made but the resource was on outage, so the request did not affect market outcomes.

requests were rejected due to lack of documentation or because the requests were for a fuel price low enough to be submitted through the automated process.

After the first phase of FERC Order 831 compliance was enacted on March 20, there were no bids from resource-specific resources or imports for over $1,000/MWh. There were some virtual bids over $1,000 from March 28 to March 31, averaging about 100 MW a day, but none of these bids cleared the market.

1 Market performance

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

- **Market prices were significantly higher** than the same quarter of 2020. The frequency of high day-ahead market prices increased substantially in February, while negative day-ahead prices remained roughly the same compared to the first quarter of 2020.

- **Average ISO monthly 5-minute prices were lower** than both 15-minute and day-ahead market prices during the first quarter. Day-ahead prices averaged $44/MWh, 15-minute prices averaged $43/MWh, and 5-minute prices averaged $37/MWh.

- **Gas prices increased** at both SoCal Citygate and PG&E Citygate compared to the same quarter in 2020. During the period February 13 through 19, a severe winter storm across the central and mid-continent United States caused supply wellhead and pipeline freeze-offs. This led to record high prices at most trading hubs across the west. This increase in natural gas prices resulted in higher system marginal energy prices across the ISO footprint during the first quarter.

- **Renewable production** increased by 6 percent compared to the same quarter in 2020, despite a decrease of 25 percent for hydroelectric production.

- **Generation outages** over the quarter were higher than any first quarter in the previous five years.

- **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, therefore 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 2020. 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 for upward capacity in the ISO were positive in about 10 percent of intervals, and were non-zero in about 22 percent of intervals.

- **The day-ahead market was structurally competitive** in all hours of the first quarter.

- **Congestion in** the day-ahead market increased SDG&E and SCE area prices. Total day-ahead congestion rent was $194 million, an increase from $103 million in the previous quarter and $75 million in the same quarter of the previous year.

- **Imbalance conformance adjustments** reached 1,100 MW during the peak net load ramp hours, on average, continuing the increase in operator use of imbalance conformance that began in 2017. The widening gap between high conformance in the 15-minute market and lower conformance in the 5-minute market contributes to the price difference between these markets.

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 period February 13 through 19, a severe winter storm across the central and mid-continent United States caused supply wellhead and pipeline freeze-offs. This led to record high prices at most trading hubs across the west. This increase in natural gas prices resulted in higher system marginal energy prices across the ISO footprint during the first quarter.

Figure 1.1 shows monthly average natural gas prices at key delivery points across the west including PG&E Citygate, SoCal Citygate, Kern, 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 SoCal Citygate, Kern, and Permian hubs spiked to record high levels in the middle of February.

The Permian supply basin in West Texas was significantly affected by the freeze-offs. The spot price at the Permian hub reached a record high of $220/MMBtu for the February 17 gas day. Overall, the average gas price for the first quarter was $9.48/MMBtu which is significantly higher than $0.88/MMBtu during the same quarter of 2020.

SoCal Citygate also experienced these high prices because a significant amount of its natural gas supply comes from the Permian Basin. As a result, the price at SoCal Citygate reached a high of $136.00/MMBtu in the next-day trading window effective over the Presidents' Day weekend. By comparison, the spot price at PG&E Citygate was considerably lower at $6.25/MMBtu because it receives most of its natural gas from the Rocky Mountain region and Western Canada.

Over the first quarter, prices at the SoCal Citygate gas hub averaged $11.30/MMBtu compared to $2.95/MMBtu in the first quarter of 2020. 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.[2] In the first quarter, SoCal Gas withdrew gas from Aliso Canyon storage facility on 44 gas days.

In addition, for the period October 1, 2020, through May 31, 2021, SoCal Gas 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 is consistent with the California Public Utilities Commission's ruling on April 29, 2019.[3] With the revisions from the ruling set to expire in October 2021, DMM submitted comments to a new CPUC ruling to revise

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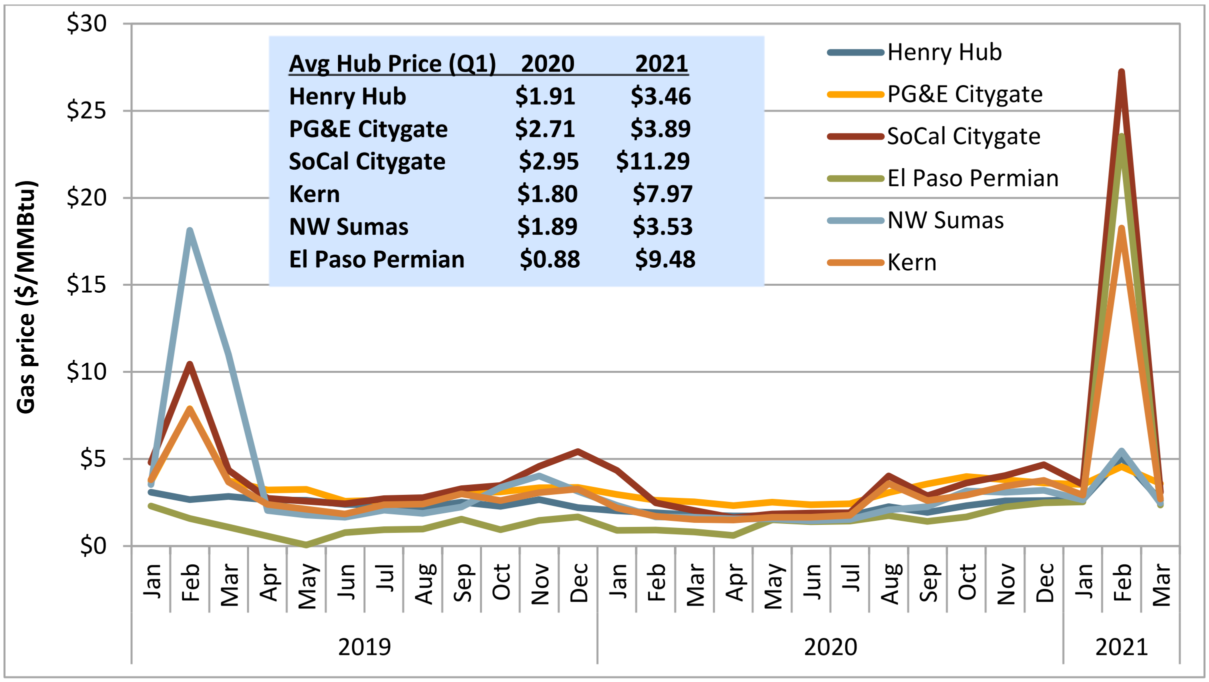
[2] Aliso Canyon Withdrawal Protocol, July 23, 2019: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/UpdatedWithdrawalProtocol_2019-07-23%20-%20v2.pdf

[3] 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

the existing OFO penalty structure.[4] During the first quarter, SoCal Gas Company declared low OFOs on 40 gas days, primarily either Stage 1 or Stage 2. Stage 4 low OFOs were declared on February 16, 17, and 18 gas days.

Figure 1.1 Monthly average natural gas prices



1.1.2 Renewable generation

In the first quarter, the combined average hourly generation from hydroelectric, solar, wind, geothermal, and biogas-biomass resources increased by 481 MW (6 percent) compared to the same quarter of 2020. Generation from non-hydro renewable resources increased 15 percent while hydroelectric generation decreased 25 percent, compared to the first quarter of 2020.[5]

Figure 1.2 shows the average hourly renewable generation by month and fuel type.[6] Non-hydroelectric renewable generation, which includes wind, solar, geothermal, and biogas-biomass resources, increased by a total of 221 MW (15 percent) compared to the same quarter in 2020, primarily due to increases in

4 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

5 Figures and data provided in this section for Q1 2021 are preliminary and may be subject to change.

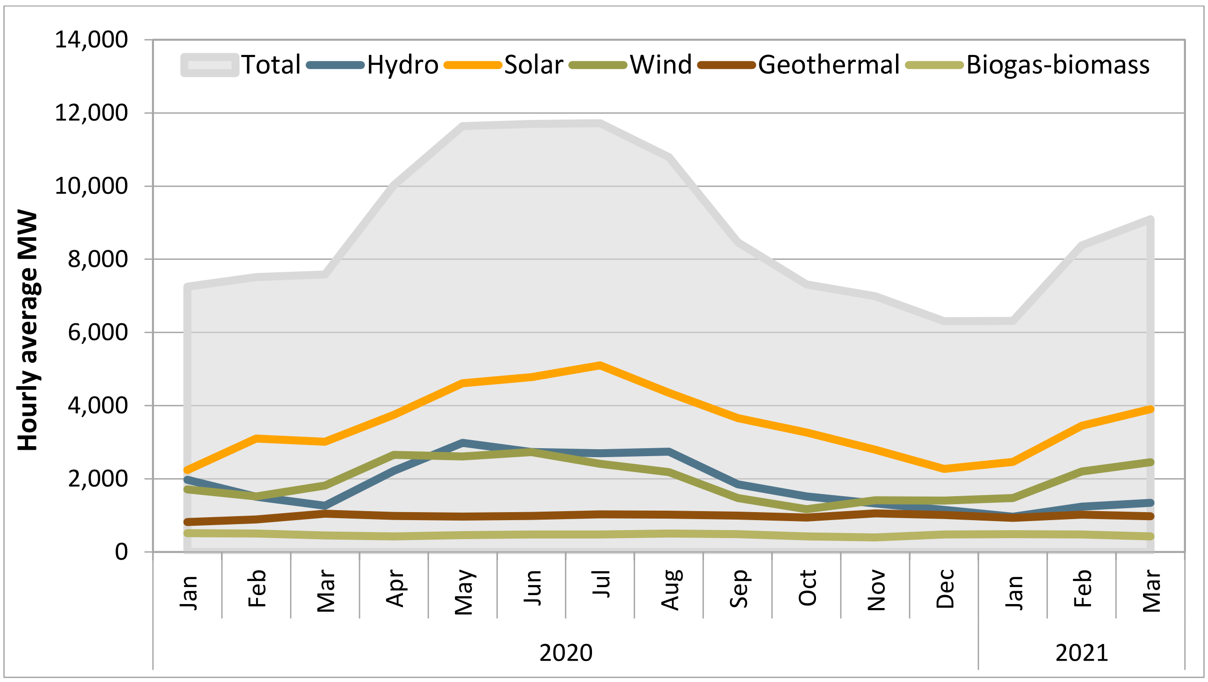
6 Hydroelectric generation greater than 30 MW is included.

solar and wind generation. Compared to the first quarter of 2020, geothermal generation increased by about 58 MW (6 percent), while biogas-biomass generation decreased by about 27 MW (5 percent).

Compared to the same period in 2020, hourly average hydroelectric production in the first quarter decreased by roughly 400 MW (25 percent). As of April 1, 2021, the statewide weighted average snowpack in California was 62 percent of normal compared to 50 percent of normal on April 1, 2020.[7]

Compared to the first quarter of 2020, hourly average wind and solar production increased by about 22 percent and 18 percent, respectively. The availability of variable energy resources contributes to price patterns both seasonally and hourly due to their low marginal cost relative to other resources. Although wind, solar, and geothermal generation increased, hydroelectric and biogas-biomass generation declined compared to the same time last year.

Figure 1.2 Average hourly renewable generation by month



1.1.3 Downward dispatch and curtailment of variable energy resources

Wind and solar curtailments and downward dispatch increased 9 percent in the first quarter of 2021, relative to the same time last year. However, the EIM had a 74 percent decrease in the amount of wind and solar output reductions over the quarter compared to the same time last year. The majority of the reduction in wind and solar output continued to be the result of economic downward dispatch.

When the amount of supply on-line exceeds demand, the real-time market dispatches generators down. Generally, generators are dispatched down in merit order from the highest bid to lowest. As with typical

7 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/.

incremental dispatch, the last unit dispatched sets the system price and dispatch instructions are subject to constraints including transmission, ramping, and minimum generation. During some intervals, wind and solar resources, which generally have very low or negative bids, are dispatched down economically.

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

Figure 1.3 shows the curtailment of wind and solar resources by month in the ISO. Curtailments fall into six categories:

- **economic downward dispatch**, in which an economically bid resource is dispatched down and the market price falls within one dollar of a resource bid, below a resource bid, or the resource's upper limit is binding;[8]
- **exceptional economic downward dispatch**, in which a resource receives an exceptional dispatch or out of market instruction to decrease dispatch;
- **other economic downward dispatch**, in which the market price is greater than one dollar above a resource bid and that resource is dispatched down;
- **self-schedule curtailment**, in which a price-taking self-scheduled resource receives an instruction to reduce output while the market price is below a resource bid or the resource's upper limit is binding;
- **exceptional self-schedule curtailment**, in which a self-scheduled resource receives an exceptional dispatch or out-of-market instruction to reduce output; and
- **other self-schedule curtailment**, in which a self-scheduled resource receives an instruction to reduce output and the market price is above the bid floor.

The majority of the reduction in wind and solar output during the first quarter of 2021 (98 percent) was a result of economic downward dispatch, rather than self-schedule curtailment. Most renewable generation dispatched down in the ISO were solar resources (94 percent) rather than wind (6 percent) since solar resources typically bid more economically.

In the ISO, economic downward dispatch rose sharply over the course of the first quarter of 2021; from 65,000 MWh in January to 358,750 MWh in March. Economic downward dispatch in the quarter accounted for about 98 percent of total wind and solar curtailment. The high level of economic downward dispatch over the quarter was due to higher renewable production, lower load, and congestion from south to north. Self-schedule curtailment totaled 9,000 MWh for the quarter, a 68 percent decrease relative to the first quarter of 2020.

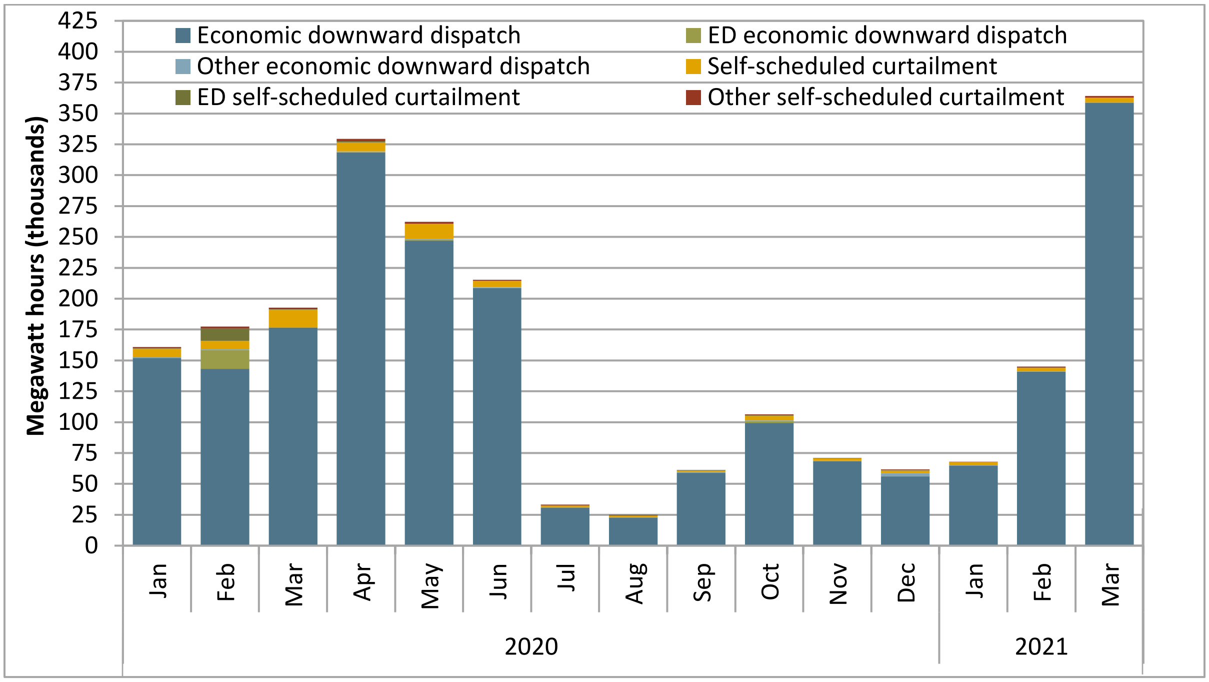
Figure 1.4 shows the amount of downward dispatch of non ISO wind and solar resources. Curtailments in the EIM fall into four categories: economic downward dispatch, other economic downward dispatch, self-schedule curtailment, and other self-schedule curtailment, each defined above.

Downward dispatch fell in the energy imbalance market areas outside of the ISO. Economic downward dispatch in the EIM accounted for the majority of reductions in wind and solar output. During February

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

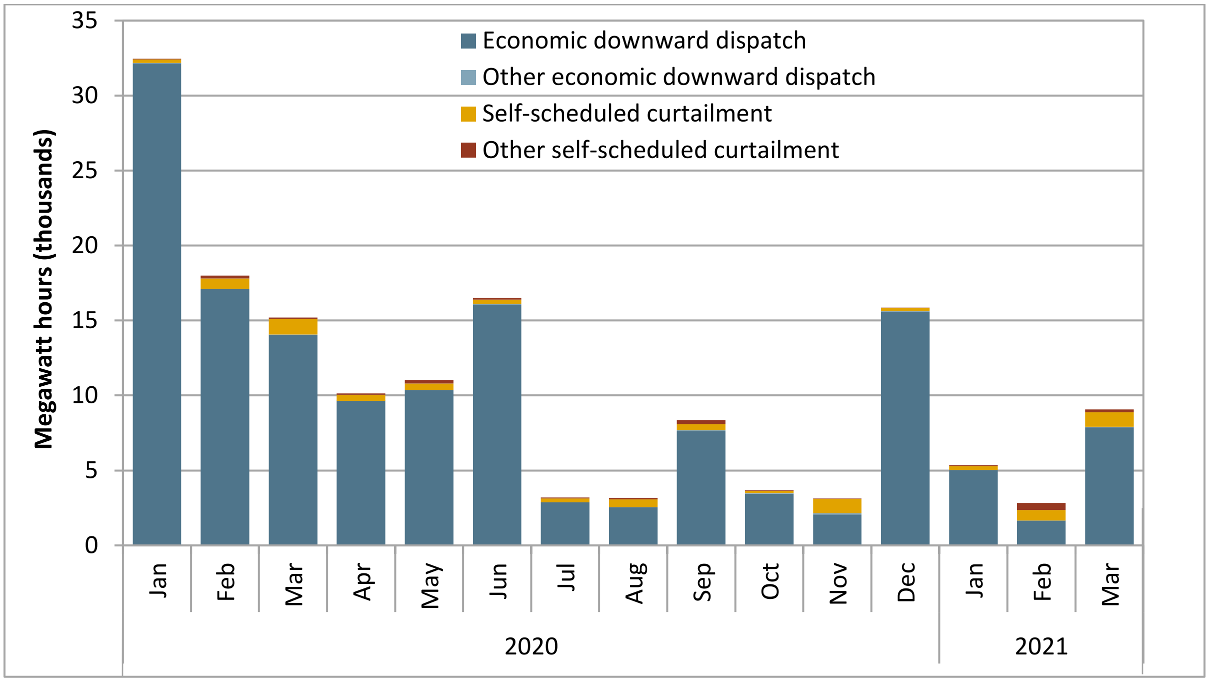
2021, total reductions in wind and solar output fell to 2,800 MWh, an 84 percent decrease compared to February 2020. Much of the curtailment in the EIM is due to the high frequency of congestion on the Wyoming Export constraint, which leads to one resource being heavily curtailed.[9]

Figure 1.3 Reduction of wind and solar generation by month (ISO)



9 The Wyoming_Export constraint was congested during 33.4 percent of intervals during the quarter as shown in Table 1.5. The overall effects of transfer congestion are discussed in detail in Section 1.9.2.

Figure 1.4 Reduction of wind and solar generation by month (EIM)



1.1.4 Generation by fuel type

In the first quarter, generation increased on average for some fuel types, while decreasing sharply for others. Average hourly generation by wind and solar resources increased by 21 percent and 18 percent, respectively, while average hourly generation by nuclear and hydroelectric fell by 30 percent and 26 percent, respectively, compared to the same quarter of 2020.[10] [11] As shown in Figure 1.5, on average, nuclear, geothermal, and bio-based resources comprised about 3,500 MW of inflexible base generating capacity, about 800 MW less than the same quarter of 2020. Generation from "other" resources, including coal, battery storage, demand response, and additional non-gas technologies, increased 27 percent this quarter compared to the first quarter of 2020, but continued to be a small share of overall generating capacity at about 320 MW on average.

[10] Figures and data provided in this section are preliminary and may be subject to change.

[11] The primary cause of the decrease in average hourly nuclear generation is attributed to generation outages that occurred during the quarter.

Figure 1.5 Average hourly generation by fuel type (Q1 2021)

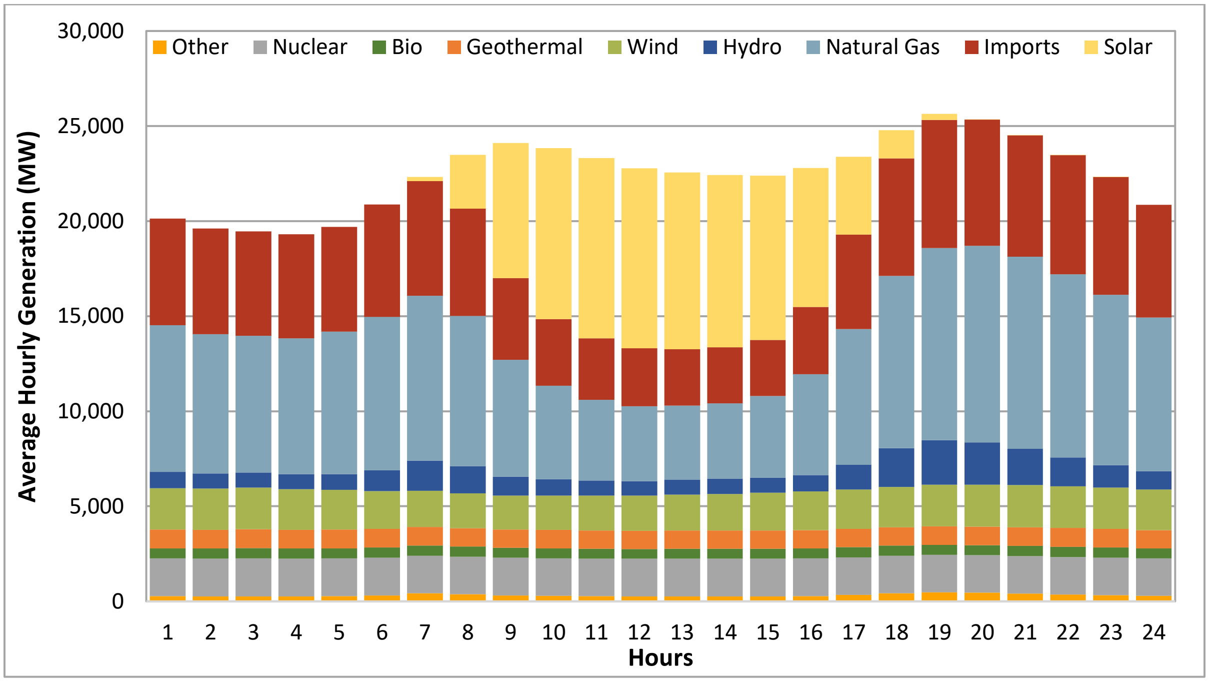
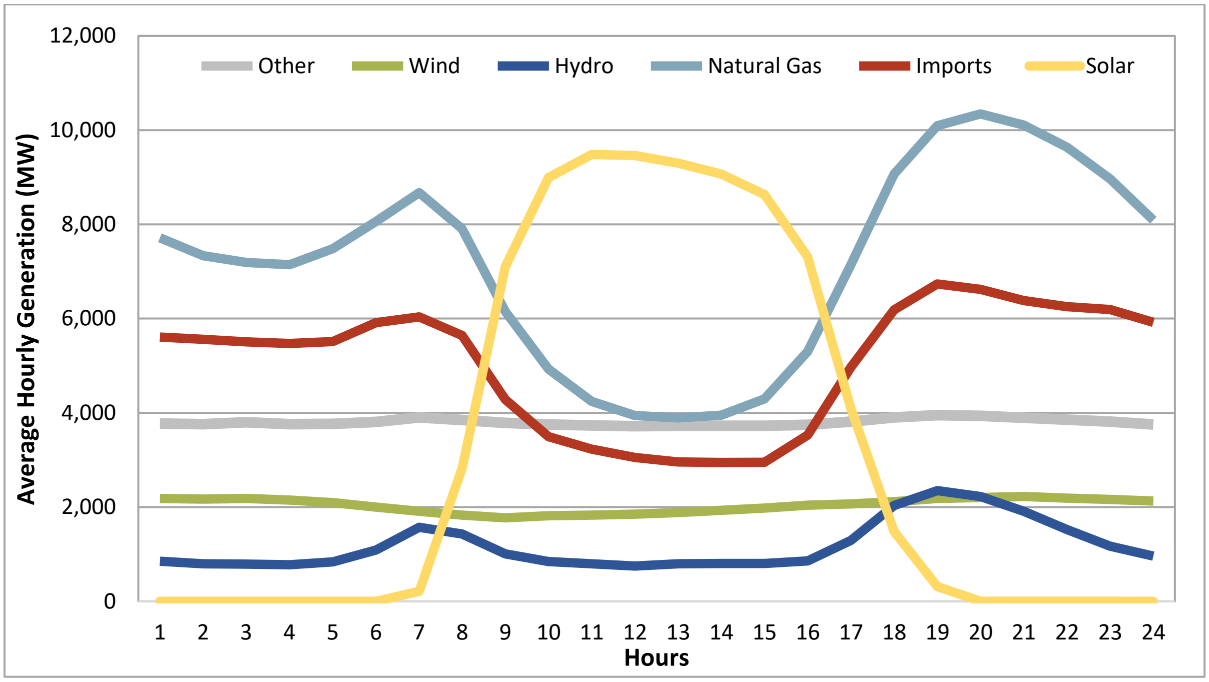


Figure 1.6 shows hourly variation of generation by fuel group, driven primarily by hourly variation of solar production. In the first quarter, differences in hourly average natural gas generation were similar to changes in solar production, as gas generation produced significantly more than any resource during the peak net load hours. Compared to the first quarter of 2020, natural gas generation variability increased 25 percent, driven by a decrease in nuclear and hydroelectric production. Wind generation in the first quarter continued to have low hourly variability on average, although it increased 15 percent compared to the first quarter of 2020.

Import variability trended similarly to natural gas generation over the quarter, with a large dip in the middle of the day once solar generation peaks. Average hourly generation from resources in the “other” category was less variable throughout the day, down 16 percent compared to the same quarter of 2020.[12]

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

Figure 1.6 Hourly variation in generation by fuel type (Q1 2021)



1.1.5 Generation outages

The total amount of generation outages over the first quarter of 2021 was higher than the same quarter of the last five years. Planned and forced outages increased 20 percent and 6 percent, respectively, relative to the same time last year.

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 1.7 shows the monthly averages of maximum daily outages during peak hours broken out by type for 2020 and 2021. Figure 1.8 shows the quarterly averages of maximum daily outages during peak hours by type from 2017 to 2021. The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are typically performed outside of the high summer load period.

During the first quarter of 2021, the average total generation on outage in the ISO surpassed the same period in 2020 by about 1,450 MW, as shown in Figure 1.8.[13] Planned maintenance outages averaged 4,725 MW, while other types of planned outages averaged 1,450 MW. Some common types of outages that fall into the other planned outages category include ambient outages (both due to temperature and

13 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.

not due to temperature) and transmission outages. These planned outage categories combined for the quarter were about 20 percent higher than the first quarter of 2020.

Total forced outages averaged 7,675 MW during peak hours in the first quarter of 2021, about 6 percent higher than the same time last year. Forced outages for either plant maintenance or plant trouble averaged 2,250 MW, while all other types of forced outages averaged 5,450 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.

On a monthly basis, total outages steadily increased from January to March. The March 2021 average outages reached 17,250 MW, a 3,450 MW increase from the same time last year. The high increase in outages, both forced and planned, may be a symptom of the growing share of the thermal fleet nearing retirement, resulting in higher outage rates. Based on the historical seasonal trend, generation outages are expected to decrease throughout the second and third quarter due to reductions in planned outages.

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

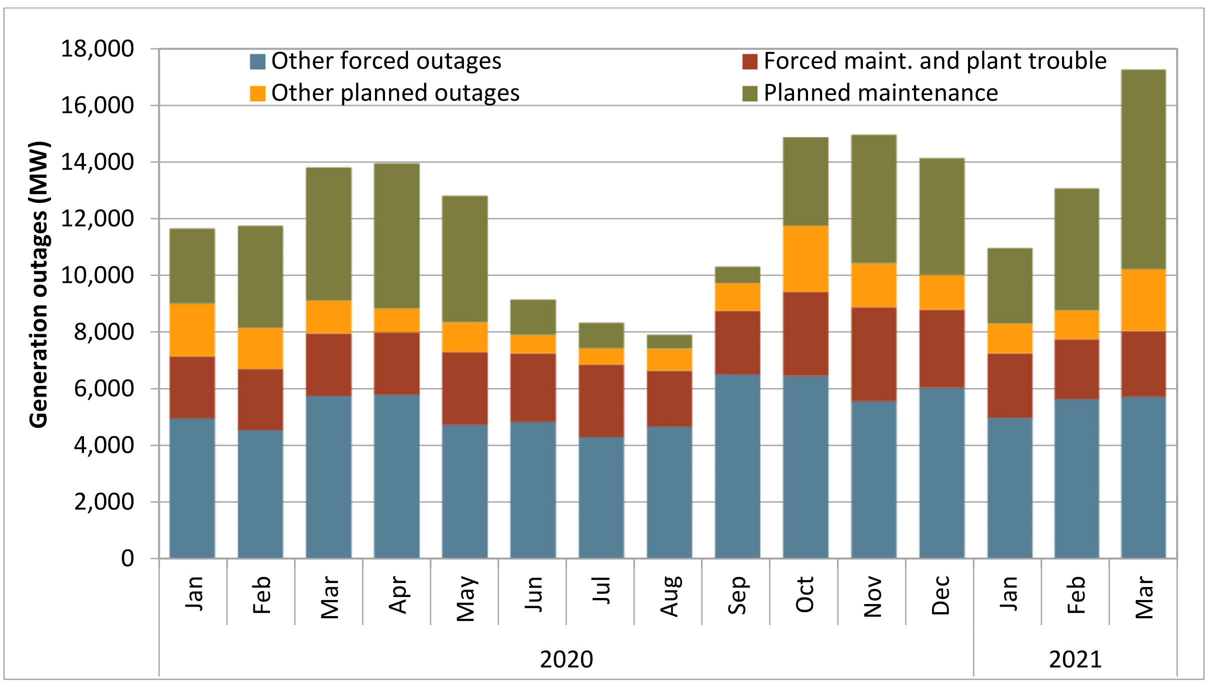
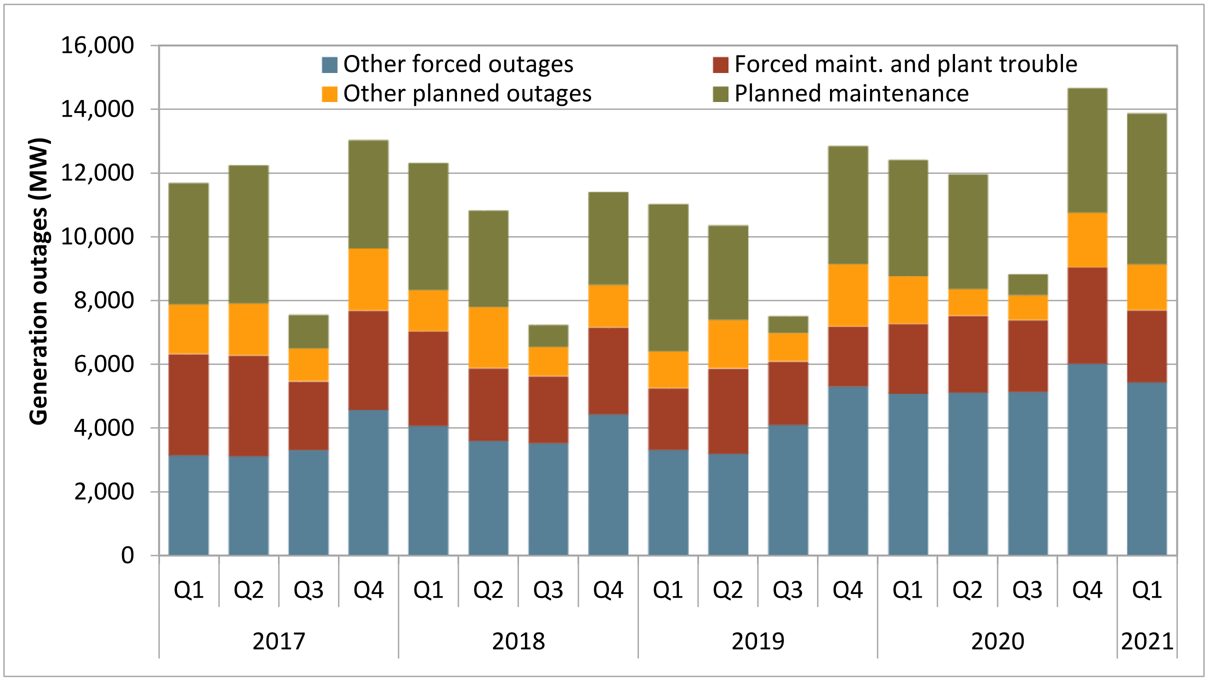


Figure 1.8 Quarterly average of maximum daily generation outages by type – peak hours



1.2 Energy market performance

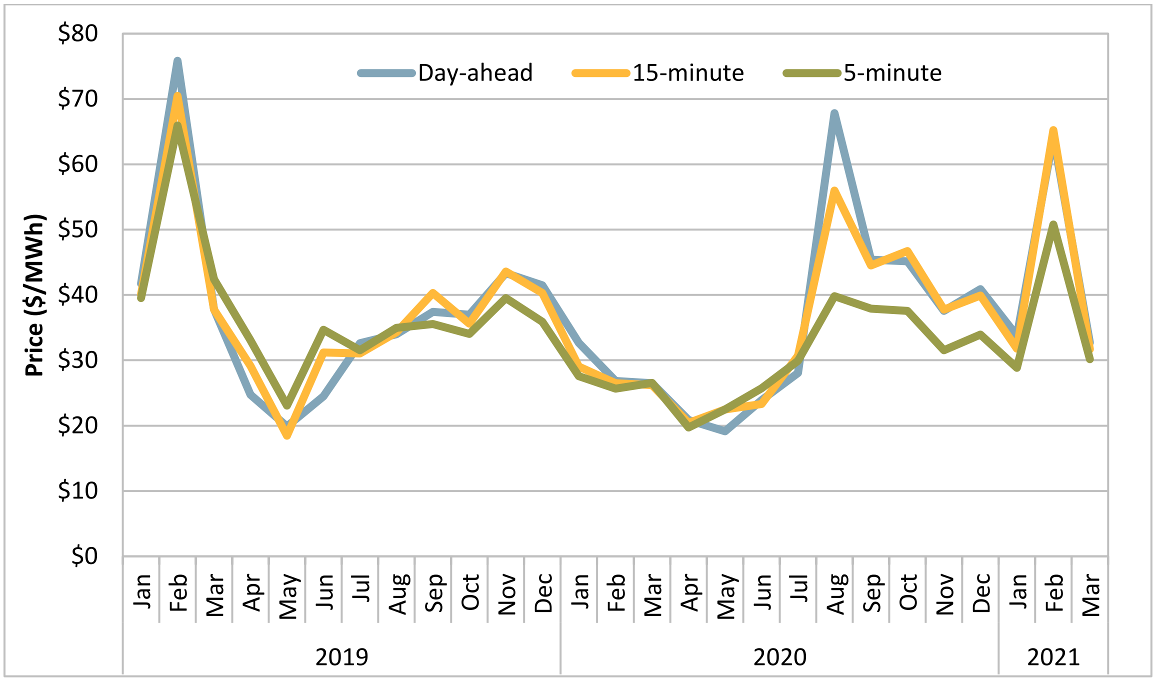
1.2.1 Energy market prices

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 first quarter of 2020, prices in all three markets were higher in 2021. Most of this increase can be explained by the spike in natural gas prices in February due to extreme cold weather in Texas and the Midwest.

Prices in the 5-minute market increased to an average of $37/MWh. Day-ahead and 15-minute market prices each increased about 50 percent to averages of $44/MWh and $43/MWh, respectively. These large increases in prices compared to the first quarter last year were driven by higher average costs in February. Prices across all three markets were roughly twice as high in February of 2021 compared to February 2020. January and March prices were slightly higher in 2021 compared to the previous year.

Figure 1.9 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 March 2021.

Figure 1.9 Monthly load-weighted average energy prices (all hours)

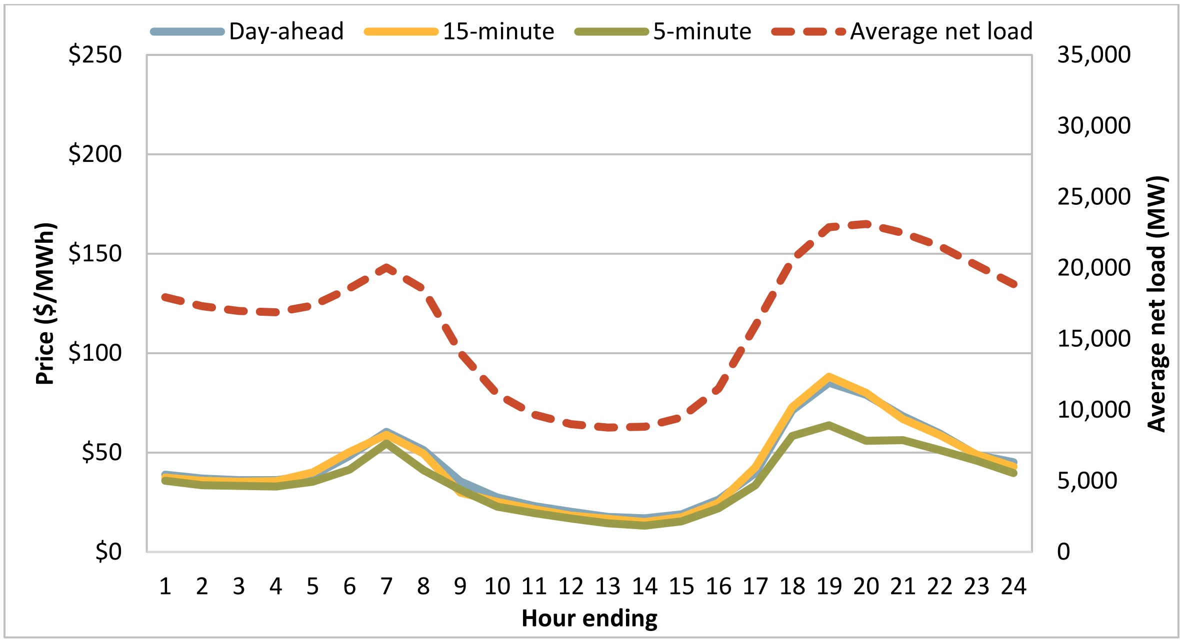


Average prices in this quarter were similar to that of the first quarter of 2019. In both of these quarters gas prices spiked in February pushing the average energy prices up, highlighting the correlation between natural gas prices and electricity price. In 2019, prices across all three markets tracked closely together, however in 2021 prices in the 5-minute market are distinctly lower than prices in the day-ahead and 15-minute market. Prices in March normalized quite a bit after the February spike, but were still higher than March 2019.

Figure 1.10 illustrates load-weighted average energy prices on an hourly basis for the quarter compared to average hourly net load.[14] 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.

[14] 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 1.10 Hourly load-weighted average energy prices (January - March)



Average hourly prices continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours. Wind and solar generation was about 25 percent higher this quarter compared to the same quarter last year resulting in lower net load, particularly in hours ending 9 through 16. As mentioned, prices this quarter were substantially higher due to the spike in natural gas prices. The largest increase in prices happened in hours ending 18 through 20, where prices were roughly 80 percent higher across all three markets.

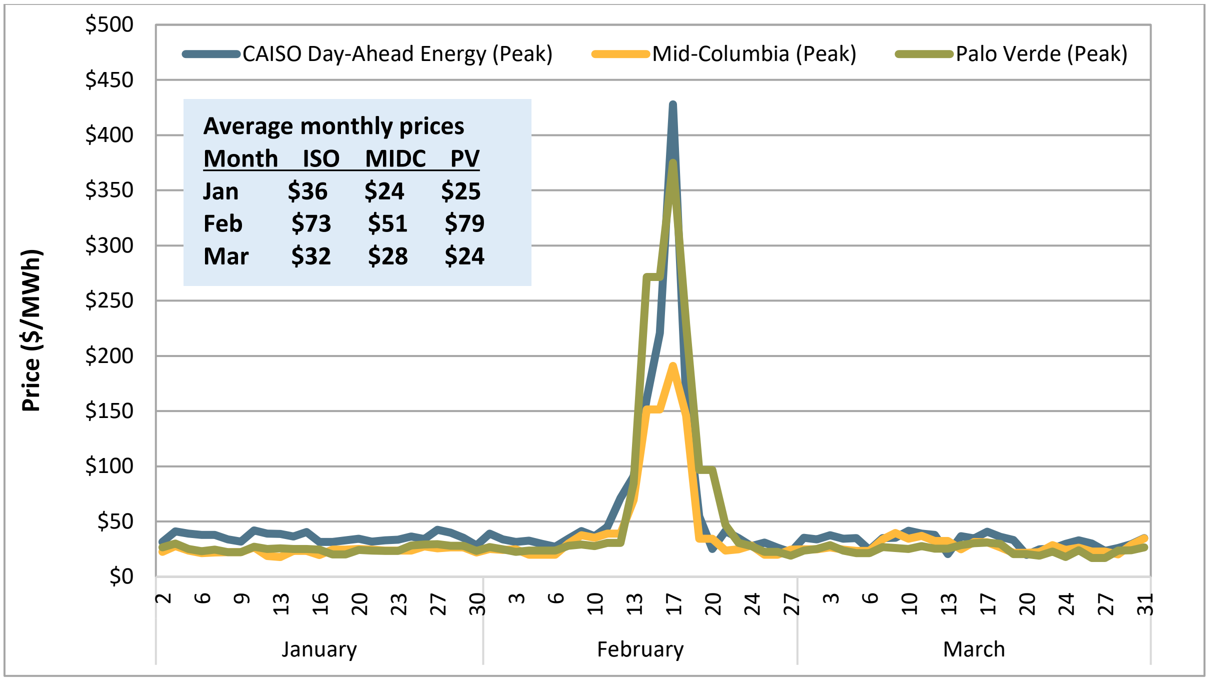
1.2.2 Bilateral price comparison

During the February 2021 high gas price event across the west, average day-ahead market prices in the ISO across peak hours were greater than prices at the Mid-Columbia hub and lower than Palo Verde electricity hub. The ISO prices also reflect transmission constraints as well as greenhouse gas compliance costs.

Figure 1.11 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 days of the first 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 $12/MWh and $5/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 $3/MWh, respectively.

Figure 1.11 Day-ahead ISO and bilateral market prices (Jan – Mar)



Imports and exports

Average net imports decreased compared to the same quarter in 2020. This may be due to low hydroelectric production caused by California's 2020 drought conditions.[15]

As shown in Figure 1.12, peak imports in the day-ahead (dark blue line) decreased slightly in hour ending 19, from about 7,030 MW to 6,590 MW, compared to the first quarter of 2020. Peak 15-minute cleared imports (dark yellow line) decreased slightly, from about 7,520 MW to 7,100 MW, compared to last year. Peak exports (shown as negative numbers below the horizontal axis in pale blue and yellow), increased compared to the first quarter of 2020, by about 135 MW and 210 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 1,100 MW in hour ending 13. The greatest import transfer into the ISO from the EIM occurred in hour ending 22, at about 820 MW, compared to about 650 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 14, at about 1,900 MW, which was an increase of about 400 MW from the same quarter in 2020.

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

Figure 1.12 Average hourly net interchange by quarter

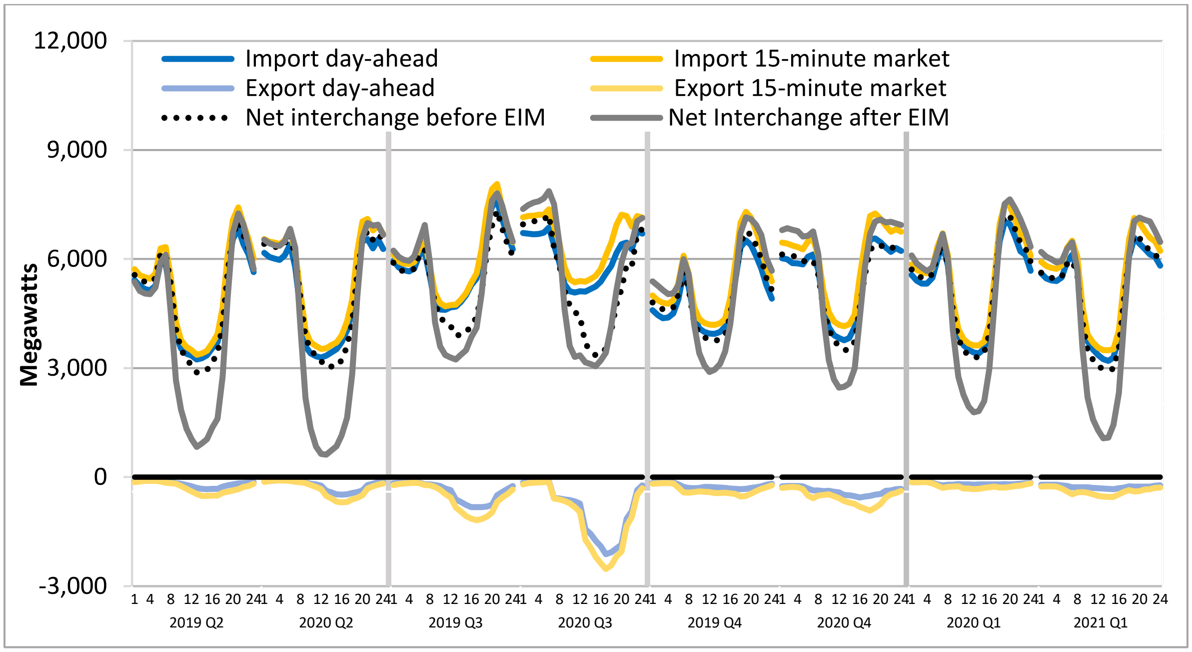
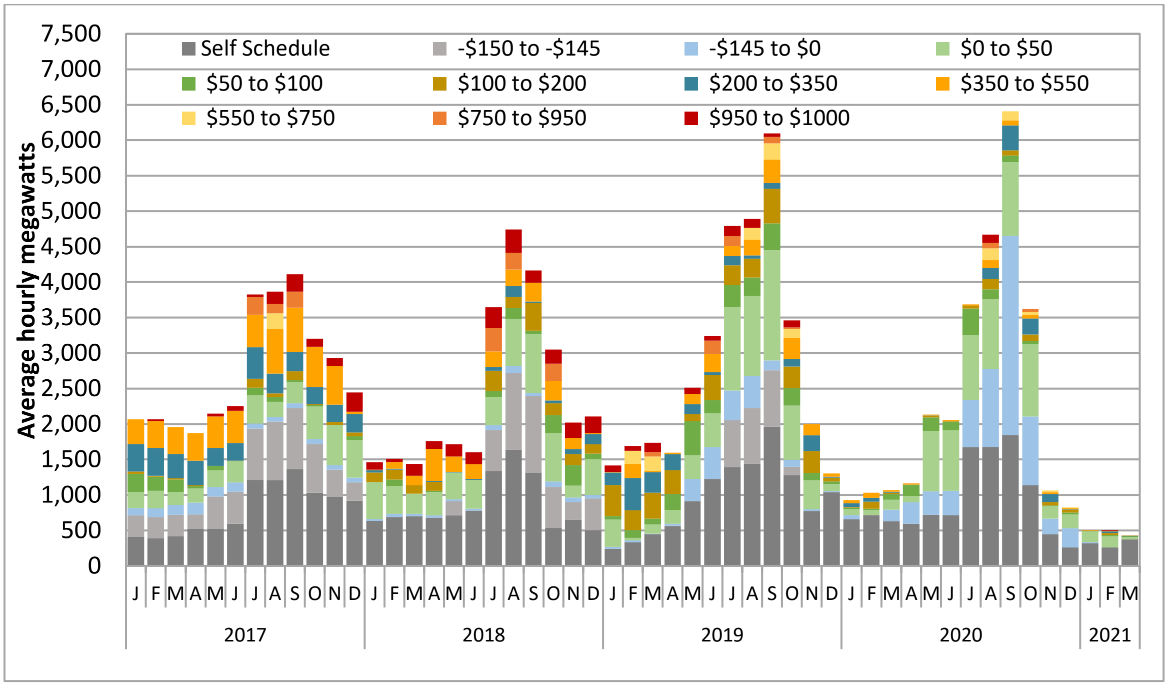


Figure 1.13 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[16] The grey bars reflect import capacity that was self-scheduled or bid near the price floor, while the remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market. A dramatic decline in the quantity of all types of resource adequacy bids has occurred in the first quarter of 2021.

16 Peak hours in this analysis reflect non-weekend and non-holiday periods between hours ending 17 and 21.

Figure 1.13 Average hourly resource adequacy imports by price bin



1.3 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.[17] 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.

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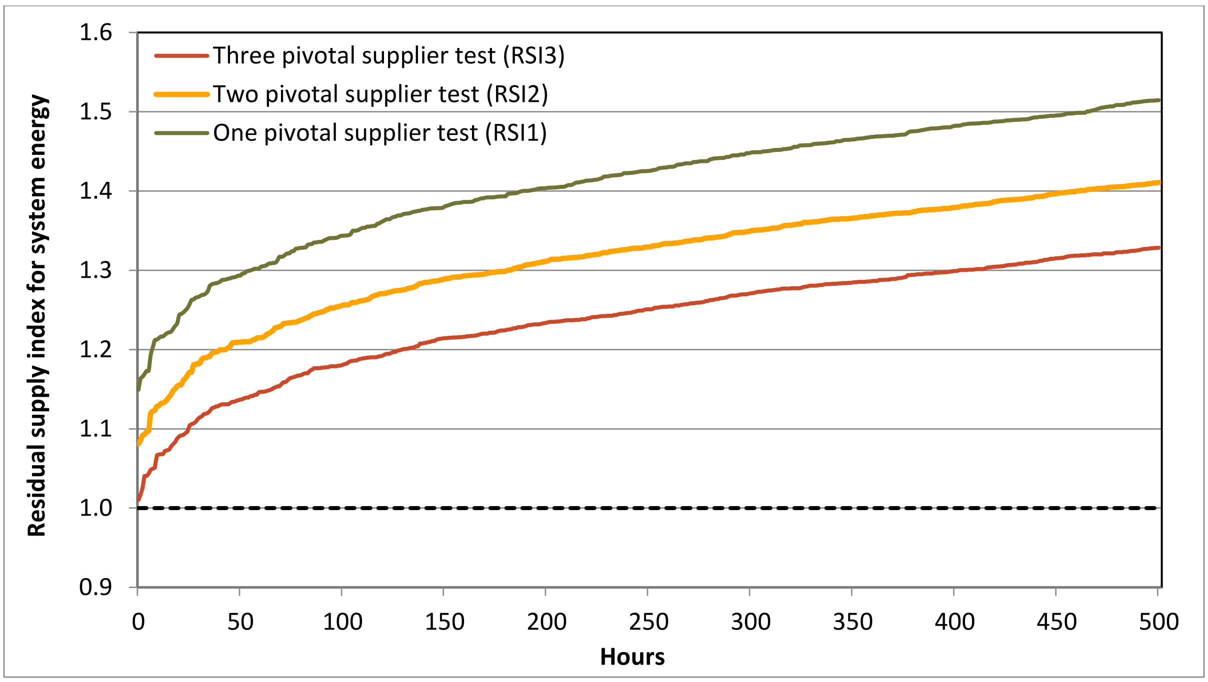
17 For instance, assume demand equals 100 MW and the total available supply equals 120 MW. If one supplier owns 30 MW of this supply, the residual supply index equals 0.90, or (120 – 30)/100.

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.[18]

The first quarter of 2021 was structurally competitive. Figure 1.14**Error! Reference source not found.** illustrates the level of the residual supply index measurements by showing the lowest 500 RSI values during the quarter. During the first quarter, there were no hours with an RSI less than one. Lower loads and higher rates of renewable production helped contribute to a reduction in potentially non-competitive hours from the previous quarter.

Figure 1.14 Lowest 500 residual supply index with largest one, two, or three suppliers excluded (January – March)



1.4 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.

18 For more information on the supply and demand elements used to calculate the residual supply index, see the *Q4 2020 Report on Market Issues and Performance,* April 2021, pp. 111: [2020-Fourth-Quarter-Report-on-Market-Issues-and-Performance-April-28-2021.pdf]

One of the fundamental differences between the day-ahead market and the real-time market are 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.[19] Due in part to this difference, the magnitude of the variation tends to be higher in the real-time market.

1.4.1 Day-ahead price variability

In the first quarter of 2021, the frequency of high day-ahead market prices increased substantially in February while negative day-ahead prices remained roughly the same compared to the first quarter or 2020.

High prices

Figure 1.15 shows the frequency of day-ahead market prices in various high priced ranges from January 2021 to March 2021. The frequency of hours with prices over $250/MWh increased compared to the first quarter last year, driven entirely by high prices in February caused by a spike in natural gas price.

Negative prices

Figure 1.16 shows the frequency of day-ahead market prices in various low priced ranges from January 2021 to March 2021. Prices in the day-ahead market were below $1/MWh in about 2 percent of hours in the first quarter of 2021, similar to the first quarter last year. There was a slight increase in the percentage of hours with negative prices in February 2021 compared to the same month of the previous year.

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

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

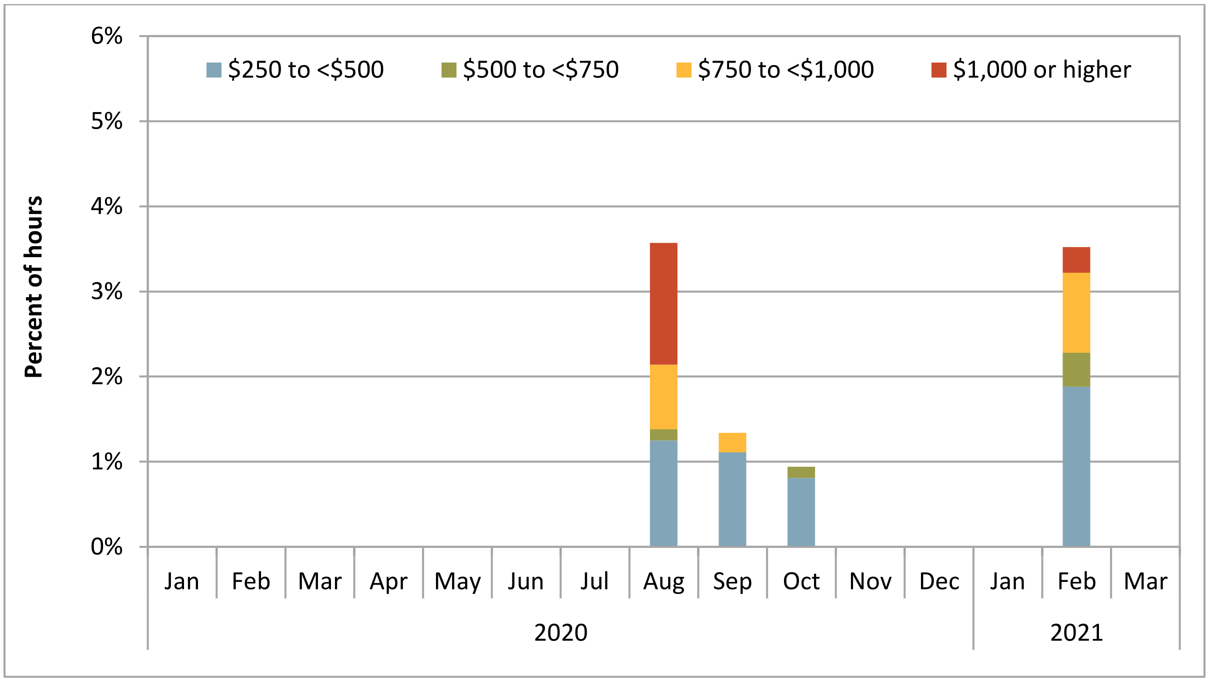
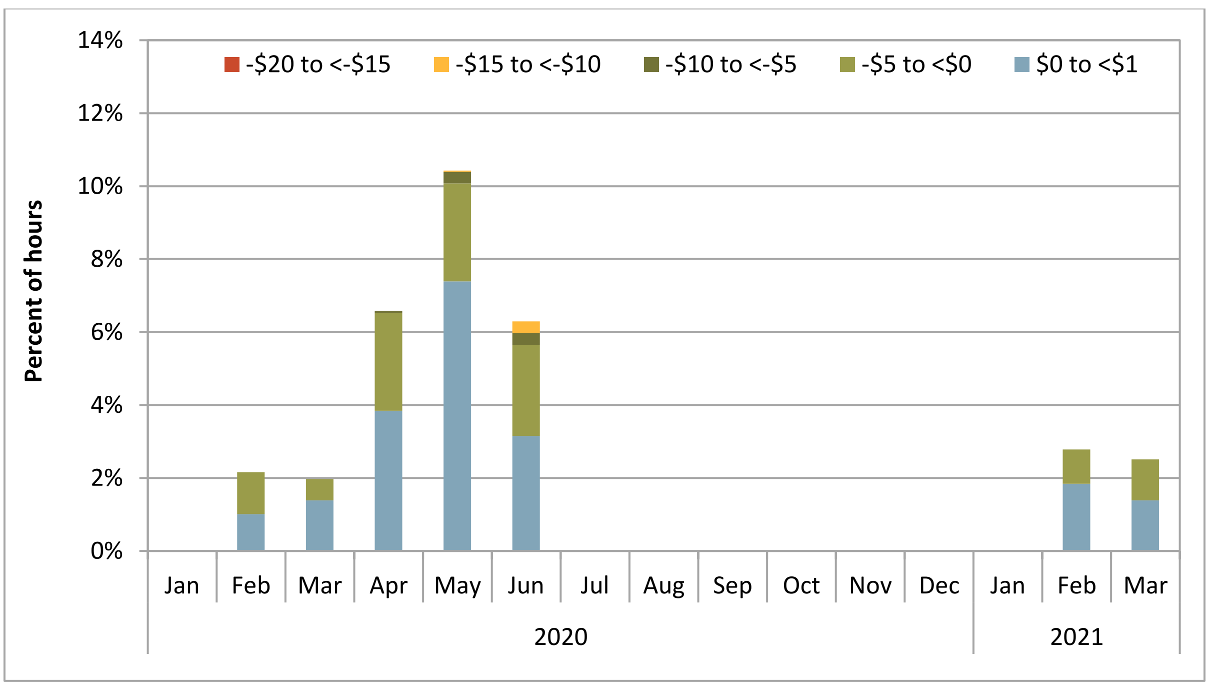


Figure 1.16 Frequency of negative day-ahead prices ($/MWh) by month



1.4.2 Real-time price variability

During the first quarter of 2021, the frequency of high real-time prices was significantly higher due to a gas price spike in February 2021.

High prices

Figure 1.17 and Figure 1.18 show the frequency of prices above $250/MWh across the three largest load aggregation points (LAP) in the ISO. As shown in Figure 1.17, the occurrence of high prices in the 15-minute market greater than $250/MWh was much more frequent in the first quarter this year compared to the same quarter last year. Usually the first quarter has fairly low prices since California's higher demand days tend to be during months with warmer weather and more usage of air conditioning. However, the spike in gas prices drove energy prices extremely high in February, with over 4 percent of intervals having prices over $250/MWh, and 1 percent of intervals with prices at or above $1,000/MWh.

Figure 1.18 shows the frequency of high prices in the 5-minute market. While there was a higher frequency of price spikes in the 5-minute market, the price spikes do not seem to be as extreme as they are in the 15-minute market, with less than 3 percent of intervals above $250/MWh in the 5-minute market and only 0.1 percent at or above $1,000/MWh

Figure 1.19 and Figure 1.20 show the corresponding frequency of under-supply infeasibilities in the 15-minute and 5-minute markets. Valid under-supply infeasibilities were very infrequent in both the 15-minute and 5-minute markets. There was only one valid interval of under-supply infeasibility in February in the 15-minute market and three intervals (one in January and two in March) in the 5-minute market.

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

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

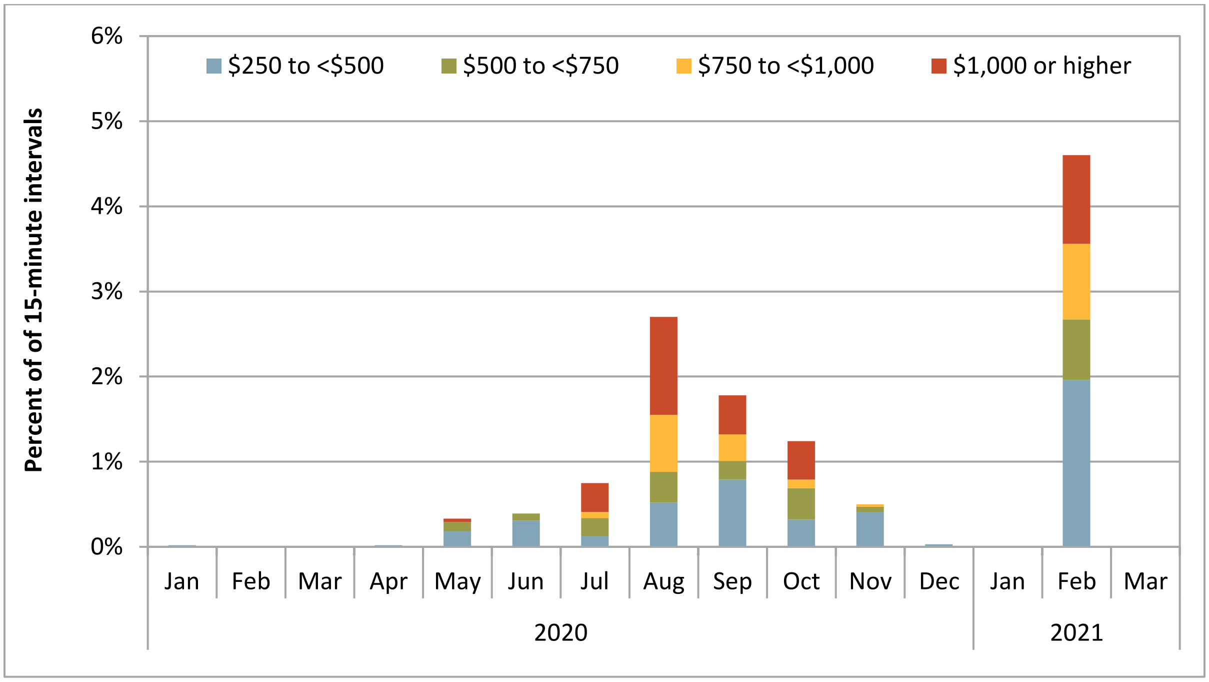


Figure 1.18 Frequency of high 5-minute prices by month (ISO LAP areas)

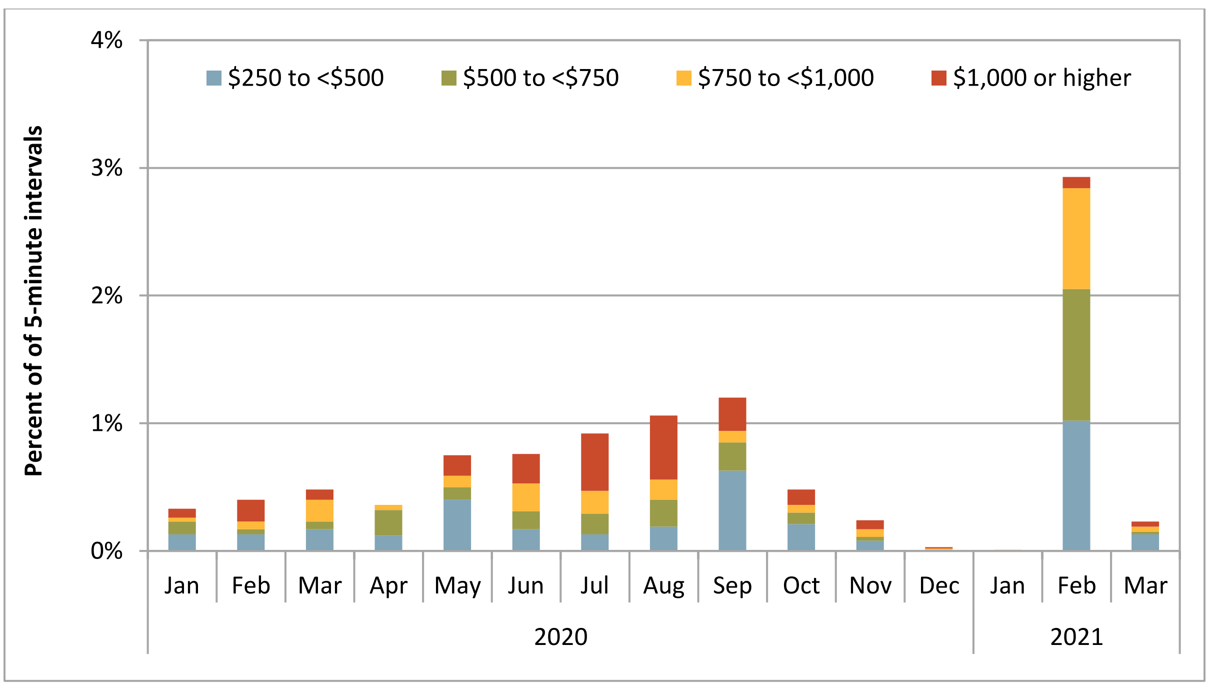


Figure 1.19 Frequency of under-supply power balance constraint infeasibilities (15-minute market)

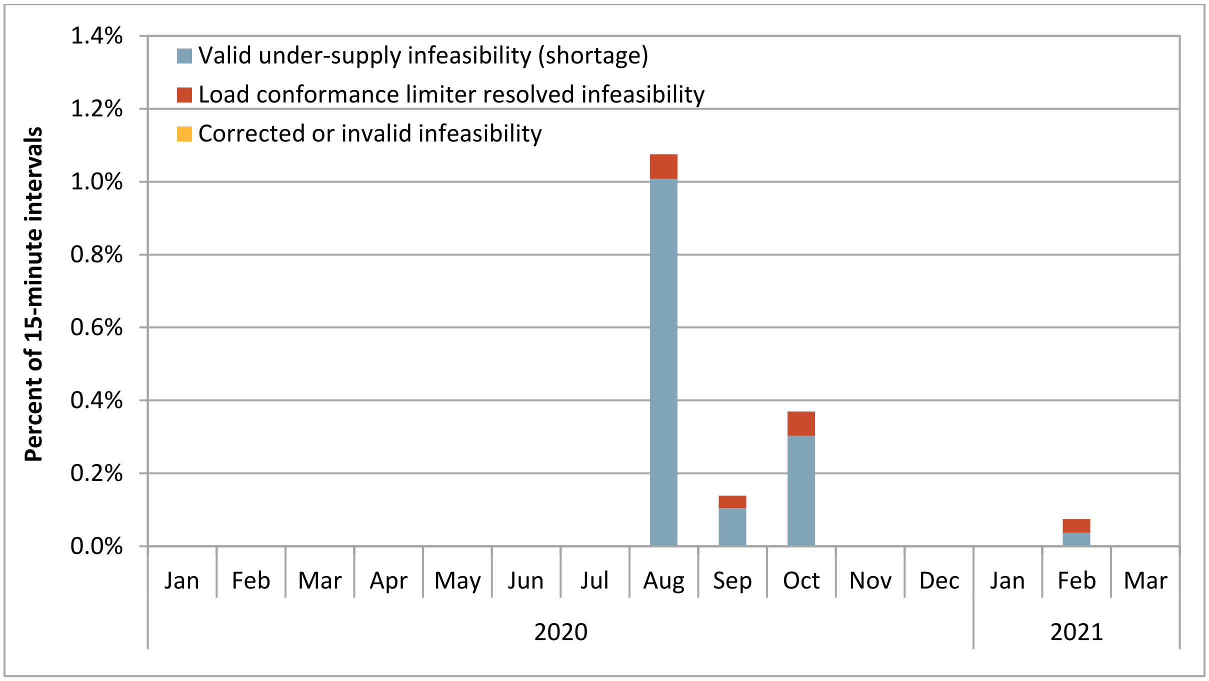
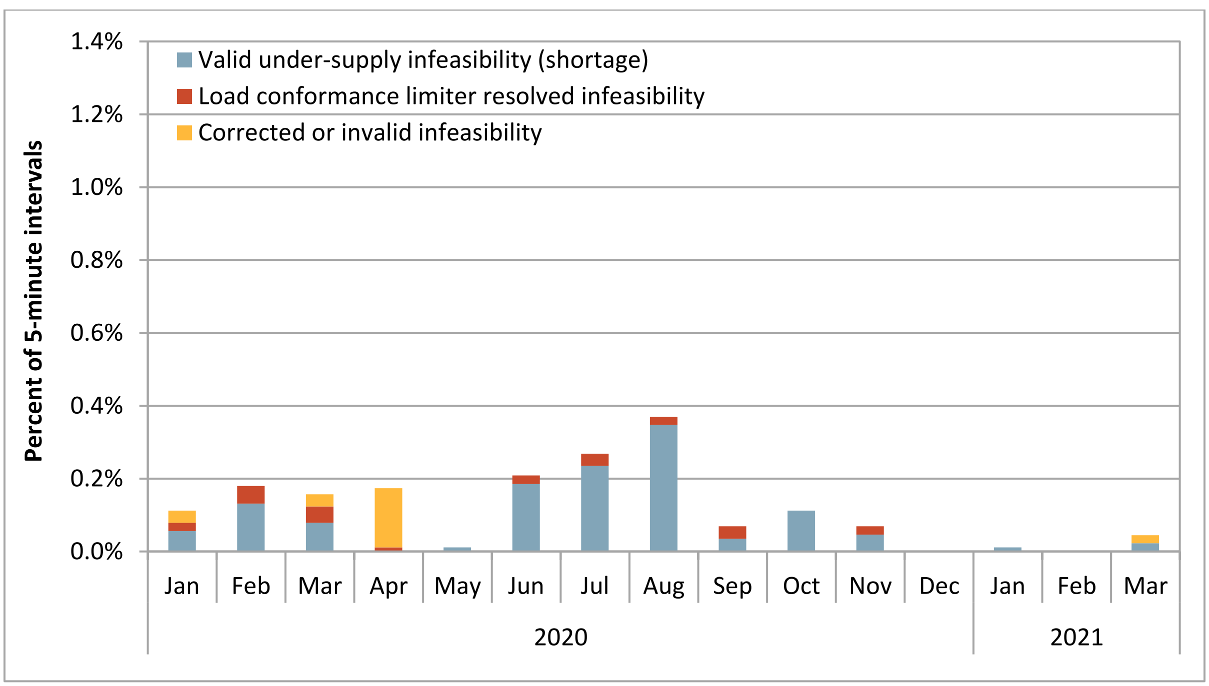


Figure 1.20 Frequency of under-supply power balance constraint infeasibilities (5-minute market)

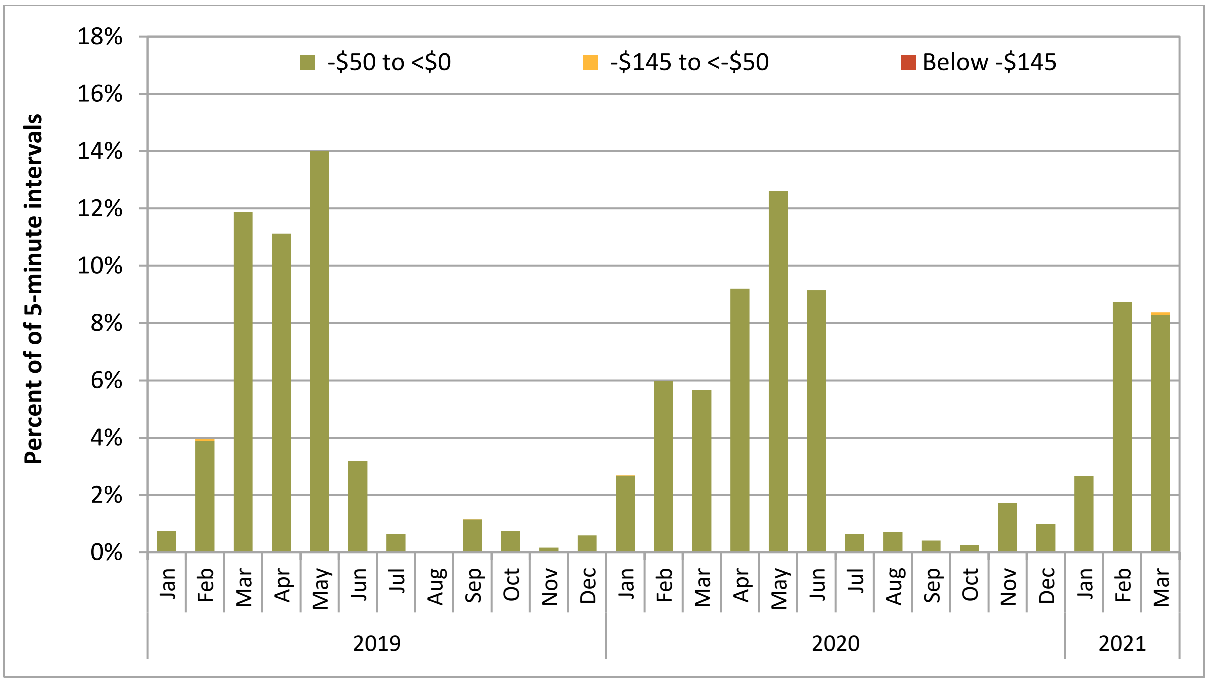


Negative prices

Figure 1.21 shows the frequency of negative prices in the 5-minute market by month across the three largest load aggregation points in the ISO.[20] The frequency of negative prices in the 15-minute and 5-minute markets were a bit higher than the first quarter of 2020. Negative prices occurred during about 4.5 percent of 15-minute market intervals and 6.6 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 10 and 17 when loads, net of wind and solar, were lowest.

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



1.5 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

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

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 enough ramping capacity is available to manage differences between the consecutive 5-minute market intervals.

1.5.1 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.[21] 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 early November 2020, if an individual balancing authority area requirement 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.[22] 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 1.22 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, 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 within 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 the minimum requirement should be included in the 5-minute market as an enhancement to improve the effectiveness of the flexible ramping product.

Figure 1.23 shows the frequency in which a minimum requirement was enforced for all other energy imbalance market areas.[23] Non-ISO areas, which exceed the 60 percent threshold in any interval, can

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[21] 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.

[22] 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

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

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 approximately 3 percent of intervals.

Figure 1.22 California ISO frequency of enforced minimum requirement (15-minute market)

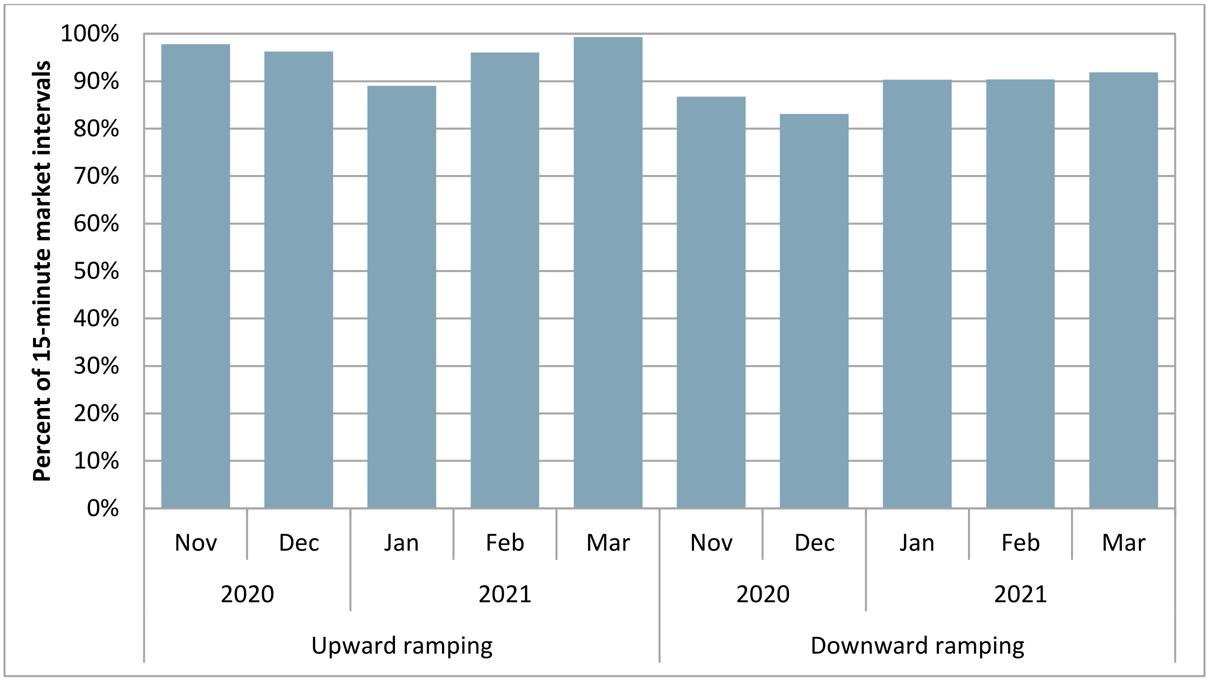
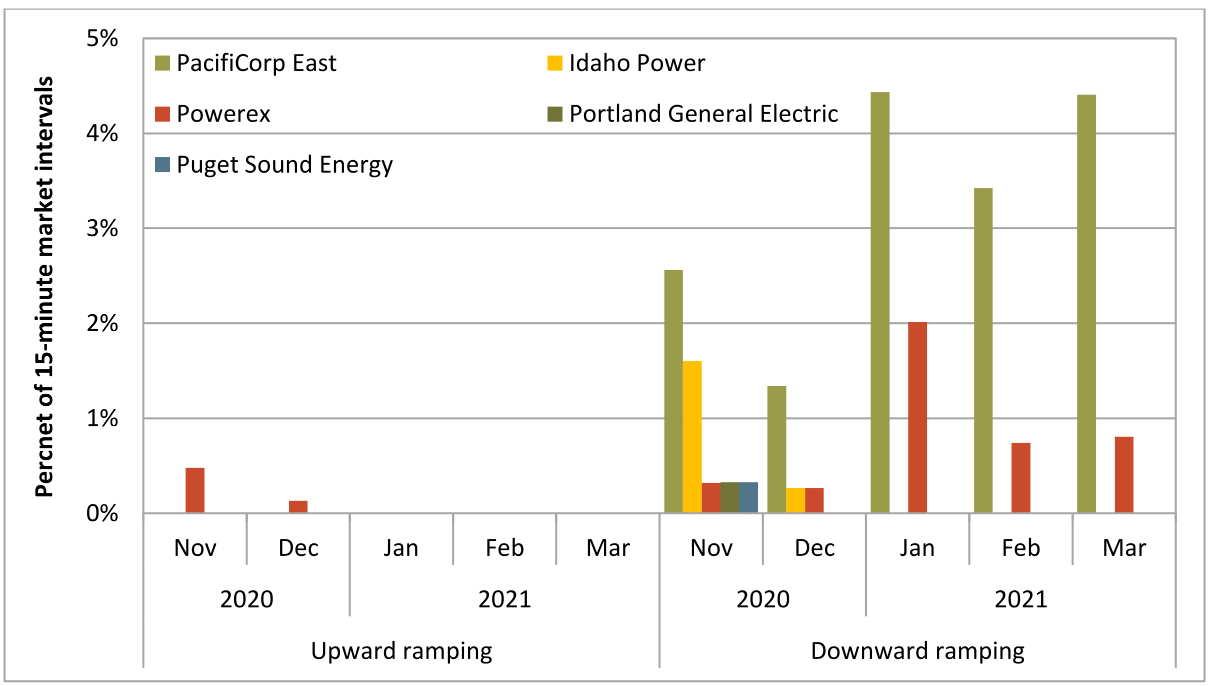


Figure 1.23 Energy imbalance market frequency of enforced minimum requirement (15-minute market)



1.5.2 Flexible ramping product prices

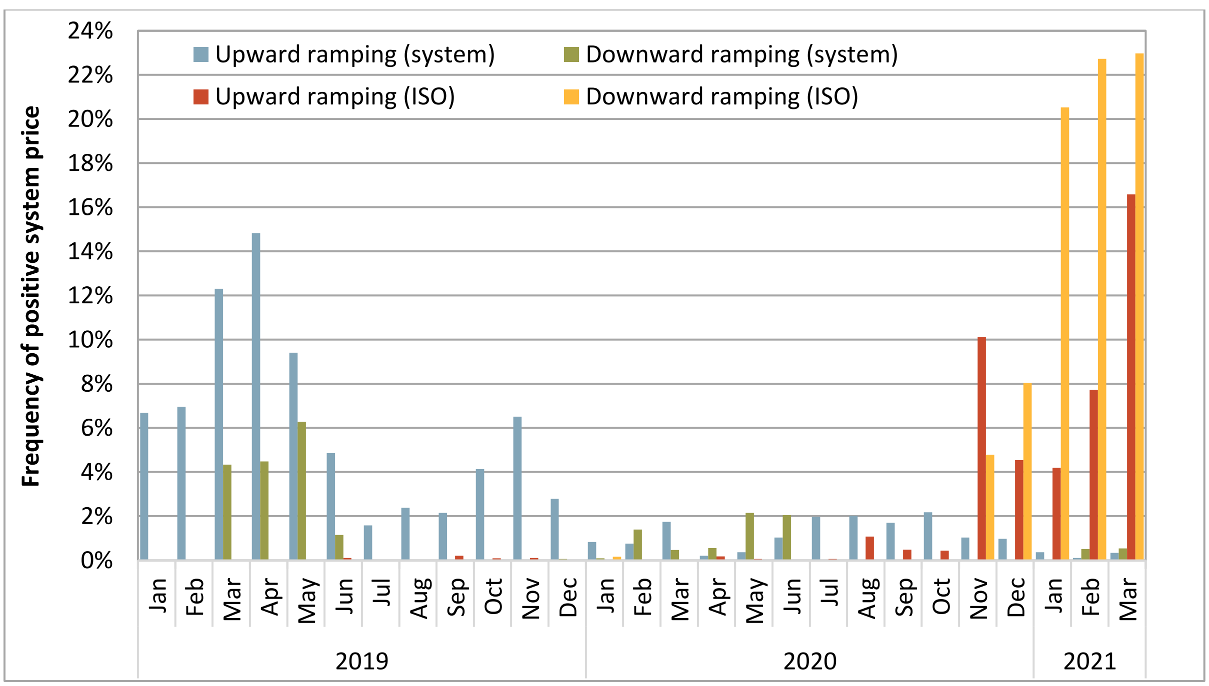
The flexible ramping product procurement and shadow prices are determined from demand curves. When the shadow price is $0/MWh, the full value of capacity on the demand curve is procured. This reflects that flexible ramping capacity was readily available relative to the need for it, such that there is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

Figure 1.24 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 less than 1 percent of intervals for upward ramping and downward ramping. However, the ISO-specific demand curve bound more frequently because of the implementation of the minimum requirement. During the first quarter, there was a positive shadow price for downward ISO flexible ramping capacity during approximately 22 percent of intervals. The frequency of a positive shadow price for upward flexible ramping capacity in the ISO increased in every month of the quarter, reaching almost 17 percent of intervals in March.

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



1.6 Convergence bidding

Convergence bidding was profitable overall for the first quarter of 2021. Combined net revenue for virtual supply and demand was about $8.2 million, after including about $1.5 million of virtual bidding bid cost recovery charges. Virtual demand generated revenues of about $1.9 million for the quarter, while virtual supply generated less at about $7.2 million, before accounting for bid cost recovery charges.

1.6.1 Convergence bidding trends

Average hourly cleared volumes were about 3,400 MW, a slight increase of 300 MW from the same quarter of 2020. Average hourly cleared virtual supply remained about the same from the fourth quarter of 2020, about 2,100 MW. Cleared virtual demand averaged 200 MW higher than from the same quarter of the previous year at about 1,300 MW during each hour of the quarter, which was also about the same as the fourth quarter of 2020. On average, about 41 percent of virtual supply and demand bids offered into the market cleared in the quarter, which was up from 24 percent in the first quarter of 2020.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 740 MW on average, an increase from 720 MW of net virtual supply in the same quarter of 2020. On average, in all hours except hour-end 17, net cleared virtual supply exceeded net cleared virtual demand. Cleared virtual supply exceeded virtual demand by over 450 MW during all hours except hours ending 17 through 20.

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, convergence bidding volumes were consistent with average price differences between the day-ahead and real-time markets during 23 of 24 hours. Hour ending 5 was the only hour where volumes were inconsistent with price differences.

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 supply and demand bids at different locations during the same hour. These virtual supply and demand 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 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 910 MW of virtual demand, offset by 910 MW of virtual supply, in each hour of the quarter. This represented an increase of about 150 MW over the first quarter of 2020. These offsetting bids represented about 54 percent of all cleared virtual bids in this quarter, an increase of about 6 percent from the same quarter of 2020.

1.6.2 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 $9.7 million. Net revenues for virtual supply and demand fell to about $8.24 million after the inclusion of about $1.5 million of virtual bidding bid cost recovery charges,[24] primarily associated with virtual supply.

Figure 1.25 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 $9.7 million, compared to about $4.8 million during the same quarter from the previous year, and about $16.7 million during the previous quarter.
- Virtual demand net revenues were negative $1.7 million, $4.3 million, and negative $0.6 million for January, February and March, respectively.
- Virtual supply net revenues were $2.5 million, $2 million, and $3 million for January, February and March, respectively.

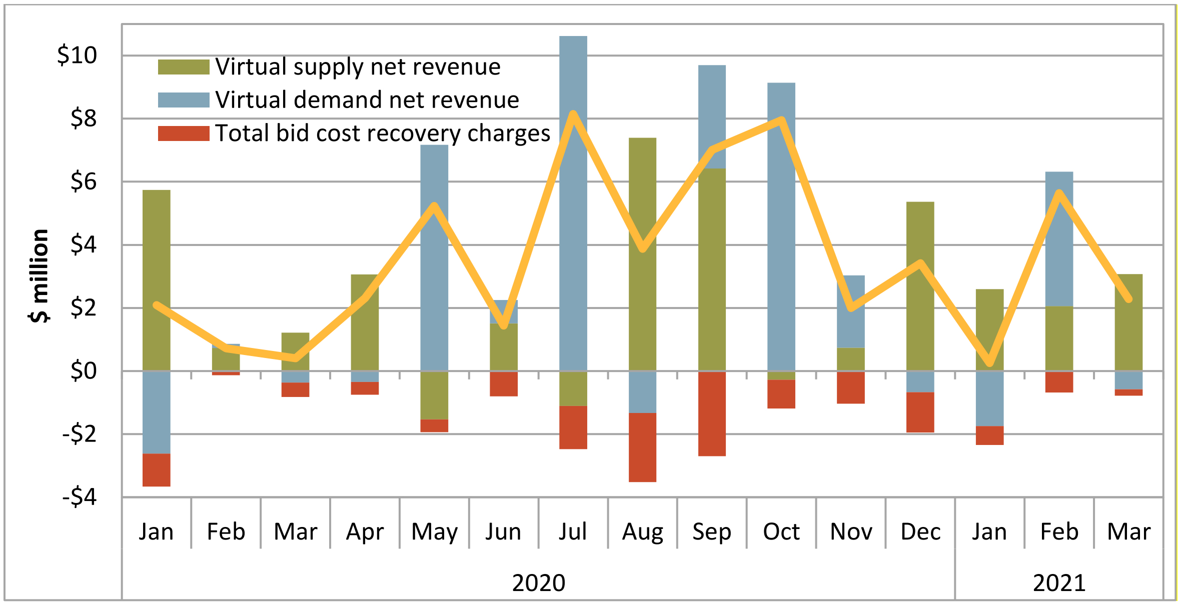
Convergence bidders received approximately $8.2 million after subtracting bid cost recovery charges of about $1.5 million for the quarter. [25,26] Bid cost recovery charges were about $0.6 million, $0.7 million and $0.2 million for January, February and March, respectively.

24 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.

25 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.

26 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.

Figure 1.25 Convergence bidding revenues and bid cost recovery charges



Net revenues and volumes by participant type

Table 1.1 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.[27] As with the previous quarter, financial entities represented the largest segment of the virtual bidding market, accounting for about 73 percent of volume and 85 percent of settlement revenue, an increase in from about 73 percent from the same quarter of 2020. Marketers represented about 24 percent of the trading volumes and about 32 percent of settlement revenue, a revenue decrease from about 28 percent from the same quarter in 2020. 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 4 percent and 2 percent respectively. Generation owners and load serving entities accounted for a total negative revenue of $0.08 million in the market.

[27] DMM has defined financial entities as participants who do not own 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.

Table 1.1 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	953	1,493	2,446	$1.59	$7.06	$8.66
Marketer	338	487	825	$0.35	$0.75	$1.10
Physical load	0	27	27	$0.00	-$0.24	-$0.25
Physical generation	12	40	52	$0.00	$0.16	$0.16
Total	**1,303**	**2,047**	**3,350**	**$1.94**	**$7.73**	**$9.67**

1.7 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 1.26, residual unit commitment capacity is procured primarily 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 5 percent higher in the first quarter of 2021 than in the same quarter of 2020.

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 decreasing residual unit commitment requirements in the first quarter of 2021 averaging about -284 MWh.

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 1.26.

Figure 1.26 Determinants of residual unit commitment procurement

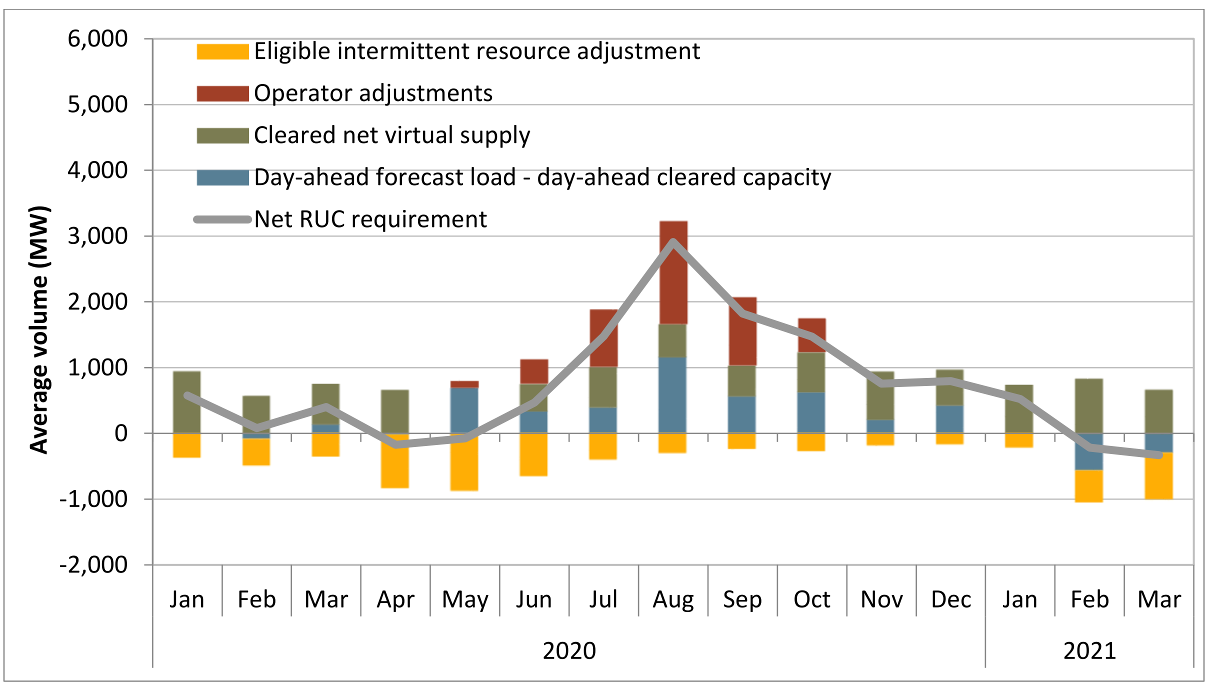
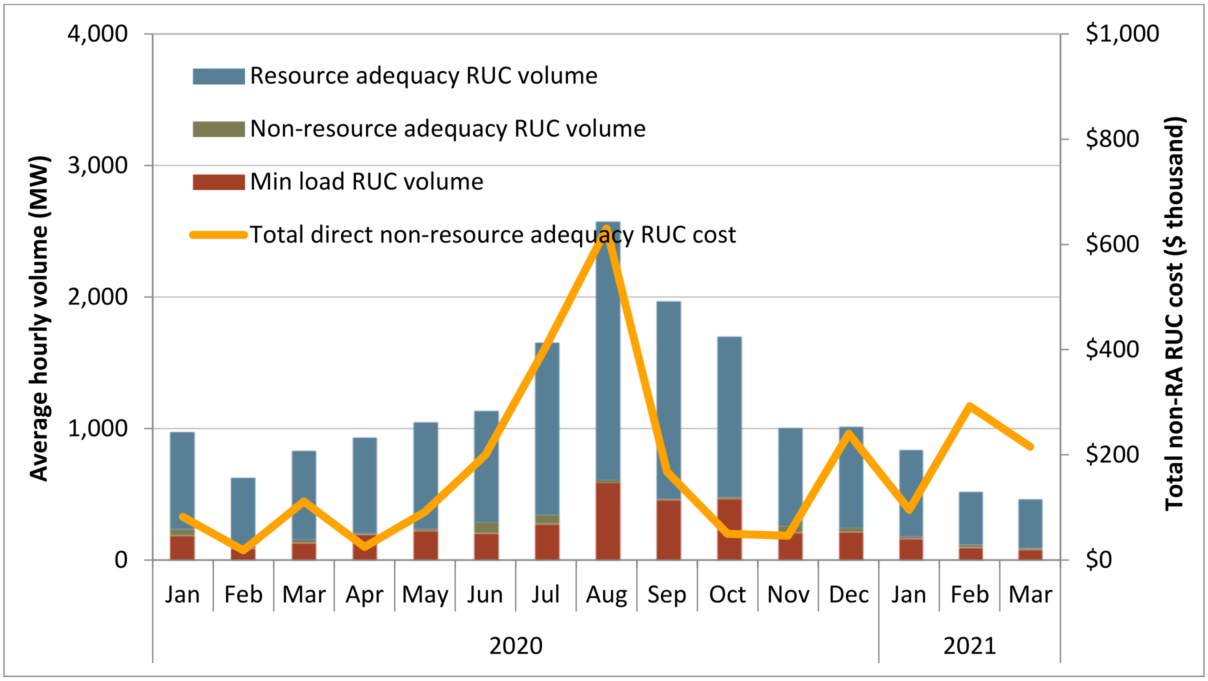


Figure 1.27 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement decreased to about 605 MWh in the first quarter of 2021 from an average of 810 MWh in the same quarter of 2020. Of the 605 MWh capacity, the capacity committed to operate at minimum load averaged 113 MWh compared to 136 MWh in the first quarter of 2020.

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.[28] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.27. In the first quarter of 2021, these costs increased to $0.6 million compared to about $0.2 million in the same quarter of 2020.

Figure 1.27 Residual unit commitment costs and volume



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

1.8 Ancillary services

Ancillary service payments decreased during the quarter to about $44 million, compared to about $49 million in the previous quarter and $30 million during the same quarter in 2020. Higher payments from the previous year were driven, in part, by higher requirements for regulation.

1.8.1 Ancillary service requirements

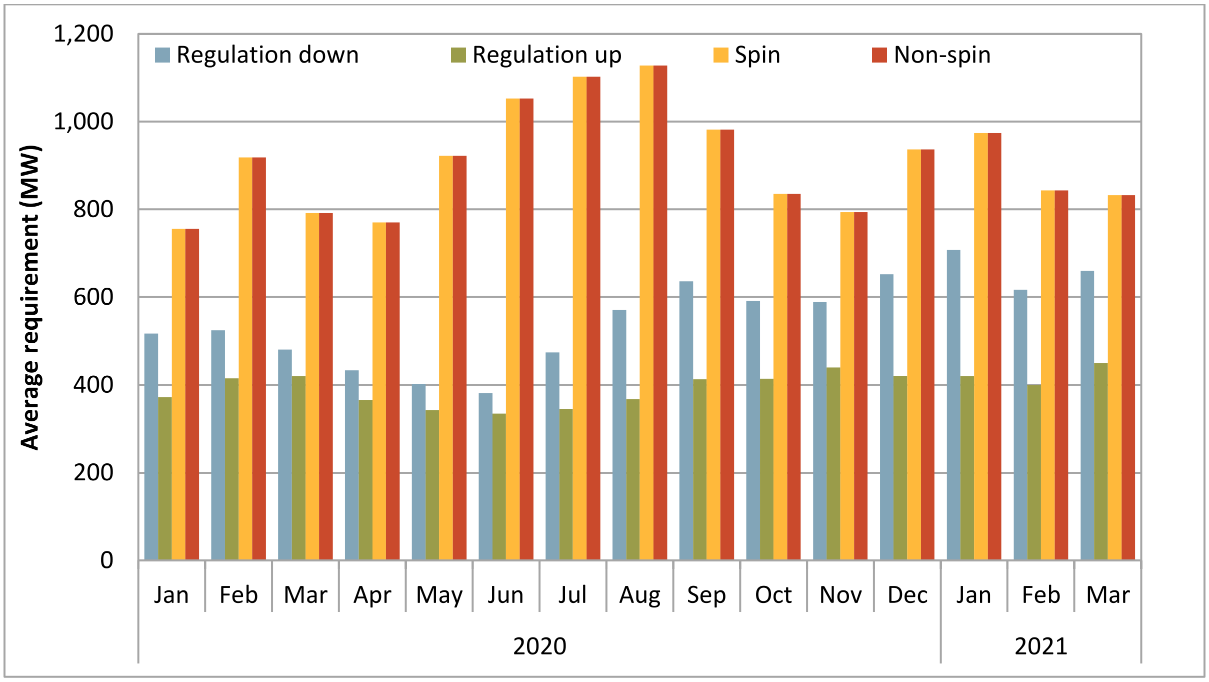
The ISO procures four ancillary services in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (WECC) 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 also 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. Then, both internal resources and imports 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 1.28 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. As shown, average requirements for regulation down increased from the previous quarter.

Figure 1.28 Average monthly day-ahead ancillary service requirements



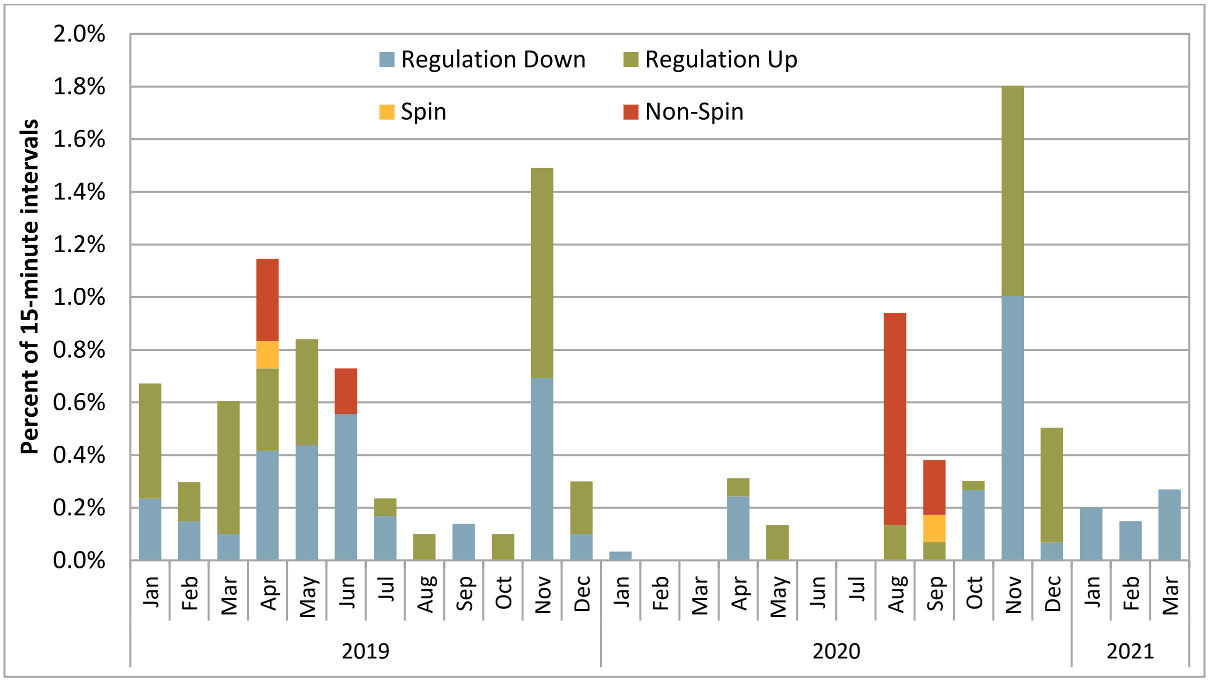
1.8.2 Ancillary service scarcity

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 1.29, the frequency of intervals with scarcity pricing decreased during the quarter. During the quarter, all of the scarcity intervals were for regulation down.

During February and March, each of the scarcity intervals were for a 0.11 MW shortage of regulation down in the expanded North of Path 26 region. This was because of an issue with the requirement setting tool, which caused a marginally higher regulation requirement in real-time than in day-ahead for the expanded North and South of Path 26 regions. In some cases, it was economic to relax the real-time requirement at the scarcity price in lieu of committing or moving a unit to a higher bid segment in order to meet this difference.

Figure 1.29 Frequency of ancillary service scarcities (15-minute market)

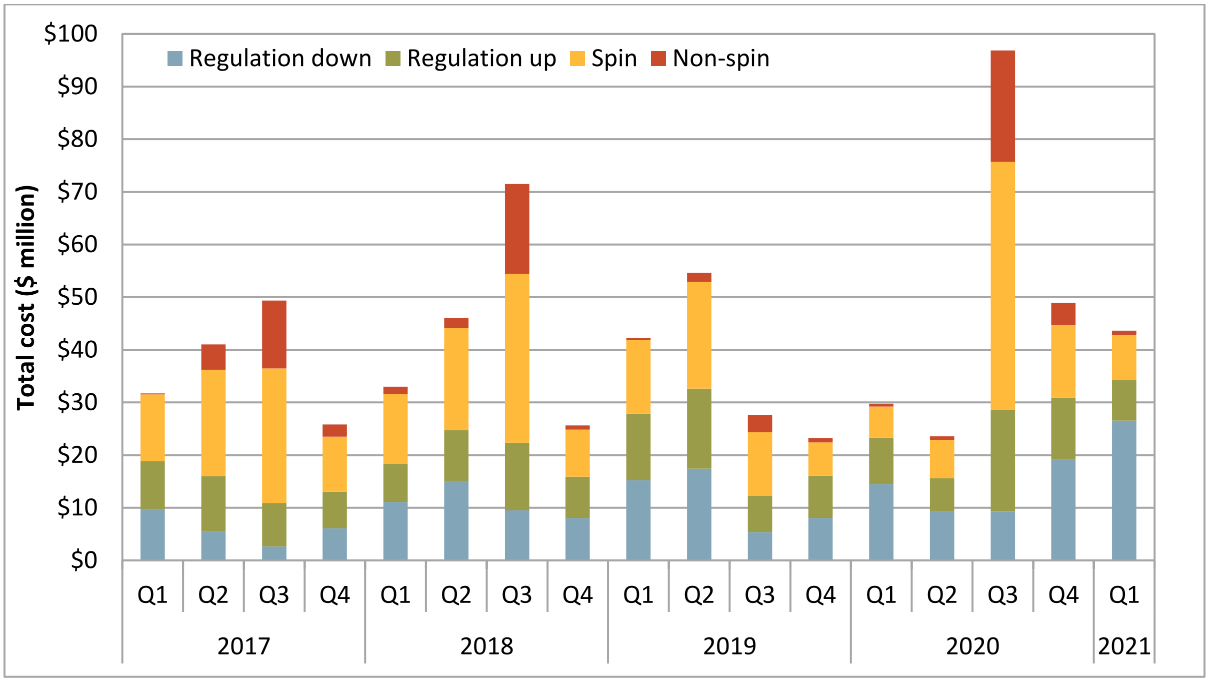


1.8.3 Ancillary service costs

Ancillary service payments decreased slightly during the quarter to about $44 million, compared to about $49 million in the previous quarter and $30 million during the same quarter in 2020. Higher payments from the previous year were driven in part from higher regulation requirements.

Figure 1.30 shows the total cost of procuring ancillary service products by quarter. 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 1.30 Ancillary service cost by product



1.9 Congestion

In the day-ahead market, congestion in the first quarter decreased prices in the PG&E area and increased prices in the SCE and SDG&E areas. In the 15-minute market, the impact of congestion on internal constraints increased significantly in most areas relative to the same quarter of 2020. Gas supply shortages during the quarter were a key reason for the increase.

The following sections provide an assessment of the frequency and impact of congestion on prices in the day-ahead and 15-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.[29]

[29] 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.

1.9.1 Congestion in the day-ahead market

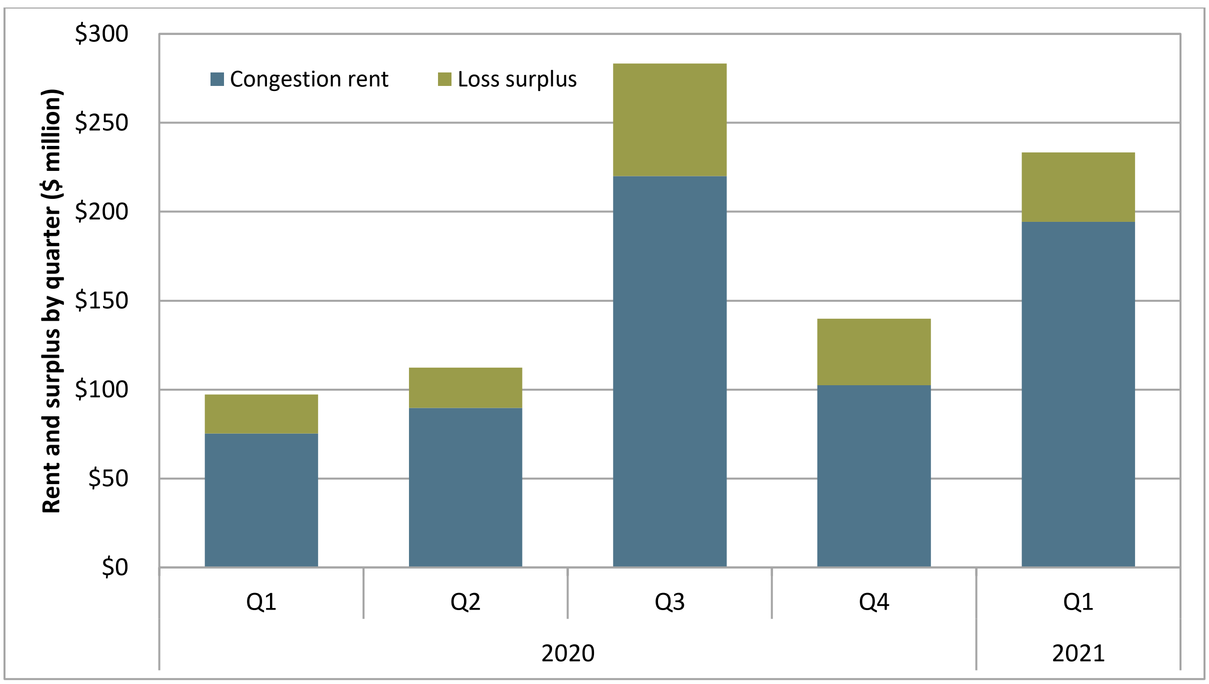
Day-ahead market congestion frequency tends to be higher than in the 15-minute market but price impacts to load tend to be lower. The congestion pattern in this quarter reflects this overall trend.

Congestion rent and loss surplus

In the first quarter of 2021, congestion rent and loss surplus reached $194 million and $39 million, respectively. These respective amounts represent a 158 percent and 77 percent increase relative to the same quarter of 2020. Figure 1.31 shows the congestion rent and loss surplus by quarter for 2020 and 2021.

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.[30]

Figure 1.31 Day-ahead congestion rent and loss surplus by quarter (2020-2021)



[30] 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 1.32 shows the overall impact of congestion on day-ahead prices in each load area in 2020 and 2021. Figure 1.33 shows the frequency of congestion. Highlights for this quarter include:

- In the first quarter of 2021, the overall net impact of congestion on price separation increased in PG&E, SCE, and SDG&E relative to the same quarter of 2020. The frequency of congestion decreased in all three areas, compared to the same quarter in 2020.
- Congestion decreased quarterly average prices in PG&E by $0.46/MWh (1.1 percent), while it increased prices in SCE and SDG&E by $0.43/MWh (1.0 percent) and $1.00/MWh (2.3 percent), respectively.
- The congestion impact was less frequently offsetting in all areas, compared to the same quarter of 2020. 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 Path 26 Control Point 1 nomogram, the Imperial Valley nomogram, and the Path 26 Control Point 7 nomogram.

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

Figure 1.32 Overall impact of congestion on price separation in the day-ahead market

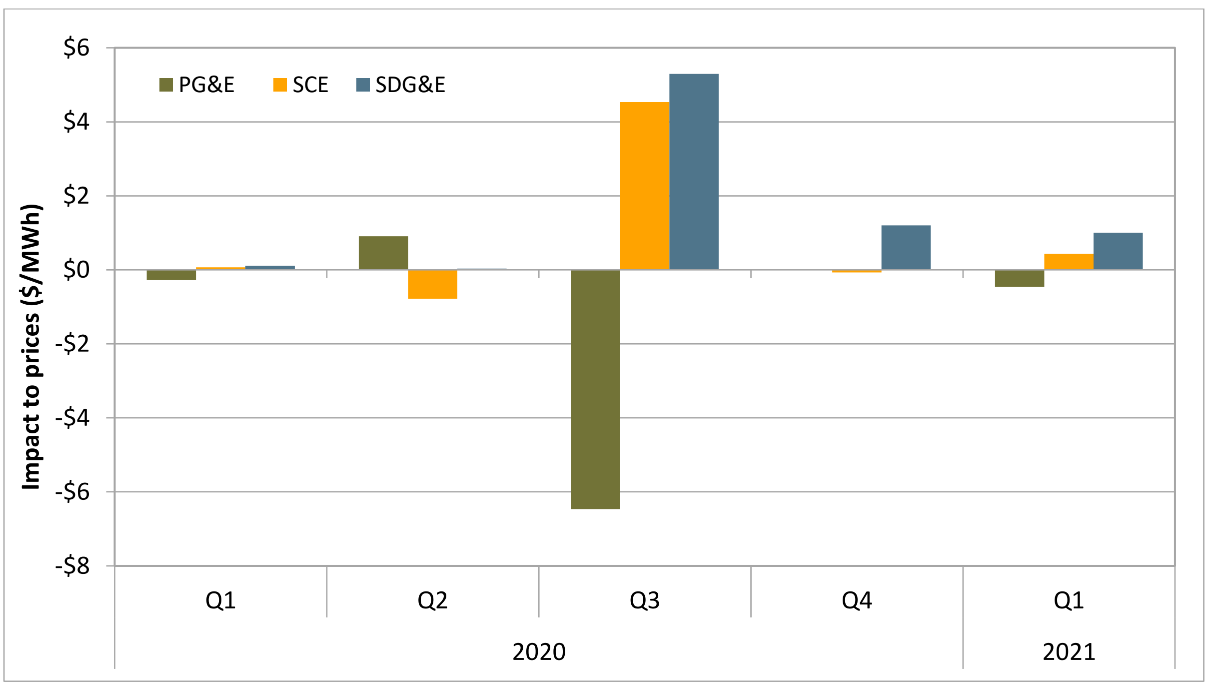


Figure 1.33 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)

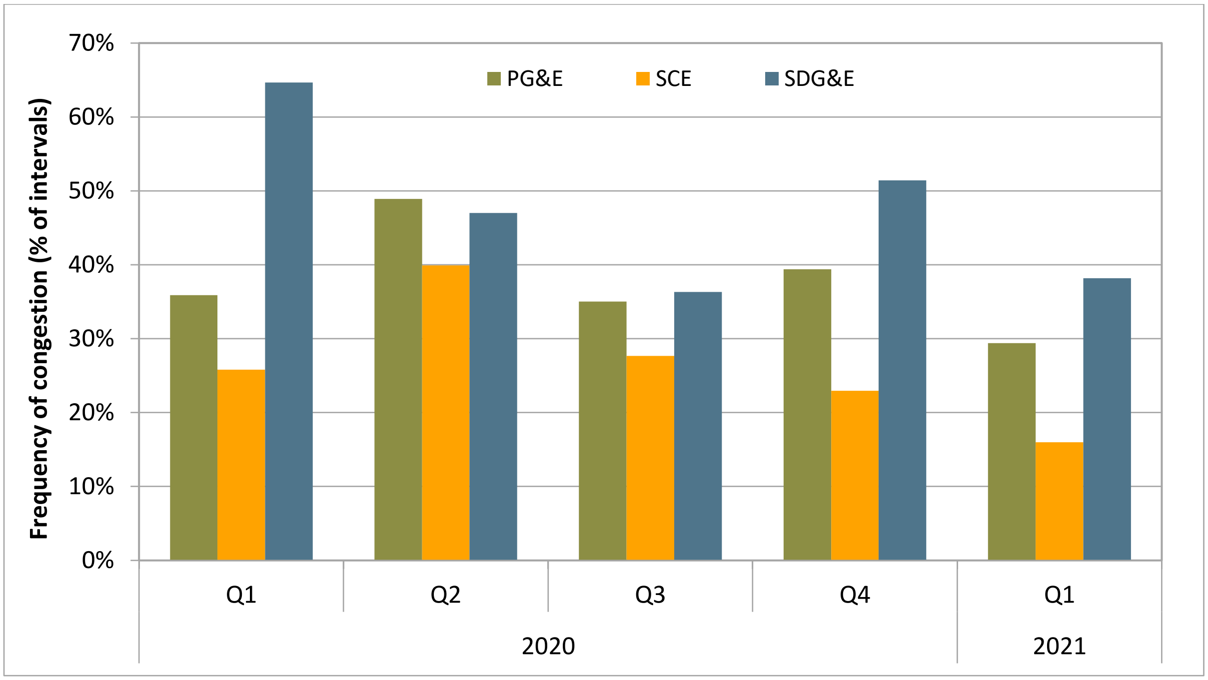
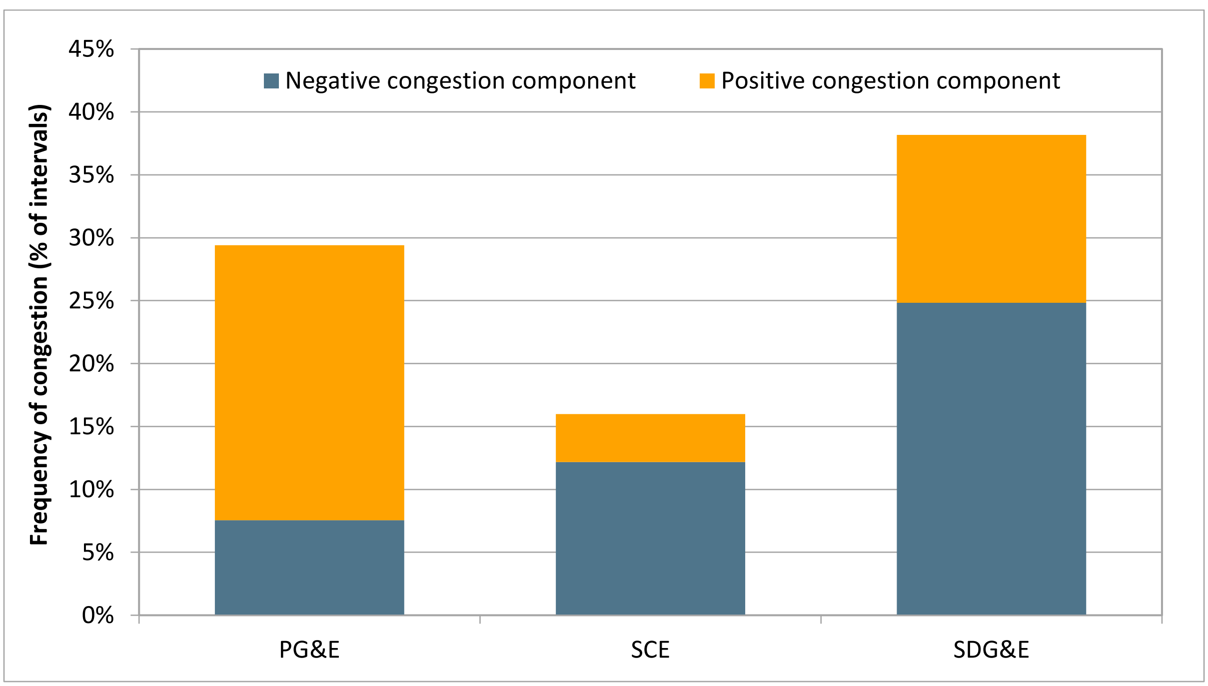


Figure 1.34 Percent of hours with congestion increasing versus decreasing day-ahead prices in the first quarter (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.2 breaks down the congestion impact on price separation in the first quarter by constraint.[31] Table 1.3 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 Path 26 Control Point 1 nomogram, the Imperial Valley nomogram, and the Path 26 Control Point 7 nomogram.

Path 26 Control Point 1 nomogram

The Path 26 Control Point 1 nomogram (6410_CP1_NG) had the greatest impact on day-ahead prices during the first quarter on average. It was not the most frequently binding constraint in the quarter, binding in a little under 1 percent of hours. However, when binding, it decreased PG&E prices by about $78.15/MWh and increased SCE and SDG&E prices by $70.27/MWh and $69.29/MWh, respectively. Over the entire quarter, it decreased average PG&E prices by about $0.72/MWh (1.7 percent) and increased average SCE and SDG&E prices by $0.65/MWh (1.5 percent) and $0.64/MWh (1.5 percent), respectively.

Imperial Valley nomogram

The Imperial Valley nomogram (7820_TL230S_OVERLOAD_NG) had a marginal impact on prices in PG&E and SCE, but a significant impact in SDG&E on average for the quarter. Overall for the quarter, the nomogram decreased average prices in PG&E by about $0.04/MWh (0.1 percent), while it increased prices in SDG&E by $0.45/MWh (1.0 percent). In the 2017-2018 transmission planning cycle, an upgrade to the Imperial Valley-El Centro 230 kV S-line was approved, which will help to alleviate congestion in this area. The project is expected to begin construction in Summer 2021, with an in-service date of 2022.

Path 26 Control Point 7 nomogram

The Path 26 Control Point 7 nomogram (6410_CP7_NG) was binding during about 3.4 percent of hours during the quarter. When binding, the nomogram increased PG&E prices by about $2.96/MWh, while it decreased prices in SCE and SDG&E by about $2.62/MWh and $2.44/MWh, respectively. Overall for the quarter, it increased average PG&E prices by about $0.10/MWh (0.2 percent), and decreased average prices in SCE and SDG&E by $0.09/MWh (0.2 percent) and $0.08/MWh (0.2 percent), respectively.

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

Table 1.2 Impact of congestion on overall day-ahead prices

Constraint Location	Constraint	PG&E		SCE		SDG&E	
		$ per MWh	Percent	$ per MWh	Percent	$ per MWh	Percent
PG&E	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	$0.03	0.06%	-$0.02	-0.06%	-$0.02	-0.05%
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	$0.01	0.03%	$0.00	0.00%	$0.00	0.00%
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	$0.01	0.03%	-$0.01	-0.03%	-$0.01	-0.03%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.01	0.03%	-$0.01	-0.02%	$0.00	-0.01%
	RM_TM21_NG	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.03%
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	$0.01	0.01%	-$0.01	-0.01%	-$0.01	-0.01%
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	$0.01	0.01%	$0.00	-0.01%	$0.00	-0.01%
SCE	6410_CP1_NG	-$0.72	-1.69%	$0.65	1.52%	$0.64	1.46%
	OMS 8797800_D-VST1_OOS_CP3	$0.01	0.02%	$0.00	0.00%	-$0.06	-0.13%
	6410_CP10_NG	$0.06	0.13%	-$0.05	-0.12%	-$0.05	-0.11%
	6410_CP7_NG	$0.10	0.23%	-$0.09	-0.21%	-$0.08	-0.19%
	7820_TL 230S_OVERLOAD_NG	-$0.04	-0.09%	$0.00	0.00%	$0.45	1.03%
SDG&E	MIGUEL_BKs_MXFLW_NG	-$0.01	-0.02%	$0.00	0.00%	$0.19	0.44%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _S	-$0.01	-0.02%	$0.00	0.00%	$0.05	0.12%
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	22740_SANYSDRO_69.0_22608_OTAY TP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.01	0.02%
	OMS 8797559_EC-SB_OOS_CP3	$0.02	0.04%	$0.00	-0.01%	$0.00	-0.01%
	OMS 8797659_SB-VSTA_OOS_CP6	$0.01	0.03%	-$0.01	-0.02%	-$0.02	-0.05%
	OMS 9076082 ELD-MHV_NG	$0.00	0.00%	$0.00	0.00%	-$0.03	-0.07%
	OMS 8797939_D-SBLR_OOS_CP3	$0.02	0.05%	$0.00	0.00%	-$0.07	-0.17%
Other		$0.02	0.04%	$0.00	0.00%	$0.02	0.05%
Total		**-$0.46**	**-1.07%**	**$0.43**	**1.01%**	**$1.00**	**2.28%**

Table 1.3 Impact of congestion on day-ahead prices during congested hours[32]

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	0.2%	$5.65	-$5.05	-$4.66
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	0.2%	$3.34	-$2.69	-$2.51
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	0.2%	$2.77	-$2.33	-$2.14
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	1.0%	$2.70	-$2.33	-$2.18
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	0.4%	$2.47	-$1.95	-$1.79
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	0.7%	$1.91	$0.00	$0.00
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	1.6%	$0.84	-$0.68	-$0.67
	RM_TM21_NG	2.3%	$0.46	-$0.35	-$0.51
SCE	6410_CP1_NG	0.9%	-$78.15	$70.27	$69.29
	OMS 8797800_D-VST1_OOS_CP3	4.4%	$0.45	-$0.13	-$1.30
	6410_CP7_NG	3.4%	$2.96	-$2.62	-$2.44
	6410_CP10_NG	1.2%	$4.58	-$4.12	-$3.84
	OMS 9076082 ELD-MHV_NG	5.1%	$0.19	$0.00	-$0.63
SDG&E	MIGUEL_BKs_MXFLW_NG	1.1%	-$1.45	$0.00	$17.28
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _S	0.6%	-$1.38	$0.00	$9.12
	7820_TL 230S_OVERLOAD_NG	7.3%	-$0.55	$0.00	$6.18
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	0.2%	-$0.77	$0.00	$5.55
	22740_SANYSDRO_69.0_22608_OTAY TP_69.0_BR_1 _1	0.5%	$0.00	$0.00	$1.95
	OMS 8797659_SB-VSTA_OOS_CP6	3.7%	$0.32	-$0.29	-$0.57
	OMS 8797559_EC-SB_OOS_CP3	2.9%	$0.52	-$0.40	-$0.63
	OMS 8797939_D-SBLR_OOS_CP3	6.4%	$0.55	-$0.50	-$1.16

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

1.9.2 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 1.35 shows the overall impact of internal flow-based constraint congestion on 15-minute prices in each load area for 2020 and 2021. Figure 1.36 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 first quarter of 2021 increased in most areas compared to the same quarter of 2020. Congestion resulted in a net increase to SCE, SDG&E, NEVP, AZPS, and SRP prices, while it resulted in 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 Path 26 Control Point 1 nomogram, the Imperial Valley nomogram, and the Midway-Vincent #2 500 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 1.35 Overall impact of internal congestion on price separation in the 15-minute market

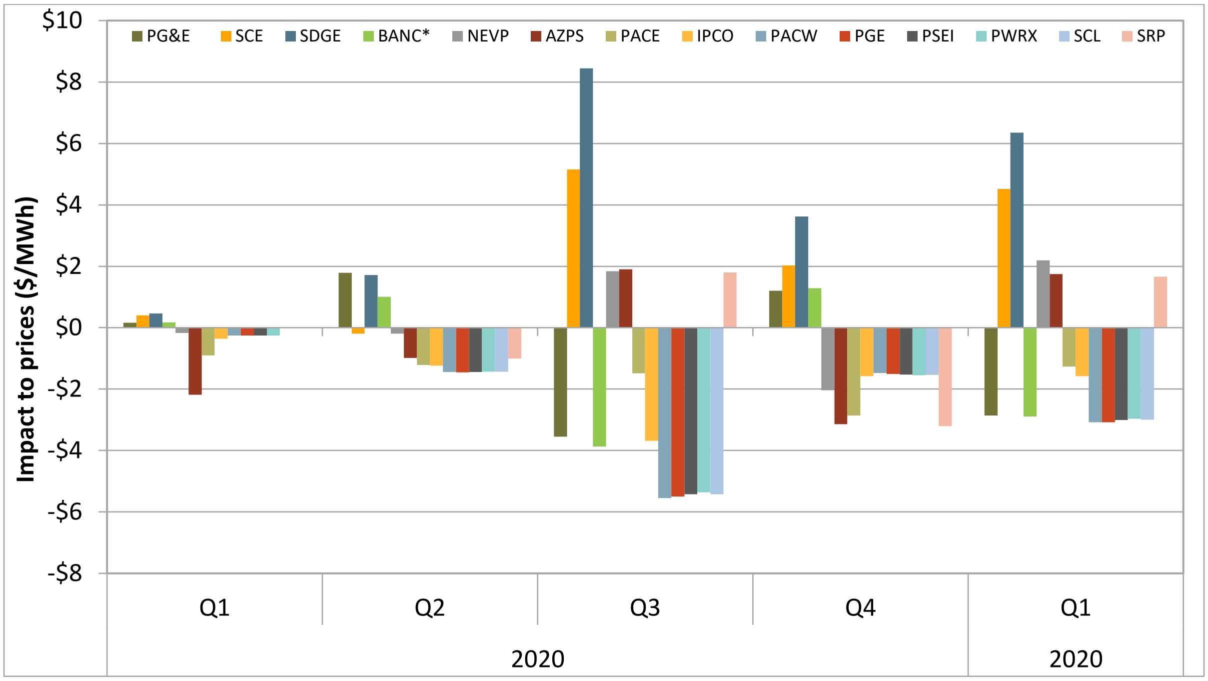
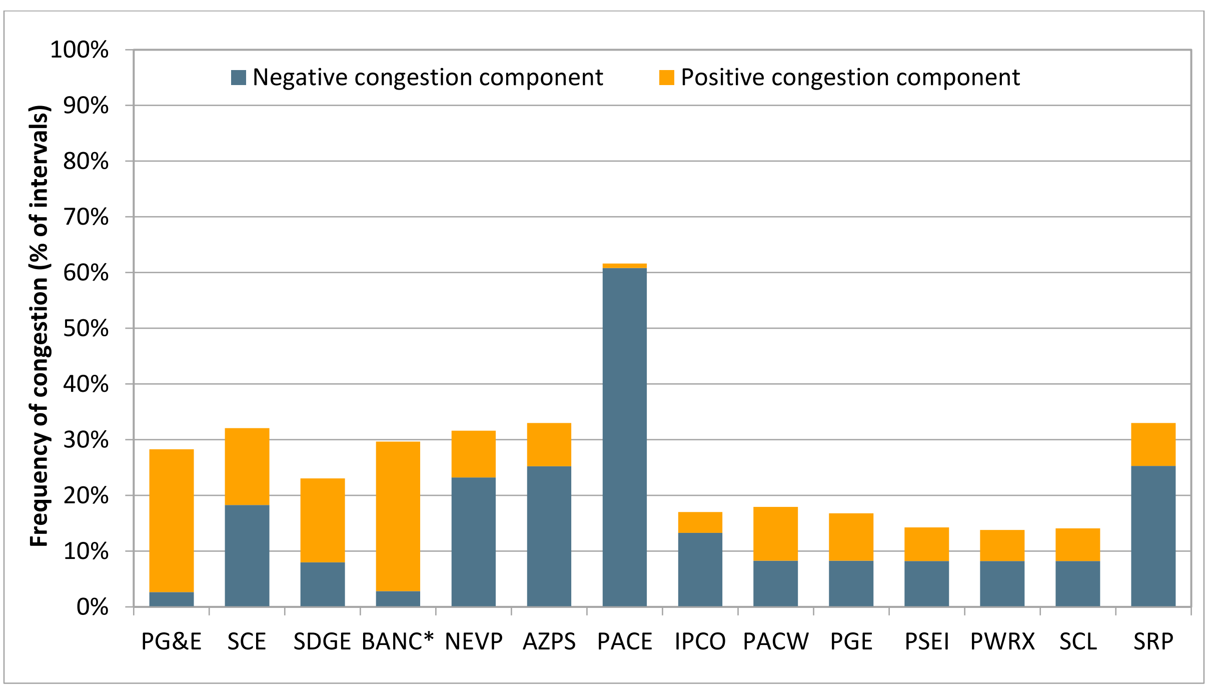


Figure 1.36 Percent of intervals with internal congestion increasing versus decreasing 15-minute prices in the first quarter (>$0.05/MWh)



*Data for BANC covers January 1, 2021 – March 24, 2021

Impact of internal congestion from individual constraints

Table 1.4 shows the overall impact (during all intervals) of internal congestion on average 15-minute prices in each load area. Table 1.5 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 1.4. 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 Path 26 Control Point 1 nomogram, the Imperial Valley nomogram, and the Midway-Vincent #2 500 kV line.

Path 26 Control Point 1 nomogram

The Path 26 Control Point 1 nomogram (6410_CP1_NG) bound frequently in the quarter during about 6 percent of intervals. When binding, it heavily affected prices across the EIM, increasing prices in SCE, SDG&E, NEVP, AZPS, SRP, and PACE by about $190.08/MWh on average, and decreasing prices elsewhere in the ISO and EIM by $155.63/MWh on average. Overall for the quarter, the constraint increased prices in the former areas by about $3.08/MWh and decreased prices in the latter areas by $2.56/MWh.

Imperial Valley nomogram

The Imperial Valley nomogram (7820_TL230S_OVERLOAD_NG) bound infrequently over the quarter, during about 2 percent of intervals. When binding, it increased prices in SCE and SDG&E by about $18.75/MWh on average, and decreased prices in NEVP, AZPS, SRP, PACE, and IPCO by $4.77/MWh on average. Overall for the quarter, the constraint increased the former areas' prices by $1.06/MWh on average and decreased prices in the latter areas by $0.27/MWh on average.

Midway-Vincent #2 500 kV line

The Midway-Vincent #2 500 kV line (30060_MIDWAY_500_24156_VINCENT_500_BR_2_3) bound very frequently during the quarter, in about 33 percent of intervals. When binding, it increased prices in SCE, SDG&E, NEVP, AZPS, SRP, and PACE by an average of $20.25/MWh, and decreased prices elsewhere in the ISO and EIM by $15.97/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 $0.17/MWh on average. This line was heavily affected by low gas supply in Southern California which resulted in high north-to-south flows over the line.

Table 1.4 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
BANC	NCY_STB1				-$0.05										
PACE	EAST_WYO_EXP								-$0.05						
	WINDSTAR EXPORT TCOR								-$0.06						
	TOTAL_WYOMING_EXPORT								-$0.74						
PG&E	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.03	-$0.05	-$0.05	$0.03	-$0.02	-$0.04	-$0.04	-$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	$0.03	-$0.04	-$0.03	$0.03	-$0.02	-$0.03	-$0.03	-$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	$0.01	-$0.02	-$0.02	$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	$0.01	-$0.01	-$0.01	$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	$0.01	-$0.01	-$0.01	$0.01	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	$0.01	-$0.01	-$0.01	$0.01	$0.00	-$0.01	-$0.01			$0.00	$0.00	$0.00	$0.00	$0.00
	30005_ROUND MT_500_30015_TABLE MT_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	$0.00
	30105_COTTNWD _230_30245_ROUND MT_230_BR_2 _1	$0.00	$0.00		$0.00					$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$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	-$0.03	$0.04	$0.04	-$0.03	$0.02	$0.03	$0.03	$0.01	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.26	$0.30	$0.29	-$0.24	$0.16	$0.26	$0.26	$0.04	-$0.07	-$0.17	-$0.17	-$0.16	-$0.16	-$0.16
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1				-$0.02	$0.35									
SCE	6410_CP1_NG	-$3.79	$4.25	$4.23	-$3.57	$2.34	$3.75	$3.73	$0.19	-$1.00	-$2.50	-$2.48	-$2.39	-$2.34	-$2.38
	7750_D-SBLR_OOS_N1SV500_NG	$0.00	$0.00		$0.00	$0.00	-$0.02	-$0.02	$0.00						
	OMS 8797822_D-VST1_OOS_CP6	$0.01	-$0.01	-$0.01	$0.01	-$0.01	-$0.04	-$0.04	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 8797800_D-VST1_OOS_CP3	$0.02	-$0.01	$0.00	$0.01	-$0.01	-$0.11	-$0.11	-$0.01		$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 8797800_D-VST1_OOS_CP6	$0.02	-$0.01	$0.00	$0.01	-$0.01	-$0.06	-$0.06	-$0.01		$0.00	$0.00	$0.00		
	6410_CP10_NG	$0.02	-$0.02	-$0.02	$0.02	-$0.01	-$0.02	-$0.02	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
SDG&E	7820_TL 230S_OVERLOAD_NG		$0.15	$1.97		-$0.16	-$0.44	-$0.47	-$0.17	-$0.09					
	MIGUEL_BKs_MXFLW_NG			$0.25		$0.00	-$0.08	-$0.08	$0.00						
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80			$0.09		$0.00	-$0.03	-$0.03	$0.00						
	7820_TL23040_IV_SPS_NG		$0.00	$0.08		$0.00	-$0.01	-$0.01	$0.00						
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _S		$0.01	$0.08		-$0.01	-$0.03	-$0.03	-$0.01						
	OMS 9773191 SNCRST_BK			$0.04		$0.00	-$0.01	-$0.01	$0.00						
	OMS SNCRST_BK			$0.02		$0.00	$0.00	$0.00	$0.00						
	OMS 8797659_SB-VSTA_OOS_CP6	$0.04	-$0.04	$0.00	$0.03	-$0.03	-$0.14	-$0.14	-$0.03		$0.00	$0.00	$0.00	$0.00	$0.00
	22710_SNLSRYSC_230_22504_MISSION _230_BR_2 _1		$0.01	-$0.04			-$0.01	-$0.01							
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	$0.03	$0.04	-$0.38	$0.03		-$0.09	-$0.09			$0.02	$0.01	$0.00	$0.00	$0.00
	7750_DV2_N1SV500_NG	$0.00	$0.00		$0.00	$0.00	-$0.02	-$0.02	$0.00						
	OMS 8797559_EC-SB_OOS_CP3	$0.04	-$0.04		$0.04	-$0.02	-$0.27	-$0.27	-$0.01		$0.00	$0.00	$0.00	$0.00	$0.00
	Other	$0.01	$0.00	$0.00	$0.02	-$0.05	-$0.03	-$0.03	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Internal Total	**-$2.86**	**$4.51**	**$6.35**	**-$2.59**	**$2.19**	**$1.74**	**$1.66**	**-$1.27**	**-$1.58**	**-$3.08**	**-$3.08**	**-$3.01**	**-$2.96**	**-$3.00**
	Transfers				$0.04	-$0.37	-$2.39	-$0.54	-$0.05	-$0.10	-$6.24	-$5.78	-$5.86	-$5.46	-$6.45
	Grand Total	**-$2.86**	**$4.51**	**$6.35**	**-$2.55**	**$1.82**	**-$0.65**	**$1.12**	**-$1.32**	**-$1.68**	**-$9.32**	**-$8.86**	**-$8.87**	**-$8.42**	**-$9.45**

Table 1.5 Impact of internal congestion on 15-minute prices during congested intervals[33]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDGE	BANC*	NEVP	AZPS	SRP	PACE	IPCO	PACW	PGE	PSEI	PWRX	SCL
PACE	WINDSTAR EXPORT TCOR	0.4%								-$0.65						
	EAST_WYO_EXP	0.7%								-$1.02						
	TOTAL_WYOMING_EXPORT	0.7%								-$1.80						
PG&E	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	17.2%	$6.72	-$8.74	-$8.20	$6.30	-$4.99	-$7.40	-$7.41	-$1.64	$1.33	$4.22	$4.17	$4.03	$3.95	$4.01
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	7.8%	$3.21	-$5.31	-$5.02	$3.80	-$2.72	-$4.49	-$4.51	-$0.78	$0.96	$2.61	$2.58	$2.48	$2.44	$2.48
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	32.7%	-$23.91	$28.23	$27.00	-$22.44	$14.95	$23.91	$23.80	$3.60	-$6.13	-$15.55	-$15.46	-$14.87	-$14.60	-$14.82
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	10.6%				-$18.67	$22.82									
SCE	6410_CP1_NG	6.0%	-$230.77	$258.30	$257.48	-$217.29	$142.29	$228.12	$226.79	$27.52	-$60.93	-$151.93	-$151.03	-$145.42	-$142.66	-$144.97
	OMS 8797800_D-VST1_OOS_CP3	0.8%	$0.75	-$0.70	-$0.18	$0.69	-$0.53	-$5.17	-$5.25	-$0.45		$0.38	$0.42	$0.15	$0.18	$0.15
	OMS 8797800_D-VST1_OOS_CP6	3.4%	$1.76	-$1.58	-$0.99	$1.62	-$1.19	-$6.34	-$6.49	-$1.05		$0.75	$0.77	$0.45		
	OMS 8797822_D-VST1_OOS_CP6	0.6%	$3.63	-$3.32	-$2.45	$3.34	-$2.84	-$12.10	-$12.39	-$3.31		$1.52	$1.34	$0.99	$0.51	$0.68
SDG&E	7820_TL 230S_OVERLOAD_NG	1.5%		$2.66	$34.84		-$2.85	-$7.78	-$8.32	-$2.96	-$1.93					
	MIGUEL_BKs_MXFLW_NG	0.3%			$26.70		-$1.67	-$8.76	-$8.80	-$0.23						
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	0.7%			$21.29		-$5.37	-$7.00	-$7.09	-$3.13						
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _S	1.0%		$1.85	$16.84		-$2.05	-$5.72	-$5.76	-$2.09						
	7820_TL23040_IV_SPS_NG	10.7%		$0.01	$9.90		-$0.44	-$1.12	-$1.13	-$0.42						
	OMS 8797659_SB-VSTA_OOS_CP6	2.0%	$1.22	-$1.24	-$2.50	$1.11	-$0.92	-$4.46	-$4.59	-$0.81		$0.39	$0.33	$0.22	$0.33	$0.24
	22710_SNLSRYSC_230_22504_MISSION _230_BR_2 _1	0.7%		$1.99	-$12.92			-$2.88	-$2.93							
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	0.7%	$5.55	$6.49	-$63.16	$5.17		-$15.03	-$15.12			$3.73	$3.44	$3.45	$3.03	$3.70
	7750_DV2_N1SV500_NG	1.3%	$0.65	-$0.63		$0.60	-$0.48	-$4.68	-$5.03	-$0.73						
	OMS 8797559_EC-SB_OOS_CP3	9.3%	$1.15	-$1.22		$1.05	-$0.79	-$7.56	-$7.68	-$0.75		$0.67	$0.69	$0.89	$1.08	$0.89

*Data for BANC covers January 1, 2021 – March 24, 2021

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

Impact of congestion from transfer constraints

This section focuses on price impacts from congestion on schedule-based transfer constraints. 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 Seattle City Light area, with an average decrease of about $6.45/MWh in the 15-minute market and $3.07/MWh in the 5-minute market. 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 1.35 and Table 1.4, and schedule-based constraints as listed in Table 1.6. 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 1.6 shows the congestion frequency and average price impact from transfer constraint congestion in the 15-minute and 5-minute markets during the quarter.

Table 1.6 Quarterly average price impact and congestion frequency on EIM transfer constraints (Q1 2021)

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC*	1%	$0.04	1%	$0.16
NV Energy	3%	-$0.37	2%	-$0.35
Arizona Public Service	4%	-$2.39	3%	$0.49
PacifiCorp East	4%	-$0.05	3%	$0.44
Idaho Power	5%	-$0.10	4%	$0.12
Salt River Project	6%	-$0.54	5%	$2.35
PacifiCorp West	47%	-$6.24	33%	-$3.03
Portland General Electric	47%	-$5.78	34%	-$2.82
Puget Sound Energy	52%	-$5.86	47%	-$2.54
Seattle City Light	52%	-$6.45	47%	-$3.07
Powerex	55%	-$5.46	56%	-$2.63

*Data for BANC covers January 1, 2021 – March 24, 2021

Transfer constraint 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 1.37 shows the average impact to prices in the 15-minute market by quarter for 2020 and 2021. Figure 1.38 shows the frequency of congestion on transfer constraints by quarter for 2020 and 2021.

There was an overall increase in the impact on average prices from transfer constraint congestion in the first quarter of 2021, compared to the same quarter in 2020. Price impacts were greatest for EIM entities in the Pacific Northwest, which includes PacifiCorp West, Portland General Electric, Puget Sound

Energy, Powerex, and Seattle City Light. On average for the quarter, transfer constraint congestion decreased prices by $5.96/MWh.

The frequency of transfer constraint congestion in the first quarter of 2021 was higher than that of the same quarter of 2020, with high frequencies averaging over 50 percent across the aforementioned Pacific Northwest areas. Powerex continued to have the highest frequency of transfer congestion overall, occurring during about 55 percent of intervals.

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

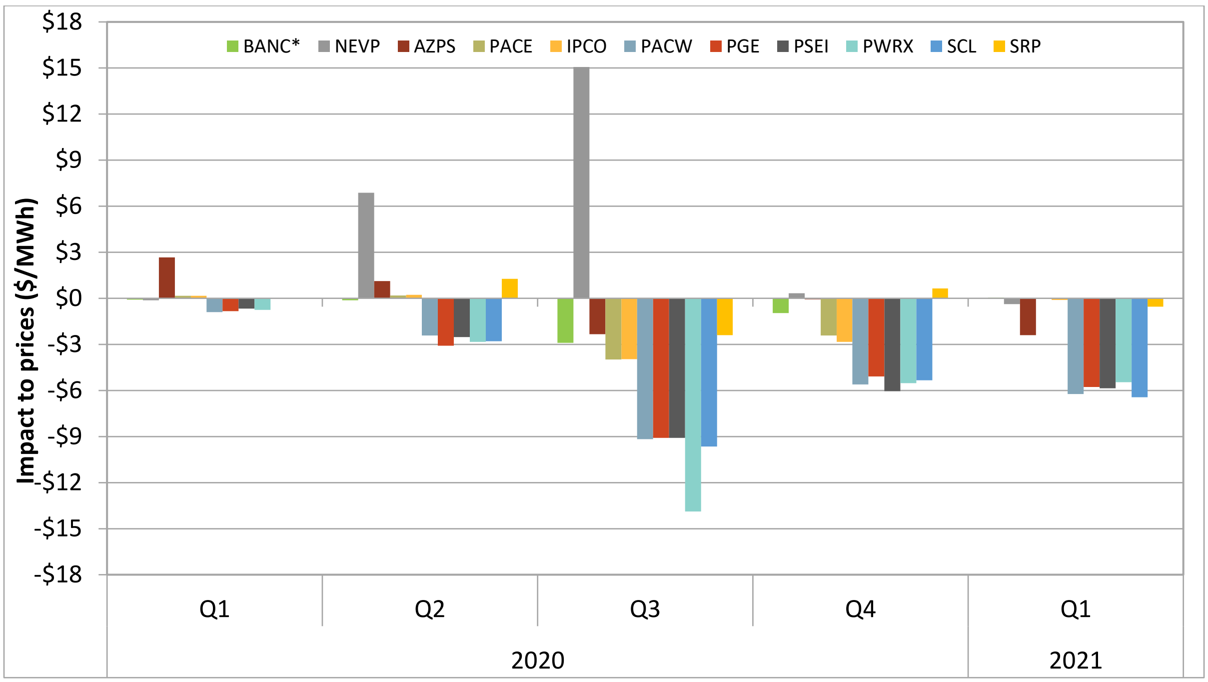
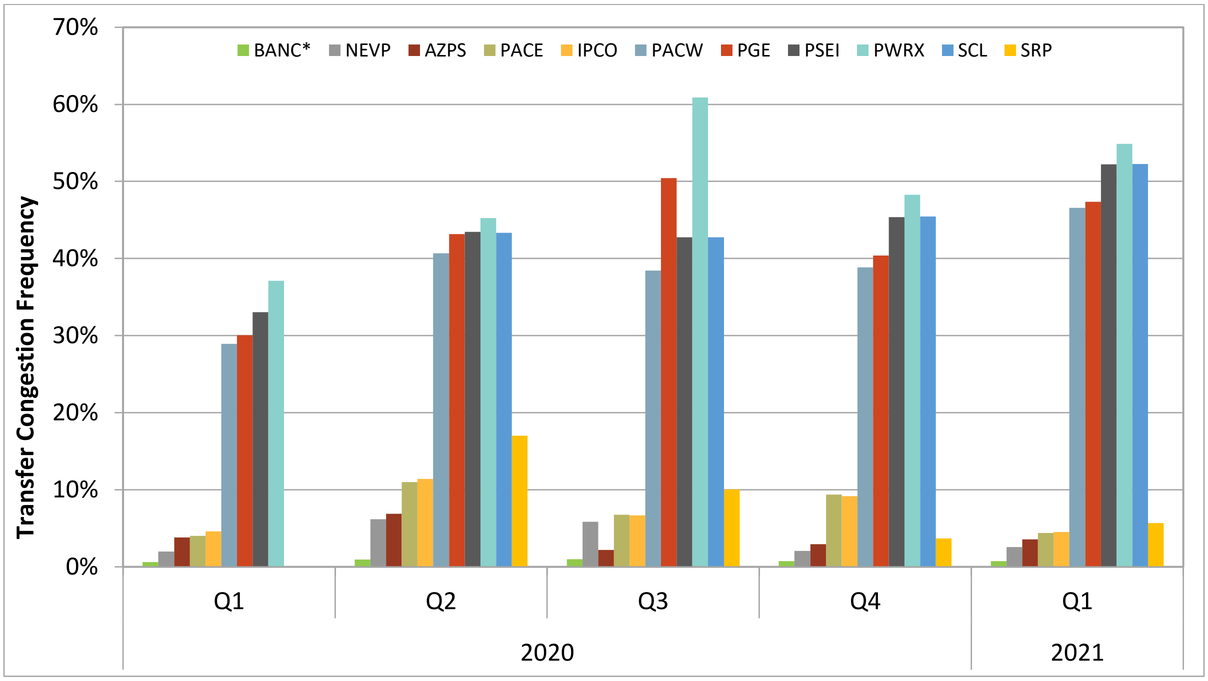


Figure 1.38 Transfer constraint congestion frequency in the 15-minute market



*First quarter 2021 data for BANC covers January 1, 2021 – March 24, 2021

Transfer constraint congestion in the 5-minute market

Transfer constraint congestion in the 5-minute market occurred with different frequencies and average price impacts across the EIM, similar to the 15-minute market. Despite this similarity, the average impact may change significantly across the two markets. On average for the quarter, four EIM areas experienced negative price impacts in the 15-minute market and positive price impacts in the 5-minute market.

Figure 1.39 shows the average impact on prices in the 5-minute market by quarter for 2020 and 2021. Figure 1.40 shows the frequency of congestion on transfer constraints in the 5-minute market by quarter for 2020 and 2021.

The impact to prices in the first quarter of 2021 was higher on average than the same quarter of 2020. Powerex consistently has the highest frequency of transfer constraint congestion, but does not have the most heavily impacted prices. Seattle City Light experienced the largest impact on prices in the 5-minute market for the quarter, where transfer congestion decreased average prices by $3.07/MWh.

The frequency of transfer constraint congestion was higher in the first quarter of 2021 compared to the same quarter in 2020. Puget Sound Energy and Seattle City Light both had transfer constraint congestion frequencies of 47 percent on average, while Powerex had the highest frequency at an average of 56 percent of 5-minute intervals.

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

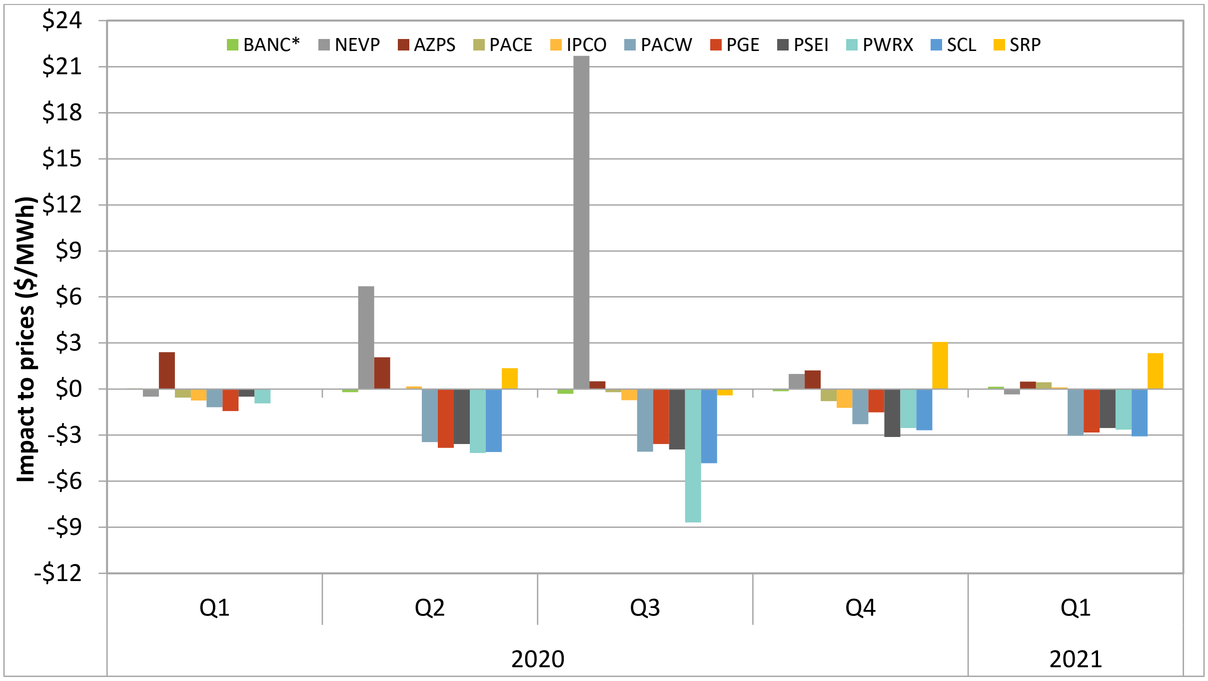
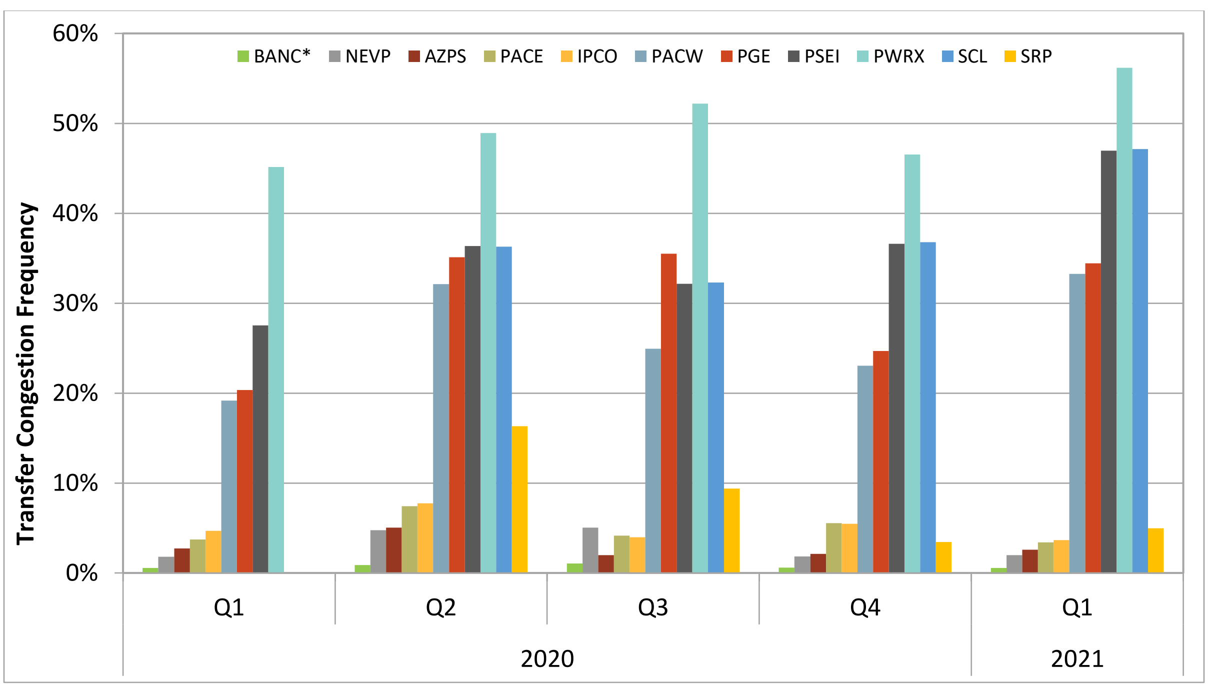


Figure 1.40 Transfer constraint congestion frequency in the 5-minute market



*First quarter 2021 data for BANC covers January 1, 2021 – March 24, 2021

1.9.3 Congestion on interties

In the first quarter of 2021, both frequency and import congestion charges increased on PACI/Malin 500 and NOB relative to the same quarter in 2020. Figure 1.41 shows total import congestion charges in the day-ahead market for 2020 and 2021. Figure 1.42 shows the frequency of congestion on five major interties. Table 1.7 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 first quarter of 2021 increased to about $22 million compared to about $10 million in the same quarter of 2020. This increase is driven by an increase in congestion on the PACI/Malin 500 intertie, which accounted for 68 percent of the total import congestion charges for the quarter.
- The frequency of congestion in the first quarter increased significantly on PACI/Malin 500, rising from 17 percent in the first quarter of 2020 to 39 percent this quarter.
- The frequency of congestion and magnitude of congestion charges is typically highest on the PACI/Malin 500, NOB, and Palo Verde interties. The first quarter followed this trend on PACI/Malin 500 and NOB, while the frequency and congestion charges decreased significantly on Palo Verde. Congestion on other interties continued to remain relatively low relative to these constraints.

Figure 1.41 Day-ahead import congestion charges on major interties

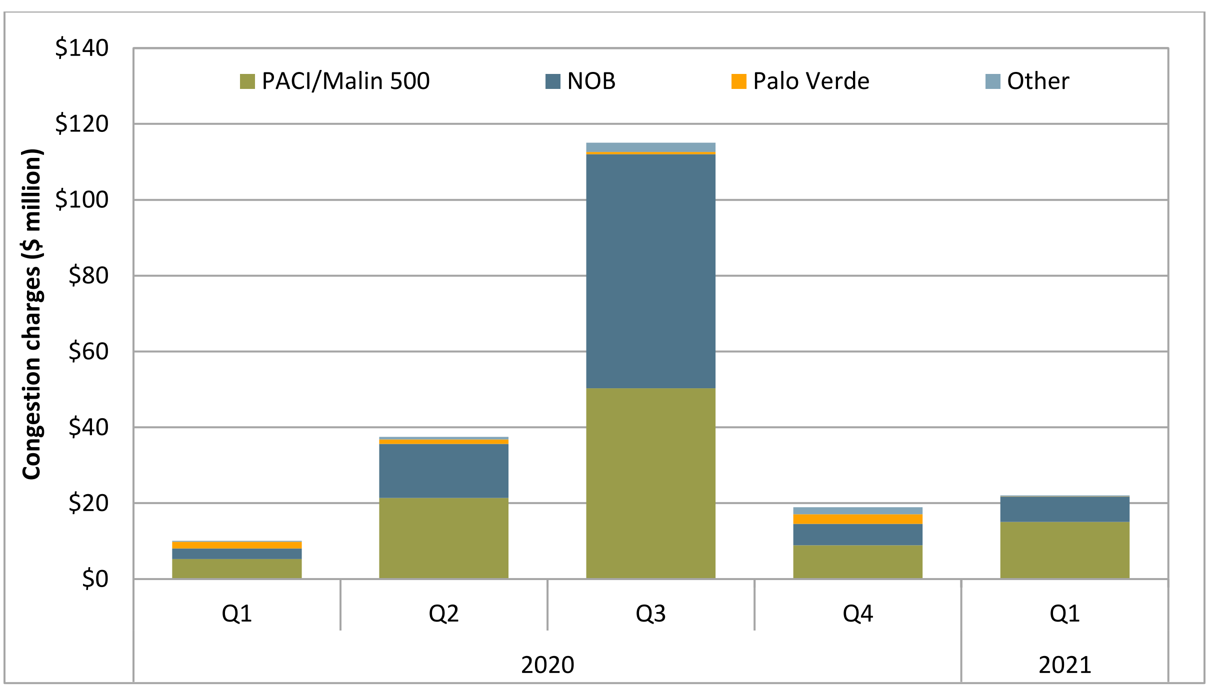


Figure 1.42 Frequency of import congestion on major interties in the day-ahead market

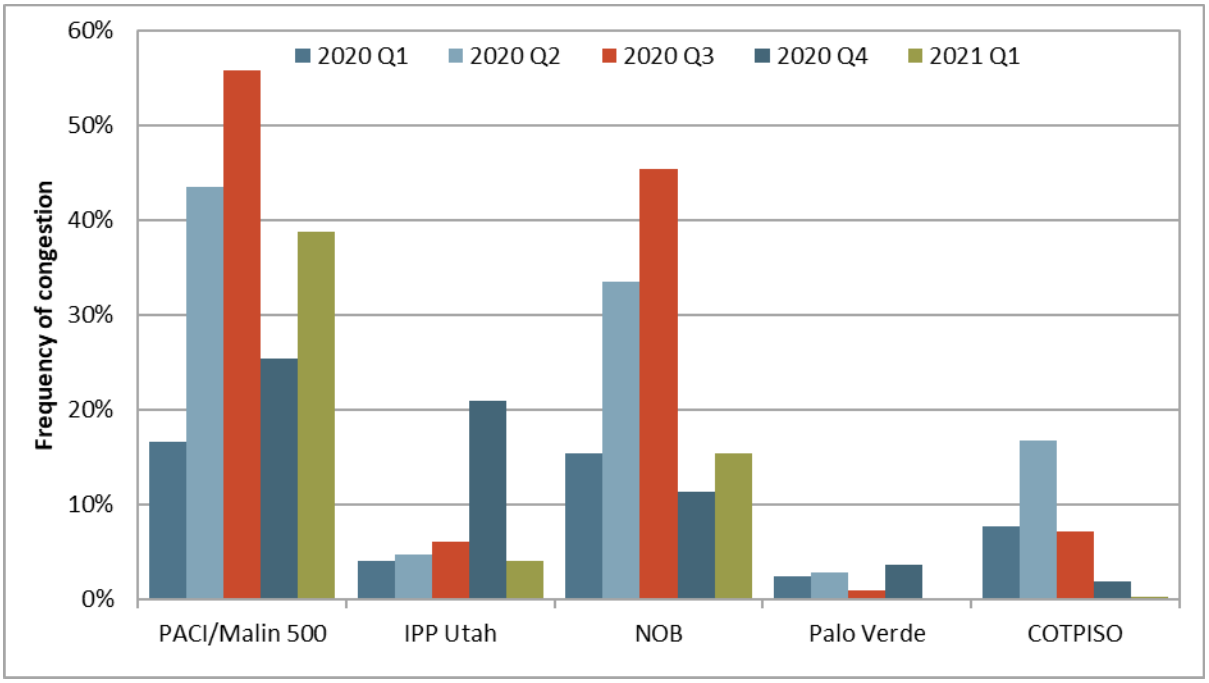


Table 1.7 Summary of import congestion in day-ahead market (2020-2021)

Area	Intertie	Frequency of import congestion					Import congestion charges ($ thousand)				
		2020				2021	2020				2021
		Q1	Q2	Q3	Q4	Q1	Q1	Q2	Q3	Q4	Q1
Northwest	PACI/Malin 500	17%	44%	56%	25%	39%	5,318	21,358	50,334	8,919	15,055
	NOB	15%	34%	45%	11%	15%	2,715	14,317	61,672	5,670	6,689
	COTPISO	8%	17%	7%	2%	0%	85	258	66	14	3
Southwest	Merchant					1%					150
	IPP Utah	4%	5%	6%	21%	4%	136	136	528	1,459	65
	IPP Adelanto		0%	0%		1%		96	12		38
	Palo Verde	2%	3%	1%	4%	0%	1,827	1,174	576	2,516	35
	Mead		1%	1%	2%	0%		133	856	357	10

1.10 Local market power mitigation

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 either 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 re-running the market software without bid mitigation. Currently, DMM does not have the ability to re-run 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 also estimate the additional energy dispatched from these price changes.[34]

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 first quarter of 2020. 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 as well as load in the portfolios of net buyers. In addition, for some days in the first quarter, DMM identified an issue where some load serving entities were being classified as net sellers instead of net buyers. This issue might have resulted in over mitigation during those days.

As shown in Figure 1.43, in the day-ahead market, an hourly average of about 928 MW was subject to mitigation but corresponding bids were not lowered, compared to 635 MW in the same quarter of 2020. About 235 MW of incremental energy had bids lowered due to mitigation compared to 198 MW in 2020. As a result, there was an average of 6 MW increase in dispatch, similar to that of in 2020.

Figure 1.44 and Figure 1.45 show the same metrics but for the ISO's 15-minute and 5-minute markets on a monthly level instead. As shown in the figures, the average incremental energy that is subject to mitigation either had bids lowered or not because mitigation in the ISO is consistently higher in the 5-minute market than in the 15-minute market. The frequency of mitigation in both 15-minute and 5-minute markets increased significantly in the first quarter relative to the same quarter in 2020.

[34] 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 captured 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 1.43 Average incremental energy mitigated in day-ahead market

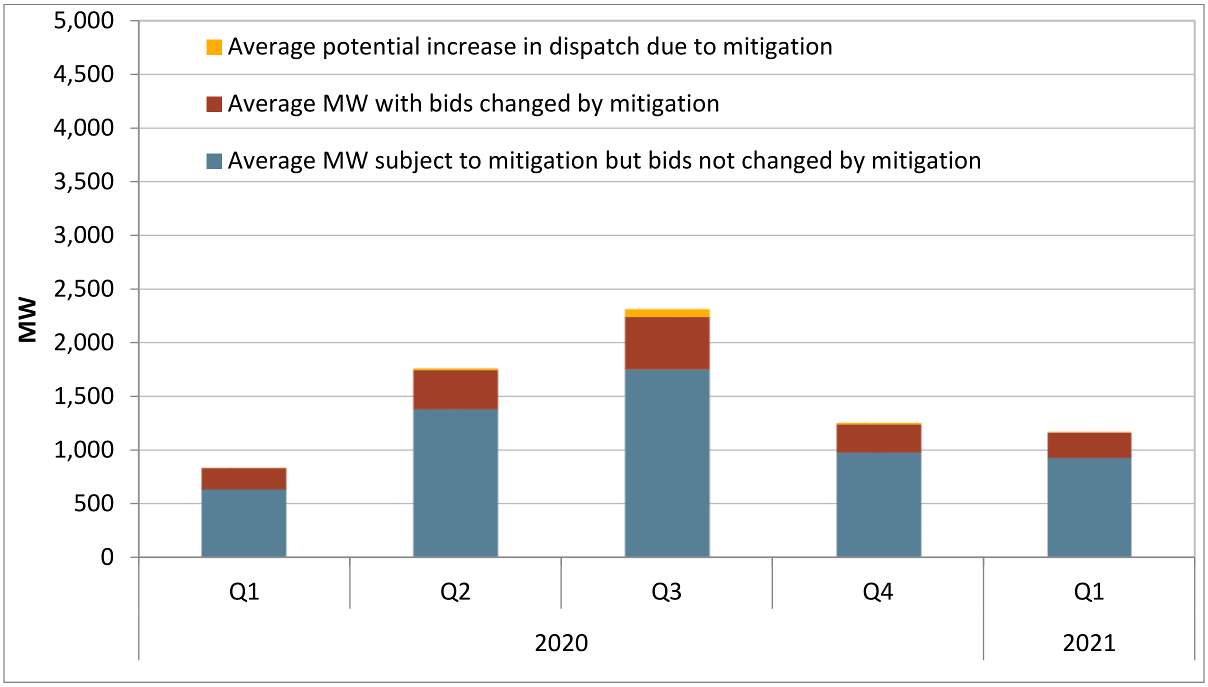


Figure 1.44 Average incremental energy mitigated in 15-minute real-time market (ISO)

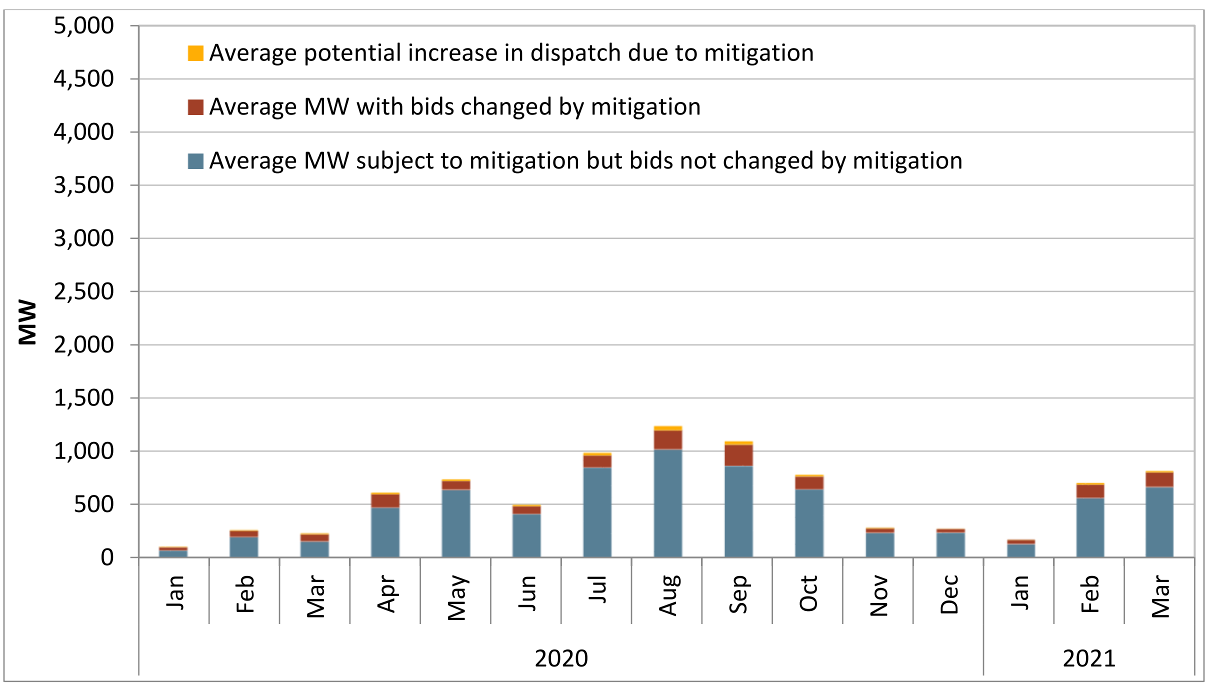
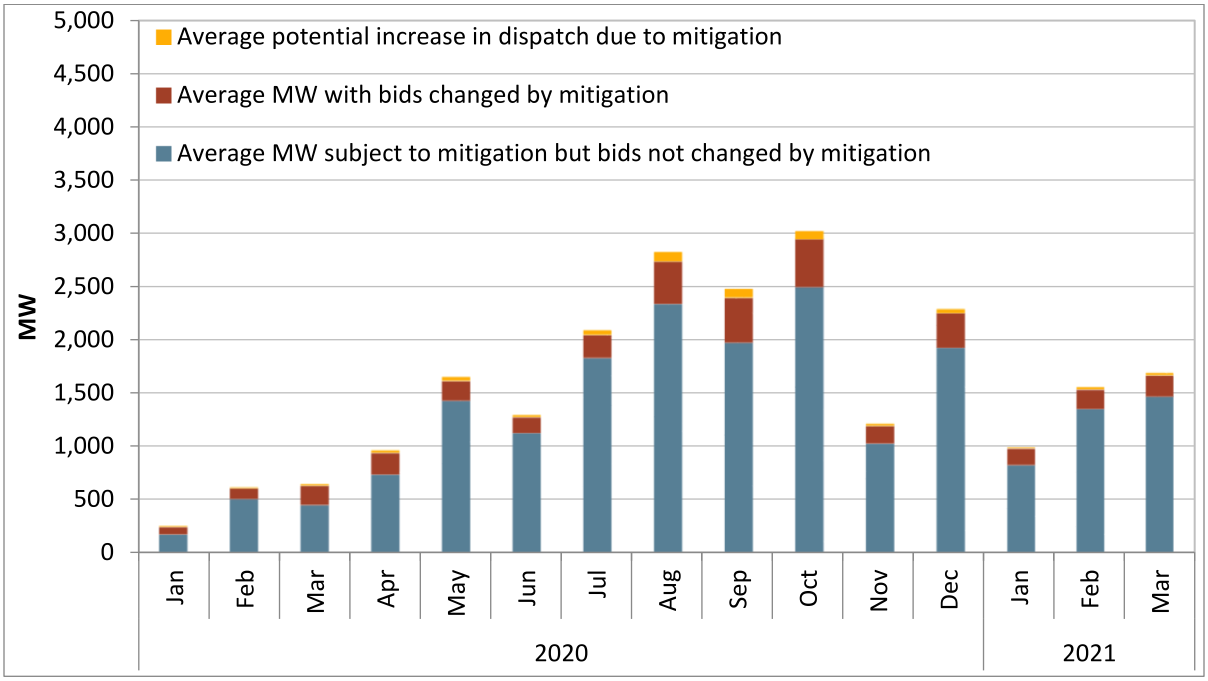


Figure 1.45 Average incremental energy mitigated in 5-minute real-time market (ISO)



1.11 Imbalance conformance

Operators in the California 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.

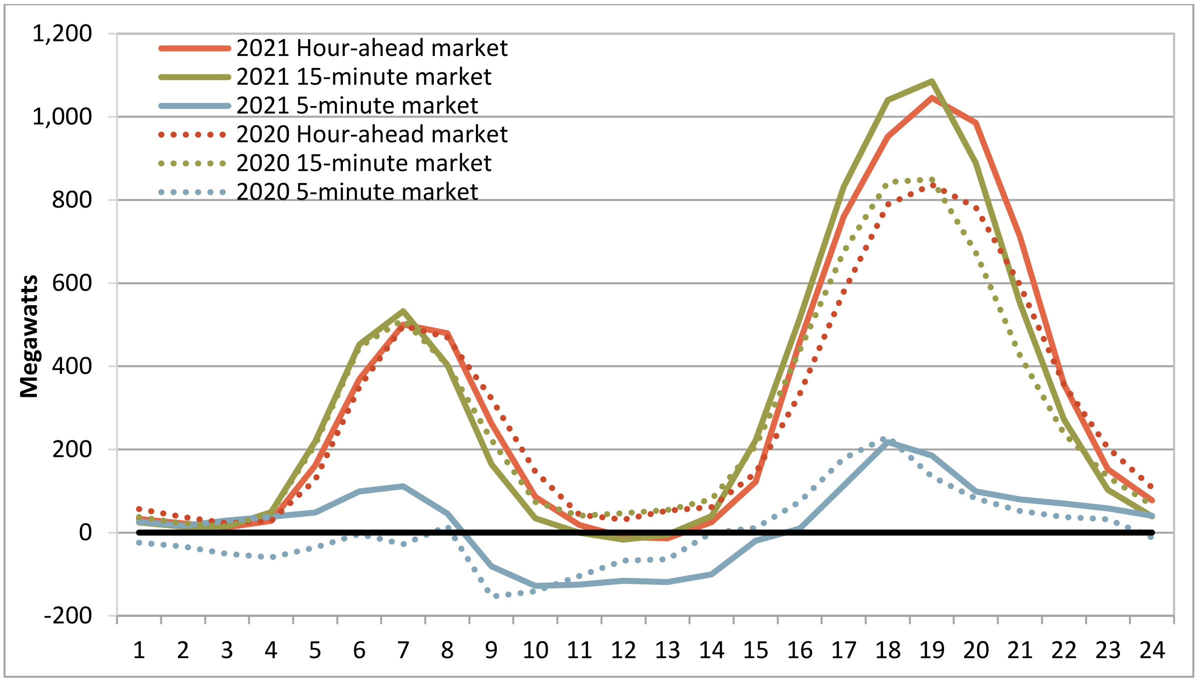
Frequency and size of imbalance conformance adjustments, generation/import prices and imports

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 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 just about 1,100 MW, which is about 200 MW greater than the similar peak in the same quarter of the previous year. Imbalance conformance in the morning ramp up period was very similar this quarter compared to the prior year, with averages around 500 MW in hour ending 7.

Figure 1.46 shows imbalance conformance adjustments in 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.

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

Figure 1.46 Average hourly imbalance conformance adjustment (Q1 2020 – Q1 2021)



1.12 Exceptional dispatch

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

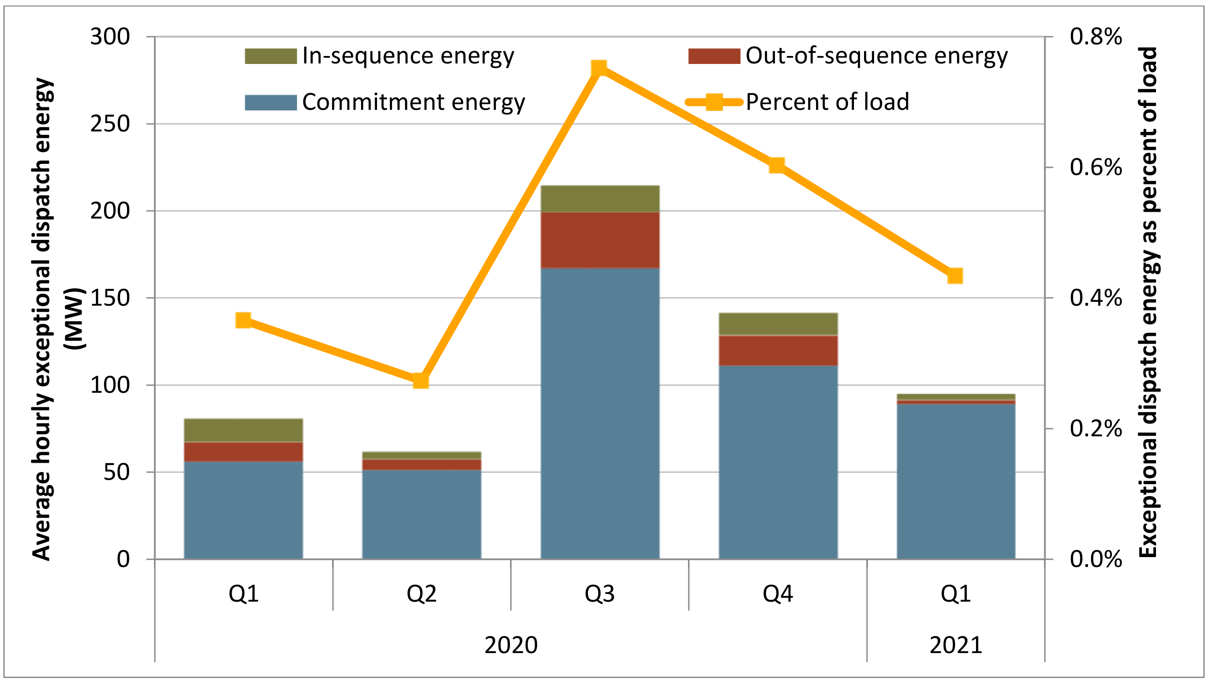
- **Out-of-sequence real-time energy** — Exceptional dispatches may also result in out-of-sequence real-time energy. This occurs when exceptional dispatch energy has an energy bid priced above the market clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to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

Energy from exceptional dispatch

Energy from exceptional dispatch accounted for under 0.5 percent of total load in the ISO balancing area. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 95 MWh in the first quarter of 2021, which is up from 81 MWh in the same quarter in 2020.

As shown in Figure 1.47, exceptional dispatches for unit commitments accounted for about 93 percent of all exceptional dispatch energy in this quarter.[35] About 3 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 4 percent was from in-sequence energy.

Figure 1.47 Average hourly energy from exceptional dispatch



Exceptional dispatches for unit commitment

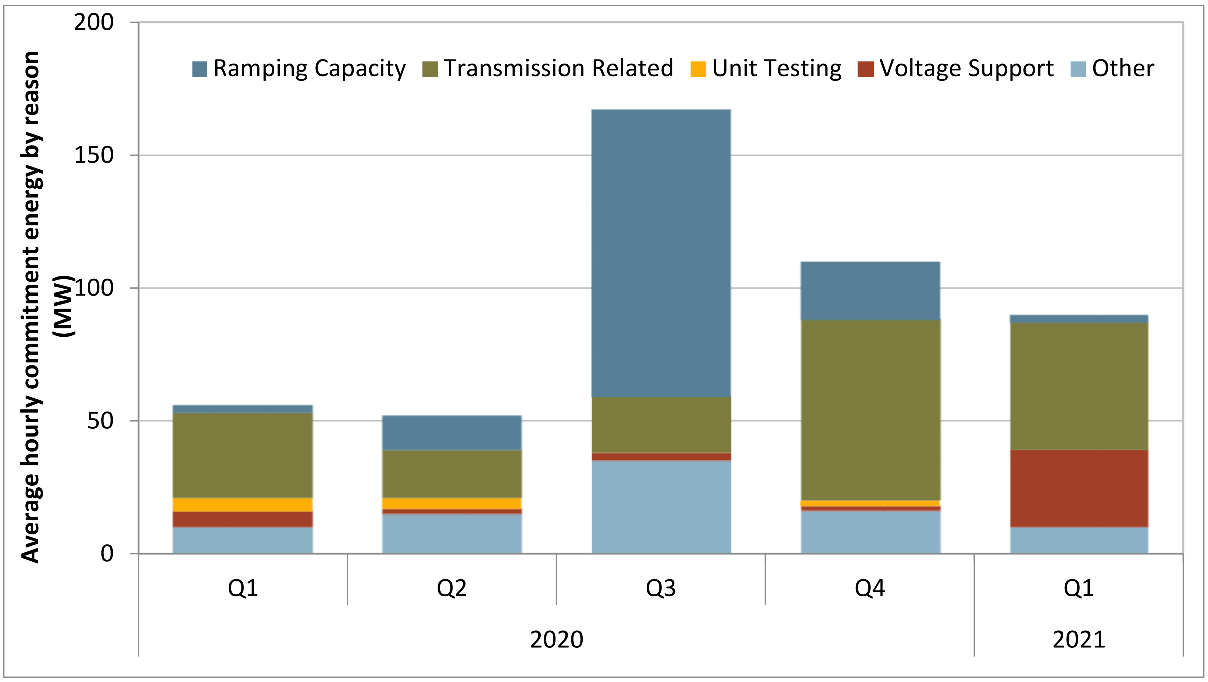
ISO operators sometimes find instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements indirectly incorporated in the day-ahead market model. In these instances, the ISO may commit additional capacity by issuing an exceptional dispatch for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

35 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. As a result of these enhancements, exceptional dispatch data reflected in this report may differ from previous annual and quarterly reports.

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

As shown in Figure 1.48, minimum load energy from exceptional dispatch unit commitments in the first quarter increased on average by about 61 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.

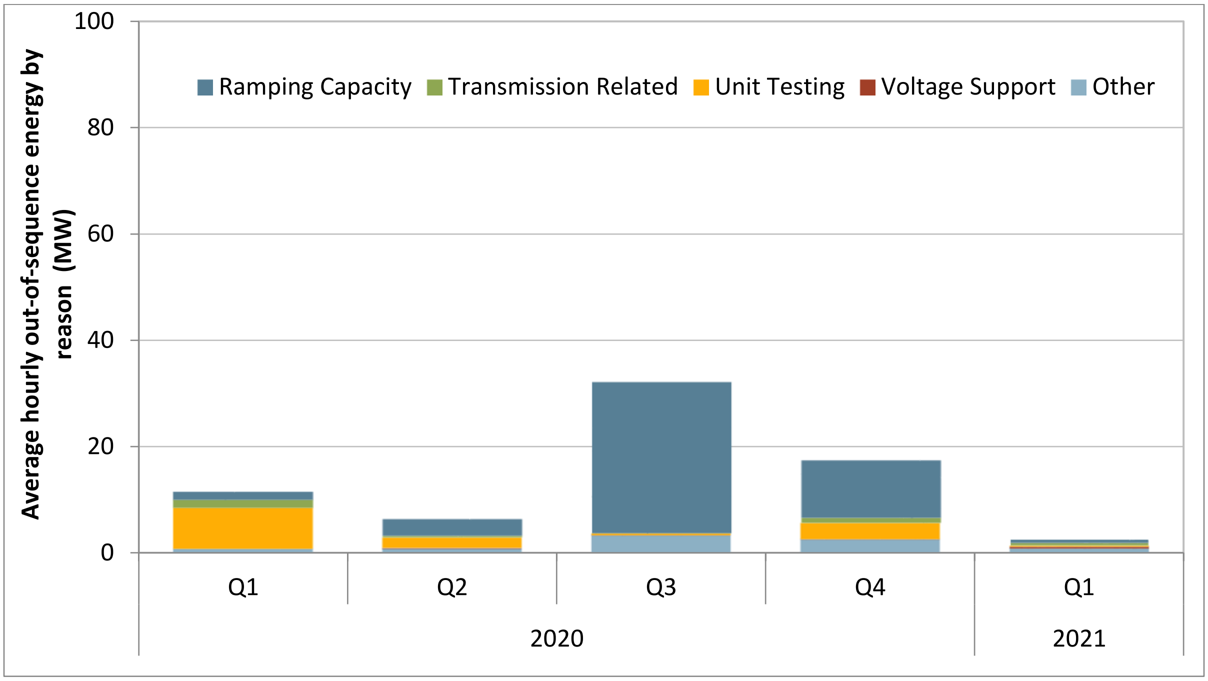
Figure 1.48 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

As shown in Figure 1.47, in the first quarter of 2021, energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch decreased by about 76 percent from the same quarter in 2019. Figure 1.47 also shows that about 3 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 1.49 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2020 and 2021. In the first quarter, the primary reason logged for out-of-sequence energy was for reliability assessments which are grouped under “other” category.

Figure 1.49 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.

Due to changes in the availability of cost data, exceptional dispatch costs are not available at the time of publication.

2 Western Energy Imbalance Market

This section covers Western Energy Imbalance Market (EIM) performance during the first quarter. Key observations and findings include:

- **The Turlock Irrigation District and the Balancing Authority of Northern California** joined the Western EIM on March 25, bringing over 6 GW of additional participating generation capacity and over 3 GW of transfer capacity.
- **Prices in the Southwestern areas averaged over $60/MWh in February**, exceeding the rest of the system, driven by high gas costs associated with a cold weather event in Texas and across the Midwestern United States.
- **Prices in the California ISO and the Balancing Authority of Northern California were on average more than $5/MWh higher than other regions of the energy imbalance market.** Prices tend to be higher in California than the rest of the Western Energy Imbalance Market 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 California 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 in peak net load hours.
- **Following modification of the penalty price with FERC Order 831 implementation in March 2021**, the majority of intervals with power balance relaxations were priced at the penalty parameter of $2,000/MWh. Failures of the downward sufficiency test, also most common in the same areas, increase the likelihood of over-supply infeasibilities priced at the -$150/MWh penalty price.

2.1 Western EIM performance

New Western EIM balancing authority areas

On March 25, 2021, Turlock Irrigation District and the Balancing Authority of Northern California joined the Western Energy Imbalance Market, bringing the total number of participants up to 12. The Sacramento Municipal Utility District area within the Balancing Authority of Northern California was already an existing member of the EIM. Turlock Irrigation District and the Balancing Authority of Northern California (BANC) bring with them about 722 MW and 5,408 MW of participating capacity, respectively. Turlock Irrigation District added roughly 1,300 MW of import and export transfer capacity with the California ISO (CAISO) while phase 2 of the BANC implementation added roughly 1,800 MW of import and export capacity with CAISO.

These areas were only a part of the EIM for one week of the first quarter; therefore, they are not included in this section's analysis of the Western Energy Imbalance Market. The Department of Market

Monitoring's monthly EIM transition reports will provide more information on these entities' transition into the Western EIM and will be available in the latter part of 2021.[36]

Western EIM prices

This section details the factors that generally influence changes in Western EIM balancing authority prices and what causes price separation between the 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.

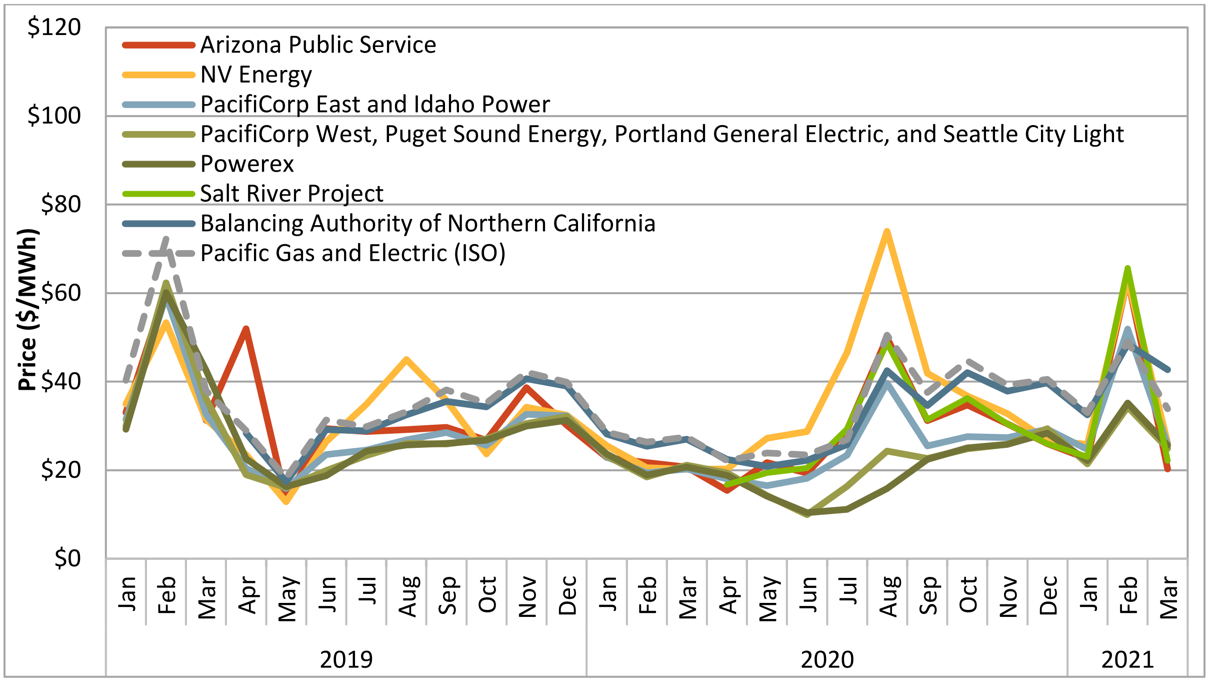
Figure 2.1 shows average monthly prices for the 15-minute market by each balancing authority area from January 2019 to March 2021.[37] Several balancing areas are grouped together due to similar average monthly prices. Prices for the Balancing Authority of Northern California (dark blue line) begin in April of 2019 when the Sacramento Municipal Utility District joined the market, while 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.[38] Prices for Pacific Gas and Electric (grey dashed line) are included in the figure as a point of comparison for this analysis.

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

[37] Data for Balancing Area of Northern California for March 2021 only includes March 1 through March 24.

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

Figure 2.1 Monthly 15-minute market prices



Combined average Western EIM prices outside of California were below Balancing Authority of Northern California and Pacific Gas and Electric average prices by $8.01/MWh and $5.42/MWh on average for the quarter, respectively. Prices in NV Energy and Salt River Project in February of 2021 were notable exceptions to this trend as monthly average prices in these areas reached $63.09/MWh and $65.65/MWh. These spikes occurred during the gas supply shortages that heavily impacted southwest areas during this time.

Price separation between Western EIM balancing authorities occurs for several reasons. California 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.[39] 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 CAISO and other balancing areas because of limited transfer capability out of the region.

Figure 2.2 and Figure 2.3 show the variation in Western EIM prices throughout the day in the first quarter of 2021. Average hourly prices are shown for participating balancing authorities between January 1 and March 31, 2021.[40] Prices continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours in most Western EIM balancing areas, just as in CAISO. 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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39 See Section 2.5 for more information about California's greenhouse gas compliance cost and its impact on the California ISO and EIM.

40 With the exception of Balancing Area of Northern California, the data for which covers January 1 to March 24, 2021.

Figure 2.2 Hourly 15-minute market prices (January – March)

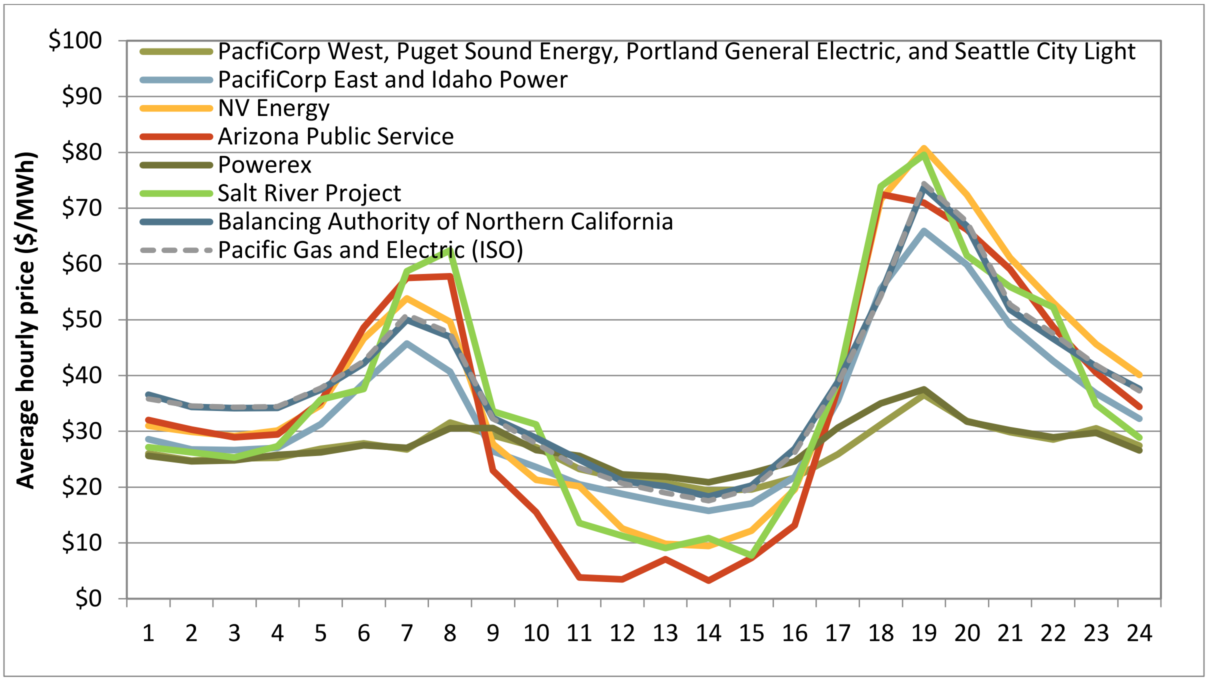
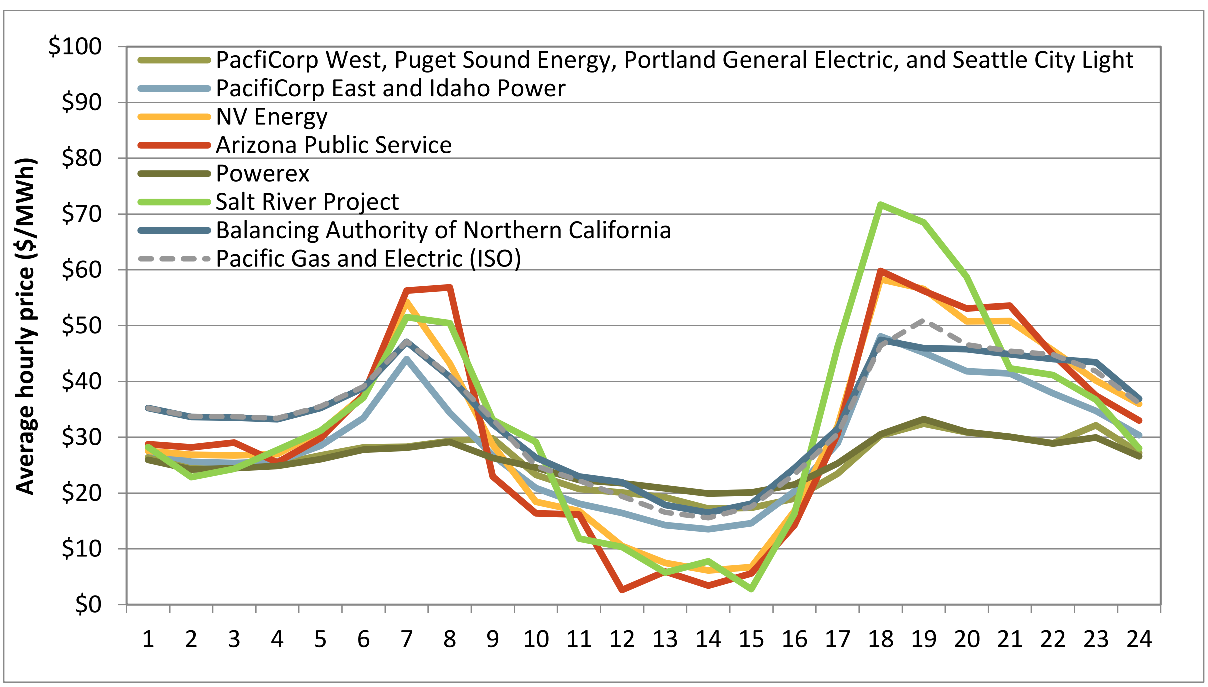


Figure 2.3 Hourly 5-minute market prices (January – March)



The relative price differences between Western EIM entities vary throughout the day. Prices in entities outside of California tend to be lower than CAISO prices in most hours. This price divergence is most pronounced during the evening ramping periods and net load peak hours, when CAISO is typically importing energy that is subject to greenhouse gas compliance costs. Western EIM entity prices converge with CAISO prices in the middle of the day, when CAISO 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 BANC continued to track very closely with prices in CAISO during the quarter because of significant transfer capability and little congestion between the areas.

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, with slight increases 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.

2.2 Flexible ramping sufficiency and bid range capacity tests

As part of the energy imbalance market, each area including the California 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 (capacity test)** requires that each area provide incremental bid-in capacity to meet the imbalance between load, intertie, and generation base schedules.
- **The flexible ramping sufficiency test (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 either the bid range capacity test or flexible ramping sufficiency test, energy imbalance market transfers into that area cannot be increased.[41]

In January 2021, the ISO held a workshop to review the design of the resource sufficiency evaluation and its application during the August heatwave.[42] The ISO identified two errors in the way the bid range capacity test was implemented:

- Resource derates and outages were not accounted for, resulting in higher resource capacity relative to actual availability. This affected both CAISO and energy imbalance market areas.
- Mirror resources were incorrectly included for CAISO, impacting net scheduled interchange and the capacity test requirement.[43] This only affected CAISO.

California ISO corrected these issues effective February 4, 2021 and has also proposed to add net load uncertainty to the requirement of the bid range capacity test as part of a package of market

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41 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.

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

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

enhancements for Summer 2021 Readiness.[44] For more information on the impact of the implementation errors and proposed uncertainty on the bid range capacity test, see DMM's special report on the topic.[45]

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 transfer capability also affects the ability for an area to balance load, since 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 the area did not fail the test during the month.

During the first quarter of 2021, across all areas:

- Around 25 percent of upward sufficiency test failures, and less than 1 percent of downward sufficiency test failures, were caused entirely by failing the capacity test.
- During 61 percent of upward capacity test failures and 91 percent of downward capacity test failures, the sufficiency test would have failed regardless, resulting in the same outcome.

In particular, for the first quarter of 2021, NV Energy and Arizona Public Service each failed the downward sufficiency test in roughly 3 percent of intervals. Salt River Project failed the upward capacity test during 8 percent of intervals during February, which contributed to failed upward sufficiency test failures in almost 10 percent of intervals during the month.

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

45 *Report on Resource Sufficiency Tests in the Energy Imbalance Market*, May 20, 2021: http://www.caiso.com/Documents/Report-on-Resource-Sufficiency-Tests-in-the-Energy-Imbalance-Market-May-20-2021.pdf

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

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

	2020												2021		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
California ISO	—	—	—	0.1	0.2	—	—	—	—	—	—	—	—	—	—
BANC	—	—	—	—	—	—	0.0	0.0	—	0.1	0.0	—	—	—	0.1
NV Energy	—	—	—	0.0	0.0	—	—	—	—	0.1	0.2	—	—	0.3	0.1
Arizona PS	—	—	0.1	—	—	0.0	—	—	—	—	—	0.3	0.2	0.4	0.1
Salt River Project				0.2	—	—	—	—	—	0.1	0.1	—	—	8.0	0.1
Idaho Power	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.1
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	0.1	—	—	—	0.1
PacifiCorp West	—	0.1	—	—	—	—	—	—	—	—	0.1	—	—	—	0.2
Portland GE	—	—	—	—	—	—	—	—	—	—	—	—	—	0.1	0.1
Seattle City Light				—	0.1	—	0.2	0.1	—	—	—	—	—	—	0.1
Puget Sound En	—	0.1	—	—	—	—	—	—	—	—	—	—	—	0.1	0.7
Powerex	0.4	0.2	0.3	0.2	0.3	—	—	—	0.1	0.1	0.1	—	0.1	0.0	0.1

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

	2020												2021		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
California ISO	—	—	—	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	—	—	0.1
NV Energy	—	0.6	0.1	0.7	2.6	2.3	4.5	7.1	2.6	1.5	0.8	—	0.1	0.7	0.5
Arizona PS	1.3	1.1	1.5	0.1	1.0	0.0	—	—	0.3	0.8	0.7	0.6	0.5	0.6	0.3
Salt River Project				1.9	0.1	0.5	0.7	1.8	1.1	1.8	0.9	0.3	0.2	9.8	0.4
Idaho Power	—	—	—	—	0.1	0.3	0.1	0.2	—	—	—	—	—	0.1	0.1
PacifiCorp East	0.0	0.0	0.1	0.0	0.2	0.1	0.2	0.2	0.1	0.5	0.2	—	0.1	0.1	0.3
PacifiCorp West	0.2	0.3	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.0	0.2	0.3
Portland GE	—	0.2	0.1	—	—	0.0	0.2	0.2	0.6	0.1	0.1	0.2	0.3	0.6	0.2
Seattle City Light				—	0.1	—	0.2	0.1	0.1	0.2	0.2	0.1	—	—	0.1
Puget Sound En	—	0.3	—	—	0.0	0.3	0.6	0.4	—	0.2	—	—	—	0.1	0.7
Powerex	0.5	0.3	0.3	0.2	0.5	0.2	0.2	0.1	0.3	0.1	0.7	0.2	0.4	0.1	0.2

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

	2020												2021		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BANC	—	0.0	0.0	0.2	0.2	—	—	—	—	0.1	0.1	—	—	0.0	0.1
NV Energy	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—	—	—	0.1
Arizona PS	—	—	0.3	0.3	0.1	—	—	—	—	0.1	0.1	—	—	—	0.0
Salt River Project				0.6	0.6	0.0	—	—	—	0.1	0.1	—	—	—	0.0
Idaho Power	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—	—	—	0.0
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	—	—	—	0.0
Puget Sound En	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—	—	—	—
Powerex	—	—	—	0.1	0.3	—	0.0	0.0	—	0.2	0.1	—	—	—	0.1

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

	2020												2021		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BANC	—	0.9	0.7	0.6	1.3	0.3	—	—	—	0.1	0.4	—	—	0.6	0.4
NV Energy	0.4	2.1	2.4	4.9	6.7	5.1	0.7	0.8	2.2	0.7	1.5	1.1	0.2	6.1	1.5
Arizona PS	3.0	1.3	3.0	1.2	0.7	2.3	0.1	—	0.1	2.1	1.1	2.5	2.2	2.3	4.4
Salt River Project				1.0	1.2	0.2	—	0.0	0.1	0.2	0.3	0.8	1.1	1.6	1.3
Idaho Power	—	0.1	0.2	0.1	0.8	—	0.0	—	—	0.2	0.2	—	—	—	0.1
PacifiCorp East	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—	—	—	—
PacifiCorp West	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—	—	—	0.1
Portland GE	0.1	—	—	0.1	0.4	0.1	—	—	—	0.1	0.1	—	0.0	—	—
Seattle City Light				0.6	0.1	—	0.1	0.2	0.2	0.2	0.2	0.1	—	—	0.0
Puget Sound En	—	—	—	0.1	0.6	0.8	0.1	—	—	0.1	0.1	—	—	—	—
Powerex	0.2	0.4	0.0	0.1	0.3	—	0.1	0.1	0.1	0.2	0.1	—	0.4	—	1.5

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 2.1 shows average 15-minute market limits between each of the areas between January 1 and March 24, 2021 (prior to the implementation of BANC phase 2 and Turlock Irrigation district).[47] 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 210 MW on average during the quarter, or roughly 2 percent of total import capability. However, significant transfer capability between the ISO, NV Energy, Arizona Public Service, Salt River Project, and BANC allowed energy to flow between these areas with relatively little congestion.

Turlock Irrigation District added roughly 1,300 MW of import and export transfer capacity with the ISO while phase 2 of the BANC implementation added roughly 1,800 MW of import and export capacity with the ISO.

Table 2.1 Average 15-minute market energy imbalance market limits (January 1 – March 24)

	To Balancing Authority Area												*Total export limit*
From Balancing Authority Area	CISO	BANC	NEVP	AZPS	SRP	PACE	IPCO	PACW	PGE	PSEI	SCL	PWRX	
California ISO		1,580	3,470	1,080	1,860			50	100	0		130	8,270
BANC	1,590												1,590
NV Energy	3,710			400		790	500						5,400
Arizona Public Service	2,260		380		7,970	630							11,240
Salt River Project	2,470			5,030		0							7,500
PacifiCorp East			650	610	0		900	430					2,590
Idaho Power			500			1,920		450		0	30		2,900
PacifiCorp West	120					260	350		410	150	10		1,300
Portland GE	90							410		150	10		660
Puget Sound Energy	0						10	90	150		350	150	750
Seattle City Light							30	30	10	450			520
Powerex	0									300			300
Total import limit	10,240	1,580	5,000	7,120	9,830	3,600	1,790	1,460	670	1,050	400	280	

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.[48] The bars show the average hourly transfers with the connecting areas. The grey line shows the average hourly net transfer.

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.

48 Average transfers for the first quarter of 2021 is only January 1 to March 24, and therefore do not include transfers following the addition of the Balancing Area of Northern California (phase 2) and Turlock Irrigation District on March 25.

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

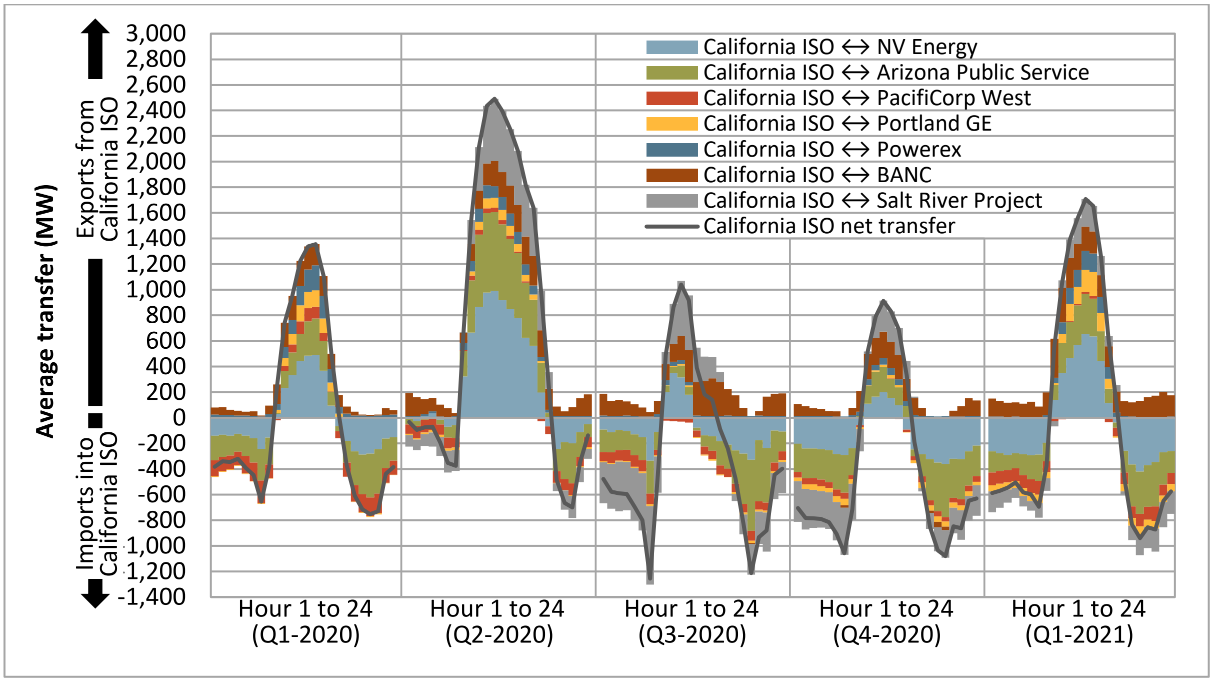


Figure 2.9 through Figure 2.17 show the same quarterly information on imports and exports for the other energy imbalance market areas in the 15-minute market.[49] The amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[50]

49 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.

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

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

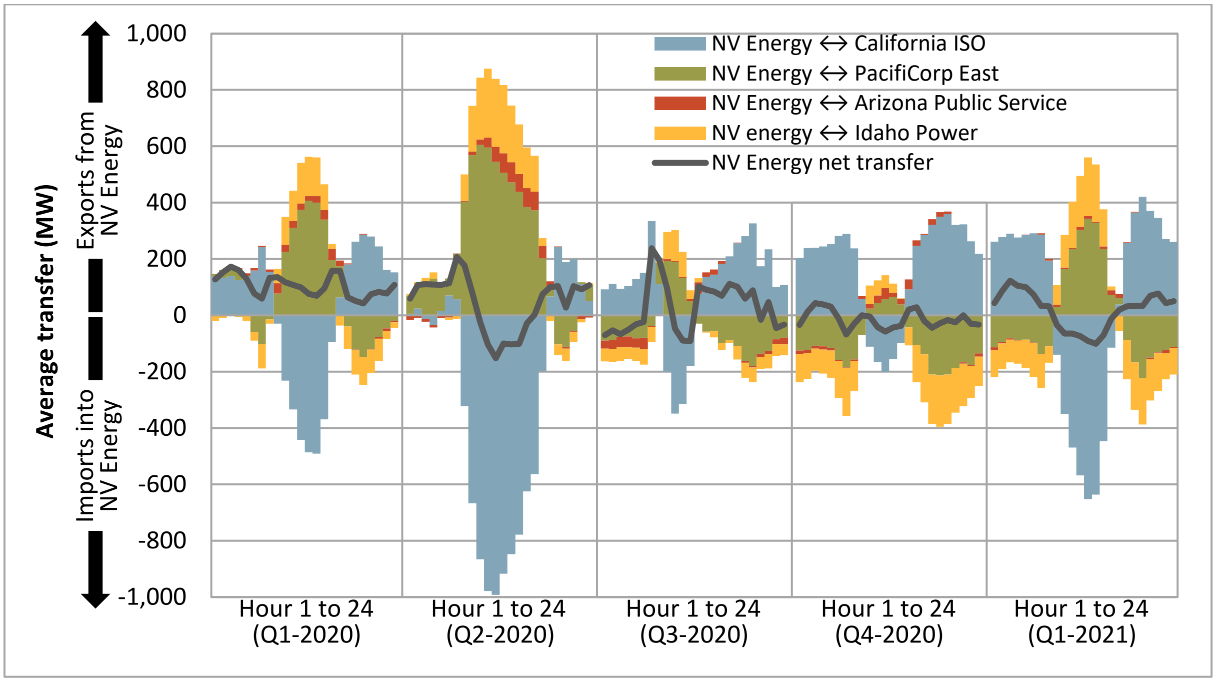


Figure 2.10 Arizona Public Service – average hourly 15-minute market transfer

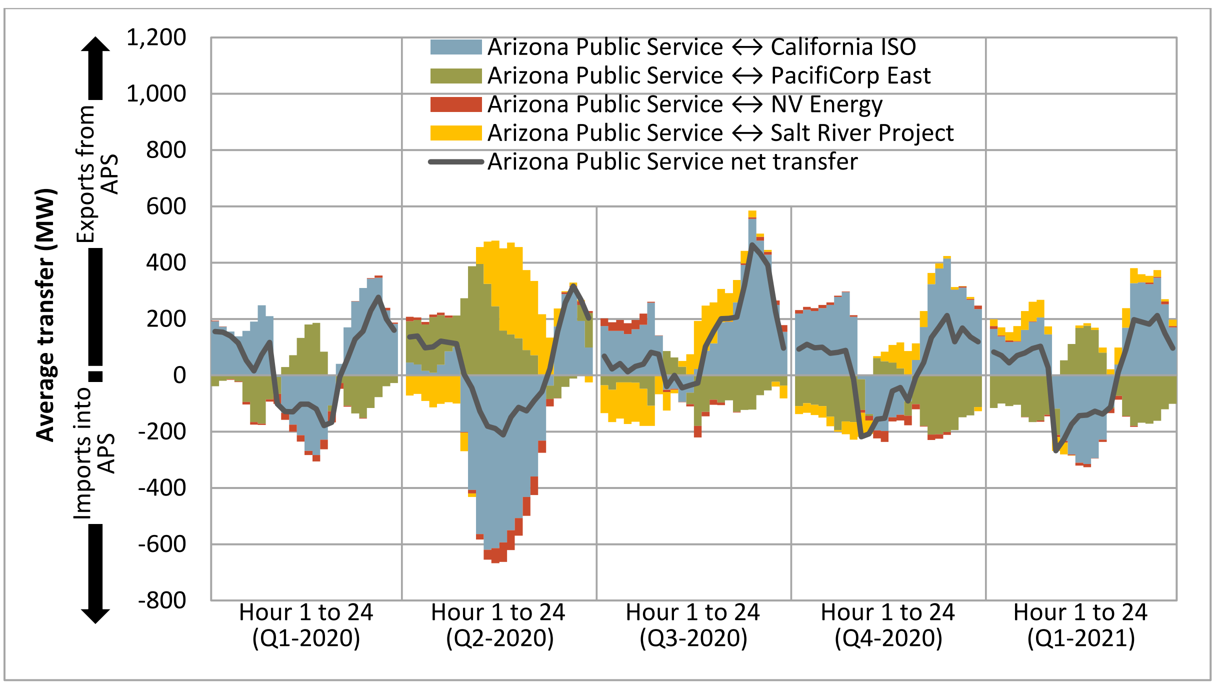


Figure 2.11 Idaho Power – average hourly 15-minute market transfer

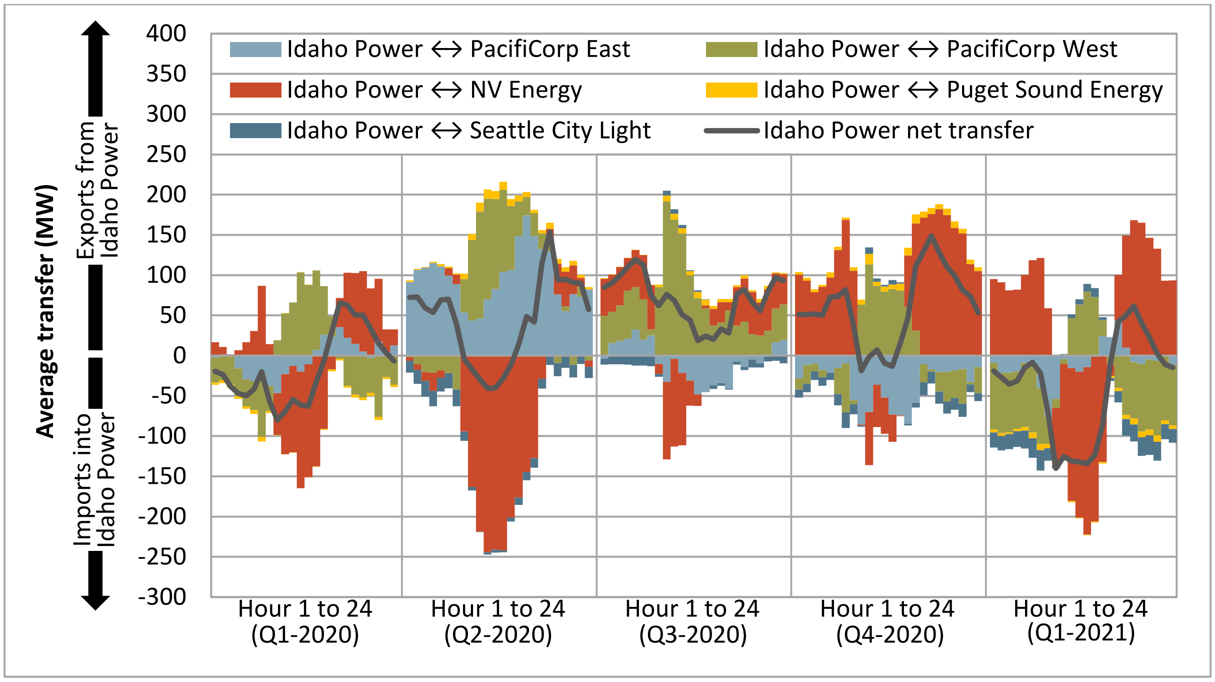


Figure 2.12 PacifiCorp East – average hourly 15-minute market transfer

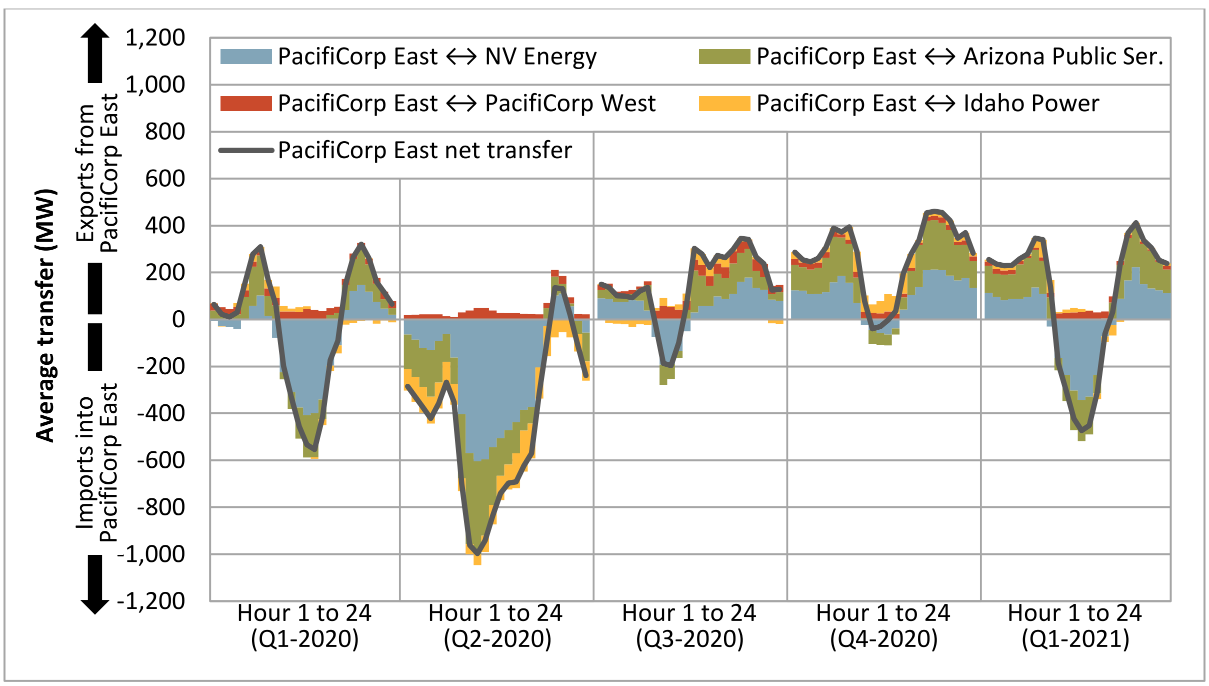


Figure 2.13 PacifiCorp West – average hourly 15-minute market transfer

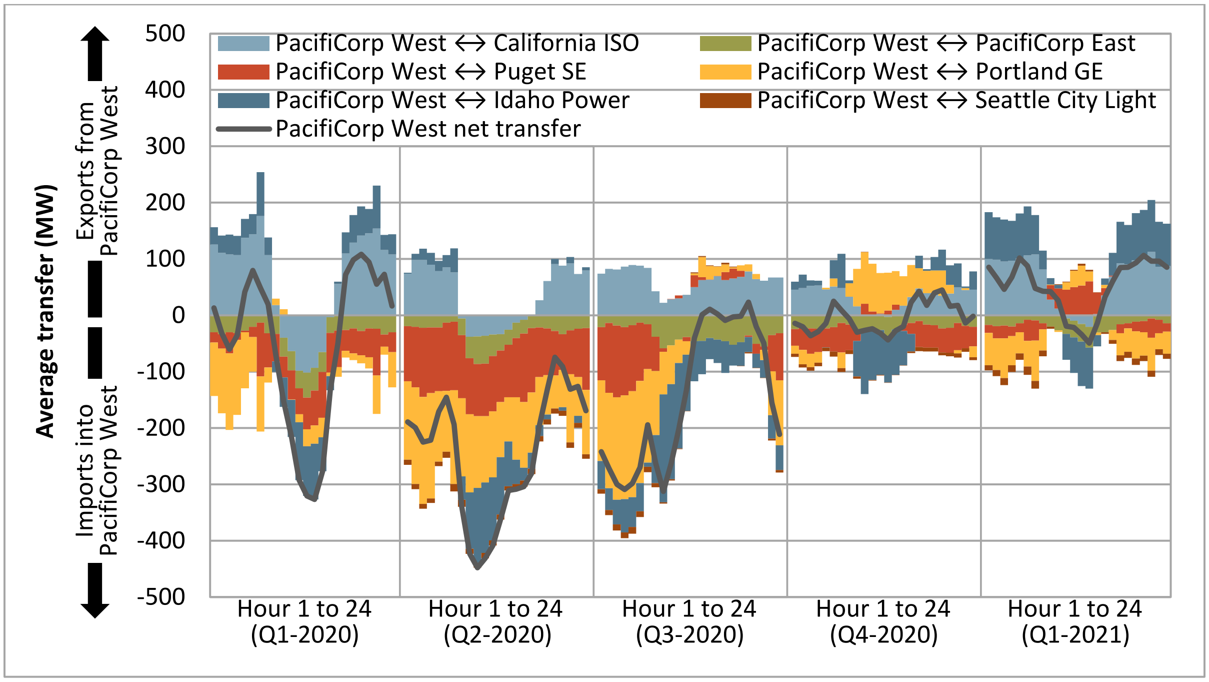


Figure 2.14 Puget Sound Energy – average hourly 15-minute market transfer

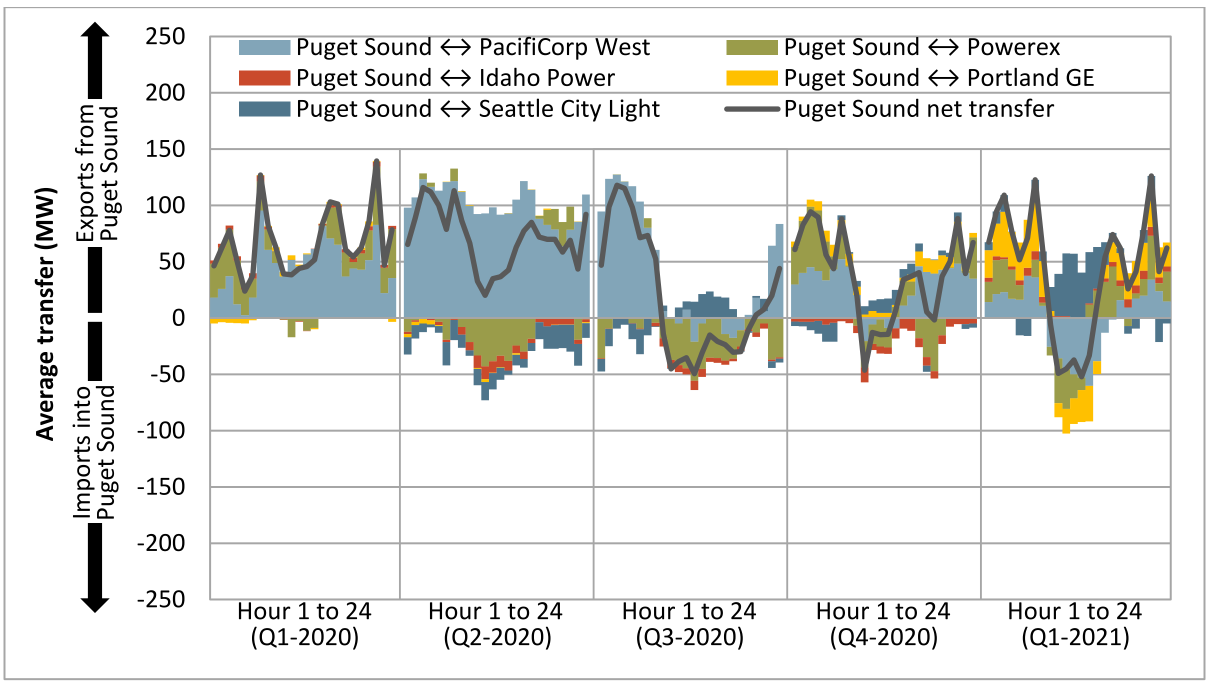


Figure 2.15 Powerex – average hourly 15-minute market transfer

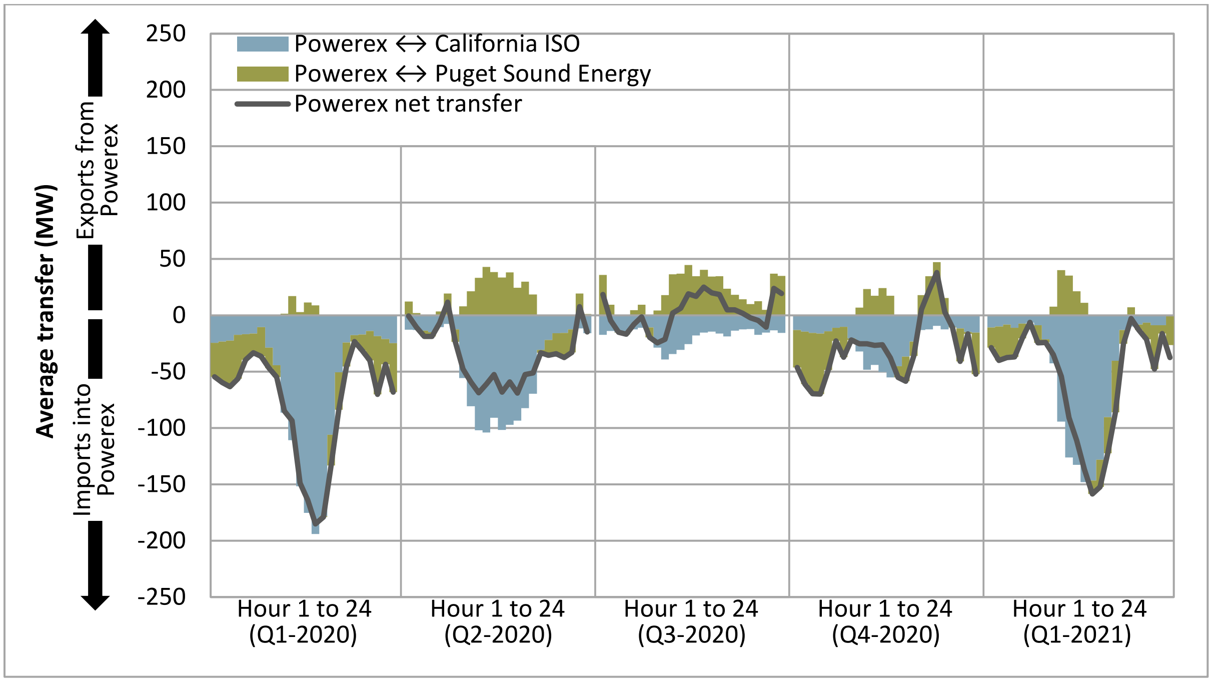


Figure 2.16 Portland General Electric – average hourly 15-minute market transfer

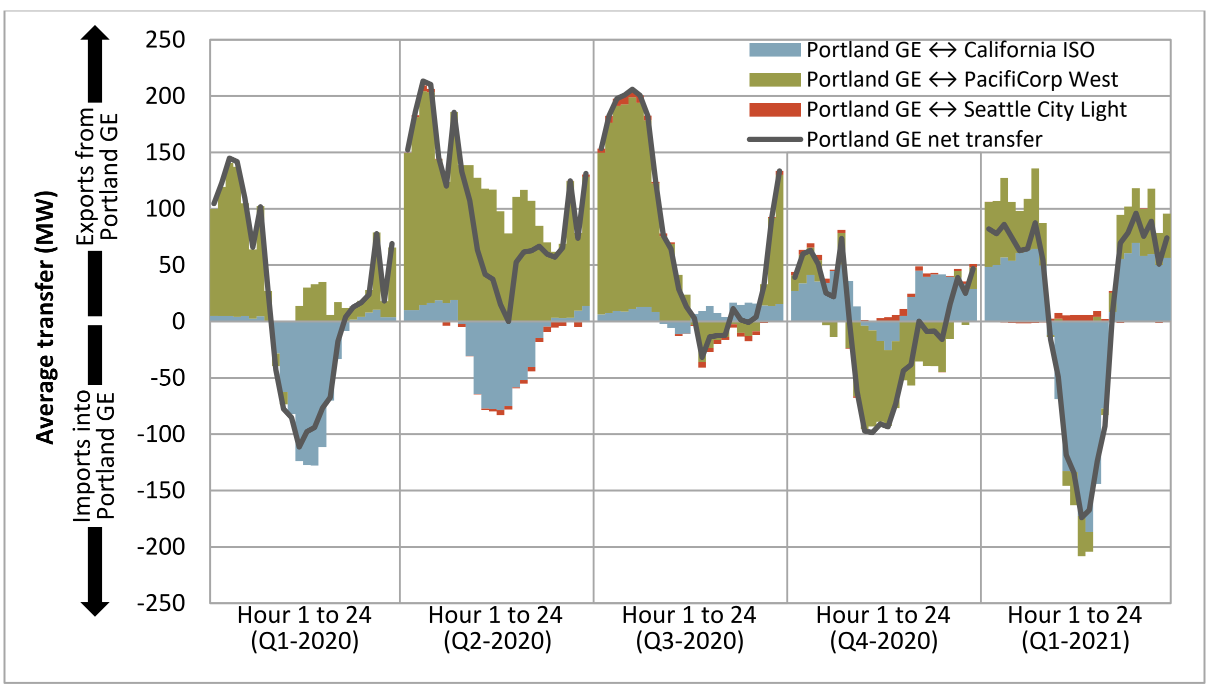
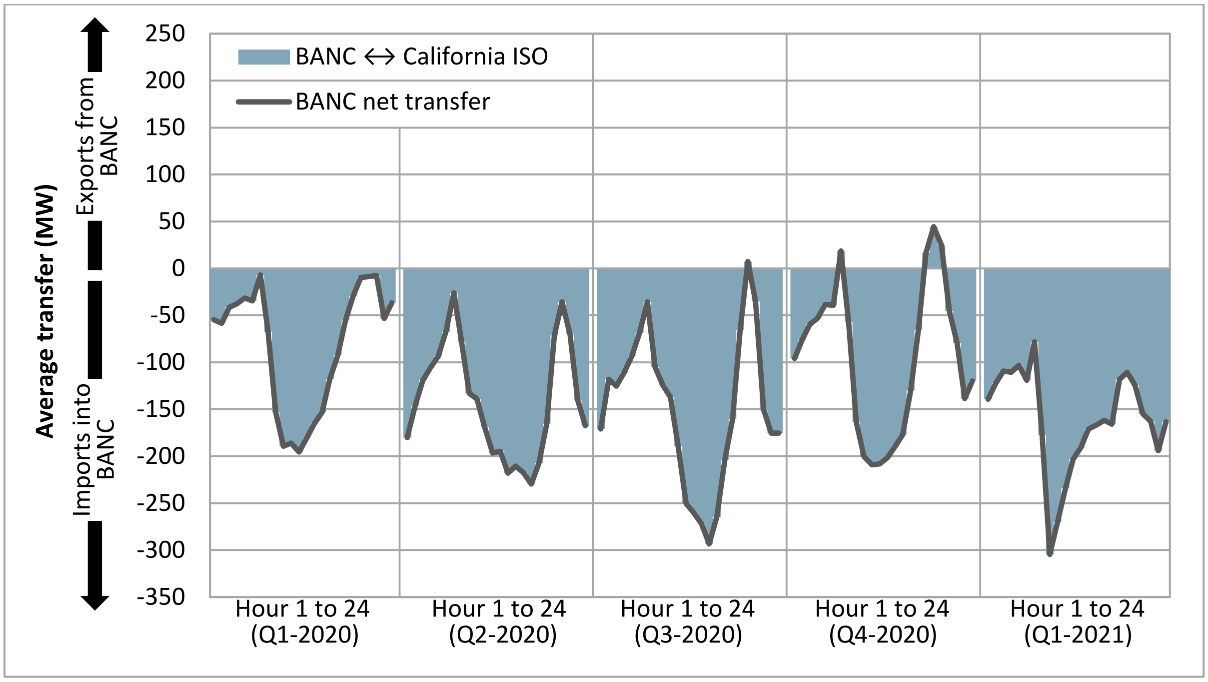


Figure 2.17 Balancing Authority of Northern California - average hourly 15-minute market transfer



Inter-balancing area congestion

Congestion between an energy imbalance market area and the rest of the system limits an area's import and export capability. In addition, during intervals when there is net import congestion into an energy imbalance market area, the market software triggers local market power mitigation for resources in that area.[51]

Table 2.2 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.[52] 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. 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.

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51 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.

52 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.

Table 2.2 Frequency of congestion in the energy imbalance market (January – March)

	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	2%	0%	2%	0%
Arizona Public Service	3%	1%	2%	1%
PacifiCorp East	2%	2%	1%	2%
Idaho Power	2%	3%	1%	3%
Salt River Project	4%	2%	3%	2%
PacifiCorp West	41%	6%	28%	6%
Portland General Electric	41%	6%	28%	6%
Puget Sound Energy	44%	8%	35%	12%
Seattle City Light	44%	8%	35%	12%
Powerex	43%	12%	36%	20%

*Data for BANC covers January 1, 2021 – March 24, 2021

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 Powerex occurred during 43 percent of intervals on average during the quarter. This is higher than the same quarter of 2020 when congestion from these areas occurred during an average of 25 percent of intervals.[53]

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 12 percent of 15-minute market intervals and 20 percent of 5-minute market intervals during the first quarter.

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

[53] Not including Seattle City Light as it yet to participate in the energy imbalance market.

2.4 Imbalance conformance in the Western EIM

Frequency and size of imbalance conformance

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

Table 2.3 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 quarter.[54] The same data for the ISO is provided as a point of reference. In particular, Arizona Public Service entered positive imbalance conformance in around 27 percent of 15-minute and 5-minute intervals, at an average of around 60 MW. Seattle City Light entered negative imbalance conformance in around 13 and 64 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.

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

Table 2.3 Average frequency and size of imbalance conformance (January – March)

	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	46%	692	2.9%	2.7%	-325	1.7%	312
5-minute market	37%	252	1.1%	29%	-238	1.1%	25
PacifiCorp East							
15-minute market	0.0%	N/A	N/A	0.6%	-69	1.2%	0
5-minute market	16%	88	1.7%	29%	-96	1.9%	-13
PacifiCorp West							
15-minute market	0.0%	N/A	N/A	0.1%	-65	2.3%	0
5-minute market	1.5%	43	1.7%	21%	-52	2.1%	-10
NV Energy							
15-minute market	0.0%	150	3.9%	0.0%	N/A	N/A	0
5-minute market	16%	90	2.4%	8.2%	-117	3.6%	5
Puget Sound Energy							
15-minute market	2.2%	27	0.8%	33%	-40	1.3%	-12
5-minute market	2.0%	30	0.9%	51%	-40	1.3%	-20
Arizona Public Service							
15-minute market	27%	60	2.1%	56%	-90	3.4%	-34
5-minute market	27%	61	2.2%	56%	-90	3.5%	-34
Portland General Electric							
15-minute market	0.2%	36	1.3%	0.0%	N/A	N/A	0
5-minute market	40%	27	1.0%	1.2%	-34	1.4%	10
Idaho Power							
15-minute market	2.7%	46	2.4%	4.5%	-50	2.8%	-1
5-minute market	6.5%	45	2.4%	10%	-47	2.7%	-2
BANC*							
15-minute market	0.0%	N/A	N/A	0.2%	-54	5.2%	0
5-minute market	0.4%	27	2.2%	1.4%	-36	3.2%	0
Seattle City Light							
15-minute market	0.4%	24	1.9%	13%	-20	1.7%	-3
5-minute market	3.6%	22	1.8%	64%	-20	1.7%	-12
Salt River Project							
15-minute market	0.3%	101	3.3%	0.4%	-92	3.4%	0
5-minute market	3.7%	74	2.5%	3.8%	-71	2.6%	0

*Data for BANC covers January 1, 2021 – March 24, 2021

2.5 Greenhouse gas in the Western EIM

In the first quarter, weighted 15-minute and 5-minute greenhouse gas average prices were nearly the same compared to the same quarter last year. This is likely occurred due to the same portion of hydro-electric and natural gas capacity that was deemed delivered in to California year over year.

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.[55] 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.[56] 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.

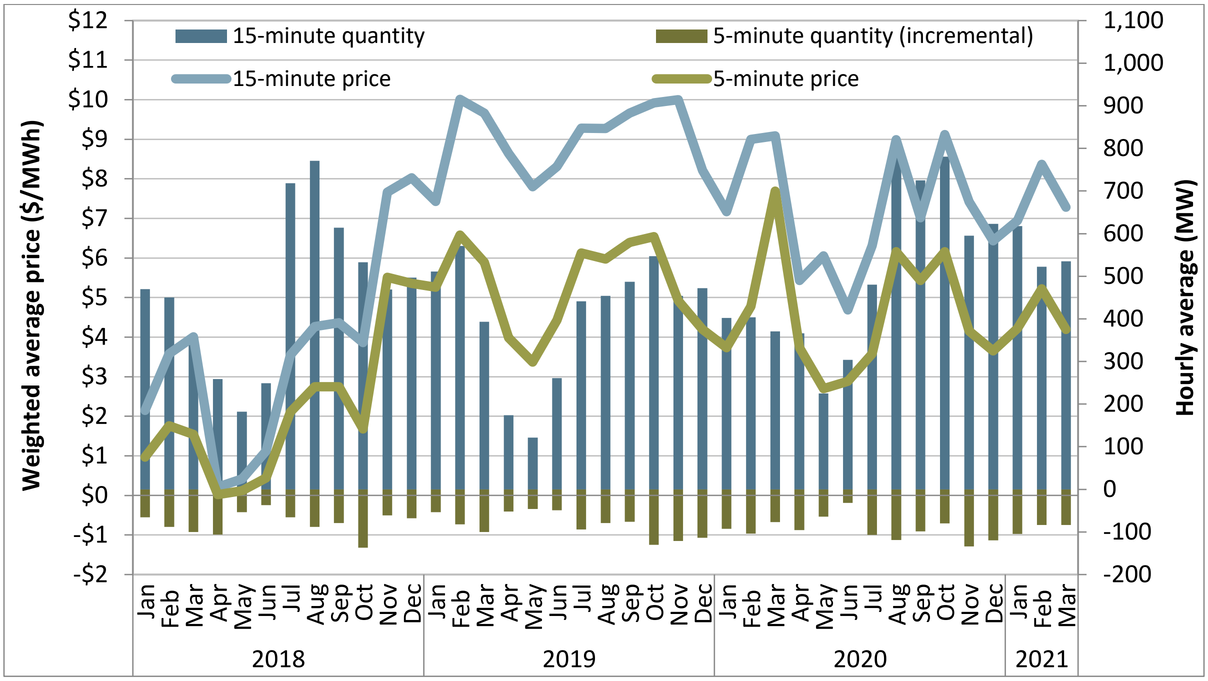
Greenhouse gas prices

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.

55 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.

56 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 first quarter while 5-minute prices averaged $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.

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 2019. In the first quarter, the highest 15-minute price and 5-minute price was $190.96/MWh and $266.79/MWh, respectively, which is significantly higher than the highest bid-in offer.

Figure 2.19 High 15-minute EIM greenhouse gas prices

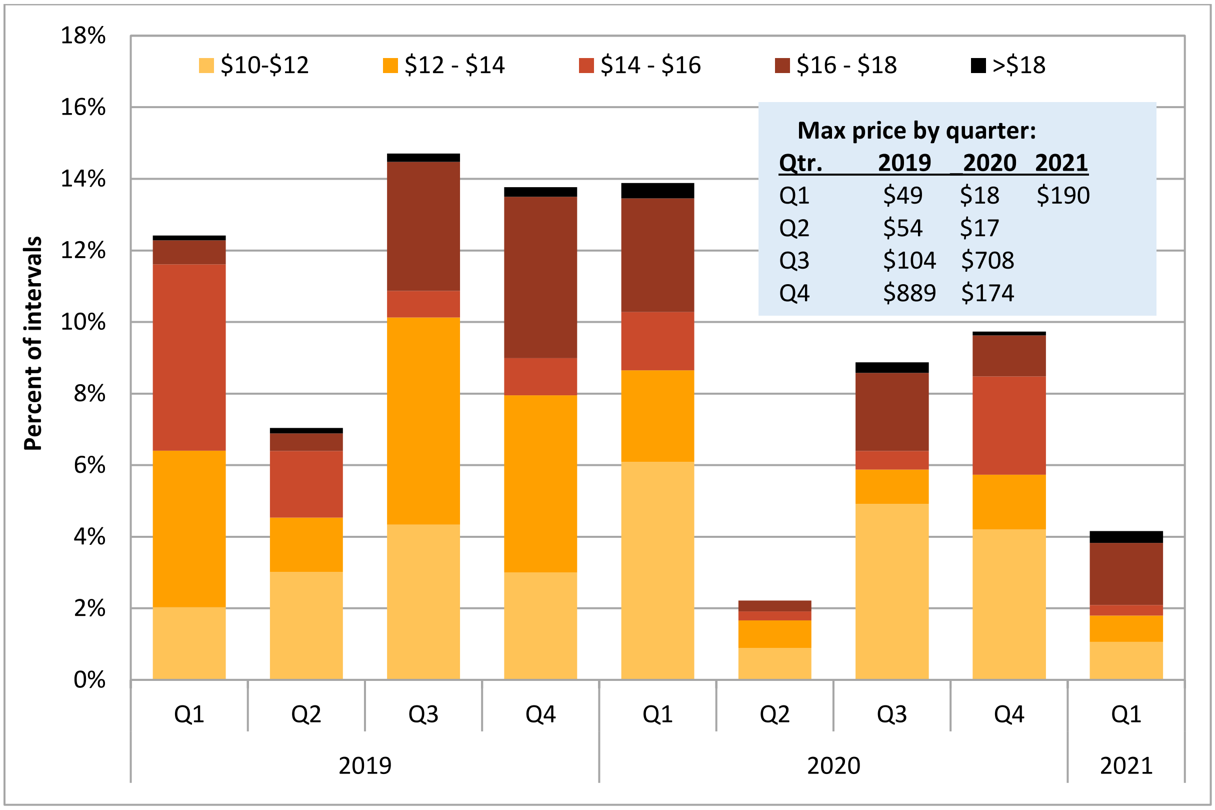
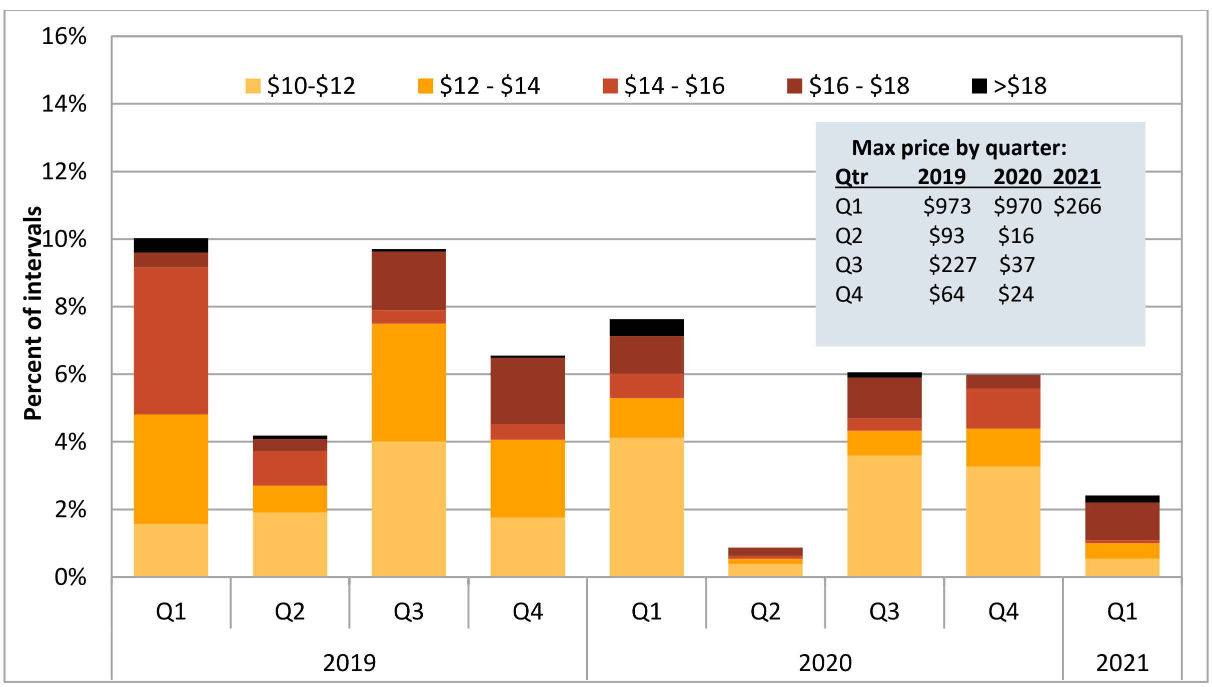


Figure 2.20 High 5-minute EIM greenhouse gas prices

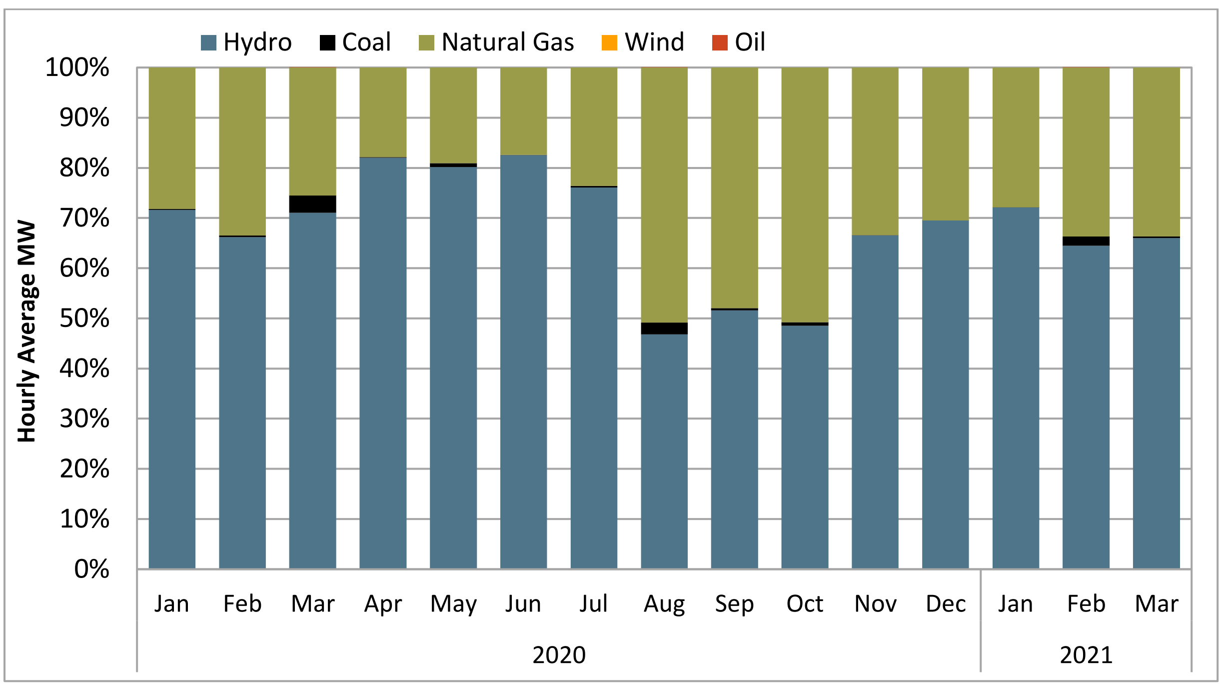


DMM estimates the total revenue accruing for greenhouse gas bids attributed to EIM participating resources serving the ISO load before subtracting estimated compliance costs from greenhouse gas revenue calculated in each interval. This value totaled around $9.5 million in the first quarter, compared to roughly $7.4 million in the same quarter of the previous year.

Energy delivered to California by fuel type

Figure 2.21 shows the hourly average energy deemed delivered to California by fuel type and by month. In the first quarter, about 32 percent of EIM greenhouse gas compliance obligations were awarded to gas resources; slightly more than the first quarter of the previous year. Hydro-electric resources accounted for about 68 percent of total energy delivered to California, which decreased slightly from around 70 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 first quarter; about the same amount as in the first quarter of 2020.

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 first quarter of 2021, 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 2020. 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 first quarter of 2021, on average, this portion has increased by about 150 MW when compared to the same quarter in 2020.
- A small volume of bids were lowered as a result of mitigation in the Western EIM.

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

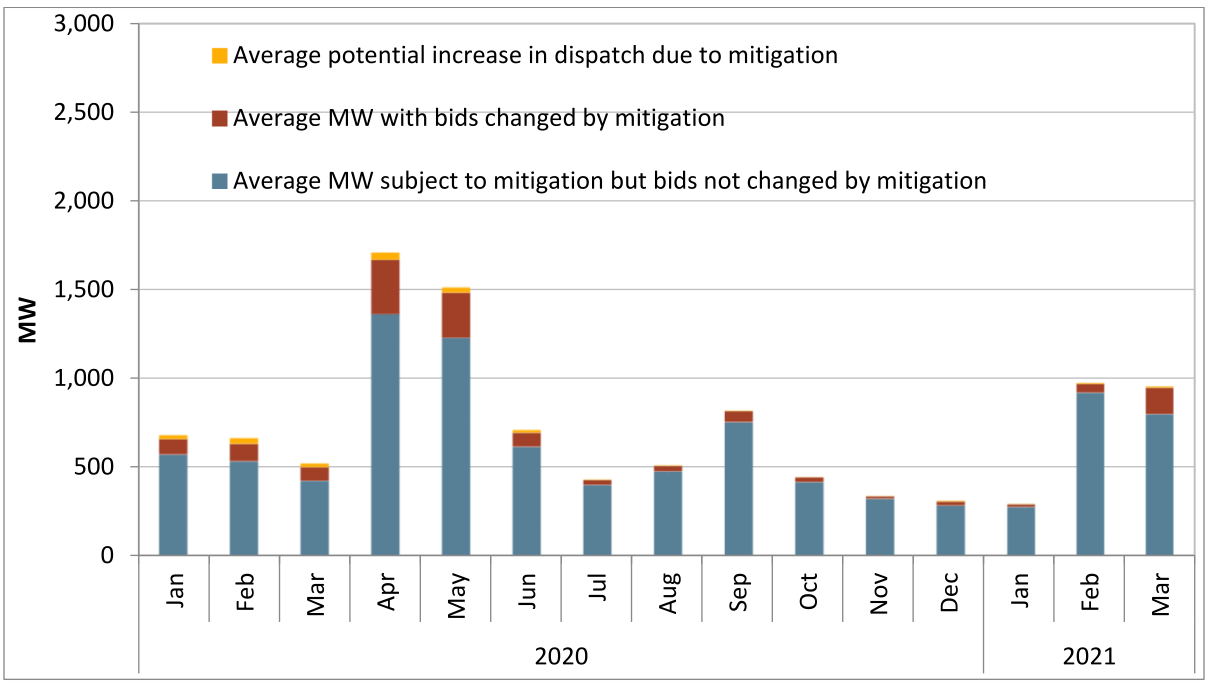
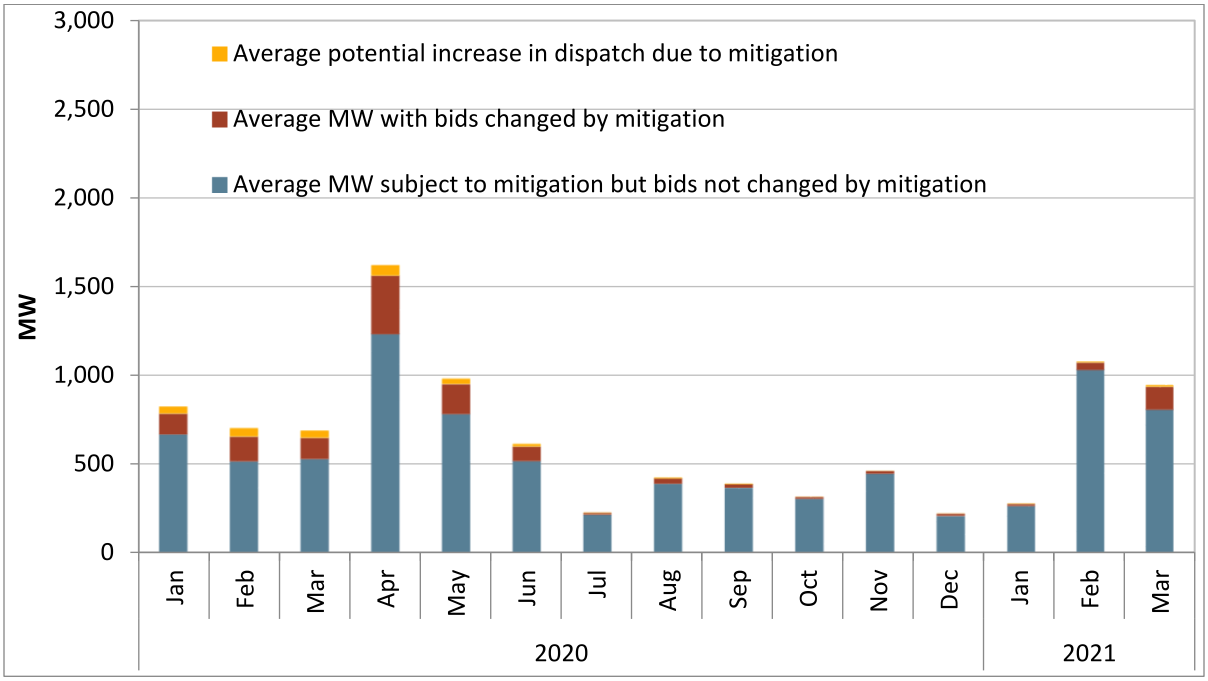


Figure 2.23 Average incremental energy mitigated in 5-minute real-time market (EIM)



3 Special issues

In mid-February gas prices spiked due to supply shortages caused by extreme winter conditions in Texas and the Midwest. Many natural gas generators across the ISO and western EIM footprint experienced gas costs over $100/MMBtu. This high gas price event led to the implementation of two tariff amendments that had been approved in 2020.

First, effective February 16, 2021, the ISO implemented Commitment Costs and Default Energy Bids Enhancements Phase 1 (CCDEBE).[57] Under this market design, generators can submit adjustments to commitment costs and default energy bids reference levels calculated by the ISO and also be eligible to receive after-market cost recovery. However, cost recovery associated with incremental energy was still capped at $1,000/MWh.

Second, the ISO requested permission from FERC to accelerate the implementation of a portion of the tariff amendment associated with Phase 1 of FERC Order 831.[58] In 2016, FERC issued Order 831, which requires each Independent System Operator (ISO) and Regional Transmission Organization (RTO) to increase the incremental energy bid cap to $2,000/MWh and establish a process to verify cost-based incremental energy bids over $1,000/MWh.[59]

The ISO began the CCDEBE initiative to comply with Order 831 and to address concerns that stakeholders were unable to accurately reflect their fuel or fuel-equivalent costs in ISO calculated reference levels for commitment costs and default energy bids. This initiative would allow resources to request adjustments to their fuel or fuel-equivalent costs in the ISO market optimization. The ISO also argued that this process proposed in the CCDEBE initiative could be used to meet the cost-verification process required by Order 831.

In response to the high gas prices, and to ensure resources could get after-the-fact cost recovery over the $1,000/MWh energy bid cap, the ISO implemented CCDEBE phase 1 and submitted an emergency filing request to FERC to implement the cost recovery portion of the tariff amendment associated with Phase 1 of Order 831. This was originally planned to be implemented on March 21, 2021, but was approved for emergency implementation by FERC and was effective starting February 17, 2021.[60]

The following sections explain the bidding rules under the CCDEBE policy and FERC Order 831, and how they affect the ISO market processes.

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57 Market Notice - Commitment Costs and Default Energy Bids Enhancements Phase 1: Deployment Effective for Trade Date 2/16/21: http://www.caiso.com/Documents/CommitmentCost-DefaultEnergyBidEnhancementsPhase1-DeploymentEffective-TradeDate21621.html

58 Emergency Filing for FERC Order 831: After-the-Fact Energy Cost Recovery, February 17, 2021: http://www.caiso.com/Documents/EmergencyFiling-FERCOrder831After-the-FactEnergyCostRecovery.html

59 FERC Order 831: Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators, November 17, 2016: https://www.ferc.gov/sites/default/files/2020-06/RM16-5-000.pdf

60 FERC Order Accepting Order No. 831 Compliance – ER21-1164: http://www.caiso.com/Documents/Feb22-2021-LetterOrderAccepting-FERCOrderNo831-ER21-1164.pdf

3.1 Commitment Cost and Default Energy Bids Enhancements

The CCDEBE stakeholder initiative started at the end of 2016 due to concerns that resources were unable to reflect their actual costs in the market. Although FERC rejected certain portions of the tariff amendment in 2019, the ISO made some adjustments[61] and suggested that the CCDEBE proposal would also provide a mechanism to verify cost-based energy offers over $1,000/MWh as required by FERC Order 831. Effective February 16, 2021, the ISO implemented Phase 1 of the CCDEBE tariff provisions.

One objective of the proposal was to enable suppliers to request an adjustment to their commitment cost and energy price reference levels.[62] The ISO uses these calculated cost-based reference levels in four circumstances:

(1) Suppliers can bid commitment costs (start-up, transition, and minimum load costs) up to a resource's default commitment cost bids[63]

(2) Market systems cap a resource's incremental energy bid at the maximum of the competitive local market power (LMP) or default energy bid when its bid is mitigated as part of the local market power mitigation mechanism[64]

(3) Default energy bids are also used as part of various energy financial settlement provisions[65]

(4) Default energy bids are used to produce generated bids[66]

The CCDEBE tariff provisions specify two avenues for resources to request an adjustment to their fuel or fuel-equivalent cost component of their reference level. First, resources can request an automated reference level adjustment through the Scheduling Infrastructure Business Rules software (SIBR), the ISO system used by market participants to place bids in the market. Market participants make these requests by bidding in their re-calculated commitment cost and/or default energy bid using actual or expected fuel or fuel-equivalent costs. These requests are evaluated against the reasonableness thresholds calculated by the ISO which are explained further below.

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61 FERC found that CAISO had not demonstrated that the proposal to apply a 125 percent multiplier on top of supplier-submitted proxy commitment costs was just and reasonable, January 21, 2020: https://cms.ferc.gov/sites/default/files/2020-05/20200121172727-ER19-2727-000.pdf

62 Tariff Amendment to Enable Updates to Default Commitment Costs and Default Energy Bids, July 9, 2020: http://www.caiso.com/Documents/Jul9-2020-TariffAmendment-CommitmentCostsandDefaultEnergyBidEnhancementsCCDEBE-ER20-2360.pdf

63 Tariff Sections 30.4.1.1.1 (b), 30.4.1.1.2 (b), 30.4.1.1.4, 30.7.9 (c), and 30.7.10: http://www.caiso.com/Documents/Section30-Bid-and-Self-ScheduleSubmission-in-CaliforniaISOMarkets-asof-Mar21-2021.pdf

64 Tariff Section 31.2.1, pp 3: http://www.caiso.com/Documents/Section31-Day-AheadMarket-asof-Feb15-2021.pdf
Tariff Section 39.7.1, pp 8: http://www.caiso.com/Documents/Section39-MarketPowerMitigationProcedures-asof-Mar21-2021.pdf

65 Tariff Section 11.8: http://www.caiso.com/Documents/Section11-CaliforniaISOSettlements-and-Billing-asof-Mar21-2021.pdf

66 Tariff Section 39.7.3.4: http://www.caiso.com/Documents/Section39-MarketPowerMitigationProcedures-asof-Mar21-2021.pdf

Second, resources can submit a manual reference level adjustment request through the Customer Inquiry, Dispute & Information system (CIDI). The request should contain an actual or expected fuel price or fuel equivalent cost with supporting documentation. If approved, the ISO will recalculate the resource's reference levels to be used in the applicable market runs.

Automated requests

Automated requests must be made prior to the time that the applicable ISO market process is executed. These requests are made for specific hours of a particular trade date through SIBR. Requests made through this process will be compared to a resource-specific reasonableness threshold and the request will be capped at this threshold. The reasonableness threshold for commitment costs is based on the proxy cost formula. For default energy bids (DEBs), it is based on the variable cost-based formula.

The fuel or fuel-equivalent cost component of the reasonableness threshold is scaled up using a fuel volatility scalar. For days without a published gas index, e.g., days after holidays and weekends, a scalar of 125 percent will be applied to the gas commodity price. On other days, a scalar of 110 percent will be applied to the gas commodity price. For non-gas resources, the average cost for the fuel or fuel-equivalent costs will include a fuel price scalar of 110 percent on all days.[67]

When a scheduling coordinator submits an automated request, they are required to calculate their new reference level using the same methodology used to calculate the proxy cost-based commitment cost and variable-cost based DEB without applying the respective multipliers. The justification for not including these multipliers is that they are included in the ISO calculations to account for differences between the supplier purchase price and weighted average index price. Therefore, if the scheduling coordinator is able to incorporate their actual fuel or fuel-equivalent cost there is no reason to include the multiplier.[68]

When a resource's automated reference level change request is less than or equal to the resource-specific reasonableness threshold, the ISO will automatically approve the requested adjustment. If a resource submits an automated reference level change request greater than the resource-specific reasonableness threshold, the ISO will approve the adjustment up to the value of the reasonableness threshold. The resource will then be eligible to recover the remaining costs after-the-fact. While suppliers do not need to submit supporting documentation for automated requests through SIBR, they must maintain the documentation as the ISO may later audit the supplier to determine whether the request was appropriate.

Manual requests

The manual reference level adjustment process is available when a resource's requested reference level is greater than the reasonableness threshold. The ISO will reject manual requests where the requested reference level is less than the reasonableness threshold and will instruct the scheduling coordinator to submit an automated request. Manual reference level adjustment requests are submitted through CIDI

67 Reasonableness threshold formula and detailed examples are included in Market Instruments BPM Attachment O.1.2: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

68 Motion to Intervene and Comments of the Department of Market Monitoring, CCDEBE, September 20, 2019: http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoring-CCDEBE-ER19-2727-Sept202019.pdf

where a supplier must specify their actual or expected fuel or fuel-equivalent cost, and also include supporting documentation. These requests must be submitted by 8 a.m. on the business day the applicable California ISO market is executed. [69,70]

As mentioned before, automated requests require suppliers to recalculate their proxy or variable costs with their actual or expected fuel or fuel-equivalent costs. Manual requests only require suppliers to submit a request with their actual or expected fuel costs with supporting documentation. If approved, the ISO will recalculate the commitment cost bids and default energy bids using the approved fuel costs without any respective multipliers. In addition, the resource-specific reasonableness threshold will also be updated with these new reference levels.[71] For non-gas resources, manual requests can only be submitted to adjust default energy bid reference level and not commitment costs.

After-market cost recovery

An important part of the CCDEBE tariff provisions is the effect on the after-market cost recovery process. As already established in the tariff, if a resource is unable to recover the sum of their bid-in costs through the market (commitment, energy, ancillary services, and residual unit commitment costs) the resource can recover them through bid cost recovery uplift payment.[72] Hence, if a resource is better able to reflect their actual costs in their adjusted reference levels, they will be able to receive more accurate uplift payments.

Additionally, the tariff provisions provide additional flexibility for resources to receive after-market cost recovery directly from the ISO. In particular, if a supplier's reference level change request is not approved, they are eligible for after-the-fact cost recovery through resettling of uplift payments based on their actual costs. This applies to automated requests that are capped at the reasonableness threshold as well as manual requests that were not approved by the ISO before the market run.[73]

Before the implementation of CCDEBE, if a resource was unable to reflect their actual costs in the reference levels, they would need to apply for after-market recovery through FERC. Now, suppliers who make a reference level change request are eligible to apply for after-market recovery with the ISO.

In order for a supplier to be eligible for after-market cost recovery, the scheduling coordinator must have submitted a reference level change request prior to the applicable market run that was either rejected (manual request) or capped (automated request). Since requests are made before the market run, and may be based on *expected* fuel or fuel-equivalent costs, suppliers may need to provide

69 Tariff Section 30.11.4.2: http://www.caiso.com/Documents/Section30-Bid-and-Self-ScheduleSubmission-in-CaliforniaISOMarkets-asof-Feb15-2021.pdf

70 Manual request process is explained in detail in Market Instruments BPM Attachment O.1.3: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

71 The updated reasonableness threshold after a manual request is approved will be equal to the default value since no multipliers are used to recalculate reference levels. Reasonableness thresholds are only used as a comparison for automated requests so these updated reasonableness thresholds would only be used if a resource submitted an automated request after they had submitted a manual request.

72 Tariff Section 11.8: http://www.caiso.com/Documents/Section11-CaliforniaISOSettlements-and-Billing-asof-Mar21-2021.pdf

73 After-market cost recovery process is explained in detail in Market Instruments BPM Attachment O.3: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

additional information on the *actual* costs which will determine the adjusted uplift payment from the ISO.

CCDEBE usage

After CCDEBE provisions were implemented on February 16, 2021, all of the reference level change requests were made between February 16 and February 19 when gas prices were historically high. There were about 20 manual requests made during this time period but only 3 were accepted. Reasons the California ISO rejected manual requests include:

- Requested fuel price was low enough such that the scheduling coordinator should have submitted an automated request;
- The ISO cannot cover Operational Flow Order (OFO) penalties;
- The ISO is unable to determine specific price requested and how that price was reflected in documentation provided by scheduling coordinator; and
- Scheduling coordinator did not provide supporting documentation.

3.2 FERC Order No. 831

In 2016, FERC issued Order No. 831 which requires each Independent System Operator (ISO) and Regional Transmission Organization (RTO) to cap a resource-specific resource's energy offer at the higher of the soft offer cap of $1,000/MWh or verified cost-based incremental energy bid, where verified cost-based energy bids for resource-specific resources are capped at $2,000/MWh. FERC found the existing $1,000/MWh offer cap could potentially lead to inefficient market outcomes by not allowing resources to reflect costs, artificially suppress locational marginal prices, and discourage resources from offering supply that the market may be willing to purchase. Although the $1,000/MWh cap may be too low under certain conditions there are concerns about unjustifiably high prices. To address these concerns, the order requires bids over the soft offer cap to be cost-verified and implementation of a hard offer cap of $2,000/MWh since ISOs and RTOs have imperfect information about the resource's costs.

As mentioned earlier, to comply with this order, the California ISO developed a process to cost-verify energy bids over $1,000/MWh in the CCDEBE initiative. The ISO would use the reference level adjustment requests to allow resources to increase their default energy bids over the soft cap of $1,000/MWh and cap them at the hard cap of $2,000/MWh. Hence, any incremental energy bid over soft offer cap will be evaluated against the verified adjustment request. Similarly, default minimum load cost bids will also be capped at $2,000/MWh. This is calculated by dividing the minimum load cost bid by the resource's Pmin.

There are three important implementation dates for tariff amendments associated with Order No. 831. The first was an emergency filing effective February 17, 2021, to deal with the high gas prices experienced across the west.[74] This change allowed for after-market cost recovery of commitment costs

[74] Emergency Filing for FERC Order 831: After-the-Fact Energy Cost Recovery, February 17, 2021: http://www.caiso.com/Documents/EmergencyFiling-FERCOrder831After-the-FactEnergyCostRecovery.html

and incremental energy over $1,000/MWh. This filing along with the implementation of CCDEBE on February 16 allowed resources to submit reference level change requests. Any manual requests submitted were used as basis to receive after-market recovery since many suppliers experienced high gas prices leading to energy costs more than $1,000/MWh.

Secondly, effective March 20, 2021, the remainder of the first phase of FERC Order 831 was implemented. These tariff provisions authorize the ISO to verify fuel price increases before the market run so that the market prices appropriately reflect those costs. Specifically, default energy bids (DEBs) calculated by the ISO will be capped at soft offer cap unless a resource submits an automated or manual reference level request. The updated DEBs from these requests will be capped at $2,000/MWh. This allows resources to submit incremental energy bids over the soft offer cap if they have a cost-verified adjusted DEB over $1,000/MWh. In addition, if incremental energy costs or minimum load costs exceed the hard offer cap, the remaining portion of the reference level request will be eligible for after-the-fact recovery. Lastly, Phase 2 which includes two main market enhancements will be implemented later this summer. [75,76]

Bidding rules

For an import or virtual resource to submit an incremental energy bid over the soft offer cap of $1,000/MWh, they must submit a reference level change request. If the requested default energy bid is over the soft offer cap, and is approved by the ISO, then that resource will be able to submit bids for incremental energy to the higher of $1,000/MWh or the verified cost-based default energy bid. As mentioned earlier, any verified cost-based change request will be hard-capped at $2,000/MWh. Any resource that has not submitted a reference level change request will still have their ISO-calculated default energy bid capped at soft offer cap.

After the first phase of the FERC Order 831 compliance was enacted on March 20, there were no bids from resource-specific resources or imports for over $1,000/MWh. However, there were some virtual bids over $1,000 from March 28 to March 31, averaging about 100 MW a day, but none of these bids cleared the market.

Phase 2 of FERC Order 831, to be implemented in summer 2021, focuses on import bidding and market parameters related to supply shortages. Since the California ISO is often dependent on imports to meet load, there is concern regarding import bids exceeding $1,000/MW because the ISO currently does not have the ability to cost verify these resources. To address these concerns, the ISO will only allow import and virtual bids over $1,000/MWh when (1) the ISO has accepted a cost-verified bid over $1,000/MWh or (2) the maximum import bid price (MIBP) is greater than $1,000/MWh. The maximum import bid price approximates the prevailing bilateral price of electricity and is a function of electric hub prices at Mid-Columbia and Palo Verde and is an hourly energy price shaping factor.[77]

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75 Tariff Amendment to Enhance Market Parameters and Import Bidding Related to Order No. 831, February 22, 2021: http://www.caiso.com/Documents/Feb22-2021-TariffAmendment-PricingParameters-OrderNo831-ER21-1192.pdf

76 CAISO Training for FERC Order 831 Import Bidding and Market Parameters: http://www.caiso.com/Documents/Presentation-FERC-Order-831-Import-Bidding-Market-Parameters-Training-Apr-28-2021.pdf

77 Max import bid price calculation, pp 26: http://www.caiso.com/InitiativeDocuments/RevisedFinalProposal-FERCOrder831-ImportBidding-MarketParameters.pdf

The table below shows the circumstances under which different types of resources can submit bids over $1,000/MWh and how they will be capped in the market once Phase 2 of the FERC Order 831 compliance is implemented.[78]

Table 3.1 FERC order 831 compliance bidding rules by resource type

Resource type	Market conditions	Energy bid cap details
Resource-specific resources (generators, participating load)	Not applicable, a resource-specific resource may submit a bid between $1,000/MWh and $2,000/MWh through submission of a reference level change request to a resource's DEB	Bids above $1,000/MWh will be capped at the higher of $1,000/MWh and the resource's revised DEB (revised DEB cannot exceed $2,000/MWh)
Non-resource specific resources that are resource adequacy (RA imports)	(1) ISO-calculated MIBP exceeds $1,000/MWh **OR** (2) ISO has accepted a cost-verified energy bid above $1,000/MWh for the applicable trading hours	Bids above $1,000/MWh will be reduced to the greater of the MIBP or the highest-priced energy bid from a resource-specific resource.
Non-resource specific resources that are not RA (imports and exports) Virtual resources	(1) ISO-calculated MIBP exceeds $1,000/MWh **OR** (2) ISO has accepted a cost-verified energy bid above $1,000/MWh for the applicable trading hours[79]	These resources can submit bids up to $2,000/MWh. They will not be capped in the same way as RA imports.

Market parameters

The second enhancement in Phase 2 of the FERC Order 831 tariff provisions focus on the market parameters that are dependent on the energy bid cap, particularly the parameter used in the market to calculate locational marginal prices when there is insufficient supply. Before Order 831, the market would administratively set prices at the $1,000/MWh offer cap when there was a power balance constraint under-supply infeasibility. After Order 831, since a soft offer cap of $1,000/MWh and a hard

[78] BPM for Market Instruments, Attachment P: Energy Bid Caps: http://www.caiso.com/Documents/BPM_for_MarketInstruments_Attachment_P_DRAFT.pdf

[79] These rules for non-resource adequacy imports and exports and virtual resources do not begin until Phase 2 is implemented. Under Phase 1 non-resource adequacy imports and exports and virtual resources may bid between $1,000/MWh and $2,000/MWh in any circumstance.

offer cap of $2,000/MWh exist, the ISO proposed additional rules for setting the power balance constraint shortage penalty price over the soft offer cap.

The California ISO will calculate a threshold value and compare that to the supply shortfall. These threshold values are calculated each year for each balancing authority area (BAA) using a formula based on the North American Electric Reliability Corporation (NERC) Reliability Standard (BAL-001-2 Requirement R2). Details on the penalty pricing rules under FERC Order 831 are provided in Table 3.2.[80,81]

Table 3.2 Penalty pricing rules under FERC Order 831 Phase 2

Situations where power balance constraint (PBC) shortage penalty price is set over $1,000/MWh	
(1) CAISO accepted (and validated) energy bid over $1,000/MWh soft offer cap	
(2) Maximum import bid price over $1,000/MWh soft offer cap	
BAA PBC infeasibility ≤ BAA-specific threshold	**BAA PBC infeasibility > BAA-specific threshold**
• Penalty price set at highest cleared economic bid • Lower bound of penalty price is $1,000/MWh (when infeasibility is positive)	• Penalty price set to $2,000/MWh hard energy bid cap

80 Tariff Amendment to Enhance Market Parameters and Import Bidding Related to Order No. 831: http://www.caiso.com/Documents/Feb22-2021-TariffAmendment-PricingParameters-OrderNo831-ER21-1192.pdf pp 14-17

81 Business Requirements Specification, Appendix B – SIBR Logic: http://www.caiso.com/Documents/BusinessRequirementsSpecificationFERC831ImportBiddingMarketParameters.pdf