Q4 2021 Report on Market Issues and Performance

April 4, 2022

Prepared by: Department of Market Monitoring

California Independent System Operator

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Executive summary

This report covers market performance during the fourth quarter of 2021 (October - December).

Key highlights during this quarter include the following:

- **Market prices were significantly higher** than the same quarter of 2020 on average. Day-ahead prices in the California ISO rose about 50 percent. Increases were due to higher natural gas prices.
- **Gas prices increased more than $2/MMBtu** at Henry Hub, SoCal Citygate, PG&E Citygate, NW Sumas and El Paso Permian hubs compared to the same quarter in 2020. This represents an increase of more than 50 percent in some natural gas prices, and resulted in higher marginal energy prices across the Western Energy Imbalance Market, including the California ISO.
- **Renewable production increased** by 9 percent compared to the same quarter in 2020, due to an increase of wind, solar, and hydro-electric production.
- **Bilateral market prices in other balancing areas were often significantly lower than California ISO** market prices, due to both transmission constraints as well as greenhouse gas compliance costs.
- **Flexible ramping product** system level prices were zero for over 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.
- **Non-zero flexible ramping product prices** occurred in areas where minimum area flexible ramping product constraints were binding. The 15-minute market minimum area constraint was introduced in November 2020 and bound frequently for the California ISO but no other areas. The 5-minute minimum area constraint was introduced effective February 2022.
- **Congestion** in the day-ahead market decreased SCE prices while it increased SDG&E and PG&E area prices. Total day-ahead congestion rent was $155 million, an increase from $103 million in the same quarter of the previous year.
- **Imbalance conformance adjustments** averaged almost 800 MW during the morning load peak and almost 1,500 MW during the peak net load ramp hours, 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)

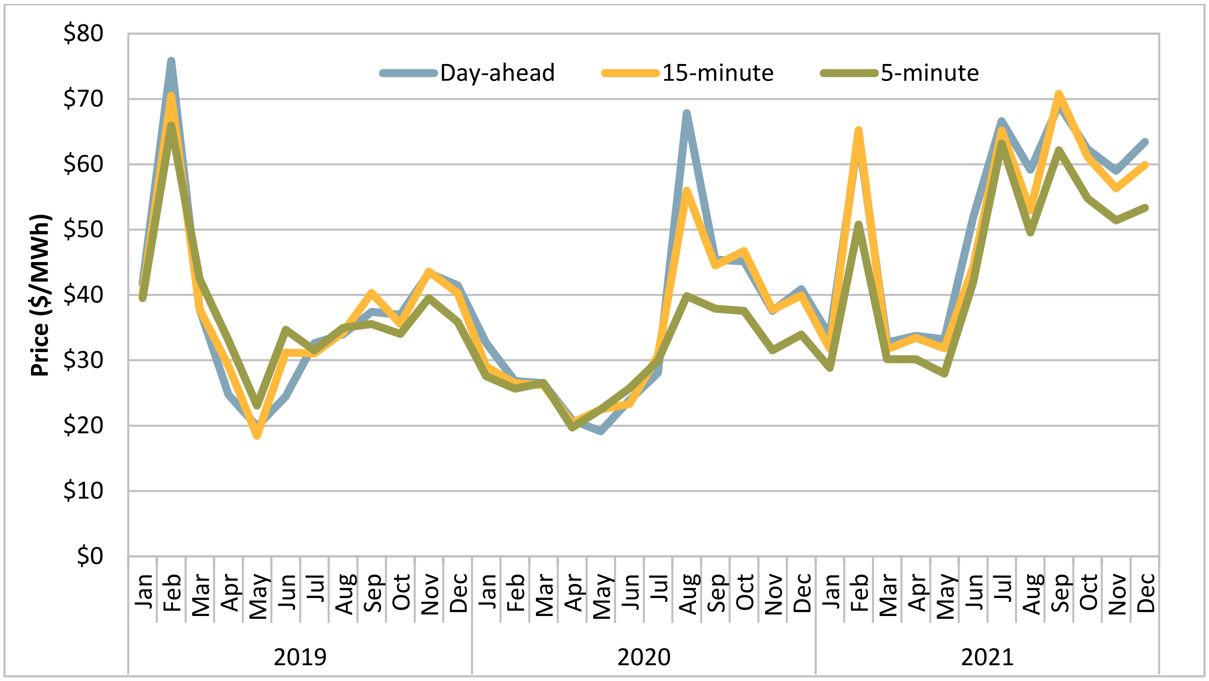
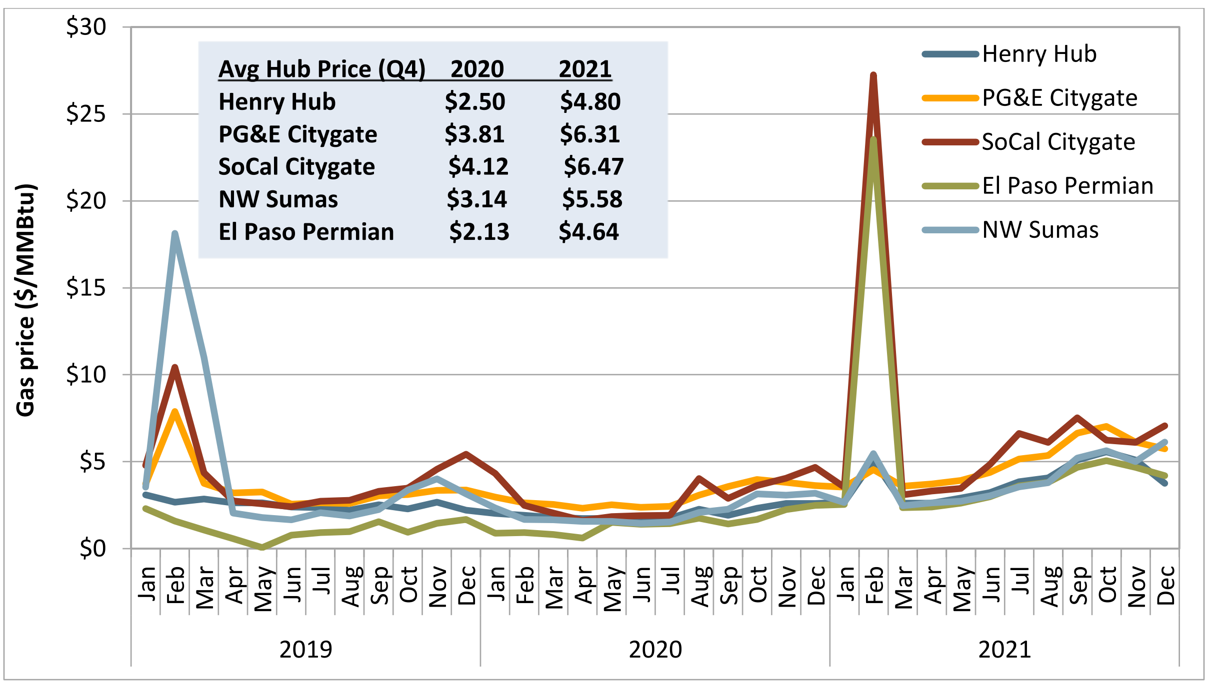


Figure E.2 Natural gas prices



Western Energy Imbalance Market

- **Natural gas prices rose across the WEIM**, resulting in higher energy prices in all balancing areas.
- **Prices in California areas were over $18/MWh higher than other regions.** Prices tend to be higher in California than the rest of the system due to both transfer constraint congestion and greenhouse gas compliance costs for energy that is delivered to California.
- **Prices in the Northwest region** were regularly lower than prices in other balancing areas due to limited transfer capability out of this region during peak system load hours. This region includes PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex,
- **The California ISO was a net importer** during most hours except the middle of the day when low priced solar generation was typically exported to the rest of the system. Compared to the fourth quarter of 2020, imports into the California ISO from Arizona Public Service and Salt River Project were partially replaced by imports from Los Angeles Department of Water and Power.
- **On June 16, 2021, the California ISO added net load uncertainty to the requirement of the bid range capacity test**. This uncertainty caused most capacity test failures in the fourth quarter. Net load uncertainty was removed from the bid-range capacity test on February 15, 2022, while intertie uncertainty is expected to be removed at a future date.
- **NorthWestern Energy** failed the upward capacity and flexibility tests test in roughly 8 percent of intervals in October. These failures did not have any direct impact on the rest of the WEIM because NorthWestern Energy did not offer incremental import capacity in the WEIM during this period. Since NorthWestern Energy did not import energy through the WEIM during the fourth quarter, this balancing area was also not leaning on the rest of the WEIM in any way.
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in monthly reports** as part of the WEIM resource sufficiency evaluation stakeholder initiative. DMM is seeking feedback from stakeholders on existing or additional metrics and analysis that would be most valuable.

1 Market performance

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

- **Electricity prices were about 50 percent higher** than the same quarter of 2020 due to higher natural gas prices. Day-ahead prices averaged $62/MWh, 15-minute prices averaged $59/MWh, and 5-minute prices averaged $53/MWh.
- **Gas prices increased by 57 percent at SoCal Citygate** and by 65 percent at PG&E Citygate, compared to the same quarter in 2020. This resulted in higher system marginal energy prices across the California ISO footprint.
- **Renewable production increased** by 9 percent compared to the same quarter in 2020, due to an increase of wind, solar, and hydro-electric production.
- **Bilateral market prices in other balancing areas were often significantly lower than California ISO** market prices, due to both transmission constraints as well as greenhouse gas compliance costs.
- **Flexible ramping product** system level prices were zero for over 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.
- **Non-zero flexible ramping product prices** occurred in areas where minimum area flexible ramping product constraints were binding. The 15-minute market minimum area constraint was introduced in November 2020 and bound frequently for the California ISO but no other areas. The 5-minute minimum area constraint was introduced effective February 2022.
- **Congestion** in the day-ahead market decreased SCE prices while it increased SDG&E and PG&E area prices. Total day-ahead congestion rent was $155 million, an increase from $103 million in the same quarter of the previous year.
- **Imbalance conformance adjustments** averaged almost 800 MW during the morning load peak and almost 1,500 MW during the peak net load ramp hours, 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 gas-fired units are often the marginal source of generation in the California ISO (CAISO) balancing area and other regional markets. During the fourth quarter of 2021, gas prices at major trading hubs across the west trended higher when compared to the same quarter of 2020. This increase in natural gas prices resulted in higher system marginal energy prices across the CAISO footprint.

Figure 1.1 shows monthly average natural gas prices at key delivery points across the west including PG&E Citygate, SoCal Citygate, Northwest Sumas, and El Paso Permian, as well as the Henry Hub trading point, which acts as a point of reference for the national market for natural gas. SoCal Citygate prices often affect overall electric system prices because there are large numbers of natural gas resources in the south, and these resources can set system prices in the absence of congestion.

Over the fourth quarter, prices at the SoCal Citygate gas hub averaged $6.47/MMBtu compared to $4.12/MMBtu (up 57 percent) in the fourth quarter of 2020. On November 4, 2021, the California Public Utilities Commission (CPUC) issued an order increasing the inventory limit for the Aliso Canyon Storage Field from 34 Bcf to 41.16 Bcf.[1] This is an interim solution for the winter season to maintain reliability in the SoCalGas territory because of ongoing pipeline constraints since mid-August 2021 on the El Paso system which restricted access to the Permian basin gas supply.

Consistent with the CPUC's ruling on April 29, 2019, SoCalGas Company made changes to its operational flow orders (OFO) stages and associated non-compliance penalty structure.[2] For the summer period, June 1 through September 30, SoCalGas temporarily reduced the number of non-compliance stages from 8 to 5. The non-compliance charge was reduced from $25/Dth and capped at $5/Dth for Stage 4 and Stage 5 flow orders.

For the winter period, October 1 through May 31, SoCalGas expanded the number of non-compliance stages from 5 to 8. The non-compliance charge for Stage 3 flow orders follows a tiered structure ranging from $5/Dth to $20/Dth and for Stage 4 and Stage 5 was set at $25/Dth.

The revisions from the CPUC's ruling expired on October 31, 2021. DMM submitted comments to a new CPUC ruling to revise the existing penalty structure.[3] Until a final decision on this new ruling is reached, CPUC has temporarily extended the 8-stage winter OFO structure for six months commencing on November 1, 2021.[4] During the fourth quarter, SoCalGas Company declared low OFOs on 10 gas days, out of which 3 gas days had Stage 3 in effect; the other gas days had either Stage 1 or Stage 2 in effect.

Gas prices at other major gas trading hubs in this quarter were also higher than prices during the fourth quarter of 2020. At Henry Hub, PG&E Citygate, El Paso Permian, and Northwest Sumas gas hubs, the prices rose by 92 percent, 66 percent, 117 percent, and 78 percent, respectively.

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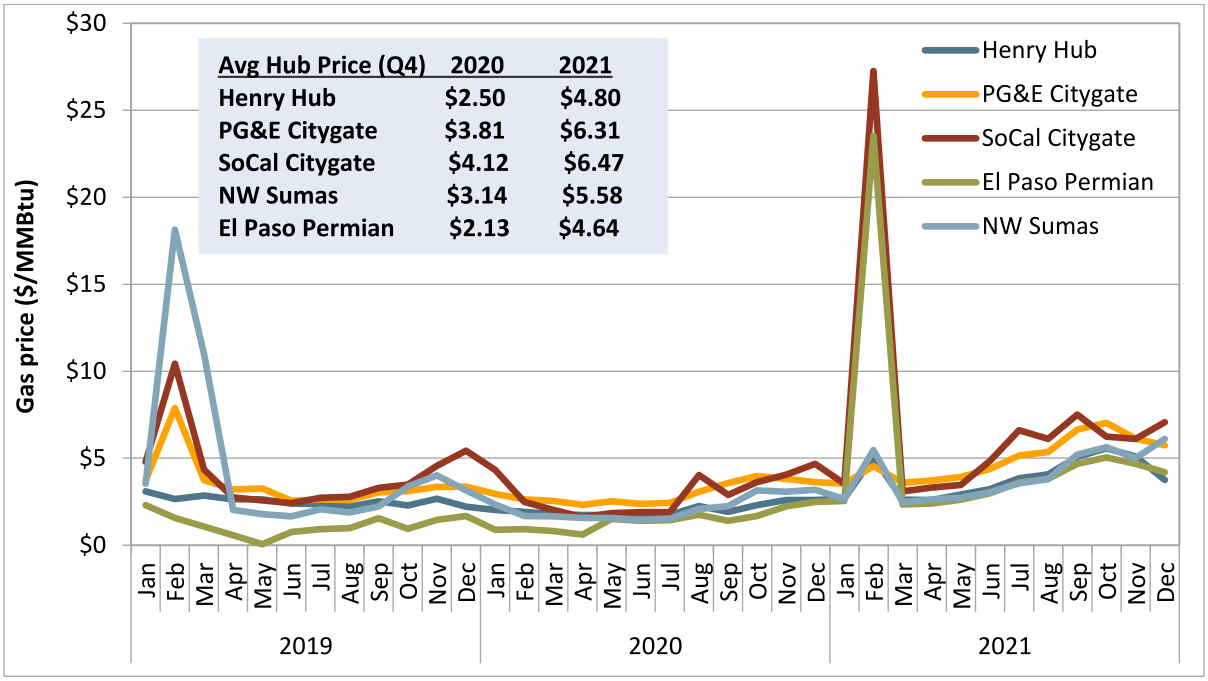
1 *Decision setting the interim range of Aliso Canyon Storage Capacity at Zero to 41.16 Bcf, D21-11-008*, November 4, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K086/421086399.PDF

2 *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

3 *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

4 *Proposed decision ordering Southern California Gas Company and San Diego Gas & Electric Company to implement Rule 30 Operational Flow Order non-compliance charge structure for the six months commencing November 1, 2021*, R20-01-007: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M423/K447/423447100.PDF

Figure 1.1 Monthly average natural gas prices



1.1.2 Renewable generation

In the fourth quarter, the combined average hourly generation from renewable resources increased by about 600 MW (9 percent) compared to the same quarter of 2020. Generation from hydroelectric, wind, and solar resources increased 12 percent while geothermal and biogas-biomass generation decreased 4 percent, compared to the fourth quarter of 2020.[5] The availability of variable energy resources contributes to price patterns both seasonally and hourly due to their low marginal cost relative to other resources.

Figure 1.2 shows the average hourly renewable generation by month and fuel type.[6] The largest increase in generation was from wind resources, which increased about 450 MW (33 percent), compared to the same quarter of 2020. Solar generation increased by 168 MW (6 percent), while geothermal and biogas-biomass generation decreased by 37 MW (4 percent) and 19 MW (4 percent), respectively.

Hourly average hydroelectric production in the fourth quarter increased by about 50 MW (3 percent), compared to the same period in 2020.[5] 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]

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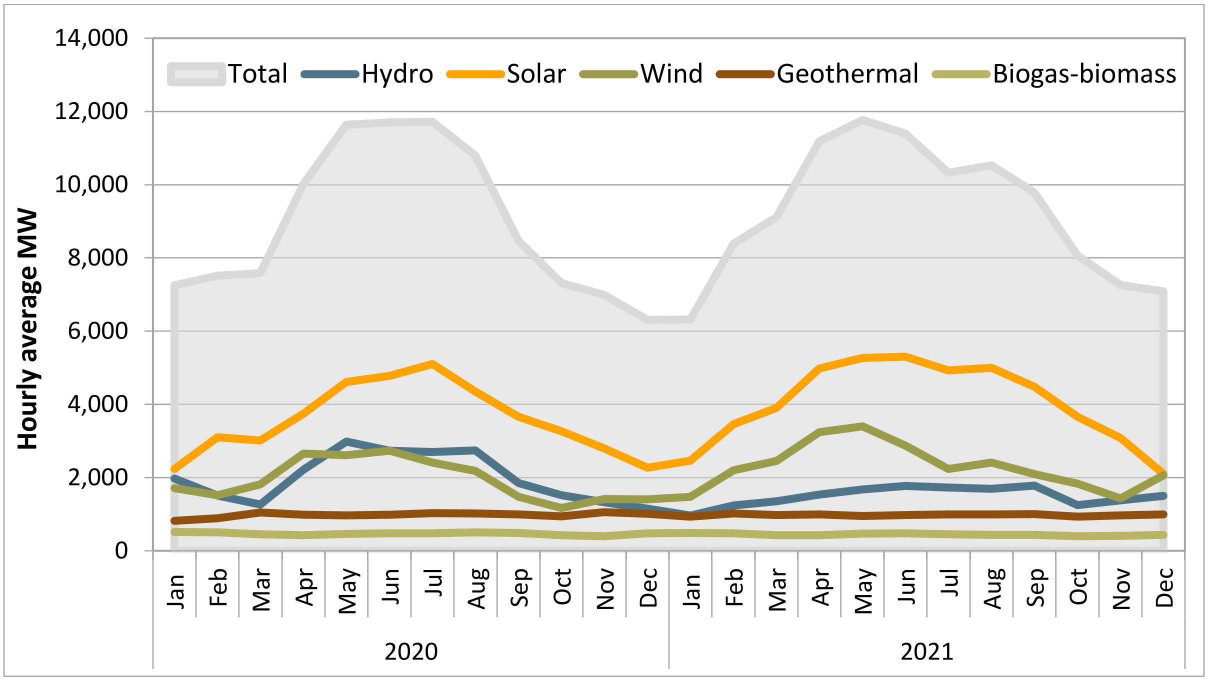
5 Figures and data provided in this section are preliminary and may be subject to change.

6 Hydroelectric generation greater than 30 MW is included.

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/.

Figure 1.2 Average hourly renewable generation by month



1.1.3 Downward dispatch and curtailment of variable energy resources

Wind and solar downward dispatch and curtailments increased in the fourth quarter by 6 percent in the California ISO and 632 percent in the Western Energy Imbalance Market (WEIM), relative to the fourth quarter of 2020. The sharp rise in downward dispatch in the WEIM was due to congestion on the Wyoming Export constraint, which heavily impacted resources in one area. The majority of the reduction in wind and solar output continued to be the result of economic downward dispatch, meaning the wind/solar bid price was above (or close to) the resulting market price.

When scheduled supply exceeds demand, the real-time market dispatches generators down in merit order from the highest bid to lowest. The last unit dispatched sets the system price and dispatch instructions are subject to constraints including transmission, ramping, and minimum generation. During some intervals, even wind and solar resources are dispatched down when the nodal price drops below low priced bids from these renewable resources. If the supply of bids to decrease energy is exhausted in the real-time market, the software may curtail self-scheduled generation, including wind and solar generation.

Figure 1.3 shows the curtailment of wind and solar resources by month in the California ISO. DMM has developed the following six categories for curtailment based on whether the resource bid in economically or self-scheduled, whether the resource received an exceptional dispatch/out of market instruction to decrease supply, and the relationship between the resource's bid price and the resulting market price:

- **economic downward dispatch**, in which an economically bid resource is dispatched down and the market price falls within one dollar of or below a resource's 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;[9]
- **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 -$150/MWh bid floor.

The majority of the reduction in wind and solar output during the quarter (96 percent) was a result of economic downward dispatch, rather than self-schedule curtailment. Most renewable generation dispatched down in the California ISO were solar resources (97 percent) rather than wind.

In the California ISO, economic downward dispatch peaked in October and totaled 243 GWh for the quarter. This represents a 9 percent increase relative to the same quarter of 2020. Self-schedule curtailment totaled 5.5 GWh for the quarter, a 28 percent decrease relative to the same quarter of 2020.

Figure 1.4 shows the amount of downward dispatch of WEIM wind and solar resources. Curtailments in the WEIM fall into four categories: economic downward dispatch, other economic downward dispatch, self-schedule curtailment, and other self-schedule curtailment, as defined above. Downward dispatch in the WEIM increased significantly in October, more than 20 times more than October of 2020. Much of the curtailment in the WEIM is due to the high frequency of congestion on the Wyoming Export constraint, which leads to resources in one area being heavily curtailed.[10]

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

9 The one-dollar threshold is included in the categorization of downward dispatch and curtailment types to mitigate small price discrepancies between bids and market prices.

10 The Total_Wyoming_Export constraint was congested during 59.1 percent of intervals during the quarter as shown in Table 1.6. The overall effects of transfer congestion are discussed in detail in Section 1.8.3.

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

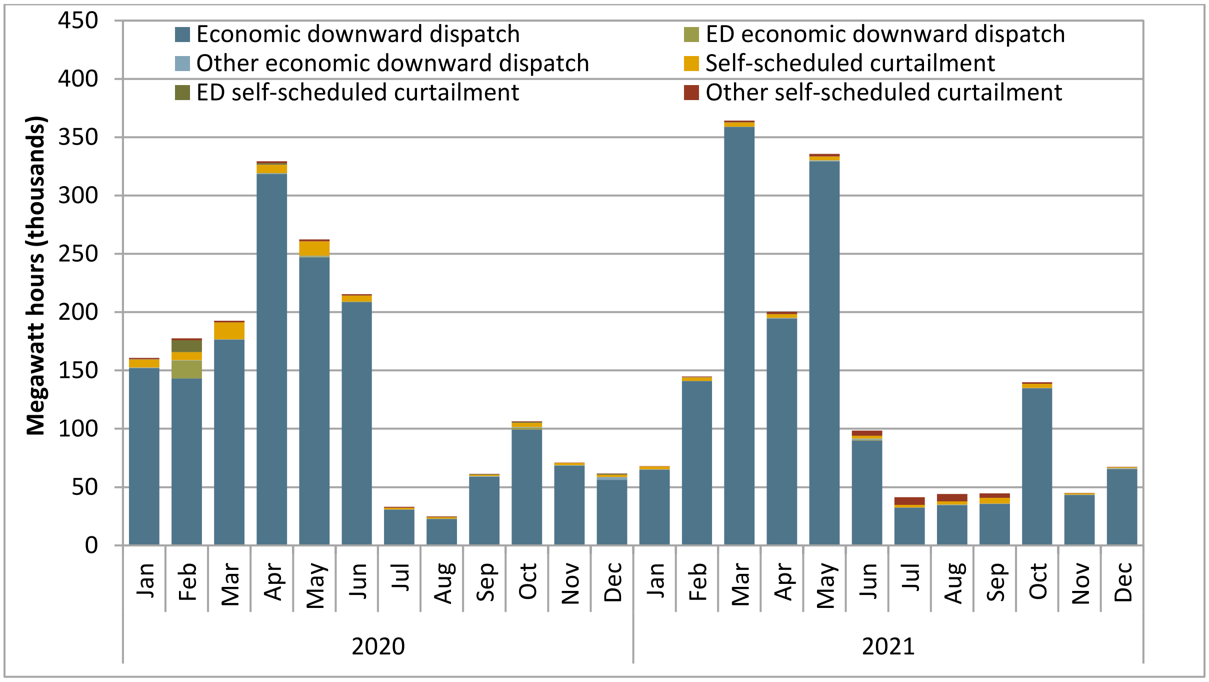
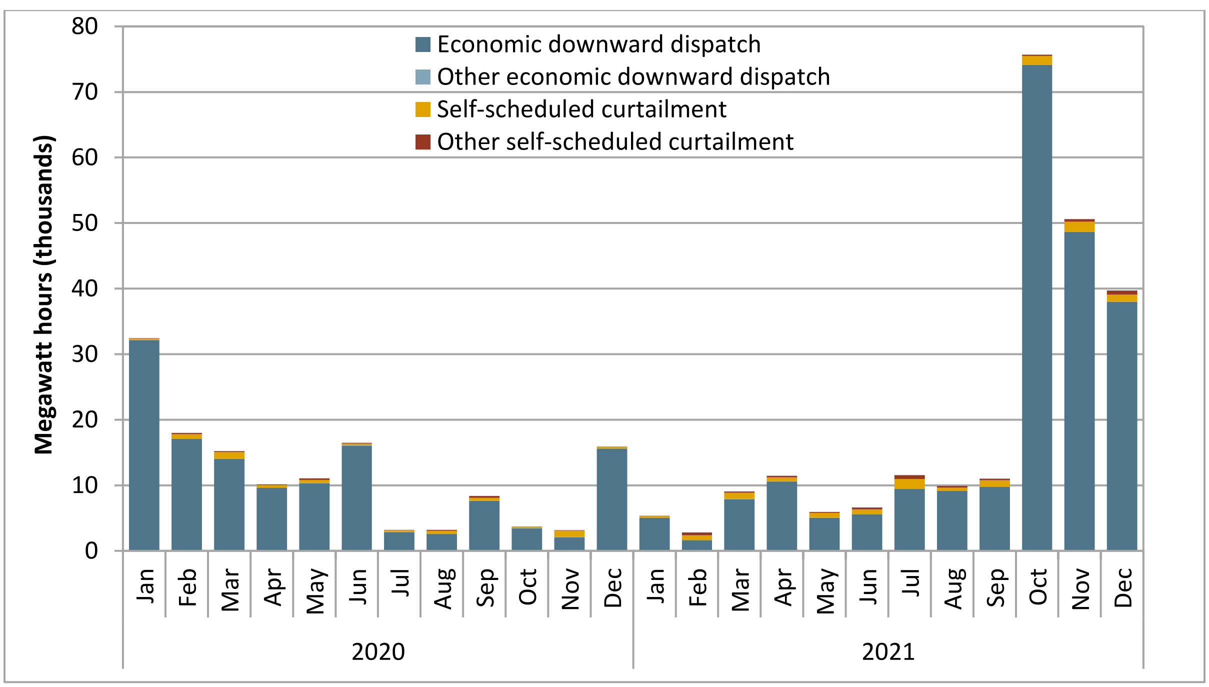


Figure 1.4 Reduction of wind and solar generation by month (WEIM)



1.1.4 Generation by fuel type

In the fourth quarter, natural gas generation and imports decreased while renewable and nuclear generation increased. Average hourly generation by natural gas resources and imports fell by 11 percent and 15 percent, respectively, compared to the same quarter of 2020.[11] Average hourly generation by nuclear, wind, and solar resources increased by 73 percent, 34 percent, and 7 percent, respectively.

Figure 1.5 shows the average hourly generation by fuel type during the fourth quarter of 2021. Total hourly average generation peaked at about 27,200 MW during hour ending 19. During the net peak load hours of 17 through 21, natural gas generation accounted for 42 percent of total generation. Non-hydroelectric renewable generation, including geothermal, biogas-biomass, wind, and solar resources, contributed 15 percent of total generation during these hours.

Figure 1.5 Average hourly generation by fuel type (Q4 2021)

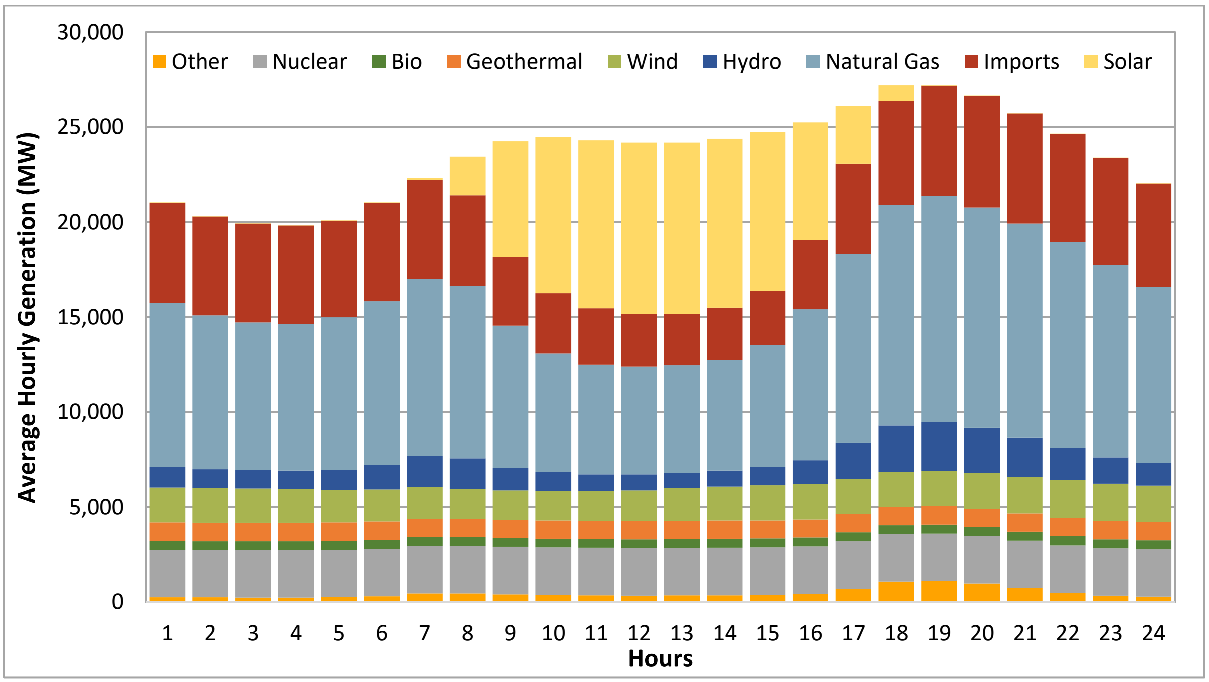


Figure 1.6 shows the change in hourly generation by fuel type between the fourth quarter of 2020 and the fourth quarter of 2021. In the chart, positive values represent increased generation in the fourth quarter compared to the fourth quarter of 2020 and negative values represent a decrease in generation.

Overall, the net change shows that there was an increase in average hourly generation in the morning hours and a decrease during net peak load hours. During all hours of the day, natural gas generation and imports were lower than the fourth quarter of 2020. These reductions were matched by increased generation from nuclear and renewable resources. Other resources saw increased generation from last year during the net load peak hours as more batteries came online throughout 2021.

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

Figure 1.6 Change in average hourly generation by fuel type (Q4 2020 to Q4 2021)

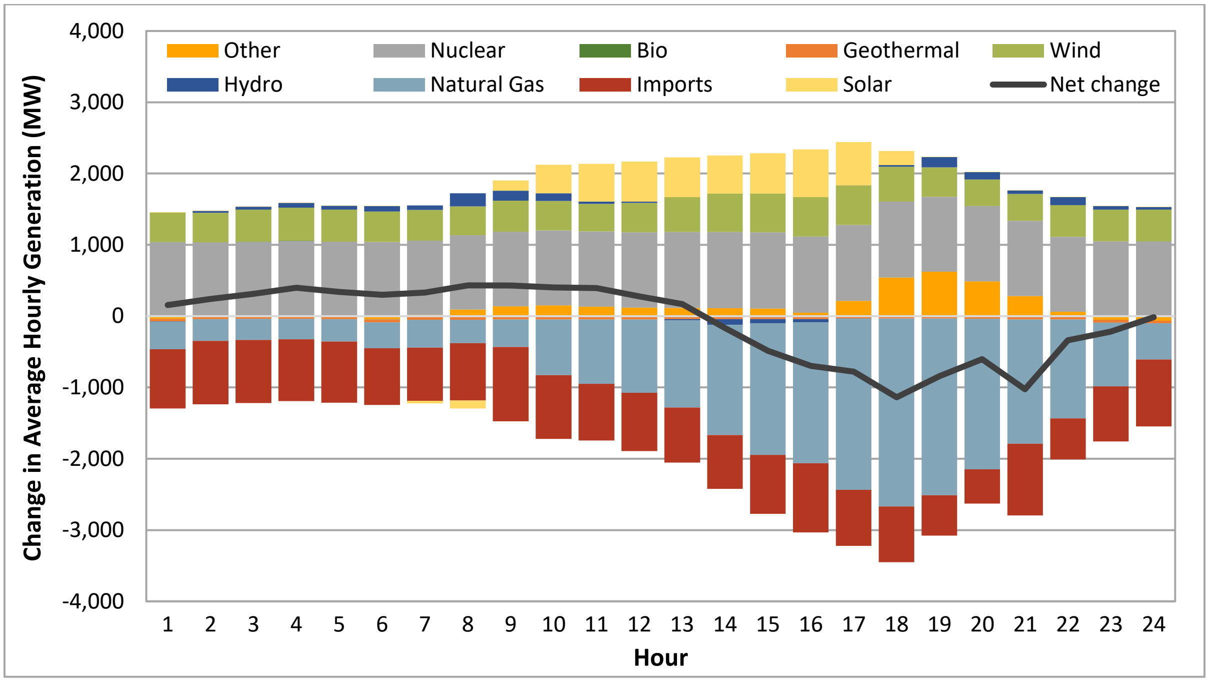
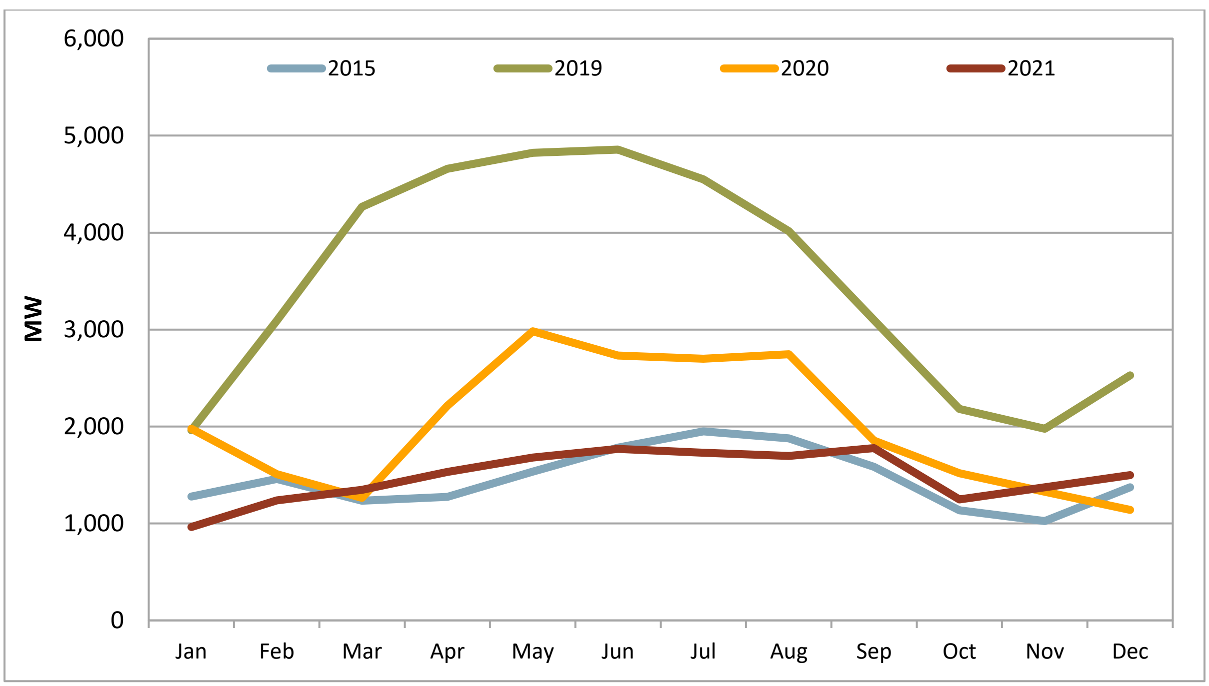


Figure 1.7 shows the monthly average hydroelectric generation for 2015, 2019, 2020, and 2021. Hydroelectric generation in 2021 is well below 2019 and 2020, while trending similarly to 2015. Conditions are similar to those of 2015 as both years saw April 1 snowpack percentages that were below normal, with 62 percent of normal in 2021 and 5 percent in 2015. Hydroelectric generation for the quarter was 3 percent higher than the fourth quarter of 2020.

Figure 1.7 Monthly average hydroelectric generation by year



1.1.5 Generation outages

Total generation in the California ISO on outage averaged about 14,700 MW, about the same as the fourth quarter of 2020. Forced outages increased and planned outages decreased relative to the same time last year. The total generation on outage was not significantly higher than the first quarter of 2021, representing a deviation from historical trends.

Under the California 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 1.8 shows the quarterly averages of maximum daily outages during peak hours by type from 2019 to 2021. Figure 1.9 shows the monthly averages of maximum daily outages during peak hours broken out by type for 2020 and 2021. The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period.

During the fourth quarter of 2021, the average total generation on outage in the California ISO was 14,700 MW, very close to the fourth quarter of 2020, as shown in Figure 1.8.[12] While the overall total was close, there were 20 percent more forced outages and 32 percent less planned outages than the same quarter last year. Looking out over a longer period, generation outages have been steadily increasing since 2019. This trend is driven primarily by forced outages, which have been increasing by 500 MW per quarter on average.

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12 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 California ISO balancing area and do not include outages from the Western Energy Imbalance Market.

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

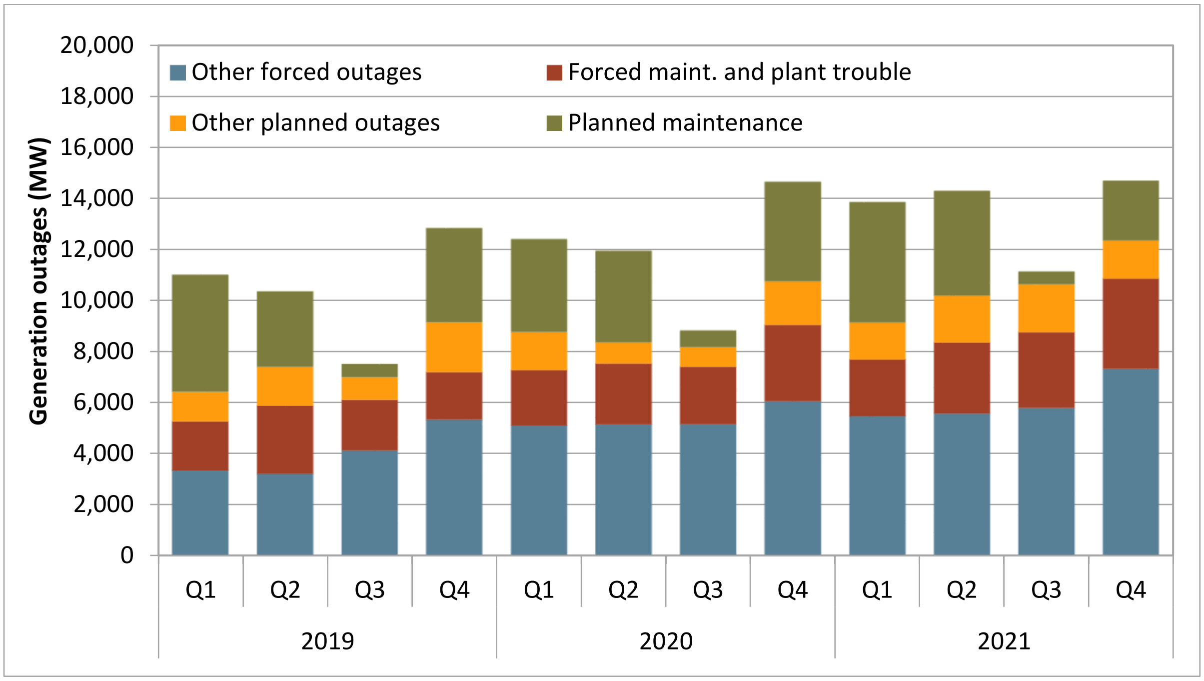
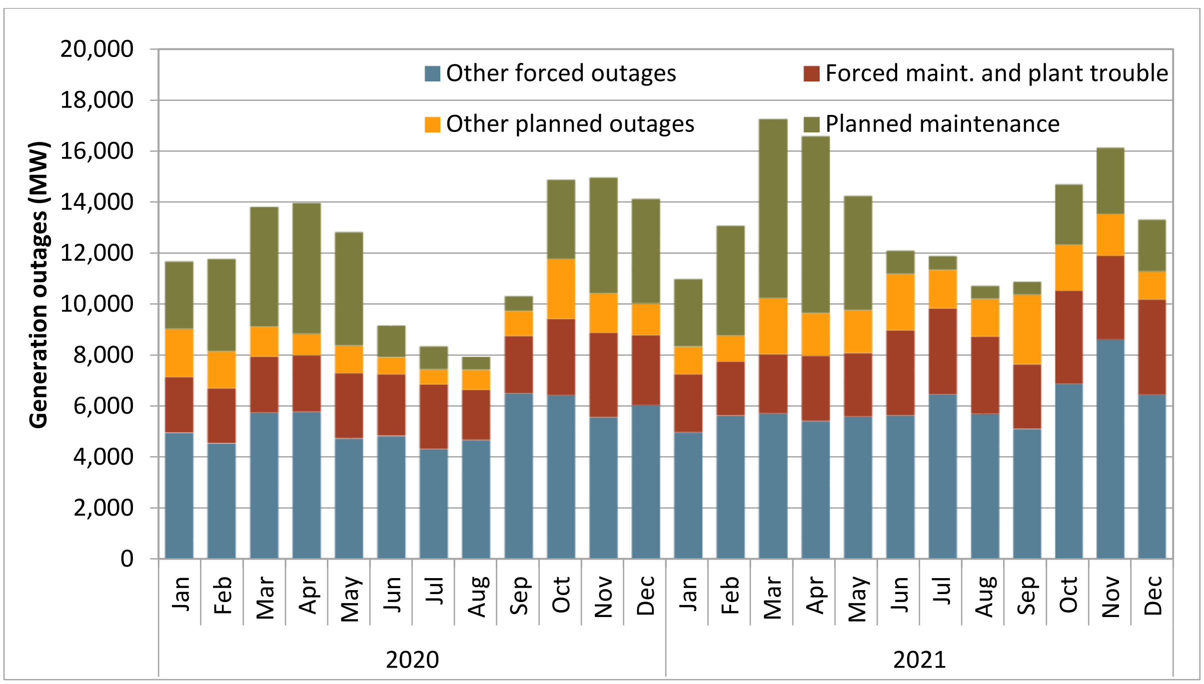


Figure 1.9 Monthly average of maximum daily generation outages by type – peak hours

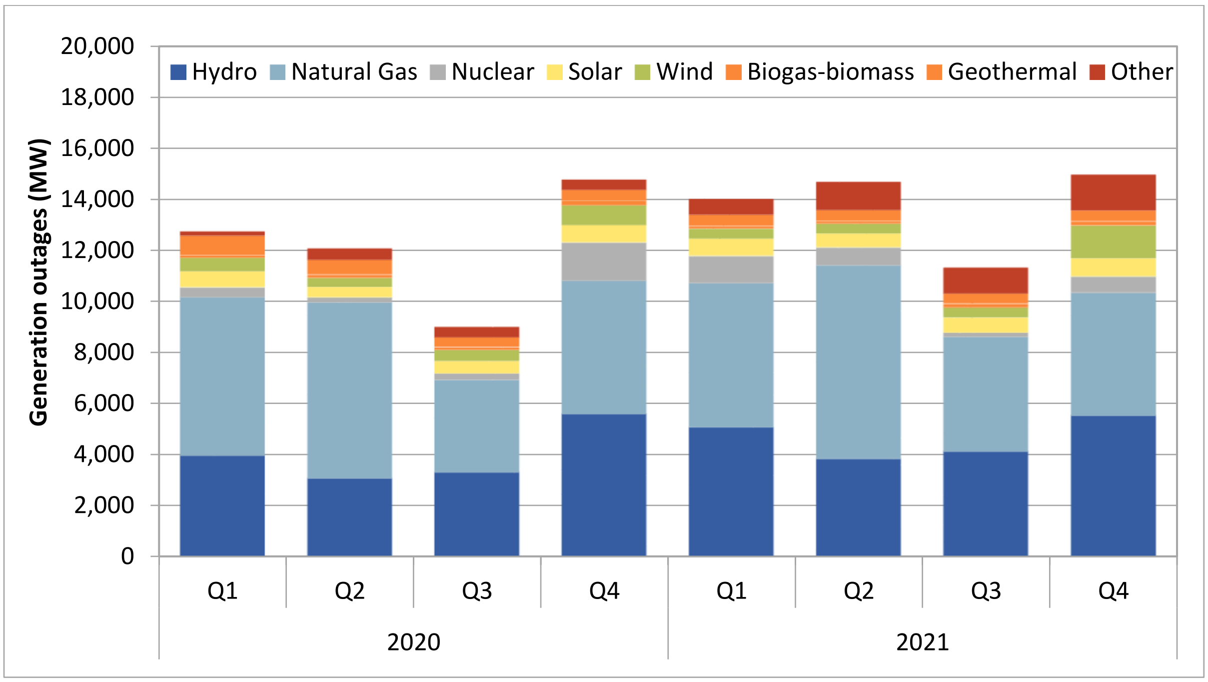


Generation outages by fuel type

Hydroelectric and natural gas generation on outage averaged about 5,500 MW and 4,800 MW during the fourth quarter, respectively. These two fuel types accounted for a combined 69 percent of the generation on outage for the quarter.

Figure 1.10 shows the quarterly average of maximum daily generation outages by fuel type during peak hours. Nuclear generation returned to service from outages earlier in the year, showing 57 percent less generation on outage compared to the same time last year. This was balanced out by higher wind and other generation outages, which increased 64 percent and 248 percent, respectively.[13]

Figure 1.10 Quarterly average of maximum daily generation outages by fuel type – peak hours



1.2 Energy market performance

1.2.1 Energy market prices

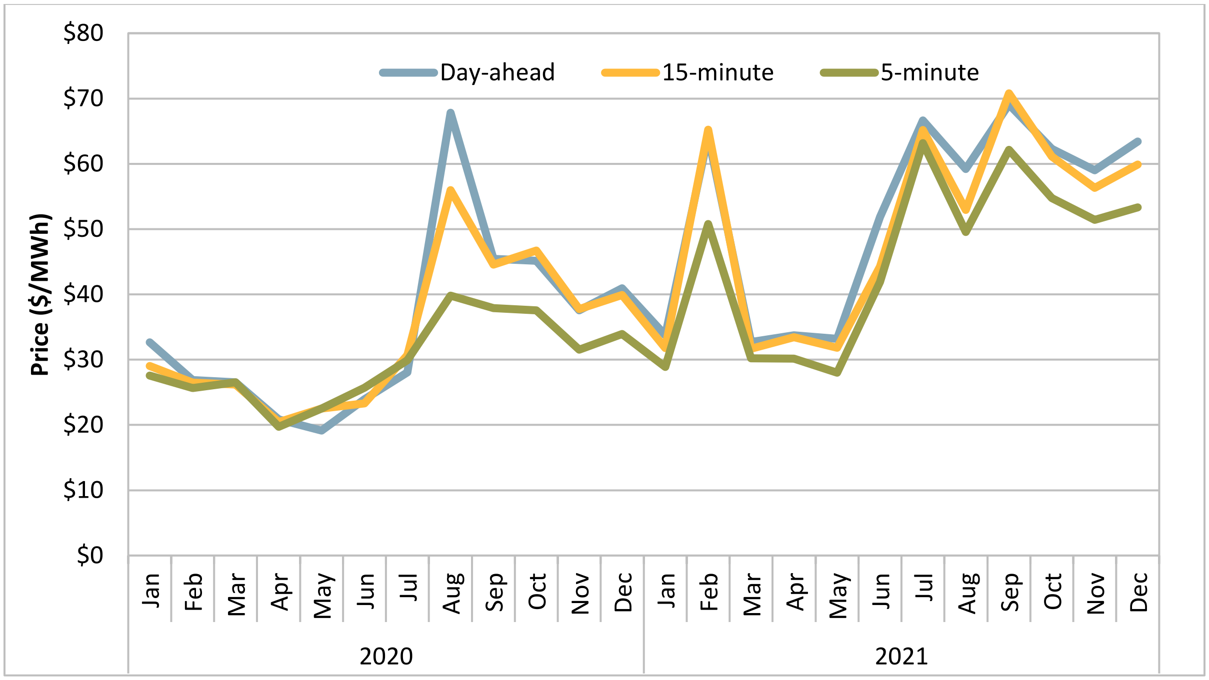
This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. Prices in all three markets were about 50 percent higher this quarter compared to the fourth quarter last year.

Figure 1.11 shows load-weighted average monthly energy prices during all hours across the four largest aggregation points in the California ISO (Pacific Gas and Electric, Southern California Edison, San Diego

13 In this figure, the "other" category contains battery storage, demand response, coal, and additional resources of unique technologies.

Gas & 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 2020 to December 2021.

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



Market prices were significantly higher this quarter. Day-ahead prices averaged $62/MWh, 15-minute prices averaged $59/MWh, and 5-minute prices averaged $53/MWh. Prices across all three markets were about 50 percent higher than the fourth quarter last year, due in part to higher natural gas prices.

As seen in Figure 1.11, prices in the 5-minute market were about 10 percent lower than prices in the day-ahead and 15-minute markets. This is an improvement compared to the fourth quarter last year when 5-minute market prices were about 20 percent lower. Price convergence between markets may help promote efficient commitment of internal and external generating resources.

Figure 1.12 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.

Average hourly prices continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours. Net load was lower across all hours, due to both lower loads and higher wind and solar production compared to the fourth quarter last year. Lower net loads and higher energy prices further indicate that higher prices this quarter were driven by the increase in natural gas price.

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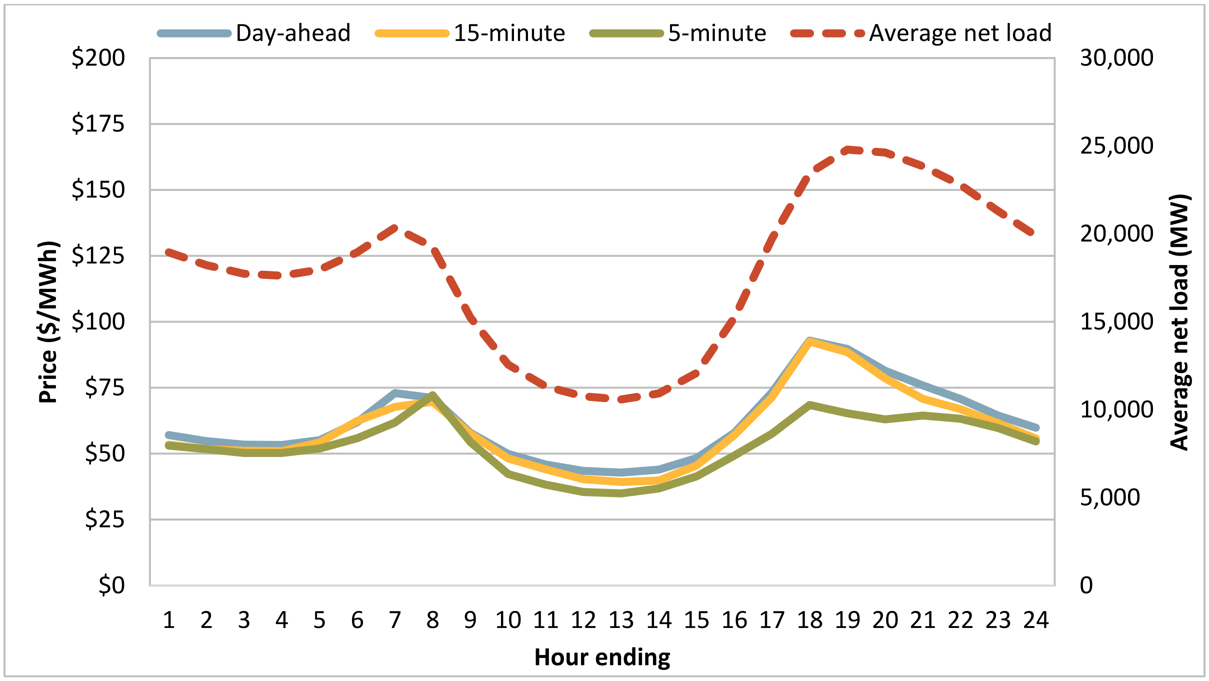
[14] Net load is calculated by subtracting the generation produced by wind and solar that is directly connected to the California ISO grid from actual load.

Figure 1.12 Hourly load-weighted average energy prices (October - December)



1.2.2 Bilateral price comparison

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

Figure 1.13 shows California 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 & 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 California ISO market. These prices were calculated during peak hours (hours ending 7 through 22) for all days, excluding Sundays and holidays. The figure shows that the California ISO prices during peak hours trended higher than bilateral hub prices across most days in the fourth quarter.

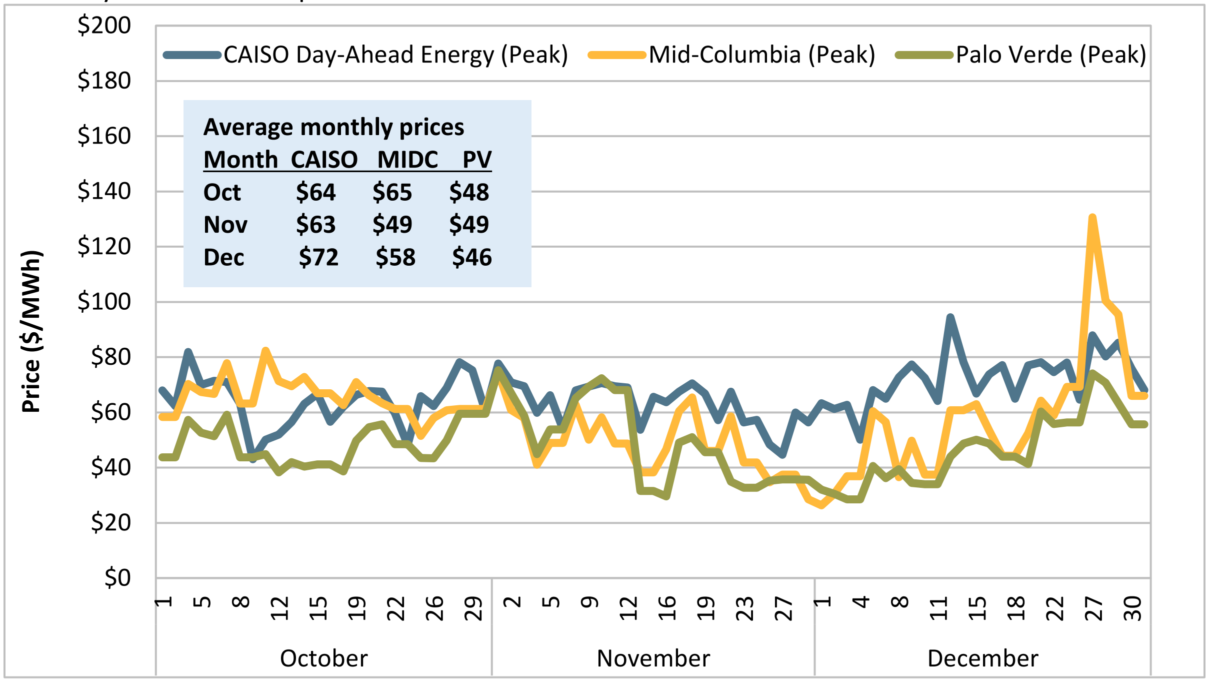


Figure 1.14 uses the same data underlying Figure 1.13 but on an average monthly basis for 2020 and 2021. Prices in the California ISO are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs). As shown in this figure, average prices at these points exceeded average bilateral prices at Mid-Columbia and Palo Verde hubs during the fourth quarter.

Average day-ahead prices in the California 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 California ISO were greater than average real-time prices at Mid-Columbia and Palo Verde by $15/MWh. Average day-ahead prices at Mid-Columbia (from ICE) were greater than average real-time prices at Mid-Columbia (from Powerdex) by $5/MWh. At Palo Verde, average real-time prices (from Powerdex) were higher than day-ahead prices (from ICE) by $1/MWh.

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

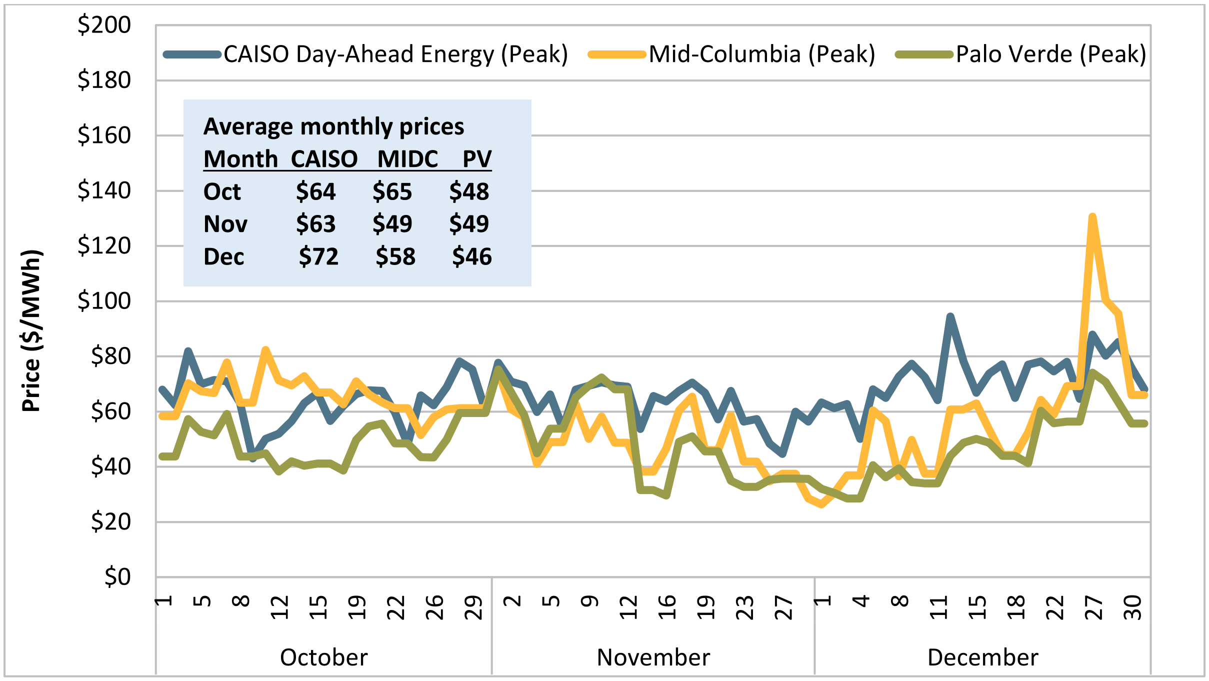
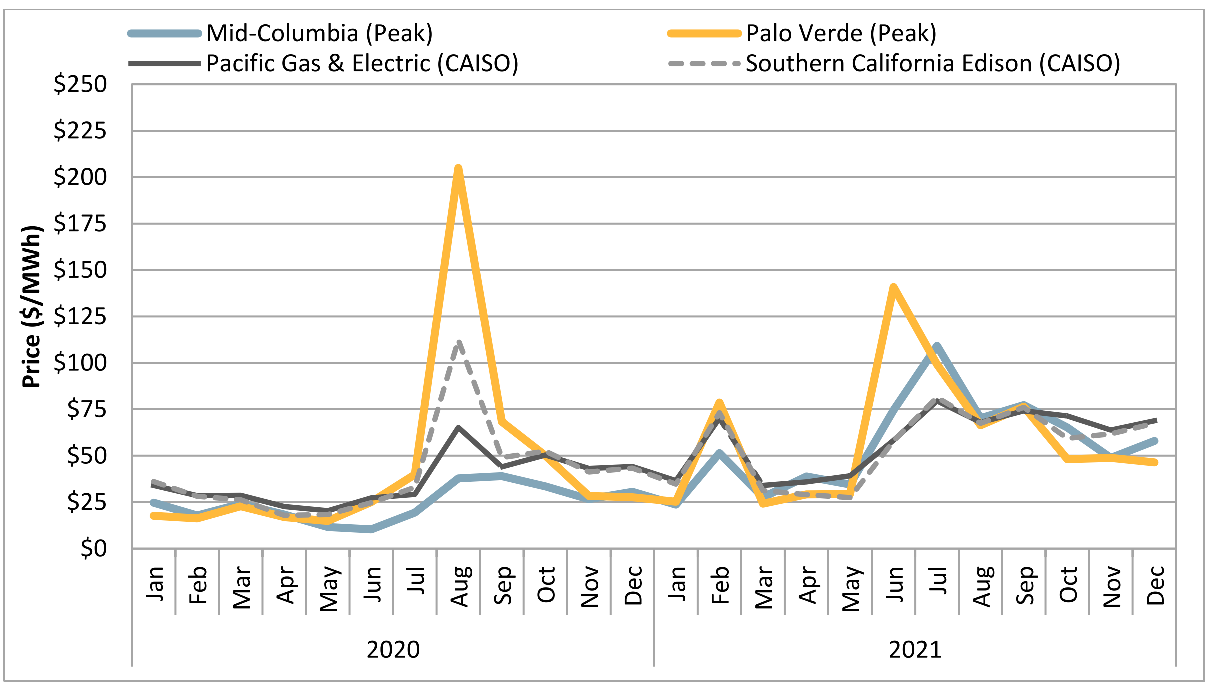


Figure 1.14 Monthly average day-ahead and bilateral market prices



Imports and exports

As with the previous quarter, average net imports decreased compared to the same quarter in 2020. This may be due to low hydroelectric production caused by ongoing drought conditions in the west.[15]

As shown in Figure 1.15, peak imports in the day-ahead (dark blue line) decreased in hour ending 21, from about 6,300 MW to 5,900 MW, compared to the same quarter of 2020. Peak 15-minute cleared imports (dark yellow line) were about the same compared to the same period last year at about 6,900 MW. Peak exports (shown as negative numbers below the horizontal axis in pale blue and yellow), increased in both the day-ahead and 15-minute markets, about 850 MW and 1,200 MW respectively, compared to the same quarter of 2020.

The average net interchange, excluding WEIM transfers (dashed black line), is based on meter data and averaged by hour and quarter. The solid grey line adds incremental WEIM interchange, which reached a low point of about 1,700 MW in hour ending 13. The greatest import transfer into the California ISO from the WEIM occurred in hour ending 22, at about 900 MW, compared to about 800 MW in hour ending 7 from the same quarter in the prior year. Export transfer from the California ISO to the WEIM occurred between hour-ending 9 to hour-ending 17, with hour-ending 13 topping out at just over 1,000 MW. This is a decrease from the same quarter of the previous year with a maximum export in hour-ending 12 at about 1,150 MW.

Figure 1.15 Average hourly net interchange by quarter

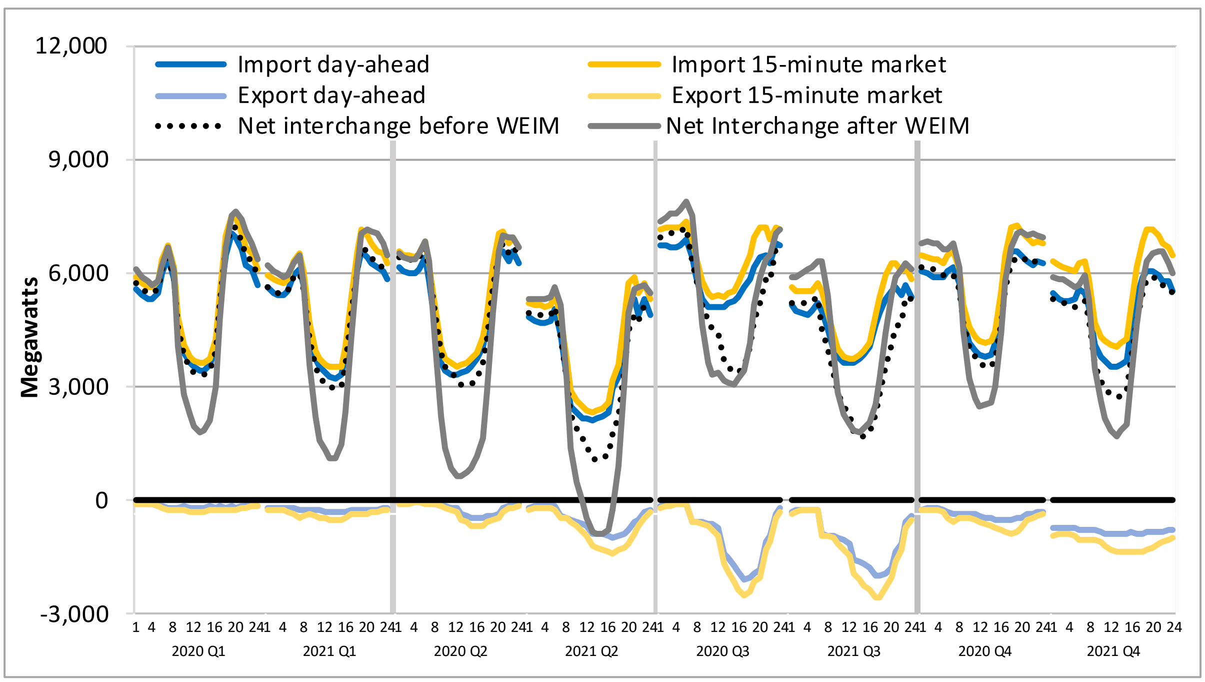


Figure 1.16 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[16] The grey bars reflect import

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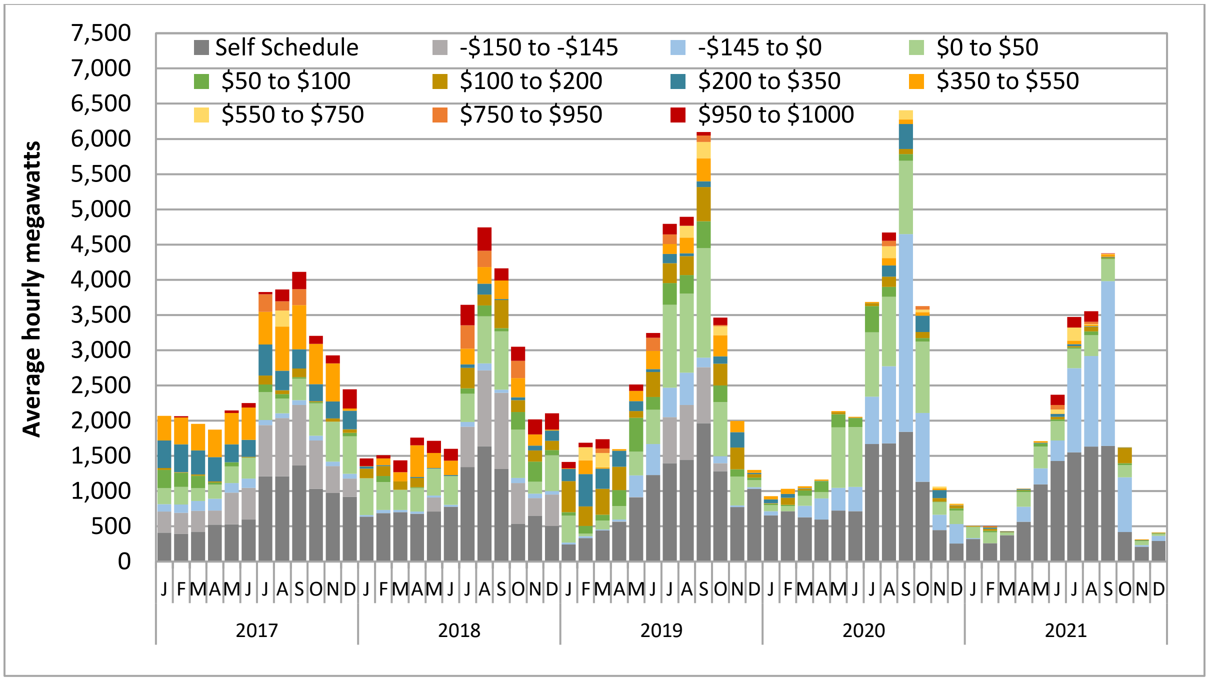
15 U.S. Drought Monitor Conditions for California: https://www.drought.gov/states/california

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

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.

Figure 1.16 Average hourly resource adequacy imports by price bin



1.3 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. Compared to the fourth quarter last year there were fewer intervals with substantially high energy prices while intervals with negative prices remained infrequent.

1.3.1 Day-ahead price variability

In the fourth quarter of 2021, the frequency of high day-ahead prices decreased while negative day-ahead prices remained the same, compared to the fourth quarter last year.

High prices

Figure 1.17 shows the frequency of day-ahead market prices in various high priced ranges from October 2020 to December 2021. The frequency of prices over $250/MWh decreased in the fourth quarter compared to last year. Overall prices were higher in the fourth quarter of 2021, but there were no extreme price spikes.

Negative prices

Figure 1.18 shows the frequency of day-ahead market prices in various low priced ranges from October 2020 to December 2021. There were no hours in this quarter where prices in the day-ahead market were below $1/MWh, just as there were none in the fourth quarter of 2020.

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

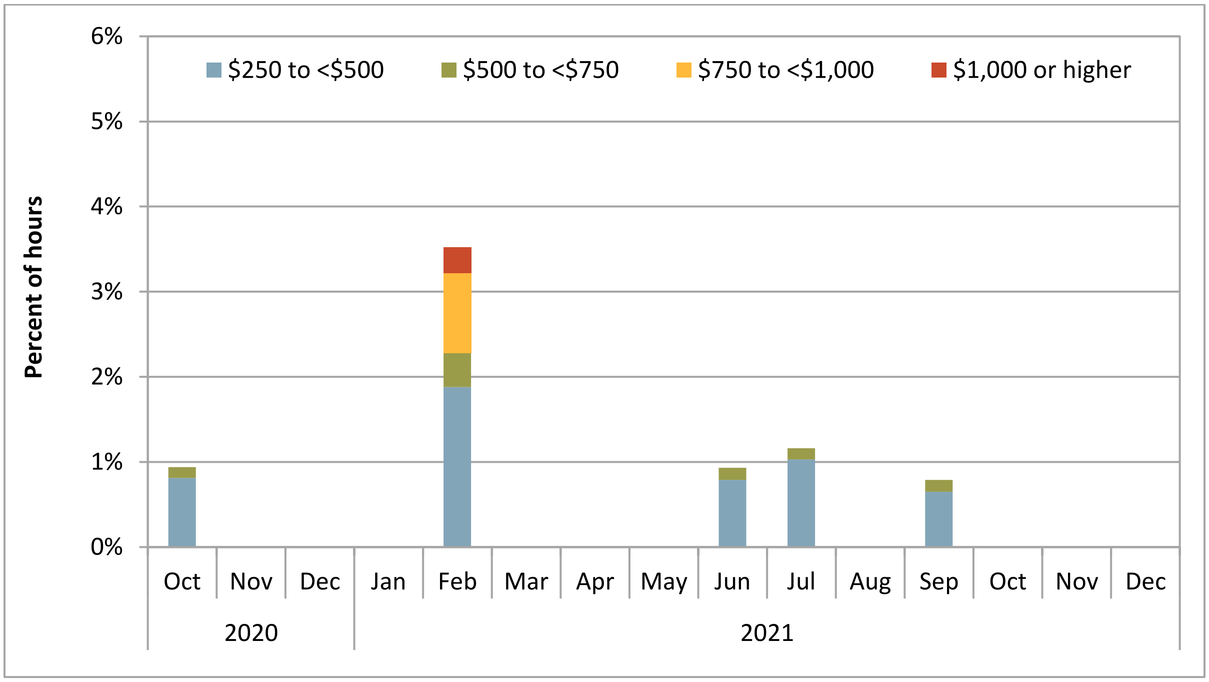
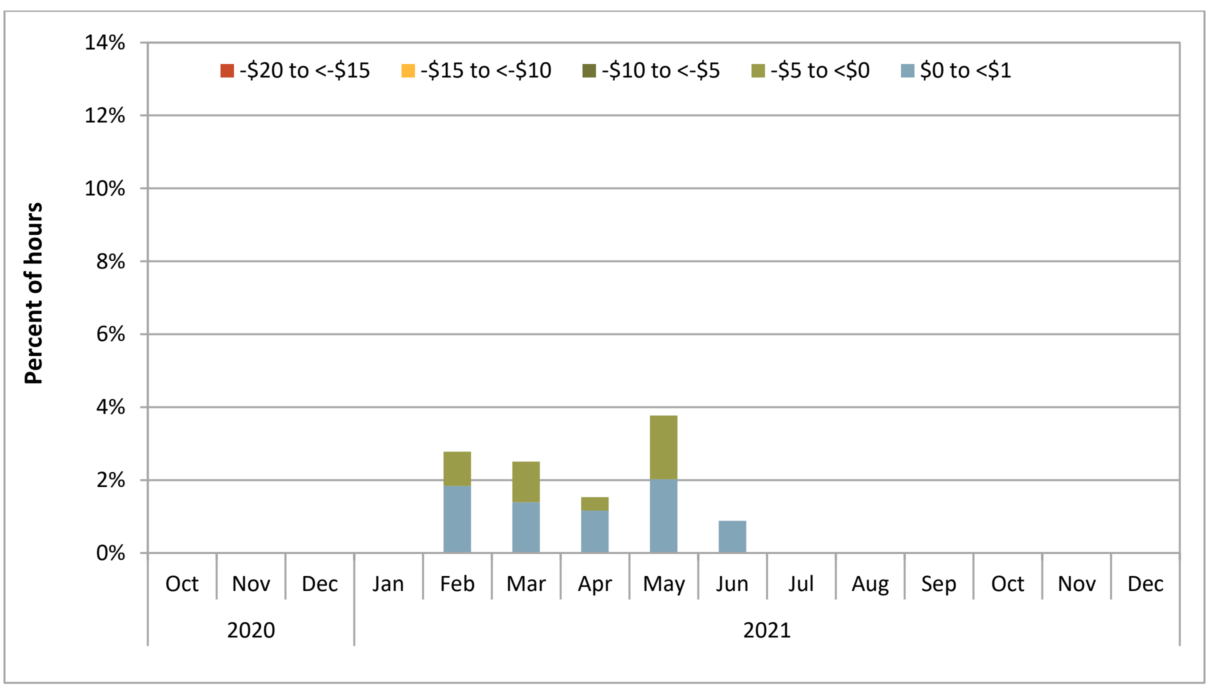


Figure 1.18 Frequency of negative day-ahead prices ($/MWh) by month



1.3.2 Real-time price variability

During the fourth quarter of 2021, variability in the real-time market was fairly similar to the fourth quarter last year. Unlike the day-ahead market, there were some instances of high price spikes, implying more variable prices in the real-time market.

High prices

Figure 1.19 and Figure 1.20 show the frequency of prices above $250/MWh across the three largest load aggregation points (LAP) in the California ISO in the 15-minute and 5-minute markets. Overall, the frequency of prices over $250/MWh decreased slightly in both markets compared to the fourth quarter last year. The decrease was more pronounced in the 15-minute market.

Figure 1.21 and Figure 1.22 show the frequency of undersupply infeasibilities and if the load conformance limiter resolved them. Infeasibilities resolved by the load conformance limiter continued to be infrequent and had an insignificant impact on prices in the California ISO. In most intervals when the limiter triggers in the California 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 1.19 Frequency of high 15-minute prices by month (California ISO LAP areas)

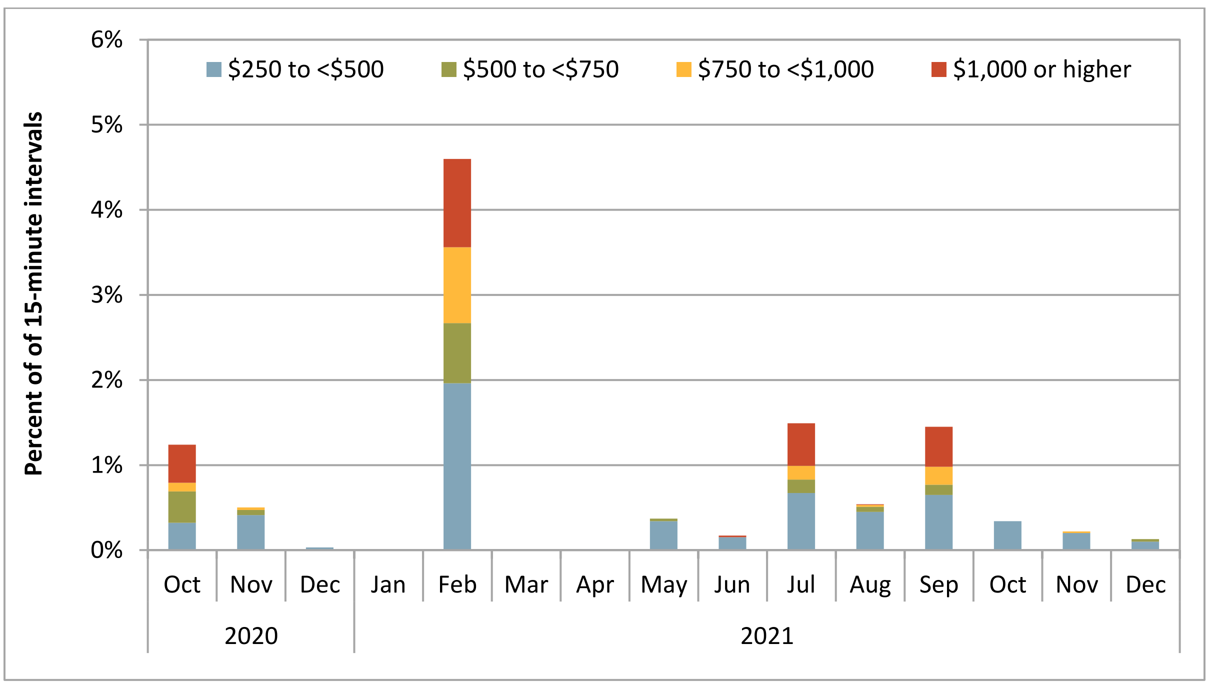


Figure 1.20 Frequency of high 5-minute prices by month (California ISO LAP areas)

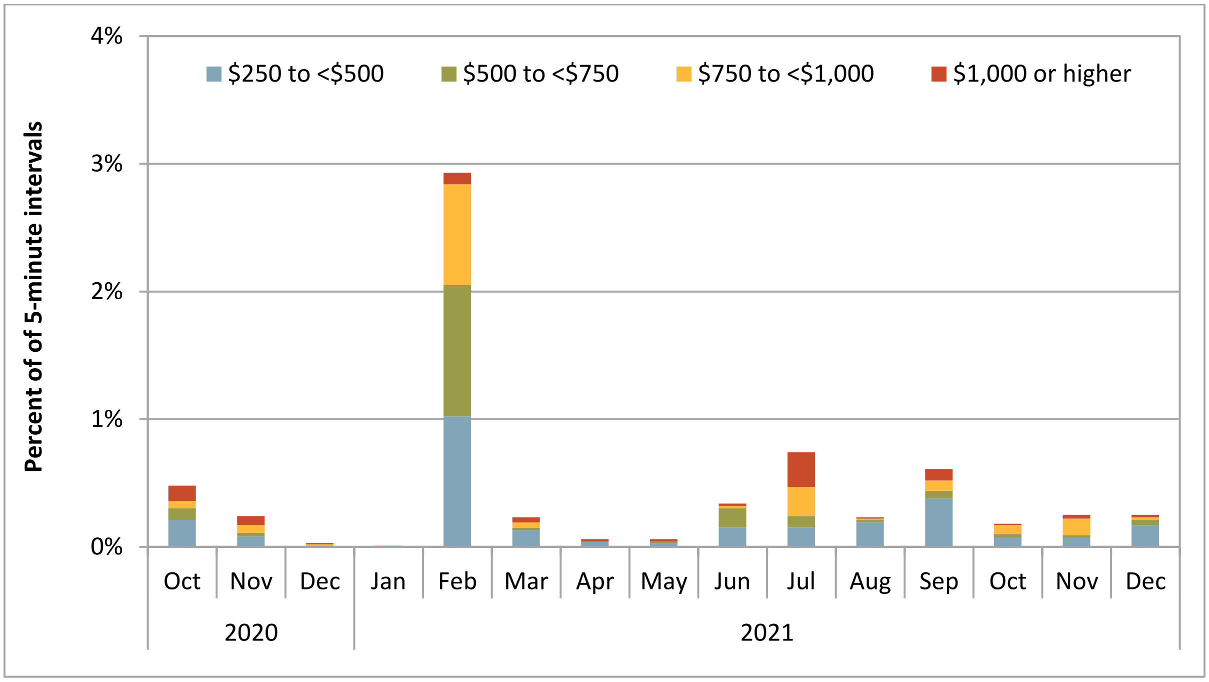


Figure 1.21 Frequency of undersupply power balance constraint infeasibilities (California ISO 15-minute market)

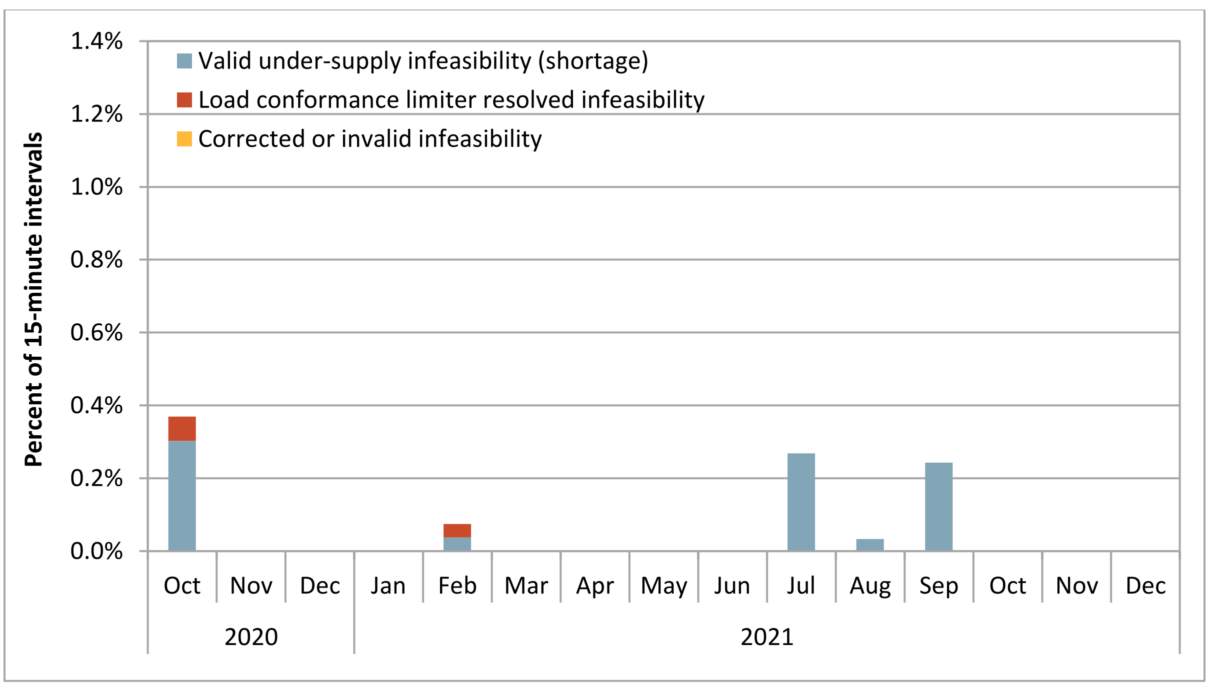
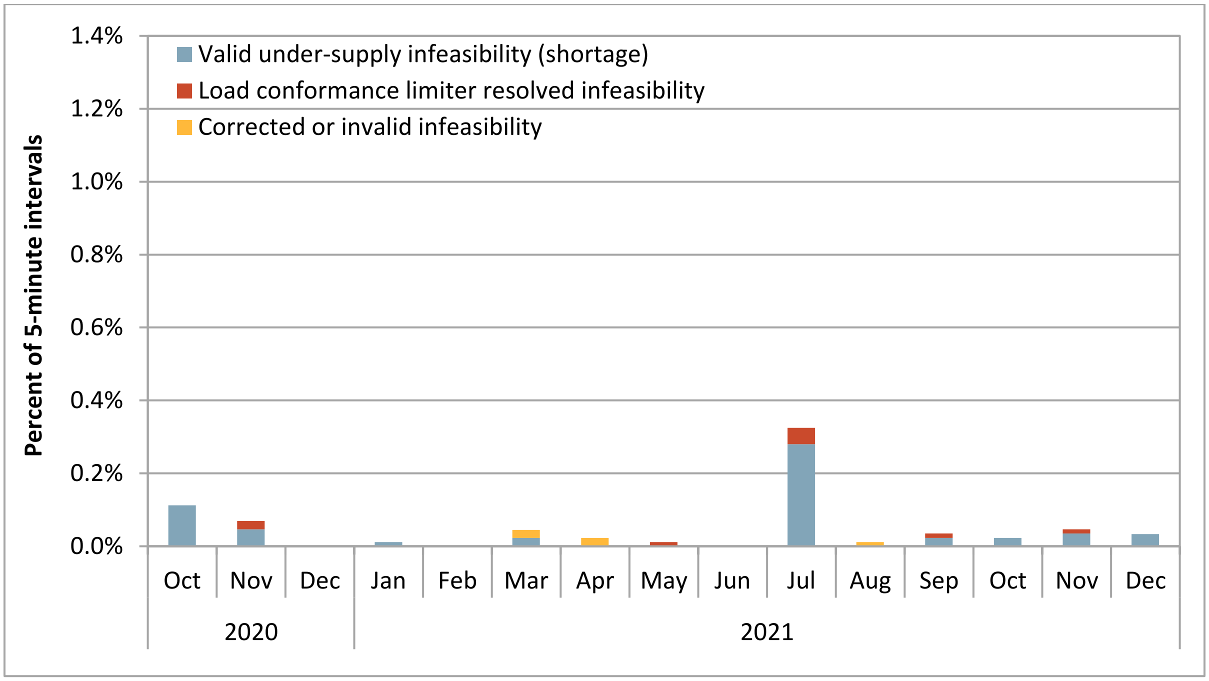


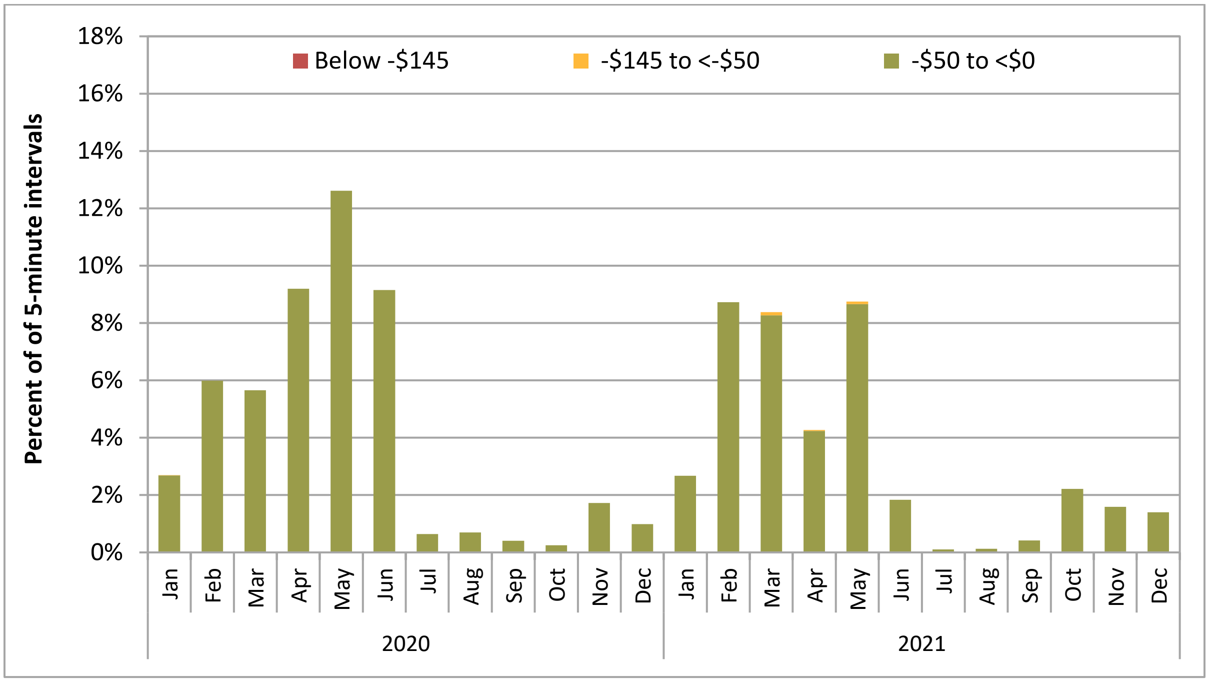
Figure 1.22 Frequency of undersupply power balance constraint infeasibilities (California ISO 5-minute market)



Negative prices

Figure 1.23 shows the frequency of negative prices in the 5-minute market by month across the three largest load aggregation points in the California ISO.[17] On average 1.7 percent of intervals this quarter had negative prices, an increase from 1 percent last year.

Figure 1.23 Frequency of negative 5-minute prices by month (California ISO LAP areas)



1.4 Flexible ramping product

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

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

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

1.4.1 Minimum flexible ramping product requirement

There are separate demand curves calculated for each WEIM 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.[18] 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. Beginning in 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.[19] 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 2022.

A minimum requirement helps procure flexible ramping capacity within areas that contribute to a large portion of system-wide uncertainty. During the fourth quarter, the California ISO had a minimum upward requirement enforced in around 92 percent of intervals, up from 84 percent of intervals in the previous quarter. A minimum downward requirement was enforced in around 60 percent of intervals, similar to the previous quarter.

The minimum requirement was initially implemented in only the 15-minute market. After becoming aware of this, DMM has recommended that the minimum requirement be included in the 5-minute market as an enhancement to improve the effectiveness of the flexible ramping product until nodal procurement is developed. The California ISO implemented the minimum requirement in the 5-minute market on February 16, 2022.

Procurement in the 5-minute market helps maintain available ramping capacity 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 California ISO and settled in the 15-minute market, is released in the 5-minute market in favor of undeliverable flexible ramping capacity stranded behind WEIM transfer constraints.

Non-California ISO areas that exceed the 60 percent threshold in any interval can similarly have a minimum requirement applied that will procure and price flexible ramping capacity in that area. In particular, PacifiCorp East had a minimum downward flexible ramping requirement in approximately 9 percent of intervals during the quarter.

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18 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.

19 For example, if a balancing authority area's upward requirement is 1,000 MW, it is greater than 60 percent of the system requirement, 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

1.4.2 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.

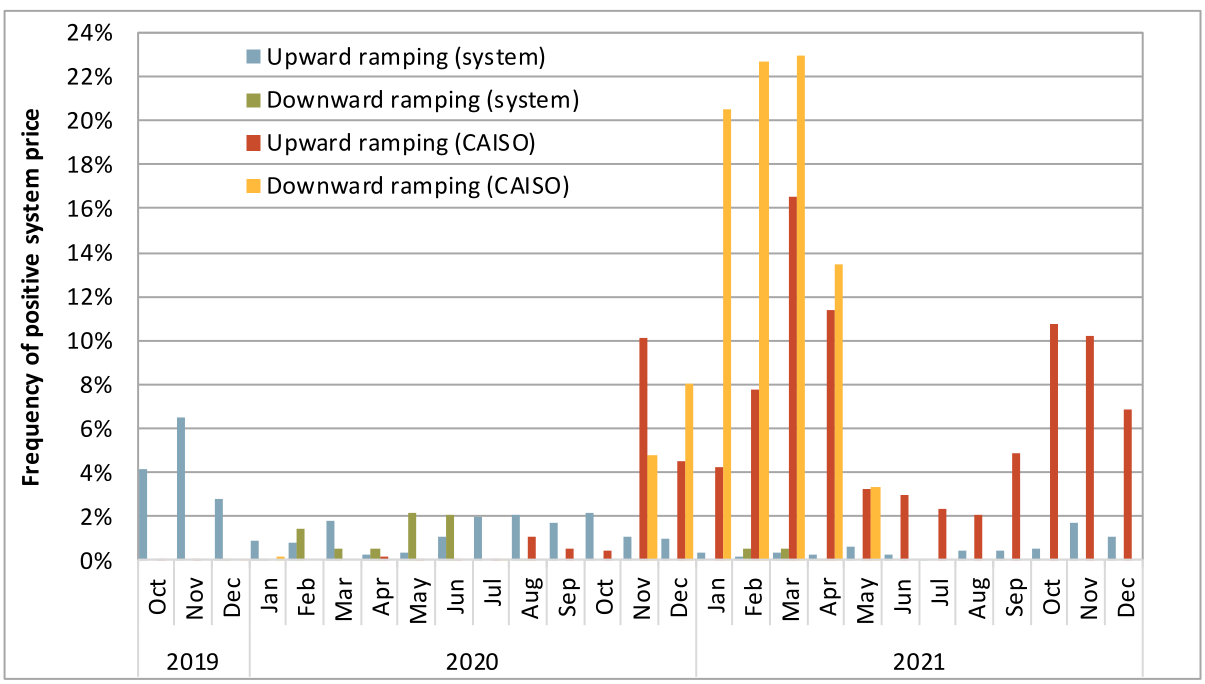
Figure 1.24 shows the percent of intervals that the system-level flexible ramping demand curve bound and had a positive shadow price in the 15-minute market. The percent of intervals in which the California ISO-specific demand curve bound at a positive shadow price is also shown.

The frequency of positive shadow prices for the *system* continued to be low overall. During the quarter, the 15-minute market system-level demand curve bound in around 1 percent of intervals for upward ramping and never for downward ramping.

Following a review by the California ISO on intermittent resources and flexible ramping product eligibility, the California ISO implemented a change effective May 9 to set all five-minute dispatchable resources with economic bids eligible to receive flexible ramping product awards. In particular, additional flexible ramping capacity from wind and solar resources (which were previously ineligible to receive these awards) contributed to the decreased frequency of positive prices. Since the change, the shadow price for downward flexible ramping capacity has been zero in all intervals.

In the 5-minute market, the system-level and California 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 California ISO flexible ramping shadow price (15-minute market)



1.5 Convergence bidding

Convergence bidding is designed to align day-ahead and real-time prices by allowing financial arbitrage between the two markets. In this quarter, the volume of cleared virtual supply exceeded cleared virtual demand, as it has in all quarters since 2014.

Overall, convergence bidding was profitable in the fourth quarter of 2021. Combined net revenue for virtual supply and demand was about $11.2 million, after including about $3.1 million of virtual bidding bid cost recovery charges. Virtual demand generated negative revenues of about $3 million for the quarter, while virtual supply generated about $17.6 million, before accounting for bid cost recovery charges.

Convergence bidding was also profitable on an annual basis.

- **Annual profits paid to convergence bidders totaled around $37.8 million**, a decrease from about $46 million in 2020, after accounting for about $21.9 million in bid cost recovery charges allocated to virtual bids. Virtual demand generated negative revenues of about $1.7 million for the year, while virtual supply generated about $61.3 million, before accounting for bid cost recovery charges.

- **Virtual supply exceeded virtual demand by an average of about 870 MW per hour**, compared to 560 MW in 2020. The percent of bid in virtual supply and demand clearing was around 34 percent, a slight increase from about 32 percent in 2020.

- **Most profits from virtual bidding continue to be received by financial entities and marketers,** who received about 85 percent and 10 percent of net revenues, respectively. Physical generators and load serving entities received about 4 percent of net virtual bidding revenues.

- **Financial participants held over 75 percent of cleared virtual positions throughout 2021**, continuing a multi-year trend. As with the previous years, financial participants bid more virtual supply than demand, which contributed to the increase in net virtual supply.

1.5.1 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 $14.2 million. Net revenues for virtual supply and demand fell to about $11.2 million after the inclusion of about $3 million of virtual bidding bid cost recovery charges,[20] 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).

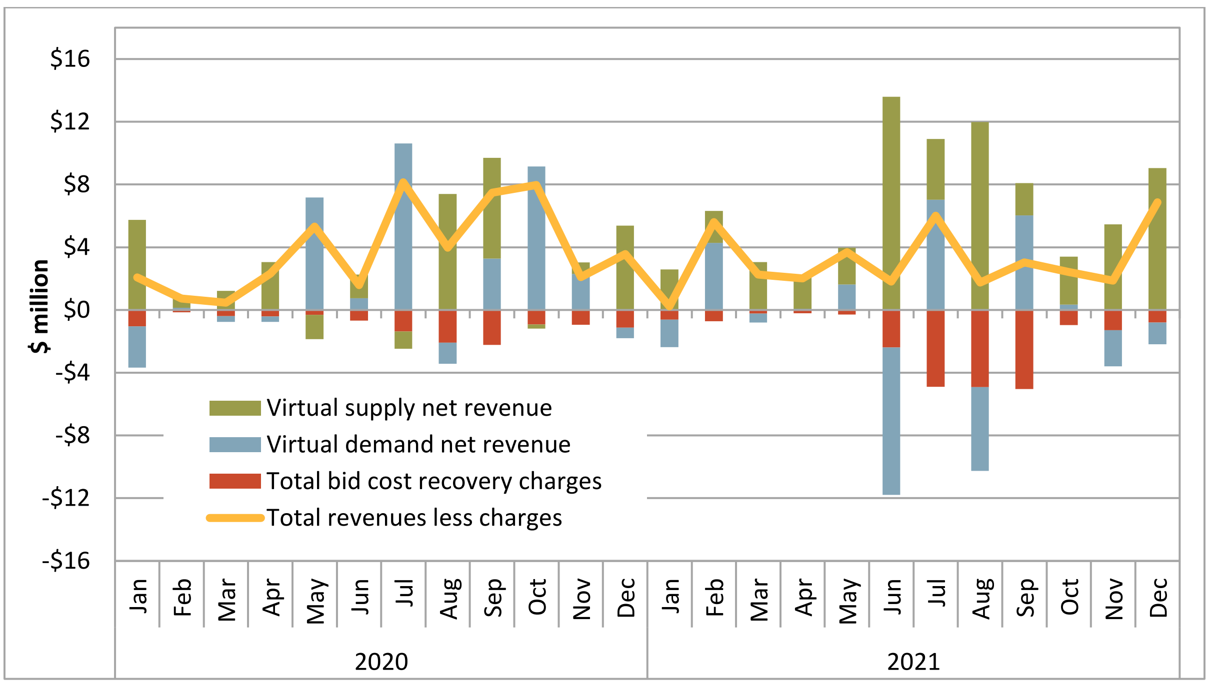
[20] For more information on how bid cost recovery charges are allocated please refer to the *Q3 2017 Report on Market Issues and Performance*, December 2017, pp. 40-41: http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf.

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 $14.2 million, compared to about $16.6 million during the same quarter from the previous year, and about $25.6 million during the previous quarter.
- Virtual demand net revenues were about $0.3 million, negative $2.3 million, and negative $1.4 million for October, November, and December, respectively.
- Virtual supply net revenues were $3 million, $5.5 million, and $9 million for October, November, and December, respectively.

Convergence bidders received approximately $11.2 million after subtracting bid cost recovery charges of about $3.1 million for the quarter.[21,22] Bid cost recovery charges were about $1 million, $1.3 million, and $0.87 million for October, November, and December, respectively.

Figure 1.25 Convergence bidding revenues and bid cost recovery charges



[21] 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.

[22] 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.

Net revenues and volumes by participant type

Table 1.1 and Table 1.2 compare the distribution of convergence bidding cleared volumes and net revenues, in millions of dollars, among different groups of convergence bidding participants.[23]

Financial entities represented the largest segment of the virtual bidding market on a quarterly and annual basis, with over 70 to 80 percent of both volume and settlement revenue, as they have in recent years. Marketers continue to have about 10 to 20 percent of both volume and settlement revenue while generation owners and load serving entities continued to represent a small segment of the virtual market in terms of both volumes and settlement revenue (sometimes negative), between 2 percent and 3 percent, respectively, throughout the year.

Table 1.1 Convergence bidding volumes and revenues by participant type – Q1 to Q4

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)				Total Revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
2021 Q1								
Financial	953	1,494	2,447	$1.59	$7.06	-$1.01	$6.05	$7.65
Marketer	338	487	825	$0.35	$0.75	-$0.38	$0.37	$0.72
Physical load	0	27	27	$0.00	-$0.24	-$0.10	-$0.35	-$0.35
Physical generation	12	40	52	$0.00	$0.16	-$0.04	$0.12	$0.12
Total	**1,303**	**2,048**	**3,352**	**$1.94**	**$7.72**	**-$1.53**	**$6.19**	**$8.14**
2021 Q2								
Financial	1,536	1,938	3,474	-$3.84	$14.33	-$2.10	$12.23	$8.39
Marketer	423	487	910	-$3.63	$3.21	-$0.58	$2.63	-$1.00
Physical load	0	38	38	$0.00	$0.22	-$0.09	$0.13	$0.13
Physical generation	14	41	56	-$0.21	$0.33	-$0.11	$0.23	$0.01
Total	**1,974**	**2,505**	**4,478**	**-$7.69**	**$18.09**	**-$2.87**	**$15.22**	**$7.53**
2021 Q3								
Financial	1,191	2,117	3,308	$7.87	$12.18	-$10.10	$2.08	$9.95
Marketer	296	527	823	$0.15	$5.46	-$2.85	$2.61	$2.76
Physical load	0	26	26	$0.00	$0.10	-$0.71	-$0.61	-$0.61
Physical generation	27	84	111	-$0.63	$0.22	-$0.72	-$0.51	-$1.13
Total	**1,515**	**2,754**	**4,268**	**$7.39**	**$17.96**	**-$14.38**	**$3.57**	**$10.96**
2021 Q4								
Financial	1,008	1,736	2,744	-$2.25	$13.74	-$2.19	$11.55	$9.30
Marketer	311	499	811	-$0.95	$3.48	-$0.67	$2.81	$1.86
Physical load	0	18	18	$0.00	$0.13	-$0.12	$0.01	$0.01
Physical generation	14	47	62	-$0.14	$0.22	-$0.09	$0.13	-$0.01
Total	**1,334**	**2,301**	**3,634**	**-$3.33**	**$17.57**	**-$3.07**	**$14.50**	**$11.17**

23 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 California 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 California ISO market.

Table 1.2 Convergence bidding volumes and revenues by participant type – 2021

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)				Total Revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
Financial	1,172	1,823	2,995	$3.4	$47.31	-$15.39	$50.68	$35.29
Marketer	342	500	842	-$4.1	$12.89	-$4.48	$8.81	$4.34
Physical load	0	27	27	$0.0	$0.21	-$1.03	$0.21	-$0.81
Physical generation	17	53	70	-$1.0	$0.92	-$0.96	-$0.06	-$1.01
Total	**1,531**	**2,403**	**3,935**	**-$1.69**	**$61.34**	**-$21.85**	**$59.65**	**$37.80**

1.6 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 was 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 340 MW higher in the fourth quarter of 2021 than in the same quarter of 2020.

Residual unit commitment procurement can be increased by operator adjustments to the day-ahead load forecast. These manual adjustments decreased by 67 percent in the fourth quarter, relative to the same quarter in 2020. In this quarter, operators used this tool on 28 days to increase the residual unit commitment requirements by an average of about 57 MW per hour.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar in Figure 1.26) represents the difference in cleared supply (both physical and virtual) compared to the California ISO's load forecast. On average, this factor contributed towards decreasing residual unit commitment requirements in the fourth quarter of 2021, averaging about -102 MW per hour.

Lastly, 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; the yellow bar in Figure 1.26 represents it.

Figure 1.26 Determinants of residual unit commitment procurement

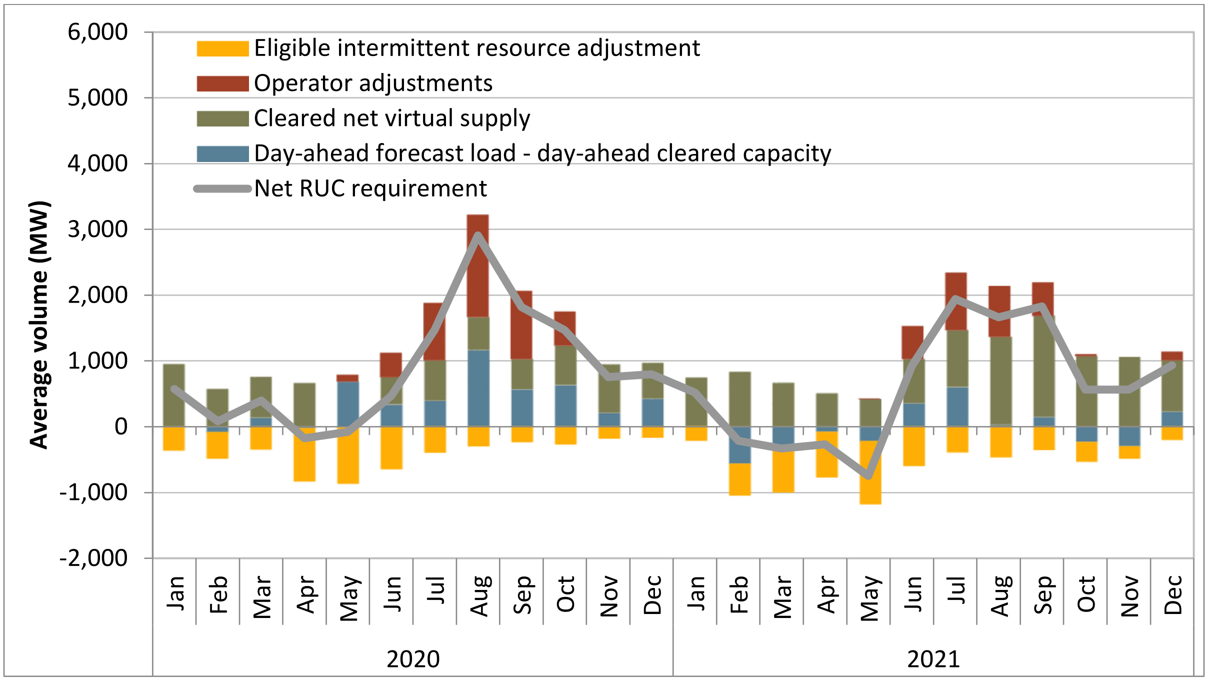


Figure 1.27 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement decreased to about 900 MW in the fourth quarter of 2021 from an average of 1,237 MW in the same quarter of 2020. Of the 900 MW capacity, the capacity committed to operate at minimum load averaged 123 MW, similar to the fourth quarter of 2020.

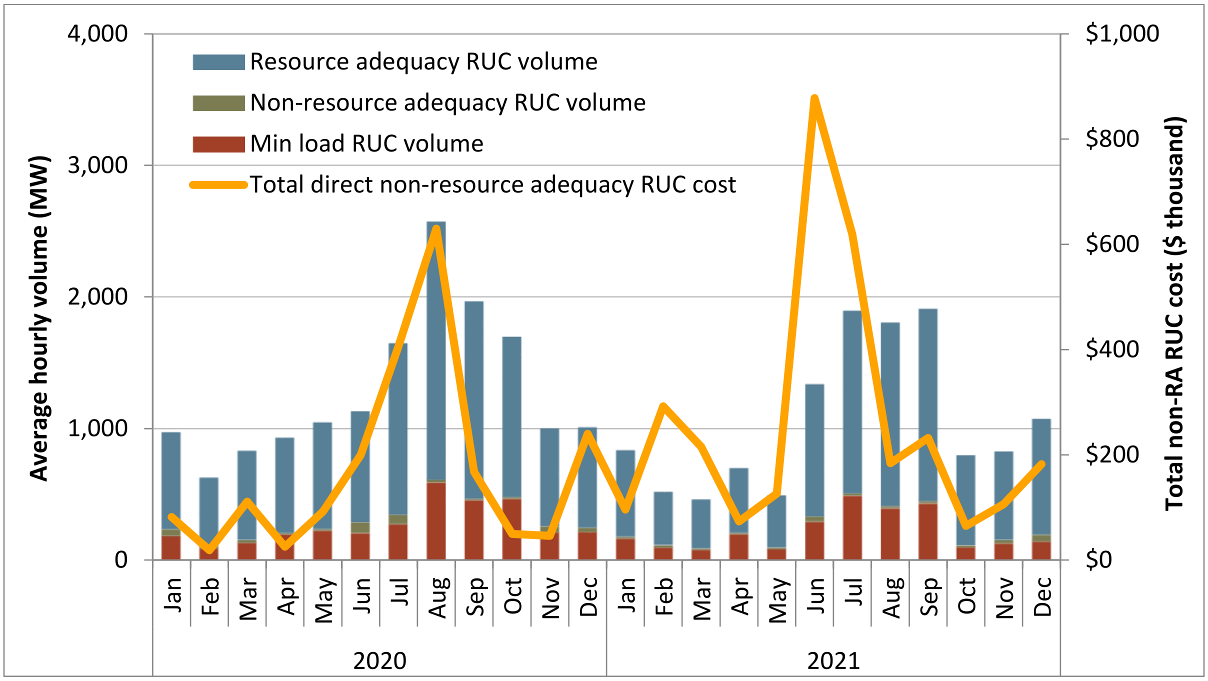
During the fourth quarter of 2021, the *residual unit commitment undersupply power balance constraint* was not infeasible in any hour. The market change that went in place on September 5, 2020, was designed to address the treatment of economic and self-scheduled exports that cleared the day-ahead integrated forward market (IFM) run. With this change, the residual unit commitment process is able to curtail certain exports before relaxing the power balance constraint. These reduced exports no longer receive a real-time scheduling priority that exceeds California ISO's real-time load and can choose to re-bid in real-time or resubmit as self-schedules in real-time.[24]

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.[25] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.27. In the fourth quarter of 2021, these costs were about $0.35 million, similar to 2020.

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

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

Figure 1.27 Residual unit commitment costs and volume



1.7 Ancillary services

Ancillary service payments this quarter totaled $32 million, a 35 percent decrease from 2020. Overall requirements for the four ancillary services were similar to the fourth quarter last year, besides an increase in regulation down services.

1.7.1 Ancillary service requirements

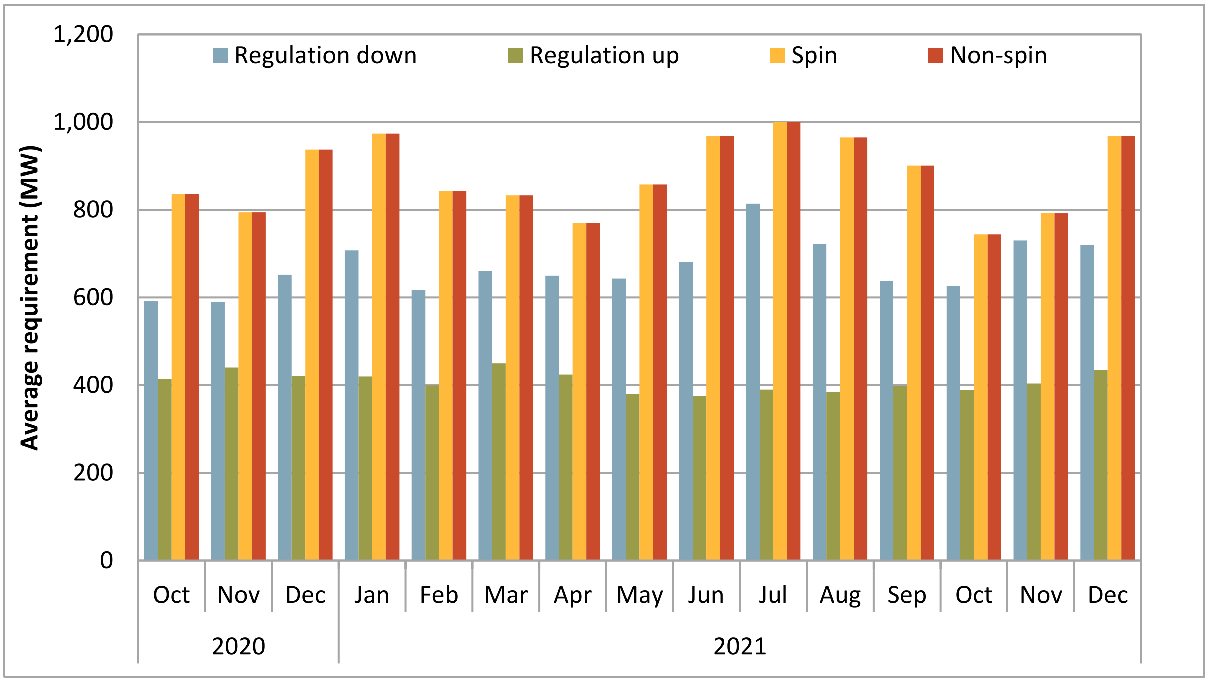
The California ISO procures four ancillary services in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's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

The California 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.[26] 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.

[26] More information on ancillary services requirements and procurement for internal and expanded regions is available in *2020 Annual Report on Market Issues & Performance*, page 161: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

Figure 1.28 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. As shown, average requirements for operating reserves and regulation up decreased slightly this quarter compared to the same quarter last year. Average regulation down requirements, on the other hand, increased about 13 percent this quarter compared to the fourth quarter last year.

Figure 1.28 Average monthly day-ahead ancillary service requirements

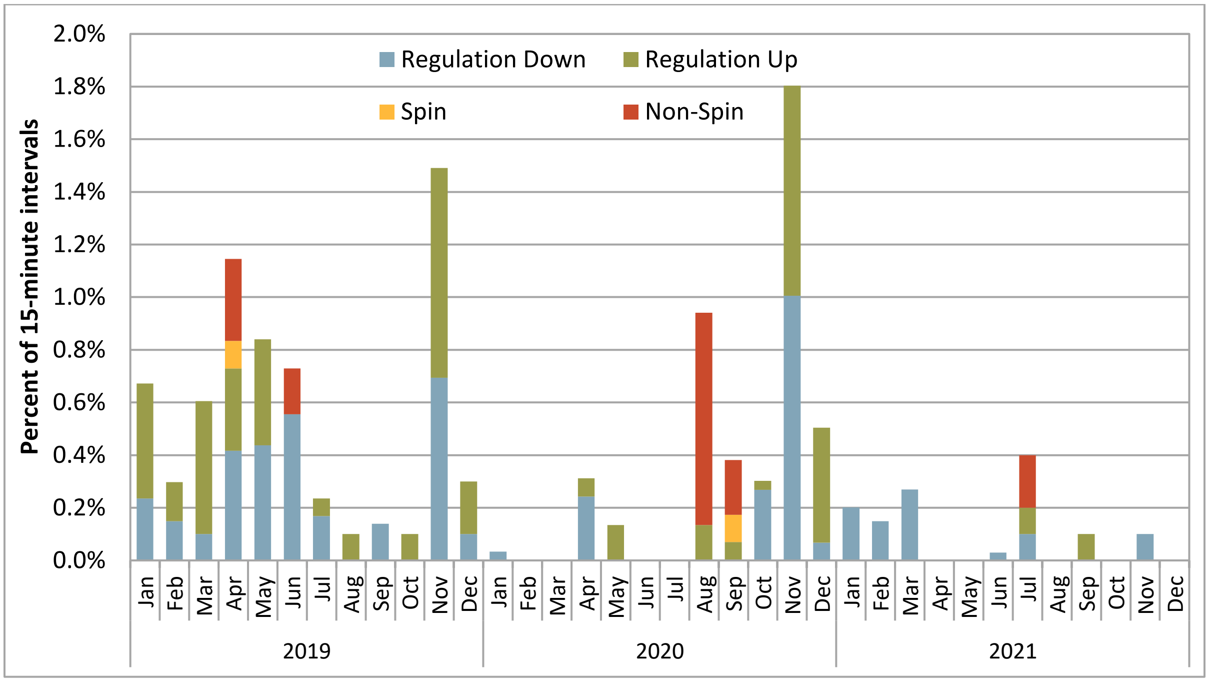


1.7.2 Ancillary service scarcity

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, the California 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 this quarter from 0.17 percent of intervals last year to 0.03 percent this year. Scarcity events occurred in two intervals in November.

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



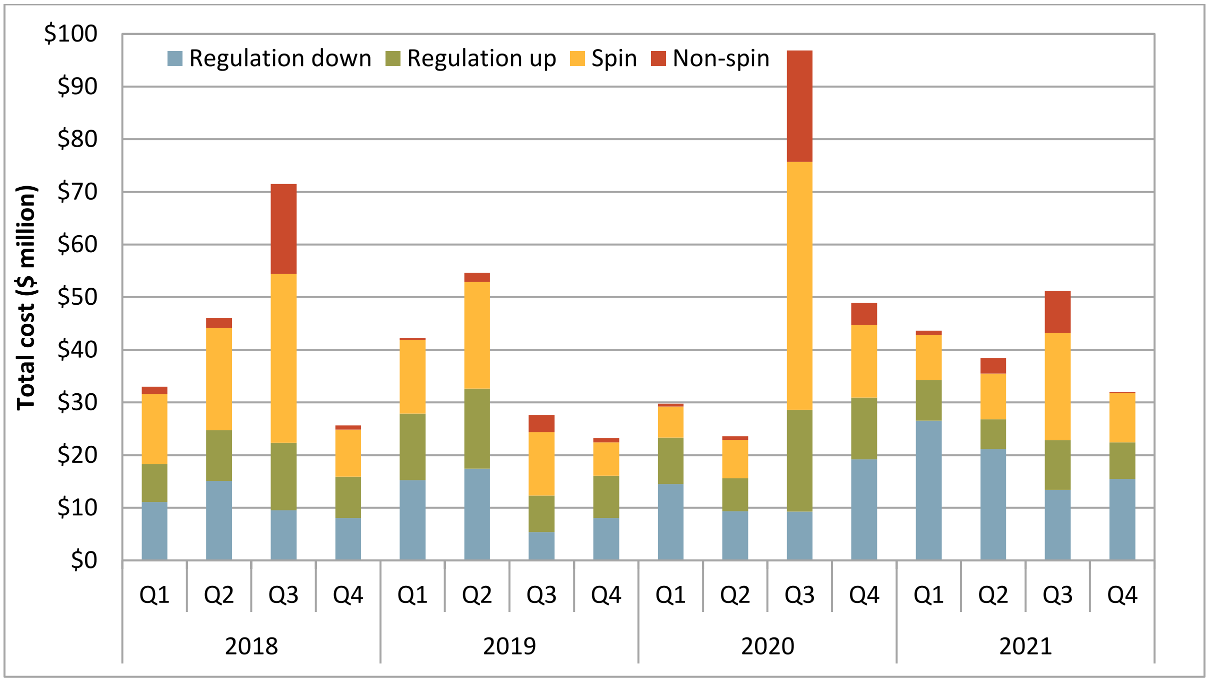
1.7.3 Ancillary service costs

Ancillary service payments decreased this quarter to about $32 million, compared to about $51 million in the previous quarter. Payments were 35 percent lower than the same quarter of 2020 when ancillary service payments were almost $49 million.

Figure 1.30 shows the total cost of procuring ancillary service products by quarter.[27] The cost to procure each type of ancillary service decreased substantially this quarter compared to fourth quarter last year. In particular, the cost to procure operating reserves and regulation services decreased by about $8.5 million each.

[27] 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. As noted elsewhere in the report, settlements values are based on statements available at the time of drafting and will be updated in future reports.

Figure 1.30 Ancillary service cost by product



1.8 Congestion

In the day-ahead market, congestion in the fourth quarter increased prices in the Pacific Gas & Electric (PG&E) and San Diego Gas & Electric (SDG&E) areas and decreased prices in the Southern California Edison (SCE) area. In the 15-minute market, the impact of internal congestion on prices increased on average relative to the same quarter of 2020.

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 California ISO (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) as well as on WEIM 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 California ISO system is calculated as the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes as well as for groups of nodes that represent different load aggregation points or local capacity areas.[28]

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

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

1.8.1 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 fourth quarter of 2021, congestion rent and loss surplus was $155 million and $42 million, respectively. These respective amounts represent a 51 percent and 12 percent increase relative to the same quarter of 2020.[29] 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]

[29] Due to the availability of data, Figure 1.31 and the comparative analysis of day-ahead congestion rent and loss surplus in the fourth quarter of 2021 are preliminary.

[30] For more information on marginal loss surplus allocation refer to the California 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 1.31 Day-ahead congestion rent and loss surplus by quarter (2020-2021)

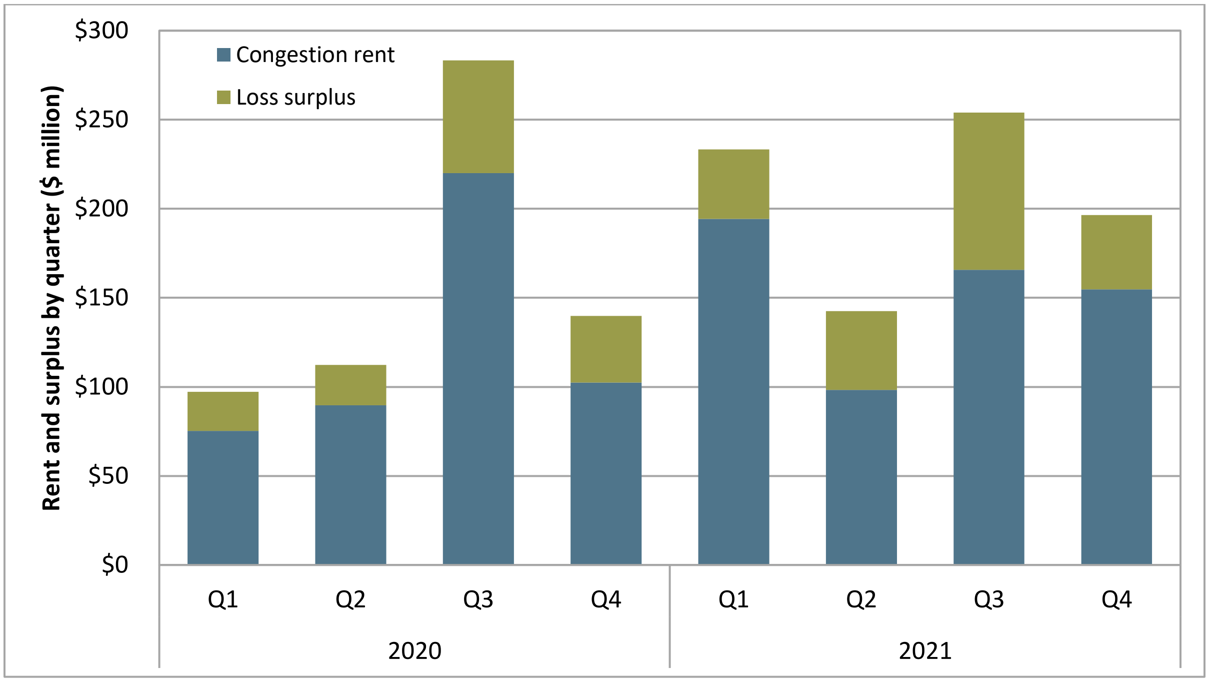


Figure 1.32 shows the overall impact of congestion on day-ahead prices in each load area in 2020 and 2021. Figure 1.33 shows the frequency of congestion. Highlights for this quarter include:

- In the fourth quarter of 2021, the overall net impact of congestion on price separation increased significantly in PG&E, SCE, and SDG&E relative to the same quarter of 2020. The frequency of congestion increased in PG&E and SCE while it decreased in SDG&E compared to the same quarter in 2020.
- Congestion increased quarterly average prices in PG&E and SDG&E by $1.50/MWh (2.4 percent) and $2.09/MWh (3.3 percent), respectively, while it decreased prices in SCE by $0.1.29/MWh (2.2 percent).
- The primary constraints impacting day-ahead market prices were the Los Banos-Quinto 230 kV line, the Miguel 500/230 kV transformer nomogram, and the Imperial Valley-El Centro 230 kV 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

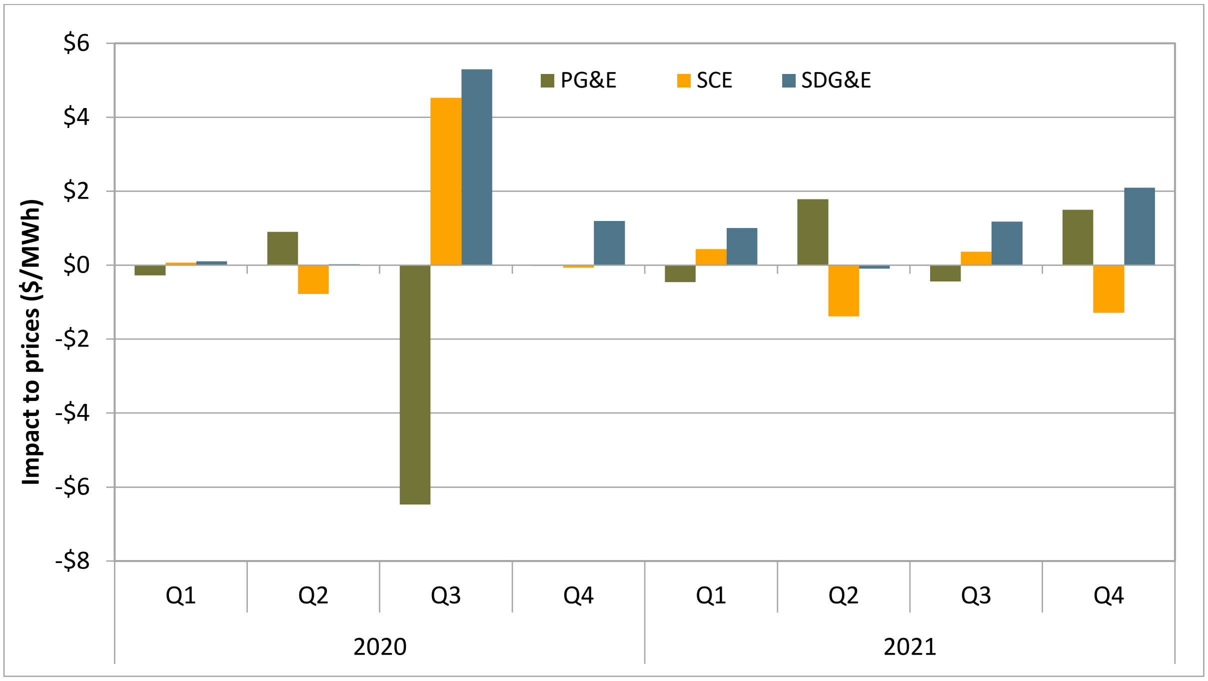
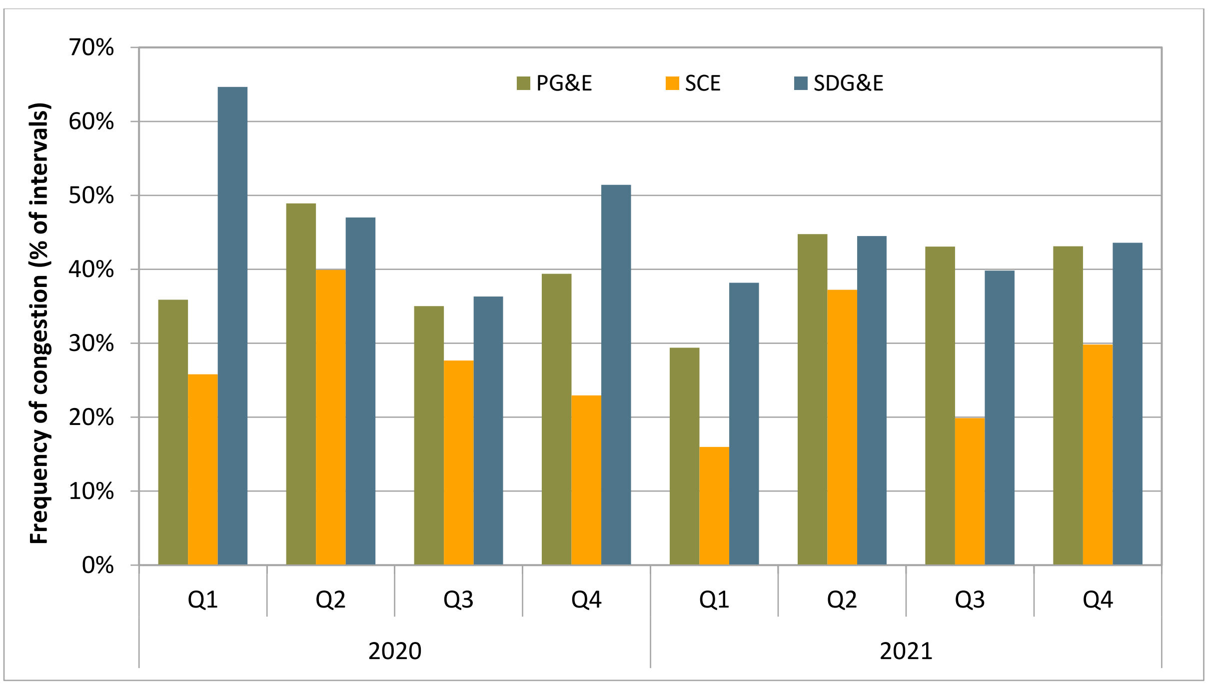


Figure 1.33 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.3 breaks down the congestion impact on price separation in the fourth quarter by constraint.[31] Table 1.4 shows the impact of congestion from each constraint only during congested intervals, where the number of congested intervals is presented separately as frequency. The constraints with the greatest impact on price separation for the quarter were the Los Banos-Quinto 230 kV line, the Miguel 500/230 kV transformer nomogram, and the Imperial Valley-El Centro 230 kV nomogram.

Los Banos-Quinto 230 kV line

The Los Banos-Quinto 230 kV line (30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1) had the greatest impact on day-ahead prices during the fourth quarter. It was one of the most frequently binding constraints of the quarter, binding in 11 percent of hours. When binding, it decreased SCE and SDG&E prices by about $8.74/MWh and $7.81/MWh, respectively, while it increased PG&E prices by $10.61/MWh. On average for the quarter, congestion on the line decreased average SCE and SDG&E prices by about $0.97/MWh (1.6 percent) and $0.86/MWh (1.4 percent), respectively, and increased average PG&E prices by $1.17/MWh (1.8 percent). This line was frequently mitigated over the quarter due to the loss of the Tesla-Los Banos 500 kV line.

Miguel 500/230 kV transformer nomogram

The Miguel 500/230 kV transformer nomogram (MIGUEL_BKs_MXFLW_NG) bound in 7 percent of hours over the quarter. When binding, it raised prices in SDG&E by $32.53/MWh and lowered prices in PG&E by $3.50/MWh. For the overall quarter, congestion on the nomogram increased average SDG&E prices by $2.31/MWh (3.7 percent) and decreased average PG&E prices by $0.16/MWh (0.2 percent). This nomogram was used to mitigate the loss of one of the 500/230 kV transformers at the Miguel substation.

Imperial Valley-El Centro 230 kV nomogram

The Imperial Valley-El Centro 230 kV nomogram (7820_TL 230S_OVERLOAD_NG) was the most frequently binding constraints of the quarter, binding in over 11 percent of hours. When binding, it increased SDG&E prices by $4.94/MWh, while it decreased prices in PG&E by $0.49/MWh. Overall for the quarter, the nomogram increased average SDG&E prices by about $0.56/MWh (0.9 percent), and decreased average prices in PG&E by $0.06/MWh (0.1 percent). This nomogram was used to mitigate the loss of the North Gila-Imperial Valley 500 kV line.

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

Table 1.3 Impact of congestion on overall day-ahead prices

Constraint Location	Constraint	PG&E		SCE		SDG&E	
		$ per MWh	Percent	$ per MWh	Percent	$ per MWh	Percent
PG&E	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$1.17	1.84%	-$0.97	-1.63%	-$0.86	-1.37%
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$0.17	0.27%	-$0.13	-0.22%	-$0.12	-0.19%
	GATES-PNOCHE_RT_NG	$0.14	0.22%	-$0.04	-0.07%	-$0.04	-0.06%
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.10	0.16%	-$0.08	-0.13%	-$0.07	-0.12%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	$0.08	0.12%	-$0.06	-0.11%	-$0.06	-0.09%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.07	0.11%	-$0.04	-0.06%	-$0.03	-0.05%
	7440_MetcalfImport_Tes-Metcalf	$0.03	0.05%	-$0.03	-0.05%	-$0.03	-0.04%
	35922_MOSSLD _115_30750_MOSSLD _230_XF_1	$0.01	0.02%	$0.00	0.00%	$0.00	0.00%
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.01%
	30885_MUSTANGS_230_30900_GATES _230_BR_1 _1	$0.01	0.02%	-$0.01	-0.01%	-$0.01	-0.01%
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	$0.01	0.01%	-$0.01	-0.01%	-$0.01	-0.01%
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	$0.01	0.01%	-$0.01	-0.01%	-$0.01	-0.01%
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	$0.01	0.01%	-$0.01	-0.01%	-$0.01	-0.01%
	30055_GATES1 _500_30900_GATES _230_XF_12_P	$0.01	0.01%	$0.00	-0.01%	$0.00	-0.01%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-$0.01	-0.01%	$0.01	0.01%	$0.01	0.01%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.07	-0.11%	$0.05	0.09%	$0.05	0.08%
SCE	6410_CP1_NG	-$0.01	-0.01%	$0.01	0.01%	$0.01	0.01%
	24091_MESA CAL_230_25001_GOODRICH_230_BR_1 _1	-$0.01	-0.01%	$0.00	0.01%	$0.01	0.01%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.05	-0.08%
SDG&E	MIGUEL_BKs_MXFLW_NG	-$0.16	-0.24%	$0.00	0.00%	$2.31	3.67%
	7820_TL 230S_OVERLOAD_NG	-$0.06	-0.09%	$0.00	0.00%	$0.56	0.90%
	OMS 10827057_TL50003_NG	-$0.01	-0.02%	$0.00	0.00%	$0.11	0.18%
	OMS 10731240_TL23054_NG	$0.00	-0.01%	$0.00	0.00%	$0.04	0.07%
	OMS 11135733_TL50003_NG	$0.00	-0.01%	$0.00	0.00%	$0.04	0.07%
	OMS 10827084_TL50003_NG	$0.00	-0.01%	$0.00	0.00%	$0.04	0.06%
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.03	0.05%
	22420_SILVERGT_69.0_22868_URBAN _69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.03	0.05%
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.04%
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.01	-0.02%	$0.01	0.01%	$0.02	0.03%
	OMS 11140689_TL50003_NG	$0.00	0.00%	$0.00	0.00%	$0.02	0.03%
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.03%
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.01	0.02%
	22773_BAY BLVD_69.0_22352_IMPRLBCH_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.01	0.02%
Other		$0.02	0.03%	$0.02	0.04%	$0.04	0.06%
Total		**$1.50**	**2.36%**	**-$1.29**	**-2.17%**	**$2.09**	**3.32%**

Table 1.4 Impact of congestion on day-ahead prices during congested hours[32]

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	11.0%	$10.61	-$8.74	-$7.81
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	0.1%	$7.62	-$6.26	-$5.82
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	0.2%	$5.70	-$4.18	-$3.74
	GATES-PNOCHE_RT_NG	3.0%	$4.62	-$1.32	-$1.21
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	3.7%	$4.57	-$3.63	-$3.51
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	1.7%	$4.56	-$3.67	-$3.39
	35922_MOSSLD _115_30750_MOSSLD _230_XF_1	0.3%	$4.42	$0.00	$0.00
	30885_MUSTANGS_230_30900_GATES _230_BR_1 _1	0.3%	$3.10	-$2.36	-$2.23
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	3.7%	$2.69	-$2.13	-$1.96
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	0.3%	$2.50	-$2.05	-$1.86
	7440_MetcalfImport_Tes-Metcalf	1.9%	$1.81	-$1.45	-$1.40
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	0.5%	$1.47	-$1.14	-$1.06
	30055_GATES1 _500_30900_GATES _230_XF_12_P	0.4%	$1.25	-$1.06	-$0.99
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	5.4%	$1.23	-$0.88	-$0.81
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	0.9%	-$7.72	$5.80	$5.51
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	0.1%	-$8.41	$6.18	$5.53
SCE	6410_CP1_NG	0.0%	-$17.77	$12.66	$11.65
	24091_MESA CAL_230_25001_GOODRICH_230_BR_1 _1	0.5%	-$1.06	$0.80	$1.34
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	3.0%	$0.00	$0.57	-$1.65
SDG&E	MIGUEL_BKs_MXFLW_NG	7.1%	-$3.50	$0.00	$32.53
	OMS 10827057_TL50003_NG	0.5%	-$2.38	$0.00	$22.51
	OMS 10731240_TL23054_NG	0.3%	-$1.45	$0.00	$16.32
	22420_SILVERGT_69.0_22868_URBAN _69.0_BR_1 _1	0.2%	$0.00	$0.00	$13.32
	OMS 10827084_TL50003_NG	0.4%	-$1.09	$0.00	$10.96
	OMS 11135733_TL50003_NG	0.5%	-$0.86	$0.00	$9.73
	OMS 11140689_TL50003_NG	0.3%	-$0.59	$0.00	$6.86
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1	0.3%	$0.00	$0.00	$5.26
	7820_TL 230S_OVERLOAD_NG	11.4%	-$0.49	$0.00	$4.94
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	1.3%	$0.00	$0.00	$2.56
	22773_BAY BLVD_69.0_22352_IMPRLBCH_69.0_BR_1 _1	0.5%	$0.00	$0.00	$2.53
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	0.8%	-$1.66	$1.04	$2.44
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1	1.0%	$0.00	$0.00	$2.37
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	0.7%	$0.00	$0.00	$2.00

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.

1.8.2 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.

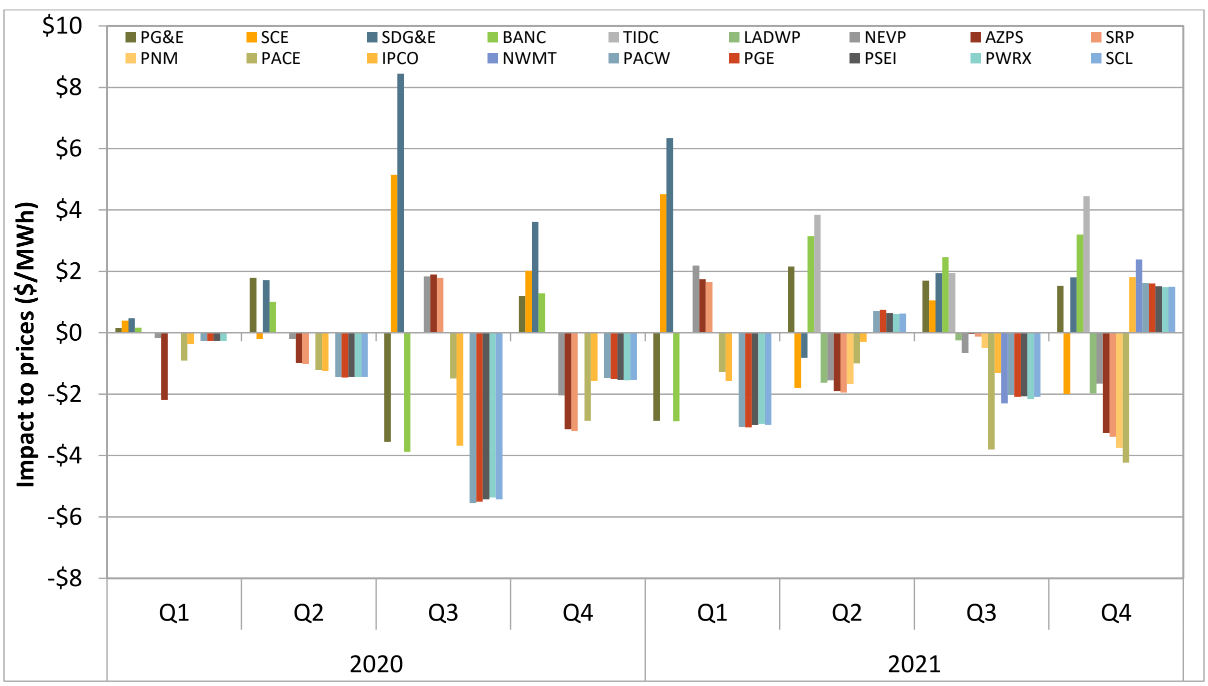
Impact of internal congestion to overall 15-minute prices in each load area

Figure 1.34 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 increased in most areas compared to the same quarter of 2020. Generally, congestion resulted in a net increase to prices in areas in the Pacific Northwest and within California, while it resulted in a net decrease to prices in South Western areas.
- The primary constraints creating price separation in the 15-minute market were the Los Banos-Quinto 230 kV line, the Midpoint 345/230 kV transformer, and a Miguel 500/230 kV transformer.

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

Figure 1.34 Overall impact of internal congestion on price separation in the 15-minute market



Impact of internal congestion from individual constraints

This section focuses on individual flow-based constraints. In the fourth quarter, the constraints that had the greatest impact on price separation in the 15-minute market were the Los Banos-Quinto 230 kV line, the Midpoint 345/230 kV transformer, and a Miguel 500/230 kV transformer.[33]

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

Table 1.5 Impact of congestion on overall 15-minute prices

Constraint Location	Constraint	PG&E	SCE	SDG&E	BANC	TIDC	LADWP	NEVP	AZPS	SRP	PNM	PACE	IPCO	NWMT	PACW	PGE	PSEI	PWRX	SCL
AZPS	LN-LL								$0.10										
BANC	HUR_NAT	$0.00			$0.00	$0.01								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
IPCO	T342.MPSN	$0.16	-$0.16	-$0.20	$0.21	$0.17	-$0.34	-$0.53	-$0.28	-$0.28	-$0.36	-$0.79	$1.16	$0.12	$0.44	$0.45	$0.44	$0.43	$0.44
	T341.BORA	$0.04	-$0.04	-$0.05	$0.05	$0.04	-$0.10	-$0.01	-$0.07	-$0.07	-$0.10	-$0.22	$0.21	$0.06	$0.09	$0.09	$0.09	$0.09	$0.09
NWMT	RIMROCK_PAR										$0.00	-$0.79		$1.52			$0.00	$0.01	$0.00
	FC-CH2		$0.03	$0.03					$0.04	$0.04	-$0.20	-$0.05	-$0.02	-$0.01					
	FC-MK	$0.02	$0.09	$0.06		$0.00	$0.00	$0.08			-$0.66	-$0.14	-$0.06	-$0.04					
PACE	WINDSTAR EXPORT TCOR											-$0.16							
	EAST_WYO_EXP											-$0.22							
	TOTAL_WYOMING_EXPORT											-$1.58							
PG&E	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.64	-$1.34	-$1.26	$1.90	$3.24	-$1.03	-$0.70	-$1.10	-$1.10	-$0.92		$0.56	$0.74	$1.00	$0.99	$0.96	$0.95	$0.96
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.22	-$0.27	-$0.25	$0.27	$0.29	-$0.20	-$0.14	-$0.22	-$0.22	-$0.19		$0.03	$0.12	$0.17	$0.17	$0.16	$0.16	$0.16
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$0.14	-$0.22	-$0.21	$0.21	$0.26	-$0.15	-$0.03	-$0.18	-$0.18	-$0.13		$0.00	$0.01	$0.10	$0.09	$0.06	$0.04	$0.06
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	$0.13			$0.28	$0.07							$0.00	-$0.09	-$0.15	-$0.17	-$0.17	-$0.16	-$0.17
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	$0.07	-$0.09	-$0.09	$0.08	$0.08	-$0.07	-$0.04	-$0.08	-$0.08	-$0.06	-$0.01	$0.03	$0.04	$0.06	$0.06	$0.06	$0.06	$0.06
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.05	$0.03	$0.02	$0.03	$0.05	$0.01	$0.01	$0.02	$0.02	$0.01	-$0.03	-$0.06	-$0.07	-$0.08	-$0.08	-$0.08	-$0.08	-$0.08
	7440_MetcalfImport_Tes-Metcalf	$0.03	-$0.02	-$0.02	$0.01	$0.02	-$0.02	-$0.01	-$0.02	-$0.02	-$0.02				$0.01	$0.01	$0.01	$0.00	$0.01
	GATES-PNOCHE_RT_NG	$0.03	-$0.15	-$0.15	$0.13	$0.17	-$0.05	-$0.03	-$0.05	-$0.05	-$0.04		$0.02	$0.03	$0.04	$0.04	$0.04	$0.04	$0.04
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	$0.02	-$0.03	-$0.03	$0.03	$0.03	-$0.02	-$0.02	-$0.03	-$0.03	-$0.02		$0.02	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.02	-$0.03	-$0.03	$0.03	$0.03	-$0.02	-$0.02	-$0.03	-$0.03	-$0.02	$0.00	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.02	-$0.04	-$0.04	$0.00	$0.01	-$0.02		-$0.02	-$0.02	-$0.01				$0.00	$0.00			
	30624_TESLA E _230_30625_TESLA D _230_BR_2 _1	$0.01			$0.03	$0.01													
	30114_DELEVAN _230_30450_CORTINA _230_BR_1 _1	$0.01	$0.00			$0.00						$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	$0.01	-$0.01	-$0.01	$0.01	$0.01	-$0.01	$0.00	-$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 _1	$0.00	-$0.01	-$0.01	$0.00	$0.00	-$0.01	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30015_TABLE MT_500_30040_TESLA _500_BR_1 _3	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30050_LOSBANOS_500_30055_GATES1 _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	$0.00	$0.00	$0.00
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _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	$0.00	$0.00	$0.00	$0.00	$0.00
SCE	6410_CP1_NG	-$0.16	$0.15	$0.15	-$0.15	-$0.16	$0.12	$0.08	$0.13	$0.13	$0.11		-$0.06	-$0.08	-$0.11	-$0.11	-$0.11	-$0.10	-$0.11
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.02	$0.02	$0.01	$0.02	$0.02	-$0.06	-$0.03	-$0.03	-$0.03	-$0.03	-$0.01		$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	OMS 10760983_OP-6610	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00
	6410_CP7_NG	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24801_DEVERS _500_24804_DEVERS _230_XF_2 _P	$0.02		$0.02	$0.01	$0.01		-$0.02	-$0.08	-$0.08	-$0.06	-$0.02							
SDG&E	MIGUEL_BKs_MXFLW_NG			$1.96				-$0.03	-$0.68	-$0.68	-$0.51	-$0.01							
	7820_TL 230S_OVERLOAD_NG		$0.06	$0.78				-$0.07	-$0.19	-$0.20	-$0.15	-$0.06	-$0.01	$0.00					
	OMS 10827054_TL50003_NG		$0.02	$0.31				-$0.02	-$0.07	-$0.07	-$0.06	-$0.02							
	OMS_10721323_TL23055_NG		$0.01	$0.21				-$0.01	-$0.07	-$0.07	-$0.06	-$0.01							
	92321_SYCA TP2_230_22832_SYCAMORE_230_BR_2 _1			$0.15					-$0.05	-$0.05	-$0.04								
	OMS 10731240_TL23054_NG			$0.12				-$0.01	-$0.03	-$0.03	-$0.02	-$0.01							
	OMS 10827229_TL50003_NG		$0.00	$0.10				-$0.01	-$0.03	-$0.02	-$0.02	-$0.01							
	OMS 11135733_TL50003_NG		$0.00	$0.06				$0.00	-$0.02	-$0.02	-$0.01	$0.00							
	OMS 10827060_TL50003_NG		$0.00	$0.04				$0.00	-$0.01	-$0.01	-$0.01	$0.00	$0.00						
	OMS 10827057_TL50003_NG		$0.00	$0.03				$0.00	-$0.01	-$0.01	-$0.01	$0.00							
	OMS 10827234_TL50003_NG			$0.03				$0.00	-$0.01	-$0.01	$0.00	$0.00							
	OMS 10827228_TL50003_NG		$0.00	$0.03				$0.00	-$0.01	-$0.01	$0.00	$0.00							
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	$0.03		$0.02	$0.02	$0.03		-$0.04	-$0.13	-$0.14	-$0.10	-$0.04							
	OMS 10827084_TL50003_NG		$0.00	$0.02				$0.00	$0.00	$0.00	$0.00	$0.00							
	OMS 10827223_TL50003_NG		$0.00	$0.02				$0.00	$0.00	$0.00	$0.00	$0.00							
	OMS 10827073_TL50003_NG		$0.00	$0.01				$0.00	$0.00	$0.00	$0.00	$0.00							
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	$0.00	$0.01	-$0.04	$0.00	$0.00	$0.00		-$0.01	-$0.01	-$0.01								
	Other	$0.01	-$0.01	$0.01	$0.01	$0.04	-$0.01	-$0.04	-$0.02	-$0.02	-$0.02	-$0.03	$0.00	$0.01	$0.00	$0.01	$0.00	$0.00	$0.00
	Internal Total	**$1.53**	**-$1.99**	**$1.80**	**$3.21**	**$4.45**	**-$1.97**	**-$1.66**	**-$3.27**	**-$3.38**	**-$3.75**	**-$4.23**	**$1.82**	**$2.38**	**$1.63**	**$1.61**	**$1.52**	**$1.48**	**$1.51**
	Transfers				-$0.01	-$0.21	$0.47	$0.58	-$0.09	$0.14	$0.01	-$0.47	$0.24	$8.54	-$1.37	-$1.46	-$3.78	-$3.05	-$4.12
	Grand Total	**$1.53**	**-$1.99**	**$1.80**	**$3.20**	**$4.24**	**-$1.50**	**-$1.08**	**-$3.36**	**-$3.24**	**-$3.74**	**-$4.70**	**$2.06**	**$10.92**	**$0.26**	**$0.15**	**-$2.26**	**-$1.57**	**-$2.61**

33 These constraints are shown as 30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1, T342.MPSN, and MIGUEL_BKs_MXFLW_NG in the tables, respectively.

Table 1.6 Impact of internal congestion on 15-minute prices during congested intervals[34]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDG&E	BANC	TIDC	LADWP	NEVP	AZPS	SRP	PNM	PACE	IPCO	NWMT	PACW	PGE	PSEI	PWRX	SCL
AZPS	LN-LL	3.5%								$2.76										
IPCO	T342.MPSN	8.7%	$1.78	-$1.85	-$2.31	$2.42	$2.00	-$3.85	-$6.03	-$3.22	-$3.26	-$4.10	-$8.98	$13.27	$1.74	$5.07	$5.13	$5.01	$4.90	$5.00
	T341.BORA	1.6%	$2.22	-$2.43	-$3.07	$3.01	$2.47	-$6.24	-$1.86	-$4.44	-$4.52	-$6.10	-$13.55	$13.07	$3.74	$5.61	$5.64	$5.53	$5.44	$5.53
NWMT	RIMROCK_PAR	3.4%										-$12.38	-$23.16		$44.43			$17.42	$16.40	$18.21
	FC-MK	2.7%	$1.69	$3.27	$2.43		$1.63	$2.24	$3.11			-$24.71	-$5.35	-$2.21	-$1.79					
	FC-CH2	0.9%		$2.80	$3.36					$4.85	$4.63	-$21.69	-$5.61	-$2.60	-$2.12					
PACE	EAST_WYO_EXP	16.1%											-$1.35							
	WINDSTAR EXPORT TCOR	8.2%											-$1.91							
	TOTAL_WYOMING_EXPORT	59.1%											-$2.67							
PG&E	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	1.5%	$9.89			$18.32	$9.95							-$8.79	-$10.68	-$10.20	-$11.03	-$10.86	-$10.79	-$10.85
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	7.4%	$8.68	-$18.17	-$17.04	$25.73	$43.93	-$13.93	-$9.44	-$14.92	-$14.84	-$12.46		$7.65	$10.07	$13.51	$13.47	$13.06	$12.90	$13.02
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	3.5%	$6.26	-$7.68	-$7.25	$7.66	$8.16	-$5.83	-$3.99	-$6.31	-$6.28	-$5.35		$1.84	$3.48	$4.91	$4.91	$4.71	$4.67	$4.69
	7440_MetcalfImport_Tes-Metcalf	0.4%	$6.11	-$4.86	-$4.68	$3.22	$3.62	-$3.97	-$2.59	-$4.21	-$4.19	-$3.67				$1.61	$1.59	$1.43	$1.37	$1.42
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	1.2%	$5.27	-$7.51	-$7.35	$6.37	$6.58	-$5.77	-$3.50	-$6.14	-$6.10	-$5.16	-$0.65	$2.46	$3.43	$4.77	$4.73	$4.55	$4.47	$4.54
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	3.2%	$4.76	-$6.83	-$6.51	$6.73	$8.30	-$5.25	-$4.53	-$5.86	-$5.83	-$4.92		$0.87	$1.43	$5.03	$4.91	$4.37	$4.01	$4.19
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	0.5%	$4.74	-$6.32	-$5.96	$5.73	$5.86	-$4.74	-$3.02	-$5.26	-$5.23	-$4.37	-$0.41	$2.22	$2.94	$4.32	$4.28	$4.13	$4.08	$4.12
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	1.1%	$3.55	-$3.78	-$3.71	$2.49	$3.01	-$3.77		-$3.93	-$3.92	-$3.63				$7.36	$7.36			
	GATES-PNOCHE_RT_NG	2.3%	$1.13	-$6.60	-$6.29	$5.78	$7.36	-$2.03	-$1.24	-$2.16	-$2.15	-$1.86		$0.85	$1.25	$1.67	$1.65	$1.60	$1.58	$1.60
SCE	6410_CP1_NG	1.2%	-$13.78	$12.61	$12.92	-$13.03	-$13.56	$10.68	$7.15	$11.38	$11.28	$9.56		-$5.08	-$6.83	-$9.60	-$9.52	-$9.16	-$9.00	-$9.13
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	0.7%	$2.54	$2.26	$1.27	$2.31	$2.48	-$7.64	-$4.59	-$4.14	-$4.14	-$4.13	-$1.97		$1.53	$1.28	$1.26	$1.17	$1.12	$1.16
	24801_DEVERS _500_24804_DEVERS _230_XF_2 _P	1.7%	$1.07		$3.66	$0.94	$1.04		-$1.35	-$4.79	-$5.12	-$3.76	-$1.32							
SDG&E	OMS 10827054_TL50003_NG	0.4%		$5.40	$75.28				-$5.79	-$18.25	-$18.21	-$14.02	-$6.11							
	MIGUEL_BKs_MXFLW_NG	4.1%			$48.05				-$4.12	-$16.65	-$16.68	-$12.54	-$25.65							
	OMS 10827229_TL50003_NG	0.4%		$1.13	$22.34				-$1.47	-$6.25	-$5.60	-$3.46	-$1.28							
	OMS 11135733_TL50003_NG	0.3%		$1.15	$18.69				-$1.33	-$6.11	-$4.98	-$2.79	-$1.23							
	7820_TL 230S_OVERLOAD_NG	4.5%		$1.45	$17.36				-$1.50	-$4.15	-$4.43	-$3.41	-$1.41	-$0.66	-$0.12					
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	2.9%	$1.06		$3.58	$1.01	$0.99		-$1.29	-$4.56	-$4.88	-$3.57	-$1.21							

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 WEIM load areas located in the Pacific Northwest, where the transfer congestion reduced prices in those areas. The largest price impact over the quarter was in NorthWestern Energy, with an average decrease of about $8.54/MWh in the 15-minute market and $1.77/MWh in the 5-minute market.

In the 15-minute market, the total impact of congestion on a specific Western Energy Imbalance Market (WEIM) area is equal to the sum of the price impact of flow-based constraints shown in Figure 1.34 and Table 1.5, and schedule-based constraints as listed in Table 1.7. Transfer constraint congestion typically has the largest impact on prices; therefore, it is isolated here to better show its effects on WEIM load areas. Table 1.7 shows the congestion frequency and average price impact from transfer constraint congestion in the 15-minute and 5-minute markets during the quarter.

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

Table 1.7 Quarterly average price impact and congestion frequency on WEIM transfer constraints (Q4 2021)

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	0%	-$0.01	0%	$0.07
L.A. Dept. of Water and Power	1%	$0.47	1%	$0.94
Turlock Irrigation District	1%	-$0.21	1%	$0.15
Arizona Public Service	1%	-$0.09	4%	$0.71
NV Energy	1%	$0.58	4%	$0.63
Public Service Company of NM	3%	$0.01	6%	$1.05
PacifiCorp East	5%	-$0.47	8%	$0.04
Idaho Power	9%	$0.24	10%	$0.87
Salt River Project	11%	$0.14	13%	$0.79
PacifiCorp West	25%	-$1.37	18%	-$0.41
Portland General Electric	27%	-$1.46	20%	-$0.61
NorthWestern Energy	37%	$8.54	31%	$1.77
Seattle City Light	42%	-$4.12	43%	-$3.12
Puget Sound Energy	42%	-$3.78	43%	-$2.96
Powerex	42%	-$3.05	66%	-$1.81

Transfer constraint congestion in the 15-minute market

Transfer constraint congestion in the 15-minute market may occur with vastly different frequencies and average price impacts across the WEIM. Figure 1.35 and Figure 1.36 shows the average impact to prices and the frequency of congestion on transfer constraints in the 15-minute market by quarter for 2020 and 2021, respectively.

There was an overall decrease on the impact of average prices from transfer constraint congestion in the fourth quarter of 2021, compared to the same quarter in 2020. The exception to this was in NorthWestern Energy, where transfer constraint congestion increased prices in the area by $8.54/MWh in the 15-minute market on average for the quarter.

The frequency of transfer constraint congestion in the fourth quarter of 2021 was lower than that of the same quarter of 2020. Frequencies decreased in each area, with the exception of SRP. In SRP, transfer constraints were congested during 11 percent of intervals, compared to 4 percent in the fourth quarter of 2020.

Figure 1.35 Transfer constraint congestion average impact on prices in the 15-minute market

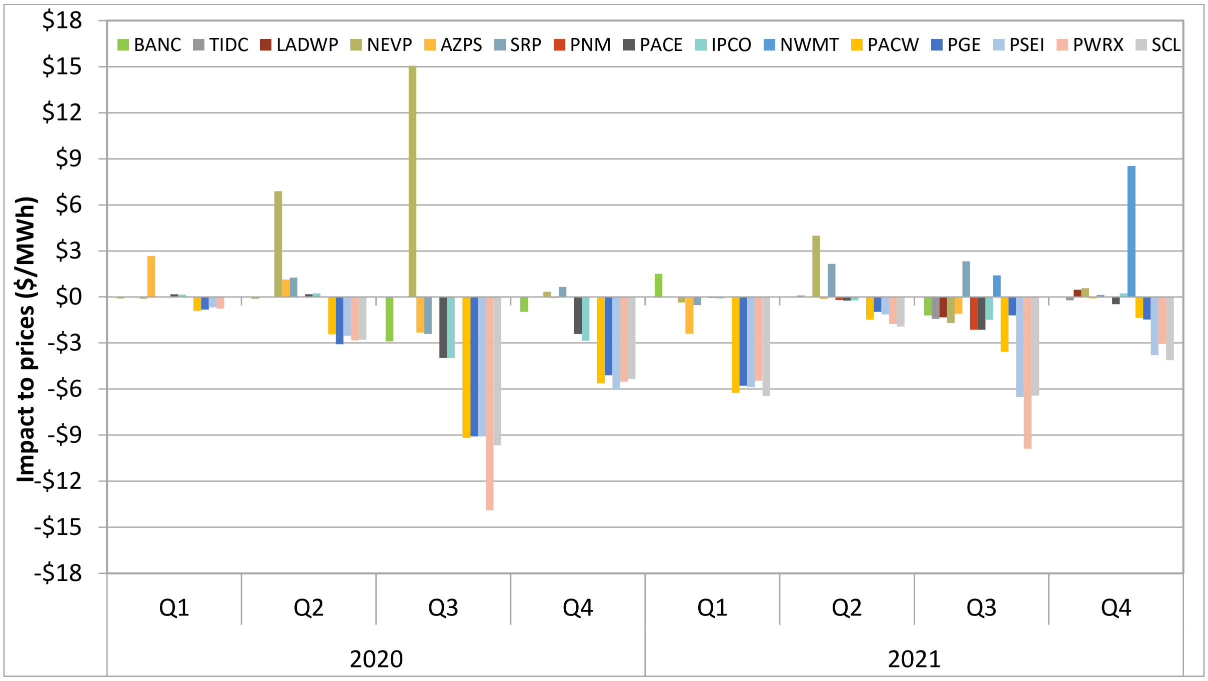
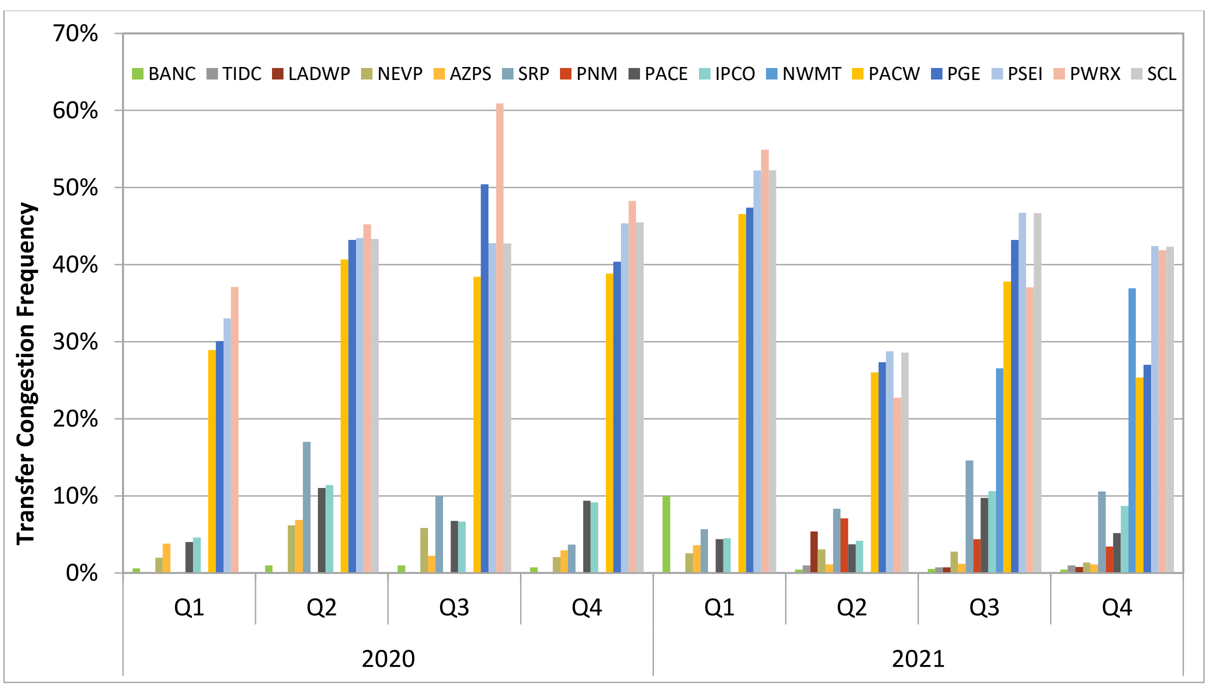


Figure 1.36 Transfer constraint congestion frequency in the 15-minute market



1.8.3 Congestion on interties

In the fourth quarter of 2021, the frequency and import congestion rent on Palo Verde remained notably high relative to the same quarter in 2020, these decreased on PACI/Malin 500 and NOB. Figure 1.37 shows total import congestion charges in the day-ahead market for 2020 and 2021. Figure 1.38 shows the frequency of congestion on five major interties. Table 1.8 provides a detailed summary of this data over a broader set of interties.

The total import congestion charges reported are the products of the shadow prices multiplied by the binding limits for the intertie constraints. For a supplier or load serving entity trying to import power over a congested intertie, assuming a radial line, the congestion price represents the difference between the higher price of the import on the California ISO side of the intertie and the lower price outside of the California ISO. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside the California ISO at points corresponding to these interties.

The charts and table highlight the following:

- Total import congestion charges for the fourth quarter of 2021 was about the same as the same quarter of 2020 at $19 million. The primary change between the quarters was a shift of congestion rent from NOB and PACI/Malin 500 to Palo Verde. Palo Verde accounted for 47 percent of the total import congestion charges in the fourth quarter of 2021, compared to 13 percent in same quarter last year.
- The frequency of congestion in the fourth quarter increased significantly on Palo Verde, rising to 16 percent of hours compared to 10 percent last quarter and 4 percent during the fourth quarter of 2020.
- The frequency of congestion and magnitude of congestion charges is typically highest on the PACI/Malin 500, NOB, and Palo Verde interties, a trend that continued in the fourth quarter of 2021. Congestion on other interties continued to remain relatively low relative to these constraints.

Figure 1.37 Day-ahead import congestion charges on major interties

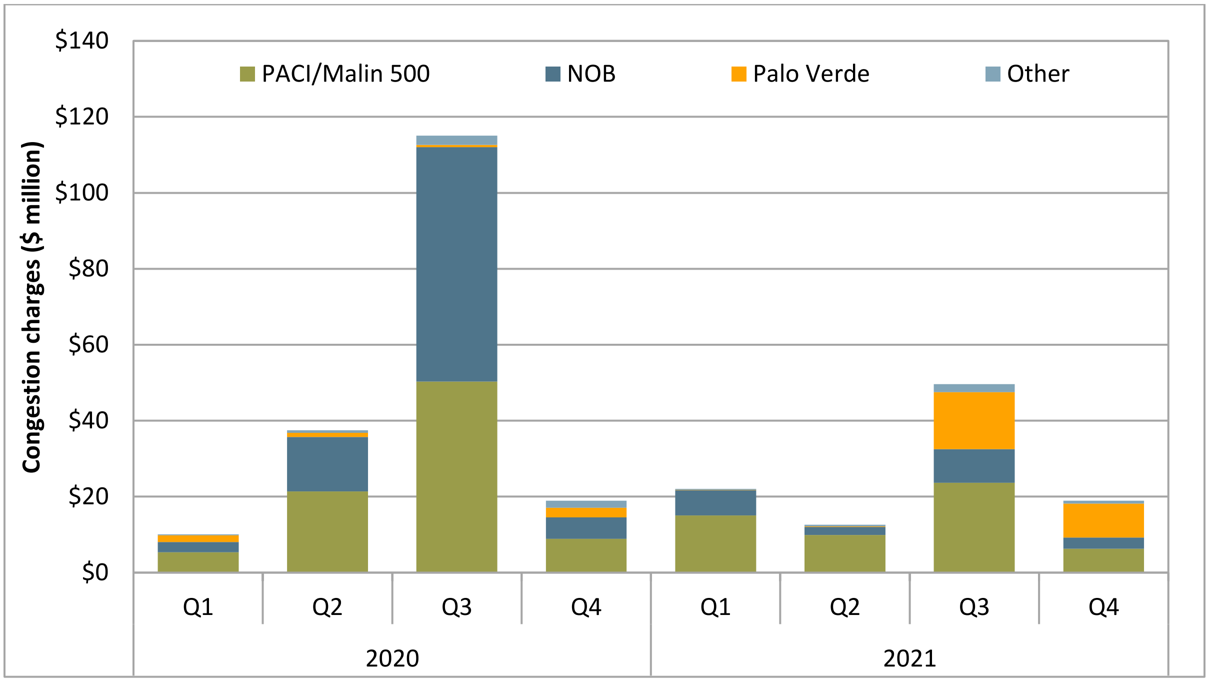


Figure 1.38 Frequency of import congestion on major interties in the day-ahead market

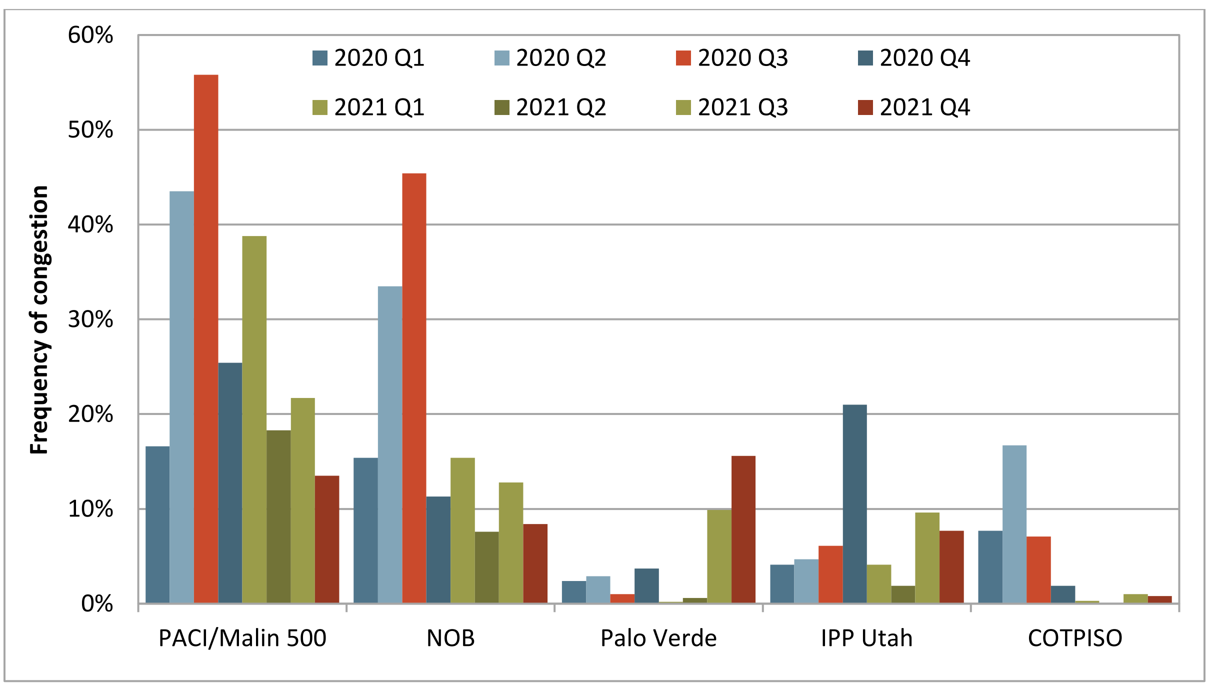


Table 1.8 Summary of import congestion in day-ahead market (2020-2021)

Area	Intertie	Frequency of import congestion								Import congestion charges ($ thousand)							
		2020				2021				2020				2021			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northwest	PACI/Malin 500	17%	44%	56%	25%	39%	18%	22%	14%	5,318	21,358	50,334	8,919	15,055	9,920	23,650	6,302
	NOB	15%	34%	45%	11%	15%	8%	13%	8%	2,715	14,317	61,672	5,670	6,689	2,132	8,899	2,976
	COTPISO	8%	17%	7%	2%	0%		1%	1%	85	258	66	14	3	0	17	11
Southwest	Palo Verde	2%	3%	1%	4%	0%	1%	10%	16%	1,827	1,174	576	2,516	35	178	15,005	8,910
	Westwing Mead				0%			1%	1%				19			142	412
	IPP Utah	4%	5%	6%	21%	4%	2%	10%	8%	136	136	528	1,459	65	16	1,278	266
	Mead		1%	1%	2%	0%		0%	0%		133	856	357	10		665	74
	Gonder IPP Utah		0%	0%		1%		0%			96	12		38		2	
	IID-SDGE						2%								339		
	IPP Adelanto														5		
	Merchant					1%								150			

1.9 Bid cost recovery

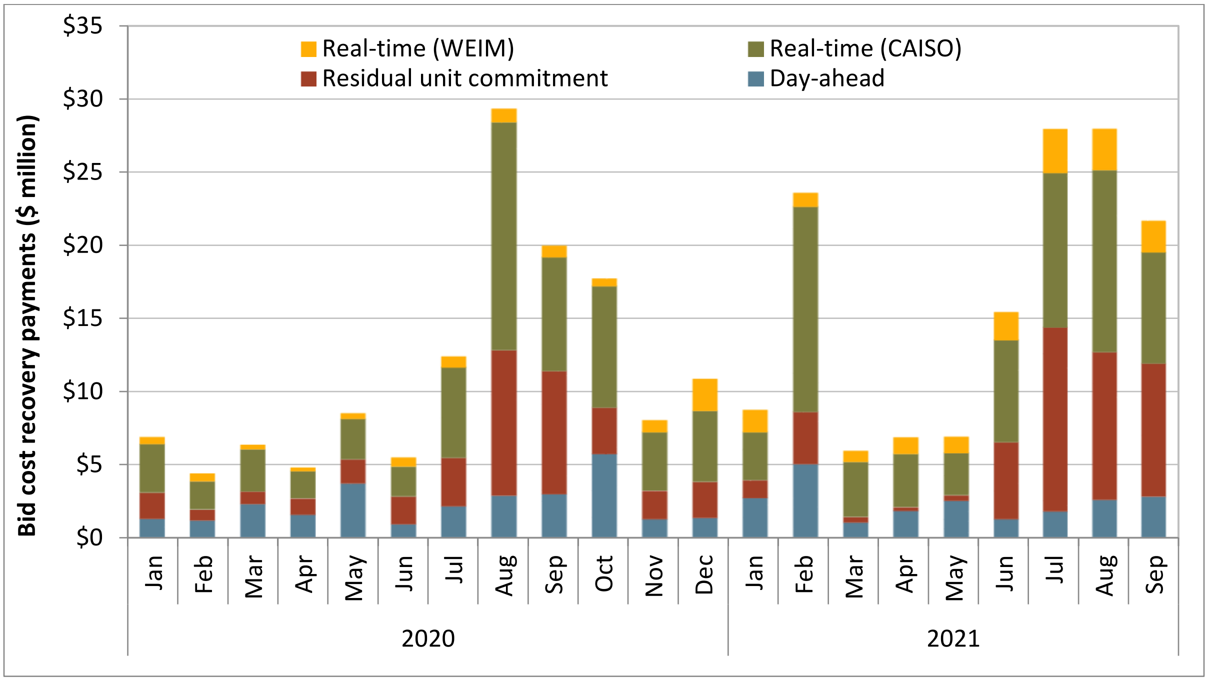
During the third quarter of 2021, estimated bid cost recovery payments for units in the California ISO and Western Energy Imbalance Market (WEIM) balancing areas totaled about $78 million.[35] This was $48 million higher than total bid cost recovery in the previous quarter and about $16 million higher than in the third quarter of 2020.

Bid cost recovery attributed to the day-ahead market totaled about $7 million, which was similar to the third quarter of 2020. Bid cost recovery payments for residual unit commitment during the quarter totaled about $32 million, compared to $22 million in the third quarter of 2020. Bid cost recovery attributed to the real-time market totaled about $39 million, or about $21 million higher than payments in the previous quarter and $7 million higher than payments in the third quarter of 2020. Out of the $39 million in real-time payments, about $8 million was allocated to resources (non-California ISO) participating in the WEIM.

Through the third quarter of 2021, total bid cost recovery payments totaled $145 million. The majority of these payments, about $135 million, were to gas resources followed by $4.6 million to hydro resources and about $2.5 million to battery energy storage resources.

[35] Due to changes in the availability of settlement data, bid cost recovery payments will be reported with a lag of one quarter.

Figure 1.39 Monthly bid cost recovery payments



1.10 Local market power mitigation

In the day-ahead market, the volume of bids lowered as a result of mitigation was similar to fourth quarter of 2020. In the real-time 5-minute market, incremental energy that was subject to mitigation and had its bids lowered declined significantly in the fourth quarter of 2021 compared to the same quarter of 2020. Effective November 1, 2021, the California ISO implemented the ESDER 4 initiative, which introduces local market power mitigation to battery energy storage resources.[36]

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

The impact on market prices of bids that were mitigated can only be assessed precisely by 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.[37]

36 Market Notice: ESDER Phase 4 Initiative: Deployment Effective for Trade Date 11/1/21: http://www.caiso.com/Documents/ESDERPhase4Initiative-DeploymentEffectiveforTradeDate-11121.html

37 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.

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

Mitigation in the California ISO balancing area

As shown in Figure 1.40, in the day-ahead market, an hourly average of about 1,367 MW was subject to mitigation but corresponding bids were not lowered, compared to 974 MW in the fourth quarter of 2020. About 268 MW of incremental energy bids were lowered due to mitigation similar to 2020. As a result, there was an average 9 MW increase in dispatch, down from 14 MW in 2020.

Figure 1.41 and Figure 1.42 show the same metrics but for the 15-minute and 5-minute markets on a monthly level instead. In the 15-minute market, frequency of mitigation was slightly higher in the fourth quarter of 2021 when compared to the same quarter of 2020. However, in the 5-minute market, the rates of mitigation had declined significantly in this quarter compared to same quarter of 2020.

Figure 1.40 Average incremental energy mitigated in day-ahead market

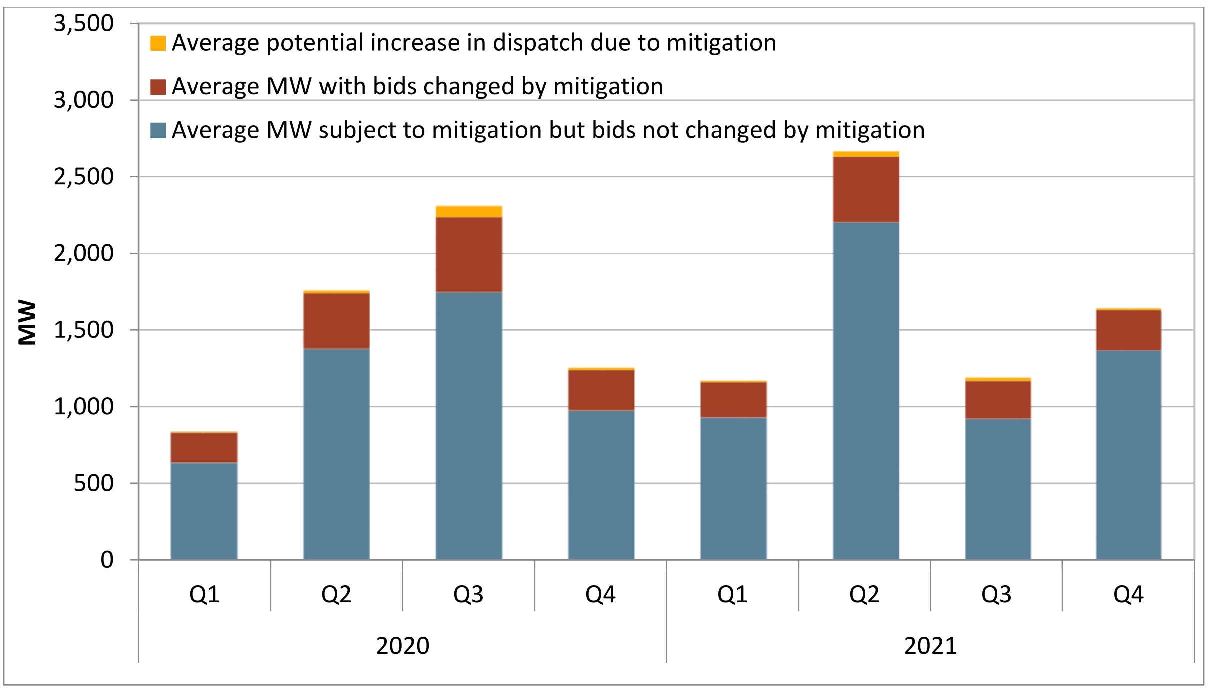


Figure 1.41 Average incremental energy mitigated in 15-minute real-time market (California ISO)

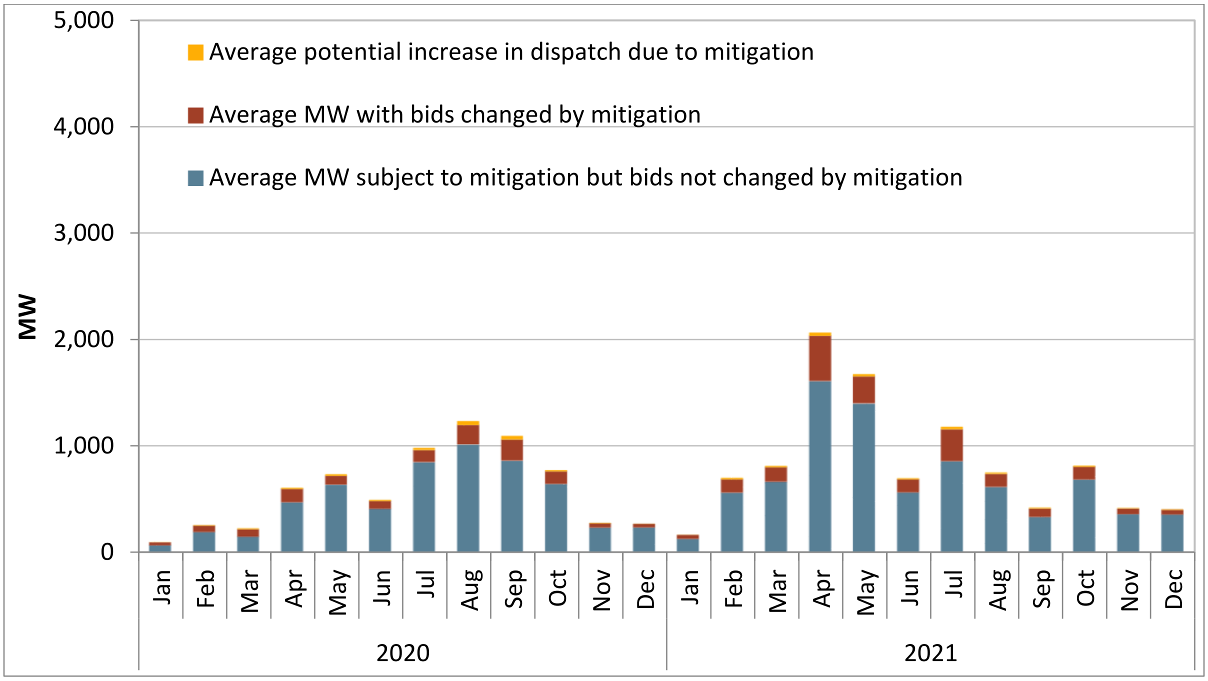
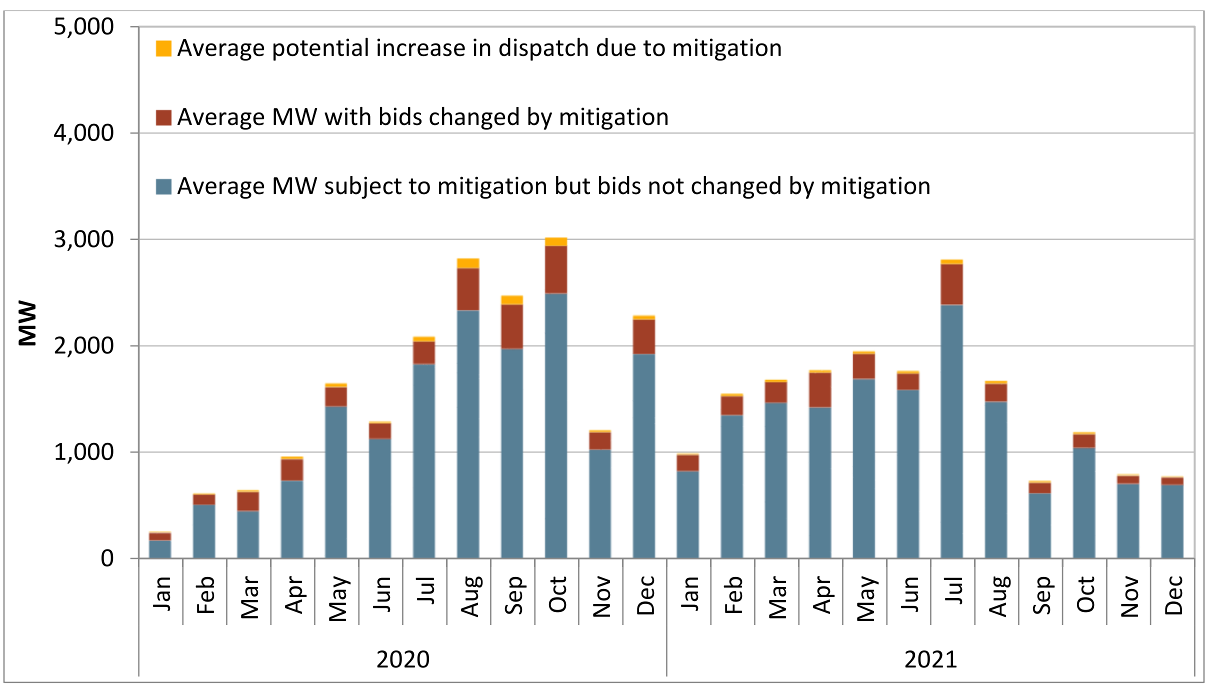


Figure 1.42 Average incremental energy mitigated in 5-minute real-time market (California ISO)



1.11 Imbalance conformance

Operators in the California ISO and WEIM 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.

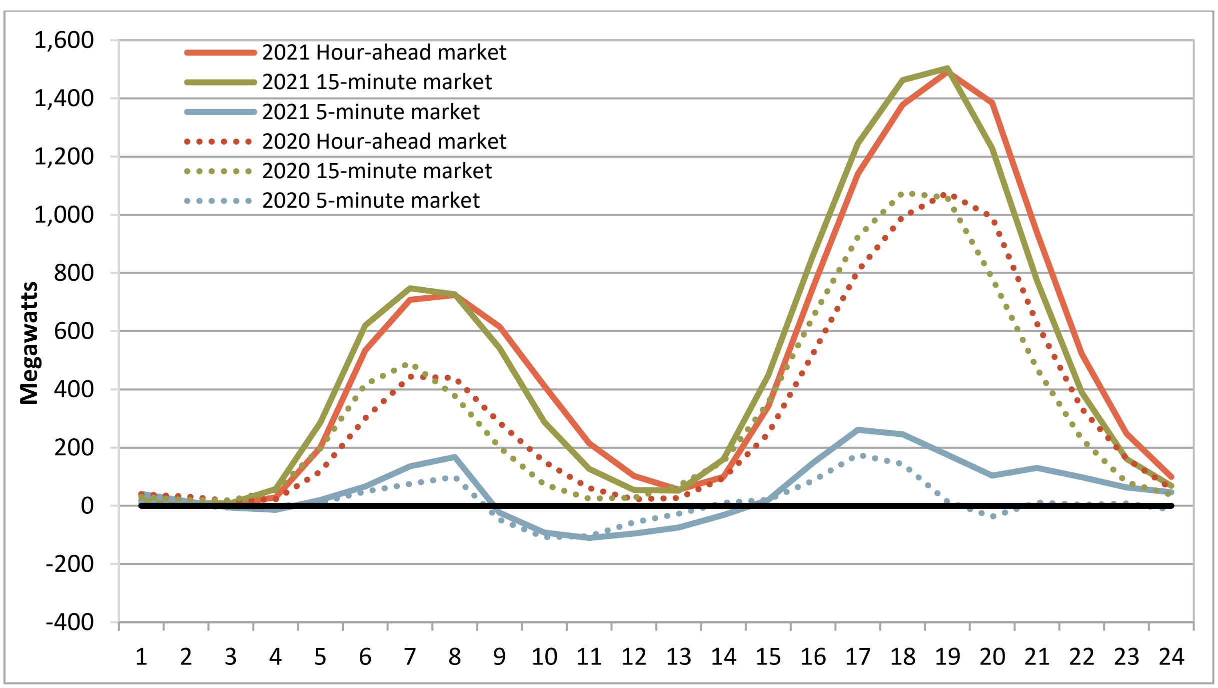
Frequency and size of imbalance conformance adjustments

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the California ISO hour-ahead and 15-minute markets. This large increase continues in both the morning solar ramp up and the afternoon peak solar ramp down period. Average hourly imbalance conformance adjustments in these markets peaked in the morning at nearly 800 MW and at just about 1,500 MW in the afternoon, about a 250 MW and 450 MW increase, respectively, over the same quarter peak periods of the previous year. Solar weather forecast ramping uncertainty contributed to the morning increase in imbalance conformance levels compared to previous quarters of the year.

Figure 1.43 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 1.43 Average hourly imbalance conformance adjustment (Q4 2020 – Q4 2021)



2 Western Energy Imbalance Market

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

- **Natural gas prices rose across the WEIM**, resulting in higher energy prices in all balancing areas.
- **Prices in California areas were over $18/MWh higher than other regions**. Prices tend to be higher in California than the rest of the system due to both transfer constraint congestion and greenhouse gas compliance costs for energy that is delivered to California.
- **Prices in the Northwest region** were regularly lower than prices in other balancing areas due to limited transfer capability out of this region during peak system load hours. This region includes PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex.
- **The California ISO was a net importer** during most hours except the middle of the day when low priced solar generation was typically exported to the rest of the system. Compared to the fourth quarter of 2020, imports into the California ISO from Arizona Public Service and Salt River Project were partially replaced by imports from Los Angeles Department of Water and Power.
- **On June 16, 2021, the California ISO added net load uncertainty to the requirement of the bid range capacity test**. This uncertainty caused most capacity test failures in the fourth quarter. Net load uncertainty was removed from the bid-range capacity test on February 15, 2022, while intertie uncertainty is expected to be removed at a future date.
- **NorthWestern Energy** failed the upward capacity and flexibility tests test in roughly 8 percent of intervals in October. These failures did not have any direct impact on the rest of the WEIM because NorthWestern Energy did not offer incremental import capacity in the WEIM during this period. Since NorthWestern Energy did not import energy through the WEIM during the fourth quarter, this balancing area was also not leaning on the rest of the WEIM in any way.
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in monthly reports** as part of the WEIM resource sufficiency evaluation stakeholder initiative. DMM is seeking feedback from stakeholders on existing or additional metrics and analysis that would be most valuable.

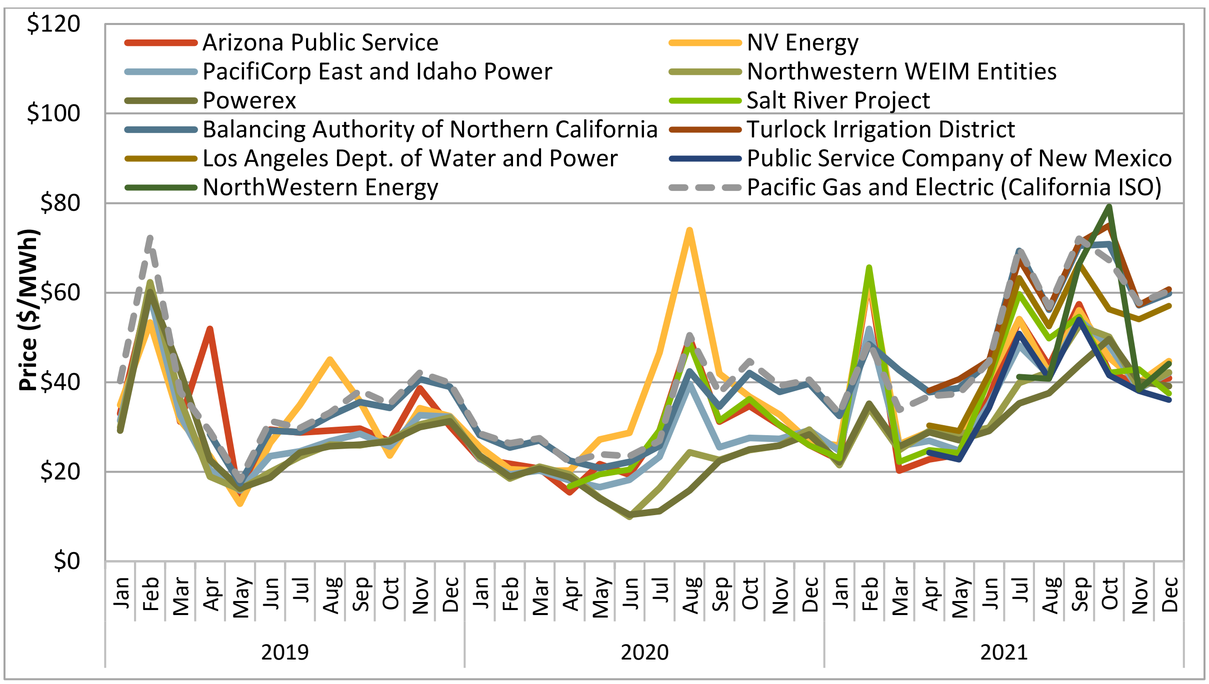
2.1 Western Energy Imbalance Market performance

Western Energy Imbalance Market prices

This section details the factors that generally influence changes in Western Energy Imbalance Market (WEIM) area prices and what causes price separation between participating areas. The WEIM benefits participating areas 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 WEIM footprint, prices within each balancing authority diverge from the system price when transfer 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 area for 2019 through 2021.[38]

Figure 2.1 Monthly 15-minute market prices



The combined average of WEIM prices outside of California were below California area prices by $18.41/MWh on average for the quarter. Prices of WEIM entities within California were closer to those of Pacific Gas & Electric. The combined average prices of these areas, which include Balancing Area of

38 The 'Northwestern WEIM Entities' line consists of PacifiCorp West, Puget Sound Energy, Portland General Electric, and Seattle City Light, which have been grouped together due to their similar average monthly prices. Prices for the Balancing Authority of Northern California (blue line) begin in April of 2019 when the Sacramento Municipal Utility District joined the market, while the rest of BANC joined in March 2021. Prices for Seattle City Light (included in medium green line) and Salt River Project (bright green line) begin in April 2020 when they joined the WEIM. Prices for Turlock Irrigation District (dark red line), Los Angeles Department of Water and Power (brown line), and Public Service Company of New Mexico (dark blue line) begin in April 2021. Turlock Irrigation District was a part of the WEIM for one week of March 2021; therefore, data for the TID area in March 2021 are not included in this section's analysis.

Northern California, Turlock Irrigation District, and Los Angeles Department of Water and Power, were $0.86/MWh lower than Pacific Gas & Electric prices.

Price separation between balancing authorities occurs for several reasons. California area prices tend to be higher than the rest of the WEIM due to greenhouse gas compliance cost for energy that is delivered to California. In addition, average prices in the Pacific Northwest are regularly lower than other balancing areas because of limited transfer capability out of the region.

Figure 2.2 Quarterly average 15-minute price by component (Q4 2021)

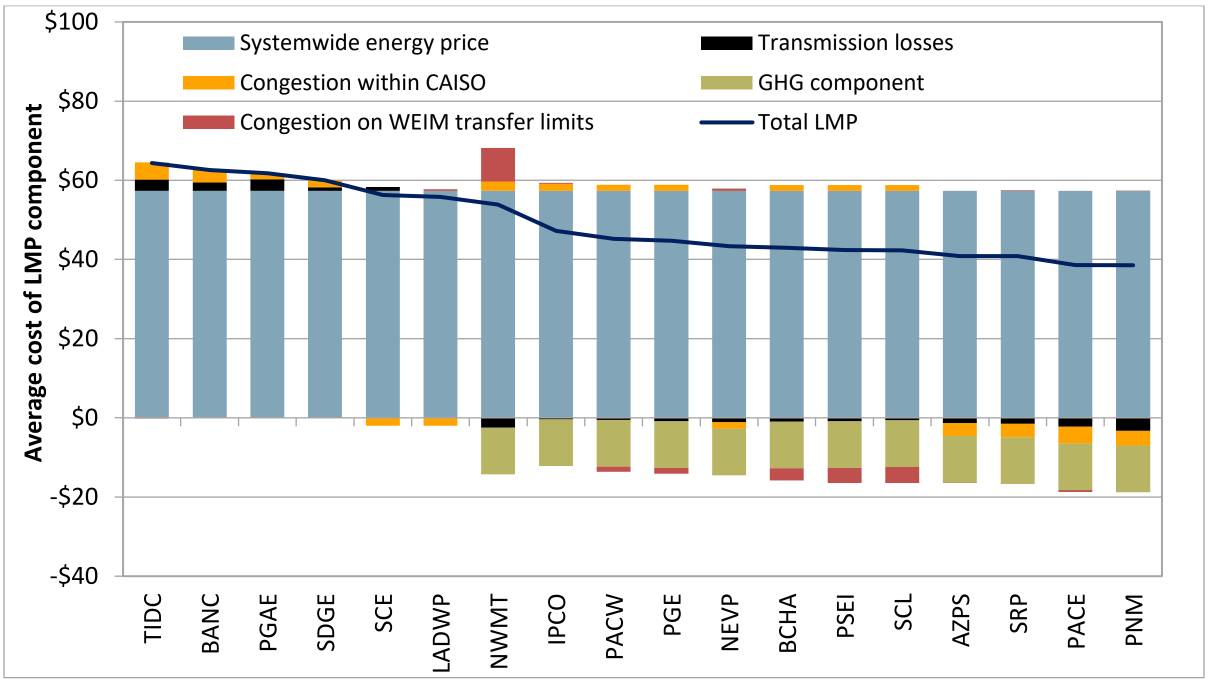


Figure 2.2 depicts the average 15-minute price by component for each balancing authority area.[39] The system marginal energy price is the same for all entities in each hour. The price difference between balancing authority areas is determined by area specific elements including transmission losses, greenhouse gas compliance costs, congestion, and power balance constraint (PBC) violations.

Congestion on WEIM transfer constraints often drives price separation between areas. Here, prices are higher on one side of the constraint with less access to supply and limited energy flow from the lower priced region to the higher priced region. In some cases, the power balance constraint may be relaxed within the constrained region at a high penalty parameter. The red segments reflect price differences caused by congestion on transfer constraints, including any PBC relaxations that increase the price in a single area.

Table 2.1 and Table 2.2 show the variation in prices throughout the day in the fourth quarter of 2021. In these tables, the colors change based on the deviation from the average system marginal energy price (SMEC). Therefore, blue represents prices below that hour's average system price and orange indicates prices above. Prices in balancing areas outside of California tend to be lower than prices in California for

39 The 'Congestion within the California ISO component represents all congestion on internal constraints, including those within California ISO and WEIM. California ISO-specific internal constraints make up the large majority of this category.

most hours, particularly during hours when California areas are typically importing energy subject to greenhouse gas compliance costs. Other differences in prices reflect transfer limitations between the different areas.

Table 2.1 Hourly 15-minute market prices (October-December)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$52	$50	$49	$49	$53	$60	$65	$67	$56	$48	$44	$41	$40	$40	$45	$56	$69	$88	$83	$75	$68	$64	$59	$54
PG&E (CAISO)	$54	$53	$52	$52	$55	$63	$69	$72	$62	$54	$51	$47	$46	$46	$51	$62	$73	$94	$90	$80	$72	$68	$62	$57
SCE (CAISO)	$53	$51	$50	$50	$54	$62	$67	$67	$52	$42	$36	$33	$33	$34	$39	$52	$69	$90	$87	$78	$70	$66	$61	$55
Arizona PS	$36	$36	$36	$36	$38	$44	$47	$48	$38	$30	$26	$25	$24	$26	$28	$39	$54	$66	$62	$55	$51	$48	$45	$41
BANC	$54	$53	$52	$51	$55	$62	$68	$71	$64	$58	$56	$52	$51	$50	$55	$65	$74	$92	$88	$79	$70	$67	$62	$56
Idaho Power	$40	$39	$38	$38	$41	$45	$48	$53	$50	$46	$46	$44	$43	$42	$44	$51	$58	$67	$61	$54	$51	$48	$45	$41
LADWP	$56	$52	$49	$49	$52	$60	$65	$66	$53	$42	$38	$35	$34	$35	$40	$52	$71	$88	$85	$75	$68	$65	$59	$53
NorthWestern	$45	$40	$40	$38	$41	$47	$55	$67	$70	$52	$55	$50	$47	$51	$47	$54	$64	$70	$74	$71	$65	$59	$57	$42
NV Energy	$38	$36	$36	$36	$38	$44	$48	$53	$47	$35	$33	$29	$30	$31	$34	$45	$55	$71	$64	$55	$50	$48	$45	$40
PacifiCorp East	$33	$32	$31	$32	$34	$39	$44	$46	$40	$34	$31	$30	$29	$29	$32	$40	$49	$59	$56	$49	$45	$42	$39	$34
PacifiCorp West	$39	$37	$37	$36	$39	$42	$43	$50	$49	$47	$47	$44	$43	$42	$43	$48	$53	$58	$54	$54	$48	$44	$49	$40
Portland GE	$38	$37	$37	$36	$38	$42	$44	$50	$49	$46	$47	$43	$42	$42	$43	$48	$55	$58	$54	$50	$46	$44	$45	$40
Powerex	$37	$38	$37	$36	$38	$40	$42	$44	$46	$45	$43	$42	$41	$40	$41	$45	$51	$58	$49	$48	$45	$44	$43	$40
PSC New Mexico	$38	$34	$31	$32	$35	$43	$46	$46	$39	$29	$27	$24	$25	$23	$28	$39	$51	$62	$58	$51	$46	$44	$39	$36
Puget Sound Energy	$42	$35	$35	$35	$37	$39	$39	$44	$46	$44	$45	$42	$41	$41	$41	$45	$50	$54	$49	$46	$43	$44	$42	$39
Salt River Project	$35	$35	$34	$34	$37	$42	$46	$47	$36	$29	$26	$25	$24	$25	$27	$38	$72	$75	$64	$53	$48	$46	$42	$37
Seattle City Light	$40	$35	$35	$35	$37	$39	$39	$45	$46	$45	$45	$42	$41	$41	$41	$45	$49	$55	$49	$46	$43	$41	$43	$39
Turlock ID	$55	$53	$51	$52	$55	$62	$68	$71	$66	$62	$61	$57	$55	$54	$60	$70	$78	$93	$87	$79	$71	$67	$62	$57

Hour ending

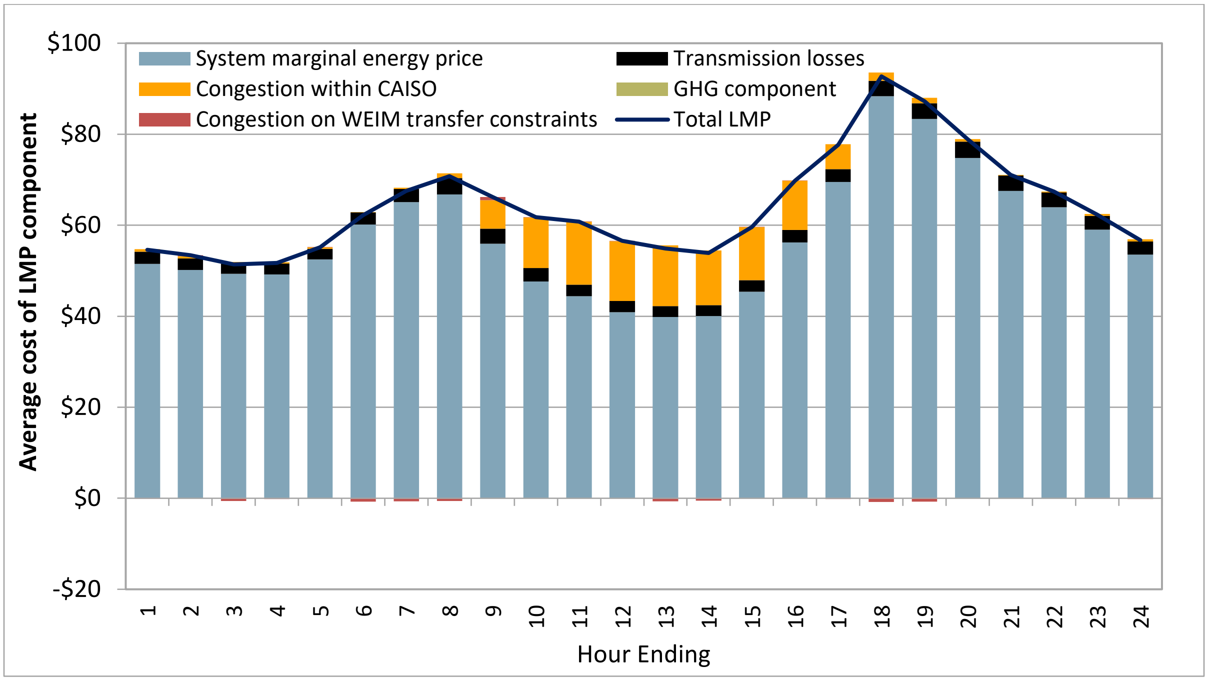
Table 2.2 Hourly 5-minute market prices (October-December)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$51	$50	$49	$49	$50	$54	$59	$69	$53	$43	$39	$37	$36	$38	$42	$49	$56	$66	$62	$60	$62	$61	$57	$53
PG&E (CAISO)	$54	$53	$51	$51	$53	$57	$63	$77	$60	$52	$47	$44	$43	$44	$49	$54	$60	$69	$66	$64	$65	$64	$61	$56
SCE (CAISO)	$52	$51	$50	$50	$51	$55	$61	$67	$47	$33	$29	$27	$26	$29	$34	$44	$55	$67	$64	$62	$64	$63	$59	$54
Arizona PS	$35	$35	$35	$35	$37	$40	$46	$51	$35	$23	$20	$25	$19	$21	$24	$36	$46	$52	$48	$46	$46	$46	$43	$36
BANC	$54	$53	$51	$52	$53	$56	$62	$77	$63	$57	$53	$50	$49	$50	$54	$57	$61	$68	$65	$63	$64	$63	$60	$55
Idaho Power	$39	$39	$38	$38	$40	$42	$45	$55	$50	$45	$44	$41	$40	$40	$42	$46	$49	$54	$48	$46	$47	$45	$44	$41
LADWP	$61	$60	$48	$48	$50	$54	$59	$65	$48	$34	$31	$29	$29	$31	$35	$45	$56	$66	$62	$60	$62	$61	$57	$52
NorthWestern	$39	$36	$36	$37	$39	$41	$47	$61	$54	$51	$46	$40	$41	$44	$43	$43	$43	$45	$45	$47	$47	$42	$40	$40
NV Energy	$38	$35	$35	$35	$37	$40	$44	$52	$41	$29	$27	$26	$27	$28	$29	$39	$51	$59	$48	$46	$46	$45	$43	$38
PacifiCorp East	$32	$31	$31	$31	$33	$36	$40	$47	$38	$29	$27	$26	$26	$27	$31	$37	$42	$49	$43	$41	$41	$40	$38	$35
PacifiCorp West	$38	$38	$37	$36	$38	$40	$42	$47	$51	$46	$45	$42	$42	$41	$41	$45	$46	$49	$46	$47	$45	$43	$46	$39
Portland GE	$38	$37	$36	$36	$37	$40	$42	$47	$51	$46	$45	$42	$42	$40	$41	$45	$46	$49	$46	$44	$44	$43	$43	$39
Powerex	$37	$36	$35	$35	$36	$39	$41	$42	$43	$42	$41	$39	$39	$38	$39	$43	$46	$48	$45	$44	$43	$43	$42	$38
PSC New Mexico	$36	$34	$31	$33	$34	$42	$40	$49	$36	$23	$21	$19	$20	$20	$24	$35	$47	$50	$46	$44	$49	$41	$37	$33
Puget Sound Energy	$38	$34	$34	$34	$35	$37	$38	$43	$42	$43	$43	$39	$39	$38	$38	$41	$43	$45	$42	$41	$40	$38	$44	$37
Salt River Project	$34	$34	$33	$34	$36	$40	$44	$48	$32	$22	$21	$20	$19	$20	$24	$35	$63	$59	$51	$44	$42	$43	$41	$36
Seattle City Light	$42	$34	$34	$34	$35	$37	$38	$41	$42	$43	$43	$39	$39	$38	$38	$42	$43	$45	$42	$43	$40	$38	$41	$38
Turlock ID	$54	$53	$51	$51	$53	$58	$63	$78	$67	$65	$60	$55	$54	$55	$59	$61	$64	$68	$65	$63	$65	$64	$62	$56

Hour ending

Turlock Irrigation District had the highest average prices during the quarter. This is due in part to transmission losses and congestion on the Los Banos-Quinto 230 kV line.[40] Figure 2.4 breaks down Turlock Irrigation District's average locational marginal price (LMP) by component throughout the day.

Figure 2.3 Turlock Irrigation District average 15-minute price by component (Q4 2021)



2.2 Resource sufficiency evaluation

As part of the Western 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 is made up of four tests: the power flow feasibility test, the balancing test, the bid range capacity test, and the flexible ramping sufficiency test. Failures of two tests constrain transfer capability:

- **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 (flexibility test)** requires that each balancing area have 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 in the upward direction, WEIM transfers into that area cannot be increased.[41] Similarly, if an area fails either test in the downward direction, transfers out of that area cannot be increased.

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40 The Los Banos-Quinto 230 kV line was congested due to maintenance on the Tesla-Los Banos 500 kV line. See Section 1.8.2 for more information on its effects on the California ISO and other WEIM entities.

41 If an area fails either test in the upward direction, net WEIM imports during the hour cannot exceed the greater of either the base transfer or optimal transfer from the last 15-minute interval prior to the hour.

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

	2020			2021											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	—	—	0.3	0.2	0.4	—	—	0.3	—	0.2	0.3	0.2	—	0.3	0.0
BANC	0.1	0.0	—	—	—	—	—	—	—	0.2	—	0.0	—	—	—
California ISO	—	—	—	—	—	—	—	—	0.1	0.2	0.0	0.2	—	—	—
Idaho Power	—	—	—	—	—	—	—	—	—	0.4	0.8	0.1	—	—	—
LADWP							—	—	0.1	—	—	—	0.3	0.2	0.1
NorthWestern									0.6	1.2	0.6	0.2	8.5	1.2	0.2
NV Energy	0.1	0.2	—	—	0.3	—	0.0	0.5	0.8	0.5	0.2	0.2	0.3	—	—
PacifiCorp East	—	0.1	—	—	—	—	—	—	0.3	0.3	0.1	0.2	0.1	—	—
PacifiCorp West	—	0.1	—	—	—	0.1	—	0.0	0.1	0.2	0.1	0.1	0.1	0.5	0.4
Portland GE	—	—	—	—	0.1	—	0.4	—	0.7	0.8	1.0	1.4	0.4	0.2	0.4
Powerex	0.1	0.1	—	0.1	0.0	—	—	—	0.0	0.0	—	0.1	0.5	0.2	0.2
PSC New Mexico							—	—	—	0.4	—	0.2	—	—	—
Puget Sound En	—	—	—	—	0.1	0.6	1.0	0.6	1.6	0.5	0.7	0.6	1.0	0.6	0.3
Salt River Proj.	0.1	0.1	—	—	8.0	—	0.1	0.1	0.7	3.0	2.6	2.0	0.1	0.7	—
Seattle City Light	—	—	—	—	—	—	—	—	—	—	0.0	0.5	0.1	—	0.1
Turlock ID						—	—	0.0	—	—	1.1	0.8	1.5	—	—

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

	2020			2021											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	0.8	0.7	0.6	0.5	0.5	0.2	—	0.6	—	0.0	—	0.2	—	0.3	0.0
BANC	0.1	—	0.1	—	—	—	—	—	—	—	—	—	—	—	—
California ISO	0.4	0.5	—	—	—	—	—	—	0.0	0.3	0.1	0.4	—	0.1	—
Idaho Power	—	—	—	—	0.1	—	—	—	—	—	—	—	—	—	0.0
LADWP							0.0	0.1	—	0.1	—	—	0.0	0.0	0.3
NorthWestern									1.3	3.6	0.7	1.6	8.3	0.5	0.5
NV Energy	1.4	0.8	—	0.1	0.5	0.4	0.4	0.7	0.9	0.4	0.5	0.1	0.3	0.0	0.0
PacifiCorp East	0.5	0.0	—	0.1	0.1	0.1	0.1	0.0	0.1	0.0	—	0.1	—	0.1	0.0
PacifiCorp West	0.1	0.0	0.1	0.0	0.2	0.1	0.1	0.0	—	0.0	0.1	—	—	0.6	0.2
Portland GE	0.1	0.1	0.2	0.3	0.6	0.1	0.2	0.2	0.3	0.5	0.2	—	0.0	—	0.2
Powerex	0.1	0.6	0.2	0.2	0.1	0.1	0.1	—	0.1	0.5	—	—	0.2	0.2	0.3
PSC New Mexico							0.4	0.0	0.1	0.5	—	0.1	—	0.1	—
Puget Sound En	0.2	—	—	—	—	—	—	0.1	0.1	0.0	0.0	—	—	0.1	—
Salt River Proj.	1.7	0.9	0.3	0.2	7.1	0.3	0.5	0.2	0.9	1.9	1.7	0.8	0.2	1.2	0.0
Seattle City Light	0.2	0.2	0.1	—	—	—	—	—	—	0.0	—	0.1	—	—	—
Turlock ID						—	—	0.3	—	—	—	0.1	0.2	—	—

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

	2020			2021											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	—	—	—	—	—	—	—	0.0	—	—	—	—	—	0.2	—
BANC	0.1	0.1	—	—	0.0	—	—	—	—	—	—	—	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Idaho Power	—	—	—	—	—	—	—	—	—	—	—	—	—	0.1	—
LADWP							—	—	0.1	—	—	—	0.2	—	—
NorthWestern									—	—	—	—	1.0	—	—
NV Energy	—	—	—	—	—	—	—	—	0.0	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Portland GE	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	0.0	—	—	—	—	—	0.0	—	0.3	0.1	—	0.8	0.3	0.0	—
PSC New Mexico							—	—	—	—	—	—	0.2	0.1	—
Puget Sound En	—	—	—	—	—	—	—	—	—	—	—	—	0.0	—	—
Salt River Proj.	—	—	—	—	—	—	0.0	—	0.0	—	—	—	—	—	0.0
Seattle City Light	—	—	—	—	—	—	—	—	—	0.0	0.0	0.0	—	0.2	0.2
Turlock ID						—	—	0.3	0.2	0.0	0.2	0.2	0.7	0.1	0.0

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

	2020			2021											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	1.9	0.9	2.5	2.2	2.3	4.3	1.9	0.3	0.1	—	0.1	0.1	0.1	0.5	0.4
BANC	0.1	0.3	—	—	0.6	—	—	—	—	—	—	—	—	—	0.1
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Idaho Power	0.0	0.0	—	—	—	—	—	0.0	—	—	—	—	—	0.3	0.0
LADWP							—	—	0.1	—	—	—	0.1	—	—
NorthWestern									0.7	0.6	0.4	1.2	2.3	0.1	0.0
NV Energy	0.5	1.4	1.1	0.2	6.1	1.4	0.5	4.3	2.0	3.0	2.5	1.7	1.1	0.4	0.4
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	0.1	—	—	0.1	—	—	—	—	0.0	—
Portland GE	—	—	—	0.0	—	—	—	—	—	—	—	—	—	—	—
Powerex	0.1	—	—	0.4	—	1.4	0.2	0.9	1.3	0.4	0.2	1.0	0.4	0.0	0.1
PSC New Mexico							1.4	—	0.0	—	—	0.1	0.4	0.7	0.1
Puget Sound En	—	—	—	—	—	—	—	—	—	—	—	—	—	0.0	—
Salt River Proj.	0.1	0.2	0.8	1.1	1.6	1.2	0.2	0.1	0.2	—	0.1	0.0	0.1	0.0	0.1
Seattle City Light	0.1	0.1	0.1	—	—	—	—	—	—	0.2	—	—	—	0.0	0.0
Turlock ID						0.4	0.1	0.5	—	—	0.0	—	0.6	0.1	0.2

Bid range capacity and flexible ramping sufficiency test results

Figure 2.4 and Figure 2.5 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 2.6 and Figure 2.7 provide the same information for the downward direction.[42] The dash indicates the area did not fail the test during the month. The flexible ramping sufficiency test and bid range capacity test failures reported below reflect results independent of the other test.

During October, NorthWestern Energy failed the upward capacity and flexibility tests test in roughly 8 percent of intervals. These failures did not have any direct impact on the rest of the WEIM because NorthWestern Energy did not make any incremental import capacity available in the WEIM during this period. Since NorthWestern Energy did not import energy through the WEIM during the fourth quarter, this balancing are was also not leaning on the rest of the WEIM in any way.

Impact of adding uncertainty to the bid range capacity test

On June 16, 2021, the California ISO added net load uncertainty to the requirement of the bid range capacity test. The California ISO stated its intention to remove both the net load and intertie uncertainty components from the capacity test while these adders are further refined as part of the stakeholder initiative on resource sufficiency evaluation enhancements.[43] Net load uncertainty was removed from the bid-range capacity test on February 15, 2022. Intertie uncertainty is expected to be removed at a future date. These adders would be expected to return once the calculations are improved as part of the next phase of the initiative.

Figure 2.8 shows the impact of adding net load uncertainty by showing actual capacity test failure intervals that would have passed the test without the extra requirement component. During the quarter, 72 percent of upward test failures would have passed without the additional uncertainty component. Figure 2.9 shows the same information, except without intervals in which the flexibility test also failed in that interval. Since the outcome of failing either the capacity or the flexibility test is the same, this figure therefore summarizes additional intervals in which WEIM transfers were capped because of the additional uncertainty component.

42 Results exclude known invalid test failures. These can occur because of a market disruption, software defect, or other error.

43 *EIM Resource Sufficiency Evaluation Enhancements Phase 1 Revised Draft Final* Proposal, December 16, 2021. http://www.caiso.com/InitiativeDocuments/RevisedDraftFinalProposal-EIMResourceSufficiencyEvaluationEnhancements.pdf

Figure 2.8 Additional capacity test failures with implemented net load uncertainty (15-minute intervals)

	Upward capacity test						Downward capacity test					
	Jul	Aug	Sep	Oct	Nov	Dec	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	3	7	2	—	5	1	—	—	—	—	1	—
BANC	3	—	1	—	—	—	—	—	—	—	—	—
California ISO	2	1	5	—	—	—	—	—	—	—	—	—
Idaho Power	13	21	3	—	—	—	—	—	—	—	4	—
LADWP	—	—	—	—	1	2	—	—	—	2	—	—
NorthWestern	30	12	6	192	30	7	—	—	—	15	—	—
NV Energy	9	6	5	6	—	—	—	—	—	—	—	—
PacifiCorp East	9	4	4	4	—	—	—	—	—	—	—	—
PacifiCorp West	7	2	2	2	14	5	—	—	—	—	—	—
Portland GE	20	25	34	13	4	11	—	—	—	—	—	—
Powerex	1	—	2	9	5	3	3	—	4	5	1	—
PSC New Mexico	3	—	2	—	—	—	—	—	—	7	—	—
Puget Sound En	8	10	8	19	13	8	—	—	—	1	—	—
Salt River Proj.	49	19	32	3	17	—	—	—	—	—	—	1
Seattle City Light	—	1	6	—	—	1	—	—	1	—	2	2
Turlock ID	—	9	10	18	—	—	—	1	2	3	3	1

Figure 2.9 Additional capacity test failures with implemented net load uncertainty excluding flexibility test failures (15-minute intervals)

	Upward capacity test						Downward capacity test					
	Jul	Aug	Sep	Oct	Nov	Dec	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	3	7	2	—	1	1	—	—	—	—	—	—
BANC	3	—	1	—	—	—	—	—	—	—	—	—
California ISO	2	—	2	—	—	—	—	—	—	—	—	—
Idaho Power	13	21	3	—	—	—	—	—	—	—	—	—
LADWP	—	—	—	—	1	1	—	—	—	2	—	—
NorthWestern	9	9	—	105	23	5	—	—	—	13	—	—
NV Energy	9	6	5	6	—	—	—	—	—	—	—	—
PacifiCorp East	8	4	4	4	—	—	—	—	—	—	—	—
PacifiCorp West	6	2	2	2	11	5	—	—	—	—	—	—
Portland GE	19	25	34	13	4	11	—	—	—	—	—	—
Powerex	1	—	2	6	1	2	1	—	2	4	1	—
PSC New Mexico	1	—	2	—	—	—	—	—	—	7	—	—
Puget Sound En	8	10	8	19	13	8	—	—	—	1	—	—
Salt River Proj.	34	15	27	2	14	—	—	—	—	—	—	1
Seattle City Light	—	1	3	—	—	1	—	—	1	—	2	2
Turlock ID	—	9	10	18	—	—	—	1	2	1	1	—

Transfer consequences for failing the bid range capacity or flexible ramping sufficiency tests

This section summarizes current consequences of failing the bid range capacity or flexible ramping sufficiency tests in terms of the import limit that is imposed when a balancing area fails either of these tests in the upward direction. When either test fails in the upward direction, imports will be capped at the greater of the base transfer or the optimal transfer from the last 15-minute market interval.

Figure 2.10 summarizes *incremental* WEIM import limits above base transfers (fixed bilateral transactions between entities) after failing either test during the quarter. The incremental import limit after a test failure is set by the greater of (1) zero or (2) the transfer from the last 15-minute market interval minus the current base transfer. The incremental import limit therefore shows the incremental flexibility that is available through the WEIM after a resource sufficiency evaluation failure. The black horizontal line (right axis) shows the number of 15-minute intervals with an import limit imposed after a test failure while the bars (left axis) show the frequency of various quantity ranges.[44]

Figure 2.10 Upward capacity/sufficiency test failure intervals by incremental import limit amount (October – December 2021)

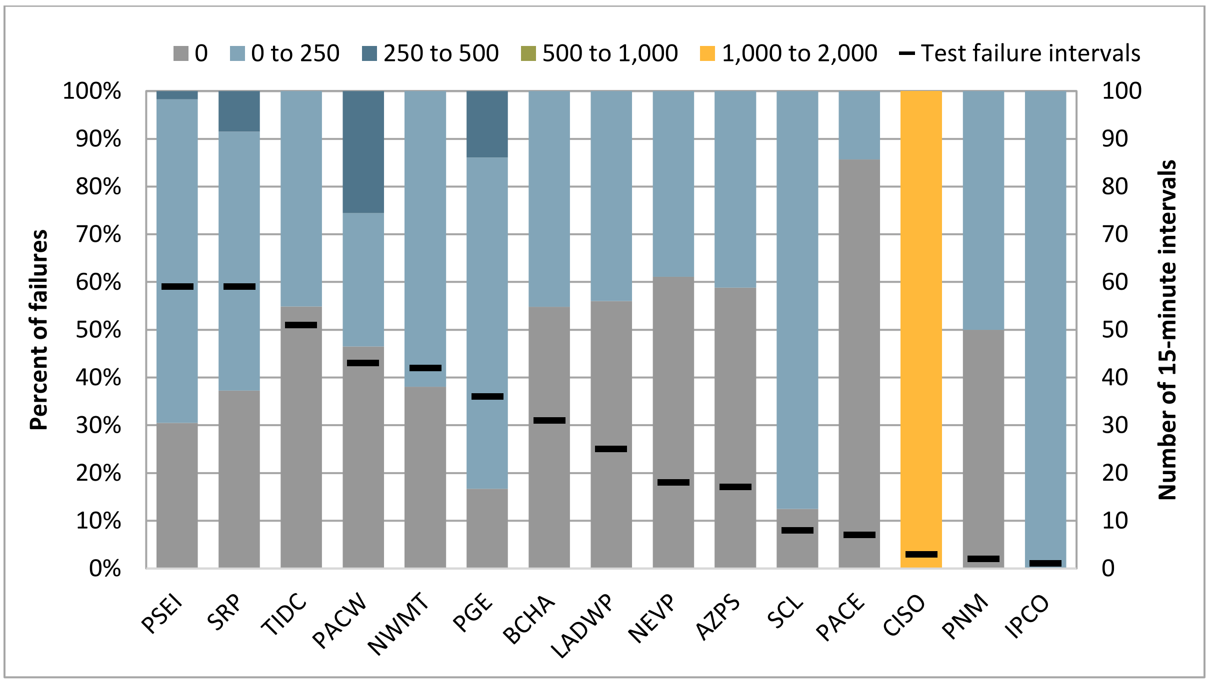


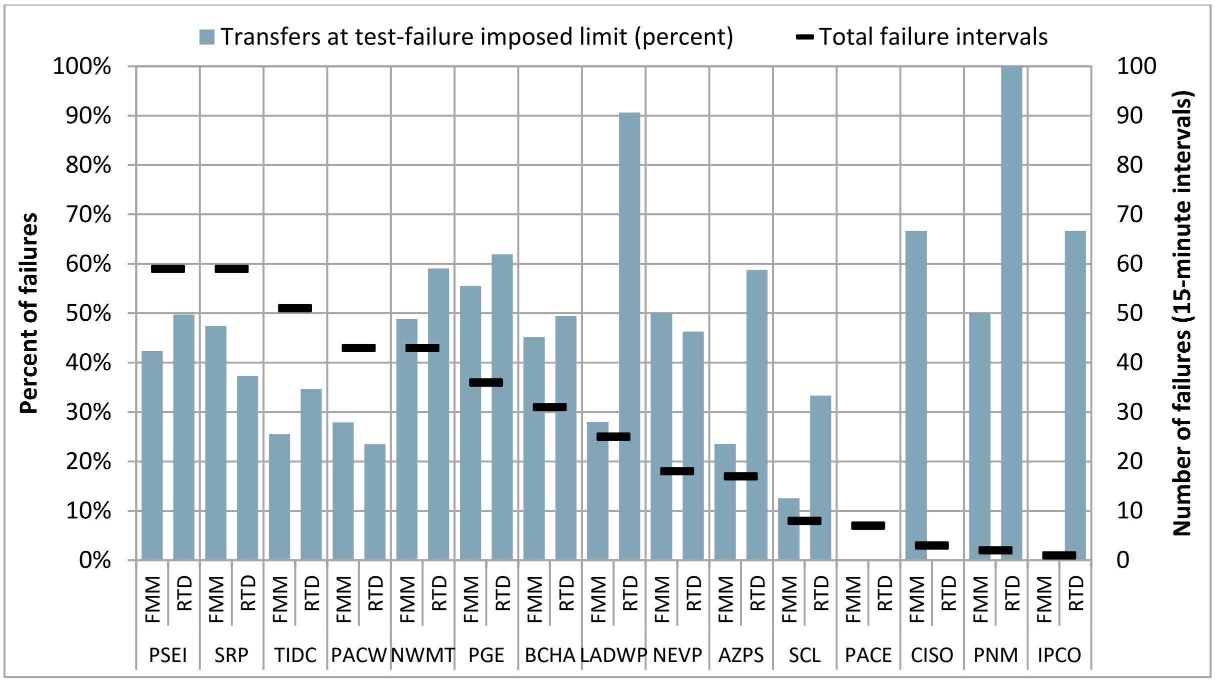
Figure 2.11 summarizes whether the import limit that was imposed after failing either test in the upward direction ultimately impacted market transfers. It shows the percent of failure intervals in which the resulting transfers are constrained to the limit imposed after failing the test during the quarter. These results are separated between WEIM transfers in the 15-minute and 5-minute markets.

In the California ISO area, 15-minute market transfers were impacted by transfer limits during 67 percent of intervals when test failures occurred. In the 5-minute market, market transfers were not impacted during any of the intervals when test failures occurred. This is in part because conformance

[44] Test failure intervals in which an import limit was not imposed because it was at or above the unconstrained total import capacity were excluded from this summary.

adjustments entered by California ISO operators are much higher in the 15-minute market than in the 5-minute market. These adjustments can set a higher import limit than would exist absent imbalance conformance because the optimal transfer in the last 15-minute interval prior to the test increases as the optimization solves for load plus imbalance conformance. The limit enforced in both the 15-minute and 5-minute markets is set by the last optimal 15-minute transfer prior to the failed test.

Figure 2.11 Percent of upward test failure intervals with market transfers at the imposed cap (October – December 2021)



Resource sufficiency evaluation monthly reports

As part of the WEIM resource sufficiency evaluation stakeholder initiative, DMM is providing additional transparency surrounding test accuracy and performance in monthly reports specific to this topic. This includes many metrics and analyses not included in this quarterly report such as the impact of several changes proposed or adopted through the stakeholder process as well as a detailed look at the uncertainty adders used in the tests.

Both the latest reports and data underlying most metrics are available on DMM's website under Western Energy Imbalance Market resource sufficiency evaluation reports.[45] DMM welcomes feedback from stakeholders on existing or additional metrics and analysis that would be most valuable. Please communicate any suggestions either through comments in the California ISO's Western Energy Imbalance Market resource sufficiency evaluation stakeholder initiative or directly to DMM.[46]

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45 Department of Market Monitoring reports and presentations: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx#special

46 Please submit comments within the stakeholder process when the opportunity is available here: https://stakeholdercenter.caiso.com/StakeholderInitiatives/EIM-resource-sufficiency-evaluation-enhancements. If unable to do so, please submit comments to DMM directly via email to dmm@caiso.com.

2.3 Balancing area transfers

Balancing area transfer limits

One of the key benefits of the Western Energy Imbalance Market is the ability to transfer energy between areas in the 15-minute and 5-minute markets. Table 2.3 shows average 15-minute market limits between each of the areas during the fourth quarter.[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.

Table 2.3 Average 15-minute market WEIM limits (October – December)

From Balancing Authority Area	To Balancing Authority Area																Total
	CAISO	BANC	TIDC	LADWP	NEVP	AZPS	SRP	PNM	PACE	IPCO	NWMT	PACW	PGE	PSEI	SCL	PWRX	*export limit*
California ISO		3,670	1,210	4,160	3,710	1,360	1,590					30	20	0		270	16,020
BANC	3,480		640														4,120
Turlock Irrig. District	1,220	740															1,960
LADWP	7,020				1,570	300			320								9,210
NV Energy	4,030			1,170		300			680	500							6,680
Arizona Public Service	2,470			480	280		6,860	1,000	690								11,780
Salt River Project	2,850					5,260		90	0								8,200
PSC New Mexico						1,050	0										1,050
PacifiCorp East				310	610	530	0			900	300	390					3,040
Idaho Power					600				1,870		140	580		20	30		3,240
NorthWestern Energy									260	150		0	0	0			410
PacifiCorp West	130								340	350	40		380	150	10		1,400
Portland GE	130										80	380		20	10		620
Puget Sound Energy	0									0	10	100	20		350	60	540
Seattle City Light										30		10	10	380			430
Powerex	0													110			110
Total import limit	21,330	4,410	1,850	6,120	6,770	8,800	8,450	1,090	4,160	1,930	570	1,490	430	680	400	330	

Hourly transfers

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

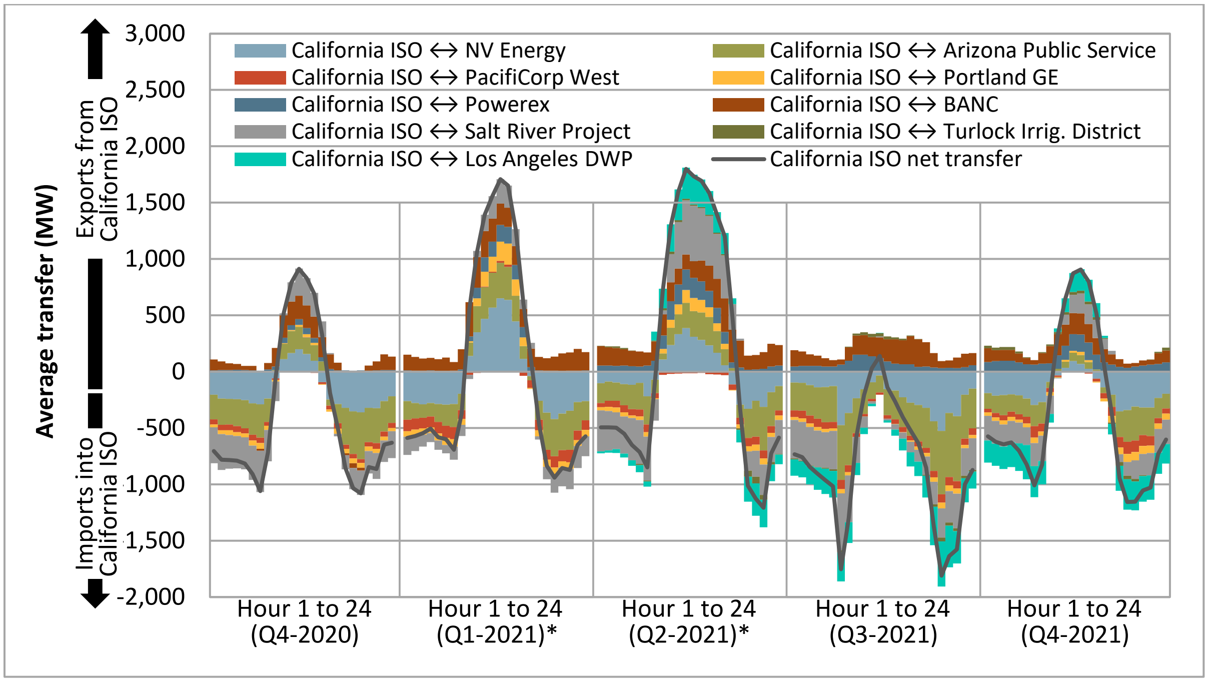
Figure 2.12 compares average hourly imports (negative values) and exports (positive values) between the California ISO and other areas during the last five quarters in the 15-minute market.[48] The bars show the average hourly transfers with the connecting areas. The grey line shows the average hourly net transfer.

The California ISO was a net exporter, on average, in the middle of the day when low priced solar generation was typically exported to the rest of the system. Compared to the fourth quarter of 2020, imports into the California ISO from Arizona Public Service and Salt River Project have been replaced in part by imports from Los Angeles Department of Water and Power.

[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 include 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. Transfers from March 25 to March 31 are included in the second quarter average.

Figure 2.12 California ISO - average hourly 15-minute market transfer



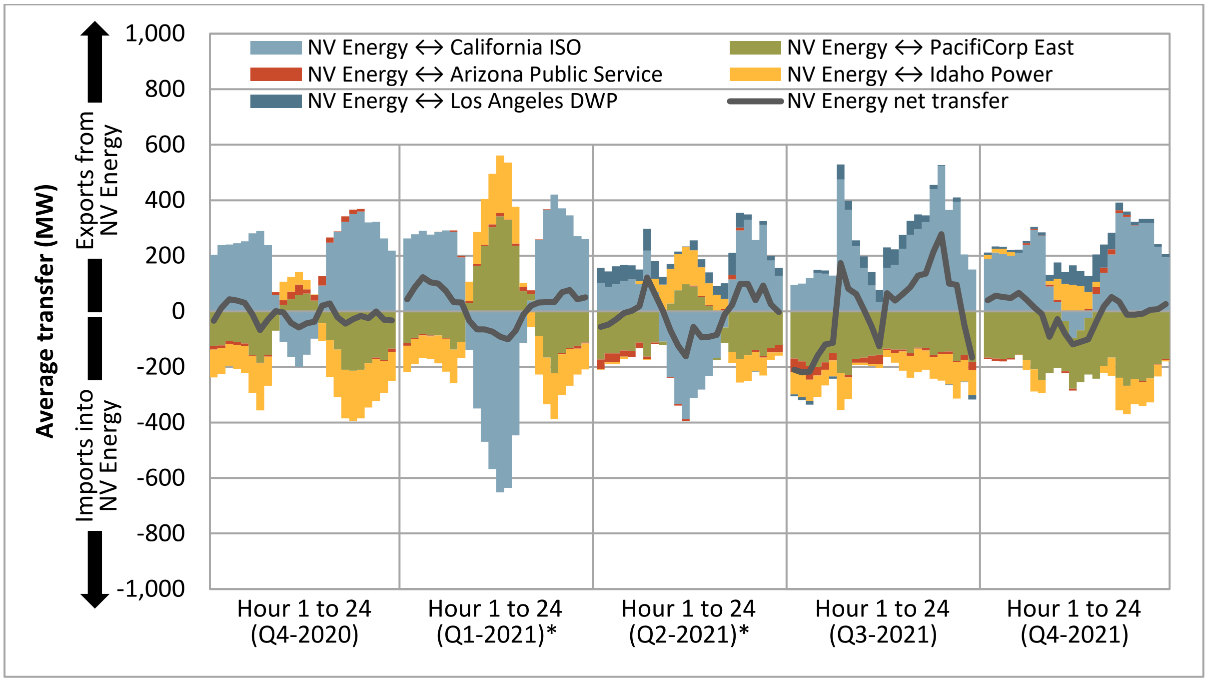
*See footnote 48

Figure 2.13 through Figure 2.23 show the same quarterly information on imports and exports for the other WEIM 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 WEIM entities.[50]

49 Figures showing transfer information from the perspective of Los Angeles Department of Water and Power, Turlock Irrigation District, Public Service Company of New Mexico, and NorthWestern Energy are not explicitly included, but are depicted in the other figures.

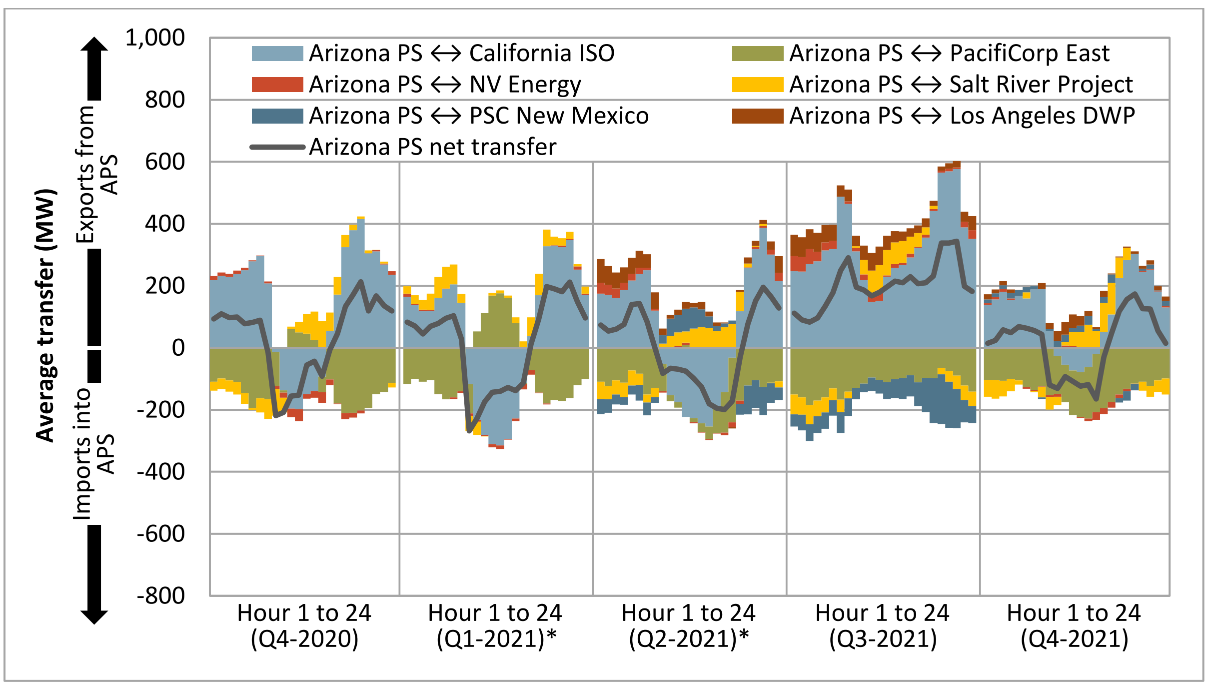
50 Base schedules on WEIM transfer system resources are fixed bilateral transactions between WEIM entities.

Figure 2.13 NV Energy – average hourly 15-minute market transfer



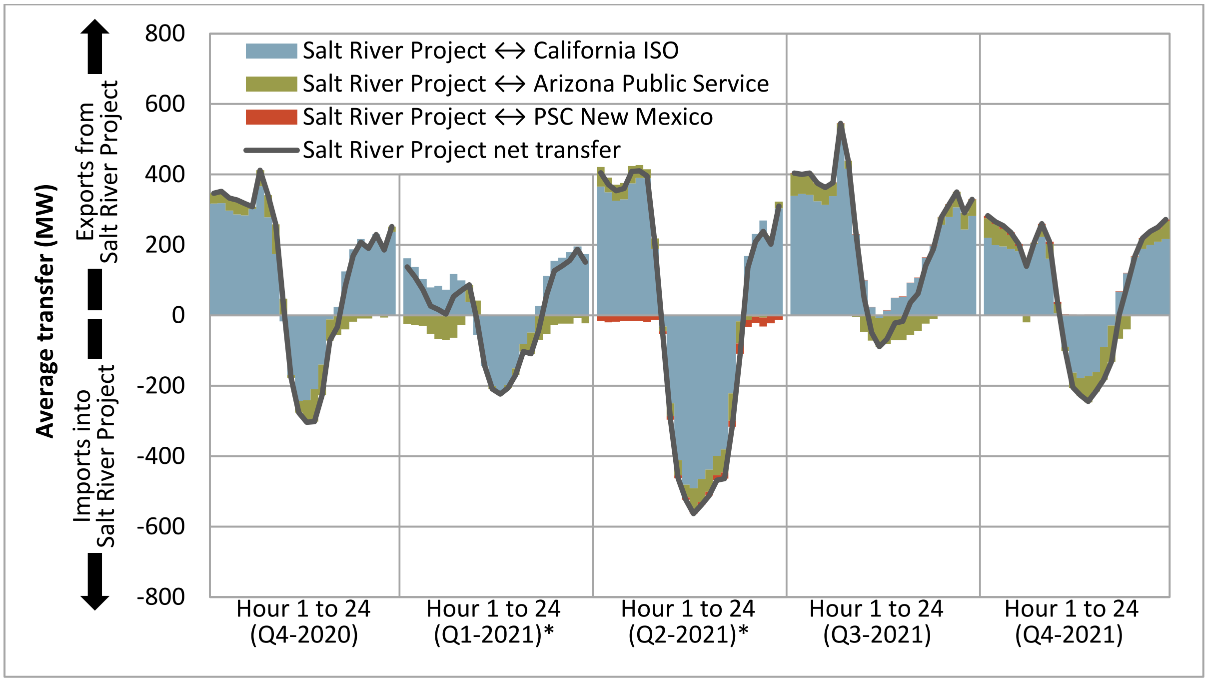
*See footnote 48

Figure 2.14 Arizona Public Service – average hourly 15-minute market transfer



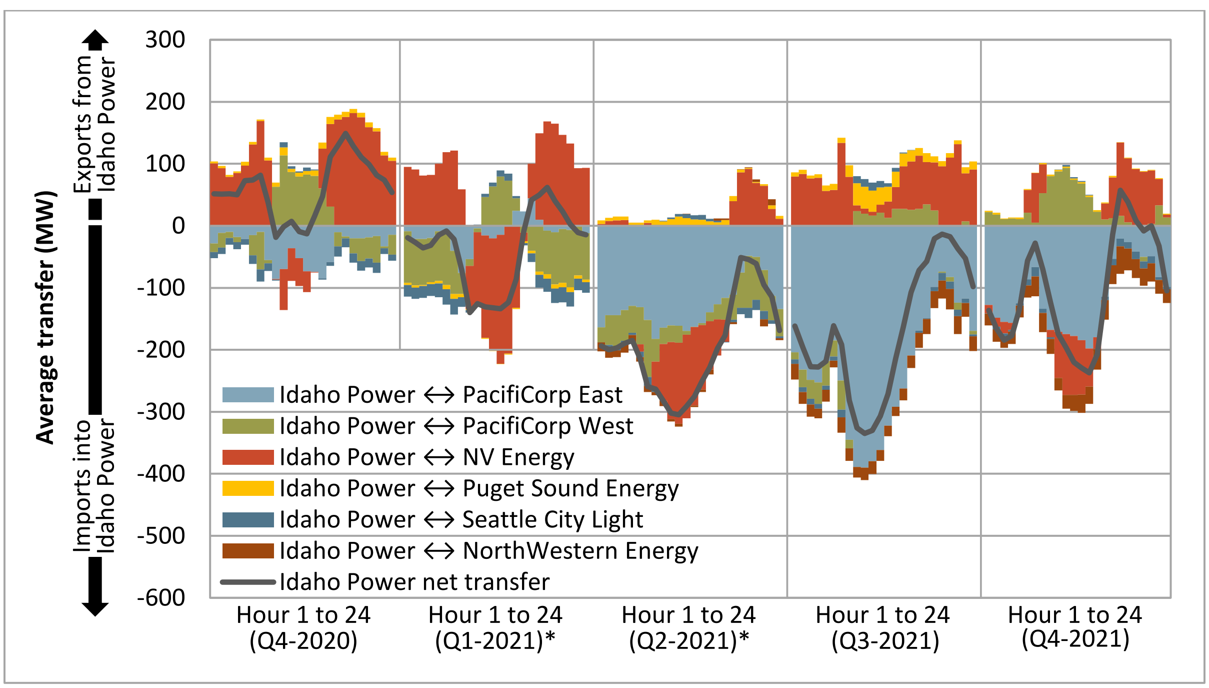
*See footnote 48

Figure 2.15 Salt River Project – average hourly 15-minute market transfer



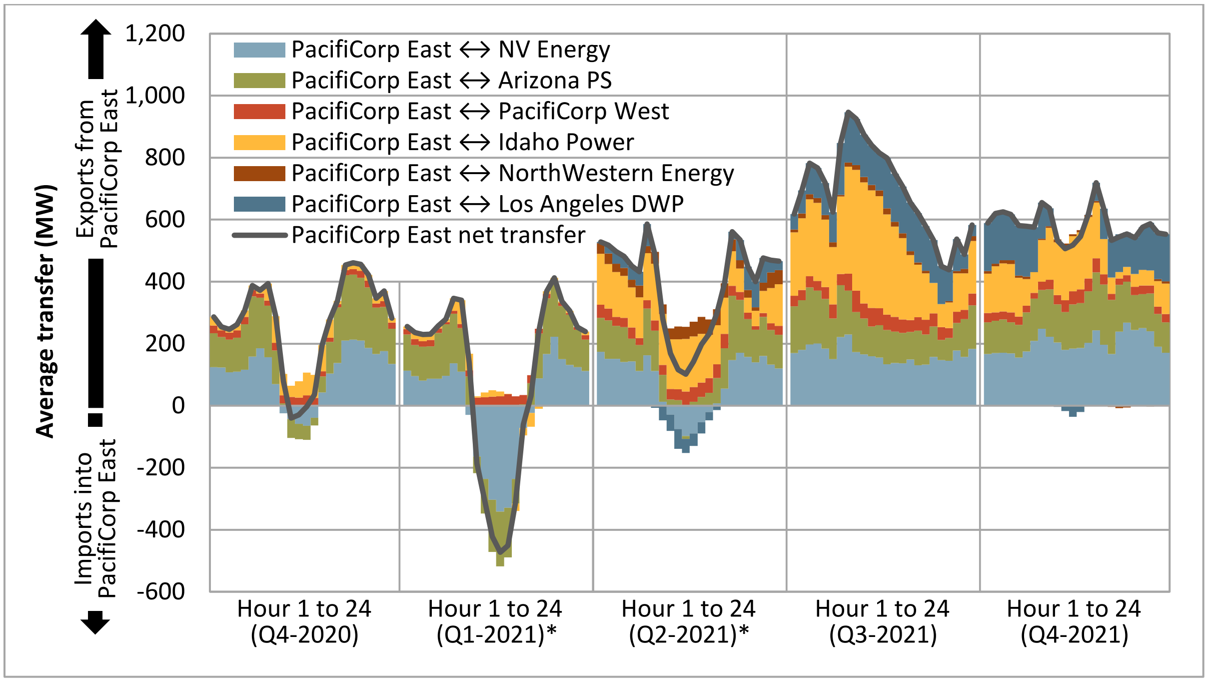
*See footnote 48

Figure 2.16 Idaho Power – average hourly 15-minute market transfer



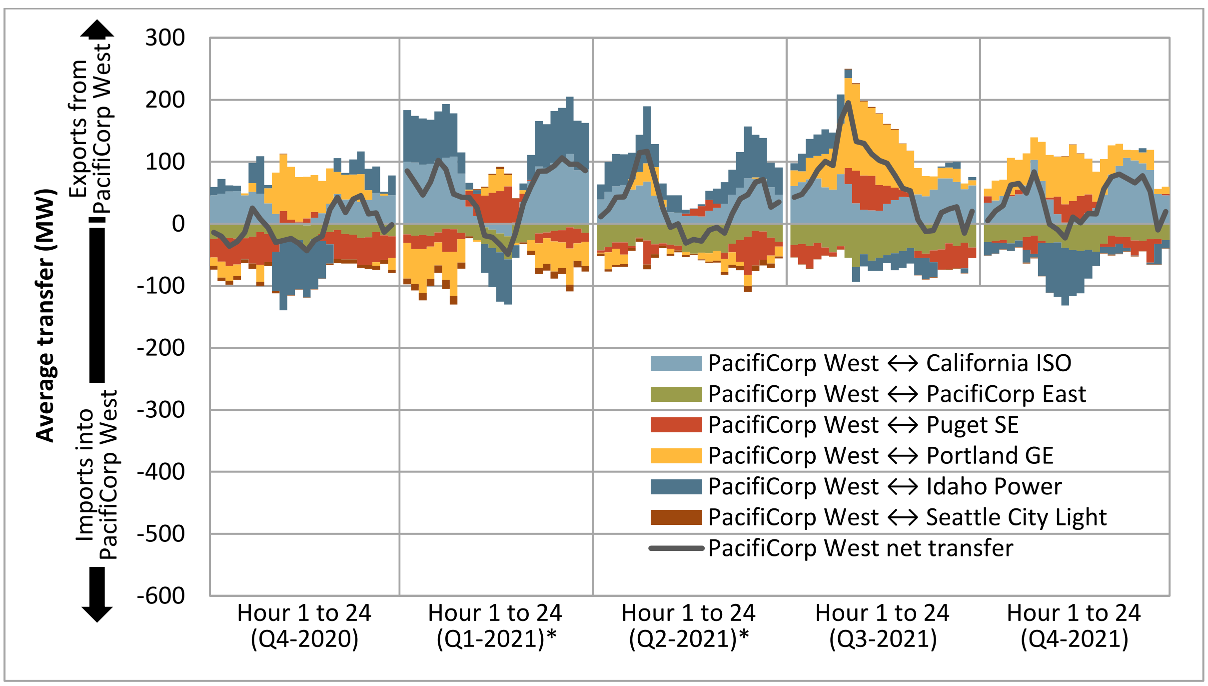
*See footnote 48

Figure 2.17 PacifiCorp East – average hourly 15-minute market transfer



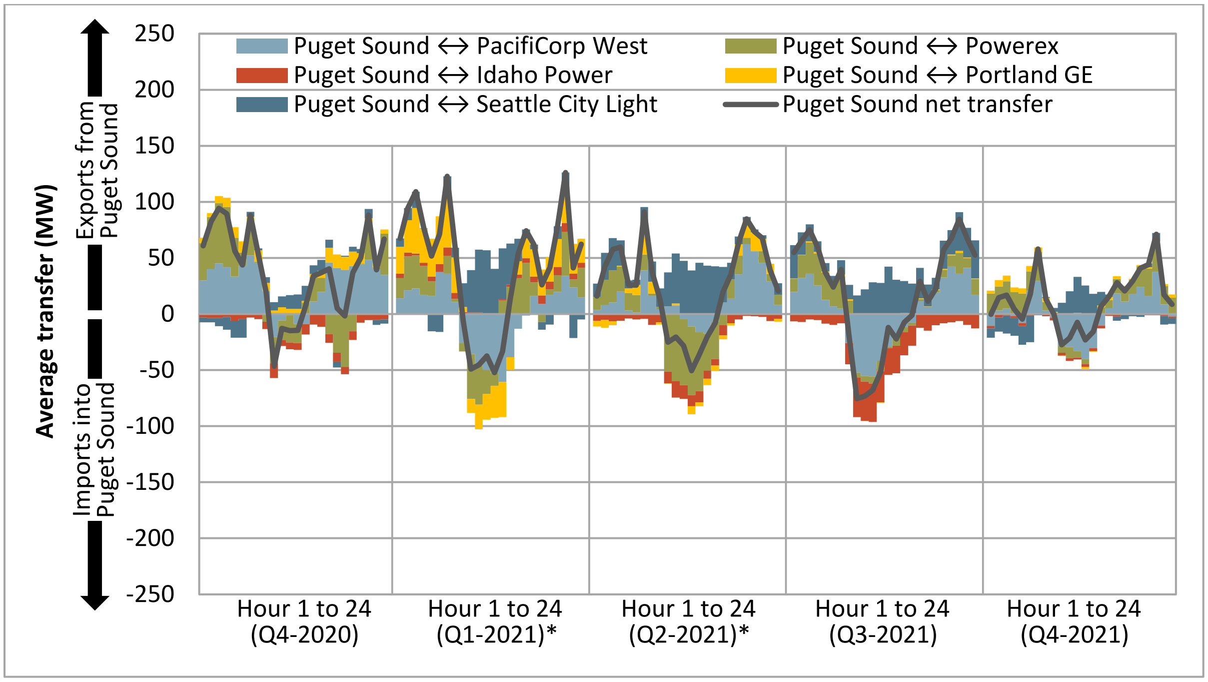
*See footnote 48

Figure 2.18 PacifiCorp West – average hourly 15-minute market transfer



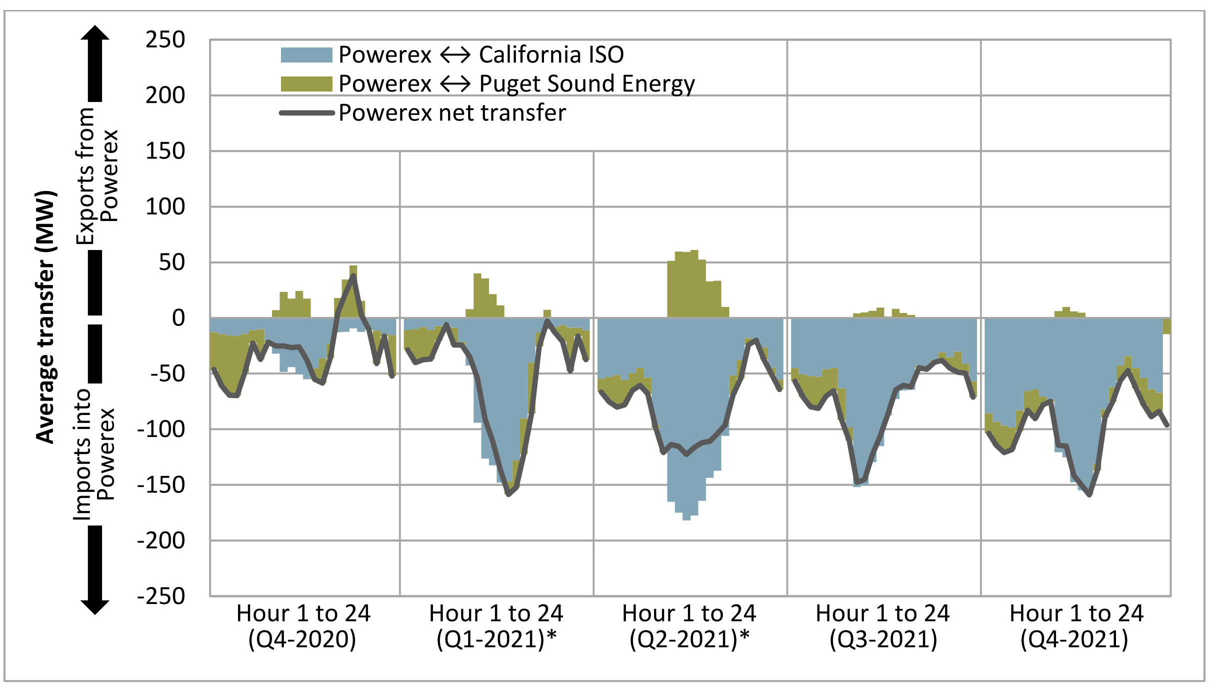
*See footnote 48

Figure 2.19 Puget Sound Energy – average hourly 15-minute market transfer



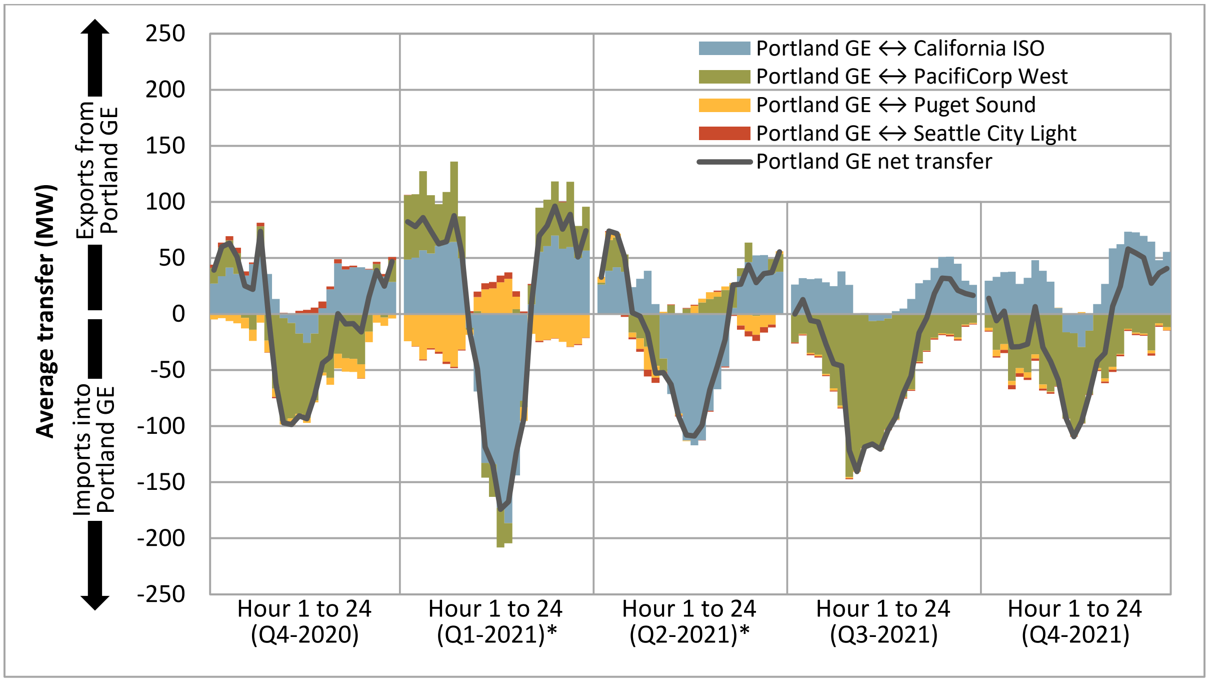
*See footnote 48

Figure 2.20 Powerex – average hourly 15-minute market transfer



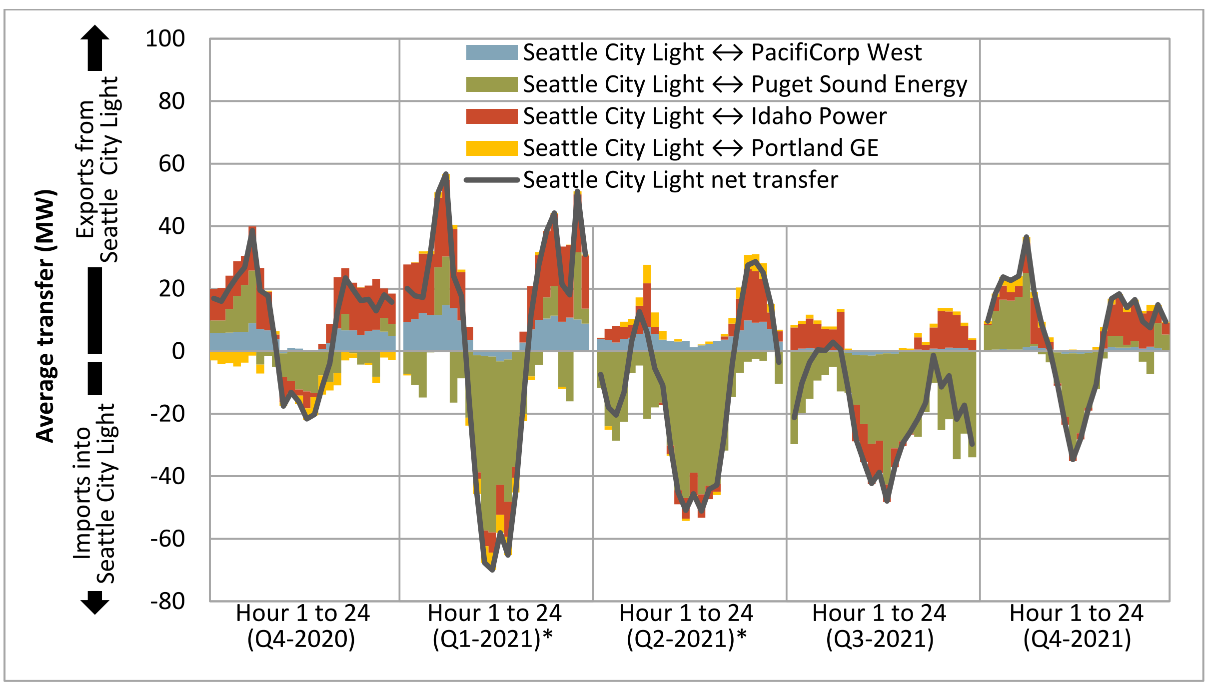
*See footnote 48

Figure 2.21 Portland General Electric – average hourly 15-minute market transfer



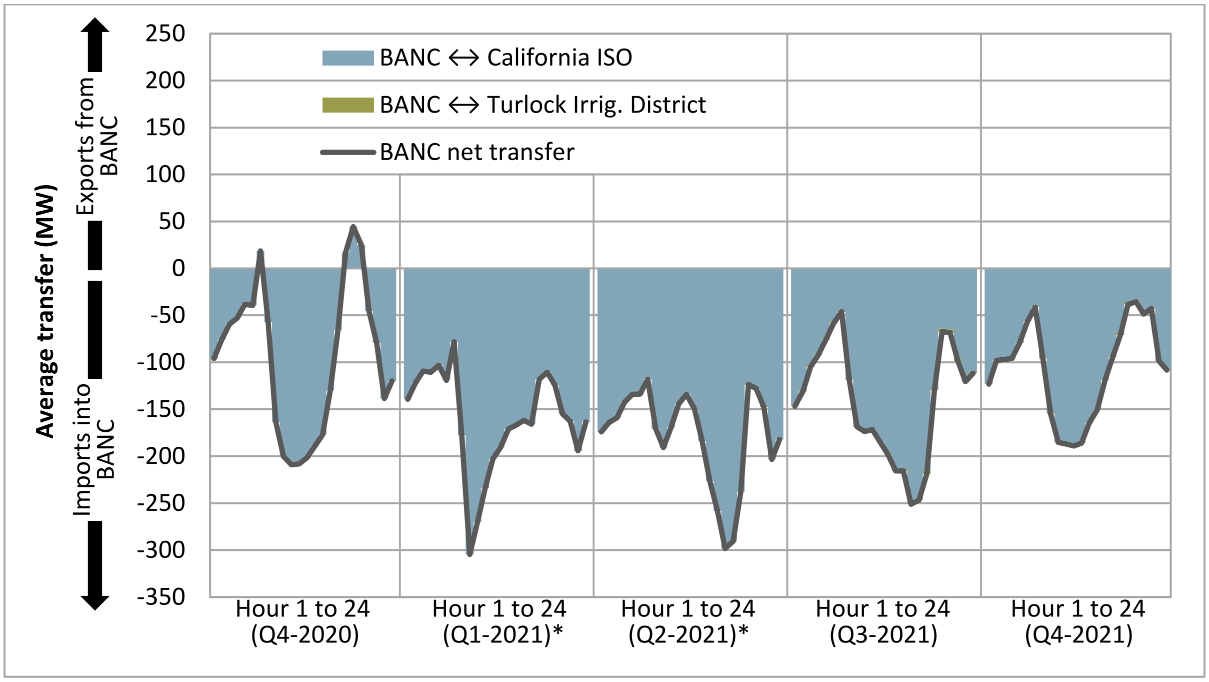
*See footnote 48

Figure 2.22 Seattle City Light – average hourly 15-minute market transfer



*See footnote 48

Figure 2.23 Balancing Authority of Northern California - average hourly 15-minute market transfer



*See footnote 48

Inter-balancing area congestion

Congestion between a WEIM 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 area, the market software triggers local market power mitigation for resources in that area.[51]

Table 2.4 shows the percent of 15-minute and 5-minute market intervals with congestion on transfer constraints into or out of a WEIM 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 WEIM 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.

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 California ISO or other competitive markets. The California ISO area is not subject to market power mitigation under these conditions.

52 Greenhouse gas prices can contribute to lower WEIM prices relative to those inside the California ISO. The current methodology uses the WEIM greenhouse gas prices in each interval to account for and omit price separation that is the result of greenhouse gas prices only.

Table 2.4 Frequency of congestion in the WEIM (October – December)

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	0%	0%	0%	0%
L.A. Dept. of Water and Power	0%	0%	0%	0%
Turlock Irrigation District	1%	0%	0%	0%
Arizona Public Service	1%	0%	1%	4%
NV Energy	1%	0%	1%	4%
Public Service Company of NM	3%	0%	2%	4%
PacifiCorp East	5%	0%	4%	3%
Idaho Power	3%	6%	1%	9%
Salt River Project	9%	1%	9%	5%
PacifiCorp West	18%	8%	9%	9%
Portland General Electric	18%	9%	9%	11%
NorthWestern Energy	16%	21%	13%	17%
Seattle City Light	33%	9%	30%	13%
Puget Sound Energy	33%	9%	30%	13%
Powerex	29%	13%	34%	33%

The highest frequency of congestion in the WEIM continued to be from areas in the Pacific Northwest toward the larger system. Congestion from these areas occurred less compared to last quarter, while congestion into these areas increased.

The highest frequency of net import congestion (such that the California ISO market software triggers local market power mitigation in that area) occurred in the Powerex and NorthWestern Energy areas. These areas were import congested during 13 percent and 21 percent of 15-minute market and 33 percent and 17 percent of 5-minute market intervals during the quarter, respectively.

Congestion in either direction for BANC, Los Angeles Department of Water and Power, Turlock Irrigation District, Arizona Public Service, and NV Energy was relatively infrequent during the quarter. Congestion that did occur for these areas was often the result of a failed capacity or flexibility test, which limited transfer capability.

2.4 Imbalance conformance in the Western Energy Imbalance Market

Frequency and size of imbalance conformance

Seattle City Light had the highest overall frequency of imbalance conformance during the fourth quarter. Turlock Irrigation District rarely utilized imbalance conformance; however, its average megawatt biased was the highest average percentage of its total load.

Table 2.5 Average frequency and size of imbalance conformance (October – December)

	Positive imbalance conformance			Negative imbalance conformance			Average hourly adjustment MW
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO							
15-minute market	54%	929	3.8%	2.7%	-300	1.5%	493
5-minute market	44%	257	1.1%	25%	-244	1.1%	54
BANC							
15-minute market	0.5%	35	1.9%	0.5%	-29	1.8%	0
5-minute market	1.7%	44	2.4%	0.9%	-37	2.2%	0
Los Angeles Dept. of Water and Power							
15-minute market	3.2%	69	2.7%	0.5%	-45	1.8%	2
5-minute market	17%	55	2.2%	4.6%	-45	1.8%	8
Turlock Irrigation District							
15-minute market	0.1%	30	9.0%	0.2%	-125	47%	0
5-minute market	0.1%	20	6.0%	0.2%	-131	51%	0
Northwestern Energy							
15-minute market	25%	14	1.1%	1.5%	-21	1.6%	3
5-minute market	39%	16	1.3%	3.6%	-30	2.3%	5
NV Energy							
15-minute market	0.0%	N/A	N/A	0.0%	N/A	N/A	0
5-minute market	11%	117	3.0%	4.7%	-150	4.2%	5
Arizona Public Service							
15-minute market	0.3%	56	1.9%	0.2%	-150	5.0%	0
5-minute market	31%	73	2.5%	32%	-67	2.4%	1
Salt River Project							
15-minute market	0.7%	57	1.9%	0.3%	-54	1.9%	0
5-minute market	5.2%	58	1.9%	2.7%	-58	2.0%	1
Idaho Power							
15-minute market	0.2%	50	2.8%	0.0%	N/A	N/A	0
5-minute market	11%	50	2.8%	4.2%	-46	2.7%	4
Public Service Company of New Mexico							
15-minute market	0.0%	N/A	N/A	0.0%	-91	6.5%	0
5-minute market	1.5%	112	8.4%	3.4%	-146	11%	-3
PacifiCorp East							
15-minute market	0.0%	N/A	N/A	0.2%	-125	2.4%	0
5-minute market	13%	103	2.0%	33%	-112	2.3%	-24
PacifiCorp West							
15-minute market	0.0%	N/A	N/A	0.0%	N/A	N/A	0
5-minute market	3.6%	59	2.4%	25%	-57	2.3%	-12
Portland General Electric							
15-minute market	1.3%	75	2.5%	0.0%	N/A	N/A	1
5-minute market	18%	37	1.4%	2.1%	-30	1.2%	6
Seattle City Light							
15-minute market	0.7%	19	1.6%	8.6%	-21	1.7%	-2
5-minute market	4.1%	24	2.1%	59%	-22	2.0%	-12
Puget Sound Energy							
15-minute market	0.5%	45	1.6%	6.8%	-50	1.6%	-3
5-minute market	1.4%	43	1.3%	60%	-42	1.4%	-25

Table 2.5 summarizes the average frequency and size of positive and negative imbalance conformance entered by operators in the WEIM for the 15-minute and 5-minute markets during the quarter.[53,54] The same data for the California ISO balancing area is provided as a point of reference. In particular, Seattle City Light entered positive imbalance conformance in <1 and 1 percent of 15-minute and 5-minute intervals, respectively, at an average of 44 MW and negative imbalance conformance in 9 and 59 percent of 15-minute and 5-minute intervals, respectively, at an average of 22 MW. Nearly all WEIM entities had a greater frequency of 5-minute market imbalance conformance than 15-minute market during the quarter.

2.5 Mitigation in the Western Energy Imbalance Market

In the fourth quarter of 2021, average incremental energy that was subject to mitigation increased significantly in the 15-minute and 5-minute markets, compared to the same quarter in 2020. Figure 2.24 and Figure 2.25 highlight the volume of 15-minute and 5-minute market mitigation in all the balancing authority areas in the WEIM outside the California ISO:

- Blue bars in Figure 2.24 and Figure 2.25 show average incremental energy subject to mitigation but whose bids were not lowered in the 15-minute and 5-minute markets, respectively. In the fourth quarter of 2021, on average, this portion increased by about 500 MW when compared to the same quarter in 2020.
- Volume of bids that were lowered as a result of mitigation (shown by red bars) increased significantly in the WEIM when compared to the same quarter in 2020.

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

54 Through recent revisions, load bias has been removed from the total load used in the calculation of the percentage of total load. The effect of this update is minimal, but means that the percentage of total load increased for positive imbalance conformance figures and decreased for negative imbalance conformance figures.

Figure 2.24 Average incremental energy mitigated in 15-minute real-time market (WEIM)

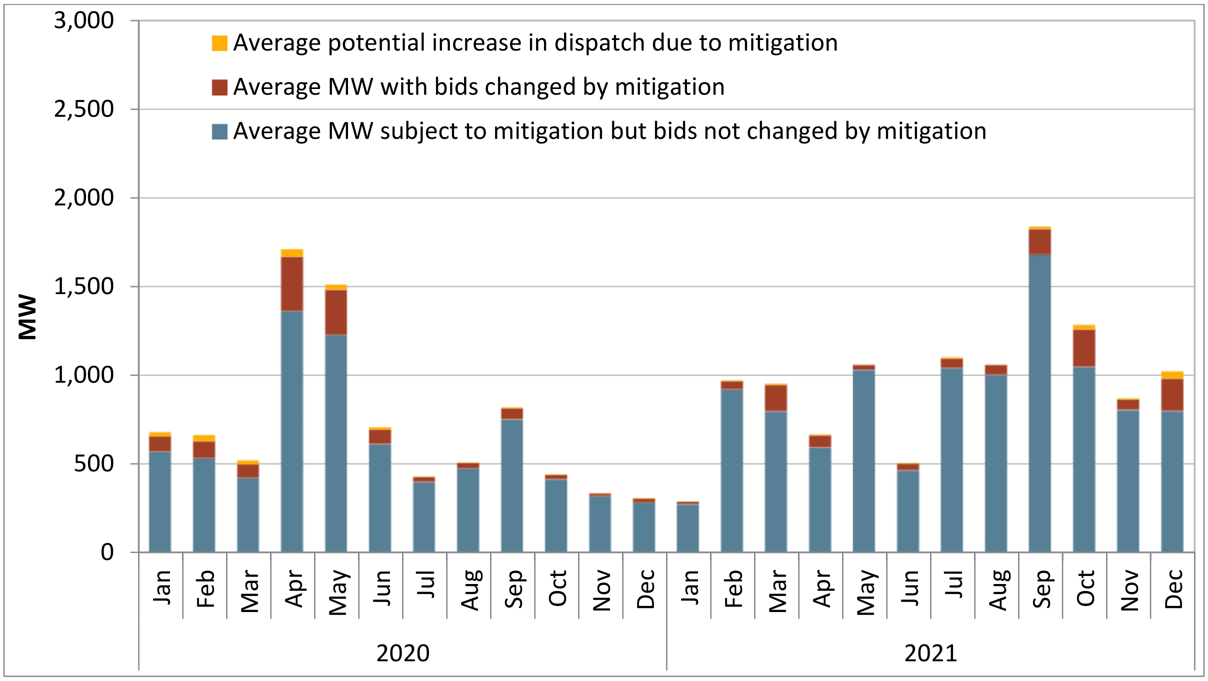

Figure 2.25 Average incremental energy mitigated in 5-minute real-time market (WEIM)