California ISO

# Q2 2021 Report on Market Issues and Performance

October 5, 2021

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California Independent System Operator

**TABLE OF CONTENTS**

## Executive summary

This report covers market performance during the second quarter of 2021 (April - June).

Key highlights during this quarter include the following:

- **Market prices were significantly higher** than the same quarter of 2020; day-ahead prices in the ISO almost doubled. Increases were due to a period of extreme heat in the West on some days in June, higher natural gas prices, and ongoing drought conditions causing low hydroelectric production.
- **Average ISO monthly 5-minute prices were lower** than both 15-minute and day-ahead market prices during the second quarter. Day-ahead prices averaged $40/MWh, 15-minute prices averaged $36/MWh, and 5-minute prices averaged $33/MWh.
- **Gas prices increased** at both SoCal Citygate and PG&E Citygate compared to the same quarter in 2020. This increase in natural gas prices resulted in higher system marginal energy prices across the ISO footprint during the second quarter.
- **Renewable production** increased by 3 percent compared to the same quarter in 2020, despite a decrease of 38 percent for hydroelectric production.
- **Generation outages** were higher than any second quarter in the previous five years.
- **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.
- **The day-ahead market was structurally uncompetitive** in more hours than any second quarter in the previous five years.
- **Congestion** in the day-ahead market decreased SDG&E and SCE area prices. Total day-ahead congestion rent was $98 million, a decrease from $194 million in the previous quarter, but an increase from $90 million in the same quarter of the previous year.
- **Congestion revenue rights** auction revenues are estimated to be $17 million less than payments made to non-load-serving entities during the second quarter and $4 million in the first quarter, representing about 12 percent and 2 percent of day-ahead congestion rent, respectively. The losses as a percent of day-ahead congestion rent were well below the average of 28 percent during the three years before the Track 1A and 1B changes (2016 through 2018).
- **Real-time offset costs totaled** $25 million in the second quarter and $58 million in the first quarter, for a semi-annual total of $84 million, the highest total for the first two quarters of any year since the introduction of the 15-minute market in 2014.
- **Imbalance conformance adjustments** reached 1,150 MW during the peak net load ramp hours, on average, continuing the increase in operator use of imbalance conformance that began in 2017. The widening gap between high conformance in the 15-minute market and lower conformance in the 5-minute market contributes to the price difference between these markets.

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

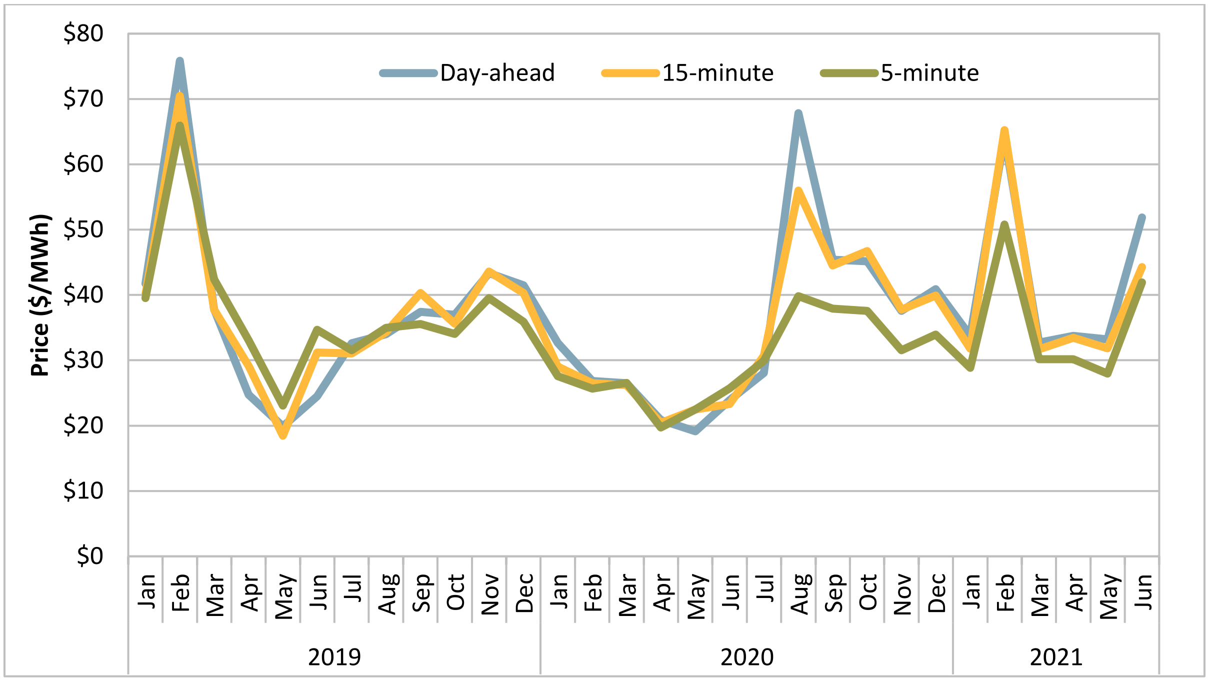
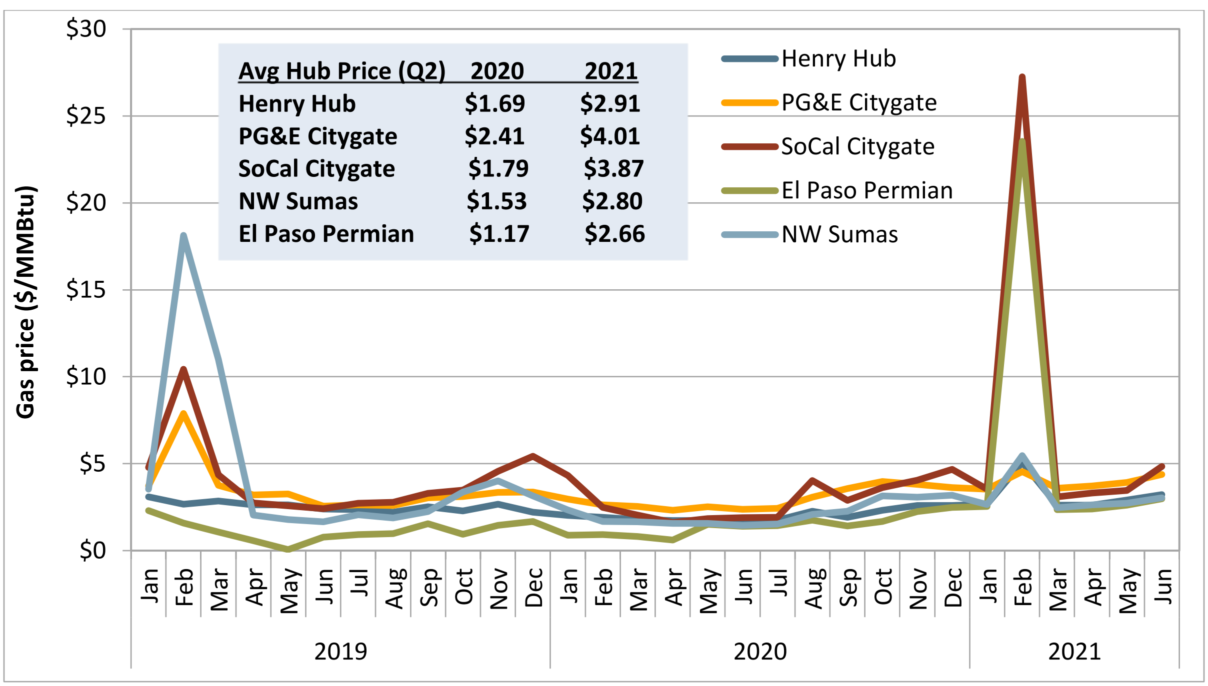



**Figure E.2 Natural gas prices**



## Western Energy Imbalance Market

- **The Los Angeles Department of Water and Power, the Public Service Company of New Mexico, and NorthWestern Energy** joined in the second quarter, bringing over 14 GW of participating generation capacity and over 20 GW of transfer capacity into the Western Energy Imbalance Market.
- **Prices in NV Energy were over $100/MWh on average in the hours between 8 and 9 pm** in both the 15-minute and 5-minute markets, driven by high penalty prices associated with under-supply infeasibilities when NV Energy was separated from the rest of the system. Penalty prices were raised from $1,000/MWh to $2,000/MWh in March. As in previous quarters, under-supply infeasibilities often occurred following the failure of a resource sufficiency test failure which can limit imports into a failing area. In June, the ISO implemented Phase 2 of FERC Order 831, limiting conditions in which the $2,000/MWh penalty price would apply.
- **Prices in California areas were more than $10/MWh higher than other regions,** on average. 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**, which includes PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex, were regularly lower than prices in other balancing areas due to limited transfer capability out of this region during peak system load hours.
- **On June 16, 2021, the ISO added net load uncertainty to the requirement of the bid range capacity test** as part of a package of market enhancements for Summer 2021 readiness. Between June 16 and June 30, there were 65 capacity test failures across all areas; 83 percent of these were caused entirely by the additional uncertainty component.
- **Over the year ending in June, NV Energy and Salt River Project had the most** flexible ramping sufficiency or bid range capacity test failures, and were net importers in almost all failure intervals. During around 89 percent of upward test failures for Arizona Public Service and PacifiCorp West, the resulting cap that was imposed was in a net export position (cannot reduce exports).
- **In the California ISO**, significantly more 15-minute market transfers were affected by test failures than 5-minute market transfers in the year ending June. This may be due in part to differences in imbalance conformance.
- **The resource sufficiency evaluation includes a balancing test** applied each hour to all non-ISO areas. Penalty payments totaling over $4.5 million over the last 3 years have been paid by non-California ISO areas to all areas, including the California ISO.
- **DMM has agreed to provide additional transparency surrounding test accuracy and performance** in regular reports specific to this topic as part of the EIM resource sufficiency evaluation stakeholder initiative. This second quarter report as well as the special reports issued by DMM in May and September summarizes some of the existing metrics that can be included in these future EIM resource sufficiency evaluation reports. DMM is seeking feedback from stakeholders on existing or additional metrics and analysis that would be most valuable.

## Special issues

### FERC Order 831 compliance

On June 13, the ISO implemented the second phase of FERC Order No. 831 compliance. Phase 1, implemented on March 20, allowed some resources to bid between $1,000/MWh and $2,000/MWh, and raised the penalty prices associated with a power balance constraint under-supply violation from $1,000/MWh to $2,000/MWh.

The second phase restricted balancing area supply shortage penalty pricing and bidding between the $1,000/MWh soft bid cap and the $2,000/MWh hard cap to hours (bids) and days (supply shortage penalty pricing) on which either (1) the ISO has accepted a cost-verified bid over $1,000/MWh or (2) the maximum import bid price (MIBP) is greater than $1,000/MWh. The maximum import bid price approximates the prevailing price of electricity and is calculated using an hourly price shaping factor and the maximum of either the Mid-Columbia or the Palo Verde hub price.[1]

Following Phase 2 implementation, there were 14 instances in which the penalty price associated with a power balance constraint under-supply violation was set at $2,000/MWh, none of which occurred in the ISO. After Phase 2 implementation there were no power balance constraint violations in the ISO balancing area. There were 24 instances of a power balance constraint violation for EIM entities during days with a high maximum import bid price, of which 14 were set at $2,000/MWh because the shortage exceeded the balancing area's threshold value.

### Intertie deviation settlement

In February, the ISO implemented the intertie deviation settlement initiative, updating the settlements methodology to increase penalties applied to over- and under-delivered intertie transactions and to apply these penalties with more precision. Undelivered intertie transactions adversely impact both market reliability and efficiency. After the initial implementation in February a number of issues that led to settlement charge errors were identified. The ISO published a paper to address the errors and to bring the tariff and intertie deviation settlement implementation into alignment. Intertie deviation penalties charged between February and June are estimated to total about $5.5 million.

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1 *FERC Order No. 831 – Import Bidding and Market Parameters Revised Final Proposal*, September 10, 2020, pp 26: http://www.caiso.com/InitiativeDocuments/RevisedFinalProposal-FERCOrder831-ImportBidding-MarketParameters.pdf

# 1 Market performance

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

- **Market prices were significantly higher** than the same quarter of 2020; day-ahead prices in the ISO almost doubled. Increases were due to a period of extreme heat in the West on some days in June, higher natural gas prices, and ongoing drought conditions causing low hydroelectric production.
- **Average ISO monthly 5-minute prices were lower** than both 15-minute and day-ahead market prices during the second quarter. Day-ahead prices averaged $40/MWh, 15-minute prices averaged $36/MWh, and 5-minute prices averaged $33/MWh.
- **Gas prices increased** at both SoCal Citygate and PG&E Citygate compared to the same quarter in 2020. This increase in natural gas prices resulted in higher system marginal energy prices across the ISO footprint during the second quarter.
- **Renewable production** increased by 3 percent compared to the same quarter in 2020, despite a decrease of 38 percent for hydroelectric production.
- **Generation outages** were higher than any second quarter in the previous five years.
- **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.
- **The ISO introduced a minimum area flexible ramping product procurement requirement** in November 2020. The requirement bound frequently for the ISO but not other areas, and is applied in the 15-minute market but not the 5-minute market. On May 9, the ISO made all five-minute dispatchable resources with economic bids eligible to receive flexible ramping product awards, including wind and solar capacity which had not been eligible. Following this change, ISO area prices were often zero.
- **The day-ahead market was structurally uncompetitive** in more hours than any second quarter in the previous five years.
- **Congestion** in the day-ahead market decreased SDG&E and SCE area prices. Total day-ahead congestion rent was $98 million, a decrease from $194 million in the previous quarter, but an increase from $90 million in the same quarter of the previous year.
- **Congestion revenue rights** auction revenues are estimated to be $17 million less than payments made to non-load-serving entities during the second quarter and $4 million in the first quarter, representing about 12 percent and 2 percent of day-ahead congestion rent, respectively. The losses as a percent of day-ahead congestion rent were well below the average of 28 percent during the three years before the Track 1A and 1B changes (2016 through 2018).
- **Real-time offset costs totaled** $25 million in the second quarter and $58 million in the first quarter, for a semi-annual total of $84 million, the highest total for the first two quarters of any year since the introduction of the 15-minute market in 2014.
- **Imbalance conformance adjustments** reached 1,150 MW during the peak net load ramp hours, on average, continuing the increase in operator use of imbalance conformance that began in 2017. The widening gap between high conformance in the 15-minute market and lower conformance in the 5-minute market contributes to the price difference between these markets.

## 1.1 Supply conditions

### 1.1.1 Natural gas prices

Electricity prices in western states typically follow natural gas price trends because natural gas units are often the marginal source of generation in the ISO and other regional markets. Following a volatile gas price event in February 2021, gas prices at major trading hubs returned to stable levels in the second quarter of 2021. However, the prices in this quarter were still higher than the same quarter of 2020. This increase in natural gas prices resulted in higher system marginal energy prices across the ISO footprint during the second quarter.

Figure 1.1 shows monthly average natural gas prices at key delivery points across the west including PG&E Citygate, SoCal Citygate, Northwest Sumas, and El Paso Permian, as well as 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 second quarter, prices at the SoCal Citygate gas hub averaged $3.87/MMBtu compared to $1.79/MMBtu in the second quarter of 2020. In April and May, prices were lower than June because of maintenance at SoCalGas Company's storage facilities which reduced the ability to inject excess gas into storage, putting downward pressure on prices. The prices started to rise in June because of increased gas demand from electric generation which led to gas withdrawals from storage.

Consistent with the California Public Utilities Commission'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. During the second quarter, SoCalGas Company declared low OFOs on only three gas days, primarily Stage 1. The revisions from the CPUC's ruling are set to expire in October 2021. DMM submitted comments to a new CPUC ruling to revise the existing penalty structure.[3]

In this quarter, PG&E Citygate gas prices averaged about $4/MMBtu compared to $2.41/MMBtu in the second quarter of 2020. This is slightly higher than the average gas price at SoCal Citygate hub. The increased gas prices at PG&E Citygate were primarily due to elevated prices at the supply regions.

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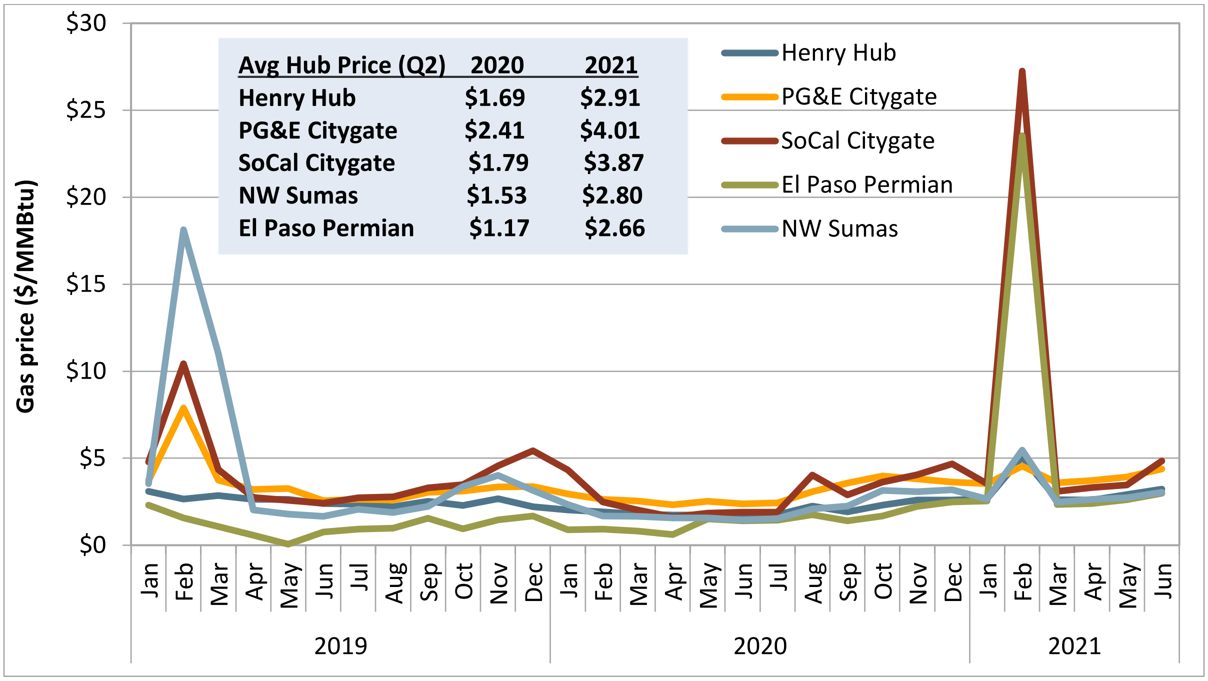
2 *CPUC's Proposed Decision Granting In Part and Denying In Part for Modification Filed by Southern California Edison & Southern CA Generation Coalition of Commission*, pp 31-32, April 29,2019: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M285/K085/285085989.PDF

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

**Figure 1.1 Monthly average natural gas prices**




## 1.1.2 Renewable generation

In the second quarter, the combined average hourly generation from hydroelectric, solar, wind, geothermal, and biogas-biomass resources increased by about 300 MW (3 percent) compared to the same quarter of 2020. Generation from non-hydro renewable resources increased 15 percent while hydroelectric generation decreased 38 percent, compared to the second quarter of 2020.[4]

Figure 1.2 shows the average hourly renewable generation by month and fuel type.[5] Non-hydroelectric renewable generation, which includes wind, solar, geothermal, and biogas-biomass resources, increased by a total of 325 MW (15 percent) compared to the same quarter in 2020. This increase is primarily due to higher solar and wind generation. Geothermal generation decreased slightly over the quarter, by less than 1 percent, while biogas-biomass generation increased slightly, by less than 1 percent.

Compared to the same period in 2020, hourly average hydroelectric production in the second quarter decreased by about 1,000 MW (38 percent). As of April 1, 2021, the statewide weighted average snowpack in California was 62 percent of normal compared to 50 percent of normal on April 1, 2020.[6]

Hourly average wind and solar production increased by about 19 percent and 18 percent, respectively, compared to the second quarter of 2020. The availability of variable energy resources contributes to price patterns both seasonally and hourly due to their low marginal cost relative to other resources.

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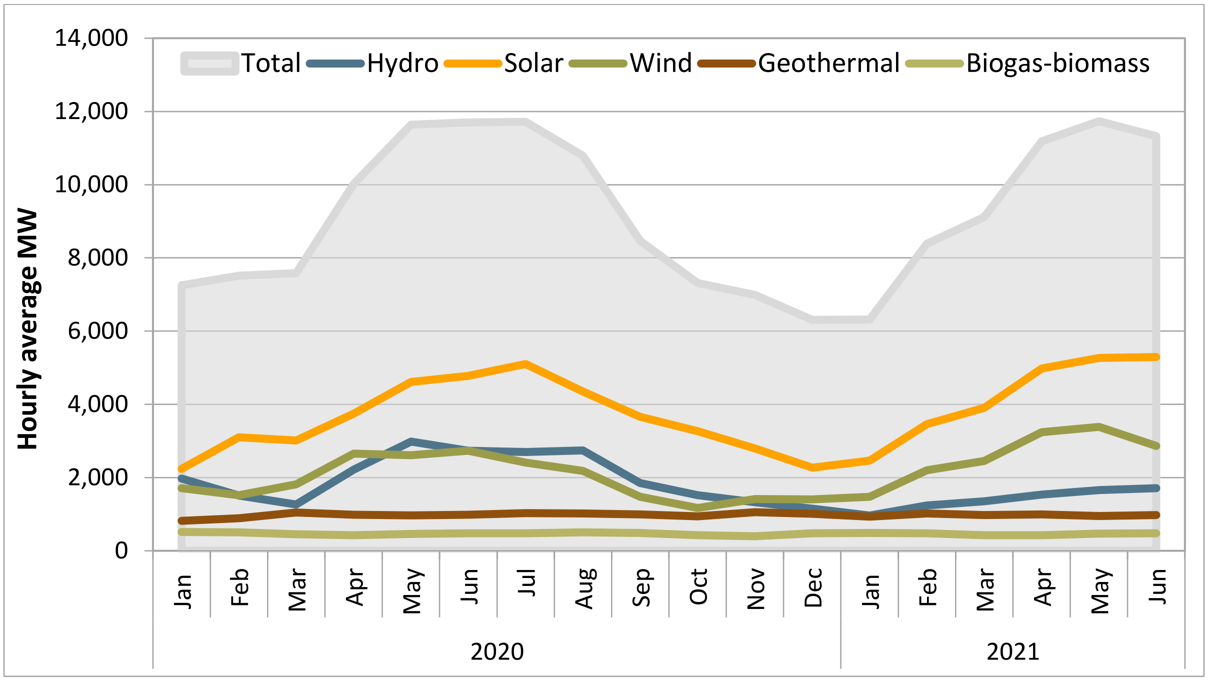
[4] Figures and data provided in this section for Q2 2021 are preliminary and may be subject to change.

[5] Hydroelectric generation greater than 30 MW is included.

[6] 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 decreased in the second quarter of 2021, relative to the same time last year, by 21 percent in the ISO balancing area and 36 percent in the energy imbalance market. 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 the amount of supply on-line exceeds demand, the real-time market dispatches generators down. Generally, generators are dispatched down in merit order from the highest bid to lowest. As with typical incremental dispatch, the last unit dispatched sets the system price and dispatch instructions are subject to constraints including transmission, ramping, and minimum generation. During some intervals, even wind and solar resources are dispatched down economically, implying that the nodal price is even lower than the typically low priced bids from wind and solar resources.

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

Figure 1.3 shows the curtailment of wind and solar resources by month in the ISO. Curtailments fall into six categories 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;[7]
- **exceptional economic downward dispatch**, in which a resource receives an exceptional dispatch or out-of-market instruction to decrease dispatch;
- **other economic downward dispatch**, in which the market price is greater than one dollar above a resource bid and that resource is dispatched down;
- **self-schedule curtailment**, in which a price-taking self-scheduled resource receives an instruction to reduce output while the market price is below a resource bid or the resource's upper limit is binding;
- **exceptional self-schedule curtailment**, in which a self-scheduled resource receives an exceptional dispatch or out-of-market instruction to reduce output; and
- **other self-schedule curtailment**, in which a self-scheduled resource receives an instruction to reduce output and the market price is above the bid floor.

The majority of the reduction in wind and solar output during the second quarter of 2021 (97 percent) was a result of economic downward dispatch, rather than self-schedule curtailment. Most renewable generation dispatched down in the ISO were solar resources (95 percent) rather than wind (5 percent), as solar resources typically bid more economically.

In the ISO, economic downward dispatch varied widely over the course of the second quarter of 2021. The sharp increase in the amount of economic downward dispatch in May was due to higher solar and wind production, lower load, and congestion from south to north. Self-schedule curtailment totaled 9,200 MWh for the quarter, a 62 percent decrease relative to the second quarter of 2020.

Figure 1.4 shows the amount of downward dispatch of non-ISO wind and solar resources. Curtailments in the EIM fall into four categories: economic downward dispatch, other economic downward dispatch, self-schedule curtailment, and other self-schedule curtailment, each defined above. Downward dispatch was lower in the energy imbalance market areas outside of the ISO compared to the same quarter of 2020. Much of the curtailment in the EIM is due to the high frequency of congestion on the Wyoming Export constraint, which leads to one resource being heavily curtailed.[8]

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

8 The Total_Wyoming_Export constraint was congested during 28.3 percent of intervals during the quarter as shown in Table 1.5. The overall effects of transfer congestion are discussed in detail in Section 1.9.2.

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

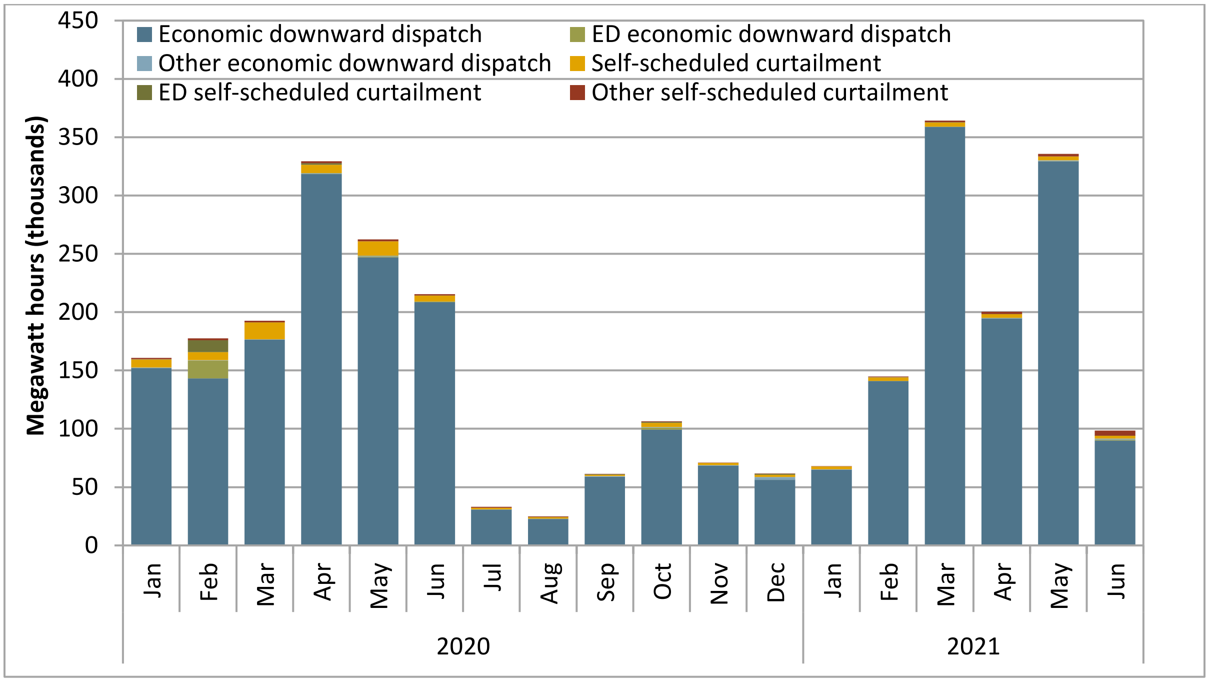
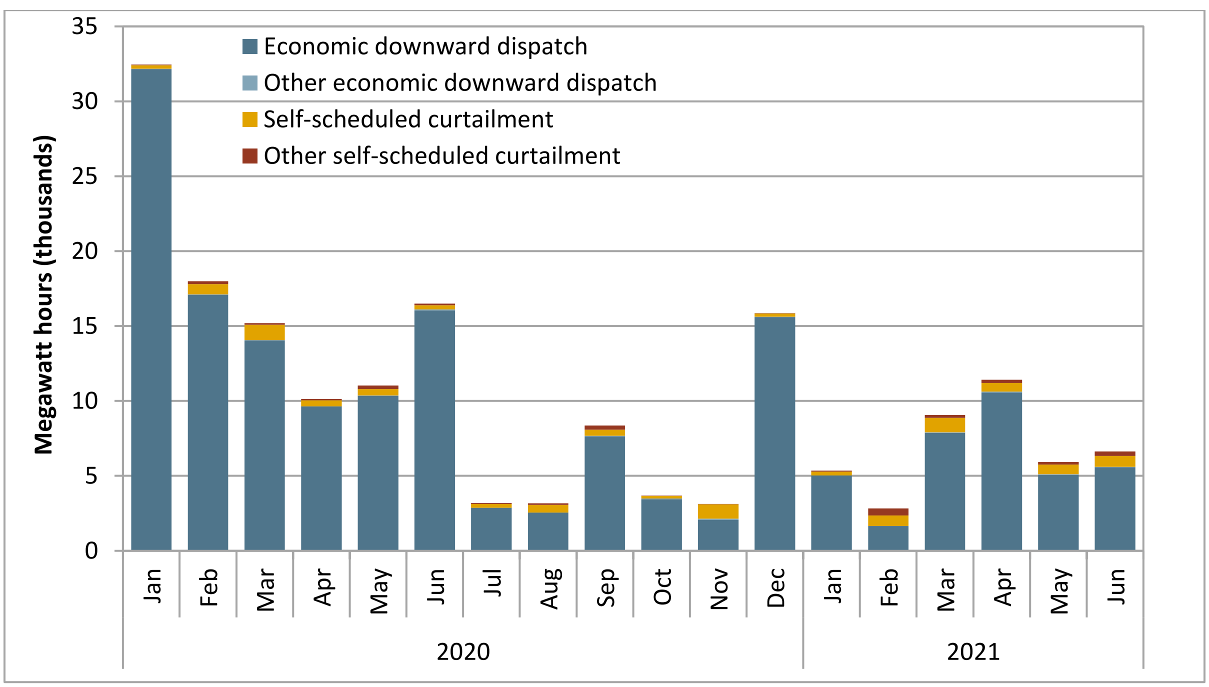



**Figure 1.4 Reduction of wind and solar generation by month (EIM)**



### 1.1.4 Generation by fuel type

In the second quarter, generation increased on average for some fuel types, while decreasing sharply for others. Average hourly generation by both wind and solar resources increased by 19 percent, while average hourly generation by imports and hydroelectric resources fell by 34 percent and 38 percent, respectively, compared to the same quarter of 2020.[9]

Figure 1.5 shows the average hourly generation by fuel type during the second quarter of 2021. As shown in the figure, average nuclear, geothermal, and bio-based resources comprised about 3,900 MW of inflexible base generating capacity, about 300 MW less than the same quarter of 2020. Hourly average natural gas generation peaked at about 11,500 MW, during hour ending 21. Natural gas generation accounted for about 33 percent of total average hourly generation during the net peak load of hours ending 17 through 21. Compared to the second quarter of 2020, total average hourly natural gas generation increased 43 percent, driven by a decrease in hydroelectric generation and imports.

**Figure 1.5 Average hourly generation by fuel type (Q2 2021)**

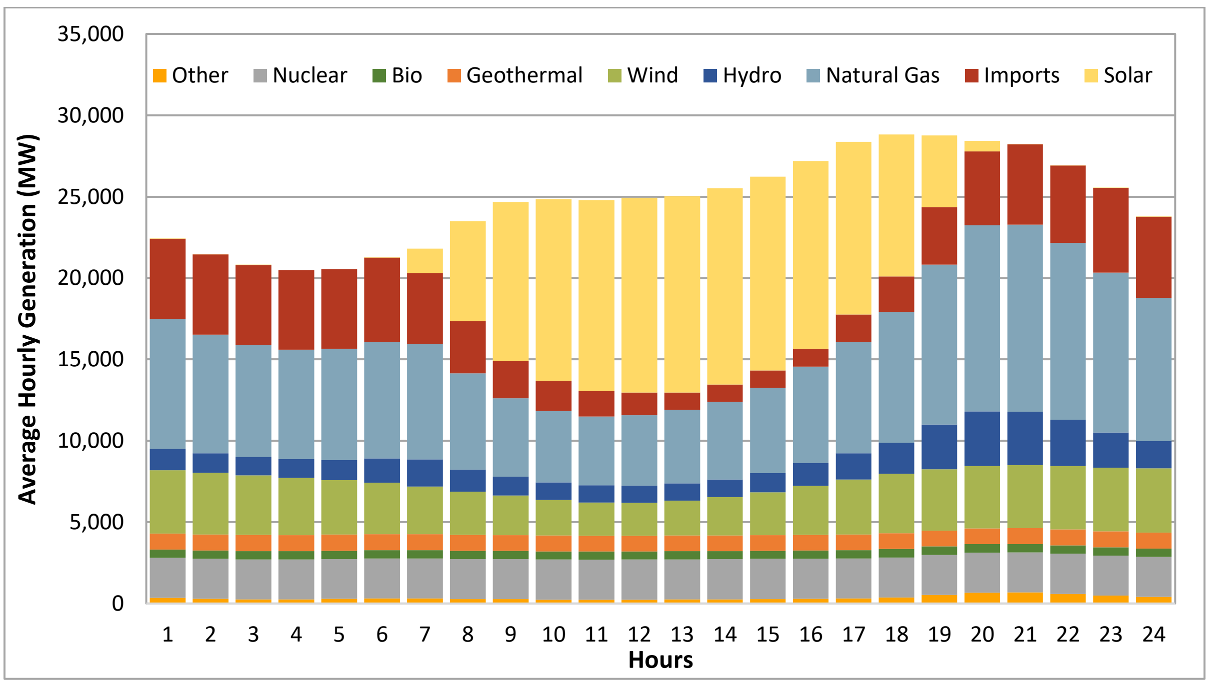



Figure 1.6 shows hourly variation of generation by fuel group, driven primarily by hourly variation of solar production. Compared to the second quarter of 2020, natural gas generation variability increased 29 percent, driven by a decrease in hydroelectric generation and imports during net peak load hours. Wind generation in the second quarter continued to have low hourly variability on average, although it increased 18 percent compared to the same quarter of 2020.

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

Average hourly imports trended similarly to natural gas generation over the quarter, with most imports occurring during non-peak hours. Average hourly generation from resources in the "other" category showed increased variability throughout the day, doubling compared to the same quarter of 2020.[10]

**Figure 1.6 Hourly variation in generation by fuel type (Q2 2021)**

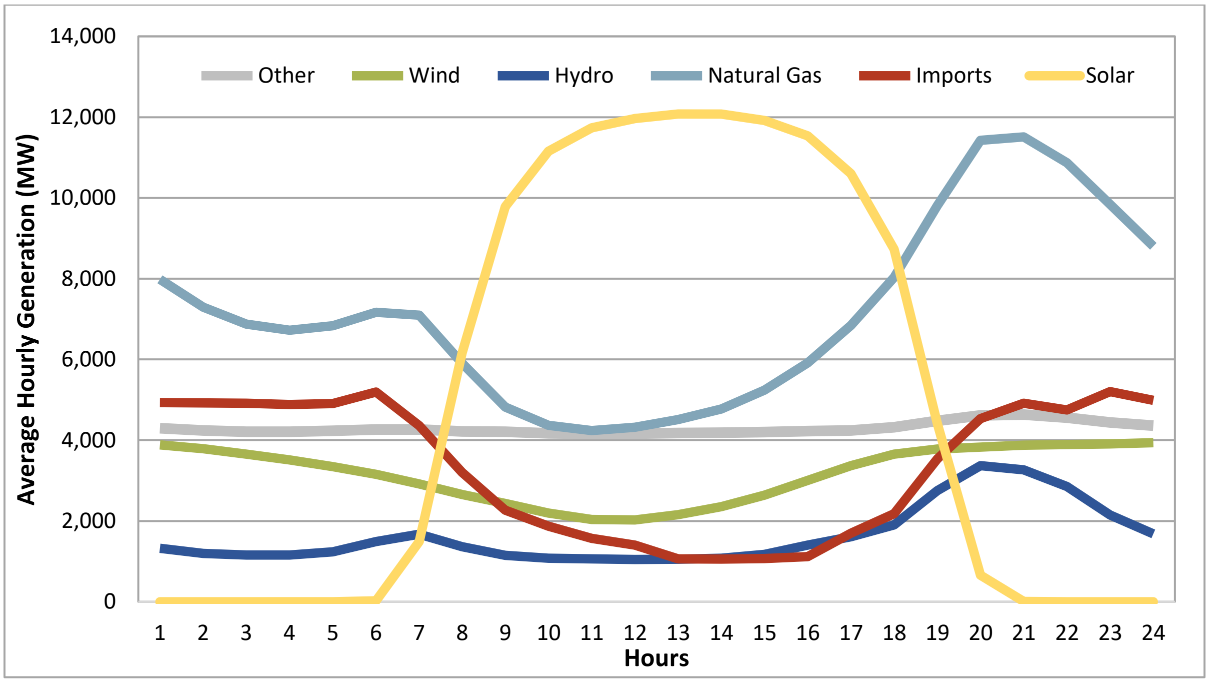
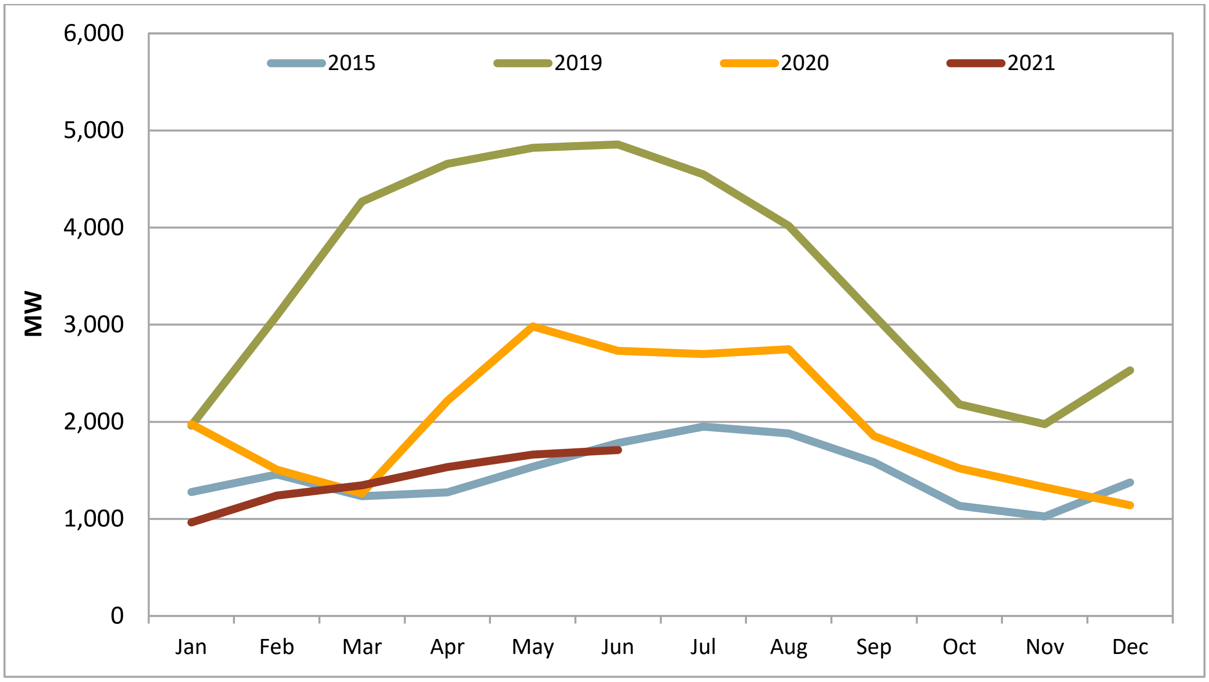



Figure 1.7 shows the monthly average hydroelectric generation for 2015, 2019, 2020, and 2021. Hydroelectric generation in 2021 is well below 2019 and 2020, while trending similar to 2015. Conditions are similar to those of 2015 as both years saw April 1 snowpack percentages that were below normal, with 62 percent of normal in 2021 and 5 percent in 2015. The decline in hydroelectric generation has been made up for in part by increased wind and solar generation.

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

**Figure 1.7 Monthly average hydroelectric generation by year**




### 1.1.5 Generation outages

The total amount of generation outages over the second quarter of 2021 was higher than the same quarter of the last five years. Planned and forced outages increased 34 percent and 11 percent, respectively, relative to the same time last year.

Under the ISO's current outage management system, known as WebOMS, all outages are categorized as either planned or forced. An outage is considered to be planned if a participant submitted it more than 7 days prior to the beginning of the outage. WebOMS has a menu of subcategories indicating the reason for the outage. Examples of such categories include plant maintenance, plant trouble, ambient due to temperature, ambient not due to temperature, unit testing, environmental restrictions, transmission induced, transitional limitations, and unit cycling.

Figure 1.8 shows the quarterly averages of maximum daily outages during peak hours by type from 2017 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 second quarter of 2021, the average total generation on outage in the ISO surpassed the same period in 2020 by about 2,350 MW, as shown in Figure 1.8.[11] Planned maintenance outages averaged 4,100 MW, while other types of planned outages averaged 1,850 MW. Some common types of outages that fall into the other planned outages category include ambient outages (both due to

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

temperature and not due to temperature) and transmission outages. These planned outage categories combined for the quarter was about 34 percent higher than the second quarter of 2020.

Total forced outages averaged 8,350 MW during peak hours in the second quarter of 2021, about 11 percent higher than the same time last year. Forced outages for either plant maintenance or plant trouble averaged 2,800 MW, while all other types of forced outages averaged 5,550 MW during the quarter. These other types of forced outages include ambient due to temperature, ambient not due to temperature, environmental restrictions, unit testing, and outages for transition limitations.

On a monthly basis, total outages steadily decreased during the quarter, driven primarily by reductions in planned maintenance outages. The April 2021 average outages reached 16,575 MW, a 2,625 MW increase from the same time last year. The high increase in outages, both forced and planned, may be a symptom of the growing share of the thermal fleet nearing retirement, resulting in higher outage rates. Based on the historical seasonal trend, the increase in generation outages between Q1 and Q2 of 2021 is relatively unexpected as it had not happened since 2017, as shown in Figure 1.8.

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

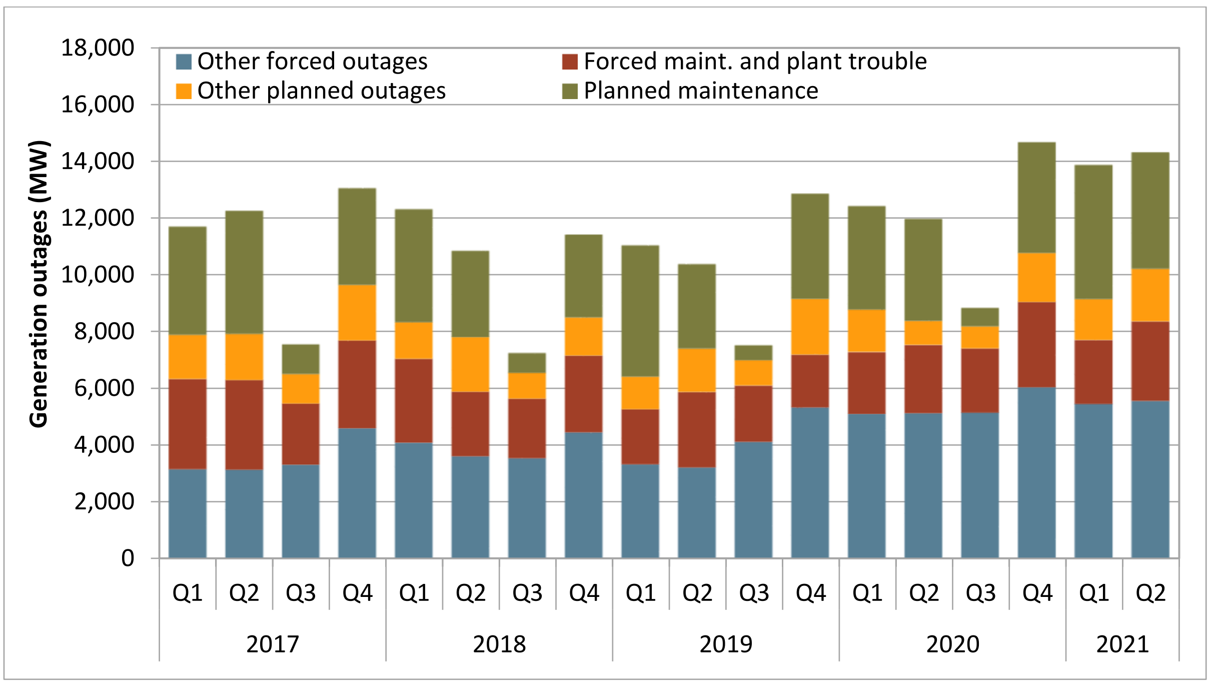
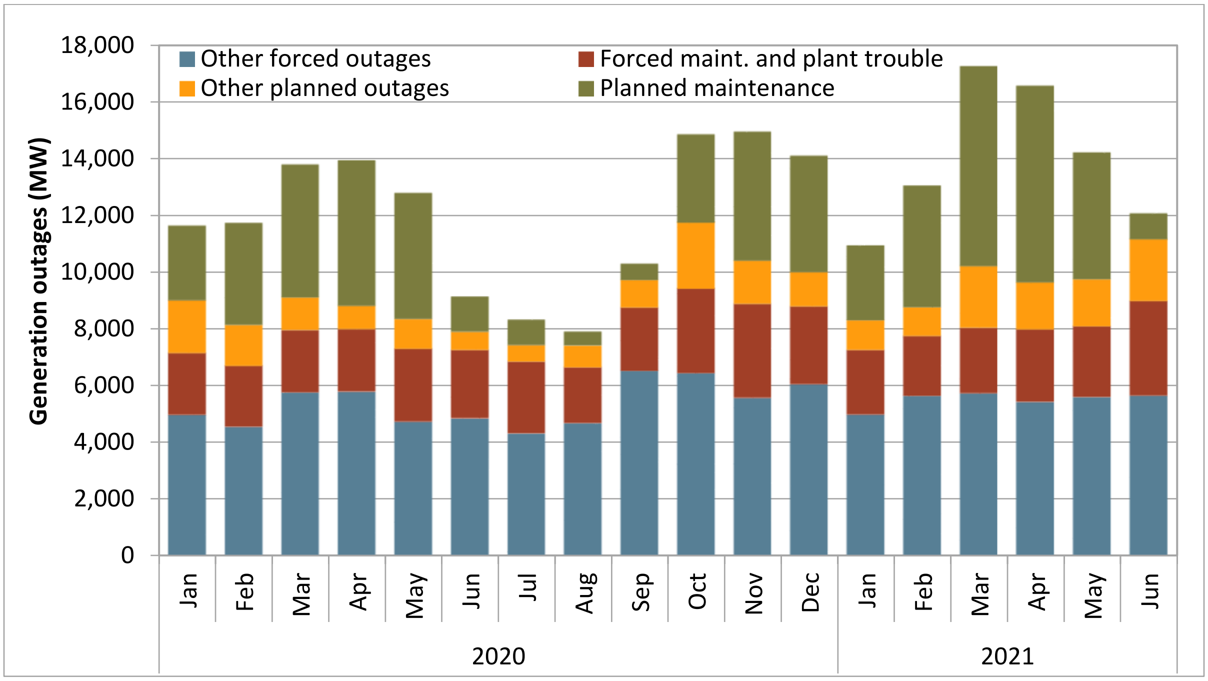


**Figure 1.9 Monthly average of maximum daily generation outages by type – peak hours**

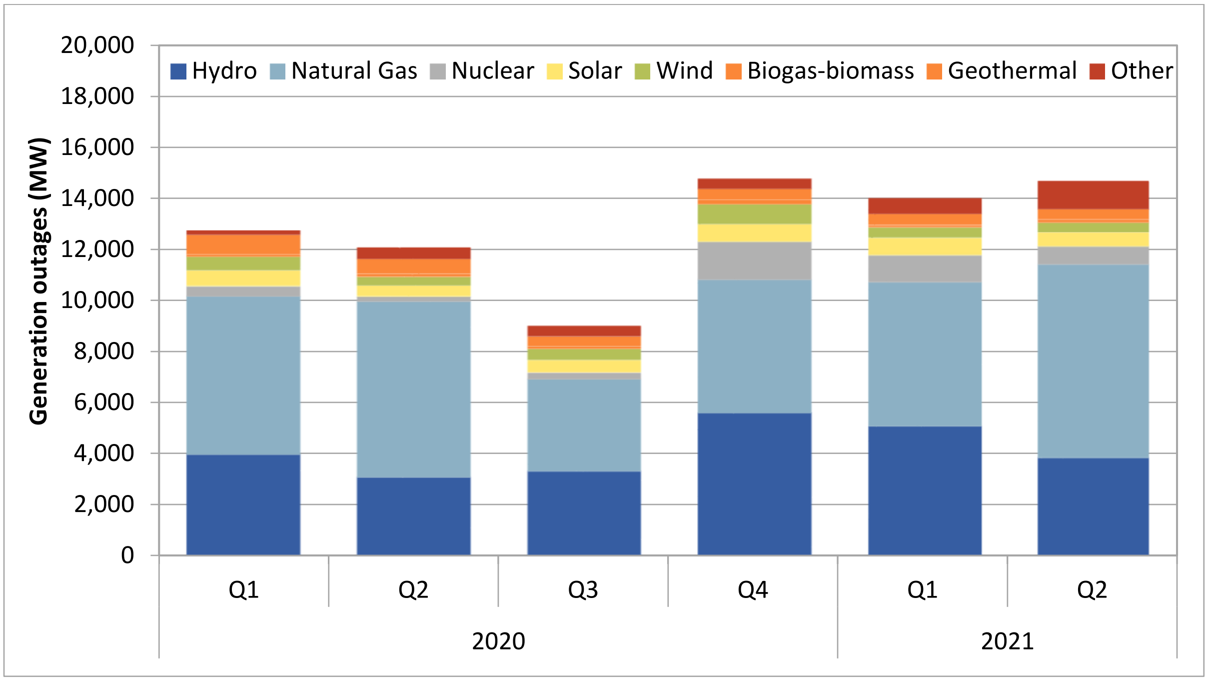



### Generation outages by fuel type

Natural gas and hydroelectric generation on outage averaged 7,560 MW and 3,833 MW during the second quarter. These two fuel types accounted for 52 percent and 26 percent of the generation on outage for the quarter, respectively.

Figure 1.10 shows the quarterly average of maximum daily generation outages by fuel type during peak hours. The overall increase in generation outages in the second quarter was primarily due to an increase in natural gas and “Other” generation outages. Compared to the same time last year, nuclear generation on outage was two and a half times higher. Biogas-biomass and geothermal generation were the only categories to have had less generation on outage compared to the second quarter of 2020, decreasing by 1 percent and 31 percent, respectively.

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



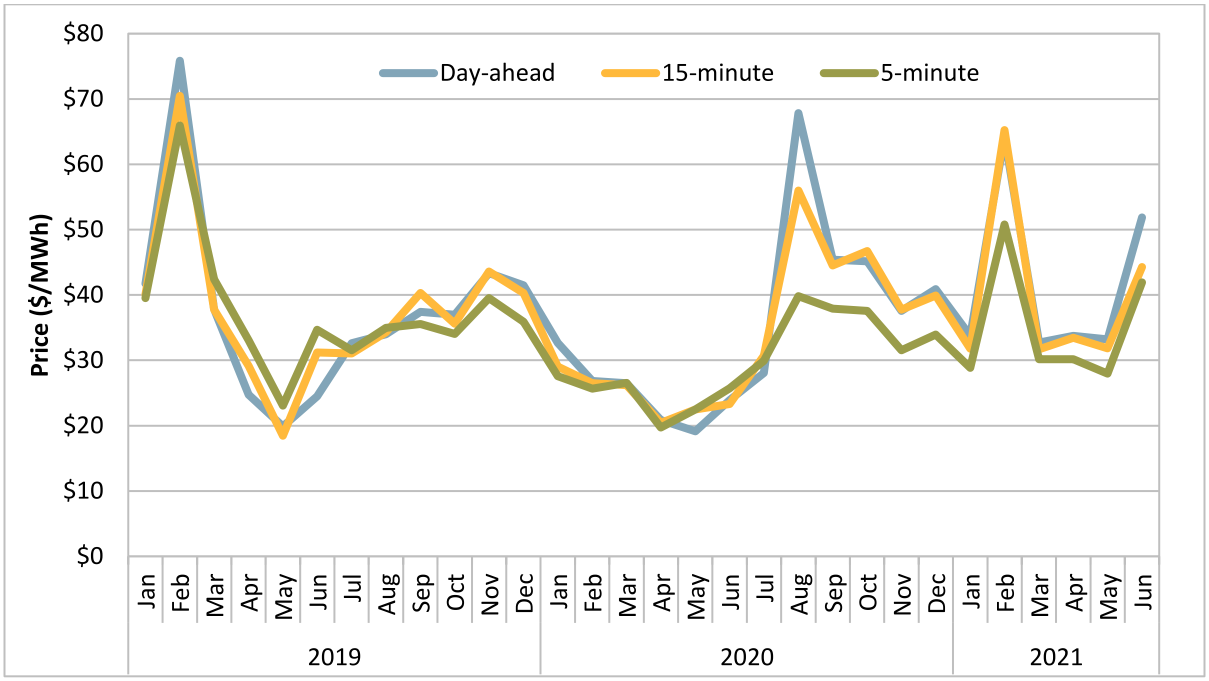

## 1.2 Energy market performance

### 1.2.1 Energy market prices

This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. Price convergence between these markets may help promote efficient commitment of internal and external generating resources. Compared to the second quarter of 2020, prices across all three markets were substantially higher this year compared to last, particularly in the month of June.

Figure 1.11 shows load-weighted average monthly energy prices during all hours across the four largest aggregation points in the ISO (Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Valley Electric Association). Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) from January 2019 to June 2021.

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




Prices in all three markets were substantially higher compared to the second quarter of last year. Prices in the 5-minute and 15-minute markets increased 47 percent and 65 percent, respectively, to averages of $33/MWh and $36/MWh. Day-ahead prices almost doubled in this quarter compared to the second quarter last year, to an average of $40/MWh. This increase in prices was consistent across all three months in the second quarter but was most pronounced in June. This is likely due to extreme heat in the west on same days along with ongoing drought conditions causing low hydroelectric production.[12]

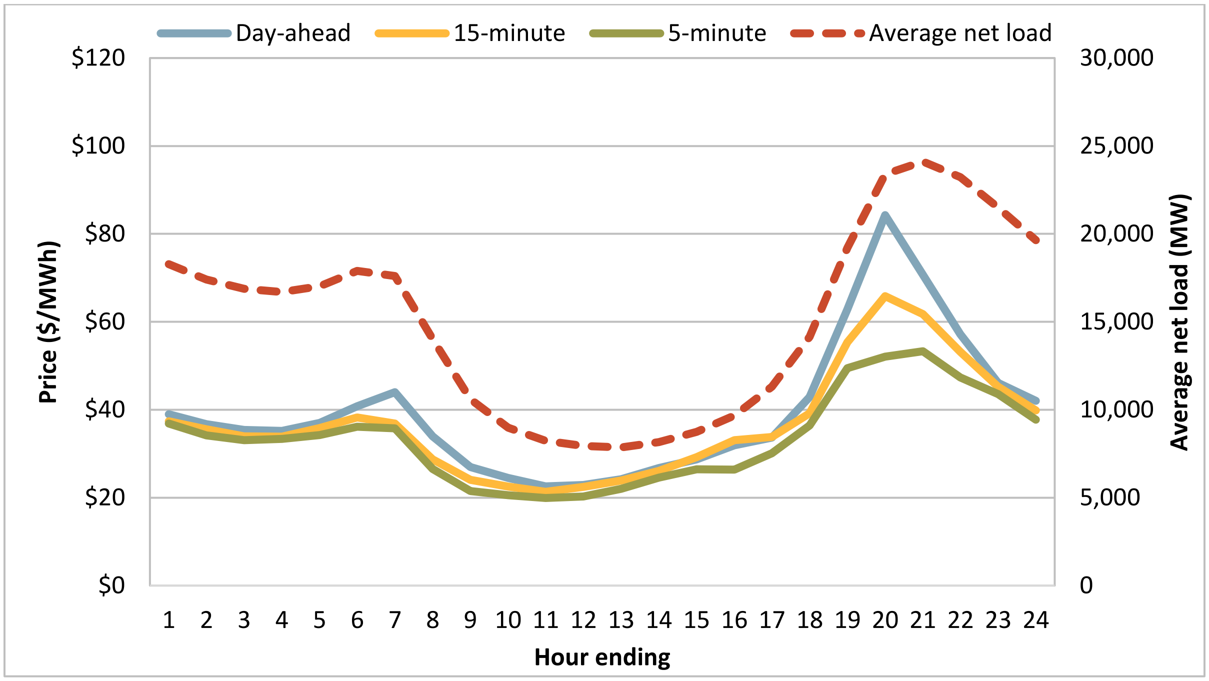
In this quarter, day-ahead market prices rose higher than prices in the 15- and 5-minute markets, compared to the second quarter last year when day-ahead prices were about 5 percent lower. This divergence was strongest in June when day-ahead prices were about 20 percent higher than prices in the other two markets.

Figure 1.12 illustrates load-weighted average energy prices on an hourly basis for the quarter compared to average hourly net load.[13] 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.

[12] *Summer Market Performance Report*, June 2021: http://www.caiso.com/Documents/SummerMarketPerformanceReportforJune2021.pdf

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

**Figure 1.12 Hourly load-weighted average energy prices (April - June)**



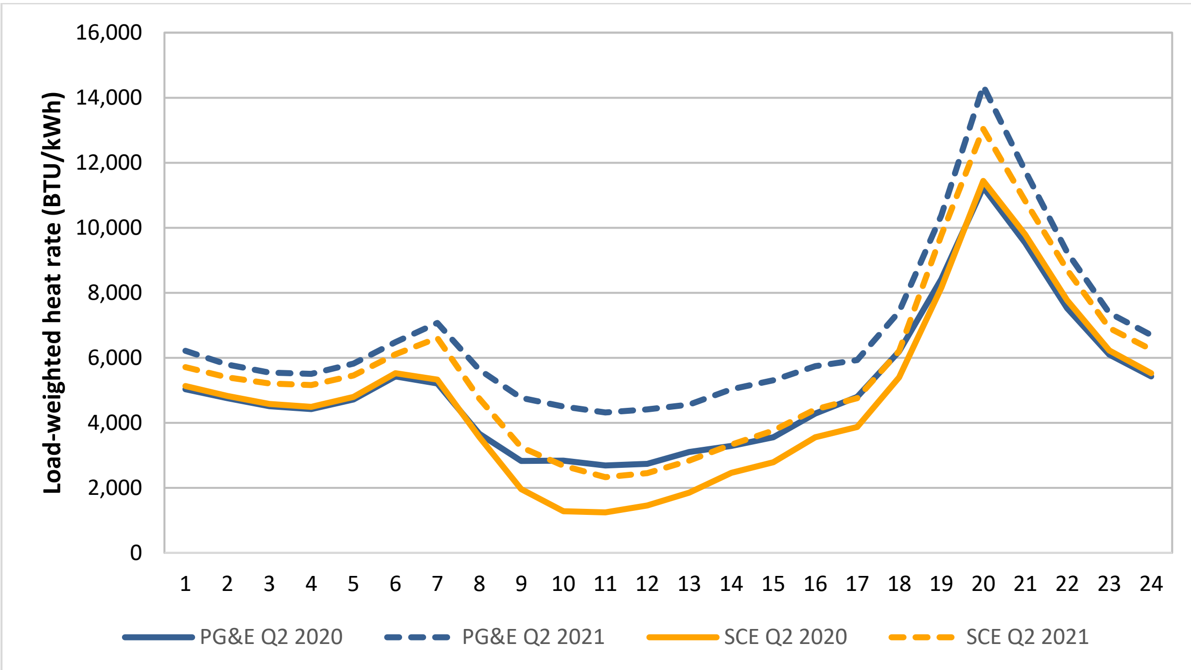

Average hourly prices continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours. Prices across all hours were higher in this quarter compared to the second quarter last year. The price increase was most pronounced during hours 10 through 17, when day-ahead prices were about twice as high on average. During these same hours, net load was roughly 16 percent lower than the same quarter in the previous year.

One explanation for this trend is the substantial decrease in hydroelectric generation which offset the increase in solar production. Solar generation increased about 20 percent in hours 10-17, leading to lower net loads. However, hydroelectric generation decreased about 40 percent and was replaced in part with natural gas generation which increased 31 percent in these hours.

One other explanation for relatively high prices is higher natural gas prices. Market heat rates are calculated by dividing the price of power by the price of natural gas for a specific term and location. DMM calculated the hourly market heat rate separately for Pacific Gas & Electric and Southern California Edison using the average day-ahead market price at each, the next-day gas prices at SoCal Citygate and PG&E Citygate, plus additional gas transportation costs and greenhouse gas emission credits.[14] Figure 1.13 compares the hourly implied heat rate for Pacific Gas & Electric and Southern California Edison in the second quarter of 2020 (solid lines) and the second quarter of 2021 (dashed lines). The hourly implied heat rate increased across all hours for both demand aggregation points, but low heat rates still suggest that day-ahead market prices were competitive in this quarter.

[14] The transportation cost is the average cost across different fuel regions for each hub. This along with the greenhouse emission credits adds about $2/MMBtu to the cost of natural gas for gas units in California. In addition, the analysis accounts for non-fuel components of marginal cost by subtracting $2.80/MWh from the market price of electricity which is the variable O&M cost for combined cycle units included in default energy bids used in bid mitigation.

**Figure 1.13 Average hourly market heat rate for PG&E and SCE (April – June)**




## 1.2.2 Bilateral price comparison

On average, day-ahead market prices in the ISO across peak hours in the second quarter were lower 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 1.14 shows the ISO's day-ahead weighted average peak prices across the three largest load aggregation points (Pacific Gas & 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 ISO market. Average prices in the ISO and bilateral trading hubs were calculated during peak hours (hours ending 7 through 22) for all days, excluding Sundays and holidays.

The figure shows significant price divergence between the ISO and these bilateral hubs during the heat wave conditions that existed during mid and late June. On June 17, 2021, prices at Mead and Palo Verde hubs exceeded the $1,000/MWh WECC soft offer cap, requiring sellers to submit cost justification for sales made above this cap to FERC. DMM has intervened in this cost justification proceeding and submitted comments on most of the company filings.[15,16] In addition, FERC also issued guidance in

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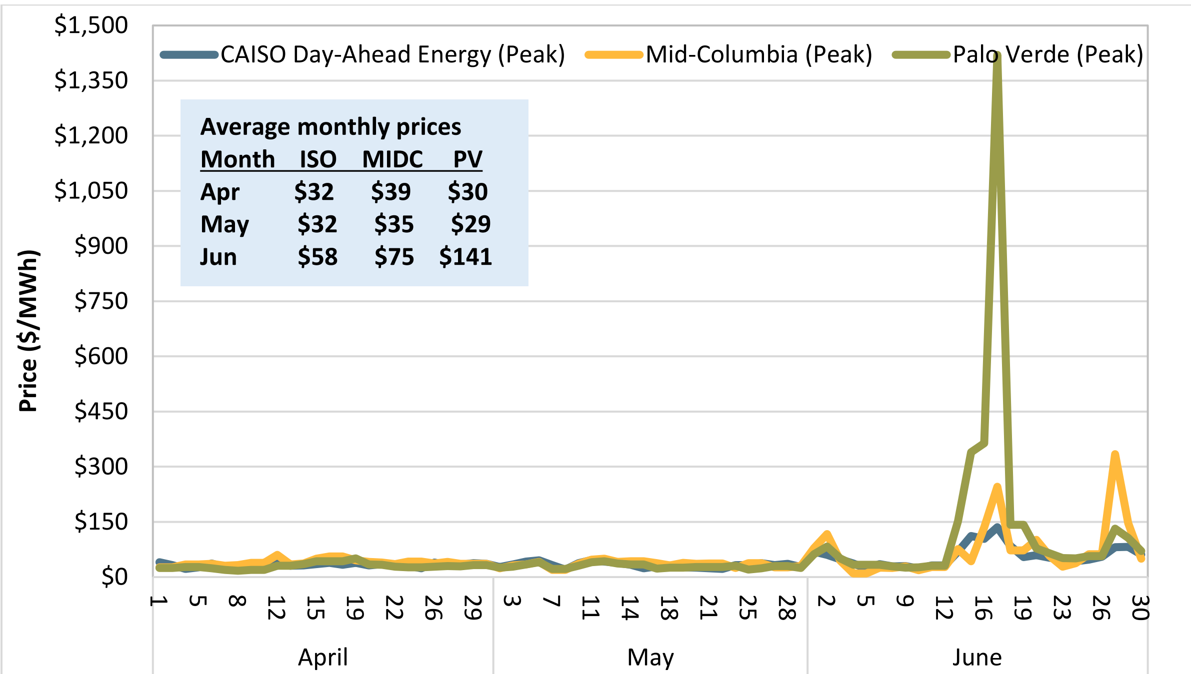
15 *Motion To Intervene Of The Department Of Market Monitoring Of The California Independent System Operator Corporation*, July 28, 2021: http://www.caiso.com/Documents/Motion-to-Intervene-of-the-Department-of-Market-Monitoring-WECC-Soft-Offer-Cap-ER21-2370-et-al-Jul-28-2021.pdf

16 DMM comments on WECC soft offer cap cost justification filings, August 9, 2021: http://www.caiso.com/Documents/Comments-of-the-Department-of-Market-Monitoring-ER21-2453-et-al-WECC-Soft-Offer-Cap-Aug-9-2021.pdf

response to the cost justification filings for sales above the WECC soft cap made during the mid-August 2020 heat wave.[17] Figure 1.15 uses the same data underlying Figure 1.14 but on an average monthly basis for 2020 and 2021. Prices in the ISO are represented at the Southern California Edison and Pacific Gas & Electric default load aggregation points (DLAPs). As shown in this figure, average bilateral prices at Mid-Columbia and Palo Verde hubs exceeded the prices at ISO DLAPs during the heat wave conditions that existed in June 2021.

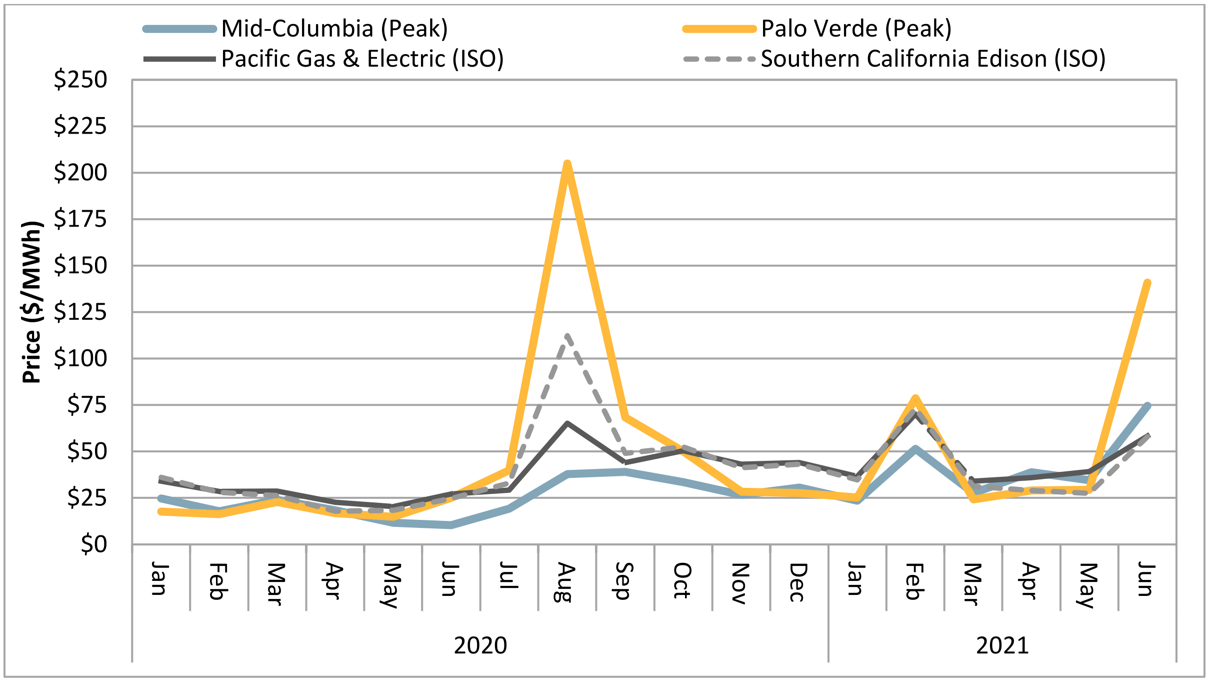
**Figure 1.14 Day-ahead ISO and bilateral market prices (Apr - Jun)**




http://www.caiso.com/Documents/Motion-to-File-Comments-Out-of-Time-of-the-Department-of-Market-Monitoring-ER21-2370-et-al-WECC-Soft-Offer-Cap-Aug-9-2021.pdf

17 FERC order providing guidance, June 17, 2021: https://www.ferc.gov/media/e-3-061721

**Figure 1.15 Monthly average day-ahead and bilateral market prices**




Average day-ahead prices in the ISO and bilateral hubs (from ICE) were also compared to real-time hourly energy prices traded at Mid-Columbia and Palo Verde hubs for all hours of the quarter using data published by Powerdex. Average day-ahead hourly prices in the ISO were greater than average real-time prices at Mid-Columbia and Palo Verde by $6/MWh and $1/MWh, respectively. Average day-ahead prices at Mid-Columbia and Palo Verde (from ICE) were greater than the average real-time prices at Mid-Columbia and Palo Verde (from Powerdex) by $11/MWh and $18/MWh, respectively.

## Imports and exports

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.[18]

As shown in Figure 1.16, peak imports in the day-ahead (dark blue line) decreased in hour ending 21, from about 6,550 MW to 5,300 MW, compared to the same quarter of 2020. Peak 15-minute cleared imports (dark yellow line) also decreased, from about 7,100 MW to 5,900 MW, compared to last year. Peak exports (shown as negative numbers below the horizontal axis in pale blue and yellow), increased compared to the same quarter of 2020, by about 530 MW and 750 MW, in the day-ahead and 15-minute markets, respectively.

The average net interchange, excluding EIM transfers (dashed grey line), is based on meter data and averaged by hour and quarter. The solid grey line adds incremental EIM interchange, which reached a low point of about negative 900 MW in hour ending 14. The greatest import transfer into the ISO from the EIM occurred in hour ending 23, at about 900 MW, compared to about 400 MW in hour ending 22 from the same quarter in the prior year. The greatest export transfer from the ISO to the EIM occurred

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

in hour ending 17, at about 2,000 MW, which was a decrease of about 550 MW from the same quarter in 2020.

**Figure 1.16 Average hourly net interchange by quarter**

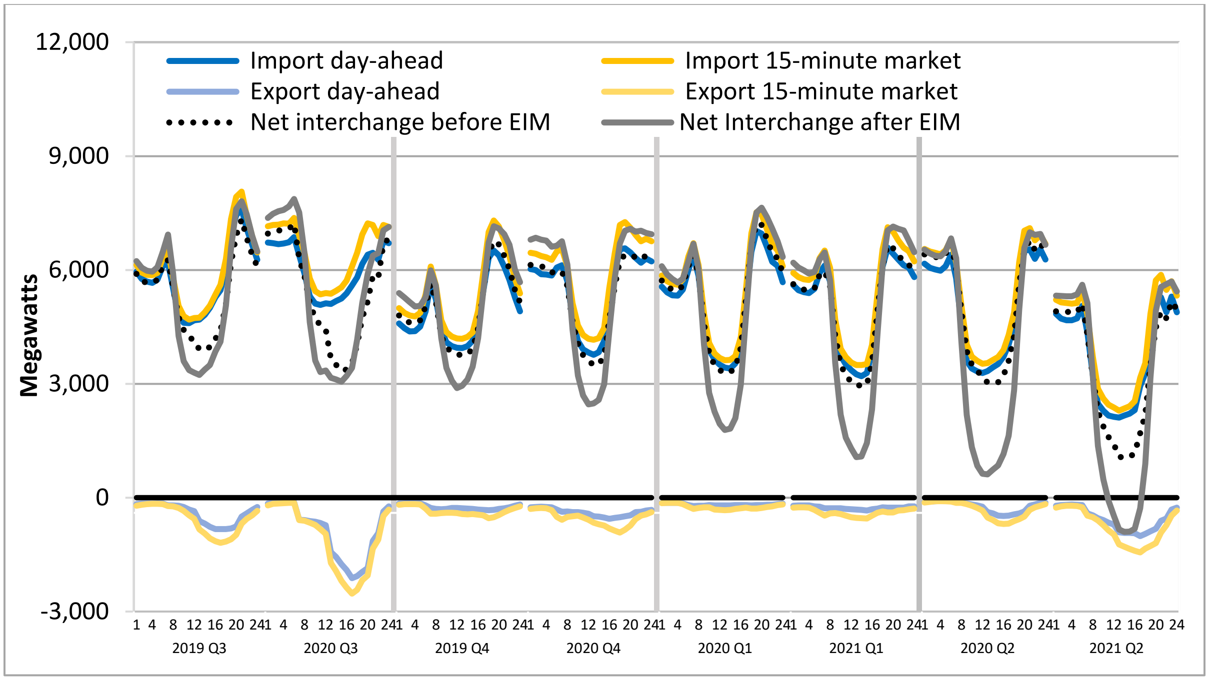
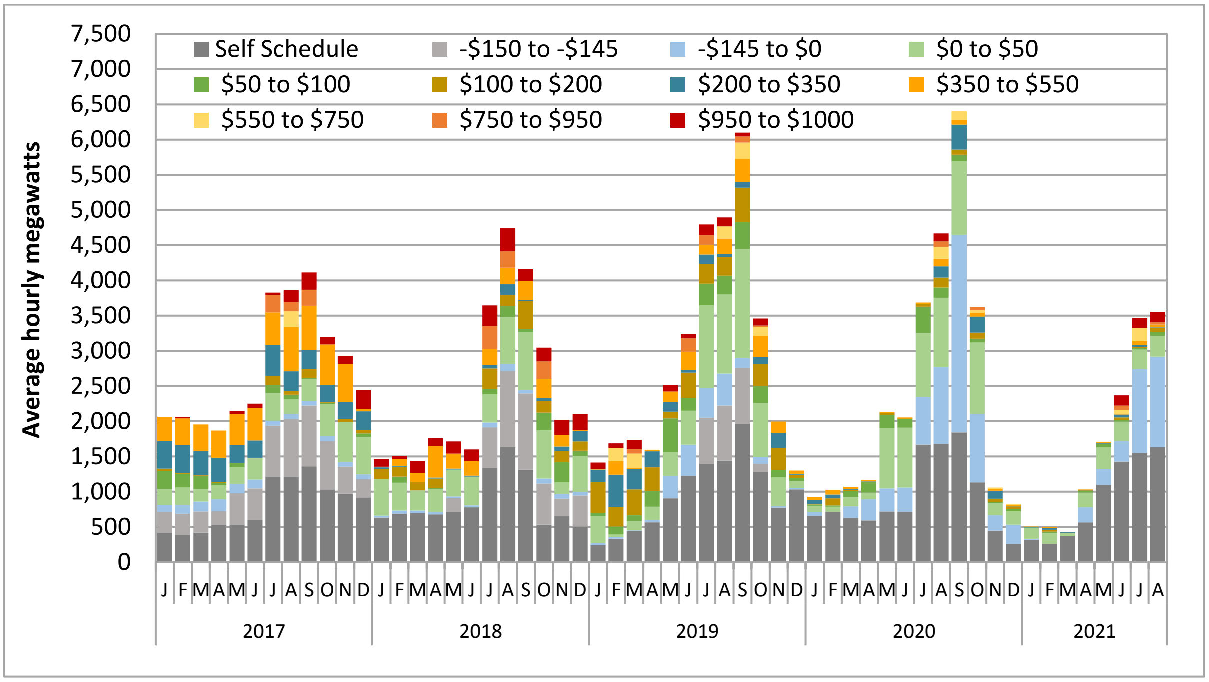



Figure 1.17 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[19] The grey bars reflect import capacity that was self-scheduled or bid near the price floor, while the remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market. The dramatic decline in the quantity of all types of resource adequacy bids that occurred in the first quarter of 2021 appears to have reversed in the second and third quarters.

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

**Figure 1.17 Average hourly resource adequacy imports by price bin**




## 1.3 Structural measures of competitiveness

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

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

- **Residual supply index.** The residual supply index is the ratio of supply from non-pivotal suppliers to demand.[20] A residual supply index less than 1.0 indicates an uncompetitive level of supply.

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

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

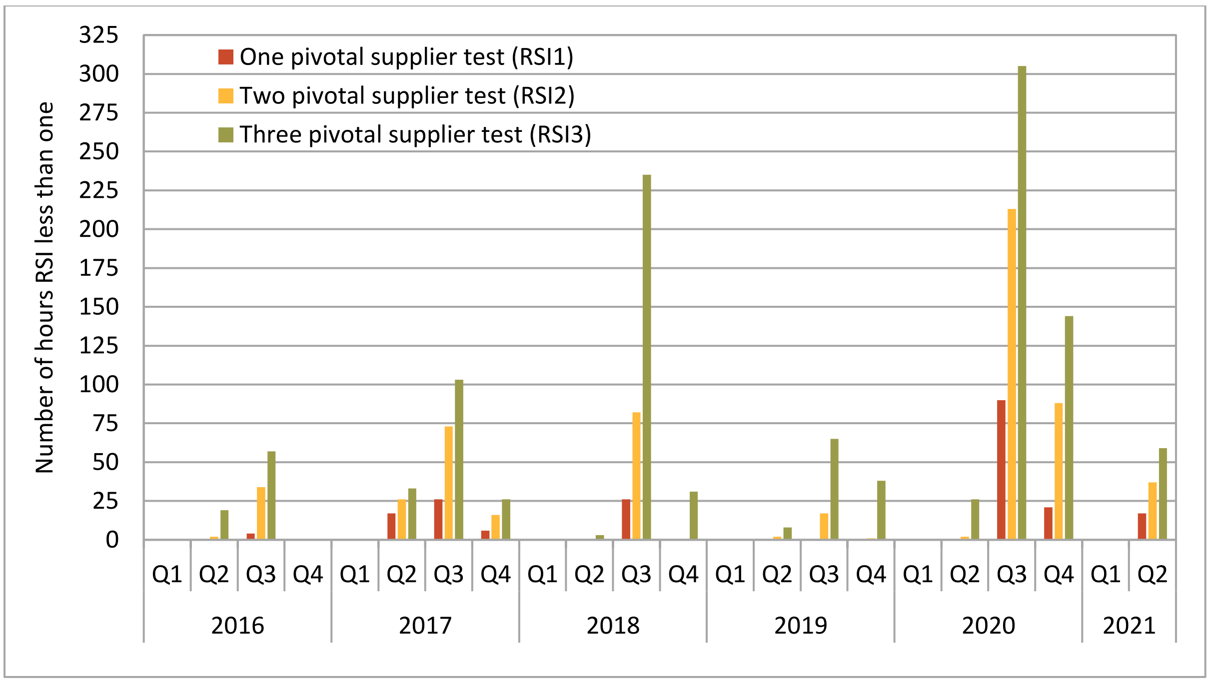
In this report, when the residual supply index is calculated by excluding the largest supplier, we refer to this measure as $RSI_1$. With the two or three largest suppliers excluded, we refer to these results as $RSI_2$ and $RSI_3$, respectively.[21]

Figure 1.18 shows the quarterly number of hours with a residual supply index less than one since 2016. During the second quarter, the number of hours with an RSI less than one was higher relative to the same quarter of the previous year. The residual supply index with the three largest suppliers removed ($RSI_3$) was less than one during 59 hours. These occurred exclusively in June.

With the largest two suppliers removed ($RSI_2$), the residual supply index for the second quarter was less than one in 37 hours. With the largest supplier removed ($RSI_1$), it was less than one in 17 hours.

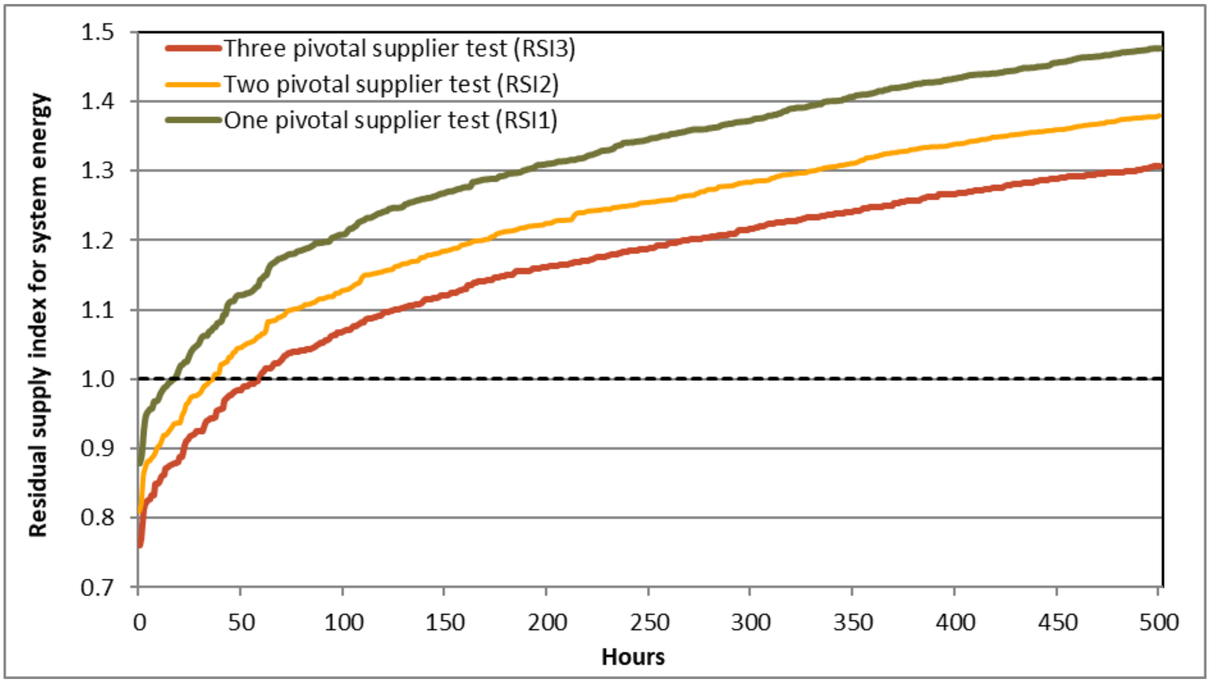
Figure 1.19 illustrates the level of the residual supply index measurements by showing the lowest 500 RSI values during the quarter. With the three largest suppliers removed, the $RSI_3$ was less than 0.9 in 22 hours, and less than 0.8 in 2 hours.

**Figure 1.18 Hours with residual supply index less than one**




21 For more information on the supply and demand elements used to calculate the residual supply index, see the *Q4 2020 Report on Market Issues and Performance,* April 2021, pp. 111: [Q4 2020 (caiso.com)]

**Figure 1.19 Lowest 500 residual supply index with largest one, two, or three suppliers excluded (April – June)**




## 1.4 Price variability

Day-ahead market prices range greatly over the course of a year, with periods of high and low prices. These variations tend to follow seasonal patterns, primarily due to the availability of variable energy resources such as wind and solar. Real-time market prices can be volatile with periods of extreme positive or negative prices; even a short period of extremely high or low prices can significantly impact average prices.

One of the fundamental differences between the day-ahead market and the real-time market is the participants who may place a bid. Bids in the day-ahead market are from ISO market participants, while the real-time market includes bids from both ISO and EIM participants.[22] Due in part to this difference, the magnitude of the variation tends to be higher in the real-time market.

### 1.4.1 Day-ahead price variability

In the second quarter of 2021, the frequency of high day-ahead market prices was similar to the second quarter last year, with the exception of June when almost 6 percent of hours had day-ahead prices over $100/MWh compared to 0.2 percent in June of 2020. On the other hand the frequency of low day-ahead prices decreased compared to the same quarter last year.

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

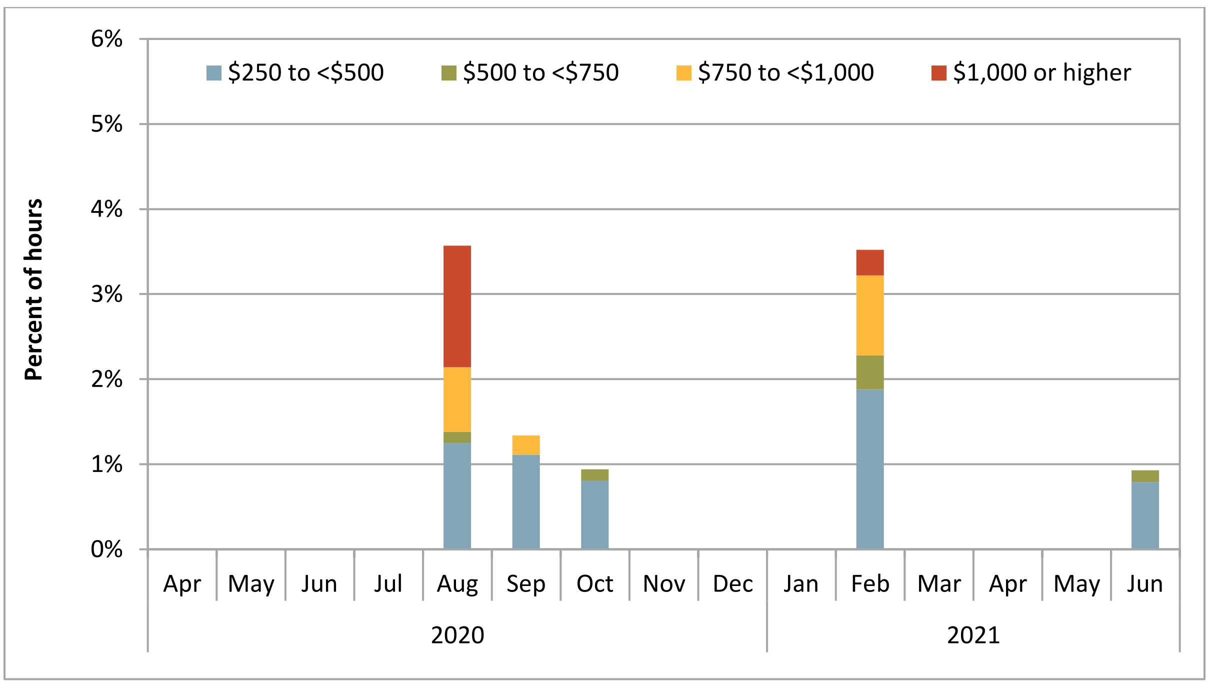
### High prices

Figure 1.20 shows the frequency of day-ahead market prices in various high priced ranges from April 2020 to June 2021. The frequency of hours with prices over $250/MWh increased compared to the second quarter last year, driven by extreme heat events in June where tight conditions led to high prices. As of March 20, 2021, resources are able to bid over the soft bid cap of $1,000/MWh under different circumstances after the implementation of FERC Order 831 tariff provisions; however, there were no day ahead prices over $1,000/MWh during the second quarter.[23]

### Negative prices

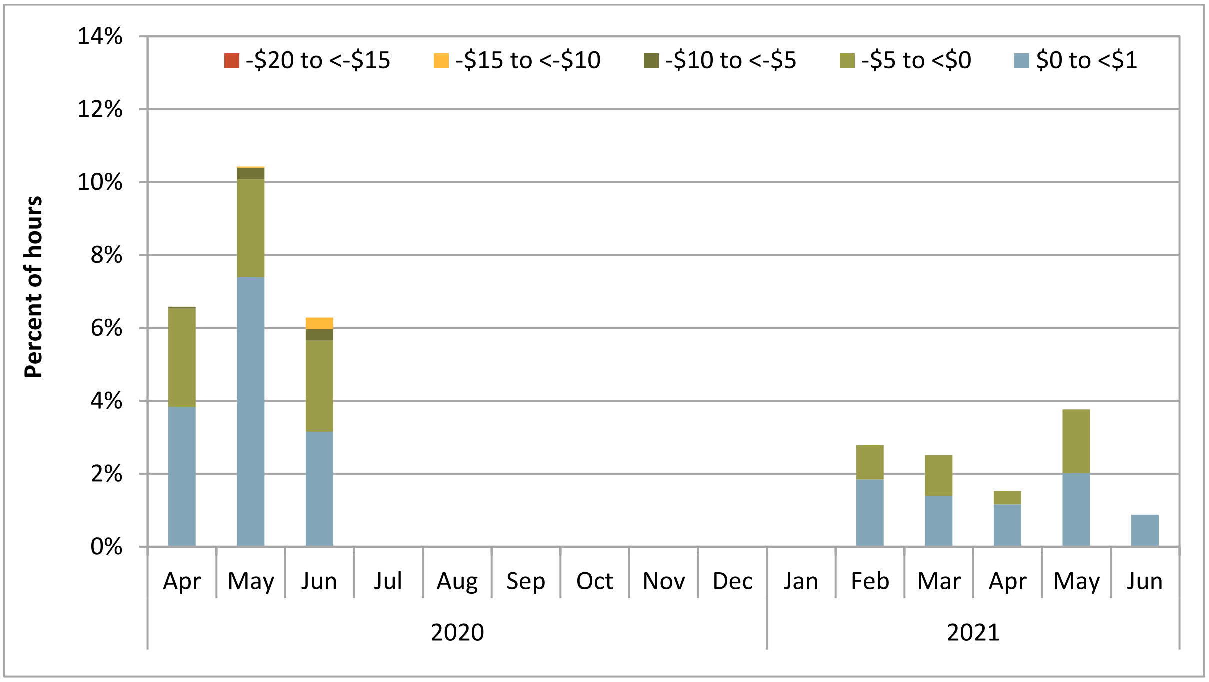
Figure 1.21 shows the frequency of day-ahead market prices in various low priced ranges from April 2020 to June 2021. Prices in the day-ahead market were below $1/MWh in about 2 percent of hours in the second quarter of 2021 compared to 8 percent in the same quarter last year.

**Figure 1.20 Frequency of high day-ahead prices ($/MWh) by month**




[23] More information about the change to bidding rules from FERC Order 831 Phases 1 and 2 is provided in Section 3.1 of this report and Section 3.2 of the 2020 Q1 report.

**Figure 1.21 Frequency of negative day-ahead prices ($/MWh) by month**




## 1.4.2 Real-time price variability

During the second quarter of 2021, there was less variability in real-time market prices. The frequency of both high and low prices was lower this year than in the second quarter of 2020.

### High prices

Figure 1.22 and Figure 1.23 show the frequency of prices above $250/MWh across the three largest load aggregation points (LAP) in the ISO. As shown in Figure 1.22, the frequency of prices over $250/MWh in the 15-minute market was slightly lower in this quarter compared to the same quarter last year. This trend was more pronounced in the 5-minute market. Figure 1.23 shows the frequency of high prices in the 5-minute market where the frequency of prices over $250/MWh decreased from 0.62 percent in the second quarter of 2020 to 0.15 percent in 2021.

Figure 1.24 and Figure 1.25 show the corresponding frequency of under-supply infeasibilities in the 15-minute and 5-minute markets. Valid under-supply infeasibilities were very infrequent in both the 15-minute and 5-minute markets.

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

**Figure 1.22 Frequency of high 15-minute prices by month (ISO LAP areas)**

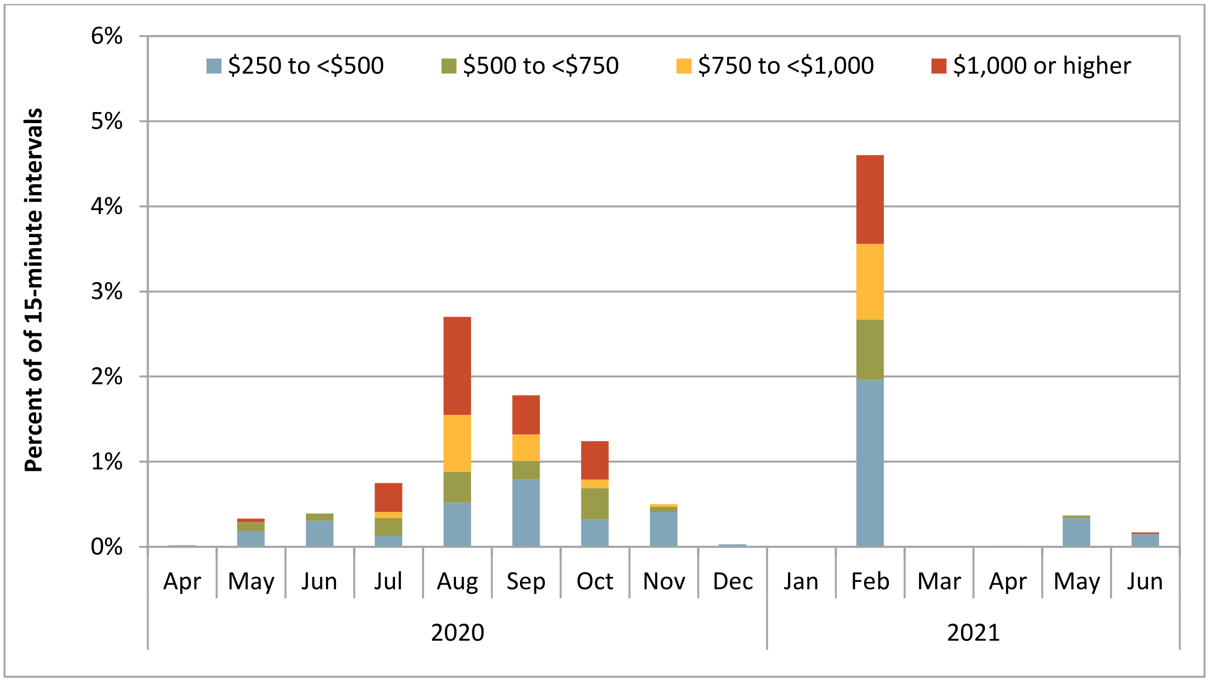



**Figure 1.23 Frequency of high 5-minute prices by month (ISO LAP areas)**

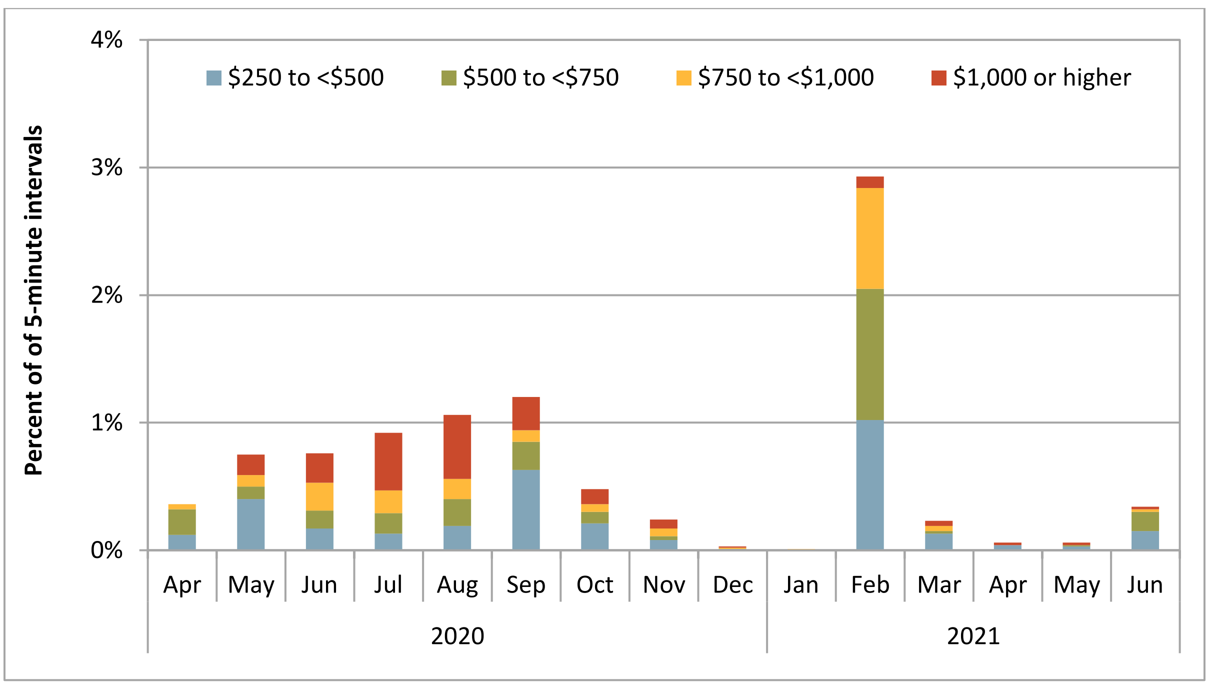


**Figure 1.24 Frequency of under-supply power balance constraint infeasibilities (15-minute market)**

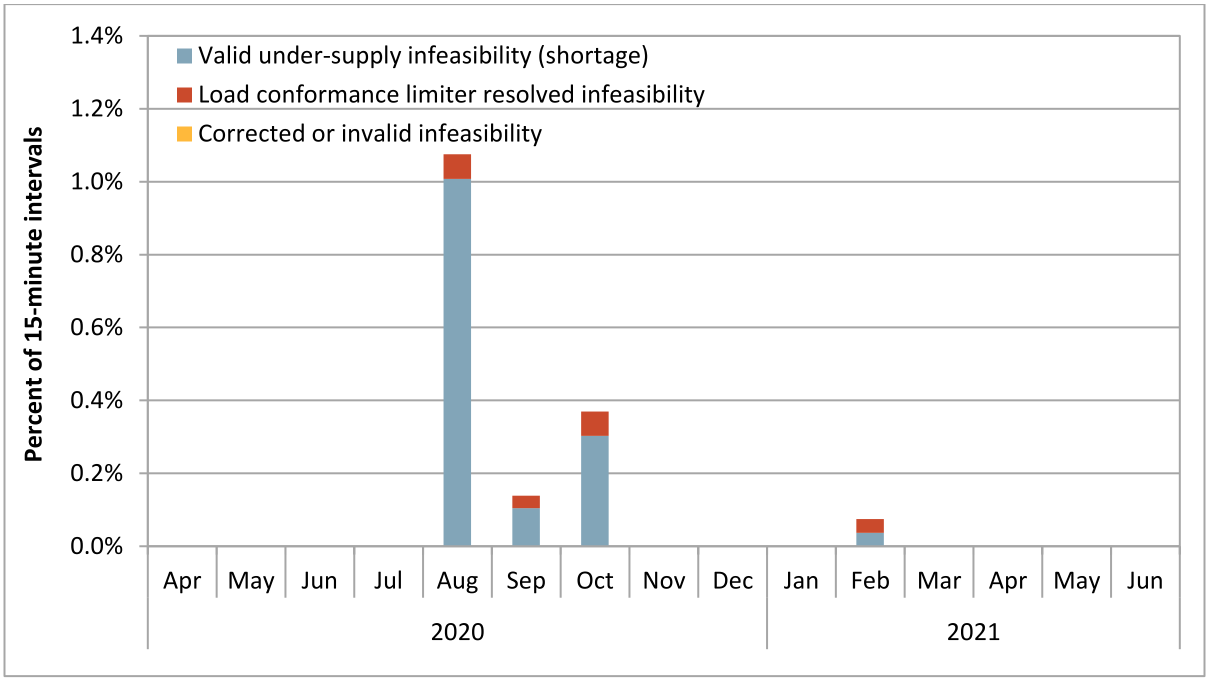
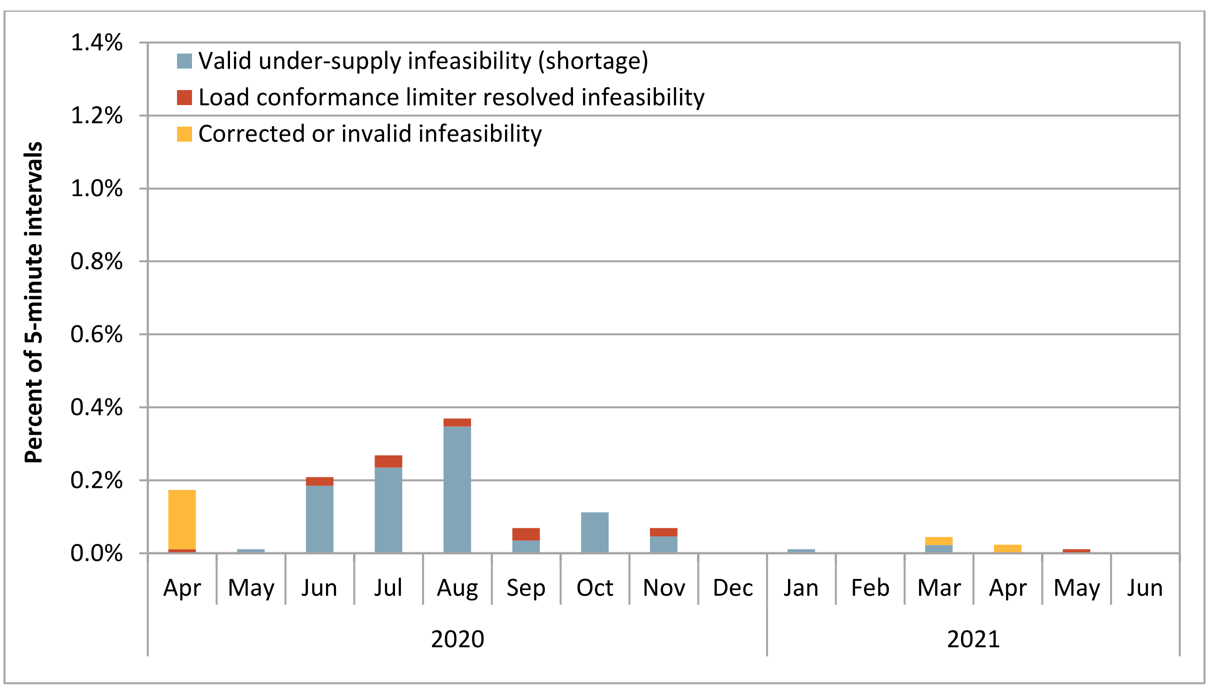



**Figure 1.25 Frequency of under-supply power balance constraint infeasibilities (5-minute market)**

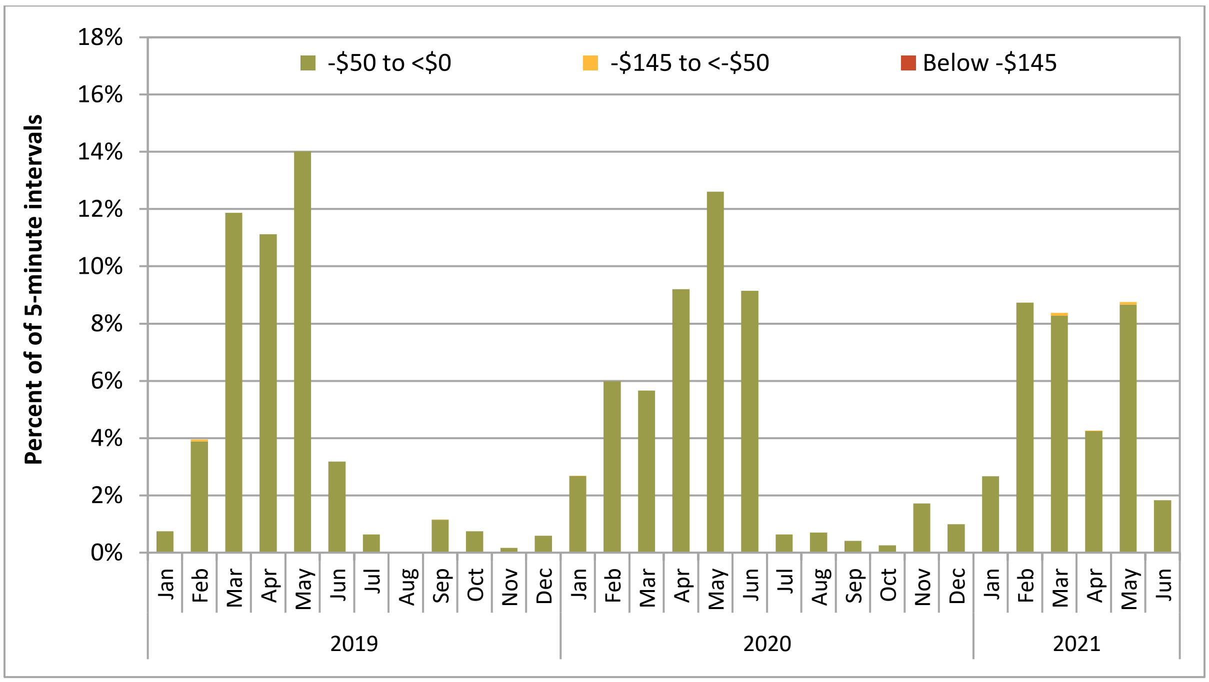


### Negative prices

Figure 1.26 shows the frequency of negative prices in the 5-minute market by month across the three largest load aggregation points in the ISO.[24] The frequency of negative prices in the 15-minute and 5-minute markets was a bit higher in this quarter than the second quarter last year. Negative prices occurred during 3.5 percent of 15-minute market intervals and 5 percent of 5-minute market intervals.

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

**Figure 1.26 Frequency of negative 5-minute prices by month (ISO LAP areas)**




## 1.5 Flexible ramping product

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

The flexible ramping product procures both upward and downward flexible capacity in both the 15-minute and 5-minute markets. Procurement in the 15-minute market is intended to ensure that 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

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

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

### 1.5.1 Minimum flexible ramping product requirement

There is separate demand curves calculated for each energy imbalance market area in addition to a system-level demand curve. The system-level demand curve for the entire footprint is always enforced in the market, while the uncertainty requirement for the individual balancing areas is reduced in every interval by their transfer capability.[25] Previously, if the transfer capability for each area was sufficient, then only the system-level uncertainty requirement was active.

The flexible ramping product refinements stakeholder initiative introduced a new minimum flexible ramping product requirement. Effective early November 2020, if an individual balancing authority area requirement is greater than 60 percent of the system requirement, then a minimum will be enforced, equal to the balancing authority area's share of the diversity benefit.[26] 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 spring 2022.

A minimum requirement helps procure flexible ramping capacity within areas that contribute to a large portion of system-wide uncertainty. Figure 1.27 shows the frequency in which a minimum requirement was active for the ISO in the 15-minute market since the implementation of the minimum requirement in early November. During the second quarter, the ISO had a minimum upward requirement enforced in around 92 percent of intervals, and a minimum downward requirement enforced in around 83 percent of intervals.

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

Figure 1.28 shows the frequency in which a minimum requirement was enforced for all other energy imbalance market areas.[27] Non-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

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[25] 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.

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

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

that area. In particular, PacifiCorp East had a minimum downward flexible ramping requirement in approximately 10 percent of intervals during the second quarter.

**Figure 1.27 California ISO frequency of enforced minimum requirement (15-minute market)**

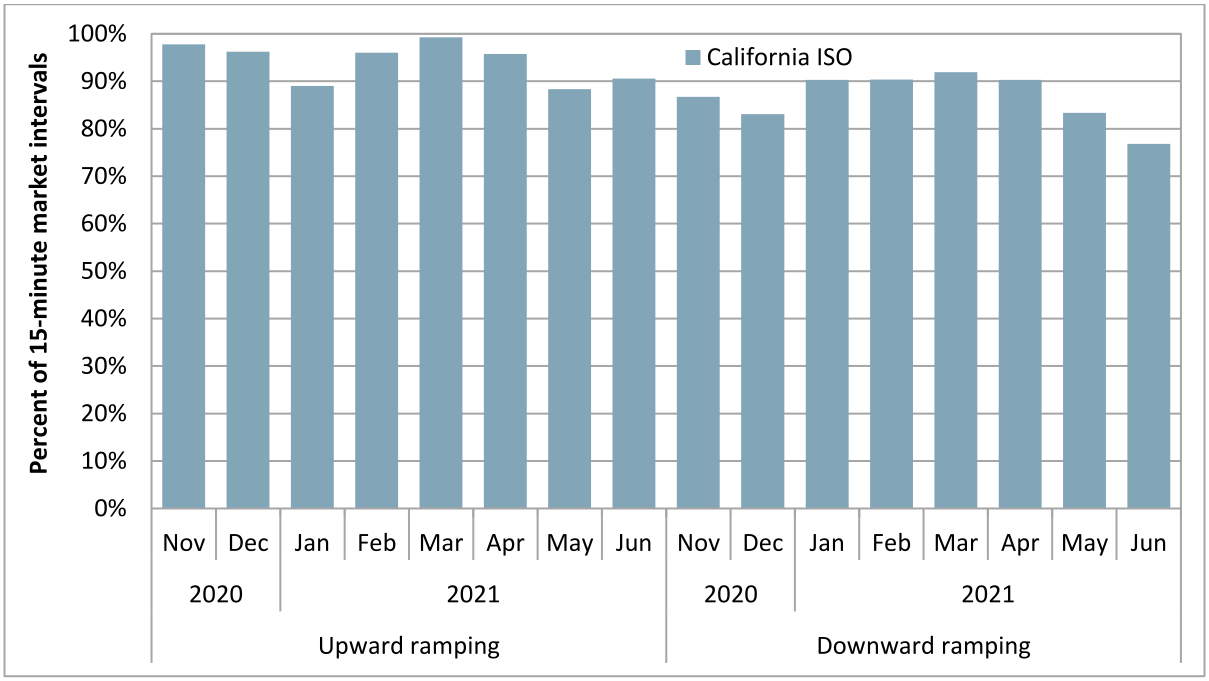
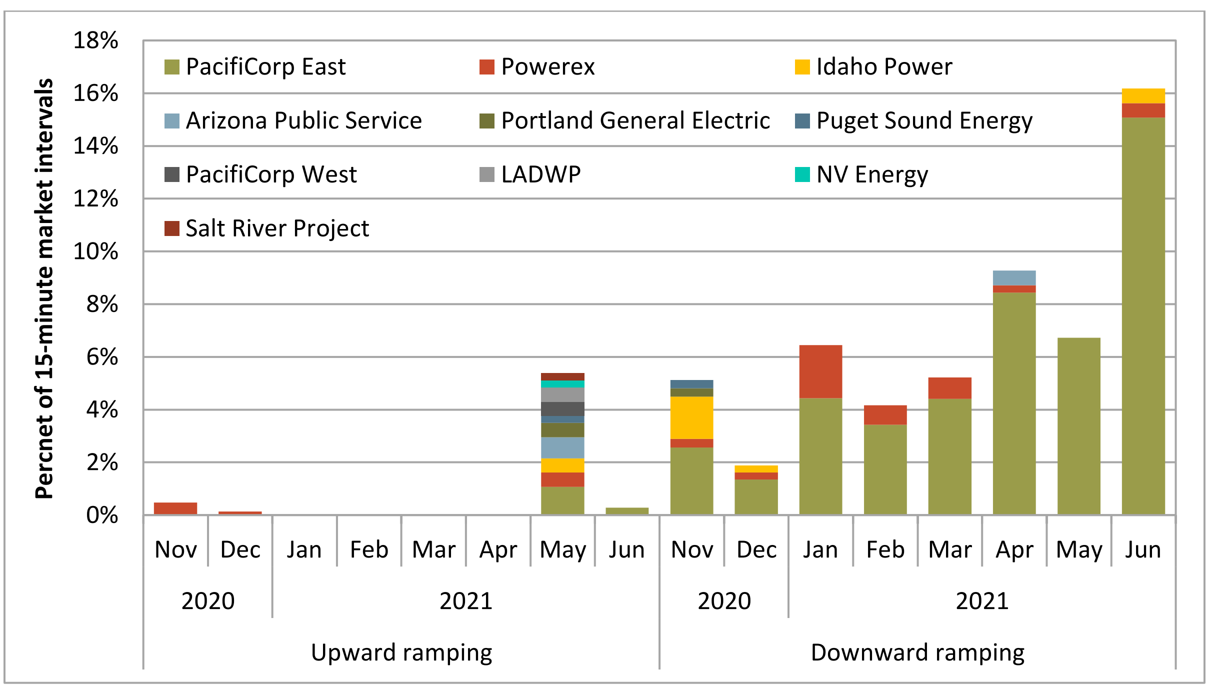



**Figure 1.28 Energy imbalance market frequency of enforced minimum requirement (15-minute market)**



### 1.5.2 Flexible ramping product prices

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

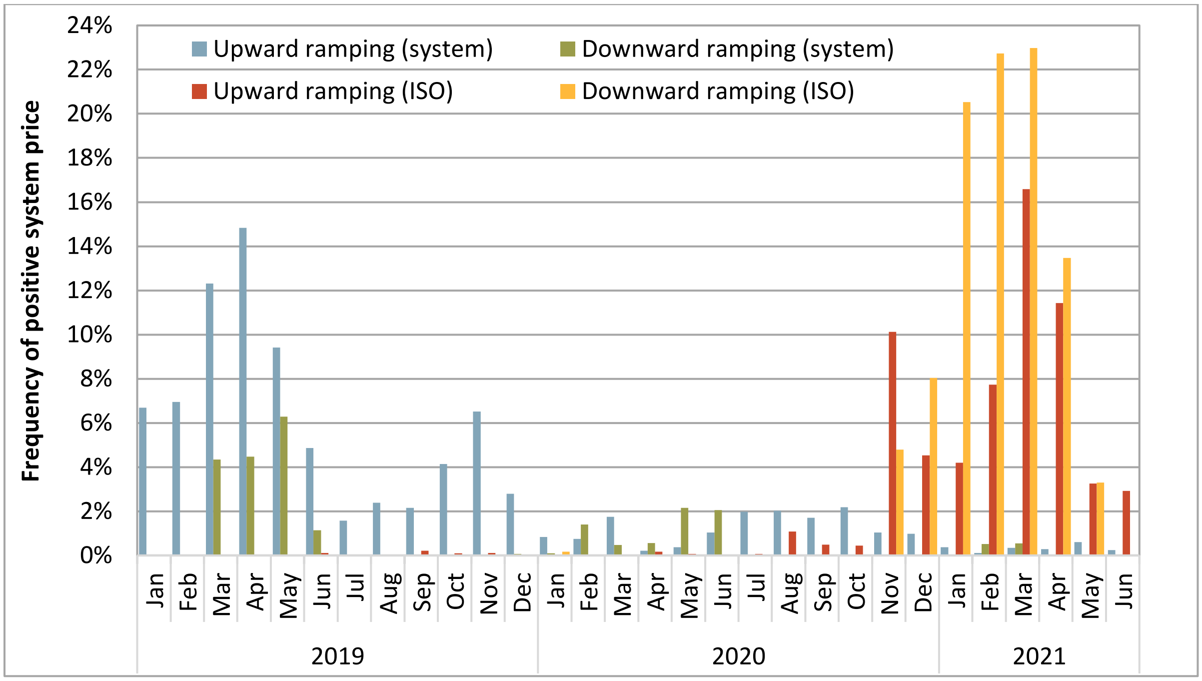
Figure 1.29 shows the percent of intervals that the system-level flexible ramping demand curve bound and had a positive shadow price in the 15-minute market. Given the high frequency of the minimum requirement for the ISO, the percent of intervals in which the ISO demand curve bound at a positive shadow price is also shown.

The frequency of positive shadow prices for the *system* continued to be low overall. During the quarter, the 15-minute market system-level demand curve bound in less than 1 percent of intervals for upward ramping and downward ramping.

At the start of the quarter, the *ISO-specific* demand curve continued to bind frequently because of the minimum requirement. During April, there was a positive shadow price for downward ISO flexible ramping capacity during 13 percent of intervals and for upward ISO flexible ramping capacity during 10 percent of intervals. Following a review by the ISO on intermittent resources and flexible ramping product eligibility, the 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 ISO-specific demand curves for upward and downward ramping capacity bound in less than 0.1 percent of intervals.

**Figure 1.29 Monthly frequency of positive system or ISO flexible ramping shadow price (15-minute market)**




## 1.6 Convergence bidding

Convergence bidding was profitable overall for this quarter in 2021. Combined net revenue for virtual supply and demand was about $7 million, after including about $3.6 million of virtual bidding bid cost recovery charges. Virtual demand generated negative revenues of about $7.6 million for the quarter, while virtual supply generated about $18.1 million, before accounting for bid cost recovery charges.

### 1.6.1 Convergence bidding trends

Average hourly cleared volumes were about 4,500 MW, an increase of about 600 MW from the same quarter of 2020. Average hourly cleared virtual supply increased about 400 MW to about 2,500 MW, from about 2,100 MW in the first quarter of 2021. Cleared virtual demand averaged 180 MW higher than from the same quarter of the previous year at about 2,000 MW during each hour of the quarter, which was also about 700 MW more than the first quarter of 2021. On average, about 45 percent of virtual supply and demand bids offered into the market cleared in the quarter, up from 36 percent from the same quarter of the previous year.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 530 MW on average, an increase from 350 MW of net virtual supply in the same quarter of the previous year. On average, in all hours except hours ending 15 to 21, net cleared virtual supply exceeded net cleared virtual demand. Cleared virtual supply exceeded virtual demand by over 1,000 MW during hours ending 23 and 24 as well as hours ending 1 through 8.

Convergence bidding is designed to align day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between the two markets.

For the quarter, convergence bidding volumes were consistent with average price differences between the day-ahead and real-time markets during 16 of 24 hours.

#### Offsetting virtual supply and demand bids

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

Offsetting virtual positions accounted for an average of 1,300 MW of virtual demand, offset by 1,300 MW of virtual supply, in each hour of the quarter. This represented an increase of about 300 MW over the same quarter from the previous year. These offsetting bids represented about 58 percent of all cleared virtual bids in this quarter, an increase of about 7 percent from the same quarter of the previous year.

### 1.6.2 Convergence bidding revenues

Participants engaged in convergence bidding in this quarter were overall profitable. Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $10.5 million. Net revenues for virtual supply and demand fell to about $7 million after the inclusion of about $3.6 million of virtual bidding bid cost recovery charges,[28] primarily associated with virtual supply.

Figure 1.30 shows total monthly net revenues for virtual supply (green bars), total net revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line).

Before accounting for bid cost recovery charges:

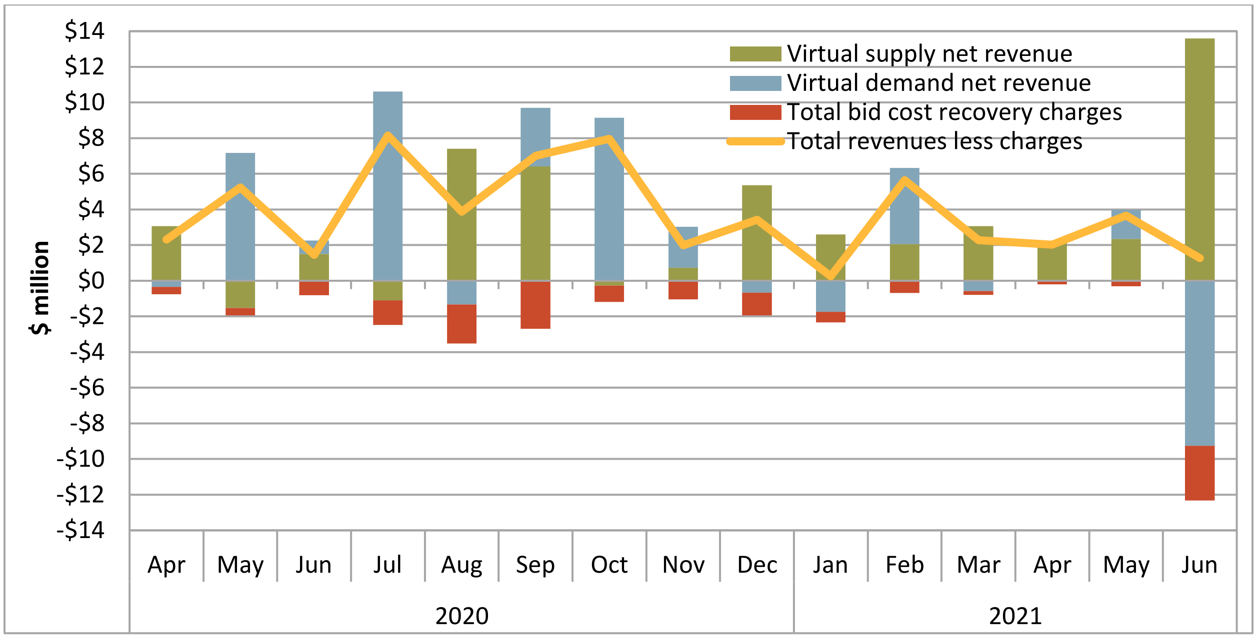
- Total market revenues were positive during all months of the quarter. Net revenues during the quarter totaled about $10.5 million, compared to about $10.6 million during the same quarter from the previous year, and about $9.7 million during the previous quarter.
- Virtual demand net revenues were about $10 thousand, $1.6 million, and negative $9.3 million for April, May, and June, respectively.
- Virtual supply net revenues were $2.1 million, $2.4 million, and $13.6 million for April, May, and June, respectively.

[28] 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.

Convergence bidders received approximately $7 million after subtracting bid cost recovery charges of about $3.6 million for the quarter.[29] [30] Bid cost recovery charges were about $0.2 million, $0.3 million, and $3.1 million for April, May, and June, respectively.

June is a month of note since day-ahead prices were consistently higher than 15-minute prices, even during the two heat events and during the solar evening ramp down period. This resulted in high positive virtual supply revenues and inversely low negative virtual demand revenues.

**Figure 1.30 Convergence bidding revenues and bid cost recovery charges**




## Net revenues and volumes by participant type

Table 1.1 compares the distribution of convergence bidding cleared volumes and net revenues, in millions of dollars, among different groups of convergence bidding participants in the quarter.[31] As with the previous quarter, financial entities represented the largest segment of the virtual bidding market, accounting for about 78 percent of volume and 91 percent of settlement revenue, an increase from about 70 percent from the same quarter of 2020. Marketers represented about 20 percent of the trading volumes and about 3 percent of settlement revenue, a revenue decrease from about 30 percent

29 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.

30 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.

31 DMM has defined financial entities as participants who do not own physical power and participate in the convergence bidding and congestion revenue rights markets only. Physical generation and load are represented by participants that primarily participate in the ISO markets as physical generators and load serving entities, respectively. Marketers include participants on the interties and participants whose portfolios are not primarily focused on physical or financial participation in the ISO market.

from the same quarter in 2020. Generation owners and load serving entities continued to represent a small segment of the virtual market in terms of both volumes and settlement revenue, at about 2 percent and 6 percent, respectively.

**Table 1.1 Convergence bidding volumes and revenues by participant type**

| Trading entities | Average hourly megawatts | | | Revenues\Losses ($ million) | | |
|---|---|---|---|---|---|---|
| | Virtual demand | Virtual supply | Total | Virtual demand | Virtual supply | Total |
| Financial | 1,536 | 1,938 | 3,474 | -$3.74 | $14.33 | $10.59 |
| Marketer | 423 | 487 | 910 | -$3.61 | $3.21 | -$0.40 |
| Physical load | 0 | 79 | 80 | -$0.04 | $0.55 | $0.51 |
| Physical generation | 14 | 0 | 14 | -$0.17 | $0.00 | -$0.17 |
| **Total** | **1,974** | **2,505** | **4,478** | **-$7.56** | **$18.09** | **$10.54** |

## 1.7 Residual unit commitment

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real time. The residual unit commitment market runs immediately after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of load cleared in the day-ahead market and the day-ahead forecast load.

As illustrated in Figure 1.31, residual unit commitment capacity is procured primarily to replace cleared net virtual supply bids, which can offset physical supply in the day-ahead market run. On average, cleared virtual supply (green bar) was about 50 percent higher in the second quarter of 2021 than in the same quarter of 2020.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar) represents the difference in cleared supply (both physical and virtual) compared to the ISO's load forecast. On average, this factor contributed towards increasing residual unit commitment requirements in the second quarter of 2021 averaging about 17 MWh.

Residual unit commitment procurement can be increased by operator adjustments to the day-ahead load forecast. These manual adjustments increased in the second quarter relative to the same quarter in 2020, especially in June. The operators used this tool on 20 days in June and the adjustment averaged about 498 MW per hour compared to about 368 MW per hour during the same month in 2020.

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; it is represented by the yellow bar in Figure 1.31.

**Figure 1.31 Determinants of residual unit commitment procurement**

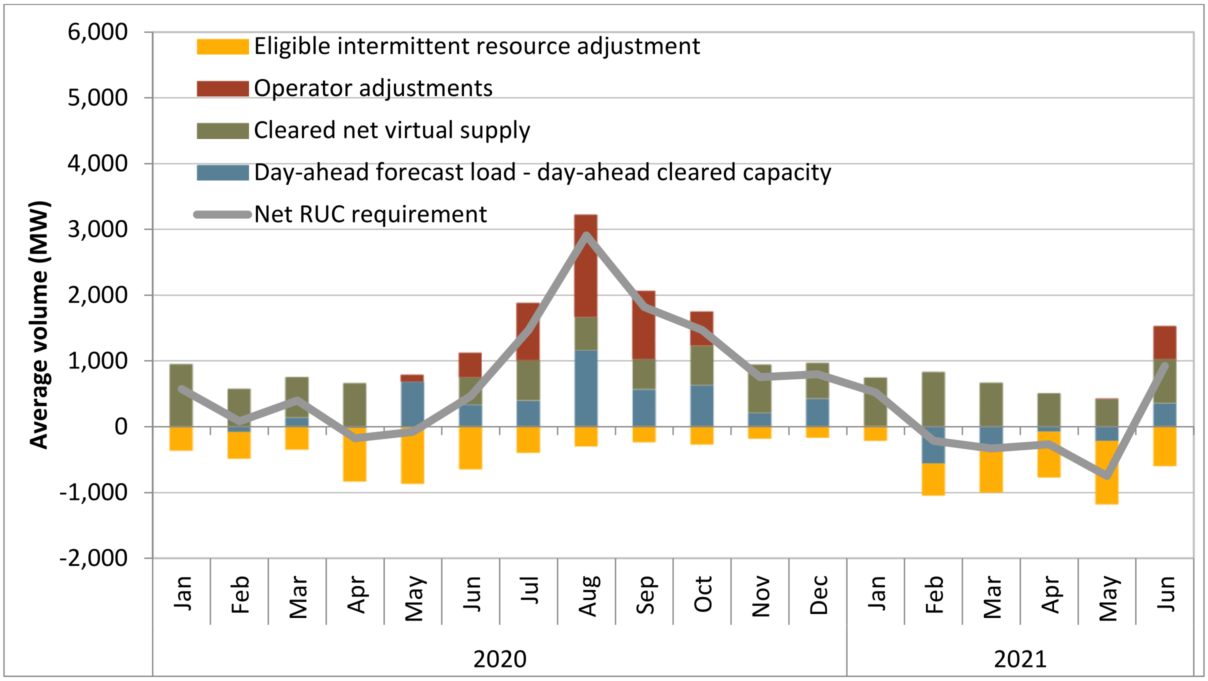



Figure 1.32 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement decreased to about 843 MWh in the second quarter of 2021 from an average of 1,036 MWh in the same quarter of 2020. Of the 843 MWh capacity, the capacity committed to operate at minimum load averaged 192 MWh compared to 207 MWh in the second quarter of 2020.

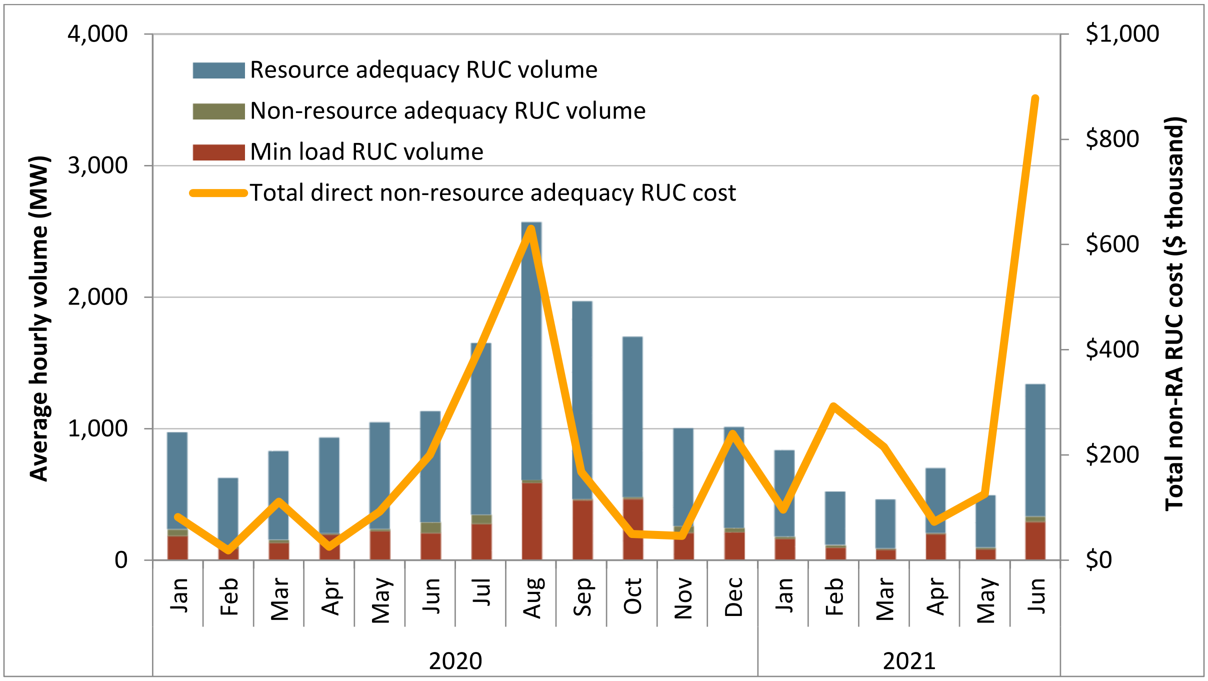
Following the August 2020 heatwave, the ISO implemented several software modifications in the residual unit commitment process designed to reduce exports from being scheduled in the real-time market at high day-ahead penalty prices which could not be supported by available physical supply in the ISO system. This market change went in place effective September 5, 2020.[32] With this change, the residual unit commitment process is able to curtail certain exports before relaxing the power balance constraint. These reduced exports no longer receive a real-time scheduling priority that exceeds real-time ISO load's priority and can choose to re-bid in real-time or resubmit as self-schedules in real-time.[33] During the second quarter of 2021, the residual unit commitment under-supply power balance constraint was infeasible on one day, June 17, during hours 19 through 22. The maximum magnitude of these infeasibilities was about 3,000 MW which occurred in hour ending 20.

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

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

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.[34] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.32. In the second quarter of 2021, these costs increased to $1.1 million compared to about $0.2 million in the same quarter of 2020. About $0.7 million of this cost occurred over seven days in June when the western United States experienced excessive heat. This is the highest single month total since June 2017.

**Figure 1.32 Residual unit commitment costs and volume**




## 1.8 Ancillary services

Ancillary service payments decreased during the quarter to about $38 million, compared to about $44 million in the previous quarter and $24 million during the same quarter in 2020. Higher payments compared to the previous year were driven, in part, by higher requirements for regulation.

### 1.8.1 Ancillary service requirements

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

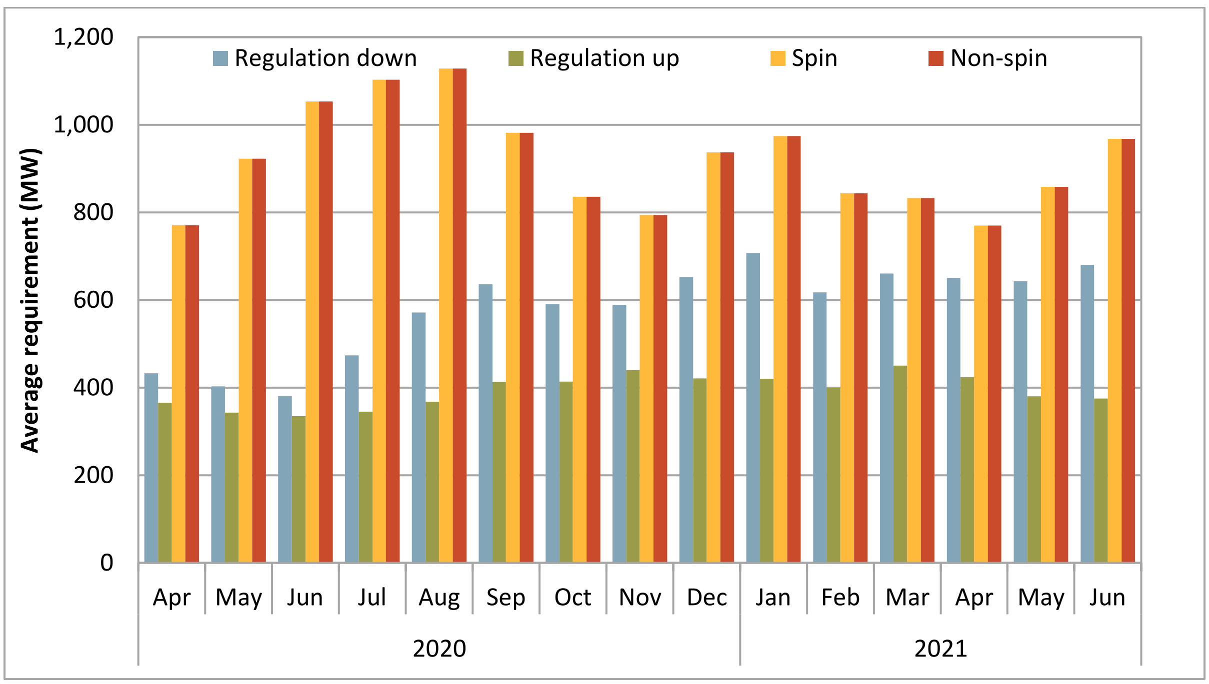
[34] If committed, resource adequacy units may receive bid cost recovery payments in addition to resource adequacy payments.

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

Operating reserve requirements in the day-ahead market are typically set by the maximum of (1) 6.3 percent of the load forecast, (2) the most severe single contingency, and (3) 15 percent of forecasted solar production. Operating reserve requirements in real-time are calculated similarly except using 3 percent of the load forecast and 3 percent of generation instead of 6.3 percent of the load forecast.

Figure 1.33 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. As shown, average requirements for regulation down increased substantially in this quarter compared to the same quarter last year.

**Figure 1.33 Average monthly day-ahead ancillary service requirements**

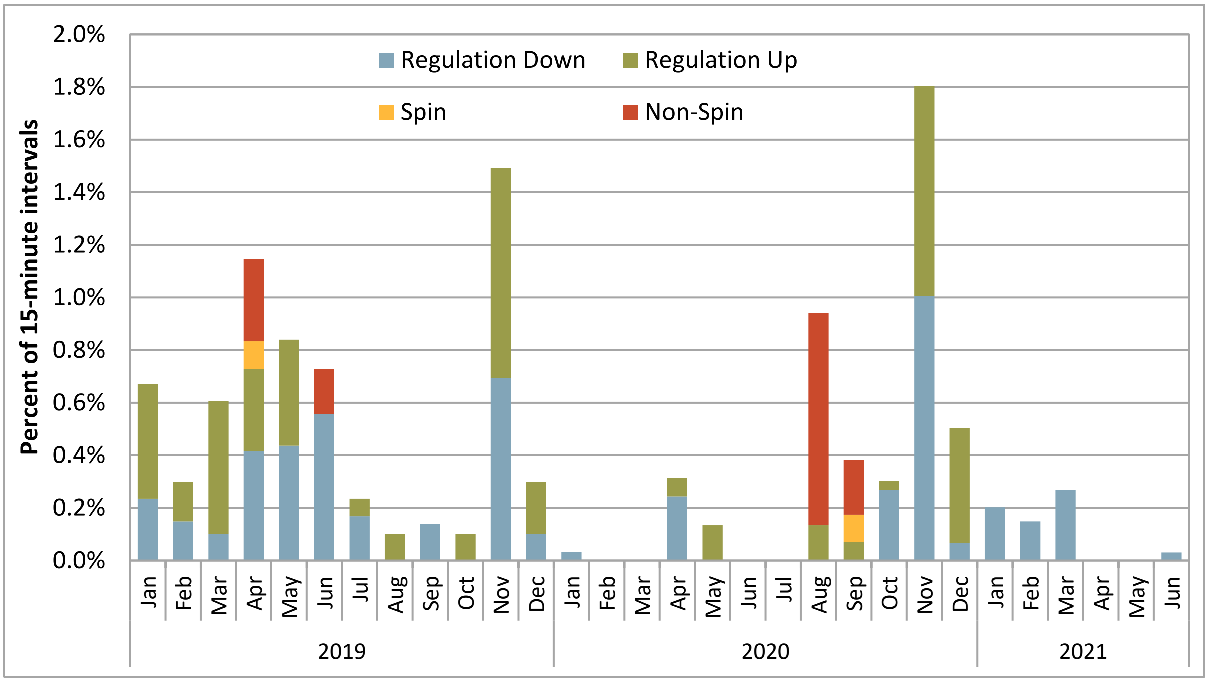



## 1.8.2 Ancillary service scarcity

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

As shown in Figure 1.34, the frequency of intervals with scarcity pricing decreased during the quarter. During the quarter, there was only one scarcity interval and it was for regulation down. During June the single scarcity interval was for a 14.96 MW shortage of regulation down in the expanded North of Path 26 region.

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

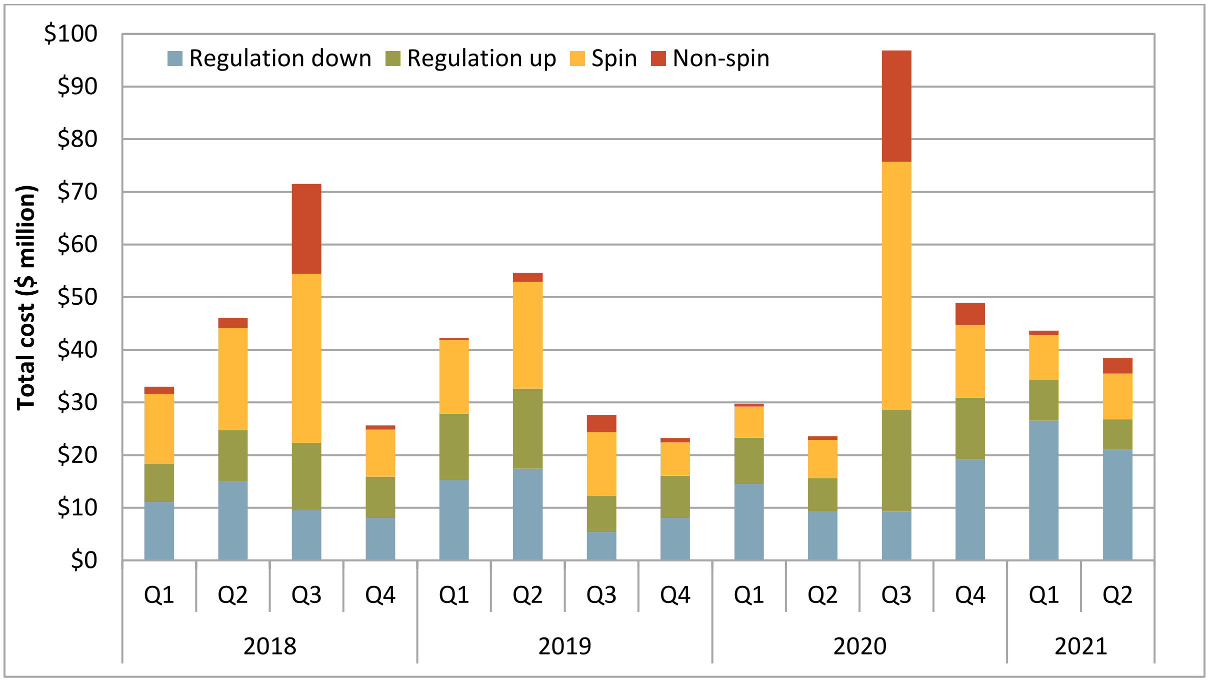



## 1.8.3 Ancillary service costs

Ancillary service payments decreased slightly during the quarter to about $38 million, compared to about $44 million in the previous quarter and $24 million during the same quarter in 2020. Higher payments compared to the previous year were driven in part from higher regulation requirements.

Figure 1.35 shows the total cost of procuring ancillary service products by quarter. The costs reported in this figure account for rescinded ancillary service payments. Payments are rescinded when resources providing ancillary services do not fulfill the availability requirements associated with the awards. As elsewhere in the report, settlements values are based on statements available at the time of drafting and will be updated in future reports.

**Figure 1.35 Ancillary service cost by product**




## 1.9 Congestion

In the day-ahead market, congestion in the second quarter increased prices in the Pacific Gas &Electric area and decreased prices in the Southern California Edison and San Diego Gas & Electric areas. In the 15-minute market, the impact of internal congestion on prices increased in most areas 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 ISO (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) as well as on EIM entities.

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

The impact of congestion on each pricing node in the ISO system is calculated as the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes as well as for groups of nodes that represent different load aggregation points or local capacity areas.[35]

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

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

### 1.9.1 Congestion in the day-ahead market

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

#### Congestion rent and loss surplus

In the second quarter of 2021, congestion rent and loss surplus was $98 million and $44 million, respectively. These respective amounts represent a 10 percent and 95 percent increase relative to the same quarter of 2020.[36] Figure 1.36 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.[37]

36 Due to the availability of data, Figure 1.36 and the comparative analysis of day-ahead congestion rent and loss surplus in the second quarter of 2021 are preliminary.

37 For more information on marginal loss surplus allocation refer to ISO's business practice manual for Settlements and Billing, CG CC6947 IFM Marginal Losses Surplus Credit Allocation: https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

**Figure 1.36 Day-ahead congestion rent and loss surplus by quarter (2020-2021)**

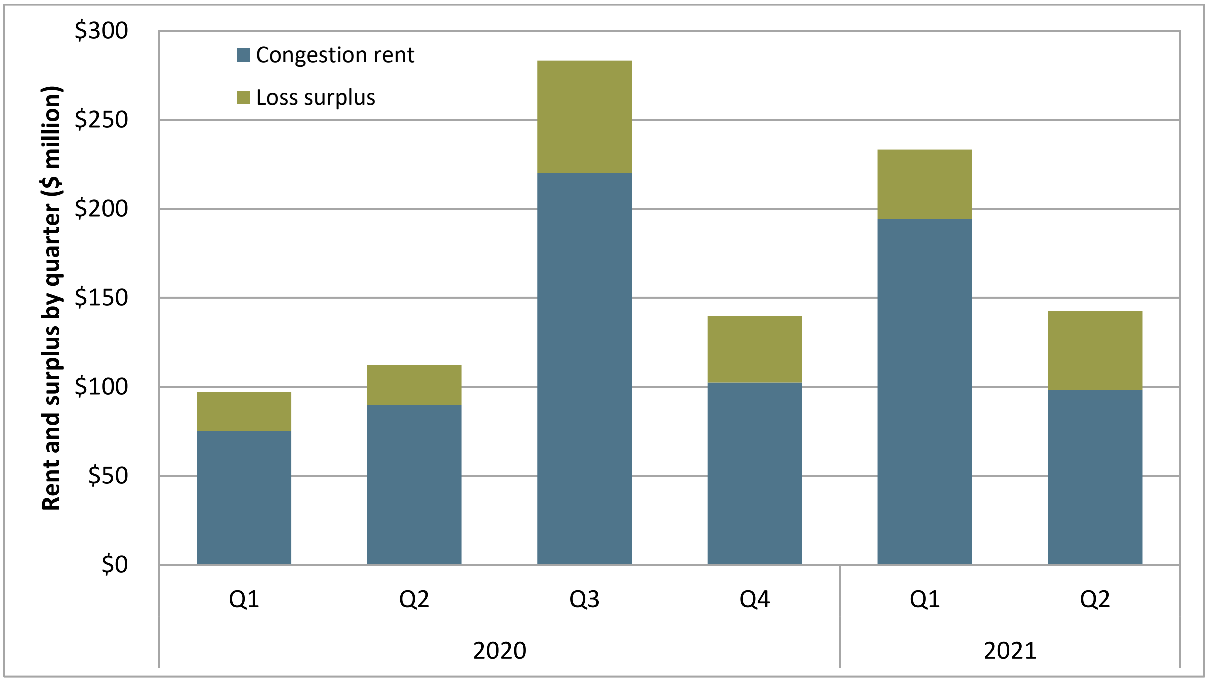



Figure 1.37 shows the overall impact of congestion on day-ahead prices in each load area in 2020 and 2021. Figure 1.38 shows the frequency of congestion. Highlights for this quarter include:

- In the second quarter of 2021, the overall net impact of congestion on price separation increased in PG&E, SCE, and SDG&E relative to the same quarter of 2020. The frequency of congestion decreased slightly in all three areas compared to the same quarter in 2020.
- Congestion increased quarterly average prices in PG&E by $1.78/MWh (4.2 percent), while it decreased prices in SCE and SDG&E by $1.38/MWh (3.7 percent) and $0.09/MWh (0.2 percent), respectively.
- The congestion impact was less frequently offsetting in PG&E and SCE compared to the same quarter of 2020. For the quarter, PG&E experienced positive congestion more frequently, while SCE and SDG&E experienced negative congestion more frequently.
- The primary constraints impacting day-ahead market prices were the Los Banos-Gates 500 kV line, the Moss Landing-Las Aguilas 230 kV line, and the Gates-Midway 230 kV line.

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

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

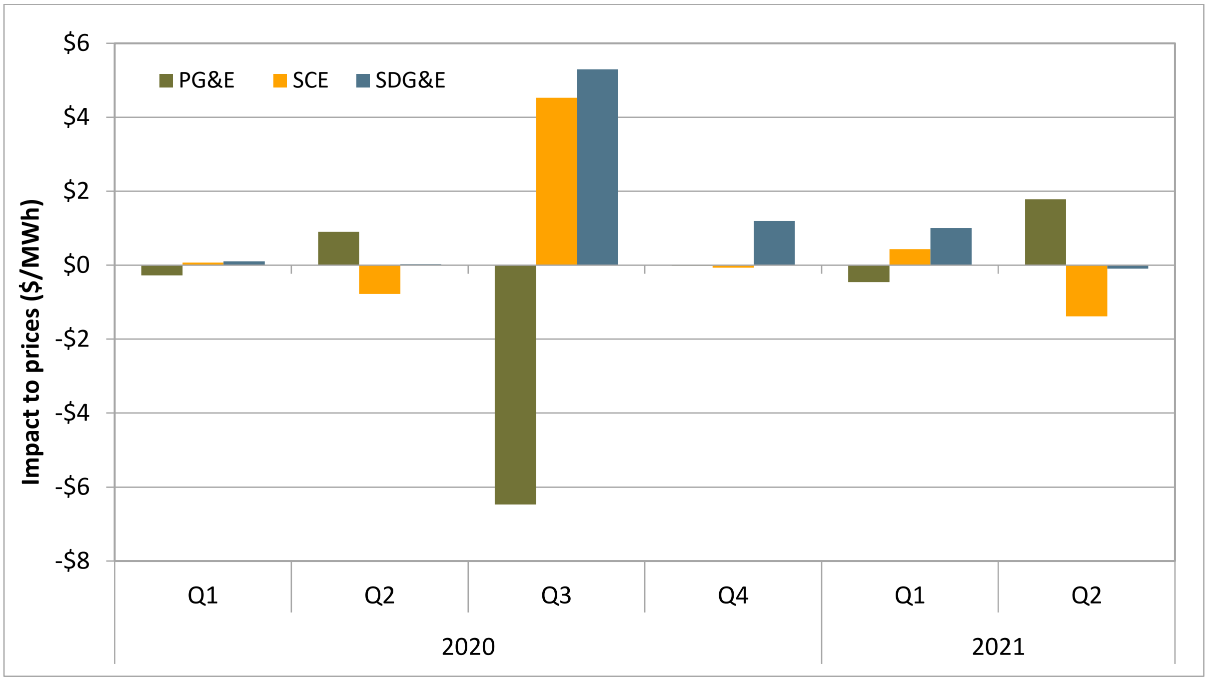



**Figure 1.38 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)**

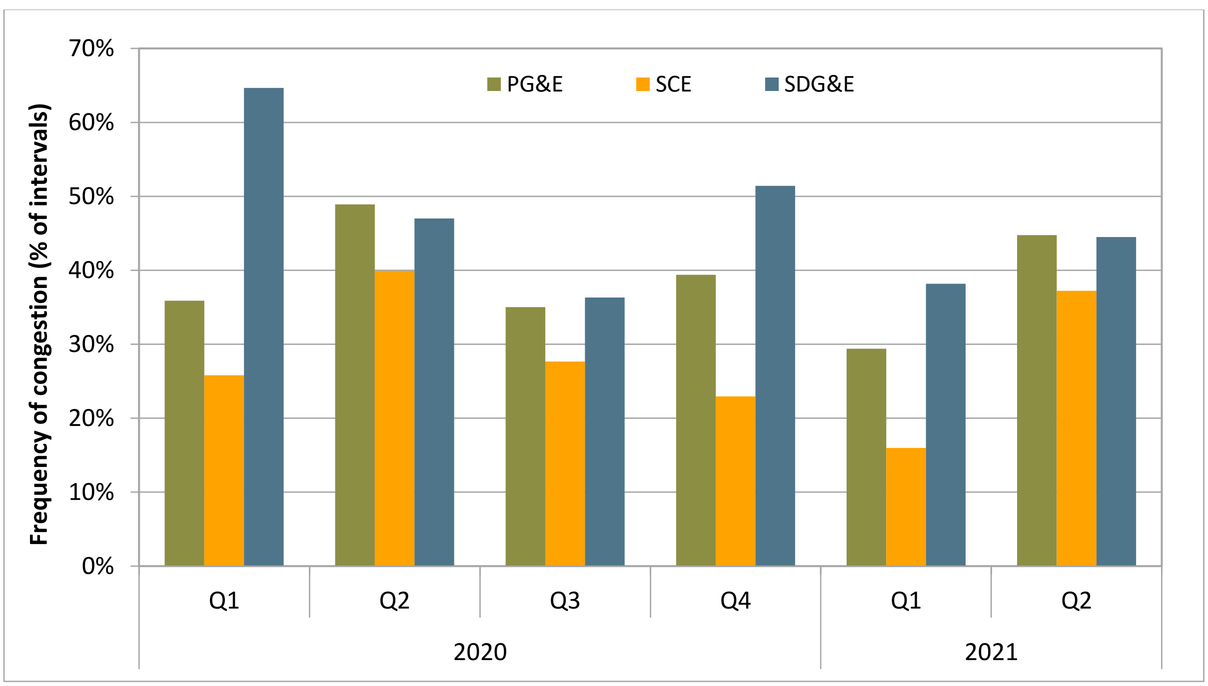
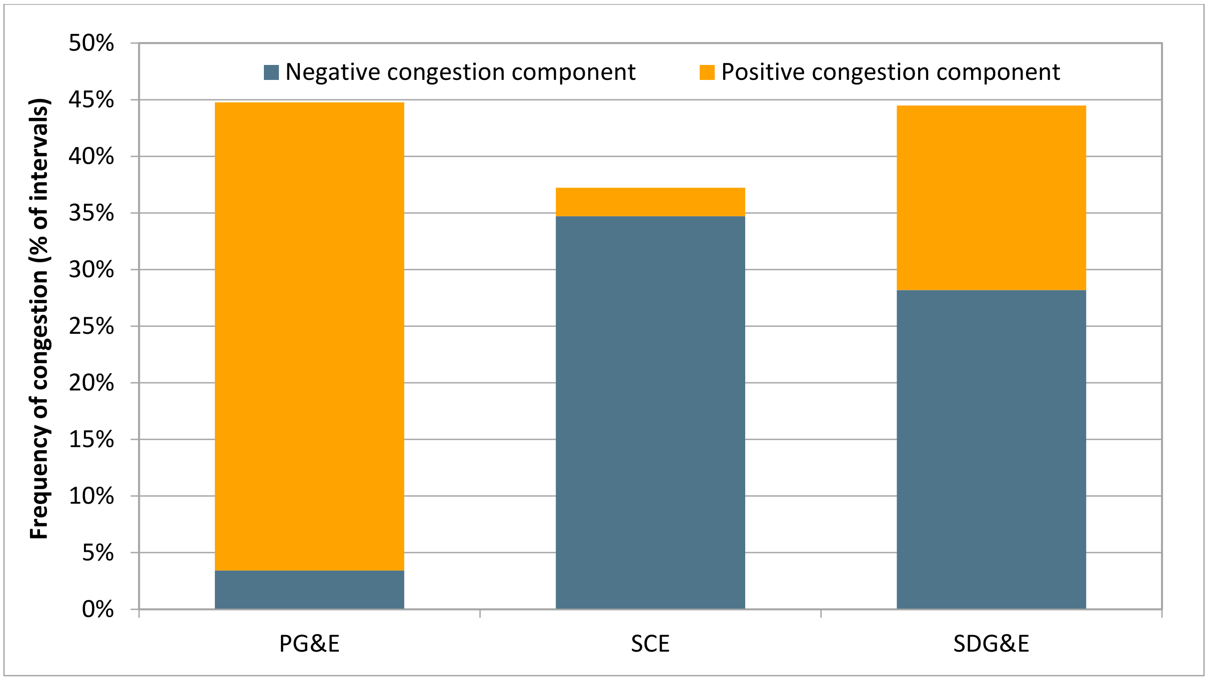


**Figure 1.39 Percent of hours with congestion increasing versus decreasing day-ahead prices in the second quarter (>$0.05/MWh)**




### Impact of congestion from individual constraints

Table 1.2 breaks down the congestion impact on price separation in the second quarter by constraint.[38] Table 1.3 shows the impact of congestion from each constraint only during congested intervals, where the number of congested intervals is presented separately as frequency. The constraints with the greatest impact on price separation for the quarter were the Los Banos-Gates 500 kV line, the Moss Landing-Las Aguilas 230 kV line, and the Gates-Midway 230 kV line.

**Los Banos-Gates 500 kV line**

The Los Banos-Gates 500 kV line (30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2) had the greatest impact on day-ahead prices during the second quarter. It was not the most frequently binding constraint of the quarter, binding in 4 percent of hours. When binding, it increased PG&E prices by about $7.13/MWh and decreased SCE and SDG&E prices by $5.79/MWh and $5.46/MWh, respectively. On average for the quarter, it increased average PG&E prices by about $0.28/MWh (0.7 percent) and decreased average SCE and SDG&E prices by $0.23/MWh (0.6 percent) and $0.22/MWh (0.6 percent), respectively.

**Moss Landing-Las Aguilas 230 kV line**

The Moss Landing-Las Aguilas 230 kV line (30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1) was the most frequently binding constraint for the quarter, binding during 15 percent of hours. When binding, it raised prices in PG&E by $2.45/MWh and lowered prices in SCE and SDG&E by $3.62/MWh and $4.19/MWh, respectively. Overall for the quarter, congestion on the line increased average PG&E

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

prices by $0.37/MWh (0.9 percent) and decreased average SCE and SDG&E prices by $0.16/MWh (0.4 percent) and $0.13/MWh (0.3 percent), respectively. This line was affected by maintenance on the Moss Landing-Los Banos 500 kV line.

**Gates-Midway 230 kV line**

The Gates-Midway 230 kV line (30900_GATES _230_30970_MIDWAY _230_BR_1 _1) bound during about 6 percent of hours during the quarter. When binding, it increased PG&E prices by about $4.30/MWh, while it decreased prices in SCE and SDG&E by about $3.23/MWh and $2.95/MWh, respectively. Overall for the quarter, it increased average PG&E prices by about $0.25/MWh (0.6 percent) and decreased average prices in SCE and SDG&E by $0.19/MWh (0.5 percent) and $0.17/MWh (0.4 percent), respectively. This line was affected by maintenance on the Gates-Midway 500 kV line.

**Table 1.2 Impact of congestion on overall day-ahead prices**

| Constraint Location | Constraint | PG&E | | SCE | | SDG&E | |
|---|---|---|---|---|---|---|---|
| | | $ per MWh | Percent | $ per MWh | Percent | $ per MWh | Percent |
| PG&E | 30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1 | $0.37 | 0.89% | -$0.16 | -0.42% | -$0.13 | -0.34% |
| | 30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2 | $0.28 | 0.68% | -$0.23 | -0.62% | -$0.22 | -0.56% |
| | 30900_GATES _230_30970_MIDWAY _230_BR_1 _1 | $0.25 | 0.59% | -$0.19 | -0.50% | -$0.17 | -0.44% |
| | 30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1 | $0.19 | 0.46% | -$0.16 | -0.43% | -$0.15 | -0.38% |
| | 30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3 | $0.18 | 0.42% | -$0.14 | -0.37% | -$0.13 | -0.32% |
| | 30790_PANOCHE _230_30900_GATES _230_BR_1 _1 | $0.17 | 0.41% | -$0.14 | -0.37% | -$0.13 | -0.33% |
| | 30790_PANOCHE _230_30900_GATES _230_BR_2 _1 | $0.17 | 0.41% | -$0.14 | -0.37% | -$0.13 | -0.33% |
| | 30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1 | $0.17 | 0.41% | -$0.14 | -0.39% | -$0.13 | -0.34% |
| | 30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1 | $0.12 | 0.29% | -$0.11 | -0.28% | -$0.10 | -0.26% |
| | 7440_MetcalfImport_Tes-Metcalf | $0.11 | 0.25% | -$0.09 | -0.23% | -$0.08 | -0.21% |
| | 37585_TRCY PMP_230_30625_TESLA D _230_BR_2 _1 | $0.02 | 0.05% | -$0.02 | -0.05% | -$0.02 | -0.05% |
| | 30735_METCALF _230_30042_METCALF _500_XF_13 | $0.01 | 0.02% | -$0.01 | -0.02% | -$0.01 | -0.02% |
| | 30055_GATES1 _500_30900_GATES _230_XF_12_P | $0.01 | 0.02% | -$0.01 | -0.02% | -$0.01 | -0.01% |
| | RM_TM21_NG | $0.01 | 0.01% | $0.00 | 0.00% | -$0.01 | -0.02% |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 | -$0.18 | -0.43% | $0.10 | 0.27% | $0.10 | 0.25% |
| SCE | 24087_MAGUNDEN_230_24153_VESTAL _230_BR_1 _1 | $0.00 | -0.01% | $0.01 | 0.01% | $0.00 | -0.01% |
| SDG&E | 7820_TL 230S_OVERLOAD_NG | -$0.05 | -0.11% | $0.00 | 0.00% | $0.53 | 1.38% |
| | 22420_SILVERGT_69.0_22868_URBAN _69.0_BR_1 _1 | $0.00 | 0.00% | $0.00 | 0.00% | $0.16 | 0.40% |
| | OMS 9964817_TL50003_NG | -$0.01 | -0.03% | $0.00 | 0.00% | $0.14 | 0.35% |
| | 7820_TL23040_IV_SPS_NG | $0.00 | -0.01% | $0.00 | 0.00% | $0.12 | 0.32% |
| | 22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P | -$0.01 | -0.03% | $0.00 | 0.00% | $0.10 | 0.26% |
| | MIGUEL_BKs_MXFLW_NG | $0.00 | 0.00% | $0.00 | 0.00% | $0.05 | 0.14% |
| | 24138_SERRANO _500_24137_SERRANO _230_XF_1 _P | -$0.03 | -0.06% | $0.02 | 0.04% | $0.05 | 0.12% |
| | 22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1 | $0.00 | 0.00% | $0.00 | 0.00% | $0.02 | 0.06% |
| | 22668_POWAY _69.0_22664_POMERADO_69.0_BR_1 _1 | $0.00 | 0.00% | $0.00 | 0.00% | $0.02 | 0.06% |
| | 24138_SERRANO _500_24137_SERRANO _230_XF_2 _P | $0.00 | -0.01% | $0.00 | 0.01% | $0.00 | 0.01% |
| | 22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1 | $0.00 | 0.00% | $0.00 | 0.00% | -$0.01 | -0.02% |
| | 22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1 | $0.00 | 0.00% | $0.00 | 0.00% | -$0.01 | -0.02% |
| | 22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1 | $0.00 | 0.00% | $0.00 | 0.00% | -$0.03 | -0.08% |
| Other | | $0.00 | 0.00% | $0.00 | 0.00% | $0.05 | 0.14% |
| **Total** | | **$1.78** | **4.24%** | **-$1.38** | **-3.72%** | **-$0.09** | **-0.24%** |

**Table 1.3 Impact of congestion on day-ahead prices during congested hours[39]**

| Constraint Location | Constraint | Frequency | PG&E | SCE | SDG&E |
|---|---|---|---|---|---|
| PG&E | 30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2 | 4.0% | $7.13 | -$5.79 | -$5.46 |
| | 30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3 | 2.6% | $6.69 | -$5.24 | -$4.80 |
| | 7440_MetcalfImport_Tes-Metcalf | 1.9% | $5.54 | -$4.49 | -$4.29 |
| | 37585_TRCY PMP_230_30625_TESLA D _230_BR_2 _1 | 0.4% | $5.51 | -$4.16 | -$4.36 |
| | 30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1 | 3.5% | $5.44 | -$4.54 | -$4.17 |
| | 30900_GATES _230_30970_MIDWAY _230_BR_1 _1 | 5.7% | $4.30 | -$3.23 | -$2.95 |
| | 30735_METCALF _230_30042_METCALF _500_XF_13 | 0.2% | $4.30 | -$3.68 | -$3.66 |
| | 30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1 | 3.9% | $3.10 | -$2.68 | -$2.55 |
| | 30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1 | 15.3% | $2.45 | -$3.62 | -$4.19 |
| | 30790_PANOCHE _230_30900_GATES _230_BR_1 _1 | 7.1% | $2.41 | -$1.94 | -$1.84 |
| | 30790_PANOCHE _230_30900_GATES _230_BR_2 _1 | 7.1% | $2.41 | -$1.94 | -$1.84 |
| | 30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1 | 10.2% | $1.68 | -$1.41 | -$1.29 |
| | RM_TM21_NG | 0.5% | $1.07 | $0.00 | -$1.21 |
| | 30055_GATES1 _500_30900_GATES _230_XF_12 _P | 0.9% | $0.77 | -$0.64 | -$0.62 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 | 2.7% | -$6.67 | $3.75 | $3.60 |
| SCE | 24087_MAGUNDEN_230_24153_VESTAL _230_BR_1 _1 | 0.6% | -$0.69 | $0.79 | -$0.69 |
| SDG&E | 22420_SILVERGT_69.0_22868_URBAN _69.0_BR_1 _1 | 0.4% | $0.00 | $0.00 | $42.65 |
| | OMS 9964817_TL50003_NG | 1.1% | -$1.05 | $0.00 | $12.46 |
| | MIGUEL_BKs_MXFLW_NG | 0.5% | $0.00 | $0.00 | $9.83 |
| | 22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P | 1.1% | -$1.16 | $0.00 | $8.71 |
| | 7820_TL23040_IV_SPS_NG | 1.5% | -$0.31 | $0.00 | $8.19 |
| | 7820_TL 230S_OVERLOAD_NG | 13.0% | -$0.37 | $0.00 | $4.12 |
| | 22668_POWAY _69.0_22664_POMERADO_69.0_BR_1 _1 | 0.6% | $0.00 | $0.00 | $3.60 |
| | 24138_SERRANO _500_24137_SERRANO _230_XF_1 _P | 1.6% | -$1.56 | $0.95 | $2.78 |
| | 22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1 | 1.1% | $0.00 | $0.00 | $2.08 |
| | 24138_SERRANO _500_24137_SERRANO _230_XF_2 _P | 0.3% | -$1.50 | $1.09 | $1.50 |
| | 22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1 | 1.7% | $0.00 | $0.00 | -$0.53 |
| | 22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1 | 1.6% | $0.00 | $0.00 | -$2.05 |
| | 22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1 | 0.1% | $0.00 | $0.00 | -$10.05 |

## 1.9.2 Congestion in the real-time market

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

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

Figure 1.40 shows the overall impact of internal flow-based constraint congestion on 15-minute prices in each load area for 2020 and 2021. Figure 1.41 shows the frequency of this congestion. Highlights for this quarter include:

- The overall net impact of internal flow-based constraint congestion on price separation in the second quarter of 2021 increased in most areas compared to the same quarter of 2020. Congestion

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

resulted in a net increase to PG&E, BANC, PACW, PGE, PSEI, PWRX, SCL, and TIDC prices, while it resulted in a net decrease to prices in all other EIM areas.

- Congestion continued to impact prices in both the positive and negative direction over the quarter in each load area, which worked to offset some of the impact of congestion over the quarter. The overall frequency of congestion was highest in PACE, where congestion predominantly decreased prices.
- The primary constraints impacting price separation in the 15-minute market were the Panoche-Gates 230 kV line, the Gates-Midway 230 kV line, and the Los Banos-Quinto 230 kV line.

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

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

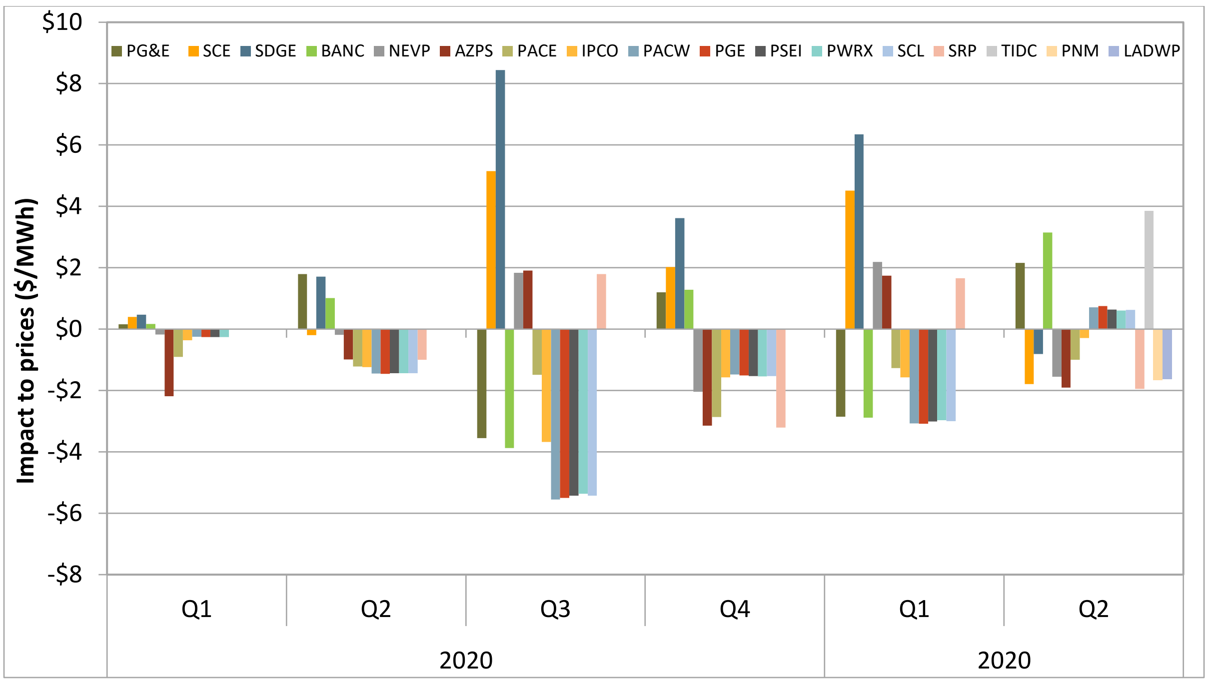
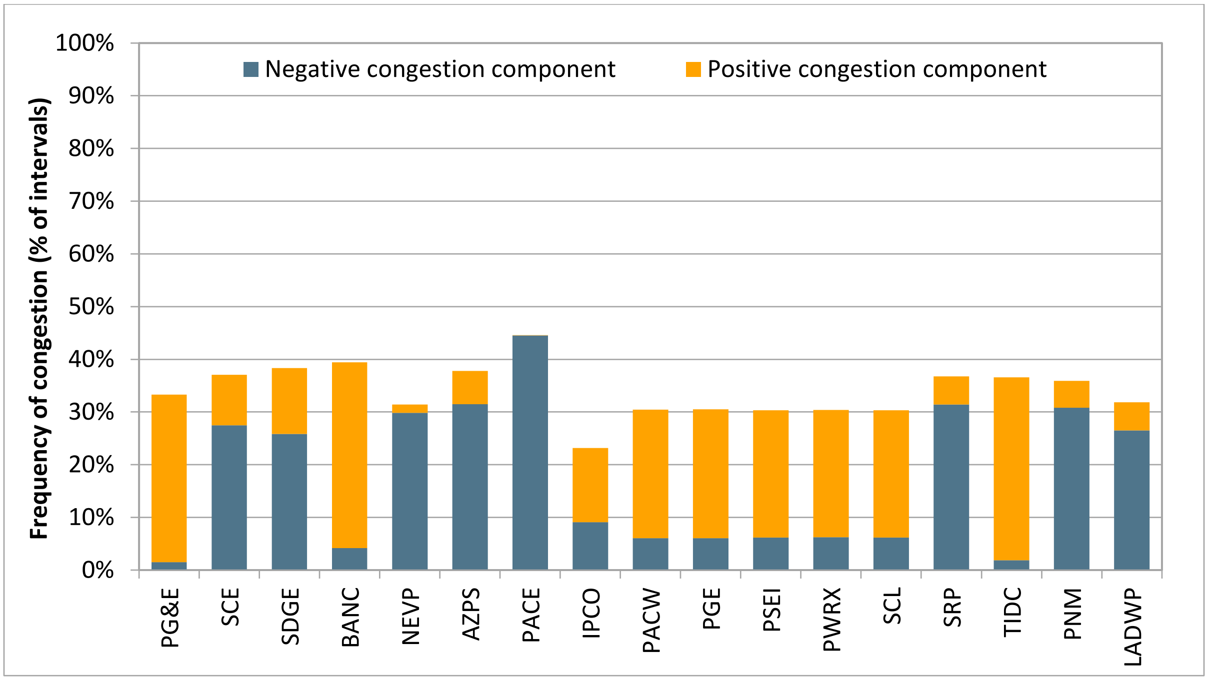


**Figure 1.41 Percent of intervals with internal congestion increasing versus decreasing 15-minute prices in the second quarter (>$0.05/MWh)**




### Impact of internal congestion from individual constraints

Table 1.4 shows the overall impact (during all intervals) of internal congestion on average 15-minute prices in each load area. Table 1.5 shows the impact of internal congestion from each constraint only during congested intervals, where the number of congested intervals is presented separately as frequency. The color scales in the table below apply only to the individual constraints, and therefore excludes “other” in Table 1.4. The category labeled “other” includes the impact of power balance constraint (PBC) violations, which often have an impact on price separation. These topics are discussed in greater depth in Chapter 2. This section will focus on individual flow-based constraints.

The constraints that had the greatest impact on price separation in the 15-minute market were the Panoche-Gates 230 kV line, the Gates-Midway 230 kV line, and the Los Banos-Quinto 230 kV line.

**Panoche-Gates 230 kV line**

The Panoche-Gates 230 kV line (30790_PANOCHE _230_30900_GATES _230_BR_1 _1) bound during about 7 percent of intervals during the quarter. When binding, it affected prices across most of the EIM, increasing prices in PG&E, BANC, TIDC, IPCO, PACW, PGE, PSEI, PWRX, and SCL by about $7.57/MWh on average, and decreasing prices elsewhere in the ISO and EIM, with the exception of PACE which was unaffected, by $6.85/MWh on average. Overall for the quarter, the constraint increased prices in the former areas by about $0.49/MWh and decreased prices in the latter areas by $0.48/MWh.

**Gates-Midway 230 kV line**

The Gates-Midway 230 kV line (30900_GATES _230_30970_MIDWAY _230_BR_1 _1) bound during about 7 percent of intervals over the quarter. When binding, it affected prices across most of the EIM, increasing prices in PG&E, BANC, TIDC, IPCO, PACW, PGE, PSEI, PWRX, and SCL by about $6.18/MWh on average, and decreasing prices elsewhere in the ISO and EIM, with the exception of PACE which was unaffected, by $6.34/MWh on average. Overall for the quarter, the constraint increased the former areas' prices by $0.43/MWh on average and decreased prices in the latter areas by $0.46/MWh on average.

**Los Banos-Quinto 230 kV line**

The Los Banos-Quinto 230 kV line (30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1) bound very frequently during the quarter, in about 5.1 percent of intervals. When binding, it affected prices across most of the EIM, increasing prices in PG&E, BANC, TIDC, IPCO, PACW, PGE, PSEI, PWRX, and SCL by about $7.94/MWh on average, and decreasing prices elsewhere in the ISO and EIM, with the exception of PACE which was unaffected, by $5.76/MWh on average. Over the entire quarter, it increased the former areas' prices by about $0.40/MWh on average, and decreased the latter areas' prices by about $0.29/MWh on average.

## Table 1.4 Impact of congestion on overall 15-minute prices

| Constraint Location | Constraint | PG&E | SCE | SDGE | BANC | NEVP | AZPS | PACE | IPCO | PACW | PGE | PSEI | PWRX | SCL | SRP | TIDC | PNM | LADWP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AZPS | LN-LL | | | | | | $0.03 | | | | | | | | | | | |
| BANC | HED_SCY2 | | | | $0.06 | | | | | | | | | | | | | |
| NEVP | RBS 525\|345 XF1 | | $0.00 | $0.01 | | $0.00 | $0.01 | -$0.01 | -$0.01 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.01 | | $0.00 | |
| | RBS 525\|345 XF2 | | $0.01 | $0.01 | | $0.00 | $0.01 | -$0.01 | -$0.01 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.01 | | $0.00 | |
| PACE | EAST_WYO_EXP | | | | | | | -$0.02 | | | | | | | | | | |
| | WINDSTAR EXPORT TCOR | | | | | | | -$0.06 | | | | | | | | | | |
| | TOTAL_WYOMING_EXPORT | | | | | | | -$0.49 | | $0.00 | | | | | | | | |
| PG&E | 30790_PANOCHE _230_30900_GATES _230_BR_1 _1 | $0.56 | -$0.63 | -$0.60 | $0.74 | -$0.23 | -$0.52 | | $0.00 | $0.46 | $0.46 | $0.45 | $0.44 | $0.44 | -$0.52 | $0.86 | -$0.42 | -$0.46 |
| | 30900_GATES _230_30970_MIDWAY _230_BR_1 _1 | $0.47 | -$0.56 | -$0.53 | $0.62 | -$0.30 | -$0.48 | | $0.04 | $0.44 | $0.44 | $0.42 | $0.41 | $0.42 | -$0.47 | $0.64 | -$0.41 | -$0.47 |
| | 40687_MALIN _500_30005_ROUND MT_500_BR_1 _3 | $0.35 | $0.17 | $0.15 | $0.34 | $0.00 | $0.11 | -$0.21 | -$0.38 | -$0.50 | -$0.52 | -$0.51 | -$0.50 | -$0.51 | $0.11 | $0.33 | $0.05 | $0.08 |
| | 30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1 | $0.27 | -$0.33 | -$0.31 | $0.33 | -$0.17 | -$0.27 | $0.00 | $0.12 | $0.24 | $0.24 | $0.23 | $0.23 | $0.23 | -$0.27 | $0.34 | -$0.23 | -$0.32 |
| | 30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1 | $0.19 | -$0.36 | -$0.34 | $0.60 | -$0.20 | -$0.30 | | $0.16 | $0.30 | $0.29 | $0.28 | $0.28 | $0.28 | -$0.30 | $1.24 | -$0.25 | -$0.29 |
| | 30885_MUSTANGS_230_30900_GATES _230_BR_1 _1 | $0.13 | -$0.04 | -$0.03 | $0.04 | -$0.02 | -$0.03 | | | | | | | | -$0.03 | $0.09 | -$0.02 | -$0.02 |
| | 30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3 | $0.11 | -$0.15 | -$0.14 | $0.14 | -$0.08 | -$0.12 | $0.00 | $0.05 | $0.10 | $0.10 | $0.10 | $0.10 | $0.10 | -$0.12 | $0.15 | -$0.10 | -$0.14 |
| | 7440_MetcalfImport_Tes-Metcalf | $0.06 | -$0.04 | -$0.04 | $0.03 | -$0.03 | -$0.03 | | | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 | -$0.03 | $0.03 | -$0.03 | -$0.03 |
| | 30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1 | $0.04 | $0.00 | | $0.10 | | | -$0.03 | -$0.05 | -$0.09 | -$0.09 | -$0.09 | -$0.09 | -$0.09 | | $0.04 | | |
| | 30885_MUSTANGS_230_30900_GATES _230_BR_2 _1 | $0.04 | -$0.01 | -$0.01 | $0.01 | -$0.01 | -$0.01 | | | | | | | | -$0.01 | $0.02 | -$0.01 | -$0.01 |
| | RM_TM21_NG | $0.02 | $0.01 | $0.01 | $0.02 | | $0.01 | -$0.02 | -$0.03 | -$0.04 | -$0.04 | -$0.04 | -$0.04 | -$0.04 | $0.01 | $0.02 | | $0.00 |
| | 30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1 | $0.02 | -$0.02 | -$0.02 | $0.03 | -$0.01 | -$0.02 | $0.00 | $0.01 | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 | -$0.02 | $0.03 | -$0.02 | -$0.02 |
| | 6110_SOL10_NG | $0.02 | $0.02 | $0.01 | $0.05 | $0.00 | $0.01 | -$0.02 | -$0.03 | -$0.04 | -$0.05 | -$0.05 | -$0.05 | -$0.05 | $0.01 | $0.02 | $0.01 | $0.01 |
| | ROUND_MOUNTAIN | $0.02 | $0.01 | $0.01 | $0.02 | | $0.01 | -$0.01 | -$0.02 | -$0.03 | -$0.03 | -$0.03 | -$0.03 | -$0.03 | $0.01 | $0.02 | $0.00 | $0.00 |
| | 30055_GATES1 _500_30900_GATES _230_XF_11_P | $0.01 | -$0.01 | -$0.01 | $0.01 | $0.00 | -$0.01 | | | | | | | | -$0.01 | $0.01 | $0.00 | -$0.01 |
| | 30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1 | $0.01 | -$0.08 | -$0.04 | $0.04 | | -$0.02 | | | $0.00 | $0.00 | | | | -$0.01 | $0.04 | | |
| | SUMMIT-DRUM #2 | $0.01 | | | $0.01 | -$0.02 | | $0.00 | $0.00 | | | | | | | $0.01 | | |
| | 30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1 | $0.01 | -$0.01 | -$0.01 | $0.01 | $0.00 | -$0.01 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | -$0.01 | $0.01 | $0.00 | -$0.01 |
| | 30622_EIGHT MI_230_30624_TESLA E _230_BR_1 _1 | $0.01 | | | $0.01 | | | | | | | | | | | $0.00 | | |
| | 37585_TRCY PMP_230_30625_TESLA D _230_BR_2 _1 | $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 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | -$0.01 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 | -$0.26 | $0.16 | $0.16 | -$0.25 | $0.10 | $0.14 | -$0.01 | -$0.12 | -$0.20 | -$0.20 | -$0.19 | -$0.19 | -$0.19 | $0.14 | -$0.26 | $0.11 | $0.11 |
| | 30515_WARNERVL_230_30800_WILSON _230_BR_1 _1 | | | | -$0.03 | | | | | | | | | | | -$0.05 | | |
| | 30529_BRDSLDNG_230_30525_C.COSTA _230_BR_1 _1 | | | | | | | | | | | | | | | $0.04 | | |
| | 32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1 | | | | | -$0.11 | | | | | | | | | | | | |
| | 32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1 | | | | | -$0.28 | | | | | | | | | | | | |
| | 32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1 | | | | | -$0.09 | | | | | | | | | | | | |
| | 30765_LOSBANOS_230_30766_PADR FLT_230_BR_1 _1 | | -$0.02 | -$0.01 | $0.04 | | | | | $0.01 | $0.01 | $0.01 | $0.00 | $0.01 | | $0.06 | | |
| | 7430_CP6_NG | | | | $0.18 | | | | | | | | | | | $0.08 | | |
| | 7430_MEL_WIL_NG | | | | -$0.05 | | | | | | | | | | | | | |
| | 30900_GATES _230_30889_CAFLTSSS_230_BR_1 _1 | | -$0.02 | $0.00 | $0.03 | | | | | $0.00 | $0.00 | | | | | $0.04 | | -$0.01 |
| PGE | MCL_PE_SHW_V682 | -$0.01 | | | -$0.01 | | | | | | $0.08 | $0.01 | $0.01 | $0.01 | | -$0.01 | | |
| SCE | SYLMAR-AC_BG | $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 | -$0.01 |
| | 6410_CP7_NG | $0.01 | -$0.01 | -$0.01 | $0.01 | $0.00 | -$0.01 | | $0.00 | $0.01 | $0.01 | $0.00 | $0.00 | $0.00 | -$0.01 | $0.01 | -$0.01 | -$0.01 |
| | Victorville_Los_Angeles | -$0.02 | -$0.05 | $0.02 | | $0.07 | $0.07 | $0.04 | $0.02 | | | | | | $0.07 | -$0.02 | $0.07 | -$0.07 |
| SDG&E | 7820_TL 230S_OVERLOAD_NG | $0.00 | $0.09 | $1.21 | | -$0.08 | -$0.24 | -$0.08 | -$0.04 | | | | | | -$0.25 | $0.00 | -$0.20 | $0.00 |
| | OMS 10214484 ML_BK80_NG | | $0.01 | $0.24 | | | -$0.06 | | | | | | | | -$0.06 | | -$0.05 | |
| | 7820_TL23040_IV_SPS_NG | | $0.00 | $0.09 | | $0.00 | -$0.01 | $0.00 | | | | | | | -$0.01 | | -$0.01 | |
| | 92321_SYCA TP2_230_22832_SYCAMORE_230_BR_2 _1 | | | $0.05 | | | -$0.01 | | | | | | | | -$0.01 | | -$0.01 | |
| | OMS 10022868_50002_OOS_TDM | | | $0.04 | | | -$0.01 | | | | | | | | -$0.01 | | | |
| | OMS 9965163_50001_OOS_NG | | $0.00 | $0.03 | | $0.00 | -$0.01 | $0.00 | | | | | | | -$0.01 | | $0.00 | |
| | MIGUEL_BKs_MXFLW_NG | | | $0.02 | | | $0.00 | | | | | | | | $0.00 | | $0.00 | |
| | 22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1 | | $0.00 | $0.01 | | $0.00 | -$0.01 | | | | | | | | -$0.01 | | -$0.01 | |
| | 24138_SERRANO _500_24137_SERRANO _230_XF_3 | $0.00 | $0.00 | $0.01 | $0.00 | $0.00 | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | | $0.00 | | |
| | 22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1 | | | -$0.04 | | | | | | | | | | | | | | |
| | 22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1 | | | -$0.06 | | | | | | | | | | | | | | |
| | 22716_SANLUSRY_230_22232_ENCINA _230_BR_1 _1 | $0.01 | $0.01 | -$0.06 | $0.00 | $0.00 | -$0.02 | | | | | | | | -$0.02 | $0.01 | -$0.01 | $0.00 |
| | 22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1 | | | -$0.60 | | | | | | | | | | | | | | |
| | Other | $0.07 | $0.04 | -$0.03 | $0.02 | -$0.08 | -$0.09 | -$0.05 | $0.00 | $0.00 | $0.01 | $0.00 | -$0.01 | $0.00 | -$0.09 | $0.05 | -$0.08 | $0.06 |
| | **Internal Total** | **$2.16** | **-$1.79** | **-$0.81** | **$3.15** | **-$1.55** | **-$1.91** | **-$1.00** | **-$0.29** | **$0.71** | **$0.76** | **$0.64** | **$0.60** | **$0.63** | **-$1.95** | **$3.85** | **-$1.66** | **-$1.62** |
| | **Transfers** | | | | $0.00 | $4.00 | -$0.14 | -$0.25 | -$0.22 | -$1.47 | -$0.96 | -$1.14 | -$1.77 | -$1.93 | $2.15 | $0.10 | -$0.19 | -$0.02 |
| | **Grand Total** | **$2.16** | **-$1.79** | **-$0.81** | **$3.15** | **$2.45** | **-$2.05** | **-$1.25** | **-$0.51** | **-$0.76** | **-$0.20** | **-$0.50** | **-$1.17** | **-$1.30** | **$0.20** | **$3.95** | **-$1.85** | **-$1.64** |

### Table 1.5 Impact of internal congestion on 15-minute prices during congested intervals[40]

| Constraint Location | Constraint | Freq. | PG&E | SCE | SDGE | BANC | NEVP | AZPS | PACE | IPCO | PACW | PGE | PSEI | PWRX | SCL | SRP | TIDC | PNM | LADWP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AZPS | LN-LL | 2.1% | | | | | | $1.29 | | | | | | | | | | | |
| BANC | HED_SCY2 | 0.5% | | | | $11.03 | | | | | | | | | | | | | |
| NEVP | RBS 525\|345 XF1 | 0.4% | | $1.40 | $1.46 | | -$0.69 | $1.52 | -$2.24 | -$2.63 | $0.00 | $0.00 | -$1.21 | -$1.25 | -$1.21 | $1.46 | | -$0.73 | |
| | RBS 525\|345 XF2 | 0.3% | | $1.49 | $1.55 | | -$0.78 | $1.61 | -$2.35 | -$2.77 | $0.00 | $0.00 | -$1.34 | -$1.39 | -$1.35 | $1.55 | | -$0.69 | |
| PACE | WINDSTAR EXPORT TCOR | 10.1% | | | | | | | -$0.62 | | | | | | | | | | |
| | TOTAL_WYOMING_EXPORT | 28.3% | | | | | | | -$1.75 | | -$0.28 | | | | | | | | |
| | EAST_WYO_EXP | 1.3% | | | | | | | -$1.91 | | | | | | | | | | |
| PG&E | 7440_MetcalfImport_Tes-Metcalf | 0.4% | $13.97 | -$9.21 | -$8.76 | $7.73 | -$6.01 | -$7.95 | | | $4.01 | $3.92 | $3.75 | $3.70 | $3.75 | -$7.94 | $7.50 | -$6.90 | -$7.76 |
| | 30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1 | 0.7% | $13.01 | $3.33 | | $13.96 | | | -$12.39 | -$14.96 | -$16.54 | -$17.39 | -$17.07 | -$16.93 | -$17.04 | | $13.01 | | |
| | 40687_MALIN _500_30005_ROUND MT_500_BR_1 _3 | 3.6% | $9.63 | $4.82 | $4.22 | $9.61 | $0.02 | $3.06 | -$5.96 | -$10.50 | -$14.08 | -$14.41 | -$14.16 | -$14.03 | -$14.14 | $3.02 | $9.19 | $1.43 | $2.32 |
| | 30885_MUSTANGS_230_30900_GATES _230_BR_1 _1 | 1.6% | $8.05 | -$3.59 | -$3.08 | $3.72 | -$2.36 | -$2.86 | | | | | | | | -$2.85 | $5.48 | -$2.55 | -$2.64 |
| | 30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1 | 3.5% | $7.76 | -$9.46 | -$8.86 | $9.57 | -$4.92 | -$7.89 | -$0.15 | $3.49 | $6.97 | $6.91 | $6.70 | $6.60 | $6.69 | -$7.87 | $9.76 | -$6.67 | -$9.21 |
| | 30790_PANOCHE _230_30900_GATES _230_BR_1 _1 | 7.5% | $7.52 | -$8.37 | -$7.99 | $9.82 | -$4.61 | -$7.15 | | $5.73 | $6.92 | $6.87 | $6.63 | $6.48 | $6.61 | -$7.15 | $11.55 | -$6.22 | -$6.45 |
| | 30900_GATES _230_30970_MIDWAY _230_BR_1 _1 | 7.3% | $6.51 | -$7.71 | -$7.30 | $8.48 | -$4.10 | -$6.56 | | $2.48 | $6.07 | $6.03 | $5.78 | $5.65 | $5.75 | -$6.54 | $8.86 | -$5.65 | -$6.52 |
| | 30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3 | 2.0% | $5.74 | -$7.36 | -$6.92 | $7.15 | -$3.80 | -$6.20 | -$0.83 | $2.67 | $5.22 | $5.17 | $5.02 | $4.94 | $5.01 | -$6.18 | $7.33 | -$5.23 | -$7.21 |
| | 30622_EIGHT MI_230_30624_TESLA E _230_BR_1 _1 | 1.3% | $5.71 | | | $1.12 | | | | | | | | | | | $1.84 | | |
| | 30885_MUSTANGS_230_30900_GATES _230_BR_2 _1 | 0.8% | $5.41 | -$2.28 | -$2.20 | $2.30 | -$1.79 | -$2.04 | | | | | | | | -$2.04 | $4.26 | -$1.81 | -$1.89 |
| | 6110_SOL10_NG | 0.5% | $4.14 | $3.00 | $2.64 | $9.15 | $0.30 | $1.97 | -$3.27 | -$5.86 | -$8.47 | -$9.48 | -$9.30 | -$9.24 | -$9.29 | $1.95 | $4.70 | $1.15 | $2.00 |
| | 30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1 | 5.1% | $3.76 | -$7.11 | -$6.70 | $11.90 | -$3.88 | -$5.94 | | $3.15 | $5.82 | $5.76 | $5.58 | $5.49 | $5.56 | -$5.92 | $24.46 | -$5.01 | -$5.76 |
| | 30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1 | 1.9% | $3.20 | -$4.04 | -$3.33 | $3.42 | | -$3.20 | | | $1.64 | $1.49 | | | | -$3.13 | $3.53 | | |
| | 30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1 | 0.9% | $2.38 | -$2.64 | -$2.51 | $2.77 | -$1.50 | -$2.25 | -$0.46 | $0.71 | $1.98 | $1.96 | $1.88 | $1.84 | $1.88 | -$2.24 | $2.86 | -$1.93 | -$2.04 |
| | 30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1 | 0.4% | $1.69 | -$1.81 | -$1.69 | $1.61 | -$0.93 | -$1.52 | -$0.23 | $0.49 | $1.10 | $1.09 | $1.05 | $1.04 | $1.05 | -$1.52 | $1.67 | -$1.32 | -$1.92 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3 | 1.0% | $0.03 | -$0.41 | -$0.38 | $0.01 | -$0.11 | -$0.36 | -$0.31 | -$0.26 | -$0.15 | -$0.17 | -$0.17 | -$0.16 | -$0.17 | -$0.36 | $0.03 | -$0.36 | -$0.83 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 | 2.5% | -$10.34 | $6.54 | $6.31 | -$9.94 | $3.79 | $5.50 | -$0.86 | -$4.80 | -$7.79 | -$7.82 | -$7.57 | -$7.46 | -$7.56 | $5.48 | -$10.22 | $4.44 | $4.25 |
| | 30515_WARNERVL_230_30800_WILSON _230_BR_1 _1 | 0.4% | | | | -$6.97 | | | | | | | | | | | -$10.37 | | |
| | 30765_LOSBANOS_230_30766_PADR FLT_230_BR_1 _1 | 1.8% | | -$1.59 | -$1.20 | $2.07 | | | | | $1.37 | $1.27 | $1.30 | $1.36 | $1.30 | | $3.12 | | |
| | 30900_GATES _230_30889_CAFLTSSS_230_BR_1 _1 | 3.5% | | -$0.83 | -$0.94 | $1.00 | | | | | $0.85 | $0.84 | | | | | $1.04 | | -$0.87 |
| | 32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1 | 0.6% | | | | | -$18.36 | | | | | | | | | | | | |
| | 32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1 | 1.1% | | | | | -$24.82 | | | | | | | | | | | | |
| | 32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1 | 0.5% | | | | | -$17.40 | | | | | | | | | | | | |
| | 7430_CP6_NG | 2.2% | | | | $8.18 | | | | | | | | | | | $4.55 | | |
| | 7430_MEL_WIL_NG | 0.6% | | | | -$8.34 | | | | | | | | | | | | | |
| SDG&E | OMS 10214484 ML_BK80_NG | 0.7% | | $1.08 | $33.64 | | | -$9.14 | | | | | | | | -$9.17 | | -$7.07 | |
| | 7820_TL23040_IV_SPS_NG | 0.5% | | $0.97 | $16.57 | | -$0.53 | -$1.58 | -$0.36 | | | | | | | -$1.59 | | -$1.25 | |
| | 7820_TL 230S_OVERLOAD_NG | 8.9% | $0.08 | $1.08 | $13.65 | | -$0.94 | -$2.66 | -$0.98 | -$0.70 | | | | | | -$2.89 | $0.07 | -$2.32 | $0.04 |
| | 22716_SANLUSRY_230_22232_ENCINA _230_BR_1 _1 | 0.6% | $1.11 | $1.82 | -$9.99 | $1.18 | -$6.46 | -$2.58 | | | | | | | | -$2.61 | $1.09 | -$1.98 | $0.80 |
| | 22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1 | 0.5% | | | -$10.10 | | | | | | | | | | | | | | |
| | 22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1 | 1.9% | | | -$31.94 | | | | | | | | | | | | | | |

## Impact of congestion from transfer constraints

This section focuses on price impacts from congestion on schedule-based transfer constraints. The highest frequency occurred either into or away from the EIM load areas located in the Pacific Northwest, where the transfer congestion reduced prices in those areas. The largest price impact over the quarter was in the NV Energy area, with an average increase of about $4.00/MWh in the 15-minute market and $8.24/MWh in the 5-minute market.

In the 15-minute market, the total impact of congestion on a specific energy imbalance market (EIM) area is equal to the sum of the price impact of flow-based constraints as shown in Figure 1.40 and Table 1.4, and schedule-based constraints as listed in Table 1.6. Transfer constraint congestion typically has the largest impact on prices; therefore, it is isolated here to better show its effects on EIM load areas. Table 1.6 shows the congestion frequency and average price impact from transfer constraint congestion in the 15-minute and 5-minute markets during the quarter.

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

**Table 1.6 Quarterly average price impact and congestion frequency on EIM transfer constraints (Q2 2021)**

| | 15-minute market | | 5-minute market | |
|---|---|---|---|---|
| | Congestion Frequency | Price Impact ($/MWh) | Congestion Frequency | Price Impact ($/MWh) |
| BANC | 0% | $0.00 | 0% | $0.00 |
| Turlock Irrigation District | 1% | $0.10 | 1% | $0.01 |
| Arizona Public Service | 1% | -$0.14 | 1% | $0.80 |
| NV Energy | 3% | $4.00 | 3% | $8.24 |
| PacifiCorp East | 4% | -$0.25 | 3% | $1.61 |
| Idaho Power | 4% | -$0.22 | 4% | $0.08 |
| L.A. Dept. of Water and Power | 5% | -$0.02 | 5% | -$0.11 |
| Public Service Company of NM | 7% | -$0.19 | 5% | -$0.41 |
| Salt River Project | 8% | $2.15 | 9% | $4.88 |
| PacifiCorp West | 26% | -$1.47 | 16% | -$0.56 |
| Portland General Electric | 27% | -$0.96 | 17% | -$0.53 |
| Seattle City Light | 29% | -$1.93 | 21% | -$1.06 |
| Puget Sound Energy | 29% | -$1.14 | 21% | $2.05 |
| Powerex | 23% | -$1.77 | 37% | -$1.18 |

### 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 EIM. Figure 1.42 shows the average impact to prices in the 15-minute market by quarter for 2020 and 2021. Figure 1.43 shows the frequency of congestion on transfer constraints by quarter for 2020 and 2021.

There was an overall decrease in the impact on average prices from transfer constraint congestion in the second quarter of 2021 compared to the same quarter in 2020. Price impacts were greatest for two EIM entities in the Southwest: NV Energy and Salt River Project. On average for the quarter, transfer constraint congestion increased prices in these areas by $3.08/MWh.

The frequency of transfer constraint congestion in the second quarter of 2021 was lower than that of the same quarter of 2020. Frequencies averaged less than 30 percent across the EIM during the quarter, compared to the same quarter of 2020 where some EIM entities experienced frequencies above 40 percent. Powerex continued to have the highest average frequency of transfer congestion overall, occurring during about 23 percent of 15-minute market intervals and 37 percent of 5-minute market intervals.

**Figure 1.42 Transfer constraint congestion average impact on prices in the 15-minute market**

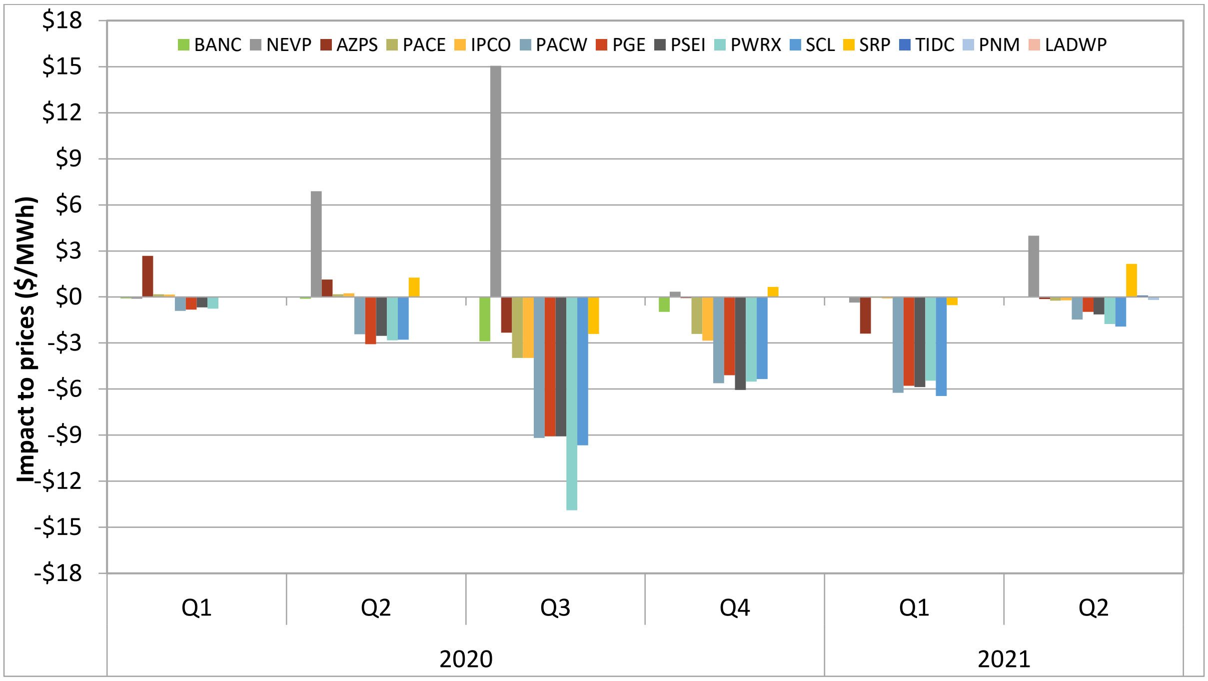
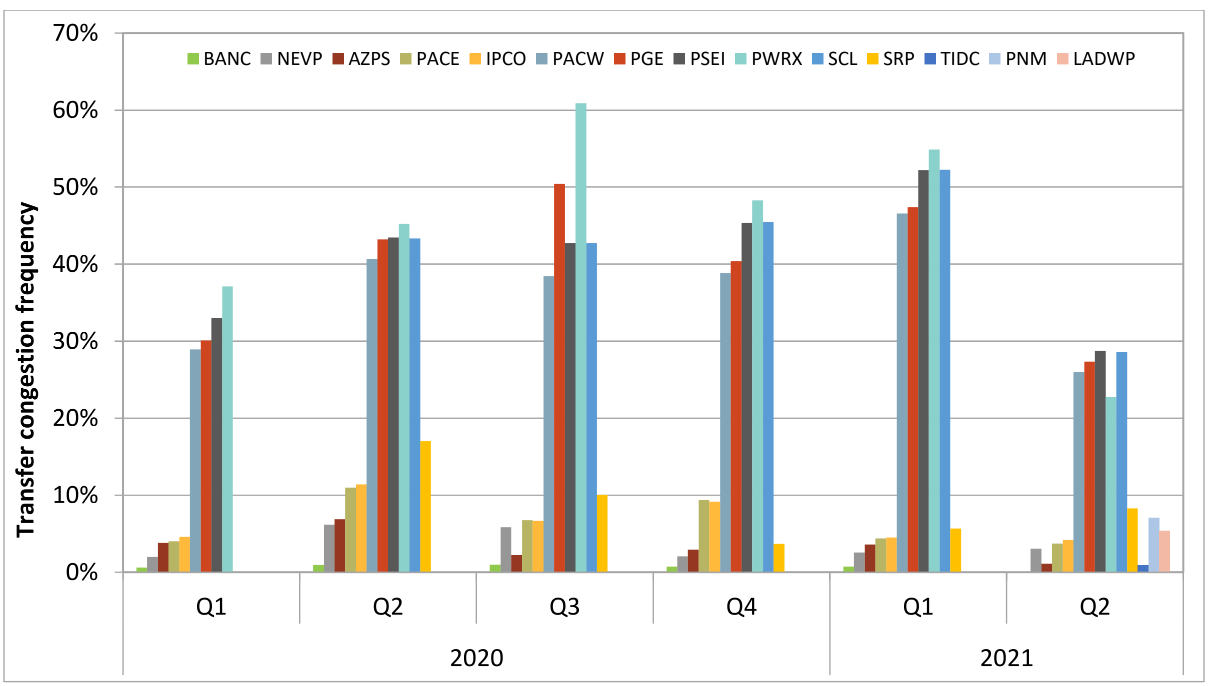



**Figure 1.43 Transfer constraint congestion frequency in the 15-minute market**




## 1.9.3 Congestion on interties

In the second quarter of 2021, both frequency and import congestion rent decreased on PACI/Malin 500 and NOB relative to the same quarter in 2020. Figure 1.44 shows total import congestion charges in the day-ahead market for 2020 and 2021. Figure 1.45 shows the frequency of congestion on five major interties. Table 1.7 provides a detailed summary of this data over a broader set of interties.

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

The charts and table highlight the following:

- Total import congestion charges for the second quarter of 2021 decreased to about $13 million compared to about $37 million in the same quarter of 2020. This decrease is driven by a decrease in congestion on the PACI/Malin 500 and NOB interties, which together account for 96 percent of the total import congestion charges for the quarter.
- The frequency of congestion in the second quarter decreased significantly on PACI/Malin 500, falling from 44 percent in the second quarter of 2020 to 18 percent this quarter.
- The frequency of congestion and magnitude of congestion charges is typically highest on the PACI/Malin 500, NOB, and Palo Verde interties. The second quarter followed this trend on PACI/Malin 500 and NOB, while the frequency and congestion charges decreased significantly on Palo Verde compared to the same quarter of 2020. Congestion on other interties continued to remain relatively low relative to these constraints.

**Figure 1.44 Day-ahead import congestion charges on major interties**

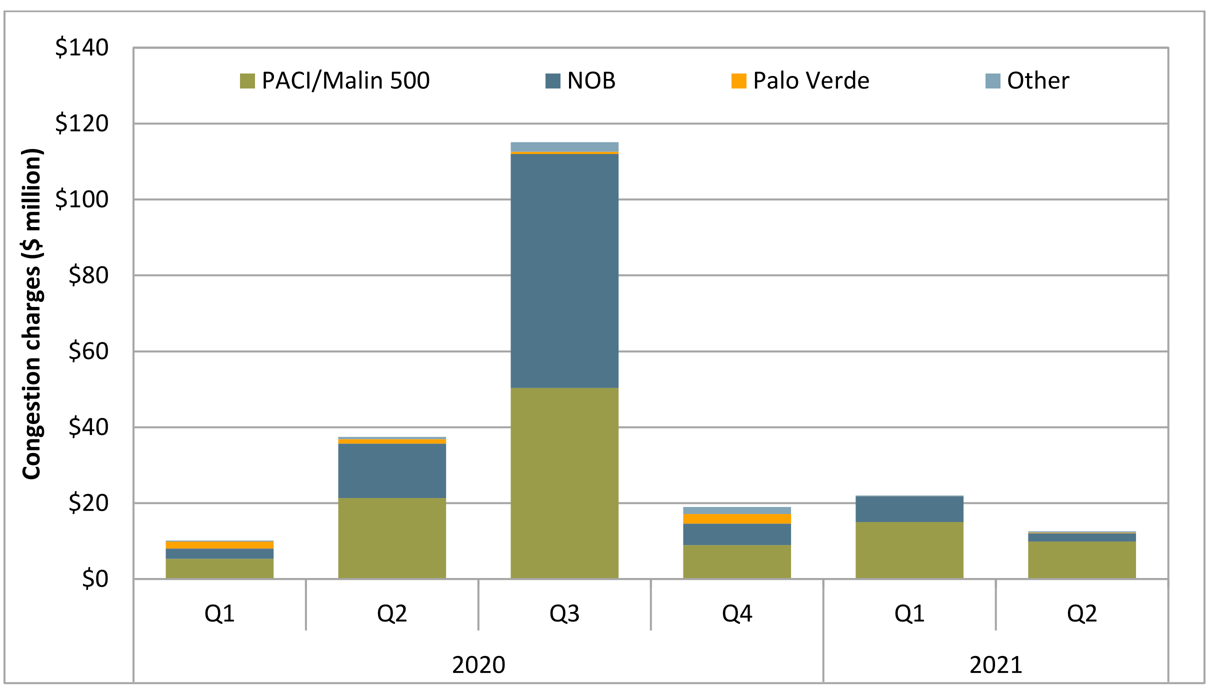


**Figure 1.45 Frequency of import congestion on major interties in the day-ahead market**

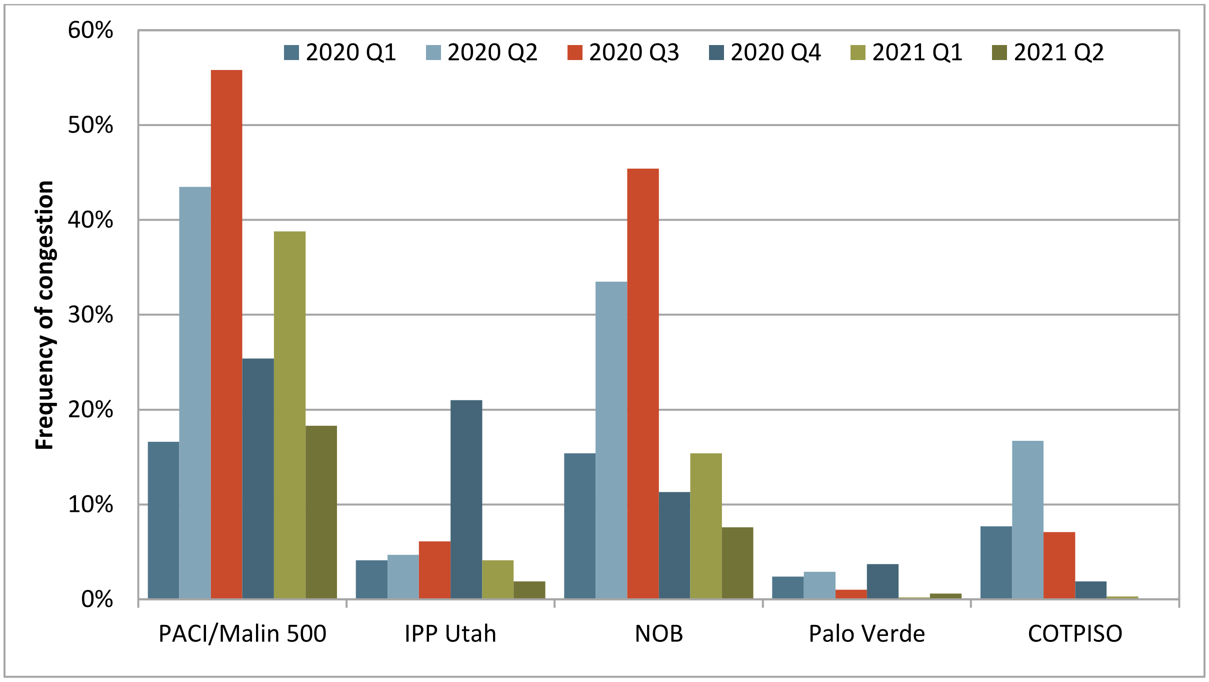



**Table 1.7 Summary of import congestion in day-ahead market (2020-2021)**

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

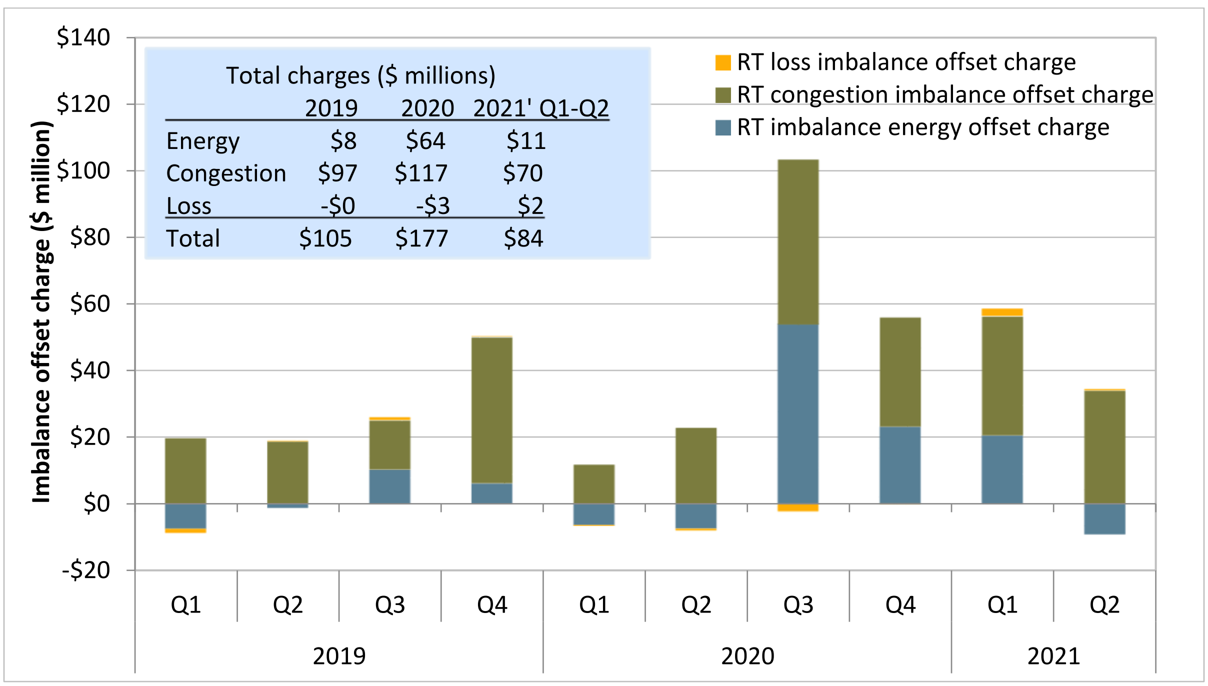
## 1.10 Real-time imbalance offset costs

Second quarter real-time imbalance offset costs were about $25 million, down from over $58 million in the first quarter of 2021. Real-time imbalance offset costs were comprised of about $34 million in congestion deficits and about $9 million in energy imbalance surpluses.[41]

The real-time imbalance offset charge consists of three components corresponding to the main components of real-time settlement prices: energy, congestion, and loss.[42] Any revenue imbalance from the energy components of real-time settlement prices is collected through the real-time imbalance energy offset charge (RTIEO). Revenue imbalance from the congestion component is recovered through the real-time congestion imbalance offset charge (RTCIO), and revenue imbalance from the loss component is collected through the real-time loss imbalance offset charge.

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

**Figure 1.46 Real-time imbalance offset costs**




41 Values reported here are based on available settlement data at the time of drafting (September 23, 2021) and thus include both preliminary and post-meter data submission settlements. Following settlement timeline changes effective January 1, 2021, only preliminary data is available until meter data is received and more final settlement statements are issued at trade day plus 70 business days. Settlements can change substantially between statements. For example, estimates of Q2 offset costs rose from $12 million, based on data available July 27 2021, to $25 million about 8 weeks later. For further information on settlement timeline changes see: http://www.caiso.com/Documents/Presentation-MarketSettlementsTimelineTransformationTraining.pdf

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

## 1.11 Congestion revenue rights

### Congestion revenue right auction returns

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

As shown in Figure 1.47, transmission ratepayers lost about $17 million during the second quarter of 2021 as payments to auctioned congestion revenue rights holders exceeded auction revenues. This is higher than the $4 million loss in the first quarter of 2021. Auction revenues were 60 percent of payments made to non-load-serving entities during the second quarter, down from 82 percent during the first quarter.

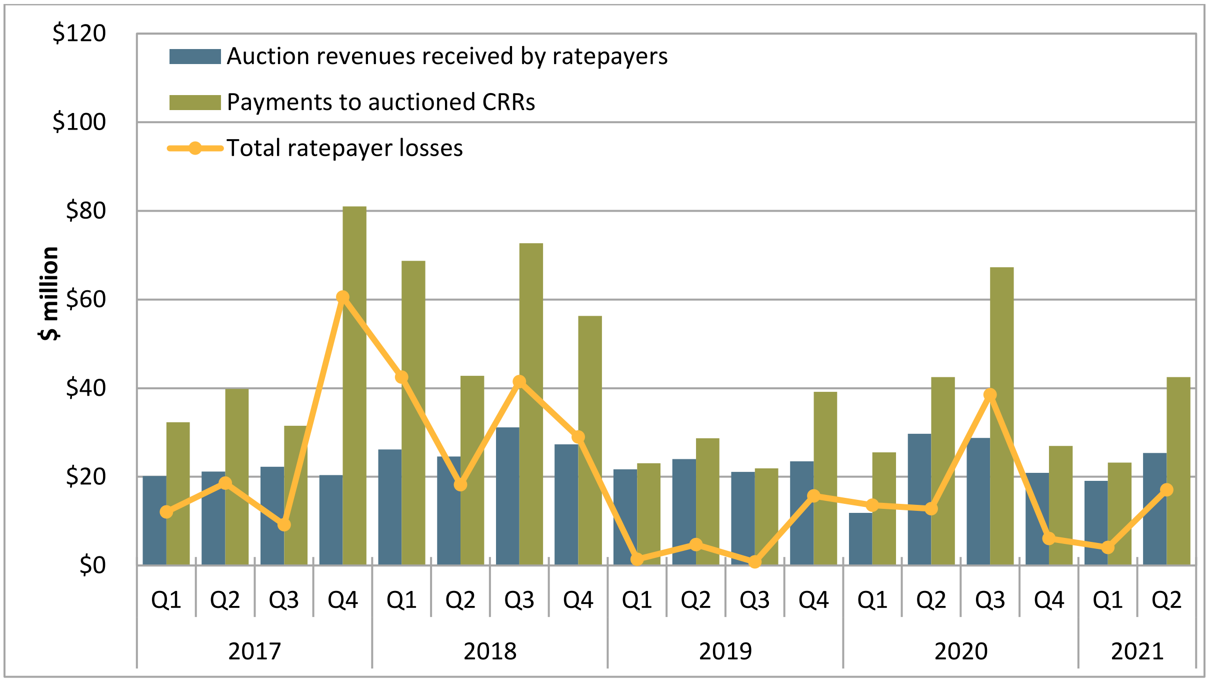
In the third quarter of 2020, a majority of transmission ratepayer losses were from congestion revenue right sales made by load serving entities. This was the first time this has happened. In the fourth quarter, ratepayer losses returned to the normal pattern of being primarily from sales of congestion revenue rights by the ISO. This pattern has continued through the first half of 2021 with load serving entities on net making a small amount on their congestion revenue right trades.

In the second quarter, financial entities (which do not schedule or trade physical power or serve load) had profits of nearly $13 million, up from nearly $3 million in profits during the first quarter of 2021. Marketers' profits were a little over $2 million, up from just over $1 million in the first quarter. Generators had profits of about $2 million in the second quarter up from breaking even in the first quarter.

The $17 million in second quarter 2021 auction losses was about 12 percent of day-ahead congestion rent. This is up from 2 percent of rent in the first quarter of 2021 and down slightly from the 14 percent for the second quarter of 2020. The losses as a percent of day-ahead congestion rent were below the average of 28 percent during the three years before the Track 1A and 1B changes (2016 through 2018).

The impact of Track 1A changes which limit the types of congestion revenue rights that can be sold in the auction cannot be directly quantified. However, based on current settlement records, DMM estimates that changes in the settlement of congestion revenue rights made under Track 1B reduced payments to non-load-serving entities by about $15 million in the second quarter. The Track 1B effects on auction bidding behavior and reduced auction revenues are not known.

**Figure 1.47 Auction revenues and payments to non-load-serving entities**




Rule changes made by the ISO reduced losses from sales of congestion revenue rights significantly in 2019, particularly in the first three quarters following their implementation. However, DMM continues to recommend that the ISO take steps to discontinue auctioning congestion revenue rights on behalf of ratepayers. The auction continues to consistently cause millions of dollars of losses to transmission ratepayers each year, while exposing transmission ratepayers to risk of significantly higher losses in the event of unexpected increases in congestion or modeling errors. If the ISO believes it is highly beneficial to actively facilitate hedging of congestion costs by suppliers, DMM recommends that the ISO modify the congestion revenue rights auction into a market for financial hedges based on clearing of bids from willing buyers and sellers.

## 1.12 Bid cost recovery

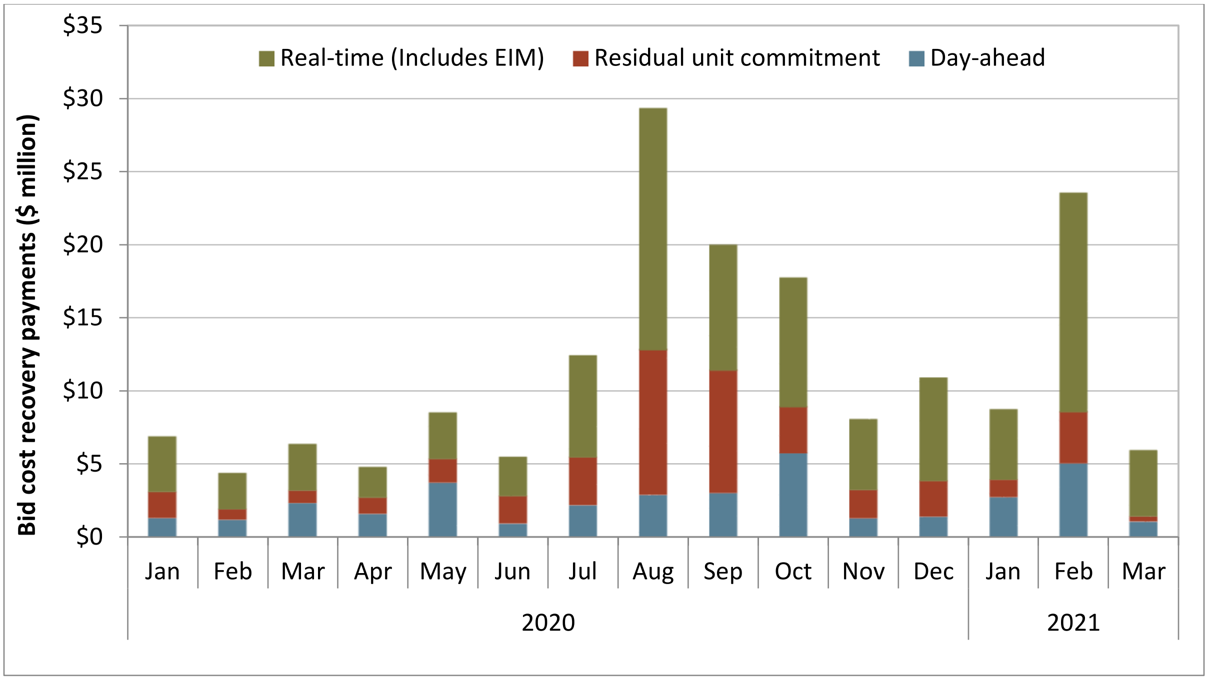
During the first quarter of 2021, estimated bid cost recovery payments for units in the ISO and energy imbalance market totaled about $38 million.[43] This was $2 million higher than total bid cost recovery in the previous quarter and about $20 million higher than in the first quarter of 2020. These significantly higher payments can be attributed to the rise in gas prices at major trading hubs during February 13 through 18.

Bid cost recovery attributed to the day-ahead market totaled about $9 million, about $4 million higher than the same quarter in 2020. Bid cost recovery payments for residual unit commitment during the quarter totaled about $5 million, compared to $3.4 million in the first quarter of 2020. Bid cost recovery attributed to the real-time market totaled about $24 million, or about $4 million higher than payments in the previous quarter and $15 million higher than payments in the first quarter of 2020. Out of the

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

$24 million in real-time payments, about $11.6 million was accrued during the volatile gas price event that existed from February 13 through 17.

**Figure 1.48 Monthly bid cost recovery payments**




## 1.13 Local market power mitigation

The ISO's automated local market power mitigation (LMPM) procedures are triggered when congestion occurs on a constraint that is determined to be uncompetitive. When this occurs, bids are mitigated to 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.[44]

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

[44] 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.

### Mitigation in the ISO balancing area

In the day-ahead and real-time markets, rates of mitigation increased significantly relative to the second quarter of 2020. Incremental energy subject to mitigation continues to increase relative to prior years due, in part, to the increase in concentration of generation in the portfolios of net sellers as well as load in the portfolios of net buyers.

As shown in Figure 1.49, in the day-ahead market, an hourly average of about 2,200 MW was subject to mitigation but corresponding bids were not lowered, compared to 1,377 MW in the second quarter of 2020. About 429 MW of incremental energy bids were lowered due to mitigation compared to 368 MW in 2020. As a result, there was an average 34 MW increase in dispatch, up from 14 MW in 2020.

Figure 1.50 and Figure 1.51 show the same metrics but for the ISO's 15-minute and 5-minute markets on a monthly level instead. As shown in the figures, the frequency of mitigation in both 15-minute and 5-minute markets increased significantly in the second quarter relative to the same quarter in 2020.

**Figure 1.49 Average incremental energy mitigated in day-ahead market**

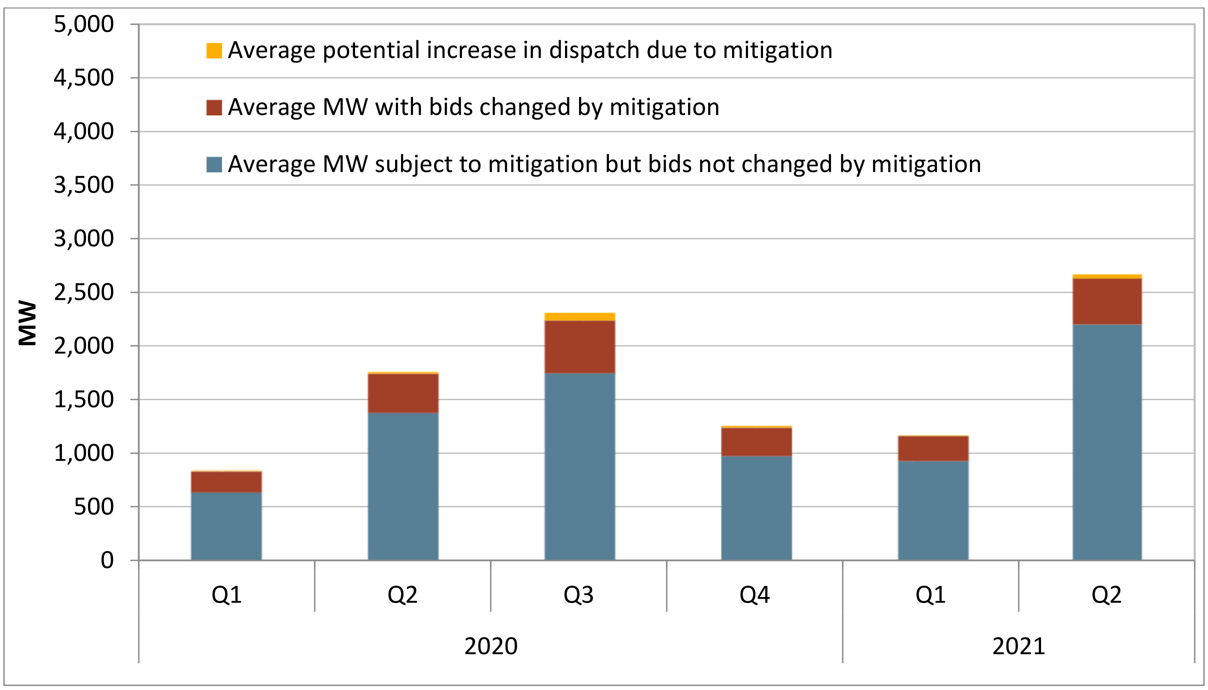


**Figure 1.50 Average incremental energy mitigated in 15-minute real-time market (ISO)**

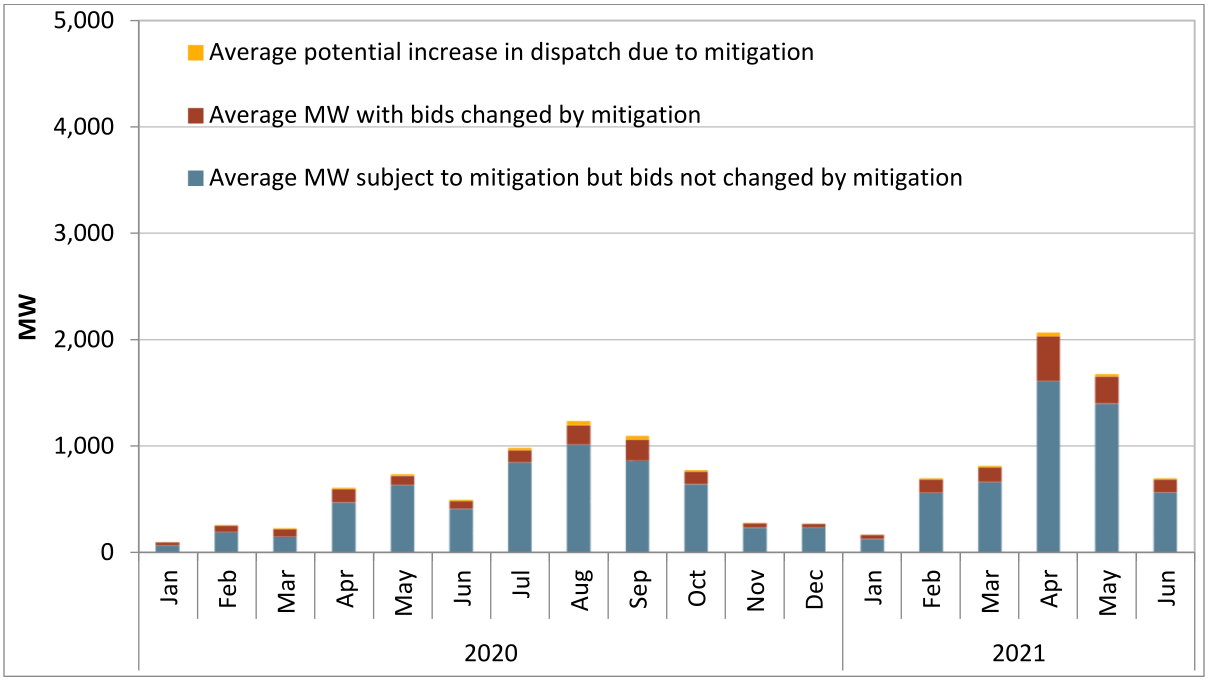
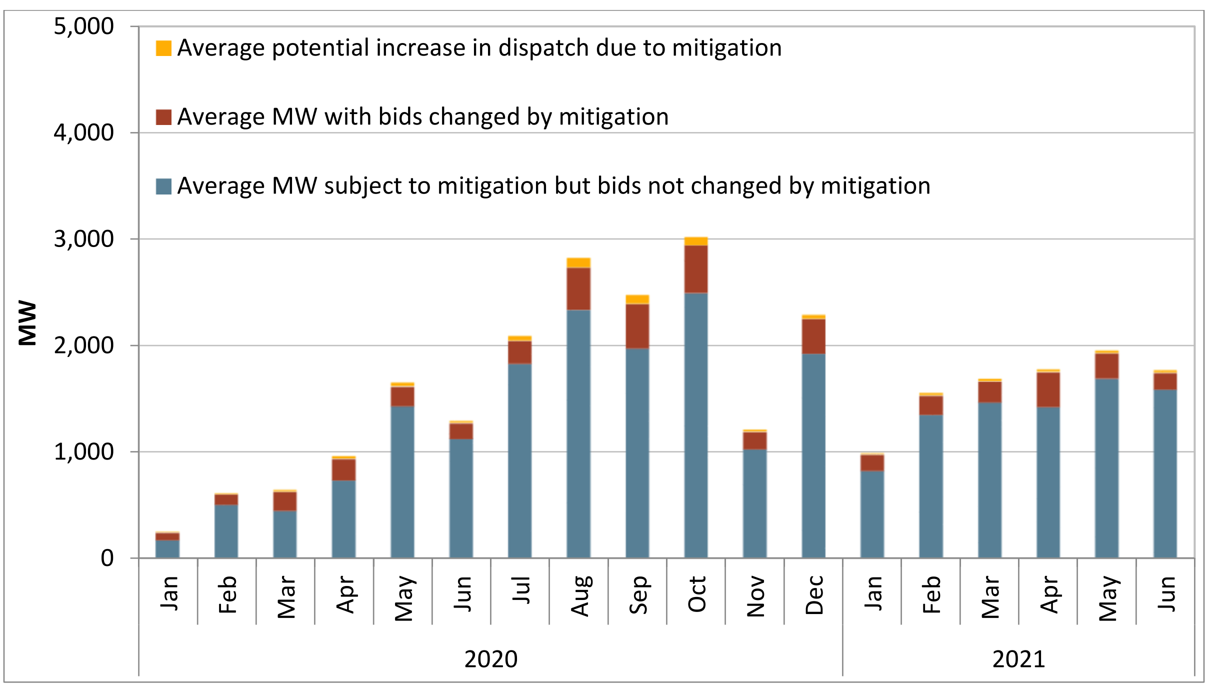



**Figure 1.51 Average incremental energy mitigated in 5-minute real-time market (ISO)**



## 1.14 Imbalance conformance

Operators in the California ISO and EIM can manually adjust the amount of imbalance conformance used in the market to balance supply and demand conditions to maintain system reliability. Imbalance conformance adjustments are used to account for potential modeling inconsistencies and inaccuracies.

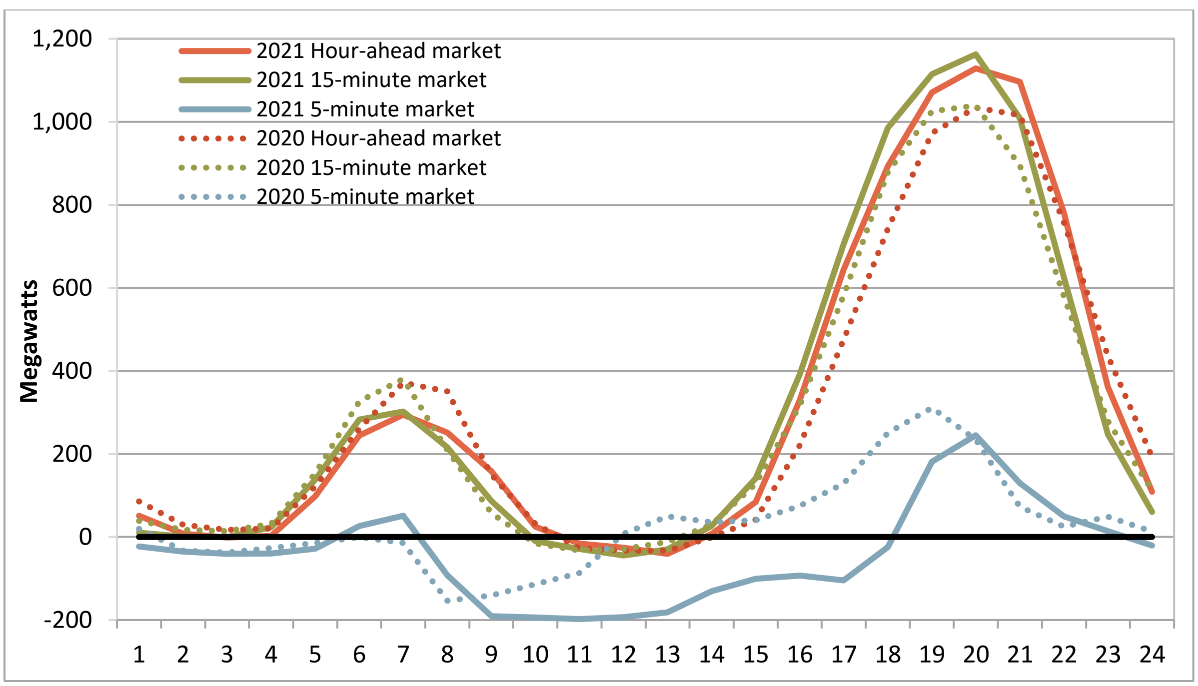
### Frequency and size of imbalance conformance adjustments

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the ISO hour-ahead and 15-minute markets. This large increase continues in the afternoon peak solar ramp down period, with average hourly imbalance conformance adjustments in these markets peaking at just about 1,150 MW, which is about 100 MW greater than the similar peak in the same quarter of the previous year. Imbalance conformance in the morning ramp up period decreased this quarter compared to the prior year, with averages around 300 MW in hour ending 7.

Figure 1.52 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 1.52 Average hourly imbalance conformance adjustment (Q2 2020 – Q2 2021)**



## 1.15 Exceptional dispatch

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

Exceptional dispatches can be grouped into three distinct categories:

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

- **In-sequence real-time energy** — Exceptional dispatches are also issued in the real-time market to ensure that a unit generates above its minimum operating level. This report refers to energy that would likely have cleared the market without an exceptional dispatch (i.e., that has an energy bid price below the market clearing price) as in-sequence real-time energy.

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

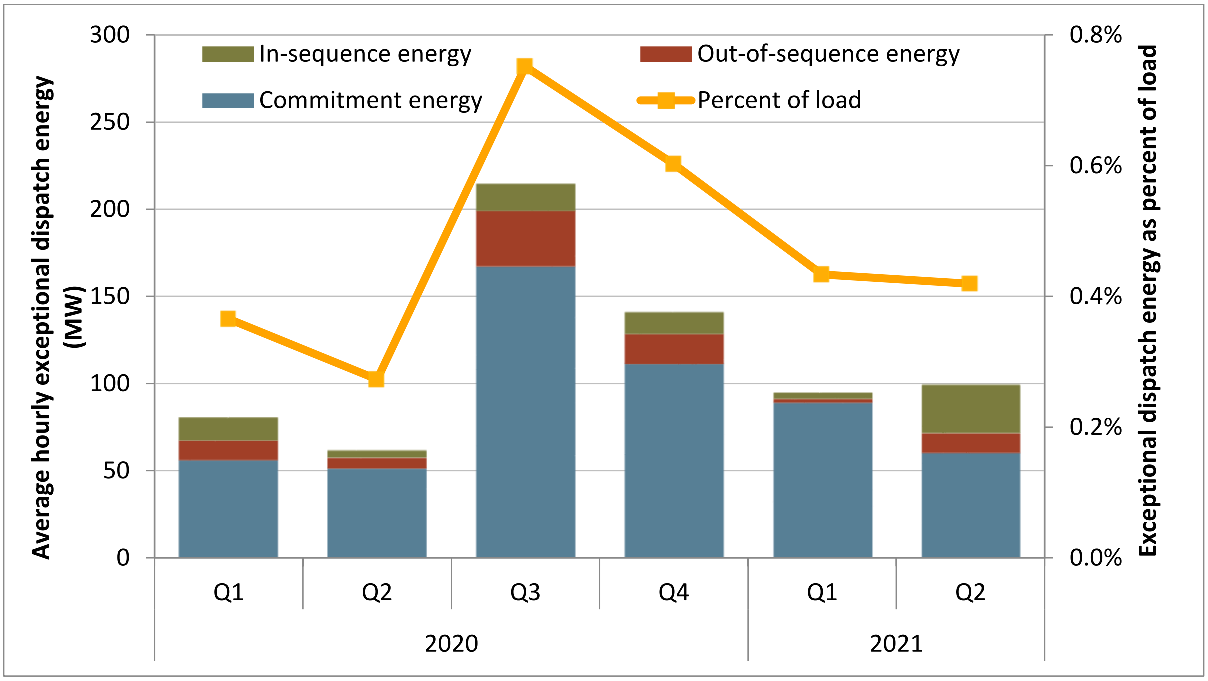
### Energy from exceptional dispatch

Energy from exceptional dispatch accounted for under 0.5 percent of total load in the ISO balancing area. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 100 MWh in the second quarter of 2021, which is up from 62 MWh in the same quarter in 2020.

As shown in Figure 1.53, exceptional dispatches for unit commitments accounted for about 61 percent of all exceptional dispatch energy in this quarter.[45] About 11 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 28 percent was from in-sequence energy.

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

**Figure 1.53 Average hourly energy from exceptional dispatch**

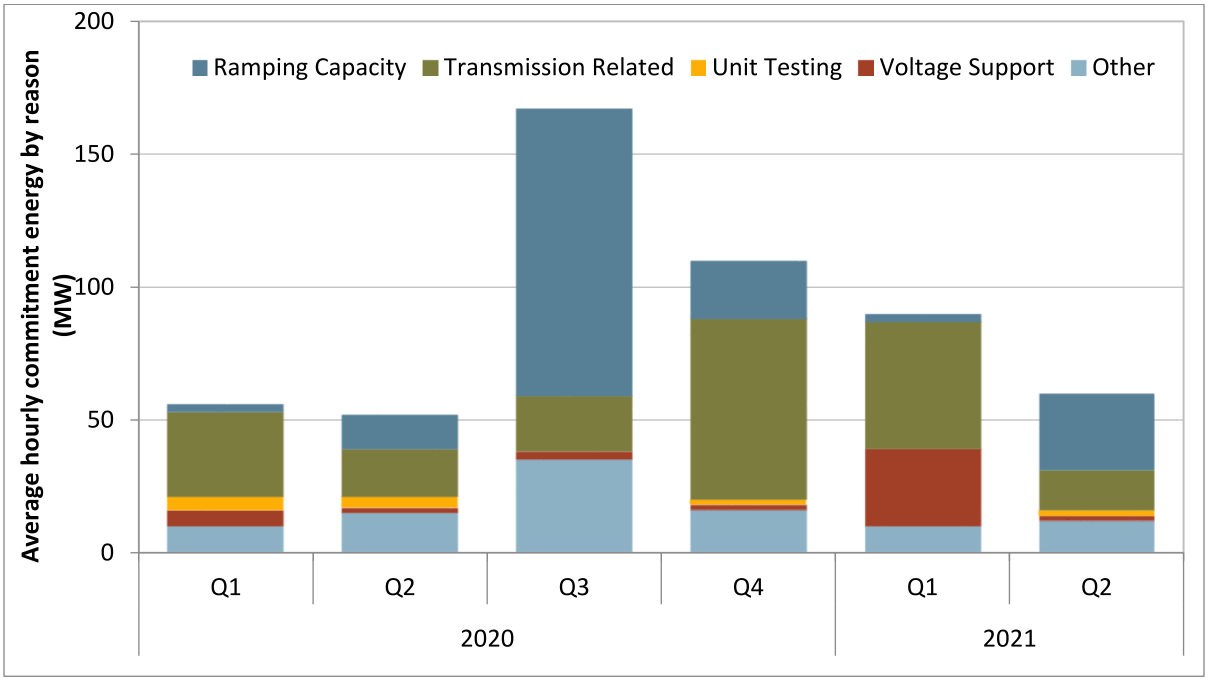



### Exceptional dispatches for unit commitment

ISO operators sometimes find instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements indirectly incorporated in the day-ahead market model. In these instances, the ISO may commit additional capacity by issuing an exceptional dispatch for resources to come on-line and operate at minimum load. Multi-stage generating units may be committed to operate at the minimum output of a specific multi-stage generator configuration, e.g., one by one or duct firing.

As shown in Figure 1.54, minimum load energy from exceptional dispatch unit commitments in the second quarter increased slightly on average by about 15 percent relative to the same quarter of the prior year. The most frequent reason given for exceptional dispatch unit commitments was for ramping capacity. Exceptional dispatch unit commitments for ramping capacity may be issued to address load forecast uncertainty or to commit a unit to its minimum dispatchable level.

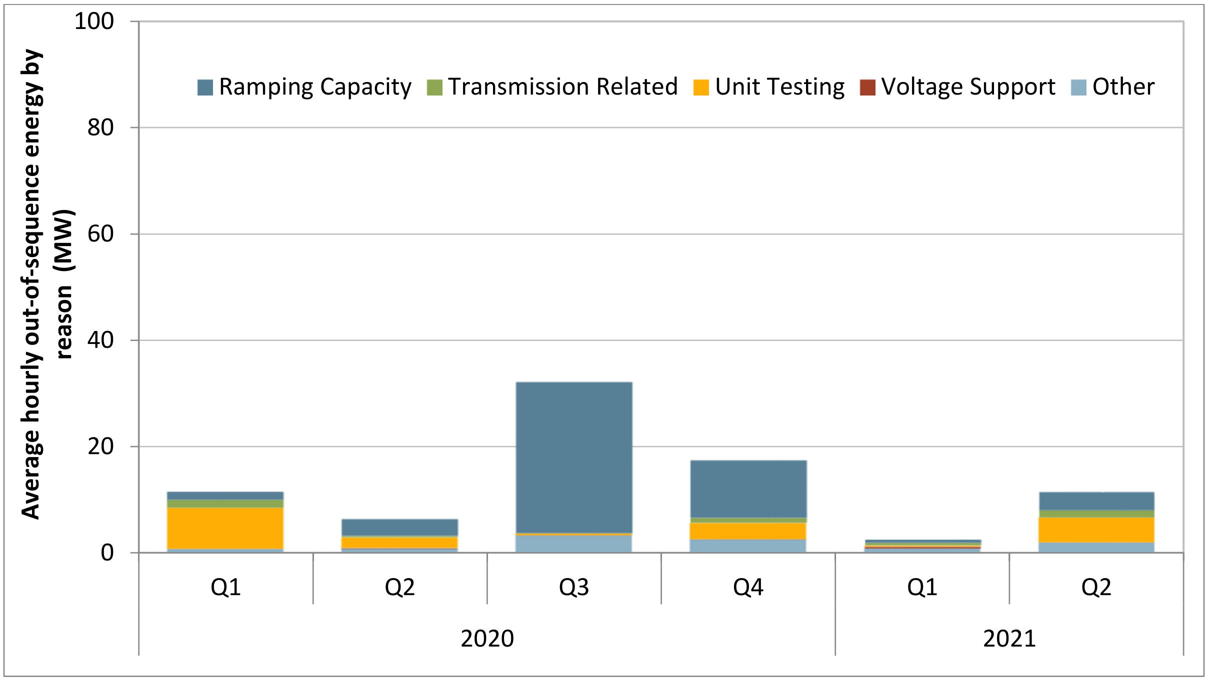
**Figure 1.54 Average minimum load energy from exceptional dispatch unit commitments**




## Exceptional dispatches for energy

As shown in Figure 1.53, in the second quarter of 2021, energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch almost quadrupled from the same quarter in 2020. Figure 1.53 also shows that about 11 percent of the total exceptional dispatch energy was out-of-sequence, meaning the bid price (or default energy bid if mitigated or if the resource did not submit a bid) was greater than the locational market clearing price. Figure 1.55 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2020 and 2021. In the second quarter, the primary reason logged for out-of-sequence energy was for unit testing followed by ramping capacity.

**Figure 1.55 Out-of-sequence exceptional dispatch energy by reason**




## Exceptional dispatch costs

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

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

Figure 1.56 shows the estimated costs for unit commitment and additional energy resulting from exceptional dispatches in excess of the market clearing price for this energy.[46] In the first quarter of 2021, commitment costs for exceptional dispatch paid through bid cost recovery increased significantly to about $10 million, compared to the same quarter of 2020. This increase can be attributed to significantly high gas prices during February 13 through 17 when these payments totaled $8.7 million. The figure also shows that out-of-sequence energy costs increased slightly to $1.2 million.[47]

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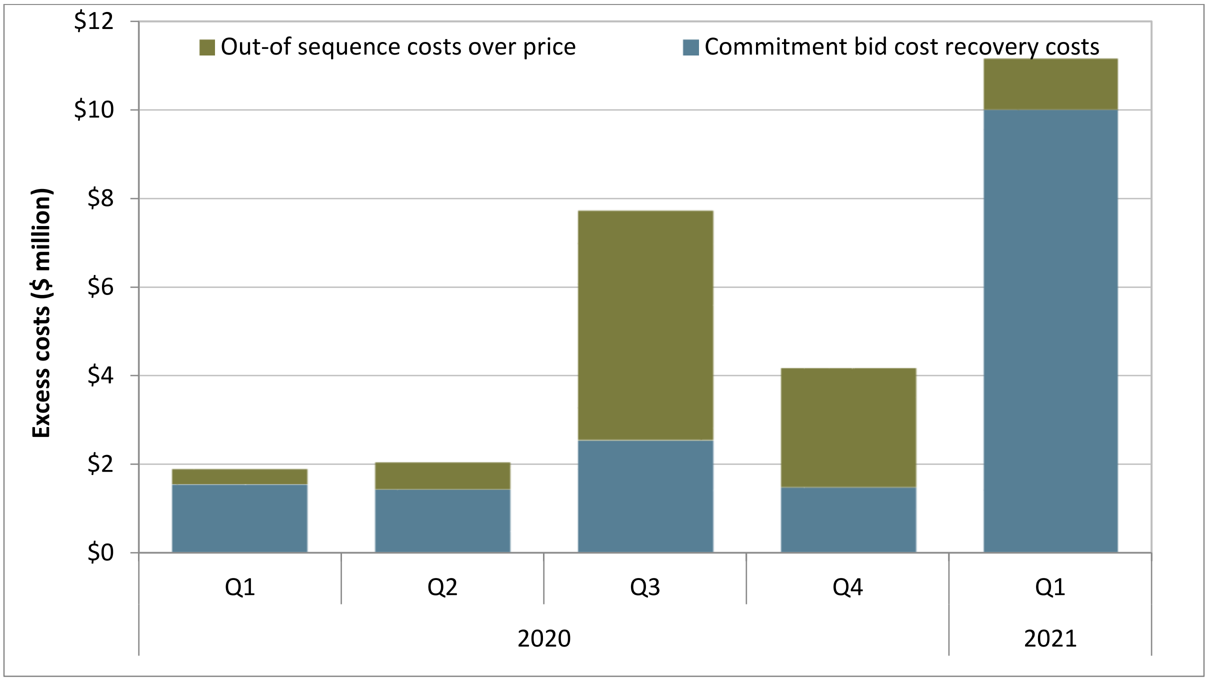
46 Due to changes in the availability of cost data, exceptional dispatch costs will be reported with a lag of one quarter.

47 The out-of-sequence costs are estimated by multiplying the out-of-sequence energy by the bid price (or the default energy bid if the exceptional dispatch was mitigated or the resource had not submitted a bid) minus the locational price for each relevant bid segment. Commitment costs are estimated from the real-time bid cost recovery associated with exceptional dispatch unit commitments.

**Figure 1.56 Excess exceptional dispatch cost by type**



# 2 Western Energy Imbalance Market

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

- **The Los Angeles Department of Water and Power, the Public Service Company of New Mexico, and NorthWestern Energy** joined in the second quarter, bringing over 14 GW of participating generation capacity and over 20 GW of transfer capacity into the Western EIM.
- **Prices in NV Energy were over $100/MWh on average in the hour between 8 and 9 pm** in both the 15-minute and 5-minute markets, driven by high penalty prices associated with under-supply infeasibilities when NV Energy was separated from the rest of the system. Penalty prices were raised from $1,000/MWh to $2,000/MWh in March. As in previous quarters, under-supply infeasibilities often occurred following the failure of a resource sufficiency test failure which can limit imports into a failing area. In June, the ISO implemented Phase 2 of FERC Order 831, limiting conditions in which the $2,000/MWh penalty price would apply.
- **Prices in California areas were more than $10/MWh higher than other regions,** on average. 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**, which include PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex, were regularly lower than prices in other balancing areas due to limited transfer capability out of this region during peak system load hours.
- **On June 16, 2021, the ISO added net load uncertainty to the requirement of the bid range capacity test** as part of a package of market enhancements for Summer 2021 readiness. Between June 16 and June 30, there were 65 capacity test failures across all areas; 83 percent of these were caused entirely by the additional uncertainty component.
- **Over the year ending in June, NV Energy, and Salt River Project had the most** flexible ramping sufficiency or bid range capacity test failures, and were net importers in almost all failure intervals. During around 89 percent of upward test failures for Arizona Public Service and PacifiCorp West, the resulting cap that was imposed was in a net export position (cannot reduce exports).
- **In the California ISO**, significantly more 15-minute market transfers were affected by test failures than 5-minute market transfers in the year ending June. This may be due in part to differences in imbalance conformance.
- **The resource sufficiency evaluation includes a balancing test** applied each hour to all non-ISO areas. Penalty payments totaling over $4.5 million over the last 3 years have been paid to all areas, including the California ISO.
- **DMM has agreed to provide additional transparency surrounding test accuracy and performance** in regular reports specific to this topic as part of the EIM resource sufficiency evaluation stakeholder initiative. This second quarter report, as well as the special reports issued by DMM in May and September, summarizes some of the existing metrics that can be included in these future EIM resource sufficiency evaluation reports. DMM is seeking feedback from stakeholders on existing or additional metrics and analysis that would be most valuable.

## 2.1 Western EIM performance

### New Western EIM balancing authority areas

On April 1, 2021, the Los Angeles Department of Water and Power and Public Service Company of New Mexico joined the EIM, followed by NorthWestern Energy, which joined on June 15, 2021. The addition of these entities brings the total number of participants up to 15. The Los Angeles Department of Water and Power, Public Service Company of New Mexico, and NorthWestern Energy bring with them about 9,200 MW, 3,800 MW, and 1,300 MW of participating capacity, respectively. Los Angeles Department of Water and Power adds about 6,900 MW of import and 10,700 MW export transfer capacity; Public Service Company of New Mexico adds about 1,000 MW of import and export capacity; and NorthWestern Energy adds roughly 800 MW of import and 500 MW of export capacity.[48] The Department of Market Monitoring's monthly EIM transition reports provide more information on these entities' transition into the Western EIM and will detail each entity's first six months in the market.[49]

### Western EIM prices

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

Figure 2.1 shows average monthly prices for the 15-minute market by balancing authority area for 2019 through 2021. The 'Northwestern EIM 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.[50] Prices for the Balancing Authority of Northern California (dark blue line) begin in April of 2019 when the Sacramento Municipal Utility District joined the market, while 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 Western EIM. 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.[51] Prices for Pacific Gas & Electric (grey dashed line) are included in the figure as a point of comparison.

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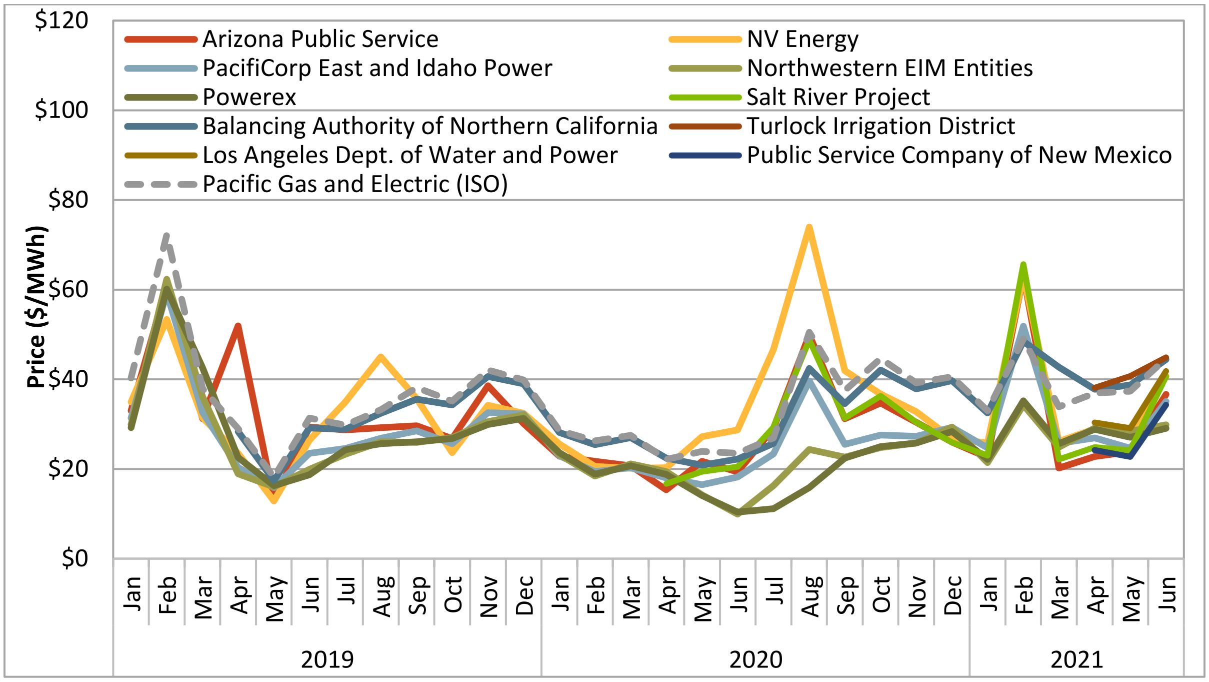
48 NorthWestern Energy data is for June 16 – June 30 only. Average import and export limits for NorthWestern Energy are subject to change in future reports.

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

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

51 Turlock Irrigation District was a part of the EIM for one week of March 2021; therefore, data for the TID area in March 2021 are not included in this section's analysis.

**Figure 2.1 Monthly 15-minute market prices**




The combined average of Western EIM prices outside of California were below California area prices by $10.59/MWh on average for the quarter. Prices of EIM entities within California were closer to those of Pacific Gas & Electric. The combined average prices of these areas, which include Balancing Area of Northern California, Turlock Irrigation District, and Los Angeles Department of Water and Power, was $1.21/MWh lower than Pacific Gas & Electric prices.

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

Figure 2.2 depicts the average 15-minute price by component for each balancing authority area in the EIM during the second quarter.[52] The system marginal energy price is the same for all entities in each hour. The price difference between EIM 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 EIM 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 EIM transfer constraints, including any PBC relaxations that increase the price in a single area.

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52 The 'Congestion within CAISO' component represents all congestion on internal constraints, including those within CAISO and the EIM. CAISO-specific internal constraints make up the large majority of this category.

**Figure 2.2 Quarterly average 15-minute price by component (Q2 2021)**

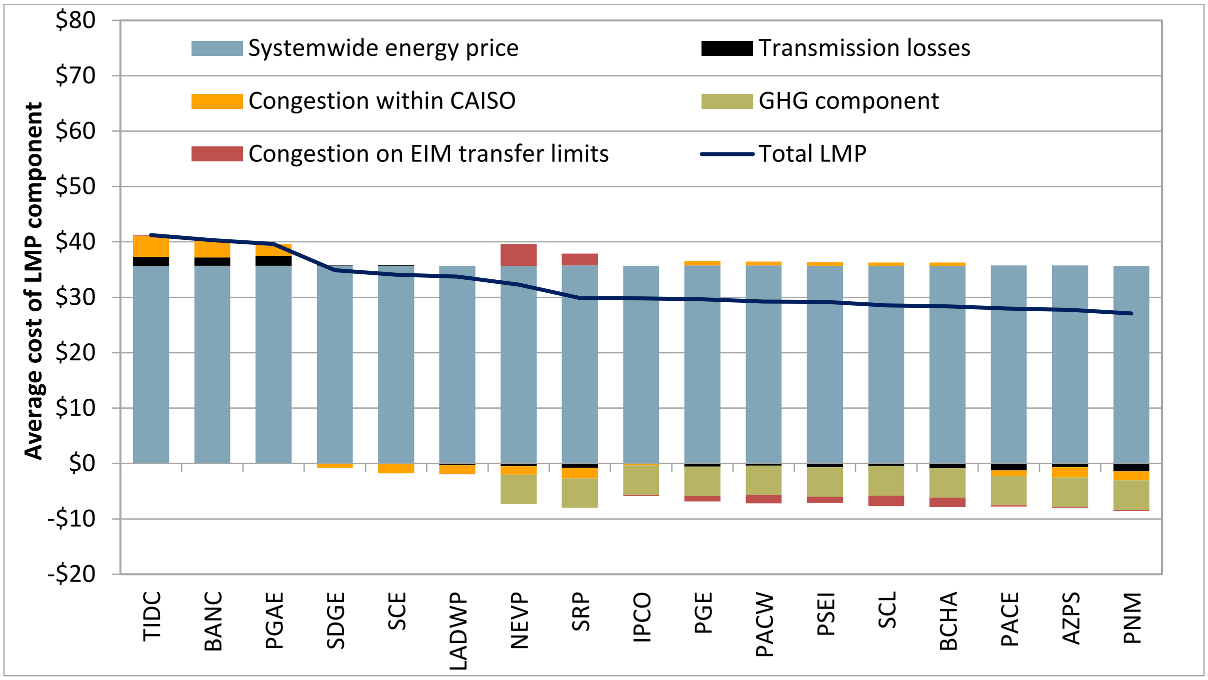



Figure 2.3 and Figure 2.4 show the variation in Western EIM prices throughout the day in the second quarter of 2021. Average hourly prices are shown for participating balancing authorities between April 1 and June 30, 2021. Prices followed the net load pattern with the highest energy prices during the evening peak net load hours in most Western EIM balancing areas, just as in the California ISO balancing area. As in the previous analysis, several balancing areas are grouped together because of similar average hourly pricing, and prices at the Pacific Gas & Electric default load aggregation point are shown as a point of comparison.[53]

[53] The 'Northwestern EIM Entities' line consists of PacifiCorp West, Puget Sound Energy, Portland General Electric, and Seattle City Light

**Figure 2.3 Hourly 15-minute market prices (April – June)**

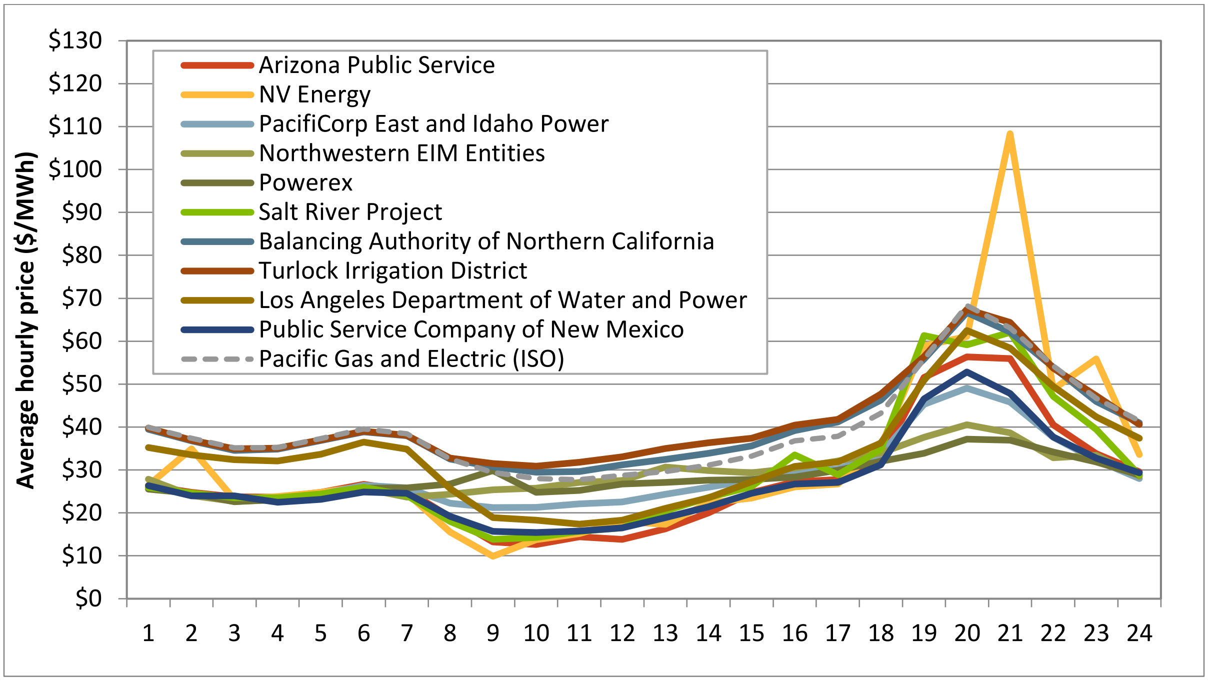
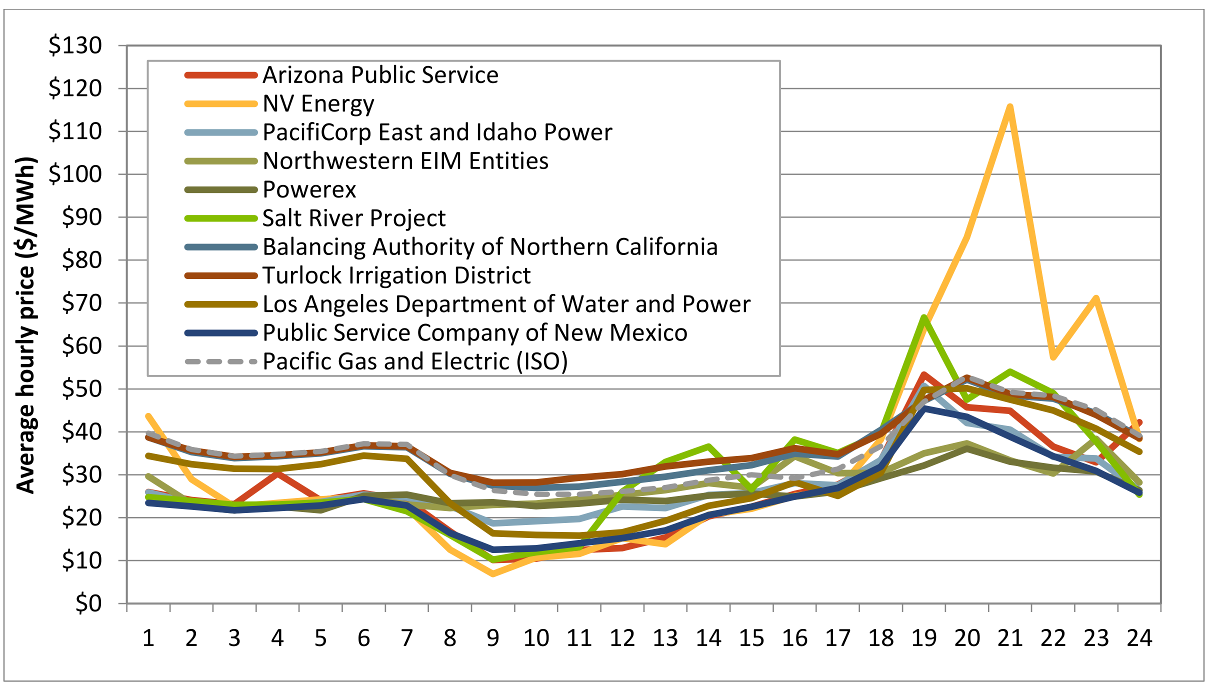



**Figure 2.4 Hourly 5-minute market prices (April – June)**




The relative price differences between Western EIM entities vary throughout the day. Prices in entities outside of California tend to be lower than California prices in most hours. This price divergence is most pronounced during the evening ramping periods and net load peak hours, when the California areas are typically importing energy subject to greenhouse gas compliance costs. Western EIM entity prices converge with California area prices in the middle of the day, when these areas tend to export energy.

Prices in EIM entities within California tracked relatively close with prices in the California ISO balancing area during the quarter because of significant transfer capability and little congestion between the areas.

Average prices in the Northwest region (including PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex) remain more consistent throughout the day, with small increases during ramping hours. This reflects the limited transmission available in the Western EIM to support transfers from the Northwest to California and other balancing authorities in the Southwest.

As seen in Figure 2.3 and Figure 2.4, NV Energy had a significant price spike in hour ending 21. This is due in part to the relatively high frequency of power balance constraint (PBC) shortages in the NV Energy area in this particular hour. Figure 2.5 breaks down NV Energy's average locational marginal price (LMP) by component for every hour of the day. In hour ending 21, the EIM congestion component drastically increases. As mentioned above, this component includes intervals in which a single balancing authority experiences a PBC shortage and is then subject to penalty prices. In this quarter PBC penalty prices were scaled up to the hard bid cap of $2,000/MWh until the implementation of the second phase of FERC Order 831 on June 13, 2021.

Similar figures are provided across different regions of the EIM and provide further evidence of the regional trends discussed earlier. Figure 2.6 shows the hourly price composition for Los Angeles Department of Water and Power and reflects typical trends seen in the California region, where congestion from high levels of solar production drives down prices in southern areas. Figure 2.7 shows the hourly price composition for Seattle City Light and highlights how the limited transfer capability in the Northwest region lowers prices during the peak evening hours. Figure 2.8 shows the hourly price composition for Arizona Public Service, and exemplifies the congestion trend experienced by entities in the Southwest region. Congestion in this region typically constrains the ability of these entities to export power in the middle of the day and import power during evening net peak load hours.

**Figure 2.5 NV Energy average 15-minute price by component (Q2 2021)**

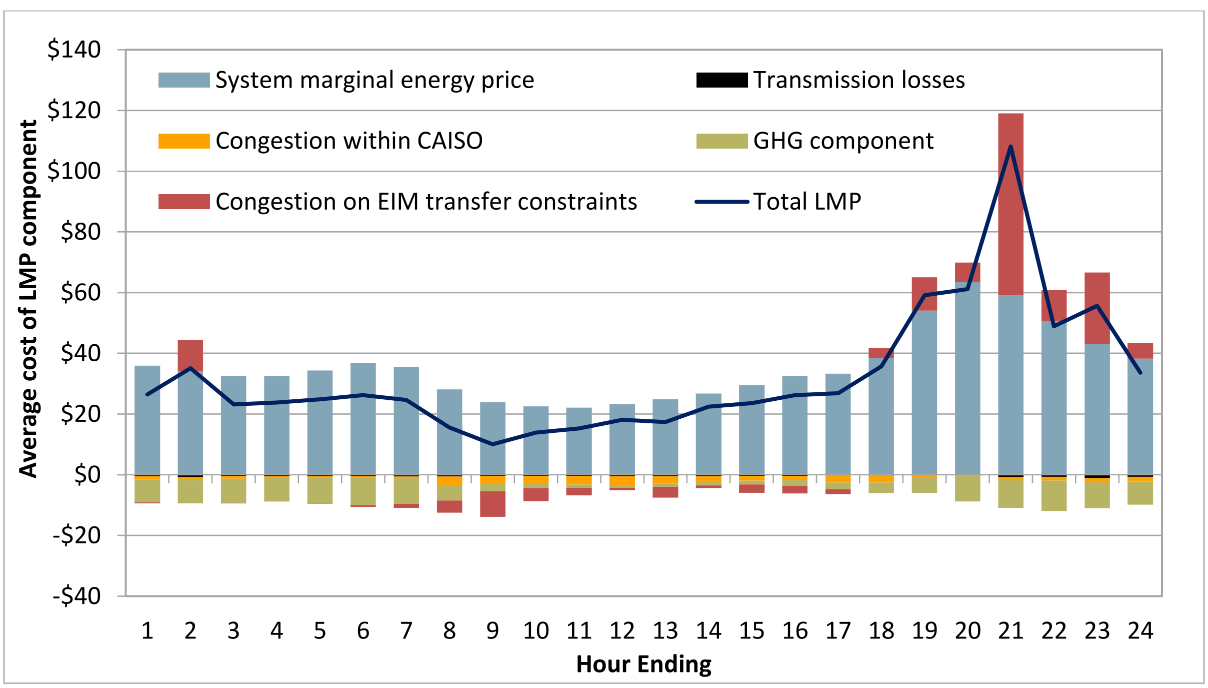


**Figure 2.6 Los Angeles Department of Water and Power average 15-minute price by component (Q2 2021)**

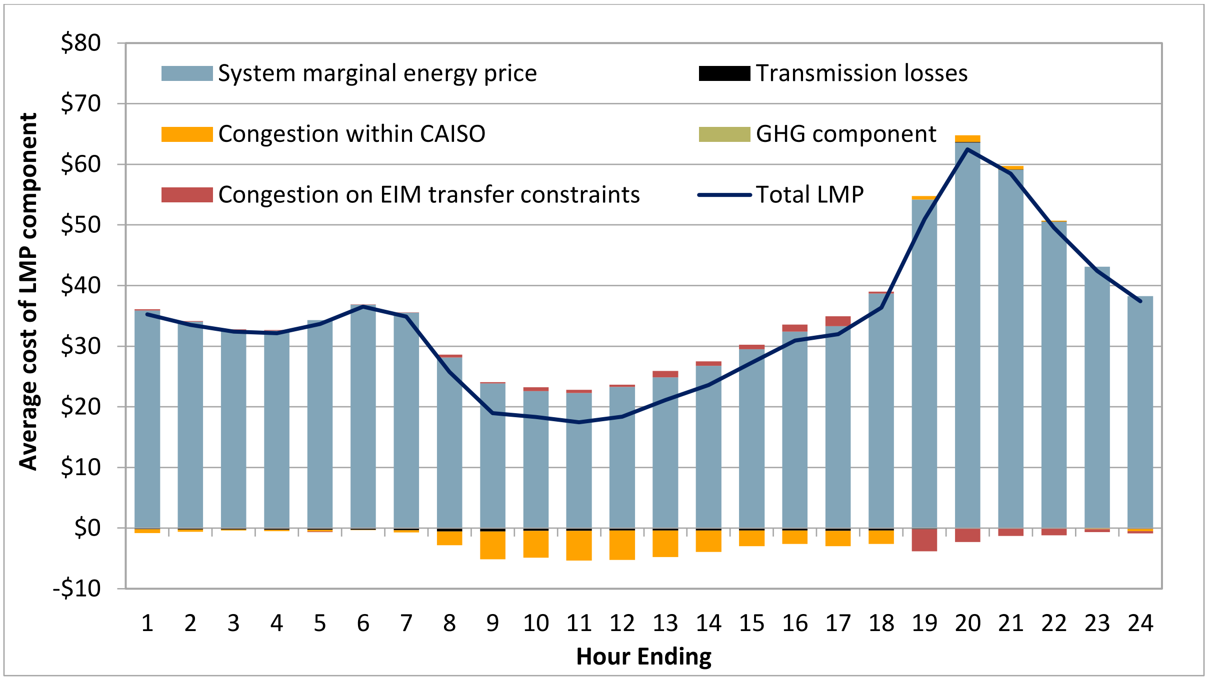



**Figure 2.7 Seattle City Light average 15-minute price by component (Q2 2021)**

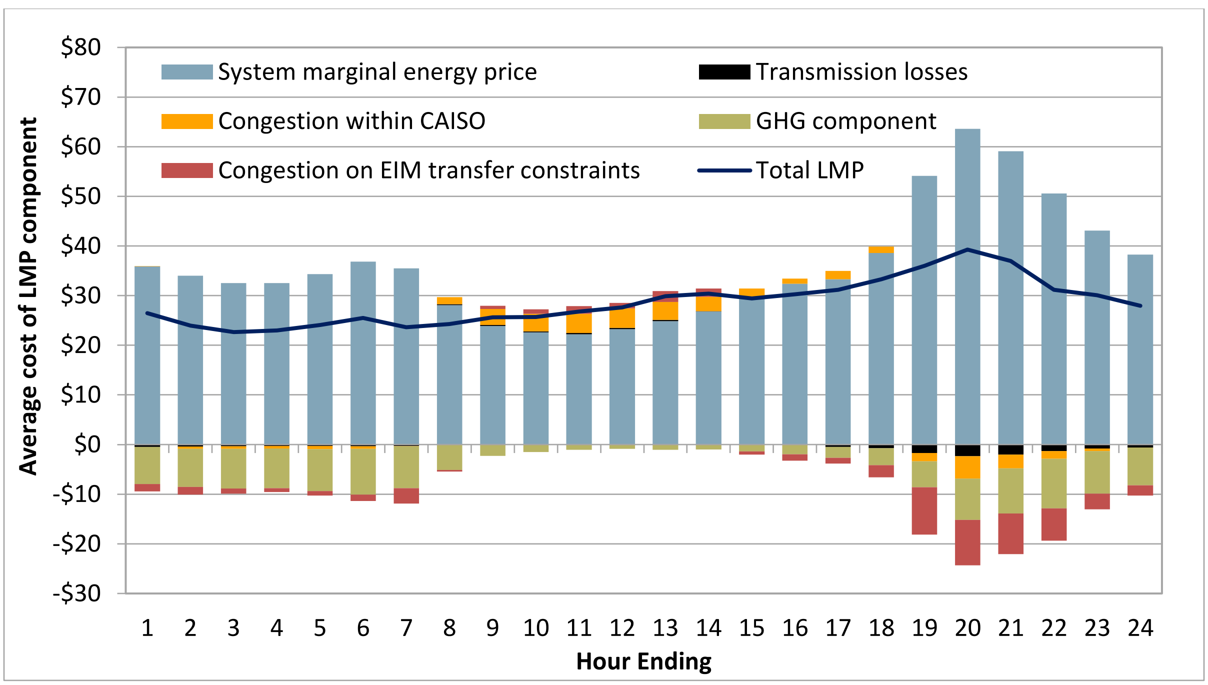
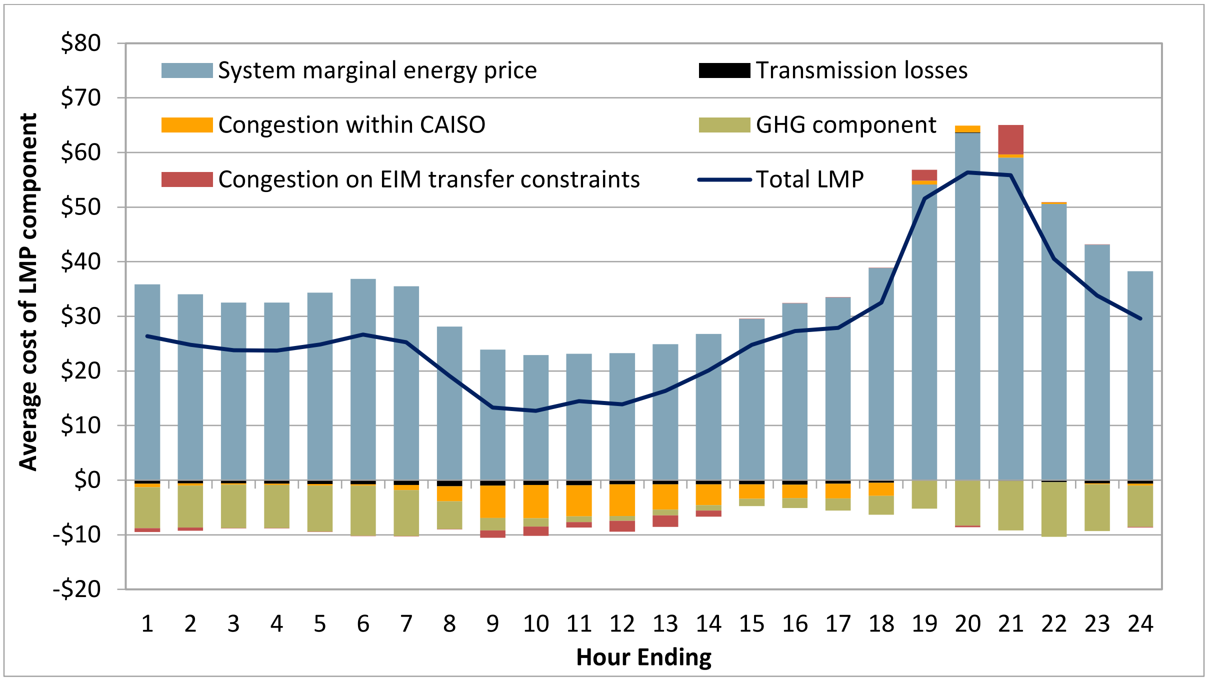


**Figure 2.8 Arizona Public Service average 15-minute price by component (Q2 2021)**




## 2.2 EIM resource sufficiency evaluation

As part of the energy imbalance market, each area including the California ISO is subject to a resource sufficiency evaluation. The evaluation is performed prior to each hour to ensure that generation in each area is sufficient without relying on transfers from other balancing areas. The evaluation 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 (sufficiency test)** requires that each balancing area has enough ramping flexibility over an hour to meet the forecasted change in demand as well as uncertainty.

If an area fails either the bid range capacity test or flexible ramping sufficiency test in the upward direction, energy imbalance market transfers into that area cannot be increased.[54]

On June 16, 2021, the ISO added net load uncertainty to the requirement of the bid range capacity test as part of a package of market enhancements for Summer 2021 readiness. Between June 16 and June 30, there were 65 capacity test failures across all areas; 83 percent of these were caused entirely by the

[54] If an area fails either test in the upward direction, net EIM imports during the hour cannot exceed the more lenient of either the base transfer or optimal transfer from the last 15-minute interval prior to the hour.

additional uncertainty component.[55] The ISO has proposed a series of additional enhancements as part of the resource sufficiency evaluation stakeholder initiative.[56]

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

### Bid range capacity and flexible ramping sufficiency test results

Figure 2.9 and Figure 2.10 show the percent of intervals in which each EIM area failed the upward capacity and sufficiency tests, while Figure 2.11 and Figure 2.12 provide the same information for the downward direction.[57] 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.

In particular, for the second quarter of 2021, NV Energy failed the downward sufficiency test in more than 2 percent of intervals while Arizona Public Service and Powerex each failed this test in roughly 1 percent of intervals. Puget Sound Energy failed the upward capacity test in roughly 1 percent of intervals.

55 For additional analysis on the impact of the uncertainty component on 2020 data (as well as the impact of the errors identified and corrected by the ISO in early 2021) see DMM's special report: http://www.caiso.com/Documents/Report-on-Resource-Sufficiency-Tests-in-the-Energy-Imbalance-Market-May-20-2021.pdf

56 *EIM Resource Sufficiency Evaluation Enhancements Straw Proposal*, August 16, 2021. http://www.caiso.com/InitiativeDocuments/StrawProposal-ResourceSufficiencyEvaluationEnhancements.pdf

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

**Figure 2.9 Frequency of upward capacity test failures by month and area (percent of intervals)**

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

**Figure 2.10 Frequency of upward sufficiency test failures by month and area (percent of intervals)**

| | 2020 | | | | | | | | | 2021 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun |
| Arizona PS | 0.1 | 1.0 | — | — | — | 0.3 | 0.8 | 0.7 | 0.6 | 0.5 | 0.5 | 0.2 | — | 0.6 | — |
| BANC | — | — | — | — | 0.2 | 0.0 | 0.1 | — | 0.1 | — | — | — | — | — | — |
| California ISO | — | — | — | 0.1 | 1.1 | 0.5 | 0.4 | 0.5 | — | — | — | — | — | — | 0.0 |
| Idaho Power | — | 0.1 | 0.3 | 0.1 | 0.2 | — | — | — | — | — | 0.1 | — | — | — | — |
| LADWP | | | | | | | | | | | | | 0.0 | 0.1 | — |
| NorthWestern | | | | | | | | | | | | | | | 1.3 |
| NV Energy | 0.7 | 2.6 | 2.3 | 4.5 | 7.1 | 2.6 | 1.4 | 0.8 | — | 0.1 | 0.5 | 0.4 | 0.4 | 0.7 | 0.9 |
| PacifiCorp East | 0.0 | 0.2 | 0.1 | 0.2 | 0.2 | 0.1 | 0.5 | 0.0 | — | 0.1 | 0.1 | 0.1 | 0.1 | 0.0 | 0.1 |
| PacifiCorp West | 0.1 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.0 | 0.1 | 0.0 | 0.2 | 0.1 | 0.1 | 0.0 | — |
| Portland GE | — | — | 0.0 | 0.2 | 0.2 | 0.6 | 0.1 | 0.1 | 0.2 | 0.3 | 0.6 | 0.1 | 0.2 | 0.2 | 0.3 |
| Powerex | — | 0.5 | 0.2 | 0.2 | 0.1 | 0.3 | 0.1 | 0.6 | 0.2 | 0.2 | 0.1 | 0.1 | 0.1 | — | 0.1 |
| PSC New Mexico | | | | | | | | | | | | | 0.4 | 0.0 | 0.1 |
| Puget Sound En | — | 0.0 | 0.3 | 0.6 | 0.4 | — | 0.2 | — | — | — | — | — | — | 0.1 | 0.1 |
| Salt River Proj. | 1.8 | 0.1 | 0.5 | 0.7 | 1.8 | 1.1 | 1.7 | 0.9 | 0.3 | 0.2 | 7.1 | 0.3 | 0.5 | 0.2 | 0.9 |
| Seattle City Light | — | — | — | 0.1 | — | 0.1 | 0.2 | 0.2 | 0.1 | — | — | — | — | — | — |
| Turlock ID | | | | | | | | | | | | — | — | 0.3 | — |

**Figure 2.11 Frequency of downward capacity test failures by month and area (percent of intervals)**

| | 2020 | | | | | | | | | 2021 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun |
| Arizona PS | 0.1 | — | — | — | — | — | — | — | — | — | — | — | — | 0.0 | — |
| BANC | 0.2 | 0.2 | — | — | — | — | 0.1 | 0.1 | — | — | 0.0 | 0.1 | — | — | — |
| California ISO | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Idaho Power | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| LADWP | | | | | | | | | | | | | — | — | 0.1 |
| NorthWestern | | | | | | | | | | | | | | | — |
| NV Energy | — | — | — | — | — | — | — | — | — | — | — | — | — | — | 0.0 |
| PacifiCorp East | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| PacifiCorp West | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Portland GE | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Powerex | — | 0.1 | — | 0.0 | 0.0 | — | 0.0 | — | — | — | — | — | 0.0 | — | 0.3 |
| PSC New Mexico | | | | | | | | | | | | | — | — | — |
| Puget Sound En | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Salt River Proj. | 0.5 | 0.5 | 0.0 | — | — | — | — | — | — | — | — | — | 0.0 | — | 0.0 |
| Seattle City Light | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Turlock ID | | | | | | | | | | | | — | — | 0.3 | 0.2 |

**Figure 2.12 Frequency of downward sufficiency test failures by month and area (percent of intervals)**

| | 2020 | | | | | | | | | 2021 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun |
| Arizona PS | 0.9 | 0.5 | 2.3 | 0.1 | — | 0.1 | 1.9 | 0.9 | 2.5 | 2.2 | 2.3 | 4.3 | 1.9 | 0.3 | 0.1 |
| BANC | 0.5 | 1.3 | 0.3 | — | — | — | 0.1 | 0.3 | — | — | 0.6 | 0.4 | — | — | — |
| California ISO | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Idaho Power | — | 0.7 | — | 0.0 | — | — | 0.0 | 0.0 | — | — | — | — | — | 0.0 | — |
| LADWP | | | | | | | | | | | | | — | — | 0.1 |
| NorthWestern | | | | | | | | | | | | | | | 0.7 |
| NV Energy | 4.8 | 6.5 | 5.1 | 0.7 | 0.8 | 2.2 | 0.5 | 1.4 | 1.1 | 0.2 | 6.1 | 1.4 | 0.5 | 4.3 | 2.0 |
| PacifiCorp East | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| PacifiCorp West | — | — | — | — | — | — | — | — | — | — | — | 0.1 | — | — | 0.1 |
| Portland GE | — | 0.2 | 0.1 | — | — | — | — | — | — | 0.0 | — | — | — | — | — |
| Powerex | — | 0.1 | — | 0.0 | 0.1 | 0.1 | 0.1 | — | — | 0.4 | — | 1.4 | 0.2 | 0.9 | 1.3 |
| PSC New Mexico | | | | | | | | | | | | | 1.4 | — | 0.0 |
| Puget Sound En | — | 0.5 | 0.8 | 0.1 | — | — | — | — | — | — | — | — | — | — | — |
| Salt River Proj. | 0.8 | 1.0 | 0.1 | — | 0.0 | 0.1 | 0.1 | 0.2 | 0.8 | 1.1 | 1.6 | 1.2 | 0.2 | 0.1 | 0.2 |
| Seattle City Light | 0.5 | — | — | 0.1 | 0.2 | 0.2 | 0.1 | 0.1 | 0.1 | — | — | — | — | — | — |
| Turlock ID | | | | | | | | | | | | 0.4 | 0.1 | 0.5 | — |

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

As part of the stakeholder initiative for resource sufficiency evaluation enhancements, the ISO is considering additional consequences for bid range capacity or flexible ramping sufficiency test failures. This section summarizes existing consequences, focusing on the import limit imposed because of failing either test in the upward direction.

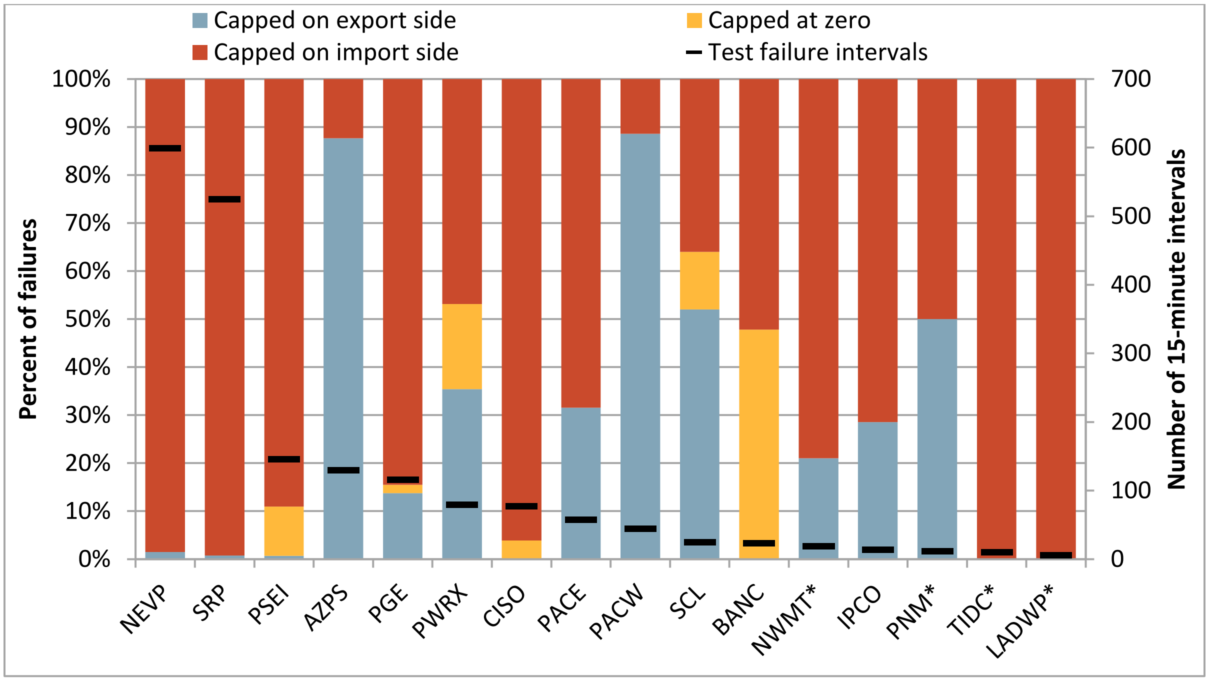
When either test fails in the upward direction, imports will be capped at the more lenient of the base transfer or the optimal transfer from the last 15-minute market interval. If both the base transfer and the last 15-minute transfer are in a net export position, the cap will be imposed on the export side (cannot export less than the imposed level).

Figure 2.13 summarizes the import limits that were imposed after failing either test by area and position. Each of the charts in this subsection cover one year of data, July 2020 through June 2021. The black horizontal line (right axis) shows the number of 15-minute intervals with either a capacity or sufficiency test failure. The energy imbalance market areas are shown in descending number of failure intervals. The bars (left axis) show the percent of the failure intervals that meet the condition.

During around 89 percent of upward test failures for Arizona Public Service and PacifiCorp West, the resulting cap that was imposed was in a net export position (cannot reduce exports). NV Energy and Salt River Project, which had the most test failures during this period, were net importers in almost all failure intervals.

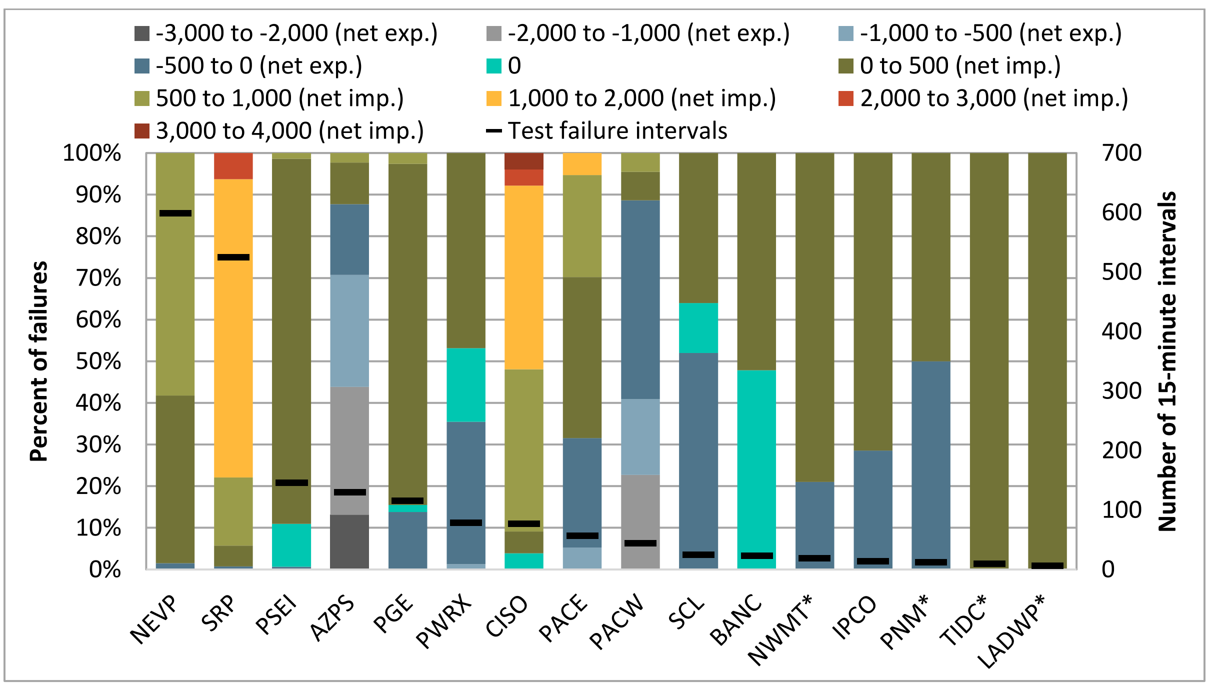
Figure 2.14 summarizes the same information, except with the import limit itself categorized by various quantity buckets. In particular, the net import limit for Salt River Project was greater than 1,000 MW during 78 percent of test failure intervals. The net import limit for the ISO was greater than 1,000 MW during 52 percent of test failure intervals.

**Figure 2.13 Upward capacity/sufficiency test failure intervals by import limit position (July 2020 – June 2021)**




*Since joining the energy imbalance market in the spring of 2021

**Figure 2.14 Upward capacity/sufficiency test failure intervals by import limit amount (July 2020 – June 2021)**

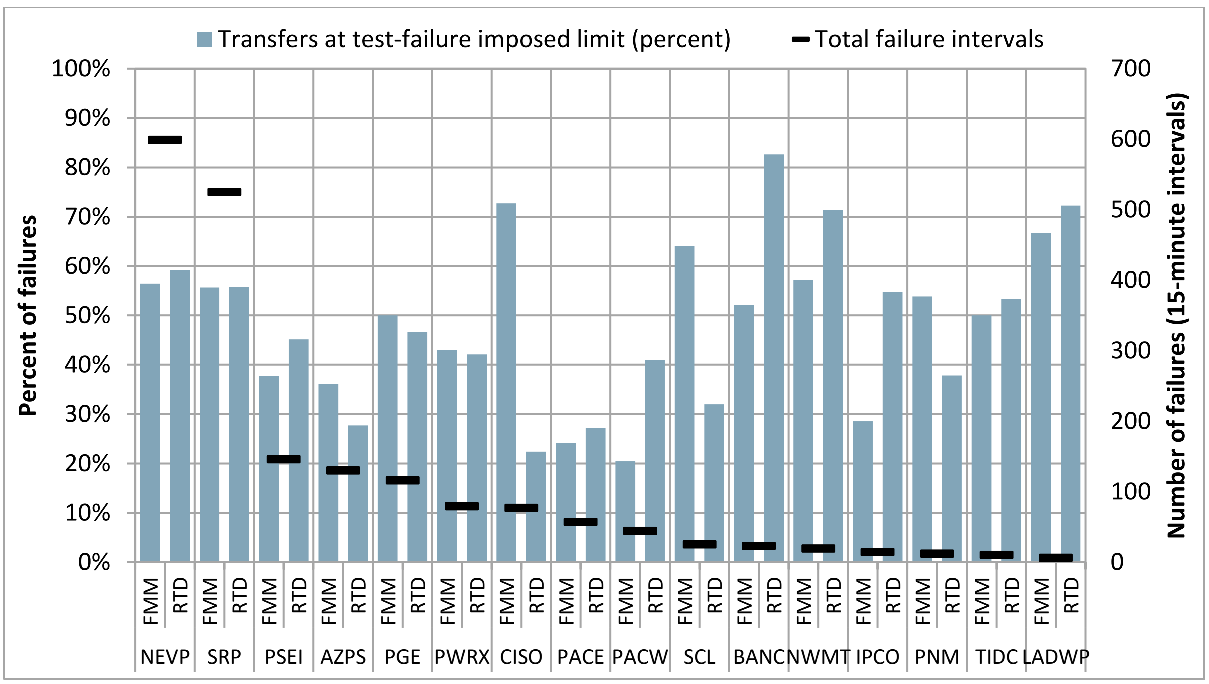



*Since joining the energy imbalance market in the spring of 2021

Figure 2.15 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. These results are separated between energy imbalance market transfers in the 15-minute and 5-minute markets.

In the California ISO balancing area, 73 percent of 15-minute market transfers during failure intervals were affected by the test failure but only 22 percent of 5-minute market transfers. This is in part because of systematically higher imbalance conformance adjustments entered by ISO operators in the 15-minute market relative to the 5-minute market. Here, the optimal transfer in the last 15-minute interval prior to the test increases as the optimization solves for load plus imbalance conformance, potentially setting a higher import limit than would exist absent 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 2.15 Percent of upward test failure intervals with market transfers at the imposed cap (July 2020 – June 2021)**




## Balancing test failures and settlement

The resource sufficiency evaluation includes a balancing test applied each hour to all non-ISO energy imbalance market areas. Here, areas that elect to use the ISO-generated load forecast must show base schedules to be within 1 percent of the forecast. Areas that fail the balancing test are subject to potential over-scheduling or under-scheduling penalties. The penalty is then applied if the final area metered load is 5 percent more or less than the base schedules. There are then two tiers of prices depending on whether the under/over scheduling is above 5 percent or above 10 percent.

Figure 2.16 and Figure 2.17 show under-scheduling and over-scheduling balancing test failures by area for one year, between April 1, 2020, and March 31, 2021. The failure amounts are shown both as a number of hours (left axis) and a percent of hours (right axis). The categories summarize the final calculation between base schedules and metered load and whether the penalty was ultimately applied. During this period, balancing test failures for under-scheduling and over-scheduling were infrequent. As shown across Figure 2.16 and Figure 2.17, Salt River Project, Arizona Public Service, and NV Energy each failed the test in either direction in around 2 percent of hours. Across all areas, 20 percent of under-scheduling balancing test failures and 14 percent of over-scheduling balancing test failures ultimately met the threshold to incur penalties.

Powerex is not included in these charts because they do not use the ISO-generated load forecast. EIM entities that elect to use their own forecast are not subjected to the initial balancing test but are instead subject to potential under-scheduling or over-scheduling penalties in *all* hours. Powerex met the 5 percent threshold for under- or over-scheduling penalties in less than 0.2 percent of hours.

Figure 2.18 shows balancing-test-triggered under-scheduling and over-scheduling penalty payments and allocation from 2019 through the first quarter of 2021.[58] During each of 2019 and 2020, there was a total of roughly $1 million in penalties. Here, around 47 percent of these payments were allocated to ISO load. Penalties in only the first quarter of 2021 totaled around $2.4 million. This was predominantly from a single extreme hour associated with under-scheduling. As part of the stakeholder initiative for resource sufficiency evaluation enhancements, the ISO has proposed to exclude the ISO balancing authority area from potential revenue allocation.

[58] Due to the availability of settlement data, information reported in this subsection is lagged one quarter.

**Figure 2.16 Under-scheduling balancing test failures (April 2020 – March 2021)**

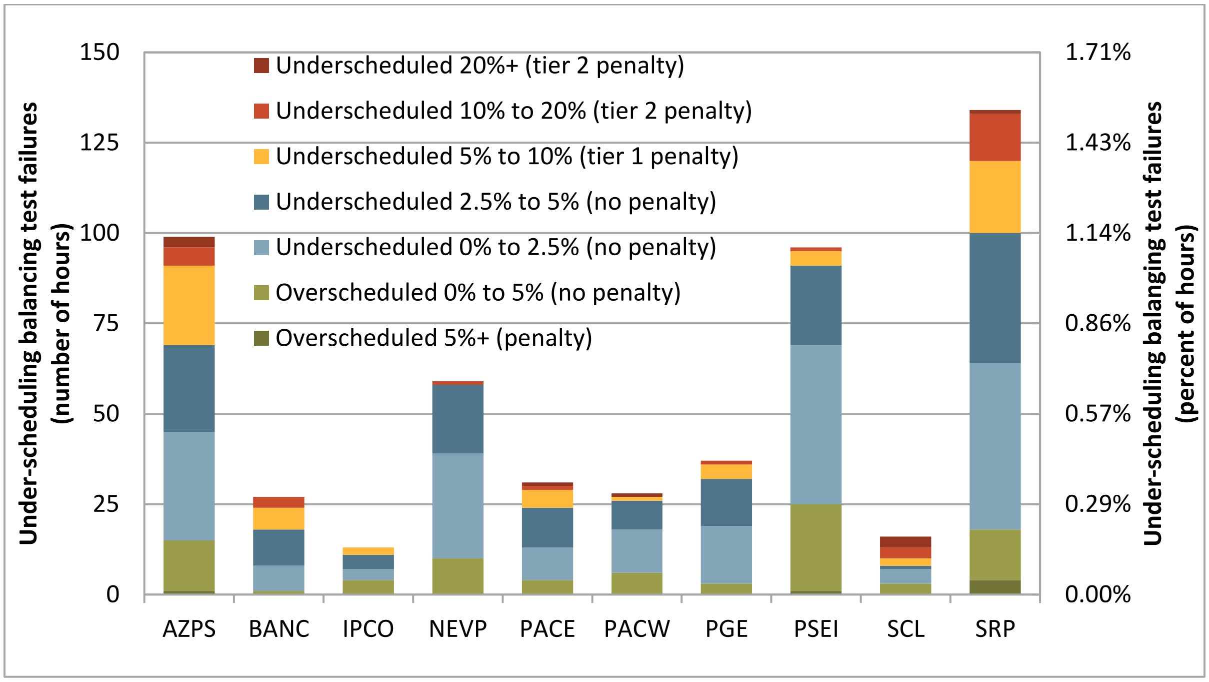



**Figure 2.17 Over-scheduling balancing test failures (April 2020 - March 2021)**

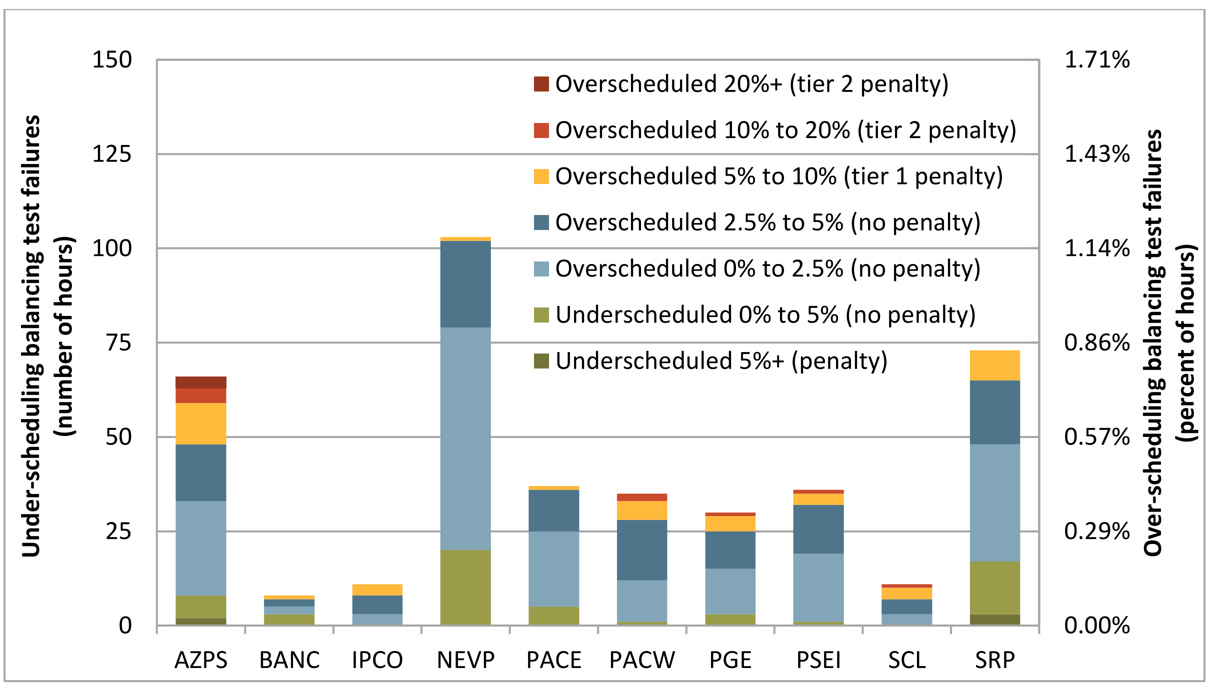
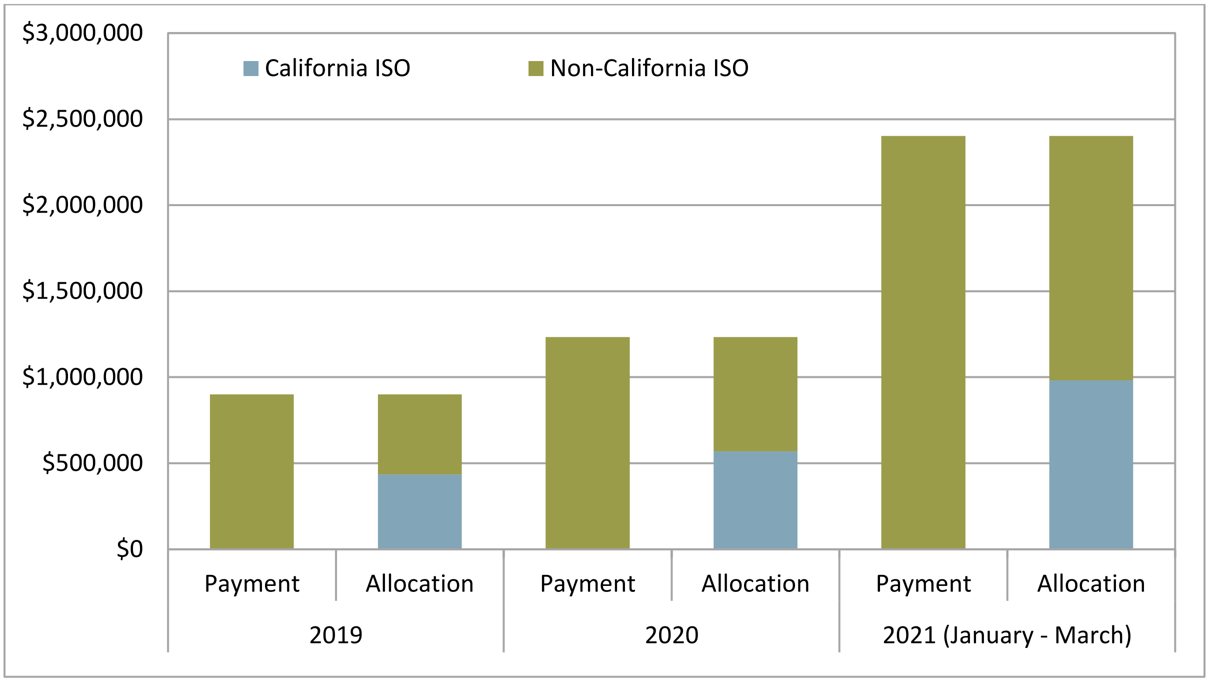


**Figure 2.18 Under-scheduling and over-scheduling penalty payments and allocation by year**




### The ISO and stakeholders should reassess the need for applying the balancing test to any EIM balancing area

DMM recommends that the ISO and stakeholders reassess whether or not the balancing test and over- and under-scheduling penalties are appropriate elements of the resource sufficiency test framework. Based on policy developed in the EIM Foundation stakeholder initiative, the purpose of the resource sufficiency tests appears to be to serve two purposes: (1) to prevent one EIM balancing area from leaning on others for capacity, and (2) to notify EIM entities if base schedules are overloading flow based constraints.[59]

Well-designed flexible ramping sufficiency tests and bid range capacity tests may be sufficient for identifying if one area is leaning on other areas for capacity. It is not clear to DMM that there is additional value added in assessing whether or not an EIM area's base generation schedule is close to its load forecast.

Furthermore, over- and under-scheduling penalties may be more appropriate additional consequences of failing the flexible ramping sufficiency or bid range capacity tests, rather than a consequence of base schedules not being close to load forecasts.

Therefore, DMM recommends that the ISO and stakeholders clarify what the intended purpose of the balancing test is and consider eliminating this test for all EIM areas before designing other potential changes to the balancing test.

59 See Section 3.3.6 of *Energy Imbalance Market Draft Final Proposal*, California ISO, September 23, 2013, pp. 37-39: http://www.caiso.com/Documents/EnergyImbalanceMarket-DraftFinalProposal092313.pdf

### Department of Market Monitoring additional reporting

As part of the EIM resource sufficiency evaluation stakeholder initiative, DMM has agreed to provide additional transparency surrounding test accuracy and performance in regular reports specific to this topic. DMM looks forward to providing ongoing reporting and data on the EIM tests before and after changes adopted through this stakeholder process. DMM has developed numerous metrics and has also begun to develop additional metrics and analysis to assess the potential impact and implications of the changes being proposed.

This second quarter report as well as the special report issued by DMM in May summarize some of the existing metrics that can be included in these future EIM resource sufficiency evaluation reports.[60] DMM also recently published its first monthly EIM resource sufficiency report in September.[61] Both the reports and data underlying most metrics will be available on DMM's website.[62]

DMM is seeking feedback from stakeholders on existing or additional metrics and analysis that would be most valuable. Suggestions for existing metric refinements are also welcome, particularly suggestions on the level of detail and publication venue for each metric. Possible publication venues include quarterly reports to the EIM Governing Body, monthly reports published to DMM's website, daily metrics updated on the ISO's website on OASIS or elsewhere, and non-public data provided to market participating balancing areas through existing platforms. Please communicate any suggestions either through comments in the ISO's EIM resource sufficiency evaluation stakeholder initiative or directly to DMM.[63]

## 2.3 Western EIM transfers

### Western EIM transfer limits

One of the key benefits of the energy imbalance market is the ability to transfer energy between areas in the 15-minute and 5-minute markets. Table 2.1 shows average 15-minute market limits between each of the areas between April 1 and June 30.[64] The sum of each column reflects the average total import limit into each balancing area, while the sum of each row reflects the average total export limit from each area. For example, import transfer capacity into the ISO from areas in the Northwest region including PacifiCorp West, Portland General Electric, Puget Sound Energy, and Powerex, was around 200 MW on average during the quarter, or roughly 1 percent of total import capability. However,

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60 *Resource sufficiency tests in the energy imbalance market*, May 20, 2021: http://www.caiso.com/Documents/Report-on-Resource-Sufficiency-Tests-in-the-Energy-Imbalance-Market-May-20-2021.pdf

61 *EIM Resource Sufficiency Evaluation Metrics Report covering July and August 2021*, September 23, 2021: http://www.caiso.com/Documents/Report-on-Resource-Sufficiency-Evaluation-in-the-Energy-Imbalance-Market-for-July-and-August-2021-Sep-23-2021.pdf

62 Department of Market Monitoring website: http://www.caiso.com/market/Pages/MarketMonitoring/Default.aspx

63 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.

64 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.

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

During the second quarter, Turlock Irrigation District averaged roughly 1,200 MW of import and export transfer capacity with the ISO while BANC (phase 1 and phase 2) averaged roughly 3,200 MW of import and export capacity with the ISO. LADWP averaged around 8,590 MW of import capacity and 4,990 MW of export capacity with the ISO as well as roughly 2,000 MW of import and export capacity with other energy imbalance market areas.

Public Service Company of New Mexico averaged roughly 1,000 MW of import and export capacity with Arizona Public Service Company and Salt River Project combined. Between June 16 and June 30, NorthWestern Energy averaged around 490 MW of import capacity and 780 MW of export capacity with other energy imbalance market areas.

**Table 2.1 Average 15-minute market energy imbalance market limits (April 1 – June 30)**

| From Balancing Authority Area | To Balancing Authority Area: CISO | BANC | TIDC | LADWP | NEVP | AZPS | SRP | PNM | PACE | IPCO | NWMT* | PACW | PGE | PSEI | SCL | PWRX | *Total export limit* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| California ISO | | 3,200 | 1,130 | 4,990 | 3,320 | 1,070 | 1,450 | | | | | 0 | 90 | 0 | | 260 | 15,510 |
| BANC | 3,240 | | 650 | | | | | | | | | | | | | | 3,890 |
| Turlock Irrig. District | 1,220 | 790 | | | | | | | | | | | | | | | 2,010 |
| LADWP | 8,590 | | | | 1,500 | 400 | | | 180 | | | | | | | | 10,670 |
| NV Energy | 3,990 | | | 1,240 | | 240 | | | 860 | 470 | | | | | | | 6,800 |
| Arizona Public Service | 2,680 | | | 490 | 330 | | 6,900 | 900 | 810 | | | | | | | | 12,110 |
| Salt River Project | 2,230 | | | | | 4,920 | | 110 | 0 | | | | | | | | 7,260 |
| PSC New Mexico | | | | | | 850 | 180 | | | | | | | | | | 1,030 |
| PacifiCorp East | | | | 170 | 670 | 670 | 0 | | | 1,020 | 410 | 280 | | | | | 3,220 |
| Idaho Power | | | | | 530 | | | | 1,760 | | 280 | 320 | | 50 | 30 | | 2,970 |
| NorthWestern Energy* | | | | | | | | | 390 | 100 | | 0 | 0 | 0 | | | 490 |
| PacifiCorp West | 90 | | | | | | | | 380 | 350 | 40 | | 330 | 150 | 0 | | 1,340 |
| Portland GE | 110 | | | | | | | | | | 30 | 330 | | 130 | 10 | | 610 |
| Puget Sound Energy | 0 | | | | | | | | | 0 | 20 | 180 | 130 | | 350 | 90 | 770 |
| Seattle City Light | | | | | | | | | | 30 | | 30 | 20 | 350 | | | 430 |
| Powerex | 0 | | | | | | | | | | | | | 210 | | | 210 |
| *Total import limit* | 22,150 | 3,990 | 1,780 | 6,890 | 6,350 | 8,150 | 8,530 | 1,010 | 4,380 | 1,970 | 780 | 1,140 | 570 | 890 | 390 | 350 | |

* NorthWestern Energy data is for June 16 – June 30 only

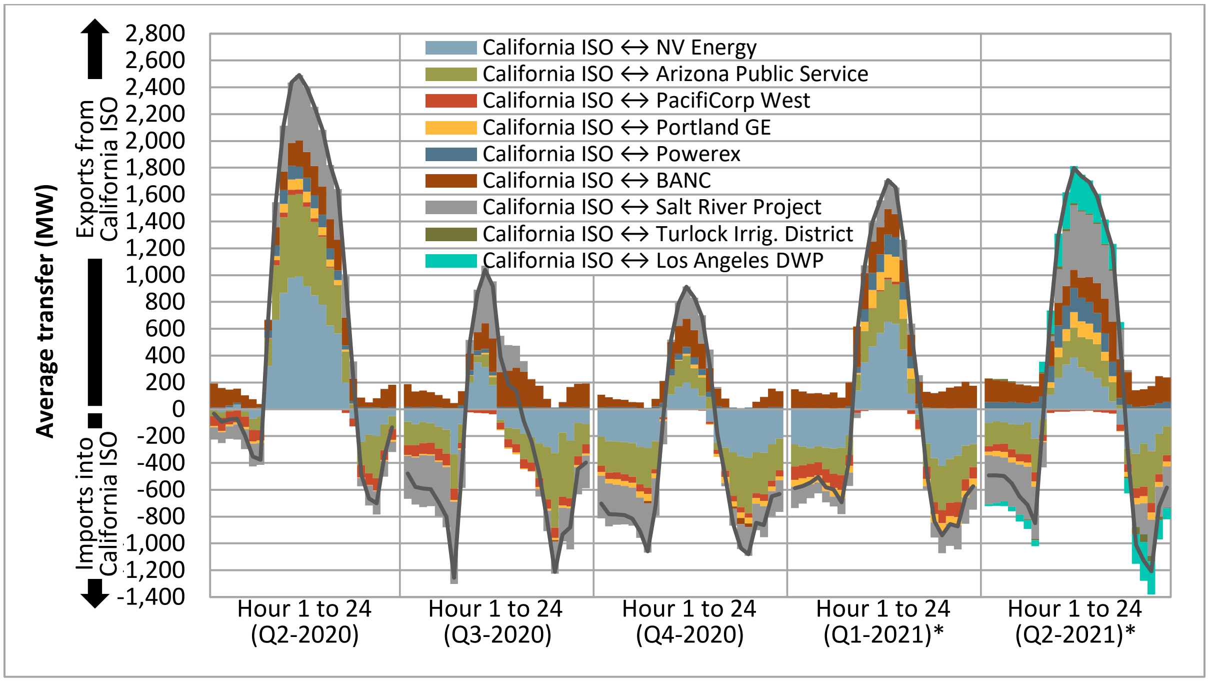
## Hourly energy imbalance market transfers

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

Figure 2.19 compares average hourly imports (negative values) and exports (positive values) between the ISO and other EIM areas during the last five quarters in the 15-minute market.[65] The bars show the average hourly transfers with the connecting areas. The grey line shows the average hourly net transfer.

[65] 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. NorthWestern Energy, which joined the energy imbalance market towards the end of the second quarter on June 16, is not included.

**Figure 2.19 California ISO - average hourly 15-minute market transfer**



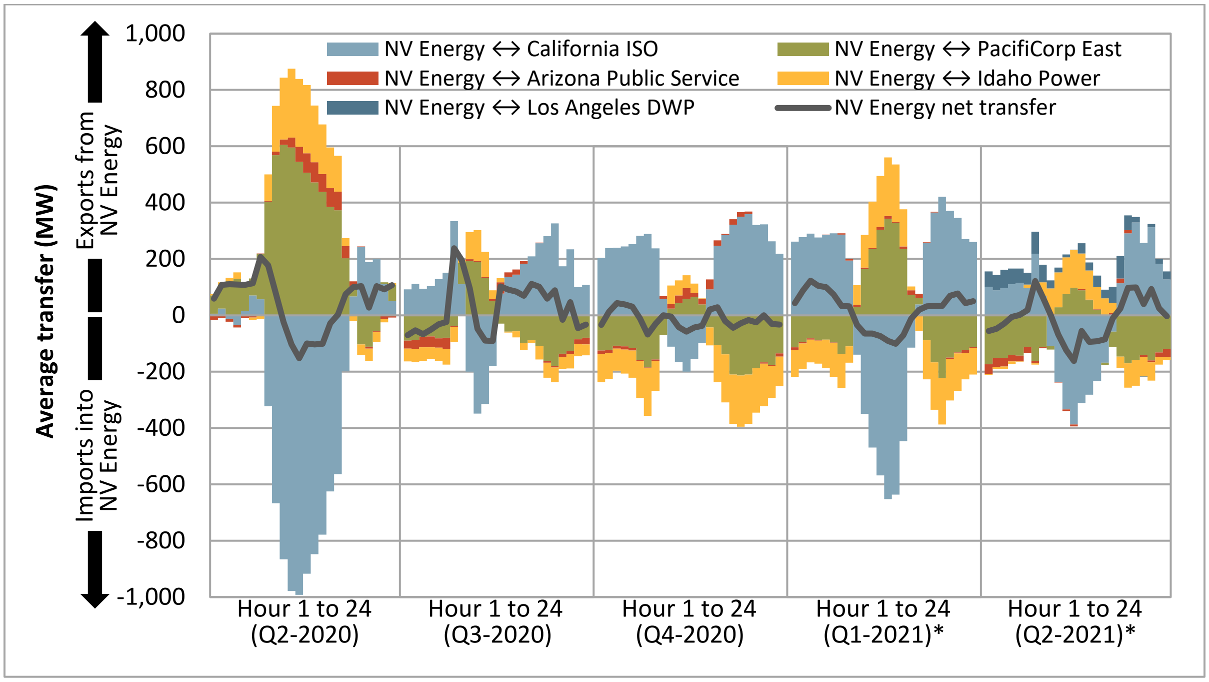

*See footnote 65

Figure 2.20 through Figure 2.30 show the same quarterly information on imports and exports for the other energy imbalance market areas in the 15-minute market.[66] The amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[67]

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

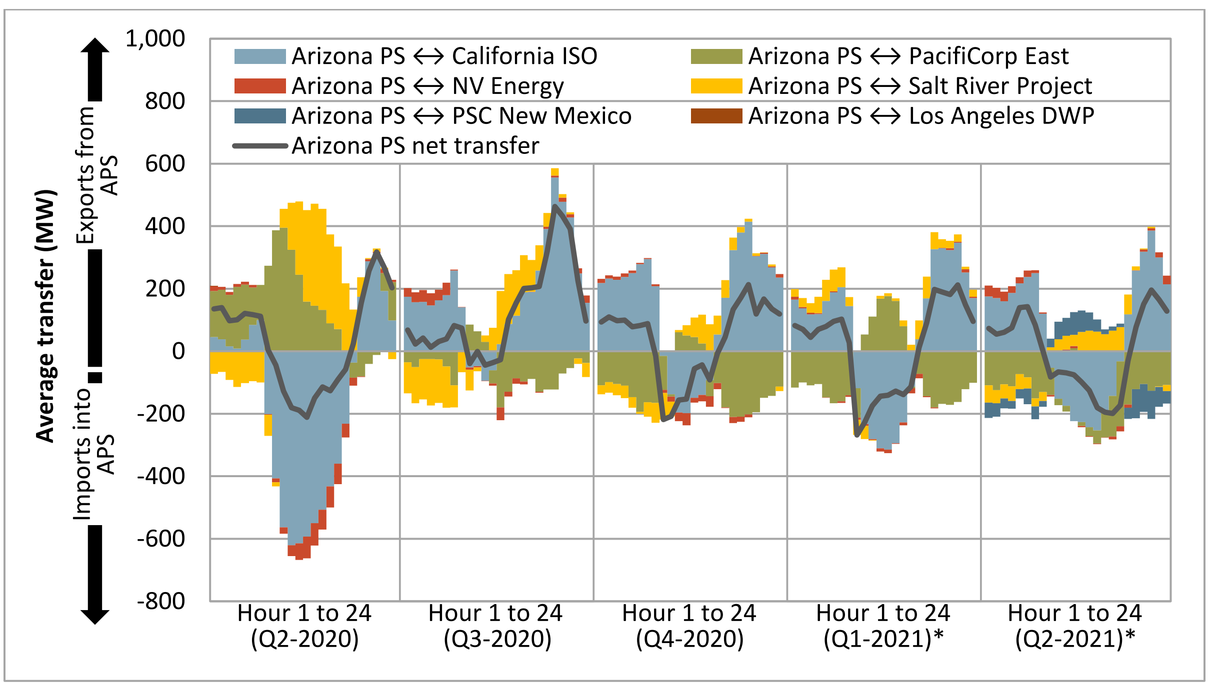
67 Base schedules on EIM transfer system resources are fixed bilateral transactions between EIM entities.

**Figure 2.20 NV Energy – average hourly 15-minute market transfer**



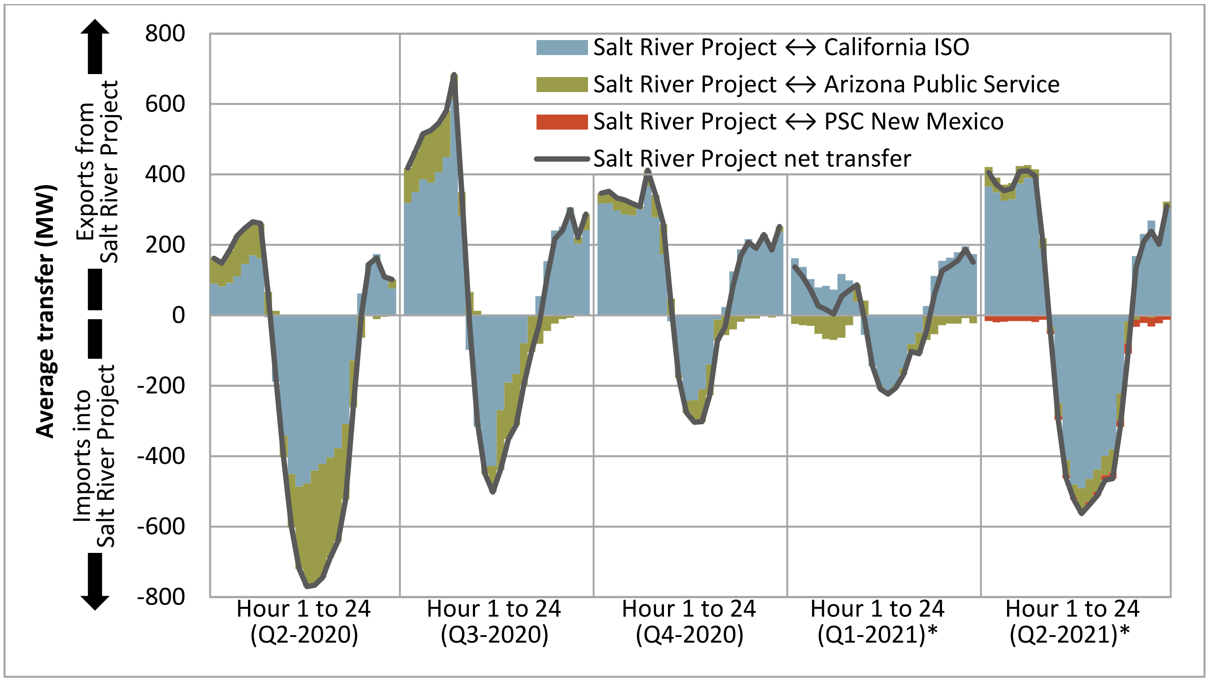

*See footnote 65

**Figure 2.21 Arizona Public Service – average hourly 15-minute market transfer**



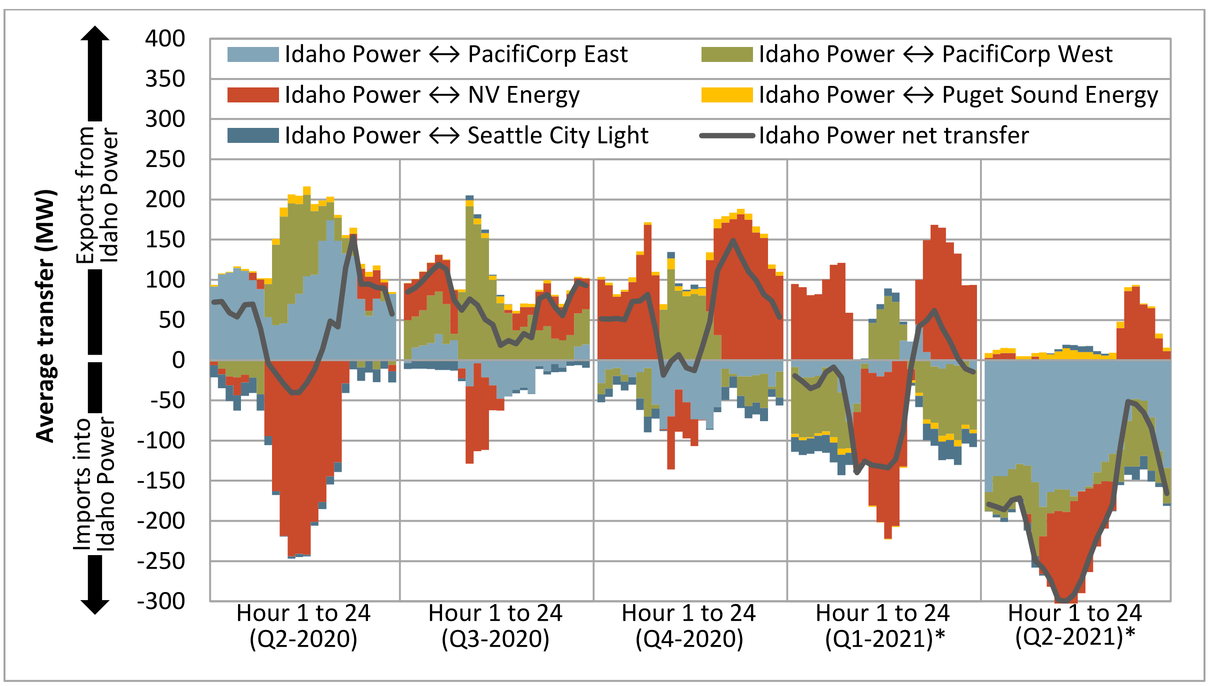

*See footnote 65

**Figure 2.22 Salt River Project – average hourly 15-minute market transfer**



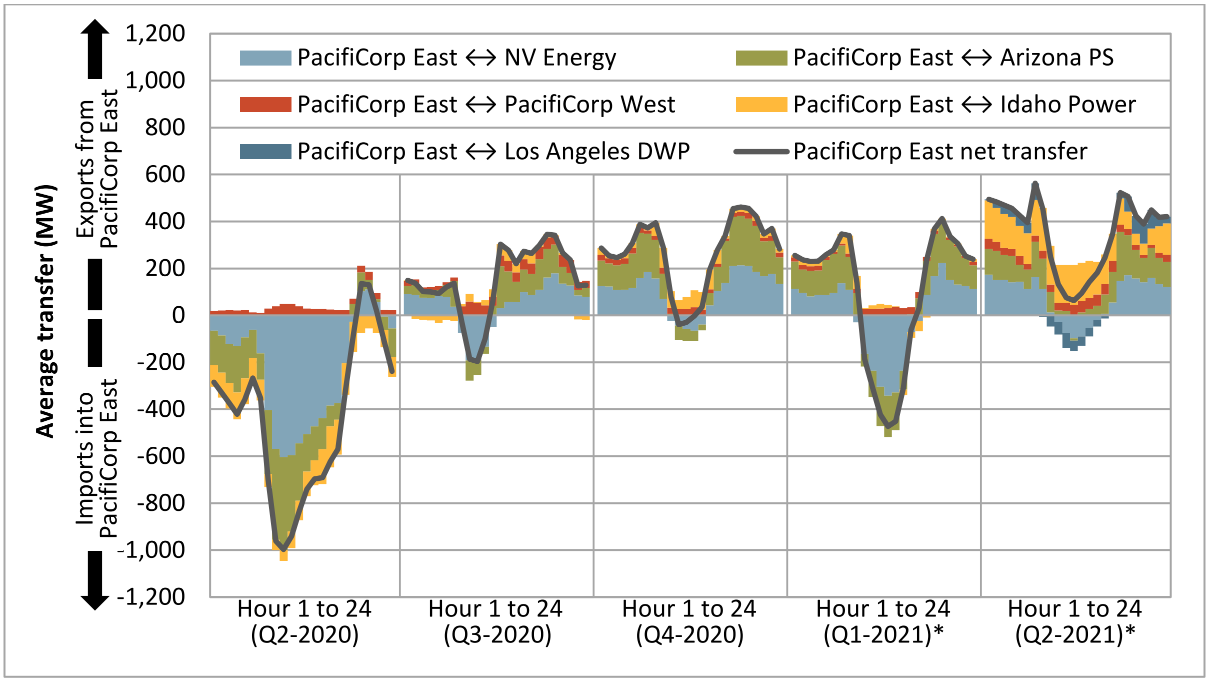

*See footnote 65

**Figure 2.23 Idaho Power – average hourly 15-minute market transfer**



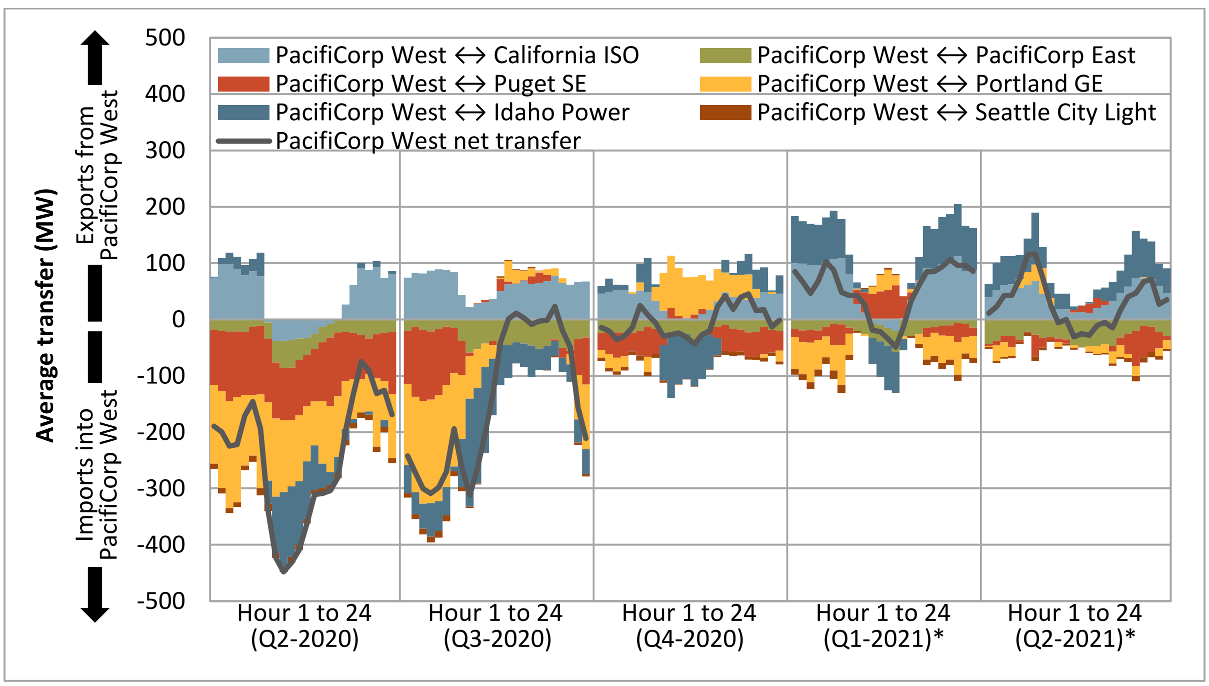

*See footnote 65

**Figure 2.24 PacifiCorp East – average hourly 15-minute market transfer**



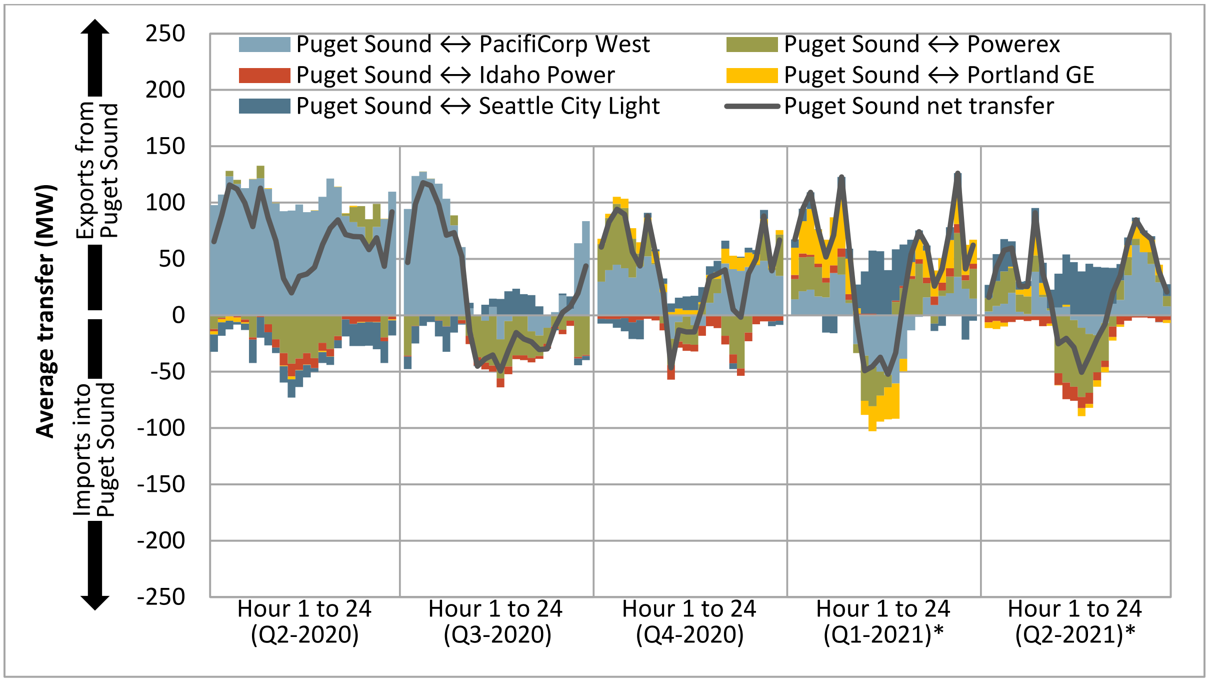

*See footnote 65

**Figure 2.25 PacifiCorp West – average hourly 15-minute market transfer**



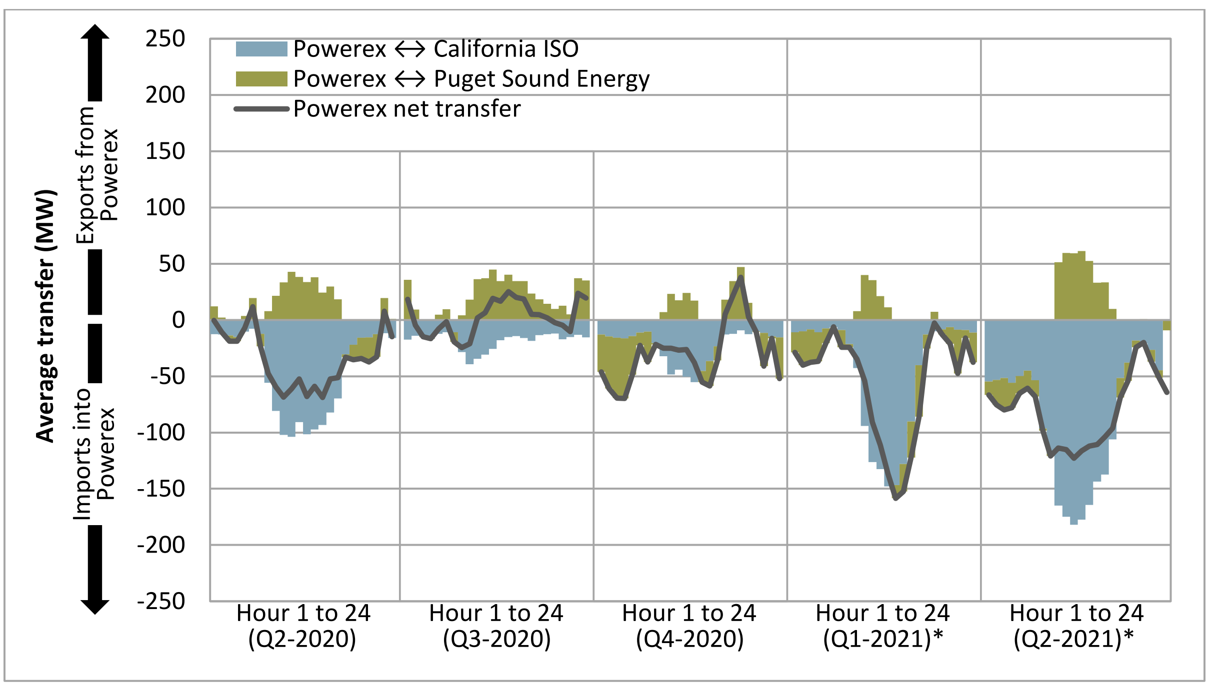

*See footnote 65

**Figure 2.26 Puget Sound Energy – average hourly 15-minute market transfer**



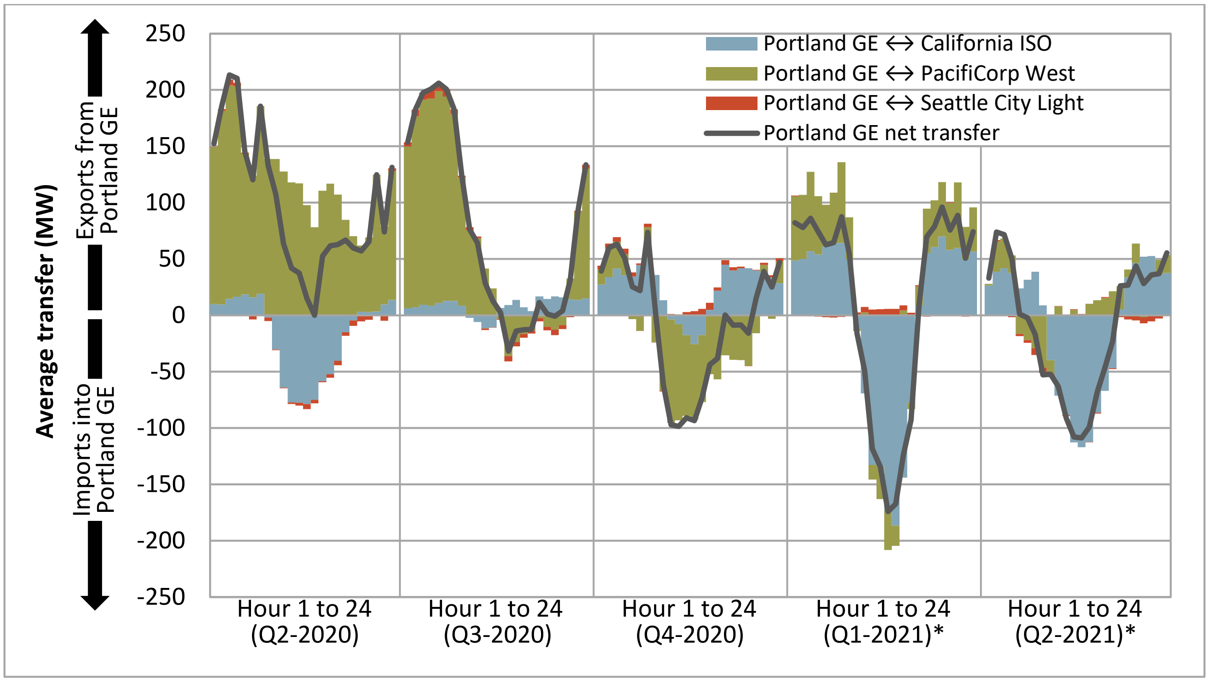

*See footnote 65

**Figure 2.27 Powerex – average hourly 15-minute market transfer**



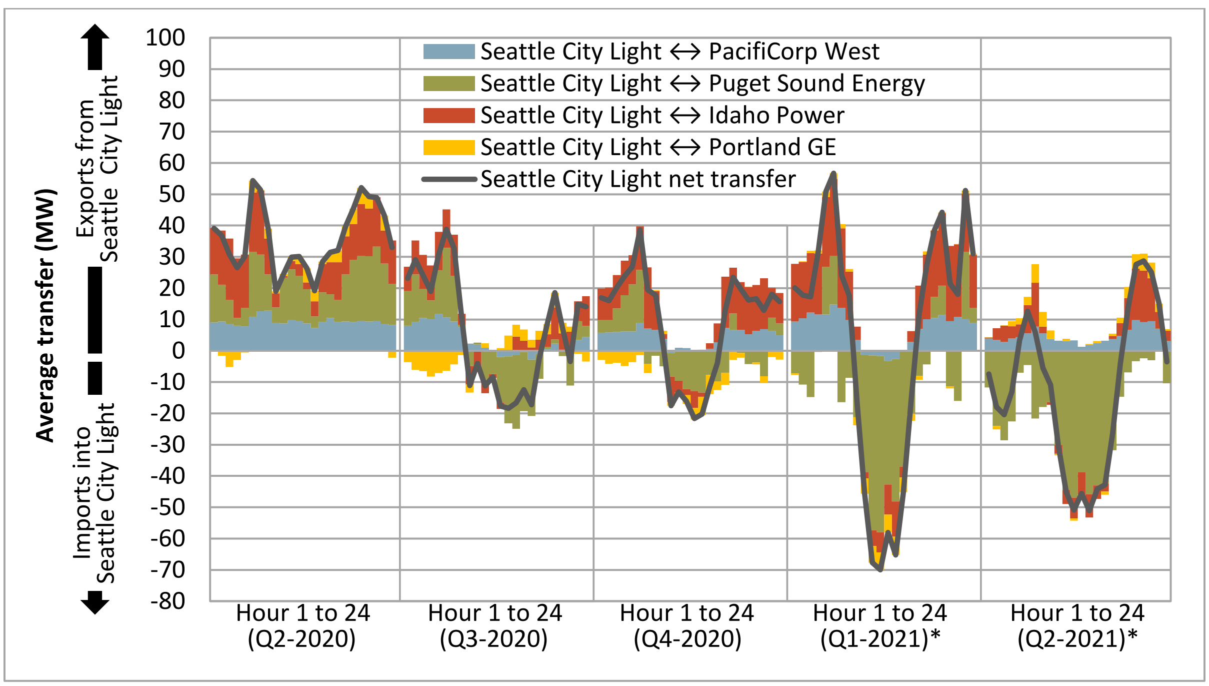

*See footnote 65

**Figure 2.28 Portland General Electric – average hourly 15-minute market transfer**



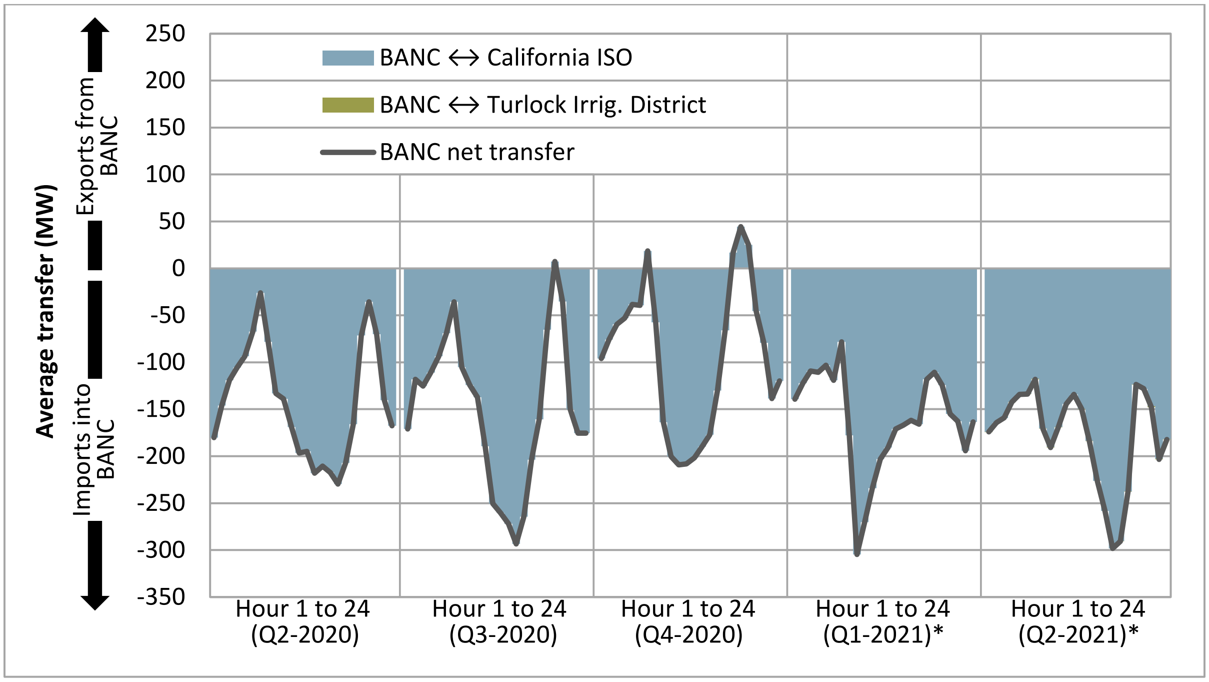

*See footnote 65

**Figure 2.29 Seattle City Light – average hourly 15-minute market transfer**




*See footnote 65

**Figure 2.30 Balancing Authority of Northern California - average hourly 15-minute market transfer**




*See footnote 65

### Inter-balancing area congestion

Congestion between an energy imbalance market area and the rest of the system limits an area's import and export capability. In addition, during intervals when there is net import congestion into an energy imbalance market area, the market software triggers local market power mitigation for resources in that area.[68]

Table 2.2 shows the percent of 15-minute and 5-minute market intervals with congestion on transfer constraints into or out of an energy imbalance market area. This is calculated as the frequency of intervals where the shadow price on an area's transfer constraint was positive or negative, indicating higher or lower prices in an area relative to prevailing system prices.[69] When prices are lower relative to the system, this indicates congestion out of an area and limited export capability. Conversely, when prices are higher within an area, this indicates that congestion is limiting the ability for energy outside of an area to serve that area's load. Chapter 1 focused on the impact of congestion to EIM prices, whereas this section describes the same information in terms of the impact to import or export capability and the potential for market power mitigation.

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68 Structural market power may exist if the demand for imbalance energy within a balancing area exceeds the transfer capacity into that balancing area from the ISO or other competitive markets. The ISO area is not subject to market power mitigation under these conditions.

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

**Table 2.2 Frequency of congestion in the energy imbalance market (April – June)**

| | 15-minute market | | 5-minute market | |
|---|---|---|---|---|
| | Congested from area | Congested into area | Congested from area | Congested into area |
| BANC | 0% | 0% | 0% | 0% |
| Turlock Irrigation District | 1% | 0% | 0% | 1% |
| Arizona Public Service | 1% | 0% | 1% | 1% |
| NV Energy | 2% | 1% | 2% | 1% |
| PacifiCorp East | 3% | 1% | 2% | 1% |
| Idaho Power | 3% | 2% | 2% | 2% |
| L.A. Dept. of Water and Power | 2% | 4% | 1% | 4% |
| Public Service Company of NM | 5% | 2% | 3% | 2% |
| Salt River Project | 3% | 5% | 3% | 6% |
| PacifiCorp West | 19% | 7% | 11% | 5% |
| Portland General Electric | 20% | 8% | 12% | 5% |
| Seattle City Light | 20% | 8% | 14% | 7% |
| Puget Sound Energy | 21% | 8% | 14% | 7% |
| Powerex | 17% | 6% | 21% | 16% |

The highest frequency of congestion in the energy imbalance market continued to be from the Northwest areas toward the larger energy imbalance market system. This congestion in the 15-minute market from PacifiCorp West, Portland General Electric, Seattle City Light, Puget Sound Energy, and Powerex occurred during 19 percent of intervals on average during the quarter. This is lower than the same quarter of 2020 when congestion from these areas occurred during an average of 32 percent of intervals.

The highest frequency of net import congestion (such that the ISO market software triggers local market power mitigation in that area) occurred in the Powerex area, during 6 percent of 15-minute market intervals and 16 percent of 5-minute market intervals during the second quarter.

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

## 2.4 Imbalance conformance in the Western EIM

### Frequency and size of imbalance conformance

Arizona Public Service had the highest frequency of positive and negative imbalance conformance during the second quarter. While Turlock Irrigation District infrequently used positive or negative imbalance conformance, its average megawatt biased was the highest average percent of its total load.

**Table 2.3 Average frequency and size of imbalance conformance (April – June)**

| | Positive imbalance conformance | | | Negative imbalance conformance | | | Average hourly adjustment MW |
|---|---|---|---|---|---|---|---|
| | Percent of intervals | Average MW | Percent of total load | Percent of intervals | Average MW | Percent of total load | |
| ***California ISO*** | | | | | | | |
| 15-minute market | 42% | 749 | 2.9% | 2.9% | -285 | 1.3% | 308 |
| 5-minute market | 28% | 232 | 0.9% | 42% | -251 | 1.1% | -41 |
| ***BANC*** | | | | | | | |
| 15-minute market | 1.7% | 55 | 1.8% | 0.3% | -32 | 1.4% | 1 |
| 5-minute market | 2.8% | 46 | 1.8% | 1.4% | -32 | 2.0% | 1 |
| ***Los Angeles Dept. of Water and Power*** | | | | | | | |
| 15-minute market | 9.4% | 85 | 2.9% | 7.0% | -128 | 5.8% | -1 |
| 5-minute market | 21% | 69 | 2.6% | 13% | -107 | 4.7% | 1 |
| ***Turlock Irrigation District*** | | | | | | | |
| 15-minute market | 0.0% | 8 | 3.0% | 0.1% | -33 | 11% | 0 |
| 5-minute market | 0.5% | 6 | 2.6% | 0.1% | -23 | 8.1% | 0 |
| ***NV Energy*** | | | | | | | |
| 15-minute market | 0.7% | 101 | 2.1% | 0.7% | -100 | 2.0% | 0 |
| 5-minute market | 15% | 89 | 1.9% | 8.5% | -118 | 2.9% | 3 |
| ***Arizona Public Service*** | | | | | | | |
| 15-minute market | 28% | 59 | 1.5% | 52% | -78 | 2.4% | -25 |
| 5-minute market | 28% | 59 | 1.5% | 52% | -78 | 2.4% | -24 |
| ***Salt River Project*** | | | | | | | |
| 15-minute market | 0.5% | 68 | 1.5% | 0.3% | -94 | 2.6% | 0 |
| 5-minute market | 6.2% | 67 | 1.6% | 2.9% | -84 | 2.3% | 2 |
| ***Idaho Power*** | | | | | | | |
| 15-minute market | 3.9% | 47 | 2.0% | 3.5% | -52 | 2.5% | 0 |
| 5-minute market | 7.9% | 50 | 2.1% | 14% | -54 | 2.6% | -4 |
| ***Public Service Company of New Mexico*** | | | | | | | |
| 15-minute market | 1.1% | 94 | 6.6% | 2.8% | -134 | 11% | -3 |
| 5-minute market | 5.0% | 75 | 5.1% | 7.7% | -103 | 8.3% | -4 |
| ***PacifiCorp East*** | | | | | | | |
| 15-minute market | 0.6% | 112 | 2.4% | 0.3% | -143 | 3.0% | 0 |
| 5-minute market | 24% | 107 | 1.9% | 27% | -109 | 2.1% | -4 |
| ***PacifiCorp West*** | | | | | | | |
| 15-minute market | 0.0% | N/A | N/A | 0.0% | N/A | N/A | 0 |
| 5-minute market | 3.8% | 48 | 1.9% | 27% | -51 | 2.3% | -12 |
| ***Portland General Electric*** | | | | | | | |
| 15-minute market | 0.0% | N/A | N/A | 0.1% | -44 | 1.0% | 0 |
| 5-minute market | 28% | 27 | 1.1% | 1.0% | -55 | 1.9% | 7 |
| ***Seattle City Light*** | | | | | | | |
| 15-minute market | 0.2% | 24 | 2.3% | 15% | -20 | 2.1% | -3 |
| 5-minute market | 1.1% | 21 | 2.1% | 72% | -22 | 2.4% | -15 |
| ***Puget Sound Energy*** | | | | | | | |
| 15-minute market | 1.3% | 27 | 0.8% | 52% | -41 | 1.7% | -21 |
| 5-minute market | 1.2% | 32 | 1.0% | 57% | -41 | 1.7% | -23 |

Table 2.3 summarizes the average frequency and size of positive and negative imbalance conformance entered by operators in the EIM for the 15-minute and 5-minute markets during the quarter.[70] The same data for the ISO balancing area is provided as a point of reference. In particular, Arizona Public Service entered positive imbalance conformance in around 28 percent of 15-minute and 5-minute intervals, at an average of around 59 MW. Puget Sound Energy entered negative imbalance conformance in around 52 and 57 percent of 15-minute and 5-minute intervals, respectively, at an average of around 41 MW. Nearly all EIM entities had a greater frequency of 5-minute market imbalance conformance than 15-minute market during the quarter.

## 2.5 Mitigation in the EIM

The elimination of carryover mitigation appears to have reduced mitigation rates in the Western EIM. In the second quarter of 2021, average incremental energy that was subject to mitigation with bids lowered or not declined significantly in the 15-minute and 5-minute markets, compared to the same quarter in 2020. Figure 2.31 and Figure 2.32 highlight the volume of 15-minute and 5-minute market mitigation in all the balancing authority areas in the EIM outside the ISO:

- Blue bars in Figure 2.31 and Figure 2.32 show average incremental energy subject to mitigation but whose bids were not lowered in the 15-minute and 5-minute markets, respectively. In the second quarter of 2021, on average, this portion has decreased by about 500 MW when compared to the same quarter in 2020.
- A relatively small volume of bids were lowered as a result of mitigation in the Western EIM when compared to the same quarter in 2020.

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

**Figure 2.31 Average incremental energy mitigated in 15-minute real-time market (EIM)**

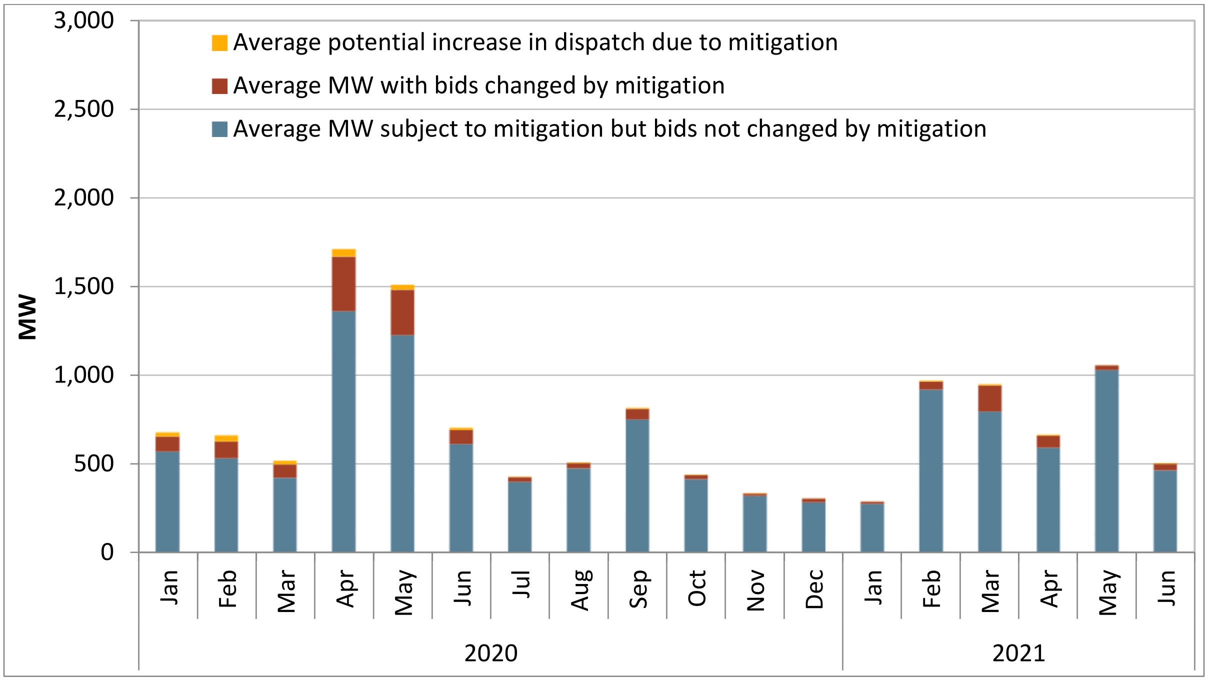
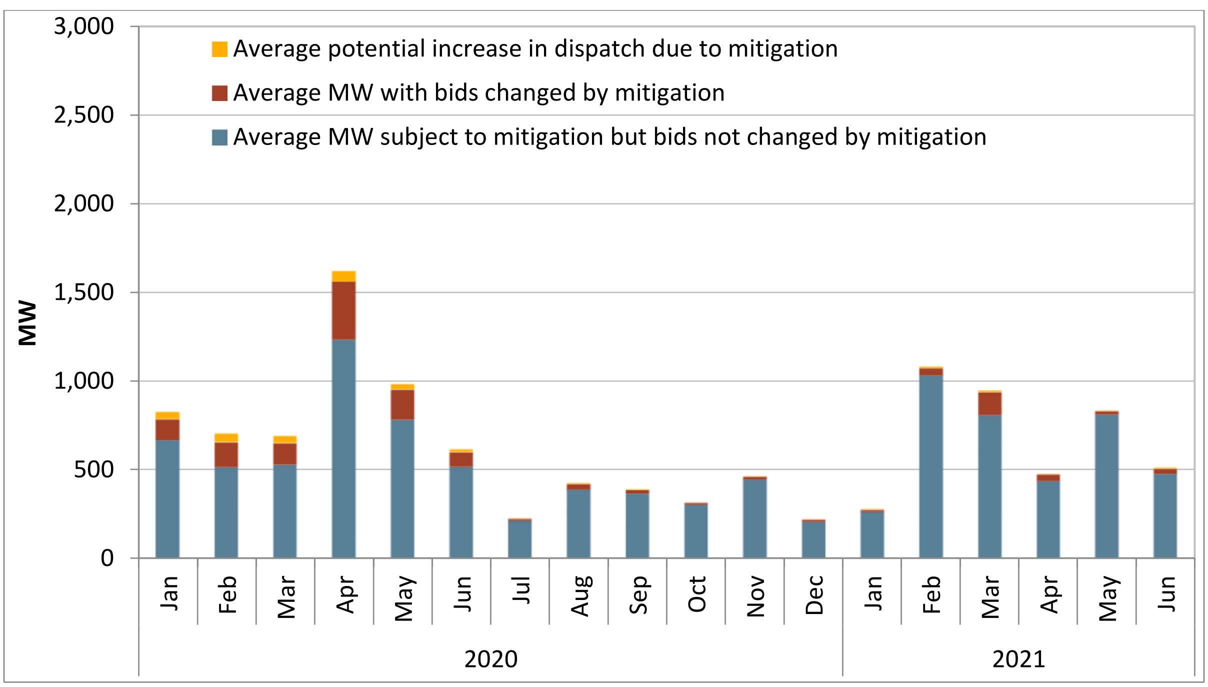



**Figure 2.32 Average incremental energy mitigated in 5-minute real-time market (EIM)**



# 3 Special issues

## 3.1 FERC Order 831

On June 13, 2021, the ISO implemented the second phase of the FERC Order 831 tariff amendment.[71] The first phase was implemented on March 20, 2021, and allowed for resources to bid above the $1,000/MWh soft bid cap. The market changes associated with the two phases are summarized below:

- Phase 1
    - Resource-specific resources can bid over the soft bid cap through the reference level request process
    - Imports and virtual bidders able to bid over soft bid cap at any time
    - Power balance constraint penalty price set at $2,000/MWh hard bid cap
- Phase 2
    - Imports and virtual bidders are only able to bid over soft bid cap under certain market conditions (discussed below)
    - Resource adequacy import bids are capped at a maximum import bid cap
    - Power balance constraint penalty price only set over $1,000/MWh soft bid cap in certain conditions (discussed below)

The bidding rules in the second phase of FERC Order 831 set limitations on when import and virtual bidders can bid over the soft bid cap. The ISO will only allow import and virtual bids over $1,000/MWh when either (1) the ISO has accepted a cost-verified bid over $1,000/MWh or (2) the maximum import bid price (MIBP) is greater than $1,000/MWh. The maximum import bid price approximates the prevailing price of electricity and is calculated using an hourly price shaping factor and the maximum of either the Mid-Columbia or the Palo Verde hub price.[72]

From March 20 to June 13, import and virtual bids were able to bid over the soft bid cap in any circumstance. During this time period there were very few import bids over $1,000/MWh, none of which cleared the market. There was substantial convergence bidding above the soft bid cap; however, only a total of 4 MW cleared.

After the implementation of Phase 2 on June 13, imports and virtual bids over the soft bid cap were only allowed under the circumstances explained above. There were no cost-verified bids over $1,000/MWh from June 13 to the end of the second quarter, and there were only a handful of hours with a maximum import bid price over $1,000/MWh. During June 15-17, high peak prices at Palo Verde led to MIBP values far higher than the $1,000/MWh threshold as seen in Figure 3.1.[73] Over these three days there were some import bids over the soft bid cap, on June 16 and 17, although none cleared the market. On June 17 there was substantial convergence bidding but only about 400 MW cleared.

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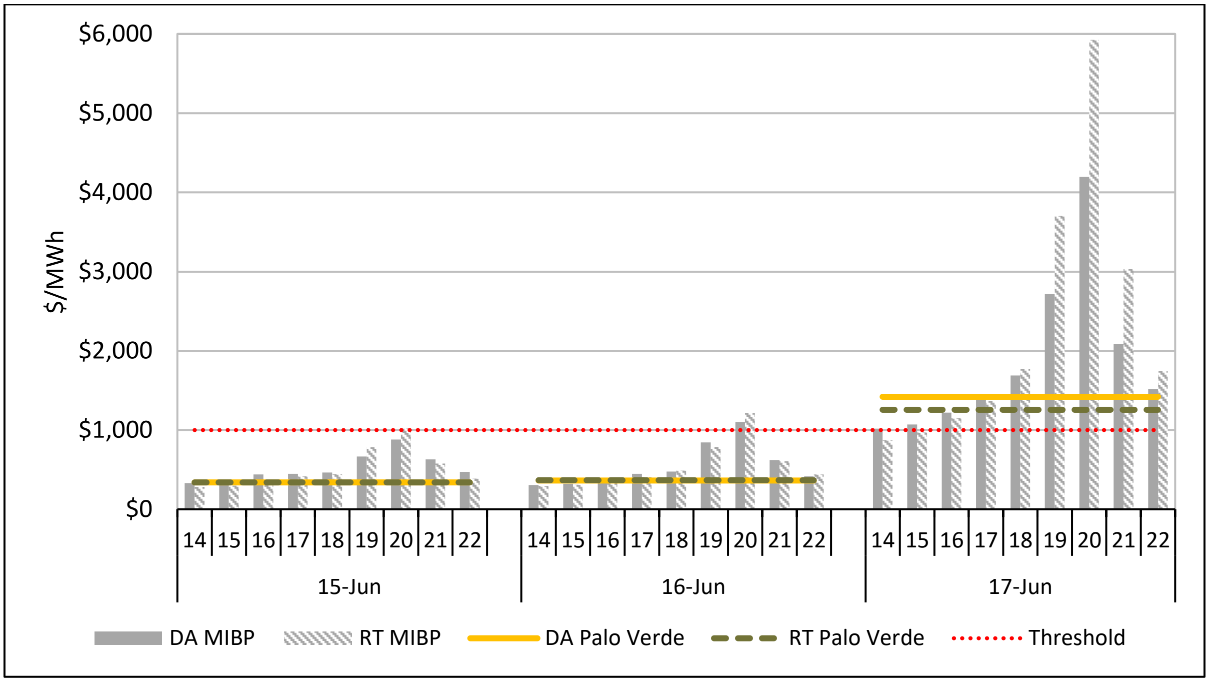
[71] *Tariff Amendment to Enhance Market Parameters and Import Bidding Related to Order No. 831*, February 22, 2021: http://www.caiso.com/Documents/Feb22-2021-TariffAmendment-PricingParameters-OrderNo831-ER21-1192.pdf

[72] *FERC Order No. 831 – Import Bidding and Market Parameters Revised Final Proposal*, September 10, 2020, pp 26: http://www.caiso.com/InitiativeDocuments/RevisedFinalProposal-FERCOrder831-ImportBidding-MarketParameters.pdf

[73] The MIBP is based on the higher of prices at the Mid-Columbia or Palo Verde hub. Because prices at Palo Verde were much higher on these days, the MIBP was based on prices at that hub.

**Figure 3.1 Maximum import bid price on days with high bilateral market prices**




In addition to enforcing restrictions on when bids over $1,000/MWh can enter the market, Phase 2 also included rules about capping bids from different types of resources when they bid over the soft cap.[74] Resource-specific resources will be capped at the higher of the soft bid cap or the resource's revised default energy bid (DEB), and the revised default energy bid cannot exceed the $2,000/MWh hard bid cap. Imports will be capped differently depending on whether or not they are resource-adequacy (RA) imports. The ISO will cap resource adequacy imports over $1,000/MWh at the greater of the maximum import bid price or the highest cost-verified bid from a resource-specific resource. Non-resource adequacy imports will not be capped in the same way; they will only be capped at the hard bid cap of $2,000/MWh, the same as for virtual resources.

The second phase also included rules regarding market parameters, particularly the parameter used in the market to calculate locational marginal prices when there is a power balance constraint (PBC) violation due to a supply shortage.[75] Before FERC Order 831 the power balance constraint penalty price was scaled to the $1,000/MWh bid cap. After Phase 1 the penalty was scaled to $2,000/MWh regardless of the circumstance. Phase 2 set limits on when the penalty price will be set over $1,000/MWh based on whenever whether the maximum import bid price or a cost-verified bid exceeds the soft bid cap.

Additionally, when there is a power balance constraint violation due to a supply shortage, the ISO will now compare the shortage to a threshold value specific to each balancing authority area that is calculated once a year based on NERC reliability standards. If the power balance constraint infeasibility is lower than the area-specific threshold then the penalty price will be set at the higher of $1,000 or the

74 Refer to DMM's *Q1 2021 Report on Market Issues and Performance*, Table 3.1.

75 Refer to DMM's *Q1 2021 Report on Market Issues and Performance*, Table 3.2.

highest cleared economic bid. If the infeasibility is greater than the area-specific threshold then the penalty price will be set at the hard energy bid cap.

Until June 13, penalty prices in the second quarter were scaled to $2,000/MWh regardless of the circumstances. Although there were only two hours when the ISO failed the power balance constraint, other entities experienced more frequent shortages and therefore higher average prices in those hours due to the $2,000/MWh penalty price.[76] After Phase 2 implementation there were no power balance constraint violations in the ISO balancing area. There were 24 instances of a power balance constraint violation for EIM entities during days with a high maximum import bid price, of which 14 were set at $2,000/MWh because the shortage exceeded the balancing area's threshold value.

## 3.2 Intertie deviation settlement

In February, the ISO updated the settlements methodology to increase penalties applied to over- and under-delivered intertie transactions and to apply these penalties with more precision. Undelivered intertie transactions adversely impact both market reliability and efficiency. Charges intended to reduce undelivered intertie transactions appeared ineffective, and in February 2019 the ISO Board approved a revision to the intertie non-delivery charge. This revision was designed to lead to more accurate estimates of the net scheduled interchange, increased grid reliability, and more accurate market pricing.

### Implementation and requirements

The intertie deviation settlement initiative was implemented in February 2021 to provide stronger economic incentives to deliver intertie resources.[77]

The ISO settlements charge code 'CC 6456 – Intertie Deviation Settlement' applies to both under- and over-tagging of intertie resources awarded in the day-ahead market, hour-ahead scheduling process, or 15-minute market and to incremental and decremental changes between the day-ahead market and hour-ahead scheduling process or the 15-minute market. The business practice manual (BPM) for CC6456 outlines the details on the calculation requirements, which include three components:[78]

- Hourly Block Economic Bid Intertie calculation (minimum penalty of $10/MWh)
- Undelivered ADS Additional Penalty
- 15 Minute Economic Bid calculation (minimum penalty of $10/MWh)

After the initial implementation in February a number of issues that led to settlement charge errors were identified. The ISO published a paper to address the errors and to bring the tariff and intertie deviation settlement implementation into alignment.[79] Deployment, initially scheduled on February 1, was completed on February 8. Since this time, additional defects have been identified that impacted

[76] See Section 2.1 and Figure 2.5 for more discussion on this point.

[77] CAISO | Home | Stay Informed | Stakeholder Initiatives | Intertie deviation settlement | INITIATIVE: Intertie deviation settlement https://stakeholdercenter.caiso.com/StakeholderInitiatives/Intertie-deviation-settlement

[78] BPM - CG CC 6456 Intertie Deviation Settlement: https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

[79] Intertie Deviation Settlement (IDS) Issue Summary: http://www.caiso.com/Documents/SummaryofIssues-DraftTariffLanguage-TariffClarifications.pdf

settlement for certain wheeling resources, import and export resources, and tag curtailments. Details of these issues and potential resolution were provided on March 17, 2021, during a Settlements User Group meeting.[80]

Table 3.1 summarizes total intertie deviation settlement charges by component and by month between February and June. This table is based on ISO settlements data, which has an updated timeline in 2021 intended to increase accuracy.[81,82] The table reflects data pulled according to the payment calendar, with green text identifying settlements data past the original trade date plus the dispute window (T+70B plus the 22B dispute window = T+92B) and red text identifying settlements data within the initial statement period (T+9B) which may be revised up to the T+92B period.[83]

The total for this period is about $5.5 million. The largest component was 'Hourly Block Economic Bid Intertie + floor penalty of $10' comprising $3.7 million, followed by 'Undelivered ADS Additional Penalty' and '15 Minute Economic Bid + floor penalty of $10' with $1.6 million and $0.2 million, respectively.

**Table 3.1 Intertie deviation settlement components by month**

| Intertie Deviation Settlements Components | Month | | | | | Grand Total |
|---|---|---|---|---|---|---|
| | February | March | April | May | June | |
| Hourly Block Economic Bid Intertie + floor penalty of $10 | $1,207,548 | $187,054 | $241,841 | $255,978 | $1,767,341 | **$3,659,762** |
| Undelivered ADS Additional Penalty | $484,264 | $71,518 | $71,027 | $88,660 | $860,157 | **$1,575,626** |
| 15 Minute Economic Bid + floor penalty of $10 | $84,649 | $34,360 | $49,613 | $41,814 | $15,458 | **$225,894** |
| **Total** | $1,776,461 | $292,932 | $362,481 | $386,452 | $2,642,956 | **$5,461,282** |
| | | T+92B | | | T+9B | |

The highest month was June, which is still within the period between the initial statement and the last required statement. Over half of the June settlements fell on one day – June 21. There were a number of market disruptions and HASP failures on this day that may influence the rerun calculations.[84] Market participants are encouraged to review settlement statements and communicate with the ISO for clarification when appropriate.

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80 California ISO Settlement User Group Meeting, March 17, 2021: http://www.caiso.com/Documents/Agenda-SettlementUserGroup-Mar17-2021.pdf

81 Market settlement timeline stakeholder initiative: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-settlement-timeline

82 *Market Settlements Timeline Transformation*, Rashele Wiltzius, Manager, Customer Readiness, July 20, 2020: https://www.caiso.com/Documents/Presentation-MarketSettlementsTimelineTransformationTraining.pdf

83 CAISO Payments Calendar January 1, 2021, through December 31, 2021: https://www.caiso.com/Documents/DraftCaliforniaISOPaymentsCalendar2021.pdf

84 *Market Disruption Report Jun 16, 2021 to Jul 15, 2021,* August 16, 2021: http://www.caiso.com/Documents/Aug16-2021-MarketDisruptionReport-Period-June16-2021-Jul15-2021-ER06-615-ER07-1257.pdf