

**California ISO**

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**Report on system and market conditions,  
issues and performance:****August and September 2020****November 24, 2020****Department of Market Monitoring**



## 1 Summary

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### 1.1 Background

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This report reviews system conditions and performance of the CAISO's day-ahead and real-time markets from mid-August to September 7, 2020. During this period, regional high temperatures led to a high demand heat wave across the entire western region. On August 14 and 15, CAISO grid operators called upon load serving entities to curtail load due to system-wide conditions for the first time since 2001. In the following days and weeks, CAISO loads remained high but were well below forecasted levels, due largely to voluntary conservation efforts. Prices in the CAISO, Western Energy Imbalance Market and bilateral markets reached record levels on August 17-19, but no further load curtailments occurred.

This report was prepared by the CAISO's Department of Market Monitoring (DMM) which serves as the independent market monitor for the CAISO and Western Energy Imbalance markets. A prior report, prepared by the CAISO, CPUC and CEC, focuses on the root causes of the load shedding events occurring on August 14-15.<sup>1</sup> The CAISO/CPUC/CEC report includes more detailed background information on issues such as the state's resource adequacy program, CAISO market rules and operational practices, and weather and system conditions during this period.

DMM has reviewed the CAISO/CPUC/CEC report and has worked with the CAISO to understand and resolve differences in key metrics appearing in that report and analysis in DMM's report. DMM concurs with many of the key findings and recommendations in the CAISO/CPUC/CEC report, including the reports main conclusion that "there was no single root cause of the outages, but rather, a series of factors that all contributed to the emergency."<sup>2</sup>

This report provides additional analysis and some recommendations based on DMM's own independent analysis. This report also covers periods through September 7, during which CAISO energy demand was forecast to be higher than August 14 and 15, but further load curtailments were avoided due to a combination of different market conditions and steps taken by the CAISO and other entities.

### 1.2 Key findings

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Key findings in this report are consistent with findings in the joint CAISO/CPUC/CEC report, which found that there was no single root cause of the load shedding events occurring on August 14-15. These load outages resulted from the combined effect of a series of factors, which include the following:

- **Extreme temperatures and energy demand** across the entire western region, which resulted in demand for electricity well in excess of current resource planning targets.

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<sup>1</sup> *Preliminary Root Cause Analysis: Mid-August 2020 Heat Storm*, October 6, 2020, prepared by the California Independent system Operator, California Public Utilities Commission and California Energy Commission. <http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf>. CAISO/CPUC/CEC report

<sup>2</sup> CAISO/CPUC/CEC report, cover letter, p. 1 of 3.

- **California state resource adequacy requirements** based on 1-in-2 year loads plus a 15 percent planning reserve margin, which are insufficient to reflect actual system conditions during this period.
- **Counting rules for resource adequacy capacity** which overestimate the actual capacity that is available from many resources during the early evening hours, when solar production is very low and demand is still very high.
- **Residual unit commitment (RUC) process and related real-time bid processing design.** The CAISO/CPUC/CEC report explains that “a prior market enhancement was unintentionally causing the CAISO’s RUC process to mask the load under-scheduling and convergence bidding supply effects, reinforcing the signal that more exports were supportable.”<sup>3</sup> This report provides a detailed discussion of this issue, along with changes that were subsequently made to address this issue.
- **Transmission capacity from the Pacific Northwest was de-rated by about 650 MW** as a result of a weather-related forced outage which prevented additional available supply – including some resource adequacy imports -- from being imported into the CAISO.
- **The sudden loss of several large gas fired units** contributed to triggering the load curtailment events on both August 14 and 15. Although the overall level of gas capacity on outage was not unusually high on these days, this sudden loss of a significant amount of gas capacity came at a time when the amount of excess supply was very low due to a combination of other factors.
- **Self-scheduling of relatively large volumes of exports** in the day-ahead market that were not backed by imports being wheeled through or contracts with capacity within the CAISO. This increased the overall demand that had to be met in both the CAISO day-ahead and real-time markets because exports not supported by physical supply were passed from the residual unit commitment process into the real-time market at this time. These export schedules were not subsequently curtailed in real-time during hours when the CAISO was curtailed.

The most significant and actionable of these factors involve California’s resource adequacy program. To limit the potential for similar conditions in future years, system level resource adequacy requirements should be modified to ensure more capacity is available during net load peak hours. In addition, capacity counting rules for different resource types should be modified to more accurately reflect the actual availability of these resources during the net load peak hours. These recommendations are discussed in more detail in this report.

Additional findings highlighted in this report include the following:

- **The overall availability of resource adequacy capacity shown on supply plans during the most critical days and hours from mid-August to early September was not unusually low.** Of the 51,000 MW of capacity counted towards August resource adequacy requirements, about 6,100 to 8,200 MW (or 10 to 15 percent) was not bid or self-scheduled in the real-time market during the peak net load hours.
- **Solar and wind resources accounted for a significant portion of resource adequacy capacity that was not available in the real-time market during hours of load curtailments.** For August, solar and wind resources, including pseudo-tie resources, had a combined resource adequacy rating of 4,300 MW. Output from these resources averaged about 2,490 MW (57 percent) below this resource

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<sup>3</sup> CAISO/CPUC/CEC report, pp. 13-14.

adequacy rating during hours 19-20 on August 14-15. The output from these resources is predictably lower in these evening hours when net loads are highest, compared to the output of these resources in hours with highest gross load which are used to determine their resource adequacy rating.

- **Gas units accounted for about 1,870 MW of resource adequacy capacity unavailable in real-time during hours of load curtailments.** This represented about 6.7 percent of the 27,743 MW of gas-fired resource adequacy capacity. Almost half of this unavailable capacity (or about 3 percent of total resource adequacy capacity from gas units) was due to ambient de-rates which occur in very hot weather – when the total output from gas units falls below their normal rated capacity due to ambient temperature. This is an example of one of the types of factors that should be factored in resource adequacy counting rules.
- **Demand response resources accounted for about 650 MW of resource adequacy capacity that was unavailable in real-time during hours of load curtailment on August 14. Demand response accounted for about 820 MW of resource adequacy was unavailable in real-time during hours of load curtailment on August 15.** This represents over one-third of the 1,847 MW of resource adequacy capacity requirement that was met by demand response in August. The actual performance of demand response resources that were dispatched has not yet been fully evaluated.
- **Imports and hydro units combined account for about 1,436 MW of resource adequacy capacity that was unavailable in real-time during hours of curtailment.** About 9 percent of non-resource specific resource adequacy imports was unavailable (664 MW), with much of this capacity being unavailable due to transmission limitations. About 9 percent of resource adequacy capacity from hydro was unavailable (572 MW).
- **The Western energy imbalance market functioned well and helped facilitate transfers of available capacity in real-time across the west.** The CAISO was the largest net importer in the energy imbalance market during the most critical evening ramping hours of the summer 2020 heat wave. During curtailment intervals on August 14-15, the energy imbalance market provided an average of 1,346 MW and 530 MW respectively into the CAISO system.
- **The CAISO market was structurally uncompetitive during the high load days in August.** Although prices were very high during the high load days in August, analysis using the CAISO's day-ahead market software indicates that system wide mitigation of imports and gas-fired resources during this period would not have lowered prices. This reflects the fact that gas-fired and other resources that may be subject to mitigation were generally infra-marginal in re-runs of the day-ahead market using cost-based bids, and that high prices were set by demand response and other resources not subject to mitigation.
- **DMM has carefully reviewed major outages which occurred on August 14-15.** Based on its data analysis and conversations with plant operators, DMM has found no indication that outages were falsely declared at strategic times in order to allow generation owners to profit from higher prices (e.g. from output of other generating units under their control or virtual demand positions taken in the day-ahead market).
- **DMM closely monitored and reviewed market behavior during the August 14-15 heatwave.** Contrary to some suggestions in the media, DMM has found no evidence that market results on these days were the result of market manipulation.

### 1.3 Recommendations

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

- ***Increase resource adequacy requirements to more accurately reflect increasing risk of extreme weather events*** (e.g. beyond the 1-in-2 year load forecast and 15 percent planning reserve margin currently used to set system resource adequacy targets). Prior to this summer, CAISO peak load fell under the 1-in-2 years forecast four of the last five years.<sup>4</sup> However, summer 2020 illustrates that higher reliability will require that resource adequacy requirements be based on load forecasts which reflect the high likelihood of much higher load conditions than are reflected in the 1-in-2 year forecast.
- ***Continue to work with stakeholders to clarify and revise the resource adequacy capacity counting rules***, especially as they apply to hydro resources, demand response resources, renewable resources, imports and other use limited resources. Counting rules should specifically take into account the availability of different resource types during the net load peak. Beginning in 2019, DMM has provided analysis and expressed concern in reports and CPUC filings about the cumulative impacts of various energy-limited or availability-limited resources which are being relied upon to meet an increasing portion of resource adequacy requirements.<sup>5</sup> This report includes additional analysis of the availability of different resource types during the peak net load hour in which load was curtailed in August, and highlights a variety of specific factors which could be incorporated into the resource adequacy ratings of these resources to better reflect their actual availability during the most critical net load peak hours.

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

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

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

Ensure that market processes appropriately curtail lower priority exports that are not supported by non-resource adequacy resources to minimize the export of capacity that could be related to RA resources during reliability events.<sup>6</sup>

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<sup>4</sup> 2019 Annual Report on Market Issues and Performance, Department of Market Monitoring, June 2020, pp.34-35.  
<http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf>

<sup>5</sup> 2019 Annual Report on Market Issues and Performance, pp. 26-27, 299-302.

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

[DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf](http://www.caiso.com/Documents/CPUC-DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf)

<sup>6</sup> CAISO/CPUC/CEC Report, p. 66.

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

DMM's understanding is that CAISO's current policy is still to prioritize exports that receive RUC awards over native CAISO balancing area load in real-time. DMM appreciates that curtailment of exports should be avoided when possible, given the potentially detrimental direct and indirect impacts of export curtailment on other balancing areas and the CAISO itself, as discussed in the CAISO/CPUC/CEC report.<sup>7</sup> However, DMM believes that additional changes and clarifications to the residual unit commitment rules and other market processes are needed to address the issue of exports.

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

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

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

Analysis in this report indicates that less than two thirds of the 1,847 MW of resource adequacy capacity requirements that were met by demand response were available for dispatch in real-time during the hours of load curtailment on August 14 and August 15. The actual performance of demand response resources that were dispatched has not yet been fully evaluated based on retail customer meter data. However, even if performance of demand response is high relative to the amount dispatched in the CAISO market, the amount of demand response that was available relative to the amount of resource adequacy capacity requirements met by demand response was relatively low.

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

A more detailed discussion of recommendations relating to demand response is provided in Section 3.13 of this report.

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<sup>7</sup> CAISO/CPUC/CEC Report, pp. 106-107.

## 2 Chronological summary

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This section provides a short chronological summary of key events, conditions and findings for three distinct periods from mid-August to early September 2020. As summarized below, these three periods represent a series of different heat waves marked by different system and market conditions. In addition, a variety of different actions were taken by the CAISO, state agencies, market participants, and end use consumers which had a significant impact on system and market outcomes in these different periods.

### August 14 and 15

- On Friday August 14, peak load was forecasted to be just over 45,750 MW in the day-ahead market, close to the one-in-two year peak used in setting resource adequacy requirements. Actual system loads on August 14 reached about 46,750 MW, about 1,000 more than the day-ahead forecast. Peak load on Saturday August 15 reached about 45,000 MW, similar to the day-ahead forecast.
- Regionally, the heat wave led to record levels of load across the EIM and the WECC.
- Load serving entities within the CAISO continued to submit self-schedules or very high bids to purchase energy in the day-ahead market on these days. Total physical load clearing the day-ahead market on these two days during hours 16 to 21 averaged about 95 percent of forecasted load.
- DMM’s analysis indicates that the amount of resource adequacy capacity scheduled or offered in the day-ahead market was slightly above the day-ahead load forecast on August 14 and 15.
- On these days additional demand was placed on the CAISO system by exports that were purchased in the day-ahead market. Most of these exports were self-scheduled (indicating a willingness to export at any market clearing price), with some additional exports clearing at very high bid prices to buy energy.
- The CAISO curtailed a very limited amount of export energy after the day-ahead energy market or in real-time, about 90 MW on August 14 and 30 MW on August 15. Thus, the remaining cleared exports added thousands of MW of additional demand to total CAISO area demand in both the day-ahead and real-time markets.
- On these two days, virtual supply bids clearing the day-ahead market at relatively high prices allowed additional export schedules and bids to clear the day-ahead market. About 2,900 MW of exports were scheduled out of the day-ahead market on interties connecting the CAISO with adjacent balancing areas in the southwest (NEVP, APS, SRP).<sup>8</sup>
- Most of the 4,500 MW of non-resource specific resource adequacy import capacity bid into the day-ahead market cleared (85 percent). Almost all of the capacity which did not clear (99 percent) was bid on interties from the Pacific Northwest, where congestion lowered prices below bids and limited the quantity available to import.

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<sup>8</sup> Exports cited here are the average during hours 17-22 on August 14 and 15 on ITCs in the southwest, including: CFE\_ITC, NORTHGILA500\_ITC, PALOVRDE\_ITC, ELDORADO\_ITC, MEAD\_ITC, IPPUTAH\_ITC, ADLANTO-SP\_ITC, ADLANTOVICTVL-SP\_ITC, WSTWGMED\_ITC, VICTVL\_ITC, and LAUGHLIN\_ITC.



- With the exception of a single gas resource which was returning from an outage, all available gas-fired capacity was committed to be in operation through the day-ahead residual unit commitment process or exceptional dispatch commitments.
- The overall amount of capacity on outage on these days was not abnormally high, but a few large gas-fired units had sudden outages. These created sudden changes in available generation and appear to have increased uncertainty about real-time supply at critical times.
- On August 14, the ISO manually dispatched about 800 MW of utility reliability demand response (RDRR) to reduce load during net peak load hours. On August 15, the ISO manually dispatched almost 900 MW of utility reliability demand response to reduce load during net peak load hours.
- Operating reserve levels were short of requirements for multiple intervals during peak hours in both the day-ahead and real-time markets and during load shedding.
- Both load shed events on August 14 and August 15 began in hour ending 19 when CAISO grid operators called upon all utility distribution companies within the CAISO system to curtail a total of about 1,000 MW and 500 MW of load respectively.<sup>9</sup> The August 14 event began load restoration in about an hour while on August 15 this process began after approximately 20 minutes.
- Actual load curtailments were implemented by utility distribution companies. The actual amount of load curtailed cannot be precisely quantified, but may be higher than called upon by CAISO operators.
- During the peak ramping hours, net transfers into the CAISO system from the rest of the energy imbalance market averaged about 1,500 MW on August 14 and 550 MW on August 15. Most of these transfers were from adjacent balancing areas in the southwest (NEVP, APS, SRP). Thus, these transfers offset a significant portion of the additional CAISO area demand that was created by exports to these balancing areas made through the day-ahead markets.
- During a few 15-minute intervals on these two days, the CAISO balancing area failed the resource sufficiency test applied to all balancing areas in the Western energy imbalance market. Balancing areas failing this test have their net import limit capped for subsequent 15-minute intervals. This limitation is designed to deter balancing areas from leaning excessively or systematically on the energy imbalance market to meet their resource and ramping energy requirements. However, DMM's analysis indicates that this limitation had little or no impact on net transfers from the energy imbalance market into the ISO during these intervals. EIM transfers were, however, limited by the total available greenhouse gas import supply in some intervals on both of these days.

### **August 17 to August 19**

- During this three day period, CAISO system loads were projected to reach record levels. However, actual demand during these days was significantly lower than the day-ahead forecast. The lower-than-expected loads on these days appear to be due in large part to an extraordinary response by

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<sup>9</sup> CAISO/CPUC/CEC Report, pp. 41-42.

consumers to efforts by the Governor’s office, state agencies and CAISO to promote reduced energy usage during the peak afternoon and early evening hours.

- Regionally, the RC West reported historical peak load levels reaching 127,631 MW on August 17, 2020 in the 6 pm hour.<sup>10</sup>
- On the evening of August 16, the ISO announced the suspension of virtual bidding effective in the day-ahead market occurring on August 17 for operating day August 18. The ISO also informed scheduling coordinators with scheduled day-ahead exports for August 17 that if conditions warranted curtailing load, export schedules could be curtailed as well.
- This suspension was designed in part to prevent virtual supply bids from allowing additional exports from being scheduled in the day-ahead market which would ultimately need to be met by physical supply from within the CAISO system. At this time, RUC was not identifying exports with IFM schedules that could not be supported by physical supply capacity. Analysis by DMM suggests that, given this RUC implementation issue, the suspension of virtual bidding did have a significant impact on reducing exports from the CAISO system scheduled in the day-ahead market.
- On these days, DMM’s analysis indicates available resource adequacy capacity would not have been sufficient to meet the day-ahead load forecast of system loads during the peak ramping hours.
- On these days, the state of California and other entities took a variety of actions to allow additional supplies of energy to be made available to the CAISO grid and to reduce behind-the-meter loads.<sup>11</sup>
- On August 17 to 19, load within the CAISO system was not curtailed and, on August 18, the ISO market curtailed exports from the CAISO system.
- The ISO reinstated virtual bidding in the day ahead market for August 22. Despite the ISO not having yet fixed the underlying RUC export and real-time schedule processing issue, by this time system and market conditions had changed so that virtual bidding was again viewed as providing market benefits without presenting a risk to system reliability. DMM concurred with the decision to reinstate virtual bidding based on its analysis of the change in market and system conditions which had occurred by that time.
- As discussed below, the CAISO took other actions prior to the next heat wave in early September to help mitigate the risk to real-time system reliability that could be created by a high level of exports from the CAISO’s day-ahead market.

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<sup>10</sup> September 24, 2020. California ISO: Board of Governors Memorandum <http://www.aiso.com/Documents/CEORepor-Sep2020.pdf>.

<sup>11</sup> CAISO/CPUC/CEC Report, pp. 38 - 40.

**September 5 to 7 (Labor Day weekend).**

- CAISO system loads were again projected to exceed the 1-in-10 year peak forecast on September 6. Real-time load on these days was high, but lower than forecast, exceeding the 1-in-2 forecast and reaching levels close to August 14 and 18.<sup>12</sup>
- The ISO announced a year-to-date peak load record of 47,236 MW on Sunday, September 6, 2020.<sup>13</sup>
- On these days, DMM's analysis indicates available resource adequacy capacity would not have been sufficient to meet either day-ahead load forecast or actual real-time system loads during the peak ramping hours.
- Beginning with the day-ahead market for September 5, the ISO implemented several software modifications designed to reduce exports from being scheduled in the day-ahead market which could not be supported by available physical supply in the CAISO system.
- These changes resulted in a significant reduction in exports from the CAISO system.
- On September 5 to 7, no load within the CAISO system was shed.

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<sup>12</sup> Actual load measures are not adjusted for dispatched demand response, which may have reduced load on these days.

<sup>13</sup> All other sources of data available to DMM indicate that load on August 18 exceeded load on September 6. These sources include real-time telemetry, the real-time market requirement and settlement data. See California ISO, Board of Governors Memorandum, September 24, 2020 <http://www.caiso.com/Documents/CEOReport-Sep2020.pdf>.



### 3 Analysis of key market Issues

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This section provides a summary of findings concerning specific key market issues examined in this report.

#### 3.1 Demand conditions

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During the 2020 heat wave, actual peak load exceeded the 1-in-2 year peak forecast on August 14, 18, and 19, as well as on September 5 and 6. Figure 3.1 and Figure 3.2 show the actual system load peak in the ISO by day compared to the 2020 1-in-2 and 1-in-10 year peak forecasts during the time frames of August 13-21 and September 5-7, respectively.<sup>14</sup> The day-ahead load forecast peak in the CAISO system surpassed the 1-in-10 year peak forecast on August 17, 18, and September 6.

As discussed in the CAISO/CPUC/CEC report, the high CAISO loads on these days resulted from record-high temperatures, and coincided with extremely high loads across the entire west.<sup>15</sup> As shown in Figure 3.1, actual peak loads exceeded the day-ahead load forecast by about 1,000 MW on August 14. Additionally, Figure 3.2 shows that actual peak load also exceeded the day-ahead load forecast on September 5 by about 1,500 MW.

Actual peak load also exceeded the CEC's adjusted August 2020 1-in-2 peak forecast used to set resource adequacy requirements (44,740 MW) on August 14, 15, 18, and 19.<sup>16</sup> The adjusted August 2020 1-in-2 forecast is over 1000 MW less than the CAISO 1-in-2 year peak forecast, as shown in Figure 3.1.

Both load shed events on August 14 and August 15 began in hour ending 19 when CAISO grid operators called upon all utility distribution companies within the CAISO system to curtail a total of about 1,000 MW and 500 MW of load respectively. The August 14 event began load restoration in about an hour while on August 15 this process began after approximately 20 minutes. Actual load curtailments were implemented by utility distribution companies. The actual amount and timing of load curtailed by the individual utility distribution companies cannot be precisely quantified, but is reported to have been higher and longer in duration than called upon by CAISO operators.<sup>17</sup>

Figure 3.3 compares the CAISO's day-ahead forecast to the actual market requirement for energy used by the real-time market software over the August heat wave. As shown in Figure 3.3, loads were forecasted to reach above 49,000 MW on Monday August 17 and were forecasted to exceed 50,000 MW on Tuesday August 18. Although the CAISO real-time requirement for energy reached almost 49,000 on August 18, it remained well below the day-ahead demand forecast on August 17 and 19.

The difference between the forecasted load peaks and the actual load peaks on August 17 to 19 appears to be due in large part to both the conservation efforts of Californians and out of market production in

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<sup>14</sup> The 1-in-2 year and 1-in-10 year peak forecasts are estimated by CAISO and reported annually in the Summer Loads and Resource Assessment report. The 2020 peak forecasts used for this analysis may be found on the CAISO website: <http://www.caiso.com/Documents/2020SummerLoadsandResourcesAssessment.pdf>

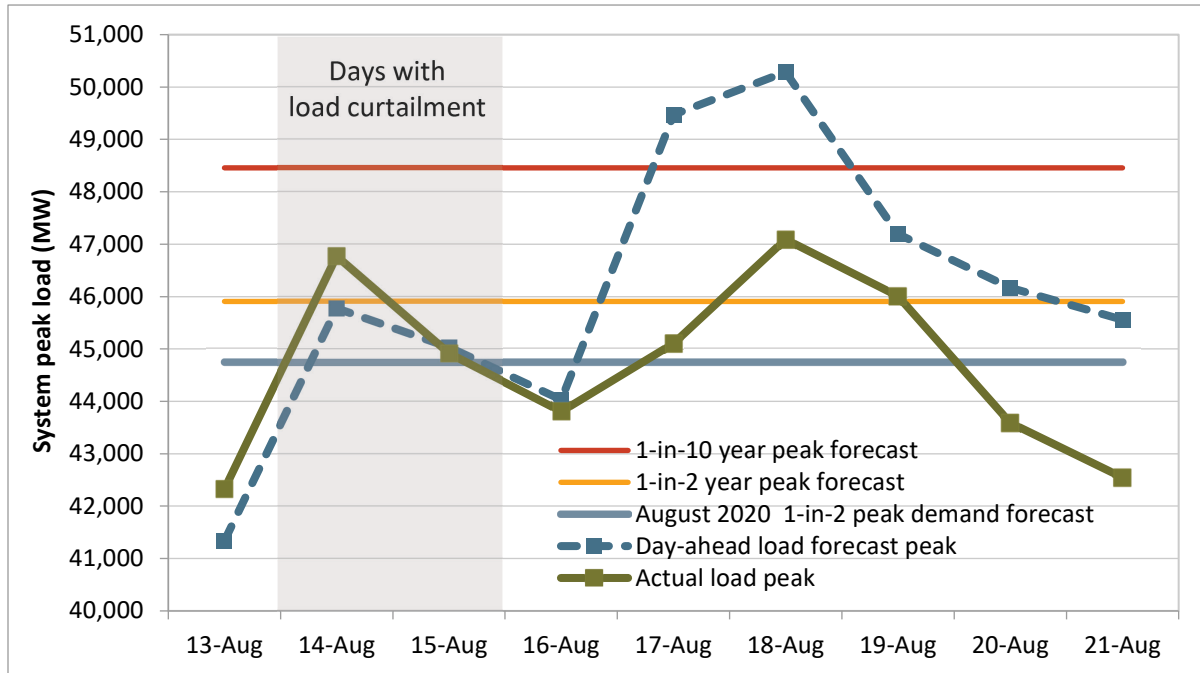
<sup>15</sup> CAISO/CPUC/CEC Report, pp. 27-28.

<sup>16</sup> CAISO/CPUC/CEC Report, pp. 45.

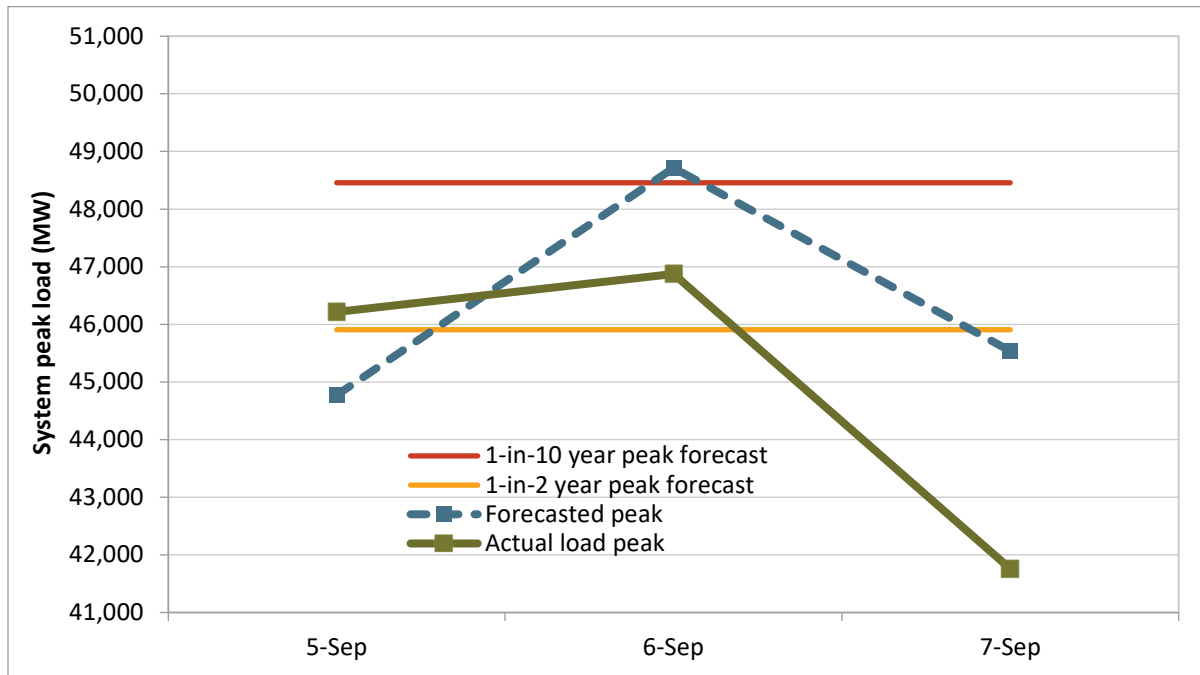
<sup>17</sup> CAISO/CPUC/CEC Report, pp. 41-42.

response to the efforts of the Governor’s office, state agencies and CAISO to promote reduced energy usage during the peak afternoon and early evening hours. The combination of voluntary load reductions and emergency assistance from surrounding balancing authority areas helped avoid the need for any further load curtailments.

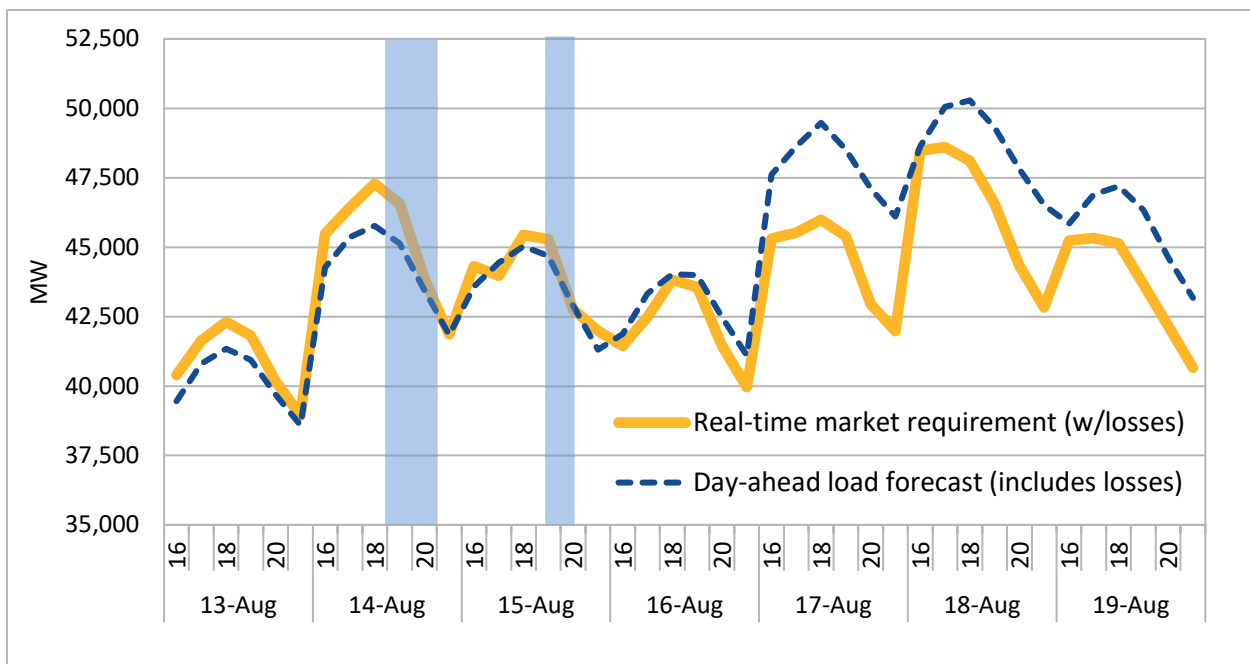
**Figure 3.1 Actual peak load in the ISO compared to day-ahead forecast peaks (August 13 – 21)**



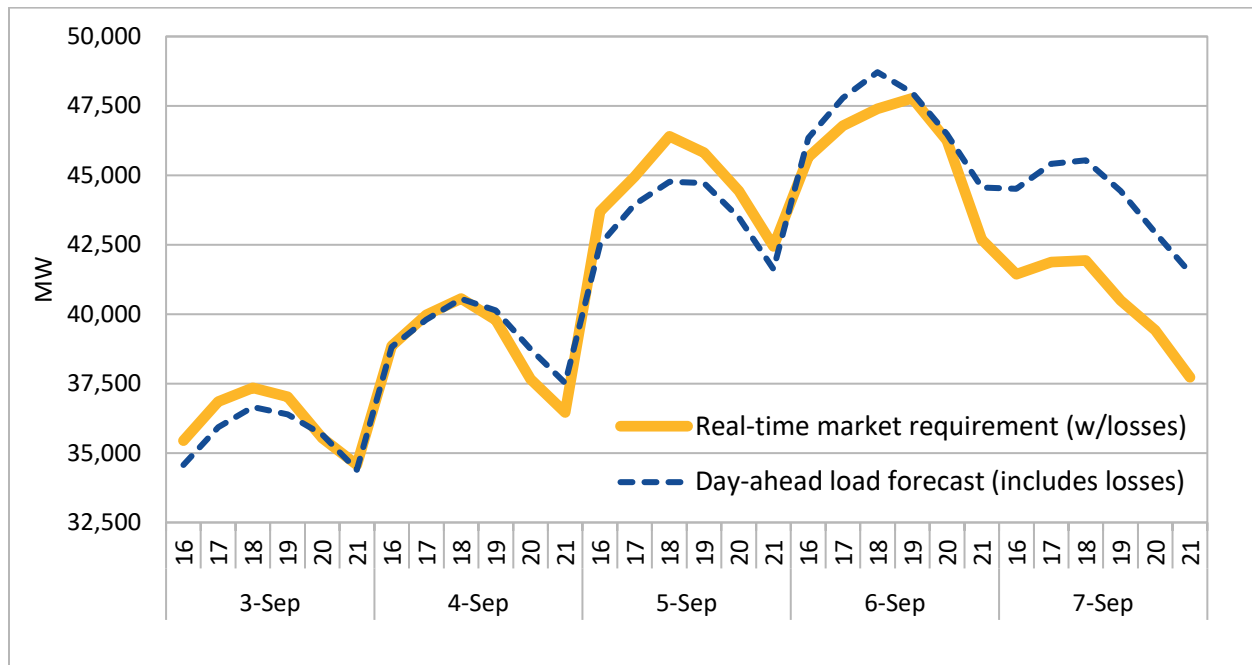
**Figure 3.2 Actual ISO peak load compared to day-ahead load forecast peaks (September 5 – 7)**



**Figure 3.3 CAISO day-ahead load forecast vs real-time load (August 13 – August 19)**



**Figure 3.4 CAISO day-ahead load forecast vs real-time load (September 3 – September 7)**



### 3.2 Energy market prices

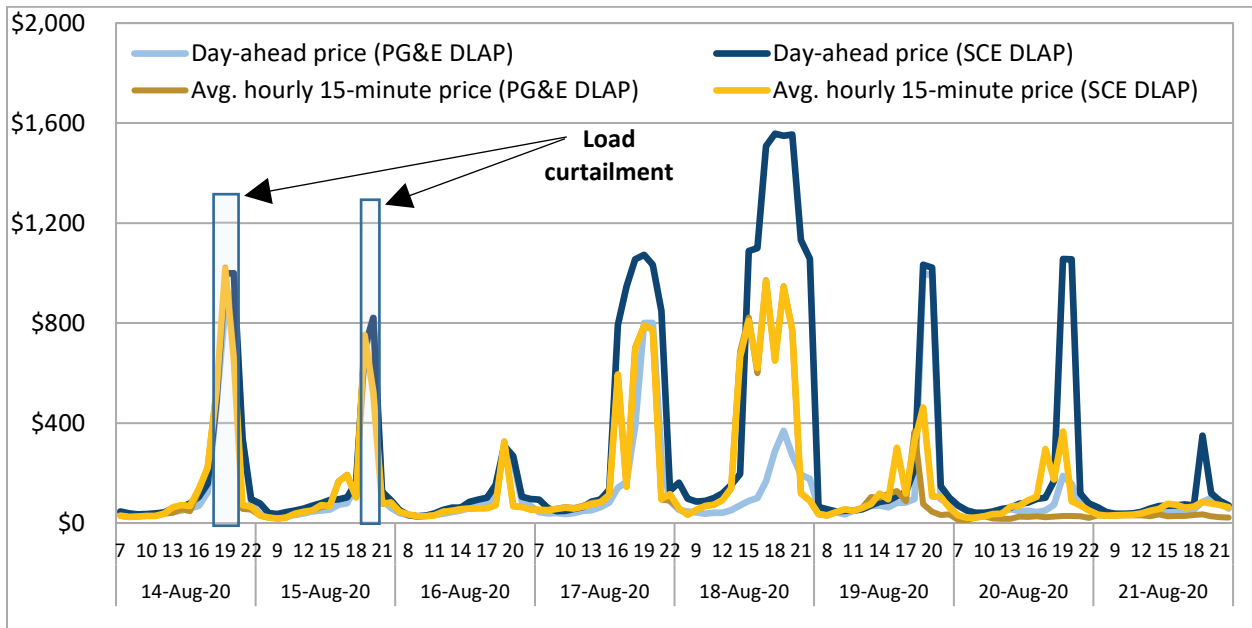
Figure 3.5 shows hourly prices in the CAISO day-ahead and real-time market from August 13 to 21, with the hours in which curtailments occurred highlighted.

As shown in Figure 3.5, day-ahead and real-time prices spiked sharply on August 14 and 15 during some of the early evening hours. Prices reached the cap in at least one of the PG&E, SCE or SDG&E areas in 2 day ahead intervals, 4 intervals in the 15-minute market and 15 intervals in the 5-minute market on August 14. On August 15, prices hit the \$1,000/MW price cap in at least one area for 3 intervals in the 15-minute market and for 12 intervals in the 5-minute market.

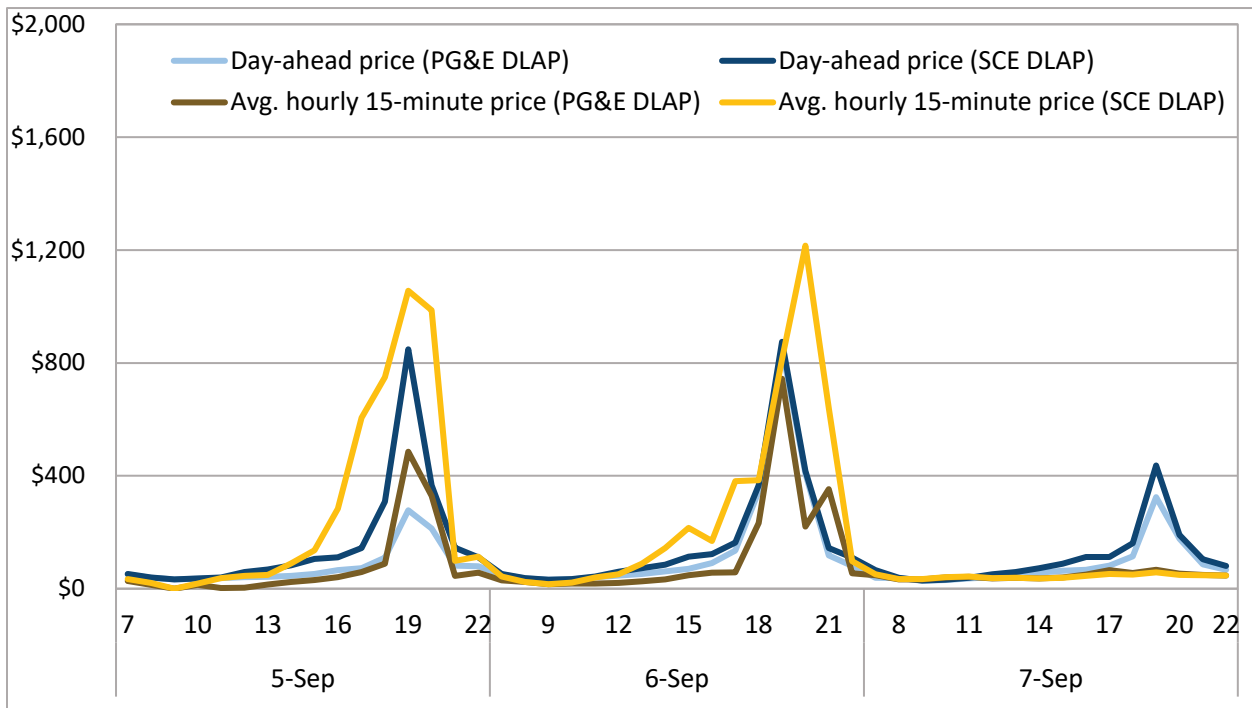
Day-ahead prices rose sharply on August 17 and 18, with system marginal energy costs (SMEC) reaching the \$1,000/MW bid cap numerous hours, while prices for southern California (SP15) being driven well above the \$1,000/MW by north-to-south congestion within the CAISO system. On these days, real-time prices remained high but were well below day-ahead prices. On these days, actual loads in real-time were well below the day-ahead forecast, as previously shown in Figure 3.1 and Figure 3.2.



**Figure 3.5 CAISO day-ahead and real time peak hour prices (August 14-21)**



**Figure 3.6 CAISO day-ahead and real time peak hour prices (September 5-7)**



### 3.3 Load bidding and scheduling

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

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

Figure 3.7 through Figure 3.11 compare the amount of load bid and scheduled in the day-ahead market with the CAISO day-ahead forecast. These figures also compare aggregate day-ahead load schedules to DMM's calculation of the energy requirement used by the real-time market software.<sup>18</sup>

As shown in Figure 3.7, Figure 3.8 and Figure 3.9 total physical load clearing the day-ahead market on August 14 during hours 16 to 21 averaged about 97 percent of forecasted load and 95 percent of the real-time market software requirement. On August 15, physical load clearing the day-ahead market in these hours averaged about 94 percent of forecasted load and 93 percent of the real-time requirement during hours 16 to 21.

While load under-scheduling in these hours was relatively small as a percentage of the total load forecast, the amount of unscheduled load that needed to be met by additional supply in the real-time market was still significant. For example:

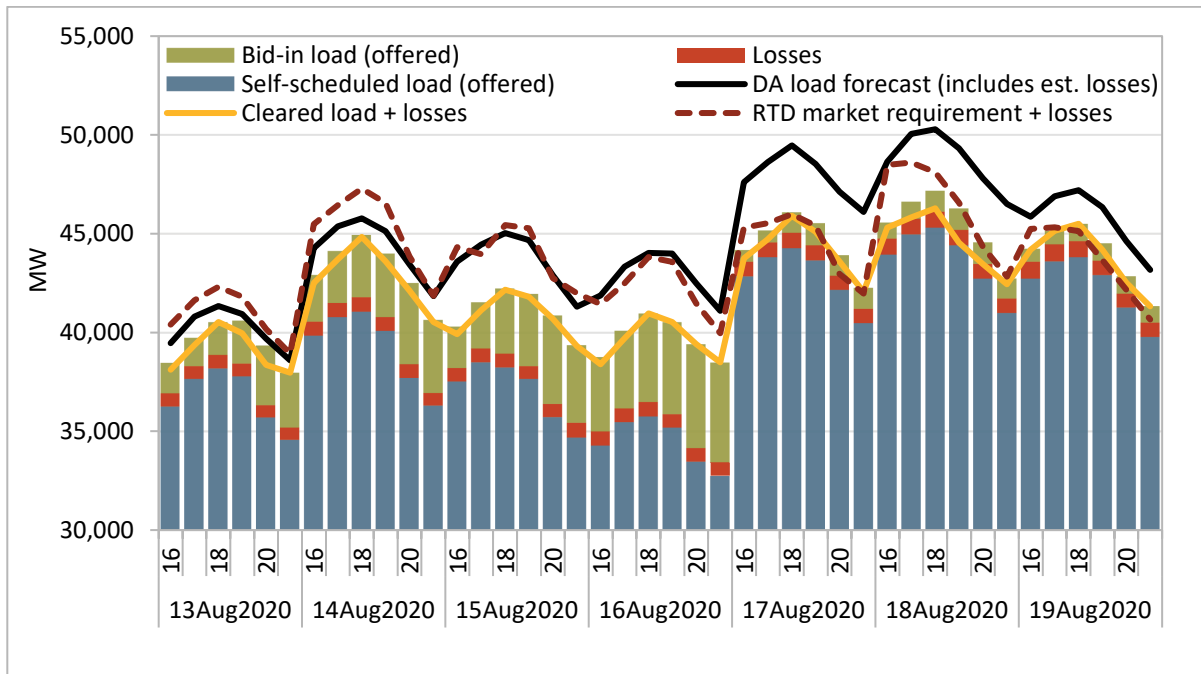
- On August 14, during the net load peak (hour ending 19), while load scheduled in the day-ahead market totaled 97 percent of the day-ahead forecast, this equated to 1,527 MW of unscheduled load that needed to be met in the real-time market.
- On August 15, during hour ending 19 load scheduled in the day-ahead market totaled 94 percent of the day-ahead forecast, which equated to 2,866 MW of unscheduled load in the real-time market.

As shown in Figure 3.7, beginning on Monday August 17, load serving entities increased the portion of load self-scheduled in the day-ahead market significantly, but had fewer price sensitive load bids offered and accepted in the market. Total physical load clearing the day-ahead market on August 17 to 19 during hours 16 to 21 averaged about 93 percent of day-ahead load forecast. Since real-time loads were well below day-ahead forecast on these days, physical load schedules averaged about 99 percent of the real-time market requirement during the evening hours of August 17 to 19.

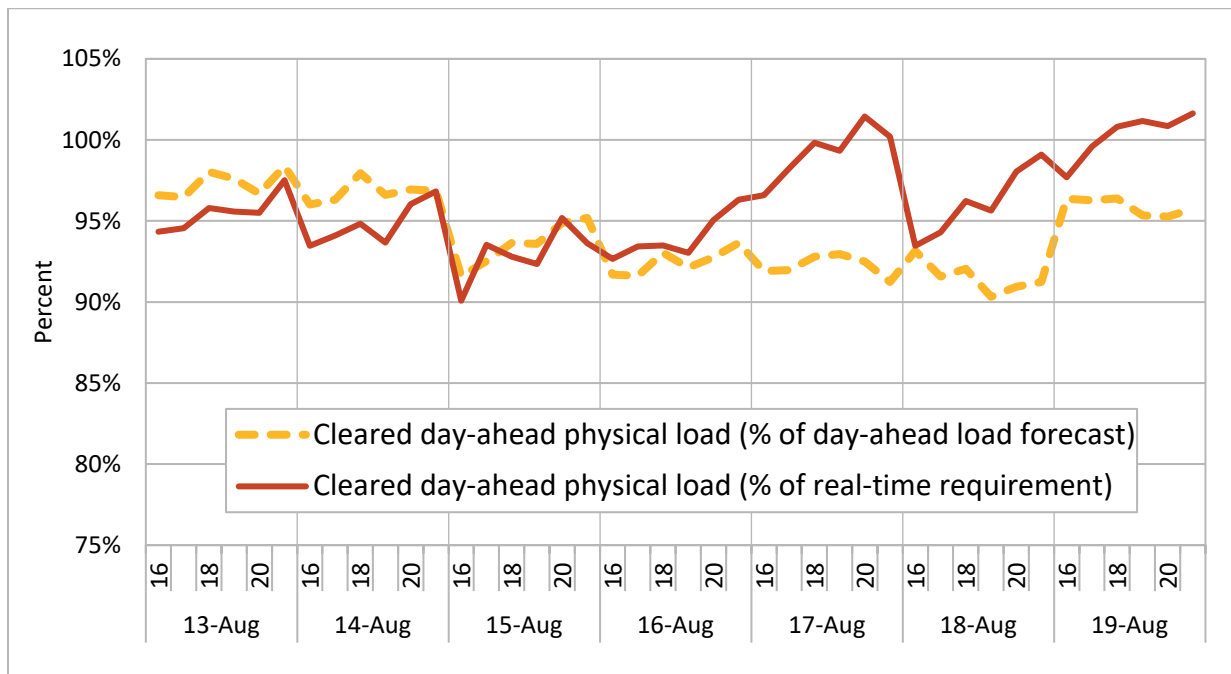
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<sup>18</sup> This is the measure of real-time demand produced by the market software. It includes biasing of 5-minute real-time load forecast by operators, which often exceeded 1,000 MW in the hours covered in this report. This measure is different than the measure of load from the PI system used by CAISO.

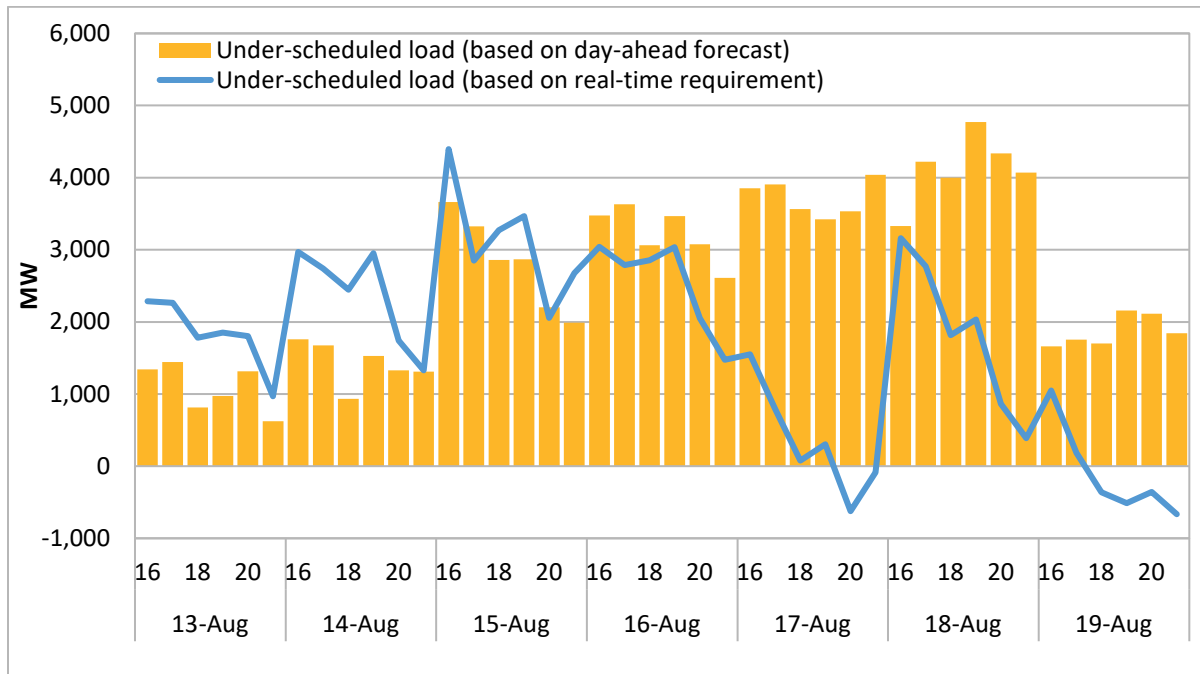
**Figure 3.7 Physical load scheduled in day-ahead market (August 13 – August 19)**



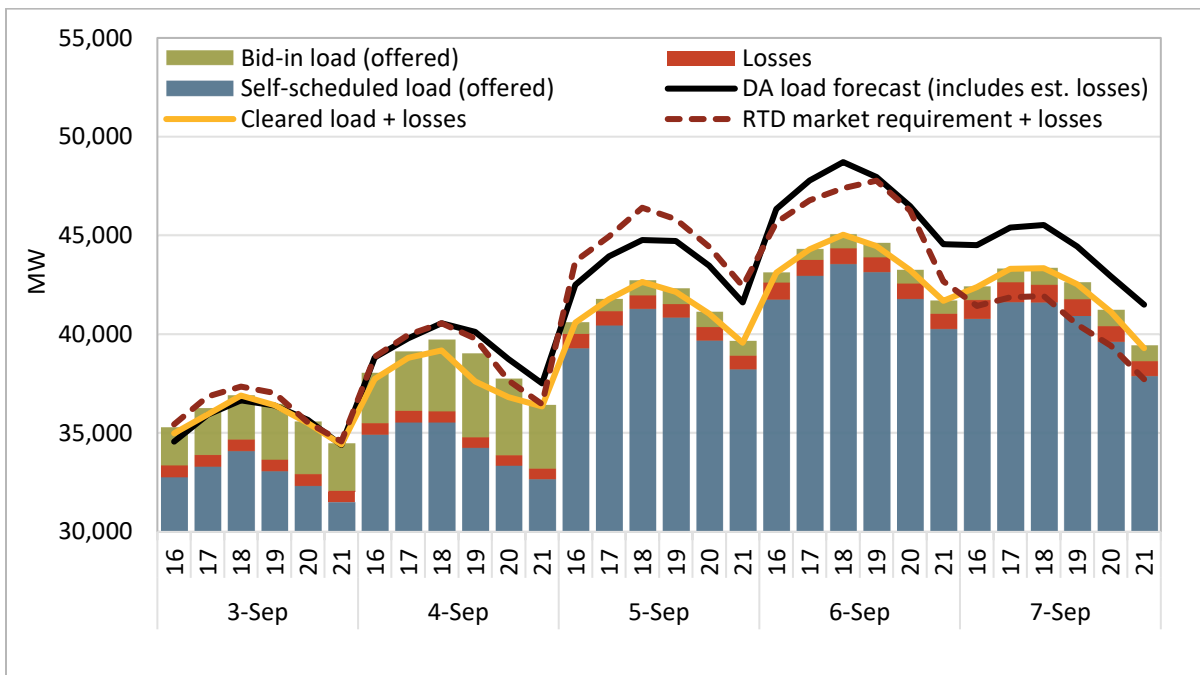
**Figure 3.8 Physical load scheduled in day-ahead market (August 13 – August 19) (as a percentage of forecast and real-time load)**



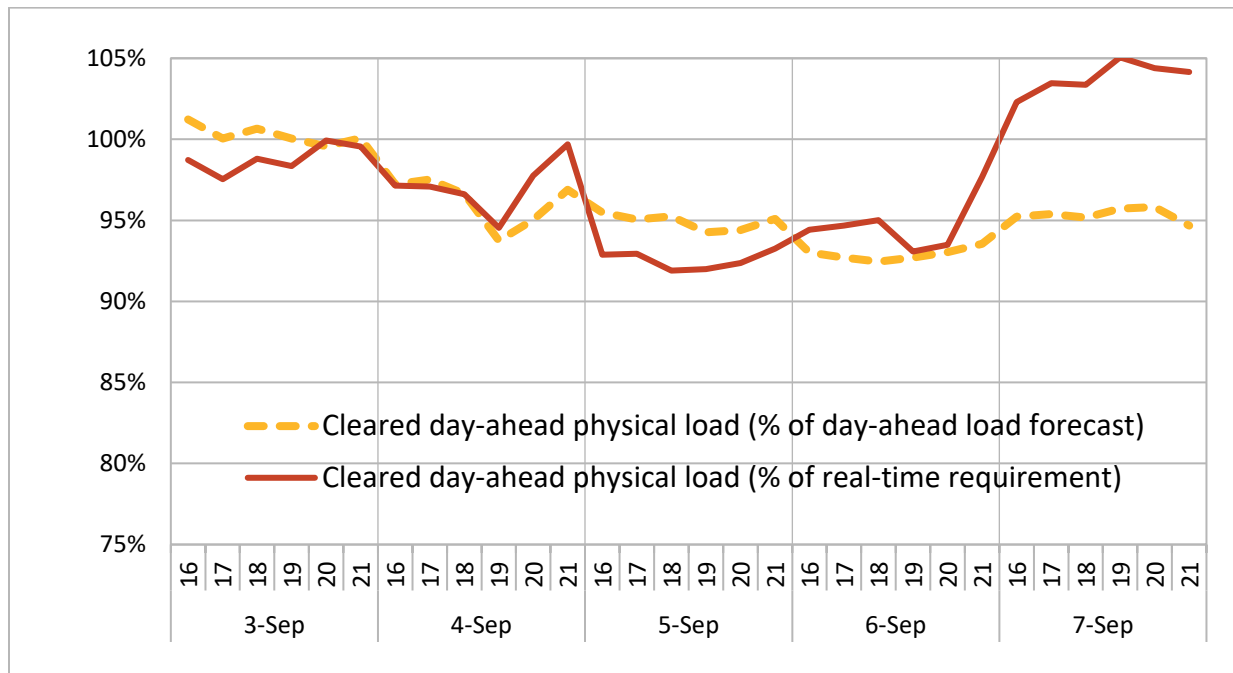
**Figure 3.9 Under-scheduled load based on day-ahead forecast and real-time market requirement**



**Figure 3.10 Physical load scheduled in day-ahead market (September 3 – September 7)**



**Figure 3.11 Physical load scheduled in day-ahead market (September 3 – September 7) (as a percentage of forecast and real-time market requirement)**



### 3.4 Ancillary service requirements

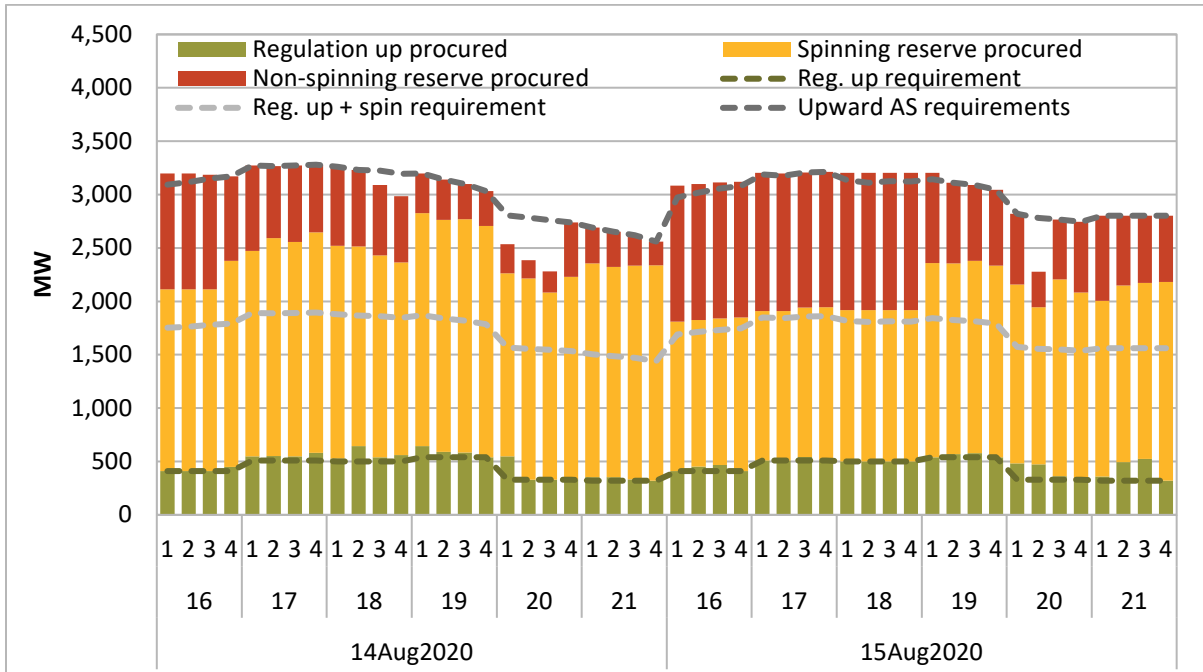
This section provides a summary of ancillary service requirements, procurement and scarcities during the August heat wave.

Figure 3.12 and Figure 3.13 compare real-time upward ancillary service requirements (dotted lines) with the amount of ancillary service capacity procured (bars) for the expanded CAISO system region during the peak load hours. The dotted lines distinguish the ancillary service requirements for regulation up (dark green), regulation up and spin combined (light gray), and all upward ancillary services (dark gray). The cumulative requirements for these different ancillary service types reflect how higher quality ancillary services can be substituted for lower quality ancillary services. The white space below the total upward ancillary service requirement and the amount procured reflects ancillary service scarcities.

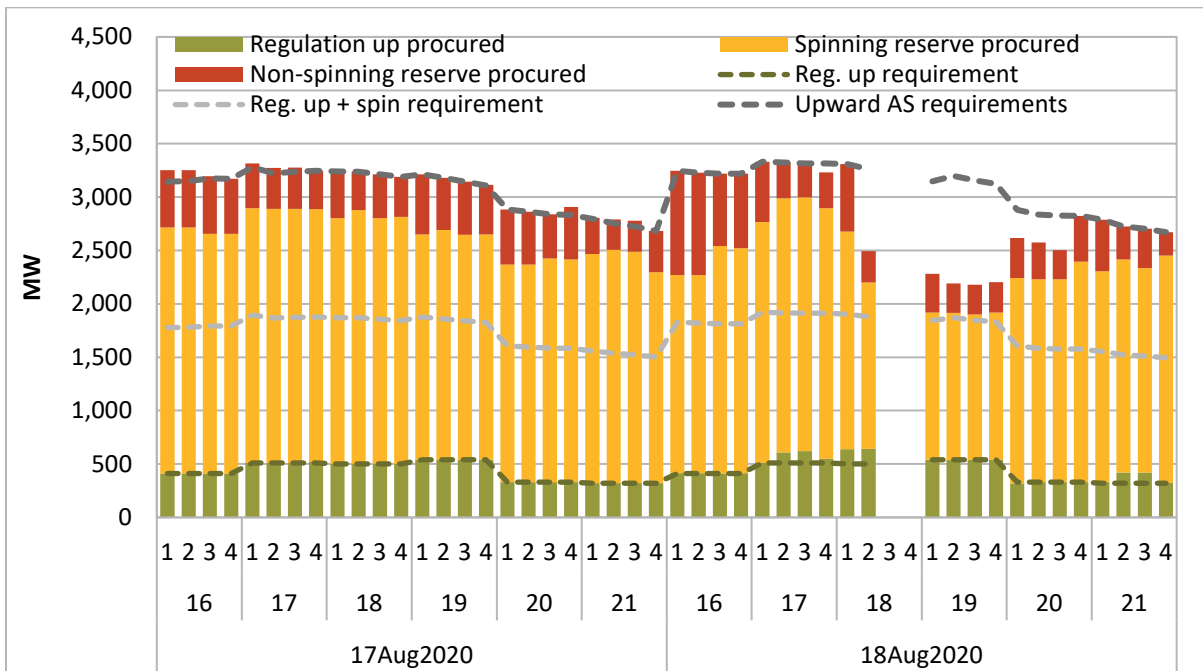
Figure 3.12 shows this information for August 14 and August 15, the days in which the ISO curtailed load. During the hours when the ISO curtailed load, the market procured around 2,800 MW of upward ancillary services. As shown in the figure, there was multiple 15-minute market intervals with scarcity of non-spinning reserve during these days, ranging from 133 MW to 505 MW.

Figure 3.13 shows the same information for August 17 and August 18, the days in which load was forecasted to be the highest. On August 18 hour 19, non-spinning reserve scarcity at the expanded system region level averaged around 940 MW. There was also some scarcity of regulation up on this day, ranging from 1 to 12 MW. The market run failed to publish for August 18 hour 18, interval 3 or 4. Prices are filled according to administrative pricing rules in these intervals.

**Figure 3.12 Ancillary service requirements, procurement, and scarcity (August 14-15, 2020)**



**Figure 3.13 Ancillary service requirements, procurement, and scarcity (August 17-18, 2020)**

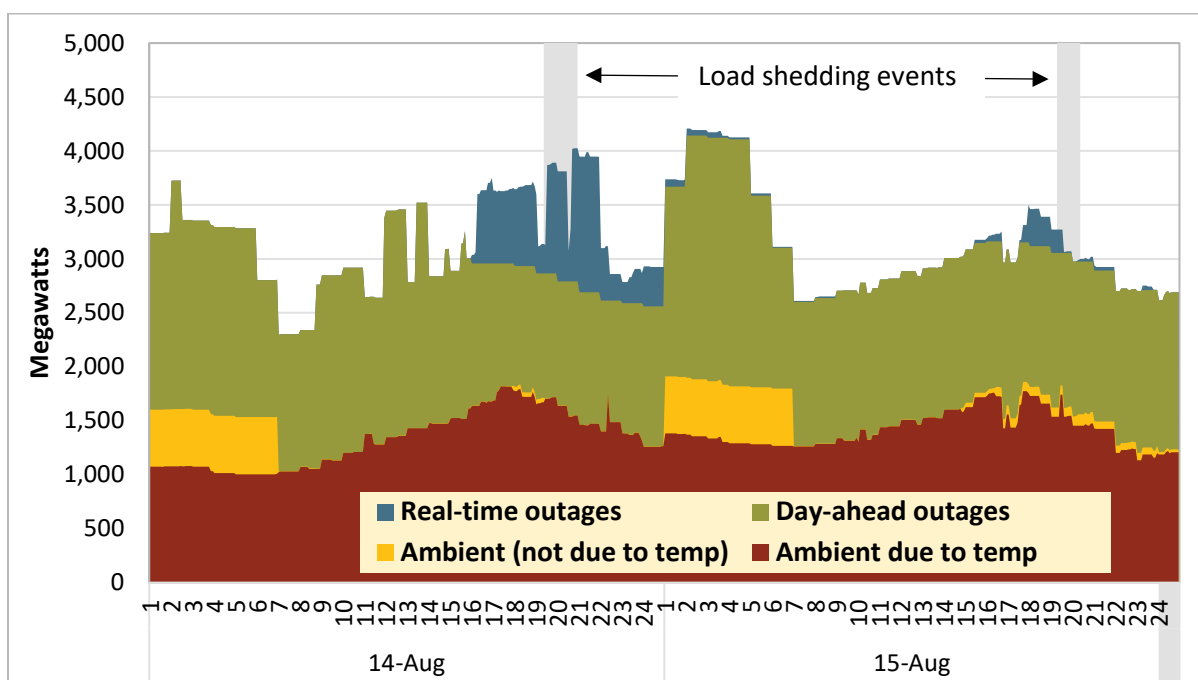


### 3.5 Generation outages

One of the key factors cited for triggering the load curtailment events on August 14 and 15 were sudden forced outages of several large gas-fired units in real-time. Figure 3.14 shows the gas-fired capacity (including resource adequacy and non-resource adequacy capacity) on outage during August 14 and 15.

On August 14, there was a large spike in outages in the hours leading up to load curtailment. On August 15, there was also a significant increase in the amount of capacity on outage in the hours leading up to load curtailment. Although the overall level of gas capacity on outage was not unusually high on these days, this sudden loss of a significant amount of gas capacity came at a time when the amount of available supply was very low due to a combination of other factors, as explained in other sections of this report.

**Figure 3.14 Gas unit outages and load shedding events (August 14-15)**



As shown in Figure 3.14, about half of the gas-fired capacity unavailable was due to ambient de-rates which occur in very hot weather – when the total output from gas units falls below their normal rated capacity due to ambient temperature. During the hours of load curtailment on August 14, about 12 percent of total gas-fired capacity was on outage, with about 5.3 percent of total gas-capacity reporting ambient de-rates due to high temperatures. On August 15, just over 10 percent of total gas-fired capacity was on outage during hours of load curtailment, with about 5 percent of total gas-capacity reporting ambient de-rates due to high temperatures.

As described in section 3.6 of this report, about 1,870 MW of resource adequacy capacity from gas units was unavailable in real-time during hours of load curtailments. This represents about 6.7 percent of the 27,743 MW of gas-fired resource adequacy capacity on these days. Almost half of this unavailable capacity (or about 3 percent of total resource adequacy capacity from gas units) was unavailable due to

ambient de-rates due to very hot weather. This is an example of one of the types of factors that should be factored in resource adequacy counting rules.

DMM has reviewed major outages which occurred on August 14 and 15. Based on data available to DMM at this time, there is no indication that on these days any outages were falsely declared at strategic times in order to allow generation owners to profit from higher prices (e.g. from output of other generating units under their control or virtual demand positions taken in the day-ahead market).

### 3.6 Resource adequacy capacity

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California's wholesale market relies heavily on a long-term procurement planning process and resource adequacy program adopted by the CPUC to provide sufficient capacity to ensure reliability. The following analysis shows the availability of capacity that was used to meet system resource adequacy requirements as measured by bids into the day-ahead and real-time markets. This analysis does not include bids and transfers from EIM entities.

Resource adequacy capacity in this analysis reflects the capacity that is shown to the ISO on resource adequacy supply plans and also includes CPM capacity, RMR resources, and investor-owned utility demand response.<sup>19</sup> The CAISO/CPUC/CEC report includes two additional categories of resource adequacy capacity in some metrics: (1) capacity above resource adequacy showings from resources that are shown for part of their total operating range and (2) capacity from resources not shown as resource adequacy. These two additional categories are included in the analysis below as separate categories, where appropriate.

Day-ahead market bids include energy bids and non-overlapping ancillary service bids; real-time market bids include energy bids only.<sup>20</sup> Bids are capped at the resource adequacy capacity values shown for individual resources to measure the availability of capacity that was secured in the planning timeframe. Bids are also capped according to individual resource outages and derates. This analysis also compares aggregated bids from resource adequacy capacity to actual load levels to measure how forward resource adequacy planning requirements compared to actual peak loads. While the analysis below includes all available resource adequacy bids at the system level, congestion and operating constraints may prevent the market from actually utilizing all of the bid capacity in this analysis.

#### Available resource adequacy vs loads

Day-ahead resource adequacy bids were sufficient to meet forecast load during peak hours on August 13 – 16, but not during the second half of the August heatwave (August 17 – 20), when loads were forecast to be above 46 GW on each day. However, resource adequacy bids were insufficient to meet forecast load plus ancillary service requirements during peak net load hours on each day from August 14 – 20. On these days, resource adequacy bids were also insufficient to meet the sum of forecast load, ancillary service requirements, and self-scheduled exports.

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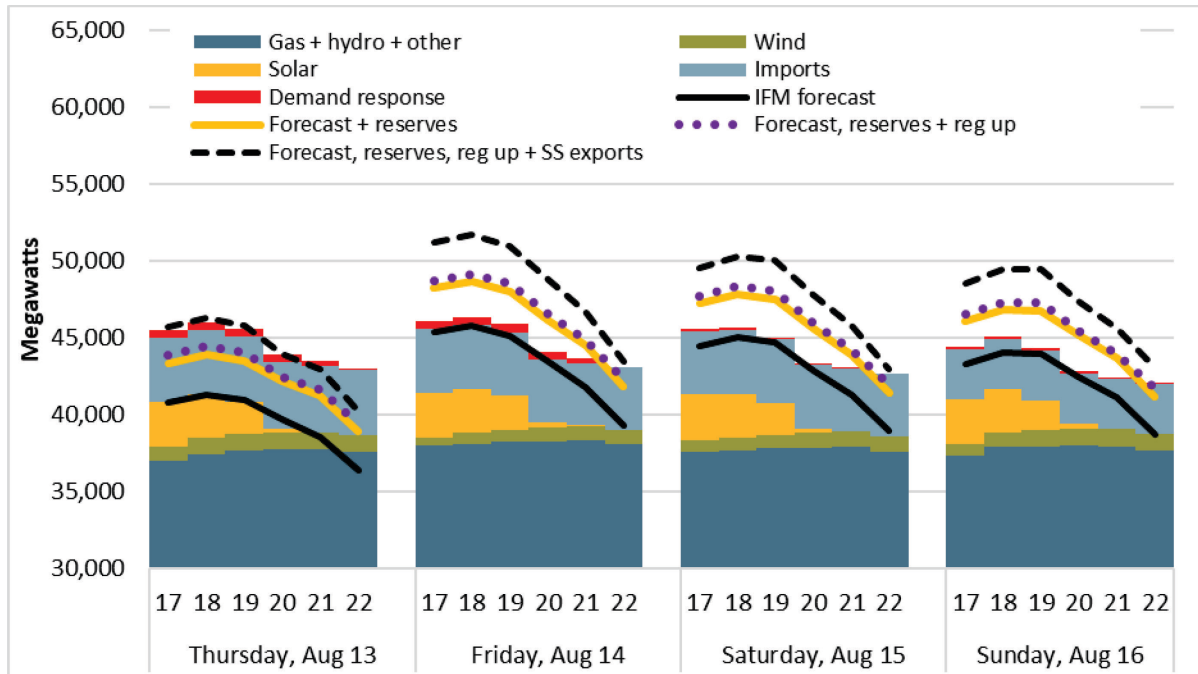
<sup>19</sup> Other than investor-owned utility demand response, Figures 3.13-3.16 do not include the potential availability of resource adequacy supply that is reflected to the ISO as credits to overall resource adequacy obligations. As discussed in this section of the report, a portion of credited resource adequacy capacity cannot be tied to specific resources in the ISO market. CAM resources shown on investor-owned utility supply plans are included in relevant fuel categories.

<sup>20</sup> To calculate hourly real-time bid amounts, bids from variable energy resources were averaged over the hour. Bids from non-VER resources reflect the maximum hourly bid in the HASP, RTPD, and RTD markets adjusted for derates, due to data issues.

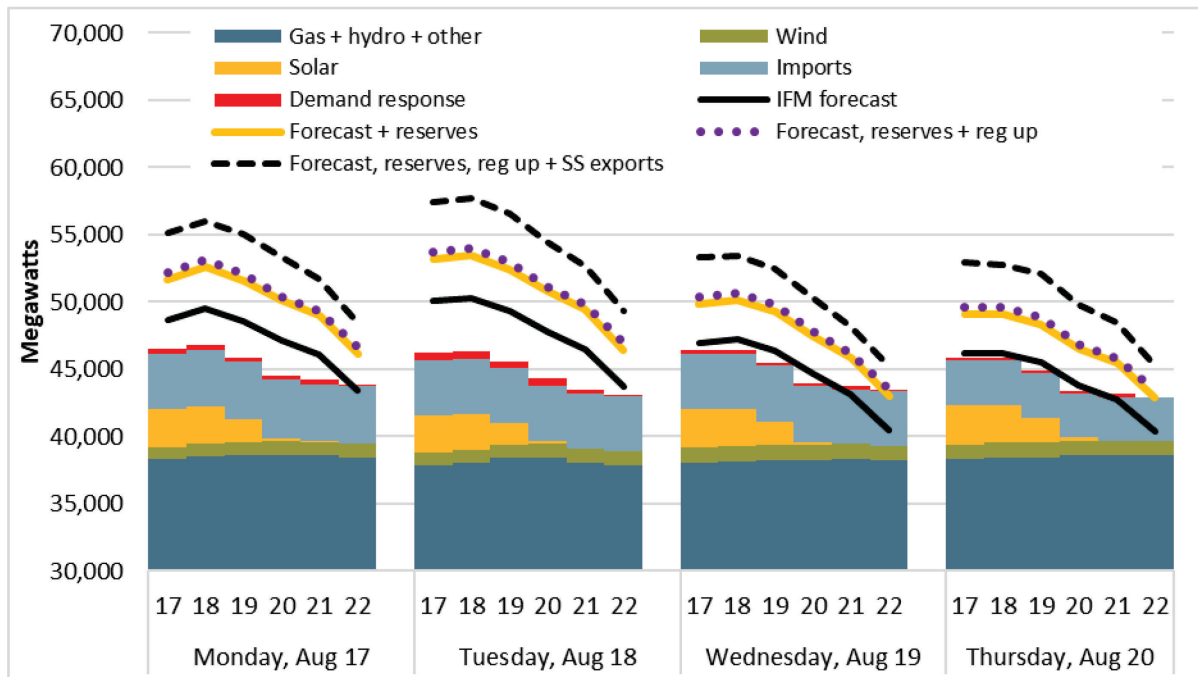


Figure 3.15 and Figure 3.16 show the hourly bids for resource adequacy resources by fuel type in the day-ahead market for August 13 – 20. Energy and non-overlapping ancillary service bids from resources shown to meet system resource adequacy requirements were sufficient to meet peak day-ahead load forecast (solid black line) on August 13 – 16, but not in several peak net load hours on August 17 - 20. Bids from these resources were not sufficient to meet the load forecast after the addition of non-spin reserve requirements (solid orange line), regulation up requirements (dotted purple line), and the amount of self-scheduled exports (dashed black line) above the load forecast for most hours from August 14 – 20.

**Figure 3.15 Day-ahead market hourly resource adequacy bids by fuel type (August 13 - 16, 2020)**



**Figure 3.16 Day-ahead market hourly resource adequacy bids by fuel type (August 17 - 20, 2020)**



Real-time resource adequacy bids were sufficient to meet the real-time market requirement in most peak load hours on August 13 – 20, with the exception of August 14 and 18. However, resource adequacy bids were not sufficient to meet the real-time market requirement and ancillary service requirements during most peak net load hours. The real-time market requirement can exceed actual load as it includes upward biasing of the real-time imbalance forecast by grid operators, which is often ranges from 1,000 to 2,000 MW during the early evening hours, as was the case over this time period.

Figure 3.17 and Figure 3.18 show the hourly average resource adequacy bids by fuel type in the real-time market for August 13-20, 2020. Energy bids from these resources were sufficient to meet the real-time market requirements and losses (solid black line) for most hours during these days. Similar to the results from the day-ahead market, these bids were not sufficient to meet the added spin and non-spin reserve requirements (solid orange line), regulation up requirements (dotted purple line), and the amount of self-scheduled exports (dashed black line) above the load forecast in most hours depicted.

**Availability by resource type**

Table 3.1 lists the average hourly availability of resource adequacy capacity in the day-ahead and real-time markets during the hours when load was curtailed on August 14 and 15. This table shows resource adequacy capacity bids compared to the amount of capacity that was shown or credited towards resource adequacy obligations, by resource type. Bids and self-schedule megawatt totals for the day-ahead and real-time markets are derived by adjusting the bids and self-schedules of individual resources for outages and derates and aggregating by fuel type.

As shown in the bottom rows of Table 3.1, a total of 51,373 megawatts of capacity was shown on resource adequacy supply plans on August 14 and 51,333 megawatts was shown on August 15, 2020. A small amount of this capacity (between 3 to 4 percent) was on outage in the day-ahead market. During

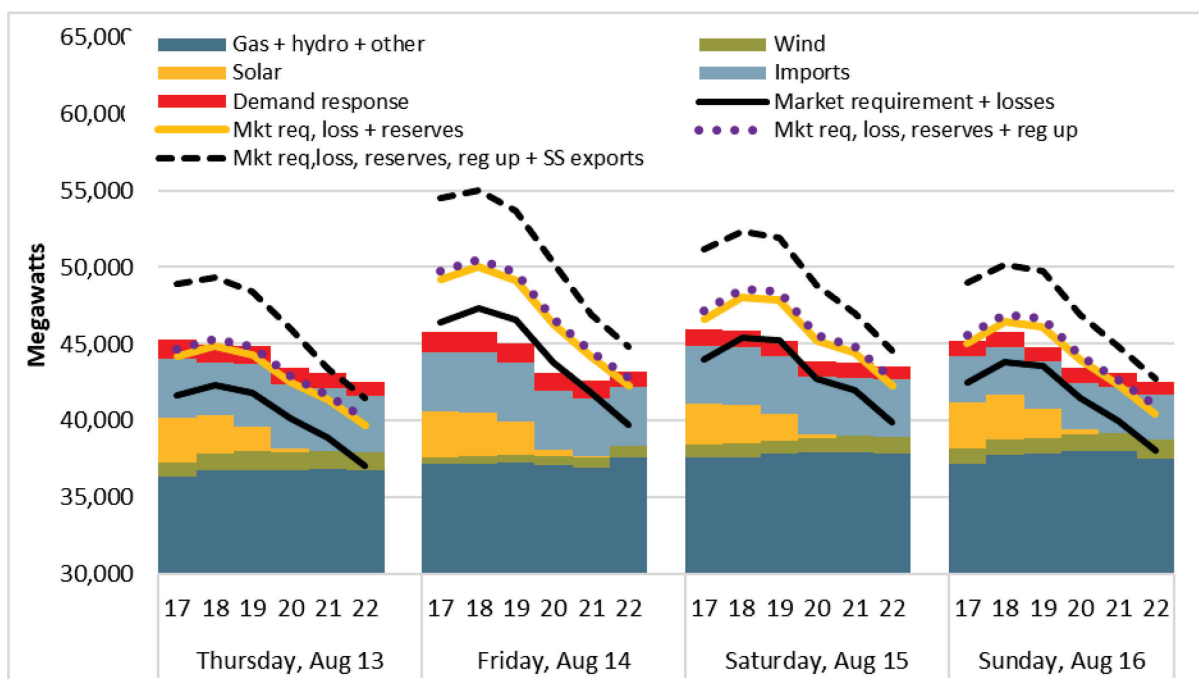
the hours in which load was curtailed on August 14 and 15, about 84 to 89 percent of this capacity was bid or self-scheduled in the day-ahead and real-time markets. A total of about 6,100 to 8,200 MW of resource adequacy capacity was not bid or self-scheduled into the real-time market during these hours.

**Solar and wind**

Solar and wind resources accounted for about 4,300 MW of shown resource adequacy capacity in August. The net qualified capacity of solar resources for the month of August equaled about 27 percent of solar resources’ maximum generating capacity. The resource adequacy rating of wind resources for the month of August equaled about 21 percent of wind resource’s maximum generating capacity.<sup>21</sup>

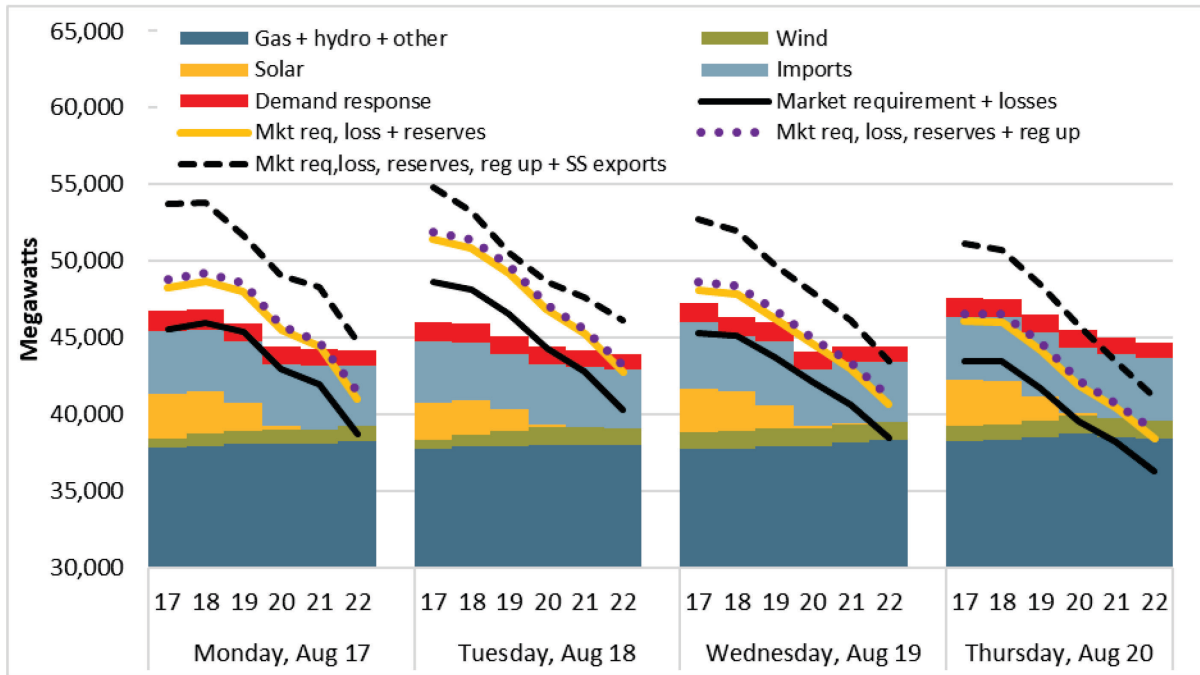
However, during the evening ramping period when net loads are highest, the actual output of solar and wind resources was lower than the net qualified capacity and shown resource adequacy values of these resources. During the hours when load curtailments occurred, the amount of solar and wind that was bid or self-scheduled into the real-time market equaled about 43 percent of the shown resource adequacy capacity of these resources.

**Figure 3.17 Real-time market hourly resource adequacy bids by fuel type (August 13 - 16, 2020)**



<sup>21</sup> Though these values include resources contracted with both CPUC-jurisdictional and non-CPUC jurisdictional load serving entities, solar and wind, overall these resource adequacy ratings are consistent with the CPUC’s effective load carrying capacity values for wind and solar adopted under D.19-06-026: *Decision Adopting Local Capacity Obligations for 2020-2022, Adopting Flexible Capacity Obligations for 2020, and Refining the Resource Adequacy Program*, CPUC, June 27, 2019: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K463/309463502.PDF>

**Figure 3.18 Real-time market hourly resource adequacy bids by fuel type (August 17 - 20, 2020)**



**Table 3.1 Average resource adequacy capacity and availability by fuel type<sup>22</sup>**

Resource type	Date	Hour ending	Total resource adequacy capacity (MW)	Day-ahead market				Real-time market		
				Adjusted for outages		Bids and self-schedules		Bids and self-schedules		Bids and self-schedules below cap
				MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.	MW
Gas	8/14/2020	19	27,743	26,668	96%	26,629	96%	25,710	93%	2,033
		20	27,743	26,727	96%	26,687	96%	25,441	92%	2,302
	8/15/2020	19	27,716	26,197	95%	26,159	94%	26,062	94%	1,654
		20	27,716	26,258	95%	26,220	95%	26,234	95%	1,482
Solar	8/14/2020	19	3,077	3,071	100%	2,202	72%	2,197	71%	880
		20	3,077	3,071	100%	330	11%	427	14%	2,650
	8/15/2020	19	3,079	3,073	100%	2,072	67%	1,729	56%	1,350
		20	3,079	3,073	100%	268	9%	202	7%	2,877
Wind	8/14/2020	19	1,253	1,253	100%	824	66%	483	39%	770
		20	1,253	1,253	100%	886	71%	538	43%	715
	8/15/2020	19	1,253	1,253	100%	895	71%	864	69%	389
		20	1,253	1,253	100%	959	77%	935	75%	318
Hydro	8/14/2020	19	6,663	6,250	94%	6,074	91%	5,955	89%	708
		20	6,663	6,250	94%	6,075	91%	6,090	91%	573
	8/15/2020	19	6,661	6,253	94%	6,144	92%	6,155	92%	506
		20	6,661	6,253	94%	6,144	92%	6,160	92%	501
Utility demand response	8/14/2020	19	1,604	1,604	100%	315	20%	1,040	65%	564
		20	1,604	1,604	100%	288	18%	1,022	64%	582
	8/15/2020	19	1,604	1,604	100%	8	1%	931	58%	673
		20	1,604	1,604	100%	0	0%	917	57%	687
Supply plan demand response	8/14/2020	19	243	243	100%	195	80%	142	58%	101
		20	243	243	100%	195	80%	142	58%	101
	8/15/2020	19	243	243	100%	130	53%	100	41%	143
		20	243	243	100%	130	53%	100	41%	143
Imports	8/14/2020	19	4,171	4,100	98%	4,100	98%	3,834	92%	337
		20	4,171	4,100	98%	4,100	98%	3,833	92%	338
	8/15/2020	19	4,131	4,126	100%	4,098	99%	3,739	91%	392
		20	4,131	4,126	100%	4,098	99%	3,743	91%	388
Metered subsystem imports	8/14/2020	19	327	327	100%	26	8%	26	8%	301
		20	327	327	100%	27	8%	27	8%	300
	8/15/2020	19	327	327	100%	27	8%	27	8%	300
		20	327	327	100%	27	8%	27	8%	300
Other	8/14/2020	19	1,936	1,877	97%	1,837	95%	1,827	94%	109
		20	1,936	1,878	97%	1,829	94%	1,825	94%	111
	8/15/2020	19	1,936	1,871	97%	1,824	94%	1,808	93%	128
		20	1,936	1,871	97%	1,829	94%	1,813	94%	123
Qualifying facilities	8/14/2020	19	960	959	100%	890	93%	892	93%	68
		20	960	959	100%	876	91%	886	92%	74
	8/15/2020	19	987	986	100%	890	90%	876	89%	111
		20	987	986	100%	893	90%	878	89%	109
Legacy RMR	8/14/2020	19	165	164	99%	0	0%	100	61%	65
		20	165	164	99%	0	0%	100	61%	65
	8/15/2020	19	165	164	99%	0	0%	133	81%	32
		20	165	164	99%	0	0%	73	44%	92
Nuclear	8/14/2020	19	2,797	2,797	100%	2,797	100%	2,797	100%	0
		20	2,797	2,797	100%	2,797	100%	2,797	100%	0
	8/15/2020	19	2,797	2,797	100%	2,797	100%	2,797	100%	0
		20	2,797	2,797	100%	2,797	100%	2,797	100%	0
<b>Total</b>	<b>8/14/2020</b>	<b>19</b>	<b>51,373</b>	<b>49,313</b>	<b>96%</b>	<b>45,889</b>	<b>89%</b>	<b>45,003</b>	<b>88%</b>	<b>6,370</b>
		<b>20</b>	<b>51,373</b>	<b>49,373</b>	<b>96%</b>	<b>44,090</b>	<b>86%</b>	<b>43,128</b>	<b>84%</b>	<b>8,245</b>
	<b>8/15/2020</b>	<b>19</b>	<b>51,333</b>	<b>48,894</b>	<b>95%</b>	<b>45,044</b>	<b>88%</b>	<b>45,221</b>	<b>88%</b>	<b>6,112</b>
		<b>20</b>	<b>51,333</b>	<b>48,955</b>	<b>95%</b>	<b>43,365</b>	<b>84%</b>	<b>43,879</b>	<b>85%</b>	<b>7,454</b>

### Solar and wind (continued)

Solar and wind resources accounted for most of the resource adequacy capacity that was not available in the real-time market during these hours. The availability of solar resources was about 2,800 MW below the shown resource adequacy capacity of these resources during hour ending 20 on these days. This represents the largest amount of unavailable resource adequacy capacity of any fuel category.

### Natural gas

Natural gas resources accounted for over half of shown resource adequacy capacity on August 14 and August 15 (27,730 MW). About 5 percent of this capacity was unavailable in the day-ahead market due to outages and derates, and about 6.7 percent was unavailable in real-time. Almost half of this unavailable capacity (or just over 3 percent of total resource adequacy capacity from gas units) was unavailable due to ambient de-rates due to very hot weather. This is an example of one of the types of factors that should be factored in resource adequacy counting rules.

As a proportion of overall procured capacity, the availability of capacity from natural gas resources was relatively high compared to other resource types with over 92 percent of gas-fired resource adequacy capacity available in the real-time market during hours of load curtailment. However, because gas resources account for such a large portion of resource adequacy capacity, this fuel-type accounted for the second highest amount of resource adequacy capacity that was not available in the real-time market. About 1,500-2,300 MW of this capacity was not bid into the real-time market during these hours.

### Hydro

Hydro resources accounted for the second highest amount of resource adequacy capacity on August 14 and August 15 (6,700 MW). The net qualifying capacity of hydro resources for the month of August equaled about 72 percent of their maximum generating capacity. About six percent of shown hydro resource adequacy capacity was unavailable to the day-ahead market due to outages and derates. About 500 to 700 MW (or 8 to 11 percent) of resource adequacy capacity from hydro resources was not bid into the real-time market during these hours.

### Demand response

Demand response that was shown on resource adequacy supply plans as well as utility demand response that is credited towards resource adequacy obligations accounted for about 1,850 MW of resource adequacy capacity in August. On August 14 in hours 19 and 20, about 64 percent of utility demand response and 58 percent of demand response shown on resource adequacy supply plans was bid into the real-time market.

In the same hours on August 15, about 58 percent of utility demand response and 41 percent of demand response shown on supply plans was bid into the real-time market. Demand response availability dropped between August 14 and August 15 because several demand response programs are unavailable on weekends and holidays. Section 3.13 of this report provides additional discussion on demand response resources used to meet resource adequacy requirements.

## Imports

Non-resource specific import capacity accounted for almost 4,500 MW of shown resource adequacy capacity in August.<sup>23</sup> This figure includes non-resource-specific imports shown by load-following metered sub-system entities. About 330 to 370 MW (8 percent) of import resource adequacy capacity was not bid into the day-ahead market on August 14 and August 15.

The majority (300 MW) of the import resource adequacy capacity not available in the day-ahead market was capacity shown and scheduled by load-following metered sub-system entities. This capacity is not subject to must-offer obligations or bid insertion. The remaining import resource adequacy capacity not bid into the day-ahead market on August 14 was declared on outage. About 28 MW of import resource adequacy capacity that was not bid into the day-ahead market on August 15 was not declared on outage but was not subject to bid insertion because August 15 was a weekend and thus fell outside of ISO availability assessment hours.

Most of the non-resource specific resource adequacy import capacity bid into the day-ahead market cleared (85 percent). Almost all of the capacity which did not clear (99 percent) was bid on interties from the Pacific Northwest, where congestion lowered prices below bids and limited the quantity available to import. On these congested paths, non-resource adequacy imports bid at a lower price could therefore clear, utilizing limited transmission capacity and replacing resource adequacy imports. The RUC process cleared an additional 1 percent on August 14, but no additional capacity on August 15. The additional capacity cleared on August 14 was on the same congested interties from the Pacific Northwest.

Most of the import resource adequacy capacity bid into the real-time market cleared, as in the day-ahead market (92 percent). Congestion on interties from the Pacific Northwest again lowered prices below bids and limited the total quantity of imports on these paths. High price bids from some resource adequacy import capacity on these paths (about 6 percent of all import resource adequacy bids) did not clear, allowing lower priced non-resource adequacy import capacity to clear on these congested paths. These imports were essentially replaced by non-resource adequacy imports that were bid at a lower price than these resource adequacy imports, and therefore cleared the market and utilized transmission capacity that could otherwise be utilized for higher priced resource adequacy imports. Congestion on interties from the Southwest also limited imports in the real-time market.

Revised CPUC import resource adequacy rules taking effect next year will require non-resource specific resource adequacy imports to be bid at \$0 or lower in the day-ahead and real-time markets during the availability assessment hours.<sup>24</sup> Although these requirements are not applicable on weekends and holidays, these new rules should help ensure that resource adequacy imports procured by CPUC-jurisdictional entities are available and delivered in the day-ahead and real-time markets. DMM continues to recommend that the ISO work with the CPUC to develop alternative approaches that would ensure that resource adequacy

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<sup>23</sup> Pseudo-tie resources are not included under the import category in this analysis. Pseudo-tie resource adequacy capacity is included under the relevant fuel type category.

<sup>24</sup> *Decision Adopting Resource Adequacy Import Requirements* (D.20-06-028), CPUC, 6/25/2020: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF>

imports are available in the day-ahead and real-time markets when needed, but could provide more flexibility to submit price-responsive bids in some or most hours.<sup>25</sup>

### **Non-resource adequacy capacity**

The analysis in the CAISO/CPUC/CEC report includes three categories of supply that were not included in DMM's analysis of resource adequacy capacity shown in Figure 3.16 through Figure 3.19 and Table 3.1. These three other categories of supply include:

- (1) capacity above resource adequacy showings from resources within the CAISO that are shown for part of their total operating range;
- (2) capacity from resources within the CAISO not shown as resource adequacy and
- (3) bids from non-resource adequacy import resources.

Figure 3.19 through Figure 3.22 show analysis which includes these three other categories of capacity that were included in the CAISO/CPUC/CEC report.

As shown in Figure 3.19 and Figure 3.20, day-ahead bids from resource adequacy resources (including bid quantities above resource adequacy showings), were not sufficient to meet load forecast plus ancillary service requirements during multiple hours on August 17 and 18. However, day-ahead bids from these resources were sufficient to meet forecast load plus ancillary service requirements on other days during the August heat wave.

In Figure 3.19 and Figure 3.20, bids for energy and ancillary services from resources shown to meet system resource adequacy requirements are shown in blue. Extra capacity bid from wind and solar resources in excess of resource adequacy showings from these resources is shown in yellow. Additional bids from other resource adequacy units in excess of their resource adequacy capacity showing is shown in green.

As shown in Figure 3.19 and Figure 3.20, during most days and hours these bids from all these resources exceeded the peak day-ahead load forecast (solid black line), as well as the load forecast plus various ancillary service requirements (solid light blue and dotted purple lines).

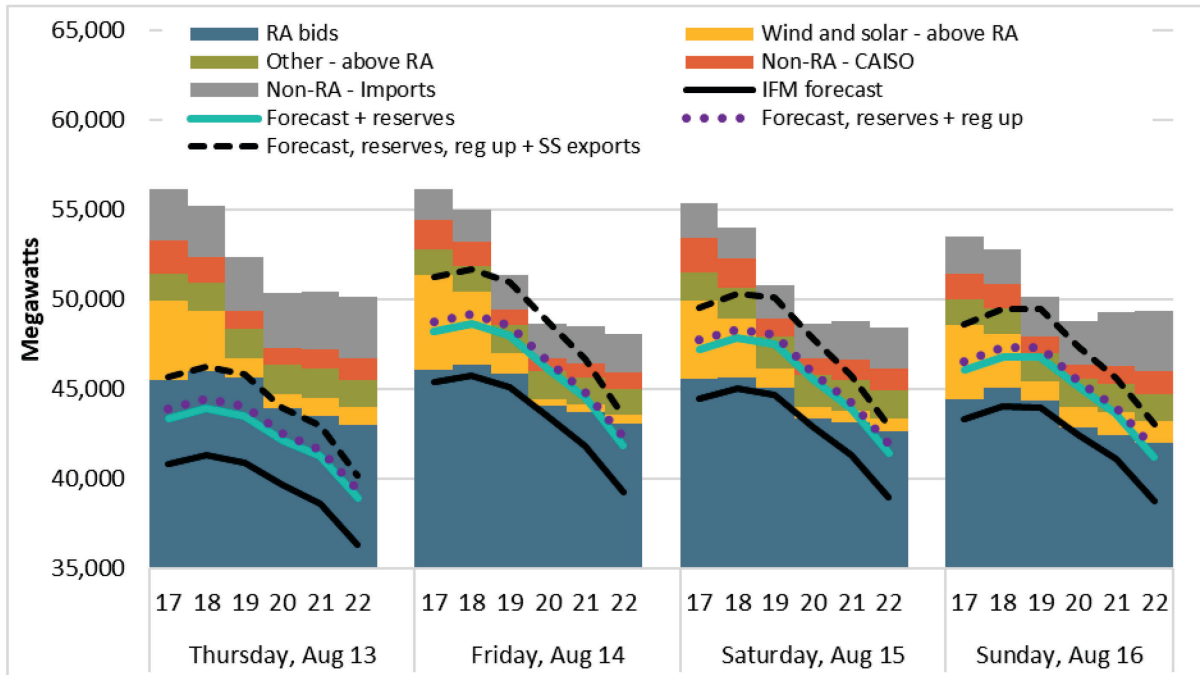
The dashed black line in Figure 3.19 and Figure 3.20 shows the additional demand created by exports that are self-scheduled in the day-ahead market. As shown in these figures, day-ahead bids from resource adequacy resources (including bid quantities above resource adequacy showings), were not sufficient to meet additional load from self-scheduled exports during peak hours on any day during the August heat wave period. However, bids from non-resource adequacy resources, shown in grey (imports) and orange (other fuels), were sufficient to support self-scheduled exports in the day-ahead market during almost all hours except August 17 and 18.

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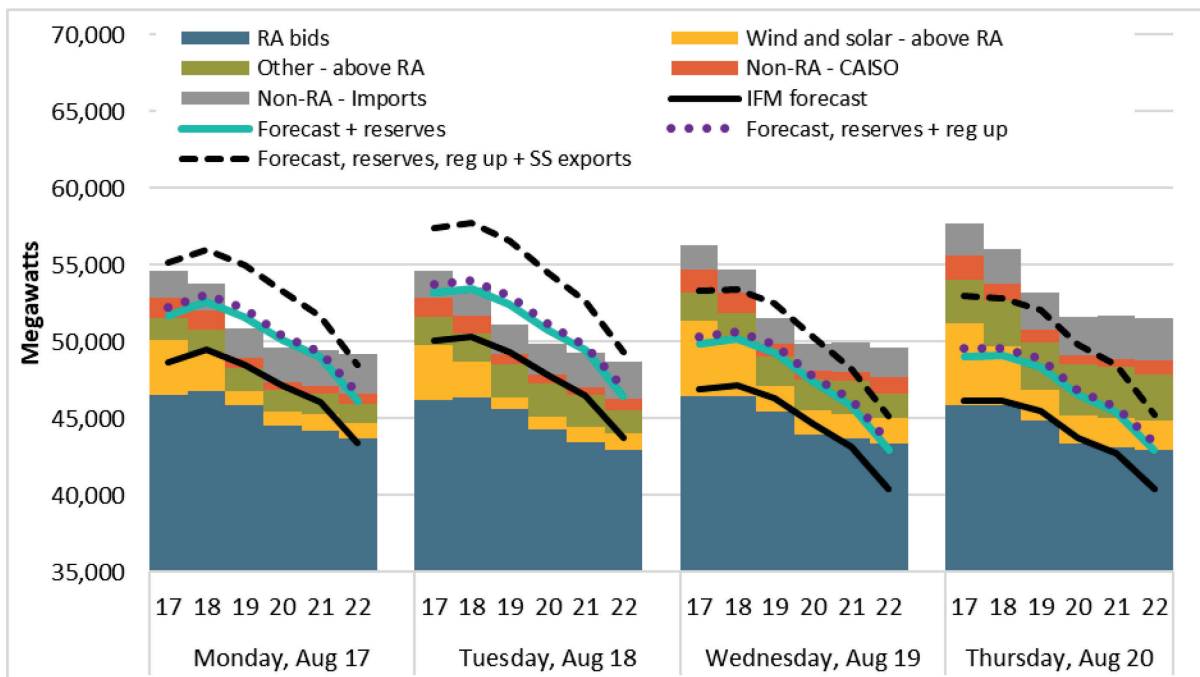
<sup>25</sup> *Comments on Proposed Decision Adopting Resource Adequacy Import Requirements (17-09-020)*, June 8, 2020, Department of Market Monitoring. <http://www.caiso.com/Documents/CPUC-CommentsonProposedDecisionAdoptingResourceAdequacyImportRequirements-R17-09-020-Jun82020.pdf>



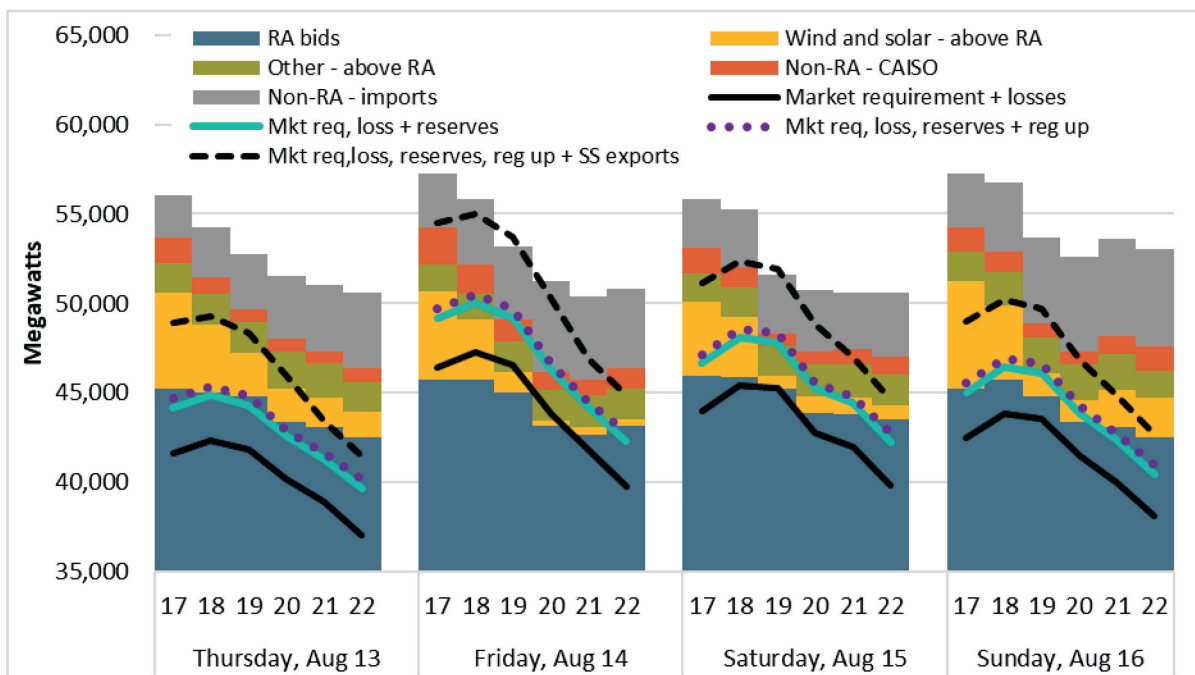
**Figure 3.19 Day-ahead market hourly bids by resource adequacy status (August 13 - 16, 2020)**



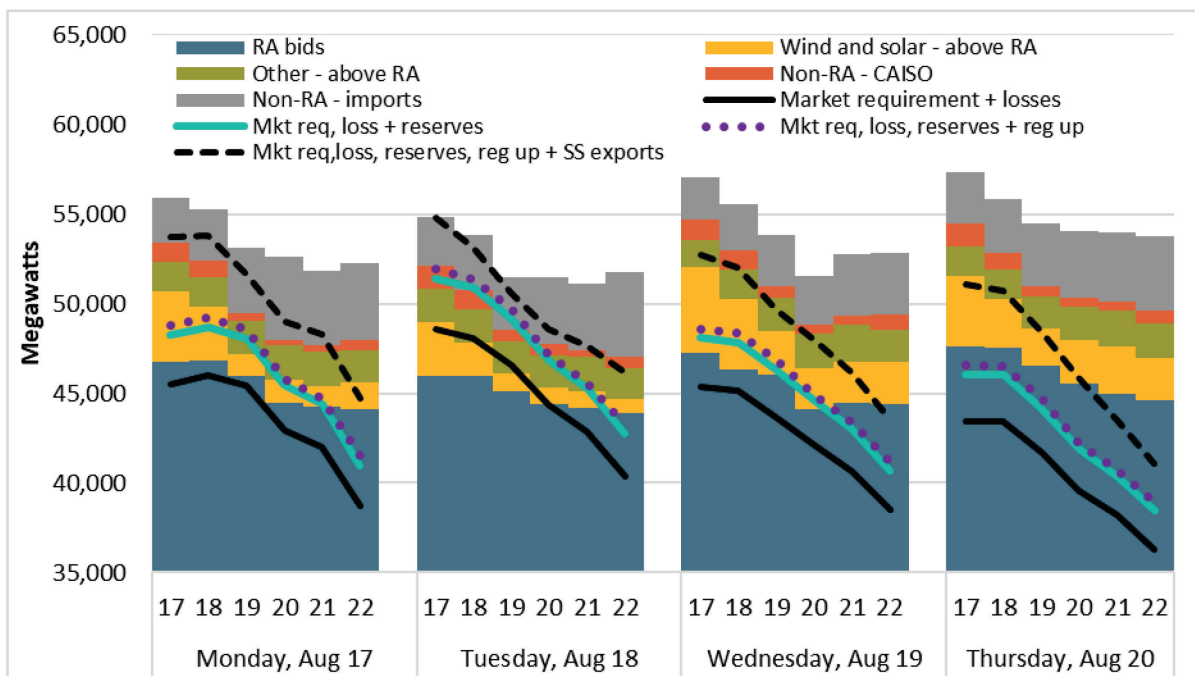
**Figure 3.20 Day-ahead market hourly bids by resource adequacy status (August 17 - 20, 2020)**



**Figure 3.21 Real-time market hourly bids by resource adequacy status (August 13 - 16, 2020)**



**Figure 3.22 Real-time market hourly bids by resource adequacy status (August 17 - 20, 2020)**



Real-time bids from resource adequacy units (including bid quantities above these units' resource adequacy showings), were sufficient to meet the real-time market requirement plus ancillary service requirements in most peak hours on August 13 – 20, with the exception of several hours on August 14 and August 18.<sup>26</sup> Additional bid capacity from non-resource adequacy resources (shown in orange and grey) was necessary to meet the additional demand of self-scheduled exports during peak hours on all days during the August heat wave period, as shown in Figure 3.22 and Figure 3.23.<sup>27</sup>

### Resource adequacy credits

The ISO's resource adequacy obligations are met with capacity which is reflected on supplier and load serving entity supply plans and capacity that is credited against load serving entity total resource adequacy obligations. Credited capacity consists primarily of utility demand response programs and liquidated damages credits. While the majority of monthly system resource adequacy obligations are met by capacity reflected on supply plans, the ISO also relies on credited capacity to be available. Credited capacity is not subject to the same must-offer obligations, bid insertion rules, and resource adequacy availability incentives as resources reflected on supply plans.

DMM estimates that 970 to 1,100 MW of capacity counted as resource adequacy credits was either unavailable or not directly accessible to the ISO in peak net load hours on August 14 and August 15. As discussed further in Section 3.13, on August 14, about 540 to 560 MW of utility demand response credits were unavailable in hours 19 and 20. On August 15, about 670 to 690 of utility demand response credits were unavailable in hours 19 and 20. These figures include the CPUC's planning reserve margin adder applied to demand response program capacity and non-CPUC local regulatory authority demand response program credits.

Additionally, 434 MW of liquidated damages credits were counted towards August resource adequacy requirements by non-CPUC-jurisdictional LSEs but cannot be tied to specific resources in the ISO market. While the capacity underlying liquidated damages credits may be reflected in the ISO in the form of imports or a combination of imports and inter-SC trades, these contracts are not associated with specific resource IDs in the ISO market. This capacity is also not subject to must-offer obligations, bid insertion or RAAIM like resource adequacy capacity on supply plans. The ISO does not have clear insight into these resources from an operational or market perspective.

Based on observations in August and September, there are improvements that the ISO and local regulatory authorities could consider to enhance the reliability of credited resource adequacy capacity. In its report, the ISO notes that it has taken action to eliminate the practice of resource adequacy crediting through a Business Practice Manual revision.<sup>28</sup> However, the ISO's proposed revisions are in the process of being reviewed and discussed with stakeholders.

### Resource adequacy in September

System conditions on September 5 – 7 were similar to those experienced during the August heat wave, but the ISO did not need to shed load over this time period. Day-ahead resource adequacy bids were sufficient to meet most, but not all, forecast load during peak hours on September 5 – 7. However, resource adequacy bids were insufficient to meet forecast load plus ancillary service requirements

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<sup>26</sup> The real-time market requirement can exceed actual load as it includes ISO operator imbalance conformance.

<sup>27</sup> Bid totals exclude bids from Western energy imbalance market resources.

<sup>28</sup> CAISO/CPUC/CEC report, pp. 10, 46, 52, 77.

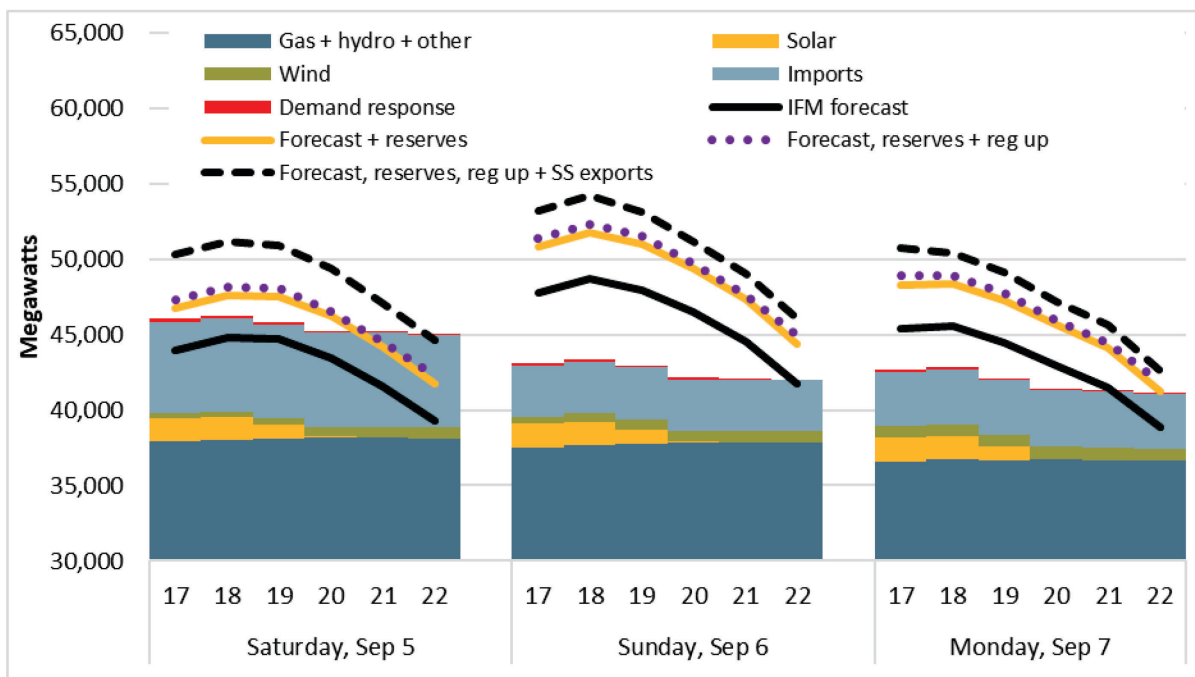
during most peak net load hours, and were also insufficient to meet the sum of forecast load, ancillary service requirements, and self-scheduled exports during most hours on these dates.

Figure 3.23 shows the hourly bids for resource adequacy resources by fuel type in the day-ahead market for September 5 – 7. Energy and non-overlapping ancillary service bids from resources shown to meet system resource adequacy requirements were sufficient to meet peak day-ahead load forecast (solid black line) during most hours. However, bids from these resources were not sufficient to meet the added spin and non-spin reserve requirements (solid orange line), regulation up requirements (dotted purple line), and the amount of self-scheduled exports (dashed black line) above the load forecast for most hours.

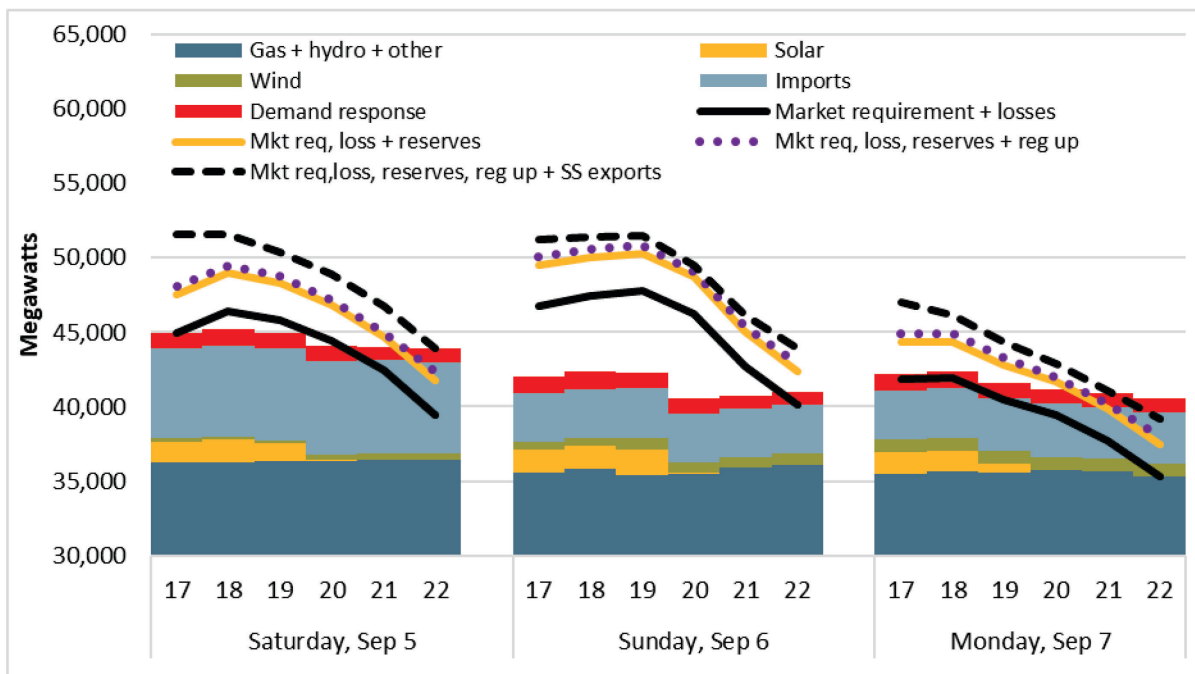
Real-time resource adequacy bids were sufficient to meet the real-time market requirement in most peak load hours on September 5 – 7, with the exception of September 6. However, resource adequacy bids were not sufficient to meet the real-time market requirement and ancillary service requirements during most peak net load hours. These conditions were similar to those experienced in August, but the ISO did not need to curtail internal load over these dates.

Figure 3.24 shows the hourly average resource adequacy bids by fuel type in the real-time market for September 5 – 7, 2020. Energy bids from these resources were sufficient to meet the real-time market requirements and losses (solid black line) for most hours during these days. Similar to the results from the day-ahead market, these bids were not sufficient to meet the added spin and non-spin reserve requirements (solid orange line), regulation up requirements (dotted purple line), and the amount of self-scheduled exports (dashed black line) above the load forecast in most hours in this time period.

**Figure 3.23 Day-ahead market hourly resource adequacy bids by fuel type (September 5 - 7, 2020)**



**Figure 3.24 Real-time market hourly resource adequacy bids by fuel type (September 5 - 7, 2020)<sup>29</sup>**



<sup>29</sup> Wind and solar actual schedules are depicted in place of bids for solar and wind for hour-ending 19 on Sunday, September 6 due to data issues

### 3.7 Import and exports

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This section provides a graphical summary of total CAISO system import and exports on the highest load days from mid-August to the September 7, 2020 during the key evening ramping hours (17-22). This summary highlights important trends and changes in CAISO system import and exports which reflect different market conditions and actions taken by the CAISO over this time period.<sup>30</sup>

Figure 3.25 shows total gross and net imports to and exports from the CAISO system during hours 17-22 on August 13 to 16. Figure 3.26 shows the same data for August 17 to 20. The shaded area of these figures shows total resource adequacy imports delivered to the CAISO system. Most imports on these days were from the Pacific Northwest, while most exports were to the southwest.

As shown in

Figure 3.25 and Figure 3.26, total net imports during these days increased significantly after the day-ahead market (dotted red lines) due to increased imports in the CAISO's 15-minute market (dashed red line) and also through the energy imbalance market (solid red line). During many hours on these days, total net imports (solid red line) exceeded the amount of resource adequacy imports scheduled in the day ahead market (shaded gray area).

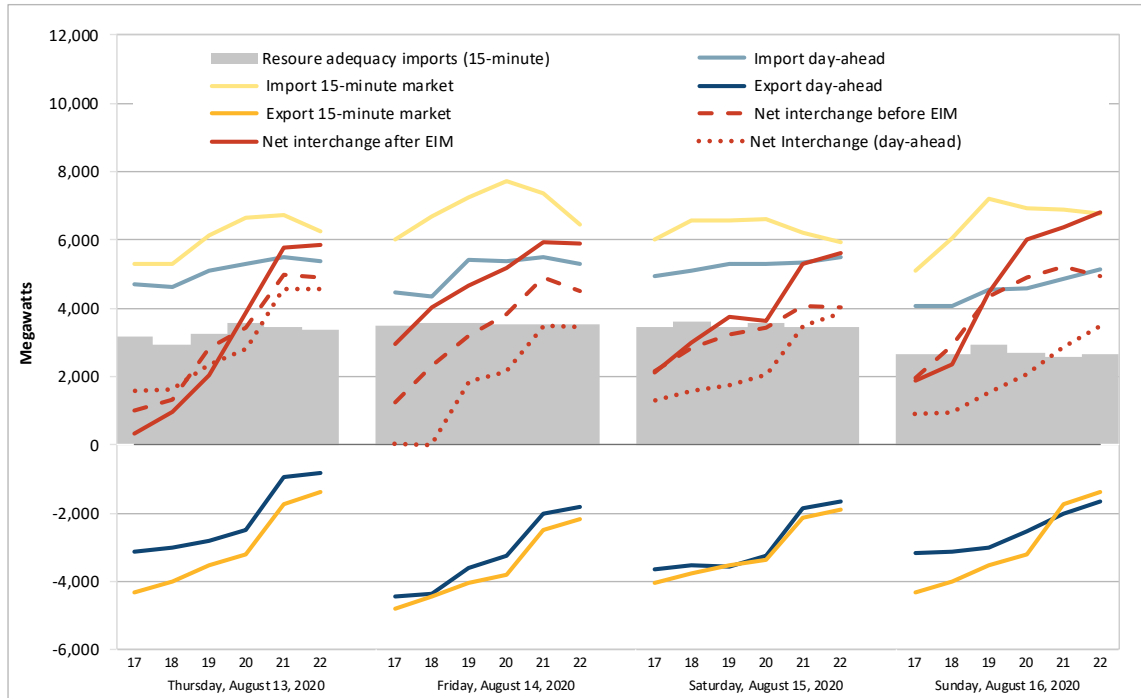
Figure 3.26 also highlights how exports scheduled in the day-ahead market dropped on August 18 – the first day on which virtual bidding was suspended. This is discussed in more detail in Section 3.9 of this chapter.

Figure 3.27 shows the same data for September 4 to 7. As shown in these charts, exports scheduled in the day-ahead market were extremely high on September 4, but declined over this period. This decline in exports reflects the changes in the residual unit commitment process discussed in Section 3.10 of this chapter.

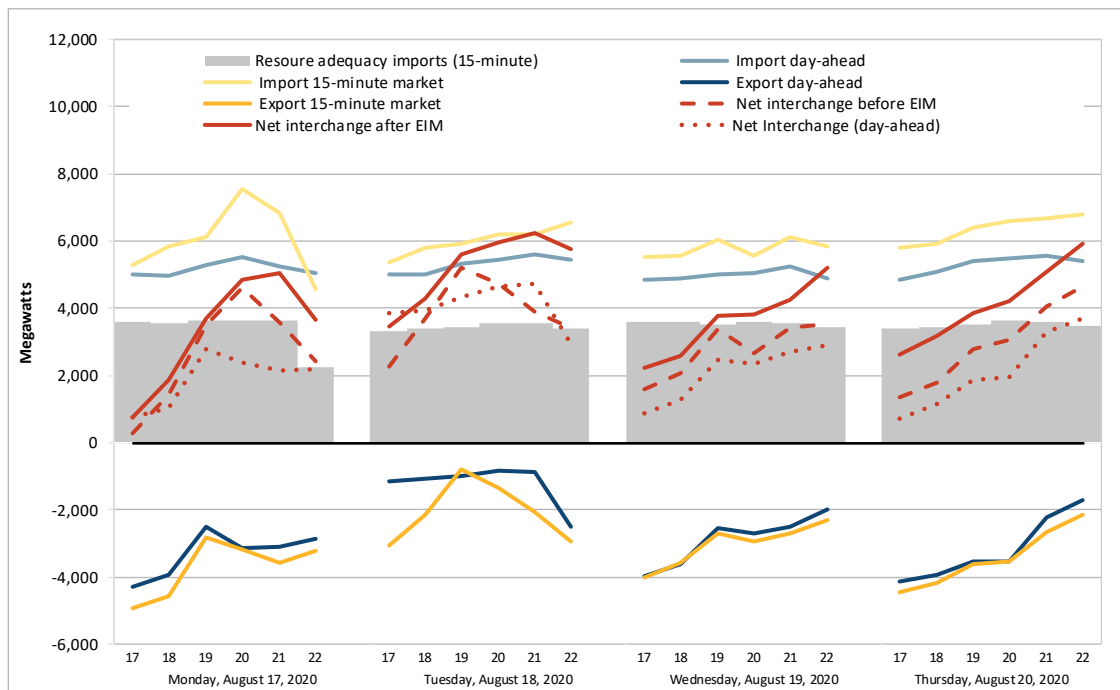
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<sup>30</sup> As elsewhere in this report, imports exclude tie-generators. Although physically located outside of the ISO, these resources are treated as internal generators by the market. Analysis in this report includes these generators with internal generation of the same fuel type. Tie-generators can add up to 2 GW to net interchange figures and appear to be included in the net interchange values publicly posted by the ISO (<http://www.caiso.com/TodaysOutlook/Pages/supply.aspx>).

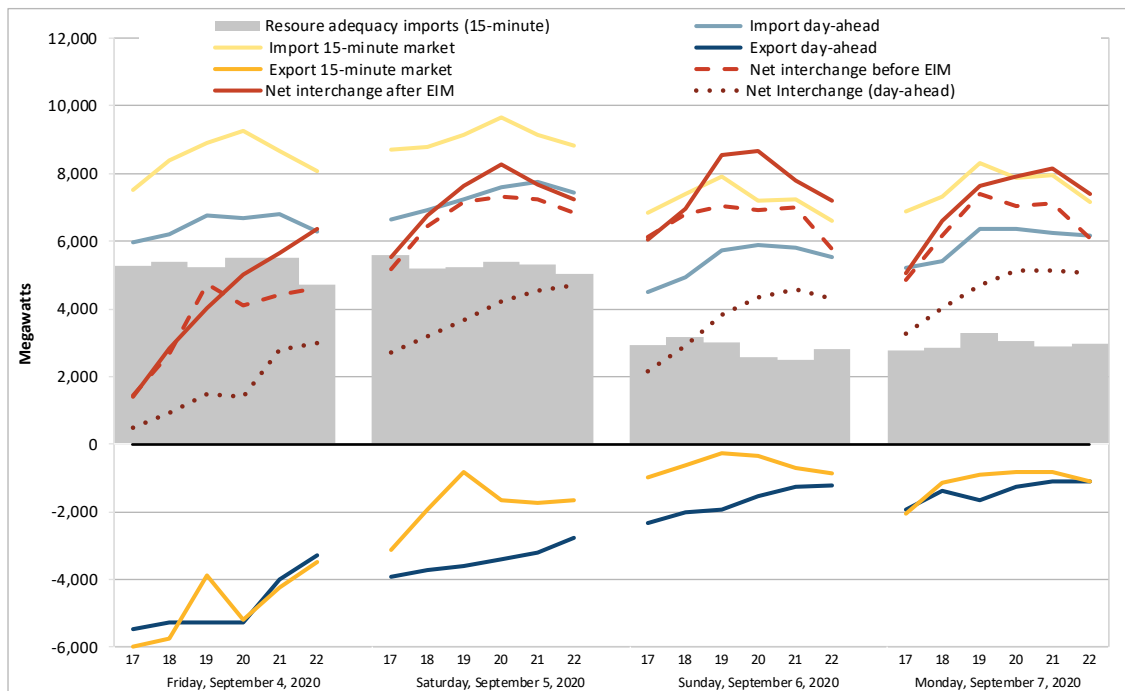
**Figure 3.25 Total CAISO system imports and exports (August 13-16, 2020)**



**Figure 3.26 Total CAISO system imports and exports (August 17-20, 2020)**



**Figure 3.27 Total CAISO system imports and exports (September 4-7, 2020)**



### 3.7.1 Out-of-market imports and export curtailments

Exceptional dispatches on the interties are instructions issued by ISO operators when the market optimization is not able to address a particular reliability requirement or constraint. Energy dispatches issued by ISO operators are sometimes referred to as *manual* or *out-of-market* dispatches. When conditions are tight, the ISO may call upon neighboring balancing authority areas to request imported energy on the interties in the real-time markets. ISO operators also may curtail self-scheduled exports to external balancing authority areas to prevent potential load shed and maintain system reliability.

Figure 3.28 shows the average hourly megawatts from all out-of-market actions taken by the ISO operators during peak net load hours (17-22). These include exceptional dispatches of internal generation within the ISO as well as manually dispatched imports, imports from emergency assistance by other balancing areas, and export curtailments determined by the market.

Imports coming from emergency assistance reflect energy imported from balancing authority areas with whom the ISO has contractual agreements during emergency conditions. All other manual dispatches reflect energy from offers made by ISO operators for imports from neighboring balancing areas for imports in the real-time market. These types of imports are often paid a negotiated price, typically for ‘bid or better’.<sup>31</sup>

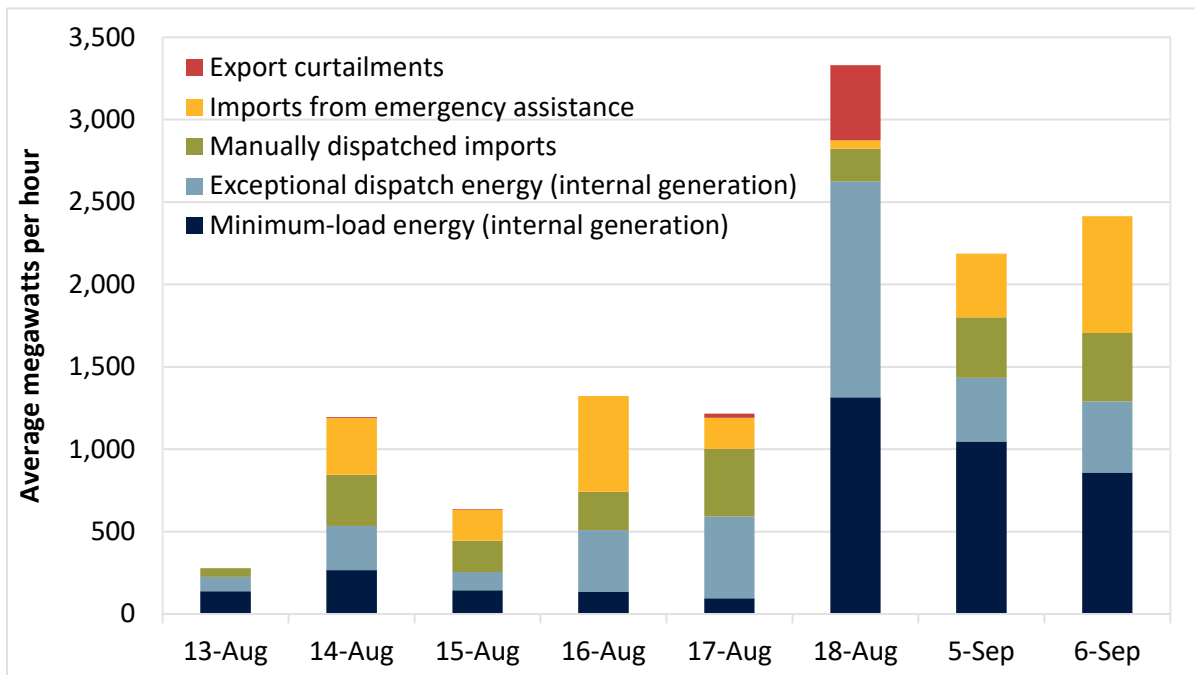
Figure 3.29 shows the volume of out-of-market energy dispatches on the interties and curtailments of self-scheduled exports by the ISO operators from mid-August through September 6 during peak net load hours (17-22). In this figure, out-of-market import energy dispatches are shown for different scheduling

<sup>31</sup> DMM’s 2017 annual report (pp. 206-207) provides more detail on manual dispatch types and prices paid for out-of-market imports, <http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf>

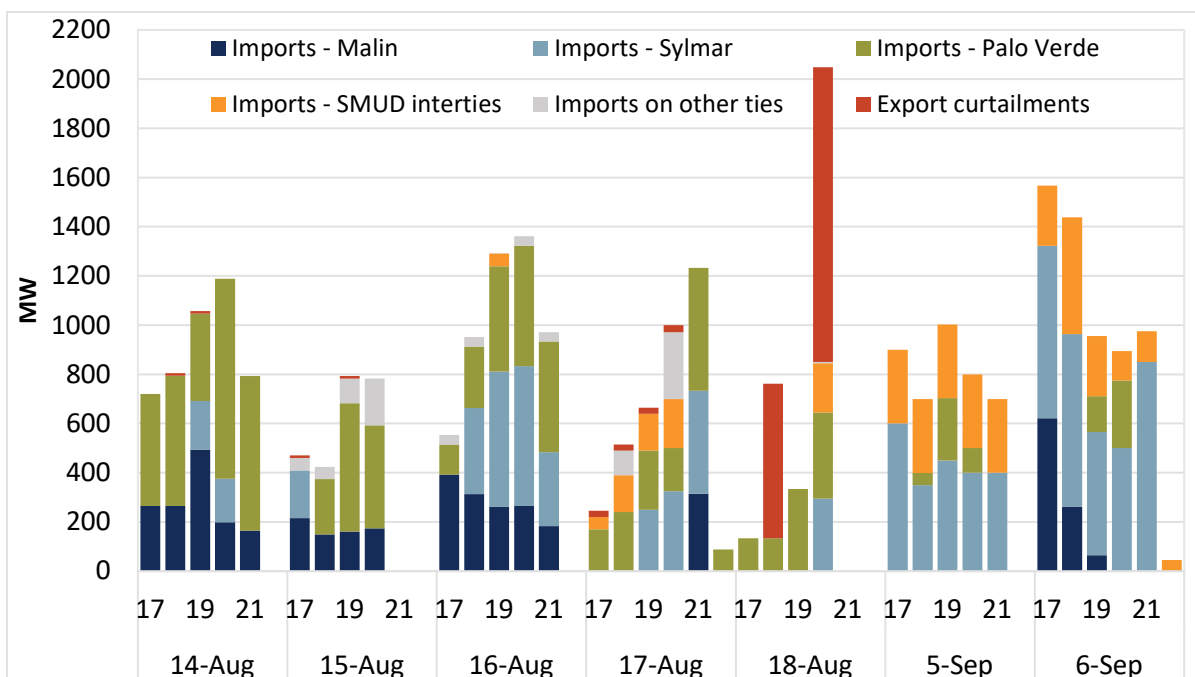


points into the ISO. Export curtailments show all self-scheduled exports leaving the ISO to outside balancing authority areas that were curtailed in the real-time market.

**Figure 3.28 Average hourly out-of-market energy and market export curtailments (hours 17-22)**



**Figure 3.29 Hourly out-of-market imports and market export curtailments (hours 17-22)**



### 3.8 Energy imbalance market performance

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One of the key benefits of the Western energy imbalance market is the ability to transfer energy between areas in the 15-minute and 5-minute markets. During the heat wave periods, the energy imbalance market functioned well under tight conditions, facilitating transfers from areas with surplus to areas with tighter supply conditions.

The CAISO was a net importer in the energy imbalance market during the most critical evening ramping hours of the summer 2020 heat wave. During curtailment intervals on August 14-15, the energy imbalance market provided an average of 1,346 MW and 530 MW respectively into the CAISO system.

#### 3.8.1 Energy imbalance market transfers and congestion

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Figure 3.30 and Figure 3.31 show average hourly transfers in and out of each energy imbalance market area for hours ending 19 and 20 on August 14 and August 15.<sup>32</sup> These figures cover the four hours in which the ISO curtailed load on these days.

- As shown in Figure 3.30, the CAISO was the only major net importer in the energy imbalance market during these hours on August 14, with the NV Energy and Portland Gas & Electric areas also importing relatively small quantities.
- As shown in Figure 3.31, the CAISO was also the largest net importer in the energy imbalance market during these hours on August 15, with the other areas being a mix of net importers and exporters during different hours.

Energy imbalance market transfers are a function of both regional supply conditions and transfer limitations. Figure 3.32 and Figure 3.33 summarize which areas were export constrained, import constrained, or part of the greater CAISO/EIM system during the peak hours on August 14 and August 15.<sup>33</sup> Each of these categories is described in further detail below.

- **Export Constrained.** The green space indicates that the area was export constrained relative to the greater CAISO/EIM system. Combined export flows out of these areas generally helped conditions in the greater system, but only to the extent of export limits out of this region. In particular, the Northwest region, which includes PacifiCorp West, Portland General Electric, Seattle City Light, Puget Sound Energy, were mostly export constrained in hours-ending 19 and 20 on August 14.<sup>34</sup>
- **Import Constrained.** The red space indicates that the area was import constrained relative to the greater CAISO/EIM system. On August 14 and August 15, NV Energy regularly failed the upward sufficiency test and was constrained by net import limits imposed as a result of failing the test. Here, the constraint limited the ability for energy outside of NV Energy to serve its load.

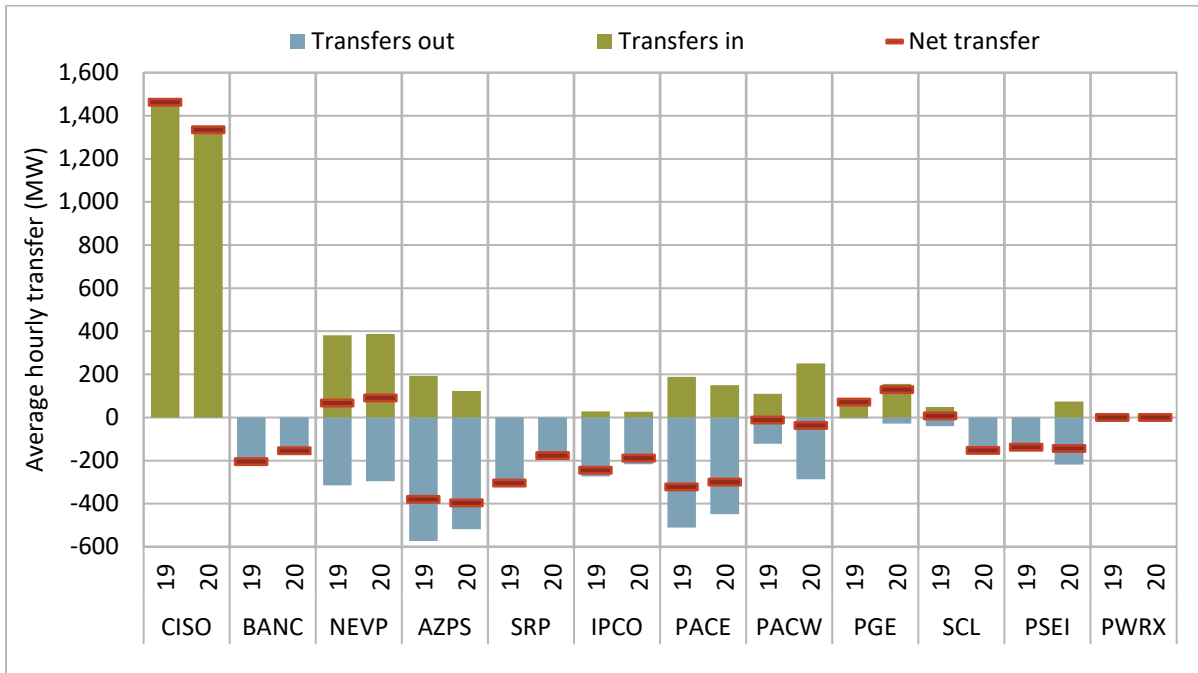
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<sup>32</sup> EIM transfers in these figures are net of all base schedules and therefore reflect dynamic market flows from the market optimization. Base schedules on EIM transfer system resources are fixed bilateral transactions between EIM entities.

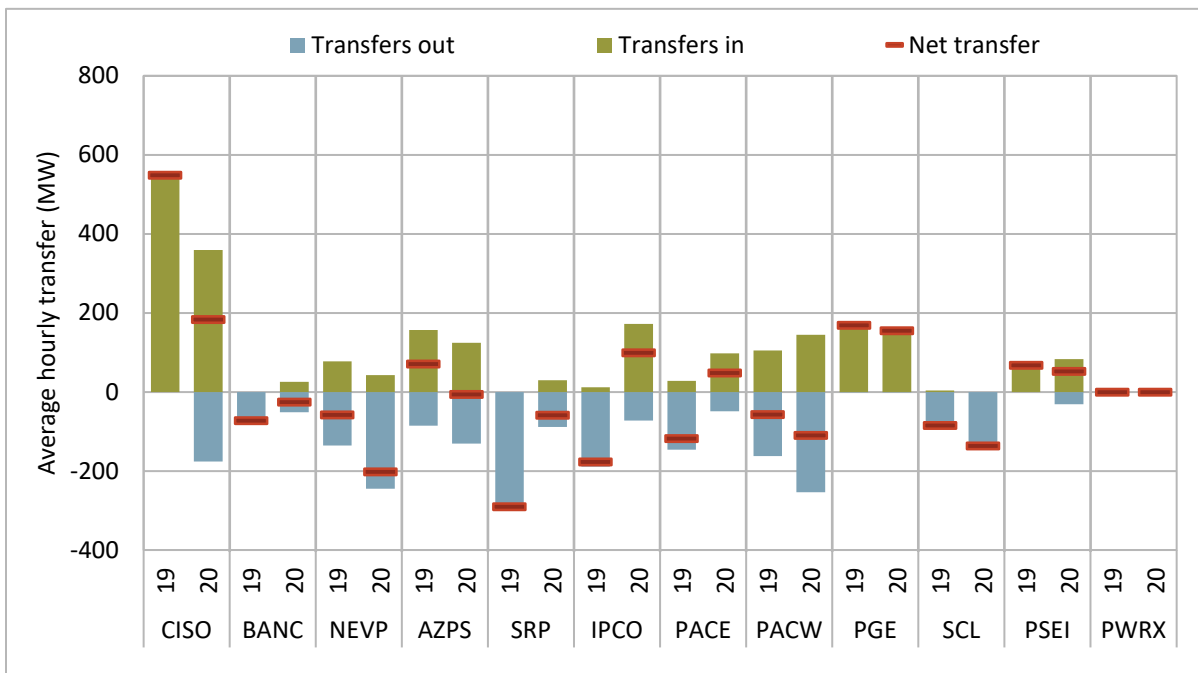
<sup>33</sup> This is calculated from the shadow price on an area's transfer constraint relative to prevailing system prices. When prices are lower relative to the system, this indicates congestion out of an area and limited export capability. The reverse is true when prices are higher relative to the system.

<sup>34</sup> Export capability from the Powerex area was set to 0 MW both days, so Powerex is excluded from this figure.

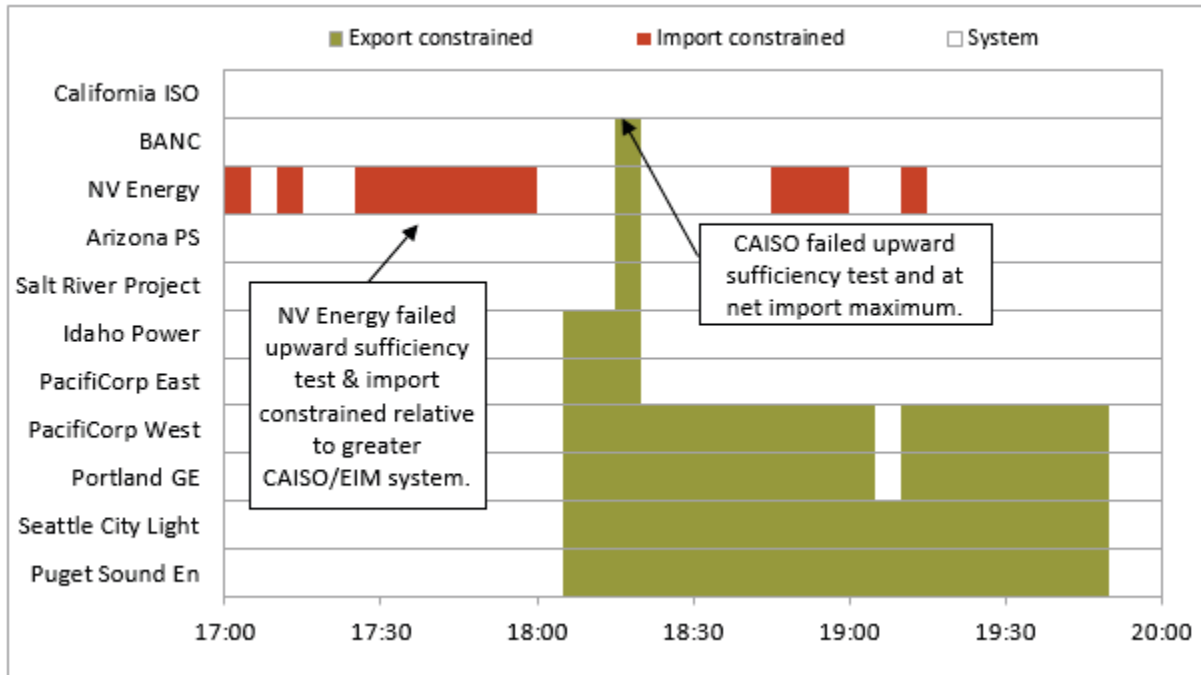
**Figure 3.30 Average hourly 5-minute market energy imbalance market transfers (Hours ending 19-20, August 14, 2020)**



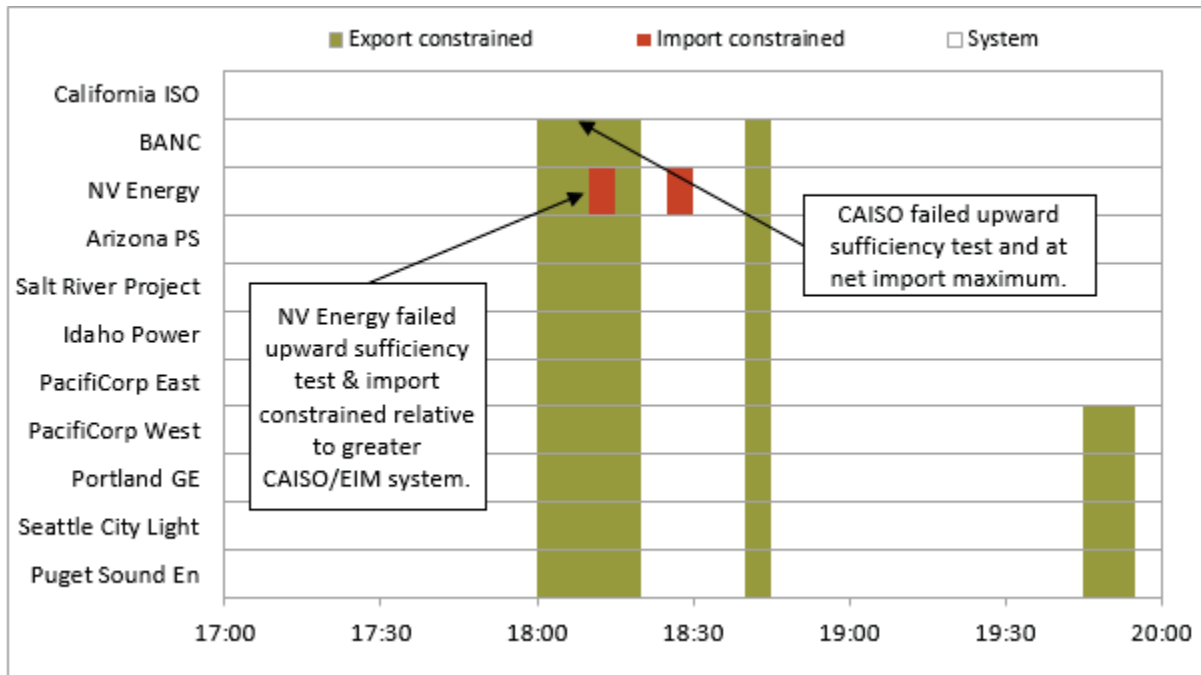
**Figure 3.31 Average hourly 5-minute market energy imbalance market transfers (Hours ending 19-20, August 15, 2020)**



**Figure 3.32 5-minute market congestion on energy imbalance market transfer constraints (August 14, 2020)**



**Figure 3.33 5-minute market congestion on energy imbalance market transfer constraints (August 15, 2020)**



- **System.** The white space in Figure 3.33 and Figure 3.33 indicates that the area was part of the greater CAISO/EIM system. In these intervals, the market optimization freely facilitated transfers to support regional demand conditions, limited only by the amount of surplus supply available within in each balancing area.

### 3.8.2 Flexible ramping sufficiency test impact

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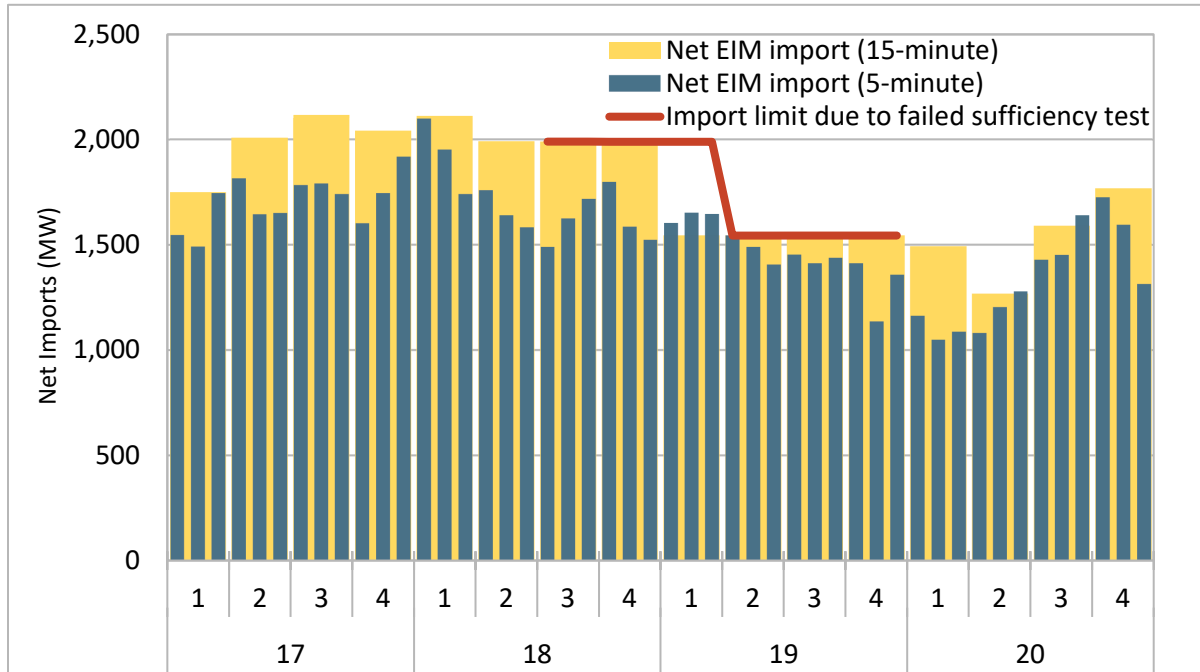
The flexible ramping sufficiency test is applied to all balancing areas in the Western energy imbalance market. If an area fails the upward sufficiency test, net energy imbalance market transfers into that area are capped for the corresponding intervals in the 15-minute and 5-minute markets. This limitation is designed to deter balancing areas from leaning excessively or systematically of the energy imbalance market to meet their resource and ramping energy requirements.

The CAISO balancing area failed the upward flexible ramping sufficiency test on both days with load shedding events (August 14 and August 15). Figure 3.34 and Figure 3.35 show net EIM imports in the 15-minute and 5-minute markets, as well as the net import limit imposed as a result of failing the upward sufficiency test. The net import limit imposed is the same in both markets, and is set by the previous 15-minute market net import.

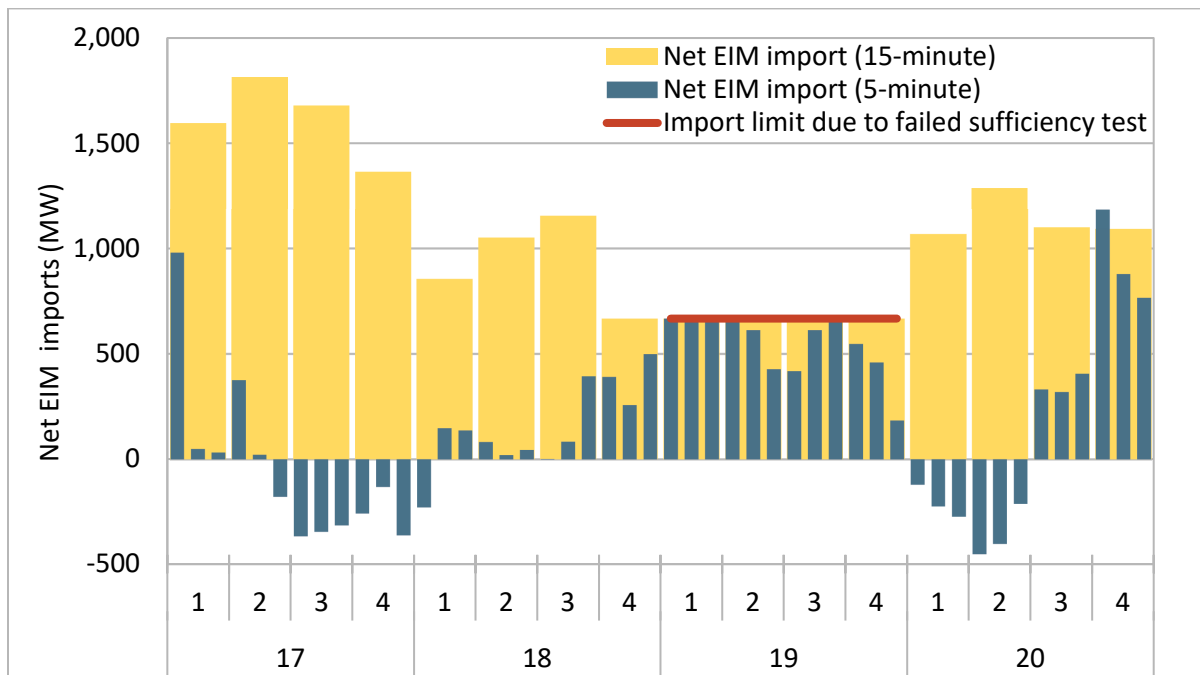
To the extent that the net EIM imports in the 5-minute market (blue bars) are below the sufficiency test import limit, the sufficiency test did not have an impact on CAISO's ability to access generation from the energy imbalance market. For August 14, the net EIM import was set at around 1,500 MW in hour-ending 19, intervals 2-4. The only RTD interval which was at the sufficiency test imposed import limit for this hour was interval 4, which was prior to the declaration of the Stage 3 Emergencies.

On August 15, the failure of the sufficiency test imposed an import limit of around 670 MW during all of hour-ending 19. For this hour, the 5-minute market net EIM import was at the imposed import limit for intervals 1 through 4 and 9. For each of these intervals, prices in the surrounding energy imbalance market areas with export capability to the ISO were also at extremely high levels. This signals that limited energy would have been available for the ISO had the net EIM import cap not been imposed. The failing of the flexible ramping sufficiency test had little or no impact on net transfers from the energy imbalance market into the ISO on August 14 and August 15.

**Figure 3.34 Limit on EIM imports to CAISO due to resource sufficiency test failures (August 14)**



**Figure 3.35 Limit on EIM imports CAISO due to resource sufficiency test failures (August 15)**

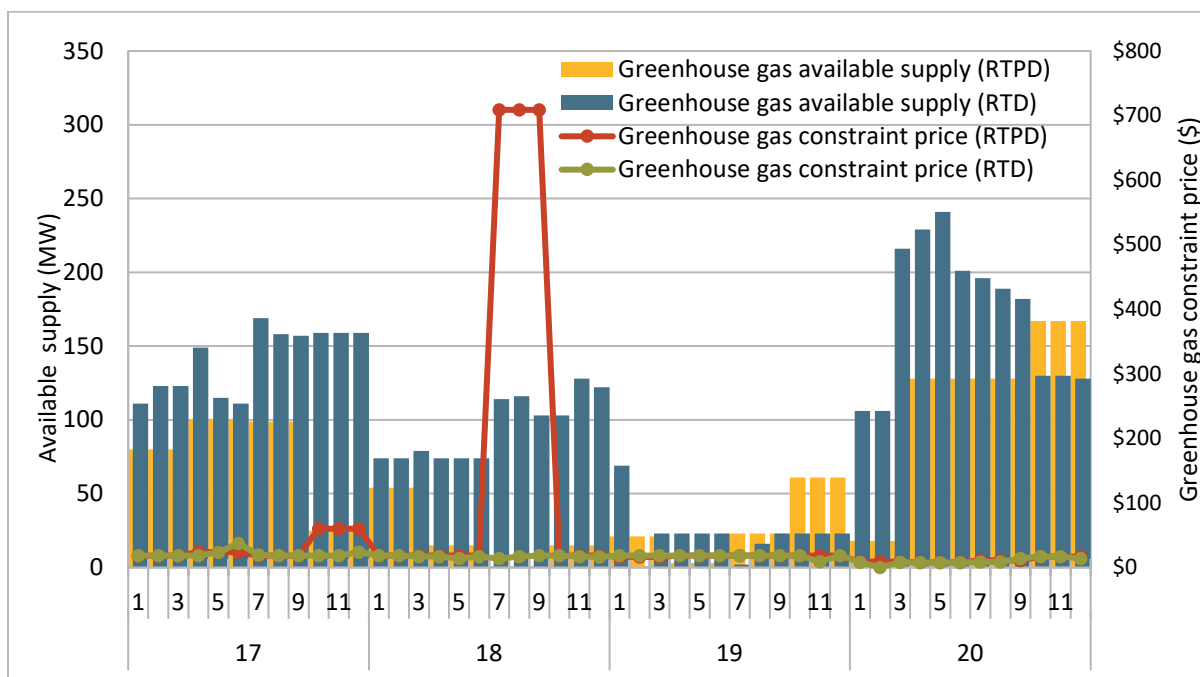


### 3.9 Limited greenhouse gas imports in the Western energy imbalance market

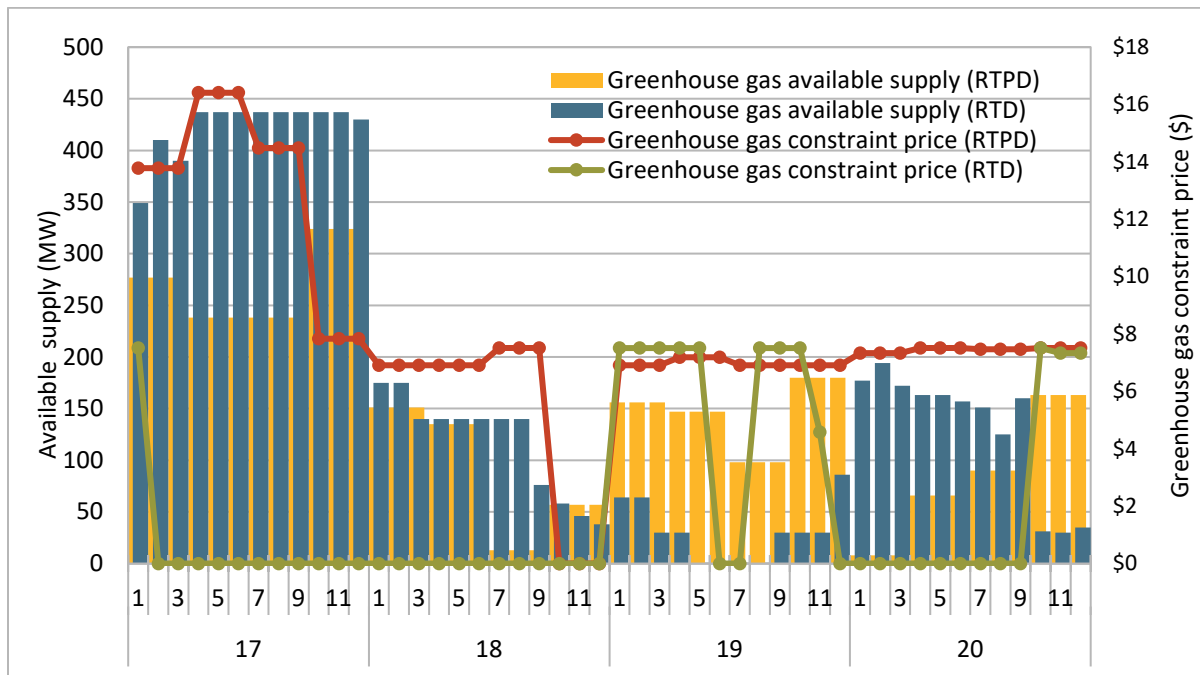
Imports for the energy imbalance market into California are limited by total supply bid into the energy imbalance market as being willing to be transferred into California and made subject to California’s greenhouse gas cap-and-trade program. In November 2018, the ISO implemented a revised EIM greenhouse gas bid design which limited greenhouse gas bid capacity to the differences between base schedule and available capacity. EIM greenhouse gas supply was very limited on both days with load shedding events (August 14 – August 15).

Figure 3.36 and Figure 3.37 show available EIM greenhouse gas supply above net EIM imports into California, that is additional available EIM imports into California, in both the 15-minute market (yellow bars) and the 5-minute market (blue bars). As shown in these figures, additional available capacity was zero in several intervals in both markets on both days in hour 19 when load was shed (although never simultaneously in both the 15-minute and 5-minute markets). EIM imports were capped at transfer levels shown above during intervals when no additional EIM greenhouse gas supply was available.

**Figure 3.36 Additional available energy imbalance market greenhouse gas capacity (August 14)**



**Figure 3.37 Additional available energy imbalance market greenhouse gas capacity (August 15)**



### 3.10 Day-ahead exports in real-time

In the days leading up to August 14 and 15, market participants offered increasing volumes of exports in the day-ahead market at very high prices or as self-schedules.<sup>35</sup> The quantity of exports clearing the IFM over this period also increased, as shown in Figure 3.38. Both self-scheduled and economically bid exports cleared the day-ahead market on both the August 14 and 15, with over 3,000 MW clearing during the hours when load was shed.

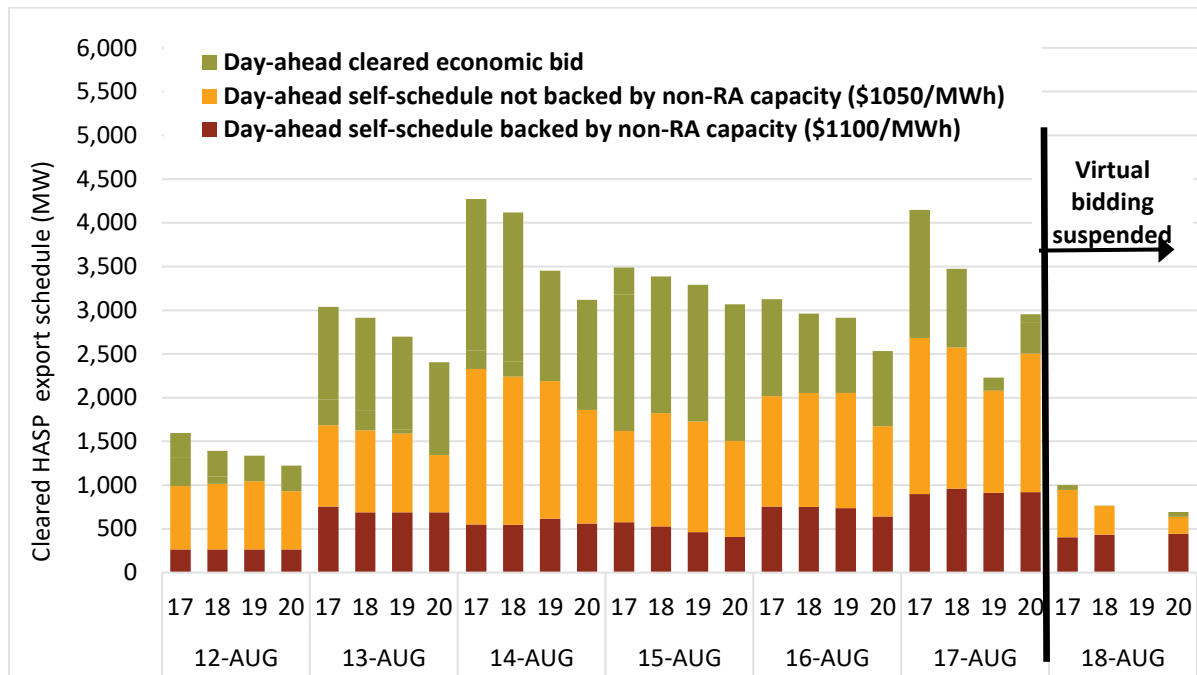
Prior to September 5, 2020, all export schedules that cleared the day-ahead market’s integrated forward market (IFM) automatically received among the highest real-time self-schedule priorities for demand, unless rebid in real-time. This real-time scheduling priority is independent of day-ahead scheduling priority, and exceeds that of all real-time submitted export self-schedules, as well as the real-time market energy balance priority established to meet CAISO balancing area forecast load.

As shown in Figure 3.38, in each of the three hours when load was shed, there was close to 3,000 MW of HASP export schedules that were not backed by capacity contracts but that received a real-time scheduling priority above that of native CAISO balancing area load because the exports had cleared the IFM.

<sup>35</sup> Market participants submitting export self-schedules have the option of specifying non-RA capacity to support the export. Exports that are backed by specified non-RA capacity receive a “price-taker” scheduling priority. Export schedules that are not identified as backed by non-RA capacity receive a lower scheduling priority as “less-than price taker” self-schedules, with a corresponding lower penalty price. This “less-than price taker” scheduling priority is below that of self-scheduled exports backed by non-RA and self-schedules of CAISO demand.



**Figure 3.38 Day-ahead export schedules cleared in HASP with real-time scheduling priority above real-time load curtailment (by HASP scheduling priority penalty price) <sup>36</sup>**



ISO operators can manually curtail exports for reliability reasons. However, as noted in that report, this is not a common practice because of concerns about potential detrimental direct and indirect reliability impacts on the CAISO and other balancing areas:

... CAISO operators may curtail export or import schedules for purposes of reliable operations. However, there are significant operational matters that need careful consideration before curtailing cleared and tagged exports in real-time. In order for such curtailments to be even be implemented effectively, information about the individual exports and relative priorities would have to be readily available to the operators. Furthermore, those relying on such exports need to be made aware of the potential risk of such exports being curtailed in advance so that they can take measures to avoid being put into an emergency condition upon loss of such exports. Absent such operator information or neighboring BAAs being aware of curtailments in a timely manner, curtailing cleared and tagged exports during quickly emergent real-time conditions would not be consistent with coordinated and good utility practices. Furthermore, the curtailment of the export may not be effective in addressing the reliability issue. In other cases, cutting the exports may further exacerbate conditions as curtailment of an export may result in the cutting of an import at the applicable intertie because the interchange was permissible only due to counterflow provided by the export. Finally, when the CAISO is in the position of relying on emergency energy from its neighbors, the threat of an export curtailment to another BAAs when conditions are constrained throughout the system may prevent access to emergency energy either at that time or in the future.<sup>37</sup>

<sup>36</sup> HASP data are missing for hour 19 on August 18.

<sup>37</sup> CAISO/CPUC/CEC report, pp. 106-107

The ISO took measures to limit exports entering the real-time market with scheduling priority above real-time load following the load shed event. First, as an interim measure, the ISO suspended virtual bidding effective August 18. Second, on September 5, the ISO implemented a change to the treatment of export schedules in RUC and real-time which limits the real-time self-scheduled quantities associated with day-ahead cleared schedules to quantities cleared in the RUC process. These measures are discussed in detail below.

### 3.11 Virtual bidding

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To assess the impact of virtual bidding during mid-August leading up to the suspension of virtual bidding on August 18, DMM re-ran the day-ahead market software *without* virtual bids during this period. The change in the amount of different resources clearing the day-ahead market when the software is re-run without virtual bids shows the impact of the virtual bids that actually cleared the market.

Figure 3.39 shows the amount of virtual supply bids (green bars) and virtual demand bids (blue bars) that actually cleared in the market in hours 16 to 21 from August 14 to August 17, when virtual bidding was still in effect. As shown in Figure 3.39, the net impact of these virtual bids was to provide over 1,000 MW of net virtual supply in the peak ramping hours of 18 to 20 on Friday August 14 and Monday August 17. On the weekend of August 15 – 16, virtual bidding resulted in net virtual demand of 1,000 MW to 3,000 MW in hours 16 to 21.

Figure 3.40 shows the impact of removing virtuals on net supply in hours 16 to 21 from August 14 to August 17. This change is quantified based on the difference in bids clearing in the market software with and without virtual bids. The charts show the net supply impact of removing virtuals, so that a reduction in generation with the removal of virtuals is shown as a negative supply impact and a reduction in exports will appear as a positive supply impact.

As shown in Figure 3.40, when net virtual demand cleared the market, removing these virtual bids reduces the amount of generation that clears the day-ahead market by almost an equal amount (shown in the dark blue bars in Figure 3.40). This indicates that the primary impact of virtual bidding in hours when net virtual supply clears is to increase the physical generation within the CAISO system that receives day-ahead energy market awards.

As shown by the yellow bars in Figure 3.40, the net virtual supply which cleared the day-ahead market on August 14 had the effect of increasing the amount of physical load clearing the day-ahead market on this day during hours 19 and 20. However, as shown by the red bars in Figure 3.40, the net virtual supply which cleared the day-ahead market on August 17 had the effect of increasing the amount of exports clearing the day-ahead market on this day during hours 17 to 21.

When additional exports clear due to net virtual supply, additional physical supply is needed in real-time to meet the increased demand created by these exports. If RUC and related real-time bid processing is not functioning as intended under tight supply conditions, this scenario could create significant reliability risks in the real-time market. Concern about the potential reliability risk created by this situation was a major consideration in the CAISO's decision to suspend virtual bidding beginning with the day-ahead market for Tuesday August 18 – a day on which CAISO system load was expected to exceed 50,000 MW.

Figure 3.41 and Figure 3.42 below illustrate trends in day-ahead export bidding and awards in the days surrounding the CAISO's suspension of virtual bidding on August 18.

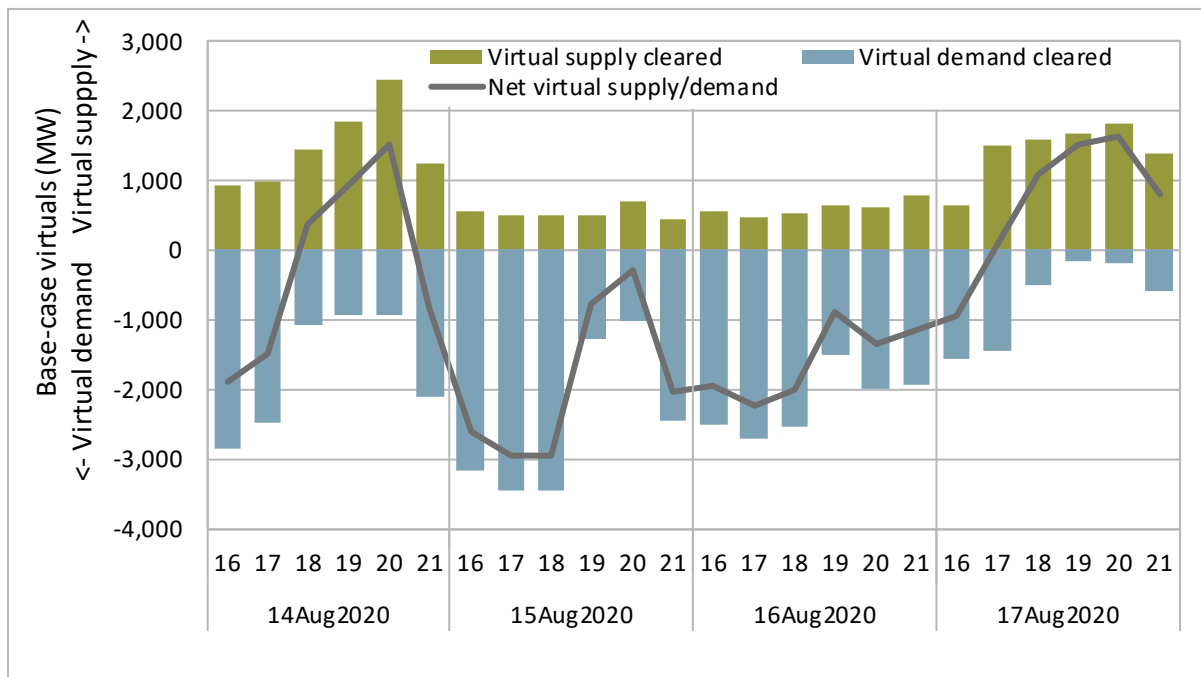
Figure 3.41 shows that although August 18 had the highest volume of submitted export bids and self-schedules in the day-ahead market, the volume of cleared exports on this day was considerably less than surrounding days. This also resulted in a lower volume of cleared real-time export schedules. Because many day-ahead export bids and self-schedules did not clear the day-ahead market, these quantities did not enter real-time market as self-schedules at the priority of a cleared day-ahead export schedule.

Figure 3.42 shows the quantities of exports clearing in the HASP in the real-time market that are associated with schedules cleared in the day-ahead market by scheduling priority. These are schedules that received a real-time self-scheduling priority exceeding that of real-time market energy balance, and any export self-schedules first submitted in real-time, regardless of IFM scheduling priority.

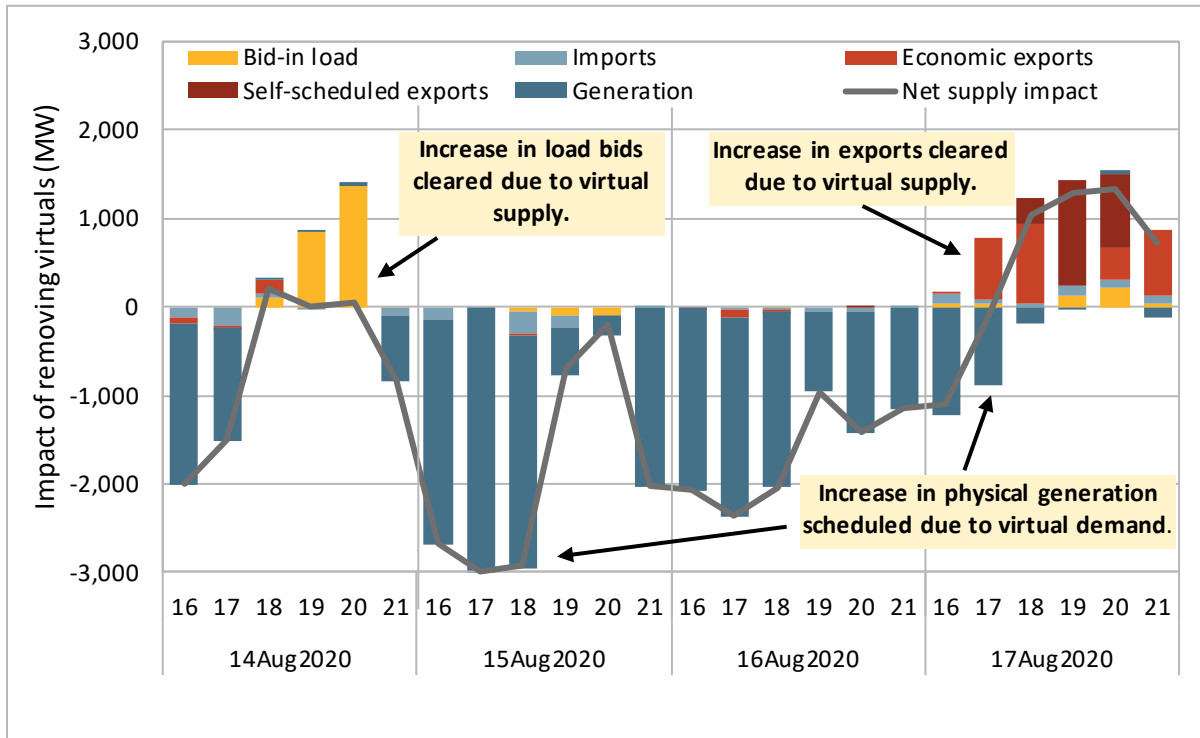
In the day-ahead market, self-scheduled exports not backed by non-RA capacity, and economic schedules each have a day-ahead scheduling priority below that of self-scheduled CAISO demand. When these schedules are submitted in the real-time market, they are prioritized similarly, with a scheduling priority below that of real-time market energy balance. However, by clearing first in the day-ahead market, these schedules receive a higher real-time scheduling priority above real-time market energy balance.

Figure 3.42 highlights the quantity of exports clearing HASP which received a higher real-time scheduling priority as a result of first clearing in the day-ahead market, and the drop in these quantities on August 18 that occurred with the suspension of virtual bidding.

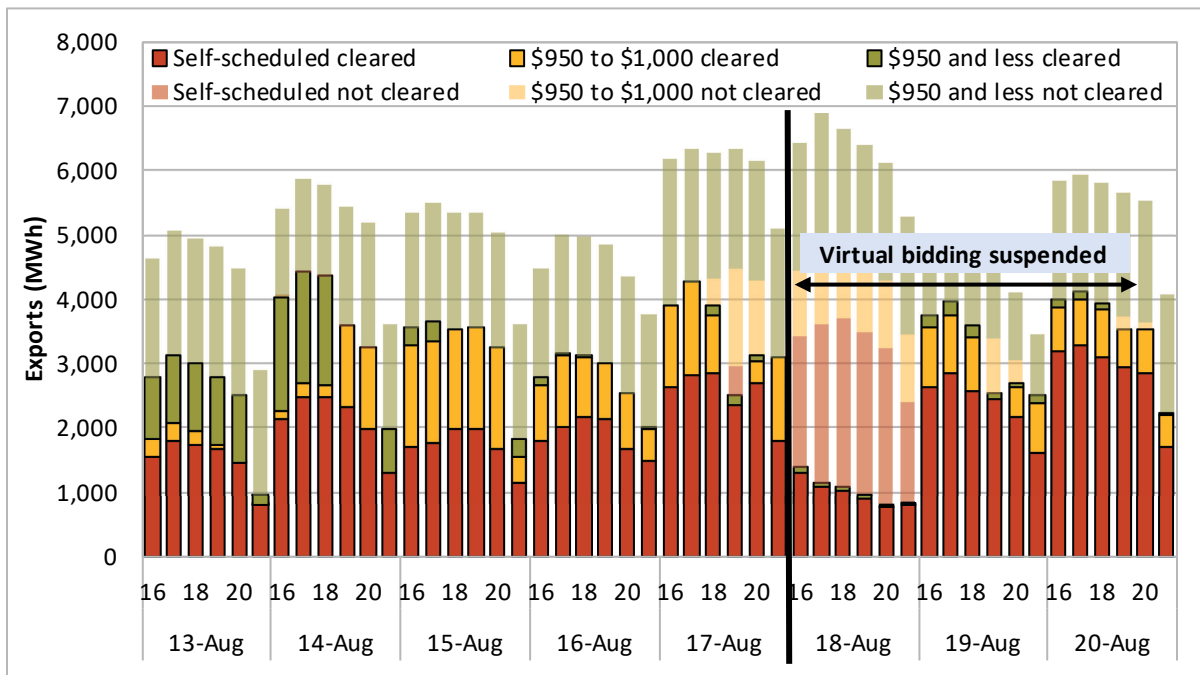
**Figure 3.39 Total virtual supply and demand bids cleared in day-ahead market (August 14 to 17)**



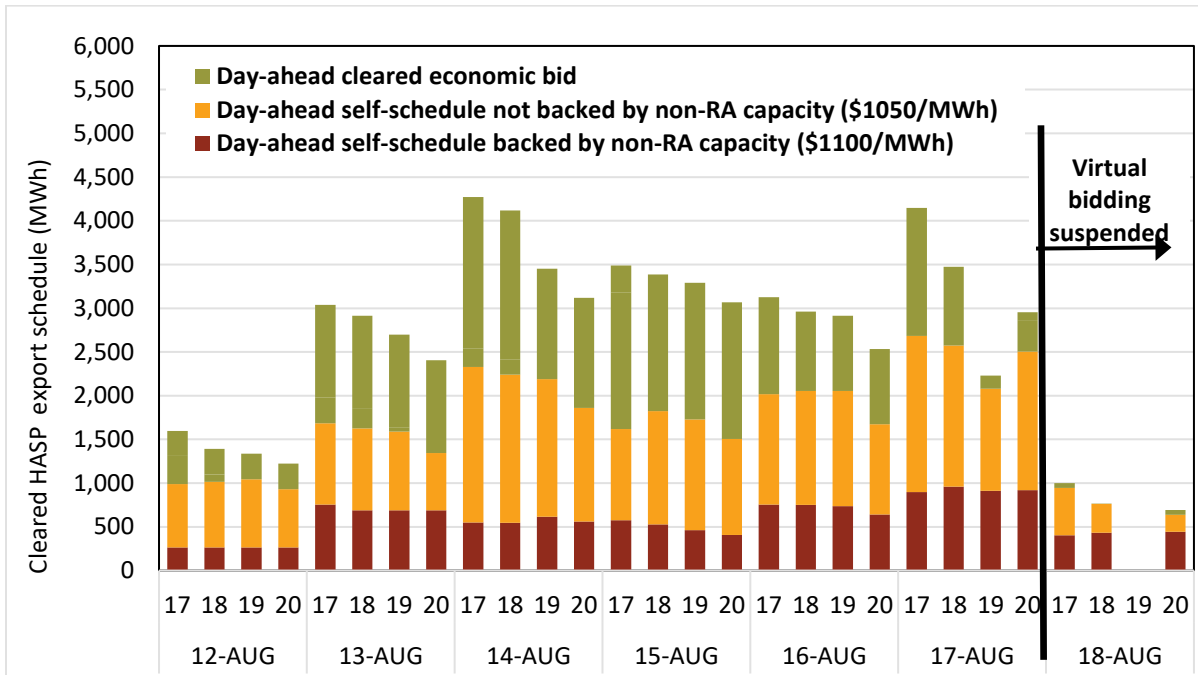
**Figure 3.40 Impact of virtual bidding on resources clearing day-ahead market (August 14 to 17)**



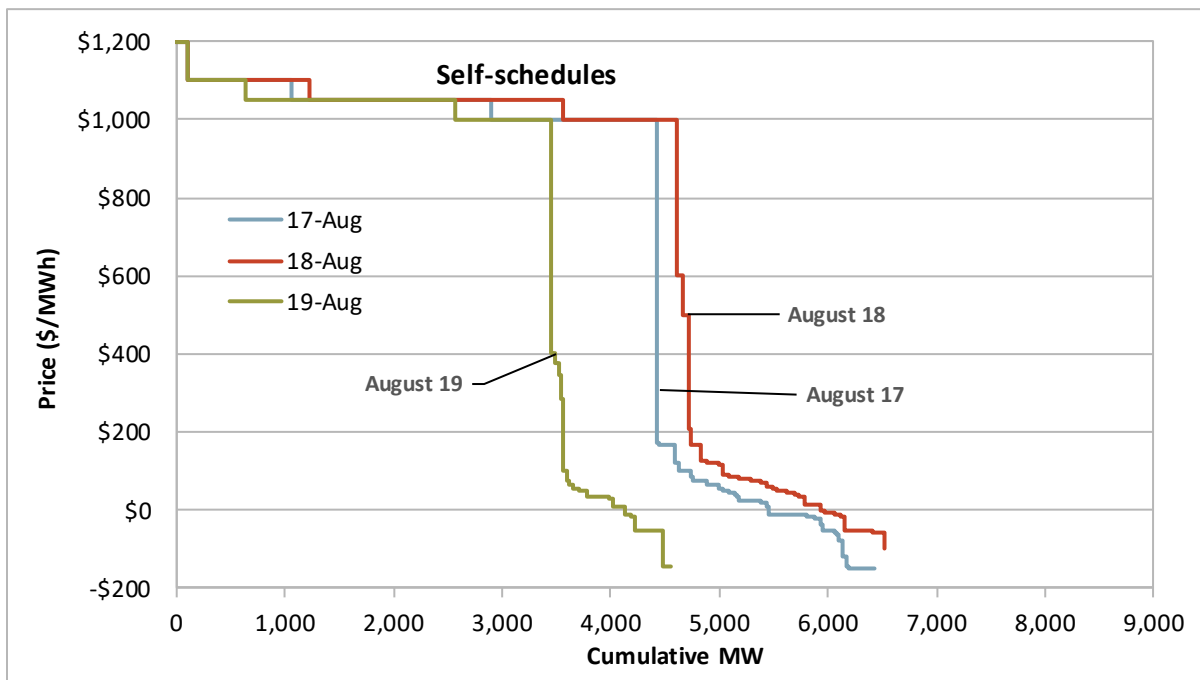
**Figure 3.41 Exports before and after suspension of virtual bidding**



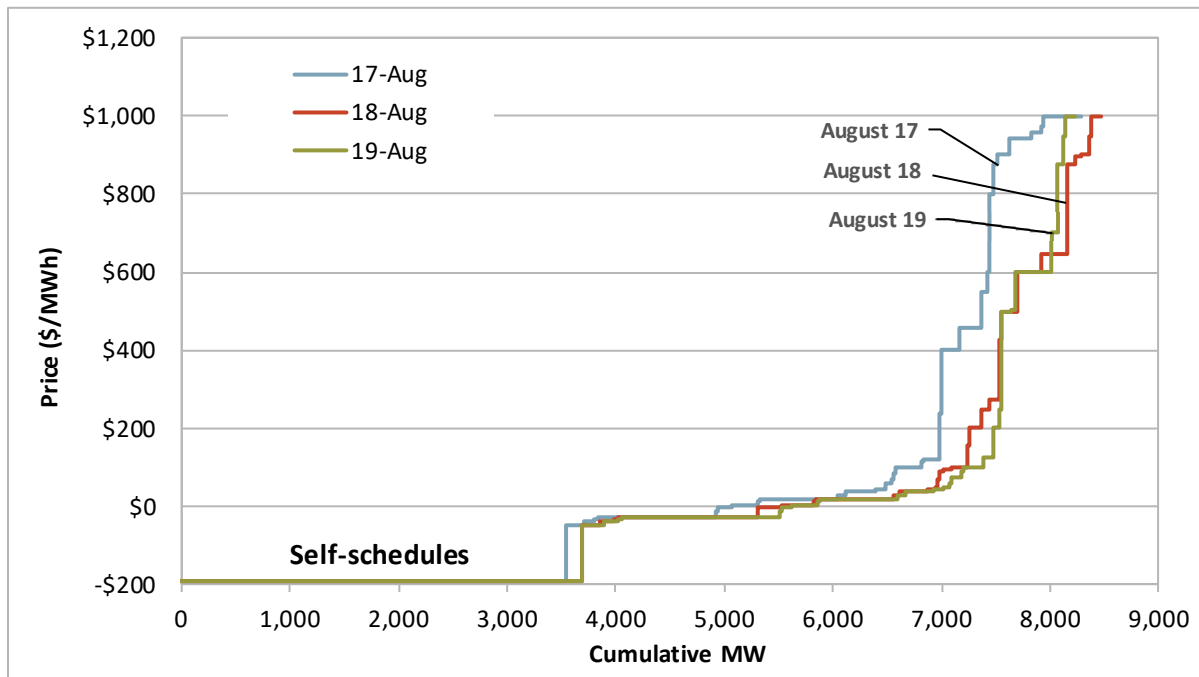
**Figure 3.42** Day-ahead export schedules cleared in HASP with real-time scheduling priority above real-time load curtailment (by HASP scheduling priority penalty price)<sup>38</sup>



**Figure 3.43** Day-ahead market export bids (August 17-19, Hour 19)



<sup>38</sup> HASP data are missing for hour 19 on August 18.

**Figure 3.44 Day-ahead market import bids (August 17-19, Hour 19)**

### 3.12 Residual unit commitment process

The ability of load serving entities to submit demand bids into the day-ahead market is a standard component of all ISO/RTO markets. Demand bidding allows load serving entities to manage their exposure to day-ahead and real-time prices.

Because the results of clearing all generation, load and other financial bids in the day-ahead market are not guaranteed to create resource commitments that can feasibly meet real-time load forecasts, ISOs/RTOs run supplementary reliability processes. In the California ISO this reliability process is called the Residual Unit Commitment (RUC). The RUC process should ensure that meeting the load forecast is feasible if it has sufficient resources to select from.

California's resource adequacy program is meant to ensure sufficient resources to meet load under most circumstances. If both the resource adequacy program and RUC process function to procure sufficient capacity, then meeting the real-time load forecast will be feasible regardless of how the day-ahead market clears bids.

Prior to September 5, 2020, RUC was allowing exports that were not supported by physical supply to receive RUC awards. Also, prior to September 5 all day-ahead cleared export schedules from the IFM that did not submit revised economic bids in real-time received the highest real-time export self-scheduling priority as a result of receiving a day-ahead market award. This real-time scheduling priority was assigned independent of whether the export was identified as backed by non-RA capacity or not. This real-time scheduling priority exceeds the real-time scheduling priorities for all real-time submitted self-schedules, as well as that for CAISO native load, whose priority is represented by the real-time market energy power balance penalty price.

On September 5, the ISO adjusted the RUC process. The change ensured that IFM exports not backed by capacity contracts would not receive RUC awards if there was insufficient physical supply in RUC to support them. On September 5, the ISO also adjusted the real-time market export scheduling priorities. With this change, exports that clear the integrated forward market, but subsequently receive a reduced RUC award in the RUC process, no longer receive a real-time scheduling priority that exceeds real-time ISO load. If a scheduling coordinator wishes for these schedules to be reinstated in real-time, the schedules must be re-bid in real-time or resubmitted as self-schedules in real-time.<sup>39</sup> This results in the scheduling priority below real-time ISO load.

The change implemented on September 5 appears to have had at least two notable impacts. First, as shown in Figure 3.45, the volume of exports offered into and clearing the IFM fell steadily over the period September 5-7 as RUC curtailments occurred each day over the high-load period. Second, the volume of exports ultimately scheduled in real-time was significantly below the quantities cleared in IFM over the same period. On these days, in the majority of hours 17-20, IFM export schedules were almost entirely eliminated by RUC curtailment.

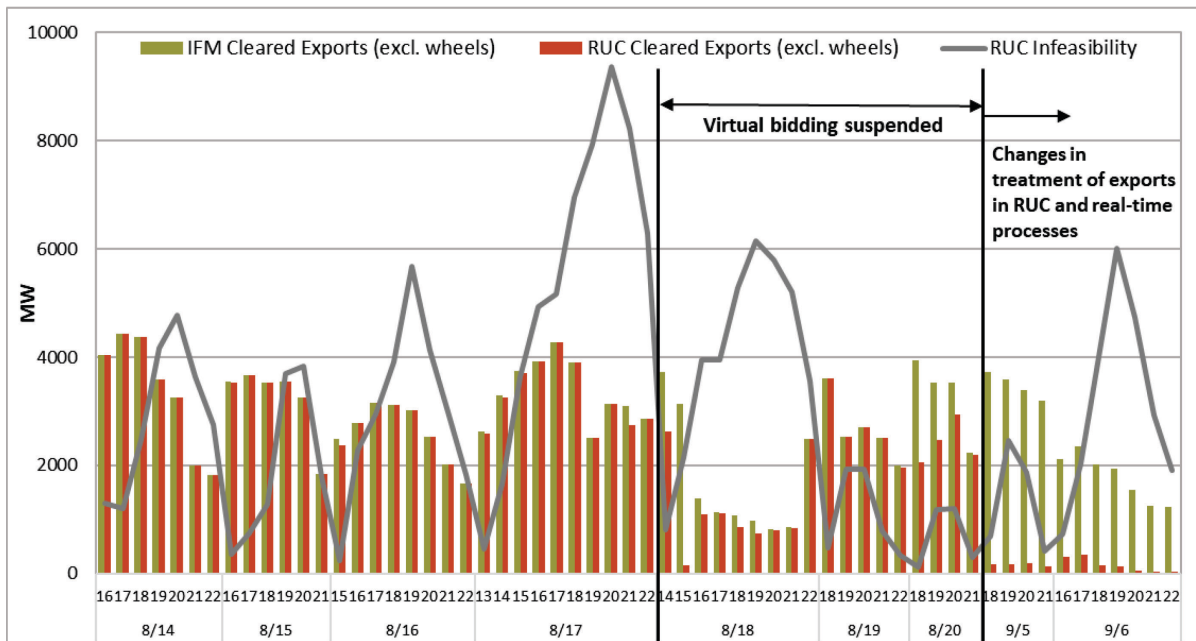
Although more than half of these RUC curtailed schedules were resubmitted and cleared in HASP as real-time self-schedules or economic bids, the quantity of HASP cleared exports was still reduced by as much as 1,500 MW over IFM cleared values that may have been physically infeasible in real-time. As shown in Figure 3.47, the schedules that did ultimately clear HASP did so based on real-time market conditions, and at real-time scheduling priorities below that of real-time self-schedules associated with day-ahead awards.

These changes improved the alignment of export self-schedules with real-time system conditions, and may have led to a reduced need for manual intervention by operators.

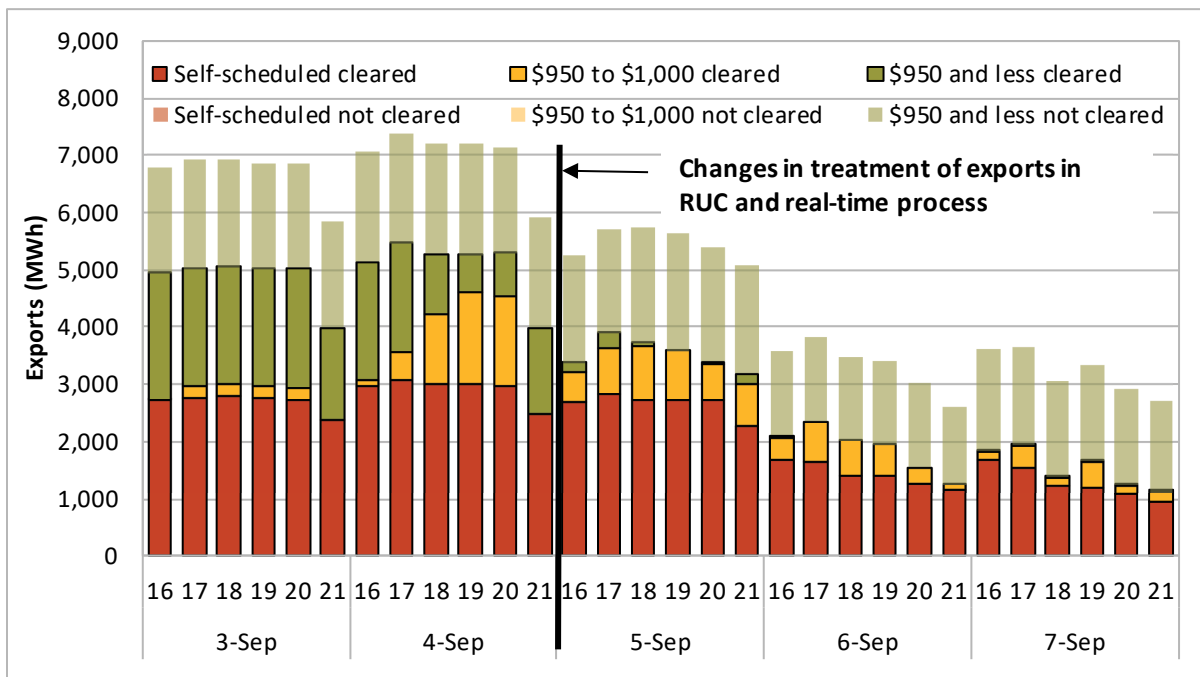
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<sup>39</sup> The ISO provided details and examples of this change in the Market Performance and Planning Forum meeting on September 9, 2020: <http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Sep9-2020.pdf#search=market%20performance%20and%20planning%20forum>

**Figure 3.45 RUC under-supply infeasibilities and cleared exports (Aug 14 – 20 and Sep 5 - 6)**

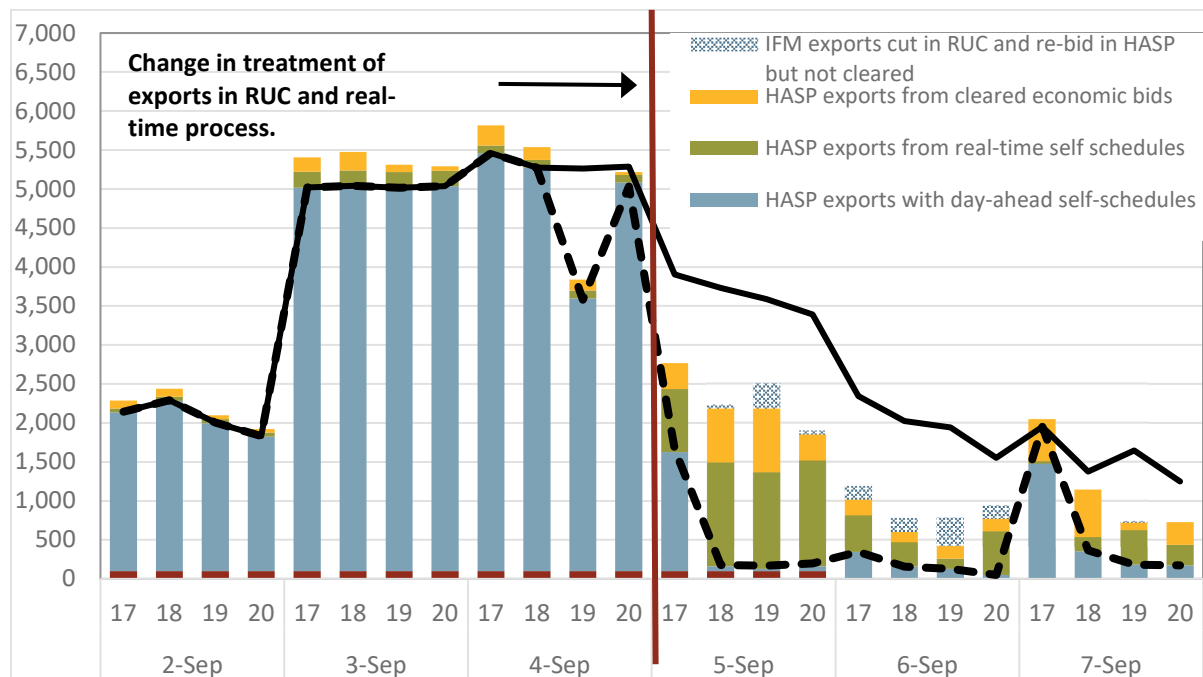


**Figure 3.46 Exports bid and scheduled in day-ahead market (September 3-7)**





**Figure 3.47 Reduction in exports due to changes in RUC and real-time process (September 2-7)**



### 3.13 Demand response

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

#### Demand response shown on resource adequacy supply plans

Demand response capacity shown on resource adequacy supply plans currently represents demand response programs scheduled by third party non-utility providers. This capacity is primarily contracted with load serving entities through the CPUC’s Demand Response Auction Mechanism (DRAM), but also includes third party demand response contracted with load serving entities and vetted through the CPUC’s Load Impact Protocol (LIP) process. This capacity is generally subject to must-offer obligations and the ISO’s resource adequacy availability incentive mechanism (RAAIM).

In August, supply plan demand response counted for 244 MW of resource adequacy capacity. In September, supply plan demand response counted for 237 MW of resource adequacy capacity.

Figure 3.48 shows the availability of supply plan demand response capacity as reflected by day-ahead and real-time bids, where bids are capped at individual resource shown resource adequacy values. Figure 3.48 also shows real-time dispatches of supply plan demand response. On August 14, 48 MW of supply plan demand response capacity was not bid into peak net load hours in the day-ahead market. Of the capacity not bid into the day-ahead market on August 14 through August 18, 23 MW was associated

with resources sized less than 1 MW and thus was exempt from RAAIM. On September 5 and 6, 25 MW of supply plan demand response capacity not bid into the day-ahead market was associated with resources sized less than 1 MW. The majority of underbid capacity from resources sized less than 1 MW was associated with resources under the same scheduling coordinator, where more than one resource sized less than 1 MW existed in the same sub-lap.

On August 15, 113 MW of supply plan demand response was not bid into the day-ahead market. Supply plan demand response capacity bids are generally concentrated in availability assessment hours (hours ending 17 through 21 on non-holiday weekdays), indicating that several underlying programs are defined around the ISO's availability assessment hours. Thus only about 53 percent of supply plan demand response resource adequacy capacity was available to the ISO on August 15.

Figure 3.48 also shows that real-time availability of supply plan demand response consistently drops off from day-ahead availability. On August 14, there was 53 MW less capacity available in real-time compared to day-ahead and on August 15 there was 30 MW less available in real-time compared to day-ahead. The additional capacity not available in real-time is associated with long-start proxy demand response resources which have no obligation to be available to the ISO's residual unit commitment (RUC) or real-time markets if not scheduled in the integrated forward market.<sup>40</sup> These underlying resources have start-up times of 5 hours or greater. Most of this underlying capacity was offered in the day-ahead market at the \$1,000/MWh bid cap while also submitting high startup and minimum load costs, resulting in resources being uneconomic to commit in the day-ahead market.

On August 14 in hours 19 and 20, about 50 percent of demand response capacity shown on resource adequacy supply plans was dispatched by the ISO. On August 15 in hours 19 and 20, only about 25 percent of supply plan demand response capacity was dispatched by the ISO.<sup>41</sup> There were no manual dispatches of supply plan demand response resources on August 14 or August 15.

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<sup>40</sup> ISO Tariff, Section 40.6.4.4.

<sup>41</sup> In the CAISO/CPUC/CEC report (Figure ES.5), the ISO also reports on supply plan proxy demand response dispatches in select peak hours. The ISO's figures show dispatches on supply plan demand response resources in excess of shown resource adequacy values. Figure 3.48 shows demand response dispatches capped at individual resources' shown resource adequacy values (red line) and dispatches on supply demand response resources in excess of shown resource adequacy values (dashed red line). Of note, 99 percent of supply plan demand response dispatches in excess of shown resource adequacy in this timeframe were associated with a single demand response provider.

**Figure 3.48 Day-ahead and real-time availability of supply plan demand response**

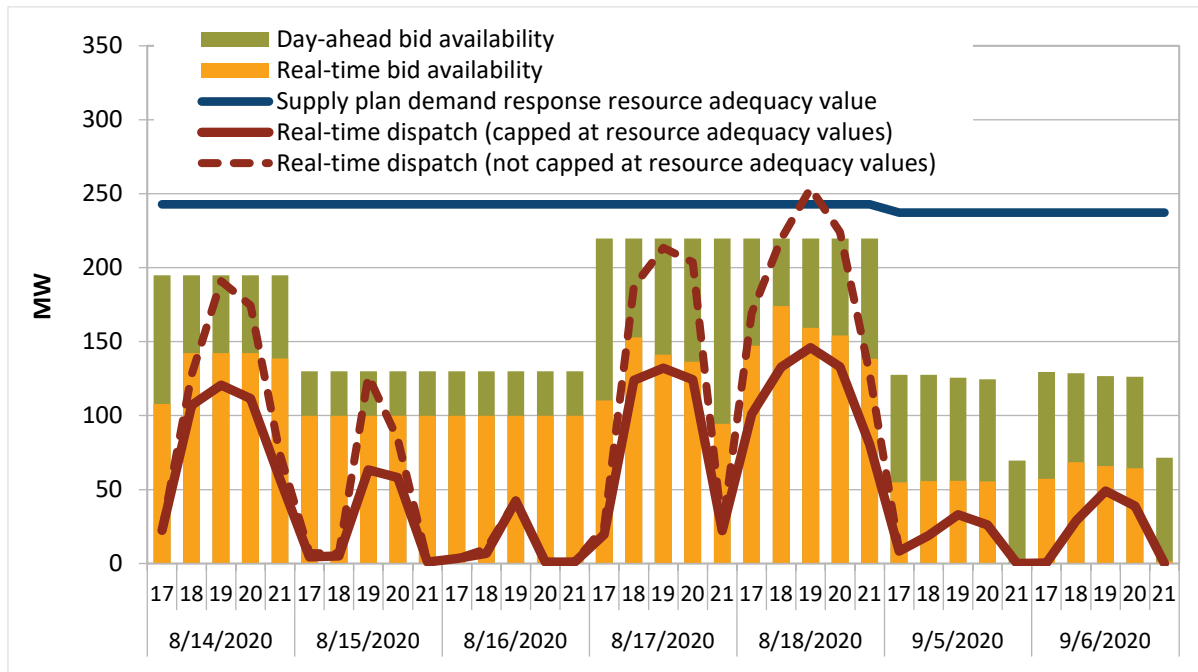


Figure 3.52 only reflects the aggregated dispatch of supply plan demand response, or *expected* load curtailment from supply plan demand response resources. DMM is continuing to review the self-reported performance, or self-reported load curtailment, of demand response resources in this timeframe.

### Utility demand response programs

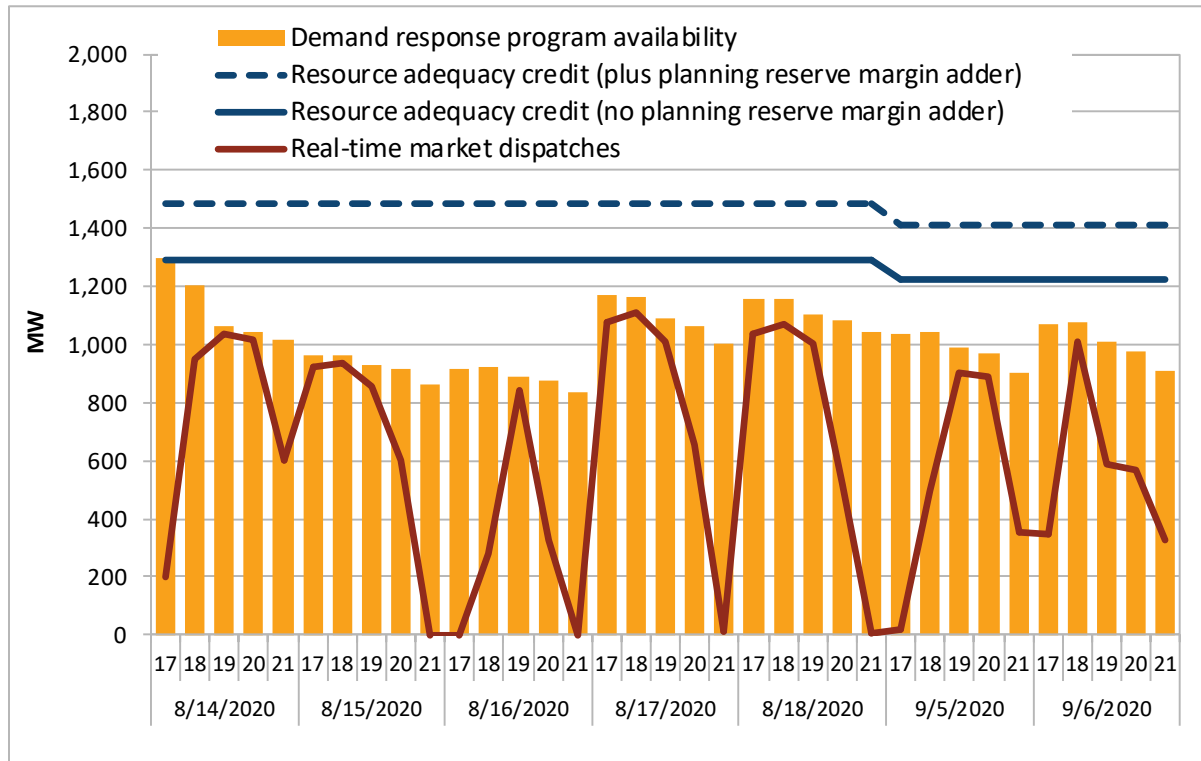
Demand response programs administered by load serving entities also count towards meeting resource adequacy requirements. These utility demand response programs count as credits against load serving entity resource adequacy obligations. While many of these demand response programs are also registered as resources in the ISO market, this capacity is not subject to the ISO’s must-offer obligations and resource adequacy availability incentive mechanism (RAAIM).

Utility demand response programs counted for 1,604 MW of resource adequacy credits in August. Of these utility demand response credits, demand response programs under the CPUC local regulatory authority (LRA) accounted for 1,482 MW. System resource adequacy demand response credits under the CPUC local regulatory authority also include a 15 percent planning reserve margin adder. In August, the CPUC planning reserve margin adder represented 193 MW.

Investor-owned utilities serve as scheduling coordinators for the demand response programs counted towards resource adequacy obligations under the CPUC local regulatory authority. The majority of this capacity is reliability demand response, or RDRR, which can only be called by the ISO under emergency conditions. The ISO relied on RDRR capacity between August 14 and August 18, and again on September 5 and September 6. The ISO communicates with IOU schedulers to activate their demand response programs when needed by the ISO.

Figure 3.49 shows the availability of CPUC-jurisdictional utility demand response capacity from August 14 to August 18, and September 5 to September 6, compared to total resource adequacy credits in respective months. Figure 3.49 also shows the real-time schedules of ISO-integrated utility demand response capacity (both proxy demand response and reliability demand response). Program availability is based on daily reports submitted by utilities to the ISO and demand response programs bid into the ISO markets. The higher of availability reflected in daily operational reports and bid capacity is reflected in Figure 3.49 to account for some demand response capacity that may not be integrated into the ISO market but can be activated by IOUs at the direction of the ISO.<sup>42</sup>

**Figure 3.49 CPUC-jurisdictional demand response availability and resource adequacy credits**



The demand response credits under CPUC-jurisdictional IOUs that represent the CPUC’s 15 percent planning reserve margin (193 MW in August) is never physically available to the ISO. Even after accounting for the planning reserve margin adder, the availability of CPUC-jurisdictional utility demand response capacity fell short of the amount of system resource adequacy capacity credits that these programs were counted for. This shortfall was particularly significant in hours ending 19 and 20 when net loads were the highest on the ISO system. This trend appears to reflect that the underlying load profiles of these demand programs tend to drop off in peak net load hours. Some utility demand response programs are also unavailable on weekends and holidays, which accounted for the drop in utility demand response capacity available on August 15 and August 16.

<sup>42</sup> Bid capacity includes real-time bids, plus any capacity bid into the day-ahead market which was not scheduled or not re-bid into real-time. While available capacity may include some demand response capacity that is not integrated in the ISO market, real-time schedules shown in Figure 3.49 are limited to demand response resources which are integrated in the ISO market.

On August 14, available CPUC-jurisdictional utility demand response fell short of resource adequacy credits (without the planning reserve margin adder) by 230 to 240 MW in hours 19 and 20. On August 15, available CPUC-jurisdictional utility demand response fell short of resource adequacy credits (without the planning reserve margin adder) by 350 to 370 MW in hours ending 19 and 20.

While utility demand response programs were not available up to credited capacity, nearly all available IOU demand response capacity was dispatched by the ISO either by the market or by manual dispatch across peak net load hours on August 14 and 15. DMM is continuing to review the self-reported performance, or self-reported load curtailment, of demand response resources in this timeframe.

Demand response capacity under the jurisdiction of non-CPUC local regulatory authorities also accounted for an additional 122 MW of demand response system resource adequacy credits in August. These programs are not directly integrated in the ISO market, nor does the ISO have a process to be informed of the availability of these demand response programs as they do with CPUC-jurisdictional utility programs. DMM understands that the ISO is working with these local regulatory authorities to develop processes similar to those that exist with CPUC-jurisdictional utilities in order to be able to call on these demand response programs when needed.

### Non-resource adequacy demand response programs

Some third-party demand response programs that do not provide resource adequacy also participate in the ISO market. These programs do not receive capacity payments or count towards resource adequacy credits. However, participation from these types of programs was limited on high load days in August and September. These programs were dispatched to deliver less than 1 MW of load reduction across peak net load hours on these days.

### Reliability demand response resources

From August 14 to August 18, ISO operators activated between 820 and 975 megawatts of reliability demand response resources (RDRR) during peak net load hours. In several hours, the ISO operators activated available RDRR out-of-market similar to exceptional dispatch instructions. RDRR resources represent CPUC-jurisdictional demand response programs that can be called by the ISO under emergency conditions.

The bulk of the RDRR was dispatched in real-time.<sup>43</sup> RDRR resources have minimum bids of \$950 per megawatt hour. Because RDRRs were manually dispatched in many hours, they were often dispatched when prices were well below \$950 and RDRRs received significant bid cost recovery payments. Of the total \$8.6 million in real-time bid cost recovery payments between August 14 and August 18, \$4.8 million was paid to RDRRs.<sup>44, 45</sup>

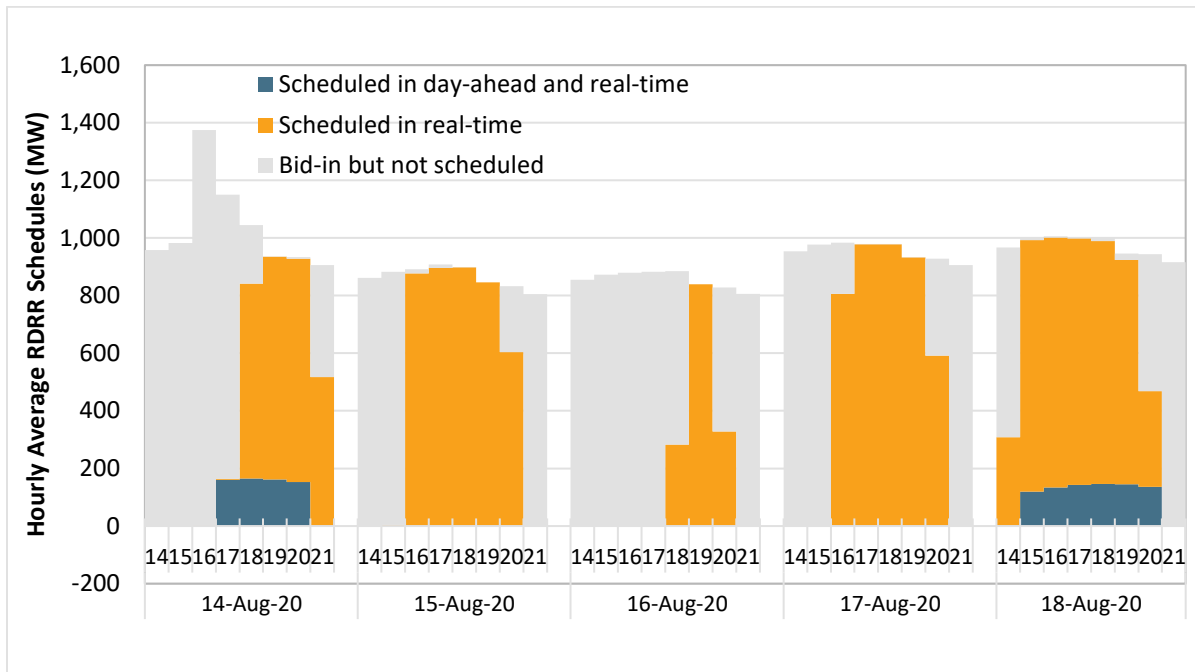
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<sup>43</sup> The ISO is looking into why the real-time dispatch recognized the RDRR instructions but the fifteen-minute market did not.

<sup>44</sup> Day-ahead bid cost recovery payments during this period were negligible at less than \$100,000.

<sup>45</sup> Most of the rest of the real-time payments went to: resources exceptionally dispatched before the start of their day-ahead schedules such that commitment costs were incurred in real-time but most of the revenues from higher priced hours were from the day-ahead market; and to a lesser extent resources with real-time schedules below their day-ahead while prices exceeded offer prices.

**Figure 3.50 Hourly average reliability demand response resource schedules by market**



**Recommendations for enhancing the treatment of demand response as capacity**

There are several enhancements that the ISO and local regulatory authorities could consider to enhance the reliability of both demand response resources shown on resource adequacy supply plans and utility demand response programs. Demand response programs which are either compensated for or credited towards meeting resource adequacy requirements should be expected to curtail load before firm load is curtailed.

DMM recommends that the ISO and CPUC consider the following enhancements for supply plan demand response resources:

1. The ISO should be able to manually dispatch supply plan demand response before needing to resort to exceptional dispatch of non-resource adequacy capacity and firm load curtailment. The ISO has the ability to manually dispatch utility demand response and did so on high load days in August and September. However, there were no exceptional dispatches issued to supply plan demand response on these days.
2. Consider removing the exemption for long-start proxy demand response to be available in the residual unit commitment process. This exemption does not exist for other types of long-start resources providing resource adequacy.
3. Continue to review why demand response resources in the same sub-lap continue to be sized less than 1 MW. Consider applying RAAIM to demand response resource adequacy capacity at the demand response provider and sub-lap level rather than the resource level to ensure this capacity remains exposed to resource adequacy availability incentives.

4. Consider revising DRAM contract provisions to ensure that demand response that is available and receiving capacity payments can be activated before firm load is curtailed even if this is outside of availability assessment hours.

DMM recommends that the ISO and local regulatory authorities consider the following enhancements for utility demand response programs:

1. Continue efforts between the ISO and CPUC to better reflect the availability of demand response programs with variable load in capacity values.
2. Adopt the ISO's recommendation to remove the 15 percent planning reserve margin adder applied to utility demand response capacity counted towards system resource adequacy requirements under the CPUC jurisdiction. In CPUC's recent Track 2 resource adequacy proceeding, the ISO recommended that the planning reserve margin adder applied to demand response capacity which is credited toward system resource adequacy supply obligations be removed.<sup>46</sup> Though this provision was not adopted, DMM supports the ISO's recommendation. The capacity reflected by the planning reserve margin adder cannot be utilized by the ISO, yet counts as supply towards meeting system resource adequacy obligations.
3. Ensure that non-CPUC jurisdictional load serving entities that schedule for demand response programs used to meet resource adequacy requirements communicate the capacity available from these programs to the ISO on a daily basis so that this capacity can be considered and called by the ISO when needed.

### 3.14 Competitiveness

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#### 3.14.1 Structural measures of market power

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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. 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

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<sup>46</sup> California Independent System Operator Corporation Consolidated Comments on all Workshops and Proposals, R.19-11-009, March 23, 2020, pp. 10-11: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M330/K052/330052136.PDF>

electric industry because the demand for electricity is highly inelastic, and competition from new sources of supply is limited by long lead times and regulatory barriers to siting of new generation.

In this report, when the residual supply index is calculated by excluding the largest supplier, we refer to this measure as RSI1. With the two or three largest suppliers excluded, we refer to these results as RSI2 and RSI3, respectively. The residual supply index analysis includes the following elements for accounting for supply and demand:

- Day-ahead market bids for physical generating resources (adjusted for outages and de-rates).
- Using the day-ahead load forecast as demand in combination with upward ancillary service requirements and self-scheduled exports.
- Transmission losses were not explicitly added to demand. The day-ahead load forecast already factors in losses. This reflects a change from prior DMM analyses.
- Including ancillary services bids in excess of energy bids to account for this additional supply available to meet ancillary service requirements in the day-ahead market.
- Exclusion of CPUC jurisdictional investor-owned utilities as potentially pivotal suppliers.
- Accounting for the maximum availability of non-pivotal imports offered relative to import transmission constraint limits.
- As in prior DMM analyses, virtual bids are excluded.

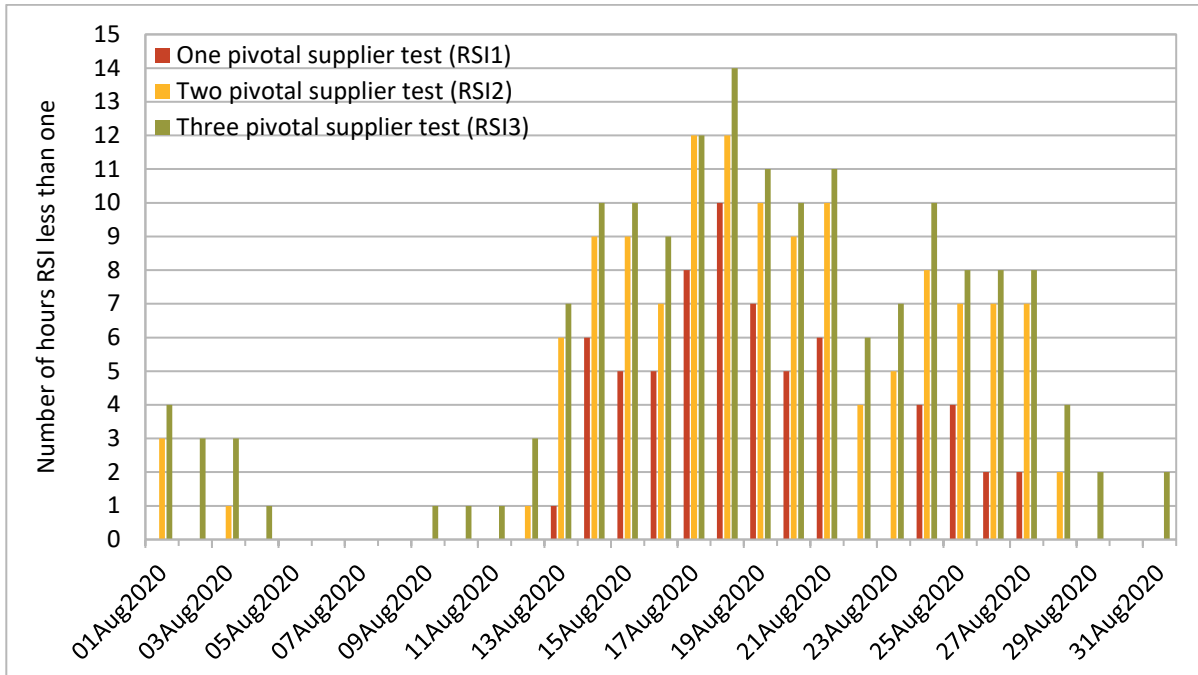
Results of this analysis for August and September are shown in Figure 3.51 and Figure 3.52. The assumptions listed above represent what DMM believes are the most appropriate supply and demand inputs. As shown in these figures, there were many hours with RSI1, RSI2, and RSI3 less than 1 during the heatwaves. For August and September alone, the residual supply index with the three largest suppliers removed (RSI3) was less than one during 256 hours. In comparison, there were 111 hours with RSI3 less than one during all of 2019, and 269 hours with RSI3 less than one during all of 2018.

With the largest two suppliers removed (RSI2), the residual supply index for August and September was less than one in 185 hours. With the largest supplier removed (RSI1), it was less than one in 88 hours.

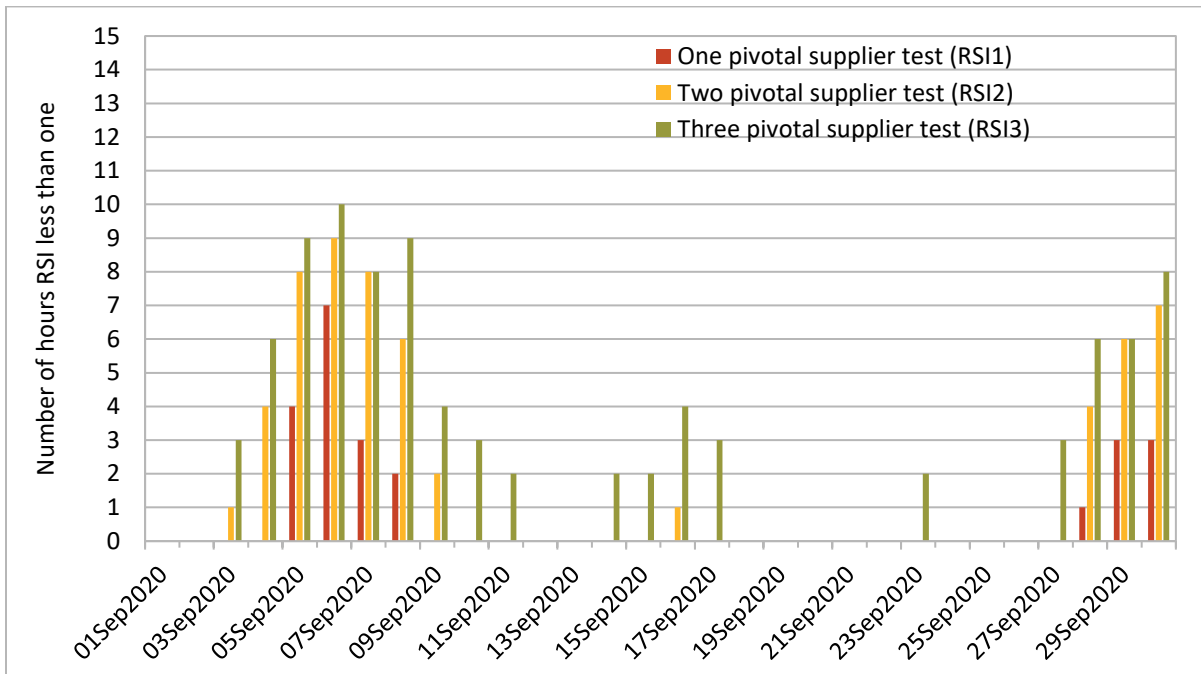
Figure 3.53 shows the lowest 300 RSI values during August and September. Extremely low RSI values (at the bottom of the curve) can instead indicate scarcity conditions. During this period, calculated supply was less than demand in 22 hours. However, other hours shown in this figure with RSI less than one reflects potentially non-competitive conditions. With the three largest suppliers removed, the RSI was less than 0.9 in 136 hours, and less than 0.8 in 43 hours.



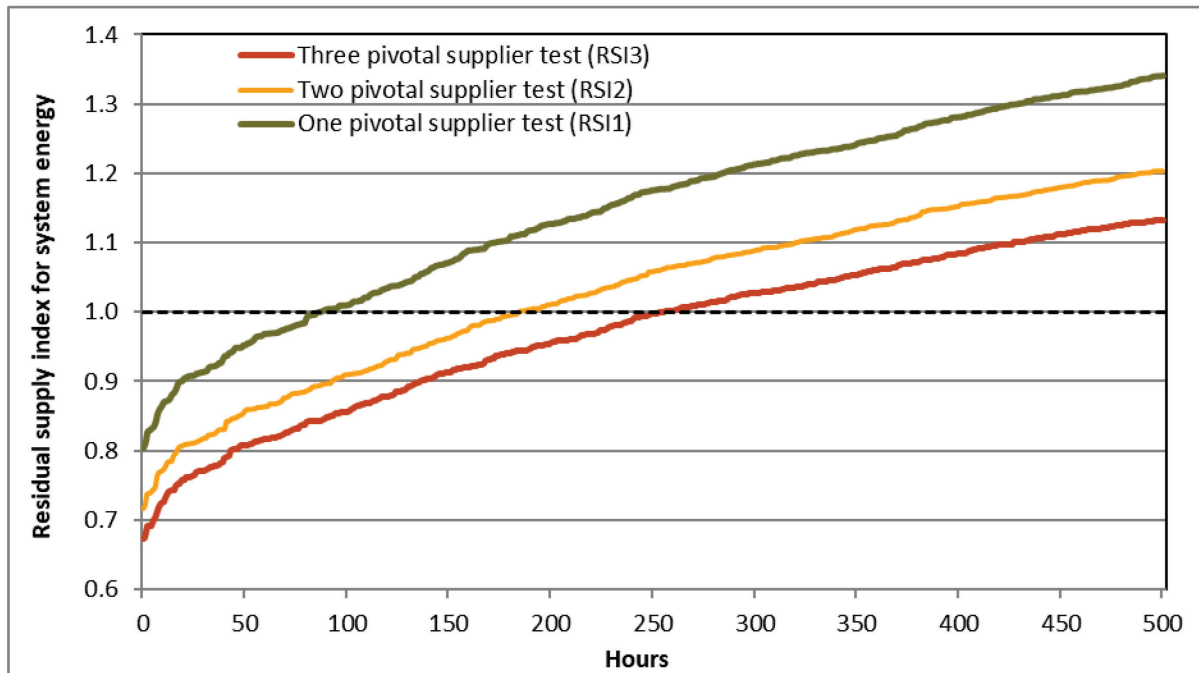
**Figure 3.51 Hours with residual supply index less than one by day (August)**



**Figure 3.52 Hours with Residual supply index less than one by day (September)**



**Figure 3.53**      **Lowest 300 residual supply index with largest one, two, or three suppliers excluded (August – September 2020)**



### 3.14.2 Competitiveness of day-ahead market prices

To assess the competitiveness of the ISO energy markets, DMM compares actual market prices to *competitive benchmark prices* we estimate would result under highly competitive conditions. DMM estimates competitive benchmark prices by re-simulating the market after replacing bids or other market inputs using DMM’s version of the actual market software.

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

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

1. **Scenario 1:** Replace market bids of gas-fired units with the lower of their submitted bids or their default energy bids (DEBs), to capture the effect of competitive bidding of energy by gas resources
2. **Scenario 2:** In addition to inputs for Scenario 1, replace bid-in commitment costs (start-up, transition, and minimum load) of gas-fired units with the lower of their submitted bids or 110

percent of their proxy cost, to capture the effect of competitive bidding of commitment costs by gas resources

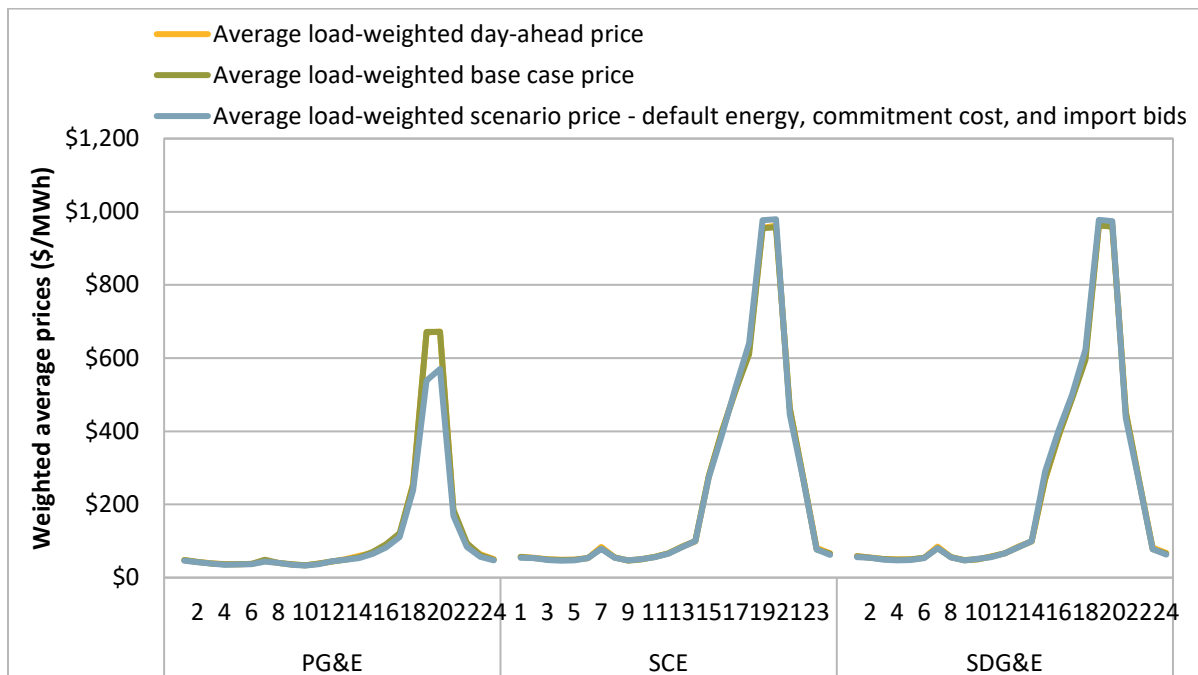
3. **Scenario 3:** In addition to inputs for Scenario 1, replace bids for import resources with the lower of their submitted bids or an estimated default energy bid based on a generous opportunity cost default energy bid option offered by the ISO (the hydro DEB), to capture the potential effect of uncompetitive bidding of imports

Each market simulation run is preceded by a base case rerun with all of the same inputs as the original market run before completing the benchmark simulation, to screen for accuracy. The price-cost markup is calculated as the difference between load-weighted average scenario prices compared to load-weighted average prices from this base case rerun.

As shown in Table 3.2, average hourly scenario prices are very similar to actual market results when comparing with the scenarios where bids for gas-fired resources are set to the minimum of the submitted bid or the default energy bid, bids for gas-fired resources’ commitment costs are set to the minimum of the bid or 110 percent of proxy cost, and import bids are set to the minimum of the bid or an estimated hydro default energy bid.

As shown in Figure 3.54, on average, prices in the combined competitive scenario (blue line) were higher than the average base case price (green line) in peak hours in SCE and SDG&E where average prices were close to \$1,000/MWh. Competitive scenario prices were lower in PG&E in peak hours, with competitive scenario prices over \$100/MWh less in hours 19 and 20 when base case and market prices were over \$600/MWh. On a load-weighted average basis the price cost markup across all hours and areas was low (3 percent or \$5.67).

**Figure 3.54 Average hourly price results for day-ahead market re-run with cost-based bids for gas resources and opportunity cost-based bids for imports (Aug 14-19)**



**Table 3.2 Price-cost markup by scenario (Aug 14 – Aug 19)**

Scenario	Load-wtd avg day-ahead prices	Load-wtd avg base case prices	Load-wtd avg scenario prices	Price-cost markup (\$/MWh)	Price-cost markup (%)
Gas resources at min(bid,DEB)	\$217	\$216	\$214	\$2.32	1%
Commitment costs for gas resources at min(bid,110% proxy)	\$217	\$216	\$218	-\$1.17	-1%
Import bids at min(bid,hydro DEB)	\$217	\$216	\$217	-\$0.58	0%
Energy and commitment cost bids capped for gas resources, imports capped	\$217	\$216	\$211	\$5.67	3%

## 4 Recommendations

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

- **Increase resource adequacy requirements to more accurately reflect increasing risk of extreme weather events** (e.g. beyond the 1-in-2 year load forecast and 15 percent planning reserve margin currently used to set system resource adequacy targets). Prior to this summer, CAISO peak load fell under the 1-in-2 years forecast four of the last five years.<sup>47</sup> However, summer 2020 illustrates that higher reliability will require that resource adequacy requirements be based on load forecasts which reflect the high likelihood of much higher load conditions than are reflected in the 1-in-2 year forecast.
- **Continue to work with stakeholders to clarify and revise the resource adequacy capacity counting rules**, especially as they apply to hydro resources, demand response resources, renewable resources, imports and other use limited resources. Counting rules should specifically take into account the availability of different resource types during the net load peak. Beginning in 2019, DMM has provided analysis and expressed concern in reports and CPUC filings about the cumulative impacts of various energy-limited or availability-limited resources which are being relied upon to meet an increasing portion of resource adequacy requirements.<sup>48</sup> This report includes additional analysis of the availability of different resource types during the peak net load hour in which load was curtailed in August, and highlights a variety of specific factors which could be incorporated into the resource adequacy ratings of these resources to better reflect their actual availability during the most critical net load peak hours.

In addition, DMM provides a third major recommendation regarding the issue of how exports are treated in the day-ahead real-time markets.

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

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

Ensure that market processes appropriately curtail lower priority exports that are not supported by non-resource adequacy resources to minimize the export of capacity that could be related to RA resources during reliability events.<sup>49</sup>

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<sup>47</sup> 2019 Annual Report on Market Issues and Performance, Department of Market Monitoring, June 2020, pp.34-35. <http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf>

<sup>48</sup> 2019 Annual Report on Market Issues and Performance, pp. 26-27, 299-302.

Reply Comments of the Department of Market Monitoring, Rulemaking 16-02-007, August 12, 2019,

[http://www.caiso.com/Documents/CPUC-](http://www.caiso.com/Documents/CPUC-DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf)

[DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf](http://www.caiso.com/Documents/CPUC-DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf)

<sup>49</sup> CAISO/CPUC/CEC Report, p. 66.

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

DMM's understanding is that CAISO's current policy is still to prioritize exports that receive RUC awards over native CAISO balancing area load in real-time. DMM appreciates that curtailment of exports should be avoided when possible, given the potentially detrimental direct and indirect impacts of export curtailment on other balancing areas and the CAISO itself, as discussed in the CAISO/CPUC/CEC report.<sup>50</sup> However, DMM believes that additional changes and clarifications to the residual unit commitment rules and other market processes are needed to address the issue of exports.

The rules and processes for curtailment of exports by the CAISO and other balancing areas should be reviewed, clarified, and potentially modified -- with a goal of establishing equal treatment and expectations of exports by all balancing areas. CAISO and other WECC balancing areas' ultimate policy on how they will prioritize exports relative to native load will be a critical factor in CPUC resource adequacy reforms and many major CAISO market design initiatives such as the extended day-ahead market, day-ahead market enhancements, system market power mitigation phase 2, resource adequacy enhancements, scarcity pricing, and refinements to export bidding rules.

More discussion of residual unit commitment enhancements and the need to clarify, and potentially refine, how CAISO and other balancing areas treat exports is provided below.

### Residual unit commitment process

***DMM supports the changes made to the residual unit commitment process which limit export schedules clearing the day-ahead energy market that are passed into the real-time market based on the quantity of exports supported by physical capacity.***

Because the results of clearing all generation, load and other financial bids in the day-ahead market are not guaranteed to create resource commitments that can feasibly meet real-time load forecasts, ISOs/RTOs run supplementary reliability processes. In the California ISO this reliability process is called the Residual Unit Commitment (RUC). The RUC process should ensure that meeting the load forecast is feasible if it has sufficient resources to select from.

California's resource adequacy program is meant to ensure sufficient resources to meet load under most circumstances. If both the resource adequacy program and RUC process function as intended – to procure sufficient capacity – then meeting the real-time load forecast will be feasible regardless of how much load underschedules relative to its forecast, and regardless of how much virtual supply or exports clear in the integrated forward energy market. During the August heat waves, the ISO discovered that the RUC implementation was causing this critical backup reliability process to not function as intended.

Prior to September 5, RUC was implemented to allow exports that had received energy market awards to still receive RUC awards even when there was not enough supply to meet the CAISO balancing area load forecast. DMM's understanding is that CAISO's policy was to prioritize exports that receive RUC awards over native CAISO balancing area load in real-time. Therefore, this RUC implementation issue contributed to decreasing the reliability of CAISO balancing area native load.

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<sup>50</sup> CAISO/CPUC/CEC Report, pp. 106-107.

Prior to September 5, any export that cleared the day-ahead market, such as the almost 3,000 MWs of exports that cleared during hour ending 19 on August 14 that were not wheels and not contracted to non-RA CAISO generation, was also given a higher scheduling priority than CAISO balancing area load by the real-time market. This could also have impacted reliability because cuts to export schedules in advisory runs of the real-time market could give CAISO operators advance warning to begin working with other balancing areas on whether or not CAISO native load or exports out of CAISO may need to be cut.

On September 5, the ISO made important enhancements to RUC and the real-time scheduling priority of day-ahead energy market export schedules that do not receive RUC awards. RUC was adjusted to consistently reduce the RUC awards of exports not backed by contracts with specific generators when there was not enough physical supply to meet the CAISO load forecast. Export scheduling priorities were enhanced to only give exports that received RUC awards a higher scheduling priority than CAISO native load in the real-time markets.

DMM supports the enhancements to the residual unit commitment process and the real-time scheduling priority of day-ahead energy market exports made by the ISO on September 5. However, DMM's understanding is that CAISO's current policy is still for both operators and the real-time market to prioritize exports that receive RUC awards over native CAISO balancing area load. As explained in the following recommendation in this report, DMM recommends CAISO review the prioritization that other WECC balancing areas give to exports that marketers schedule out of their areas in the day-ahead time frame and that CAISO work with these balancing areas and other stakeholders to clarify and potentially refine how CAISO prioritizes exports. As part of this process, the ISO should consider potential changes to export bidding rules and scheduling priorities in both the day-ahead market and RUC process.

#### **Export scheduling and prioritization relative to CAISO balancing area native load**

***The rules and process for curtailment of exports by the CAISO and other balancing areas should be reviewed, clarified, and potentially modified -- with a goal of establishing equal treatment and expectations of exports by all balancing areas.***

As highlighted in this report, exports scheduled in the day-ahead market can significantly increase the overall demand that must be met by available supply in the CAISO day-ahead and real-time markets. DMM understands that limiting exports in the day-ahead market or curtailment of exports after the day-ahead market involves a wide range of operational and market considerations. Due to the interdependence of different control areas, curtailment of exports can have potential adverse impacts to other balancing areas as well the balancing area from which exports may be curtailed.

However, DMM believes that experience during the summer 2020 heatwave highlights the need to review and potentially modify rules and processes for curtailment of exports by the CAISO, as well as other balancing areas in the west. DMM recommends a much more detailed discussion of this very important issue which includes balancing areas across the west, with a goal of establishing equal treatment and expectations of exports by all balancing areas. DMM believes this discussion is particularly relevant to efforts to design a regional extended day-ahead market and discussions of developing more formal resource adequacy programs in other balancing areas across the west.

The sections below provide some initial discussion and recommendations on this issue.

### Exports backed by specific resources

The CAISO already offers a scheduling feature which allows scheduling coordinators to explicitly link specific exports to energy from non-resource adequacy capacity in the CAISO. These exports are afforded a very high scheduling priority, equivalent to internal CAISO load. As discussed in this report, only a very small volume of exports are explicitly supported by non-resource adequacy capacity.

DMM has been recommending that exports from other balancing areas supporting resource adequacy imports into the CAISO be afforded this same scheduling priority. Specifically, DMM has recommended that “to ensure that external supply is truly dedicated to the ISO, particularly when other BAAs also face supply shortages, the ISO should ensure that BAAs cannot recall or curtail energy backing resource adequacy imports ...”<sup>51</sup> Based on a benchmark with other RTOs, DMM understands that this is how all other RTO markets with resource adequacy or capacity markets work.<sup>52</sup> To date, the CAISO has not adopted this recommendation, although CAISO has stated that it “seeks to adopt similar types of requirements for RA imports to the CAISO *to the extent practicable*” (emphasis added).<sup>53</sup>

Adopting DMM’s recommendation for resource adequacy imports would still not provide totally uniform rules across the CAISO and other balancing areas. If adopted, the requirement suggested by DMM would only be applicable to exports from other balancing areas which are specifically identified in advance as being responsible for supporting resource adequacy imports. Meanwhile, current CAISO rules allow scheduling coordinators to schedule exports which are backed by any non-resource adequacy capacity on a daily and even hourly basis without any other advance notice or contractual agreement.

### Exports not backed by specific resources

As explained in the residual unit commitment section above, on September 5 the ISO made important enhancements to RUC and the real-time scheduling priority of day-ahead energy market export schedules that do not receive RUC awards.

However, DMM’s understanding is that CAISO’s current policy is still for both operators and the real-time market to prioritize exports not backed by specific resources, but that receive RUC awards, over native CAISO balancing area load. It is also DMM’s understanding that CAISO’s approach differs from how exports are treated in other RTO markets, and it is unclear how the CAISO’s rules and procedures compare to those of other balancing areas in the west.

There could still be uncertainty in generation availability and inflexible load between the day-ahead processes and real-time. That is why other RTOs and other balancing areas in the west may have emergency procedures to curtail some scheduled exports that clear their day-ahead processes before curtailing their native load.

CAISO’s policy exposes its balancing area to the risk of cutting native load when conditions change between the day-ahead time frame and real-time, and when there would have been sufficient resource adequacy capacity to avoid cutting CAISO native load if CAISO hadn’t committed capacity to exporters in

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<sup>51</sup> *Comments on Resource Adequacy Enhancements Working Group on September 15 and 17*, October 1, 2020, p. 4.  
<http://www.caiso.com/Documents/DMMLComments-ResourceAdequacyEnhancementsWorkingGroupSept15and17-Oct12020.pdf>

<sup>52</sup> *Comments on Resource Adequacy Enhancements Revised Straw Proposal*, July 24, 2019 pp 5-9.  
<http://www.caiso.com/Documents/DMMLComments-ResourceAdequacyEnhancements-RevisedStrawProposal.pdf>

<sup>53</sup> *Resource Adequacy Enhancements Fifth Revised Straw Proposal*, CAISO, July 7, 2020, p. 70.  
<http://www.caiso.com/InitiativeDocuments/FifthRevisedStrawProposal-ResourceAdequacyEnhancements.pdf>



the day-ahead market time-frame. As described above, DMM understands that curtailment of exports after the day-ahead market involves a wide range of operational and market considerations. So any policy of curtailing exports with RUC awards not backed by specific capacity should obviously only be implemented after working carefully through all the issues with the western reliability coordinators, balancing areas, and other stakeholders and ensuring that the policy aligns with the export curtailment policies of other western balancing areas.

Prior to the August heat wave, the CAISO tariff and business practice manuals described day-ahead market exports not supported by specific generation being clearly prioritized below CAISO load in real-time.<sup>54</sup> Therefore, it was DMM's understanding that CAISO already had such a carefully defined process in place. Now, it is DMM's understanding that CAISO may not have such a procedure and that its policy may not be aligned with export curtailment policies of other western balancing areas. As a result, DMM recommends a much more detailed discussion of this very important issue which includes balancing areas across the west, with a goal of establishing equal treatment and expectations of exports by all balancing areas.

The CAISO and other WECC balancing areas' ultimate policy on how they will prioritize exports relative to native load will be a critical factor in CPUC resource adequacy reforms and many major CAISO market design initiatives such as the extended day-ahead market, day-ahead market enhancements, system market power mitigation phase 2, resource adequacy enhancements, scarcity pricing, and refinements to export bidding rules.

Finally, DMM provides the following recommendation regarding demand response.

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

Analysis in this report indicates that less than two thirds of the 1,847 MW of resource adequacy capacity requirements that were met by demand response were available for dispatch in real-time during the hours of load curtailment on August 14 and August 15. The actual performance of demand response that was dispatched has not yet been fully evaluated based on retail customer meter data. However, even if performance of demand response is high relative to the amount dispatched in the CAISO market, the amount of demand response that was available relative to the amount of resource adequacy capacity requirements met by demand response was relatively low.

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

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<sup>54</sup> *California Independent System Operator Corporation Fifth Replacement Electronic Tariff*, November 13, 2019, Section 34.12.1 – Increasing Supply: <http://www.caiso.com/Documents/Section34-Real-TimeMarket-asof-Nov13-2019.pdf>  
BPM\_for\_Market Operations\_V65\_clean, pp. 233-5:  
<https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Operations>