California ISO

Summer Market Performance Report July 2021

August 31, 2021

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Market Analysis and Forecasting

Content

1 Executive Summary

The California ISO regularly reports on the performance of its markets to provide timely and relevant information. This is the second of a series of customized monthly reports that will focus on the CAISO's market performance and system conditions during the 2021 summer months (June through September), when system conditions are particularly constrained in California and the Western Interconnection. These monthly reports will also provide an assessment of the performance of specific market enhancements implemented as part of the CAISO's summer readiness market rules changes.[1]

July 2021 Highlights

On July 9, 2021 the CAISO's balancing authority area entered into an EEA3 Stage 2, arming load and releasing operating reserves to meet energy needs. Prior to the peak hours, derates on Malin and NOB interties resulted in a loss of over 1,500 MWs of imports. These challenging conditions were managed without the need to conduct rotating outages.

CAISO implemented four elements of the summer readiness initiative: i) make-whole incentives for hourly imports during tight system conditions, ii) real-time pricing of use of contingency reserves at the bid cap, iii) adding an uncertainty component to the capacity test requirements in the Energy Imbalance Market (EIM), and iv) improvements to the management of storage resources under Resource Adequacy (RA) requirements during tight supply system conditions.[2]

July experienced high temperatures across the Western United States, with two heat events and above average temperatures throughout California and the Western United States. The most noticeable heat event was from July 8 through July 11, as temperatures were 5 to 15 degrees above normal, impacting California, the Southwest, and Northern Mountain West.

Reduced levels of hydroelectric production due to drought conditions. Reservoir conditions for California and the West are significantly below normal. Storage in major reservoirs statewide was 58 percent of average for this time of year and 39 percent of capacity overall[3]. Hydro production in July 2021 was about 62 percent of 2020's production, and about 35 percent of the 2019's production.

CAISO called for Flex Alerts on July 9, 10, 12 and 28. CAISO estimates that energy conservation triggered by these Flex Alerts resulted in hourly load reductions of up to 940 MW during peak hours. These

[1] This report is targeted in providing timely information regarding the CAISO's market's performance for the month of July. Several metrics provided in this report are preliminary and based on data still subject to change. It is also important to note that the data and analysis in this report are provided for informational purposes only and should not be considered or relied on as market advice or guidance on market participation.
[2] Additional market rule changes will be implemented in August 2021, and CAISO will report on the performance of those changes as they become functional in the CAISO's production systems. The complete list of enhancements that will be implemented this summer and their expected activation dates are provided in the next section.
[3] https://cdec.water.ca.gov/reportapp/javareports?name=STORSUM

conservation estimates were in part due to an emergency proclamation signed by Governor Newsom of California to free up additional energy capacity amid a major heat wave.[4]

CAISO's load peaked at about 43,285 MW on July 9, 2021, and was below the July 2021 monthly showings forecast of 43,517 MW used in resource adequacy (RA) programs.

Monthly RA capacity was at 49,780 MW and was above the level of actual load needs (demand plus operating reserves). RA capacity from hydro resources for July 2021 was 370 MW less than it was in July 2020, and static imports (this does not include dynamics and pseudo ties) were reduced by 608 MW. Gas and solar increased by 622 MW and 513 MW, respectively. RA capacity from storage resources increased by 782 MW. RA capacity available in the market was generally sufficient to cover actual load needs. Above RA capacity available in the market was consistently over 4,000 MW through the month, and was supported by both internal supply and imports.

CAISO's prices diverged across markets during July 8 through July 10. Real-time prices were higher than day-ahead prices during the heat wave of July 9, while for the rest of the month day-ahead prices were generally higher. The large difference observed on July 9 is mainly driven by the tighter supply conditions observed once supply became limited with the loss of supply through Malin and NOB interties. On July 9, when arming load, CAISO released operating reserves at the bid cap, under the new logic of the summer readiness enhancements, and some of these resources were dispatched at the bid cap which allowed the real-time market to better reflect tight supply conditions.

The residual unit commitment (RUC) process was unable to meet the adjusted load forecast in one hour of July 9, and concurrently found over 4,000 MW of exports to be infeasible. The infeasible exports were low priority self-schedules. The high priority exports, which are exports that are backed by resources contracted to serve external load, were rebid into the real-time market and were fully scheduled in real time. In the real-time market, total export curtailments were about 3,800 MW for hour ending 20 and only for low-priority exports, which are exports not backed by resources contracted to serve external load.

Hourly average of net imports was about 4,200 MW for peak hours in July, a decrease from 4,800MW in June. Net imports reached their minimum levels on July 9 through 12, and July 28 through 30 when CAISO experienced the largest volume of exports in the system. In certain intervals during these days, the intertie transactions represented a net export when the volume of exports outpaced the volume of imports. These net export conditions were typically observed prior to the peak hours.

Western EIM transfers into the CAISO area were consistently over 1,000 MW during the heat wave days across the peak hours. Transfers into CAISO were from multiple areas, including adjacent areas and also from farther reaching areas. On July 9, when there were tight supply conditions across multiple areas, EIM imports to CAISO were minimal. Overall, EIM transfers reflect the economic and operational benefits that EIM offers to participating entities by maximizing supply diversity.

[4] https://www.gov.ca.gov/wp-content/uploads/2021/07/Extreme-Heat-Proc-7-8-21.pdf

About 98 percent of RA imports bid at $0/MWh or lower prices in the day-ahead market, while about 99 percent of real-time bids for RA imports bid in at $0/MWh or lower. This is assessed for static RA imports related to CPUC-jurisdictional load serving entities and for hours ending 17 through 21 on weekdays.

Self-scheduled wheel-through transactions reached a maximum of 722 MW in the day-ahead market on July 11. Likewise, a maximum of 1051 MW of self-scheduled wheels were observed in the real-time on July 9, with about a half of these wheels scheduled directly in the real-time market. Unlike June's pattern, wheel-through transactions were self-scheduled consistently throughout the month of July. Two of the most used paths were from Malin to PaloVerde and from NOB to PaloVerde with a maximum day-ahead hourly wheel volume of 186 and 321MW, respectively.

Reliability demand response resources were activated and dispatched in the real-time market on July 9 to about 800 MW, while proxy demand response was dispatched up to 190 MW.

Additional storage capacity was added to the system during the summer and provided a dispatch of up to 1,150 MW during critical real-time periods. The maximum discharge for storage resources occurred between hour ending 19 and 21, while charging mostly occurred in early hours when solar supply was plentiful. The maximum level of state of charge increased to about 5200 MWh in July from 3,000 MWh in June because of additional storage capacity available on the system.

The addition of uncertainty to the capacity test resulted in about a threefold increase of capacity test failures, with the CAISO area experiencing an increase of upward capacity failures from 4 intervals to 6 intervals. The total number of capacity test failures in July for all EIM entities increased from 84 when uncertainty was not included in the test to 245 when it was. About half of the test failures in July occurred in the peak hours 18 through 21. This enhancement was implemented on June 15, 2021.

On average, CAISO's daily market costs were $56.2 million in July, an increase from $37.8 million in June. The highest daily cost accrued on July 29 at about $97 million. These cost levels are consistent with summer conditions when increasing loads and services settled at higher energy prices.

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4 Acronyms

AZPS	Arizona Public Service
BAA	Balancing Authority Area
BANC	Balancing Authority of Northern California
BCHA	Powerex
CAISO	California Independent System Operator
CCA	Community Choice Aggregator
CEC	California Energy Commission
CMRI	Customer Market Results Interface
CPUC	California Public Utilities Commission
DAM	Day ahead market
DLAP	Default Load Aggregated Point
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capacity
ESP	Energy Service Provider
ETC	Existing Transmission Contract
F	Fahrenheit
FMM	Fifteen Minute Market
HASP	Hour Ahead Scheduling Process
HE	Hour Ending
IEPR	Integrated Energy Policy Report
IFM	Integrated Forward Market
IOU	Investor-Owned Utility
IPCO	Idaho Power Company
LADWP	Los Angeles Department of Water and Power
LMP	Locational Marginal Price
LMPM	Local Market Power Mitigation
LPT	Low priority export. This is a scheduling priority assigned to price-taker exports that do not have a non-RA supporting resource
LSE	Load Serving Entity
MSG	Multi-Stage Generator
MW	Megawatt
MWh	Megawatt-hour
NEVP	NV Energy
NGR	Non-Generating Resource
NOB	Nevada-Oregon Border
NSI	Net Scheduled Interchange
NWMT	Northwestern Energy
OASIS	Open Access Same-Time Information System
OR	Operating Reserves
PACE	PacifiCorp East
PACW	PacifiCorp West
PGE	Portland General Electric
PNM	Public Service Company of New Mexico
PRM	Planning Reserve Margin
PSEI	Puget Sound Energy
PST	Pacific Standard Time

PTO	Participating Transmission Owner
PTK	High priority assigned to a schedule. Exports are assigned this priority when they can have a non-RA resource supporting its export.
QC	Qualifying Capacity
RA	Resource Adequacy
RDRR	Reliability Demand Response Resource
RTM	Real-Time Market
RUC	Residual Unit Commitment
SCL	Seattle City Light
SMEC	System Marginal Energy Component
SOC	State of Charge
SRP	Salt River Project
TIDC	Turlock Irrigation District
TOR	Transmission Ownership Right

5 Background

In mid-August 2020, a historical heat wave affected the Western United States, resulting in energy supply shortages that required two rotating power outages in the CAISO balancing authority area (BAA) on August 14 and 15, 2020. The heat wave extended through August 19. CAISO declared Stage emergencies for August 17 and 18 but avoided rotating outages. Over the 2020 Labor Day weekend, California experienced another heat wave and again the CAISO avoided rotating outages.

In a joint effort, the California Public Utilities Commission, the California Energy Commission and the California ISO initiated an analysis of the causes for the rotating outages. The findings were documented in the Final Root Cause Analysis report.[5]

The Final Root Cause Analysis found three major causal factors contributing to the rotating outages of August 14 and 15, 2020,

1. The extreme heat wave experienced in mid-August 2020 was a 1-in-30 year weather event in California and resulted in higher loads that exceeded resource adequacy and planning targets. This weather event extended across the Western United States, impacting loads in other balancing areas and straining supply across the West.

2. In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand for both the gross and net load (gross peak of demand less solar and wind production) peaks.

3. Some existing practices in the day-ahead energy market at that time exacerbated the supply challenges under highly stressed conditions.

Effective September 5, 2020, while still facing high-load conditions, the CAISO identified one area of improvement to existing market practices regarding the treatment of export priorities. The CAISO made an emergency business practice manual change to address this issue. The first part of the change was to use the intertie schedules derived from the scheduling run, instead of the pricing run, in the reliability unit commitment (RUC) process to more accurately reflect the feasible export schedules coming from the day-ahead market. These schedules serve as a reference for E-tagging. The second part of the change was to use the RUC schedules, instead of the integrated forward market (IFM) schedules, in determining the day-ahead priority utilized in the real-time market for exports being self-scheduled. Prior to this change, any export cleared in the IFM market received a day-ahead priority in the real-time market up to the cleared IFM schedule. With the change, exports cleared in the day-ahead market receive a day-ahead priority up to the cleared schedule in the RUC process. After the implementation of the export priorities in August 2021, the practice of using RUC schedules as the reference for feasible export schedules remain in place.

[5] California Independent System Operator, California Public Utilities Commission, and California Energy Commission. Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave. January 13, 2021. http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

Following publication of the Final Joint Root Cause Analysis, the CAISO initiated an effort to identify, discuss with market participants and propose enhancements across different areas of the market practices. This effort was initiated with educational workshops to level the understanding of existing market practices and their implications. This was followed by the formal launch of the Market Enhancements for Summer 2021 Readiness initiative[6].

The summer 2021 enhancements include:

1. Load, Export and wheeling priorities
2. Import market incentives during tight system conditions
3. Real-time scarcity pricing enhancements
4. Reliability demand response dispatch and real-time price impacts
5. Additional publication of intertie schedules
6. Addition of uncertainty component to the EIM resource capacity test
7. Management of storage resources during tight system conditions
8. Interconnection process enhancements
9. New displays in Today's outlook for projected conditions seven days in advance

These enhancements are being implemented at different times during summer 2021.

[6] The policy initiative material can be found at https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-enhancements-for-summer-2021-readiness

6 Summer Readiness Enhancements

The summer readiness initiative was organized into two main efforts. The second phase of the initiative largely focuses on Load, Export, and Wheeling Priorities. The first phase includes all other items of the summer readiness initiative.

The first phase of the summer readiness initiative was approved by FERC on May 25, 2021[7] and includes the following components, which have been implemented at different times earlier this year:

1. EIM resource capacity sufficiency test. This enhancement adds the uncertainty component utilized in the flexible ramp sufficiency test to the capacity test and applies to all areas participating in the Western Energy Imbalance Market (EIM), including the CAISO's area.

   Implementation date: June 15, 2021.

   This feature is evaluated in this report for the month of July.

2. Import market incentives during tight system conditions. This enhancement provides improved incentives for import supplies to be available during tight system conditions because the prior settlement rules may have paid imports less than they bid, which could exacerbate conditions when supplies are tight. During very tight system conditions (*i.e.,* when CAISO has issued an alert by 3 PM PST, or a warning or emergency notice), the CAISO will provide bid cost make-whole payments for real-time hourly block economic imports.

   Implementation date: June 15, 2021.

   This feature was triggered on July 9 and 10 between 5pm and 9pm. This calculation is based on settlements data, which were not available at the time this analysis was performed and prevented a full evaluation of the implications of triggering this feature. This will be evaluated in subsequent reports as the settlements data becomes available.

3. Additional publication of intertie schedules information on OASIS. This provides greater transparency of intertie schedules through a new OASIS display. Intertie schedules are organized by Import and Exports and by individual intertie location.

   Implementation date: July 26, 2021.

4. Enhanced real-time pricing signals during tight supply conditions. The enhancement allows the CAISO to price energy released from operating reserves deployed to serve load at the applicable

[7] FERC order accepting Tariff revisions for the Summer readiness initiative can be found at http://www.caiso.com/Documents/May25-2021-OrderAcceptingSummerReadinessFiling-ER21-1536.pdf

energy bid cap. This applies to energy associated with either contingent or non-contingent operating reserves. This new logic can trigger when the CAISO is in a warning or emergency.

Implementation date: June 15, 2021.

This feature was active on July 9 while the CAISO had an emergency and spinning and non-spinning reserves were indeed released at the price caps.

5. Management of storage resources during tight system conditions. This enhancement includes three features involving the management of storage resources:

    a. Updated state-of-charge requirements when storage resources provide regulation. In scheduling and awarding storage resources, the market ensures resources will have a State- of-Charge (SOC) that can maintain the awarded Regulation Up and Regulation Down for a defined period of time. This specific change was implemented on May 30, 2021.

    b. Minimum state-of-charge requirement. This is to ensure storage resources providing RA capacity are sufficiently charged in the Real Time Market (RTM) to meet the Day Ahead Market (DAM) discharge schedules when storage resources are needed to meet the evening net-load peak. This is implemented through a minimum state-of-charge (MSOC) tool and will be used when the RUC process identifies supply shortfalls.

    c. New OASIS display to report on the critical hours used to calculate the minimum state-of-charge and the hours with RUC shortfalls. There is also a new resource-specific report via the CAISO Market Results Interface (CMRI).

    Implementation date: June 30, 2021.

    In the month of July, the MSOC was utilized on July 9, 28 and 29 since these were days with RUC infeasibilities.

6. Reliability demand response (RDRR) dispatch and real-time price impacts. This enhancement expands functionality to dispatch RDRR resources in the fifteen-minute market (FMM). RDR resources have new bidding options to be 15- or 60-minute dispatchable, allowing them to reflect their operational capabilities more accurately. This will also allow RDRR resources to be marginal resources in FMM.

    Implementation date: August 4, 2021.

The second part of the initiative (Load, Export, and Wheeling Priorities) was approved by FERC on June 25, 2021[8] and was implemented on August 4, 2021. This enhancement involves a revised set of scheduling priorities for exports, wheel transactions and the CAISO load, including a newly specified priority for wheeling through transactions.

In addition to the above market enhancements and based on the lessons learned from the summer 2020 events, the CAISO has also implemented:

1. Interconnection process enhancements. This enhances the independent study interconnection process to provide the ISO additional capacity for summer 2021, removes the 100MW/125% cap on behind the meter expansion requests and enables the ISO to award available deliverability on a temporal basis to online projects. This took effect with the tariff provision of May 25, 2021.

2. Additions to the CAISO's public communications messaging and protocols to enable more transparent and timely communication of projected and existing conditions that may impact the supply conditions of the system. In addition to communication protocols with involved system entities, the CAISO is providing communication to the public and market at large in advance of possible stress on the system to allow them time to prepare and participate in conservation efforts.

   These include expanded communication on the CAISO social media platforms for high temperature conditions, a Heat Bulletin news release, and a System Conditions Bulletin posted to the News page and updated as needed during a heat event. The Heat Bulletin alerts media and public that hot weather in any of the next seven days could affect grid conditions; the System Conditions Bulletin continually provides the most recent and developing information on grid conditions, including load and weather forecasts, operational actions, Flex Alerts, and emergency notifications.

3. The Today's Outlook display, available on the CAISO's website, has been enhanced to increase transparency on the electric system's projected conditions, with new charts for daily resource adequacy capacity trends for the current day, as well as resource adequacy capacity with seven-day trends. This also includes load and net load trends for seven days. This enhancement was activated on August 17, 2021.

Table 1 summarizes the different enhancements being implemented through the summer.

[8] FERC order accepting Tariff revisions for the Summer readiness initiative can be found at http://www.caiso.com/Documents/Jun25-2021-OrderAcceptingTariffRevisionsSubjecttoFurtherCompliance-SummerReadiness-ER21-1790.pdf

Table 1: Summary of enhancements implemented in the Summer 2021

Summer enhancement	Date Implemented	Trigger	Dates
1. EIM resource capacity sufficiency test	15-Jun	Permanent feature	All the time
2. Import market incentives during tight system conditions	15-Jun	Warning or Emergency	July 9 and 10, 5-9pm
3. Intertie schedules information on OASIS	26-Jul	Permanent feature	All the time
4. Enhanced real-time pricing signals during tight supply conditions	15-Jun	Warning or Emergency	July 9, 5-9pm
5. Management of storage resources during tight system conditions	30-Jun	RUC undersupply	July 9, 28 and 29
6. Reliability demand response dispatch and real-time price impacts	4-Aug	Activation of RDRR	Not active in July
Load, export and wheeling priorities	4-Aug	Permanent feature[9]	Not active in July
Interconnection process enhancements	25-May	Permanent feature	Not used yet
CAISO's public communication protocols	29-May	System Event driven	July 9, 10, 12 and 28
Today's Outlook displays	Aug 18	Permanent feature	Not active in July

[9] The wheeling through priorities the CAISO placed into effect are interim only and will sunset after May 31, 2022.

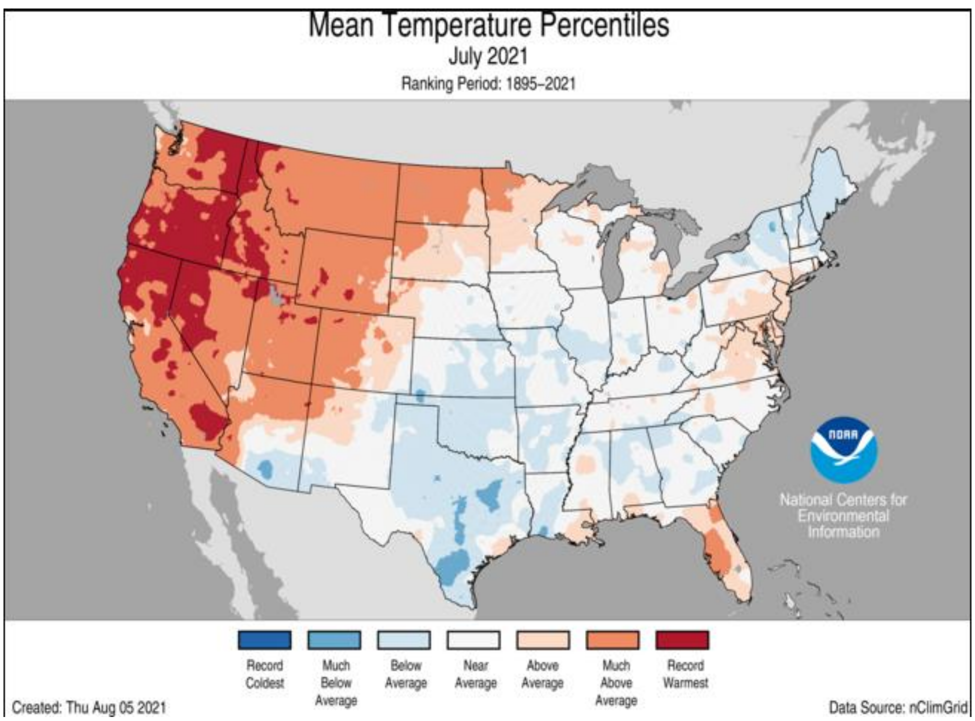
7 Weather and Demand Conditions

Weather such as temperatures and hydro conditions play a key role in the variables affecting the market and system operations, including hydro production, renewable production and load levels.

7.1 Temperature

Above average, much above average, and record warmest temperature percentiles were observed throughout California and the Western United States for minimum, maximum, and average temperatures during the month of July. This is shown in Figure 1, the July mean temperature percentiles for the United States.

Figure 1: Mean temperature percentiles for July 2021[10]

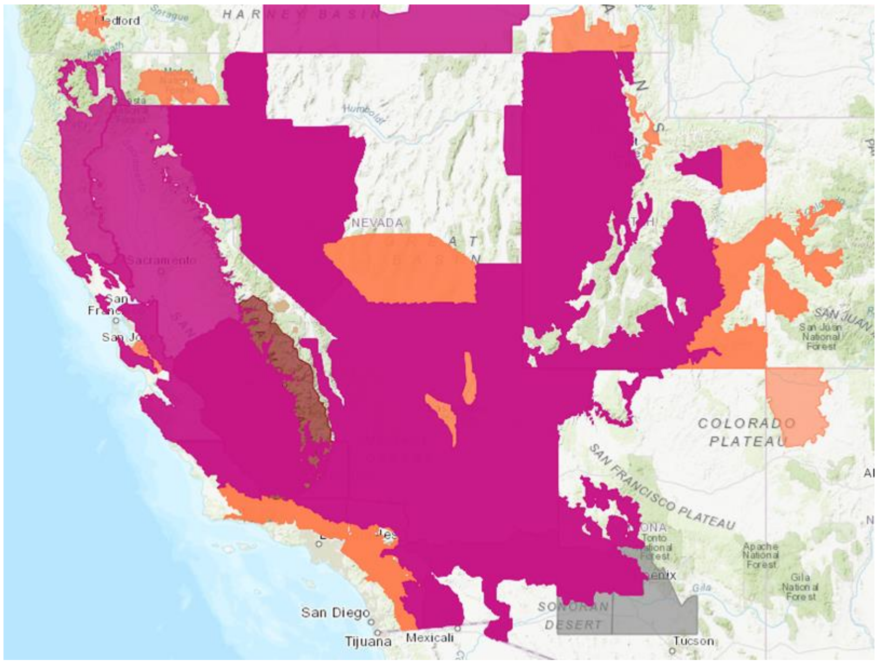


During the month of July there were not heat events that were as extreme as those observed during June. Throughout the Western U.S., many locations were experiencing above normal temperatures throughout the month, with the Pacific Northwest and far Northern CA experiencing the warmest mean July temperatures compared to normal. The most notable heat event for the CAISO occurred from July 8 through July 11, 2021. During this event, extreme heat occurred in California, the Southwest, and the

[10] https://www.ncdc.noaa.gov/temp-and-precip/us-maps/

Northern Mountain West, leading to temperatures 5-15 degrees above normal. During this mid-July event, much of the western United States was within an Excessive Heat Warnings (most extreme), Heat Advisories, or Excessive Heat Watches (least extreme) issued by the National Weather Service on July 8, 2021, as depicted by Figure 2.

Figure 2: National Weather Service alerts and warnings on heat for the Western United States[11]



Excessive Heat Warning Heat Advisory Excessive Heat Watch

During the mid-July event, California, the Southwestern EIM, and Northeastern Mountain West entities were impacted from the high pressure ridge throughout the week. As seen in Figure 3 and Figure 4, during this event, the CAISO was running 3-7 degrees Fahrenheit (F) above normal starting on July 8, 2021, lasting through July 11, 2021, with the warmest days being on Friday the 9 and Saturday the 10. In addition, Arizona and Nevada were running 3-11 degrees Fahrenheit (F) above normal starting on July 5, 2021 through July 14, 2021, with the warmest days being Friday the 9 through Sunday the 11.

[11] National Weather Service (https://www.wrh.noaa.gov/map/?obs=true&wfo=mtr)

Figure 3: Desert Southwest EIM Entity high temperature departure from normal[12]

Arizona Public Service (APS)

High temperature departure from normal

July 2021

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
				1 -2	2 -3	3 -2
4 -6	5 -0.1	6 3	7 4	8 3	9 4	10 6
11 4	12 -3	13 -0.7	14 -11	15 -7	16 -7	17 -5
18 -8	19 -5	20 0	21 -1	22 -0.7	23 -23	24 -22
25 -24	26 -10	27 -3	28 -2	29 -2	30 -5	31 -7
				days < normal 24	days > normal 7	Deg +/- normal -4

above normal	below normal	Normals: 1990-2020

Nevada Energy (NVE)

High temperature departure from normal

July 2021

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
				1 3	2 3	3 3
4 -0.3	5 4	6 7	7 7	8 7	9 11	10 11
11 8	12 8	13 4	14 4	15 -2	16 0.3	17 0.7
18 -6	19 -9	20 -1	21 -3	22 -3	23 -0.4	24 -1
25 -1	26 -8	27 -7	28 -3	29 -0.8	30 -7	31 -9
				days < normal 16	days > normal 15	Deg +/- normal + 0.6

above normal	below normal	Normals: 1990-2020

Figure 4: CAISO high temperature departure from normal

California ISO (CAISO)

High temperature departure from normal

July 2021

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
				1 -0.3	2 -0.2	3 -0.2
4 -2	5 -2	6 -1	7 -1	8 3	9 7	10 7
11 3	12 -1	13 -3	14 -2	15 -3	16 -2	17 0.1
18 2	19 2	20 0.2	21 0.7	22 -0.6	23 0.3	24 -2
25 -3	26 -8	27 -0.7	28 1	29 2	30 1	31 -1
				days < normal 18	days > normal 13	Deg +/- normal -.2

above normal	below normal	Normals: 1990-2020

As seen in Figure 1, the Pacific Northwest experienced the largest departures from normal for average daily, minimum, and maximum temperatures for the month of July. This is also present in Figure 5, where many days of above normal temperatures were observed throughout the entire month, with the warmest periods coming during the first week of July and again in the last week of the month.

[12] National Weather Service (NWS Phoenix Twitter)

Figure 5: High temperature departure from normal for Northwestern EIM entities

Portland Gas and Electric (PGE)
High temperature departure from normal
July 2021

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
				1 -4	2 7	3 9
4 7	5 7	6 10	7 -5	8 -1	9 8	10 6
11 5	12 4	13 4	14 0.5	15 -4	16 -4	17 -1
18 4	19 5	20 -4	21 -8	22 -1	23 2	24 7
25 6	26 6	27 2	28 10	29 13	30 7	31 -1
				days < normal 10	days > normal 21	Deg +/- normal + 3.1

above normal | below normal | Normals: 1990-2020

Idaho Power Company (IPCO)
High temperature departure from normal
July 2021

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
				1 9	2 10	3 10
4 8	5 7	6 12	7 10	8 7	9 4	10 7
11 8	12 9	13 5	14 3	15 4	16 3	17 2
18 7	19 -2	20 -4	21 1	22 -3	23 -0.4	24 -0.2
25 2	26 5	27 3	28 1	29 2	30 -0.4	31 -4
				days < normal 7	days > normal 24	Deg +/- normal + 4

above normal | below normal | Normals: 1990-2020

Looking at the whole Western United States in Figure 6 below, there were some maximum temperature records which were tied or broken during the month of July. This is a significant reduction compared to what was observed in June 2021.

Figure 6: Maximum temperature records –July ^{t} through July 3^{t}, 2021[13]

Excessive heat, depending on the day of week, has the potential to bring load to the electrical system that may higher than those anticipated during long-term planning and forecasts about the supply expected to

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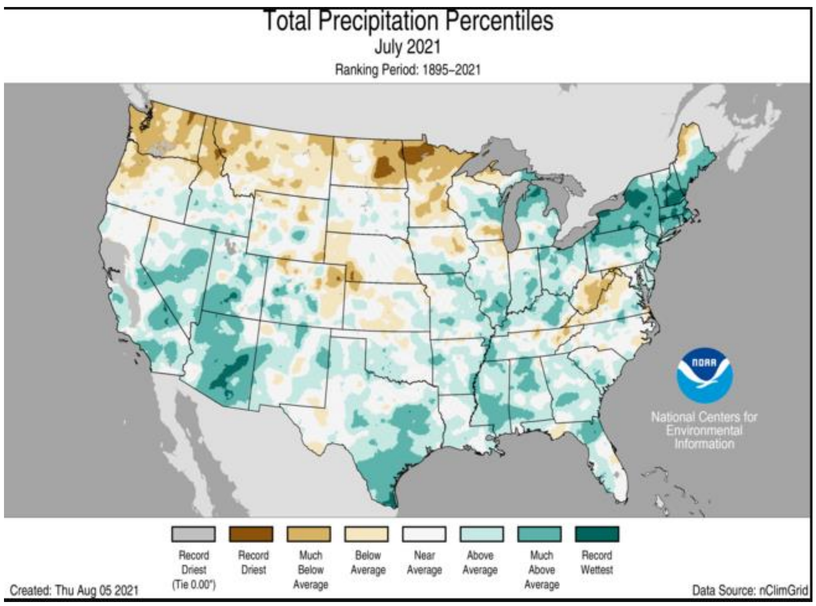
[13] https://www.ncdc.noaa.gov/cdo-web/datatools/records

be necessary to meet demand. In addition, during excessive heat events, supply resources (thermal and renewable) typically operate less efficiently, creating de-rates on the maximum energy that can be produced depending on the temperature and other characteristics, such as air flow.

7.2 Hydro conditions

The Western United States, including California, has experienced one of the driest water years on record. For the Northern Sierra 8-station index, the water year of October 2020 through May 2021 currently ranks third driest water year on record, with observed precipitation of 23.1 inches.[14] During the month of July, precipitation percentiles improved throughout the Southwestern United States due to monsoonal activity. The Pacific Northwest remained below average and continued to experience record driest conditions through the month of July. Figure 7 illustrates the total precipitation in the United States.

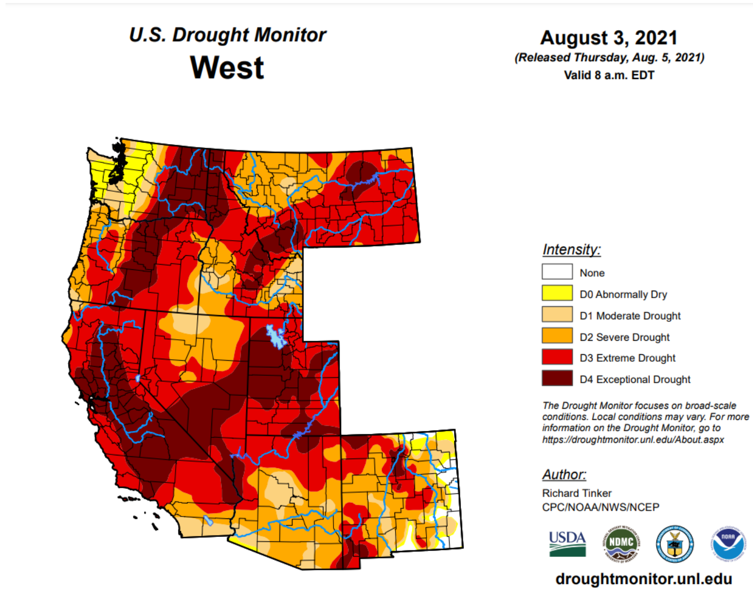
Figure 7: The United States total precipitation percentiles for July 2021[15]



Due to the lack of total precipitation throughout this water year, the majority of the Western United States remains in drought conditions, extending from abnormally dry to exceptionally dry. The extent of the drought coverage is shown in Figure 8 below.

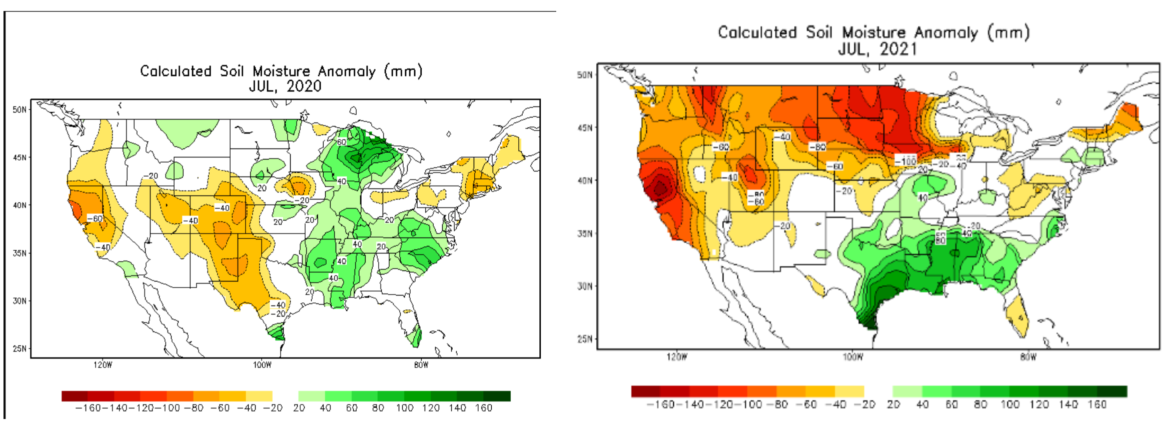
[14] Sacramento National Weather Service Spring 2021 Climate and Drought Summary
[15] https://www.ncdc.noaa.gov/temp-and-precip/us-maps/

Figure 8: The Western United States drought monitor[16]



As shown in Figure 9, drought conditions and reduced rainfall have also led to soil moisture that is much drier throughout the West for 2021 compared to 2020. This has reduced the amount of water flowing into the California reservoirs from the snowpack during the 2020 -2021 water season.

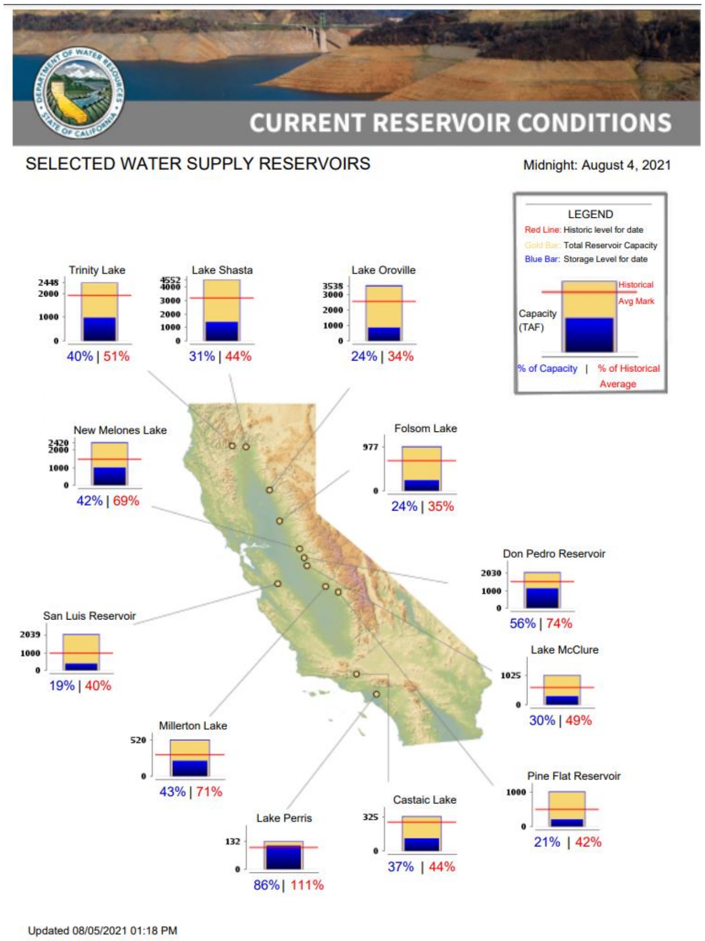
Figure 9: The United States soil moisture anomaly July 2020 vs July 2021[17]



Based on all the factors discussed above related to temperatures, precipitation, drought conditions, and soil moisture levels, reservoir conditions for California and the West are significantly below normal, as shown in Figure 10. The statewide storage in major reservoirs is currently 58 percent of average and at 39 percent of capacity[18].

[16] https://droughtmonitor.unl.edu/data/pdf/20210803/20210803_west_text.pdf
[17] https://www.cpc.ncep.noaa.gov/products/Soilmst_Monitoring/US/Soilmst/Soilmst.shtml#
[18] https://cdec.water.ca.gov/reportapp/javareports?name=STORSUM

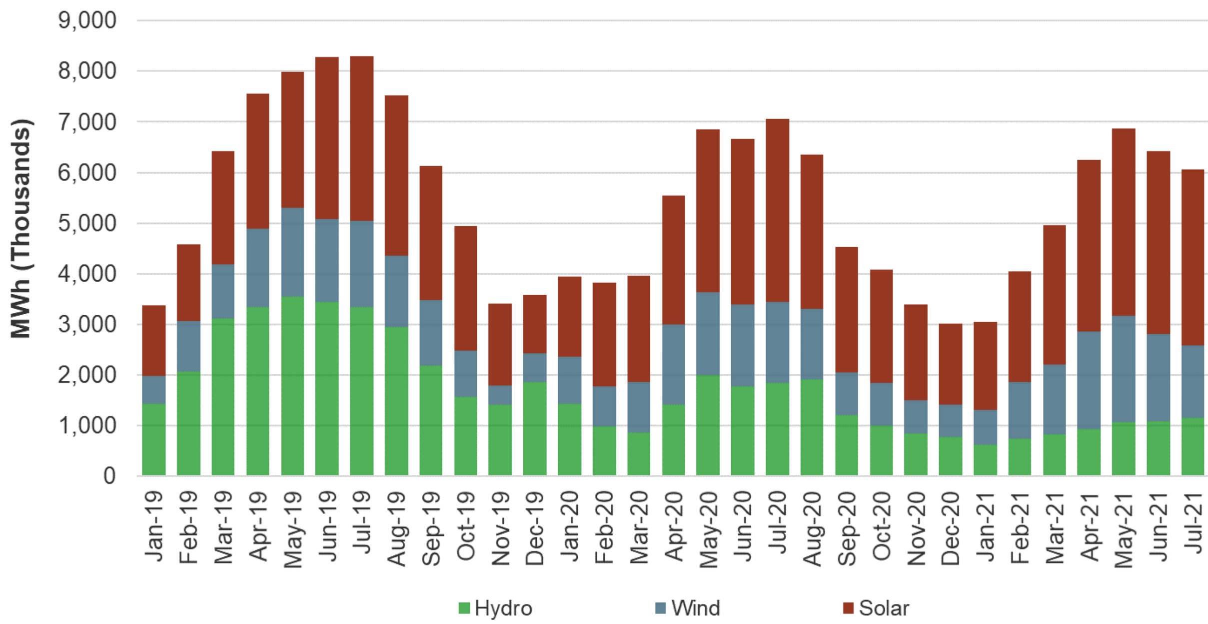
Figure 10: California's reservoir conditions as of July 2021[19]



The CAISO's electrical system utilizes hydro production throughout the year to meet the CAISO demand needs. Due to the significant reduction in available water capacity currently observed in the reservoirs and the expectation of deteriorating conditions throughout the summer, the CAISO is expecting significantly reduced capacity in hydro production this year. Figure 11 below shows the historical trend of total energy produced from hydro resources, as well as renewable resources, in which hydro production for 2021 so far has been significantly lower than the previous two years. Hydro production in July 2021 is about 63 percent of the production in July 2020, and 35 percent of the production in July 2019. In contrast, renewables production has grown over the three-year span. Although such conditions will reduce the overall available energy available over the summer, hydro resource operators typically strive to conserve their more limited water to provide peaking energy, which helps mitigate the adverse impact of limited hydro.

[19] Department of water resources. Available at https://cdec.water.ca.gov/cgi-progs/products/rescond.pdf

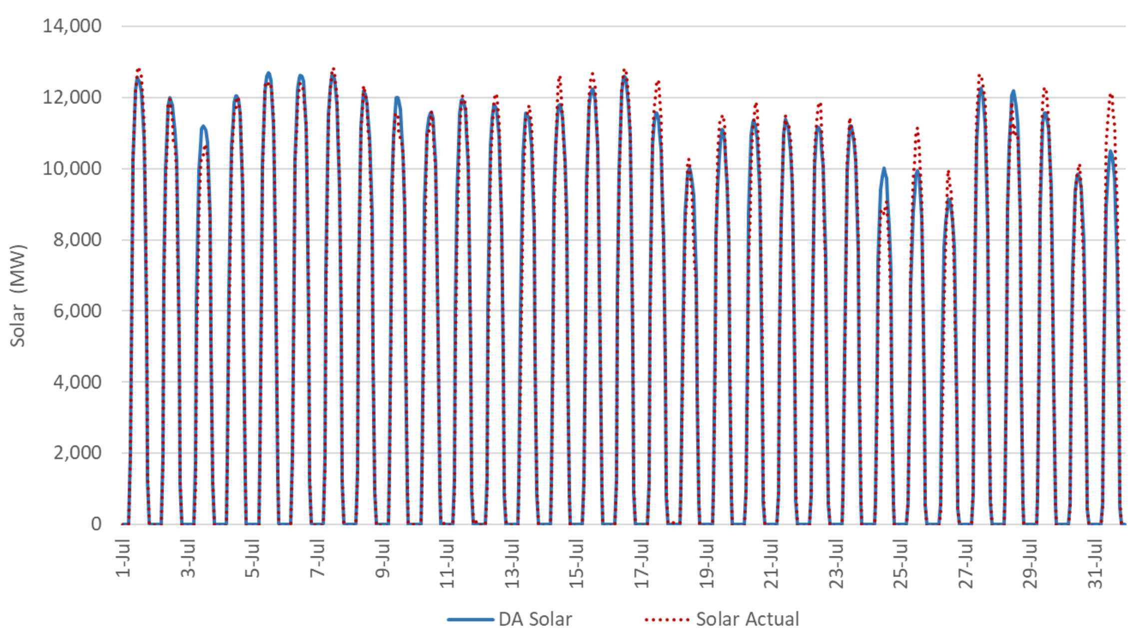
Figure 11: Historical trend of hydro and renewable production



7.3 Renewable forecasts

July 2021 led to a more typical summer pattern for both solar and wind forecasting, with accuracy values falling in the range of what has been observed during previous years for the month of July. Figure 12 and Figure 13 below show the solar and wind day-ahead renewable forecasts compared to actual plus supplemental dispatch.

Figure 12: Day-ahead solar forecasts for CAISO's area



Supplemental dispatch reflects the market's downward dispatch relative to the resource's forecast based on their bids. This allows the CAISO to measure the performance of the full-fuel forecast that is utilized in RUC and the real-time market optimization.

During the month of July, there was increased monsoonal moisture over the California mountain ranges, as well as the Desert Southwest, leading to increased cloud cover, rain showers, and thunderstorms. This caused more variable and reduced solar production. During these periods of increased monsoonal moisture, the day-ahead forecast for solar resources had greater uncertainty, as shown in Figure 13. Although there was some increased error compared to June, the average error[20] for the day-ahead solar forecast in June had a 2.5 percent mean absolute percent error and the average error for the day-ahead solar forecast in July was 3.02 percent. The average error observed in July 2021 is between the day-ahead solar forecast error observed for the month of July in 2019 and 2020[21].

Figure 13: Day-ahead wind forecasts for CAISO's area

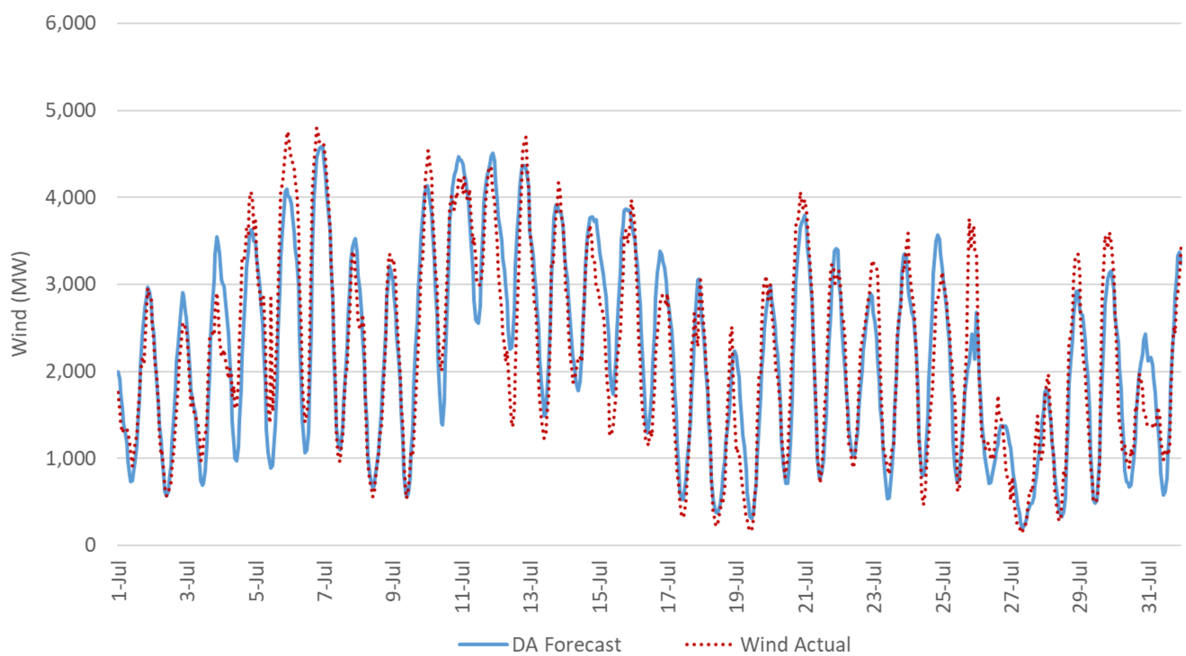


Figure 13 shows the day-ahead wind forecast compared to the actuals plus curtailments throughout the month of July for wind in the CAISO's system. The average error[22] for the day-ahead wind forecast in July was 4.77 percent. The average error observed in July 2021 is comparable to the day-ahead demand forecast error observed for the month of July in 2020 and lower than the day-ahead wind forecast error observed for July 2019.[23]

[20] Accuracy error is measured with the Mean Absolute Percentage Error (MAPE); ((Forecast-Actual)/Nameplate Capacity).
[21] http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Jun222021.pdf
[22] Accuracy error is measured with the Mean Absolute Percentage Error (MAPE); ((Forecast-Actual)/Nameplate Capacity).
[23] http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Jun222021.pdf

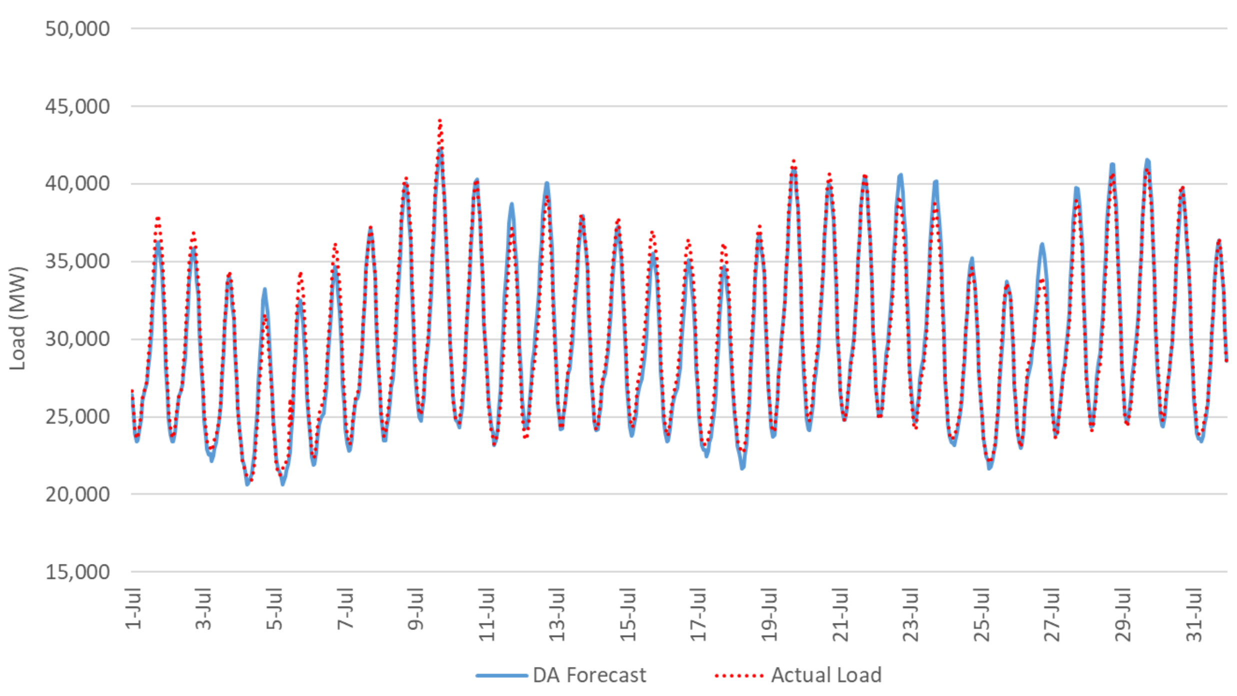
7.4 Demand forecasts

The CAISO produces load forecasts for the day-ahead and real-time markets for all areas participating in the CAISO markets.

7.4.1 CAISO's demand forecasts

The CAISO demand during the month of July 2021 was very responsive to the temperature changes observed throughout the month. Figure 14 shows the trend of the CAISO's load. The highest hourly average July load of 42,924MW[24] was observed on July 9, 2021 when the CAISO footprint was running 8 degrees F above normal for maximum temperatures. The maximum hourly average load observed within a single hour in July 2021 was 593 MW under the CEC month ahead forecast for July Peak of 43,517 MW. During the month of July, the CAISO called on demand response in addition to issuing a Flex Alert for July 9, July 10, July 12, and July 28. These actions have been accounted for in the Actual Load displayed below to compare the Day-Ahead (DA) forecast against what actuals would have been based on the estimated response from Demand Response as well as the Flex Alerts. Further details on the Flex Alert analysis is described below in the section titled Impact of Energy Conservation.

Figure 14: Day-ahead demand forecast for CAISO's area



The average accuracy error[25] for the day-ahead demand forecast in July was 1.99 percent, while the error for peak hours was 2.44 percent. The average error observed in 2021 is comparable to the day-ahead demand forecast error observed for the month of July in 2019 and 2020. Looking at the month of July, increased error in the Day-Ahead forecast was observed during July 15th through July 17th. The errors

[24] Averaged Hourly Load Value is CAISO System TAC at the peak hour, please note at the peak hour there was 475 MWs of scheduled and cleared demand Response.

[25] Accuracy error is measured with the Mean Absolute Percentage Error (MAPE); ((Forecast-Actual)/Actual).

observed during July 15th through July 17th were due to temperatures coming in warmer than expected throughout the state as well as model error present in some regions throughout the CAISO footprint. Table 2 and Table 3 below detail the range of the error by region.

Table 2: Temperature error for July 15, 2021

Weather Regions	Forecast Max	Actual Max	Deviation	Forecast Min	Actual Min	Deviation
PGE Bay	75	74	-1	57	56	-1
PGE Non Bay	89	88	-1	59	60	1
SCE Coast	77	81	4	67	68	1
SCE Inland	96	98	2	71	74	3
SDGE	82	84	2	62	64	2
CAISO (weighted)	85	86	1	64	65	1

Table 3: Temperature error for July 16, 2021

Weather Regions	Forecast Max	Actual Max	Deviation	Forecast Min	Actual Min	Deviation
PGE Bay	77	80	3	56	56	0
PGE Non Bay	91	92	1	58	58	0
SCE Coast	77	78	1	66	67	1
SCE Inland	97	98	1	69	71	2
SDGE	82	84	2	62	62	0
CAISO (weighted)	86	87	1	63	64	1

7.4.2 EIM area demand forecasts

Similar to load in the CAISO area, demand in other EIM areas was very responsive to temperature changes experienced throughout the month of July. Figure 15 to Figure 17 below show the impact of the differing heat events described within the weather section above throughout the EIM footprint areas. The graphs in the figures capture the sum of the maximum energy demand by day grouped by geographical regions.

Similar to the CAISO area, the Southwestern EIM areas observed peaking conditions during the July 6 through July 11 heatwave, while the EIM in the Coastal Pacific Northwestern peaked during the end of July. The Mountain Northwestern areas saw a less pronounced trend, even though this area also peaked around July 7, 2021.

Figure 15: Demand actuals for Southwestern EIM areas

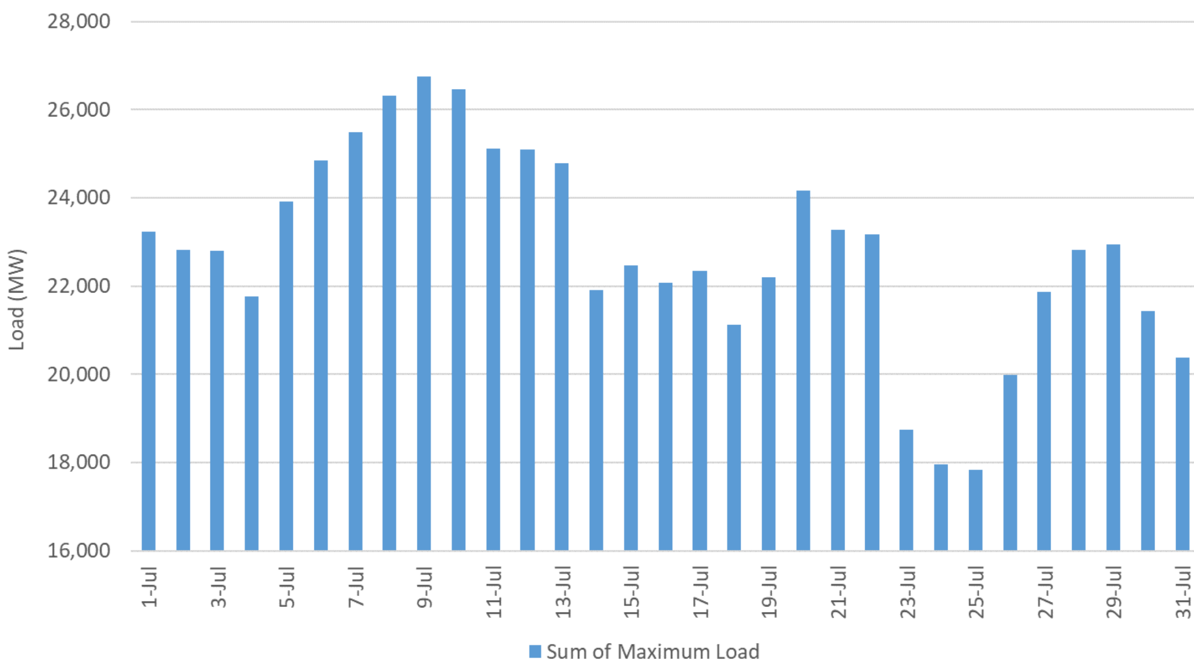


Figure 16: Day-ahead demand actuals for Coastal Pacific Northwest EIM areas

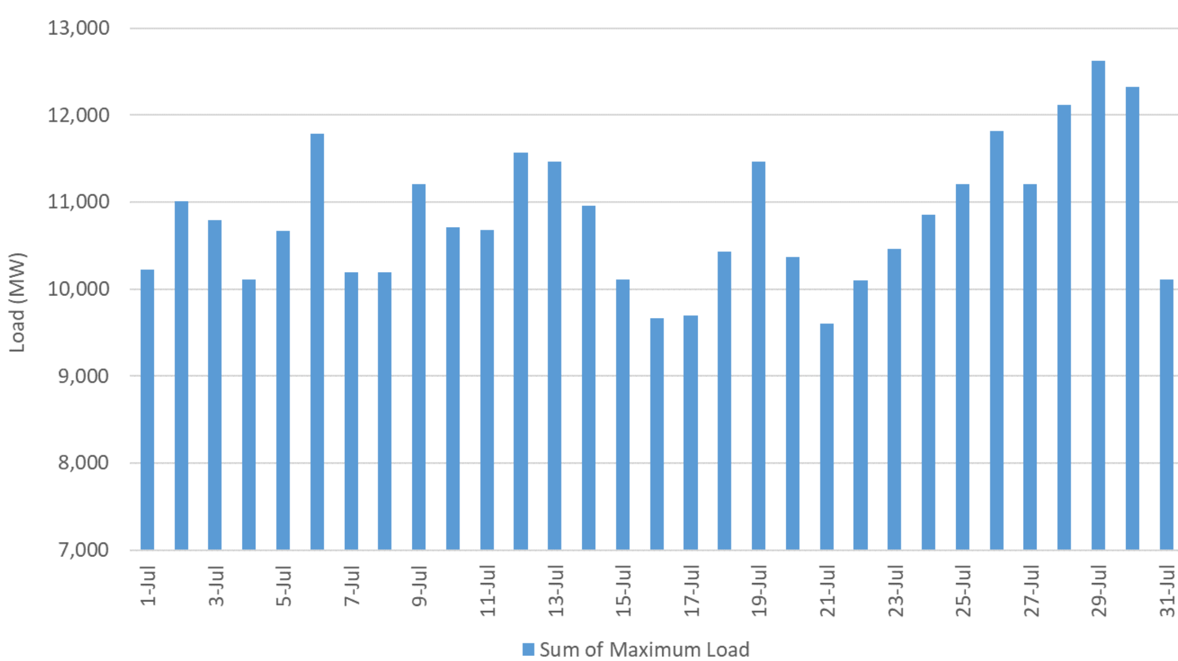
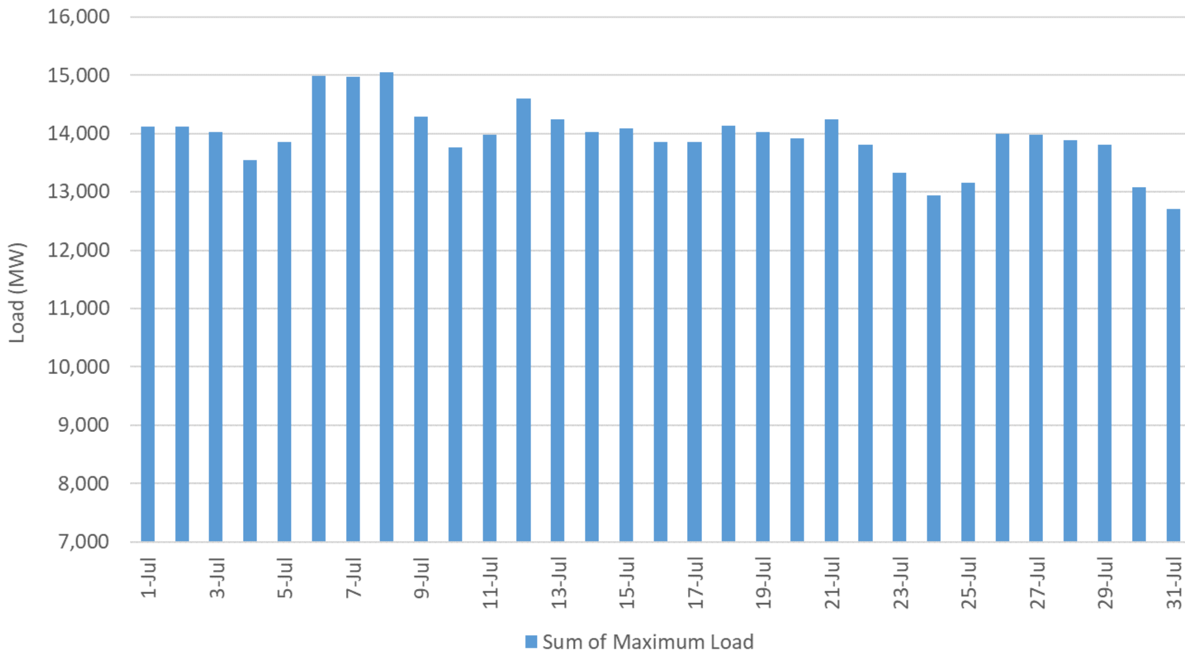


Figure 17: Day-ahead demand actuals for Mountain Northwest EIM areas



7.5 Impact of energy conservation

The CAISO issued Flex Alerts[26] to assist in meeting the net load peak on July 9, July 10, July 12, and July 28. In addition, on July 9, 2021, California Governor Newsom signed an emergency proclamation to free up additional energy capacity in the midst of the heat wave, which also impacted conservation responses.[27] The estimated response to Flex Alerts looks at the back-casted model results, taking actual weather and behind the meter (BTM) solar conditions into account. This allows the CAISO to isolate weather and BTM solar error within the demand forecast. In addition, the CAISO also estimates the hourly model error that exists looking at similar day model performance.[28] Table 4 summarizes the estimated Flex Alert range of conservation, which fluctuates based on hourly impacts during the declared Flex Alert. On July 9 and July 28, 2021, Flex Alerts had a limited impact on the overall energy demand. During July 10, 2021 the hourly conservation impacts from the Flex Alerts ranged from 18 MW to 190 MW, with the biggest impacts observed during HE 18 and 19. On July 12, 2021 the hourly conservation impacts ranged from 380 MW to 940 MW, with the biggest impacts observed in HE 18 through HE 20. The beginning of both events showed lower conservation impacts. These observations are illustrated in Figure 18. Due to the emergent conditions on July 9, the Flex Alert could not be issued in advance within the day-ahead timeframe; this may have been the cause for the limited effectiveness of the alert and requests for conservation.

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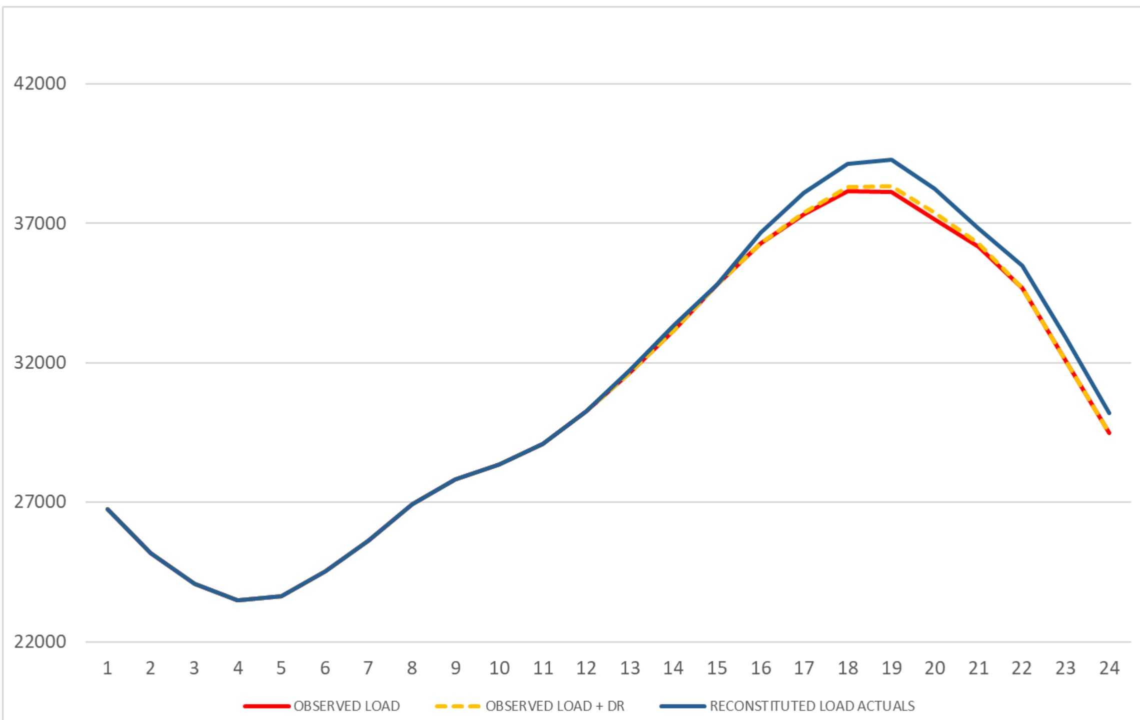
[26] The Flex Alerts for July 9, 10, 12, and 28 were effective from 4pm to 9pm.
[27] https://www.gov.ca.gov/wp-content/uploads/2021/07/Extreme-Heat-Proc-7-8-21.pdf
[28] Note Flex Alert conservation values are an estimated value and do have uncertainty associated with the result.

Table 4: Estimated Flex Alert impact

Date	Conservation
July 9th, 2021	None Observed
July 10th, 2021	18-190 MWs
July 12th, 2021	380-940 MWs
July 28th, 2021	0-100 MWs

Further details of the estimated savings can be seen during the net load peak hours in Figure 18 below for July 12, 2021.

Figure 18: Flex Alert impact for July 12, 2021



8 Demand and Supply

8.1 Resource adequacy

The CAISO manages the resource adequacy (RA) program established by the CPUC for its jurisdictional load serving entities (LSEs), which include Investor Owned Utilities (IOUs), Community Choice Aggregators (CCAs) and Energy Service Providers (ESPs). Collectively, these LSEs cover about 90 percent of CAISO's load. The RA program ensures through contractual obligations that there is sufficient supply capacity to meet the system's needs and to operate the grid reliably. The CPUC RA program sets and enforces the program's rules within the jurisdictional LSE's footprint. This program also includes setting the monthly obligations based on an electric load forecast and planning reserve margin (PRM). The California Energy Commission estimates the electric load forecast used by the CPUC in its RA program. Non-CPUC jurisdictional LSEs can set their own RA program. RA capacity from both CPUC and non-CPUC jurisdictional LSEs is shown to the CAISO annually and monthly following a process established by the CAISO.

Through the RA program, there are three types of capacity: System, Local and Flexible. All three products serve a purpose in ensuring a reliable operation of the system. The events of August 2020 were primarily a result of insufficient system RA since it was a condition of insufficient supply to meet the overall system demand. For system capacity, the RA requirement ensures the contracted capacity is sufficient to cover the 1-in-2-year (average) peak load plus a 15 percent PRM.[29] This PRM is to cover the 6 percent of operating reserves while the rest is a contingent headroom to account for higher-than-expected load forecast and resource outages.

The monthly RA showing for July 2021 was 49,780 MW, which is slightly higher than July's 2020 monthly showing of 48,691 MW.[30] Figure 19 compares the total monthly RA capacity in July 2020 and July 2021 by fuel type. Although the total RA capacity in 2021 is 1089 MW higher than that of 2020, there are some marked variations in the RA composition. RA capacity increased by 622 MW in gas and 513 MW from solar, and reduced by 307 MW in hydro and 608 MW in imports. RA capacity from storage resource increased by 782 MW. The hydro reduction is expected given drought conditions materializing in 2021.

Static RA imports decreased from 3,753 MW in July 2020 to 3,145 MW in July 2021.[31] The composition by intertie varied between years as shown in Figure 20; RA imports through Malin decreased from 1,790 MW to 1,535 MW from July 2020 to July 2021 while imports through NOB decreased from 1,067 MW to 794

[29] The official planning reserve margin is 15 percent for the CPUC jurisdictional entities. Per Decision 21-03-056, the CPUC increased the "effective" planning reserve margin to 17.5 percent for 2021 and 2022 but this is met with both RA and above RA resources that may also not be in the wholesale market.

[30] These values are based on the monthly showings estimates available at the time of preparing this report. These monthly showings are provided through the supply plans in order to meet the final RA obligation. The final RA obligation is composed by the forecast plus PRM and then all credits, including DR, are deducted. The total RA values can change through the month, with weekend showing typically a significant reduction. For simplicity in the reporting and comparison, the simple average through the month is used as a reference in this report. Also, the total RA values represented in this report include any CPM and RMR capacity.

[31] Dynamic and pseudo tie resources are grouped into the corresponding fuel type instead of the generic import group. Generic imports are referred as Static imports in this report.

MW across the same timeframe. Imports on Malin and NOB account for about 74 percent of all static RA imports.

Figure 19: July 2021 RA organized by fuel type

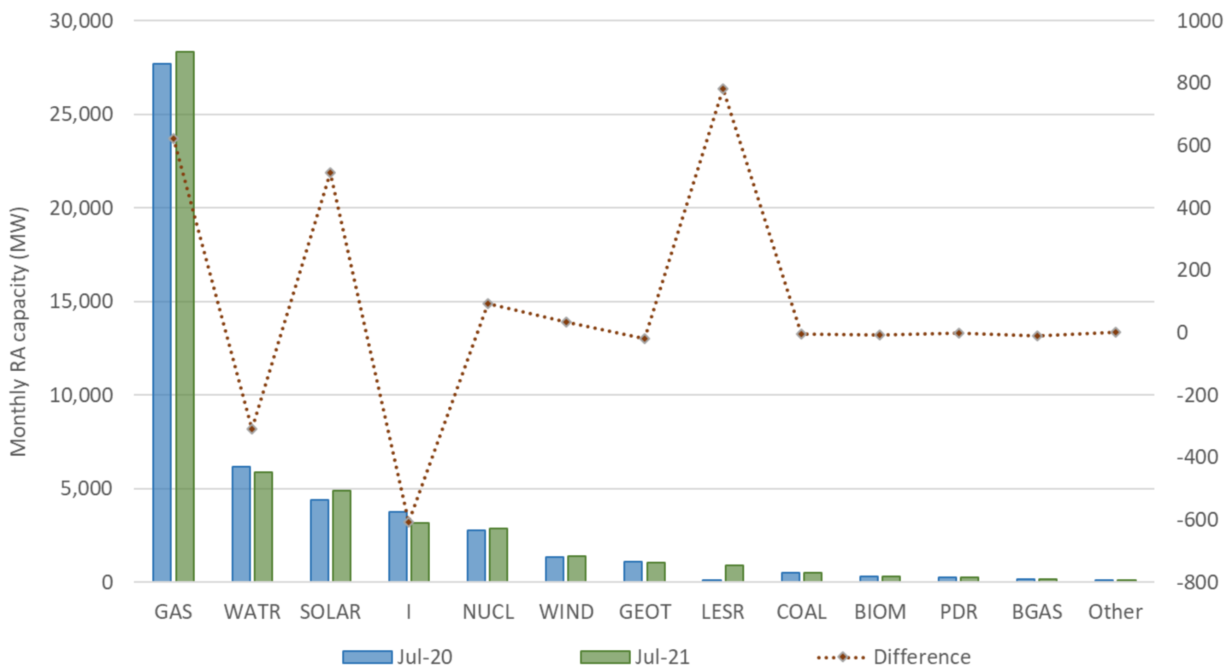
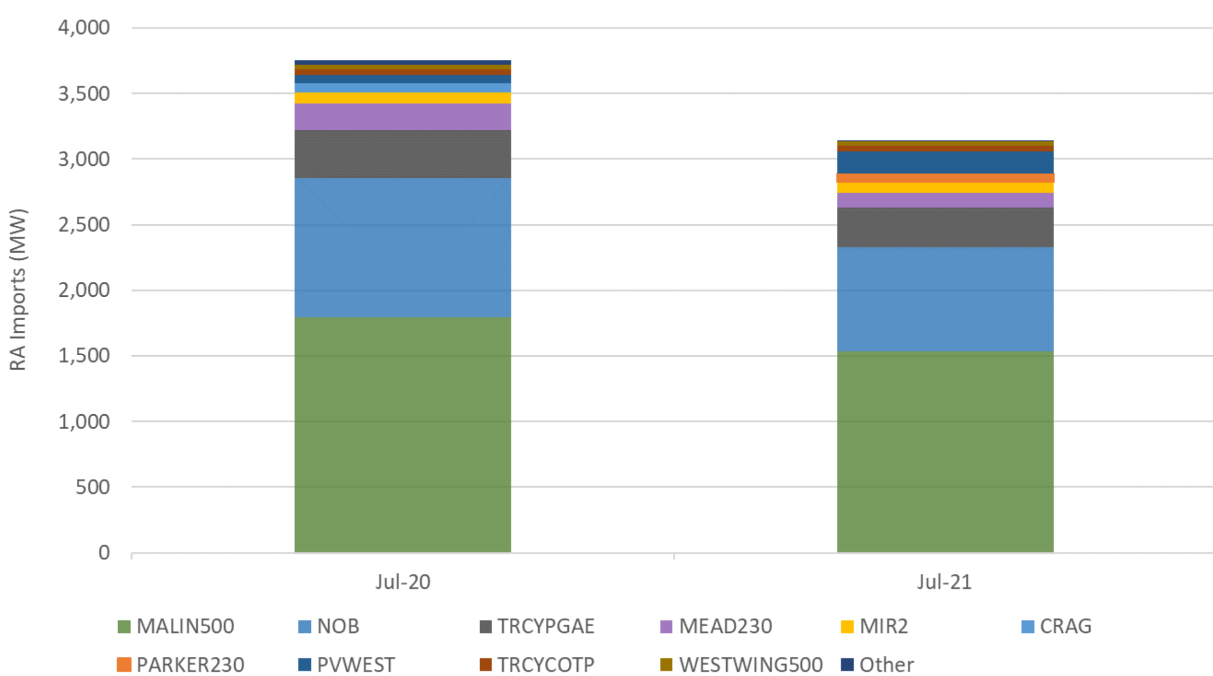


Figure 20: Monthly RA organized by tie



The RA capacity shown to the CAISO for August 2021 was 48,512 MW. RA imports declined in August 2021 to 3,283 MW relative to 4,485 MW of August 2020. However, RA imports in August were higher than RA imports in July 2021. These trends are shown in Figure 21 and Figure 22.

Figure 21: Monthly RA showings

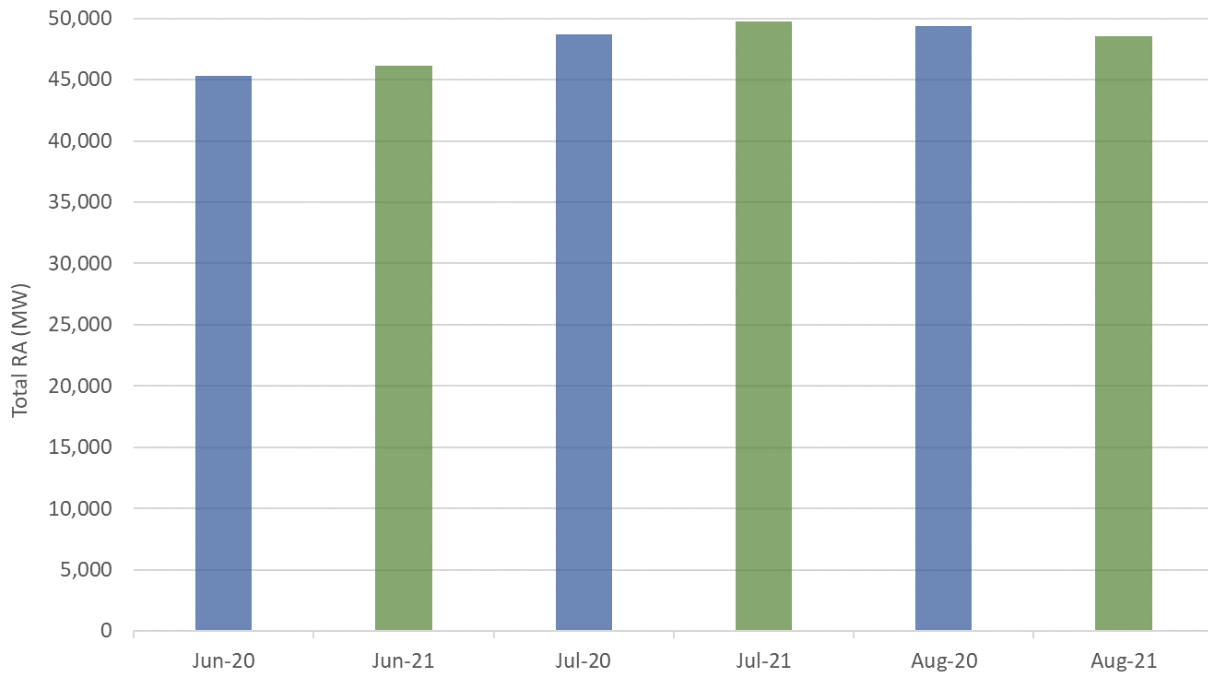
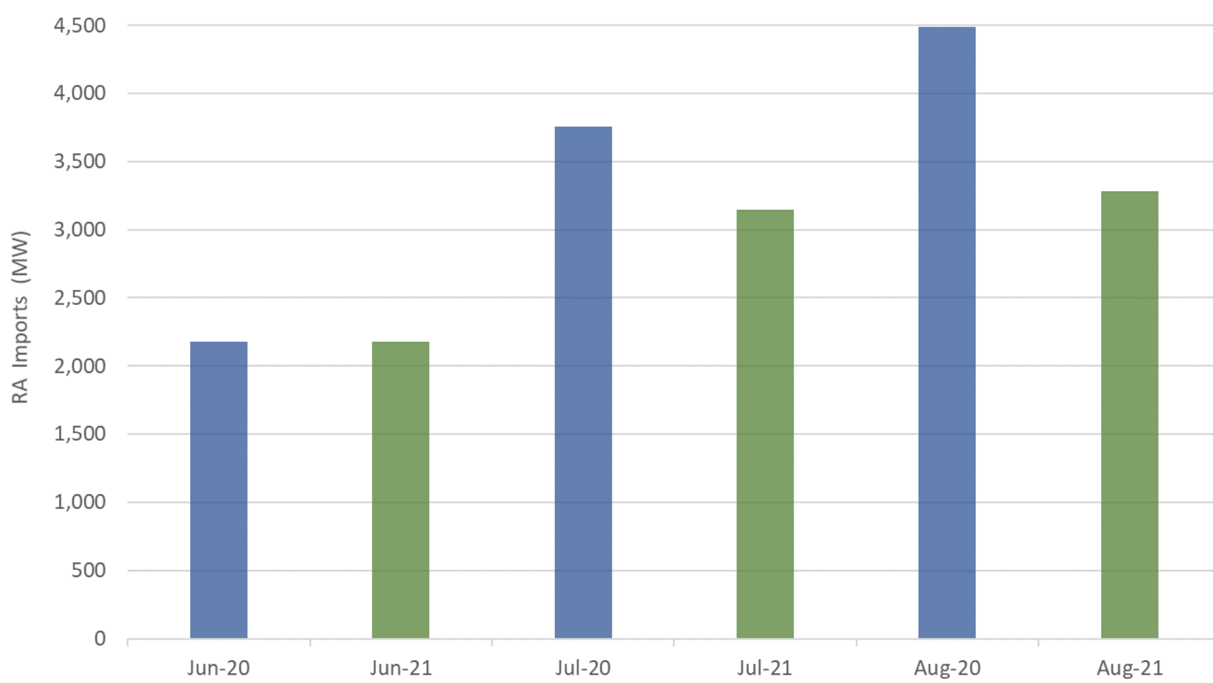


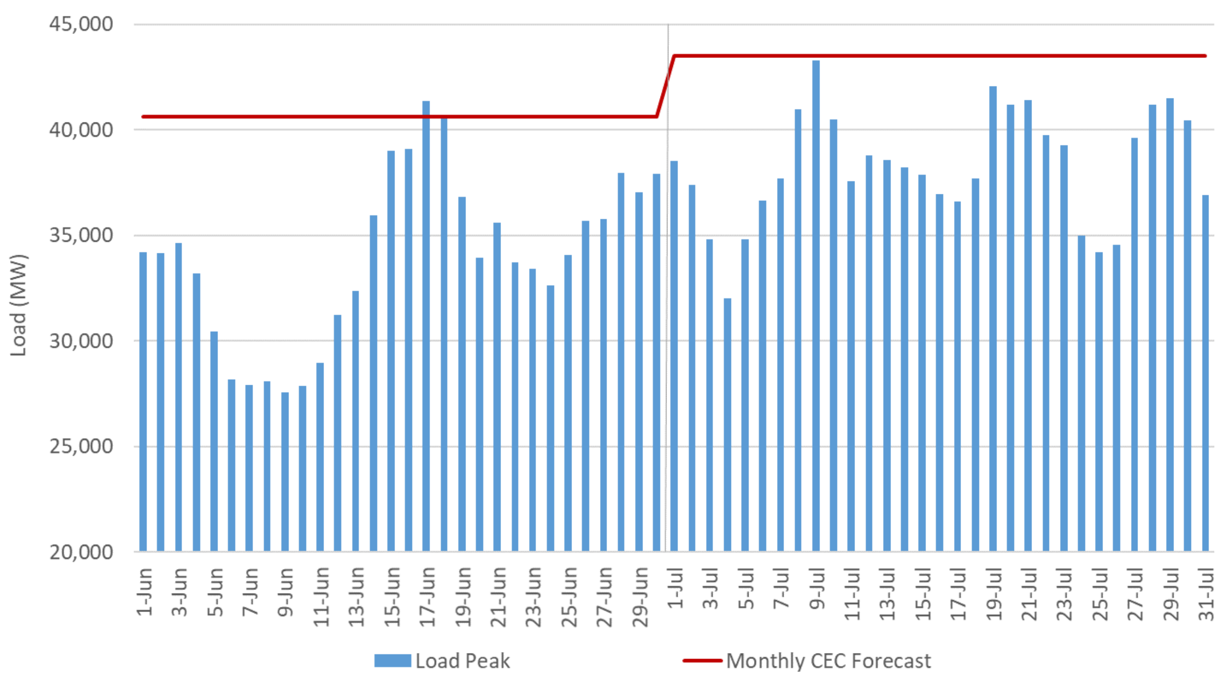
Figure 22: Monthly trend of static RA Imports



8.2 Peak loads

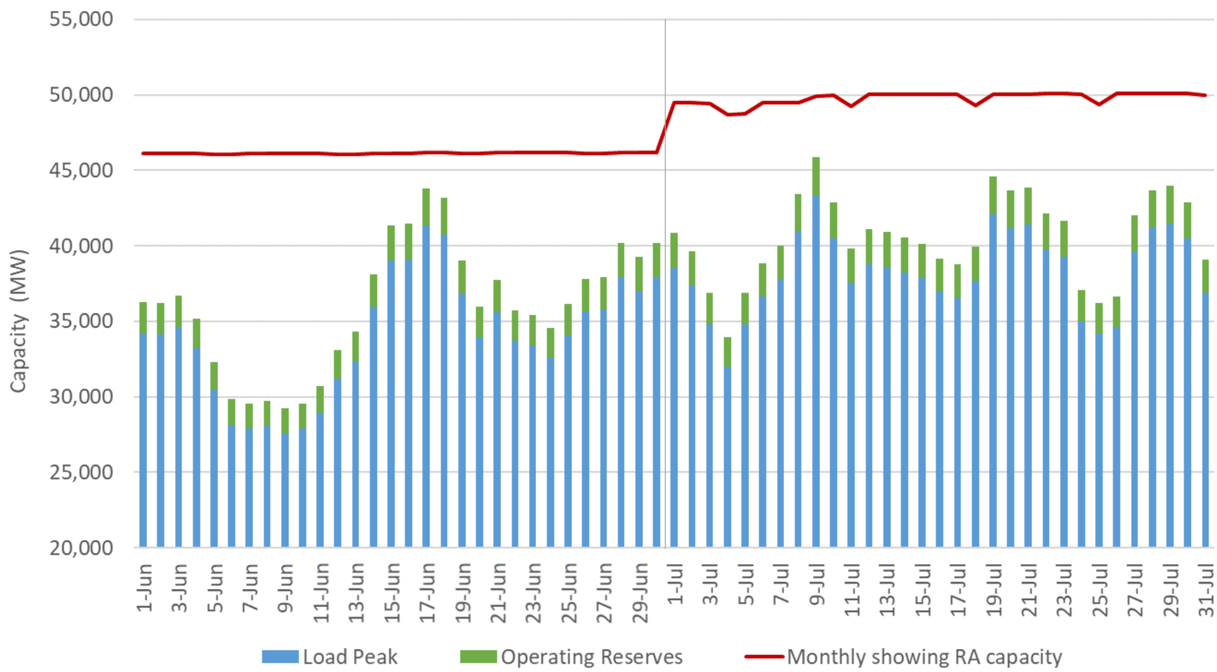
Peak loads in July 2021 exceeded 40,000 MW in multiple days. The average peak load in June was about 33,990 MW and increased to an average of 38,260 MW in July. The peak load on July 5 came in as low as 32,000 MW but quickly rose to 43,285 MW on July 9 due to heat conditions. For subsequent days, load trended down. So far in 2021, July 9 has been the peak day of the year. Figure 23 shows the five-minute daily load peak for the months of June and July 2021 in comparison to the CEC month ahead forecast used to assess the resource adequacy requirements. Actual load of 43,285 MW did not exceed the CEC month-ahead forecast of 43,517 MW in July.

Figure 23: Daily peaks of actual load in June and July



The actual load did not exceed the monthly RA showings for the month of July 2021 as a whole, as illustrated in Figure 24. The red line indicates nominal monthly RA showings. As discussed later in this report, the actual capacity made available into the CAISO's market (accounting for outages and other factors) during July 2021 was generally lower than the nominal RA monthly showings but generally was above the load forecast plus operating reserves. In subsequent sections, the actual RA capacity made available in the market is represented as a trend over for the month on an hourly basis, which more accurately represents RA capacity available to meet demand.

Figure 24: Daily peaks and RA capacity for June and July 2021



8.3 Market prices

Market prices naturally reflect supply and demand conditions; as the market supply tightens, prices rise. Locations marginal prices have three components: the marginal cost of energy on the system, the marginal cost of congestion reflecting constraints, and the marginal cost of losses. The marginal energy component reflects the impact of supply and demand conditions. Congestion conditions may also create local or regional price separations. Figure 25 compares the average prices across CAISO's markets.[32] Naturally, prices increased during the period of the first heat event around July 9 and at the end of July. In the month of July, day-ahead prices were generally higher than real-time prices, but on July 9, real-time prices were higher than day-ahead prices. This was the result of much tighter supply conditions in the real-time market when imports on Malin and NOB were derated due to fires. Figure 26 shows average daily prices across markets in June and July; price divergence can be observed primarily in the peak hours.

[32] Default Load Aggregation Point (DLAP) prices are a good indicator of overall prices. However, congestion may create price separation among DLAPs. The metrics presented here are based on a weighted average price of the DLAPs within the CAISO area.

Figure 25: Average daily prices across markets

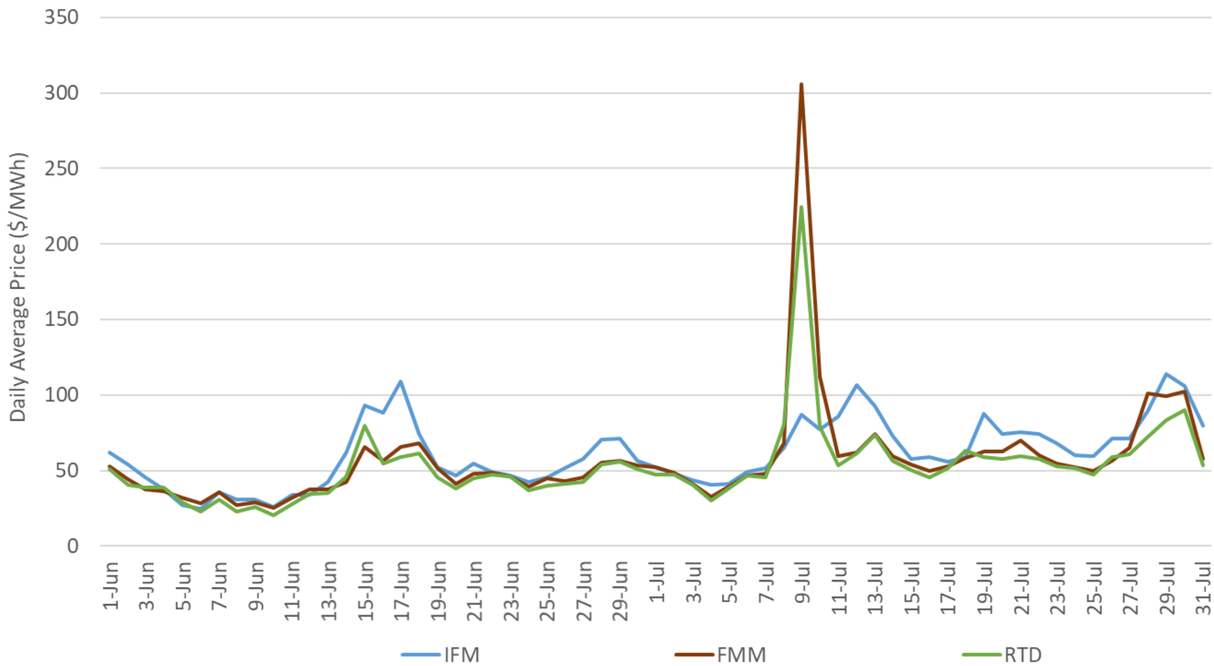


Figure 26: Average hourly prices across markets

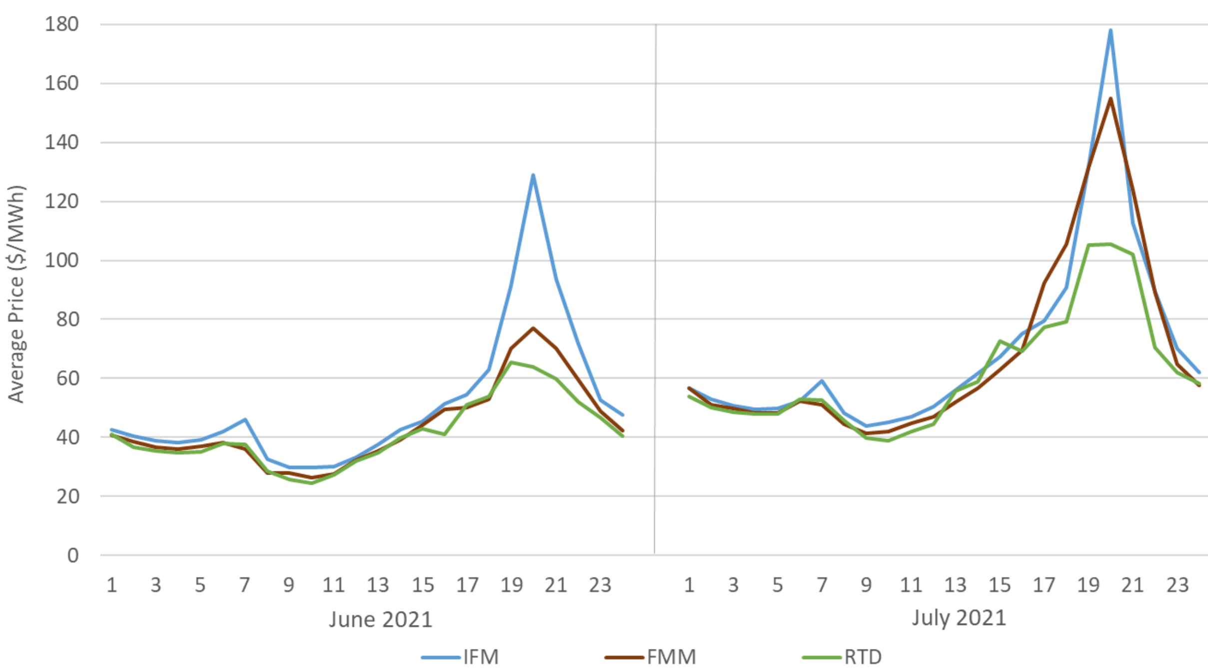


Figure 27 and Figure 28 show the daily and hourly distribution of June and July day-ahead prices with box-whisker plots. The whiskers represent the maximum and minimum prices in a given day or hour, while the boxes represent the 10th and 90th percentile of the prices. The red dots represent the average prices for the day. These plots better illustrate the full distribution of prices in the months of June and July. Prices in July were comparable to prices in June, with July 9 observing the highest price in the month of about $517/MWh.

Figure 27: Daily distribution of IFM prices

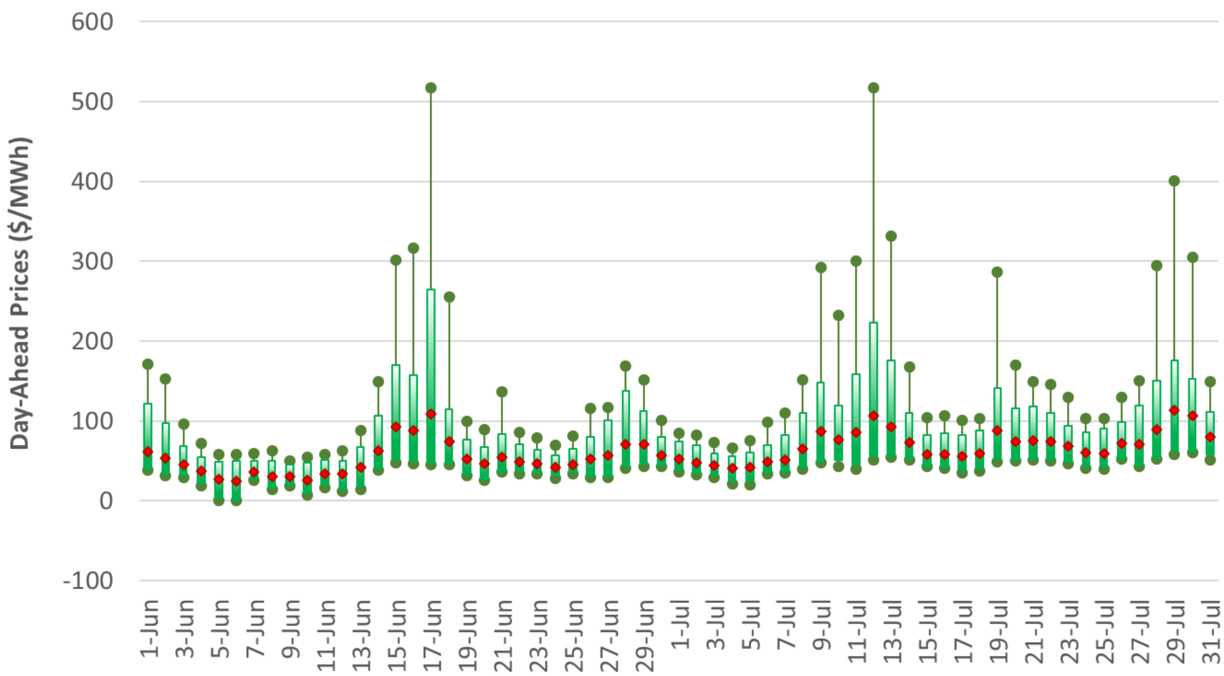
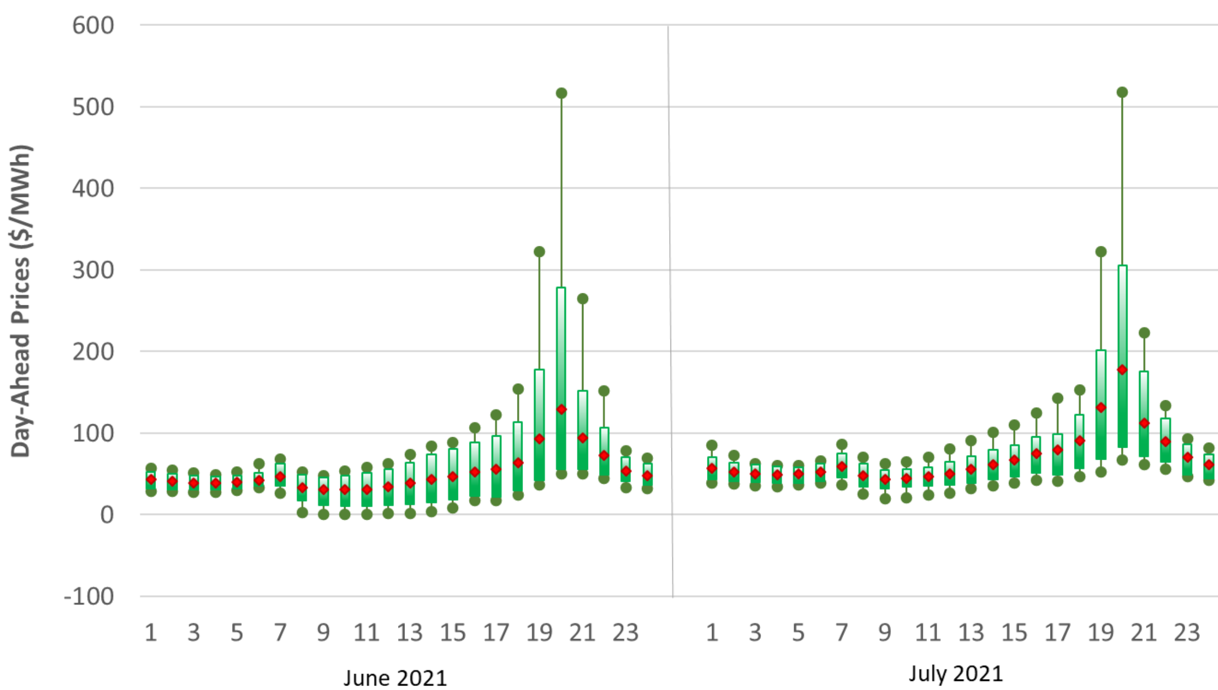


Figure 28: Hourly distribution of IFM prices in July



Similarly, Figure 29 and Figure 30 show distributions of real-time (FMM) prices in June and July. The day-ahead prices exhibit a larger spread, mainly in the days and hours when higher demand occurred. In contrast, real-time prices show a narrower distribution under $100/MWh with a few outliers. Given the dynamic conditions of real-time, such price excursions are expected to happen even though they are short in duration.

Figure 29: Distribution of FMM prices by day

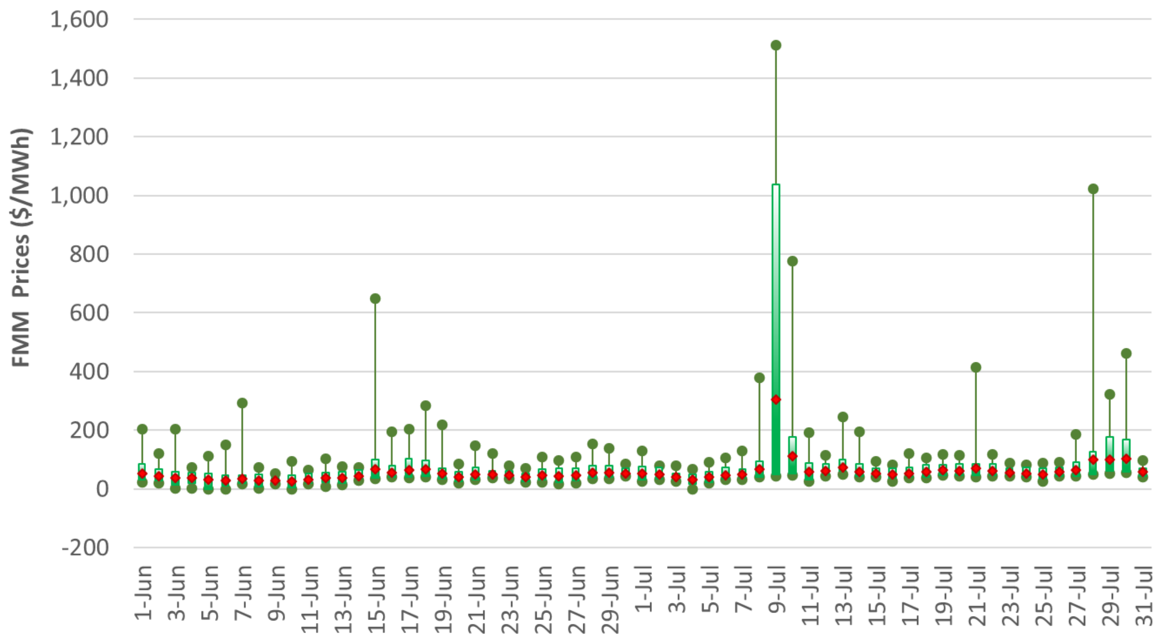
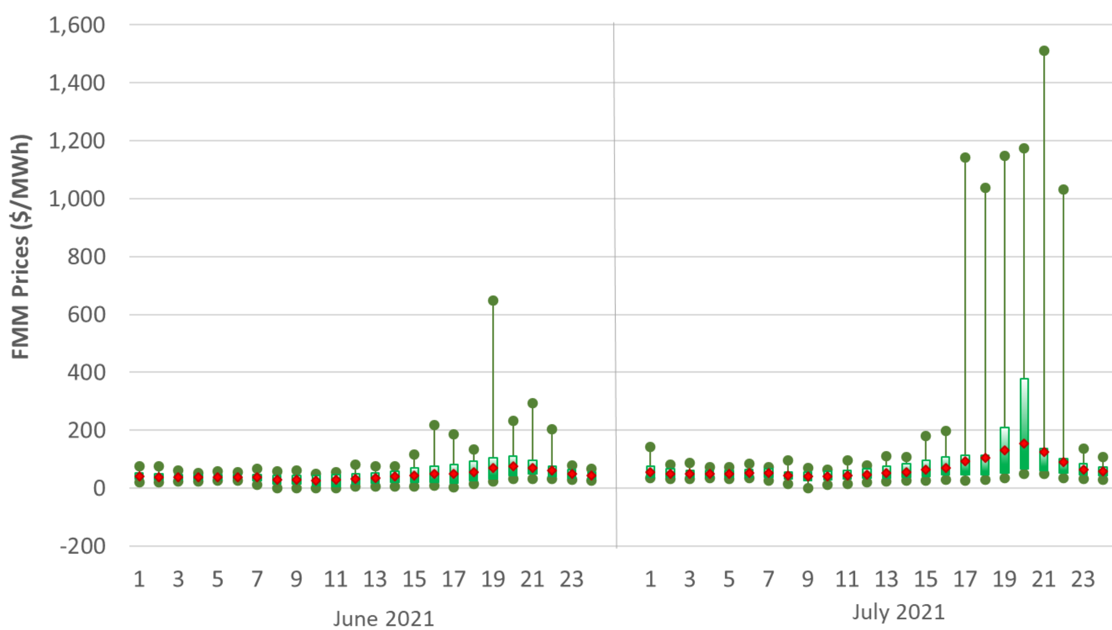


Figure 30: Distribution of FMM prices by hour



With the CAISO's generation fleet consisting of a meaningful share of gas resources, dynamics from the gas market and system can typically have an impact on the electric market. Electricity prices generally track gas prices. Figure 31 shows the average prices (bars in blue and green), and the maximum and minimum prices (whiskers in purple), for the two main gas hubs in California. Gas prices in July were higher than in June. The average price in July for PG&E Citygate was $5/MMBtu and was $6.26/MMBtu for SoCal Citygate.

Figure 31: Gas prices at two main California hubs

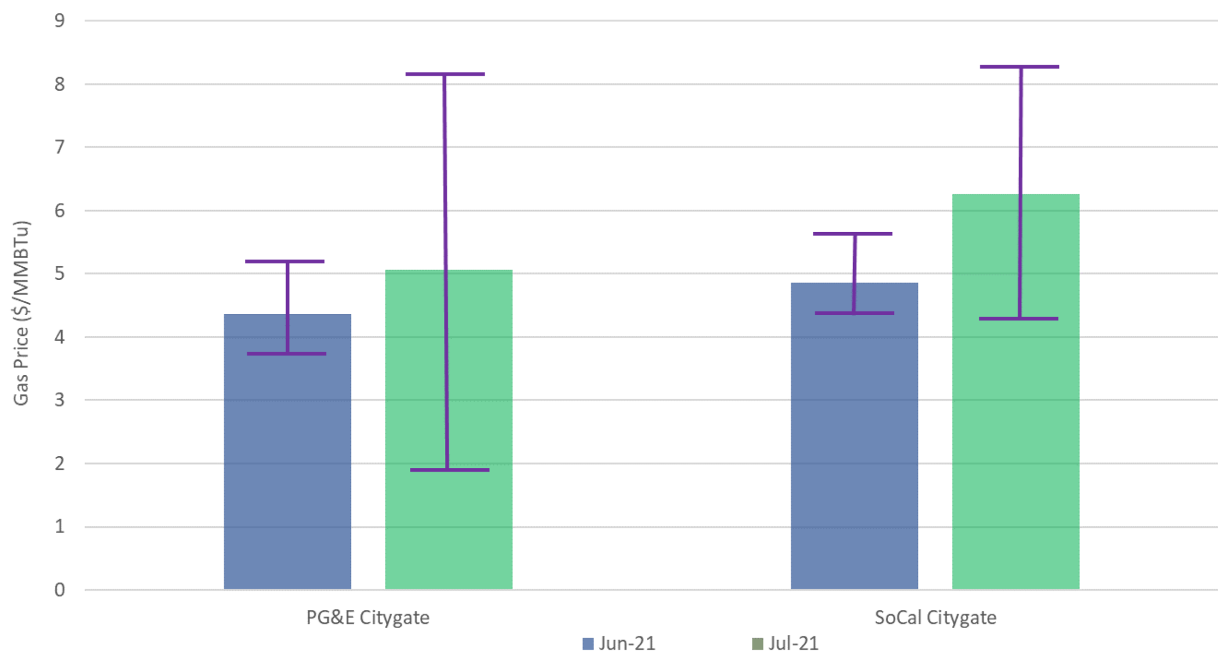
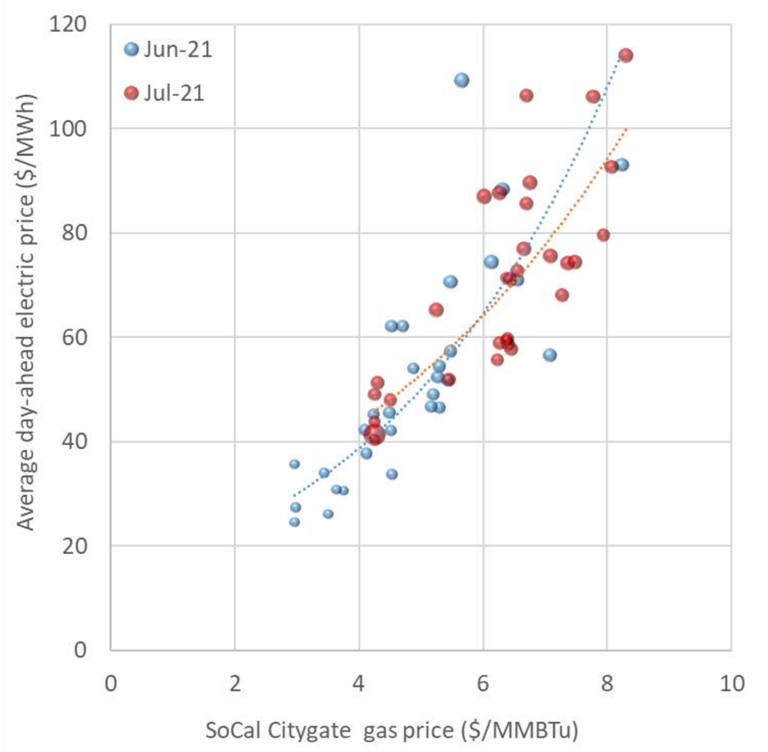


Figure 32 shows daily average electricity prices from the CAISO day-ahead market (y-axis) relative to next-day gas prices at SoCal Citygate (x-axis) and the peak load (size of the bubbles) on a daily basis for July. Peak loads ranged widely and this comparison exhibits a good degree of correlation between electricity and gas prices. In addition, it can be observed that electricity prices rise when load levels are higher.

Figure 32: Correlation between electricity prices, gas prices and peak load level



9 Bid-In Supply

The CAISO's markets rely on supply made available from different resources, including internal supply of various technologies and imports. Supply capacity is bid into the market with three components: startup costs, minimum load costs and incremental energy costs. The bid-in capacity is adjusted for any outages and derates on an hourly basis to reflect the actual available supply. That available bid-in capacity is then considered in the market optimization along with the resource's characteristics and system constraints. In addition to supply capacity from RA resources, the market also considers bid-in supply from above RA resources. This supply does not have an RA obligation but economically and voluntarily participates in the CAISO's markets. Based on the submitted bids, the market will optimally determine the least-cost dispatch of all resources to meet the bid-in demand in IFM or the load forecast in RUC. It is not unusual that above RA capacity be dispatched before all the RA capacity is exhausted since resource dispatches are based entirely on prices and resource characteristics and system conditions, and there is no merit order based on whether they are RA or not.

In the RA program, there are certain qualifiers for a resource's capacity to be eligible to count towards meeting the RA requirements. The CPUC developed a Qualifying Capacity (QC) requirement based on what a resource can produce during peak load hours. For conventional resources such as gas and hydro, the QC value is based on maximum output of the resource. For wind and solar resources, the QC values are based on a statistical methodology known as effective load carrying capability (ELCC). This approach will estimate QC values for wind and solar significantly below their maximum output. Resources are then assessed for deliverability to determine their net qualifying capacity, which is ultimately what is used to determine their RA capacity.

9.1 Supply and RA Capacity

Since the summer 2020 events, the CAISO has been tracking whether RA capacity available in the CAISO's markets could be sufficient to meet the needs of both load and operating reserves. To assess this condition, all supply capacity is classified accordingly relative to its monthly RA value. For any wind or solar resource that has any RA capacity assigned in the month, the entire supply available in the market from that resource is considered RA. For instance, if a solar or wind resource has a supply available in the day-ahead market for 100 MW in a given hour and its RA capacity is 30 MW, the full 100 MW are considered RA capacity. For any other type of resource such as gas, hydro or imports, RA capacity is determined up to the RA monthly value; any capacity above the RA value is considered or above RA.

Figure 33 shows the breakdown of the day-ahead supply capacity[33] as RA capacity and above RA capacity. The black dotted line is a reference of the nominal RA showings for the month, which stays relatively consistent for July. The purple line represents the day-ahead load forecast plus the capacity required to meet operating reserves (OR), which is typically about 6 percent of the load value. The dashed line represents the adjusted load forecast plus OR plus export self-schedules, which represents the overall

[33] This capacity is assessed based on the supply bid in the market and reflects any outages or derates of resources as long as they are known and recorded before the market is run.

need to be met in the day-ahead market. Figure 34 has the same capacity breakdown but the comparison is relative to the net load (gross load minus VER forecast). Since this figure represents net load, the supply side is also reduced by subtracting all VER contributions. Tracking the available capacity for the net load peak hour is as important as tracking available capacity for the gross peak hour.

Figure 33: Supply capacity available relative to load forecast in the day-ahead market

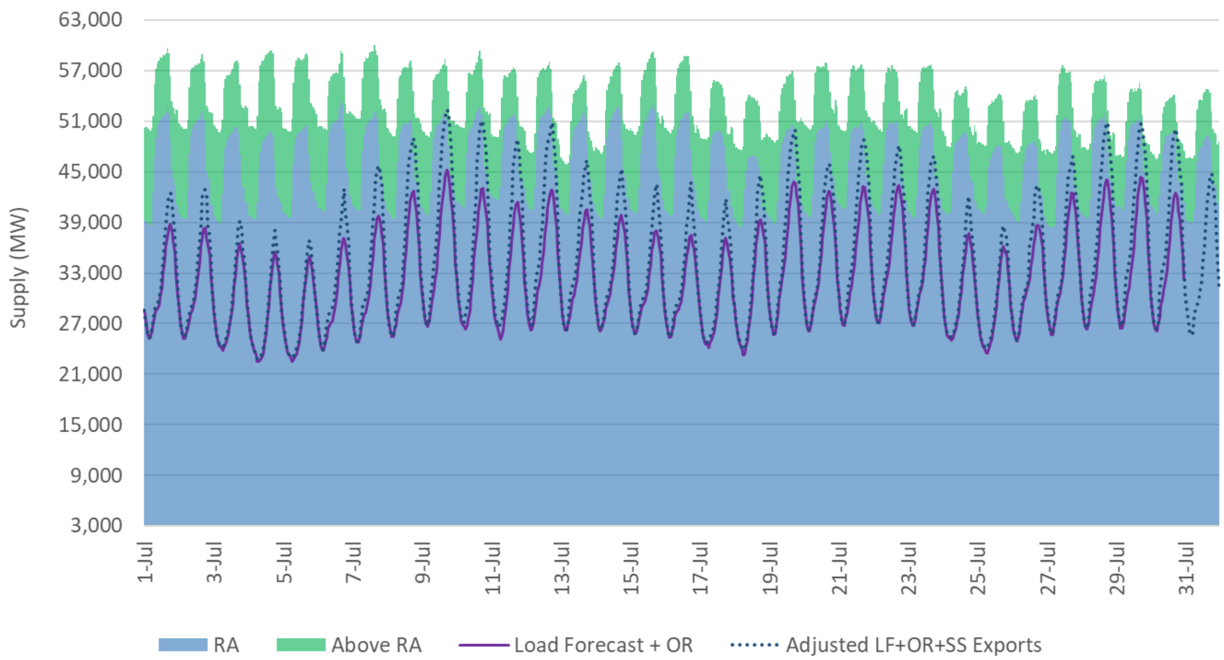
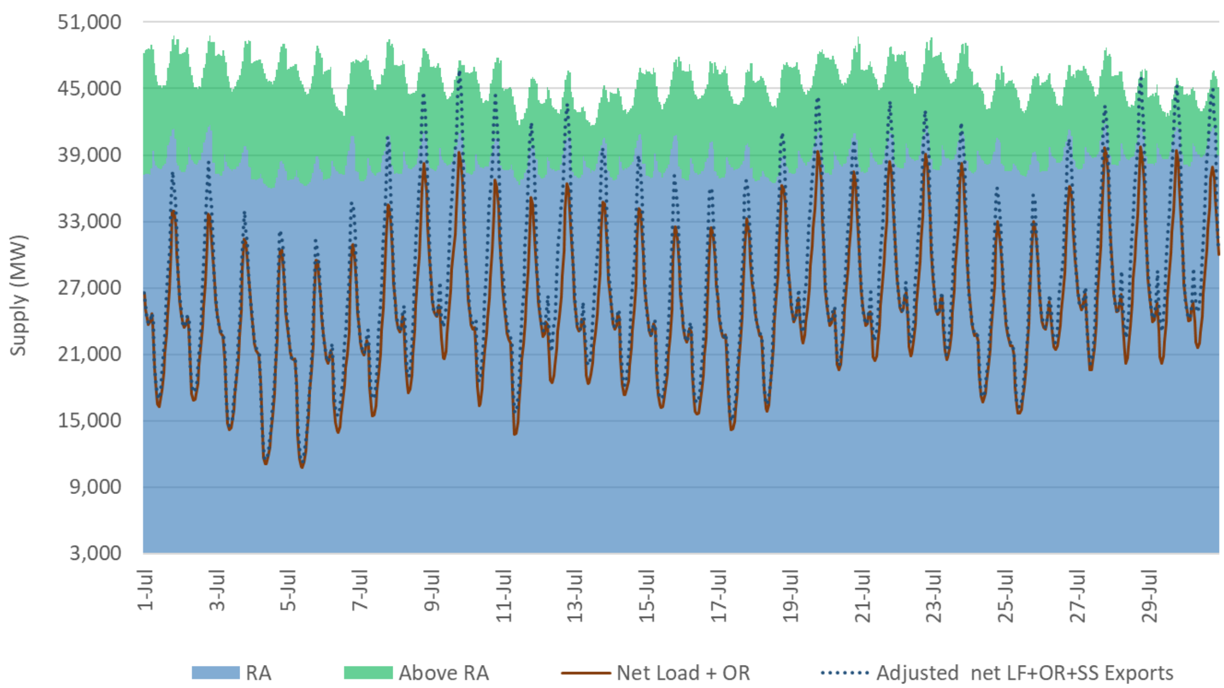


Figure 34: Supply capacity available relative to net load forecast in the day-ahead market



In both trends, the load increases steeply during the heat event of July 9, and again towards the end of the month. When using the adjusted load forecast as a reference, the total load need was above RA for 2 hours after the gross peak. The RA capacity was sufficient relative to the unadjusted load forecast.

Figure 35: Supply capacity available in the day-ahead market on July 9

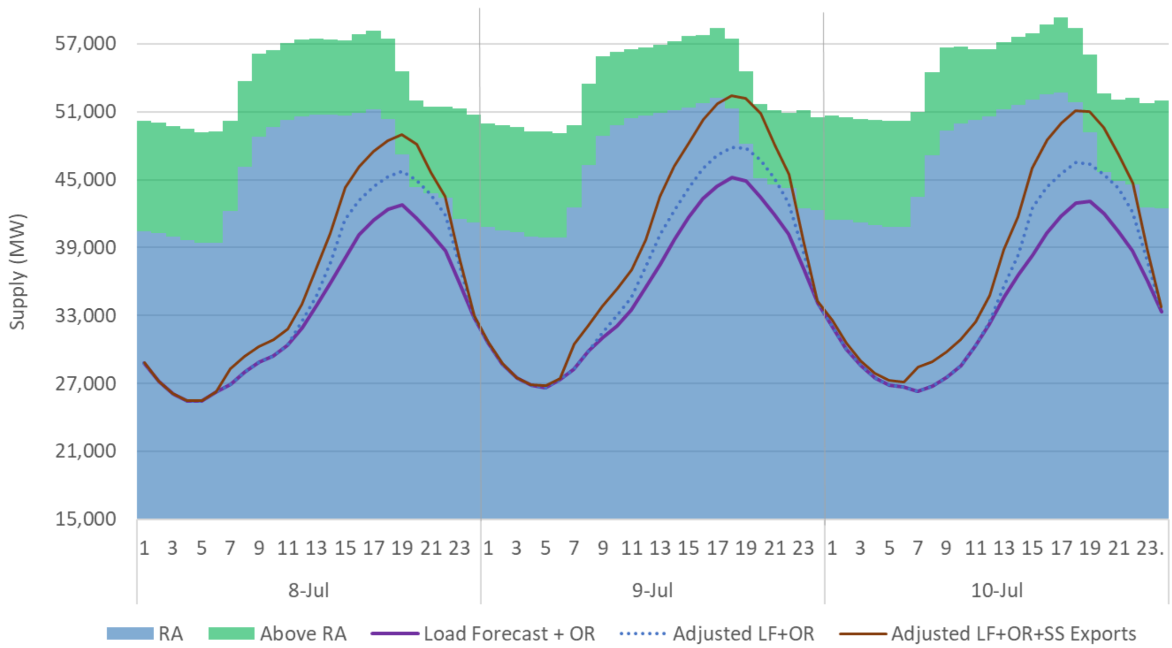


Figure 36: Day-Ahead net load relative to net RA capacity on July 9

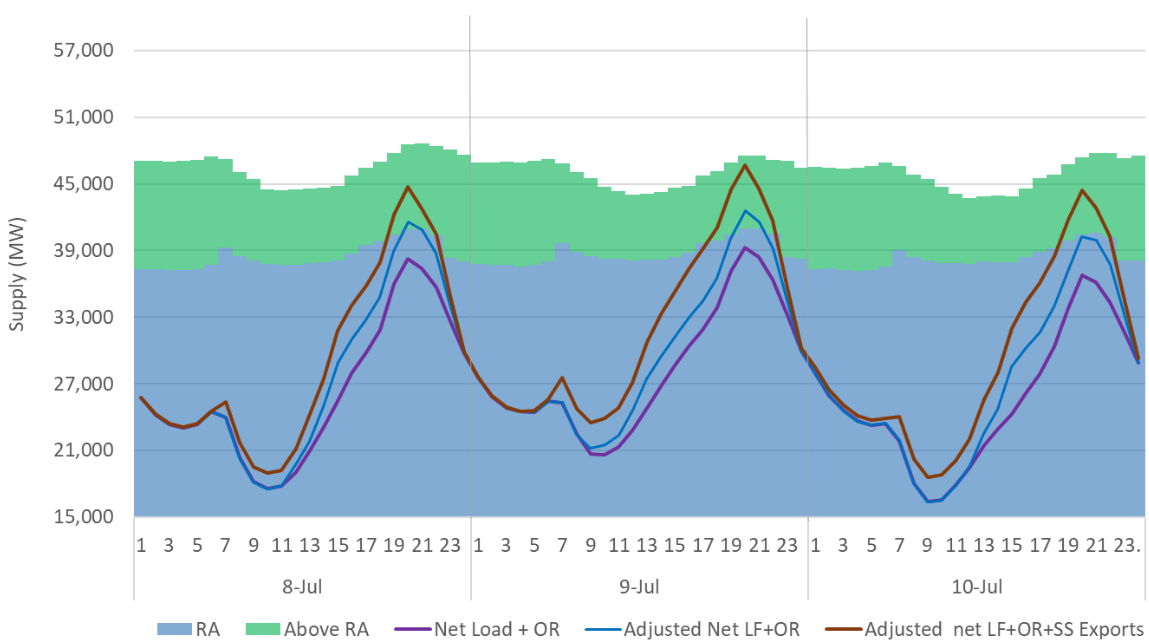
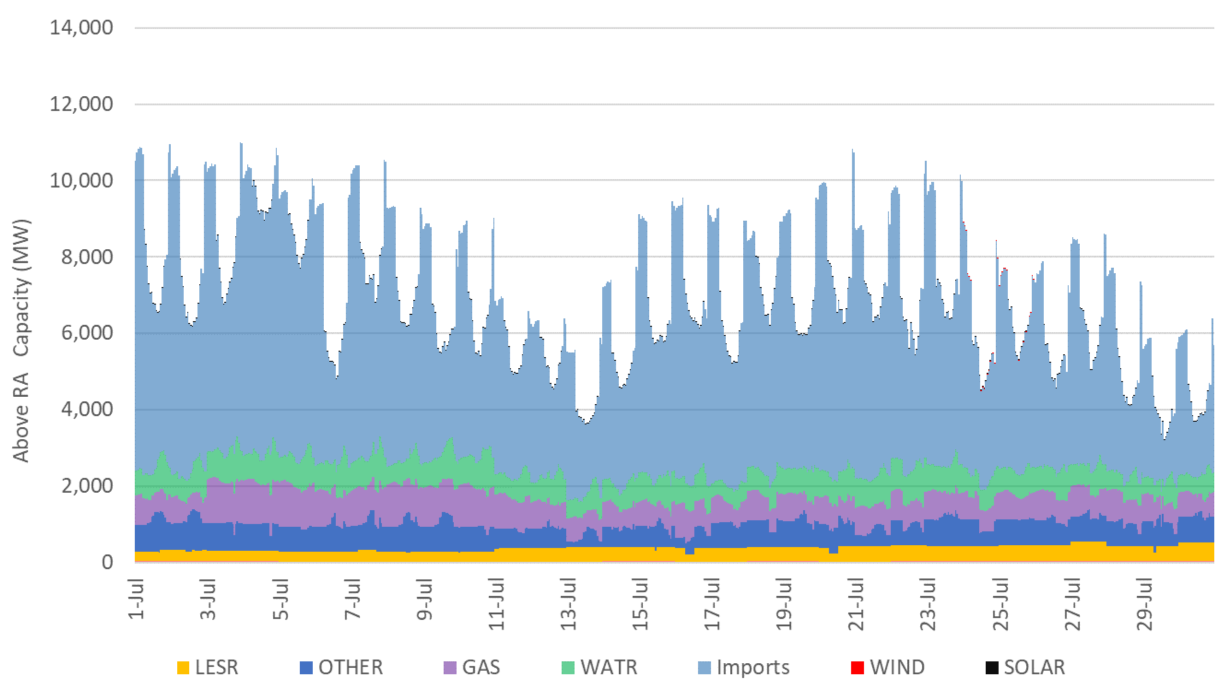


Figure 35 and Figure 36 provide a more granular detail of the capacity conditions for July 9. For a period of two hours passed the gross peak, July 9's RA capacity was below the adjusted load and operating reserves obligation. The RA capacity level was also below the net load needs. Under this condition, there was still above RA capacity that could have been utilized to meet CAISO's load needs. As conditions unfolded into the real-time market with less supply unavailable, CAISO faced an EEA3 stage 2.

For instances in which the load needs exceed the available RA capacity, the market will utilize any other above RA available capacity. For the month of July, above RA capacity was consistently bid into the market. Figure 37 shows the above RA capacity available in the day-ahead market organized by fuel type. The major contributor to this above RA capacity is imports. Since imports are limited by the intertie scheduling limits, not all of that supply could actually be utilized in the market if needed. Import volumes came in higher at the beginning of the month and then reduced as CAISO and the West entered into the heat events of July 9 and late July. Because of how RA is accounted for wind and solar resources in this metric, there is not essentially above RA capacity classified for these type of resources. Furthermore, some of that above RA capacity may be actually supporting exports.[34] Lacking information of what other types of contractual arrangements may exist for that above RA capacity, this metric serves as an upper range of how much supply capacity available in the market is above.

Figure 37: Above RA capacity available in the CAISO's market



[34] Since July had some days in which high priority (non-recallable) exports were bid-in and cleared, the maximum hourly high priority export quantity is used as a proxy to estimate how much of that above RA capacity is actually in the market to support the high priority exports and, thus, is not included as capacity available towards meeting CAISO's load. For simplicity, that capacity is discounted to the gas-based generation portion across all hours of the month.

9.2 Demand and supply cleared in the markets

The day-ahead market is composed of three different passes: local market power mitigation (LMPM), IFM and RUC. Each of these market runs has a purpose and each of them is solved based on a cost-minimization optimization problem. The first pass of the day-ahead market, LMPM, identifies structural conditions for the potential exercise of local market power enabled by transmission constraints. The outcome is the identification of uncompetitive constraints and potentially results in the mitigation of specific resource bids. These mitigated bids are then used, together with the rest of non-mitigated bids, in the IFM process to solve the financially binding market where bid-in demand is cleared against bid-in supply. This IFM clears both physical and convergence bid supply against bid-in demand, convergence bid demand and exports, and produces awards and prices that are financially binding for all resources. The RUC process uses the IFM solution as a starting point to further refine the supply schedules that can meet the day-ahead load forecast. Operators may adjust the day-ahead forecast to factor in other foreseeable conditions such as load uncertainty. The RUC process will clear supply against the final adjusted load forecast. Figure 38 compares the IFM schedules for physical resources versus the day-ahead load forecast and the adjusted load forecast eventually used in the RUC process.

Figure 38: Day-ahead demand

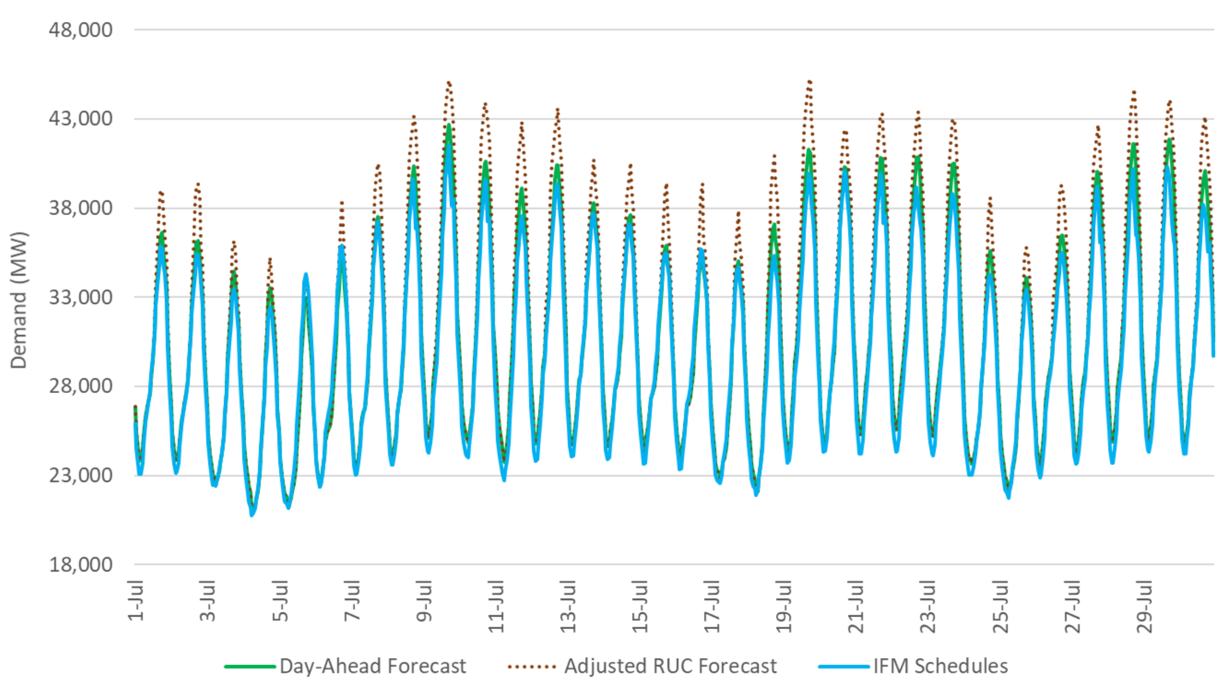
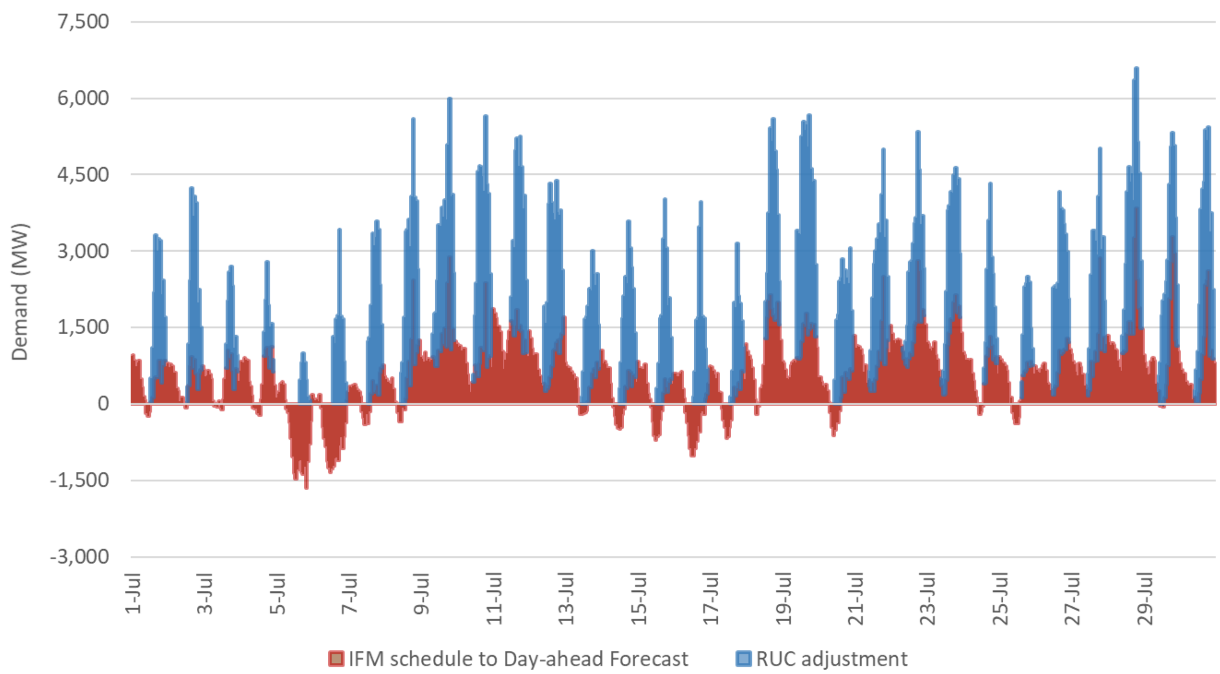


Figure 39 shows the differences between the IFM schedules for physical resources versus the nominal day-ahead load forecast. This is the additional capacity starting from the IFM solution RUC determines is needed to meet the day-ahead load forecast. Effectively, this is either the shortfall or surplus capacity from IFM that RUC has to meet. The delta is driven by the difference between cleared bid-in demand and the load forecast, as well as any displacement driven by convergence bids. The area in blue is the RUC adjustment to the day-ahead load forecast. In cases when RUC is infeasible, some of this additional capacity will not be met.

Figure 39: Differences of day-ahead demand for July



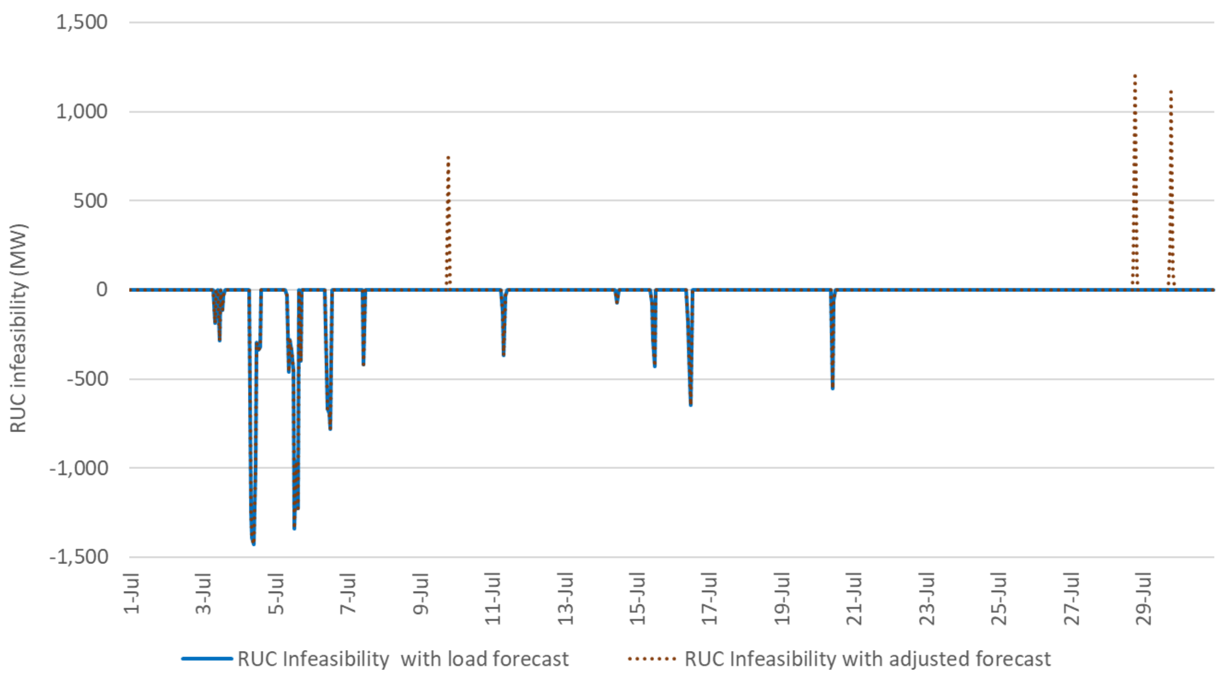
The RUC forecast adjustment is typically guided by a reference of an upper confidence bound and is estimated by the CAISO with consideration to weather and load model and renewables uncertainty. In some cases, there may be other factors to consider by operators to determine the final adjustments. With summer conditions fully at play, for the most part of July IFM schedules and RUC adjustments were positive, meaning that RUC had to clear higher physical supply than IFM.

Since RUC clears against a load forecast which is not price sensitive, under certain conditions RUC may relax the power balance constraint due to a surplus or shortfall of supply capacity. A relaxation signals that there is an imbalance between the load requirements and the supply available. An infeasible power balance can be in either direction. In hours with low levels of load and minimum downward capability, RUC may observe an oversupply condition, resulting in a negative infeasibility. Conversely, in hours where there is insufficient supply to meet the load requirement, RUC may have an undersupply condition, resulting in a positive infeasibility. Negative RUC infeasibilities occur because RUC can only dispatch a resource down to its minimum load and cannot actually de-commit a resource or set up additional exports. Conversely, positive RUC infeasibilities occur because all incremental RUC bids have been exhausted and RUC has curtailed all the economic and LPT exports,[35] which leaves just the power balance

[35] There are different type of exports participation. They can be based on economic bids with prices between the bid floor and the bid cap; they can be price takers, also referred to as low priority exports and labeled as LPT (*i.e.*, exports that may be backed by capacity that is committed to CAISO load under its resource adequacy program). Exports can also be high priority self-schedule labeled as PTK (*i.e.*, not backed by capacity that may be committed to CAISO load under its resource adequacy program).

constraint to be relaxed and reducing PTK (high priority) exports, to allow RUC to clear. Figure 40 shows the RUC infeasibility against two metrics: one infeasibility is relative to the final RUC adjusted forecast, while the other is relative to the standard day-ahead forecast. Only July 9, 28, and 29, had an undersupply infeasibility relative to the adjusted load forecast; there were no RUC infeasibilities relative to the standard load forecast. July 9 is the day CAISO had an energy emergency and RUC projected supply shortfall.

Figure 40: RUC infeasibilities



In addition to relaxing the power balance constraint, the RUC process utilized other scheduling priorities to enforce the power balance. Indeed, before relaxing the power balance (and based on current scheduling priorities), RUC will first reduce economic exports (exports bid-in at a given price) and lower priority price-taker exports. Only when RUC has exhausted these LPT exports, PTK exports may be reduced concurrently to relax the power balance constraint.[36]

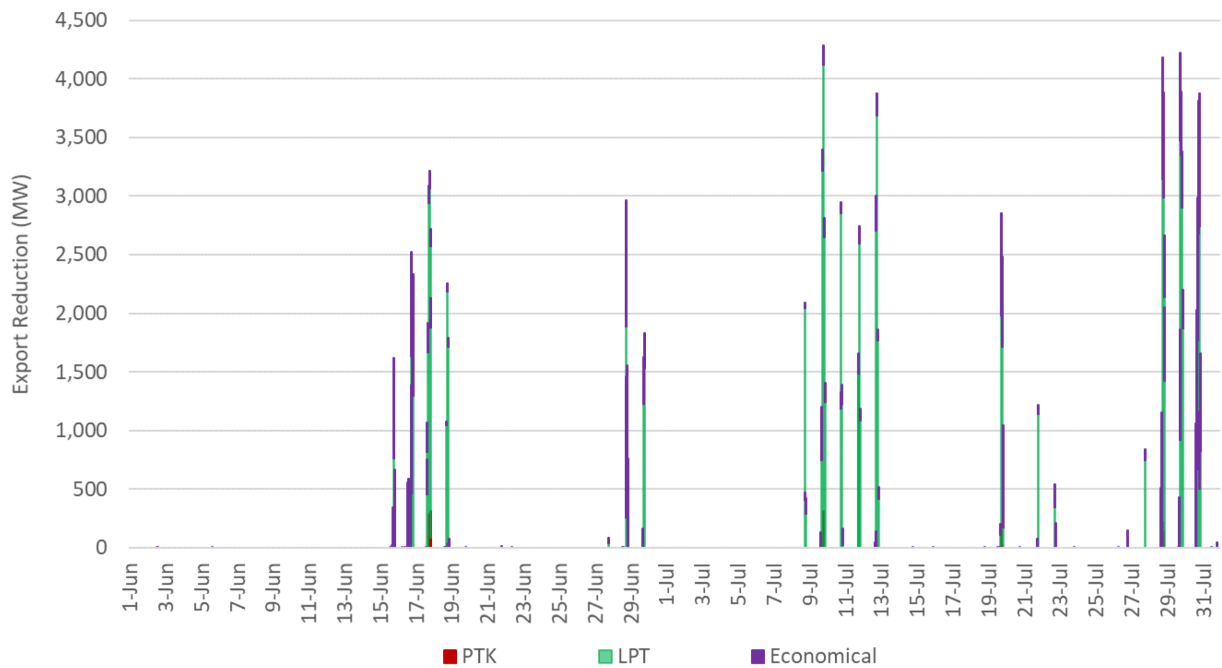
Figure 41 shows the volume of hourly export reduction in the RUC process, which mainly happened in the periods of July 9 through July 12 and July 28 through July 30. The majority of export reductions were for economic and LPT exports. Since they have the lowest priority and are reduced first. However, on July 9,

If the market clearing process encounters constraints, the CAISO will treat PTK exports similar to internal loads, but treats LPT exports as recallable and the market will curtail LPT exports before relaxing the power balance constraint.

[36] Under the current setup of scheduling priorities, PTK exports and the RUC power balance constraint have the same priority reflected with the same penalty price utilized in the market optimization. What level of curtailment relative to the level of power balance relaxation is achieved will depend on many other conditions in the optimization process, such as the location of the exports that may look more or less attractive for reduction in comparison to the power balance. Thus, typically, both export reduction and power balance infeasibilities can be observed in an RUC solution under tight supply conditions.

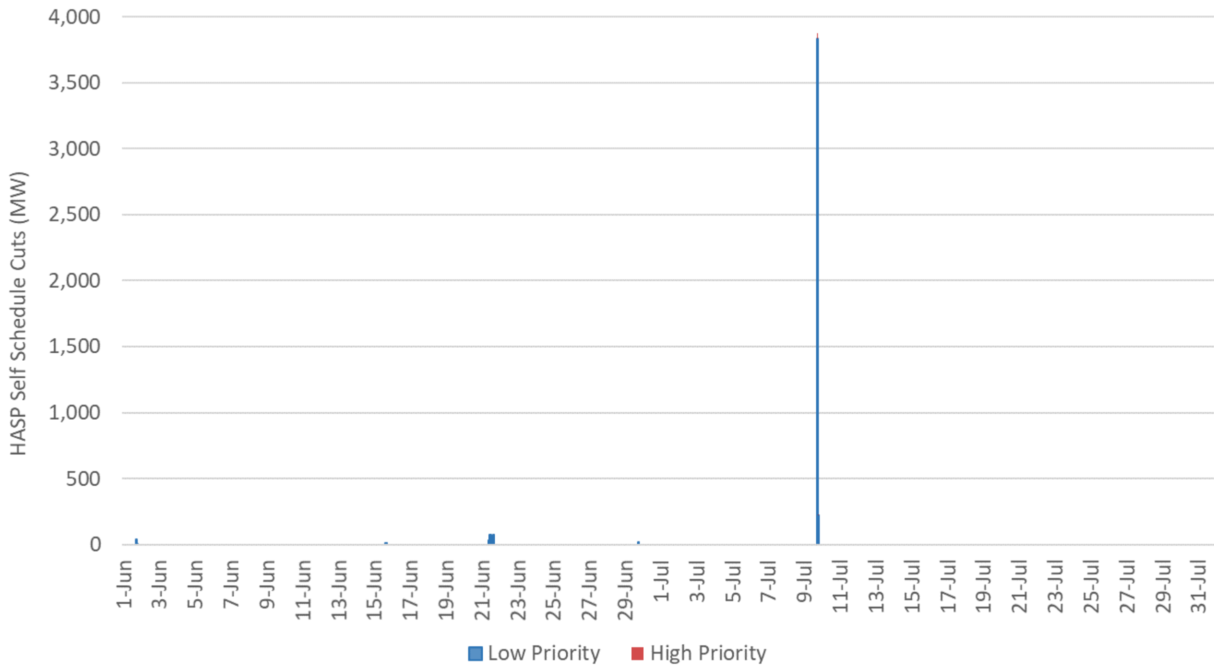
19, and 28, RUC reduced up to 313 MW of PTK exports, concurrent with RUC power balance infeasibilities because both PTK exports and CAISO's load are treated at the same scheduling priority in the RUC process.

Figure 41: Exports reduction RUC



Subsequently, market participants can rebid the PTK exports that were curtailed in RUC into the real-time market. Market participants can self-schedule exports cleared in the day-ahead into the real-time market. Under the market rules and scheduling priorities still applicable in July, these cleared day-ahead schedules are treated in the real-time market as having a higher day-ahead priority, which is above the priority of LPT and PTK exports submitted in the real-time. Thus, exports cleared in the day-ahead are unlikely to be cut in the real-time. Participants can also submit PTK or LPT self-schedules in the real-time market, which are more at risk of curtailments in the hour-ahead scheduling process (HASP) process. On July 9, the real-time market significantly curtailed exports through HASP across peak hours. The export curtailments were due to supply limitations. In hour ending 19, 3,830 MW of LPT exports were required by the HASP solution to be curtailed, including 43 MW of PTK exports. The curtailments of PTK exports were not actually issued in actuality because they were reinstated by CAISO operators having found these to be feasible in the operational timeframe. Only LPT exports curtailments were actually issued by the market as shown in Figure 42 below.

Figure 42: Exports reductions in HASP



10 Intertie Transactions

The CAISO's system relies on imports that arrive into the balancing authority area through various interties, including Malin and NOB from the Northwest and Paloverde and Mead from the Southwest, among others. Interties are generally grouped into static imports and exports, or dynamic and pseudo tie resources, which are generally resource-specific. Similar to internal supply resources, interties can participate in both the day-ahead and real-time markets through bids and self-schedules. Additionally, the CAISO's markets offer the flexibility to organize pair-wise imports and export to define a wheel. This transaction defines a static import and export at given intertie scheduling points which are paired into the system to ensure both parts of the transaction will always clear at the same level. Wheel transactions must be balanced, thus, do not add or subtract supply to the overall CAISO system, regardless of the cleared level. However, they utilize scheduling capacity on interties and transmission capacity on CAISO's internal transmission system. All intertie transactions will compete for scheduling and transmission capacity via scheduling priority and economic bids to utilize the scarce capacity on the transmission system.

Economic bids for imports are treated similarly to internal supply bids, while exports are treated similarly to demand bids (or fixed load through the load forecast feeds). These bids are bounded between the bid floor (-$150/MWh) and bid cap ($1,000/MWh or $2,000/MWh). Each part of a wheel is also treated accordingly as supply or demand but its net bid position is defined as the spread between its import and export legs.

Intertie transactions also have the flexibility to self-schedule. The CAISO's market utilizes a series of self-schedules which defines higher priorities than economic bids based on the attributes applicable to such resources. Participants with such entitlements can submit intertie self-schedules using transmission ownership rights (TORs) or Existing Transmission Contracts (ETCs), as well as PTK and LPT.

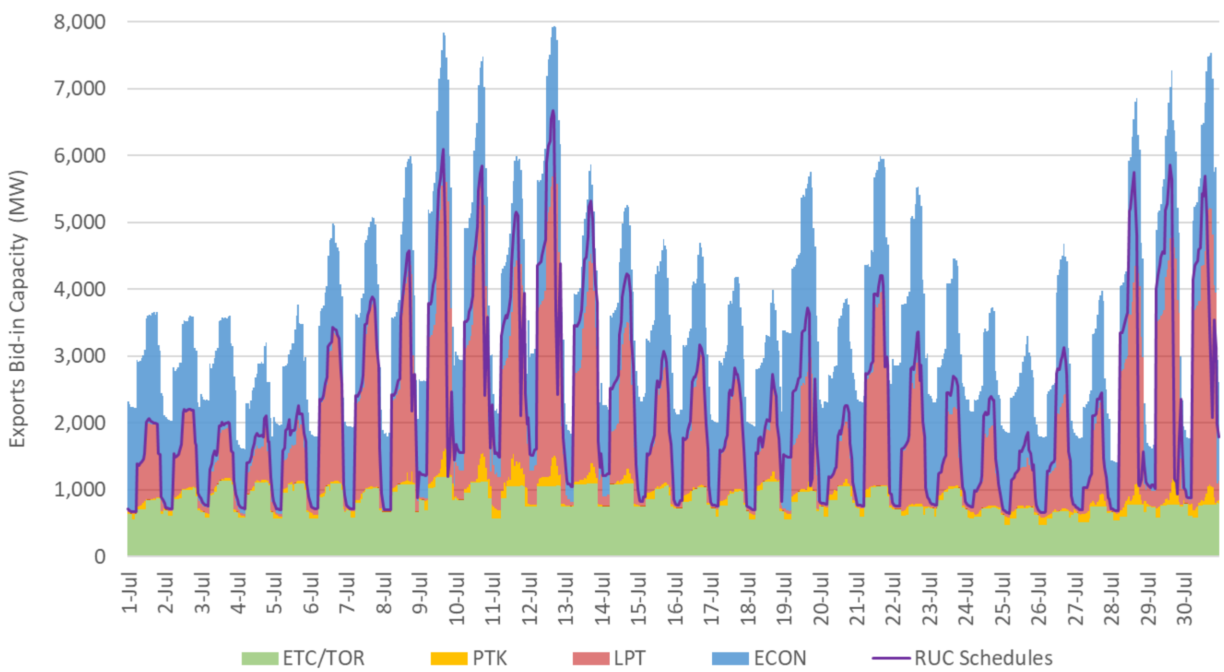
The CAISO's markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics, and system conditions, are taken into account. In the upward direction, when supply capacity is limited, imports with self-schedules clear first, followed by economic bids from cheapest to most expensive, up to the level of the market clearing price. Conversely, exports will clear first for ETC/TORs, then PTK exports, followed by LPT exports and lastly economic bids from most expensive to cheapest. Wheel transactions have a higher priority in the clearing process defined as the relative spread of penalty prices between the import and export sides.

10.1 Intertie supply

Figure 43 shows the capacity from static export-based transactions in the day-ahead market for the month of July 2021 organized by the various types of exports. This capacity does not include export capacity associated with explicit wheel transactions[37] of any type because wheels are in balance on a net basis and, thus, the export side of wheels does not reduce supply to the CAISO supply stack.

This figure also illustrates the clearing schedules from the RUC process with the line in purple. The RUC schedules are used as reference, instead of the IFM schedules, because they are the relevant schedules for clearing interties in the day-ahead market. As defined in Section 31.8 of the CAISO tariff, in the day-ahead market, the CAISO enforces a net physical intertie scheduling limit in the RUC process and enforces a net physical and virtual intertie schedules limit in the IFM process of the day-ahead market. This is to ensure that intertie schedules cleared in the day-ahead market are physically feasible and not encumbered by virtual intertie schedules. Prior to May 1, 2014, the CAISO enforced a net physical intertie scheduling limit in the IFM. As a result of this change where physical-based flows from the RUC process are the most reliable reference of feasible schedules on interties, the CAISO operators use the RUC schedules to evaluate E-tags submitted in the pre-scheduling timeframe.

Figure 43: Bid-in and RUC cleared export capacity



[37] An explicit wheel is an import and an export transaction matched in the system such that the market will always considered them as a single transaction that must clear in balance; i.e., the export and export will be forced to clear at the same MW value. However, there are other transactions that are not explicitly submitted as wheels and, thus, not treated as wheels. Given the assigned priorities for those imports and exports, however, they are typically cleared in balance. Cases like that are present for TOR/ETC self-schedules that have very high penalty prices and even when they are not submitted as explicit wheels, the market is typically clearing them in balance.

The RUC schedule represents the expected delivery and E-tags that market participants should submit in the pre-scheduling timeframe, and not the IFM schedule. While not required to submit their E-tags in the day-ahead timeframe, market participants are encouraged to do so and in such cases should base their E-tag on the RUC schedule. If not, E-tags greater than RUC schedules may be curtailed by the CAISO. This applies to all dynamic and static intertie schedules.

Export bid capacity in the day-ahead market varies by hour and typically follows a daily profile. About 43 percent, 23 percent, 32 percent and 2 percent of the export capacity were for economic bids, ETC/TOR, LPT and PTK, respectively. Overall, for the month of July, about 73 percent of all export bids in in the day-ahead market were cleared in RUC.

The volume of self-schedule capacity for TOR/ETC exports remained generally stable through the month, which is expected because rights are used consistently by their holders. The volume of PTK exports was modest for most of the month, and increased only in the periods of heat and higher loads around July 9-11 and July 28-31. The hourly volume of LPT and economic exports increased during the high load periods, rising to as much as 4,200MW on July 12. Hourly economic bids for exports were generally over 1,000 MW throughout the month, reaching up 2,200 MW on July 12.

Figure 44 shows the same illustration for imports. These volumes include both static imports and dynamic resources. Both ETC/TOR and self-schedule imports show a stable trend throughout the month with averages of about 1,000 MW and 1,930 MW, respectively. Hourly economic imports were about 5,200 MW on average for the month, with decreasing volumes during the two period of higher load. The "Other" group includes regulatory must run priority capacity and the portion of Pmin for dynamic resources with a Pmin above 0 MW.

Figure 44: Bid-in and RUC cleared import capacity

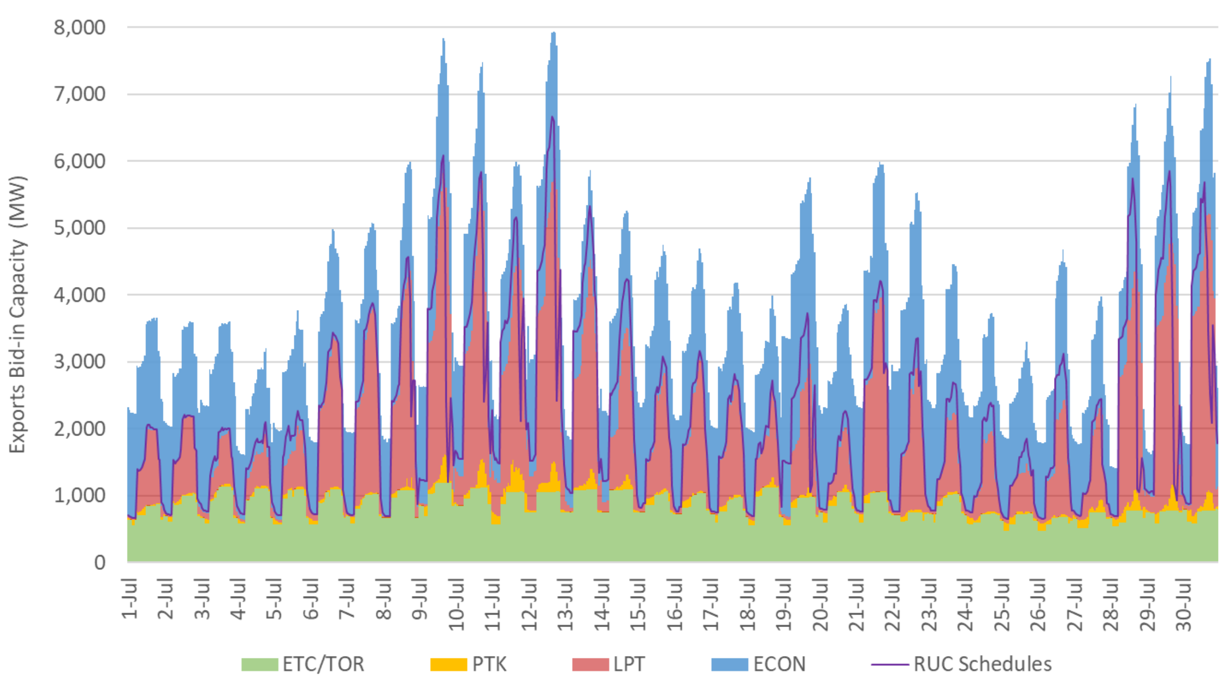


Figure 45 shows the overall intertie schedules organized by type of schedule, as well as the net interchange based on the RUC solution. The net interchange projected in the RUC process dipped very low, reaching a negative value (net exporter condition) on July 12, when the overall exports were greater than the overall imports. Similar trends occurred at the end of the month.

Figure 45: Breakdown of RUC cleared schedules

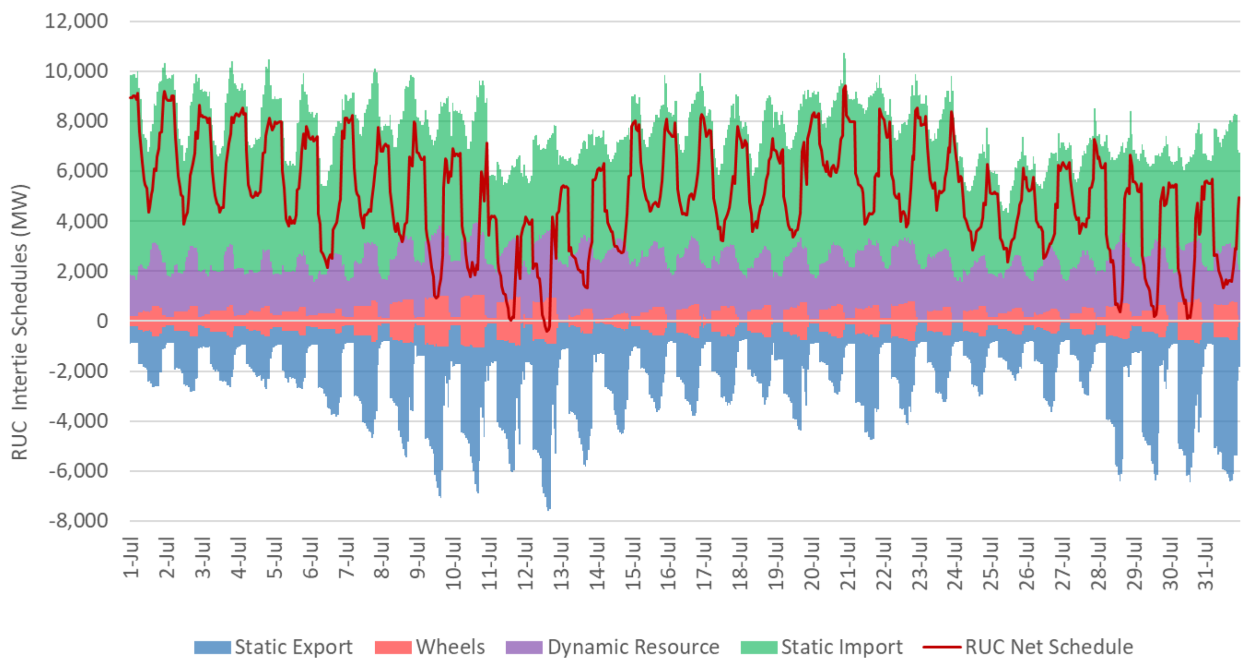
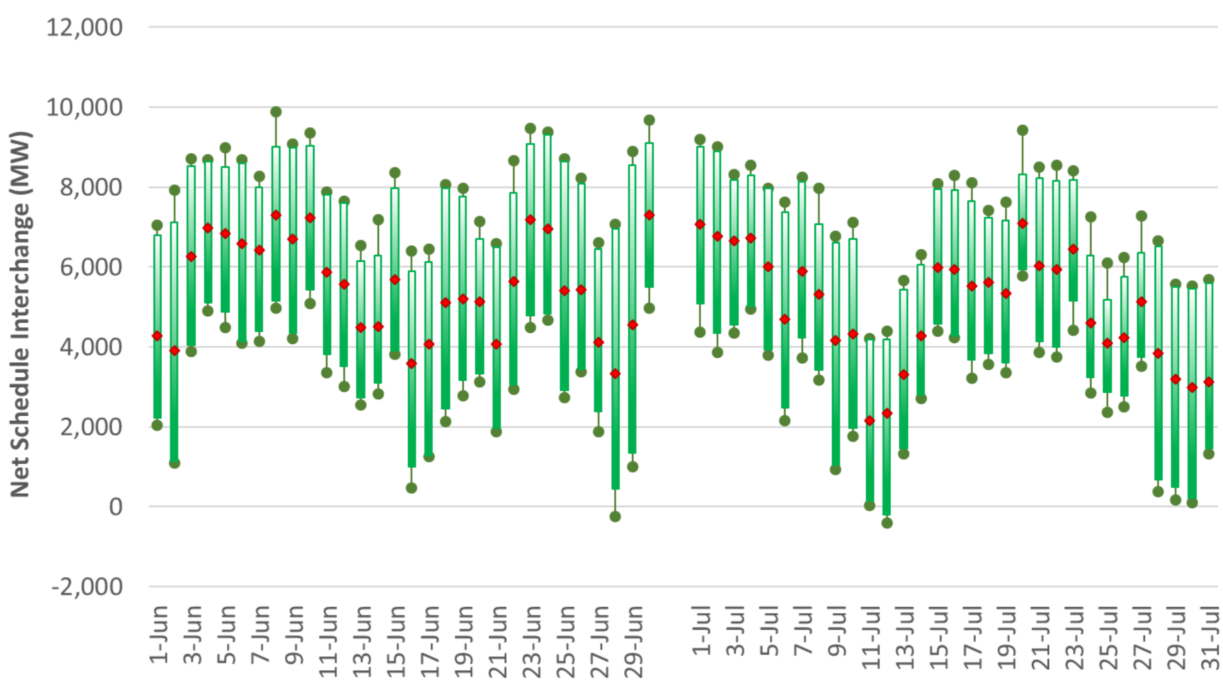


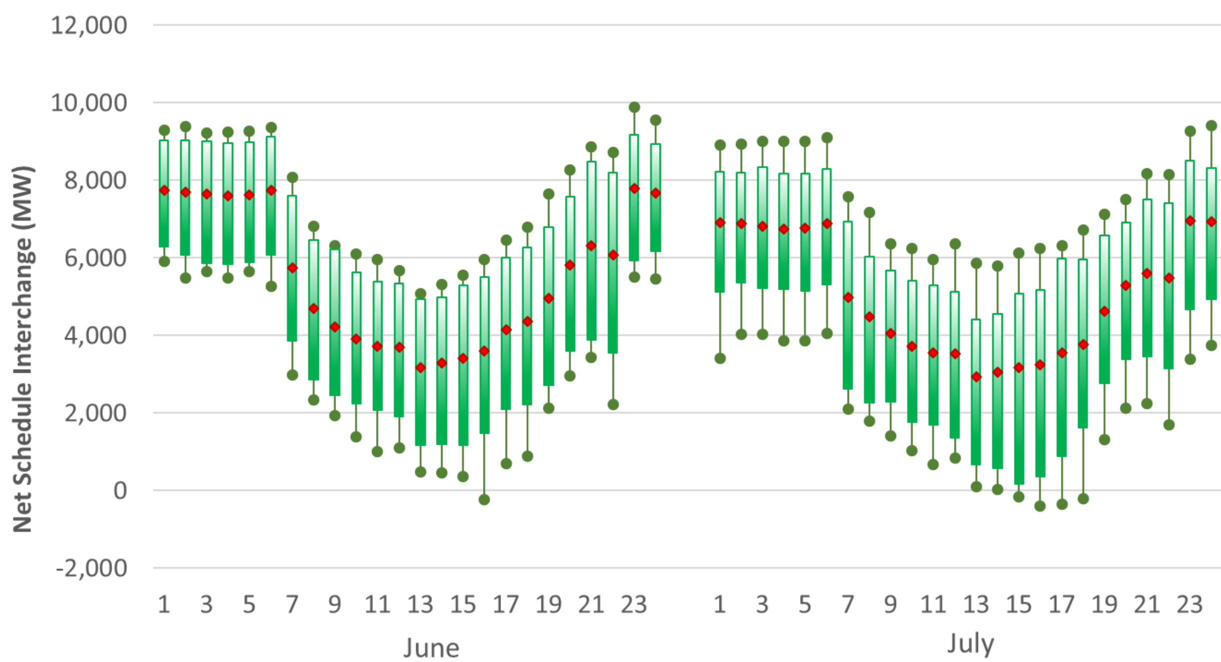
Figure 46: Daily distribution of hourly RUC net schedule interchange



Net schedule interchange is the algebraic balance of static imports, dynamic and pseudo resources and exports, and it measures the overall contribution to the system supply from scheduling over the interties. Figure 46 is a box-whisker plot to illustrate the distribution of hourly net schedule interchanges using the RUC schedules. The hourly net schedule interchange reached its minimum levels on July 12 and 30, which were the periods of heat and higher load. This outcome reflects both a reduction of imports and an increase of exports. This trend is similar to the one observed in June during periods of high loads.

Figure 47 illustrates the hourly net schedule interchange distribution by hour in the month of July. This trend is useful to visualize the hourly profile of schedules and shows that net schedules reduce in midday hours when solar production comes in and start to increase as the solar production fades away in the evening hours. It also shows two well-defined blocks of On- and Off-peak schedules. The lowest net interchange values are attained in hours prior to the gross peak when solar supply is still plentiful.

Figure 47: Hourly RUC net schedule interchange



An area of interest since summer 2020 is the trend of exports in the CAISO's system. Figure 48 trends the distribution of hourly RUC schedule for exports for each day of July. There are two clear periods, July 9-11, and July 28 and 30, when the market cleared the most exports. These periods coincide with the periods of heat and high loads experienced by the CAISO system and across the Southwest and Northwest. In particular, July 12 observed cleared exports over 6,000 MW. As explained earlier these high volume of exports typically occurred prior to the peak hours when there excess supply coming from solar resources.

Figure 48: Daily distribution of hourly RUC exports

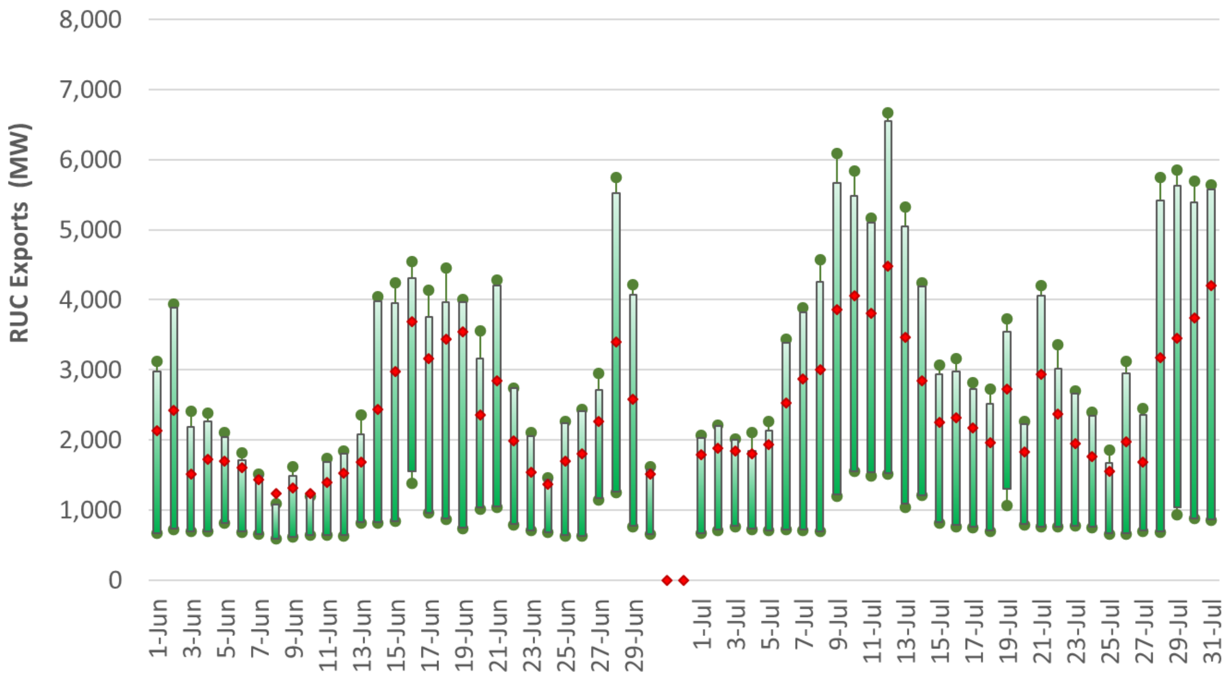


Figure 49 illustrates the hourly distribution of RUC schedules for exports, and that the highest volume occurred during midday hours when CAISO's system has excess solar supply; exports were in high demand during the evening hours of July 12 and 29, when the heat wave led to tight supply conditions outside the CAISO's system.

Figure 49: Hourly RUC exports

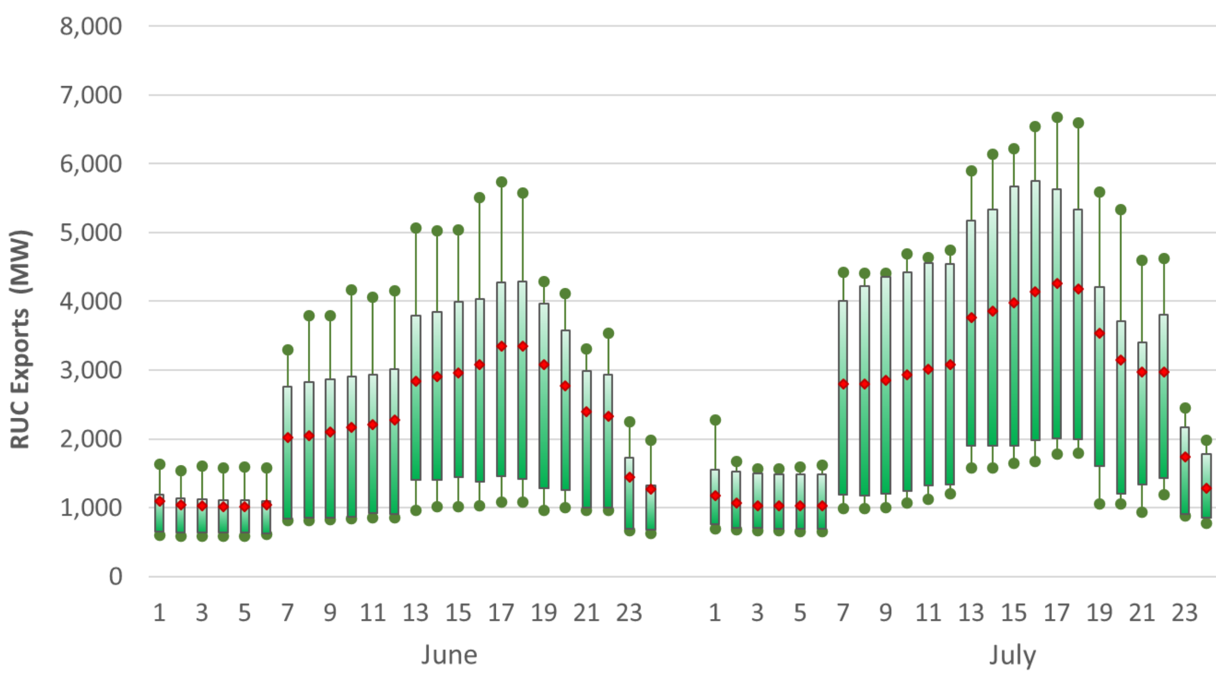
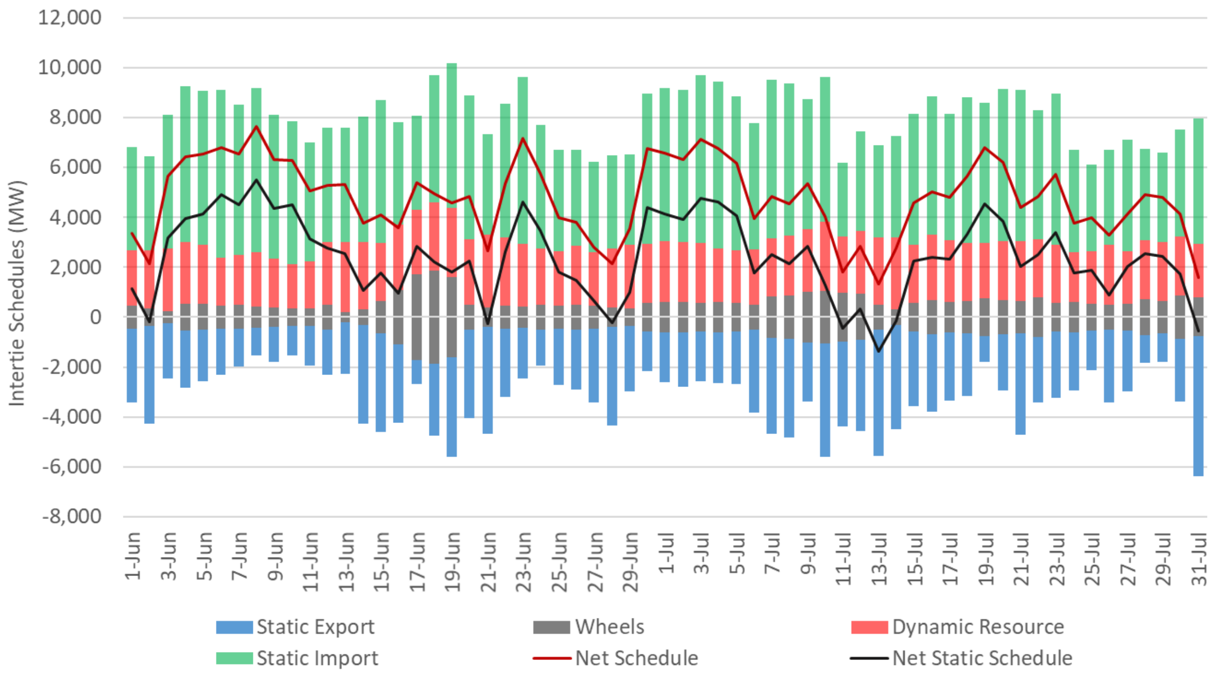


Figure 50 shows the intertie capacity available in the day-ahead market for hour ending 19 to highlight the conditions around peak time, when the CAISO's system faces the highest supply needs.

Figure 50: RUC schedules for interties for hour ending 19

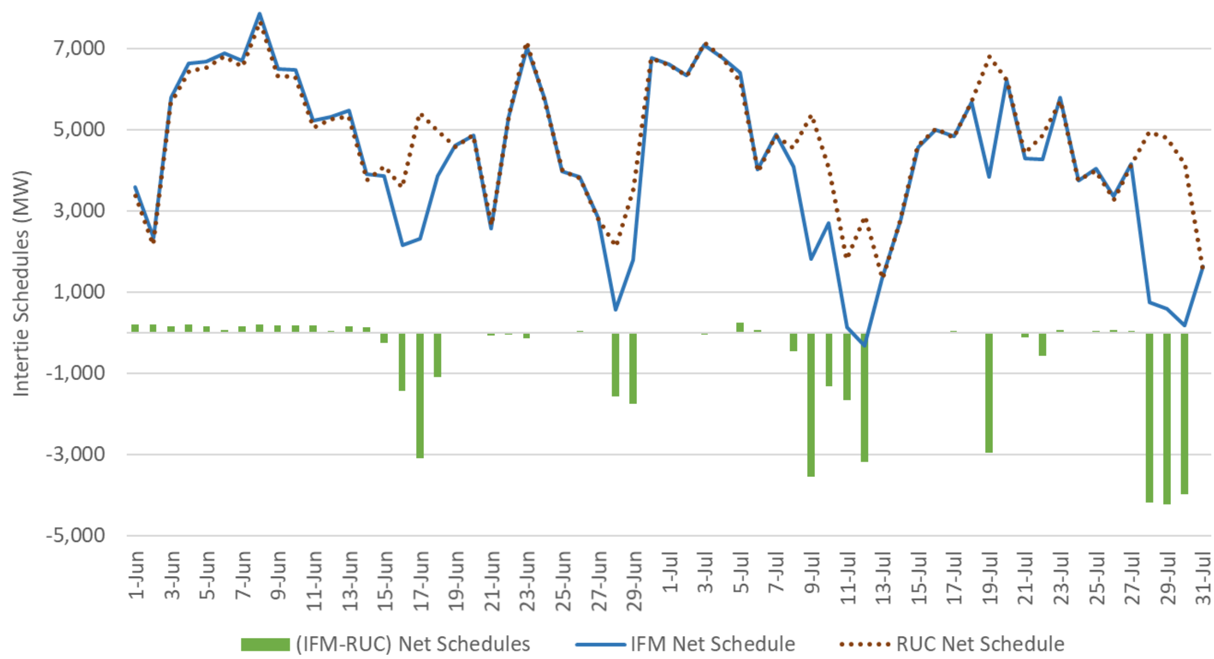


This balance does not include any imports or exports associated with explicit wheeling transactions. Including wheels will increase the volume of imports and exports by the same amount such that the net schedule remains the same. The red line represents the net schedules cleared in RUC (imports plus dynamics less exports), while the blue line represents the net schedule in RUC when considering only static imports and exports. The net static schedule was negative for July 13 and 31, indicating the volume of static exports outpaced the volume of static import.

The RUC process may schedule additional supply to meet the load forecast, above what was scheduled in the IFM. Under tight supply conditions, the RUC process may also identify that export schedules cleared in the IFM process are not feasible, and signals to the participant that their exports is not feasible in the real-time. Therefore, for interties, the RUC schedules are the relevant schedules for assessing what is feasible to flow into real-time, and they are what should be tagged if participants submit a day-ahead tag for their export. IFM schedules are still financially binding. Figure 51 compares the net schedule cleared in both IFM and RUC for hour ending 19, and provides the relative change of schedules between the two processes as shown with the bars in green.[38] IFM schedules for exports were reduced in the RUC process during the periods of heat and high loads for July 9 through July 12, and July 28 through 30. With these export reductions, the RUC net schedules were higher than IFM schedules.

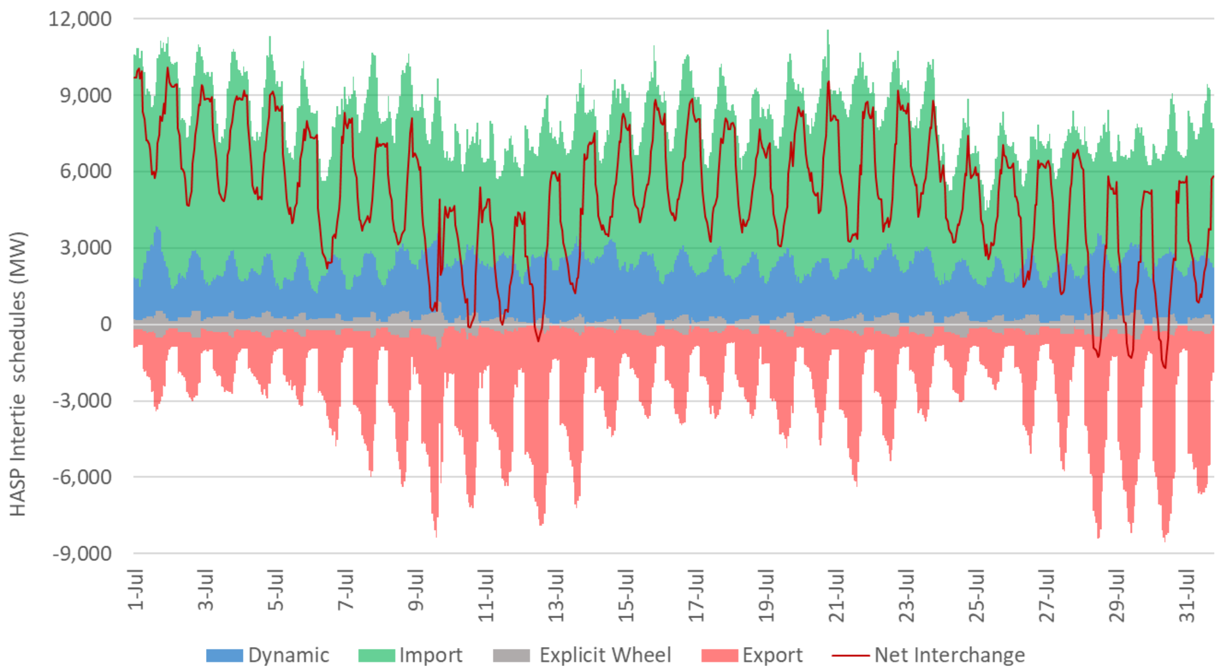
[38] The June report had the bars in green reporting an incorrect value. This has been corrected in this report.

Figure 51: IFM and RUC schedule interchange for hour ending 19



Intertie positions are largely set from the day-ahead market. Import or exports cleared in the day-ahead may tend to self-schedule into the real-time to preserve the day-ahead award by being given a day-ahead priority. There may still be incremental participation in the real-time market through the HASP process, which allows resources to bid-in economically to buy back their day-ahead position, or also enables the procurement or clearing of additional capacity in the real-time market. Figure 52 shows the cleared schedules in real time for interties of different groups, and the net intertie schedules cleared, referred as Net Schedule Interchange. The net schedule interchange is at its lowest value during peak hours in mid-July and end of July, in part due to the increased level of exports. The net schedule indeed becomes negative (net export) on July 12 and July 28-30 driven by the large volume of exports. The real-time market largely follows the trend observed in the day-ahead market.

Figure 52: HASP cleared schedules for interties



The HASP market presents an opportunity for interties to clear through the market clearing process after the DAM is complete. Interties cleared in the day-ahead market can submit self-schedules into HASP and will have, under current practices, a day-ahead priority that is higher than PTK or LPT schedules in the real-time market. Effectively, these day-ahead schedules cleared in the IFM and RUC are presumed to be feasible through the DAM and the CAISO considers them as inputs to the real-time market and provides them higher priority than bids coming in to the real-time. Clearing the RUC process indicates that these exports were feasible to flow based on the projected system conditions in RUC.[39] Additionally, exports can participate directly into the real-time market with either PTK self-schedules, LPT self-schedules, or economic bids.

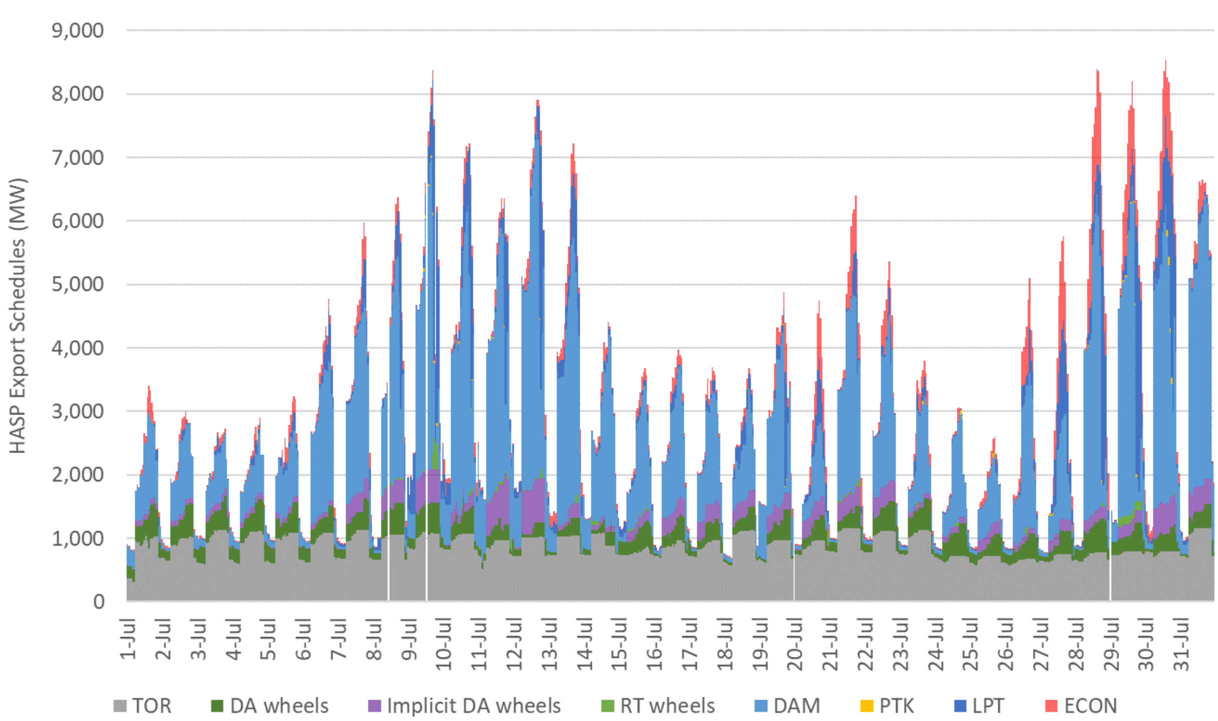
Each market, RUC or HASP, can assess reduction of exports based on the overall system conditions and economics. Export reductions in RUC can no longer self-schedule into real-time with day-ahead priority but they are able to be rebid into the real-time market and fully be assessed based on real-time conditions. LPT or economic exports cuts in the RUC process are most likely to be cut again in HASP since they will have the lowest priority in the presence of tight supply conditions. Figure 53 shows all the exports cleared in the HASP process and identifies the nature of such exports. TOR is for export with scheduling priorities associated with transmission rights. Day-ahead (DA) wheels are for the export component of a wheel

[39] Based on these rules as they existed in July, export schedules cleared in the day-ahead were also treated with higher priority than the power balance constraint (effectively load) in the real-time market. Through the summer initiatives enhancements described above and now in place, the CAISO will no longer provide this higher priority to exports a higher priority than load in the real-time, and will only provide them equal priority to load if the participant demonstrates that they continue to be supported by resources contracted to serve external load.
Details are available at http://www.caiso.com/Documents/Jun25-2021-OrderAcceptingTariffRevisionsSubjecttoFurtherCompliance-SummerReadiness-ER21-1790.pdf

cleared in the day-ahead market that carries over the real-time market by explicit bidding from its scheduling coordinator. Implicit DA wheels are for wheels cleared in the RUC process that did not rebid explicitly by its scheduling coordinator and, consequently, the market creates a self-schedule for it. Under this process, this export record is no longer tracked as an explicit wheel in real time and will have a scheduling priority as a high PTK export. Real-time (RT) wheels are explicit wheels bid directly in the real-time market with no relationship to the RUC schedules. Day-ahead Market (DAM), PTK, LPT are the standard day-ahead priority, high priority and low priority for exports. ECON stands for economic exports.

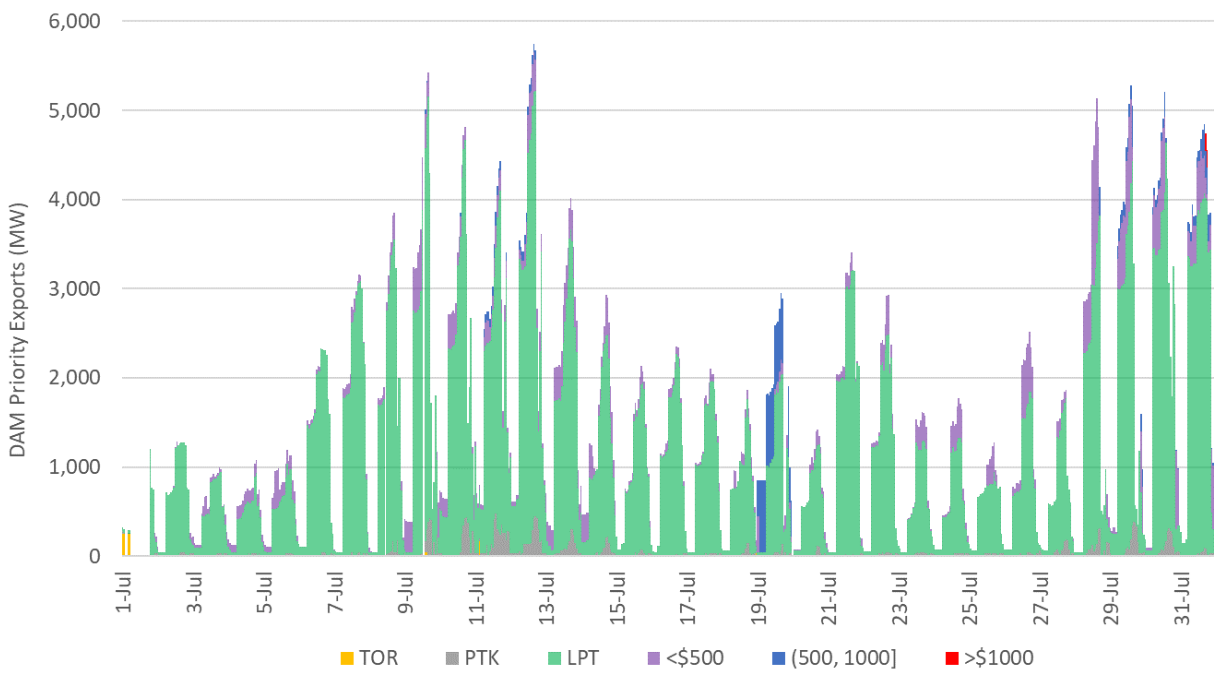
The volume of exports cleared in real-time follows the high temperature pattern when the CAISO, and the West, observed increasing temperatures in mid-July and also again at the end of the month. About 85 percent of exports cleared in the real-time market were in the HASP process with a high priority above the power balance constraint since they are associated with either TOR, wheels or day-ahead priority. Effectively, only LPT and ECON exports will be reduced in the HASP process before reaching power balance constraint relaxation or cuts for PTK exports.

Figure 53: Exports schedules in HASP



Exports cleared in the RUC process can be self-scheduled in the real-time market with a day-ahead priority, regardless of the type of exports submitted in the day-ahead market. For instance, either an economic bid or a price taker export cleared in RUC will have a day-ahead priority in real-time by virtue of having cleared in the day-ahead market. About 84 percent of these exports that cleared in the RUC process and had day-ahead priority in real-time were submitted as LPT in the day-ahead market, while about 10 percent were exports with economic bids under $500/MWh in the day-ahead market. Figure 54 shows the trend of exports with DAM priority in the HASP process. The largest volume of these exports happened during the heatwave of July 9 and late July.

Figure 54: Exports in HASP with a DAM priority



Imports and exports were scheduled over more than 20 different intertie scheduling points in July, with Malin, Paloverde and NOB seeing the highest volume of transactions. Figure 55 through Figure 57 illustrate the trend of import and export schedules cleared in HASP for the top three intertie points. Although schedules in the import direction are the predominant schedules, exports cleared at different levels on these major interties when supply was tight.[40] The trend of increasing exports in mid-July, when the Southwest was experiencing high demand, is fairly marked at the Palo Verde intertie.

[40] The breakdown of imports and exports at the system or tie level may be subject to different levels of aggregation. For instance, wheels are in balance and the import side of a wheel nets out with the export side of the wheel. There are some transactions like TORs that behave like wheels although they are not explicit wheels in the market clearing process; i.e., the market can clear the import at a value different than the export's value. Generally they may clear in balance and thus the export side may not add demand needs to the system, like stand-alone exports, even though it is counted in the total volume of exports for a specific tie.

Figure 55: HASP schedules at Malin intertie

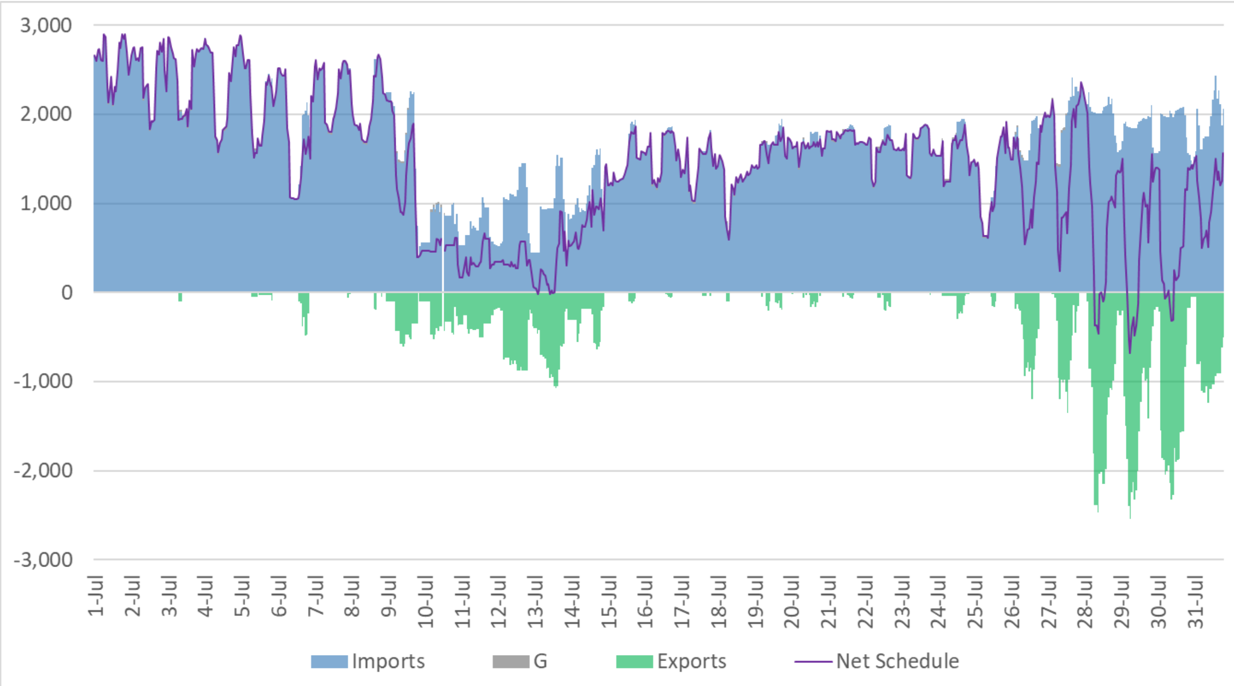


Figure 56: HASP schedules at PaloVerde intertie

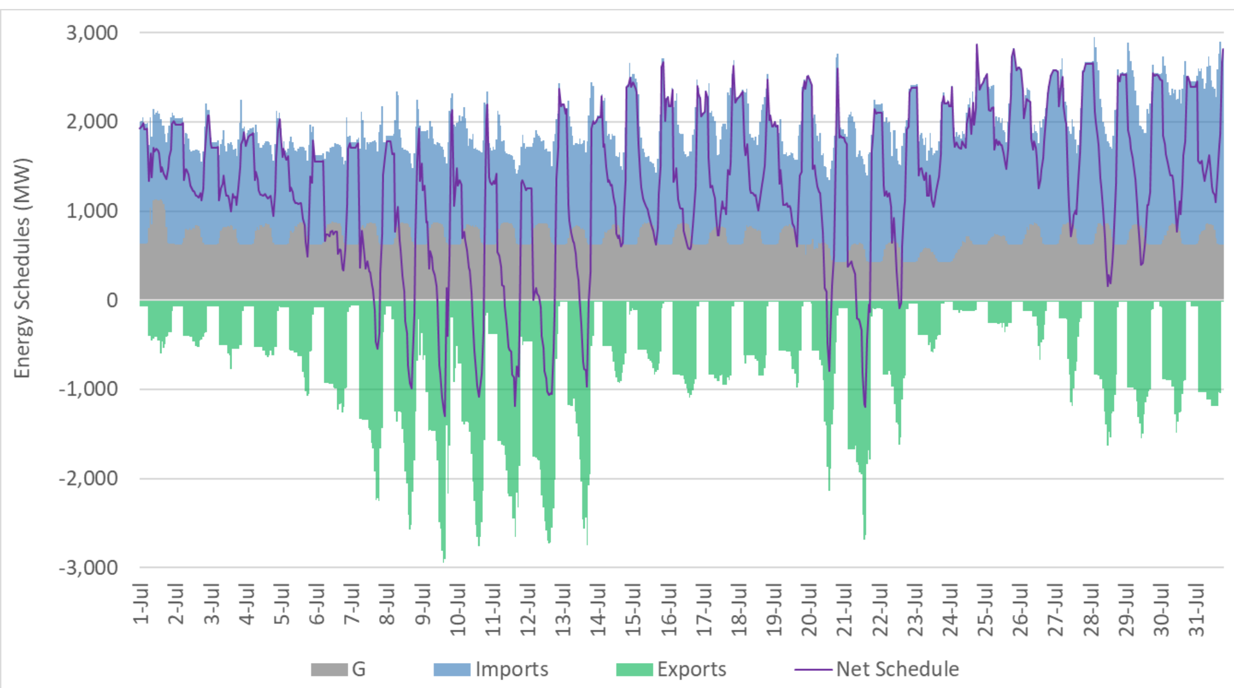
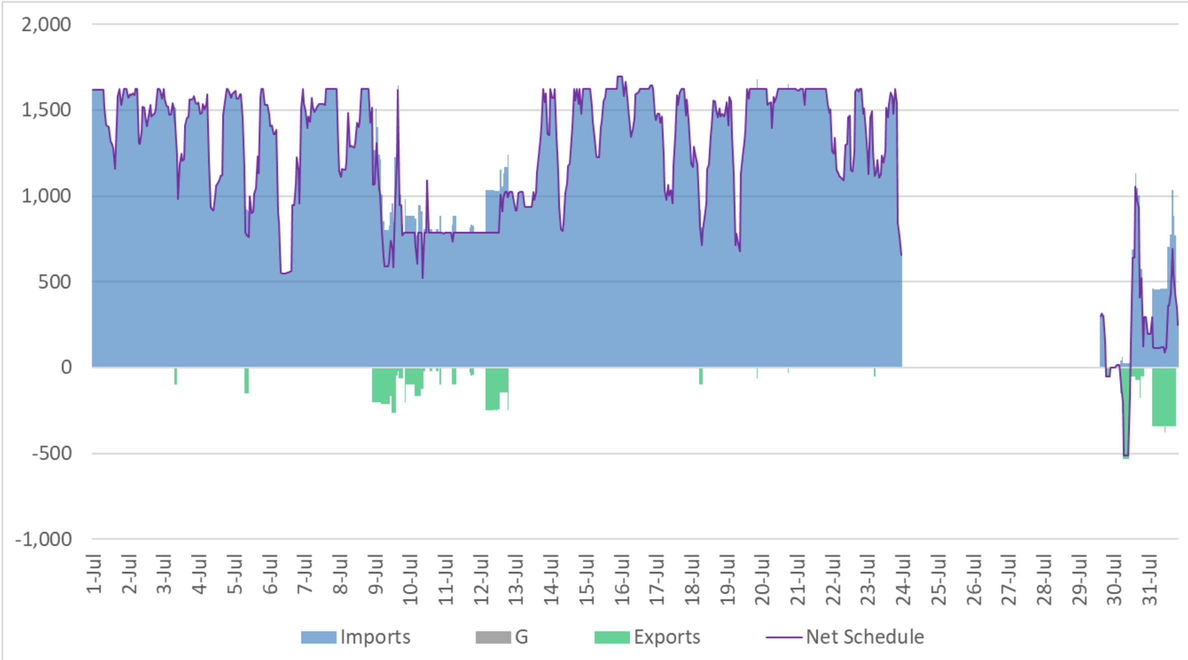
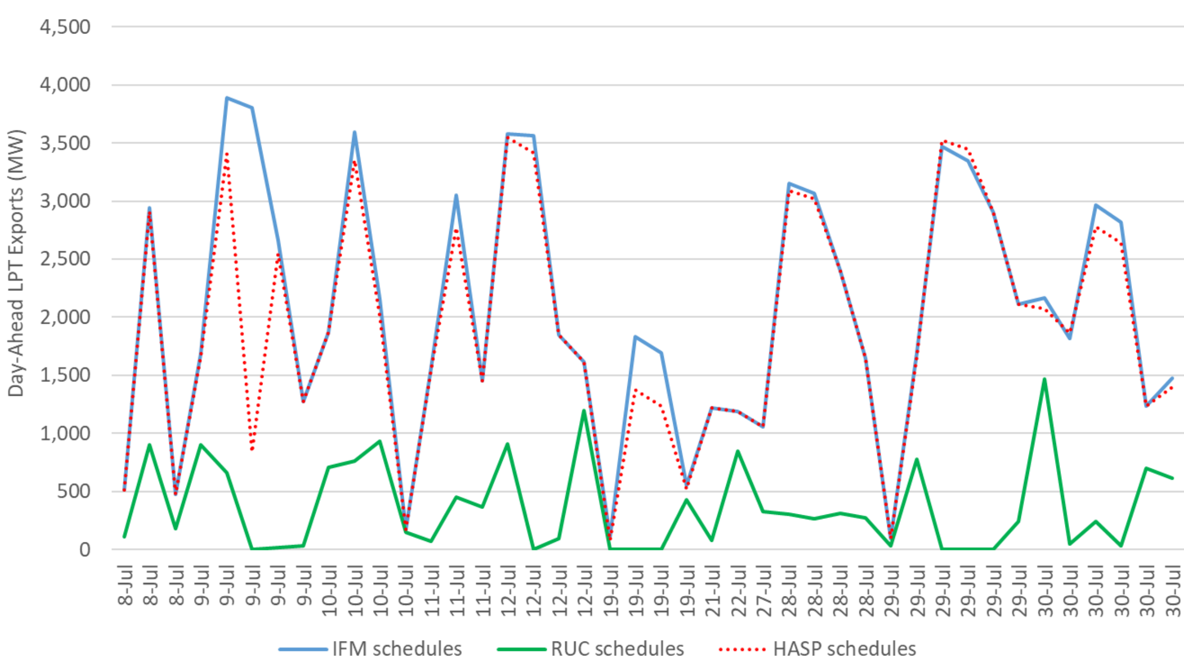


Figure 57: HASP schedules at NOB intertie



The RUC process identifies what exports can be feasible given the expected system conditions within the day-ahead time frame. An export reduced in the RUC process can still rebid in the real-time market and it will be fully assessed based on real-time conditions. In analyzing the RUC export reductions in July, the vast majority of exports curtailed in RUC effectively rebid into the real-time market and cleared in HASP relatively closer to the original IFM awards.

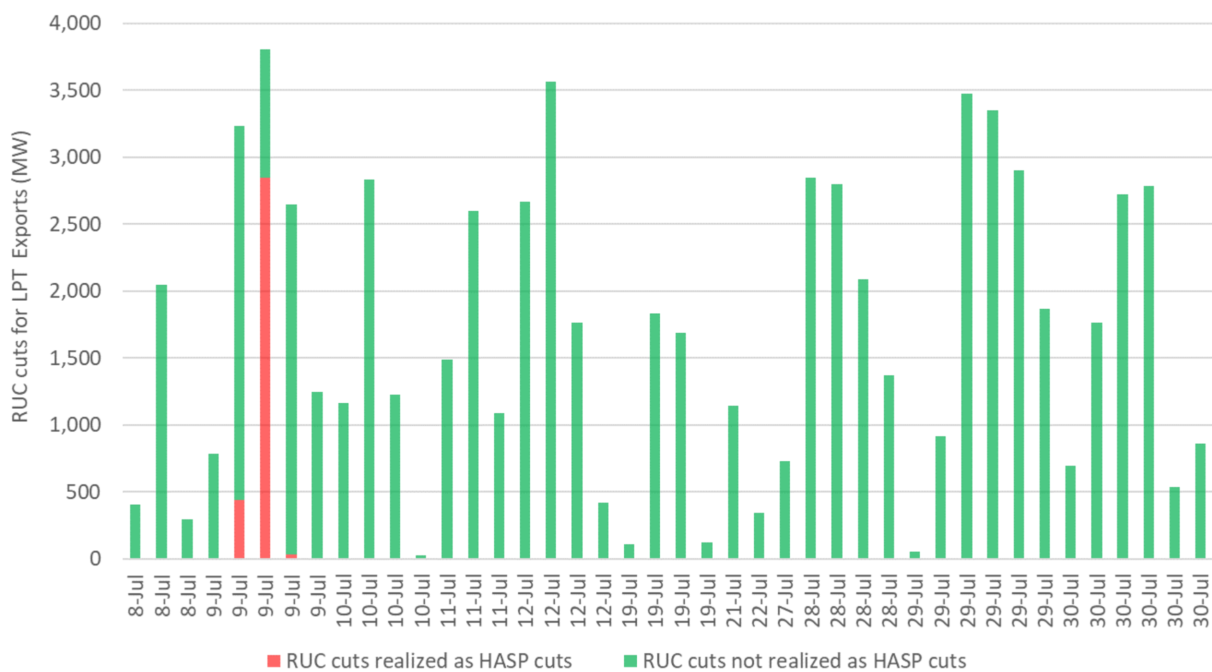
Figure 58: Comparison of LPT export schedules across markets



This can be seen in Figure 58, which shows a comparison of export schedules among IFM, RUC and HASP only for the subset of exports related to LPT priority in the day-ahead processes, and only for the days and hours in which there was a RUC reduction.

About 95 percent of the time, the exports reduced in the RUC process and that were rebid, cleared successfully in the HASP process. The only time this did not happen was for the peak hours of July 9 as shown in Figure 59 when system supply was very tight.

Figure 59: Share of RUC export reduction materialized in HASP



10.2 Resource adequacy imports

Imports can be used to meet Resource Adequacy (RA) requirements and they can be resource-specific or non-resource specific. For simplicity, this analysis relies on static imports as a proxy for non-specific resources. The other type of imports are dynamic or pseudo tie resources, which typically will be resource-specific. The total amount of RA supported by static imports in July was about 3,269 MW, with about 2,646 MW related to LSEs under CPUC jurisdiction.

Under RA rules, non-resource specific RA imports for LSEs under CPUC jurisdiction must self-schedule or bid with economics bids between -$150/MWH and $0/MWh at least for the availability assessment hours. Figure 60 is an approximation of the supply bid in the day-ahead market by static RA imports associated with LSEs under CPUC jurisdiction and for hours ending 17 through 21 of weekdays only. This supply is organized by price range, including self-schedules. Based on this subset, about 98 percent of the total RA import capacity was bid with either self-schedules or economic bid at or below $0/MWh in July.[41] This plot also shows the cleared imports, which largely covered all imports with self-schedules and bids with prices at or below $0/MWh. A small volume of imports with high bid prices did not clear in the day-ahead market.

Figure 60: Day-Ahead RA import for hour endings 17 through 21 for weekdays

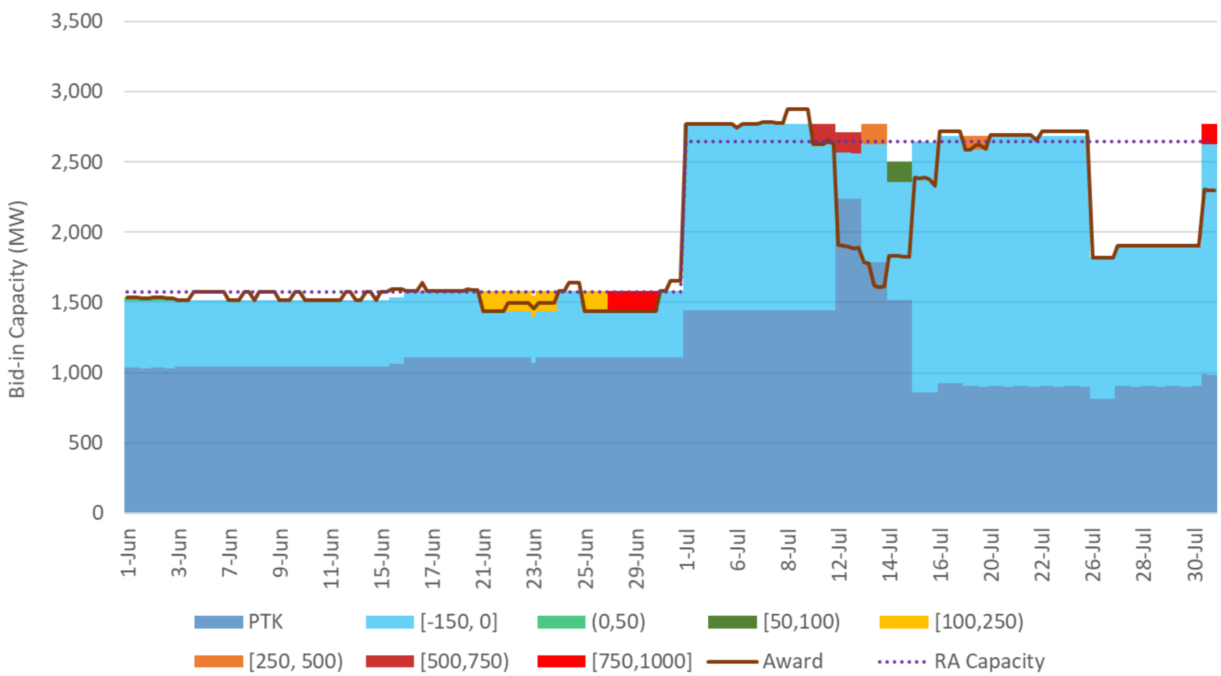
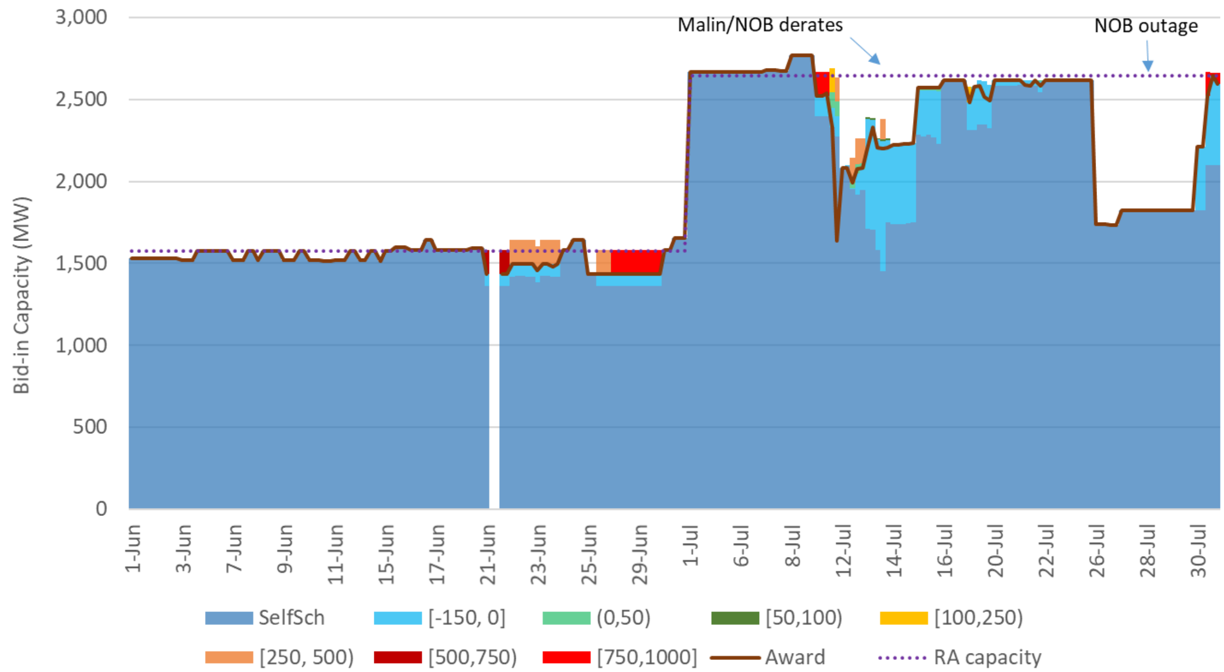


Figure 61 shows the same information for the real-time market using the HASP bids. The majority of RA imports come in as self-schedules in the real-time market, with only a small fraction of imports coming with an economic bid. In the day-ahead market, about 97.3 percent and 98.5 percent of RA imports bid in at prices at or lower than $0/MWh in June and July, respectively.

[41] In the June performance report reported that 94 percent of bids from RA imports were at or below $0/MWh. This metric included any bid capacity that an RA import may have submitted above its RA level. In this July report, this metric is now based only on the bid-in capacity covered by the RA level. If a resource bids above its RA level, that incremental capacity is not considered in the percentage estimated of bids at or below $0/MWh. Using this approach, the metric for June is about 97.3 percent rather than the previously reported 94 percent.

Figure 61: HASP RA import for hour endings 17 through 21 for weekdays



10.3 Wheel transactions

Figure 62 shows an hourly average of wheels cleared in the RUC process. Wheels participating in the day-ahead market in the month of July were ETC/TOR, or self-schedules. There were no wheels with economic bids. The volume of explicit wheels associated with ETC/TOR was stable throughout the month, unlike June self-schedule wheels that came in consistently through the month of July. Figure 63 provides an hourly breakdown of self-schedule wheels, with hourly cleared RUC volumes of 722 MW on July 11; this is lower than the volumes observed in June when RUC reached a maximum wheel volume of 1,204 MW.

In July wheels generally came as block schedules matching the time-of-use of the day; *i.e.,* the submitted self-schedules were at the same MW value for blocks of multiple hours that define off-peak (hours ending 1 through 6 and hours ending 23 through 24) and on-peak hours (hours ending 7 through hour ending 22). Wheels in June 2021 did not show such a marked profile.

Figure 62: Hourly average volume of wheel transactions by type of bid

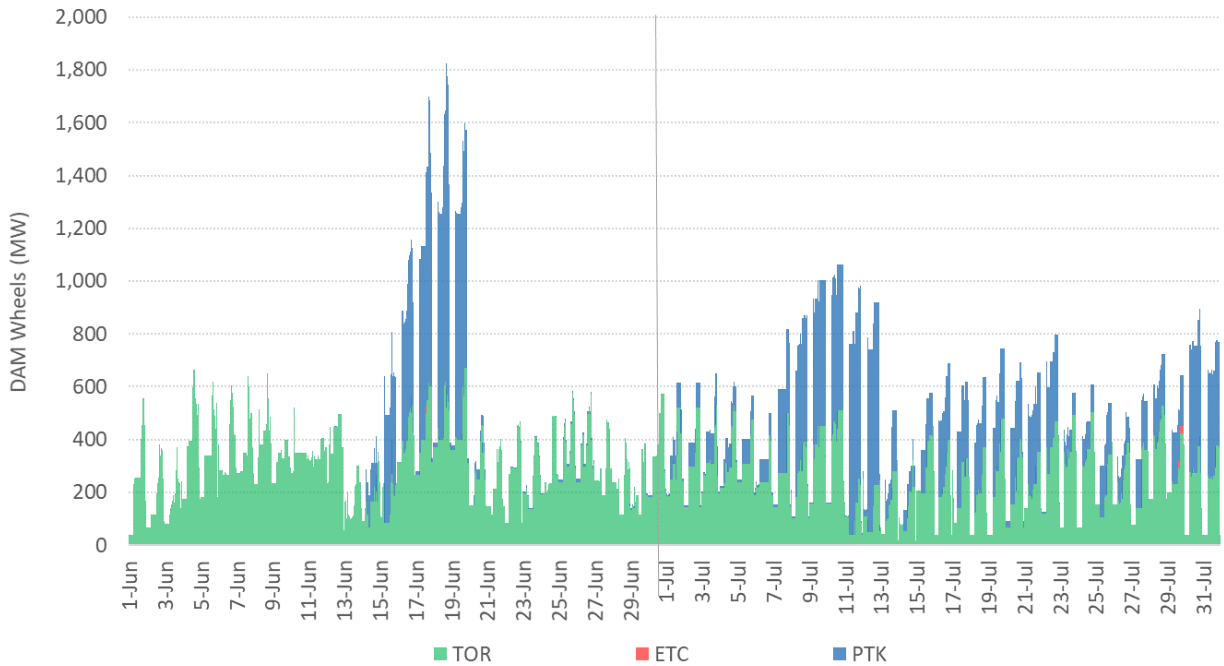


Figure 63: Hourly volume high-priority wheels

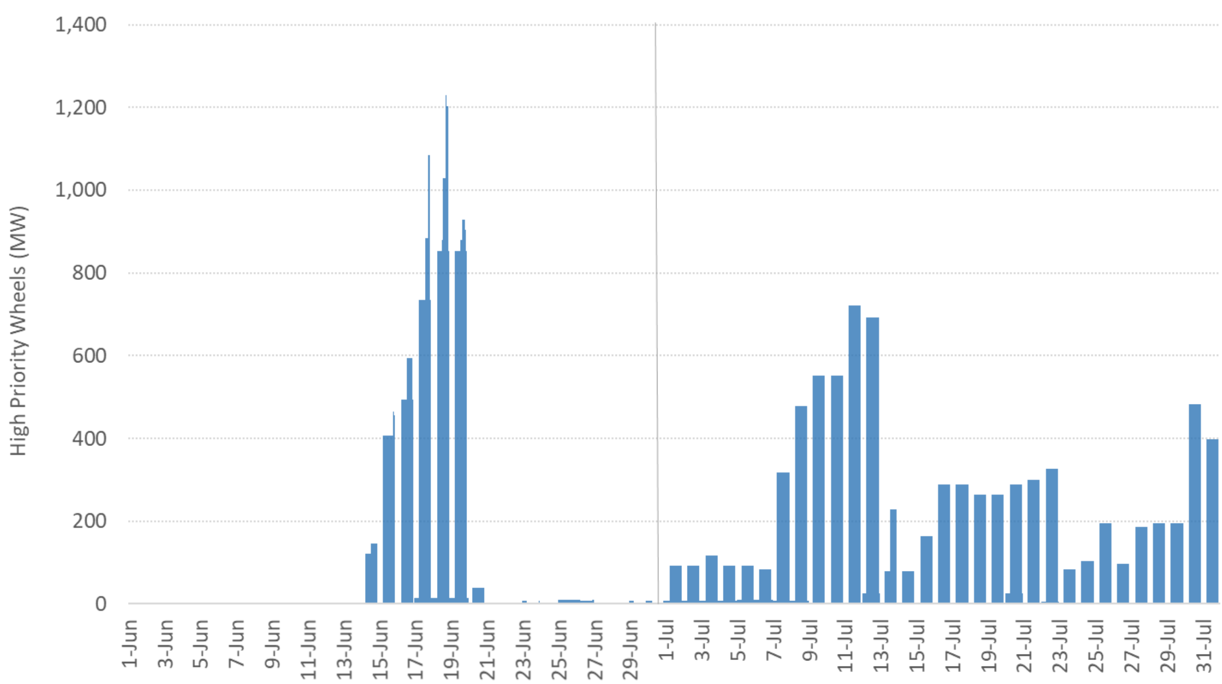
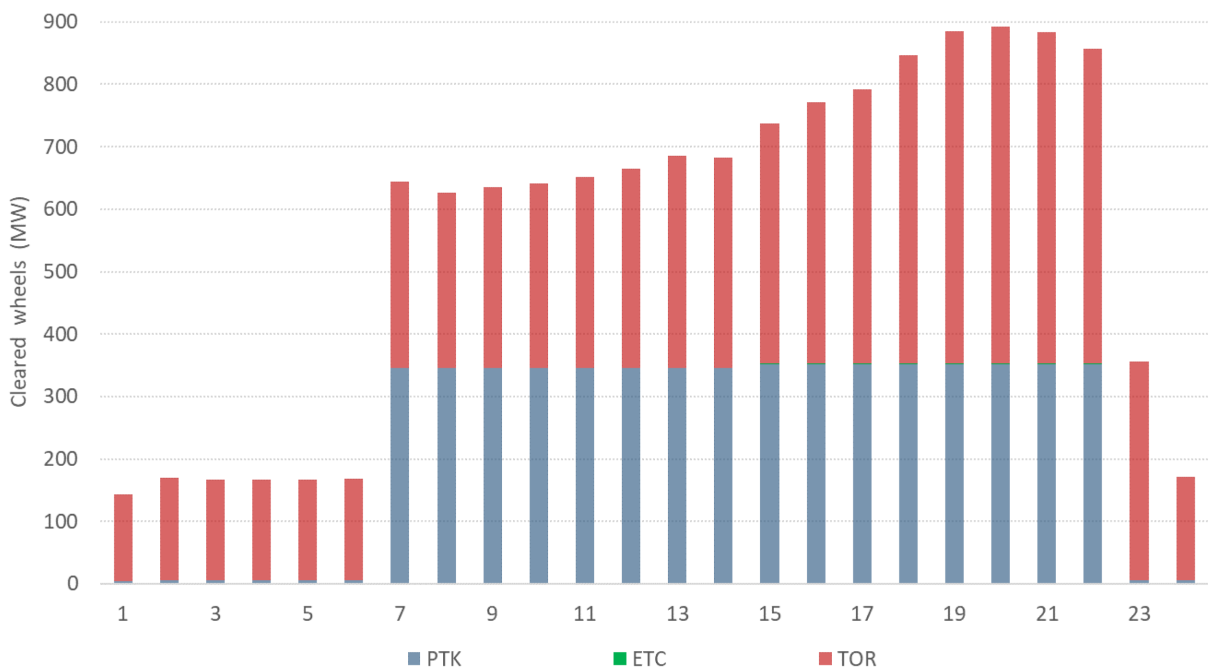


Figure 64: Day-ahead hourly profile of wheels in July



Wheels are defined with a source and sink location in the CAISO's markets to factor in their contribution to the flows on either intertie constraints or internal transmission constraints. Figure 65 summarizes the hourly average of wheels organized by source and sink combinations. An empty entry reflects that no wheels were present for that given source-to-sink combination in July. *Source* refers to the import scheduling point while *sink* refers to the export scheduling point. The largest volume of wheels in July in the day-ahead market were cleared for the path from Sylmar to Mcculloug500, followed by wheels from NOB to Palo Verde. These are the expected paths that wheel power through California from the Northwest to the Southwest.

Figure 65: Hourly average volume (MWh) of wheels by path in July

	Sink							
Source	MCCULLOUG500	PVWEST	ELDORADO230	MEAD230	WESTWING500	MDWP	MALIN500	NOB
CRAG	5.5	18.6						
MALIN500		23.7	8.5	3.1	0.3			
NOB	10.0	35.3		2.3	1.8	0.6		
PVWEST							6.4	6.4
SYLMAR	44.4	4.2						
TRCYCOTP	0.5	12.8						

Figure 66 summarizes the maximum hourly wheels cleared in any hour in July in the day-ahead market by source-to-sink combination. The maximum wheel transaction of 321 MW in July occurred from NOB to Paloverde, which is the same condition observed in June.

Figure 66: Maximum hourly volume (MW) of wheels by path in July

	Sink							
Source	MCCULLOUG500	PVWEST	ELDORADO230	MEAD230	WESTWING500	MDWP	MALIN500	NOB
CRAG	79	79						
MALIN500		186	96	13	15			
NOB	75	321		55	15	25		
PVWEST							288	288
SYLMAR	122	38						
TRCYCOTP	8	117						

Although wheels do not add or subtract capacity to the overall power balance of the CAISO market, they compete for limited scheduling and transmission capacity. With self-schedule wheels having higher priority than stand-alone imports or exports, wheels can clear before other imports on paths with limited capacity available. Figure 67 and Figure 68 show the IFM limits and schedules on Malin and NOB interties, respectively. It also shows the shadow prices when the constraint is binding. These constraints were binding slightly for the first part of July, but they saw high congestion once the derates were in place. IN hours when the interties are binding, imports available may not be able to clear and the market relies on the scheduling priorities to achieve an optimal scheduling where wheels will have the highest priority followed by PTK, LPT and the economic bids.

Figure 67: IFM schedules on Malin intertie in July

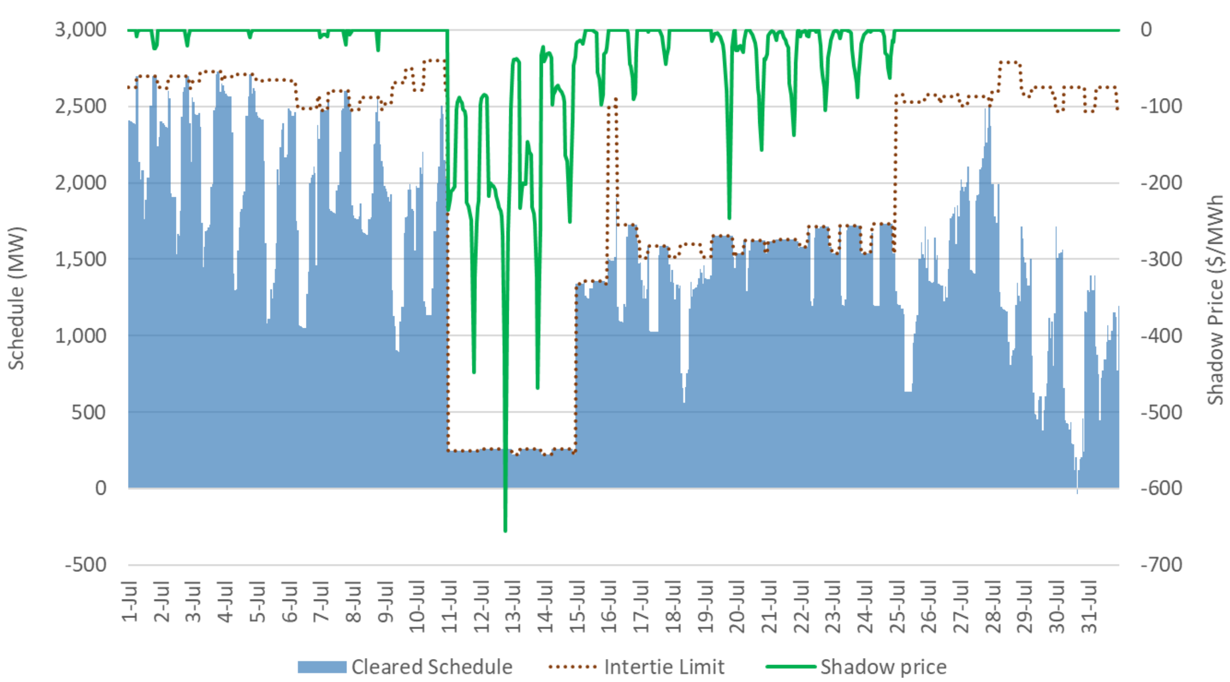
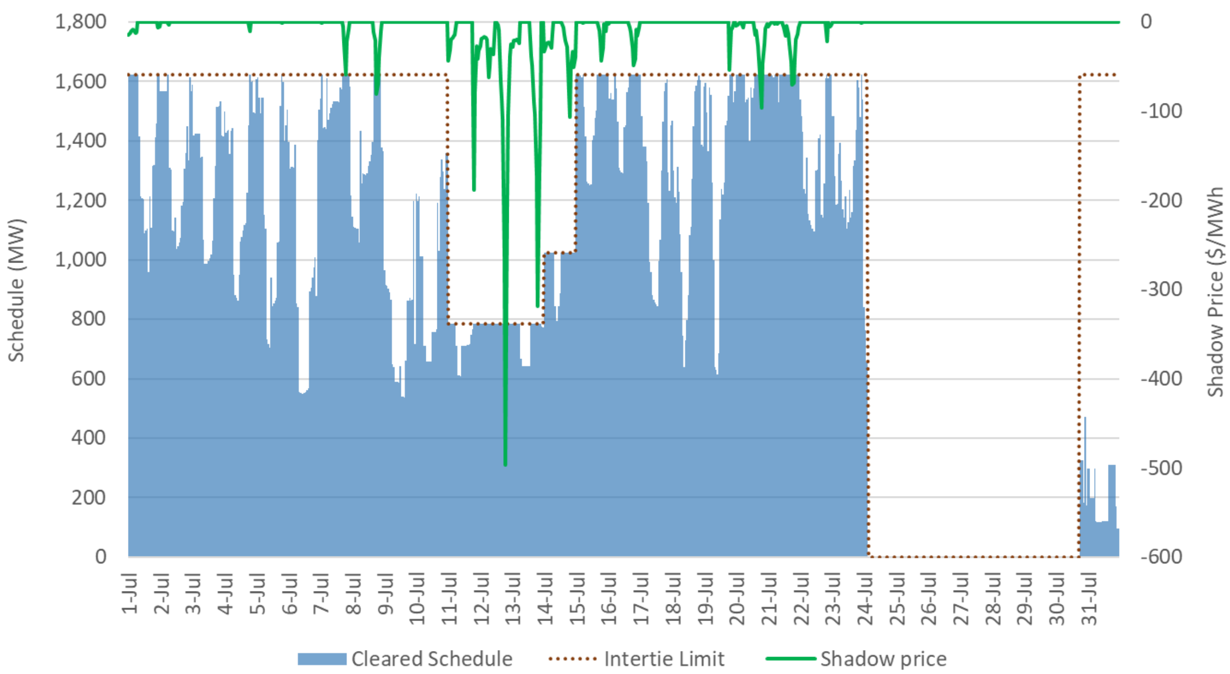
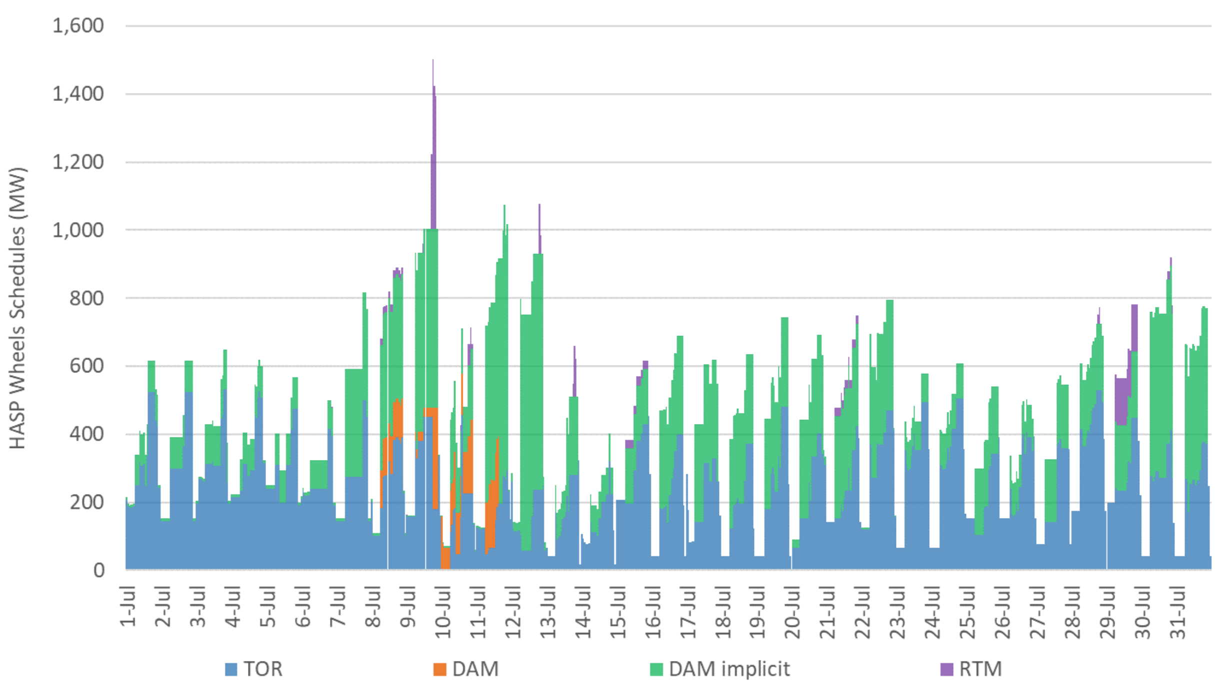


Figure 68: IFM schedules on NOB intertie in July



Wheels cleared in the day-ahead market can be carried over into the real-time market with a day-ahead priority or be directly self-scheduled in HASP process. Figure 69 shows the volume of wheels cleared eventually in the real-time market, organized by the various types of priority and relative changes.

Figure 69: Wheels cleared in real-time market



The *TOR* group represents the wheels with priority of transmission rights. This group includes those wheels that explicitly bid as wheels in real-time for either brand new wheels or carryover from the wheels cleared in RUC. This includes those wheels that cleared in RUC and did not explicitly bid in real-time and thus were self-scheduled into real-time as individual imports and legs with TOR priority. On July 9 and 10, some TOR wheels cleared in the day-ahead market subsequently came in to the real-time market with a day-ahead priority. These specific wheels were still classified as TOR instead of day-ahead priority wheels.

The *DAM* group is for wheels that cleared in RUC and effectively rebid into the real-time market. The *DAM Implicit* group captures the wheels cleared in the RUC process as explicit wheels but then they did not come as explicit wheels in real-time. Instead, they came in as default day-ahead priority imports or exports into the real-time market. The RTM group reflects wheels that came in directly into real-time and that did not have any scheduled cleared in the RUC process. These are incremental bids and procurement of wheels happening in real-time.

Notably, a large portion of the wheels cleared in real-time are essentially the same wheels cleared in the day-ahead market. Although the volume of incremental changes or new wheel bids coming in to real-time were minimal over the month, they rose to 500 MW on July 9, and to about 140 MW on July 29 during peak hours; these are the days in July with higher loads.

11 Demand Response

The CAISO markets consider demand response programs designed to reduce demand based on system needs, and trigger demand response programs through market dispatches. In the CAISO's markets, there are two main programs for demand response: economic (proxy) and emergency demand response. These programs use supply-type resources that can be dispatched similar to conventional generating resources.

Figure 70 shows the dispatch for proxy demand resources (PDR) in both the day-ahead and real-time markets. PDRs are dispatched economically in either market based on their bid-in prices. During the month of July, PDR resources were consistently dispatched in both the day-ahead and real-time markets. The largest volume of PDR dispatches occurred on July 9 at about 192 MW.

Figure 70: PDR Dispatches in day-ahead and real-time markets

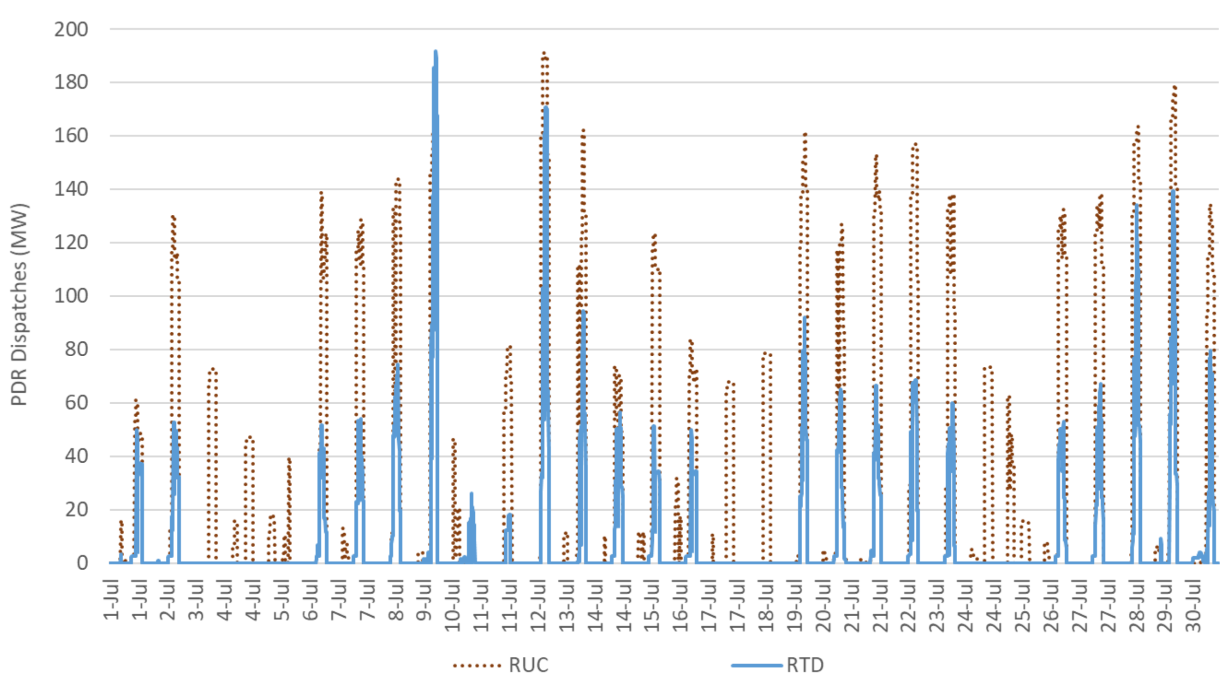
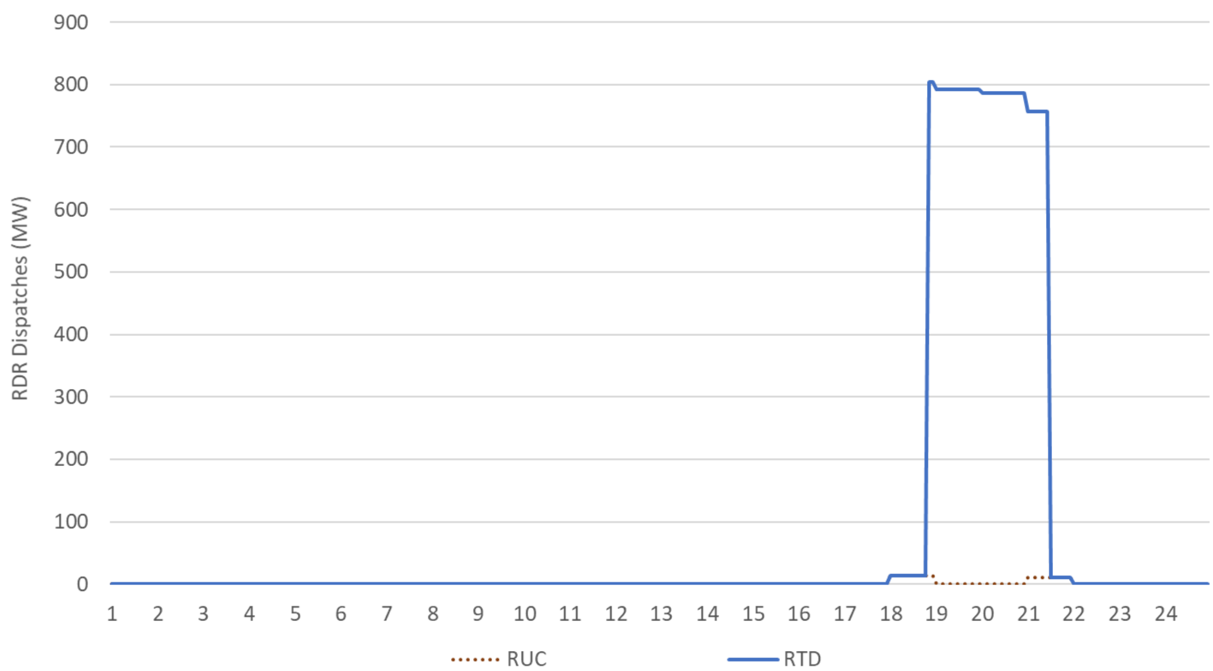


Figure 71 shows the dispatches for reliability demand response resources (RDRRs) in both the day-ahead and real-time markets. In the day-ahead market, these types of resources can be dispatched based on economics. The real-time market will consider these DAM dispatches as self-schedules. Therefore, these RDRRs will be dispatched in the real-time market even when there is no energy emergency declaration. Although most RDRRs are only deployed in the real-time when the CAISO has declared at least a CAISO Warning, some RDRRs may bid-in economically into the CAISO day-ahead market. In that case, any cleared RDRRs will come into the real-time market as a self-schedule and be dispatched generally at the same level of the day-ahead market award. RDRRs were dispatched in the real-time market only on July 9 up to 804 MW.

Figure 71: RDRR dispatches in day-ahead and real-time markets for July 9



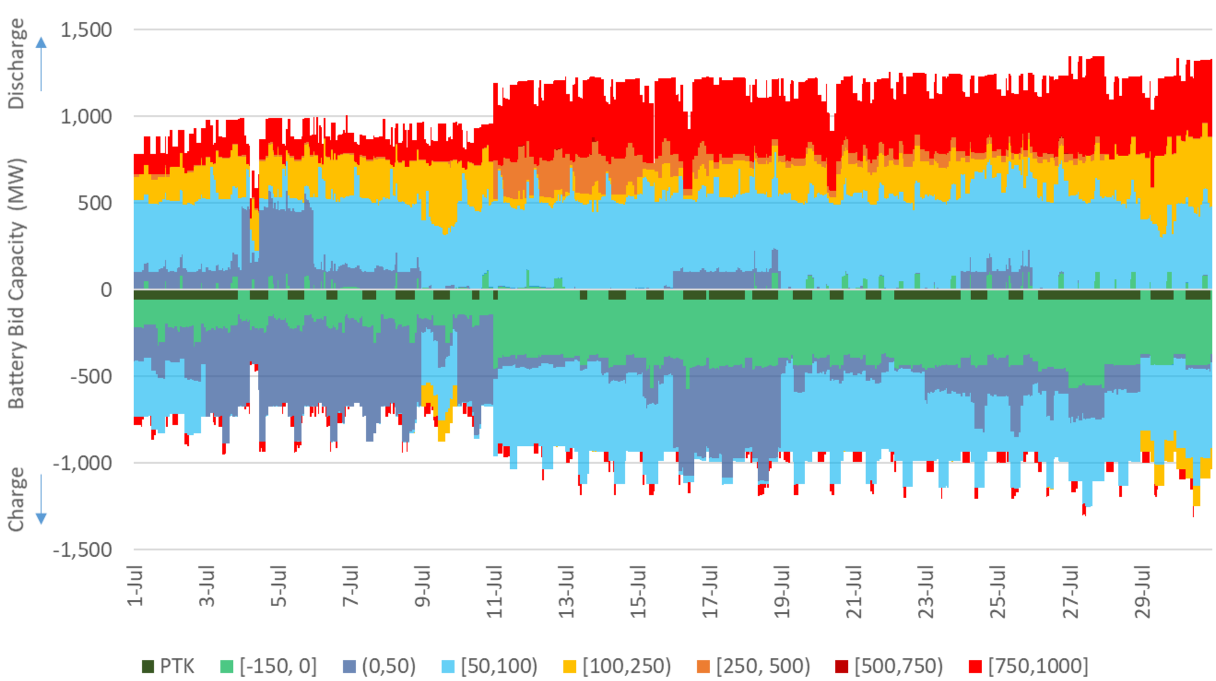
At the time this report was prepared, there were no estimates yet of the demand response performance. Estimates become available about two months after the trade date based on settlement data submitted by the scheduling coordinators and are used to measure the performance of demand response resources relative to a baseline. The CAISO will report on their performance when the data becomes available.

12 Non Generating Storage Resources

The CAISO's markets use the Non-Generating Resource (NGR) model to accommodate energy-constrained storage resources that can consume and produce energy. The NGR model allows storage resources to participate in the regulation market only, or participate in both energy and ancillary service markets. In June 2021, there were 30 storage resources actively participating in the CAISO markets. Of these 28 resources, 26 storage resources participated in both the energy and ancillary service market, whereas two resources participated only in the regulation market. In July, five additional storage resources were actively participating in the CAISO market and their total storage capacity was 2,093 MWh. Storage resources can arbitrage the energy price by consuming energy (storing charge) when prices are low, then subsequently delivering energy (discharging) during market intervals with high prices. Each storage resource has a maximum storage capability that reflects the physical ability of the resource to store energy.

In July, the smallest storage capacity of the 30 storage resources was 4.4 MWh, and the largest storage capacity was 920 MWh. In July the total storage capacity of all the active resources participating in the market was 5,646 MWh. Figure 72 shows the bid-in capacity for storage resources in the day-ahead market.

Figure 72: Bid-in capacity for batteries in the day-ahead market



The negative area represents charging while the positive area represents discharging. The bid-in capacity is organized by $/MWh price ranges. The green area represents batteries bidding negative prices for charging and shows a consistent pattern in July. There is a fair amount of capacity willing to charge at positive prices only when prices are higher than $50/MWh, as shown in light blue. On July 11 the overall capacity increased with additional units available in the market. As the CAISO experienced the July heat conditions, batteries were bidding to charge even at prices higher than $50/MWh. Conversely, in this period they were willing to discharge at higher prices. There is a consistent pattern of batteries bidding to discharge only at high prices of over $250/MWh. The bright red shows bids close to or at the bid cap and shows that there is certain volume of storage capacity that is expecting to discharge only at these high prices. Figure 73 shows the bid-in capacity for the real-time market. The majority of bids into the real-time market are between -$150/MWh and $100/MWh.

Figure 73: Bid-in capacity for batteries in the real-time market

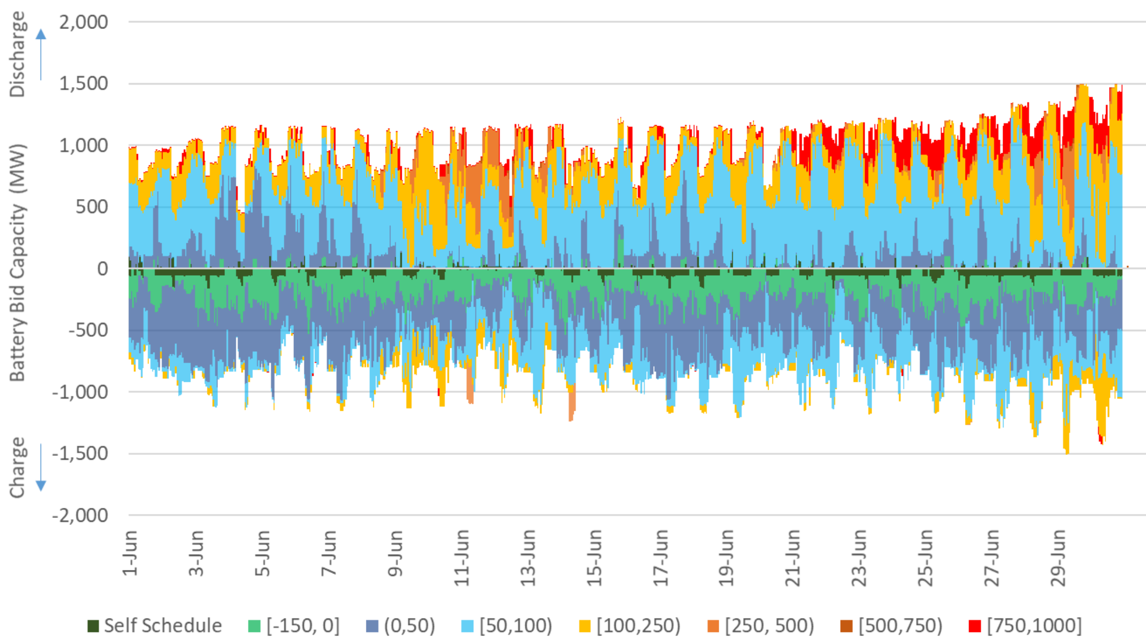


Figure 74 IFM distribution of state of charge for June and July 2021

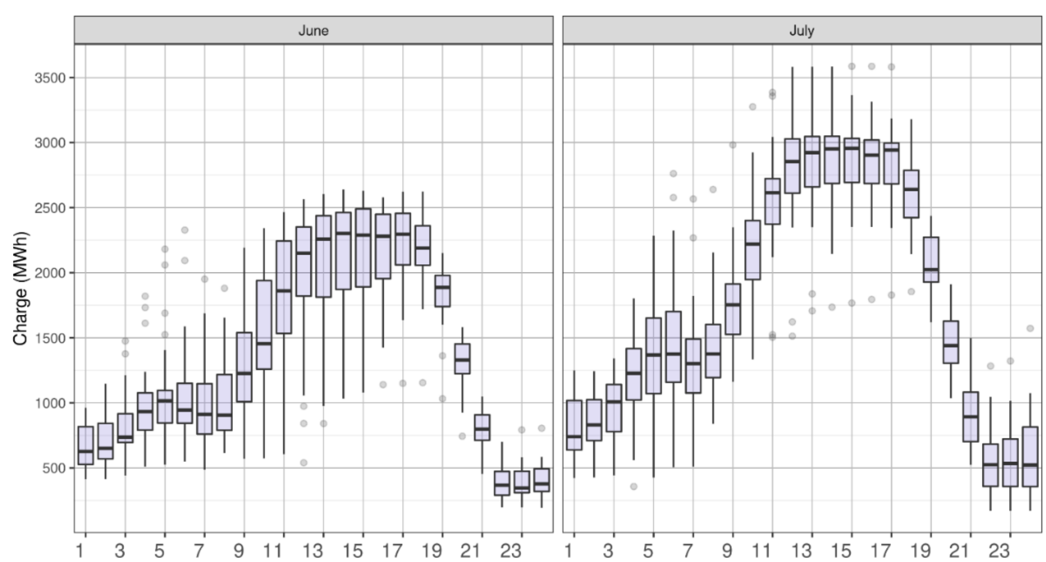
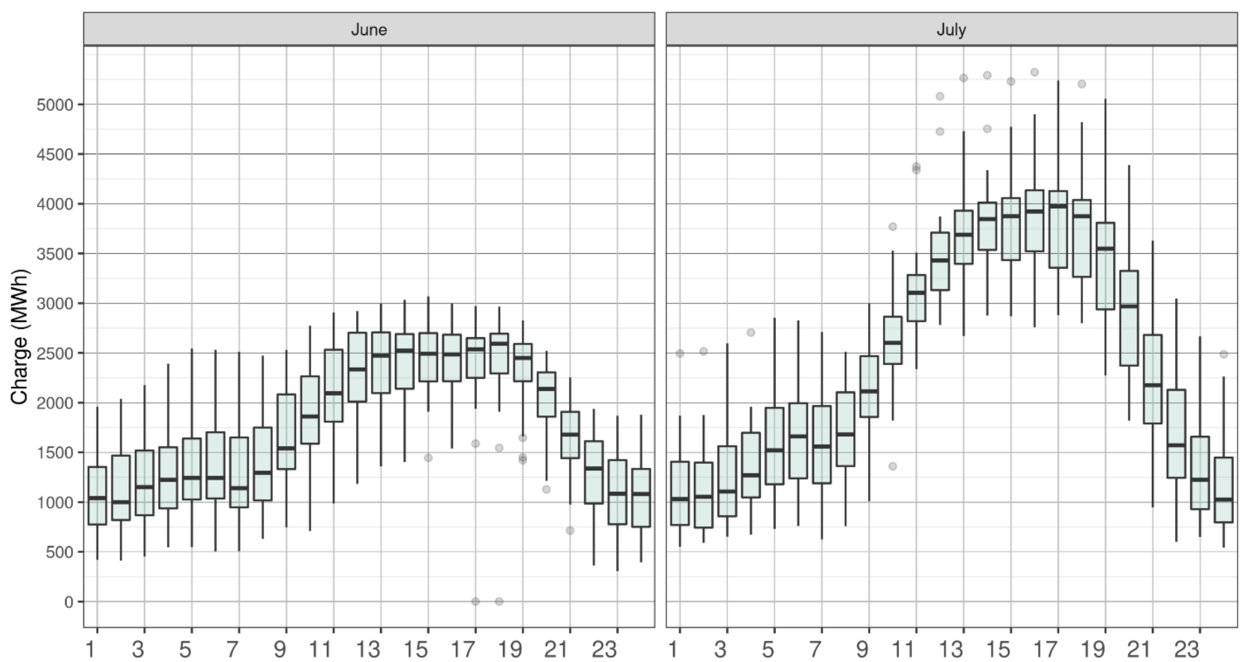


Figure 74 shows the hourly distribution of the storage capacity of resources participating in IFM for June and July 2021. The box bar plot shows the median, 25th percentile, 75th percentile, and outliers for the total state of charge in IFM. Storage resources charge in hours when there is abundantly cheap energy from solar resources during the morning and early afternoon, between hour ending eight and 17. The system reached maximum stored energy by hour ending 17, followed by a period of steady discharge from hours ending 18 through 24. The highest median system state of charge in July occurred in hour ending 17 and it was higher than the median total system state of charge in June because there were more storage resource participating in the ISO market in July compared to June. Figure 75 shows the distribution of state of charge for the real-time market for June and July 2021. The hourly average state of charge in the real-time market is higher than the average stage of charge in the day-ahead market because some of the storage resource did not receive an award in the IFM market based on their bid and some above RA resource did not participate in the day-ahead market.

Figure 75 Real-Time Market distribution of state of charge for June and July 2021



Most of the storage resources in the CAISO market are four-hour batteries, which implies that if a resource is fully charged, it will take four hours to discharge this resource completely. To arbitrage prices, it is expected that the resource would be charged to full capacity just prior to the hours with high energy prices. Figure 76 shows the average hourly system marginal energy component (SMEC) of the locational marginal price in IFM for July 2021. The hourly average SMEC is the highest in hours ending 18, 19, 20, 21, and 22 compared to all other hours, and these hours are indicated in red. With the need for more supply as solar production diminishes, it is expected that storage resources would be discharging during these hours. The chart in Figure 77 and Figure 78 shows the distribution of energy awards in hours ending 19 through hours ending 22 in a different color than the energy awards in other hours, to show that the storage resources are being discharged in intervals with the highest energy prices.

Figure 76: IFM hourly average system marginal energy price for July 2021

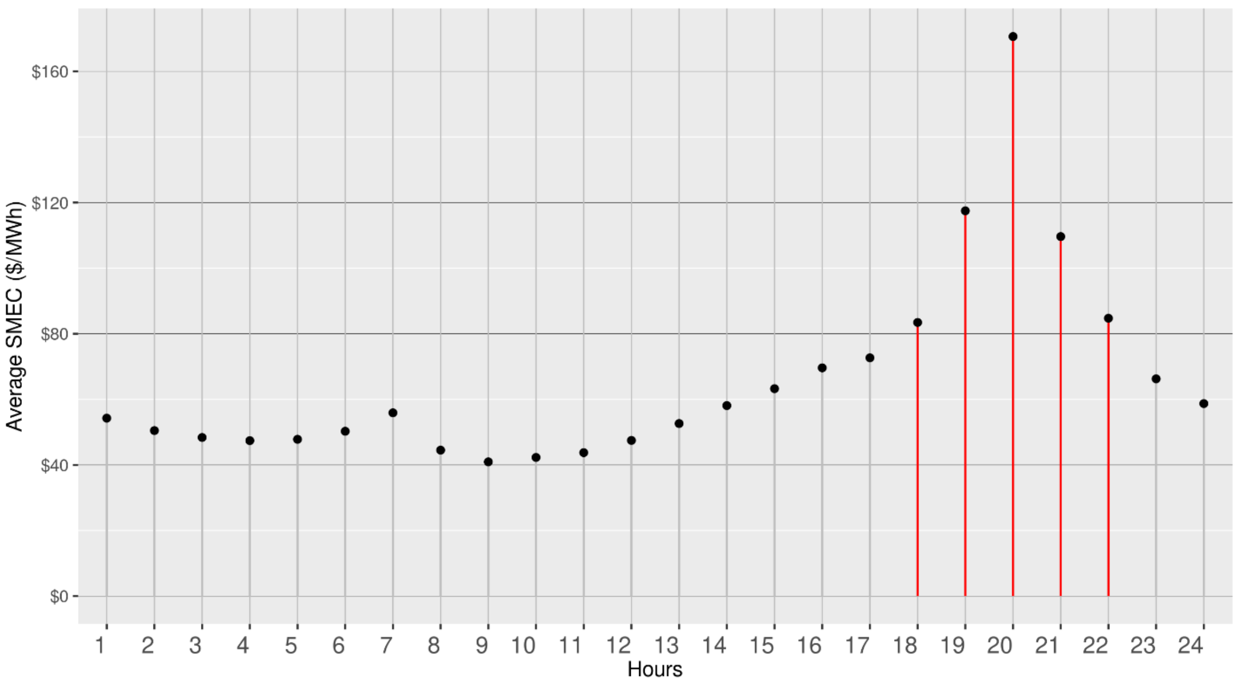


Figure 77: Hourly distribution of IFM energy awards for batteries in July 2021

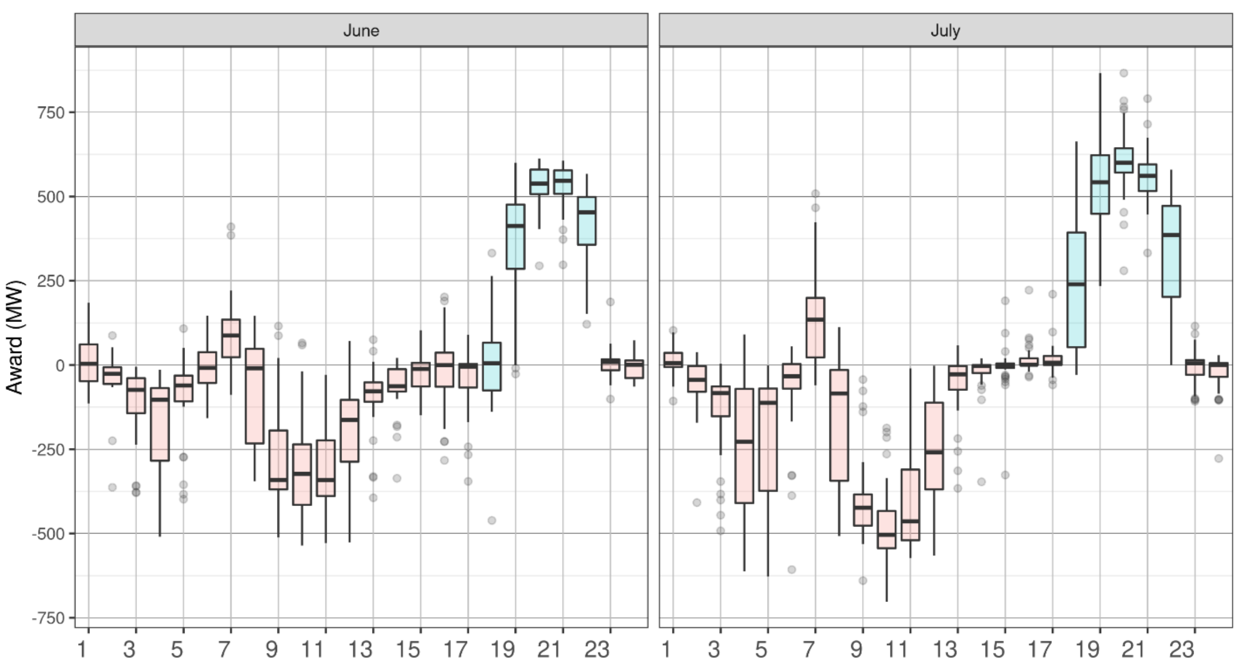


Figure 78: Hourly Distribution of real-time dispatch for batteries in July 2021

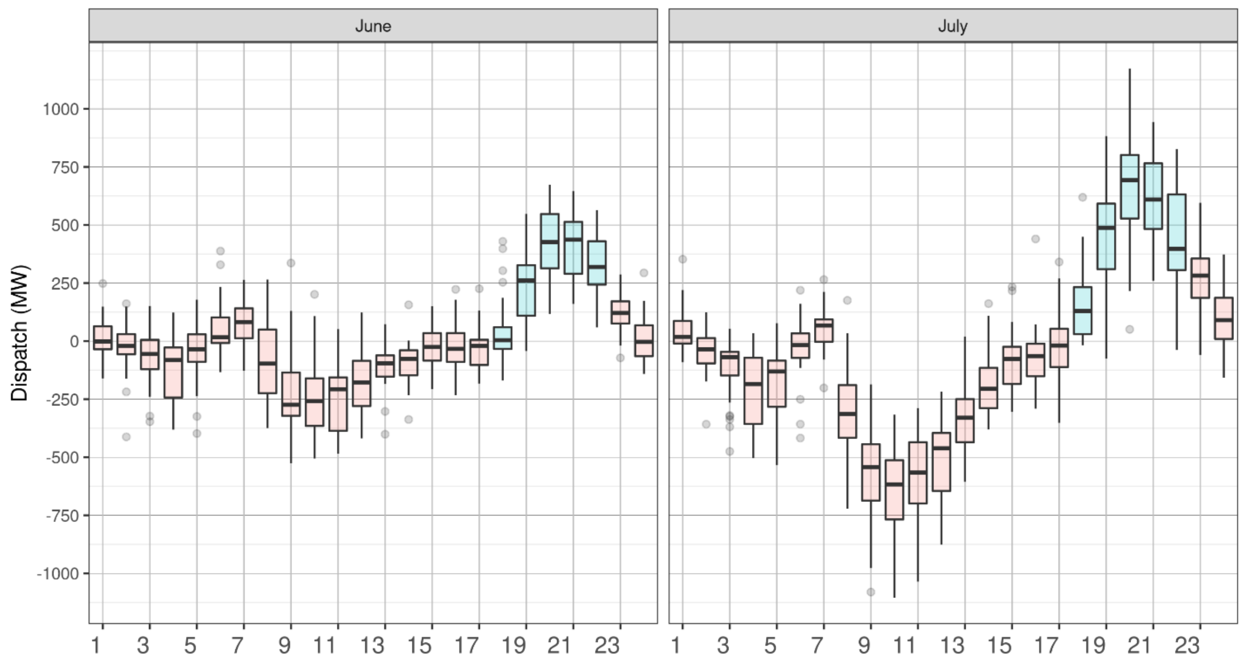


Figure 79: Daily RTD award in June and July 2021

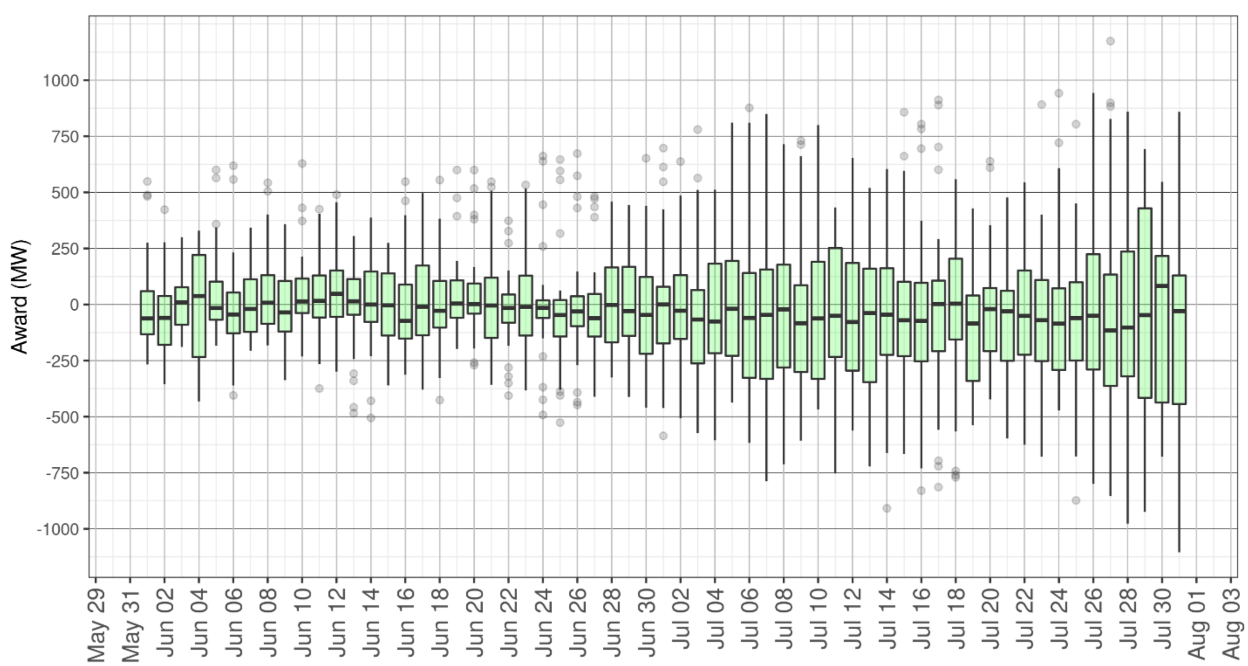
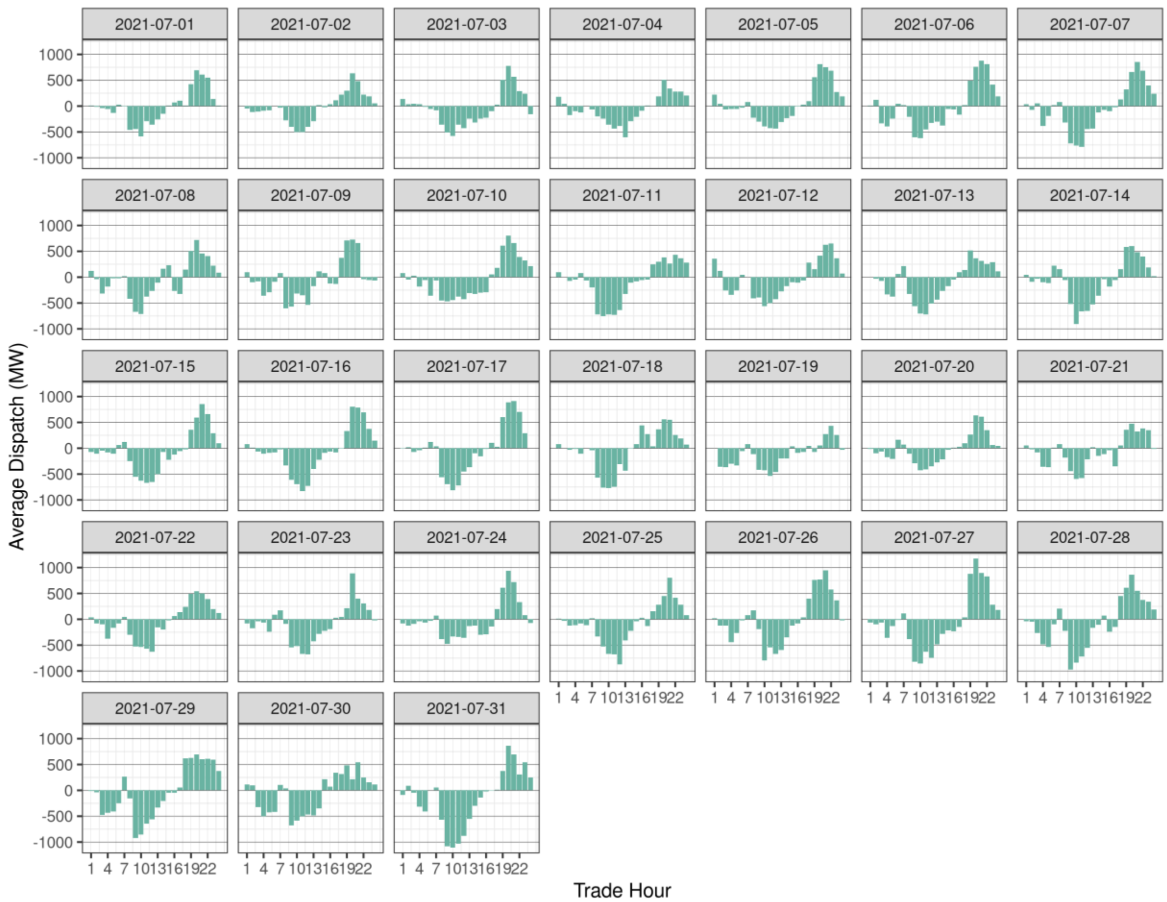


Figure 80 Hourly average real-time dispatch in June and July 2021



13 Energy Imbalance Market

13.1 EIM transfers

The Energy Imbalance Market, or EIM, provides an opportunity for participating balancing authority areas to serve its load while realizing the benefits of increased resource diversity. The CAISO estimates EIM gross economic benefits on a quarterly basis.[42] One main benefit of the EIM is the realized economic transfers among areas. These transfers are the realization of a least cost dispatch by reducing more expensive generation in an area and replacing it with cheaper generation from other areas. In a given interval, one area may have an import transfer with another area while concurrently having an export transfer with another area. Figure 81 shows the distribution of five-minute EIM transfers for the CAISO area. A negative value represents an export from the CAISO area. This trend shows that for the first half of June, the CAISO area has a predominant EIM export condition which evolved to a more dominant Import position as it entered into the mid-June heatwave. On June 16 through June 19, CAISO's area saw net import transfers for almost the whole time. With the exception of the long weekend of July 4, where EIM transfers into the CAISO were mainly exports, the predominant trend of imports continued through July.

Figure 81: Daily distribution of EIM transfers for CAISO area

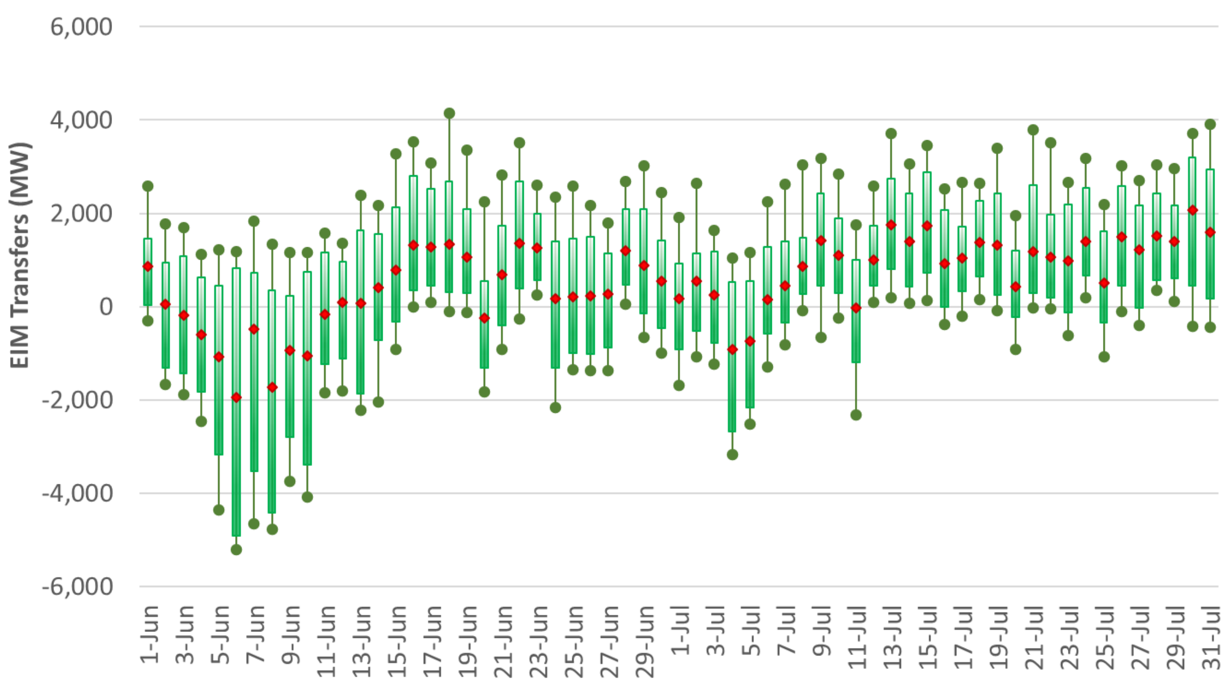


Figure 82 shows the EIM transfers in an hourly distribution, which highlights the typical profile of CAISO transfers which are generally export transfers during periods of solar production. During the evening ramp as the evening peak approaches, the transfers become a net import to the CAISO area.

[42] The EIM quarterly reports are available at https://www.westerneim.com/pages/default.aspx

Figure 82: Hourly distribution of five-minute EIM transfers for CAISO area

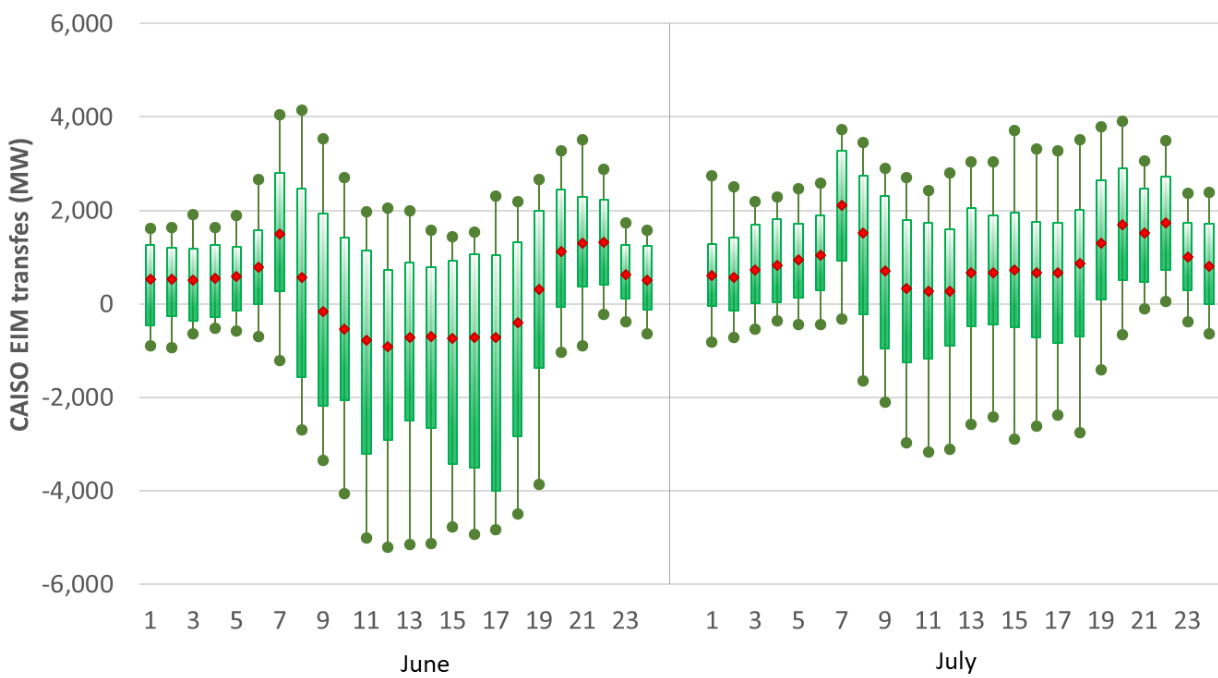
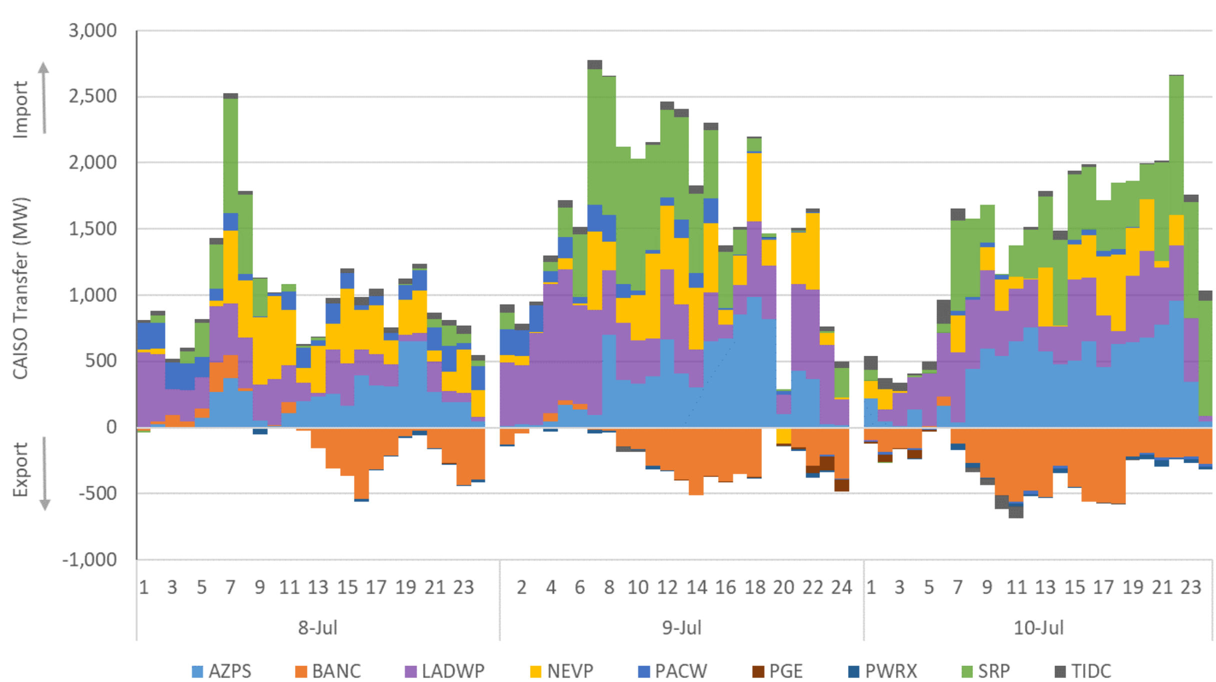


Figure 83 shows a more granular trend of the CAISO EIM transfers with all adjacent balancing areas. To ease the illustration the five-minute transfers are averaged on an hourly basis.

Figure 83: Hourly EIM transfers breakdown for CAISO area during the heatwave period



Each color bar represents the EIM transfers with another area, either imports or exports. These are direct transfers between CAISO and its adjacent balancing areas. In some cases, the EIM transfers are wheeling through these adjacent areas and not necessarily being all sourced from the adjacent areas.

During the week of the heat wave, EIM transfers into the CAISO were largely imports. Some of these transfers wheeled through CAISO into the BANC area.

13.2 Capacity test

The EIM system performs a series of resource sufficiency evaluations to ensure each EIM entity is able to meet its demand with its net-supply prior to engaging in transfers with other EIM balancing areas in the real-time market. The resource sufficiency evaluation is comprised of four tests: 1) feasibility, 2) balancing, 3) capacity and 4) flexibility. The capacity and flexibility test results affect the ability of a balancing authority area to utilize the benefits of EIM transfers. Thus, this section will mainly focus on these two tests.

The capacity test determines whether an EIM entity balancing authority area (BAA) is participating in the EIM with sufficient supply to meets its demand forecast and uncertainty in tagging import and export transactions.[43] Starting on June 15, 2021, due to the recent Market Enhancements for 2021 Summer Readiness,[44] the capacity test also requires an additional amount of resource capacity to account for net-load uncertainty. Before June 15, 2021, if an EIM entity failed the bid-range capacity test, it automatically failed the flexible ramp sufficiency test; however, starting on June 15, 2021 the market application performs the capacity test independent of the flexible ramp sufficiency tests. This means that if the EIM entity fails the capacity test, it does not automatically fail the flexible ramp sufficiency test. The CAISO performs the bid capacity test in both upward and downward directions. If an EIM entity fails the upward capacity test, then its import EIM transfers are capped to the optimized EIM transfers from the last 15-minute interval before the test failure. The net effect of failing the capacity test has not changed after the Market Enhancements for the 2021 Summer Readiness; in other words, even though the capacity test and flexible ramp sufficiency test are performed independent of each other, the system caps their EIM transfers level to least restrictive of the either the last 15-minute transfer or the base schedule transfer.

Figure 84 below shows the daily frequency of upward capacity test failures for all EIM BAAs for June 2021. There were 16 EIM BAAs participating in the real-time EIM in July, including the CAISO. The SRP BAA had the most intervals with the upward capacity test failure for a total of 3 percent of intervals for the month, whereas there were two EIM BAAs that passed the upward capacity test in all 15-minute intervals for the month. The SRP BAA failed the upward capacity test most frequently, in 22 percent of intervals on July 22, 2021. The CAISO failed the upward capacity test in 0.20 percent of the 15-minute intervals, which account for six intervals of the month. The CAISO failed the upward capacity tests in hour ending 19 on July 9, 28, 29 and 30. Figure 85 displays the hourly frequency of capacity test failures for all EIM BAAs for July 1, 2021 until June 30, 2021. Of the total upward capacity test failures for the month, 49 percent of the upward capacity test failures occurred in hours ending 18, 19, 20 and 21.

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[43] Bautista Alderete, Guillermo and Kalaskar, Rahul. Resource Sufficiency Evaluation Bid Range Capacity Test. Mar 2021- PowerPoint Presentation
[44] Market Enhancements for Summer 2021 Readiness- Final Proposal

Figure 84 Daily frequency of upward capacity test failure for June and July 2021

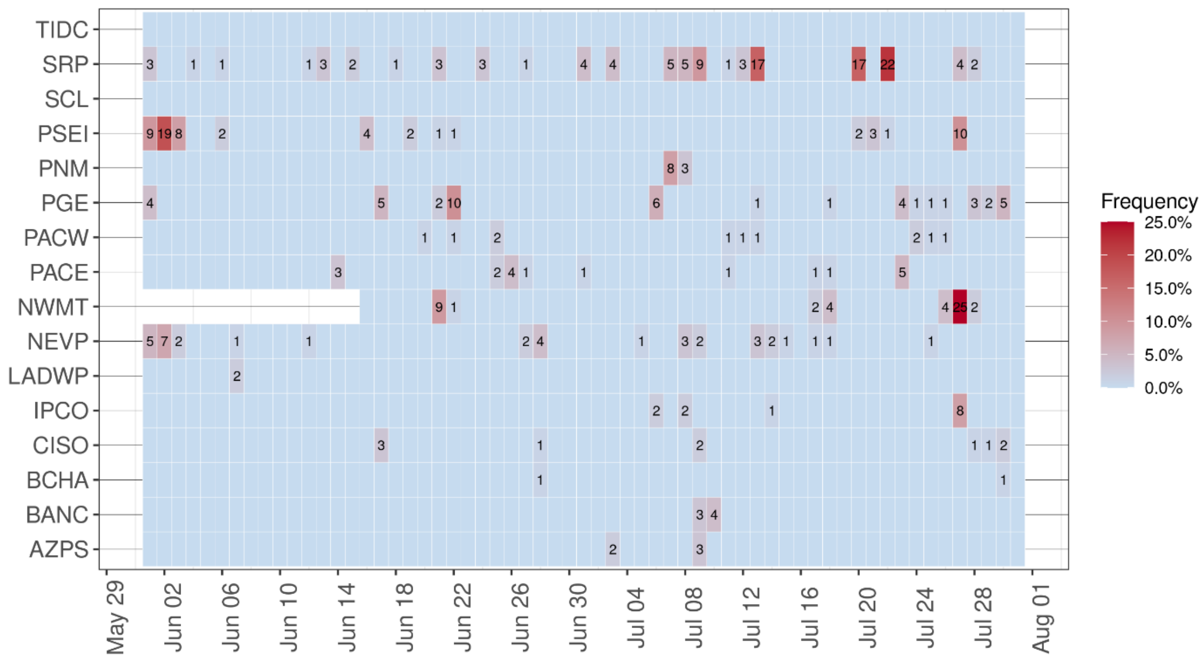


Figure 85 Hourly frequency of upward capacity test failures for July 2021

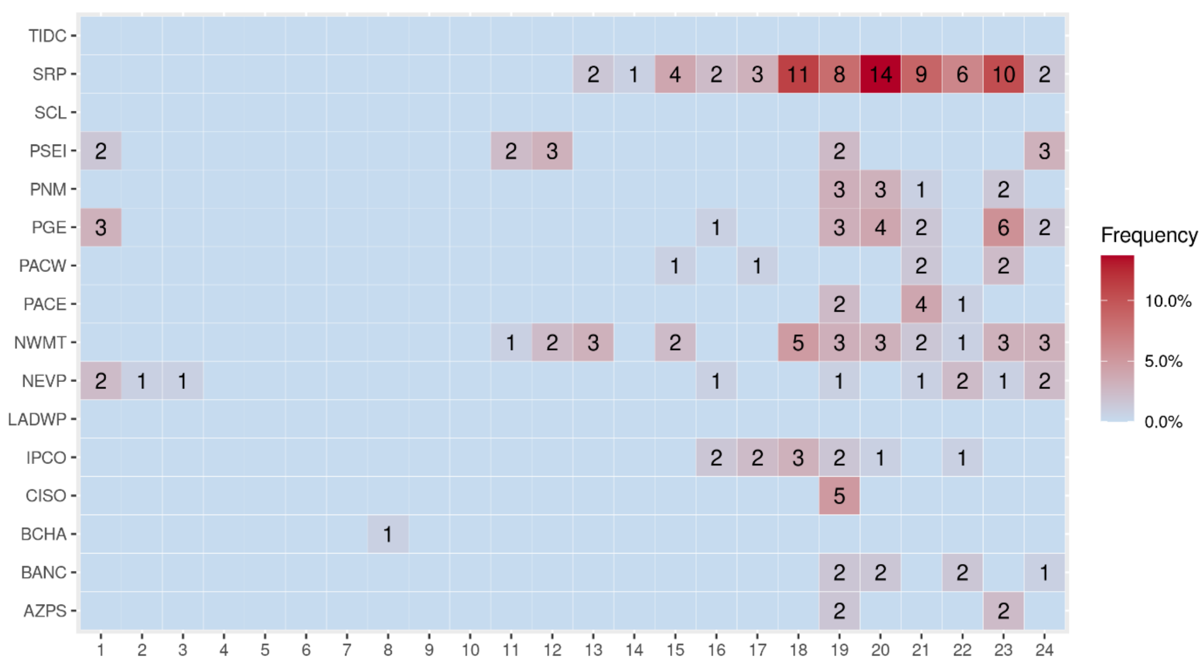
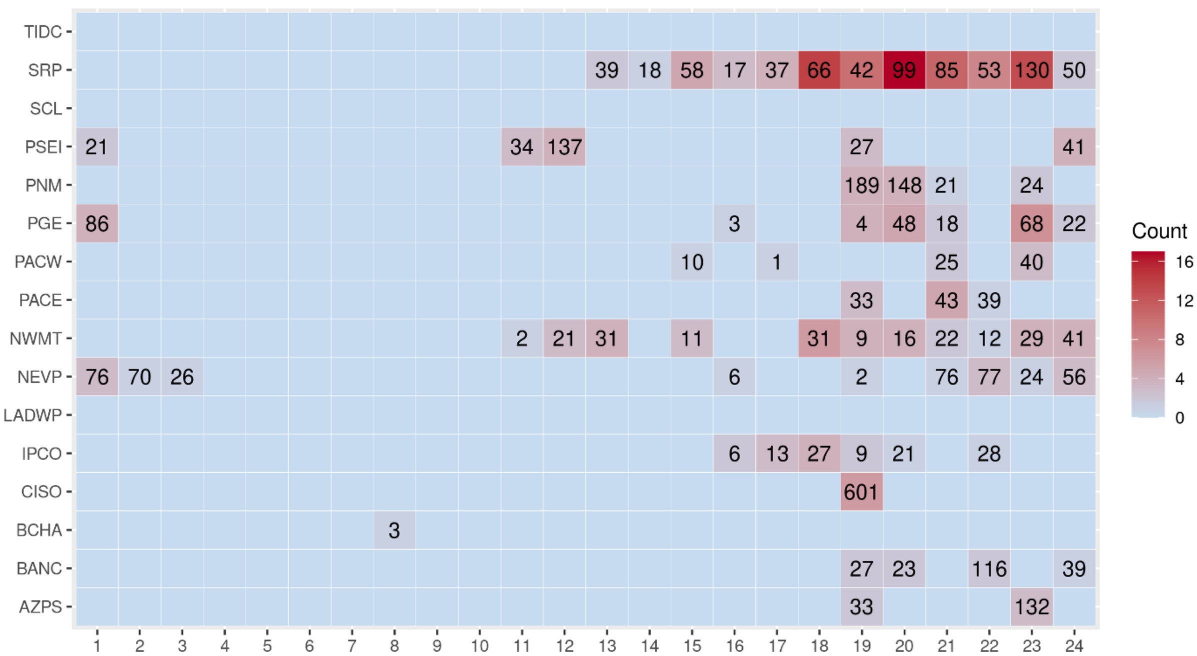


Figure 86 shows the heat map for the amount of upward capacity test failures for July 2021. The color in each cell reflects the level of capacity test failures, where a darker red shows higher MW failures. The number in each cell represents the average MW imbalance of the capacity test failure. This imbalance represents the difference between the BAA's requirement for the upward capacity test and the available supply for the upward capacity test. The SRP BAA had the highest frequency of upward capacity test failures, occurring in hour ending 20 and shown in the darker red color. The CAISO BAA had the maximum number of capacity test failures in hour ending 19 with the average imbalance from the upward capacity test of 601 MW.

Figure 86 Hourly frequency of upward capacity test and average imbalance for July 2021



A policy change based on the Market Enhancement for Summer 2021 led the CAISO to enhance the capacity test on June 15, 2021 to include the net load uncertainty in the capacity test requirement. The CAISO performed a counterfactual calculation to determine the upward capacity test failure without net load uncertainty included in the test. Figure 87 shows the comparison of the upward capacity test failures with and without uncertainty. This is a plain comparison between the capacity test scenarios and does not include any outcome of the flexible ramp sufficiency test. Overall. The number of failures for capacity test with the addition of the uncertainty component increased to 245 interval in July, relative to 84 failures when no uncertainty is considered in the test (counterfactual).

Figure 87: Daily Frequency of upward capacity test failures for all EIM BAAs

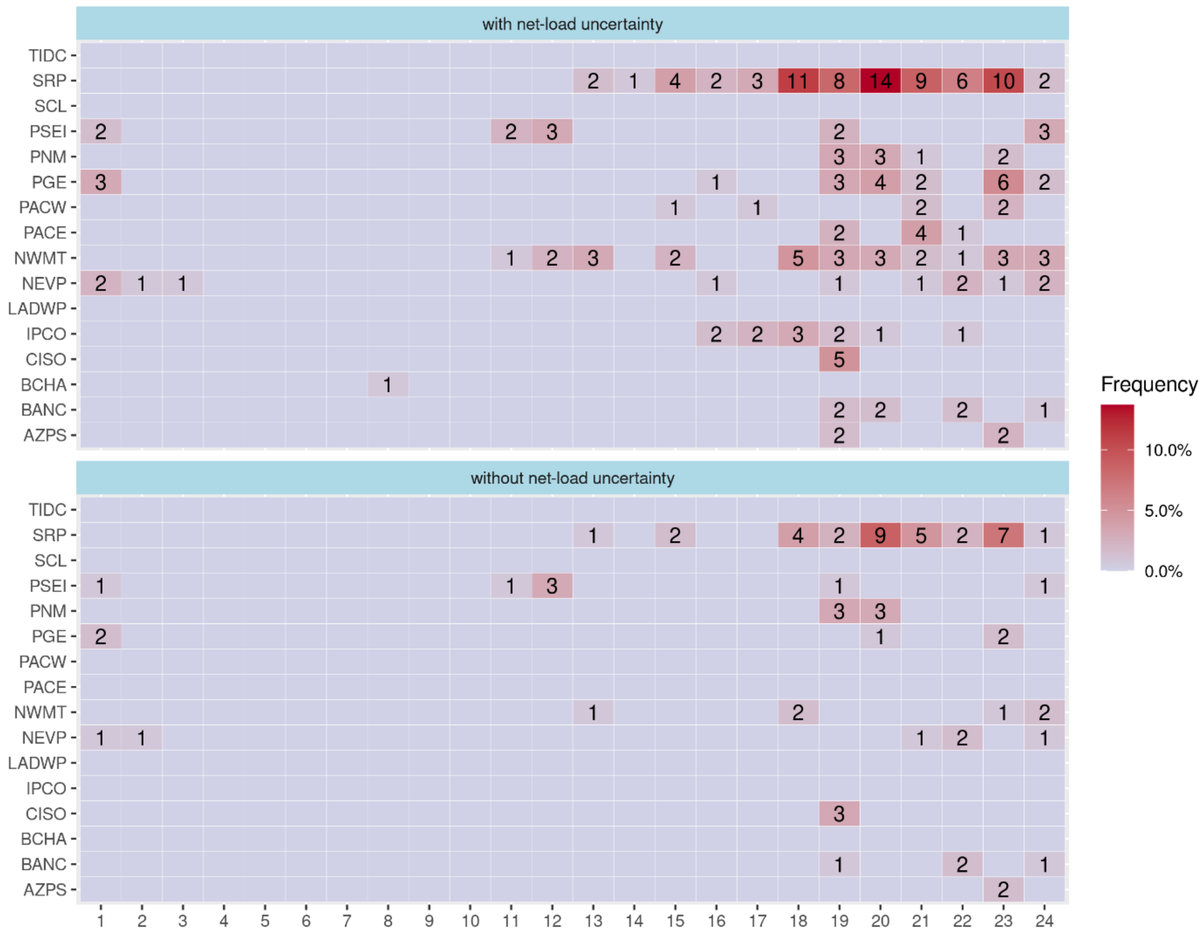


Figure 88 shows two heat maps: the top heat map shows the original capacity test results and the bottom heat map shows the capacity test results excluding the net load uncertainty requirement but including the impact of flexible ramp up sufficiency test. If an EIM BAA fails either the capacity up test or the flexible ramp up sufficiency test then it affects the import EIM transfer capability for the BAA. Therefore, if an EIM entity passed the capacity test when the effect of net load uncertainty was not considered but failed the flexible ramp up test in the same interval, that interval is counted as a failure for the dataset used to create the heat map for chart labeled without net load uncertainty. For July, the SRP BAA had failed the upward capacity test in 3 percent of intervals, which reduced to a failure rate of 1.88 percent when the counterfactual calculation was performed. Similarly, for July, the CAISO BAA had failed the upward capacity test in 0.20 percent of intervals, which reduced to 0.134 percent when the counterfactual calculation was performed; the CAISO's total count of upward capacity test failures in July went from six intervals to four intervals. The SRP BAA had 90 15-minute intervals of upward capacity test failures in July, which reduced to 56 intervals when the counterfactual calculation was performed.

Figure 88: Daily Frequency of upward capacity test failures for all EIM BAAs with consideration of flex failures

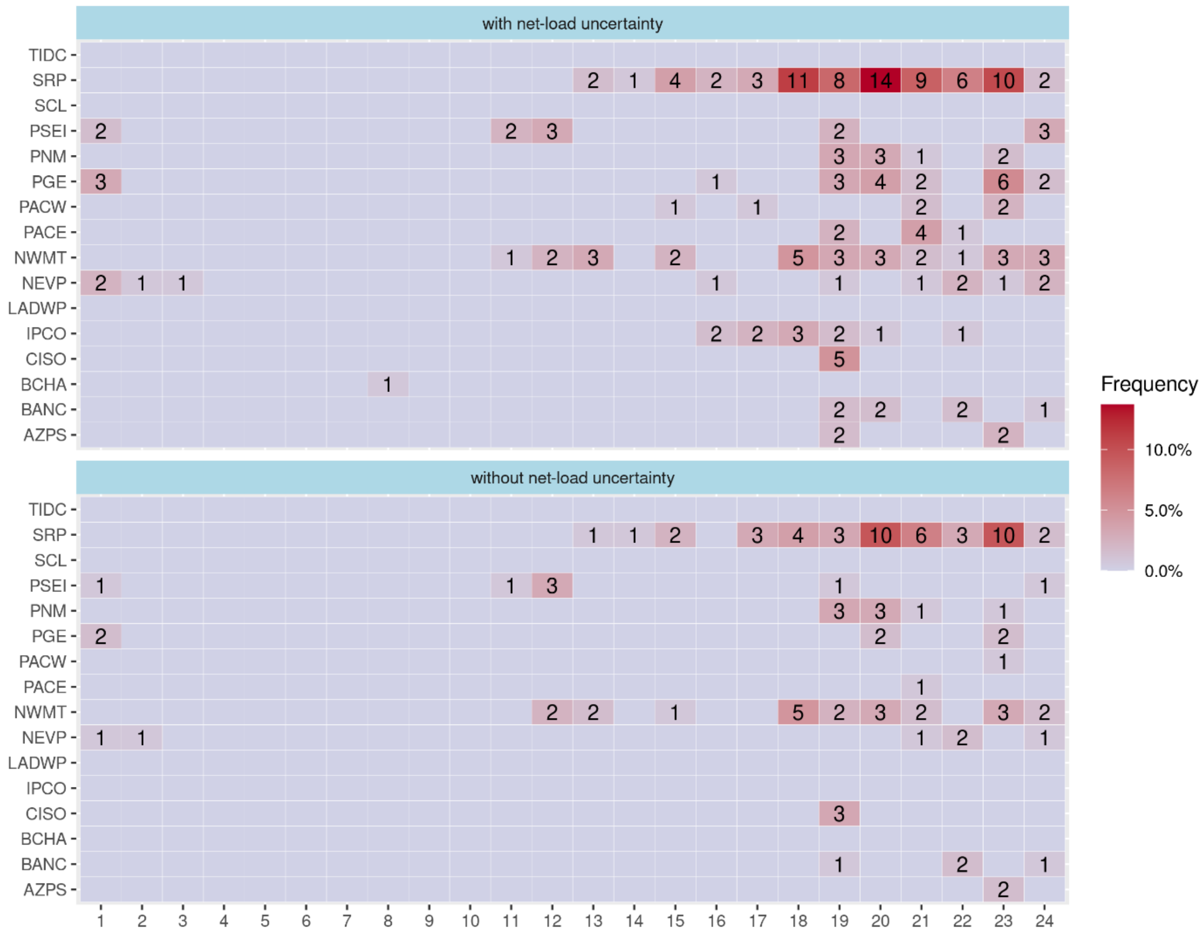


Figure 89 below shows the daily frequency of downward capacity test failures for all EIM BAAs for June 1, 2021 until July 31, 2021. In June, there were 16 EIM BAAs participating in the real-time EIM including the CAISO. There were minimal capacity test down failures for July 2021; the BCHA BAA had the maximum number of intervals with the downward capacity test failure for a total of 0.10 percent of intervals in the month, whereas, there were thirteen EIM BAAs that passed the downward capacity test in all 15-minute intervals for the month. Figure 90 shows the hourly frequency of downward capacity test failures for all EIM BAAs for July 2021. There were very few hours with downward capacity test failures for the EIM BAAs, and occurrence of downward capacity test failure was spread evenly across all 24 hours.

Figure 89: Daily frequency of downward capacity test failures in July

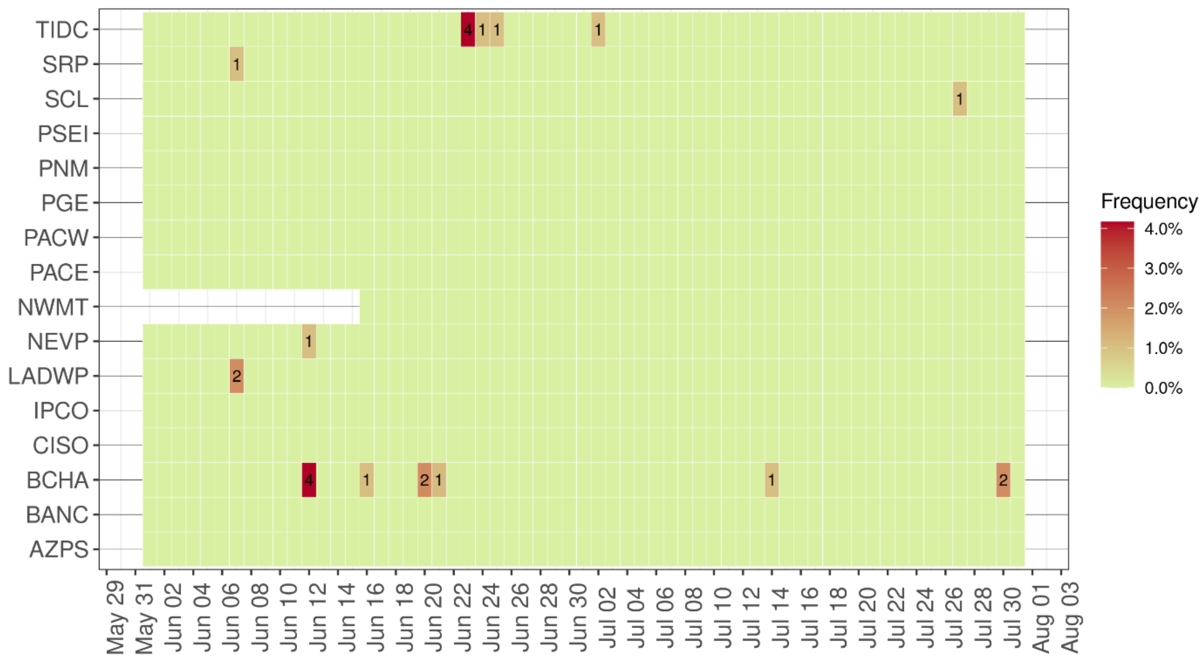
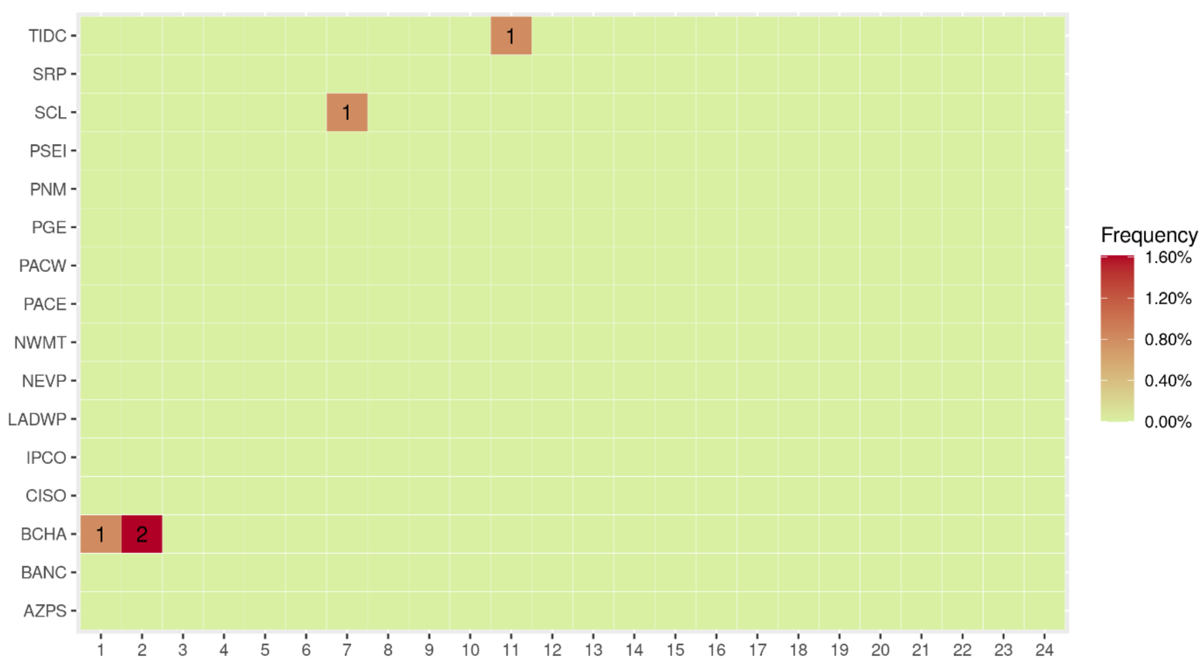


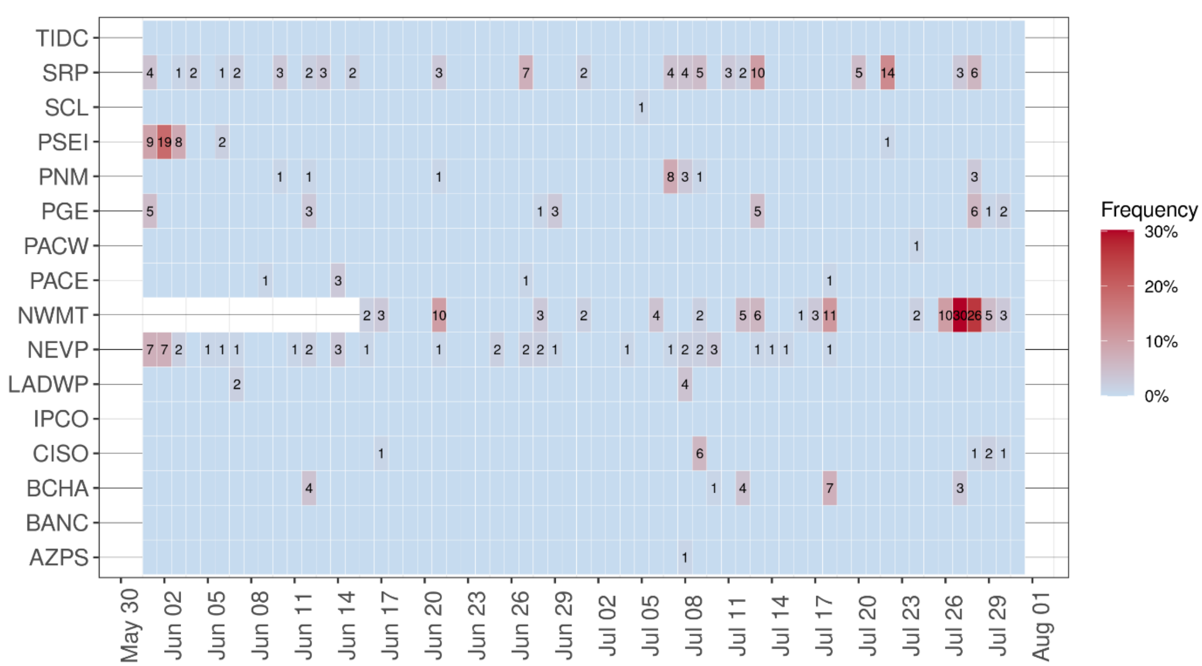
Figure 90: Hourly frequency of downard capacity test failures in July



13.3 Flexibility test

The flexible ramp sufficiency, or flexibility, test ensures EIM BAA have sufficient ramping capabilities to meet load forecast change and net load uncertainty (uncertainty in demand forecast, solar generation forecast and wind generation forecast). The system performs the flexibility ramp tests for each 15-minute interval in both the upward and downward direction. If an EIM BAA fails the flexibility test, the system caps its EIM transfers level to least restrictive of the either the last 15-minute transfer or the base schedule transfer. After the June 15 implementation of the Market Enhancement for 2021 Summer Readiness, the net effect of failing the capacity and flexibility test are the same. Figure 91 shows the daily frequency of upward flexibility test failures for June and July 2021.[45] In July, NWMT BAA had the highest monthly percentage of upward flexibility ramp test failure at 3.63 percent, whereas there were three EIM BAAs that passed the upward flexibility test in all 15-minute intervals. The CAISO BAA failed the upward flexibility ramp test in 0.34 percent of 15-minute intervals, which is equal to failing the test in 10 intervals for July 2021. Figure 92 displays the hourly frequency of upward flexibility ramp test failures for July 2021.[46] Out of the total number of failures, about 45 percent of upward flexibility test failures occurred in hours ending 18, 19, 20 and 21, with about 15 percent of the total upward flexibility ramp test failures occurring in hour ending 23.

Figure 91 Daily frequency of upward flexibility test failures for June and July 2021



[45] The daily frequency of failures are fractional numbers that are rounded up to whole numbers.
[46] The hourly frequency of failures are fractional numbers that are rounded up to whole numbers.

Figure 92 Hourly frequency of upward flexibility test failures

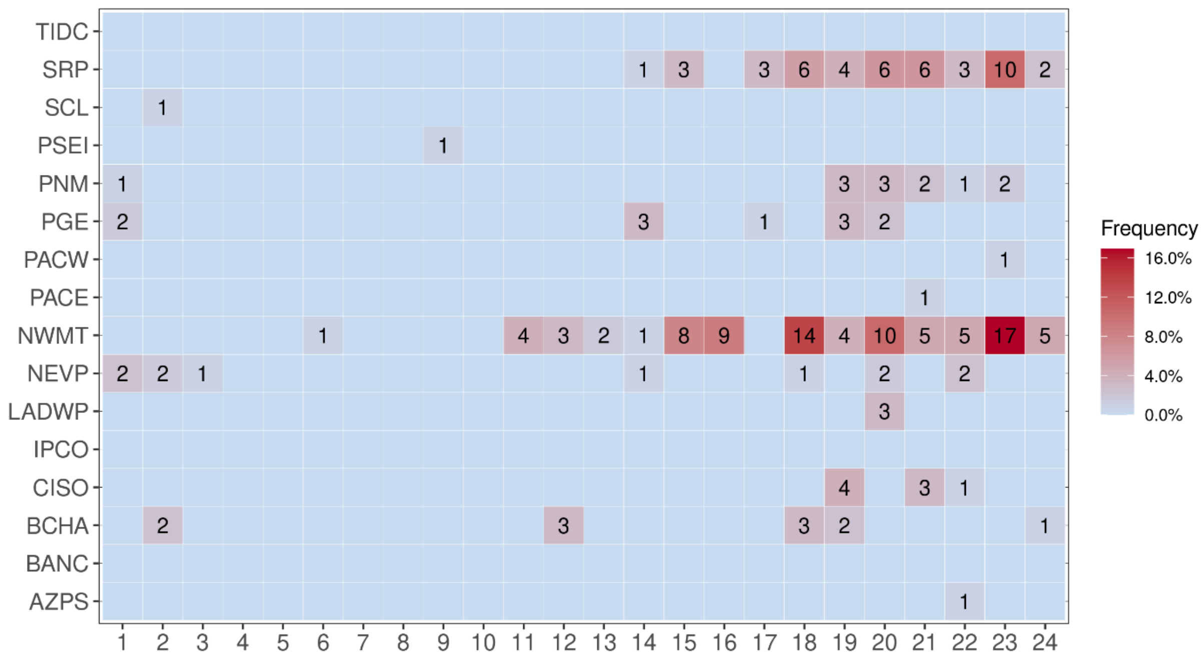


Figure 93 shows the daily frequency of downward flexibility test failures for July 2021.[47] In July, the NEVP BAA had the highest monthly percentage of downward flexibility ramp test failure at 3.39 percent, whereas there were 12 EIM BAAs that passed the downward flexibility test in all 15-minute intervals. The CAISO was among the 12 EIM BAAs without any downward flexibility test failures in June. Figure 94 shows the hourly frequency of downward flexibility test failures in July. More than 48 percent of the downward flexibility test failures in July occurred in hours ending 7, 8 and 9.

[47] The daily frequency of failures are fractional numbers that are rounded up to whole numbers.

Figure 93 Daily frequency of downward flexibility test failures for June and July 2021

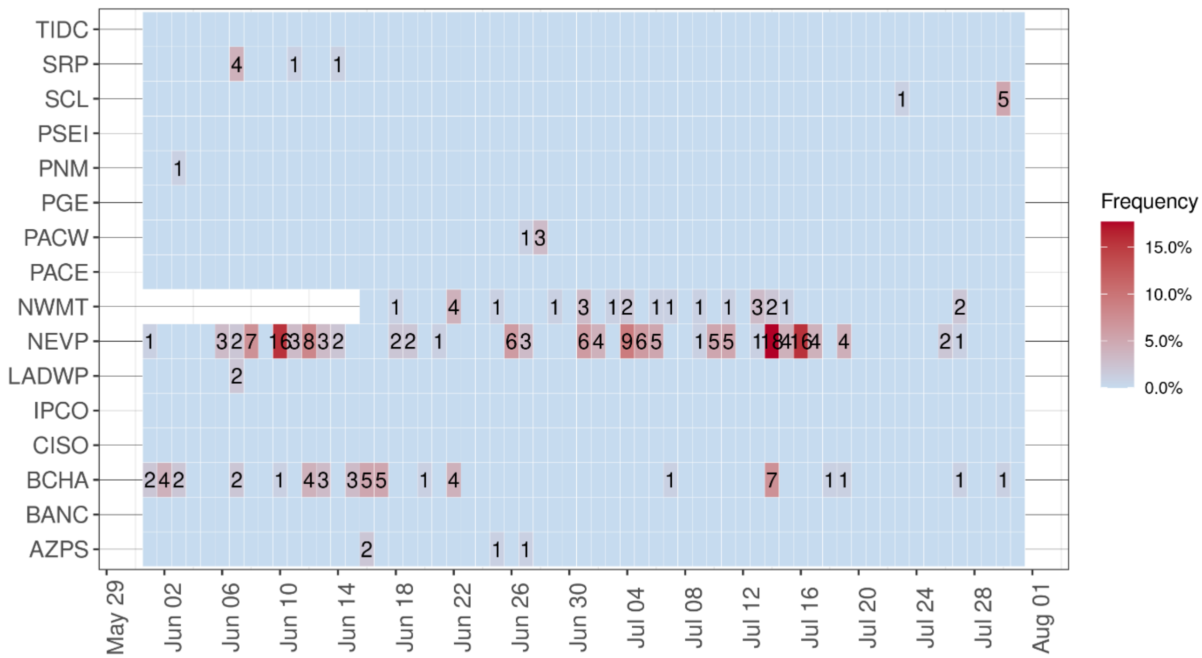
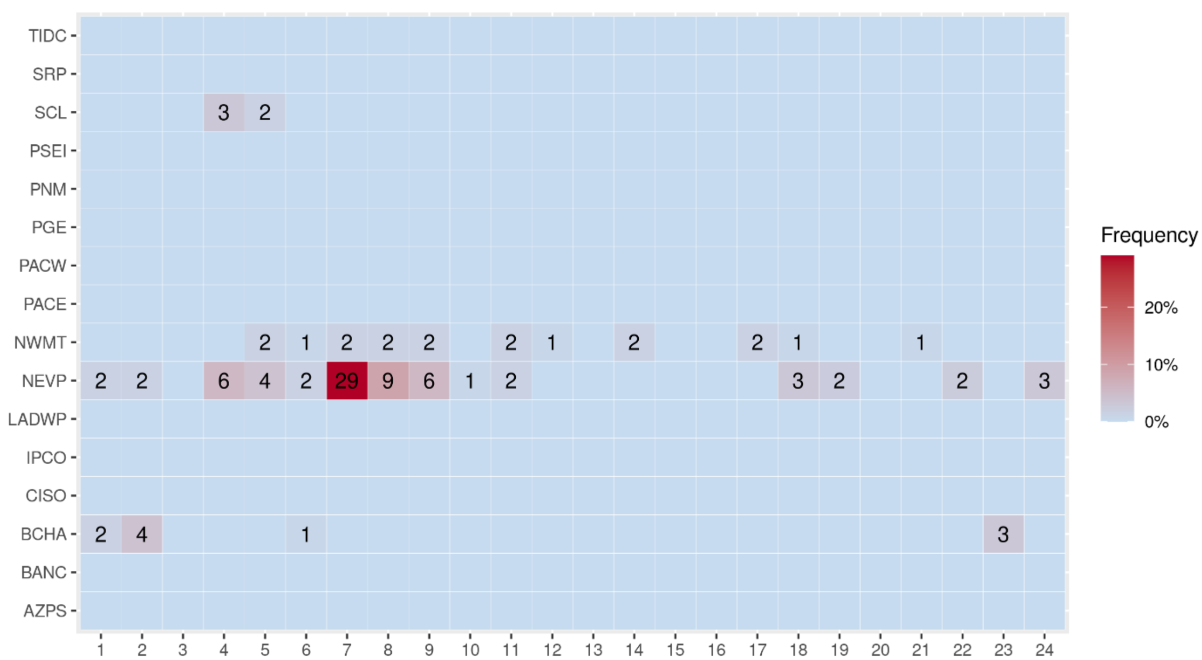


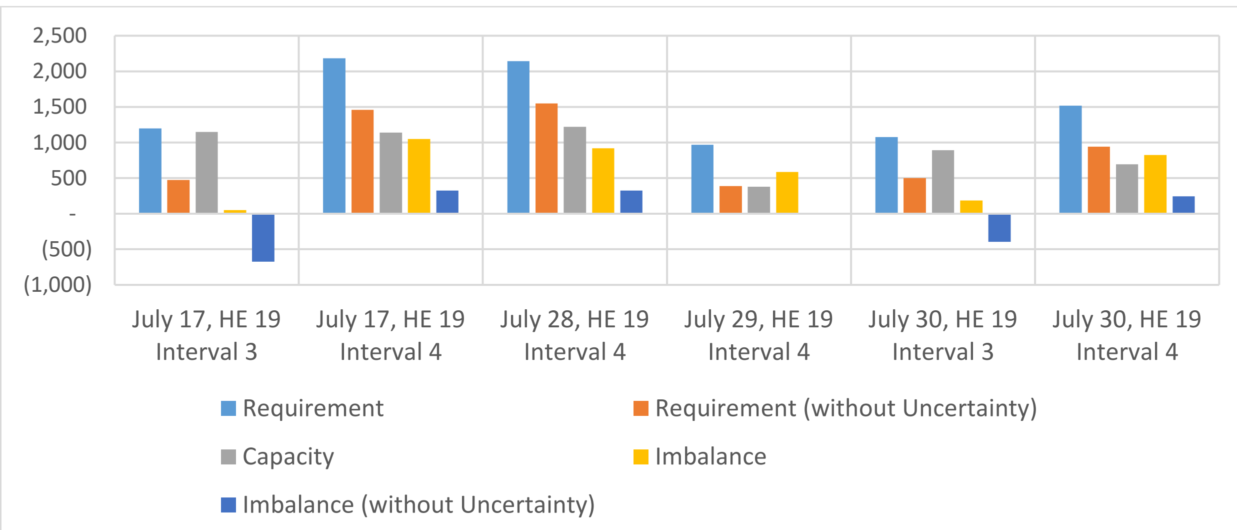
Figure 94 Hourly frequency of downward flexibility test failures for July 2021



13.4 CAISO's capacity test failures

The CAISO failed the upward capacity test in six 15-minute intervals in July 2021. All the capacity test failures occurred in hour ending 19 for four days in July: 17, 28, 29 and 30 Figure 95 below shows the upward capacity test requirement and bid range capacity for the four 15-minute intervals in which the CAISO failed the capacity test. This figure shows two capacity test requirements: the "Requirement" bar shows the capacity test requirement for all six days when the CAISO failed the capacity test, whereas, the "Requirement (no Uncertainty)" bar shows the requirement excluding the effect of net load uncertainty. The "Imbalance" bar shows the difference between the test requirements and the incremental supply. An additional "Imbalance (no uncertainty)" bar shows the difference between the "Requirement (without uncertainty)" and "Incremental Supply" columns. Out of the six 15-minute intervals in June when the CAISO failed the capacity test, the imbalance amount for the two intervals was less than the net load uncertainty such that if net load uncertainty were not included in the capacity test requirement, the CAISO would have passed the capacity test. The CAISO would have failed the upward capacity test on July 17, 2021 in hour ending 19 interval 4, July 28, 2021 in hour ending 19 interval 4, July 29, 2021 in hour ending 19 interval 4 and July 30, 2021 in hour ending 19 interval 4 even if the net load uncertainty were not included in the capacity test requirement.

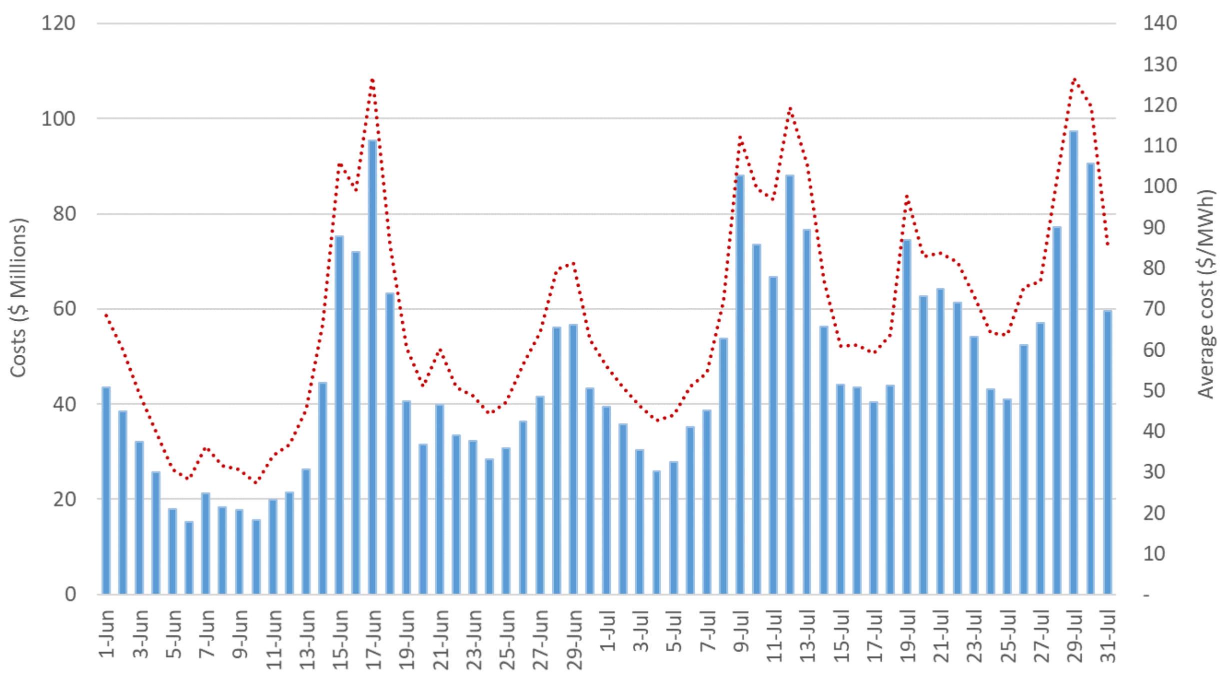
Figure 95: CAISO's upward capacity test requirement and imbalance for intervals with failure



14 Market Costs

CAISO's markets are settled based on awards and prices derived from the markets through specific settlement charge codes; these include day-ahead and real-time energy, and ancillary services, among others. The majority of the overall costs accrue on the day-ahead settlements. Figure 96 shows the daily overall settlements costs for the CAISO balancing area; this does not include EIM settlements. As demand and prices rise, the overall settlements is expected to increase. This trend shows the increase in the overall costs during July in the mid-month and end-of-month heatwaves, reaching a maximum daily value of about $97 million on July 29. When considering the overall costs relative to the volume of demand transacted, the dotted red line provides a reference of an average cost per MWh. For July 29, that average costs rose up to $126/MWh

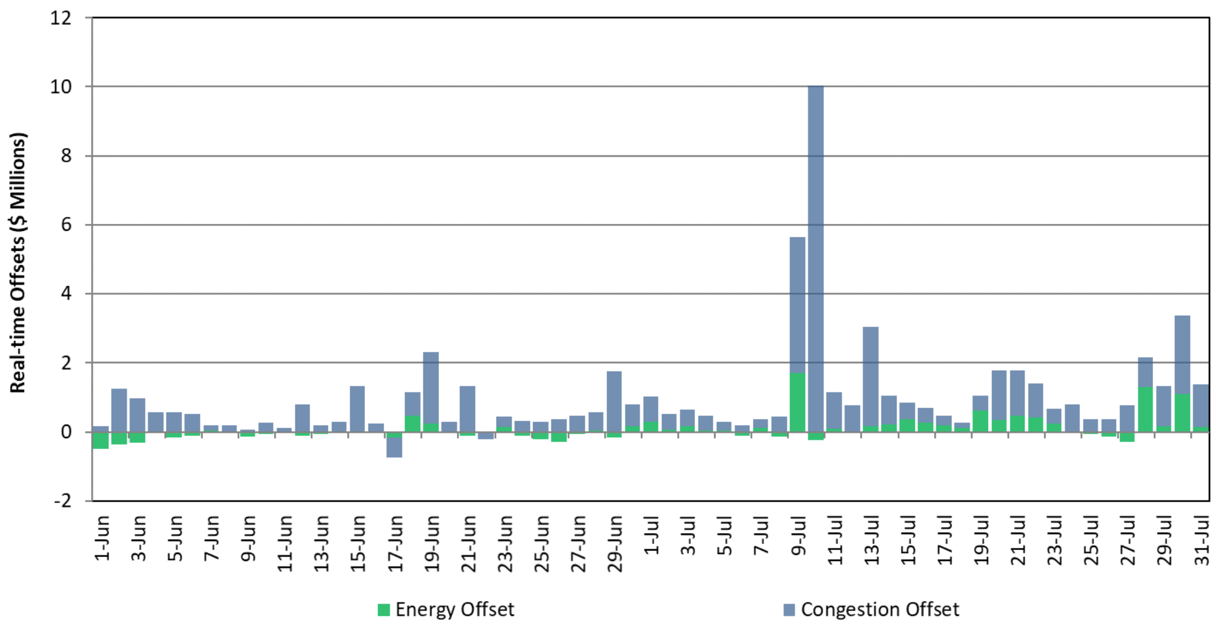
Figure 96: CAISO's market costs in June 2021



The average daily cost in June was $37.8 million (or an average daily price of $57/MWh), which increased to an average cost of $56.2 million (or an average daily price of $77.5/MWh) in July.

Two components of this overall cost are the real-time energy and congestion offsets. These costs reflect the settlements of differences between the day ahead and real-time markets for energy and congestion. These cost typically track system conditions. The increasing costs observed on July 9 and 10 coincide with the derates of Malin and NOB interties, as shown in Figure 97. These derates were in place on July 9 and 10 only in the real-time market, while the day-ahead market that runs in advance had the nominal limits. This represented a reduction of supply that had to be rebalanced with real-time dispatches, which may have created this large delta in settlements as reflected in the offsets.

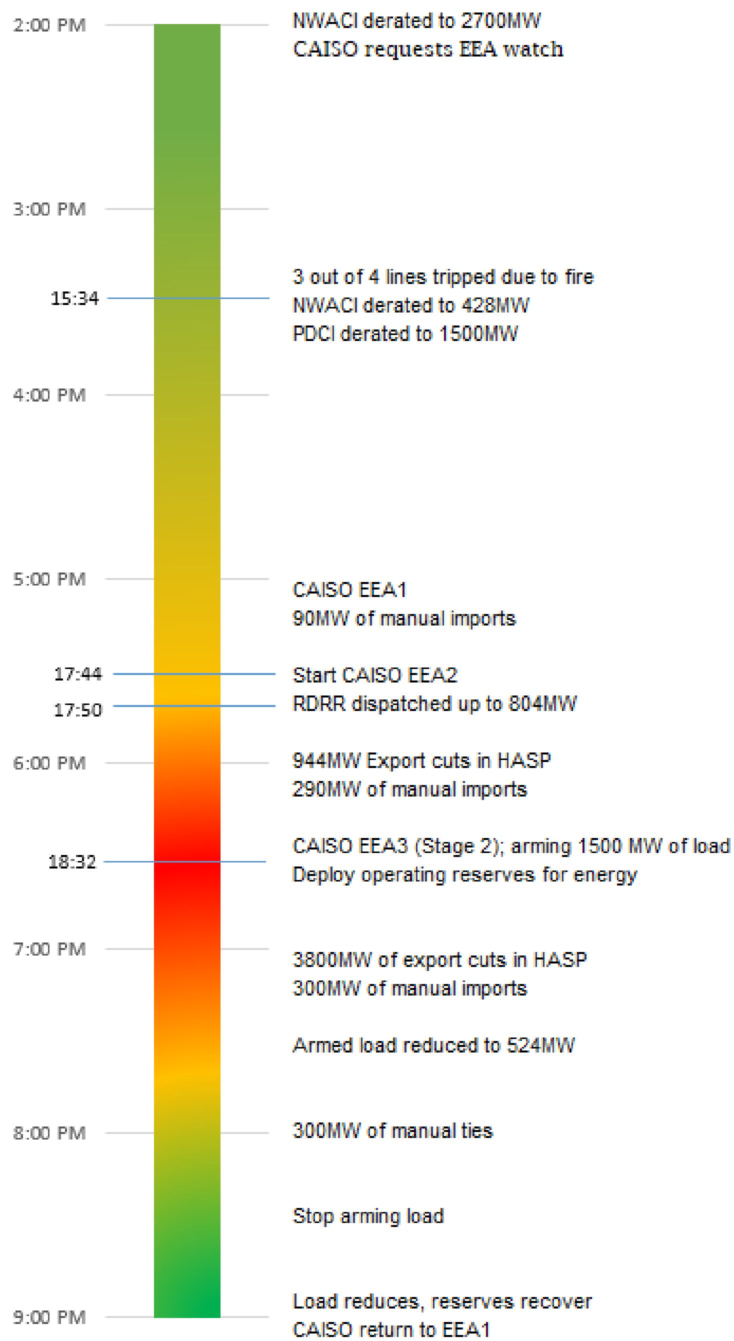
Figure 97: Real-time energy and congestion offsets



15 July 9, 2021 Conditions

The CAISO experienced tight supply conditions on July 9, which has been so far the peak day of 2021. CAISO issued a flex alert on July for July 9. Figure 98 illustrates the sequence of the main events during the evening of July 9.

Figure 98: Sequence of events on July 9



On July 9, 2021 at 15:35hrs, 3 out of 4 lines north of Malin intertie tripped due to the impact of the Bootleg fire, resulting in derates on Malin intertie and also on NOB intertie. As early as 16:16hrs, the CAISO was forecasting a resource deficiency with all available resources in use or forecasted to be in use between 17:00 through 22:00hrs. At 17:44, the ISO declared EEA2 and at 18:32 the CAISO declared EEA3 and began arming load up to 1500MW that could be reduced in 10 minutes. This led to the deployment of operating reserves to meet energy needs. As part of the market solution, HASP for hour ending 19 and 20 projected the need to cut 944MW and 3800MW, respectively. Additional 804MW of supply were made available through the dispatch of RDRR resources. Armed load reducing through hour ending 20 and eventually ceased in hour ending 21. At 21:30, the ISO terminated the stage 2 emergency and returned to warning. At 22:00, it moved to EEA-0.

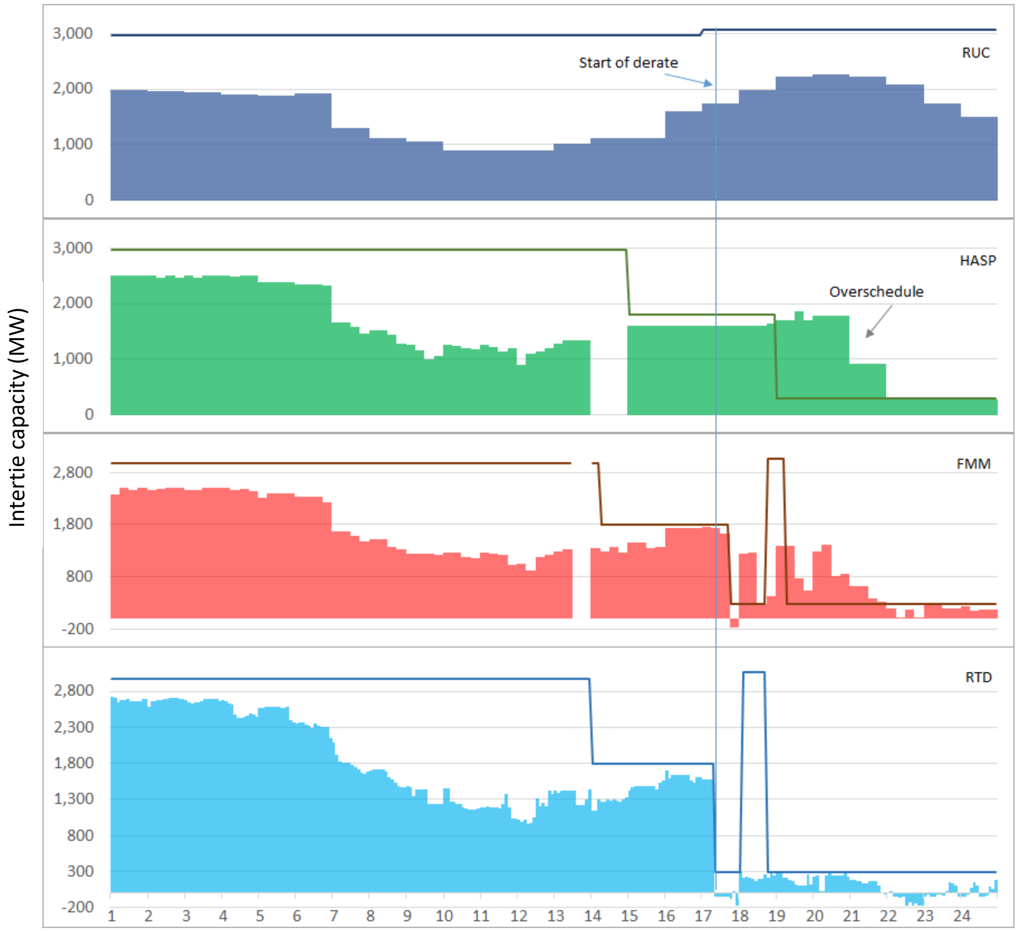
Figure 99 and Figure 100 show the profile of the limits and schedules for Malin and NOB interties, respectively. Each subplot represents the RUC, HASP, FMM and RTD markets. The solid lines represent scheduling limits while the shaded areas indicate the net scheduled flows (imports less exports) on the intertie. These net schedules are the optimized imports and exports utilizing the available capacity on the intertie. [48] Due to the Bootleg fire, the Malin and NOB interties were derated. The first derate occurred as early as hour ending 14 on Malin, with capacity reducing from 2,967MW to 1,800MW. The second derate occurred in hour ending 17 and reduced Malin further to 285 MW; NOB capacity was also reduced from 1,622MW to 785MW. Since this occurred in real-time and after the day-ahead market run, the limits utilized for both interties in the day-ahead market were not impacted.

During the period of derates, there were three main conditions identified. First, the full derates started in hour ending 17. Generally, when these restrictive limits come into the market, they will be implemented by each of the markets in the next available market run. This means that the first market to have and start enforcing the limit will be RTD since it runs more frequently (i.e., every five minutes); then, the next FMM run will start utilizing the derates. Eventually, the HASP market that runs once every hour will be able to consume and utilize the derates. When the most restrictive derate was in place around 4:00 pm PST, the HASP market that runs 75 minutes in advance of the trading hour had already run for hour endings 17 and 18; therefore, the first time the derate was utilized in the HASP market was for hour ending 19, which starts to run about 16:47. This resulted in the derates being utilized and enforced at different times in the real-time submarkets. Since FMM and RTD cannot optimize hourly intertie schedules to enforce the derates, operators were required to implement tie schedule cuts for these periods until the hourly interties could be optimized with the derated limits.

Second, after imposing the most restrictive derate in hour ending 17 and after executing various updates and steps to impose the derates, the Malin and NOB intertie limits were unintentionally lifted to the nominal pre-derate values. With the frequency at which FMM and RTD markets run (every 15 and 5 minutes), the un-derated limits were utilized in two and eight FMM and RTD intervals, respectively. Since this lasted for less than an hour, the HASP market (which runs once per hour) was not impacted. This can be observed in the limit trends increasing in hour ending 18 for FMM and RTD in the figures below, right after the full derates were implemented.

[48] The nominal limit on an intertie is referred as the operating transmission capacity (OTC). For some interties, like Malin, there are transmission reservation to accommodate ETCs/TORs. This transmission capacity is not made available in the market clearing process for all imports and bids. The market relies only on the available transmission capacity (ATC), which is derived as the difference between the OTC and the ETC/TOR reservation.

Figure 99: Malin limit and schedules across markets on July 9 2021



This issue had little impact on the FMM and RTD markets because the intertie limits were fully optimized through the HASP process, which is the only market to clear hourly interties. FMM and RTD generally do not optimize interties.[49] Schedules on these interties were within the derated limit in FMM and RTD due to operator curtailments that were eventually consumed in FMM and RTD through the E-tags.

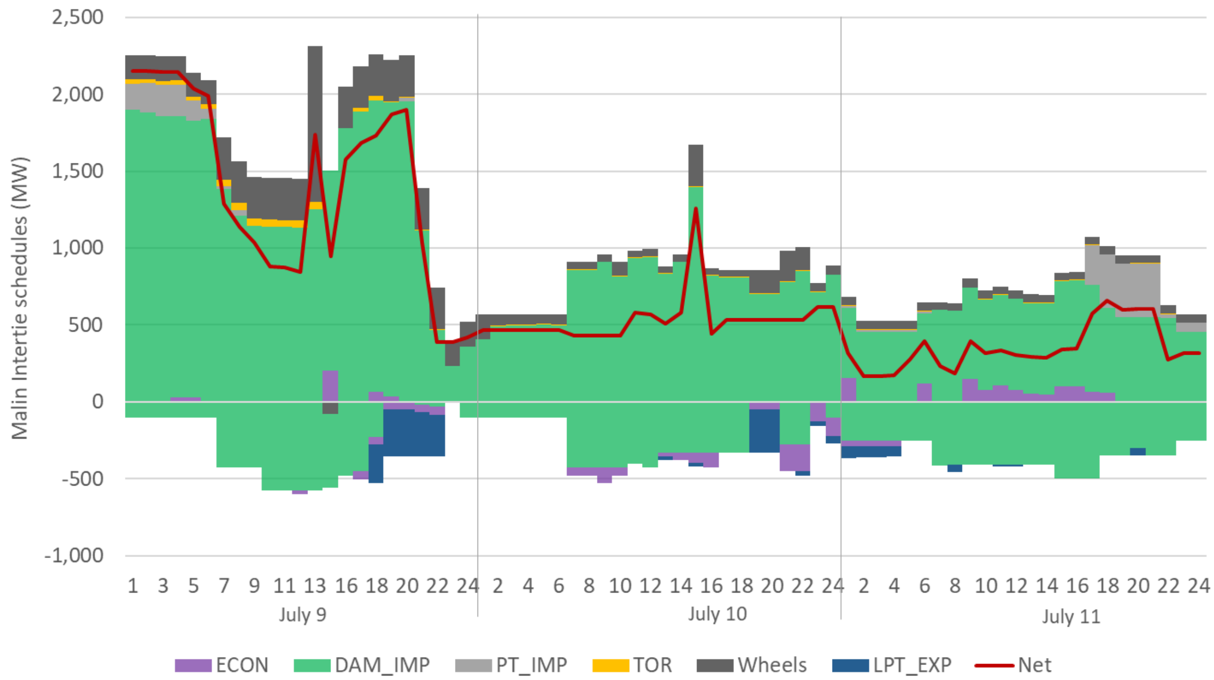
The third issue was the overscheduling of the Malin and NOB interties, as reflected in both the HASP and FMM trends once HASP and FMM started to utilize the derated limits. Since the same dynamic happened in both HASP and FMM, for illustration this is explained using HASP for simplicity. Consider the Malin intertie on which the HASP market of hour ending 19 enforced the derated limit of 285MW. The HASP plot illustrates that the optimal schedule on Malin was above the enforced limit. While the limit was 285MW, the cleared schedules on Malin were about 1,709MW, which is an overschedule of the intertie by about 1,424MW. The overscheduled imports had to be managed by CAISO operators though manual cuts of imports in real-time.

[49] There is an opportunity for 15-minute intertie resources to participate and clear on the 15-minute basis in FMM. Historically, however, 15-minute intertie participation has been very minimal.

Figure 100: NOB limit and schedules across markets on July 9 2021

The reason that the HASP market overscheduled the intertie is due to the interplay of three main factors: the penalty prices associated with the intertie limit, the self-schedule priority of the imports coming through Malin, and the power balance constraint. The penalty price of the intertie constraint is currently defined in the CAISO's Tariff as $1,500/MWh, while the penalty price associated with the power balance constraint was at $1,450/MWh, and the day-ahead priority imports is at $1,200MW. Figure 101 shows the type of schedules cleared in HASP for the Malin constraint, which includes both imports and exports. These represent self-schedules of different priorities, as well as economic bids. The vast majority of schedules in HASP had a day-ahead priority, as represented by the area in green. In order to respect the intertie scheduling limit, the self-schedules needed to be reduced and the power balance constraint needed to be further relaxed. The optimization found it cheaper to relax the intertie limit to provide additional supply at the cost of the $1,500/MWh penalty price and respect the import self-schedules and alleviate the undersupply condition reflected through the power balance constraint relaxation. Effectively, overscheduling on the interties provided additional supply to the HASP clearing process, which resulted in a HASP failing to consider how tight conditions were in actuality due to the intertie derate. The overscheduling subsided in HASP starting with hour ending 22 when market conditions changes and prices decreased to such a level that supply conditions improved and the interplay with penalty prices no longer relaxed the intertie limits.

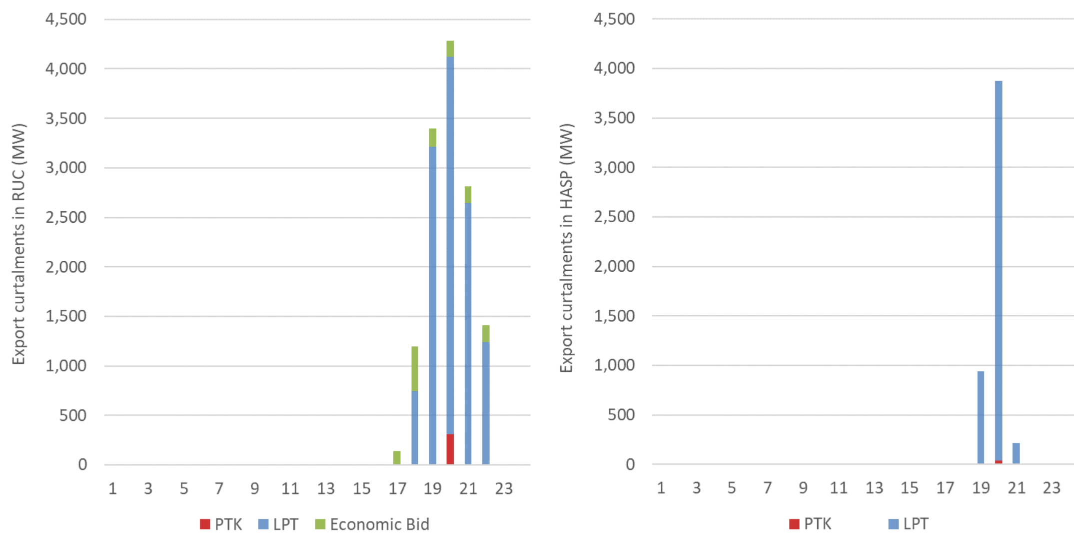
Figure 101: Composition of Schedules on Malin constraint



Under typical conditions, the intertie limit is not expected to relax. The intertie limit relaxations observed in July were caused by a combination of factors including a large derate capacity on Malin, with a large number of self-schedules on the intertie, all occurring when the system was tight on supply with a power balance constraint relaxation and high energy prices. Under these conditions procuring additional supply by overscheduling the intertie was numerically the optimal solution. This indicates that under these conditions, the penalty price of the intertie limit may be too low. The CAISO is proceeding with an expedited process to seek a change to the existing penalty prices for intertie scheduling limits in both the RUC and HASP process to utilize penalty prices for intertie constraints that prevent overscheduling interties.

Figure 102 shows the export reduction in the RUC and HASP markets, which were significant during peak hours. The reductions in RUC imply that exports awarded in IFM do not have a day-ahead priority coming into the real-time market. However, these exports that are reduced in RUC can still bid into HASP and will be cleared in HASP based on real-time conditions. On July 9, there were 3,830MW and 43 MW of reductions for LPT and PTK exports, respectively. The 43 MW of PTK exports did not materialize since they were reinstated based on the assessment of real-time conditions. All the LPT export reductions were issued by the HASP market. However, further analysis showed that there were about 566MW of exports that were still tagged into the system to flow, which effectively means that about 566MW of the projected export reductions were not realized.

Figure 102: Export reductions in CAISO's markets



The RUC or HASP markets can assess reduction of exports based on both overall system conditions and economics. With the changes implemented on September 5, 2020 and under the scheduling priorities still in place in July, export reductions in RUC can no longer self-schedule into real-time with a day-ahead priority, but they are able to be rebid into the real-time market and are fully assessed based on real-time conditions. LPT or economic export cuts in the RUC process are most likely to be cut again in HASP since they will have the lowest priority in the presence of tight supply conditions. Figure 103 maps the HASP cuts to the original cuts assessed in the RUC process, and arranges them into three main groups. The first group in blue represents HASP cuts for exports bid directly in the real-time market; they were not originally bid into RUC. The second group in green represents HASP export cuts that are the same cuts assessed in the RUC process. For instance, if a self-schedule export bid 100MW in RUC and was cut down to 10MW, then the export is bid again in HASP up to 100MW and HASP cuts that export again to 10MW. This is a case in which the RUC properly projected how much of an export scheduled in the IFM could eventually be feasible in the real-time market. The third group in red represents HASP cuts that were lower than the cuts originally projected in RUC. For instance, a self-scheduled bid of 100MW in day-ahead was reduced to 10MW in RUC, then this export is rebid in the real-time market and now is cut to 40 MW. In this scenario, the HASP cut was less restrictive than what RUC was projecting. On July 9, about 72 percent of HASP export cuts were projected in the RUC reductions and captured with the green and red groups.

Figure 103: Breakdown of interties in the real-time dispatch

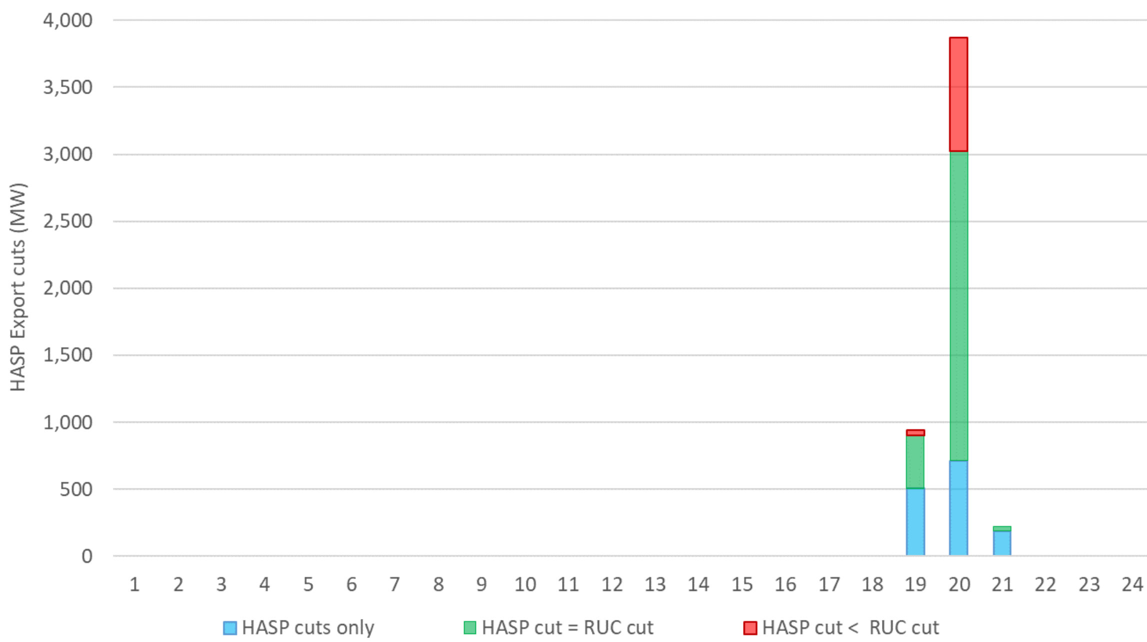
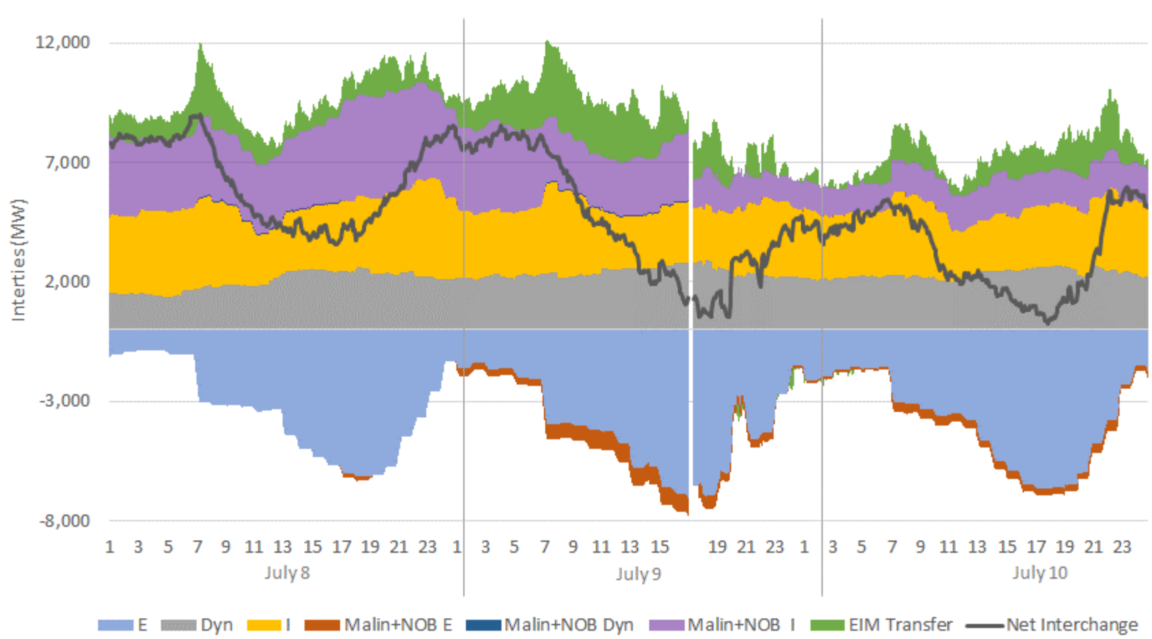


Figure 104 illustrates the intertie schedule profiles from the real-time interval dispatch market, and is organized by type (i.e. static imports, exports, and dynamic resources[50]).

Figure 104: Breakdown of interties in the real-time dispatch

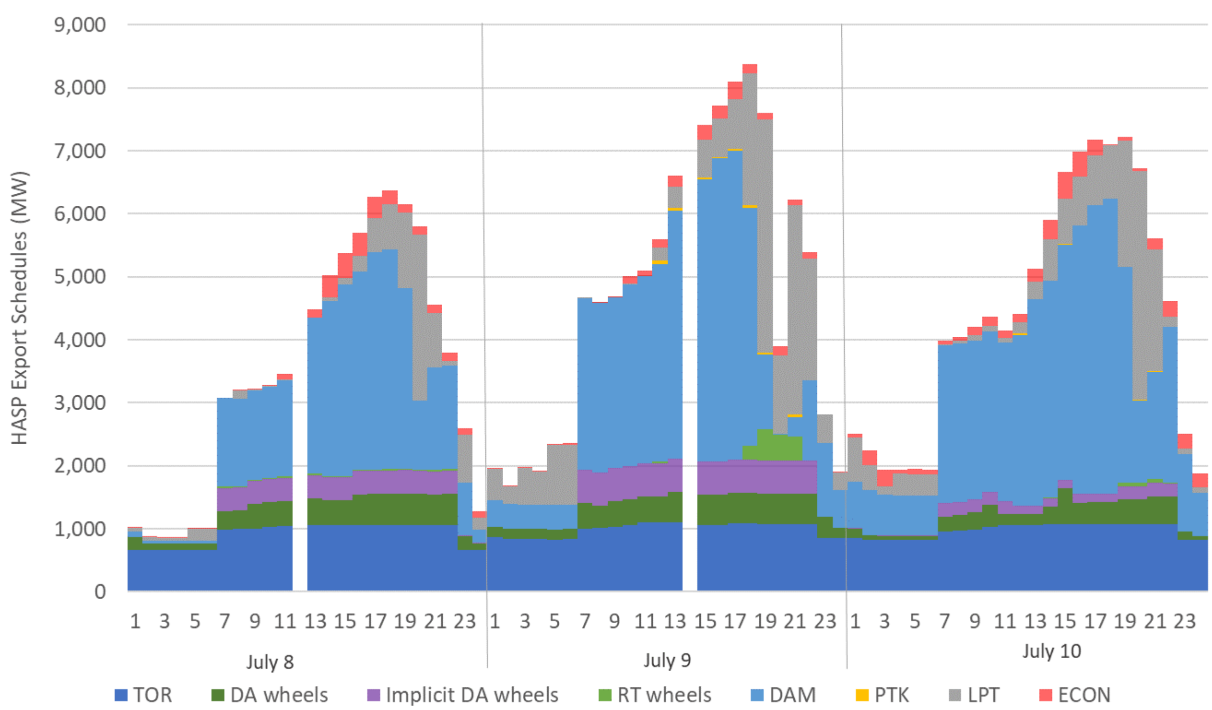


[50] Wheel transactions are embedded for simplicity in the imports and exports because they are in balance and at the end do not impact the net interchange.

The contribution of both Malin and NOB schedules are explicitly represented to highlight the impact of the overall interchange after the derates on these interties. The EIM RTD transfers are also included to give a more complete picture of the interchange. The derates on Malin and NOB starting in hour ending 17 on July 9 resulted in a meaningful reduction of the overall imports into the system and naturally reduced the net interchange. The EIM imports increased the overall imports to the system.

The net interchange on July 9 was low due to a lower volume of imports and a higher volume of exports. The last opportunity for hourly interties -either import or export- to clear is through the HASP process. Figure 105 shows the export breakdown.

Figure 105: Breakdown of exports cleared in HASP



The category of *DAM wheels* represent wheels that explicitly bid in and cleared in RUC and then were explicitly bid in HASP by scheduling coordinators. The category of *Implicit DA wheels* is for those wheels that were cleared in the RUC process as explicit wheels but were then inserted as individual imports and exports self-schedules in the real-time market since they were not explicitly rebid as wheels by their scheduling coordinator. Consequently, these implicit DA wheels are not treated as wheels in HASP. Instead, they are treated as individual import or export with self-schedule priority. Under extreme conditions, the import and export legs may not clear in balance. They could be included in the other explicit groups of self -schedules as well. The category of *RT wheels* are new wheels bid directly into HASP with no previous clearing in the RUC process. The group labeled as *DAM* is for exports cleared in RUC which now come with a day-ahead priority in HASP. The groups *LPT* and *PTK* are the standard high and low priority exports submitted in real-time, while the group ECON represents economic bids in real-time. The group of TORs is for exports backed up with existing transmission rights. Some of these exports act like wheels with a corresponding import leg, even though they may not be flagged explicitly as wheels. Since TORs have a very high scheduling priority above any other self-schedule, they will generally be cleared regardless. With this set of exports and corresponding priorities in the real-time market, effectively about 80 percent of all exports (TOR, DAM, Wheels) in real-time come with a priority high enough that will not be curtailed before the power balance constraint is relaxed. Only Economic and LPT exports will be effectively curtailed before going into a power balance constraint relaxation.

When an EIM entity fails either the capacity or flexible ramp test, the EIM transfers are limited based on the least restrictive of either the last EIM transfer or the base schedules. On July 9, the CAISO BAA failed the sufficiency test in the following intervals:

- Hour ending 19, RTD intervals 7 through 12
- Hour ending 21, all 12 RTD intervals
- Hour ending 22, RTD intervals 1 through 3

In such intervals, the EIM transfers were limited as shown with the red lines in Figure 106. In hour ending 19, the failure did not restrict EIM transfers because the natural dynamics of the market already produced EIM transfers at 1,178MW, which was lower than the imposed transfer limitation of 1,660MW. Only in RTD intervals 7 through 9 of hour ending 21 the RTD transfers were limited at 1,416MW. Given the trajectory of the transfers in adjacent intervals, this appears to be a mild limitation.

Figure 106: EIM transfer into CAISO BAA in RTD with periods of test failures

Figure 107 shows the volume of RA capacity for resources that were not dispatched at all in the real-time market. Naturally, many resources with or without RA capacity that can actively bid in the market may not be dispatched in RTD because of economic and system considerations. This is more typically observed during off-peak hours when load levels are low and there is sufficient supply to economically dispatch the least cost resources to meet load. However, as the load increases towards the evening peak, more resources are dispatched and during days with tight supply conditions, like July 9, it is expected that RA resources will be fully dispatched in the market.

Figure 107: Capacity from RA resources not dispatched in real-time

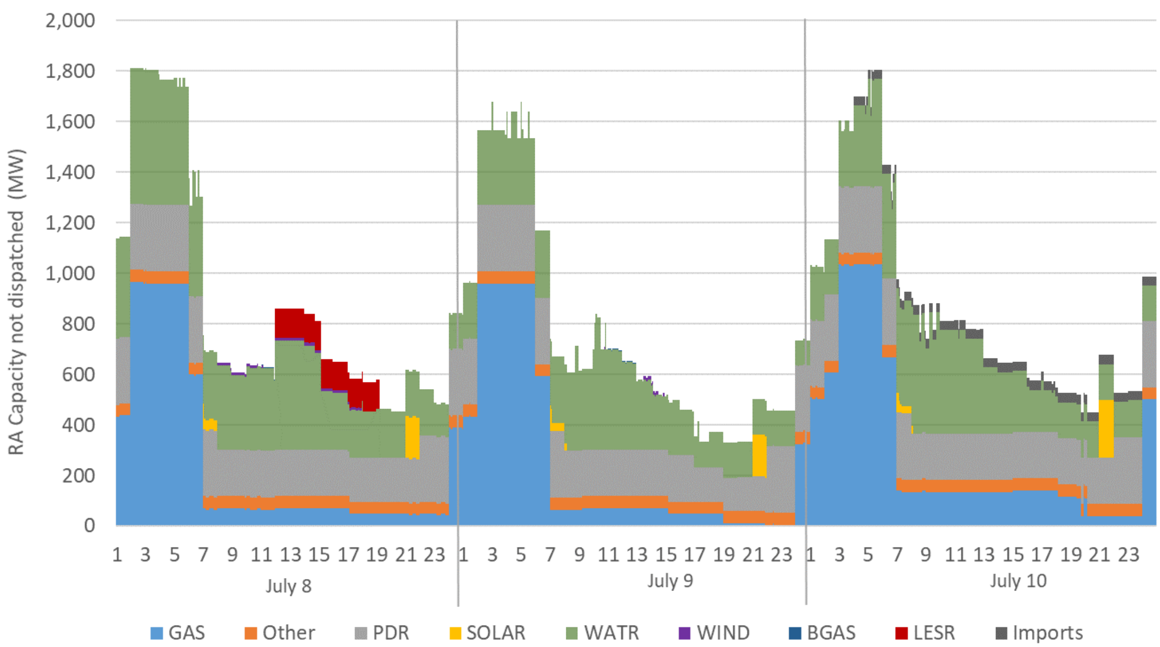
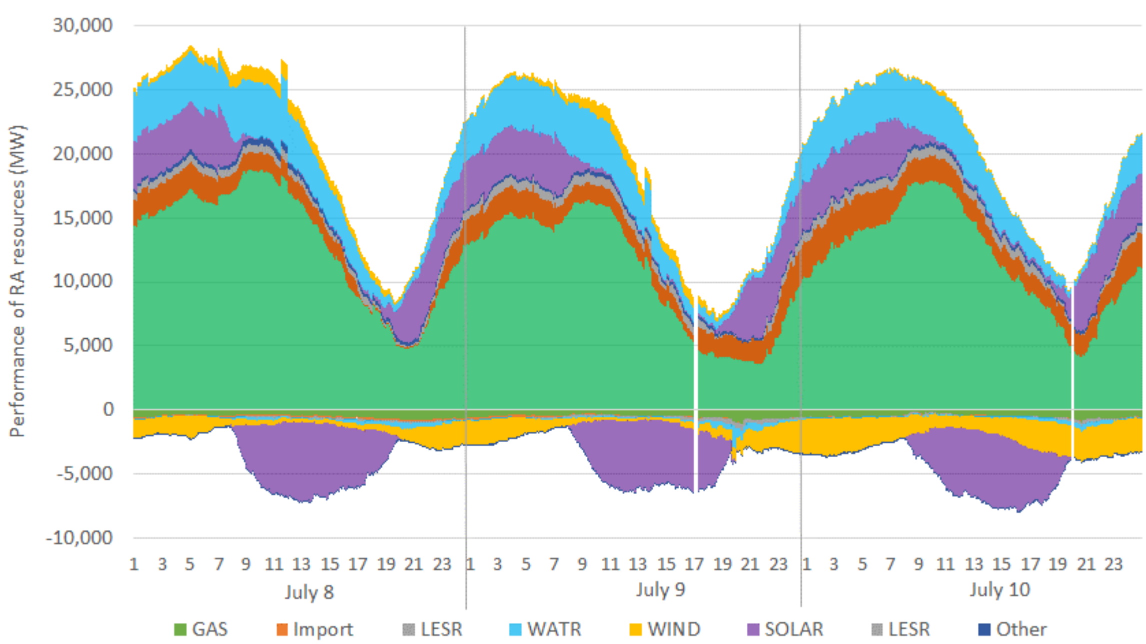


Figure 108 shows the volume of supply that RA resources provided either above (negative values) or below (positive values) their RA capacity[51].

Figure 108: Real-time dispatches above or below RA capacity

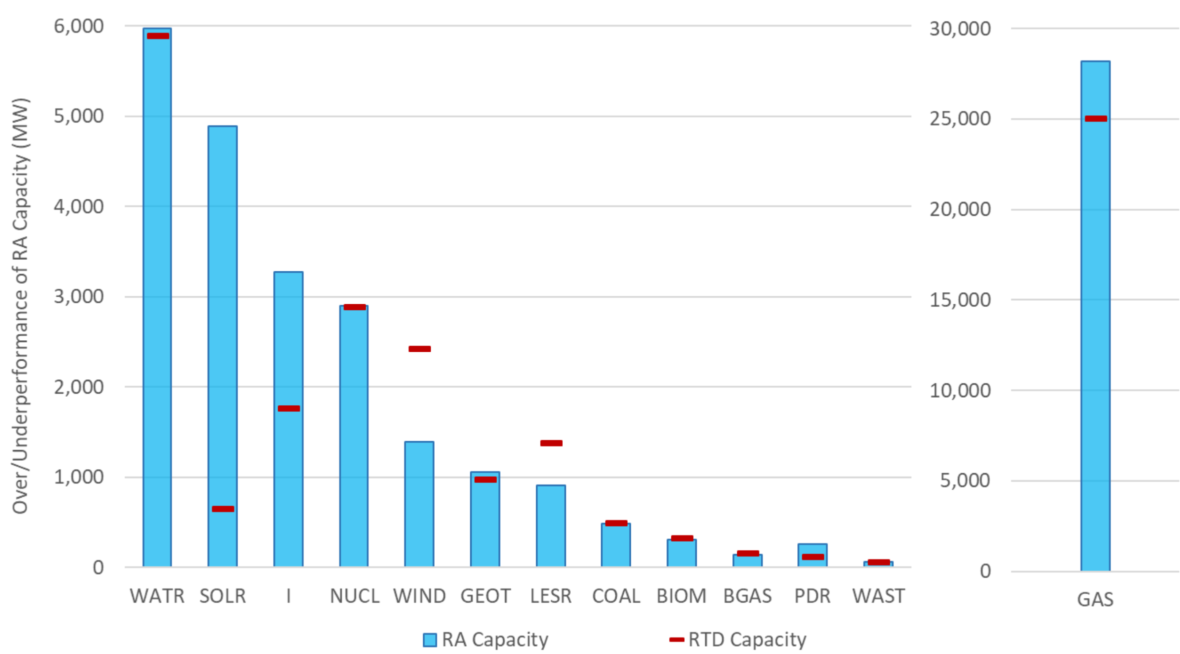


[51] The difference is estimated at the resource level and positive differences are kept separate from positive differences. For this reason, each fuel group can have positive and negative values at the same time interval.

For instance, if a resource has an RA capacity of 100MW and in real-time it was dispatched at 120MW, this metric will show -20MW, which is a performance of 20MW above its RA capacity. This trend shows large volume of supply from RA resources dispatch below RA capacity (positive values) in the off-peak hours when load levels do not require to have all resources dispatched. As load ramps up for the evening peak, the volume of dispatches below RA levels reduces. Conversely, there is certain volume of supply coming from RA resources dispatched above their nominal RA capacity as shown with the negative values. A clear illustration is for solar resources producing above their RA values in the middle of the day, or wind resources producing above their RA values.

On July 9, as the system reached its load peak and experienced tight supply conditions, it was expected that all RA resources be dispatched at their RA capacity. However, Figure 108 shows that more than 5,000MW of RA capacity was not being utilized across the peak time. The RTD interval of July 9 at 7:35pm was used as a benchmark to assess how RA resources were dispatched during the peak. Figure 109 shows a comparison between the RA capacity and the RTD dispatches for all RA resources, aggregated by fuel type. Relative to their share of RA capacity, the underutilization was largely observed for gas, solar, imports and demand response resource types.[52] Conversely, wind and storage resource provided additional capacity above their RA values. At the net load peak, capacity from solar is expected to be low and eventually disappear as the sun sets; this is the main reason that solar shows a large difference in comparison to its RA values at this time of the day.

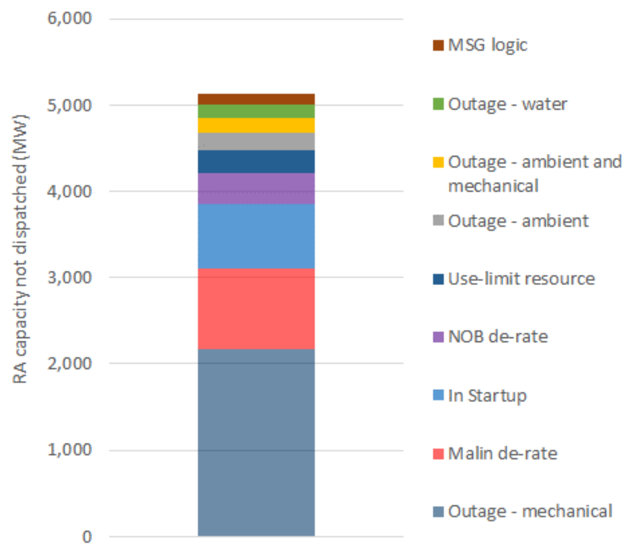
Figure 109: Real-time dispatches of RA resources by fuel type



[52] Prices were over $1,000/MWh and thus even those bidding at the bid cap were able to be dispatched in the market. Currently, a large share of demand response resources utilize the 60-minuite option, which dispatched them in a single block for the hour. Upon further investigation, there were DR resources that did not bid for that peak time so that the DR supply available in the market was below the nominal RA capacity.

The largest differences between RA monthly shows and the actual dispatch of resources were further investigated and summarized and organized by the main reasons in Figure 110. This figure is based primarily on resources with fuel types of gas and water. Outages were the main reason why some real-time RA capacity was not dispatched.

Figure 110: Real-time RA capacity not dispatched by fuel type



The Imports classification is concentrated on Malin and NOB, mainly driven by their limit derates. On the night of July 9, there was a large unit coming back from outage that was starting up, which resulted in that unit capacity not being available at its RA value. There is some RA capacity not dispatched which is related to use limited resources. For the peak time, they were either not bidding or bidding below the RA level. There was also one multi-stage generator (MSG) unit that could not be dispatched up to its maximum capacity because it was carrying regulation down and it could not transitioned upward.

16 Minimum State of Charge Constraint

The minimum State-Of-Charge (SOC) requirement is a new tool to ensure Limited Energy Storage (LES) resources with RA capacity obligations maintain sufficient SOC to provide energy during tight system conditions. This requirement was implemented as part of the market enhancements for the summer readiness 2021 stakeholder initiative and has a two-year sunset provision.

The minimum SOC constraint is only applied on days when system needs are critical. The constraint is activated when there are one or more hours with under-gen infeasibilities in RUC, which occurs infrequently but indicates tight system conditions. When activated, the constraint ensures that all LES resources with an RA obligation maintain sufficient SOC to cover energy schedules cleared in RUC over a set of critical hours. These critical hours are defined by the operators prior to running RUC, and remain consistent from RUC into the real-time markets.

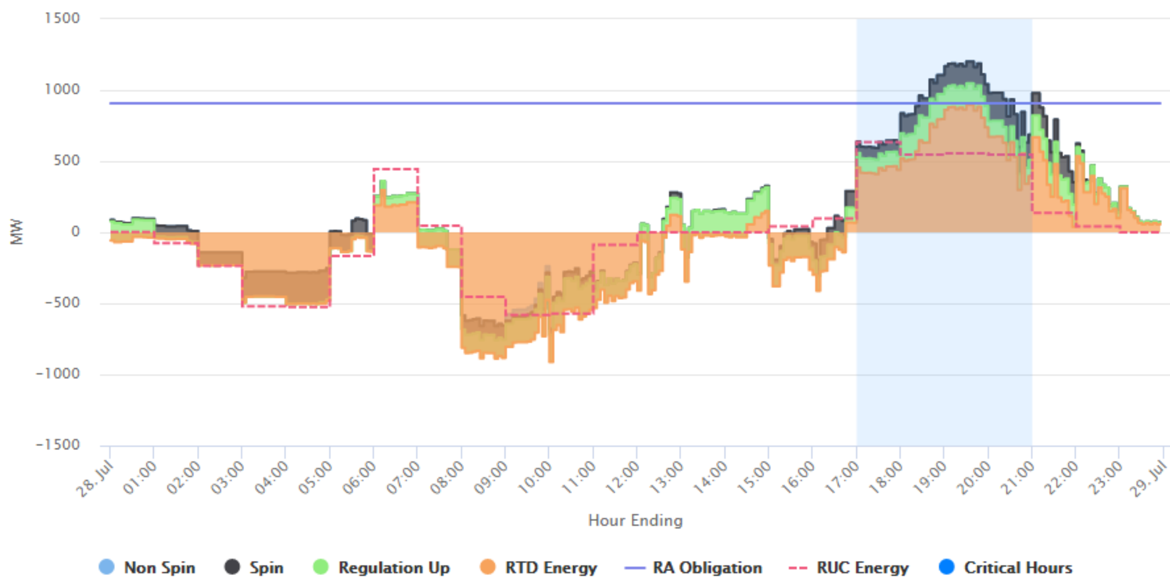
The goal of the constraint is to ensure that each LES resource with an RA obligation will have enough SOC to meet its positive RUC schedules in the real-time markets in each critical hour. This means each resource needs to have enough SOC at the beginning of each critical hour to meet the RUC schedules in that hour plus all future critical hours, taking into account the resource's charging efficiency and operating limits. The minimum SOC constraint is defined as an end-of-hour constraint. In practice, this often means the minimum SOC will build up in the hours preceding the critical hours, and peak at the sum of the positive RUC schedules in the hour preceding the start of the critical hours.

The minimum SOC constraint was activated on three days in July 2021: July 9, 28, and 29. To evaluate the performance of the new minimum SOC feature, the real-time energy output and SOC during the critical hours on these days were compared to the awards in RUC, as well as assessing the number of resources with this constraint binding in RTD at the end of each hour. The goal of the constraint is to ensure these resources were not depleted earlier in the day in the real-time market, and that they maintained their limited energy for use during the most critical hours.

Based on the overall energy and ancillary service awards, in almost all critical hours the resources were providing energy and upward ancillary services at a level equal to or greater than their RUC awards. This can be seen in Figure *111* below. This is a good indication that LES resources are being dispatched during the critical hours, and they are not being depleted earlier in the day. This trend held across all three days with the constraint enforced.

Over the critical peak hours, the real-time SOC of the LES resources with RA obligations and awards in RUC were near the RUC level SOC, and as a whole significantly above the minimum SOC constraints. Figure 112 and Figure 113 below show this data for July 28. The RTD EOH Min SOC Shortfall represents the total amount of shortfall between the minimum SOC requirement and the actual SOC in RTD at the end of the hour. The most prevalent causes of shortfall were ancillary service awards impeding the amount of energy available for charging in the market, and resources bidding in with lower charging availability in the RTM compared with IFM. The constraint was designed to allow ancillary services awards to take precedence over the minimum SOC requirement, so some shortfall may be expected. The issue with resources bidding in with lower charging availability in real-time was identified as a potential issue during the design of the constraint, and may warrant further investigation. However, the overall impact of these two issues remains minimal, as they represent a relatively small amount of shortfall.

Figure 111: Profile of RTD dispatches and AS awards for RA LES resources on July 28



To better understand how much of an impact the constraint had in real-time, the resources with the minimum SOC constraint binding at the end of the hour in RTD were examined. The results for July 28 can be seen in Figure 114. The constraint is binding for the greatest number of resources in the intervals leading up to the critical hours, which is expected. For a large number of resources, their economic bids are already keeping them above the minimum SOC imposed by the requirement. However, there remains a significant number of resources for which the SOC constraint was effectuating the dispatches to ensure adequate SOC was available to meet their RUC schedules in real-time.

LES resources bidding into the DA market with very low charging bids and very high discharging energy bids would have only been cleared when IFM reached the bid floor and caps, which is not a very frequent condition. Under today's practice, the ISO does not submit a bid for RA LES resources to be used in RUC. This means that if not dispatched in IFM, the RUC will also not commit them. Any LES not committed in the IFM or RUC process will effectively not have an applicable minimum SOC requirement. If these resources are dispatched in real-time, they will be consequently dispatched above the day-ahead schedules. If this is aggregated at the system level, it will appear that LES as a whole are performing in real time well above their RUC schedules. To get a sense of the scale of this dynamic, resources with no IFM energy or ancillary service awards have been broken out for July 28. These resources represented a few hundred MWs of additional energy in the real-time market during the critical hours.

Overall, the minimum SOC constraint appears to be working as designed, and is ensuring LES resources with RA obligations are maintaining minimum state-of-charge for the critical hours. The constraint is binding for some resources in the hours before and during the critical period, and the RA LES resources as a whole are receiving energy and ancillary service awards during the critical hours.

Figure 112: Profile of RTD and RUC SOC and MSOC for RA LES resources on July 28

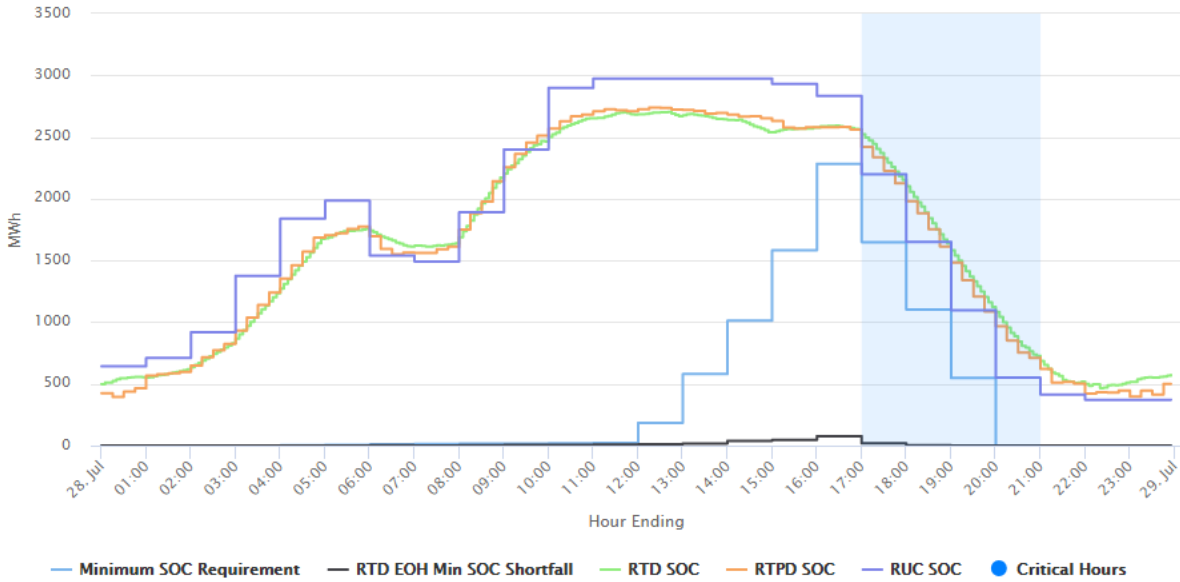


Figure 113: Real-time energy dispatches for resources without day-ahead awards, July 28

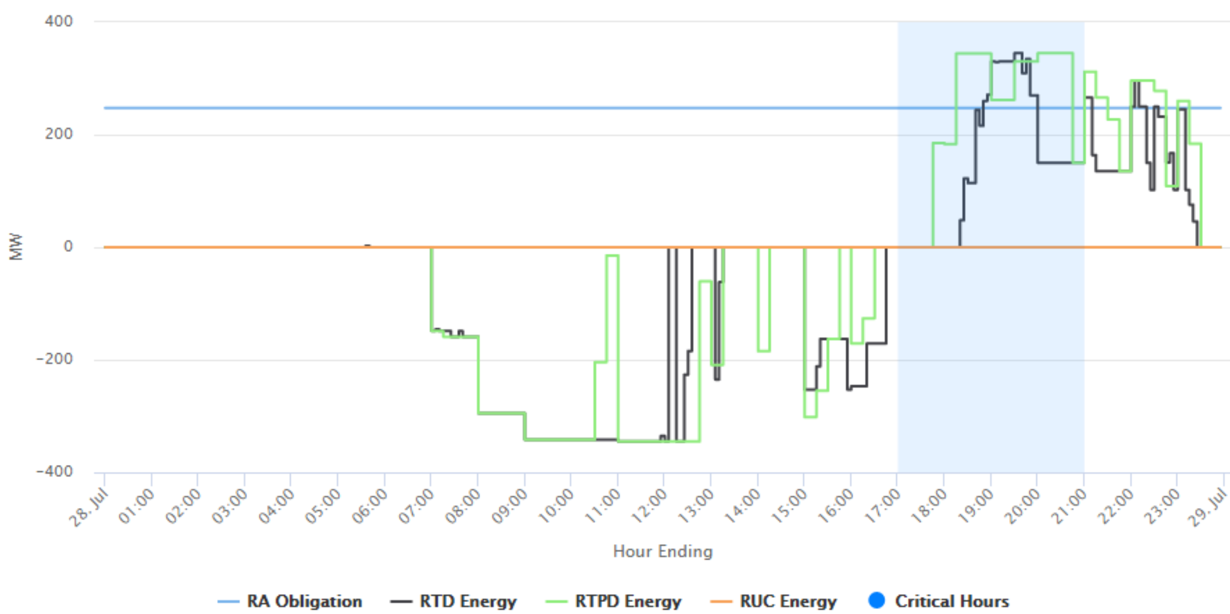
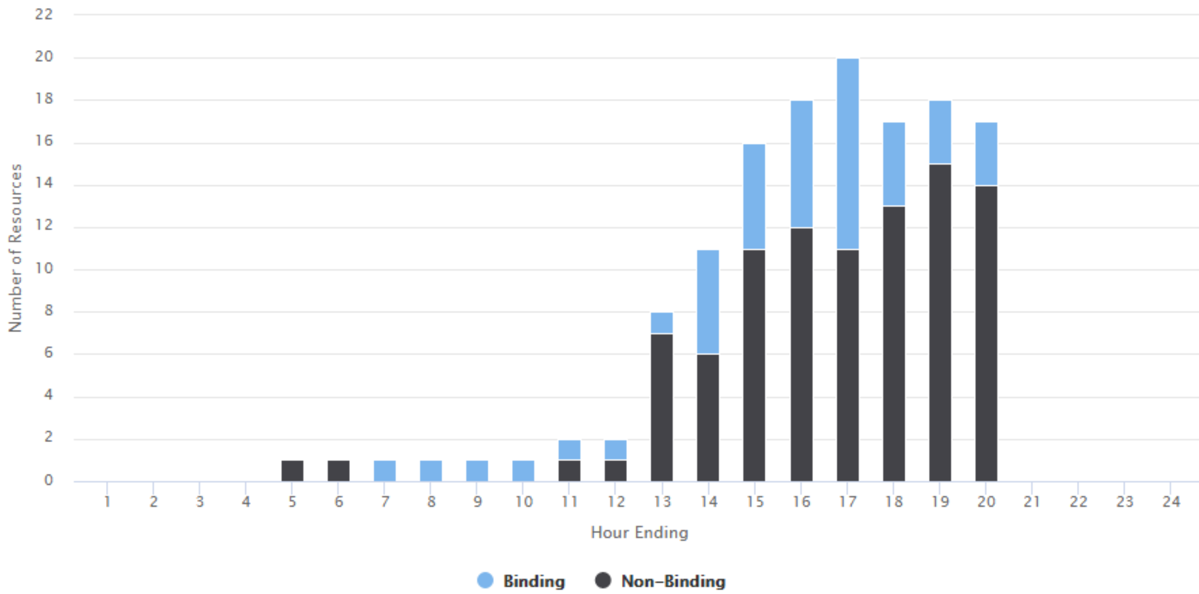


Figure 114: Number of resources with MSOC binding at end of hour in RTD on July 28



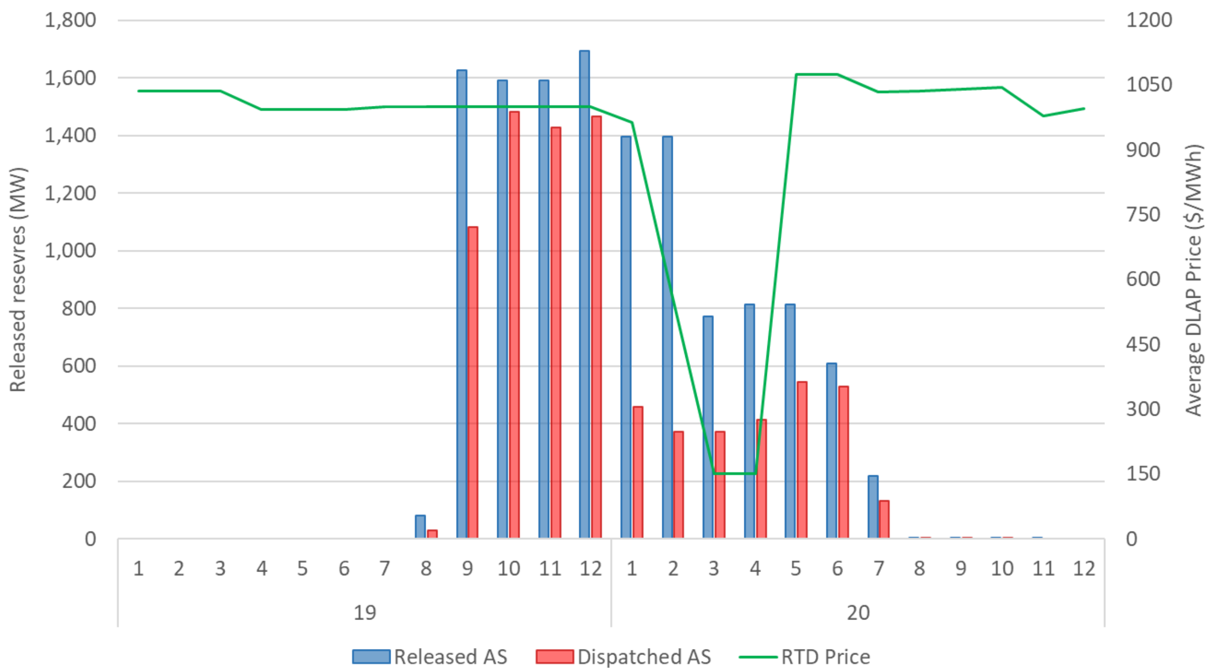
17 Scarcity Pricing Enhancements

When the CAISO meets its real-time demand requirement with generation it has originally reserved to meet its contingency reserve requirement, the market may produce lower energy price at a time when it should be signaling very tight supply conditions with high prices. When the CAISO is in a Stage 2 Energy Emergency, it is allowed to use generator providing contingency reserves to serve demand and meet its contingency reserve requirement by arming load. CAISO generally enters into Stage 2 Energy Emergency with the intent to begin “arming load” to meet reserve requirements. “Arming load” is a process where CAISO system operators inform load-serving entities to make all preparations necessary to be able to drop load in controlled manner. With the summer enhancement implemented on June 15, when arming load to meet contingency reserve requirements, the CAISO will release both the contingency and non-contingency operating reserves at the bid cap price. This will set prices at the offer cap when there is insufficient generation supply to meet both energy and contingency reserve requirements and the released operating reserves are dispatched for energy.

On July 9, 2021, at 16:06 due to a loss of resources and fire threat to the transmission system, the CAISO was forecasting a resource deficiency with all available resources in use or forecasted to be in use between 17:00 through 22:00hrs. At 17:44 the ISO declared EEA2, and at 18:32 the CAISO declared EEA3 and began arming load that could be reduced in 10 minutes. At 21:00, the ISO terminated the Stage 2 Emergency. Between 18:00 and 20:00, the ISO operators made available contingency spinning reserve and contingency non-spinning reserve in the market for energy dispatch at the bid cap. The spinning reserve and non-spinning reserve capacity were dispatched by the market.

Figure 115 shows the total ancillary service released in the market and the total ancillary service dispatched in the five-minute market. During hour endings 19 and 20, operating reserves capacity from multiple resources were released into the energy market at the id cap. Once available in the energy bid stack, these resources were assessed on their economic merit to be dispatched for energy. The green line shows the average DLAP price observed during these interval and they are generally in the range of the bid cap such that the capacity coming from the released operating reserves cleared economically. In hour ending 20 intervals 3 and 4, there is capacity from these resources till dispatched even though the clearing prices was significantly below their bids of $1000/MWh. This happened because some of the resources carrying the released operating reserves were actually exceptionally dispatched to hold their dispatch at an operating target no lower than a specified threshold (exceptional dispatch for minimum level

Figure 115: Real-Time contingency Ancillary Service Contingency Dispatch on July 9, 2021



The ISO had declared similar grid warnings on July 10 and July 29. However, based on system conditions operating reserves were not released for energy dispatch.

18 Market Issues

Through the analysis of the market outcomes and performance, there were several market issues identified during the month of July 2021, which either have been resolved or are expected to be addressed. These include:

1. *Overscheduling on the Malin and NOB interties*. With the derates applied on Malin and NOB due to fire conditions, Malin's capacity was reduced to 285 MW while NOB's capacity was reduced to 785 MW. The Malin intertie had import self-schedules that exceeded that capacity. Given the existing penalty prices associated with intertie limits and the relative calibration of other penalty prices related to power balance constraint and self-schedules, the optimal solution for the HASP market was to relax the intertie limits, which resulted in overscheduling of Malin and NOB interties. These overschedules had to be curtailed in real-time by system operators.

   The penalty prices for intertie constraints are prescribed in the tariff and, consequently, they cannot be adjusted until a tariff change is filed before and approved by FERC. The CAISO is considering revisions to the penalty prices, which will require a tariff change, to avoid the overscheduling of intertie limits while preserving other scheduling priorities.

2. *Reversion of derates on the Malin and NOB interties.* While derates were in place for the Malin and NOB interties, limits for these two interties temporarily reverted back to the full limits. This occurred for a total of two FMM intervals and eight RTD intervals. Although the respective markets ran with these reverted limits during the indicated number of intervals, there were no detrimental impacts to the market solution, mainly because the FMM and RTD markets do not optimize hourly intertie schedules. The market consumed and used the normal limits because an outage record, which was tracking the derated value, was terminated prematurely and with no replacement to continue tracking the derate. With no derated values in place, the intertie limits defaulted to their nominal value. Once a new outage record was in place to continue tracking the derate, the market resumed with using the derated values. The systems and the market worked as expected in this scenario.

   The CAISO is reviewing its operating practices to minimize this type of gap when intertie limits are being dynamically updated.

3. *Congestion revenue right (CRRs) settlements on the Malin constraint*. CRRs are settled based on congestion prices produced in the IFM solution, using a pro-rata funding logic. This revised logic relies on shift factors and shadow prices of transmission constraints (including interties) to assess the value of, and the pro-rata funding applicable to, all CRRs. CRRs are financially settled based on pro-rata adjustments to CRRS based on estimated flow contributions using the shift factors and shadow prices of the IFM solution. Although the flows estimated on the Malin constraint in the IFM solution were calculated correctly, with the major derates applied on Malin, flow contributions from external locations were erroneously accounted for in the CRR settlements calculation. This issue arose when shift factors from external locations were transferred to the CRR settlements system. The incorrect use of these shift factors has been present since January 15, 2021, but it did not became noticeable until the flows on the Malin intertie were largely

derated such that the flow contribution of the external locations were of comparable size to the rest of the flow contributions.

The CAISO implemented a fix for this issue prospectively on August 23, and is currently assessing the conditions to retroactively address all impacted days.

4. *Storage resource capacity not accounted for in the RUC process*. Currently, the CAISO does not insert bids for RA storage resources. RUC process cannot commit them further, and storage resources may leave the DAM without a day-ahead schedule. When the real-time market bidding begins, these resources may bid and be awarded/dispatched in the real-time market. However, if RUC did not consider the resources for dispatch, their capacity may not be properly accounted to meet the load forecast needs in the day-ahead timeframe. Consequently, RUC may have to either rely on other supply, or reduce exports and relax the power balance constraint, if supply is limited.

   CAISO is currently assessing this condition to determine if a change of treatment in the RUC process for these resources is applicable.

5. *Export cuts not performing per HASP schedule.* On July 9 during peak hours, the HASP process assessed the need to curtail exports based on the prevalent supply-demand conditions. Once an intertie schedule is issued, entity should follow through with submitting an E-tag up to the cleared schedule. On July 9 hour ending 20, out of the 3,800MW of export cuts in the HASP process, there were about 566 MW of export cuts that deviated (uninstructed deviation). Effectively, these 566MW of cuts did not occur in the actual system either because the export reflecting the cut was denied or the original export was retagged by the counterparties of the exports. These exports that were deviating were subject to settlements penalties based on the existing intertie deviation feature.

   Based on this finding, the CAISO is assessing the tagging rules.

6. *Miscalculation of flexible ramp capacity in resource sufficiency test*. The CAISO identified an issue in the calculation of the flexible ramp capacity in the resource sufficiency test. The issue arises for Multi-Stage Generating (MSG) units transitioning upward. During this period of transitioning, the existing logic does not account for the additional capacity gained by the MSG unit transitioning to a higher configuration. As a result, the additional supply available from the higher configuration will not be accounted for in the test. This can result in any EIM entity failing the test, depending on the amount of capacity at play.

   The CAISO identified the software defect and is working with its vendor to have a fix for it.

7. *Missed calculation of import uplifts*. On July 9, CAISO entered into an energy emergency and under the new summer 2021 enhancements functionality, there is a provision for imports to receive uplift during these tight conditions. Although the trigger was properly set in the market, this information did not flow into the necessary downstream systems. Due to this lack of information in the downstream system, the settlements calculation for import uplifts did not trigger.

At the time of the publication of this report, the full data set was available to analyze this part of the summer enhancement. CAISO will report on its performance in a future opportunity when data becomes available.