Summer Market Performance Report
July 2024

August 30, 2024

Prepared by
Market Performance and Advanced Analytics

Contents

List of Figures

Acronyms

AET	Assistance Energy Transfer
BAA	Balancing Authority Area
BANC	Balancing Authority of Northern California
ISO	California Independent System Operator
CCA	Community Choice Aggregator
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DAM	Day ahead market
DALPT	Day-ahead low priority exports
DLAP	Default Load Aggregated Point
ED	Exceptional Dispatch
ELCC	Effective Load Carrying Capacity
ESP	Energy Service Provider
ETC	Existing Transmission Contract
FMM	Fifteen Minute Market
HASP	Hour Ahead Scheduling Process
HE	Hour Ending
IFM	Integrated Forward Market
IOU	Investor-Owned Utility
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
LRA	Local Regulatory Authority
MW	Megawatt
MWh	Megawatt-hour
NGR	Non-Generating Resource
NOB	Nevada-Oregon Border
NSI	Net Scheduled Interchange
OASIS	Open Access Same-Time Information System

OR	Operating Reserves
PDR	Proxy Demand Response Resource
PRM	Planning Reserve Margin
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.
PV	Palo Verde
QC	Qualifying Capacity
RA	Resource Adequacy
RDRR	Reliability Demand Response Resource
RTM	Real-Time Market
RTLPT	Real-time low priority export
RUC	Residual Unit Commitment
SMEC	System Marginal Energy Component
SOC	State of Charge
TOR	Transmission Ownership Right
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market

1 Executive Summary

The California Independent System Operator (ISO) regularly reports on market performance to provide timely and relevant information. This report is part of a series of monthly reports focusing on the ISO's market performance and system conditions during summer months, June through September. These months are of interest because it is when system conditions are often constrained in California and the Western Interconnection. These monthly reports also provide a performance assessment of specific market enhancements implemented as part of the ISO's ongoing effort to ensure readiness for summer conditions.[1]

Parts of California and the West experienced a prolonged heatwave in July, with triple-digits temperatures persisting over many consecutive days. California's mean temperature in July was ranked as the warmest on record (1st of 130 years) with much of the state experiencing its warmest temperatures. The highly urbanized areas of Los Angeles and San Diego did not experience well above normal temperatures, keeping the ISO's total demand lower than in 2022 or 2023. The Western Interconnection reached a new all-time peak of 167,988 MW on July 10. This record surpassed the previous peak of 167,530 MW in 2022. On the same day, ISO-area load peak reached 43,969 MW.The instantaneous peak load for the ISO area occurred on July 24 at 45,426 MW, significantly lower than the all-time system peak demand of 52,061 MW on September 6, 2022.

ISO supply was more than sufficient to meet forecast demand in July. On July 24, the ISO declared an energy emergency alert watch due to the Park Fire threatening transmission facilities that could result in loss of imports to California. The system was able to manage a reduction of imports and did not require any additional actions. The market and system operated well while ensuring demand was met. Additionally, coordination and planning with state agencies, load-serving entities, and regional partners helped the ISO prepare for and manage the July heat events. The major highlights for the month are:

Average peak ISO loads in July 2024 were moderate at 39,772 MW, which was higher than the average daily peak loads in July 2023 of 37,351 MW. The highest instantaneous peak load for the month of July was 45,426 MW on July 24, which was below the California Energy Commission's (CEC) month-ahead forecast of 45,596 MW.

Monthly resource adequacy capacity was 52,441 MW, more than enough to meet load, inclusive of demand, operating reserves, and supply and demand uncertainties. This is higher than the 51,144 MW of resource adequacy capacity for July 2023. Compared to July 2023, RA capacity for storage resources increased by 3,612 MW while static imports increased by 784 MW. Hydro and gas resources saw a decrease of 379 MW and 3,449 MW, respectively.

[1] This report is targeted in providing timely information regarding the ISO'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.

The ISO's average prices in July were $50/MWh and $43/MWh for the integrated forward and real-time markets, respectively, up from $26/MWh and $23/MWh in June. The daily prices saw an increasing trend through July reaching maximum levels on July 24, with similar trends observed for prices in other regions of the Western Energy Imbalance Market (WEIM). Bilateral prices at the Mid-C and Palo Verde hubs trended higher than ISO day-ahead prices, most likely reflecting the high-demand conditions in the overall West. The average next-day bilateral prices for Mid-C and Palo-Verde hubs were about $82/MWh and $77/MWh, respectively.

There was sufficient supply to meet the adjusted California ISO load forecast in peak hours in the residual unit commitment (RUC) process for all days in July. There were economic and low-priority export reductions in the RUC during July 9-11 to balance supply with demand.

Capacity offered to the ISO market by storage resources continues to increase. In July 2024, there were 164 batteries registered in the ISO markets. The bid-in capacity for energy was consistently over 7,000 MW in July. The maximum state of charge in real time was about 31,934 MWh, and real-time dispatches reached a maximum of 7,608 MW. This capacity helped to meet peak conditions. Storage resources continued to supply a significant portion of regulation capacity.

The hourly average of net imports was 1,810 MW for peak hours 17 through 21 in July. This low level was due to lower level of imports while increasing demand for exports. The ISO market was able to accommodate and clear over 9,000 MW of exports on July 9 as high demand conditions persisted in the broader West. The larger volume of exports generally occurred prior to the peak hours when solar production was plentiful and prices were moderate.

WEIM transfers were predominantly exports from the ISO balancing authority area (BAA) during midday hours. Overall, WEIM transfers reflect the economic and operational benefits that WEIM offers to participating entities by maximizing supply diversity and transferring supply from where it is available to where it is needed in real-time.

About 99 percent of the resource adequacy imports to the ISO bid at $0/MWh or lower in the day-ahead and real-time markets. This assessment is for static imports related to load-serving entities under the jurisdiction of the California Public Utilities Commission (CPUC).

Up to 680 MW of the 690 MW of registered high-priority wheel-through transactions for the month of July participated in the day-ahead market. This represents a 99 percent utilization of the registered wheels. For low priority wheels, the maximum transaction was 275 MW from the Palo Verde to Mirage locations. All high-priority wheels were honored in the markets in July.

Reliability demand response resources were dispatched at a maximum of 201 MW in the real-time market on July 11 after they were economically bid and cleared in the day-ahead market. The largest volume of dispatches for proxy demand response resources in the day-ahead timeframe occurred on July 11 at 201 MW, whereas in the real-time market, there was a maximum of 161 MW for the same trade date. There were no emergency events to trigger dispatch of reliability demand response resources.

On average, the ISO's daily average market costs were $43.3 million in July, representing an average daily cost of $58.35/MWh, an increase from $18.35/MWh in June. The highest daily cost accrued on July 11 at about $93 million. These higher costs are expected in summer conditions with higher demand levels settled at higher energy prices.

2 Background

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

Following the publication of the Final Joint Root Cause Analysis, the ISO 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 the summer 2021 Readiness initiative[2].

For summer 2024, the following enhancements continue to be in place:

1. Import market incentives during tight system conditions
2. Real-time scarcity pricing enhancements
3. Reliability demand response dispatch and real-time price impacts
4. Transmission service and market scheduling priorities

The minimum state of charge constraint was active only through the summer 2023, and is no longer in place for summer 2024. As part of the energy storage enhancements, new functionality was implemented for storage resources through exceptional dispatches for better management of state of charge during tight system conditions.

As part of the ISO's effort to assess market performance, the summer performance reports are published for the months of June through September.

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

3 Demand and Supply Conditions

Resource adequacy

The ISO 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 ISO's load. The ISO also manages the RA program for several other Local Regulatory Authorities (LRAs) in the ISO's footprint. 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 and respective LRAs set and enforce RA program rules for LSEs within their jurisdictional footprint. This includes setting monthly obligations based on an electric load forecast and planning reserve margin (PRM), and resource counting rules. The California Energy Commission (CEC) estimates the electric load forecast used by the CPUC and other LRAs in respective RA programs. RA capacity from both CPUC and non-CPUC jurisdictional LSEs is shown to the ISO annually and monthly following a process established by the ISO.

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. For system capacity, the RA requirement ensures the contracted capacity is sufficient to cover the 1-in-2-year (average) peak load plus a PRM.[3] This PRM is to cover the 6 percent of operating reserves plus a contingent headroom to account for higher-than-expected load forecast and resource outages.

The monthly RA showing for July 2024 was 52,441 MW, which is higher than July 2024's monthly showing of 51,144 MW.[4] Figure 1 compares the total monthly RA capacity by fuel type in July 2023 and July 2024. In general, total RA capacity increased across fuel types from year to year with some exceptions. For July 2024 , RA capacity for storage resources increased by 3,612 MW to about 7,675 MW, and static imports increased by 784 MW. Hydro RA decreased by 379 MW and gas-fired RA decreased by 3,449 MW.

Static RA imports increased from 2,634 MW in July 2023 to 3,418 in July 2024.[5] The composition by intertie varied between years as shown in Figure 2. RA imports through the Malin intertie between Oregon and California increased from 1,113 MW to about 1,334 MW from July 2023 to July 2024, and imports through Nevada-Oregon Border (NOB) intertie increased from 717 MW to about 1,081 MW across the same timeframe. Monthly RA capacity tends to increase as the summer progresses and was generally on par

[3] The planning reserve margin is 17 percent for the CPUC jurisdictional entities in2024. Other LRAs may set their own respective PRMs. In Decision 21-12-015, the CPUC established an "effective" PRM for 2022 and 2023 which may be met with both RA and non-RA resources that may not be in the wholesale market. Decision 23-06-029 extended an "effective" PRM of 1,700 to 3,200 MW to 2024 and 2025.

[4] 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 to meet the final RA obligation. The final RA obligation is composed of 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.

[5] 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.

with quantities from 2023. Generally, monthly static RA imports also increase as the summer progresses through the months of July and August. These trends are shown in Figures 3 and Figure 4.

Figure 1: RA capacity organized by fuel type

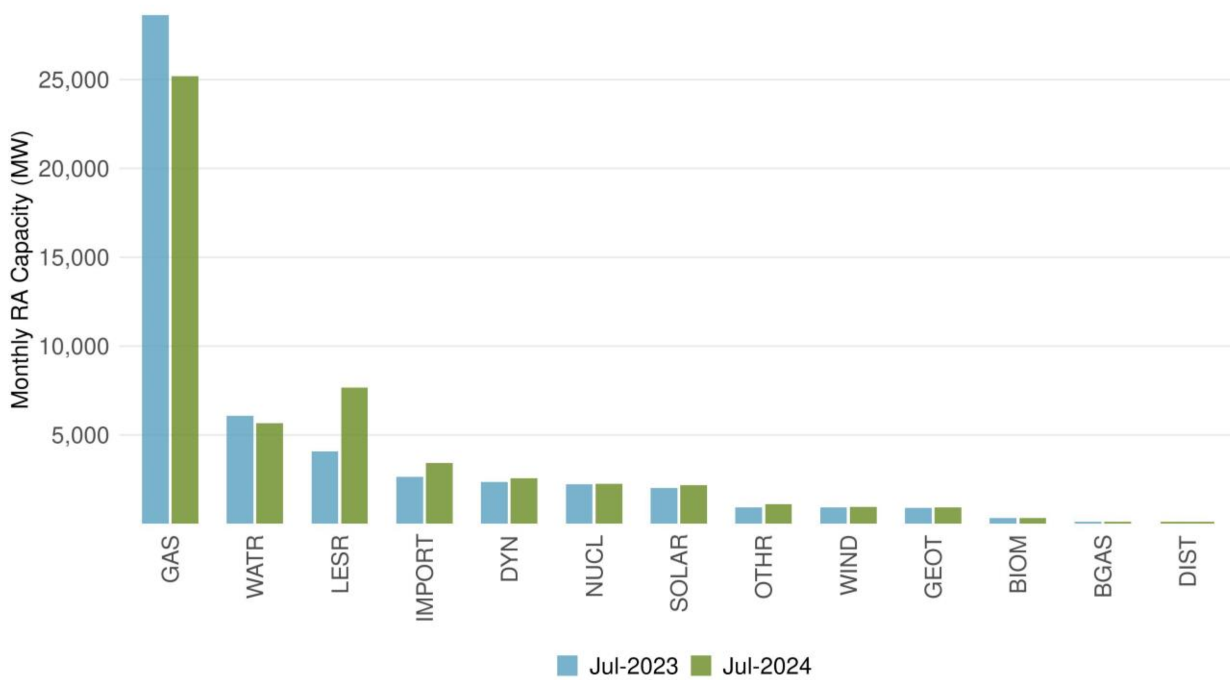


Figure 2: Monthly RA imports organized by tie

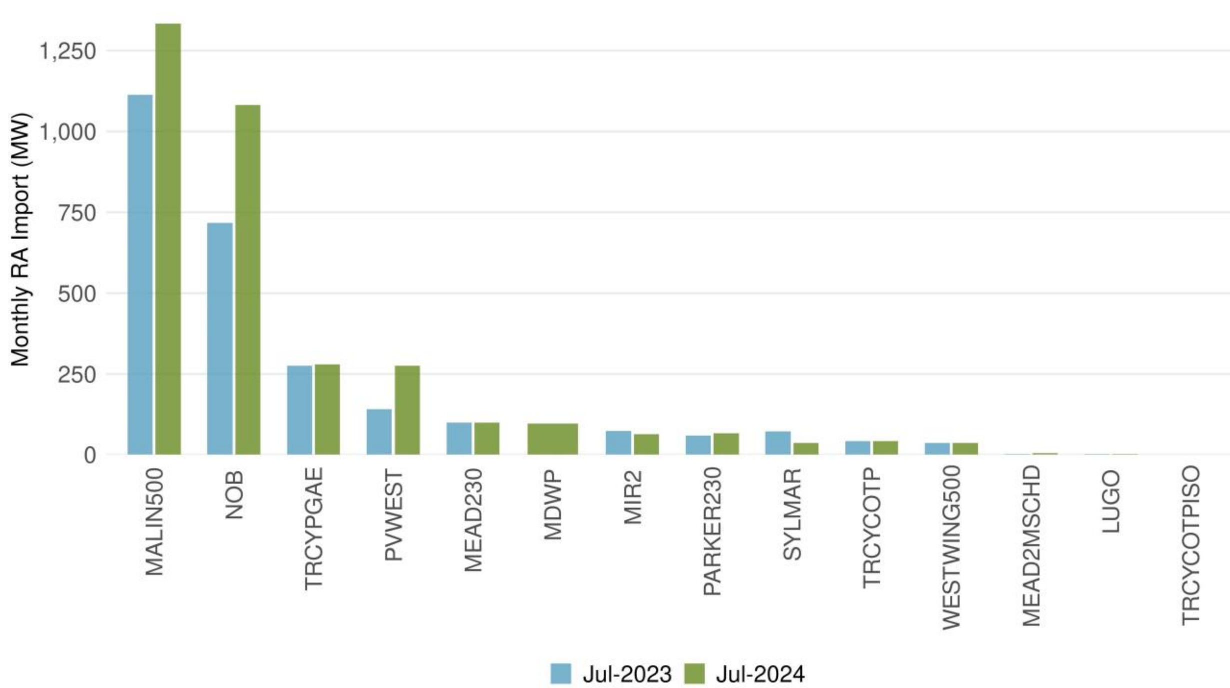


Figure 3: Monthly RA showings

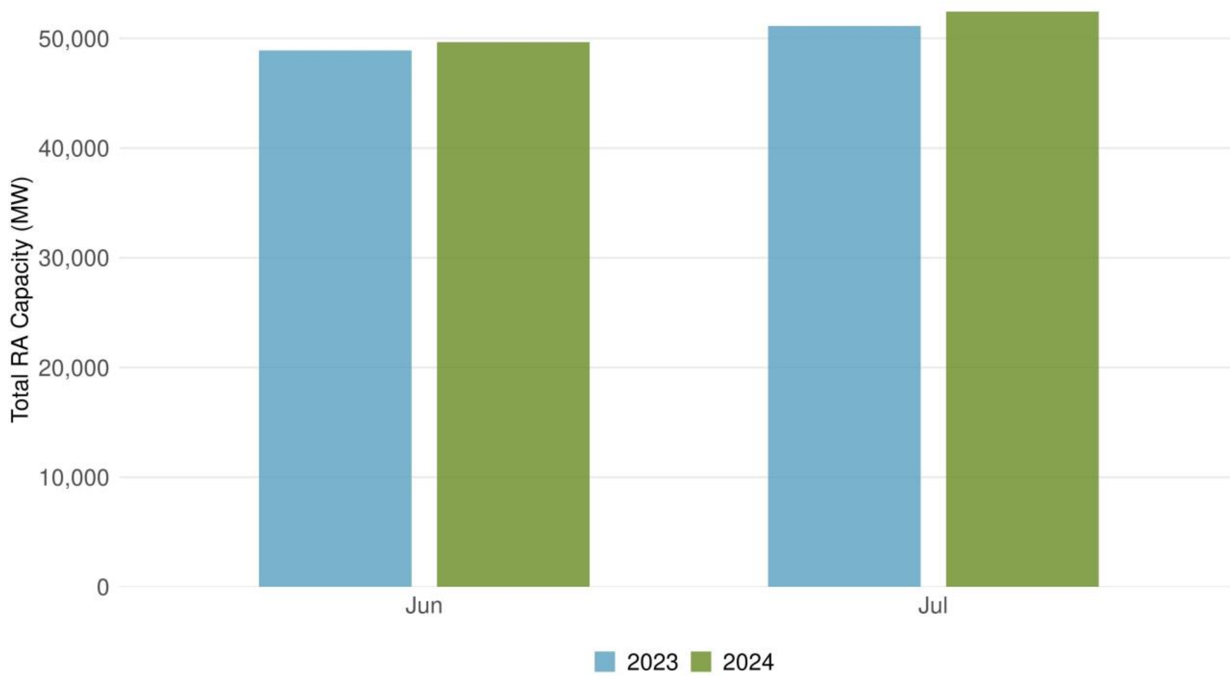
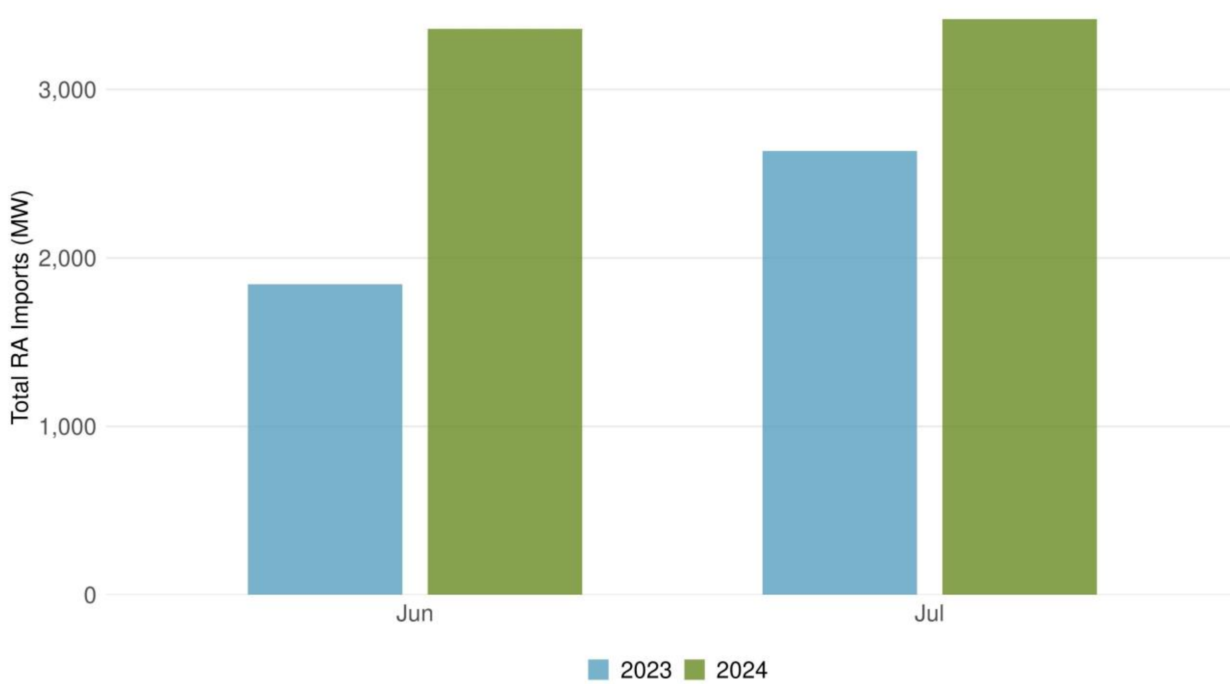


Figure 4: Monthly trend of static RA Imports

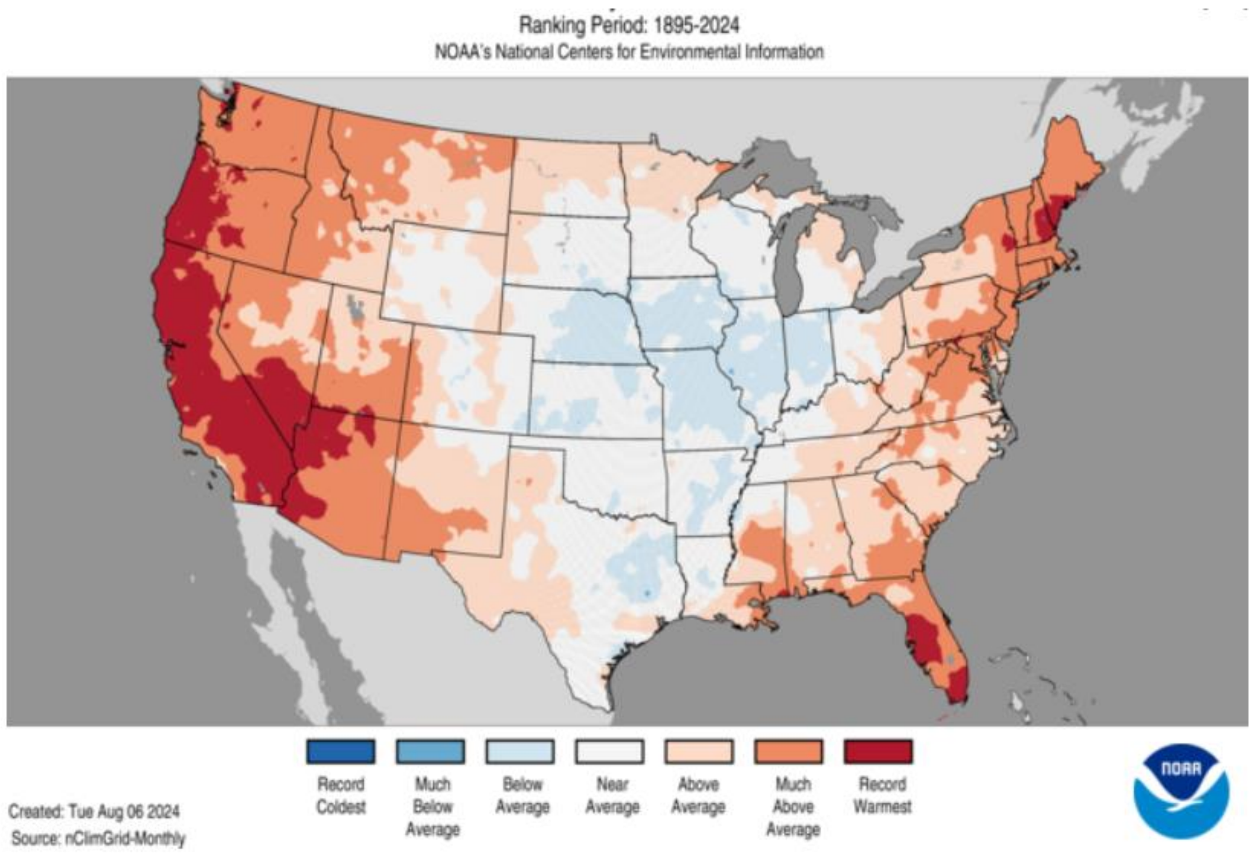


Weather

Above average, much above average, and record warmest mean temperatures were observed across the far western United States throughout July.

On July 1st, Hurricane Beryl became the earliest Category 5 hurricane and the second category 5 on record during the month of July in the Atlantic Ocean. Due to the strength of Hurricane Beryl moving through the Gulf of Mexico and central United States, parts of California and the West experienced a prolonged heatwave in July, with triple-digit temperatures persisting over many consecutive days. California's mean temperature in July was ranked as the warmest on record (1st of 130 years) with much of the state experiencing their warmest temperature. However, the highly urbanized areas of Los Angeles and San Diego did not experience well above normal temperatures, keeping ISO's total demand lower than 2022 or 2023. This is illustrated with the geographic map of temperatures from NOAA[6] in Figure 5 and the additional figures in the appendix.

Figure 5: Mean temperature percentiles for July 2024



Similarly, the pacific northwest, portions of the central and desert southwest regions also experienced record warmest and much above average temperature conditions. Figure 5 and Figure 6 shows the daily temperature deviation from normal for sample areas in the west. During the week of July 8th through July

[6] [Assessing the U.S. Climate in July 2024 | News | National Centers for Environmental Information (NCEI) (noaa.gov)]

12th, areas throughout the west experienced average temperatures of 6-16 degrees Farienheight above normal. The highest above normal temperatures in the west were in the pacific northwest, western desert southwest, and central regions where temperatures were 9-16 degrees above normal.

Figure 6: Average temperature depature from normal for sample areas in the west

Portland Gas and Electric (PGE)

Average temperature departure from normal

July 2024

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
	1 5	2 -0.7	3 1	4 7	5 12	6 13
7 14	8 15	9 16	10 11	11 5	12 3	13 8
14 8	15 4	16 10	17 5	18 4	19 5	20 8
21 2	22 -2	23 -1	24 -0.5	25 -4	26 -1	27 -2
28 -3	29 -5	30 3	31 4			
				days < normal 10	days > normal 21	Deg +/- normal + 4.6

above normal	below normal	Normals: 1990-2020

Idaho Power Company (IPCO)

Average temperature departure from normal

July 2024

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

above normal	below normal	Normals: 1990-2020

California ISO (CAISO)

Average temperature departure from normal

July 2024

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
	1 3	2 6	3 7	4 7	5 7	6 7
7 6	8 4	9 3	10 4	11 7	12 5	13 3
14 2	15 0.2	16 -0.4	17 -0.2	18 2	19 4	20 5
21 2	22 5	23 7	24 7	25 7	26 4	27 -4
28 -4	29 -3	30 -2	31 -0.6			
				days < normal 10	days > normal 21	Deg +/- normal + 3.2

above normal	below normal	Normals: 1990-2020

Nevada Energy (NVE)

Average temperature departure from normal

July 2024

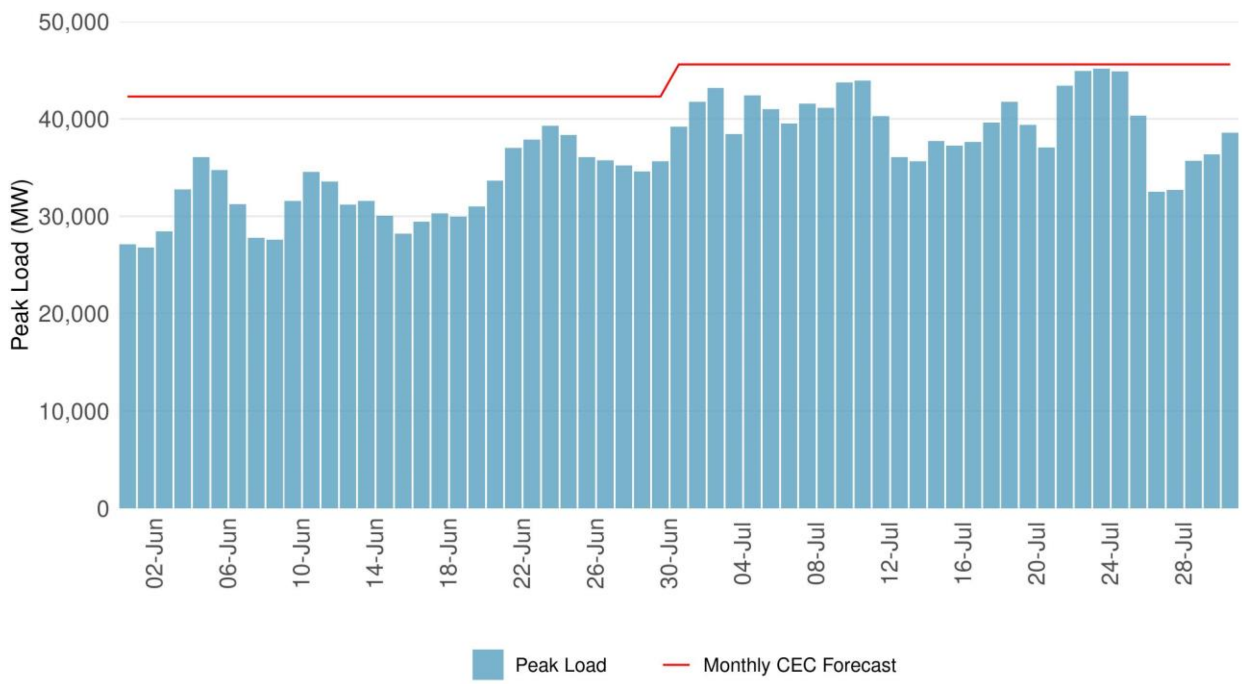
Sun	Mon	Tues	Wed	Thurs	Fri	Sat
	1 3	2 4	3 6	4 8	5 7	6 9
7 11	8 9	9 11	10 11	11 10	12 12	13 8
14 0.8	15 2	16 5	17 5	18 2	19 5	20 7
21 9	22 8	23 9	24 6	25 7	26 5	27 0.5
28 -2	29 -2	30 -0.8	31 2			
				days < normal 6	days > normal 25	Deg +/- normal + 5.7

above normal	below normal	Normals: 1990-2020

Peak ISO loads

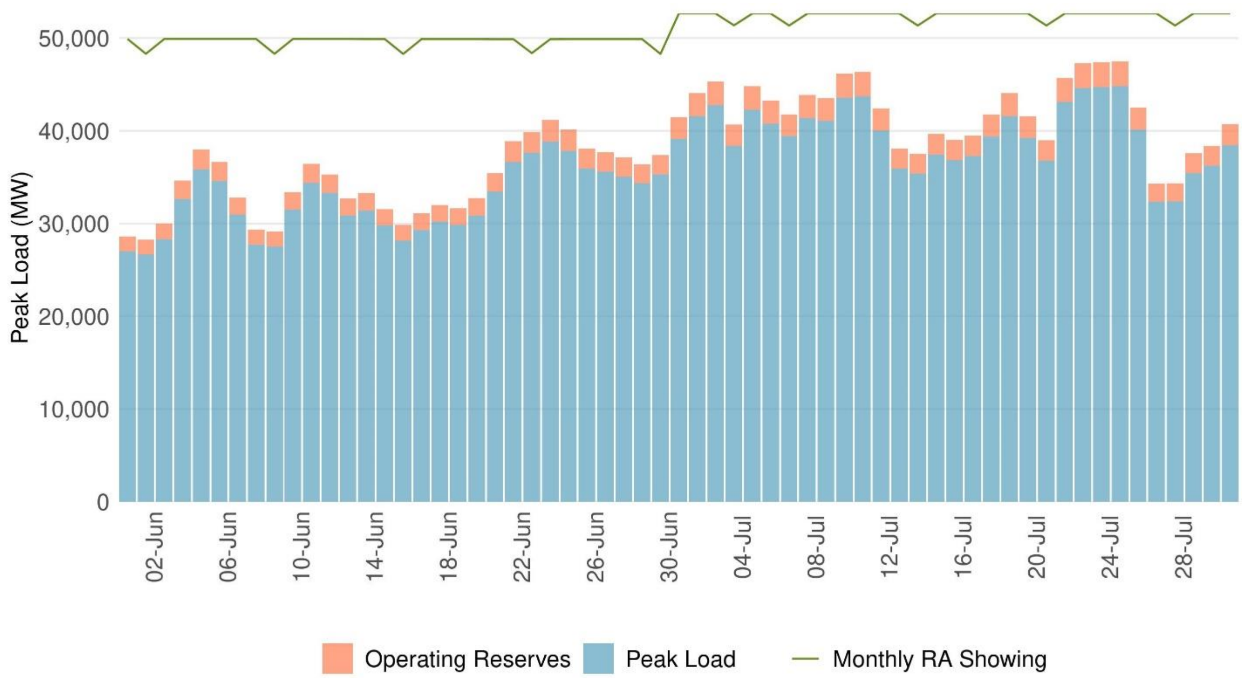
Peak loads in July were elevated from the previous month, exceeding 40,000 MW on several days, but did not exceed 45,000 MW. The average daily peak load in July 2024 was 39,772 MW which was higher than the average daily peak load from the previous year in July 2023 of 37,351 MW. Figure 7 shows the 5-minute average daily load for June and July relative to the CEC month-ahead forecast used to assess the resource adequacy requirements. The instantaneous load peak in July 2024 was 45,426 MW on July 24. This peak was below the CEC month-ahead forecast of 45,596 MW. The below figure is based on the five minute averages of the actual load. The highest five-minute average peak load for the month of July was 45,160 MW.

Figure 7: Daily peak load and CEC month-ahead forecast



The actual load did not exceed the monthly RA showings in July 2024 as illustrated in Figure 8. The green line indicates nominal monthly RA showings. As discussed later in this report, the actual capacity made available into the ISO's market (accounting for outages and other factors) varies from day to day. In subsequent sections, the actual RA capacity made available in the market is shown more granularly for the month on an hourly basis.

Figure 8: Daily peak load, operating reserves and RA capacity



Although high temperatures in the Western U.S. throughout most of July drove a load peak record in the Western Interconnection (WECC), load in ISO area remained within moderate summer levels. The WECC area demand reached a new all-time peak of 167,988 MW on July 10. This record surpassed the previous WECC peak of 167,530 MW in 2022. On this day, ISO area load peak was at 43,969 MW, while the summer peak load for ISO area in July occurred on July 24 at 45,160 MW, significantly lower than the all-time system peak demand of 52,061 MW of September 6, 2022. The July's peaks for WECC and ISO areas are shown in the daily- peak profile in Figure 9.

Figure 10 shows the load distributions for summer months in the WECC area. Although the peaks observed in July 2024 and September 2022 were relatively close in magnitude, there were many more hours with higher loads in July 2024 (taller right-hand tail of the distribution) given the sustained high temperatures experienced in the month. A similar plot is provided for ISO area in the appendix.

Figure 9: Daily load peak for WECC and ISO area in summer months

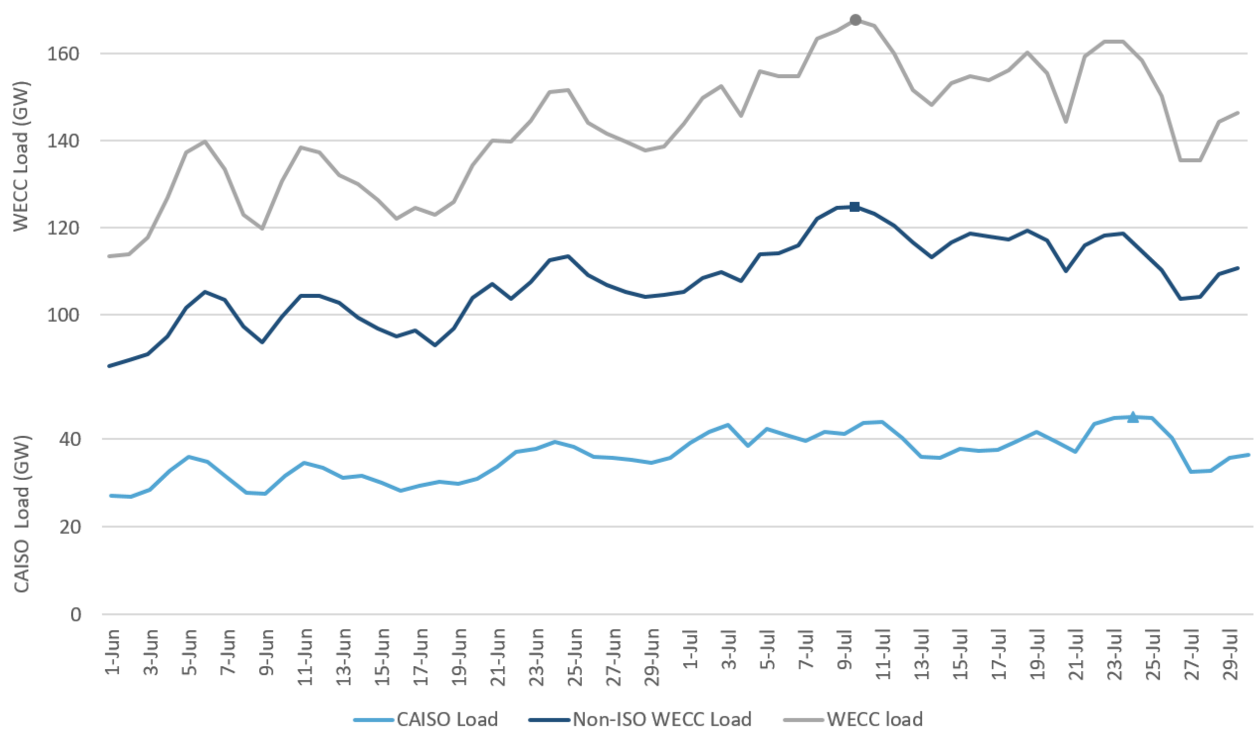
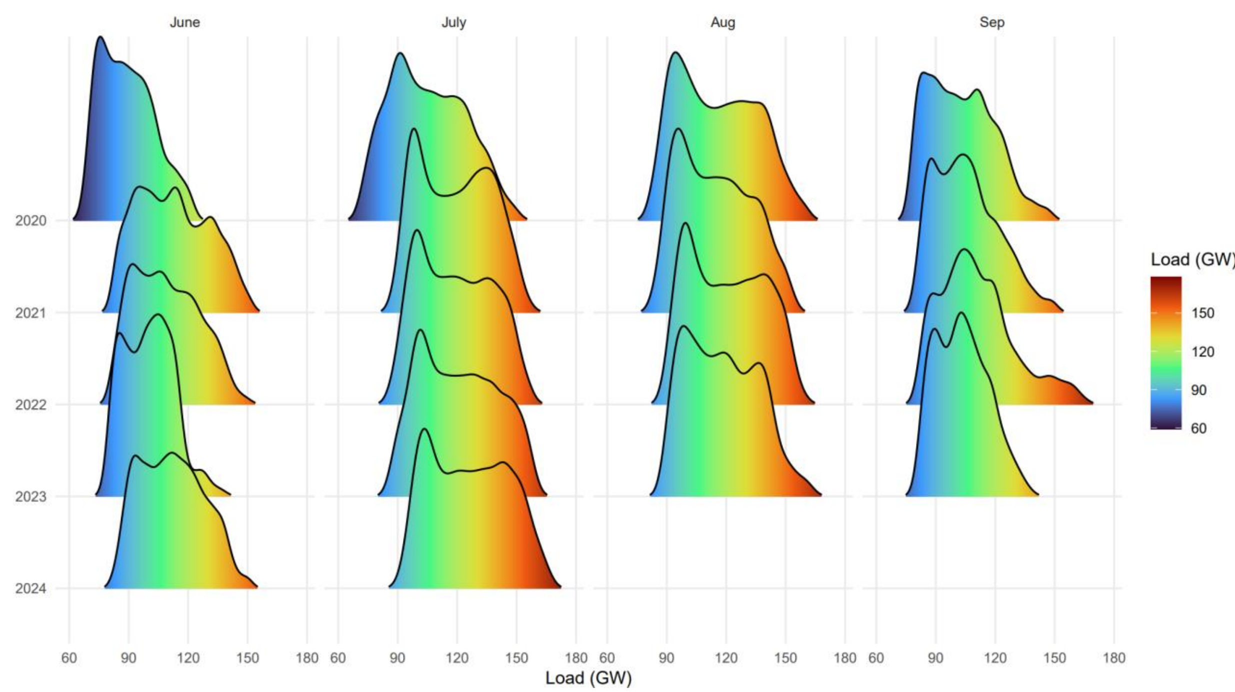


Figure 10: Daily load peak for WECC area in summer months



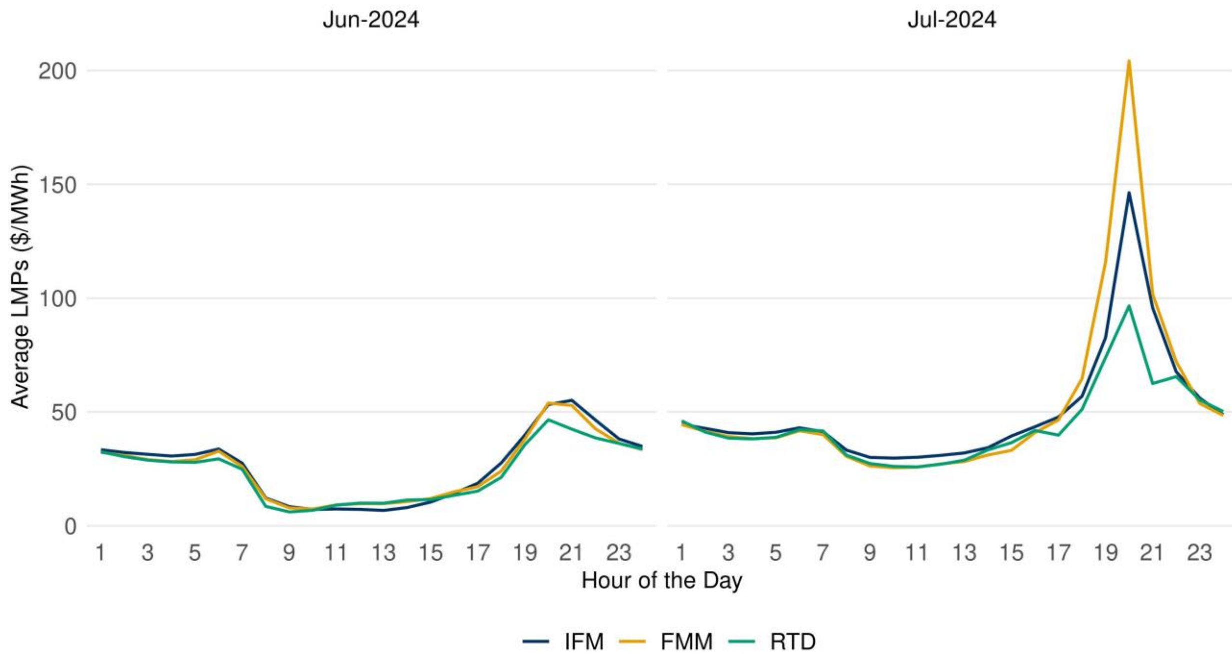
Market prices

Market prices naturally reflect supply and demand conditions. As the market supply tightens, prices tend to rise. Locational marginal prices in the ISO have three components: the marginal cost of energy on the system, the marginal cost of congestion reflecting constraints, and the marginal cost of losses. With the introduction of the WEIM, the ISO introduced a 4th comoponent, GHG which reflects the marginal cost applied to account for GHG imported into California. The marginal energy component reflects the overall supply and demand conditions. Congestion conditions may also create local or regional price separations. Figure 11 compares the daily average prices across ISO's markets for the months of June and July.[7] The daily average fifteen minute market prices reached $160/MWh ($60 in June) while the daily average day-ahead prices trailed at about $90/MWh ($45 in June), while the five minute market prices reached a maximum of about $128/MWh ($54 in June). In comparison with June, the July maximum for IFM occurs 12 days before RTD and FMM instead of same day. Figure 12 shows average hourly prices across ISO's markets for both June and July 2024. FMM and RTD prices reached a maximum on July 23, with values of $971 and $922, respectively, while IFM reached a maximum of $573 on July 11. The hourly average prices for both the integrated forward market and the fifteen-minute market peaked in trade hour 20 at $146/MWh and $204/MWh, respectively, higher than the real-time dispatch market prices of about $96/MWh in trade hour 20.

Figure 11: Average daily prices across markets- June and July 2024

[7] 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 ISO area.

Figure 12: Average hourly prices across markets



The following figure below shows daily average LMPs for all four regions in FMM for the months of June and July. In both months, for real-time dispatch (RTD) and fifteen-minute market (FMM), the California region produced the highest average LMPs. It peaked on the 25th of June and the 23rd (RTD) and 24th (FMM) of July. For the peak in June, the four regions all climb to be approximately $50/MWh. On July 23, the Pacific Northwest region peaks at about $75/MWh, while Central/Mountain and Southwest reach about $130/MWh. California area prices peaked on July 24, producing an average of over $150/MWh. Figures in the following page will further explore the peaks by depicting three-day periods of hourly averages for WEIM Load Aggregation Point (ELAP) prices aggregated by geographical region for RTD and FMM.[8]

[8] The Pacific Northwest region includes balancing areas such as Bonneville Power Administration, Powerex, Avista Corporation, Avangrid Renewables, Tacoma Power, Seattle City Light, Puget Sound Energy, Portland General Electric Company and PacifiCorp West. Southwest region includes Tuscon Electric Power, Public Service Company of New Mexico, Salt River Project, Western Area Power Administration, Arizona Public Service Company, El Paso Electric Company and Nevada Power Company. Central/Mountain region includes Idaho Power Company, NorthWestern Energy and PacifiCorp East. California region includes ISO, Los Angeles Department of Water & Power, Balancing Authority of Northern California and Turlock Irrigation District.

Figure 13: Average daily prices across region for FMM market - June and July 2024

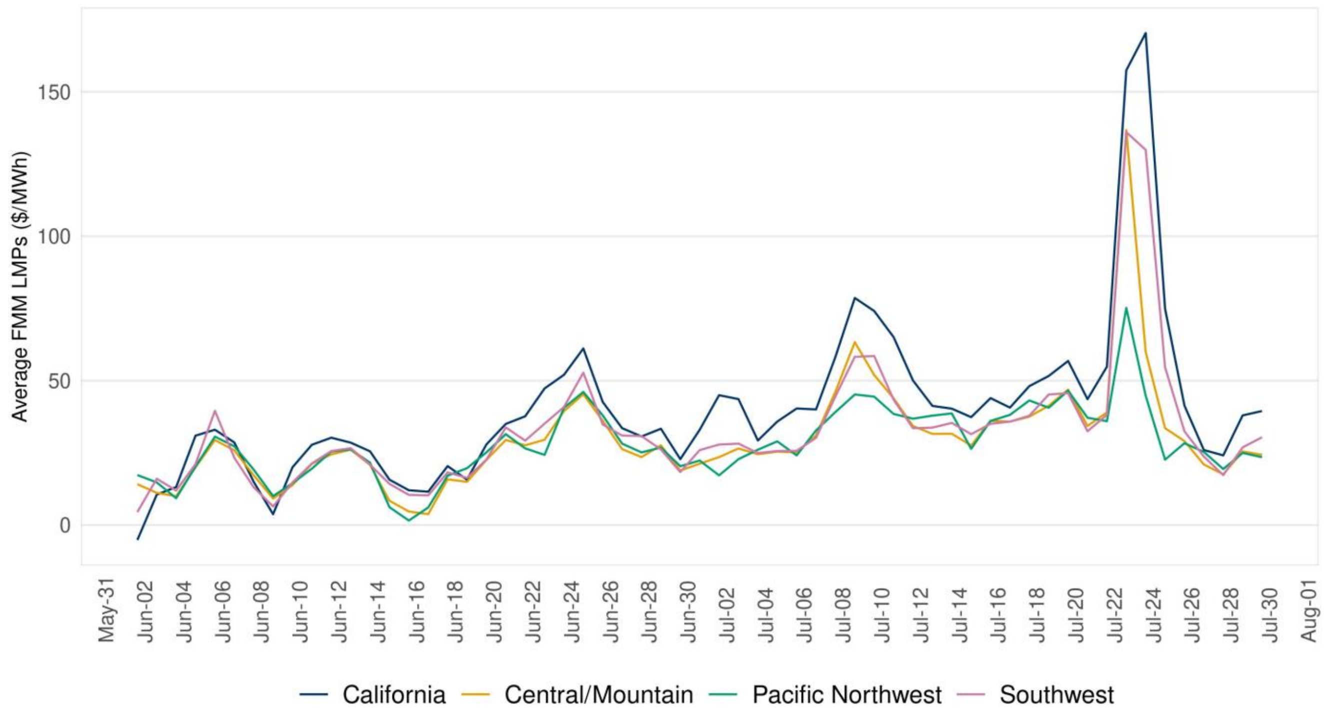
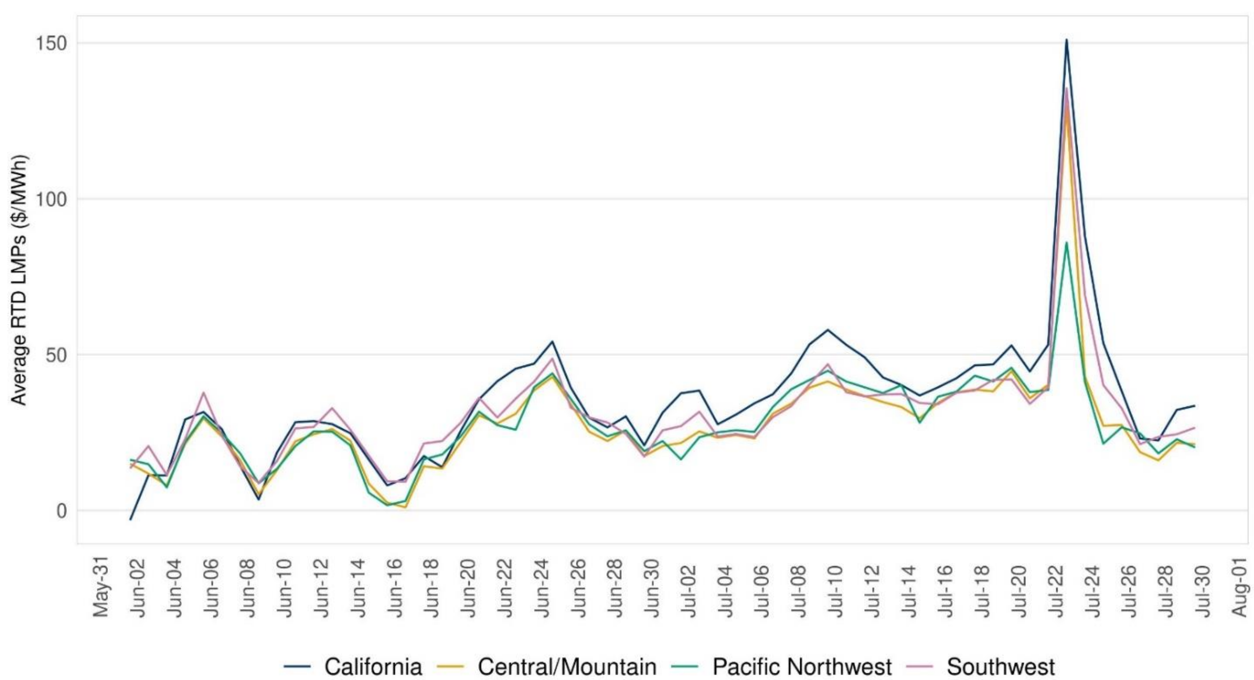
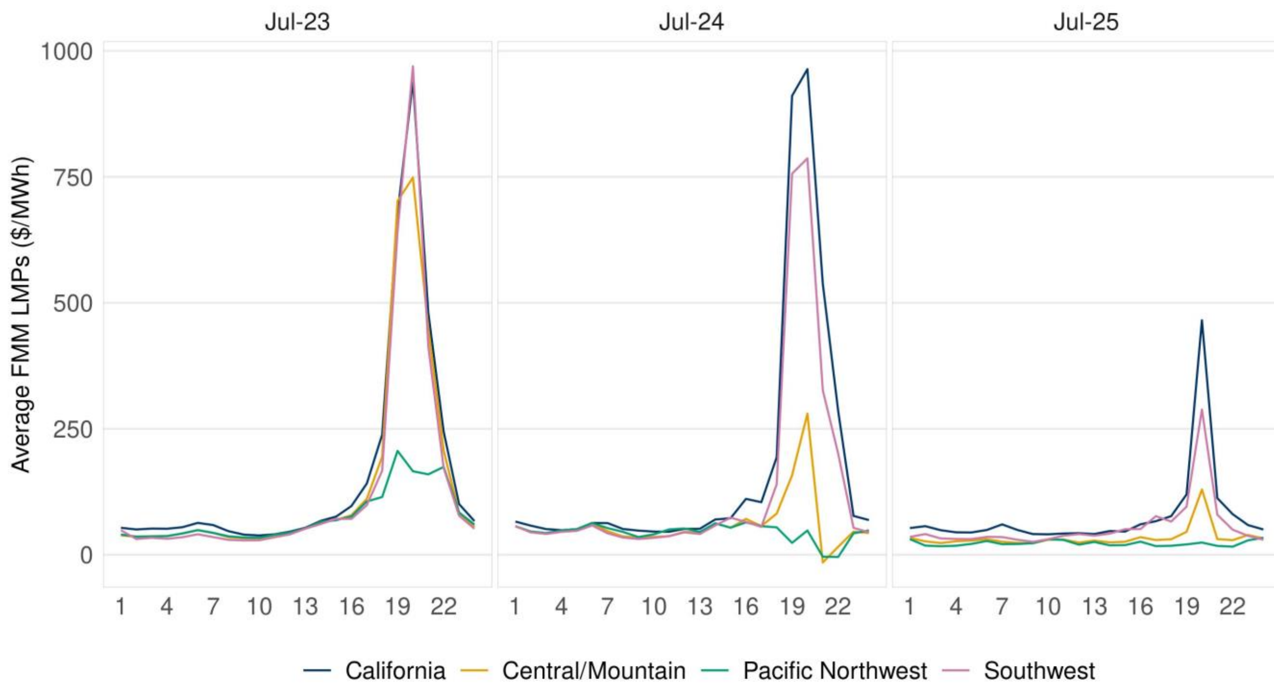


Figure 14: Average daily prices across region for RTD market - June and July 2024



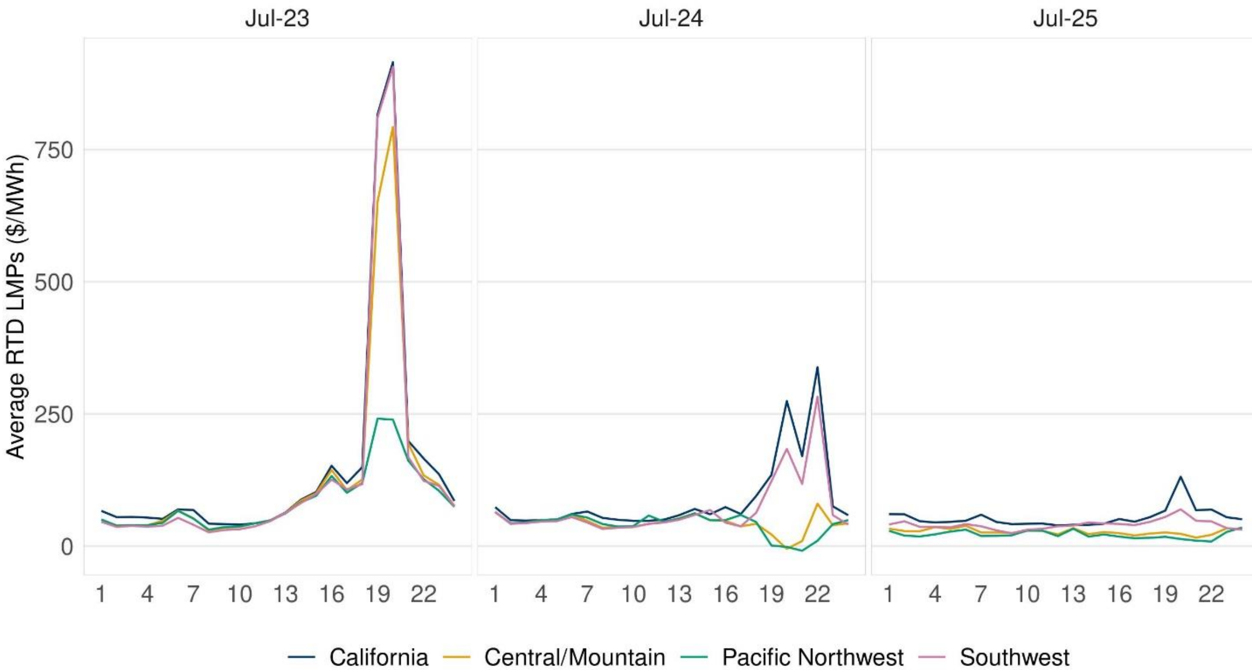
For FMM, the Southwest region is the highest at $969/MWh on July 23, followed closely by the California region at $941/MWh. California peaks at $963/MWh on July 24 and $465/MWh on July 25, with Southwest following at $786/MWh and $288/MWh on these same two days.

Figure 15: Average hourly prices across region for FMM market - for July 23 - 25, 2024



For RTD, the California region is the highest at $915/MWh on July 23, followed very closely by the Southwest region at $906/MWh. California peaks at $338/MWh on July 24 and $131/MWh on July 25, with Southwest following at $282/MWh and $69/MWh on these same two days.

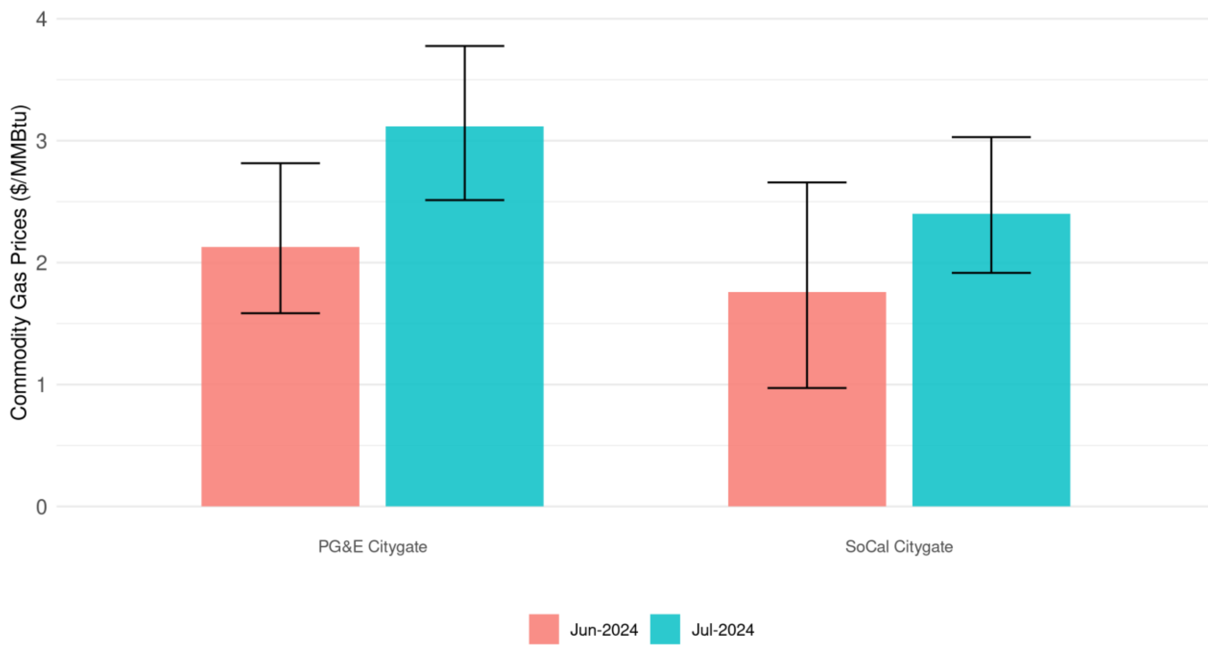
Figure 16: Average hourly prices across region for RTD market for 23 - 25 July 2024



Index prices

With a considerable share of the ISO's generation fleet consisting of gas resources, gas market and system conditions can have an impact on the electric market. Electricity prices generally track gas prices. Figure 17 shows the average prices (bars in red and blue), and the maximum and minimum prices (whiskers in black), for the two main gas hubs in California, PG&E Citygate and SoCal Citygate. For July 2024, next-day gas prices averaged $3.12/MMBtu and $2.40/MMBtu for PG&E Citygate and SoCal Citygate, respectively. The maximum next-day gas prices were $3.78/MMBtu and $3.03/MMBtu for PG&E Citygate and SoCal Citygate, respectively. These are generally moderate gas prices.

Figure 17: Gas prices at the two main California hubs



Energy trading outside the ISO's footprint on the bilateral power market provides a useful indication of broader price trends and conditions in the West. Prices at hubs like Mid-Columbia (Mid-C) in the north and Palo Verde (PV) in the south may reflect ISO system conditions or vice versa. Power trades bilaterally on both a spot market for physical next-day delivery and on a forward basis for future months.

Next-day power trades in blocks for on-peak and off-peak periods.[9] Trading is conducted for next-day delivery and typically concludes prior to 10:00 AM PST. The figures below show a comparison between northern and southern hubs and their corresponding day-ahead LMP for the PG&E DLAP. For the northern region, Figure 18 shows that the Mid-C on-peak bilateral price generally traded lower than the highest hourly day-ahead LMP for the corresponding trading day. However, due to the block nature of the bilateral power prices, the block price for Mid-C was generally higher than IFM LMPs for hours outside the evening ramp period. The NP15 bilateral price traded more infrequently throughout the month, hence the sporadic availability of data in the trend. Figure 11 for the southern region shows a similar pattern of bilateral on-peak prices at PV and SP15 where SP15 prices were trading lower than the highest hourly IFM LMP for the SCE DLAP. PV prices traded closely while SP15 prices tended to trade lower for on-peak periods. Because bilateral prices trade in block intervals, Figure 10 and Figure 11 below show similar trends with the corresponding day-ahead LMP averaged over the on-peak block interval. This trend attempts to smooth out the highest peak prices and provide a similar comparison to the block nature of

[9] Peak is typically defined as hours-ending 7-22 on weekdays and Saturdays; off-peak is typically defined as hours-ending 1-6 and 23-24 on weekdays and Saturdays, and hours-ending 1-24 on Sundays and holidays.

the bilateral prices. Once averaged, the day-ahead LMPs are generally lower or closer to the corresponding bilateral prices throughout the month.

Figure 18: Northern hub prices and PG&E IFM LMP (block average) for on-peak

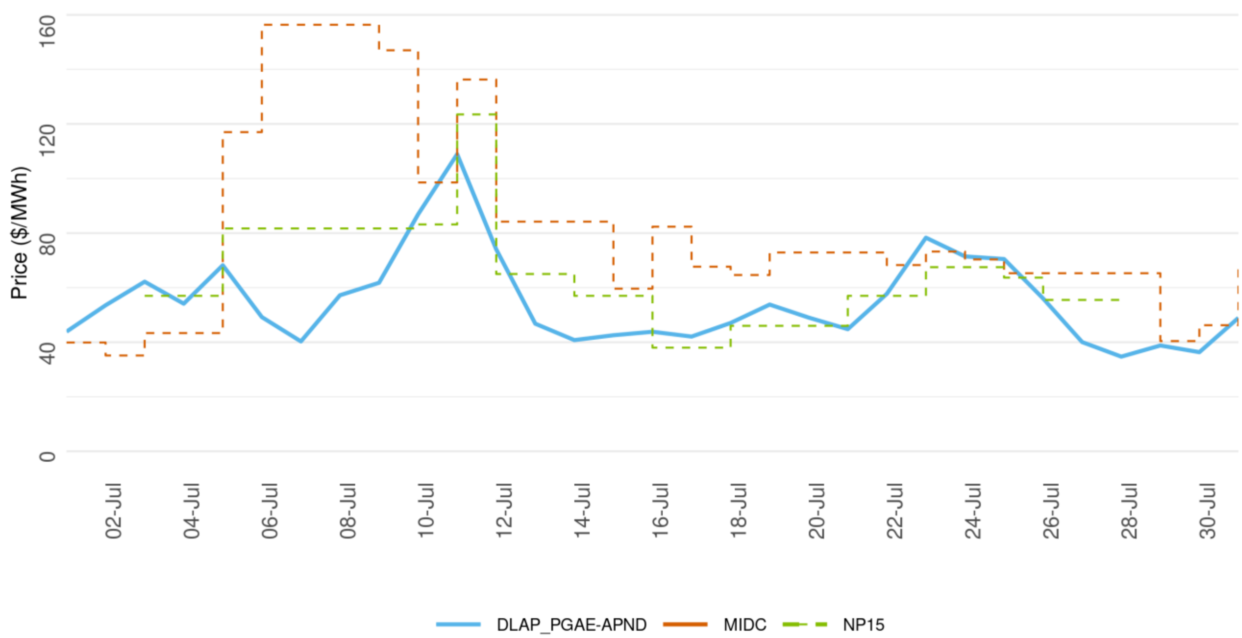


Figure 19: Southern hub prices and SCE IFM LMP (block average) for on-peak

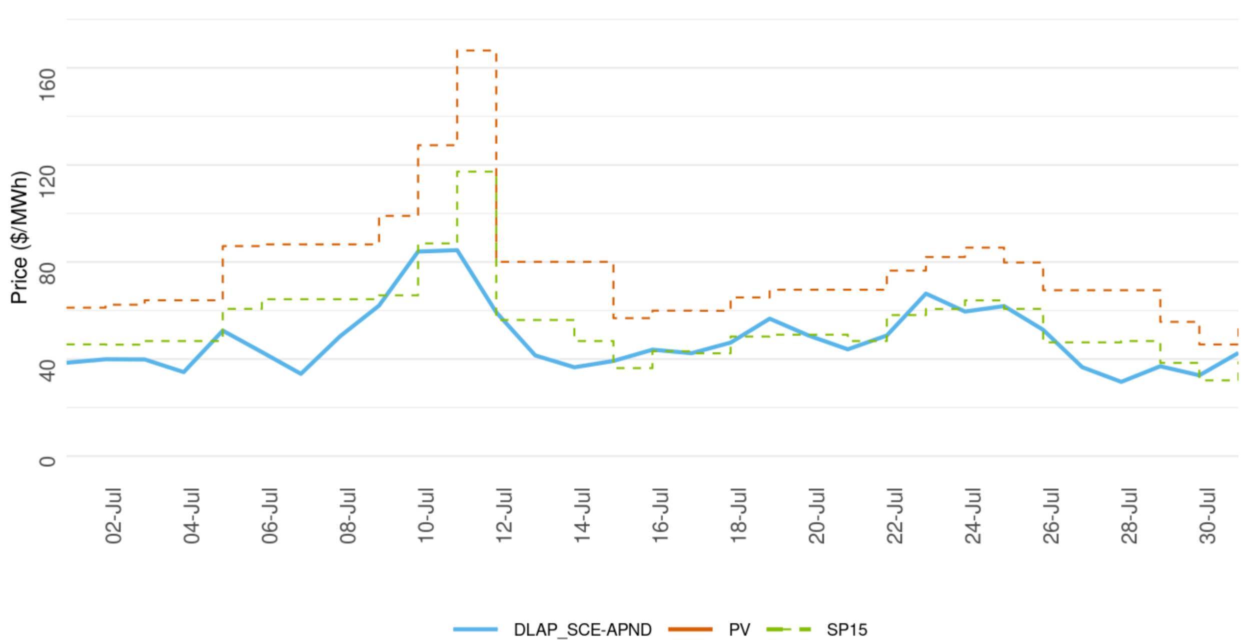


Figure 20 shows a year-to-date trend of on-peak future power prices traded for the 2024 summer months of July, August, and September. Price trends are captured for Mid-C and Palo Verde, as well as the NP15 and SP15 options that trade bilaterally. On-peak future prices have traded dynamically for summer months. Price separation can be observed between the two groups of hubs, with Mid-C and PV generally trading higher than SP15 and NP15.

Figure 20: On-peak future power prices for summer 2024

4 Bid-In Supply

The ISO'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 that is above RA level. This supply does not have an RA obligation but economically and voluntarily participates in the ISO'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 for above RA capacity to be dispatched before all the RA capacity is exhausted since resource dispatches are based entirely on prices, resource characteristics and system conditions, and there is no merit order based on whether supply is 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 and other LRAs establish Qualifying Capacity (QC) calculations, which are generally 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 potential 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.

Supply and RA Capacity

Since the summer 2020 events, the ISO has been tracking whether RA capacity available in the ISO's markets is 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 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 above-RA capacity.

Figure 21 shows the breakdown of the day-ahead supply capacity[10] as RA capacity and above-RA capacity. 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 shows the adjusted load forecast, plus OR, plus high-priority export self-schedules. It represents the overall load obligation to be met in the day-ahead market.

[10] 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.

Figure 21: Supply capacity available relative to load forecast in the day-ahead market

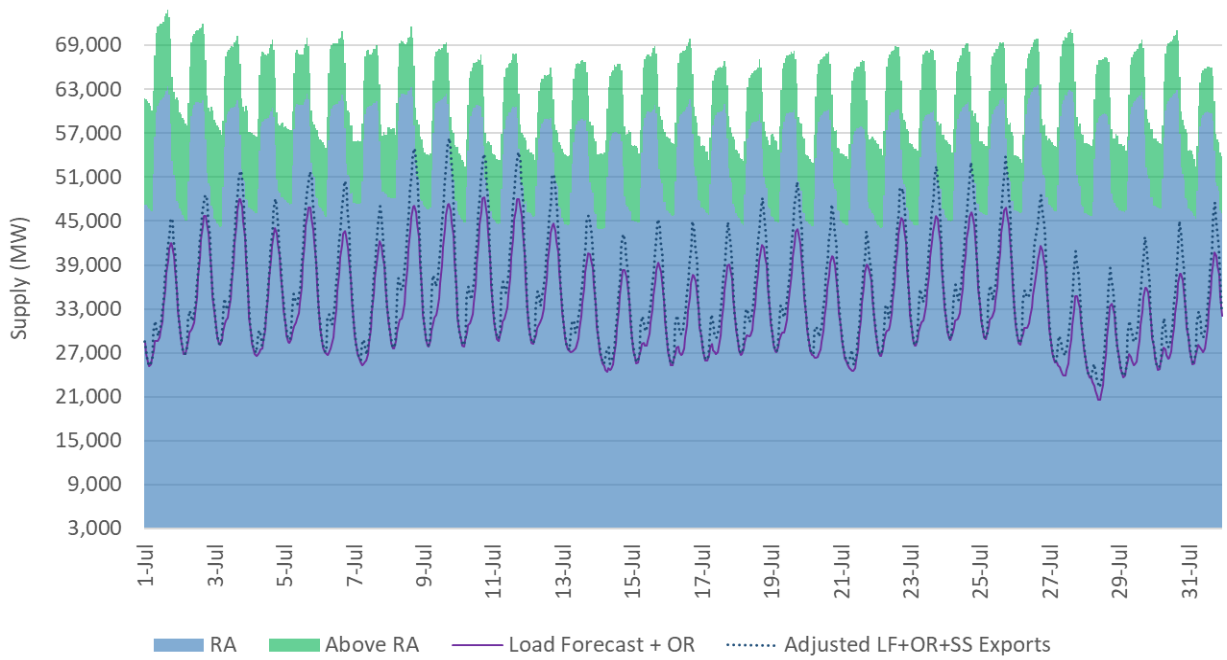


Figure 22 shows the same capacity breakdownfor July 23-25. In the peak hours of these three days, there was enough capacity to meet the demand. On July 24, the ISO area declared an EEA Watch due to a path capacity derate on Malin intertie due to impacts of the Park fire. As shown in subsequent sections, this resulted in a loss of up to 640 MW of RA supply capacity coming through Malin intertie. This reduction was absorbed by the market and did not require any other major steps.

Figure 22: Supply available relative to load forecast in the day-ahead market – July 23-25

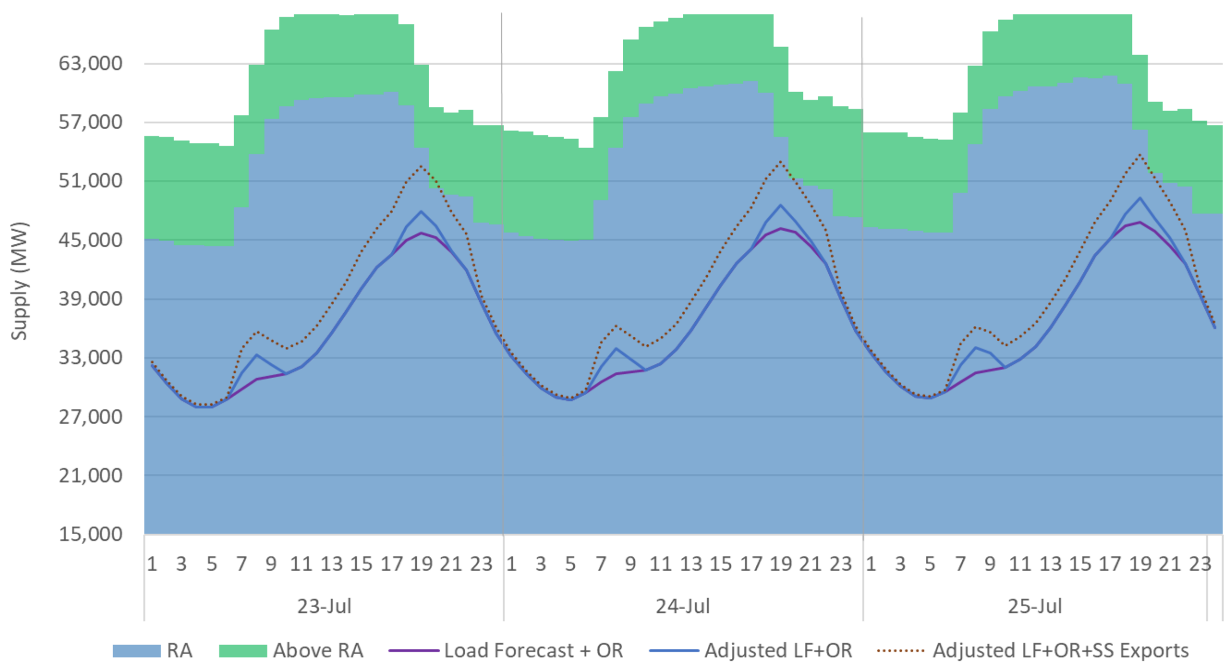
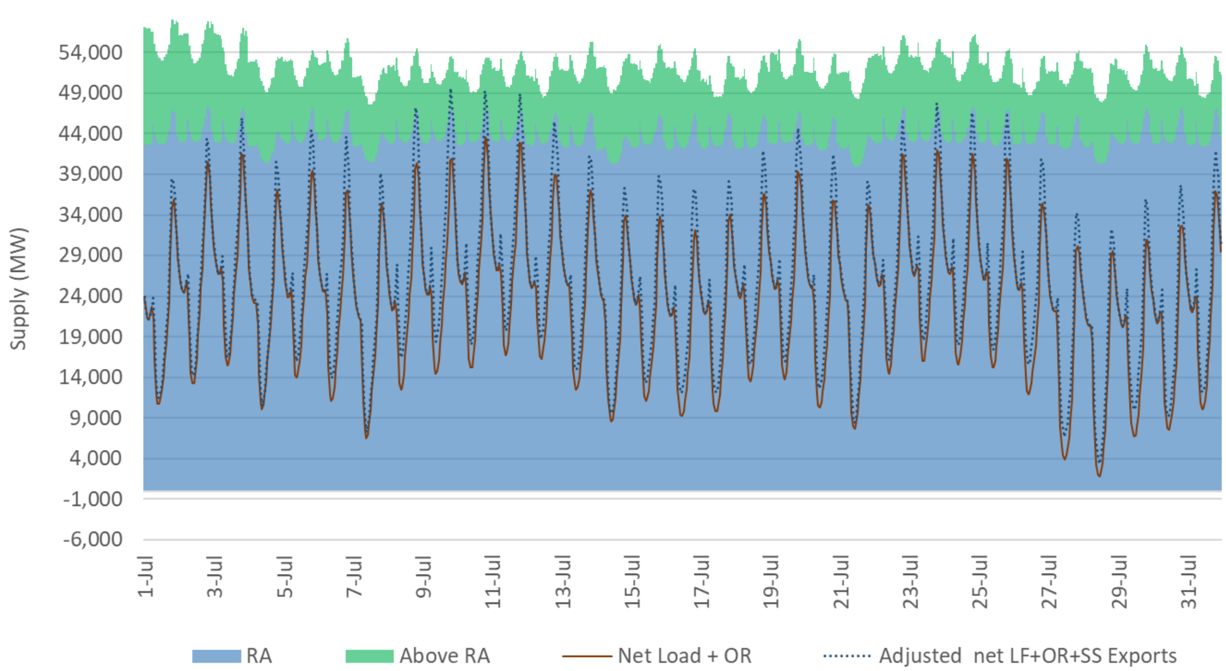


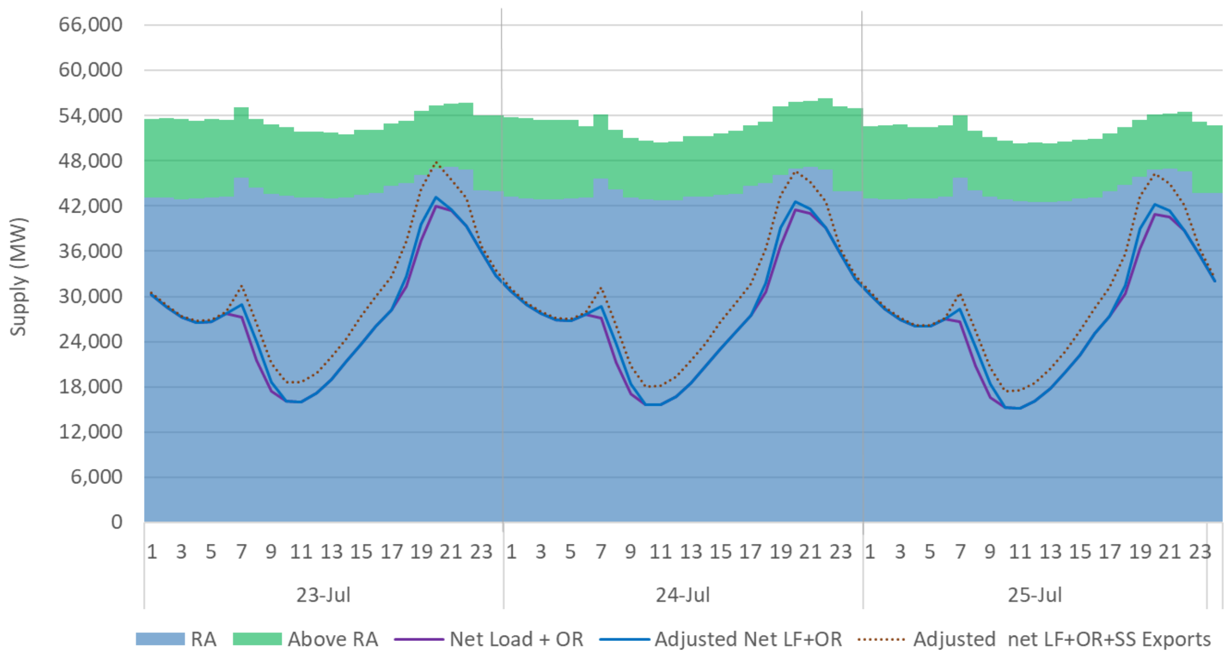
Figure 23 has similar convention for the same capacity breakdown as Figure 21, but the comparison is relative to the net load (gross load minus VER forecast). Since this figure represents net load, the supply side is also reduced by subtracting all VER contributions. Tracking the available capacity for the net load peak hour is as important as tracking available capacity for the gross peak hour.

Figure 23: Supply capacity available relative to net load forecast in the day-ahead market



For the month of July, above-RA capacity was consistently available into the market. The supply available in the market was sufficient to cover the load forecast, and also the load forecast plus the RUC adjustments. For some hours in July, the net-load needs were negative when the VER forecast was high but loads were mild. Figure 24 shows the capacity breakdown from July 23 to 25. In most hours of the three days, RA capacity is sufficient to cover the adjusted net load, operating reserve and self-schedule export. For all three days, RA capacity and above-RA capacity were above the demand.

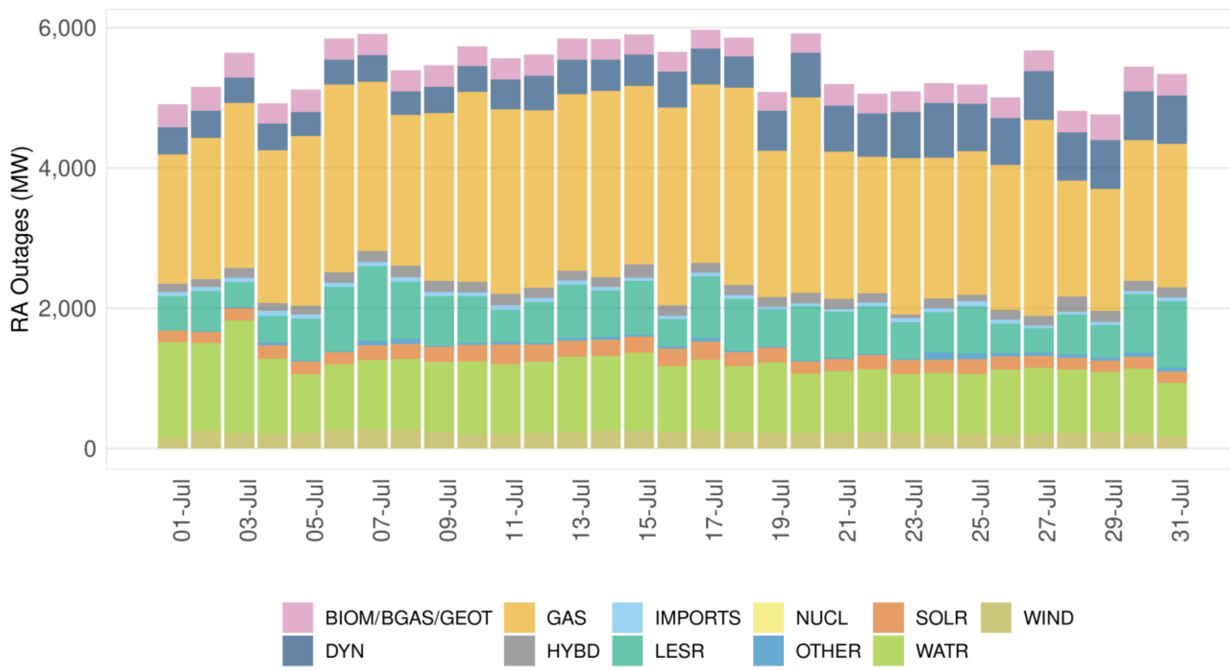
Figure 24: Supply available relative to net load forecast in the day-ahead market – July 23-25



Unavailable RA capacity

Generating units can face operating conditions that require them to be derated or to be offline. The ISO tracks these outages through the outage system and the outages are reflected in the resource capacity made available in the market. The market considers the outages and derates to impose these limitations on the units, making them unavailable or derating their capacity accordingly. Some outages may be planned while others may be forced. Figure 25 provides the trend of RA capacity on outage organized by fuel type during the month of July. The average daily capacity on outage was about 5,423 MW.

Figure 25: Volume of RA capacity by fuel type on outage in July



Renewable Production

The ISO's area utilizes hydro production throughout the year to meet demand needs. Figure 26 shows the historical trend of total energy produced from hydro and other renewable resources. Hydro production for 2024 so far has been higher than in 2022 but lower than 2023. Hydro production in July 2024 was about 13 percent lower than the production observed in July 2023. With the addition of more solar resources into the system, solar production in July 2024 was 15 percent higher than the production in July 2023.

Figure 27 shows the historical trend of solar production. Generation from hydro tends to be higher in the morning and evening hours while reaches lower values during midday hours when solar production is plentiful. Figure *28* below shows the hourly profile of the average energy produced from hydro resources as well as solar and wind resources for July 2024.

Figure 26: Historical trend of hydro and renewable production

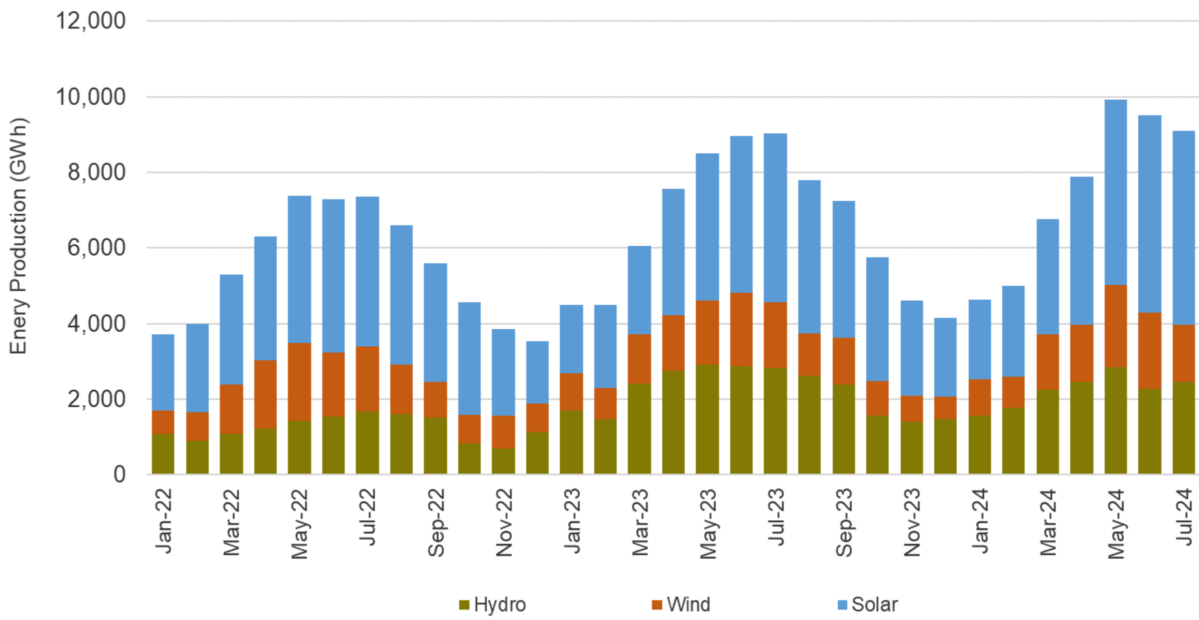


Figure 27: Historical trend of solar production

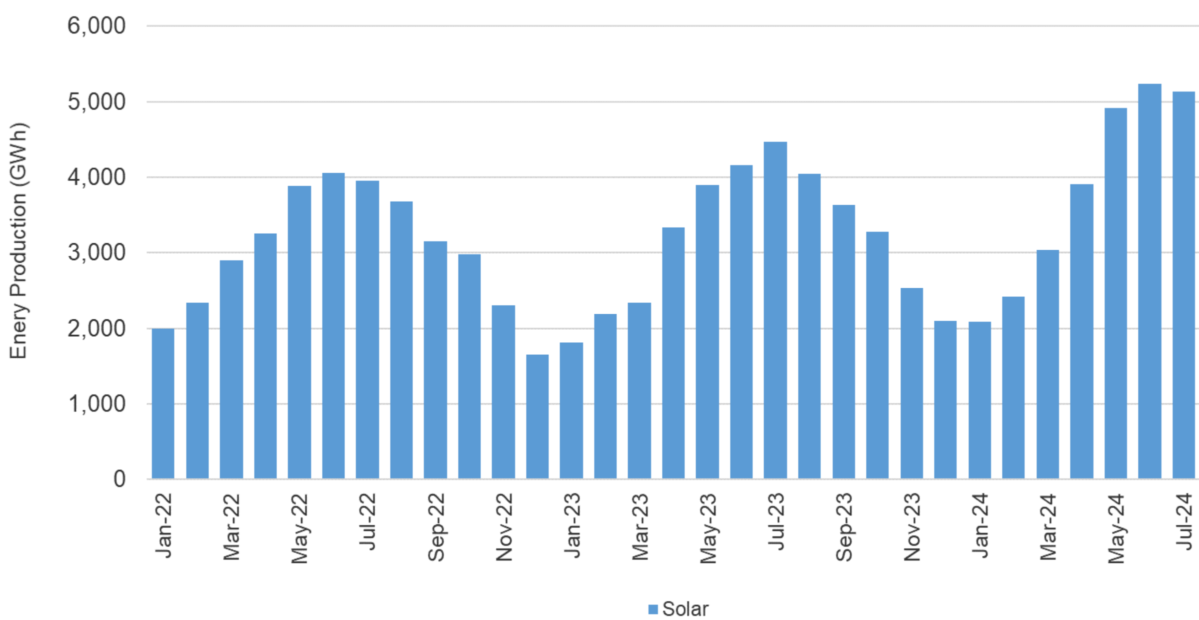
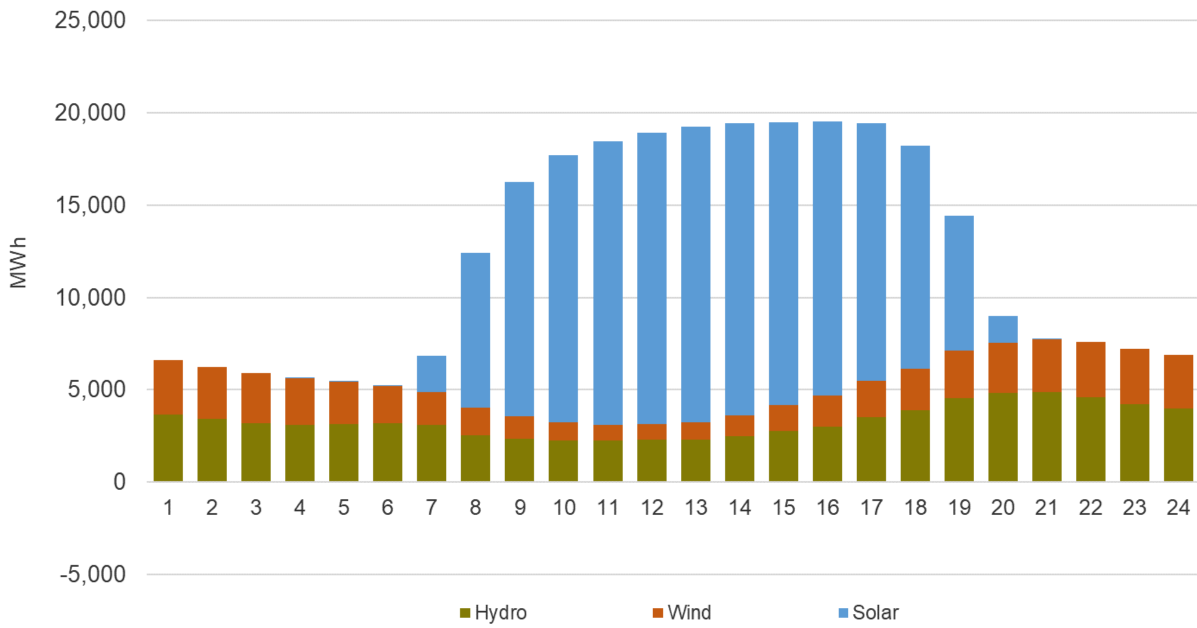


Figure 28: Hourly profile of wind, solar and hydro production for July



Demand and supply cleared in the markets

Figure 29 compares the IFM schedules for physical resources versus the day-ahead load forecast and the adjusted load forecast eventually used in the RUC process. Day-ahead load forecasts tracked the temperature changes observed throughout the month. Day-ahead load forecasts peaked when the system was experiencing average temperature departures from normal of seven degrees as shown in the section of Weather.

The IFM process is the financial 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. Afterwards, 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 and renewable uncertainties. The RUC process will clear supply against the final adjusted load forecast. Since RUC adjustments were used occasionally for morning and peak hours only, the adjusted load forecast used in the RUC process followed similar trend to day-ahead load forecast.

Figure 29: Day-ahead demand trend in July 2024

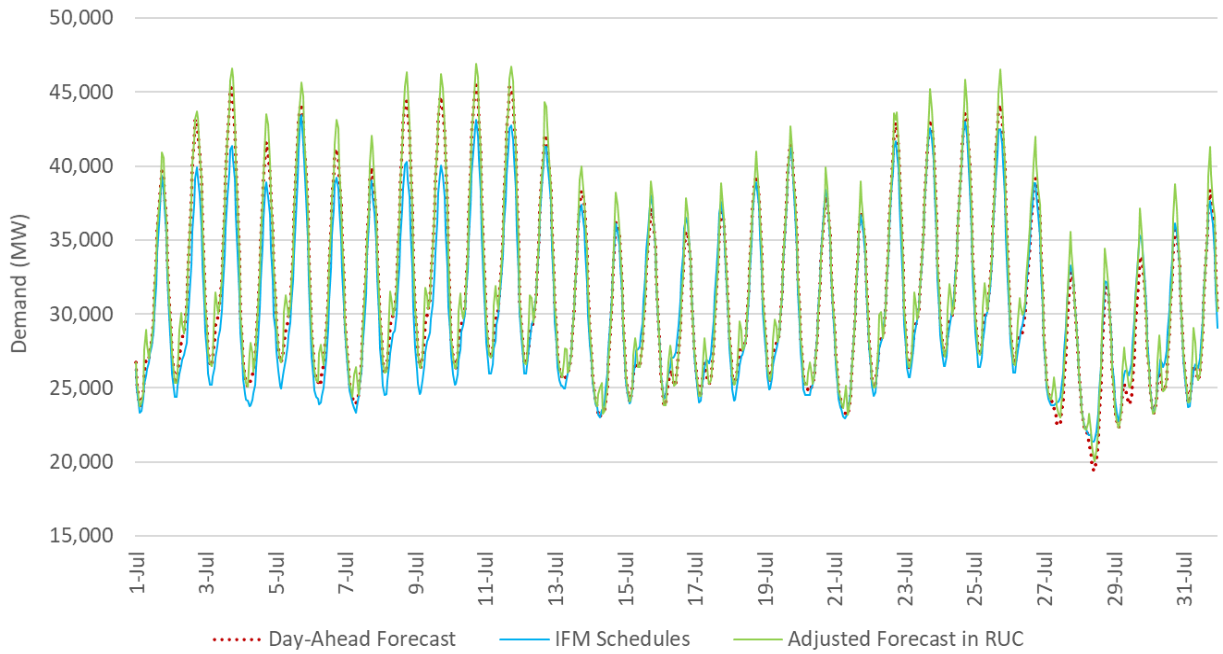


Figure 30 shows the IFM schedules for physical resources versus the day-ahead load forecast and the adjusted load forecast in the RUC process for July 23-25 during the heat wave.

Figure 30: Day-ahead demand trend - July 23-25, 2024

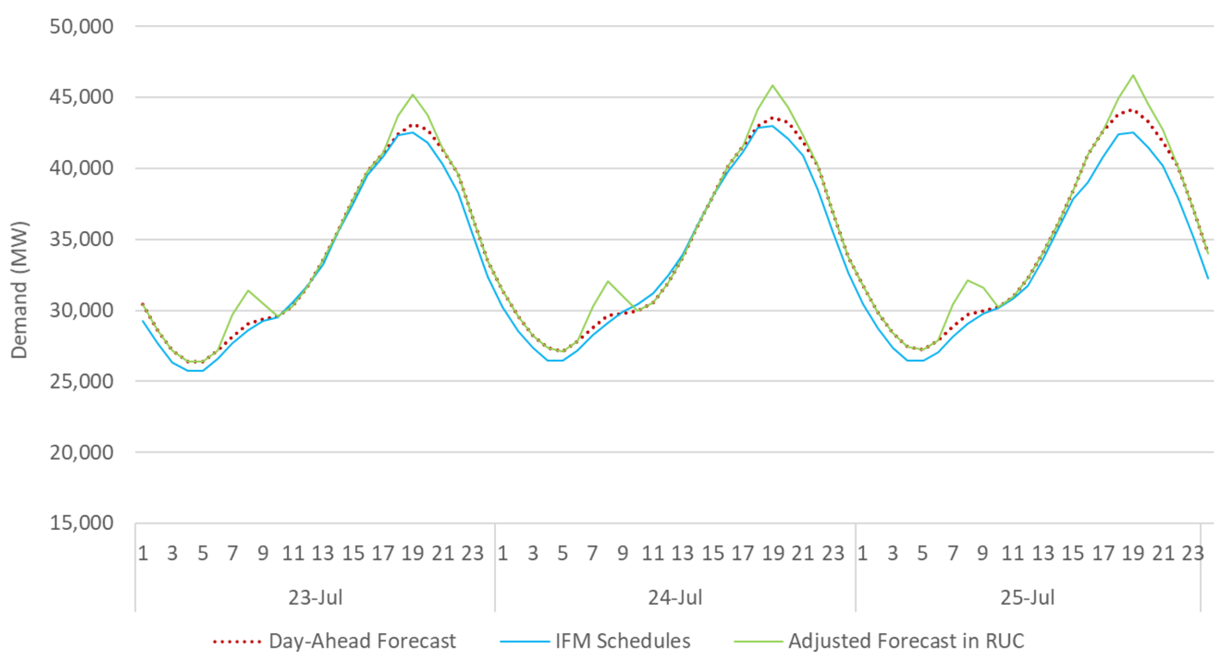
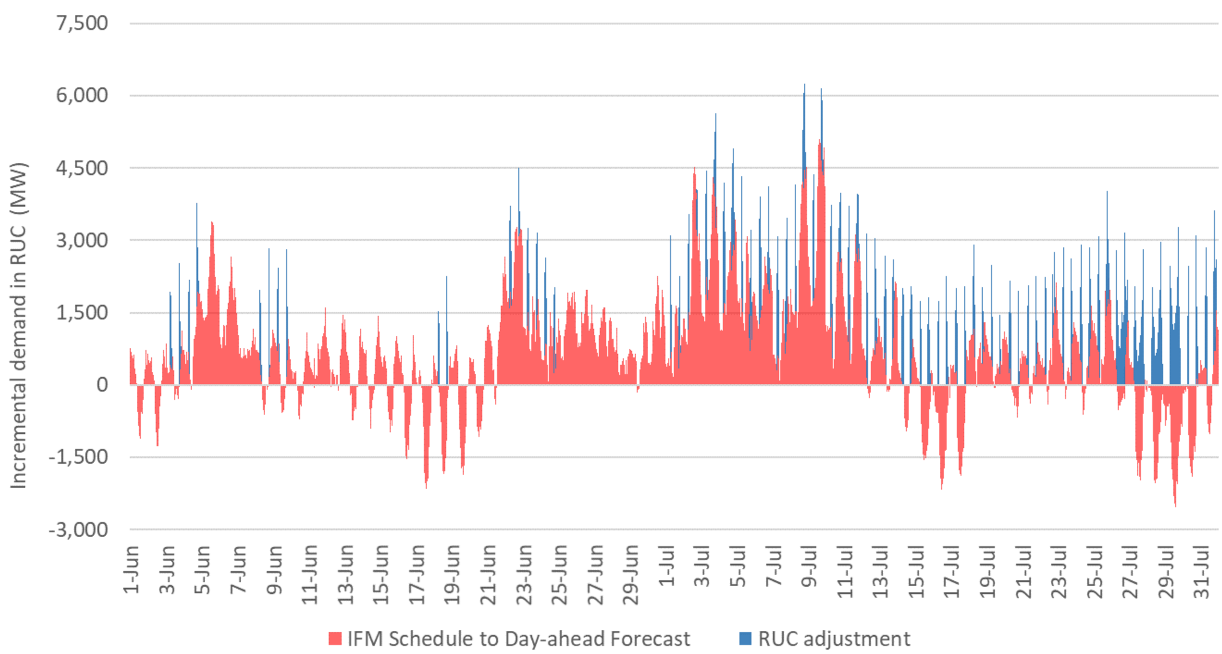


Figure 31 shows the differences between the IFM schedules versus the nominal day-ahead load forecast for RUC. This is the additional capacity relative to the IFM solution that RUC determines is needed to meet the day-ahead load forecast. Effectively, this is either the shortfall or surplus capacity from IFM that RUC has to rebalance. 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 RUC adjustments was used more frequently than June when the demand is high due to high temperature.

Figure 31: Incremental demand required in RUC in July 2024



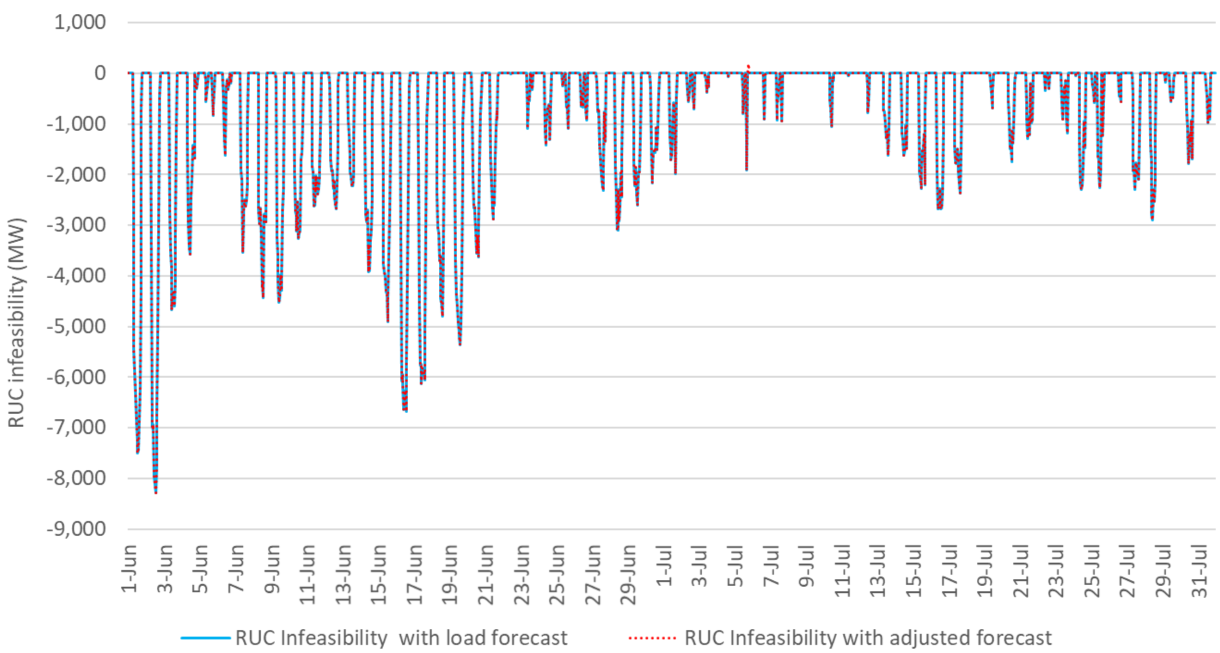
The RUC forecast adjustment is guided by historical uncertainty of load, wind and solar from the day-ahead to the real time market. In some cases, there may be other factors to consider by operators to determine the final adjustments. ISO continues to further tune and assess the conditions and the need for RUC adjustments.[11]

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

[11] Recent enhancements to the estimation of RUC adjustments can be found in the Market Performance and Market forum meeting material at https://www.caiso.com/meetings-events/topics/market-performance-and-planning-forum

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 reduced all possible economic and low priority exports,[12] which leaves just the power balance constraint to be relaxed and reducing PTK (high priority) exports to allow RUC to clear. Figure 32 shows the RUC infeasibility against two reference points: one infeasibility is relative to the final adjusted forecast in RUC, while the other is relative to the raw day-ahead forecast. In June there were only over-supply infeasibilities. In July oversupply condition occurred less frequently than June due to hot weather driving demand up. There was only a small RUC undersupply infeasibility triggered on July 4 due to a pre-processing error of exports in the market. This issue was corrected the day after.

Figure 32: RUC infeasibilities in June and July 2024



In addition to relaxing the power balance constraint in the RUC market, there were some under supply infeasibilities in RTD and FMM market for July 9 and July 23. For July 23, the power balance constraint was

[12] 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. Exports can also be high priority self-schedule labeled as PTK (i.e., not backed by capacity that may be committed to ISO load under its resource adequacy program). If the market clearing process encounters constraints, the ISO will treat PTK exports similar to internal loads, but treats LPT exports as recallable, and the market will reduced LPT exports before relaxing the power balance constraint.

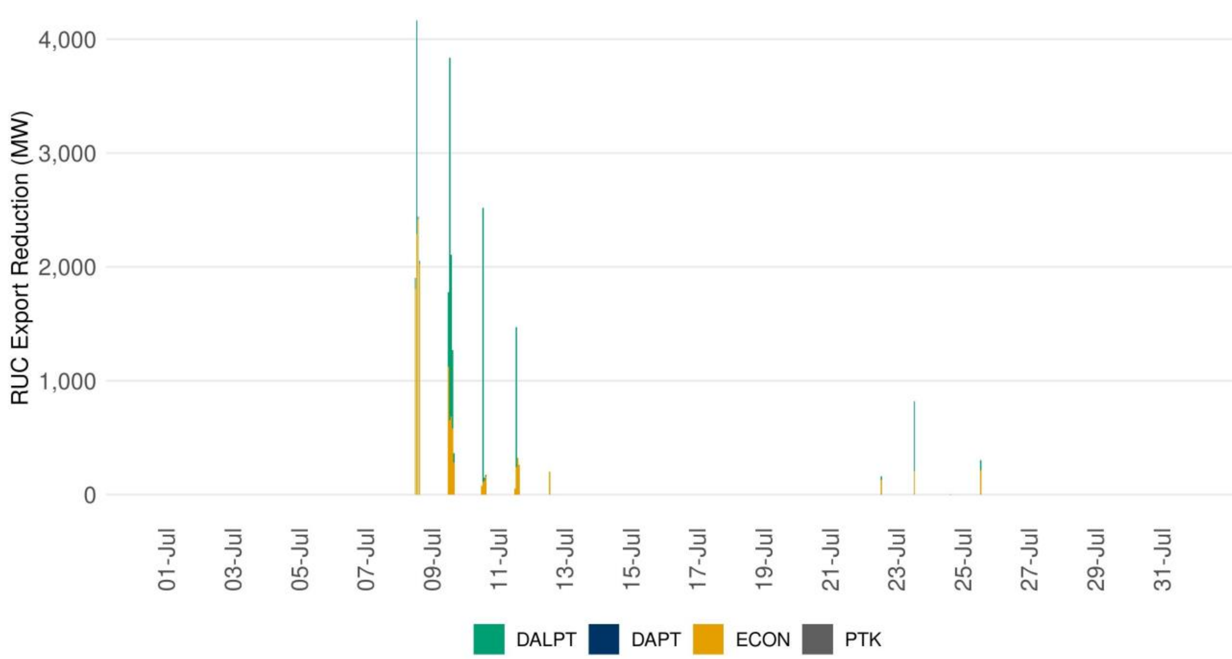
relaxed in the positive direction at maximum of 2110 MW for HE 20 in FMM market. The maximum of under supply infeasibility in RTD reached a maximum of 1346 MW in HE 19 for the same trade date.

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, PT exports may be reduced concurrently to relaxing the power balance constraint.[13]

In the month of July there were instances of export reductions in the RUC process. Exports can still participate in the real-time market by rebidding relative to the DAM solution, or directly into the real-time market with either high or low priority, as well as with economical bids.

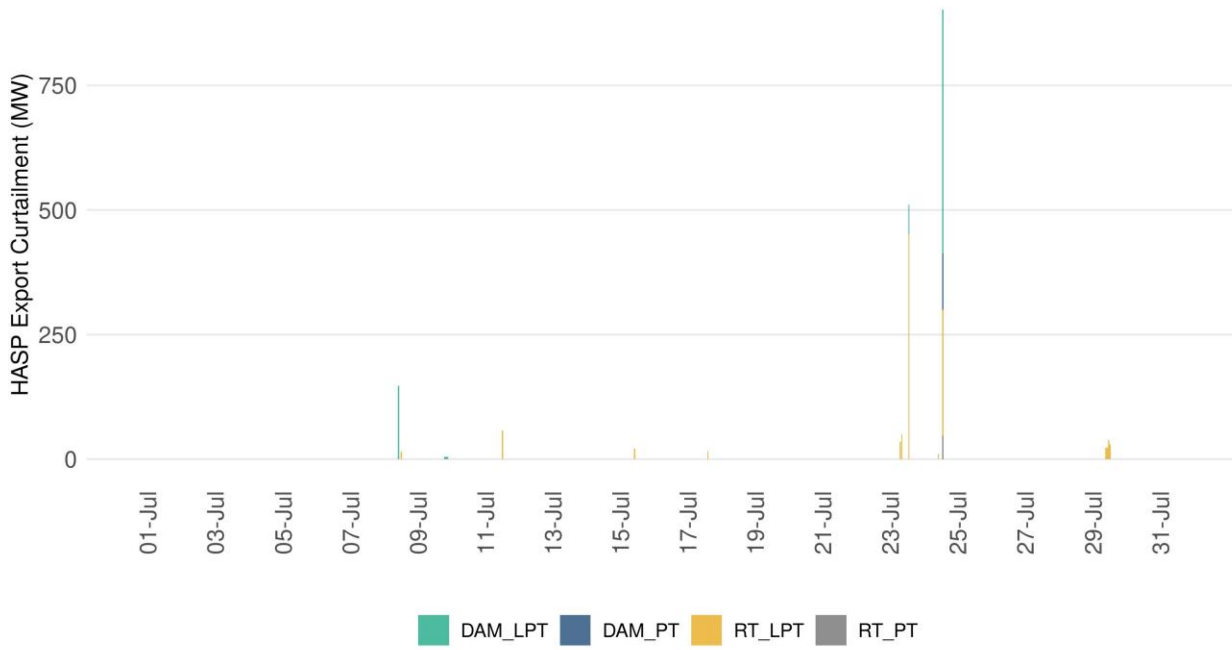
Figure 34 shows the instances when the real-time market reduced exports in July, with the largest reduction happening on July 8 mainly for economic and low priority exports. These reducitons were observed during the times when WECC load was the highest and set a new peak records. ISO area was already clearing over 8,000 MW of exports, and these export reductions reflect the level of addional exports that could not be supported.

Figure 33: RUC export reduction for July 2024



[13] Under the current setup of scheduling priorities, PT 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 reductions 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.

Figure 34: Exports reductions in HASP



As part of the root cause analysis of the emergencies experienced in July 2023, ISO identified certain export transactions did not follow the intended reductions. The ISO implemented two enhancements to mitigate for this outcome. The ISO has assessed the performance of the exports reduced in July 2024 and found that the exports reductions in July 2024 were largely followed by scheduling coordinators. There were two transactions potentially impacted by unintended logic in the bid validation process that created subsequent complications to handle their priority and scheduling. As explained in the subsequent section of areas for improvement, the ISO is further investigating this outcome.

Load Conformance

Load conformance effectively modifies the final load requirement the markets need to clear against supply. In all ISO markets, except the FM where demand is bid in, system operators can adjust either demand (through conformance) or supply (through Exceptional Dispatches, or EDs) based on expected system conditions. Changes to market inputs can influence market clearing prices. The adjustment to the load forecast in the day-ahead timeframe is referred as RUC net short, while in the real-time market it is referred to as Load conformance. These adjustments can effectively increase or decrease the overall demand requirements that the market optimization uses to clear against supply. Operators may use load adjustments to true up the market to the real-time system based on projected or observed system conditions. Positive conformance effectively increases the load requirements while negative conformance decreases the load requirements.

Figure 35 shows the daily distribution of load conformance for all the markets for the month of July. The figure illustrates the daily distribution of load conformance in RUC, FMM and RTD markets for the month of July. Because simple averages may not reflect the more complex dynamics of load conformance, these trends are shown as box-plot distribution. The box represents the 25th to the 75th percentile while the dot represents the outliers. It shows that the load conformance for the RUC market reached a maximum of about 3,286 MW for July 29. The FMM market generally reflect the operator efforts to ensure that adequate balancing energy is available for real – time system conditions. Load conformance used in real-time is generally much lower than FMM market, because it serves more to manage the minute by minute imbalances in the real time system. In the month of July, similar pattern was observed where FMM load conformance adjustment reached a maximum of 5,500 MW on July 23 during the peak hours. Similarly RTD market much lower load conformance adjustments had a range of about -900 MW to about +2,000 MW for the month of July.

Figure 36 shows the hourly distribution of load conformance adjustment for the month of July by markets. The RUC load conformance adjustment shows a typical pattern across the month of having adjustments during the morning and evening peak hours. Similarly, FMM load conformance shows a pattern with high adjustment during the evening peak hours from HE 17 – 21. RTD load conformance shows a different pattern with negative conformance during the middle hours of the day due to oversupply conditions and positive conformance during the evening peak hours. Figure 37 shows the hourly profile of load conformance for July 23 – 25, 2024 across markets.

Figure 35: Daily load conformance for the month of July 2024 - by market

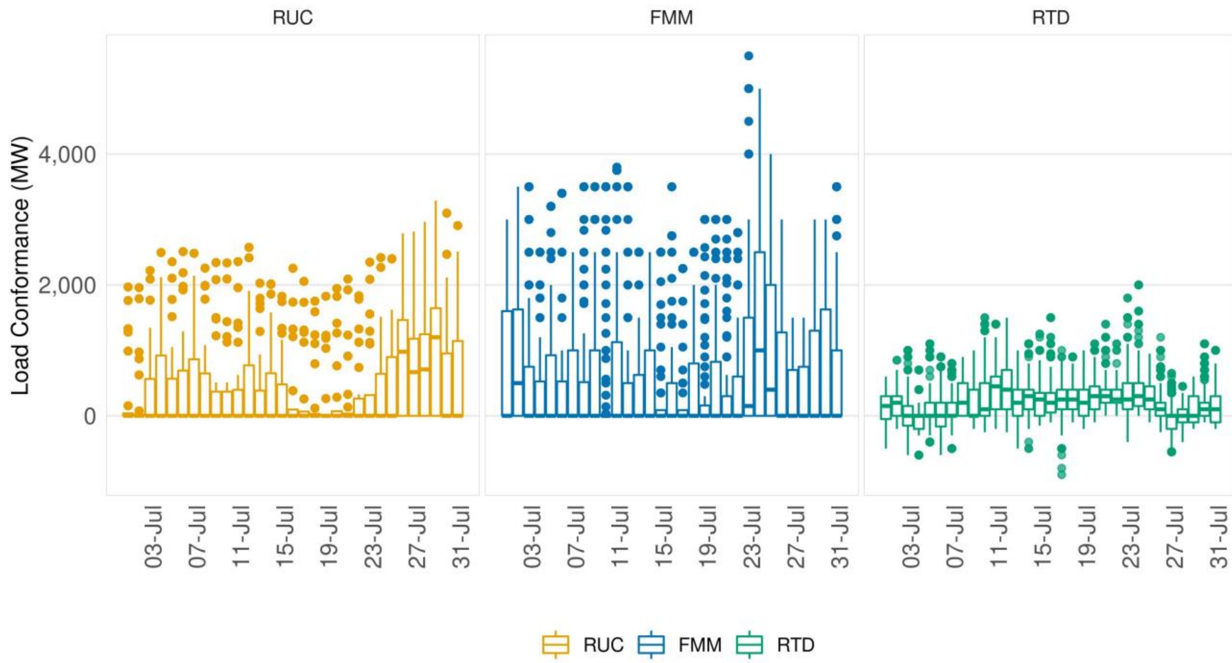


Figure 36: Hourly load conformance for the month of July 2024 - by market

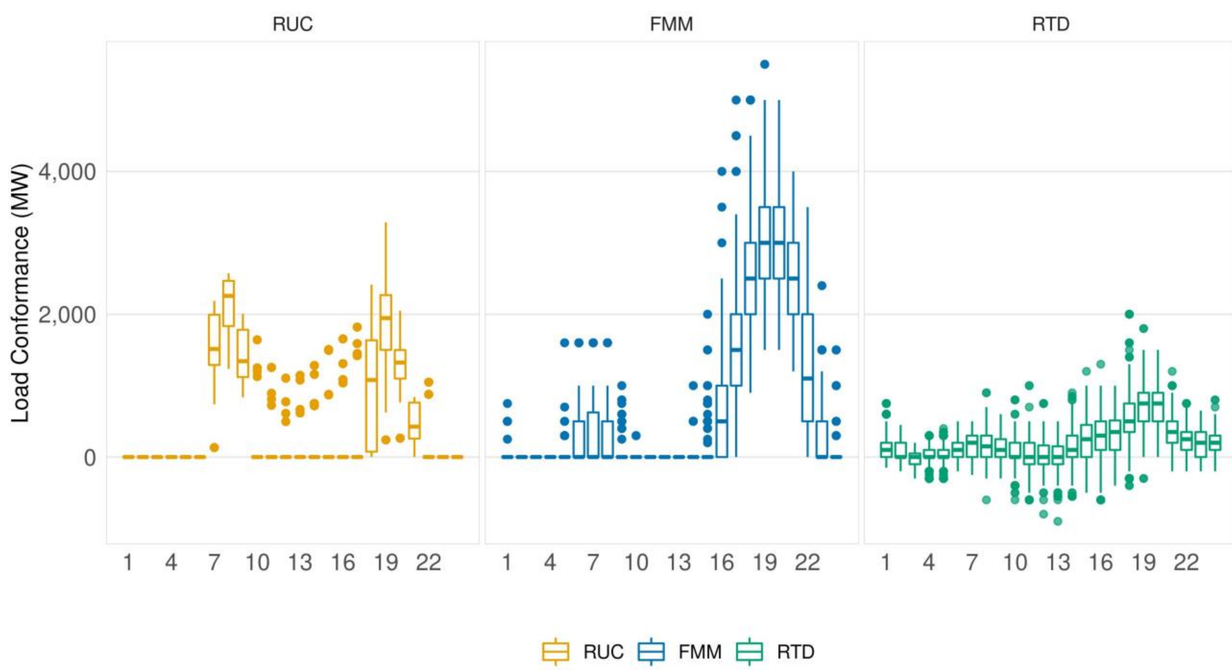
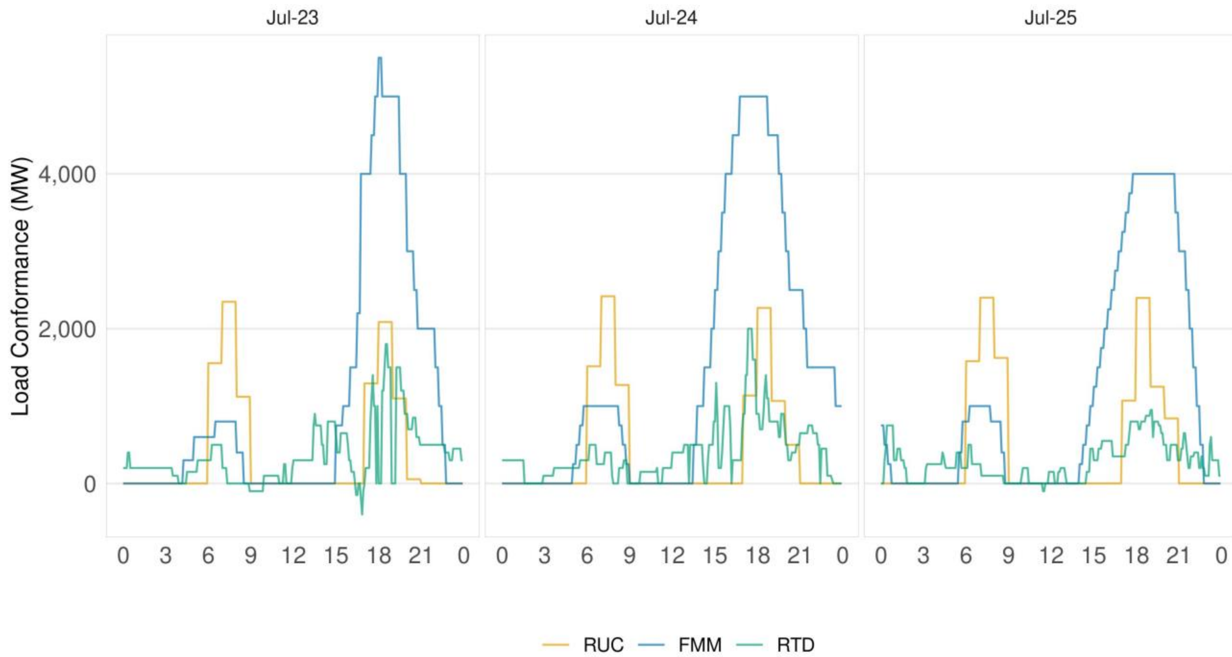


Figure 37: Hourly load conformance for July 23 - 25, 2024



Demand Response

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

Reliability demand response resources (RDRRs) were not triggered in the real-time market during July. Figure 39 shows the dispatches of RDRRs in both the day-ahead and real-time markets for July. 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 alert declaration. The largest volume of RDRR dispatches in the real time market was on July 11 to about 201 MW for HE 18. RDRRs were dispatched in RUC and RTD market to the same amount of 201 MW on July 11 for HE 18, hence the yellow line for RUC MW and blue line for RTD MW are overlapping.

Figure 38 shows the dispatch for proxy demand resources (PDR) in both the day-ahead and real-time markets. PDRs are dispatched economically in all markets 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 in the day-ahead timeframe occurred on July 11 at about 202 MW, whereas in the real-time market, it was a maximum of 161 MW on July 11.

Reliability demand response resources (RDRRs) were not triggered in the real-time market during July. Figure 39 shows the dispatches of RDRRs in both the day-ahead and real-time markets for July. 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 alert declaration. The largest volume of RDRR dispatches in the real time market was on July 11 to about 201 MW for HE 18. RDRRs were dispatched in RUC and RTD market to the same amount of 201 MW on July 11 for HE 18, hence the yellow line for RUC MW and blue line for RTD MW are overlapping.

Figure 38: PDR Dispatches in day-ahead and real-time markets in July 2024

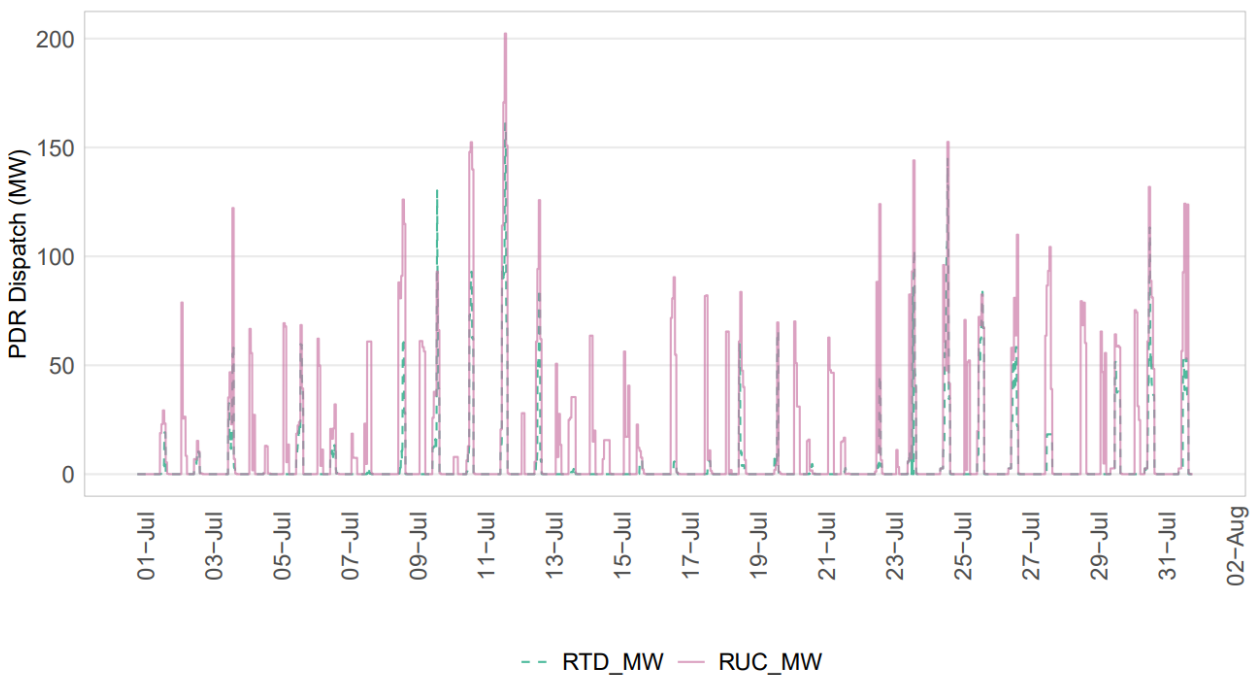


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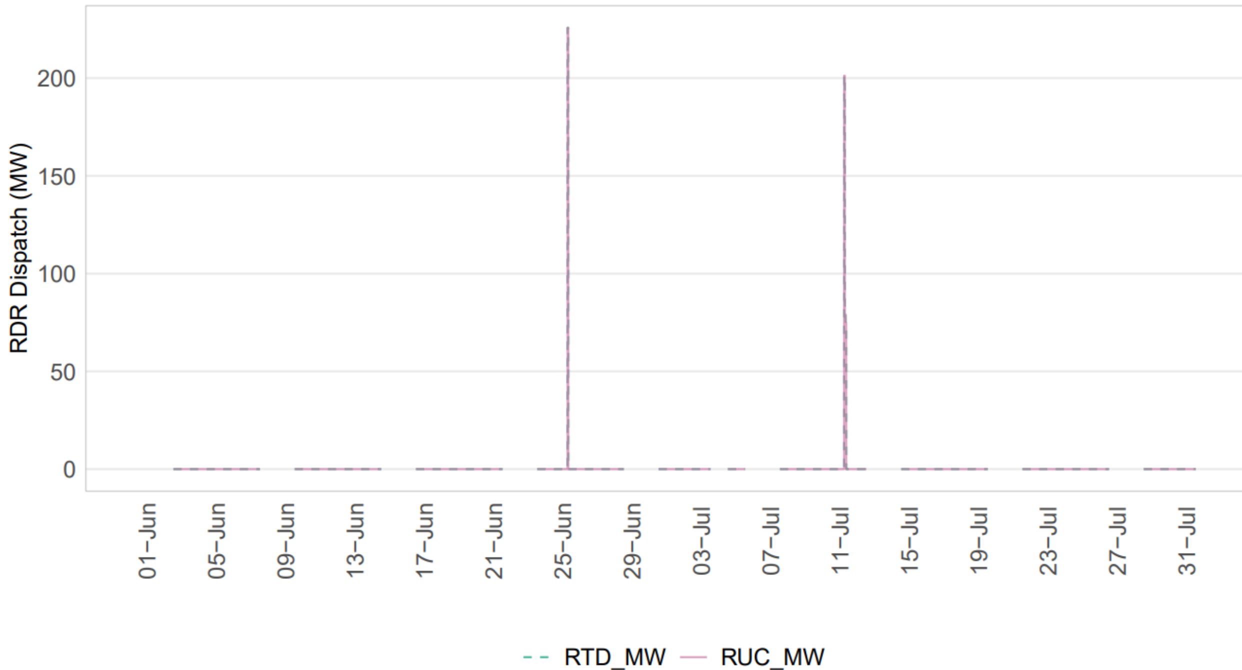
Figure 39: RDRR dispatches in day-ahead and real-time markets for July 2024



5 Intertie Transactions

The ISO's system relies on imports that arrive into the balancing authority area through various interties, including Malin and NOB from the Northwest and Palo Verde and Mead from the Southwest. 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 ISO's markets offer the flexibility to organize pair-wise imports and exports to define wheels. 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 transactions will always clear at the same level. Because wheel transactions must be balanced, they do not add or subtract supply to the overall ISO system, regardless of the cleared level. However, they utilize scheduling capacity on interties and transmission capacity on ISO'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 ISO's market utilizes a series of self-schedules which define higher priorities than economic bids based on the attributes applicable to 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.

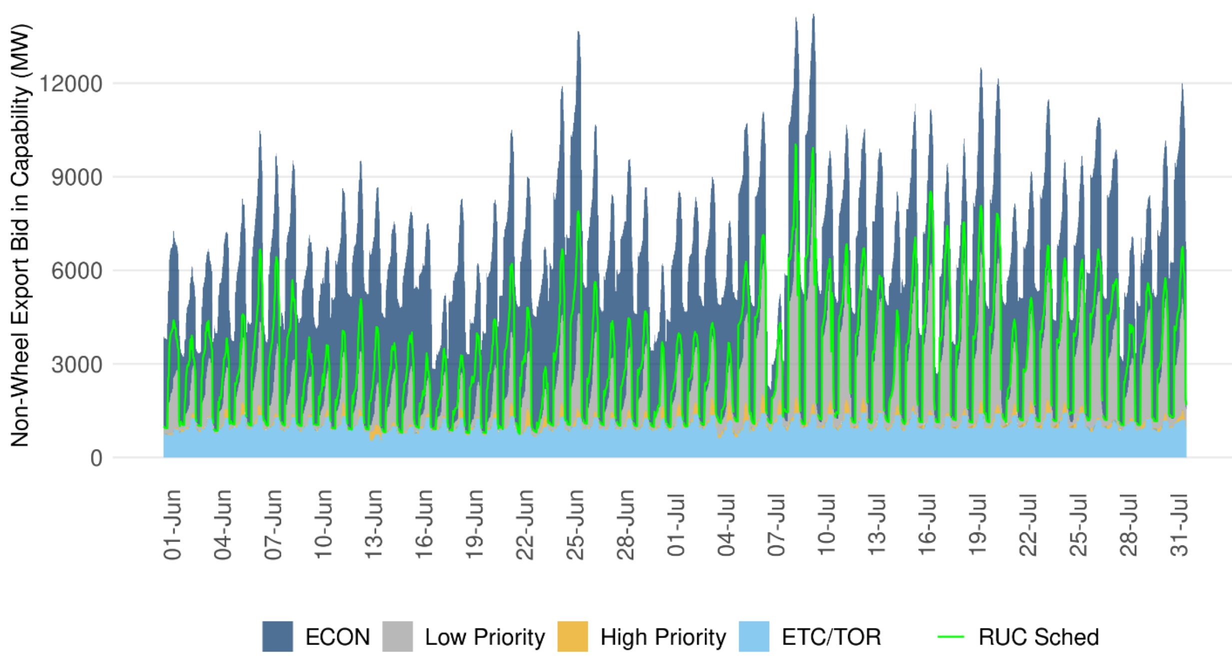
The ISO's markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics, and system conditions, are taken into account. 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.

Intertie supply

Figure 40 shows the capacity from static export transactions in the day-ahead market organized by types of exports. This capacity does not include export capacity associated with wheel transactions of any type because wheels are in balance on a net basis, and the export side of wheels does not reduce supply to the ISO supply stack.

This figure also illustrates the clearing schedules from the RUC process with the line in green. 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.

Figure 40: Day-ahead Bid-in capacity and RUC cleared export



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 adjusted by the ISO. 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 63 percent, 20 percent, 15 percent and 2 percent of the export capacity were for economic bids, LPT, ETC/TOR and PTK, respectively. There were larger volumes of LPT in July comparing to June, resulting in a slightly higher total of bid in export volume. The highest RUC scheduled was in hour ending 17 on July 8, at about 10,037 MW.

Figure 41: Day-ahead bid-in capacity and RUC-cleared imports

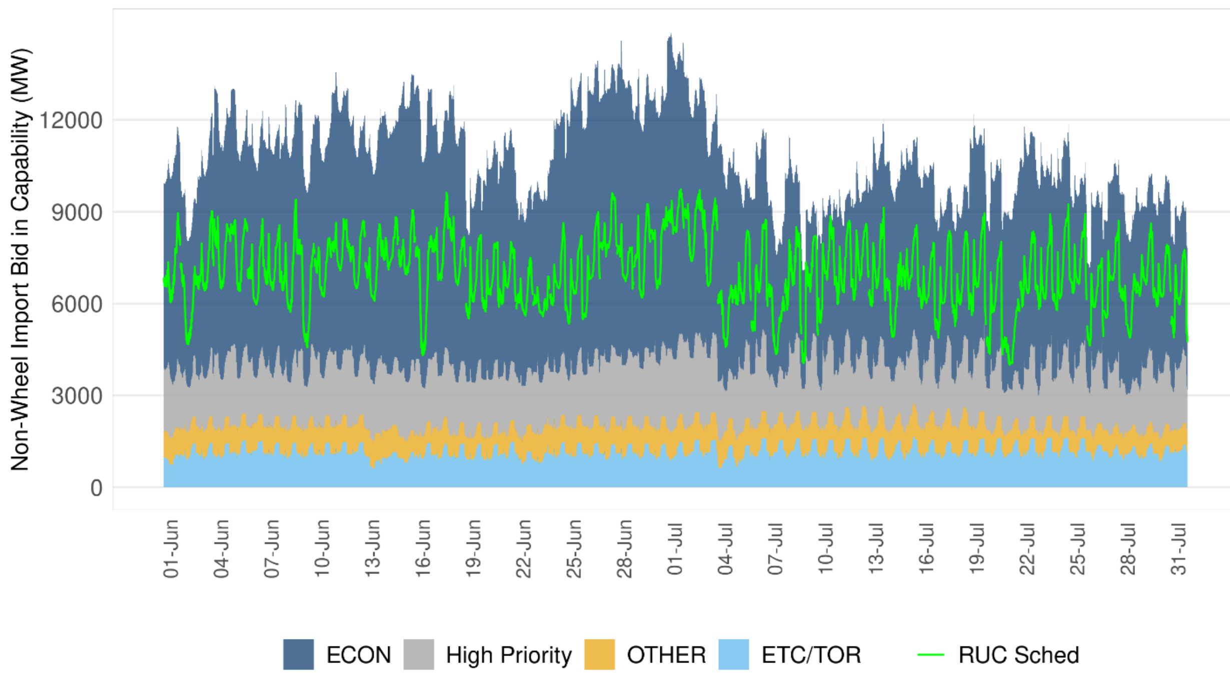


Figure 41 shows the same metric for imports. These volumes include both static imports and dynamic resources. Both ETC/TOR remained relatively stable through the months. There were smaller volumes of economic bids in July comparing to June, resulting in a slightly lower total of bid in capacity. The “other” group includes regulatory must run priority capacity and the portion of Pmin for dynamic resources with a Pmin above 0 MW.

Figure 42 shows the overall intertie schedules organized by type of schedule, as well as the net interchange based on the RUC solution for two months. Figure 43 shows the overall intertie RUC schedules during the heatwave, July 23 – 25. The net interchange projected in the RUC process reached its lowest level on July 9 in HE 18 at about -1755.5 MW due to the higher level of exports cleared.

Figure 42: Breakdown of RUC cleared schedules

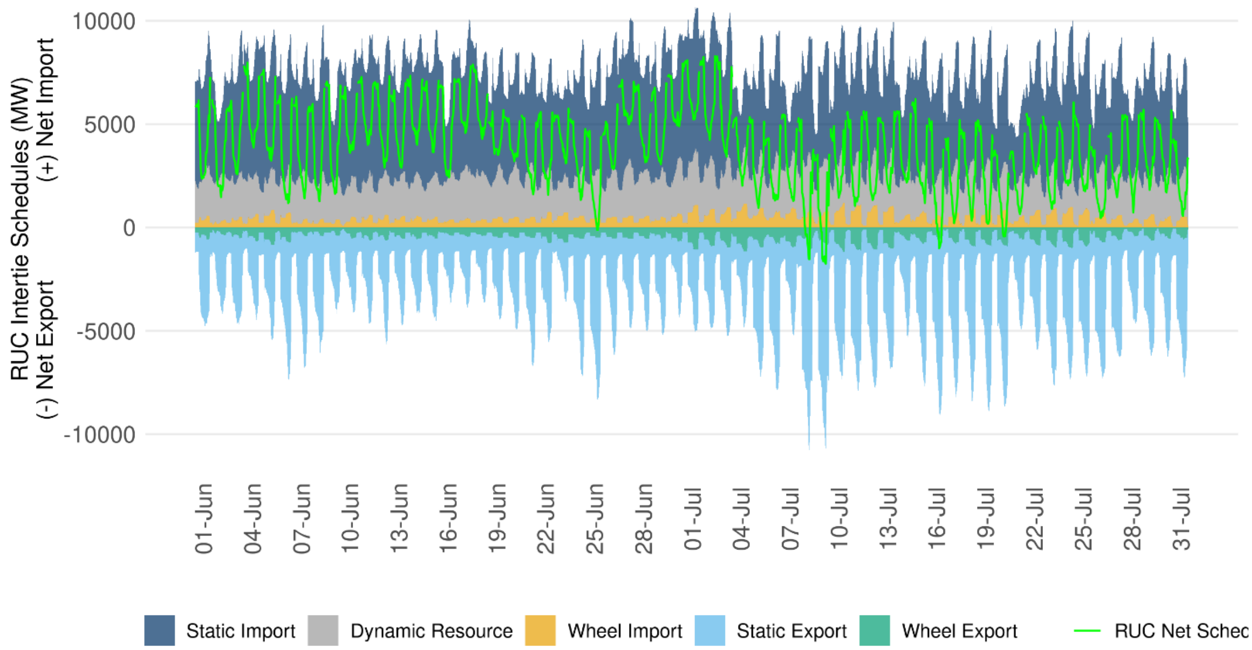
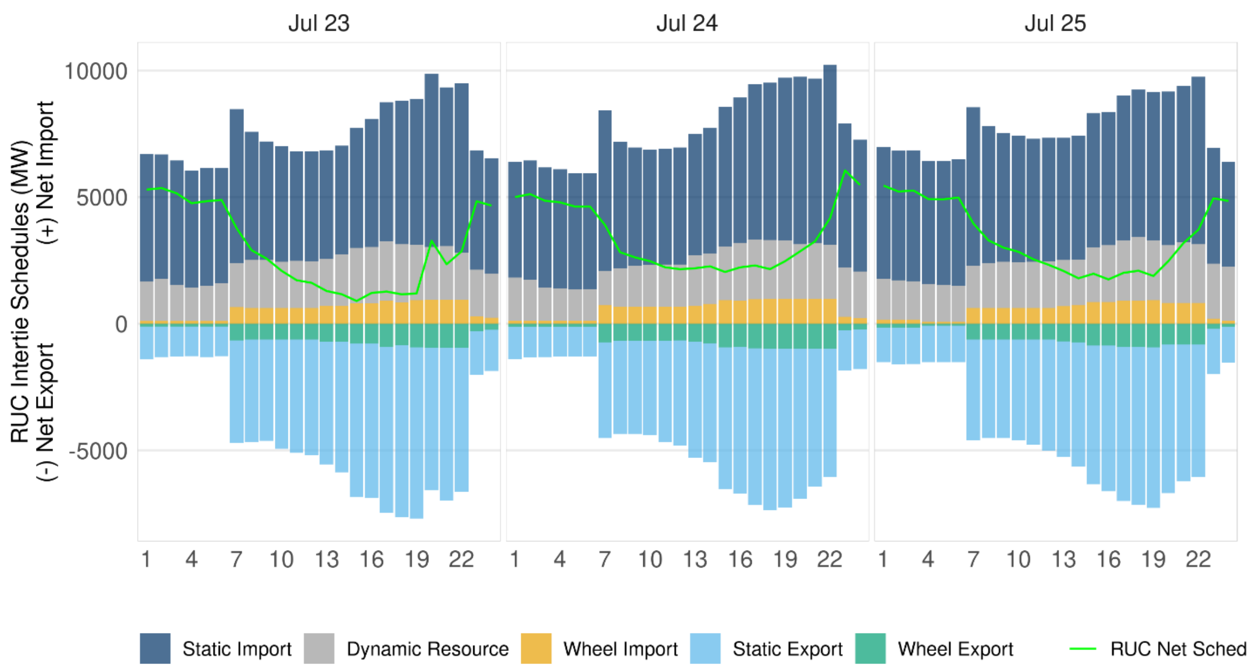
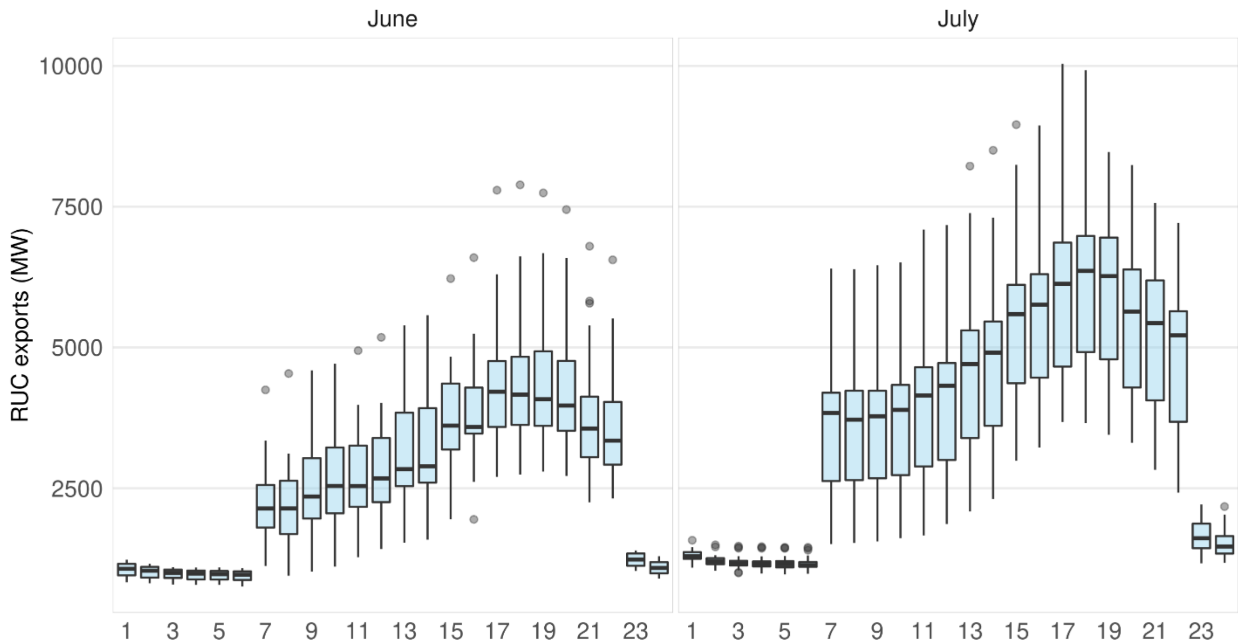


Figure 43: Breakdown of RUC cleared schedules, July 23-25, 2024



An area of interest since summer 2020 is the trend of exports in the ISO's system. Figure 44 illustrates the hourly distribution of RUC schedules for exports and that the highest volume occurred during afternoon hours. Comparing to June, July had higher RUC exports for majority of the hours, hour ending 7 through 22. The highest volumes were cleared in hour ending 17 and 18.

Figure 44: Hourly RUC exports



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 their 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 additional capacity in the real-time market.

Figure 45 shows both the cleared schedules in real time for interties of different groups, and the net intertie schedules cleared, referred to as net schedule interchange. The net schedule interchange was at its lowest value on July 9 due to the highest level of exports cleared on that day. The real-time market largely follows the trend observed in the day-ahead market. The net schedule is generally lower in July comparing to June. On average, for July, the net schedule in HASP was about 3,191 MW across all the hours of the month and about 1,810 MW for peak hours.

Figure 46 shows the cleared and net schedules during the heatwave, July 23 – 25. The net schedule was close to or below 0 for a few early afternoon hours on 23 and 24.

Figure 45: HASP cleared schedules for interties

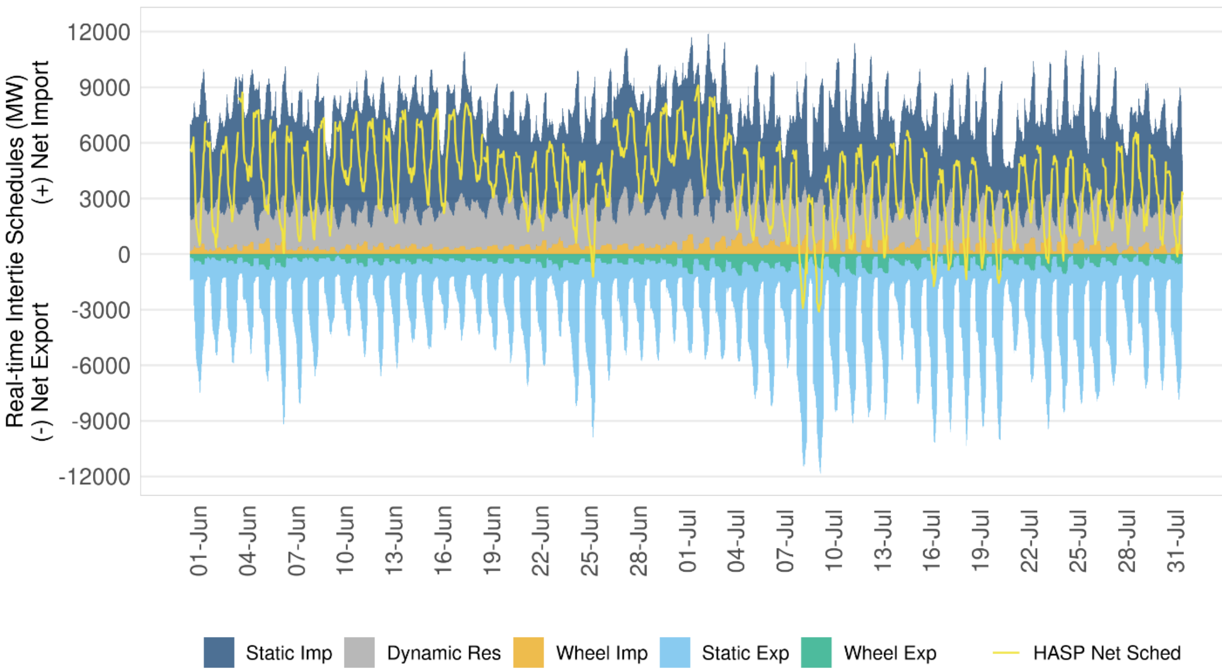
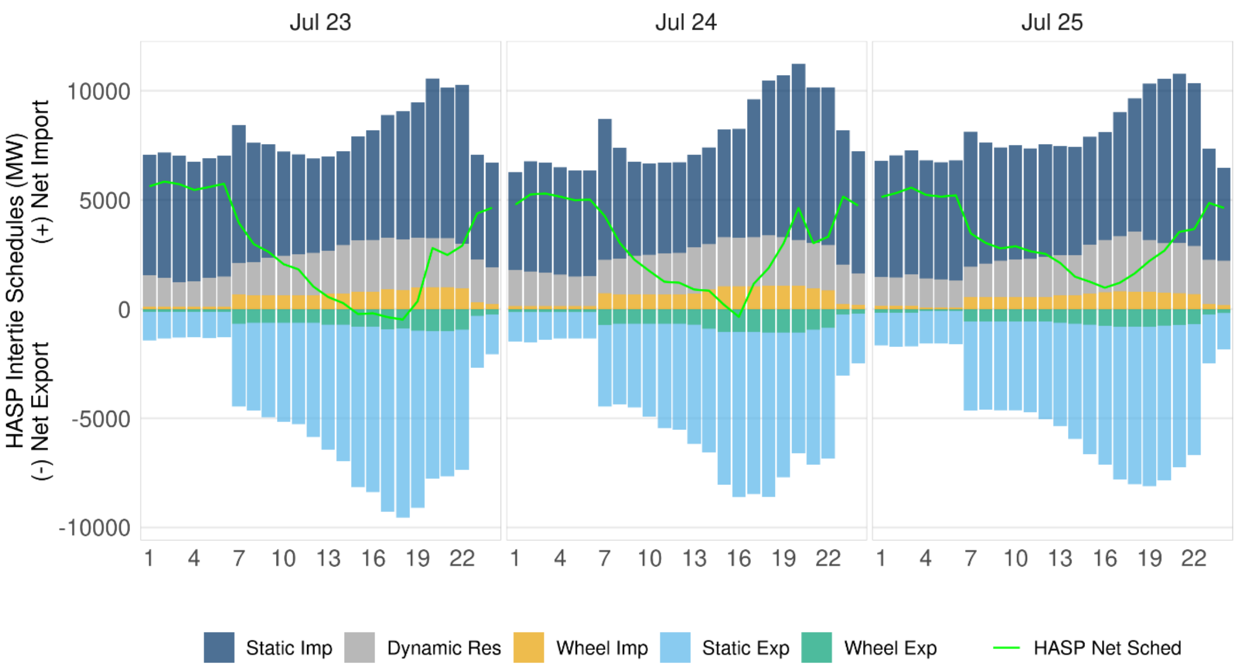


Figure 46: HASP cleared schedules for interties, July 23 – 25, 2024



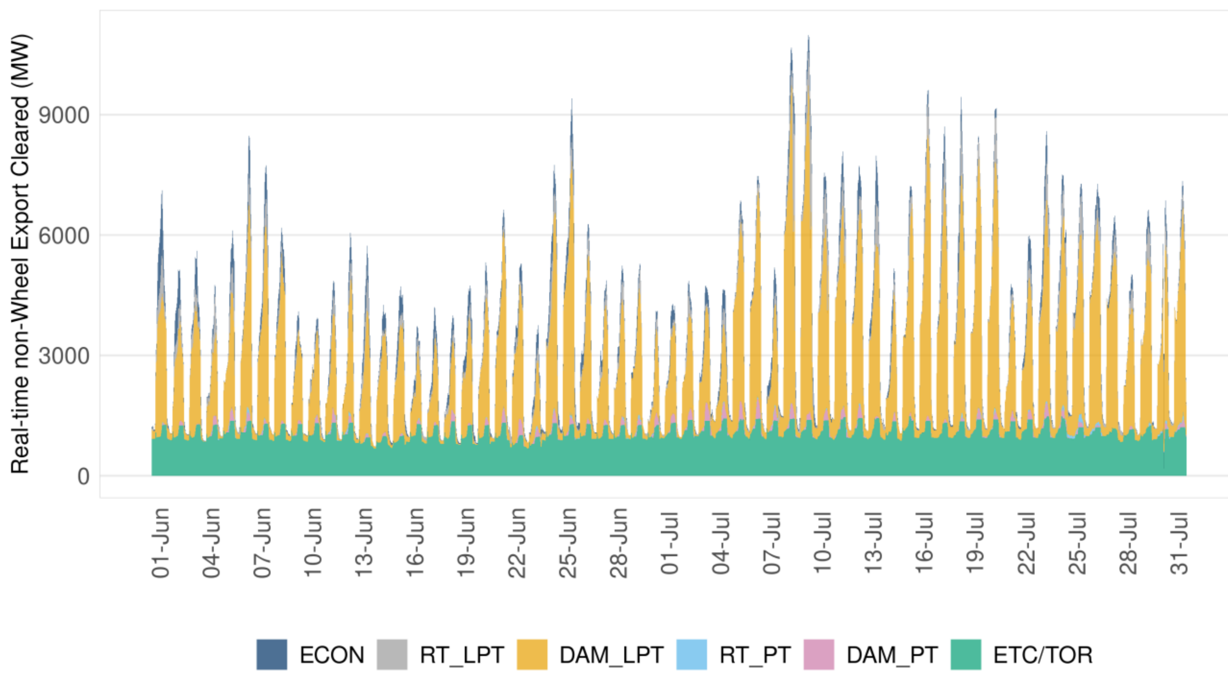
The HASP market presents an opportunity for interties to clear through the market clearing process after the DAM is complete. Clearing the RUC process indicates that these exports were feasible to flow based on the projected system conditions in RUC, and will be reassessed in real time.[14]

Each market, RUC or HASP, can assess reduction of exports based on prevailing system conditions and economics. Export reductions in RUC cannot self-schedule into real-time with day-ahead priority, but they are able to rebid into the real-time market and be fully assessed based on real-time conditions.

Figure 47 shows all the exports cleared in the HASP process and identifies the nature of such exports. Figure 48 shows the exports cleared for the priod of July 23 – 25. TOR is for export with scheduling priorities associated with transmission rights. The groups of DAM_PT or DAM_LPT stand for day-ahead exports coming into real-time market as self-schedules with high or low priorities. Similar classification is followed for those high and low priority exports coming into real-time directly (RT_PT and RT_LPT). ECON stands for economic exports. These exports are only for non-wheel transactions. A granular breakdown of wheels is provided in a subsequent section of wheels.

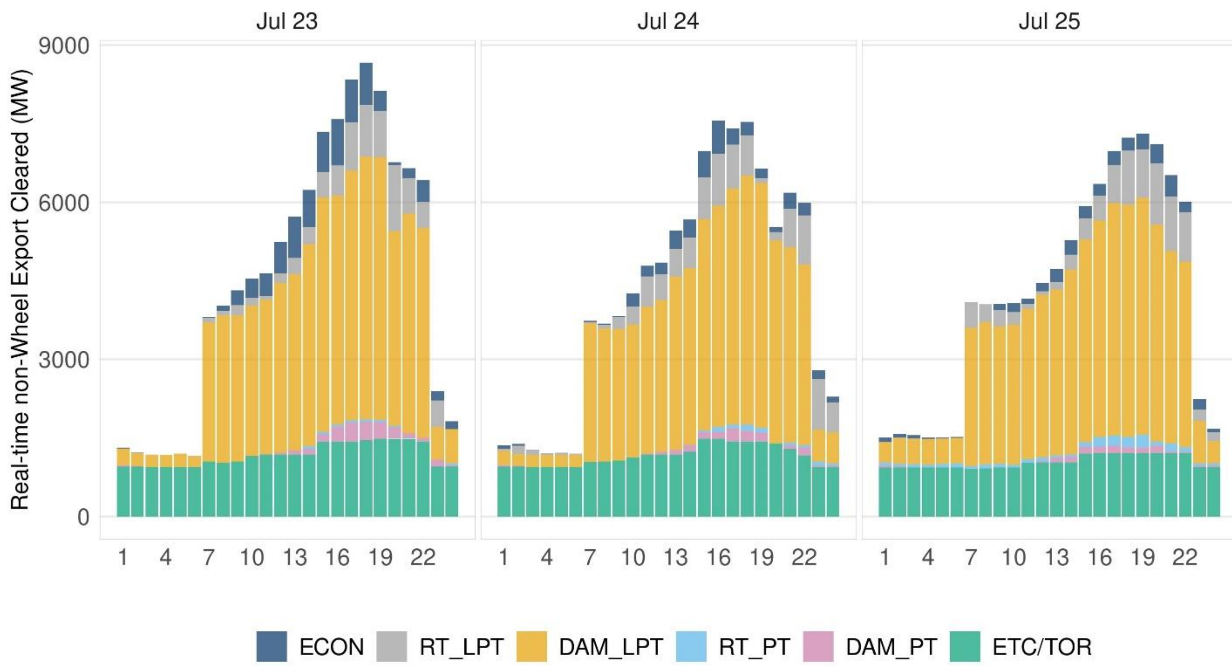
The volume of exports cleared in real time peaked at 11,056MW on July 9. In July, higher volumes of exports were cleared comparing to June, and low priority bids constituted a significant portion of cleared exports.

Figure 47: Exports schedules in HASP



[14] Based on these rules implemented on August 4, 2021, through the summer enhancements described earlier and now in place, the ISO will no longer provide exports a higher priority than load in the real-time, and will only provide them equal in 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

Figure 48: Exports schedules in HASP, July 23 – 25



Imports and exports were scheduled over multiple intertie scheduling points in July, with Malin, Palo Verde and NOB seeing the highest volume of transactions. Figure 49 through Figure 51 illustrate the trend of import and export schedules cleared in HASP for these top three intertie points. In July, the prevailing schedules were in the import direction.

Figure 49: HASP schedules at Malin intertie

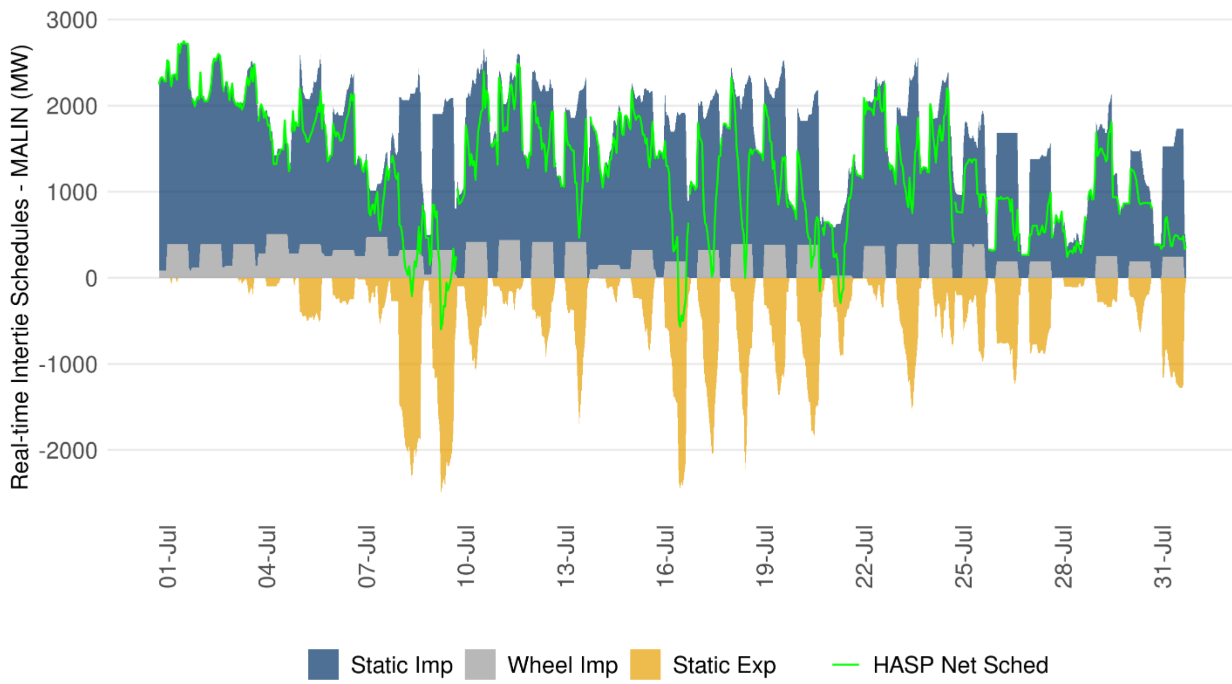


Figure 50: HASP schedules at Palo Verde intertie

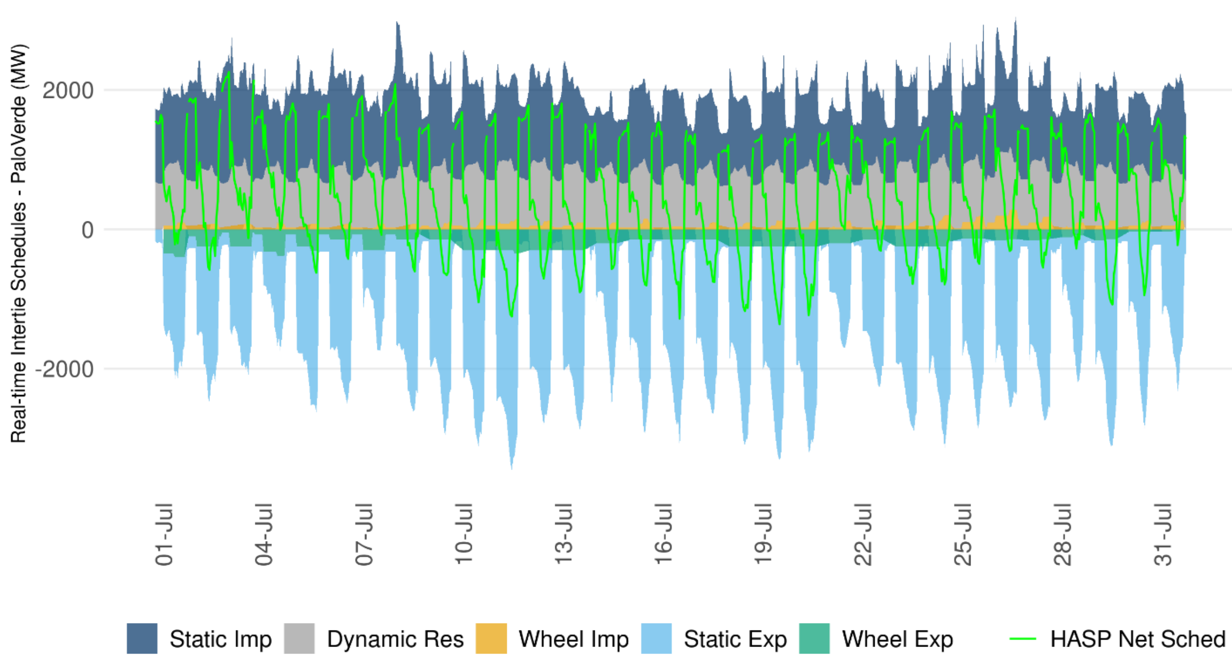
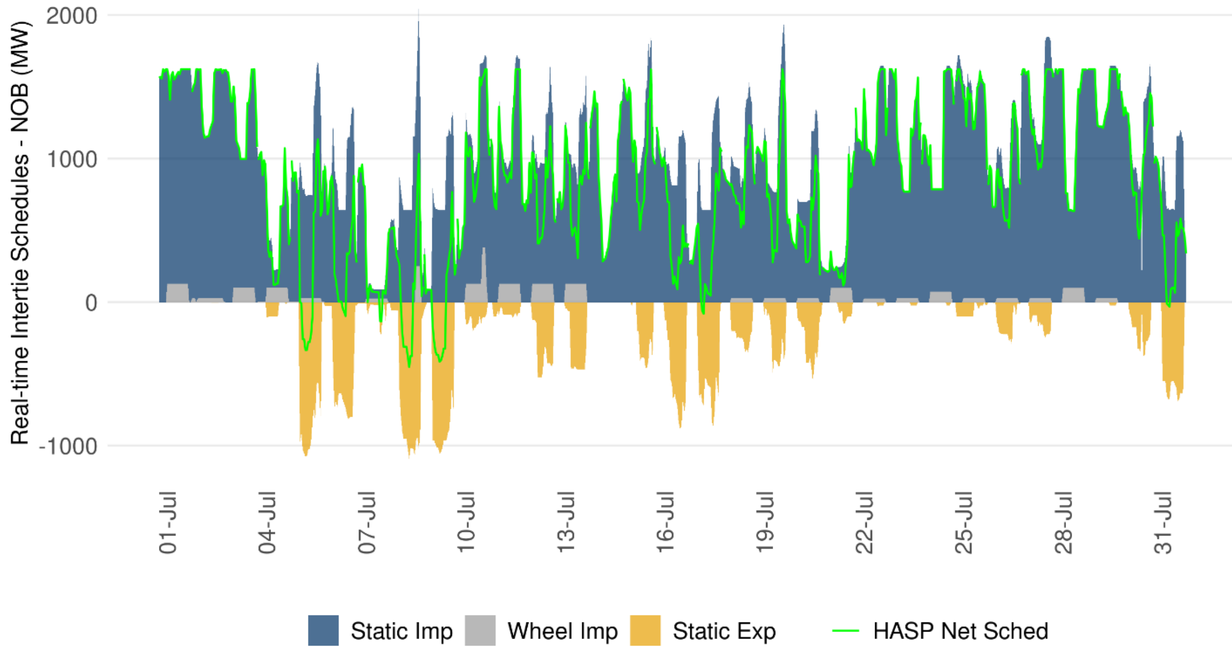


Figure 51: HASP schedules at NOB intertie



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 3,006 MW related to LSEs under CPUC jurisdiction.

Under the CPUC's RA rules, non-resource specific RA imports for LSEs under CPUC jurisdiction must self-schedule or bid economically with prices between -$150/MWh and $0/MWh at least for the availability assessment hours. Figure 52 shows 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, and also differentiates between RA capacity and above RA capacity. Based on this subset, about 99.5 percent of all RA import capacity bid with either self-schedules or economic bids at or below $0/MWh in the day ahead timeframe in July. There was only one RA import that bid about 50 MW less during July 22 through July 26.

This plot also shows the cleared imports, which largely utilized all the bid-in volume for RA and above RA. The exception is for July 26 where the day-ahead market could not clear about 540 MW of bid-in RA imports coming from Malin due to a path derate applied to the Malin intertie due to the Park Fire impact.

Figure 52: Day-Ahead RA import for hour endings 17 through 21 for weekdays

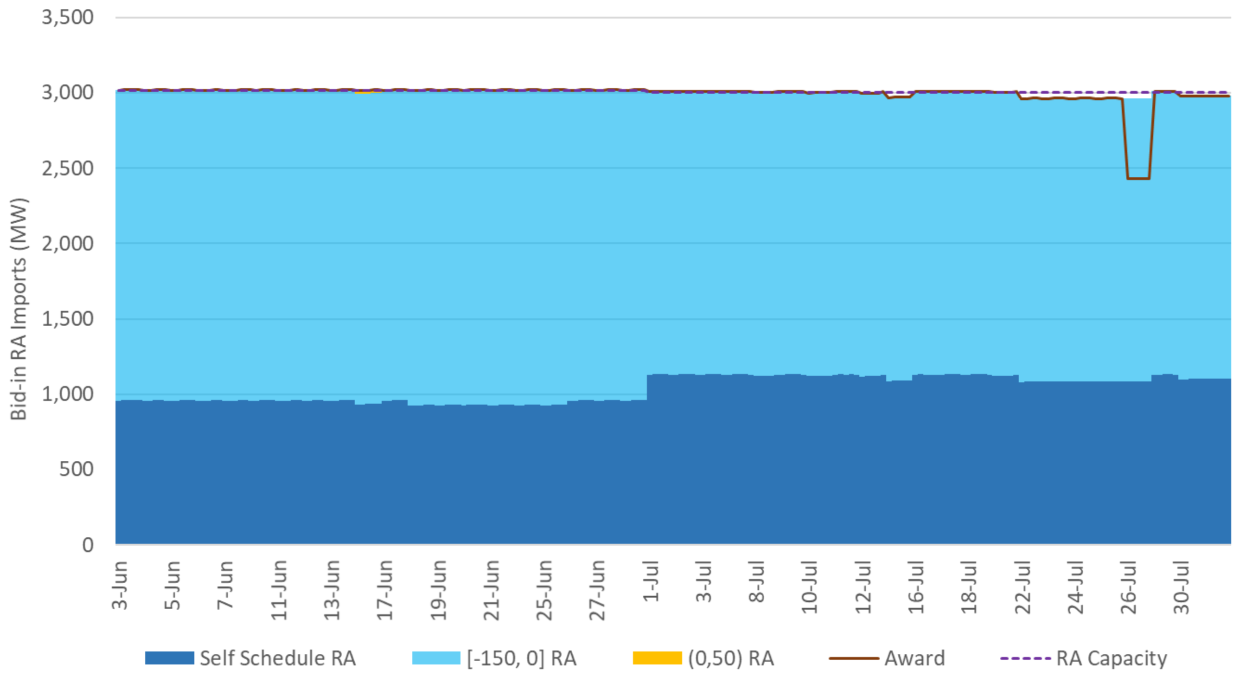
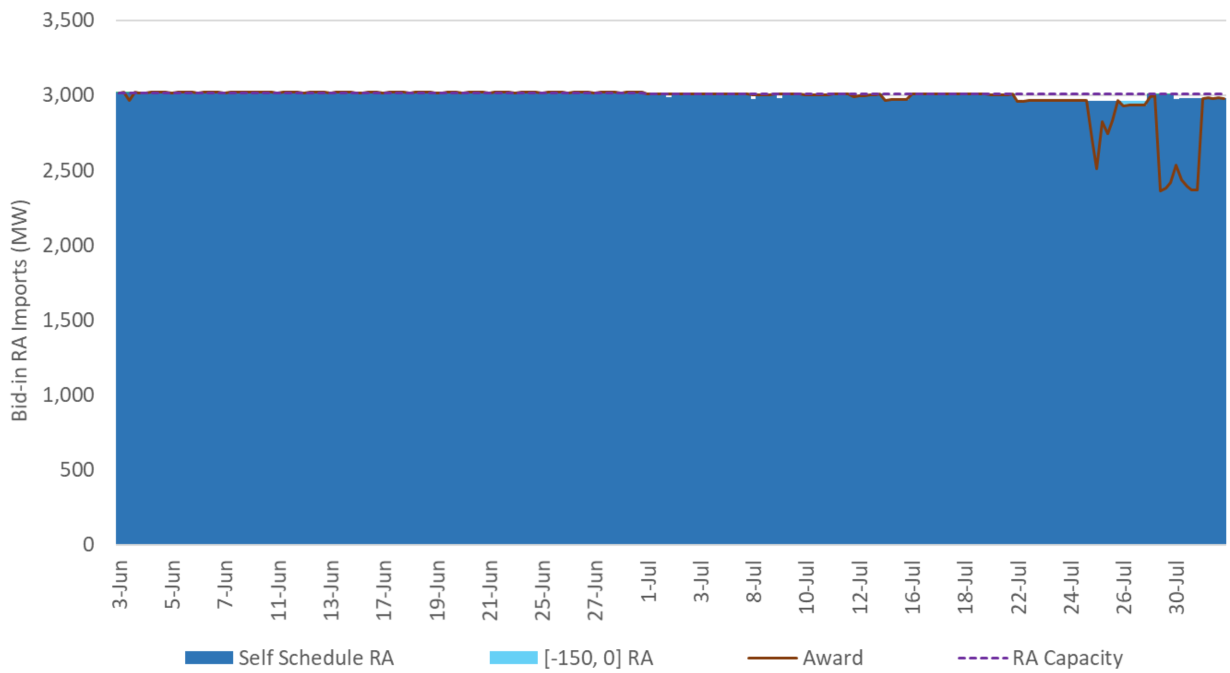


Figure 53 shows the same information for the real-time market using the HASP bids and awards. All CPUC-jurisdictional RA imports submitted in the real-time market were with self-schedules. About 99.5 percent of RA imports bid with self schedules or economic bids below $0/MWh. There was only one RA import that bid about 50 MW less than it s RA capacity during the period of July 22-26. Similar to the day-ahead, in the real-time, up to 640 MW of bid-in RA imports could not clear given the path derates on Malin intertie due to impacts of the Park Fire.

Figure 53: HASP RA import for hour endings 17 through 21 for weekdays



Wheel Transactions

With the summer enhancements for exports, loads and wheeling scheduling priorities extended for summer 2024, wheels can seek higher priority for their wheels.[15] For the month of July 2024, there was a total of 690 MW of high-priority wheels from eight different scheduling coordinators. Table 1 lists all the wheel-through definitions used in July.

Table 1. Wheel-through quantities registered for July 2024

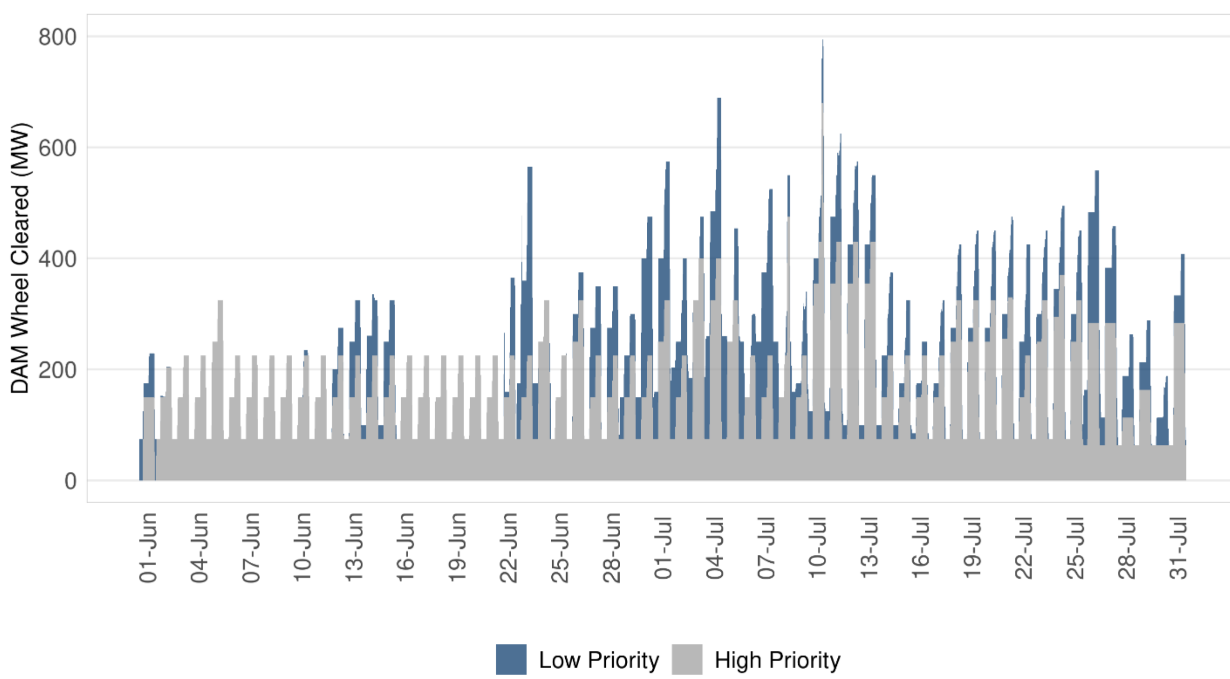
Source	Sink	Total (MW)
MALIN500	PVWEST	77
NOB	MEAD230	325
NOB	PVWEST	53
PVWEST	SYLMAR	10
RDM230	MCCULLOUG500	75
RDM230	PVWEST	150
Grand Total		690

[15] For more information on the enhancements implemented for estimating the priority wheel through capacity - https://stakeholdercenter.caiso.com/StakeholderInitiatives/Transmission-service-and-market-scheduling-priorities

Once these transactions are granted high priority, they can be scheduled in the ISO's markets and receive a high scheduling priority. Scheduling coordinators can opt to utilize these wheels on an hourly basis through the month.

Figure 54 shows the hourly high and low priority wheels cleared in the RUC process throughout the month. ETC/TOR wheels are excluded. Wheels participating in the day-ahead market with high- and low-scheduling priority, reached a total maximum at 800 MW on July 10, with 680 MW of high priority and 120 MW of low priority wheels.

Figure 54: Hourly volume high- and low-priority wheels cleared in RUC



Wheels are defined with a source and sink location in the ISO's markets to factor in their contribution to the flows on either intertie constraints or internal transmission constraints.

Figure 55 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 path with the largest volume of wheels in July in the day-ahead market was from RDM (Round Mountain located in norther California) to PVWEST (Palo Verde located in Southern California).

Figure 55: Hourly average volume (MWh) of wheels by path in July

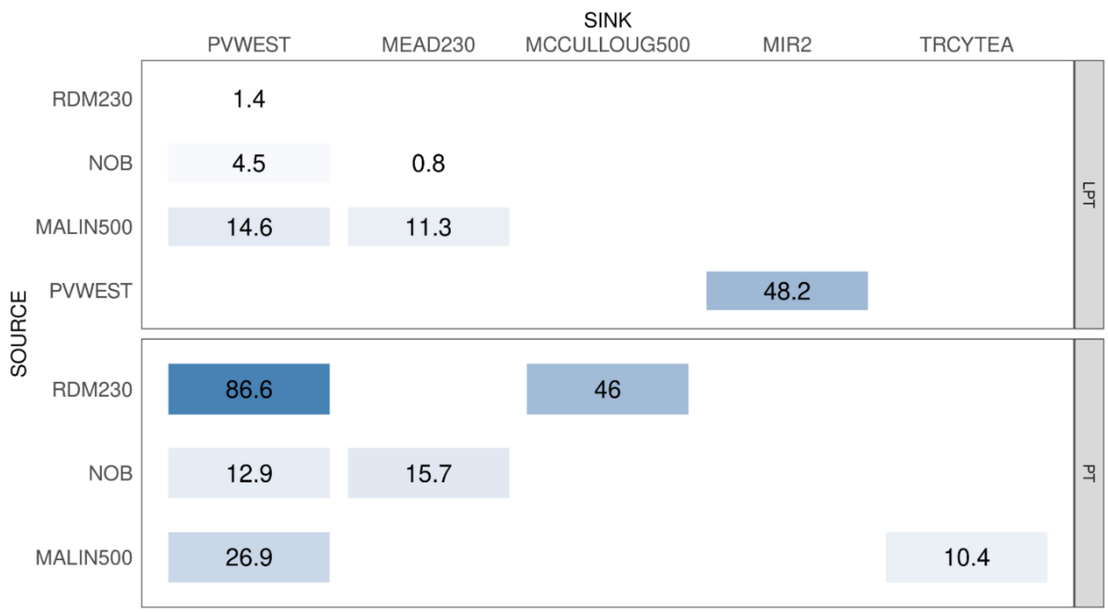
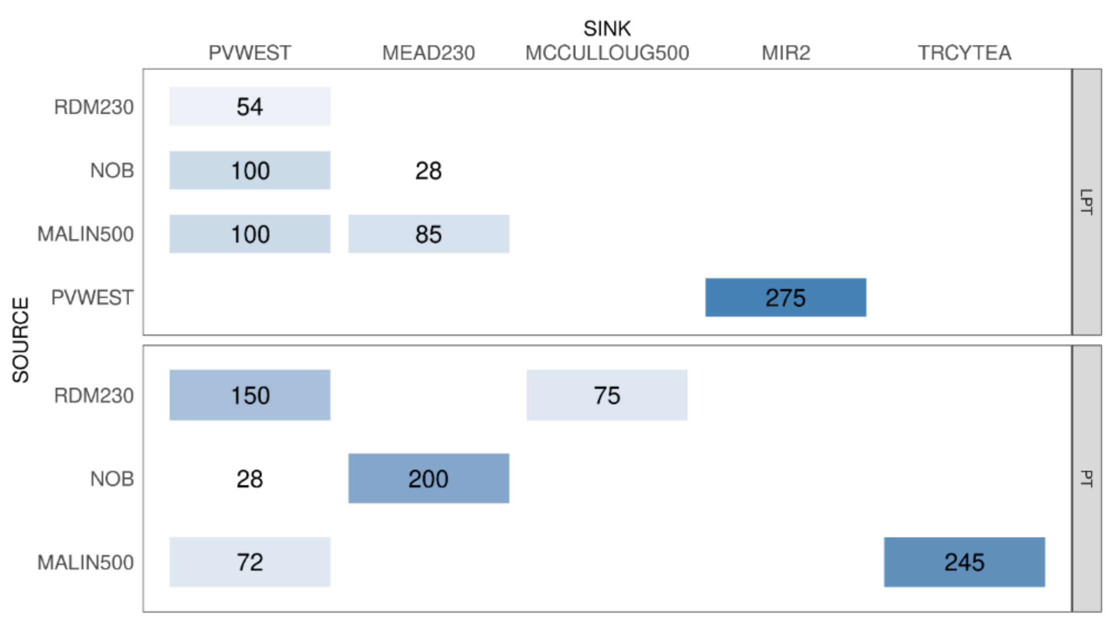


Figure 56 summarizes the maximum hourly wheels cleared in any hour in July in the day-ahead market by source-to-sink combination. The maximum volume of wheels in a given path occurred from PV West to MIR2 (Mirage locations).

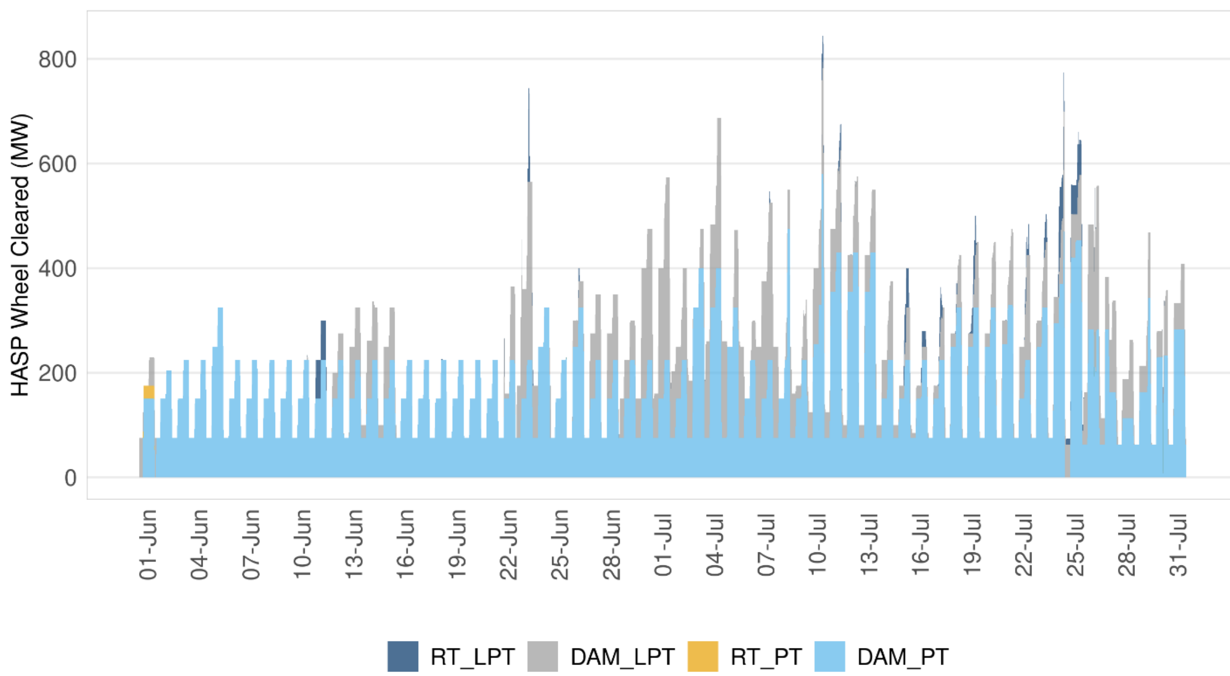
Figure 56: Maximum hourly volume (MW) of wheels by path in July



Although wheels do not add or subtract capacity to the overall power balance of the ISO market, they compete for limited scheduling and transmission capacity.

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 57 shows the volume of high- and low-priority wheels cleared eventually in the real-time market, organized by the various types of priority and relative changes.

Figure 57: Wheels cleared in real-time market



The *DAM*_PT is for wheel-through transactions with high priority that cleared in the day-ahead market and then rebid into real-time. RT_PT is high priority that came in directly into real-time market. DAM_LPT is for wheels with low priority cleared in day-ahead and rebid into real-time. Similarly. RT_LPT is for wheels bid in directly into real time. Econ is for economical wheels. The volume of wheels bid in directly into real time was negligible.

6 Storage and Hybrid Resources

In July 2024, there were 164 storage resources registered in the ISO market. Storage resource here refers to the Limited Energy Storage Resource (LESR) type. Most storage resources participated in both the energy and ancillary service market. Batteries can arbitrage the energy price by consuming energy (charging) when prices are low, then subsequently delivering energy (discharging) during market intervals when prices are higher. Each storage resource has a maximum storage capability that reflects the physical ability of the resource to store energy.

The total state of charge from all the active resources participating in the market was 35,699 MWh. In terms of the capacity made available to the markets, Figure 58 and Figure 59 present the daily average and the hourly average of bid-in capacity for storage resources in the day-ahead market in June and July, organized by price ranges.

Figure 58: Bid-in capacity for batteries in the day-ahead market, daily average

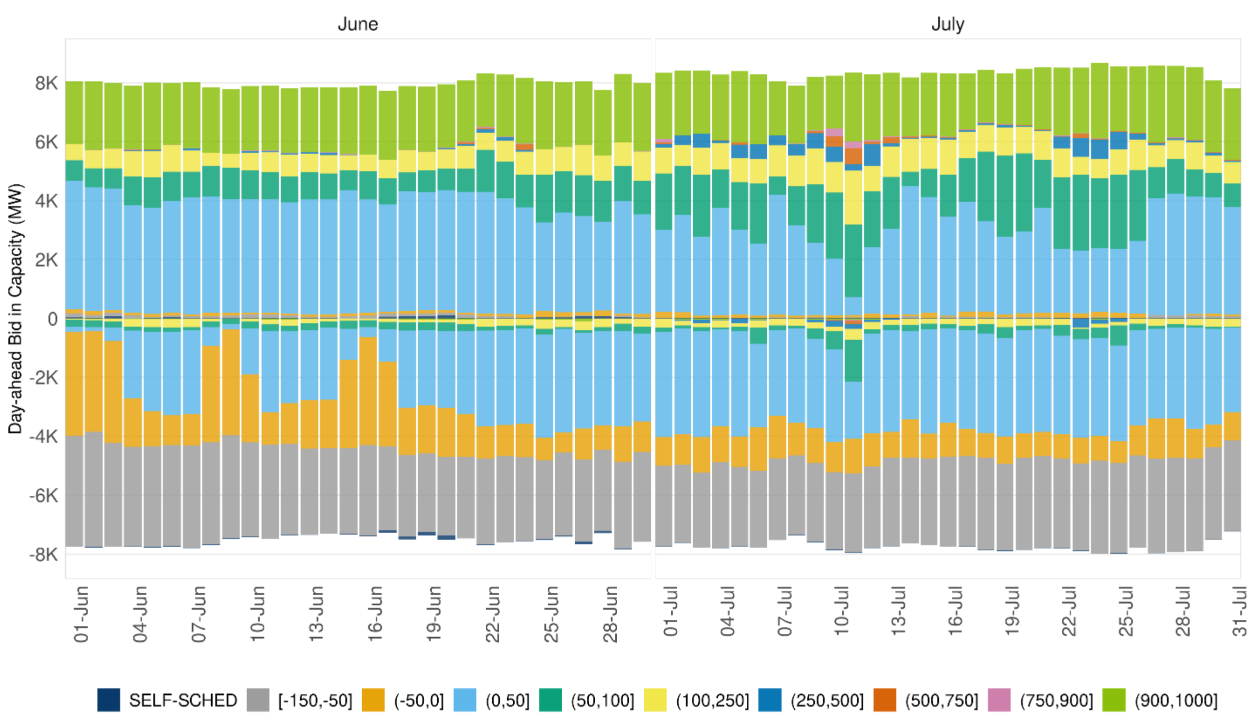
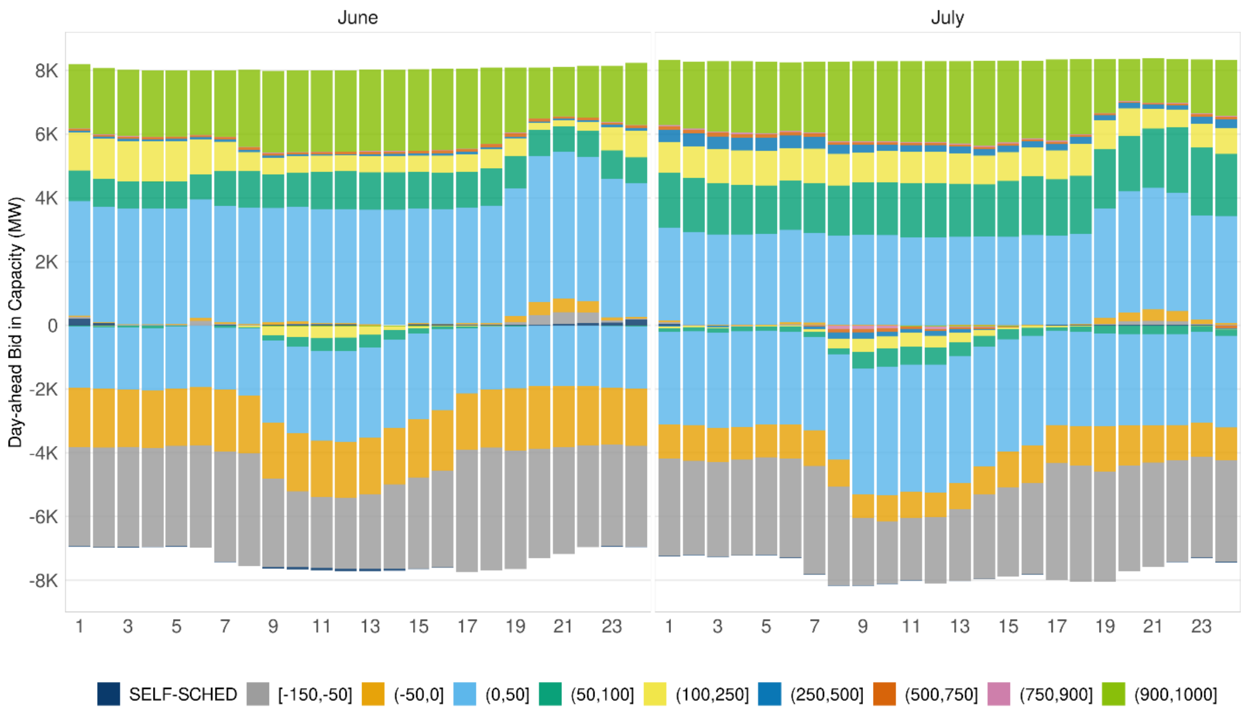


Figure 59: Bid-in capacity for batteries in the day-ahead market, hourly average



The negative area represents charging while the positive area represents discharging. The overall capacity in the market was roughly consistent through the months at about 7,500 – 8,000 MW. The bid-in capacity is organized by $/MWh price ranges. There were consistent patterns of batteries bidding to charge at negative prices and discharge at positive prices. Some resources bid reflected the willingness to charge when prices were up to $50. Conversely, they were almost always willing to discharge at higher prices. The green segments show bids close to or at the soft energy bid cap of $1,000/MWh and show that there was a certain volume of storage capacity expecting to discharge only at these high prices.

Figure 60 and Figure 61 present the bid-in capacity for the real-time market. The overall capacity follows the similar trend as the day-ahead market.

Figure 60: Bid-in capacity for batteries in the real-time market, daily average

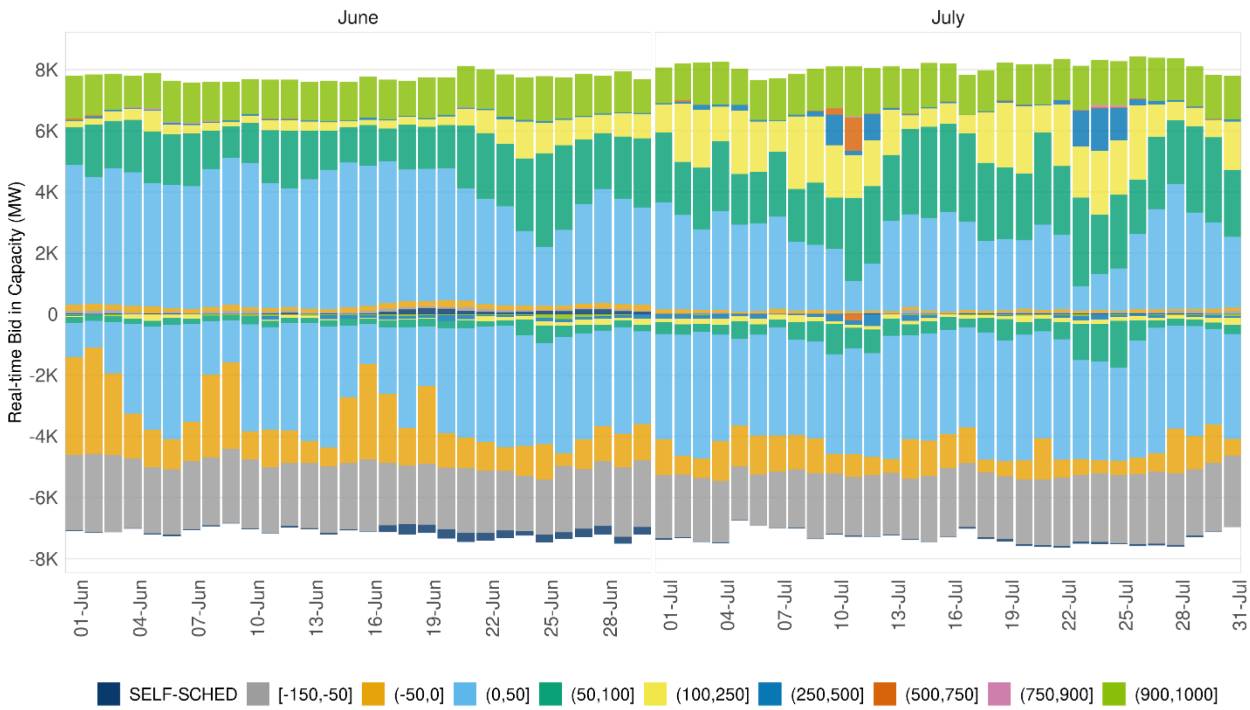


Figure 61: Bid-in capacity for batteries in the real-time market, hourly average

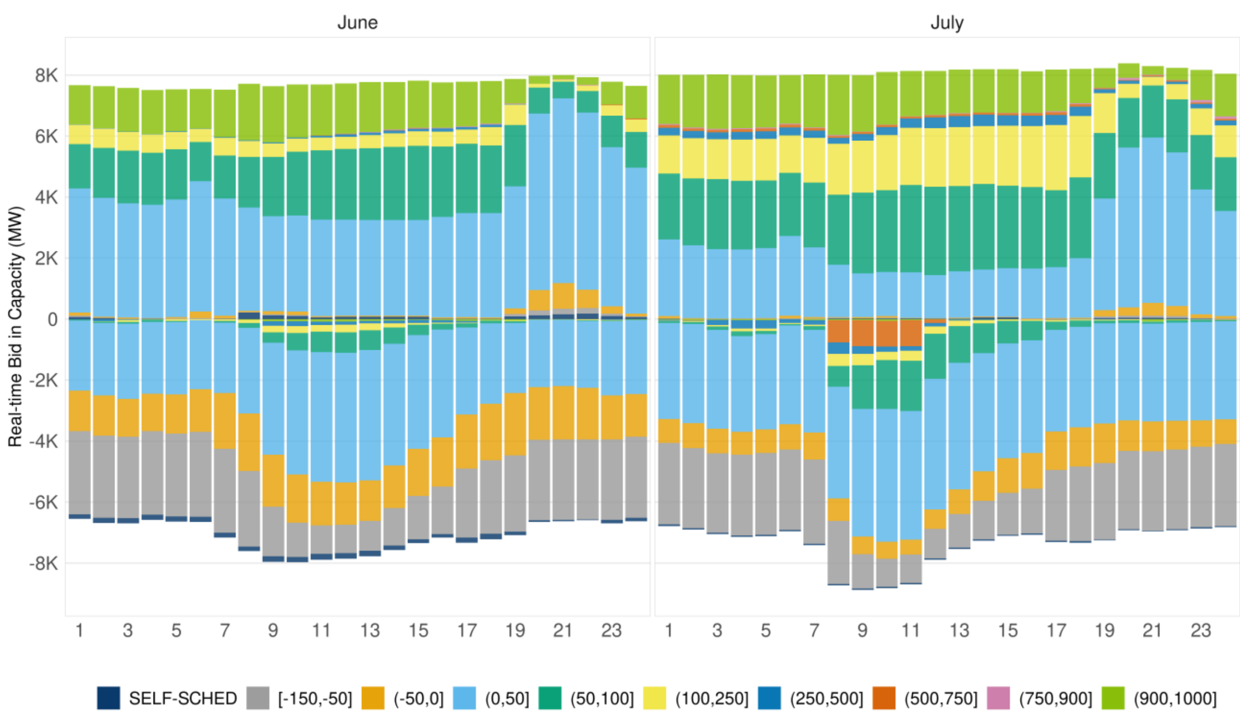


Figure 62: Distributions of state of charge for July 2024

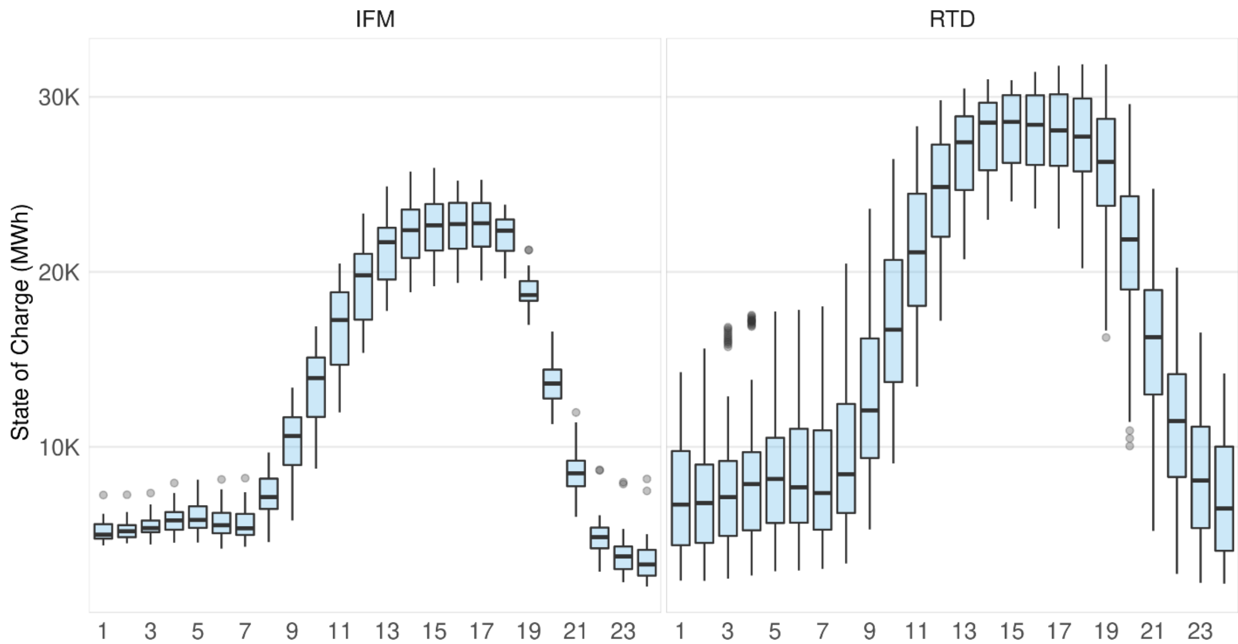


Figure 62 shows the hourly distribution of the storage capacity of resources participating in IFM and RTD for July. The box plot shows the median, 25th percentile, 75th percentile, and outliers for the total state of charge. Storage resources charge in hours when there is abundantly cheap energy from solar resources in the daytime, between hours ending 9 to 18. The system reached maximum stored energy by hour ending 16, followed by a period of steady discharge from hours ending 18 through 24. In July, the highest system state of charge in IFM was around 25,943 MWh, roughly 73 percent of the total capacity, which occurred in the hour ending 15. The peak hourly state of charge in the real-time market was 31,934 MWh in hour ending 18, at roughly 89 percent of the total capacity, higher than the day-ahead peak state of change. Also, the state of charge in the real-time market had a wider spread compared to the day-ahead market.

Most of the storage resources in the ISO 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 as much as possible just prior to the hours with high energy prices. With the need for more supply as solar production diminishes, it is expected that storage resources would be discharging during net load peak hours. Figure 63 shows the distributions of energy awards in IFM, and Figure 64 shows the hourly distribution of real-time dispatch for batteries in June and July. These statistics are for batteries, either stand alone or the battery component of col-located resources; they do not include hybrid resources.

Figure 63: Hourly distribution of IFM energy awards for batteries

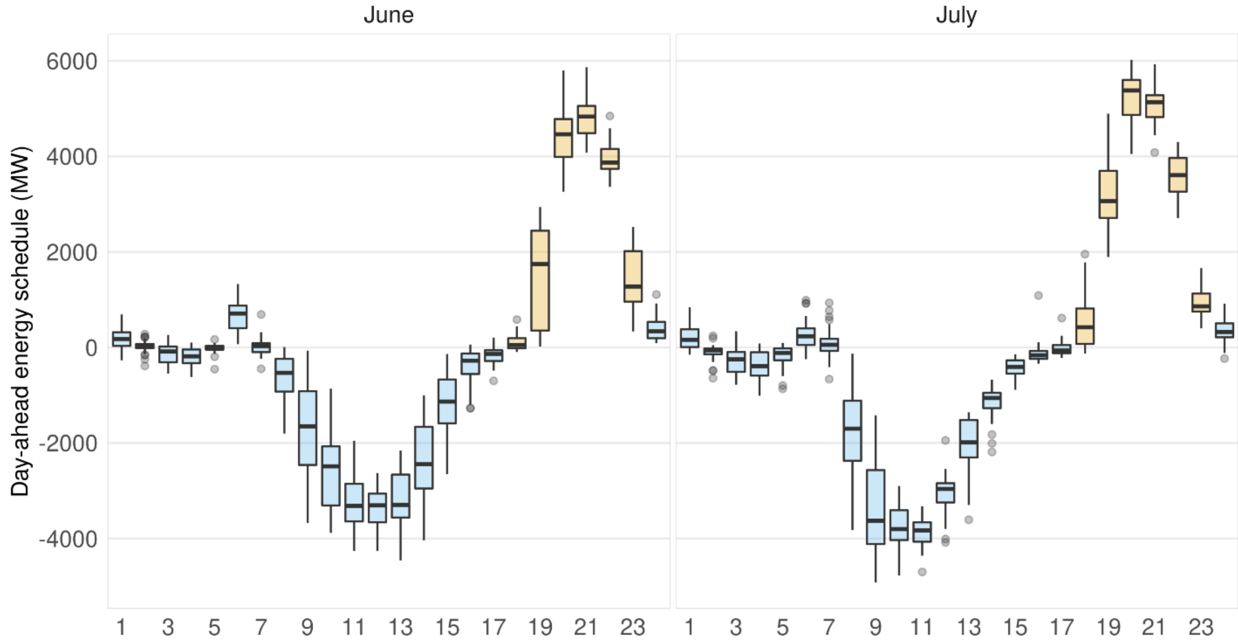
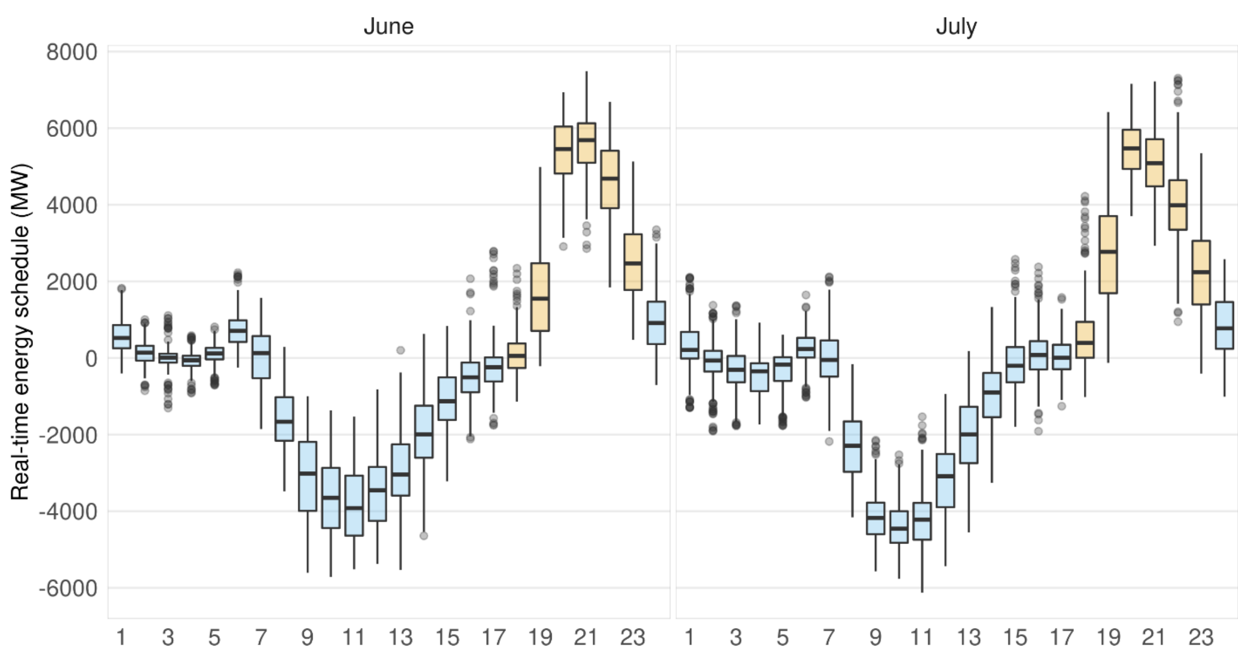
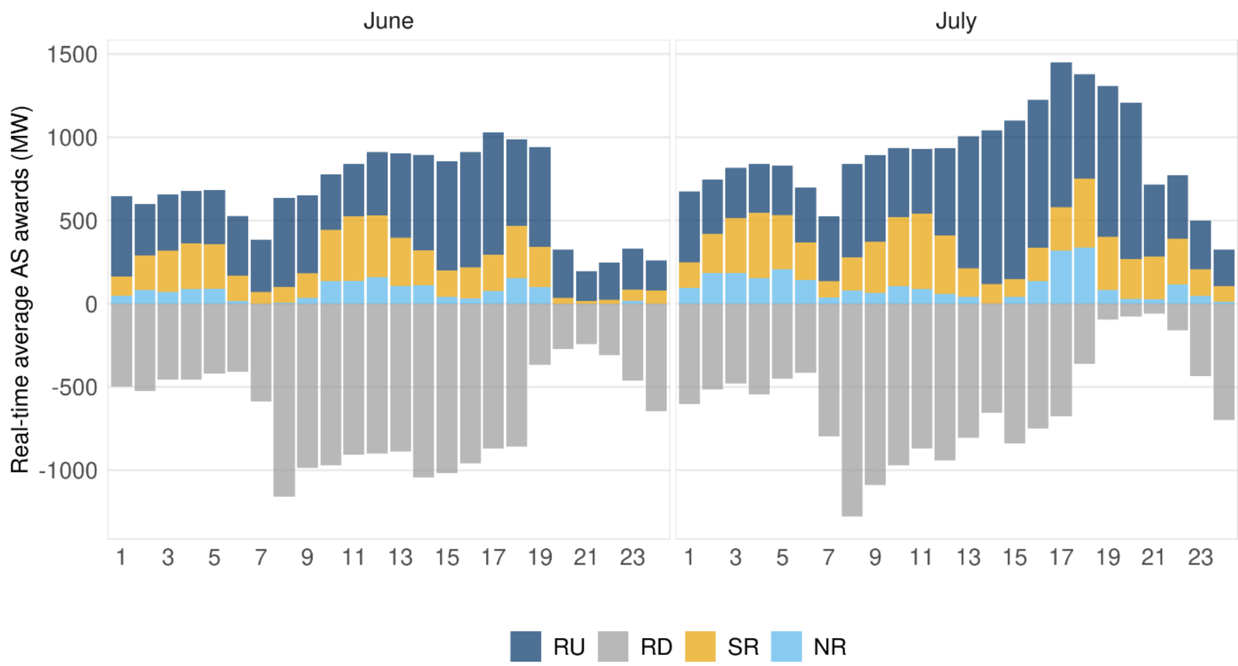


Figure 64: Hourly distribution of real-time dispatch for batteries



The storage resources continue to provide ancillary services to the market for the following products: regulation up, regulation down, spinning reserve, and non-spinning reserve. Figure 65 shows the average hourly AS awards in the real-time market.

Figure 65: Hourly average real-time storage AS awards



Beginning with the implementation of the Hybrid Resources Phase 2B project in February 2023, the ISO began tracking more formally the market performance of hybrid resources. Hybrid resources are different resource types that sit behind a single resource ID – typically a solar resource paired with a storage resource.

Figure 66 and Figure 67 show the IFM and real-time energy awards for hybrid resources, respectively. The pattern matches more closely the dispatch patterns of solar resources with some differences. The energy awards dip in the middle of the day when solar resources typically reach peak output. This is likely due to the energy storage component of the resource charging off of the solar component of the resource, resulting in a lower energy award. Another notable difference is that the evening ramp down as the sun sets is less steep compared to solar resources. This pattern is attributed to the storage component of the resource discharging in these evening hours, offsetting the decreased production of the solar component and resulting in a flatter decline in output. The energy schedules in IFM in July had a roughly 30 percent increase in the midday hours comparing to schedules in June, while the scales remain similar in the real time market.

Figure 66: Hourly distribution of IFM energy awards for hybrid resources

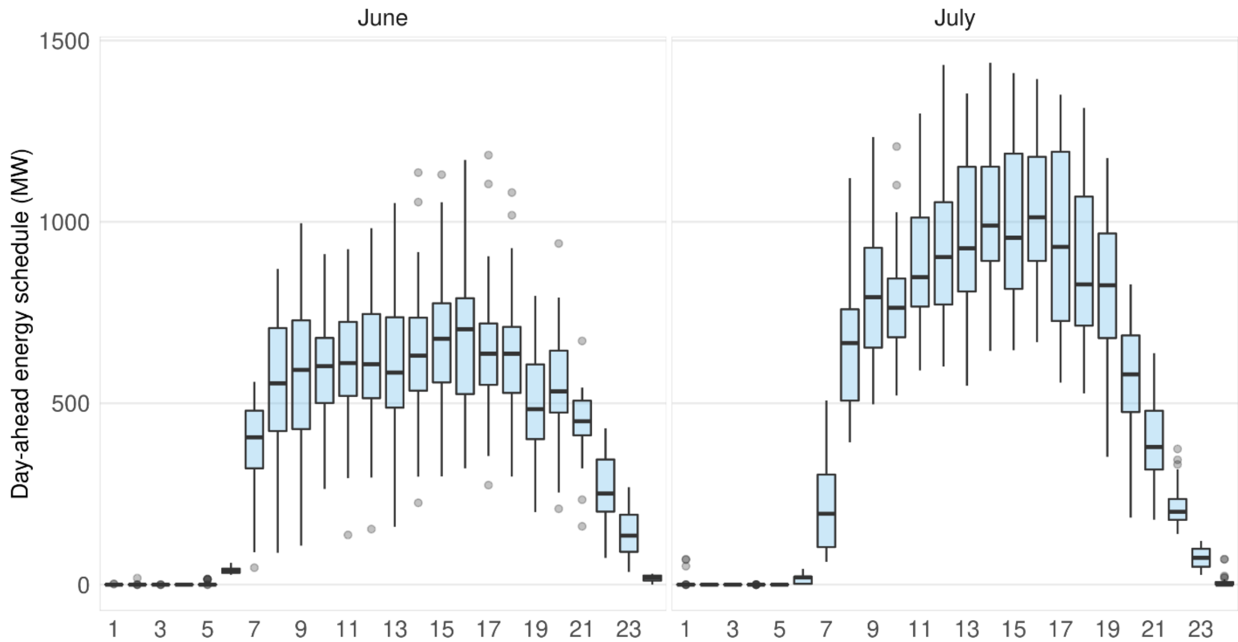
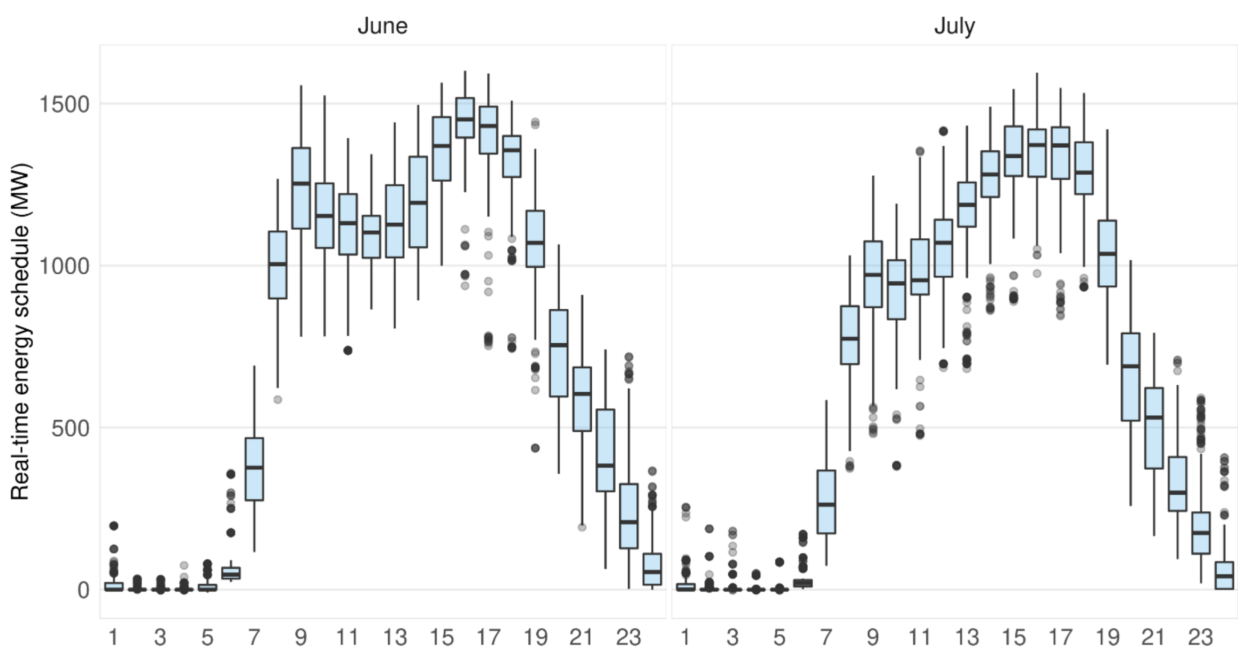
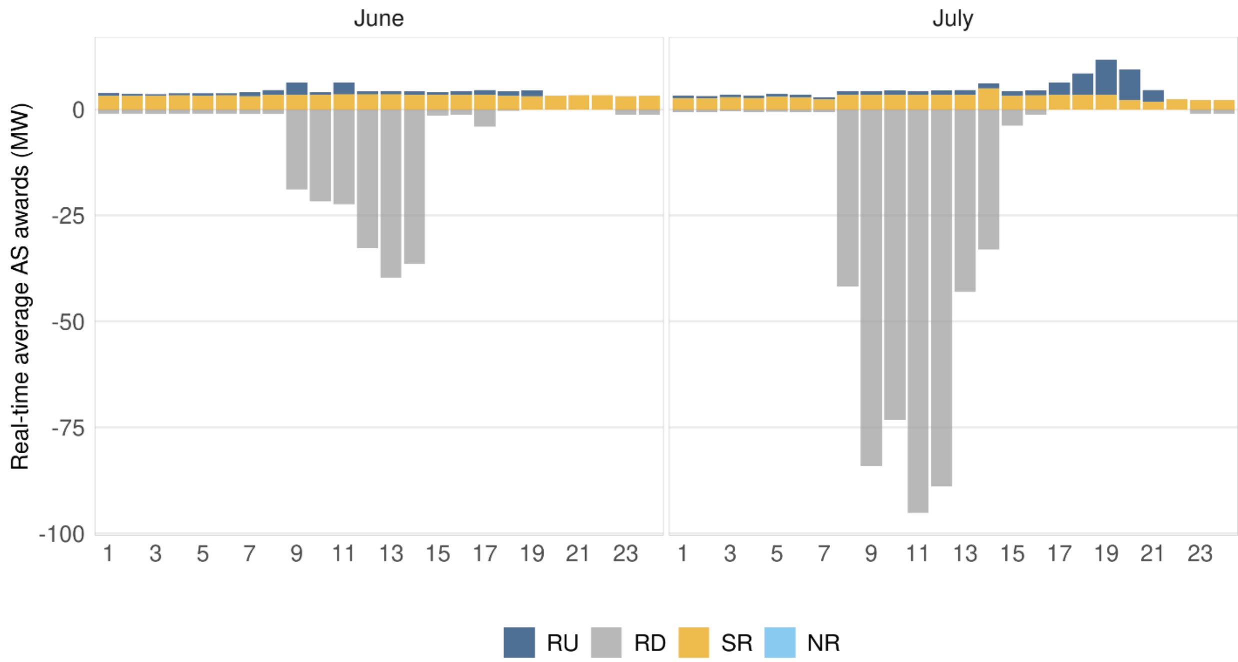


Figure 67: Hourly distribution of real-time dispatch for hybrid resources



Similar to storage resources, hybrid resources can also provide ancillary services to the market. Figure 68 shows the average hourly AS awards in real-time June and July 2024.

Figure 68: Hourly average real-time hybrid AS awards



7 Western Energy Imbalance Market

Peak Load

With the prevailing heatwave across the estern Interconnection, demand peaks at different days and times in the different regions of the WEIM footprint. Figure 69 shows the daily peak load aggregated by WEIM regions for the month of July[16]. The California region reached a maximum of 54,762 MW on July 24. The Central/Mountain reached a peak of 15,948 MW on July 11. However Pacific Northwest reached a maximum of 35,375 MW on July 9. Southwest WEIM region reached a maximum load of about 30,934 MW on July 10. The figure shows the circle marker indicating the peak load for that region for the month of July.

Figure 69: Peak load for the month of July 2024 across WEIM regions

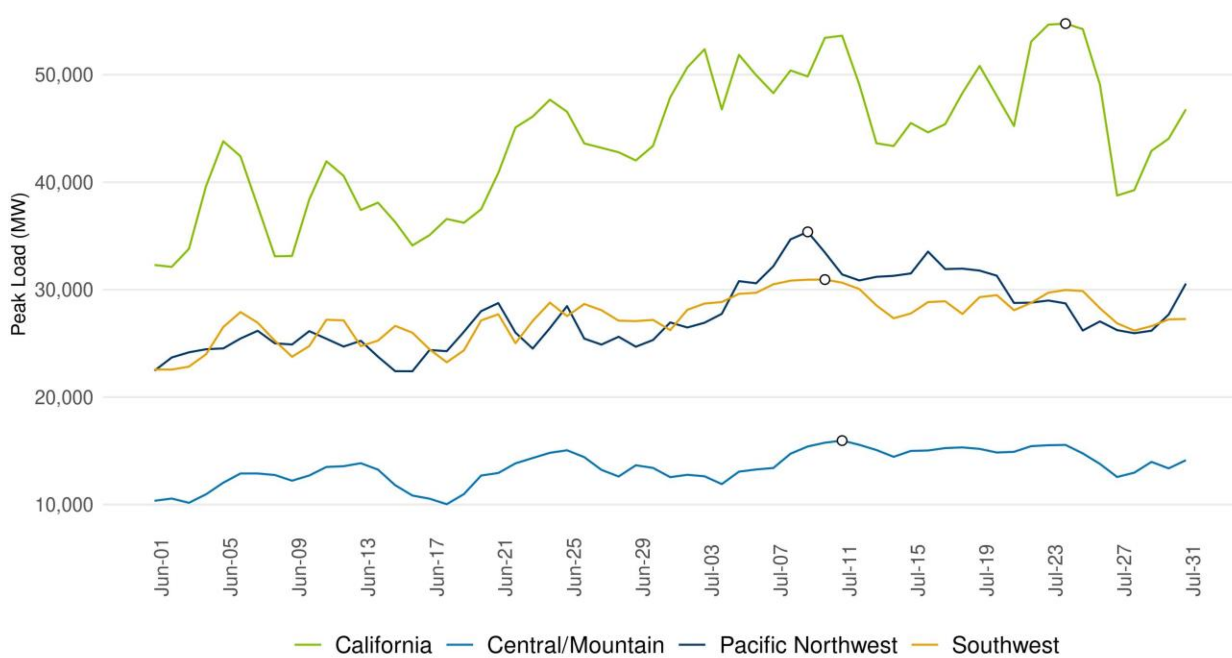
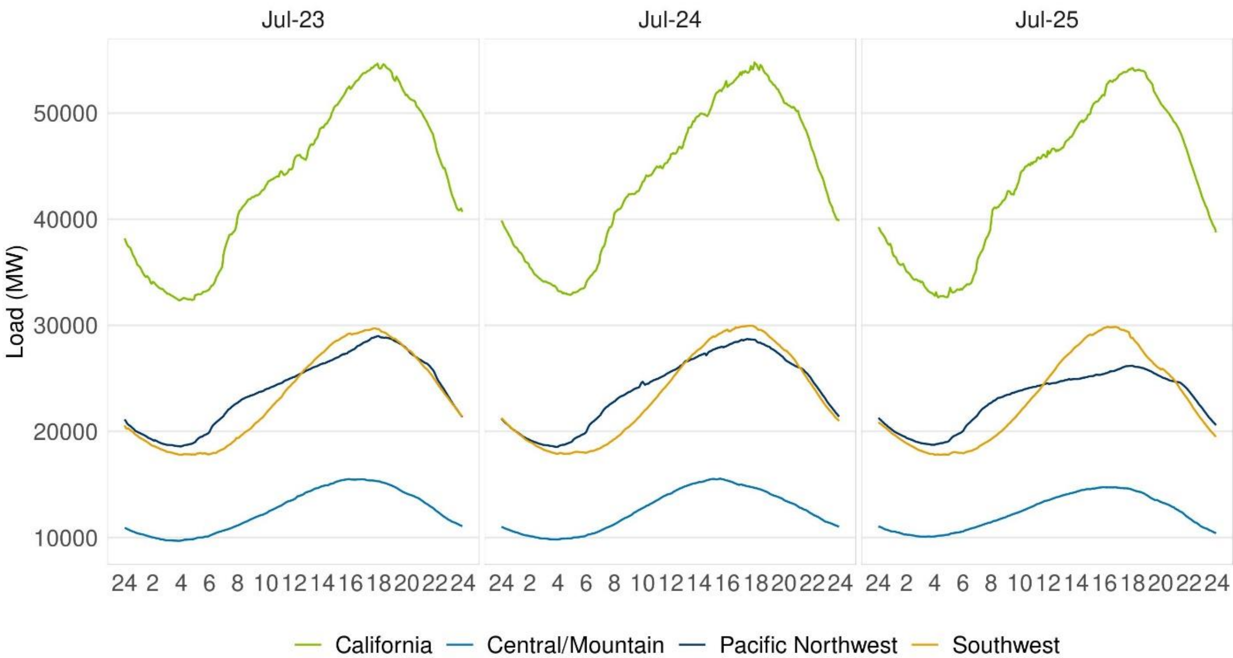


Figure 70 shows the hourly profile of actual load for the WEIM regions for July 23 – 25, 2024. ISO region peaked later in the day relative to other regions, while the central area tended to peak earlier in the day.

[16] These regions are only for display purposes of the regional dynamics. The WEIM market clears supply and demand for each individual balancing area.

Figure 70: Hourly load profile across WEIM regions for July 23 - 25, 2024



WEIM transfers

The Western Energy Imbalance Market, or WEIM, provides an opportunity for participating balancing authority areas to serve their load while realizing the benefits of increased resource diversity. The ISO estimates WEIM's gross economic benefits on a quarterly basis.[17] One main benefit of the WEIM is the realized economic transfers among areas. These transfers are the realization of a least-cost dispatch by reducing more expensive generation in one area and replacing it with cheaper generation from other area. In a given interval, import and export transfers can concurrently happen for one area. In July, the ISO did not apply any transfer limits to dynamic transfers.

Figure 71 shows the distribution of five-minute WEIM transfers for the ISO area. A negative value represents an import into the ISO from other WEIM entities. In July the majority of the transfers were exports from ISO area to other areas in the WEIM. This further added to the dynamic of hourly exports cleared in the ISO market to support other areas in the west.

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

Figure 71: Daily distribution of WEIM transfers for ISO area in RTD

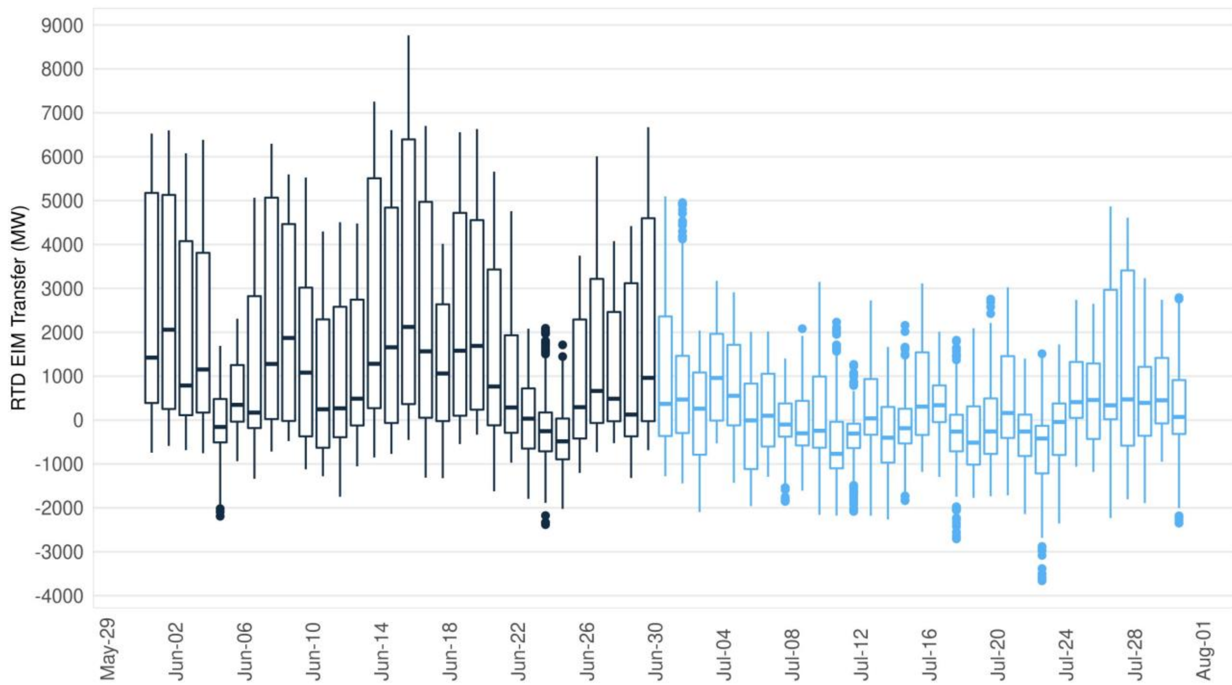


Figure 72: Hourly distribution of 5-minute WEIM transfers for ISO area

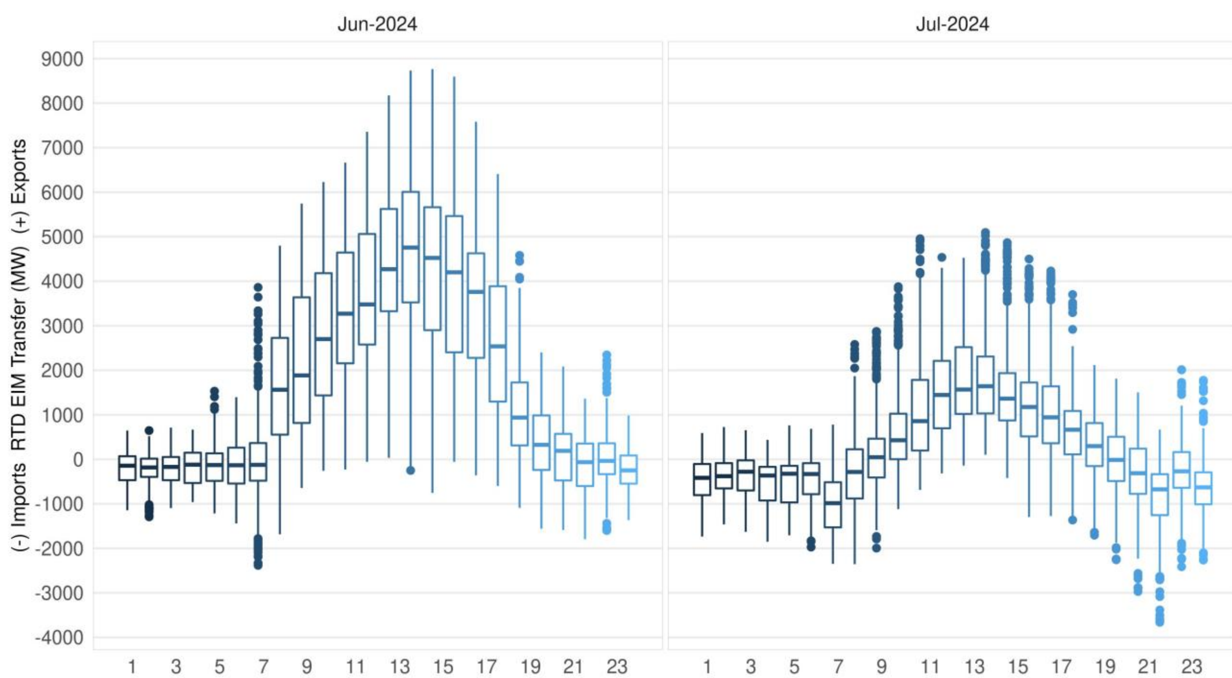


Figure 72 shows the WEIM transfers in an hourly distribution, which highlights the typical profile of the ISO transfers which are generally export transfers during periods of solar production. During the evening ramp as the evening peak approaches, the transfers become a net import to the ISO area. This trend is typical across summer months.

Figure 73: Hourly distribution of 5-min ISO WEIM transfers for July 23 - 25, 2024

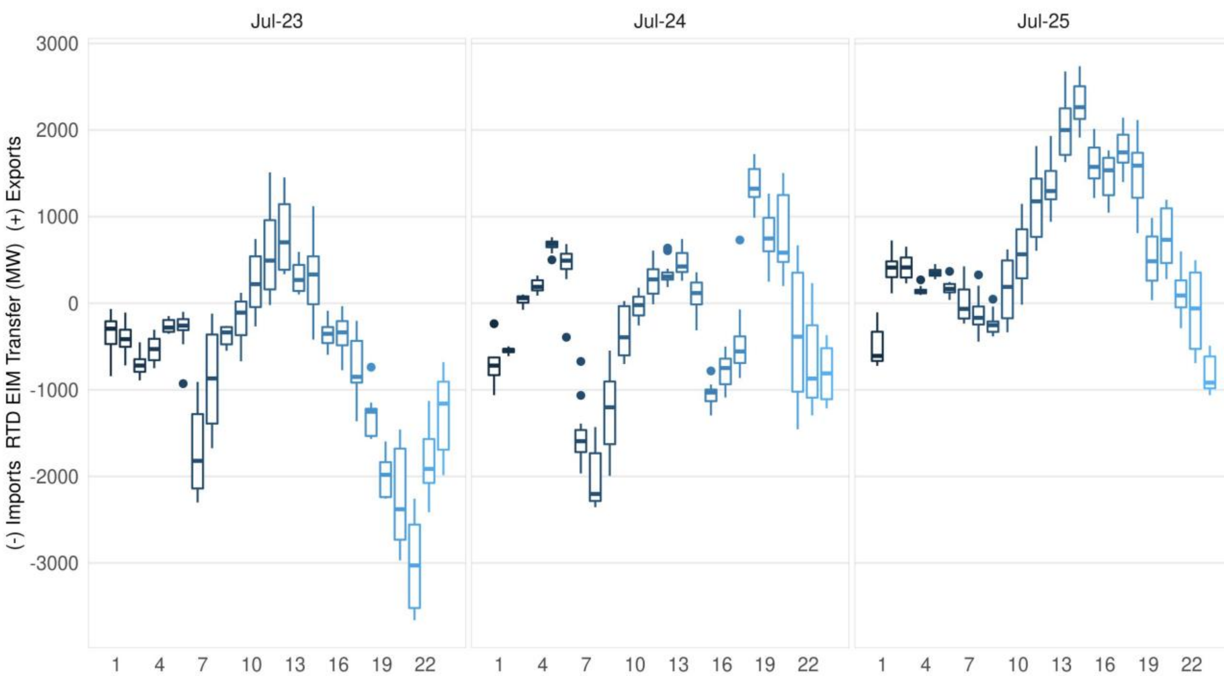


Figure 74: Daily distribution of 5-min WEIM transfers across regions

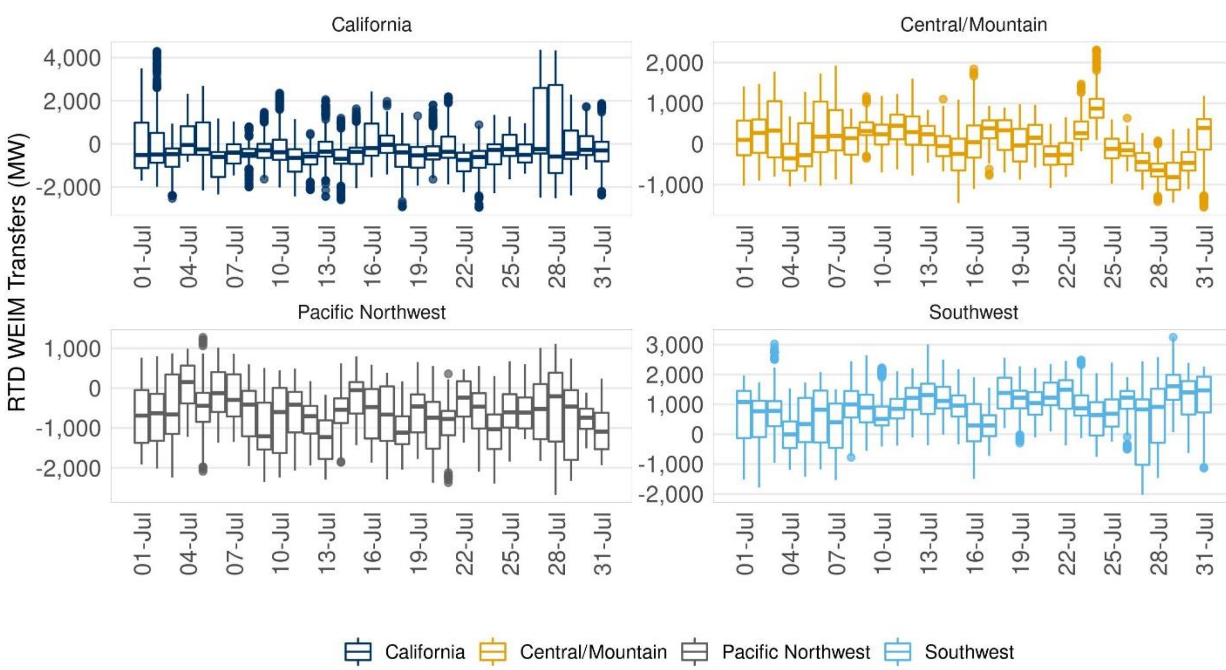


Figure 75: Hourly distribution of 5-min WEIM transfers across regions for July 23 – 25, 2024

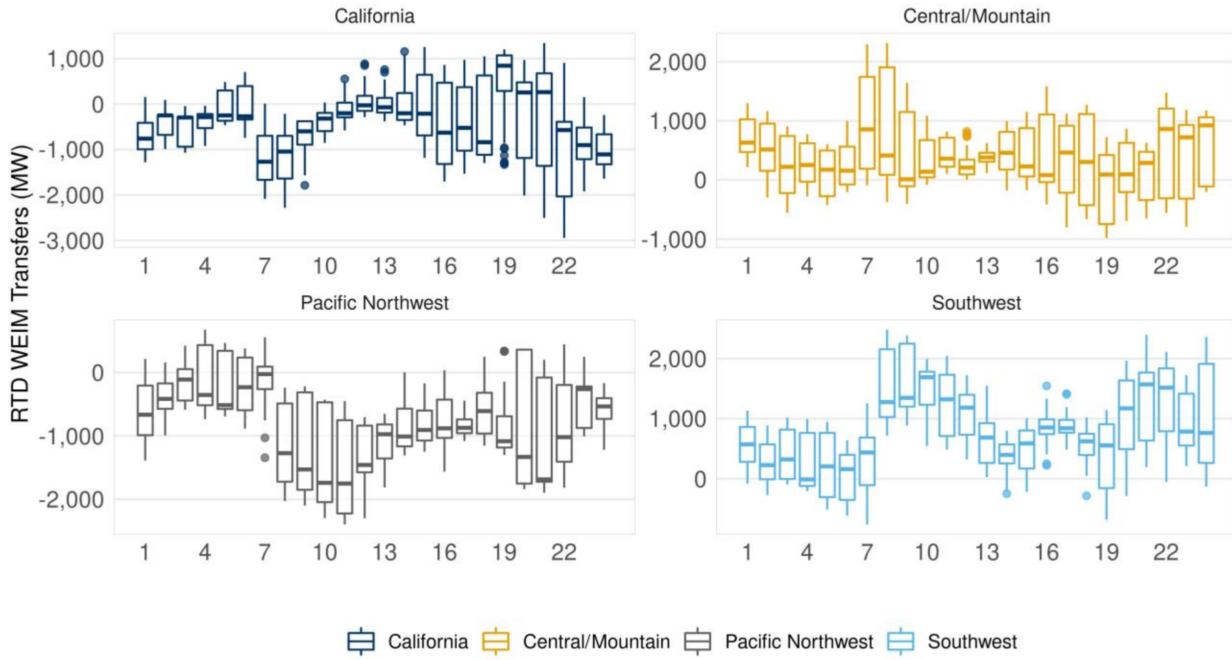
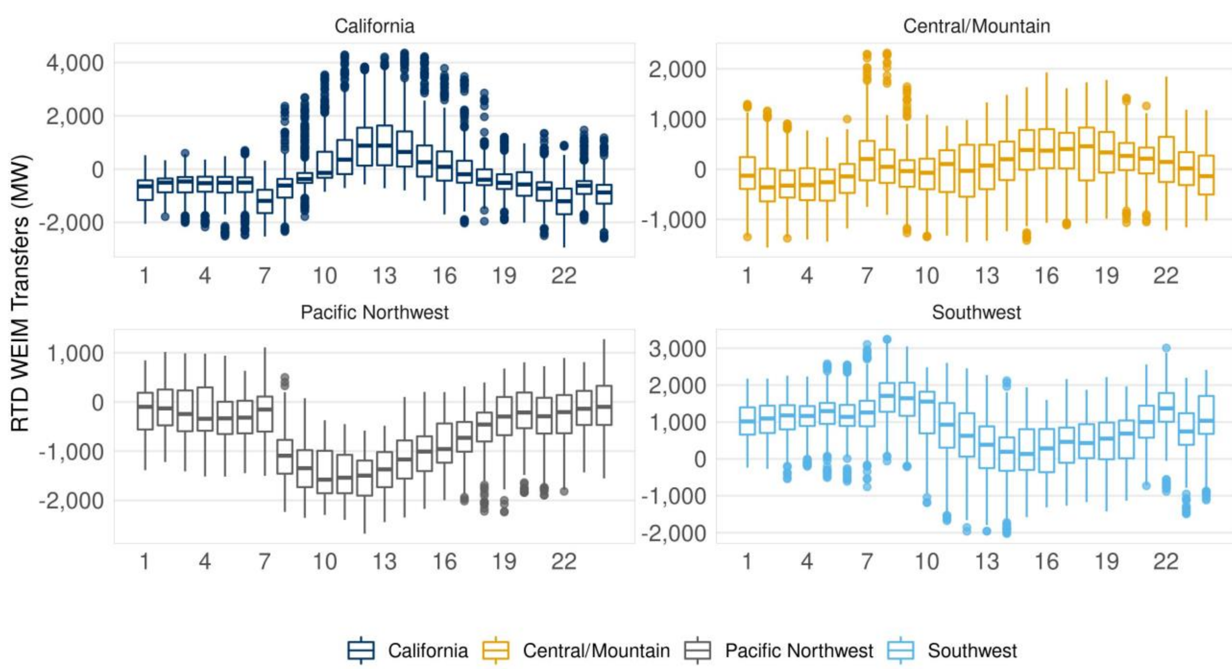


Figure 76: Hourly distribution of 5-min WEIM transfers across regions for the month of July 2024



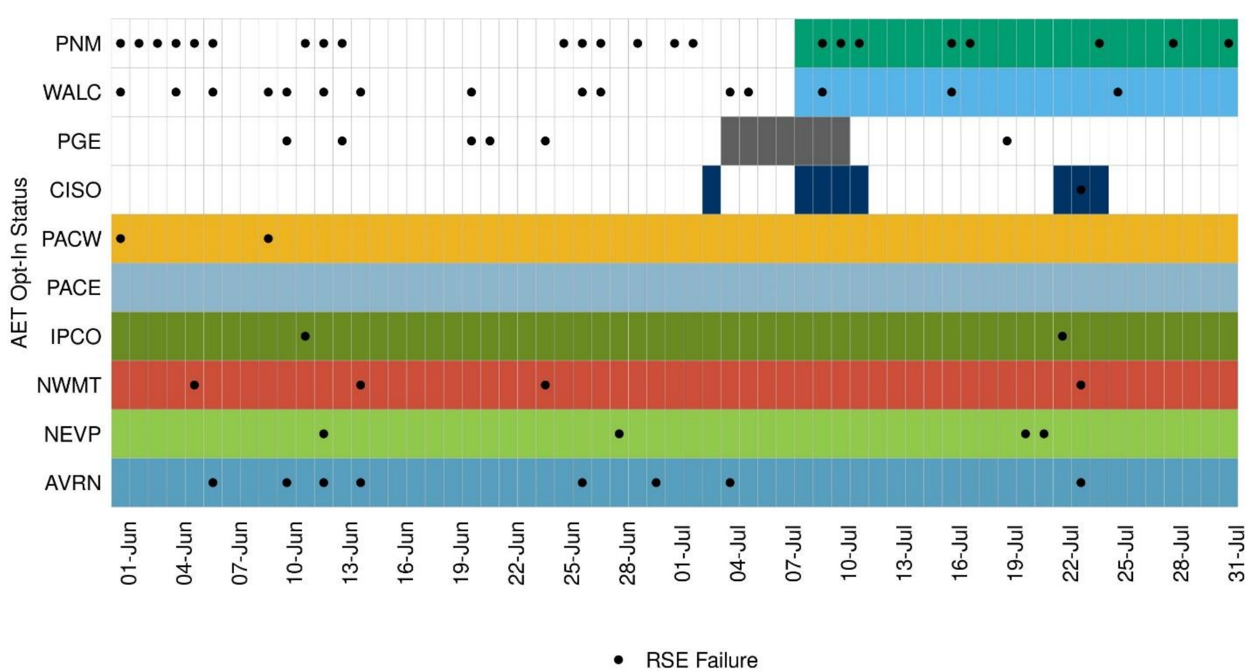
Assistance Energy Transfer

Assistance Energy Transfer (AET) was implemented with the Resource Sufficiency Evaluation Enhancements Phase 2, Track 1, effort which went live on July 1, 2023. The purpose of AET is to leverage the WEIM for energy assistance during under-supply conditions by optionally allowing incremental transfers at pre-set financial consequence following the failure of the WEIM Resource Sufficiency Evaluation (RSE). Assistance energy transfers are sourced from supply offers that are made voluntarily into the WEIM. Each WEIM BAA may voluntarily opt in to utilize assistance energy by notifying the ISO five business days in advance for a forward requested timeframe.

When a BAA that is not opted into AET fails the RSE, under current market rules, the market limits its WEIM energy transfers to the greater of the transfer amount from the last passed run's interval or the base scheduled transfer amount. If a BAA is opted into AET and fails the RSE in the upward direction, the BAA will still be allowed to receive WEIM energy transfers and pay an after-the-fact surcharge that is calculated based on the applicable energy bid cap of $1,000/MWh or $2,000/MWh. The surcharge is only applied to net-import WEIM BAAs and is limited to the lower of the quantity of the upward RSE insufficiency amount or the tagged dynamic transfers.

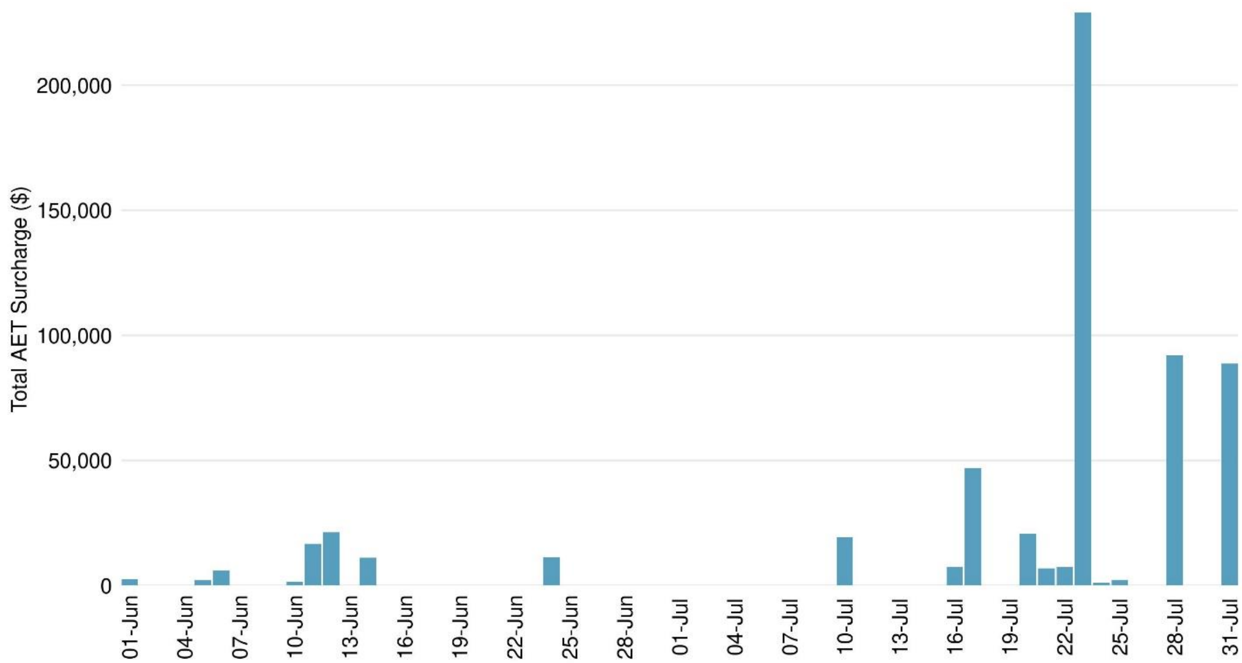
In July 2024, ten WEIM BAAs opted into AET for some duration of the month. shows six BAA entities that opted in for each trade date during June 2024 and July 2024 with a shaded box indicating opt-in status for that date, whereas four BAA entities opted-in some days on July 2024 The black dots indicate instances where the BAAs failed the RSE, specifically the upward capacity test and/or the upward flexible ramping test. The ISO BAA opt-in for eight days and failed the RSE on July 23rd.

Figure 77: BAAs opted into Assistance Energy Transfers, June and July 2024



The total AET surcharges assessed in July were approximately $521,904 for all the BAAs that opted in. shows the breakdown of total AET surcharges assessed per day for July 2024. By design, AET is only assessed for WEIM BAAs that fail the RSE and opt in ahead of time. Thus, the AET surcharge was only assessed for a total of eleven trading days in July.

Figure 78: Total daily AET surcharge assessed, June and July 2024



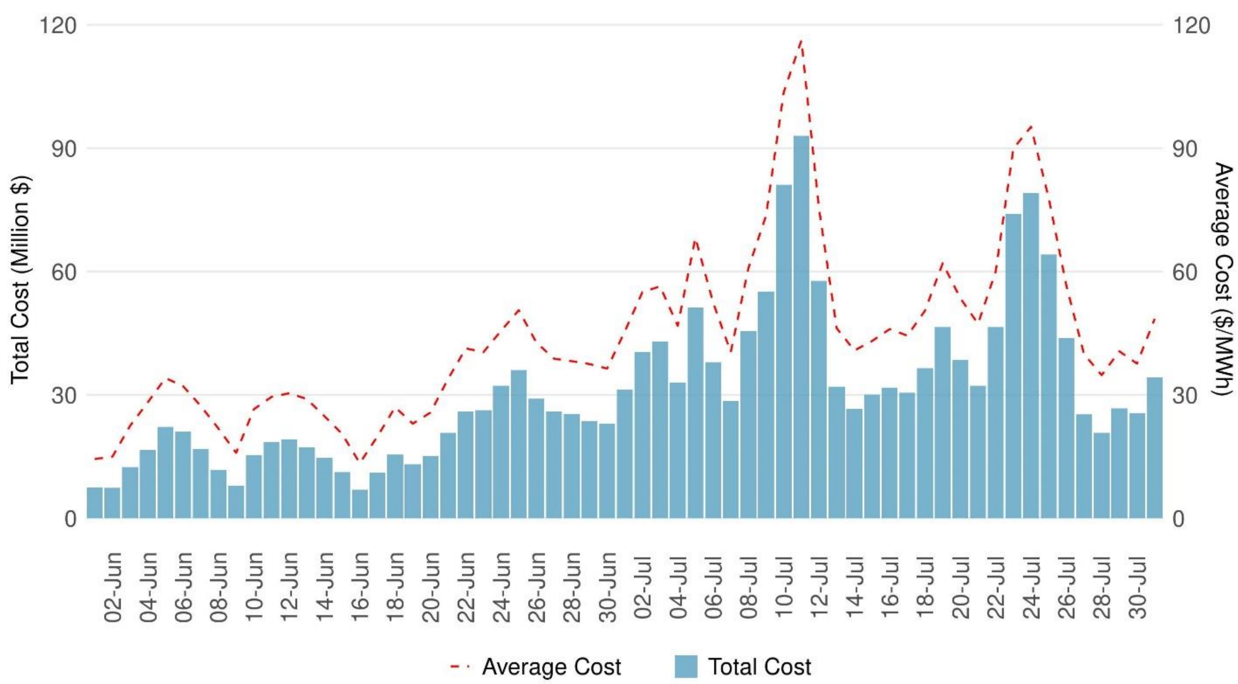
8 Market Costs

The ISO 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 79 shows the daily overall settlements costs for the ISO balancing area; this does not include WEIM settlements. As demand and prices rise, the overall settlements are expected to increase. 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. The average daily cost in July was $43.30 million, representing an average daily price of $58.35/MWh. The maximum daily cost of $93.05 million occurred on July 11. [18]

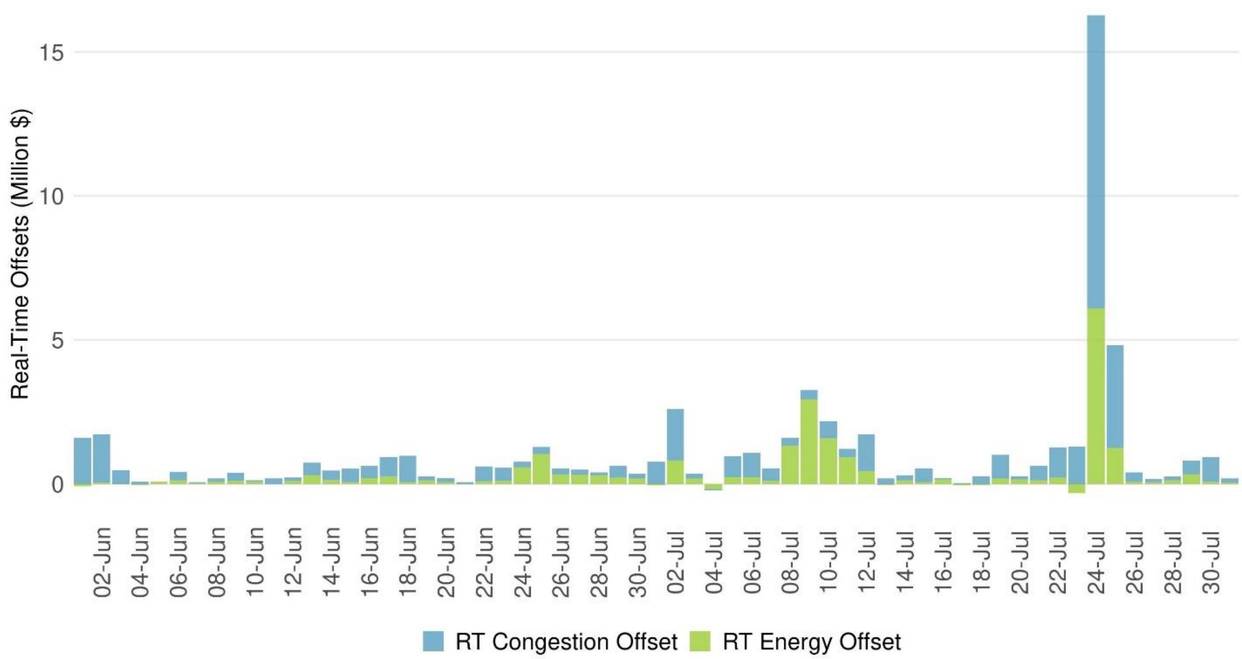
Two components of this overall cost are the real-time energy and congestion offsets. These costs reflect the settlements of differences between the day ahead and real-time markets for energy and congestion. These costs typically track system conditions. The daily trend is shown below in Figure 80.

Figure 79: ISO's daily total and average market costs



[18] These estimates are based on preliminary settlements data, which are subject to changes in subsequent settlements updates.

Figure 80: Real-time energy and congestion offsets for ISO area



9 Import market incentives during tight system conditions

On June, 15, 2021, the ISO implemented an enhancement that 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 the ISO has issued an alert by 3 PM PST or a warning or emergency notice), the ISO will provide bid cost make-whole payments for real-time hourly block economic imports rather than simply settling the imports at the FMM price. This feature was implemented as part of summer readiness in 2021.

This feature was not triggered in July 2024.

10 Exceptional Dispatch for Storage resources

Exceptional Dispatch (ED) refers generally to a subset of manual commitment or dispatch instructions that are not determined as a result of the market software in the IFM, RUC, FMM or RTM. ISO operators can issue ED through the ISO's Automated Dispatch System (ADS) or direct communication with the Scheduling Coordinator (SC) and, at times, direct communication with the resource operator. There are several categories of ED, all of which are summarized in Business Practice Manual (Attachment K). As part of the Energy Storage Enhancements, a new functionality was introduced that will allow storage resources to hold a certain state of charge (MWh), in addition to the traditional (MW) exceptional dispatch. This functionality will allow for dispatch of storage resources to charge to and hold a specific level of state of charge for a specific duration of time in the real-time market. In July 2024, there was no ED to hold or charge SOC to any energy storage resources.

11 Strategic Reliability Reserves and Non-Market Demand Response

As detailed in Operating procedure 4420, the ISO may access additional supply that is part of California's Strategic Reliability Reserve program. As the heat wave developed in early July, the ISO projected heightened electricity demands across much of California and the West on July 10 and July 11. In light of these ongoing high temperatures across much of California, persisting heat potentially overtaxing generators running at high outputs for long periods of time, active wildfires in many areas of the state posing potential threats to grid infrastructure, and West-wide heat potentially limiting access to imported energy, the ISO instructed long-start strategic reserve (LS-SRR) resources to start up and remain on standby at minimum operating levels to be ready to help manage demand conditions starting July 11. On July 10 and 11, as projections of grid conditions improved, the ISO did not require LS-SRR dispatch above minimum operating levels for reliability. Additionally, the ISO forecasted temperatures and demands across California and the West to subside in forward days. As such, the ISO instructed the LS-SRR fleet to shut down by the end of July 11.

Throughout the July heat events, the ISO also received support from out of market demand response programs including the California Energy Commission (CEC) Demand Side Grid Support (DSGS) program and the CPUC Emergency Load Reduction Program (ELRP) . DSGS Option 3 triggered when ISO day-ahead DLAP prices exceeded $200/MWh, and subsets of DSGS and ELRP triggered when the ISO called an EEA Watch on July 24. The ISO plans to coordinate with the CEC and CPUC later this year to understand actual load reduction impacts from these programs.

12 Areas for Improvement

Through the analysis of the market outcomes and performance, the ISO tracks any areas for improvements. There were three issues identified in July

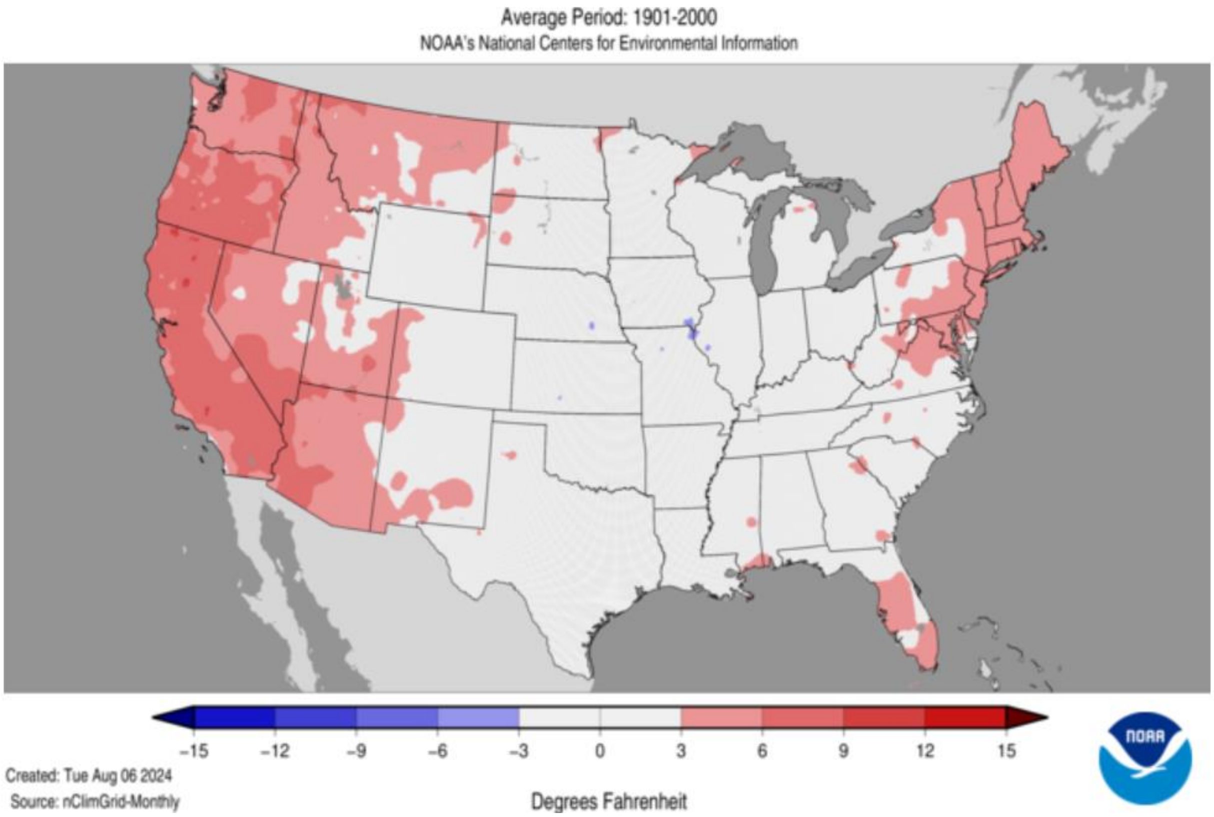
1. Incorrect triggering of RUC infeasibility. On July 4, the RUC process triggered undersupply infeasibility without any prior reduction of low-priority exports. Based on existing priorities and under tight supply conditions, the RUC process will first reduce economic exports followed by low-priority exports before reducing high-priority export or relaxing the power balance constraint. Due to a misprocessing of certain low-priority exports in the RUC market, they were not reduced and instead the market trigger undersupply infeasibility. This issue was fixed on July 5, 2024.

2. Incorrect reporting of exports reductions in the customer portal (CMRI). For results of trading date July 8, the CMRI display incorrectly reported certain exports to be awarded the full bid-in capacity, even though the market had reduced them partially. This was a reporting issue and was fixed on July 9.

3. Incorrect loss of high priority to certain exports. Based on the specific combination of self-schedules submitted in either the day-head market or/and the real-time market, different bid validation rules triggered and resulted in an unintended loss of high-priority for certain exports, defaulting these exports to be treated as low priority. Consequently, the market reduced these exports when experiencing tight supply conditions such as in instances experienced on July 24. ISO is currently assessing an enhancement to the bid validation rules that are triggered under concurrent between day-ahead and real-time markets and will provide a target date for resolution in subsequent reports.

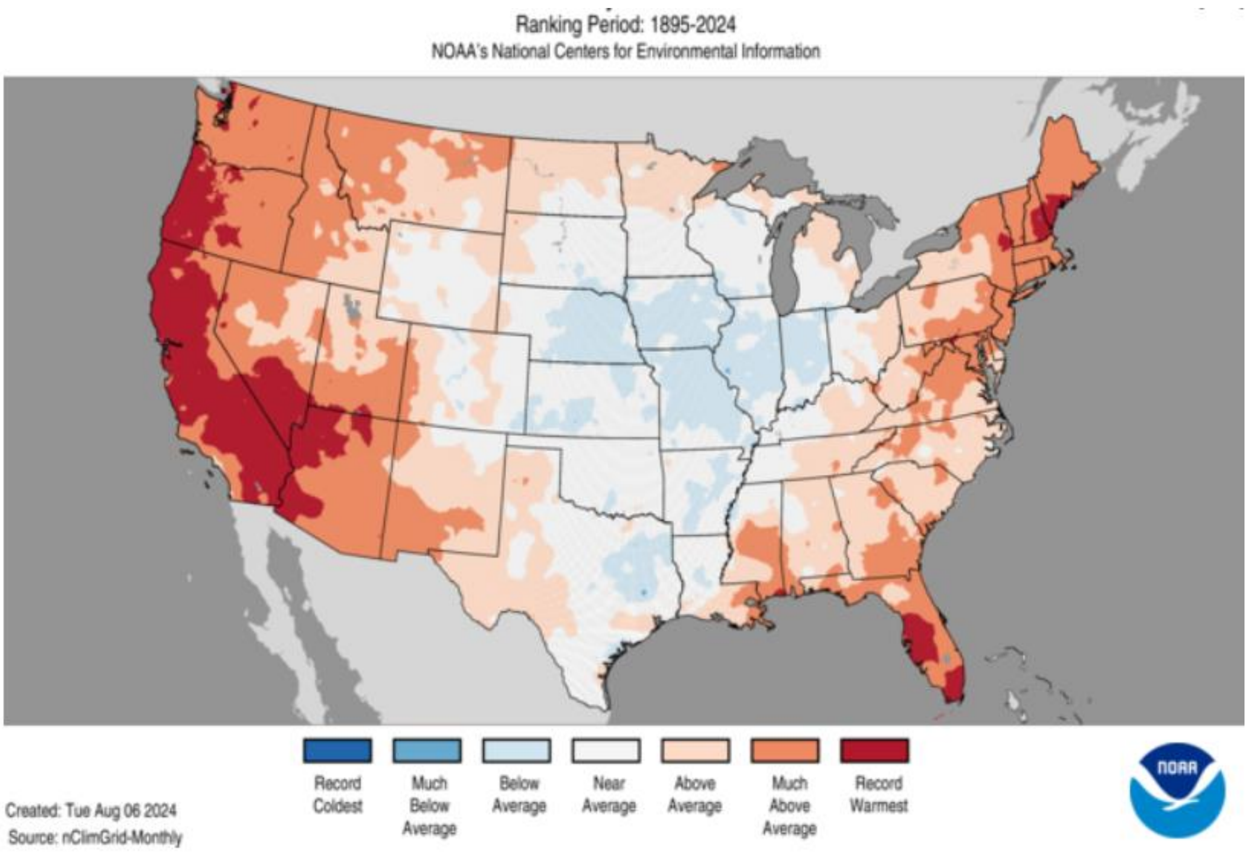
Appendix

Figure 81: July 2024 Mean temperature departures from average



Source: [Assessing the U.S. Climate in July 2024 | News | National Centers for Environmental Information (NCEI) (noaa.gov)]

Figure 82: Mean temperature percentiles



Source: [U.S. Maps | National Centers for Environmental Information (NCEI) (noaa.gov)]()

Figure 83: Historical load profiles for ISO area