California ISO

Summer Market Performance Report
August 2024

September 30, 2024

Prepared by
Market Performance and Advanced Analytics

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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]

Market and system conditions in August were generally uneventful and the grid operated well.

ISO supply was more than sufficient to meet forecast demand in August. The market and system operated well while ensuring demand was met. The major highlights for the month are:

Average peak ISO loads in August 2024 were moderate at 38,015 MW, which was lower than the average daily peak loads in July 2024 of 39,772 MW. The highest instantaneous peak load in August was 43,461 MW on August 6, which was below the California Energy Commission's (CEC) month-ahead forecast of 46,212 MW. Similarly loads in the different regions of the western energy imbalance market were moderate and their peaks lower than the ones observed in July.

Monthly resource adequacy capacity was 52,836 MW, more than enough to meet load, inclusive of demand, operating reserves, and supply and demand uncertainties. This is higher than the 51,685 MW of resource adequacy capacity of August 2023. Compared to August 2023, RA capacity for storage resources increased by 3,454 MW while static imports increased by 923 MW. Hydro and gas resources saw a decrease of 374 MW and 3,690 MW, respectively.

The ISO's average prices in August were $40/MWh and $33/MWh for the day-ahead and real-time dispatch (RTD) markets, respectively, down from $50/MWh and $43/MWh in July. The daily prices saw a decreasing trend through August reaching maximum levels on August 5, 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. The average next-day bilateral prices for Mid-C and Palo-Verde hubs were about $40/MWh and $61/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 August. There were low-priority export reductions in the RUC during August 1 - 7 to balance supply with demand.

[1] This report is targeted in providing timely information regarding the ISO's market's performance for the month of August. 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.

Capacity offered to the ISO market by storage resources continues to increase. In August 2024, there were 166 batteries registered in the ISO markets. The bid-in capacity for energy was consistently over 7,000 MW in August. The maximum state of charge in real time was about 32,649 MWh, and real-time dispatches reached a maximum of 7,853 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 3,831 MW for peak hours 17 through 21 in August. This low level was due to lower imports and increasing demand for exports. The ISO market was able to accommodate and clear over 9,000 MW of exports on August 2 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 675 MW of the 735 MW of registered high-priority wheel-through transactions for the month of August participated in the day-ahead market. This represents a 92 percent utilization of the registered wheels. For low priority wheels, the maximum transaction was 200 MW from the Palo Verde to Mirage locations and NOB to Mead locations. All high-priority wheels were honored in the markets in August.

Reliability demand response resources were dispatched at a maximum of 273 MW in the real-time market on August 20 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 August 5 at 163 MW, whereas in the real-time market, there was a maximum of 88 MW on August 6. There were no emergency events to trigger dispatch of reliability demand response resources.

On average, the ISO's daily average market costs were $30.97 million in August, representing an average daily cost of $43.79/MWh, about $15/MWh lower than $58.35/MWh in July. The highest daily cost accrued on August 5 at about $70 million. These higher costs are expected in summer conditions with higher demand levels settled at higher energy prices.

Effective August 1, the ISO implemented an enhancement to the bid offer rules, allowing storage and hydro resources to bid above the soft offer cap of $1000/MWh. The enhancement has been working as intended and, given the market conditions, no instances of bids above $1,000/MWh cleared in August.

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 August 2024 was 52,836 MW, which is higher than August 2023's monthly showing of 51,685 MW.[4] Figure 1 compares the total monthly RA capacity by fuel type in August 2023 and August 2024. In general, total RA capacity increased across fuel types from year to year with some exceptions. For August 2024, RA capacity for storage resources increased by 4,743 MW to about 8,197 MW, and static imports increased by 923 MW. Hydro RA decreased by 374 MW and gas-fired RA decreased by 3,690MW.

Static RA imports increased from 2,537MW in August 2023 to 3,460 in August 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 1,043 MW to about 1,327 MW from August 2023 to August 2024, and imports through Nevada-Oregon Border (NOB) intertie increased from 740 MW to about 1,088 MW across the same timeframe. Monthly RA capacity tends to increase as the summer progresses and was generally

[3] The planning reserve margin is 17 percent for the CPUC jurisdictional entities in 2024. 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.

on par 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 Figure 3 and Figure 4.

Figure 1: RA capacity organized by fuel type

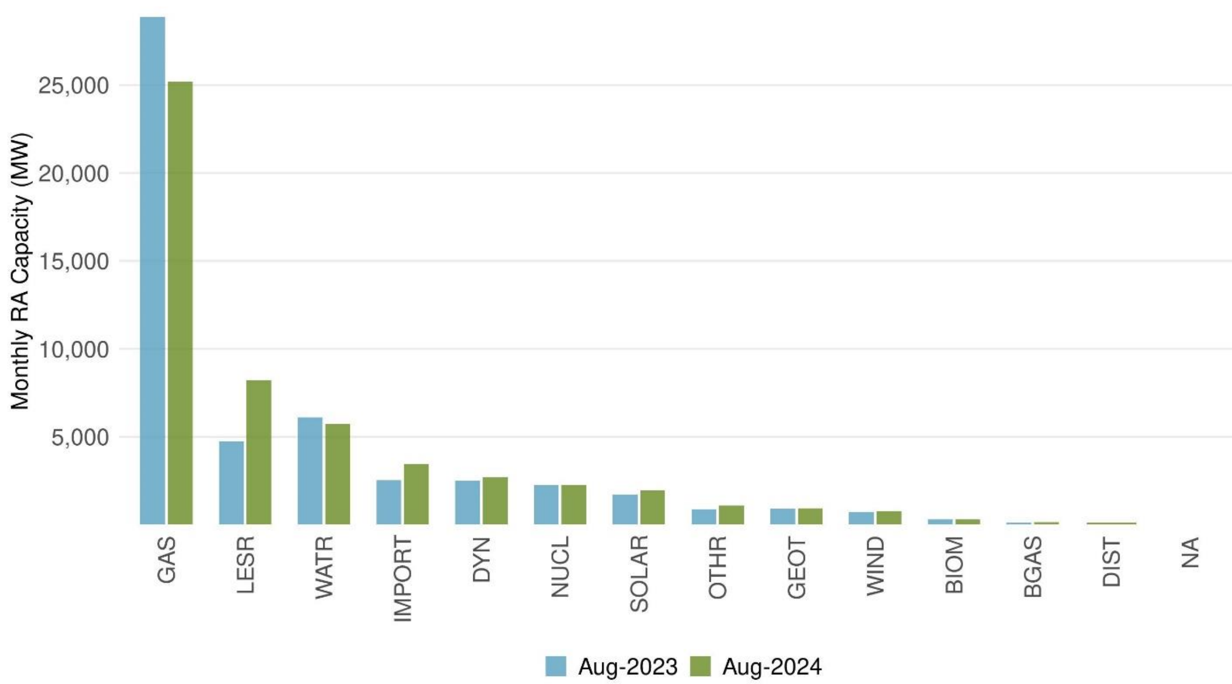


Figure 2: Monthly RA imports organized by tie

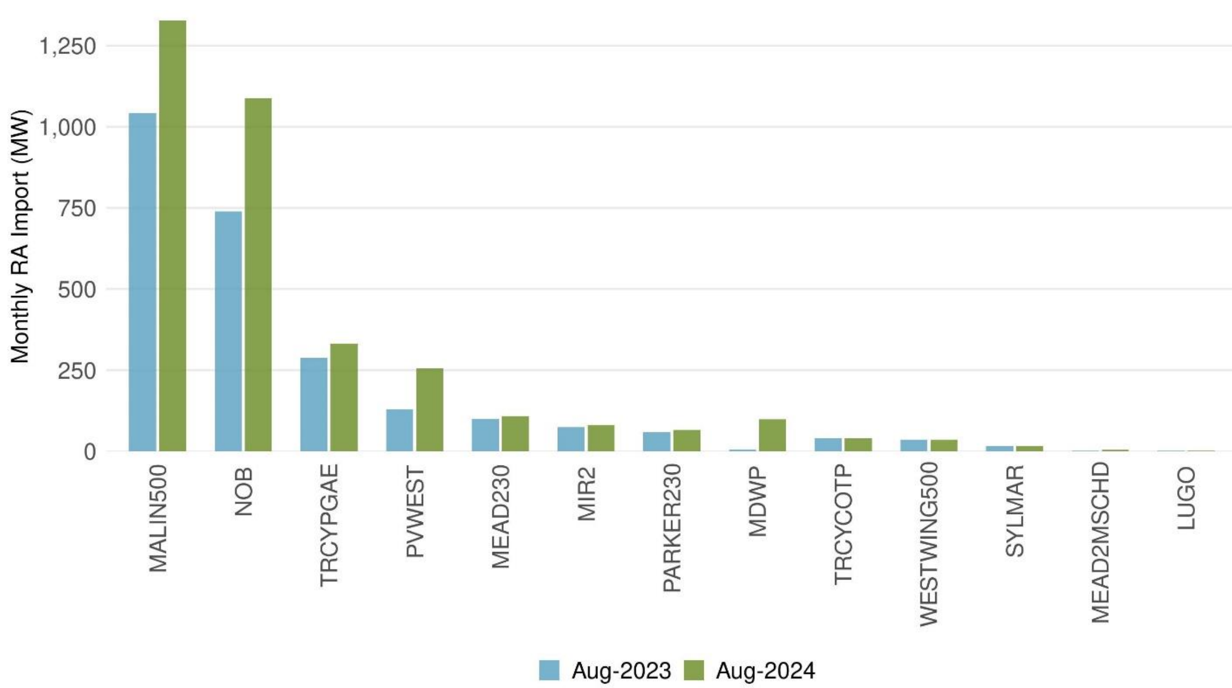


Figure 3: Monthly RA showings

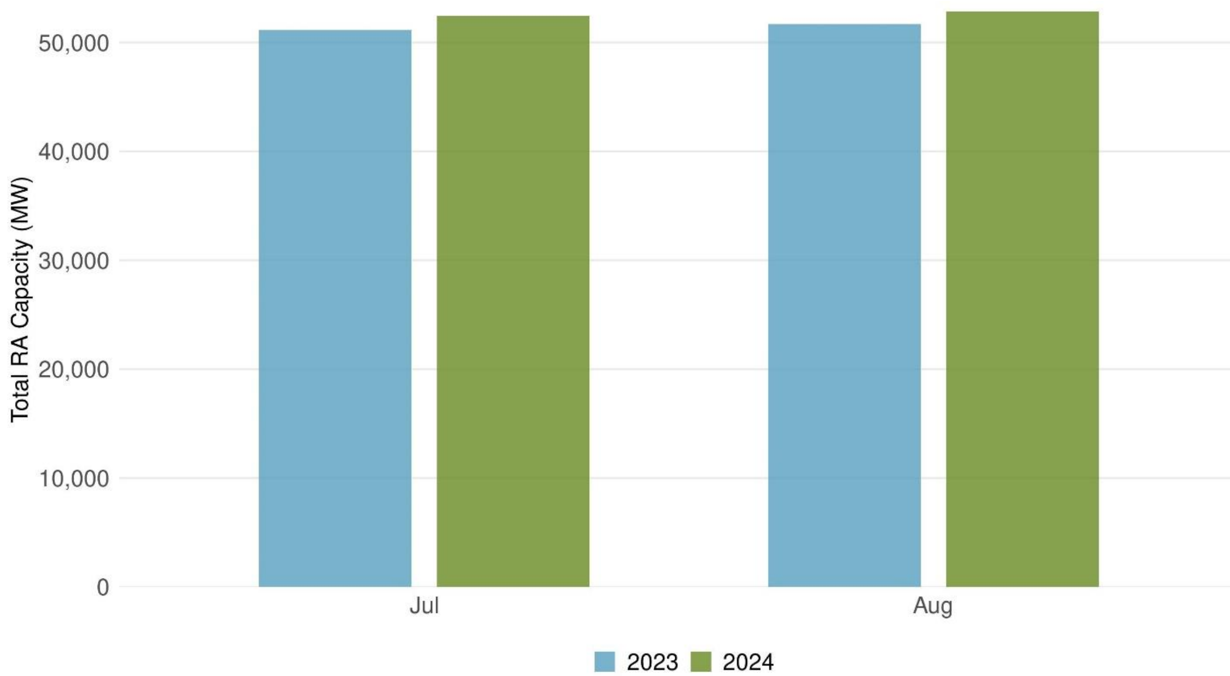
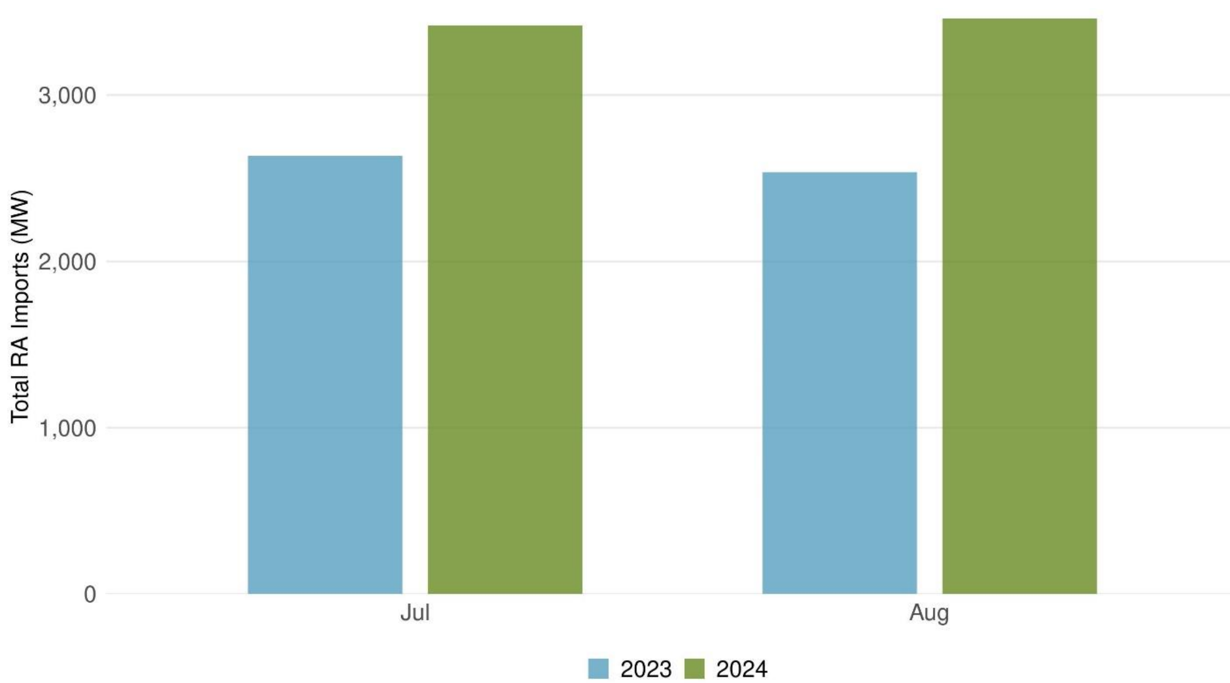


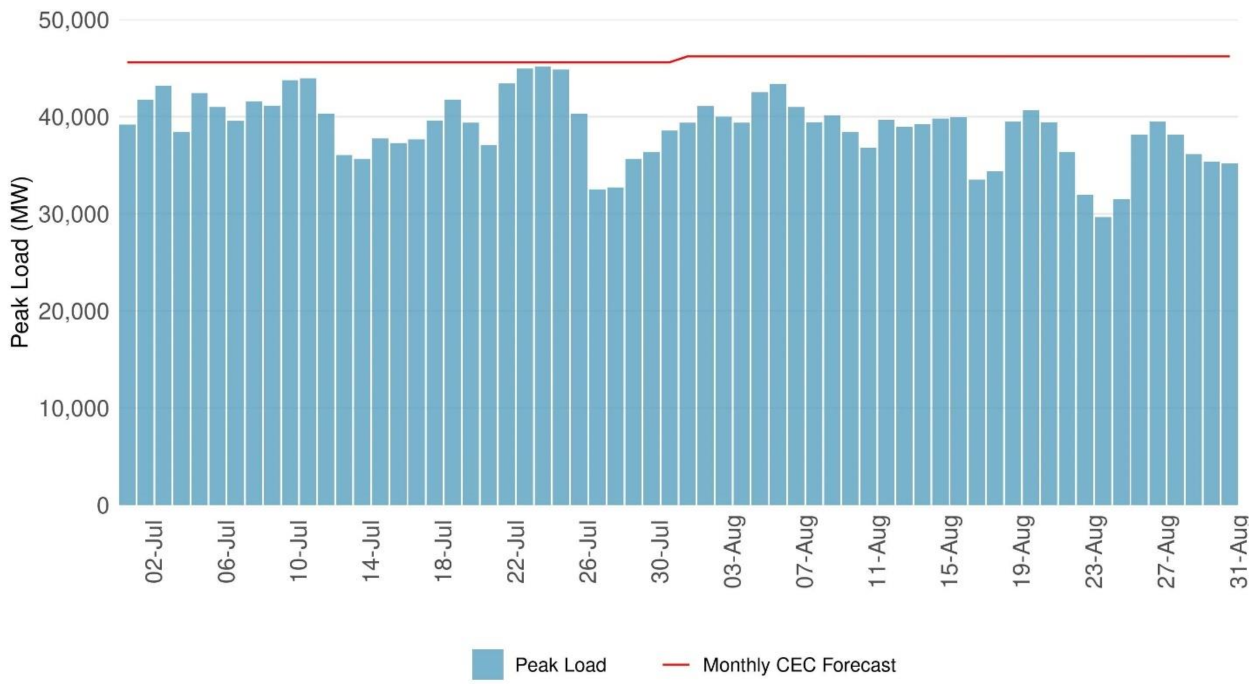
Figure 4: Monthly trend of static RA Imports



Peak ISO loads

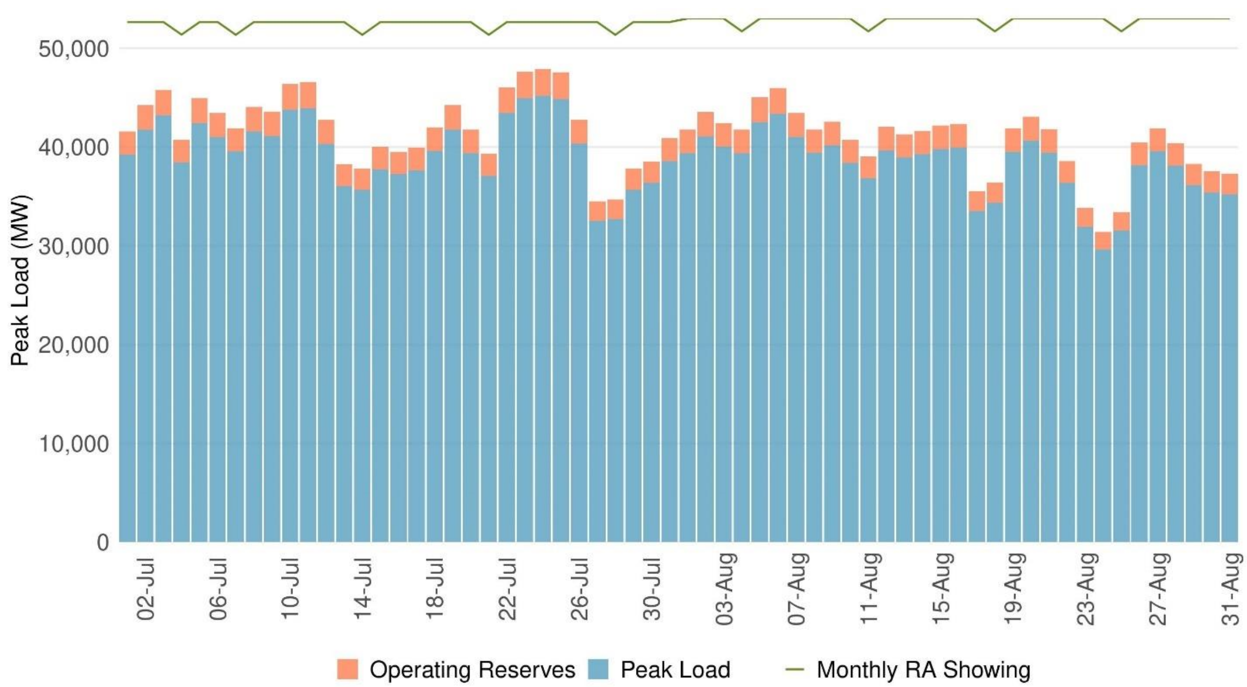
Peak loads in August 2024 were depressed from the previous month, only exceeding 40,000 MW on six days of the month. The average daily peak load in August was 38,015 MW which was higher than the average daily peak load from the previous year in August 2023 of 37,819 MW. Figure 5 shows the 5-minute average daily load for July and August relative to the CEC month-ahead forecast used to assess the resource adequacy requirements. The highest five-minute average peak load for the month of August was 43,358 MW. The instantaneous load peak in August was 43,461 MW on August 6. This peak was below the CEC month-ahead forecast of 46,212 MW. Figure 5 is based on the five minute average of the actual load.

Figure 5: Daily peak load and CEC month-ahead forecast



The actual load did not exceed the monthly RA showings in August 2024 as illustrated in Figure 6. 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 6: Daily peak load, operating reserves and RA capacity



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 component, 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 7 compares the daily average prices across ISO's markets for the months of July and August.[6] The daily average fifteen minute market prices reached $67/MWh on August 1 ($160 in July), the daily average day-ahead prices led at about $83/MWh on August 4 ($90 in July), while the five minute market prices reached a maximum of about $62/MWh on August 01 ($128 in July). In comparison with July, the August maximum for IFM occurs 3 days after RTD and FMM instead of same day. Figure 8 shows average hourly prices across ISO's markets for both July and August 2024. FMM and RTD prices reached a maximum on trade dates August 1 and August 20, with values of $662 and $518, respectively, while IFM reached a maximum of $429 on trade date August 5. For the hourly average prices, the integrated forward market and the fifteen-minute market peaked in trade hour 20 at $97/MWh ($146/MWh in July) and trade hour 19 at $63/MWh ($204/MWh in July), respectively, higher than the real-time dispatch market prices of about $45/MWh ($96/MWh in July) in trade hour 20.

[6] 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 7: Average daily prices across markets- July and August 2024

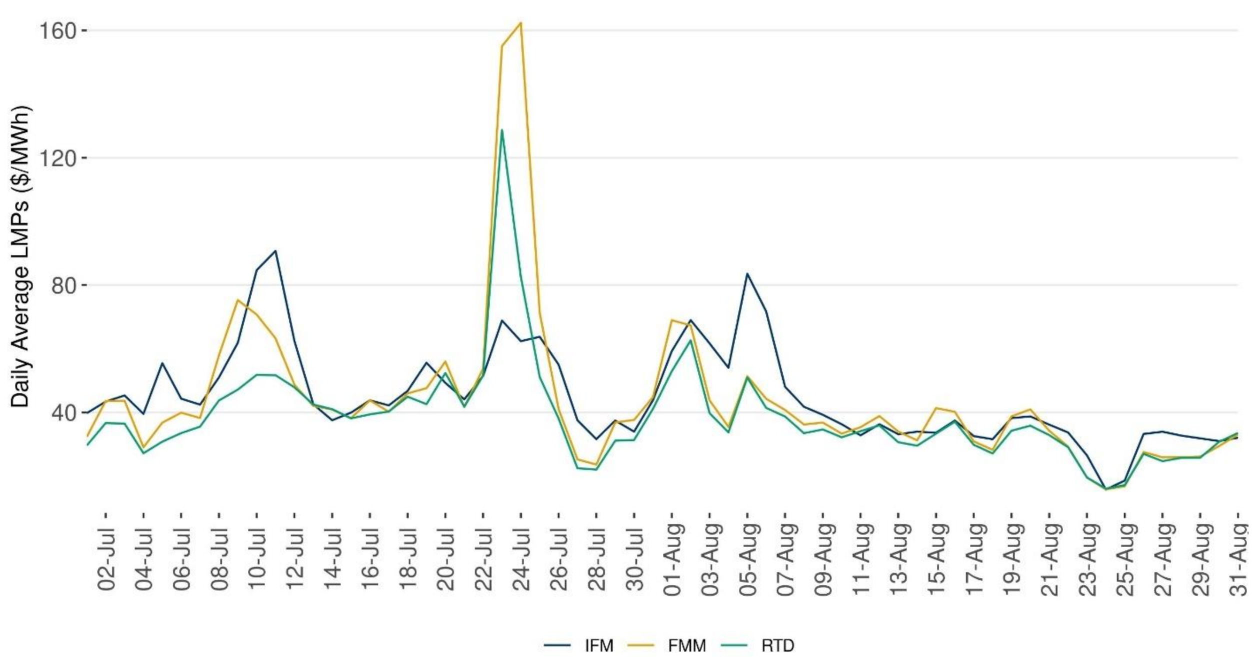
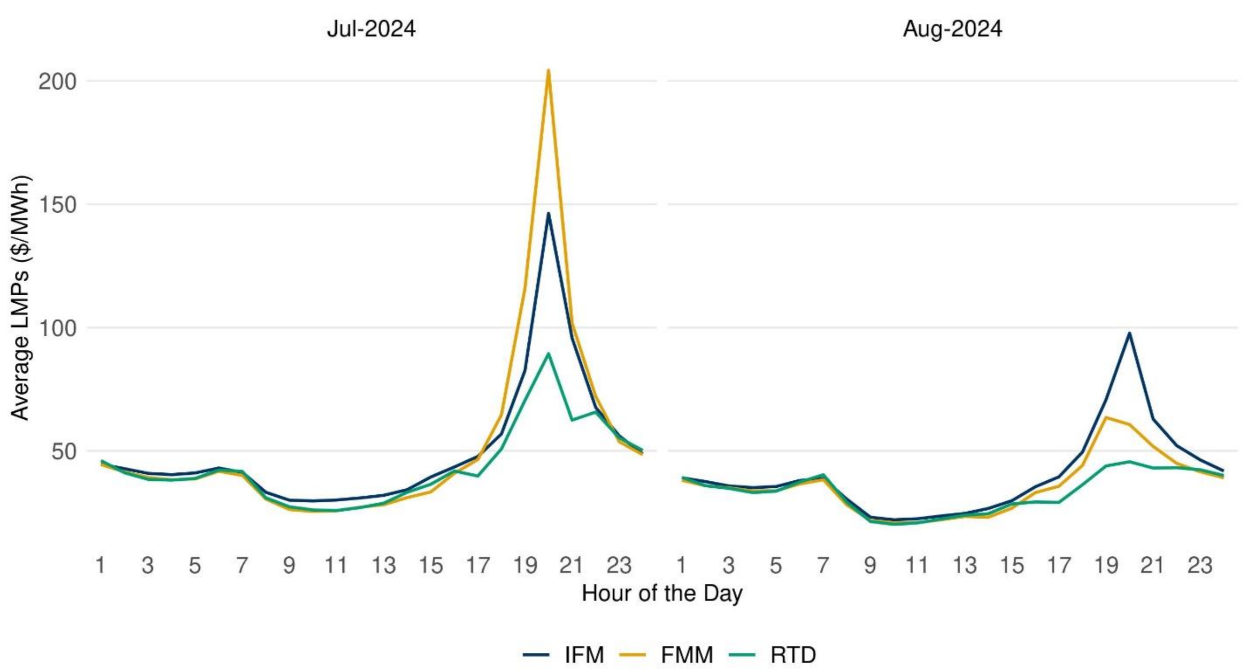
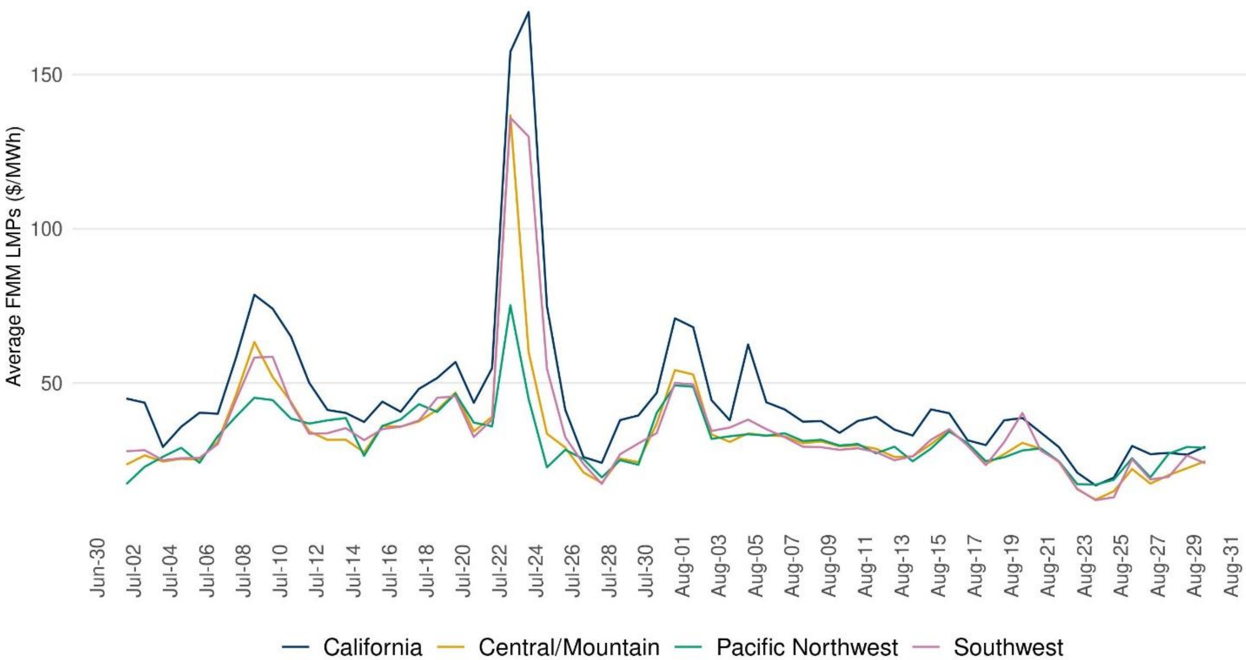


Figure 8: Average hourly prices across markets



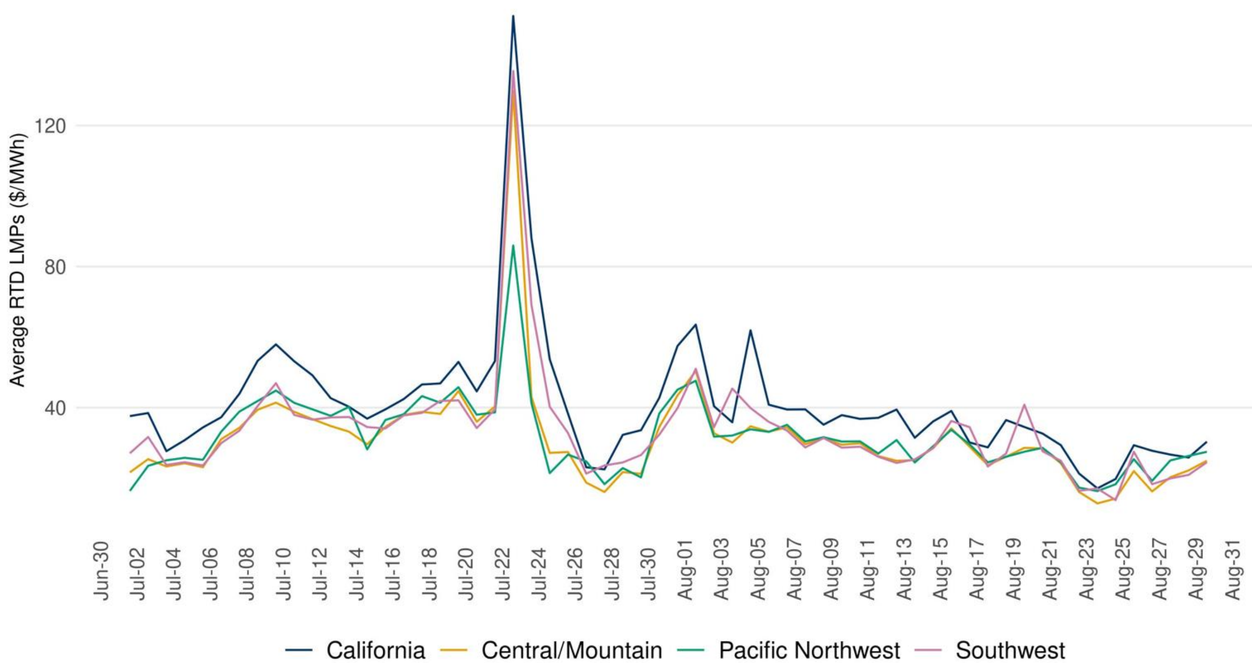
The following figure below shows daily average LMPs for all four regions in FMM for the months of July and August. In both months, for 5-minute real-time dispatch (RTD) and fifteen-minute market (FMM), the California region produced the highest average LMPs. It peaked on the 20th of August (RTD) and 1st of August (FMM). For the peak in July, the four regions all climb to peak around July 22nd to 24th. On July 23, the Pacific Northwest region peaks at about $75/MWh, while Central/Mountain and Southwest reach about $130/MWh. In August, the four regions average LMPs peak on August 1st. California area prices peaked, producing an average of approximately $75/MWh in FMM. For RTD, California peaked at approximately $60/MWh, also on the first of the month. The remaining three regions are clustered very closely when peaking, all around $50/MWh for both FMM and RTD[7].

Figure 9: Average daily prices across region for FMM market – July and August 2024



[7] 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 Tucson 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.

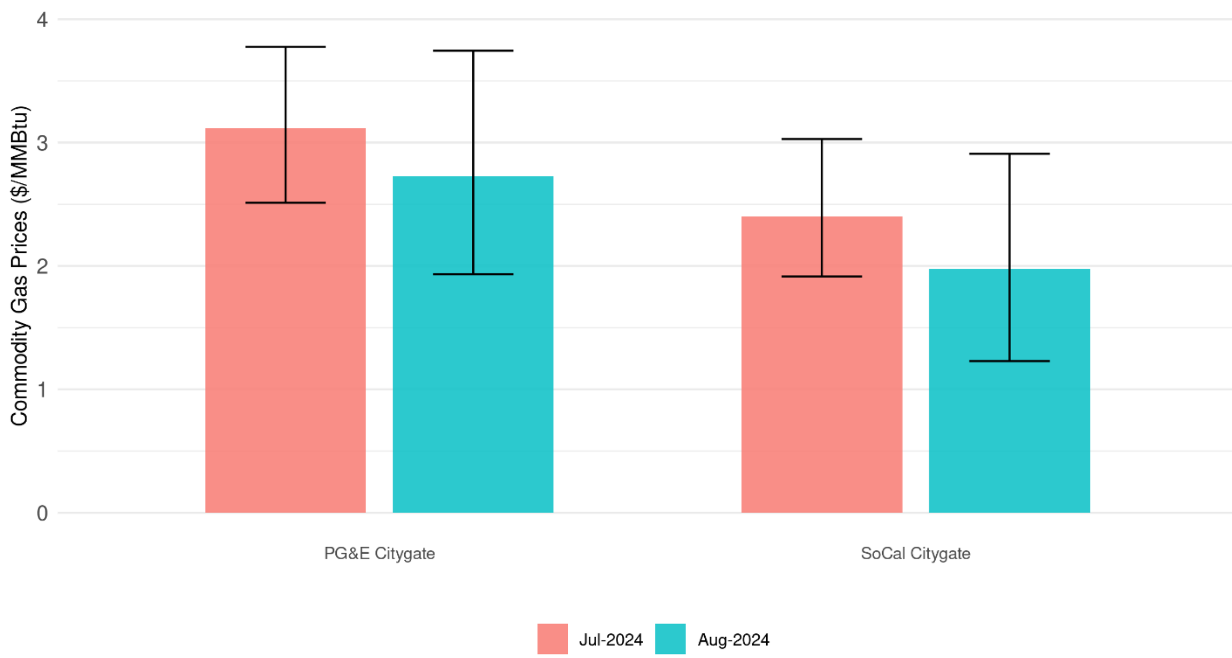
Figure 10: Average daily prices across region for RTD market - July and August 2024



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 11 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 August 2024, next-day gas prices averaged $2.73/MMBtu and $1.97/MMBtu for PG&E Citygate and SoCal Citygate, respectively. The maximum next-day gas prices were $3.74/MMBtu and $2.91/MMBtu for PG&E Citygate and SoCal Citygate, respectively. These are generally moderate gas prices.

Figure 11: 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.[8] 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 12 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 *13* 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 14 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 the bilateral prices. Once averaged, the day-ahead LMPs are generally lower or closer to the corresponding bilateral prices throughout the month.

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[8] 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.

Figure 12: Northern hub prices and PG&E IFM LMP (block average) for on-peak

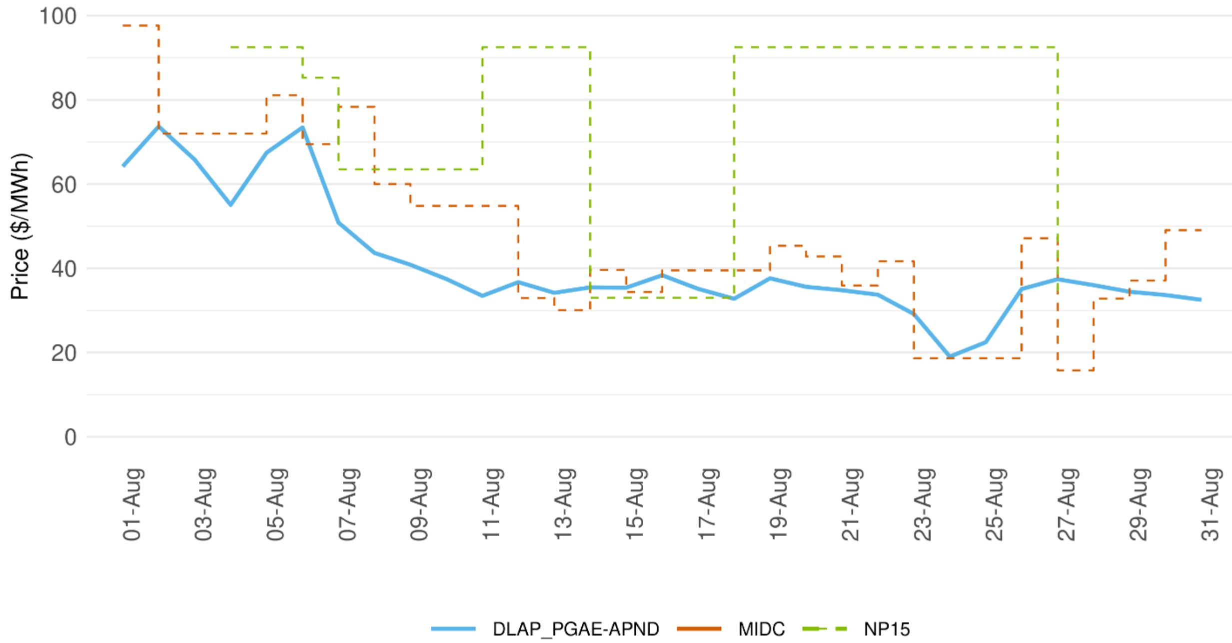


Figure 13: Southern hub prices and SCE IFM LMP (block average) for on-peak

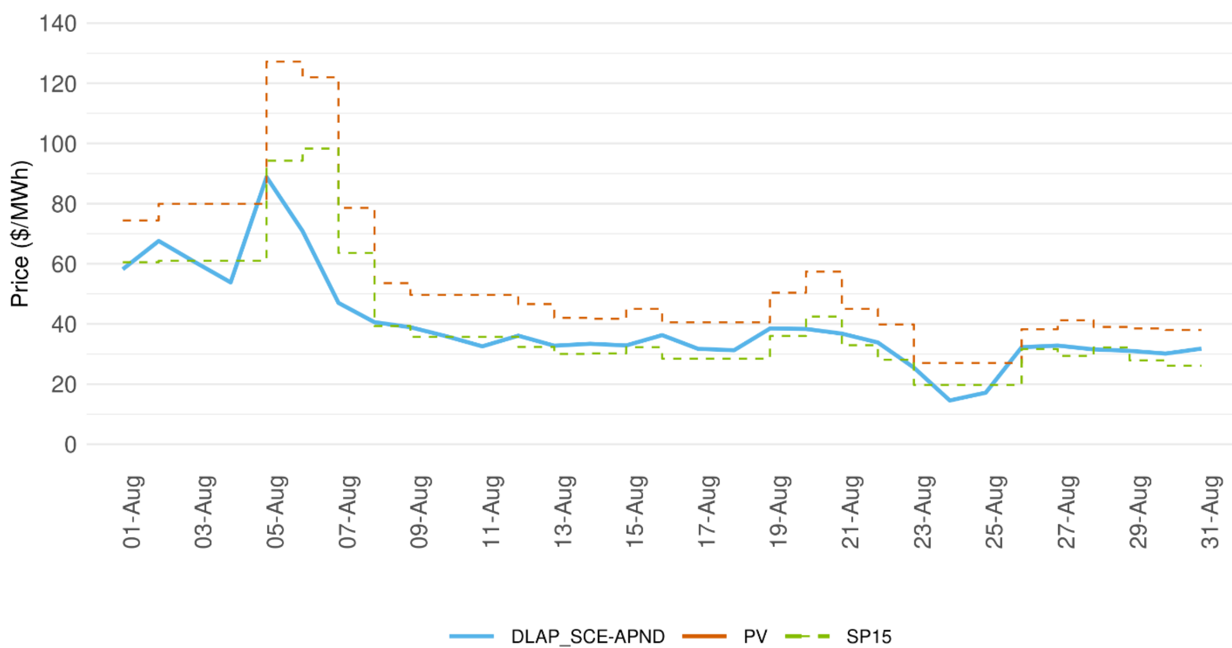
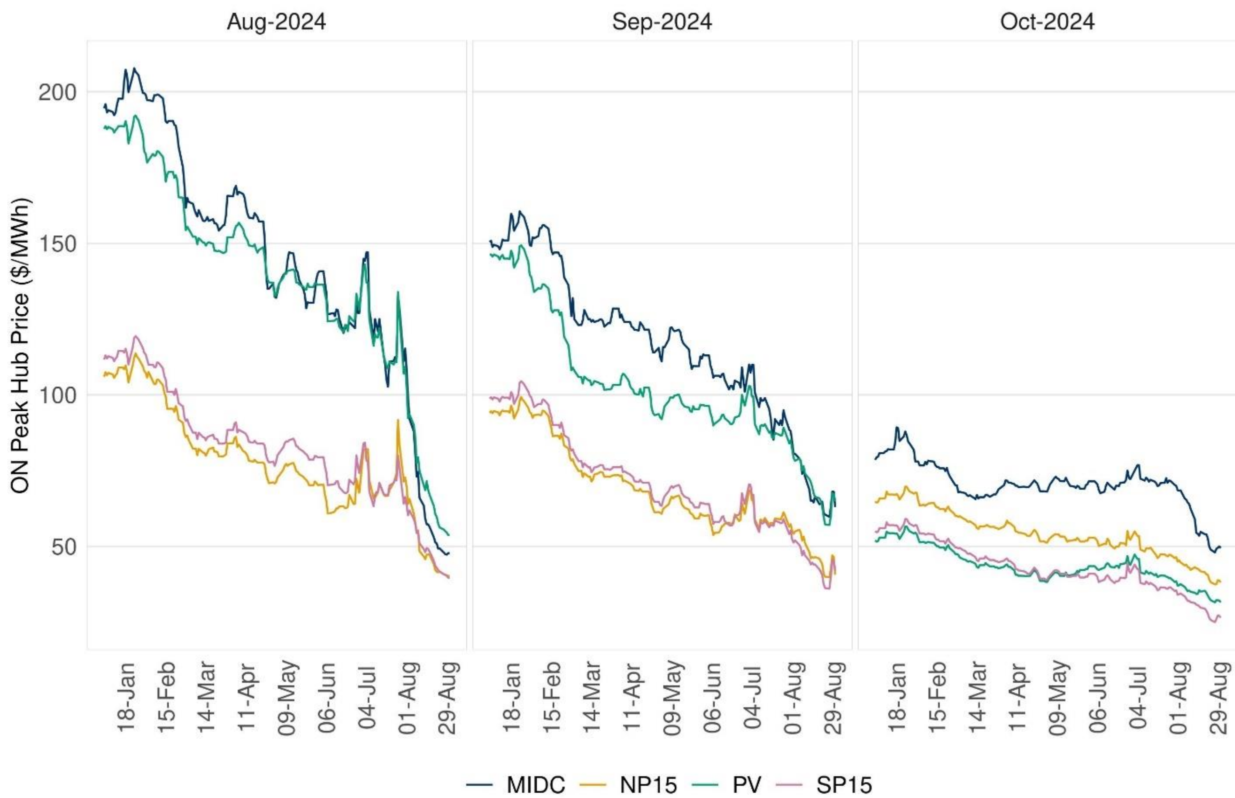


Figure 14 shows a year-to-date trend of on-peak future power prices traded for the 2024 summer months of August, September, and October. Price trends are captured for Mid-C and Palo Verde, as well as the NP15 and SP15 options that trade bilaterally. On-peak future prices have traded dynamically for summer 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 14: 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 15 shows the breakdown of the day-ahead supply capacity[9] 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.

[9] 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 15: Supply capacity available relative to load forecast in the day-ahead market

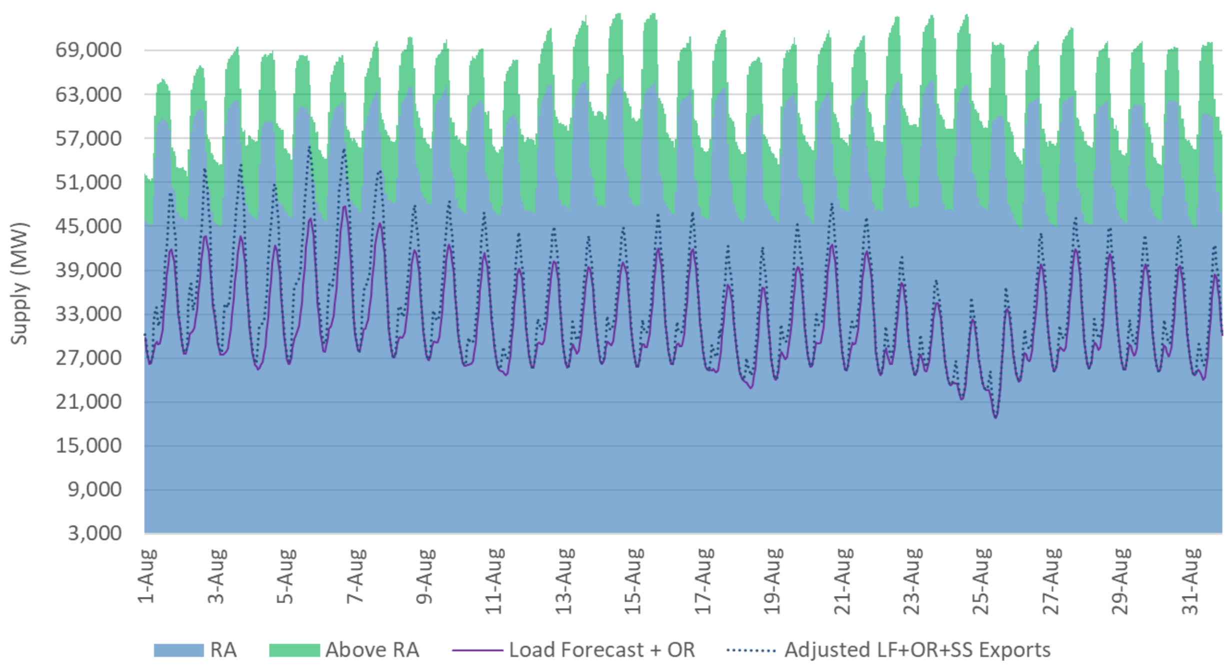
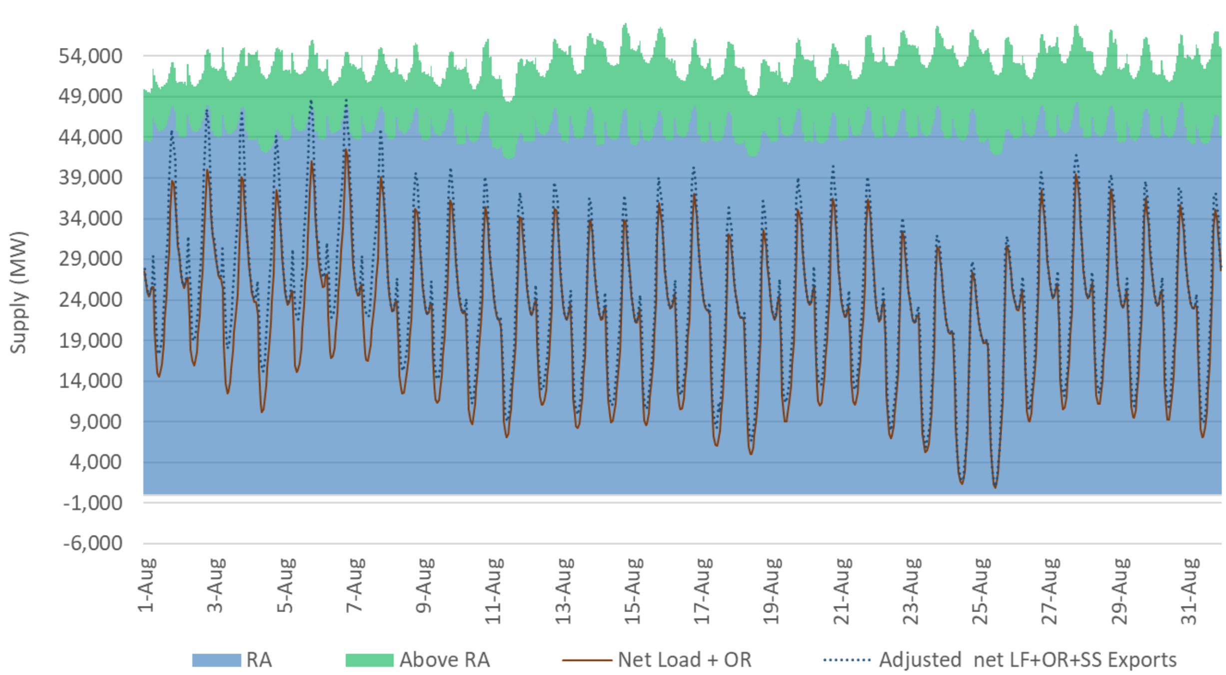


Figure 16 has similar convention for the same capacity breakdown as Figure 15, but the comparison is relative to the net load (gross load minus VER forecast). Since this figure represents net load, the supply side is also reduced by subtracting all VER contributions. Tracking the available capacity for the net load peak hour is as important as tracking available capacity for the gross peak hour.

Figure 16: Supply capacity available relative to net load forecast in the day-ahead market

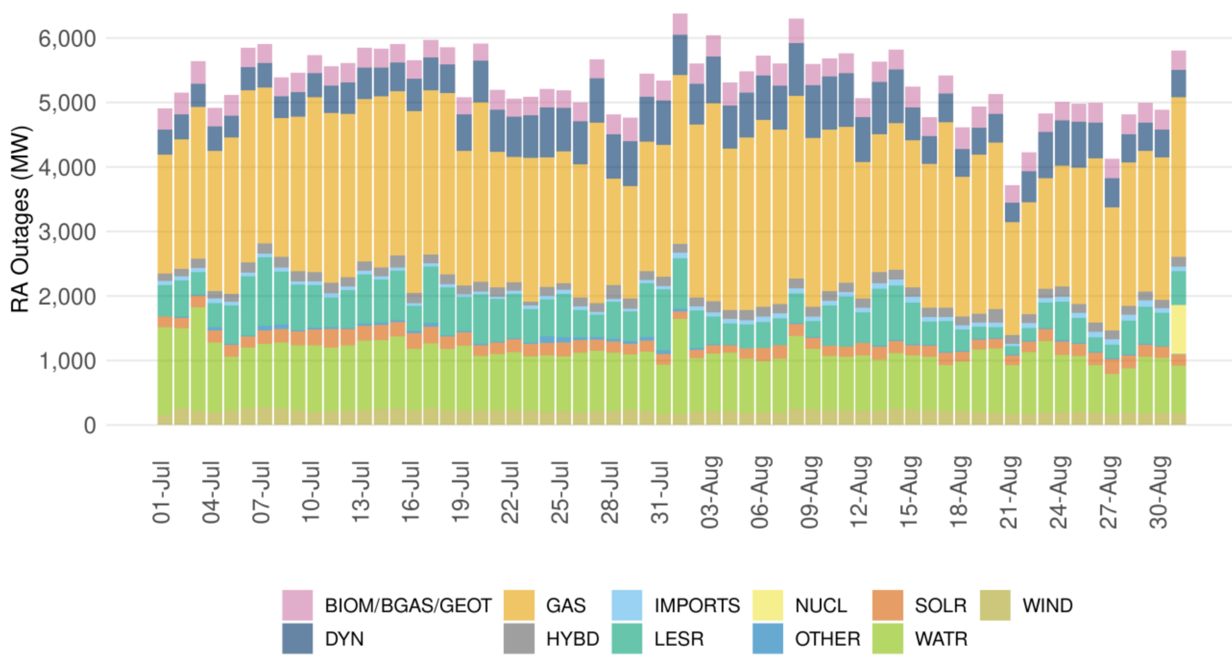


For the month of August, above-RA capacity was consistently available into the market. The supply available in the market was sufficient to cover the load forecast, and also the load forecast plus the RUC adjustments.

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 17 provides the trend of RA capacity on outage organized by fuel type during the month of July and August. The average daily capacity on outage was about 5,243 MW for the month of August as compared to 5,423 MW for the month of July.

Figure 17: Volume of RA capacity by fuel type on outage in July and August



Renewable Production

The ISO's area utilizes hydro production throughout the year to meet demand needs. Figure 18 shows the historical trend of total energy produced from hydro and other renewable resources. Hydro production for 2024 so far has been higher than 2022 but lower than 2023. Hydro production in August 2024 was about 4 percent lower than the production observed in August 2023. With the addition of more solar resources into the system, solar production in August 2024 was 24 percent higher than the production in

August 2023. Figure 19 shows the historical trend of solar production. Solar production decreased slightly in August. Figure 20 below shows the hourly profile of the average energy produced from hydro resources as well as solar and wind resources for August 2024. 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 18: Historical trend of hydro and renewable production

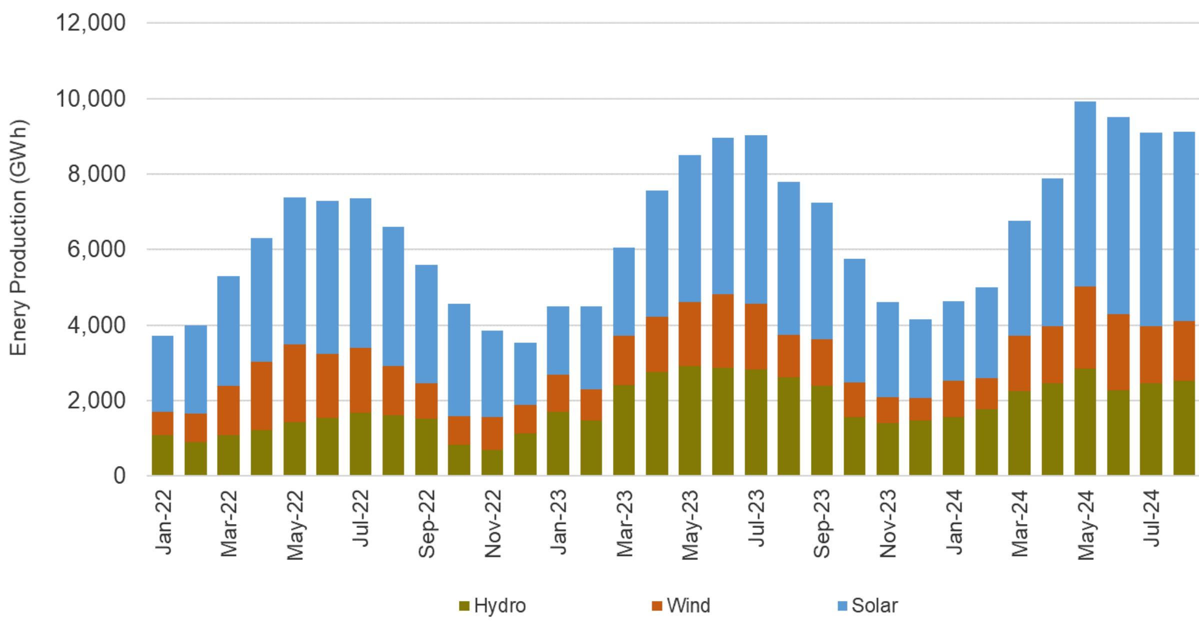


Figure 19: Historical trend of solar production

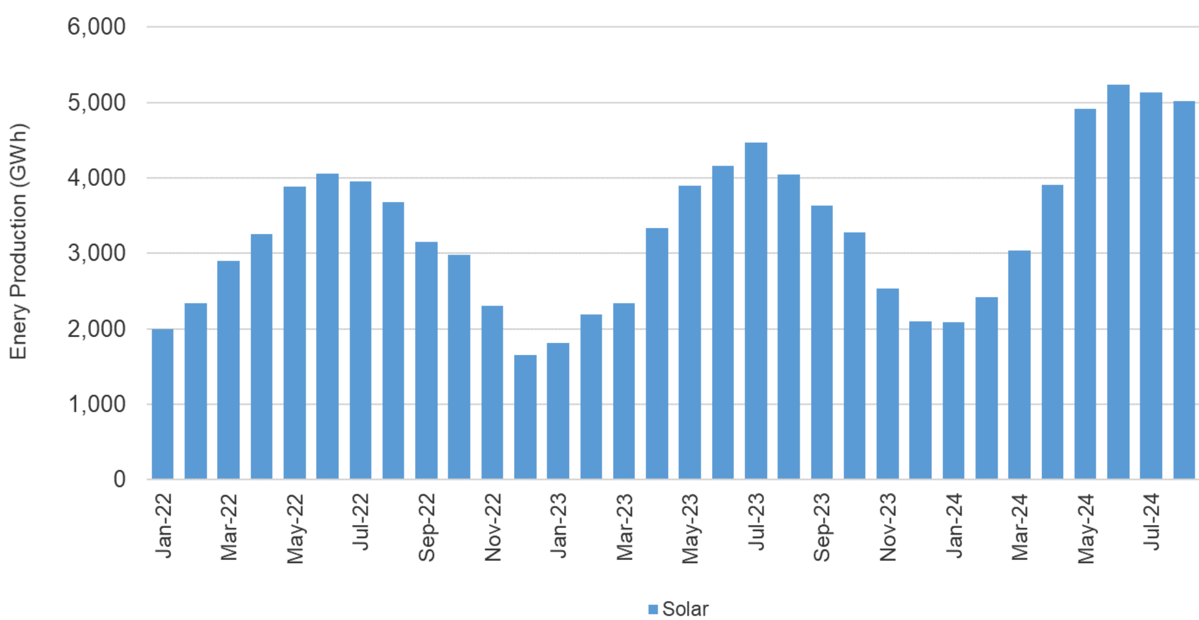
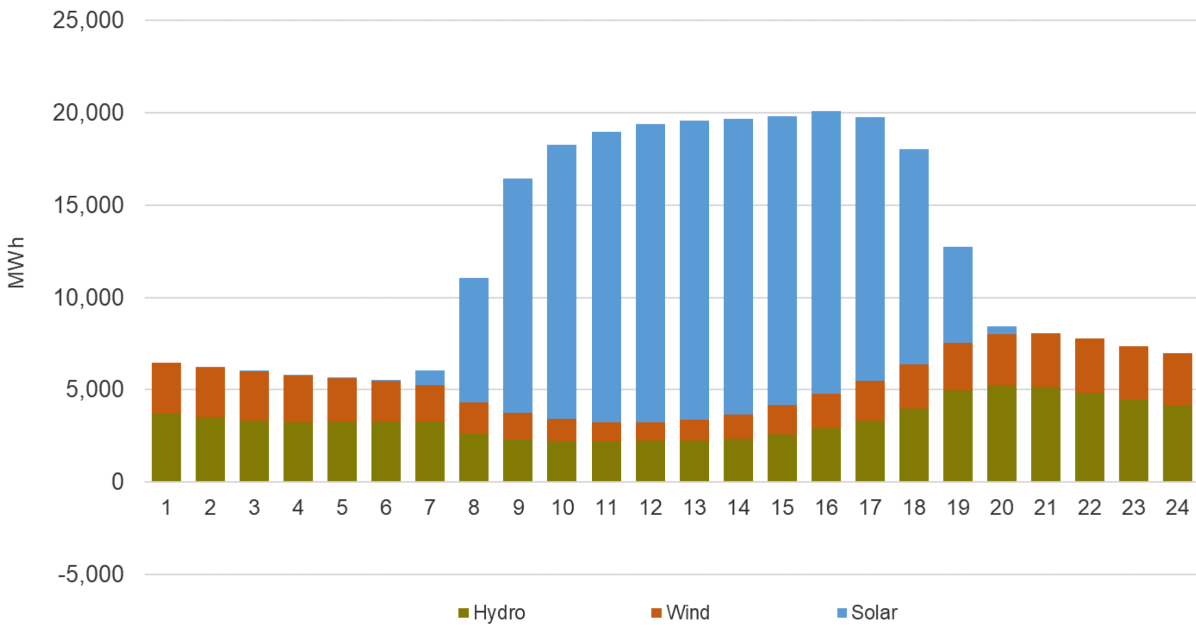


Figure 20: Hourly profile of wind, solar and hydro production for August



Demand and supply cleared in the markets

Figure 21 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 21: Day-ahead demand trend in August 2024

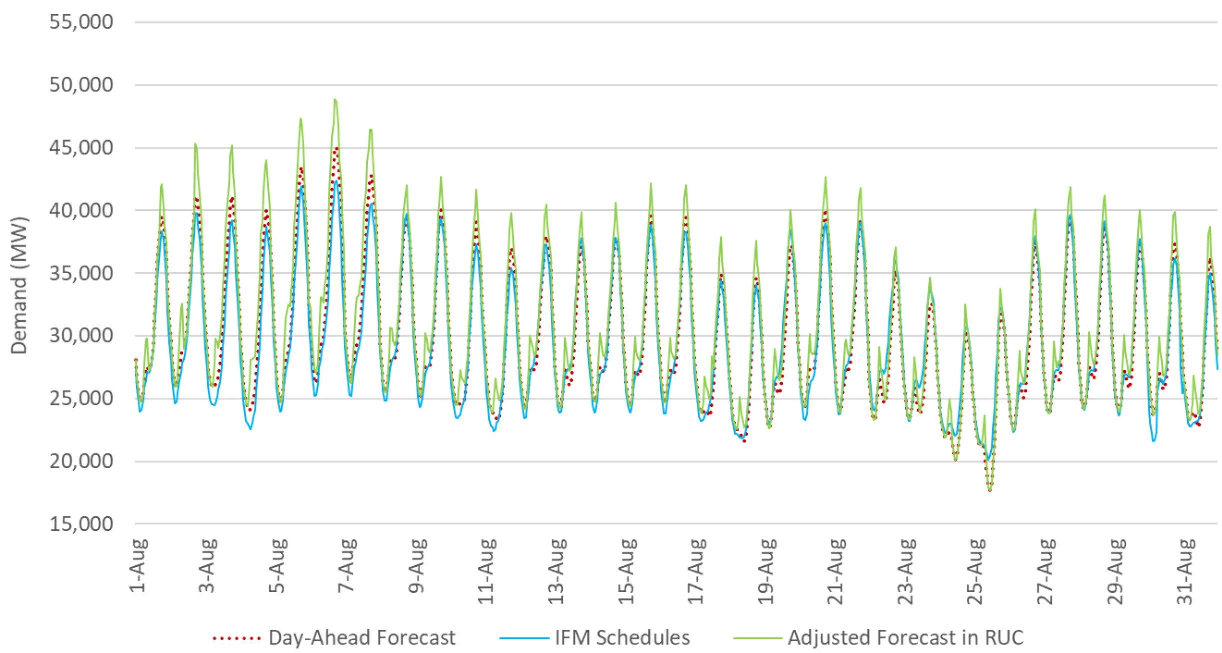
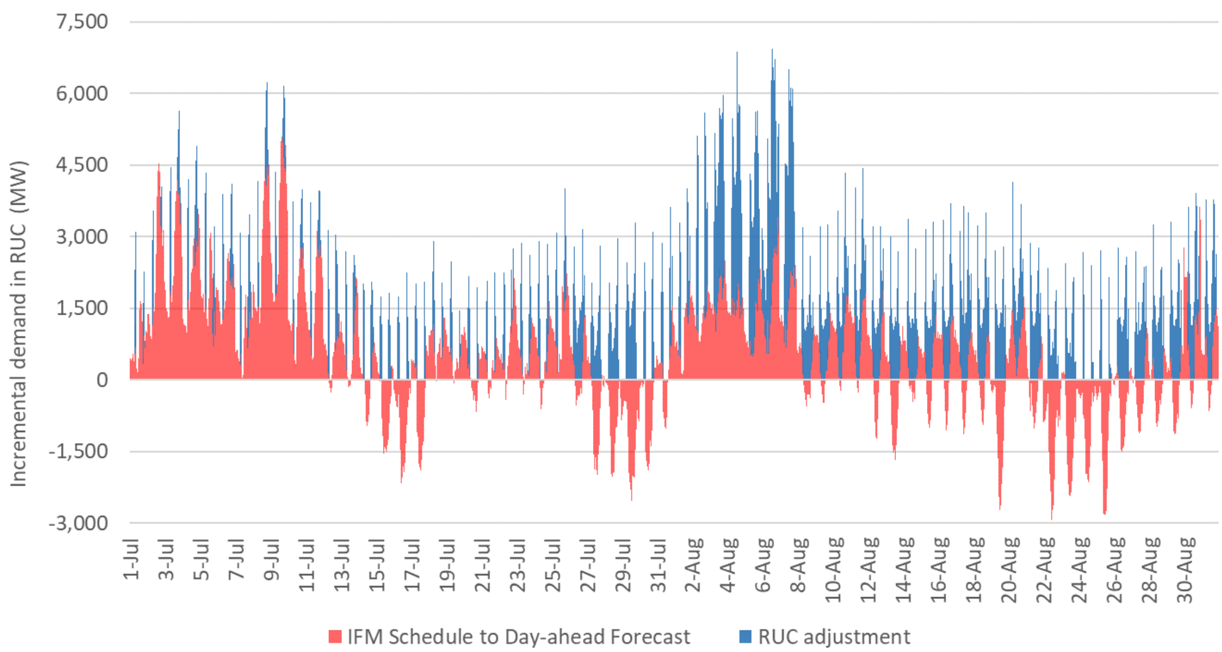


Figure 22 shows the differences between the IFM schedules versus the nominal day-ahead load forecast for RUC. This is the additional capacity relative to the IFM solution that RUC determines is needed to meet the day-ahead load forecast. Effectively, this is either the shortfall or surplus capacity from 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 in the beginning of this month when loads were high and RUC has to clear additional supply to meet the day-ahead load forecast..

Figure 22: Incremental demand required in RUC in August 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.[10]

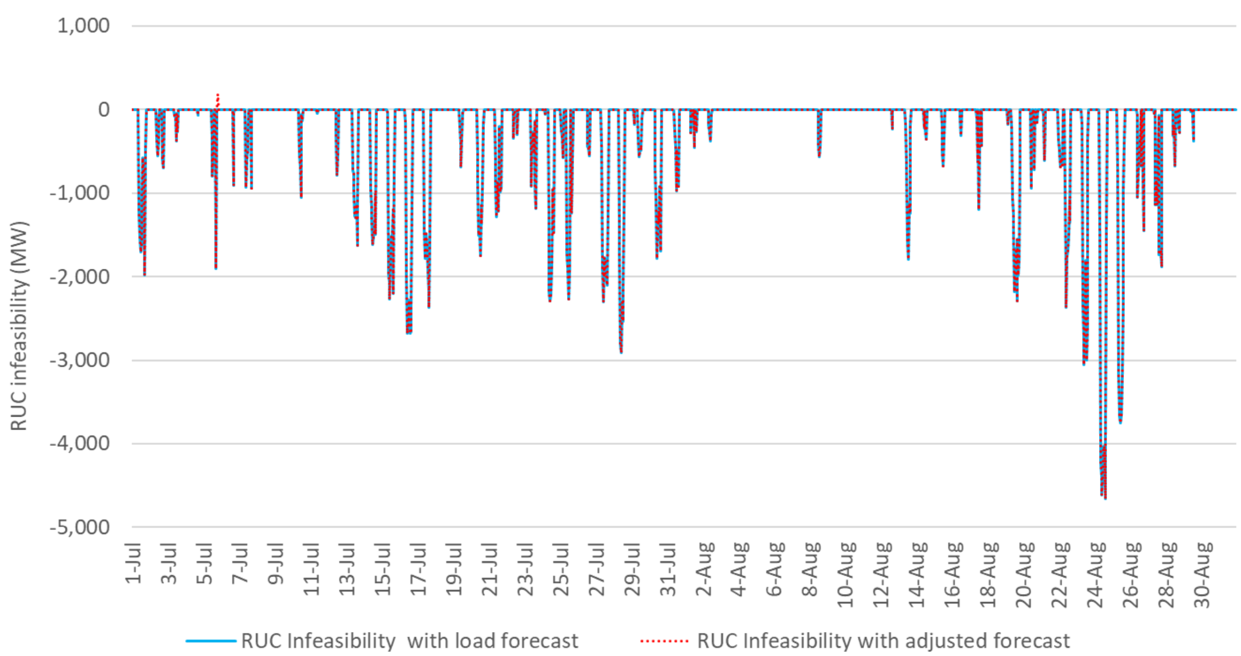
Since RUC clears against a load forecast which is not price sensitive, under certain conditions RUC may relax the power balance constraint due to a surplus or shortfall of supply capacity. A relaxation signals that there is an imbalance between the load requirements and the supply available. An infeasible power balance can be in either direction. In hours with low levels of load and minimum downward capability, RUC may observe an oversupply condition, resulting in a negative infeasibility. Conversely, in hours where there is insufficient supply to meet the load requirement, RUC may have an undersupply condition, resulting in a positive infeasibility. Negative RUC infeasibilities occur because RUC can only dispatch a resource down to its minimum load and cannot actually de-commit a resource or set up additional exports. Conversely, positive RUC infeasibilities occur because all incremental RUC bids have been exhausted and RUC has reduced all possible economic and low priority exports,[11] which leaves just the power balance constraint to be relaxed and reducing PTK (high priority) exports to allow RUC to clear.

[10] 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

[11] 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.

Figure 23 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 August there were only over-supply infeasibilities. In late August, oversupply condition occurred more frequently due to cooler weather driving demand down.

Figure 23: RUC infeasibilities in July and August 2024



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.[12]

In the month of August 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 economic bids. Figure 25 shows the instances when the real-time market reduced exports, happening mainly on August 2 and for low priority exports.

[12] 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 24: RUC export reduction for August 2024

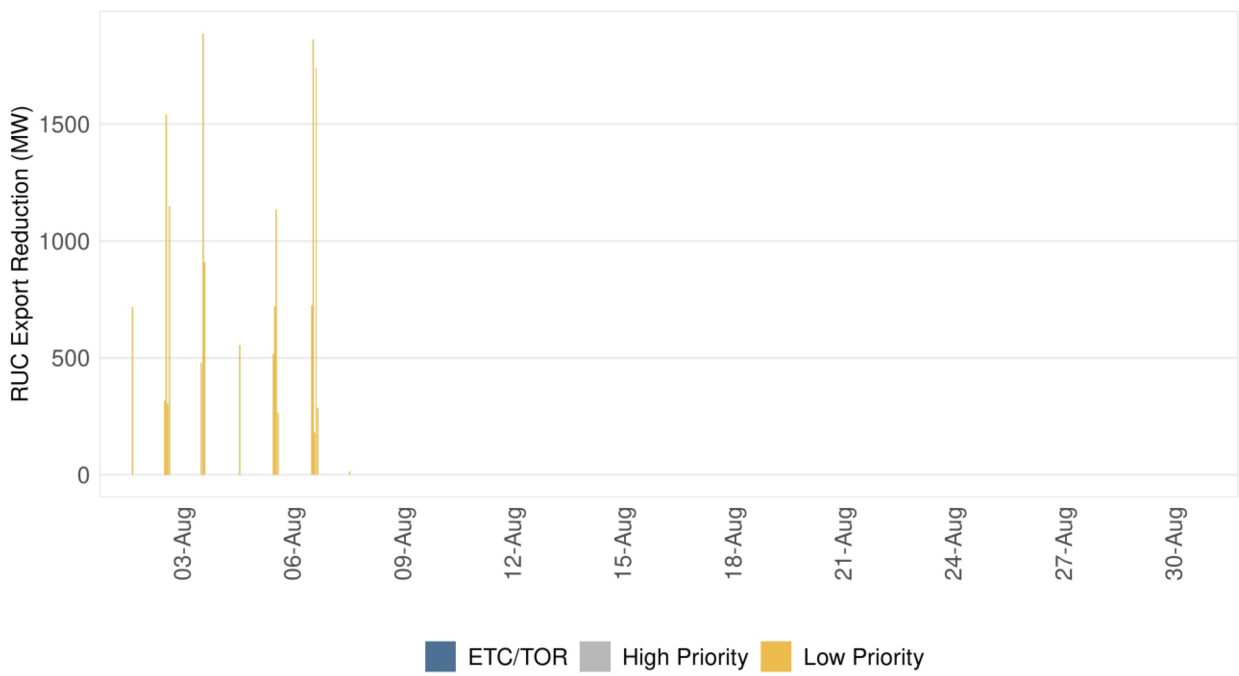
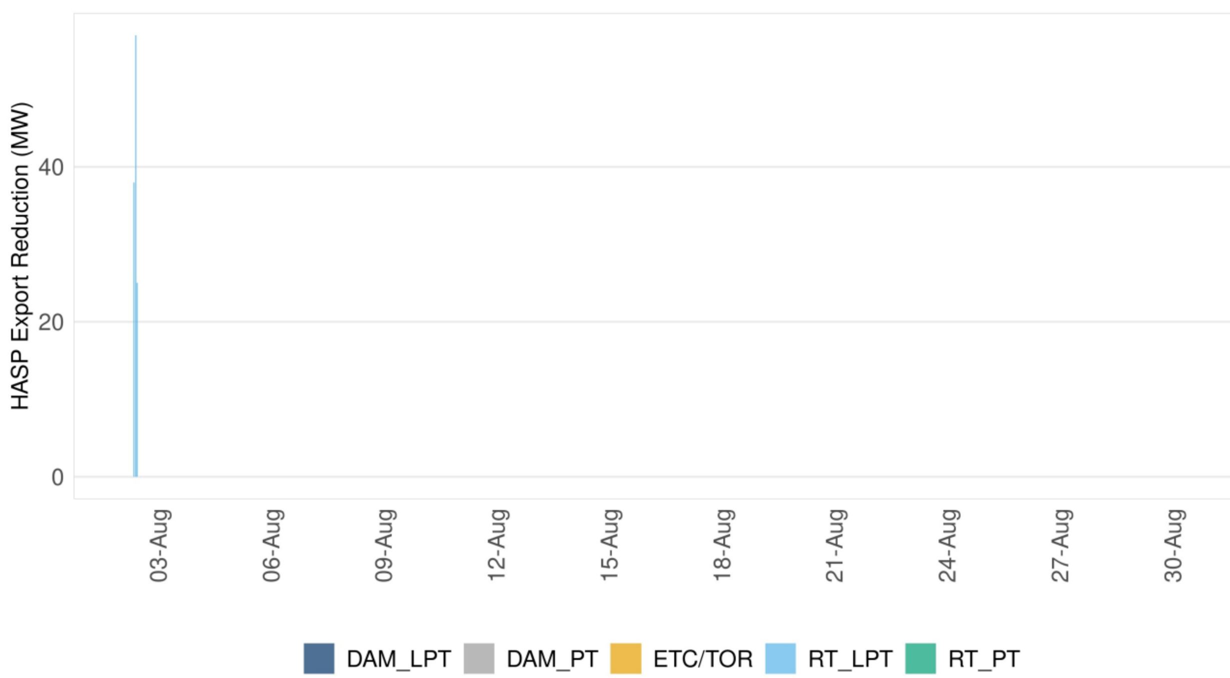


Figure 25: Exports reductions in HASP



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 26 shows the daily distribution of load conformance for all the markets for the month of August. The figure illustrates the daily distribution of load conformance in RUC, FMM and RTD markets for the month of August. 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 4,920 MW for August 4th. 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 August, similar pattern was observed where FMM load conformance adjustment reached a maximum of 5,000 MW on August 1st during the peak hours. Similarly RTD market much lower load conformance adjustments had a range of about -1,000 MW to about +1,500 MW for the month of August.

Figure 27 shows the hourly distribution of load conformance adjustment for the month of August 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 26: Daily load conformance for the month of August 2024 - by market

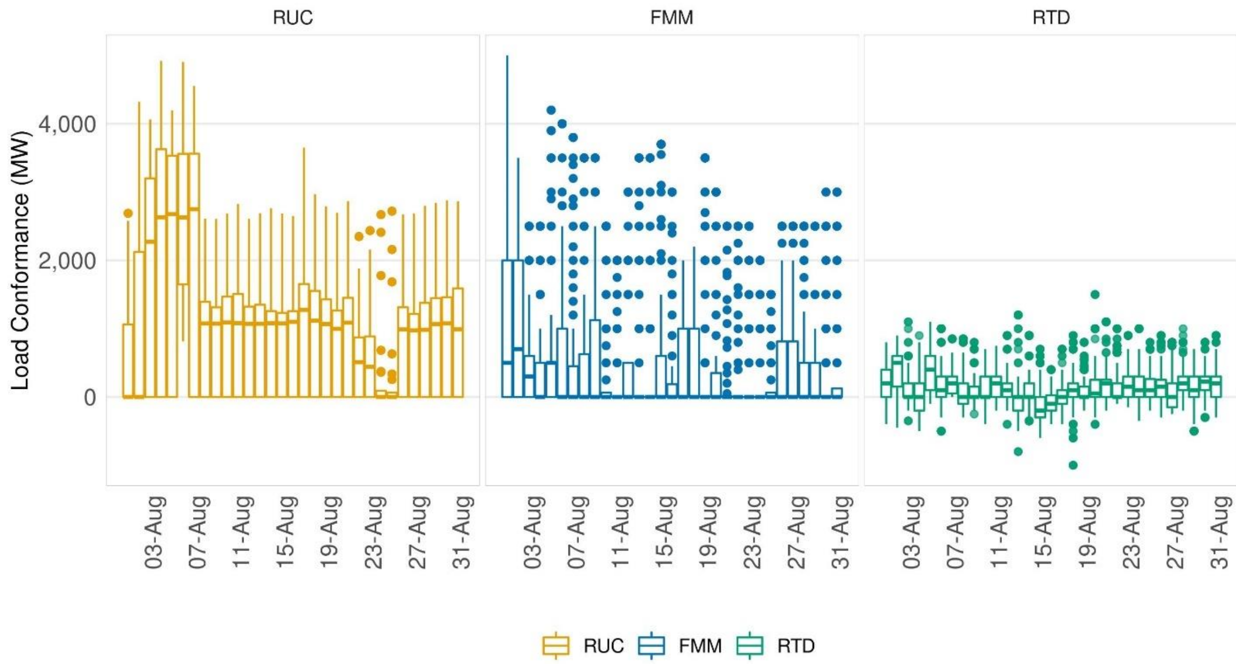
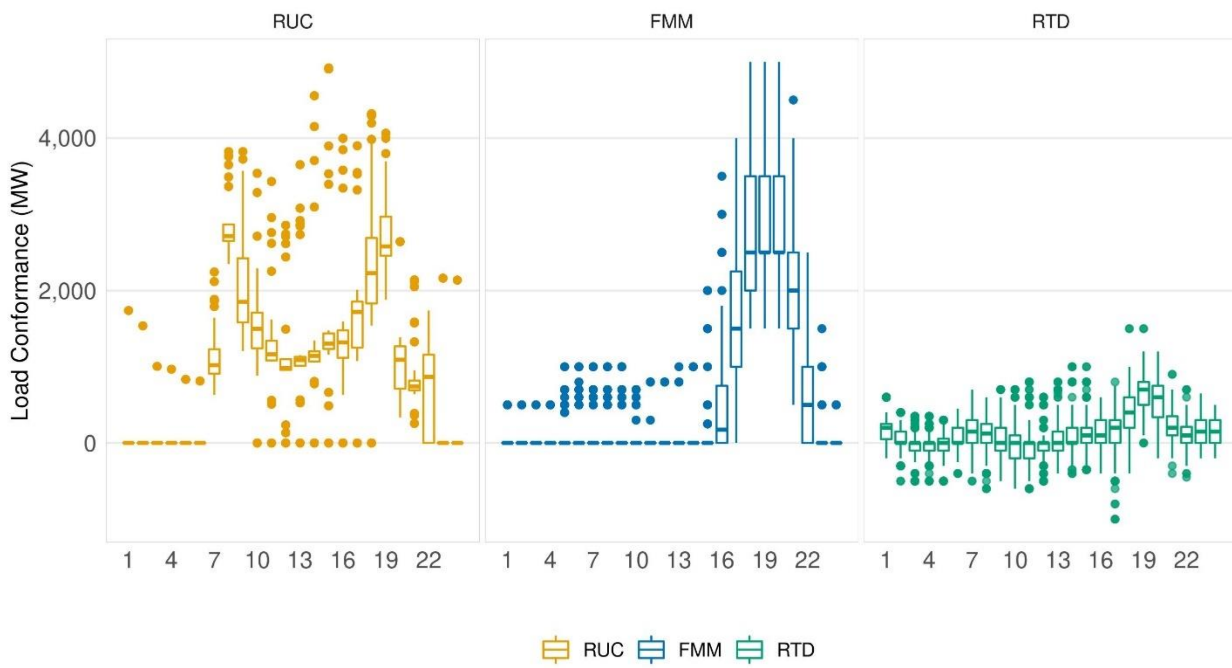


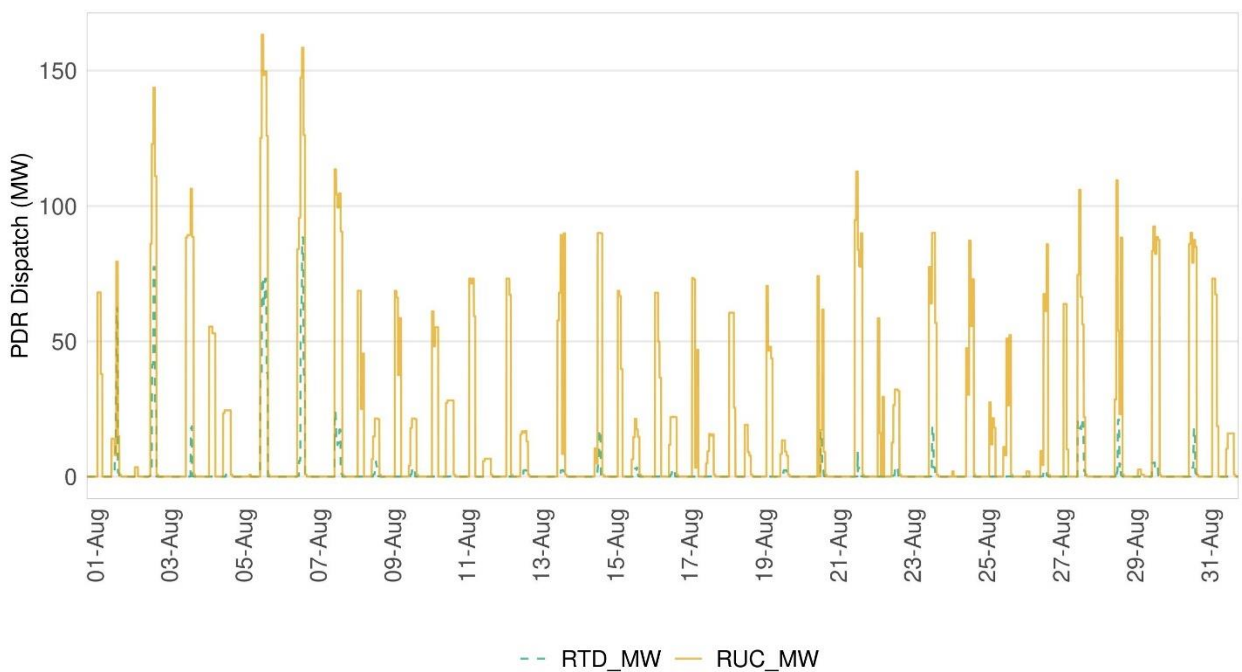
Figure 27: Hourly load conformance for the month of August 2024 - by market



Demand Response

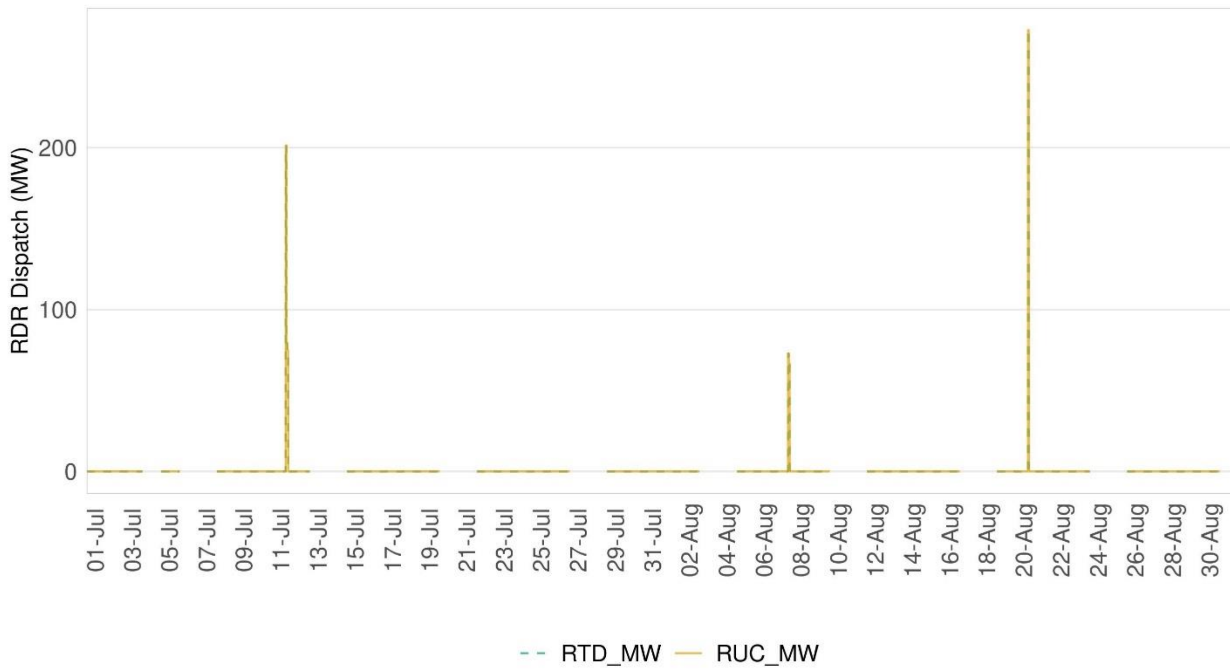
The ISO markets consider demand response programs designed to reduce demand based on system needs and trigger demand response programs through market dispatches. In the ISO's markets, there are two main market programs for demand response: economic (proxy) and reliability demand response. These programs use supply-type participation models that can be dispatched similar to conventional generating resources. Figure 28 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 August, PDR resources were consistently dispatched in the day-ahead market. The largest volume of PDR dispatches in the day-ahead timeframe occurred on August 5 at about 163 MW, whereas in the real-time market, it was a maximum of 88 MW on August 6.

Figure 28: PDR Dispatches in day-ahead and real-time markets in August 2024



Reliability demand response resources (RDRRs) were triggered in the real-time market during August. Figure 39 shows the dispatches of RDRRs in both the day-ahead and real-time markets. In the day-ahead market, these types of resources can be dispatched based on economics. The real-time market will consider these DAM dispatches as self-schedules. Therefore, these RDRRs will be dispatched in the real-time market even when there is no energy emergency alert declaration. The largest volume of RDRR dispatches in the real time market was on August 20 to about 273 MW for HE 17. RDRRs were dispatched in RUC and RTD market to the same amount of 273 MW, hence the yellow line for RUC MW and blue line for RTD MW are overlapping.

Figure 29: RDRR dispatches in day-ahead and real-time markets for August 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.

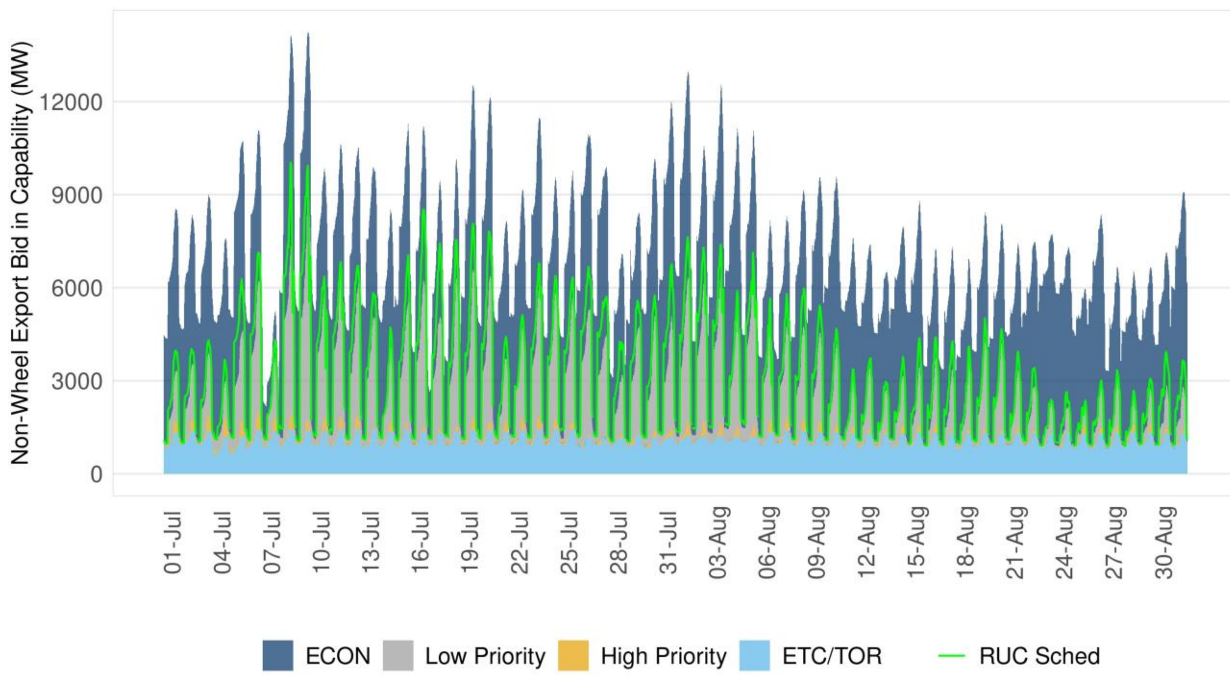
The ISO's markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics, and system conditions, are taken into account. 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 30 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 30: 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 62 percent, 17 percent, 18 percent and 3 percent of the export capacity were for economic bids, LPT, ETC/TOR and PTK, respectively. There were lower volumes of LPT in August comparing to July, resulting in a slightly higher total of bid in export volume. The highest RUC scheduled was in hour ending 18 on August 1, at about 7,949 MW.

Figure 31: Day-ahead bid-in capacity and RUC-cleared imports

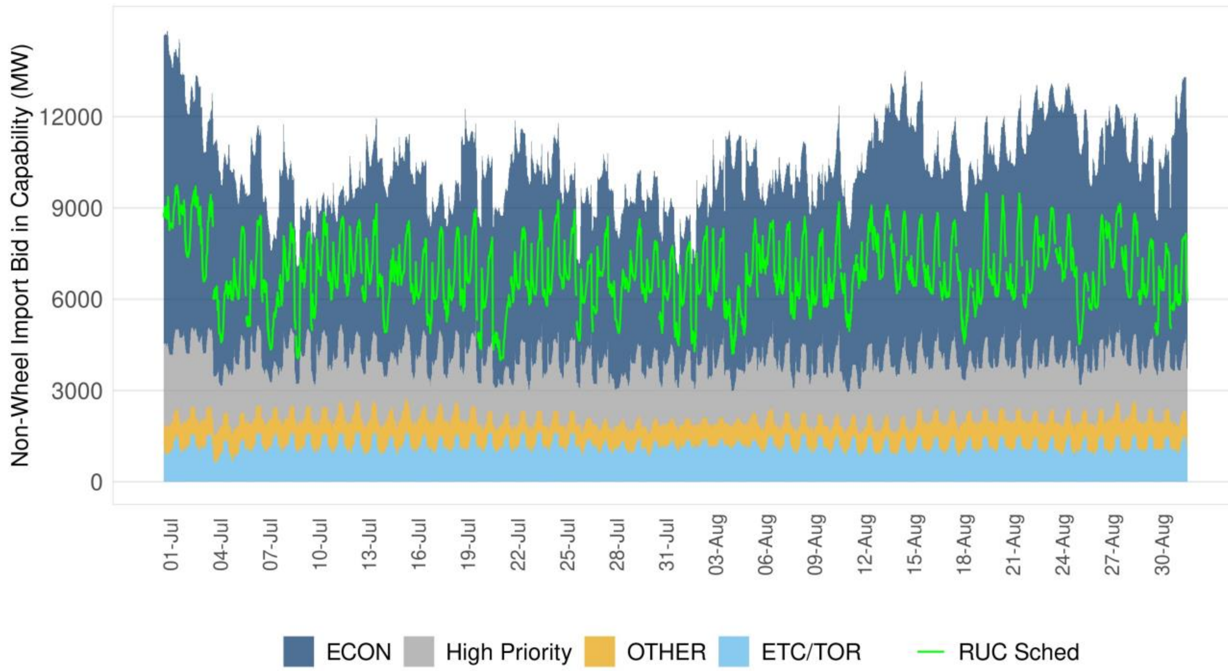
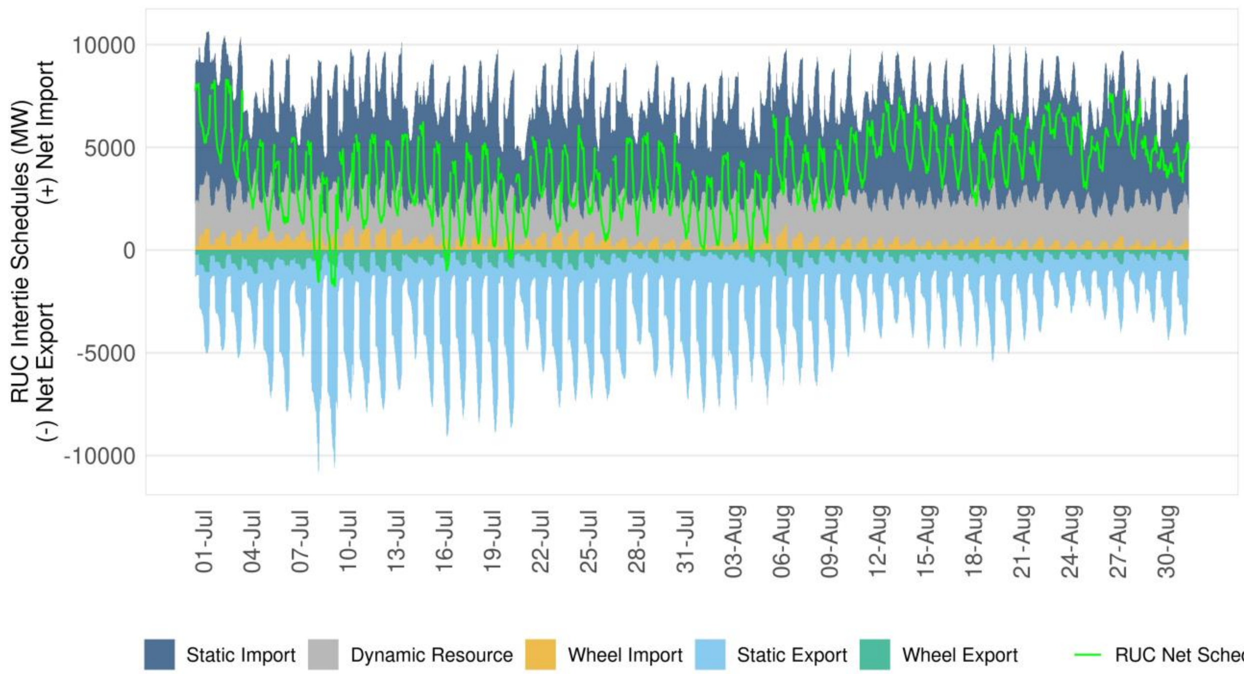


Figure 31 shows the same metric for imports. These volumes include both static imports and dynamic resources. Both ETC/TOR remained relatively stable through the months. There were larger volumes of economic bids in August comparing to July, resulting in a slightly higher total of bid in capacity. The “other” group includes regulatory must run priority capacity and the portion of Pmin for dynamic resources with a Pmin above 0 MW.

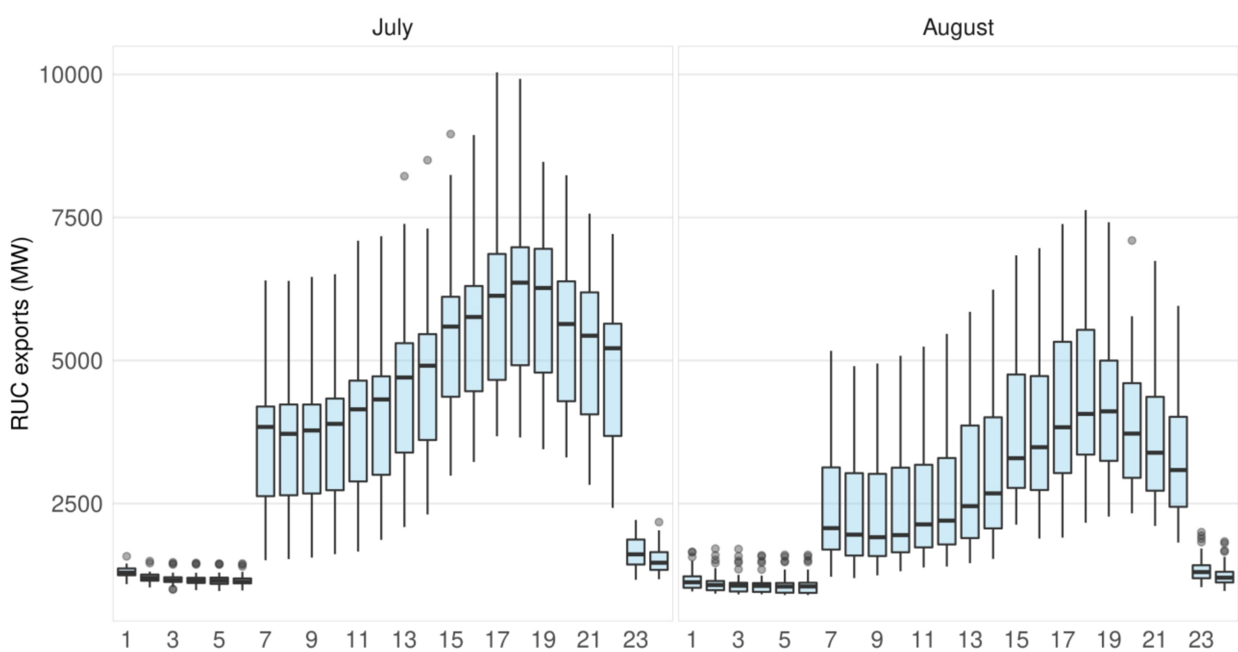
Figure 32 shows the overall intertie schedules organized by type of schedule, as well as the net interchange based on the RUC solution for two months. The net interchange projected in the RUC process reached its lowest level on August 4 in HE 18 at about -246 MW due to the higher level of exports cleared.

Figure 32: Breakdown of RUC cleared schedules



An area of interest since summer 2020 is the trend of exports in the ISO's system. Figure 33 illustrates the hourly distribution of RUC schedules for exports and that the highest volume occurred during afternoon hours. Comparing to July, August had lower RUC exports for majority of the hours, hour ending 7 through 22. The highest volumes were cleared in hour ending 18.

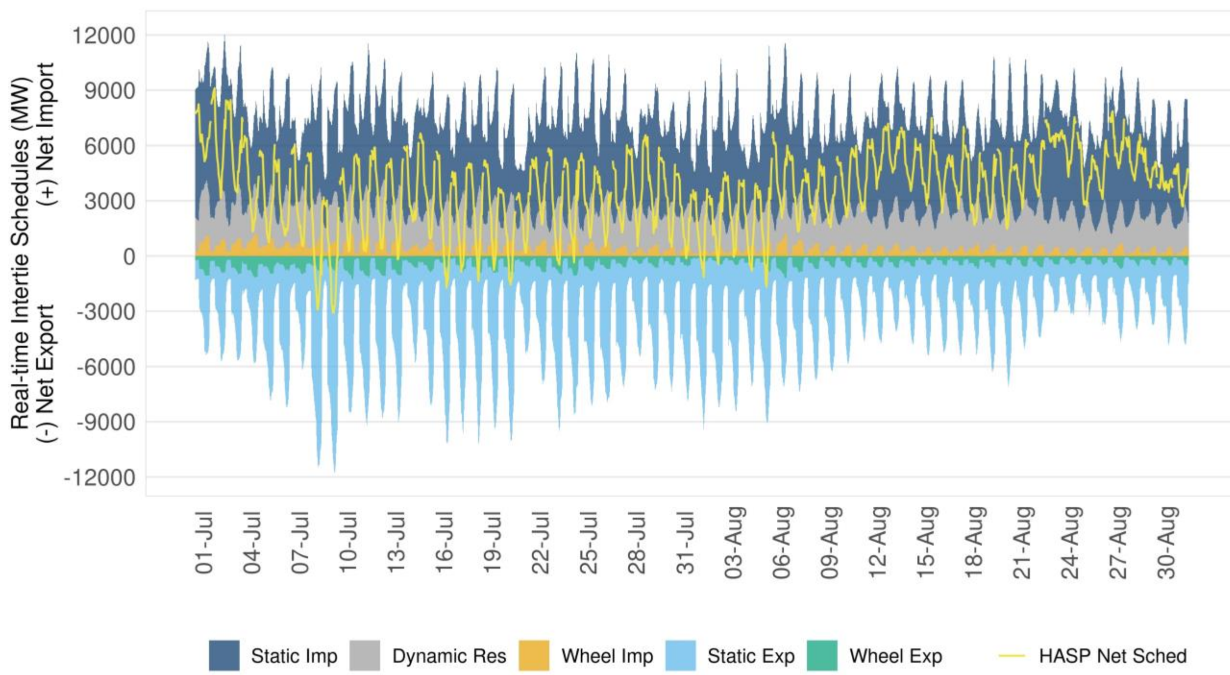
Figure 33: Hourly RUC exports



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 34 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 higher in August comparing to July. On average, for August, the net schedule in HASP was about 4,194 MW across all the hours of the month and about 3,622 MW for peak hours.

Figure 34: HASP cleared schedules for interties



The HASP market presents an opportunity for interties to clear through the market clearing process after the DAM is complete. 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.[13]

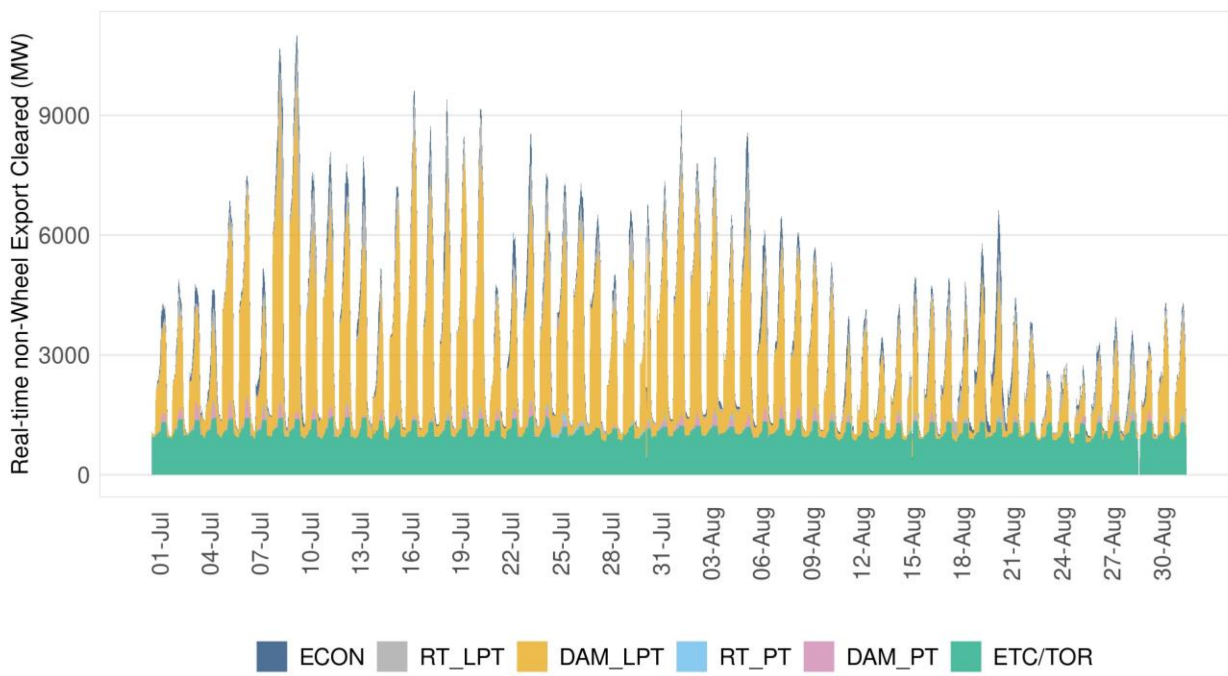
[13] Based on these rules implemented on August 4, 2021, through the summer enhancements described earlier and now in place, the ISO will no longer provide exports a higher priority than load in the real-time, and will only provide them equal in priority to load if the participant demonstrates that they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

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 35 shows all the exports cleared in the HASP process and identifies the nature of such exports. TOR is for export with scheduling priorities associated with transmission rights. 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.

In August, the volume of exports cleared in real time peaked at 9,233MW on August 1. In August, lower volumes of exports were cleared comparing to July, and low priority bids constituted a significant portion of cleared exports.

Figure 35: Exports schedules in HASP



Imports and exports were scheduled over multiple intertie scheduling points in August, with Malin, Palo Verde and NOB seeing the highest volume of transactions. Figure 36 through Figure 38 illustrate the trend of import and export schedules cleared in HASP for these top three intertie points. In August, the prevailing schedules were in the import direction.

Figure 36: HASP schedules at Malin intertie

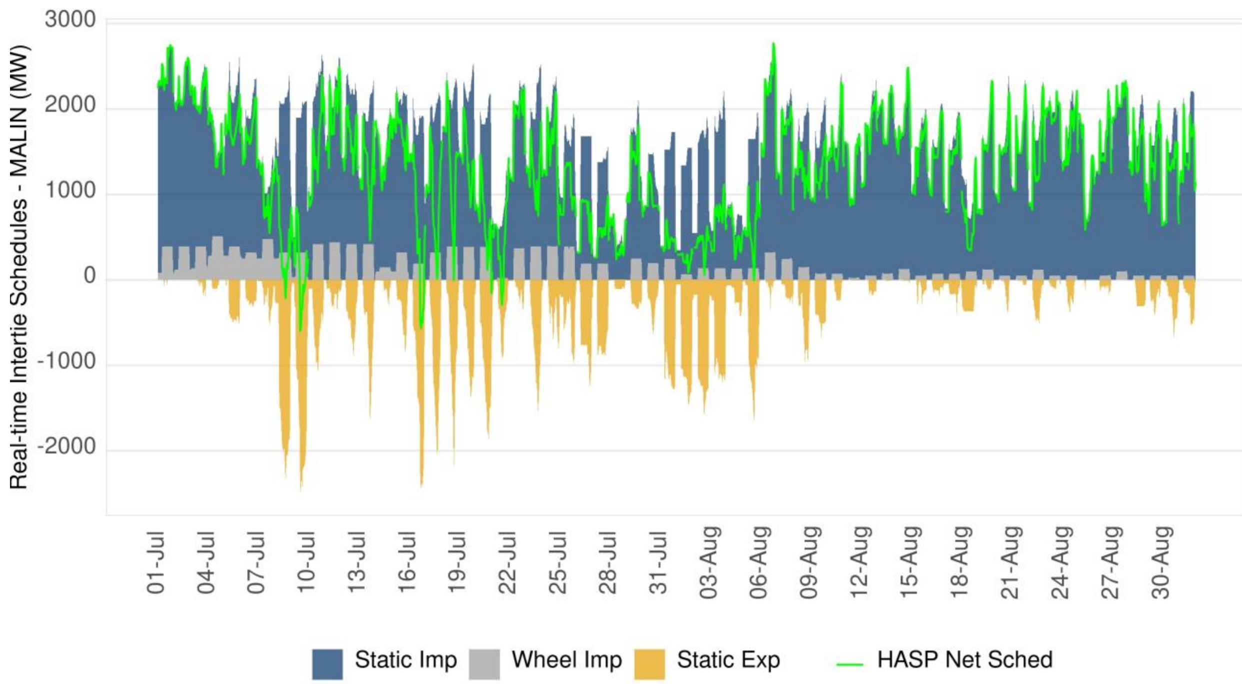


Figure 37: HASP schedules at Palo Verde intertie

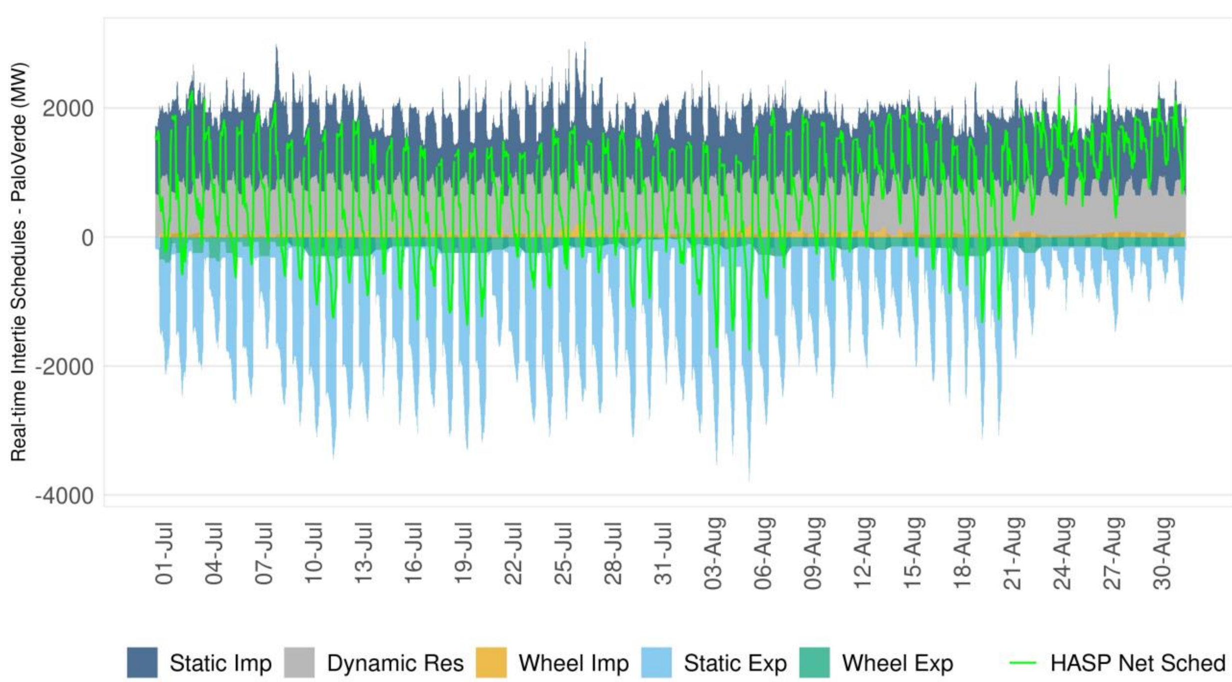


Figure 38: HASP schedules at NOB intertie

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 August was about 2,948 MW for LSEs under CPUC jurisdiction, and slighter lower than the 3,006 MW for July.

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 39 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 99.8 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 August. There was one RA import that bid above $0/MWh for about 75 MW on August 15.

This plot also shows the cleared imports, which largely utilized all the bid-in volume for RA and above RA.

Figure 39: Day-Ahead RA import for hour endings 17 through 21 for weekdays

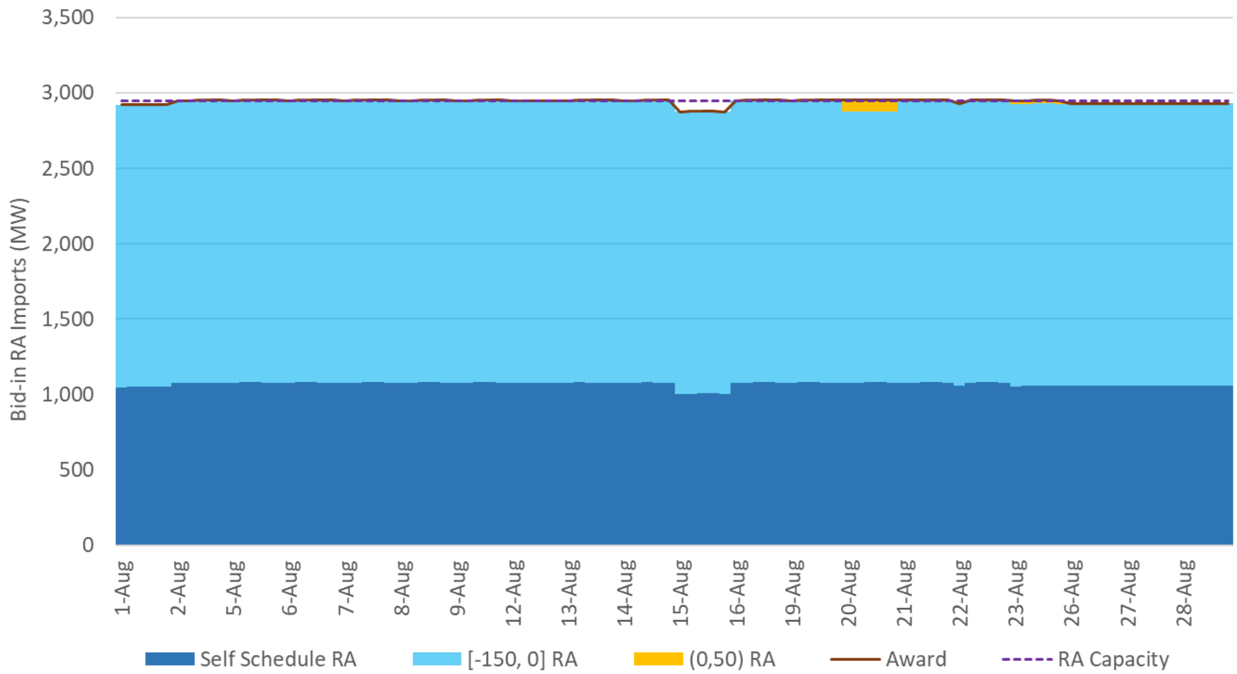
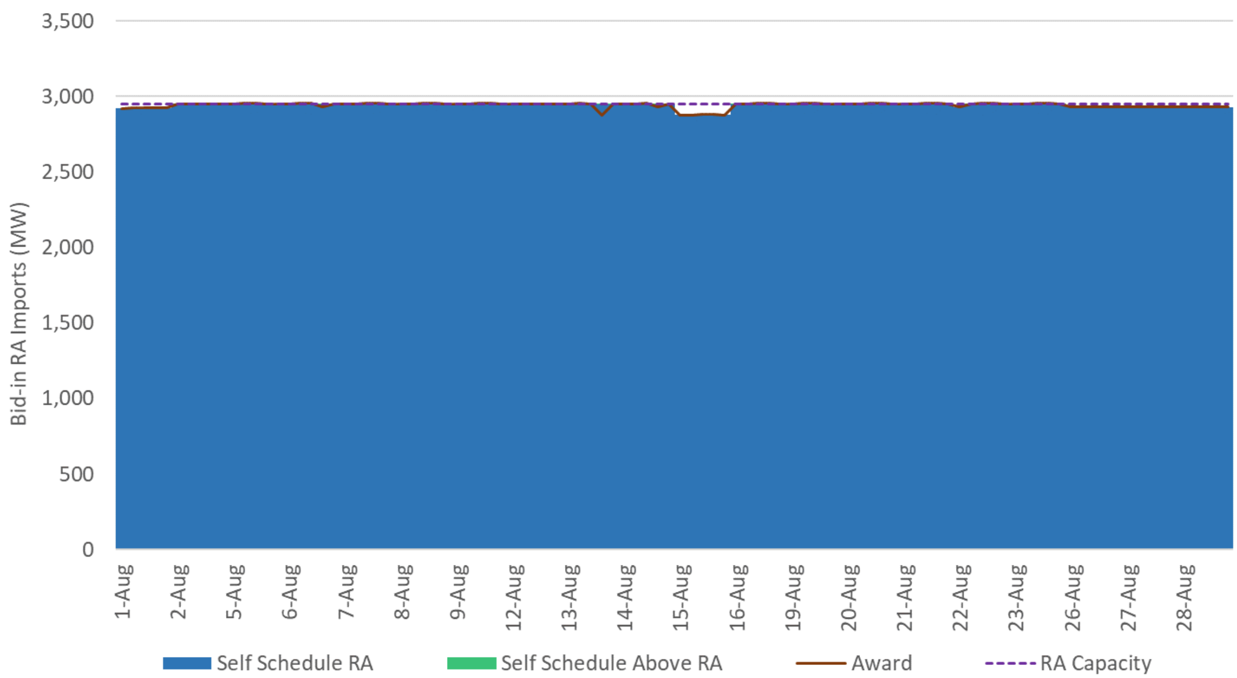


Figure 40 shows the same information for the real-time market using the HASP bids and awards. All CPUC-jurisdictional RA imports submitted in the real-time market were with self-schedules. About 99.8 percent of RA imports bid with self-schedules or economic bids below $0/MWh. There was one RA import that did not bid about 75 MW less than its RA capacity during August 15, and consequently that capacity did not clear in the market.

Figure 40: 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.[14] For the month of August 2024, there was a total of 735 MW of high-priority wheels from five different scheduling coordinators. Table 1 lists all the wheel-through definitions used in August.

Table 1. Wheel-through quantities registered for August 2024

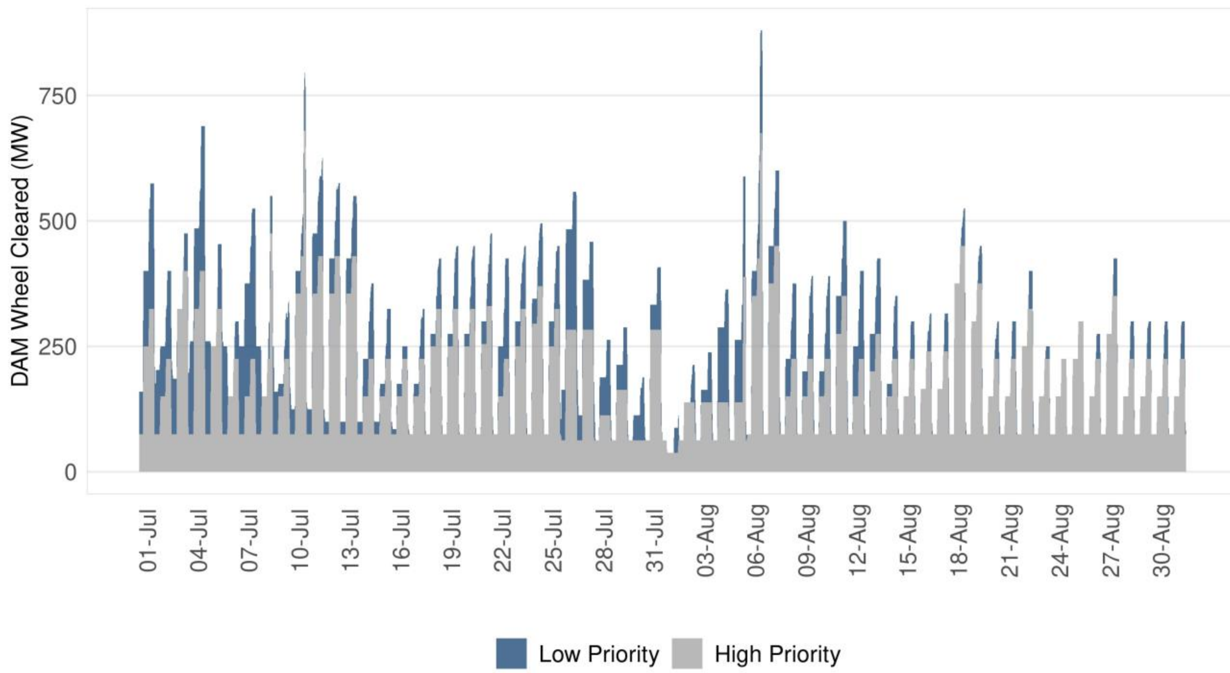
	Sink			
Source	MCCULLOUG500	MEAD230	PVWEST	SYLMAR
IPP				25
MALIN500			97	
NOB		325	53	
PVWEST				10
RDM230	75		150	
Total				**735**

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.

[14] 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

Figure 41 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 880 MW on August 6, with 675 MW of high priority and 205 MW of low priority wheels.

Figure 41: 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 42 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 August. Source refers to the import scheduling point while sink refers to the export scheduling point. The path with the largest volume of wheels in August in the day-ahead market was from RDM (Round Mountain located in northern California) to PVWEST (Palo Verde located in Southern California).

Figure 42: Hourly average volume (MWh) of wheels by path in August

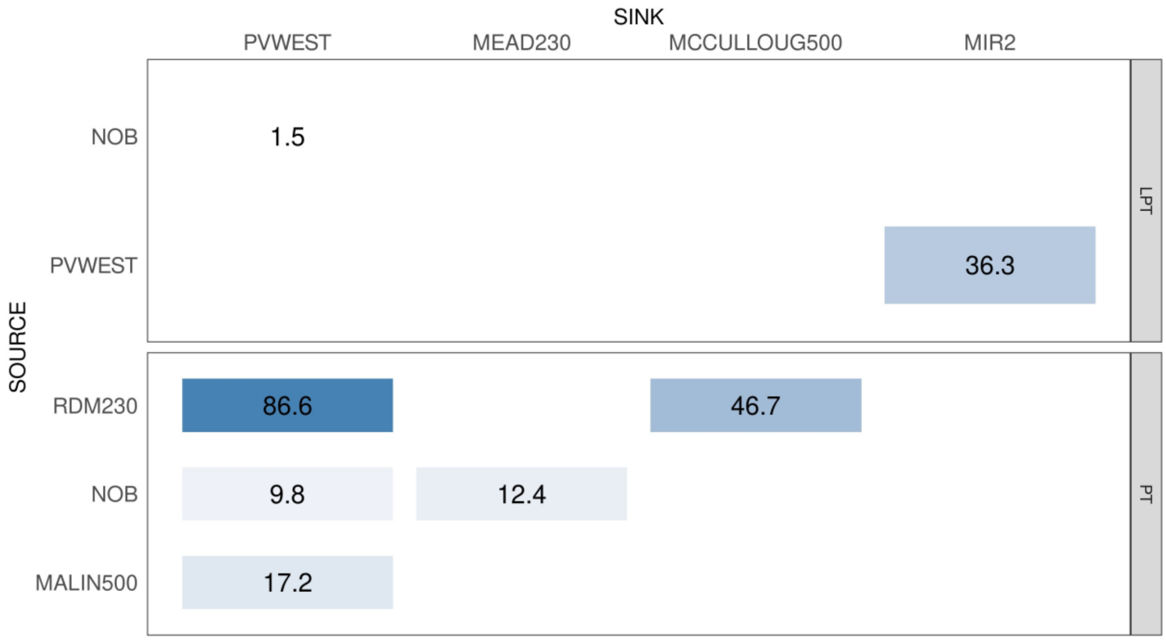
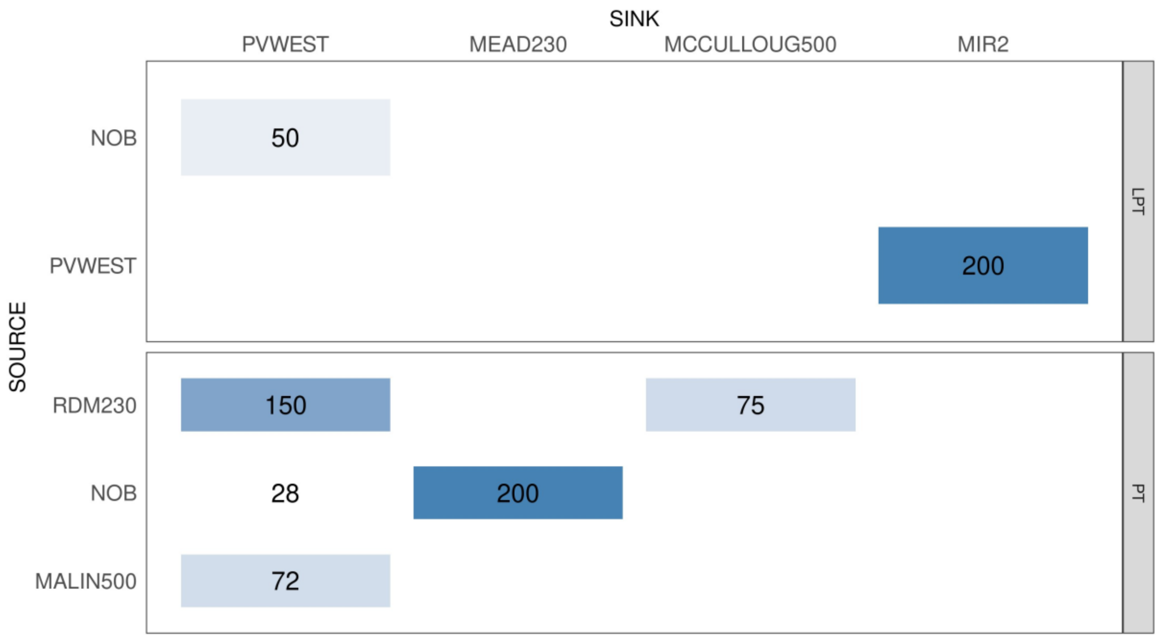


Figure 43 summarizes the maximum hourly wheels cleared in any hour in August in the day-ahead market by source-to-sink combination. The maximum volume of wheels in a given path occurred from PV West to MIR2 (Mirage locations) and NOB to Mead location.

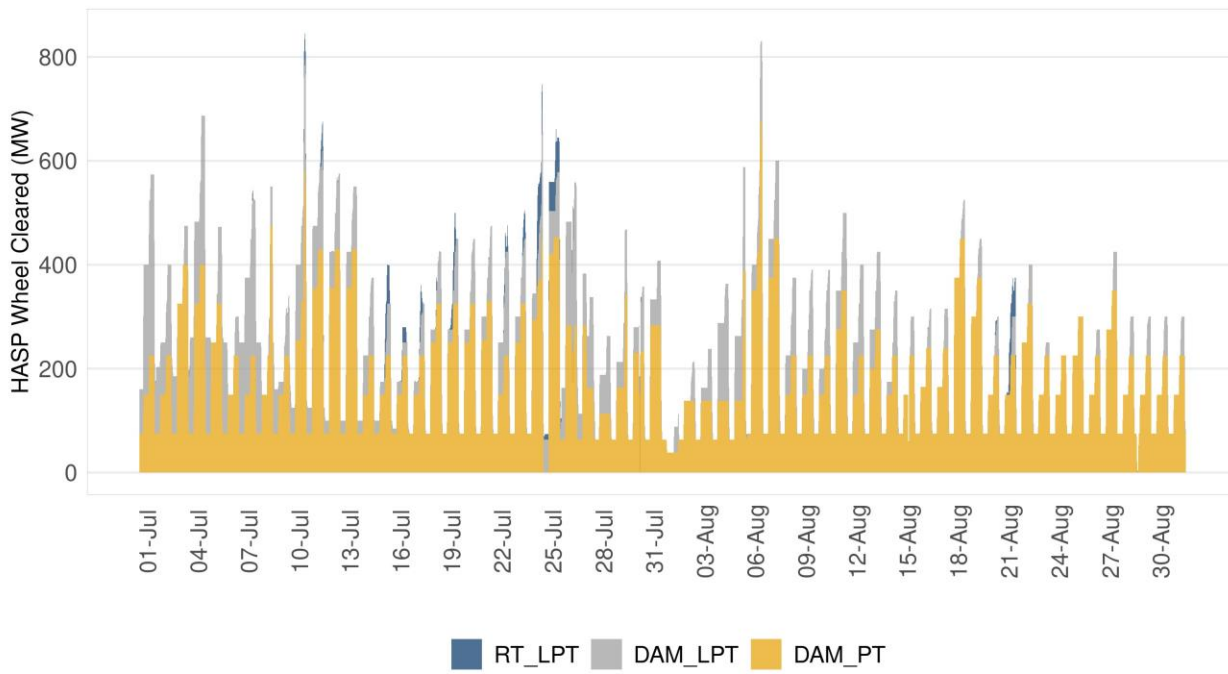
Figure 43: Maximum hourly volume (MW) of wheels by path in August



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 44 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 44: 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 economic wheels. The volume of wheels bid in directly into real time was negligible.

6 Storage and Hybrid Resources

In August 2024, there were 166 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 37,768 MWh. In terms of the capacity made available to the markets, Figure 45 and Figure 46 present the daily average and the hourly average of bid-in capacity for storage resources in the day-ahead market in July and August, organized by price ranges.

Figure 45: Bid-in capacity for batteries in the day-ahead market, daily average

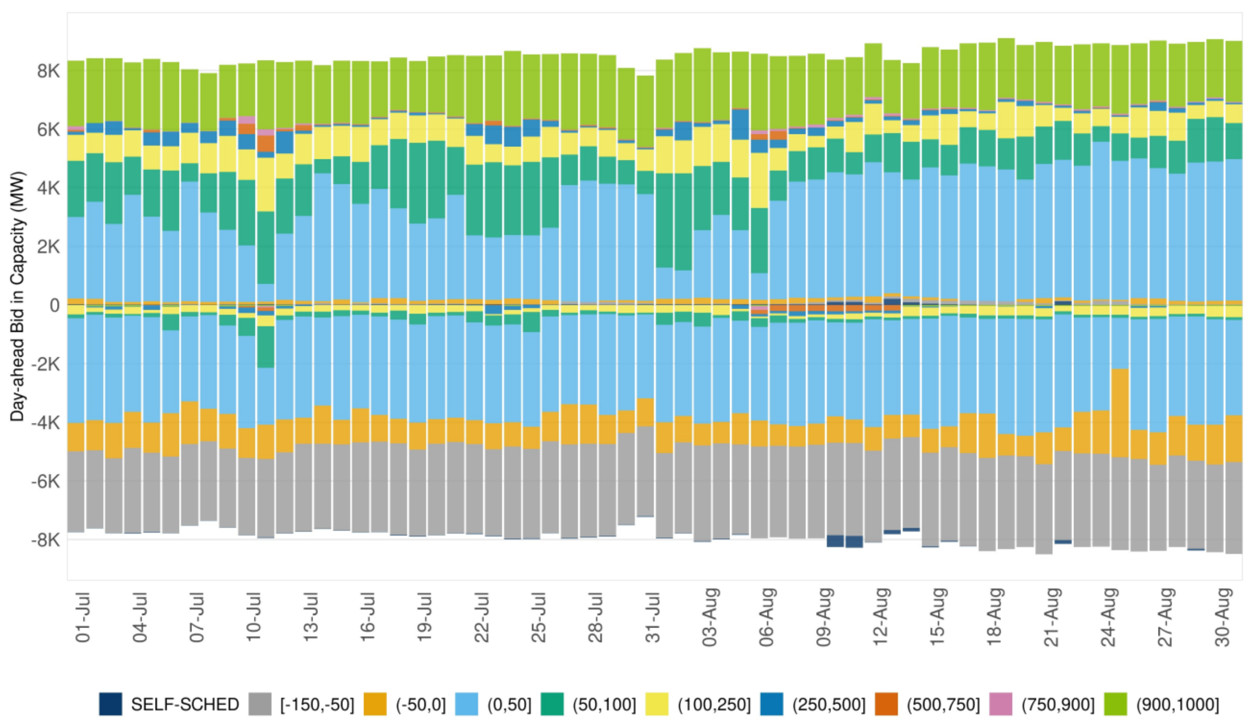
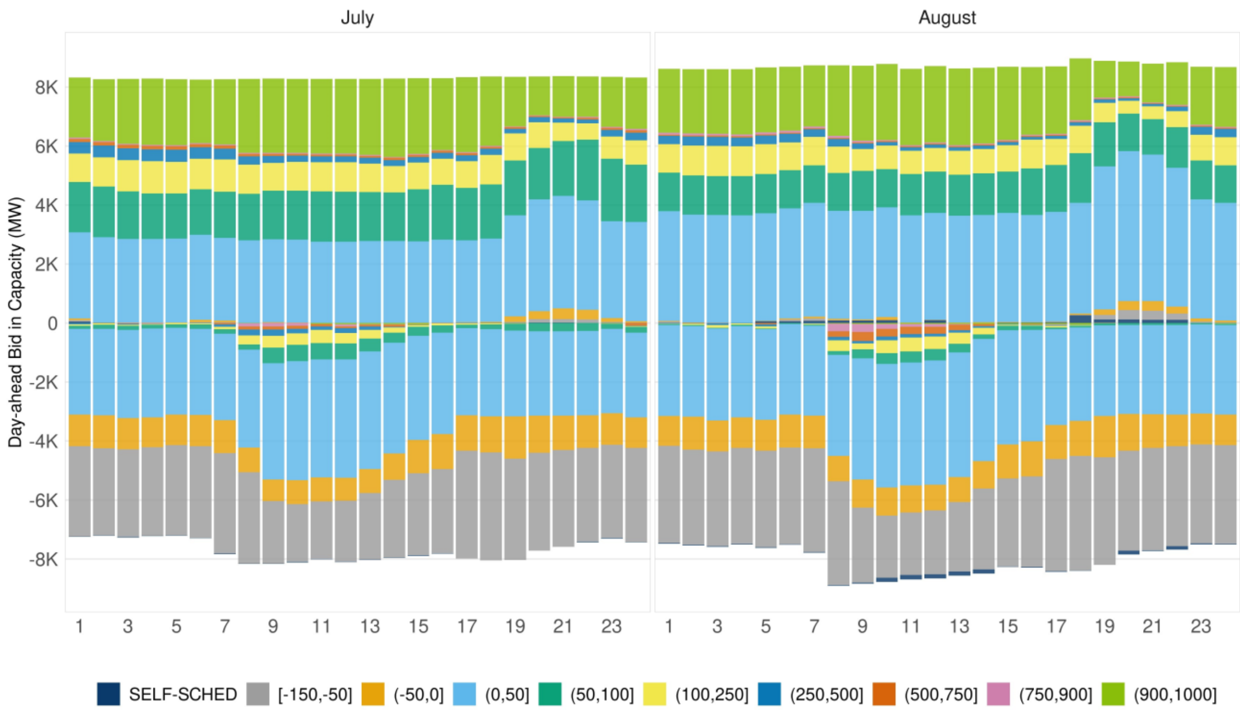


Figure 46: Bid-in capacity for batteries in the day-ahead market, hourly average



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 – 8,500 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 47 and Figure 48 present the bid-in capacity for the real-time market. The overall capacity follows the similar trend as the day-ahead market.

Figure 47: Bid-in capacity for batteries in the real-time market, daily average

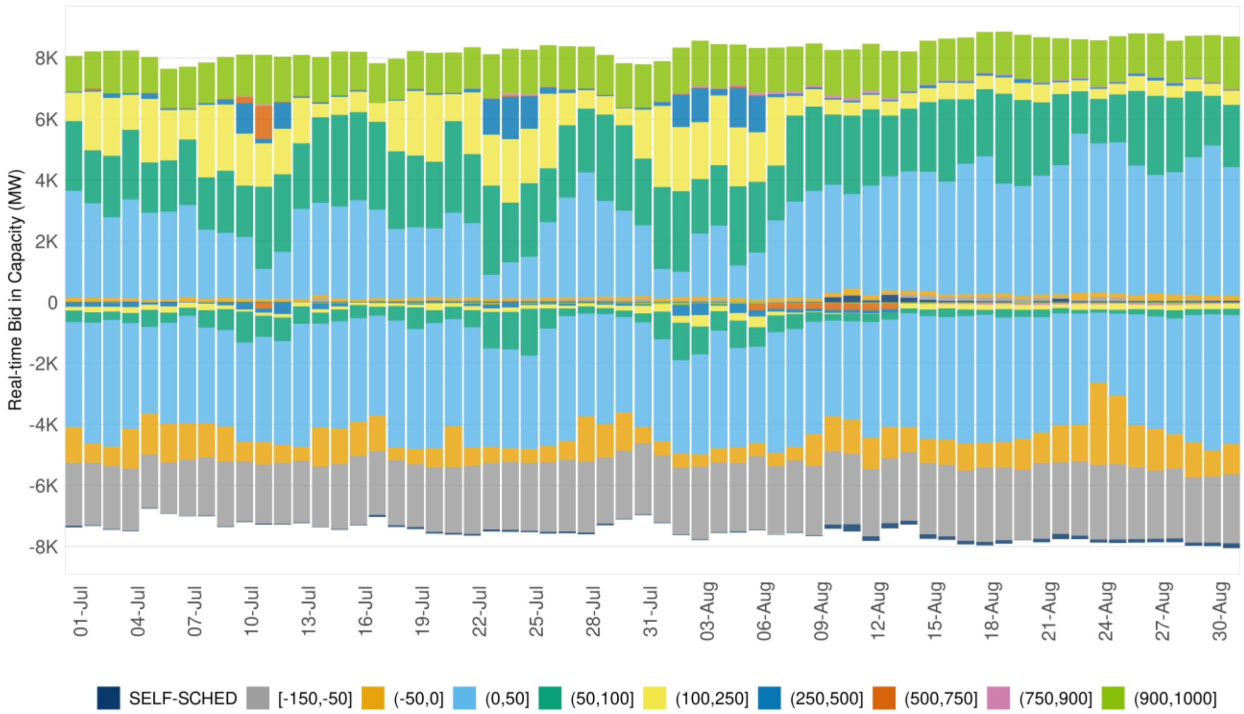


Figure 48: Bid-in capacity for batteries in the real-time market, hourly average

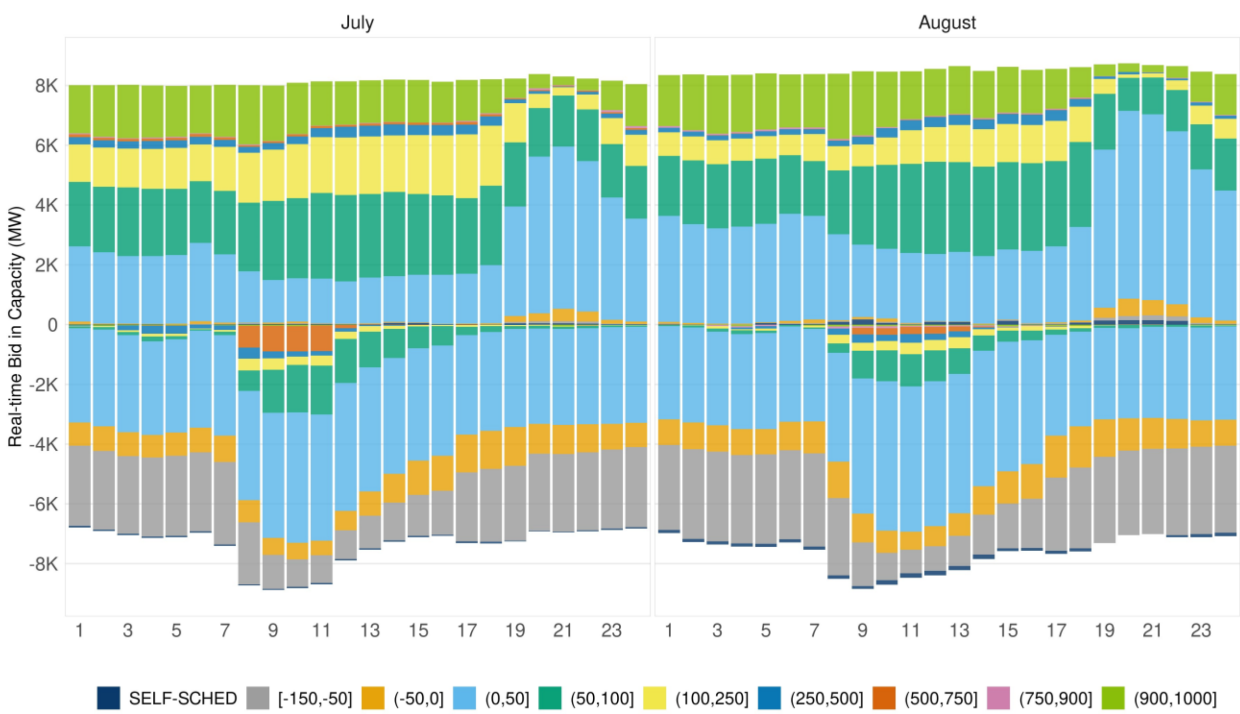


Figure 49: Distributions of state of charge for August 2024

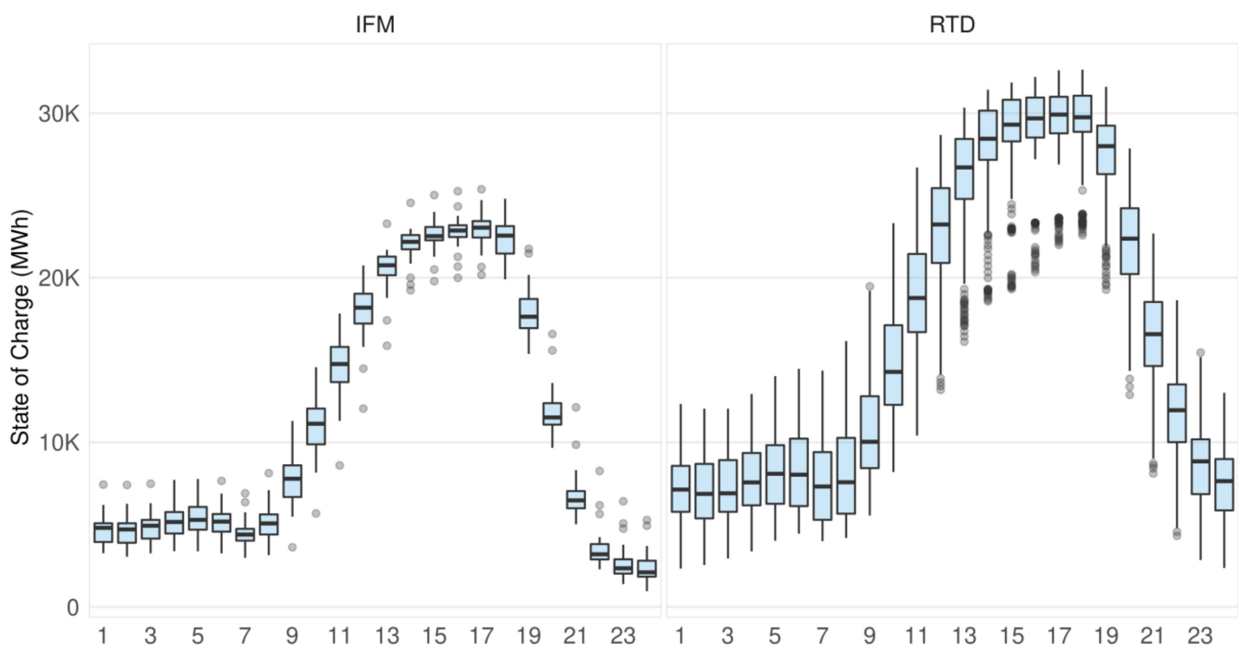


Figure 49 shows the hourly distribution of the state of charge for storage resources participating in IFM and RTD for August. The box plot shows the median, 25th percentile, 75th percentile, and outliers for the total state of charge. Storage resources charge in hours when there is abundantly cheap energy 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 August, the highest system state of charge in IFM was around 25,378 MWh, roughly 67 percent of the total capacity, which occurred in the hour ending 17. The peak hourly state of charge in the real-time market was 32,649 MWh in hour ending 18, at roughly 86 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 50 shows the distributions of energy awards in IFM, and Figure 51 shows the hourly distribution of real-time dispatch for batteries in July and August. These statistics are for batteries, either stand alone or the battery component of col-located resources; they do not include hybrid resources.

Figure 50: Hourly distribution of IFM energy awards for batteries

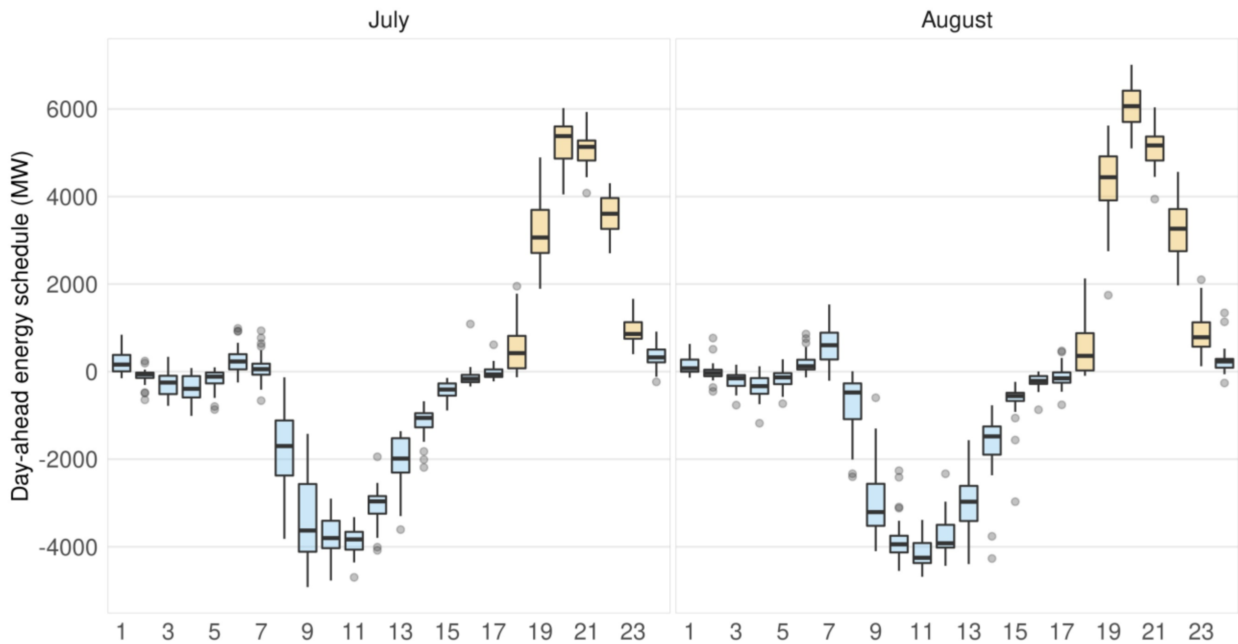
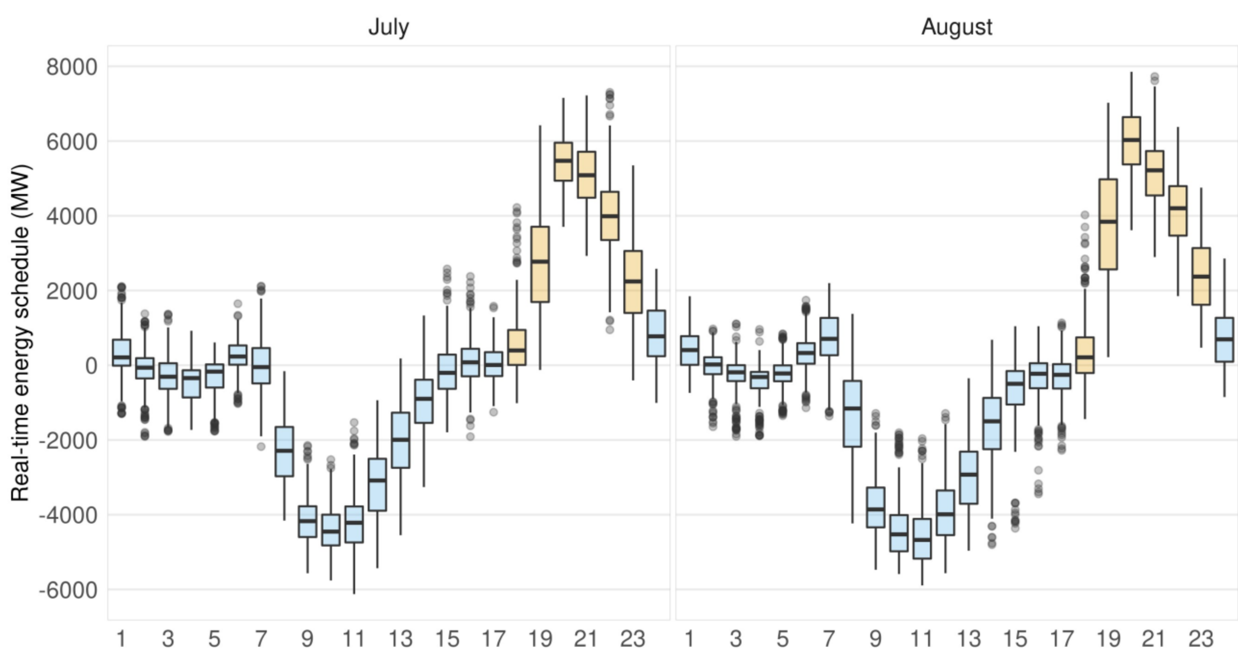
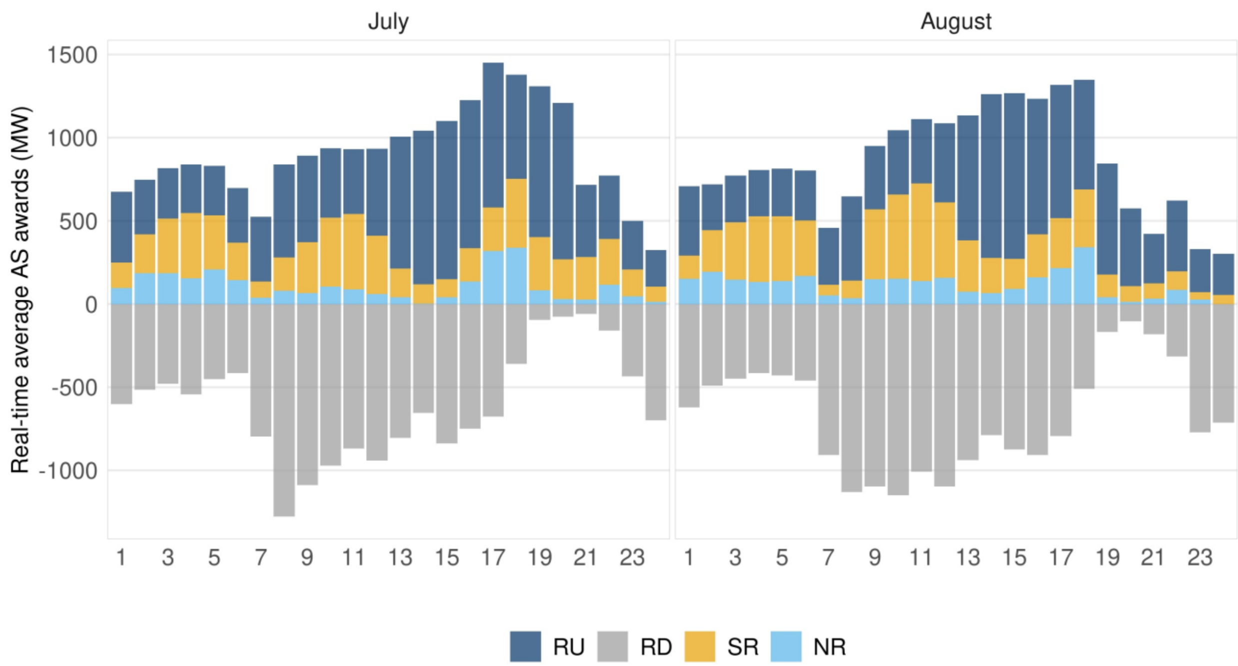


Figure 51: Hourly distribution of real-time dispatch for batteries



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 52 shows the average hourly AS awards in the real-time market.

Figure 52: 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 53 and Figure 54 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 and real – time market were similar for both August and July in the midday hours.

Figure 53: Hourly distribution of IFM energy awards for hybrid resources

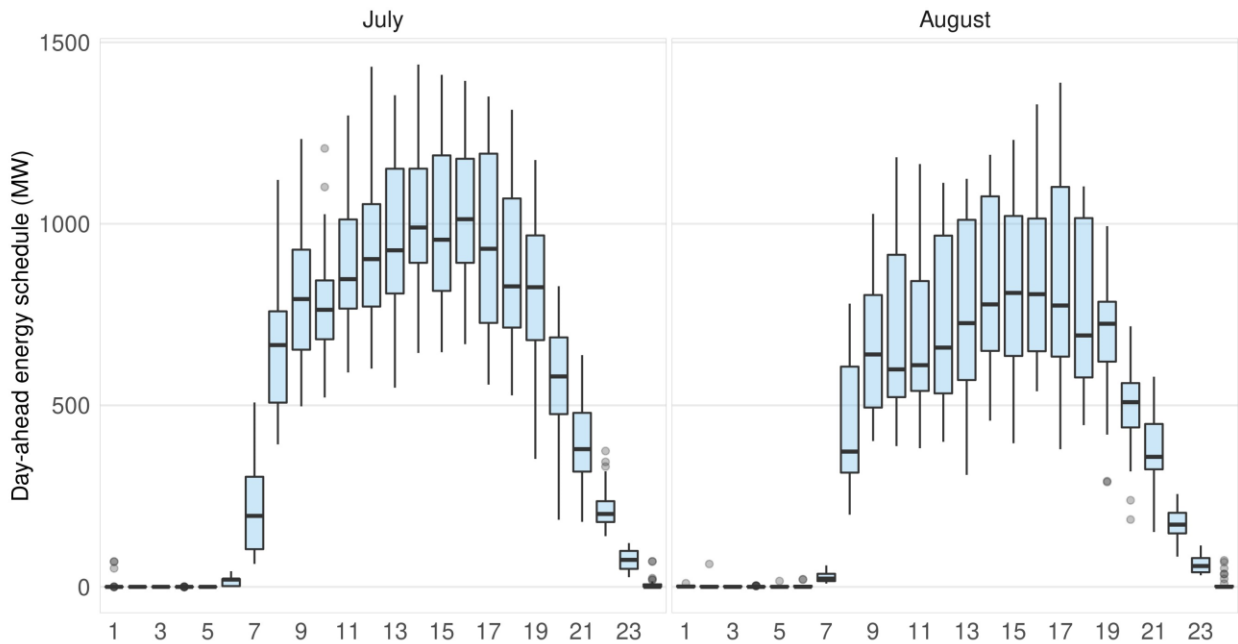
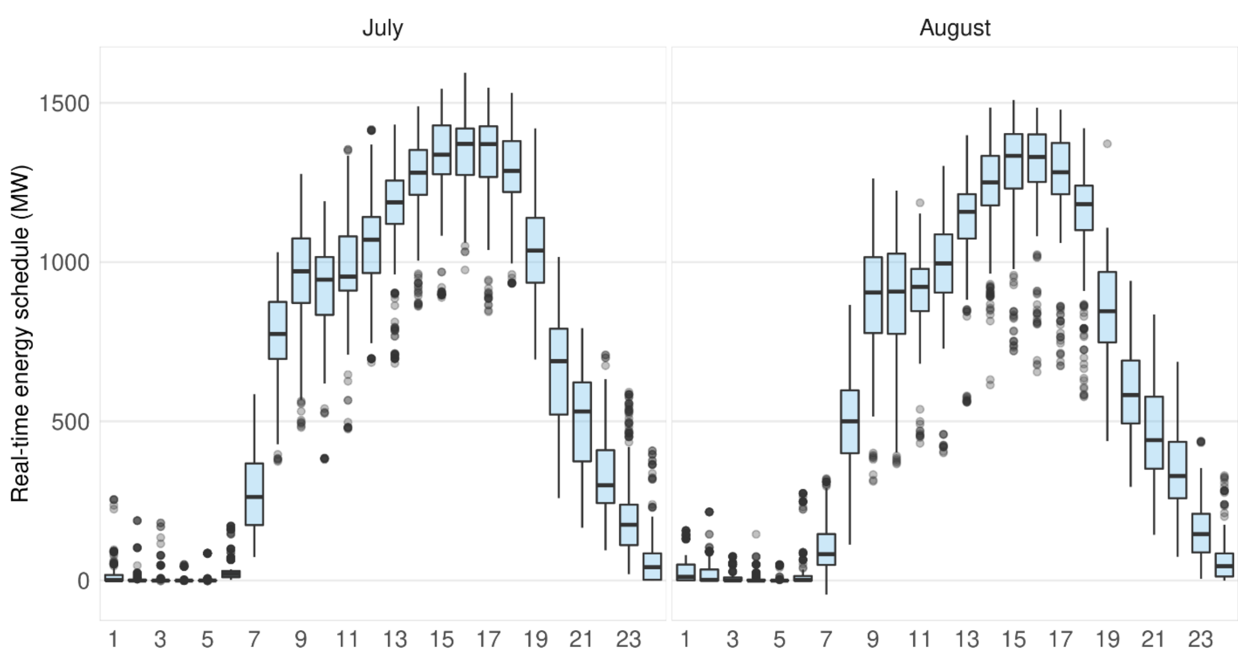
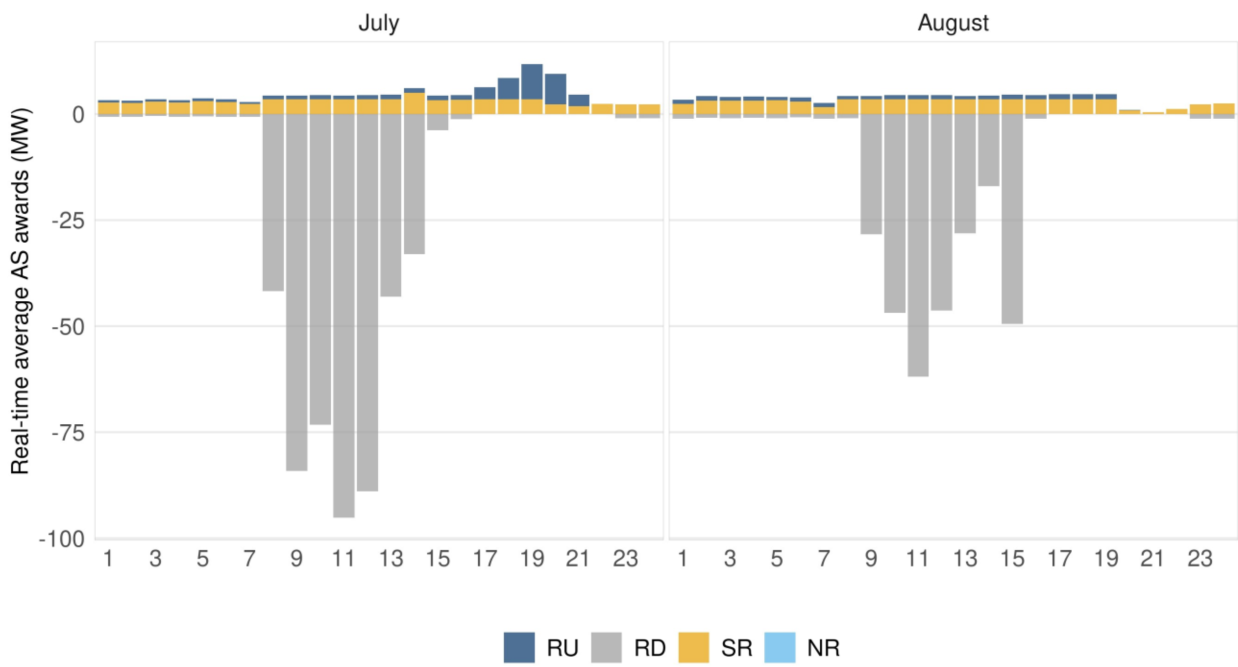


Figure 54: Hourly distribution of real-time dispatch for hybrid resources



Similar to storage resources, hybrid resources can also provide ancillary services to the market. Figure 55 shows the average hourly AS awards in real-time July and August 2024.

Figure 55: Hourly average real-time hybrid AS awards

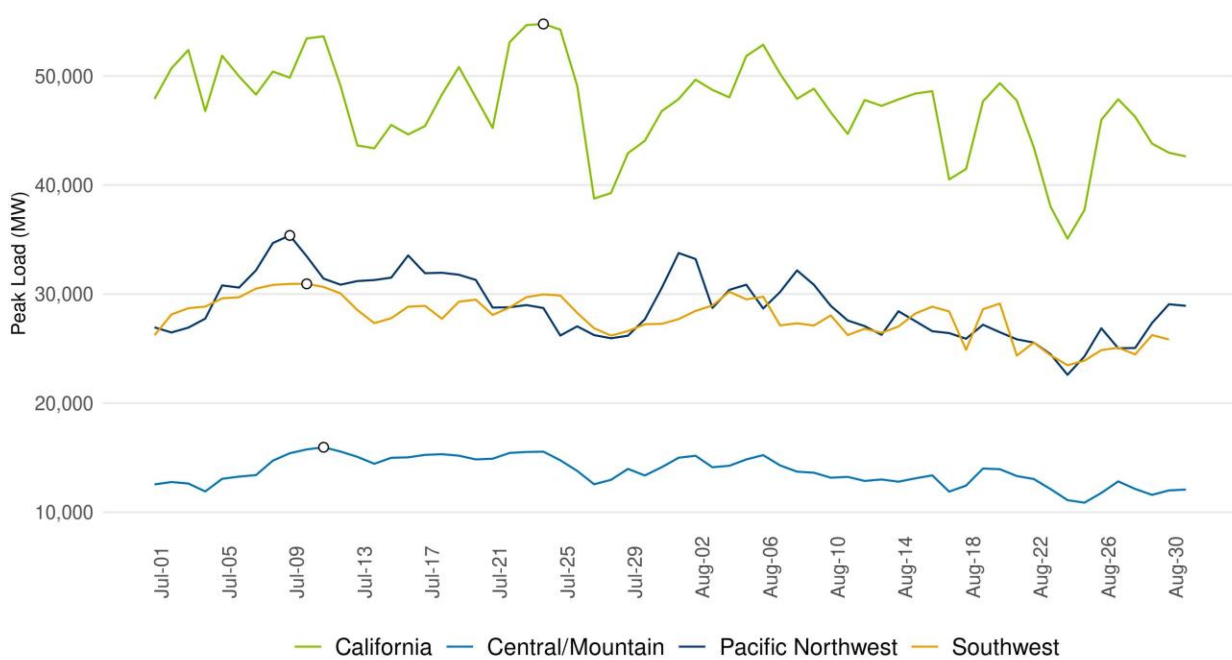


7 Western Energy Imbalance Market

Peak Load

Figure 56 shows the daily peak load aggregated by WEIM regions for the month of August[15]. The peak load for each day shows the comparison across July and August. The month of August saw a slight decrease in the peak load for the California region. Between the days in July and August, the peak load were highest in the month of July. The California region reached a maximum of 54,762 MW in the month of July. Similarly, the Central/Mountain reached a peak of 15,948 MW in the month of July. Pacific Northwest and Southwest reached a maximum of 35,375 MW and 30,934 in the month of July. The figure shows the circle marker indicating the peak load for that region for the month of July and August.

Figure 56: Peak load for the month of August 2024 across WEIM regions



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.[16] 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.

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

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

In a given interval, import and export transfers can concurrently happen for one area. In August, the ISO did not apply any transfer limits to dynamic transfers.

Figure 57 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 August 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.

Figure 58 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 57: Daily distribution of WEIM transfers for ISO area in RTD

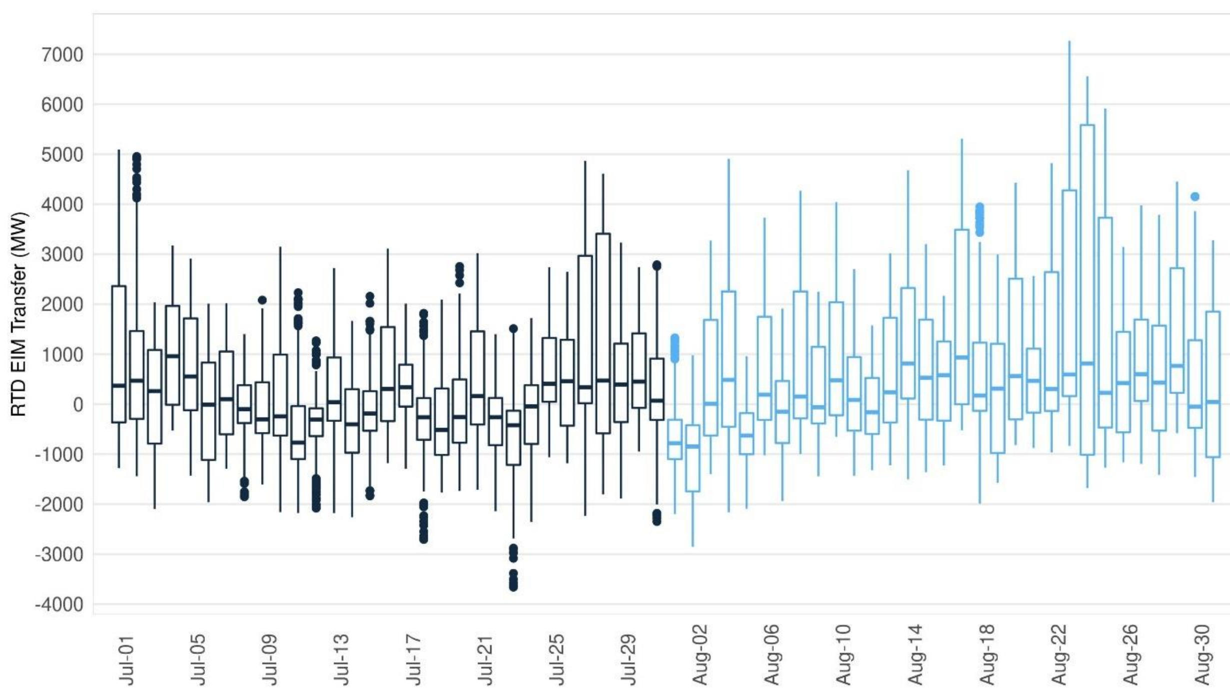


Figure 58: Hourly distribution of 5-minute WEIM transfers for ISO area

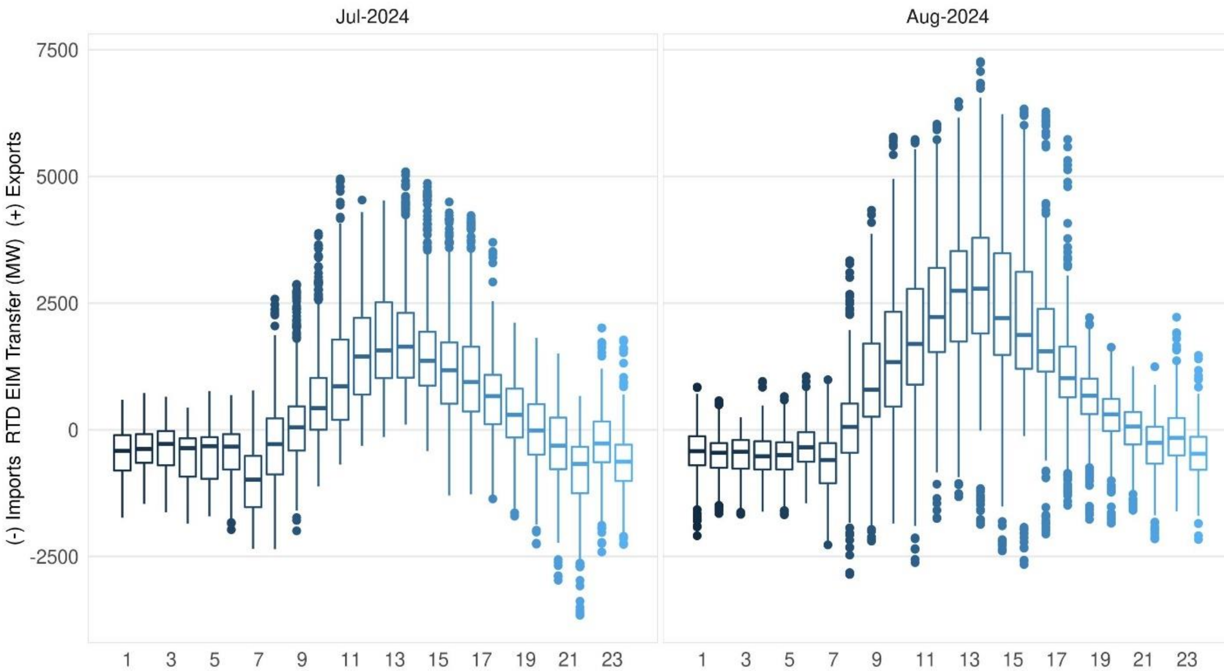


Figure 59: Daily distribution of 5-min WEIM transfers across regions

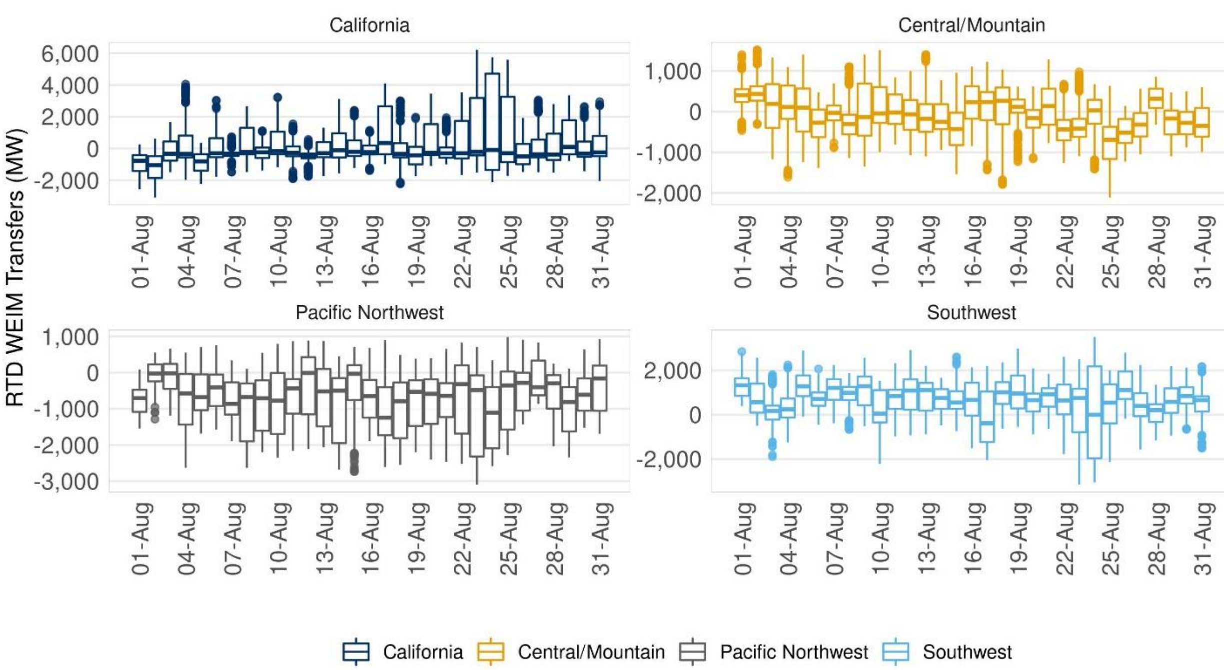
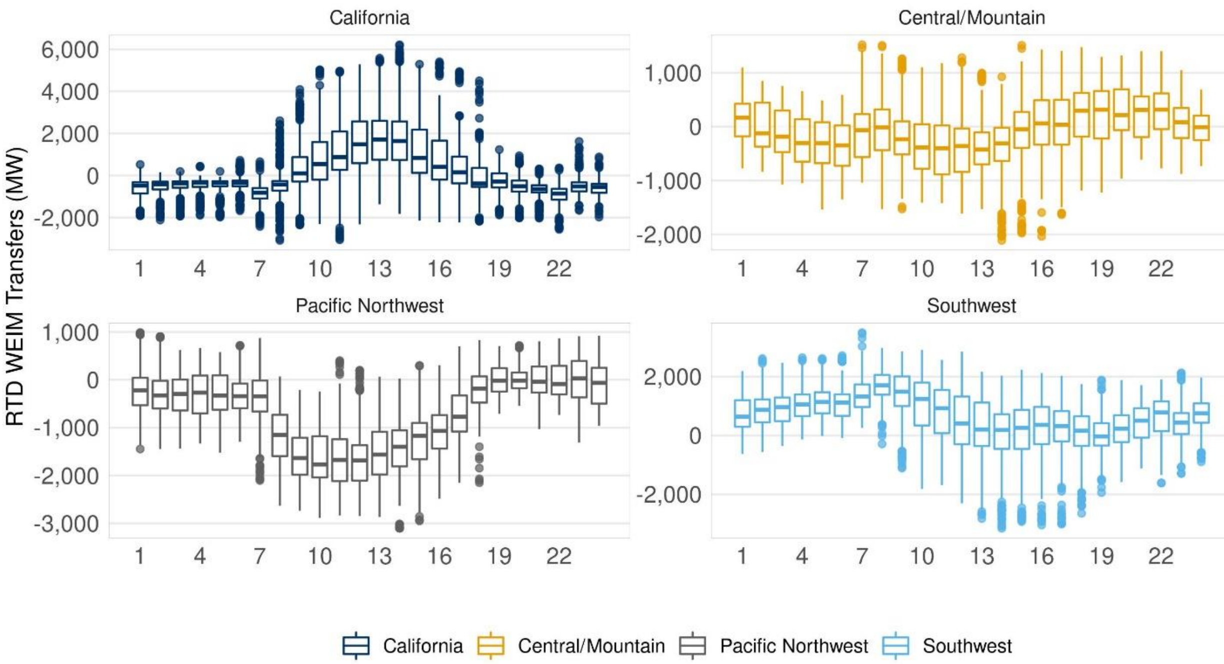


Figure 60: Hourly distribution of 5-min WEIM transfers across regions for the month of August 2024



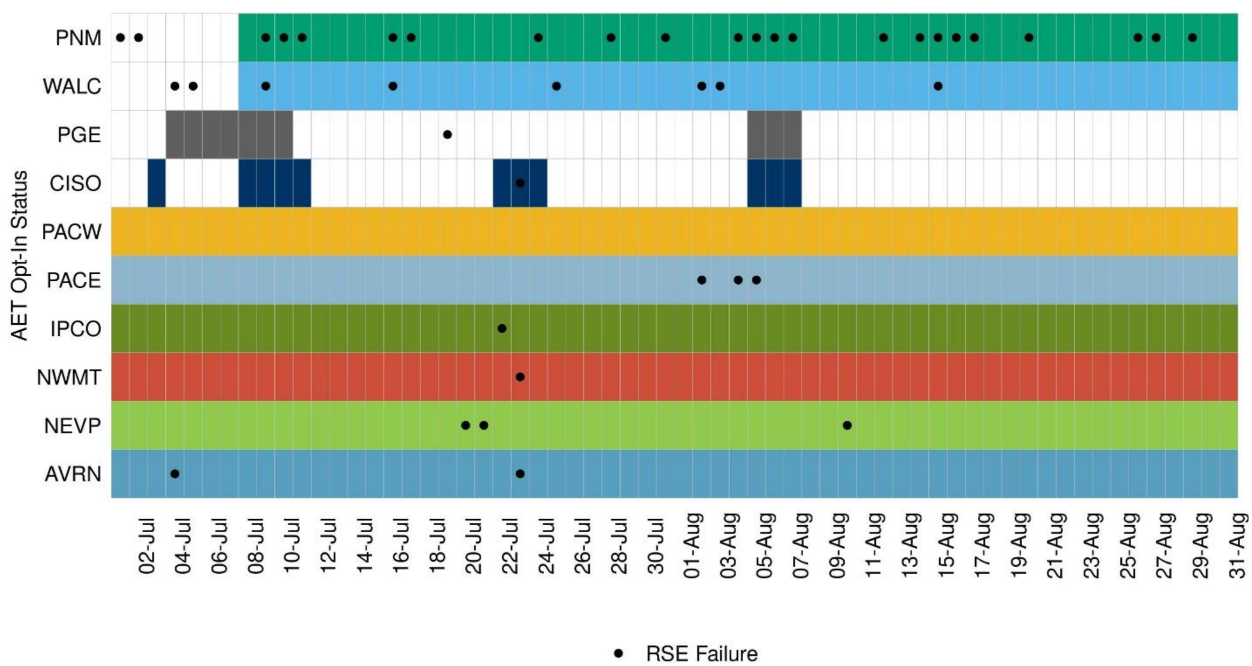
Assistance Energy Transfer

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.

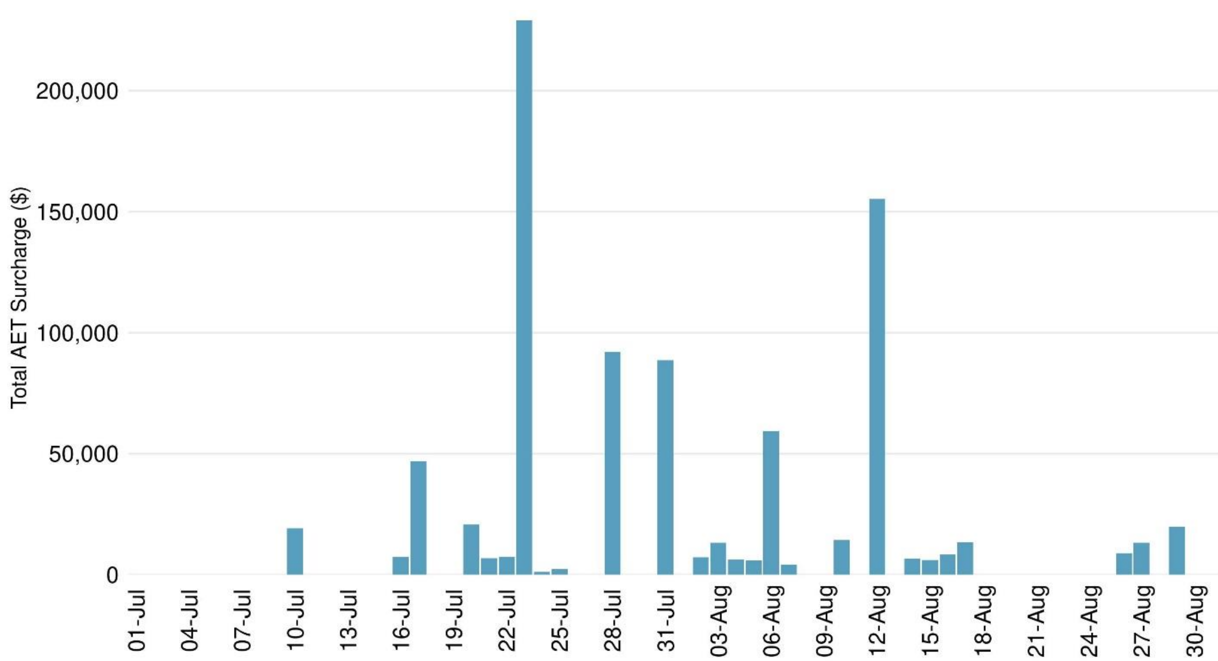
In August 2024, ten WEIM BAAs opted into AET for some duration of the month. Figure 61 shows six BAA entities that opted in for each trade date during July 2024 and eight BAA entities opted in August 2024 with a shaded box indicating opt-in status for that date, whereas two BAA entities opted-in some days on August 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 opted-in for three days.

Figure 61: BAAs opted into Assistance Energy Transfers, July and August 2024



The total AET surcharges assessed in August were approximately $863,540 for all the BAAs that opted in. shows the breakdown of total AET surcharges assessed per day for August2024. 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 fifteen trading days in August.

Figure 62: Total daily AET surcharge assessed, July and August 2024



8 Market Costs

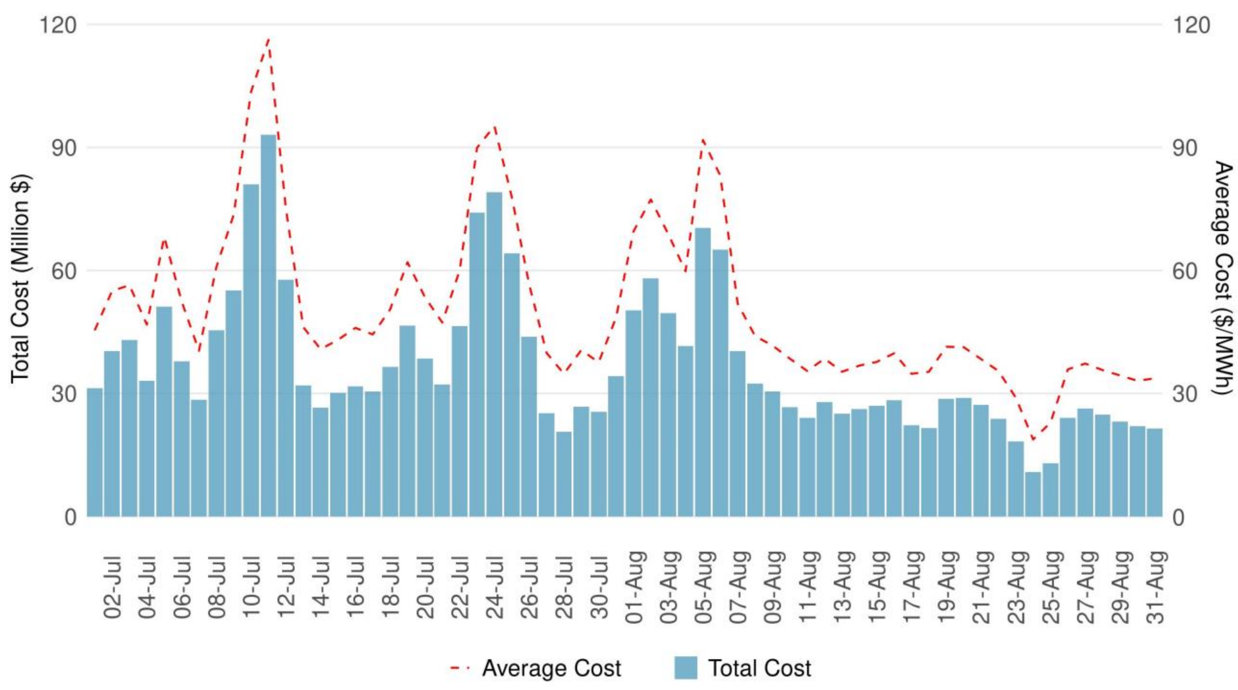
The ISO markets are settled based on awards and prices derived from the markets through specific settlement charge codes; these include day-ahead and real-time energy, and ancillary services, among others. The majority of the overall costs accrue on the day-ahead settlements.

Figure 63 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 August was $30.97 million, representing an average daily price of $43.79/MWh. The maximum daily cost of $70.34 million occurred on August 5. [17]

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

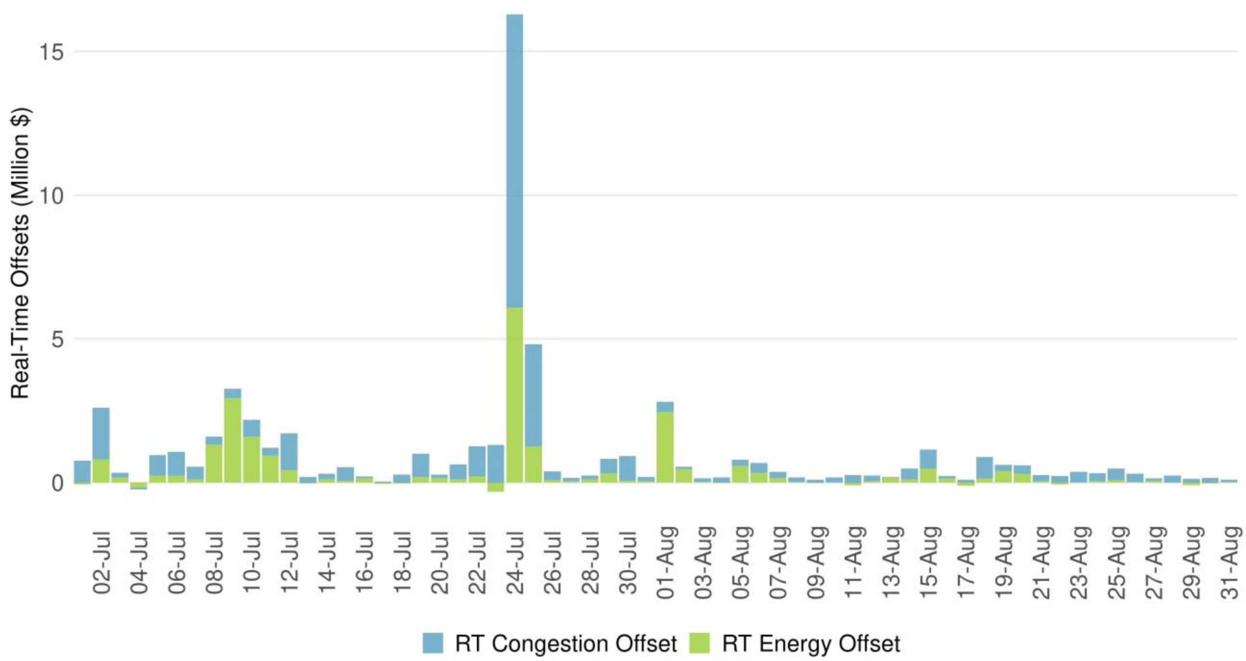
Figure 64.

Figure 63: ISO's daily total and average market costs



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

Figure 64: Real-time energy and congestion offsets for ISO area



9 Import market incentives during tight system conditions

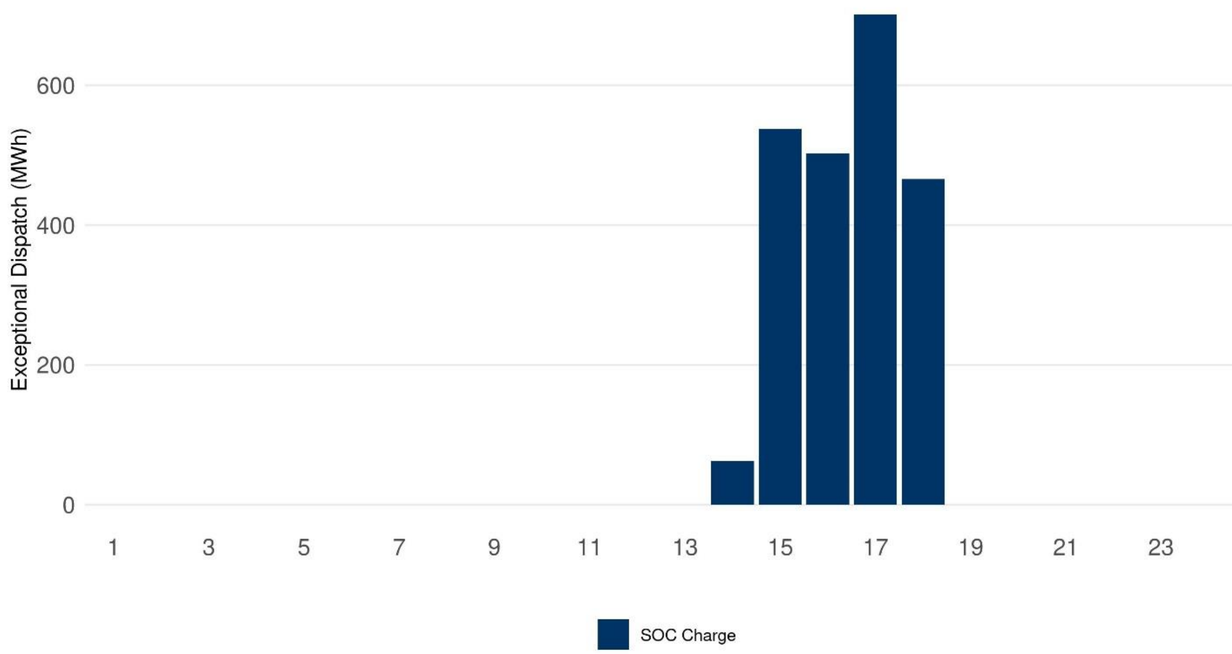
On June, 15, 2021, the ISO implemented an enhancement that provides improved incentives for import supplies to be available during tight system conditions because the prior settlement rules may have paid imports less than they bid, which could exacerbate conditions when supplies are tight. During very 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 August 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 August 2024, there was ED to charge SOC on August 2 to energy storage resources to hold their charge to a specific limit. There were seven resources that were issued exceptional dispatches to charge SOC. Below shows the hourly pattern for August 2 when SOC charge was issued.

Figure 65: Exceptional Dispatch volume for SOC Charge for August 2



11 Enhancements to Bidding Rules above the Soft Offer Cap

Through the Price Formation Enhancements (PFE) stakeholder working group[18], market participants requested policy enhancements that would allow resources with intra-day opportunity costs to reflect those costs in their energy bids particularly on days with stressed grid conditions when high prices can exceed the $1,000/MWh soft offer cap. On August 1, 2024, the ISO made effective two enhancements to the bidding rules for resources to bid above the $1,000/MWh soft offer cap. The enhancements were to (1) remove the $1,000/MWh cap on Default Energy Bids (DEBs), and (2) modify the real-time market bid cap for energy storage resources to provide bidding flexibility using a proxy opportunity cost value.

This section reviews the impacts of the new enhancements from the period of August 1 to September 8. The analysis concludes that the new functionality was not used since August 1, 2024. Firstly, while there was a DEB calculated above $1,000/MWh, there were no corresponding bids above $1,000/MWh. Additionally, the new storage bid cap did not increase above $1,000/MWh as none of the bid cap components were triggered, and consequently, there were no storage bids above $1,000/MWh in the market including on days with stressed grid conditions and high prices like September 5.

While stakeholders expressed concern that this policy change could increase prices, the backstops recommended by stakeholders worked and bidding seems competitive. One of the backstops stakeholders recommended was using the 4th highest MIBP instead of the highest, and in the first month of implementation although the MIBP did go over $1000/MWh the 4th highest did not, which

[18] https://stakeholdercenter.caiso.com/StakeholderInitiatives/Price-formation-enhancements

appropriately maintained the cap at $1000/MWh when prices stayed well below the cap. Some stakeholders were concerned that using the highest cost verified bid would raise the cap for everyone. Data shows that a DEB value did go above $1000/MWh but that resource still bid competitively and did not result in a higher cap for storage resources.

FERC Order No. 831 requires that bids above $1,000/MWh be cost verified by market operators. To comply with this order, the ISO uses its "reference level change request" (RLCR) process to verify the costs above $1,000/MWh. A reference level change request enables suppliers to update their DEBs, and if approved, enables them to bid up to their adjusted DEB if it exceeds the soft offer cap.

The DEB mirrors a resource's competitive marginal costs in the market in conditions when market participants might have market power. Absent perfect information, the DEB serves as a reasonable benchmark for a resource's specific short run marginal costs. Prior to August 1, 2024, all DEBs were capped at $1,000/MWh when initially calculated, but could be adjusted to above $1,000/MWh and up to $2,000/MWh through the RLCR process. However, a resource's DEB might have otherwise been calculated above $1,000/MWh if not for the cap on the DEB. In this case, though the ISO already has sufficient information to verify the resource's costs, the previous process required the resource's scheduling coordinator to take action through the RLCR process to reflect those costs in the market.

The RLCR process to adjust the DEB was initially designed to be tailored towards gas resources that faced discrepancies between their actual fuel costs and those that CAISO's market systems used to calculate their DEBs. However, it lacks similar functionality for processing changes to the opportunity costs associated with storage, hydro and demand response resources, because the ISO does not have rules to determine a reasonable cost expectation upon which to base an intra-day opportunity cost adjustment request. Without the ability to use the automated RLCR process, hydro and storage resources cannot request DEB adjustments and could not bid above the soft offer cap.

The two enhancements the ISO implemented on August 1, 2024 addresses these issues as follows:

1. Removing the $1,000/MWh cap on DEBs allows fuel or fuel equivalent based generating resources to bid up to a value above $1,000/MWh that reflects their marginal costs as defined by the DEB, and allows hydro resources to bid up to a value above $1,000/MWh that reflects their opportunity costs already defined in their DEBs, without needing to take action through the RLCR process.[19]

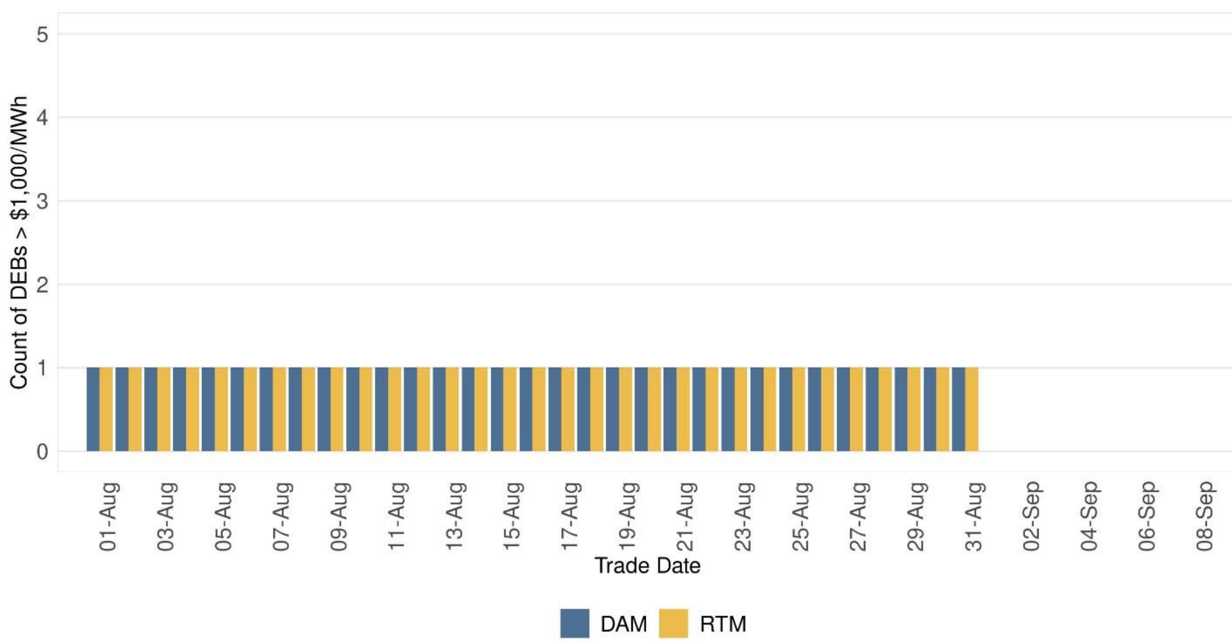
2. Modifying the bid cap for energy storage resources allows energy storage resources to bid up to a value above $1,000/MWh in the real-time market to indicate to the market their intra-day opportunity costs that support their availability for discharge during more stressed grid conditions when prices can exceed the soft offer cap. The new storage bid cap is calculated as:

[19] Storage DEBs could not be uncapped to go above $1,000/MWh due to implementation complexities which would delay the implementation of the enhancements

Storage bid cap = MAX (DEB[20], 1000, 4th highest RTM MIBP[21], highest cost-verified bid)

Figure 66 shows that, since August 1, 2024, there has been only one DEB calculated above $1,000/MWh. The DEB was for a hydro resource, and was driven by the monthly opportunity cost adder estimated for August, hence the DEB applied for the whole month of August in both the day-ahead and real-time markets.

Figure 66: Default Energy Bids (DEBs) calculated above $1,000/MWh



The storage bid cap remained at $1,000/MWh from August 1 to September 8 as none of the components of the storage bid cap calculation exceeded $1,000/MWh. There were no DEBs for storage resources above $1,000/MWh. There were no cost-verified bids above $1,000/MWh either from a RLCR or from a bid above $1,000/MWh when that resource's DEB was above $1,000/MWh. The 4th highest RTM MIBP reached a maximum of $488/MWh on September 5 as shown in

[20] Only applies to storage resources using a DEB option other than the Storage DEB
[21] Maximum Import Bid Price

Figure 67.

Figure 67: 4th highest MIBP from August 1 to September 8

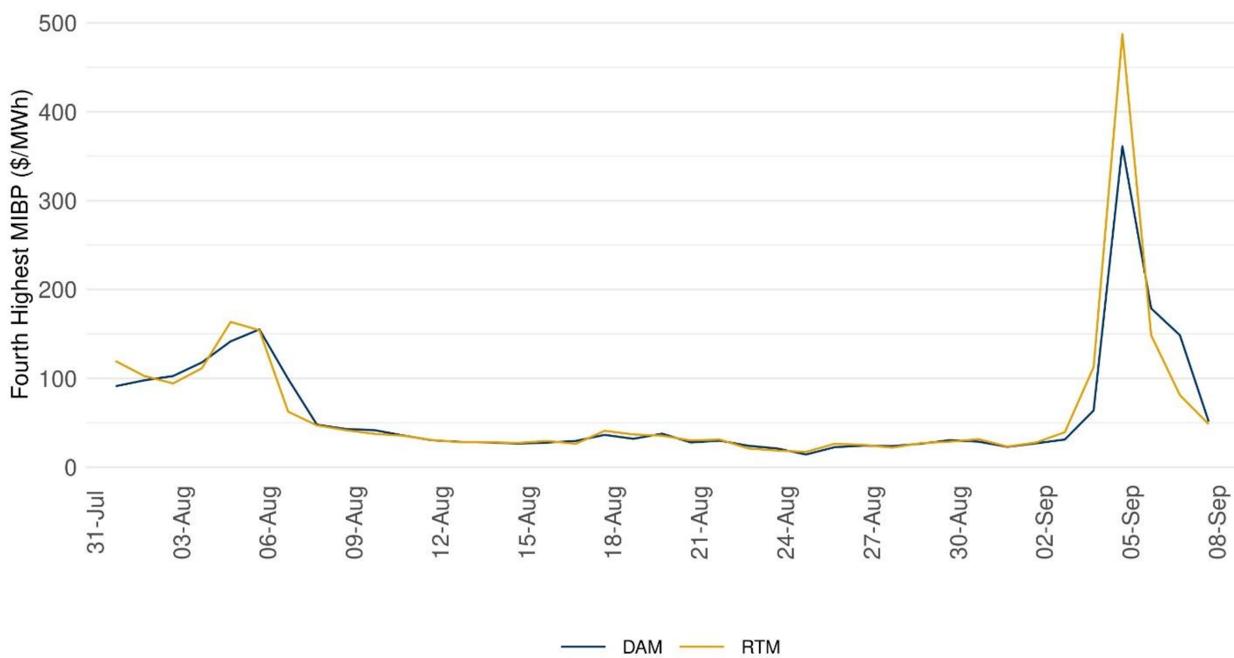
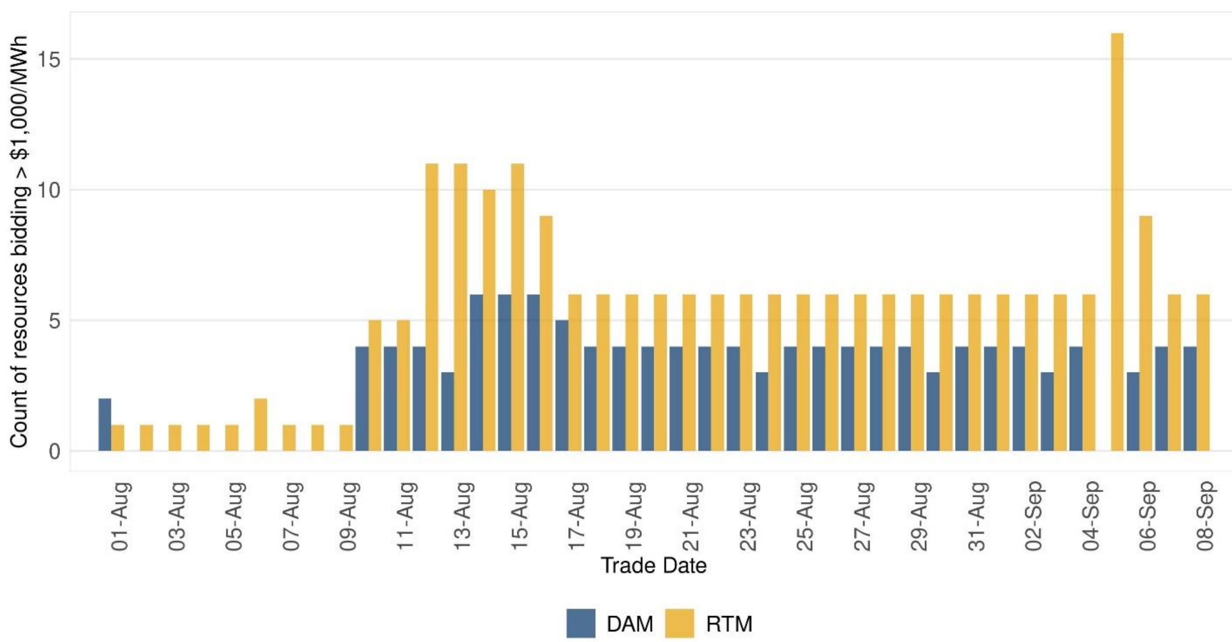


Figure 68 shows that storage resources submitted bids above $1,000/MWh each day from August 1 to September 8 in the real-time market, with the most bids above $1,000/MWh submitted on September 5. There were no storage resource bids in the market above $1,000/MWh during this period as expected since the storage bid cap remained at $1,000/MWh.

Figure 68: Storage resource bids above $1,000/MWh from August 1 to September 8



With the implementation of the enhancements, there was a bid validation issue with a very narrow and isolated impact. There were two distinct forms of the issue observed as described below.

In the first case, for a storage resource with two bid segments, one for charging and one for discharging, when the discharging bid was submitted above $1,000/MWh, the charging bid was revised inappropriately to $0/MWh. The issue was corrected in Production on July 31, 2024 before the real-time market for August 1. The impact extended to two resources in the day-ahead market for August 1.

MW1	MW2	Initial Bid	Revised Bid	Expected result	Comment
-75	0	-150	0	-150	Bid revised inappropriately
0	75	2000	1000	1000	Bid capped at $1000 appropriately

The second case affected storage resources with three or more energy bid segments. When the discharging bid for the highest segment was submitted above $1,000/MWh, and lower segment bid above the DEB value was revised inappropriately to the DEB. The issue was corrected in Production on August 8, 2024, and the impact extended to two resources for two days in the real-time market.

DEB	MW1	MW2	Initial Bid	Revised Bid	Expected result	Comment
0.2	-10	0	-15	-15	-15	Bid allowed as is
0.2	0	5	65	0.2	65	Bid revised inappropriately to DEB
0.2	5	10	1050	1000	1000	Bid capped at $1,000 appropriately

12 Areas for Improvement

Through the analysis of the market outcomes and performance, the ISO tracks any areas for improvements. There were two issues introduced with the implementation of the enhancements for the bid offer cap; these issues and their resolution are explained in detail in section 11 of this report.