



California ISO

Extended Day-Ahead Market Performance September Report

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California Independent System Operator

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Executive Summary

On May 1, 2026, the California ISO, in partnership with PacifiCorp, successfully launched the Extended Day-Ahead Market (EDAM) alongside a suite of Day-Ahead Market Enhancements (DAME). This September report is the fifth in a series of customized monthly reports assessing market performance during EDAM's initial months of operation. The report focuses on market outcomes across participating balancing authority areas (BAAs), including price formation, reliability, new product performance, congestion, transfers, and settlement outcomes.

September likely represented the last significant test of summer conditions for the year, including the highest peak load hour in CAISO, even as average hourly load declined from July and August. Consistent with those more moderate average conditions, wholesale prices fell from August levels and were generally comparable to July. In CAISO, September prices were also comparable to September 2025. The exception came during the September 9th peak, when high loads contributed to significant price increases in both CAISO and PacifiCorp West. Ancillary service prices were also elevated in the CAISO market on that day.

September brought another month of high demand conditions this summer, with CAISO recording a peak load of 50,335 MW on September 9, exceeding the California Energy Commission's month-ahead forecast of 46,360 MW. CAISO peak load exceeded 40,000 MW on 4 days during the month. The average daily peak load in September was lower than in August. While September experienced the highest peak load since EDAM implementation, load levels remained broadly consistent with recent historical experience and below monthly Resource Adequacy showings, indicating sufficient capacity and comfortable reliability margins throughout the period. As a result, many of the changes observed in September market outcomes were driven by seasonal fundamentals rather than changes in EDAM market design or performance. At the same time, EDAM market outcomes continued to stabilize as participants gained experience with the new market framework matured and multiple settlements issues have been addressed.

Key Takeaways

Transfers continued to adapt to changing regional conditions

EDAM transfers continued to demonstrate the ability of the expanded footprint to shift energy and flexibility among areas as operating conditions changed. The pattern that developed over the summer became increasingly clear by September:

- **Energy:** CAISO became increasingly reliant on imports as summer progressed, while PACE emerged as a significant net exporter.
- **Imbalance Reserve Up:** CAISO remained an important supplier of upward flexibility, particularly to PACE, while PACW became a more meaningful source for CAISO during key operating hours.
- **Imbalance Reserve Down:** The most significant shift occurred in downward reserves. CAISO's large exports earlier in the summer declined, while PACE transitioned from a net importer to the principal exporter by September.
- **Reliability Capacity Up:** Regional transfers increased through the summer, reaching their highest levels in August before moderating somewhat in September. CAISO remained predominantly an importer, with PACE and PACW supplying upward capacity.
- **Reliability Capacity Down:** Transfer activity declined as the summer progressed and was relatively limited by September.

Taken together, these patterns show that regional sharing remained important even as September conditions moderated. More importantly, the source and direction of that flexibility changed over the summer, demonstrating how EDAM transfers can adapt dynamically to changing system needs.

Imbalance reserves provided flexibility at generally lower prices

Imbalance Reserves (IR) continued to provide flexible capacity to manage changes in load and renewable forecasts between the day-ahead and real-time markets. EDAM's broader footprint reduced combined reserve requirements by sharing variability across participating areas. Requirements remained broadly stable in CAISO and PACE, while declining in PACW.

Imbalance Reserve Up (IRU) prices fell from August across all three areas, with PACE's monthly average declining from \$4.84/MWh to \$2.37/MWh. Prices generally peaked around morning and evening ramping periods and rose during tighter conditions. On September 9, daily average IRU prices reached \$11.87/MWh in CAISO, \$7.22/MWh in PACW, and \$6.36/MWh in PACE. Imbalance Reserve Down (IRD) prices remained low in CAISO and PACE, while PACW experienced several late-month spikes, including a daily average of \$12.99/MWh on September 30. IRU procurement costs across the three areas totaled \$2.9 million, down from \$5.3 million in August, while IRD costs totaled \$0.41 million.

Across the EDAM footprint, more than 80 percent of awarded upward reserve capacity was available in real time in all hours, while downward availability exceeded 90 percent most of the time. In September, the share of day-ahead awards deployed in the fifteen-minute market averaged 13 percent upward and 12.8 percent downward in CAISO, 59 percent and 24 percent in PACE, and 19.1 percent and 24.7 percent in PACW, respectively. PACE's upward utilization increased from 43.2 percent in August, while CAISO's and PACW's declined. Deployment in both directions was generally higher during morning and evening peak hours.

Lower utilization did not necessarily indicate unavailable capacity: approximately 60 percent of CAISO's upward awards were not deployed because gas resources remained offline when starting and operating them was uneconomic. In PACE and PACW, the largest category of unused upward capacity was on resources already online but more expensive to dispatch than other available supply. Resources without day-ahead reserve awards, including those elsewhere in WEIM, could also meet realized needs at lower cost.

Congestion generally had a limited effect on reserve prices, although contingency-related constraints not modeled in the day-ahead reserve scenarios could restrict delivery in real time.

Reliability capacity costs and RUC adjustments declined

Reliability Capacity (RC) prices generally declined across the three balancing areas but rose when system needs tightened. On September 9, daily average upward RC prices reached \$24.15/MWh in CAISO and \$19.37/MWh in PACE. PACW experienced higher downward prices later in the month, reaching a daily average of \$27.77/MWh on September 18.

CAISO's upward RC procurement costs fell to \$1.51 million from \$14.5 million in August. Costs in PACE and PACW were generally consistent with August, aside from lower upward RC costs associated with reduced procurement.

Residual Unit Commitment (RUC) adjustments, historically used to account for uncertainty outside standard market procurement, occurred 11 percent of the time in September, compared with 65 percent in September 2025. No RUC infeasibilities were observed. These results suggest that the new reserve framework may be reducing reliance on RUC adjustments, although additional experience is needed to assess that relationship.

Congestion remained concentrated within the CAISO footprint

Congestion continued to be driven primarily by transmission constraints within the CAISO footprint, with much of the congestion reflecting north-to-south patterns. Total congestion revenues declined to \$52.7 million in September from \$74.5 million in August,

consistent with generally lower prices and more moderate average system conditions. Preliminary results indicate that nearly \$400,000 in net congestion revenues were allocated to the PacifiCorp areas. Putting these values into broader context of the market costs, congestion represented roughly 5% of the overall wholesale market costs in September, a figure generally consistent with the long-run trend in the CAISO market pre-EDAM launch.

Wholesale costs eased from August but remained above last year

Lower average prices and more moderate system conditions contributed to a decline in total wholesale costs from August. Total wholesale energy costs in CAISO decreased from approximately \$1.3 billion in August to approximately \$1 billion in September, equivalent to an average energy cost of \$51.4/MWh. September 2026 wholesale energy costs were roughly 5 percent higher than September 2025 levels.

Settlement outcomes continue to be closely reviewed

While EDAM's operational results have generally been encouraging, settlement outcomes remain an area for continued review. Energy and congestion offsets, which reconcile differences between amounts collected and paid through market settlements, have at times been larger or more variable than historical experience. Day-ahead energy offsets generally increased as summer loads and prices rose, while real-time energy offsets changed materially following EDAM implementation. Because EDAM introduced area-specific marginal energy costs and revised greenhouse gas accounting, post-implementation energy offsets are not directly comparable with historical results.

Bid Cost Recovery (BCR) outcomes also warrant continued monitoring. After adjusting for identified settlement issues, IFM BCR increased in September following declines during the first several months of EDAM, while total RTM BCR continued to decline. September RTM BCR totaled approximately \$4.8 million across the three EDAM areas, down from roughly \$8.3 million in August. IFM BCR, however, increased to approximately \$5.1 million from \$6.2 million in August as reported, although the August and September PACE values remain subject to correction. Several other BCR results, including the approximately \$1.9 million CAISO RTM BCR on August 26, are also expected to change through settlement recalculations.

These results highlight an important distinction between market operations and settlement performance. While EDAM's energy and reliability products have demonstrated increasing regional coordination during their first summer, the settlement framework remains an area where additional experience, data corrections, and analysis are needed to better understand outcomes and identify potential improvements.

Other market performance indicators remained strong

Operational performance remained generally strong despite more challenging summer conditions.

- No Resource Sufficiency Evaluation failures occurred in any EDAM BAA.
- Convergence bidding activity increased in September compared to August and cleared bids were mostly net supply.
- Average day-ahead GHG price was \$9.33/MWh and followed expected intraday patterns.
- EDAM results were posted before 1:00 p.m. on 77 percent of September operating days, higher than August with 46 percent, with most delays occurring during periods of higher market demand and increased complexity.
- Based on early EDAM operational experience, the ISO is implemented an enhancement effective October 1, 2026, to improve the treatment of storage resources in the Residual Unit Commitment process. The enhancement will enable greater use of storage resources in the day-ahead market. The ISO will report on its performance in the subsequent report.
- Market issues continued to be tracked through stakeholder forums and monthly reporting processes.

Conclusion

September continued to provide meaningful assessment of EDAM performance under sustained summer operating conditions. Higher temperatures, stronger regional demand, and drove most of the notable differences between September, August, July and the May-June implementation period, including higher prices, changing transfer patterns, greater reliance on imports during peak periods, and increased market costs.

Despite these more challenging conditions, EDAM continued to operate reliably and largely as expected. Market outcomes generally became more stable over the first three months of operation, reliability products functioned effectively during periods of elevated demand, and interregional transfers helped balance supply and demand across the Western footprint. These results suggest that EDAM provides value under both moderate spring conditions and more demanding summer operating environments, while market participants continue to gain experience with the new framework.

Table of Contents

Executive Summary	iii
Table of Contents	viii
Figures	xi
Introduction	18
Day-Ahead Market Run	19
Resource Sufficiency Evaluation	21
Day-Ahead Market Products.....	23
Day-Ahead Demand	23
Day-Ahead Supply	25
Energy prices.....	29
Price Volatility	34
Changes in price formation with EDAM.....	37
Marginal energy cost	37
GHG prices	40
Bilateral power price comparisons	41
Ancillary services	46
Imbalance reserves	48
Imbalance reserve prices	48
Imbalance reserve requirements	53
Imbalance reserve awards.....	57
Imbalance reserves input bids	59
Imbalance reserve utilization	71
Reliability capacity.....	82
Reliability capacity prices	82
Reliability capacity procurement	87
Reliability capacity input bids.....	89
Export reduction	97
Convergence bids	99
Greenhouse gas emission product.....	102
CAISO/MD&A/MPAA	viii
CAISO Public	

EDAM Transfers	107
Energy transfers.....	107
Imbalance reserves transfers	113
Imbalance reserve up.....	113
Imbalance reserve down	120
Reliability capacity transfers.....	126
Reliability capacity up	126
Reliability capacity down	133
Congestion	138
Parallel flows.....	141
Congestion revenues.....	145
Congestion revenue rights.....	153
EDAM Net Export Constraints and RUC Adjustments	155
EDAM net export constraints	155
RUC adjustments	156
RUC infeasibilities	161
Transitional Pricing	162
Market Power Mitigation.....	163
Summer Conditions	167
Peak ISO Load	167
RUC Adjustment	169
Market Prices.....	170
Renewable Production.....	175
Demand Response.....	177
Intertie Transactions	179
Intertie supply	180
Storage and Hybrid Resources	188
Western Energy Imbalance Market	199
WEIM transfers.....	201
Assistance energy transfer	205

Market Costs	208
Wholesale costs	208
Bid cost recovery	210
Market offsets.....	213
Day-Ahead congestion offset	214
Day-Ahead energy offset	215
Real-Time congestion offset	216
Real-Time imbalance energy offset	217
Imbalance reserves	220
Reliability capacity.....	222
GHG settlement	225
Market Issues	227
Stakeholder Feedback and ISO's responses	229

Figures

Figure 1: Run times for the extended day-ahead market.....	20
Figure 2: Average upward and downward requirements by area and month	22
Figure 3: Bid-in demand vs. day-ahead demand	24
Figure 4: Hourly average energy awards by fuel type for CAISO	25
Figure 5: Hourly average energy awards by fuel type for PACE	26
Figure 6: Hourly average energy awards by fuel type for PACW	27
Figure 7: Pricing of EDAM products for September 2026	28
Figure 8: Monthly average LMP since May 2026	30
Figure 9: Monthly average LMP for CAISO area since January 2025	30
Figure 10: Monthly average LMP for PACW since January 2025	31
Figure 11: Monthly average LMP for PACE since January 2025	31
Figure 12: Daily average IFM LMP by BAA	32
Figure 13: Average difference between IFM LMP and FMM LMP	33
Figure 14: Hourly IFM LMP averaged by month.....	34
Figure 15: CAISO RTD LMP range frequency	35
Figure 16: PACW RTD LMP range frequency	35
Figure 17: PACE RTD LMP Range Frequency	36
Figure 18: Frequency of low- and high-end RTD LMPs	36
Figure 19: LMP Decomposition for Non-CAISO WEIM BAA.....	37
Figure 20: Average monthly LMP components	41
Figure 21: Monthly average LMPs and bilateral power prices	43
Figure 22: Daily average LMPs and bilateral power prices	43
Figure 23: Total monthly energy volume of bilateral trades (On-peak)	44
Figure 24: Monthly total energy volume of bilateral trades (Off-peak)	44
Figure 25: Total daily energy volume of bilateral trades (On-peak)	45
Figure 26: Total daily energy volume of bilateral trades (Off-peak)	46
Figure 27: Daily average of CAISO ancillary services prices in IFM	47
Figure 28: Monthly average AS prices in CAISO	48
Figure 29: Monthly average IR prices.....	49
Figure 30: Frequency of IRU price ranges	50
Figure 31: Frequency of IRD price ranges	50
Figure 32: Daily average price of IRU	51
Figure 33: Daily average price of IRD	51
Figure 34: Hourly average price of IRU	52
Figure 35: Hourly average price of IRD	53
Figure 36: Hourly average of IR requirements for CAISO	54

Figure 37: Hourly average of IR requirements for PACE	54
Figure 38: Hourly average for IR requirements for PACW	55
Figure 39: Hourly average diversity benefit, IRU	56
Figure 40 Hourly average diversity benefit, IRD	56
Figure 41: Hourly average cleared IR by fuel type for CAISO	57
Figure 42: Hourly average cleared IR by fuel type for PACE	58
Figure 43: Hourly average cleared IR by fuel type for PACW	58
Figure 44: Hourly average volume of IR bids organized by price for CAISO	60
Figure 45: Daily average volume of IR bids organized by price for CAISO	60
Figure 46: Hourly average volume of IR bids organized by fuel type for CAISO	61
Figure 47: Daily average volume of IR bids organized by fuel type for CAISO	61
Figure 48: Hourly average volume of IR bids by price for PACE	62
Figure 49: Daily average volume of IR bids by price for PACE	63
Figure 50: Hourly average volume of IR bids by fuel type for PACE	64
Figure 51: Daily average volume of IR bids by fuel type for PACE	64
Figure 52: Hourly average volume of IR bids organized by price for PACW	65
Figure 53: Daily average volume of IR bids organized by price by PACW	66
Figure 54: Hourly average volume of IR bids organized by fuel type for PACW	67
Figure 55: Daily average volume of IR bids organized by fuel type for PACW	67
Figure 56: Average imbalance reserve demand curve procurement, IRU	68
Figure 57: Average imbalance reserve demand curve procurement, IRD	69
Figure 58: Average net demand with imbalance reserve procurement, CISO	70
Figure 59: Average net demand with imbalance reserve procurement, PACE	70
<i>Figure 60: Average net demand with imbalance reserve procurement, PACW</i>	<i>71</i>
Figure 61: Hourly average IR requirement, procurement and utilization. CISO	72
Figure 62: Hourly average IR requirement, procurement and utilization. PACE	73
Figure 63: Hourly average IR requirement, procurement, and utilization, PACW	73
Figure 64: IRU awards: real time breakdown, CAISO	74
Figure 65 IRU awards: real time breakdown, PACE	75
Figure 66. IRU awards: real time breakdown, PACW	75
Figure 67: Percentage IRU availability in FMM for EDAM footprint	76
Figure 68: Percentage IRD availability in FMM for EDAM footprint	77
Figure 69: Hourly IR up utilization distribution in EDAM footprint	77
Figure 70: Hourly IR down utilization distribution in EDAM footprint	78
Figure 71: Nodal IRU congestion component of the IRU marginal price	79
Figure 72: Nodal IRD congestion component of the IRD marginal price	79
Figure 73: CISO IRU award concentration based on IFM and FMM participation	81
Figure 74: Monthly average price of RCU and RCD	83
Figure 75: Frequency of RCU price ranges	84

Figure 76: Frequency of RCD price ranges	84
Figure 77: Daily average price of RCU	85
Figure 78: Daily average price of RCD	85
Figure 79: Hourly average price of RCU	86
Figure 80: Hourly average price of RCD	87
Figure 81: Hourly average of RC procurement for CAISO	88
Figure 82: Hourly average of RC procurement for PACE	88
Figure 83: Hourly average of RC procurement for PACW	89
Figure 84: Hourly average volume of RC bids by price for CAISO	90
Figure 85: Hourly average volume of RC bids by fuel type by CAISO	90
Figure 86: Daily average volume RC bids by price for CAISO	91
Figure 87: Daily average volume of RC bids by fuel type for CAISO	91
Figure 88: Hourly average volume of RC bids by price for PACE	92
Figure 89: Hourly average volume of RC bids by fuel type for PACE	93
Figure 90: Daily average volume of RC bids by price by PACE	94
Figure 91: Daily average volume of RC bids by fuel type by PACE	94
Figure 92: Hourly average volume of RC bids by price for PACW	95
Figure 93: Hourly average volume of RC bids by fuel type for PACW	96
Figure 94: Daily average volume of RC bids by price for PACW	96
Figure 95: Daily average volume of RC bids by fuel type for PACW	97
Figure 96: RUC export reduction	98
Figure 97: Exports reductions in HASP	98
Figure 98: Average monthly cleared virtual bids	99
Figure 99: Average hourly cleared virtual bids	100
Figure 100: Average hourly cleared virtual supply	101
Figure 101: Average hourly cleared virtual demand	101
Figure 102: Average net hourly cleared virtual bids	102
Figure 103: Daily average GHG allocation by fuel type	103
Figure 104: Hourly average GHG allocation by fuel type	104
Figure 105: Daily average GHG price	105
Figure 106: Hourly average GHG price	106
Figure 107: Monthly average GHG price by market	107
Figure 108: Daily average energy transfers for CAISO	108
Figure 109: Hourly average energy transfers for CAISO	109
Figure 110: Daily average energy transfers for PACE	110
Figure 111: Hourly average energy transfers for PACE	110
Figure 112: Daily average energy transfers for PACW	111
Figure 113: Hourly average energy transfers for PACW	111
Figure 114: Hourly average energy transfers volumes in EDAM	112

Figure 115: Hourly average net energy transfers volumes in EDAM	113
Figure 116: Daily average IRU transfers for CAISO	114
Figure 117: Hourly average IRU transfers for CAISO	115
Figure 118: Daily average IRU transfers for PACE	116
Figure 119: Hourly average IRU transfers for PACE	116
Figure 120: Daily average IRU transfers for PACW	117
Figure 121: Hourly average IRU transfers for PACW	118
Figure 122: Hourly average IRU transfers volumes in EDAM	119
Figure 123: Hourly average net IRU transfers volumes in EDAM	120
Figure 124: Daily average IRD transfers for CAISO	121
Figure 125: Hourly average IRD transfers for CAISO	121
Figure 126: Daily average IRD transfers for PACE	122
Figure 127: Hourly average IRD transfers for PACE	123
Figure 128: Daily average IRD transfers for PACW	124
Figure 129: Hourly average IRD transfers for PACW	124
Figure 130: Hourly average IRD transfers volumes in EDAM	125
Figure 131: Hourly average net IRD transfers volumes in EDAM	126
Figure 132: Daily average RCU transfers for CAISO	127
Figure 133: Hourly average RCU transfers for CAISO	128
Figure 134: Daily average RCU transfers for PACE	129
Figure 135: Hourly average RCU transfers for PACE	130
Figure 136: Daily average RCU transfers for PACW	131
Figure 137: Hourly average RCU transfers for PACW	131
Figure 138: Hourly average RCU transfers volumes in EDAM	132
Figure 139: Hourly average net RCU transfers volumes in EDAM	133
Figure 140: Daily average RCD transfers for CAISO	134
Figure 141: Hourly average RCD transfers for CAISO	134
Figure 142: Daily average RCD transfers for PACE	135
Figure 143: Hourly average RCD transfers for PACE	135
Figure 144: Daily average RCD transfers for PACW	136
Figure 145: Hourly average RCD transfers for PACW	136
Figure 146: Hourly average RCD transfers volumes in EDAM	137
Figure 147: Hourly average net RCD transfers volumes in EDAM	138
Figure 148: Daily average congestion cost by area	141
Figure 149: Parallel flow matrix example	141
Figure 150: Illustration of parallel flows	142
Figure 151: Daily congestion total by BAA	146
Figure 152: Monthly congestion total by BAA	147
Figure 153: Congestion revenues on CAISO constraints from PAC schedules	148

Figure 154: Net congestion revenues on CAISO constraints from PAC schedules	148
Figure 155: Estimated total CRN congestion credit to PAC from CISO congestion	149
Figure 156: Total CRN congestion credit to PAC from CISO congestion	150
Figure 157: Total self-schedules compared to OATT self-schedules by PAC area	152
Figure 158: Total OATT self-schedule volumes by PAC area	152
Figure 159: Monthly average OATT self-schedule volume	153
Figure 160: CRR revenue adequacy	154
Figure 161: CRR auction efficiency	155
Figure 162: CAISO Reliability Margin	156
Figure 163: Day-ahead manual adjustments and demand in the ISO area	157
Figure 164: Hourly average of RUC adjustments	158
Figure 165: Historical RUC adjustments in the day-ahead market	158
Figure 166: Procurement of flexibility needs during CAISO's peak time	159
Figure 167: Hourly average of RUC adjustment, IRU procurement/requirements	160
Figure 168: Historical load conformance in the hour ahead scheduling process	161
Figure 169: RUC Infeasibilities	162
Figure 170: Resources subject to mitigation in IFM MPM, by fuel type	164
Figure 171: Resources subject to mitigation in RUC MPM, by fuel type	164
Figure 172: Resources subject to mitigation in IFM MPM, by BAA	165
Figure 173: Resources subject to mitigation d in RUC MPM, by BAA	165
Figure 174: Resources subject to mitigation in IFM MPM, by fuel type hourly	166
Figure 175: Resources subject to mitigation in RUC MPM, by fuel type hourly	166
Figure 176: Historical distribution of load levels in the ISO area	167
Figure 177: Daily peak load and CEC month-ahead forecast	168
Figure 178: Daily peak load, operating reserves and RA capacity	169
Figure 179: Daily RUC adjustment and IRU procurement/requirements	170
Figure 180: Average daily prices across markets, August and September 2026	171
Figure 181: Average hourly prices across markets	171
Figure 182: Average daily prices across region for FMM market	172
Figure 183: Average daily prices across region for RTD market	173
Figure 184: Average hourly prices across region for FMM market	173
Figure 185: Average hourly prices across region for RTD market	174
Figure 186: Historical trend of hydro and renewable production	175
Figure 187: Daily trend of hydro and renewable production	176
Figure 188: Historical trend of solar production	176
Figure 189: Hourly profile of wind, solar and hydro production for September	177
Figure 190: PDR Dispatches in day-ahead and real-time markets	178
Figure 191: RDRR dispatches in day-ahead and real-time markets	179
Figure 192: Day-ahead Bid-in capacity and RUC cleared export	181

Figure 193: Day-ahead bid-in capacity and RUC-cleared imports	182
Figure 194: Breakdown of RUC cleared schedules.....	182
Figure 195: Hourly RUC exports	183
Figure 196: HASP cleared schedules for interties	184
Figure 197: Exports schedules in HASP	185
Figure 198: Exports schedules in HASP, –September 8 - 10.....	186
Figure 199: HASP schedules at Malin intertie	186
Figure 200: HASP schedules at Palo Verde intertie.....	187
Figure 201: HASP schedules at NOB intertie	187
Figure 202: Total volume of exports sourced from the ISO area	188
Figure 203: Bid-in capacity for batteries in the day-ahead market, daily average	189
Figure 204: Bid-in capacity for batteries in the day-ahead market, hourly average	190
Figure 205: Bid-in capacity for batteries in the real-time market, daily average	191
Figure 206: Bid-in capacity for batteries in the real-time market, hourly average.....	191
Figure 207: Distributions of day-ahead state of charge	192
Figure 208: Distributions of real-time state of charge.....	193
Figure 209: Hourly distribution of IFM energy awards for batteries	194
Figure 210: Hourly distribution of real-time dispatch for batteries.....	194
Figure 211: Hourly average real-time storage AS awards	195
Figure 212: Hourly distribution of IFM energy awards for hybrid resources	196
Figure 213: Hourly distribution of real-time dispatch for hybrid resources	196
Figure 214: Hourly average real-time hybrid AS awards	197
Figure 215: Hourly real-time dispatch for storage resources, September 8 to September 10	198
Figure 216: Hourly real-time SOC for storage resources, September 8 to September 10	198
Figure 217: Daily peak load by WEIM region.....	199
Figure 218: Average hourly peak load by WEIM region	200
Figure 219: Hourly load profile for September –8-10, by WEIM region.....	201
Figure 220: Daily distribution of 5-minute RTD WEIM transfers for CAISO area	202
Figure 221: Hourly distribution of 5-minute RTD WEIM transfers for CAISO area	203
Figure 222: Daily distribution of 5-minute RTD WEIM transfers for CAISO area, September 8-10.....	203
Figure 223: Daily distribution of 5-minute RTD WEIM transfers by region.....	204
Figure 224: Hourly distribution of 5-minute RTD WEIM transfers by region, September 2026.....	205
Figure 225: BAAs opted-in to Assistance Energy Transfers and RSE Upward Failures	206
Figure 226: Daily average additional AET imports in RTD	207
Figure 227: Total daily AET surcharge assessed	207

Figure 228: Total daily costs CAISO	208
Figure 229: Monthly total costs CAISO	209
Figure 230: Monthly Total Costs CAISO, comparing 2025 to 2026	210
Figure 231: BCR of CAISO by market	211
Figure 232: BCR of PACE by market	212
Figure 233: BCR of PACW by market.....	212
Figure 234: IFM BCR by BAA	213
Figure 235: RTM BCR by BAA.....	213
Figure 236: DA Congestion Offset for PAC areas	214
Figure 237: DA Energy Offset.....	215
Figure 238: Real-Time Congestion Offset	216
Figure 239: Real-Time Imbalance Energy Offset	218
Figure 240: Monthly Total Real-Time Offsets for CAISO	219
Figure 241: Monthly Total Real-Time Offsets for WEIM	220
Figure 242: IRU settlement costs.....	221
Figure 243: IRD settlement costs.....	222
Figure 244: RCU settlement costs	223
Figure 245: RCD settlement costs.....	224
Figure 246: Monthly trend of RUC/Reliability Capacity costs by BAA	225
Figure 247: Greenhouse Gas Settlement Costs in IFM	226
Figure 248: Greenhouse Gas Settlement Costs in RTM	226

Introduction

The California ISO implemented Extended Day-Ahead Market (EDAM) operations on May 1, 2026, marking a significant transition from a single-BAA day-ahead market to a broader, multi-BAA EDAM footprint. Concurrently, new features were introduced as part of the day-ahead market enhancements (DAME). This September report provides an overview of market performance during the first five months of EDAM/DAME operations, focusing on price formation, resource sufficiency outcomes, congestion costs and settlement cost trends across participating balancing authority areas for EDAM. As with CAISO's prior monthly performance reports, the objective is to offer timely and transparent insights into market performance, particularly during the initial period of a major market design transition.

The implementation of EDAM/DAME introduced two new market products: imbalance reserves up and down (IRU/IRD) and reliability capacity up and down (RCU/RCD). The analysis includes a review of IRU/IRD and RCU/RCD prices, procurement volumes, requirements and cost allocation for the new market products. The report also provides a detailed assessment of energy prices, bilateral hub price comparisons, ancillary service procurement, imbalance reserve awards, reliability capacity procurement, and greenhouse gas (GHG) cost adders. The analysis also includes a review of convergence bidding in EDAM, highlighting changes in bid volumes and awards for virtual generation and virtual demand.

The report evaluates costs associated with congestion revenue allocation, and settlement cost trends across the EDAM footprint. This includes an assessment of congestion revenues, breakdown of marginal component of congestion (MCC) at the transmission constraint level among participating BAAs. Also, as the system experienced high loads in September, this report includes various metrics on market performance during summer conditions.

The CAISO will continue to monitor and evaluate market performance and will provide further analysis and reporting in upcoming monthly reports.

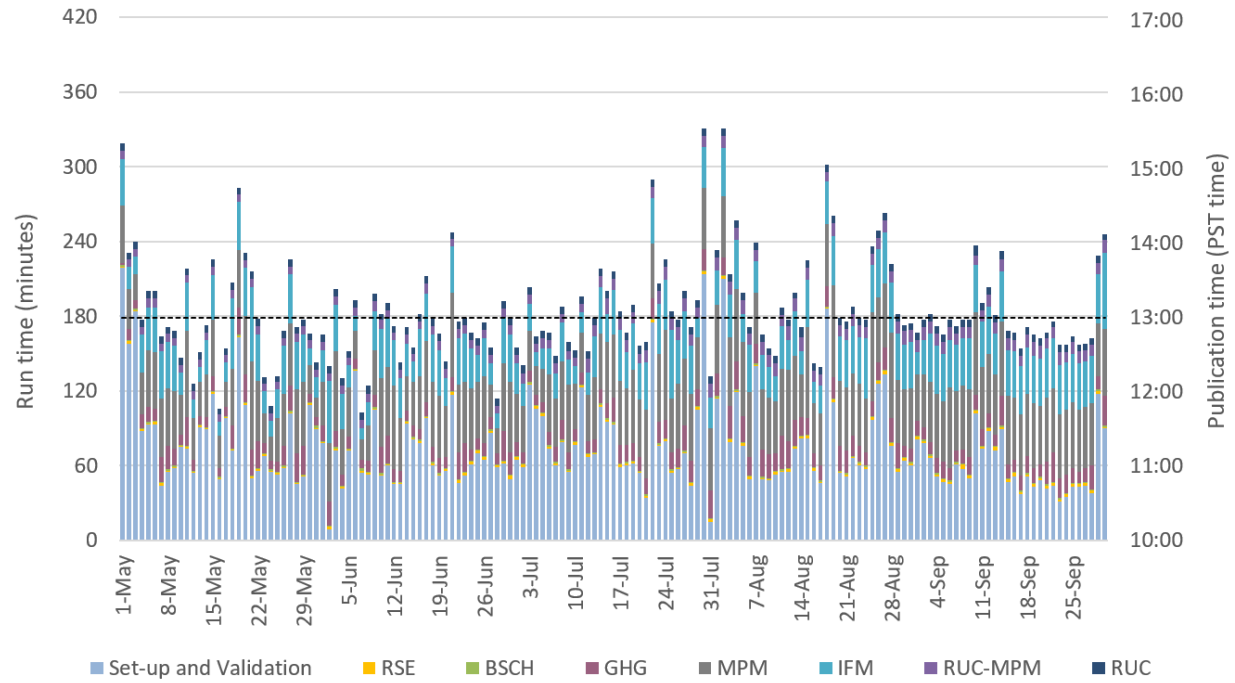
Day-Ahead Market Run

The Day-ahead (DA) market follows a daily schedule, unchanged by new market functionality. All bids submission is due by 10:00 a.m. Pacific Time, after which the CAISO runs multiple processes that comprise the day-ahead market. The standard window to run the day-ahead market is between 10:00 a.m. and 1:00 p.m., with the goal of publishing results by 1:00 p.m. To complete a day-ahead market run after the launch of the EDAM, multiple steps are performed, including:

- i) Market closing and setting up of inputs
- ii) running the binding resource sufficiency evaluation (RSE). New process
- iii) running the base schedule set up (BSCH)
- iv) running the green-house-gas emission market (GHG). New process
- v) running market power mitigation (MPM)
- vi) running the integrated forward market (IFM)
- vii) running market power mitigation for residual unit commitment (MPM-RUC). New process
- viii) running the residual unit commitment (RUC)
- ix) publishing market results
- x) validation of results after each run

In addition to running three new processes within the standard window, EDAM is inherently more complex because it solves for a wider market footprint and so has a larger optimization problem to solve multiple times. This has increased the overall computational workload. Despite the complexity, CAISO maintains the goal of a 1:00 p.m. publication time. Figure 1 illustrates the additional time the CAISO took in the first days of EDAM operations to ensure all processes and runs were properly executed, and results could be closely assessed. This has taken longer to publish market results. After the first two weeks, CAISO gradually returned to more standard runs of the market and the market was able to publish DA results before 1:00 p.m. In September, EDAM results were posted before 1:00 p.m. in 23 out of 30 days (or 77.6 percent of the time), an improvement from the posting of 14 out of 31 days in August. This higher frequency of late posting was when the market was solving for the peak days so far in the year, which represent higher loads and more complex numerical problem to solve. For a relative comparison, the day-ahead market published before 1:00 p.m. in 23 out of 30 days in April prior to EDAM implementation.

Figure 1: Run times for the extended day-ahead market



Resource Sufficiency Evaluation

The EDAM resource sufficiency evaluation (RSE) is a forward-looking test to ensure that each participating EDAM area has sufficient supply to meet their own forecasted demand, ancillary services, and uncertainty before engaging in economic transfers with other EDAM BAAs. Specifically, the RSE evaluates whether a unit-commitment optimization problem can be solved without relaxing (1) the power balance constraint, (2) the IRU/IRD procurement constraints, and (3) the ancillary services procurement constraints. These conditions are evaluated separately, and the entity passes the test without relaxing any of these constraints. This evaluation is performed on an hourly basis, in both upward and downward directions.

Table 1 shows the total monthly passing rate of each EDAM BAA for the IRU and IRD RSE tests from May to September.¹ On May 4, PACW passed the IRU RSE in 16 out of 24 hours and the IRD RSE in 23 out of 24 hours. On June 17, PACE observed an invalid RSE failure. This was due to the consideration of commitment costs in the RSE, and this issue was discussed as one of the market issues the ISO was pursuing a fix. Therefore, June's failure is not counted in the RSE statistics. In July, August, and September, there were no RSE failures for any EDAM BAA.

Table 1: RSE monthly passing rate by BAA for upward and down requirements

BAA	IRU RSE Passing Rate (%)					IRD RSE Passing Rate (%)				
	May	June	July	August	September	May	June	July	August	September
CAISO	100	100	100	100	100	100	100	100	100	100
PACE	100	100	100	100	100	100	100	100	100	100
PACW	98.92	100	100	100	100	99.87	100	100	100	100

Imbalance reserves are used to address uncertainty between the day-ahead and real-time forecasts for load, wind and solar by providing upwards and downwards dispatch capability. The requirements for IRU/IRD are based on historical load, wind, and solar forecast errors between day ahead and real time.

¹ In addition to the IRU and IRD test, the RSE performs test for upward ancillary services. Ancillary services are not optimized nor procured in the extended day-ahead market for PAC areas.

Figure 2: Average upward and downward requirements by area and month

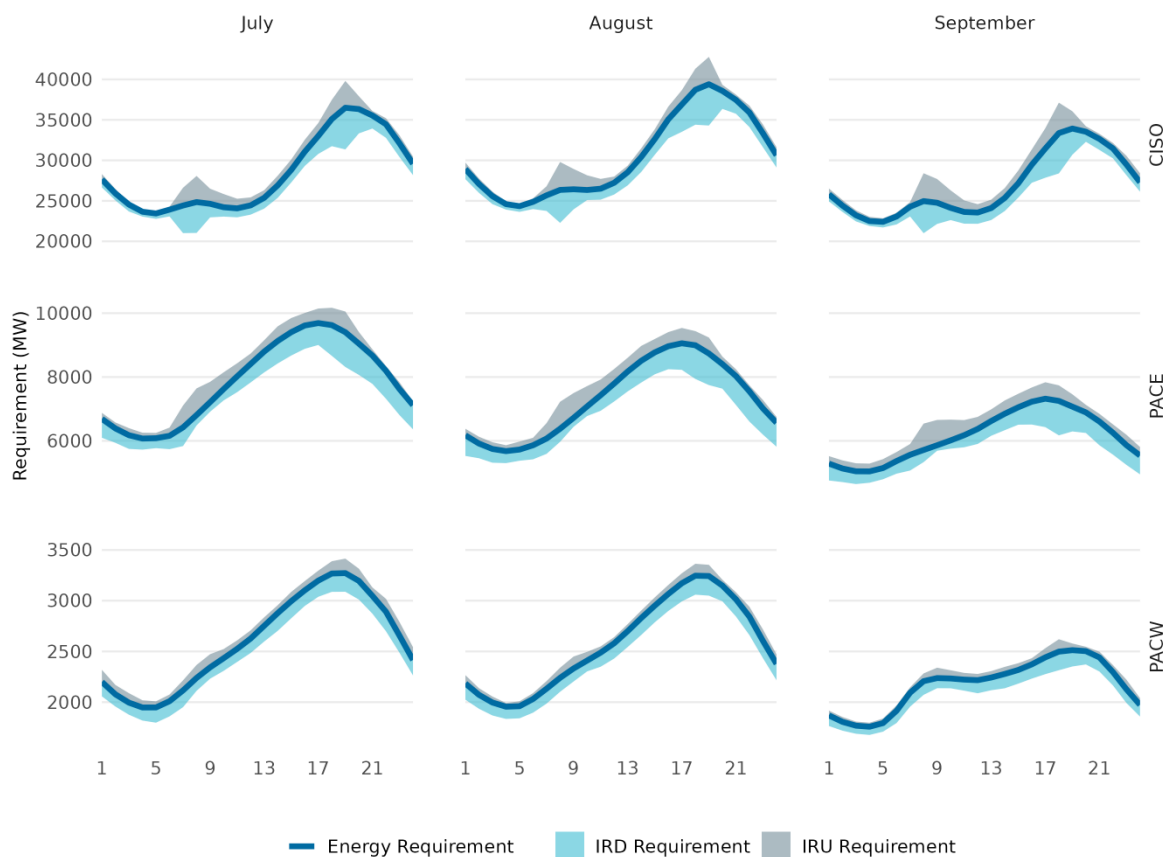


Table 2 gives the highest imbalance reserve upward and downward requirements for each BAA from May to September.

Table 2: Maximum imbalance reserve requirements by BAA

BAA	Maximum IRU Requirement (MW)					Maximum IRD Requirement (MW)				
	May	June	July	August	September	May	June	July	August	September
CAISO	3,629	3,486	3,536	3,867	3,900	5,320	5,487	5,985	5,310	5,245
PACE	1,028	1,028	964	1,045	989	1,100	1,125	1,125	1,133	1,185
PACW	225	229	214	207	194	241	259	259	252	208

For an EDAM entity to pass the RSE, it must have at least enough supply to meet the requirement for each hour. For the upward direction the RSE requirement is the summation of the energy requirement and the upward IR requirements while for the downward direction the requirement is assessed by subtracting the IRD requirement from the energy requirement.

Day-Ahead Market Products

Day-Ahead Demand

In IFM, bid-in supply is cleared to meet bid-in demand. However, bid-in demand does not necessarily match the day-ahead load forecast. Supply in RUC is cleared to meet the day-ahead demand forecast. Figure 3 shows the average day-ahead demand forecast and the average IFM schedule for each EDAM BAA from July through September 2026. On average, the bid-in demand for CAISO is slightly greater than the day-ahead demand forecast during much of the day, while the two generally track closely. From July through September, the bid-in demand for PACE generally exceeded the forecast for much of the day, with the difference between the two being the smallest during the evening peak. Generally, the day-ahead demand forecast and the bid-in demand for PACW closely match, with July through September seeing a slightly higher bid-in demand compared to the day-ahead forecast.

The day-ahead demand forecast hourly profiles remained generally similar from July through September for all three BAAs. In September, all three BAAs experienced lower demand levels and lower evening peaks compared with August. CAISO continued to show a smaller mid-day dip and a steeper afternoon ramp, while PACE and PACW had more gradual and smoother changes through the day.

Figure 3: Bid-in demand vs. day-ahead demand

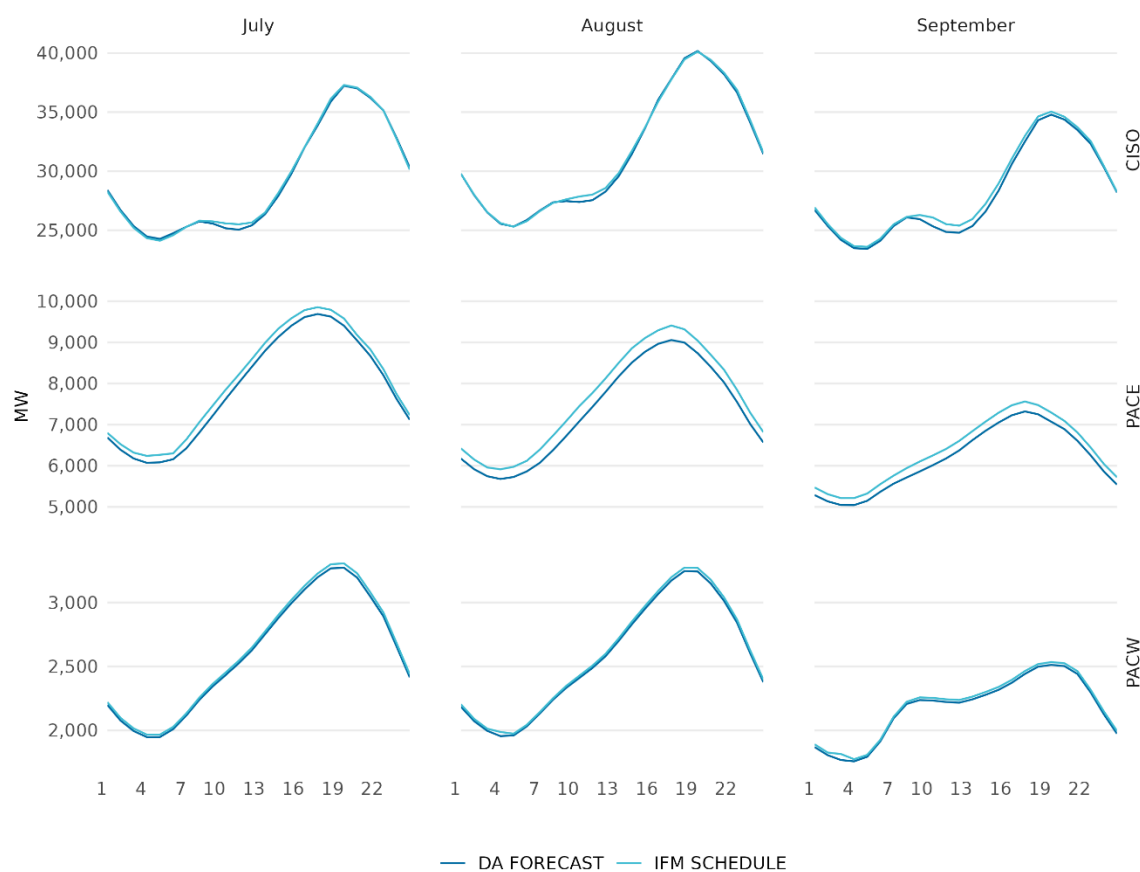


Table 3 shows the highest day-ahead demand forecast for a single hour for each EDAM BAA from May to September. From August to September, forecasted peak demand increased for CAISO but decreased for PACE and PACW. The changes were 3.6, -16.7, and -23.9 percent for CAISO, PACE, and PACW, respectively.

Table 3: Peak day-ahead demand forecasts

BAA	Peak DA Demand Forecast (MW)				
	May	June	July	August	September
CAISO	34,674	37,399	42,928	46,089	47,741
PACE	8,047	9,358	10,527	10,029	8,351
PACW	2,893	3,635	3,866	3,941	2,998

Day-Ahead Supply

Figure 4 presents the hourly average energy awards by fuel type for CAISO from July through September. The results show a clear daily pattern driven largely by solar generation and energy storage. Solar awards increase substantially during daytime hours and peak in the afternoon before declining rapidly toward the evening. Storage generally shows negative energy awards during periods of high solar output, indicating charging, and transitions to positive awards during the late afternoon and evening as solar generation declines. Overall energy awards were higher in July and August, with higher peak levels observed over 40,000 MW in August. Gas generation plays an important role in meeting evening demand, especially in July and August, with awards increasing noticeably during the evening hours. These patterns illustrate the complementary roles of solar, storage, and gas resources in supplying CAISO system demand throughout the day in the summer months.

Figure 4: Hourly average energy awards by fuel type for CAISO

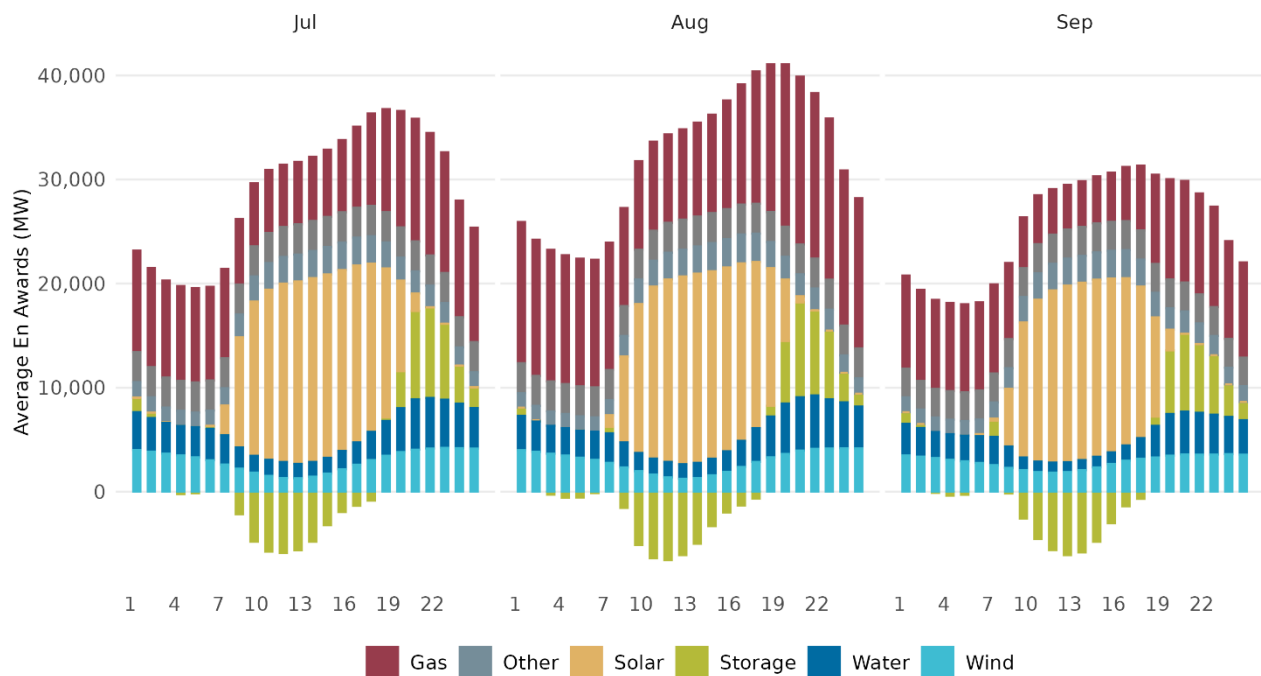


Figure 5 illustrates the hourly average energy awards by fuel type for PACE from July through September. The total cleared energy in September is lower than July and August, with peak at 8,000 MW. The results show distinct monthly and hourly patterns across the resource mix. Coal provides a relatively stable level of energy and becomes a main contributor to the overall PACE's resource mix. Solar awards follow a pronounced daytime profile. Gas awards generally increase as solar output declines, particularly during the evening hours, indicating their role in meeting system needs during the transition away from daytime solar generation. Wind awards are present

throughout the day but vary across hours and months, while storage and other resources (mainly hybrid) exhibit relatively small charging and discharging activity compared with CAISO. Overall energy awards were higher in the summer months, with the highest hourly levels about 9,000 MW observed in July and August.

Figure 5: Hourly average energy awards by fuel type for PACE

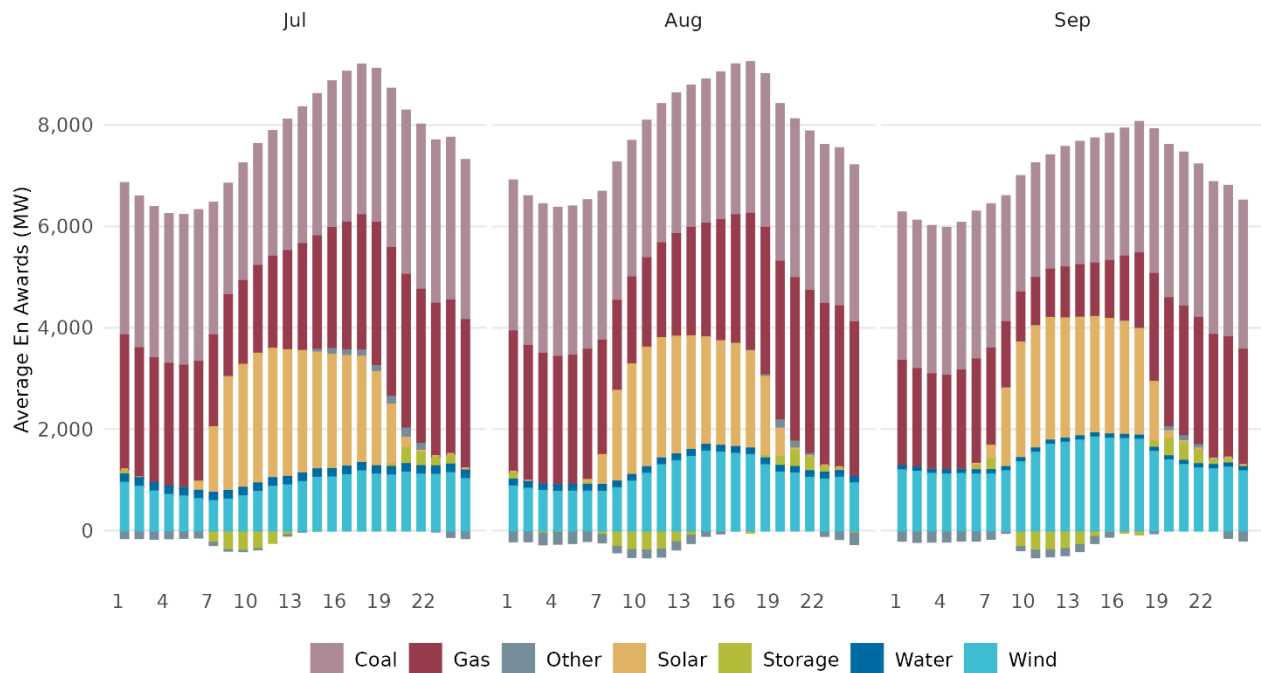
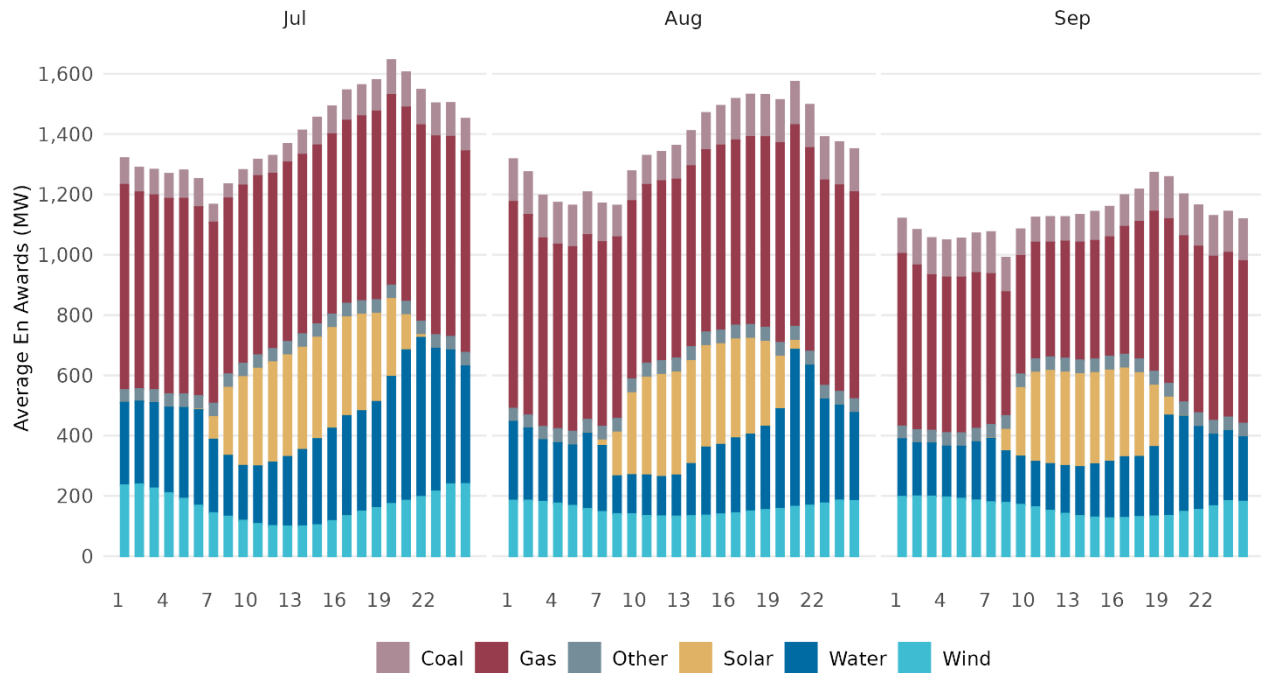


Figure 6 presents the hourly average energy awards by fuel type for PACW from July through September. Similar with CAISO and PACE, PACW's supply in September is lower than July and August. Gas, wind, and water resources still account for a substantial share of the energy awards throughout the period, and solar exhibits a clear daytime pattern. Hydro awards show relatively lower generation in September. Gas awards generally increase during periods of lower renewable output and contribute significantly to the higher evening awards. Coal and other resources represent relatively small portions of the overall resource mix. Total energy awards generally decreased from July, with the highest hourly levels over 1,600 MW occurring in July.

Figure 6: Hourly average energy awards by fuel type for PACW

As part of the day-ahead market enhancements, two new market products have been introduced: imbalance reserves and reliability capacity. These additions are designed to strengthen the market's ability to address evolving system needs while supporting reliable grid operations.

The imbalance reserve product enables the market to procure flexible capacity in advance to manage the uncertainty that exists between day-ahead scheduling and real-time operations. By securing this flexibility through a competitive market process, operators can ensure that sufficient resources are available to respond to changing system conditions while maintaining reliability.

The reliability capacity product represents supply procured in the residual unit commitment process in both the upward and downward direction to meet differences between market-cleared load schedules and demand forecast.

Procuring flexibility through the market promotes economic efficiency by identifying and securing the least-cost resources capable of providing these services. It also establishes transparent price signals that explicitly value flexibility, helping market participants better understand system needs and providing incentives to resources that can support reliable and efficient grid operations. Additionally, EDAM prices the greenhouse gas emissions associated with transfers between BAAs within the day-ahead market. This same formulation has been adapted for the real-time market. Therefore, in the day-ahead market, different products are procured and priced explicitly:

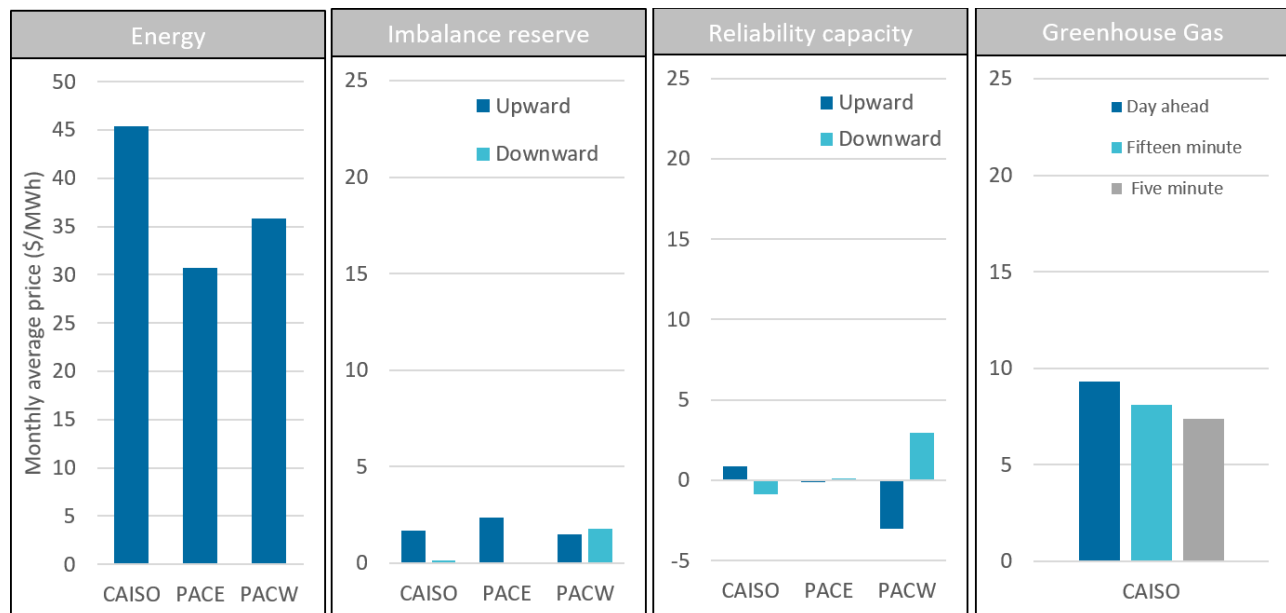
- i) energy,

- ii) ancillary services (regulation up and down, spinning reserves and non-spinning reserves),
- iii) imbalance reserves up and down,
- iv) reliability capacity up and down, and
- v) greenhouse-gas emission allocation

Energy, ancillary services and imbalance reserves are all co-optimized in the integrated forward market, while reliability capacity is optimally procured in the residual unit commitment process that is run after the financial market. The residual unit commitment process considered as fixed the procurement of ancillary services, imbalance reserves, and only procures reliability capacity relative to the energy awards from IFM. This section provides an assessment of each of these market products during September. With about five months of operational experience, the results offer an initial indication of how EDAM/DAME functionality is performing. However, as the market continues to mature, participants gain experience operating under this new framework, and summer conditions exist, the results should be viewed as preliminary. The CAISO will continue to monitor and evaluate market performance and will provide further analysis in upcoming monthly reports.

Figure 7 compares prices across all EDAM products for the month of September. Prices across all commodities, including energy, imbalance reserves, and reliability capacity, remain within expected economic ranges. These results reflect underlying supply and demand fundamentals across the broader market footprint and demonstrate that the market is effectively valuing available resources while maintaining competitive and efficient outcomes.

Figure 7: Pricing of EDAM products for September 2026



Seasonal conditions also play an important role in shaping price patterns as observed in the month of September. During the summer months, due to higher load, typically sees higher energy prices as compared to spring months. As solar production declines and demand increases during the morning and evening ramp periods, prices tend to rise, reflecting the changing balance between supply and demand. These recurring price dynamics underscore the market's ability to respond to evolving system conditions and provide transparent economic signals that support efficient resource utilization across the region.

Regional differences in supply and demand conditions are reflected in the pricing of all market products, including energy, imbalance reserves, and reliability capacity. As a result, prices exhibit expected regional variations, with PACE generally posting the lowest prices while PACW has tended to clear at higher price levels. These outcomes demonstrate that market prices properly reflect local system conditions and resource availability across the footprint when transfer capabilities are fully utilized. Another pattern that appears in the pricing of the products shows that IR and RC products command lower prices than energy prices, which is expected given that these products provide services like flexibility.

Energy prices

Day-ahead energy prices measured using LMPs reflect expected market conditions and are influenced by changes in load, generation availability, imports, exports, and transmission constraints. Ideally, day-ahead prices accurately represent the value of supply and demand realized in real time. Forecast uncertainty, congestion, shifts in supply or demand, and available transfer capability are some factors that can create differences between day-ahead and real-time price, commonly referred to as price convergence. Price convergence between BAAs also occurs, reflecting the diversity in conditions across the EDAM footprint. The figures in this section examine trends in energy prices and price convergence by showing average day-ahead and real-time LMPs for the three EDAM BAAs. The ELAP LMPs are used for PACE and PACW, while the load-weighted average of the four DLAP LMPs is used for the CAISO area.

Figure 8 shows monthly average LMPs for each EDAM BAA since EDAM implementation in May 2026. In September, day-ahead LMPs decreased across all participating BAAs reflecting lower demand than in August. Monthly average prices declined from August levels, falling from \$53/MWh to \$45/MWh in CAISO, from \$46/MWh to \$31/MWh in PACE, and from \$43/MWh to \$36/MWh in PACW. Price convergence across markets remained strong like in August. However, IFM LMPs in CAISO and PACW were higher than real-time LMPs which was a reversal from August. Across BAAs, CAISO LMPs were highest reflecting the highest demand. However, PACW LMPs were higher than PACE despite having lower demand due to a price spike on September 9 in PACW.

Figure 8: Monthly average LMP since May 2026

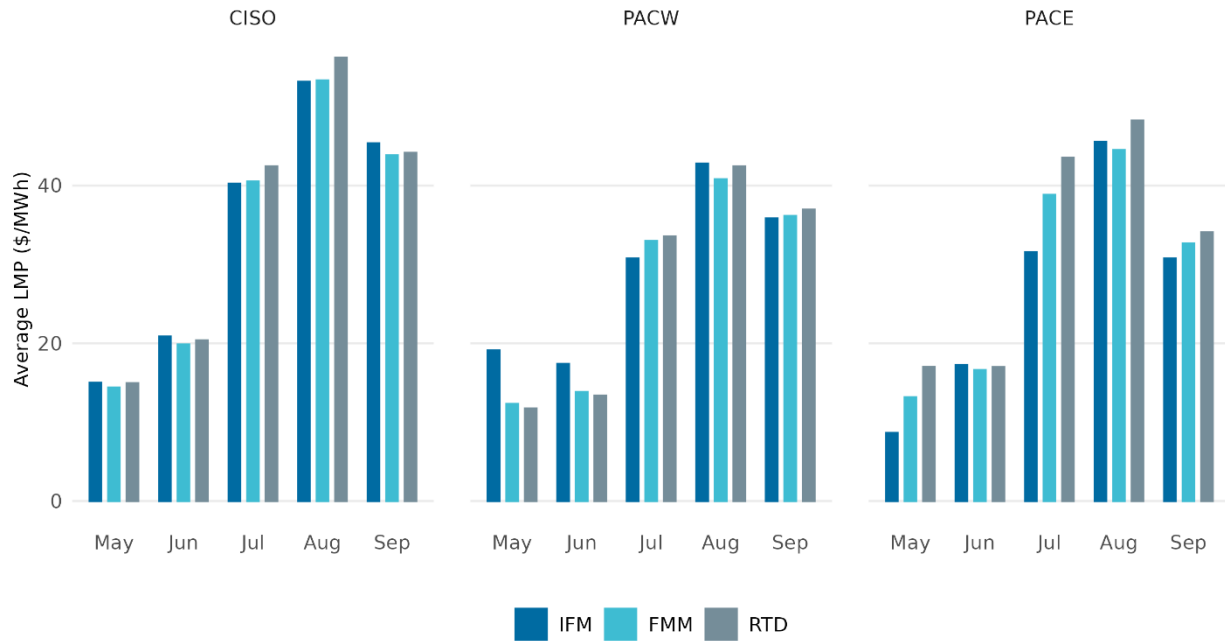


Figure 9, Figure 10 and Figure 11 show the average monthly LMPs since January 2025 and illustrate seasonal prices trends. IFM prices prior to May 2026 only exist for CAISO. Average prices are higher in the summer months in 2026 than in the spring months, consistent with seasonal trends observed in 2025. September 2026 prices were like those observed in September 2025.

Figure 9: Monthly average LMP for CAISO area since January 2025

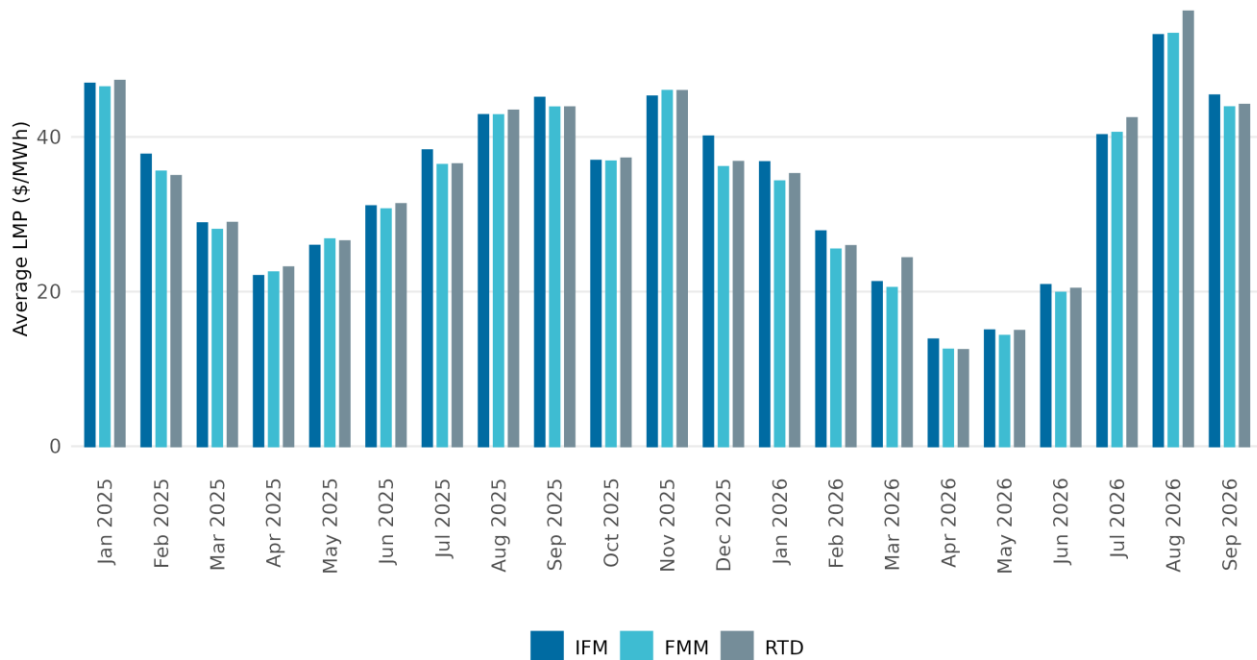


Figure 10: Monthly average LMP for PACW since January 2025

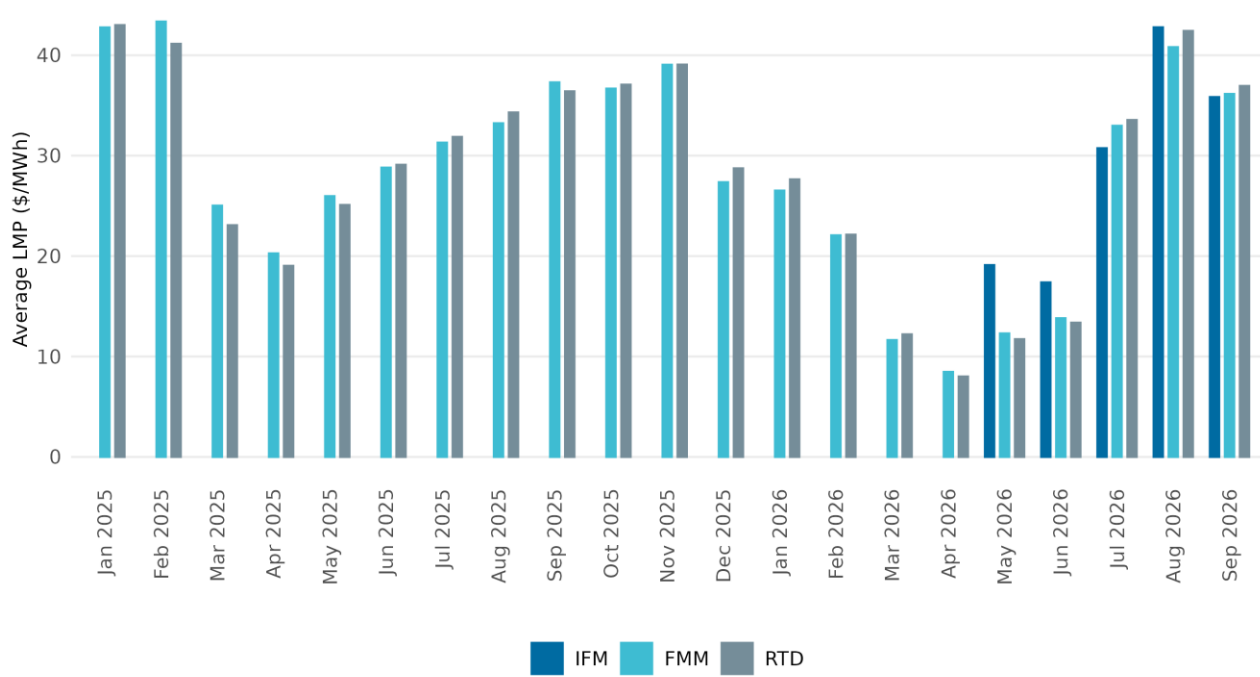


Figure 11: Monthly average LMP for PACE since January 2025



Figure 12 shows daily average LMPs for each EDAM BAA in August and September. Prices spiked on September 9th for CAISO and PACW with daily averages of approximately \$101/MWh and \$77/MWh, respectively.

Figure 12: Daily average IFM LMP by BAA

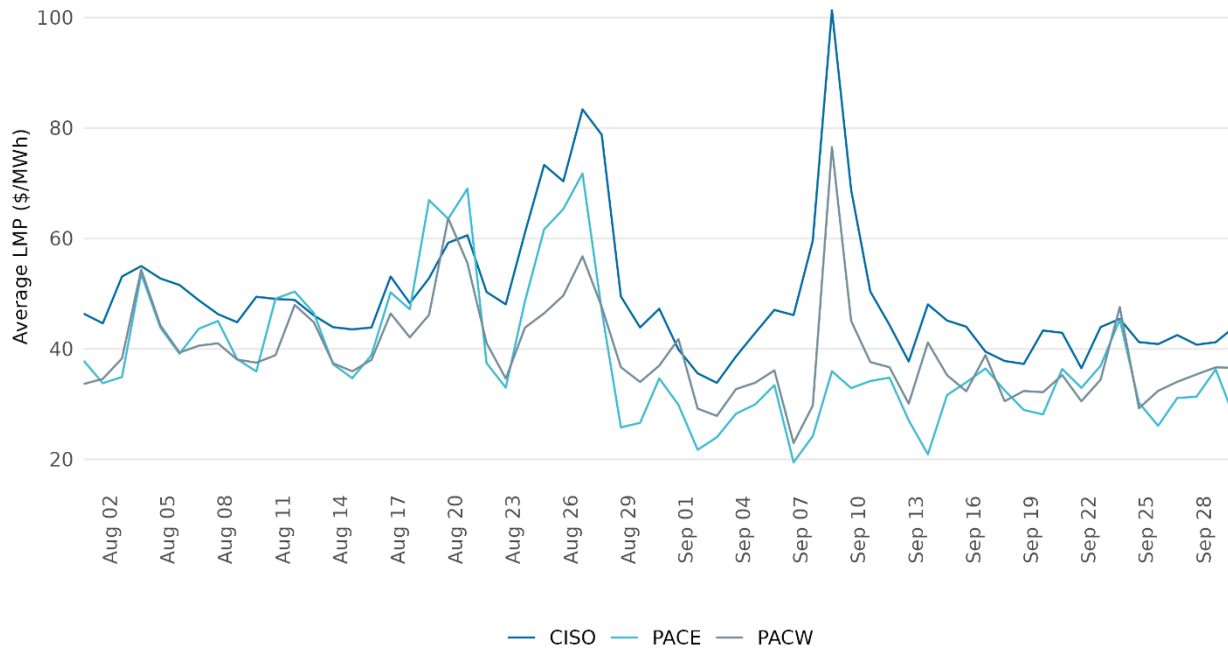


Figure 13 illustrates the price convergence between day-ahead and fifteen-minute market (FMM) prices for EDAM BAAs August and September. A negative price reflects a higher FMM price compared to day-ahead. Price convergence was tighter in September, though price separation occurred on September 9 for CAISO and PACE and on September 8 for PACW.

Figure 13: Average difference between IFM LMP and FMM LMP

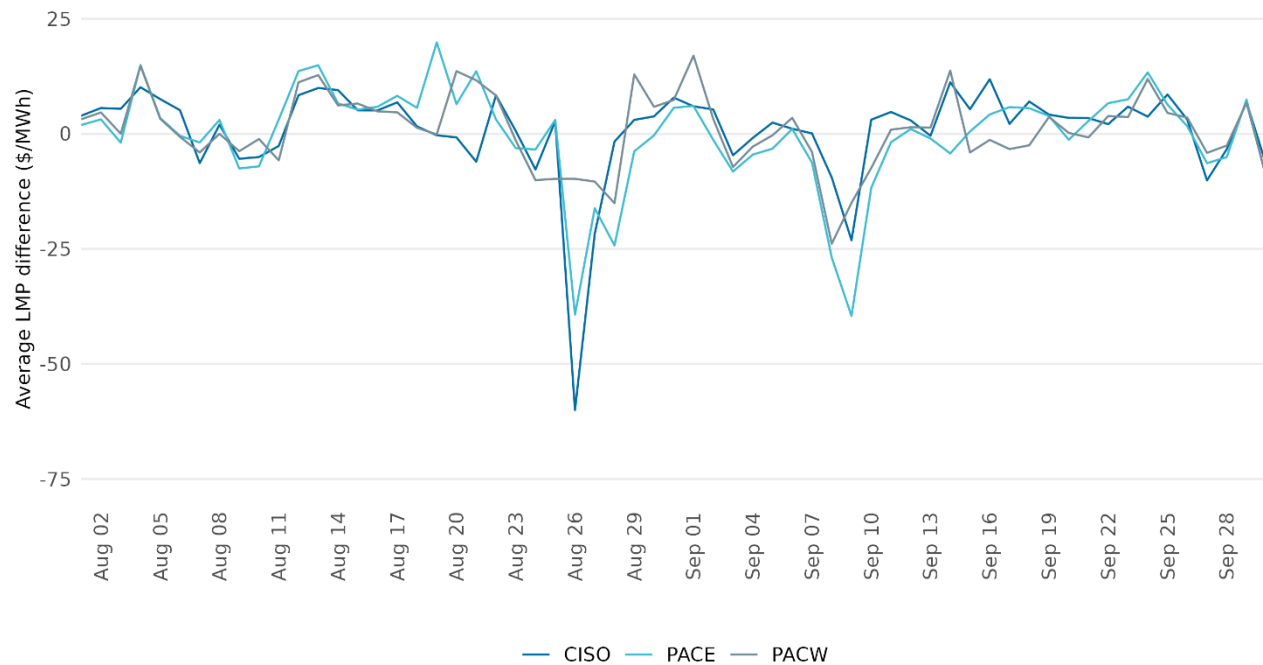
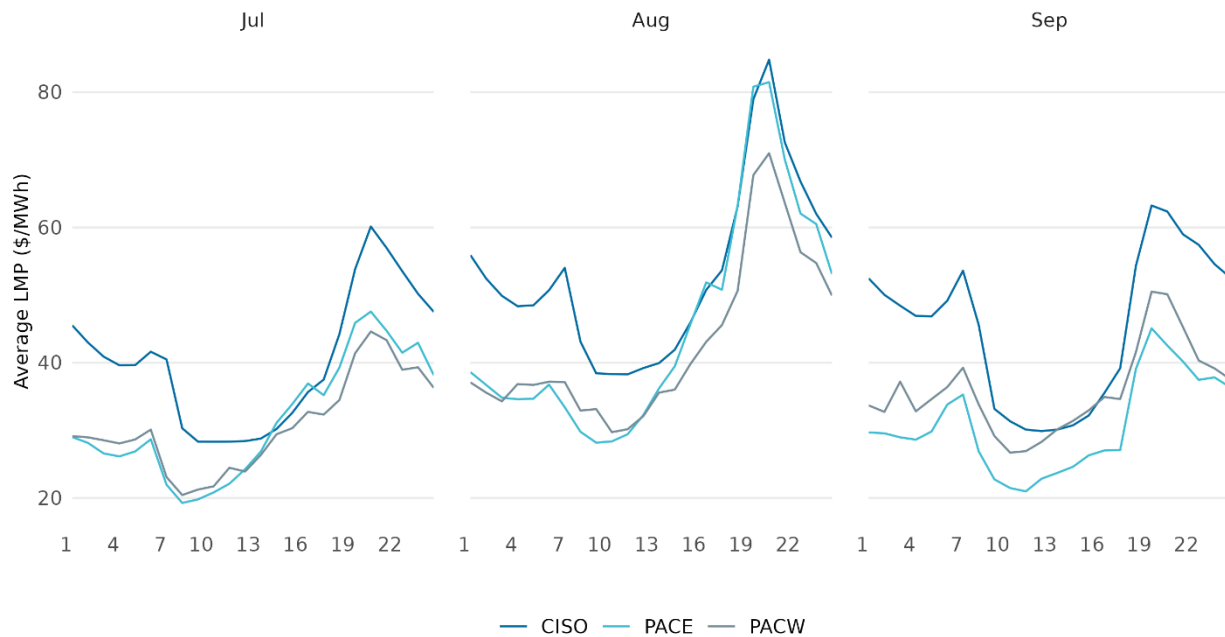


Figure 14 shows the average hourly IFM LMPs across the three EDAM BAAs from July to September. Average price separation between CAISO and both PACE and PACW was greatest from HE 1 to HE 8 and from HE 18 to 24. Price separation between PACE and PACW was higher in September on average compared to the previous two months.

Figure 14: Hourly IFM LMP averaged by month



Price Volatility

Price volatility provides insight into the stability of market outcomes and changing system conditions. In this section, price volatility is measured using the frequency of extreme LMPs across the EDAM BAAs.

Figure 15, Figure 16 and Figure 17 show the frequency of RTD LMPs falling in predefined \$/MWh ranges in the given month for each BAA. Compared to August, all three BAAs had a lower frequency of prices above \$100/MWh and a higher frequency of prices below \$20/MWh. Price volatility in September 2026 was similar to September 2025.

Figure 18 shows only the frequency of extreme RTD LMPs in price ranges below -50 \$/MWh and above 100 \$/MWh. The frequency of very high LMPs in September dropped sharply for CAISO and PACE but decreased only modestly for PACW. The frequency of negative LMPs remained low in September with no negative prices in CAISO and PACE while PACW saw negative prices in just 6 RTD intervals.

Figure 15: CAISO RTD LMP range frequency

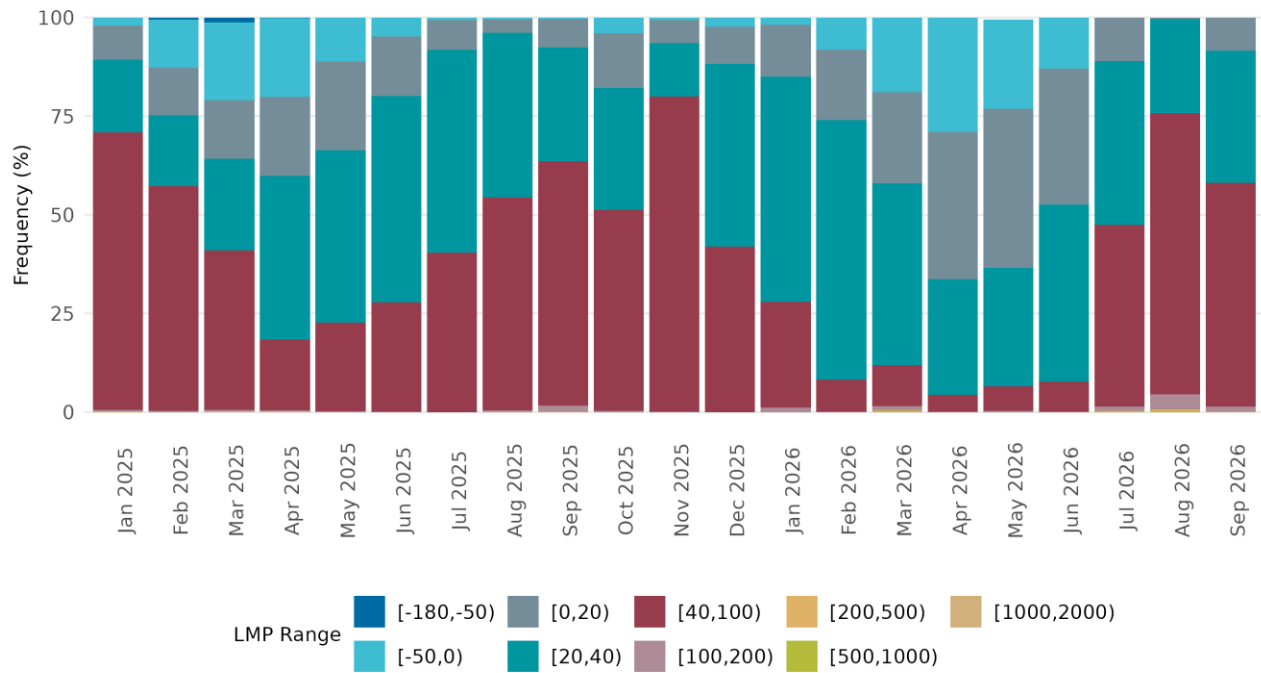


Figure 16: PACW RTD LMP range frequency

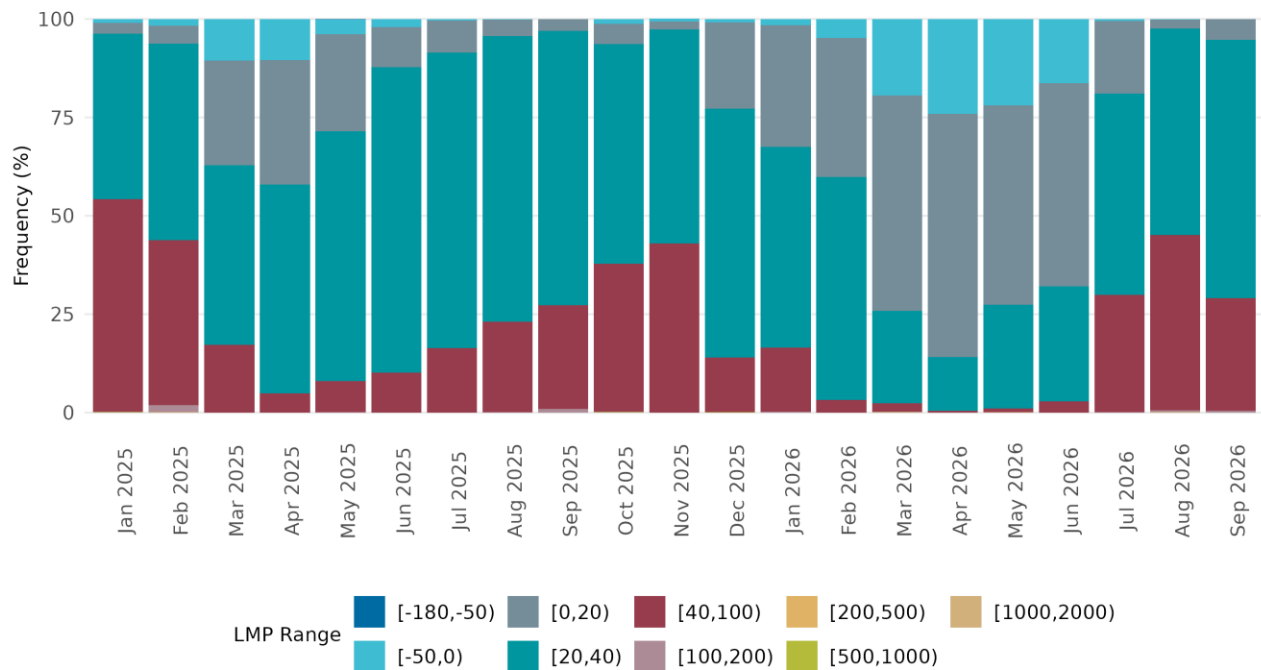


Figure 17: PACE RTD LMP Range Frequency

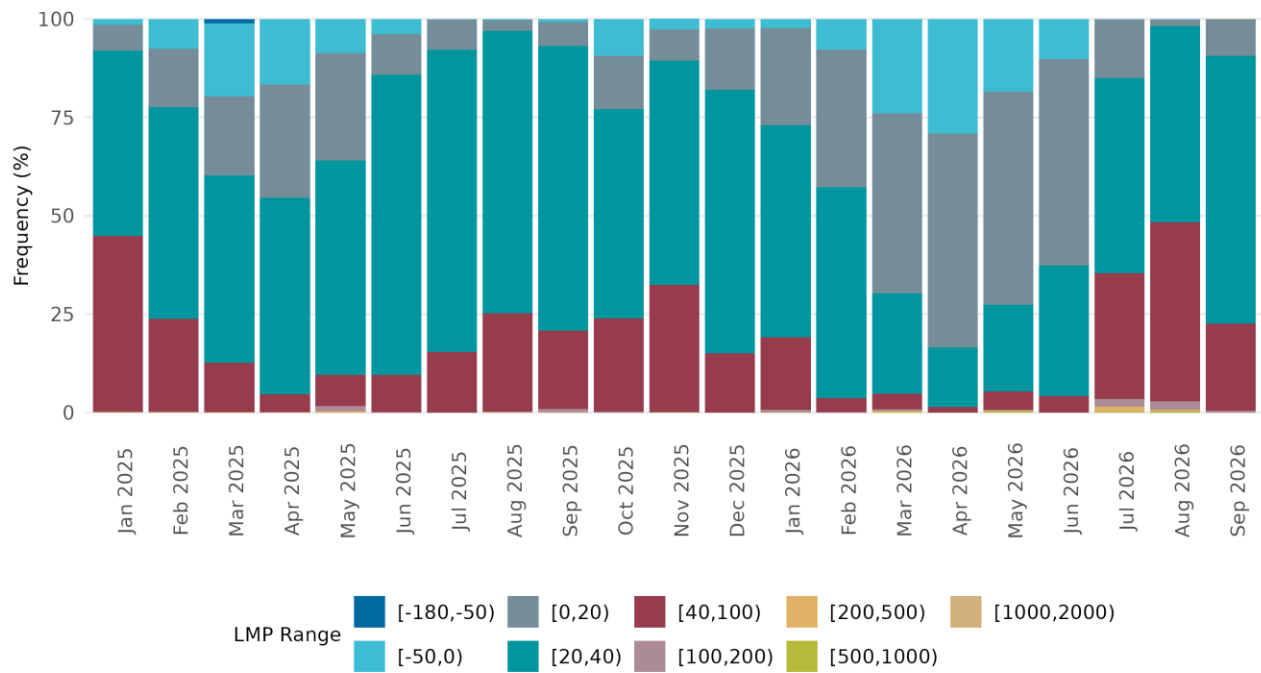
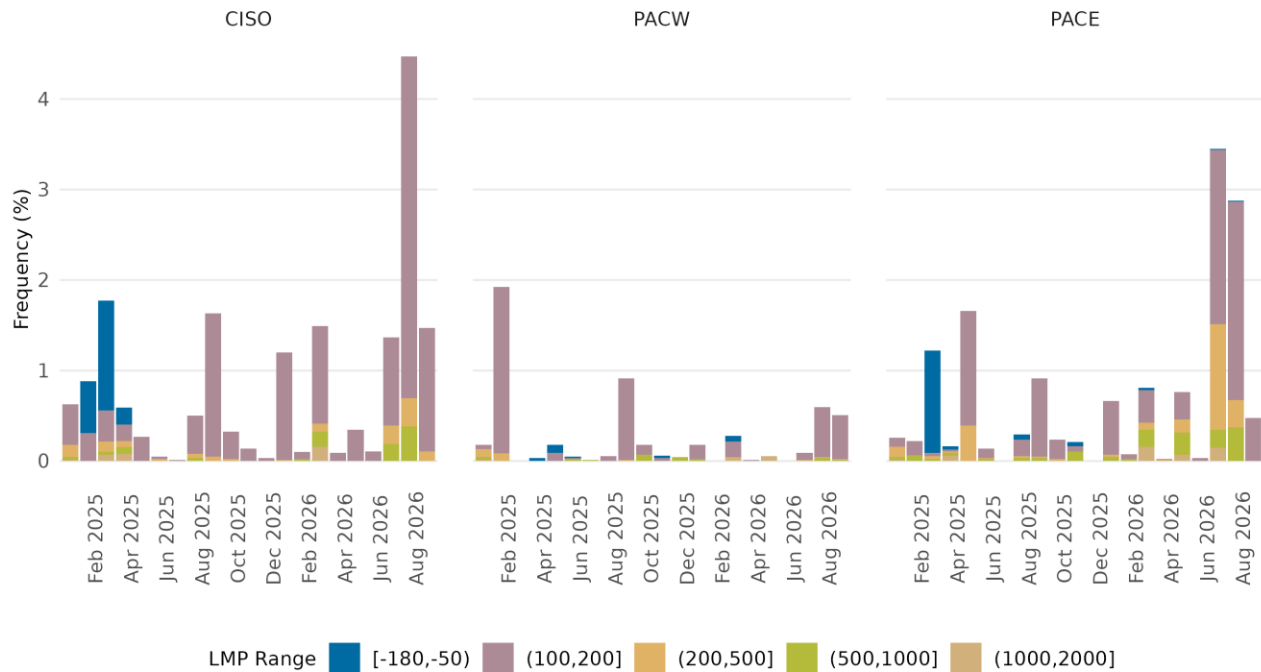


Figure 18: Frequency of low- and high-end RTD LMPs



Changes in price formation with EDAM

The previous assessment is based on the full locational marginal price (LMP). However, LMPs have different components:

- i) marginal energy cost (MEC),
- ii) marginal congestion cost (MCC),
- iii) marginal losses cost (MLC), and
- iv) marginal greenhouse gas emissions cost (MGHG).

With the introduction of EDAM/DAME, there are several significant changes to price formation in the day-ahead market.

Marginal energy cost

Before EDAM, there was a single system-level marginal energy cost (SMEC). After May 1, the marginal energy cost (MEC) is calculated separately for each BAA.

Before May 1, the day-ahead market enforced a power balance constraint (PBC) for only CAISO as there were no other BAAs in the day-ahead market. The real-time market, however, enforced two types of PBCs – a system-wide PBC and a BAA-specific PBC for every WEIM BAA except CAISO. The shadow price of the system-wide PBC (λ) served as the system marginal energy cost (SMEC) shared by all BAAs in the WEIM. On the other hand, the shadow price of the BAA-specific PBC (λ_j where j denoted BAA j other than CAISO) was included in the marginal congestion cost to drive price separation from the rest of the WEIM. See Figure 19 for the LMP decomposition of any given node in a non-CAISO WEIM BAA:

Figure 19: LMP Decomposition for Non-CAISO WEIM BAA

$$\left. \begin{aligned} SMEC &= \lambda \\ MLC_i &= (\lambda + \lambda_j - \psi) \left(\frac{1}{LPG_i} - 1 \right) \\ MCC_i &= \lambda_j - \sum_m \sum_{n \in N_m} a_{m,n} SF_{m,n,i} \mu_m \\ MGC_i &= -\psi \end{aligned} \right\}, \quad \forall i \in BAA_j \wedge j \in EIM \wedge j > 0$$

Note: i denotes node i , $j = 0$ denotes CAISO, and $j > 0$ denotes BAAs other than CAISO

The term λ_j itself consisted of multiple sub-components. Specifically, λ_j was the sum of the shadow price of the EIM Transfer Distribution Constraint for BAA j (ϕ_j) and the shadow price of either the upper EIM Transfer Scheduling Limit for BAA j (v_j) or the lower EIM Transfer Scheduling Limit for BAA j (ξ_j):

$$\lambda_j = \phi_j + v_j \text{ or } \lambda_j = \phi_j + \xi_j$$

First, the EIM Transfer Distribution Constraint ensured that the “WEIM Transfer for each WEIM BAA is distributed optimally to the applicable Energy Transfer Schedules” (Section 16.2.1.1.4 of the BPM for EIM). The WEIM Transfer for each WEIM BAA (T_j) was the sum of the schedules of all energy transfer system resources (ETSRs) defined for that BAA. $ET_{j,k,l}$ denoted an export ETSR / from BAA j to BAA k , and $IT_{j,k,l}$ denoted an import ETSR / to BAA j from BAA k :

$$\sum_{\substack{k \in EIM \\ k \neq j}} \sum_l (ET_{j,k,l} - IT_{j,k,l}) = T_j \quad \forall j \in EIM \wedge j > 0$$

The EIM Transfer Scheduling Limits constrained the total WEIM Transfer for a WEIM BAA to an upper limit $\bar{T}_j$ and a lower limit $\underline{T}_j$. These limits were defined by the WEIM BAAs:

$$\underline{T}_j \leq T_j \leq \bar{T}_j, \quad \forall j \in EIM$$

In summary, prior to May 1, the shadow price of the system-wide PBC was applied uniformly to all WEIM BAAs via the SMEC. Price separation across the individual WEIM BAAs was achieved via the MCC, which included the shadow price of the BAA-specific PBC which, in turn, consisted of the shadow prices of transfer constraints.

With the implementation of the extended day-ahead market, a new formulation of the energy component went into effect for both day-ahead and real-time markets. The formulation no longer uses a system-wide PBC; consequently, there is no longer the calculation of a system-wide SMEC. To facilitate the settlement of transfer revenues which arise when there is MEC separation between BAAs, EDAM and WEIM now only enforce BAA-specific power balance constraints for each EDAM or WEIM BAA. The shadow price of the BAA-specific PBC is the MEC for the BAA. The shadow price of the BAA-specific PBC (λ_j) still contains the shadow prices of the transfer constraints:

$$\lambda_j = \phi_j + v_j \text{ or } \lambda_j = \phi_j + \xi_j$$

The Transfer Distribution Constraint continues to be enforced for every WEIM BAA in the real-time market and is now enforced for every EDAM BAA in the day-ahead market. The Transfer Scheduling Limits continue to be enforced for every WEIM BAA in the real-time market and are now enforced for every EDAM BAA in the day-ahead market.

While the formulation of the transfer constraints did not change, the way their respective shadow prices feed into the LMP definition did change. Namely, the transfer constraint shadow prices are now part of the MEC and are no longer part of the MCC. The MCC now only reflects congestion from transmission elements (flow gates, nomograms and contingencies) and does not include any shadow price from a BAA-specific PBC.

Table 4: Comparison of LMP decomposition before and after May 1, 2026

Before 5/1/2026		5/1/2026 - Present	
SMEC Components	MCC Components	MEC Components	MCC Components
	ϕ_j	ϕ_j	μ_j
	v_j	v_j	
	ξ_j	ξ_j	
	μ_j		

Note: μ_j denotes shadow price of transmission constraint (e.g., flowgate, nomogram)

GHG prices

Before EDAM, the marginal cost of greenhouse gas (GHG) emissions was embedded into the SMEC and then subtracted from non-California BAA LMPs. With this formulation, the GHG component was applied only to non-California-area locations, and it was a negative component. In EDAM the marginal cost of GHG emissions is accounted for outside of the MEC and only applies within GHG regulation areas². The GHG component is positive and applies only to California-area locations.

Figure 20 shows the monthly average LMP composition in IFM, FMM, and RTD for the PACE and PACW ELAPs and CAISO's four default load aggregation points (DLAPs) from July to September. The figure orders areas by how often they were the highest-priced area, from most to least frequent. A negative congestion component decreases the LMP. Overall, the monthly average MEC component fell from August to September for the three BAAs. The area that was most frequently the highest priced area was SDG&E. September saw greater separation in monthly average MECs, primarily because PACE MECs declined while MECs in the other areas remained similar. The monthly average congestion component fell in SDG&E and reversed direction in PGAE, SCE and VEA areas. The monthly average GHG component in FMM remained at similar levels compared to August, but IFM and RTD saw an increase of \$1.1/MWh and \$0.9/MWh on average, respectively.

² California is currently the only GHG regulation area active within the market footprint.
CAISO/MD&A/MPAA

Figure 20: Average monthly LMP components



Bilateral power price comparisons

Outside CAISO's markets, power is historically traded through forward-looking bilateral transactions between buyers and sellers. The Intercontinental Exchange (ICE) is a marketplace where power contracts are bilaterally traded between two counterparties.

Comparing bilateral power prices from ICE to CAISO market prices is useful as both CAISO and ICE markets reflect the willingness of buyers and sellers to trade next-day power and can provide some reference of how the marketplace valued power in the West. The comparison of trends in power prices and energy quantity traded is also useful to assess what impact the new EDAM market may have on bilateral next-day power trading. However, these trends need to be monitored over a sufficient time period to provide a more robust assessment of any correlations with EDAM operations.

Figure 21 and Figure 22 below shows a comparison between EDAM BAA LMPs and next-day bilateral power prices at the Mid-Columbia (MidC) and Palo Verde (PV) hubs on a monthly average and daily average basis, respectively. These two hubs are highly liquid and geographically cover the north (MidC) and south (PV). While CAISO prices are hourly, next-day bilateral power trades in blocks for on-peak and off-peak time of use periods³, thus the bilateral prices shown are calculated as the average of hourly prices where each hour is assigned the applicable time of use price. The CAISO LMP is calculated as the load-weighted average of its four DLAP LMPs.

Across BAAs, the daily trends in September were less clear than those observed on a monthly basis due to the influence of weather and short-term volatility. On a monthly average basis, CAISO day-ahead LMPs have historically tracked a blend of next-day bilateral power prices at MidC and PV, with the degree of alignment varying between the two hubs across months. On a day-to-day basis, CAISO day-ahead LMPs tracked with a blend of MidC and PV next-day bilateral power prices, but the correlation leaned towards PV more frequently. CAISO day-ahead LMPs are a load weighted average of the four DLAPs and thus the correlation fluctuates between MidC or PV based on which DLAPs had higher loads and congestion. PACE day-ahead LMPs have been more strongly correlated to PV than MidC on a monthly average basis, however on a daily basis the correlation is weaker with several days where correlation with MidC was stronger. PACW day-ahead LMPs were historically correlated with MidC prices more than PV prices on a monthly basis. On a daily basis in September PACW maintained moderate correlation with MidC prices but less responsive to extreme prices such as September 8-10.

³ 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 21: Monthly average LMPs and bilateral power prices

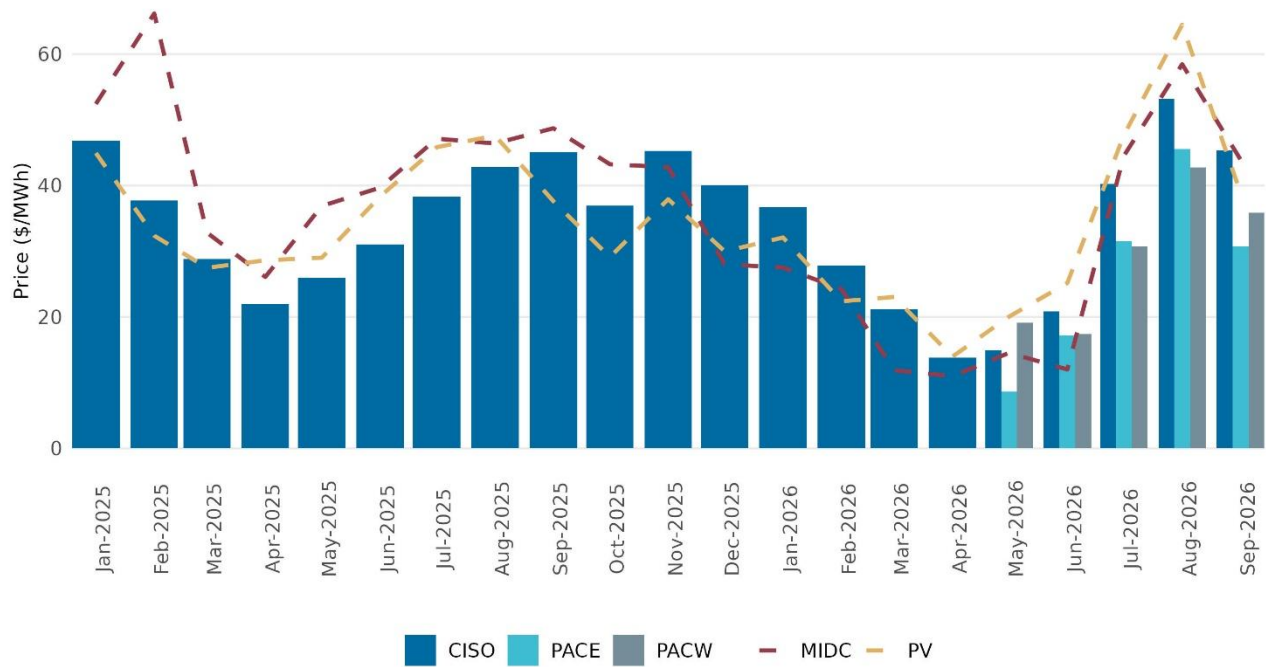


Figure 22: Daily average LMPs and bilateral power prices

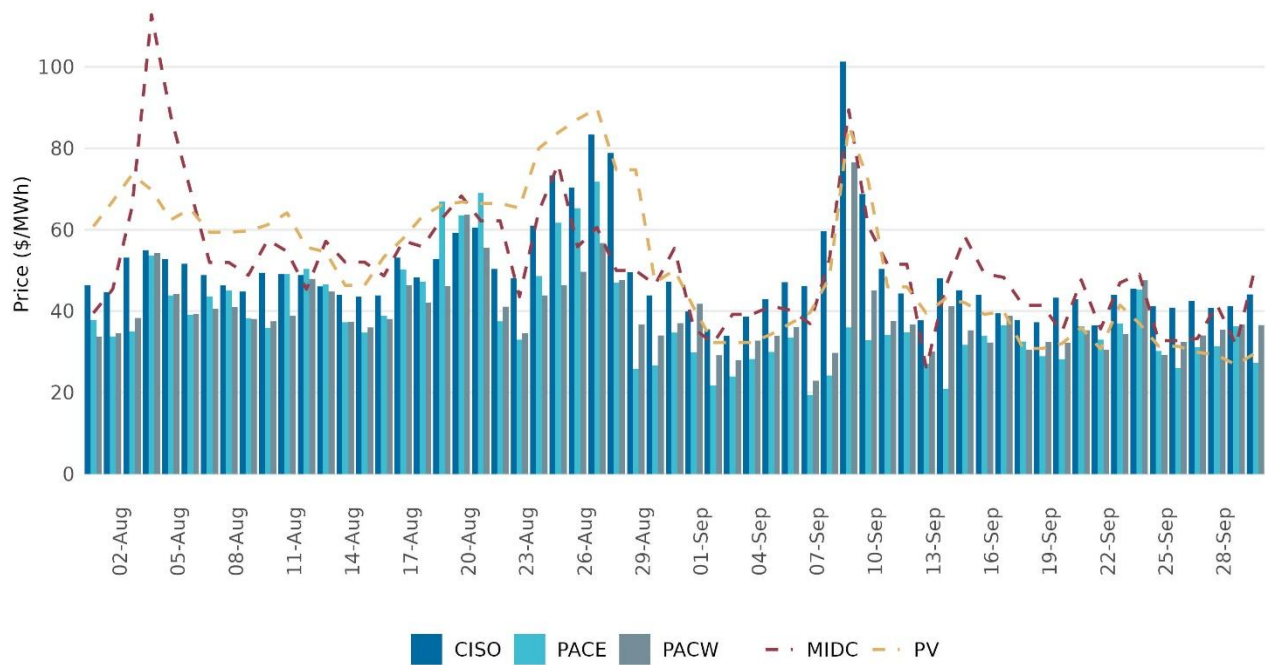


Figure 23 and Figure 24 show the monthly average energy volume traded since January 2025. On-peak volumes in September 2026 fell, similar to September 2025. Off-peak volumes fell marginally in September 2026 compared to on-peak.

Figure 23: Total monthly energy volume of bilateral trades (On-peak)

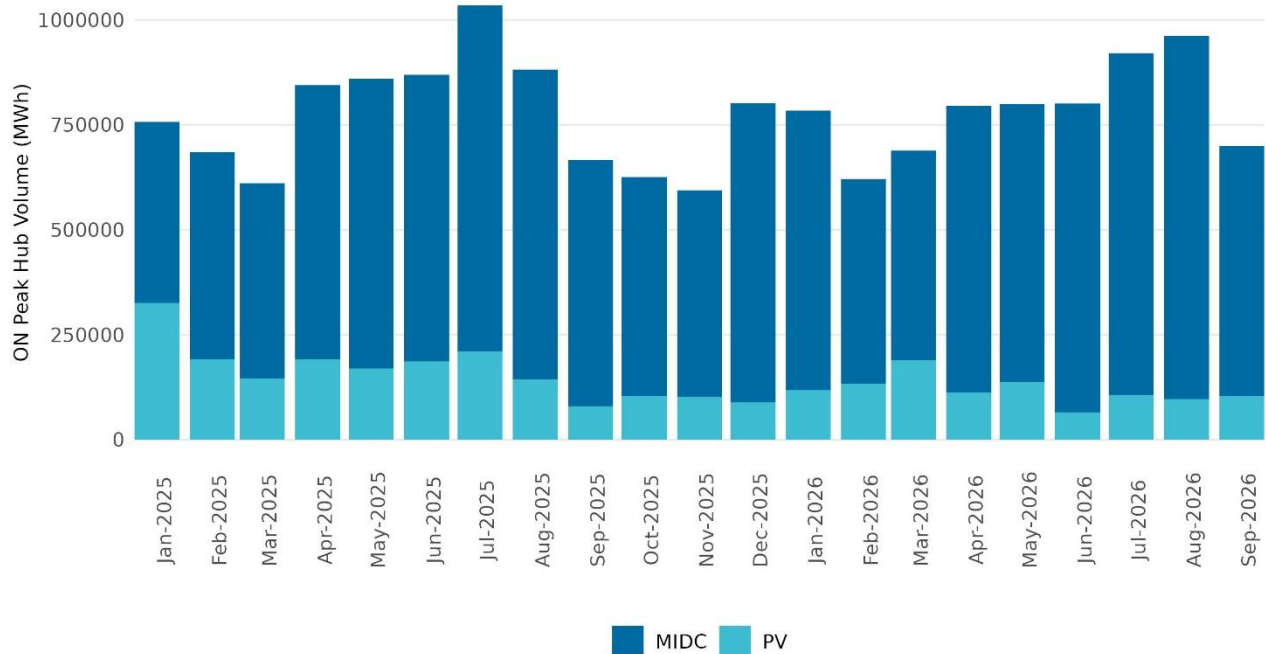


Figure 24: Monthly total energy volume of bilateral trades (Off-peak)

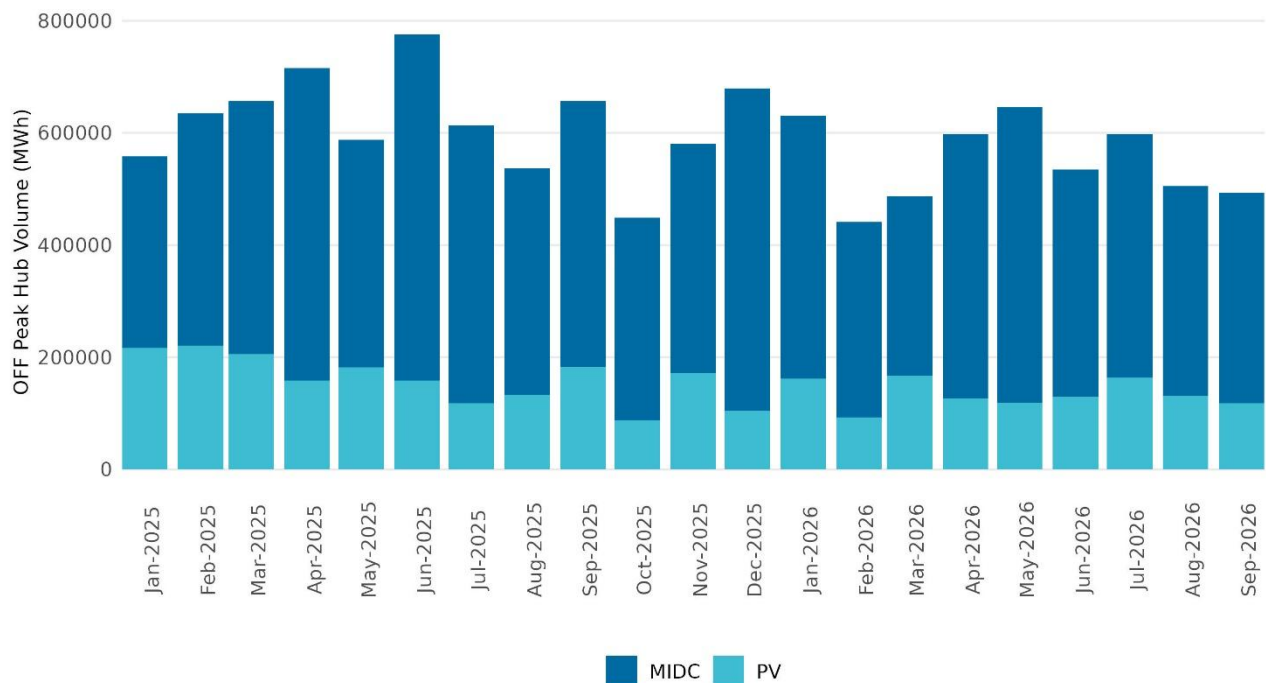


Figure 25 and Figure 26 show the daily energy volume traded for bilateral next-day power at MidC and PV hubs from April to September. For on peak, no power is traded on Sundays, which is an off-peak day. For off-peak, volumes are lowest during the weekdays. For both on- and off-peak, volumes are usually highest at the end of the week when power delivery is for Sunday and Monday. These figures show no observable change in patterns in the volume traded for on- or off-peak from pre-EDAM in April to EDAM operations from May through September. Volumes at MidC spiked around September 9 correlated with a high heat event, but PV volumes remained steady.

Figure 25: Total daily energy volume of bilateral trades (On-peak)

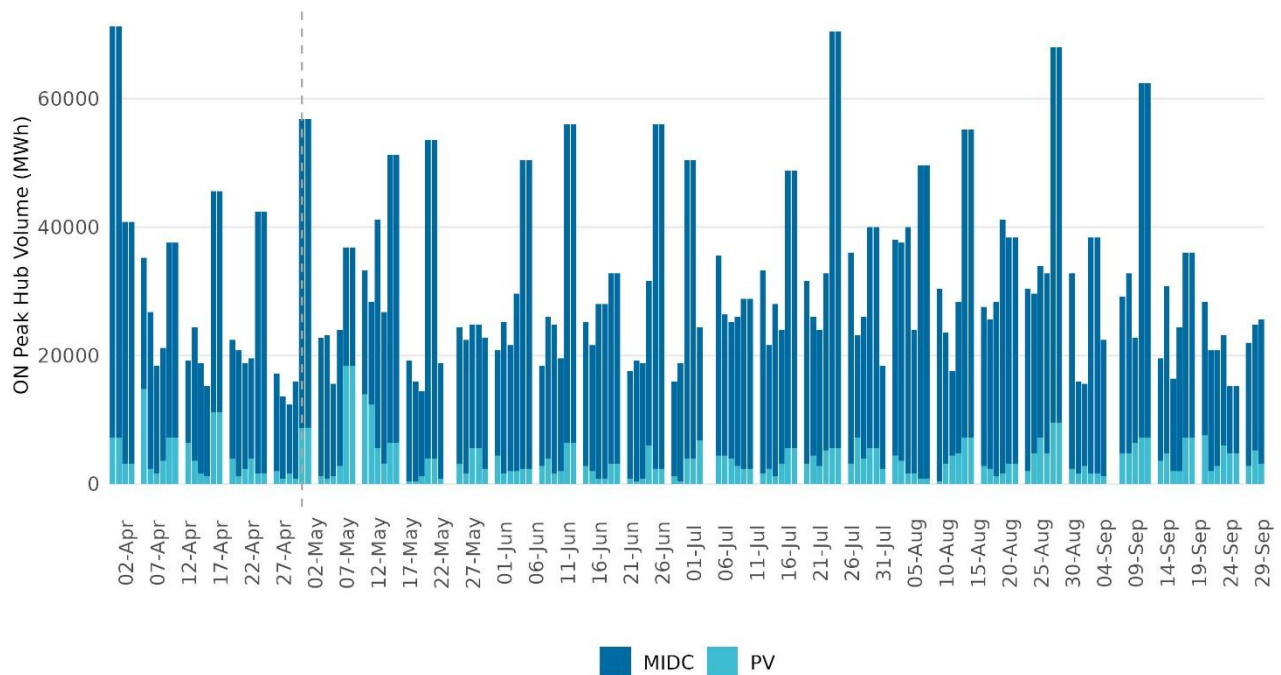
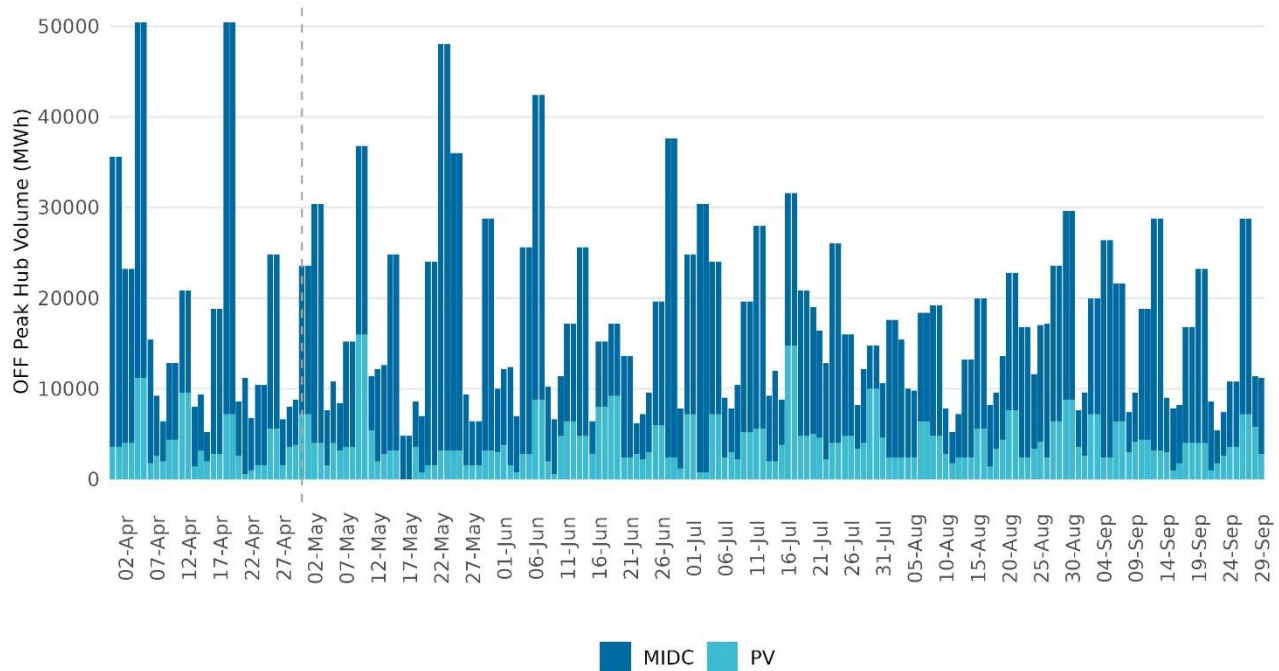


Figure 26: Total daily energy volume of bilateral trades (Off-peak)



Ancillary services

EDAM go-live made few changes to ancillary service procurement market design. The one major change applies to battery storage resource type (LESR). For these resources, new commodities were added to the envelope constraint which models the impact on state of charge of various commodities, including regulation up and down for CAISO and the new commodities imbalance reserve and reliability capacity for resources in all EDAM BAAs.

Figure 27 shows CAISO ancillary services prices in IFM from July 1st to September 30th. Overall, AS prices remained within typical ranges for all four commodities in September, with slightly elevated prices on September 9th reflecting summer conditions.

Figure 27: Daily average of CAISO ancillary services prices in IFM

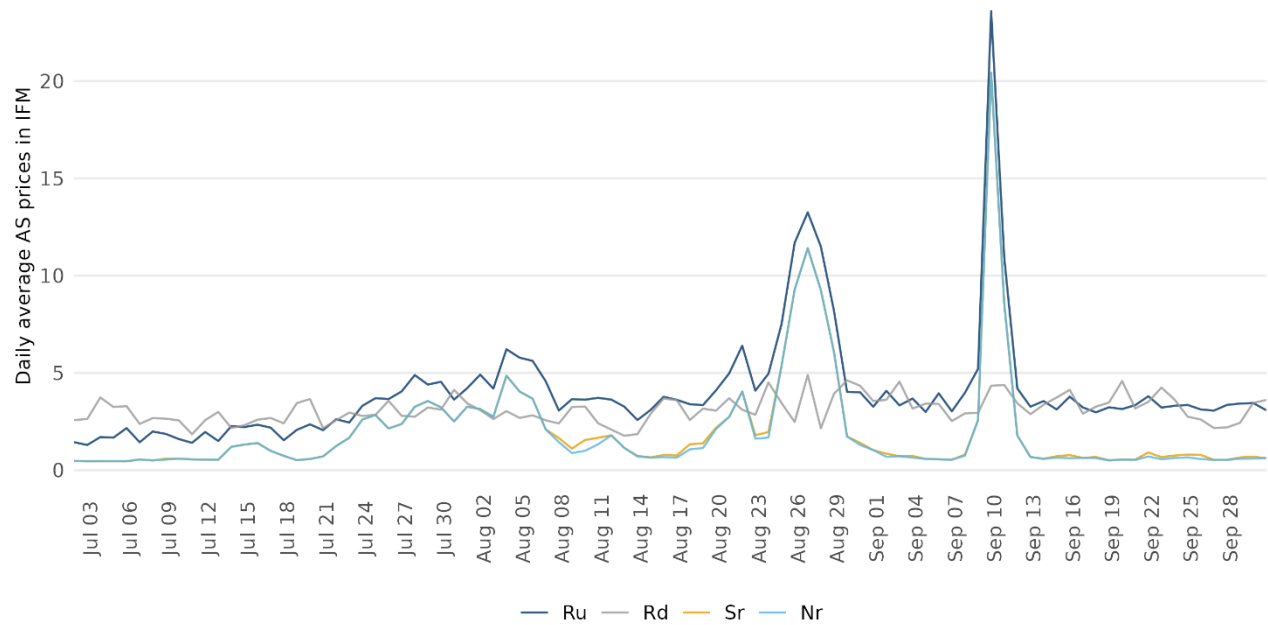
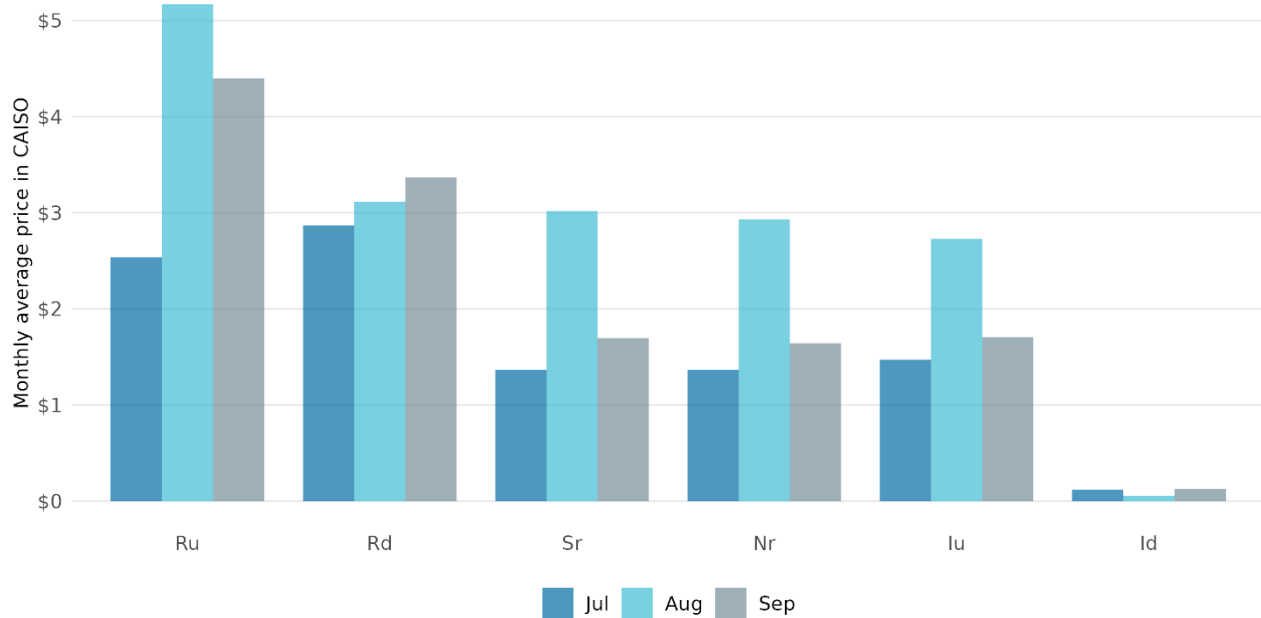


Figure 28 compares the monthly average AS prices in CAISO for July through September. Average regulation up, spin, and non-spin prices showed slight decreases, while regulation down prices remained in similar ranges. New imbalance reserve prices in CAISO are added for reference. Average price of imbalance reserve up also saw slight decline in September, at a level similar to the average prices of spin.

Figure 28: Monthly average AS prices in CAISO



Imbalance reserves

Imbalance Reserves (IR) are a new flexible reserve day-ahead product introduced with the EDAM market. The IR product covers uncertainty that materializes between the day-ahead and the real-time net load forecast, and real-time ramping needs not covered by hourly day-ahead market schedules. Net load forecast uncertainty is driven by variability in variable energy resource production forecasts and load forecasts. Imbalances in the net load forecasts between the day-ahead and real-time markets have grown due to rapid growth in variable energy resource capacity on the CAISO grid and more extreme weather throughout the Western grid. Imbalances also exist because real-time net load moves continuously and flat hourly schedules from the day-ahead market inherently cannot cover the fluctuation. The IR product ensures that each balancing authority area in EDAM has sufficient flexible capacity scheduled to meet net load imbalances between the day-ahead and real-time markets. The market procures imbalance reserves bi-directionally to ensure upward and downward net load imbalances are covered.

Imbalance reserve prices

Figure 29 shows that IRU prices in September fell compared to August. The largest decrease was observed in PACE falling from \$4.84/MWh in August to \$2.37/MWh in September. PACE recorded the highest monthly average IRU price in September, while PACW recorded the lowest at \$1.48/MWh. The monthly average IRU price in CAISO was \$1.71/MWh. Monthly average IRD prices

increased in September for PACW, rising to \$1.78/MWh from \$0.89/MWh in August. For PACE and CAISO, monthly average IRD prices remained low in September. Monthly average IRD prices have been much lower than monthly average IRU prices, however, for PACW in September the monthly average IRD price was higher than the monthly average IRU price.

Figure 29: Monthly average IR prices

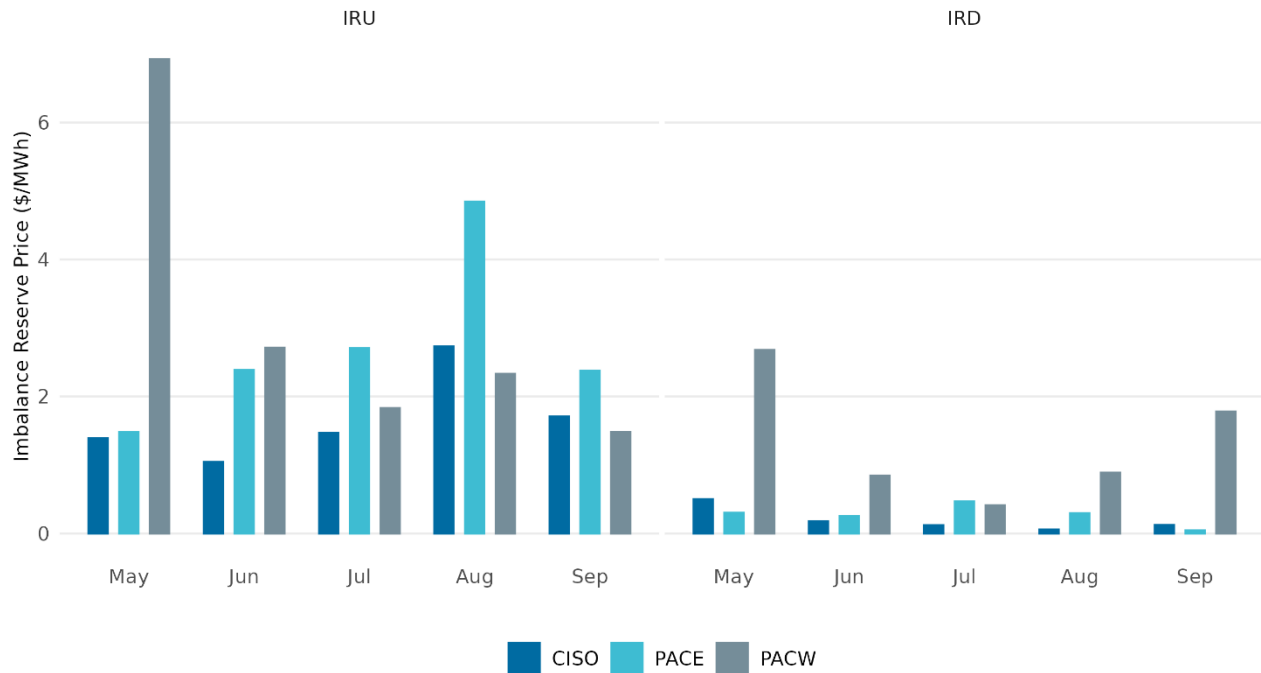


Figure 30 and Figure 31 show the frequency of IRU and IRD price ranges from May to September. For IRU, prices fell between \$0/MWh and \$5/MWh approximately 93% of the time in September for CAISO, 86% of the time for PACE and 98% of the time for PACW. For IRD, prices fell between \$0/MWh and \$5/MWh in 100% of intervals in September for CAISO. For PACE, IRD prices fell between -\$5/MWh and \$5/MWh in 100% of intervals and 90% for PACW.

Figure 30: Frequency of IRU price ranges

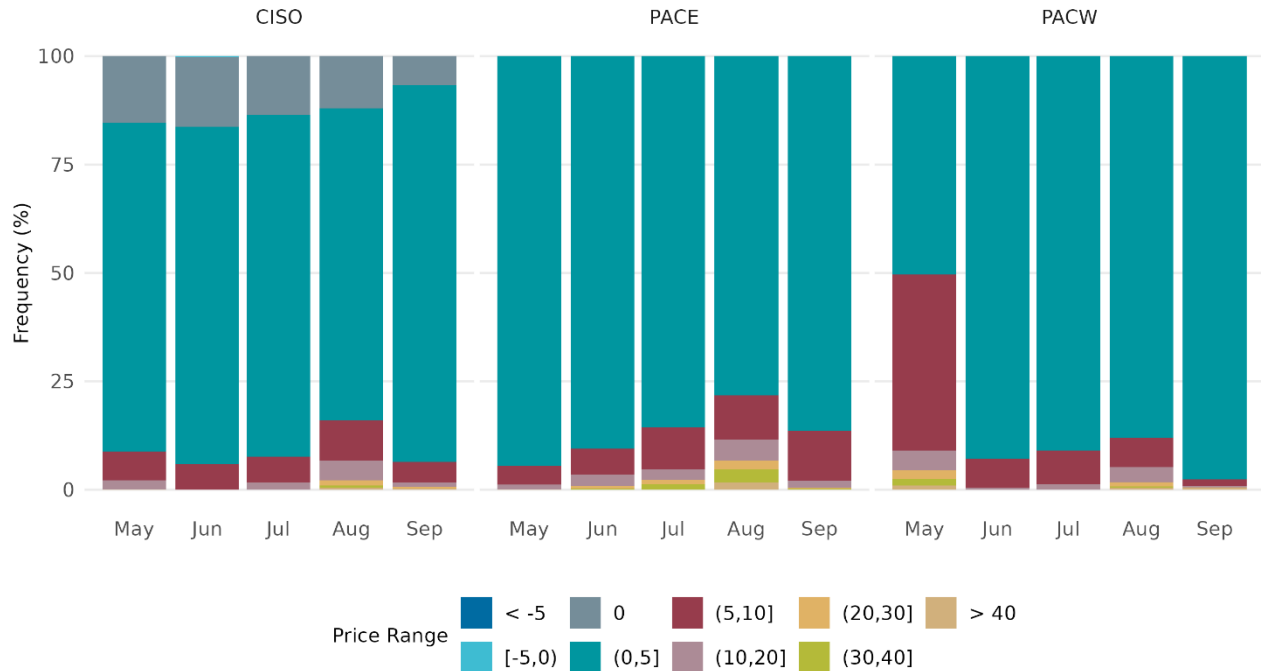


Figure 31: Frequency of IRD price ranges

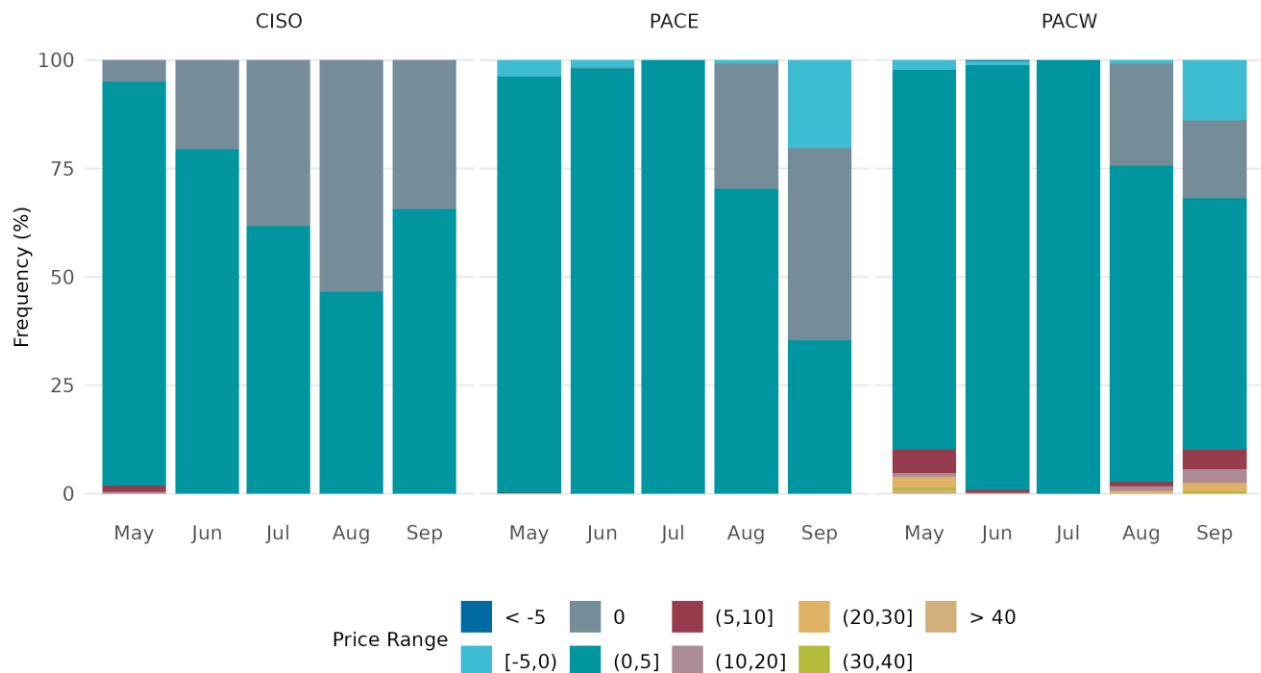


Figure 32 and Figure 33 show the daily average IR prices in September. Daily average IRU prices were less volatile in September compared to August for all three EDAM BAAs. Daily average IRU prices for all three BAAs spiked on September 9 at \$11.87/MWh for CAISO, \$7.22/MWh for PACW and \$6.36/MWh for PACE. Daily average IRD prices remained stable in September except in PACW. Volatility of IRD prices in PACW increased in August compared to July, and even more in September.

PACW experienced multiple IRD price spikes towards the end of the month, with the highest daily average IRD price occurring on September 30 at \$12.99/MWh.

Figure 32: Daily average price of IRU

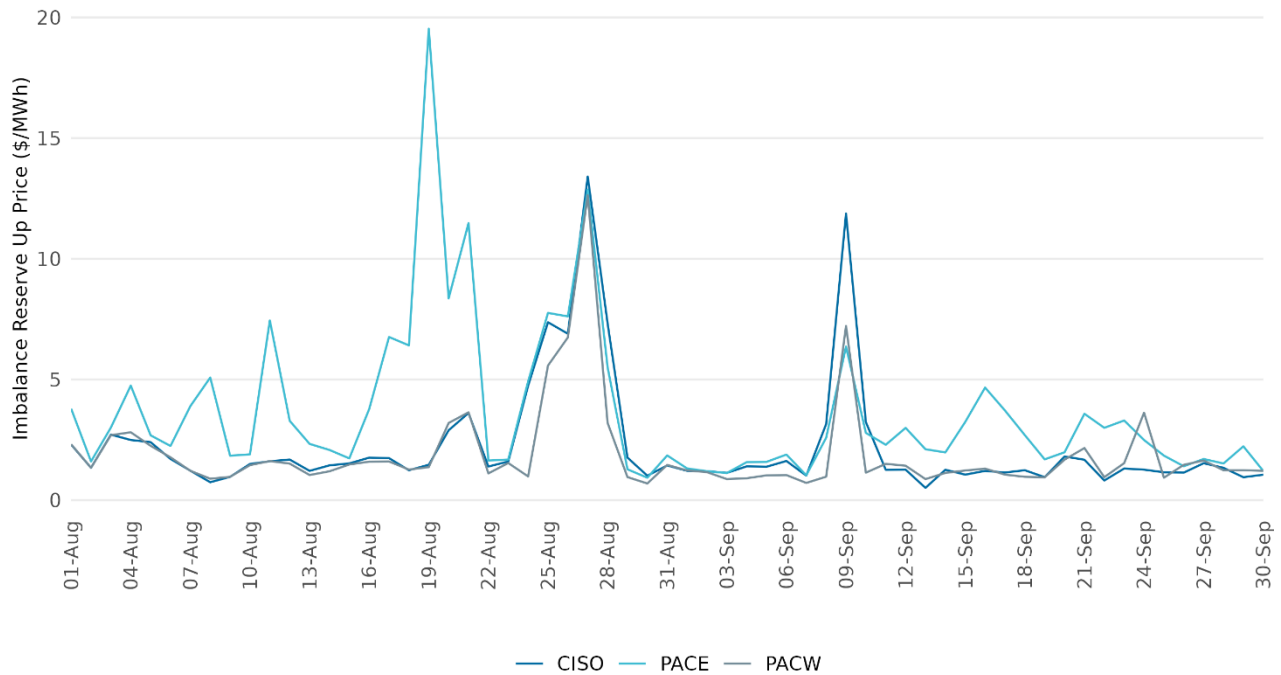


Figure 33: Daily average price of IRD

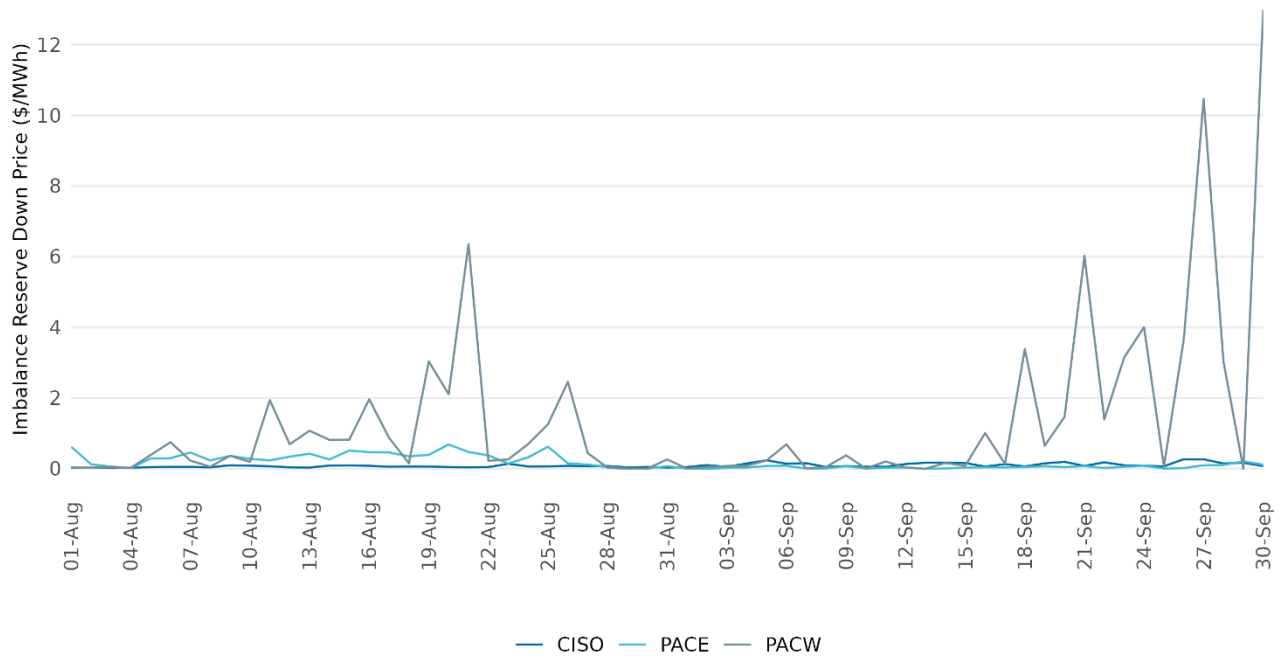


Figure 34 and Figure 35 show the hourly average IR price profiles for all BAAs in September. The highest hourly average IRU prices occurred during the morning and evening ramping periods, consistent with trends observed in prior months. This coincides with the hours of highest day-ahead demand, indicating that ramping needs are greatest when net load forecasts change during these periods. Hourly average IRD prices also peaked in these hours for all three BAAs. In particular, PACW IRD prices were highest from hours ending 13 to 18.

Figure 34: Hourly average price of IRU

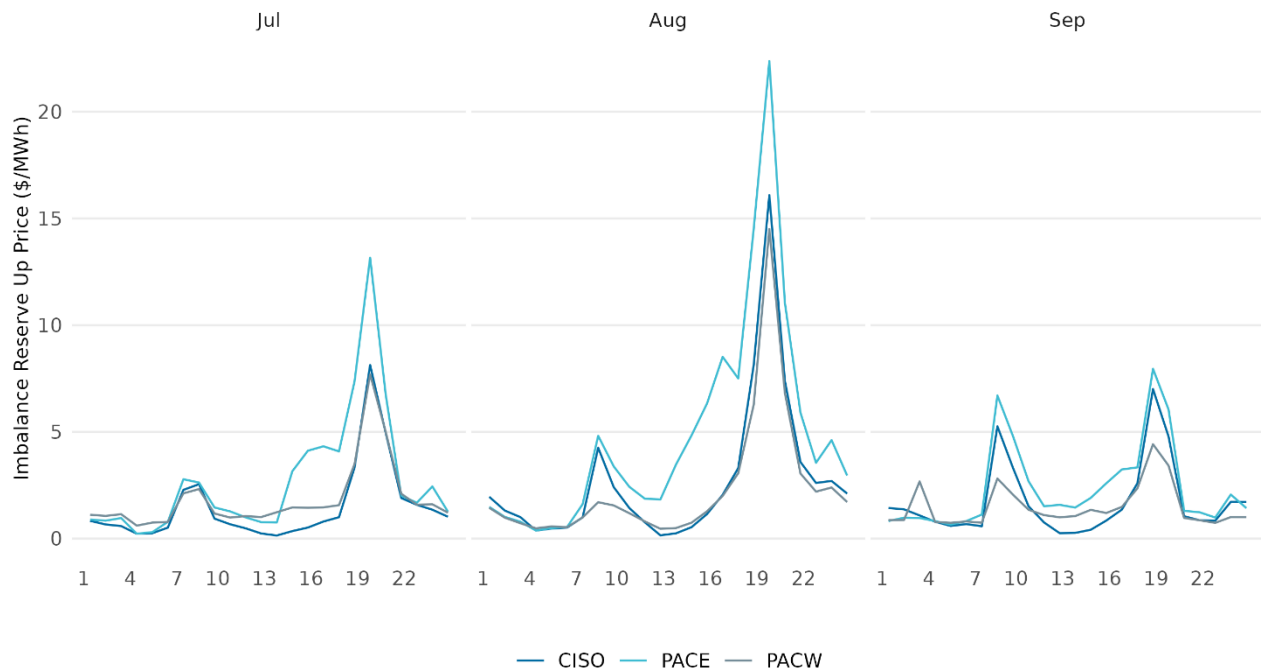
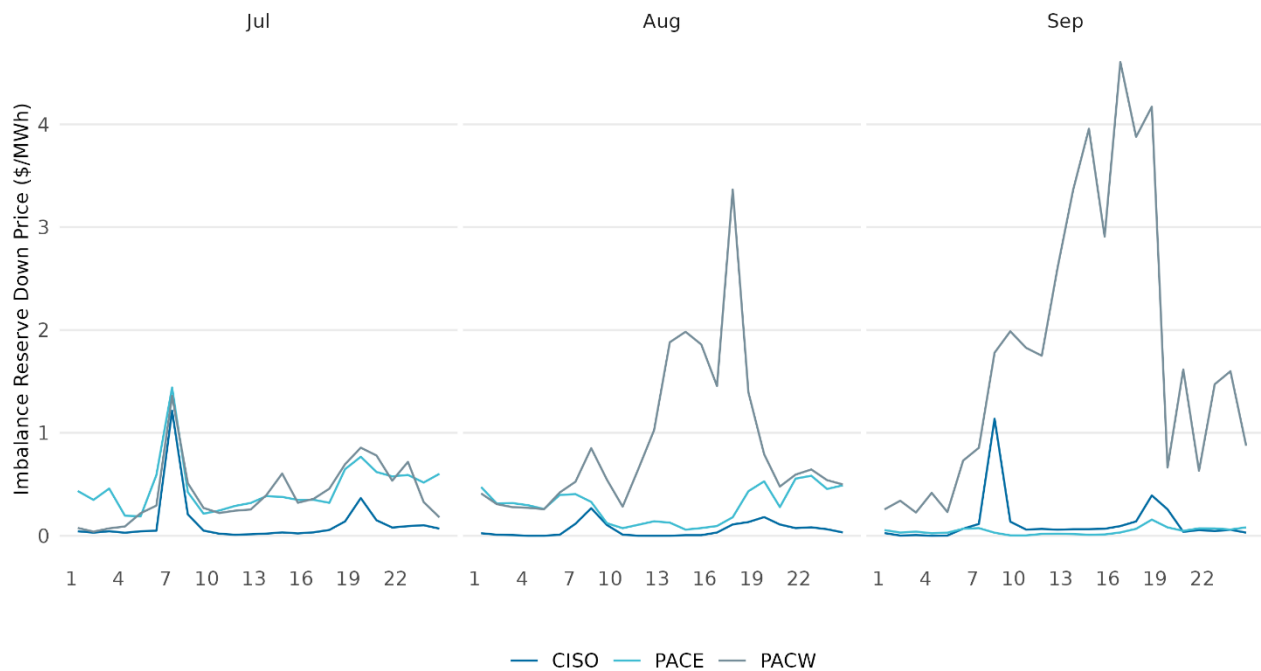


Figure 35: Hourly average price of IRD

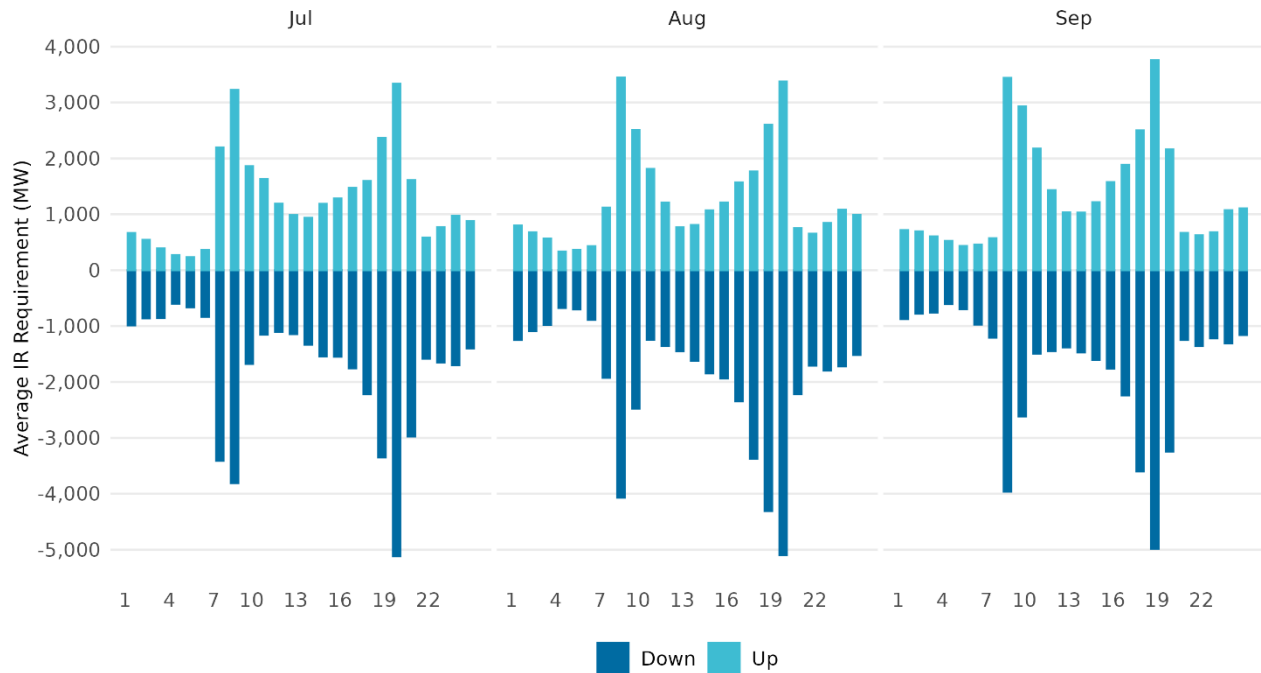


The imbalance reserve price separation observed between the three BAAs reflects the economics of the wider EDAM market footprint and each BAA's imbalance reserve requirement, available supply mix and EDAM transfers.

Imbalance reserve requirements

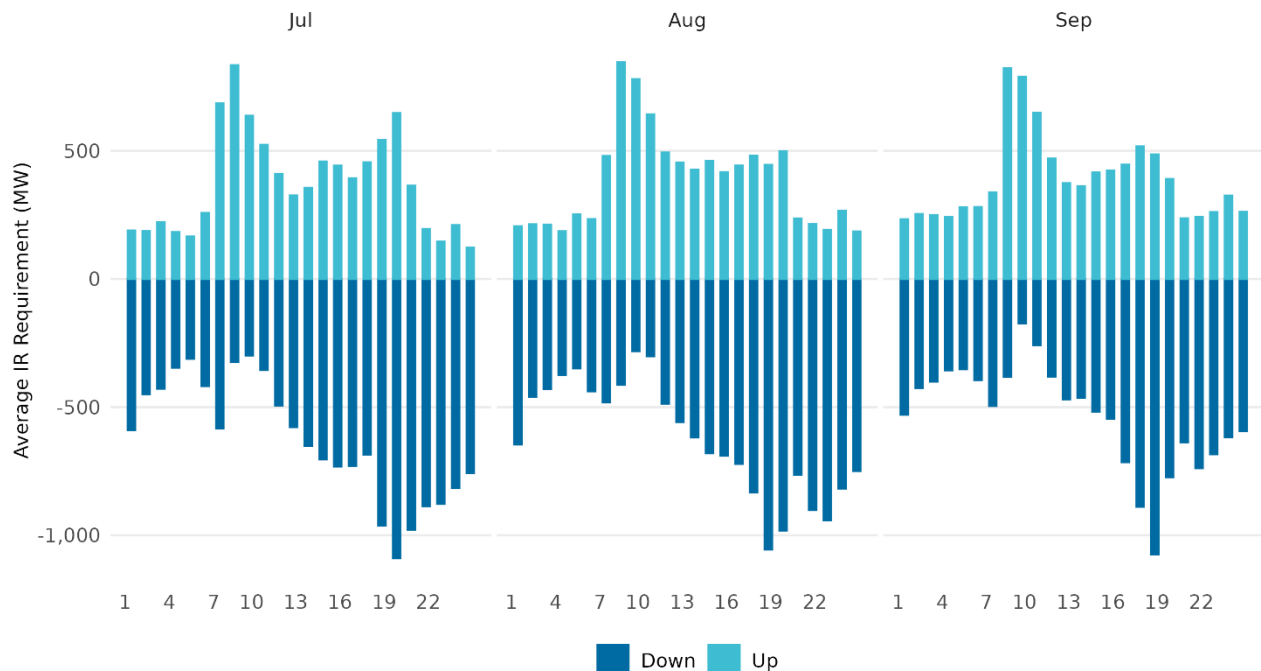
IR Requirements are calculated hourly for each BAA. Figure 36 to Figure 38 illustrate average IR requirements for each BAA by direction. The magnitude of IR procured is proportional to the magnitude of net load uncertainty associated with that BAA. CAISO is the largest footprint in the EDAM with a large assortment of variable energy resources, so naturally it sees the highest amount of IR procurement. IR requirements for CAISO BAA are consistent in shape and magnitude since July. The highest requirements typically occur during the solar ramping hours where flexibility is required if the net load forecast changes.

Figure 36: Hourly average of IR requirements for CAISO



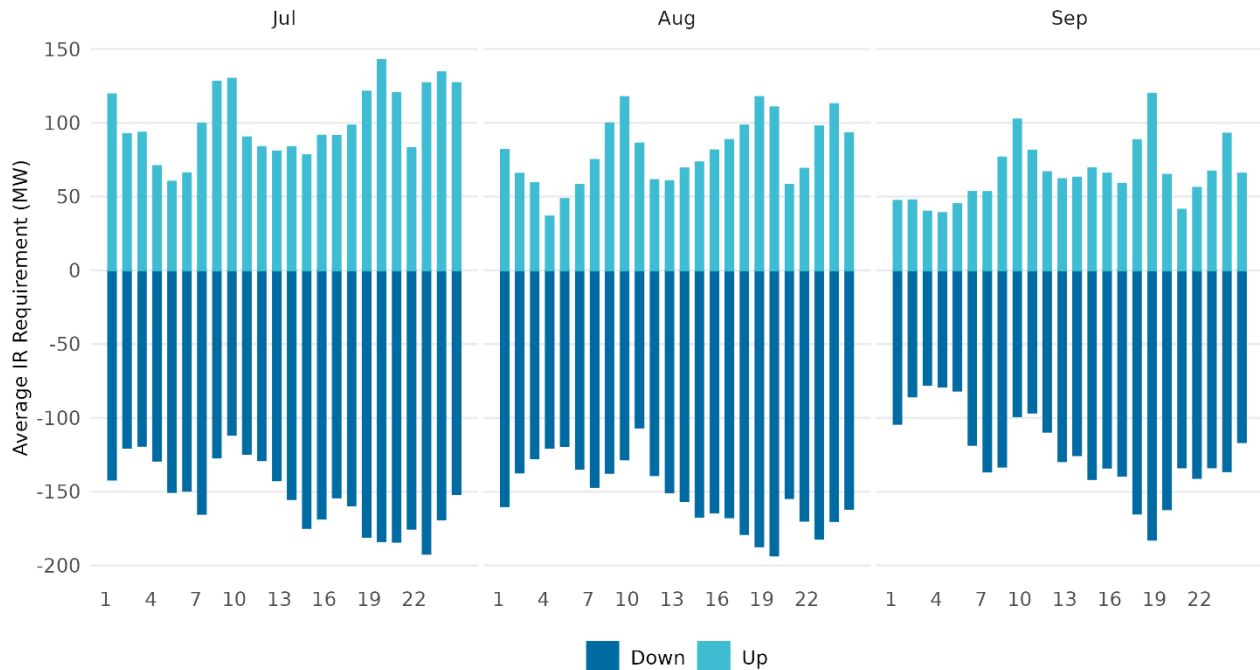
PACE IR requirements, on average, also saw the highest IRU requirements during the morning ramping hours and the highest IRD requirements during the evening peak. PACE IR requirements shape and magnitude also are stable since July.

Figure 37: Hourly average of IR requirements for PACE



PACW IRU requirements are relatively consistent throughout the day on average for both IRU and IRD. However, there was a noticeable decrease in the requirement in September in both upward and downward directions.

Figure 38: Hourly average for IR requirements for PACW



EDAM expands the day-ahead market footprint. Uncertainty in each area, due to load and renewable variability, does not usually occur at the same time. Sharing supply and demand variability across a broader footprint brings diversity benefit to the EDAM BAAs, by reducing the total requirement needed compared with the total requirements when assessing area needs separately. Figure 39 and Figure 40 presents the hourly average diversity benefit by EDAM BAA by product. Diversity benefit is defined as the difference between the sum of individual BAA IR requirement and the IR requirement of the entire EDAM footprint. The reduction of requirements is then allocated pro-rata to each EDAM BAA based on its original individual BAA requirement. In September 2026, the average diversity benefit allocation is shown in Table 5.

Table 5 Average Diversity benefit allocation

BAA	CISO		PACE		PACW	
IRU	318	68.8%	117	25.3%	27.1	5.9%
IRD	340	71.2%	117	24.5%	20.7	4.3%

Figure 39: Hourly average diversity benefit, IRU

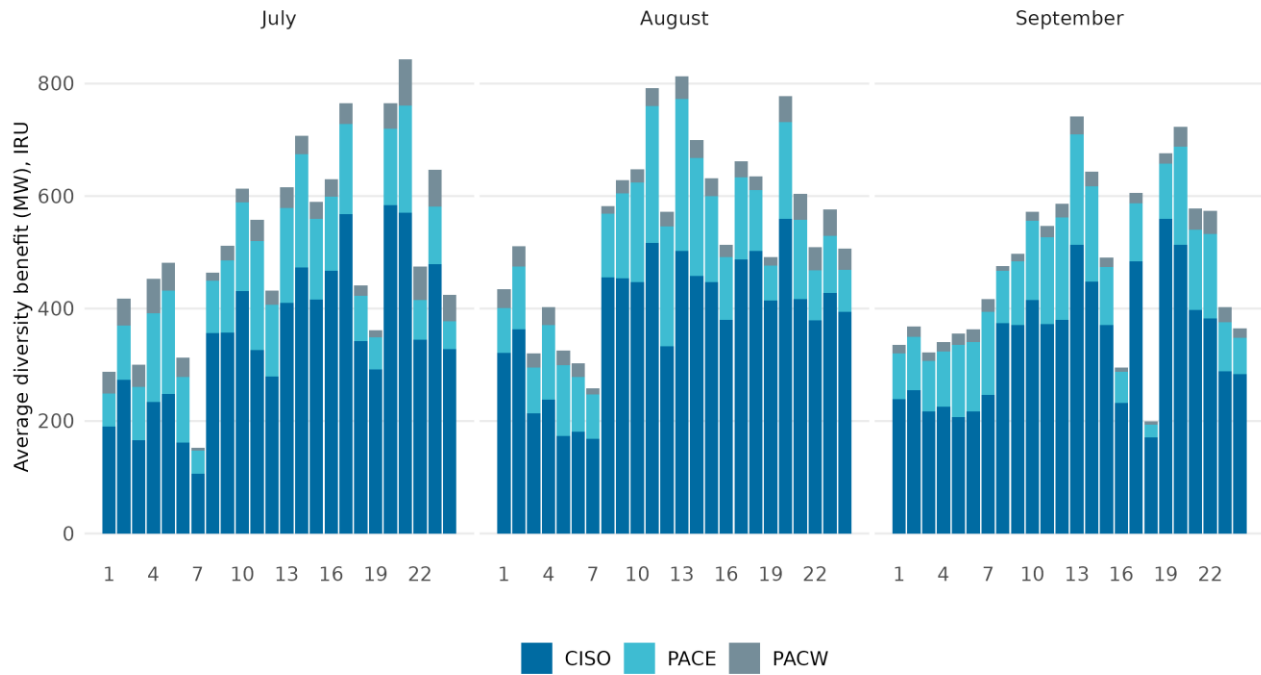
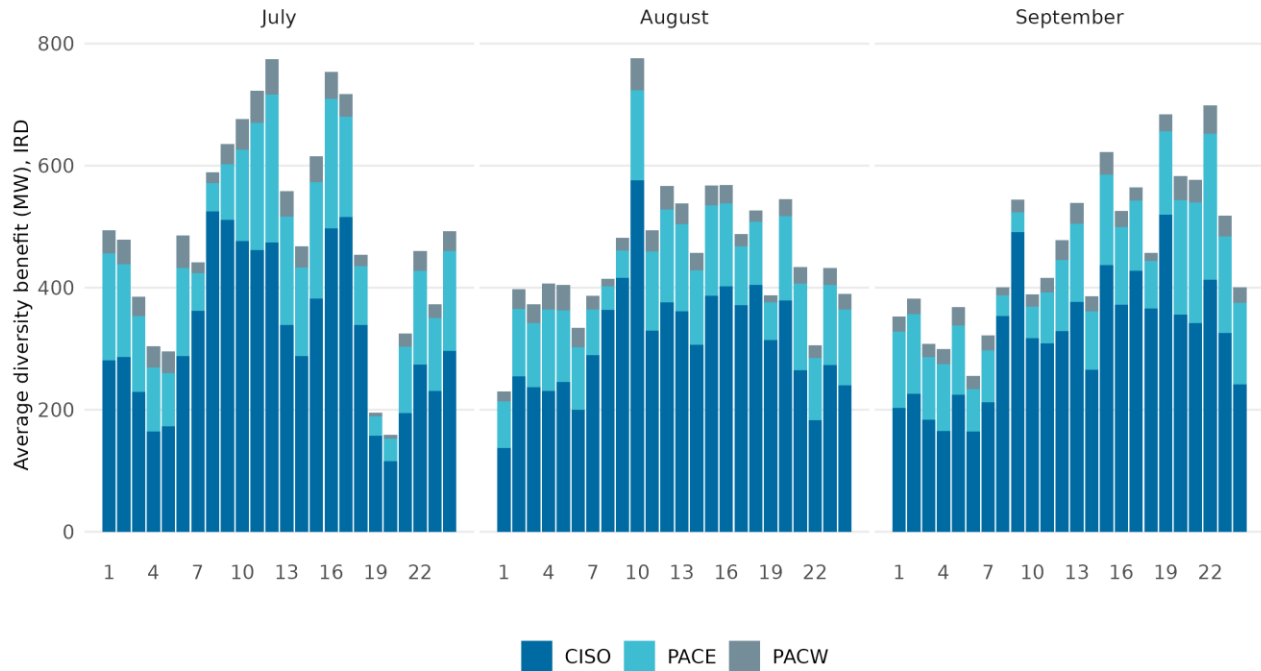


Figure 40: Hourly average diversity benefit, IRD



Imbalance reserve awards

Figure 41 illustrates hourly average cleared IR by fuel type, positive direction indicates IRU and negative values indicate IRD, respectively. For the IRU direction, the resource mix exhibits a well-defined pattern, with gas resources providing the majority of IRU supply during overnight hours and remaining a significant contributor throughout the day. Solar resources become the dominant technology during daylight hours, and batteries show narrow procurement only during morning and evening ramp periods. As for IRD, solar resources show the greatest contribution during daylight hours, while wind resources become the main technology during non-solar hours. The CAISO's IR procurement is stable across three months.

Figure 41: Hourly average cleared IR by fuel type for CAISO

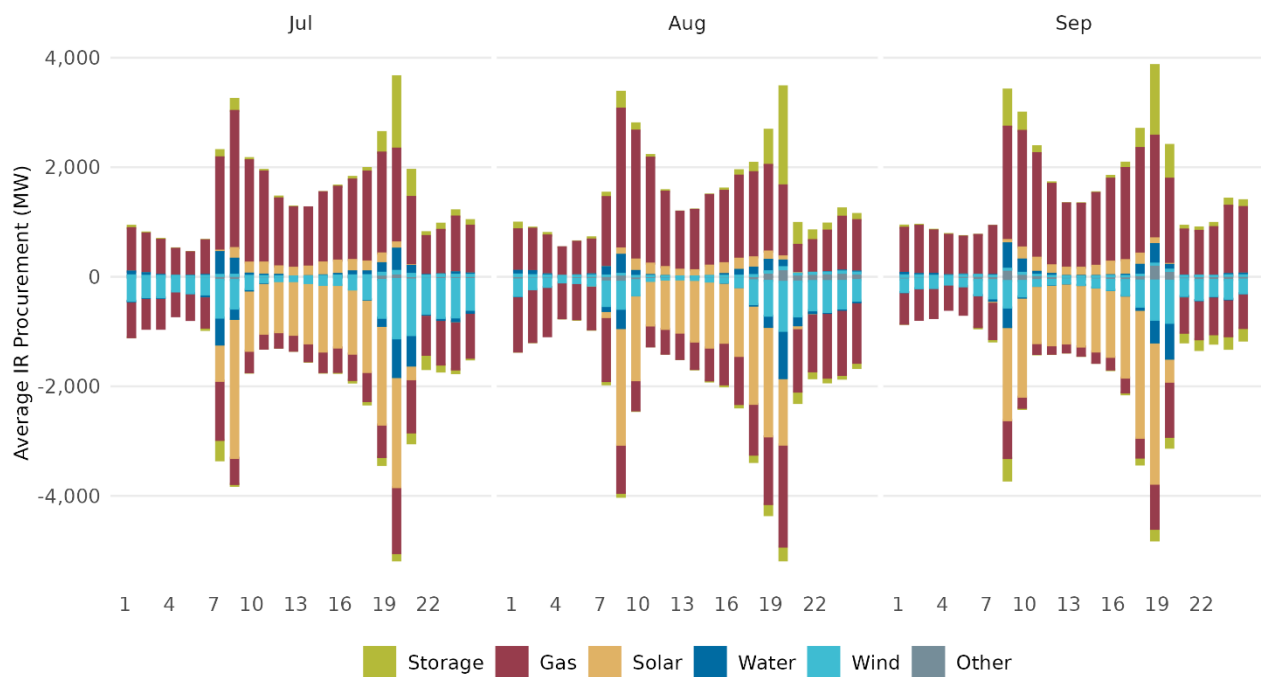


Figure 42 shows PACE's hourly average cleared IRU and IRD by fuel type, respectively. The dominant resources in PACE are coal and wind, followed by gas resources. Solar and storage have minimal contribution, with storage only during peak hours and solar during daytime hours and for IRD only. The overall IR procurement of PACE is stable across three months.

Figure 42: Hourly average cleared IR by fuel type for PACE

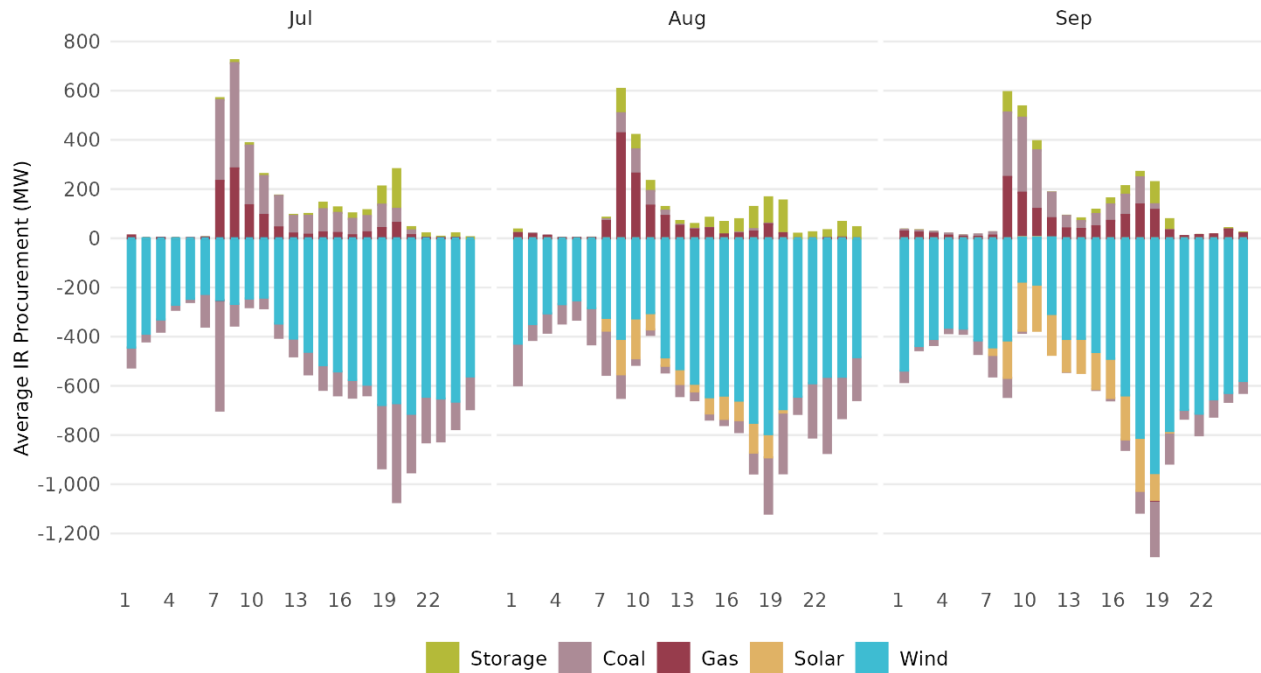
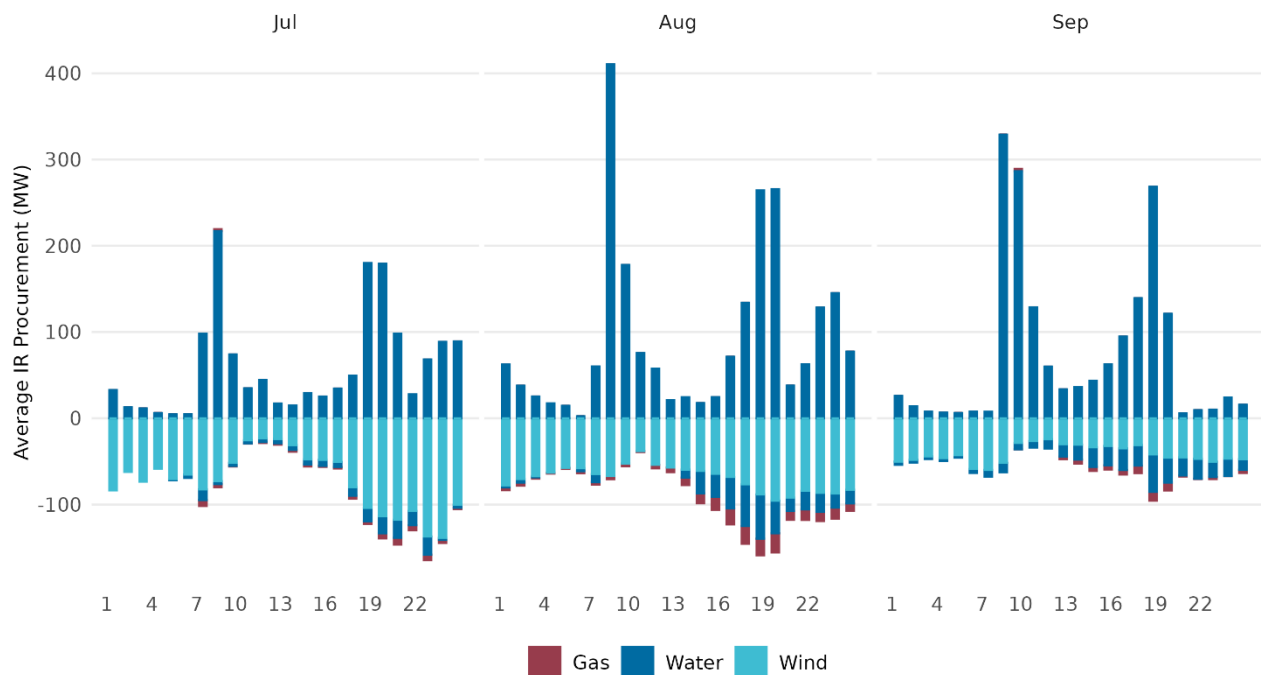


Figure 43 shows PACW's hourly average cleared IRU and IRD by fuel type, respectively. Unlike CAISO, the dominant resources in PACW are water and wind. Water resources provided nearly all the IRU supply and increased significantly in August and September. Wind resources contribute the most of IRD supply, and there were some gas resources providing IRD.

Figure 43: Hourly average cleared IR by fuel type for PACW



The technology supporting the procurement of IRU/IRD is organized by the host balancing area. However, as DAM enables economic transfers, a portion of the procured IR is indeed supported by areas transferring IR. These transfers are explicitly tracked and analyzed in subsequent.

Imbalance reserves input bids

Imbalance reserves are co-optimized with energy and ancillary services in the IFM, therefore, resources need to submit economic energy bids for intervals in which imbalance reserve bids are submitted. The energy bid includes the portion that overlaps with the imbalance reserve bid. Imbalance reserve bids are subject to a cap of 55 \$/MWh.

Figure 44 and Figure 45 illustrate CAISO's hourly and daily average IFM supply input bids for IR by bid price range, positive values represent up direction and negative represent down direction, respectively. Low-priced bids (0–5 \$/MWh) and high-priced bids (45–55 \$/MWh) consistently accounted for the largest share of submitted IR capacity throughout July and September with about 80 percent. The remaining price ranges, including zero prices, and mid-priced ranges (5–30 \$/MWh) represented a relatively small share of total submitted capacity. Hourly bid volumes were generally higher during daytime hours and lower during overnight hours.

Generally, CAISO's submitted IR capacity remained relatively stable. The overall bid-price composition showed limited variation across both hourly and daily views, indicating a stable supply offer pattern for CAISO's IR throughout July to September. The volume of bids in the upward direction is symmetrical to the volume for the downward direction.⁴

⁴ This is a measure of the bid volume in the market that can be utilized to procure IR; however, much of that capacity can also be made available to meet energy needs. In the end, the market clearing process determines how to optimally allocate the supply available among the different market commodities.

Figure 44: Hourly average volume of IR bids organized by price for CAISO

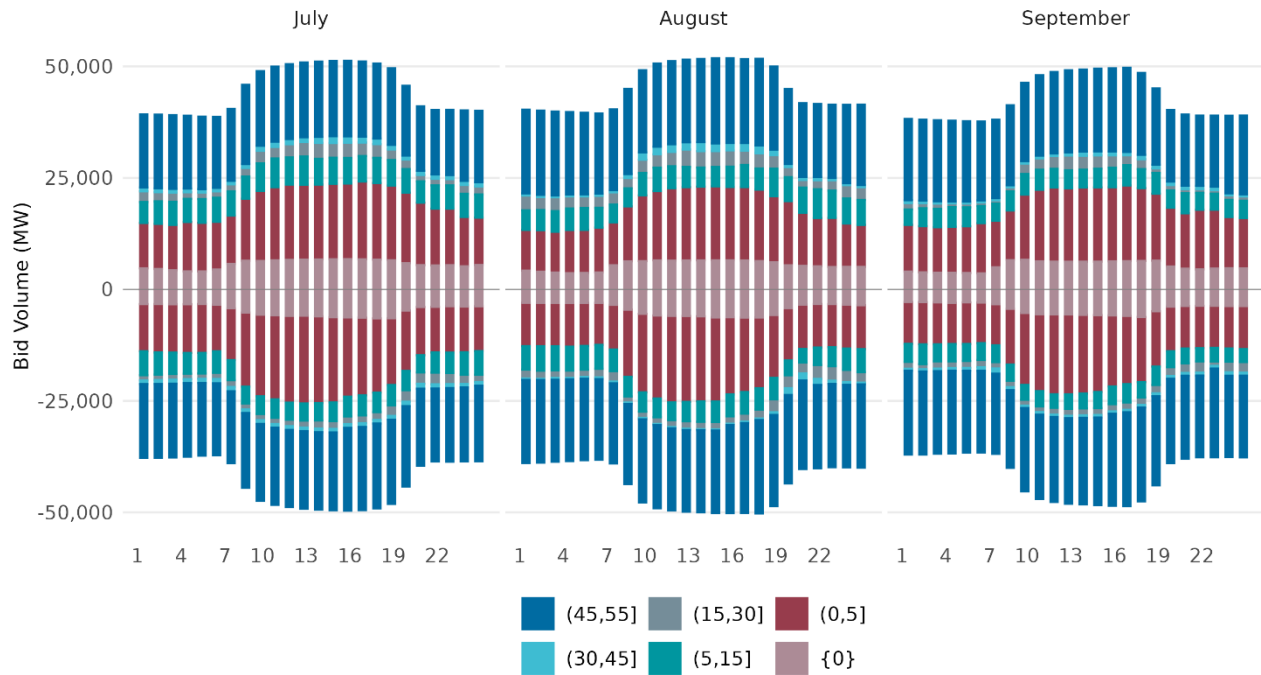


Figure 45: Daily average volume of IR bids organized by price for CAISO

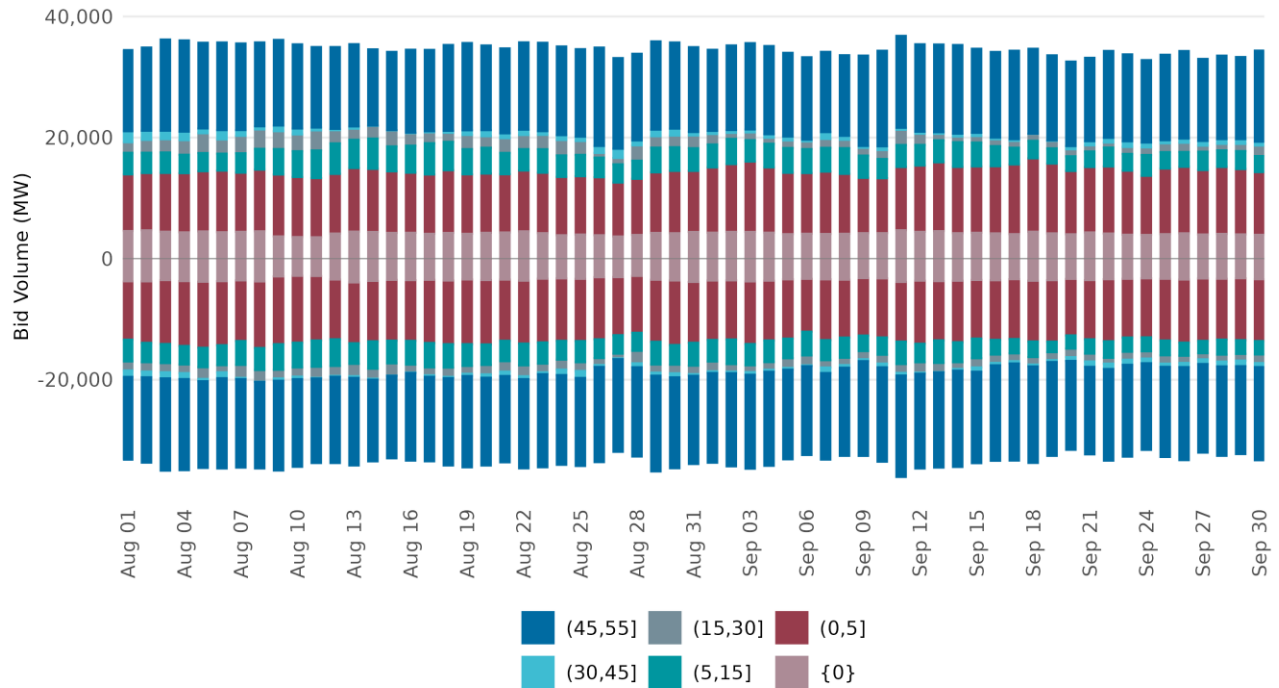


Figure 46 and Figure 47 illustrate CAISO’s hourly and daily average IFM supply input bids for IR by fuel type. Energy storage, gas, and solar resources accounted for the largest share of submitted IR capacity throughout July to September, followed by water and wind resources.

Figure 46: Hourly average volume of IR bids organized by fuel type for CAISO

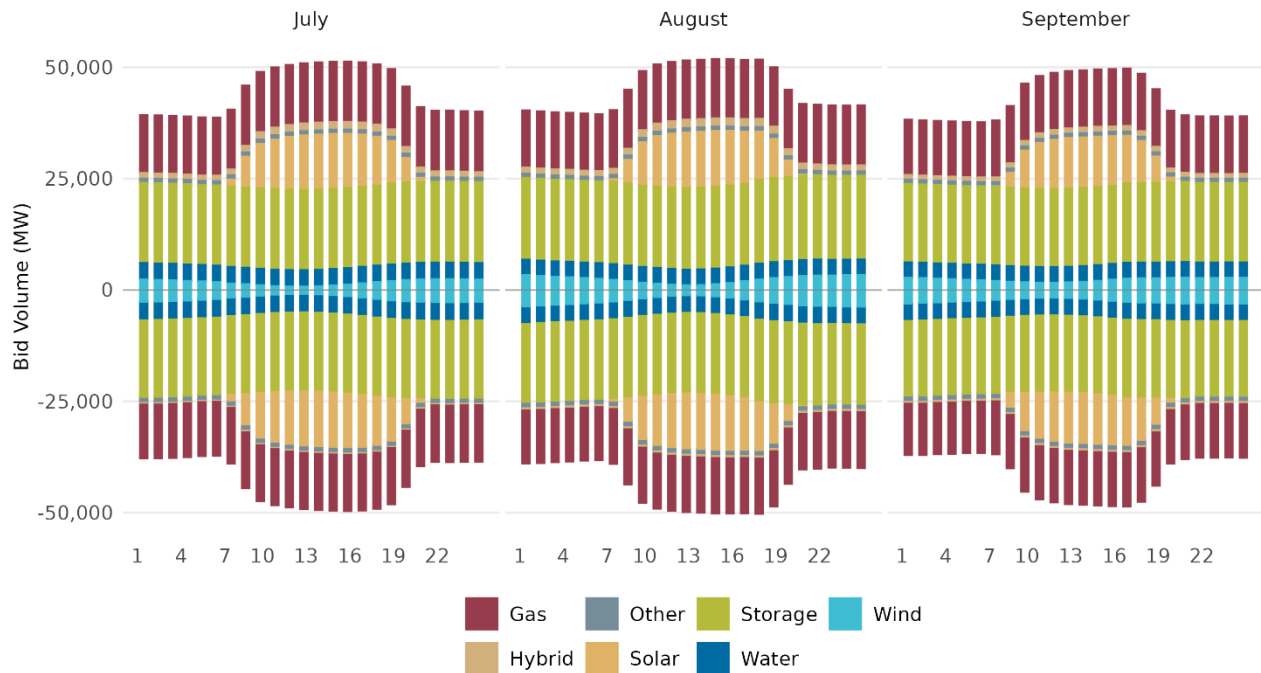


Figure 47: Daily average volume of IR bids organized by fuel type for CAISO

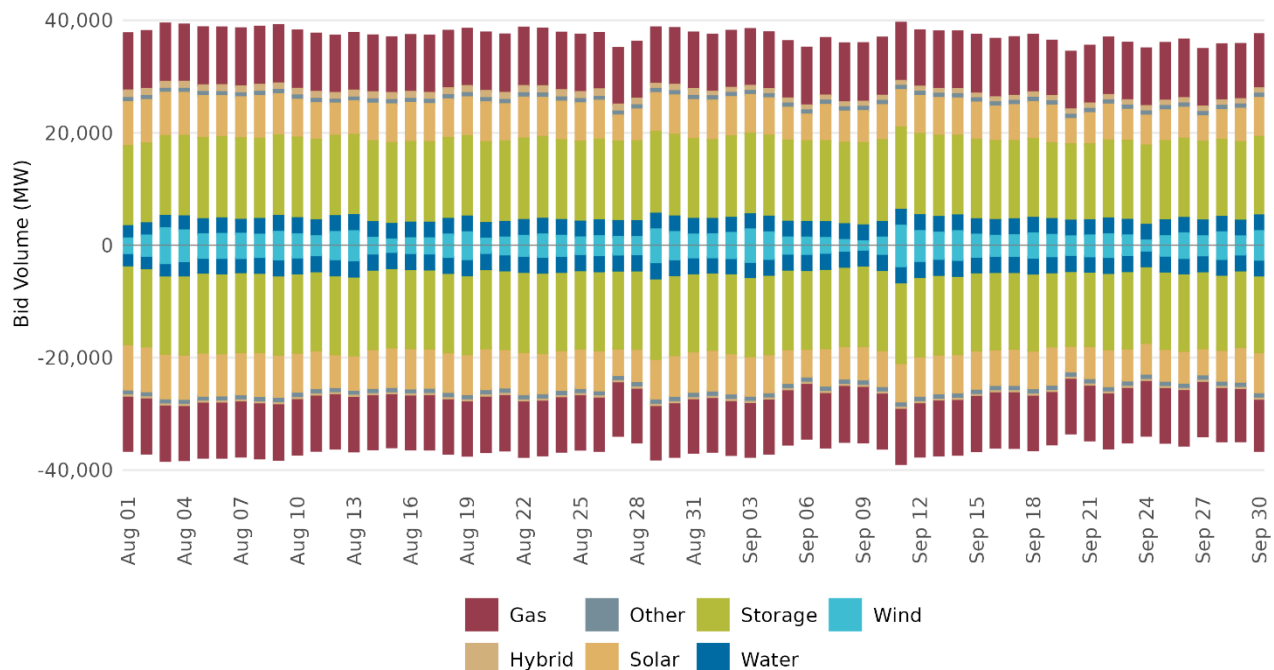


Figure 48 to Figure 50 illustrate the PACE’s hourly and daily average IFM supply input bids for IR by bid price range. Low-priced bids (\$0–5/MW) consistently accounted for the largest share of submitted IR capacity throughout the months with about 3,500 MW (or 80 percent), followed by bids in the 45–55 \$/MWh range. The remaining price ranges represented a relatively small share of total submitted capacity. Hourly bid volumes were generally higher during daytime hours and lower during overnight hours, capped by renewable outputs. Starting in August, PACE gradually shifted a portion of its bids from (\$0–5/MW) to (\$0/MW), with this trend becoming more pronounced in September. September also shows a noticeable increase in daytime bid volumes, peaking at approximately 5,600MW.

Figure 48: Hourly average volume of IR bids by price for PACE

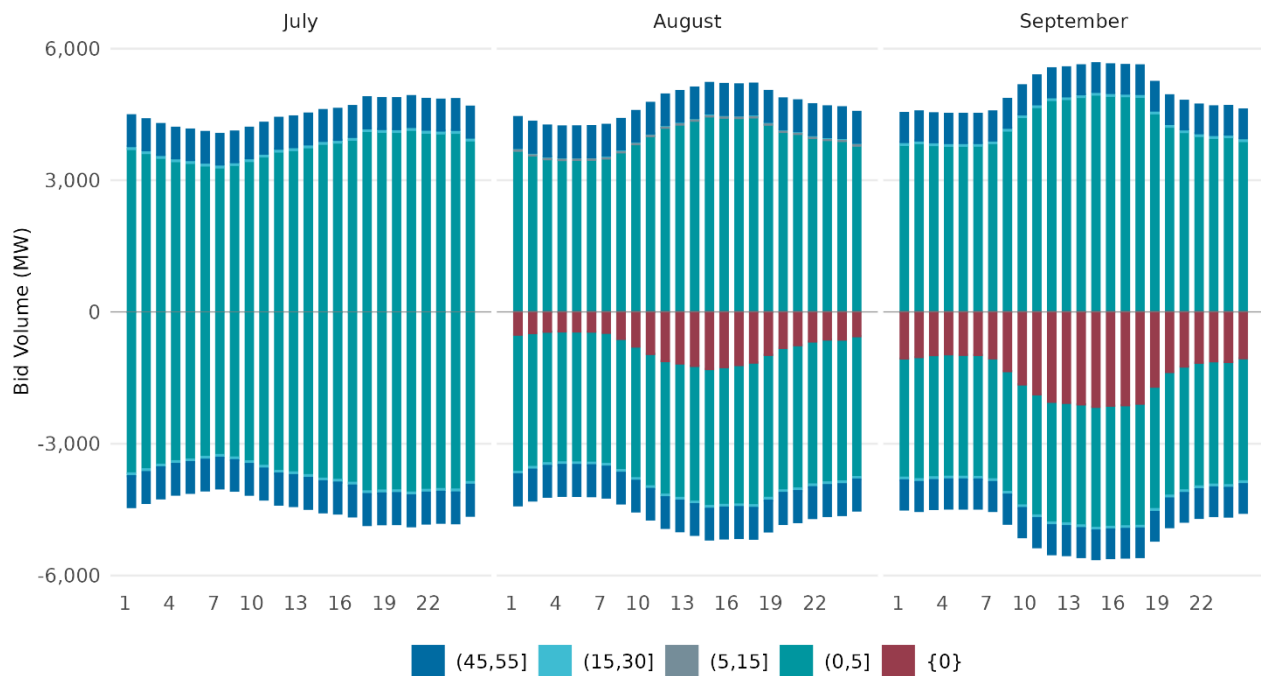


Figure 49: Daily average volume of IR bids by price for PACE

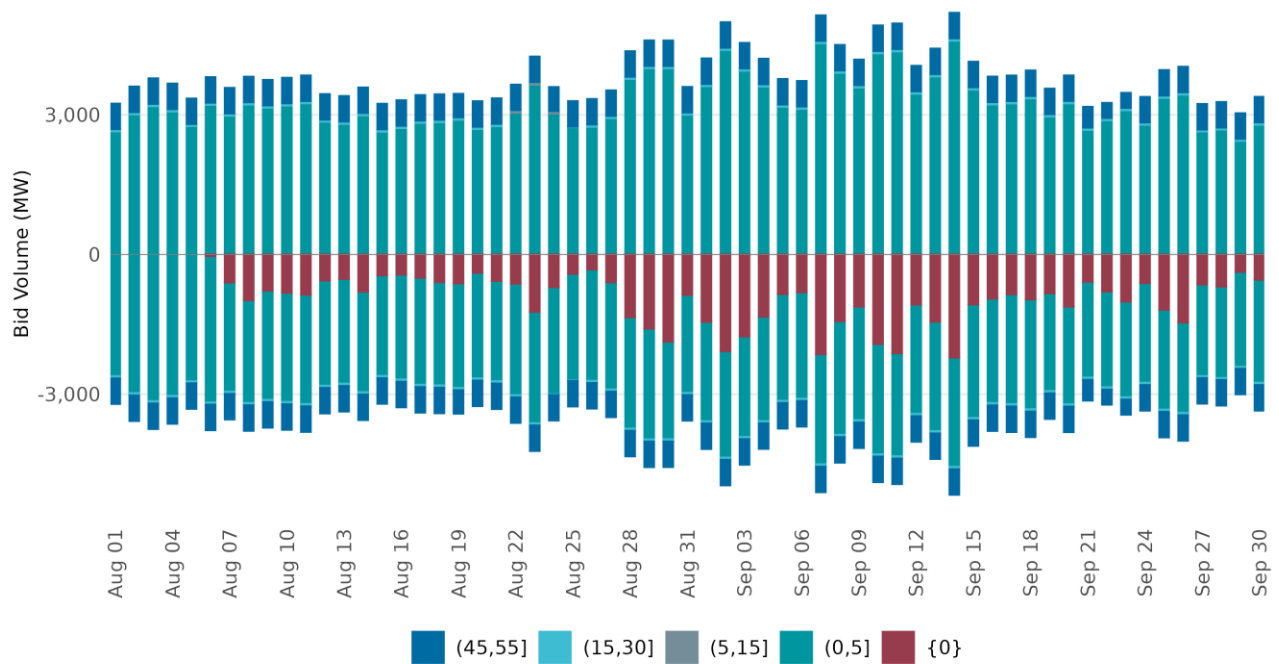


Figure 50 to Figure 51 illustrate PACE’s hourly and daily average IFM supply input bids for IR by fuel type. Wind and coal accounted for the largest share of PACE’s submitted IR capacity throughout July and September, followed by gas and storage resources. Wind resources’ capacities were capped by renewable forecasts, causing variations in total bid volumes across the three months.

Figure 50: Hourly average volume of IR bids by fuel type for PACE

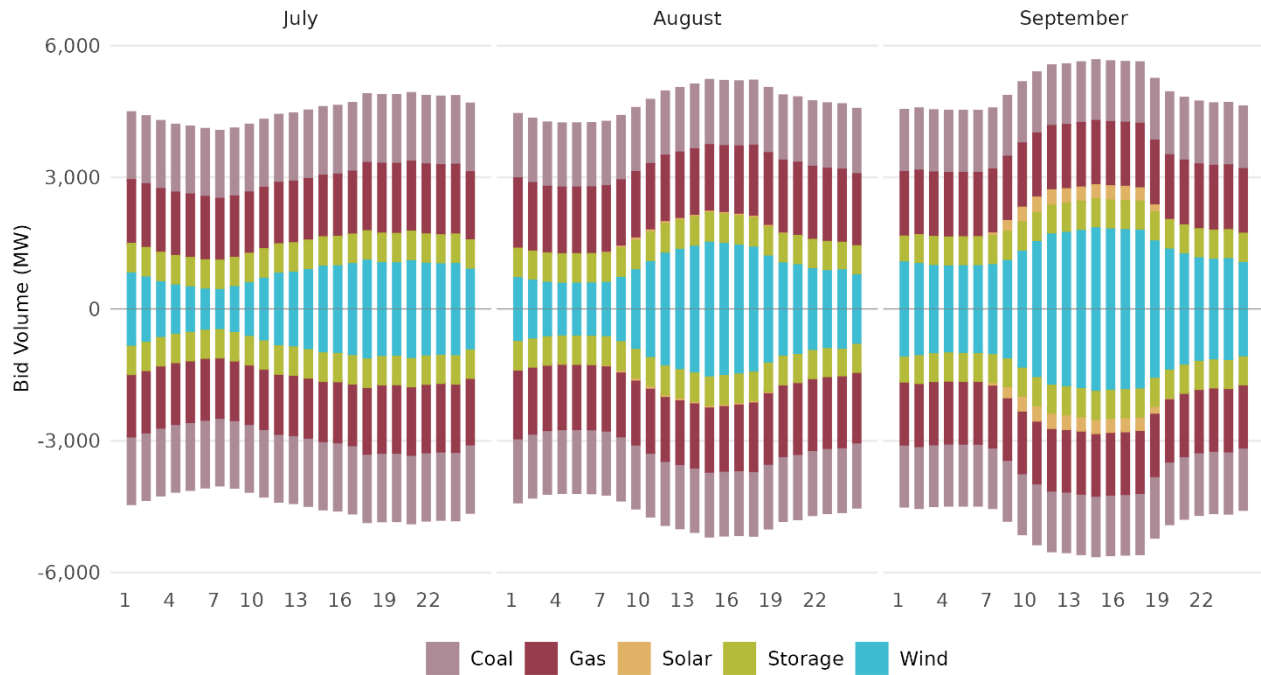


Figure 51: Daily average volume of IR bids by fuel type for PACE

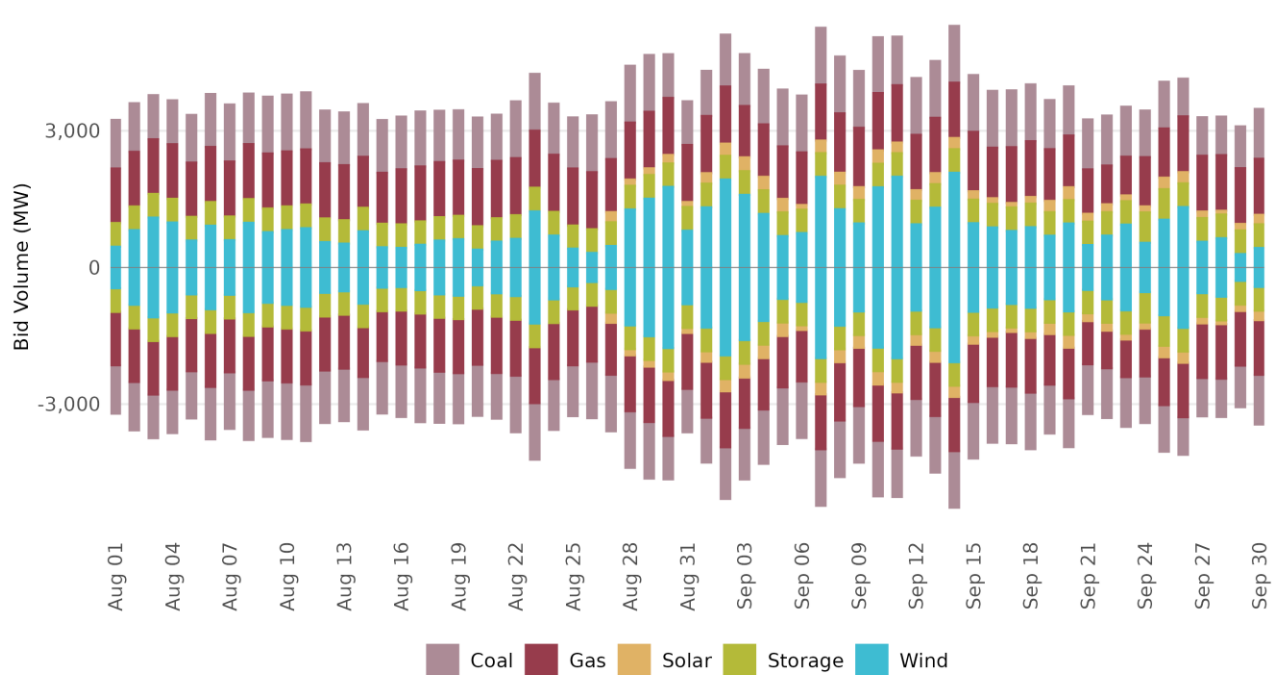


Figure 52 to Figure 55 illustrate the PACW's hourly and daily average IFM supply input bids for IR by bid price range and by fuel type. The price ranges are almost distributed across price ranges (0–5 \$/MWh) and (5–15 \$/MWh), and (45–55 \$/MWh), and the remaining price range (15–30 \$/MWh) represented a relatively small share of total submitted capacity. Water, gas, and wind accounted for the PACW's submitted IR capacity throughout July to September. PACW's submitted IR capacity exhibited a more variable pattern in both price ranges and volumes, as the overall bid-price composition showed variation across both the daily and hourly views.

Figure 52 and Figure 53 show the hourly and daily variations by price buckets, respectively. The IR bid volumes increased while prices went down during the three months. Starting in August, PACE adjusted more bid prices to \$0/MW for IRD products. In September, there was noticeable decrease in the total bid volume, as more capacity was provided by PACE.

Figure 52: Hourly average volume of IR bids organized by price for PACW



Figure 53: Daily average volume of IR bids organized by price by PACW

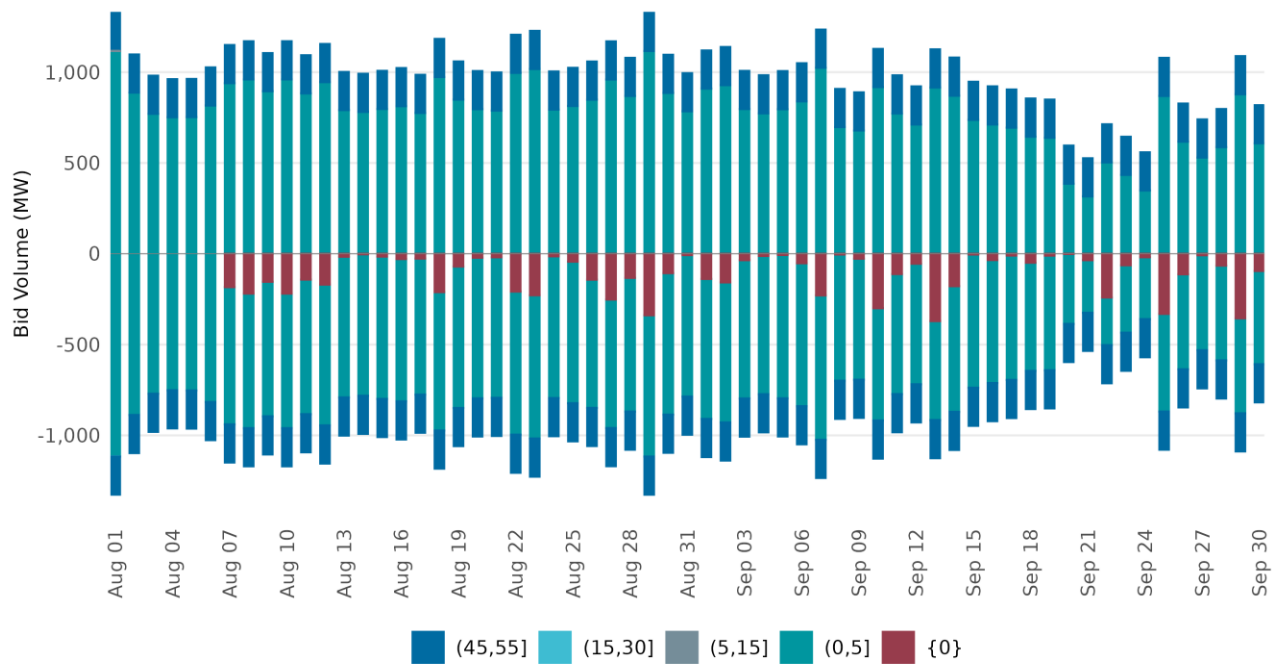


Figure 54 and Figure 55 show the hourly and daily variations by fuel type, respectively. PACW only has three fuel types bidding in IR products, i.e., gas, wind, and water. The bid volumes were highly dependent on wind forecasts, causing volume variations in both hourly and daily charts. Similarly, in September, there was noticeable decrease in the total bid volume.

Figure 54: Hourly average volume of IR bids organized by fuel type for PACW

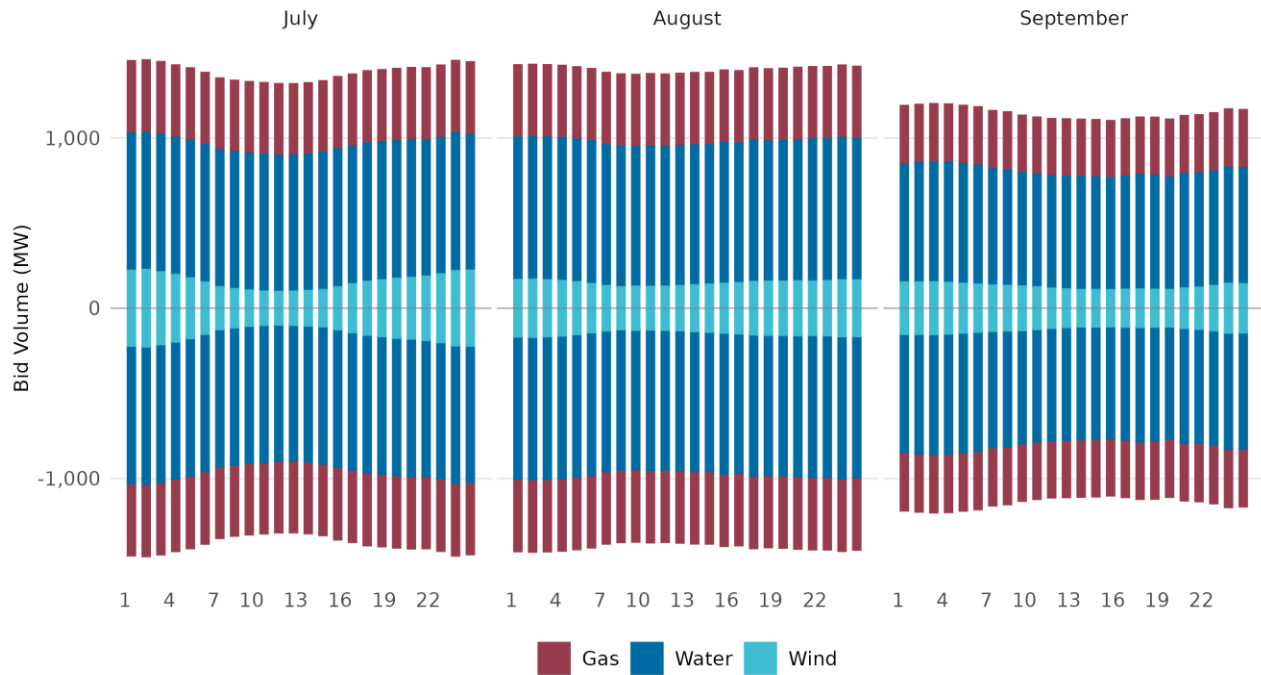
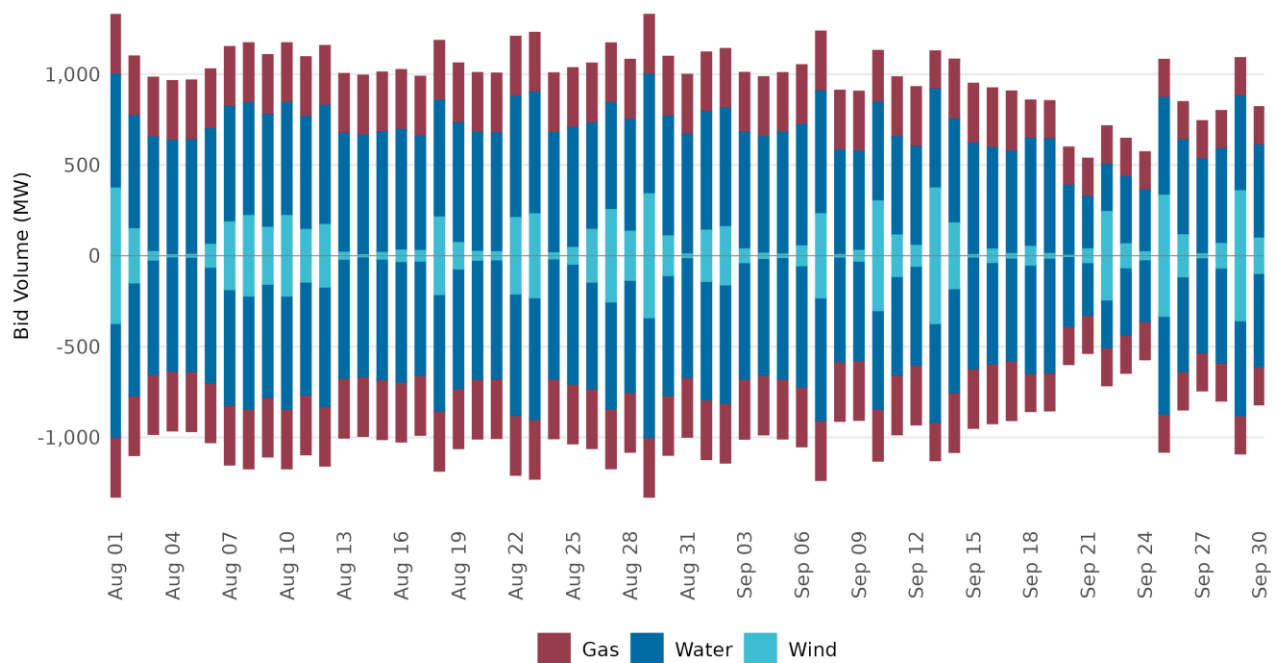


Figure 55: Daily average volume of IR bids organized by fuel type for PACW



When supply is tight, energy prices may rise to a level where IR is not procured. By design, the IR requirements may be relaxed at a cost. The IR demand curve represents the willingness to relax the IR requirement at certain price levels, capped to 55 \$/MWh, reflecting the tradeoff between CAISO/MD&A/MPAA

meeting uncertainty needs and avoiding excessive system costs. In September 2026, CAISO had demand curve procurement in the upward direction for 1 hour on one days. PACE had demand curve procurement in the upward direction for 2 hours over two days. PACW had demand curve procurement in the upward direction for 3 hours over two days, and in downward direction for 18 hours over five days. Hourly averages of demand curve procurements are shown in Figure 56 and Figure 57. Finally, some IR requirements for a BAA can be met with IR transfers from other BAAs or a BAA can also export IR transfers to other BAAs. These IR transfers are not shown explicitly in the previous metrics, and they are explicitly tracked in a subsequent section on transfers.

Figure 56: Average imbalance reserve demand curve procurement, IRU

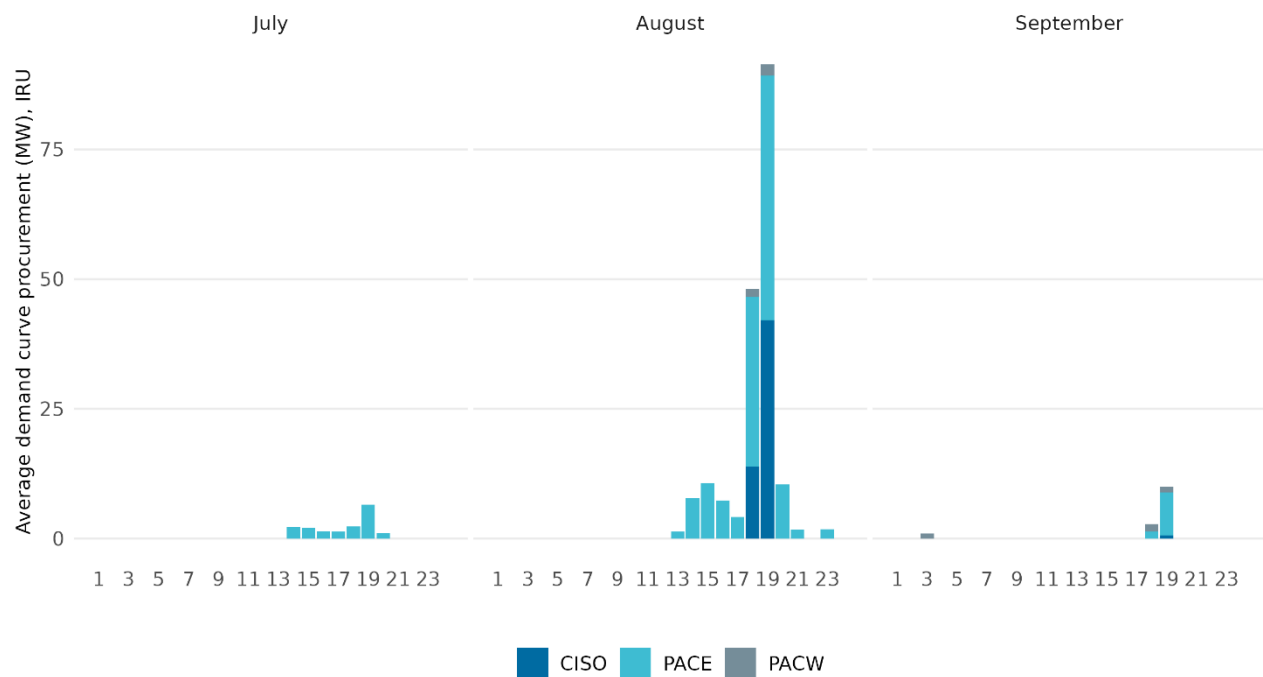


Figure 57: Average imbalance reserve demand curve procurement, IRD

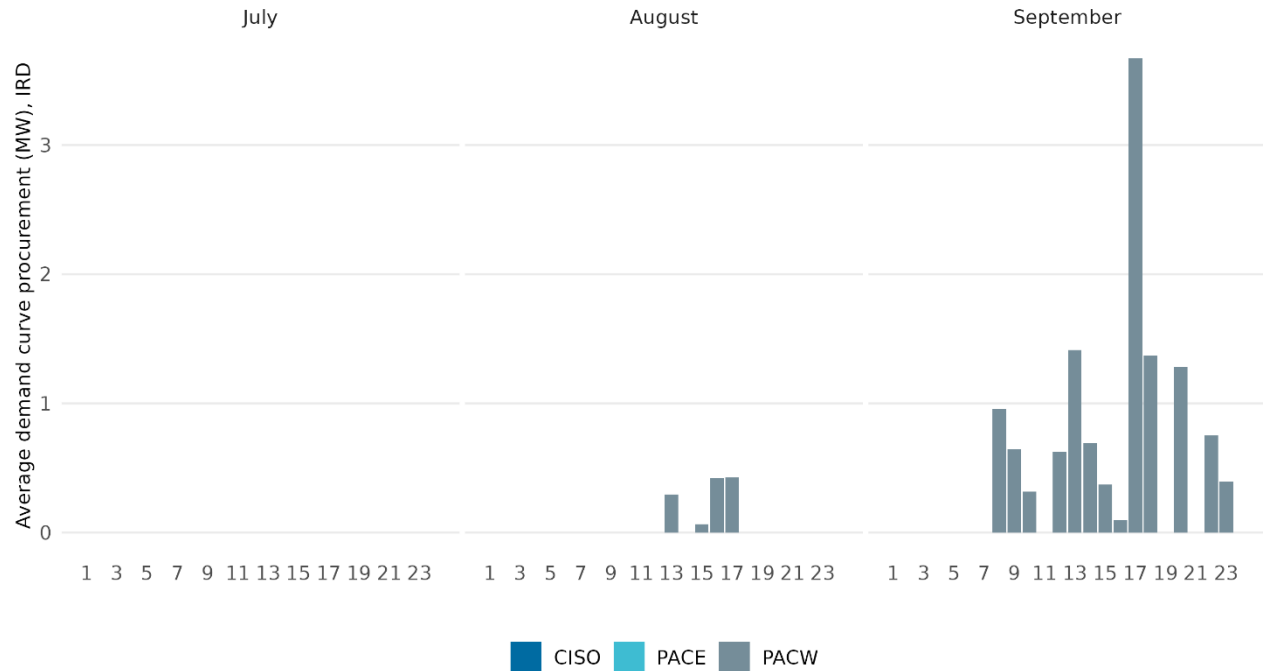


Figure 58 and

Figure 60 show the hourly average net demand by EDAM BAA in July through September. Net demand is derived from demand forecast, net solar and wind forecast. The figures overlay hourly average IR procurement and requirement, for both up and down directions, and hourly average FMM net load uncertainty, on the net demand profile by BAA. Procurement reflects internal capacity procurement net BAA imbalance reserve transfer. Overlaying the IR requirements on the net demand profile visually shows how the imbalance reserves create an envelope of flexible capacity around the net demand. Overlaying the FMM net load uncertainty shows how average uncertainty falls within the envelope of flexible capacity created by the imbalance reserve products.

Figure 58: Average net demand with imbalance reserve procurement, CISO

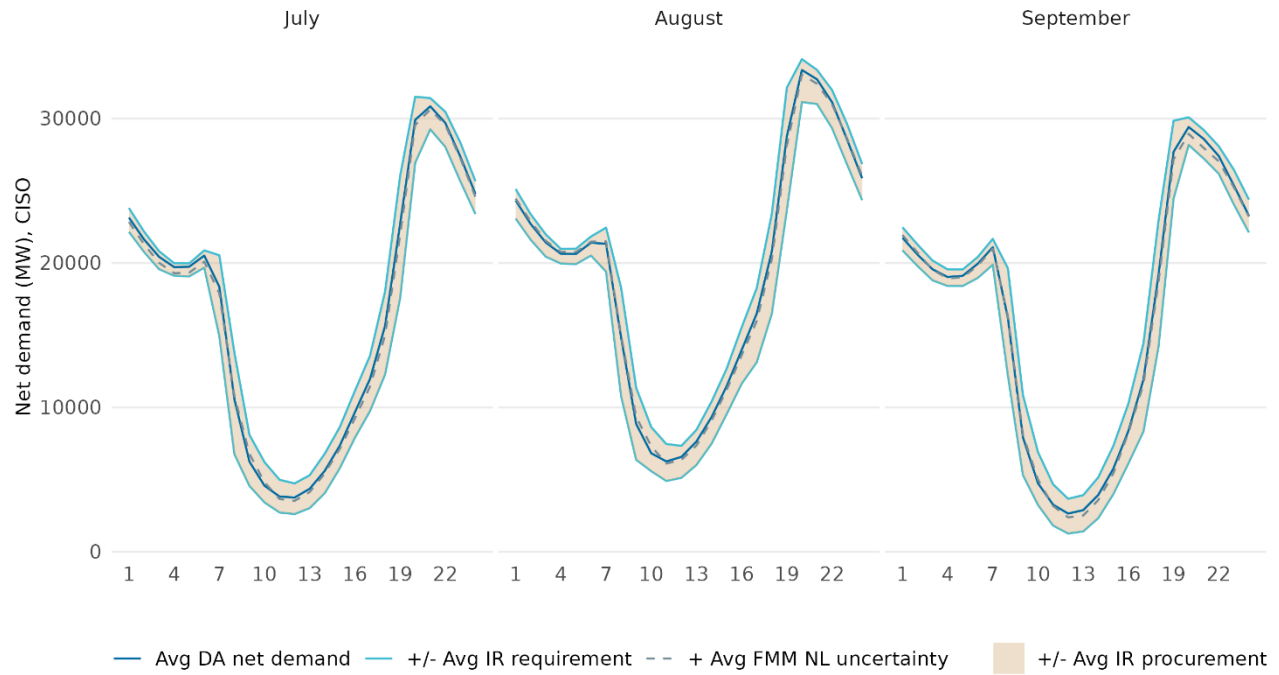
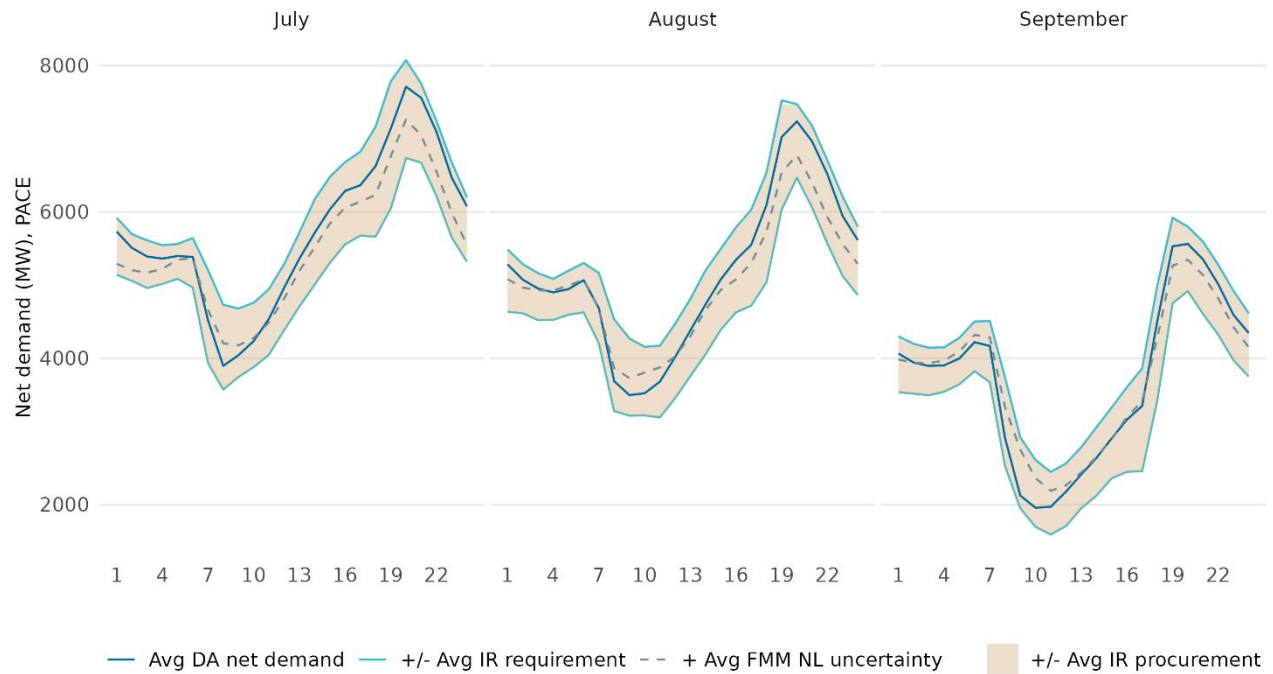
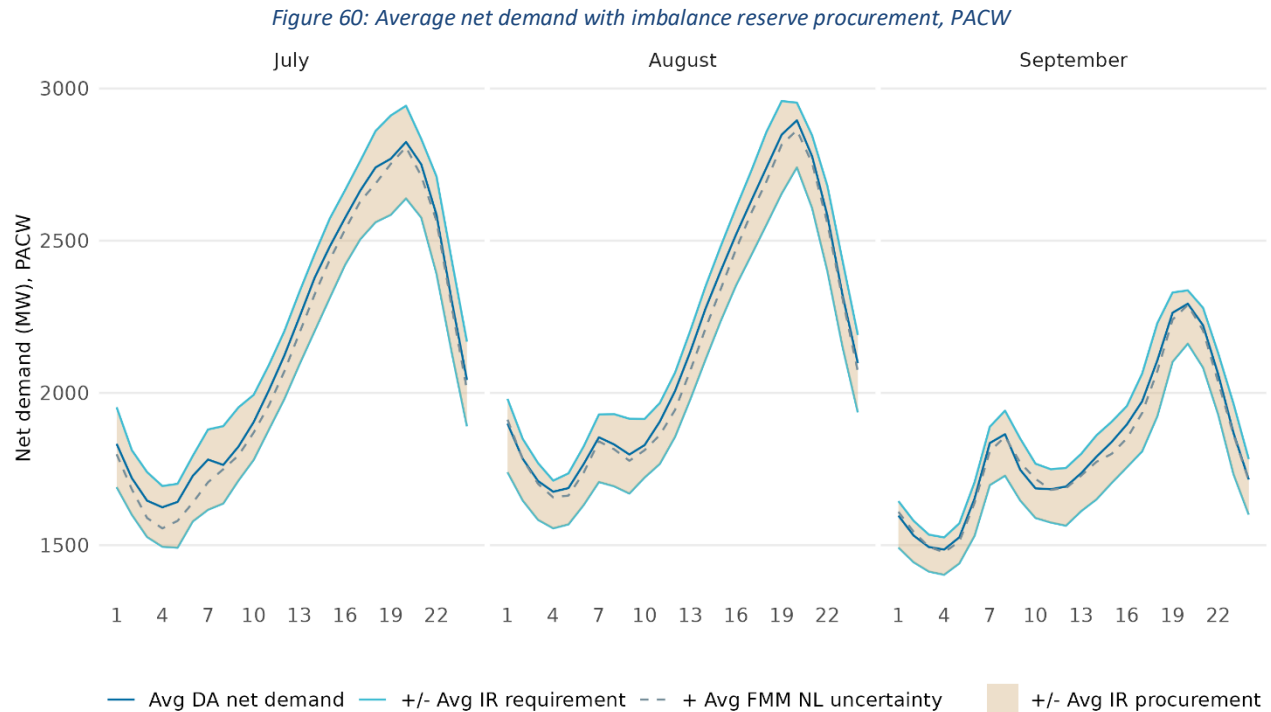


Figure 59: Average net demand with imbalance reserve procurement, PACE





Imbalance reserve utilization

Figure 61 to Figure 63 illustrate for each EDAM BAA, average available capacity in the fifteen-minute market for the capacity awards of day-ahead imbalance reserves represented in stacked bar. These bars grouped the imbalance reserves into two groups, capacity that is utilized (deployed) in the FMM market, and the second group is imbalance reserve awards that were not utilized in the FMM market. This is showing for both upward (positive) and downward (negative) directions. Average day-ahead imbalance reserve requirements and procurements from internal resources are included as reference with line trends. Internal procurement reflects the aggregated imbalance reserve awards within each BAA, to satisfy its own requirements and imbalance reserve transfer schedules. Hourly average upward and downward net-load uncertainties that is realized in FMM is also shown as a reference with the line in yellow. Realized net-load uncertainty is derived from the net load differences from day-ahead to fifteen-minute market. Utilized capacity over the reported period has been relatively small compared to available capacity and realized net load uncertainty for CAISO area. Utilized capacity for PACE and PACW on average are relatively higher in certain hours. The average percentages utilized IR relative to the awarded IR in the day-ahead market are shown in Table 6.

Table 6 Monthly average utilized imbalance reserve per EDAM BAA

	June		July		August		September	
	IRU	IRD	IRU	IRD	IRU	IRD	IRU	IRD
CISO	13.5%	11.6%	15.5%	12.9%	18.4%	12.4%	13.0%	12.8%
PACE	27.6%	23.4%	43.0%	30.7%	43.2%	23.0%	59.0%	24.0%
PACW	30.4%	15.8%	15.9%	17.7%	21.7%	17.8%	19.1%	24.7%

If the level of utilized IR in real-time is lower than the actual realized uncertainty, it means that other resources increased generation to meet that realized uncertainty, but they were not awarded IR. The larger pool of such resources is from the balancing areas participating in WEIM and that are not part of EDAM and were, therefore, not awarded IR in the day-ahead market.

Figure 61: Hourly average IR requirement, procurement and utilization. CISO

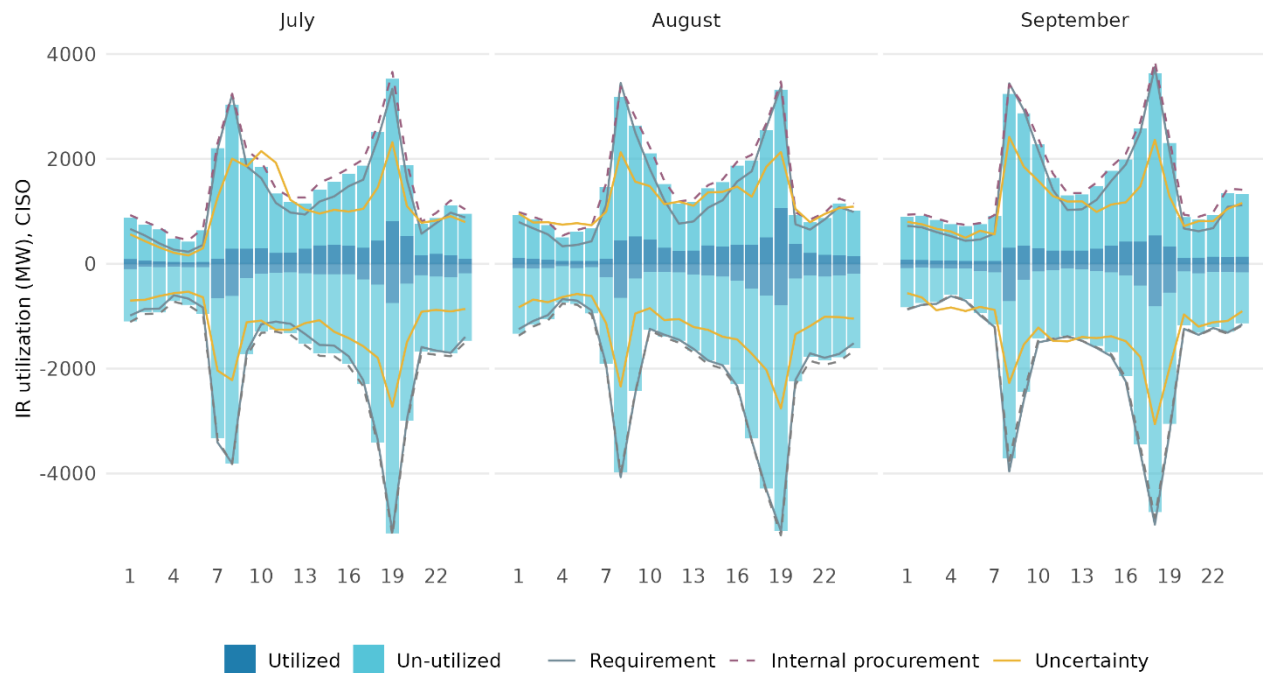


Figure 62: Hourly average IR requirement, procurement and utilization. PACE

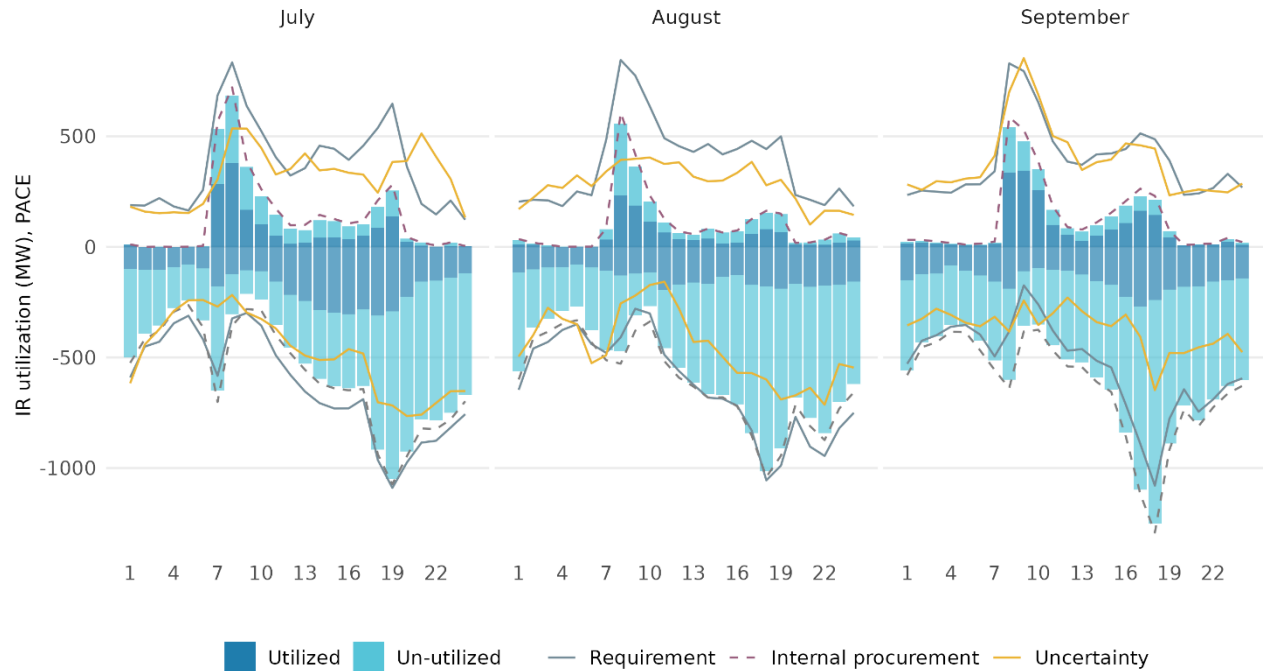


Figure 63: Hourly average IR requirement, procurement, and utilization, PACW

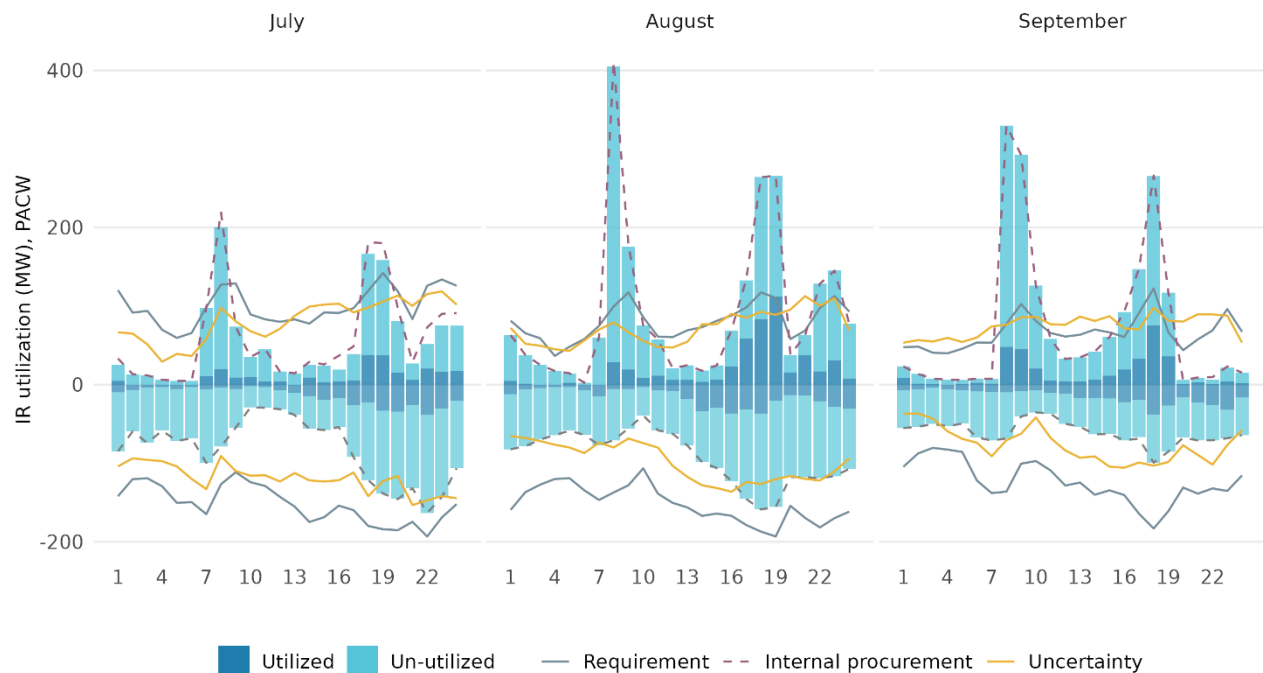


Figure 64 to Figure 66 evaluate the real-time performance of imbalance reserve up awards, by showing the estimated percentage breakdown of awarded capacity. The evaluation is estimated based on observed real time conditions, schedules and prices. The attribution of unutilized IRU

awards assumes that additional utilization would not materially alter system conditions, economics, or prices.

Utilization is measured at the resource level. Specifically, the change in a resource's energy schedule between the day-ahead market and the fifteen-minute market is compared against the corresponding imbalance reserve up awards. The portion of this schedule change that falls within the awarded capacity range is considered utilized.

From the capacity made available in real time, the portion not utilized is classified as unutilized capacity. Available capacity may remain unutilized for different reasons, including economics, congestion, among other factors. Unutilized capacity is further broken down by different categories. For CAISO BAA, approximately 60% of September IRU awards were unutilized because gas units received IRU awards but remained offline in real time. These resources were available to provide capacity but were not economical to start and operate based on their commitment costs and real-time market conditions. The second largest category of unutilized awards is economics for online resources. These resources are already online and may have utilized a portion of their awarded IRU capacity. Some awarded capacity remained unutilized because it is not economic to fully utilize the reserved capacity while other cheaper supply can be dispatched. For PACE and PACW, economics for online resources represented the largest share of unutilized capacity, at 27% and 80%, respectively.

Figure 64: IRU awards: real time breakdown, CAISO

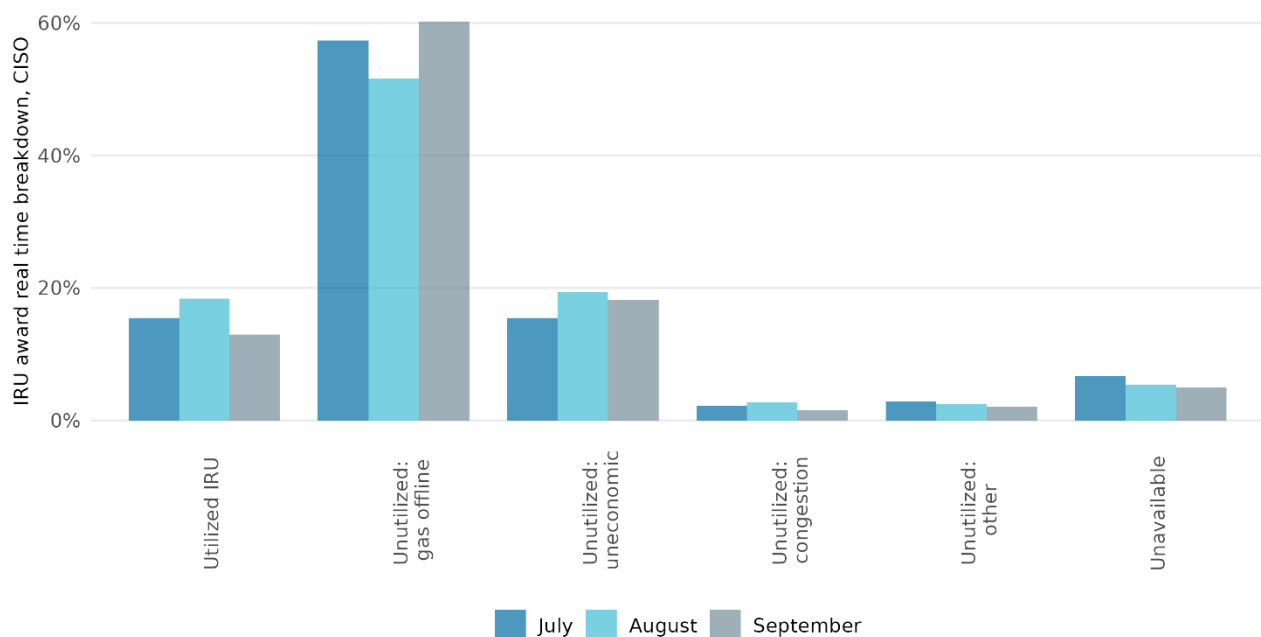


Figure 65 IRU awards: real time breakdown, PACE

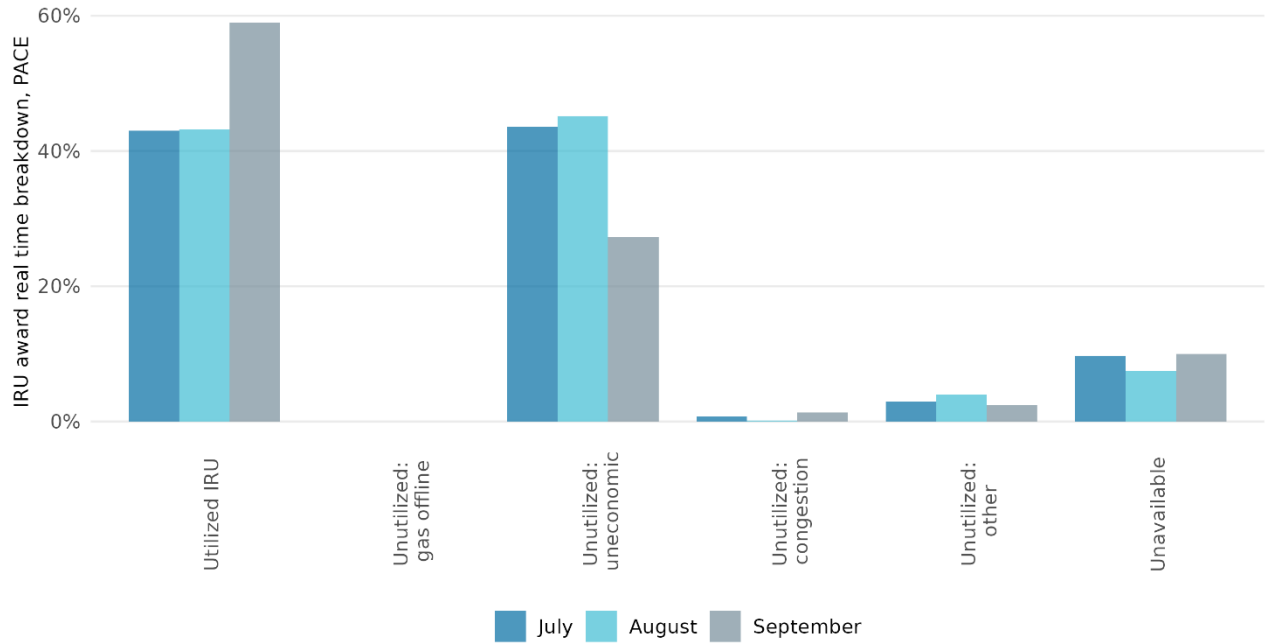
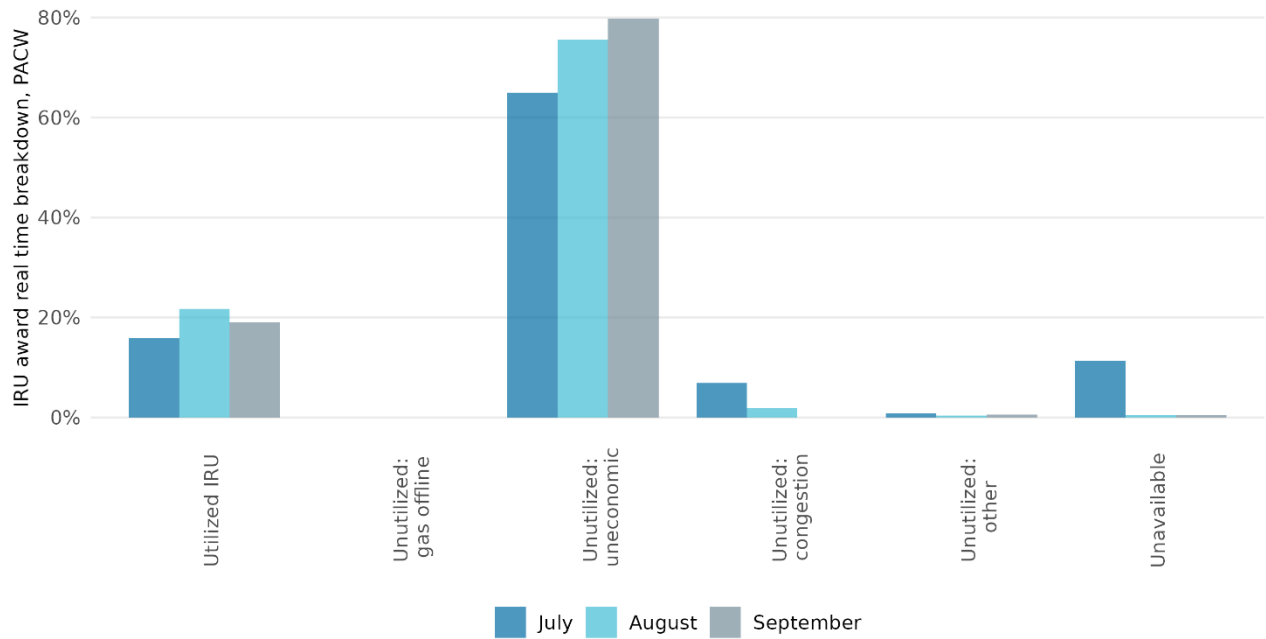


Figure 66. IRU awards: real time breakdown, PACW



EDAM resources receiving imbalance reserve awards in the day-ahead market will have bidding obligations in the real time market. Figure 67 and Figure 68 show real time available capacity corresponding to IR awards in the EDAM footprint, expressed as a percentage of imbalance reserve procurement. In the upward direction, over 80 percent of the IR capacity has been made available in the real time market in all hours. In the downward direction, the availability exceeds 90 percent majority of the time.

Figure 67: Percentage IRU availability in FMM for EDAM footprint

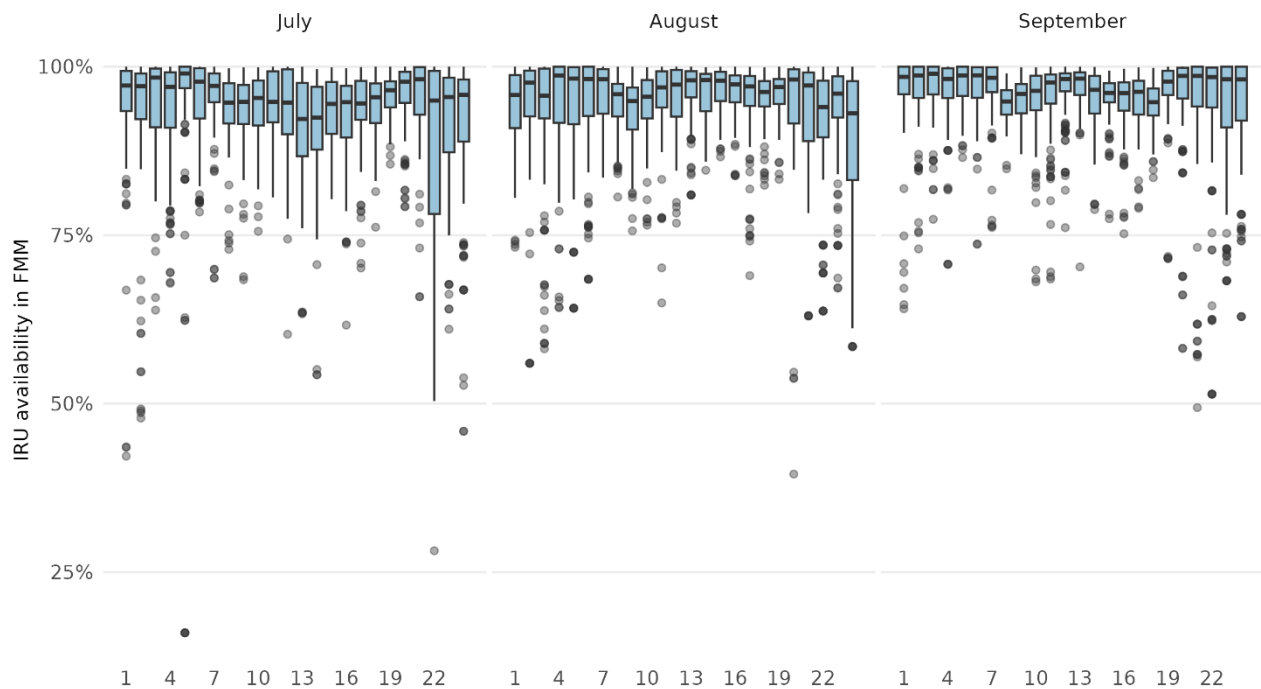


Figure 68: Percentage IRD availability in FMM for EDAM footprint

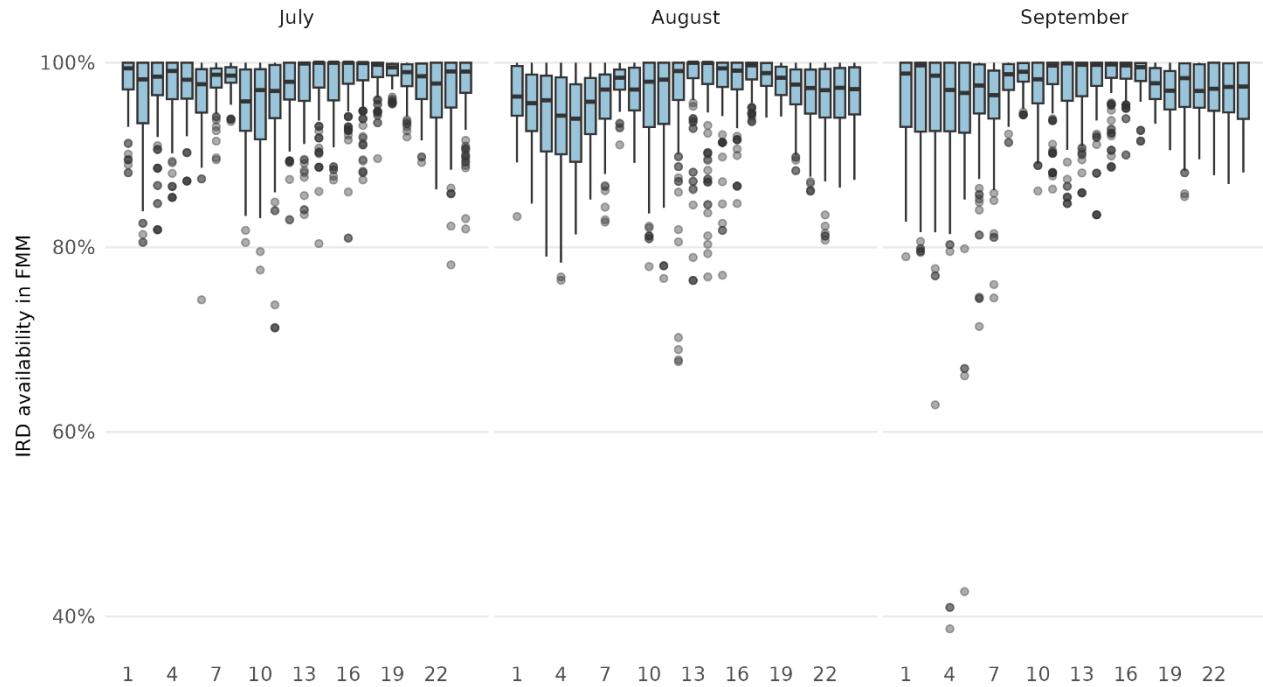


Figure 69 and Figure 70 show the hourly distributions of the utilized imbalance reserve up and down volumes, in the EDAM footprint in FMM. The utilization trends follow the shape of the imbalance reserve requirements, higher in the morning and evening peak hours for both up and down directions.

Figure 69: Hourly IR up utilization distribution in EDAM footprint

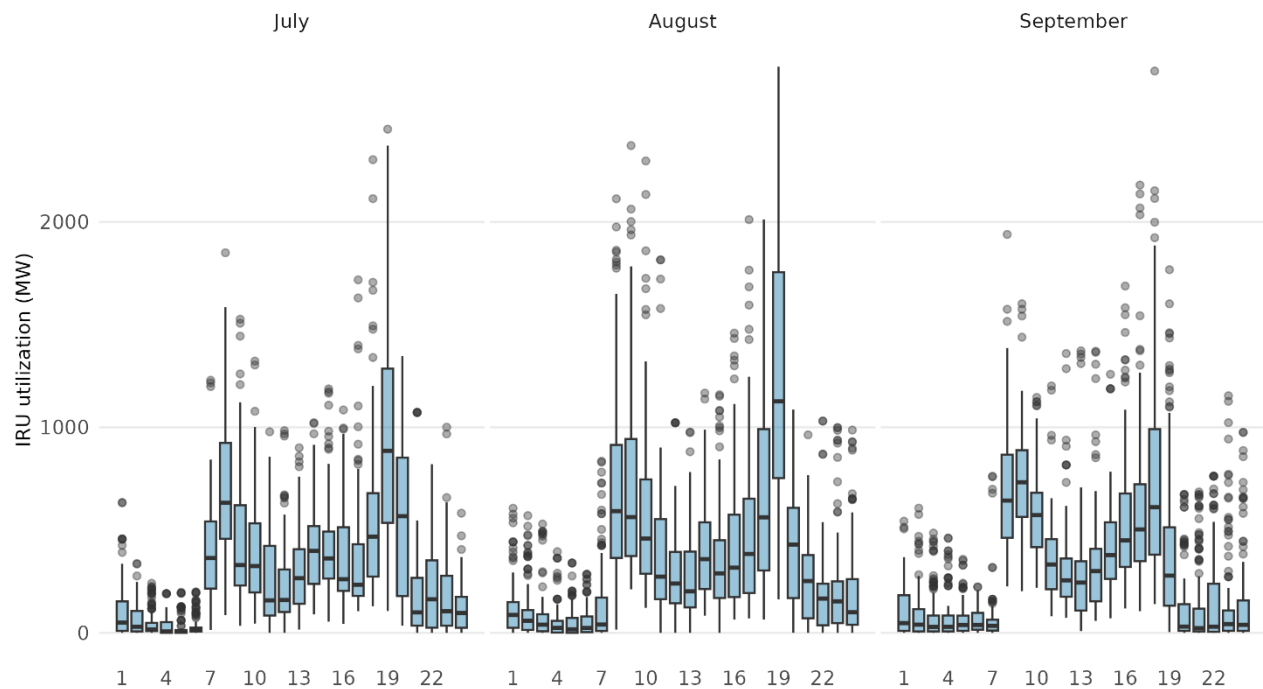
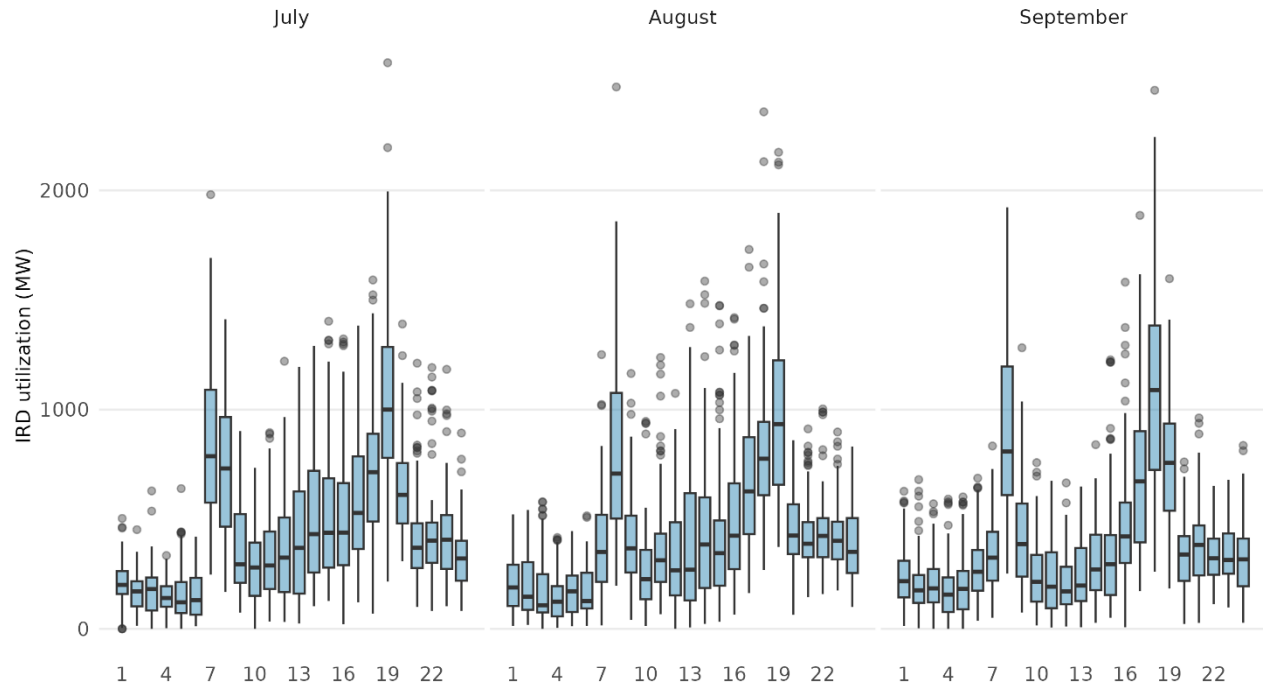


Figure 70: Hourly IR down utilization distribution in EDAM footprint



The congestion component of IRU/IRD marginal prices is impacted only by the transmission constraints enforced for IRU and IRD deployment scenarios and its trend is an estimate of how much congestion is impacting IRU/IRD marginal pricing. Figure 71 and Figure 72 show the nodal congestion components of the imbalance reserve marginal prices in upward and downward directions. For both the months of July through September, the imbalance reserve congestion is minimal and centered around \$0/MWh. When analyzing the outliers for IRU in the month of September, there is positive congestion in the SDGE region. When analyzing the outliers for IRD in the month of September, there is positive congestion for SCE and VEA, negative congestion for PG&E and outliers in both direction for SDGE. The MCC breakdown for monthly average IR congestion is provided in Table 11.

Figure 71: Nodal IRU congestion component of the IRU marginal price

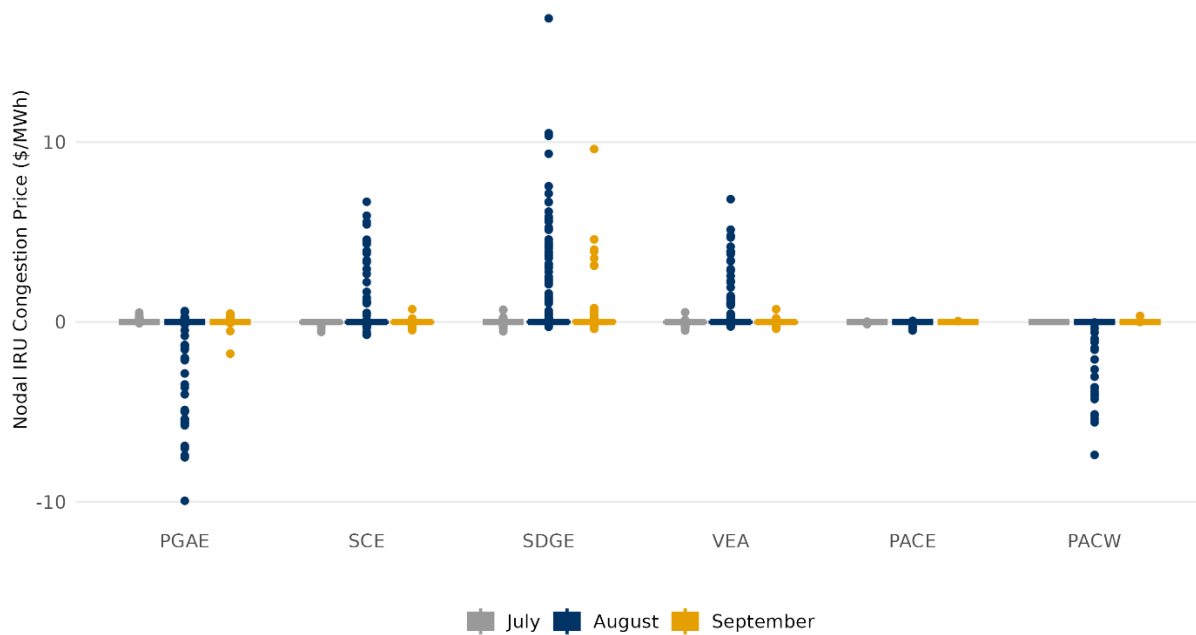
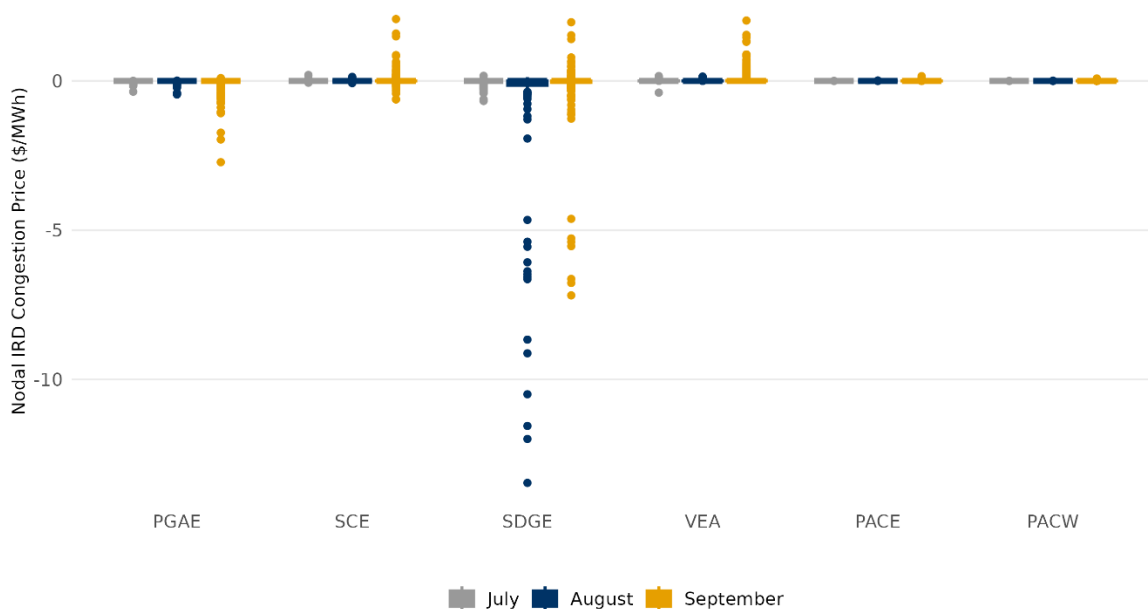


Figure 72: Nodal IRD congestion component of the IRD marginal price



Contingencies are currently not enforced in the IR scenarios for EDAM. This was a decision made through the DAME configurable parameters initiative before the launch of EDAM. Table 7 provides the constraints with the highest average congestion costs across EDAM (base and IRU) and FMM. As contingencies are not enforced in the IR scenarios, there is a possibility that contingency-related CAISO/MD&A/MPAA

congestion could materialize in FMM and get IR stranded. This is the case for the all the CISO related contingencies in the following table.

Table 7: September 2026 average congestion costs by constraint across day-ahead and FMM

September 2026 Average Congestion Costs by Constraint		Contingency	PACE			PACW			PGAE			SCE		
BAA	Constraint Name		Base	IRU	FMM	Base	IRU	FMM	Base	IRU	FMM	Base	IRU	FMM
CISO	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	Y				0.05			0.66		0.67	(0.48)		(0.66)
CISO	7760_DEV_RDB_ALIS	N	(0.22)		(0.32)			0.00	0.01		0.53	0.12		1.15
CISO	30765_LOSBANOS_230_30790_PANOCHÉ_230_BR_2_1	Y				0.61			0.29		0.07	(0.33)		(0.25)
CISO	38615_DS AMIGO_230_30790_PANOCHÉ_230_BR_1_1	Y				0.06		0.04	0.08		0.02	(0.19)		(0.62)
CISO	7820_TL 230S_OVERLOAD_NG	N	(0.16)		(0.27)	(0.08)			(0.09)		0.08	(0.04)		0.27
CISO	30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	Y	(0.00)		(0.00)	(0.13)		(0.16)	(0.17)		(0.21)	0.12		0.15
CISO	30055_GATES1_500_30060_MIDWAY_500_BR_1_1	Y			(0.00)	0.01		0.27	0.01		0.31	(0.01)		(0.31)
CISO	30790_PANOCHÉ_230_30900_GATES_230_BR_1_1	Y				0.06		0.07	0.10		0.33	(0.07)		(0.29)
CISO	34418_KINGSBRG_115_34428_CONTADNA_115_BR_1_1	Y							0.12		0.30	(0.06)		(0.10)
CISO	35618_SN JSE A_115_35616_SNJOSEB_115_BR_1_1	Y							0.06		0.29	(0.06)		(0.15)
CISO	7430_CP6_NG	N							0.06	0.02	0.20	(0.05)	(0.01)	(0.21)
CISO	30790_PANOCHÉ_230_30900_GATES_230_BR_2_1	Y				0.13			0.19			(0.14)		
CISO	30056_GATES2_500_30060_MIDWAY_500_BR_2_1	Y						0.10			0.11			(0.11)
CISO	30733_VASONA_230_30735_METCALF_230_BR_1_1	Y									0.17			(0.05)
PACE	GLENCANY_SIGURD_230	N			(0.18)									0.03

Figure 73: CISO IRU award concentration based on IFM and FMM participation

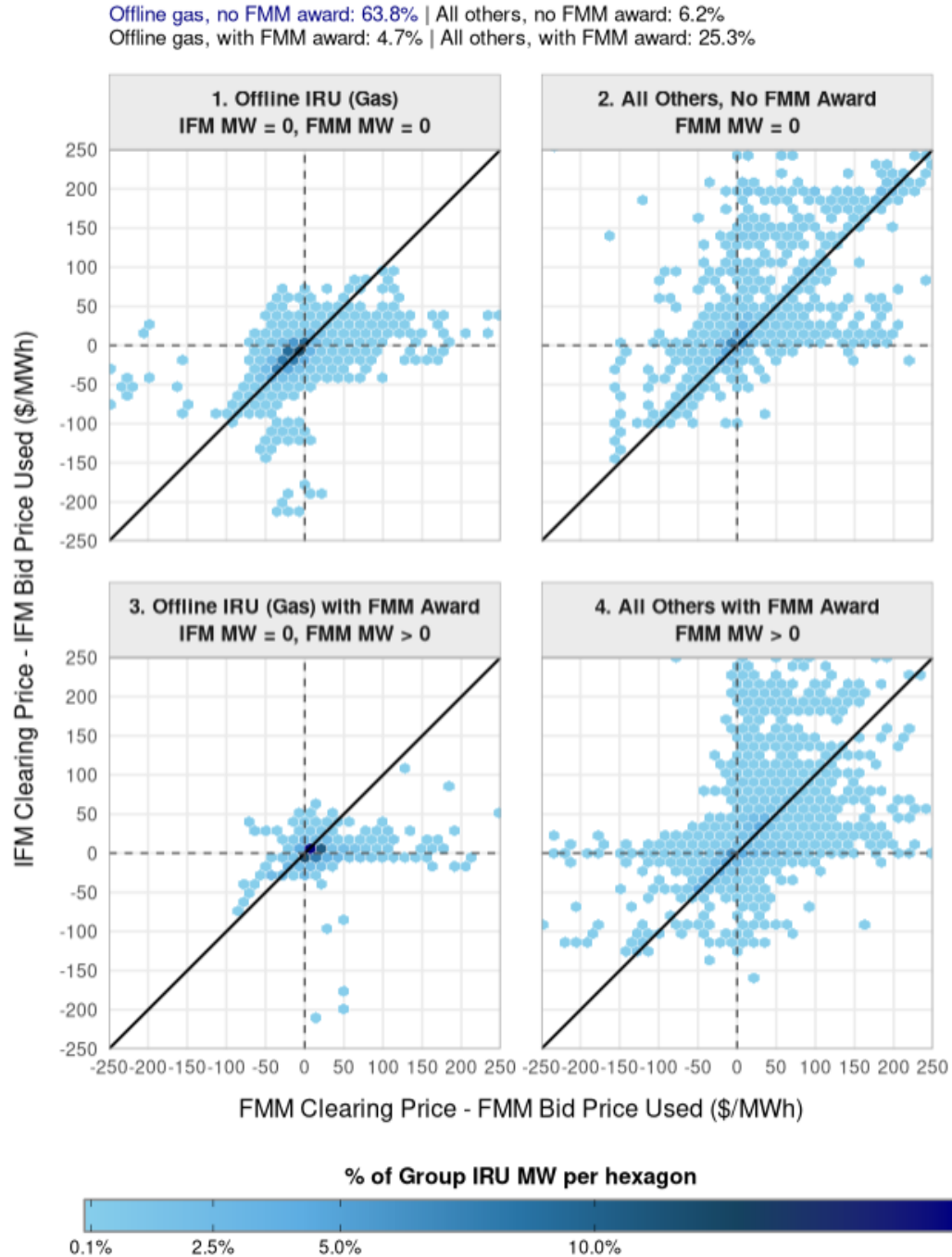


Figure 73 shows the concentration of CISO IRU awards across EDAM and FMM. The bid price used in the chart uses the following assumptions:

- 1) Use no load cost over Pmin if the resource is offline (ignore Pmin less than 1 MW)
- 2) Use the first segment of the price curve if the resource is cleared at Pmin

- 3) Startup, transition costs, outages, ramp rate restrictions, SOC and other inter temporal constraints do influence the final FMM commitment but are not captured by the input bid price.

As covered earlier in Figure 64 thru Figure 66, IRU awards can be procured from quick-start resources having startup time less than 15 mins. These resources are quick and less expensive to start; however, they are expensive to operate. A large percentage of IRU is procured from resources that are never started up in FMM due to the higher cost of operation. This is also evident from the presence of darker coloring in the upper left panel. The upper right panel includes resource with IRU that were not awarded in real-time due to other constraints mentioned as part of the assumptions.

For units that are economic in FMM, data points are concentrated in the first quadrant. The utilization percentage is based on whether the awarded IRU realizes in FMM as an energy award and the highest FMM award for that hour is used. The percentages are slightly different as not all data points are shown in this chart for clarity, the data points are limited to IFM and FMM spreads under \$250.

Based on the concentration of IRU awards with IFM and FMM spreads, congestion differences between IFM and FMM do not significantly impact the deliverability of IRU awards, the largest contributor is the set of offline resources with high commitment cost.

Reliability capacity

Reliability Capacity (RC) is the other new bi-directional day-ahead product introduced with the EDAM market. The reliability capacity product ensures there is enough capacity procured in the RUC process to meet the demand forecast. Like imbalance reserves, reliability capacity is procured in both upward and downward directions. The market procures reliability capacity to meet positive or negative differences between cleared physical supply in IFM and the load forecast. It is like the existing RUC capacity product, except RUC capacity is only procured when the forecast exceeds cleared physical supply. Reliability capacity up (RCU) covers supply shortfalls and reliability capacity down (RCD) accounts for over-supply.

Reliability capacity prices

A feature of the reliability capacity prices is that RCU and RCD prices are equal and opposite. This price symmetry is by design and a natural consequence of RUC optimization. The RUC process procures both reliability capacity up and down to address supply shortfalls or over-supply in different parts of the system. At the system level, however, there is either a net supply shortfall or

over-supply. In a net supply shortfall for instance, the system needs RCU to balance the RUC optimization constraint, and the RCU price is set by the marginal resource. If conditions materialize such that one additional megawatt of RCU is needed, the value to the system of that incremental RCU is set by the price of the marginal resource. Conversely, if another resource moved downward in the opposite direction providing one additional megawatt of RCD, there is a cost to the system in the amount of the lost value of the additional RCU megawatt. Therefore, the RCD price must be equal to the opposite of the RCU price.

Figure 74 shows the monthly average prices for RCU and RCD for all three BAAs. Overall, prices for RC decreased across all three BAAs indicating that RCD needs were higher than RCU on average. The monthly average RCD price for PACW was \$2.98/MWh, the highest since EDAM implementation.

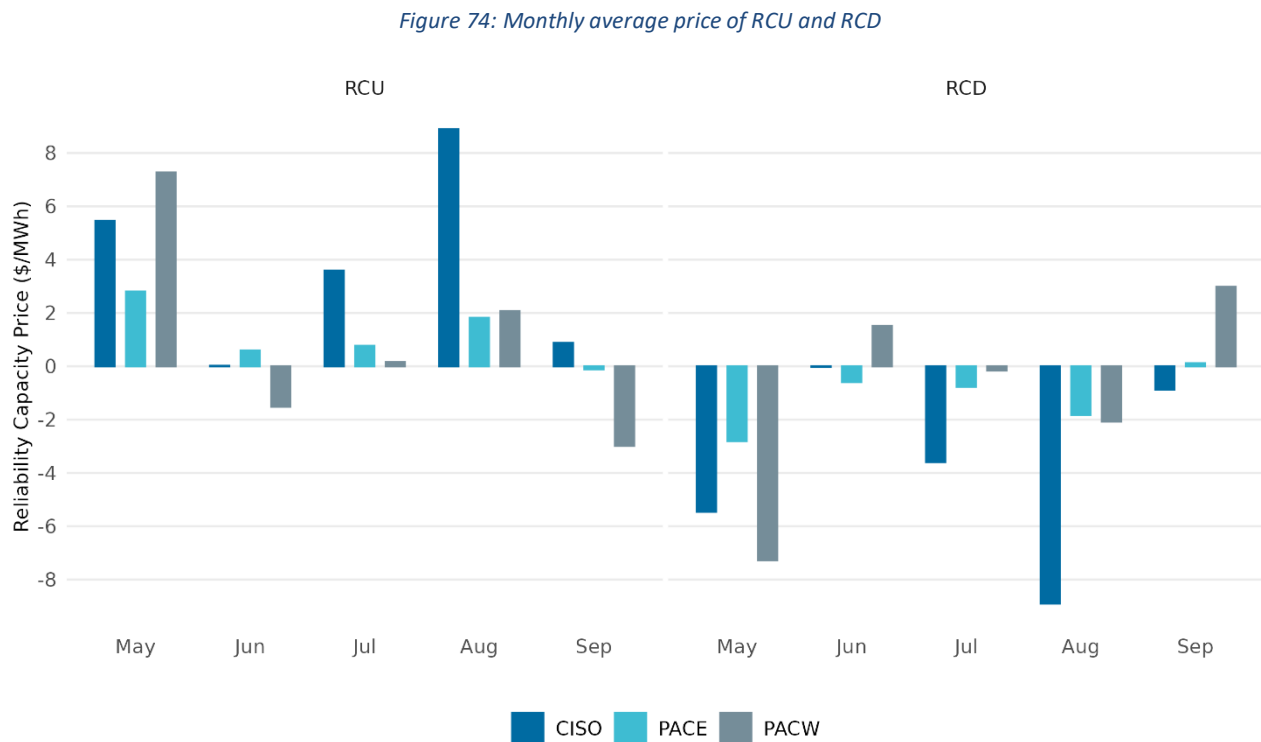


Figure 75 and Figure 76 shows the frequency of reliability capacity up and down price ranges for each BAA from May to September. Reliability capacity prices for CAISO were \$0/MWh in over 93% of intervals in September and between -\$5/MWh and \$5/MWh in over 98% of intervals in September. For PACE, reliability capacity prices fell between -\$5/MWh and \$5/MWh over 99% of the time, and over 92% of the time for PACW.

Figure 75: Frequency of RCU price ranges

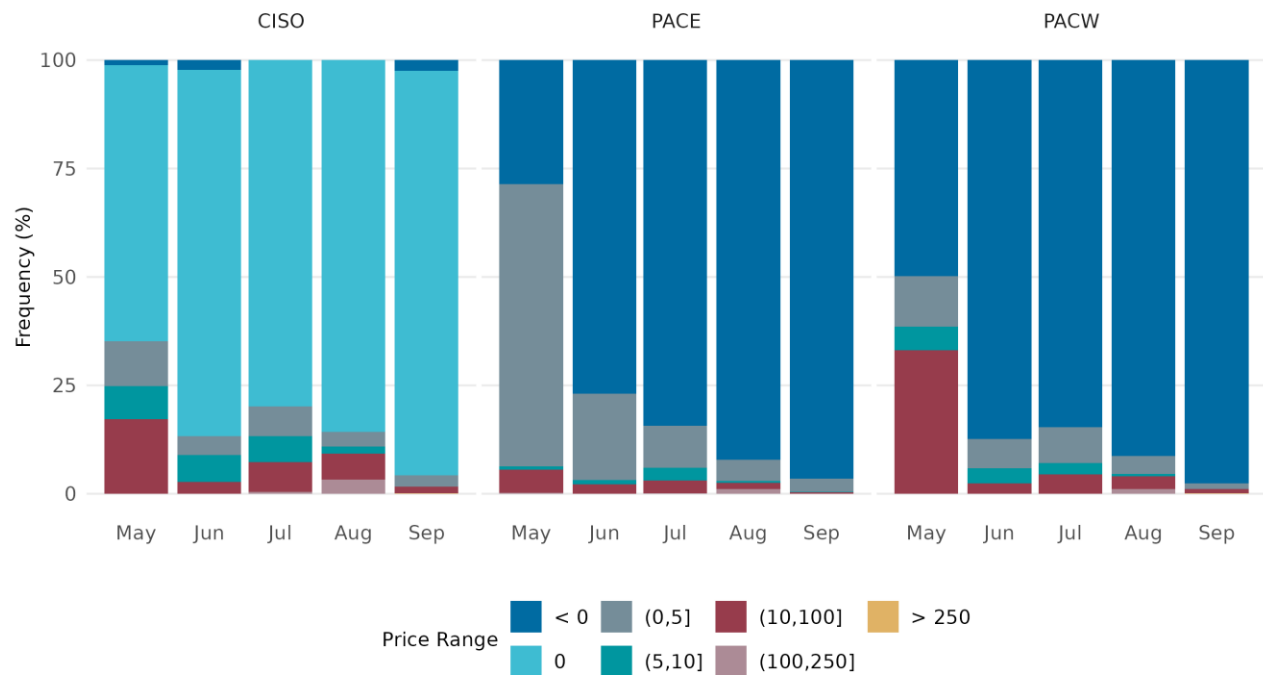


Figure 76: Frequency of RCD price ranges

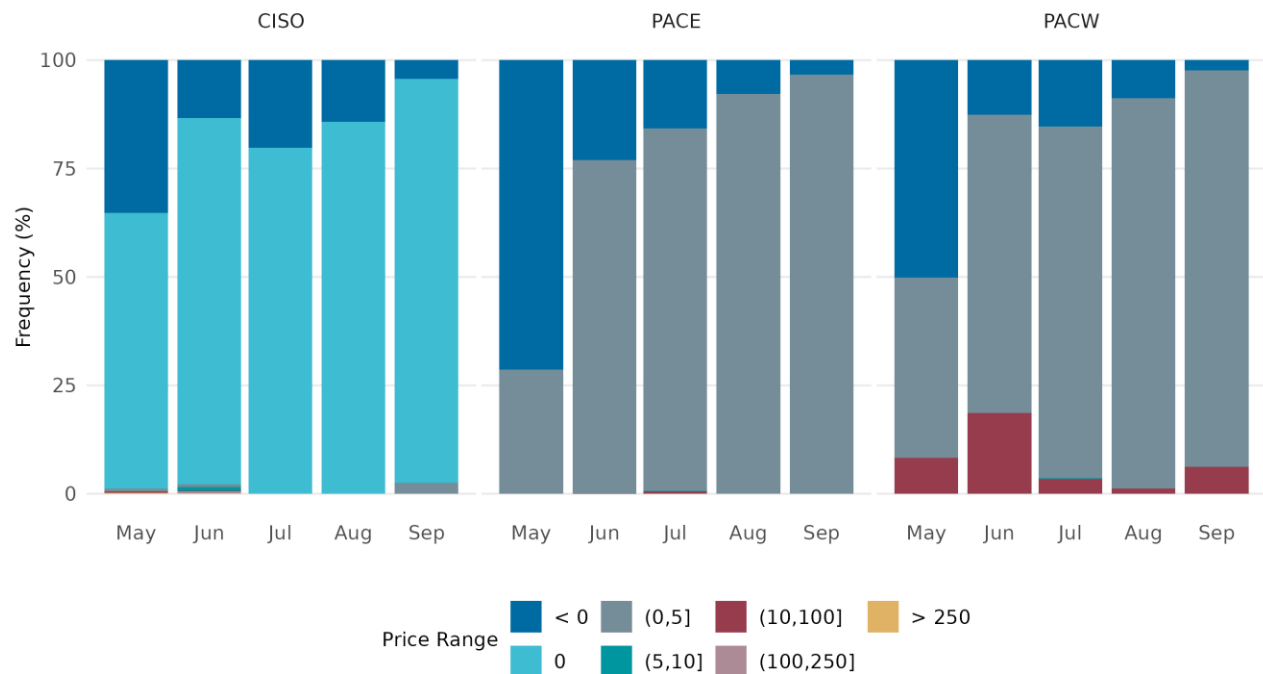


Figure 77 and Figure 78 show the daily average RCU and RCD prices in August and September. Prices were more stable in September for CAISO and PACE but remained volatile for PACW.

September 9 saw an RCU price spike for CAISO and PACE with a daily average price of \$24.15/MWh and \$19.37/MWh, respectively. Daily average prices in PACW spiked for RCD in the latter half of the month, reaching \$27.77/MWh on September 18.

Figure 77: Daily average price of RCU

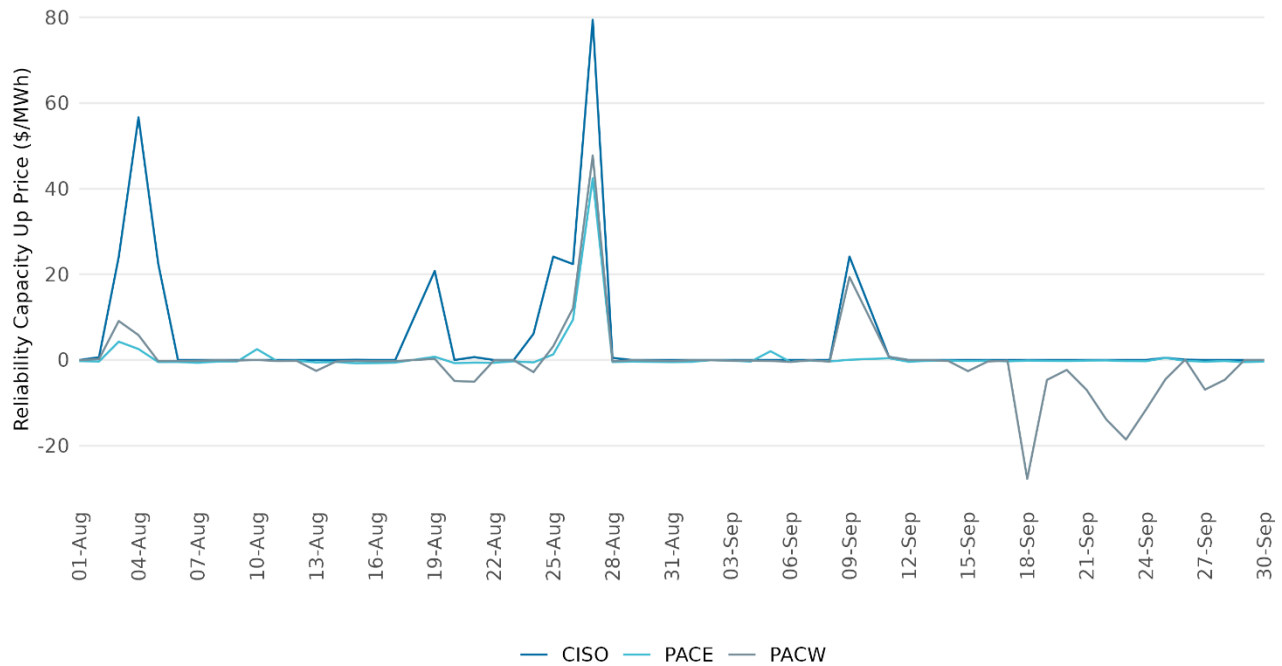


Figure 78: Daily average price of RCD

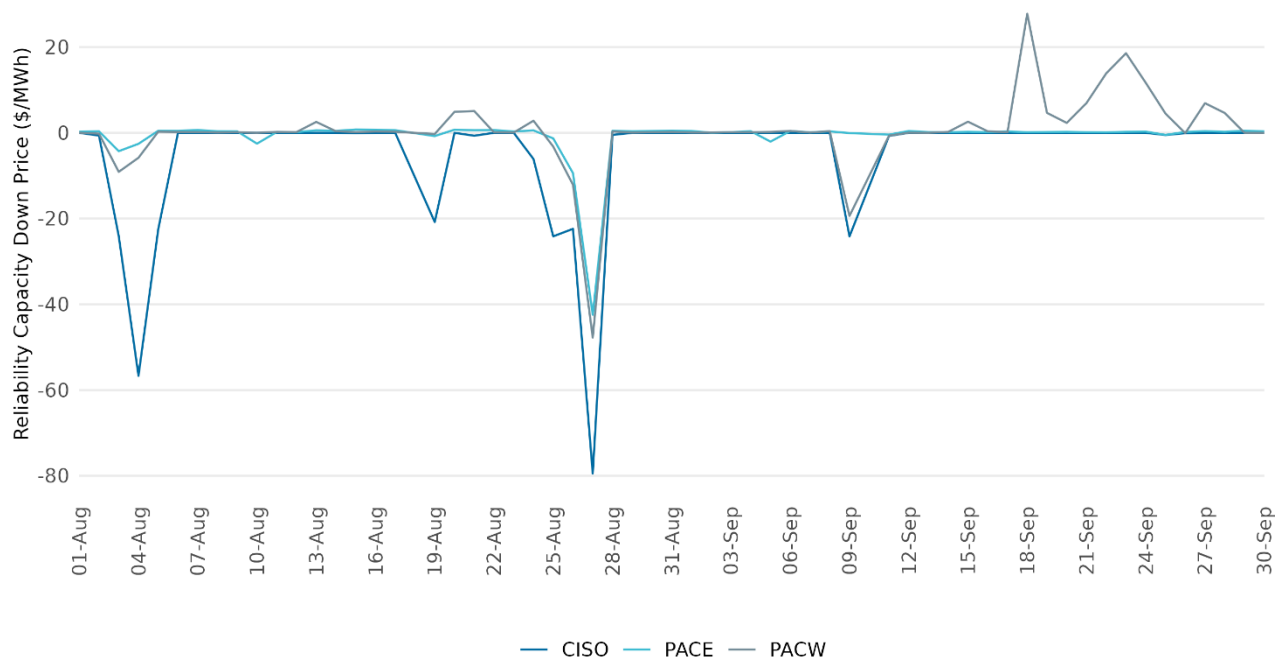


Figure 79 and Figure 80 show the hourly average RCU and RCD prices in September. On average prices were highest during the evening peak period for all three BAAs across hours ending 18 and 19. The highest hourly average RCU price was \$9.21/MWh for CAISO in hour ending 19, and in the same hour PACW saw its highest hourly average RCU price of \$6.77/MWh. PACE saw the highest hourly average RCU price in hour ending 19 of \$1.73/MWh. The highest hourly average RCD prices were in PACW occurring in the morning and evening peaks. In hour ending 18 and 8, hourly average RCD prices in PACW were \$9.99/MWh and \$7.81/MWh, respectively.

Figure 79: Hourly average price of RCU

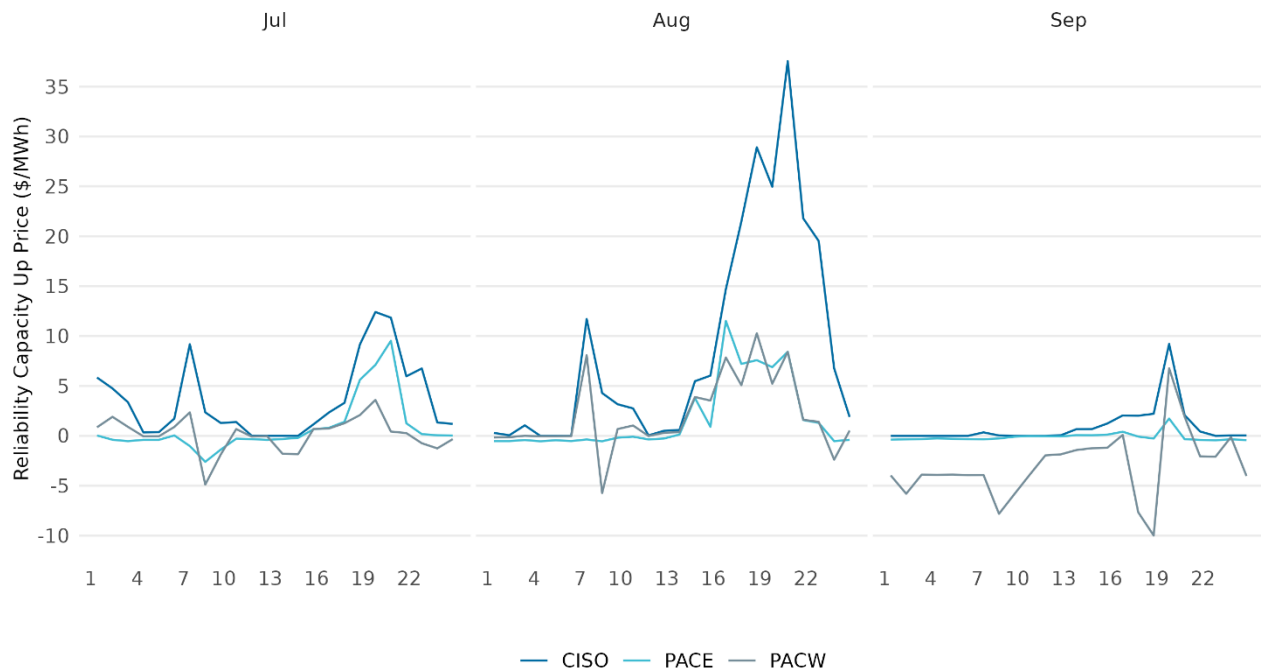
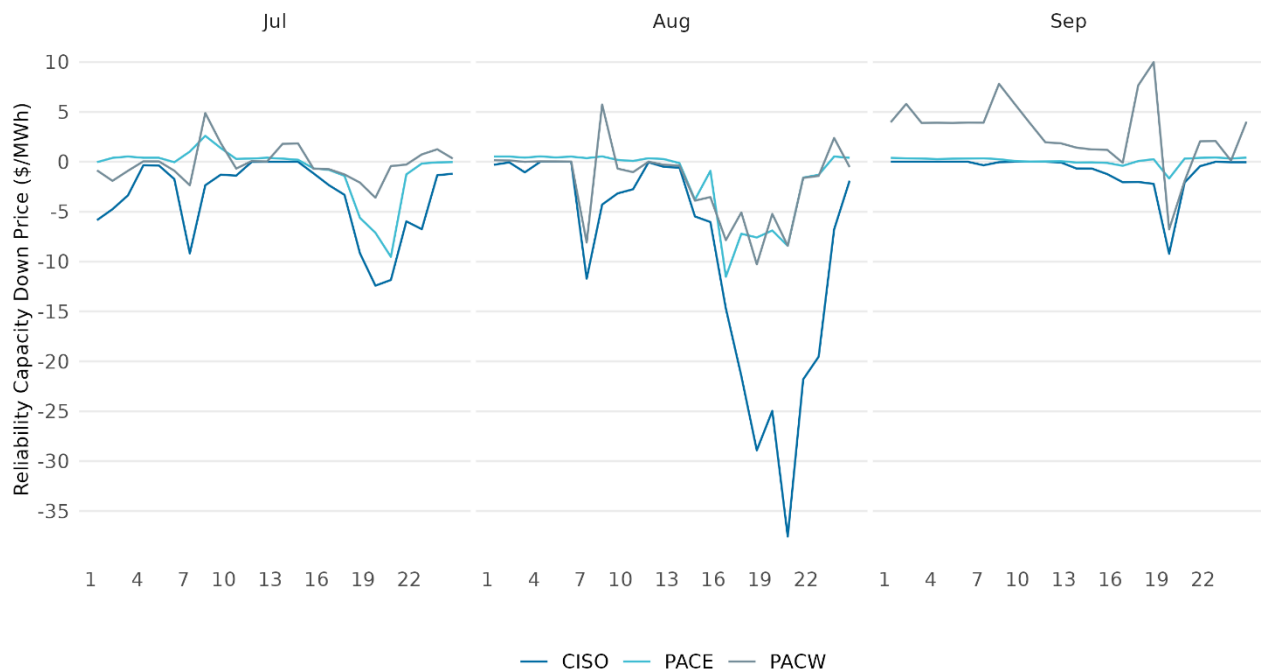


Figure 80: Hourly average price of RCD



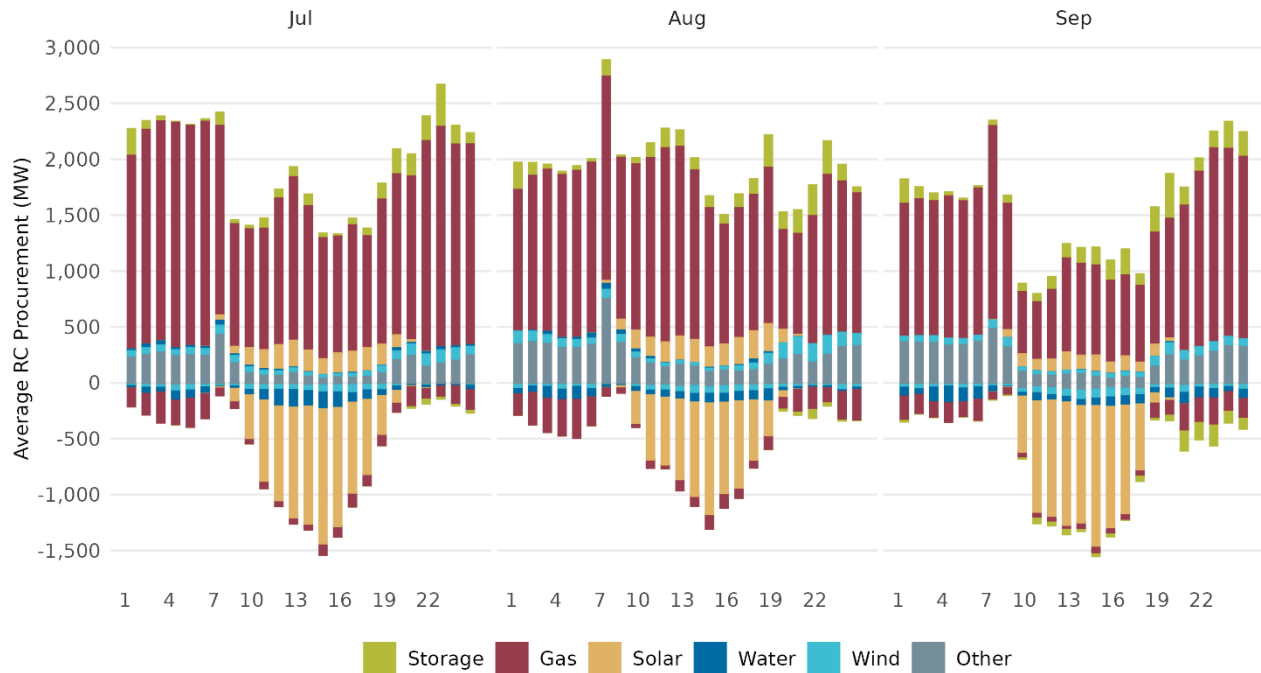
The reliability capacity price separation observed between the three BAAs reflects the economics of the wider EDAM market footprint, available supply mix and EDAM transfers.

Reliability capacity procurement

Figure 81 to Figure 83 illustrate the hourly average by technology supporting the procurement for each BAA.

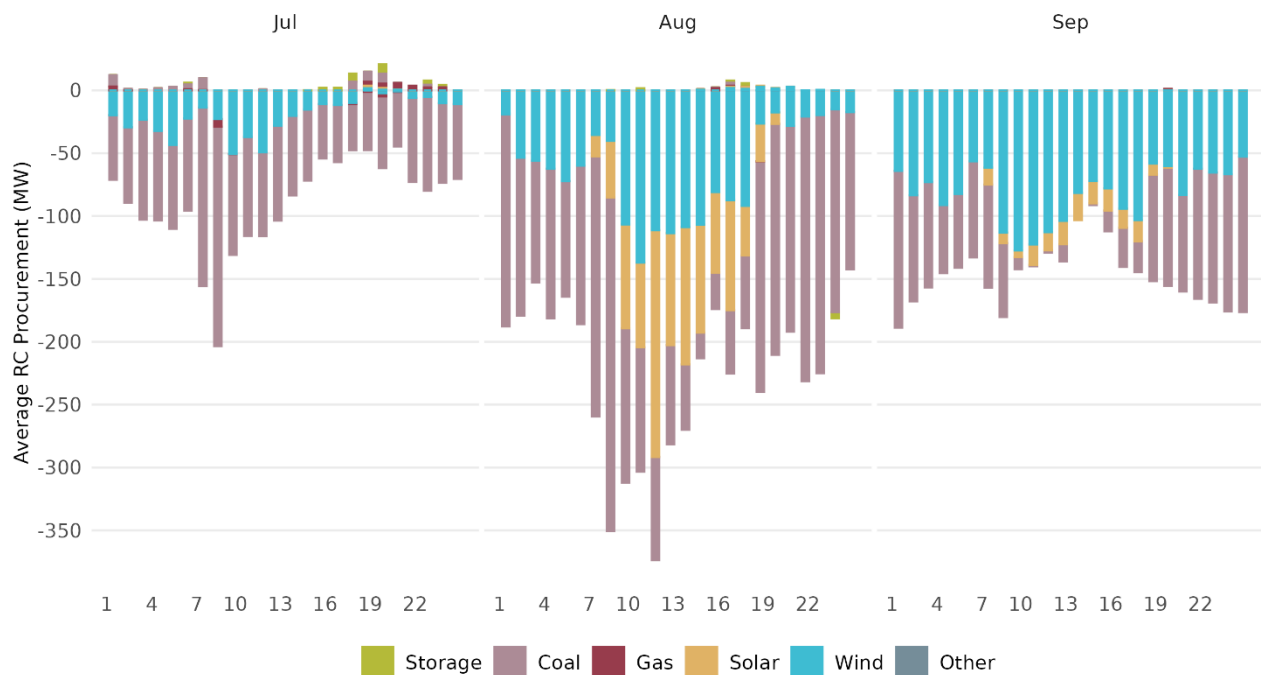
For CAISO in the past three months, gas resources continue to make up the highest proportion of RCU, mostly during non-solar hours. The majority of RCD is procured during solar hours by solar resources. September procured the same pattern of RCU on average as July and August, however, with an obvious decrease in the total procurement amount.

Figure 81: Hourly average of RC procurement for CAISO



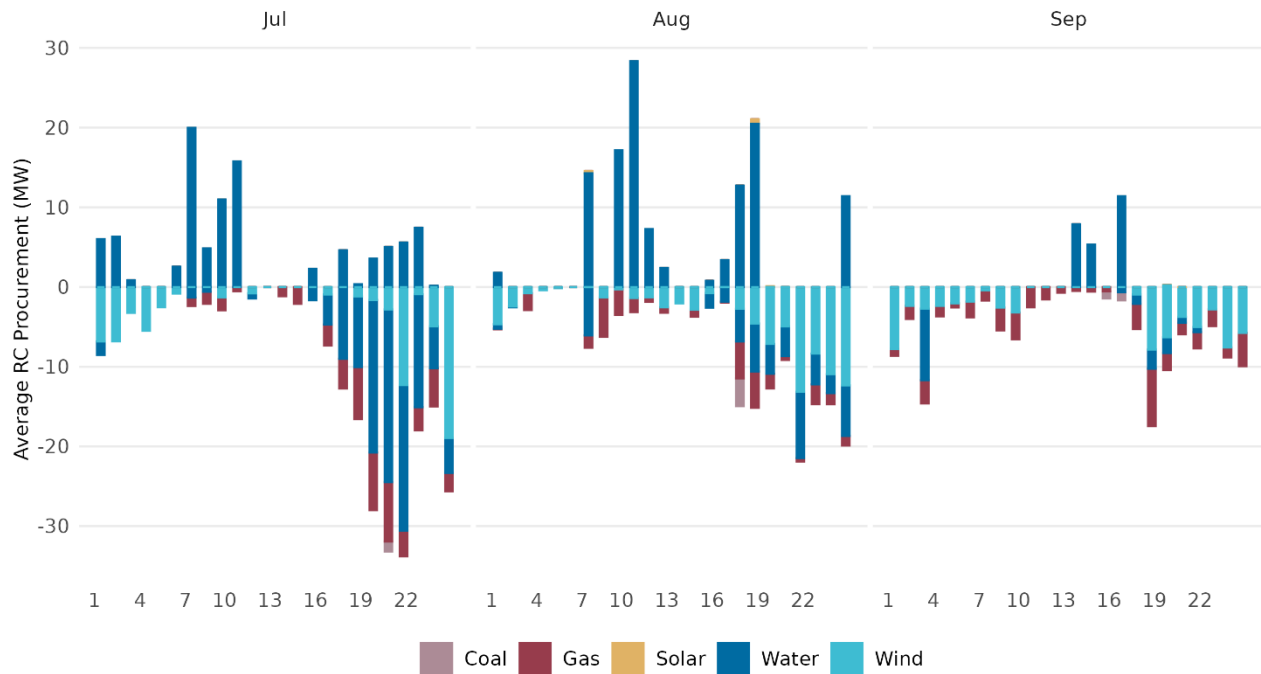
PACE reliability capacity is largely procured in the down direction and supplied primarily by coal and wind resources. RCD procurement has increased significantly, primarily from coal, wind, and solar in August. However, this pattern discontinued in September, and there was a noticeable decrease in the procurement amount compared to August.

Figure 82: Hourly average of RC procurement for PACE



PACW's RC is primarily supplied by hydro and wind resources, followed by gas resources. In September, RC procurement was pronounced less across all hours.

Figure 83: Hourly average of RC procurement for PACW



Reliability capacity input bids

Figure 84 and Figure 85 illustrate CAISO's hourly average volume of RC bids by bid price range and fuel type throughout July to September 2026, respectively. Zero-priced bids consistently accounted for the largest share of submitted RC capacity throughout July to September with about 40,000 MW (or about 60 percent of the total), followed by bids in the (40–60 \$/MWh) and high-price ranges (100–250 \$/MWh). Hourly bid volumes were generally higher during daylight hours as solar resources submitted bids in RC products.

Gas, storage and solar resources accounted for approximately 90 percent of the total. Generally, CAISO's submitted RC capacity remained stable from July to September.

Figure 84: Hourly average volume of RC bids by price for CAISO

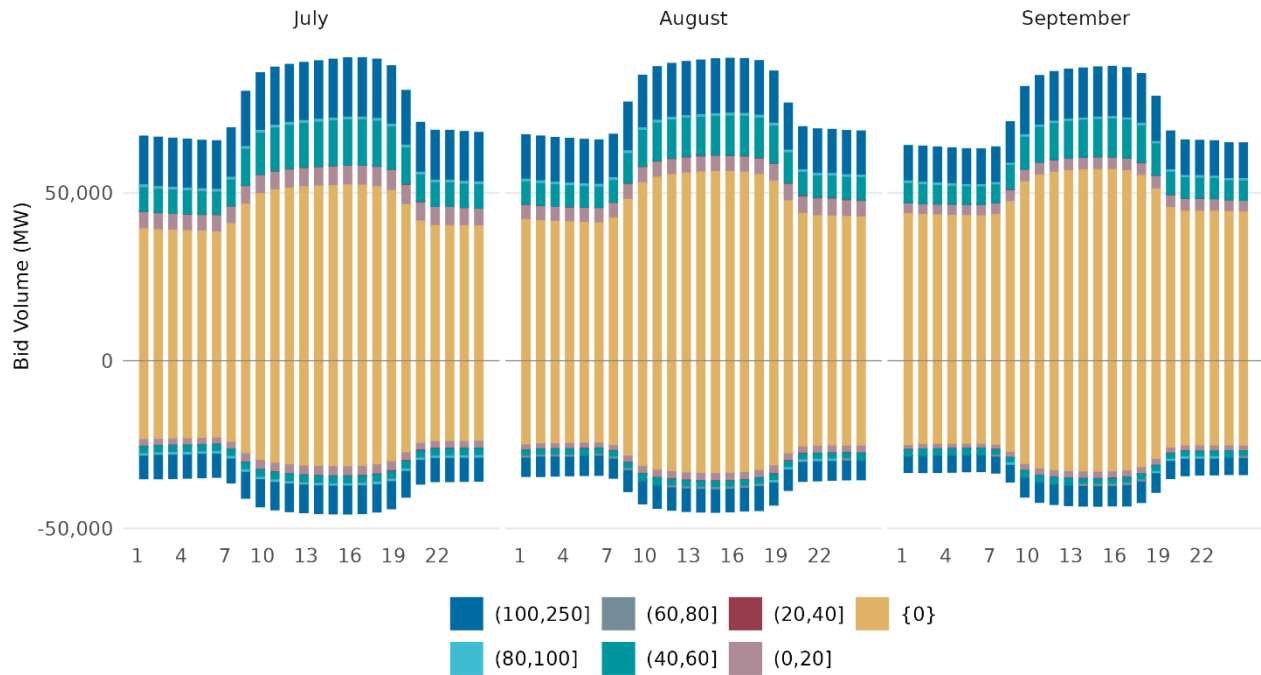


Figure 85: Hourly average volume of RC bids by fuel type by CAISO

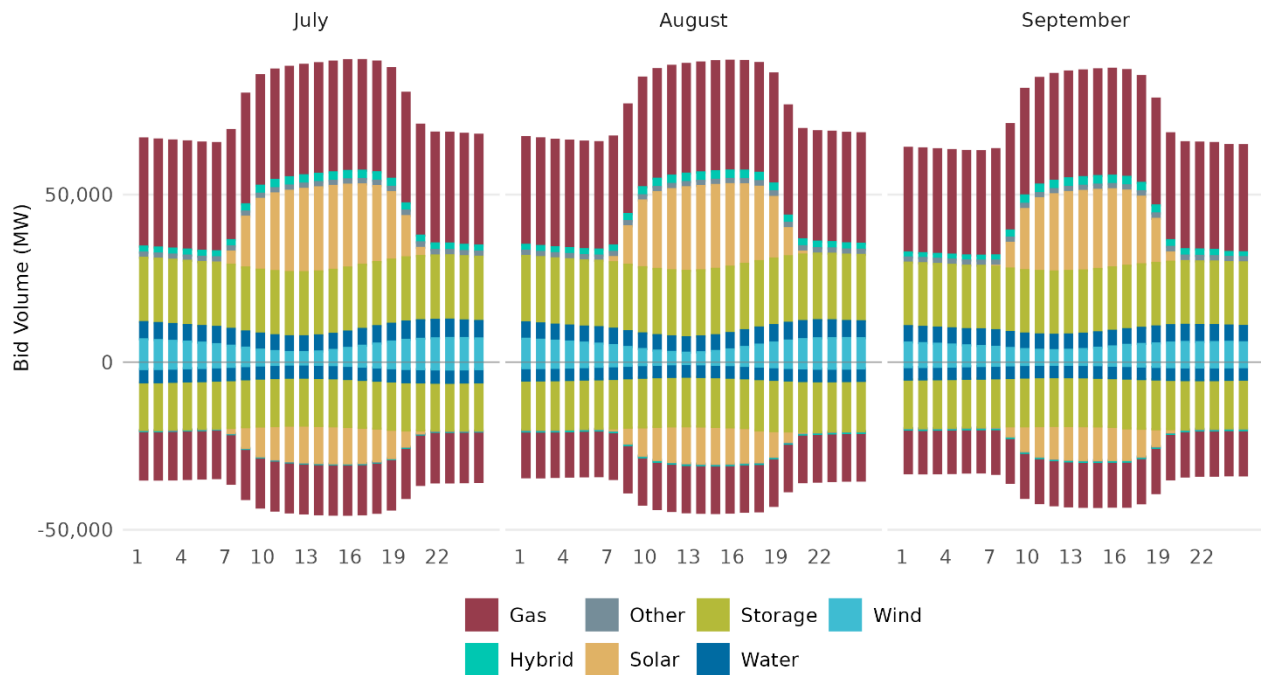


Figure 86 and Figure 87 illustrate the CAISO's daily average volume of RC bids by bid price range and fuel type, respectively. Generally, CAISO's submitted RC capacity remained relatively stable throughout August to September. Gas, solar, and energy storage accounted for the largest share of RC bid volumes.

Figure 86: Daily average volume RC bids by price for CAISO

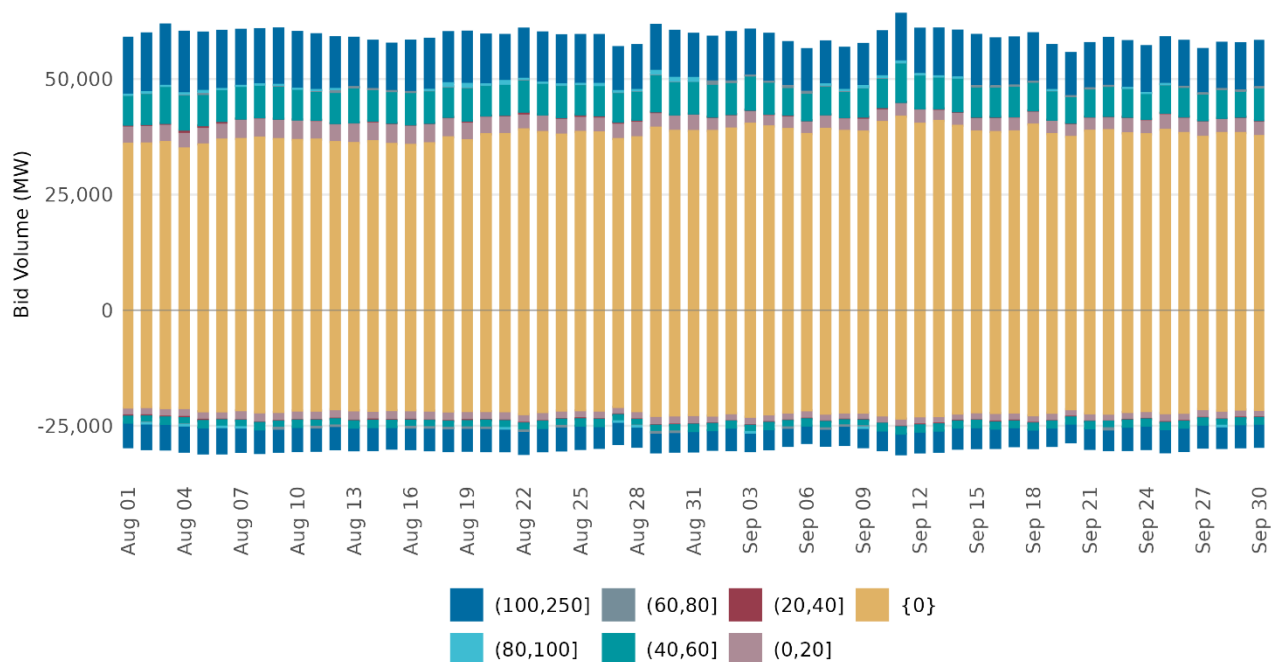


Figure 87: Daily average volume of RC bids by fuel type for CAISO

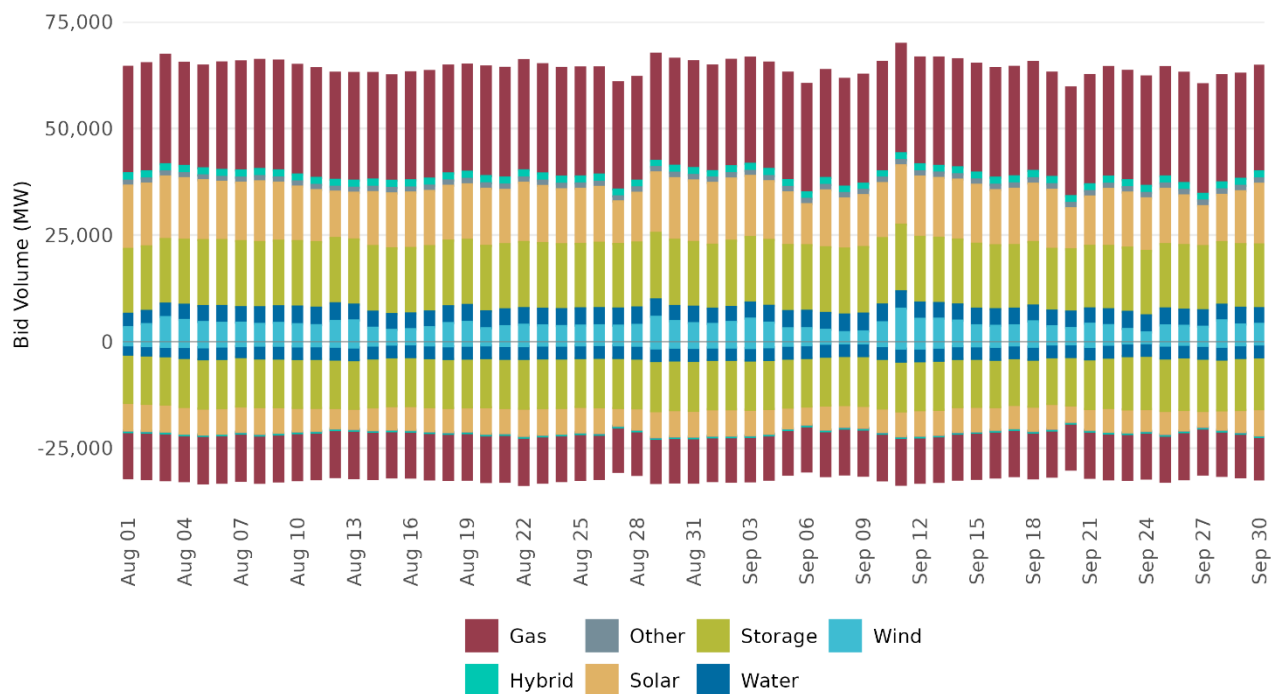


Figure 88 and Figure 89 illustrate the PACE’s hourly average volume of RC bids by bid price range and fuel type, respectively. Low-priced bids (\$0–20/MWh) and moderate priced bids (40–60 \$/MWh) consistently accounted for almost all the share of submitted RC capacity throughout the months. Coal, gas, and wind resources accounted for the largest share of submitted RC capacity, with some solar capacity bidding in RCU only.

Figure 88: Hourly average volume of RC bids by price for PACE

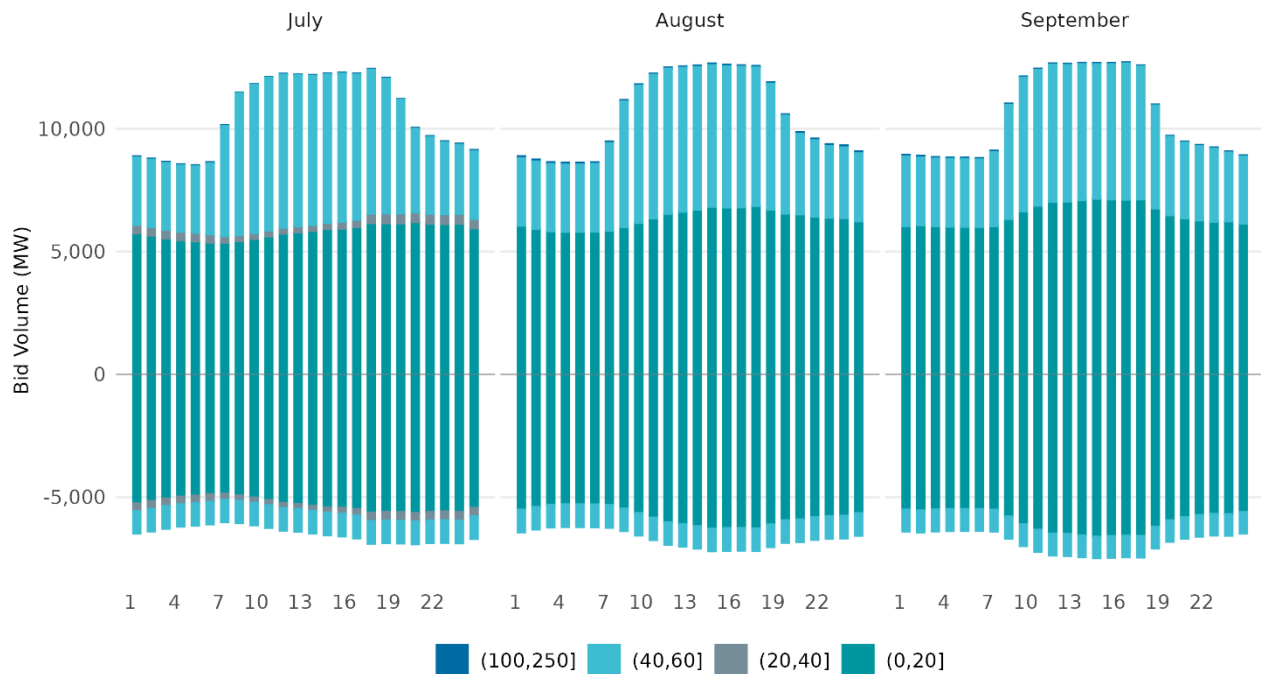


Figure 89: Hourly average volume of RC bids by fuel type for PACE

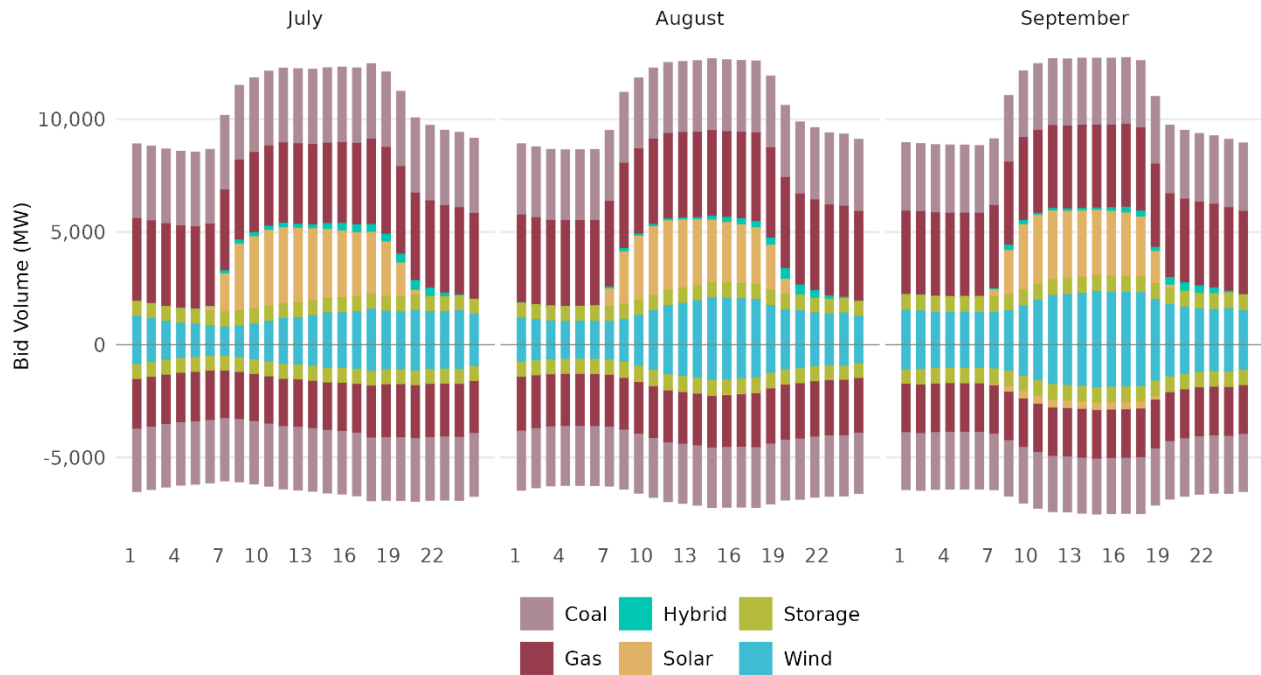


Figure 90 and Figure 91 plotted the daily average volume of PACE's RC products by price and fuel type, respectively. As for the bid volume, it is dependent on renewable forecasts, and solar resources only submitted bids in RCU, leaving an asymmetrical bid volume with RCU up to 10,000 MW and RCD only about 5,000 MW.

Figure 90: Daily average volume of RC bids by price by PACE

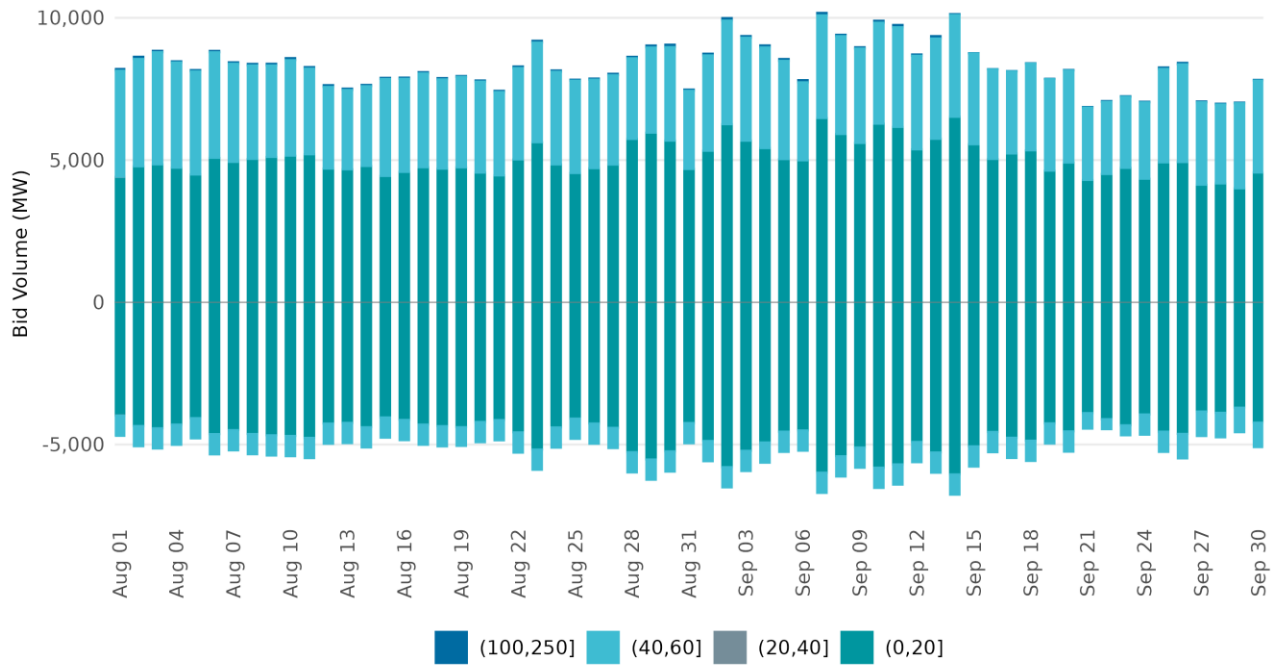


Figure 91: Daily average volume of RC bids by fuel type by PACE

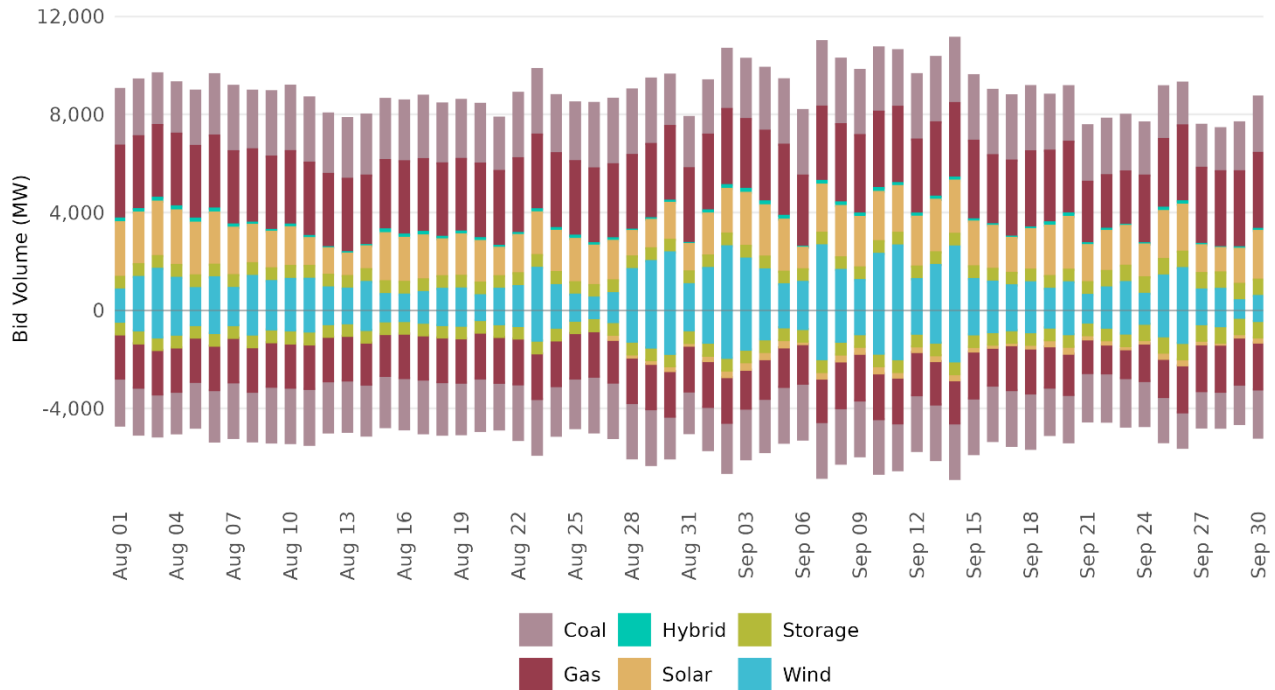


Figure 92 and Figure 93 illustrate PACW’s hourly average volume of RC bids by price range and fuel type, respectively. Low-priced bids (0-20 \$/MW) and moderate priced bids (40–60 \$/MW) consistently accounted for the largest share of submitted RC capacity throughout the month with over 2,300 MW (or 90 percent of the total), followed by bids in the (100–250 \$/MWh) range. It is noteworthy that in the down direction there are only low- and mid-priced bids submitted. Hourly bid volumes were slightly higher during daylight hours. Gas, water and wind resources accounted for the largest share of submitted RC capacity, with extra solar capacity bidding in RCU only. Similarly, PACW also has a asymmetric bid volumes, with RCU up to 2,700 MW while RCD only about 1,500 MW.

Figure 92: Hourly average volume of RC bids by price for PACW

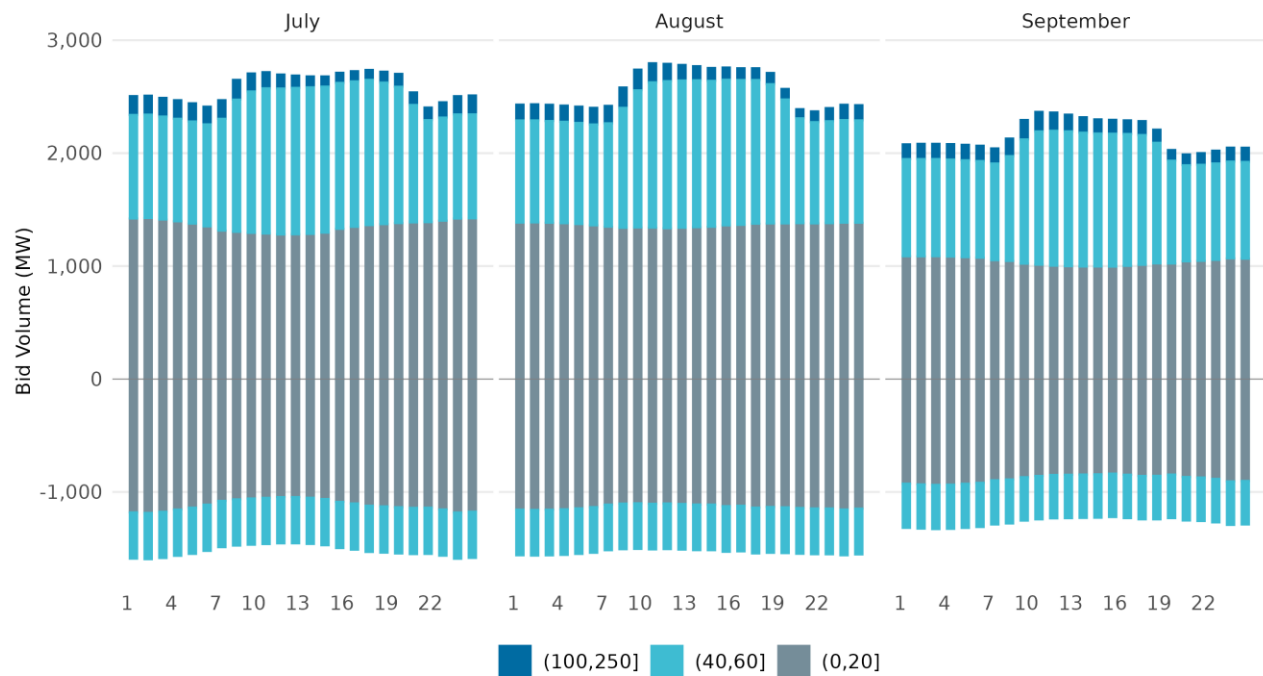


Figure 93: Hourly average volume of RC bids by fuel type for PACW

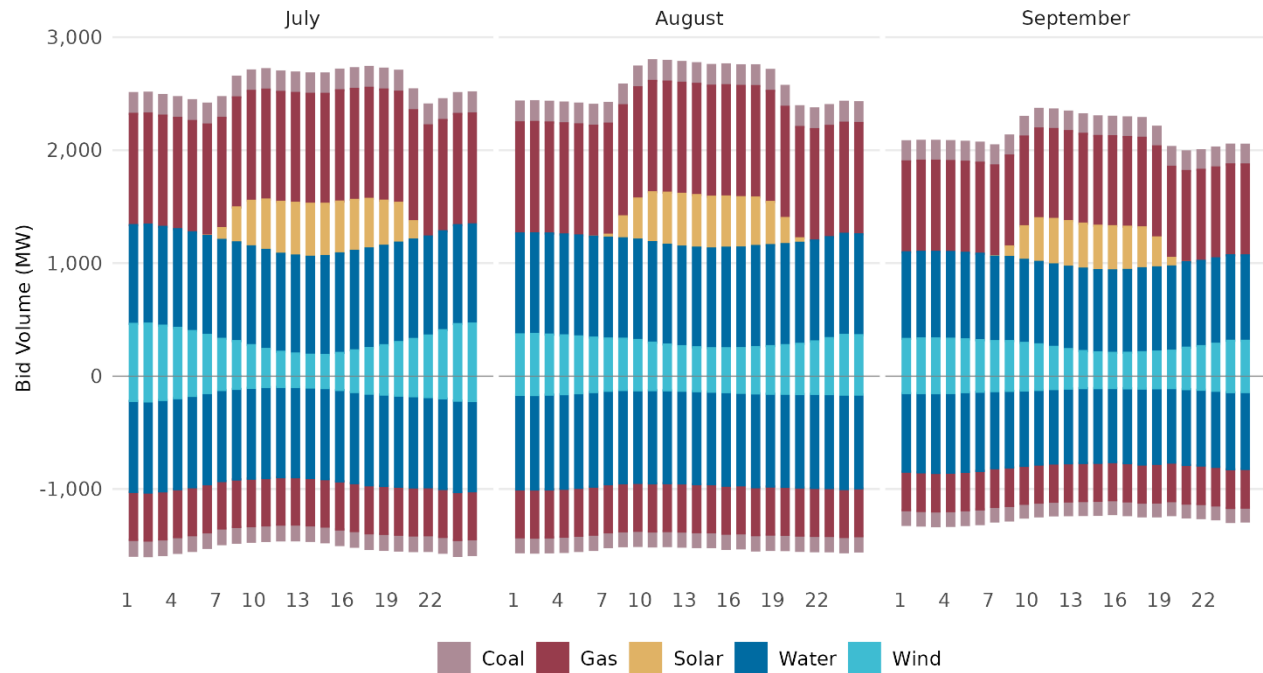


Figure 94 and Figure 95 illustrate PACW's daily average volume of RC bids. Generally, PACW's submitted RC capacity showed variations across both bid volumes and prices due to its dependency on its available renewable outputs.

Figure 94: Daily average volume of RC bids by price for PACW

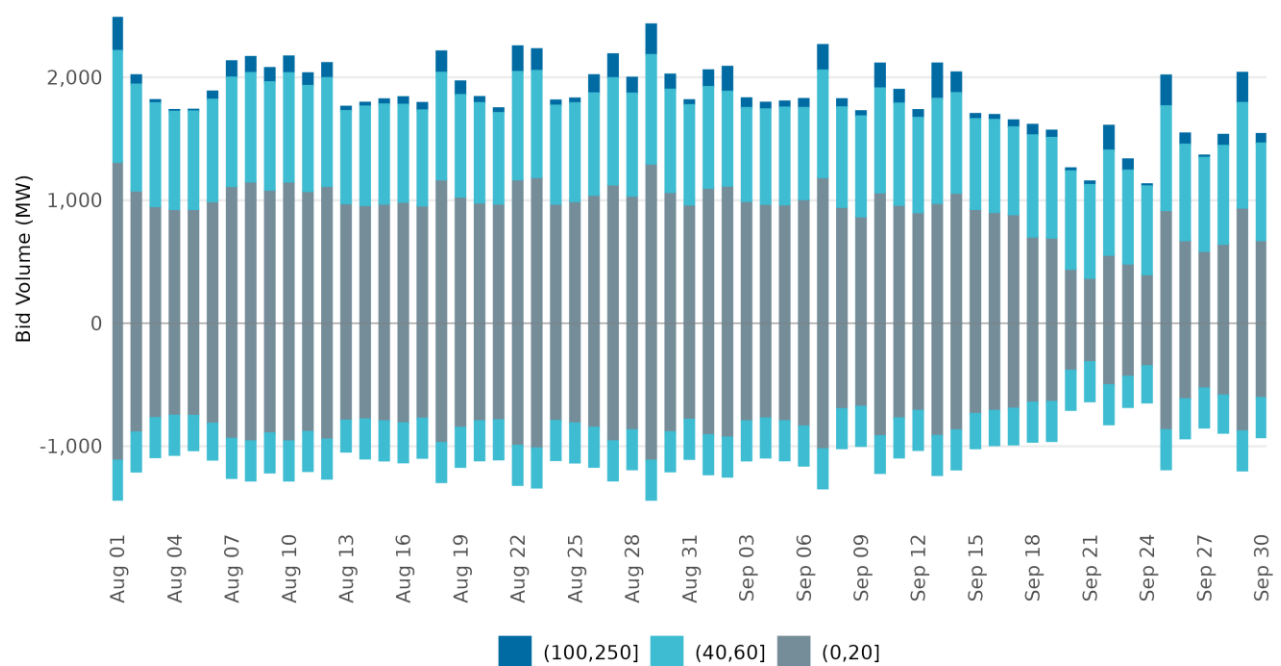
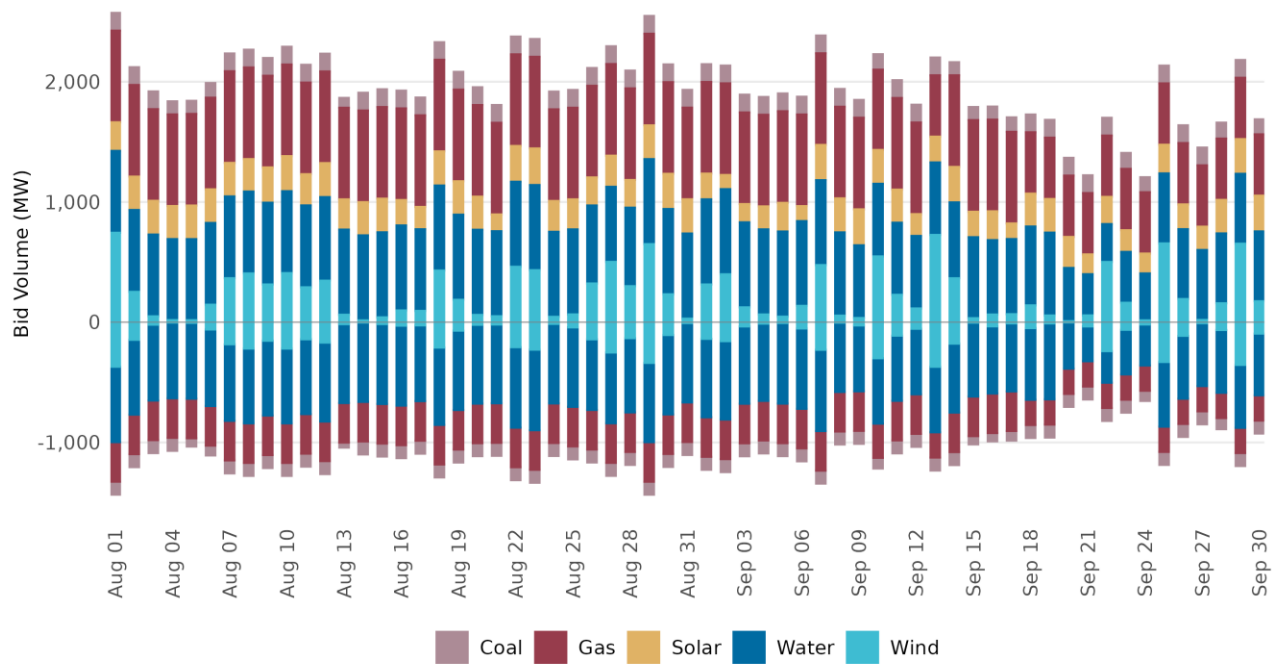


Figure 95: Daily average volume of RC bids by fuel type for PACW



Export reduction

In the month of September, there were instances of economic and low priority export reductions in the RUC process, shown in Figure 96. 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 97 shows the instances when the real-time market reduced exports in September, with the largest reduction happening on September 9 for low priority exports.

Figure 96: RUC export reduction

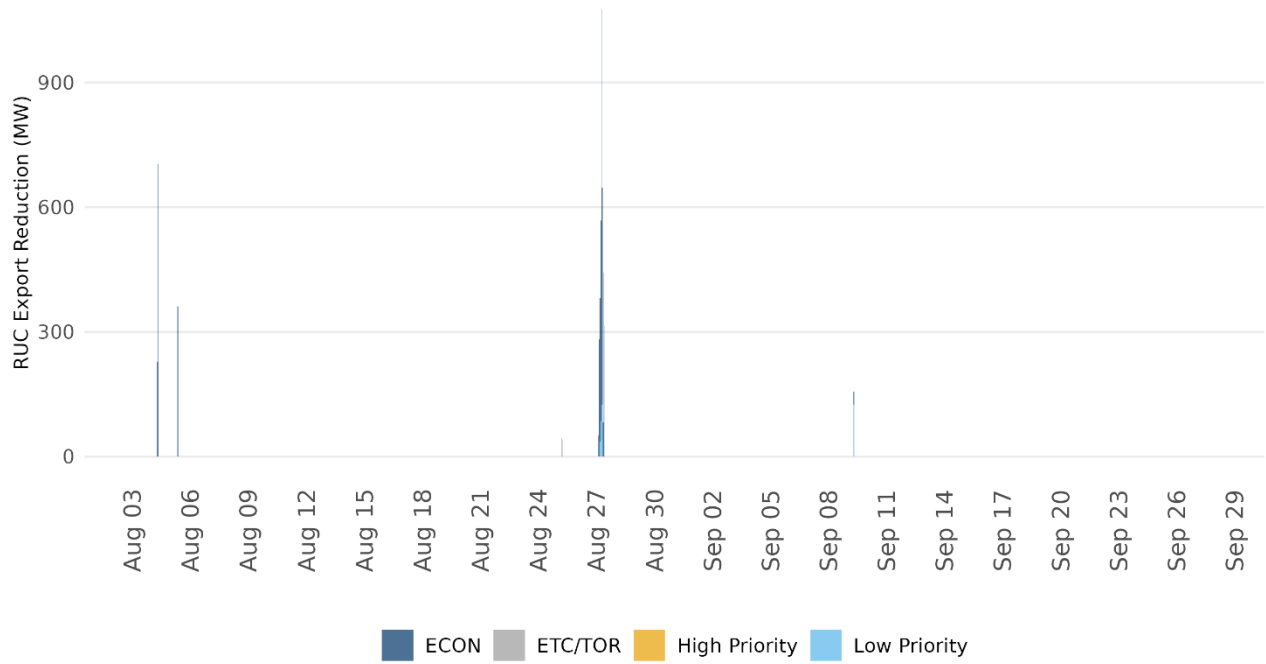
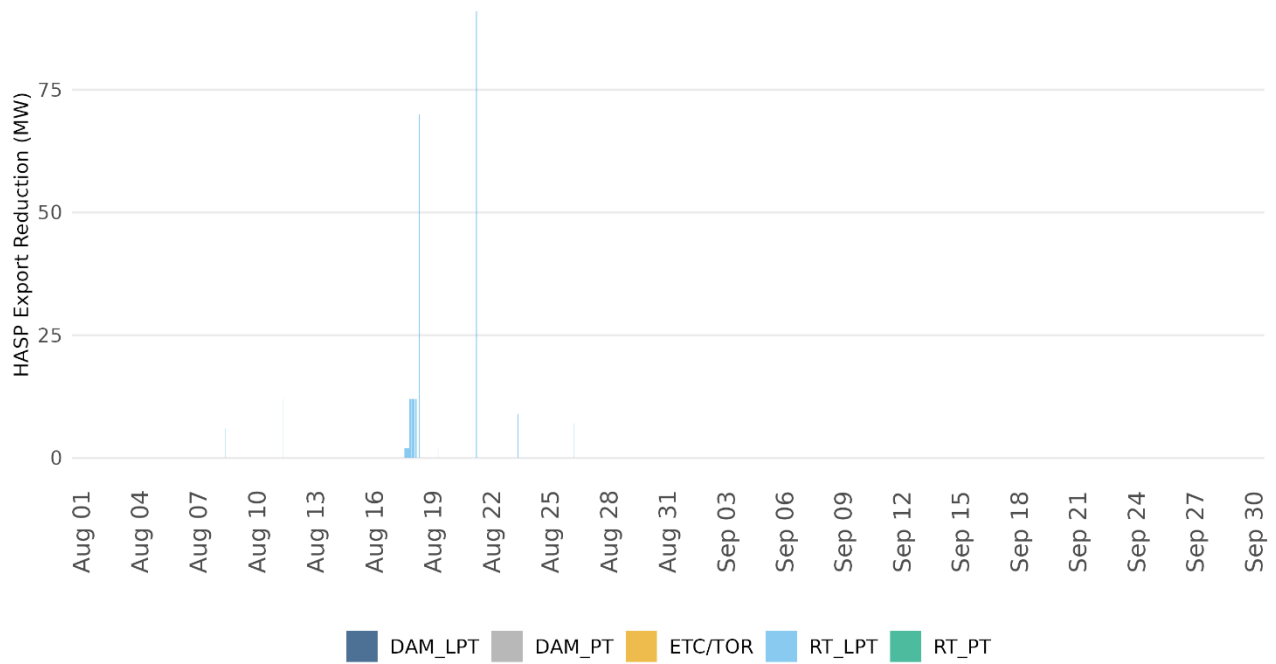


Figure 97: Exports reductions in HASP



Convergence bids

In addition to bids backed by physical resources, market participants within the CAISO area can submit virtual bids for generation or demand. Virtual generation and demand bids, also known as convergence bids, are intended to help price convergence between the day-ahead and real-time markets by arbitraging price differences between these two markets. Any virtual supply or demand cleared in the day-ahead market is liquidated in the real-time market.

Figure 98 shows the average monthly cleared virtual supply and demand bids. The average MW of cleared bids in September increased compared to August, but was less than that in July.

Figure 98: Average monthly cleared virtual bids

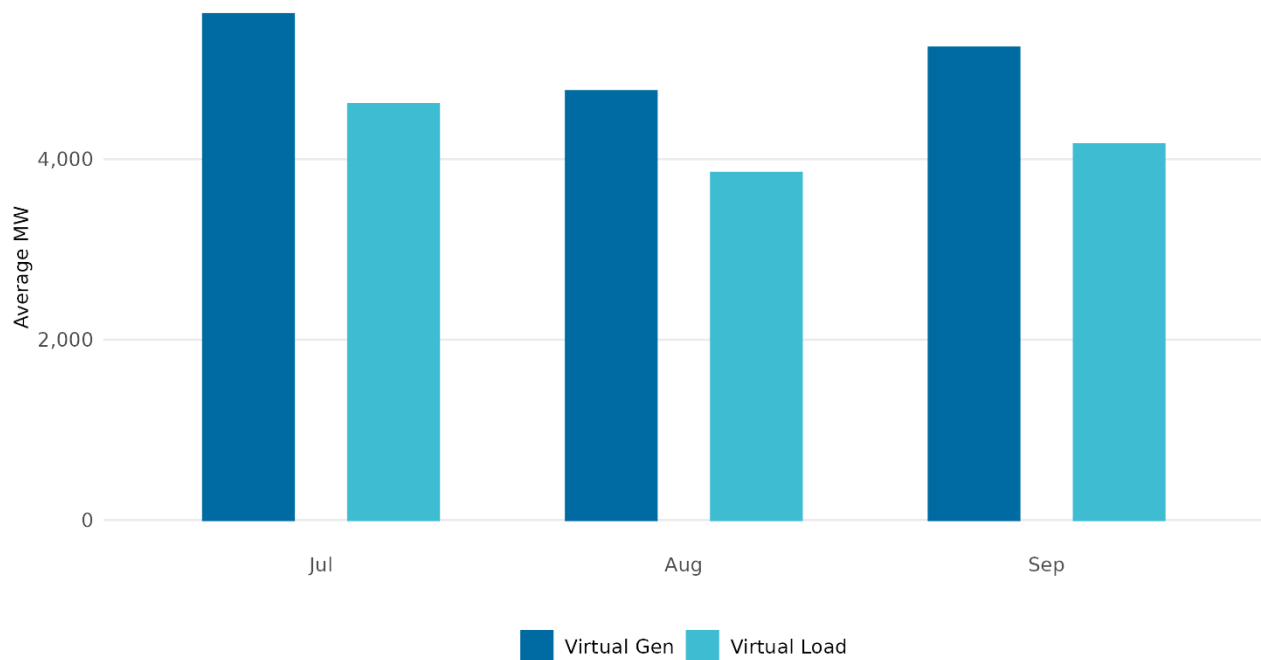


Figure 99 shows the average hourly cleared virtual generation, virtual load, and the net virtual bids for each day in August and September in the day-ahead market. The net cleared virtual bid is defined as the total cleared virtual generation minus the total cleared virtual demand. Cleared virtual bids in September were net supply except from September 8 to 10.

Figure 99: Average hourly cleared virtual bids

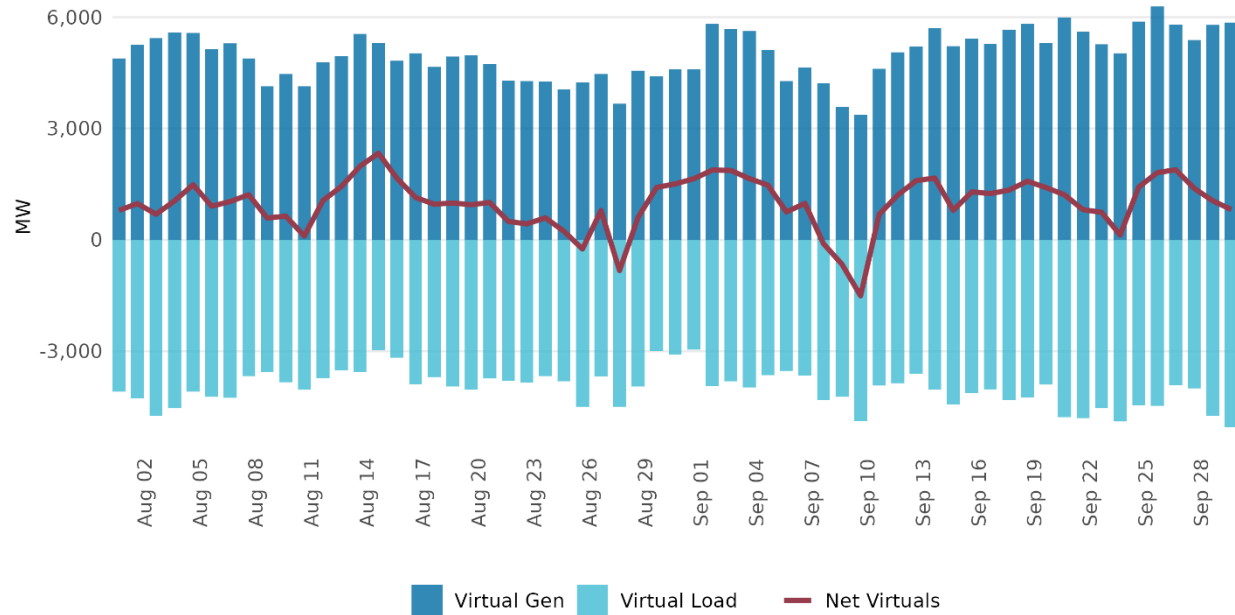


Figure 100 and Figure 101 show the hourly profile of average virtual supply and virtual demand, respectively, in August and September. Average cleared virtual supply bids in September were highest in hour ending 18, compared to hour ending 16 in July and August. Average cleared virtual demand bids in September were highest in hour ending 16, like in July and August.

Figure 100: Average hourly cleared virtual supply

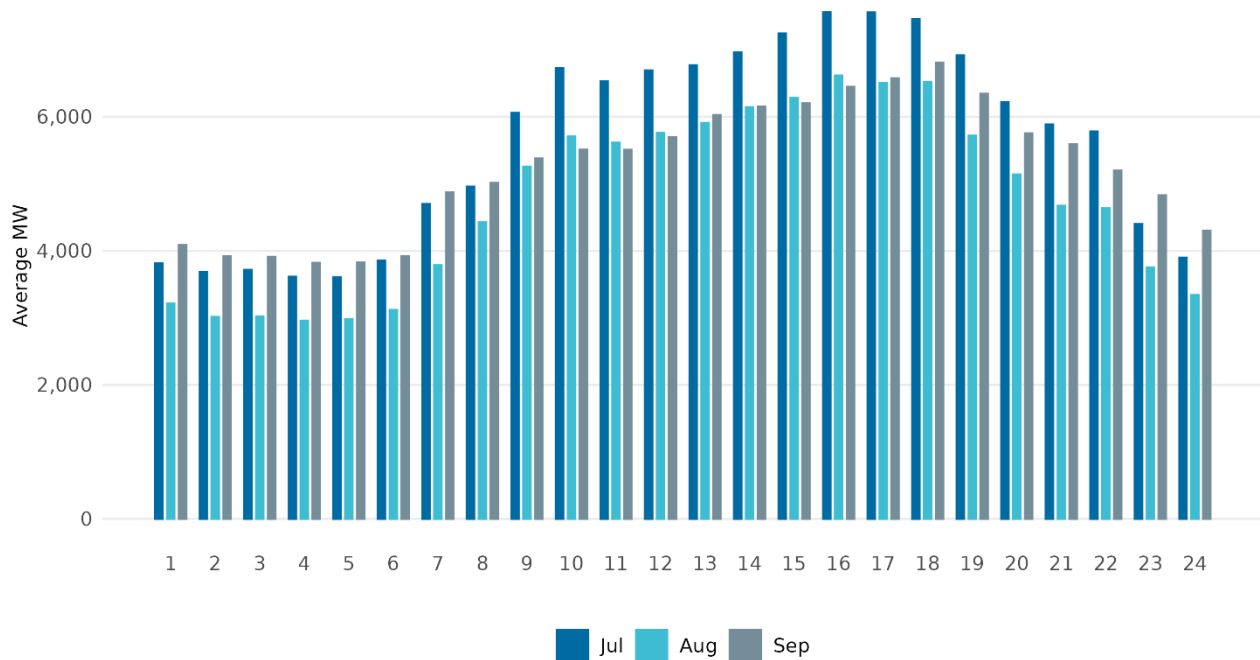


Figure 101: Average hourly cleared virtual demand

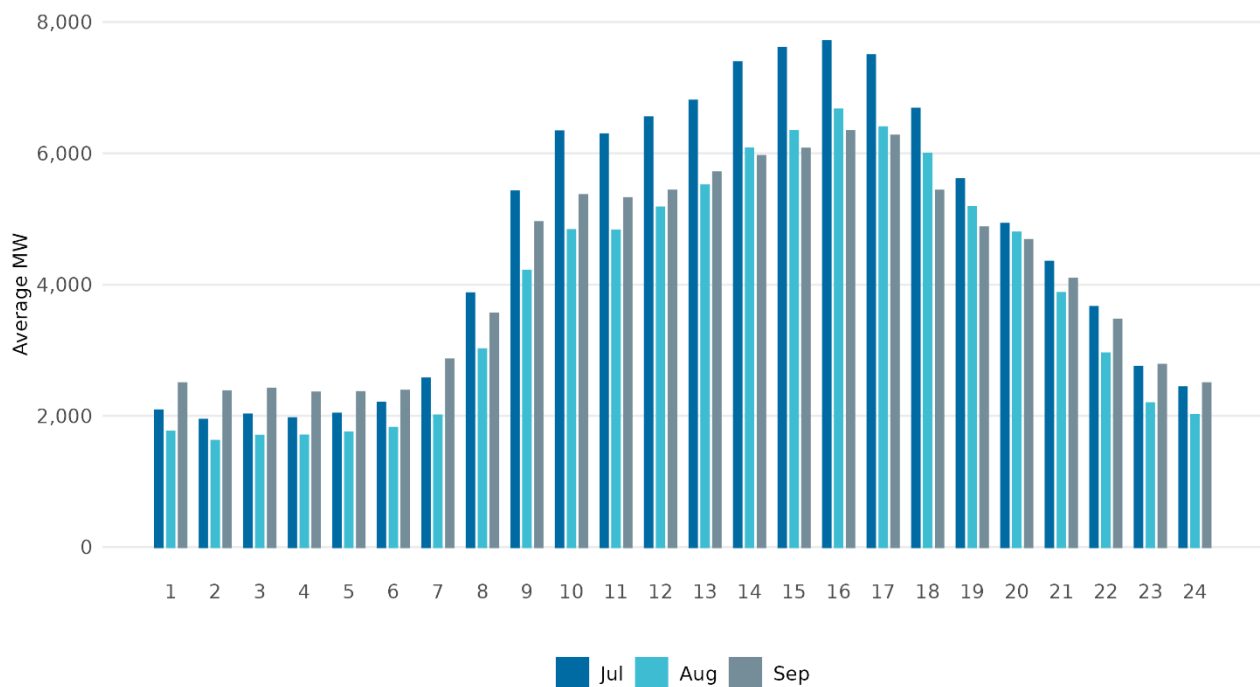
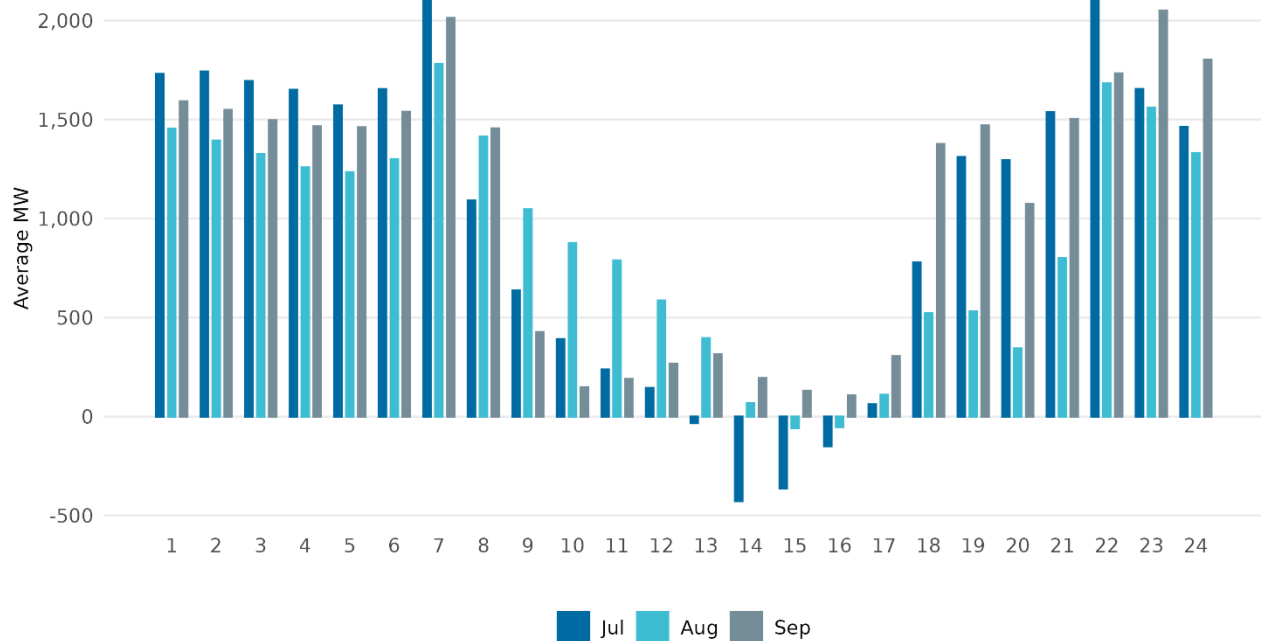


Figure 102 shows the hourly profile of average net cleared virtual bids from July through September, calculated as cleared virtual supply minus cleared virtual demand. Positive values indicate net virtual supply, while negative values indicate net virtual demand. In September, virtual cleared bids were net supply in all hours including during midday hours when they were net

demand in July and August. Compared to July and August, hours ending 23 and 24 saw a large increase in net cleared virtual bids in September.

Figure 102: Average net hourly cleared virtual bids



Greenhouse gas emission product

Greenhouse gas (GHG) regulations are designed to reduce carbon emissions associated with electricity generation and imports. In regions or states subject to GHG policies, such as California, imported electricity may incur additional costs when it is generated by resources located outside the regulated area. To ensure these environmental costs are properly reflected in market outcomes, the EDAM also incorporates the GHG model into the market optimization process.

Eligible resources located outside GHG regulation areas may voluntarily submit GHG bids in addition to their regular energy bids. The GHG model introduces GHG allocations as optimization variables that are assigned to generation outside (or across) GHG regulated areas, representing the portion of their generation attributed to serving demand within a specific GHG regulated area.

The link between GHG allocations and net imports into the regulation area is enforced through the GHG import allocation constraint in the market optimization. The shadow price of this constraint defines the GHG price (or marginal GHG cost), which becomes part of the locational marginal price (LMP) within the regulated area, while remaining zero outside. Resources receiving GHG allocations

are paid at the corresponding marginal GHG cost. This payment is separate from the regular energy schedule settlement and provides a mechanism for recovering the GHG regulation costs imposed on imports into the GHG regulation area.

Overall, the model incorporates GHG regulation costs into market optimization to ensure that dispatch decisions reflect both economic and environmental considerations. By accounting for the cost of emissions, the model prevents external resources from being dispatched solely based on energy costs while ignoring the associated GHG impacts. Throughout September, the highest GHG price reached 35.6 \$/MWh during Trade Hour 11 on September 7. The maximum hourly GHG allocation was 515 MW, occurring on multiple days in September.

Figure 103 shows the daily average GHG allocation by fuel type for both August and September. During the period covered, GHG allocation was distributed among Gas and Coal resources, with Gas resources receiving the majority of the allocation. In September, the daily average GHG allocation reached its highest level on September 8, peaking at 545 MW, followed by 437 MW on September 10. From late August through early September, several PACE resources had \$0 GHG bids due to a market issue. During this period, certain coal resources received GHG allocation, which was reflected in the allocation figures. Overall, the level of GHG allocation in September was higher than that in August.

Figure 103: Daily average GHG allocation by fuel type

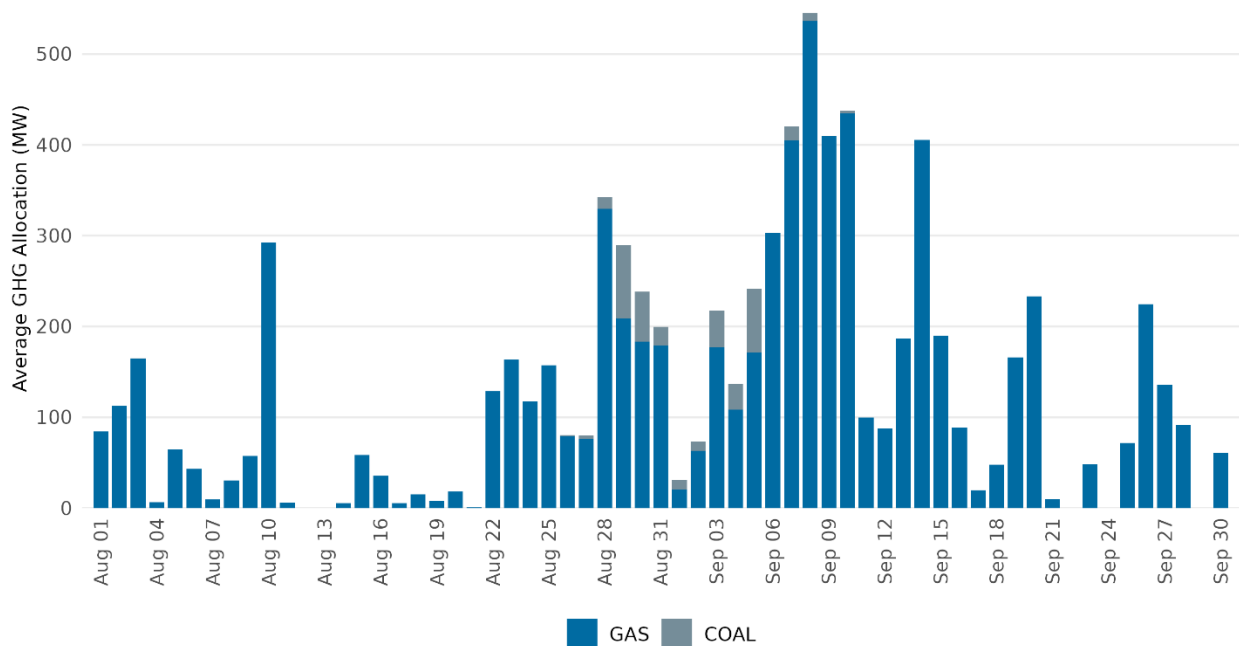


Figure 104 shows the hourly average GHG allocation by fuel type for September. GHG allocation was generally higher during the early morning and evening hours and lower during the midday hours, when solar generation within the CAISO area is typically abundant.

Figure 104: Hourly average GHG allocation by fuel type

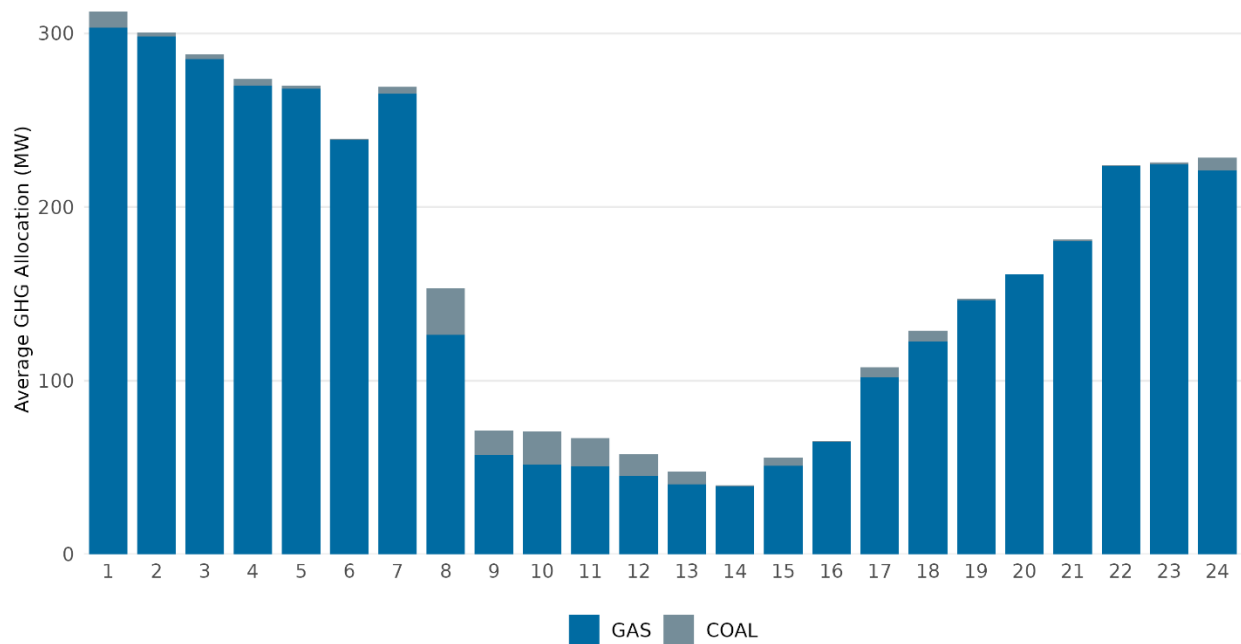


Figure 105 shows the daily average GHG prices in both August and September. In September, daily average GHG prices fluctuated throughout the month, with the highest daily average price reaching 21.4 \$/MWh on September 7. Overall, the range of daily average GHG prices in September was similar to that observed in August.

Figure 105: Daily average GHG price

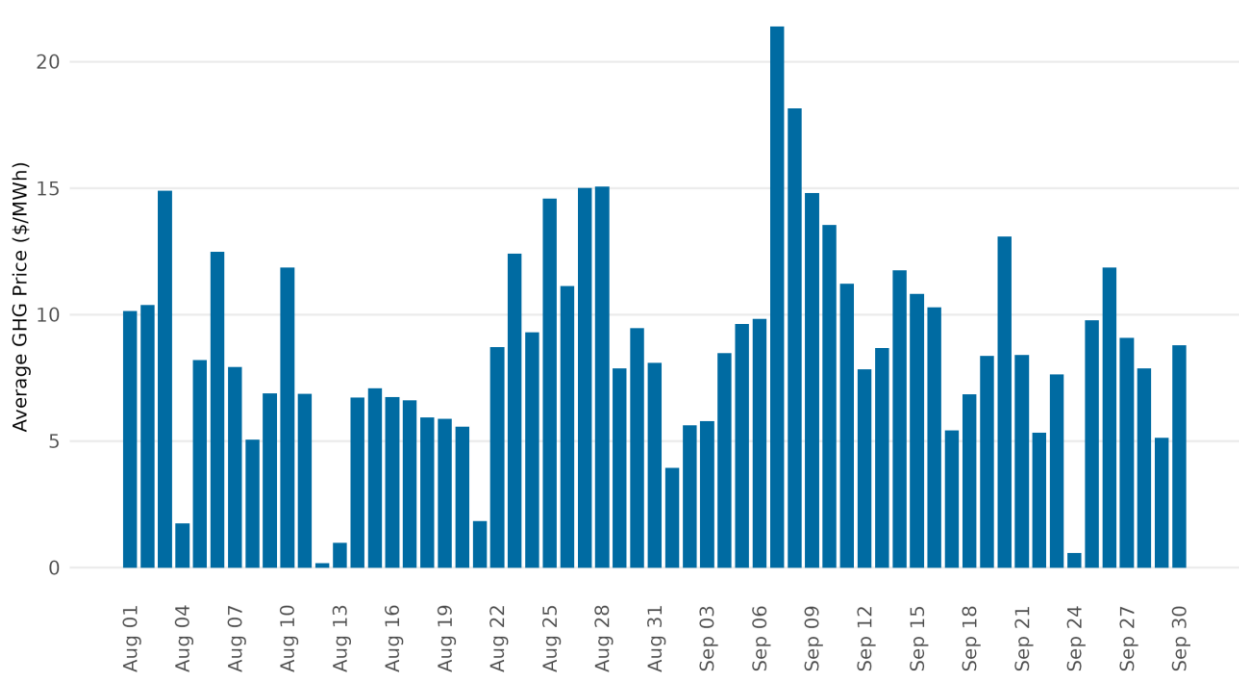


Figure 106 shows the hourly average GHG price by trade hour for July, August, and September. GHG prices were generally higher during the early morning hours (Hours 1-7), declined during the midday period (approximately Hours 10-16), and showed a modest increase again during the evening hours (Hours 19-24). The lower midday prices coincided with periods when imports into the California area were reduced due to abundant solar generation within the CAISO area.

Figure 106: Hourly average GHG price

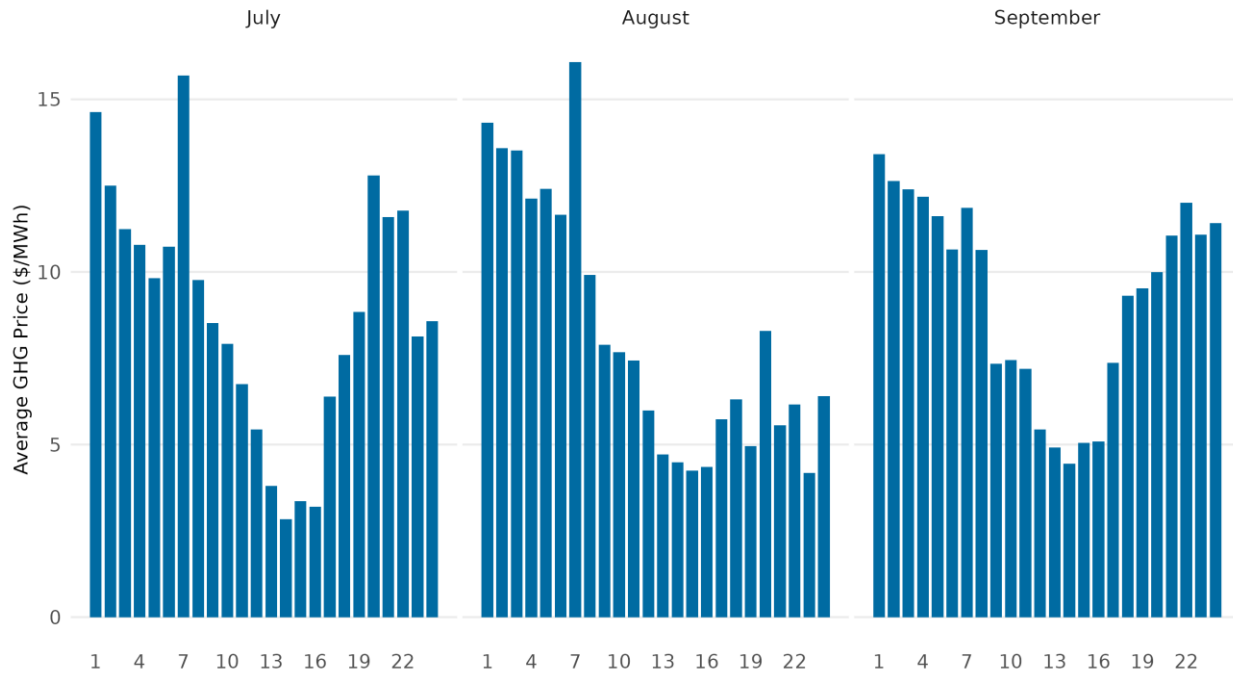
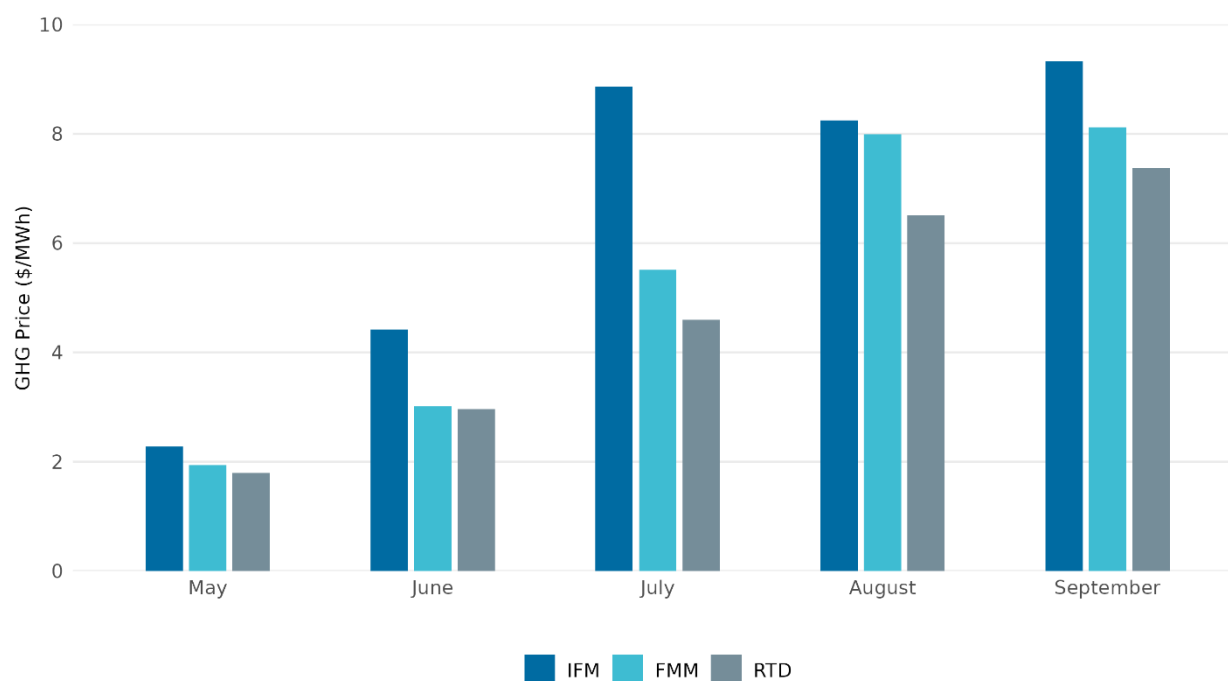


Figure 107 shows the monthly average GHG prices in the IFM, FMM, and RTD markets from May to September. GHG prices generally increased over this period, with only one exception in IFM, where GHG prices decreased slightly from July to August. Overall, IFM prices remained higher than real-time prices in all five months. Notably, the increase in GHG prices coincided with the summer months, when higher system loads can increase reliance on energy transfers and imports across BAAs in both EDAM and WEIM. Higher levels of energy transfers during these periods can increase the volume of GHG allocation, which may in turn contribute to higher GHG prices.

Figure 107: Monthly average GHG price by market



EDAM Transfers

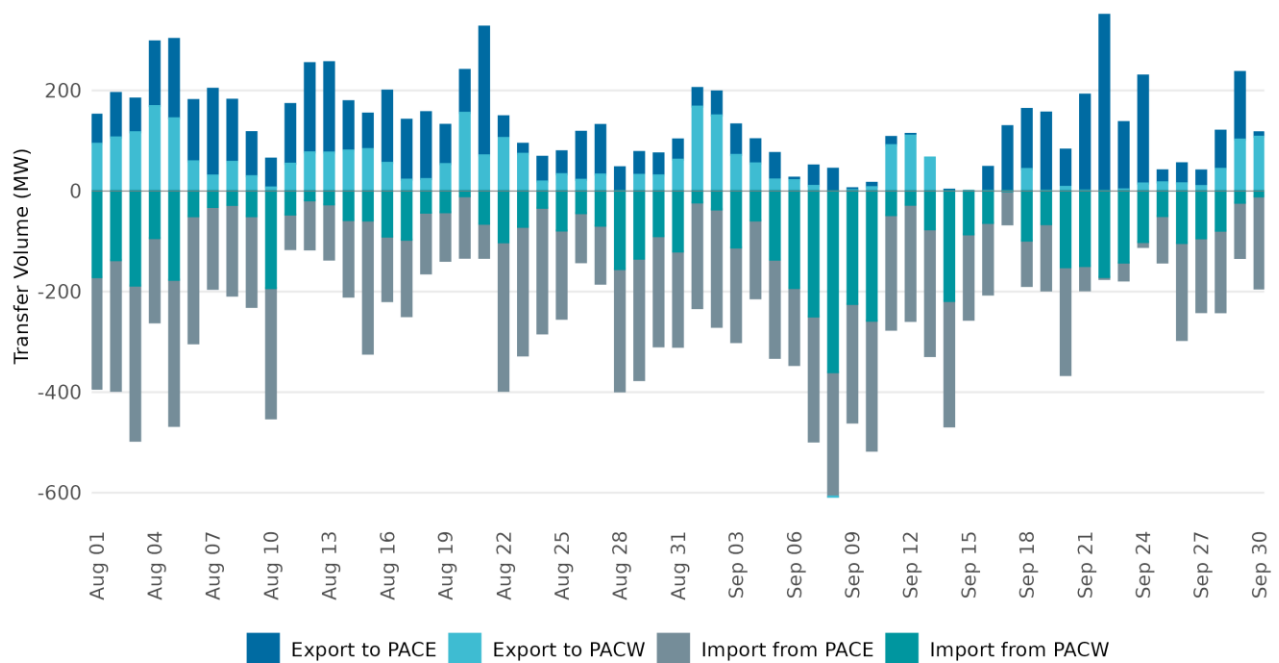
Available transfer capability among the three participating areas is enabling the market to capture the economic benefits of a larger, more integrated regional footprint. By facilitating the movement of cheaper supply across balancing areas, the market can more effectively access the most economical supply available while supporting reliable system operations.

Transfer flows are determined dynamically to these economic signals and can vary from hour to hour as market conditions evolve. Beyond supporting economic efficiency, transfers also enhance access to the geographic and fuel diversity available across the extended market footprint. This broader resource pool increases operational flexibility and improves the utilization of available generation.

Energy transfers

Figure 108 illustrates CAISO daily average energy transfers in IFM in August and September 2026 on both export (+) and import (-) directions, and the breakdown for transfer pairing entities. CAISO was a net importer in both months, and the main transfer pairing BAA is PACE, however, on a few days in September, CAISO had more imported energy from PACW. The average export volume generally decreased in August and September due to summer conditions.

Figure 108: Daily average energy transfers for CAISO



The hourly profile in Figure 109 exhibits variations in daily transfer volumes through July, August, and September. Overall, exports to PAC areas generally decreased in the past three months. July experienced the highest export levels, particularly in the daylight hours of the month. September showed comparatively lower export volumes than in August and September, but the imports were almost the same at around 300 MW. Generally, there were noticeable high energy imports and reduction in exports due to summer weather.

Figure 109: Hourly average energy transfers for CAISO

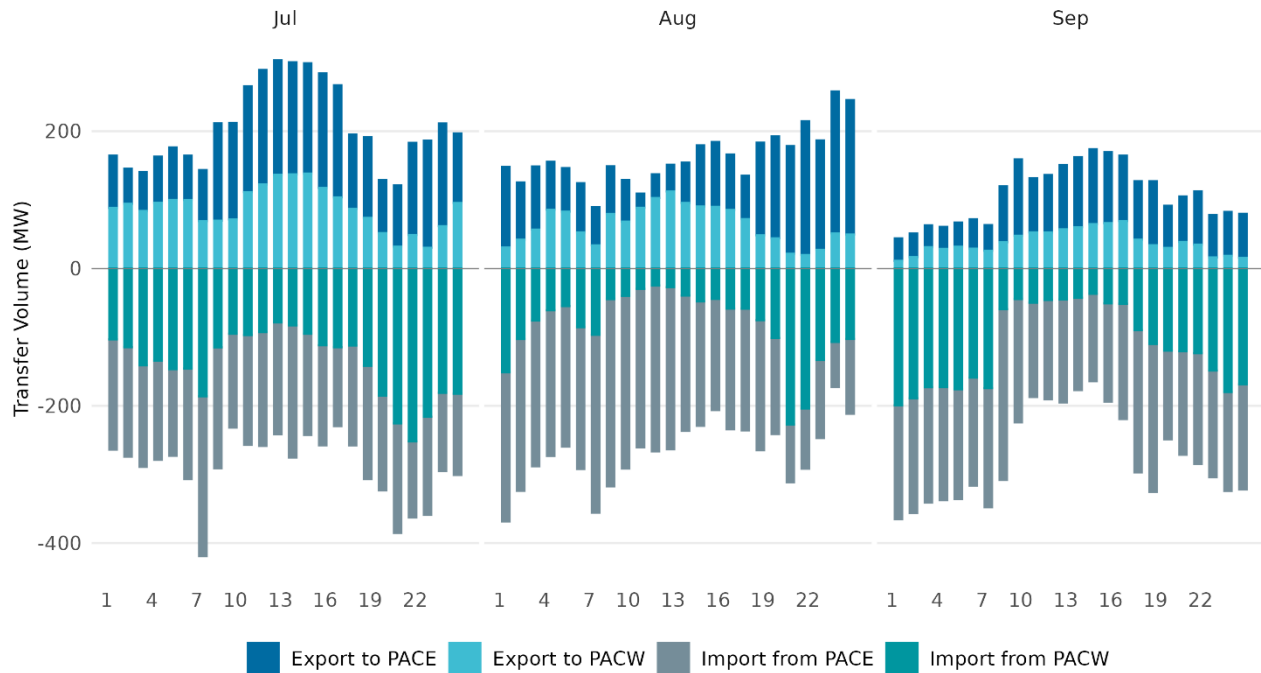


Figure 110 show PACE's daily average energy transfers throughout August to September 2026 in both export (+) and import (-) directions. Generally, PACE remained a net exporter in August and September. In August and September, the daily exports reached highest of about 500 MW on several days. In the meantime, there was noticeable decrease in energy imports from CAISO, with only a few days of peak imports over 200 MW.

The Figure 111 hourly profile also shows PACE's increasing energy exports as market evolves in August and September compared with July, with hourly average exports over 450 MW in morning peak hours. In contrast, imports from CAISO's decreased in August and September, from peak average import over 200 MW in July to about 100 MW in September.

Figure 110: Daily average energy transfers for PACE

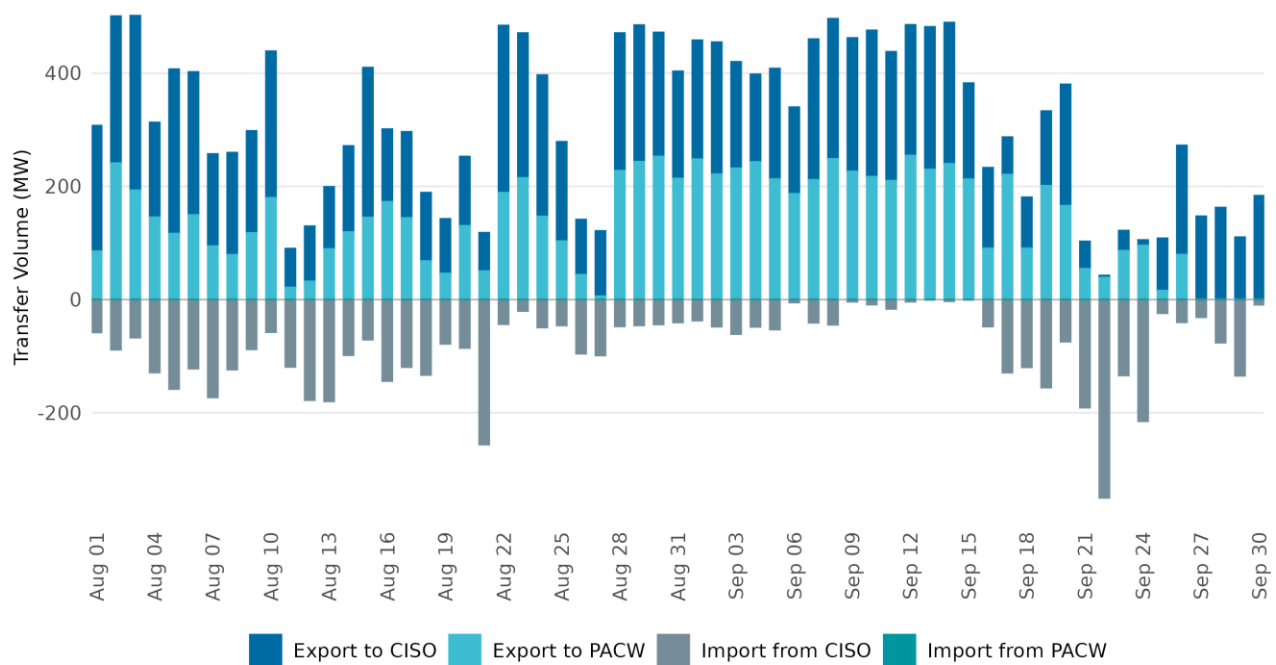


Figure 111: Hourly average energy transfers for PACE

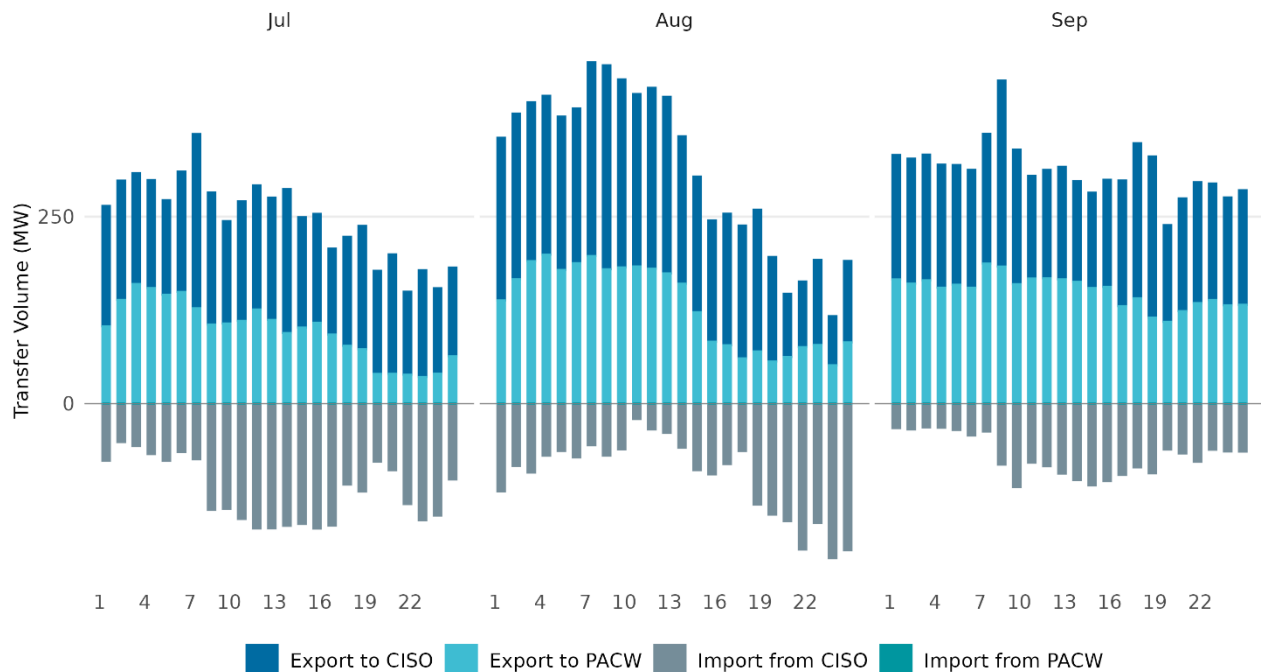


Figure 112 and Figure 113 show PACW's daily and hourly average energy transfers throughout August to September 2026 on both export (+) and import (-) directions. Generally, PACW was a net importer in both months, and more energy was imported from PACE, and September has more energy imports compared with August, with daily average maximum over 400 MW on September CAISO/MD&A/MPAA

1. The daily average profile shows an increase in energy exports in September, and almost all energy exported was to CAISO. The hourly profile shows a slight decrease in average imports in September compared with August, and exports mainly to CAISO at non-solar hours increased, with peak about 200 MW.

Figure 112: Daily average energy transfers for PACW

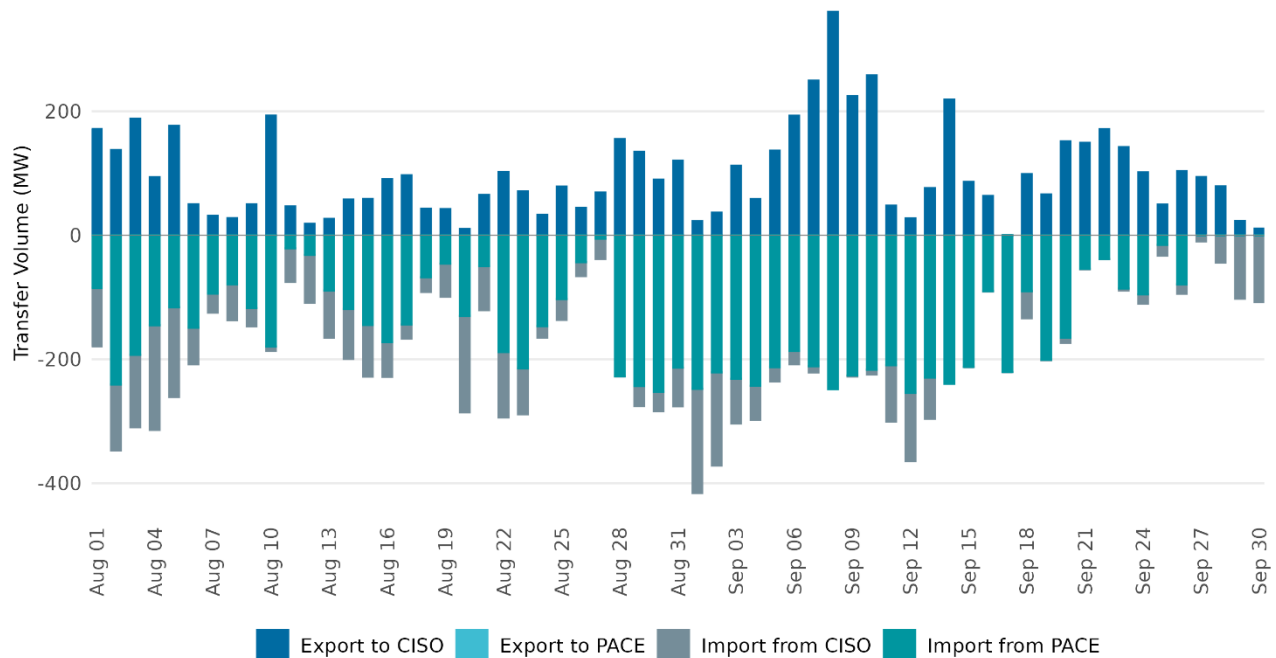


Figure 113: Hourly average energy transfers for PACW

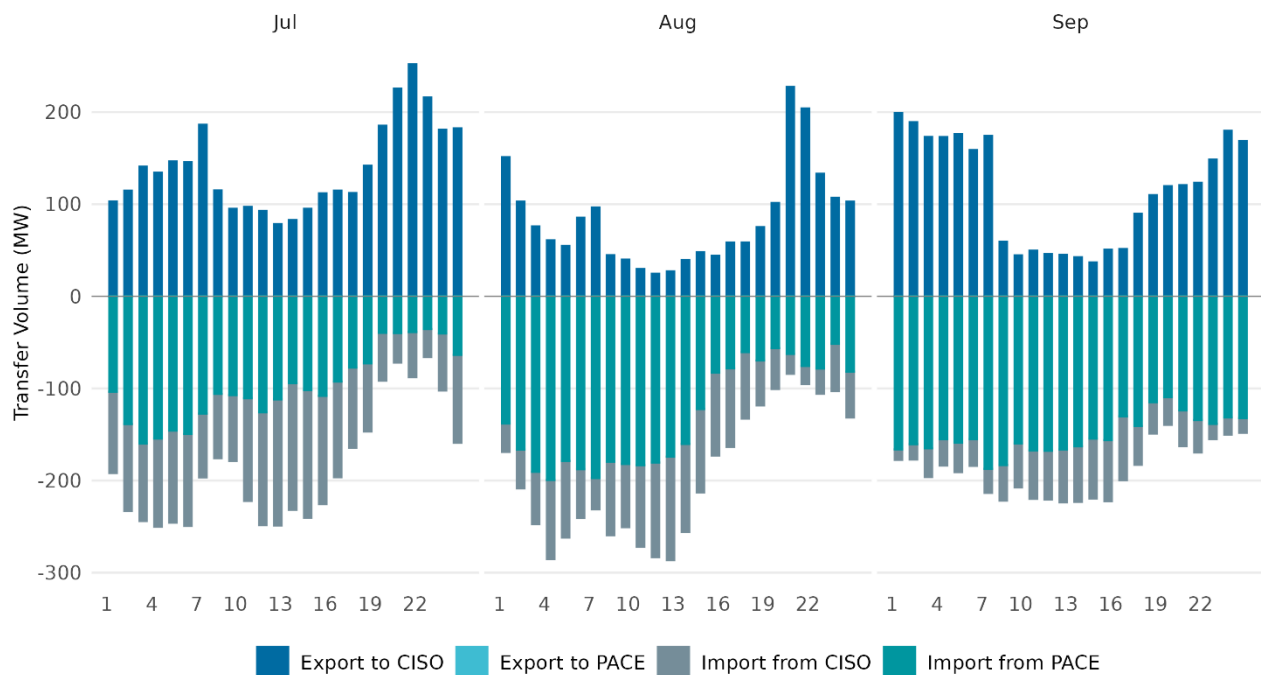
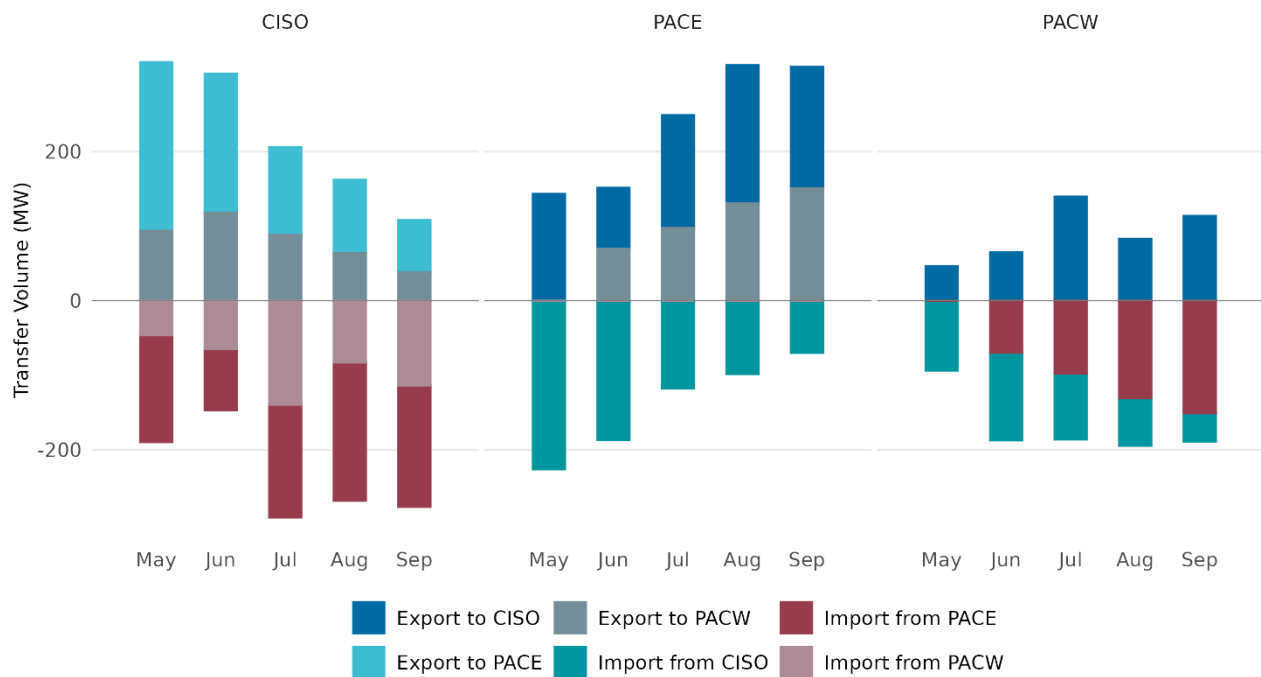


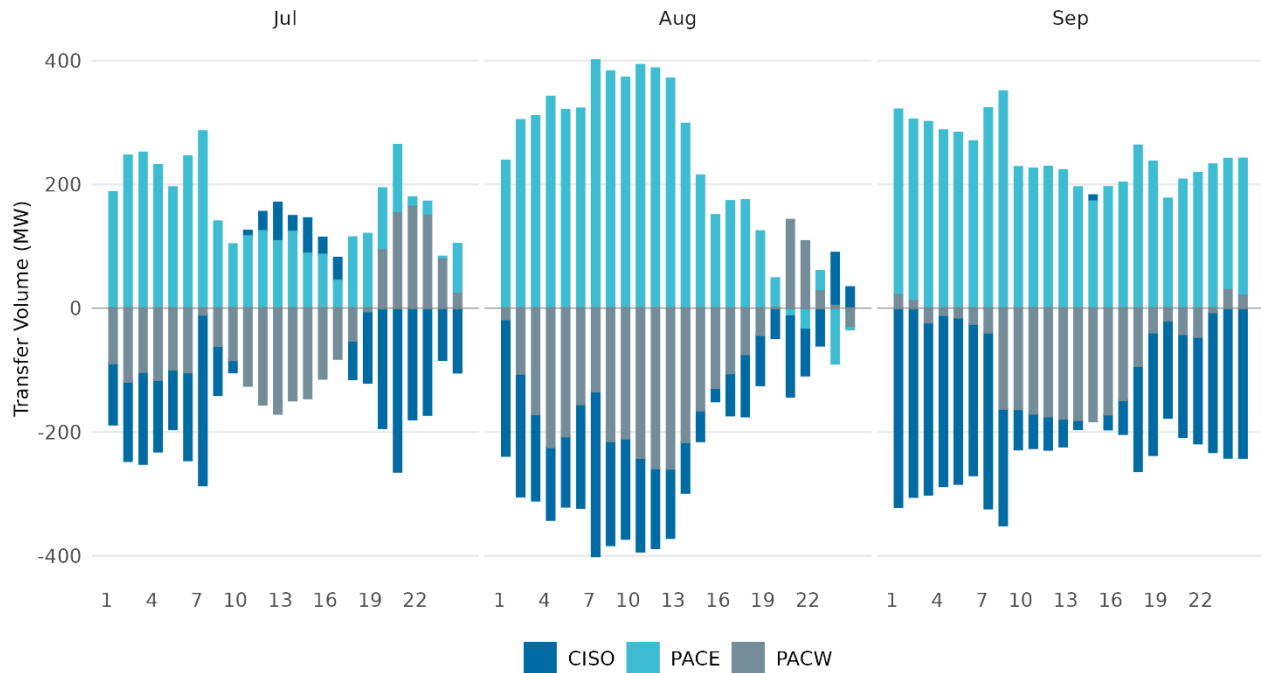
Figure 114 shows the summary of three BAAs' total energy transfer volumes throughout May to September in both export (+) and import (-) directions. For CAISO, the total export volumes show consistent downward trend over the past five months while imports increase a lot in July to September due to summer weather. In contrast, PACE's exports have been increasing, and imports have been declining over the past months. PACW's exports reached the highest level in July imports stayed stable throughout June to August. Besides, the transfer between PACW and PACE kept increasing since June.

Figure 114: Hourly average energy transfers volumes in EDAM



Hourly energy net transfer patterns varied considerably across the three BAAs throughout July to September. CISO and PACW recorded net importer in both three months, with a few exceptions during night peaks hours that PACW also exported energy to CAISO. CAISO's imports during solar hours were significantly lower than non-solar hours. PACE remained net exporter, and peak exports occur in August during daytime hours around 400 MW.

Figure 115: Hourly average net energy transfers volumes in EDAM



Imbalance reserves transfers

Imbalance reserves are a new day-ahead flexible reserve product introduced with EDAM to procure upward and downward reserve capacity for managing differences between day-ahead schedules and real-time conditions, including net load forecast uncertainty and real-time ramping needs. This section summarizes the patterns of imbalance reserves transfers among BAAs throughout July to September 2026.

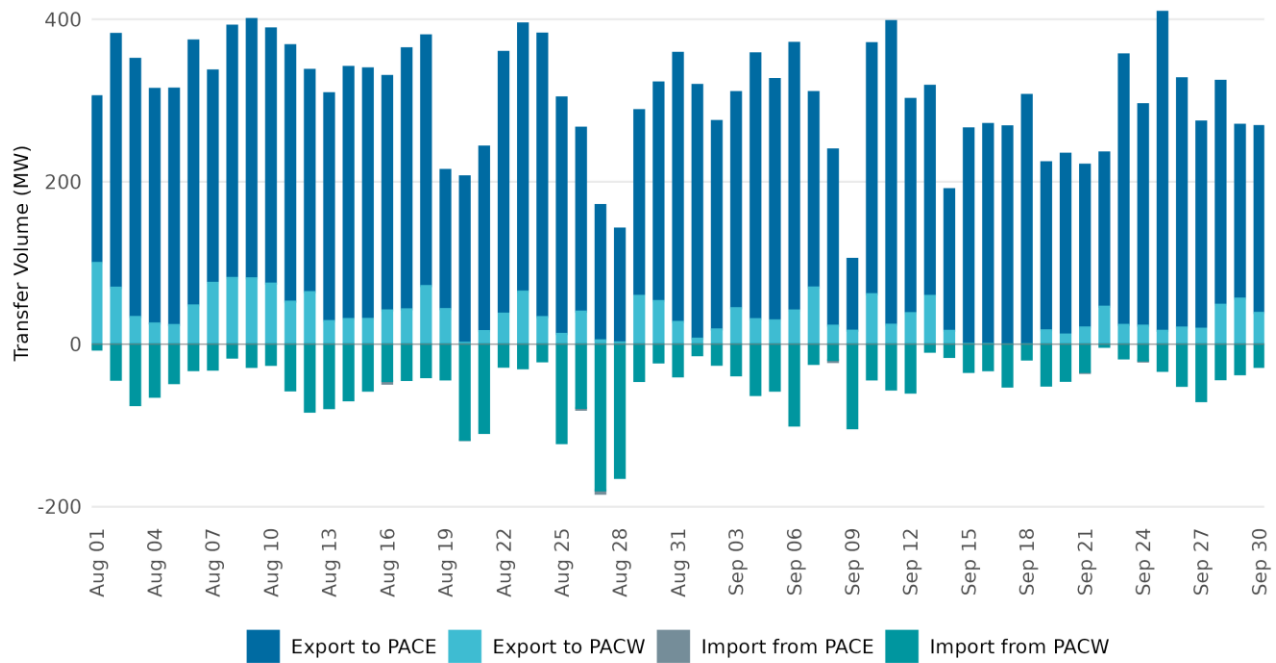
EDAM enables the transfer of imbalance reserves between balancing authority areas, allowing available reserves to be shared where they are needed most. These transfers improve the efficient use of resources while supporting reliable system operations. The following sections summarize the overall transfer activity during the month and examine the underlying patterns and market outcomes in greater detail for both up and down direction.

Imbalance reserve up

As with energy, the market can transfer imbalance reserves among BAAs, which provide revenue to exporting areas and lower costs capacity reserves to importing areas. Figure 116 and Figure 117 show CAISO's daily and hourly average IRU transfers throughout August to September on both CAISO/MD&A/MPAA

export (+) and import (-) directions. Generally, in both months CAISO exported IRU and most of the exports went to PACE, and the transfer volume stayed the same for two months, with the peak daily average IRU exports over 400 MW. Besides, there was a slight decrease in IRU exports in September.

Figure 116: Daily average IRU transfers for CAISO



The hourly profile shows that CAISO exported IRU throughout the whole day and reached peak over 400 MW. In morning peak hours, CAISO imported IRU, mainly from PACW, with the peak volume over 300 MW at HE 8.

Figure 117: Hourly average IRU transfers for CAISO

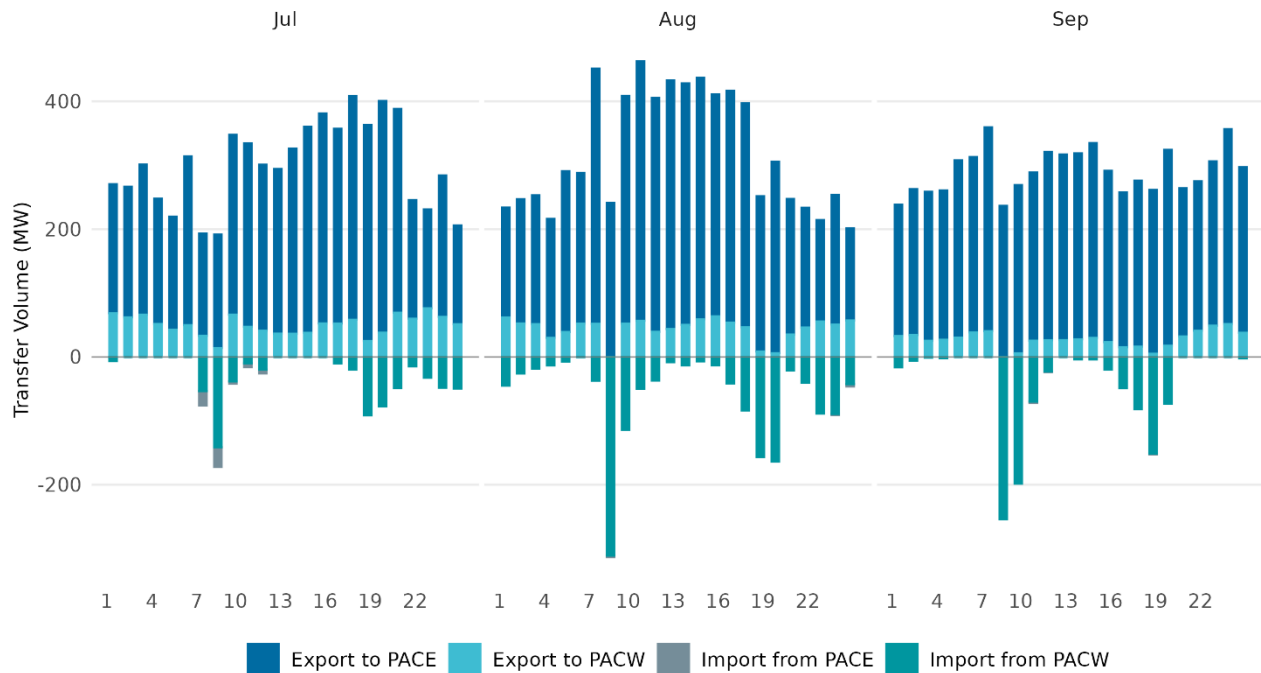


Figure 118 - Figure 119 show PACE's daily and hourly average IRU transfers throughout August to September 2026 on both export (+) and import (-) directions, respectively. Generally, PACE remained a net importer in both the months, and the imports are almost all from CAISO, with a peak import around 400 MW on September 25. There were only a few days that PACE also exported IRU to PACW.

The hourly charts showed that PACE's IRU shared the same pattern in the last three months, with peak imports over 300 MW and only limited exports throughout the whole day.

Figure 118: Daily average IRU transfers for PACE

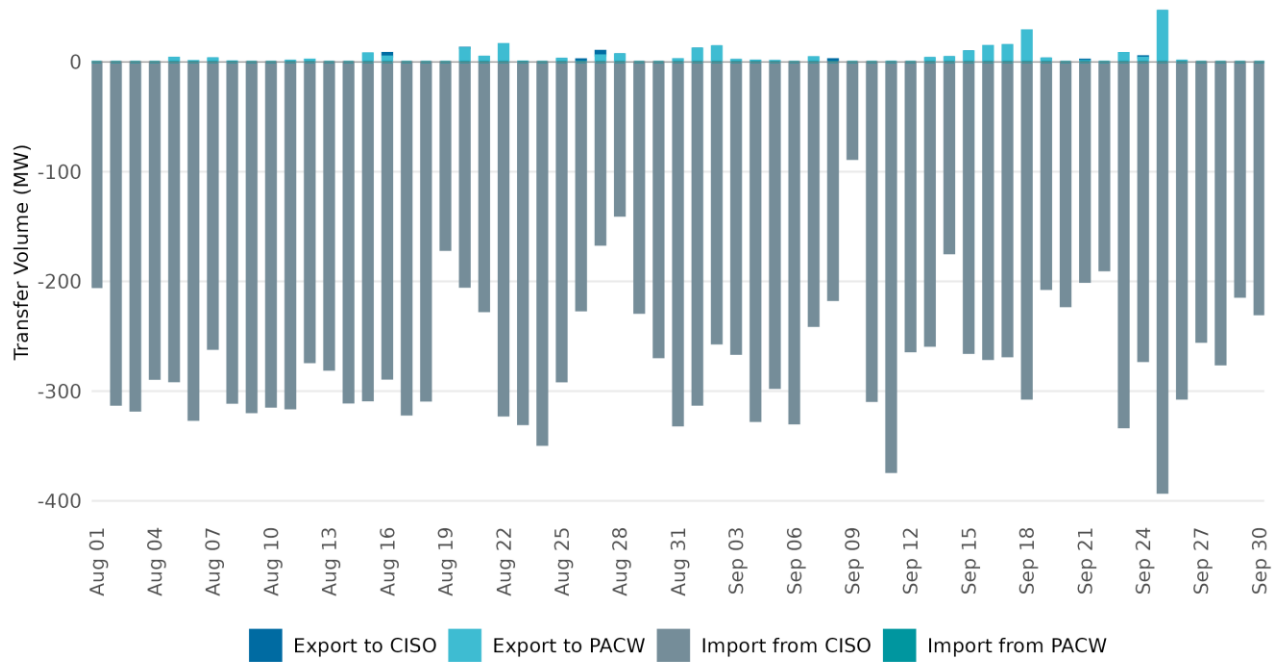


Figure 119: Hourly average IRU transfers for PACE

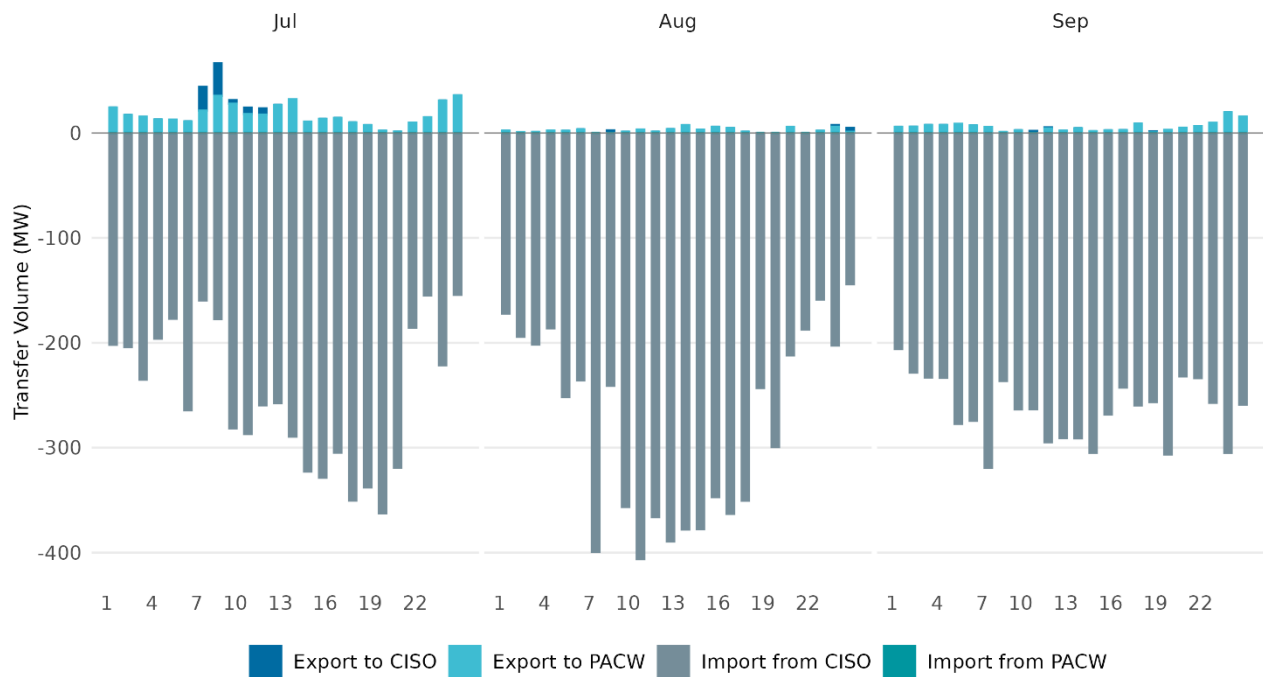


Figure 120 and

Figure 121 show PACW's daily and hourly average IRU transfers throughout August to September 2026 on both export (+) and import (-) directions, respectively. Daily average IRU transfers showed an overall increase in PACW's exports to CAISO. Export volumes were relatively higher in August, with several pronounced peaks over 180 MW, and generally decreased over the following weeks in September. Meanwhile, imports from CAISO remained persistent throughout the period but did not exhibit a clear trend. Transfers between PACW and PACE were comparatively limited. The hourly profile shows a clear increase in PACW's exports to CAISO from August to September compared with July. IRU exports were more pronounced in August and September, particularly during the morning and afternoon peak hours. The largest export volume occurred around HE 8 in August, exceeding 300 MW. In contrast, imports from CAISO remained relatively consistent throughout the three months, while transfers between PACW and PACE remained limited.

Figure 120: Daily average IRU transfers for PACW

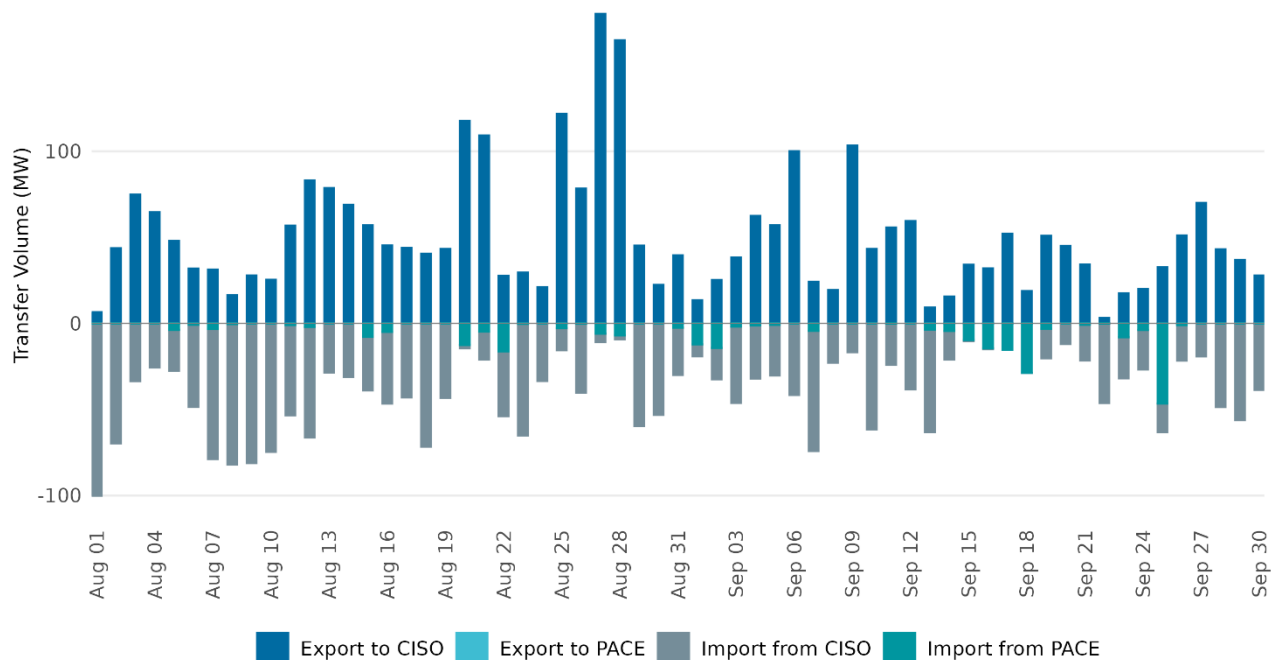


Figure 121: Hourly average IRU transfers for PACW

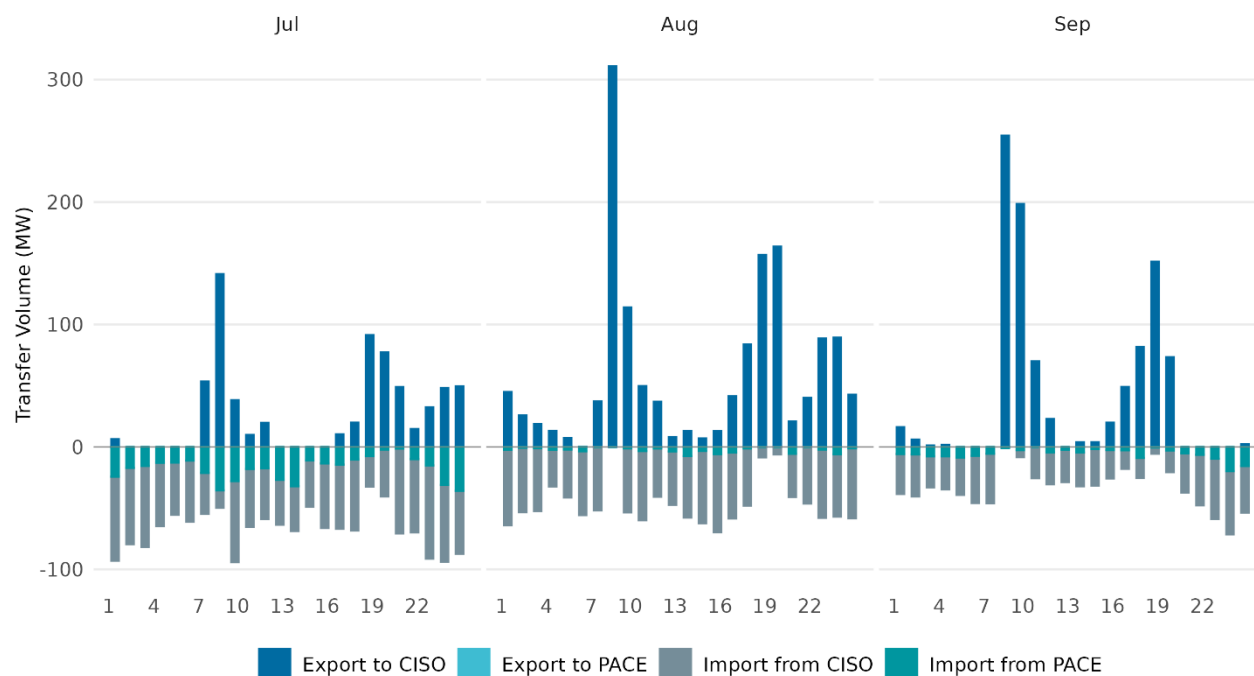
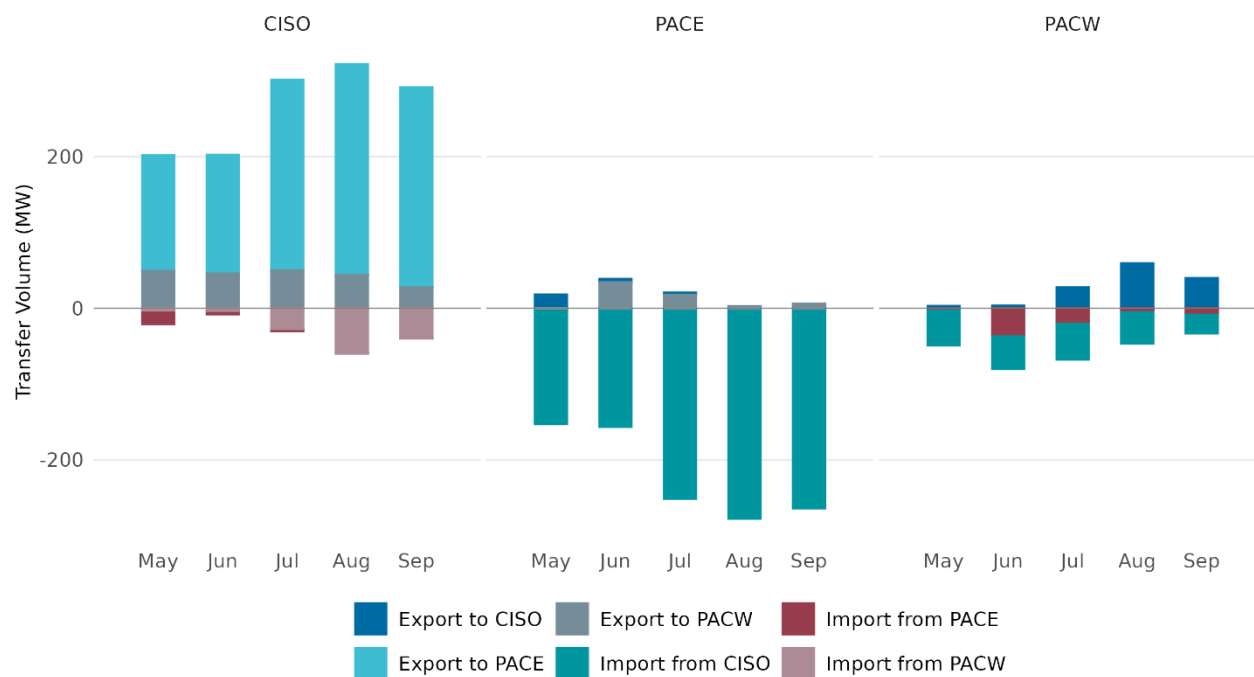


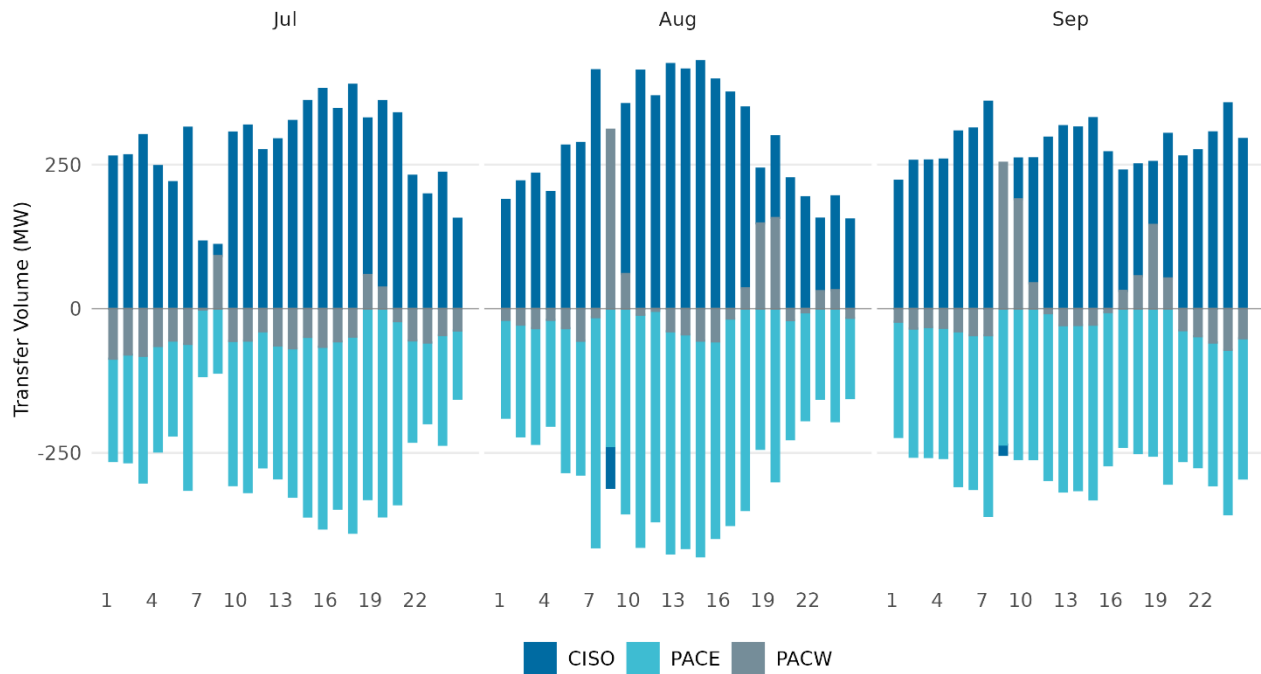
Figure 122 shows the summary of three BAAs' total IRU transfer volumes throughout May to September in both export (+) and import (-) directions. For CAISO, the total transfer volumes are almost the same in May and June, then with a noticeable increase in exports to PACE since July. PACE remained a net importer, and main IRU was obtained from CAISO. In August and September, PACW also increased its IRU exports to CAISO.

Figure 122: Hourly average IRU transfers volumes in EDAM



For hourly IRU net transfer patterns, CISO recorded net exports in all months and PACE and PACW remained net importers. In September, IRU transfers decreased as compared to August when it reached largest magnitudes during daytime hours. The only exception is morning peak HE 8 and 9 when PACW exported more IRU to CAISO and PACE.

Figure 123: Hourly average net IRU transfers volumes in EDAM



Imbalance reserve down

For IRD products, as Figure 124 and Figure 125 show, CAISO's daily average IRD transfers fluctuated significantly throughout August to September, with exports generally outweighing imports first in August then switched to net importer in September. Export volumes were primarily driven by transfers to PACE, with notable peak reaching 300 MW in early August. Beginning on August 6, overall IRD exports volumes declined only with few exports to PACE. Since the end of August, imports from PACE increased noticeably and exceeded exports on several days, resulting in a shift toward net imports.

The hourly chart in Figure 125 shows that hourly average IRD exports declined significantly from July to September. Exports peaked at above 200 MW during the afternoon in July and around 150 MW during the late evening in August. In September, exports remained relatively low, while imports from PACE increased substantially, particularly during the morning and evening hours.

Figure 124: Daily average IRD transfers for CAISO

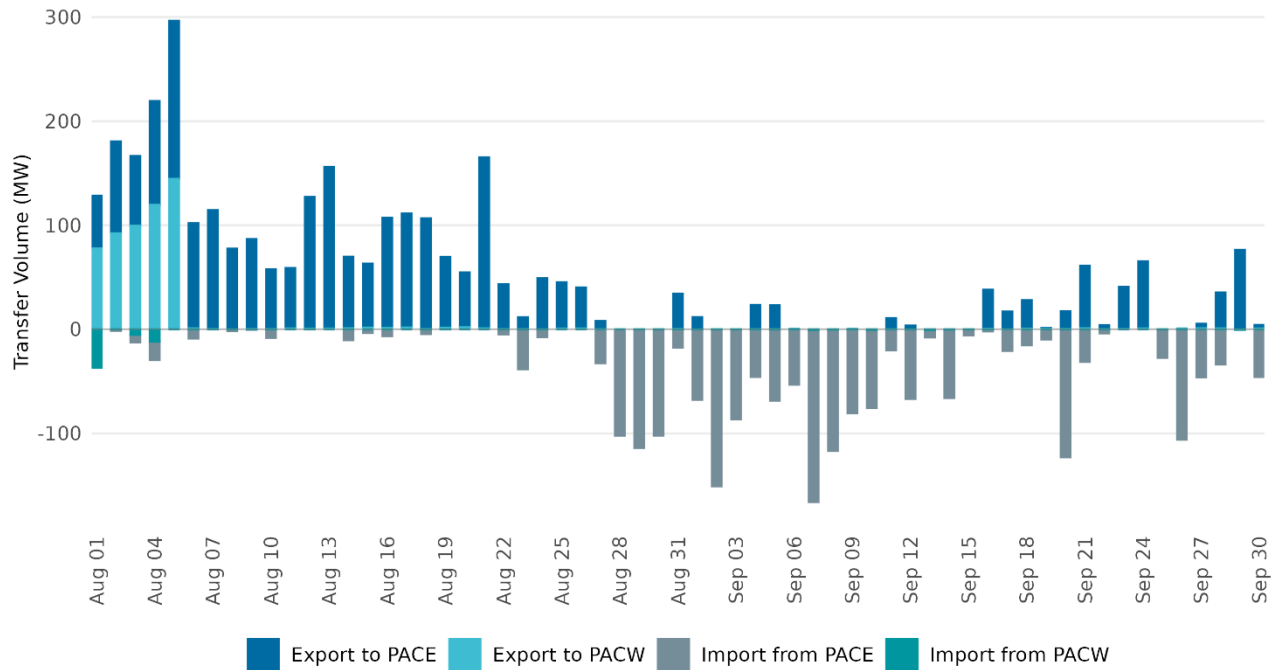
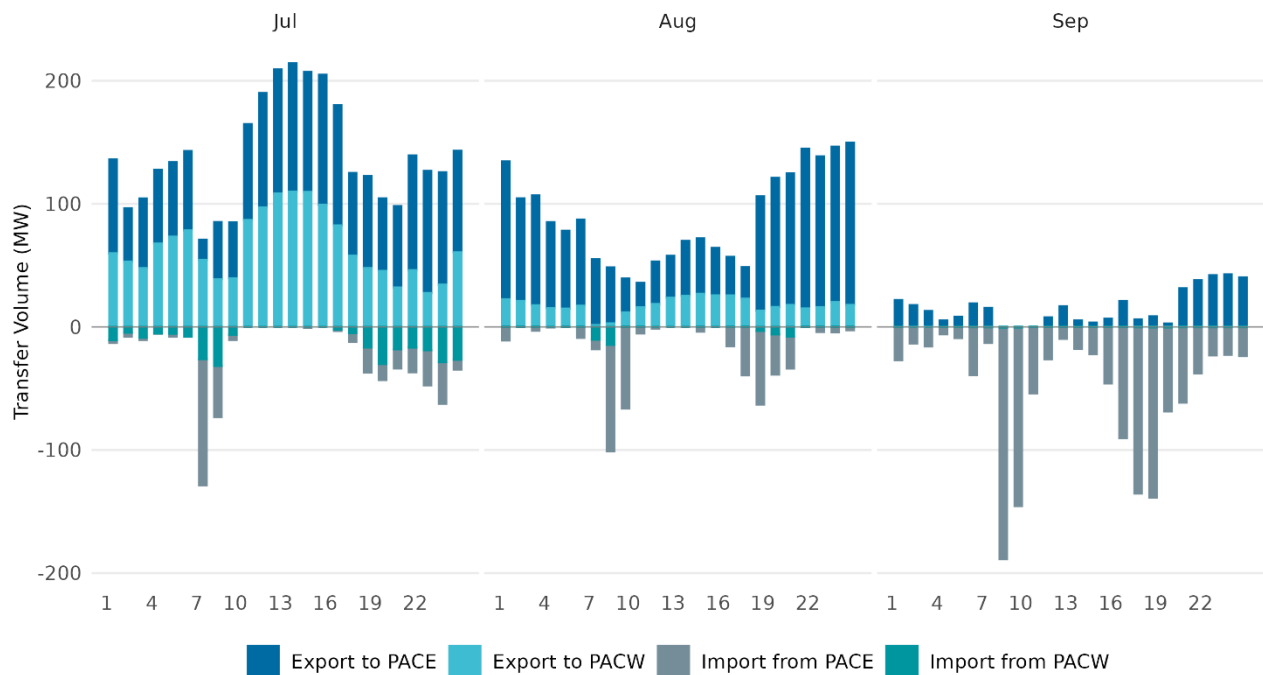
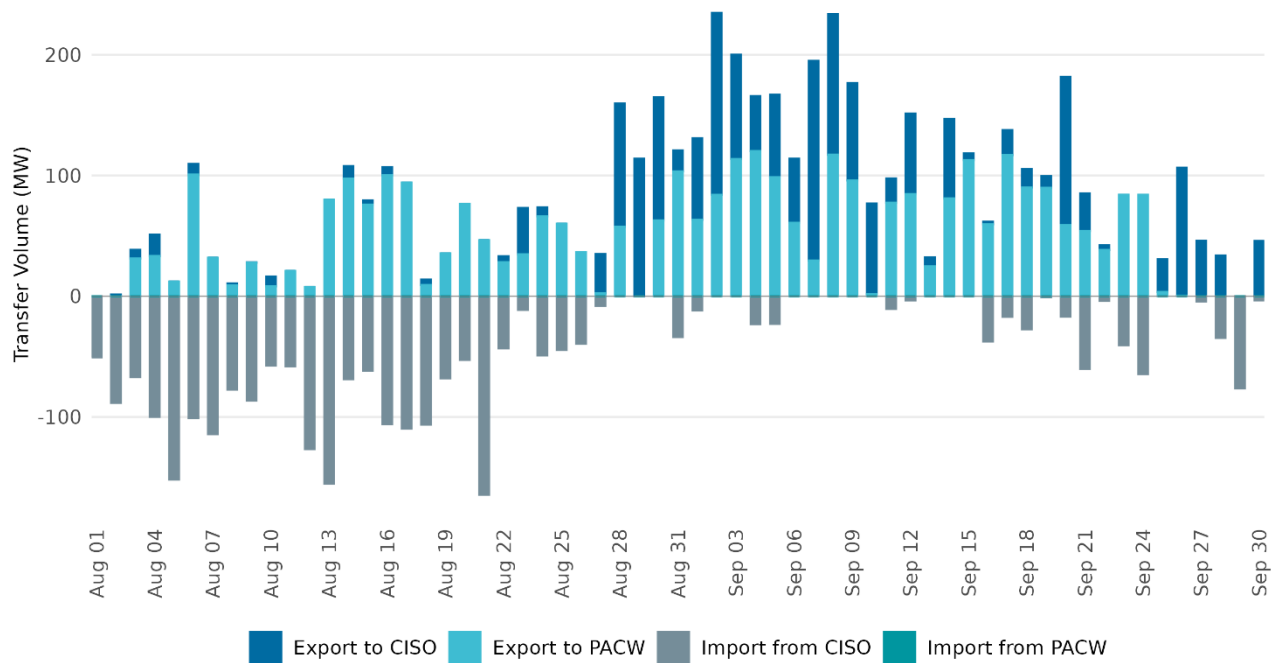


Figure 125: Hourly average IRD transfers for CAISO



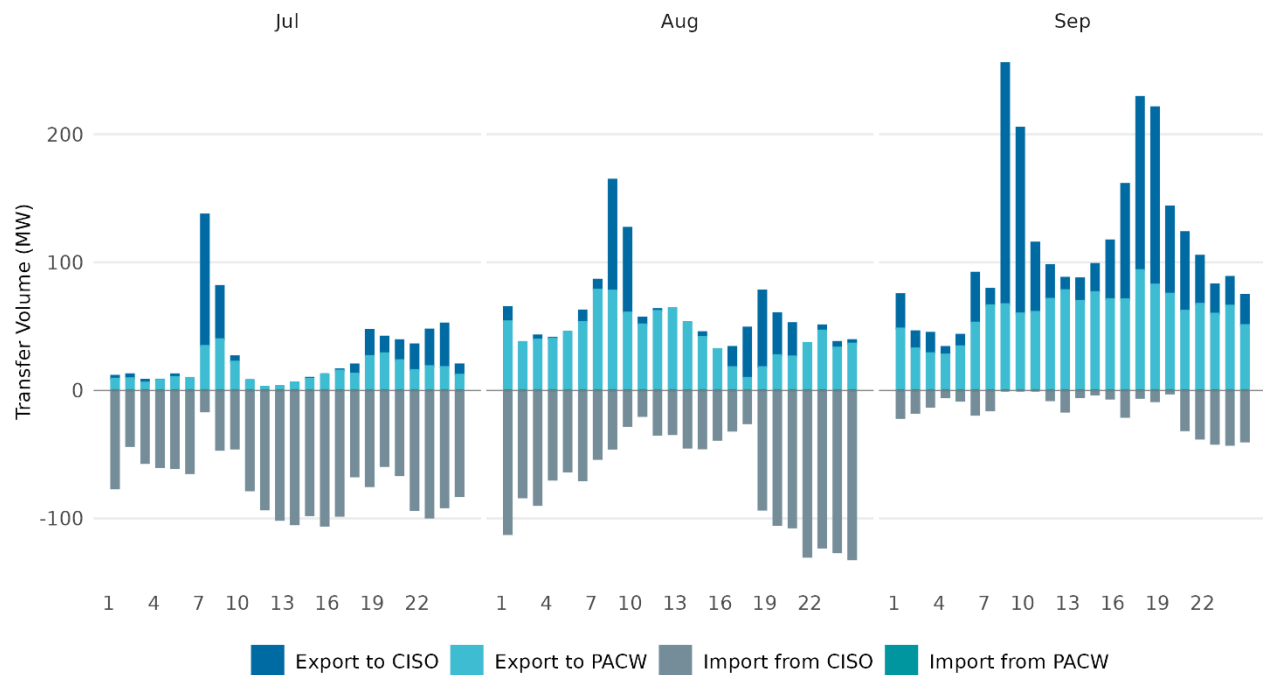
PACE's IRD transfer showed a more dynamic pattern throughout August to September. As Figure 126 shows, during most of the days in August PACE remained a net exporter of IRD from CAISO but then switched to net exporter since the end of August.

Figure 126: Daily average IRD transfers for PACE



The hourly profile Figure 127 showed that hourly average IRD exports from PACE increased from July to September, with exports to CISO peaking above 250 MW in September. Exports to PACW also increased over the three months. Meanwhile, imports from CISO were substantial in July and August, particularly during the afternoon in July and late evening in August but declined significantly in September.

Figure 127: Hourly average IRD transfers for PACE



For PACW's IRD transfers, as Figure 128 and Figure 129 shows, PACW remained a net importer throughout August and September. While imports were primarily from CISO at the beginning of August, they shifted toward PACE in August as imports from CISO declined substantially. Export activity remained relatively limited in both August and September.

Figure 128: Daily average IRD transfers for PACW

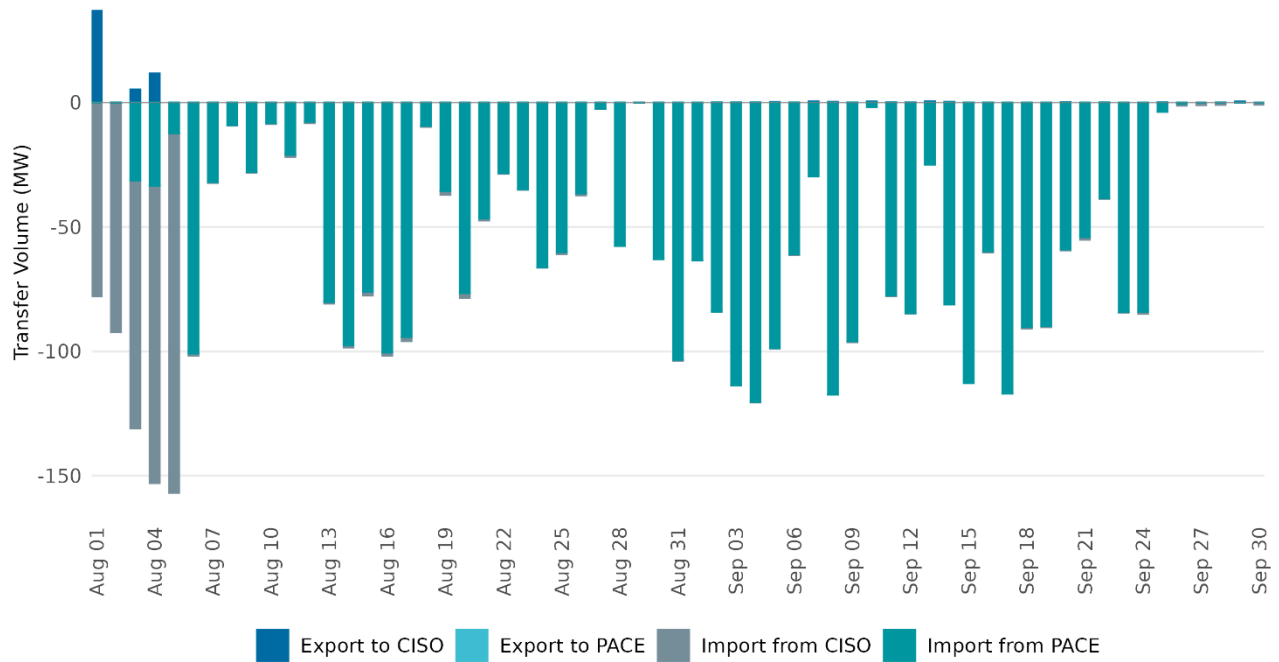


Figure 129: Hourly average IRD transfers for PACW

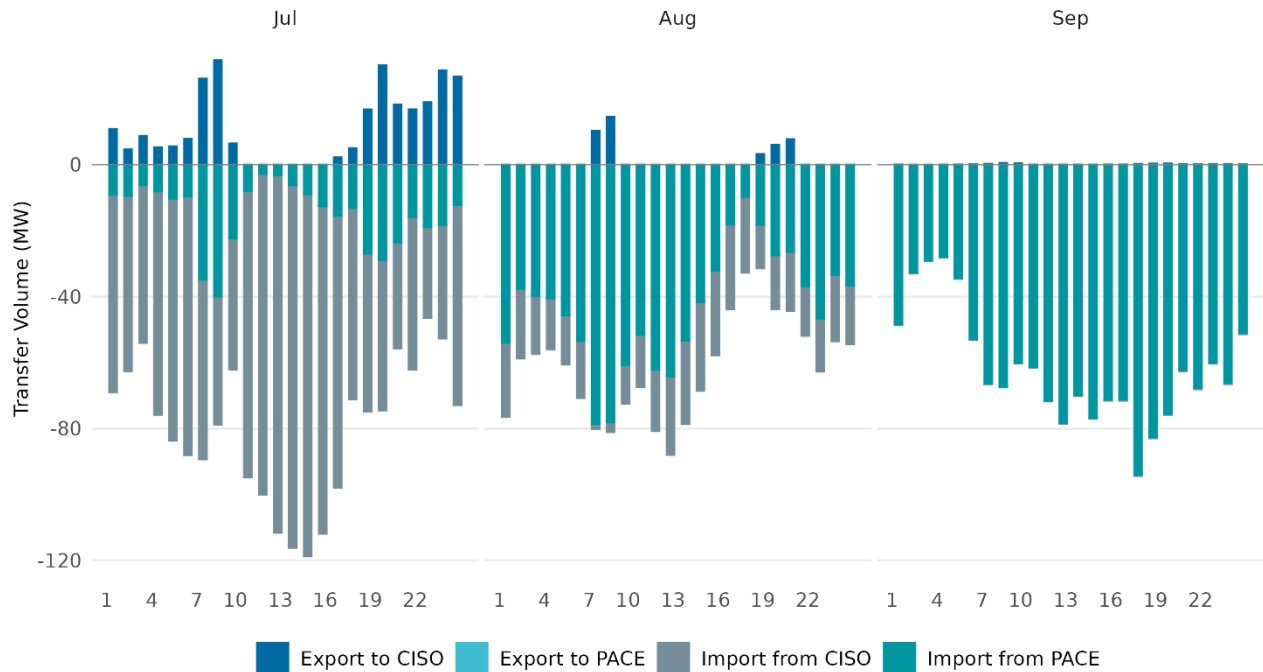


Figure 130 shows the total IRD transfer volumes varied considerably across the three BAAs from May through September. CAISO experienced increasing IRD exports transfer activity from May through July, reaching its highest level in July, followed by a decline in August and September, and its IRD imports kept decreasing throughout the first four months but increased again in September. PACE IRD exports declined from May through July before rebounding in August and September, driven largely by increased exports to PACW. PACW remained predominantly a net importer, with imports shifting from CISO toward PACE in August and September.

Figure 130: Hourly average IRD transfers volumes in EDAM

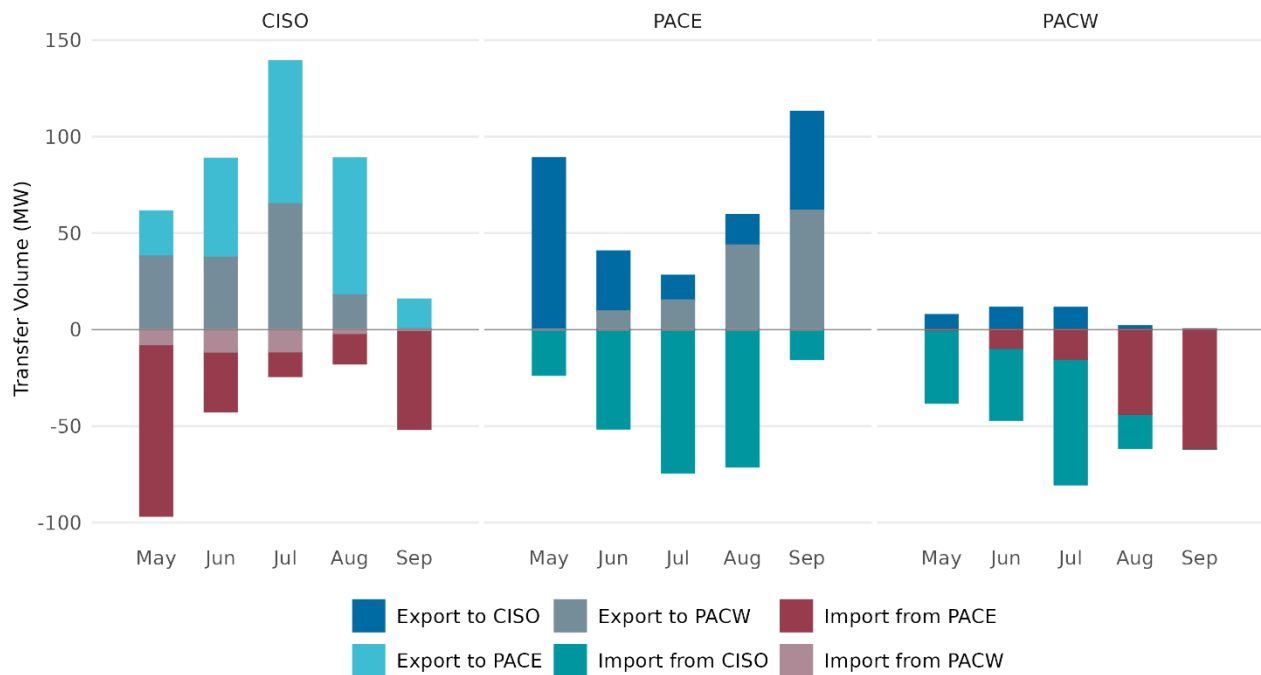
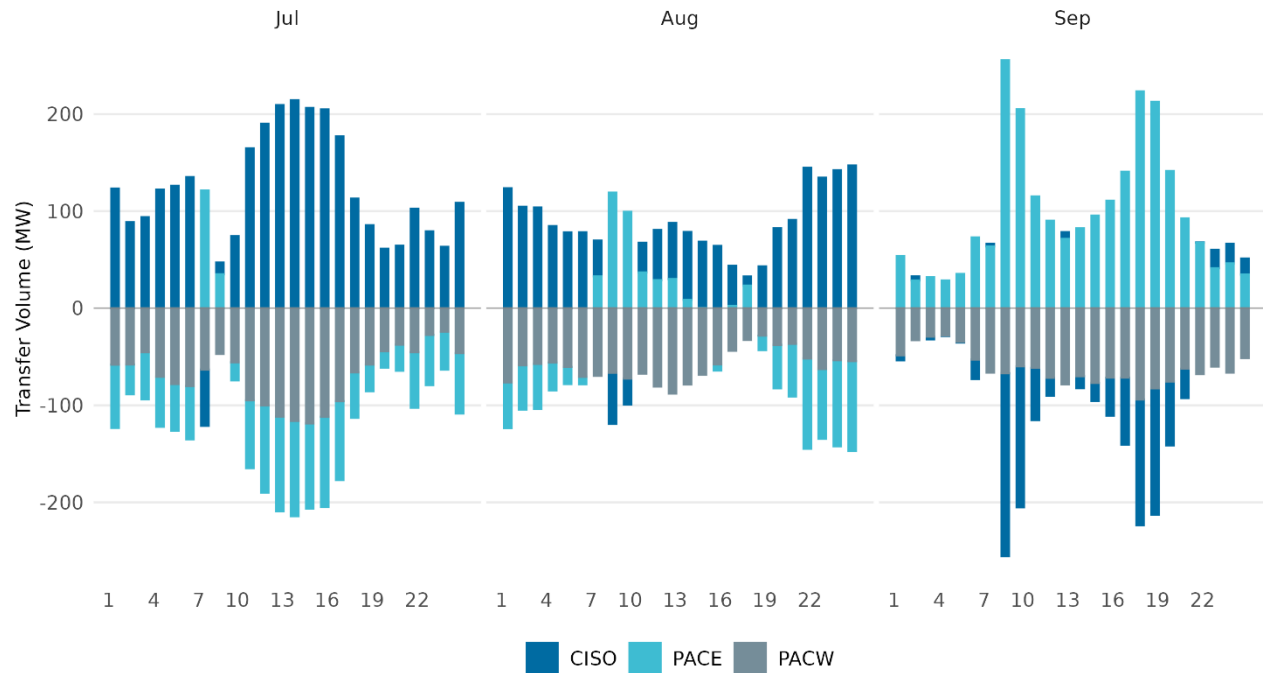


Figure 131 shows that net IRD transfers in July and August were predominantly exports from CISO and imports to PACE and PACW. CISO exports peaked above 200 MW in July, while PACE imports reached similar levels. In September, the transfer patterns reversed, with PACE becoming the dominant exporter and CISO experiencing substantial imports, particularly during the morning and evening hours.

Figure 131: Hourly average net IRD transfers volumes in EDAM



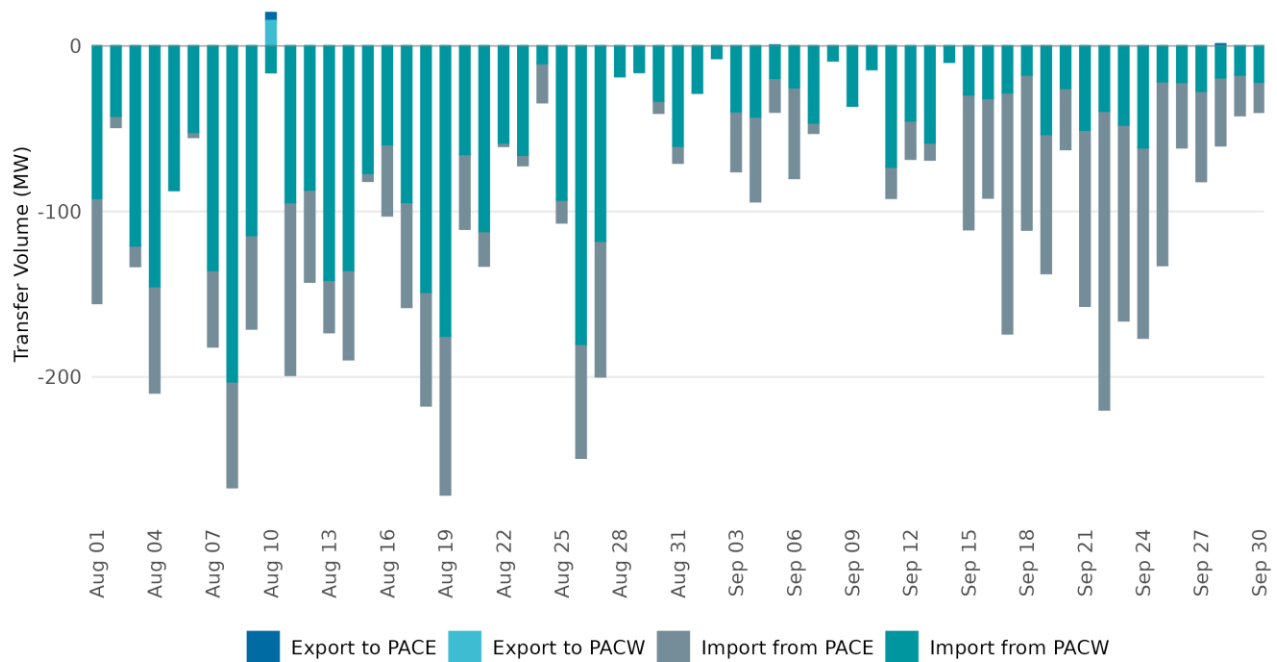
Reliability capacity transfers

Reliability capacity is a new day-ahead product introduced with EDAM to procure upward and downward capacity needed to balance differences between cleared day-ahead physical supply and the load forecast. Reliability capacity ensures sufficient capacity is available to address both supply shortfalls and oversupply. This section summarizes the patterns of reliability capacity transfers among BAAs.

Reliability capacity up

Figure 132 and Figure 133 show CAISO's daily and hourly average RCU transfers on both export (+) and import (-) directions. Generally, RCU transfers for CAISO were predominantly imports from PACE and PACW throughout August and September, with minimal exports. Import volumes were generally higher and more volatile in August, occasionally exceeding 250 MW, while September experienced relatively lower import volumes, except for a noticeable increase during the second half of the month.

Figure 132: Daily average RCU transfers for CAISO



Similarly, Figure 133 shows that hourly average RCU transfers for CAISO were predominantly imports from PACE and PACW across all three months. Import volumes were relatively stable in July but increased substantially in August, particularly during the afternoon hours, reaching over 200 MW. In September, imports remained significant during the afternoon but were generally lower than in August.

Figure 133: Hourly average RCU transfers for CAISO

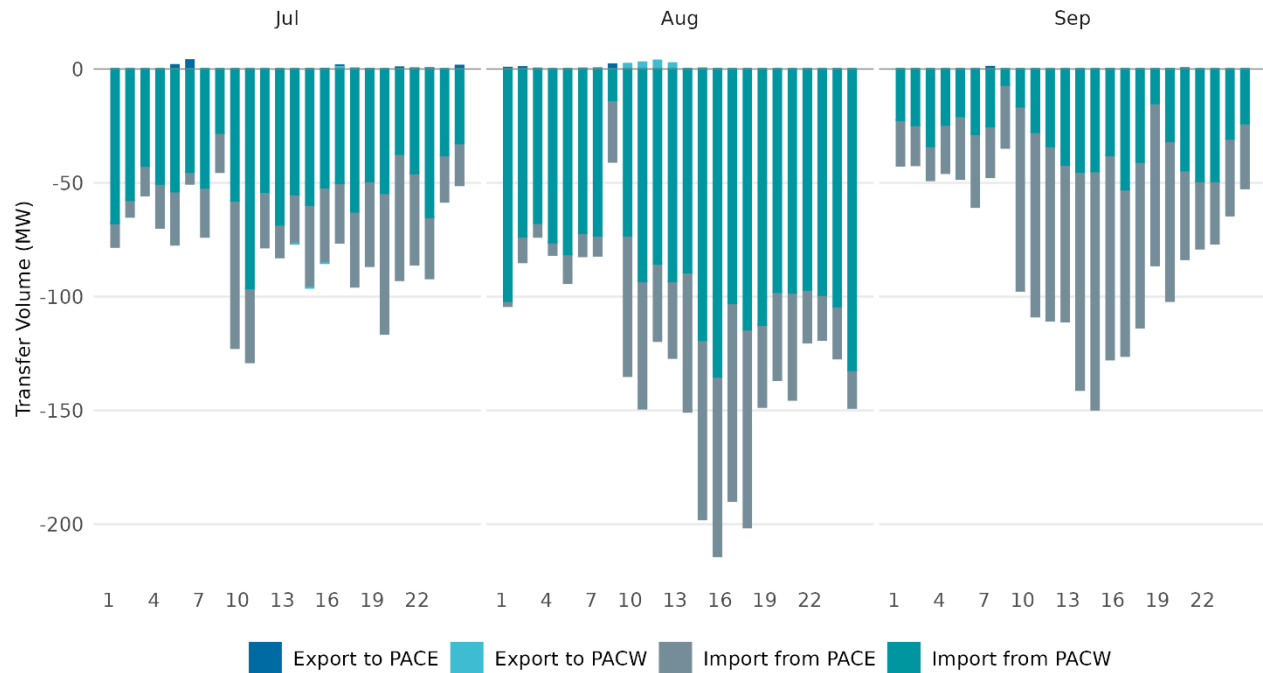
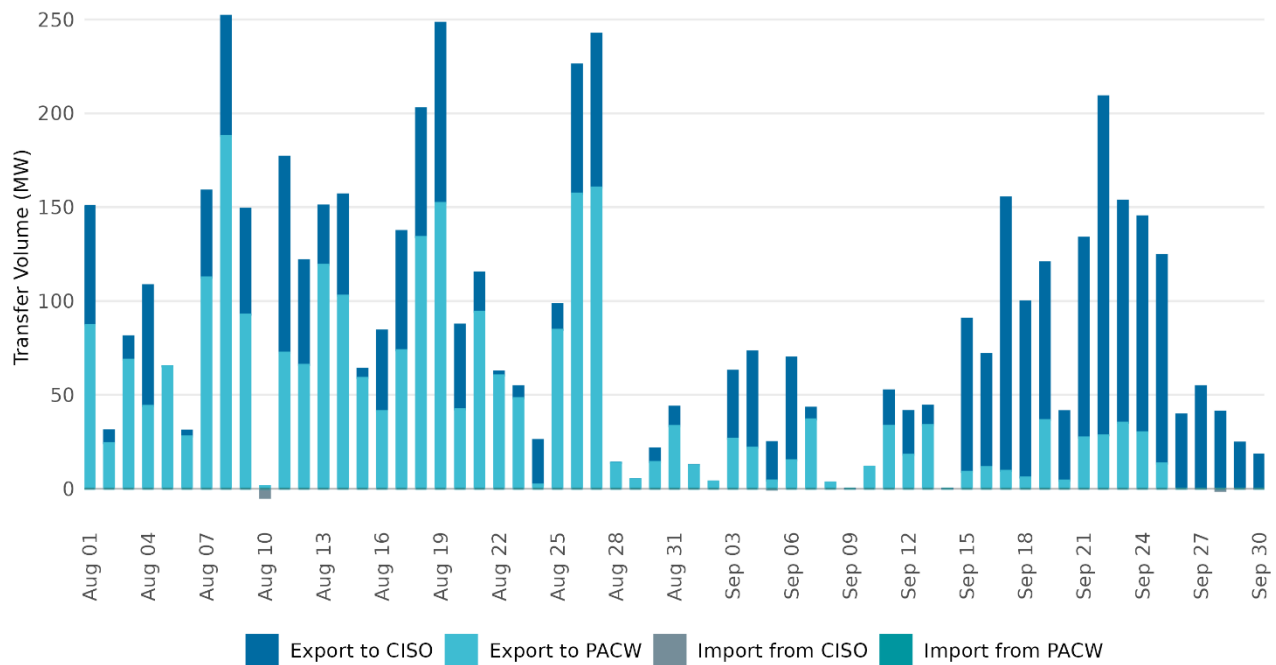


Figure 134 shows that daily average RCU transfers for PACE were predominantly exports to CISO and PACW throughout August and September, with minimal imports. Export volumes were generally higher and more volatile in August, frequently exceeding 150 MW and peaking around 250 MW. In September, exports declined significantly during the first half of the month before increasing again in the second half, particularly to CISO.

Figure 134: Daily average RCU transfers for PACE



As shown in Figure 135, export dominated the hourly average RCU transfer volumes for PACE in the past three months. Hourly average RCU transfer in August reached peaked at approximately 190 MW around HE16. The higher August volumes were primarily driven by increased exports to PACW and CISO, while imports remained limited throughout the three-month period. In September, there were more RCU exports to CAISO, although the total volume of RCU transfers was lower than August.

Figure 135: Hourly average RCU transfers for PACE

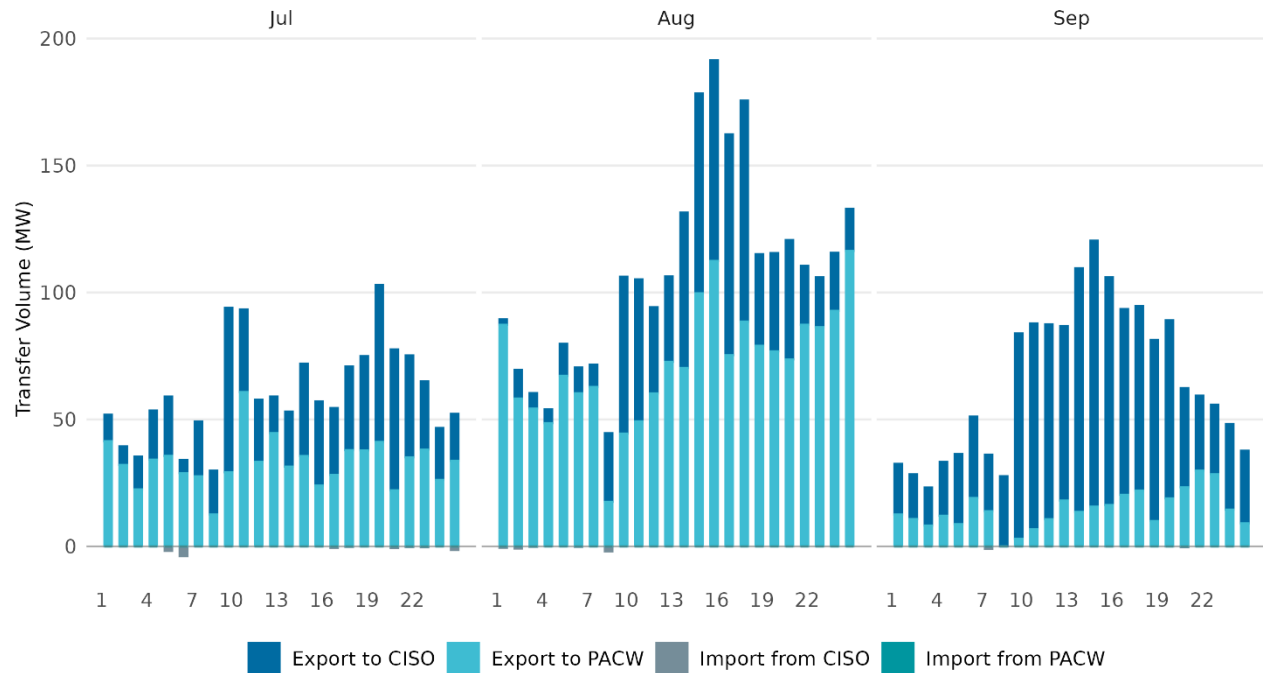


Figure 136 to Figure 137 show that RCU transfers for PACW were predominantly exports to CISO and imports from PACE, exhibiting largely mirrored patterns. Daily transfer volumes were generally higher and more volatile in August, with exports to CISO occasionally exceeding 150 MW, before declining significantly in September. Hourly patterns indicate that both exports to CISO and imports from PACE were highest during the afternoon and evening hours in August, while transfer volumes remained relatively low throughout September.

Figure 136: Daily average RCU transfers for PACW

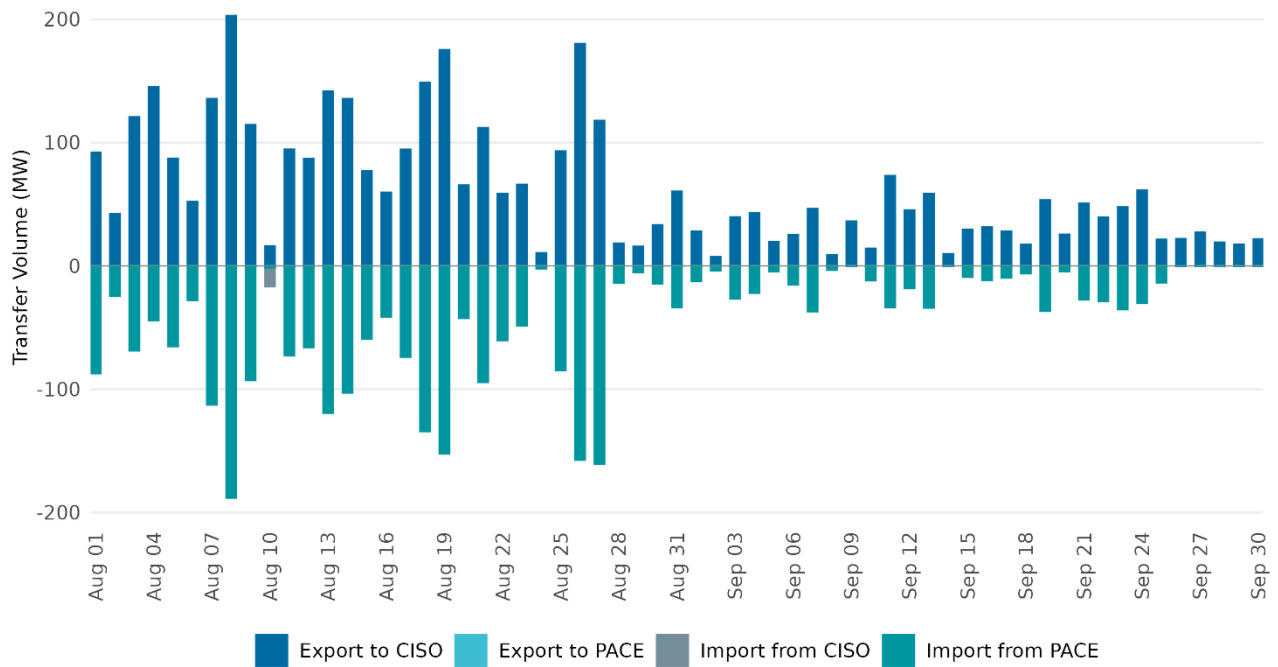


Figure 137: Hourly average RCU transfers for PACW

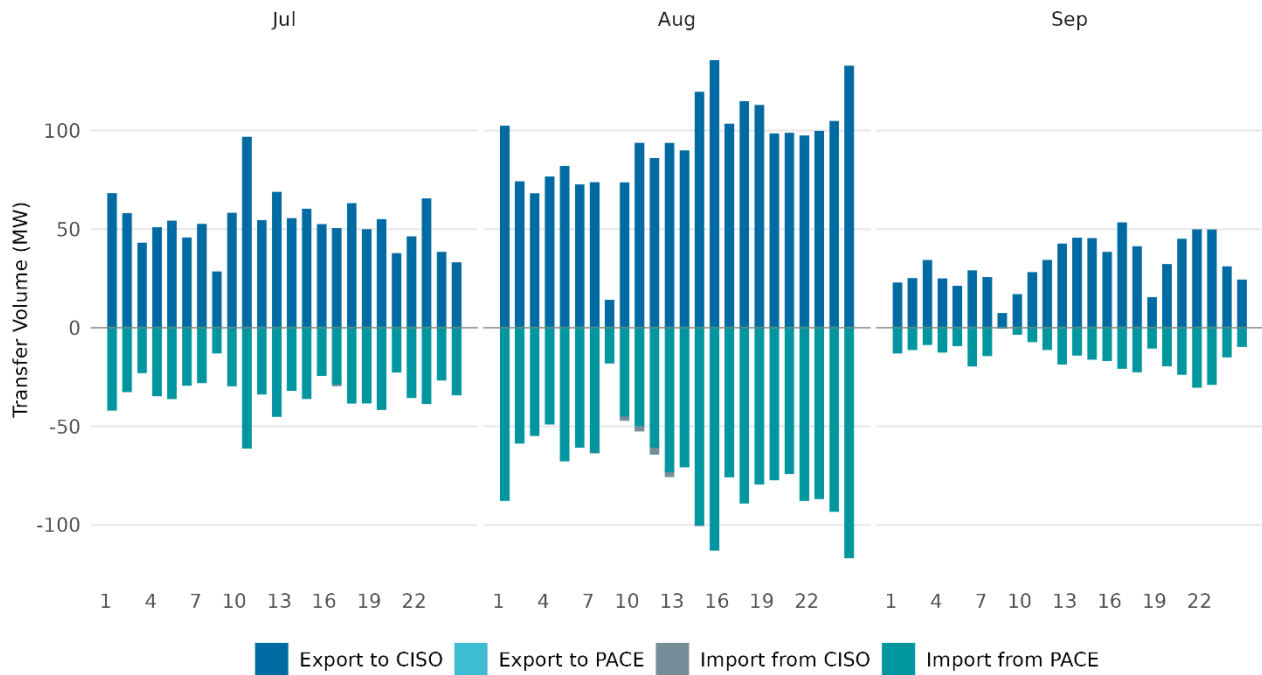


Figure 138 shows the summary of three BAAs' total RCU transfer volumes throughout May to September in both export (+) and import (-) directions. Total RCU transfer volumes increased substantially from May through August across the three BAAs, reaching their highest levels in August, then decreased a bit in September. The increase was primarily associated with higher transfers from PACE and PACW to CISO, accompanied by increased transfers between PACE and PACW. The results show a noticeable increase in overall RCU transfer activity due to summer conditions.

Figure 138: Hourly average RCU transfers volumes in EDAM

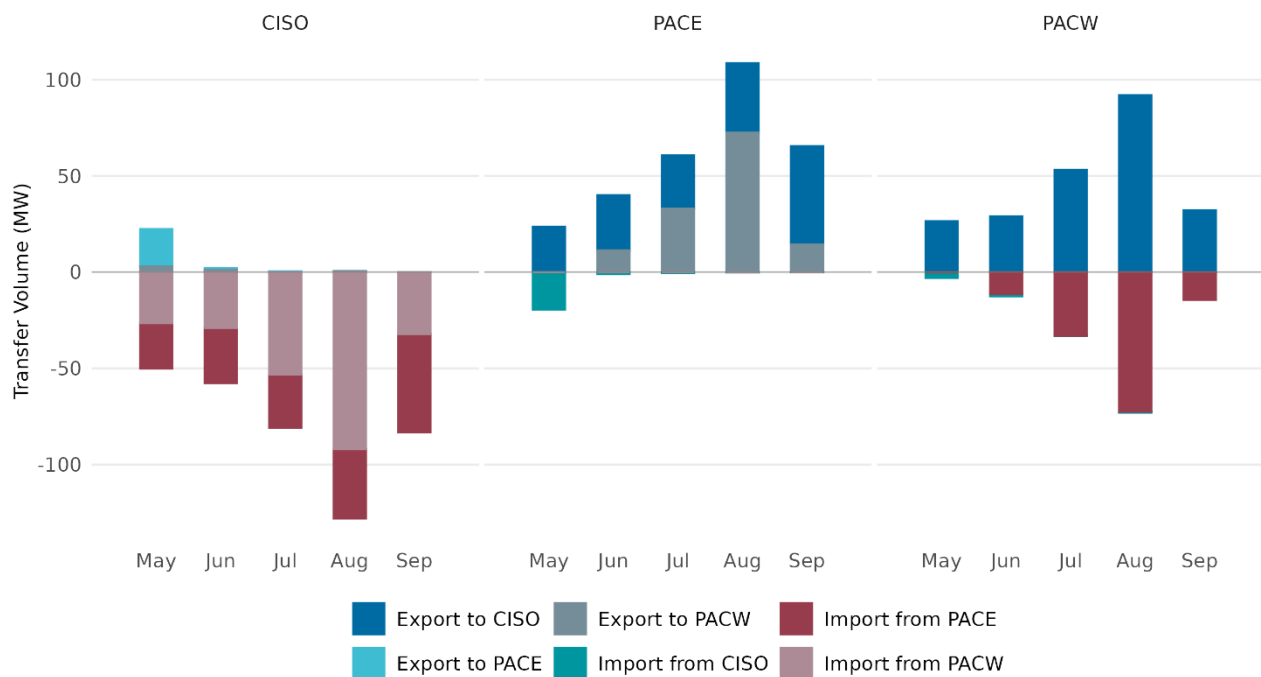
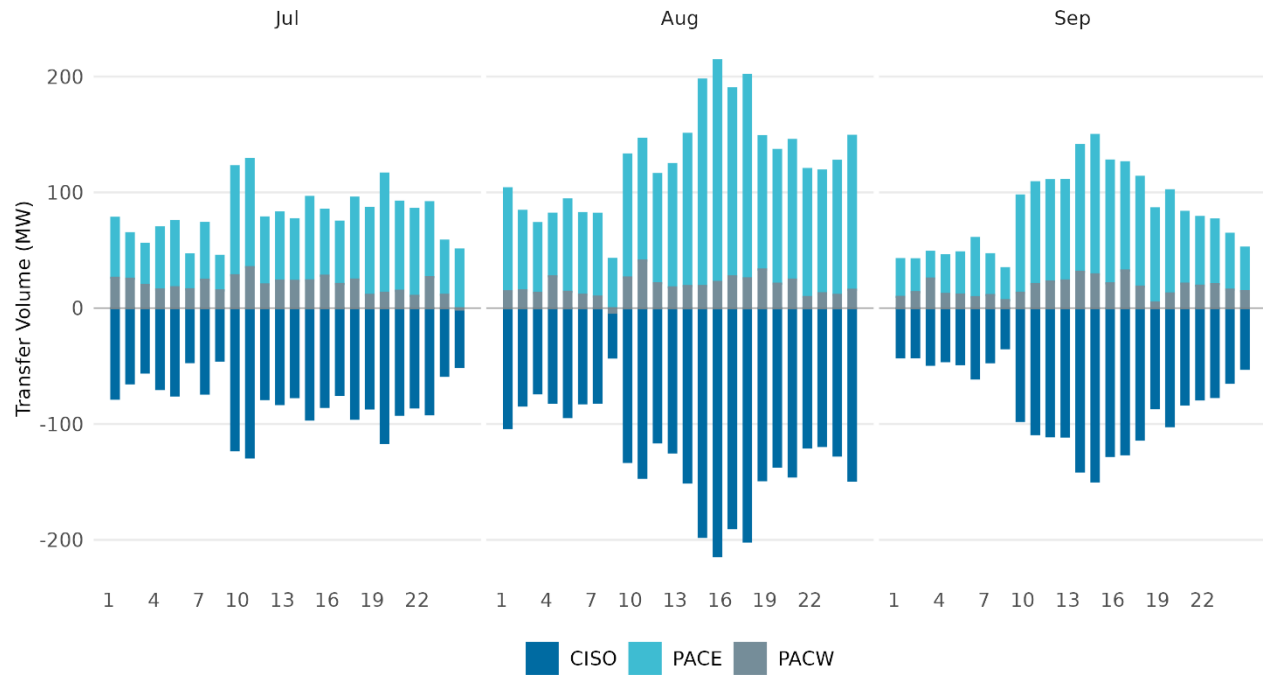


Figure 139 shows increasingly pronounced patterns from July to September. CISO generally recorded imports, while PACE and PACW showed net exports, with both reaching their largest magnitudes during afternoon hours in August. PACW's net transfers remained relatively small and stable throughout the three months.

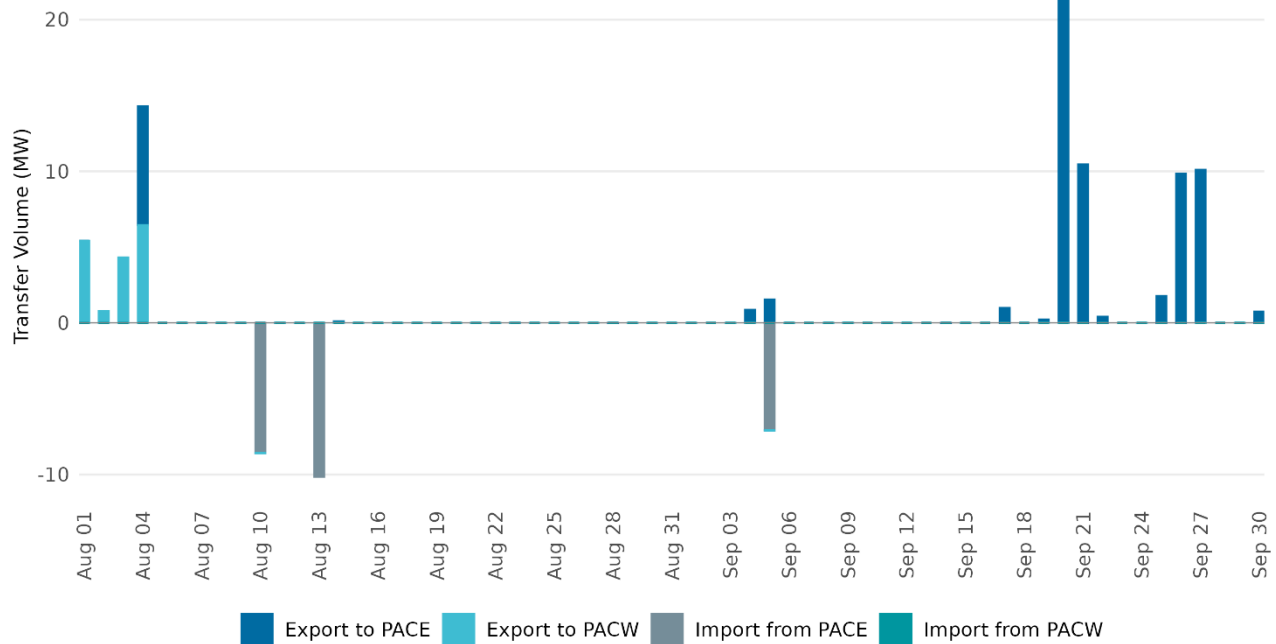
Figure 139: Hourly average net RCU transfers volumes in EDAM



Reliability capacity down

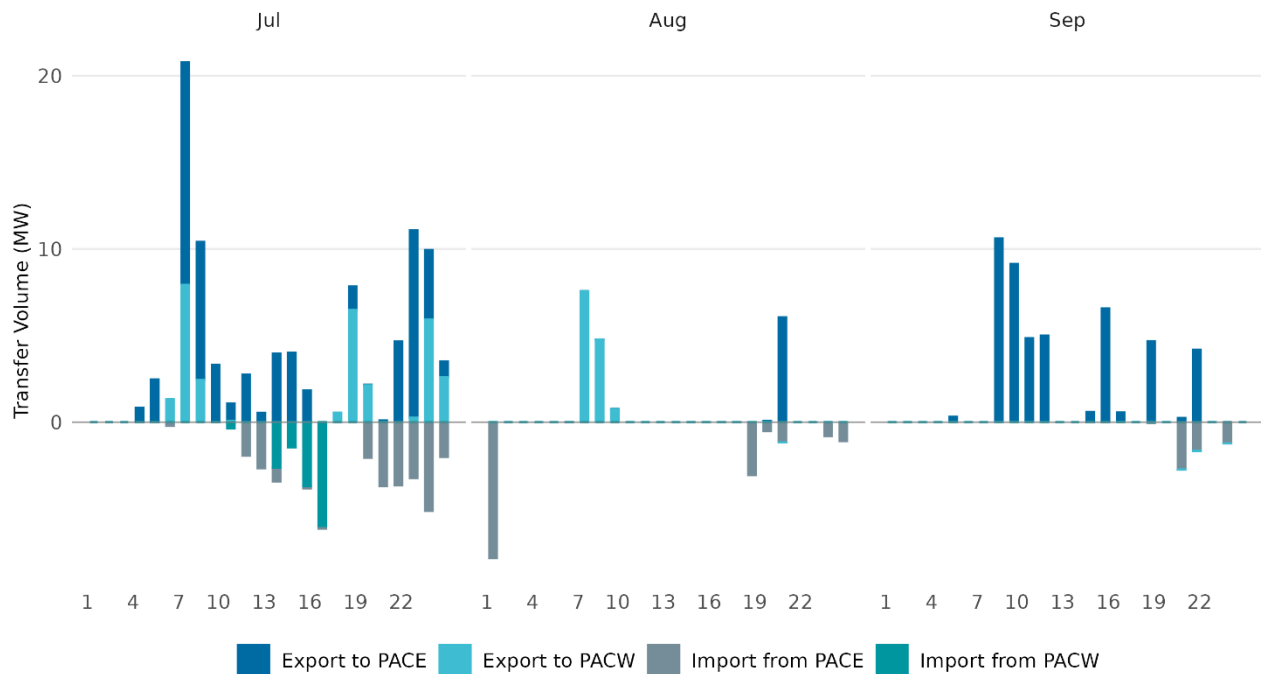
Figure 140 shows that daily average RCD transfers for CAISO were minimal throughout August and September, with most days experiencing little to no activity. Notable exports to PACE occurred in late September, peaking above 20 MW, while imports from PACE were limited to a few isolated days.

Figure 140: Daily average RCD transfers for CAISO



The hourly average RCD transfers for CAISO were generally low across all three months. July experienced the highest transfer volumes, with exports to PACE peaking above 20 MW during the morning hours. In August, transfers were minimal except for a few isolated hours, while September saw modest exports to PACE, primarily during the morning and evening peak hours.

Figure 141: Hourly average RCD transfers for CAISO



For PACE's RCD transfers, the daily and hourly average charts show variations between August and September. In August, PACE's exports were mainly to PACW, while there was limited import from CAISO. In September, there was more import CAISO, but the overall volume was still limited.

Figure 142: Daily average RCD transfers for PACE

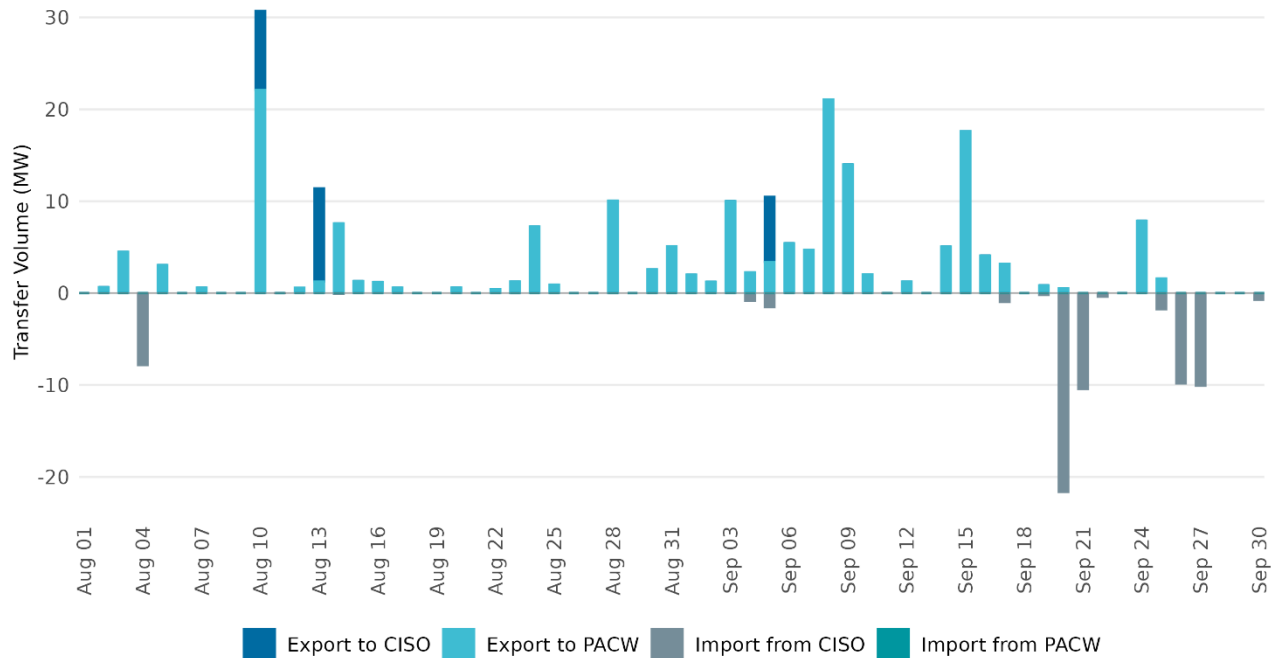
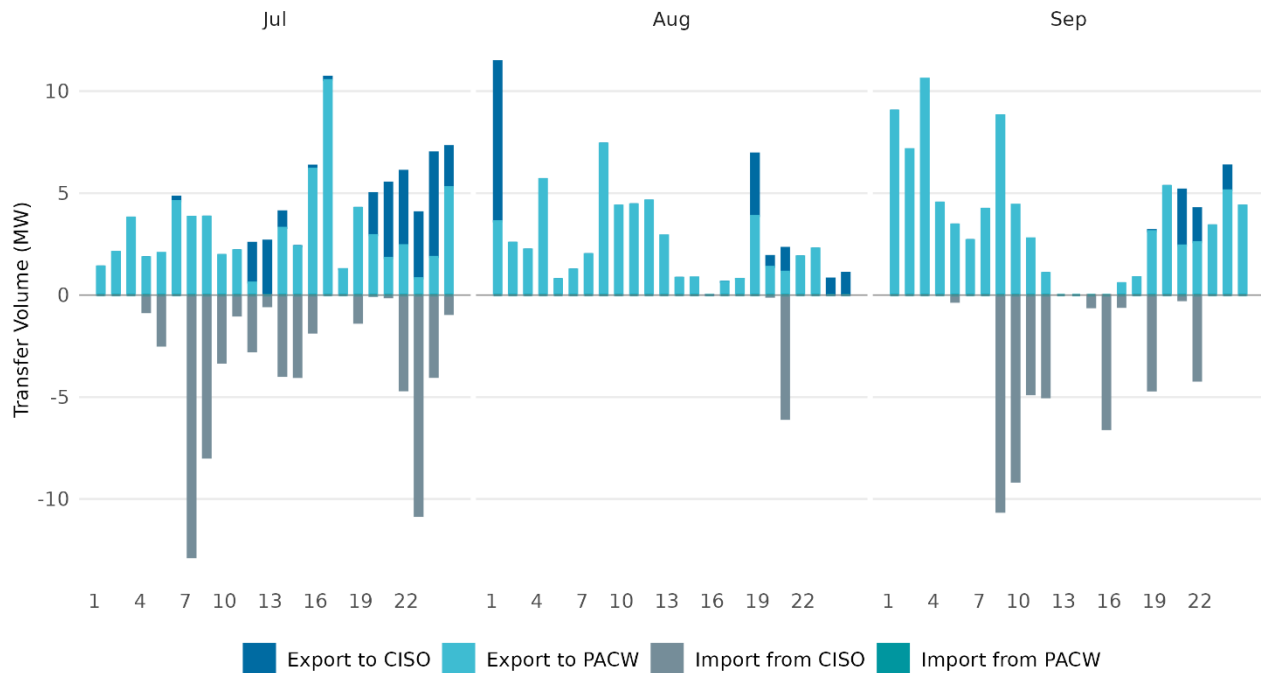


Figure 143: Hourly average RCD transfers for PACE



As for RCD transfer in PACW, the average imports were more dominantly from PACE, as a result PACW remained a net importer. The peak import was over 20MW on August 10. From the hourly average, it was observed that in July there was some exports to CAISO, however, the RCD exports to CAISO discontinued in August and September.

Figure 144: Daily average RCD transfers for PACW

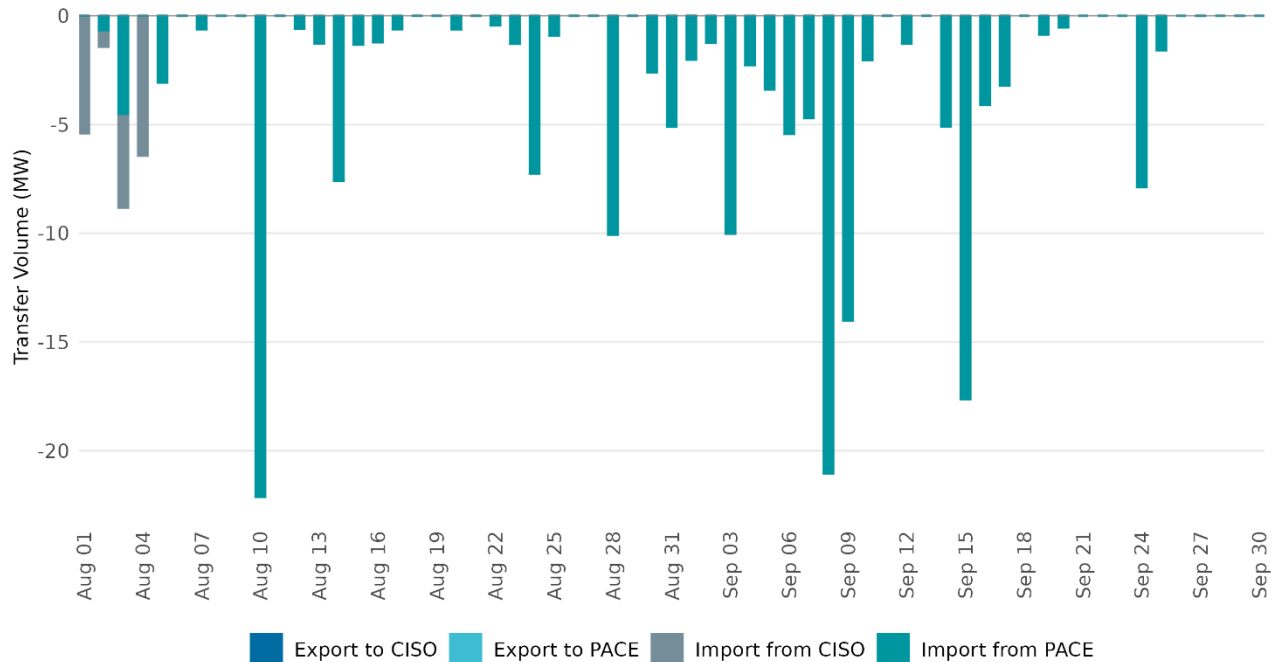


Figure 145: Hourly average RCD transfers for PACW

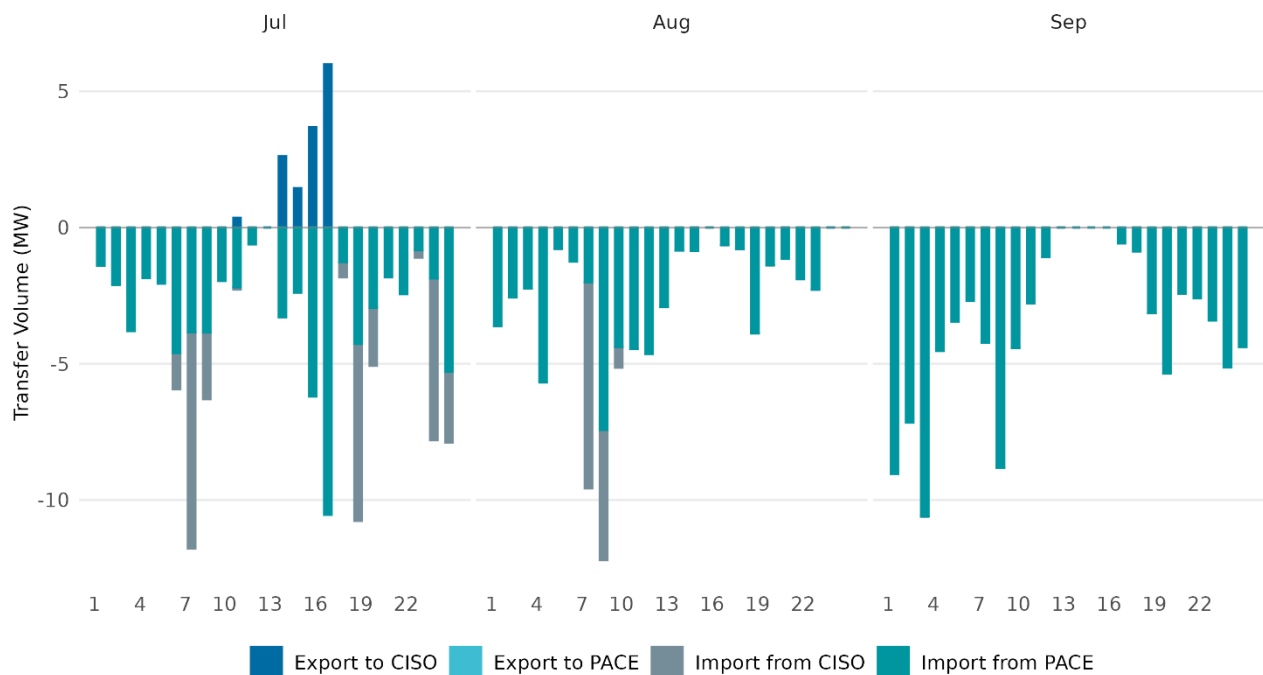
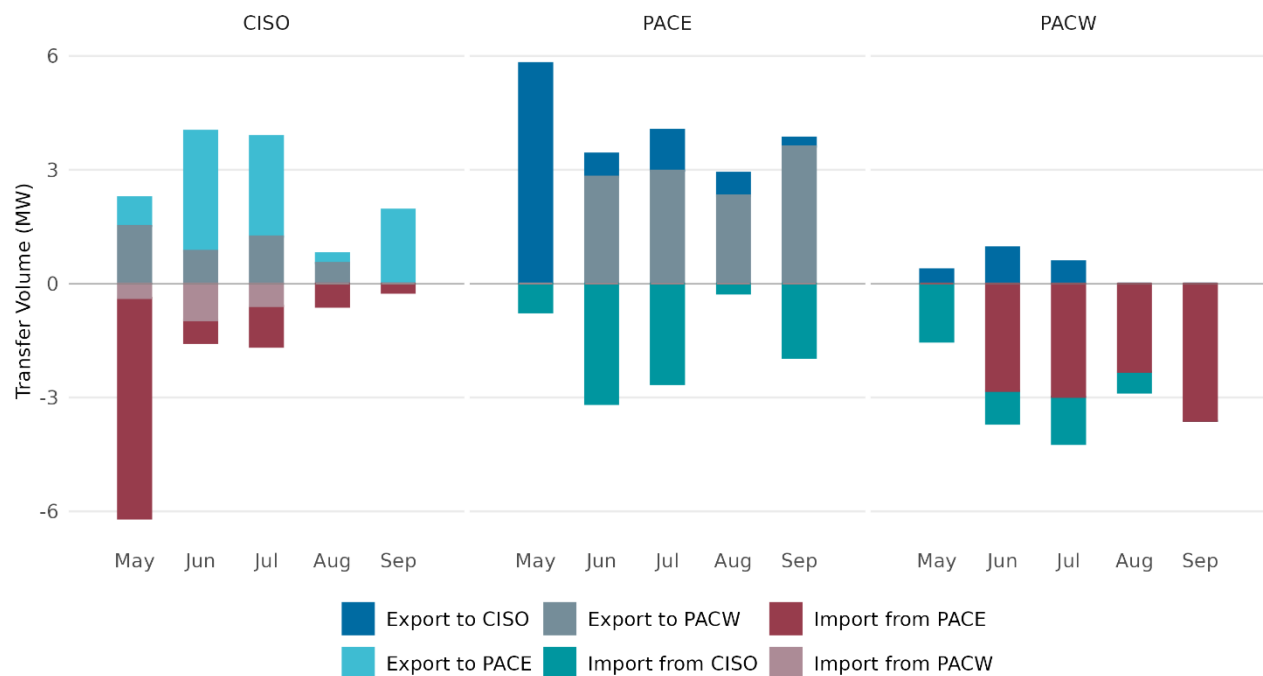


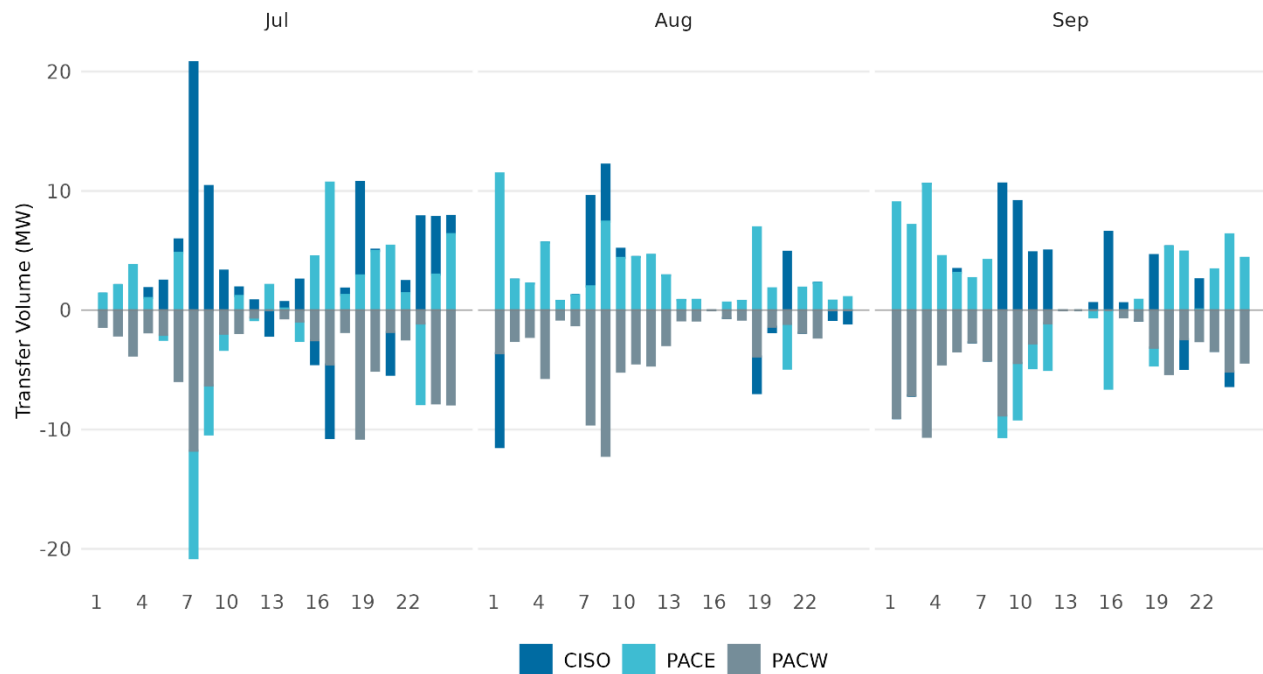
Figure 146 shows the summary of three BAAs' total RCD transfer volumes throughout May to September in both export (+) and import (-) directions. Generally, both BAAs have very different patterns across four months. CISO recorded its largest net imports in May, primarily from PACE, while PACE showed relatively high transfer activity in both directions during May through September. PACW was predominantly a net importer, with the largest import volumes occurring in June and July and primarily associated with transfers from PACE. By September, transfer volumes were substantially lower across all three BAAs.

Figure 146: Hourly average RCD transfers volumes in EDAM



Hourly RCD net transfer showed relatively small volumes across the three BAAs. Transfers were generally within ± 10 MW, except for several notable spikes, particularly during morning hours in July. Overall, RCD transfers became less volatile in August and September.

Figure 147: Hourly average net RCD transfers volumes in EDAM



Congestion

Congestion can occur when the lowest cost energy cannot be transmitted to meet demand where it is needed due to a lack of transmission capacity. In that situation, higher cost, local resources must be used to meet that demand in a constrained area. The added cost of bringing on these resources is reflected in the Locational Marginal Price (LMP) through Marginal Cost of Congestion (MCC) component. In other words, the MCC is the cost of delivering one additional MW to that node/location due to congestion on the system.

Table 8 shows the average MCC for the month of September for the EDAM DLAP/ELAP APnodes⁵. Since congestion is defined at each location, using the DLAP/ELAP of the market areas is a simple and reasonable representation of the overall congestion in each area.

⁵ These results are preliminary and subject to revision. A known data issue is currently under investigation, which may result in discrepancies in the analysis.

Table 8: Average congestion costs

DLAP/ELAP	Average MCC (\$/MWh)				
	May	June	July	Aug	Sep
PACE	(0.80)	(0.75)	(0.19)	(0.22)	(0.65)
PACW	0.48	(0.87)	(0.93)	(1.96)	0.72
PGAE	4.04	2.29	(1.10)	(2.40)	1.65
SCE	(3.68)	(1.76)	0.56	1.35	(1.60)

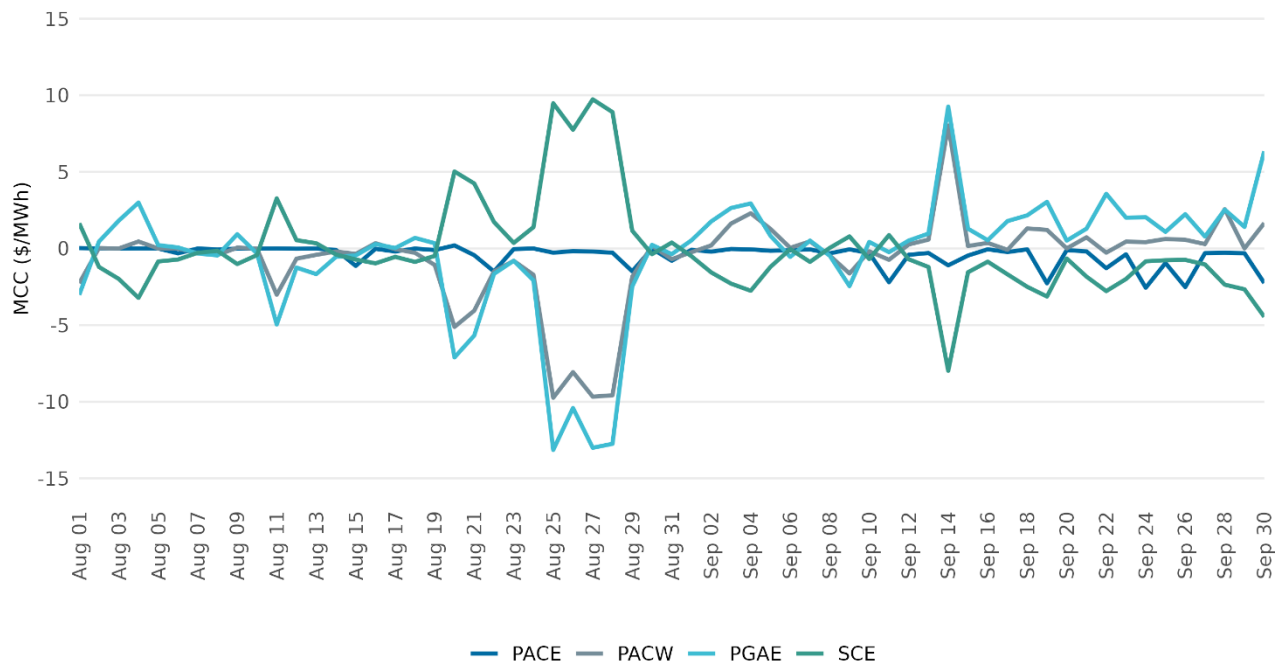
A positive number for MCC represents an increase in DLAP/ELAP LMP due to system congestion while a negative number represents a decrease in LMP from congestion. A positive MCC for a DLAP/ELAP indicates a more constrained area where cheaper energy may not be able to flow. In September, congestion impacts on PACE and PACW ELAP locational marginal prices were -\$0.65 and \$0.72, respectively. In contrast, within CAISO DLAPs, SCE MCC averaged -\$1.60, while PGAE MCC averaged \$1.65. CISO congestion patterns in September average out to a return to a predominately a South to North pattern seen in May and June before peak summer conditions across July and August. Table 9 provides an hourly average of congestion costs across areas with the blue-green gradient indicating larger positive MCC prices and the gradient of violet indicates larger negative MCC prices. The South to North pattern is predominantly during high solar hours. Otherwise, congestion prices are relatively neutral.

Table 9: Hourly average congestion costs

Trade Hour	Jul				Aug				Sep			
	PACE	PACW	PGAE	SCE	PACE	PACW	PGAE	SCE	PACE	PACW	PGAE	SCE
1	0.00	-0.94	-1.16	0.85	0.01	-1.98	-2.71	2.12	-0.19	-0.19	-0.31	0.06
2	0.04	-0.93	-1.13	0.90	0.01	-1.89	-2.61	2.03	-0.17	-0.14	-0.20	-0.01
3	-0.05	-0.53	-0.59	0.47	0.03	-1.48	-2.03	1.60	-0.13	-0.07	-0.14	-0.03
4	-0.11	-0.49	-0.62	0.53	0.04	-1.47	-2.04	1.61	-0.10	-0.12	-0.19	0.04
5	-0.20	-0.43	-0.54	0.49	0.02	-1.30	-1.79	1.40	-0.07	-0.09	-0.24	0.03
6	-0.01	-0.44	-0.60	0.42	0.05	-1.54	-2.12	1.73	-0.05	-0.08	-0.19	0.01
7	-0.03	-0.33	-0.47	0.30	0.05	-1.29	-1.72	1.42	-0.05	-0.03	-0.12	-0.07
8	-0.33	-0.11	0.11	-0.30	-0.04	-0.51	-0.54	0.28	-0.32	0.02	0.08	-0.43
9	-0.30	-0.09	0.44	-0.96	-0.18	-0.82	-0.22	-0.65	-1.06	1.98	5.15	-5.02
10	-0.33	-0.17	0.52	-0.96	-0.26	-1.06	0.06	-0.85	-1.10	1.84	6.23	-5.58
11	-0.30	-0.44	-0.20	-0.40	-0.22	-1.22	-1.63	0.10	-1.03	2.07	4.33	-4.11
12	-0.19	-0.57	-0.54	-0.19	-0.47	-1.67	-2.51	0.67	-1.00	1.93	4.08	-3.68
13	-0.15	-0.66	-0.68	-0.13	-0.52	-1.59	-2.42	0.51	-1.01	2.27	4.05	-3.66
14	-0.26	-0.65	-0.78	0.07	-0.78	-1.73	-2.51	0.68	-1.09	2.13	3.86	-3.37
15	-0.46	-0.68	-1.22	0.44	-0.87	-2.07	-2.95	0.98	-1.55	2.30	3.98	-3.26
16	-0.60	-1.42	-2.06	1.09	-1.07	-3.03	-3.59	1.51	-2.04	2.30	3.88	-3.19
17	-0.56	-1.54	-2.97	0.00	-0.46	-2.64	-3.04	0.98	-2.20	2.63	4.10	-3.45
18	-0.50	-2.66	-2.76	1.89	-0.47	-4.05	-3.84	2.12	-0.66	-0.39	0.66	-1.08
19	-0.09	-2.86	-3.13	2.50	-0.13	-3.98	-4.39	3.03	-0.50	-0.16	0.78	-0.80
20	-0.07	-1.58	-1.75	1.38	-0.04	-3.41	-4.11	2.92	-0.36	-0.09	0.39	-0.53
21	-0.03	-1.06	-1.16	0.98	-0.03	-2.00	-2.34	1.66	-0.27	-0.08	0.24	-0.40
22	-0.01	-1.49	-1.91	1.50	-0.01	-2.66	-3.50	2.64	-0.28	-0.37	-0.36	0.09
23	-0.01	-1.14	-1.50	1.26	-0.02	-1.86	-2.54	1.92	-0.19	-0.18	-0.23	-0.02
24	0.00	-1.21	-1.73	1.40	-0.01	-1.80	-2.53	1.95	-0.22	-0.26	-0.35	0.07

Figure 148 provides a daily trend of average congestion costs across the last two months. Southern California prices have returned to averaging lower than Northern California and PACW across September.

Figure 148: Daily average congestion cost by area



Parallel flows

A more fundamental assessment of EDAM transaction effects is to examine their flow contributions on transmission constraints. Transactions in one BAA can contribute to flows on transmission constraints in another BAA; these are known as *parallel flow*. The data is presented in a matrix of transactions vs. constraints to highlight potential parallel flows across PAC and CAISO constraints due to transactions in these areas.

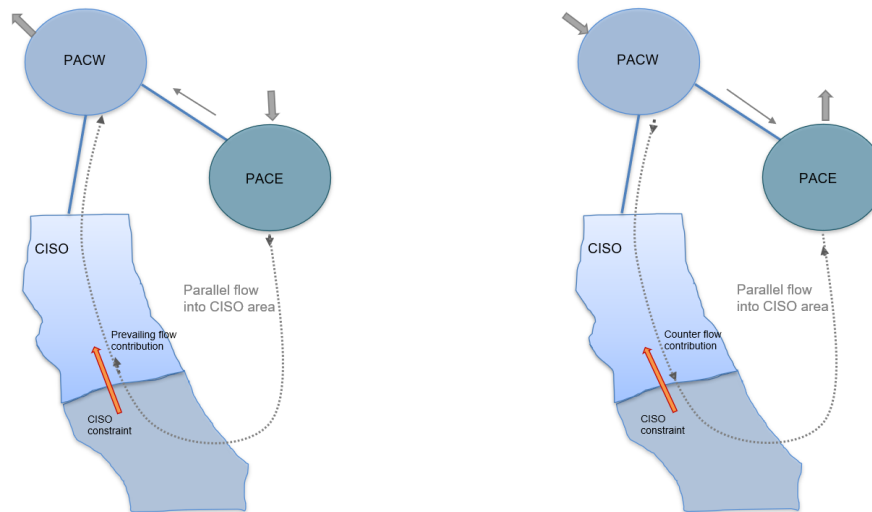
Figure 149: Parallel flow matrix example

	PACE transaction	PACW transaction	CISO transaction
PACE constraint	Internal flow on PACE	Parallel flow on PACE	Parallel flow on PACE
PACW constraint	Parallel flow on PACW	Internal flow on PACW	Parallel flow on PACW
CISO constraint	Parallel flow on CISO	Parallel flow on CISO	Internal flow on CISO

Figure 149 also highlights the impact of transactions on internal flows within each BAA, illustrating how CAISO transactions affect CAISO constraints. Parallel flows are a physical reality, independent of market constructs, economics, or contracts. They can either align with the prevailing direction CAISO/MD&A/MPAA

of congestion or oppose it, creating counterflows. Transactions in the prevailing direction are charged for contributing to congestion, while transactions in the opposite direction are credited for relieving congestion. Figure 150 illustrates the concepts of prevailing and counter flows from a transaction between PAC areas creating a parallel flow in CAISO BAA.

Figure 150: Illustration of parallel flows



In September, the impact of transactions in PAC areas over constraints in the CAISO area were meaningful, while the impact of CAISO transactions on PAC areas were minimal.

With the launch of EDAM/DAME, transactions from one EDAM BAA can directly impact transmission constraints in another BAA based on current system topology.

Table 10 goes a step further and breaks down the monthly average MCCs based on where the congestion is occurring. This is calculated by taking the shift factors of each DLAP/ELAP and applying them to across all binding transmission constraints and their shadow prices for each hour. Then, the hourly MCCs are aggregated and normalized to \$/MWh to reconstruct the monthly average MCC in the previous figure, but with a breakdown of where the congestion is occurring. With the inclusion of DAME, the table is also broken out to include constraints binding during imbalance reserve deployment scenarios, which ultimately contribute towards the total MCC. The total in Table 10 ideally should align closely with the final MCC prices found on

Table 8, but due to possible data issues and/or price corrections, they may not align exactly.

Table 10: Estimated MCC breakdown by source of congestion⁶

LAP Congestion Price Impact (\$/MWh)												
Origin of Congestion	July				Aug				Sep			
	PACE	PACW	PGAE	SCE	PACE	PACW	PGAE	SCE	PACE	PACW	PGAE	SCE
CISO	-0.19	-0.92	-1.04	0.58	-0.22	-1.96	-2.40	1.35	-0.65	0.72	1.65	-1.60
Base	-0.19	-0.92	-1.09	0.64	-0.21	-1.73	-2.11	1.16	-0.64	0.72	1.52	-1.52
IRD	0.000	0.000	0.02	-0.01	0.000	0.000	0.01	0.00	-0.007	-0.004	0.08	-0.04
IRU	-0.002		0.03	-0.05	-0.007	-0.23	-0.31	0.19	0.000	0.00	0.05	-0.04
PACE			-0.05	-0.05								
Base			-0.05	-0.05								
IRD												
IRU			-0.001	-0.001								

Based on this table, CAISO constraints across all deployment scenario constraint types, on average, had a -0.65 and 0.72 \$/MWh MCC impact on PACE and PACW, respectively. There was no direct impact from PacifiCorp congestion on CISO DLAPs which is represented by the grayed-out sections of the table.

⁶ These results are preliminary. An identified data issue impacting the availability of shift factors will result in discrepancies between the total MCC reported in 6 and the breakdown by transmission constraint.

Table 11: Congestion costs by constraint for September 2026

September 2026 Average Congestion Costs by Constraint		PACE			PACW			PGAE			SCE		
BAA	Constraint Name	Base	IRD	IRU	Base	IRD	IRU	Base	IRD	IRU	Base	IRD	IRU
CISO	22256_ESCNDIDO_69.0_22404_LILAC_69.0_BR_1_1							(0.00)			(0.00)		
CISO	22342_HDWSH_500_22536_N.GILA_500_BR_1_2	(0.04)	(0.00)		(0.02)	(0.00)		(0.01)	(0.00)		0.00	0.00	
CISO	22468_MIGUEL_500_22472_MIGUELMP_1.0_XF_80	(0.00)						(0.00)					
CISO	22773_BAY BLVD_69.0_22352_IMPRLBCH_69.0_BR_1_1							(0.00)			(0.00)		
CISO	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1_1										0.00		
CISO	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1							(0.00)					
CISO	24016_BARRE_230_24154_VILLA PK_230_BR_1_1	(0.01)			(0.01)			(0.00)			0.01		
CISO	24021_CENTER S_230_24091_MESA CAL_230_BR_1_1	(0.00)			(0.00)			(0.01)			0.00		
CISO	24091_MESA CAL_230_24076_LAGUBELL_230_BR_2_1	(0.00)			(0.00)			(0.00)			0.00		
CISO	24114_PARDEE_230_24115_PASTORIA_230_BR_1_1							0.00	0.00		(0.00)		
CISO	24156_VINCENT_500_24155_VINCENT_230_XF_2_P	(0.01)			(0.02)			(0.03)			0.02		
CISO	24602_VICTOR_115_24607_ROADWAY_115_BR_1_1										(0.00)		
CISO	24701_KRAMER_230_24601_VICTOR_230_BR_1_1							0.00			(0.01)		
CISO	24701_KRAMER_230_24601_VICTOR_230_BR_2_1							0.00			(0.05)		(0.00)
CISO	24801_DEVERS_500_24804_DEVERS_230_XF_2_P	(0.08)						0.01			0.03		
CISO	30040_TESLA_500_30050_LOSBANOS_500_BR_1_1				0.00			0.00			(0.00)		
CISO	30050_LOSBANOS_500_30055_GATES1_500_BR_1_3		0.00				0.00			0.00			(0.00)
CISO	30055_GATES1_500_30060_MIDWAY_500_BR_1_1				0.01			0.01			(0.01)		
CISO	30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	(0.00)			(0.13)			(0.18)			0.13		
CISO	30580_ALTM MDW_230_30625_TESLA D_230_BR_1_1							0.01			(0.00)		
CISO	30590_USWP-JRW_230_30530_CAYETANO_230_BR_1_1							0.00					
CISO	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1				0.05			0.68		0.01	(0.50)		(0.01)
CISO	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1_1				0.04			0.02			(0.02)		(0.00)
CISO	30765_LOSBANOS_230_30790_PANOCH_230_BR_2_1				0.63	0.00		0.30		0.00	(0.34)		(0.00)
CISO	30790_PANOCH_230_30900_GATES_230_BR_1_1				0.06			0.10			(0.08)		
CISO	30790_PANOCH_230_30900_GATES_230_BR_2_1				0.14			0.19			(0.14)		
CISO	30976_MIDWAYR12_230_30060_MIDWAY_500_XF_12	0.00						(0.00)			0.00		
CISO	31227_HGHLNDJ2_115_31950_CORTINA_115_BR_1_1							(0.03)			0.00		
CISO	32218_DRUM_115_32244_BRNSWKT2_115_BR_2_1							0.00					
CISO	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1_1							0.00					
CISO	33200_LARKIN_115_33204_POTRERO_115_BR_2_1							0.00					
CISO	33310_SANMATEO_115_33315_RAVENSWD_115_BR_1_1							0.02			(0.01)		
CISO	33541_AEC_TP1_115_33540_TESLA_115_BR_1_1							(0.01)	0.01	(0.00)	0.00	(0.01)	0.00
CISO	34100_CHWCHLLA_115_34101_CERTANJ2_115_BR_1_1							0.00					
CISO	34101_CERTANJ2_115_34116_LE GRAND_115_BR_1_1							0.02	0.01	0.00			
CISO	34116_LE GRAND_115_34115_ADRA TAP_115_BR_1_1							0.01		0.02	(0.00)		(0.00)
CISO	34214_LOS BANS_70.0_30765_LOSBANOS_230_XF_3							0.00			(0.00)		
CISO	34256_BORDEN_70.0_30805_BORDEN_230_XF_1							0.00	0.00				
CISO	34375_ULTPWRJ_115_34377_AIRPROD_115_BR_1_1							0.00					
CISO	34418_KINGSBRG_115_34405_FRWT TAP_115_BR_1_1							(0.00)					
CISO	34418_KINGSBRG_115_34428_CONTADNA_115_BR_1_1							0.12			(0.06)		
CISO	34430_HENRETTA_115_34519_LPNJCTSS_115_BR_1_1							0.00			(0.00)		
CISO	34540_HENRITTA_70.0_30881_HENRIETA_230_XF_4							(0.01)	0.00	(0.00)			
CISO	34700_SMYRNA 2_115_34742_SEMITRPJ_115_BR_1_1							(0.00)					
CISO	34706_WESTPARK_115_34752_KERN PWR_115_BR_1_1							0.00			(0.00)		
CISO	34724_KRN OL J_115_34736_MAGUNDEN_115_BR_1_1							0.00			(0.00)		
CISO	34752_KERN PWR_115_34797_KERNWTP2_115_BR_1_1							0.00			(0.00)		
CISO	35120_NEWARK D_115_36851_NORTHERN_115_BR_1_1							(0.01)			(0.01)		
CISO	35122_NWARK EF_115_35602_ZNKER J2_115_BR_1_1										(0.00)		
CISO	35122_NWARK EF_115_36851_NORTHERN_115_BR_2_1							(0.01)			(0.03)		
CISO	35603_ZNKER J1_115_35612_TRIMBLE_115_BR_1_1							0.00			(0.00)		
CISO	35618_SN JSE A_115_35616_SJOSEB_115_BR_1_1							0.07	0.01	0.00	(0.07)	(0.01)	(0.00)
CISO	35618_SN JSE A_115_35620_EL PATIO_115_BR_1_1							0.00			(0.00)		
CISO	35642_METCALF_115_30735_METCALF_230_XF_2							0.00			(0.00)		
CISO	35642_METCALF_115_30735_METCALF_230_XF_3							0.02			(0.01)		
CISO	35658_LS ESTRS_115_35659_NORTECH_115_BR_1_1										(0.01)		
CISO	35659_NORTECH_115_36851_NORTHERN_115_BR_1_1										(0.02)		
CISO	36850_KIFER_115_35615_FMC_115_BR_1_1							(0.00)			(0.00)		
CISO	36851_NORTHERN_115_36852_SCOTT_115_BR_2_1							(0.02)			(0.06)		
CISO	37585_TRCY PMP_230_30625_TESLA D_230_BR_2_1	(0.03)						0.10			(0.05)		
CISO	38610_DELTAPMP_230_30580_ALTM MDW_230_BR_1_1							0.01	0.05	0.00	(0.01)	(0.04)	(0.00)
CISO	38615_DS AMIGO_230_30790_PANOCH_230_BR_1_1				0.06			0.09			(0.20)		
CISO	39021_SC21ATP_70.0_34888_ARVIN_70.0_BR_1_1							0.01					
CISO	39070_AERAVIC1_115_34778_FELLOWS_115_BR_1_1							(0.00)					
CISO	7320_CP6_NG								0.00				
CISO	7430_CP6_NG							0.06	0.00	0.02	(0.05)	(0.00)	(0.01)
CISO	7510-Magunden-Antelope_NG								(0.00)			0.00	
CISO	7690-CONTRL-INYOKN_EXP_NG										(0.03)	(0.00)	(0.01)
CISO	7760_DEV_RDB_ALUS	(0.22)						0.01			0.12		
CISO	7820_TL 230S_OVERLOAD_NG	(0.16)	(0.01)		(0.08)	(0.00)		(0.09)	(0.00)		(0.04)	(0.00)	
CISO	7820_TL23040_IV_SPS_NG	(0.02)			(0.00)			(0.02)			(0.00)		
CISO	99254_J.HINDS2_230_24806_MIRAGE_230_BR_1_1											0.02	0.00
CISO	99970_MEADISO_230_19012_MEAD S_230_BR_PR_1							(0.00)			(0.00)		(0.00)
CISO	HUMBOLDT_EXP_NG									(0.00)			
CISO	HUMBOLDT_IMP_NG							0.00			(0.00)		
CISO	Line_Wilo-EOX_500KV	(0.01)						0.00			0.00		
CISO	Lugo AA bank outage Area EXP							0.02		0.00	(0.04)		(0.00)
CISO	OMS_20625025_TL13811_NG							0.00			0.01		
CISO	OMS_20625027_TL13811_NG							0.00			0.00		
CISO	OMS_20625030_TL13811_NG							0.00			0.00		
CISO	OMS_20625034_TL13811_NG							0.00			0.00		
CISO	OMS_20788970_MG-BK81_NG	(0.06)						(0.02)			0.00		
CISO	OMS_20956557_PARDE_PAST_WARN_EDM							0.00		0.00	(0.00)		(0.00)
CISO	OMS_20956557_PARDE_PAST_WARN_EXP								0.00			(0.00)	

In summary, the preliminary assessment 2026 congestion under EDAM is in line with the projections provided in the CRA Phase 1 analysis that leveraged historical data from the Western Energy Imbalance (See figure below)⁷ That is:

1. PAC transactions can have a sizable impact on CAISO constraints, and this is reflected with sizable MCC prices in PACE and PACW areas
2. CAISO transactions have negligible impact on PAC constraints, and this is reflected with minimal MCC prices in CAISO areas

Congestion revenues

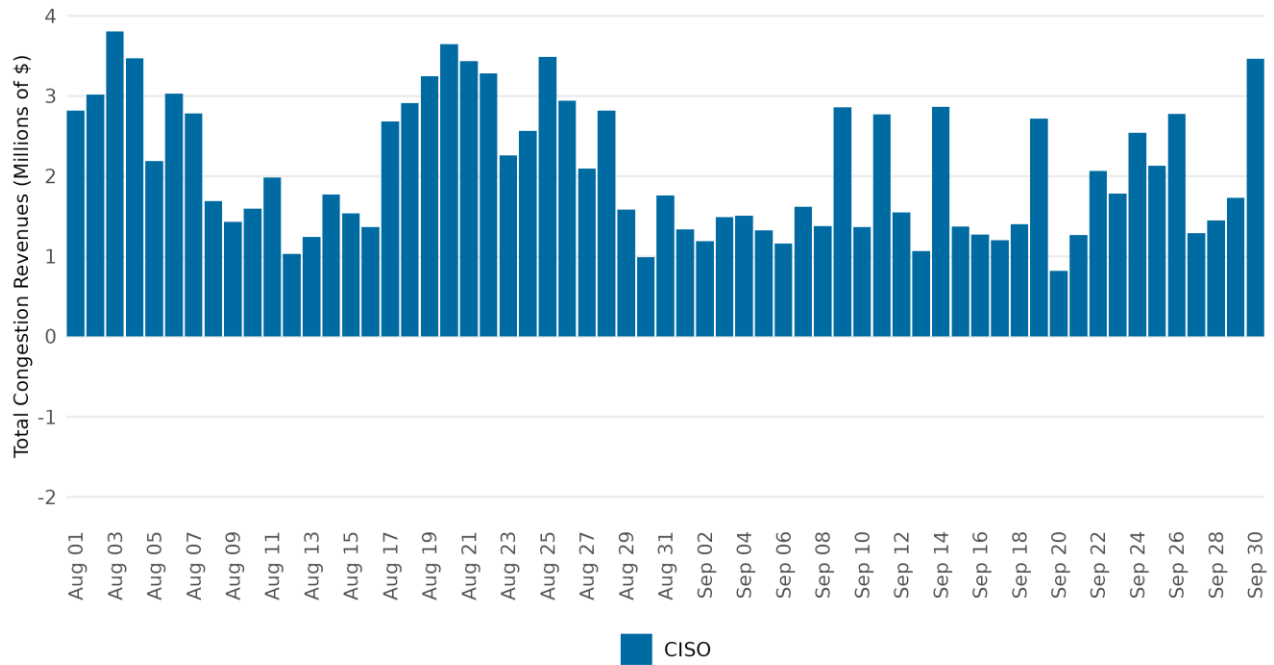
Congestion revenues are the financial surpluses based on the MCC resources are paid or getting charged when the transmission grid is constrained. This is the net total of congestion charges/credits for resources within each BAA. When a transaction at the resource level results in a charge, this is due to a generator having a negative MCC or a load resource with a positive MCC. These transactions are in aggregate contributing to congestion. Congestion credits occur in the opposite scenario where a generator resource has a positive MCC or a load resource has a negative MCC. This reflects the effect of relieving congestion. Please note that these results are preliminary and are subject to change. The following figures are representative of available data at the time of developing this report.

Figure 151 provides the daily BAA totals for congestion revenues based on the area where the congestion occurred.

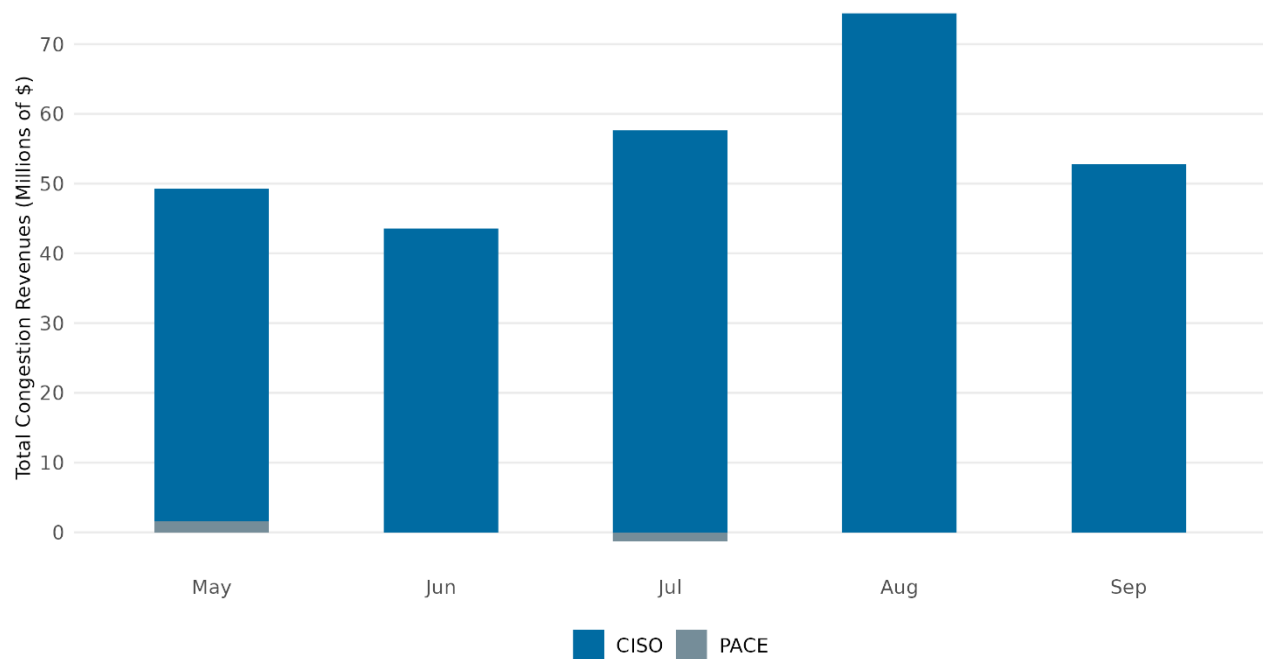
⁷

<https://stakeholdercenter.caiso.com/InitiativeDocuments/Stage-1-Analysis-Extended-Day-Ahead-Market-Congestion-Revenue-Allocation-Dec-11-2025.pdf>

Figure 151: Daily congestion total by BAA



Total congestion revenues in September at the constraint level were \$52.7M, attributed entirely to the CISO area. Figure 152 provides a monthly summary of the latest congestion totals since May 2026.

Figure 152: Monthly congestion total by BAA⁸

The current methodology implemented in EDAM allocates day-ahead congestion revenues, attributable to parallel flows, to the areas where market participants paid the congestion costs rather than to the areas where they were collected if they are associated with exercised transmission rights and self-scheduled transactions.

Figure 153 provides the breakdown of total congestion rents collected in the CISO area generated by parallel flows from PAC areas transactions, including adjustments for credits associated with firm transmission rights. The estimates in vivid blue are the congestion revenues that are returned to PAC for being associated with self-schedules supported with OATT rights; the bars in grey stand for the congestion revenues collected on CAISO constraints from PAC transactions that stay in the CISO area. The dark blue line represents the total amount of congestion revenue from constraints into the CAISO area. In September, PAC transactions resulted in a total of \$710k of congestion revenues on CISO constraints. Of the \$710k, \$392k was credited back to PAC to bring flows from self-schedules associated with OATT credits back to neutrality, resulting in a net total of \$318k remaining with CISO. Figure 154 provides a monthly summary of this metric.

⁸ This report uses more than one source of data to estimate congestion rents depending on the purpose of the metric, which in some cases may result in differences in values because certain inputs coming from settlements still reflecting data issues to be addressed. These estimates will be updated in subsequent reports.

Figure 153: Congestion revenues on CAISO constraints from PAC schedules

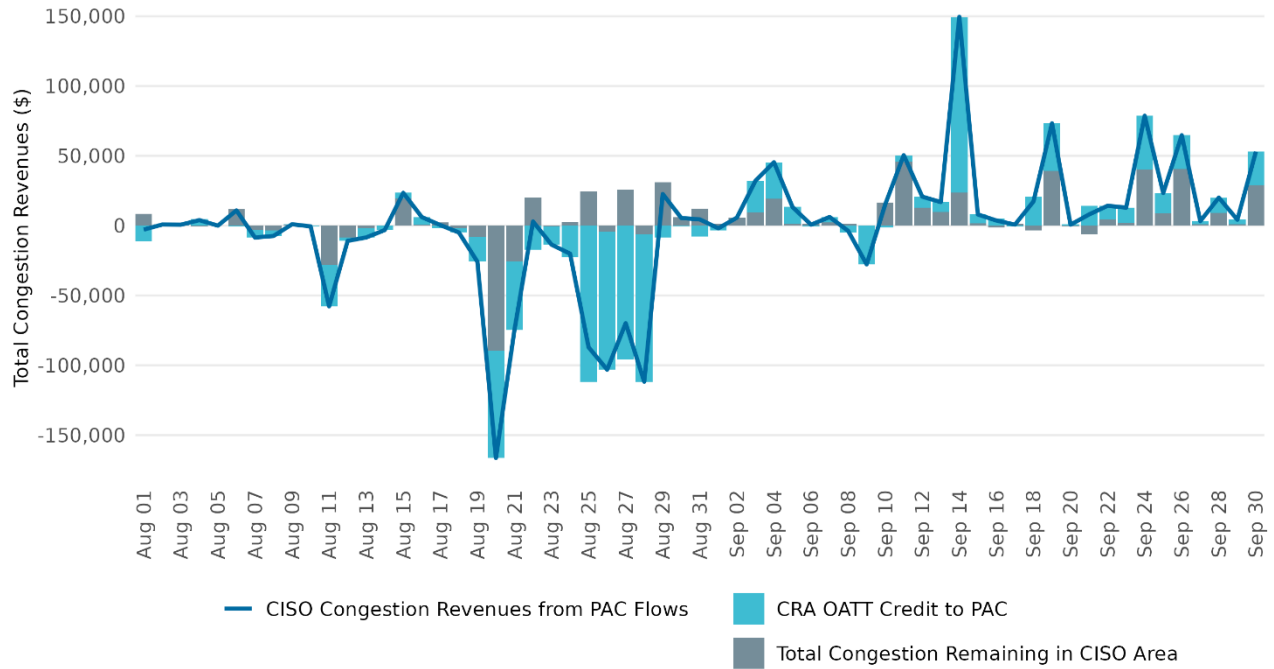


Figure 154: Net congestion revenues on CAISO constraints from PAC schedules

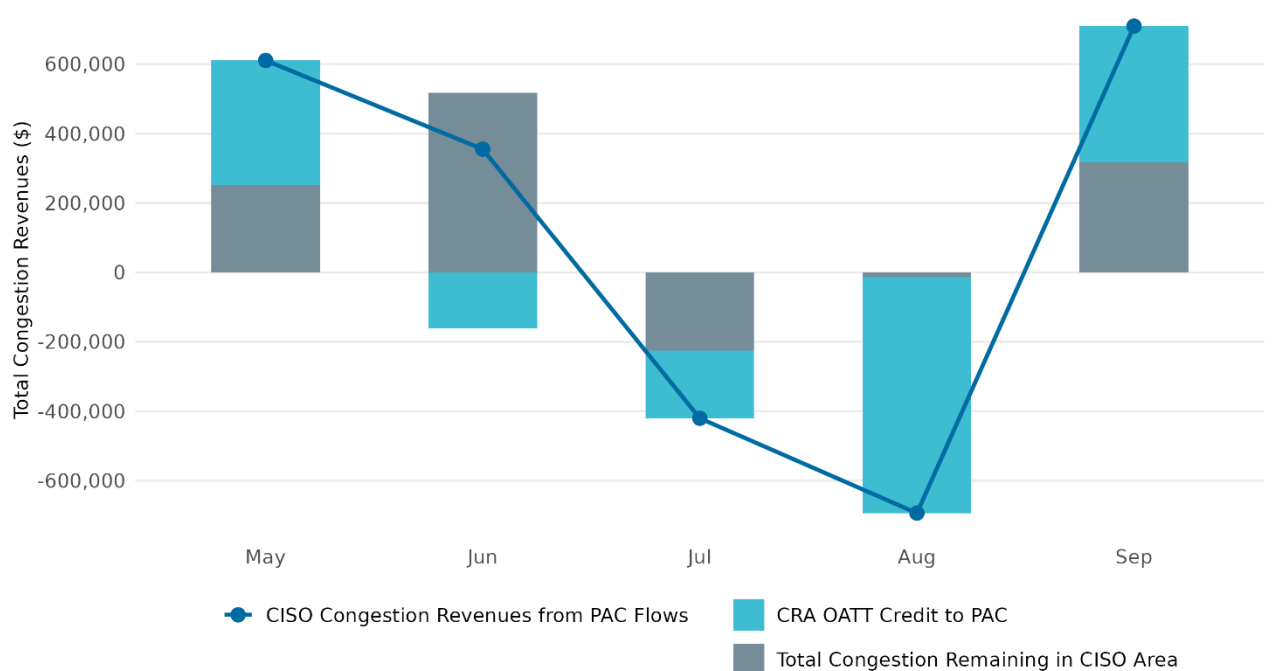


Figure 155 illustrates the daily total congestion revenues from CISO congestion that are returned to PAC areas given that they are associated with self-schedules supported by OATTs rights. These rights are either point-to-point rights or for Network service (NITS). Those rights are exercised and

can be tracked through balanced CRN self-schedules. On the chart, a positive value indicates a payment, while negative values indicate a charge.

The allocation to PAC areas is about \$392,000 in September. This is reflective of net credit back to PAC due to their schedules originally received congestion charges for providing prevailing flows on constraints the ISO areas. Figure 156 provides a monthly summary of this metric for previous months.

Figure 155: Estimated total CRN congestion credit to PAC from CISO congestion

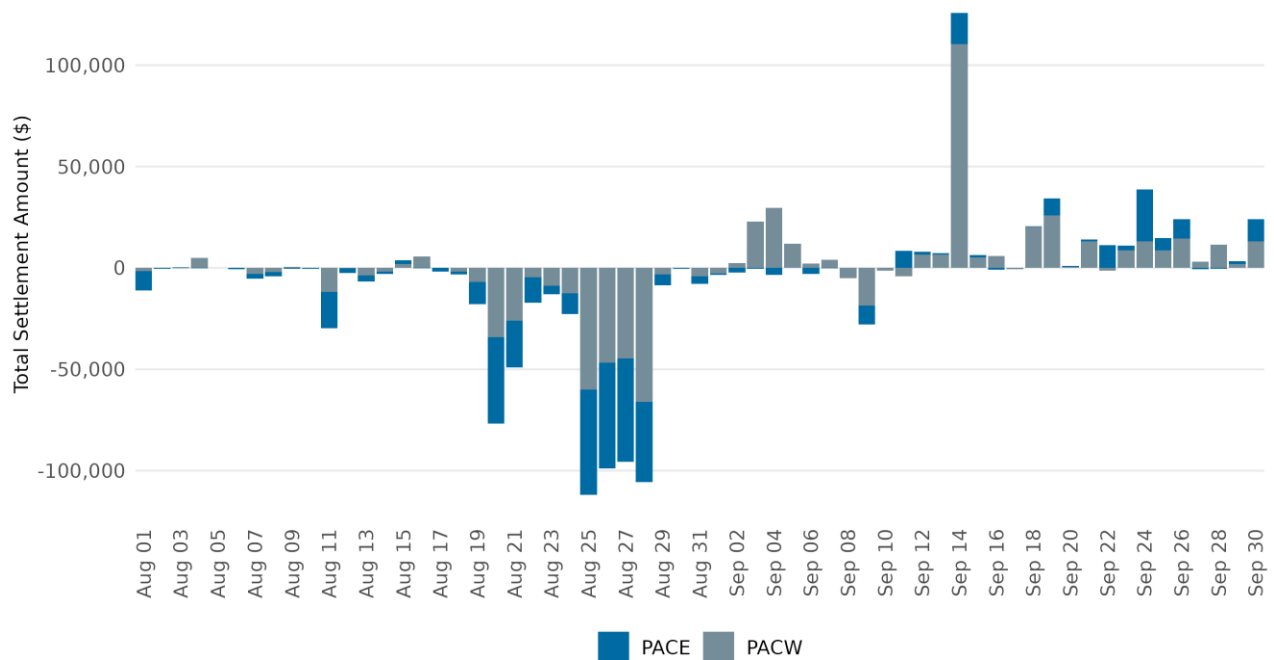
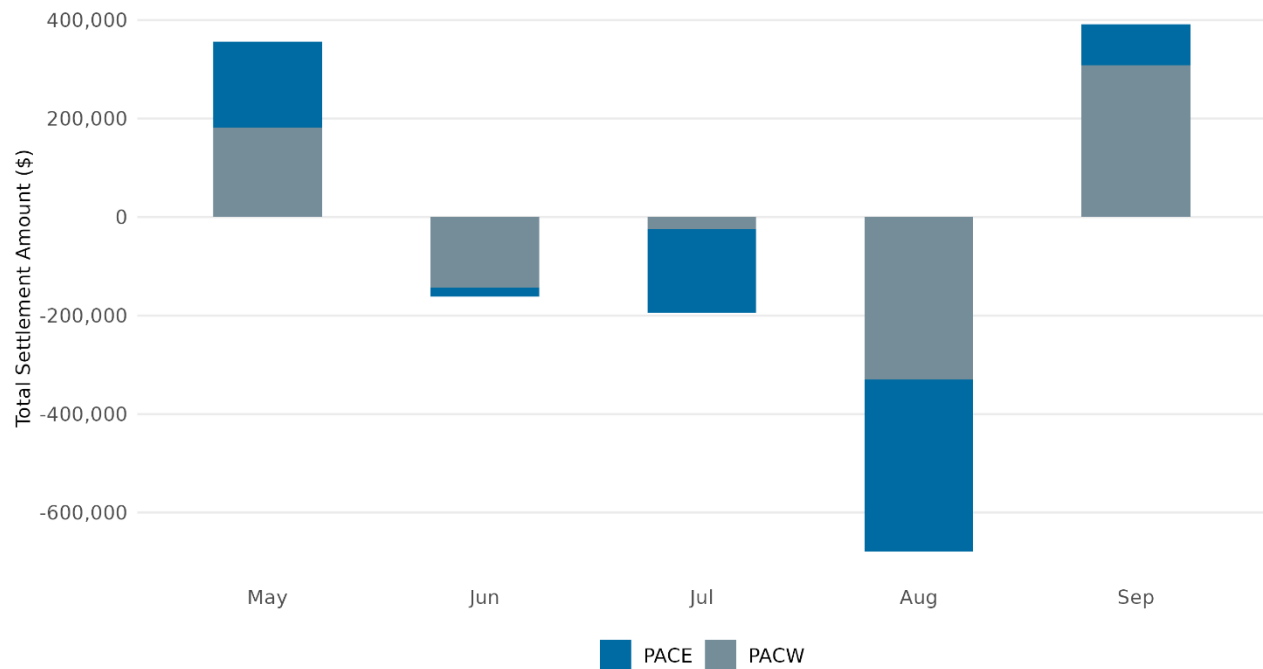


Figure 156: Total CRN congestion credit to PAC from CISO congestion



The directionality of CRA payments is driven by a combination of the constraints that bind and the relative exposure of CRA-eligible resources to those constraints. In August, PAC areas had a negative MCC relative to CAISO congestion, indicating that PAC generation and imports were, on net, contributing to CAISO congestion. Accordingly, generation and imports were charged in the IFM, resulting in a corresponding CRA payment. Conversely, load and exports with a negative MCC provided net congestion relief and received payments in the IFM, resulting in a corresponding CRA charge. While MCC direction shifted in September, the same relationship generally held.

For PACW, strong north-to-south constraints in August resulted in IFM counterflow payments to load and exports exceeding prevailing-flow charges to generation and imports, producing a net IFM payment and corresponding CRA chargeback. In September, a less directionally concentrated constraint pattern resulted in net IFM charges and a corresponding net CRA payment. PACE exhibited a more mixed pattern in August, while September showed a clearer net CRA payment as payments to generation and imports exceeded charges to load and exports.

Table 12 provides a further breakdown of the CRA totals by resource type. Table 13 provides the estimated CRA impact of the top five most impactful constraints. Impact is determined by the absolute value of CRA settlement.

Table 12: Monthly CRA totals broken down by resource type

Month, Res Type	PACE	PACW	Grand Total
Aug	(349,387)	(330,248)	(679,634)
LOAD	(260,158)	(1,815,275)	(2,075,433)
ETIE	11,467	(869,623)	(858,156)
GEN	139,059	562,358	701,417
ITIE	(239,755)	1,792,292	1,552,537
Sep	83,326	308,362	391,688
ITIE	274,675	(324,108)	(49,434)
GEN	487,162	(228,157)	259,004
ETIE	(92,871)	232,670	139,799
LOAD	(585,639)	627,958	42,319

Table 13: Estimated CRA to for top five most impactful CAISO constraints

Month, Top Constraint	PACE	PACW
Aug	(309,598)	(345,214)
24091_MESA_CAL_230_24076_LAGUBELL_230_BR_2_1	(12,151)	(8,940)
29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1_1	(43,571)	(32,681)
30060_MIDWAY_500_24156_VINCENT_500_BR_1_1	(70,777)	(73,055)
30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	(70,854)	(90,112)
30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_2	(112,245)	(140,426)
Sep	46,381	241,312
30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	(14,687)	(47,237)
30765_LOSBANOS_230_30790_PANOCHÉ_230_BR_2_1	(980)	223,500
30790_PANOCHÉ_230_30900_GATES_230_BR_2_1	12,865	55,128
7760_DEV_RDB_ALIS	30,750	21,916
7820_TL_230S_OVERLOAD_NG	18,435	(11,996)

Figure 157 shows the volumes of OATT balanced self-schedules with respect to the total volume of all types of self-schedules for each PAC area. The proportions of OATT balanced self-schedules for PACE and PACW were 46% and 72% in September, respectively. Figure 158 provides the volumes of OATT balanced self-schedules for each PAC area. In September, PACE averaged 1,511 MW while PACW averaged 1,817 MW.

Figure 157: Total self-schedules compared to OATT self-schedules by PAC area

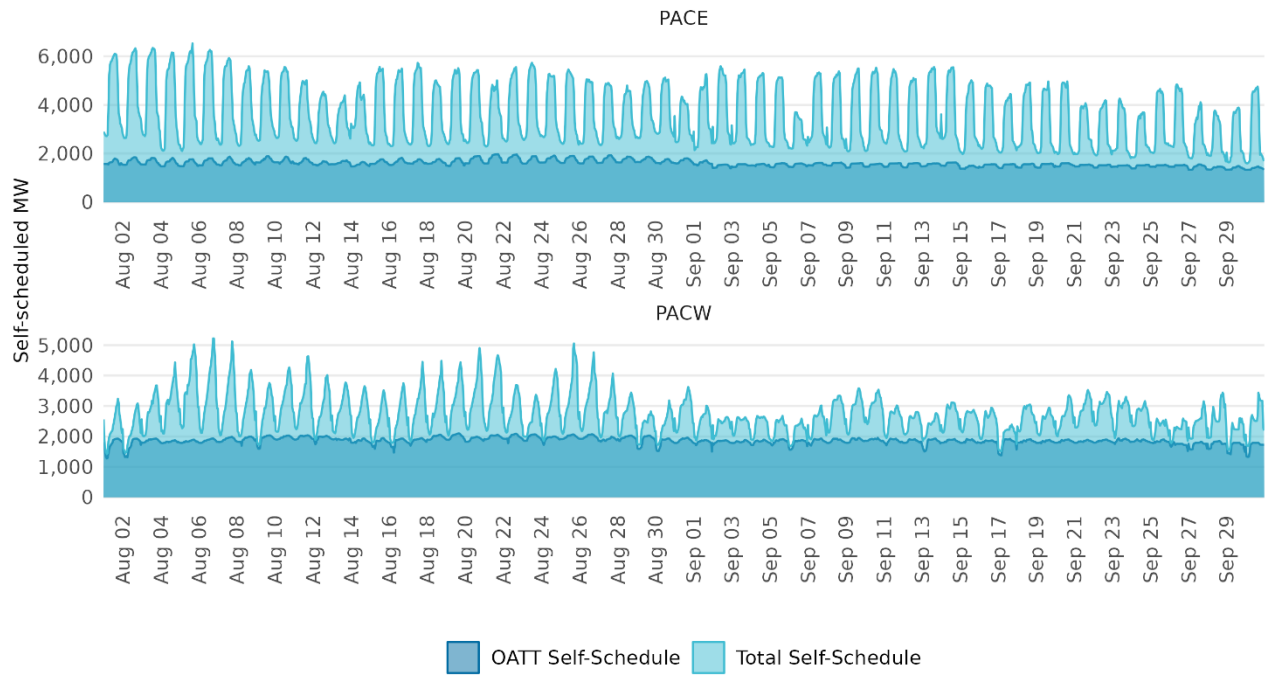


Figure 158: Total OATT self-schedule volumes by PAC area

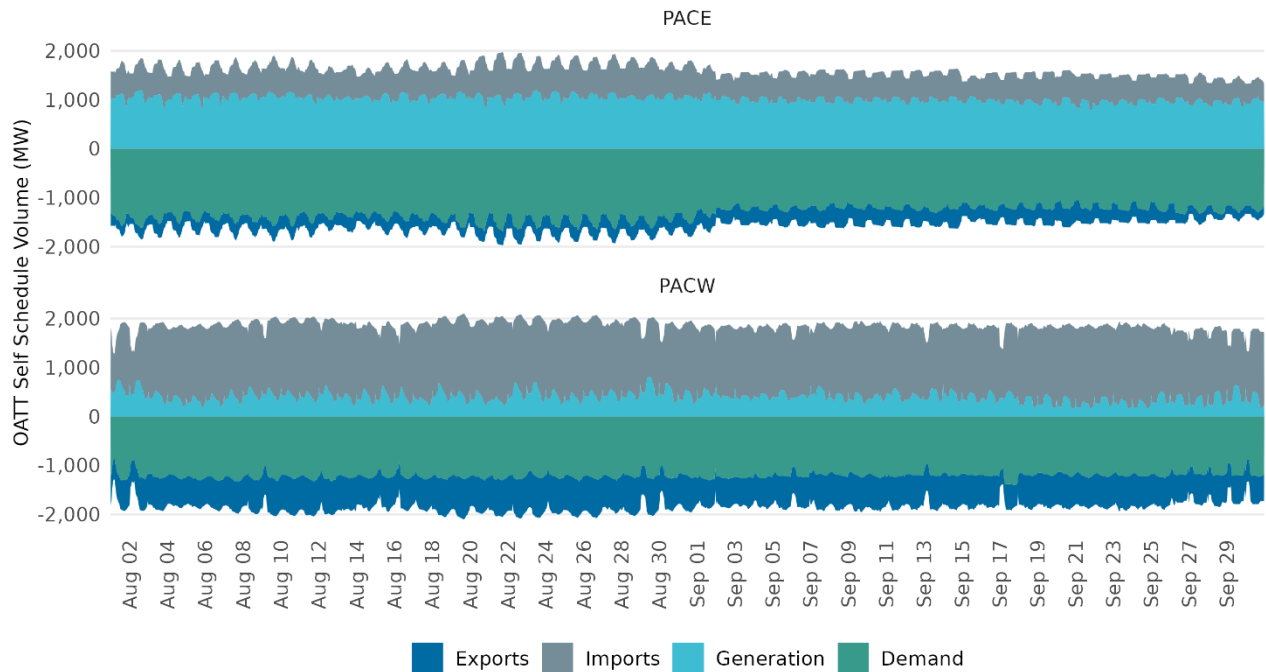
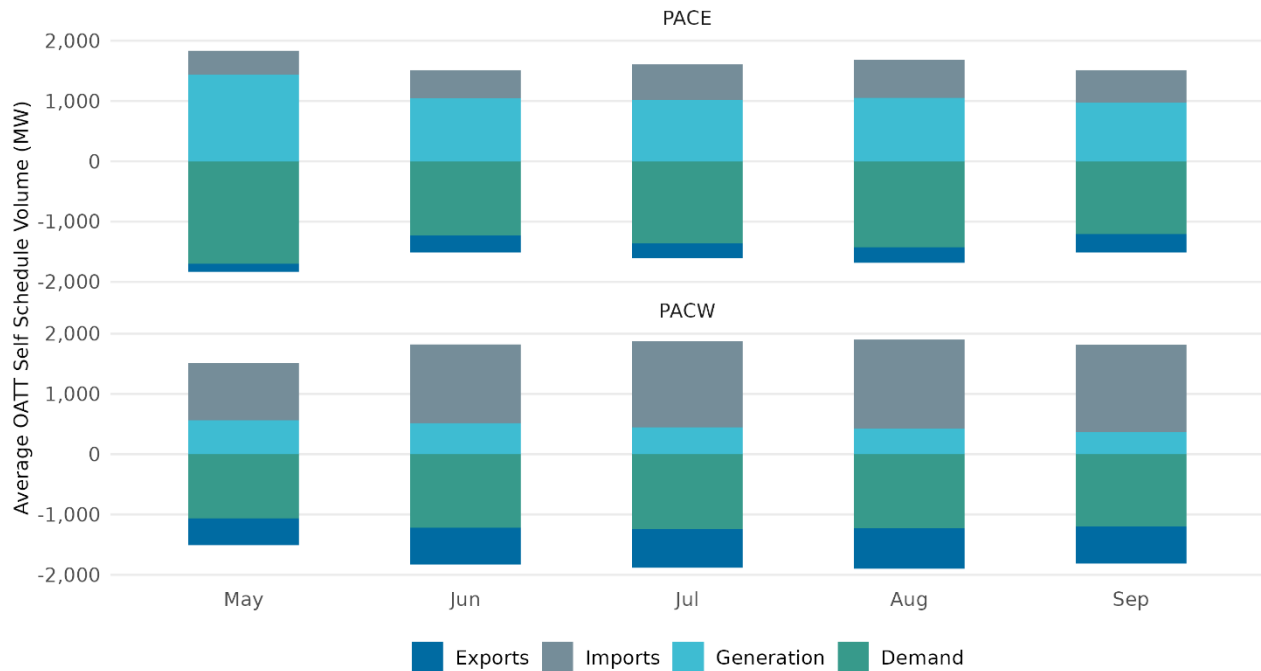


Figure 159: Monthly average OATT self-schedule volume



Congestion revenue rights

The Extended Day-Ahead Market (EDAM) continues to rely on locational marginal pricing. The existing design, under which day-ahead congestion rents are used to fund Congestion Revenue Rights (CRRs), remains fully in place for the CAISO balancing area. Congestion revenues collected on constraints within the CAISO balancing area are used to fund both allocated and auctioned CRRs. Currently, no CRRs exist for other balancing areas participating in EDAM.

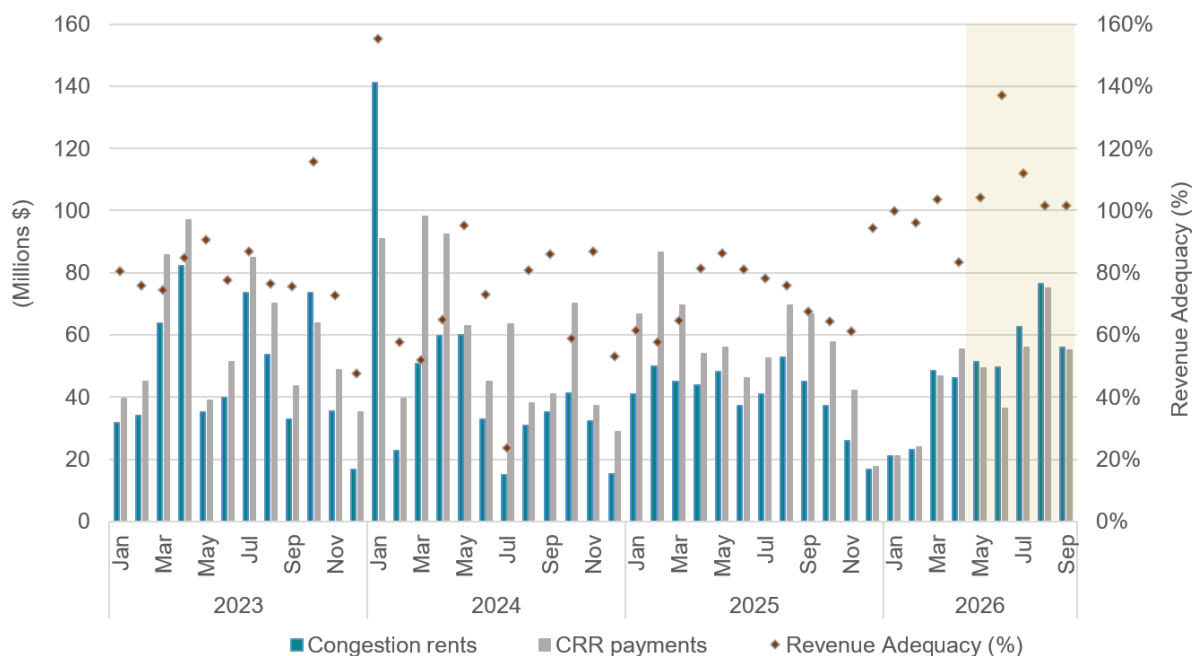
With EDAM implementation, schedules in the PacifiCorp (PAC) balancing area that impact flows on CAISO transmission constraints are assessed congestion charges based on their contribution to those constraints. However, the portion of congestion revenues collected on PAC schedules associated with self-schedules and the exercise of transmission rights is allocated back to PAC and is therefore excluded from the funds used to pay CRRs.

Revenue adequacy exists when congestion revenues collected in the day-ahead market are sufficient to cover the notional value of released CRRs. In principle, day-ahead congestion rents should fully fund CRR payments.

Under the partial funding policy adopted in January 2019, CAISO reduces CRR payments based on each CRR holder's contribution to deficits on a constraint-by-constraint basis. Because individual constraints may produce either surpluses or deficits, surpluses on one constraint are not used to offset deficits on another. While this pro-rata funding approach ensures CRR revenue neutrality, CAISO continues to monitor revenue adequacy because the primary objective is to release CRRs only up to the level that can be fully funded.

Figure 160 illustrates the monthly trend in CRR revenue adequacy. The bars show day-ahead congestion rents collected and the corresponding notional CRR payments. The purple markers indicate revenue adequacy as a percentage. Values below 100 percent reflect periods of CRR revenue inadequacy. Revenue adequacy for May through September has been over 100 percent, indicating that congestion rents collected in the day-ahead market have been greater than the CRR payments. This outcome needs to be taken with caution since there are still revisions to settlement estimates as different issues are addressed. Further, given the low level of congestion rents related to PAC schedules and the level of revenues allocated back to PAC, the level of revenue adequacy is not materially impacted by EDAM.

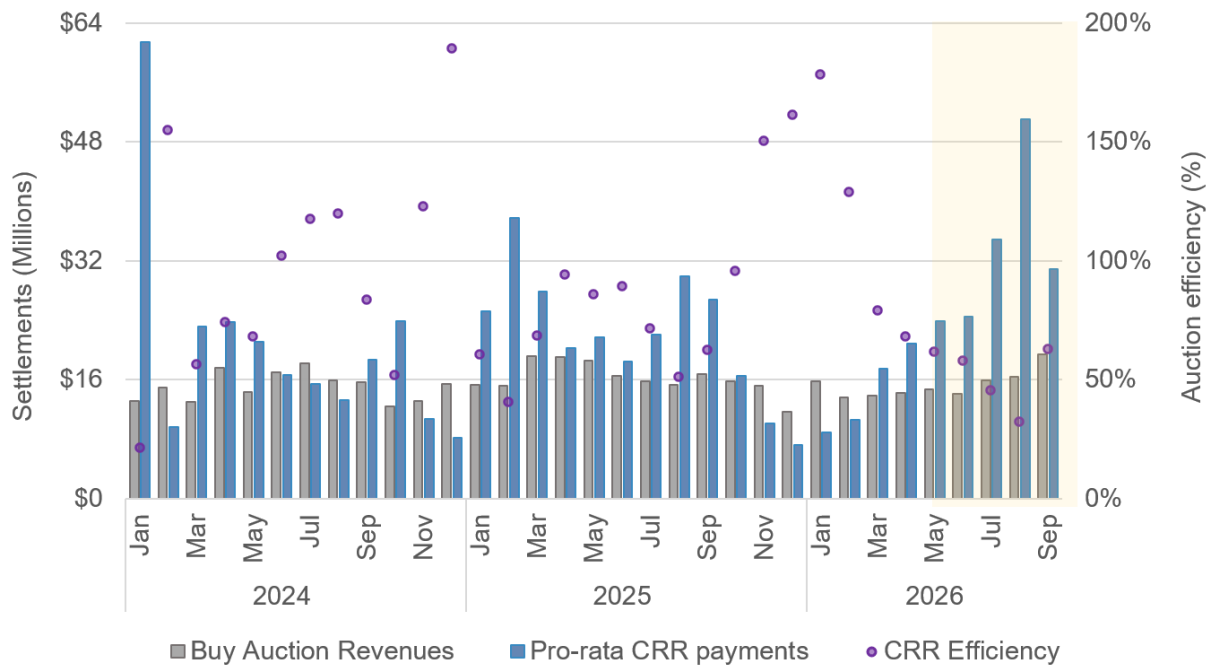
Figure 160: CRR revenue adequacy



Auction efficiency measures the difference between the price paid to acquire a CRR and the amount received through CRR settlements

Figure 161 illustrates these values in the bars, while the purple markers show auction efficiency as a percentage. Auction efficiency was relatively low from May through September, following EDAM implementation. However, this trend is consistent with historical seasonal patterns, as higher summer loading conditions generally lead to increased congestion and reduced auction efficiency.

Figure 161: CRR auction efficiency



EDAM Net Export Constraints and RUC Adjustments

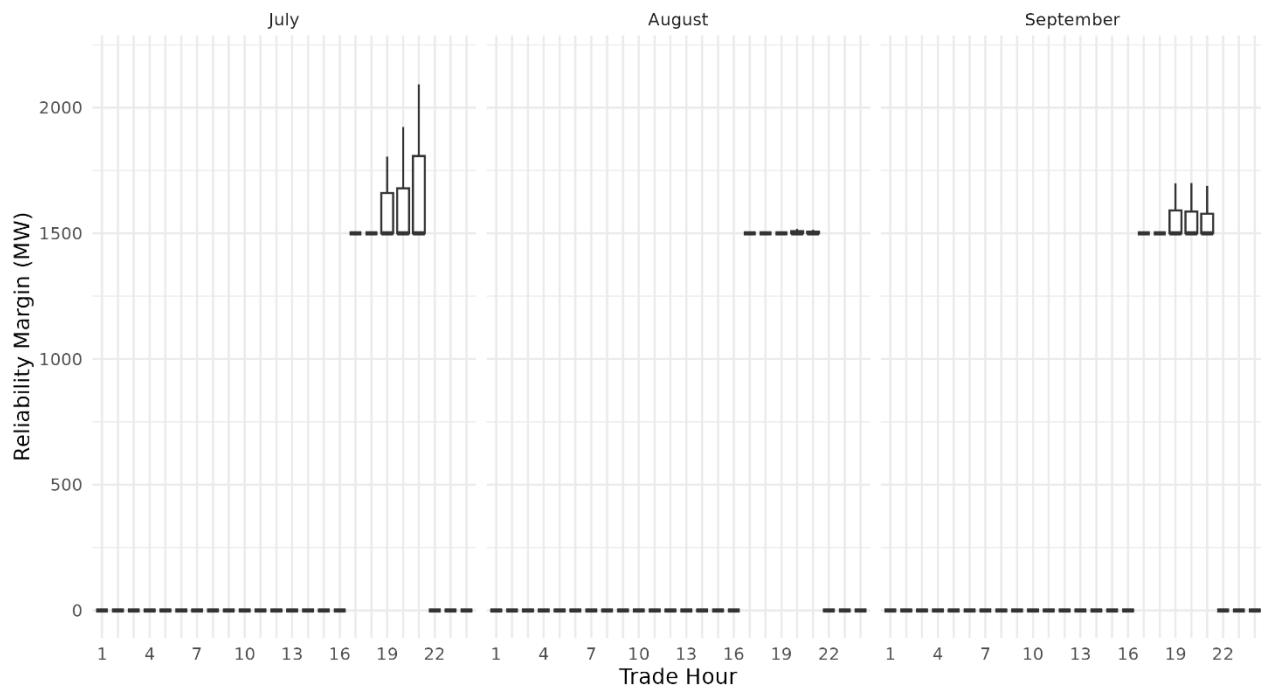
The EDAM export constraint and RUC adjustments are optional BA level constructs that help ensure sufficient procurement to support reliability going into the real-time market.

EDAM net export constraints

The EDAM net export constraint allows a BAA to limit the net exports on their TSRs to avoid exporting capacity on the TSRs that they may need for reliability. The constraint is optional and is enforced at the BA level. The constraint limits the net exports on the TSRs based on the total RSE eligible supply available above the RSE demand, with additional inputs to allow BAs to fine tune the constraint as needed.

There are two parameters that each BAA sets when the constraint is enforced: the confidence factor and the reliability margin. The confidence factor sets the percentage of supply that is not eligible for the RSE that will count in the BAA's supply that is eligible for export on the TSRs. The reliability margin is an additional buffer that the BAA may set to further limit the amount of supply that is eligible for export. The reliability margin is defined for each hour of the day as a specific MW value.

Figure 162: CAISO Reliability Margin



Based on stakeholder feedback, CAISO enforces the EDAM net export constraint on all days, with a 0% confidence factor and a reliability margin that tracks with the most severe single contingency. Full details of the CAISO implementation of the constraint are available in the Business Practice manual for EDAM. This constraint has not been binding in the CAISO area in any hour since EDAM went live in May. Neither PACE nor PACW have opted to enforce this constraint so far.

RUC adjustments

The RUC load adjustment is an optional hourly MW value added to the forecasted load in RUC. It allows for manual adjustments to the forecast to provide extra capacity to a BAA to account for situations that aren't fully captured in the day-ahead market forecast. With the launch of the Imbalance Reserve product, there is now an additional option for a BAA to add RUC adjustments based off any Imbalance Reserve amount that did not clear in IFM, along with the peak load for the day. The exact formulation for how CAISO sets the RUC adjustment is defined in the EDAM BPM.

Figure 163 and Figure 164 show a comparison of RUC adjustments used in the periods of May-August for 2025 and 2026. In September 2026 there were 78 hours with a RUC adjustment, a reduction from the 466 hours with RUC adjustments observed in September 2025. The maximum

hourly average adjustment in September 2025 was 3000 MW in hour ending 19, while the hourly average adjustment in September 2026 saw a steep reduction to 100 MW.

Figure 163: Day-ahead manual adjustments and demand in the ISO area

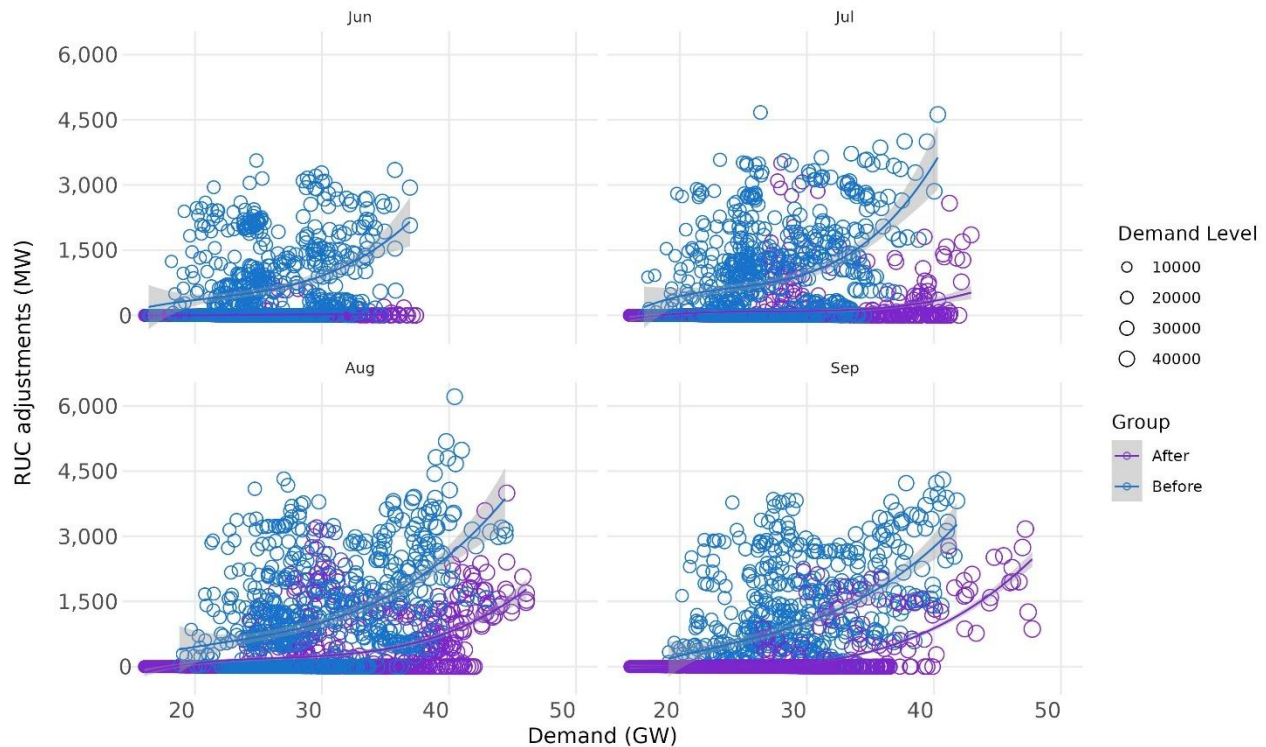


Figure 164 shows the trend over time on the use of RUC adjustment for ISO area, highlighting some key events relevant to the trends. Historically, more frequent and higher RUC adjustments are observed during conditions of high demand and tight supply conditions such as summer months. For summer 2026 and with the introduction of imbalance reserve, the daily trend of RUC adjustments has come down.

Figure 164: Hourly average of RUC adjustments

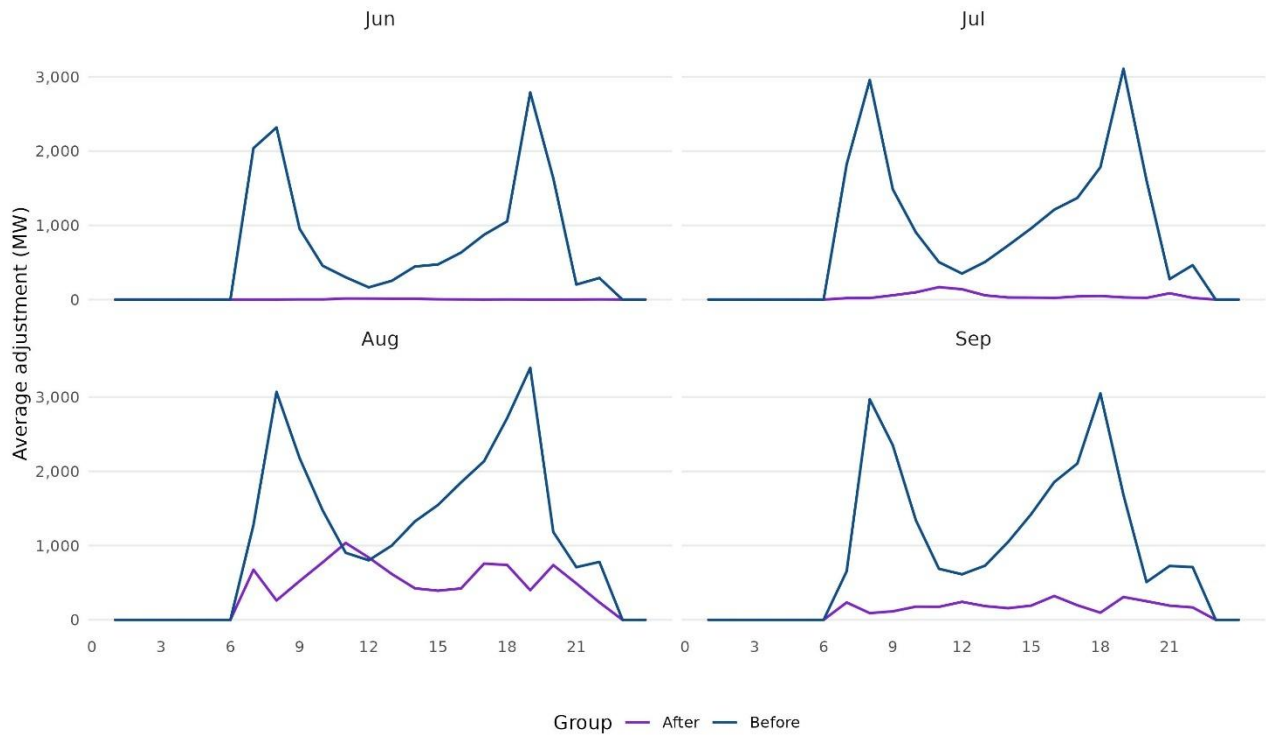


Figure 165: Historical RUC adjustments in the day-ahead market

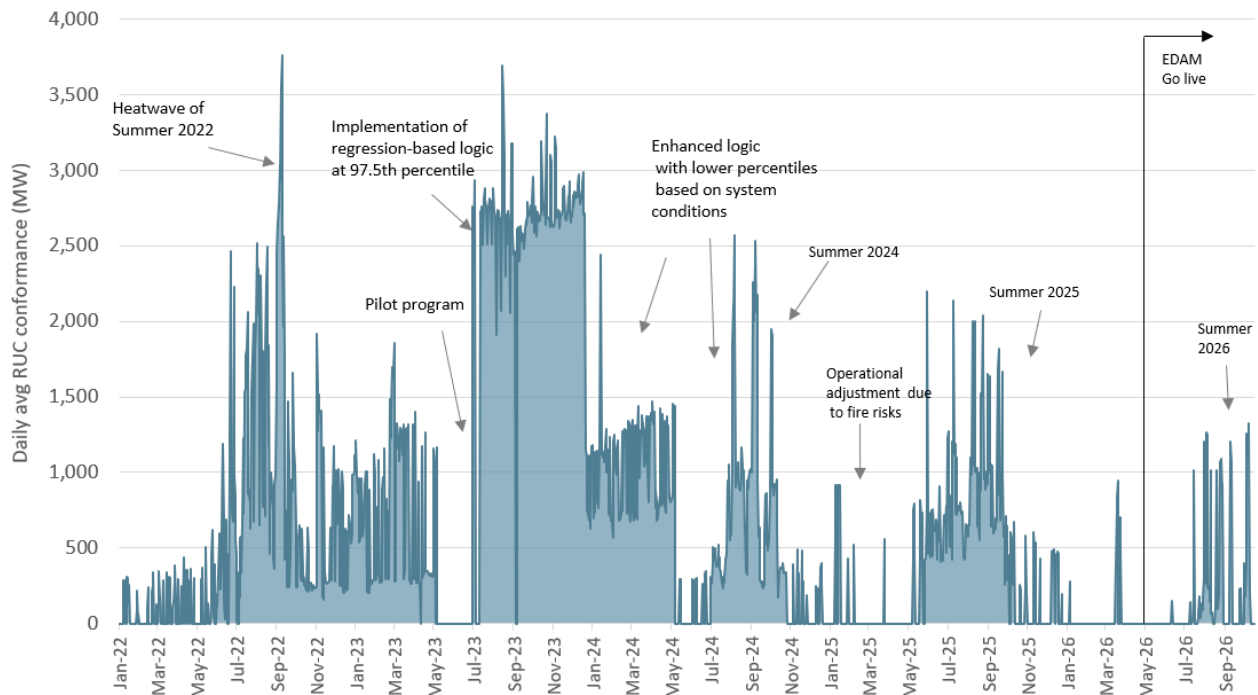
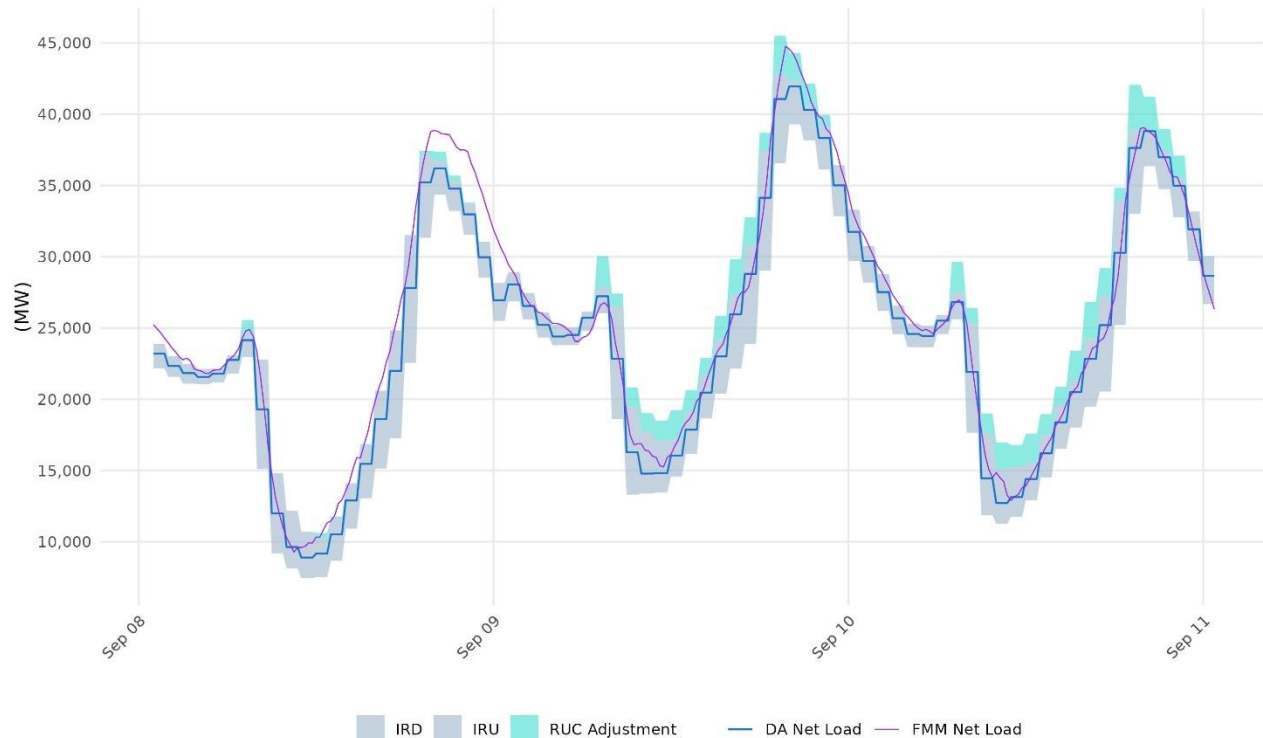


Figure 166 shows flexible capacity requirements for the day-ahead market for the days in which the ISO observed the annual peak of 2026. The blue line represents day-ahead net load (gross load minus wind and solar schedules), while the purple line represents fifteen-minute net load. Upward and downward imbalance reserves define the capacity band around day-ahead net load. The light-blue area represents additional capacity required through RUC adjustments.

Figure 166: Procurement of flexibility needs during CAISO's peak time



On September 8 and 9, load, wind, and solar forecast errors resulted in fifteen-minute net loads materially above day-ahead forecasts. These errors represent the realized uncertainty that imbalance reserves are designed to cover. However, upward imbalance reserves were insufficient to cover the full uncertainty on both days, and the ISO supplemented them with RUC adjustments. The combined capacity remained insufficient on September 8 but fully covered the realized uncertainty on September 9.

Figure 167 shows the trend over time on the use of RUC adjustment, IRU procurement, and IRU requirements for ISO area. This allows to see how IR and RUC adjustment complement to meet operational requirements for days when there is an expectation to secure capacity in the day-ahead market to meet uncertainty in real time. The IRU market requirement shows CAISO's

adjusted flex ramp requirement to clear in IFM, and the operation requirement is a referenced value based on load forecast assed by an operation procedure.

Figure 167 shows a consistent diurnal pattern from June through September, characterized by two pronounced peaks around hours 8 and 19, with lower values during midday and overnight hours. In September, the IRU procurement during morning and evening peaks where higher than previous months, reaching approximately 3,500 MW and 3,800 MW, respectively, while the operation requirement declines substantially compared with August, remaining below approximately 900 MW for most hours.

The operational requirement is generally lower than the IR requirement because it applies primarily during high-load conditions, whereas the IR requirement is determined programmatically using statistically derived uncertainty. However, when peak load exceeds 42,000 MW, the operational requirement may exceed the IR requirement because it is set to the full uncertainty level based on the 97.5th percentile.

Figure 167: Hourly average of RUC adjustment, IRU procurement/requirements

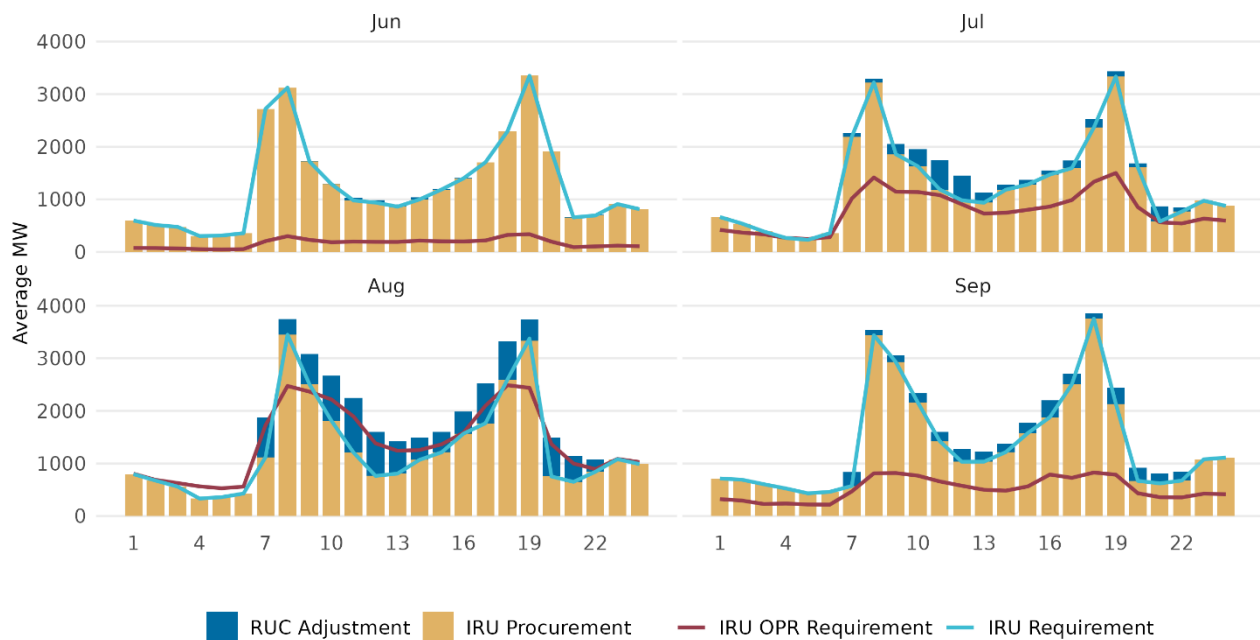
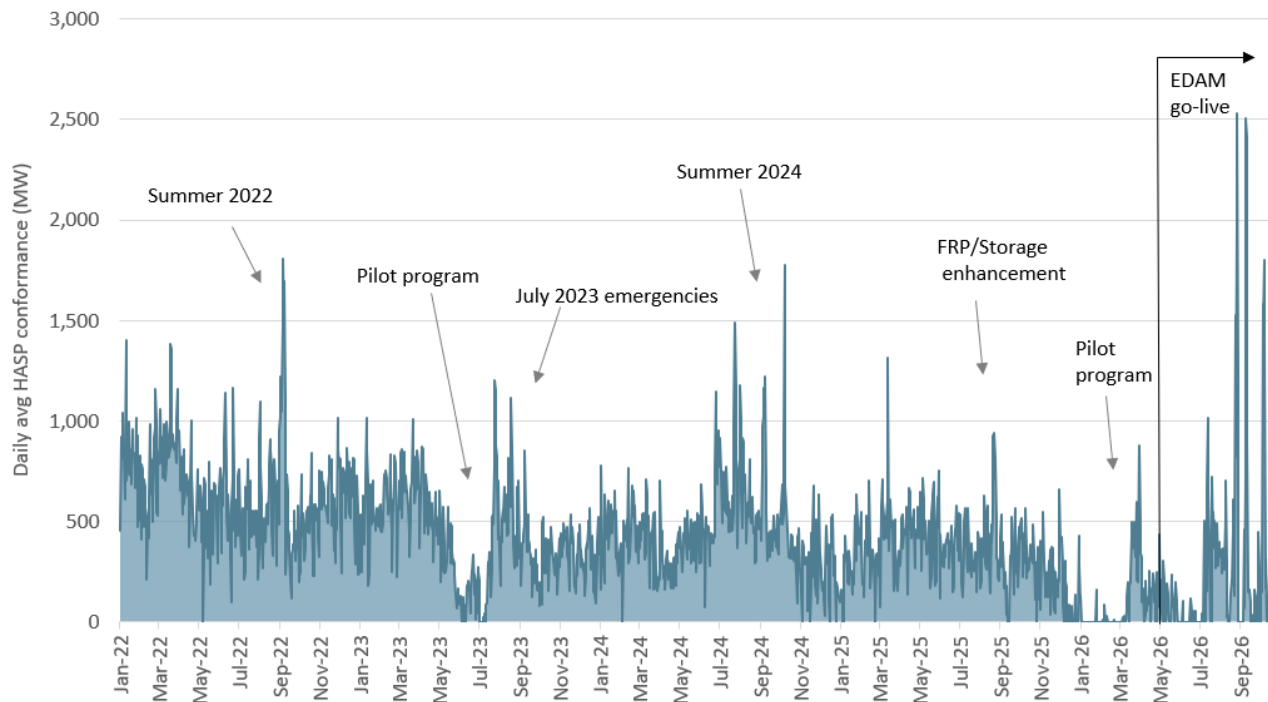


Figure 168 shows similar trend of load conformance for the hour ahead scheduling process (HASP). Historically, this market is utilized to gain additional ramping flexibility for peak hours since it is the last opportunity to schedule additional interties. Overall, the use of HASP load conformance has been consistent over time with higher use during summer conditions. In early 2026, its use was minimum during a pilot program used to understand the drivers for load conformance and its

implications in subsequent real-time submarkets. This pilot ended in early March, and its use afterwards continue to be low until the first week of July, two months after the EDAM launched. The load conformance reached up to 5,000 MW for peak hours during days when ISO area observed the peak of the year so far in September

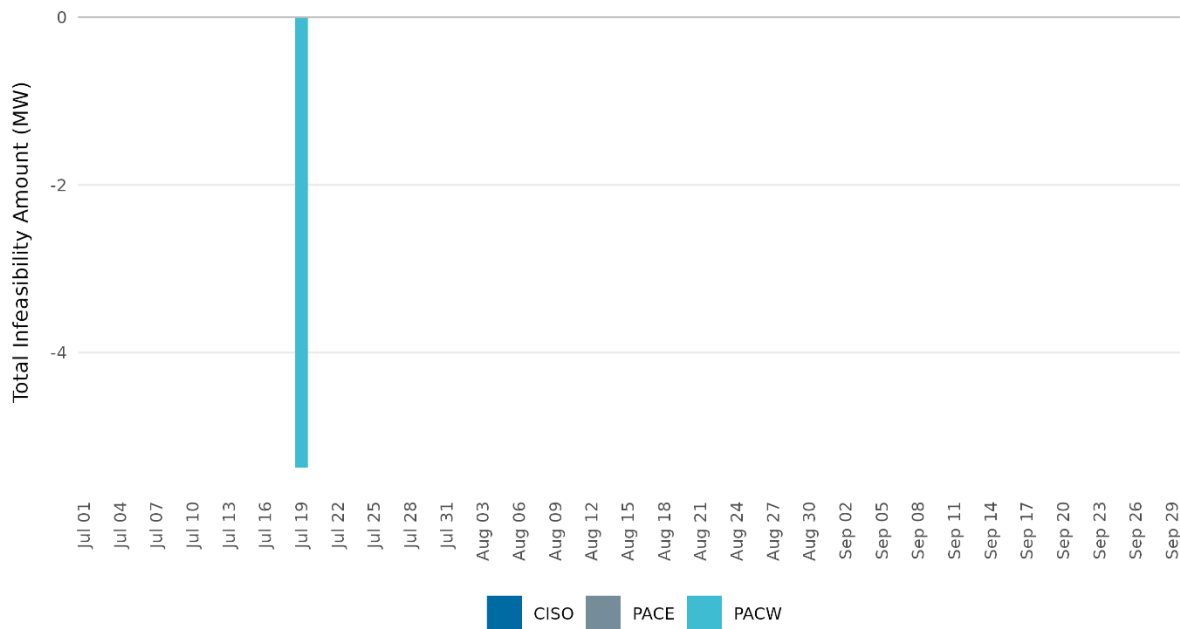
Figure 168: Historical load conformance in the hour ahead scheduling process



RUC infeasibilities

As part of the market construct, the RUC process may not be able to balance supply with total demand, which may include any RUC adjustments. This condition is known as infeasibility or RUC shortfall. The infeasibility may be in either the under-supply direction, which is indicated by a positive infeasibility, or the over-supply direction, which is indicated by a negative infeasibility. PACW observed over-generation infeasibilities of approximately 5 MW on July 19. No RUC infeasibilities were observed in August or September.

Figure 169: RUC Infeasibilities



Transitional Pricing

For the first six months following a new EDAM Entity's EDAM implementation, when power balance and/or transmission constraints within that entity's Balancing Authority Area are relaxed, CAISO will determine prices based on the last economic bid rather than administrative (penalty) prices. This transition-period pricing applies only to the new EDAM Entity's Balancing Authority Area. It does not apply to the CAISO Balancing Authority Area. This practice is also limited to the day-ahead market, and it does not apply in the real-time market⁹. The RUC infeasibilities reported in the prior section were priced using the last economic bid instead of the RUC infeasibility penalty price.

There are no RUC infeasibilities in September. For infeasibilities observed in previous months, please refer to prior versions of the monthly report.

⁹ A new WEIM Entity will receive transitional pricing in the real-time market for the first six months of its WEIM implementation.

Market Power Mitigation

Bids submitted into CAISO markets are subject to market power mitigation (MPM) to maintain a competitive market. In the day-ahead market, MPM uses a competitive path assessment for binding transmission constraints to determine whether a path is competitive or not. If a path is non-competitive, MPM procedures identify any non-competitive contribution of those binding transmission constraints to locational marginal prices for energy and reliability capacity up prices. Bids from resources within that EDAM balancing authority area will be subject to mitigation if the net contribution from non-competitive binding transmission constraints for these prices is positive.

MPM for the IFM market is a market process that existed before EDAM. Before EDAM/DAME, separate bids were not submitted for RUC. Any bid considered in the RUC process before EDAM/DAME had already been subject to the IFM MPM. As part of EDAM/DAME and the introduction of reliability capacity products that require separate bids, a MPM pass was added to assess the competitiveness of RUC reliability capacity bids. Figure 170 and Figure 171 show the total number of resources subject to mitigation as determined by the IFM MPM and RUC MPM passes daily, broken down by fuel type. Note, a resource is counted based on the number of day-ahead intervals it was subject to mitigation in, i.e., if a single resource was subject to mitigation in hours ending one through six then it will be counted six times. Gas and energy storage made up most resources subject to mitigation in IFM. In RUC, mitigation occurred much less frequently and was concentrated on a small number of days, with the largest increase occurring in late August. In general, there were far fewer resources subject to mitigation in RUC.

Figure 170: Resources subject to mitigation in IFM MPM, by fuel type

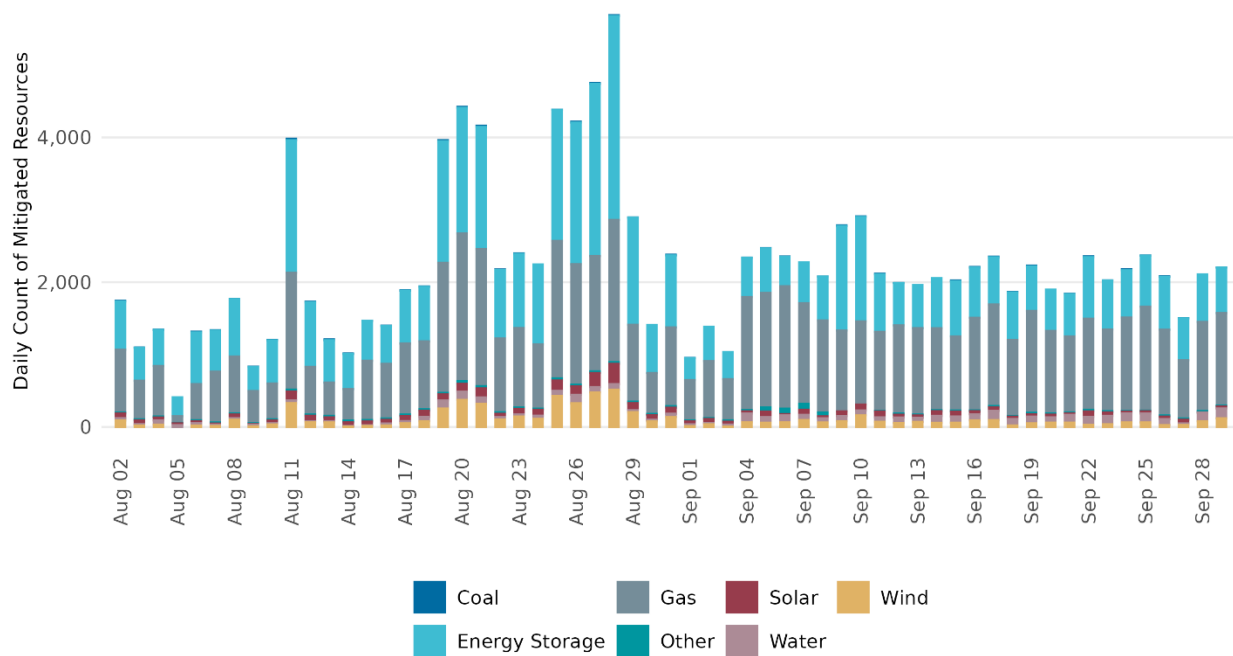


Figure 171: Resources subject to mitigation in RUC MPM, by fuel type

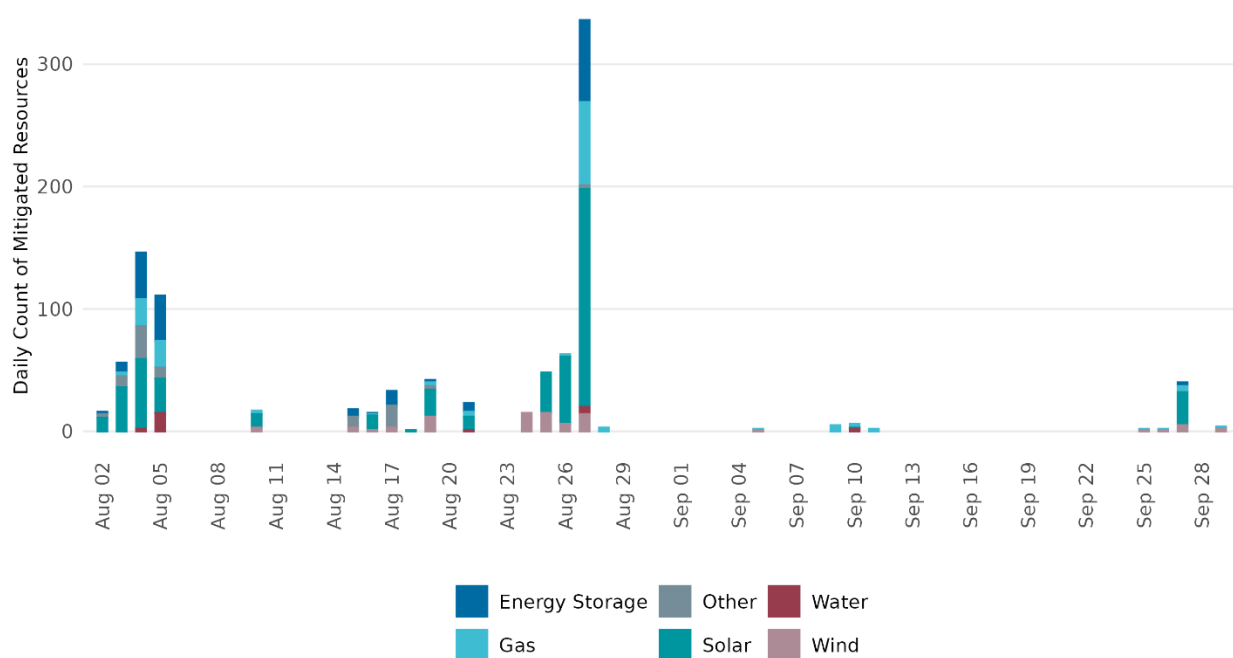


Figure 172 and Figure 173 show the same total counts as above but broken down by BAA. Figure 172 shows that the number of PACE resources subject to mitigation in IFM has been relatively consistent. The number of resources subject to mitigation in RUC was significantly lower than in IFM, especially for PACE. RUC mitigation remained relatively low through most of August and September.

Figure 172: Resources subject to mitigation in IFM MPM, by BAA

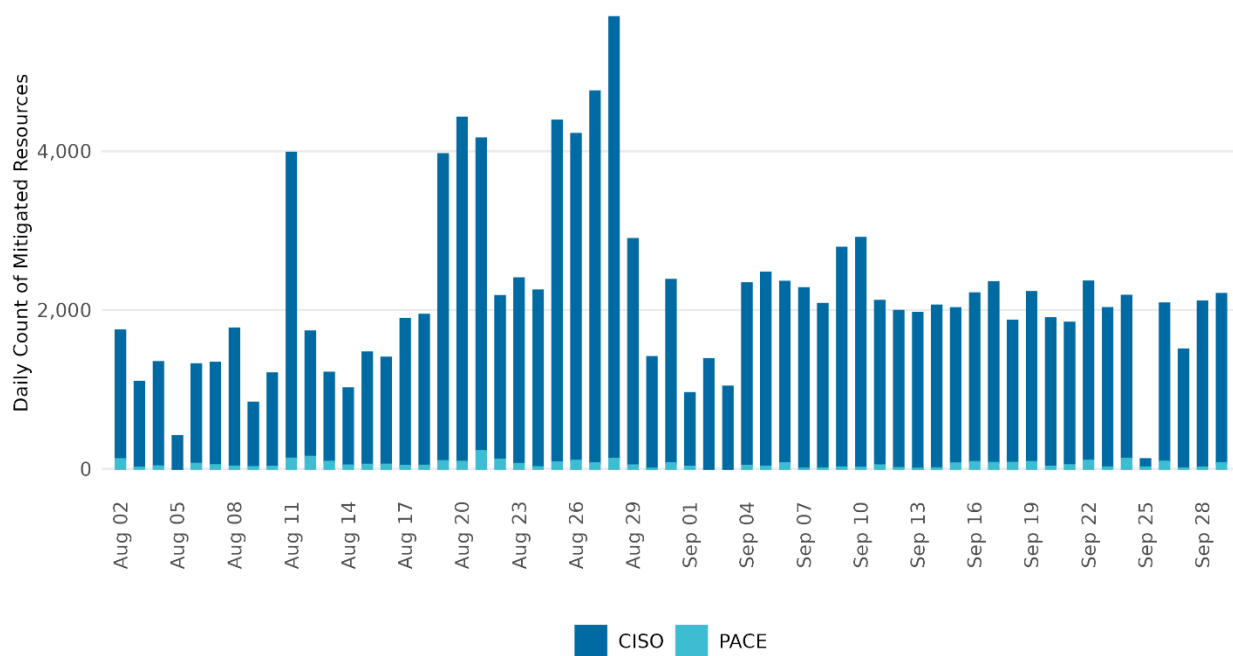


Figure 173: Resources subject to mitigation in RUC MPM, by BAA

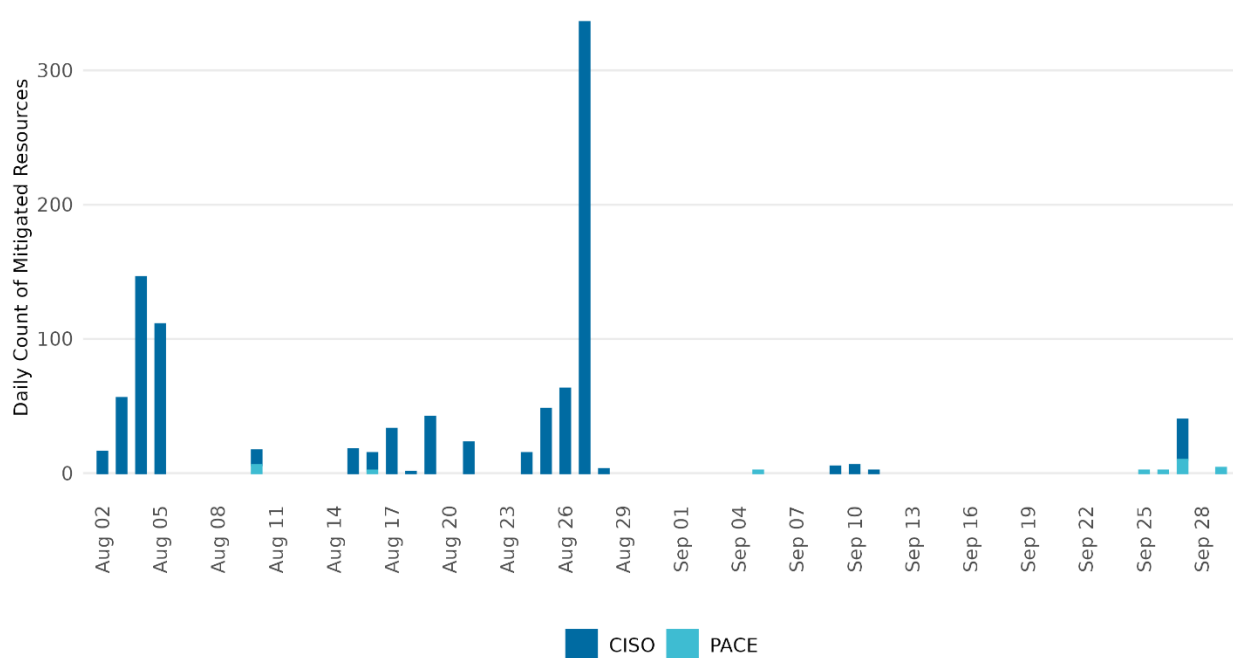


Figure 174 and Figure 175 show the average number of resources subject to mitigation in each hour of the day, by month for IFM and RUC, broken down by fuel type. Figure 174 shows that mitigation in IFM generally increased through the day and was highest during the late afternoon and evening hours in July, August, and September. There is a less consistent pattern in RUC, with relatively low levels of mitigation across most hours, particularly in September.

Figure 174: Resources subject to mitigation in IFM MPM, by fuel type hourly

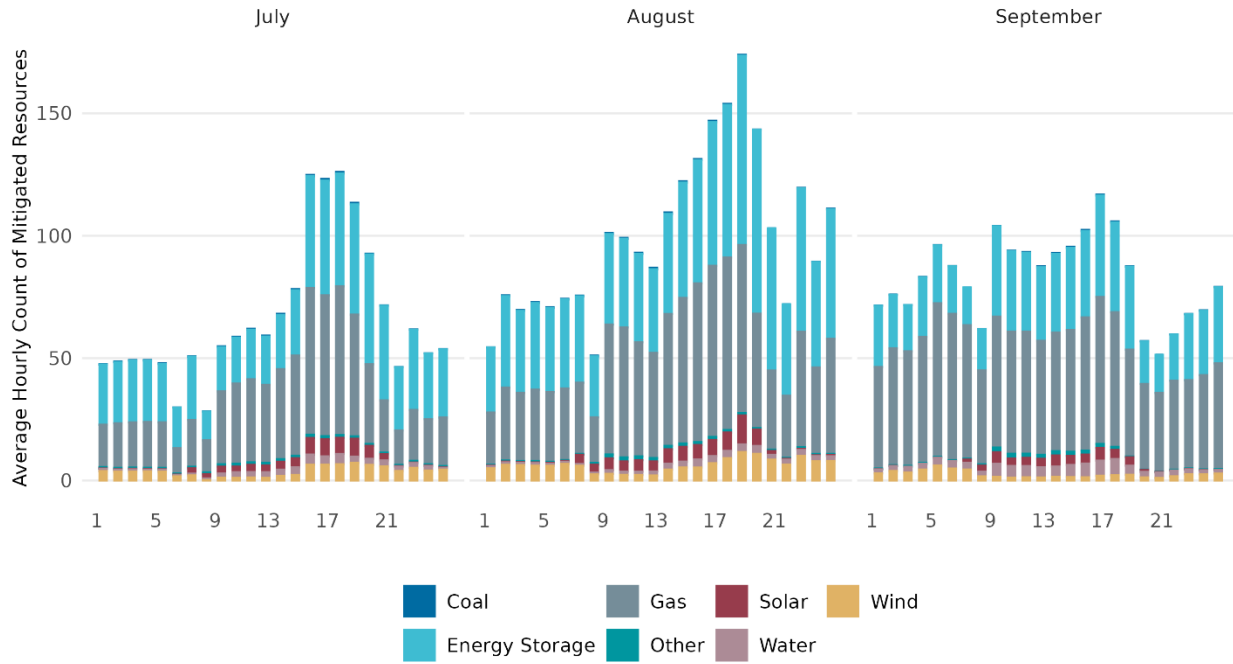
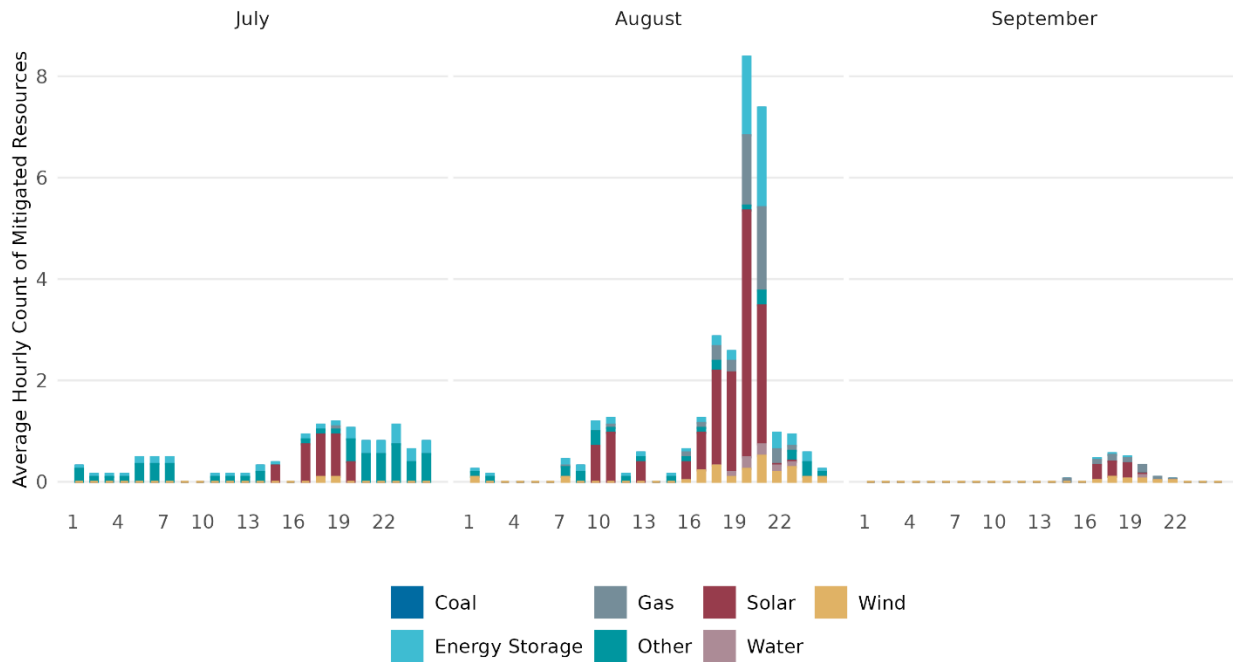


Figure 175: Resources subject to mitigation in RUC MPM, by fuel type hourly



Summer Conditions

Peak ISO Load

The ISO area recorded its highest load of the year so far on September 9 at 50,335 MW. This was the second highest record peak in the CAISO balancing area, only behind the record peak at 52 GW observed in September 6, 2022.

Figure 176 shows the historical load level distributions in the ISO area over the past six years. Load levels have generally remained within a tight range with few outliers that would indicate extreme conditions. The short distribution tails suggest that load variability has been limited. Peak loads in September exceeded 40,000 MW on 4 days. The average daily peak load in September 2026 was 35,491 MW.

Figure 176: Historical distribution of load levels in the ISO area

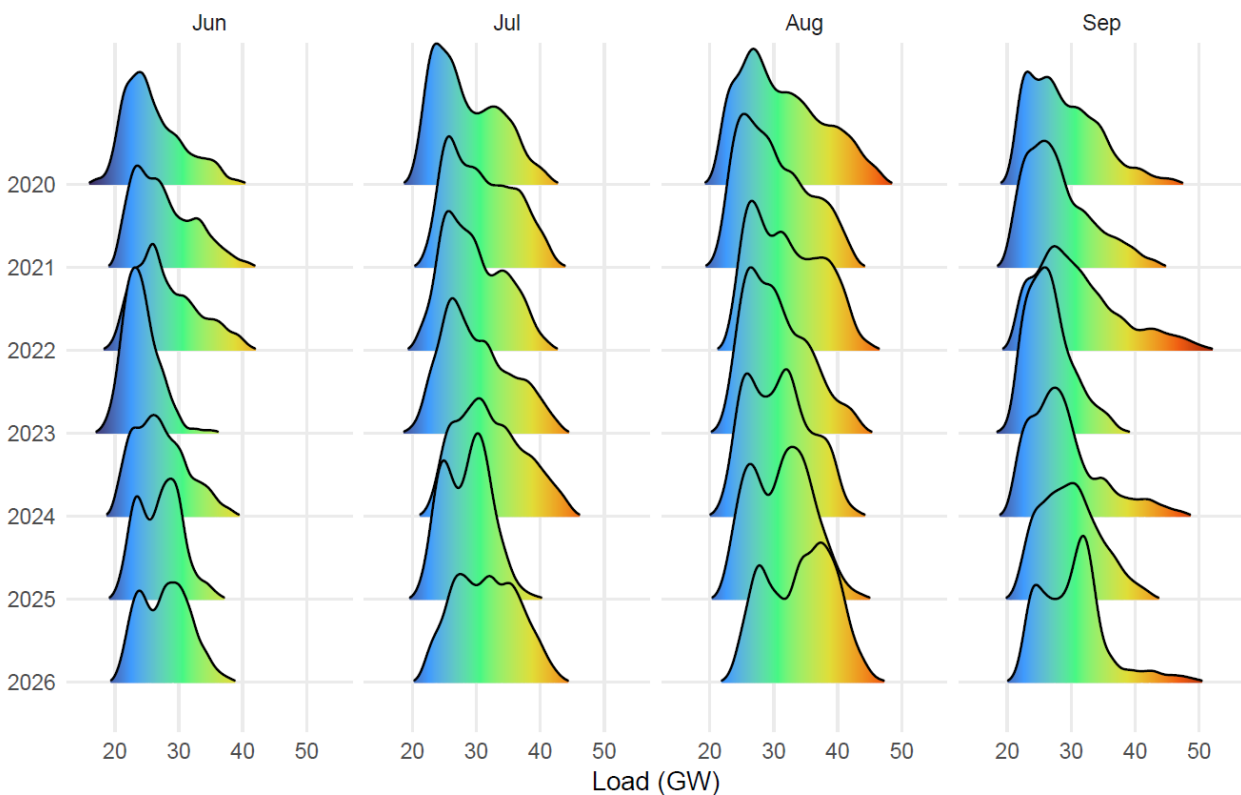
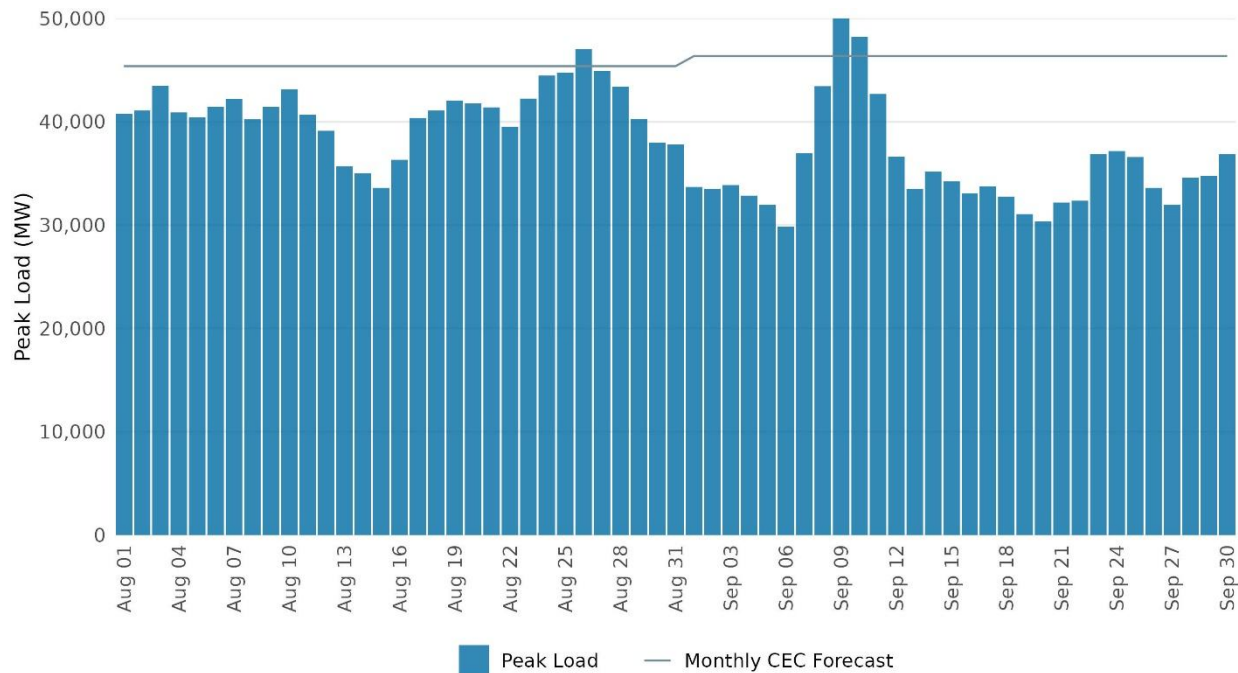


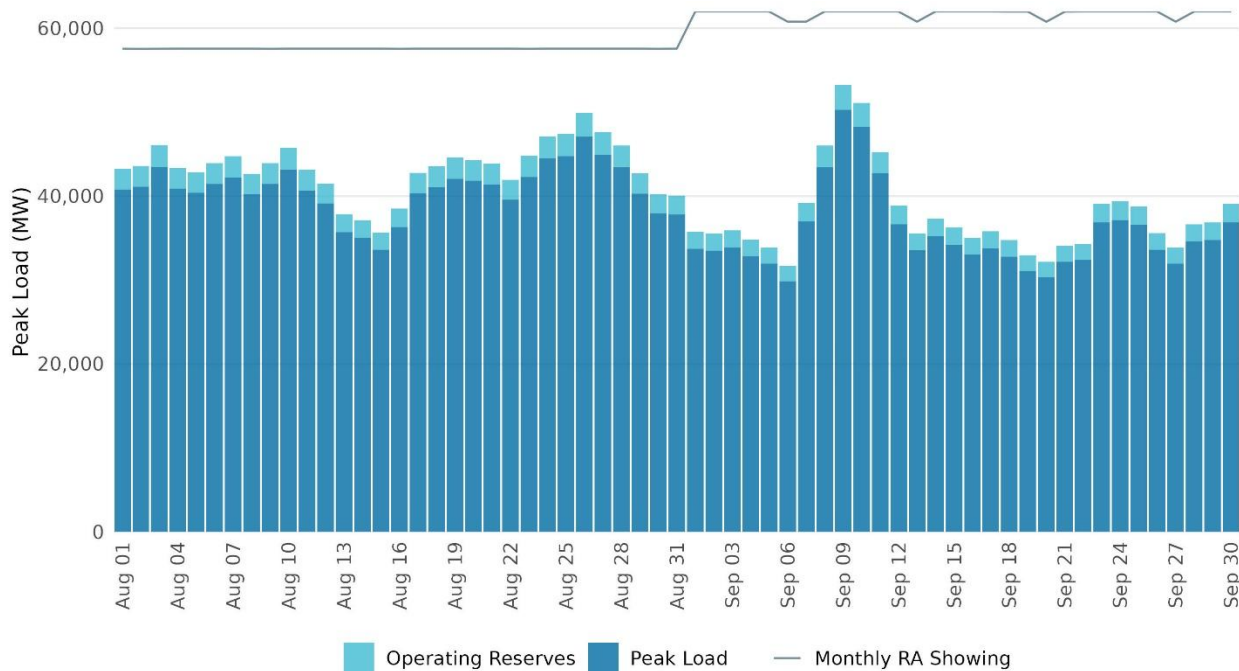
Figure 177 shows the 5-minute average daily load for August and September relative to the CEC month-ahead forecast used to assess the resource adequacy requirements. The instantaneous load peak in September 2026 was 50,335 MW on September 9. This peak exceeded the CEC month-ahead forecast of 46,360 MW. The figure below is based on the five-minute averages of the actual load. The highest five-minute average peak load for September was 50,252 MW.

Figure 177: Daily peak load and CEC month-ahead forecast



The actual load did not exceed the monthly RA showings in September 2026 as illustrated in Figure 178. There was plenty of headroom in the monthly RA supply in September to meet the observed levels of load. The gray 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 178: Daily peak load, operating reserves and RA capacity

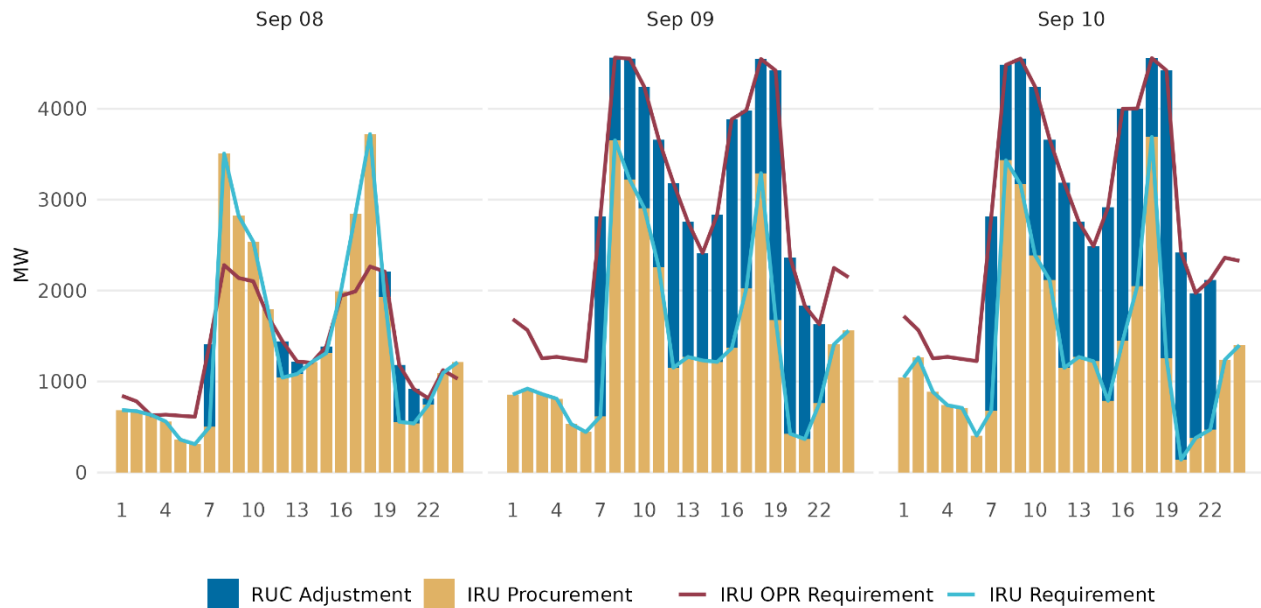


RUC Adjustment

The RUC load adjustment is an additional hourly MW value added to the forecasted load in RUC. Figure 179 shows hourly RUC adjustments, IRU procurement, IRU requirements, and IRU OPR requirements from September 8 through 10, when CAISO experienced its annual peak load. On September 8, RUC adjustments were relatively limited, and IRU procurement accounted for most of the combined volume. Two peaks occurred around hours 8 and 18, reaching approximately 3,500 MW and 3,700 MW, respectively.

On September 9 and 10, RUC adjustments increased substantially during the morning and evening peaks, bringing the combined volume above 4,500 MW. IRU procurement remained relatively stable at approximately 1,000–1,500 MW during midday, while RUC adjustments supplied a significant share of the total. Because load forecasts exceeded 42,000 MW on both days, the IRU OPR requirement tracked the 97.5th percentile of the full IRU requirement. Combined IRU procurement and RUC adjustments were sufficient to meet the full IRU requirement during these peak-load days.

Figure 179: Daily RUC adjustment and IRU procurement/requirements



Market Prices

Market prices naturally reflect supply and demand conditions. As the market supply tightens, prices tend to rise.

Figure 180 compares the daily average prices across ISO's markets for the months of August and September.¹⁰ The daily average fifteen-minute market prices reached \$119/MWh (\$143 in August), while the daily average day-ahead prices reached about \$101/MWh (\$86 in August), and the five-minute market prices reached a maximum of about \$93/MWh (\$164 in August). In September, the IFM, FMM, and RTD maximum all occurred on September 9.

¹⁰ 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 180: Average daily prices across markets, August and September 2026

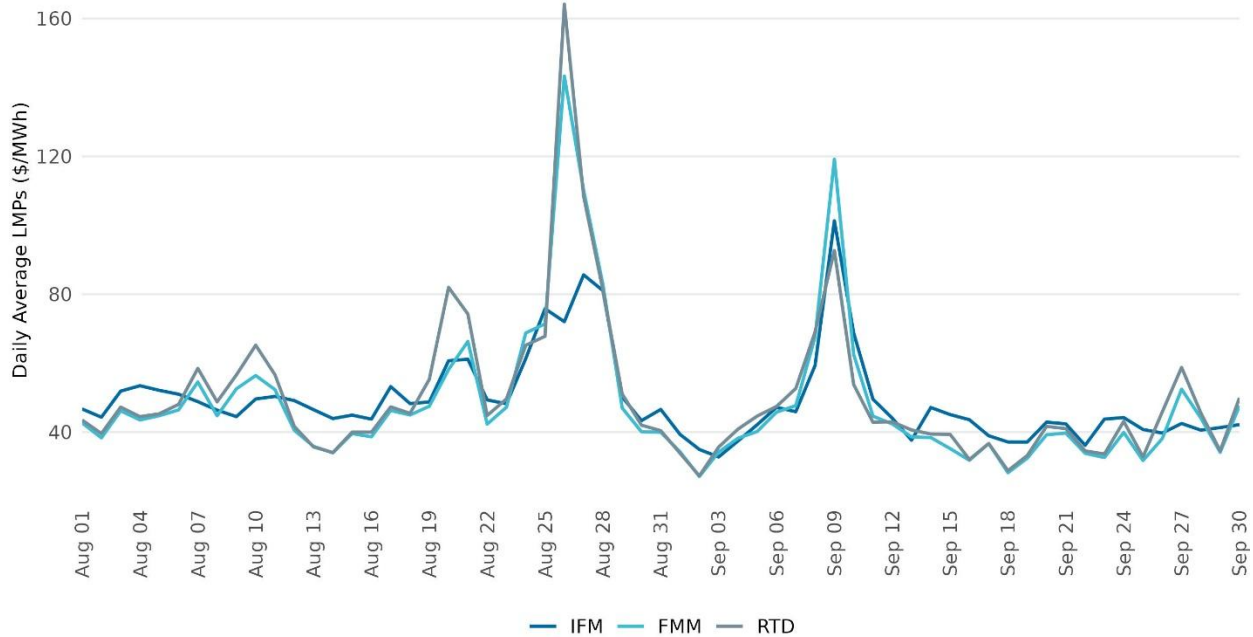


Figure 181 shows average hourly prices across ISO's markets for both August and September 2026. In September, the hourly average prices for the IFM, FMM, and RTD all peaked in trade hour 19 at \$63/MWh, \$63/MWh, and \$58/MWh, respectively.

Figure 181: Average hourly prices across markets

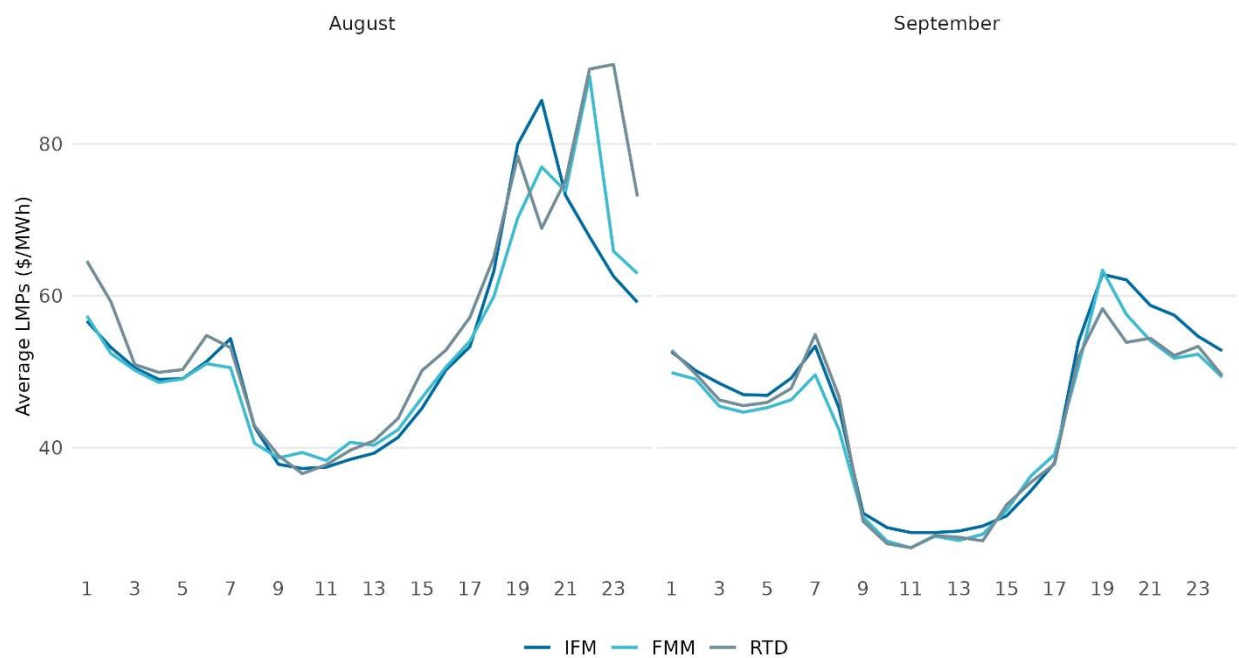
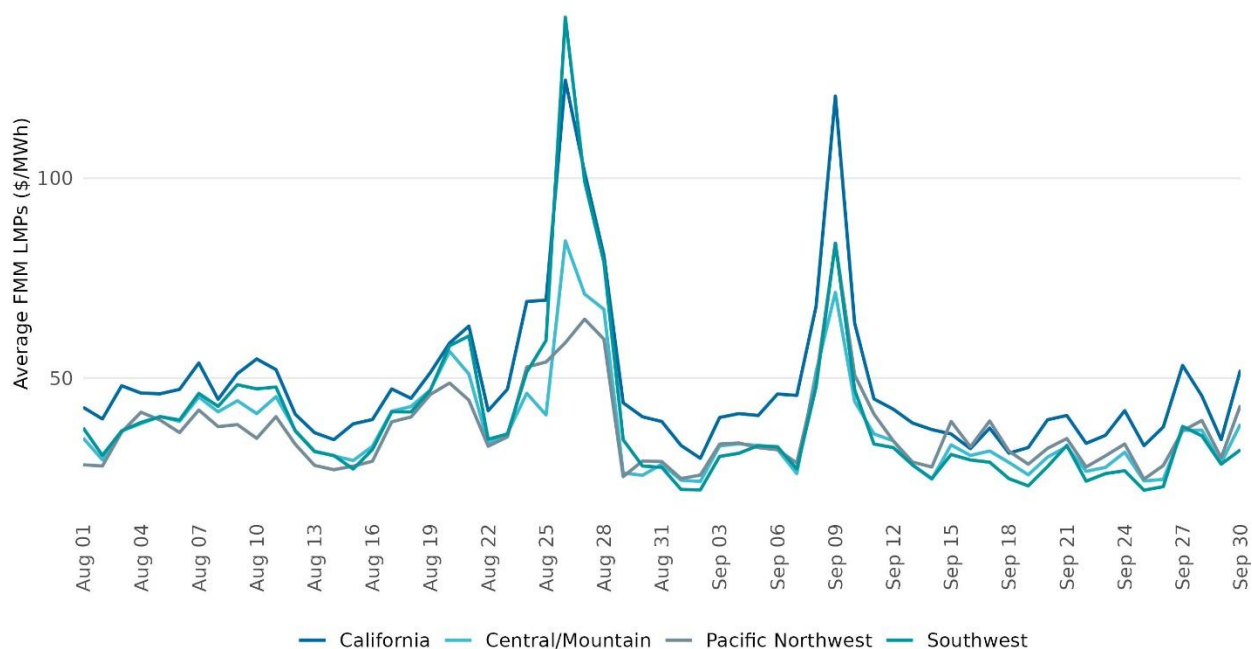


Figure 182 and Figure 183 show daily average LMPs for all four regions for the months of August and September. In August, the highest FMM regional daily average was observed in Southwest on August 26 at about \$140/MWh, while the highest RTD regional daily average occurred in Southwest on August 26 at about \$177/MWh. In September, the highest FMM regional daily average was observed in California on September 9 at about \$121/MWh, while the highest RTD regional daily average occurred in California on September 9 at about \$93/MWh. On the August FMM peak date, prices across the four regions ranged from about \$59/MWh to \$140/MWh. On the September FMM peak date, average prices were about \$121/MWh in California, \$71/MWh in Central/Mountain, \$84/MWh in Pacific Northwest, and \$84/MWh in Southwest.

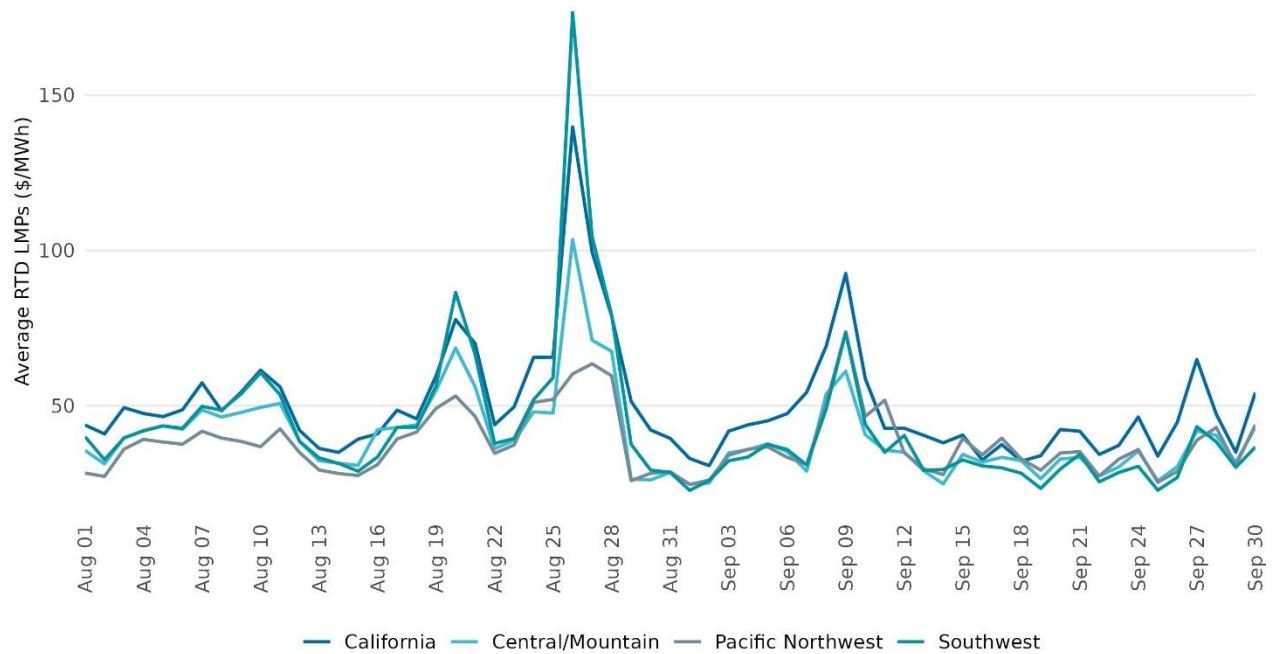
Figure 184 and Figure 185 further explore the peaks by depicting three-day periods of hourly averages for WEIM Load Aggregation Point (ELAP) prices aggregated by geographical region for RTD and FMM.¹¹

Figure 182: Average daily prices across region for FMM market



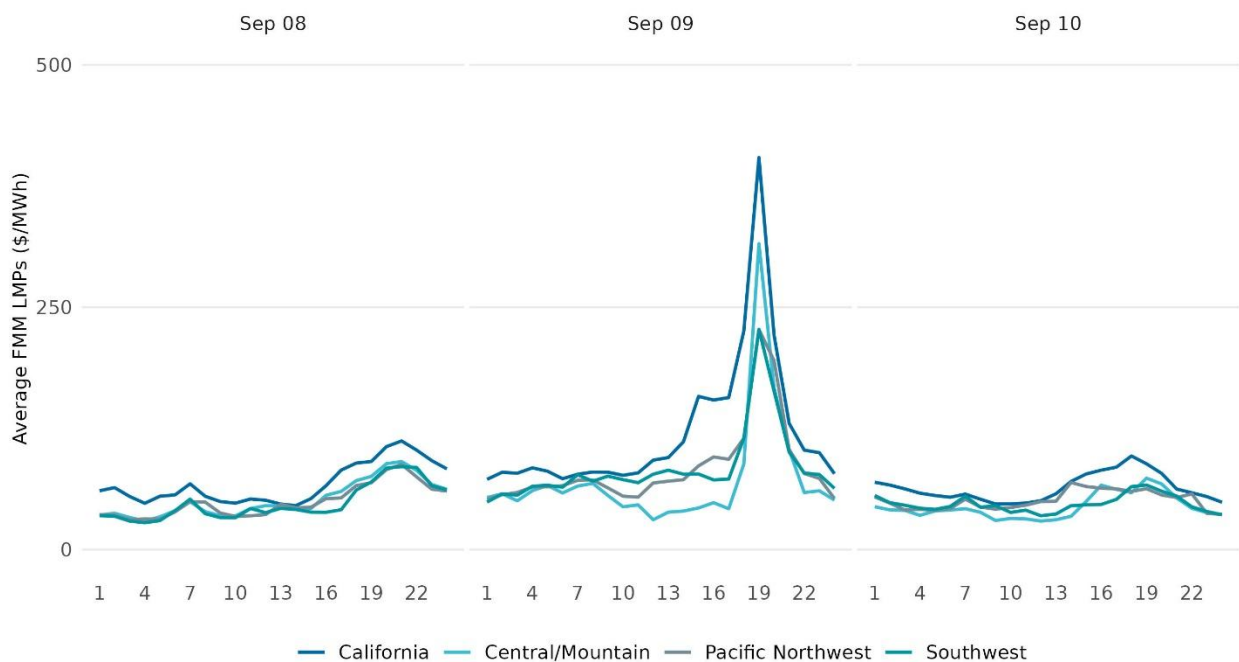
¹¹ The Pacific Northwest region includes balancing areas such as Bonneville Power Administration, Powerex, Avista Corporation, Avangrid Renewables, Tacoma Power, Seattle City Light, Puget Sound Energy, Portland General Electric Company, and PacifiCorp West. Southwest region includes Tuscon Electric Power, 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, PacifiCorp East, Black Hills, and PowerWatch (formerly BHE Montana). California region includes ISO, Los Angeles Department of Water & Power, Balancing Authority of Northern California, and Turlock Irrigation District.

Figure 183: Average daily prices across region for RTD market



For FMM, On September 8, California is the highest at \$112/MWh, followed by Central/Mountain at \$91/MWh. On September 9, California is the highest at \$405/MWh, followed by Central/Mountain at \$316/MWh. On September 10, California is the highest at \$97/MWh, followed by Central/Mountain at \$74/MWh.

Figure 184: Average hourly prices across region for FMM market



For RTD, On September 8, California is the highest at \$104/MWh, followed by Central/Mountain at \$91/MWh. On September 9, California is the highest at \$193/MWh, followed by Central/Mountain at \$170/MWh. On September 10, California is the highest at \$96/MWh, followed by Central/Mountain at \$73/MWh.

Figure 185: Average hourly prices across region for RTD market

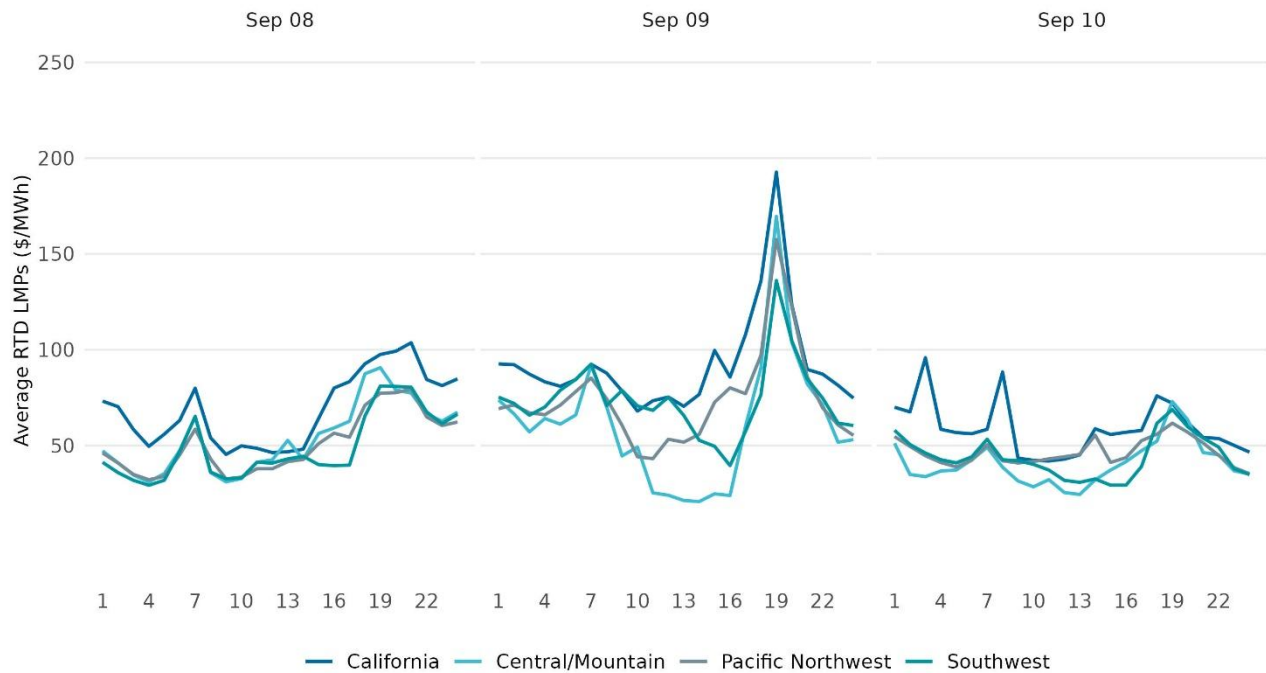


Table 14 shows the monthly average regional LMPs in the FMM and RTD markets from May through September 2026. California had the highest monthly average prices in September in both FMM and RTD, at \$43.6/MWh and \$44.6/MWh, respectively.

Table 14: Monthly Average Regional LMP (\$/MWh) by Market and Region

Region	FMM					RTD				
	May	Jun	Jul	Aug	Sep	May	Jun	Jul	Aug	Sep
California	13.3	19.9	40.6	52.9	43.6	14.0	20.4	42.6	55.6	44.6
Southwest	9.8	24.5	36.4	46.9	31.7	11.0	25.3	40.9	52.0	33.7
Pacific Northwest	12.3	12.4	29.4	39.0	35.3	10.8	12.2	31.3	39.6	36.3
Central/Mountain	12.6	15.8	37.5	43.2	32.9	14.8	15.9	43.1	46.7	34.4

Renewable Production

CAISO's area utilizes hydro production throughout the year to meet demand needs.

Figure 186 shows the historical trend of total energy produced from hydro and other renewable resources. Hydro production for 2026 so far has been lower than previous years. Hydro production in September 2026 was about 2 percent lower than the production observed in September 2025. With the addition of more solar resources into the system, solar production in September 2026 was about 10 percent higher than the production in September 2025.

Figure 187 shows the daily renewable production for July, August and September. Figure 188 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 189 below shows the hourly profile of the average energy produced from hydro resources as well as solar and wind resources for September 2026.

Figure 186: Historical trend of hydro and renewable production

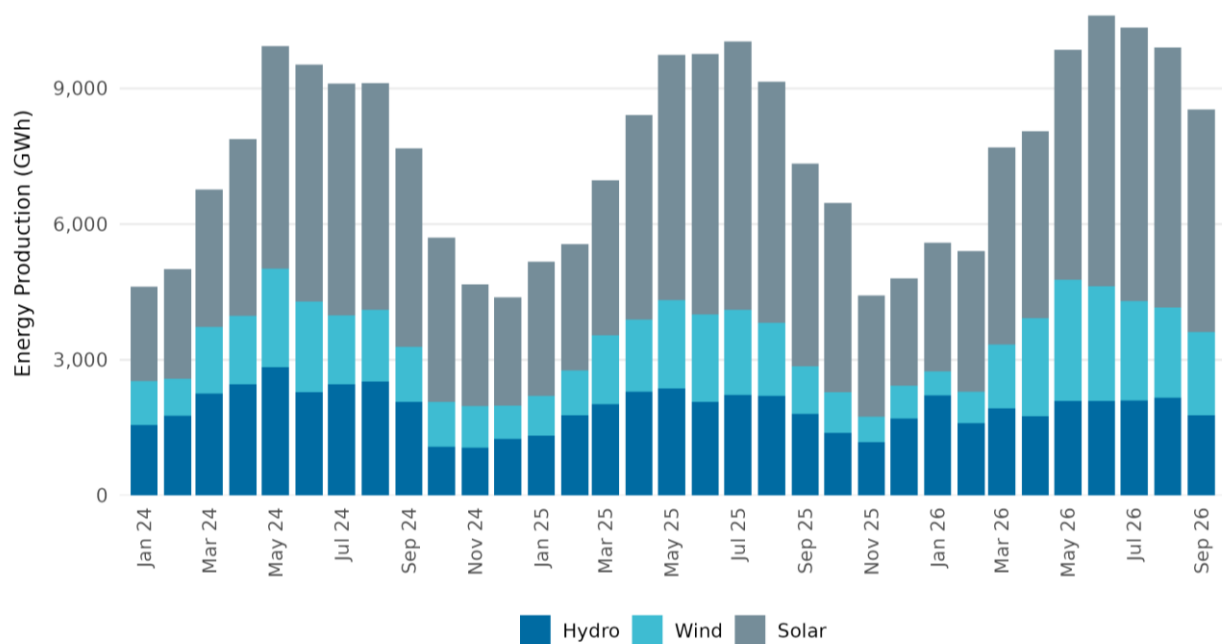


Figure 187: Daily trend of hydro and renewable production

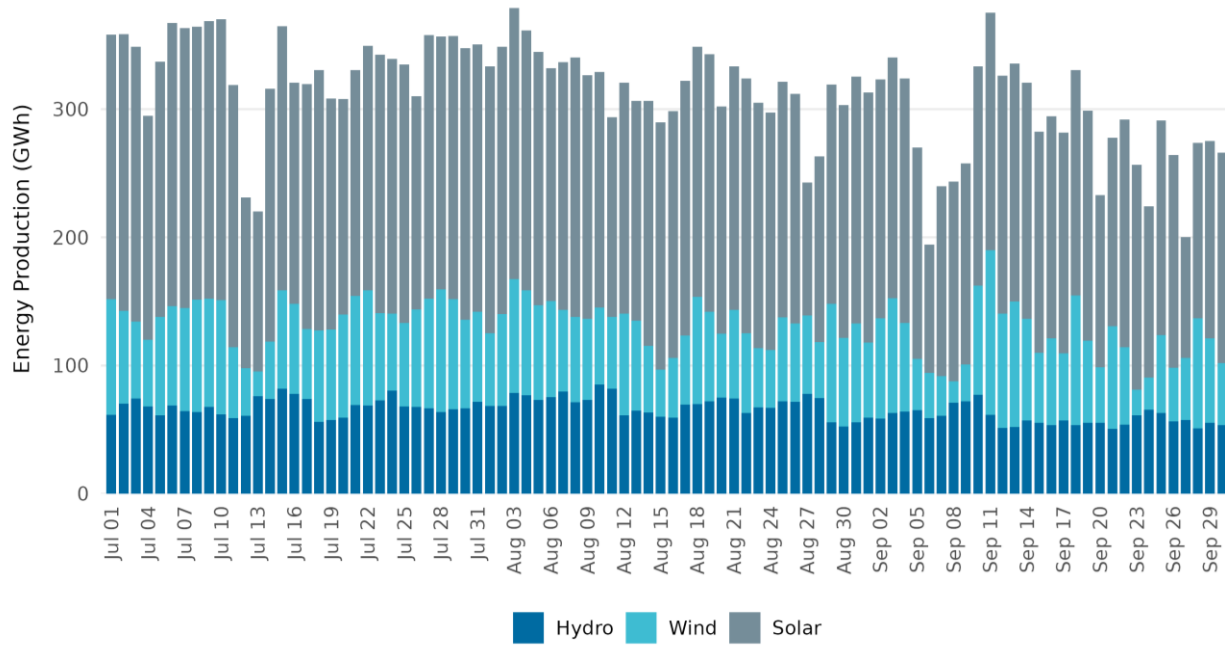


Figure 188: Historical trend of solar production

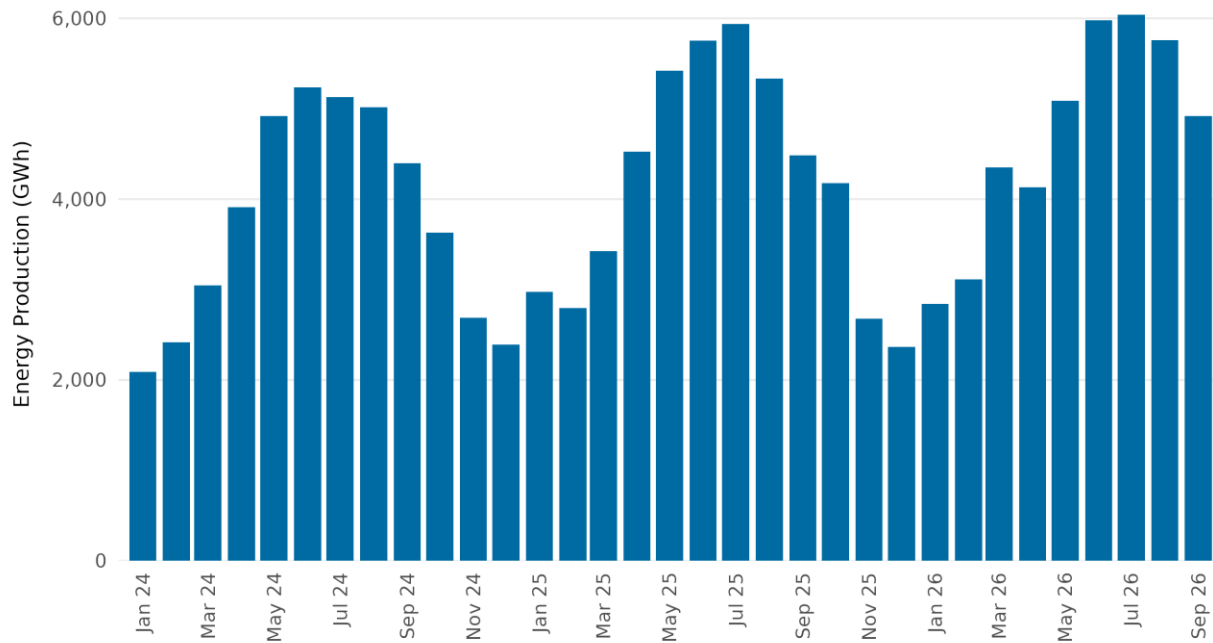
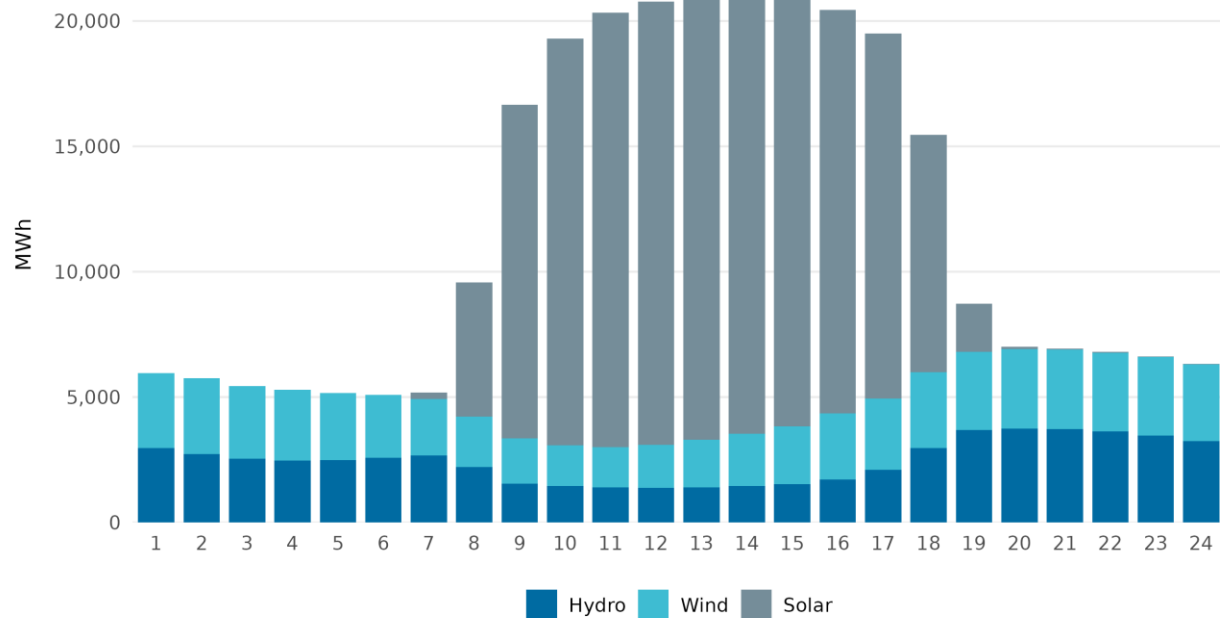


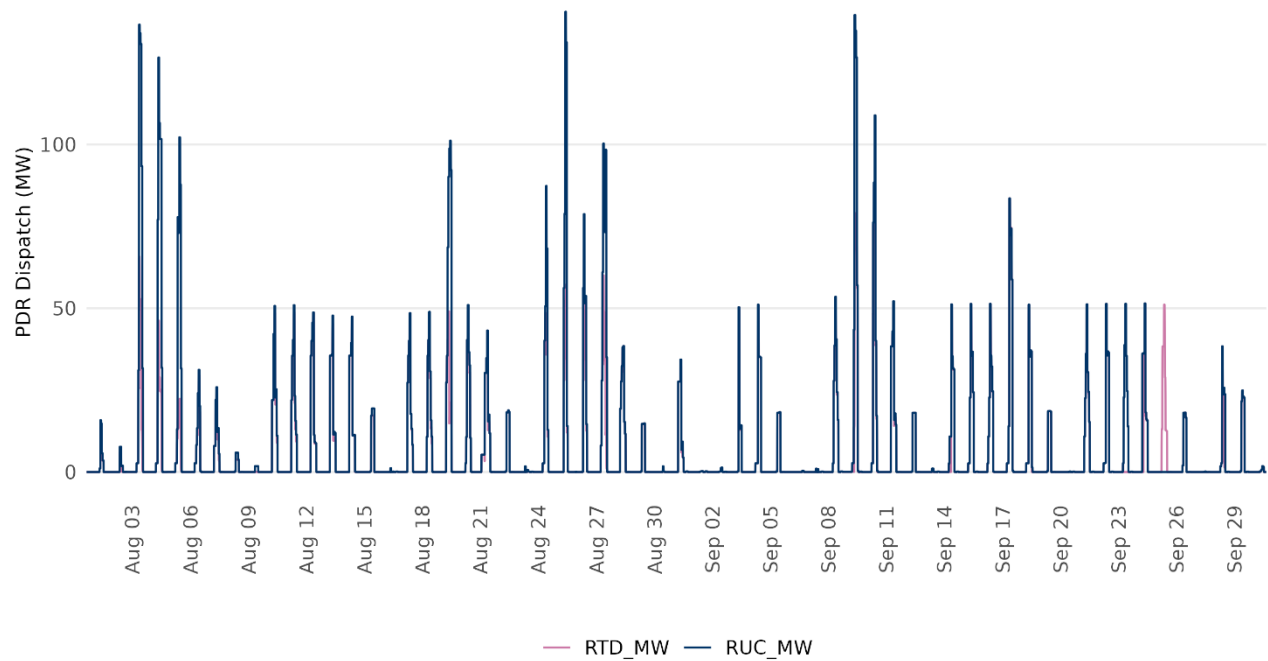
Figure 189: Hourly profile of wind, solar and hydro production for September

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.

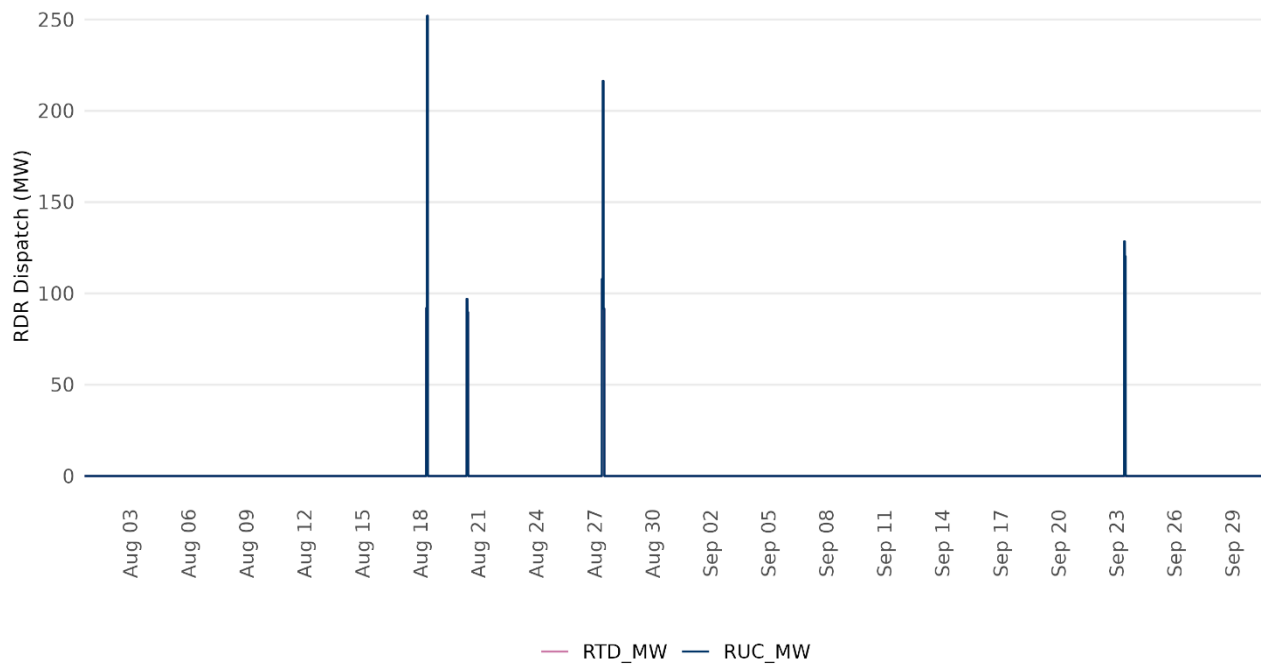
Figure 190 shows the dispatch of proxy demand resources (PDR) in both the day-ahead and real-time markets. PDRs are dispatched economically in all markets based on their bid-in prices. During the month of August and September, PDR resources were consistently dispatched in both the day-ahead and real-time markets and the times overlap but values are slightly different. The largest volume of PDR dispatches in the day-ahead timeframe occurred on August 25 at about 140 MW, whereas in the real-time market, it was a maximum of 87 MW on September 10.

Figure 190: PDR Dispatches in day-ahead and real-time markets



In September, reliability demand response resources (RDRRs) were only triggered on September 23. Figure 191 shows the dispatches of RDRRs in both the day-ahead and real-time markets for August and September. 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 18 to about 252 MW for HE 18. RDRRs were dispatched in RUC and RTD market to the same amount of 252 MW at the same time, hence the lines for RUC MW and blue line for RTD MW are overlapping.

Figure 191: RDRR dispatches in day-ahead and real-time markets



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.

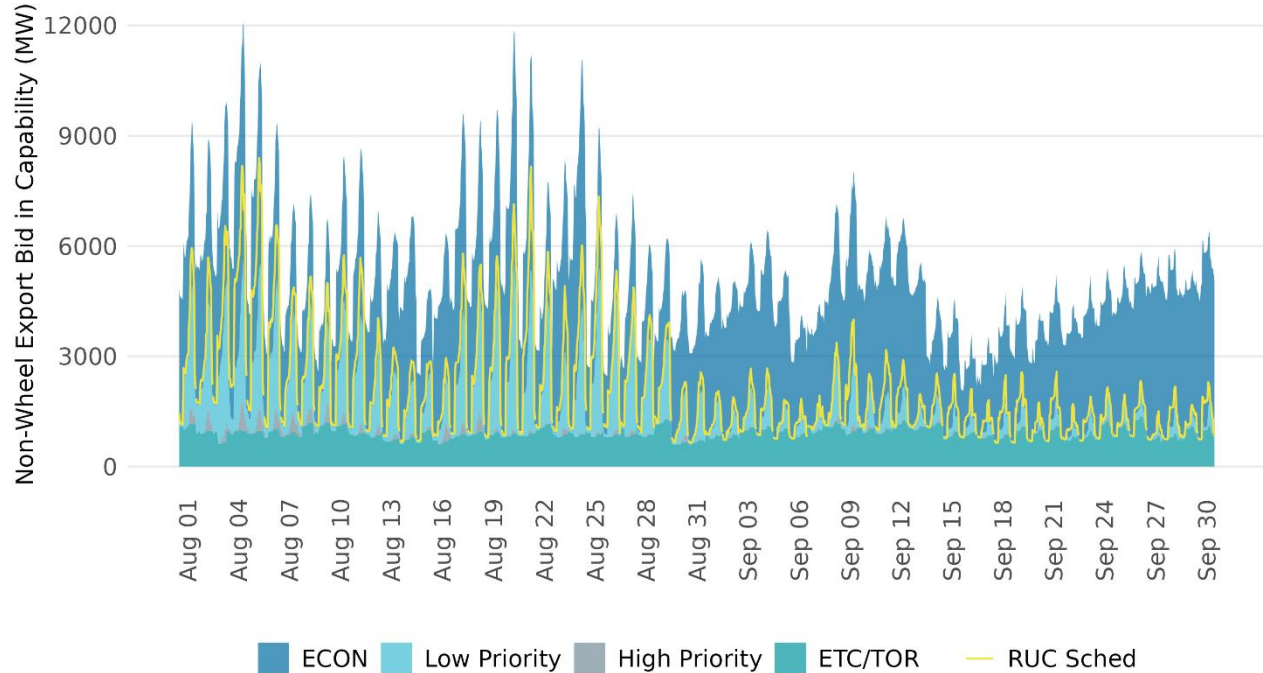
The ISO's markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics, and system conditions, are considered. In 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 192 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 yellow. The RUC schedules are used as references instead of the IFM schedules because they are the relevant schedules for clearing interties in the day-ahead market. Export volumes in September decreased compared to August.

Figure 192: Day-ahead Bid-in capacity and RUC cleared export



The RUC schedule plus RCD minus RCU 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 65 percent, 16 percent, 18 percent and 1 percent of the export capacity were for economic bids, LPT, ETC/TOR and PTK, respectively. The total of bid in export volume in September was lower comparing to August. The highest RUC scheduled was in hour ending 18 on September 9th, at about 3,999MW.

Figure 193 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 slightly larger volumes of economic bids in September comparing to August, 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 193: Day-ahead bid-in capacity and RUC-cleared imports

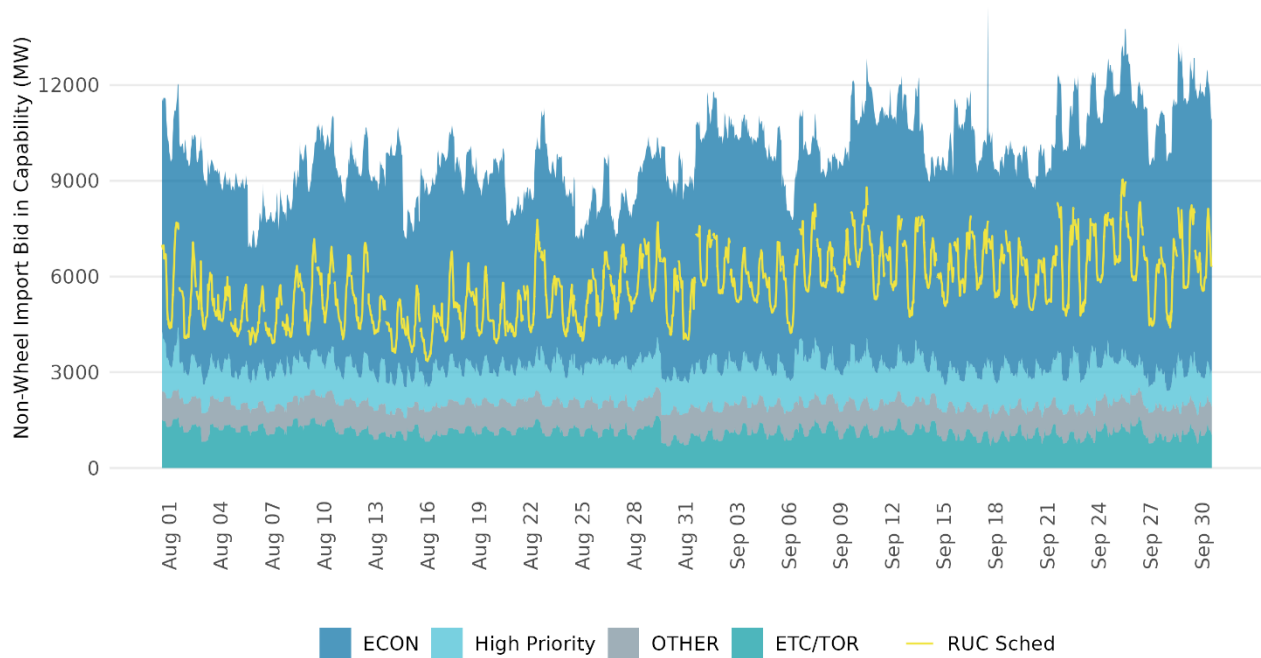
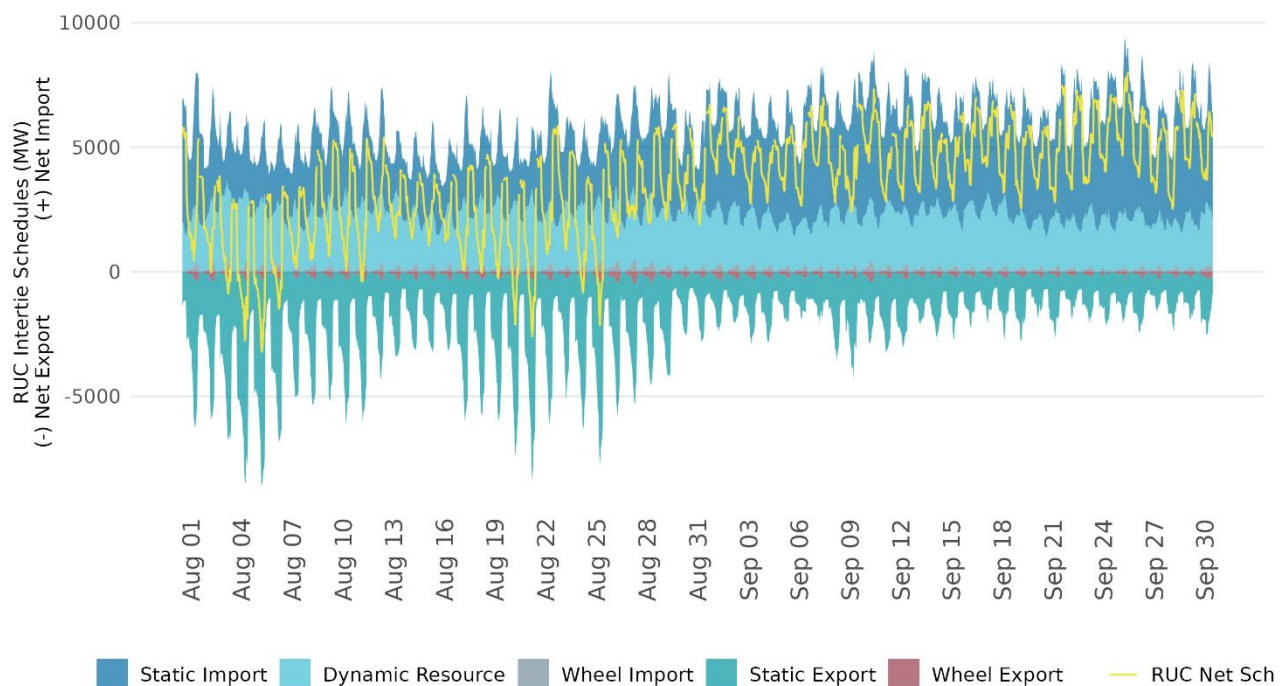


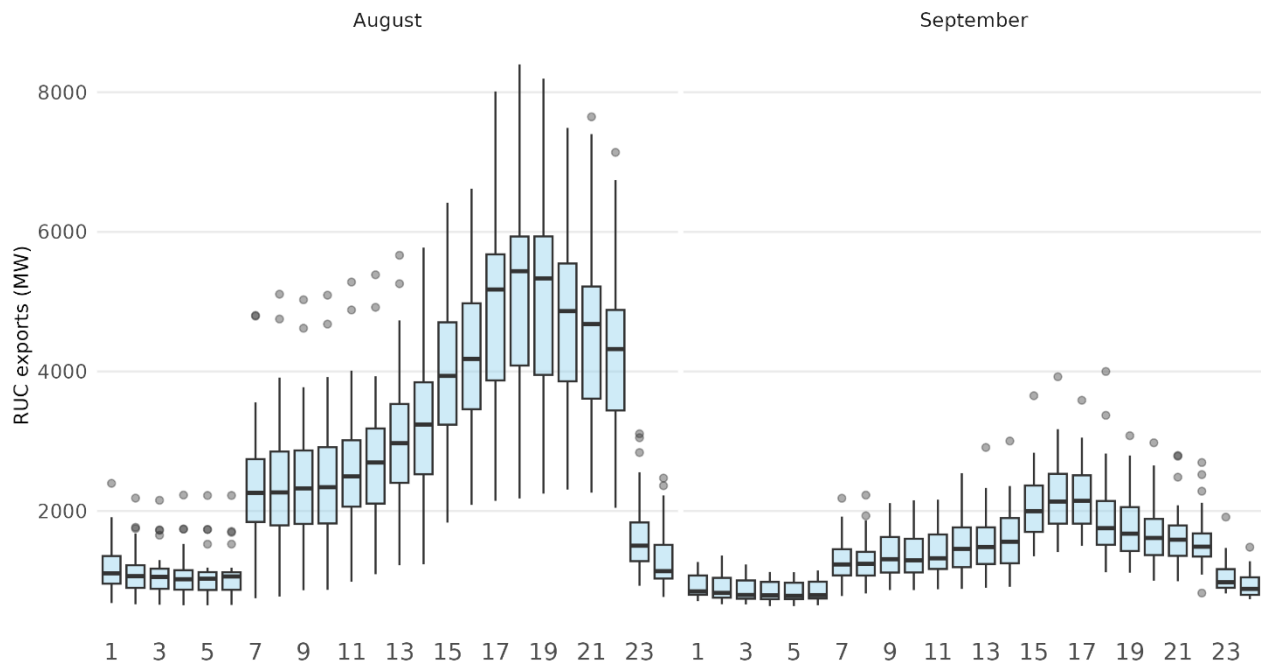
Figure 194 shows the overall intertie schedules organized by type of schedule, as well as the net interchange based on the RUC solution for two months. The net interchange projected in the RUC process reached its lowest level on September 9 in HE15 at about 2388MW due to the higher level of exports cleared.

Figure 194: Breakdown of RUC cleared schedules



An area of interest since summer 2020 is the trend of exports in the ISO's system. Figure 195 illustrates the hourly distribution of RUC schedules for exports and that the highest volume occurred during afternoon hours. Compared to August, September had lower levels of RUC export in all hours. The highest volumes were cleared in hour ending 15 and 17.

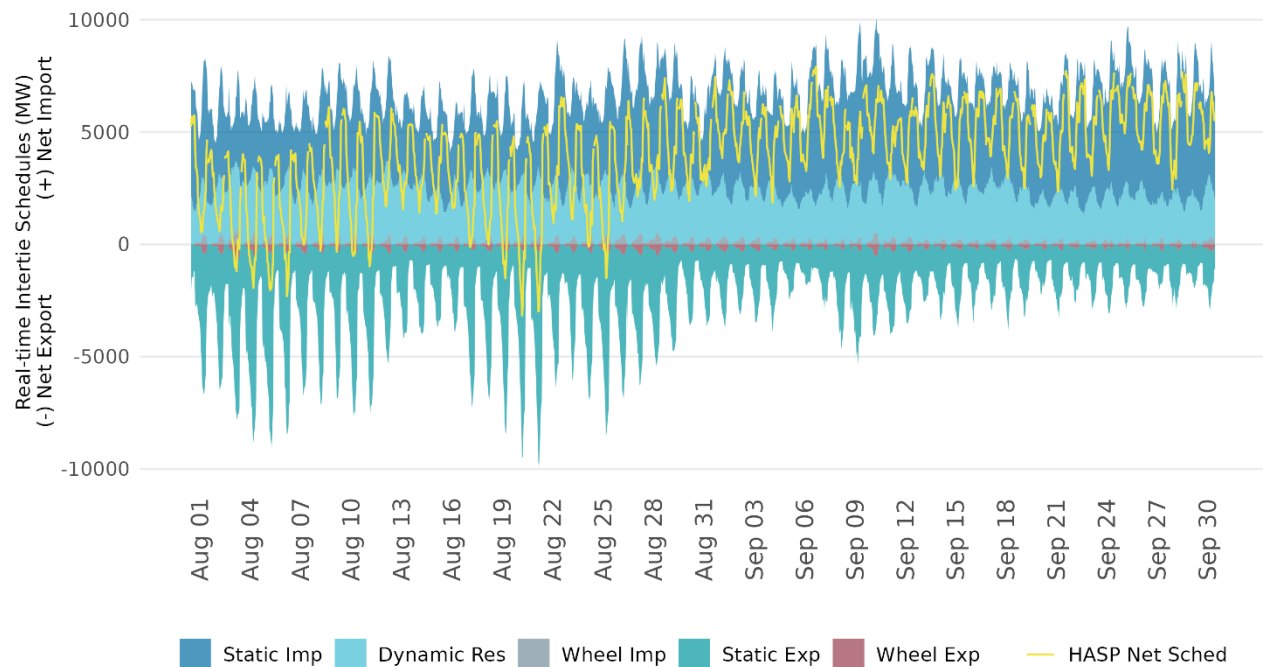
Figure 195: Hourly RUC exports



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 196 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 August 20 due to the high level of exports cleared on that day. The real-time market largely follows the trend observed in the day-ahead market. The net schedule remained low in August. On average, for August, the net schedule in HASP was about 2,806MW across all the hours of the month and about 1,088MW for peak hours.

Figure 196: 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.¹²

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 197 shows all the exports cleared in the HASP process and identifies the nature of such exports. Figure 178 shows the same breakdown for September 8 to 10. ETC/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.

¹² 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>

The volume of exports cleared in real time peaked at 5074MW on September 9. In September, volumes of exports cleared were lower than August, and low-priority bids constituted a significant portion of cleared exports.

Figure 197: Exports schedules in HASP

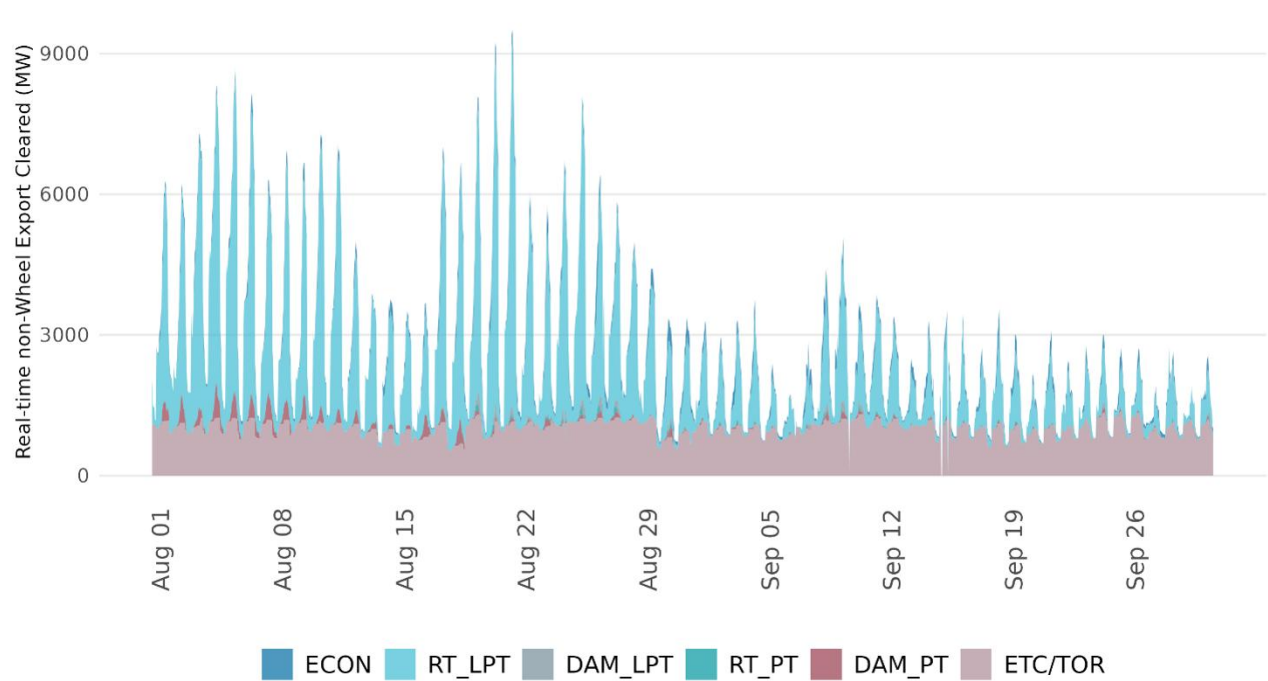
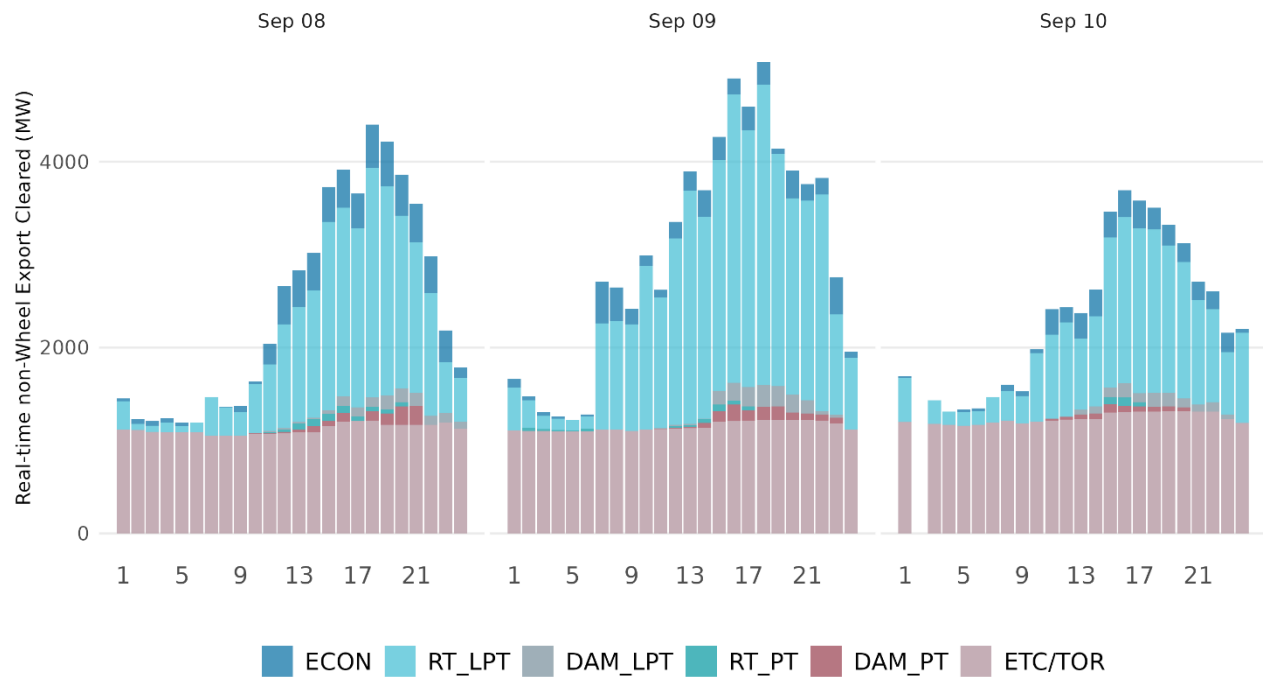


Figure 198: Exports schedules in HASP, –September 8 - 10



Imports and exports were scheduled over multiple intertie scheduling points in September, with Malin, Palo Verde and NOB seeing the highest volume of transactions. Figure 199 through Figure 201 illustrate the trend of import and export schedules cleared in HASP for these top three intertie points. In September, the prevailing schedules were in the import direction.

Figure 199: HASP schedules at Malin intertie

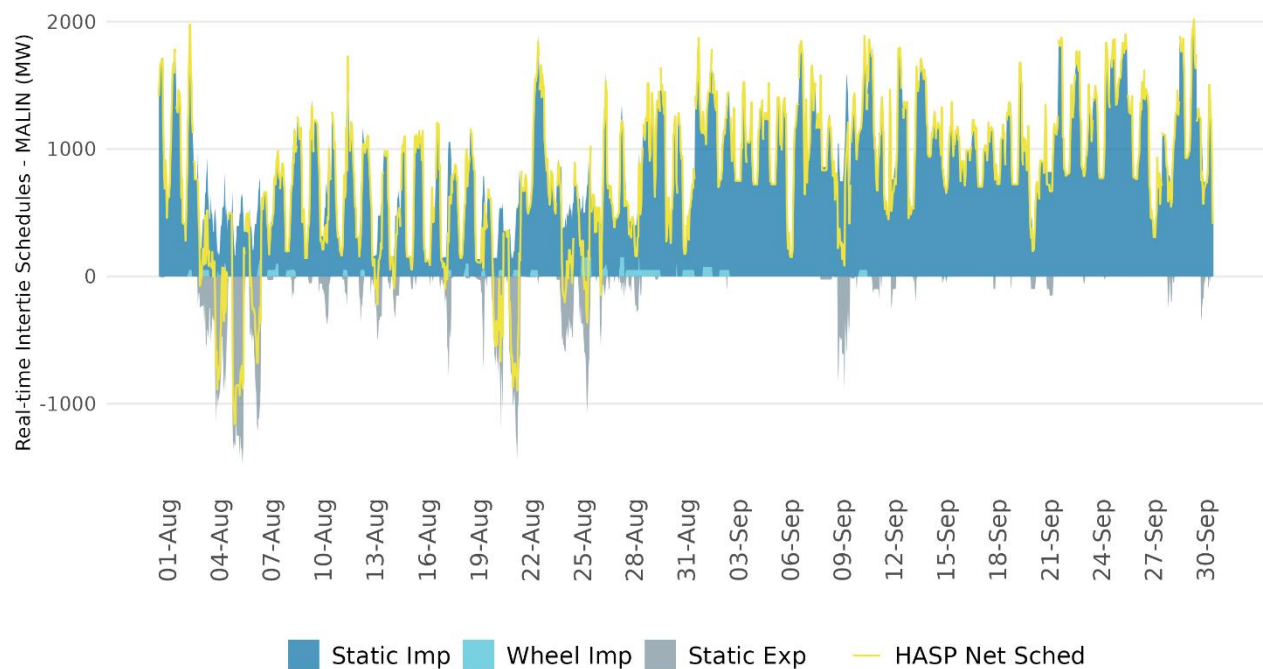


Figure 200: HASP schedules at Palo Verde intertie

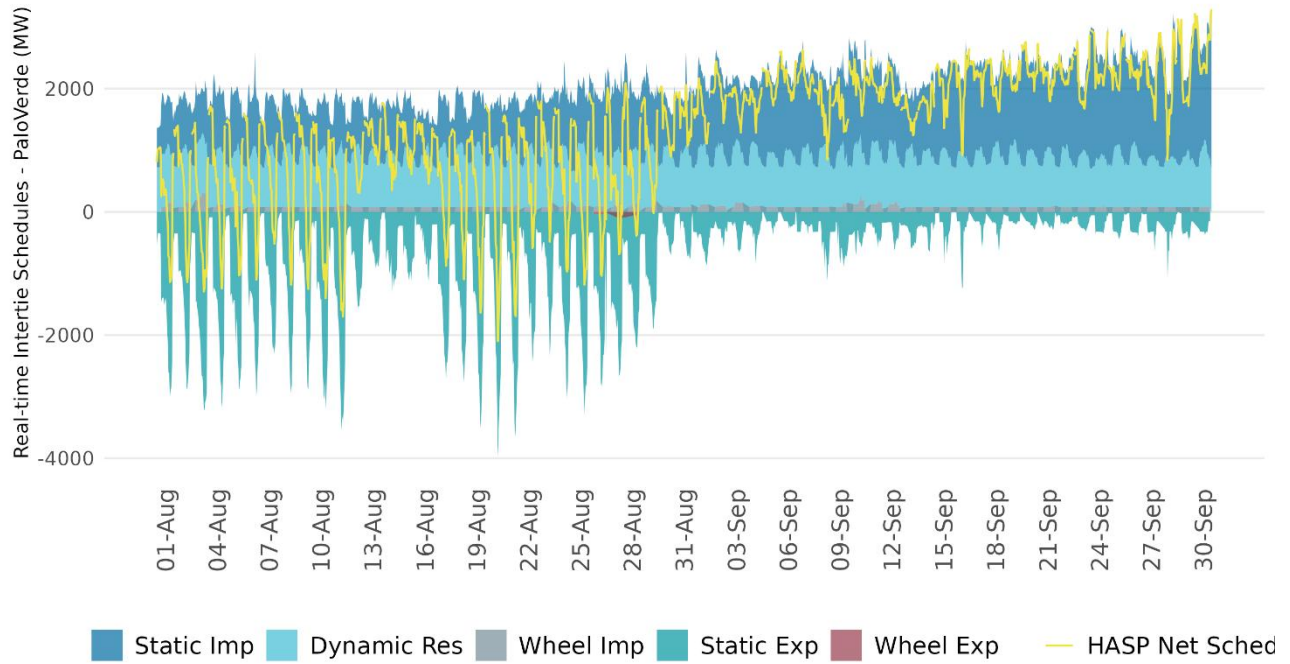
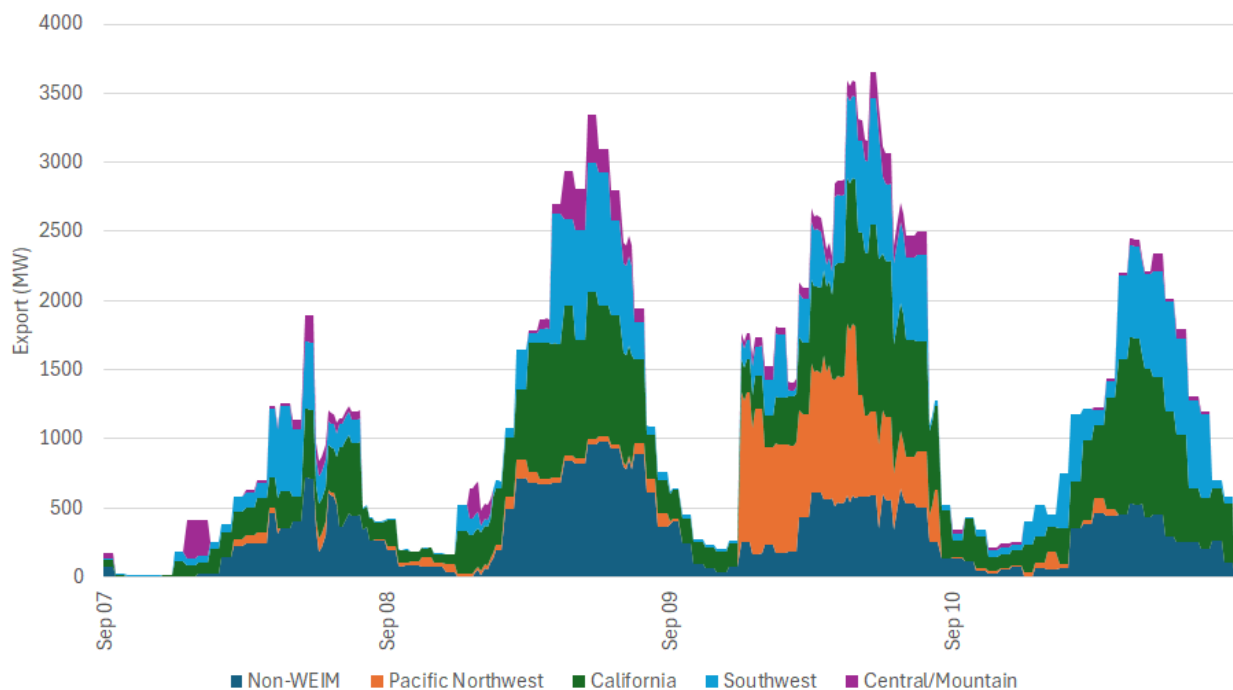


Figure 201: HASP schedules at NOB intertie



Figure 202 shows the total volume of intertie exports that are sourced from the ISO area and organized by the different areas in which the exports sink. For simplicity, these sink areas are grouped in regions of the western interconnection for all areas that are in the western energy imbalance market. There is one group also used to refer to the volume of export sinking into areas that are not part of the western energy imbalance market. During September heatwave, up to 3,654 MW of exports sourced from the ISO area supported multiple areas in the western interconnection.

Figure 202: Total volume of exports sourced from the ISO area



Storage and Hybrid Resources

In September 2026, there were about 250 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 about 71,000 MWh. In terms of the capacity made available to the markets, Figure 203 presents the daily average

of bid-in capacity for storage resources in the day-ahead market in August and September, and Figure 204 presents the hourly average from July to September, organized by price ranges. In August and September, more bid-in capacity was shifted from low-priced bucket (\$0-50/MWh) to mid-priced (\$50-100/MWh) in July in both daily and hourly average charts.

Figure 203: Bid-in capacity for batteries in the day-ahead market, daily average

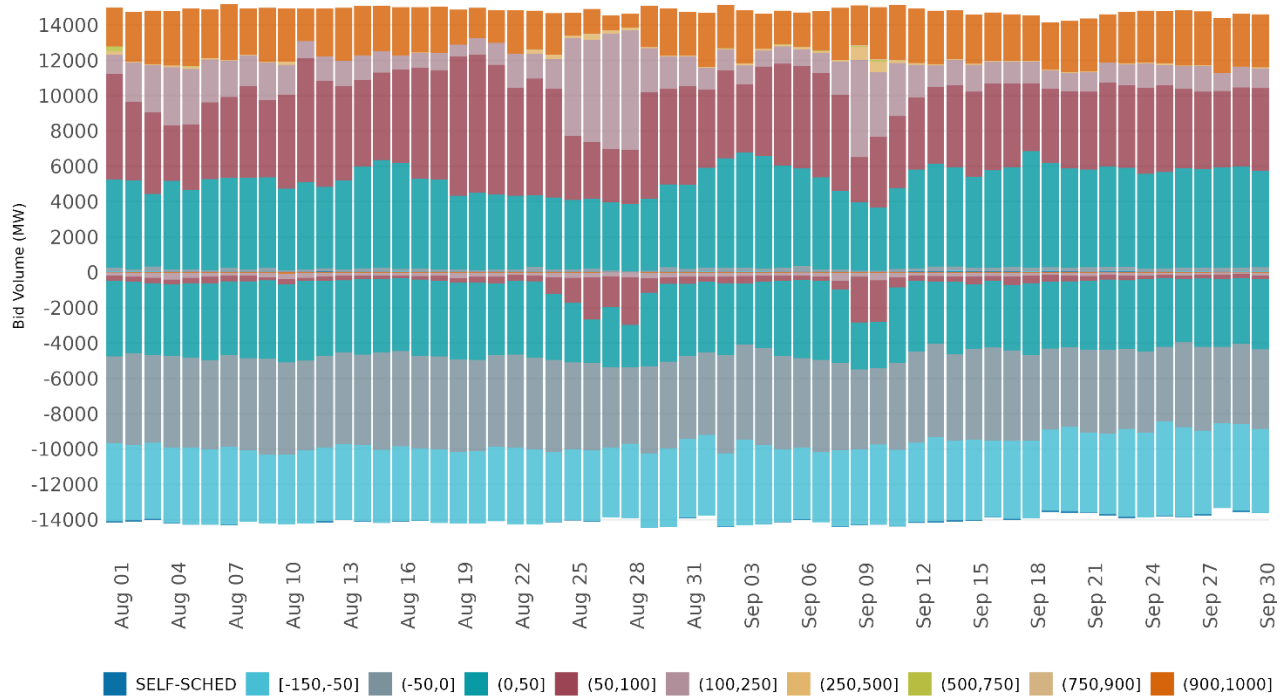
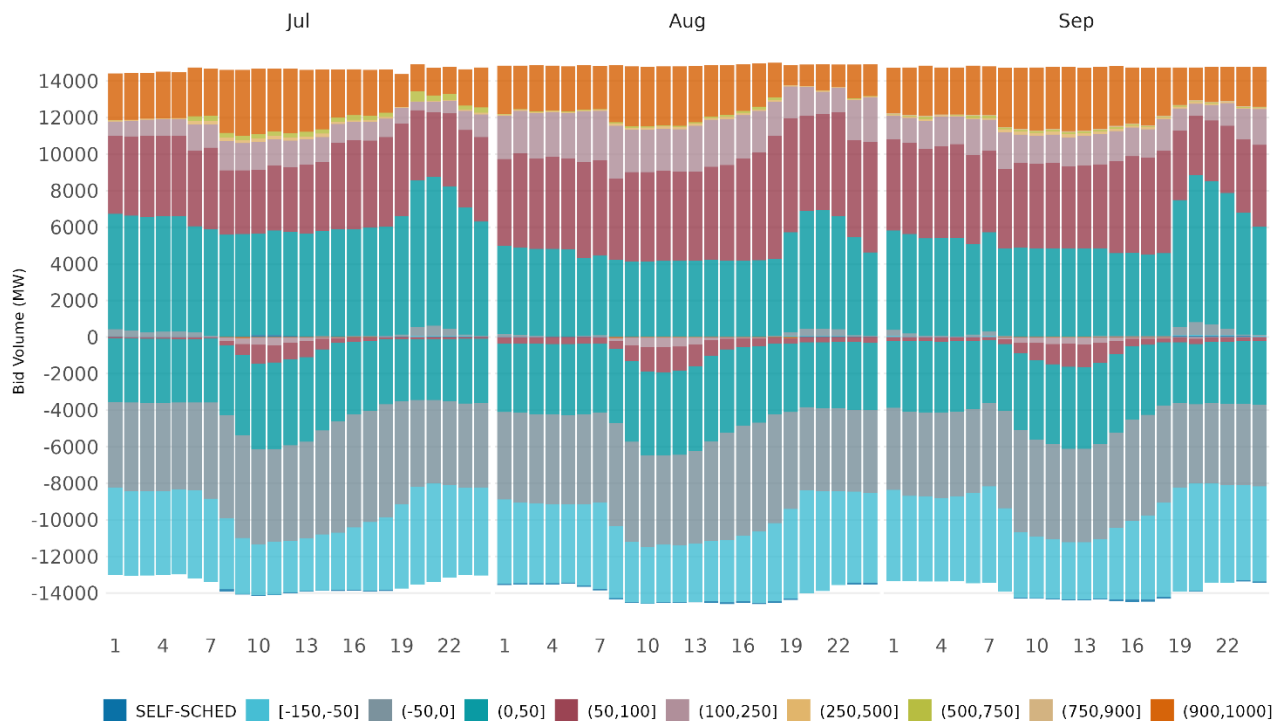


Figure 204: Bid-in capacity for batteries in the day-ahead market, hourly average



The negative area represents charging while the positive area represents discharging. The overall capacity in the market was roughly consistent throughout the months at about 14,000 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 205 and Figure 206 present the bid-in capacity for the real-time market. The overall capacity follows a similar trend as the day-ahead market. One thing to note is that more low-price buckets (\$0-50/MWh) were shifted to moderate-price buckets (\$50-100/MWh) under summer conditions.

Figure 205: Bid-in capacity for batteries in the real-time market, daily average

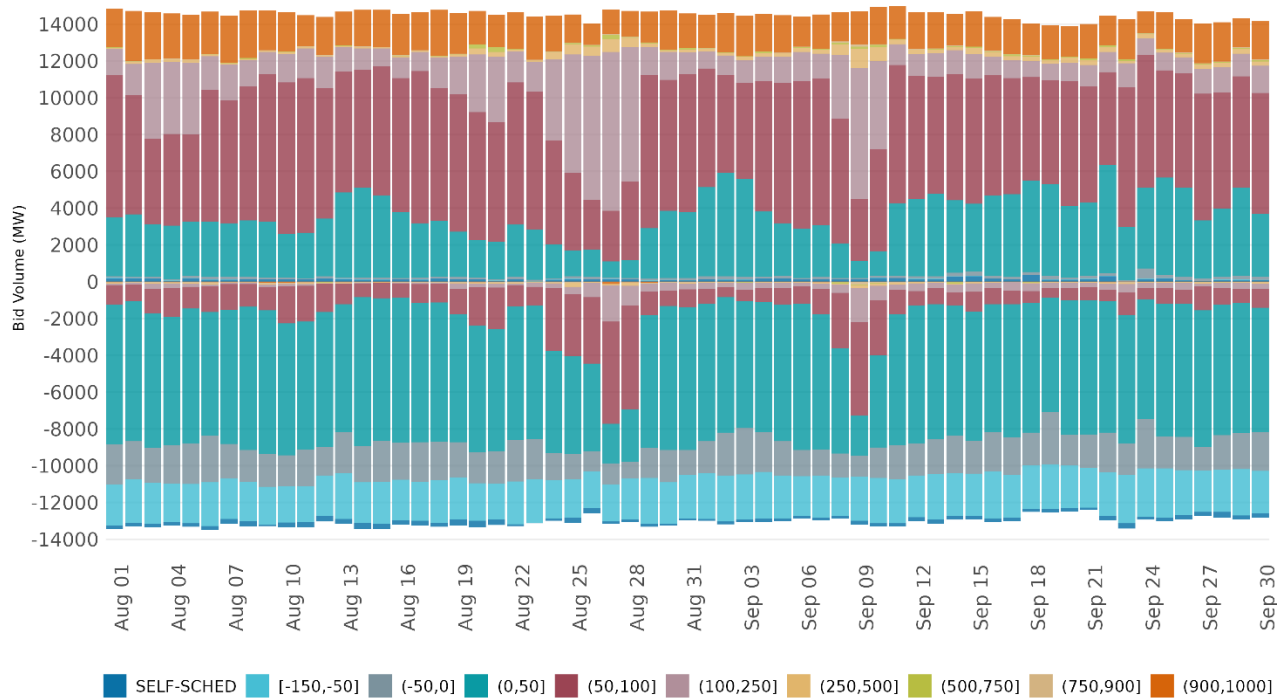


Figure 206: Bid-in capacity for batteries in the real-time market, hourly average

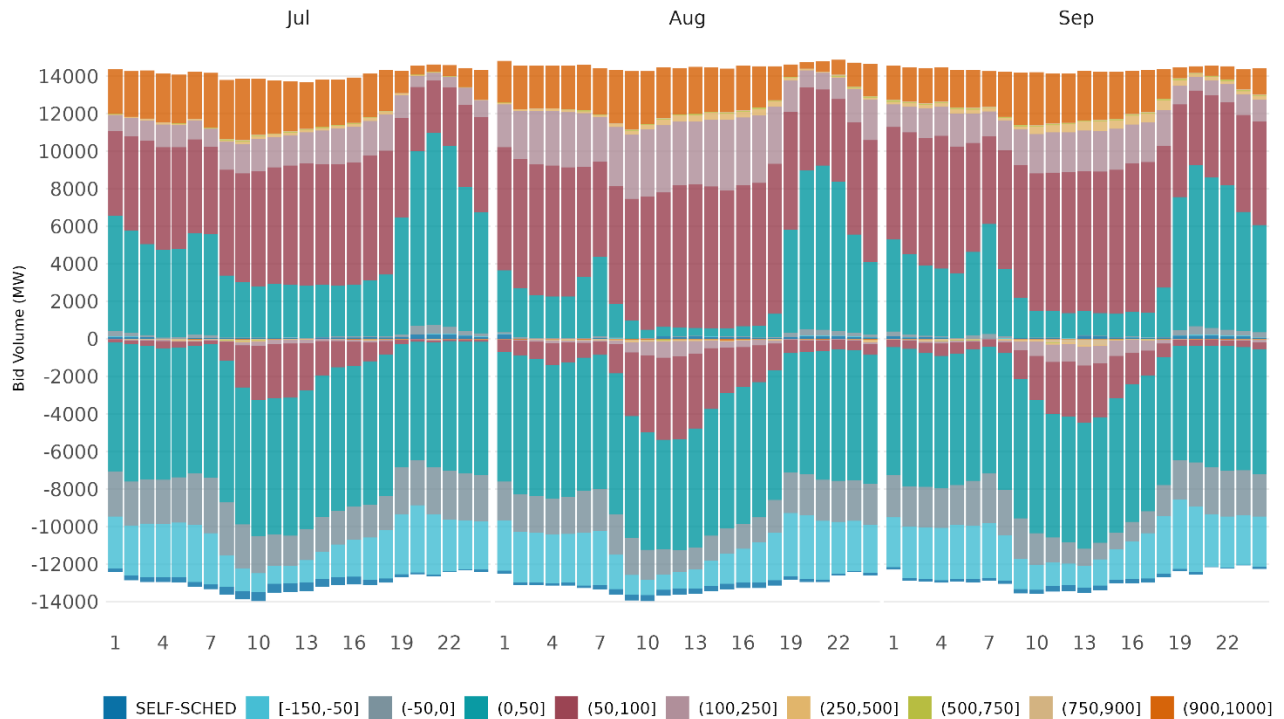


Figure 207 shows the hourly distribution of the storage capacity of resources participating in IFM and RTD throughout July to September. The box plot shows the median, 25th percentile, 75th percentile, and outliers for the total state of charge. Storage resources charge in hours when there is abundantly cheap energy from solar resources in the daytime. 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 47,625 MWh, roughly 67 percent of the total capacity, which occurred in the hour ending 17 on August 20. The peak hourly state of charge in the real-time market was 54,686 MWh in hour ending 18 on July 29, at roughly 77 percent of the total capacity, higher than the day-ahead peak state of charge. Also, the state of charge in the real-time market had a wider spread compared to the day-ahead market.

Figure 207: Distributions of day-ahead state of charge

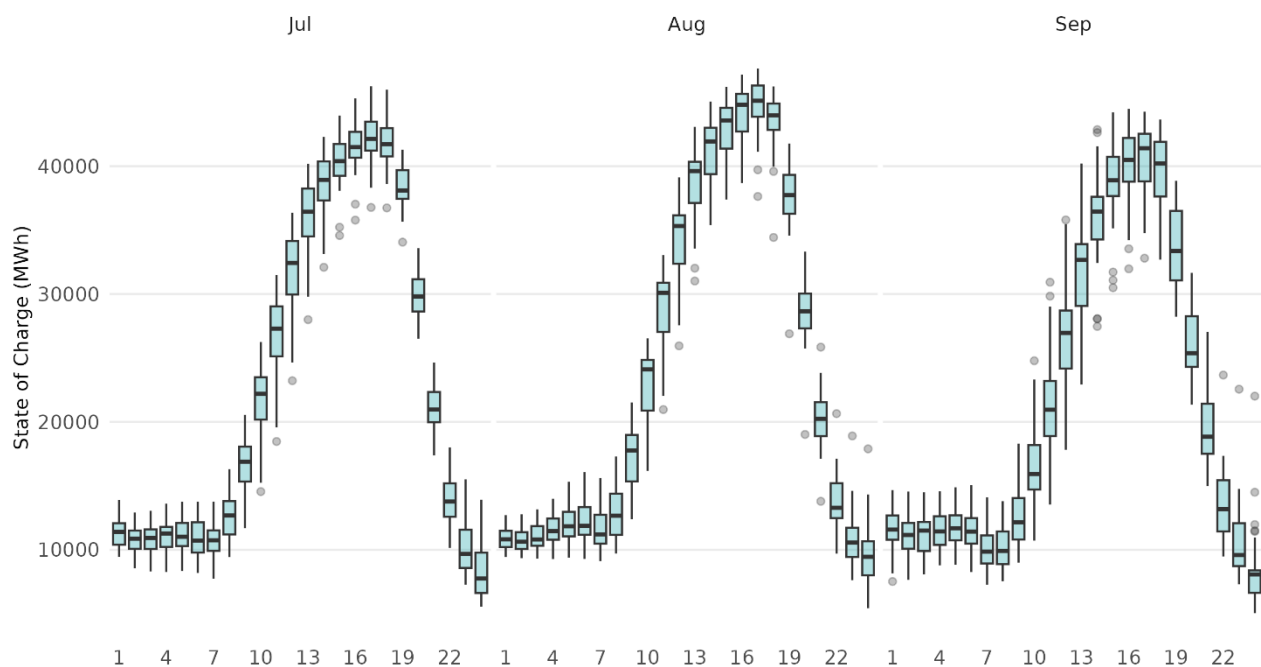
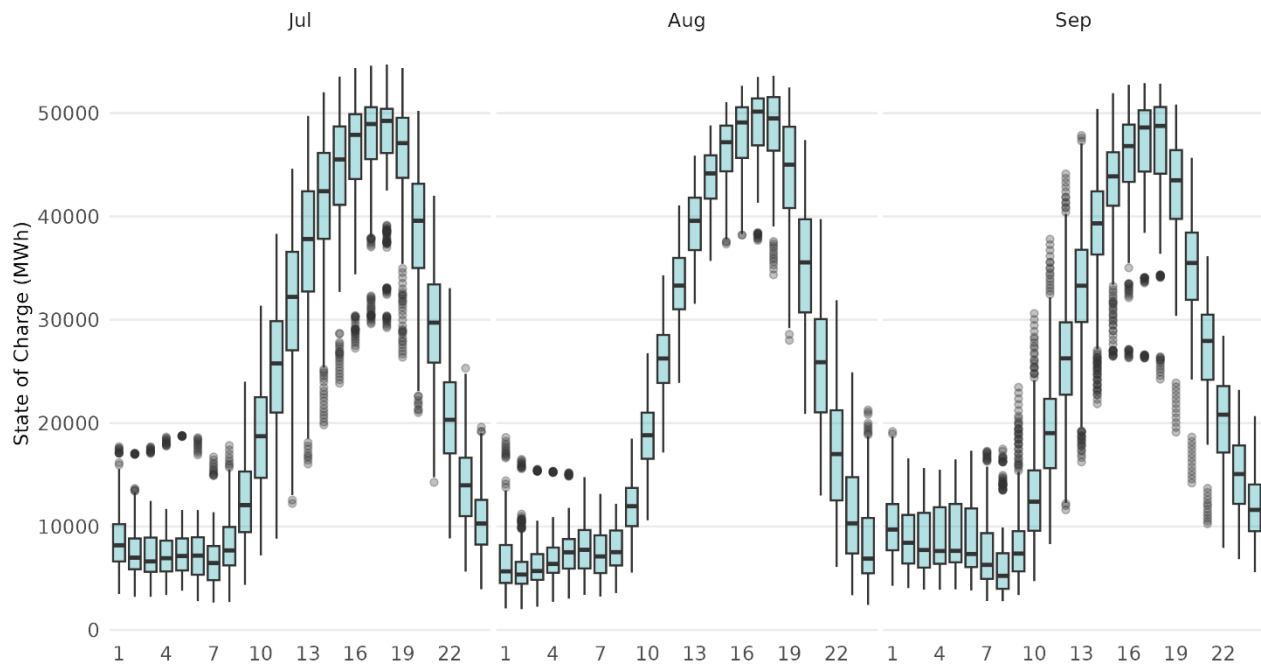
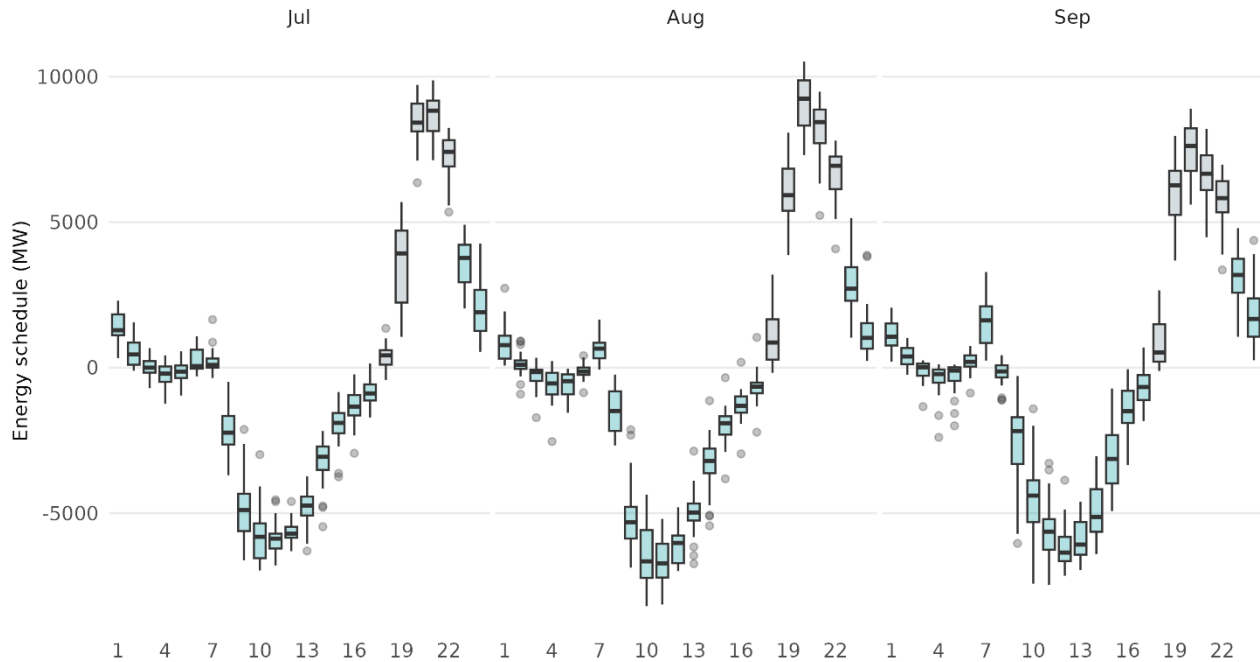
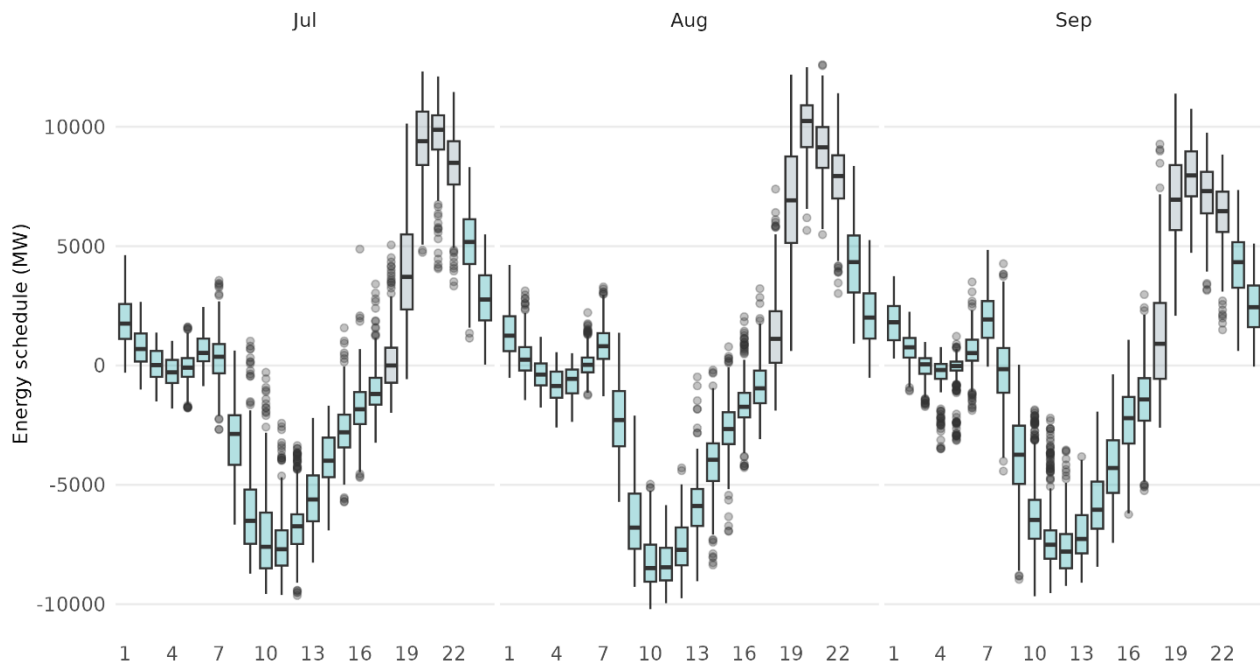


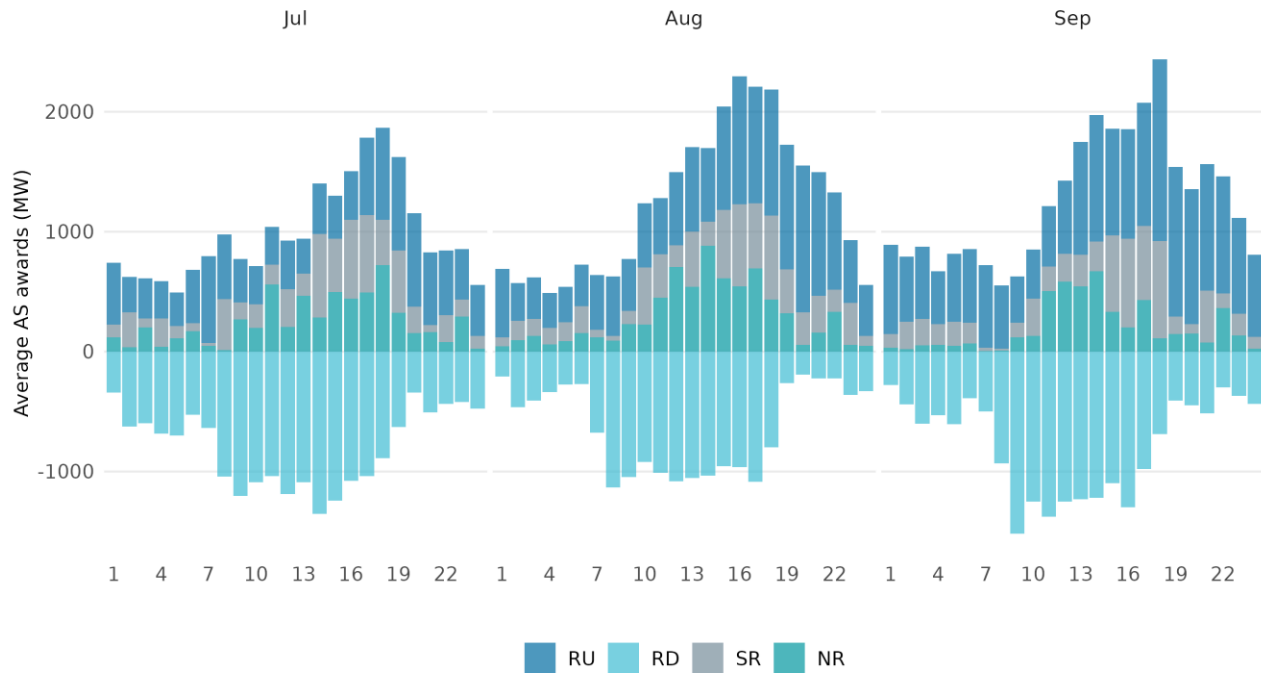
Figure 208: Distributions of real-time state of charge

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 209 shows the distributions of energy awards in IFM, and Figure 210 shows the hourly distribution of real-time dispatch for batteries from July to September. These statistics are for batteries, either stand alone or the battery component of co-located resources; they do not include hybrid resources.

Figure 209: Hourly distribution of IFM energy awards for batteries*Figure 210: 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 211 shows the average hourly AS awards in the real-time market.

Figure 211: 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 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 212 and Figure 213 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.

Figure 212: Hourly distribution of IFM energy awards for hybrid resources

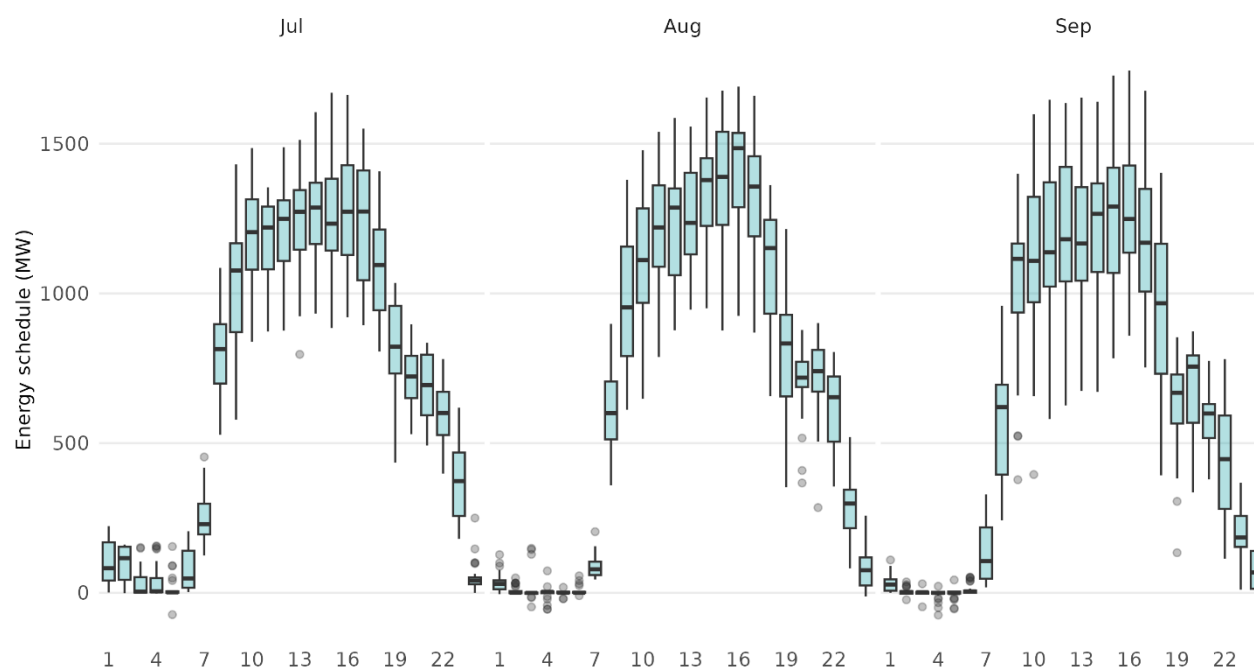
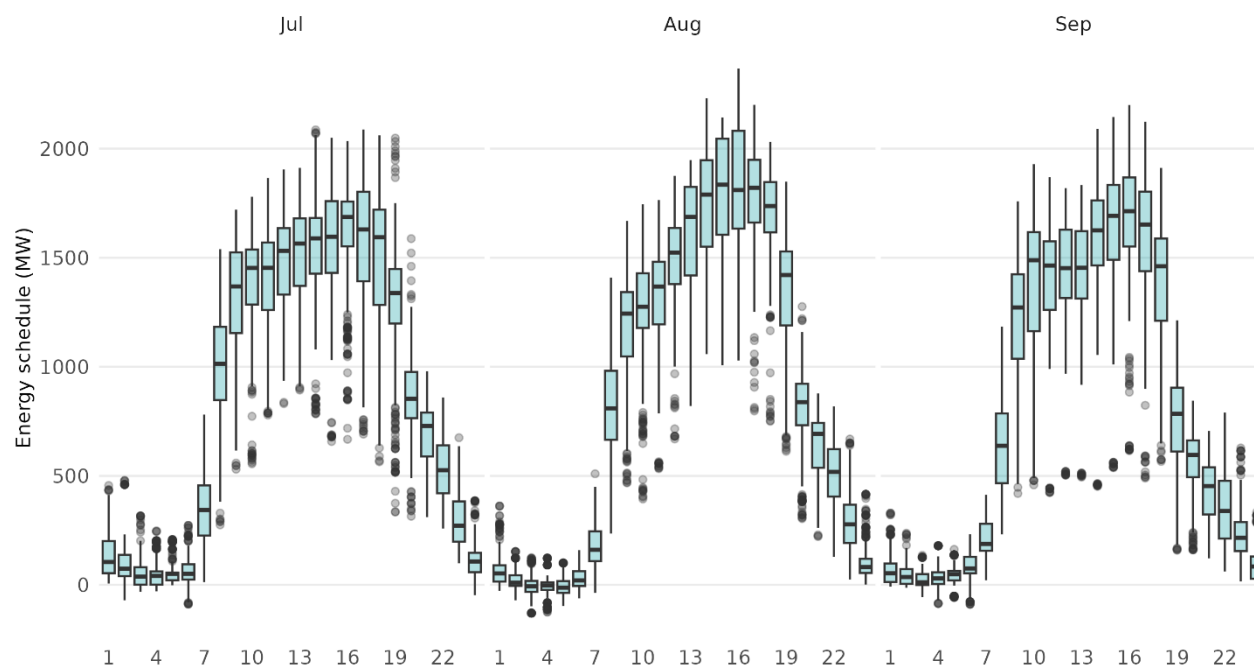
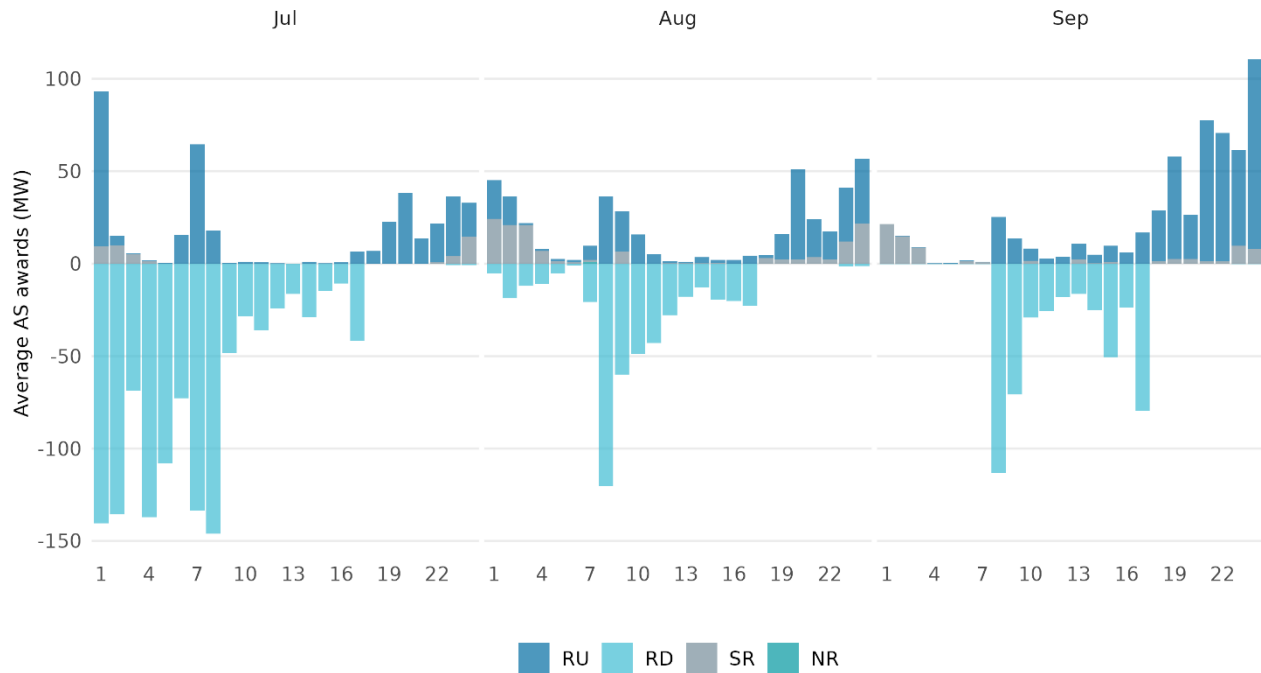


Figure 213: Hourly distribution of real-time dispatch for hybrid resources



Similar to storage resources, hybrid resources can also provide ancillary services to the market. Figure 214 shows the average hourly AS awards in real-time throughout July to September 2026.

Figure 214: Hourly average real-time hybrid AS awards



From September 8 to September 10, real-time energy schedules for storage resources exhibited a consistent daily charging and discharging pattern. Charging activity generally occurred during the late morning to early afternoon, with net schedules reaching approximately -9,000 to -9,500 MW, while discharging peaked in the evening at approximately 9,000 to 11,500 MW. The corresponding real-time SOC increased during charging periods, reaching daily highs of approximately 49,000–53,000 MWh in the late afternoon, and declined during evening discharge periods. This pattern was consistent throughout all three days, with SOC reaching its highest level on September 10. Overall, the charts illustrate the critical role of storage resources during heatwave period.

Figure 215: Hourly real-time dispatch for storage resources, September 8 to September 10

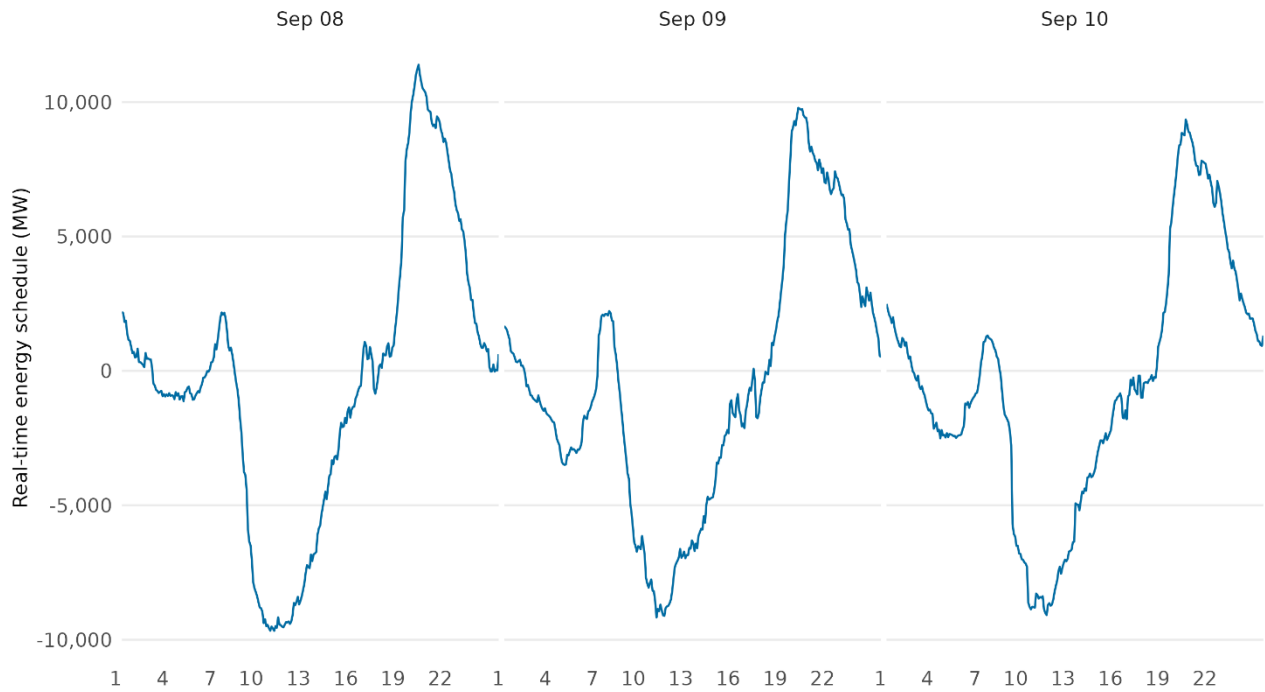
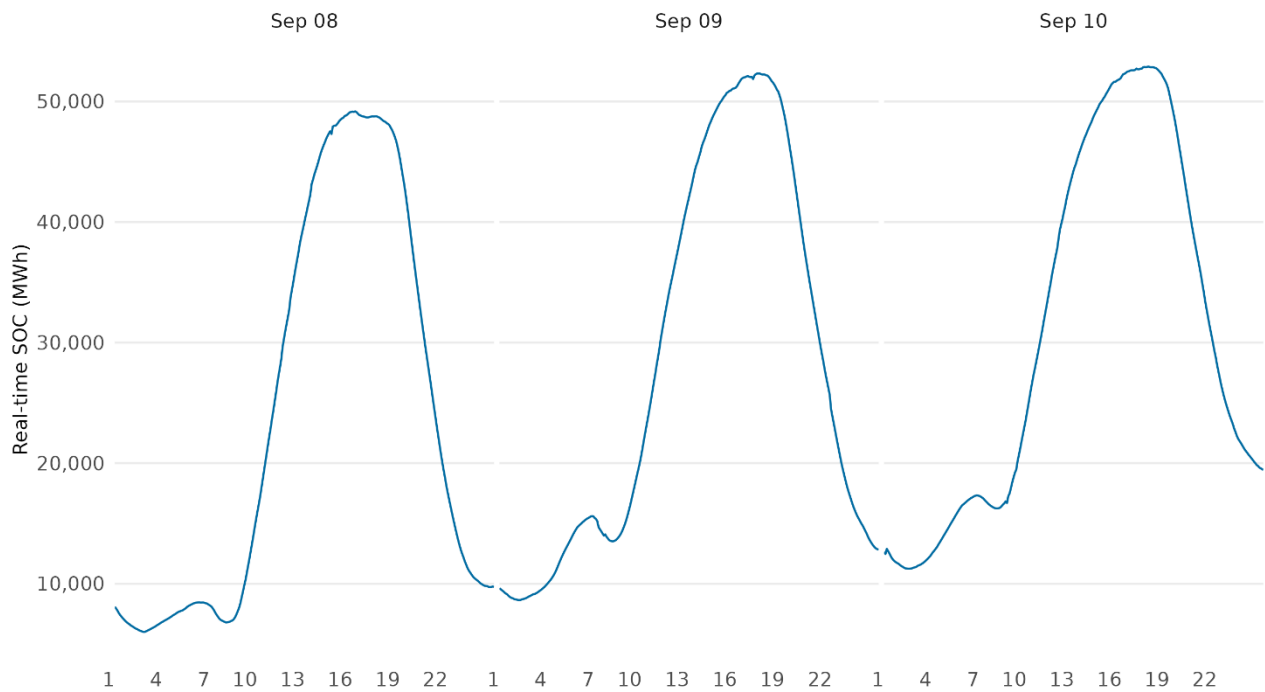


Figure 216: Hourly real-time SOC for storage resources, September 8 to September 10



Western Energy Imbalance Market

September experienced lower load conditions across the western interconnection than August. The highest load reached 134.6 GW on September 9. Figure 217 shows the daily peak load aggregated by WEIM regions for the month of September, with circle markers indicating each region's monthly peak¹³. Across the WEIM footprint, load peaks occurred on different days and times across the different regions of WEIM. The California region reached a maximum load of 60,361 MW on September 9. The Southwest region's maximum load occurred on September 10 at 33,395 MW. Pacific Northwest daily peak load was 28,400 MW on September 9. The Central/Mountain region hit its peak load on September 11 reaching 13,224 MW.

Figure 217: Daily peak load by WEIM region

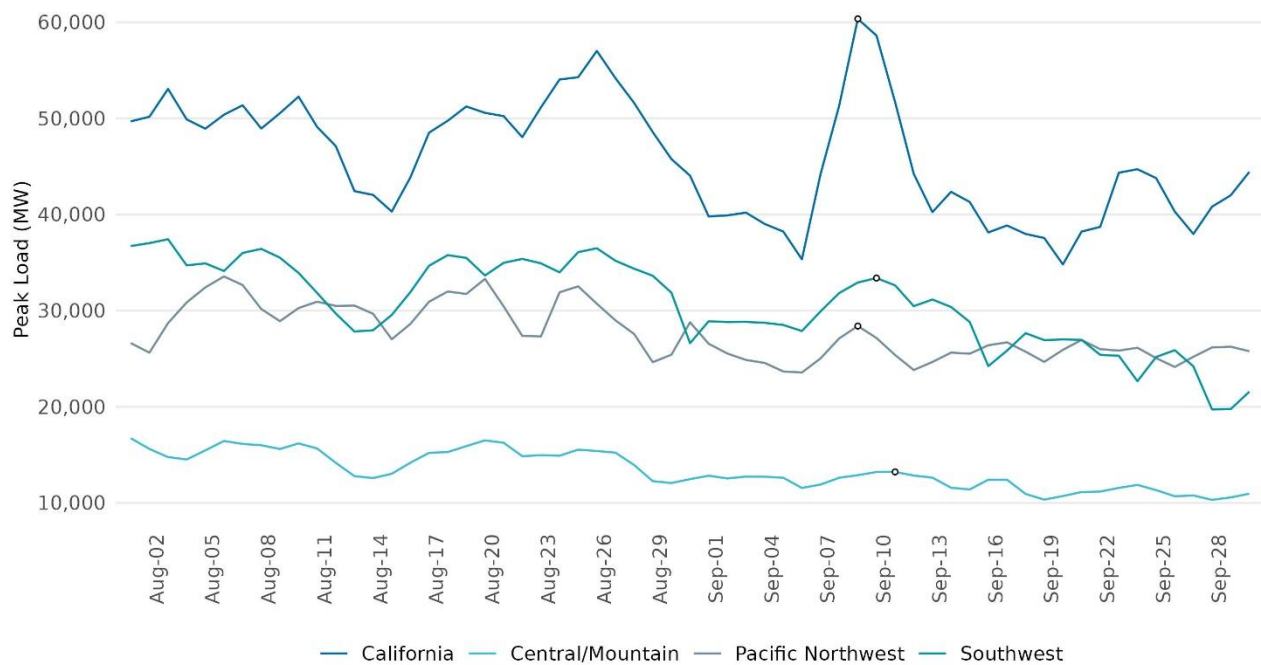


Figure 218 shows the average hourly peak load by WEIM region. Hourly peak loads occurred between hours ending 17 and 18 in August and September, on average, except for Pacific Northwest where September peak load occurred in hour ending 19.

¹³ These regions are only for display purposes of the regional dynamics. The WEIM market clears supply and demand for each individual balancing area.

Figure 218: Average hourly peak load by WEIM region

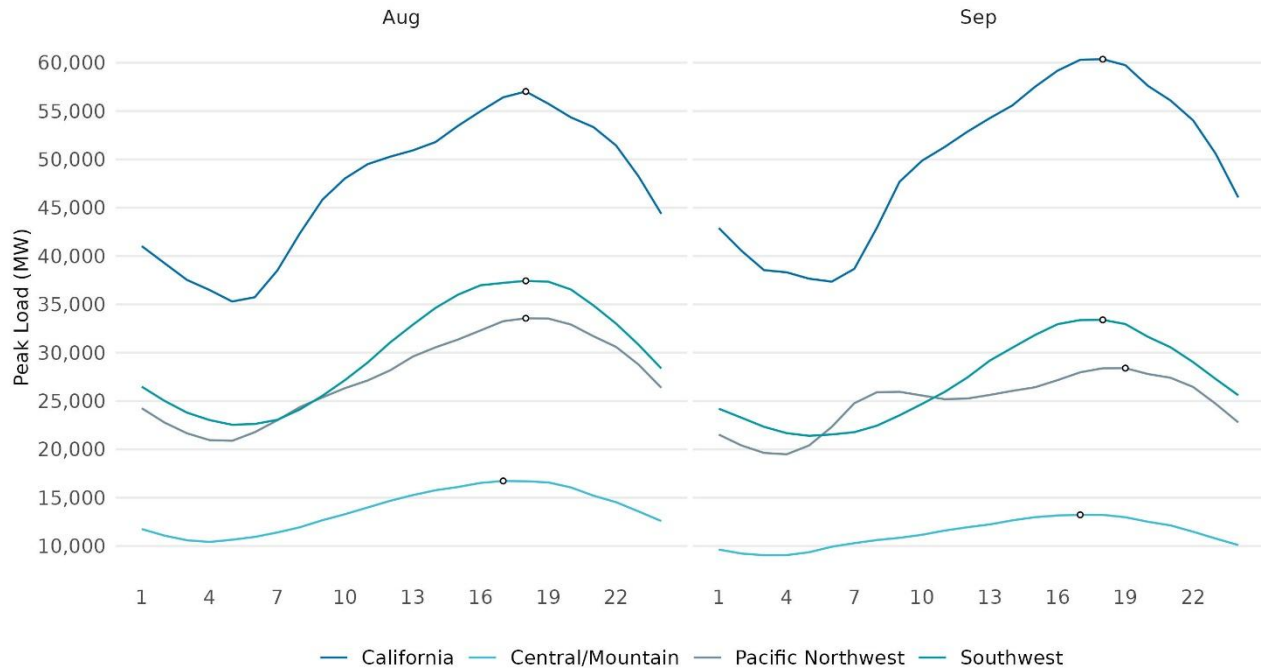
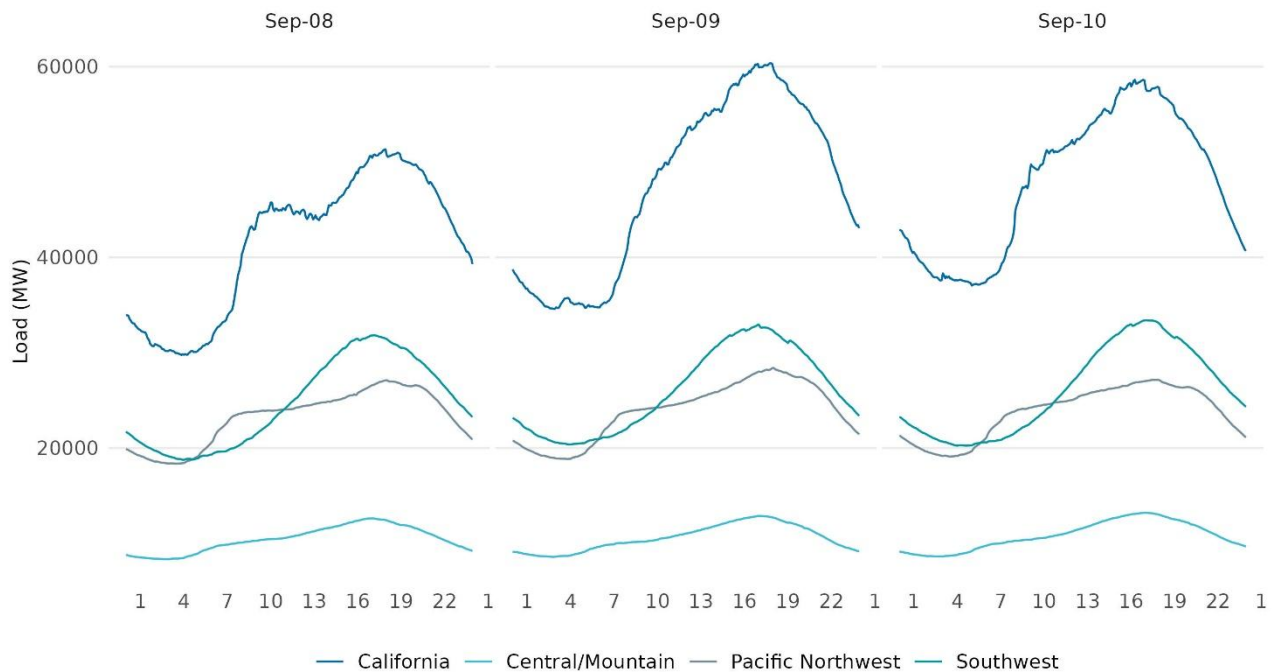


Figure 219 shows the hourly profile of actual load for the WEIM regions for September 8 to 10. California showed the strongest response to heat events, increasing from the evening peak near 51 GW on September 8 to about 60 GW on September 9, before easing slightly to 58 GW on September 10. The Southwest followed a similar pattern with the evening peak growing from near 31 GW to 33 GW on September 9 but increased slightly on September 10. Both regions showed elevated overnight loads on September 9 and 10. The Pacific Northwest and Central/Mountain regions showed a more muted response across the three days.

Figure 219: Hourly load profile for September –8-10, by WEIM region



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.¹⁴ 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 areas. In a given interval, import and export transfers can concurrently happen for one area.

Figure 220 shows the distribution of five-minute WEIM transfers for the CAISO area. A negative value represents an import into the CAISO from other WEIM entities. On average in September, CAISO transfers saw a shift towards exporting to other areas in the WEIM. CAISO recorded its highest average net imports on September 26 of 4,098 MW and highest average net exports on September 13 of 5,504 MW.

¹⁴ The WEIM quarterly reports are available at <https://www.westerneim.com/pages/default.aspx>
CAISO/MD&A/MPAA

Figure 220: Daily distribution of 5-minute RTD WEIM transfers for CAISO area

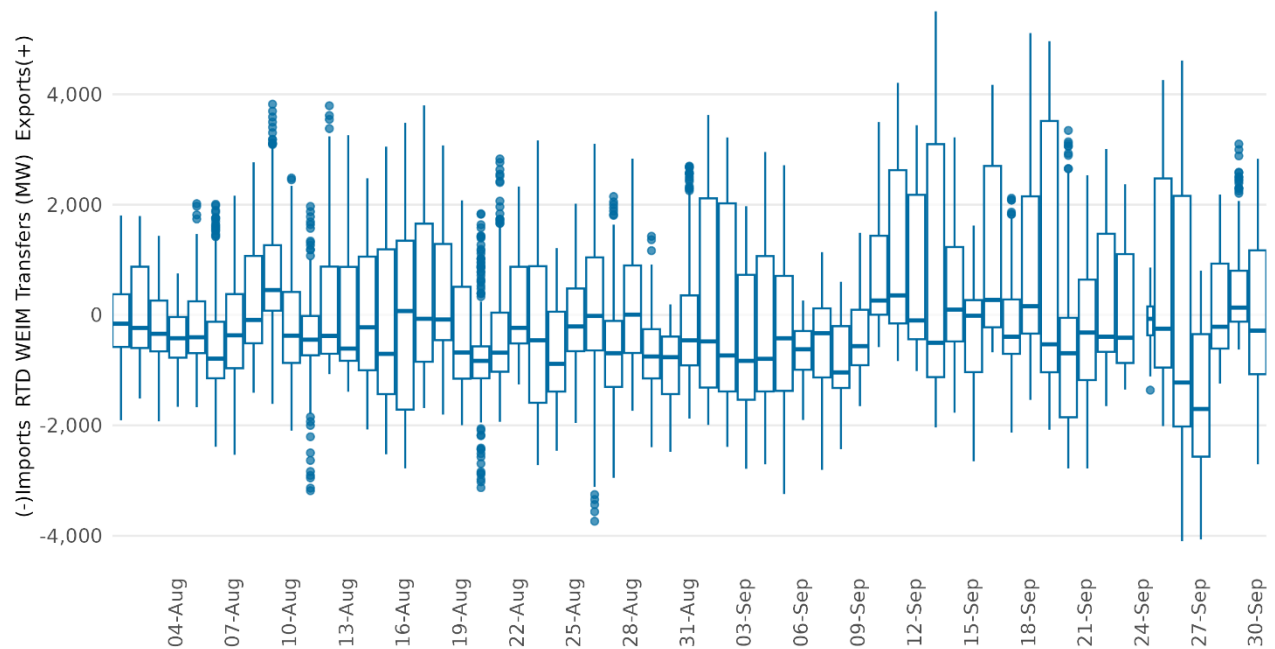


Figure 221 shows the CAISO's WEIM transfers in an hourly distribution, which highlights the typical profile of the CAISO transfers which are generally export transfers during periods of solar production. During the evening ramp the transfers become a net import to the CAISO area. This trend is typical across summer months. Net export transfers during midday hours in September were higher than in August.

Figure 221: Hourly distribution of 5-minute RTD WEIM transfers for CAISO area

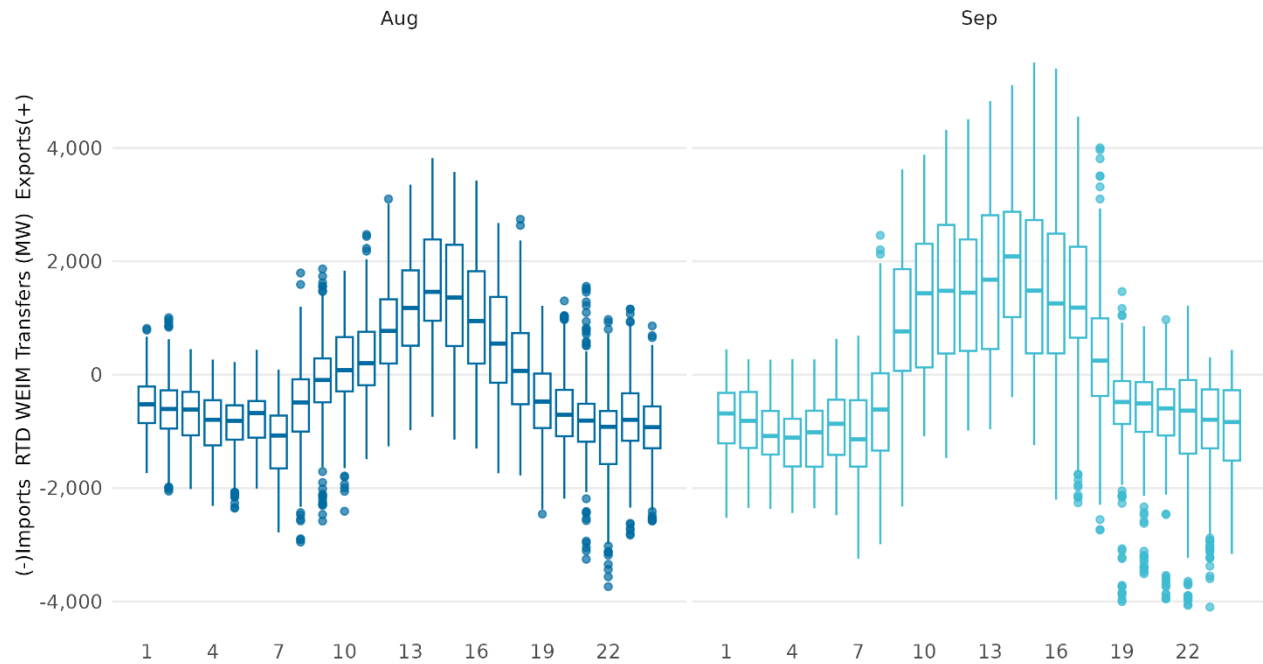


Figure 222 shows the distribution of RTD WEIM transfers for the CAISO area from September 8 to 10. CAISO transfers increased towards exports from September 9 to 10.

Figure 222: Daily distribution of 5-minute RTD WEIM transfers for CAISO area, September 8-10

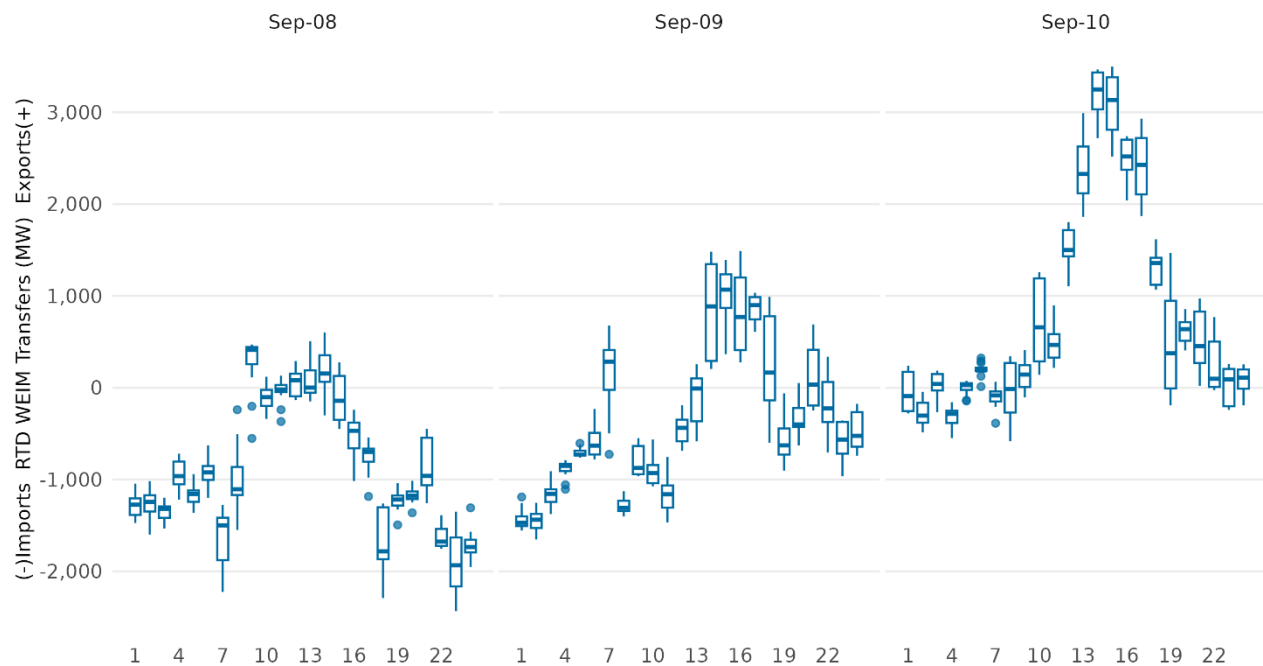


Figure 223 shows the distribution of WEIM transfers by region. California transfers shifted towards exports in September, except September 25 to 27 when transfers increased in the import direction. California's highest exports occurred on September 18 of 4,825 MW and its highest imports were on September 27 of 4,028 MW. Central/Mountain region saw the highest exports on September 7 of 2,997 MW and the highest imports on September 25 of 1,647 MW. Pacific Northwest export transfers were highest on September 30 reaching 1,393 MW while import transfers were highest on September 5 at 2,194 MW. The Southwest region's highest exports were 3,406 MW on September 27 while the highest imports were September 10 saw the highest imports of 3,761 MW.

Figure 223: Daily distribution of 5-minute RTD WEIM transfers by region

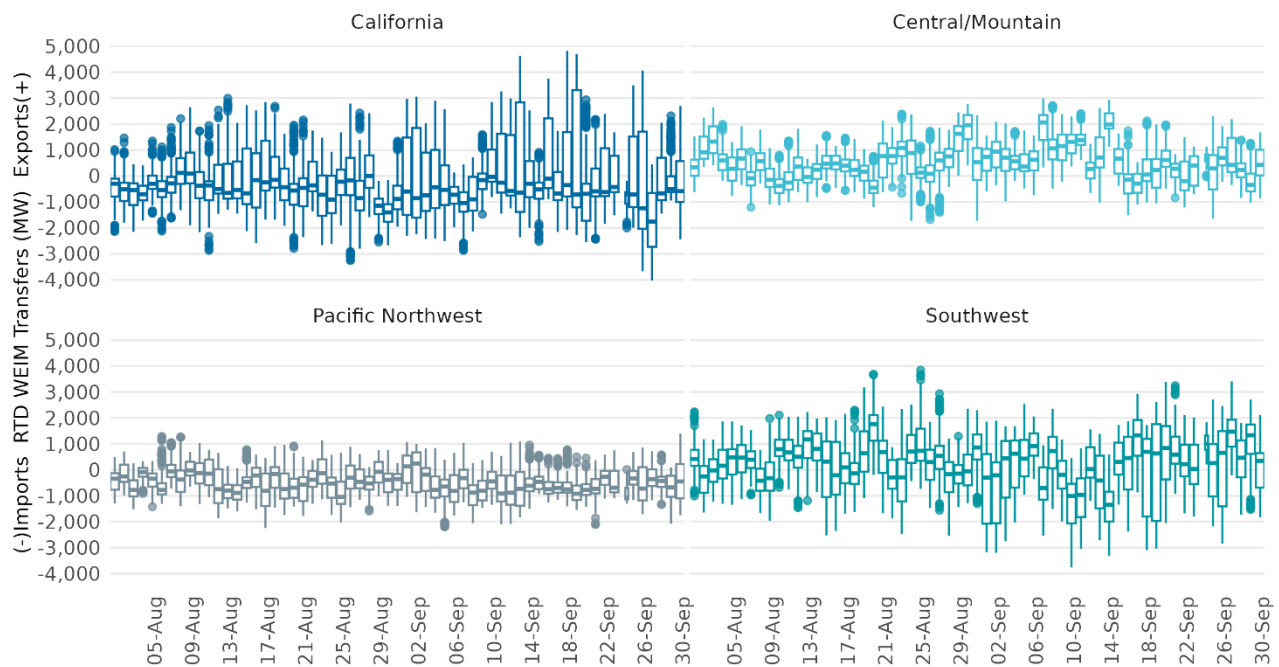
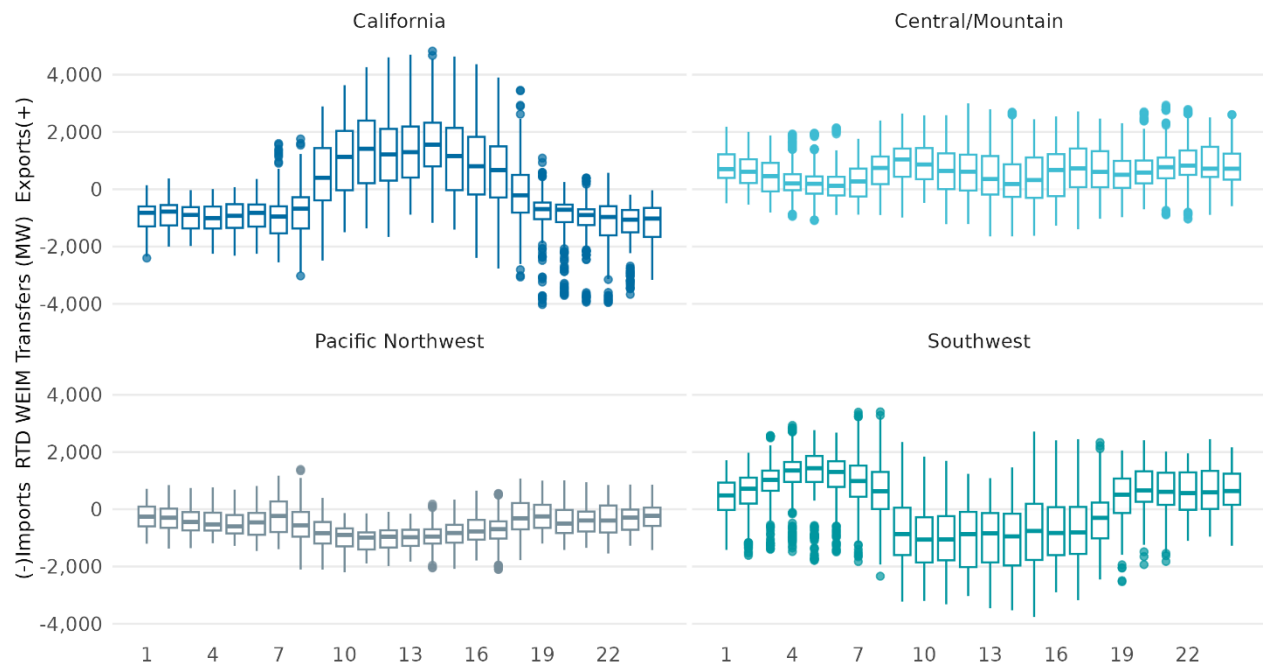


Figure 221 shows the hourly distribution of WEIM transfers by region in September. The California region was a net exporter in the midday hours and a net importer in the remaining hours particularly the evening peak and night-time hours. The Central/Mountain region was a relatively stable net exporter throughout the day generally providing 500 to 1000 MW of exports. The Pacific Northwest region's transfers were consistent in the hours spanning the late evening into the early morning, but net imports grew during the midday hours. The regions highest exports occurred in the ramping hours in the morning and evening. The Southwest region's transfers exhibit the clearest complementary pattern to California. The Southwest was a net importer during the midday hours and net exporter in the remaining hours.

Figure 224: Hourly distribution of 5-minute RTD WEIM transfers by region, September 2026



Assistance energy transfer

The Assistance Energy Transfer (AET) program 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.

Figure 225 shows days when WEIM BAAs opted-in to AET and when they failed either the upward capacity test and/or the upward flexible ramping test. In September, eleven WEIM BAAs opted into AET for some duration of the month. Of these, six BAAs did not have any instances of failed upwards RSE tests. There were fewer upwards RSE failures in September than in August.

Figure 225: BAAs opted-in to Assistance Energy Transfers and RSE Upward Failures

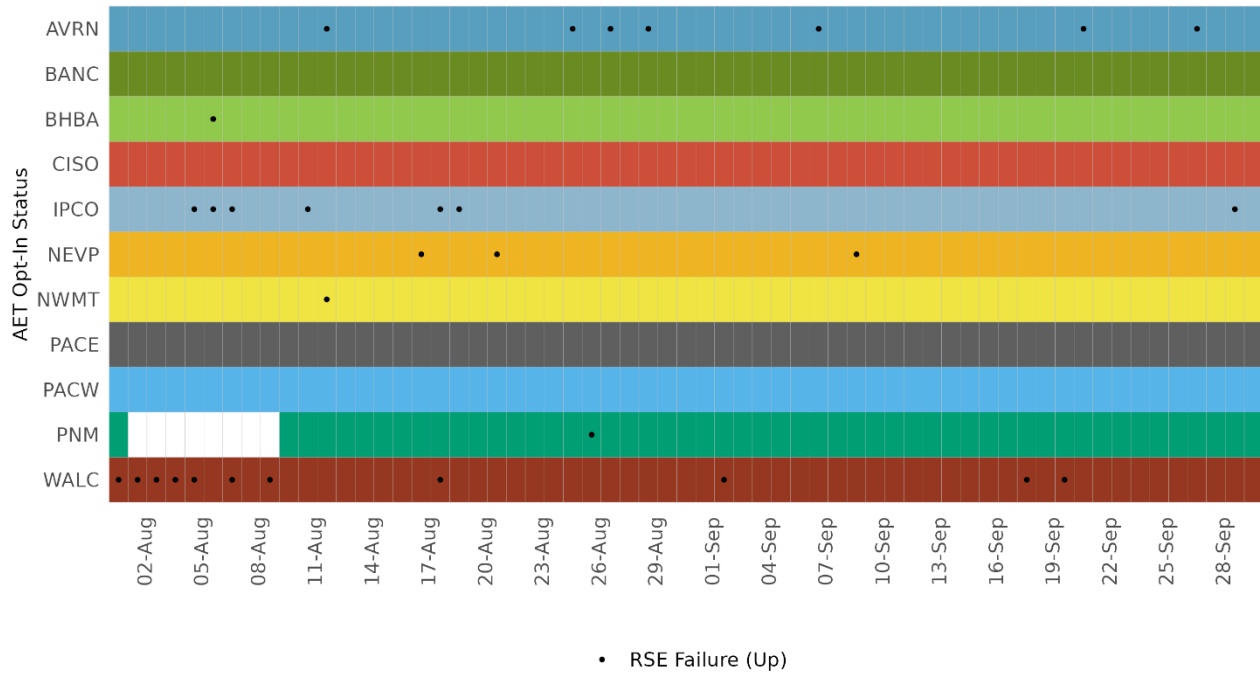


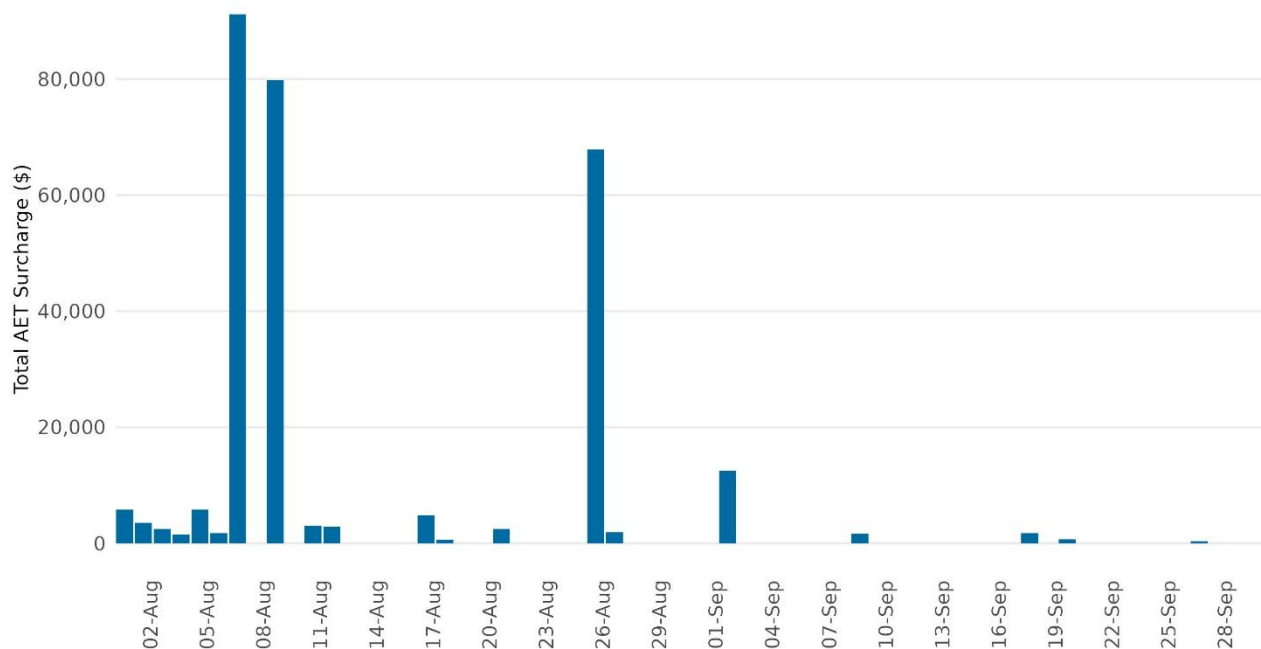
Figure 226 shows the additional AET imports in RTD received by WEIM BAAs per day on average. The WALC and NEVP BAAs received an average of 174 MW and 217 MW of additional AET imports on September 2 and 9, respectively.

Figure 226: Daily average additional AET imports in RTD



Figure 227 shows the breakdown of total AET surcharges assessed per day for September. By design, AET is only assessed for WEIM BAAs that fail the RSE and opt in ahead of time. The AET surcharge was only assessed for a total of five trading days in September. The total AET surcharges assessed in September were approximately \$17,000 for all the BAAs that opted in.

Figure 227: Total daily AET surcharge assessed



Market Costs

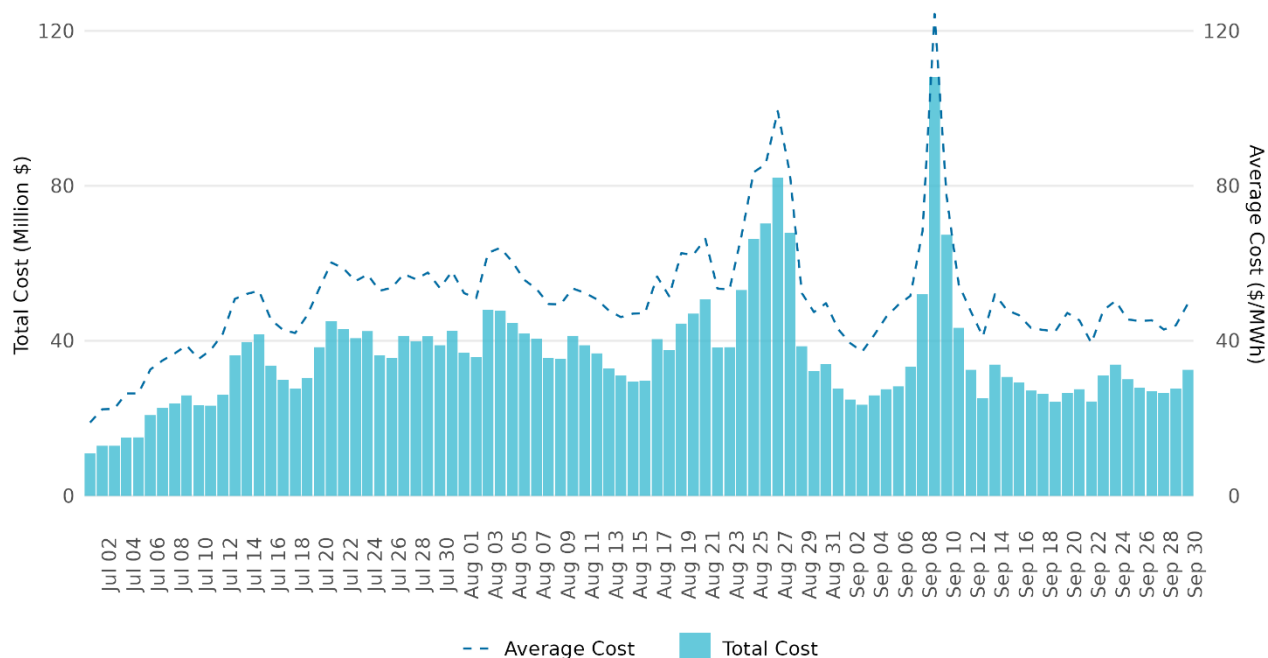
The CAISO markets are settled based on awards and prices derived from the markets through specific settlement charge codes; these include day-ahead and real-time energy, and ancillary services, among others. Most of the overall costs accrue on the day-ahead settlements.

The estimates presented in this section are from the first cycle (T-9 business days) of CAISO's market settlements. These numbers are subject to change in subsequent cycles given standard data updates, inclusion of price corrections within the extended price correction window, and the ongoing resolution of a series of issues impacting the inputs and calculations of settlements. Some of these issues are described in this report in the section for market issues.

Wholesale costs

Figure 228 to Figure 230 show the total wholesale costs for CAISO at a daily and monthly level. The average total cost per MWh is also shown in Figure 228 and Figure 229¹⁵. Looking at the monthly level, the total costs for September are down from August due to lower levels of demand overall. September surpassed the total cost of last year by about 5%.

Figure 228: Total daily costs CAISO



¹⁵ Total costs include market costs for energy, ancillary services, for both day-ahead and real-time markets, real-time offsets, bid cost recovery. For May 2026 and onwards they now include IR and RC costs.

Table 15: Monthly Total Costs for CAISO

Month	Year 2025		Year 2026	
	Cost (\$ Millions)	Avg cost (\$/MW)	Cost (\$ Millions)	Avg cost (\$/MW)
May	518.65	31.4	319.64	19.8
Jun	622.08	35	432.35	24.2
July	803.08	41.1	952.82	45.4
Aug	996.04	45.9	1,347.06	59.3
Sep	961.43	48.6	1,005.61	51.4

Figure 229: Monthly total costs CAISO

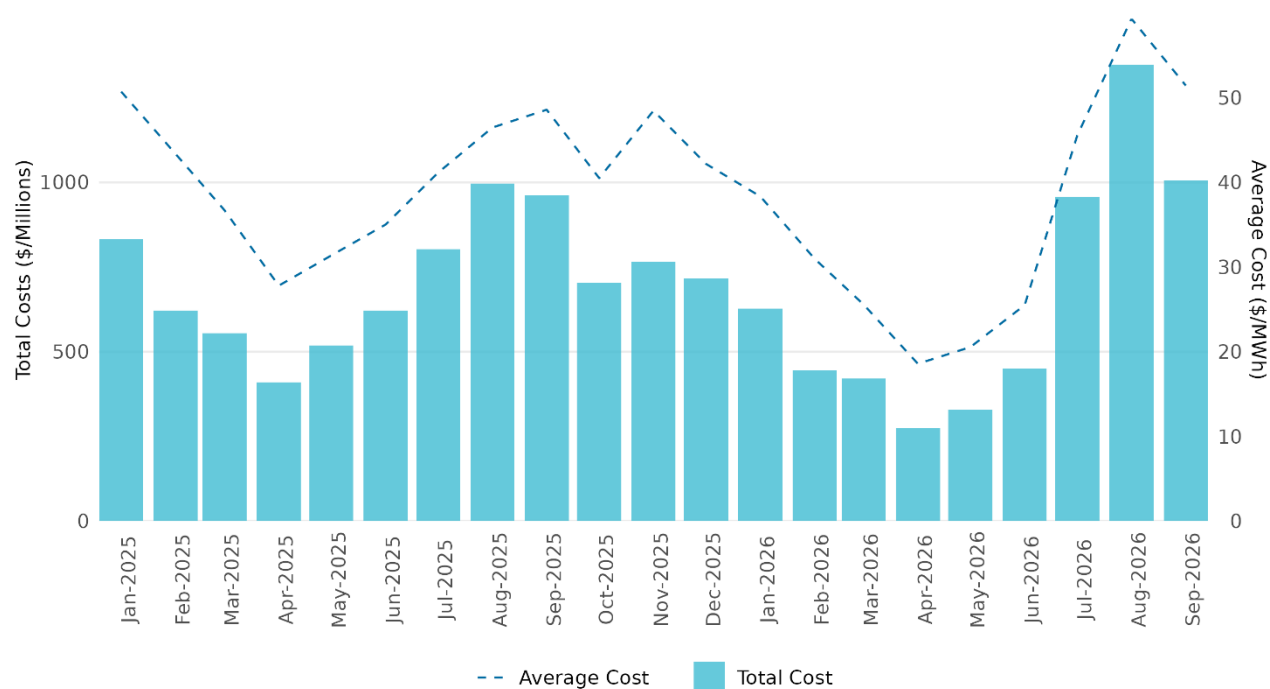
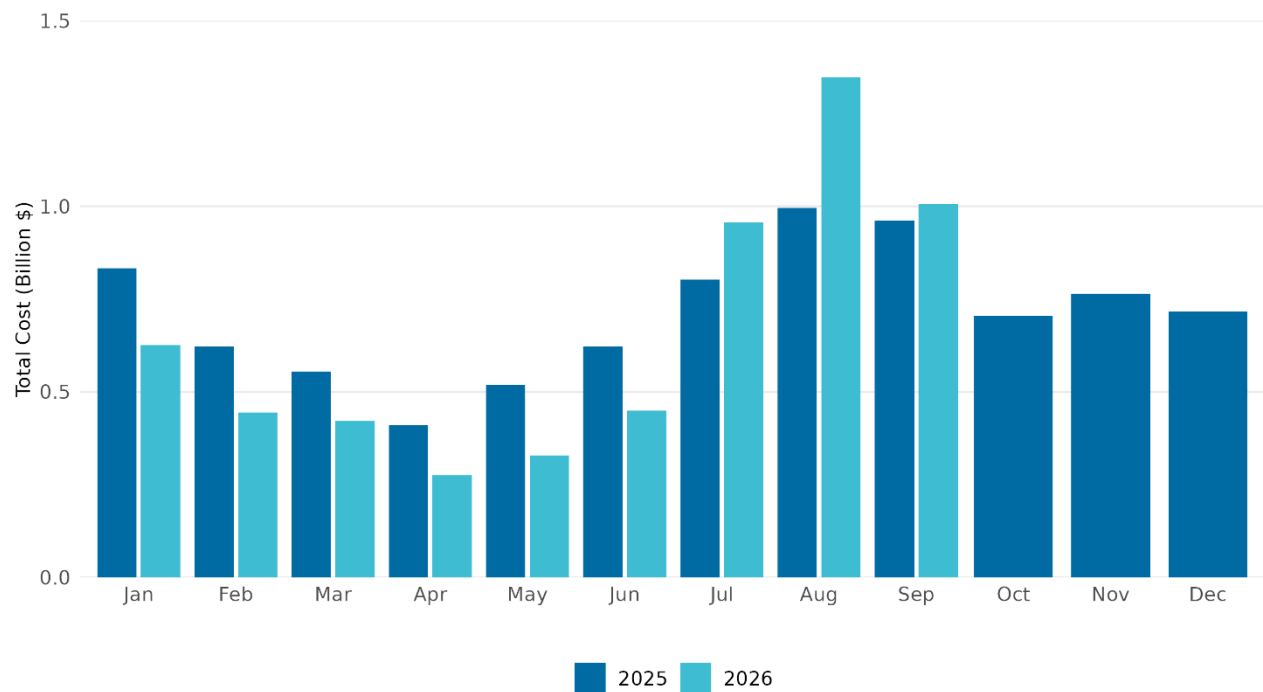


Figure 230: Monthly Total Costs CAISO, comparing 2025 to 2026



Bid cost recovery

Bid cost recovery (BCR) is a settlements mechanism in CAISO's markets to ensure participating resources are made-whole when the revenues collected on participating in the market are not enough to cover their total costs. It is defined as the difference between total costs and market revenue when the revenue is less than the cost.

At this time, we are aware of data issues that are impacting the settlement statements, which in turn may be reflected in the BCR estimates. Therefore, the estimates provided here should be considered as preliminary and subject to change once the revised settlement statements are run. For example, RTM BCR for CAISO on August 26th at approximately \$1.9 million. Internal monitoring identified one bid cost calculation issue for each trade date that will be corrected and reflected in the T+70 settlement statement¹⁶. There were other issues identified for RTM BCR for May 1 and May 29 trade dates, which are expected to be corrected in T+70 settlement cycle. These corrections will impact the numbers reported below and we will update these in the next monthly report.

Figure 231 to Figure 235 illustrate the Bid Cost Recovery (BCR) trends for CAISO, PACW, and PACE across July, August, and September. Figure 234 to Figure 235 compare BCR of three different BAAs across both the IFM and RTM. Note that PACE's IFM BCR starting the last three days of July through most of September are inaccurate and will be corrected in the T+70 settlement statement. This

¹⁶ Refer to the section of Market Issues for more details.

issue was fixed late in September and will not persist going forward. Table 16 shows the BCR comparison between IFM and RTM for all EDAM BAAs from May to September. After adjusting for the ongoing BCR settlement issues, EDAM IFM BCR saw an increase in September after a steady decline since EDAM launch. RTM BCR in total for EDAM participants has continued to decrease through September.

Table 16: BCR comparison between IFM and RTM for EDAM BAAs in \$ millions

AREA	IFM					RTM				
	May	Jun	Jul	Aug	Sep	May	Jun	Jul	Aug	Sep
CISO	3.68	2.23	1.23	0.72	2.11	8.59	3.87	7.96	7.8	4.48
PACE	0.36	0.08	0.545	5.45	2.95	1.49	0.11	0.99	0.432	0.27
PACW	0.11	0.005	0	0.009	0.002	0.25	0.025	0.06	0.028	0.027

Figure 231: BCR of CAISO by market

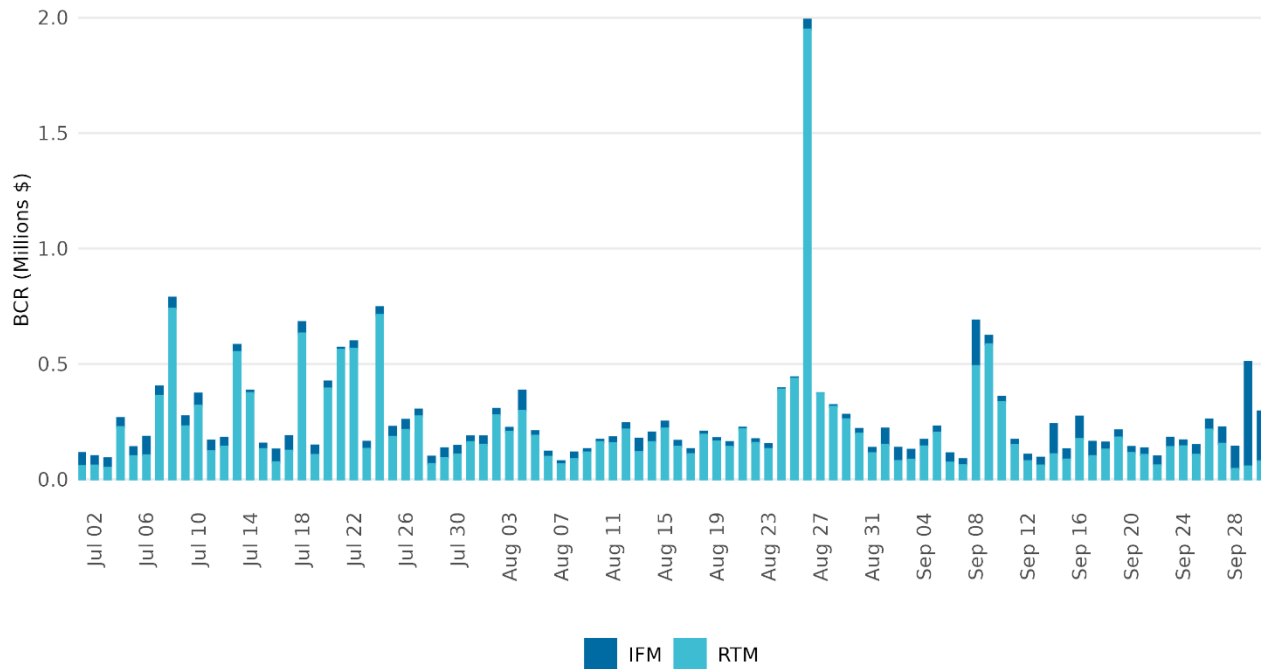


Figure 232: BCR of PACE by market

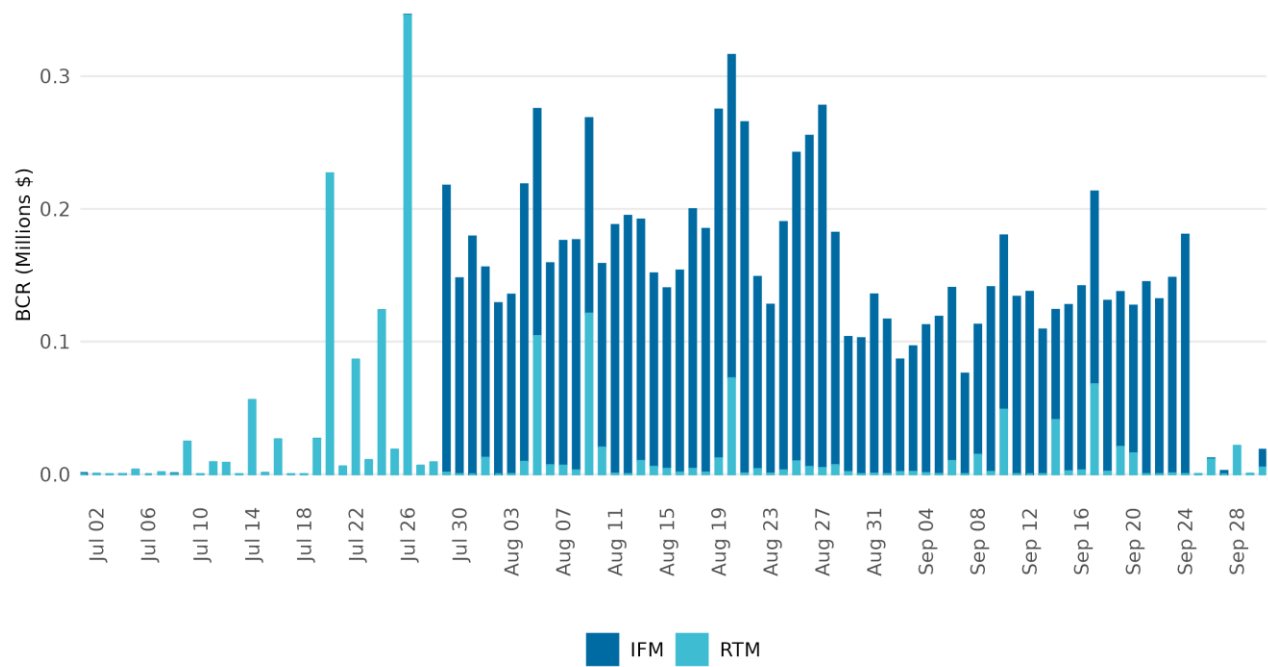


Figure 233: BCR of PACW by market

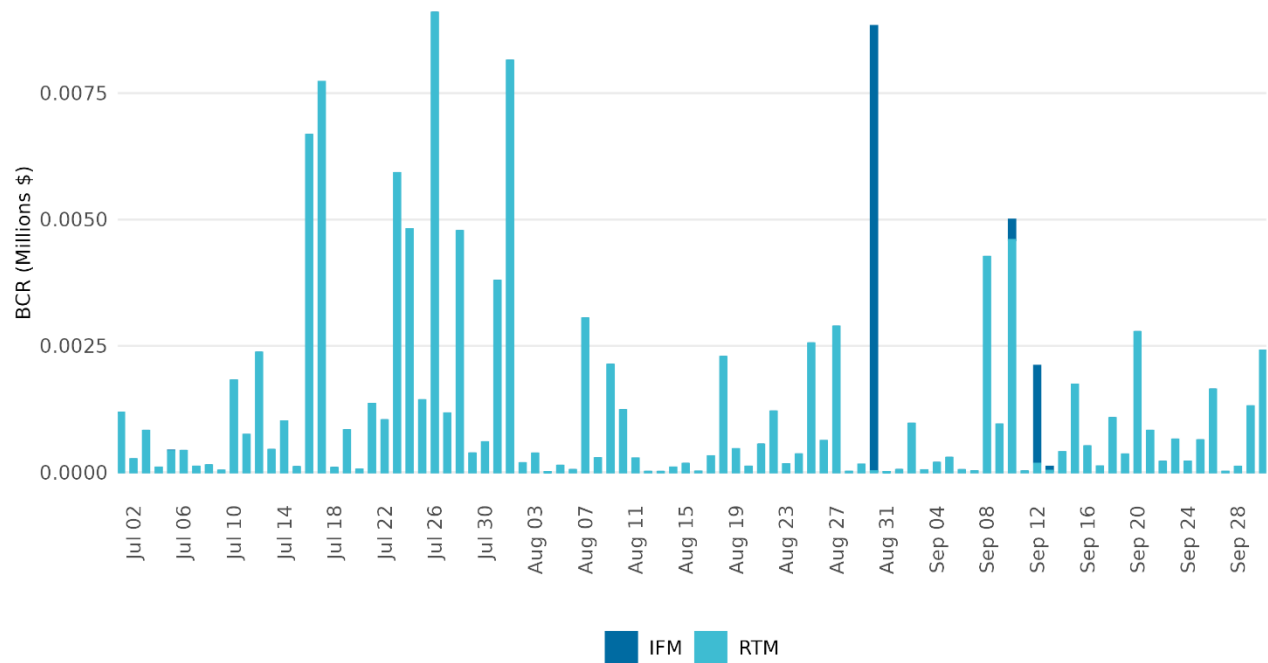


Figure 234: IFM BCR by BAA

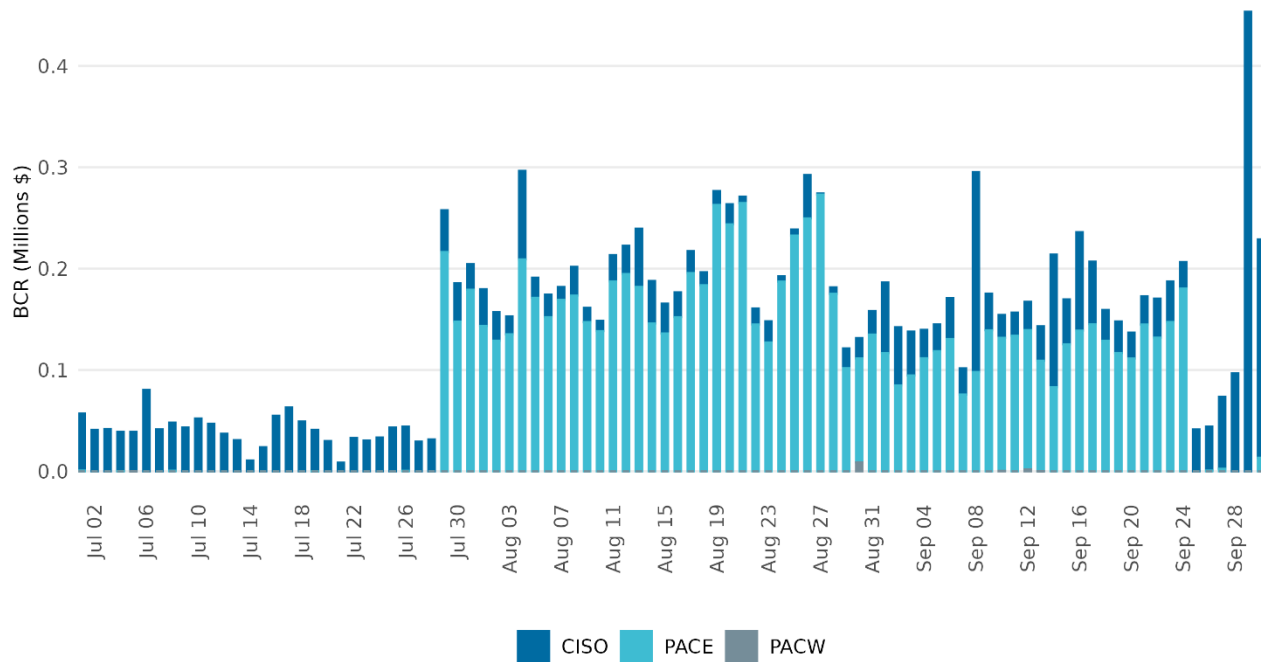
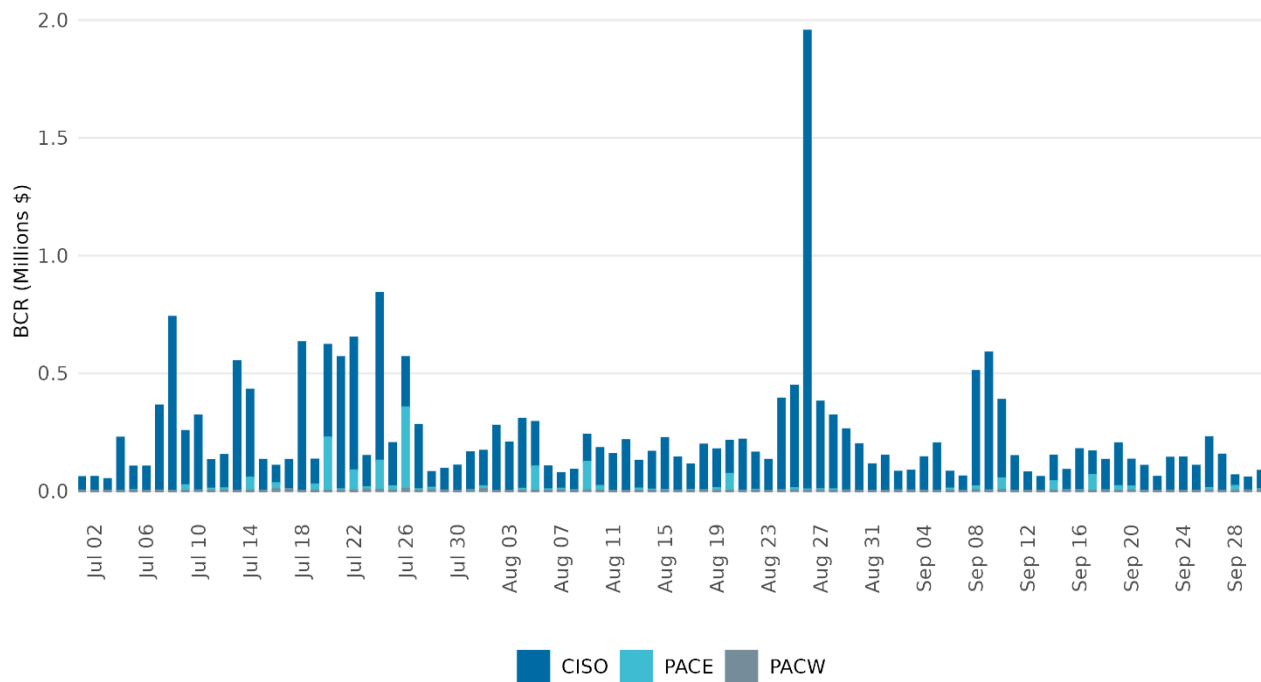


Figure 235: RTM BCR by BAA



Market offsets

In CAISO's market settlements, participants are paid or charged. The money collected from some transactions is used to pay others. However, due to the multiple configurations of the various

components of settlements such as different prices used to settle different components of energy, the total money collected may not perfectly match the money paid out. The differences are balanced through settlements offsets. These offsets are the funds that CAISO needs to collect or redistribute to maintain revenue neutrality.

Day-Ahead congestion offset

This is a new settlements component introduced with the EDAM. Day ahead congestion offset (DACO) is a settlement charge code 8704. For more information on the calculation of DA congestion offset charge code, please refer to the BPM. CAISO does not have DACO because it has a specific CRR-based balancing mechanism, while PACW and PACE use DACO to handle the congestion refunds.

In Figure 236 shows the daily DA congestion offset for PAC areas. A negative amount reflects payment to the entity. A spike in DACO indicated that congestion has a significant impact on the market dispatch during corresponding intervals. Table 17 shows the DA congestion offset comparison for PACE and PACW for the months of July to September.

Figure 236: DA Congestion Offset for PAC areas

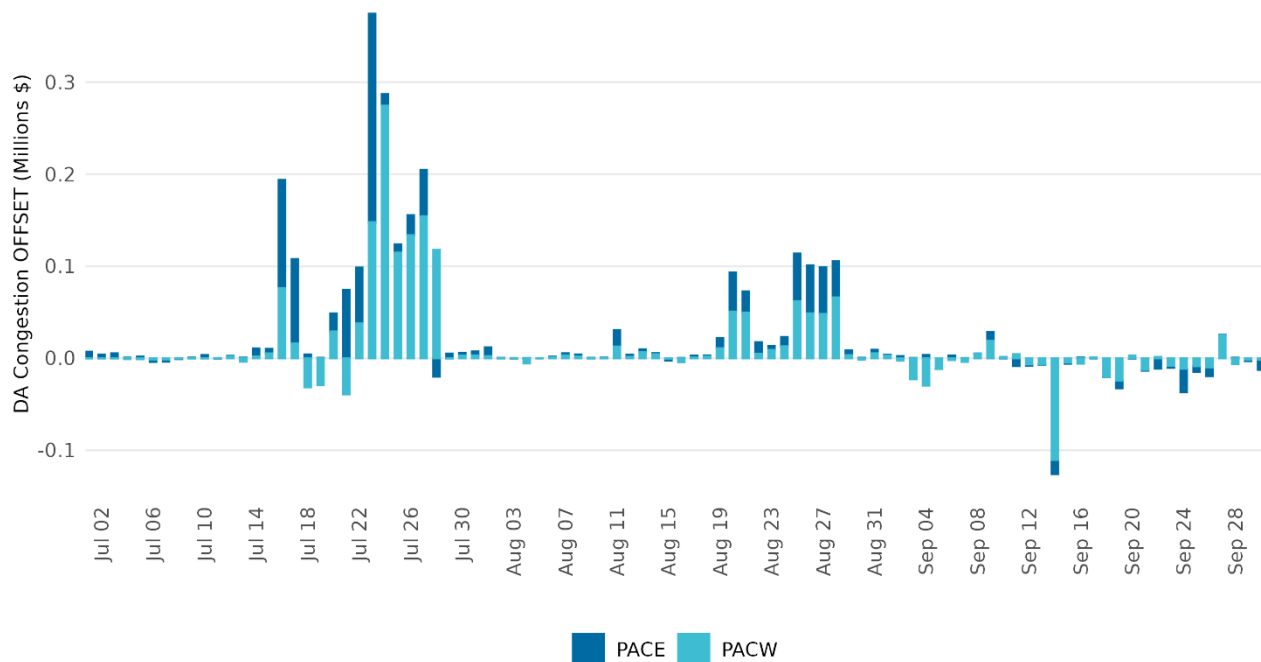


Table 17: DA Congestion Offset in \$ millions

Area	May	Jun	Jul	Aug	Sep	Total
PACE	-1.98	-0.32	0.71	0.35	-0.08	-1.32
PACW	-0.10	0.14	1.01	0.4	-0.25	1.19
Total	-2.08	-0.19	1.72	0.75	-0.33	-0.13

Day-Ahead energy offset

It captures the net financial difference between the total payments owed to supply-side resources (generation and imports) and the total revenues collected from demand-side participants (load and exports) for energy. It is an hourly accounting tool to make sure the day ahead energy market balances to zero. It adds up all the money collected from day energy schedules and convergence bidding at the marginal energy cost minus the congestion and GHG components. Any resulting imbalance within an external EDAM region is allocated directly to that specific EDAM entity's scheduling coordinator, whereas the imbalance within the CAISO region is allocated broadly to CAISO measured demand.

CAISO continues to investigate these instances on an ongoing basis, review the underlying components and implement corrections in the T+70 and T+11M cycles if any discrepancies are identified. Any corrections will impact the numbers reported below and we will update these in the next monthly report.

Positive DA energy offset means charge to the entity, while negative means additional payments needed to be sent out. Table 18 shows the DA energy offset comparison between EDAM BAAs from July to September.

Figure 237: DA Energy Offset

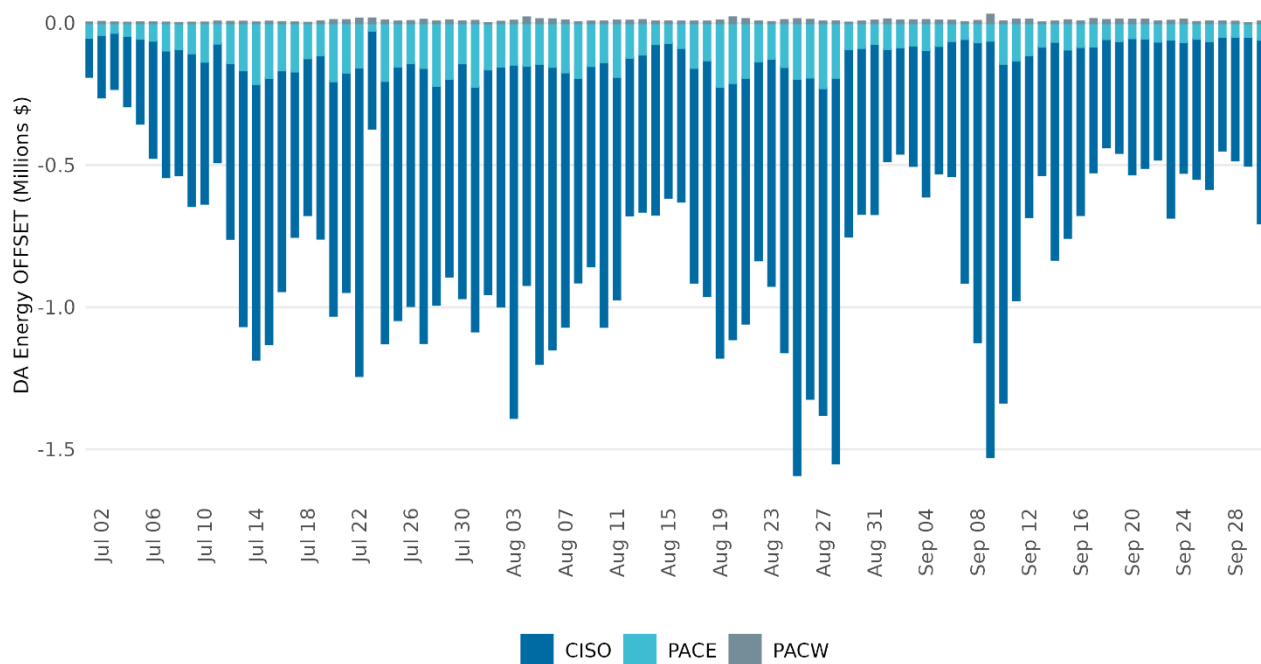


Table 18: DA Energy Offset for EDAM BAAs –in \$ millions

Area	May	Jun	Jul	Aug	Sep	Total
CISO	-6.39	-8.22	-19.66	-26.21	-17.69	-78.17
PACE	-0.23	-1.81	-4.07	-4.6	-2.21	-12.92
PACW	0.08	0.07	-0.17	0.26	0.27	0.51
Total	-6.54	-9.96	-23.9	-30.55	-19.63	-91.09

Real-Time congestion offset

Real time congestion offset (RTCO) is very similar to DACO of external BAAs in IFM market. It is used to achieve revenue neutrality for congestion. An increase means the congestion in the corresponding intervals has large impact onto market dispatch. Figure 238 displays the Real-Time Congestion Offset (RTCO) for the three balancing areas, where a negative value denotes a payment to the BAA and a positive value denotes a charge. The CISO area saw increased RTCO in late August. Congestion was higher during this period due to a planned outage on a highly impacted transmission constraint.

Figure 238: Real-Time Congestion Offset

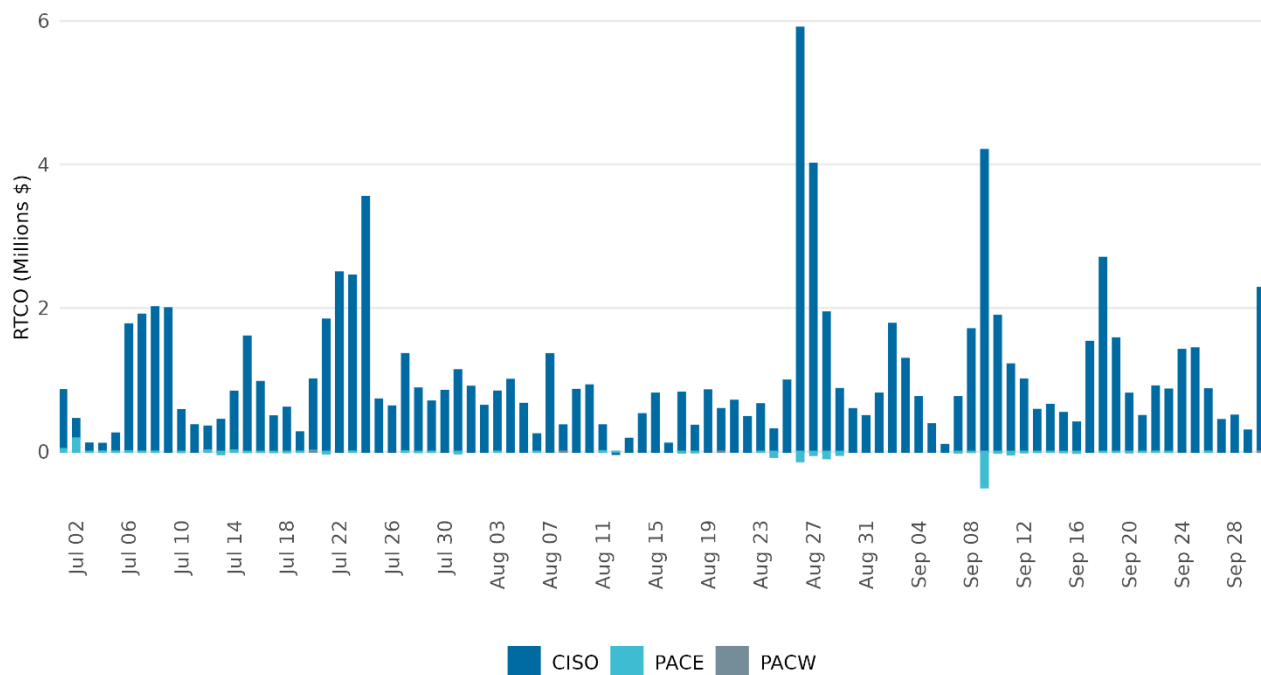


Table 19: Real-Time congestion offset for EDAM BAAs in \$ millions

Area	May	Jun	Jul	Aug	Sep	Total
CISO	18.27	28.14	33.34	29.34	34.19	143.27
PACE	0.61	1.08	0.15	-0.41	-0.64	0.78
PACW	-0.04	0.00	0.00	0.00	0	-0.04
Total	18.84	29.22	33.49	28.92	33.55	144.01

Real-Time imbalance energy offset

Real time imbalance energy offset (RTIEO) is very similar to DAEO. In settlements, RTIEO is a market neutrality charge code that ensures CAISO remains revenue neutral in the real time market. RTIEO is a residual amount due to an imbalance between real time energy payments and charges. RTIEO allocates this residual amount back to measured demand. Figure 239 illustrates a notable shift in RTIEO following the implementation of EDAM. While external BAAs, such as PACW and PACE, experienced an increase in RTIEO, there was a simultaneous reduction in CAISO's own offset.

CAISO is actively investigating several issues and disputes that may impact the T+9 settlement results. As these reviews are completed, CAISO will make appropriate corrections and adjustments as needed. These will be reflected in subsequent settlement recalculations, including at the T+70 settlement true-up. Any corrections will impact the numbers reported below and we will update these in the next monthly report.

Figure 239 illustrates the Real-Time Imbalance Energy Offset (RTIEO) for the three balancing areas, where a positive value indicates an additional charge collected from the BAA and a negative value indicates an additional payment sent out to them.

The real-time imbalance energy offset results observed after the May 1 EDAM go-live are not directly comparable to pre-EDAM outcomes. This is primarily due to fundamental design changes in the settlement calculations, including the transition from a single system marginal energy cost (SMEC) to individual area marginal energy cost references, as well as the incorporation of the GHG component within the GHG area framework. These structural differences inherently change how RTIEO values are calculated. Table 20 shows the real time energy offset comparison for EDAM BAAs.

Table 20: Real time energy offset for EDAM BAAs in \$ millions

Area	May	Jun	Jul	Aug	Sep	Total
CISO	4.84	-3.42	-3.81	-5.16	0.83	-6.72
PACE	-0.75	-0.14	-0.53	-0.06	0.06	-1.41
PACW	0.28	-0.43	-0.43	-0.49	-0.42	-1.50
Total	4.37	-3.99	-4.76	-5.71	0.47	-9.63

Figure 239: Real-Time Imbalance Energy Offset

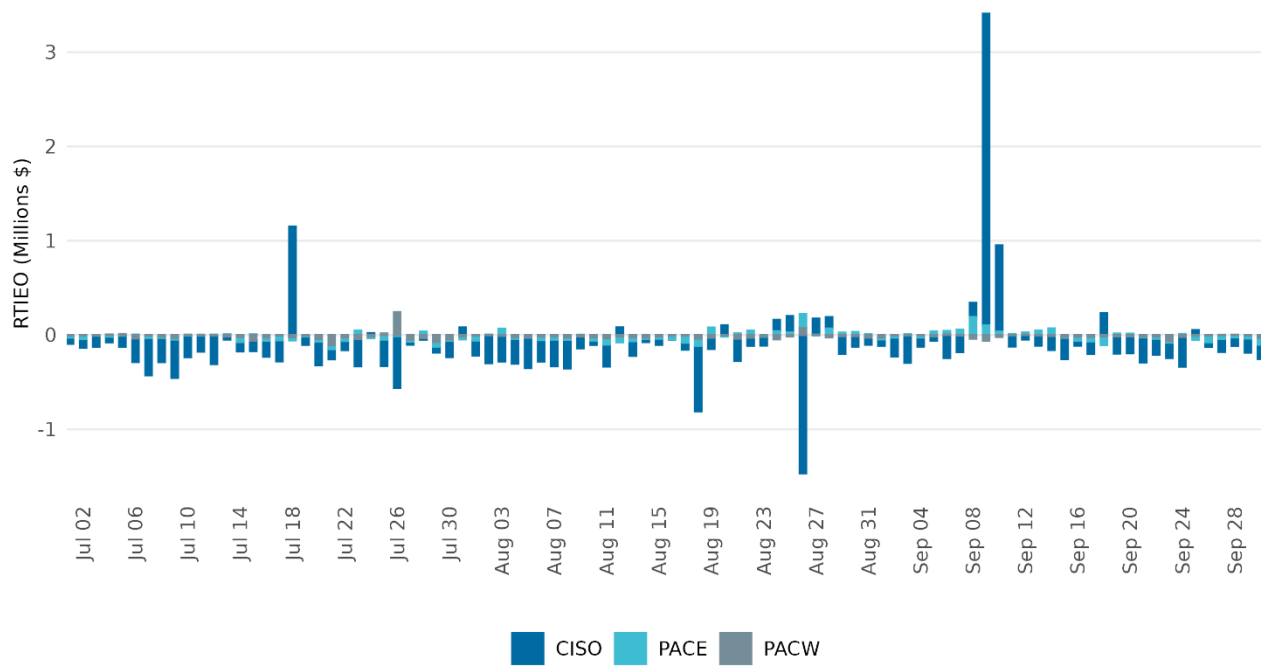
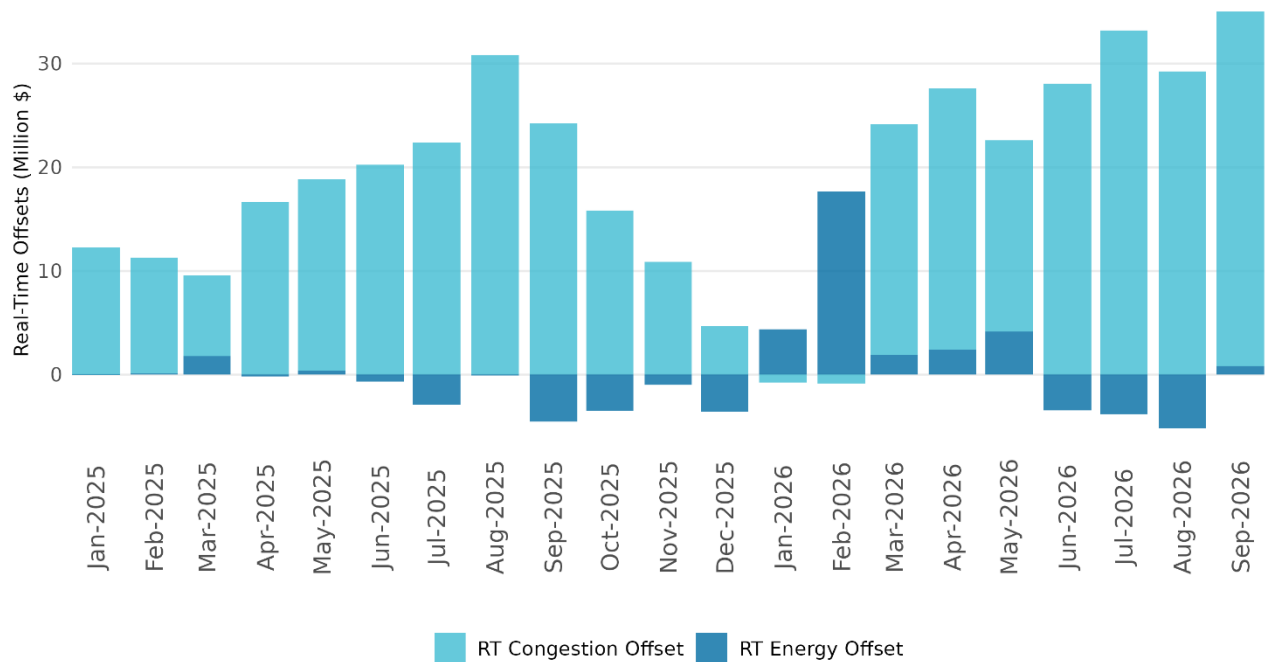


Figure 240 and Figure 241 show the monthly real-time congestion and energy offsets for CAISO area and the WEIM excluding CAISO area, respectively. CAISO offsets remained within normal ranges, with an energy offset slightly more negative than seen in other months since the start of 2025. In June, the energy offset remained negative but got significantly larger. Figure 241 shows that in May through July, the WEIM not including CAISO saw a positive congestion offset and a large, positive energy offset. August has a relatively low RTCO amount of about \$-44k.

The magnitude of the real-time energy offsets for May and June are very high compared to historical offsets. First, it is important to note that the real-time imbalance energy offset (RTIEO) results observed after the May 1 EDAM go-live are not directly comparable to pre-EDAM outcomes. This is primarily due to fundamental design changes, including the transition from a single system marginal energy cost (SMEC) to individual area marginal energy cost references, as well as the

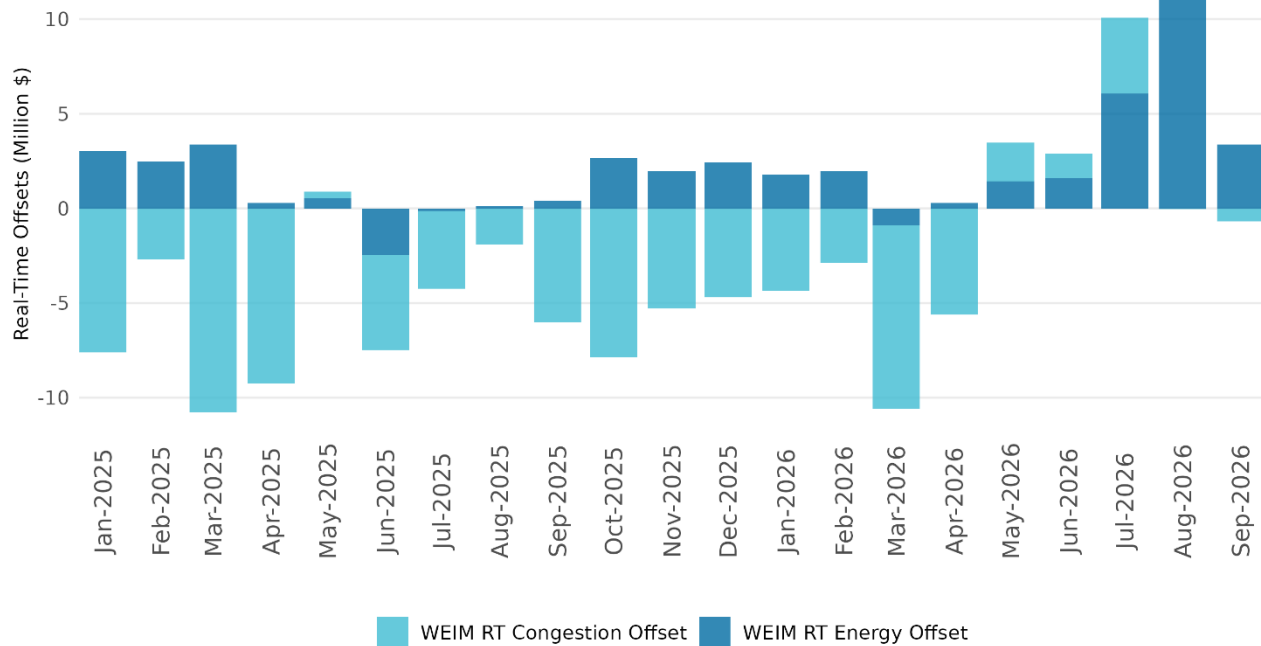
incorporation of the GHG component within the GHG area framework. These structural differences inherently change how RTIEO values are calculated.

Figure 240: Monthly Total Real-Time Offsets for CAISO



While pre- and post-EDAM RTIEO results are not directly comparable, they should be explainable. The ISO has been focused on identifying the corresponding, counterbalancing sources associated with RTIEO charges. The ISO is actively investigating several issues and disputes that may affect and be reflected in the T+9 day real-time offsets settlement results. As these reviews are taking place, the ISO has and will continue to implement corrections and adjustments as needed. These will be reflected in subsequent settlement recalculations, including at the T+70 true-up and future T+9 calculations. Any corrections will impact the numbers reported here and we will update these in the next monthly report.

Figure 241: Monthly Total Real-Time Offsets for WEIM



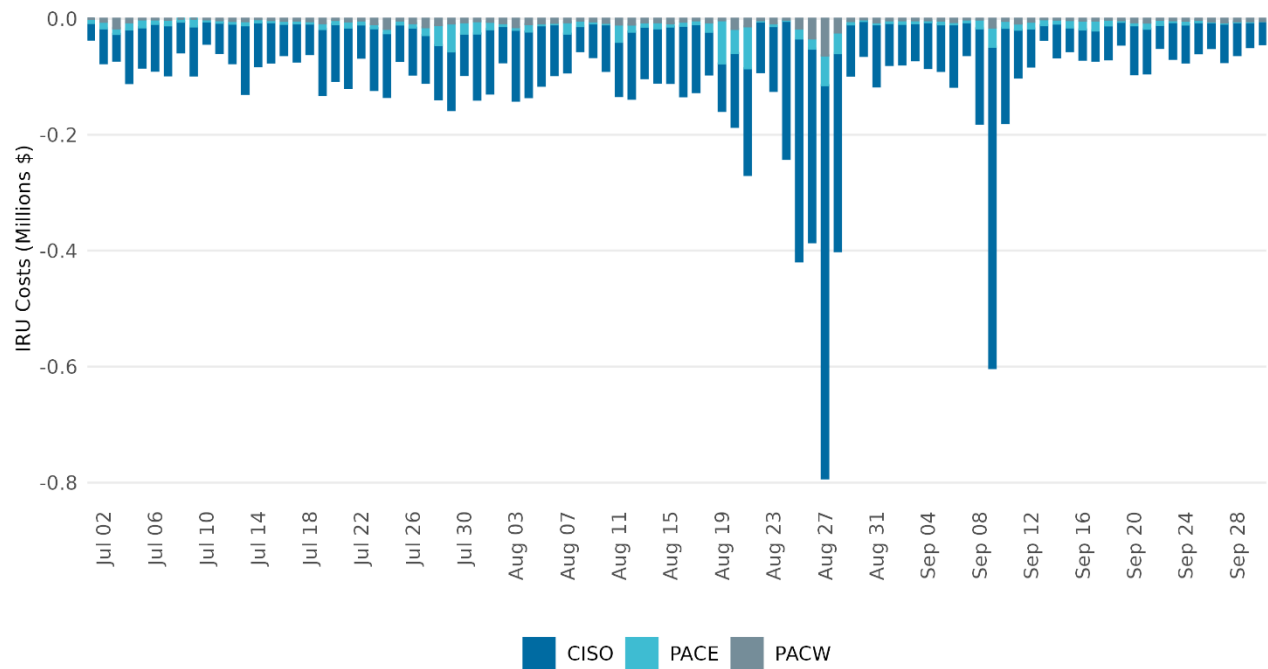
Imbalance reserves

Imbalance reserve up/down are two components of the imbalance reserve product designed to provide upward/downward dispatch capability. Procured within the IFM, Imbalance Reserves up/down (IRU and IRD) is used to ensure that sufficient dispatchable capacity is available to meet positive/negative net load imbalance that occur between the EDAM and Real-Time markets. Only resources that can be dispatched in the 15-min market would be eligible to provide imbalance reserves and the maximum award capacity would be based on a resource's 30-min ramp capability.

An IRU payment is calculated by multiplying the resources awarded IRU quantity by the locational IRU price. A negative Imbalance Reserve (IR) settlement indicates net payment to the scheduling coordinators (SC) of resources located in Balancing Authority Area (BAA). To enforce compliance, CAISO applies a no pay unavailability non-compliance charge if a resource fails to maintain its day-ahead flexible capability relative to its upper economic limit and five-minute ramp capability. Undelivered quantities are penalized using a resource-specific price equal to the higher of the real-time flexible ramp up price or the locational IRU price.

Figure 242 shows the daily trend of IRU costs for July through September. IRU costs increase significantly for the CAISO area around August 25th to August 27th. This is largely due to higher IRU prices across the same period.

Figure 242: IRU settlement costs



Similarly, The IRD payment charge code settles day-ahead market awards for resources and transfer resources on an hourly basis. The IRD payment for each resource is calculated by multiplying its hourly awarded IRD quantity by the resource's IRD price. The system tracks the resource's 5-minute ramp capable capacity portion along with IRD allocated capacity range in FMM, and If a resource fails to maintain its downward capability, it faces unavailability non-compliance charges at FMM flexible ramp down price. Figure 243 shows the daily costs for procuring IRD for July through September.

Figure 243: IRD settlement costs

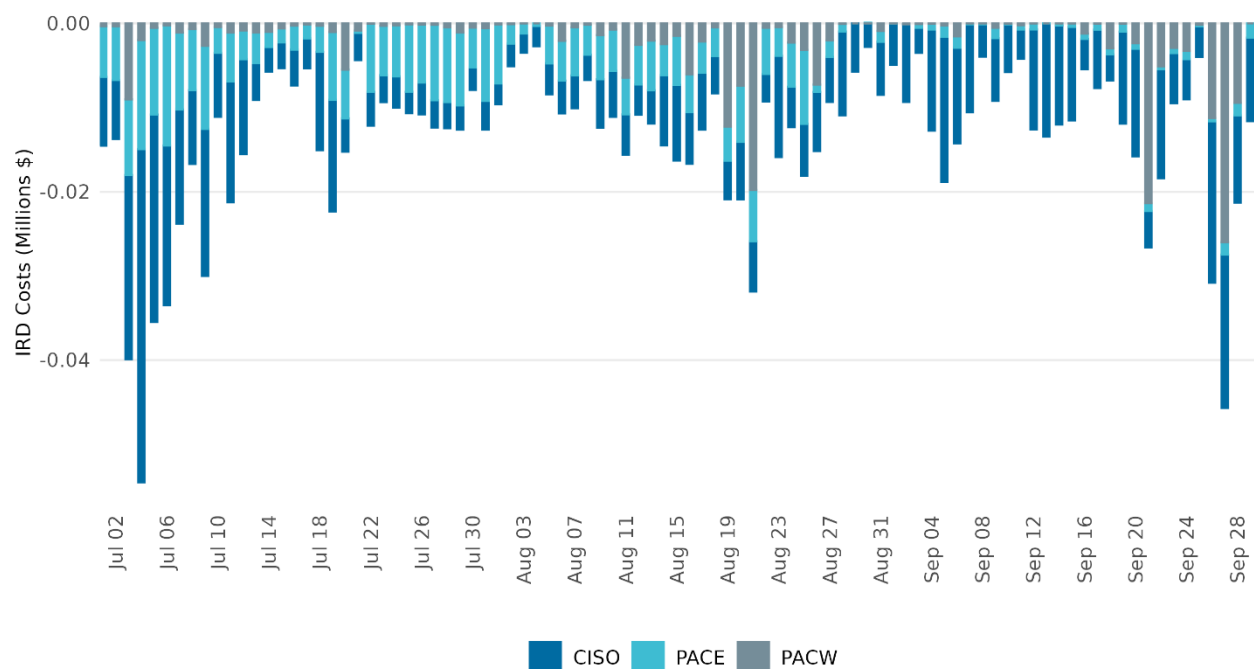


Table 21: Imbalance Reserves Total Monthly Settlement Costs

	IRU Total Costs (\$million)					IRD Total Costs (\$million)				
BAA	May	June	July	Aug	Sep	May	June	July	Aug	Sep
CAISO	-2.07	-1.79	-2.39	-4.47	-2.52	-1.23	-0.36	-0.28	-0.16	-0.27
PACW	-0.36	-0.10	-0.16	-0.32	-0.12	-0.16	-0.12	-0.20	-0.12	-0.02
PACE	-0.22	-0.48	-0.34	-0.51	-0.24	-0.21	-0.06	-0.03	-0.09	-0.12

Reliability capacity

Reliability Capacity (RC), consisting of RCU and RCD, is procured in the Residual Unit Commitment (RUC) process. The RCU settlement costs is calculated on an hourly interval to manage day-ahead awards for resources. A negative value is indicated as a payment to the scheduling coordinator, while a charge is tracked as positive values. RC settlement is the hourly financial compensation provided to resources for awarded capacity, calculated as the product of the awarded quantity and the RUC Reliability capacity price. CAISO assesses a no-pay unavailability charge if a resource fails to keep its day-ahead reliability commitment available relative to its upper economic limit and real-time outages. This penalty is calculated as the product of the unavailable quantity and the resource's RCU price.

Figure 244 shows the daily RCU costs organized by BAA in July through September. Similarly for RCD settlements, it is calculated by multiplying its hourly RCD quantity by the locational RCD price. While RCU checks resource's availability to ensure it has enough upward capability relative to its upper economic limit, RCD checks resource's downward flexibility to verify that its lower economic limit (including real-time outages) does not exceed its day-ahead energy schedule minus any downward regulations.

Figure 245 provides the daily trend of RCD cost by BAA in July through September. RCU costs spiked on the 27th due to higher RUC prices during peak hours on that day.

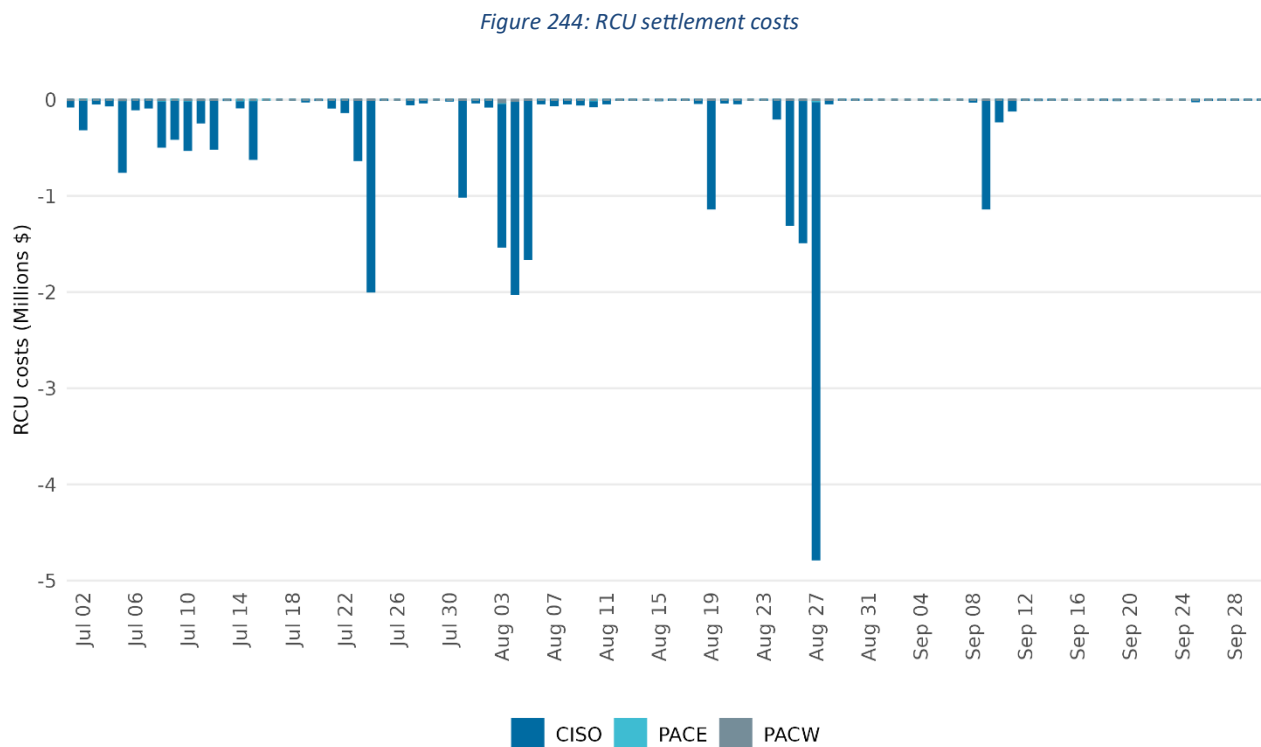


Figure 245: RCD settlement costs

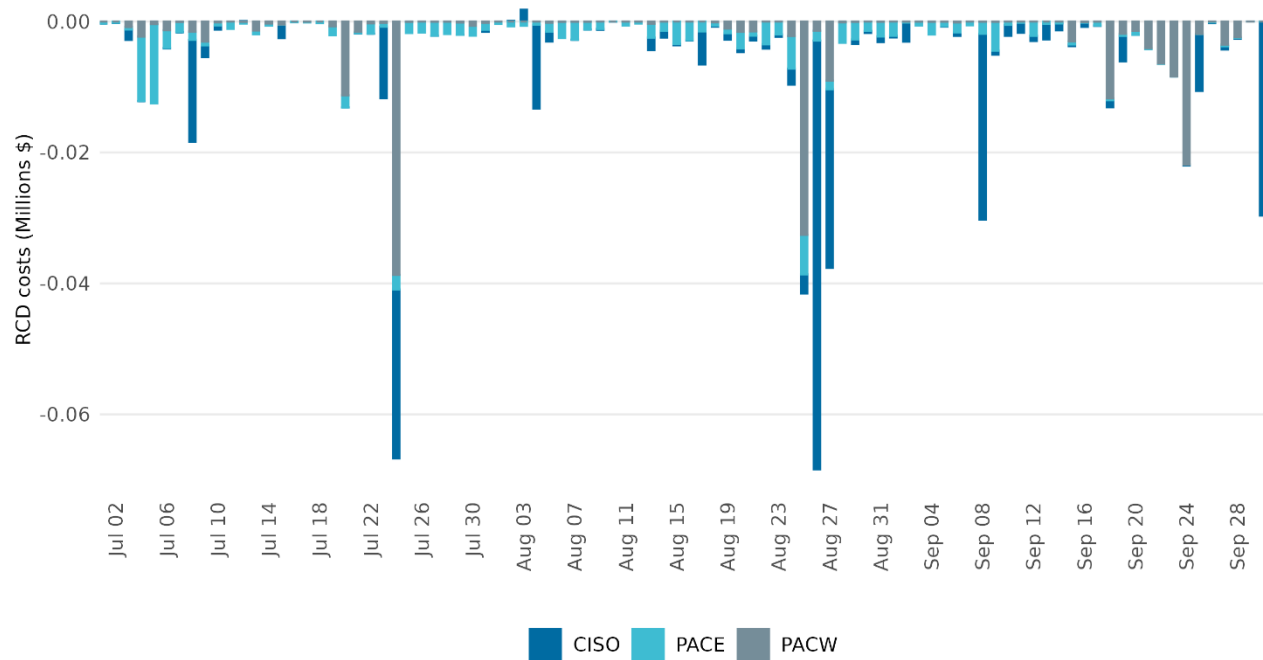
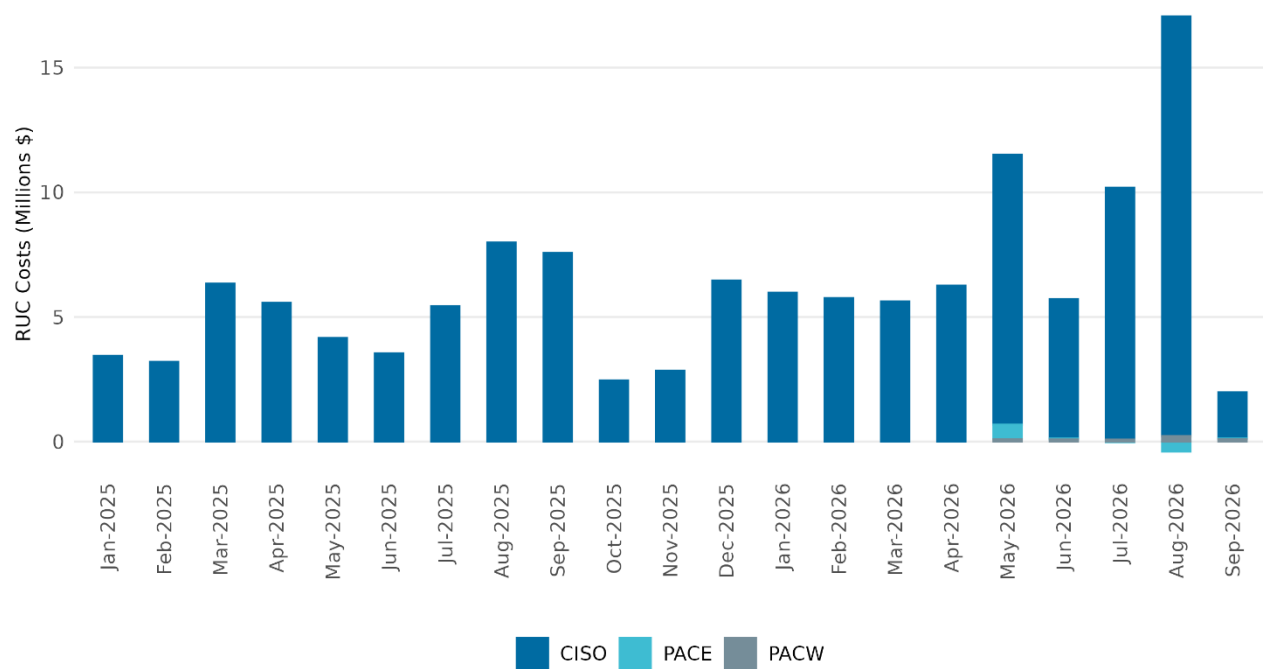


Table 22: Reliability Capacity Total Monthly Settlement Costs

BAA	RCU Total Costs (\$million)					RCD Total Costs (\$million)				
	May	June	July	Aug	Sep	May	June	July	Aug	Sep
CAISO	-9.06	-2.58	-8.16	-14.54	-1.51	-0.84	-2.82	-0.06	-0.12	-0.09
PACW	-0.22	-0.01	-0.01	-0.04	0.00	-0.02	-0.05	-0.07	-0.05	-0.07
PACE	-0.32	-0.03	-0.03	-0.03	-0.02	0.00	-0.01	-0.05	-0.06	-0.02

Figure 246 tracks total RUC costs by month, providing a consistent view of costs before and after EDAM implementation. The monthly trend highlights how RUC-related costs have evolved under the changing market design and provides a basis for assessing cost patterns in the post-EDAM period. Since EDAM go-live, total RUC costs have reached \$74.7 million, with \$73.8 million attributed to the CISO BAA. Although comparable costs over the same five-month period in 2025 totaled \$28.7 million, resulting in a substantially higher cost level in 2026, the values are not directly comparable because EDAM introduced new reliability capacity products, settlement constructs, and cost allocation methodologies. Consequently, a portion of the increase reflects differences in market design rather than solely changes in procurement costs. Prior to EDAM implementation, RA resources were excluded from RUC payments and received no compensation in RUC. After EDAM implementation, RA capacity could be scheduled for RCU and RCD and received settlement allocation.

Figure 246: Monthly trend of RUC/Reliability Capacity costs by BAA



GHG settlement

The California Cap and Trade regulation on greenhouse gas emissions requires market participants to surrender compliance instruments to the California Air Resources Board (CARB) for GHG emissions associated with energy generated from CO₂-emitting resources within California and energy imported into California. Energy generated outside California that is not imported into the state is not subject to this compliance obligation. To address these requirements, EDAM incorporates the cost of the GHG compliance obligation when dispatching generation within an EDAM entity area to serve load located in a GHG regulation area (in this case, California). This cost is not considered when the same generation is dispatched to serve load outside a GHG regulation area.

The GHG settlement mechanism is calculated on an hourly settlement interval basis. CAISO compensates the scheduling coordinator for energy deemed to have been imported into a GHG regulation area at the marginal GHG price. The settlement amount is calculated as the product of the deemed greenhouse gas quantity to the GHG regulation area and the applicable marginal GHG price. The marginal GHG price is included as a component of the LMP within the GHG regulation area. Figure 247 shows the GHG payments to EDAM entities that are supporting the energy imported into the GHG regulation area (California). Conversely, Figure 248 shows the Real Time GHG payment for the EDAM entities. Negative values indicate a payment to the Scheduling Coordinator and positive values, which will only occur in RTM, indicate a buyback amount. Table 23 summarizes the monthly total GHG costs for PACE and PACW.

Figure 247: Greenhouse Gas Settlement Costs in IFM

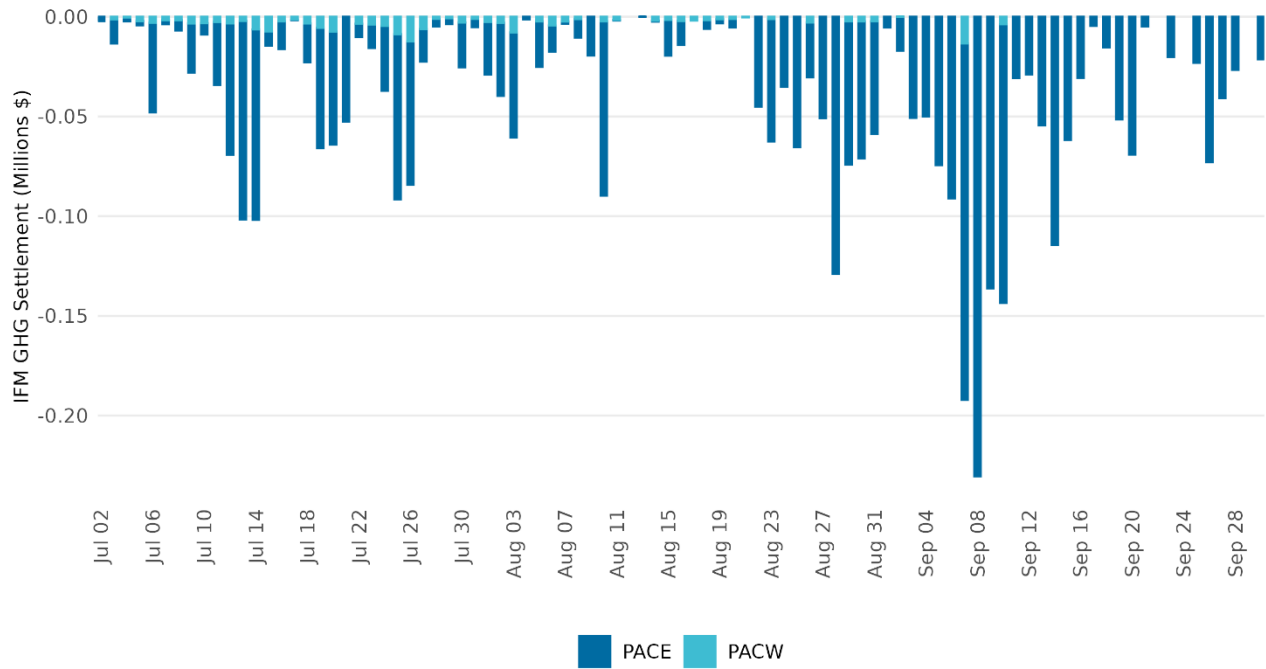


Figure 248: Greenhouse Gas Settlement Costs in RTM

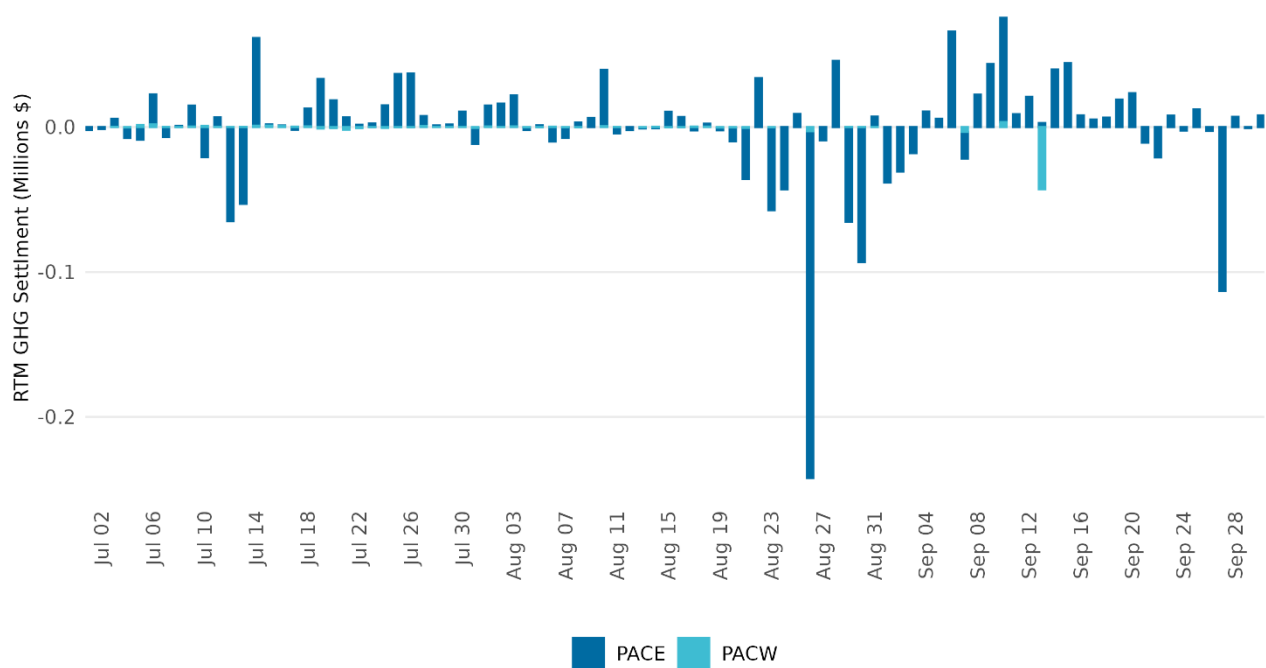


Table 23: IFM and RTM Monthly GHG Settlement Costs

	IFM GHG Costs (\$ million)					RTM GHG Costs (\$ million)				
BAA	May	June	July	Aug	Sep	May	June	July	Aug	Sep
PACW	-0.28	-0.20	-0.86	-0.92	-1.65	-0.18	-0.18	0.12	-0.37	0.18
PACE	-0.01	-0.03	-0.10	-0.05	-0.02	0.001	0.002	0.01	-0.001	-0.04

Market Issues

Through the analysis of the market outcomes and performance and settlements, CAISO tracks any areas for improvements and identifies any market issues. Given the significant change in systems and processes with the implementation of the extended day-ahead market and the day-ahead market enhancements, the ISO identified several issues impacting the market outcomes as early as May. Several of the items listed in this section have been previously introduced and discussed in either EDAM implementation calls, the market update calls or the settlement user group calls. The ISO will continue to address the resolution of these issues as necessary.

The following issues have been previously reported:

- **Reliability Capacity Awards at Negative Prices:** Reliability Capacity has been awarded to resources at negative prices due to several issues, including software issues with MSG transitions, market-driven conditions related to optimality of solution and price formation. For price formation, negative marginal losses or congestion can drive prices below \$0. CAISO has not corrected RC prices for these issues because the impact is on the capacity awards and not the prices. Other negative RC prices may simply reflect the optimality of solution or the effect of marginal losses. CAISO continues to monitor these market outcomes to ensure new products are functioning as intended.
- **In RUC when RCU and RCD bid prices are zero dollars;** the optimization may procure both RCU and RCD in the same hour. Reliability Capacity consists of two distinct products that are procured when there is a difference between the CAISO forecast of CAISO demand and the cleared physical supply. Procuring both products in the same hour from different resources is not a software issue and reflects the complications of achieving an optimal solution when the upward and downward capacity have zero prices. CAISO will continue monitoring to ensure the new market functionality is working as intended.
- **Flow Discrepancies for Intertie Constraints in the CRR system:** Discrepancies in Intertie Constraint flows are impacting the CRR Settlement. When interties are mapped to multiple Intertie Constraints, the IFM flow calculation logic produces inaccurate results, leading to

downstream misallocation of CRR revenues. This issue affects trade dates beginning May 1, 2026 and is open. CAISO is working to correct this in the T+70 BD settlement statements.

- Missing IRU and IRD deployment scenarios in the CRR clawback mechanism: The CRR clawback calculation does not account for IRU and IRD deployment scenarios due to incomplete payload data from the market application to the CRR system. This issue impacts May 1, 2026 and is open. CAISO is working to correct this in the T+70 BD settlement statements.
- High Reliability Capacity Down prices due to solution limited by IFM commitment: Reliability Capacity Down can only be awarded to resources that are on-line and committed by the IFM. Additionally, down capacity range is limited by energy self-schedules, Ancillary Services and Imbalance Reserves awarded in IFM. This is not a software issue but it is a dynamic due to the requirement to run RUC only after IFM is complete. Reliability Capacity Prices are generally low and the current market structure to run RUC only after IFM is completed will remain in place so this issue is considered closed.
- Non-Participating Resources in RUC: To prevent RUC solution failures and ensure timely day-ahead market publication, select generator and MSG configurations were excluded from RUC participation¹⁷. CAISO determined that removing some MSG configuration bids in RUC resulted in a shutdown of affected MSG plants. CAISO continues to assess and monitor underlying causes of these RUC failures and continues to monitor and assess this issue.
- Daily Energy Limit not counted in EDAM Resource Sufficiency Evaluation (RSE): Due to a software issue, the daily energy limit for use-limited resources is not enforced in the EDAM RSE allowing these resources to be credited for more capacity than is available in the market. This issue impacts trade dates from May 1, 2026 and remains open.
- Bid Cost Recovery for Hybrid Resources: There is an issue processing the submitted bid costs for hybrid resources which is resulting in high bid cost recovery payments. This issue affects trade dates from May 1, 2026 and is open.
- Bid Cost Recovery for Dispatchable Demand Resources (DDR): There is an issue processing the submitted bid costs for DDR which is resulting in high bid cost recovery payments. This issue affects trade dates from May 1, 2026 and is open.
- Low-Priority Exports in RUC: Low-priority exports receive a \$250 proxy Reliability Capacity Up bid in RUC and will be curtailed when RUC prices are \$250 or higher. There are two software issues impacting the bid set-up and curtailment for low-priority export. This issue was resolved on October 1, 2026.
- High-Priority Exports in RUC: Under the current implementation, high-priority exports (PT exports) do not have a proxy Reliability Capacity Up bid in RUC. As a result, PT exports

¹⁷ CAISO contacts the Scheduling Coordinators for resources that have bids removed in any market run.

cannot be curtailed through RUC. CAISO intends to pursue a Tariff clarification and software update regarding the treatment and prioritization of high-priority exports.

The following issues are new:

- **Greenhouse Gas (GHG) Reference Point for Multi-Stage Generators (MSGs):** An MSG resource submits a single GHG bid in the EDAM and this bid should cover the MSG to the plant Pmax. There is a software issue that is not applying the GHG bid to all MSG configurations. This issue impacts trade date from May 1, 2026 and remains open.
- **Capacity Counting in the Resupply Test:** The resupply test that occurs in the SIBR application and occurs five hours before the relevant trade hour is not accounting for day-ahead awards correctly. EDAM BAAs that fail to e-tag day-ahead intertie awards may be included in the EDAM up pool in the real-time market when they should be excluded. This issue impacts trade date from May 1, 2026 and remains open.
- **Missing Scheduling Point Intertie (SP-Tie) Pricing Point:** The Master File definitions for two SP-Tie combinations, DGAP_BPAT-APND/BPAT.PGE and DGAP_NWMT-APND/PGE.COLSTRIP, were not implemented. CAISO will correct all day-ahead and real-time market prices for these two SP-Tie pricing points from October 1-14, 2026 to be equal to the SP-Tie price on DGAP_BPAT-APND/CAPTAINJACK_PGE.

Stakeholder Feedback and ISO's responses

There was one set of stakeholder comment submitted in response to August's report. This section provides a summary of these comments and a summary of the responses as an easy reference. The detailed responses are available on the site where the stakeholder comments were originally posted.

CAISO appreciates the comments and recommendations provided by stakeholders regarding EDAM market performance, reporting transparency, congestion and transfer revenue allocation, imbalance reserve procurement, settlements, pricing mechanisms, self-scheduling, and market operations. The ISO values constructive feedback and stakeholder engagement during the initial months of EDAM operations. As the market continues to stabilize, CAISO is reviewing the requests for additional analyses, metrics, and reporting enhancements and will consider incorporating expanded information and clarifying existing metrics in future monthly EDAM performance reports and stakeholder discussions where appropriate. CAISO also recognizes the importance of continued transparency regarding operational challenges, market outcomes, and benefit allocation, and appreciates stakeholders' ongoing participation and feedback as the ISO works to further improve EDAM reporting and market understanding.

Pacific Gas & Electric Company requests clarification on several topics including the Imbalance Reserve and Reliability Capacity requirement levels, root causes for increases in energy costs and congestion revenues, additional information on Reliability Capacity procured from storage resources and the changes to the need for manual adjustments from large load growth.

CAISO response: The ISO appreciates PG&E's questions regarding the report and market performance. While the ISO will continue to evaluate additional metrics and areas for analysis, there are practical limitations to the scope of such assessments. To respond to the stakeholder feedback, The ISO is not waiting for the six-month review period to begin evaluating Imbalance Reserve (IR) performance. In fact, IR procurement and utilization have been a key focus of the last three reports, with the September report providing a more detailed assessment. This review is being conducted sequentially. The initial focus is on evaluating procurement efficiency and utilization performance to determine whether the product is operating as intended. Once that analysis is more mature, the ISO will be better positioned to assess whether the current IR requirements and procurement levels remain appropriate.

The configurable parameter review is not a discrete effort that begins and ends with the six-month review. Rather, the analysis that has been performed since May is laying the foundation for assessing whether the current configuration of EDAM and DAME, including the configurable parameters, is operating effectively and whether any adjustments may be warranted.

During this six-month period, the ISO's focus is broader than the configurable parameters alone. The effort is aimed at evaluating the overall efficiency and performance of EDAM and DAME, while simultaneously identifying and addressing market issues that have been documented in the monthly performance reports. This work provides the necessary context and analytical foundation to support any future assessment of configurable parameters. There also appears to be a misunderstanding regarding Reliability Capacity (RC) requirements from the submitted comment. RC requirements are not explicitly prescribed or calibrated to a predefined target level. Rather, RC procurement is determined dynamically based on the IFM solution and reflects prevailing system conditions, forecasts, market outcomes, and operational needs. As such, it is not a parameter that can be directly calibrated through a standalone requirement-setting methodology.

Prices for Reliability Capacity depend on several factors, including RC requirements from the difference between IFM cleared physical supply and the RUC demand forecast, RC input bids, and congestion. August 24-27 saw elevated prices for energy, imbalance reserves and congestion, not just reliability capacity. This reflected the higher loads and tighter regional conditions in those days.

There can be several types of counterfactual analyses, and it is not clear which counterfactual PG&E is proposing. For example, a counterfactual designed to assess the benefits of expanding the market footprint is fundamentally different from one intended to isolate the effects of Imbalance Reserve (IR) procurement. These analyses address different questions and therefore require different assumptions and methodologies.

The GHG Base Run is not an appropriate counterfactual for evaluating the impact of Imbalance Reserves. A proper counterfactual for that purpose would require a simulation in which no Imbalance Reserves are procured, allowing the incremental effects of the product to be isolated and measured directly.

By contrast, the GHG Base Run primarily restricts imports into the CAISO balancing authority area. It does not restrict exports from CAISO to other EDAM entities. As a result, differences between the GHG Base Run and the production run reflect multiple design and market impacts, making it unsuitable as a benchmark for assessing the specific effects of Imbalance Reserves.

The question related to manual adjustment is more focused on projecting future system conditions and operational needs, which is beyond the scope of the current Market Performance Forum. The purpose of this forum is to evaluate observed market outcomes and performance based on actual results.

The ISO has committed to continuously monitoring the performance of this area and assessing whether adjustments are warranted as system conditions evolve. As load patterns, resource mix, and operational needs change over time, the ISO will continue to evaluate performance and make modifications where appropriate.