Market Performance Report
September 2017

November 29, 2017

ISO Market Quality and Renewable Integration

CAISO
250 Outcropping Way
Folsom, California 95630
(916) 351-4400

Executive Summary[1]

The market performance in September 2017 is summarized below.

CAISO area performance,

- Peak loads for ISO exceeded 50,000 MW on September 1 due to high temperature.
- In the integrated forward market (IFM), all four DLAP prices were elevated on September 1-2 due to high load and tight supply. In the fifteen-minute market (FMM), all four DLAP prices were elevated on September 11 due to upward load adjustment, net import reduction, and renewable deviation. In the real-time market (RTD), PG&E, SCE and SDG&E prices were elevated on September 1-2 driven by transmission congestion.
- Congestion rents for interties rose to $6.83 million from $2.67 million in August. Majority of the congestion rents in September accrued on MALIN500 (52 percent) intertie and NOB (35 percent) intertie.
- In the congestion revenue rights (CRR) market, revenue adequacy was 74.47 percent, increasing from 68.54 percent in August. The transmission line 24016_BARRE_230_24154_VILLA P contributed largely to the revenue shortfall.
- The monthly average ancillary service cost to load declined to $0.70/MWh in from $1.05/MWh in August. There were two regulation up scarcity events in FMM on September 11 and 12.
- The cleared virtual supply was well above the cleared demand in most days of September. The profits from convergence bidding increased to $1.28 million from $0.13 million in August.
- The bid cost recovery dropped to $6.70 million from $8.81 million in August.
- The real-time energy offset cost increased to $5.57 million from -$2.97 million in August. The real-time congestion offset cost edged down to $1.95 million from $2.12 million in August.
- The volume of exceptional dispatch increased to 72,769 MWh from 59,733 MWh in August. Planned transmission outage and constraint contributed 44 percent of total volume. Operating procedure number and constraint contributed 22 percent of total volume. The monthly average of total exceptional dispatch volume as a percentage of load increased to 0.37 percent from 0.26 percent in August.

[1] This report contains the highlights of the reporting period. For a more detailed explanation of the technical characteristics of the metrics included in this report please download the Market Performance Metric Catalog, which is available on the CAISO web site at **http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx**.

Energy Imbalance market (EIM) performance,

- In the FMM and RTD, the prices for AZPS, PACE, and NEVP were elevated on September 11 driven by upward load adjustment, net import reduction, and renewable deviation.
- Bid cost recovery, real-time imbalance energy offset, and real-rime congestion offset costs for EIM entities (PACE, PACW, NEVP, AZPS, and PSEI) were $0.59 million, -$0.84 million and -$0.67 million respectively.

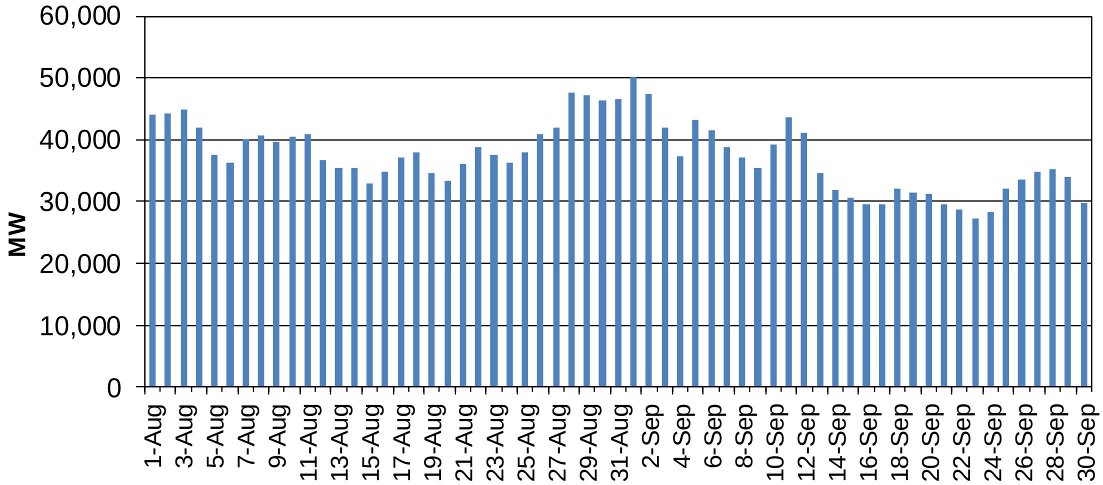
TABLE OF CONTENTS

Market Characteristics

Loads

Peak load for ISO exceeded 50,000 MW on September 1 due to high temperature.

Figure 1: System Peak Load



Resource Adequacy Available Incentive Mechanism

Resource Adequacy Availability Incentive Mechanism (RAAIM) was activated on November 1, 2016 to track the performance of Resource Adequacy (RA) Resources. RAAIM is used to determine the availability of resources providing local and/or system Resource Adequacy Capacity and Flexible RA Capacity each month and then assess the resultant Availability Incentive Payments and Non-Availability Charges through the CAISO's settlements process. Table 1 below shows the monthly average actual availability, total non-availability charge, and total availability incentive payment.[2]

Table 1: Resource Adequacy Availability and Payment

	Average Actual Availability	Total Non-availbility Charge	Total Availability Incentive Payment
Nov-16	92.23%	$3,616,895	-$1,678,657
Dec-16	96.25%	$1,878,503	-$1,878,503
Jan-17	95.64%	$2,866,734	-$2,013,269
Feb-17	92.28%	$3,262,889	-$1,875,649
Mar-17	91.94%	$3,046,829	-$1,550,469
Apr-17	89.43%	$4,096,806	-$1,543,647
May-17	95.97%	$1,812,398	-$1,429,830
Jun-17	95.13%	$2,426,279	-$1,422,549
Jul-17	96.11%	$1,298,826	-$1,298,826
Aug-17	96.30%	$1,365,268	-$1,365,268
Sep-17	96.61%	$912,045	-$912,045

[2] On September 21, 2017, the ISO indicated in the market notice that it intended to file a petition with the FERC for a limited tariff waiver on section 40.9.6 to forego assessing any Resource Adequacy Availability Incentive Mechanism (RAAIM) charges for the period April 1, 2017 through December 31, 2017 due to identified implementation issues. This waiver includes April, 2017 and May 2017. The ISO is currently estimating the penalties reflected in the charge code 8830 to be zero pursuant to tariff section 11.29.10.5.

Direct Market Performance Metrics

Energy

Day-Ahead Prices

Figure 2 shows daily prices of four default load aggregate points (DLAPs). Table 2 below lists the binding constraints along with the associated DLAP locations and the occurrence dates when the binding constraints resulted in relatively high or low DLAP prices. On September 1-2, all four DLAP LMPs were elevated due to high load and tight supply.

Figure 2: Day-Ahead Simple Average LAP Prices (All Hours)

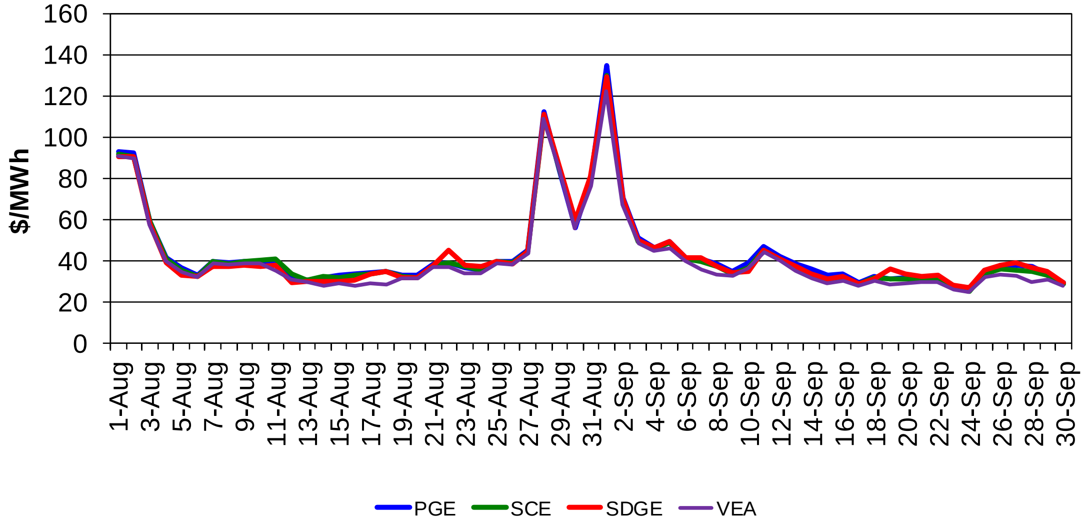


Table 2: Day-Ahead Transmission Constraints

DLAP	Date	Transmission Constraint
SDG&E	September 19	6310_CP6_NG

Real-Time Prices

FMM daily prices of the four DLAPs are shown in Figure 3. Table 3 lists the binding constraints along with the associated DLAP locations and the occurrence dates when the binding constraints resulted in relatively high or low DLAP prices. On September 5, all four DLAP prices were elevated due to upward load adjustment, net import reduction, and renewable deviation. On September 11, all four DLAP prices were high due to upward load adjustment, net import reduction, and renewable deviation.

Figure 3: FMM Simple Average LAP Prices (All Hours)

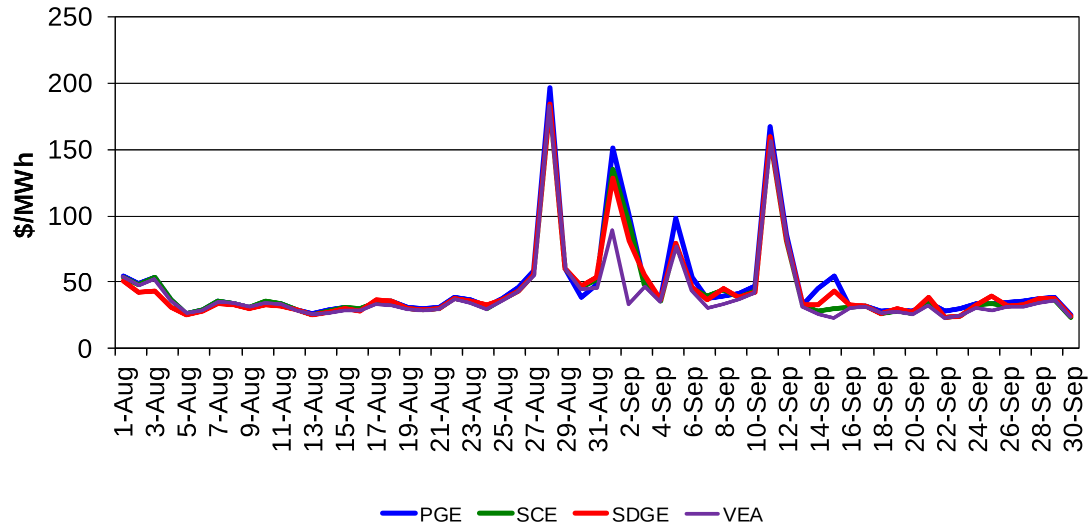
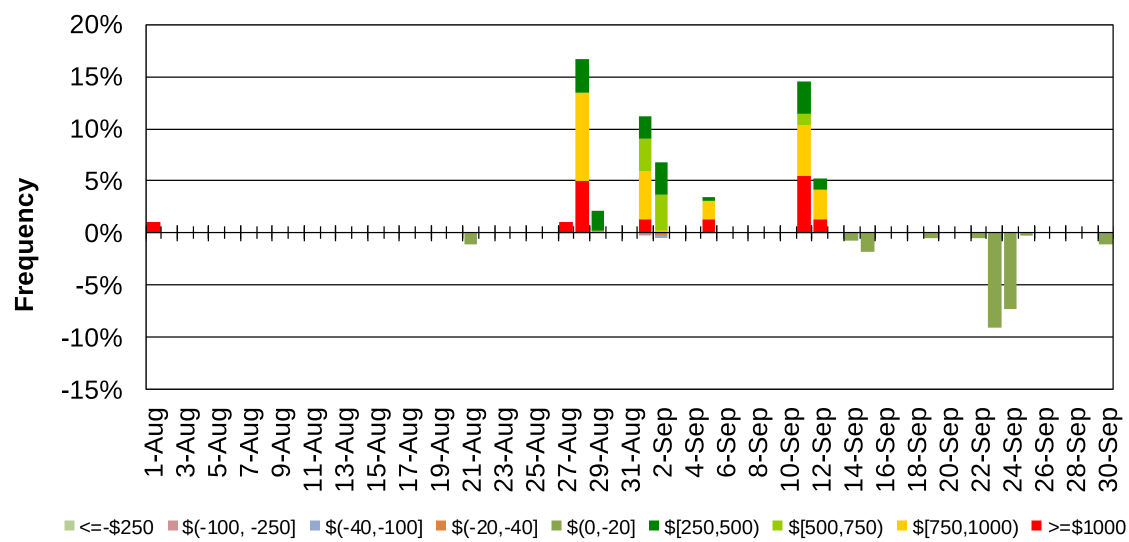


Table 3: FMM Transmission Constraints

DLAP	Date	Transmission Constraint
PG&E, SCE, SDG&E	September 1, 2	LUGO -VICTORVL-500 kV line, RM_TM12_NG
PG&E	September 15	METCALF -METCALF -230 XFMR

Figure 4 below shows the daily frequency of positive price spikes and negative prices by price range for the default LAPs in the FMM. The cumulative frequency of prices above $250/MWh increased to 1.37 percent in September from 0.67 percent in August. The cumulative frequency of negative prices increased to 0.74 percent in September from 0.03 percent in August.

Figure 4: Daily Frequency of FMM LAP Positive Price Spikes and Negative Prices



RTD daily prices of the four DLAPs are shown in Figure 5. Table 4 lists the binding constraints along with the associated DLAP locations and the occurrence dates when the binding constraints resulted in relatively high or low DLAP prices. September 11 saw relatively high prices for all four DLAPs due to net import reduction and renewable deviation.

Figure 5: RTD Simple Average LAP Prices (All Hours)

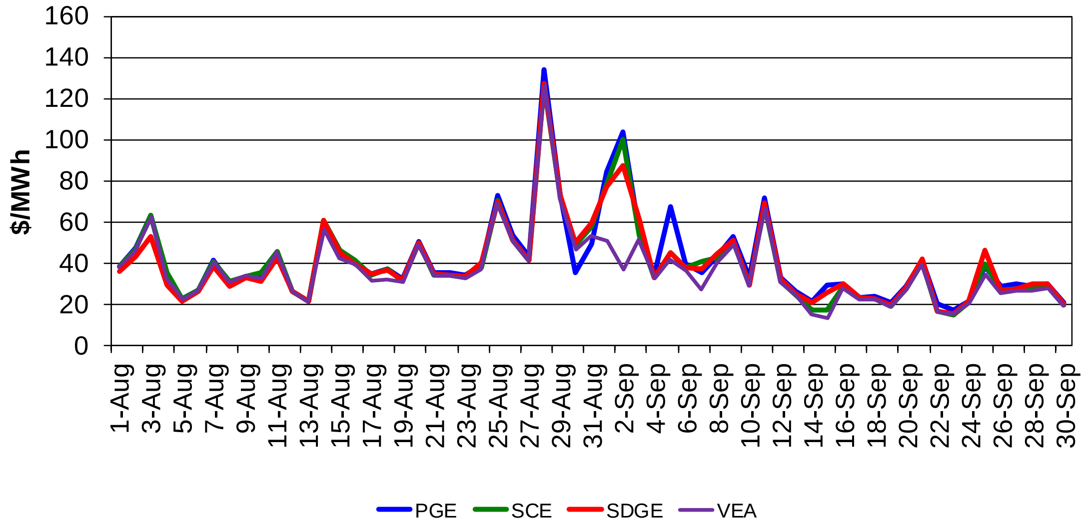
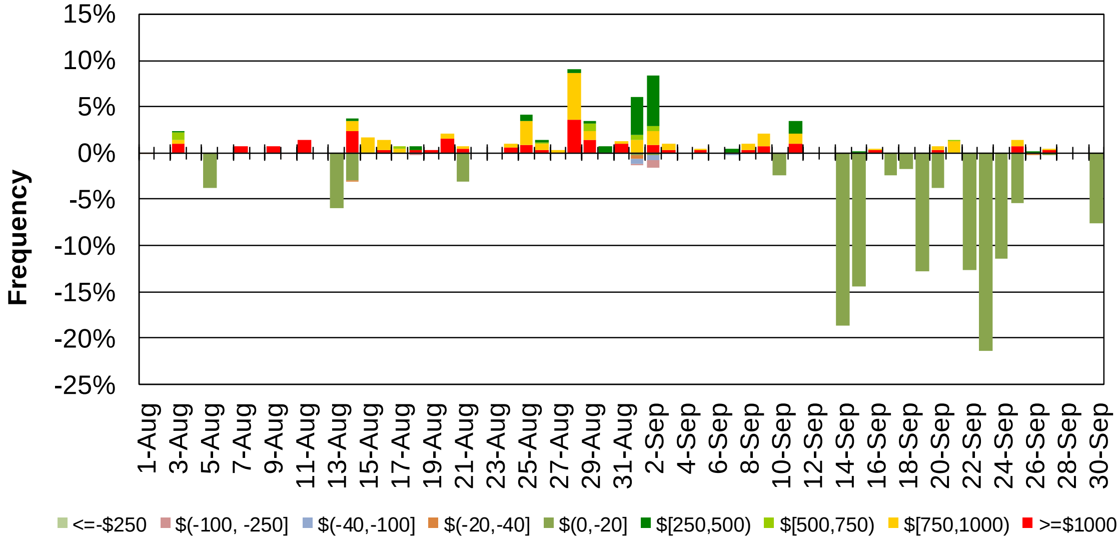


Table 4: RTD Transmission Constraints

DLAP	Date	Transmission Constraint
PG&E, SCE, SDG&E	September 1, 2	LUGO -VICTORVL-500 kV line
PG&E	September 5	METCALF -METCALF -230 XFMR

Figure 6 below shows the daily frequency of positive price spikes and negative prices by price range for the default LAPs in RTD. The cumulative frequency of prices above $250/MWh decreased to 0.91 percent in September from 1.23 percent in August. The cumulative frequency of negative prices increased to 3.94 percent in September from 0.53 percent in August.

Figure 6: Daily Frequency of RTD LAP Positive Price Spikes and Negative Price



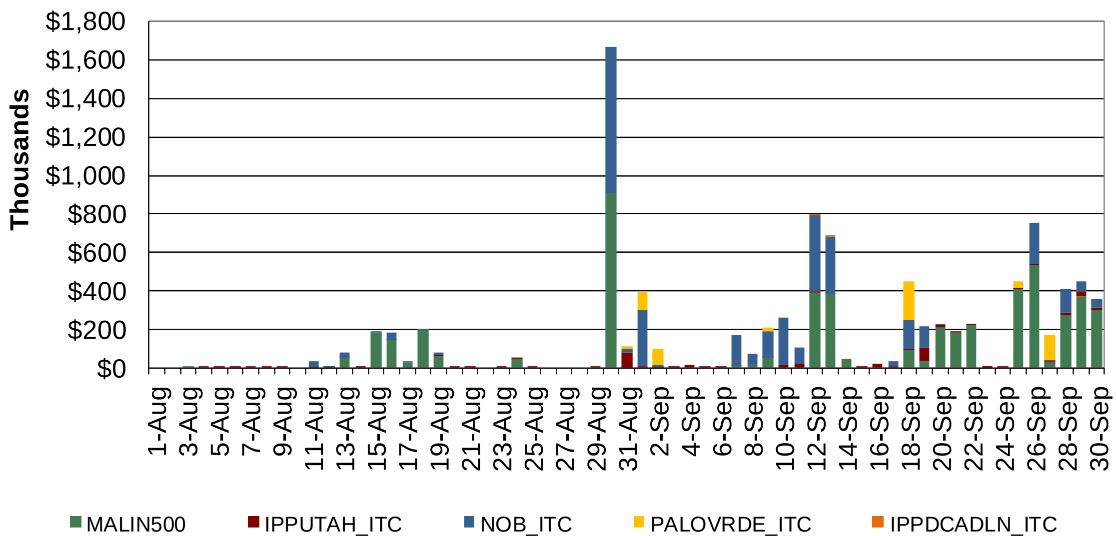
Congestion

Congestion Rents on Interties

Figure 7 below illustrates the daily integrated forward market congestion rents by interties. The cumulative total congestion rent for interties in September rose to $6.83 million from $2.67 million in August. Majority of the congestion rents in September accrued on MALIN500 (52 percent) intertie and NOB (35 percent) intertie.

The congestion rent on MALIN500 increased to $3.58 million in September from $1.62 million in August. The congestion rent on NOB rose to $2.41 million in September from $0.91 million in August.

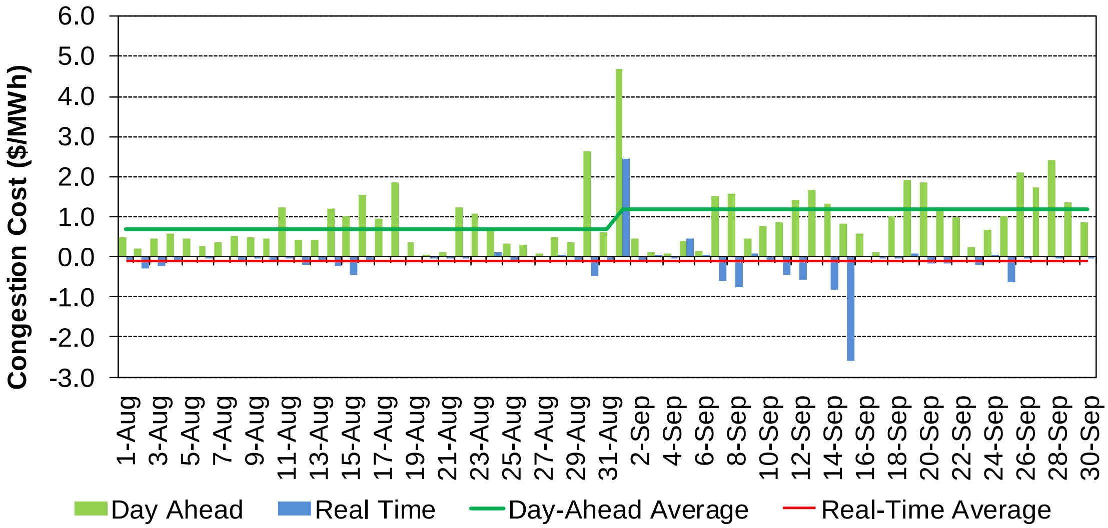
Figure 7: IFM Congestion Rents by Interties (Import)



Average Congestion Cost per Load Served

This metric quantifies the average congestion cost for serving one megawatt of load in the ISO system. Figure 8 shows the daily and monthly averages for the day-ahead and real-time markets respectively.

Figure 8: Average Congestion Cost per Megawatt of Served Load

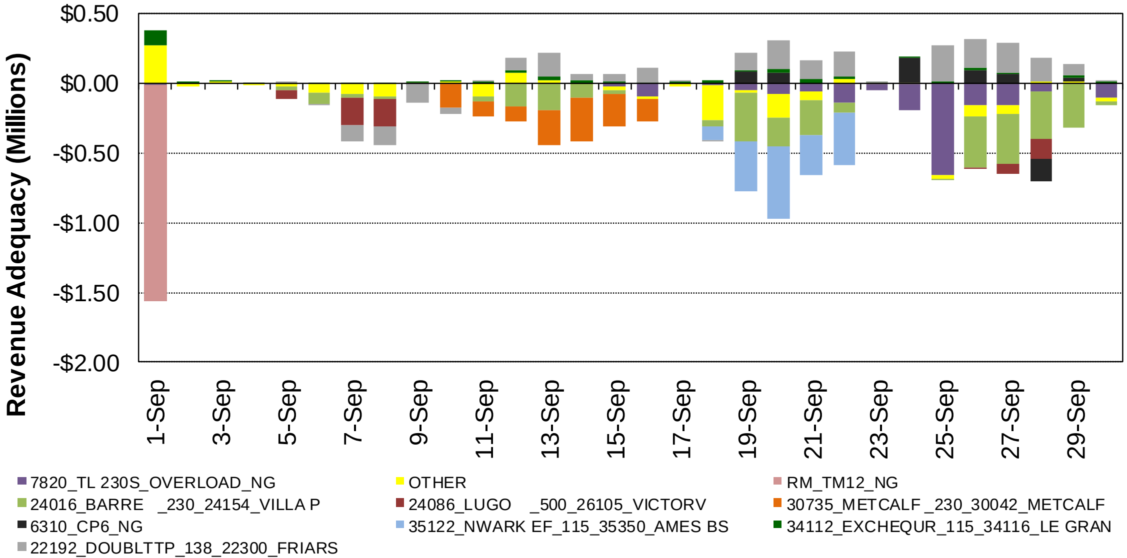


The average congestion cost per MWh of load served in the integrated forward market increased to $1.18/MWh in September from $0.69/MWh in August. The average congestion cost per load served in the real-time market edged down to -$0.10/MWh in September from -$0.09/MWh in August.

Congestion Revenue Rights

Figure 9 illustrates the daily revenue adequacy for congestion revenue rights (CRRs) broken out by transmission element. The average CRR revenue deficit in September increased to $276,004 from the average revenue deficit of $240,623 in August.

Figure 9: Daily Revenue Adequacy of Congestion Revenue Rights

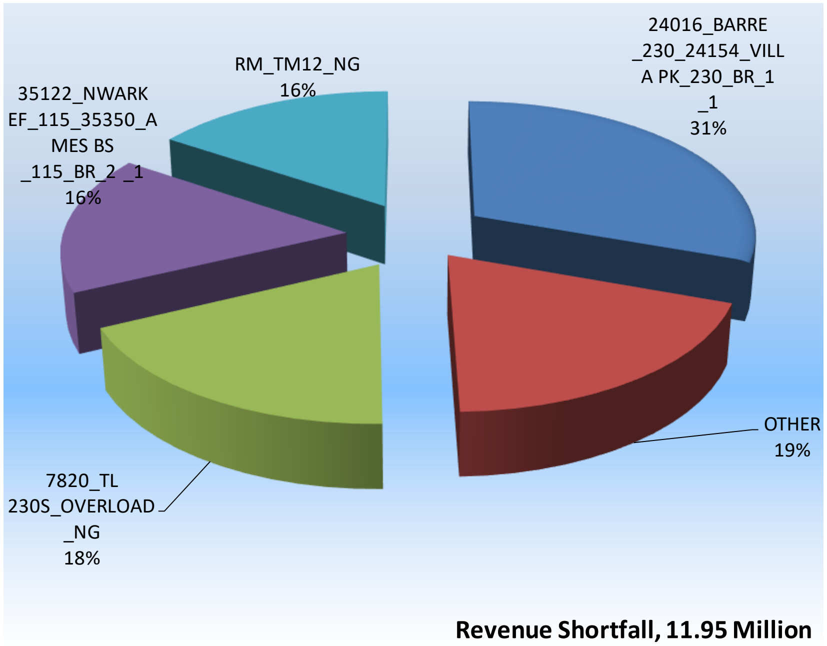


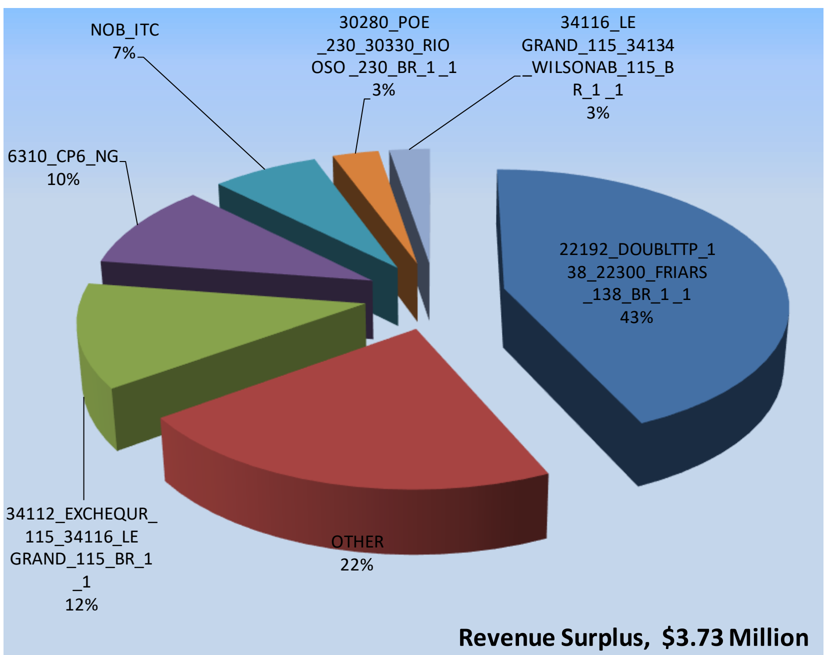
Overall, September experienced a CRR revenue deficit. Revenue shortfalls were observed in most days of September. The main reasons are shown below.

- The line 24016_BARRE_230_24154_VILLA P was binding in 20 days of this month, resulting in revenue shortfall of $3.03 million.
- The nomogram 7820_TL 230S_OVERLOAD_NG was binding in 19 days of this month, resulting in revenue shortfall of $1.82 million.
- The nomogram RM_TM12_NG was binding in one day this month, resulting in revenue shortfall of $1.55 million. This nomogram was enforced for the contingency related to operating procedure 6110.

The shares of the revenue surplus and deficit accruing on various congested transmission elements for the reporting period are shown in Figure 10 and the monthly summary for CRR revenue adequacy is provided in Table 5.

Figure 10: CRR Revenue Adequacy by Transmission Element





Overall, the total amount collected from the IFM was not sufficient to cover the net payments to congestion revenue right holders and the cost of the exemption for existing rights. The revenue adequacy level was 74.47 percent in September. Out of the total congestion rents, 3.05 percent was used to cover the cost of existing right exemptions. Net total congestion revenues in September were in deficit by $8.28 million, compared to the deficit of $7.46 million in August. The auction revenues credited to the balancing account for September were $6.14 million. As a result, the balancing account for September had a deficit of approximately $2.10 million, which will be allocated to measured demand.

Table 5: CRR Revenue Adequacy Statistics

IFM Congestion Rents	$24,911,938.05
Existing Right Exemptions	-$759,594.65
Available Congestion Revenues	$24,152,343.40
CRR Payments	$32,432,463.60
CRR Revenue Adequacy	-$8,280,120.20
Revenue Adequacy Ratio	74.47%
Annual Auction Revenues	$3,417,491.73
Monthly Auction Revenues	$2,725,205.82
CRR Settlement Rule	$38,924.69
Allocation to Measured Demand	-$2,098,497.97

Ancillary Services

IFM (Day-Ahead) Average Price

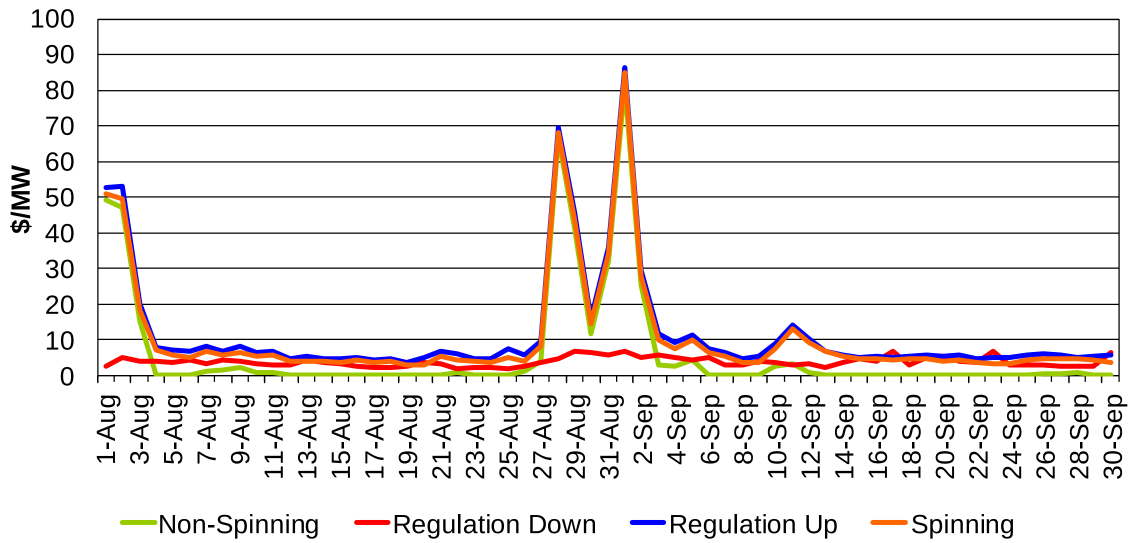
Table 6 shows the monthly IFM average ancillary service procurements and the monthly average prices. In September the monthly average procurement decreased for spinning and non-spinning reserves.

Table 6: IFM (Day-Ahead) Monthly Average Ancillary Service Procurement

	Average Procurred				Average Price			
	Reg Up	Reg Dn	Spinning	Non-Spinning	Reg Up	Reg Dn	Spinning	Non-Spinning
Sep-17	321	318	919	916	$10.16	$4.15	$9.02	$4.24
Aug-17	313	314	1037	1027	$14.19	$3.56	$12.76	$8.95
Percent Change	2.33%	1.48%	-11.31%	-10.83%	-28.38%	16.51%	-29.30%	-52.58%

The monthly average prices increased for regulation down in September. Figure 11 shows the daily IFM average ancillary service prices. The average prices for regulation up, spinning and non-spinning reserves were high on September 1-2 due to high opportunity cost of energy.

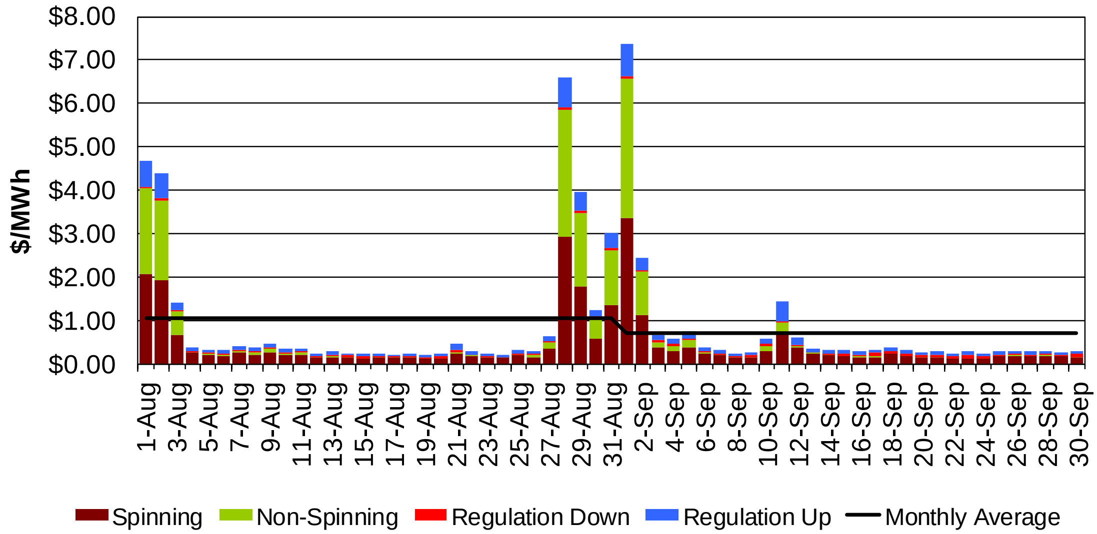
Figure 11: IFM (Day-Ahead) Ancillary Service Average Price



Ancillary Service Cost to Load

The monthly average cost to load declined to $0.70/MWh in September from $1.05/MWh in August. September 1-2 saw high average cost driven by high regulation up, spinning and non-spinning prices on those days in day-ahead market.

Figure 12: System (Day-Ahead and Real-Time) Average Cost to Load



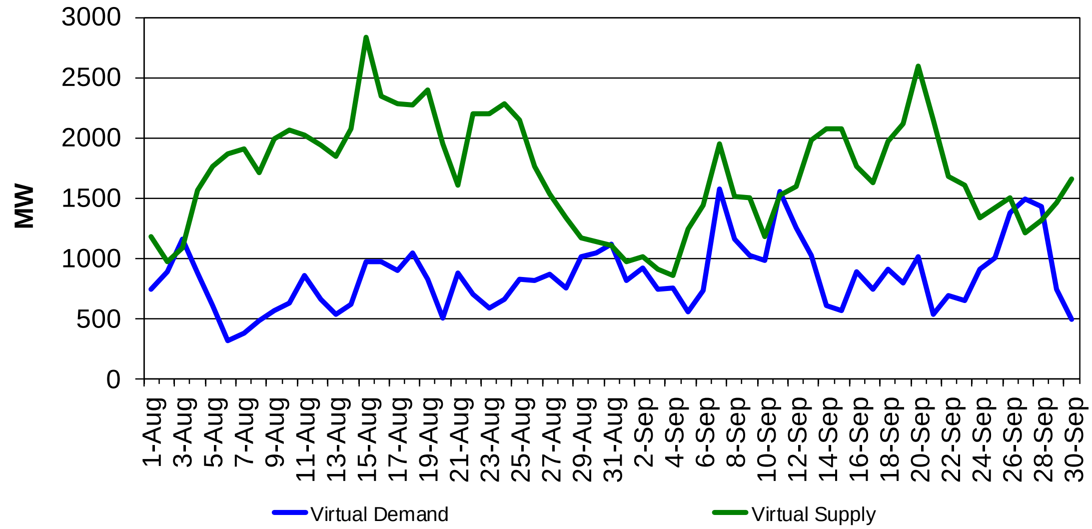
Scarcity Events

The ancillary services scarcity pricing mechanism is triggered when the ISO is not able to procure the target quantity of one or more ancillary services in the IFM and real-time market runs. On September 11, a regulation up scarcity occurred in the 15-minute market run in the ISO expanded system region for hour ending 20 interval 1. The procurement shortfall was 39.2 MW or 9.8% of the target procurement quantity in each interval. On September 12, a regulation up scarcity occurred in the 15-minute market run in the ISO expanded system region for hour ending 19 interval 2. The procurement shortfall was 3.3 MW or 0.8% of the target procurement quantity in each interval

Convergence Bidding

Figure 13 below shows the daily average volume of cleared virtual bids in IFM for virtual supply and virtual demand. The cleared virtual supply was well above the cleared demand in most days of September.

Figure 13: Cleared Virtual Bids



Convergence bidding tends to cause the day-ahead market and real-time market prices to move closer together, or “converge”. Figure 14 shows the energy prices (namely the energy component of the LMP) in IFM, hour ahead scheduling process (HASP), FMM, and RTD.

Figure 14: IFM, HASP, FMM, and RTD Prices

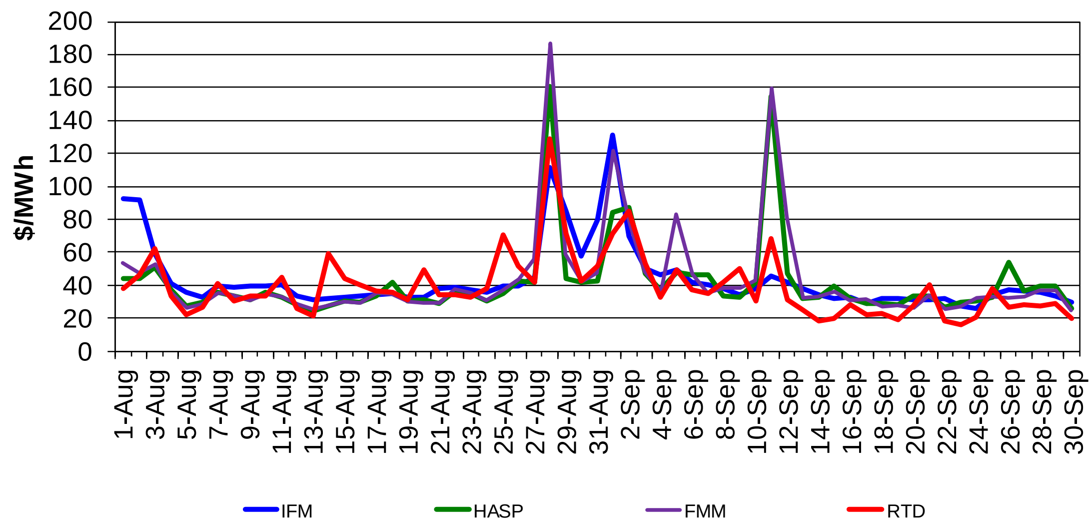
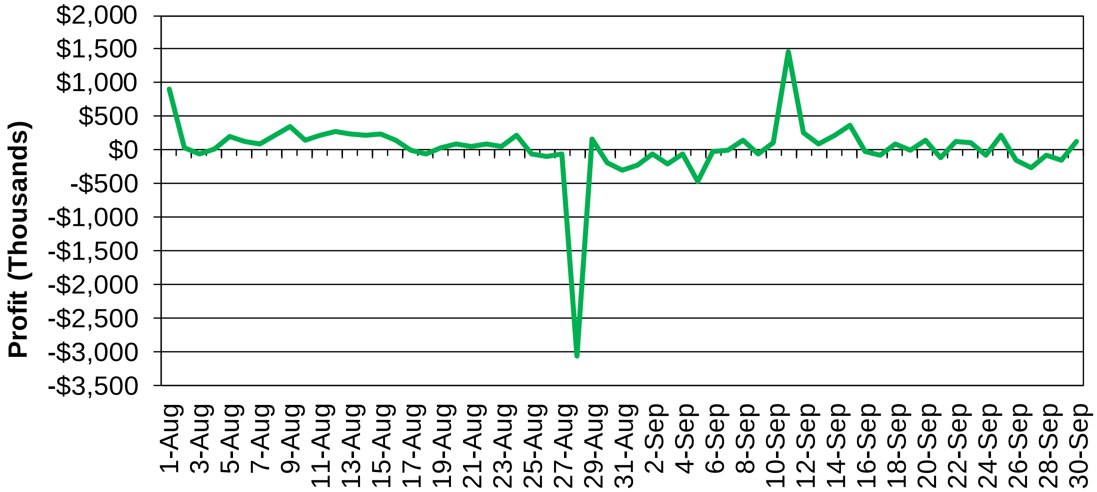


Figure 15 shows the profits that convergence bidders receive from convergence bidding. The total profits from convergence bidding rose to $1.28 million in September from $0.13 million in August.

Figure 15: Convergence Bidding Profits



Renewable Generation Curtailment

Figure 16 below shows the monthly wind and solar VERs (variable energy resource) curtailment due to system wide condition or local congestion in RTD. Figure 17 shows the monthly wind and solar VERs (variable energy resource) curtailment by resource type in RTD. Economic curtailment is defined as the resource's dispatch upper limit minus its RTD schedule when the resource has an economic bid. Dispatch upper limit is the maximum level the resource can be dispatched to when various factors are take into account such as forecast, maximum economic bid, generation outage, and ramping capacity. Self-schedule curtailment is defined as the resource's self-schedule minus its RTD schedule when RTD schedule is lower than self-schedule. When a VER resource is exceptionally dispatched, then exceptional dispatch curtailment is defined as the dispatch upper limit minus the exceptional dispatch value.

As Figure 16 and Figure 17 below indicate, the renewable curtailment increased in September. The majority of the curtailments was economic.

Figure 16: Renewable Curtailment by Reason

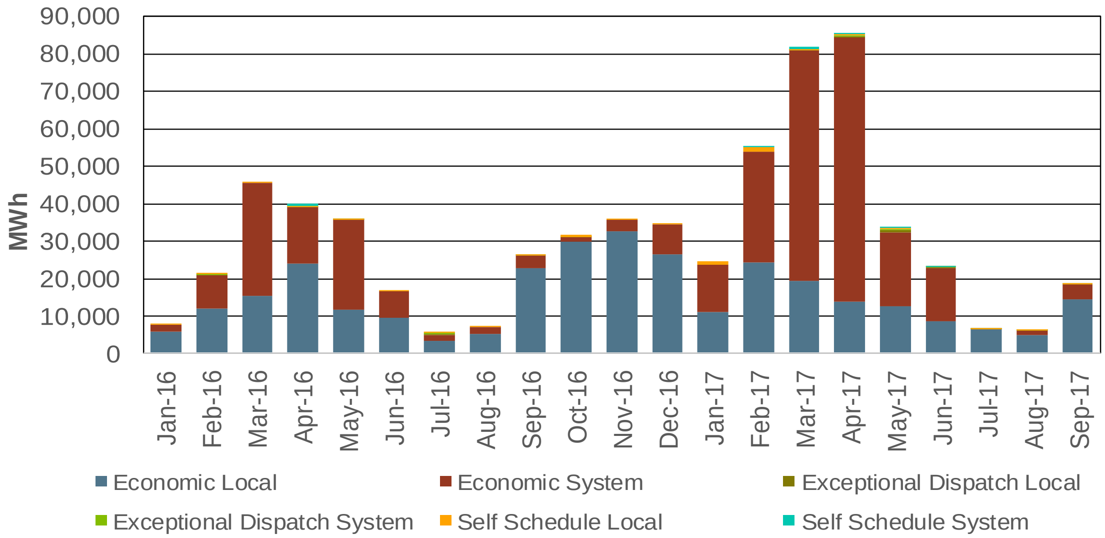
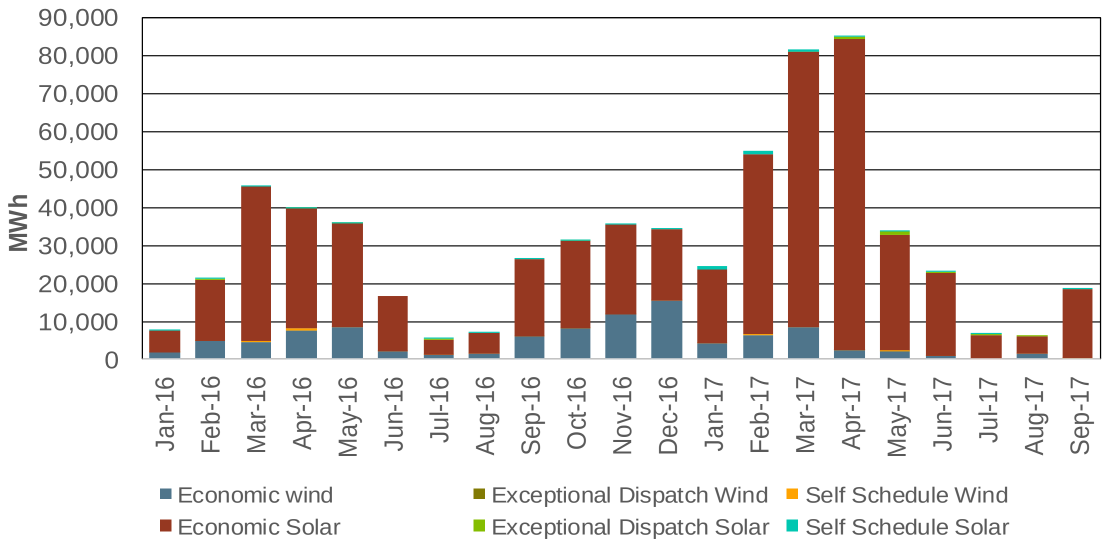


Figure 17: Renewable Curtailment by Resource Type



Flexible Ramping Product

On November 1, 2016 the ISO implemented two market products in the 15-minute and 5-minute markets: Flexible Ramping Up and Flexible Ramping Down uncertainty awards. These products provide additional upward and downward flexible ramping capability to account for uncertainty due to demand and renewable forecasting errors. In addition, the existing flexible ramping sufficiency test was extended to ensure feasible ramping capacity for real-time interchange schedules.

Flexible Ramping Product Payment

Figure 18 shows the flexible ramping up and down uncertainty payments. Flexible ramping up uncertainty payment inched up to $1.07 million in September from $0.83 Million in August. Flexible ramping down uncertainty payment increased to $7,512 in September from -$7,643 in August.

Figure 18: Flexible Ramping Up/down Uncertainty Payment

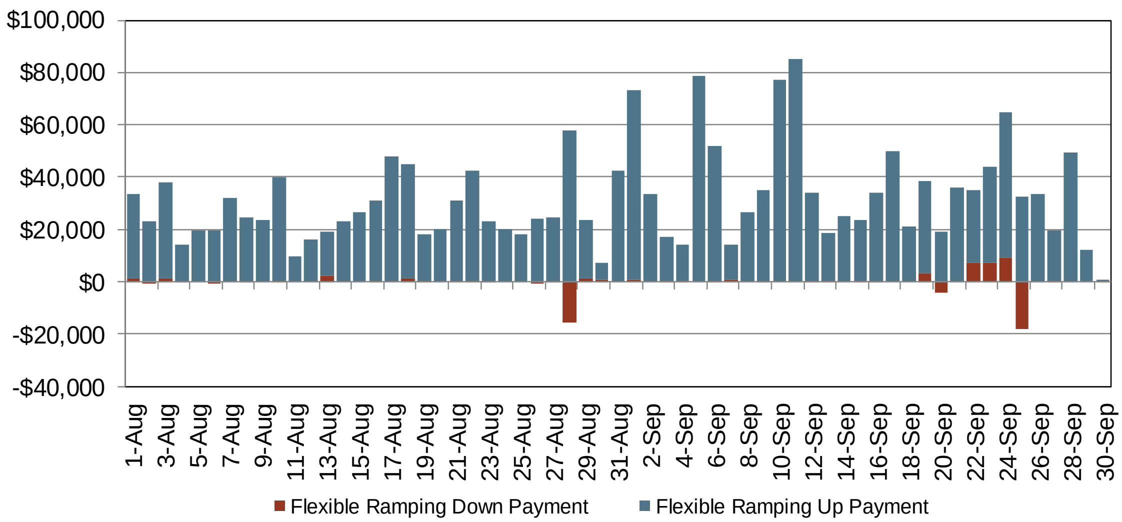
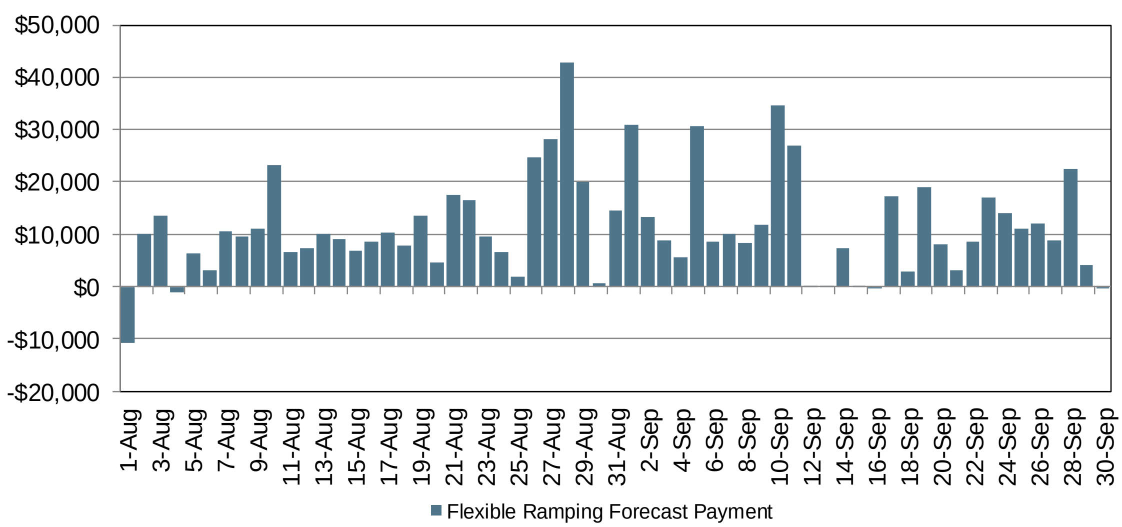


Figure 19 shows the flexible ramping forecast payment. Flexible ramping forecast payment stayed at 40.34 million this month, relatively unchanged from August.

Figure 19: Flexible Ramping Forecast Payment



Indirect Market Performance Metrics

Bid Cost Recovery

Figure 20 shows the daily uplift costs due to exceptional dispatch payments. The monthly uplift costs in September fell to $0.10 million from $0.41 million in August.

Figure 20: Exceptional Dispatch Uplift Costs

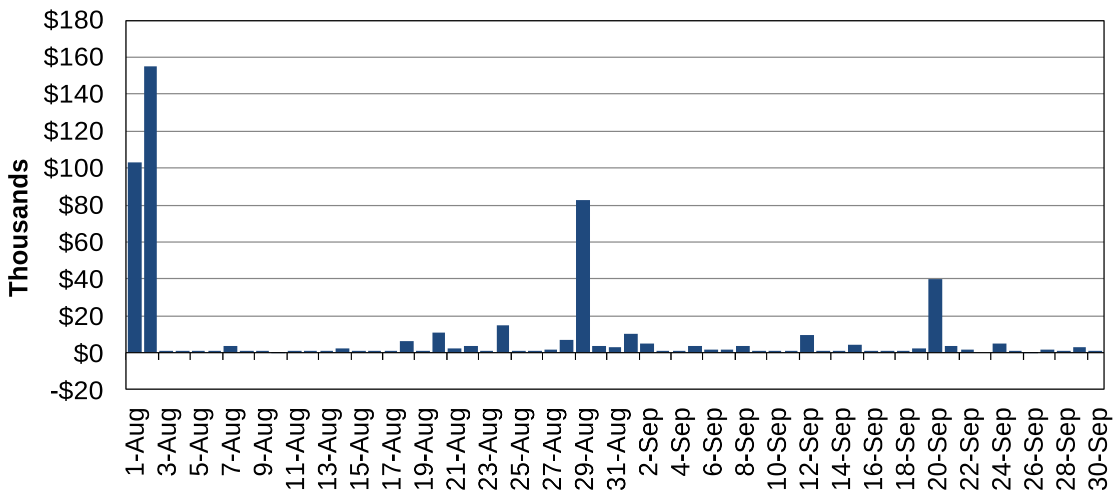


Figure 21 shows the allocation of bid cost recovery payment in the IFM, residual unit commitment (RUC) and RTM markets. The total bid cost recovery for September dropped to $6.70 million from $8.81 million in August. Out of the total monthly bid cost recovery payment for the three markets in September, the IFM market contributed 16 percent, RTM contributed 73 percent, and RUC contributed 11 percent of the total bid cost recovery payment.

Figure 21: Bid Cost Recovery Allocation

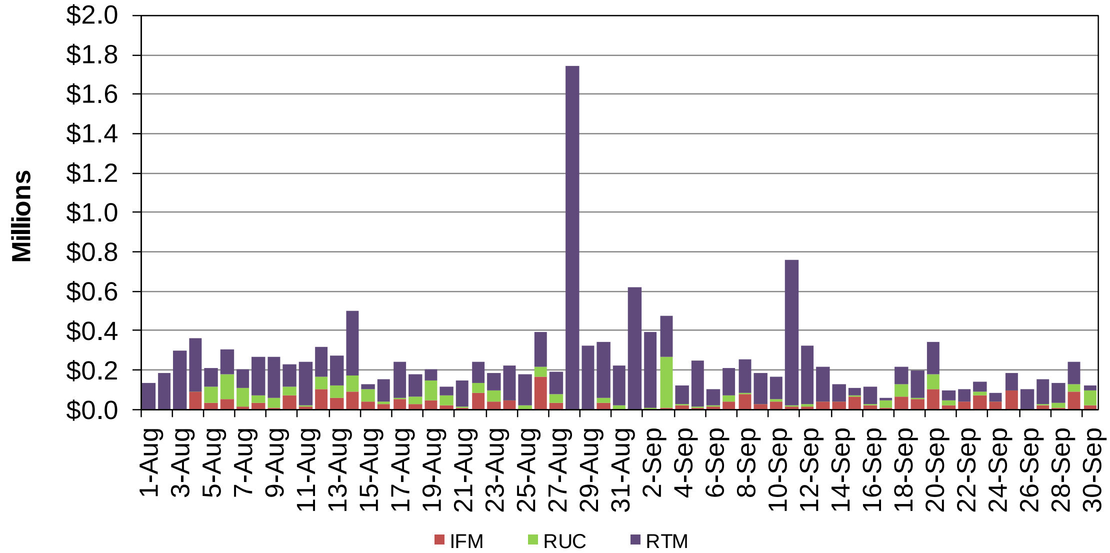


Figure 22 and Figure 23 show the daily and monthly BCR cost by local capacity requirement area (LCR) respectively.

Figure 22: Bid Cost Recovery Allocation by LCR

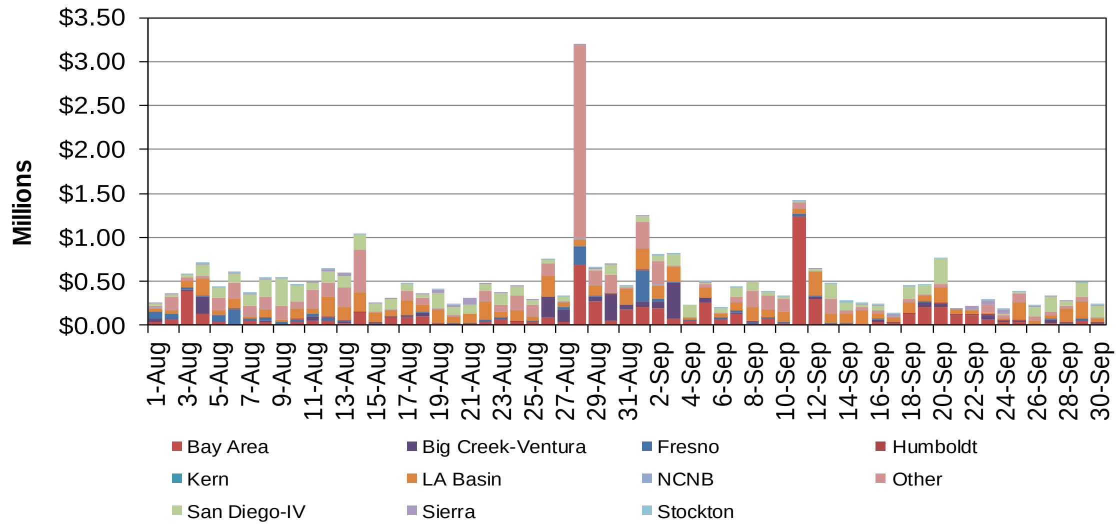


Figure 23: Monthly Bid Cost Recovery Allocation by LCR

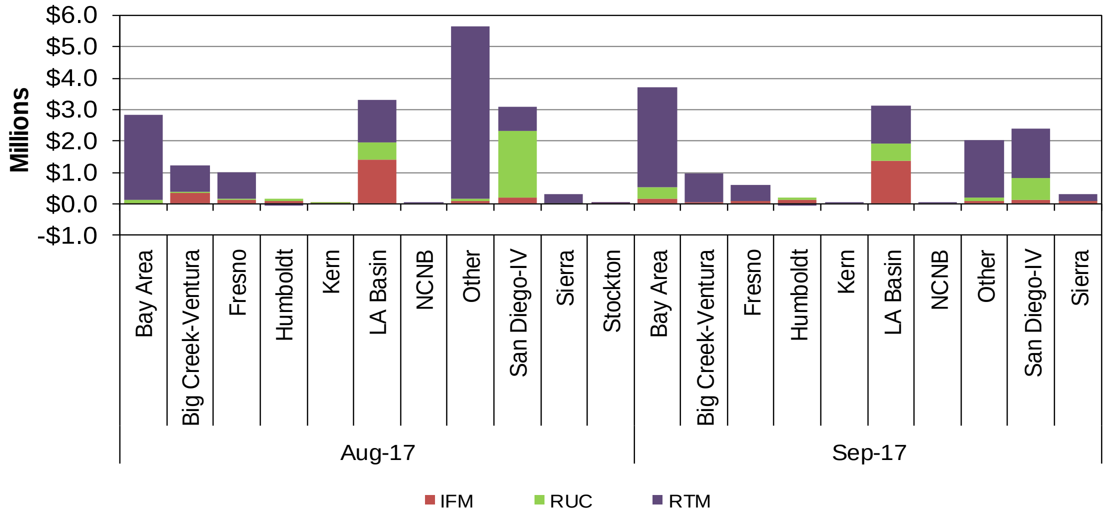


Figure 24 and Figure 25 show the daily and monthly BCR cost by utility distribution company (UDC) respectively.

Figure 24: Bid Cost Recovery Allocation by UDC

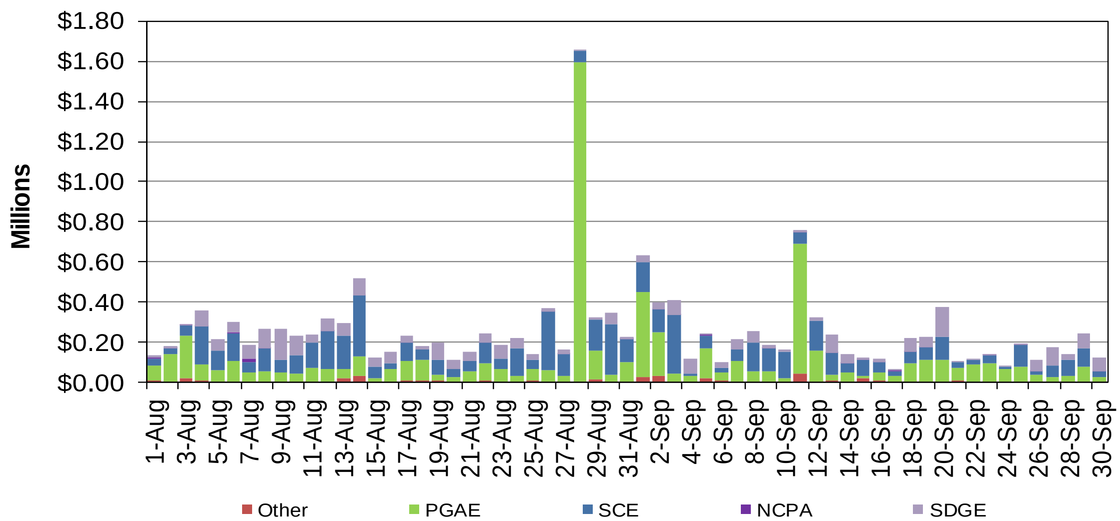


Figure 25: Monthly Bid Cost Recovery Allocation by UDC

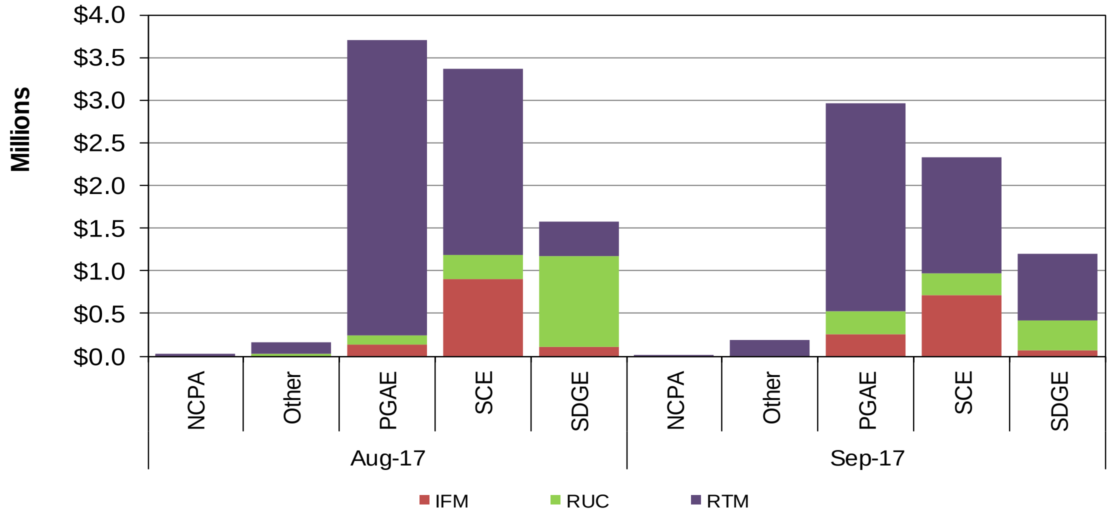


Figure 26 shows the cost related to BCR by cost type in RUC, which in September was mainly driven by minimum load cost (MLC) and start-up cost (SUC).

Figure 26: Cost in RUC

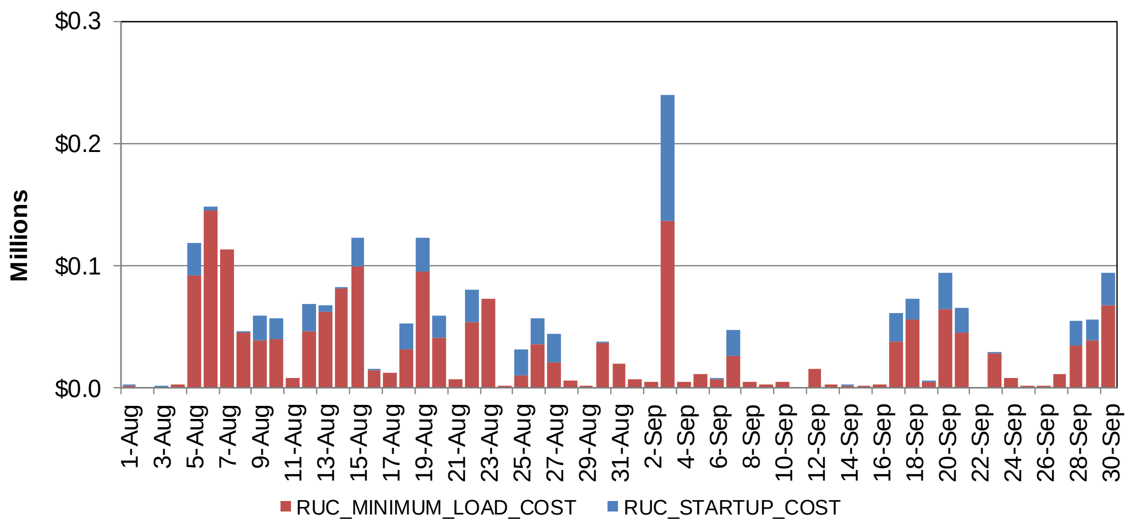


Figure 27 and Figure 28 show the daily and monthly cost related to BCR by type and LCR in RUC respectively.

Figure 27: Cost in RUC by LCR

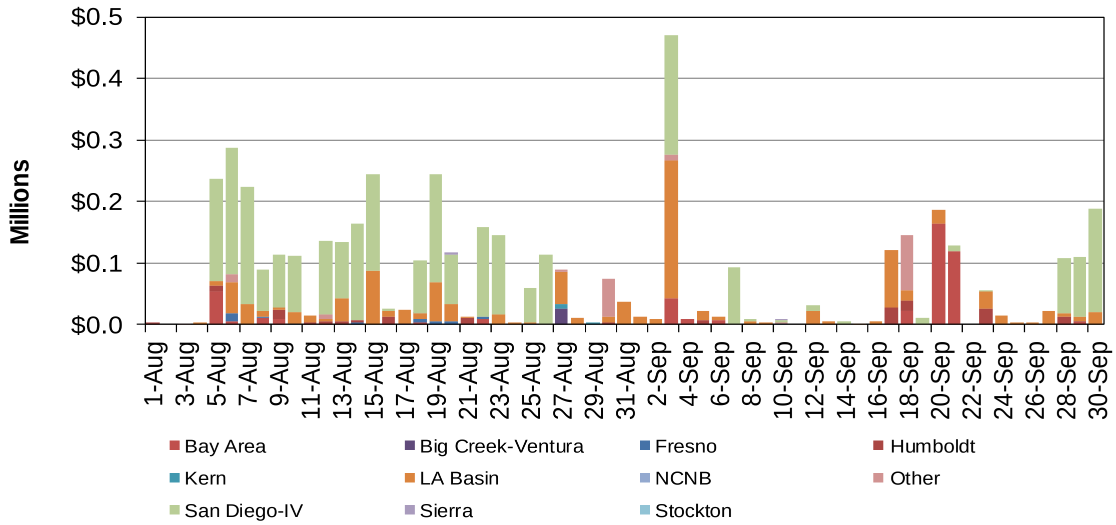


Figure 28: Monthly Cost in RUC by LCR

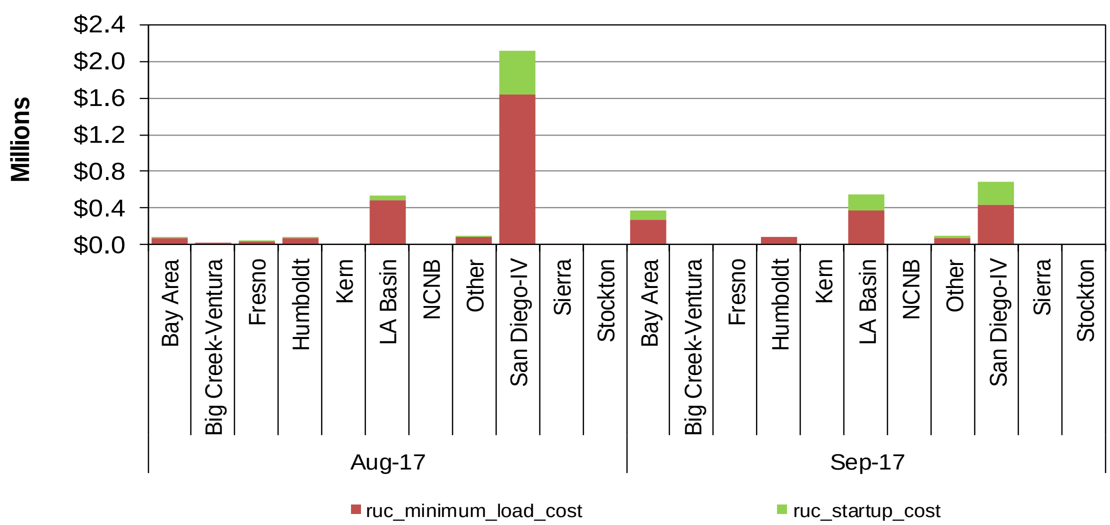


Figure 29 and Figure 30 show the daily and monthly cost related to BCR by type and UDC in RUC respectively.

Figure 29: Cost in RUC by UDC

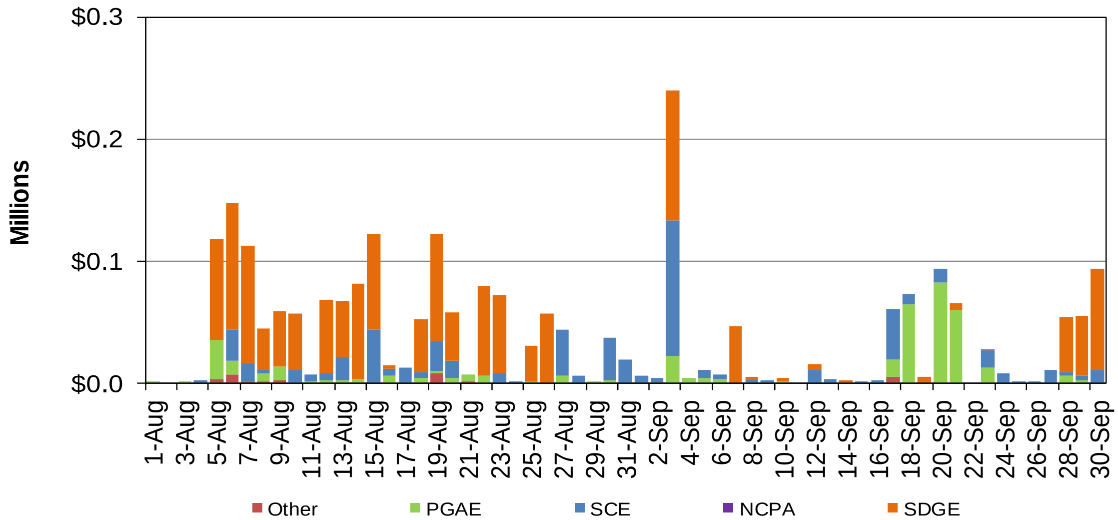


Figure 30: Monthly Cost in RUC by UDC

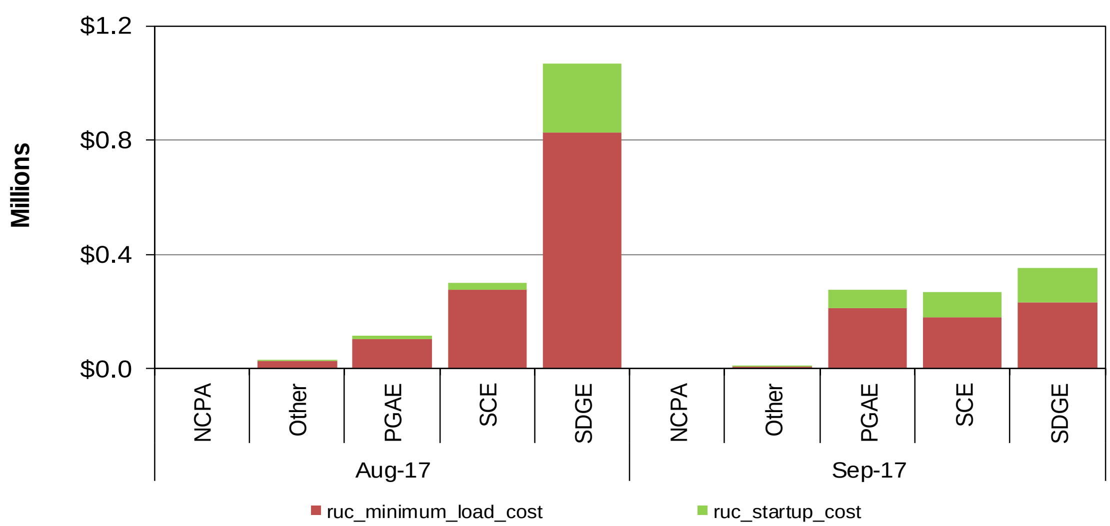


Figure 31 shows the cost related to BCR in real time by cost type. Minimum load cost and energy cost contributed mostly to the real time cost in September.

Figure 31: Cost in Real Time

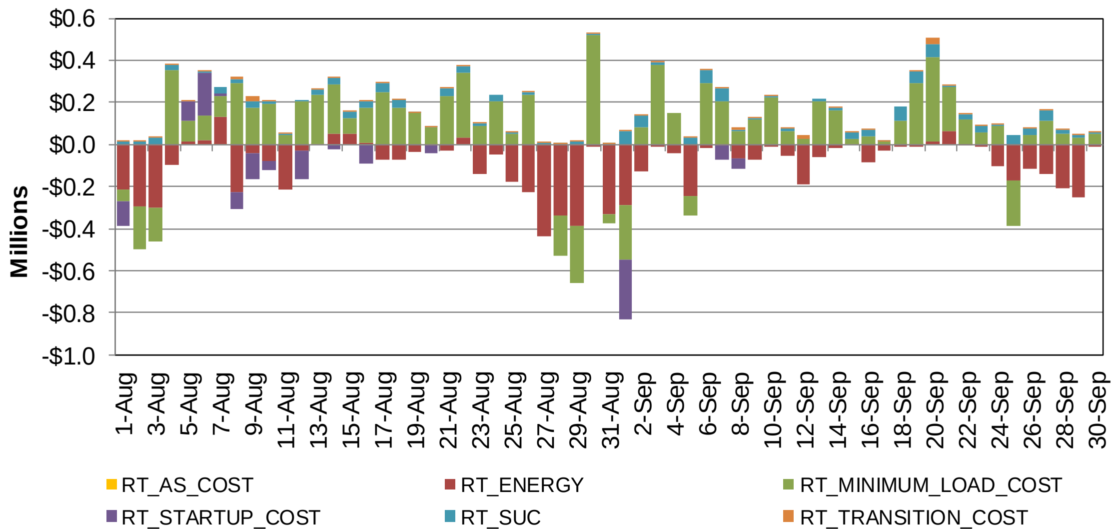


Figure 32 and Figure 33 show the daily and monthly cost related to BCR by type and LCR in real time respectively.

Figure 32: Cost in Real Time by LCR

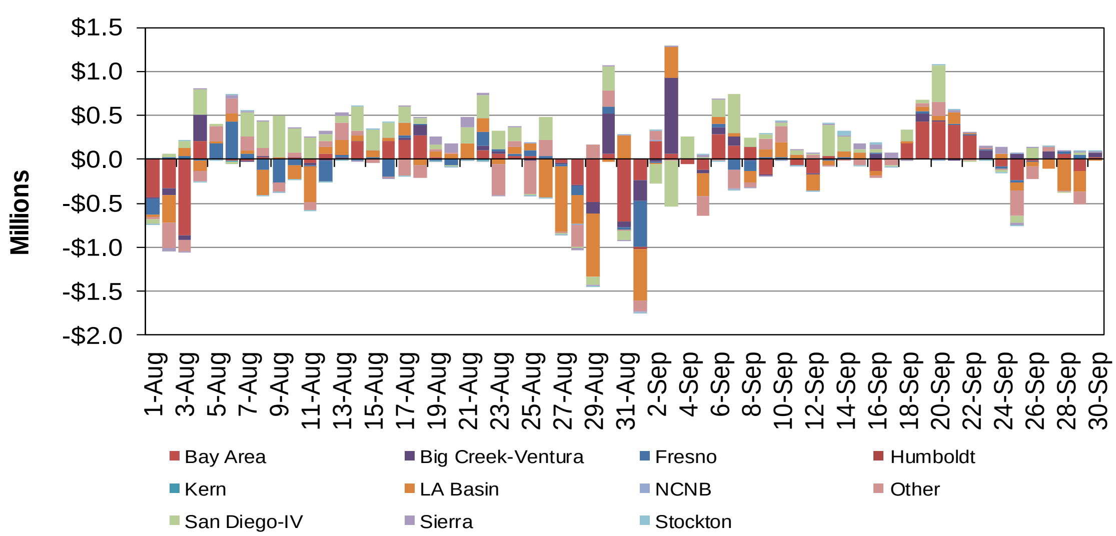


Figure 33: Monthly Cost in Real Time by LCR

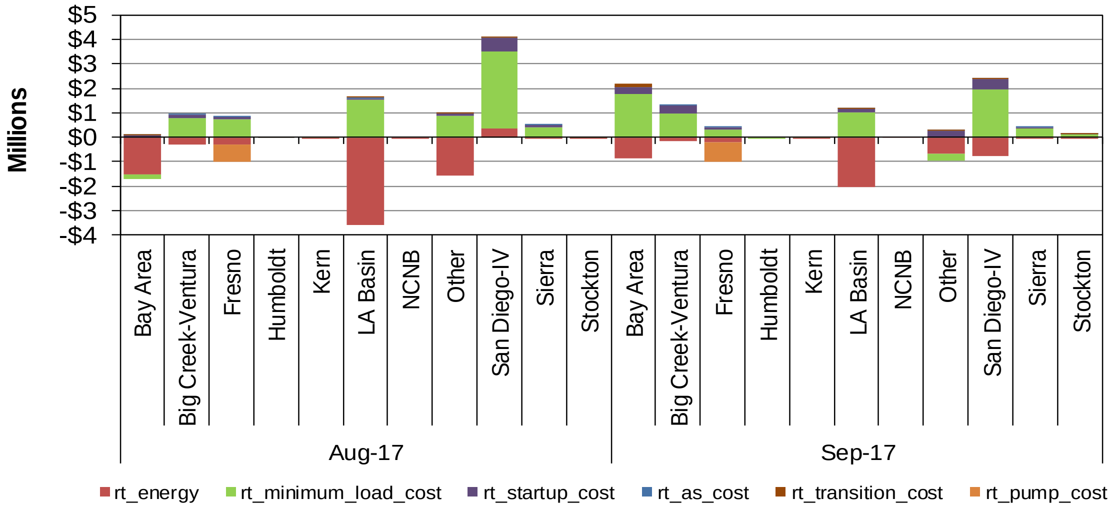


Figure 34 and Figure 35 show the daily and monthly cost related to BCR by type and UDC in Real Time respectively.

Figure 34: Cost in Real Time by UDC

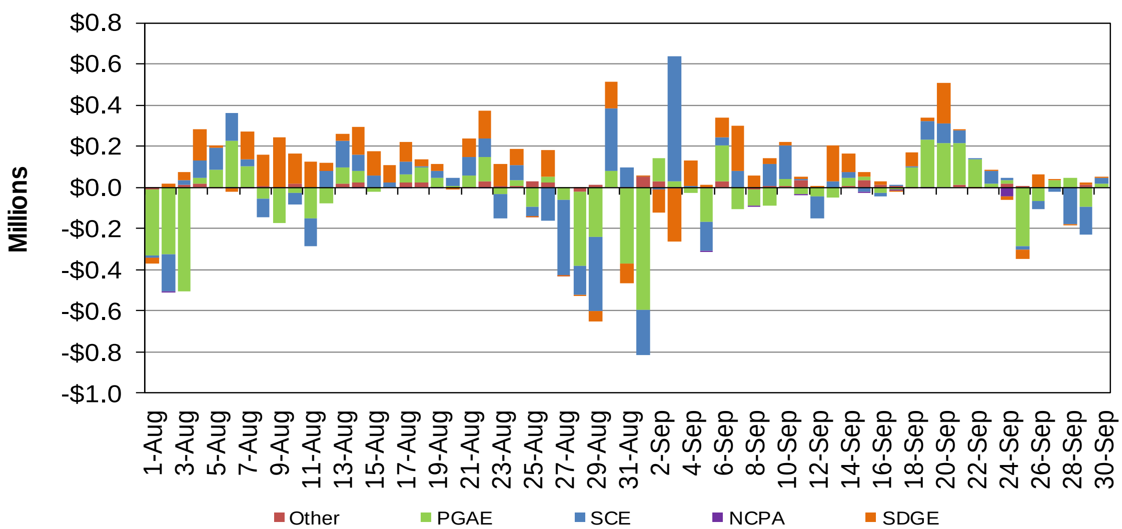


Figure 35: Monthly Cost in Real Time by UDC

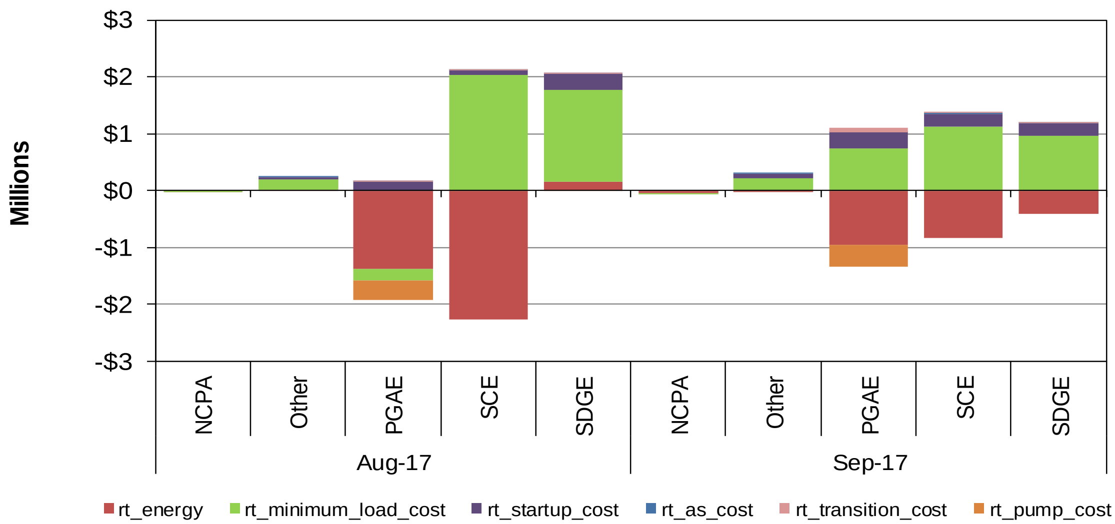


Figure 36 shows the cost related to BCR in IFM by cost type. Minimum Load cost and energy cost contributed largely to the cost in IFM in September.

Figure 36: Cost in IFM

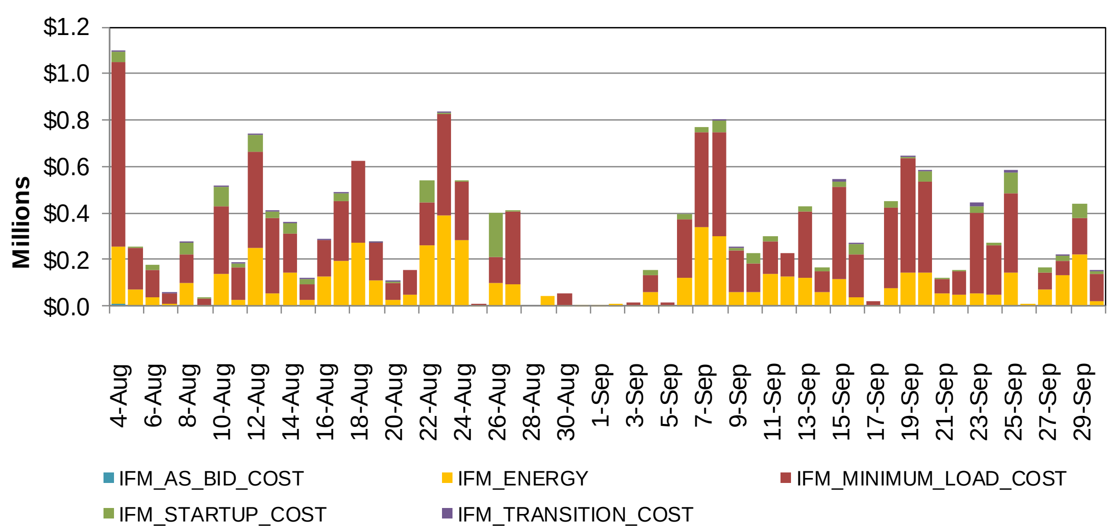


Figure 37 and Figure 38 show the daily and monthly cost related to BCR by type and location in IFM respectively.

Figure 37: Cost in IFM by LCR

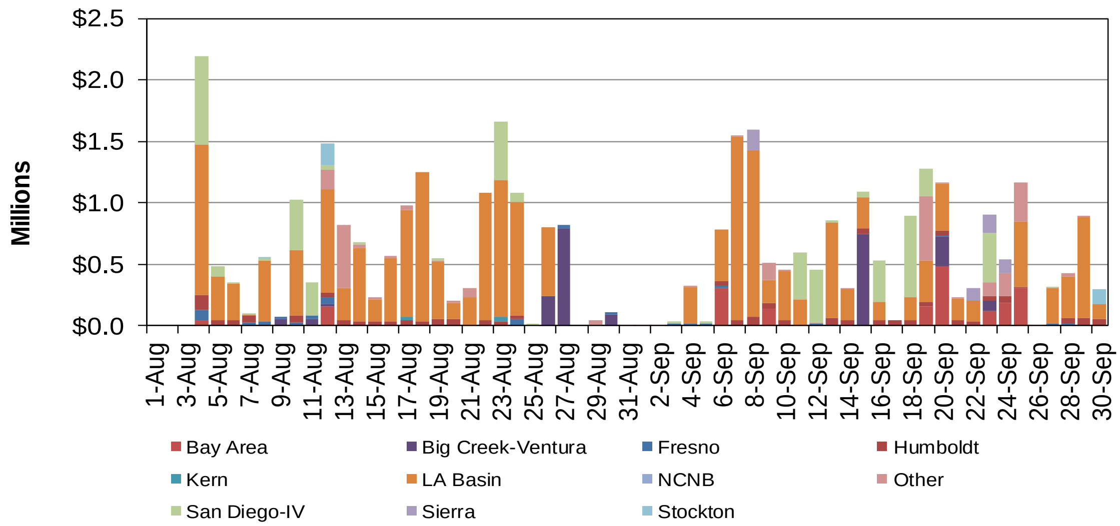


Figure 38: Monthly Cost in IFM by LCR

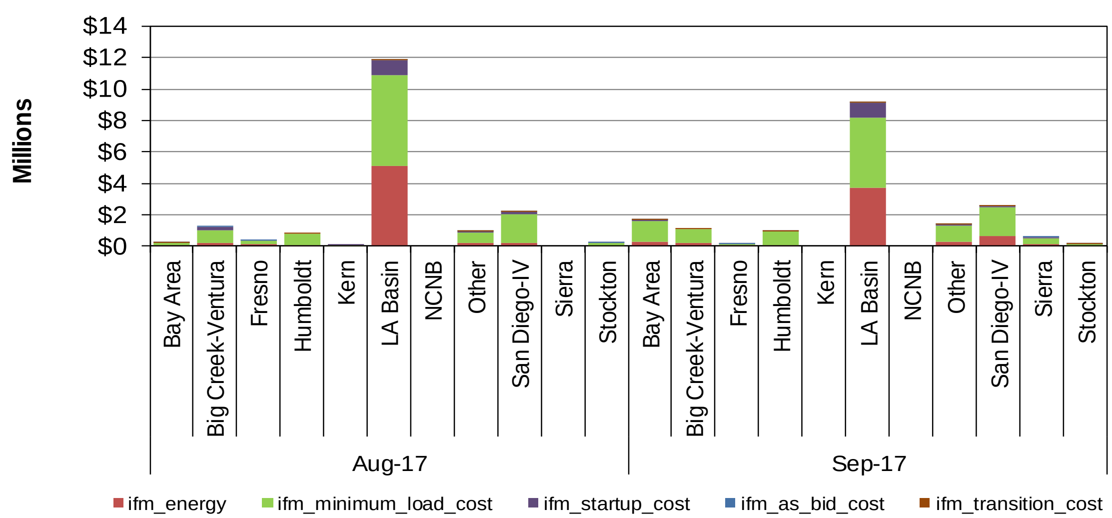


Figure 39 and Figure 40 show the daily and monthly cost related to BCR by type and UDC in IFM respectively.

Figure 39: Cost in IFM by UDC

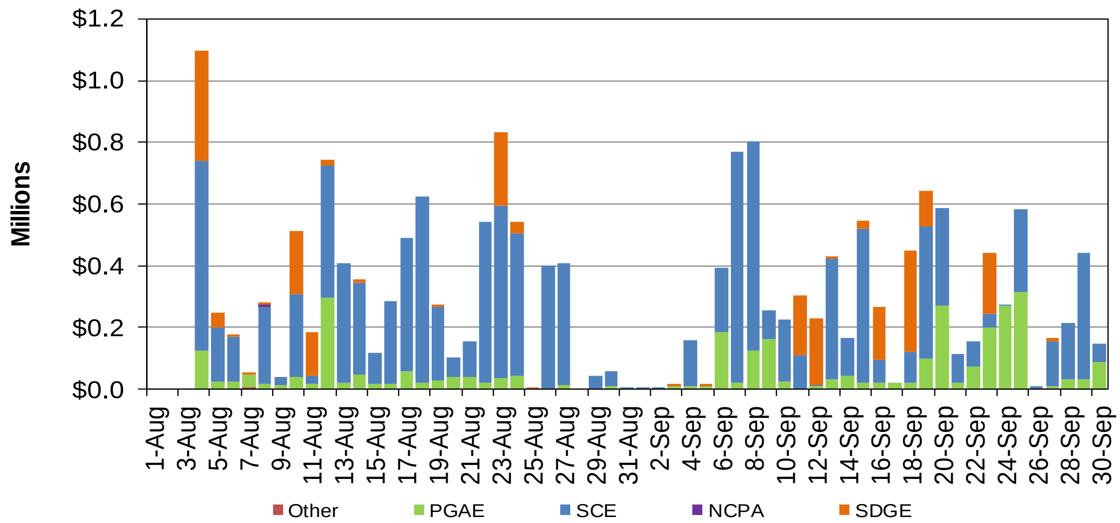
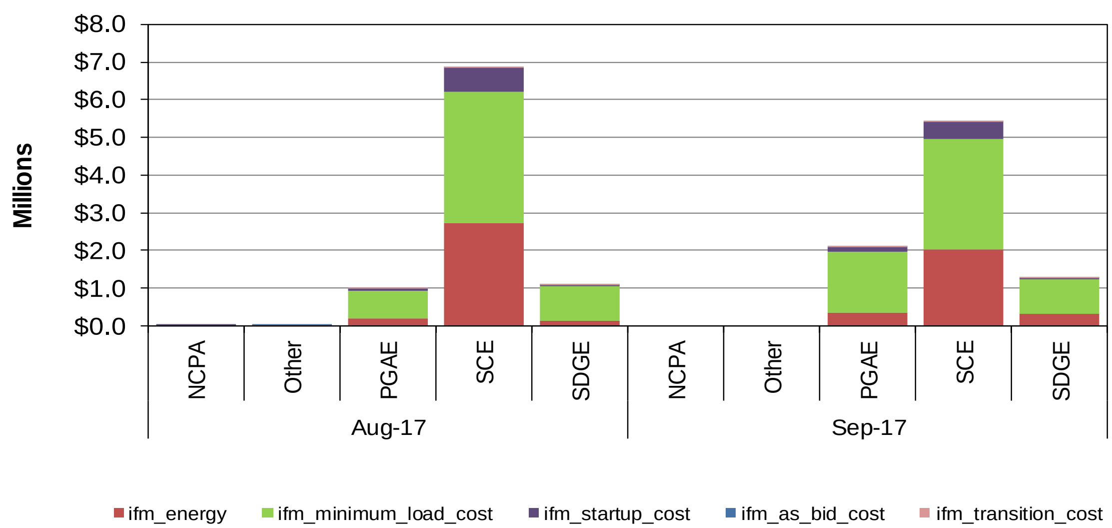


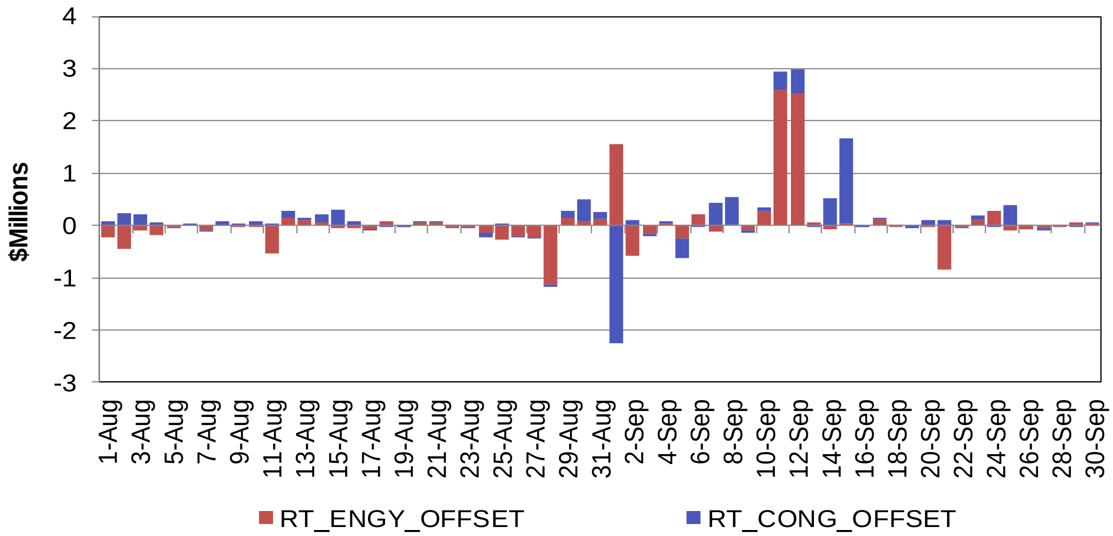
Figure 40: Monthly Cost in IFM by UDC



Real-time Imbalance Offset Costs

Figure 41 shows the daily real-time energy and congestion imbalance offset costs. Real-time energy offset cost increased to $5.57 million in September from -$2.97 million in August. Real-time congestion offset cost edged down to $1.95 million in September from $2.12 million in August.

Figure 41: Real-Time Energy and Congestion Imbalance Offset



Market Software Metrics

Market performance can be confounded by software issues, which vary in severity levels with the failure of a market run being the most severe.

Market Disruption

A market disruption is an action or event that causes a failure of an ISO market, related to system operation issues or system emergencies.[3] Pursuant to section 7.7.15 of the ISO tariff, the ISO can take one or more of a number of specified actions to prevent a market disruption, or to minimize the extent of a market disruption.

There were a total of 105 market disruptions in September. Table 7 lists the number of market disruptions and the number of times that the ISO removed bids (including self-schedules) in any of the following markets in this month. The ISO markets include IFM, RUC, FMM and RTD processes.

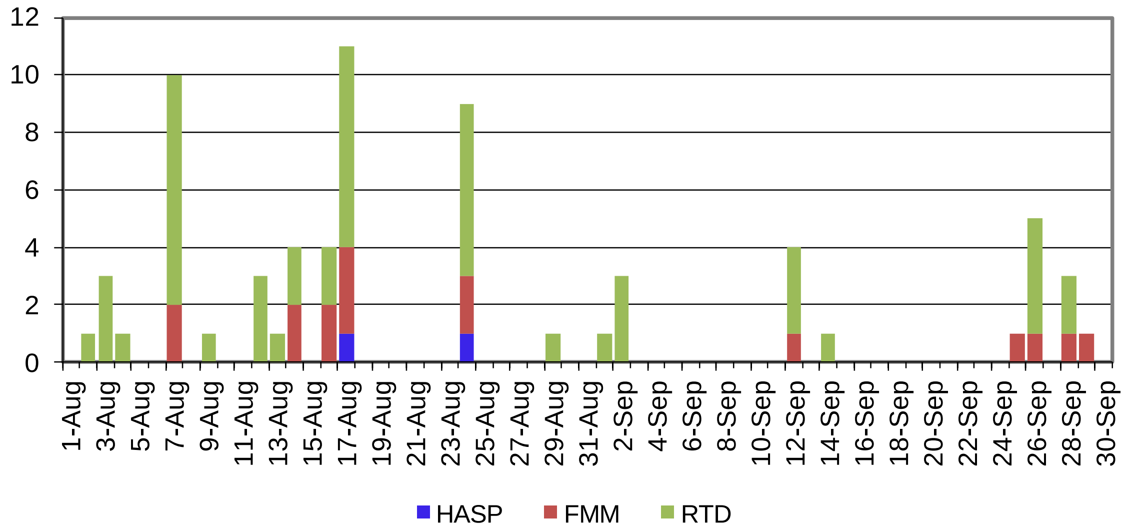
Table 7: Summary of Market Disruption

Type of CAISO Market	Market Disruption or Reportable	Removal of Bids (including Self-Schedules)
Day-Ahead		
IFM	0	0
RUC	0	0
Real-Time		
FMM Interval 1	1	0
FMM Interval 2	0	0
FMM Interval 3	1	0
FMM Interval 4	3	0
Real-Time Dispatch	14	0

Figure 42 shows the frequency of IFM, HASP (FMM interval 2), FMM (intervals 1, 3 and 4), and RTD failures. On September 26, one FMM and four RTD disruptions occurred due to application problem.

[3] These system operation issues or system emergencies are referred to in Sections 7.6 and 7.7, respectively, of the ISO tariff.

Figure 42: Frequency of Market Disruption



Manual Market Adjustment

Exceptional Dispatch

Figure 43 shows the daily volume of exceptional dispatches, broken out by market type: day-ahead, real-time incremental dispatch and real-time decremental dispatch. Generally, all day-ahead exceptional dispatches are unit commitments at the resource physical minimum. The real-time exceptional dispatches are among one of the following types: a unit commitment at physical minimum; an incremental dispatch above the day-ahead schedule and a decremental dispatch below the day-ahead schedule.

The total volume of exceptional dispatch in September rose to 72,769 MWh from 59,733 MWh in August.

Figure 43: Total Exceptional Dispatch Volume (MWh) by Market Type

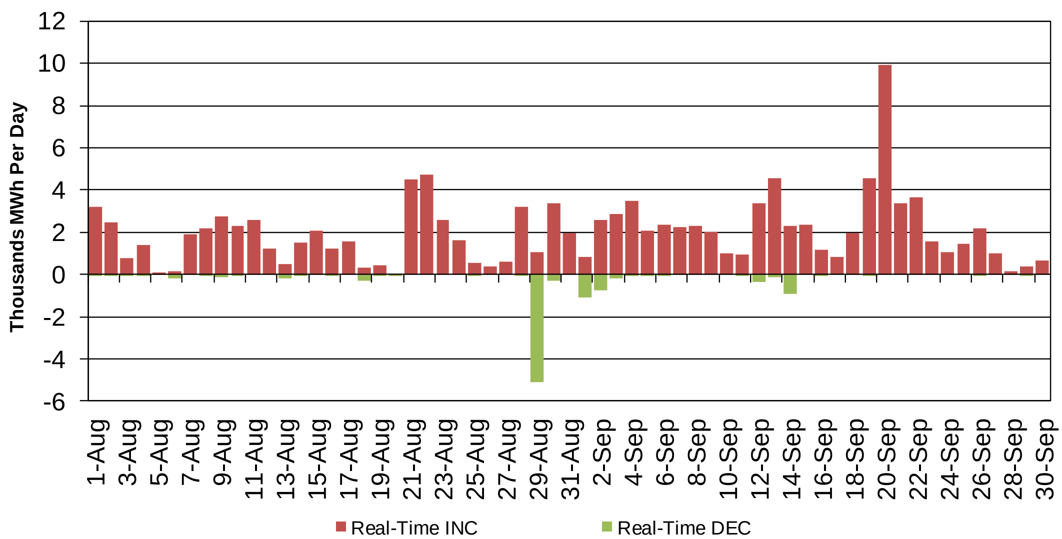


Figure 44 shows the volume of the exceptional dispatch broken out by reason.[4] The majority of the exceptional dispatch volumes in September were driven by load forecast uncertainty (13 percent), planned transmission outage and constraint (44 percent), and operating procedure number and constraint 22 percent).

[4] For details regarding the reasons for exceptional dispatch please read the white paper at this link: **http://www.caiso.com/1c89/1c89d76950e00.html**.

Figure 44: Total Exceptional Dispatch Volume (MWh) by Reason

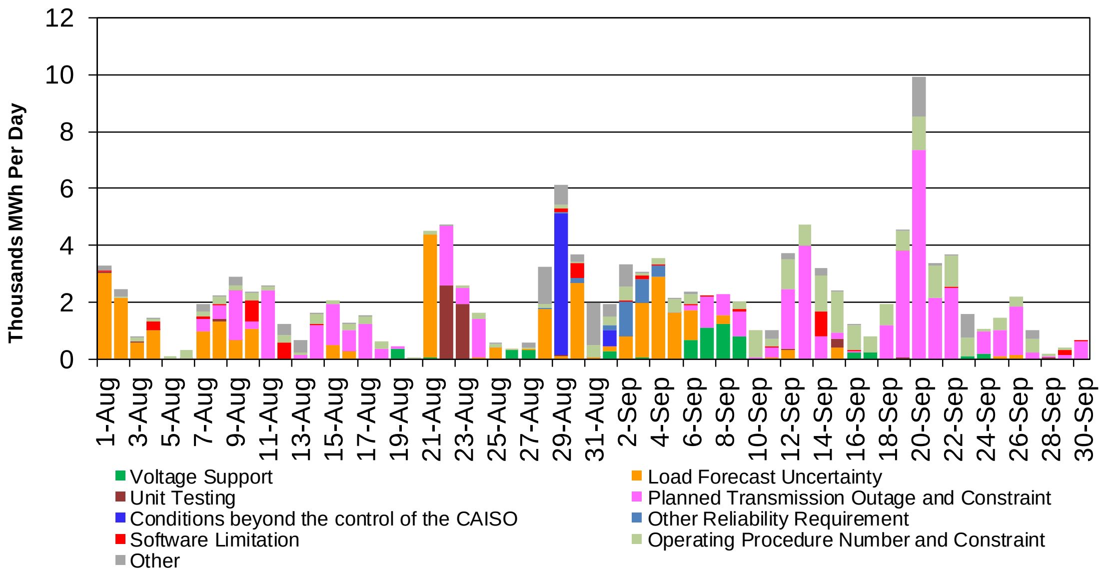
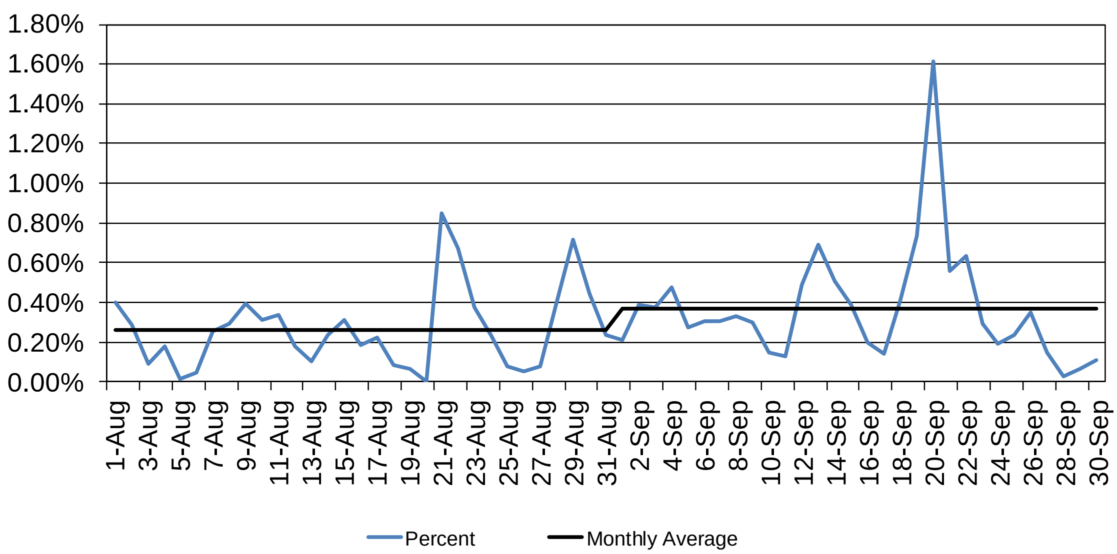


Figure 45 shows the total exceptional dispatch volume as a percent of load, along with the monthly average. The monthly average percentage increased to 0.37 percent in September from 0.26 percent in August.

Figure 45: Total Exceptional Dispatch as Percent of Load



Energy Imbalance Market

On November 1, 2014, the California Independent System Operator Corporation (ISO) and Portland-based PacifiCorp fully activated the Energy Imbalance Market (EIM). This real-time market is the first of its kind in the West. EIM covers six western states: California, Oregon, Washington, Utah, Idaho and Wyoming.

On December 1, 2015, NV Energy, the Nevada-based utility successfully began participating in the western Energy Imbalance Market (EIM). With the addition of NV Energy, the EIM expands into Nevada, where the utility serves 2.4 million customers. The ISO real-time market is now in seven states, saving millions of dollars for consumers. The newly expanded marketplace enables the ISO and participants to incorporate thousands of megawatts of variable generating resources, such as wind and solar, into the power grid while reducing greenhouse emissions, and improving grid resiliency and reliability.

On October 1, 2016, Phoenix-based Arizona Public Service (AZPS) and Puget Sound Energy (PSEI) of Washington State successfully began full participation in the western Energy Imbalance Market. With the addition of Arizona Public Service and Puget Sound Energy, The EIM is serving over 5 million consumers in California, Washington, Oregon, Arizona, Idaho, Wyoming, Nevada and Utah.

Figure 46 shows daily simple average ELAP prices for PacifiCorp east (PACE), PacifiCorp West (PACW), NV Energy (NEVP), Arizona Public Service (AZPS) and Puget Sound Energy (PSEI) for all hours in FMM. The prices for NEVP were relatively high on September 2 due to limited import and upward load forecast adjustment. The prices for AZPS, PACE, and NEVP were elevated on September 5 and 11 due to upward load adjustment., net import reduction, and renewable deviation.

Figure 46: EIM Simple Average LAP Prices (All Hours) in FMM

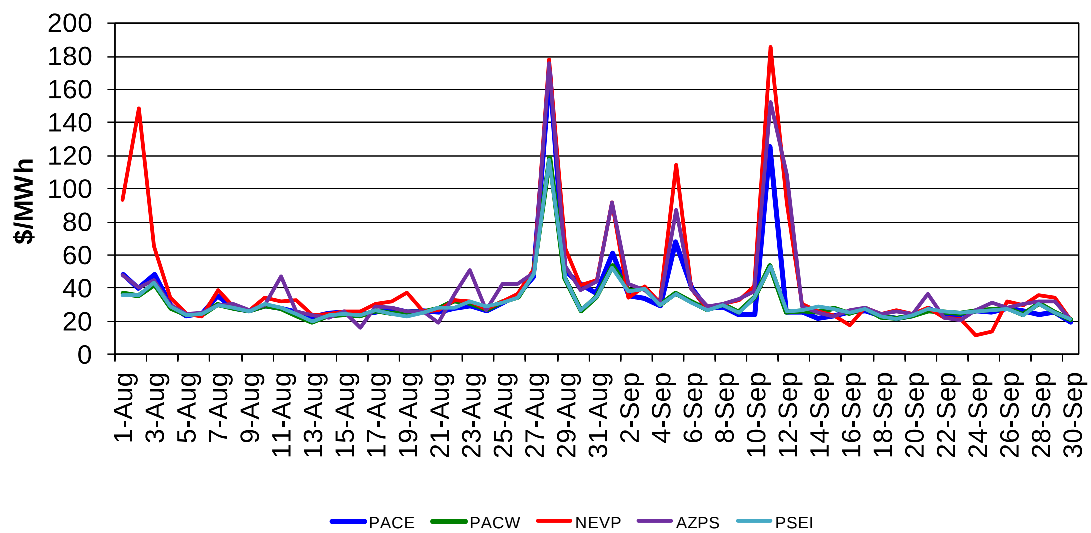


Figure 47 shows daily simple average ELAP prices for PACE, PACW, NEVP, AZPS and PSEI for all hours in RTD. The prices for AZPS, PACE, and NEVP were relatively high on September 11 driven by upward load adjustment, net import reduction, and renewable deviation.

Figure 47: EIM Simple Average LAP Prices (All Hours) in RTD

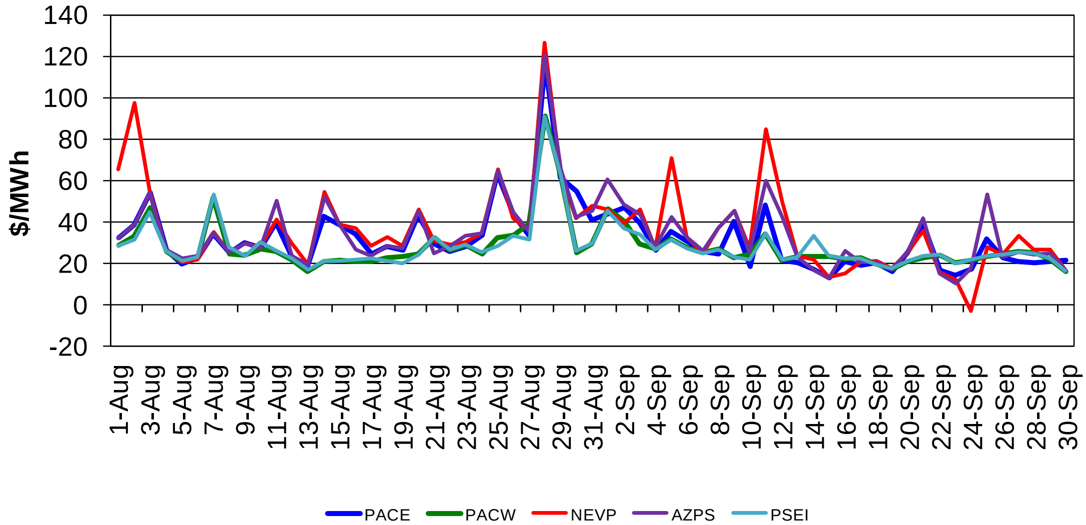


Figure 48 shows the daily price frequency for prices above $250/MWh and negative prices in FMM for PACE, PACW, NEVP, AZPS and PSEI. The cumulative frequency of prices above $250/MWh edged up to 1.48 percent in September from 1.41 percent in August. The cumulative frequency of negative prices increased to 1.31 percent in September from 0.38 percent in August.

Figure 48: Daily Frequency of EIM LAP Positive Price Spikes and Negative Prices in FMM

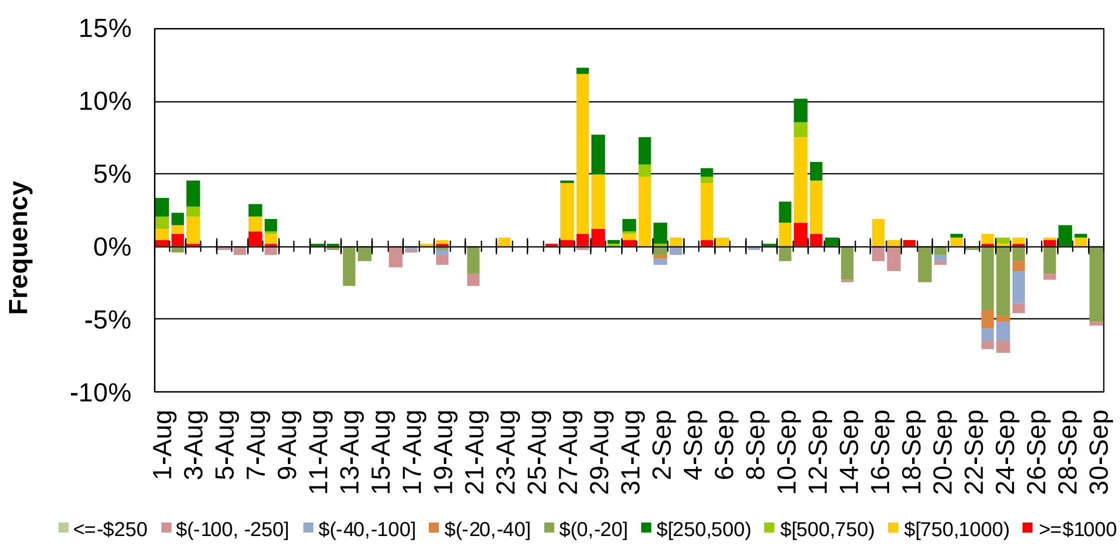


Figure 49 shows the daily price frequency for prices above $250/MWh and negative prices in RTD for PACE, PACW, NEVP, AZPS and PSEI. The cumulative frequency of prices above $250/MWh decreased to 0.59 percent in September from 1.04 percent in August. The cumulative frequency of negative prices rose to 3.07 percent in September from 0.75 percent in August.

Figure 49: Daily Frequency of EIM LAP Positive Price Spikes and Negative Prices in RTD

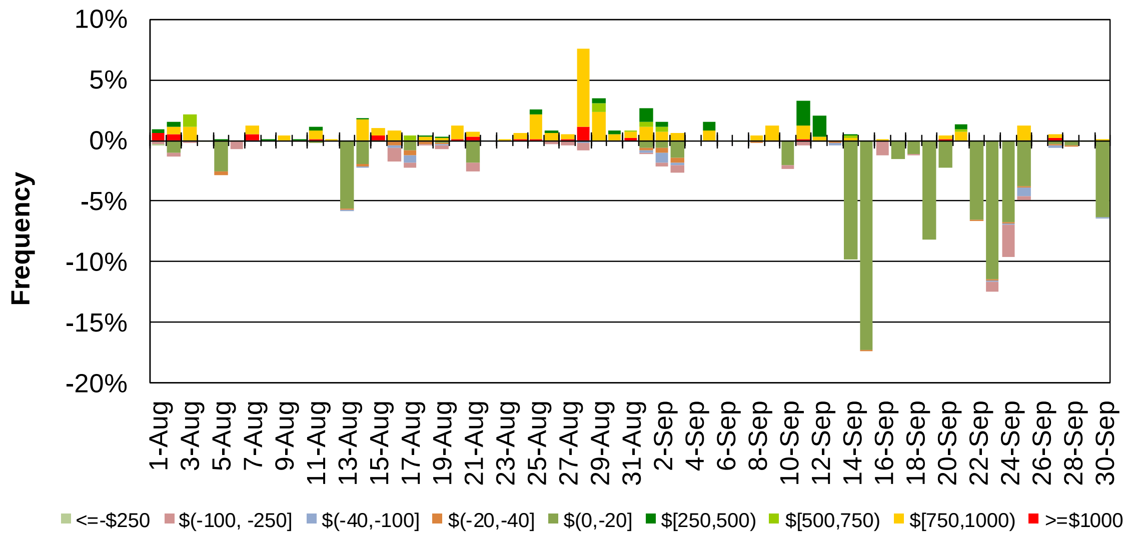


Figure 50 shows the daily volume of EIM transfer between ISO and PacifiCorp in FMM. Figure 51 shows the daily volume of EIM transfer between PACE and PACW in FMM.

Figure 50: EIM Transfer between CAISO and PAC in FMM

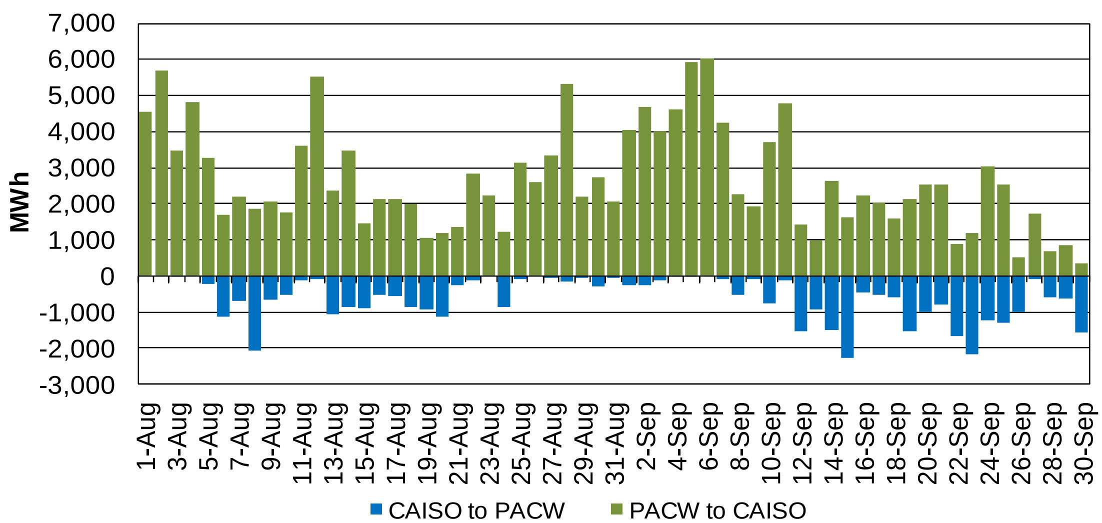


Figure 51: EIM Transfer between PACE and PACW in FMM

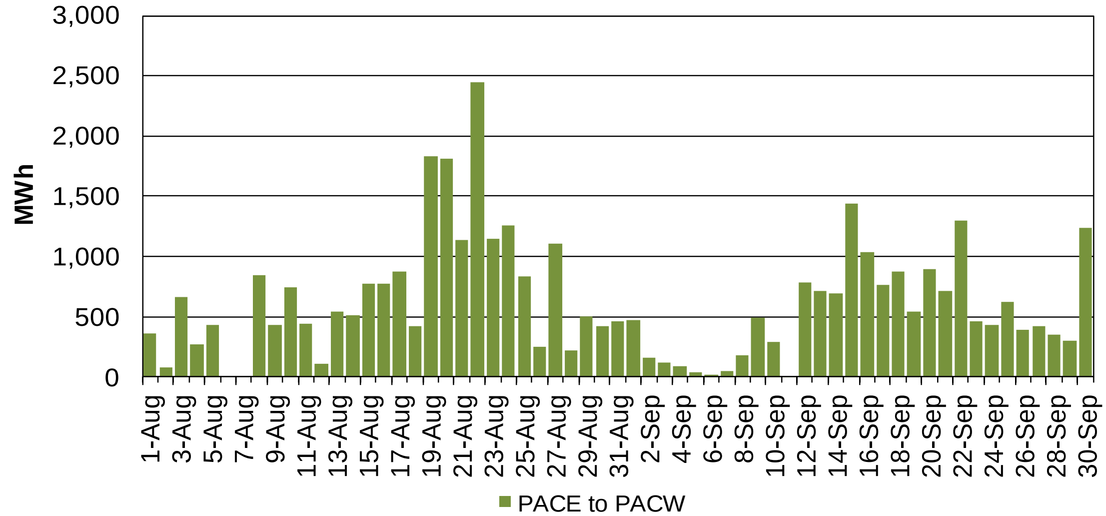


Figure 52 shows the daily volume of EIM transfer between CAISO and NEVP in FMM. Figure 53 shows the daily volume of EIM transfer between PACE and NEVP in FMM.

Figure 52: EIM Transfer between CAISO and NEVP in FMM

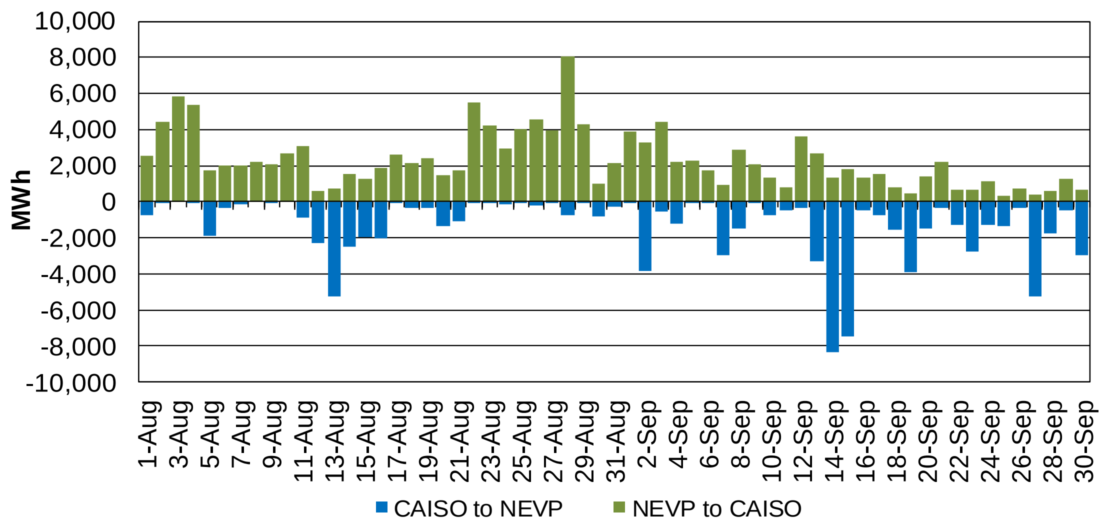


Figure 53: EIM Transfer between PACE and NEVP in FMM

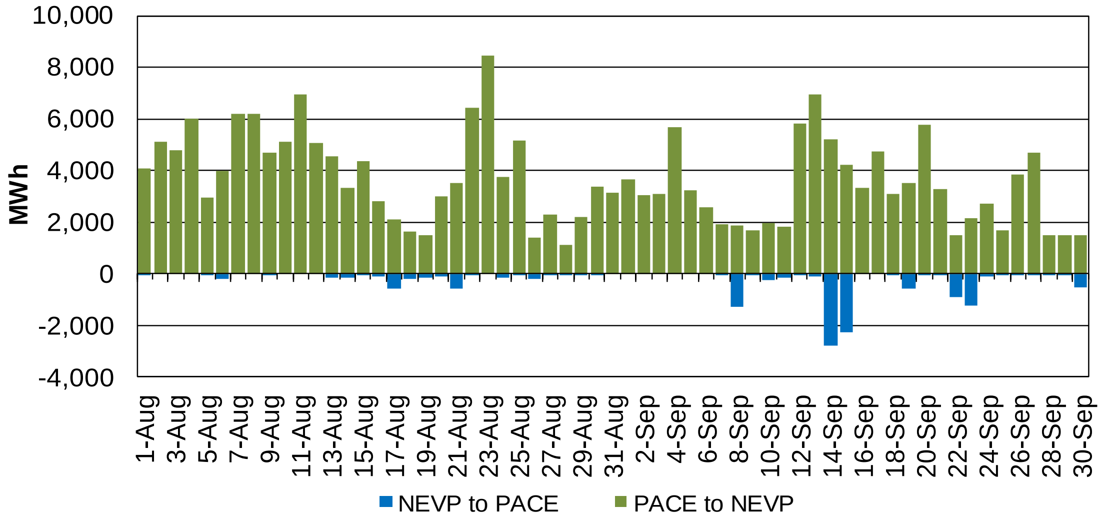


Figure 54 shows the daily volume of EIM transfer between ISO and AZPS in FMM. Figure 55 shows the daily volume of EIM transfer between PACE and AZPS in FMM. The transfer form PACE to AZPS declined this month.

Figure 54: EIM Transfer between CAISO and AZPS in FMM

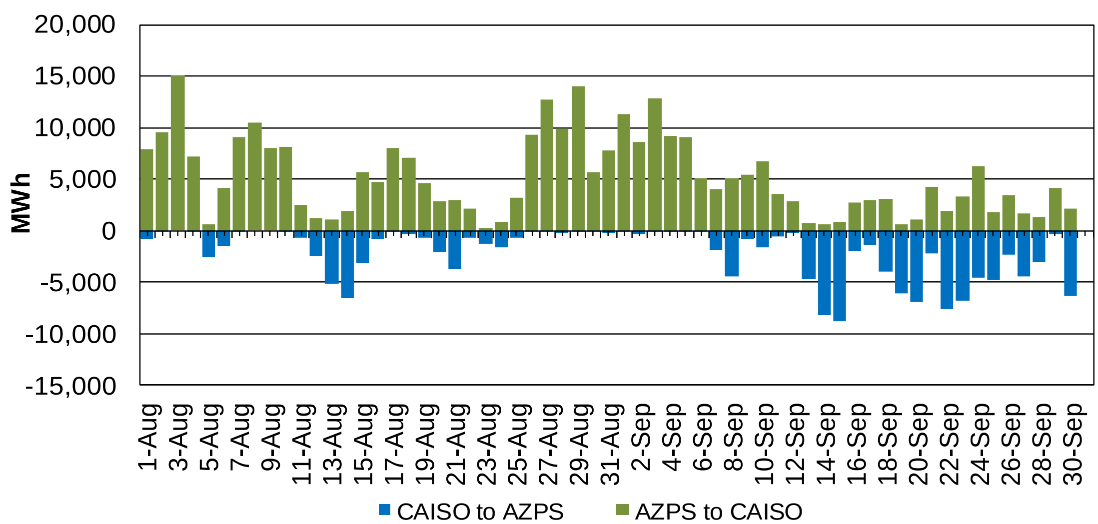


Figure 55: EIM Transfer between PACE and AZPS in FMM

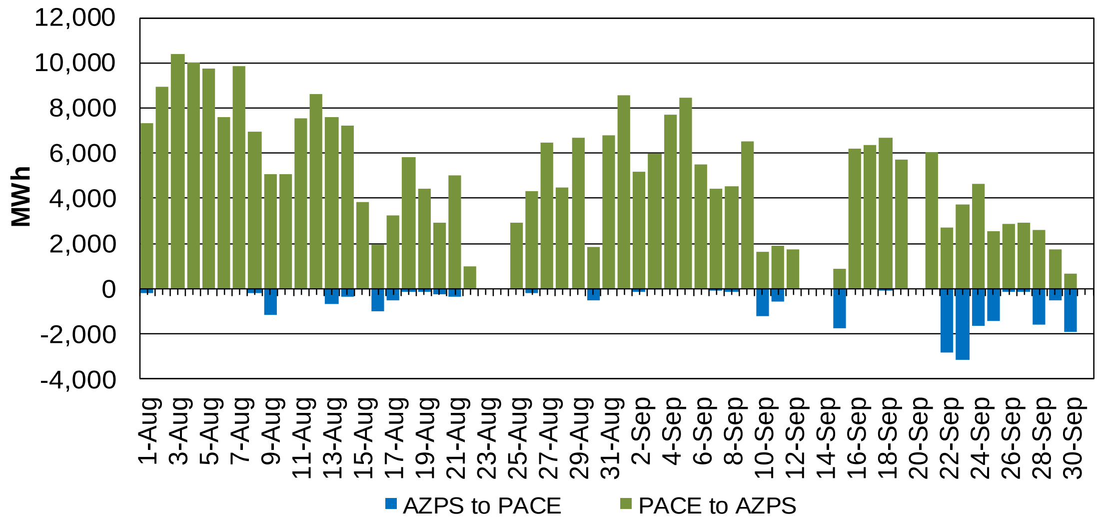


Figure 56 shows the daily volume of EIM transfer between PACW and PSEI in FMM.

Figure 56: EIM Transfer between PACW and PSEI in FMM

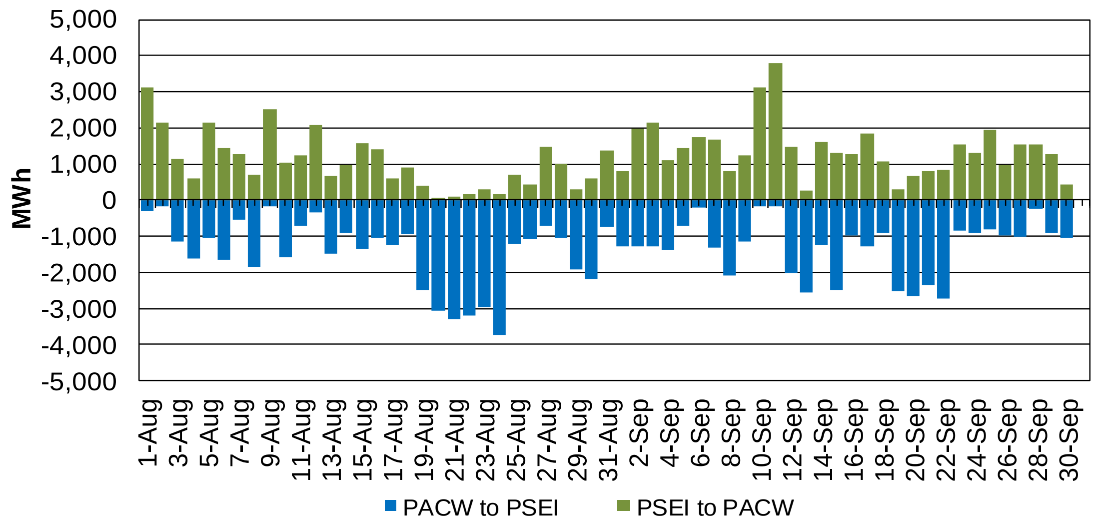


Figure 57 shows the daily volume of EIM transfer between ISO and PacifiCorp in RTD. The EIM transfer from PACW to CAISO decreased generally in September. Figure 58 shows the daily volume of EIM transfer between PACE and PACW in RTD.

Figure 57: EIM Transfer between CAISO and PAC in RTD

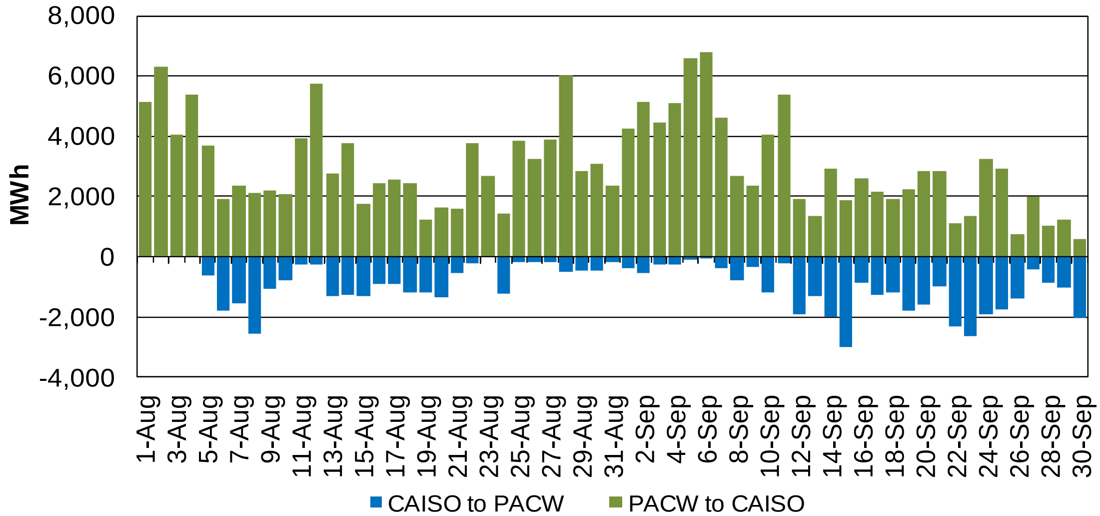


Figure 58: EIM Transfer between PACE and PACW in RTD

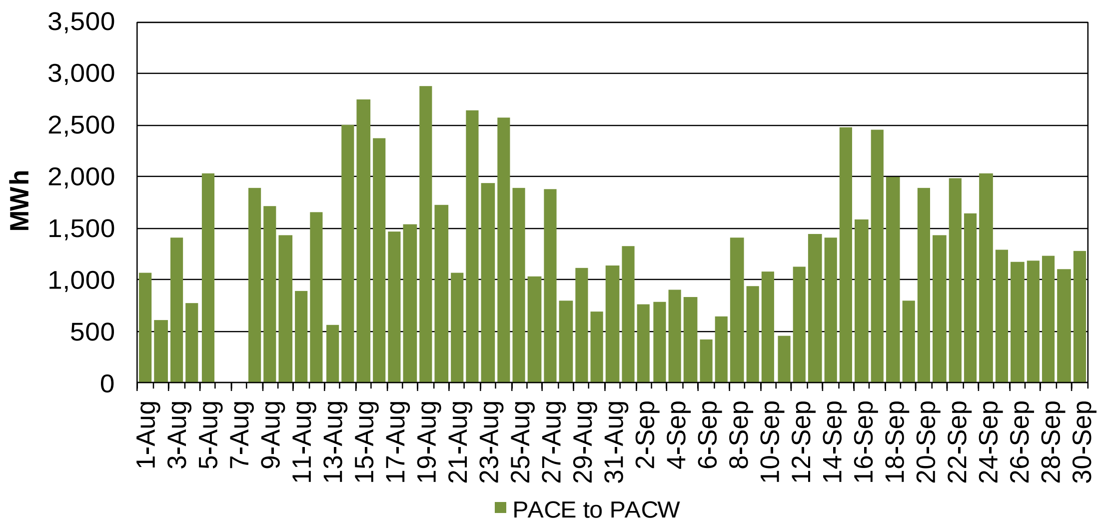


Figure 59 shows the daily EIM transfer volume between ISO and NEVP in RTD. Figure 60 shows the daily EIM transfer volume between PACE and NEVP in RTD.

Figure 59: EIM Transfer between CAISO and NEVP in RTD

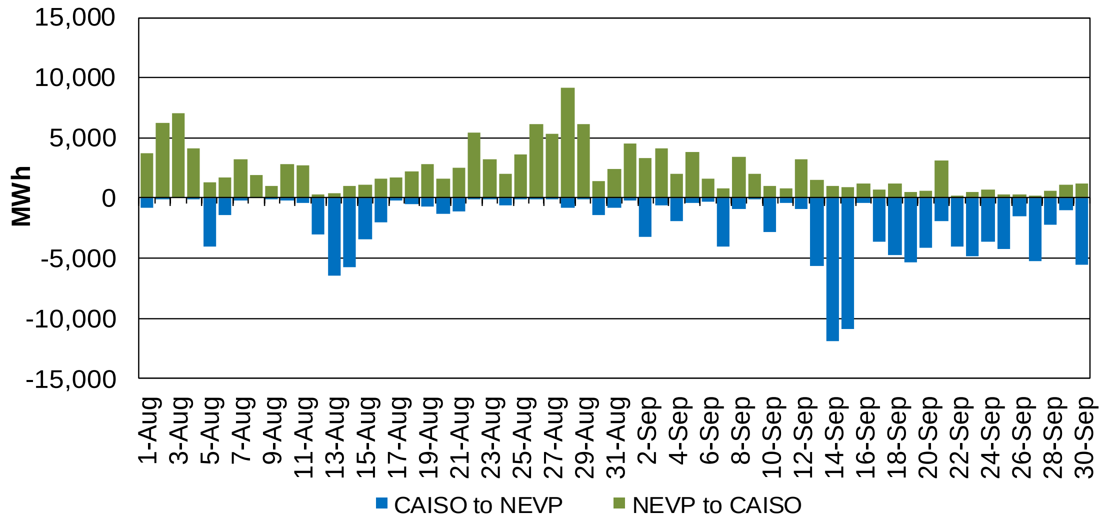


Figure 60: EIM Transfer between PACE and NEVP in RTD

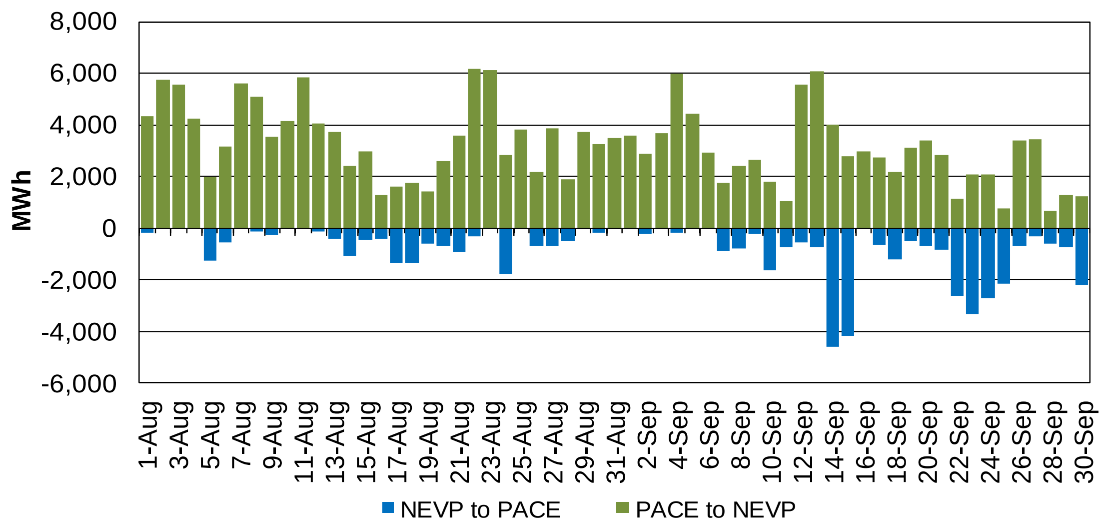


Figure 61 shows the daily volume EIM transfer between the ISO and AZPS in RTD. Figure 62 shows the daily volume EIM transfer between the PACE and AZPS in RTD.

Figure 61: EIM Transfer between CAISO and AZPS in RTD

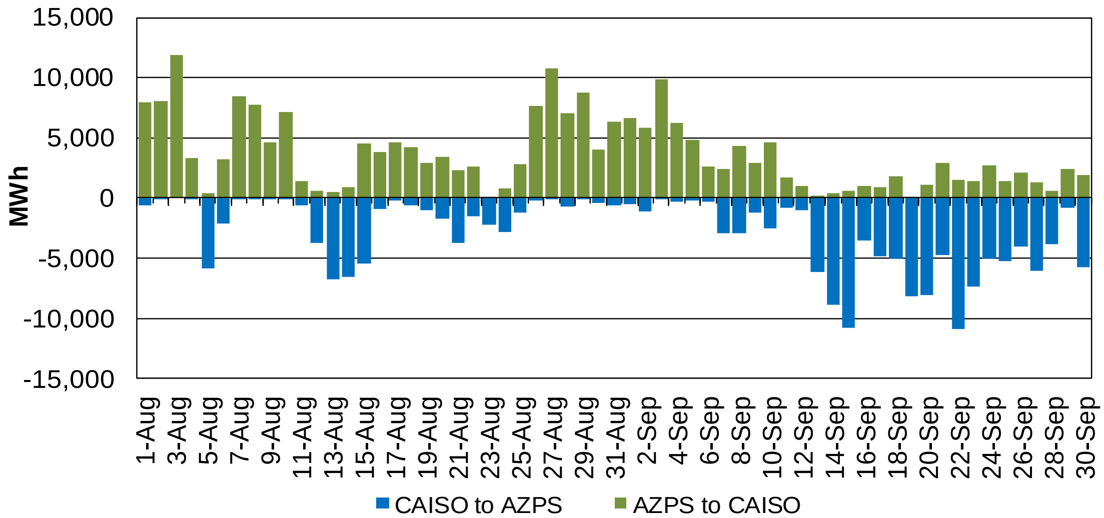


Figure 62: EIM Transfer between PACE and AZPS in RTD

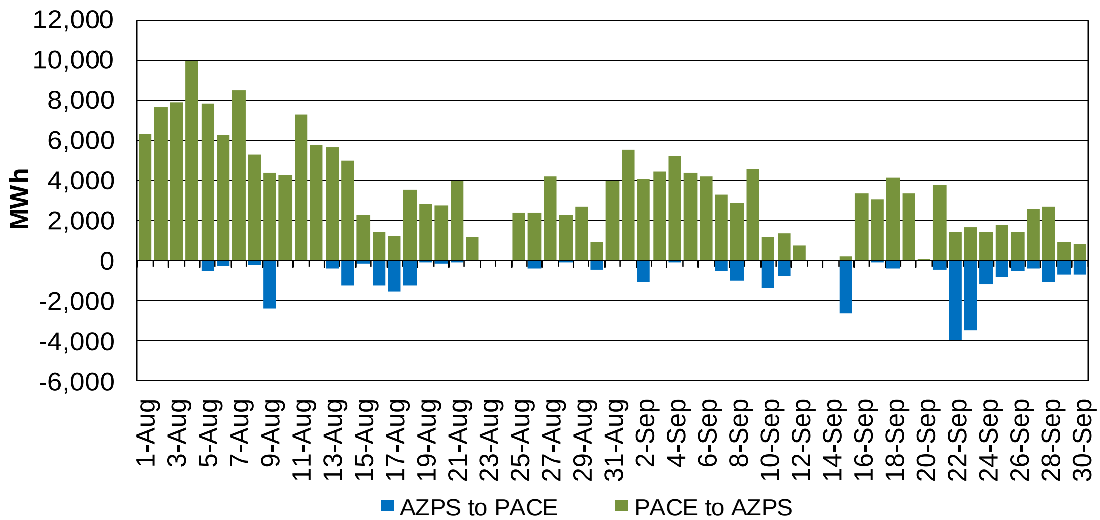


Figure 63 shows the daily volume EIM transfer between PACW and PSEI in RTD.

Figure 63: EIM Transfer between PACW and PSEI in RTD

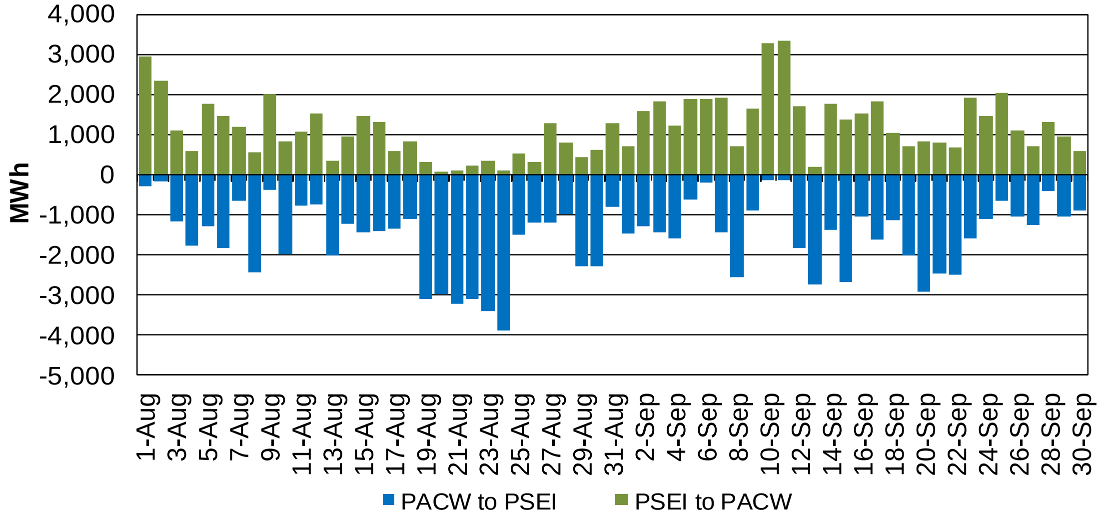


Figure 64 shows daily real-time imbalance energy offset cost (RTIEO) for PACE, PACW, NEVP, AZPS and PSEI respectively. Total RTIEO was -$0.84 million in September, increasing from -$4.62 million in August.

Figure 64: EIM Real-Time Imbalance Energy Offset by Area

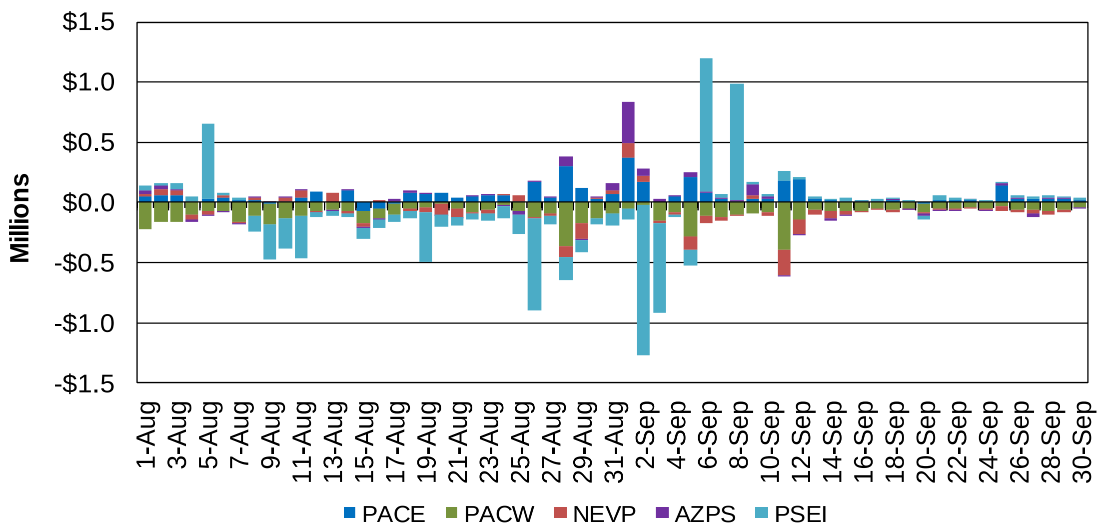


Figure 65 shows daily real-time congestion offset cost (RTCO) for PACE, PACW, NEVP, AZPS and PSEI respectively. Total RTCO fell to -$0.67 million in September from -$0.47 million in August.

Figure 65: EIM Real-Time Congestion Imbalance Offset by Area

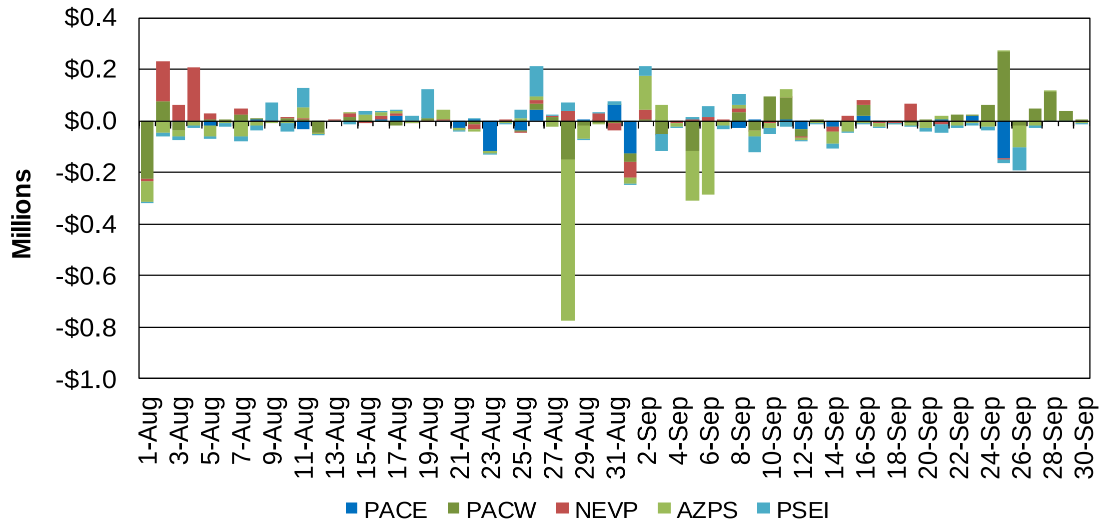


Figure 66 shows daily bid cost recovery for PACE, PACW, NEVP, AZPS and PSEI respectively. Total BCR dropped to $0.59 million in September from $1.18 million in August.

Figure 66: EIM Bid Cost Recovery by Area

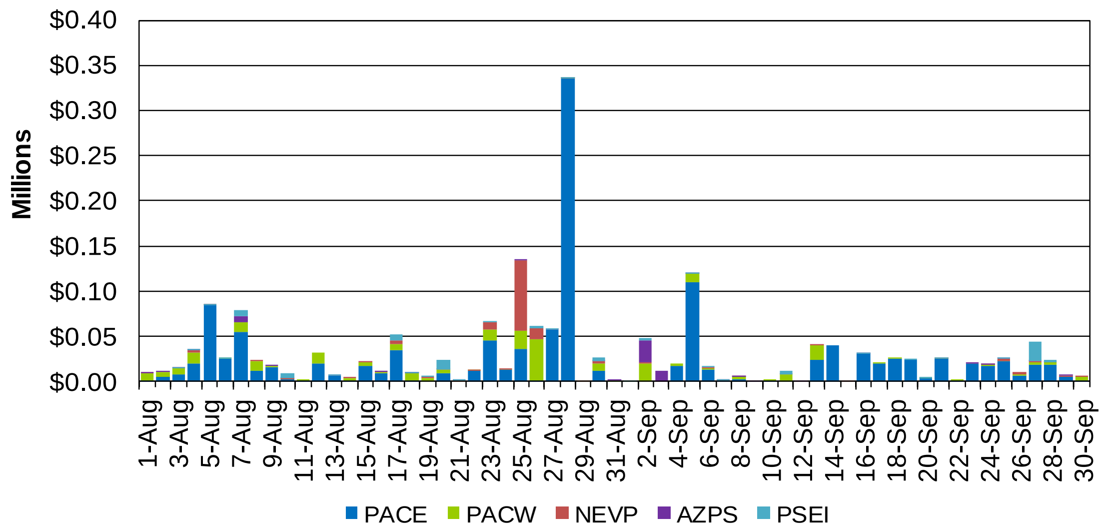


Figure 67 shows the flexible ramping up uncertainty payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total flexible ramping up uncertainty payment in September increased to $0.96 million from $0.72 million in August.

Figure 67: Flexible Ramping Up Uncertainty Payment

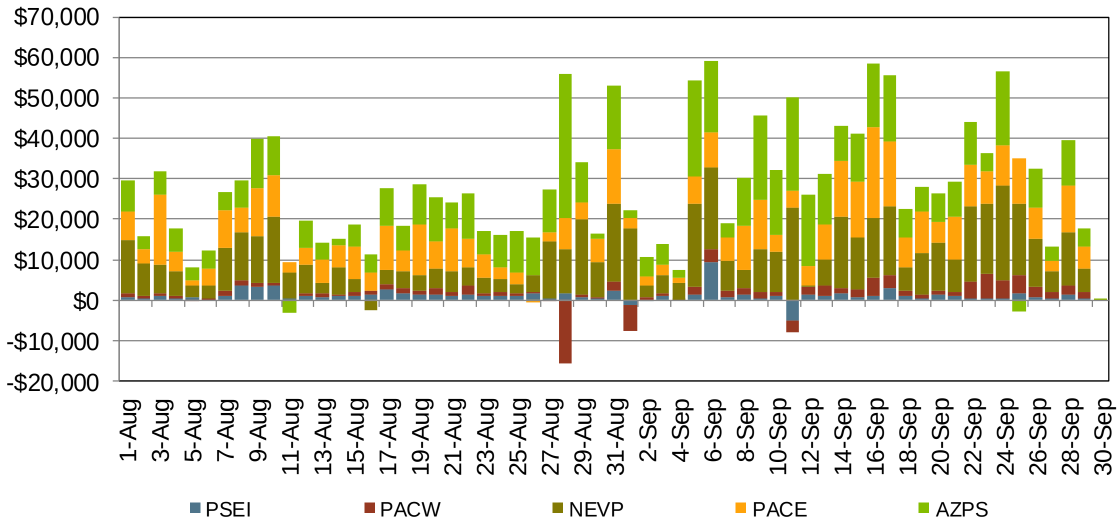


Figure 68 shows the flexible ramping down uncertainty payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total flexible ramping down uncertainty payment in September increased to $4,322 from -$3,929 million in August.

Figure 68: Flexible Ramping Down Uncertainty Payment

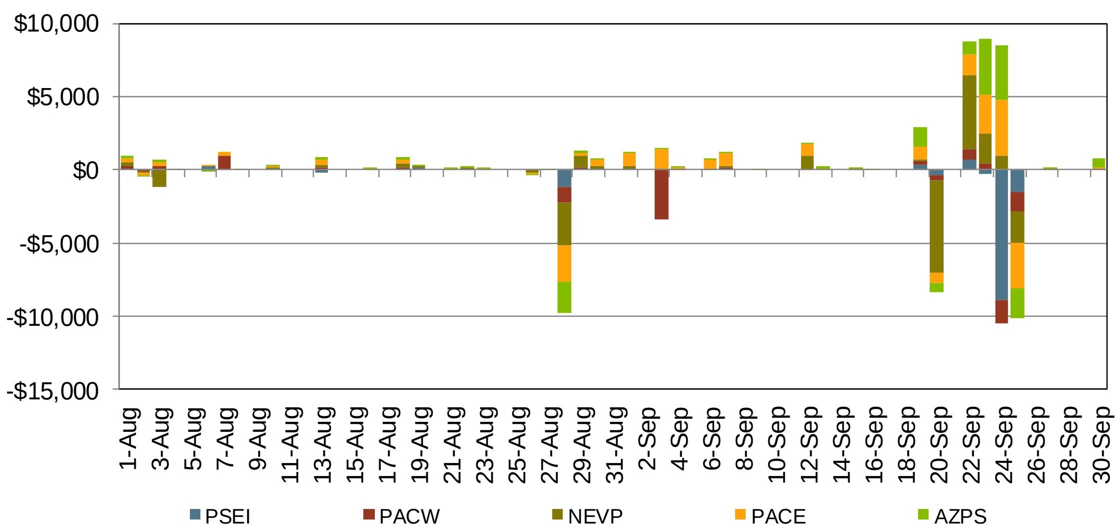
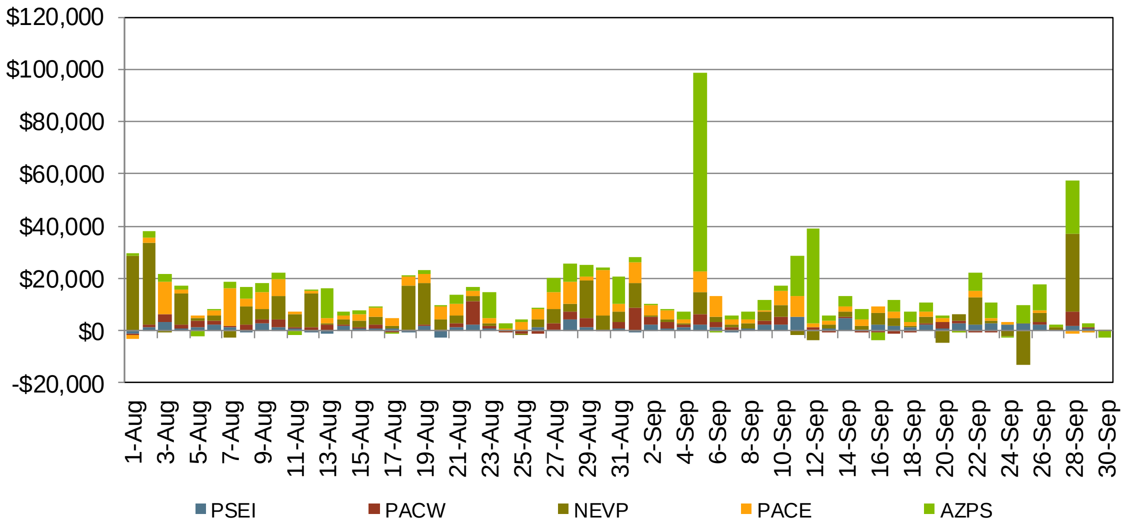


Figure 69 shows the flexible ramping forecast payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total forecast payment in September inched down to $0.44 million from $0.48 million in August.

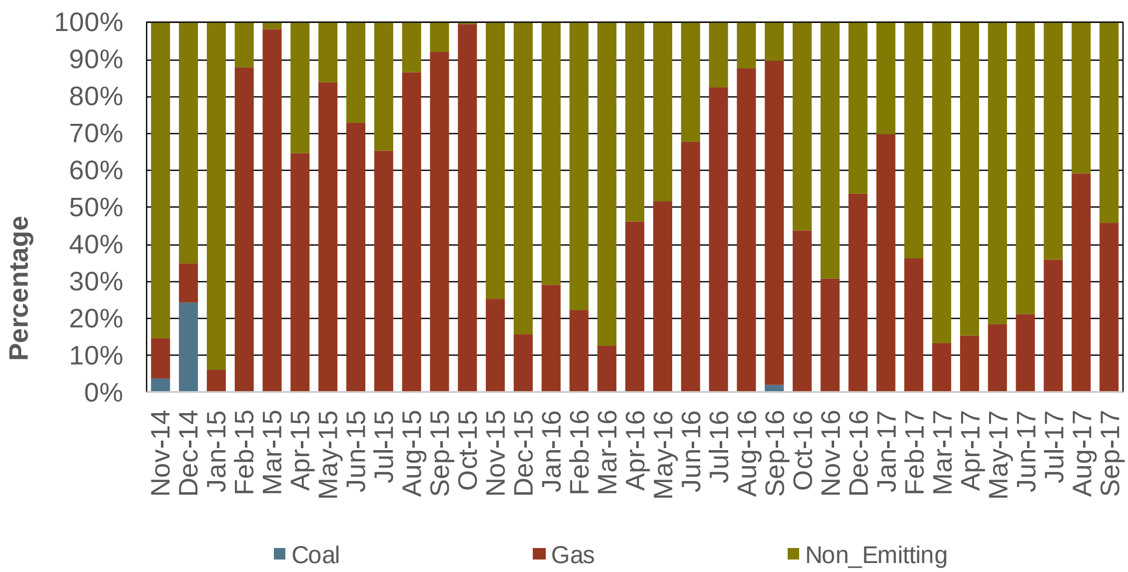
Figure 69: Flexible Ramping Forecast Payment



The ISO's Energy Imbalance Market Business Practice Manual[5] describes the methodology for determining whether an EIM participating resource is dispatched to support transfers to serve California load. The methodology ensures that the dispatch considers the combined energy and associated marginal greenhouse gas (GHG) compliance cost based on submitted bids[6].

In the first two months of EIM operations (November and December 2014), EIM startup issues related to processing GHG bid adder resulted in the dispatch of coal generation to support transfers into California. Once the adders were properly accounted for, beginning in January 2015, almost all of the EIM dispatches to support transfers into the ISO were from resources other than coal, as documented in Figure 70 and Table 8 below.

Figure 70: Percentage of EIM Transfer into ISO by Fuel Type



[5] See the Energy Imbalance Market Business Practice Manual for a description of the methodology for making this determination, which begins on page 42 -- http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy Imbalance Market.
[6] A submitted bid September reflect that a resource is not available to support EIM transfers to California.

Table 8: EIM Transfer into ISO by Fuel Type

Month	Coal (%)	Gas (%)	Non-Emitting (%)	Total
Nov-14	3.66%	11.12%	85.22%	100%
Dec-14	24.18%	10.78%	65.04%	100%
Jan-15	0.07%	6.22%	93.71%	100%
Feb-15	0.32%	87.72%	11.96%	100%
Mar-15	0.48%	97.94%	1.58%	100%
Apr-15	0.12%	64.56%	35.32%	100%
May-15	0.00%	83.83%	16.17%	100%
Jun-15	0.00%	72.88%	27.12%	100%
Jul-15	0.00%	65.41%	34.59%	100%
Aug-15	0.02%	86.51%	13.48%	100%
Sep-15	0.00%	92.13%	7.87%	100%
Oct-15	0.10%	99.70%	0.20%	100%
Nov-15	0.00%	25.25%	74.75%	100%
Dec-15	0.00%	15.79%	84.21%	100%
Jan-16	0.00%	28.96%	71.04%	100%
Feb-16	0.00%	22.21%	77.79%	100%
Mar-16	0.00%	12.72%	87.28%	100%
Apr-16	0.00%	46.26%	53.74%	100%
May-16	0.00%	51.63%	48.37%	100%
Jun-16	0.00%	67.89%	32.11%	100%
Jul-16	0.00%	82.42%	17.58%	100%
Aug-16	0.00%	87.59%	12.41%	100%
Sep-16	1.98%	87.68%	10.34%	100%
Oct-16	0.00%	43.82%	56.18%	100%
Nov-16	0.00%	30.74%	69.26%	100%
Dec-16	0.00%	53.77%	46.23%	100%
Jan-17	0.00%	69.88%	30.12%	100%
Feb-17	0.00%	36.42%	63.58%	100%
Mar-17	0.00%	13.37%	86.63%	100%
Apr-17	0.00%	15.47%	84.53%	100%
May-17	0.00%	18.47%	81.53%	100%
Jun-17	0.00%	21.33%	78.67%	100%
Jul-17	0.00%	36.08%	63.92%	100%
Aug-17	0.00%	59.20%	40.80%	100%
Sep-17	0.00%	45.94%	54.06%	100%